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UNIVERSITY OF OKLAHOMA

GRADUATE COLLEGE

Production Performance of Horizontal Wells In Gas-Condensate Reservoirs

A Dissertation

SUBMITTED TO THE GRADUATE FACULTY

In partial fulfillment of the requirements for the

Degree of

Doctor of Philosophy

By

Sarfraz Ahmed Jokhio

Norman, Oklahoma
2002

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Production Performance of Horizontal Wells In Gas-Condensate Reservoirs

A Dissertation APPROVED FOR THE
MEWBOURNE SCHOOL OF PETROLEUM AND GEOLOGICAL ENGINEERING

BY

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Acknowledgement

I thank very much my Ph.D. committee chairman Professor Dr. Djebbar Tiab not only for being my advisor but also for his guidance and specially teaching me how to be creative in research.

I also thank Dr. Samuel Osisanya, Dr. Michael Wiggins, Dr. Richard Hughes, and Dr. Musharraf Zaman for serving as my committee members and for their sincere guidance during my doctorate studies here at the University of Oklahoma and shaping my life.

I also thank very much Dr. Faruk Civan for his valuable guidance and philosophical advises during my studies.

I thank my dear friend Dur Mohammad Burdi for his sincere help and guidance in daily life matters and the stressful time during this study.

I equally thank Mr. Freddy Escobar, Mr. Mike Berry, and Mr. Yaser Bangash for their valuable help and advices.

In the end I thank my dear wife Zarina for her patience and priceless help without which this work would not have been finished.

Dedication

I dedicate this Ph.D. dissertation to my kind and loving father who made a decision 31 years ago, 1970, and it proved right and his dream realized today, December 6, 2001, with my graduation as Doctorate Student in the technologically most advanced country of the word, ***The United States of America.*** *I am proud of him.*

Abstract

A new method of establishing performance of vertical and horizontal wells completed in gas-condensate reservoirs has been developed. This method does not require relative permeability curves as a function of saturation, instead pressure transient well test data is used to establish the effective permeability as a function of pressure. Surface production data and the pressure transient data are then combined to forecast the well performance. Several new equations of effective permeability in two phase and three phase systems have been introduced from the definitions of producing gas-oil, water-oil, and gas-water ratios for two and three phase systems. Also the new method allows to determine the loss in gas well deliverability mathematically after the condensate has begun to liquefy. Thus well efficiency and damage factor can now be calculated analytically. Also well testing equations have been redefined in order to estimate the effective permeability as a function of pressure. *Tiab's Direct Synthesis (TDS)* technique of pressure transient analysis has also been applied to horizontal gas wells that can also be used for gas-condensate wells.

Gas condensate reservoirs go under two kinds of changes in their lifetime. The phase change and the physical properties change. Both the changes have been handled in this study using the pseudopressure function integral concept. In three phase system accumulating condensate, along with gas phase production, reduces the water production, a very positive impact. Much of the gas phase that goes in the liquid phase is recovered in the form of the liquid. Also it was observed that the mobile liquid condensate cleans the formation. This impact was observed from the continuously decreasing skin factor that was estimated as a function of pressure, an impact never seen before.

To predict the well performance in multiphase producing environment relative permeability as a function of saturation is used which requires the prior knowledge of the saturation at all the times. Saturation is usually estimated

from material balance and reservoir simulation. Also relative permeability curves have to be developed in the laboratory on core samples, an expensive and time consuming process. For individual operators who usually operate on minimum margins of profit, obtaining such data can be an economic challenge. In Oklahoma, regulatory bodies require every well to be tested once a year. Thus a valuable pressure transient data is available on yearly basis. Using that data to forecast well performance can have a profound economic impact on the oil and gas industry. Thus relative permeability curves as a function of saturation have been completely eliminated and it has been shown in this study how to use pressure transient data to develop effective permeability as a function of pressure from the surface measured gas, oil, and water rates and then use it to forecast the well performance.

Finally several examples have been solved for two and three phase wells to show the use of the mathematical models developed.

Table of Contents

Acknowledgement	iv
Dedication	v
Abstract	vi
Chapter I Problem Statement	
1.1 Problem Statement	1
1.2 Introduction	1
1.3 Literature Review	3
1.4 Study Organization	3
Chapter II Theory	
2.1 Derivation of 3D Diffusivity Equation for Fluid Flow in Porous Media	5
2.2 Analytical Solution to A Horizontal Gas Well	9
2.2.1 Psuedo-Steady State Solution	9
2.2.2 Estimation of Oil and Gas Flow Rates separately	12
2.2.3 Vertical Well Model	12
2.3 Pressure Transient Solution of Diffusivity Equation	13
2.3.1 Pressure Drawdown Response	14
2.3.2 Pressure Buildup Response	14
Chapter III Gas Condensate Systems and Fluid Properties Review	16
3.1 Reservoir Fluid Classification	16
3.2 Retrograde Fluids	16
3.3 Retrograde Condensation	20
3.4 Sampling Of Retrograde Fluids	20
3.5 Fluid Distribution in the Reservoir	21
3.6 Coexistence of the Flow Regions	23
3.7 Fluid Properties	25
3.7.1 Light Oil Properties (API > 31.1)	25
3.7.2 Natural Gas Properties	26
3.7.3 Condensate Properties	29
3.8 Representation of K_{rg}/K_{ro} as a Function Pressure for Volatile Oils	30
3.9 Importance of Critical Oil Saturation (S_{OC})	31
3.10 Relative Permeability Model Review	32
3.11 Relative Permeability dependence on Capillary Number (Nc)	32
3.12 Impact of trapped gas on Critical Liquid Saturation and Threshold IFT.	33
3.13 Relative Permeability-Capillary Number Models Review for Gas-Condensate Systems	34
3.14 Relative Permeability Models for Gas-Condensate Reservoirs	34
3.15 Heterogeneous Gas-Condensate Reservoirs	37

3.16 Three Phase Relative Permeability Models 38
3.17 Stone's Models 40
3.18 Saturated Weighted Interpolation 42
3.19 Non-Darcy Flow Effects 44
3.19.1. Non-Darcy Flow Equations 44
3.19.2 Correlations of Non-Darcy Flow Coefficient 45
3.19.3 Effect of Liquids on the Non-Darcy Flow Coefficient 46
3.19.4 Non-Darcy Flow Effect 48
3.20 Pseudopressure Function 50
3.20.1 Single-Phase Pseudopressure 50
3.20.2 Two-Phase Pseudopressure 51
3.21 Pseudopressure Function Behavior 52
3.22 Skin Factor In Multiphase Systems 53
Chapter IV Modeling Effective Permeability, Two-Phase and Three-Phase Pseudopressure Function For Gas Condensate Systems 55
4.1 Two Phase Systems 55
4.1.1 Producing Gas Oil Ratio (R_{pgo2p}) 55
4.1.2 Producing Oil-Water Ratio (R_{pow2p}) 59
4.1.3 Producing Gas-Water Ratio (R_{pgw2p}) (Oil Phase Absent) 60
4.2 Three Phase Systems 60
4.2.1 Producing Gas Oil Ratio in Three-Phase Systems (R_{pgo3p}) in Region-1 61
4.2.1a Producing Oil-Water Ratio (R_{pow3p}) in Region-1 62
4.2.2 Producing Gas-Water Ratio (R_{pgw3p}) in Region-1 63
4.2.3 Producing Gas-Water Ratio (R_{pgw3p}) in Region-2 63
4.3 Modeling Relative and Effective Permeability as a Function of Pressure 64
4.3.1Vertical Wells 64
4.3.1.1 Pressure Drawdown tests 65
4.3.1.2 Pressure Buildup 65
4.3.2 Horizontal Wells 69
4.3.2.1 Early Time Radial Flow Regime 72
4.3.2.2 Early Time Linear Flow Regime 72
4.3.2.3 Late Radial Flow Regime 72
4.3.2.4 Late Time Linear Flow 73
4.3.3 Estimation of Relative Permeabilities from Production Data (Pseudo-Steady State Method [25]) 80
4.3.3.1 Steady-State Method (Gherson and Civan Method) 80
4.4 Modeling Two-Phase Pseudopressure Function for Gas-Condensate Fluids 81
4.4.1 Oil Phase (Region-1) 82

4.4.2 Water Phase (oil phase absent, pure gas reservoirs with water production) 83
4.4.3 Estimation of Gas Phase PseudoPressure Function for Condensate Systems without Relative Permeability Curves [kr(S)]. 85
4.4.3.1 Gas Phase 85
4.4.3.2 Pseudopressure Function for Three phase Systems (mP) 89
4.4.3.2.1Gas Phase 90
4.4.3.2.2 Water Phase 91
4.4.3.2 .3 Gas Phase in Region-2 and Region-3 91
4.5 Effective Permeability Estimation Using Measured Surface Rate from Well Test Analysis in Two Phase Systems 91
4.6 Effective Permeability Estimation Using Measured Surface Rate from Well Test Analysis in Three Phase Systems 96
4.6.2 Effective Permeability from measured surface Rate (Region-2 and Region-3) 97
4.7 Procedure To Establish IPR 98
4.7.1 Procedure To Estimate Pseudopressure 99
Chapter V Inflow Performance Relationship for Gas Condensate Wells 101
5.1 Single phase Gas Inflow Performance 101
5.2 Gas Condensate Well Inflow Performance 101
5.2.1. Condition-a-1. Reservoir Pressure Greater than Dewpoint Pressure ($P > P_d$) 102
5.2.1.1. Case a-1.1 Wellbore flowing pressure greater than dew point pressure. ($P > P_{wf} > P_d$). (Volumetric Gas Reservoir) 102
5.2.1.2. Case-a-1.2 $P > P_d > P_{wf} > P^*$ 103
5.2.1.3. Case-a-1.3 $P > P_d > P^* > P_{wf}$ 104
5.2.1.4. Case-b-1.1 $P < P_d > P^* > P_{wf}$ ($q_o = 0$) 105
5.2.1.5. Case-b-1.2 $P^* > P > P_{wf}$ ($q_o \neq 0$) 105
5.3 Rigorous Mathematical Treatment 105
5.3.1 Case-a-1.2 $P > P_d > P_{wf} > P^*$ 105
5.3.2. Case-a-1.3 $P > P_d > P^* > P_{wf}$ 107
5.4 Vertical Wells 108
5.5 Establishing IPR 108
5.6 Well Deliverability Change due to condensation 108
5.6.1 Well Deliverability Gain Due to Condensate Production in Region-1 in Two-phase Systems 108
5.6.2 Well Deliverability Loss Due to Condensation in Region-1 in Two-phase systems 109

5.6.3 Damage Factor in Region-2 in Two-phase Systems 110
5.7 Procedure to Establish the IPR 111
Chapter VI Horizontal Gas Wells Testing 112
6.1 Introduction 112
6.2 Pressure Drawdown Response 113
6.3 Pressure Buildup Response 113
6.4 Flow Regimes 115
6.4.1 Skin Effect 118
6.4.2 Pressure Tests 119
6.4.2.1. Early Time Radial Flow 119
6.4.2.2. Early Time Linear Flow 120
6.4.2.3. Late Time Radial Flow 121
6.4.2.4. Late Time Linear Flow 122
6.5. Pressure Transient Character 122
6.5.1. Wellbore Storage Effects 124
6.6 Well Test Analysis Using Surface Measured Rates In Two-Phase Systems 127
6.6.1 Producing Gas Oil Ratio In Region-1 127
6.6.2 Mathematical Basis of Well Testing-Vertical Wells 128
6.6.3 Well Test Analysis Using Surface Measured Rates In Three-Phase Systems 134
6.6.3.1 Producing Gas Oil Ratio in Three-Phase Systems (R_{pgo}). 134
6.6.3.2 Producing Oil-Water Ratio (R_{pow}) in Three-phase Systems (Region-1) 136
6.6.3.3 Producing Gas-Water Ratio (R_{pgw}) Three-phase Systems (Region-1) 137
6.6.3.4. Pressure Response During a Well Test-Vertical Well 140
6.6.3.4.1 Skin Factor 142
6.6.3.5 Well Test Analysis Using Surface Measured Rates In Two-Phase Systems-Horizontal Wells 143
6.6.3.5.1. Early Time Radial Flow 143
6.6.3.6 Well Test Analysis Using Surface Measured Rates In Three-Phase Systems-Horizontal Wells 146
6.6.3.6.1 Early Radial 146
6.6.3.6.2.Late Radial Flow Regime 149
Chapter VII Direct Synthesis Technique for Horizontal Well Tests in Gas Condensate Reservoirs 152
7. 1 Direct Synthesis 152
7.1.1 Characteristic Points and Lines 154
7.1.2 Wellbore Storage Effects 158

7.1.3 Intersection of Flow Regime Lines with each other 161
7.1.4 Ratios of the Lines 162
7.1.5 Skin Factor 164
Chapter VIII Applications 167
8.1 Two Phase Applications 167
Example-1- Vertical Well 167
Example-2 Horizontal Well 190
8.2 Three Phase Examples 198
Example-1- Vertical Well 198
Example-2- Vertical Well 209
Example-3 Horizontal Well 220
TDS Example 230
Chapter IX Discussion of Figures 234
9.1 Chapter IV 234
9.2 Chapter V 236
9.3 Chapter V III 237
9.4 Appendix A 238
9.5 Appendix B 239
Chapter X Conclusions and Recommendation 241
10.1 Summary 241
10.2 Conclusions 245
10.3 Recommendation 246

Nomenclature 247
References 248
Appendix-A: Pseudopressure Figures [Two Phase systems] 251
Appendix-B: Pseudopressure Figures [Three phase systems] 276
Appendix-C: Algorithms 306

List of Figures

Fig. 2.1 Representative Elementary Volume for Mass Balance for Homogeneous Reservoir 5
Fig. 2.2. Babu and Odeh[6] Horizontal Well Model 10
Fig. 2.3. Pressure transient solution of Eq.2.46. 16
Fig.3.1 Phase Diagram Showing the Fluid Classification 18
Fig.3.2 Phase Diagram for Gas-Condensates[8] 19
Fig.3.3 Fluid Distribution with a Vertical Well. 23
Fig.3.4. Fluid Distribution with a Horizontal Well Completely Penetrating the Formation. 24
Fig.3.5 Fluid Distribution with a Horizontal Well Placed in the Middle of the Reservoir. 24
Fig.3.6 Capillary Number for Berea Sandstones. 35

Fig.3.7 Capillary Number for ORE Formation. 35
Fig.3.8 Capillary Number for Tarbert Formation, North Sea. 36
Fig.3.9 Capillary Number for Norse Formation, North Sea. 36
Fig.3.10 Pore occupancy in presence of two phases water and oil. 39
Fig.3.11 Pore occupancy in presence of two phases gas and oil 39
Fig.3.12 Pore occupancy in presence of three phases Water, oil and gas. 40
Fig.3.13 Pseudopressure Derivative Behavior. 53
Fig. 4.1 Producing Gas Oil Ration as a Function of Pressure. 57
Fig.4.2 Ratio of Gas Relative Permeability to Oil Relative Permeability as a Function of Pressure. 57
Fig. 4.3 Determination of P*, Pressure at Which liquid is Mobile, From Pressure Test Data in a Multiphase System. 58
Fig. 4.4 Two-phase system with developing oil phase. 58
Fig. 4.5. Thee-phase system with developing oil phase. 61
Fig.4.6 Effective Permeability from Pressure Test Data in a Multiphase System (Vertical Well). 66
Fig. 4.7 Oil phase in Gas Phase as a function of pressure. 66
Fig.4.8. Solution Gas Oil Ratio, R_{so}, as a Function of Pressure. 67
Fig.4.9. Infinite Acting Vertical Well Pressure and Pressure Derivative Response. 67
Fig.4.10. Oil Effective Permeability as a Function of Pressure (Vertical Well). 68
Fig.4.11. Oil Effective Permeability as a Function of Time (Vertical Well P* = 5000 psi). 68
Fig. 4.12. Effective Gas Permeability as a Function of Pressure During a Pressure Test. 69
Fig. 4.13. Effect of Condensate Flow Rate on Effective Oil Permeability (P_d = 5000 psi). 70
Fig. 4.14. Effect of Gas Flow Rate on Effective Gas Permeability (Pd = 5000 psi). 74
Fig.4.15 Early and late Radial Flow Towards Horizontal Well. 74
Fig.4.16. Simulated Horizontal Wellbore Pressure Response Without Wellbore Storage and Skin Indicating Early and Late Radial Flow Regimes. 75
Fig. 4.17. An infinite acting in lateral direction horizontal well pressure response without wellbore storage and skin factor.(fully developed early linear and late radial flow regimes). 75
Fig. 4.18. Profile of effective permability to oil from horizontal well pressure data with upper and lower noflow boundary effects. 76
Fig.4.19. Effective permeability to gas profile from pressure test in horizontal wells (q_o = 100 STB/D). 76
Fig.4.20. Effect of condensate flow rate on effective permeability to oil 77

(Horizontal Well Pd = 5000 psi).
Fig.4.21 Effect of condensate flow rate on effective permeability to gas (Horizontal Well Pd = 5000 psi). 77
4.22 Effective gas permeability integral from late radial flow regime. (Reservoir pressure = 3000 psia). 78
Fig. 4.23. Effective gas permeability integral from late radial flow regime. (Reservoir pressure = 2000 psia). 78
Fig. 4.24. Effective gas permeability integral from late radial flow regime. (Reservoir pressure = 1500 psia). 79
Fig. 4.25. Effective gas permeability integral from late radial flow regime. (Reservoir pressure = 1000 psia). 79
Fig.4.26. Two phase oil pseudopressure. 84
Fig.4.27. Two phase water pseudopressure. 84
Fig.4.28 Two Phase Pseudopressure. [SG = 0.6]. 86
Fig.4.29 Two Phase Pseudopressure. [SG = 0.65]. 86
Fig.4.30 Two Phase Pseudopressure. [SG = 0.70]. 87
Fig.4.31 Two Phase Pseudopressure. [SG = 0.75]. 87
Fig.4.32 Two Phase Pseudopressure. [SG = 0.80]. 88
Fig.4.33 Two Phase Pseudopressure. [SG = 0.85]. 88
Fig.4.34. Two-Phase Psuedopressure Function as a Function of SG. [T = 150 ^{O}F, API = 40, SG = 0.6]. 92
Fig.4.35. Two-Phase Psuedopressure Function as a Function of SG. [T = 150 ^{O}F, API = 45, SG = 0.6]. 92
Fig.4.36. Two-Phase Psuedopressure Function as a Function of SG. [T = 150 ^{O}F, API = 50, SG = 0.6]. 93
Fig.4.37. Two-Phase Psuedopressure Function as a Function of SG. [T = 150 ^{O}F, API = 55, SG = 0.6]. 93
Fig.4.38. Two-Phase Psuedopressure Function as a Function of SG. [T = 150 ^{O}F, API = 60, SG = 0.6]. 94
Fig. 4.39. Three-phase gas pseudopressure Region-1[Eq.4.90] [T = 200] 94
Fig. 5. 1 Production loss due to developing liquid phase. 111
Fig. 6.1. Horizontal well Configuration. 114
Fig. 6.2. Early Time Radial Flow. 115
Fig. 6.3. Hemicylindrical Flow. 116
Fig. 6.4. Linear flow. 116
Fig. 6.5. Late time radial flow. 117
Fig. 6.6. Hemiradial flow. 118
Fig. 6.7. Ideal log-log plot of horizontal well test showing unit fingerprint of flow regimes. 123
Fig. 6.8. Main features of an ideal horizontal well test. 124
Fog. 6.9. Log-log plot of horizontal well test showing radial flow regimes. 126

Fig.6.10. Flow conditions in gas-condensate reservoir under three regions. 127
Fig.6.11. Thee-phase system with developing oil phase. 134
Fig.7.1 Different Flow Regimes in a Horizontal Well. 154
Fig.7.2. Pressure response in a horizontal well illustrating the characteristic points and lines. 155
Two phase example-1
Fig.8.1. Transient Pressure semi-log plot. 175
Fig.8.2. Pseudopressure and its derivative vs. time. 175
Fig.8.3 Gas effective permeability integral as function of pressure [Eq.4.83a]. 176
Fig.8.4 Gas effective permeability integral extrapolated to zero pressure. 176
Fig. 8.5 Oil effective permeability integral as function of pressure. 177
Fig.8.6 Effect of 10% increase in Rp [10,417 /SCFSTB] on oil phase effective permeability integral. 179
Fig.8.7 Effect of 10% increase in Rp [10,417 /SCFSTB] on oil phase effective permeability. 180
Fig.8.8. Effect of 10% increase in Rp [10,417 /SCFSTB] on gas effective permeability. 180
Fig.8.9. Effect of 10% increase in Rp on skin factor [Eq.4. 20a] 181
Fig.8.10. Gas Phase IPR vs. pseudopressure. [n = 0.8 and C = 0.0948, assumed and closely matched with rate during well test]. 183
Fig. 8.11. Gas phase IPR against pressure. 184
Fig.8.12. Oil effective permeability integral. 185
Fig. 813. Oil phase effective permeability, derivative of Eq.4.83b. 186
Fig.8.14. Oil phase pseudopressure and its derivative. 186
Fig.8.15. Condensate phase well performance vs. pseudopressure. 189
Fig.8.16. Oil phase well performance against pressure. 189
Two Phase Example-2 Horizontal well.
Fig.8.17 Pseudopressure and its derivative against time. 190
Fig.8.18 Gas phase effective permeability, Eq.4.97. 191
Fig.8.19 Oil phase effective permeability, Eq.4.98. 191
Fig.8.20. Gas phase IPR against pressure. 195
Fig.8.21. Gas phase IPR against pseudopressure. 195
Fig.8.22. Oil phase IPR against pressure. 196
Fig.8.23. Comparison of IPRs from oil and gas surface production data.[Eq. 4.83a and 4.83b]. 196
Fig. 8.24. Gas and Oil effective permeability ratio against pressure. [Eq.4.7] 197
Fig. 8.25. Producing gas oil ratio against pressure. 197
Three phase Example-1 Vertical Well
Fig. 8.26. Pseudopressure and its derivative from Sapphire. 230

Fig.8.27. Pressure behavior during three phase well test. 203
Fig. 8.28. Pseudopressure behavior. 204
Fig.8.29. Pseudopressure and its derivative against time. 204
Fig. 8.30 Gas phase effective permeability Integral. 205
Fig. 8.31. Water phase effective permeability Integral. 205
Fig. 8.32.Gas phase effective permeability. 206
Fig. 8.33. Water phase effective permeability. 206
Fig.8.34. Gas Phase IPR against pressure, in Region-1, Pd = 5,000 psi. 207
Fig.8. 35. Water Phase IPR in Region-1. 208
Three phase Example-2 Vertical Well
Fig. 8.36. Semi-log Plot of pressure Vs. Time. 209
Fig.8.37. Pressure behavior during three phase well test with pseudopressure, Eq.4.90 without effective permeability term. 210
Fig. 8.38. Gas phase effective permeability Integral. 212
Fig. 8.39. Water phase effective permeability Integral. 213
Fig. 8.40. Water phase effective permeability. 214
Fig. 8.41. Gas phase effective permeability. 214
Fig.8.42. Pseudopressure and its derivative against time, Eq.490. 215
Fig.8.43. Pseudopressure and its derivative from Sapphire. 215
Fig. 8.44. Curve fit of Gas phase effective permeability Integral. 216
Fig. 8.45. Curve fit of Water phase effective permeability Integral. 217
Fig. 8.46. Gas Phase IPR[n = 0.5, C = 0.05] 218
Fig. 8.47. Water phase IPR[n = 1, C = 0.5 Assumed values] 219
Three phase Example-3 Horizontal Well
Fig.8.48. Gas phase effective permeability. 225
Fig.8.49. Pseudopressure and its derivative with new pseudopressure. 225
Fig.8.50 Oil phase effective permeability. 226
Fig.8.51. Water phase effective permeability integral. 226
Fig.8.52. Water phase effective permeability. 227
Fig.8.53. Gas Phase IPR against pressure. 227
Fig.8.54. Gas Phase IPR against pseudopressure. 228
Fig.8.55. Water Phase IPR against pressure. 228
Fig.8.56. Oil Phase IPR against pressure. 229
TDS Example
Fig.8.57. Log-log plot of pseudopressure and its derivative. 231
Appendix A Two phase Pseudopressure Charts. 252
Appendix-B Three Phase Pseudopressure Charts. 286

List of Tables

Table 3.1 Gopal Equations for Estimating Compressibility (Z) Factor (Two phase Example-1) 28
Table 4.1 Table 4.1 Summary of Equations 89

Table 8.1 Well, reservoir and fluid data is given in following table. 167
Table 8.2 PVT Properties for example-1 167
Table 8.3. Pressure and pseudopressure data, with Eq.4.83a. 170
Table 8.4. Pressure and pseudopressure data, with Eq.4.83b. 174
Table 8.5 Gas effective permeability as function of pressure. 177
Table 8.6 Percent error in effective permeability with 10% increase in Rp. 178
Table 8.7 Effect of 10% increase in GOR on oil effective permeability. 178
Table 8.8.Effect of 10% increase in Rp on gas effective permeability. 179
Table 8.9. Absolute error in skin factor to gas with 10 % increase in Rp. 182
Table 8.10. Well performance data. 183
Table 8.11. Time, pressure, pseudopressure, and effective permeability to oil data. 187
Table 8.12 Oil Phase IPR 188
Table 8.13 PVT data 192
Table 8.14 Estimation of effective permeability. 193
Table 8.15 Estimation of pseudopressure 194
Table 8.16. Well and reservoir data used in analysis. 194
Table 8.17. Well and reservoir data. 198
Table 8.18 Pressure, Pseudopressure and Effective Permeability Integral Data for the Straight line Region. 200
Table 8.19 Pressure, pseudopressure, and water effective permeability integral data. 201
Table 8.20. Gas effective permeability Integral. 207
Table 8.20. Gas effective permeability Integral. 208
Table 8.22. Well and reservoir data. 210
Table 8.23. Pressure transient data. 211
Table 8.24. Pseudopressure Data 212
Table 8.25. Water phase pseudopressure data. 213
Table 8.26. Gas effective permeability integral. 216
Table 8.27. Water effective permeability integral. 217
Table 8.28 Well and reservoir data. 220
Table 8.29. Pressure and pseudopressure for gas oil, and water phase. 220
Table 8.30. Pressure and Effective permeability integral and effective permeability of oil, gas, and water phase. 223
TDS Example 230
Table 8.31 Well reservoir data.

Chapter I

Problem Statement

1.1 Problem Statement

Pressure decline below the dew point pressure in gas condensate reservoirs causes condensation of hydrocarbons, which creates a hydrocarbon liquid zone in the reservoir. This condensed liquid does not move until a critical mobile liquid saturation, S_{oc}, is reached. Since condensate reservoirs are primarily gas reservoirs, the developing liquid zone acts as a barrier to gas production and reduces the well deliverability drastically. Further, pressure decline due to depletion may also re-vaporize some of the liquid due to retrograde behavior of the light and intermediate hydrocarbons. This retrograde behavior of the hydrocarbons is dependent on the fluid composition, its PVT properties, amount of near wellbore liquid saturation, and pressure and temperature changes around the wellbore. In such phase changing environment it is very difficult to forecast the well deliverability. Productivity above the dew point pressure is controlled by the reservoir transmissivity and below the dew-point pressure, by the critical liquid saturation and the shape of the relative permeability curves that changes with changing phase. From production engineering point of view, developing a technique to establish the well performance for condensate horizontal as well as vertical wells is the main objective of this study.

1.2. Introduction

Depletion of the gas condensate reservoirs to pressures below the dew point has been studied by the petroleum engineers for many years. The quantitative two-phase flow in the reservoirs was first studied by Muskat and

Evinger[41]. They were the first researchers who indicated that the curvature in the performance curve of solution gas drive reservoirs is due to the decreasing relative permeability of oil phase with depletion. Based on Weller's[2] approximations of constant de-saturation of oil and constant GOR at a given instant (not for the whole life of the reservoir) in the reservoir, Vogel[1] was able to solve the pseudo-steady state two phase flow equation based on relative permeabilities of each phase, and provided the oil industry an equation that would revolutionize the performance prediction of solution gas drive reservoirs. Fetkovich, Camacho and Raghavan[46], Brown, Wiggins[45], and Sukarno's[43] work on IPRs follows the Vogel's work.

Retrograde gas-condensate systems have not been treated so intensively as solution gas reservoirs have been. The main reason is again the phase behavior of the light (C1-C8) hydrocarbons in the reservoirs. Retrograde gas-condensate reservoirs are primarily gas reservoirs a zone of liquid begins to form as the dew point pressure is reached. The liquid keeps accumulating and does not flow until critical liquid saturation is reached. The pressure at this point is termed as P*. Once the critical saturation of oil is reached, it begins to flow towards the wellbore along with the gas phase. Interestingly, this liquid may re-vaporize as the pressure further crosses the lower dew point line on two-phase envelope of P-T phase diagram. This behavior of re-vaporization of the oil phase is called the "Retrograde Behavior."

With the facility of modern numerical computing and our increasing understanding, researchers have begun treating the effects of retrograde phase behavior of hydrocarbons on production performance of condensate reservoirs.

With increasing activity in horizontal well technology, we need more Vogel type solutions of two phase flow in gas-condensate reservoirs for horizontal wells. Simple Vogel IPR type algebraic equations are easy to use.

Their use in optimizing production equipment including tubing, artificial lift systems, pump sizing, and surface facilities is of paramount importance.

1.3. Literature Review

Predicting production behavior of a well in gas-condensate reservoirs has been a topic of continuous research. Simple Gilbert correlation for productivity index estimation for oil wells ($J = q/\Delta P$) was being used until 1968 for solution gas reservoirs too. Vogel[1] first published IPR for solution-gas reservoirs, which handles the two phase flow of oil and gas, in 1968. His work is mainly based on Weller's[2] approximations which did not require the assumption of constant GOR. Instead he assumed that the de-saturation of the oil phase at a given moment is constant everywhere in the reservoir. Vogel[1] using Weller's[2] concepts was able to generate a family of IPR curves in terms of only two parameters flow rate and BHP. Since Vogel's IPR curves use two phase flow for solution gas reservoirs his IPR has 20% error[1] in it as compared with 80% when Gilbert IPR is used for solution gas reservoirs.

Recently Raghavan and Jones[4] discuss the issues in predicting production performance of condensate systems in vertical. Fevang and Whitson[5] model the Gas-Condensate well deliverability using compositional simulator. Their work however, provided mathematical representation of the pseudo-pressure in gas and liquid phase. But their work is specific in nature, in which well deliverability is predicted using numerical simulator.

1.4 Study Organization

This study consists of ten chapters. Chapter-I explains the problem statement, introduces the topic, and provides the literature review. Chapter-II discusses the theory of the horizontal gas wells. Chapter-III is the classification of the reservoir fluids, fluid distribution in the reservoir, sampling of

condensates, their physical properties and other important issues related to gas-condensates.

Chapter-IV is the heart of this study and consists of the modeling effective permeability of the fluids in multiphase environment as a function of pressure from pressure transient test data and new models of pseudopressure function for gas condensate fluids flowing under two and three phase conditions. Chapter-V quantifies the horizontal well performance and the deliverability loss due to condensate deposition. Chapter-VI and Chapter-VII are the gas well test theory and the development of the Tiab's Direct Synthesis (TDS) technique to gas condensate systems respectively. Chapter-VIII is the application of the models developed. Several examples are solved in this chapter to show the use of the techniques developed. Chapter-IX is the discussion on figures. Chapter X is the summary of the dissertation, conclusions, recommendations, nomenclature, and the references.

Chapter II

Theory

2.1 Derivation of 3D Diffusivity Equation for Fluid Flow in Porous Media for Gas Wells.

Continuity equation representing the isothermal single-phase fluid flow through a homogeneous porous medium can be derived, by considering a small element shown below. The mass balance through this element is given as:

[Rate of mass accumulation] = [Rate of mass entering] + [Rate of mass leaving]

Rate of mass entering = $\rho U_{x1} + \rho U_{x2} + \rho U_{x3}$ (2.1)

Rate of mass leaving =

$$\left[\rho U_{x1} + \Delta(\rho U_{x1})\right] + \left[\rho U_{x2} + \Delta(\rho U_{x2})\right] + \left[\rho U_{x3} + \Delta(\rho U_{3})\right] \quad (2.2)$$

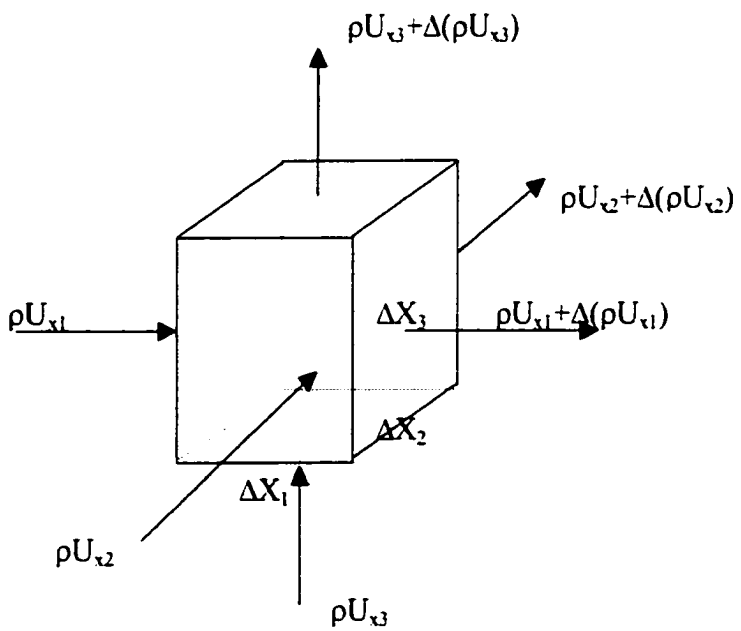


Fig. 2.1 Representative elementary volume for mass balance for homogeneous reservoir

$$\text{Rate of mass accumulation} = \frac{[\rho\phi]_{t+\Delta t} - [\rho\phi]_t}{\Delta t}\Delta X_1\Delta X_2\Delta X_3 \qquad (2.3)$$

Substituting Eq.2.1 and Eq.2.2 in Eq. 2.3 and re-arranging yields

$$\frac{[\rho\phi]_{t+\Delta t} - [\rho\phi]_t}{\Delta t}\Delta X_1\Delta X_2\Delta X_3 = \Delta(\rho U_{x1}) + \Delta(\rho U_{x2}) + \Delta(\rho U_{x3}) \qquad (2.4)$$

Dividing Eq.2.4 by $\Delta X_1\Delta X_2\Delta X_3$ and taking limit $\Delta X_1\Delta X_2\Delta X_3$ and $t \to 0$ yields

$$\frac{\partial(\rho U_{x1})}{\partial x_1} + \frac{\partial(\rho U_{x2})}{\partial x_2} + \frac{\partial(\rho U_{x3})}{\partial x_3} = \frac{\partial(\rho\phi)}{\partial t} = \nabla\bullet(\rho\vec{U}) \qquad (2.5)$$

Assuming the gravity forces are in only X3 direction, flow potential then can be expressed as

$$\psi = g\,x_3 + \int_{p_0}^{p}\frac{1}{\rho(P)}dP \qquad (2.6)$$

The general Darcy's law representing the relationship between the volumetric flux and the gradient of flow potential is

$$U_i = -\frac{\rho}{\mu}\left(K_{i1}\frac{\partial\psi}{\partial x_1} + K_{i2}\frac{\partial\psi}{\partial x_2} + K_{i3}\frac{\partial\psi}{\partial x_3}\right) \qquad (2.7)$$

For i = 1,2, and 3

Which can be written in matrix form as

$$\vec{U} = \begin{Bmatrix} U_1 \\ U_2 \\ U_3 \end{Bmatrix} = -\frac{\rho}{\mu}\begin{bmatrix} K_{11} & K_{12} & K_{13} \\ K_{21} & K_{22} & K_{23} \\ K_{31} & K_{32} & K_{33} \end{bmatrix}\begin{Bmatrix} \frac{\partial\psi}{\partial x_1} \\ \frac{\partial\psi}{\partial x_2} \\ \frac{\partial\psi}{\partial x_3} \end{Bmatrix} = -\frac{\rho}{\mu}\vec{K}\vec{\nabla}\psi \qquad (2.8)$$

The direction of x_1, x_2, and x_3 can be selected such that the permeability tensor, K, becomes a diagonal matrix. This direction is called the principle axis of porous medium. Let's denote this new axes by X, Y, and Z. Then the permeability tensor becomes

$$\vec{K} = \begin{bmatrix} K_x & 0 & 0 \\ 0 & K_y & 0 \\ 0 & 0 & K_z \end{bmatrix} \tag{2.9}$$

Where K_x, K_y, and K_z are the principle permeabilities in x, y, and z direction respectively. Neglecting gravity effects and substituting Eq. 2.6 in Eq.2.5, one gets

$$\nabla \bullet \left(\frac{\rho}{\mu} \vec{K} \nabla P \right) = \frac{\partial(\rho\phi)}{\partial t} \tag{2.10}$$

For compressible fluids

$$\rho = \frac{M}{RT}\left(\frac{P}{z(P)} \right) \tag{2.11}$$

And

$$P.\nabla P = \frac{1}{2}\nabla P^2 \tag{2.12}$$

Substituting Eq.2.11 and 2.12 in 2.10 one gets

$$\left[\left(\frac{K_x}{2\mu(P)Z(P)} \frac{\partial^2 P^2}{\partial x^2} + \frac{K_y}{2\mu(P)Z(P)} \frac{\partial^2 P^2}{\partial y^2} + \frac{K_z}{2\mu(P)Z(P)} \frac{\partial^2 P^2}{\partial z^2} \right) \right] = \phi \frac{\partial}{\partial t}\left(\frac{P}{Z(P)} \right) \tag{2.13}$$

Gas compressibility is defined as

$$C_g = \frac{1}{\rho}\frac{d\rho}{dP} = \frac{Z(P)}{P}\frac{d(P/Z)}{dP} = \frac{1}{P} - \frac{1}{Z(P)}\frac{dZ(P)}{dP} \tag{2.14}$$

Real gas pseudopressure is defined by Ramey and Hussainy as:

$$mP = 2\int_{P_m}^{P} \frac{P}{\mu Z} dP \tag{2.15}$$

Thus Eq. 2.13 in terms of pseudo-pressure becomes as

$$K_x \frac{\partial^2 mP}{\partial x^2} + K_y \frac{\partial^2 mP}{\partial y^2} + K_z \frac{\partial^2 mP}{\partial z^2} = \phi\mu C_g \frac{\partial mP}{\partial t} \tag{2.16}$$

If we define contracted coordinates as

$$X = x \tag{2.17}$$

$$Y = y\sqrt{\frac{K_x}{K_y}} \tag{2.18}$$

$$Z = z\sqrt{\frac{K_x}{K_z}} \tag{2.19}$$

Introducing above equations in Eq.2.16, one gets

$$\frac{\partial^2 mP}{\partial X^2} + \frac{\partial^2 mP}{\partial Y^2} + \frac{\partial^2 mP}{\partial Z^2} = \frac{\phi\mu C_g}{K_x}\frac{\partial mP}{\partial t} \tag{2.20}$$

Defining dimensionless space variables, pseudopressure, and time as

$$X_D = \frac{X}{\sqrt{A}} \tag{2.21}$$

$$Y_D = \frac{Y}{\sqrt{A}} \tag{2.22}$$

$$Z_D = \frac{Z}{\sqrt{A}} \tag{2.23}$$

$$mP_D = \frac{mP_i - mP}{m\tilde{P}} \tag{2.24}$$

$$t_D = \frac{K_x t}{\phi\mu C_g A} \tag{2.25}$$

Where mPi is the initial reservoir pseudopressure, A and $\tilde{P}$ are normalized factors with dimensions of $[L^2]$ and $[F/L^2]$, respectively. Substituting above dimensionless parameters in Eq.2.20, one gets the dimensionless form of the 3D diffusivity equation.

$$\frac{\partial^2 mP_D}{\partial X_D^{\,2}} + \frac{\partial^2 mP_D}{\partial Y_D^{\,2}} + \frac{\partial^2 mP_D}{\partial Z_D^{\,2}} = \frac{\phi\mu C_g}{K_x}\frac{\partial mP_D}{\partial t_D} \tag{2.26}$$

2.2 Analytical Solution to A Horizontal Gas Well

2.2.1 Pseudo-Steady State Solution

The partial differential equation governing the isothermal flow of real gases is given by[7]

$$K_x \frac{\partial^2 mP}{\partial x^2} + K_y \frac{\partial^2 mP}{\partial y^2} + K_z \frac{\partial^2 mP}{\partial z^2} = \frac{\phi \mu c}{K_x} \frac{\partial mP}{\partial t} \qquad (2.27)$$

Babu and Odeh's[6] horizontal well model in a bounded reservoir is assumed in this study, in which following assumptions are made:

1. Reservoir is homogeneous but may be anistropic.
2. Reservoir has constant thickness.
3. Gas properties such as viscosity, compressibility, are function of pressure.
4. Reservoir is assumed semi-infinite. The pressure is not affected by pressure disturbance at the wellbore.
5. No fluid flows across the lateral extremities of the reservoir, mathematically.
6. Reservoir pressure is initially constant.

Babu and Odeh[6], using Green's function and Newman's product method, applied the intersection of three infinite source planes in a bounded reservoir. This resulted in an instantaneous source point. For all no-flow boundaries, uniform flux solution of horizontal well performance for pseudo-steady state is given as follows:

$$q_o = \frac{bk_o(\bar{P} - P_{wf})}{141.2 B_o \mu_o \left[Ln \frac{A^{1/2}}{r_w} + LnC_H - 0.75 + S_R \right]} \qquad (2.28)$$

Where q_o = Flow rate B/D

L = Horizontal well length, ft. For fully penetrated well, b = L

k_o = Effective permeability to oil $(k_x k_v)^{0.5}$, md.

B_o = Oil FVF RB/STB

μ_o = Oil viscosity, cp

C_H = Geometric factor

S_R = Pseudo-skin factor for partial penetration (S_R = 0, if L = b)

A = Reservoir area, (ab), a = width, b = length, ft

For gas wells

$$q_g = \frac{hk_g(m\bar{P} - mP_{wf})}{141.2B_g\mu_g\left[\ln\left(\frac{A^{1/2}}{r_w}\right) + LnC_H - 0.75 + S_R\right]} \quad (2.29)$$

q_g = flow rate MSCF/D

k_g = Effective permeability to oil $(k_x k_y)^{0.5}$,md

B_g = Gas FVF RB/STB

μ_g = Gas viscosity, cp

Where Z_o and X_o are the vertical coordinates of the well center.

$$\ln C_H = 6.28\frac{a}{h}\sqrt{\frac{k_z}{k_x}}\left[\frac{1}{3} - \frac{X_o}{a} + \left(\frac{X_o}{a}\right)^2\right] - \ln\left[\sin\frac{180^\circ Z_o}{h}\right] - 0.5\ln\left[\frac{a}{h}\sqrt{\frac{k_z}{k_x}}\right] - 1.088 \quad (2.30)$$

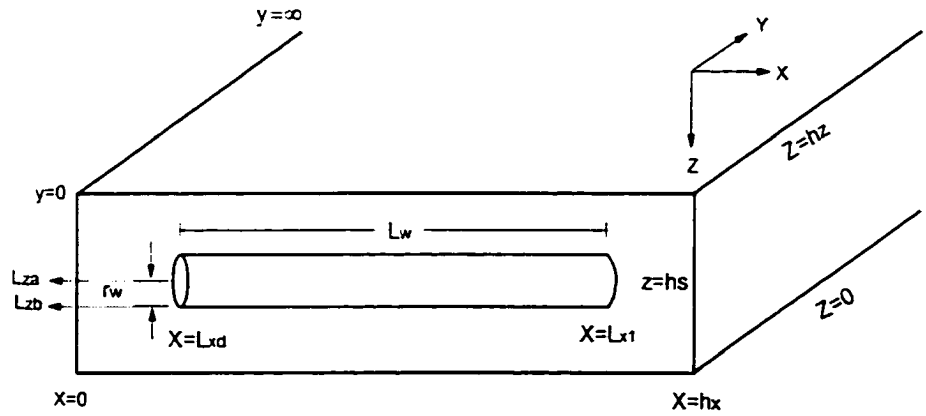


Fig. 2.2. Babu and Odeh[6] horizontal well model.

Keeping three regions in mind, gas-condensate flow in reservoir can be described as follows.

Let

$$C = \frac{0.00708.h}{\left[\ln\frac{A^{1/2}}{r_w} + \ln C_H - 0.75 + S_R\right]} \tag{2.31}$$

Then Babu-Odeh equation for gas wells can be written as follows:

$$q_T = C.\Delta mP_T \tag{2.32}$$

Where ΔmP_T is the total pseudo-pressure function change defined by Fevang and Whitson[5]:

$$\Delta mP_T = \int_{P_{wf}}^{P_i}\left(\frac{k.k_{ro}}{B_o.\mu_o}R_s + \frac{k.k_{rg}}{B_{gd}.\mu_{gd}}\right)dp \tag{2.33}$$

For all three regions, defined in chapter three, in condensate system above definition of pseudopressure function is further subdivided as:

Region-1 (Inner wellbore region where both oil and gas are mobile)

$$mP_1 = \int_{P_{wf}}^{P^*}\left(\frac{k.k_{ro}}{B_o.\mu_o}R_s + \frac{k.k_{rg}}{B_{gd}.\mu_{gd}}\right)dp \tag{2.34}$$

Region-2 (Region where liquid develops)

$$mP_2 = \int_{P^*}^{P_d}\left(\frac{k.k_{rg}}{B_{gd}.\mu_{gd}}\right)dp \tag{2.35}$$

Region-3 (Only gas region)

$$mP_3 = k.k_{rg}(S_{wi})\int_{P_d}^{P_R}\left(\frac{1}{B_{gd}.\mu_{gd}}\right)dp \tag{2.36}$$

Thus total ΔmP_T is equal to $\Delta mP_1+\Delta mP_2+\Delta mP_3$.

Above three pseudopressures require all properties such as viscosity, FVF, saturation, and relative permeabilities as a function of pressure.

Note on Gas Formation Volume Factor, Bg.

In above equations if q is in scf/D then Bg is in cf/scf. If q is in Mscf/D then Bg is in cf/Mscf. If q is in bbls then Bg is in cf/bbl.

q	B_g
Scf/D	Cf/scf
Mscf/D	cf/Mscf
Bbl/D	cf/bbl

2.2.2 Estimation of Oil and Gas Flow Rates separately

Based on Eq.2.28 flow rates of oil and gas phases can be estimated separately as follows.

$$q_o = C.\Delta mP_o \tag{2.37}$$

Where

$$mP_o = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{ro}}{B_o.\mu_o} + \frac{k.k_{rg}}{B_{gd}.\mu_{gd}} R_o \right) dp \tag{2.38}$$

And

$$q_g = C.\Delta mP_g \tag{2.39}$$

$$mP_g = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{ro}}{B_o.\mu_o} R_s + \frac{k.k_{rg}}{B_{gd}.\mu_{gd}} \right) dp \tag{2.40}$$

From Eq.2.37 and 2.39 it is possible to generate two separate IPRs for oil and gas phases.

2.2.3 Vertical Well Model

This discussion will be incomplete without vertical well.

$$q_o = C.\Delta mP_o \tag{2.41}$$

Where

$$C = \frac{0.00708.h.}{\left[Ln\frac{r_e}{r_w} - 0.75 + S \right]} \tag{2.42}$$

$$q_g = C.\Delta mP_g \tag{2.43}$$

$$S' = S + Dq \tag{2.44}$$

Where ΔmP_o and ΔmP_g are given by Eq. 2.38 and 2.40. C is the shape factor for the location of the well in the reservoir.

2.3 Pressure Transient Solution of Diffusivity Equation

The partial differential equation governing the isothermal flow of real gases in the porous medium is

$$\frac{\partial^2 mP_D}{\partial X_D^{\,2}} + \frac{\partial^2 mP_D}{\partial Y_D^{\,2}} + \frac{\partial^2 mP_D}{\partial Z_D^{\,2}} = \frac{\phi\mu C_g}{K_x}\frac{\partial mP_D}{\partial t_D} \tag{2.45}$$

$$K_x \frac{\partial^2 mP}{\partial x^2} + K_y \frac{\partial^2 mP}{\partial y^2} + K_z \frac{\partial^2 mP}{\partial z^2} = \frac{\phi\mu c}{K_x}\frac{\partial mP}{\partial t} \tag{2.46}$$

To achieve the pressure transient solution of Eq.2.27, following initial and boundary conditions are imposed.

1. The reservoir pressure is initially constant
2. The reservoir is assumed to be semi infinite in y-direction. The pressure at infinity is not influenced by the disturbance at the wellbore.
3. To develop the solution as a first approximation, the horizontal well is replaced with a thin strip of width $(L_{zb}-L_{za})$ and length $(L_{xf}-L_{xd})$. This assumption will later be removed and the horizontal well will be reinstead with its original configuration. During the drawdown period, uniform flux along the well length is assumed. No fluid will be entering the wellbore during the buildup period.
4. No fluid may flow across the upper, lower, and lateral boundaries.

Mathematically, above conditions are expressed as follows.

1. $mP = mP_i$ at $t = 0$ $\qquad \forall x, y, z$

2. $mP = mP_i$ as $y \to \infty$ $\forall x, y, z$

3. $\lim_{y \to 0}(L_{zb} - L_{za})(L_{xd} - L_{xl})\frac{\partial mP}{\partial y} = \begin{cases} 0 & 0 \le z < L_{za} \quad 0 \le z < L_{xd} \\ 0 & 0 \quad -\frac{q}{2k_y} \quad L_{za} \le z \le L_{zb} \quad L_{xd} \le z \le L_{xl} \\ & L_{zb} \le z \le h_z \quad L_{xl} \le z \le h_x \end{cases}$

4. $\frac{\partial mP}{\partial z} = 0$ at $z = 0$ and $z = h_z$

5. $\frac{\partial mP}{\partial x} = 0$ at $x = 0$ and $x = h_x$

2.3.1 Pressure Drawdown Response

The single phase pressure response when expressed in terms of pseudopressure takes the form as follows[7]

$$mP_i - mP_w = \frac{282.4qB_g r_w'}{h_x h_z k_y}\left[\begin{array}{l} \sqrt{\pi t_D} + \frac{h_x^2}{\pi^2 \nu_x}\sum_{n=1}^{\infty}\frac{1}{n}xerf\left(\nu_x \pi n\sqrt{t_D}\right)\Xi_n^2 + \frac{h_x h_z}{L_w \nu_z \pi} \\ \sum_{m=1}^{\infty}\frac{1}{m}xerf\left(\nu_z \pi m\sqrt{t_D}\right)\Xi_m^2 \cos(m\pi z_e) + \frac{h_x h_z\sqrt{\frac{k_y}{k_z}}}{2L_w r_w'}S_a \end{array}\right] \quad \text{-----(2.47)}$$

2.3.2 Pressure Buildup Response[7]

$$mP - mP_{w(t=0)} = \frac{282.4qB_g r_w'}{h_x h_z k_y}\text{x}$$

$$\left[\begin{array}{l} \sqrt{\pi}(t_D - \Delta t_D) + \frac{h_x^2}{\pi^2 \nu_x}\sum_{n=1}^{\infty}\frac{1}{n}\left\{erf\left(\nu_x \pi n\sqrt{t_D}\right) - erf\left(\nu_x \pi n\sqrt{\Delta t_D}\right)\right\}\Xi^2 \\ + \frac{h_x h_z}{L_w \nu_z \pi}\sum_{m=1}^{\infty}\frac{1}{m}\left\{erf\left(\nu_z \pi m\sqrt{t_D}\right)erf\left(\nu_z \pi m\sqrt{\Delta t_D}\right)\right\}\Xi_m^2 \cos(m\pi z_e) \end{array}\right]$$

----(2.48)

Where

$$\Xi_n = \frac{1}{nL_w}\left[\sin\left(\frac{n\pi L_{td}}{h_z}\right) - \sin\left(\frac{n\pi L_{td}}{h_z}\right)\right] \tag{2.49}$$

$$\Xi_m = \frac{1}{4mr_w}\left[\sin\left(\frac{m\pi}{h_z}\left(h_s + 2r_w\right)\right) - \sin\left(\frac{m\pi}{h_z}\left(h_s - 2r_w\right)\right)\right] \tag{2.50}$$

$$L_w = \left(L_{td} - L_{td}\right) \tag{2.51}$$

$$r_w = r_w\left(\frac{k_z}{k_r}\right)^{\frac{1}{4}} \tag{2.52}$$

$$t_D = \frac{0.000264k_y t}{\phi\mu c_t r_w^{\,2}} \tag{2.53}$$

$$\Delta t = (t - t_0) \tag{2.54}$$

$$v_r = \frac{r_w}{h_r}\sqrt{\frac{k_z}{k_y}} \tag{2.55}$$

$$v_z = \frac{r_w}{h_z}\sqrt{\frac{k_z}{k_y}} \tag{2.56}$$

$$z_e = \frac{1}{h_z}\left(h_s + 1.47r_w\right) \tag{2.57}$$

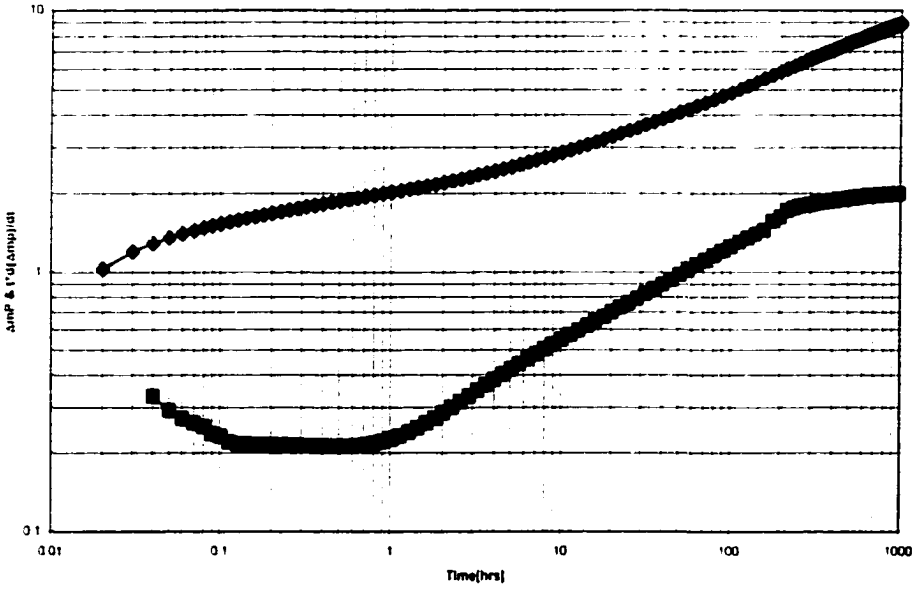


Fig. 2. 3. Pressure transient solution of Eq.2.46, simulated using Saphhire™ Well Test Software.

Chapter III

Gas Condensate Systems and Fluid Properties Review

3.1 Reservoir Fluid Classification

Reservoir fluids are classified as Black oil, Volatile oil, Gas-condensate, Wet gas, and Dry gas. This classification is necessary for the application of appropriate engineering practices to predict and utilize these natural resources efficiently and economically. Well-defined, field as well as laboratory methods of identifying these fluids have been developed. Fig. 3.1 is a schematic of a multi-component hydrocarbon mixture of constant composition. This figure has the following distinct features:

1. Region formed by the bubble-point curve
2. Critical point
3. Dew-point curve
4. Lines inside this region represent the liquid and gas saturation.

3.2 Retrograde Fluids

Retrograde gas-condensates fall in third category of the reservoir fluid classification as indicated in Fig.3.1. This type of fluids has smaller phase diagram than that of oils. Critical point is down the left side of the envelope. These differences in the properties are mainly due to the presence of fewer heavier molecules in light mixture of hydrocarbons. The critical temperature for retrograde gas-condensate is less than reservoir temperature and circondentherm greater than reservoir temperature (Fig.3.2). Initially retrograde gas is totally gas in the reservoir, as the reservoir pressure decreases retrograde-gas exhibits dew point, and liquid begins to form.

In field, condensate fluids are identified using initial GOR, specific gravity, and color of the produced liquids. Condensates are separated from

other fluids by two characteristics: the condensation of liquid phase at reservoir conditions during iso-thermal depletion and retrograde (re-vaporization) nature of these condensates. Retrograde behavior of the condensing liquid phase can be seen by tracing the change in liquid volume along constant temperature line beginning at point M in Fig.3.1.

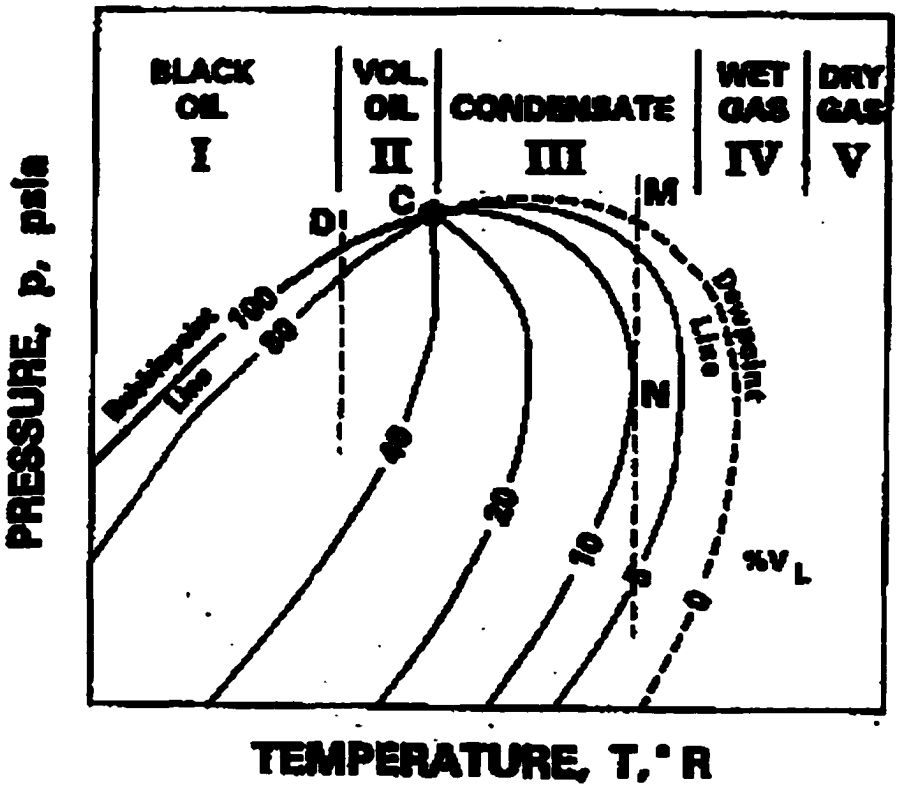


Fig.3.1 Phase Diagram Showing the Fluid Classification[4].

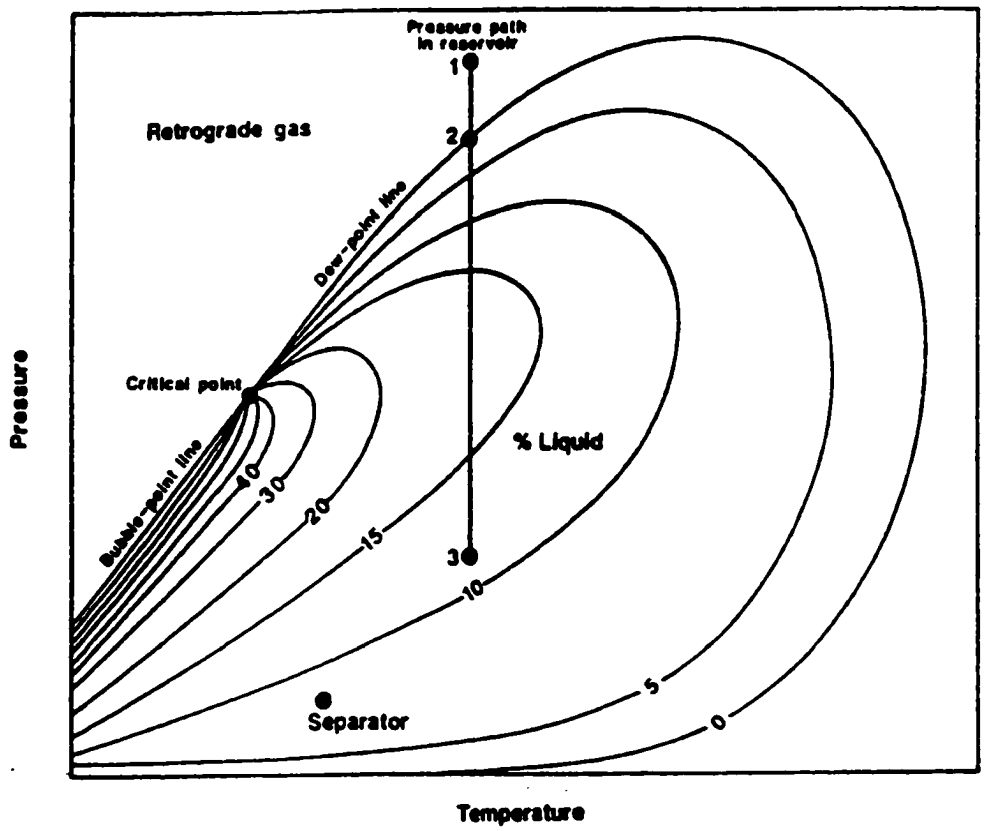


Fig. 3.2 Phase Diagram for Gas-Condensates[8].

3.3 Retrograde Condensation

In multi-component system any decrease in pressure causes change in phase from liquid to gas at temperatures below critical temperature. However, the gas re-vaporizes as the pressure drops further below the lower dew-point pressure line. This re-vaporization of the liquid is called as retrograde condensation. This phenomenon occurs at the temperature between critical temperature and circondentherm (the maximum temperature on two phase envelop.)

3.4 Sampling Of Retrograde Fluids

It is very important to determine true properties of retrograde gas condensates so that precise estimates and engineering analysis of such fluids could be made. Laboratory testing of these fluids requires, 1) Reservoir temperature, 2) Initial reservoir pressure, and 3) representative fluid sample. Reservoir temperature is usually obtained from temperature surveys or logs, initial pressure is obtained from DST or RFT. Near critical gas condensates may require very precise estimates of these properties to classify the sample accurately. Idea is to get the sample of same composition as the resident reservoir fluid. The best way to get such a sample is to sample the producing fluid at initial reservoir conditions so that the downhole pressure remains above dew-point pressure while a high rate is maintained to ensure that no liquid holdup occurs in any part of the production system including surface lines. For this case, a sample obtained by a re-combination of the high-pressure separator vapor and produced liquid at measured producing GOR should be representative of the initial reservoir fluid. This is very idealized situation because all wells must be flowed for cleanup of already existing fluid in the production system. A successful sample program consists of:

1. Well conditioning before sampling

2. Choice of collection site
3. Collection mechanism
4. Quality control checks

Once this information is obtained, detailed laboratory experiments such as constant-composition-expansion (CCE) and constant-volume-depletion (CVD) are conducted to determine the phase behavior of the fluids.

3.5 Fluid Distribution in the Reservoir

Vogel and Fetkovitch IPR equations are being used to predict horizontal well performance in solution gas reservoirs[6]. To establish the well performance with reasonable accuracy, a Gas-Condensate reservoir can be visualized as primarily gas reservoir. With depletion when pressure drops and dew point pressure (P_d) is reached heavier HCs begin to condense. The condensate is not mobile until the critical saturation is reached. This condensate occupies some of the pore space and acts as condensate-skin. The well deliverability is reduced because of reduced relative permeability to the gas phase. Pressure at this point can be termed as critical pressure (P^*). Once P^* is reached the flow is two phase in nature and covers the rest of the flow area around the well.

Thus flow in a gas condensate reservoir undergoing depletion can be seen in following fashion[5].

Region-1: An inner near wellbore region where both gas and oil are flowing simultaneously. Liquid may re-vaporize due to retrograde behavior if the pressure is reached below the lower dew point curve on the two phase envelope.

Region-2: A region of condensate builds up where only gas is flowing. The condensate saturation is lower than critical saturation and liquid is immobile.

Region-3: A region containing single-phase reservoir gas.

For a given producing condition, one, two or all three regions may exit.

These three regions define pseudo-steady state flow conditions, meaning that they represent steady-state conditions at a given point in time but that steady-state conditions change gradually with depletion.

Region-1. (Near Wellbore) The flowing composition (GOR) within this region has the same composition as the produced well stream mixture. Conversely, if we know the producing well stream, then we know the flowing fluid composition within Region-1. Region-1 is the main source of deliverability loss of a well in gas condensate reservoir. Gas relative permeability is reduced due to condensate buildup. The size of the Region-1 increases with depletion. For steady state conditions, the condensate saturation in Region-1 is found as a function of the radius specifically to ensure that all liquid that condenses from single-phase gas entering Region-1 has sufficient mobility to flow through and out the Region-1 without accumulation.

Region-2: If it exists, it defines a region of net accumulation of condensate. Only gas is flowing in this region because oil mobility is zero. Condensate saturation in Region-2 is closely approximated by liquid dropout curve from a Constant-Volume-Depletion experiment corrected for water saturation. The size of Region-2 is largest at early times just after the reservoir pressure drops below the dew point. It decreases in size with time because Region-1 is expanding. *The main consequence of Region-2 is that producing wellstream composition (GOR) is leaner than calculated by simple volumetric material balance or CVD experiments.* Incorrect use of material balance GORs in the calculation of the pseudo-pressure significantly overestimates deliverability loss in Region-1 especially at early times in depletion just after reservoir pressure drops below the dewpoint pressure.

Region-3. This region will always (and only) exist in a gas condensate reservoir that is currently undersaturated. The standard treatment of single-phase gas flow is used to quantify the contribution of Region-3 to well

deliverability. The composition of the reservoir gas is constant and is the same as of original gas.

3.6 Coexistence of the Flow Regions

If the flowing BHP is less than the dewpoint pressure, Region-1 will always exist. It will not exist if flowing BHP is greater than the dewpoint.

Region-2 will always exist together with Region-1 after reservoir pressure drops below the dewpoint. In this case Region-3 does not exist. All three regions exist for reservoirs that are slightly undersaturated and flowing BHP is less than the P*. Region-2 may "disappear" or have negligible effect for highly undersaturated reservoirs.

It is not possible for Regions-2 and 3 to exist in the absence of Region-1 after steady state conditions are reached. For a very rich (near critical) gas condensate, Region-1 may exist throughout the drainage area in the absence of Regions-2 and 3, after reservoir pressure drops below the dew point.

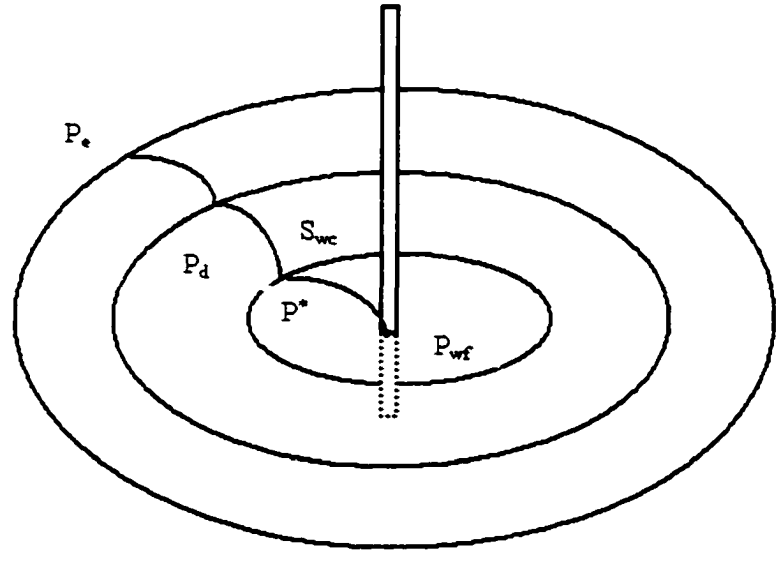


Fig. 3.3. Fluid distribution with a vertical well.

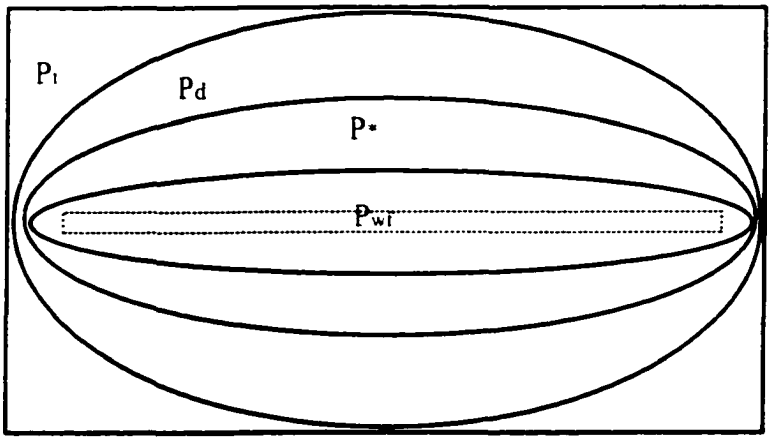


Fig.3.4. Fluid distribution with a horizontal well completely penetrating the formation.

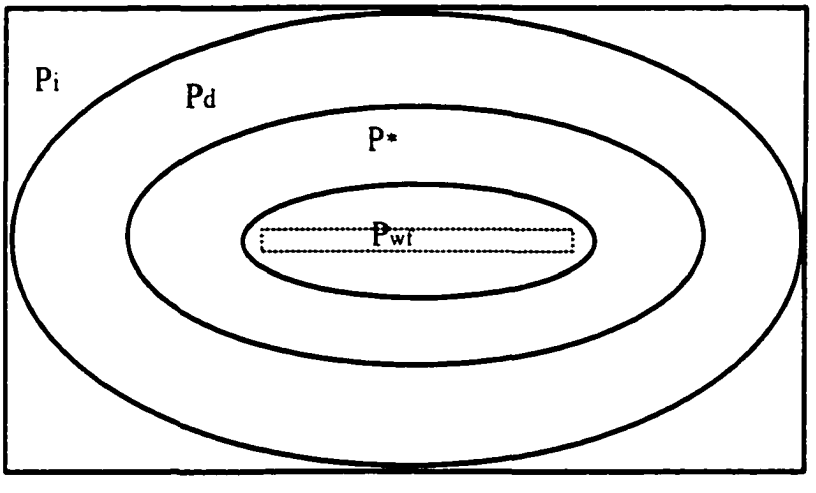


Fig.3.5 Fluid distribution with a horizontal well placed in the middle of the reservoir.

To establish the inflow performance of the well, one needs all the parameters in Eq.2.29 to be estimated. P* is estimated from pressure test data and with producing GOR (R_p) known. P* is equal to the dew point pressure of the well stream. Using PVT table where 1/Rs = r_s = 1/Rp, is the P*. If P* is greater than P_R then Region-1 and Region-2 do not exist and pseudo-pressure integral simplifies to only gas phase, Region-1 (Near wellbore). If P* is greater than P_d and less than P_R the pseudo-pressure integral consists of two regions, Region-1 and Region-3. With R_s is known from laboratory experiments, B_o, B_g, μ_g, μ_o for Region-1 can be estimated using mathematical models for light oils commonly available in literature.

3.7 Fluid Properties

Condensate liquids are very light and have API gravity greater than 40. Thus following models were chosen for this study:

3.7.1 Light Oil Properties (API > 31.1)

Bubble point Pressure: To estimate the bubble point pressure of the liquid phase of the condensate system Standings Modified Correlation has been chosen.

$$P_b = 31.7648\left[\left(\frac{R_s}{\gamma_g}\right)^{0.7857} + \left(\frac{10^{0.0009T}}{10^{0.0148.API}}\right)\right] \tag{3.1}$$

Solution Gas Oil Ratio (R_{so}): Modified Kartoatmodjo's Correlation

$$R_s = 0.01347\left(\gamma_{g,corr}\right)^{0.3873}\left(P_b\right)^{1.1715}\left(10^{\left(\frac{12.753.API}{T+460}\right)}\right) \tag{3.2}$$

Where

$$\gamma_{g,corr} = \gamma_g.P_{sp}\left[1+0.1595.API^{\,0.4078}\left(T_{sp}\right)^{-0.2466}Log\left(\frac{P_{sp}}{114.7}\right)\right] \tag{3.3}$$

Dead oil viscosity (μ_d): Modified Egbogah-Jack's Correlation

$$\log.\log\left(\mu_{od}+1\right) = 1.8513 - 0.025548.API - 0.56238.Log\left(T_g\right) \tag{3.4}$$

Gas Saturated Oil Viscosity

(Modified Beggs and Robinson Correlation

$$\mu_{ol} = -0.032124 + 0.9289.F - 0.02865.F^2 \quad (3.5)$$

$$\mu_{ol} = \left[25.1921(R_{so}+100)^{-0.6487}\right]\mu_{od}^{\left[2.7516(R_{so}+150)^{-0.2135}\right]} \quad (3.6)$$

Condensate Specific Gravity (γ_o)

$$\gamma_o = \frac{141.5}{131.5 + API} \quad (3.7)$$

Molecular Weight of Condensate (M_o)

$$M_o = \frac{5.954}{API - 8.811} \quad (3.8)$$

$$M_o = \frac{42.43\gamma_o}{1.008 - \gamma_o} \quad (3.9)$$

3.7.2 Natural Gas Properties

For the temperature range of 300-700 °F and gravity range of 0.5-1.8 the following parameters are estimated as:

Pseudocritical Temperature

Standing correlation for California gases

$$T_{sp}(^\circ R) = 295.48\gamma_{g,cor} + 181.89 \quad (3.10)$$

$R^2 = 0.9998$

Standing correlation for Oklahoma gases

$$T_{sp}(^\circ R) = 298.6\,\gamma_{g,cor} + 179.44 \quad (3.11)$$

$R^2 = 0.9995$

Pseudocritical Pressure

Californian Gases

$$P_{sp}(psia) = -44.906(\gamma_{g,cor})^3 + 93.189(\gamma_{g,cor})^2 - 108.17(\gamma_{g,cor}) + 717.85 \quad (3.12)$$

$R^2 = 1$

Oklahoma Gases

$$P_{sp}(psia) = -514.01(\gamma_{g,cor})^4 - 1788.2(\gamma_{g,cor})^3 - 2337.5(\gamma_{g,cor})^2 - 1305.3(\gamma_{g,cor}) - 415.07 \quad (3.13)$$

$R^2 = 1$

Gas Formation Volume Factor (B_g)

$$B_g = 0.02829\frac{zT}{P}, \text{ cu ft/SCF} \quad (3.14)$$

$$B_g = 0.00504\frac{zT}{P}, \text{ bbl/SCF} \quad (3.15)$$

Natural Gas Viscosity (μ_g)

For its convenient mathematical form Lee and Gonzalez model for viscosity has been used.

$$\mu_g = 10^{-4} X_1 \exp(X_2 \rho^{X_3}) \quad (3.16)$$

Where ρ is the gas density in g/cc and μ_g is the gas viscosity in cp, and

$$X_1 = \frac{(9.4 + 0.02M)T^{1.5}}{209 + 19M + T} \quad (3.17)$$

$$X_2 = 3.5 + \frac{986}{T} + 0.01M \quad (3.18)$$

$$X_3 = 2.4 - 0.2X_2 \quad (3.19)$$

$$\rho = \frac{MP}{RT} \quad (3.20)$$

$$\rho_g = 1.601846 \times 10^{-2} \frac{MW.P}{RT} \quad (3.20a)$$

Where R (10.73) is the universal gas constant, T is in °R and P is in psi. The gas density is in gm/cc. MW is the molecular weight of the gas.

Where T is in °R, ρ is in lb/cu ft, P in psia, R is 10.732 psia-cuft/[lb-mole-°R] in Eq.3.20a.

Gas Compressibility (Z)

For gas compressibility Gopal equations genertaed for computer use have been selected. (Table 3.1)

Gas Gravity at Reservoir Conditions

Three Stage Separation

$$\gamma_g = \frac{R_1\gamma_g + 4.602\gamma_o + R_2\gamma_g + R_3\gamma_g}{R_1 + \frac{133.316\gamma_o}{M_o} + (R_2 + R_3)} \tag{3.21}$$

Two Stage Separation

$$\gamma_g = \frac{R_1\gamma_g + 4.602\gamma_o + R_2\gamma_g}{R_1 + \frac{133.316\gamma_o}{M_o} + R_2} \tag{3.22}$$

Also

$$\gamma_g = \frac{R_1\gamma_g + 4.602\gamma_o + G_{pa_g}}{R_1 + V_{eq}} \tag{3.23}$$

Table 3.1

Gopal[6] Equations for Estimating Compressibility (Z) Factor

P_r	T_r	Equations	Eq.No
0.2 To 1.2	1.05 To 1.2	P_r (1.6643 T_r - 2.2114) - 0.367 T_r + 1.4385	1
	1.2 + To 1.4	P_r (0.5222 T_r - 0.8511) - 0.0364T_r *+ 1.0490	2
	1.4+ To 2.0	P_r (0.1391 T_r - 0.2988) + 0.0007T_r * + 0.9969	3+
	2.0+ To 3.0	P_r (0.0295 T_r - 0.0825) + 0.0009T_r * + 0.9967	4+
1.2 + To 2.8	1.05 To 1.2	P_r (-1.3570 T_r +1.4942) + 4.6315 T_r - 4.7009	5++
	1.2 + To 1.4	P_r (0.1717 T_r - 0.3232) + 0.5869 T_r +0.1229	6
	1.4+ To 2.0	P_r (0.0984 T_r - 0.2053) + 0.0621T_r + 0.858	7
	2.0+ To 3.0	P_r (0.0211 T_r - 0.0527) + 0.0127T_r + 0.9549	8
2.8 + To 5.4	1.05 To 1.2	P_r (-03278T_r + 0.4752) +1.8223T_r -1.9036	9+
	1.2 + To 1.4	P_r (-0.2521T_r + 0.3871) +1.6087T_r -1.6635	10+
	1.4+ To 2.0	P_r (-0.0284T_r + 0.0625) + 0.4714T_r -0.0011*	11
	2.0+ To 3.0	P_r (0.0041T_r + 0.0039) + 0.0607 T_r +0.7927	12
5.4 + To 15.0	1.05 To 3.0	P_r (0.711 + 3.66T_r)$^{-1.4667}$ -1.637/(0.319T_r + 0.522) + 2.071	13

*These terms may be ignored.

+For a very slight loss in accuracy, Equations 3 and 4 and

9 and 10 can, respectively, be replaced by the following two equations:

$$Z = P_r\ (0.0657T_r - 0.1751) + 0.0009T_r{}^{*+} - 0.9968 \qquad (3.24)$$

$$Z = P_r\ (-0.2384T_r + 0.3695) + 1.4517T_r - 1.4580 \qquad (3.25)$$

++Preferably use this equation for P_r up to 2.6 only. For P_r = 2.6+, equation 9 will give slightly better results. Also, preferably, use Equation 1 for $1.08 \leq T_r \leq 1.19$ and $P_r \leq 1.4$.

3.7.3 Condensates

Pseudo-critical Temperature

$$T_{sp}(^{\circ}R) = -71.647(\gamma_{g,cor})^2 + 333.52(\gamma_{g,cor}) + 182.2 \qquad (3.26)$$

$R^2 = 0.9999$

Pseudo-critical Pressure

$$P_{sp}(psia) = -22.334(\gamma_{g,cor})^2 - 35.575(\gamma_{g,cor}) + 704.99 \qquad (3.27)$$

$R^2 = 0.9981$

Oil formation Volume Factor (B_o)

Standing co-relation

$$B_o = 0.972 + 0.000147F^{1.175} \qquad (3.28)$$

Where $F = R_{so}\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25T$, T = °F

Oil specific gravity (γ_o)

$$\gamma_o = \frac{141.5}{131.5 + \rho_{o\,API}} \qquad (3.29)$$

Oil Viscosity (μ_o)

For crude oil viscosity (In Pa-S), Miadonye et al one parameter correlation is available.

$$\ln \mu_o = 2.30259\left[\frac{b}{\left(1+\frac{T-30}{303.15}\right)^d} - 3.002\right] \qquad (3.30)$$

Where

$$b = \log \mu_{(@\ 30^{\circ}C,0MPag)} + 3.002$$

And

$$d = 0.006694b + 3.5364$$

Where T is in °C.

Solution Gas Oil Ratio (R_{so})

In absence of laboratory analysis the solution gas oil ratio can be estimated using Standing co-relation at reservoir conditions of temperature and pressure.

$$R_{SO} = \gamma_g \left(\frac{P}{18(10^{Y_g})} \right)^{1.204} \tag{3.31}$$

Where $Y_g = 0.00091\ T - 0.0125\ P_o$

T = °F

P = psia

3.8 Representation of K_{rg}/K_{ro} as a Function Pressure for Volatile Oils

Producing GOR as a function of pressure and relative permeability ratio is expressed as[3]

$$R_P = R_s + \left(\frac{k_{rg}}{k_{ro}} \right) \left(\frac{B_o \mu_o}{B_g \mu_g} \right) \left(1 - R_O\ R_P \right) \tag{3.32}$$

Solving for GOR as a function of pressure, results

$$R_P(P) = \left[\frac{R_s + \left(\frac{k_{rg}}{k_{ro}} \right) \left(\frac{B_o \mu_o}{B_g \mu_g} \right)}{1 + R_O \left(\frac{k_{rg}}{k_{ro}} \right) \left(\frac{B_o \mu_o}{B_g \mu_g} \right)} \right] (P) \tag{3.33}$$

The ratio $\left(\frac{k_{rg}}{k_{ro}} \right)(p)$ is then expressed as follows:

$$\left(\frac{k_{rg}}{k_{ro}} \right)(p) = \frac{\left(R_p - R_s \right)}{\left(1 - R_O\ R_S \right)} \left(\frac{B_g \mu_g}{B_o \mu_o} \right) \tag{3.34}$$

Where R_o is the Solution Oil Gas Ratio (amount of liquid phase in gas phase), STB/scf. The term 1-Ro.Rso is the correction term for volatile oils.

$$R_O = \frac{\dfrac{\text{Moles Condensate from Separartor}}{\text{Molar Density of Stock Tank Condensate}}}{379(5.615)(\text{Moles of Separator Gas})} \text{ STB/SCF} \qquad (3.35)$$

$$R_o = -11.66 + 4.706x10^{-4} Rs^2 + 1.623\sqrt{Rs} - \frac{42.3815}{\sqrt{Rs}} \qquad (3.35a)$$

In absence of field data use eq.3.35b. It was developed from filed example data.

In Region-1 where liquid phase re-vaporization occurs, the value of K_{rg} may begin to increase. It may even not be noticeable because of higher gas-production rates. Thus the effect of re-vaporization depends on the ratio of q_g/R_s at a given moment. Similarly $K_{ro}(S_o)$ may begin to decrease due to decreasing oil saturation, and increasing gas saturation due to re-vaporization. The effect on K_{ro} may be noticeable because of the low-pressure profile around the well.

In Region-2 changes in gas relative permeability occur due to increasing liquid saturation. Thus increasing liquid saturation acts as increasing skin.

$$\left(\frac{dS}{dS_o}\right) = f\left(S_o(p)\right) \text{ and } K_{rg}(S_o) \qquad (3.36)$$

The gas depletion in Region-2 is constant-volume-depletion. Oil saturation in this region can be expressed in terms of CVD experiment data[5]. Since in Region-2 the liquid phase is immobile, therefore, oil relative permeability apparently approaches to zero.

3.9 Importance of Critical Oil Saturation (S_{OC})

Critical oil saturation is important in parametric studies. In relative permeability relationships oil saturation can be normalized such that normalized oil saturation becomes

$$\hat{S}_o(p) = \frac{S_o - S_{oc}}{\left(1 - S_{wi} - S_{oc}\right)} \tag{3.37}$$

Thus normalization of oil saturation results new set of gas relative permeability curve in Region-2. Critical liquid saturation is heavily dependent on the rock wettability and the IFT. Critical liquid Saturation, S_{lc}, increases with IFT[14]. Lowest values of Slc have been reported at very low values of IFT. After the Slc or the threshold value of IFT has been attained fluid relative permeability is not affected by IFT.

3.10 Relative Permeability Model Review

The ultimate use of the relative permeability is to help design, optimize, and analyze the displacement processes. Relative permeability plays central role in the drainage process of a reservoir. Core studies of relative permeability indicate that relative permeability of a phase in a porous medium is function of its saturation, capillary number, saturation history, wettability, and pore structure.

Numerous experimental studies have been conducted to correlate gas and condensate relative permeability to above mentioned properties and saturation. Studies also indicate that the relative permeability and critical condensate saturation are sensitive to flow rate and IFT[13]. Also the sensitivity studies of relative permeability in laboratory indicated that the well productivity curtailed by condensate drop out can be somewhat restored by increasing production rate. High IFT ultimately causes condensate relative permeability to decrease with increasing saturation. Also gas relative permeability has small hystersis between drainage and imbibtion.

3.11 Relative Permeability dependence on Capillary Number (Nc)

Capillary Number is the ratio of fluid velocity times the fluid viscosity to the IFT. Thus it is directly proportional to the flow rate and inversely proportional to the IFT.

$$N_c = \frac{\mu v}{IFT} \tag{3.38}$$

Capillary numbers that are relevant to well deliverability depend on flow rate, fluid type, and well flowing pressure. Typically N_c ranges between 10^{-6} and 10^{-3} have great impact on well deliverability[13].

The flow rate dependency of the relative permeability can be explained on the basis of the competition between the capillary and viscous forces. This can be achieved either by decreasing IFT or increasing flow rate. Thus wells flowing with greater values of pressure drawdown will drain more condensate. Thus Horizontal well will apply the higher drag forces on the gathering rim of the liquid.

Another definition of capillary number that also accounts for the rock properties is

$$N_c = 4\frac{\mu vr}{IFT}\left(\frac{P}{2.IFT.Cos\theta}\right) \tag{3.39}$$

Where P is the pressure where fluid starts invading the porous medium and has to be determined in the laboratory. r is the drainage radius (length in case of cores.) N_c greater than unity indicates that the viscous forces are dominant on the flow.

3.12 Impact of trapped gas on Critical Liquid Saturation and Threshold IFT.

Numerous studies on displacement process have indicated that the trapped gas prohibits the injected fluid from entering the occupied pore space. Interestingly trapped gas is independent of pressure and temperature. Also the amount of trapped gas depends on the maximum gas saturation within the reservoir[15]. It suggests that trapped gas favorably acts against the liquid dropout and helps lower the threshold IFT. Fortunately the condensate reservoirs have highest amount of the gas saturation and as high as 30% of the gas would be in the trapped form. Its impact will be observed at the later stages of the filed.

3.13 Relative Permeability-Capillary Number Models Review for Gas-Condensate Systems

1- Purdhoe Bay[15]

a) Gas Relative Permeability

$$K_{rg} = \frac{\left(1 + y_{g2}\left(\frac{S_g - S_{gt}(S_{g\max})}{1 - S_{gr}}\right)\right)^{y_{g1}}}{1 + y_{g2}\left(\frac{S_g - S_{gt}(S_{g\max})}{1 - S_{gr}}\right)^{y_{g1}\left(1 + \frac{1}{y_{g2}}\right)}} \qquad (3.40)$$

At low gas saturations the numerator in the above equation dominates and the equation approaches to Corey equation.

Where y_{g1} and y_{g2} are empirically derived constants and S_{gt} is the trapped gas saturation given by;

$$S_{g_t}(S_{g\max}) = \frac{S_{g\max}}{1 + \left(\frac{1}{S_{g_r}} - 1\right)\left(S_{g\max}\right)^{\left(1 + \frac{\Delta S_{gr}}{1 - S_{wr}}\right)}} \qquad (3.41)$$

3.14 Relative Permeability Models for Gas-Condensate Reservoirs

Numerous studies on North Sea cores indicate relative permeability as a function of capillary number as follows[12]:

Region-1

$(S_{or}/S_{or}^*) = -0.0104\text{Ln}(Nc) + 0.7731$ (3.42)

$R^2 = 0.9944$

Region-2

$(S_{or}/S_{or}^*) = -0.1124\text{Ln}(Nc) - 0.4791$ (3.43)

$R^2 = 0.9974$

Region-3

$(S_{or}/S_{or}^*) = -0.9523\text{Ln}(Nc) - 6.306$ (3.44)

$R^2 = 0.980$

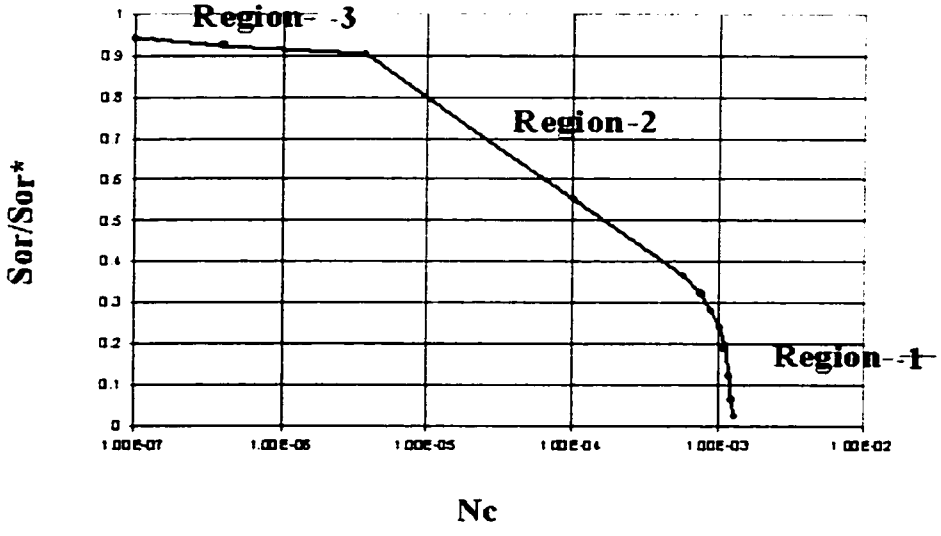


Fig.3.6 Capillary Number for Berea sandstones[18]

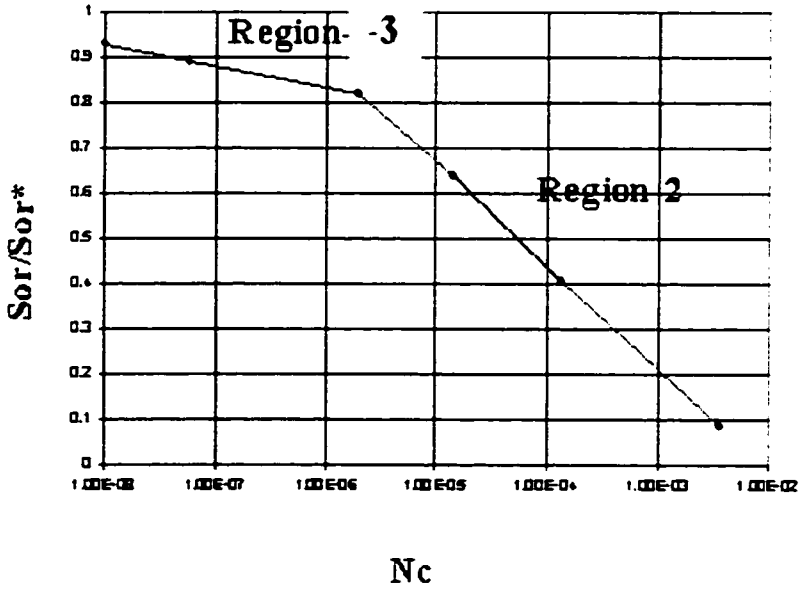


Fig.3.7. Capillary Number for ORE formation [18].

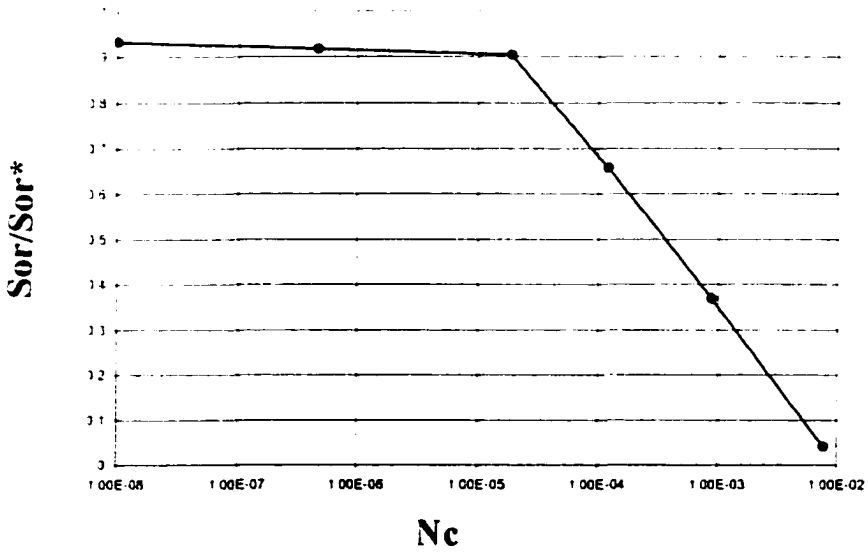


Fig. 3.8. Capillary number for Tarbert formation, North Sea[18].

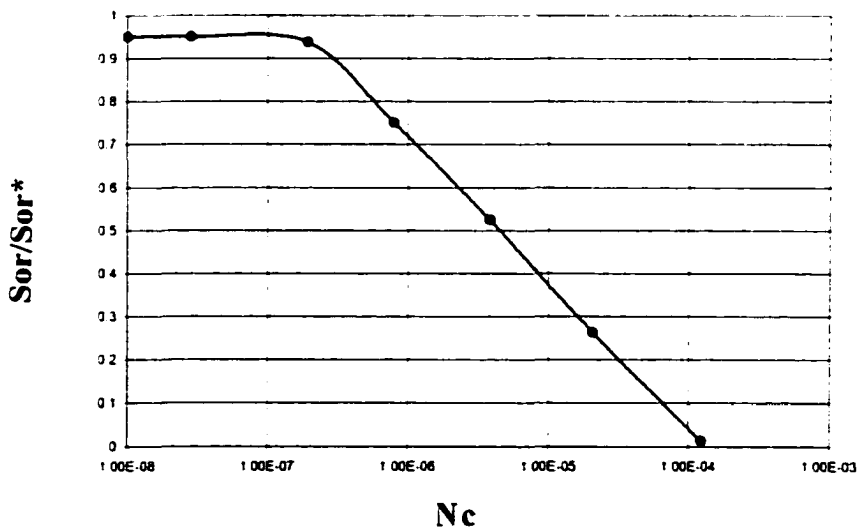


Fig.3.9. Capillary Number for Norse formation, North Sea[18].

General Correlation for gas-condensates[17].

$$k_{rg} = f_g(N_c).k_{rg(base)} + \left[1 - f_g(N_c)\right]k_{rg(misc)} \tag{3.45}$$

Where

In terms of IFT

$$f_g = \frac{1}{1 + \left(\frac{a}{\sigma}\right)^b} \tag{3.46}$$

In terms of Nc

$$f_g = \frac{1}{1 + \left(\frac{N_c}{a}\right)^{\frac{1}{b}}} \tag{3.47}$$

Where

Gas $a = 7.2x10^{-5}$	B = 2.3
Oil $a = 9.0x10^{-4}$	B = 0.20

3.15 Heterogeneous Gas-Condensate Reservoirs [21].

Samaniego correlation for relative permeability for heterogeneous reservoirs

$$N_c = 5509.687LP * \left(\frac{v\ \mu}{3.6x10^5\sigma}\right) \tag{3.48}$$

$$k_{rg} = k_{rg}^0\left(\frac{S_g - S_{gr}}{1 - S_w - S_{gr}}\right)^{ng} \tag{3.49}$$

$$k_{rc} = k_{rc}^0\left(1 - \frac{S_g - S_{gr}}{1 - S_w - S_{gr}}\right)^{nc} \tag{3.50}$$

Where k^0_{rg} is the gas relative permeability at immobile condensate saturation, and the k^0_{rc} is the condensate relative permeability at residual gas saturation.

ng and *nc* are the exponent parameter for shape of relative permeability curves. ng[22] for gas drive gravity drainage reservoirs is 1 ± 20%.

Tight Gas Sands[23]

$$k_w[md] = 431\ (S_b/P_c)^{2.109} \quad (3.51)$$

$$k_{rg}[md] = 30.5\ (S_b/P_c)^{1.56}{}_{A,Hg} \quad (3.52)$$

Where S_b is percent bulk saturation of mercury and P_c is in psi.

Water and Gas System

For water as wetting phase

$$k_{rw} = \left(\frac{S_w - S_{wi}}{1 - S_{wi}}\right)^{\left(\frac{2+3\lambda}{\lambda}\right)} \quad (3.53)$$

For Water as non-wetting phase

$$k_{rw} = \left(1 - \left\{\frac{S_w - S_{wi}}{1 - S_{wi}}\right\}\right)^2 \left(1 - \left\{\frac{S_w - S_{wi}}{1 - S_{wi}}\right\}\right)^{\left(\frac{2+\lambda}{\lambda}\right)} \quad (3.54)$$

3.16 Three Phase Relative Permeability Models

Gas reservoirs may have enough initial water saturation greater than the mobile water saturation to cause it flow along with the gas or oil and gas both. In presence of two phases water and oil smallest pores will be occupied by water phase due to its weight and wetting properties. In case of oil and gas the smallest pores will be occupied by oil phase since gas is highly non-wetting phase[20]. In presence of three phases the smallest pores will be occupied by water, intermediate by oil, and largest by the gas as indicated by Fig. 3.10 through 3.12.

There are many three phase relative permeability models reported in literature.

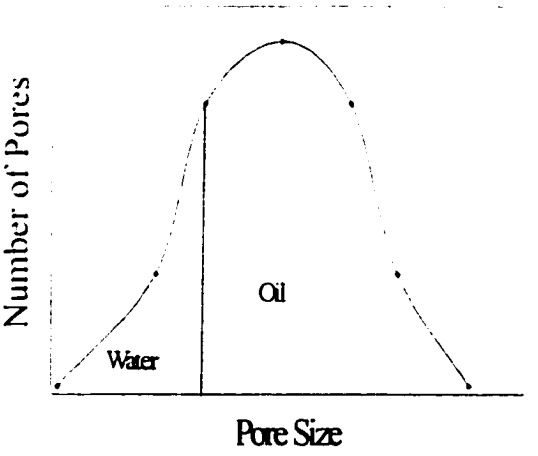


Fig.3.10 Pore occupancy in presence of two phases water and oil. Smallest pores are occupied by water due to its wetting properties.

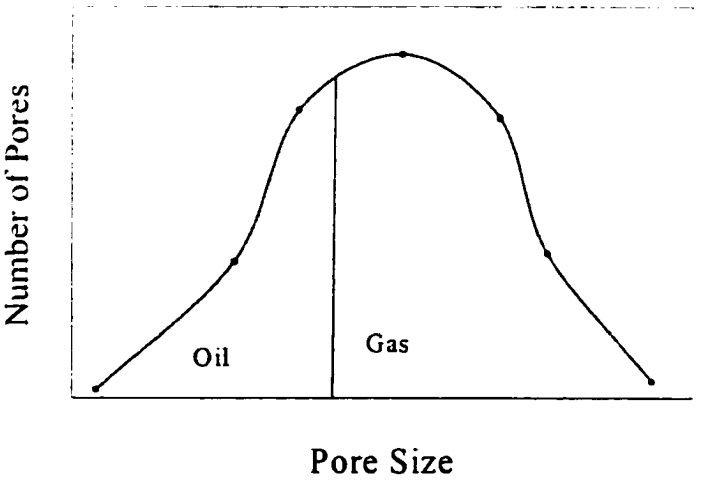


Fig.3.11 Pore occupancy in presence of two phases gas and oil Smallest pores are occupied by oil due to its wetting properties.

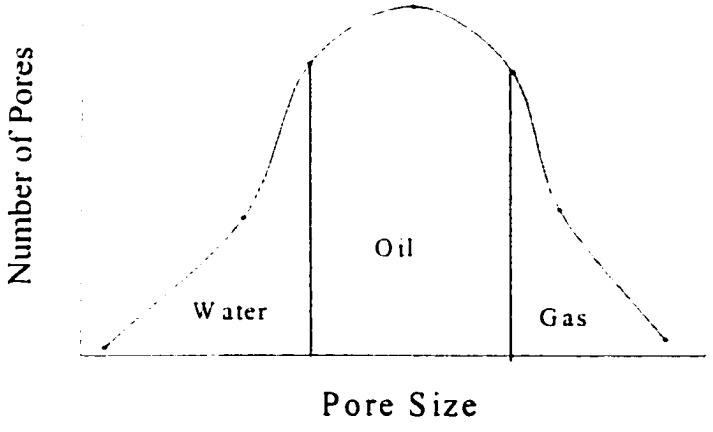


Fig.3.12 Pore occupancy in presence of three phases Water, oil and gas. Smallest pores are occupied by water, intermediate by oil, and largest by gas.

3.17 Stone's Models[19].

Stone proposed two empirical three-phase relative permeability models. His models assume:

1. Porous medium is water wet
2. Relative permeability is the function of its phase only.
3. Water and gas stop the flow of oil and the degree of blockage results in loss of relative permeability of the oil.

Stone-1 Model

$$k_{ro} = \frac{S_{oe} k_{ro(w)} k_{ro(g)}}{k_{ro(wi)} (1 - S_{we})(1 - S_{ge})} \tag{3.55}$$

Where

$$S_{oe} = \frac{S_o - S_{om}}{1 - S_{wi} - S_{om}} \tag{3.56}$$

$$S_{we} = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{om}} \tag{3.57}$$

$$S_{ge} = \frac{S_g}{1 - S_{wi} - S_{om}} \tag{3.58}$$

Terms

- $k_{ro(wi)}$ = Oil relative permeability measured at irreducible water saturation with no gas present.
- $K_{ro(w)}$ is computed at $S_o = 1\text{-}S_w$
- $K_{ro(g)}$ is estimated at $S_o = 1\text{-}S_g\text{-}S_{wi}$
- S_{om} is the three phase residual oil saturation.

$$S_{om} = \left(1 - \frac{S_g}{1 - S_{wi} - S_{org}}\right) S_{orw} + \left[1 - \left(1 - \frac{S_g}{1 - S_{wi} - S_{org}}\right) S_{org}\right] \tag{3.59}$$

Stone-II Model

This model assumes

1. Segregated flow
2. Does not require residual oil saturation to be defined

$$k_{ro} = \left(k_{ro(w)} + k_{ro(wi)} k_{rw(o)}\right)\left(k_{ro(g)} + k_{ro(wi)} kr_{g(o)}\right) - \left(k_{rw(o)} + k_{rg(wo)}\right) k_{ro(wi)} \tag{3.60}$$

Fayers and Methews studied seven three-phase experiments and showed that the Stone-1 model with S_{om} given by Eq.3.59 gives better results than Stone-2 model, Eq.3.60.

3.18 Saturated Weighted Interpolation

Baker at Amaco analyzed 3,000 samples and used saturation-weighted interpolation between two phase values to find the three phase oil relative permeability as follows

$$k_{ro} = \frac{(S_w - S_{wi})k_{ro(w)} + (S_g - S_{gr})k_{ro(g)}}{(S_w - S_{wi}) + (S_g - S_{gr})} \tag{3.61}$$

Terms

- S_{gr} = Residual gas saturation in oil water experiments (Normally set to zero)

$$k_{rw} = \frac{(S_o - S_{oi})k_{rw(o)} + (S_g - S_{gr})k_{rw(g)}}{(S_o - S_{oi}) + (S_g - S_{gr})} \tag{3.62}$$

$$k_{rg} = \frac{(S_w - S_{wi})k_{rg(w)} + (S_g - S_{gr})k_{rg(o)}}{(S_w - S_{wi}) + (S_o - S_{oi})} \tag{3.63}$$

Baker, Amoco[36], Delshad and Pope through their extensive literature review have indicated that the saturation weighted relative permeability model gives superior results than the Stone models.

Blunt Model

Blunt model of three-phase relative permeability uses saturation weighted relative permeability model as the base model. Blunt model requires six measurements on the cores.

$$k_{rg} = \alpha \left[\frac{\left\{ \begin{array}{l} (S_w - S_{wi})\left[a_g k_{ro(w)}(S_{gf}) + b_g k_{rg(w)}(S_{gf})\right] + \\ (S_o - S_{oi})\left[a_g k_{ob(w)}(S_{gf}) + b_g k_{rg(o)}(S_{gf})\right] \end{array} \right\}}{(S_w - S_{wi}) + (S_o - S_{oi}) + \beta} \right. \\ \left. \frac{Sg}{S_o + S_g}\left[a_g k_{ro(w)}(S_{hf}) + b_g k_{rg(w)}(S_{hf})\right] \right] \tag{3.64}$$

$$k_{ro} = \alpha \left[\frac{\begin{Bmatrix} (S_w - S_{wi})\left[a_o k_{ro(w)}(S_{ofb}) + b_o k_{rg(w)}(S_{ofb})\right] + \\ (S_o - S_{oi})\left[a_o k_{ob}(S_{ofb}) + b_o k_{rg(o)}(S_{ofb})\right] \end{Bmatrix}}{(S_w - S_{wi}) + (S_g - S_{gr}) + \alpha k_{ol}(S_{ol}) + \beta \frac{S_o}{S_o + S_g}\left[a_o k_{ro(w)}(S_{hf}) + b_o k_{rg(w)}(S_{hf})\right]} \right] \tag{3.65}$$

$$k_{rw} = \alpha \left[\frac{\begin{Bmatrix} a_o (S_o - S_{oi}) + a_g (S_g - S_{gr}) \end{Bmatrix} k_{rw(o)}(S_{wf}) + b_o (S_o - S_{oi}) + b_g (S_g - S_{gr}) k_{rw(g)}(S_{wf})}{(S_g - S_{gr}) + (S_o - S_{oi})} \right] \tag{3.66}$$

The degree of oil-ness, a_o and a_g are determined using following equation.

$$a_i = \max\left\{\min\left(\frac{\rho_i - \rho_{g0}}{\Delta\rho_0}, 1\right), 0\right\} \tag{3.67}$$

Degree of gas-ness

$$b_i = \max\left\{\min\left(\frac{\rho_{o0} - \rho_i}{\Delta\rho_0}, 1\right), 0\right\} \tag{3.68}$$

The hydrocarbon and water relative permeabilities are:

$$k^c_{ri(w)} = a_i k_{ro(w)} + b_i k_{rg(w)} \tag{3.69}$$

$$k^c_{rw(i)} = a_i k_{rw(o)} + b_i k_{rw(g)} \tag{3.70}$$

$$k^c_{ri(j)} = a_i k_{ro(g)} + b_i k_{rg(o)} \tag{3.71}$$

$$\alpha = \max\left\{\min\left(\frac{\gamma_{go}}{\gamma_{go}^{crit}}, 1\right), 0\right\} \tag{3.72}$$

$$\beta = \max\left\{\min\left(\frac{\gamma_{go}^{crit} - \gamma_{go}}{\gamma_{go}^{crit}}, 1\right), 0\right\} \tag{3.73}$$

3.19 Non-Darcy Flow Effects

3.19.1. Non-Darcy Flow Equations

Darcy's law has long been used as a fundamental equation to describe fluid motion through porous media

$$-\frac{dP}{dL}=\left(\frac{\mu}{k}\right)u \tag{3.74}$$

In Eq.3.74 u represents superficial velocity of the fluid, k is the permeability, μ is fluid viscosity, P is pressure, and L is the distance. Darcy's law represents a linear, empirical relationship between the pressure gradient and flow velocity. Darcy's law is valid only in the domain of low velocities and at high velocities, a common occurrence in gas reservoirs, it deviates.

Forchheimer[47] first proposed a nonlinear equation to describe additional pressure drop observed at high flow velocities by adding the term of velocity squared to the Darcy's equation.

$$-\frac{dP}{dL}=\left(\frac{\mu}{k}\right)u+\beta\rho u^{2} \tag{3.75}$$

Where β and ρ are the non-Darcy flow coefficient and fluid density respectively. β Coefficient is a fundamental rock property, which can be measured directly by special core analysis. However it is common practice to estimate it from correlations available in literature.

In the Forchheimer[47] equation, the first term on the right-hand side given by Darcy's law represents the flow governed by viscous forces, whereas the second term introduced by Forchheimer denotes the flow governed by inertial forces. At low velocities the inertial term ($\beta\rho u^{2}$) is

small and can be neglected. The Forchheimer equation, Eq.3.75, is then reduced to the Darcy's equation, Eq.3.74. At high velocities deviation from Darcy's law becomes significant and inertial effects need to be considered.

Non-Darcy flow effects are more pronounced in gas wells than oil wells because of higher flow velocities of gas resulting from the lower viscosity of the gas and higher bottomhole pressure drop in gas wells. For high-capacity gas wells, pressure drop near the wellbore needs to be estimated from the Forchheimer's equation. The non-Darcy flow coefficient in the Forchheimer's equation can be measured from core samples in laboratories, or determined from analysis of multi-rate pressure or deliverability tests in the field.

Various studies indicate that the deviation from Darcy's law is attributed to inertial forces arising from the laminar flow of fluids through curvilinear flow paths.

3.19.2 Correlations of Non-Darcy Flow Coefficient

Several researchers proposed various empirical correlations for the inertia resistance coefficient in Forchheimer's equation. Following are the correlations proposed by various researchers.

Tek, et al[29] correlation

$$\beta\left[cm^{-1}\right] = \frac{3.21 * 10^{4}}{k[darcy]^{1.25} * \phi^{0.75}} \tag{3.76}$$

Geertsma[30] Correlation

$$\beta\left[cm^{-1}\right] = \frac{50}{k[darcy]^{0.5} * \phi^{5.5}} \tag{3.77}$$

Ergun[31] Correlation

$$\beta\left[cm^{-1}\right] = \frac{1.43 * 10^{3}}{k[darcy]^{0.5} * \phi^{1.5}} \tag{3.78}$$

Blick and Civan[32] Model

$$\beta\left[cm^{-1}\right] = \frac{K_D}{8\sqrt{2} * k[darcy]^{0.5} * \phi^{1.5}} \tag{3.79}$$

Where $K_D = 80/R_e$ for R_e less than 100 and $K_D = 2.3$ for R_e greater than 4,000

Evans and Civan[33] Correlation

$$\beta = \frac{1.485 * 10^{9}}{\phi * k^{1.021}} \tag{3.80}$$

First, Forchheimer equation is a special equation, which is only valid for certain flow conditions. In fact, the exponent in Forchheimer equation may deviate from 2 significantly, as shown by Phipps and Khalil and then by Kadi. Second, most researchers relied upon the straight-line plots of the integral form of Forchheimer equation over core length by treating β as a constant value dependent solely on the porous media properties. Evans, et al[34] showed that it was a rock-fluid property. Third, in addition, the β values determined by straight-line plots of Forchheimer equation integrated over the core length must implicitly include the effect of the core length, as stated by Firoozabadi, et al.

3.19.3 Effect of Liquids on the Non-Darcy Flow Coefficient

Gewers and Nichol investigated the effect of immobile liquid on the non-Darcy flow coefficient, and found that β showed a substantial increase at liquid saturation of 20 to 30%. Wong[35] extended the work of

Gewers and Nichol to include the effect of mobile liquid on the non-Darcy flow coefficient, he found that:

- An increase in mobile liquid saturation from 40 to 70% could lead to an increase in the β coefficient by as much as eight folds.
- The non-Darcy flow coefficient could be approximated by using the effective permeability to gas at a given saturation and dry core non-Darcy flow coefficient-permeability relationship for the rock under consideration.

Evans et al[34] have also investigated the effect of two-phase fluids on the β coefficient . They confirmed the Wong's finding that the β coefficient in the presence of a liquid phase can be estimated using dry core non-Darcy flow coefficient with the replacement of absolute permeability by effective permeability at given saturation. However, in the correlation they developed, porosity ϕ is replaced by $\phi(1\text{-}S_l)$. They also found that the immobile liquid saturation should not be included in the general correlation of the non-Darcy flow coefficient as long as the effective permeability of the gas in the presence of immobile liquid is used. They proposed the following relationship.

$$\beta = \frac{7.147 * 10^{8}}{\phi k_g^{0.98}} \tag{3.81}$$

To account for the effect of liquid saturation on the non-Darcy flow coefficient, Geertsma[30] proposed the following expression

$$\beta = \frac{0.005}{\phi^{5.5}\sqrt{k}}\left(\frac{1}{(1-S_l)^{5.5}\sqrt{k_{rg}}}\right) \tag{3.82}$$

3.19.4 Non-Darcy Flow Effect

The usual assumption in conventional calculations is that the non-Darcy flow effect can be represented as a rate-dependent pseudoskin defined as

$$S_{nD} = Dq \tag{3.83}$$

Where D is a constant known as the non-Darcy flow coefficient defined by

$$D = \frac{c\beta\rho\ k}{h\,\mu\,r_w} \tag{3.84}$$

Where c is a constant. The true skin factor, S, reflecting formation damage or stimulation near the wellbore cannot be determined from a single drawdown or buildup test. Rather, the apparent or total skin factor, $S' = S + Dq_g$ is obtained. If S and D are to be determined separately, then at least two tests should be run at different rates. The two equations can then be solved simultaneously for the two unknowns, S and D. If only one test is run, so one can use Eqs.3.83 and 3.84. to determine the non-Darcy flow coefficient D and calculate the rate-dependent pseudoskin from Eq.3.84. If we apply Eq.3.82 for gas condensate fluid, with the basis that non-Darcy effect concerns the gas phase only, we get

$$-\frac{dp}{dr} = \frac{\mu_o}{k_o} v_o + \frac{\mu_g}{k_g} v_g + \beta\rho_g v_g^{\,2} \tag{3.85}$$

$$v_o = \frac{q_o}{\rho_o 2\pi r h} \tag{3.86}$$

$$v_g = \frac{q_o}{\rho_g 2\pi r h} \tag{3.87}$$

$$-\frac{dp}{dr} = \frac{\mu_o}{k_o}\frac{q_o}{\rho_o 2\pi r h} + \frac{\mu_g}{k_g}\frac{q_g}{\rho_g 2\pi r h} + \beta\rho_g\left(\frac{q_g}{\rho_g 2\pi r h}\right)^2 \tag{3.88}$$

$$\lambda_o = \frac{k_o}{\mu_o} \tag{3.89}$$

$$\lambda_g = \frac{k_g}{\mu_g} \tag{3.90}$$

Integrating Eq.3.88 from r_w to r_e.

$$p_e - p_w = \frac{q_o}{\lambda_o \rho_o 2\pi h}\int_{r_w}^{r_e}\frac{dr}{r} + \frac{q_g}{\lambda_g \rho_g 2\pi h}\int_{r_w}^{r_e}\frac{dr}{r} + \frac{\beta q_g^2}{\rho_g 4\pi^2 h^2}\int_{r_w}^{r_{nD}}\frac{dr}{r^2} \tag{3.91}$$

The last term on the right hand side is integrated from r_w to r_{nD} (Non-Darcy flow radius) because this is the region affected by turbulence effect. Eq.3.91 then becomes,

$$p_e - p_w = \frac{q_o}{\lambda_o \rho_o 2\pi h}\ln\frac{r_e}{r_w} + \frac{q_g}{\lambda_g \rho_g 2\pi h}\ln\frac{r_e}{r_w} + \frac{\beta q_g^2}{\rho_g 4\pi^2 h^2}\left[\frac{1}{r_w} - \frac{1}{r_{nD}}\right] \tag{3.92}$$

Eq.3.92 can further be simplified as

$$p_e - p_w = \frac{q_o}{\lambda_o \rho_o 2\pi h}\ln\frac{r_e}{r_w} + \frac{q_g}{\lambda_g \rho_g 2\pi h}\ln\frac{r_e}{r_w} + \frac{\beta q_g^2}{\rho_g 4\pi^2 h^2 r_w} \tag{3.93}$$

By analogy with Darcy's equation we can see that the last term of the right hand side of Eq.3.93 represents the extra pressure drop due to non-Darcy flow effect. Eq.3.20 can be written as

$$p_e - p_w = \frac{q_o}{\lambda_o \rho_o 2\pi h}\ln\frac{r_e}{r_w} + \frac{q_g}{\lambda_g \rho_g 2\pi h}\left[\ln\frac{r_e}{r_w} + \frac{\lambda_g \beta q_g}{2\pi\ h\ r_w}\right] \tag{3.94}$$

The non-Darcy flow coefficient is then be expressed as

$$D = \frac{\lambda_g \beta}{2\pi h r_w} = \frac{k_g \beta}{\mu_g 2\pi h r_w} \tag{3.95}$$

Where, in oilfield units, D is given by

$$D = \frac{5.25e-6 * k_g * \beta}{2\pi * h * \mu_{gi} * r_w} \tag{3.96}$$

The inertial coefficient, β (ft^{-1}), is measured on cores in the laboratory or may be predicted by:

$$\beta = \frac{48.205}{k_g^{0.5} * \phi_{eff}^{5.5}} \tag{3.97}$$

$$\phi_{eff} = \phi * (1 - S_{cond.}) \tag{3.98}$$

Where $S_{cond.}$ is the condensate saturation.

3.20 Pseudopressure Function

When the flowing bottomhole pressure in a gas condensate reservoir drops below the dewpoint pressure, significant decrease in productivity can be expected. This reduction is attributable to a decrease in the gas relative permeability caused by the accumulation of condensate and its immobility as a pressure gradient is formed in the reservoir. In pressure transient analysis this apparent permeability reduction has been described by a pseudoskin factor. The value of the pseudoskin factor depends on the size of the two-phase liquid-gas zone.

The steady-state inflow is affected by the compositional behavior of the fluids, and relative permeability phenomena play an important role.

3.20.1 Single-Phase Pseudopressure

As defined by Al-Hussainy et al. the conventional definition for pseudopressure is given as

$$p_p(p) = \int_{p_b}^{p} \frac{\rho_g}{\mu_g} dp \tag{3.99}$$

Eq.5.1 applies for dry gas only and ignores the existence of the liquid phase. To incorporate the influence of multiphase flow, the pseudopressure must account not only for variations in fluid properties with pressure but also for the influence of the saturation gradients. The single-phase pseudopressure takes the advantage of the unique characteristic of the condensate system that the condensate is immobile over substantial portions of the reservoir. Thus, if the

variation in the relative permeability for the gas phase is negligibly small over the region where liquid is immobile, then single phase pseudopressure should be used.

3.20.2 Two-Phase Pseudopressure

To incorporate both, variation in the fluid properties and the influence of saturation gradients, the pseudopressure (Referred as two-phase pseudopressure) is defined as

$$p_p(p) = \int_{p_b}^{p} \left(\rho_o \frac{k_{ro}}{\mu_o} + \rho_g \frac{k_{rg}}{\mu_g} \right) dp \qquad (3.100)$$

Where ρ is the molar density, μ is the viscosity and k_r is the relative permeability of the corresponding phase.

All the information pertaining to phase behavior, physical properties and relative permeability is implicit in the pseudopressure function, which allow two-phase flow to be treated by the same methods applicable to single phase flow. The concept of two-phase pseudopressure allows the results from single-phase liquid flow to be used directly in the two-phase case. One of the limitations of the steady-state two-phase pseudopressure for condensate wells is that it does not allow for a region of immobile liquid at or below the critical liquid saturation (Modeled by region-2) and may have a tendency to overestimate the liquid dropout effect.

The model based on pseudopressure function is only as accurate as the data used in its computation. The most important item of the data for characterizing a gas condensate fluid is the liquid dropout curve – a plot of liquid saturation versus pressure, which can be measured in PVT laboratory. The dew-point pressure and the maximum liquid saturation are the key elements in characterizing the condensate system.

In order to examine the inflow behavior of a two-phase compositional system it is useful to consider a typical gas condensate reservoir and construct the pseudopressure function. The pseudopressure construction requires knowledge of:

- Relative permeability curves.
- Gas and oil density curves.
- Gas and oil viscosity curves.
- Liquid dropout curve.

Proper understanding of condensate inflow behavior is limited by the accuracy of the liquid dropout, density, viscosity and particularly relative permeability measurements which are not reliable enough to analyze the rapid changes in the pressure that occur over a very short period of time. This is the main difficulty with the pseudopressure approach.

3.21 Pseudopressure Function Behavior

In the simulation work done by Raghavan *et al.*[37] the plot of single-phase and two-phase pseudopressure derivative versus time shows that both curves are identical for the time corresponding to $p_{ws} \geq p_d$ and diverge when $p_{ws} < p_d$. The two-phase curve is essentially flat, regardless of the dew-point pressure, whereas the single-phase curve takes an upward tendency for pressure less than dew-point pressure.

The pressure buildup curve is a reflection of the pressure distribution if the well is shut in. The single-phase pseudopressure derivative curve reflects the variation in fluid properties and in the saturation (relative permeability) with distance from the well. The large values of this curve for small values of shut in time (Small distance from the wellbore) reflect the low-permeability region where liquid is present.

The two-phase pseudopressure derivative curve incorporates both the effects of fluid properties and relative permeability with distance. This curve

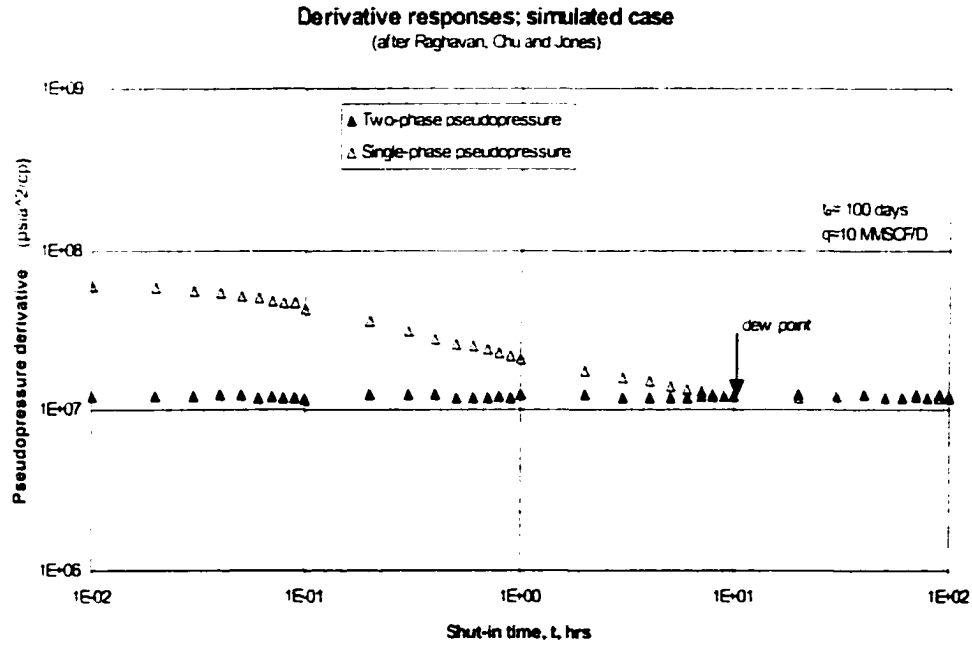


Fig.3.13 Pseudopressure Derivative Behavior[37].

is essentially flat. Both curves intersect at a point corresponding to the dew-point pressure and merge beyond this point, because $k_{ro} = 0$ and $k_{rg} \cong 1$; under these circumstances, the integrands of Eqs.3.99 and 3.100 are identical.

3.22 Skin Factor In Multiphase Systems

The total skin factor, in a gas condensate well, may contain contributions from:

- Mechanical skin associated with wellbore formation damage.
- Non-Darcy skin due to high flow conditions.
- Liquid dropout skin due to two-phase flow conditions, once pressure goes bellow the dew point pressure.

The total apparent skin factor S_{tot} is a complicated contribution of mechanical damage, two-phase flow, and the turbulence effects.

The interaction of non-Darcy flow and the liquid dropout is still not understood. Mathematically the total apparent skin factor for condensate well test interpretation may be given as

$$S_{tot} = S_{dam} + S_{nD} + S_{liq} \tag{3.101}$$

S_{dam} is a combined skin from perforations and formation damage due to mud filtrate invasion. S_{liq} is the liquid dropout skin factor due to the presence of condensate in the reservoir. S_{nD} is the non-Darcy skin factor due to the turbulence effect near the wellbore.

The total skin factor must be reduced to its constituents; this process should allow, if necessary, appropriate treatment for the well to improve its productivity. The pressure transient test analysis with the single-phase pseudopressure determines the total apparent skin factor,s_{1pp}, including near wellbore damage, liquid dropout, and non-Darcy flow effects.

The analysis with the two-phase steady-state pseudopressure gives a value of total skin factor,S_{2pp}, which includes near wellbore damage and non-Darcy flow effects. The liquid dropout effect is obtainable from the difference between both total skin values.

$$S_{liq} = S_{1pp} - S_{2pp} \tag{3.102}$$

It is notable here that the skin factor estimated by the two-phase pseudopressure will be a lower bound for the mechanical skin factor, because this pseudopressure does not allow for a transition zone and then has a tendency to overestimate the liquid dropout effect. Eq.3.102 represents an upper bound for the estimate of the skin factor caused by two-phase flow.

Chapter IV

Modeling Effective Permeability, Two-Phase and Three-Phase Pseudopressure Function For Gas Condensate Systems

Gas condensate fluids undergo two kinds of changes in their physical properties. 1) With depletion: physical properties change with pressure. 2) Phase change: The gas and the liquid phase may go under phase change due to retrograde condensation. To handle both phenomena in two phase and three phase systems mathematically can be very challenging, especially near critical conditions. Fig. 4.4 shows the idealized liquid development as the dew point pressure is reached.

4.1 Two Phase Systems

Two-phase systems include either condensate and gas systems or water and gas systems. To model such systems following cases are considered.

1) Gas-Water System
2) Gas-Oil System

4.1.1 Producing Gas Oil Ratio (R_{pgo2p})

As the pressure drops below the dew point, producing gas oil ratio GOR, increases monotonically[50], i.e., a one-to-one relationship exists between the producing gas oil ratio and the pressure as shown in Fig.4.1. It dives as the P* approaches and liquid becomes mobile. However, it stabilizes as effective liquid permeability stabilizes.

By Definition (in absence of water phase)

$$R_p = \frac{q_{gT}}{q_{oT}} = \frac{q_{g.free} + q_{o.free} R_S}{q_{o.free} + q_{g.free} R_o} \qquad (4.1)$$

$$R_P = \frac{q_{gT}}{q_{OT}} = \frac{C\left[\left(\frac{k_{rg}}{B_g \mu_g}\right) - \left(\frac{k_{ro}}{B_o \mu_o}\right) R_S\right]}{C\left[\left(\frac{k_{ro}}{B_o \mu_o}\right) - \left(\frac{k_{rg}}{B_g \mu_g}\right) R_O\right]} \tag{4.2}$$

For vertical wells

$$C = \frac{0.00708.h.}{\left[\ln \frac{r_e}{r_w} - 0.75 + S\right]} \tag{4.3}$$

For horizontal wells

$$C = \frac{0.00708.b}{\left[\ln \frac{A^{1/2}}{r_w} + \ln C_H - 0.75 + S_R\right]} \tag{4.4}$$

On simplification

$$R_P = R_s + \left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{B_o \mu_o}{B_g \mu_g}\right)\left(1 - R_O\ R_P\right) \tag{4.5}$$

$$R_P(P) = \left[\frac{R_s + \left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{B_o \mu_o}{B_g \mu_g}\right)}{1 + R_O \left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{B_o \mu_o}{B_g \mu_g}\right)}\right](P) \tag{4.6}$$

Solving for k_{rg}/k_{ro} results,

$$\left(\frac{k_{rg}}{k_{ro}}\right) = \frac{(R_P - R_s)}{\left(1 - R_O\ R_P\right)}\left(\frac{B_g \mu_g}{B_o \mu_o}\right) \tag{4.7}$$

Solving for R_p, results

$$R_p(P) = \frac{1 - C\left((1 - R_S R_O)\frac{k.k_{ro}}{B_o.\mu_o q'o}\right)}{R_O} \tag{4.8}$$

Solving for gas and oil effective permeability, yields

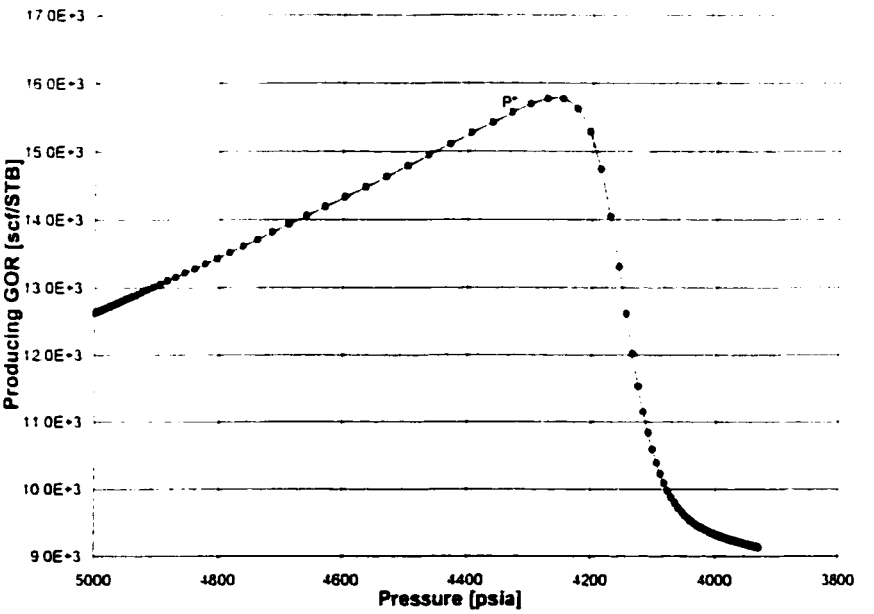


Fig. 4.1. Producing gas oil ratio as a function of pressure (Eq. 4.6) and effect of P* on it.

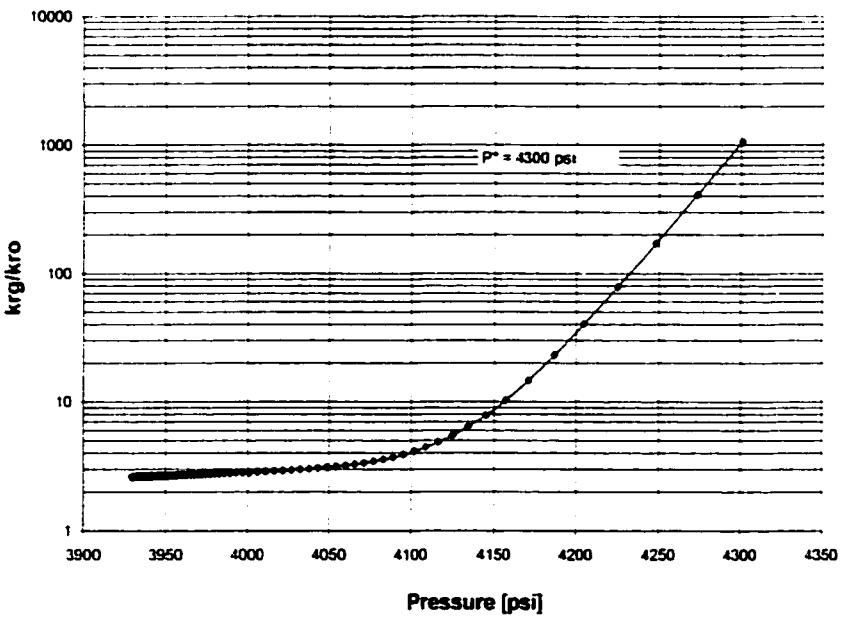


Fig. 4.2. Ratio of gas relative permeability to oil relative permeability as a function of pressure (Eq.4.6).

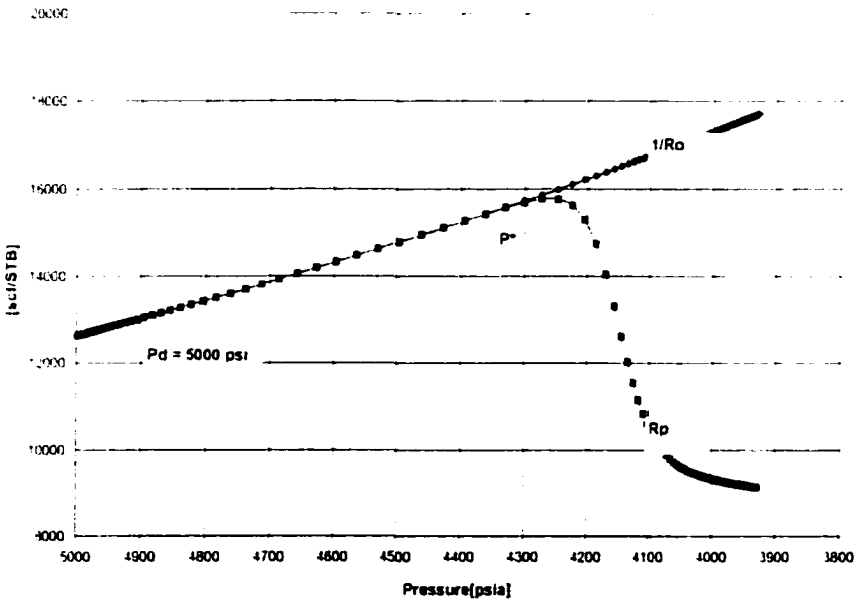


Fig. 4.3 Determination of P*, pressure at which liquid is mobile, from pressure test data in a multiphase system.

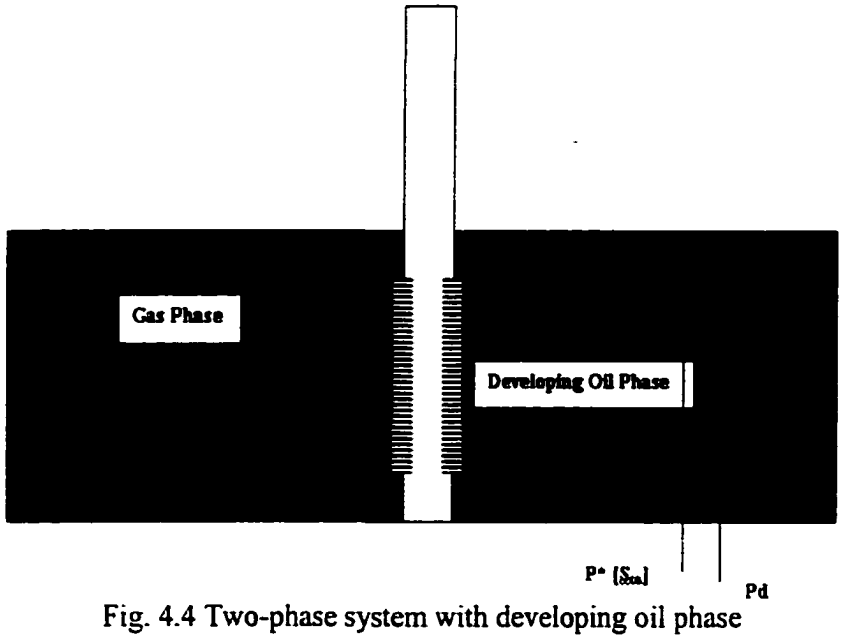


Fig. 4.4 Two-phase system with developing oil phase

$$k_g = kk_{rg} = \frac{(R_p - R_s)}{(1 - R_o R_p)}\left(\frac{\mu_g B_g \{kk_{ro}\}}{\mu_o B_o}\right) \tag{4.9}$$

$$k_o = kk_{ro} = \frac{(1 - R_o R_p)}{(R_p - R_s)}\left(\frac{\mu_o B_o \{kk_{rg}\}}{\mu_g B_g}\right) \tag{4.10}$$

4.1.2 Producing Oil-Water Ratio (R_{pow2p})

To get insight in the production phenomenon, let us derive the water oil ratio and see how it behaves and what kind of information can be derived from it.

$$R_{Pow} = \frac{q_o}{q_w} = \frac{q_{g,free} R_o + q_{O,free}}{q_w} \tag{4.11}$$

$$R_{Pow} = \frac{q_o}{q_w} = \frac{C\left[\left(\frac{k.k_{rg}}{B_g \mu_g}\right) R_o + \left(\frac{k.k_{ro}}{B_o \mu_o}\right)\right]}{C\left[\left(\frac{k.k_{rw}}{B_w \mu_w}\right)\right]} \tag{4.12}$$

Substituting the oil effective permeability from Eq. 4.11 and simplifynig, results

$$R_{Pow} = \frac{q_o}{q_w} = \left(\frac{k.k_{rg}}{k.k_{rw}}\right)\left(\frac{B_w \mu_w}{B_g \mu_g}\right)\left(\frac{1 - R_o R_p}{R_p - R_s} + R_o\right) \tag{4.13}$$

Solving for water and gas effective permeability respectively.

$$k.k_{rw} = \left(\frac{1 - R_o R_p}{R_p - R_s} + R_o\right)\left(\frac{B_w \mu_w}{B_g \mu_g}\right)\left(\frac{k.k_{rg}}{R_{Pow}}\right) \tag{4.14}$$

$$k.k_{rg} = R_{Pow}\left(\frac{B_g \mu_g}{B_w \mu_w}\right)(k.k_{rw})\frac{1}{\left(\frac{1 - R_o R_p}{R_p - R_s} + R_o\right)} \tag{4.15}$$

It is important to note that even the producing oil-water ratio can be derived from the free gas production and the water production data. The base fluid in gas condensate wells is the gas phase. Oil production may be hard to

measure downhole. Therefore every parameter is expressed in terms of gas properties and water properties.

4.1.3 Producing Gas-Water Ratio (R_{pgw2p}) (Oil Phase Absent)

Similarly

$$R_{Pgw} = \frac{q_g}{q_w} = \frac{q_{g,free} + q_w R_{sgw}}{q_w} \tag{4.16}$$

Where R_{sgw} is the solution gas-water ratio expressed as SCF /STB.

$$R_{Pgw} = \frac{q_{gT}}{q_w} = \frac{C\left[\left(\frac{k.k_{rg}}{B_g \mu_g}\right) + \left(\frac{k.k_{rw}}{B_w \mu_w}\right) R_{sgw}\right]}{C\left[\left(\frac{k.k_{rw}}{B_w \mu_w}\right)\right]} \tag{4.17}$$

$$R_{Pgw} = \frac{q_{gT}}{q_w} = \left(\frac{k.k_{rg}}{k.k_{rw}}\right)\left(\frac{B_w \mu_w}{B_g \mu_g}\right) + R_{sgw} \tag{4.18}$$

Solving for water and gas effective permeability respectively.

$$k.k_{rw} = \frac{k.k_{rg}}{(R_{Pgw} - R_{sgw})}\left(\frac{B_w \mu_w}{B_g \mu_g}\right) \tag{4.19}$$

$$k.k_{rg} = (R_{Pgw} - R_{sgw})(k.k_{rw})\left(\frac{B_g \mu_g}{B_w \mu_w}\right) \tag{4.20}$$

Above equations indicate that only one phase effective permeability is required to know all other phase effective permeabilities provided their production is known.

4.2 Three Phase Systems

Three phase systems comprise of all the gas, water, and oil phase under flowing conditions. Fig. 4.5 shows the conceptual model of developing oil phase in three-phase systems. Such systems are better understood by modeling phase-to-phase interactions.

1) Gas-Water phase
2) Gas-Oil Phase
3) Oil-Water Phase

4.2.1 Producing Gas Oil Ratio in Three-Phase Systems (R_{pgo3p}) in Region-1

By Definition

$$R_P = \frac{q_{gT}}{q_{OT}} = \frac{q_{g,free} + q_{o,free}R_s + q_w R_{sgw}}{q_{o,free} + q_{g,free}R_s} \tag{4.21}$$

$$R_{Pgo} = \frac{q_{gT}}{q_{OT}} = \frac{C\left[\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{B_o\mu_o}\right)R_s + \left(\frac{k.k_{rw}}{B_w\mu_w}\right)R_{sgw}\right]}{C\left[\left(\frac{k.k_{ro}}{B_o\mu_o}\right) + \left(\frac{k.k_{rg}}{B_g\mu_g}\right)R_o\right]} \tag{4.22}$$

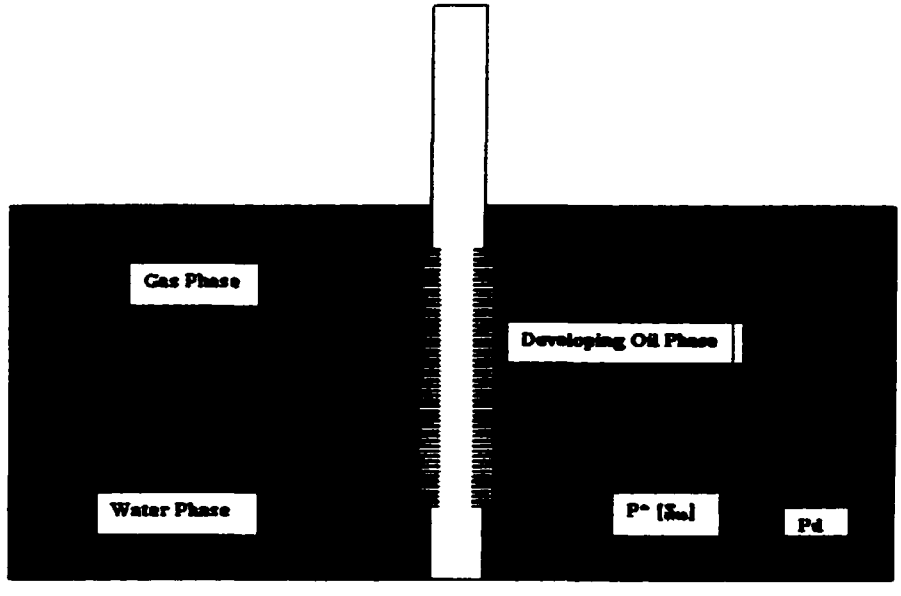


Fig. 4.5. The conceptual model of three-phase system with developing oil phase.

On simplification

$$R_{Pgo} = \frac{q_{gT}}{q_{OT}} = \frac{\left[\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{B_o\mu_o}\right)R_s + \left(\frac{k.k_{rw}}{B_w\mu_w}\right)R_{sgw}\right]}{\left[\left(\frac{k.k_{ro}}{B_o\mu_o}\right) + \left(\frac{k.k_{rg}}{B_g\mu_g}\right)R_o\right]} \tag{4.23}$$

Simplifynig and solving for individual phase effective permeabilities, yields

$$k_g = kk_{rg} = \left(\frac{\mu_g B_g}{\mu_o B_o}\right)\frac{kk_{ro}}{\left(R_s R_{Pgo} - 1\right)}\left[\left(R_{so} - R_{Pgo}\right) + R_{sgw}\left(\frac{k.k_{rw}}{\mu_o B_o}\right)\right] \tag{4.24}$$

$$k_o = kk_{ro} = \left[\frac{\left(R_s R_{Pgo} - 1\right)}{\left[\left(R_{so} - R_{Pgo}\right) + R_{sgw}\left(\frac{k.k_{rw}}{\mu_w B_w}\right)\right]}\right]\left(\frac{\mu_o B_o}{\mu_g B_g}\right)\left[kk_{rg}\right] \tag{4.25}$$

$$kk_{rw} = \left[\left(\frac{\mu_o B_o}{\mu_g B_g}\right)\left(\frac{kk_{rg}}{kk_{ro}}\right)\left(R_s R_{Pgo} - 1\right) - \left(R_{so} - R_{Pgo}\right)\right]\left(\frac{\mu_w B_w}{R_{sgw}}\right) \tag{4.26}$$

4.2.1a Producing Oil-Water Ratio (R_{pow3p}) in Region-1

Assuming that the oil and water phase are completely immiscible,

$$R_{Pow} = \frac{q_o}{q_w} = \frac{q_{g.free} R_s + q_{o.free}}{q_w} \tag{4.27}$$

$$R_{Pow} = \frac{q_o}{q_w} = C\left[\left(\frac{k.k_{rg}}{B_g \mu_g}\right) R_s + \left(\frac{k.k_{ro}}{B_o \mu_o}\right)\right]\frac{1}{C\left[\left(\frac{k.k_{rw}}{B_w \mu_w}\right)\right]} \tag{4.28}$$

On simplifying, results

$$R_{Pow} = \frac{q_o}{q_w} = \left(\frac{k.k_{rg}}{k.k_{rw}}\right)\left(\frac{B_w \mu_w}{B_g \mu_g}\right) R_s + \left(\frac{k.k_{ro}}{k.k_{rw}}\right)\left(\frac{B_w \mu_w}{B_o \mu_o}\right) \tag{4.29}$$

Solving for water and gas effective permeability respectively.

$$k.k_{rw} = \left(\frac{B_w \mu_w}{R_{Pow}}\right)\left[\left(\frac{k.k_{rg}}{B_g \mu_g}\right) R_s + \left(\frac{k.k_{ro}}{B_o \mu_o}\right)\right] \tag{4.30}$$

$$k.k_{rg} = \left[\left(\frac{R_{Pow}}{B_w \mu_w}\right)\left(k.k_{rw}\right) - \left(\frac{k.k_{ro}}{B_o \mu_o}\right)\right]\left(\frac{B_g \mu_g}{R_s}\right) \tag{4.31}$$

$$k.k_{ro} = \left[\left(\frac{R_{Pow}}{B_w \mu_w}\right)\left(k.k_{rw}\right) - \left(\frac{k.k_{rg}}{B_g \mu_g}\right) R_s\right]\left(B_o \mu_o\right) \tag{4.32}$$

4.2.2 Producing Gas-Water Ratio (R_{pgw3p}) in Region-1

Similarly

$$R_{Pgw} = \frac{q_g}{q_w} = \frac{q_{g,free} - q_o R_s - q_w R_{sgw}}{q_w} \tag{4.33}$$

Where R_{sgw} is the solution gas-water ratio expressed as SCF /STB. For two phase systems $R_{sgw} = 0$.

$$R_{Pgw} = \frac{q_{gT}}{q_w} = \frac{C\left[\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{B_o\mu_o}\right)R_s + \left(\frac{k.k_{rw}}{B_w\mu_w}\right)R_{sgw}\right]}{C\left[\left(\frac{k.k_{rw}}{B_w\mu_w}\right)\right]} \tag{4.34}$$

Simplifying

$$R_{Pgw} = \frac{q_{gT}}{q_w} = \left(\frac{k.k_{rg}}{k.k_{rw}}\right)\left(\frac{B_w\mu_w}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{k.k_{rw}}\right)\left(\frac{B_w\mu_w}{B_o\mu_o}\right)R_s + R_{sgw} \tag{4.35}$$

Solving for water and gas effective permeability respectively.

$$k.k_{rw} = \frac{B_w\mu_w}{(R_{Pgw} - R_{sgw})}\left(\frac{k.k_{rg}}{B_g\mu_g} + \frac{k.k_{ro}}{B_o\mu_o}R_s\right) \tag{4.36}$$

$$k.k_{rg} = \left[(R_{Pgw} - R_{sgw})\left(\frac{k.k_{rw}}{B_w\mu_w}\right) - \left(\frac{k.k_{ro}}{B_o\mu_o}R_s\right)\right](B_g\mu_g) \tag{4.37}$$

$$k.k_{ro} = \left[(R_{Pgw} - R_{sgw})\left(\frac{k.k_{rw}}{B_w\mu_w}\right) - \left(\frac{k.k_{rg}}{B_g\mu_g}\right)\right]\left(\frac{B_o\mu_o}{R_s}\right) \tag{4.38}$$

4.2.3 Producing Gas-Water Ratio (R_{pgw3p}) in Region-2 and Region-3

$$R_{Pgw} = \frac{q_g}{q_w} = \frac{q_{g,free} + q_w R_{sgw}}{q_w} \tag{4.38a}$$

Where R_{sgw} is the solution gas-water ratio expressed as SCF /STB. For two phase systems $R_{sgw} = 0$.

$$R_{Pgw} = \frac{q_{gT}}{q_w} = \frac{C\left[\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + +\left(\frac{k.k_{rw}}{B_w\mu_w}\right)R_{sgw}\right]}{C\left[\left(\frac{k.k_{rw}}{B_w\mu_w}\right)\right]} \tag{4.38b}$$

Simplifying

$$R_{P_{pw}} = \frac{q_{gf}}{q_w} = \frac{k.k_{rg}}{k.k_{rw}}\left(\frac{B_w\mu_w}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{k.k_{rw}}\right)\left(\frac{B_w\mu_w}{B_o\mu_o}\right)R_s + R_{vpw} \quad (4.38c)$$

Solving for water and gas effective permeability respectively.

$$k.k_{rw} = \frac{B_w\mu_w}{(R_{P_{pw}} - R_{vpw})}\left(\frac{k.k_{rg}}{B_g\mu_g}\right) \quad (4.38d)$$

$$k.k_{rg} = \left[(R_{P_{pw}} - R_{vpw})\left(\frac{k.k_{rw}}{B_w\mu_w}\right)\right](B_g\mu_g) \quad (4.38e)$$

4.3 Modeling Relative and Effective Permeability as a Function of Pressure

4.3.1Vertical Wells

4.3.1.1 Pressure Drawdown tests

The effective oil and gas permeability during pressure transient period can be expressed as follows, respectively:

$$k_o = kk_{ro} = -\frac{70.6q_{o.free}\mu_o B_o}{h\left(\frac{\partial P_{wf}}{\partial \ln(t)}\right)} \quad (4.39)$$

$$k_g = kk_{rg} - \frac{70.6q_{g.free}}{h\left(\frac{\partial mP_{wf}}{\partial \ln(t)}\right)_{SP}} \quad (4.40)$$

$$k_w = kk_{rw} = -\frac{70.6q_{w.free}\mu_w B_w}{h\left(\frac{\partial P_{wf}}{\partial \ln(t)}\right)} \quad (4.41)$$

Above equations are valid for a fully developed semi-log straight line. Fig. 4.6, 4.8, 4.9, and 4.10 show the behavior of efective permeability as a function of pressure and time respectively during a pressure transient test. Fig. 4.11 and 4.12 are the effect of different well operating conditions on the effective permeability. It is clear from Fig.4.11 that effective permeability of not affected by the well operation. Several algorithms are available in

literature for estimationg the log derivative of the pressure recorded during a pressure test. It is clear from above equations that during the well developed semi-log period when the presssure transience has overcome wellbore storage and skin effects, the pressure is function of Boltzman variable. Thus For $t_D/r_D^2 \geq 50$ pressure is function of Boltzman variable $z = r^2/t$. Fig. 4.7 shows the pressure and pressure derivative behavior during a well test. The well developed radial (horizonatl) section on the derivative curve is used to estimate the ffective permeabity.

4.3.1.2 Pressure Buildup

The phase effective permeabilities in multi-phase environment are expressed as follows:

$$k_o = kk_{ro} = -\frac{70.6 q_o \mu_o B_o}{h\left(\frac{\partial P_{ws}}{\partial \ln\left(\frac{t+\Delta t}{\Delta t}\right)}\right)} \tag{4.42}$$

Similarly

$$k_g = kk_{rg} = -\frac{70.6 q_{g,free}}{h\left(\frac{\partial m P_{ws}}{\partial \ln\left(\frac{t+\Delta t}{\Delta t}\right)}\right)_{SP}} \tag{4.43}$$

$$k_w = kk_{rw} = -\frac{70.6 q_w \mu_w B_w}{h\left(\frac{\partial P_{ws}}{\partial \ln\left(\frac{t+\Delta t}{\Delta t}\right)}\right)} \tag{4.44}$$

To be more accuarte following equation can be used.

$$k_g = kk_{rg} = -\frac{70.6 q_{g,free}}{h\left(\frac{dm P_{ws}}{d \ln\left(\frac{(t+\Delta t)\mu_g c_t}{\Delta t \mu_{gi} c_{ti}}\right)}\right)_{SP}} \tag{4.45}$$

Several gas well tests were simulated in order to establish relationship between pressure and effective permeability for gas wells.

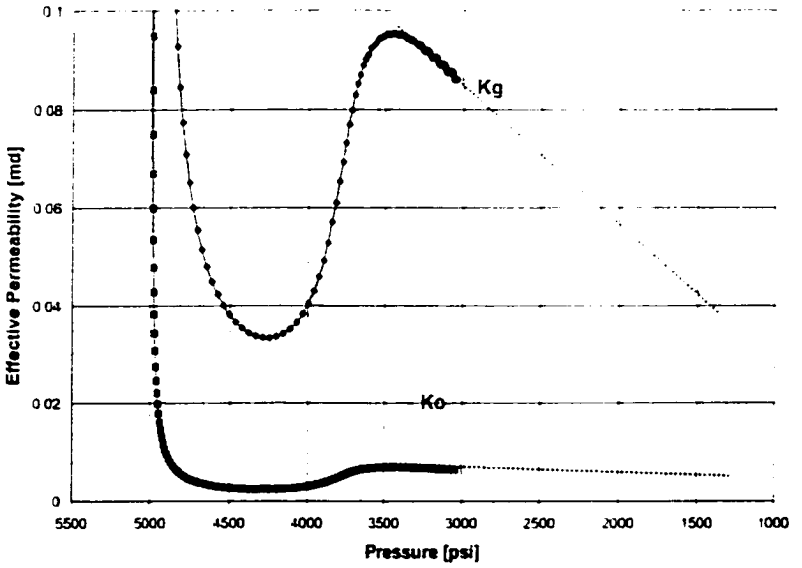


Fig. 4.6. Effective permeability from pressure test data in a multiphase system. [Eq. 4.39 and 4.40] (Vertical well).

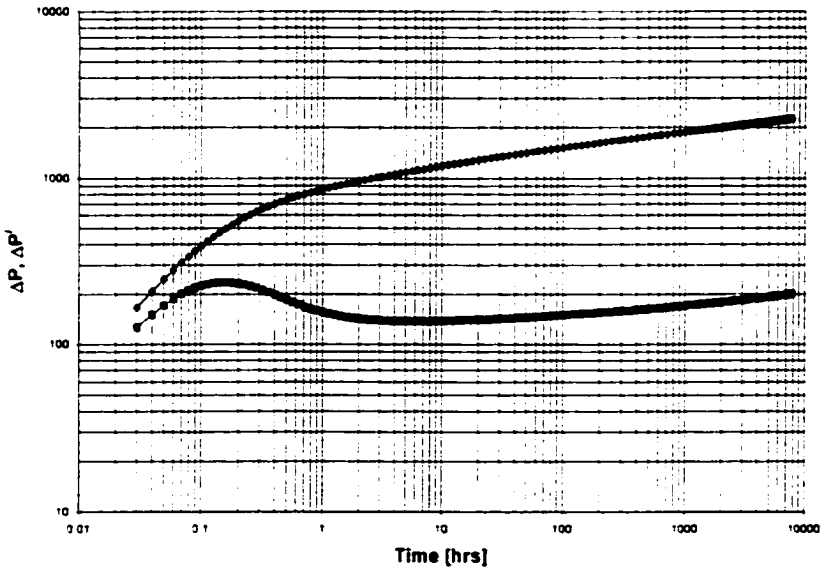


Fig.4.7. Infinite acting vertical well pressure and pressure derivative response. The radial flow, straight-line portion, is used to calculate effective permeability as function of pressure.

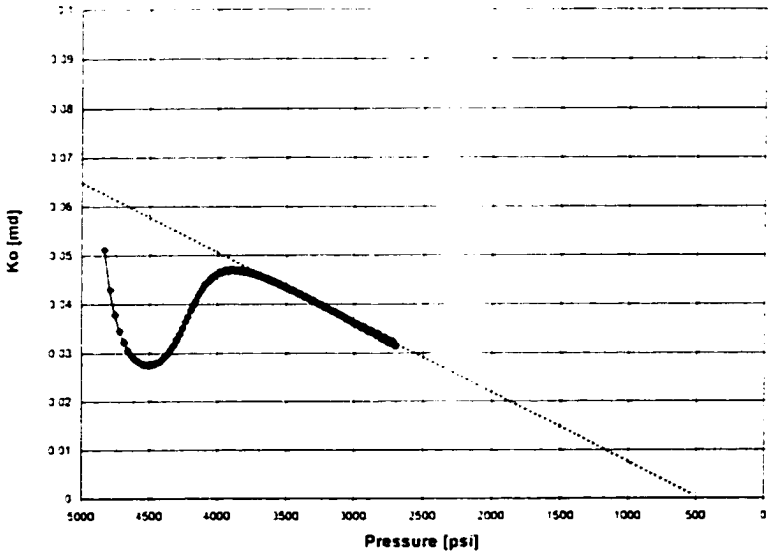


Fig.4.8. Oil Effective permeability as a function of pressure (Vertical Well)

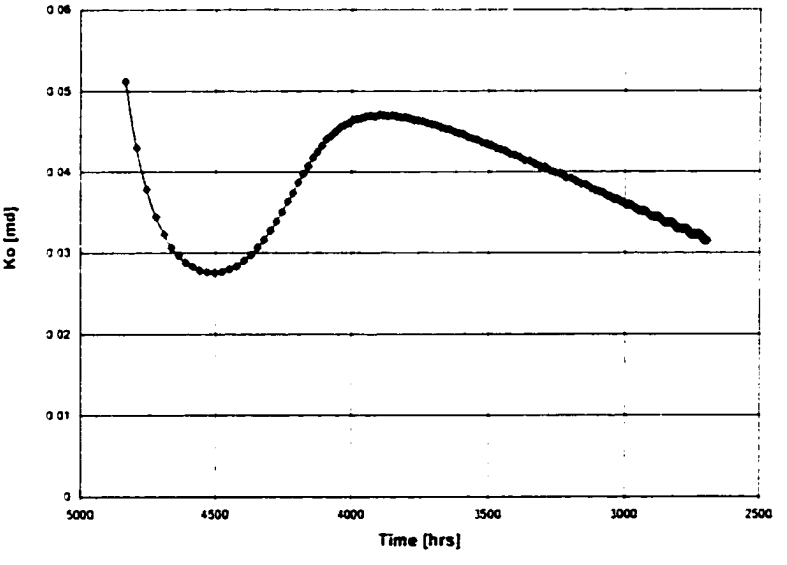


Fig.4.9. Oil effective permeability as a function of time (Vertical Well P* = 5000 psi)

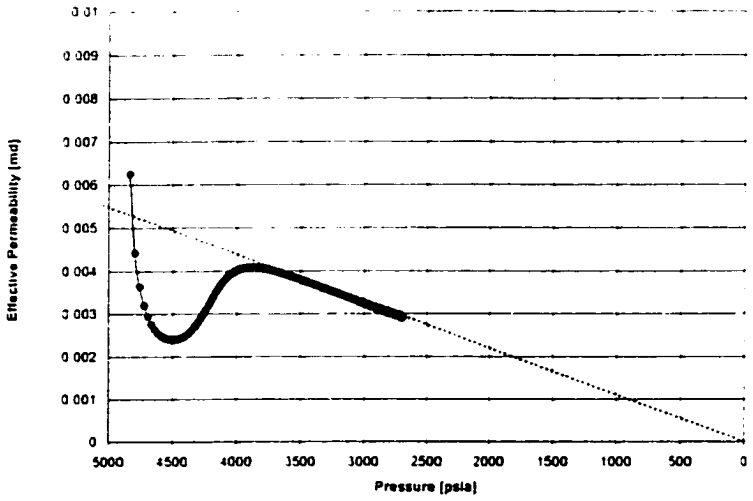


Fig. 4.10. Effective gas permeability as a function of pressure during a pressure test.

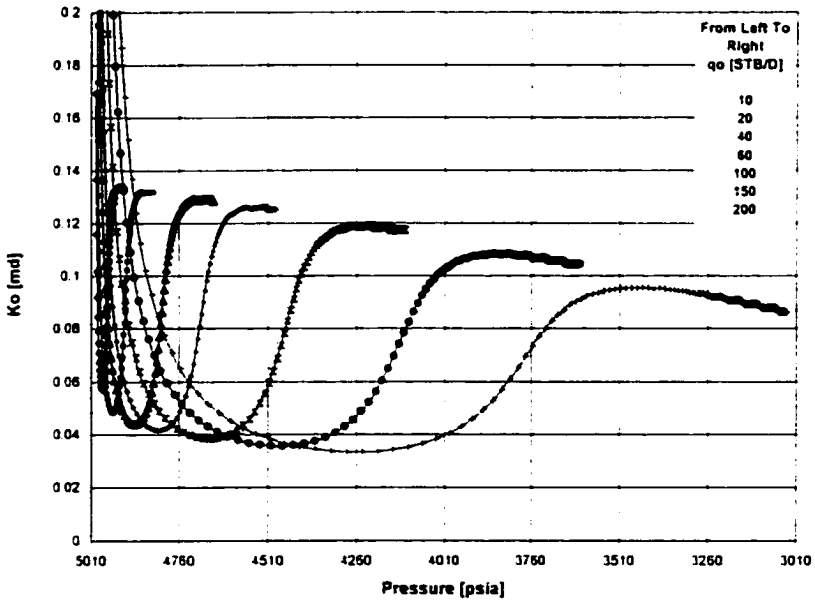


Fig. 4.11. Effect of condensate flow rate on effective oil permeability (P_d = 5000 psi)

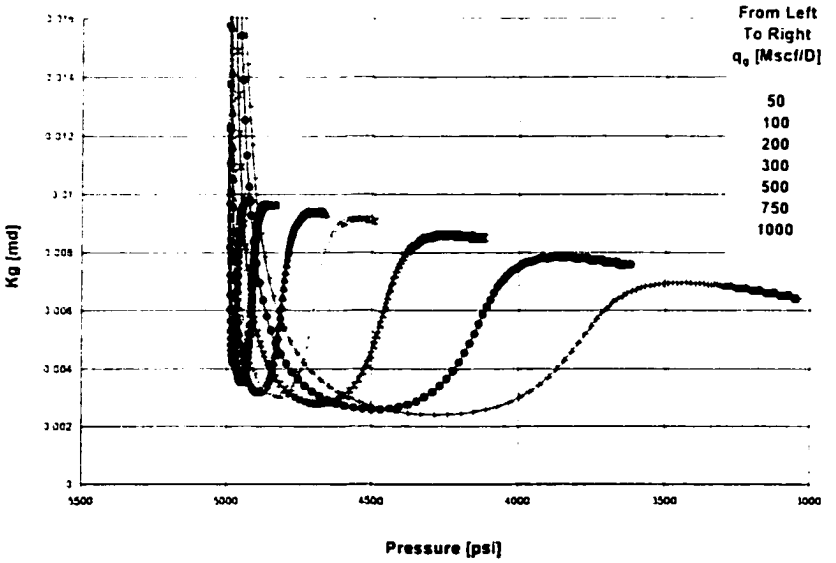


Fig. 4.12. Effect of gas flow rate on effective gas permeability (Pd = 5000 psi)

4.3.2 Horizontal Wells

The effective permeability from the well test conducted in a horizontal well can be obtained from the late radial flow regime because this is the only flow regime that represents the radial flow in the reservoir.

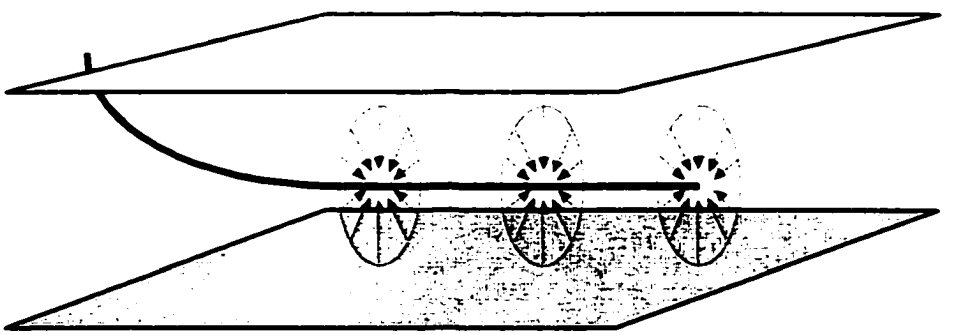


Fig.4.13-a. Early Radial Flow Towards Horizontal Well[39].

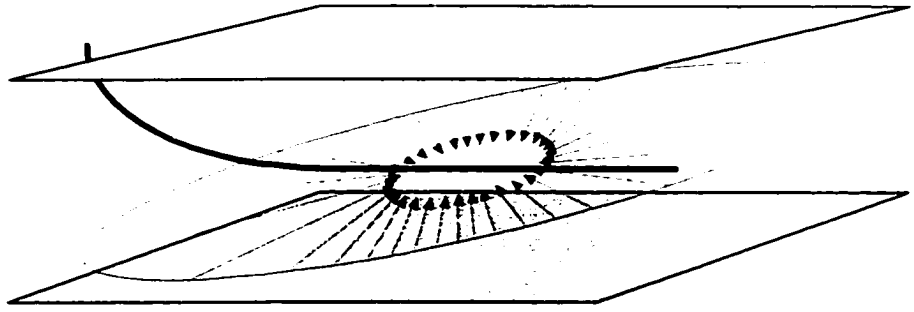


Fig.4.13-b. Late Radial Flow Towards Horizontal Well[39].

4.3.2.1 **Early Time Radial Flow Regime.**

Equation of this flow regime during a pressure drawdown test is[38];

$$P_i - P_{wf} = 162.6\frac{q\mu B}{L_w\sqrt{k_y k_z}}\left[\log\left(\frac{\sqrt{k_y k_z}\,t}{\phi\,\mu c_t r_w^2}\right) - 3.227 + 0.866 s_m\right] \qquad (4.46)$$

This flow regime is shown as the first staright line section in Fig. 4.14. According to Darcy law the flow rate of any phase towards the wellbore is the function of the preesure. But pressure is function of the distance from the wellore.

$$q_m = 1.127x10^{-3}\left[\frac{2\pi\, rLkk_{rm}}{\mu_m B_m}\right]\left(\frac{\partial P}{\partial r}\right)_w \qquad (4.47)$$

Where absolute permeability $k = \sqrt{k_H k_v}$ and K_H is the permeability in horizontal direction.

For $t_D/r_D^2 \geq 50$ pressure is function of Boltzman variable $z = r^2/t$. Thus one can write $r\frac{\partial P}{\partial r} = 2z\left(\frac{dP}{dz}\right) = -2t\frac{\partial P}{\partial t} - 2\frac{\partial P}{\partial \ln(t)}$ (4.48)

Substituting above equation in a Darcy law, one gets

$$q_m = -1.127x10^{-3}\left[\frac{2\pi\, Lkk_{rm}}{\mu_m B_m}\right]\left(2\frac{\partial P_{wf}}{\partial \ln(t)}\right) \qquad (4.49)$$

Solving for Effective permeability, results

$$kk_{rm} = -\frac{70.6 q_m \mu_m B_m}{L\left(\frac{\partial P_{wf}}{\partial \ln(t)}\right)} \tag{4.50}$$

For Oil phase

$$kk_{ro} = -\frac{70.6 q_{o,free} \mu_o B_o}{L\left(\frac{\partial P_{wf}}{\partial \ln(t)}\right)} \tag{4.51}$$

And for gas phase

$$kk_{rg} = -\frac{70.6 q_{g,free}}{L\left(\frac{\partial m P_{wf}}{\partial \ln(t)}\right)_{SP}} \tag{4.52}$$

$$\text{Also } k_g = kk_{rg} = \frac{(R_p - R_s)}{(1 - R_o R_p)}\left(\frac{\mu_g B_g \{kk_{ro}\}}{\mu_o B_o}\right) \tag{4.53}$$

Similarly for pressure buildup

$$kk_{ro} = -\frac{70.6 q_o \mu_o B_o}{L\left(\frac{\partial P_{ws}}{\partial \ln(\frac{t+\Delta t}{\Delta t})}\right)} \tag{4.54}$$

$$kk_{rg} = -\frac{70.6 q_{g,free}}{L\left(\frac{\partial m P_{ws}}{\partial \ln(\frac{t+\Delta t}{\Delta t})}\right)_{SP}} \tag{4.46}$$

Also

$$k_g = kk_{rg} = \left[\frac{R_P(\Delta t = 0) - R_S}{(1 - R_o R_p)}\right]\left(\frac{\mu_g B_g \{kk_{ro}\}}{\mu_o B_o}\right) \tag{4.55}$$

Above equations are valid for a fully developed radial regime that appears for $t_{D_y}/r_D^2 \geq 50$. Thus it is possible from a transient well pressure data to develop the relative permeability curves provided absolute formation permeability is known as a function of pressure or effective permeability as a function of pressure, incase absolute permeability is not known. Such curves like the absolute permeability obtained from the transient well test data in single-phase fluids is an average and the true representative curve of the entire reservoir that captures the fluid and formation properties. If the radial line is masked by the wellbore effects or the linear flow regime, it should be extrapolated.

4.3.2.2 Early Time Linear Flow Regime

This flow period is represented by[38];

$$P_i - P_{wf} = \frac{8.128qB}{L_w h_z}\sqrt{\frac{\mu t}{k_y \phi c_t}} + \frac{141.2q\mu B}{L_w\sqrt{k_y k_z}}(s_z + s_m) \tag{4.56}$$

Taking the derivative of pressure with respect to square root of time gives

$$\frac{d\Delta P}{d\sqrt{t}} = \frac{8.128qB}{L_w h_z}\sqrt{\frac{\mu}{k_{ey}\phi c_t}} \tag{4.57}$$

Solving for K_{ey}, the effective permeability in lateral direction, y, results

$$\sqrt{k_{ey}}(P) = \frac{8.128q_o B_o}{L_w h_z \dfrac{d\Delta P}{d\sqrt{t}}}\sqrt{\frac{\mu_o}{\phi c_t}} \tag{4.58}$$

For Gas phase

$$\sqrt{k_{ey}}(P) = \frac{8.128q_g}{\sqrt{\mu_g(P)}L_w h_z \dfrac{d\Delta mP_{SP}}{d\sqrt{t}}}\sqrt{\frac{1}{\phi c_t}} \tag{4.59}$$

4.3.2.3 Late Radial Flow Regime

This flow regime is represented by[38];

$$P_i - P_{wf} = \frac{162.6q\mu B_O}{h_z\sqrt{k_y k_x}}\left[\log\left(\frac{k_x t}{\phi\mu c_t L_w^2}\right) - 2.023\right] + \frac{141.2q\mu B}{L_w\sqrt{k_y k_z}}(s_z + s_m) \qquad (4.60)$$

Taking the time derivative of this equation, and then solving for effectve permeability, results

Oil Phase

$$k_{exy}(P) = \sqrt{k_y k_x} = \frac{70.6q\mu_O B_O}{h_z \dfrac{dP_{wf}}{d\ln(t)}} \qquad (4.61)$$

Gas Phase

$$k_{exy}(P) = k_{rg}\sqrt{k_y k_x} = \frac{70.6q_{g.free}}{h_z\left(\dfrac{dmP_{wf}}{d\ln(t)}\right)_{SP}} \qquad (4.62)$$

This flow regime is evident as the second straight line segment in Fig. 4.14.

4.3.2.4 **Late Time Linear Flow**

This flow period during a drawdown pressure test is represented by[38];

$$P_i - P_{wf} = \frac{8.128qB}{h_x h_z}\sqrt{\frac{\mu t}{k_y\phi c_t}} + \frac{141.2q\mu B}{L_w\sqrt{k_y k_z}}(s_x + s_z + s_m) \qquad (4.63)$$

Thus effective permeability in y-direction from this period is estimated as follows

Oil Phase

$$\sqrt{k_{ey}}(P) = \frac{8.128q_O B_O}{h_X h_z \dfrac{d\Delta P}{d\sqrt{t}}}\sqrt{\frac{\mu_O}{\phi c_t}} \qquad (4.64)$$

Gas Phase

$$\sqrt{k_{ey}}(P) = \frac{8.128q_g}{\sqrt{\mu_g(P)}\ h_Z h_X \dfrac{d\Delta mP_{SP}}{d\sqrt{t}}}\sqrt{\frac{1}{\phi c_t}} \qquad (4.65)$$

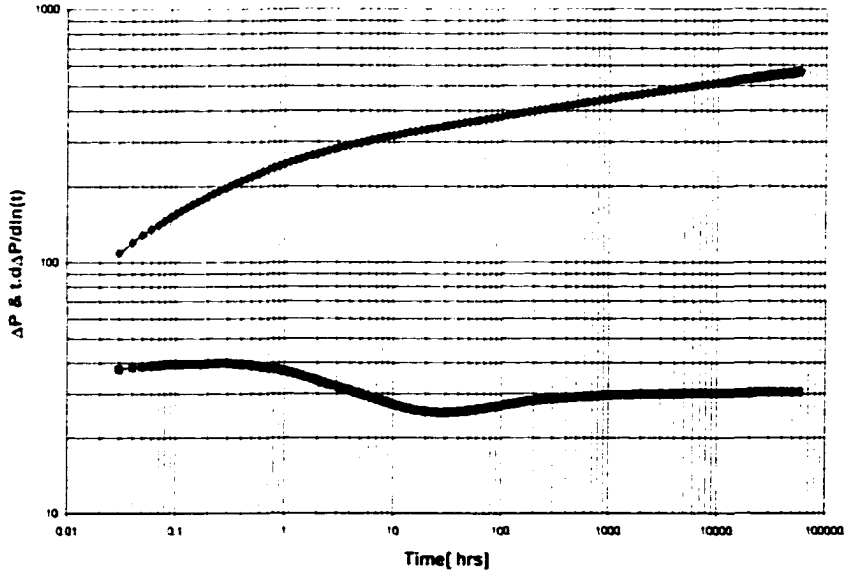


Fig.4.14. Simulated horizontal wellbore pressure response without wellbore storage and skin indicating early and late radial flow regimes. Late radial flow portion provides the effective permeability.

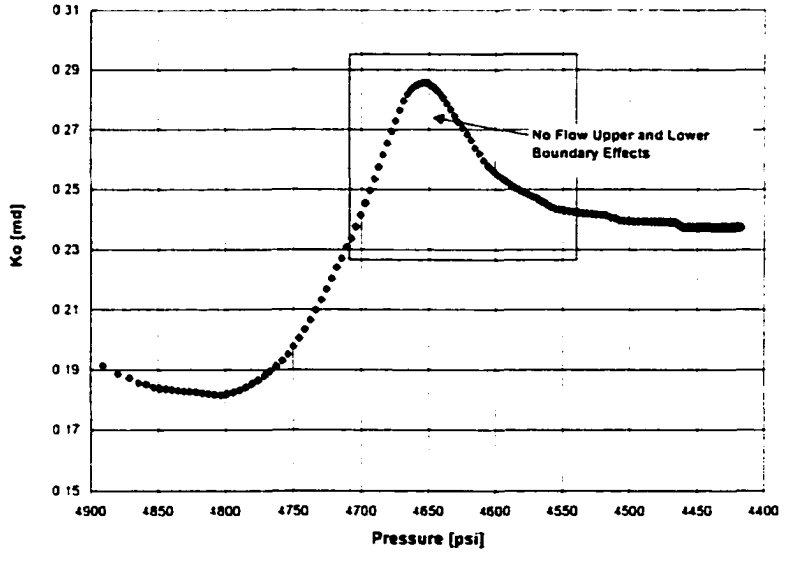


Fig. 4.15. Profile of effective permability to oil from horizontal well pressure data with upper and lower noflow boundary effects.

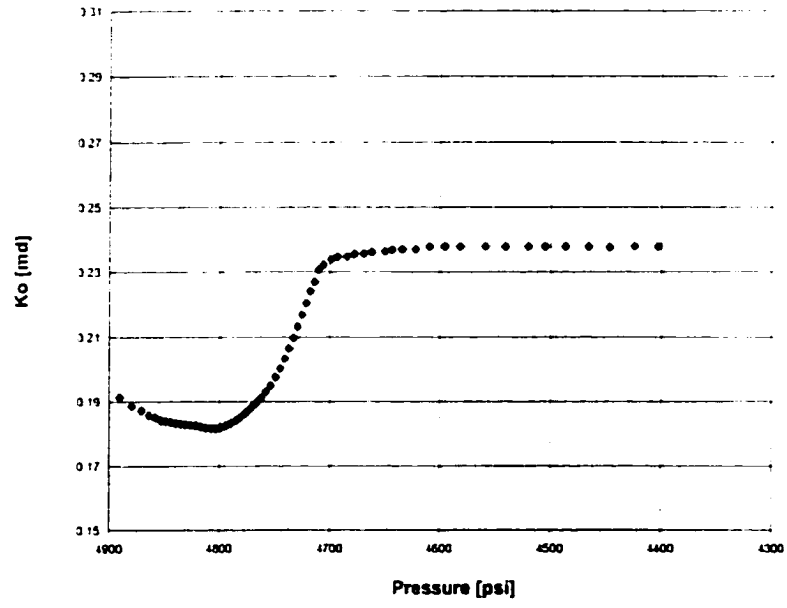


Fig. 4.16. Profile of effective permability to oil from horizontal well pressure data without upper and lower noflow boundary effects.

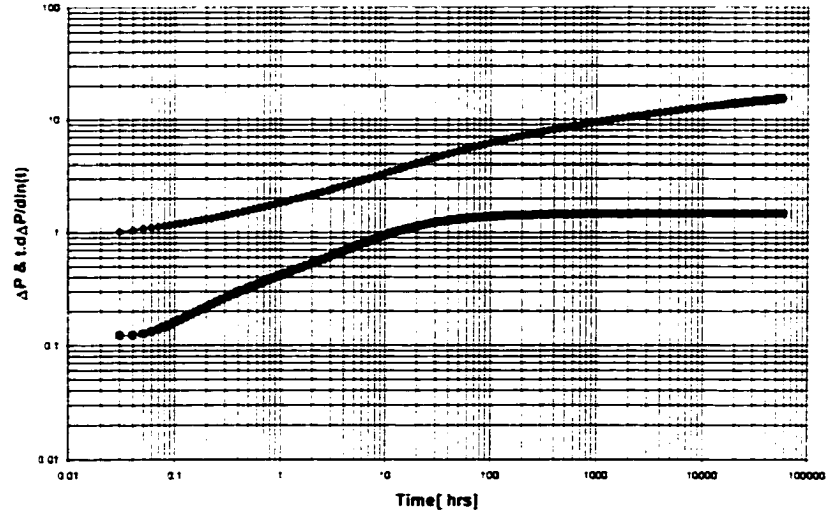


Fig. 4.17. An infinite acting in lateral direction horizontal well pressure response without wellbore storage and skin factor.(fully developed early linear and late radial flow regimes)

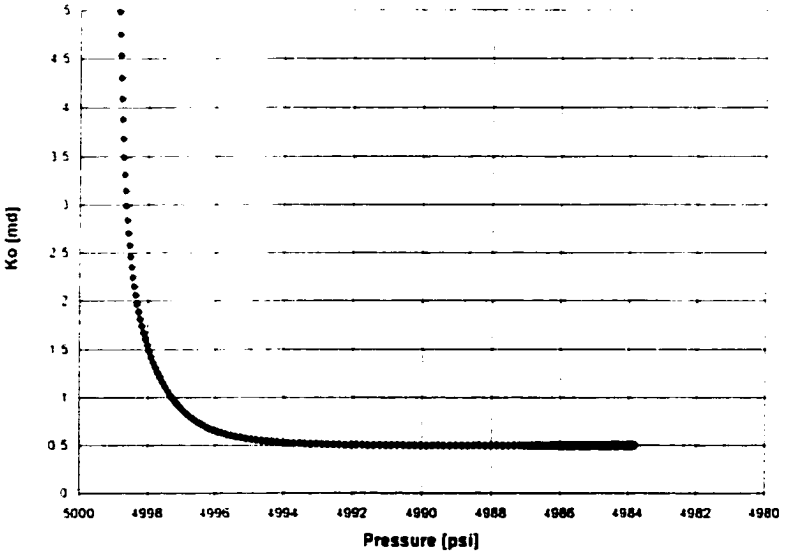


Fig. 4.18. Profile of effective permability to oil from horizontal well pressure data with upper and lower noflow boundary effects.

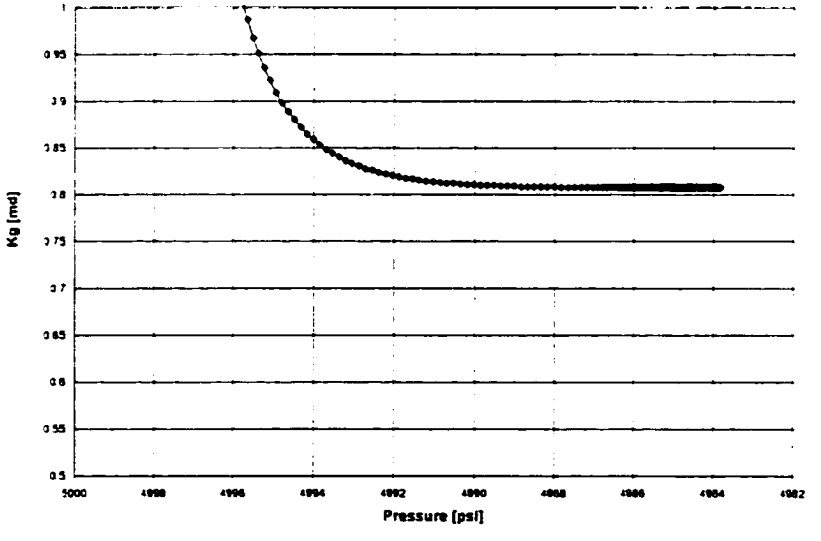


Fig.4.19. Effective permeability to gas profile from pressure test in horizontal wells (q_o = 100 STB/D).

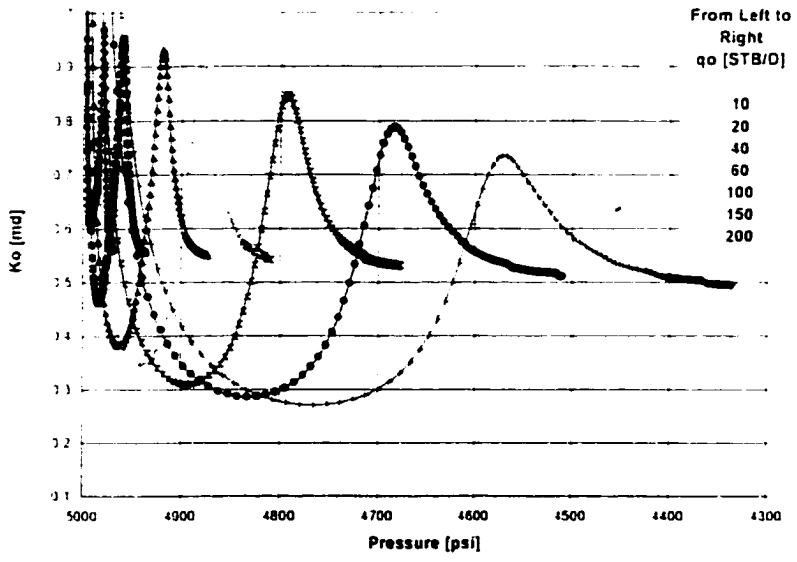


Fig.4.20. Effect of condensate flow rate on effective permeability to oil (Horizontal Well Pd = 5000 psi)

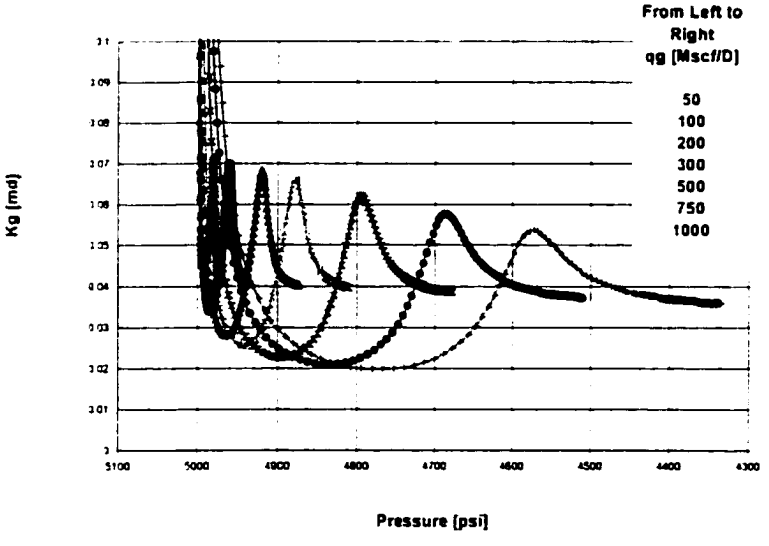
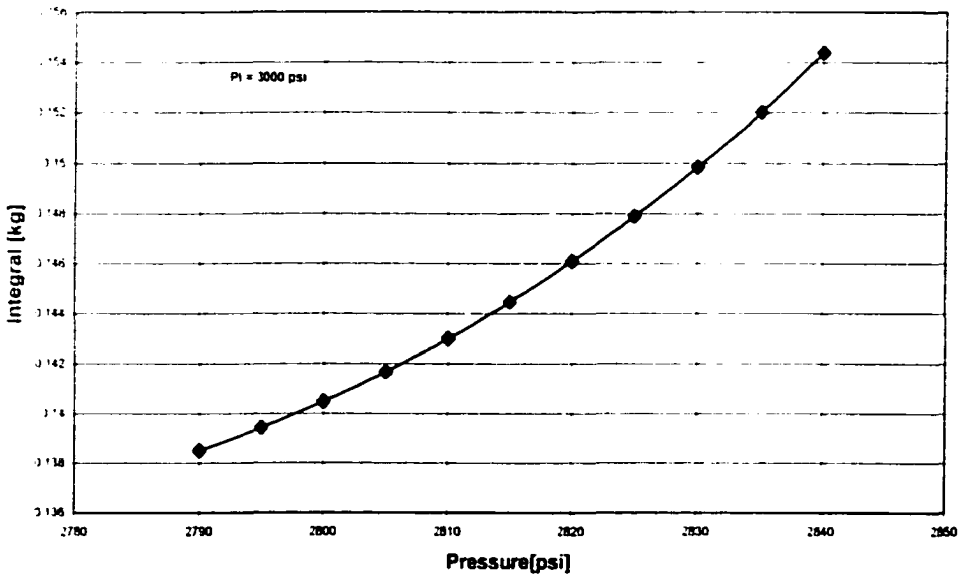


Fig.4.21 Effect of condensate flow rate on effective permeability to gas (Horizontal Well Pd = 5000 psi)



4.22 Effective gas permeability integral from late radial flow regime. (Reservoir pressure = 3000 psia)

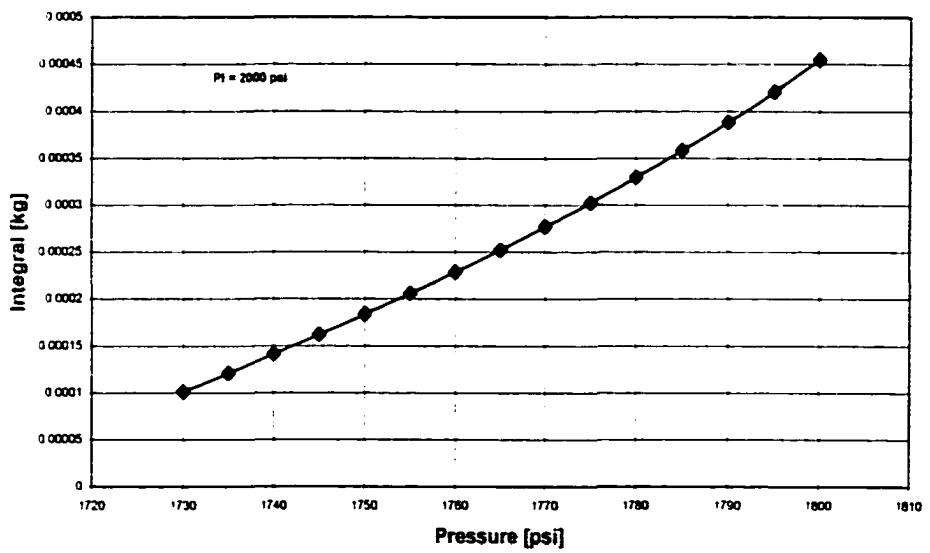


Fig. 4.23. Effective gas permeability integral from late radial flow regime. (Reservoir pressure = 2000 psia)

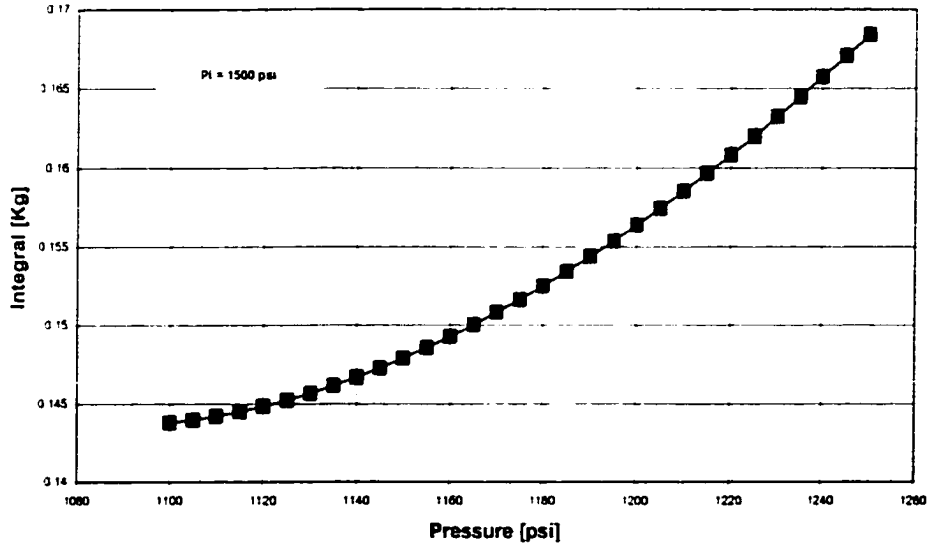


Fig. 4.24. Effective gas permeability integral from late radial flow regime. (Reservoir pressure = 1500 psia)

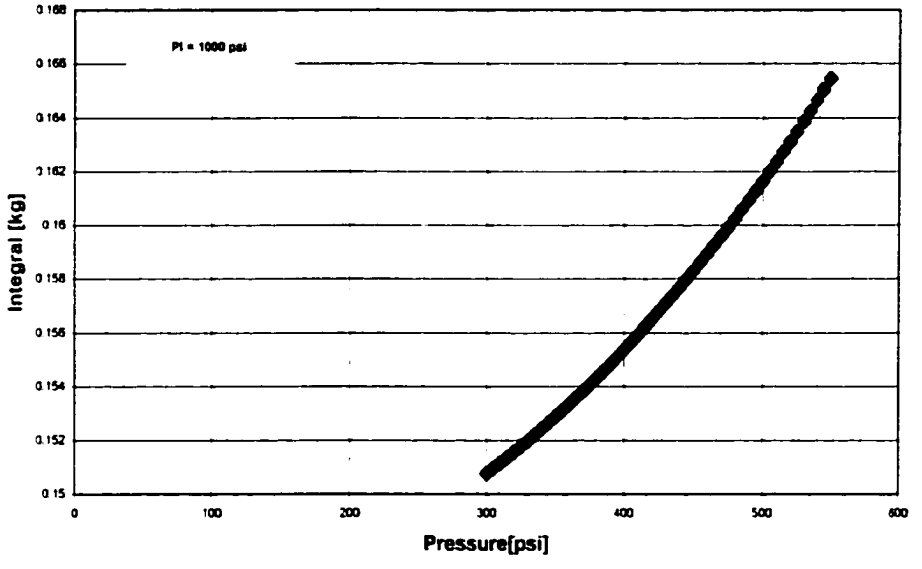


Fig. 4.25. Effective gas permeability integral from late radial flow regime. (Reservoir pressure = 1000 psia)

4.3.3 Estimation of Relative Permeabilities from Production Data (Pseudo-Steady State Method [25])

$$k_{rg} = \frac{q_{g.free}}{C\left[m\bar{P} - mP_{wf}\right]_{SP}} \tag{4.66}$$

Where

$$q_{g.free} = q_{g.meas} - q_{o.free} \cdot R_s \tag{4.67}$$

mP = Single phase gas pseudopressure function

For vertical wells

$$C = \frac{0.703kh}{\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S\right]} \tag{4.68}$$

For horizontal wells

$$C = \frac{0.00708.b\bar{K}}{\left[Ln\frac{A^{1/2}}{r_w} + LnC_H - 0.75 + S_R\right]} \tag{4.69}$$

Where k is absolute permeability and b is the horizontal well length.

In case of the single-phase gas flow (P>Pwf>Pd), a multiple point production test can provide a fair correlation between pressure and relative permeability of each phase.

4.3.3.1 Steady-State Method (Peneula and Civan Method [26])

For high flow rate conditions (High cappilary number) very common in gas condensate reservirs, thr oil relative permeability can be expressed as:

$$k_{ro} = \frac{\mu_o S_o}{\mu_o S_o + \mu_g S_g} \tag{4.70}$$

and the gas relative permeability, as

$$k_{rg} = \frac{\mu_g S_g}{\mu_o S_o + \mu_g S_g} \tag{4.71}$$

This method requires the knowledge of oil and gas saturations at any given moment in depletion within the reservoir. It is apperant from the above equations that the variation in gas saturation within the reservoir will result variation in the relative permeability of both the phases.

4.4 Modeling Two-Phase Pseudopressure Function for Gas-Condensate Fluids

The absolute permeability is usually determined from well test analysis. For multiphase flow conditions effective permeability is required. Thus from the theory of well testing during pressure transient period for $t_D > 50$, when the pressure wave has crossed the wellbore and skin effects (During a semi-log straight line period)

$$kk_{rg} = \frac{70.6 q_{g.free}}{h\left(\frac{\partial mP}{\partial \ln(t)}\right)_{SP}} \tag{4.72}$$

Eq. 4.72 is expressed in absolute value. mP can be replaced by flowing and shut-in conditions depending on the well test being Drawdown or Buildup. Horner time and adjusted time can also be used. Equations 4.51, 4.52, and 4.53 indicate that the effective permeability is inversely proportional to the derivative of the pressure with natural logarithm of time. On semi-log plot of time versus pseudopressure, the rate of change of pseudopressure is just the slope of the straight line, m_{gSP}. Thus Eq.4.72 results a relationship of the effective permeability with the pressure at certain level of depletion in time. A carefully designed pressure test with this additional purpose in mind can provide the average effective permeability over a long range of pressure that can be used for pseudo steady state over a long period of time. Oklahoma

Corporation Commission requires every well to be tested every year. Thus, fortunately, the value of effective permeability can be updated every year for each well. Relative permeability curves, if available, can also be used to evaluate the two-phase integral.

Solution gas oil ratio is function of API gravity of condensate, gas specific gravity, and the bubble point pressure of the condensate. Most of the gas reservoirs produce much over the bubble point pressure of the condensate and free gas gravity and API gravity are constant values. Thus for the reservoir pressure above the bubble point pressure of condensate and well producing at the wellbore flowing pressure within the test pressure range in the Regeion-1, the oil phase pseudopressure function (Eq.2.40) can be written as follows.

4.4.1 Oil Phase (Region-1)

$$\Delta mP_o = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{ro}}{B_o.\mu_o} + \frac{k.k_{rg}}{B_g.\mu_g} R_o \right) dp \tag{4.73}$$

Substituting Eq.4.10 and 4.9 in above equation and simplifying results pseudopressure function in terms of gas and oil effective permeability, respectively.

$$\Delta mP_o = \int_{P_{wf}}^{P^*} \left(\left(\frac{\left(1 - R_o R_p\right)}{R_p - R_s} + R_o \right) \frac{k.k_{rg}}{B_g.\mu_g} \right) dp \tag{4.74}$$

$$\Delta mP_o = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{ro}}{B_o.\mu_o} \left(\frac{1 - R_o R_s}{1 - R_o R_p} \right) \right) dp \tag{4.74a}$$

Now substituting Equation 4.15 in Eq. 4.73, and simplifying yields pseudopressure function in terms of second reliable phase, water phase.

$$\Delta mP_o = \int_{P_{wf}}^{P^*} R_{pow} \left(\frac{k.k_{rw}}{B_w.\mu_w} \right) dp \tag{4.75}$$

Equations 4.74 and 4.75 indicate that the oil production can also be predicted from water and gas production. Since water phase itself is the most reliable phase (water properties rarely change with pressure and temperature), therefore, it is not necessary to express water phase in terms of oil phase and gas phase terms.

4.4.2 Water Phase (oil phase absent, pure gas reservoirs with water production)

Due to its phase stability water stays in liquid state as long as reservoir temperature is below the saturation temperature. In very shallow basins like and volcanic areas, however, a substantial amount of water phase go in vapor phase and flow with gas phase.

$$\Delta mP_w = \int_{P_{wf}}^{P_r} \left(\frac{k.k_{rw}}{B_w.\mu_w} \right) dp \tag{4.76}$$

If water phase exist in vapor phase then

$$\Delta mP_w = \int_{P_{wf}}^{P_r} \left(\frac{k.k_{rw}}{B_w.\mu_w} + \frac{k.k_{rg}}{B_g.\mu_g} R_w \right) dp \tag{4.77}$$

Where R_w is the amount of water phase in gas phase and expressed as STB/SCF. For reservoir pressure below the saturation pressure, pressure at which vapor phase begins to liquefy, of the water, $R_w = 0$. At pressure greater than 1000 psi, saturation temperature reaches about 700 °F, a condition never achieved in petroleum reservoirs. Thus for all practical purposes, $R_w = 0$.

Substituting Eq.4.20 in Eq.4.76 and simplifying it results

$$\Delta mP_w = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{rw}}{B_w.\mu_w} \right) dp \tag{4.78}$$

$$\Delta mP_w = \int_{P_{wf}}^{P^*} \frac{}{(R_{pgw} - R_{sgw})} \left(\frac{k.k_{rg}}{B_g.\mu_g} \right) dp \tag{4.79}$$

Eq. 4.79 shows how water phase pseudopreessure can be expressed as a function of gas properties and producing gas water ratio.

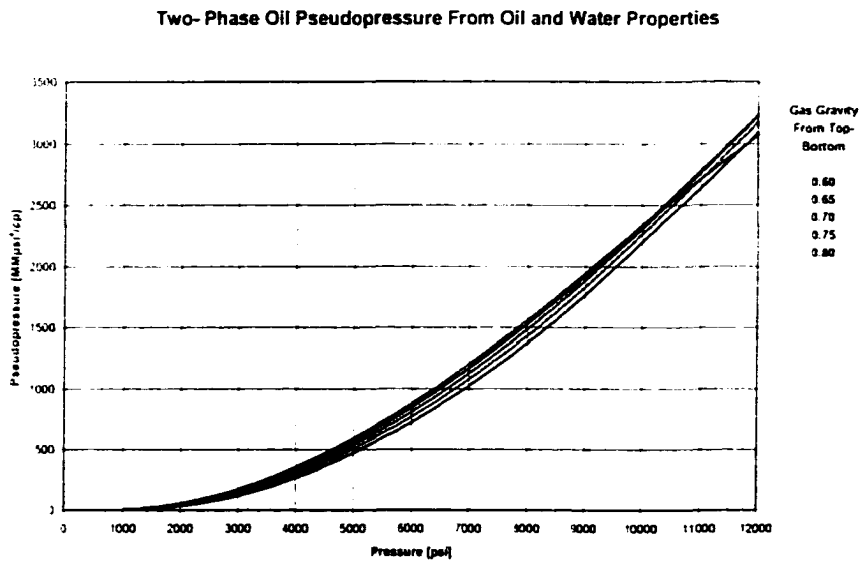


Fig.4.26. Two phase oil pseudopressure.

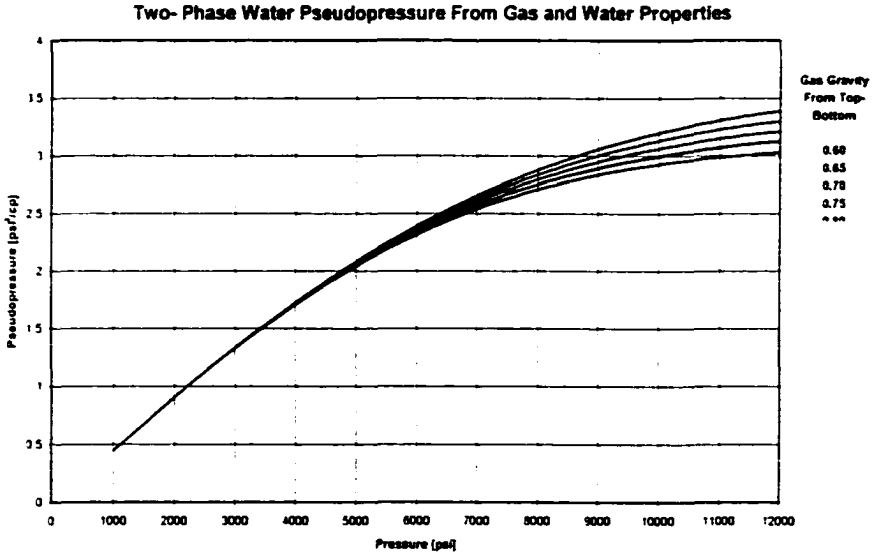


Fig.4.27. Two phase water pseudopressure.

4.4.3 Estimation of Gas Phase PseudoPressure Function for Condensate Systems without Relative Permeability Curves [kr(S)].

4.4.3.1 Gas Phase

In chapter 2 the two-phase pseudo-pressure function was defined as:

The total pseudopressure

$$mP_T = \int_{P_{wf}}^{P_i} \left(\frac{k.k_{ro}}{B_o.\mu_o} R_s + \frac{k.k_{rg}}{B_g.\mu_g} \right) dp \tag{4.80}$$

Region-1 (Inner wellbore region)

$$mP_1 = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{ro}}{B_o.\mu_o} R_s + \frac{k.k_{rg}}{B_g.\mu_g} \right) dp \tag{4.81}$$

Region-2 (Region where liquid develops)

$$mP_2 = \int_{P^*}^{P_d} \left(\frac{k.k_{rg}}{B_g.\mu_g} \right) dp \tag{4.82}$$

Region-3 (Only gas region)

$$\Delta mP_3 = kk_{rg}(S_{wi}) \int_{P_d}^{P_i} \left(\frac{1}{B_g.\mu_g} \right) dp \tag{4.83}$$

Thus total ΔmP_T is equal to $\Delta mP_1 + \Delta mP_2 + \Delta mP_3$.

Region-1

Substituting Eq.4.9 and 4.10 in above equation respectively, result the gas phase pseudopressure function in terms of gas and oil effective permeability.

$$mP_{g1} = \left[\int_{P_{wf}}^{P^*} \left(\frac{\mathrm{k.k_{rg}}}{(\mu_g B_g)} \right) \frac{R_p(1 - R_O R_S)}{(R_p - R_s)} (P) dp \right] \tag{4.83a}$$

$$mP_{g1} = \int_{P_{wf}}^{P} \left[\frac{k.k_{ro}}{B_o.\mu_o} \left(R_s + \frac{(R_p - R_s)}{(1 - R_o R_p)} \right) \right] dp \tag{4.83b}$$

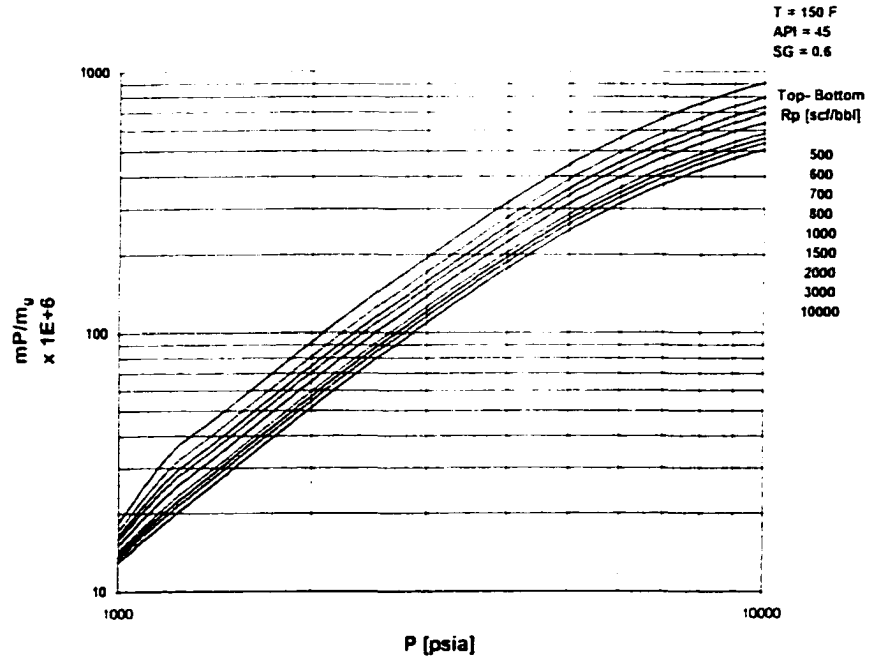


Fig.4.28 Two phase pseudopressure in Region-1 [SG = 0.60]

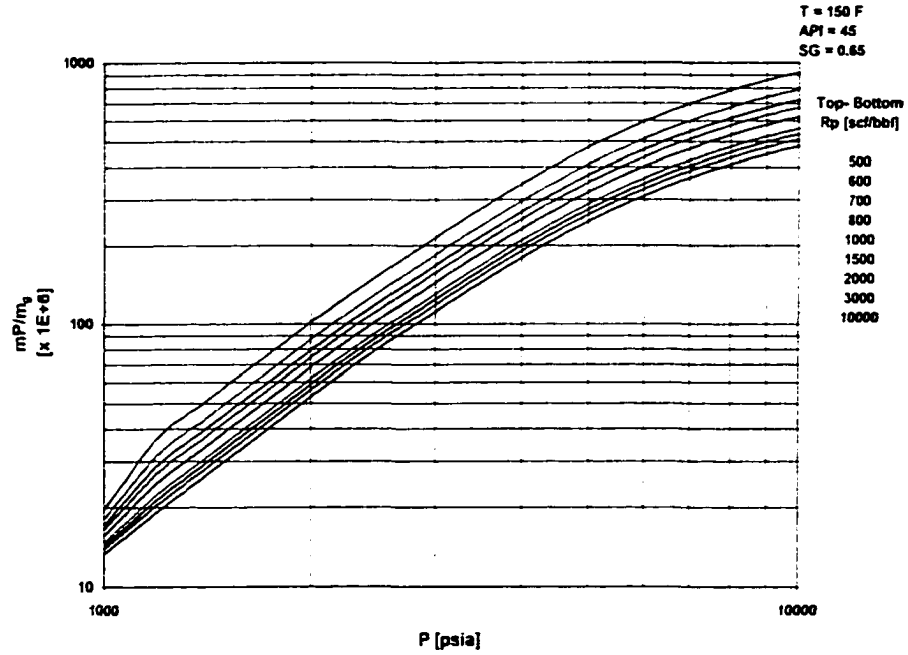


Fig.4.29 Two phase pseudopressure in Region-1 [SG = 0.65]

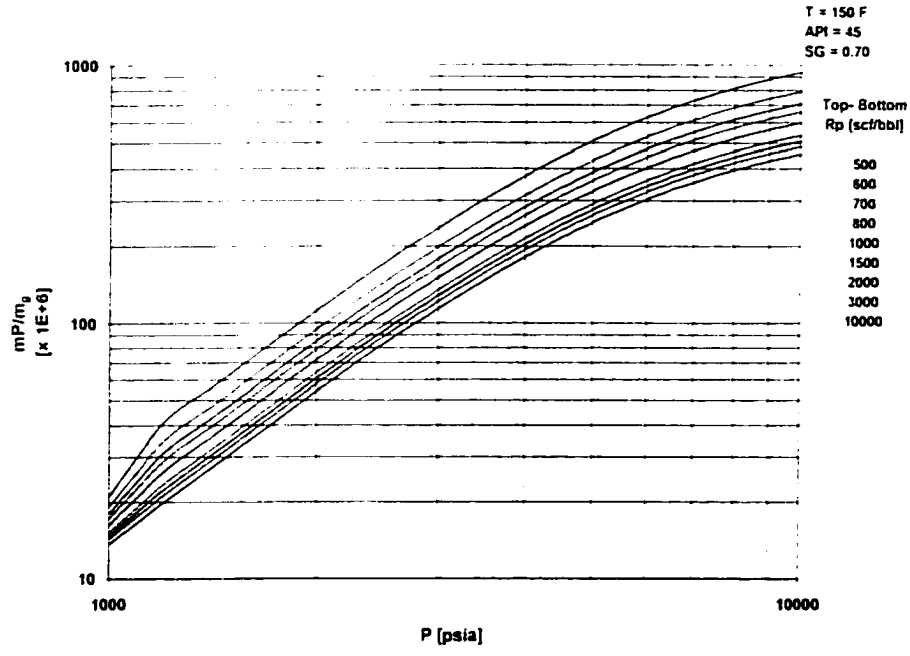


Fig.4.30. Two phase pseudopressure in Region-1 [SG = 0.70]

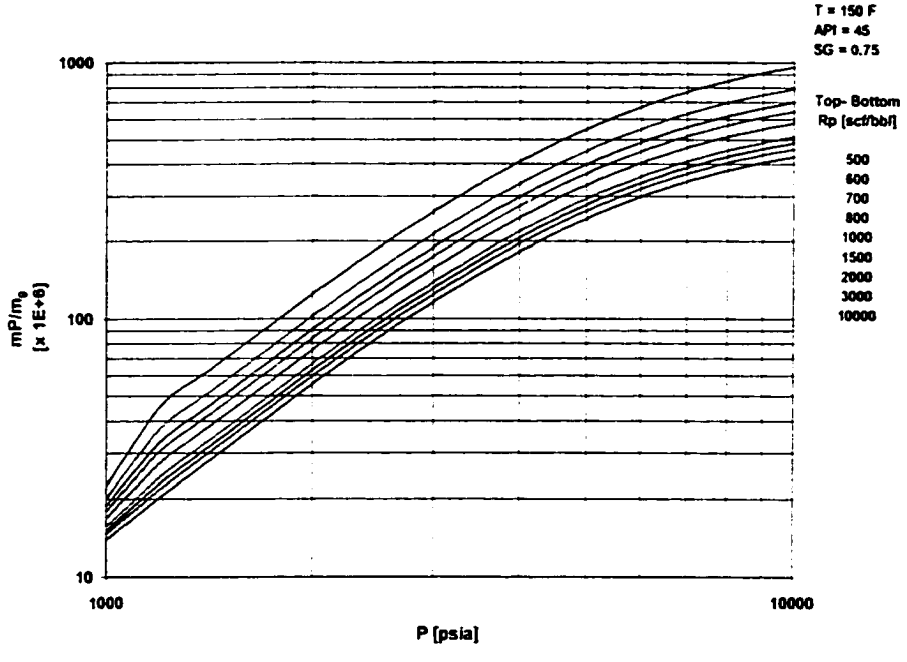


Fig.4.31 Two phase pseudopressure in Region-1 [SG = 0.75]

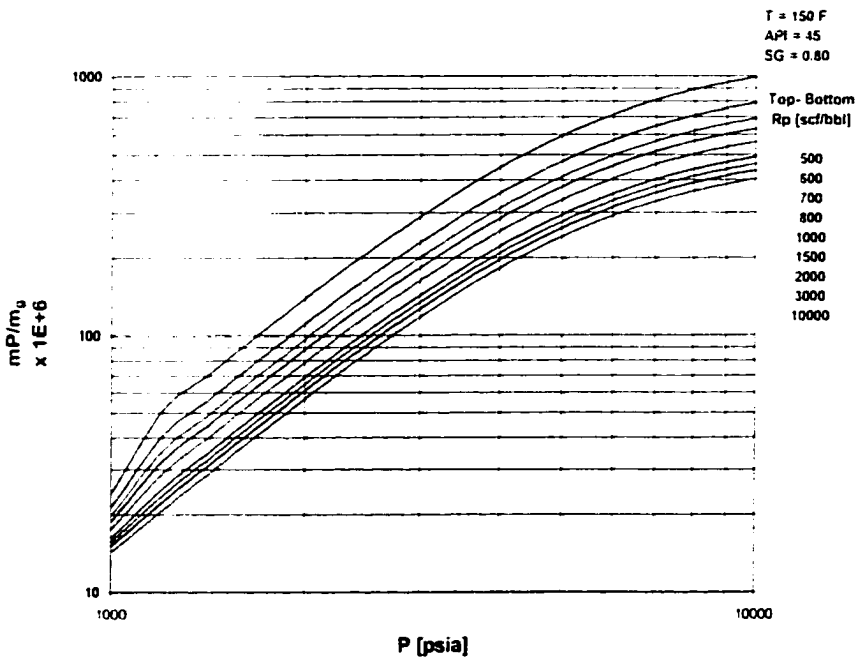


Fig.4.32. Two phase pseudopressure in Region-1 [SG = 0.80]

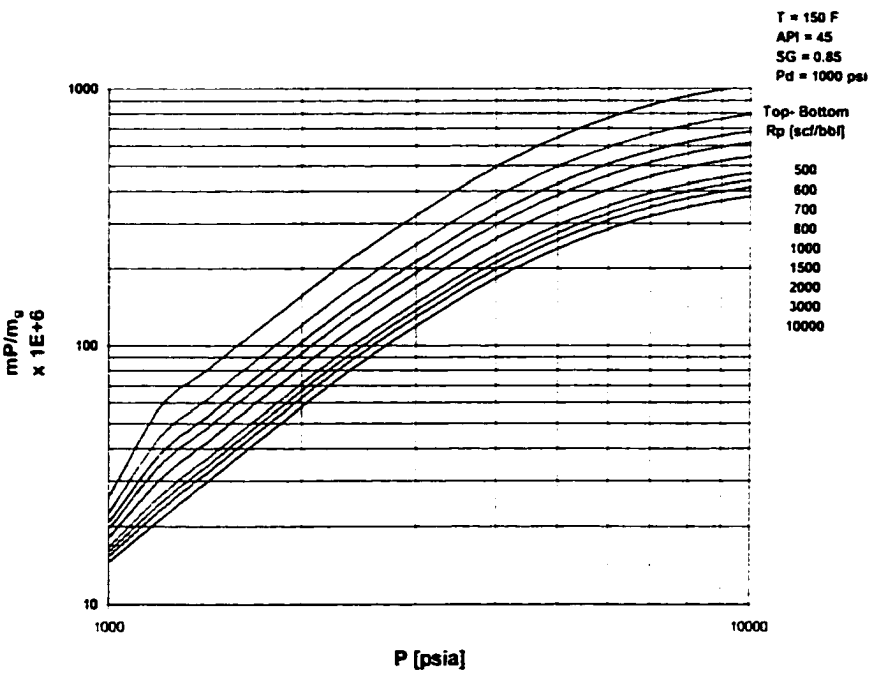


Fig.4.33. Two phase pseudopressure in Region-1 [SG = 0.85]

Table 4.1 Summary of Equations

Eq. No.	Equation [Gas Phase]
4.83a Region-1	$mP_{g1} = \left[\int_{P_{wf}}^{P^*}\left(\frac{k.k_{rg}}{(\mu_g B_g)}\right)\frac{R_p(1-R_O R_S)}{(R_p - R_s)}(P)dp\right]$
4.83b Region-1	$mP_{g1} = \int_{P_{wf}}^{P}\left[\frac{k.k_{ro}}{B_o.\mu_o}\left(R_s + \frac{(R_p - R_s)}{(1-R_o R_p)}\right)\right]dp$
4.82 Region-2	$mP_2 = \int_{P^*}^{P_i}\left(\frac{k.k_{rg}}{B_{gd}.\mu_{gd}}\right)dp$
4.83 Region-3	$\Delta mP_3 = kk_{rg}(S_{wi})\int_{P_d}^{P_i}\left(\frac{1}{B_{gd}.\mu_{gd}}\right)dp$
	Oil Phase
4.73 Region-1	$\Delta mP_o = \int_{P_{wf}}^{P^*}\left(\frac{k.k_{ro}}{B_o.\mu_o} + \frac{k.k_{rg}}{B_{gd}.\mu_{gd}}R_o\right)dp$
4.74 Region-1	$\Delta mP_o = \int_{P_{wf}}^{P^*}\left(\left(\frac{(1-R_o R_p)}{R_p - R_s} + R_o\right)\frac{k.k_{rg}}{B_{gd}.\mu_{gd}}\right)dp$

4.4.3.2 **Pseudopressure Function for Three phase Systems (mP)**

In case of three phase systems, if any two effective permeabilities are known, third phase effective permeability can be calculated using equations 4.24 through 4.26, and 4.36 through 4.38 depending on the availability of the variables used in those equations.

Substituting Eq.4.25 in Eq.4.86 and simplifying it yields the oil pseudopressure function in terms of gas phase and the water phase properties.

Region-1.

$$\Delta mP_o = \int_{P_{wf}}^{P^*}\left(\frac{k.k_{rg}}{B_g.\mu_g}\left[\frac{(R_o R_{pgo} - 1)}{(R_s - R_{pgo}) + R_{sgw}\left(\frac{k.k_{rw}}{B_o.\mu_w}\right)} + R_o\right]\right)dp \qquad (4.84)$$

Now substituting Eq.4.32 in Eq. 4.73 yields,

$$\Delta mP_{\cdot} = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{rw}}{B_w.\mu_w} R_{pgw} \right) dp \tag{4.85}$$

Now Substituting Eq. 4.38 in Eq. 4.73 gives

$$\Delta mP_{\cdot} = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{rw}}{B_w.\mu_w} \frac{\left(R_{pgw} - R_{sgw}\right)}{R_s} + \frac{k.k_{rg}}{B_g.\mu_{gw}} \left(R_o - \frac{1}{R_s} \right) \right) dp \tag{4.86}$$

Eq. 4.84, 4.85, and 4.86 are in terms of gas and water properties and provide the pseudopressure for oil phase.

4.4.3.2.1Gas Phase

Total gas flow at the surface in three phase systems is the contribution of all the three phases. It comprises of free gas flow, dissolved gas flow in oil phase, and dissolved gas flow in water phase.

Mathematically,

$$mP_g = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{rg}}{B_{gd}.\mu_{gd}} + \frac{k.k_{ro}}{B_o.\mu_o} R_s + \frac{k.k_{rw}}{B_w.\mu_w} R_{sgw} \right) dp \tag{4.87}$$

Now substituting Eq. 4.38 in above equation and simplifying it results the gas phase pseudopressure function in terms of water phase properties.

$$mP_g = \int_{P_{wf}}^{P^*} \frac{k.k_{rw}}{B_w.\mu_w} R_{pgw} dp \tag{4.88}$$

Substituting Eq.4.36 in Eq.4.87 and simplifying results

$$mP_g = \int_{P_{wf}}^{P^*} \left(\frac{R_{pgw}}{R_{pgw} - R_{sgw}} \right) \left(\frac{k.k_{rg}}{B_{gd}.\mu_{gd}} + \frac{k.k_{ro}}{B_o.\mu_o} R_s \right) dp \tag{4.89}$$

Above equation eliminates the water phase properties required in Eq. 4.87.

Now substituting Eq.4.30 in Eq.4.87 and simplifying results

$$mP_{g1} = \int_{P_{wf}}^{P \le P^*} \mathrm{k.k}_g \left(\frac{R_{pgw}}{\left(R_{pgw} - R_{sgw}\right)\left(\mu_g B_g\right)} \left(1 + R_{so} \left(\frac{1 - BR_o}{B - R_{so}} \right) \right) \right) dp \tag{4.90}$$

Where

$$B = \left(R_{pgo} - R_{pwn} R_{sgw}\right)$$

4.4.3.2.2 Water Phase

Two-phase equations Eq.4. 78 and 4.79 of water phase also apply for three phase systems.

4.4.3.2 .3 Gas Phase in Region-2 and Region-3

Since oil phase is immobile in Region-2 and does not exist in Region-3 therefore, only gas and water phase are flowing.

$$mP_g = \int_{P^*}^{P_i} \left(\frac{k.k_{rg}}{B_{gd} \cdot \mu_{gd}} + \frac{k.k_{rw}}{B_w \cdot \mu_w} R_{sgw} \right) dp \qquad (4.91)$$

Where R_{sgw} is the solution gas water ratio. Substituting Eq.4.38d in above equation results

$$mP_g = \int_{P^*}^{Pd} \left(\frac{R_{pgw}}{R_{pgw} - R_{sgw}} \right) \left(\frac{k.k_{rg}}{B_{gd} \cdot \mu_{gd}} \right) dp \qquad (4.92)$$

Now substituting Eq. 4.38e, results

$$mP_g = \int_{P^*}^{Pd} \left(R_{pgw} \right) \left(\frac{k.k_{rw}}{B_w \cdot \mu_w} \right) dp \qquad (4.93)$$

Equation 4.91, 4.92, and 4.93 are applicable to Region-3 but with different pressure limits.

4.5 Effective Permeability Estimation Using Measured Surface Rate from Well Test Analysis in Two Phase Systems

In phase changing multiphase environment such as gas condensate systems it is hard to measure the free rate at surface. The total rate is the combination of the free oil and gas flow and dissolved gas in oil and vapor phase in the gas phase. Thus a scheme is devised to get effective permeability using the surface measured rate from well test analysis instead of free rate.

Pressure transient response in terms of pseudopressure can be represented as

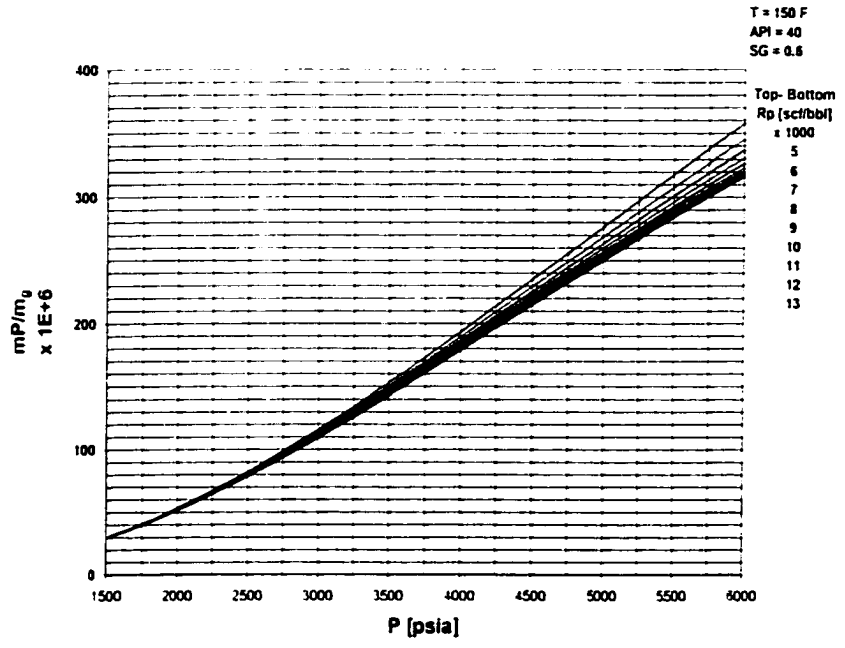


Fig.4.34. Two-phase pseudopressure function as a function of R_p.

[T = 150 ^{O}F, API = 40, SG = 0.6]

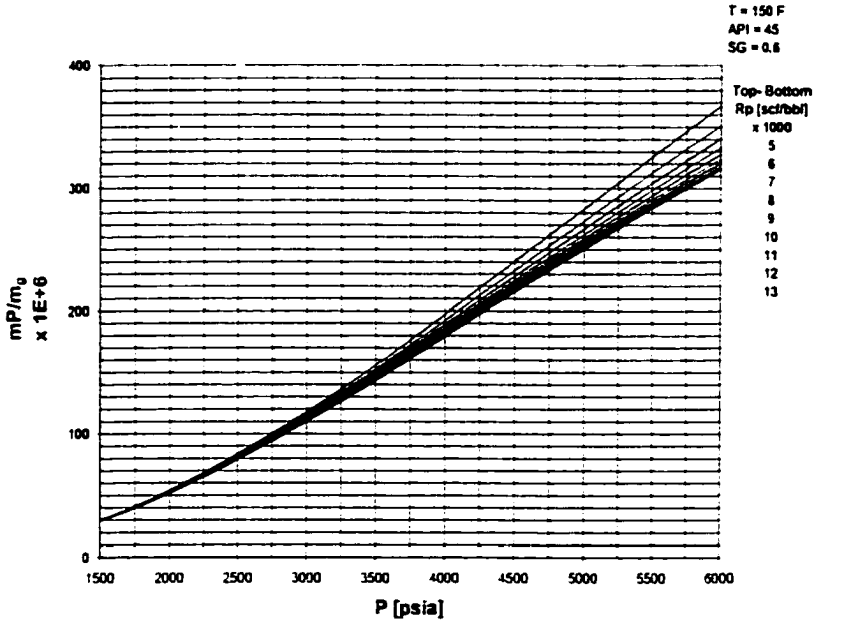


Fig.4.35. Two-phase pseudopressure function as a function of R_p.

[T = 150 ^{O}F, API = 45, SG = 0.6]

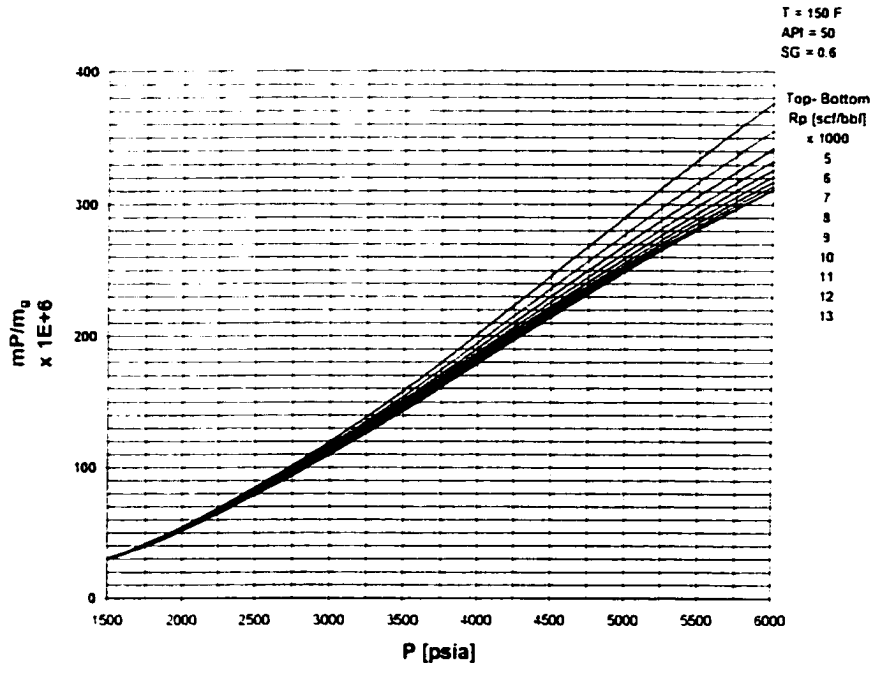


Fig.4.36. Two-phase pseudopressure function as a function of R_p.

[T = 150 ^{O}F, API = 50, SG = 0.6]

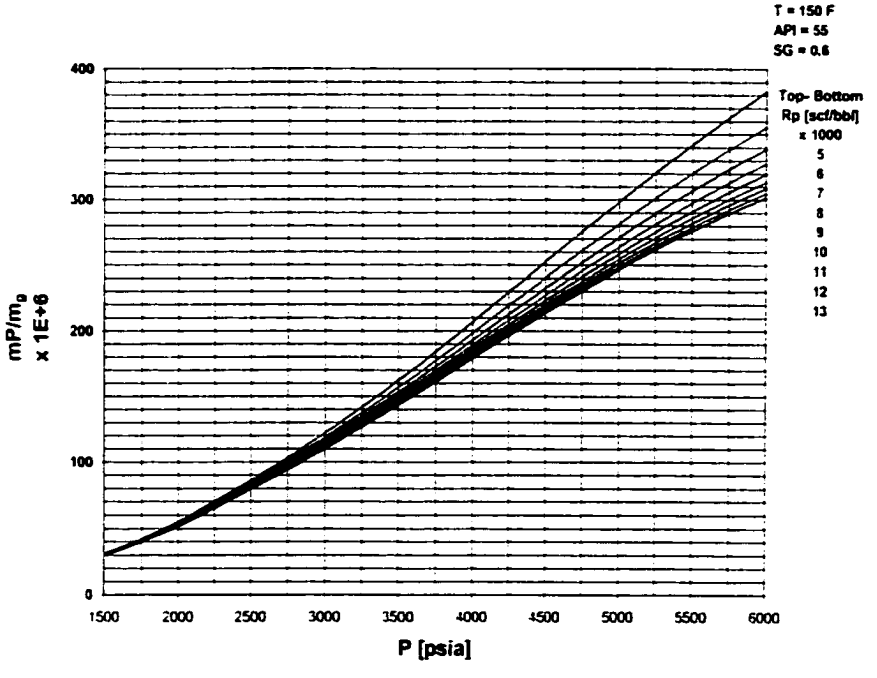


Fig.4.37. Two-phase pseudopressure function as a function of R_p.

[T = 150 ^{O}F, API = 55, SG = 0.6]

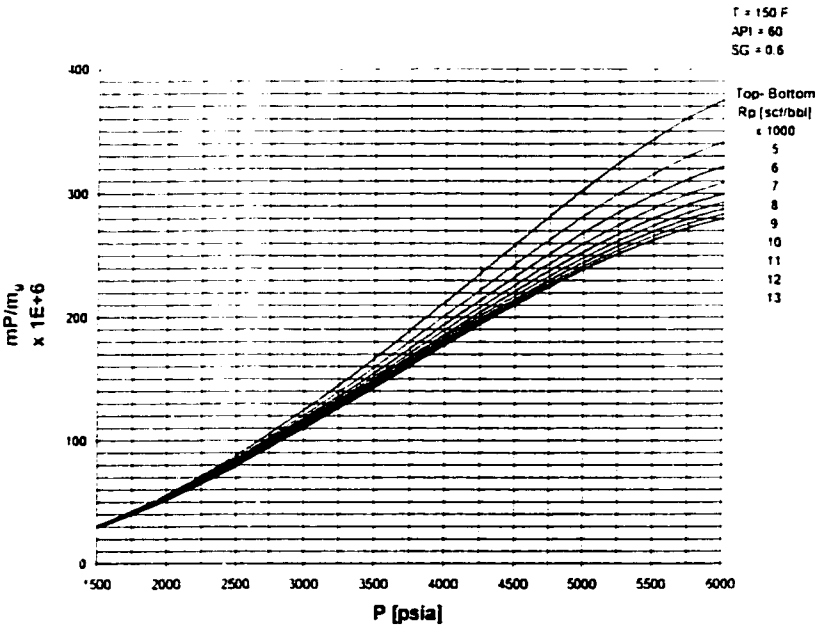


Fig.4.38. Two-phase pseudopressure function as a function of R_p.

[T = 150 ^{O}F, API = 60, SG = 0.6]

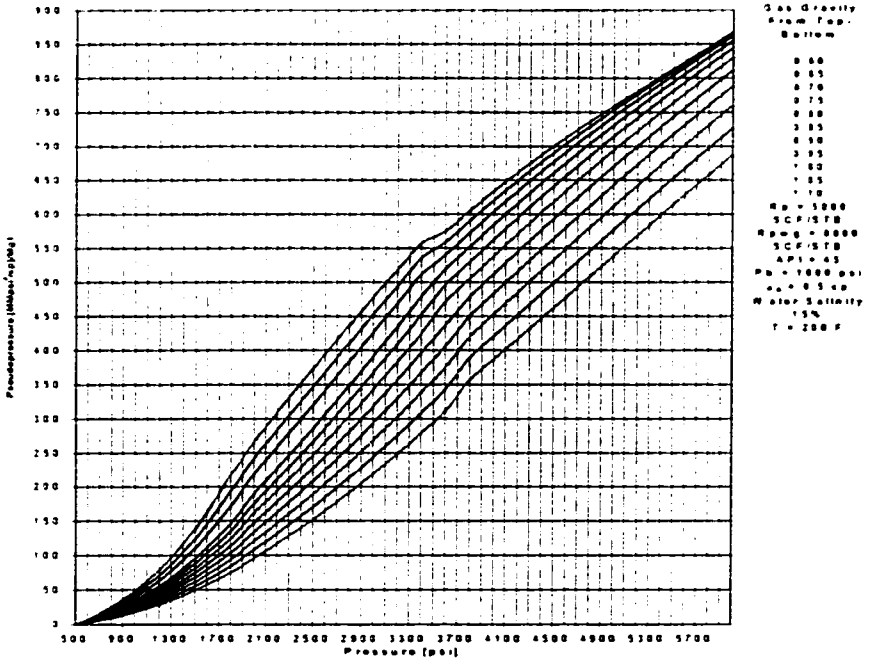


Fig. 4.39. Three-phase gas pseudopressure Region-1[Eq.4.90] [T = 200]

$$mP_{P<P^*} - mP_{wf} = 162.6\left(\frac{q_{g,meas}}{h}\right)\left[\begin{matrix}\log(t) + \log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right) - \\ 3.2275 + 0.8686S\end{matrix}\right] \quad (4.94)$$

Gas phase pseudopressure for Region-1 has been define by Eq.4.83a and 4.83b. With equation 4.83a, Eq. 4.94 can be expressed as follows

$$\int_{P_{wf}}^{P^*}\left(\frac{k.k_{rg}}{(\mu_g B_g)}\right)\frac{R_p(1-R_o R_S)}{(R_p - R_s)}(P)dp = 162.6\left(\frac{q_{g,meas}}{h}\right)\left[\begin{matrix}\log(t) + \log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right) - \\ 3.2275 - 0.8686S\end{matrix}\right] \quad (4.95)$$

Re-arranging, yields

$$\int_{P_{wf}}^{P^*}\frac{R_p(1-R_o R_S)}{(\mu_g B_g)(R_p - R_s)}(P)dp = 162.6\left(\frac{q_{g,meas}}{\left[\int_{P_{wf}}^{P^*} k.k_{rg}\,(P)dp\right]h}\right)\left[\begin{matrix}\log(t) + \log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right) - \\ 3.2275 + 0.8686S\end{matrix}\right] \quad (4.96)$$

Now gas phase effective permeability integral as a function pressure can be estimated as

$$\int_{P_{wf}}^{P^*} k.k_{rg}\,(P)dp = 162.6\frac{q_{g,meas}}{h\left(\frac{d\Delta mP_{gl,g}}{d\ln(t)}\right)} \quad (4.97)$$

Gas phase effective permeability now is the derivative of the above equation. Similarly oil phase effective permeability integral can be estimated by substituting q.4.83b in 4.94.

$$\int_{P_{wf}}^{P^*} k.k_{ro}\,(P)dp = 162.6\frac{q_{g,meas}}{h\left(\frac{d\Delta mP_{gl,o}}{d\ln(t)}\right)} \quad (4.98)$$

Oil phase effective permeability then is the derivative of above equation. Using surface oil rate, the effective permeability of the each phase can be estimated as follows.

$$\int_{P_{wf}}^{P^*} k.k_{rg}\,(P)dp = 162.6\frac{q_{o,meas}}{h\left(\frac{d\Delta mP_{ol,g}}{d\ln(t)}\right)} \tag{4.99}$$

$$\int_{P_{wf}}^{P^*} k.k_{ro}\,(P)dp = 162.6\frac{q_{o,meas}}{h\left(\frac{d\Delta mP_{ol,o}}{d\ln(t)}\right)} \tag{4.100}$$

4.6 Effective Permeability Estimation Using Measured Surface Rate from Well Test Analysis in Three Phase Systems

Effective permeability from well test analysis can also be estimated using surface measured rate for three phase systems. Following the same methodology used for two phase systems,

4.6.1 From measured Gas Rate (Region-1)

Using Eq.4.88,

$$mP_g = \int_{P_{wf}}^{P^*} \frac{k.k_{rw}}{B_w.\mu_w} R_{pgw}\,dp$$

Substituting above equation in Eq. 4.94, results

$$\int_{P_{wf}}^{P^*} \frac{k.k_{rw}}{B_w.\mu_w} R_{pgw}\,dp = 162.6\left(\frac{q_{g,meas}}{h\int_{P_{wf}}^{P^*} k.k_{rw}\,dp}\right)\left[\begin{matrix}\log(t) + \log\left(\frac{k_g(P)}{\phi\mu c_t r_w^2}\right) - \\ 3.2275 + 0.8686S\end{matrix}\right] \tag{4.101}$$

The water effective permeability integral using surface measured gas rate then is becomes

$$\int_{P_{wf}}^{P^*} k.k_{rw}\,(P)dp = 162.6\frac{q_{g,meas}}{h\left(\frac{d\Delta mP_{gl,w}}{d\ln(t)}\right)} \tag{4.102}$$

Now substituting Eq.90 in Eq. 4.94 and solving for gas effective permeability integral, results

$$\int_{P_{wf}}^{P^*}\left(\frac{R_{pgw}}{(R_{pgw}-R_{sgw})(\mu_g B_g)}\left(1+R_{so}\left(\frac{1-BR_o}{B-R_{so}}\right)\right)\right)dp =$$

$$162.6\left(\frac{q_{g,meas}}{h\int_{P_{wf}}^{P^*}k.k_{rg}\,dp}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right)-3.2275+0.8686S\right] \tag{4.103}$$

Where

$$B=\left(R_{pgo}-R_{pwo}R_{sgw}\right)$$

Thus gas phase integral becomes

$$\int_{P_{wf}}^{P^*}\mathrm{k.k_{rg}}\,(P)dp=162.6\frac{q_{g,meas}}{h\left(\frac{d\Delta mP_{gl,g}}{d\ln(t)}\right)} \tag{4.104}$$

Once k_w and k_g are known for Region-1, use these values in Eq. 4.30, 4.31, and 4.32 to calculate k_o. All these three equations should provide same value.

4.6.2 Effective Permeability from measured surface Rate (Region-2 and Region-3)

Substituting Eq.4.92 and 4.93 in Eq.4.94 respective and solving for gas and water effective permeability respectively result,

$$\int_{P^*}^{Pd}\left(\frac{R_{pgw}}{R_{pgw}-R_{sgw}}\right)\left(\frac{1}{B_{gd}\cdot\mu_{gd}}\right)dp=162.6\left(\frac{q_{g,meas}}{h\int_{P^*}^{Pd}k.k_{rg}(P)dp}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right)-3.2275+0.8686S\right] \tag{4.105}$$

$$\int_{P^*}^{Pd}\left(\frac{R_{pgw}}{B_w\cdot\mu_w}\right)dp=162.6\left(\frac{q_{g,meas}}{h\int_{P^*}^{Pd}k.k_{rw}(P)dp}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right)-3.2275+0.8686S\right] \tag{4.106}$$

The gas and water phase effective permeability integrals the can be calculated as follows

$$\int_{P^*}^{P_{wf}} k.k_{rg}\,(P)dp = 162.6\frac{q_{g,meas}}{h\left(\frac{d\Delta mP_{g2,g}}{d\ln(t)}\right)} \tag{4.107}$$

$$\int_{P^*}^{P_{wf}} k.k_{rw}\,(P)dp = 162.6\frac{q_{g,meas}}{h\left(\frac{d\Delta mP_{g2,w}}{d\ln(t)}\right)} \tag{4.88}$$

Similarly the gas and water phase effective permeability integrals in Region-3 are

$$\int_{P_{wf}}^{P} k.k_{rg}\,(P)dp = 162.6\frac{q_{g,meas}}{h\left(\frac{d\Delta mP_{g3,g}}{d\ln(t)}\right)} \tag{4.109}$$

$$\int_{P_{wf}}^{P} k.k_{rw}\,(P)dp = 162.6\frac{q_{g,meas}}{h\left(\frac{d\Delta mP_{g3,w}}{d\ln(t)}\right)} \tag{4.110}$$

4.7 Procedure to Calculate Pseudopressure Function

For well test analysis use this procedure to estimate pseudopressure

Gas Phase

1. Estimate gas FVF, B_g, at various pressure values using a suitable pressure step, using Eq.3.15.

$$B_g = 0.02829\frac{zT}{P}$$

2. Estimate gas viscosity at same pressure values using Eq.3.16,

$$\mu_g = 10^{-4}X_1\exp(X_2\rho^{X_3})$$

3. Calculate solution gas oil ratio as a function of pressure using Eq. 3.2 or Eq.3.31

$$R_s = 0.01347(\gamma_{g,corr})^{0.3873}(P_b)^{1.1715}\left(10^{\left(\frac{12.753.API}{T+460}\right)}\right) \tag{3.2}$$

Where

$$\gamma_{g,corr} = \gamma_g.P_{sp}\left[1+0.1595.API^{\,0.4078}(T_{sp})^{-0.2466}Log\left(\frac{P_{sp}}{114.7}\right)\right]$$

4. Calculate solution oil gas ratio. Ro. using Eq.3.35. In absence of field data, use following equation.

$$R_o = -11.66 + 4.706x10^{-9} R_s^3 + 1.623\sqrt{R_s} - \frac{42.3815}{\sqrt{R_s}}$$

5. Producing gas oil ratio, Rp. is measured at surface.
6. Now estimate gas phase pseudopressure function using Eq.4.83a, 4.83b, 4.82 and 4.83 depending on which region is under treatment. Use Simpson's rule for numerical integration.

Oil Phase

1. Follow same procedure as for gas phase but with oil FVF, Eq.3.28, and oil viscosity, Eq.3.30.
2. Use equation 4.74 for oil phase

Water Phase

1. Similarly use water FVF and viscosity for water phase integral.

4.7.1 Procedure To Estimate Pseudopressure

4.7.1.1 Test Pressure Data in Order to Establish IPR.

1. Convert the well test pressure data in to pseudopressure using above procedure.
2. Also calculate the dmp/dln(t), the derivative of the pseudopressure data.
3. Plot the above estimated pseudopressure vs. time on a semi-log plot and locate the start of semi-log straight line.
4. use the pseudopressure derivative from this point on to calculate the effective permeability integral. Use proper equation (Eq.4.97 through 4.100) for oil, water and gas phase.
5. Plot this effective permeability integral of each phase vs. pressure and get a good curve fit such that the end point of the curve end at zero. This is equal to the value of the integral at reservoir pressure and BHFP both equal to zero. Repeated simulation indicated that the

effective permeability integral practically becomes zero at pressure equal to 400-500 psi.

6. Now using well test pseudopressure procedure convert the production test pressure (P_{wf}) into pseudopressure.
7. Using the curve fit equation, calculate the value of the integral at the P_{wf} data.
8. Multiply the value of the integral to the value obtained from above step (7) to get final value of the pseudopressure.
9. If more than one region exist in the reservoir, estimate the pseudopressure for each region and add them to get the total value.

Note: Use same procedure for three-phase systems.

Three-Phase Systems

1. Follow the steps 1-5 as for two-phases systems
2. Choose proper equation from Eq. 4.84 through 4.93 depending on the oil, gas, and water phase and the number of the region.

Chapter V

Inflow Performance Relationship for Gas Condensate Wells

5.1 Single phase Gas Inflow Performance

Before we discuss and derive performance correlation for gas condensate wells, let us review the single phase IPR for gas wells. This will help us to compare both the forms.

Single-phase pseudopressure function for real gases is expressed as

$$mP_{sp} = \int_{P_{wf}}^{P^*} \left(\frac{1}{B_g \cdot \mu_g} \right) dp \tag{5.1}$$

The gas viscosity and compressibility as a function of pressure is handled by the integral.

Where

$$a_{SP} = \frac{141.2}{k.h} \left[\ln\left(\frac{r_e}{r_w} \right) - 0.75 + (S + S_{cl}) \right] \tag{5.2}$$

And

$$b_{SP} = \frac{141.2}{kh} D \tag{5.3}$$

Forkhheimer[46] form the the well performace is expressed as follows.

$$mP - mP_{wf} = \Delta mP_{SP} = aq_g - bq_g^2 \tag{5.4}$$

or

$$q_g = C \left(\Delta mP_{SP} \right)^n \tag{5.5}$$

Equation 5.5 is the Rawlins and Schellhardt equation.

5.2 Gas Condensate Well Inflow Performance

Depending on the reservoir pressure conditions discussed in Chapter IV, well performance of a gas-condensate horizontal well can be estimated in following fashion.

5.2.1. Condition-a-1. Reservoir Pressure Greater than Dewpoint Pressure ($P > P_d$)

5.2.1.1. Case a-1.1 Wellbore flowing pressure greater than dew point pressure. ($P > P_{wf} > P_d$). (Volumetric Gas Reservoir)

In this case the well pressure response can be written as

$$\Delta mP = \frac{141.2 q_g}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + Dq)\right] \tag{5.6}$$

Where

L = Ye = b width of the reservoir in Y-direction and

$$\ln C_H = 6.28\frac{X_e}{h}\sqrt{\frac{k_z}{k_x}}\left[\frac{1}{3} - \frac{X_w}{a} + \left(\frac{X_w}{a}\right)^2\right] - \ln\left[\sin\frac{180^o Z_w}{h}\right] - 0.5\ln\left[\frac{X_e}{h}\sqrt{\frac{k_z}{k_x}}\right] - 1.088 \tag{5.7}$$

One can write:

The gas flow rate

$$q_g = \frac{L_w(m\bar{P} - mP_{wf})}{141.2\left[\ln\frac{A^{1/2}}{r_w} + \ln C_H - 0.75 + S_R\right]} \tag{5.8}$$

and the pressure drawdown

$$\Delta mP = \frac{141.2 q_g}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + S\right] + \frac{141.2}{L} D q_g^2 \tag{5.9}$$

Which is Forkhhiemer[46] form of the Darcy Law.

Thus

$$mP - mP_{wf} = aq_g - bq_g^2 \tag{5.10}$$

Where

$$a = \frac{141.2}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + S\right] \tag{5.11}$$

$$b = \frac{141.2}{L} D \tag{5.12}$$

Also

Eq. 5.6 then can be written as

$$q_g = \frac{\Delta mP}{\frac{141.2}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + Dq)\right]} \tag{5.13}$$

Or

$$(mP_i - mP_{wf}) = C_3 q_{g3} \tag{5.14}$$

More precisely one can write

$$q_{g3} = C_3 (mP_i - mP_{wf})^n$$

Ideally, n = 1.

$$(mP_i - mP_{wf}) = C_3 q_{g3}$$

$$C_3 = \frac{141.2}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + Dq_{g3})\right] \tag{5.15}$$

Equation 5.6 is an equation of straight line. Thus we need just one point to plot the ΔmP *Vs* q_g to establish IPR above the dew point pressure provided initial conditions are known.

5.2.1.2. Case-a-1.2 P > P_d > P_{wf} > P* (Well flowing at pressure lower than dewpoint pressure with no oil flow)

Forkhheimer equation

$$mP - mP_{wf} = aq_g - bq_g^2 \tag{5.16}$$

$$a = \frac{141.2}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_d)\right] \tag{5.17}$$

b is given by Eq.5.12.

$$b = \frac{141.2}{L} D$$

For pressure from dewpoint to wellbore flowing pressure, Eq. 5.1 can be written as

$$mP_d - mP_{wf} = \frac{141.2 q_{g2}}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_d + Dq_{g2})\right] \tag{5.18}$$

or

$$mP_i - mP_{wf} = C_2 q_{g2} \tag{5.19}$$

Where

$$C_2 = \frac{141.2}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_{ic} + Dq_{g2})\right] \tag{5.20}$$

Above equation is valid as long as wellbore flowing pressure is above the P*.

5.2.1.3. Case-a-1.3 $P > P_d > P^* > P_{wf}$ All three Regions exist ($q_o \neq 0$)

In case of two-phase flow two separate IPRs for each phase can be established if the effective permeabilities are estimated from a well test.

For pressures between Pd and P*, one can write

$$mP_d - mP^* = C_2 q_{g2} \tag{5.21}$$

For wellbore flowing pressure below P*, we can write

$$mP^* - mP_{wf} = C_1 q_{g1,free} \tag{5.22}$$

$$C_1 = \frac{141.2}{Lk}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_{ic} + Dq_{g1})\right] \tag{5.23}$$

In case the wellbore flowing pressure is below the P* and reservoir pressure is above dewpoint, a rare condition, we need only three points to establish IPR, first at dew- point, second at P*, and third below the P*.

The oil flow can be modeled as

$$mP^* - mP_{wf} = C_{o1} q_{o1} \tag{5.24}$$

$$C_{o1} = \frac{141.2}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_{ic})\right] \tag{5.25}$$

Where

$$mP = \int_{P_{wf}}^{P^*}\left(\frac{k.k_{ro}}{B_o.\mu_o}\right)dp \tag{5.26}$$

5.2.1.4. Case-b-1.1 $P_d > P > P^* > P_{wf}$ ($q_o = 0$)

$$mP_i - mP_{wf} = \frac{141.2q_{g2}}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_{lc} + Dq_{g2})\right] \quad (5.27)$$

$$mP_i - mP_{wf} = C_2 q_{g2} \quad (5.28)$$

5.2.1.5. Case-b-1.2 $P_d > P^* > P > P_{wf}$ ($q_o \neq 0$) Only first region exist

$$mP^* - mP_{wf} = C_1 q_{g1,free} \quad (5.29)$$

$$C_1 = \frac{141.2}{Lk}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_{lc} + Dq_{g1})\right] \quad (5.30)$$

The oil flow can be modeled as

$$mP^* - mP_{wf} = C_{o1} q_{o1,} \quad (5.31)$$

$$C_{o1} = \frac{141.2\mu_o B_o}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_{lc})\right] \quad (5.32)$$

Where

$$mP = \int_{P_{wf}}^{P^*}\left(\frac{k.k_{ro}}{B_o.\mu_o}\right)dp \quad (5.33)$$

5.3 Further Mathematical Treatment

5.3.1 Case-a-1.2 $P > P_d > P_{wf} > P^*$ (Well flowing at pressure lower than dewpoint pressure with no oil flow)

$$(mP_i - mP_d) = C_3.q_{g3} \quad (5.34)$$

$$(mP_{di} - mP_{wf}) = C_2.q_{gc} \quad (5.35)$$

Adding both equations, yield

$$(mP_i - mP_d) + (mP_{di} - mP_{wf}) = C_3.q_{g3} + C_2.q_{gc} \quad (5.36)$$

Where

$$C_3 = \frac{141.2}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + Dq_{g3})\right] \quad (5.37)$$

$$C_2 = \frac{141.2}{L}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_c + Dq_{g2})\right] \tag{5.38}$$

On adding and simplifying . one gets

$$(mP_i - mP_{wf}) = \frac{141.2}{Lk} q_{g3}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + Dq_{g3})\right] + \frac{141.2}{L} q_{g2}\left[\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_{lc} + Dq_{g2})\right] \tag{5.39}$$

If we use average properties, then

$$(m\bar{P} - mP_{wf}) = \frac{141.2}{L}\left[q_{g3}\left\{\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + Dq_{g3})\right\}\right] + \left[q_{g2}\left\{\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + (S + S_{lc} + Dq_{g2})\right\}\right] \tag{5.40}$$

On simlification

$$(m\bar{P} - mP_{wf}) = \left[a_1 q_{g3} + b_1 q^2_{g3}\right] + \left[a_1 q_{g2} + b_1 q^2_{g2} + c_1\right] \tag{5.41}$$

Or

$$(m\bar{P} - mP_{wf}) = \left[a_1 (q_{g3} + q_{g2})\right] + \left[b_1 (q^2_{g3} + q^2_{g2}) + c_1)\right] \tag{5.42}$$

$$(m\bar{P} - mP_{wf}) = \underbrace{\left[a_1 (q_{g3} + q_{g2})\right]}_{Geometric\ Term} + \left[\underbrace{b_1 (q^2_{g3} + q^2_{g2})}_{Non-DarcyFrictionTerm} + \underbrace{c_1}_{CondensationTerm}\right]$$

If initial conditions are known, then a plot of ΔmP Vs. $(q_{g3} + q_{g2})$ will defime the IPR as a straight line with aslope of a_1 and intercept I as follows

$\left[b_1 (q^2_{g3} + q^2_{g2}) + c_1)\right]$

If D is known then the skin due to liquid condensation can be estimated from the intercept. This IPR is an average production response of a gas condensate horizontal well that incorporates the production loss due to non-Darcy, skin factor, and liquid condensation.

Where

$$a_1 = \frac{141.2}{L}\left\{\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + S\right\} \tag{5.43}$$

$$b_1 = \frac{141.2}{L} D \tag{5.44}$$

$$c_1 = \frac{141.2}{L} q_{g2} S_{..} \tag{5.45}$$

5.3.2. Case-a-1.3 $P > P_d > P^* > P_{wf}$ All three Regions exist ($q_o \neq 0$)

$$(mP_i - mP_d) + (mP_d - mP^*) + (mP^* - mP_{wf}) = C_3 q_{g3} + C_2 q_{gc} + C_2 q_{gc} \tag{5.46}$$

Substituing values of C_1, C_2, and C_3 and on simplification results

$$(m\bar{P} - mP_{wf}) = \left[a_1(q_{g3} + q_{g2} + q_{g1})\right] + \left[b_1(q^2_{g3} + q^2_{g2} + q^2_{g1}) + (q_{g1}S_{lc1} + q_{g2}S_{lc2})\right] \tag{5.47}$$

$$(m\bar{P} - mP_{wf}) = \underbrace{\left[a_1(q_{g3} + q_{g2} + q_{g1})\right]}_{GeometricTerm} + \left[\underbrace{b_1(q^2_{g3} + q^2_{g2} + q^2_{g1})}_{NonDrcyTerm} + \underbrace{(q_{g1}S_{lc1} + q_{g2}S_{lc2})}_{CondensateTerm}\right]$$

Simplifying results

$$(m\bar{P} - mP_{wf}) = \left[a_3(q_{g3} + b_3 q^2_{g3} + c_3)\right] + \left[(a_2 q_{g2} + b_2 q^2_{g2} + c_2)\right] + \left[(a_1 q_{g1} + b_1 q^2_{g1} + c_1)\right] \tag{5.48}$$

Where

$$a_3 = a_2 = a_1 = \frac{141.2}{L}\left\{\ln\left(\frac{A^{0.5}}{r_w}\right) + \ln C_H + S\right\} \tag{5.49}$$

$$b_3 = b_2 = b_1 = a_1 D \tag{5.50}$$

$$c_1 = a_1 q_{g1} S_{lc1} \tag{5.51}$$

$$c_2 = a_1 q_{g2} S_{lc2} \tag{5.52}$$

$$c_3 = 0 \tag{5.53}$$

Thus it is clear from Eq.5.43 that the inflow performance of the gas condensate wells is a piecewise continuous function and its nodes are the initial pressure, dew point pressure, pressure at which liquid saturation is at its threshold value (P*) and the wellbore flowing pressure.

5.4 Vertical Wells

All above equations with same coefficients apply to vertical wells by replacing L with h, $A^{1/2}$ with r_e and setting $ln\,(C_H) = 0$.

5.5 Establishing IPR

Since pseudopressure has been developed, Rawlins and Schellhardt[43] equation can be used to establish well performance.

Gas phase

$$q_g = C(\Delta mP_g)^n \tag{5.54}$$

Oil phase

$$q_o = C(\Delta mP_o)^n \tag{5.55}$$

Water phase

$$q_w = C(\Delta mP_w)^n \tag{5.56}$$

5.6 Well Deliverability Change due to condensation

Deliverability of a gas condensate well changes when dew point conditions are reached. The liquid begins to condense thereby resulting loss in gas phase production. In this section the analytical model is achieved to calculate the well deliverability loss due to condensation.

5.6.1 Well Deliverability Gain Due to Condensate Production in Region-1 in Two-phase Systems

Single-phase gas pseudopressure for gas reservoirs can be expressed as

$$\Delta mP_{g,sp} = \int_{P_{wf}}^{P^*} \left(\frac{k.k_{rg}}{B_g.\mu_g} \right)_{sp} dp \tag{5.57}$$

And Eq.16 is the pseudopressure in gas condensate reservoirs.

$$\Delta mP_{g,sp} = \left[\int_{P_{wf}}^{P^*} \left(\frac{k.k_{rg}}{(\mu_g B_g)} \right) \frac{R_P(1 - R_o R_S)}{(R_p - R_s)} (P) dp \right] \quad (5.58)$$

Comparing the integral in Eq.16 with single-phase gas pseudopressure in Eq. 52, the difference is the gas phase recovery due to liquid production. Effective permeability in Eq.16 is lower than that in Eq.52. Using the mean value theorem, the recovery term is equal to

$$\int_{P_{wf}}^{P^*} \frac{\frac{R_P(1 - R_o R_S)}{(R_p - R_s)}(P)d}{P^* - P_{wf}} p \quad (5.59)$$

Or

$$q_{g,sp} \int_{P_{wf}}^{P^*} \frac{R_P(1 - R_O R_S)}{(R_p - R_s)(P^* - P_{wf})}(P) dp = q_{gt,2P} \quad (5.60)$$

Term in Eq. 53 is the production gain factor in the Region-1 due to liquid mobility. This can be converted into vapor equivalent as follows.

$$V_{eq} = 133{,}000 \frac{\gamma_o}{M_o} \quad (5.61)$$

V_{eq} is the gas equivalent of the condensate.

5.6.2 Well Deliverability Loss Due to Condensation in Region-1 in Two-phase systems

The recovery in the absence of liquid accumulation in Regio-1 would be

$$q_{g,sp} = C\, \Delta mP_{g,sp} \quad (5.62)$$

$$\Delta mP_{g,sp} = \int_{P_{wf}}^{P} \left(\frac{k}{B_g \cdot \mu_g} \right)_{ip} dp \quad (5.63)$$

Since $q_{g,sp} > q_{gt,2P}$, (flow rate with condensate accumulation) therefore, well efficiency in this case can be expressed as

$$\eta_{w,2p}[\%] = \frac{q_{gt,2P}}{q_{g,sP}} x100 \quad (5.64)$$

And the damage factor then is

$$1-\eta_{w,2p}=\frac{q_{g,iP}-q_{gr,2P}}{q_{g,iP}} \tag{5.65}$$

$$\eta_{w,2p}=\frac{C\int_{P_{wf}}^{P^*}\left(\frac{\mathrm{k.k_{rg}}}{(\mu_g B_g)}\right)\frac{R_P(1-R_O R_S)}{(R_p-R_s)}(P)dp}{C\int_{P_{wf}}^{P}\left(\frac{kk_{rg}}{B_g.\mu_g}\right)_{ip}dp} \tag{5.66}$$

$$\eta_{w,2p}=\frac{\int_{P_{wf}}^{P^*}\left(\frac{(\mathrm{k.k_{rg}})_{2p}}{(kk_{rg})_{ip}}\right)\frac{R_P(1-R_o R_S)}{(R_p-R_s)}(P)dp}{(P^*-P_{wf})} \tag{5.67}$$

Since effective permeability in single-phase gas reservoirs is equal to absolute permeability, therefore, above equation can be rewritten as

$$\eta_{w,2p}=\frac{\int_{P_{wf}}^{P^*}\left(\frac{(\mathrm{k.k_{rg}})_{2P}}{k}\right)\frac{R_P(1-R_o R_S)}{(R_p-R_s)}(P)dp}{(P^*-P_{wf})} \tag{5.68}$$

The damage factor then is

$$DF_1=1-\eta_{w,2p}=1-\frac{\int_{P_{wf}}^{P^*}\left(\frac{(\mathrm{k.k_{rg}})_{2P}}{k}\right)\frac{R_P(1-R_o R_S)}{(R_p-R_s)}(P)dp}{(P^*-P_{wf})} \tag{5.69}$$

Eq.5.69 shows that the delivery loss in Region-1 is only due to relative permeability loss of the gas phase. Partially the loss is recovered as liquid production.

5.6.3 Damage Factor in Region-2 in Two-phase Systems

In this region, only gas phase is mobile, therefore;

$$DF_2=1-\frac{\int_{P^*}^{P_d}\left(\frac{(\mathrm{k.k_{rg}})_{2P}}{k}\right)}{(P_d-P^*)} \tag{5.70}$$

Equation 5.70 indicates that the delivery loss in Region-2 is the result of permeability loss due to condensation.

5.7 Procedure to Establish the IPR

1. Estimate the pseudopressure using procedure at the end of the Chapter-IV.
2. Plot the measured surface gas rate vs pseudopressure on a log-log plot and calculate the slope, n, and intercept, C. These are the Rawlins and Schellhardt[43] equation parameters.
3. Establsih the well performance using Rawlins and Shellhardt[43] equation. $q_g = C\left(\Delta mP\right)^n$.
4. Use Eq.5.55 and 5.56 for condensate and water phase production.
5. In case of prediction condensate and water phase production use the proper equations for oil and water pseudopressure defined in Chapter -IV.

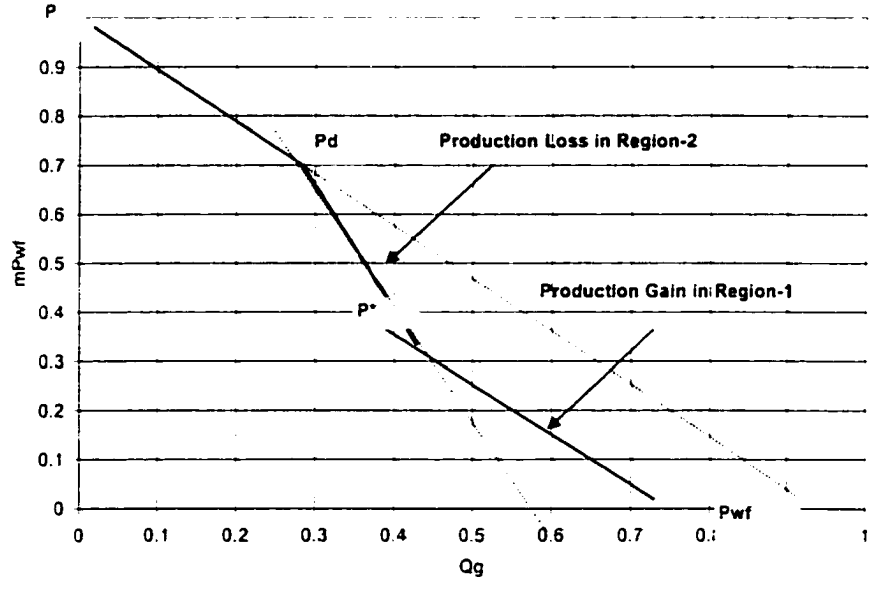


Fig. 5.1 Well performance behavior during the depletion as the Pd and P* are approached.

Chapter VI

Horizontal Gas Wells Testing

6.1 Introduction

The partial differential equation governing the isothermal flow of real gases in the porous media is

$$\frac{\partial^2 mP_D}{\partial X_D^2} + \frac{\partial^2 mP_D}{\partial Y_D^2} + \frac{\partial^2 mP_D}{\partial Z_D^2} = \frac{\phi\mu C_g}{K_t}\frac{\partial mP_D}{\partial t_D} \qquad (6.1)$$

$$K_x \frac{\partial^2 mP}{\partial x^2} + K_y \frac{\partial^2 mP}{\partial y^2} + K_z \frac{\partial^2 mP}{\partial z^2} = \frac{\phi\mu c}{K_t}\frac{\partial mP}{\partial t} \qquad (6.2)$$

To achieve the pressure transient solution of Eq.6.2, following initial and boundary conditions are imposed.

1. The initial reservoir pressure is constant through out the reservoir.
2. The reservoir is assumed to be semi infinite in y-direction. The pressure at infinity is not influenced by the disturbance at the wellbore.
3. To develop the solution as a first approximation, the horizontal well is replaced with a thin strip of width $(L_{zb}-L_{za})$ and length $(L_{xf}-L_{xd})$. This assumption will later be removed and the horizontal well will be re-instead with its original configuration. During the drawdown period, uniform flux along the well length is assumed. No fluid will be entering the wellbore during the buildup period.
4. No fluid may flow across the upper, lower, and lateral boundaries.
5. Well is produced at constant rate during the well test period.
6. Gravity effects are negligible.

Fig. 6.1 illustrates the horizontal well configuration presented by Goode and Thambynayagam[37].

Mathematically, above conditions are expressed as follows.

1. $mP = mP_i$ at $t = 0$ $\qquad \forall x, y, z$

2. $mP = mP_i$ as $y \to \infty$ $\forall x, y, z$

3. $\lim_{y \to 0}(L_{zb} - L_{za})(L_{xd} - L_{xl})\frac{\partial mP}{\partial y} = \begin{cases} 0 & 0 \le z < L_{za} \quad 0 \le z < L_{xd} \\ 0 & 0 \le z < L_{za} \quad L_{xd} \le z \le L_{xl} \\ 0 & 0 \le z < L_{za} \quad L_{xl} \le z \le h_x \\ -\frac{q}{2k_y} & L_{za} \le z \le L_{zb} \quad L_{xd} \le z \le L_{xl} \\ 0 & L_{zb} \le z \le h_z \quad L_{xl} \le z \le h_x \end{cases}$

4. $\frac{\partial mP}{\partial z} = 0$ at $z = 0$ and $z = h_z$

7. $\frac{\partial mP}{\partial x} = 0$ at $x = 0$ and $x = h_x$

6.2 Pressure Drawdown Response

$$mP_i - mP_w = \frac{282.4qB_g r_w'}{h_x h_z k_y}\left[\begin{array}{l} \sqrt{\pi t_D} + \frac{h_x^2}{\pi^2 v_x}\sum_{n=1}^{\infty}\frac{1}{n}xerf\left(v_x \pi n\sqrt{t_D}\right)\Xi_n^2 + \frac{h_x h_z}{L_w v_z \pi} \\ \sum_{m=1}^{\infty}\frac{1}{m}xerf\left(v_z \pi m\sqrt{t_D}\right)\Xi_m^2 \cos(m\pi z_e) + \frac{h_x h_z\sqrt{\frac{k_y}{k_z}}}{2L_w r_w}S_a \end{array}\right] \quad (6.3)$$

6.3 Pressure Buildup Response

$$mP - mP_{w(t=0)} = \frac{282.4qB_g r_w'}{h_x h_z k_y}\mathrm{x}$$

$$\left[\begin{array}{l} \sqrt{\pi}(t_D - \Delta t_D) + \frac{h_x^2}{\pi^2 v_x}\sum_{n=1}^{\infty}\frac{1}{n}\left\{erf\left(v_x \pi n\sqrt{t_D}\right) - erf\left(v_x \pi n\sqrt{\Delta t_D}\right)\right\}\Xi^2 \\ + \frac{h_x h_z}{L_w v_z \pi}\sum_{m=1}^{\infty}\frac{1}{m}\left\{erf\left(v_z \pi m\sqrt{t_D}\right)erf\left(v_z \pi m\sqrt{\Delta t_D}\right)\right\}\Xi_m^2 \cos(m\pi z_e) \end{array}\right] \quad (6.4)$$

Where

$$\Xi_n = \frac{1}{nL_w}\left[\sin\left(\frac{n\pi L_{xl}}{h_x}\right) - \sin\left(\frac{n\pi L_{xd}}{h_x}\right)\right] \quad (6.5)$$

$$\Xi_m = \frac{1}{4mr_w}\left[\sin\left(\frac{m\pi}{h_z}\left(h_s + 2r_w\right)\right) - \sin\left(\frac{m\pi}{h_z}\left(h_s - 2r_w\right)\right)\right] \tag{6.6}$$

$$L_w = \left(L_{xl} - L_{xd}\right) \tag{6.7}$$

$$r_w = r_w\left(\frac{k}{k_z}\right)^{\frac{1}{4}} \tag{6.8}$$

$$t_D = \frac{0.000264k_x t}{\phi\mu c_t r_w^2} \tag{6.9}$$

$$\Delta t = \left(t - t_0\right) \tag{6.10}$$

$$v_x = \frac{r_w}{h_x}\sqrt{\frac{k_z}{k_y}} \tag{6.11}$$

$$v_z = \frac{r_w}{h_z}\sqrt{\frac{k_z}{k_y}} \tag{6.12}$$

$$z_e = \frac{1}{h_z}\left(h_s + 1.47r_w\right) \tag{6.13}$$

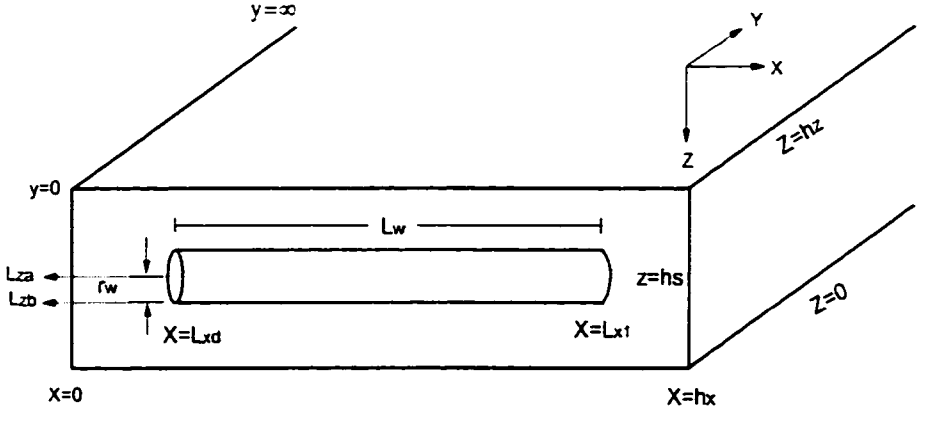


Fig. 6.1. Horizontal well Configuration [38].

6.4 Flow Regimes

A number of different flow regimes can be observed while analyzing transient-pressure responses in horizontal wells. The parameters which play a significant role in the behavior of a horizontal well pressure transience are the vertical to horizontal permeability ratio, the relative position of the well in the stratum and the length of the horizontal well compared to the formation thickness. Four recognizable flow patterns have been identified that may be theoretically possible to be observed during a pressure drawdown or buildup test in a horizontal well. As soon as a well is put on the production the pressure transience moves in radial direction away from the wellbore, as illustrated in Fig. 6.2. This is equal to the radial flow in vertical wells. This flow regime has been recognized as *early time radial flow* and its duration is very short when the reservoir is a thin strata or high vertically permeable.

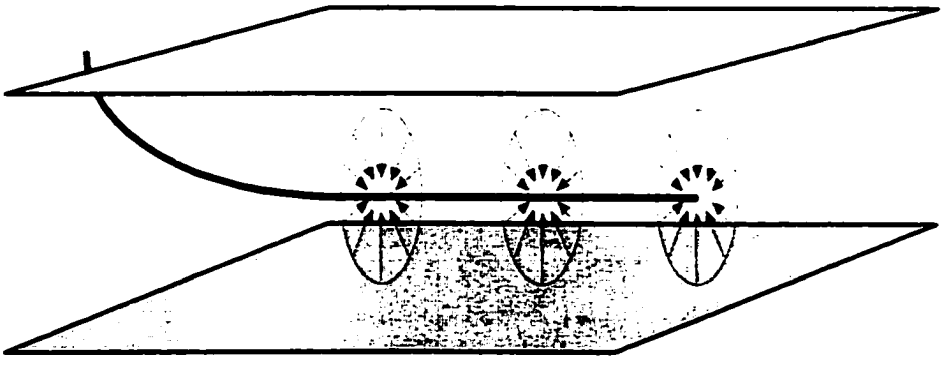


Fig. 6.2. Early Time Radial Flow[39].

When the well is close to a no-flow boundary and its presence is felt by the pressure disturbance, a *hemicylindrical* flow occurs as shown in Fig. 6.3.

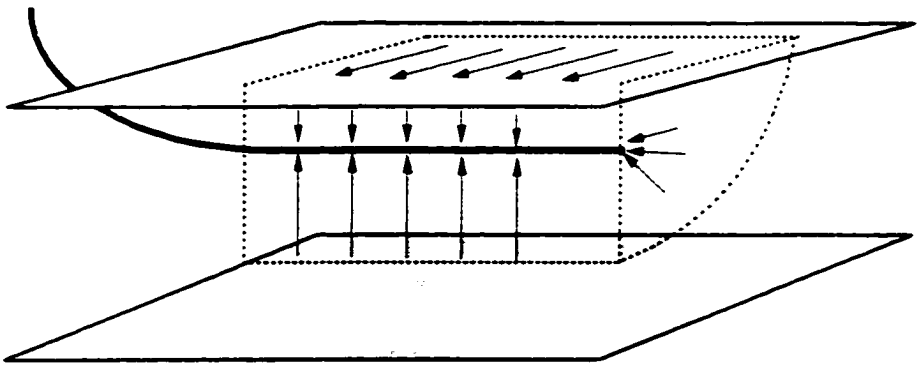


Fig. 6.3. Hemicylindrical Flow[39].

Often, the length of the horizontal well is much greater than the reservoir thickness which contributes to the formation of the second primary flow regime. This is known as *early linear flow* regime and is developed when pressure disturbance reaches both the lower and upper boundaries of the reservoir. This is shown in Fig. 6.4. The effective duration of this flow is related to the onset of the end effects. This flow regime does not appear when the horizontal well length is short as compared to the formation thickness. Instead, a lengthy transition zone will develop prior to the next identifiable flow period.

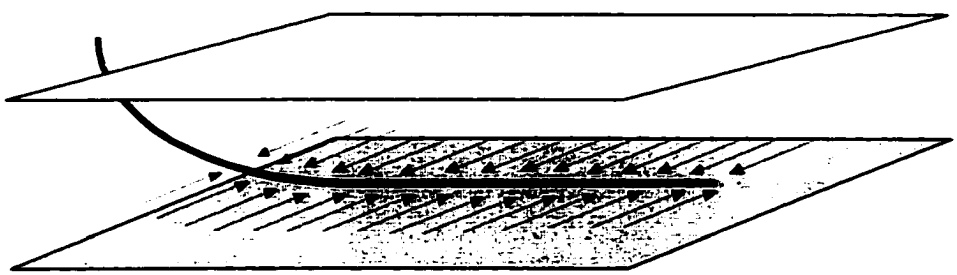


Fig. 6.4. Linear flow[39].

If there is no constant pressure boundary and there are no boundaries to horizontal flow over a reasonable distance, flow towards the horizontal wellbore becomes effectively radial in nature after a long time, with the

horizontal plane acting somewhat like a point source as shown in Fig. 6.5. This flow regime, called *late time radial*, may be unobserved if other external boundaries are felt first or will not be observed when the reservoir has constant pressure boundaries.

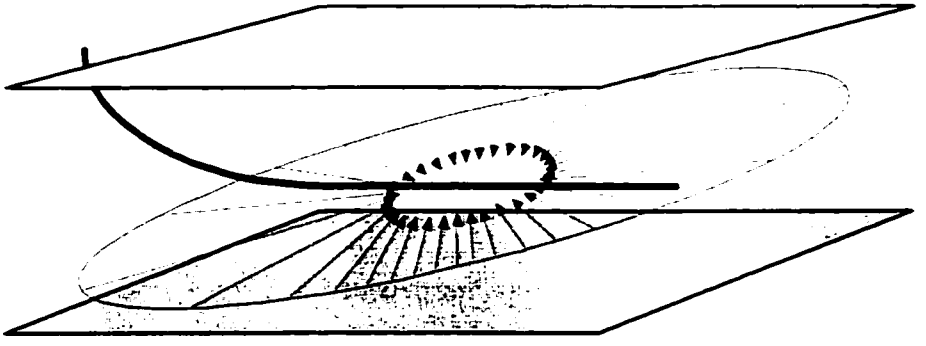


Fig. 6.5. Late time radial flow[39].

Between the early and late radial flow periods it is possible to observe a *linear flow* regime caused by the influence of the top and bottom boundaries while the horizontal length of the wellbore is important relative to the radius of investigation. In other words, In a semi-infinite reservoir, once the parallel boundaries have been contacted, a linear flow regime will develop. Following the early radial flow, there may appear an intermediate period if the well is located close to one of the upper or lower boundaries; this period is called *hemiradial flow* regime as indicated by Fig. 6.6. This flow regime will usually not develop if the position of the well relative to the thickness of the formation is 1 or zero, indicating that the well is very close to either the upper or lower boundary.

A regime that might be established when a horizontal well in drawn down, but is not considered common, is steady state. This will only develop when there is a constant pressure source such as an aquifer or gas cap.

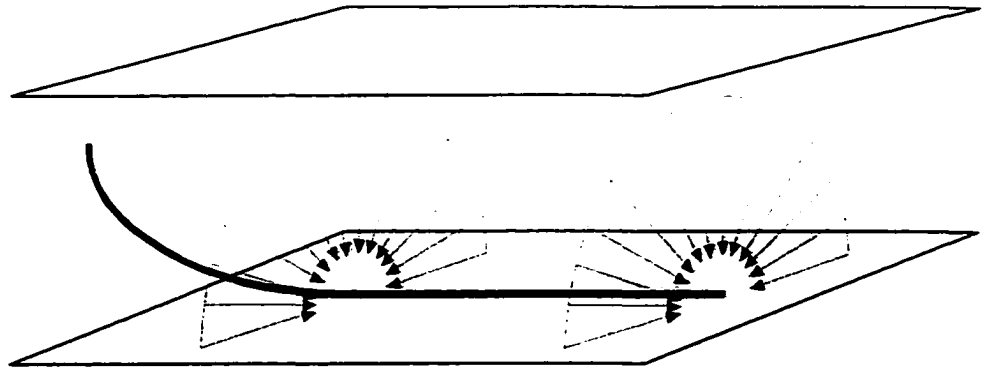


Fig. 6.6. Hemiradial flow[39].

In summary, there are four primary distinct flow regimes that can theoretically develop when a horizontal well is drawn down or built up; their identification is critical to the proper interpretation of a horizontal well test. In chronological order of development, they are:

- Early time radial flow
- Intermediate time linear flow
- Late time radial flow
- Late time linear flow (pseudo steady state)

6.4.1 Skin Effect

It is becoming apparent that although the mechanical process of drilling a horizontal well has become reasonably accurate, the process all too often results in restrictive amounts of wellbore damage. Therefore, it becomes important to be able to correctly identify and quantify actual wellbore damage.

Mathematically, three components of skin are inherent to the analytic solutions, as follows:

1. Mechanical skin, s_m, attributable to wellbore damage, which typically results from the drilling and completion process,

2. Pseudo skin, s_z, related to the effects of partial penetration in the vertical direction. Its magnitude is a direct function of reservoir thickness and the geometric location of the horizontal well in the vertical plane. It is not present during early time radial flow,
3. Pseudo skin, s_x, caused by partial penetration effects in x direction. It only presents during the late time linear flow period.

For pressure buildup, the skin factor can be determined by subtracting the buildup equations corresponding to the various time periods from the relevant drawdown equation. Different formulations are required for the cases when the reservoir is finite and infinite.

It is important to estimate the times relating to each of the flow regimes because each flow regime has a unique mathematical solution relating to it, and certain reservoir parameters can only be approximated during particular flow regimes. Goode and Thambynayagam[37] developed generalized mathematical response functions at the horizontal wellbore for conditions of both pressure drawdown and pressure buildup. These general equations assumed an effective pressure point along the wellbore.

6.4.2 Pressure Tests

6.4.2.1. Early Time Radial Flow

The flow is radial around the well. This is equivalent to a fully penetrating, vertical well in an infinite reservoir. For this time period, the pressure response can be approximated by:

$$mP_i - mP_{wf} = \frac{162.6q_g}{\sqrt{k_y k_z}L_w}\left[\log\left(\frac{\sqrt{k_y k_z}}{\phi\,\mu c_t (L_{zb}-L_{za})^2}t\right) - 3.227 + 0.866S_{a,1}\right] \qquad (6.14)$$

$$S_{a.1} = 1.151\left[\frac{mP_i - mP_{wf(1hr)}}{m_{1r}} - \log\left(\frac{\sqrt{k_y k_z}}{\phi\,\mu c_t r_w^2}\right) - 3.227\right] \tag{6.15}$$

$S_{a.1} = S_m + Dq + S_{cl}$

A semi log plot of the wellbore pressure vs. of time would exhibit a linear section given by Eq. 6.14. This first linear section has a slope defined by the length of the well and by the effective isotropic permeability in the y, z plane. The mechanical skin, s_m, is determined by the intercept. The early time radial flow period ends at approximately:

$$t_{erfl} = \frac{190.0\,h_z^{2.095}\phi\mu c_t}{k_z r_w^{0.095}} \tag{6.16}$$

6.4.2.2. Early Time Linear Flow

Because a horizontal well will generally be long compared to the formation thickness, a period of linear flow may develop once the pressure transient reaches the upper and lower boundaries. This period results from the spread of the flow beyond the ends of the well being negligible compared to the length of the well:

$$mP_i - mP_{wf} = \frac{8.128q_g}{\sqrt{k_y}L_w}\left[\frac{3.545r_w}{h_z}\sqrt{\frac{0.0002637t}{\phi\,\mu c_t (L_{zb}-L_{za})^2}} + (S_z + S_m + S_{cl} + Dq)\frac{1}{\sqrt{k_z}}\right] \tag{6.17}$$

Where s_z is the pseudoskin resulting from partial penetration in the vertical direction. For pressures greater than dew point $S_{cl} = 0$

$$s_m = \frac{0.058}{h_z}\sqrt{\frac{k_z}{\phi\mu c_t}}\left(\frac{P_i - P_{wf(0hr)}}{m_{1l}}\right) - s_z - Dq - S_{cl} \tag{6.18}$$

The linear flow periods given by Eq. 6.4 can be analyzed by a plot of pressure vs. the square root of time. For the complete development of this flow period, the length of the well must be long compared with the formation thickness. The slope of the linear section resulting from the p vs. $\sqrt{t}$ plot is defined by the square root of the mobility in the y direction, the thickness of the formation, and the length of the well. s_m can be determined from the intercept. The intermediate time linear flow is estimated to end at:

$$t_{elfl} = \frac{20.8\phi\mu c_t L_w^2}{k_x} \qquad (6.19)$$

If the time calculated from Eq. 6.6 is less than the time calculated for the early time radial flow to end, Eq. 6.3, it may mean that the length of the horizontal well is not sufficient compared to the formation thickness. Thus, the intermediate time linear flow may not develop.

6.4.2.3. Late Time Radial Flow

During this time period, a second radial flow pattern will develop, this time in the x, y plane.

$$mP_i - mP_{wf} = \frac{162.6q}{h_z\sqrt{k_y k_x}}\left[\log\left(\frac{r_w^2 k_x t}{\phi\mu c_t r_{wa}^2}\right) - 3.23\right] + \frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_x k_z}} \qquad (6.20)$$

$$S_{a2} = S_z + S_m + S_{cl} + SDq$$

$$s_m = \frac{1.151 L_w}{h_z}\sqrt{\frac{k_z}{k_x}}\left[\frac{mP_i - mP_{wf(1hr)}}{m_{2r}} - \log_{10}\left(\frac{k_x}{\phi\mu c_t L_w^2}\right) + 2.023\right] - s_z - Dq - S_{cl} \quad (6.21$$

A plot of the wellbore pressure vs. the logarithm of time would exhibit a linear section given by Eq. 6.7. This section has a slope defined by the thickness of the formation and the effective isotropic permeability in the x, y

plane. For this flow period to develop, the length of the well should be sufficiently short when compared with the width of the reservoir. s_m can be obtained from the intercept. If late time radial flow develops, it will begin at approximately:

$$t_{brf2} = \frac{1230 L_w^2 \phi \mu c_t}{k_x} \tag{6.22}$$

For a reservoir of finite width, would end at:

$$t_{erf2} = 297 \frac{(L_{xl} + L_{xd})^{2.095} \phi \mu c_t}{k_x L_w^{0.095}} \tag{6.23}$$

If the estimated time to the end of late time radial flow, Eq. 6.10, is less than the calculated beginning, Eq. 6.9, this may imply that the reservoir is small compared to the length of the well and this radial flow period will not develop.

6.4.2.4. Late Time Linear Flow

Late time linear flow regime for gas wells is represented using following equation.

$$mP_i - mP_{wf} = \frac{8.128 q_g}{\sqrt{k_x} L_w} \left[\frac{3.545 r_w}{h_z} \sqrt{\frac{0.0002637 t}{\phi \mu c_t (L_{zb} - L_{za})^2}} + (S_Z + S_M + S_X + S_{cl} + Dq) \frac{1}{\sqrt{k_Z}} \right] \tag{6.24}$$

6.5. Pressure Transient Character

Horizontal well tests are best interpreted using a log-log representation of the pressure-time data in conjunction with the derivative curve. This representation provides the best distinction between the various flow regimes, which not only improves the ability to correctly identify the flow regimes, but also maximizes the chance for regressing to a more unique solution of the data.

Fig. 6.7 illustrates the character of the log-log plot in relation to the two radial flow regimes under ideal conditions. Following the effects of wellbore damage, they are associated with the minimum and maximum flexures on the derivative curves. The intermediate time linear flow period is theoretically located as a constant slope line between these two radial flexures. Each of the flow regimes, which ideally establishes a unique fingerprint on the log-log plot, provides an opportunity for estimating particular reservoir parameters that are much more difficult to determine during other flow regime. See Fig. 6.8.

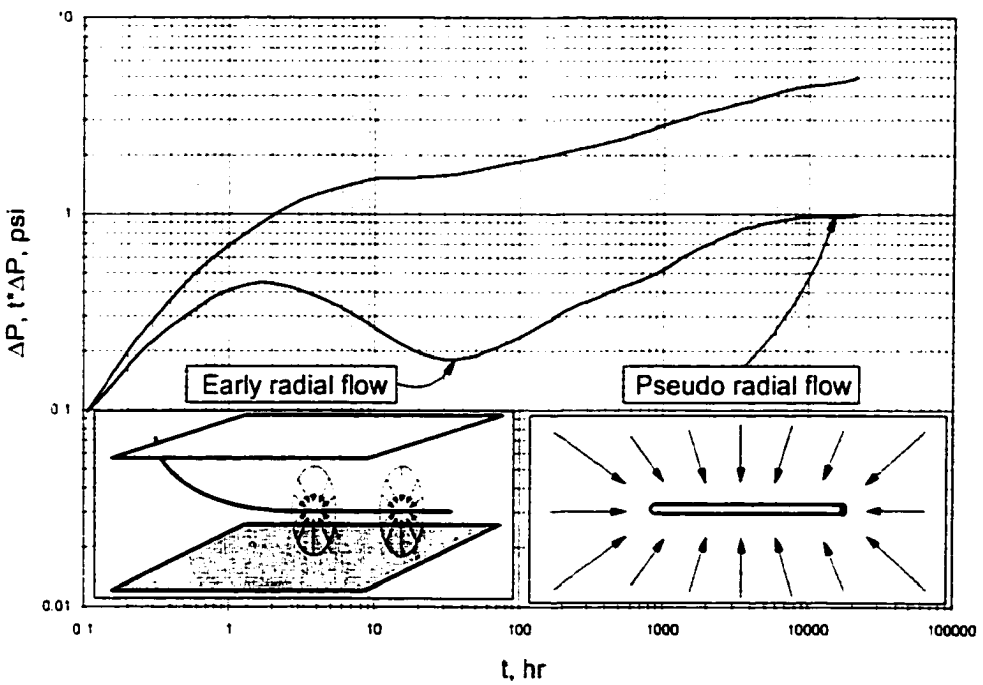


Fig. 6.7. Ideal log-log plot of horizontal well test showing unit fingerprint of flow regimes[39].

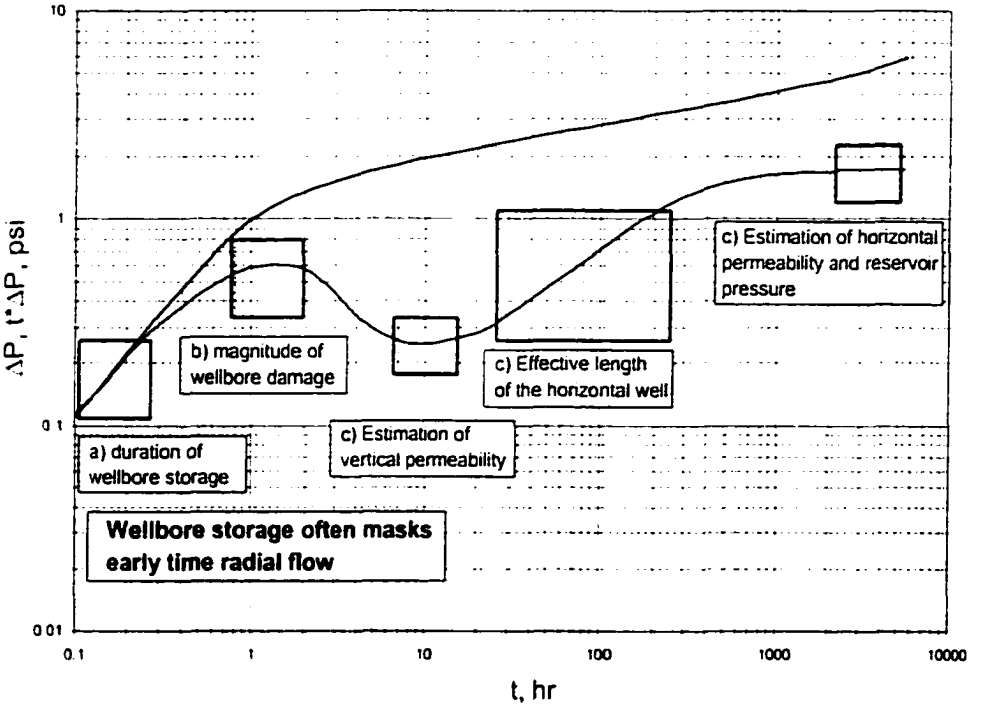


Fig. 6.8. Main features of an ideal horizontal well test[39].

6.5.1. Wellbore Storage Effects

For a constant wellbore storage coefficient, C, wellbore-storage-dominated flow is identified on the diagnostic plot by a collinear graph of ΔP and P' with unit slope. During this period, conventional interpretation methods will yield no information about the reservoir or completion parameters.

Typically, there is a substantial storage volume associated with a horizontal wellbore, which can have serious consequences on the effectiveness of a pressure transient test, even when the measurement tool is located below a downhole shut-in device. Daviau et al.[38] showed that the first semi log straight line associated with early time radial flow almost always disappears because of the effects of wellbore storage, see Fig. 9.

Kuchuk et al. [6] noted that the storage effect in a horizontal well typically lasts longer than that for a vertical well in the same formation, because of (a)

greater wellbore volume, (b) anisotropy reduces the effective permeability for a horizontal well.

It is significant that the first semi log straight line commonly does not appear due to wellbore storage because true wellbore damage s_m and horizontal permeability h_z can only be effectively estimated during that time. It has been suggested that this concern can some times be overcome by concurrently measuring downhole flow rates and pressures.

The end of the unit slope and the start of interpretable data, t_{eus}, can be estimated for the following equation which is derived from Agarwal et al.'s correlation.

$$t_{eus} = \frac{(4000 + 240 S_m)C}{\sqrt{k_H k_v} L_w / \mu} \tag{6.25}$$

The wellbore storage coefficient, C (bbl/psi), for a wellbore filled with a single-phase fluid is calculated as:

$$C = \frac{V_{wb}}{c_{fwb}} \tag{6.26}$$

For a liquid with a free gas/liquid interface in a wellbore of volume per unit length, V_u, making an angle, with the vertical, θ,

$$C = \frac{144 V_u}{\rho \cos\theta} \tag{6.27}$$

The most reliable value for C is obtained from data points on the unit slope of the diagnostic plot.

$$C = \frac{qB}{24} \frac{\Delta t}{\Delta P} \tag{6.31}$$

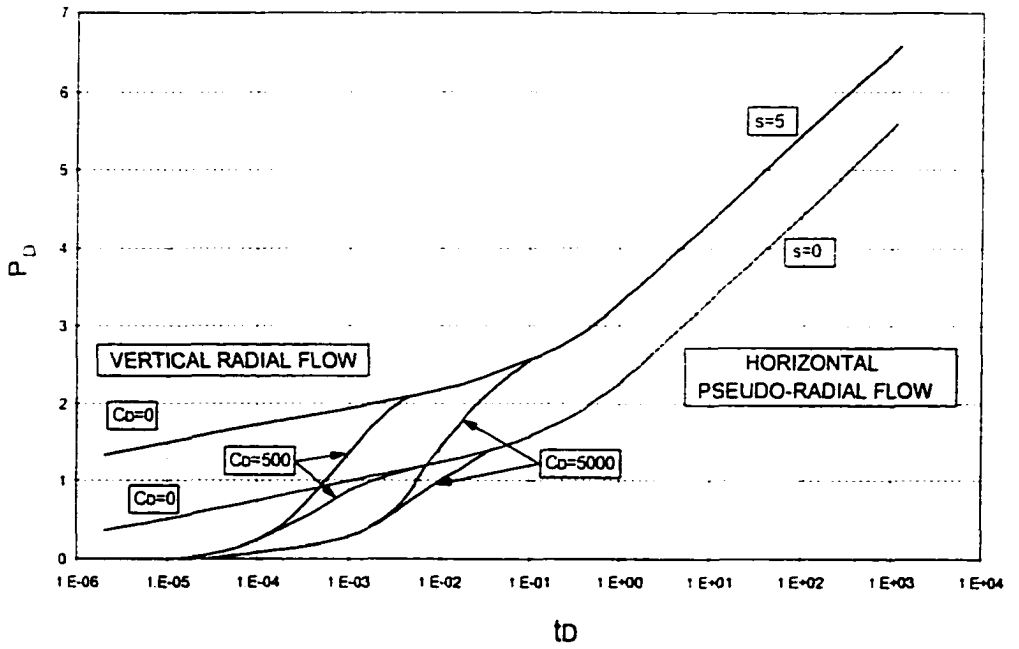


Fig. 6.9. Log-log plot of horizontal well test showing radial flow regimes[39].

6.6 Well Test Analysis Using Surface Measured Rates In Two-Phase Systems

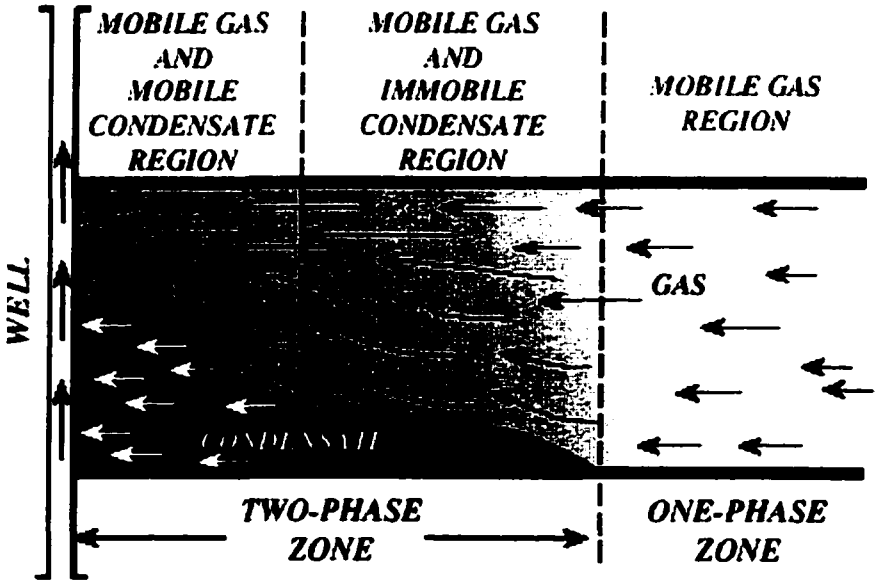


Fig.6.10. Flow conditions in gas-condensate reservoir under three regions[26].

6.6.1 Producing Gas Oil Ratio In Region-1

Producing gas oil ratio was treated in chapter four. For convenience it is treated here too for well test analysis.

By Definition

$$R_p = \frac{q_{gT}}{q_{oT}} = \frac{q_{g,free} + q_{o,free} R_s}{q_{o,free} + q_{g,free} R_o} \tag{6.32}$$

$$R_p = \frac{q_{gT}}{q_{oT}} = \frac{C\left[\left(\frac{k_{rg}}{B_g \mu_g}\right) + \left(\frac{k_{ro}}{B_o \mu_o}\right) R_s\right]}{C\left[\left(\frac{k_{ro}}{B_o \mu_o}\right) + \left(\frac{k_{rg}}{B_g \mu_g}\right) R_o\right]} \tag{6.33}$$

On simplification

$$R_P = R_s + \left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{B_o\mu_o}{B_g\mu_g}\right)\left(1 - R_O\ R_P\right) \tag{6.34}$$

$$R_P(P) = \left[\frac{R_s + \left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{B_o\mu_o}{B_g\mu_g}\right)}{1 + R_O\left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{B_o\mu_o}{B_g\mu_g}\right)}\right](P) \tag{6.35}$$

Solving for k_{rg}/k_{ro} results,

$$\left(\frac{k_{rg}}{k_{ro}}\right) = \frac{(R_P - R_s)}{(1 - R_O\ R_P)}\left(\frac{B_g\mu_g}{B_o\mu_o}\right) \tag{6.36}$$

6.6.2 Mathematical Basis of Well Testing-Vertical Wells

$$q_m = C_1\Delta mP_1 + C_2\Delta mP_2 + C_3\Delta mP_3 \tag{6.37}$$

Gas Phase

$$mP_1 = \int_{P_{wf}}^{P^*}\left(\frac{k.k_{ro}(P)}{B_o.\mu_o}R_s + \frac{k.k_{rg}(P)}{B_{gd}.\mu_{gd}}\right)dp \tag{6.38}$$

Let

$$M_{o1} = \int_{P_{wf}}^{P^*} k.k_{ro}(P)dp \tag{6.39}$$

$$M_{g1} = \int_{P_{wf}}^{P^*} k.k_{rg}(P)dp \tag{6.40}$$

Then

$$mP_{g1} = M_{o1}\int_{P_{wf}}^{P^*}\left(\frac{R_s}{B_o.\mu_o}\right)dp + M_{g1}\int_{P_{wf}}^{P^*}\left(\frac{1}{B_{gd}.\mu_{gd}}\right)dp \tag{6.41}$$

Region-1

Pressure transient response in terms of pseudopressure can be represented as[47]

$$mP_{P<P^*} - mP_{wf} = 162.6\left(\frac{q_{g,meas}}{h}\right)\left[\log(t) + \log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right) - 3.2275 + 0.8686S\right] \tag{6.42}$$

Above equation is valid until the upper limit of pressure reaches the P* and we enter the Region-2.

Thus one can write

$$\int_{P_{wf}}^{P}\left(\frac{k.k_{ro}(P)}{B_o.\mu_o}R_s+\frac{k.k_{rg}(P)}{B_{gd}.\mu_{gd}}\right)dp-\int_{P_{wf}}^{P_{wf}}\left(\frac{k.k_{ro}(P)}{B_o.\mu_o}R_s+\frac{k.k_{rg}(P)}{B_{gd}.\mu_{gd}}\right)dp$$
$$=162.6\left(\frac{q_{g.meas}}{h}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right)-3.2275+0.8686S\right] \quad (6.43)$$

Simplifying and then substituting Eq.6.36 (for k.kg) in above equation results

$$\int_{P_{wf}}^{P}\left[\frac{1}{B_o.\mu_o}\left(R_s+\frac{(R_p-R_s)}{(1-R_sR_p)}\right)\right]dp \quad (6.44)$$
$$=\frac{162.6}{\int_{P_{wf}}^{P}(k.k_{ro}(P))dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right)-3.2275+0.8686S\right]$$

Above equation is the pseudopressure response of a well in gas condensate reservoirs, and provides the Oil effective permeability as a function of pressure.

Now substituting Eq.6.36 (k.kro) and simplifying yields

$$\int_{P_{wf}}^{P}\left[\frac{1}{B_g.\mu_g}\frac{(1-R_sR_o)R_p}{(R_p-R_s)}\right]dp \quad (6.45)$$
$$=\frac{162.6}{\int_{P_{wf}}^{P}(k.k_{rg}(P))dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right)-3.2275+0.8686S\right]$$

Above equation provides gas phase effective permeability since it has been put in the slope of the above equation.

Region-2

$$mP_{g2} = \int_{P^*}^{P_i} \left(\frac{k.k_{rg}(P)}{B_{gd} \cdot \mu_{gd}} \right) dp \tag{6.46}$$

Similarly

$$M_{g2} = \int_{P^*}^{P_i} k.k_{rg}(P) dp \tag{6.47}$$

$$mP_{g2} = M_{g2} \int_{P^*}^{P_i} \left(\frac{1}{B_{gd} \cdot \mu_{gd}} \right) dp \tag{6.48}$$

Pressure Response

$$mP_d - mP^* = 162.6 \left(\frac{q_{g,meas}}{h} \right) \left[\log(t) + \log\left(\frac{k_e(P)}{\phi \mu c_t r_c^2} \right) - 3.2275 + 0.8686S \right] \tag{6.49}$$

$$\int_{P^*}^{P_i} \left(\frac{1}{B_{gd} \cdot \mu_{gd}} \right) dp = \frac{162.6}{M_{g2}} \left(\frac{q_{g,meas}}{h} \right) \left[\log(t) + \log\left(\frac{k_e(P)}{\phi \mu c_t r_c^2} \right) - 3.2275 + 0.8686S \right] \tag{6.50}$$

Where r_c is the distance at which P = P*.

$$r_c = 0.029 \sqrt{\frac{ke(P^*)\ t^*}{\phi \mu^* c_t}} \tag{6.51}$$

Where * values are taken at the intersection of first and second straight line. Straight-line section represents the different flow regimes on the pressure derivative curve as shown in Fig.6.7 and Fig. 6.8. At this point Pressure is P*. Viscosity, effective permeability are function of P*. Solving Eq.6.44 and 6.45 for skin factor respectively'

$$S_1 = 1.1513 \left[\frac{h \Delta mP_{g1,1hr}}{q_{g,meas} M_{g1hr}} - \log\left(\frac{k_{eg}(P_{1hr})}{\phi \mu c_t r_w^2} \right) + 3.2275 \right] \tag{6.52}$$

$$S_1 = 1.1513 \left[\frac{h \Delta mP_{1hr}}{q_{g,meas} M_{o1hr}} - \log\left(\frac{k_{eo}(P_{1hr})}{\phi \mu c_t r_w^2} \right) + 3.2275 \right] \tag{6.53}$$

Similarly from Eq.6.49

$$S_2 = 1.1513\left[\frac{h\Delta mP_{g2,1hr}}{q_{g,meas}\cdot M_{g2,1hr}} - \log\left(\frac{k_{eg2}(P_{1hr})}{\phi\mu c_t r_c^2}\right) + 3.2275\right] \quad (6.54)$$

Intersection of 1st and 2nd straight line is P* and intersection of 2nd and 3rd straight line is the Pd.

Region-3

In Region-3 no phase change occurs. Therefore

$$mP_{g3} = \int_{P_i}^{P_3}\left(\frac{1}{B_{gd}\cdot\mu_{gd}}\right)dp \quad (6.55)$$

$$mP_e - mP_d = 162.6\left(\frac{q_{g,meas}}{h\,k}\right)\left[\log(t) + \log\left(\frac{k}{\phi\mu c_t r_d^2}\right) - 3.2275 + 0.8686S\right] \quad (6.56)$$

$$\int_{P_d}^{P_3}\left(\frac{1}{B_{gd}\cdot\mu_{gd}}\right)dp = 162.6\left(\frac{q_{g,meas}}{h\,k}\right)\left[\log(t) + \log\left(\frac{k}{\phi\mu c_t r_d^2}\right) - 3.2275 + 0.8686S\right] \quad (6.57)$$

Where r_d is the distance where P = Pd and k is the absolute permeability.

Solve Eq.6.57 for r_d by taking points at intersection of 2nd and 3rd straight lines.

Pressure Buildup

Region-1

Pressure buildup response in terms of pseudopressure is written as

$$mP_{ws} - mP_{wf(\Delta t=0)} = 162.6\left(\frac{q_{g,meas}}{h}\right)\left[\log(t) + \log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right) - 3.2275 + 0.8686S\right] \quad (6.58)$$

Eq. 6.44 for pressure buildup becomes

$$\int_{P_{wf(\Delta t=0)}}^{P_{ws}}\left[\frac{1}{B_o\cdot\mu_o}\left(R_s + \frac{(R_p - R_s)}{(1 - R_s R_p)}\right)\right]dp \quad (6.59)$$

$$= \frac{162.6}{\int_{P_{wf(\Delta t=0)}}^{P_{ws}}(k.k_{ro}(P))dp}\left(\frac{q_{g,meas}}{h}\right)\left[\log(t) + \log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right) - 3.2275 + 0.8686S\right]$$

Eq. 6.45 similarly can be written as follows

$$\int_{P_{wf}(\Delta t=0)}^{P_{ws}} \left[\frac{1}{B_g \cdot \mu_g}\frac{(1-R_s R_o)R_p}{(R_p - R_s)}\right]dp \qquad (6.60)$$

$$= \frac{162.6}{\int_{P_{wf}(\Delta t=0)}^{P}(k.k_{rg}(P))dp}\left(\frac{q_{g,meas}}{h}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right)-3.2275+0.8686S\right]$$

Above equations are valid until Pws = P*

Region-2

$$mP_{ws} - mP^* = 162.6\left(\frac{q_{g,meas}}{h}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_c^2}\right)-3.2275+0.8686S\right] \qquad (6.61)$$

$$\int_{P^*}^{P_{ws}}\left(\frac{1}{B_{gd}\cdot\mu_{gd}}\right)dp = \frac{162.6}{M_{g2}}\left(\frac{q_{g,meas}}{h}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_c^2}\right)-3.2275+0.8686S\right] \qquad (6.62)$$

Region-3

$$mP_{ws} - mP_d = 162.6\left(\frac{q_{g,meas}}{h\,k}\right)\left[\log(t)+\log\left(\frac{k}{\phi\mu c_t r_d^2}\right)-3.2275+0.8686S\right] \qquad (6.63)$$

$$\int_{P_d}^{P_{wf}}\left(\frac{1}{B_{gd}\cdot\mu_{gd}}\right)dp = 162.6\left(\frac{q_{g,meas}}{h\,k}\right)\left[\log(t)+\log\left(\frac{k}{\phi\mu c_t r_d^2}\right)-3.2275+0.8686S\right] \qquad (6.64)$$

Summary of Equations

Region-1

E.No.	Parameter	Equation
6.45	Keg	$\int_{P_{wf}}^{P}(k.k_{rg}(P))dp = \frac{162.6}{\Delta mPg_1}\left(\frac{q_{g,meas}}{h}\right)$
6.44	Koe	$\int_{P_{wf}}^{P}(k.k_{ro}(P))dp = \frac{162.6}{\Delta mPo_1}\left(\frac{q_{g,meas}}{h}\right)$

	Skin	$S_1 = 1.1513\left[\frac{h\Delta mP_{g1.1hr}}{q_{g.meas}M_{g1hr}} - \log\left(\frac{k_{eg}(P_{1hr})}{\phi\mu c_t r_w^2}\right) + 3.2275\right]$
6.53	Skin	$S_1 = 1.1513\left[\frac{h\Delta mP_{1hr}}{q_{g.meas}M_{g1hr}} - \log\left(\frac{k_{eo}(P_{1hr})}{\phi\mu c_t r_w^2}\right) + 3.2275\right]$

Region-2

E.No.	Parameter	Equation
6.50	Keg	$\int_{P^*}^{P_d}(k.k_{rg}(P))dp = \frac{162.6}{\Delta mPg_2}\left(\frac{q_{g.meas}}{h}\right)$
6.54	Skin	$S_2 = 1.1513\left[\frac{h\Delta mP_{g2.1hr}}{q_{g.meas}M_{g21hr}} - \log\left(\frac{k_{eg2}(P_{1hr})}{\phi\mu c_t r_c^2}\right) + 3.2275\right]$

Region-3

E.No.	Parameter	Equation
6.64	Keg	$\int_{P_{df}}^{P}(k.k_{rg}(P))dp = \frac{162.6}{\Delta mPg_3}\left(\frac{q_{g.meas}}{h}\right)$

6.6.3 Well Test Analysis Using Surface Measured Rates In Three-Phase Systems

Fig.6.11 is the conceptual model of the condensate development as the dew point is reached. It begins to flow when P* approaches.

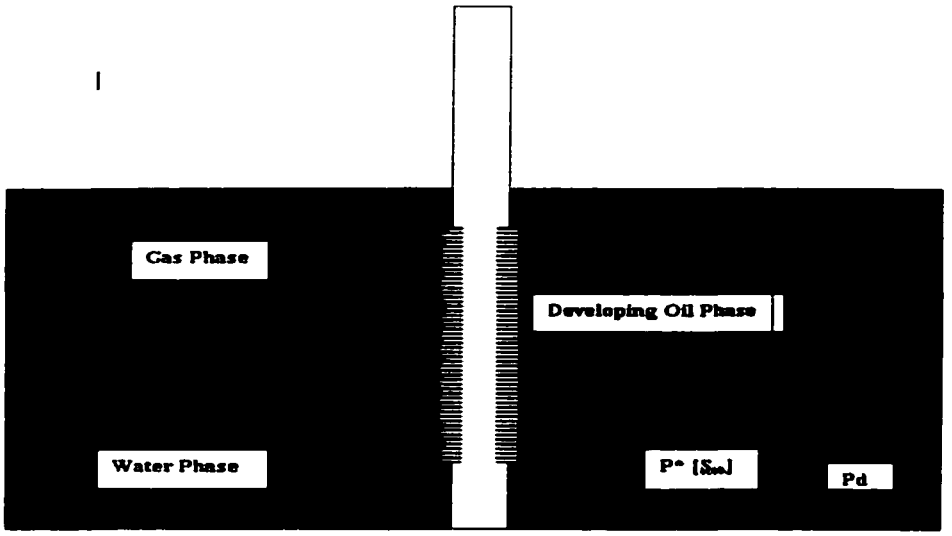


Fig.6.11. Thee-phase system with developing oil phase

6.6.3.1 Producing Gas Oil Ratio in Three-Phase Systems (R_{pgo}).

By Definition (In Region-1)

$$R_p = \frac{q_{gT}}{q_{OT}} = \frac{q_{g.free} + q_{o.free}R_S + q_w R_{sgw}}{q_{O.free} + q_{g.free}R_o} \tag{6.65}$$

One can write

$$R_p = \frac{q_{gT}}{q_{OT}} = \frac{q_{g.free} + q_{o.free}R_S}{q_{O.free} + q_{g.free}R_o} + \frac{q_w R_{sgw}}{q_{O.free} + q_{g.free}R_o} \tag{6.66}$$

or

$$R_p = \frac{q_{gT}}{q_{OT}} = \frac{q_{g.free} + q_{o.free}R_S}{q_{O.free} + q_{g.free}R_o} + R_{pwo}R_{sgw} \tag{6.67}$$

$$R_{Pgo} = \frac{q_{gT}}{q_{oT}} = \frac{\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{B_o\mu_o}\right)R_s}{\left(\frac{k.k_{ro}}{B_o\mu_o}\right) + \left(\frac{k.k_{rg}}{B_g\mu_g}\right)R_o} + R_{pwo}R_{sgw} \tag{6.68}$$

$$\left(R_{Pgo} - R_{pwo}R_{sgw}\right) = \frac{\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{B_o\mu_o}\right)R_s}{\left(\frac{k.k_{ro}}{B_o\mu_o}\right) + \left(\frac{k.k_{rg}}{B_g\mu_g}\right)R_o} \tag{6.69}$$

Solving for Oil and gas effective permeabilities respectively, results

$$k.k_{rg} = \left(B_g\mu_g\right)\left(\frac{k.k_{ro}}{B_o\mu_o}\right)\frac{\left(B - R_{so}\right)}{\left(1 - BR_{so}\right)} \tag{6.70}$$

$$k.k_{ro} = \left(B_o\mu_o\right)\left(\frac{k.k_{rg}}{B_g\mu_g}\right)\frac{\left(1 - BR_{so}\right)}{\left(B - R_{so}\right)} \tag{6.71}$$

Where

$$B = \left(R_{pgo} - R_{pwo}R_{sgw}\right) \tag{6.72}$$

Equation 6.65 can also be written as

$$R_{Pgo} = \frac{q_{gT}}{q_{oT}} = \frac{C\left[\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{B_o\mu_o}\right)R_s + \left(\frac{k.k_{rw}}{B_w\mu_w}\right)R_{sgw}\right]}{C\left[\left(\frac{k.k_{ro}}{B_o\mu_o}\right) + \left(\frac{k.k_{rg}}{B_g\mu_g}\right)R_o\right]} \tag{6.73}$$

On simplification

$$R_{Pgo} = \frac{q_{gT}}{q_{oT}} = \frac{\left[\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{B_o\mu_o}\right)R_s + \left(\frac{k.k_{rw}}{B_w\mu_w}\right)R_{sgw}\right]}{\left[\left(\frac{k.k_{ro}}{B_o\mu_o}\right) + \left(\frac{k.k_{rg}}{B_g\mu_g}\right)R_o\right]} \tag{6.74}$$

Simplifynig and solving for individual phase effective permeabilities, yields

$$k_g = kk_{rg} = \left(\frac{\mu_g B_g}{\mu_o B_o}\right)\frac{kk_{ro}}{\left(R_o R_{Pgo} - 1\right)}\left[\left(R_{so} - R_{Pgo}\right) + R_{sgw}\left(\frac{k.k_{rw}}{\mu_o B_o}\right)\right] \tag{6.75}$$

$$k_o = kk_{ro} = \left[\frac{(R_s R_{Pgo} - 1)}{\left[(R_{so} - R_{Pgo}) + R_{sgw}\left(\frac{k.k_{rw}}{\mu_w B_w}\right)\right]}\right]\left(\frac{\mu_o B_o}{\mu_g B_g}\right)\left[kk_{rg}\right] \tag{6.76}$$

$$kk_{rw} = \left[\left(\frac{\mu_o B_o}{\mu_g B_g}\right)\left(\frac{kk_{rg}}{kk_{ro}}\right)(R_o R_{Pgo} - 1) - (R_{so} - R_{Pgo})\right]\left(\frac{\mu_w B_w}{R_{sgw}}\right) \tag{6.77}$$

6.6.3.2 Producing Oil-Water Ratio (R_{pow}) in Three-phase Systems (Region-1)

Assuming that the oil and water phase are completely immissible, the two-phase system equation for production oil-water apply. This assumption is not an unreasonable assumption.

$$R_{Pow} = \frac{q_o}{q_w} = \frac{q_{g.free} R_o + q_{o.free}}{q_w} \tag{6.78}$$

$$R_{Pow} = \frac{q_o}{q_w} = C\left[\left(\frac{k.k_{rg}}{B_g \mu_g}\right)R_o + \left(\frac{k.k_{ro}}{B_o \mu_o}\right)\right]\frac{1}{C\left[\left(\frac{k.k_{rw}}{B_w \mu_w}\right)\right]} \tag{6.79}$$

On simplifying, results

$$R_{Pow} = \frac{q_o}{q_w} = \left(\frac{k.k_{rg}}{k.k_{rw}}\right)\left(\frac{B_w \mu_w}{B_g \mu_g}\right)R_o + \left(\frac{k.k_{ro}}{k.k_{rw}}\right)\left(\frac{B_w \mu_w}{B_o \mu_o}\right) \tag{6.80}$$

Solving for water and gas effective permeability respectively.

$$k.k_{rw} = \left(\frac{B_w \mu_w}{R_{Pow}}\right)\left[\left(\frac{k.k_{rg}}{B_g \mu_g}\right)R_o + \left(\frac{k.k_{ro}}{B_o \mu_o}\right)\right] \tag{6.81}$$

$$k.k_{rg} = \left[\left(\frac{R_{Pow}}{B_w \mu_w}\right)(k.k_{rw}) - \left(\frac{k.k_{ro}}{B_o \mu_o}\right)\right]\left(\frac{B_g \mu_g}{R_o}\right) \tag{6.82}$$

$$k.k_{ro} = \left[\left(\frac{R_{Pow}}{B_w \mu_w}\right)(k.k_{rw}) - \left(\frac{k.k_{rg}}{B_g \mu_g}\right)R_o\right](B_o \mu_o) \tag{6.83}$$

6.6.3.3 Producing Gas-Water Ratio (R_{pgw}) Three-phase Systems (Region-1)

Similarly

$$R_{Pgw} = \frac{q_o}{q_w} = \frac{q_{g.free} + q_o R_s + q_w R_{sgw}}{q_w} \tag{6.84}$$

Where R_{sgw} is the solution gas-water ratio expressed as SCF /STB. For two phase systems $R_{sgw} = 0$.

$$R_{Pgw} = \frac{q_{gT}}{q_w} = \frac{C\left[\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{B_o\mu_o}\right)R_s + \left(\frac{k.k_{rw}}{B_w\mu_w}\right)R_{sgw}\right]}{C\left[\left(\frac{k.k_{rw}}{B_w\mu_w}\right)\right]} \tag{6.85}$$

Simplifying, results

$$R_{Pgw} = \frac{q_{gT}}{q_w} = \left(\frac{k.k_{rg}}{k.k_{rw}}\right)\left(\frac{B_w\mu_w}{B_g\mu_g}\right) + \left(\frac{k.k_{ro}}{k.k_{rw}}\right)\left(\frac{B_w\mu_w}{B_o\mu_o}\right)R_s + R_{sgw} \tag{6.86}$$

Solving for water and gas effective permeability respectively.

$$k.k_{rw} = \frac{B_w\mu_w}{(R_{Pgw} - R_{sgw})}\left(\frac{k.k_{rg}}{B_g\mu_g} + \frac{k.k_{ro}}{B_o\mu_o}R_s\right) \tag{6.87}$$

$$k.k_{rg} = \left[\left(R_{Pgw} - R_{sgw}\right)\left(\frac{k.k_{rw}}{B_w\mu_w}\right) - \left(\frac{k.k_{ro}}{B_o\mu_o}R_s\right)\right]\left(B_g\mu_g\right) \tag{6.88}$$

$$k.k_{ro} = \left[\left(R_{Pgw} - R_{sgw}\right)\left(\frac{k.k_{rw}}{B_w\mu_w}\right) - \left(\frac{k.k_{rg}}{B_g\mu_g}\right)\right]\left(\frac{B_o\mu_o}{R_s}\right) \tag{6.89}$$

Region-2

$$R_{Pgw} = \frac{q_g}{q_w} = \frac{q_{g.free} + q_w R_{sgw}}{q_w} \tag{6.90}$$

$$R_{Pgw} = \frac{q_{gT}}{q_w} = \frac{C\left[\left(\frac{k.k_{rg}}{B_g\mu_g}\right) + \left(\frac{k.k_{rw}}{B_w\mu_w}\right)R_{sgw}\right]}{C\left[\left(\frac{k.k_{rw}}{B_w\mu_w}\right)\right]} \tag{6.91}$$

$$R_{Pgw} - R_{sgw} = \left(\frac{k.k_{rg}}{B_g \mu_g}\right)\left(\frac{B_w \mu_w}{k.k_{rw}}\right) \tag{6.92}$$

Solving for oil and gas effective permeability respectively, results

$$k.k_{rg} = (B_g \mu_g)(R_{Pgw} - R_{sgw})\left(\frac{k.k_{rw}}{B_w \mu_w}\right) \tag{6.93}$$

$$k.k_{rw} = \left(\frac{k.k_{rg}}{B_g \mu_g}\right)\left(\frac{B_w \mu_w}{R_{Pgw} - R_{sgw}}\right) \tag{6.94}$$

Region-2

$$R_{Pgw} = \frac{q_g}{q_w} = \frac{q_{g,free} + q_w R_{sgw}}{q_w} \tag{6.95}$$

$$R_{Pgw} = \frac{q_{gT}}{q_w} = \frac{C\left[\left(\frac{k.k_{rg}}{B_g \mu_g}\right) + \left(\frac{k.k_{rw}}{B_w \mu_w}\right) R_{sgw}\right]}{C\left[\left(\frac{k.k_{rw}}{B_w \mu_w}\right)\right]} \tag{6.96}$$

$$R_{Pgw} - R_{sgw} = \left(\frac{k.k_{rg}}{B_g \mu_g}\right)\left(\frac{B_w \mu_w}{k.k_{rw}}\right) \tag{6.97}$$

Solving for oil and gas effective permeability respectively, results

$$k.k_{rg} = (B_g \mu_g)(R_{Pgw} - R_{sgw})\left(\frac{k.k_{rw}}{B_w \mu_w}\right) \tag{6.98}$$

$$k.k_{rw} = \left(\frac{k.k_{rg}}{B_g \mu_g}\right)\left(\frac{B_w \mu_w}{R_{Pgw} - R_{sgw}}\right) \tag{6.99}$$

Pseudopressure Function for Three phase Systems (mP)

Region-1

$$mP_{g1} = \int_{P_{wf}}^{P \le P^*} \left(\frac{\mathrm{k.k}_g}{\mu_g B_g} + \frac{\mathrm{k.k}_o}{\mu_o B_o} R_{so} + \frac{\mathrm{k.k}_w}{\mu_w B_w} R_{sgw}\right) dp \tag{6.100}$$

Substituting Eq. 6.87 in above equation and simplifying results

$$mP_{g1} = \int_{P_{wf}}^{P \le P^*} \left(\frac{\text{k.k}_g}{\mu_g B_g} A + \frac{\text{k.k}_o}{\mu_o B_o} A R_{so} \right) dp \tag{6.101}$$

Where

$$A = \frac{R_{pgw}}{R_{pgw} - R_{sgw}} \tag{6.102}$$

Now substituting Eq.6.81 in Eq.6.100 and simplifying results

$$mP_{g1} = \int_{P_{wf}}^{P \le P^*} \text{k.k}_g \left(\frac{R_{pgw}}{(R_{pgw} - R_{sgw})(\mu_g B_g)} \left(1 + R_{so} \left(\frac{1 - BR_o}{B - R_{so}} \right) \right) \right) dp \tag{6.103}$$

Where

$$B = (R_{pgo} - R_{pwo} R_{sgw}) \tag{6.104}$$

Now substituting Eq.6.72 in Eq.6.100 and simplifying results

$$mP_{g1} = \int_{P_{wf}}^{P \le P^*} \text{k.k}_{ro} \left(\frac{R_{pgw}}{(R_{pgw} - R_{sgw})(\mu_o B_o)} \left(\frac{B(1 - R_o)}{1 - BR_o} \right) \right) dp \tag{6.105}$$

Substituting Eq.6.88 in Eq.6.99 and simplifying results

$$mP_{g1} = \int_{P_{wf}}^{P \le P^*} R_{pgw} \frac{\text{k.k}_{rw}}{\mu_w B_w} dp \tag{6.106}$$

Region-2

$$mP_{g2} = \int_{P^*}^{P \le P_d} \left(\frac{\text{k.k}_{rg}}{\mu_g B_g} + R_{sgw} \frac{\text{k.k}_{rw}}{\mu_w B_w} \right) dp \tag{6.107}$$

Substituting equations 6.97 and 6.98 in Eq.6.107 result, respectively

$$mP_{g2} = \int_{P^*}^{P \le P_d} \left(\frac{\text{k.k}_{rg}}{\mu_g B_g} \left(1 + \frac{R_{sgw}}{R_{pgw}} \right) \right) dp \tag{6.108}$$

$$mP_{g2} = \int_{P^*}^{P \le P_d} \left(\frac{\text{k.k}_{rw}}{\mu_w B_w} R_{pgw} \right) dp \tag{6.109}$$

Region-3

Similarly

$$mP_{g3} = \int_{P_i}^{P}\left(\frac{\text{k.k}_{rg}}{\mu_g B_g} + R_{sgw}\frac{\text{k.k}_{rw}}{\mu_w B_w}\right)dp \tag{6.110}$$

$$mP_{g3} = \int_{P_i}^{P}\left(\frac{\text{k.k}_{rg}}{\mu_g B_g}\left(1 + \frac{R_{sgw}}{R_{pgw}}\right)\right)dp \tag{6.111}$$

$$mP_{g3} = \int_{P_i}^{P}\left(\frac{\text{k.k}_{rw}}{\mu_w B_w} R_{pgw}\right)dp \tag{6.112}$$

6.6.3.4. Pressure Response During a Well Test-Vertical Well

Drawdown

Equation of pressure response during pressure transient test is[47]

$$mP_{P<P^*} - mP_{wf} = 162.6\left(\frac{q_{g.meas}}{h}\right)\left[\log(t) + \log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right) - 3.2275 + 0.8686S\right] \tag{6.113}$$

Region-1

Substituting Eq. 6.103 in Eq.6. 113 and simplifying results

$$\int_{P_{wf}}^{P\le P^*}\left(\frac{R_{pgw}}{(R_{pgw} - R_{sgw})(\mu_g B_g)}\left(1 + R_{so}\left(\frac{1 - BR_o}{B - R_{so}}\right)\right)\right)dp$$
$$= \frac{162.6}{\int_{P_{wf}}^{P\le P^*}\text{k.k}_g\,dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log(t) + \log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right) - 3.2275 + 0.8686S\right] \tag{6.114}$$

$$B = (R_{pgo} - R_{pwo}R_{sgw})$$

Eq.6.114 provides gas phase effective permeability as a function of pressure. Now substituting Eq. 6.104 in Eq. 6.113 and simplifying results the correlation for oil effective permeability.

$$\int_{P_{wf}}^{P\le P^*}\left(\frac{R_{pgw}}{(R_{pgw} - R_{sgw})(\mu_o B_o)}\left(\frac{B(1 - R_o)}{1 - BR_o}\right)\right)dp$$
$$= \frac{162.6}{\int_{P_{wf}}^{P\le P^*}\text{k.k}_{ro}\,dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log(t) + \log\left(\frac{k_e(P)}{\phi\mu c_t r_w^2}\right) - 3.2275 + 0.8686S\right] \tag{6.115}$$

Substituting Eq.6.106 in 6.113 provides the water phase effective permeability

$$\int_{P_{wf}}^{P<P^*} \frac{R_{pgw}}{\mu_w B_w} dp = \frac{162.6}{\int_{P_{wf}}^{P<P^*} \text{k.k}_{rw} dp} \left(\frac{q_{g,meas}}{h} \right) \left[\log(t) + \log\left(\frac{k_e(P)}{\phi \mu c_t r_w^2} \right) - 3.2275 + 0.8686S \right] \quad (6.116)$$

Equations 6.114, 6.115, and 6.116 provide gas, oil, and water phase effective permeability as function of pressure from Region-1.

Region-2

Similarly the pressure response for Region-2 is obtained using the definition of pseudopressure for Region-2.

$$\int_{P^*}^{P<P_d} \left(\frac{1}{\mu_g B_g} \left(1 + \frac{R_{sgw}}{R_{pgw}} \right) \right) dp = \frac{162.6}{\int_{P^*}^{P<P_d} (\text{k.k}_{rg}) dp} \left(\frac{q_{g,meas}}{h} \right) \left[\log(t) + \log\left(\frac{k_e(P)}{\phi \mu c_t r_e^2} \right) - 3.2275 + 0.8686S \right] \quad (6.117)$$

$$\int_{P^*}^{P<P_d} \left(\frac{1}{\mu_w B_w} R_{pgw} \right) dp = \frac{162.6}{\int_{P^*}^{P<P_d} (\text{k.k}_{rw}) dp} \left(\frac{q_{g,meas}}{h} \right) \left[\log(t) + \log\left(\frac{k_e(P)}{\phi \mu c_t r_e^2} \right) - 3.2275 + 0.8686S \right] \quad (6.118)$$

Equations 6.117 and 6.118 provide gas and water phase effective permeability in Region-2. The oil phase is immobile in this region.

Region-3

In Region-3 pseudopressure has same definition but different pressure limits of reservoir pressure and dew point pressure.

$$\int_{P_d}^{P} \left(\frac{1}{\mu_g B_g} \left(1 + \frac{R_{sgw}}{R_{pgw}} \right) \right) dp = \frac{162.6}{\int_{P_d}^{P} (\text{k.k}_{rg}) dp} \left(\frac{q_{g,meas}}{h} \right) \left[\log(t) + \log\left(\frac{k_e(P)}{\phi \mu c_t r_d^2} \right) - 3.2275 + 0.8686S \right] \quad (6.119)$$

$$\int_{P_i}^{P}\left(\frac{1}{\mu_w B_w}R_{pcw}\right)dp=\frac{162.6}{\int_{P_i}^{P}(k.k_{rw})dp}\left(\frac{q_{c\,meas}}{h}\right)\left[\log(t)+\log\left(\frac{k_e(P)}{\phi\mu c_t r_d^2}\right)-3.2275+0.8686S\right] \quad (6.120)$$

Equations 6.119 and 1.120 provide gas and water phase effective permeability in Region-2. For pressure Buildup $\Delta mP = mP_{sw}-mP_{wf(\Delta t=0)}$. Since the existence of the all three regions is time and depletion dependent, it is rare that all three regions exist all together at the same time in the reservoir. If they do, we should observe three straight lines on semi-log plot. The regions can be recognized by the prior knowledge of dew point pressure. If any two straight lines are observed and the highest test pressure during a buildup test achieved is lower that the dew point pressure then Region-1 and Region-2 exist. The intersection of these two lines is the P*. If highest test pressure is above the dew point pressure and only two straight lines are observed, regions 2 and 3 exist. The intersection of these two lines is the Pd. The extrapolation of the 3rd region to $\Delta t = 1$ on Horner plot is the reservoir pressure.

6.6.3.4.1 Skin Factor

Skin factor at the wellbore in three-phase systems is the combination of formation damage, condensate blockage, and non-Darcy flow. The maximum well deliverability in gas phase, the main production of such wells, may however be due to the immobile liquid condensate that buildup in Region-2 and acts as skin factor. Solving Eq.6.114, 6.115, and 6.116 respectively for skin factor in Region-1 results

$$S_1=1.1513\left[\Delta mP_{g1,1hr}\frac{M_{g1hr}h}{q_{g,meas}}-\log\left(\frac{k_{eg}(P_{1hr})}{\phi\mu c_t r_w^2}\right)+3.2275\right] \quad (6.121)$$

$$S_1=1.1513\left[\Delta mP_{1hr}\frac{M_{o1hr}h}{q_{g,meas}}-\log\left(\frac{k_{eo}(P_{1hr})}{\phi\mu c_t r_w^2}\right)+3.2275\right] \quad (6.122)$$

$$S_1 = 1.1513\left[\Delta mP_{1hr}\frac{M_{a1hr}h}{q_{g,meas}} - \log\left(\frac{k_{ew}(P_{1hr})}{\phi\mu c_t r_w^2}\right) + 3.2275\right] \quad (6.123)$$

Solving Eq. 6.117, and 6.118 for skin factor respectively, results

$$S_2 = 1.1513\left[\Delta mP_{g2,1hr}\frac{M_{g21hr}h}{q_{g,meas}} - \log\left(\frac{k_{eg2}(P_{1hr})}{\phi\mu c_t r_c^2}\right) + 3.2275\right] \quad (6.124)$$

$$S_2 = 1.1513\left[\Delta mP_{g2,1hr}\frac{M_{a21hr}h}{q_{g,meas}} - \log\left(\frac{k_{ew2}(P_{1hr})}{\phi\mu c_t r_c^2}\right) + 3.2275\right] \quad (6.125)$$

And r_c is the distance at which P = P*.

$$r_c = 0.029\sqrt{\frac{ke(P^*)\ t^*}{\phi\mu^* c_t}} \quad (6.126)$$

6.6.3.5 Well Test Analysis Using Surface Measured Rates In Two-Phase Systems-Horizontal Wells

6.6.3.5.1. Early Time Radial Flow

Region-1

Comparing Eq.6.14 with Eq.6.44, the pressure response of a horizontal well during early radial flow regime in Region-1 can be expressed using the definition of the gas phase pseudopressure function in Region-1. The gas phase pseudopressure function contains oil phase effective permeability term. Thus oil phase effective permeability can be estimated from the early radial flow regime.

Oil Phase

$$mP_i - mP_{wf} = \int_{P_{wf}}^{P}\left[\frac{1}{B_o\cdot\mu_o}\left(R_s + \frac{(R_p - R_s)}{(1 - R_s R_p)}\right)\right]dp$$

$$= \frac{162.6}{\int_{P_{wf}}^{P}\left((k.k_{ro})_y (k.k_{ro})_z (P)\right)dp}\left(\frac{q_{g,meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{ro})(kk_{ro})(p)}}{\phi\ \mu c_t (L_{zb} - L_{za})^2}t\right) - 3.227 + 0.866S_{a,1}\right] \quad (6.127)$$

To solve above equation t and the $(k.k_{ro})_y.(k.k_{ro})_z$ correspond to a specific point such as P_{1hr} etc on the semi-log plot. Above equation provides oil phase effective permeability using surface measured gas rate.

Gas Phase

Comparing Eq.6.14 with Eq.6.45 provides the gas effective permeability during early radial flow regime in the Region-1.

$$\int_{P_{wf}}^{P}\left[\frac{1}{B_g.\mu_g}\frac{(1-R_s R_o)R_p}{(R_p-R_s)}\right]dp$$

$$=\frac{162.6}{\int_{P_{wf}}^{P}\left((k.k_{rg})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g,meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{rg})_y(kk_{rg})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a,1}\right]$$

(6.128)

Region-2

Comparing Eq.6.14 with Eq.6.50 and then simplifying results

$$\int_{P^*}^{P_d}\left(\frac{1}{B_{gd}.\mu_{gd}}\right)dp$$

$$=\frac{162.6}{\int_{P^*}^{Pd}\left((k.k_{rg})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g,meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{rg})_y(kk_{rg})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a,1}\right]$$

(6.129)

Thus gas effective permeability in Region-2 can be calculated from Eq.6.129.

Region-3

Comparing Eq.6.14 with Eq.6.57 and then simplifying results the effective permeability of gas in Region-3.

$$\int_{Pd}^{P}\left(\frac{1}{B_{gd}\cdot\mu_{gd}}\right)dp$$

$$=\frac{162.6}{\int_{Pd}^{P}\left((k.k_{rg})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{rg})_y(kk_{rg})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a1}\right]$$

(6.130)

Late Radial Flow Regime

The equation of pressure response during late radial flow regime has been expressed using Eq.6.20.

$$mP_i-mP_{wf}=\frac{162.6q}{h_z\sqrt{k_yk_x}}\left[\log\left(\frac{r_w^2k_xt}{\phi\mu c_tr_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_xk_z}} \qquad (6.20)$$

Comparing Eq.6.20 with Eq.6.44 and simplifying results the oil phase effective permeability in Region-1 during late radial flow regime.

Region-1

$$mP_i-mP_{wf}=\int_{P_{wf}}^{P}\left[\frac{1}{B_o\cdot\mu_o}\left(R_s+\frac{(R_p-R_s)}{(1-R_sR_p)}\right)\right]dp$$

$$=\frac{162.6}{\int_{P_{wf}}^{P}\left((k.k_{ro})_y(k.k_{ro})_x(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2(k_{ro})_xt}{\phi\mu c_tr_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_xk_z}}$$

(6.131)

The gas phase effective permeability can be calculated using the gas phase pseudopressure function that contains the gas effective permeability term.

$$\int_{P_{wf}}^{P}\left[\frac{1}{B_g\cdot\mu_g}\frac{(1-R_sR_o)R_p}{(R_p-R_s)}\right]dp$$

$$=\frac{162.6}{\int_{P_{wf}}^{P}\left((k.k_{rg})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2(k_{rg})_xt}{\phi\mu c_tr_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_xk_z}} \qquad (6.132)$$

This equation provides gas phase effective permeability in Regio-1 during the late radial flow regime.

Region-2

Similarly if the reservoir falls under Region-2 condition, pressure response during the late radial flow regime can be expressed as follows with the pseudopressure defined for Region-2.

$$\int_{P^*}^{P_d}\left(\frac{1}{B_{gd}.\mu_{gd}}\right)dp = \frac{162.6}{\int_{P^*}^{Pd}\left((k.k_{rg})_v(k.k_{rg})_r(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2(k_{rg})_r t}{\phi\mu c_t r_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_r k_z}} \quad (6.133)$$

Region-3

If the reservoir pressure is above the dew point pressure then the radial flow regime can be expressed as

$$\int_{Pd}^{P}\left(\frac{1}{B_{gd}.\mu_{gd}}\right)dp = \frac{162.6}{\int_{Pd}^{P}\left((k.k_{rg})_v(k.k_{rg})_r(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2(k_{rg})_r t}{\phi\mu c_t r_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_r k_z}} \quad (6.134)$$

6.6.3.6 Well Test Analysis Using Surface Measured Rates In Three-Phase Systems-Horizontal Wells

6.6.3.6.1 Early Radial

Region-1

Comparing Eq. 6.14 with Eq.6.114 and on simplification, one gets;

Gas Phase: If the well is flowing under three phase conditions, and is in Region-1 (reservoir pressure is below the P*), the pressure response is expressed with the definition of the pseudopressure in Region-1 for three phase

systems. Thus the gas phase effective permeability can be estimated form Eq.6.135.

$$\int_{P_{wf}}^{P\le P^*}\left(\frac{R_{pgw}}{(R_{pgw}-R_{sgw})(\mu_g B_g)}\left(1+R_{so}\left(\frac{1-BR_o}{B-R_{so}}\right)\right)\right)dp$$

$$=\frac{162.6}{\int_{P_{wf}}^{P\le P^*}(k.k_{rg})_y(k.k_{rg})_z\,dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{rg})_y(kk_{rg})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a.1}\right]$$

(6.135)

Oil Phase

Similarly for the oil phase effective permeability in Region-1 in three phase systems can be obtained during the early radial flow regime as follows

$$\int_{P_{wf}}^{P\le P^*}\left(\frac{R_{pgw}}{(R_{pgw}-R_{sgw})(\mu_o B_o)}\left(\frac{B(1-R_o)}{1-BR_o}\right)\right)dp$$

$$=\frac{162.6}{\int_{P_{wf}}^{P}((k.k_{ro})_y(k.k_{ro})_z(P))dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{ro})(kk_{ro})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a.1}\right]$$

(6.136)

Water Phase

The water phase pressure response during early radial flow regime in three phase systems can be expressed using the definition of three phase pseudopressure in Region-1.

$$\int_{P_{wf}}^{P\le P^*}\frac{R_{pgw}}{\mu_w B_w}dp$$

$$=\frac{162.6}{\int_{P_{wf}}^{P}((k.k_{rw})_y(k.k_{rw})_z(P))dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{rw})_z(kk_{rw})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a.1}\right]$$

(6.137)

Region-2, similarly

Gas Phase

The definition of pseudopressure in Region-2 is used to express pressure response in Region-2.

$$\int_{P^*}^{P\le P_d}\left(\frac{1}{\mu_g B_g}\left(1+\frac{R_{sgw}}{R_{pgw}}\right)\right)dp$$

$$=\frac{162.6}{\int_{P^*}^{Pd}\left((k.k_{rg})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g,meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{rg})_y(kk_{rg})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a,1}\right]$$

(6.138)

Water Phase

Similarly, the water phase effective permeability in Raegion-2 can be estimated from following equation of pressure response in Region-2.

$$\int_{P^*}^{P\le P_d}\left(\frac{1}{\mu_w B_w}R_{pgw}\right)dp$$

$$=\frac{162.6}{\int_{P^*}^{Pd}\left((k.k_{rw})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g,meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{rg})_y(kk_{rg})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a,1}\right]$$

(6.139)

Region-3

Gas Phase

The gas phase in Region-3 is expressed with the definition of the pseudopressure in Region-3.

$$\int_{Pd}^{P_d}\left(\frac{1}{\mu_g B_g}\left(1+\frac{R_{sgw}}{R_{pgw}}\right)\right)dp$$

$$=\frac{162.6}{\int_{Pd}^{P}\left((k.k_{rg})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g,meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{rg})_y(kk_{rg})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a,1}\right]$$

(6.140)

Water Phase

Similarly, the water phase is modeled using the definition of three phase pseudopressure function in Region-3

$$\int_{Pd}^{P}\left(\frac{1}{\mu_w B_w}R_{pgw}\right)dp$$

$$=\frac{162.6}{\int_{Pd}^{P}\left((k.k_{rg})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{\sqrt{(k.k_{rg})_y(kk_{rg})_z(p)}}{\phi\,\mu c_t(L_{zb}-L_{za})^2}t\right)-3.227+0.866S_{a.1}\right]$$

(6.141)

6.6.3.6.2.Late Radial Flow Regime

Similarly the late radial flow regime in Region-1, Region-2, and Region-3 is expressed as follows:

Region-1

$$\int_{P_{wf}}^{P\le P^*}\left(\frac{R_{pgw}}{(R_{pgw}-R_{sgw})(\mu_o B_o)}\left(\frac{B(1-R_o)}{1-BR_o}\right)\right)dp$$

$$=\frac{162.6}{\int_{P_{wf}}^{P}\left((k.k_{ro})_y(k.k_{ro})_z(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2(k_{ro})_z t}{\phi\mu c_t r_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_z k_Z}}$$

(6.142)

Above equation provides oil phase effective permeability.

$$\int_{P_{wf}}^{P\le P^*}\left(\frac{R_{pgw}}{(R_{pgw}-R_{sgw})(\mu_g B_g)}\left(1+R_{so}\left(\frac{1-BR_o}{B-R_{so}}\right)\right)\right)dp$$

$$=\frac{162.6}{\int_{P_{wf}}^{P}\left((k.k_{rg})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2(k_{rg})_z t}{\phi\mu c_t r_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_z k_Z}}$$

(6.143)

This equation provides gas phase effective permeability in Regio-1 during the late radial flow regime.

Region-2

The gas phase effective permeability during a late radial flow regime in Region-2 in a three phase systems can be obtained by expressing the pressure response in terms of the pseudopressure in Region-2.

$$\int_{P^*}^{P\le P_d}\left(\frac{1}{\mu_g B_g}\left(1+\frac{R_{sgw}}{R_{pgw}}\right)\right)dp = \frac{162.6}{\int_{P^*}^{Pd}\left((k.k_{rg})_y (k.k_{rg})_z (P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2 (k_{rg})_z t}{\phi\mu c_t r_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_z k_Z}} \quad (6.144)$$

Water Phase

Similarly the water effective permeability can be obtained as follows;

$$\int_{P^*}^{P\le P_d}\left(\frac{1}{\mu_w B_w}R_{pgw}\right)dp = \frac{162.6}{\int_{P^*}^{Pd}\left((k.k_{rw})_y (k.k_{rw})_z (P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2 (k_{rw})_z t}{\phi\mu c_t r_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_z k_Z}} \quad (6.145)$$

Region-3

Gas Phase

Similarly if the reservoir conditions fall in Region-3 then gas effective permeability is estimated using the definition of pseudopressure function in that region.

$$\int_{Pd}^{P}\left(\frac{1}{\mu_g B_g}\left(1+\frac{R_{sgw}}{R_{pgw}}\right)\right)dp$$

$$=\frac{162.6}{\int_{Pd}^{P}\left((k.k_{rg})_y(k.k_{rg})_z(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2(k_{rg})_z t}{\phi\mu c_t r_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_z k_Z}}$$

(6.146)

Water Phase

Similarly water phase effective permeability can be calculated as

$$\int_{Pd}^{P}\left(\frac{1}{\mu_w B_w}R_{pgw}\right)dp$$

$$=\frac{162.6}{\int_{P}^{P}\left((k.k_{rw})_y(k.k_{rw})_z(P)\right)dp}\left(\frac{q_{g.meas}}{h}\right)\left[\log\left(\frac{r_w^2(k_{rw})_z t}{\phi\mu c_t r_{wa}^2}\right)-3.23\right]+\frac{141.2q}{L}\frac{S_{a2}}{\sqrt{k_z k_Z}}$$

(6.147)

Chapter VII

Direct Synthesis Technique for Horizontal Well Tests in Gas Condensate Reservoirs

7. 1 Direct Synthesis

Consider the well and reservoir configuration of Fig.6.1. The reservoir of thickness h_z is bounded by impermeable upper and lower boundaries. In the horizontal plane the reservoir can be infinite or semi-infinite (bounded in the x direction) depending on the horizontal well length and width thickness h_x. The permeabilities are anisotropic and parallel to the principal directions. The horizontal well is parallel to the upper and lower boundaries, but does not have to be centered within the formation thickness. It is also parallel to a principal axis. The pressure drop within the horizontal well is assumed negligible; therefore, the infinite conductivity boundary condition applies.

The solution of Goode And Thambynayagam[36] is also adopted in this section because of its mathematically convenient form. The dimensionless solution for an infinite or semi-infinite reservoir penetrated by a horizontal well in an anisotropic, homogeneous porous media is given by:

$$mP_D = \frac{2L_w r_{wa}}{h_x h_z}\left[\sqrt{\pi t_D} + \frac{h_x^2}{\pi^2 \nu_x}\sum_{n=1}^{\infty}\operatorname{erf}(\nu_x \pi n\sqrt{t_D})\frac{\xi_n^2}{n} + \frac{h_x h_z}{L_w \nu_z \pi}\sum_{m=1}^{\infty}\operatorname{erf}(\nu_z \pi m\sqrt{t_D})\frac{\xi_m}{m}\cos(m\pi z_e)\right] + \sqrt{\frac{k_y}{k_z}}s_m \qquad (7.1)$$

The derivative with respect to time of Eq. 7.1 is:

$$mP'_D = \frac{2L_w r_{wa}}{h_x h_z}\sqrt{\frac{\pi}{t_D}}\left[\frac{1}{2} + \frac{h_x^2}{\pi^2}\sum_{n=1}^{\infty}\exp[-(\nu_x \pi n)^2 t_D]\xi_n^2 + \frac{h_x h_z}{L_w \pi}\sum_{m=1}^{\infty}\exp[-(\nu_z \pi m)^2 t_D]\xi_m\cos(m\pi z_e)\right] \qquad (7.2)$$

The dimensionless variables are:

$$mP_D = \frac{k_y L_w}{141.2q} \Delta mP \tag{7.3}$$

$$t_D = \frac{0.0002637 k_y t}{16\phi\mu c_t (r_{wa})^2} \tag{7.4}$$

$$C_D = \frac{0.8935C}{\phi c_t L r_w^2} \tag{7.5}$$

$$v_x = \frac{L_{zb} - L_{za}}{h_x} \sqrt{\frac{k_x}{k_y}} \tag{7.6}$$

$$v_z = \frac{L_{zb} - L_{za}}{h_z} \sqrt{\frac{k_z}{k_y}} \tag{7.7}$$

$$\xi_n = \frac{\sin\frac{m\pi L_{xl}}{h_x} - \sin\frac{m\pi L_{xd}}{h_x}}{m(L_{xl} - L_{xd})} \tag{7.8}$$

$$\xi_m = \frac{\sin\frac{m\pi L_{za}}{h_z} - \sin\frac{m\pi L_{zb}}{h_z}}{m(L_{zb} - L_{za})} \tag{7.9}$$

The apparent wellbore radius converts the strip source to a well of radius r_w. Accounting for anisotropy the relationship can be expressed as:

$$4r_{wa} = 4r_w \left(\frac{k_z}{k_y}\right)^{1/4} = (L_{zb} - L_{za}) \tag{7.10}$$

The dimensionless wellbore length is defined as:

$$L_D = \frac{h_z}{2L_w} \sqrt{\frac{k_z}{k_h}} \tag{7.11}$$

The point at which the effective pressure is measured in the horizontal well is expressed by:

$$z_e = \frac{1}{h_z}(h_s + 1.47 r_{wa}) \tag{7.12}$$

L_{zb}-L_{za} = $4r_{wa}$

$$\frac{d\Delta mP_D}{dt_D} = \Delta mP'_D = 429.709\frac{(\phi\ \mu\ c_t)(r_{wa})^2 L}{q}\Delta mP' \tag{7.13}$$

$$(t_D \bullet \Delta mP_D) = \frac{k_v L}{141.2q}(t \bullet \Delta mP\ ) \tag{7.14}$$

$$\frac{t_D}{C_D} = 1.844x10^{-5}\frac{k_Y L\left(\frac{r_w}{r_{wa}}\right)^2}{C\ \mu}t \tag{7.15}$$

$$\left(\frac{t_D}{C_D} \bullet \Delta mP_D\right) = \frac{7.93x10^{-3} k_v (\phi c_t)(Lr_w)^2}{qC}(t \bullet \Delta mP\ ) \tag{7.16}$$

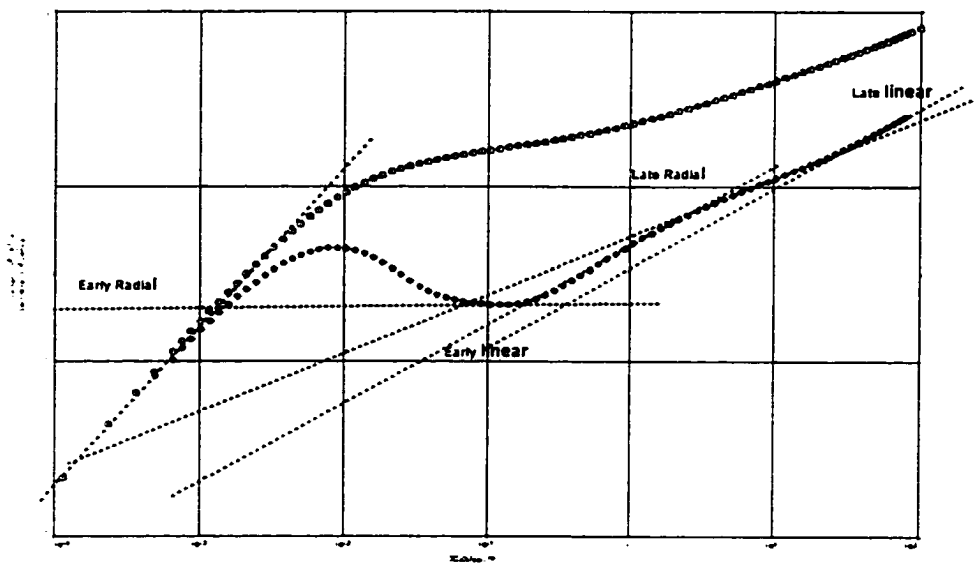


Fig.7.1 Different Flow Regimes in a Horizontal Well

7.1.1 Characteristic Points and Lines

A log-log plot of dimensionless pressure and pressure derivative versus time is shown in Fig.7.2. Identified on this figure are the characteristic points and lines available for evaluating the pressure test. Referring to this figure the following analysis can be achieved.

(1) The first flow regime represents infinite-acting, *early time radial flow* in the yz plane, Fig. 6.1. The dimensionless flow equation which describes this region is:

$$mP_d = \frac{1}{2}\sqrt{\frac{k_y}{k_z}}\left[\ln\left(\sqrt{\frac{k_z}{k_y}}\,t_D\right) + 0.80907 + 2s_m\right] \tag{7.17}$$

with the corresponding pressure derivative given by:

$$t_D \cdot mP_D = \frac{1}{2}\sqrt{\frac{k_y}{k_z}} \tag{7.18}$$

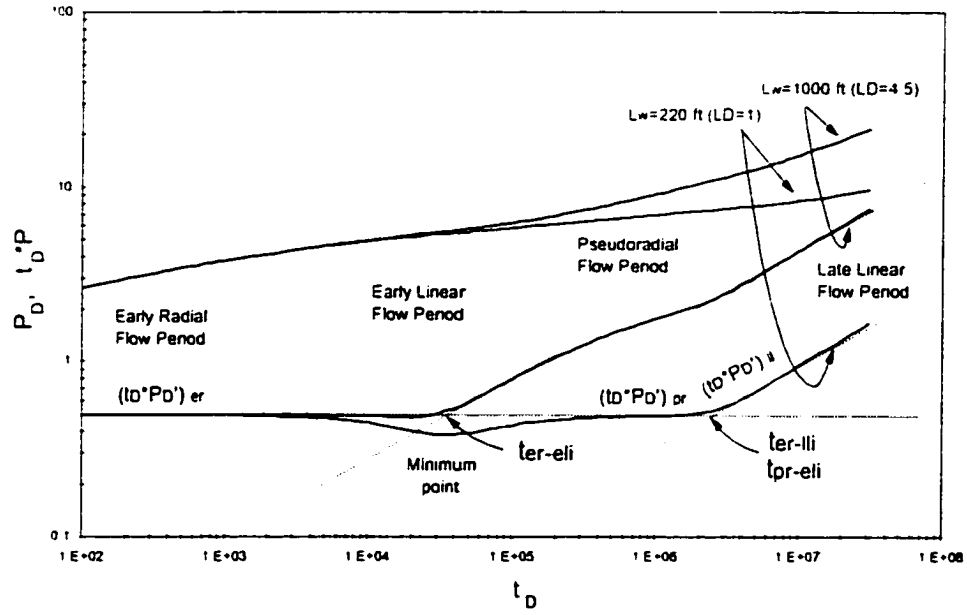


Fig. 7.2. Pressure response in a horizontal well illustrating the characteristic points and lines.

Substituting the Eq. 7.14 in 7.18, results

$$\sqrt{k_y\,k_z} = 70.6\frac{q}{L\left(t \bullet \Delta mP'\right)_{ER}} \tag{7.19}$$

(2) The second flow regime, as discussed in the previous section, corresponds to early time linear flow in response to the pressure transient reaching the upper and lower boundaries simultaneously. This flow period occurs when the horizontal well length is sufficiently long in comparison to the thickness and/or the vertical permeability is greater than the horizontal permeability. In dimensionless form the pressure equation for this linear flow period is given by:

$$mP_D = \frac{2r_w}{h_z}\sqrt{\pi t_D} + (s_z + s_m)\sqrt{\frac{k_y}{k_z}} \tag{7.20}$$

And the corresponding pressure derivative by:

$$(t_D \bullet mP'_D) = \frac{r_w}{h_z}\sqrt{\pi t_D} \tag{7.21}$$

Taking the logarithm of both sides of Eq.7.21 results

$$\log(t_D \bullet \Delta mP_D') = \frac{1}{2}\log(t_D) + \log\left(\frac{\sqrt{\pi} r_w}{h_z}\right) \tag{7.22}$$

Substituting Eqs 7.4 and 7.14 in 7.22 and taking log on both sides, yields

$$\log(t \bullet \Delta P') = \frac{1}{2}\log(t) + \log(M_{L1}) \tag{7.23}$$

Where

$$M_{L1} = \frac{1.016q\left(\frac{r_w}{r_{wa}}\right)}{\sqrt{(k_y \phi \mu c_t)L}\, h_z} \tag{7.24}$$

At t = 1 hr, Eq. 7.23 reduces to

$$\log(t_D \bullet \Delta mP_D') = \log(M_{L1}) \tag{7.25}$$

From which

$$\sqrt{k_Y} = \frac{1.016q\left(\frac{r_w}{r_{wa}}\right)}{\sqrt{(\phi \mu c_t)h_z L}\left(t \bullet \Delta mP'\right)_{EL-1hr}} \tag{7.26}$$

(3) The third flow regime is known as pseudoradial flow in the xy plane. This flow regime may not be present if the horizontal length is long compared to the reservoir thickness or if the reservoir width is small relative to the horizontal length. The dimensionless pressure and pressure derivative equations for pseudoradial flow are:

$$mp_D = \frac{L_w}{2h_z}\sqrt{\frac{k_y}{k_x}}\left[\ln\left(\frac{16k_x r_w^2}{k_y L_w^2}t_d\right) + 0.80907\right] + \frac{k_y}{\sqrt{k_x k_z}}(s_z + s_m) \tag{7.27}$$

and

$$(t_D \bullet mP'_D) = \frac{1}{2}\frac{L_w}{h_z}\sqrt{\frac{k_y}{k_x}} \tag{7.28}$$

In real units, Eq. 7.28 provides an expression for the permeability product in X and Y direction.

$$\sqrt{k_x k_y} = \frac{70.6q}{h_z(t \bullet \Delta mP)_{LR}} \tag{7.29}$$

(4) A second linear flow period is observed if the width boundaries (h_x) affect the pressure response. Assume the horizontal well is symmetrically located between the two width boundaries. This assumption, however, does not have to be enforced. Asymmetric boundaries or a single no flow boundary representing a fault can be modeled with this method. The dimensionless pressure and pressure derivative equations are:

$$mP_D = 2\left(\frac{L_w r_w}{h_x h_z}\right)\sqrt{\pi t_D} + (s_r + s_z + s_m + S_{cl} + Dq)\sqrt{\frac{k_y}{k_z}} \tag{7.30}$$

$$(t_D \bullet mP'_D) = \left(\frac{L_w r_w}{h_x h_z}\right)\sqrt{\pi t_D} \tag{7.31}$$

$$\log(t_D \Delta P') = \frac{1}{2}\log(t_D) + \log(M_{L2}) \tag{7.32}$$

$$M_{L2} = \frac{1.016q\left(\frac{r_w}{r_{wa}}\right)}{\sqrt{(k_y \phi \mu c_t)L}\, h_X h_Z} \tag{7.33}$$

$$k_Y = \frac{1.016q\left(\frac{r_w}{r_{wa}}\right)}{\sqrt{(\phi \mu c_t)h_x h_Z L}\,(t \bullet \Delta mP')_{LL-1hr}} \tag{7.34}$$

Equation 7.34 can be used to calculate reservoir width, h_x.

Summary of Equations

Eq. #	Flow Regime	Equation
7.19	Early Radial	$\sqrt{k_Y k_Z} = 70.6 \frac{q}{L\left(t \bullet \Delta mP\right)_{ER}}$
7.26	Early Linear	$\sqrt{k_Y} = \frac{1.016q\left(\frac{r_w}{r_{wa}}\right)}{\sqrt{(\phi \mu c_t)} h_Z L \left(t \bullet \Delta mP\right)_{EL-1hr}}$
7.29	Late Radial	$\sqrt{k_x k_y} = \frac{70.6q}{h_z\left(t \bullet \Delta mP\right)_{LR}}$
7.34	Late Linear	$k_Y = \frac{1.016q\left(\frac{r_w}{r_{wa}}\right)}{\sqrt{(\phi \mu c_t)} h_X h_Z L \left(t \bullet \Delta mP'\right)_{LL-1hr}}$

7.1.2 Wellbore Storage Effects

5) Theory of wellbore storage effects is well established. Wellbore storage effects are recognized by early time unit slope line on log-log plot of pressure versus time and pressure derivative versus time. The equation of this unit slope line is

$$mP_D = \frac{t_D}{C_D} \tag{7.35}$$

On pressure derivative plot the equation of this line is

$$\frac{t_D}{C_D} mP'_D = \frac{t_D}{C_D} \tag{7.36}$$

The left hand side of the Eq.7.36 in field units for real gases can be written as

$$\frac{t_D}{C_D} mP'_D = \frac{k_Y L}{141.2q}\left(t \bullet \Delta mP'\right) \tag{7.37}$$

6) At the intersection of early radial line and unit slope line have co-ordinates t_i and $(t \bullet \Delta mP')_I$ Thus Eq. 7.19 can be written as

$$\sqrt{k_Y k_Z} = 50.9 \text{x} 10^3 \frac{qT}{L\left(t \bullet \Delta mP'\right)_{i-ER}} \tag{7.38}$$

$$\frac{t_D}{C_D} = 0.5 \tag{7.39}$$

Substituting the values, one gets

$$C = \frac{3.69x10^{-5} k_Y L\left(\frac{r_w}{r_{wa}}\right)^2}{\mu} t_i \tag{7.40}$$

$$\text{Or } t_i = \frac{1}{3.69x10^{-5}} \frac{C\mu}{k_Y L\left(\frac{r_w}{r_{wa}}\right)^2} \tag{7.40a}$$

7) At the intersection of unit slope line indicating wellbore storage effects with early time linear flow line

Eq. 7.40 can be rearranged as

$$t_i = \frac{C\mu}{3.69x10^{-4} k_Y L\left(\frac{r_w}{r_{wa}}\right)^2} \tag{7.41}$$

At the intersection early time linear line is expressed as

$$\log(t_{D\bullet}\Delta mP_D')_i = \frac{1}{2}\log(t_{D,i}) + \log\left(\frac{\sqrt{\pi} r_w}{h_Z}\right) \tag{7.42}$$

In filed units and solving for ti, results

$$t_i = \frac{2(\phi\ \mu\ c_t L^2 z)}{0.0002637}\left[\frac{9.818x10^{-6} L(t \bullet \Delta mP)_i}{q} - M_{Li}\right] \tag{7.43}$$

Equating Eqs.7.41 and 7.43 and solving for wellbore storage co-efficient, C

$$C = (\phi\ c_t L^2 z)(k_Y L)\left(\frac{r_w}{r_{wa}}\right)^2\left[\frac{6.89x10^{-6} L(t \bullet \Delta mP')_i}{q} - 0.702M_{Li}\right] \tag{7.44}$$

$Lz = (L_{Zb}-L_{Za})$

$$\frac{\sqrt{k_x k_y}\, h_z}{141.2qL}\left(t \bullet \Delta mP'\right)_{i\text{-}LR} = 0.5 \qquad (7.45)$$

Also

$$\frac{t_D}{C_D} = 0.5$$

In oilfield units

$$\frac{1.844x10^{-5} k_Y L\left(\frac{r_w}{r_{wa}}\right)^2}{\mu C} t_i = 0.5 \qquad (7.46)$$

Equation 7.45 and 7.46 and solving for C, results

$$C = 2.6x10^{-3}\left(\sqrt{\frac{k_Y}{k_X}}\right)\left(\frac{qL}{h_Z}\right)\left(\frac{r_w}{r_{wa}}\right)^2\left(\frac{t_i}{\left(t \bullet \Delta mP'\right)_i}\right)_{US\text{-}LR} \qquad (7.47)$$

Summary of Equations (Wellbore Storage)

Eq. #	Intersection of	Equation
7.40	Early Radial and Unit Slope Line	$C = \dfrac{3.69x10^{-5} k_Y L\left(\frac{r_w}{r_{wa}}\right)^2}{\mu} t_i$
7.44	Early Linear with Unit slope Line	$t_i = \dfrac{C\mu}{3.69x10^{-4} k_Y L\left(\frac{r_w}{r_{wa}}\right)^2}$
7.47	Late Radial	$C = 2.6x10^{-3}\left(\sqrt{\frac{k_Y}{k_X}}\right)\left(\frac{qL}{h_Z}\right)\left(\frac{r_w}{r_{wa}}\right)^2\left(\frac{t_i}{\left(t \bullet \Delta mP'\right)_i}\right)_{US\text{-}LR}$

7.1.3 Intersection of Flow Regime Lines with each other

On extrapolation the intersection of the different lines representing different flow regimes will intersect each other revealing more information Fig.7.1

9) Intersection of Early Radial (ER) line with Early Linear (EL)

At intersection Eq. 7.19 can be rewritten as follows

$$\left(t \bullet \Delta mP\right)_{ER-EL} = 50.9x10^{3} \frac{q}{L\sqrt{k_y k_z}} \tag{7.48}$$

Eq. 7.21 can be written as

$$\log(t_{\bullet}\Delta P') = \frac{1}{2}\log(t_{\bullet}) + \log(M_{L1})$$

Or

$$(t_{\bullet}\Delta P') = M_{L1}\,(t_{\bullet})^{0.5} \tag{7.49}$$

At the intersection both line have same solution. Thus equating Eqs. 7.48 and 7.49 and solving for k_z results

$$\sqrt{k_z} = 69.45\left(\sqrt{(\phi\ \mu\ c_t)}\right)\left(\frac{r_{wa}}{r_w}\right)(h_z)\left(\frac{1}{\sqrt{t_i}}\right)_{ER-EL} \tag{7.50}$$

10) Intersection of Early Linear (EL) with Late Radial (LR)

Equation of late radial line is (Eq.7.29)

$$\left(t \bullet \Delta mP'\right)_{LR} = \frac{50.9x10^{3}qT}{h_z\sqrt{k_x k_y}} \tag{7.51}$$

Equating Eqs. 7.50 and 7.49 and solving for k_x results.

$$\sqrt{k_x} = 69.45\left(\sqrt{(\phi\ \mu\ c_t)}\right)\left(\frac{r_{wa}}{r_w}\right)(L)\left(\frac{1}{\sqrt{t_i}}\right)_{LR-EL} \tag{7.52}$$

11) Intersection of Late Radial (LR) with Late Linear (LL)

The equation of late linear line is

$$\log(t_{\bullet}\Delta P') = \frac{1}{2}\log(t_D) - \log(M_{L2})$$

At intersection

$$\log(t_{\bullet}\Delta P')_{i\text{-}LR\text{-}LL} = \frac{1}{2}\log(t_i) + \log(M_{L2}) \qquad (7.53)$$

In oilfield units

Or

$$(t_{\bullet}\Delta P')_{i\text{-}LR\text{-}LL} = (M_{L2})(t_i)^{\frac{1}{2}} \qquad (7.54)$$

Equating Eqs. 7.51 and 7.54 and solving for kx, yields

$$\sqrt{k_x} = 69.45\left(\sqrt{(\phi\ \mu\ c_t)}\right)\left(\frac{r_{wa}}{r_w}\right)(h_x)\left(\frac{1}{\sqrt{t_i}}\right)_{LR\text{-}EL} \qquad (7.55)$$

Summary of Equations (Intersection of Flow Regimes)

Eq. #	Intersection of	Equation
7.50	Early Radial-Early Linear	$\sqrt{k_z} = 69.45\left(\sqrt{(\phi\ \mu\ c_t)}\right)\left(\frac{r_{wa}}{r_w}\right)(h_z)\left(\frac{1}{\sqrt{t_i}}\right)_{ER\text{-}EL}$
7.52	Early Linear-Late Radial	$\sqrt{k_x} = 69.45\left(\sqrt{(\phi\ \mu\ c_t)}\right)\left(\frac{r_{wa}}{r_w}\right)(L)\left(\frac{1}{\sqrt{t_i}}\right)_{LR\text{-}EL}$
7.55	Late-Radial- Late Linear	$\sqrt{k_x} = 69.45\left(\sqrt{(\phi\ \mu\ c_t)}\right)\left(\frac{r_{wa}}{r_w}\right)(h_x)\left(\frac{1}{\sqrt{t_i}}\right)_{LR\text{-}EL}$

7.1.4 Ratios of the Lines

Horizontal well pressure derivative response is a composite response of the various flow regimes. Taking ratio of these lines results in additional information.

12) Ratio of Early Radial Line with Late Radial line.

Dividing Eq. 7.29 with Eq.7.19, results

$$\frac{(t \bullet \Delta mP)_{LR}}{(t \bullet \Delta mP)_{ER}} = \frac{70.6 \dfrac{q}{\sqrt{k_x k_y h_z}}}{70.6 \dfrac{q}{\sqrt{k_y k_z} L}}$$

$$\frac{(t \bullet \Delta mP)_{LR}}{(t \bullet \Delta mP)_{ER}} = \sqrt{\frac{k_z}{k_x}}\left(\frac{L}{h_z}\right) \qquad (7.56)$$

13) Ratio of Early Linear line with Late Linear line

$$\frac{(t \bullet \Delta mP')_{LL-1hr}}{(t \bullet \Delta mP')_{EL-1hr}} = \frac{\dfrac{1.016q\left(\dfrac{r_w}{r_{wa}}\right)}{\sqrt{(\phi\ \mu\ c_t)h_x h_z L\ k_y}}}{\dfrac{1.016q\left(\dfrac{r_w}{r_{wa}}\right)}{\sqrt{(\phi\ \mu\ c_t)h_z L}\ \sqrt{k_y}}}$$

On simplification

$$\frac{(t \bullet \Delta mP')_{LL-1hr}}{(t \bullet \Delta mP')_{EL-1hr}} = \frac{L}{h_x} \qquad (7.57)$$

14) Ratio of Early Radial with Early Linear (t =1hr)

$$\frac{(t \bullet \Delta mP')_{ER}}{(t \bullet \Delta mP')_{EL-1hr}} = \frac{70.6 \dfrac{q}{\sqrt{k_y k_z} L}}{\dfrac{1.016q\left(\dfrac{r_w}{r_{wa}}\right)}{\sqrt{(\phi\ \mu\ c_t)h_z L}\ \sqrt{k_y}}}$$

$$\frac{(t \bullet \Delta mP')_{ER}}{(t \bullet \Delta mP')_{EL-1hr}} = 69.45 \frac{\sqrt{(\phi\ \mu\ c_t)h_z}}{\left(\dfrac{r_w}{r_{wa}}\right)\sqrt{k_z} L} \qquad (7.58)$$

15) Ratio of Early Radial to Late Linear (t = 1hr)

$$\frac{(t \bullet \Delta mP)_{ER}}{(t \bullet \Delta mP)_{LL-1hr}} = \frac{50.9x10^3 \dfrac{q}{\sqrt{k_Y k_Z}L}}{\dfrac{732.85q\left(\dfrac{r_w}{r_{wa}}\right)}{\sqrt{(\phi\ \mu\ c_t)h_Z h_X}\sqrt{k_Y}\sqrt{k_Y}}}$$

$$\frac{(t \bullet \Delta mP)_{ER}}{(t \bullet \Delta mP)_{LL-1hr}} = 69.45\frac{\sqrt{(\phi\ \mu\ c_t)h_Z h_X}}{\left(\dfrac{r_w}{r_{wa}}\right)L}\left(\sqrt{\frac{k_Y}{k_Z}}\right) \qquad (7.59)$$

16) Ratio of Late Radial to Early Linear

$$\frac{(t \bullet \Delta mP')_{LR}}{(t \bullet \Delta mP')_{EL-1hr}} = \frac{50.9x10^3 \dfrac{q}{\sqrt{k_x k_y}h_z}}{\dfrac{732.85q\left(\dfrac{r_w}{r_{wa}}\right)}{\sqrt{(\phi\ \mu\ c_t)h_Z}L\sqrt{k_Y}}}$$

$$\frac{(t \bullet \Delta mP')_{LR}}{(t \bullet \Delta mP')_{EL-1hr}} = 69.45\frac{\sqrt{(\phi\ \mu\ c_t)}L}{\left(\dfrac{r_w}{r_{wa}}\right)}\left(\frac{1}{\sqrt{k_x}}\right) \qquad (7.60)$$

7.1.5 Skin Factor

From the theory of the horizontal well testing, it is clear that the early time radial flow regime is equal to the infinite acting radial flow in vertical wells. In horizontal wells, however, this flow regime is very short and is usually masked by wellbore storage effects and skin effects. Wellbore storage region, the hump, is same in both vertical and horizontal wells. This region is infact the transition from the unit slope wellbore storage line to radial flow in the formation.

The equation of this transition zone is [48].

$$Log\left(C_D e^{2S}\right) = 0.35\left(\frac{t_D}{C_D}\right)^{1.24} \qquad (7.61)$$

And

$$Log(C_D e^{2S}) = 1.71\left(\frac{t_D}{C_D}\Delta mP_D\right)^{1.1} \tag{7.62}$$

Substituting Eqs.715 in 7.61, results

$$Log(C_D e^{2S}) = 4.72x10^{-7}\left(\left(\frac{r_w}{r_{wa}}\right)^2 \frac{k_v}{C\mu} t_X\right)^{1.24} \tag{7.63}$$

Now Substituting Eqs.740 and 7.5 in 7.63 and solving for S, yield

$$S = 1.28x10^{-2}\left(\frac{t_X}{t_{i-ER}}\right)^{1.24} - 0.5\ln\left(\frac{0.8935C}{\phi\mu c_t L r_w^2}\right) \tag{7.64}$$

Similarly substituting Eq. 7.16 in 7.62 results

$$Log(C_D e^{2S}) = 1.71\left(\frac{6.78x10^{-7} k_v L^2(\phi c_t)(r_w)^2}{qC}(t \bullet \Delta mP')_X\right)^{1.1} \tag{7.64a}$$

Now substituting Eq.7.19 for K_y and 7.5 for C_D in above equation and solving for S, gives

$$S = 3.22x10^3\left(\frac{(\phi c_t)(r_w)^2}{k_z qC}\right)^{1.1}\left(\frac{(t \bullet \Delta mP')_X}{(t \bullet \Delta mP')^2_{i-ER}}\right)^{1.1} - 0.5\ln\left(\frac{0.8935C}{\phi\mu c_t L r_w^2}\right) \tag{7.65}$$

Summary of Equations (Ratios of Flow Regimes)

Eq. #	Ratio of	Equation
7.56	Late Radial-Early Radial	$\frac{(t \bullet \Delta mP')_{LR}}{(t \bullet \Delta mP')_{ER}} = \sqrt{\frac{k_Z}{k_X}}\left(\frac{L}{h_Z}\right)$
7.57	Late Linear-Early Linear	$\frac{(t \bullet \Delta mP')_{LL-1hr}}{(t \bullet \Delta mP')_{EL-1hr}} = \frac{L}{h_X}$
7.58	Early-Radial-Early Linear	$\frac{(t \bullet \Delta mP')_{ER}}{(t \bullet \Delta mP')_{EL-1hr}} = 69.45\frac{\sqrt{(\phi\ \mu\ c_t)}h_Z}{\left(\frac{r_w}{r_{wa}}\right)\sqrt{k_Z}L}$
7.59	Early Radial-Late Linear	$\frac{(t \bullet \Delta mP')_{ER}}{(t \bullet \Delta mP')_{LL-1hr}} = 69.45\frac{\sqrt{(\phi\ \mu\ c_t)}h_Z h_X}{\left(\frac{r_w}{r_{wa}}\right)L}\left(\sqrt{\frac{k_Y}{k_Z}}\right)$
7.60	Late Radial- Late Linear	$\frac{(t \bullet \Delta mP')_{LR}}{(t \bullet \Delta mP')_{EL-1hr}} = 69.45\frac{\sqrt{(\phi\ \mu\ c_t)}L}{\left(\frac{r_w}{r_{wa}}\right)}\left(\frac{1}{\sqrt{k_x}}\right)$

Summary Skin Factor Equations

Eq. #	Intersection of	Equation
7.64	Early Radial and Unit Slope Line	$S = 1.28x10^{-2}\left(\frac{t_X}{t_{i-ER}}\right)^{1.24} - 0.5\ln\left(\frac{0.8935C}{\phi\mu c_t L r_w^2}\right)$
7.65	Early Radial and Unit Slope Line	$S = 3.22x10^{3}\left(\frac{(\phi c_t)(r_w)^2}{k_z qC}\right)^{1.1}\left(\frac{(t \bullet \Delta mP')_X}{(t \bullet \Delta mP')^2_{i-ER}}\right)^{1.1} - 0.5\ln\left(\frac{0.8935C}{\phi\mu c_t L r_w^2}\right)$

Chapter VIII

Applications

8.1 Two Phase Applications

Example-1

This example is taken from reference 27. The 11, 500 ft deep well KAL-5 (Yugoslavia) has following properties. The initial conditions coincide with retrograde conditions.

Table 8.1 Well, reservoir and fluid data is given in following table.

P_i	6750 psia	q_c	2.8 STB/D
P_d	6750 psia	h	216.5 ft
GOR	9470 scf/STB	ϕ	0.062
T	354 °F	r_w	0.54 ft
Gas SG	0.94 [MW =27.17]	API	50 [Assumed]
q_g	75.4 Mscf/D	ΔT	2.85 °F/100FT

Table 8.2 PVT Properties for example-1

P	Ppr	Z	Bg	Gas Viscosity	Rso	Ro	Density
psi			[bbl/scf]	[Cp]	[scf/bbl]	[B/scf]	Gmm/cc
200	0.30276674	0.98177538	0.020138962	0.01538971	42.4507256		0.00996688
600	0.90830022	1 0.94906255	0.00648931	0.01583345	150.7455444	.83E-06	0.02990064
1000	1.51383376	1 0.91861828	0.003768687	0.0164451	271.735901	1.26E-05	0.04983439
1400	2.119367123	0.8991542	0.002634882	0.0171969	400.595154	1.90E-05	0.06976815
1800	2.724900723	0.8796901	0.00200499	0.0180827	535.3081672	.48E-05	0.08970191
2200	**3.330434322**	**0.87014161**	**0.00162264**	**0.01910453**	**674.7324223**	**.03E-05**	**0.10963567**
2600	3.935967684	0.87772531	0.00138497	0.0202691	818.1232913	.59E-05	0.12956943
3000	4.541501045	0.88530901	0.001210678	0.02158655	964.9534914	.16E-05	0.14950319
3400	5.147034645	0.89289271	0.001077396	0.02306997	1114.828254	.78E-05	0.16943695
3800	5.752568245	0.88109907	0.000951253	0.02473525	1267.439945	.45E-05	0.18937069
4200	6.35810184	5 0.9149046	0.000893679	0.02660116	1422.541876	.20E-05	0.20930445
4600	6.963634968	0.94871011	0.000846117	0.02868952	1579.931157	.03E-05	0.22923821
5000	7.569168568	0.98251564	0.000806166	0.03102551	1739.437877	.98E-05	0.24917197
5400	8.174702644	1.0163212	0.000772133	0.03363803	1900.917249	.05E-05	0.26910573
5800	8.780235291	1.05012668	0.000742794	0.03656014	2064.244871	.03E-04	0.28903949
6200	9.38576889	1.08393221	0.000717241	0.03982965	2229.311771	.16E-04	0.30897325
6750	10.21837807	1.13041484	0.000687051	0.04497274	2458.945561	.38E-04	0.33638215

Procedure to calculate 8.2

1. Calculate the critical temperature and pressure. I used correlation for California gases using following equation.

Tpc = 298.6 SG + 181.89

Tpc = 298.6 (0.94) +181.89 = 462.574 °R

Ppc = -514.01 SG^4 + 1788.2 SG^3 - 2337.5 SG^2 + 1305.3SG + 415.07

Ppc = -514.01 $(0.94)^4$ + 1788.2 $(0.94)^3$ - 2337.5 $(0.94)^2$ + 1305.3(0.94) + 415.07 = 660.57 psi

At 2200 psi

Tr = T/Tpc = 354 + 460 /462.574 = 1.759

Ppr = P/Ppc = 2200/660.57 = 3.33

2. Calculate the compressibility factor using Gopal equations given in Table 3.1. Choose proper equation. Following equation fits the above critical conditions of temperature and pressure.

$Z = P_r$ (-0.0284T_r + 0.0625) + 0.4714T_r -0.0011

Z =(3.33) [-0.0284(1.759) + 0.0625] + 0.4714(1.759) -0.001 = 0.8699

3. Calculate the Bg using Eq.3.15. $B_g = 0.00504\frac{zT}{P}$

$$B_g = 0.0504\frac{(0.8699)(354+460)}{2,200} = 0.0016 \text{ bbl/scf}$$

4. Calculate gas density using Eq.3.20a.

$$\rho_g = 1.601846x10^{-2}\frac{MW.P}{RT} \qquad (3.20a)$$

$$\rho_g = 1.601846x10^{-2}\frac{(27.17)22,00}{(10.73)(354+460)} = 0.10962 \text{ gm/cc}$$

Where R (10.73) is the universal gas constant, T is in °R and P is in psi. The gas density is in gm/cc. MW is the molecular weight of the gas.

5.Calculate the gas viscosity using Lee and Gonzalez Eq.3.16,

$$X_1 = \frac{(9.4+0.02M)T^{1.5}}{209+19M+T}$$

$$X_1 = \frac{(9.4 + 0.02(27.17))(354)^{1.5}}{209 + 19(27.17) + (354)} = 61.365$$

$$X_2 = 3.5 + \frac{986}{T} + 0.01M$$

$$X_2 = 3.5 + \frac{986}{354} + 0.01(27.17) = 6.557$$

$$X_3 = 2.4 - 0.2X_2$$

$$X_3 = 2.4 - 0.2(6.557) = 1.0886$$

$$\mu_g = 10^{-4} X_1 \exp(X_2 \rho^{X_3})$$

$$\mu_g = 10^{-4}(61.365)\exp(6.557)(0.1096)^{1.0886}) = 0.011 \text{ cp}$$

5. Calculate Rso using Eq.3.2

I used following equation for light oils

$Rso = (P^{1.1535}) (SG / 37.966)\ 10^{(9.441\ API / T)}$

$Rso = (2{,}200^{1.1535}) (0.94 / 37.966)\ 10^{(9.441\ (50) / (354+460))} = 674.73$ scf/STB

6. Calculate vapor phase in gas phase, Ro [STB/MMscf], using Eq.3.35a

$$R_o = -11.66 + 4.706x10^{-9} R_s^3 + 1.623\sqrt{R_s} - \frac{42.3815}{\sqrt{R_s}}$$

$$R_o = -11.66 + 4.706x10^{-9}(674.73)^3 + 1.623\sqrt{674.73)} - \frac{42.3815}{\sqrt{674.73}} = 30.31233$$

STB/MMscf = $3.0312x10^{-5}$ STB/scf.

7. Producing gas oil ratio, Rp, is measured at surface during the well test, 9,470 SCF/STB.

Table 8.3. Pressure and pseudopressure data, with Eq.4.83a

Time hrs	P psi	mP1g,g Eq.4.83a	ΔmP	t.dΔmP/d(ln(t)	Integral[Keg]
Pr =	6750	248.3555			
0	1083.1	9.690342	0		
0.167	1174.5	11.4	1.709663		
0.333	1226.7	12.4369	2.746561		
0.5	1303.6	14.04406	4.353722	3.84810177	
1	1490.6	18.34433	8.653984	6.18010128	
2	1751.6	25.25937	15.56903	16.4412385	
3	2046	34.35381	24.66347	22.5880236	
4	2279.4	42.35781	32.66747	33.7942807	
6	2759.4	60.66817	50.97782	49.9686048	
8	3246.5	81.41431	71.72397	79.5896594	
12	4210	127.6456	117.9553	117.600946	
16	5162	174.5628	164.8725	133.490764	
22	6161	221.9433	212.2529	92.4258768	
28	6336.5	229.9477	220.2574	66.411804	0.000852685
34	6406.1	233.0914	223.4011	20.7617509	0.002727533
42	6452.5	235.1772	225.4869	12.3720492	0.004577121
50	6487.3	236.7363	227.046	7.66378648	0.007389084
58	6507.6	237.6437	227.9533	7.0386556	0.008045338
68	6526.5	238.4871	228.7967	6.60753927	0.008570265
82	6556.9	239.8407	230.1504	4.96192743	0.011412573
97	6574.3	240.614	230.9236	5.41043564	0.010466507
112	6587.3	241.1909	231.5005	3.83858505	0.014752405
141	6601.8	241.8336	232.1433		

Procedure to calculate Table 8.3

1. Having calculated table 8.2 convert the pressure data into pseudopressure using Eq. 4.83a. without the k.krg term.

$$mP_{gl} = \left[\int_{P_{wf}}^{P} \left(\frac{1}{(\mu_g B_g)} \right) \frac{R_p(1 - R_O R_S)}{(R_p - R_s)} (P) dp \right]$$

2. I used Simpson's rule to evaluate the integral.

P	Bg	Gas Viscosity	Rso	Ro	$X = R_p(1-R_oR_s)/[(R_p-R_{so})(B_g\mu_g)]$
Xpsi	[bbl/scf]	[Cp]	[scf/bbl]	[B/scf]	Rp = 9,470
200	0.020138962	0.01538971	42.4507256	-7.58E-06	3242.079135
600	0.00648931	0.01583345	150.745544	4.83E-06	9882.761598
1000	0.003768687	0.0164451	271.735901	1.26E-05	16554.87436
1400	0.002634882	0.0171969	400.595154	1.90E-05	22868.63006
1800	0.00200499	0.0180827	535.308167	2.48E-05	28846.64708
2200	0.00162264	0.01910453	674.732422	3.03E-05	34022.62432
2600	0.00138497	0.0202691	818.123291	3.59E-05	37847.212
3000	0.001210678	0.02158655	964.953491	4.16E-05	40893.98613
3400	0.001077396	0.02306997	1114.82825	4.78E-05	43171.70082
3800	0.000951253	0.02473525	1267.43994	5.45E-05	45676.80014
4200	0.000893679	0.02660116	1422.54187	6.20E-05	45136.22568
4600	0.000846117	0.02868952	1579.93115	7.03E-05	43948.96444
5000	0.000806166	0.03102551	1739.43787	7.98E-05	42180.59821
5400	0.000772133	0.03363803	1900.91724	9.05E-05	39887.95688
5800	0.000742794	0.03656014	2064.24487	1.03E-04	37120.43519
6200	0.000717241	0.03982965	2229.31177	1.16E-04	33921.35589
6750	0.000687051	0.04497274	2458.94556	1.38E-04	28887.92587

$$mP_{gi} = \left[\int_{P_{wf}}^{P^*}\left(\frac{1}{(\mu_g B_g)}\right)\frac{R_P(1-R_O R_S)}{(R_p - R_s)}(P)dp\right]$$

$$mP_{gi} = \int_{P_a}^{P^*} X(P)dp$$

$$mP(200) = \frac{X_0 + X_{200}}{2}(200-0)$$

$$mP(200) = \frac{0+3242.079}{2}(200-0) = 324207.9 = .3242\ x10^6\ psi^2/cp$$

$$mP(600) = mP(200) + \frac{3242.079+9882.76}{2}(600-200) =$$

$$mP(600) = 324207.9 + \frac{3242.079+9882.76}{2}(600-200) = 2949175.7 \text{ an so on.}$$

3. Procedure to calculate pseudopressure derivative group, $t.d\Delta mP/d(\ln(t)$

Using following equation

$\Delta mp = mP\text{-}mP_{(t=0)}$

$$\left(\frac{d\Delta mP}{d\ln(t)}\right)_i = \frac{\left(\frac{d\Delta mP_{i-1}}{\Delta\ln(t)_{i-1}}\right)\Delta\ln(t)_{i-1} + \left(\frac{d\Delta mP_{i+1}}{\Delta\ln(t)_{i+1}}\right)\Delta\ln(t)_{i-1}}{\left[\Delta\ln(t)_{i+1} + \Delta\ln(t)_{i-1}\right]}$$

At t = 68 hours and P = 6526.5 psi

ΔmP = 511.067-23.3728 = 487.6942

At t = 82 hours and P = 6556.9 psi

ΔmP = 511.9648-23.3728 = 488.592

$d\Delta mP = \Delta mP_{(t=82)} - \Delta mP_{(t=68)}$ 488.592 – 487.6942 = 0.8978

dΔln(t) = ln(82)-ln(68) = 0.1872

At t = 97 hours and P = 6574.3 psi

ΔmP = 512.4781-23.3728 = 489.1053

dΔmP = 489.1053- 488.592 = 0.5133

Δln(t) = ln(97)-ln(82) = 0.16799

At t = 112 hours and P = 6587.3 psi

ΔmP = 512.8614-23.3728 = 489.4886

dΔmP = 489.4886 – 489.1053 = 0.3833

dΔln(t) = ln(112)-ln(91) = 0.143787

Then the derivative at 97 hours, P = 6574.3 is

$d\Delta mP_{i-1}$ = 0.8978

$\Delta\ln(t)_{i-1}$ = 0.1872

$d\Delta mP_{i+1}$ = 0.3833

$\Delta\ln(t)_{i+1}$ = 0.143787

$$\left(\frac{d\Delta mP}{d\ln(t)}\right)_i = \frac{\left(\frac{0.8978}{0.1872}\right)0.143787 + \left(\frac{0.3833}{0.143787}\right)0.1872}{\left[0.1872 + 0.143787\right]} = 3.590871565$$

Where the point i is the point where derivative is calculated and point i-1 is the point before it and i+1 is the point after it. $\Delta \ln(t) = \ln(t_1) - \ln(t_2)$

4. Plot the pseudopressure and its derivative and locate the start of radial straight line. This is the semi-log straight line on the semi-log plot of pressure vs. time.

The effective permeability

5.The integral [Keg] is calculated from the straight line portion and onwards using following equation

$$\int_{P_{wf}}^{P}(k.k_{rg}(P))dp = \frac{162.6}{\frac{dmP}{d\ln(t)}}\left(\frac{q_{g.meas}}{h}\right)$$

The effective permeability integral is calculated using following equation, after the semi-log straight line has developed.

$$\int_{P_{wf}}^{P}(k.k_{rg}(P))dp = \frac{162.6}{\frac{dmP}{d\ln(t)}}\left(\frac{q_{g.meas}}{h}\right)$$

$$\int_{P_{wf}}^{P}(k.k_{rg}(6574.3))dp = \frac{162.6}{3.5908715x10^{6}}\left(\frac{75.4*1000}{216.5}\right)$$

$= 0.01577$

Oil effective permeability

Use same procedure for table 8.4 with equation 4.83b in step-1. and following equation in Step5 to calculate oil effective permeability.

$$\int_{P_{wf}}^{P}(k.k_{ro}(P))dp = 162.6\left(\frac{q_{g.meas}}{h}\right)\frac{1}{\Delta mP'}$$

Table 8.4. Pressure and pseudopressure data, with Eq.4.83b.

Time hrs	P psi	mP1g,o Eq.4.83b	ΔmP	t.dΔmP/d(ln(t)	Integral[Keo]
Pr =	6750	517.6423			
0	1083.1	23.3728	0		
0.167	1174.5	25.82054	2.447743		
0.333	1226.7	27.24284	3.870043		
0.5	1303.6	29.37082	5.998017	4.876688764	
1	1490.6	34.71134	11.33854	7.493499072	
2	1751.6	42.57468	19.20188	17.59814272	
3	2046	52.05665	28.68385	23.02276104	
4	2279.4	60.07426	36.70146	33.95911145	
6	2759.4	78.13077	54.75797	50.2170588	
8	3246.5	99.00624	75.63344	86.65745905	
12	4210	151.2229	127.8501	180.0784224	
16	5162	233.9581	210.5853	524.924176	
22	6161	500.2031	476.8303	142.9481323	
28	6336.5	505.4348	482.062	323.2790984	0.000175169
34	6406.1	507.5021	484.1293	13.60094325	0.004163561
42	6452.5	508.8777	485.5049	8.151117177	0.006947313
50	6487.3	509.908	486.5352	5.062244746	0.011186413
58	6507.6	510.5084	487.1356	4.655564686	0.012163586
68	6526.5	511.067	487.6942	4.376948091	0.012937864
82	6556.9	511.9648	488.592	3.290109705	0.017211694
97	6574.3	512.4781	489.1053	3.590871565	0.015770088
112	6587.3	512.8614	489.4886	2.549689479	0.022209905
141	6601.8	513.2888	489.916		

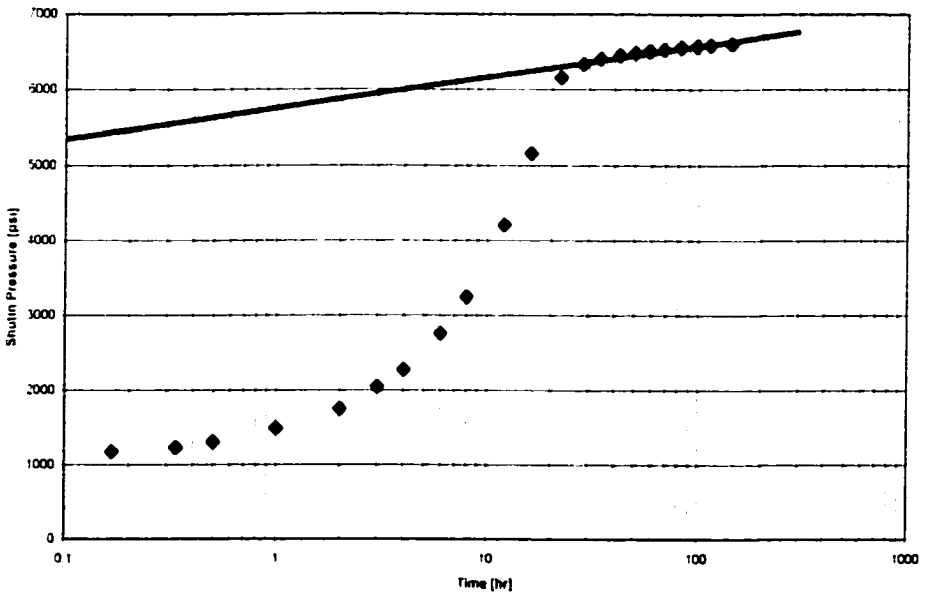


Fig.8.1. Transient Pressure semi-log plot.

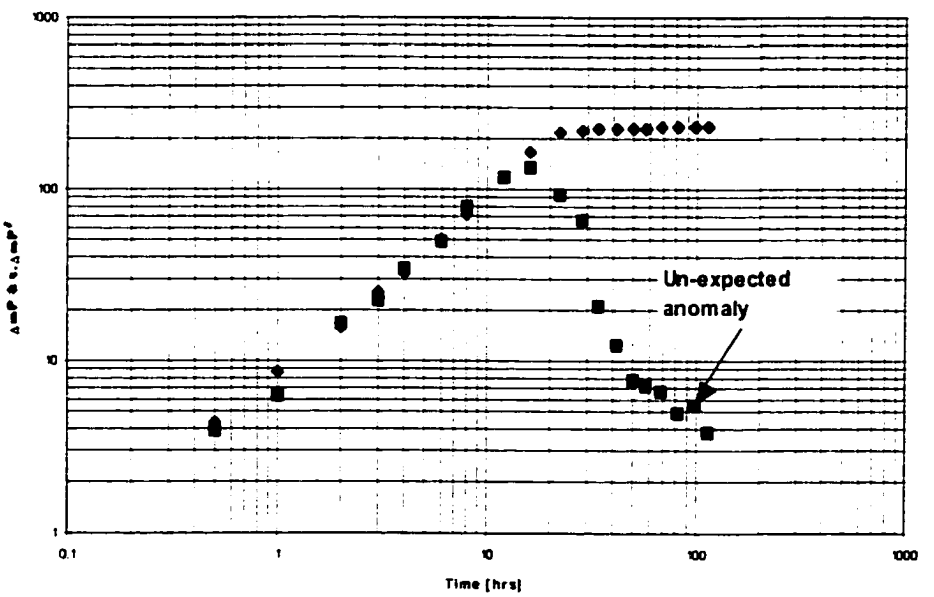


Fig.8.2. Pseudopressure and its derivative vs. time. The unexpected anomaly is observed. The initial reservoir pressure is equal to dew point pressure. Thus it is suspected that the anomaly is the approaching P*.

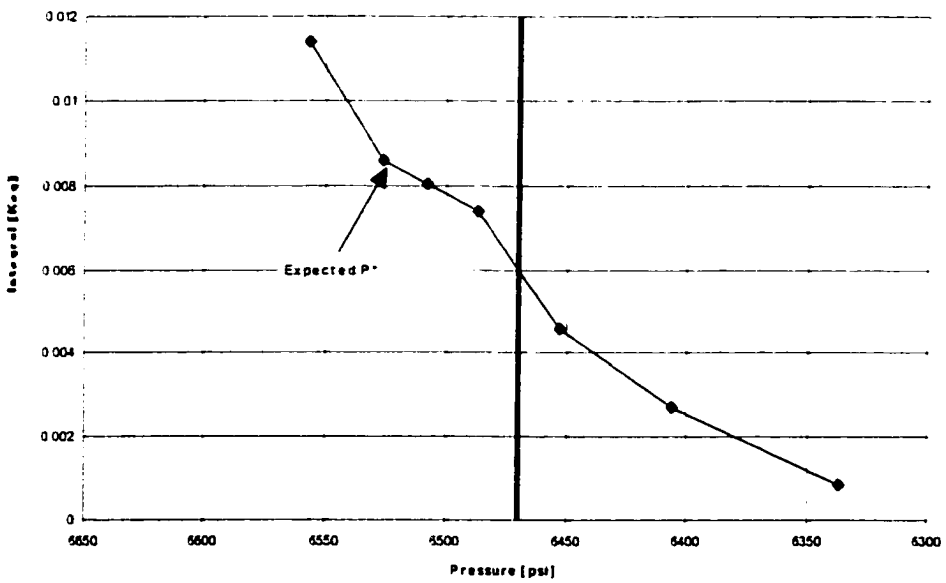


Fig.8.3 Gas effective permeability integral as function of pressure. Vertical solid line is the start of semi-log straight line [Eq.4.83a]

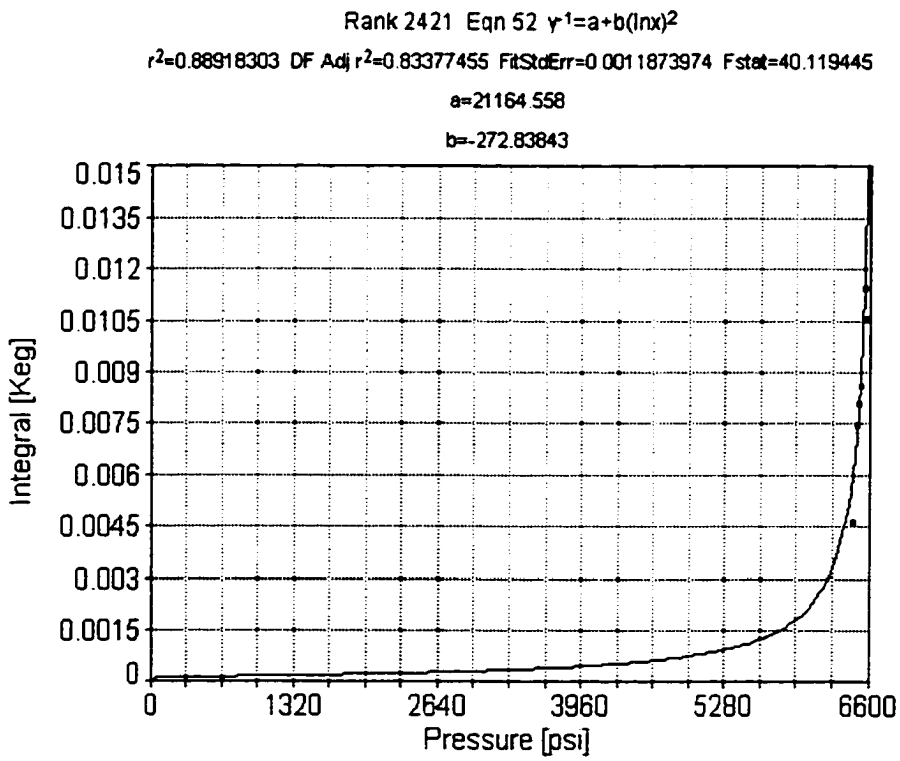


Fig.8.4 Gas effective permeability integral extrapolated to zero pressure.

Table 8.5 Gas effective permeability as function of pressure.

500	6.0054306286161744e-08
1000	5.6811540314944094e-08
1500	6.1591361787830839e-08
2000	7.1074697954301932e-08
2500	8.5754731204464197e-08
3000	1.0782358679616312e-07
3500	1.4182443400759054e-07
4000	1.9714794948473317e-07
4500	2.9522081166790355e-07
5000	4.9369198441850205e-07
5500	9.9498268994937031e-07
6000	2.974746515424735e-06
6500	4.1047263623145517e-05

Two point numerical derivative can also be used to calculate effective permeability as a function of pressure.

$$k.k_{rg} = \frac{Integral[kg]_2 - Integral[kg]_1}{P_2 - P_1}$$

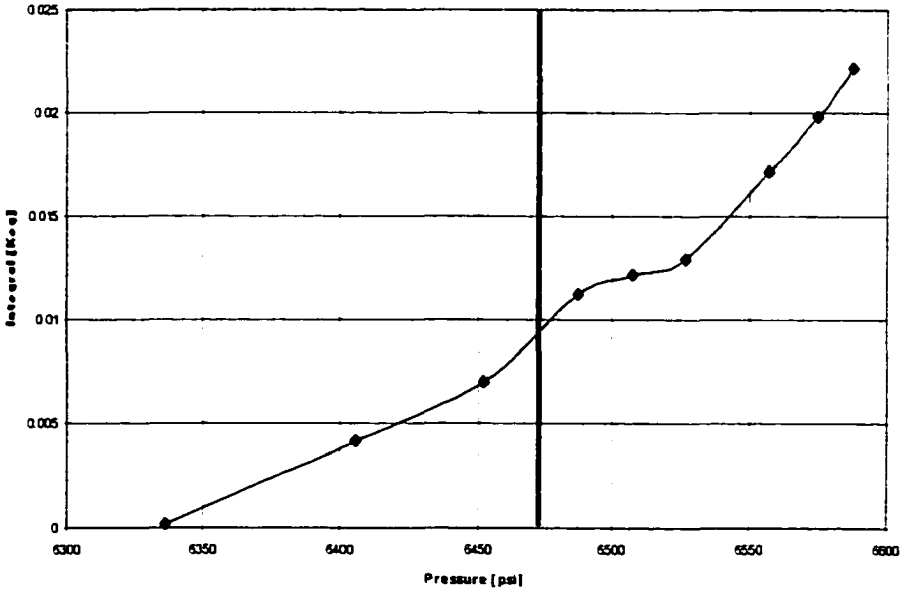


Fig. 8.5 Oil effective permeability integral as function of pressure. Vertical solid line is the start of semi-log straight line [Eq.4.83b]

It is possible that the producing gas oil ratio estimated at the surface may have human error in it. Thus a sensitivity analysis was performed by increasing the GOR by 10% and see its impact on the effective permeability and skin factor since in gas condensate systems skin factor is also added due to change in effective permeability. This was done by using the skin factor equation at different values of gas effective permeability.

Table 8.6 Percent error in effective permeability with 10% increase in Rp.

P	Integral [Keo]	Integral [Keo]	% Error
psi	Rp = 9,470	Rp = 10,417	
6336.5	0.000175169	0.000190026	8.481654
6406.1	0.004163561	0.003785056	9.090909
6452.5	0.006947313	0.006315739	9.090909
6487.3	0.011186413	0.010169466	9.090909
6507.6	0.012163586	0.011057805	9.090909
6526.5	0.012937864	0.011761695	9.090909
6556.9	0.017211694	0.015646994	9.090909
6574.3	0.015770088	0.014336444	9.090909
6587.3	0.022209905	0.020190822	9.090909

Table 8.7 Effect of 10% increase in GOR on oil effective permeability.

P	Keo	Keo	% Error
psi	Rp = 9,470	Rp = 10,417	
6406.1	5.73045E-05	5.16527E-05	9.862689
6452.5	5.99946E-05	5.45406E-05	9.090909
6487.3	0.000121813	0.000110739	9.090909
6507.6	4.81366E-05	4.37605E-05	9.090909
6526.5	4.09671E-05	3.72428E-05	9.090909
6556.9	0.000140586	0.000127806	9.090909
6574.3	8.28509E-05	7.5319E-05	9.090909
6587.3	0.000495371	0.000450337	9.090909

For oil phase effective permeability, slope of Eq. 6.44 can be used.

$$\int_{P_{wf}}^{P}(k.k_{ro}(P))dp = \frac{162.6}{\frac{dmP}{d\ln(t)}}\left(\frac{q_{g,meas}}{h}\right)$$

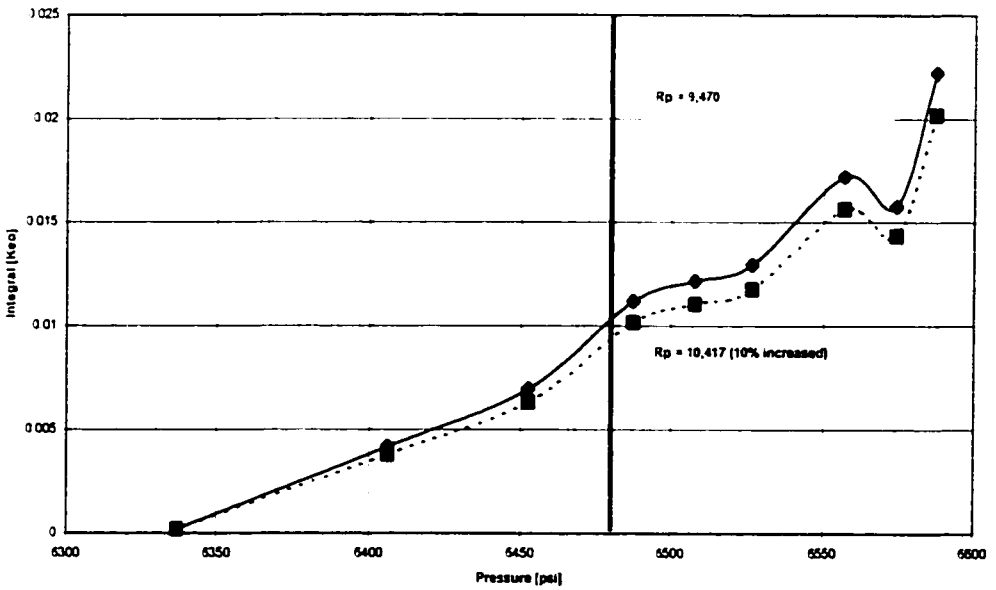


Fig.8.6 Effect of 10% increase in Rp [10,417 /SCFSTB] on oil phase effective permeability integral. Lower dotted line is the effective permeability with 10% increase in Rp.

Table 8.8.Effect of 10% increase in Rp on gas effective permeability.

Time hrs	P psi	Keg md Rp = 9,470	Keg md Rp =10,417	% Error
34	6406.1	2.69E-05	2.78E-05	3.02190686
42	6452.5	3.99E-05	4.11E-05	3.06048534
50	6487.3	8.08E-05	8.33E-05	3.04016961
58	6507.6	3.23E-05	3.34E-05	3.21625527
68	6526.5	2.78E-05	2.87E-05	3.35208414
82	6556.9	9.35E-05	9.64E-05	3.07862887
97	6574.3	5.44E-05	5.59E-05	2.88401789
112	6587.3	0.00033	0.00034	3.08949186
141	6601.8			

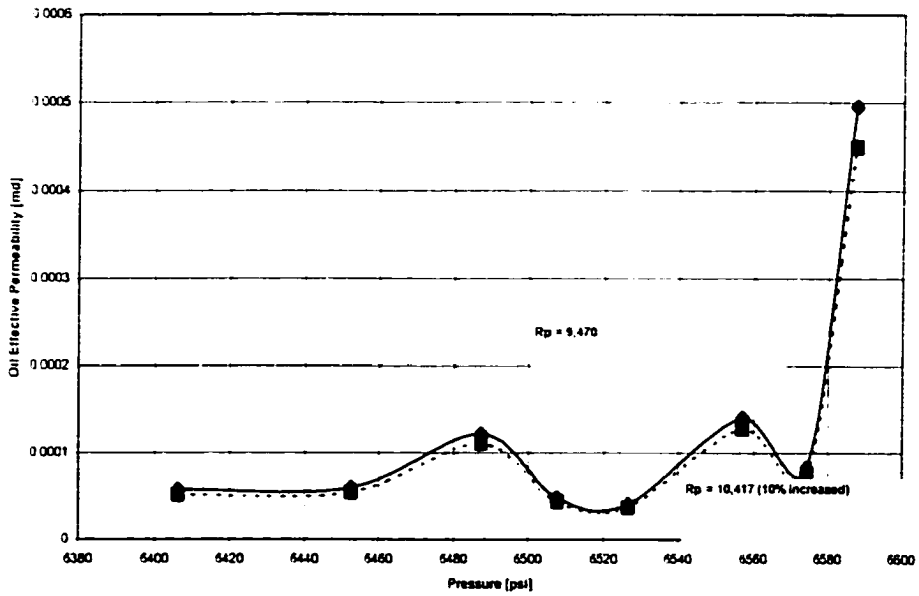


Fig.8.7 Effect of 10% increase in Rp [10,417 /SCFSTB] on oil phase effective permeability . Lower dotted line is the effective permeability with 10% increase in Rp.

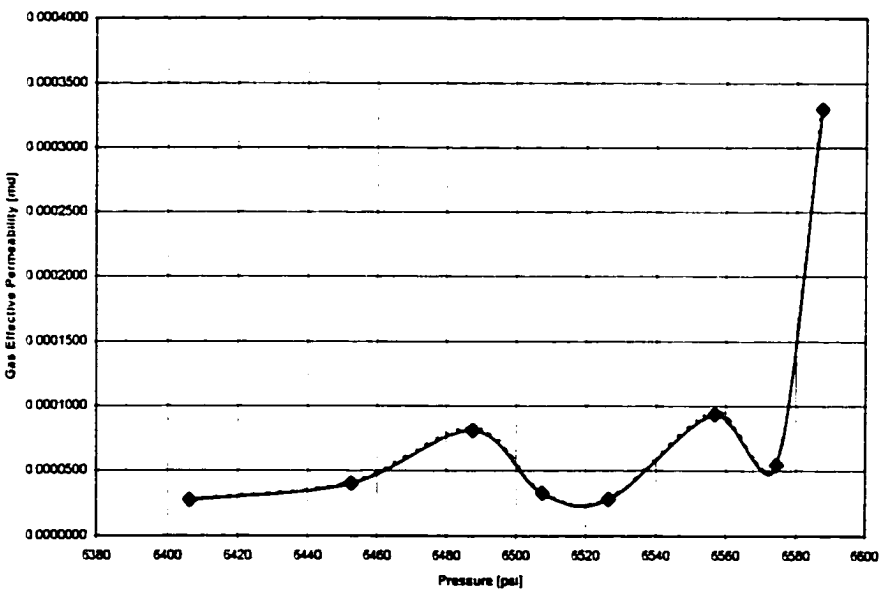


Fig.8.8. Effect of 10% increase in Rp [10,417 /SCFSTB] on gas effective permeability . Lower dotted line is the effective permeability with 10% increase in Rp.

Using Equation 6.121 for various values of pressure and effective permeability, skin factor was estimated as function of pressure. The upper dotted line in Fig.8.9 is the skin factor at 10% increase in the producing gas oil ratio. It indicates that the increase in gas oil ratio also causes increase in skin factor. This may be due to the fact that the increase in gas rate gives rise in the non-Darcy flow. Condensed liquid occupies more space thereby reducing the rate and the non-Darcy flow effects.

$$S_1 = 1.1513\left[\frac{\Delta m P_g M_g h}{q_{g,meas}} - \log\left(\frac{k_{eg}(P)}{\phi \mu c_t r_w^2}\right) + 3.2275\right]$$

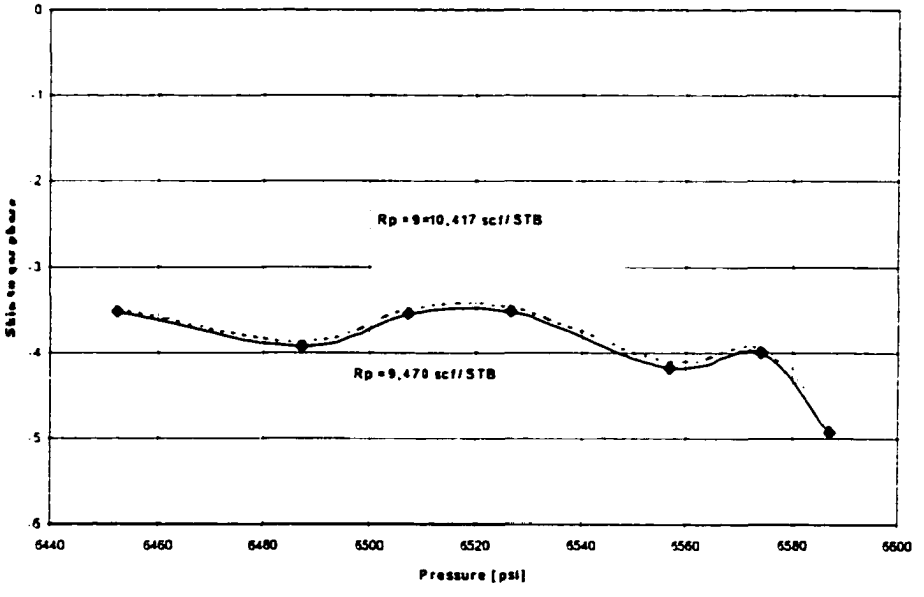


Fig.8.9. Effect of 10% increase in Rp on skin factor [Eq.4. 20a] Upper dotted line Rp = 10417 SCF/STB. Solid line Rp = 9470 SCF/STB.

Table 8.9. Absolute error in skin factor to gas with 10 % increase in Rp.

P	Skin	Skin	% Error
Psi	Rp = 9,470	Rp = 10,417	
6452.5	-3.53405	-3.488564948	1.287002
6487.3	-3.92994	-3.866652757	1.610467
6507.6	-3.53555	-3.467571977	1.922726
6526.5	-3.53051	-3.45896314	2.026399
6556.9	-4.18602	-4.098223812	2.097282
6574.3	-4.01019	-3.929811734	2.004447
6587.3	-4.92164	-4.813667252	2.193882

Procedure to calculate IPR

1. Chose the pressure data as shown in Table 8.10, column 1.
2. Convert the pressure data into pseudopressure as we did earlier in this example without Krg term. This is equal to mP/Mg. (Column-2)
3. Using same pressure data (Column 1) evaluate integral using equation given in Fig. 8.3. This is the term Mg (Column-3)
4. Now calculate the final value of pseudopressure by multiplying the mP/Mg with Mg to get mP (Column-4)
5. Plot the mP Vs flow rate on a log-log plot and calculate the sole n, and intercept Y. In this example we assumed values such that they match the rate and BHFP during the well test since we did not have production data for this well. Estimate these parameters separately for oil, water and gas.
6. Now establish IPR using Rawlins and Schellhardt[43] equation.

   Gas phase

   $q_g = C.(\Delta mP_g)^n$

   Oil phase

   $q_o = C.(\Delta mP_o)^n$

   Water phase

   $q_w = C.(\Delta mP_w)^n$

Table 8.10. Well performance data. [n = 0.8, C = 0.948, Assumed Values]

P	mP/Mg	Integral[Keg] Mg	mP	q
0	0	0	0	74.91424
200	0.32339411	7.40445E-05	2.39456E-05	74.91232
600	2.94400525	0.000100002	0.000294406	74.89056
1000	8.25361881	0.000122767	0.001013273	74.83273
1400	16.1918666	0.000146064	0.002365048	74.72395
1800	26.6565599	0.000171361	0.004567893	74.54659
2200	39.5642106	0.000199845	0.007906711	74.27757
2600	54.3308111	0.000232845	0.01265068	73.89491
3000	70.6711157	0.000272102	0.019229763	73.36341
3400	88.3323739	0.000320103	0.028275479	72.63107
3800	107.419393	0.00038065	0.040889153	71.60676
4200	127.150589	0.000459941	0.058481785	70.17197
4600	146.954463	0.000568898	0.083602079	68.11042
5000	166.651224	0.000728781	0.121452239	64.97424
5400	186.091089	0.000987312	0.183729879	59.72925
5800	205.150979	0.001478542	0.303324261	49.31097
6200	223.731447	0.002779552	0.621873294	17.75325
6750	248.355527	0.003	0.74506658	0

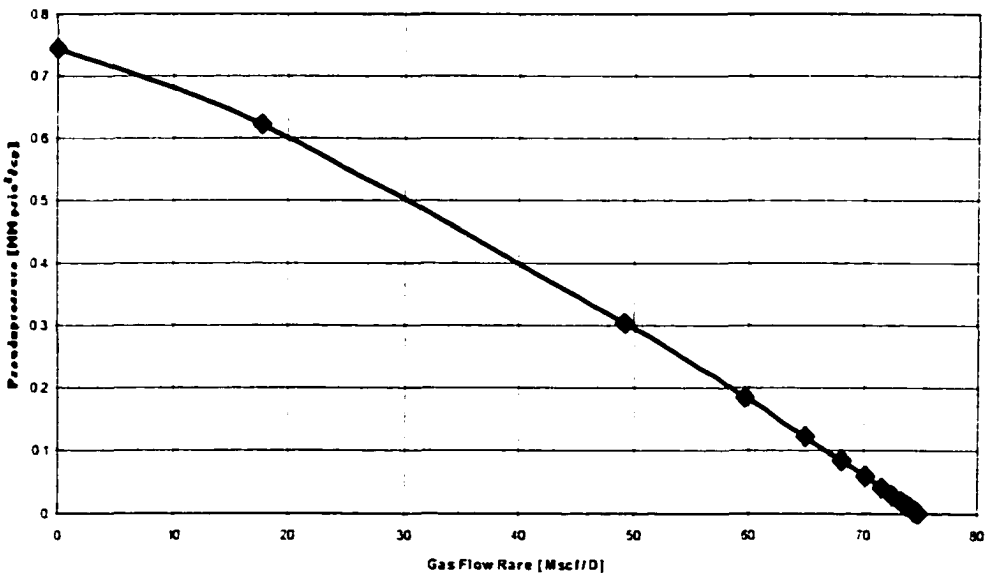


Fig.8.10. Gas Phase IPR vs. pseudopressure. [n = 0.8 and C = 0.0948, assumed and closely matched with rate during well test]

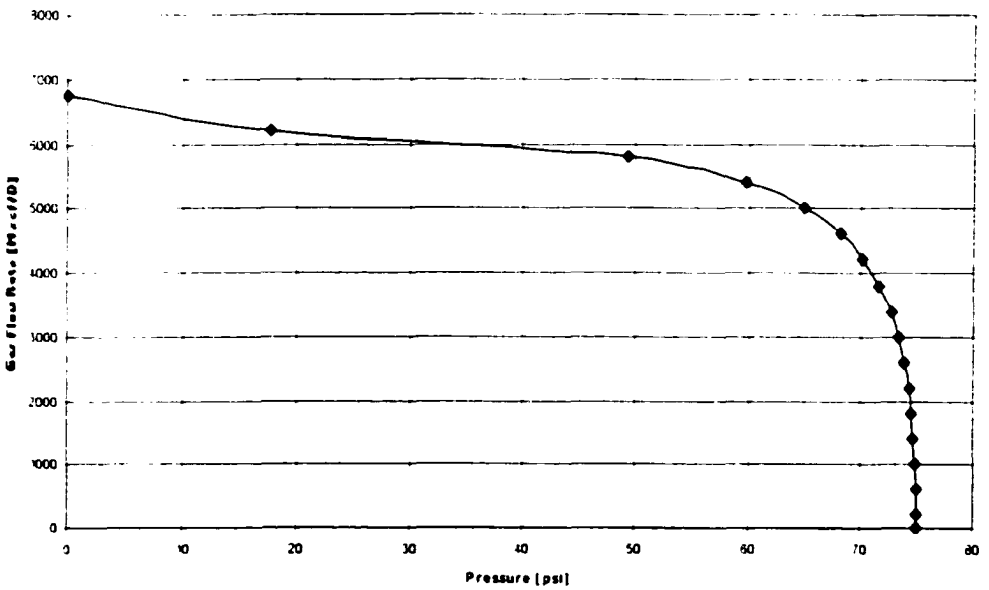


Fig. 8.11. Gas phase IPR against pressure.

Oil Phase

For oil phase use following equations

1. Pseudo-critical Temperature

$$T_{sp}(^{\circ}R) = -71.647(\gamma_{g,cor})^2 + 333.52(\gamma_{g,cor}) + 182.2 \quad (3.26)$$

2. Pseudo-critical Pressure

$$P_{sp}(psia) = -22.334(\gamma_{g,cor})^2 - 35.575(\gamma_{g,cor}) + 704.99 \quad (3.27$$

3. Oil formation Volume Factor (B_o)

Standing co-relation

$$B_o = 0.972 + 0.000147F^{1.175} \quad (3.28)$$

Where $F = R_{so}\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25T$, T = °F

4. Viscosity

For crude oil viscosity (In Pa-S), Miadonye et al one parameter correlation is available.

$$\ln \mu_o = 2.30259\left[\frac{b}{\left(1+\frac{T-30}{303.15}\right)^d} - 3.002\right] \tag{3.30}$$

Where

$b = \log \mu_{(@30°C)cP} + 3.002$

And

$d = 0.006694b + 3.5364$

Where T is in °C.

5. Use Eq.4.74a without k.kro term. to calculate pseudopressure

$$\Delta mP_o = \int_{P_{wf}}^{P^*}\left(\frac{1}{B_o.\mu_o}\left(\frac{1-R_oR_s}{1-R_oR_p}\right)\right)dp$$

6. Use equation $\int_{P_{wf}}^{P}(k.k_{ro}(P))dp = \frac{162.6}{\frac{dmP_o}{d\ln(t)}}\left(\frac{q_{o,meas}}{h}\right)$ to calculate oil effective permeability integral.

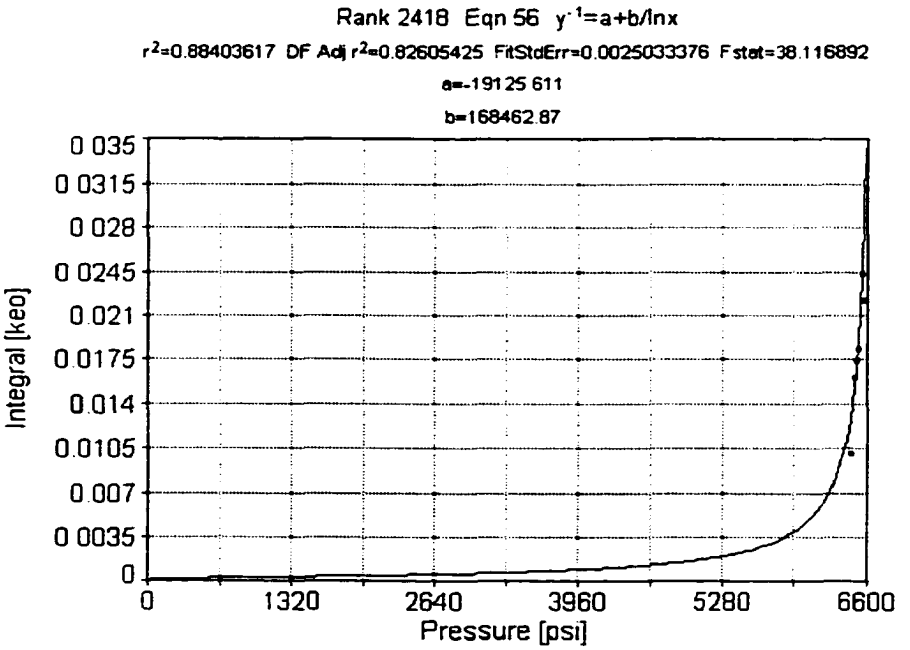


Fig.8.12. Oil effective permeability integral.

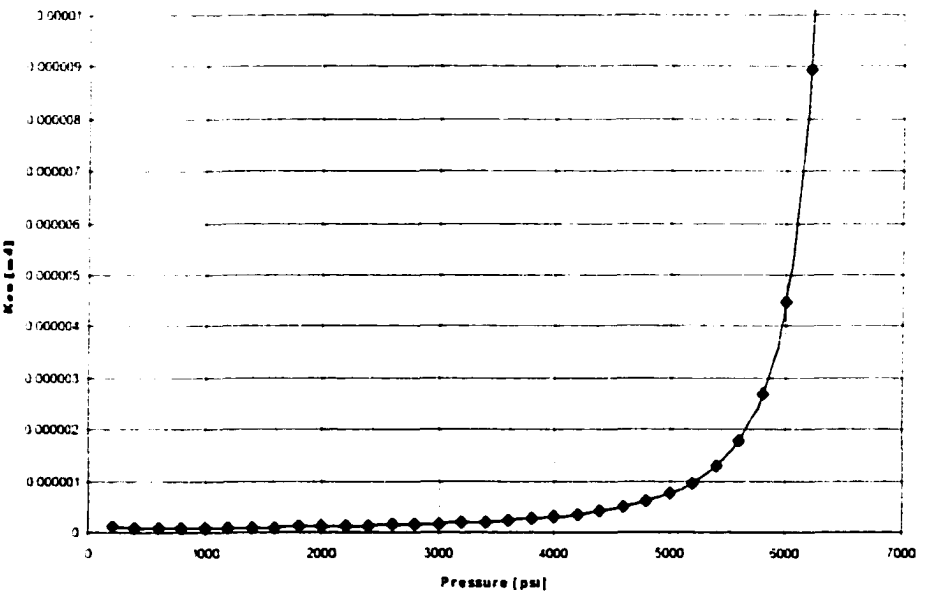


Fig. 813. Oil phase effective permeability, derivative of Eq.4.83b.

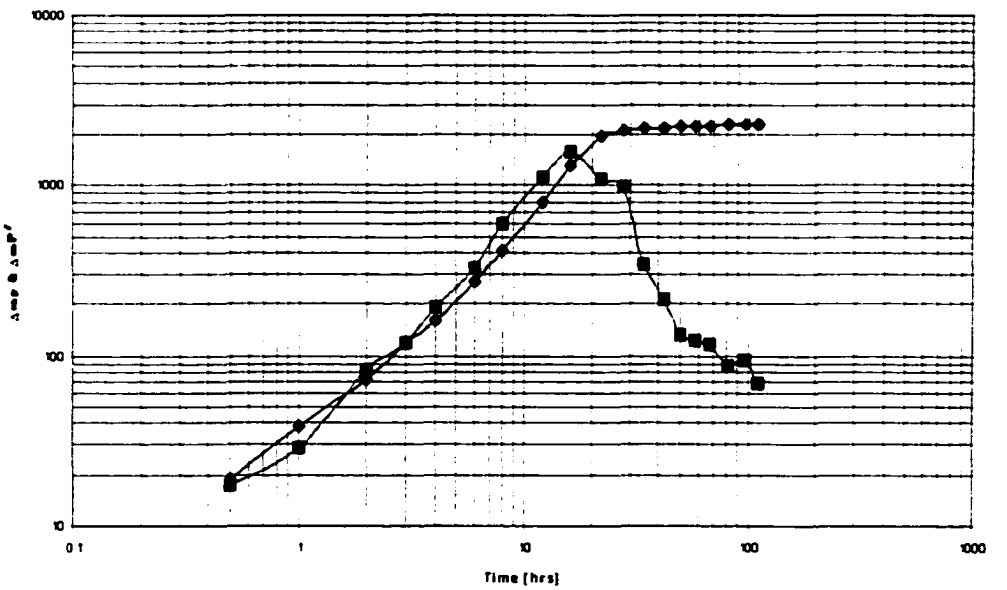


Fig.8.14. Oil phase pseudopressure and its derivative.

Table 8.11. Time, pressure, pseudopressure, and effective permeability to oil data.

Time hrs	P psi	$mP_{to.o}$ $Psia^2/cp$	ΔmP Eq.4.74a	t.dΔmP/d(ln(t))	Integral[Keo]	Keo
0	1083.1	37.69242	0			
0.167	1174.5	45.06127	7.368851			
0.333	1226.7	49.60332	11.9109			
0.5	1303.6	56.74562	19.05319	17.46048		
1	1490.6	76.42196	38.72953	28.77838		
2	1751.6	109.62	71.92376	82.02722		
3	2046	155.6	117.9054	120.4391		
4	2279.4	198.9084	161.216	191.8662		
6	2759.4	308.5168	270.8244	321.6509		
8	3246.5	450.2727	412.5802	603.1635		
12	4210	829.7878	792.0953	1133.067		
16	5162	1339.958	1302.266	1594.884		
22	6161	2012.652	1974.959	1104.705		
28	6336.5	2143.882	2106.189	969.7653	0.002168	
34	6406.1	2196.913	2159.22	344.0685	0.006112	0.0000567
42	6452.5	2232.571	2194.878	210.5204	0.009989	0.0000836
50	6487.3	2259.472	2221.78	131.9755	0.015934	0.0001708
58	6507.6	2275.226	2237.534	121.9627	0.017242	0.0000644
68	6526.5	2289.935	2252.242	115.2834	0.018241	0.0000529
82	6556.9	2313.675	2275.982	86.96564	0.024181	0.0001954
97	6574.3	2327.308	2289.615	95.23596	0.022081	0.0001207
112	6587.3	2337.515	2299.823	67.81678	0.031009	0.0006867
141	6601.8	2348.921	2311.229			

Table 8.12 Oil Phase IPR

P	$mP_{to,o}$ Eq. 4.74a	Integral	mP psi^2/cp	q_o STB/D
0	0	0	0	2.862683
200	1.005179	7.89E-05	7.93358E-05	2.862681
600	10.36004	0.000139	0.00143703	2.862644
1000	31.6242	0.00019	0.006010048	2.862518
1400	66.47398	0.000242	0.01609866	2.86224
1800	116.5378	0.000299	0.034792975	2.861724
2200	183.47	0.000362	0.066391755	2.860853
2600	268.93	0.000435	0.117008362	2.859458
3000	374.5329	0.000522	0.195527471	2.857294
3400	501.7112	0.000628	0.315218734	2.853995
3800	651.6465	0.000762	0.496653232	2.848993
4200	825.1444	0.000937	0.773404912	2.841363
4600	1022.557	0.001178	1.204296865	2.829481
5000	1243.743	0.00153	1.903079384	2.810206
5400	1488.069	0.002099	3.123445954	2.776527
5800	1754.464	0.003177	5.573699342	2.708841
6200	2041.501	0.006013	12.27577953	2.52324
6600	2347.504	0.034292	80.50032368	0.573717
6750	2466.777	0.04	98.67109403	0

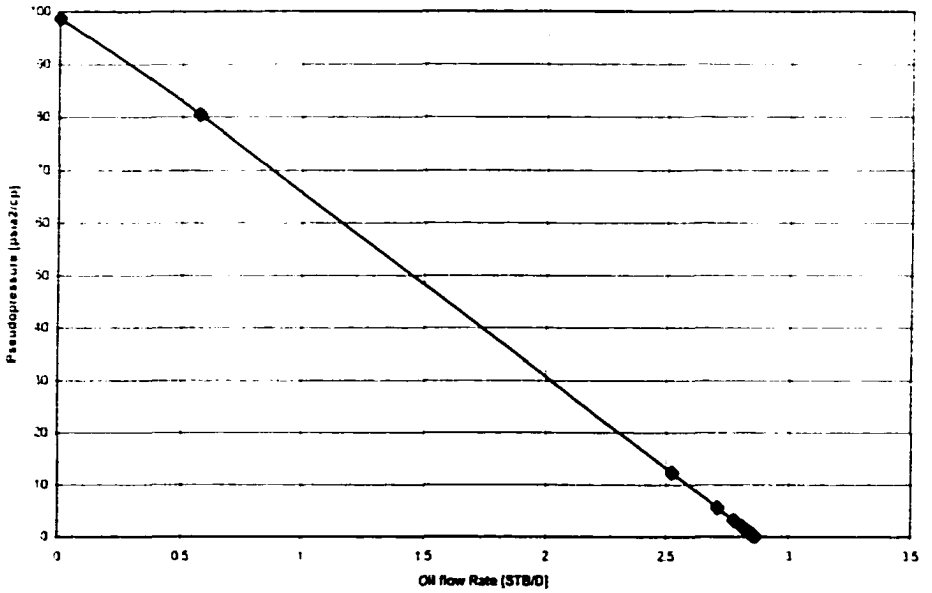


Fig.8.15. Condensate phase well performance vs. pseudopressure.

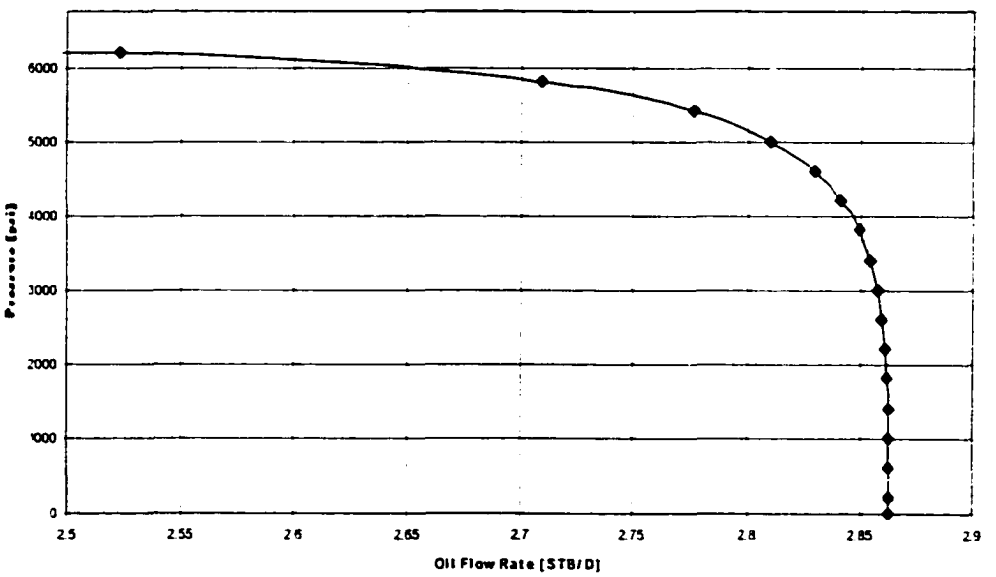


Fig.8.16. Oil phase well performance against pressure.

Example-2 Horizontal Well

Following the same procedure as for vertical wells in example-1, horizontal well performance example was solved.

Rates used in well test simulation are;

q_o = 100 STB/D

q_g = 0.5 MM scf/D

Step-1 Estimation of effective permeability with pressure

Using Eq.4.83a and 4.83b gas phase pseudopressure function was estimated, ignoring the effective permeability terms. From the third radial flow regime, effective permeability of each phase was estimated as a function of pressure and following correlations were obtained using Table Curve 2D curve fitting software.

$$k_o = \left(578 + 2.4249\sqrt{P} - 87.84\ln(P)\right)^{-1}$$

$$k_g = 2.659 \text{x} 10^{-5} P - 0.0773$$

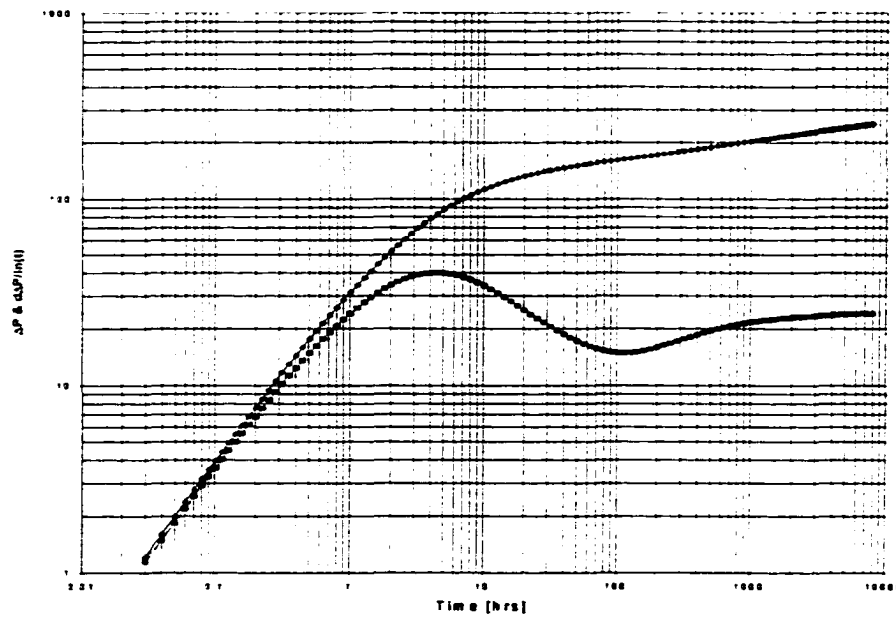


Fig.8.17 Pseudopressure and its derivative against time.

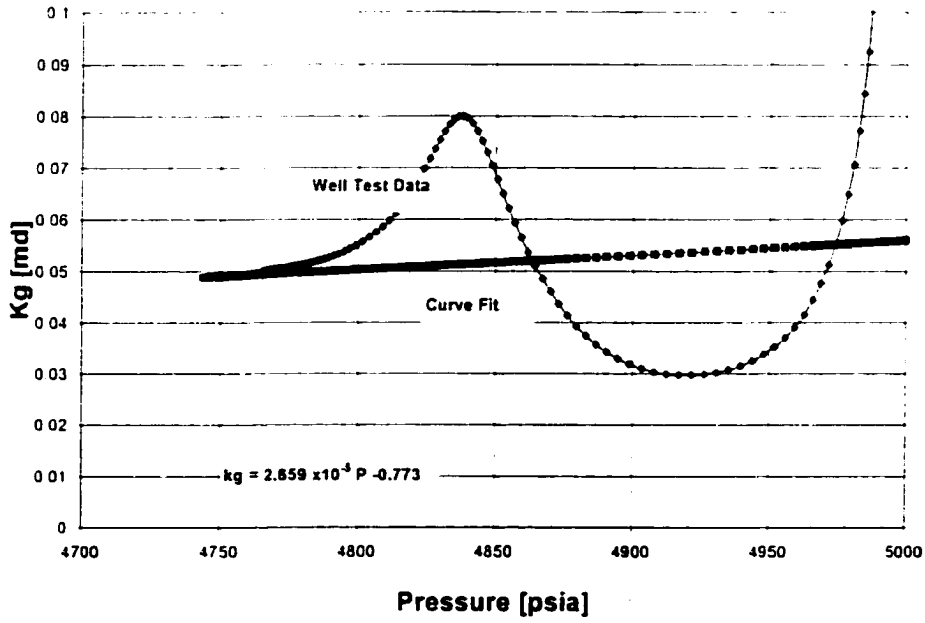


Fig.8.18 Gas phase effective permeability, Eq.4.97.

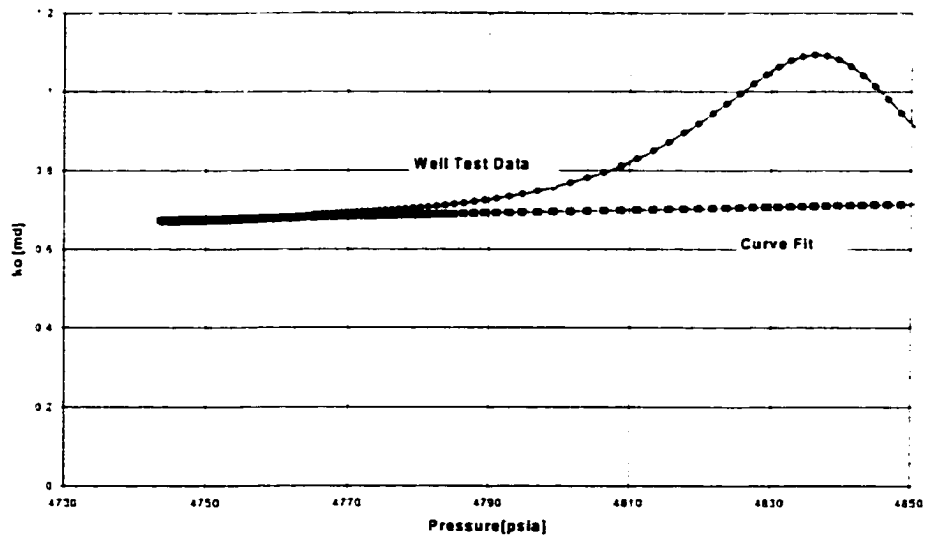


Fig.8.19 Oil phase effective permeability, Eq.4.98.

Table 8.13 PVT data

P	Z	Bg	ρ_g	μ_g	Rso	Bo	μo	Ro
Psia		cf/SCF	gm/cc	cp	scf/bbl	RB/STB	cp	bbl/scf
5000	983.9E-3	753.7E-6	227.1E-3	28.2E-3	1.6E+3	1.2E+0	100.7E-3	73.1E-6
4800	967.7E-3	772.2E-6	218.0E-3	27.2E-3	1.6E+3	1.2E+0	102.1E-3	68.8E-6
4600	951.6E-3	792.4E-6	209.0E-3	26.3E-3	1.5E+3	1.2E+0	103.5E-3	64.9E-6
4400	935.4E-3	814.3E-6	199.9E-3	25.4E-3	1.4E+3	1.2E+0	105.2E-3	61.1E-6
4200	919.3E-3	838.4E-6	190.8E-3	24.6E-3	1.3E+3	1.2E+0	107.0E-3	57.5E-6
4000	903.2E-3	864.9E-6	181.7E-3	23.8E-3	1.3E+3	1.2E+0	108.9E-3	54.1E-6
3800	887.0E-3	894.1E-6	172.6E-3	23.0E-3	1.2E+3	1.2E+0	111.0E-3	50.9E-6
3600	910.7E-3	969.0E-6	163.5E-3	22.3E-3	1.1E+3	1.2E+0	113.2E-3	47.8E-6
3400	907.3E-3	1.0E-3	154.4E-3	21.6E-3	1.0E+3	1.2E+0	115.5E-3	44.8E-6
3200	904.0E-3	1.1E-3	145.4E-3	21.0E-3	972.8E+0	1.2E+0	117.9E-3	41.9E-6
3000	900.6E-3	1.1E-3	136.3E-3	20.4E-3	903.0E+0	1.2E+0	120.3E-3	39.2E-6
2800	897.3E-3	1.2E-3	127.2E-3	19.8E-3	833.9E+0	1.2E+0	122.8E-3	36.5E-6
2600	893.9E-3	1.3E-3	118.1E-3	19.3E-3	765.6E+0	1.2E+0	125.4E-3	33.8E-6
2400	890.6E-3	1.4E-3	109.0E-3	18.8E-3	698.1E+0	1.2E+0	127.9E-3	31.2E-6
2200	887.2E-3	1.5E-3	99.9E-3	18.3E-3	631.4E+0	1.2E+0	130.4E-3	28.6E-6
2000	883.9E-3	1.7E-3	90.9E-3	17.8E-3	565.7E+0	1.2E+0	132.8E-3	26.0E-6
1800	895.9E-3	1.9E-3	81.8E-3	17.4E-3	500.9E+0	1.2E+0	135.0E-3	23.4E-6
1600	904.2E-3	2.2E-3	72.7E-3	17.0E-3	437.3E+0	1.2E+0	137.1E-3	20.6E-6
1400	912.4E-3	2.5E-3	63.6E-3	16.6E-3	374.9E+0	1.2E+0	139.0E-3	17.8E-6
1200	920.7E-3	2.9E-3	54.5E-3	16.3E-3	313.8E+0	1.1E+0	140.7E-3	14.8E-6
1000	928.9E-3	3.6E-3	45.4E-3	16.0E-3	254.3E+0	1.1E+0	142.0E-3	11.6E-6
800	941.2E-3	4.5E-3	36.3E-3	15.7E-3	196.6E+0	1.1E+0	143.1E-3	8.1E-6
600	955.5E-3	6.1E-3	27.3E-3	15.4E-3	141.1E+0	1.1E+0	143.7E-3	4.1E-6
400	0.9697	0.00929	0.01817	0.0152	88.3669	1.133	0.144083	0
200	0.98393	0.01884	0.00909	0.015	39.7239	1.13	0.1440597	0
150	0.98749	0.02522	0.00681	0.015	28.5059	1.1293	0.1439992	0

Table 8.14 Estimation of effective permeability.

P Psia	1/Ro	K.Krg	K.Kro	Krg/Kro	μo.Bo/μg.Bg	Rp scf/STB
5000	13686	0.05595	0.9429002	0.05934	5839.742676	1925
4800	14526	0.05036	0.8451206	0.05959	5957.96582	1862
4600	15419	0.04512	0.721659	0.06253	6074.278809	1814
4400	16373	0.04023	0.5964375	0.06746	6187.102539	1777
4200	17392	0.03568	0.4839925	0.07373	6294.479492	1749
4000	18486	0.03146	0.3897116	0.08073	6394.036133	1726
3800	19663	0.02756	0.3134919	0.08792	6482.943359	1707
3600	20937	0.02397	0.2529157	0.09479	6271.156738	1662
3400	22324	0.02069	0.2050378	0.10089	6231.542969	1626
3200	23846	0.01769	0.1671531	0.10584	6169.115234	1582
3000	25532	0.01498	0.137029	0.1093	6080.428223	1528
2800	27419	0.01254	0.112911	0.11102	5961.92334	1461
2600	29561	0.01035	0.0934503	0.1108	5810.027832	1379
2400	32031	0.00842	0.0776189	0.10851	5621.263184	1284
2200	34939	0.00673	0.0646342	0.1041	5392.380859	1174
2000	38444	0.00526	0.0538981	0.09762	5120.513672	1052
1800	42800	0.00401	0.0449508	0.08919	4720.806641	913
1600	48432	0.00296	0.0374359	0.07903	4306.680664	772
1400	56104	0.0021	0.0310741	0.06747	3857.075928	632
1200	67365	0.00141	0.0256437	0.05493	3373.763916	498
1000	85900	0.00088	0.0209654	0.04197	2859.558838	374
800	123315	0.00049	0.0168891	0.0293	2308.330322	264
600	246181	0.00024	0.0132803	0.01774	1736.704834	172
400	0	8.3E-05	0.0099972	0.00828	1156.613159	98
200	0	1.4E-05	0.0068152	0.00203	575.0005493	41
150	0	6.6E-06	0.0059732	0.0011	430.2695313	29

Now converting the production pressure data into the pseudopressure well performance is established using Rawlins and Shellhardt equation. In this example n is assumed 1.

Table 8.15 Estimation of pseudopressure.

mP 2-Ph	mP 1-Ph	mPo Oil-Phase	mPo From Dry Gas	DF
551.55	3.56959	7857.5232	8055.054176	14450.4783
501.16	3.066821	6428.4378	6590.125024	13928.7942
453.79	2.610776	5188.5144	5319.237482	13437.6816
410.69	2.199907	4157.0885	4261.832932	12993.6345
372.18	1.83246	3321.7674	3404.7786	12601.2076
337.87	1.506482	2654.8008	2719.321314	12253.2543
307.33	1.219838	2125.1513	2174.591121	11950.3773
279.79	0.970477	1704.6048	1741.702266	11672.2412
256.12	0.766337	1370.2204	1398.168107	11520.2894
233.82	0.595197	1102.926	1123.32617	11275.3839
213.42	0.453695	888.23106	902.8778872	11045.9833
194.6	0.338515	714.95528	725.1022039	10825.8795
178.79	0.246411	574.47386	581.9239259	10844.3621
162.65	0.174251	460.11868	465.1747157	10647.8389
147.68	0.119041	366.70581	370.1854668	10461.9373
133.47	0.077964	290.18429	292.4649547	10264.5533
120.45	0.04855	227.37633	229.1154997	10095.7186
108.2	0.028598	175.77621	177.2504885	9906.065
96.365	0.015658	133.38956	134.5085566	9681.1591
85.026	0.007791	98.641501	99.52167305	9431.71719
74.23	0.003401	70.289006	71.19436855	9160.89653
63.952	0.001226	47.358414	48.38005644	8896.497
52.825	0.000329	29.103395	30.12093508	8459.40178
39.929	5.19E-05	14.986815	15.94787153	7727.95294
20.63	2.87E-06	4.7162313	5.161342734	5813.99634
11.647	1.31E-06	2.7548946	2.64615927	4401.98882

Table 8.16. Well and reservoir data used in analysis.

Data					
Pi	5000	psia	Width, a	200	ft
h	80		Length, b	5000	ft
A	1000000	Ft2	n	1	
r_e	117752	ft	C	0.86247	
r_w	0.35		API	55	
Sa	33		LnC_H	0.85	
Lw	1500	ft	SG	0.9	

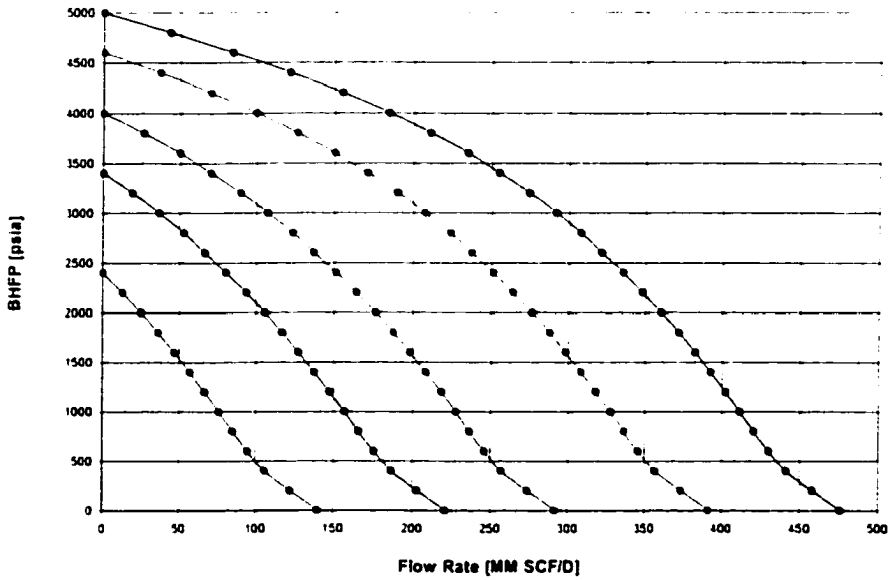


Fig.8.20. Gas phase IPR against pressure.

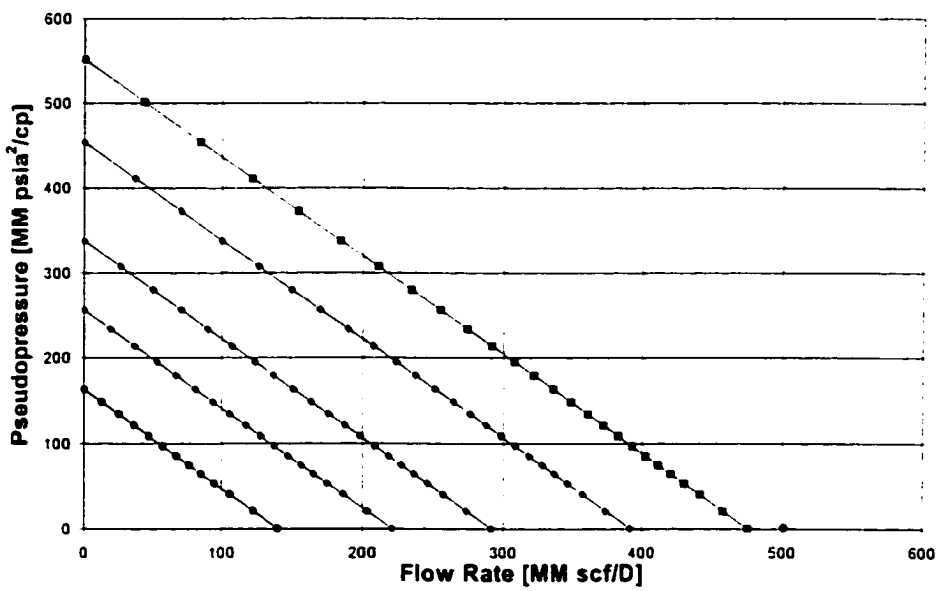


Fig.8.21. Gas phase IPR against pseudopressure.

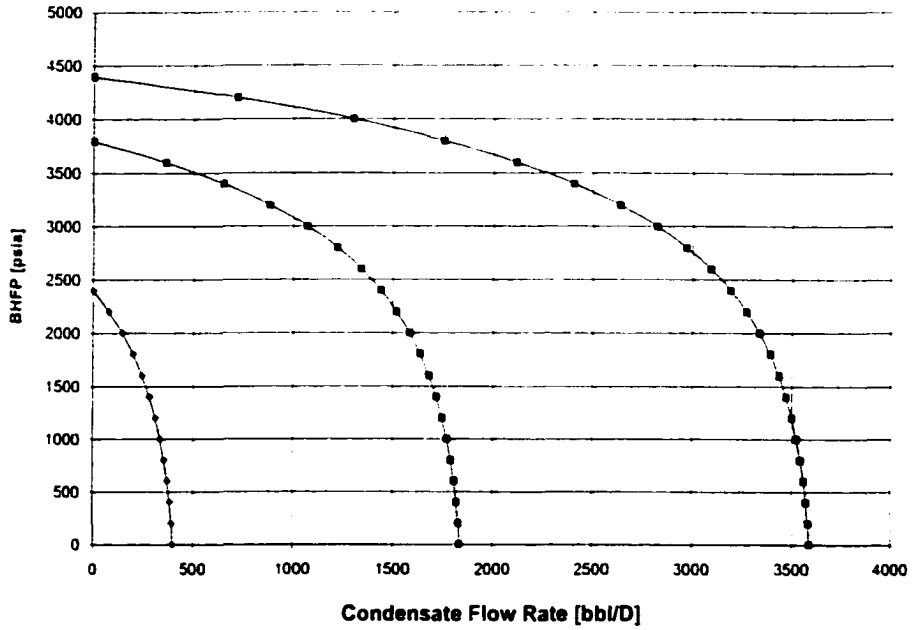


Fig.8.22. Oil phase IPR against pressure

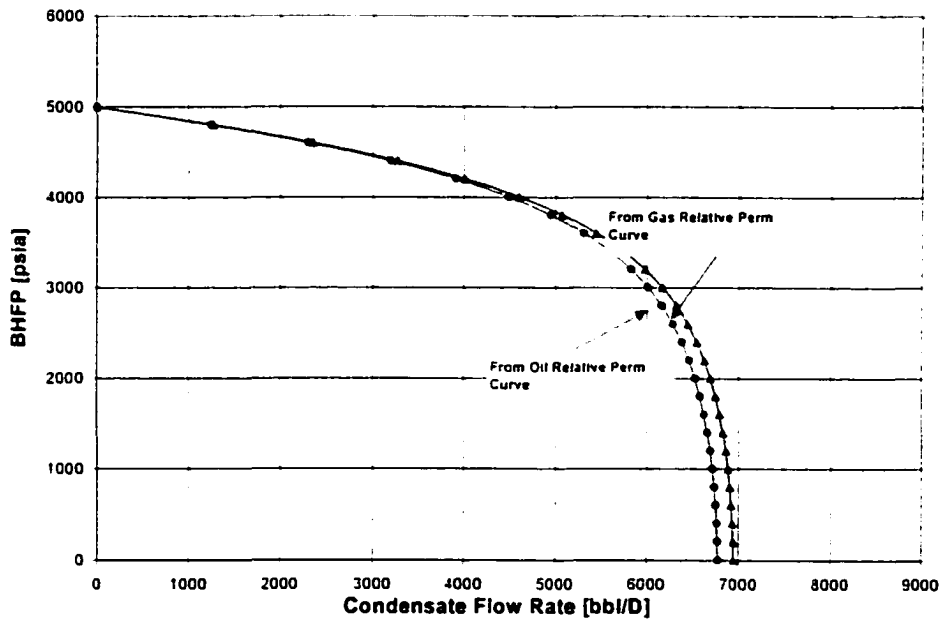


Fig.8.23. Comparison of IPRs from oil and gas surface production data.[Eq. 4.83a and 4.83b]

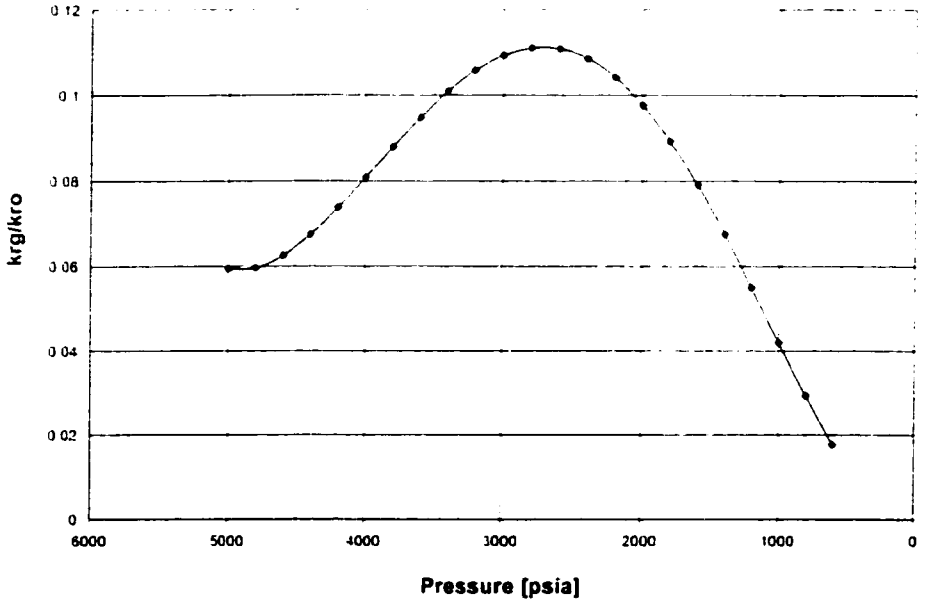


Fig. 8.24. Gas and Oil effective permeability ratio against pressure. [Eq.4.7]

$$\left(\frac{k_{rg}}{k_{ro}}\right) = \frac{(R_P - R_s)}{(1 - R_O\ R_P)}\left(\frac{B_g \mu_g}{B_o \mu_o}\right)$$

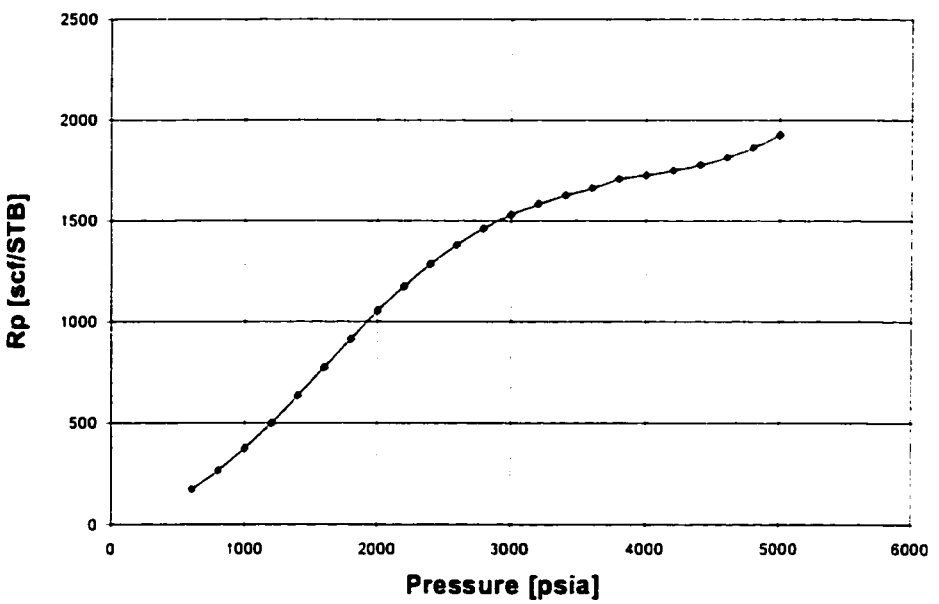


Fig. 8.25. Producing gas oil ratio against pressure.

8.2 Three Phase Examples

Vertical Wells-Pressure Drawdown

Example-1

This example was generated using Sapphire Well test Software. Reservoir pressure is above the dew point pressure therefore only Region-3 exists. Only water and gas phases are mobile in this region.

Table 8.17. Well and reservoir data.

Data	
Pi	8000psi
GWR	50000CF/STB
WGR	20STB/MMscf
SG	0.75
P_d	5000psi
t_p	500hrs
Cr	3.00E-061/psi
T	212F
GOR	8000cf/STB
r_w	0.3ft
H	100ft
C	0.2STB/Psi
S	5
kh	2000md-ft
K	20md
q_g	2MMcf/D
q_w	40STB/D
API	45

1. Following the procedure given in section 4.5 convert the pressure data into pseudopressure function ignoring the effective permeability. Algorithm given in Appendix C can also be used.
2. Using equation 4. 92, pressure test data is analyzed, (without gas effective permeability term.)

$$mP_g = \int_{P^*}^{Pd} \left(\frac{R_{pgw}}{R_{pgw} - R_{sgw}} \right) \left(\frac{k.k_{rg}}{B_{gd} \cdot \mu_{gd}} \right) dp$$

3. Using Eq.4.93 well test data is analyzed for water phase effective permeability

$$mP_g = \int_{P^*}^{P_d} \left(R_{pgw}\left(\frac{k.k_{rw}}{B_w.\mu_w}\right)dp\right.$$

4. Using the slope of Eq.6.34 the gas and water phase effective permeability integrals are estimated.

$$\int_{P_{wf}}^{P}(k.k_{rg}(P))dp = \frac{162.6}{\frac{dmP_g}{d\ln(t)}}\left(\frac{q_{g,meas}}{h}\right) \quad \text{.....(a)}$$

$$\int_{P_{wf}}^{P}(k.k_{rw}(P))dp = \frac{162.6}{\frac{dmP_g}{d\ln(t)}}\left(\frac{q_{g,meas}}{h}\right) \quad \text{.....(b)}$$

5. Now the wellbore flowing pressure (production data) is converted using equations in Step 1 and 2, this time with effective permeability integrals for both gas and water phase.
6. Plot the flow rate vs. mP_{wf} on the log-log plot and estimate n (Slope) and C (intercept).
7. Establish the well performance using Rawlins and Schelhart[43] equation, Eq.5.54 through 5.56.

Gas phase

$$q_g = C.(\Delta mP_g)^n \qquad (5.54)$$

Oil phase

$$q_o = C.(\Delta mP_o)^n \qquad (5.55)$$

Water phase

$$q_w = C.(\Delta mP_w)^n \qquad (5.56)$$

Table 8.18 Pressure, Pseudopressure and Effective Permeability Integral Data for the Straight line Region.

Time hrs	P psi	mP Psi^2/cp	ΔmP 10^6	Δ(ΔmP)	ΔX Ln(t1)-Ln(t2)	t*d(ΔmP)/dt	Integral-Keg
10.09817	7930.564	337.0989	2420990	11580.13	0.115129	100616.5	32.32073
11.33033	7930.236	337.0874	2432498	11508.62	0.115129	99991.36	32.52281
12.71284	7929.91	337.076	2443942	11443.73	0.115129	99429.37	32.70663
14.26404	7929.586	337.0646	2455328	11385.85	0.115129	98920.97	32.87473
16.00452	7929.263	337.0533	2466661	11333.66	0.115129	98469.72	33.02538
17.95736	7928.941	337.042	2477949	11287.64	0.115129	98063.72	33.16211
20.14849	7928.621	337.0307	2489195	11246.34	0.115129	97706.82	33.28324
22.60698	7928.301	337.0195	2500406	11210.18	0.115129	97386.73	33.39264
25.36545	7927.983	337.0084	2511583	11177.78	0.115129	97106.81	33.4889
28.4605	7927.666	336.9972	2522733	11149.49	0.115129	96856.47	33.57545
31.93321	7927.349	336.9861	2533857	11124.24	0.115129	96637.74	33.65145
35.82965	7927.033	336.975	2544959	11102.17	0.115129	96442.7	33.7195
40.20152	7926.717	336.9639	2556042	11082.51	0.115129	96272.07	33.77927
45.10685	7926.402	336.9528	2567107	11065.29	0.115129	96119.87	33.83275
50.61072	7926.087	336.9418	2578157	11049.91	0.115129	95986.79	33.87966
56.78616	7925.773	336.9307	2589194	11036.49	0.115129	95867.68	33.92175
63.71512	7925.459	336.9197	2600218	11024.44	0.115129	95764.11	33.95844
71.48954	7925.146	336.9087	2611232	11014.01	0.115129	95670.81	33.99156
80.21258	7924.833	336.8977	2622237	11004.58	0.115129	95590.1	34.02026
90	7924.52	336.8867	2633233	10996.42	0.115129	95515.49	34.04684
100	7924.233	336.8766	2643290	10056.9	0.105361	95453.31	34.06901
110	7923.974	336.8676	2652383	9092.908	0.09531	95403.34	34.08686
120	7923.738	336.8593	2660680	8297.659	0.087011	95362.9	34.10131
130	7923.521	336.8516	2668311	7630.388	0.080043	95329.73	34.11318
140	7923.32	336.8446	2675373	7062.598	0.074108	95300.94	34.12348
150	7923.133	336.838	2681947	6573.419	0.068993	95276.85	34.13211
160	7922.958	336.8318	2688094	6147.643	0.064539	95255.95	34.1396
170	7922.794	336.8261	2693868	5773.746	0.060625	95237.43	34.14624
180	7922.639	336.8206	2699311	5442.711	0.057158	95221.56	34.15193
190	7922.493	336.8155	2704459	5147.59	0.054067	95207.51	34.15697
200	7922.354	336.8106	2709341	4882.862	0.051293	95194.65	34.16158
210	7922.222	336.806	2713985	4644.009	0.04879	95183.93	34.16543
220	7922.096	336.8015	2718413	4427.493	0.04652	95173.42	34.1692
230	7921.975	336.7973	2722643	4230.226	0.044452	95164.82	34.17229
240	7921.86	336.7932	2726693	4049.823	0.04256	95155.8	34.17553
250	7921.75	336.7894	2730577	3884.127	0.040822	95148.54	34.17814
260	7921.643	336.7856	2734309	3731.507	0.039221	95141.84	34.18054
270	7921.541	336.782	2737899	3590.474	0.03774	95135.07	34.18298
280	7921.443	336.7786	2741359	3459.631	0.036368	95130.31	34.18469
290	7921.348	336.7752	2744697	3338.054	0.035091	95123.81	34.18703
300	7921.256	336.772	2747921	3224.669	0.033902	95119.59	34.18854
310	7921.167	336.7689	2751040	3118.795	0.03279	95114.55	34.19035
320	7921.082	336.7659	2754060	3019.642	0.031749	95110.61	34.19177

330	7920.998	336.7629	2756986	2926.592	0.030772	95107.22	34.19299
340	7920.918	336.7601	2759826	2839.134	0.029853	95102.81	34.19457
350	7920.839	336.7574	2762582	2756.689	0.028988	95100.32	34.19547
360	7920.763	336.7547	2765261	2678.964	0.028171	95096.58	34.19681
370	7920.689	336.7521	2767867	2605.483	0.027399	95093.7	34.19785
380	7920.617	336.7495	2770403	2535.901	0.026668	95090.75	34.19891
390	7920.547	336.7471	2772873	2469.944	0.025975	95088.61	34.19968
400	7920.478	336.7447	2775280	2407.386	0.025318	95085.38	34.20084
410	7920.411	336.7423	2777628	2347.857	0.024693	95083.48	34.20152
420	7920.346	336.74	2779919	2291.206	0.024098	95081.98	34.20206
430	7920.282	336.7378	2782156	2237.295	0.02353	95078.69	34.20325
440	7920.22	336.7356	2784342	2185.775	0.02299	95078.56	34.20329
450	7920.16	336.7335	2786479	2136.642	0.022473	95075.38	34.20444
460	7920.1	336.7314	2788568	2089.619	0.021979	95074.1	34.2049
470	7920.042	336.7293	2790613	2044.632	0.021506	95072.39	34.20552
480	7919.985	336.7273	2792615	2001.569	0.021053	95070.08	34.20635
490	7919.929	336.7254	2794575	1960.244	0.020619	95069.65	34.2065

Table 8.19 Pressure, pseudopressure, and water effective permeability integral data.

Time hrs	P psi	mP Psi^2/cp	ΔmP 10^6	Δ(ΔmP)	ΔX	t*d(ΔmP)/dt	Integral-Keg
11.33033	7930.236	1263.714	42746.01	0.115129	371394.6	8.756184	
12.71284	7929.91	1263.671	42503.26	0.115129	369290.6	8.806073	0.153006
14.26404	7929.586	1263.629	42286.31	0.115129	367387.1	8.8517	0.140655
16.00452	7929.263	1263.587	42090.73	0.115129	365695	8.892656	0.126844
17.95736	7928.941	1263.545	41918.08	0.115129	364171.1	8.929868	0.115727
20.14849	7928.621	1263.503	41762.76	0.115129	362830.5	8.962863	0.102996
22.60698	7928.301	1263.462	41626.73	0.115129	361626.4	8.992707	0.093466
25.36545	7927.983	1263.42	41504.77	0.115129	360571.5	9.019016	0.08264
28.4605	7927.666	1263.379	41397.93	0.115129	359627.1	9.042699	0.074583
31.93321	7927.349	1263.337	41302.42	0.115129	358799.8	9.06355	0.065817
35.82965	7927.033	1263.296	41218.78	0.115129	358060.2	9.08227	0.059212
40.20152	7926.717	1263.255	41143.99	0.115129	357411.8	9.098748	0.052214
45.10685	7926.402	1263.214	41078.33	0.115129	356831.9	9.113536	0.046936
50.61072	7926.087	1263.173	41019.58	0.115129	356322.6	9.12656	0.041398
56.78616	7925.773	1263.132	40967.99	0.115129	355866.1	9.138269	0.037264
63.71512	7925.459	1263.091	40921.62	0.115129	355466.1	9.148551	0.032761
71.48954	7925.146	1263.05	40881.11	0.115129	355105.8	9.157835	0.02961
80.21258	7924.833	1263.009	40844.51	0.115129	354790.7	9.165967	0.025961
90	7924.52	1262.969	40812.47	0.115129	354499.2	9.173505	0.024085
100	7924.233	1262.931	37324.01	0.105361	354253.8	9.179859	0.022196
110	7923.974	1262.897	33745.15	0.09531	354055.5	9.185001	0.019869
120	7923.738	1262.867	30792.85	0.087011	353894	9.189191	0.017747
130	7923.521	1262.838	28315.74	0.080043	353760.2	9.192667	0.016007
140	7923.32	1262.812	26207.98	0.074108	353643.9	9.195692	0.015051
150	7923.133	1262.788	24392.12	0.068993	353544.9	9.198265	0.013756

160	7922.958	1262.765	22811.59	0.064539	353459.5	9.200489	0.012714
170	7922.794	1262.744	21423.76	0.060625	353382.3	9.202498	0.01223
180	7922.639	1262.723	20194.99	0.057158	353316.5	9.204213	0.011069
190	7922.493	1262.704	19099.59	0.054067	353256.8	9.205767	0.010615
200	7922.354	1262.686	18116.98	0.051293	353202.7	9.207178	0.010157
210	7922.222	1262.669	17230.45	0.04879	353156.4	9.208386	0.009138
220	7922.096	1262.652	16426.85	0.04652	353111.4	9.209558	0.009307
230	7921.975	1262.637	15694.69	0.044452	353073.6	9.210544	0.008192
240	7921.86	1262.622	15025.12	0.04256	353034.9	9.211553	0.008758
250	7921.75	1262.607	14410.18	0.040822	353002.4	9.212403	0.007695
260	7921.643	1262.594	13843.75	0.039221	352972.8	9.213176	0.007278
270	7921.541	1262.58	13320.34	0.03774	352942.4	9.213967	0.00775
280	7921.443	1262.567	12834.74	0.036368	352920.4	9.214543	0.005849
290	7921.348	1262.555	12383.57	0.035091	352891.5	9.215298	0.007949
300	7921.256	1262.543	11962.78	0.033902	352871.9	9.215808	0.005563
310	7921.167	1262.531	11569.89	0.03279	352848.5	9.216419	0.006893
320	7921.082	1262.52	11201.9	0.031749	352830.2	9.216898	0.005576
330	7920.998	1262.509	10856.6	0.030772	352813.1	9.217346	0.005373
340	7920.918	1262.499	10532.03	0.029853	352793.4	9.217858	0.00635
350	7920.839	1262.489	10226.11	0.028988	352779.9	9.218212	0.004506
360	7920.763	1262.479	9937.667	0.028171	352762.9	9.218656	0.005835
370	7920.689	1262.469	9664.996	0.027399	352748.5	9.219032	0.005064
380	7920.617	1262.46	9406.799	0.026668	352733.9	9.219413	0.005292
390	7920.547	1262.45	9162.033	0.025975	352723.2	9.219695	0.004012
400	7920.478	1262.442	8929.915	0.025318	352707.5	9.220106	0.005996
410	7920.411	1262.433	8709.011	0.024693	352697.6	9.220364	0.003868
420	7920.346	1262.424	8498.799	0.024098	352688.8	9.220594	0.003529
430	7920.282	1262.416	8298.758	0.02353	352673.5	9.220993	0.006279
440	7920.22	1262.408	8107.584	0.02299	352670.2	9.22108	0.001386
450	7920.16	1262.4	7925.276	0.022473	352655.4	9.221466	0.006361
460	7920.1	1262.392	7750.793	0.021979	352648	9.221661	0.003283
470	7920.042	1262.385	7583.872	0.021506	352639.7	9.221877	0.003704

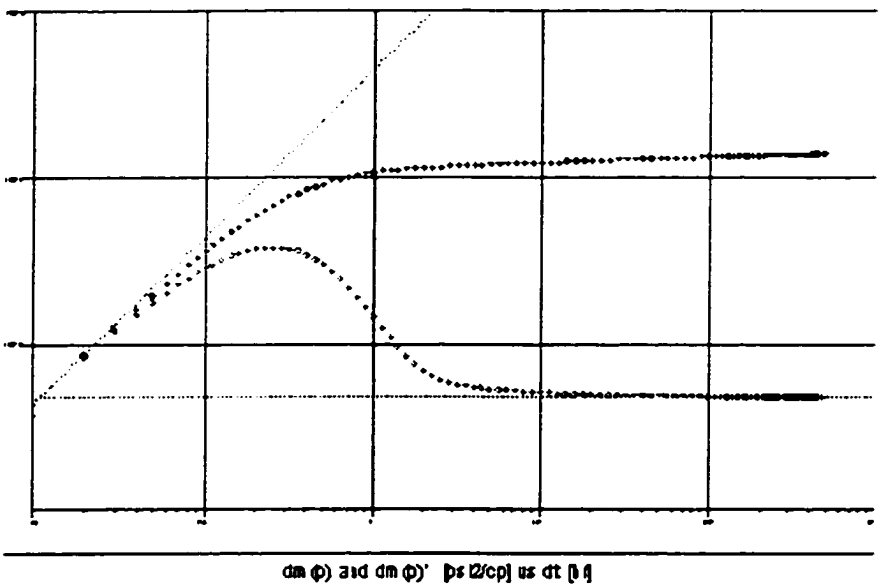


Fig. 8.26. Pseudopressure and its derivative from Sapphire™.

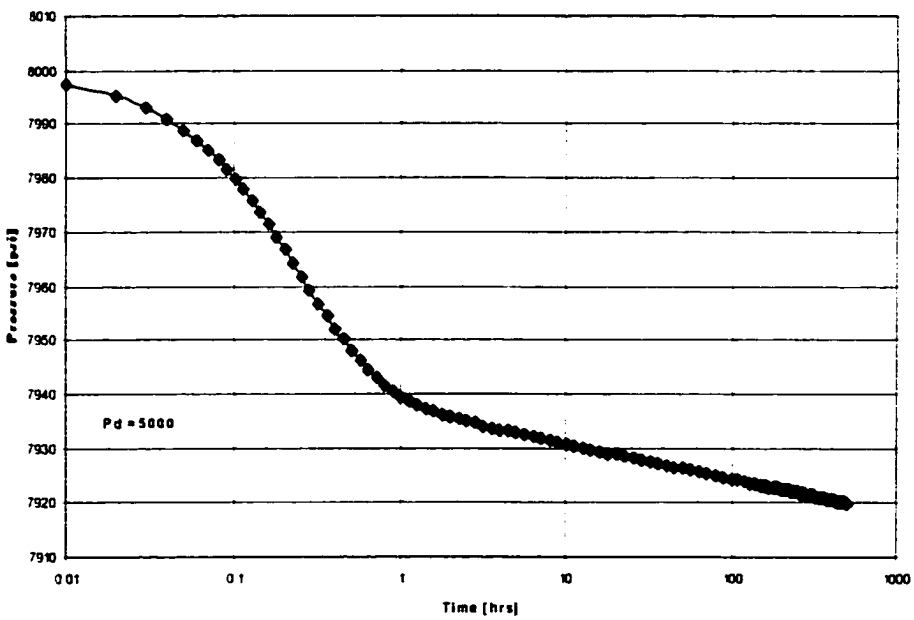


Fig.8.27. Pressure behavior during three phase well test.

Since the test last up to 7910 psi and the dew point pressure is 5000 psi, therefore, only one Region-3, single phase gas region with water production was observed during this test.

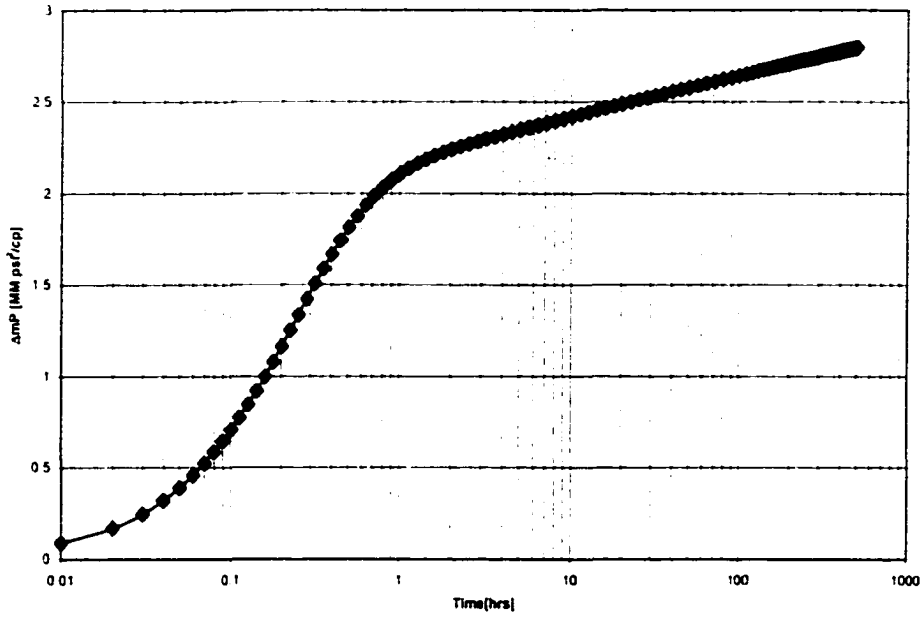


Fig. 8.28. Pseudopressure behavior.

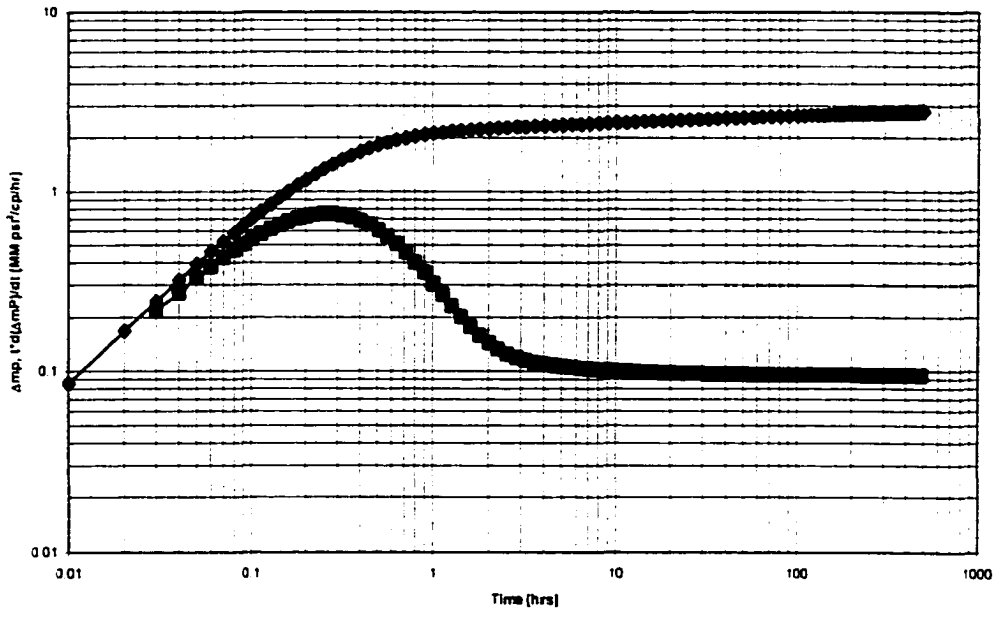


Fig.8.29. Pseudopressure and its derivative against time.

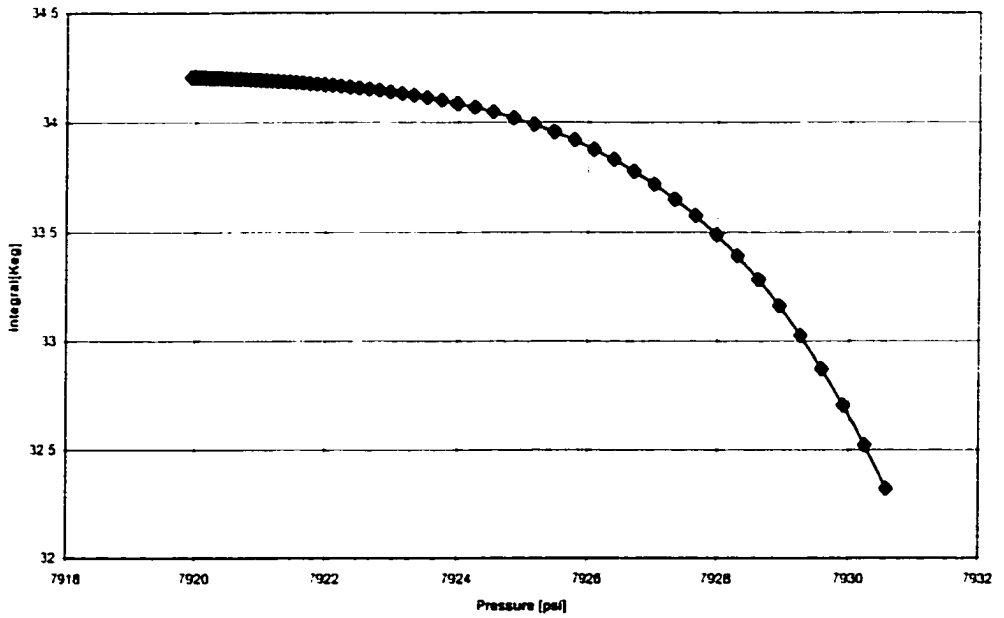


Fig. 8.30 Gas phase effective permeability Integral, Eq.a.Step-3.

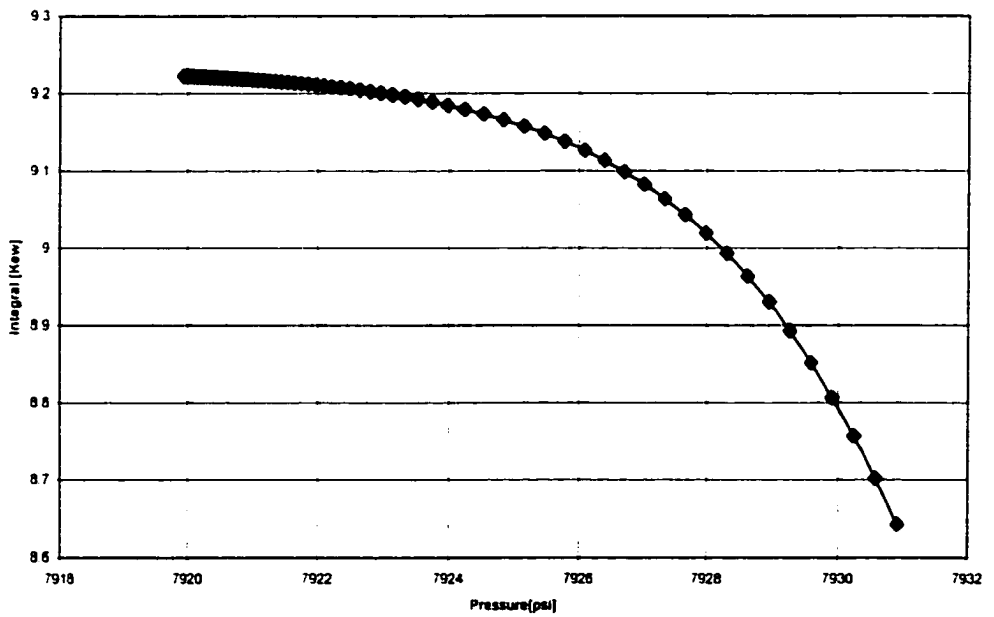


Fig. 8.31. Water phase effective permeability Integral, Eq.b.Step-3.

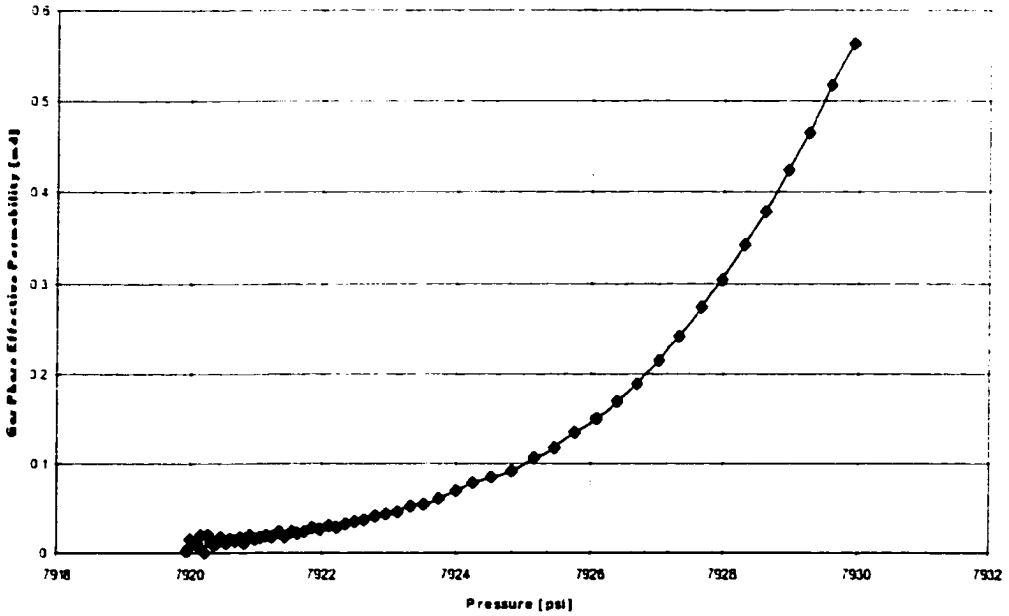


Fig. 8.32.Gas phase effective permeability, derivative of Eq.a.Step-3.

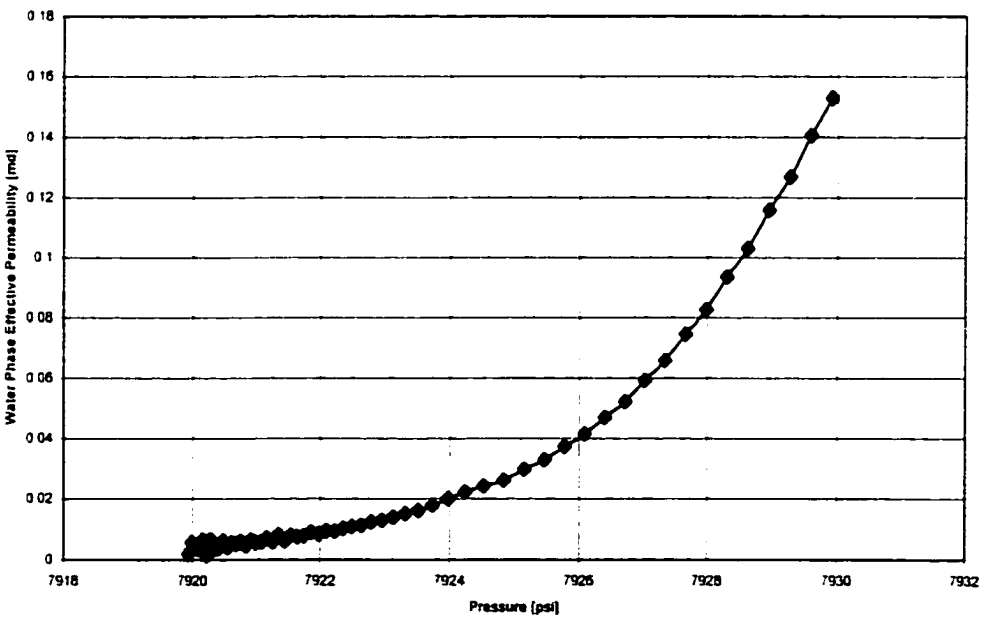


Fig. 8.33. Water phase effective permeability, derivative of Eq.b.Step-3.

Table 8.20. Gas effective permeability Integral.

Pressure	Integral (k_{eg})
5000	30.476471637928624
5200	30.631891184301181
5400	30.795983644540905
5600	30.969129442903928
5800	31.15174520450631
6000	31.344289374502508
6200	31.547270060542279
6400	31.761256836033446
6600	31.986900257845223
6800	32.224968032864444
7000	32.476421828527052
7200	32.74261028416964
7400	33.025876464272628
7600	33.332271093338032
7800	33.696972432023308
8000	33.688467604648922

Well Performance
C = 0.5, n = 0.8

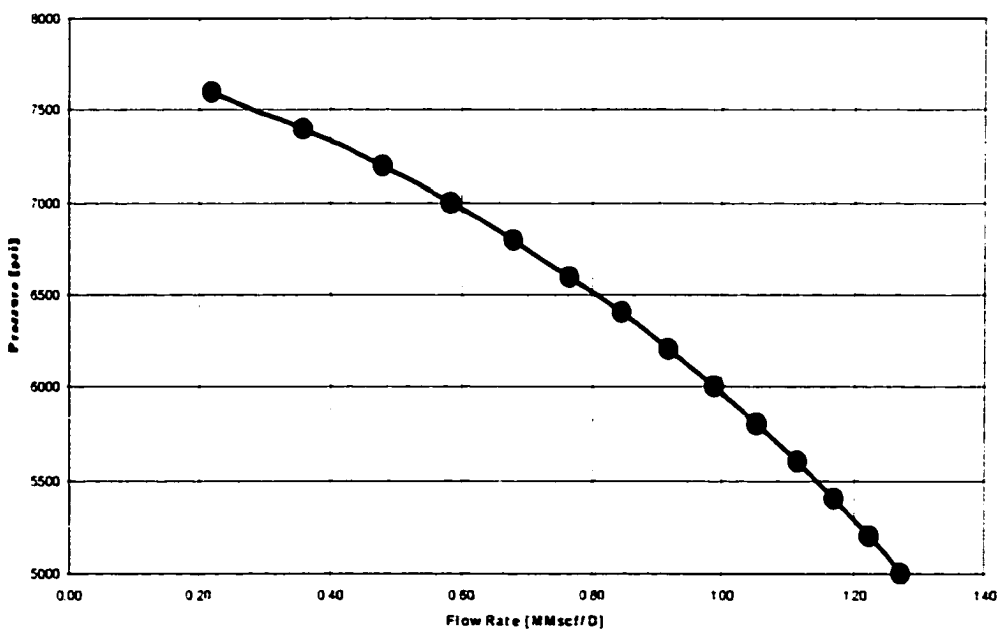


Fig.8.34. Gas Phase IPR against pressure, in Region-1, Pd = 5,000 psi.

Table 8.21. Water phase effective permeability.

Pressure	Integral(kew)
5000	10.116158420583201
5200	10.044798023019742
5400	9.9734377384218023
5600	9.9022283647546126
5800	9.8313100887163723
6000	9.7608134581254411
6200	9.6908609278103778
6400	9.6215694038350044
6600	9.5530547391367231
6800	9.4854404920007789
7000	9.4188772084256887
7200	9.3535920091200848
7400	9.2900466165207281
7600	9.229646563845015
7800	9.1813748736733521
8000	9.0312612761992642

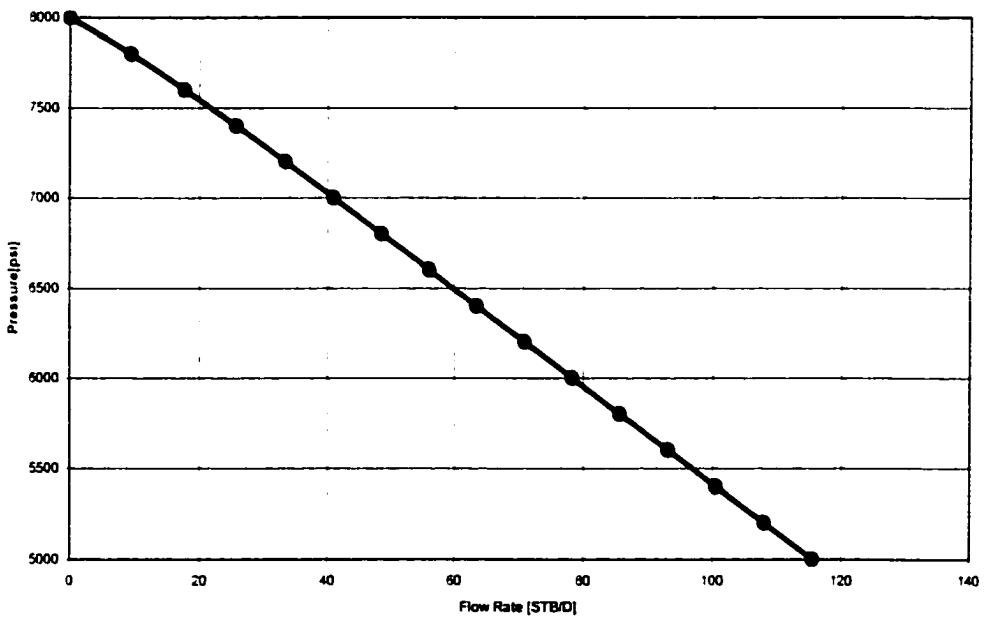


Fig.8. 35. Water Phase IPR in Region-1.

Note. In Region-3 Oil rate is zero.

Three Phase Examples
Example-2
Vertical Wells-Pressure Buildup

This example was simulated with reservoir pressure just above the dew point pressure to simulate the Region-1, Region,2 and Region-3 together. But the pressure did not drop far below to see all the three regions altogether. The lowest pressure is 3500 psi. But the initial data is masked by the wellbore storage effects, Region-1, Pd < Pwf = 4800 psi, is well developed. After 100 hours we are in radial portion and in the Region-1.

Thus using same procedure as in example 1, well performance is established.

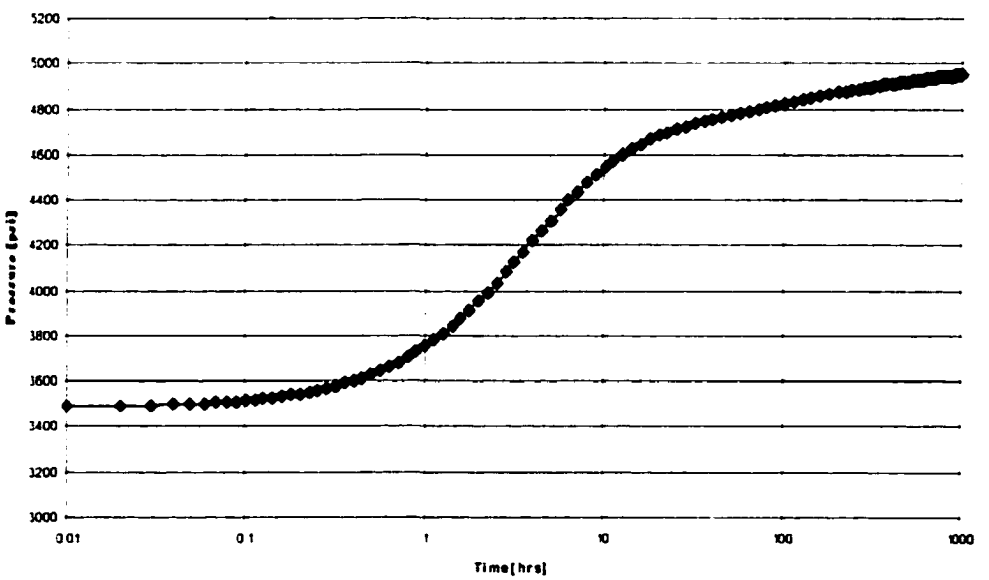


Fig. 8.36. Semi-log Plot of pressure Vs. Time.

Table 8.22. Well and reservoir data.

Pi	5000 Psi
GWR	10000 CF/STB
WGR	100 STB/MMscf
SG	0.7
P_d	4,800 psi
t_p	1000 Hrs
C_r	3.00E-06 Psi^{-1}
T	250 F
GOR	20000 cf/STB
r_w	0.35 Ft
H	100 Ft
C	0.2 STB/Psi
S	3
Kh	50 md-ft
K	0.5 Md
q_g	1 MMcf/D
q_o	50
q_w	100
API	50

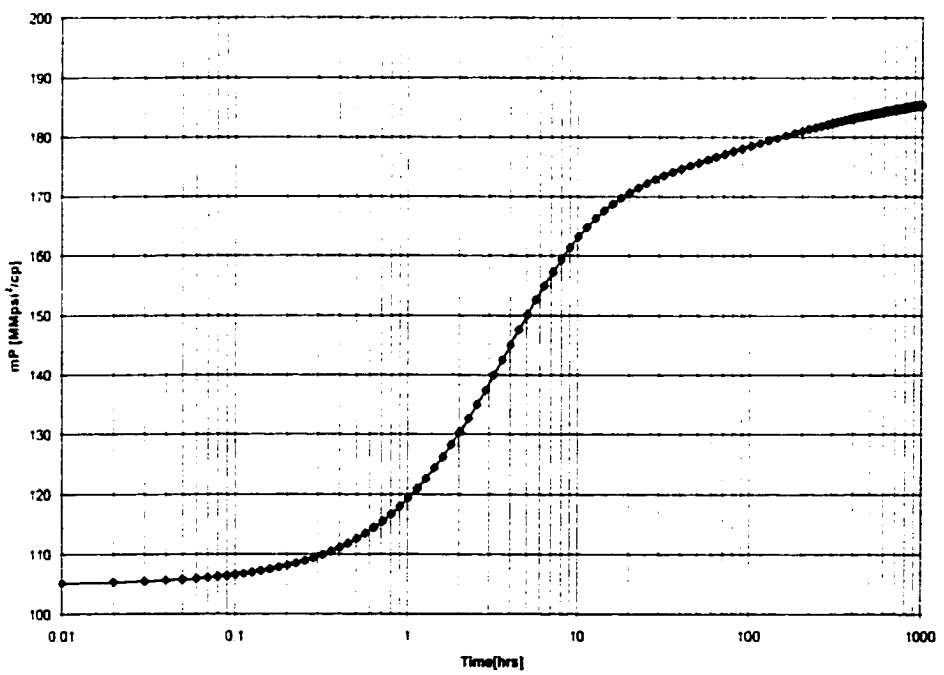


Fig.8.37. Pressure behavior during three phase well test with pseudopressure, Eq.4.90 without effective permeability term.

Table 8.23. Pressure transient data.

Time hr	P psi	Time hr	P psi	Time hr	P psi	Time hr	P psi
0	3293.836	1.009817	3545.368	31.93321	4677.055	479.5736	4902.691
0.01	3296.69	1.133033	3571.888	35.82965	4690.89	499.5736	4905.07
0.02	3299.532	1.271284	3600.754	40.20152	4703.788	519.5736	4907.323
0.03	3302.365	1.426404	3632.027	45.10685	4715.912	539.5736	4909.46
0.04	3305.188	1.600451	3665.805	50.61072	4727.54	559.5736	4911.492
0.05	3308.002	1.795736	3702.13	56.78616	4738.683	579.5736	4913.425
0.06	3310.807	2.014849	3741.04	63.71512	4749.472	599.5736	4915.273
0.07	3313.604	2.260698	3782.434	71.48954	4759.941	619.5736	4917.044
0.08	3316.392	2.536545	3826.304	80.21258	4770.189	639.5736	4918.737
0.09	3319.174	2.84605	3872.415	90	4780.224	659.5736	4920.358
0.100982	3322.217	3.193321	3920.641	100.9817	4790.043	679.5736	4921.91
0.113303	3325.622	3.582965	3970.589	113.3033	4799.649	699.5736	4923.398
0.127128	3329.425	4.020152	4021.971	127.1284	4809.054	719.5736	4924.827
0.14264	3333.676	4.510685	4074.255	142.6404	4818.276	739.5736	4926.2
0.160045	3338.42	5.061072	4126.976	160.0451	4827.33	759.5736	4927.52
0.179574	3343.717	5.678616	4179.525	179.5736	4836.175	779.5736	4928.791
0.201485	3349.621	6.371512	4231.289	199.5736	4844.104	799.5736	4930.016
0.22607	3356.206	7.148954	4281.693	219.5736	4851.119	819.5736	4931.196
0.253654	3363.536	8.021258	4330.071	239.5736	4857.39	839.5736	4932.335
0.284605	3371.705	9	4376.007	259.5736	4863.044	859.5736	4933.435
0.319332	3380.783	10.09817	4418.917	279.5736	4868.2	879.5736	4934.498
0.358296	3390.871	11.33033	4458.668	299.5736	4872.922	899.5736	4935.525
0.402015	3402.058	12.71284	4494.906	319.5736	4877.26	919.5736	4936.519
0.451069	3414.458	14.26404	4527.703	339.5736	4881.264	939.5736	4937.481
0.506107	3428.193	16.00452	4557.023	359.5736	4884.976	959.5736	4938.413
0.567862	3443.369	17.95736	4583.203	379.5736	4888.43	979.5736	4939.316
0.637151	3460.105	20.14849	4606.397	399.5736	4891.654	999.5736	4940.192
0.714895	3478.55	22.60698	4627.034	419.5736	4894.673	1000	4940.211
0.802126	3498.82	25.36545	4645.458	439.5736	4897.507		
0.9	3521.041	28.4605	4661.974	459.5736	4900.175		

Table 8.24. Pseudopressure Data

P	mP/Mg	Integral(keg)	mP	qg MMscf/D
4650	168.936	0.443020274	74.84208902	5.733662
4670	170.0356	0.541023676	91.99329463	5.523039
4690	171.1345	0.649302819	111.1181424	5.285781
4710	172.2328	0.762656808	131.3545149	5.031797
4730	173.3304	0.874624744	151.5990132	4.774461
4750	174.4272	0.978679374	170.7082872	4.528334
4770	175.5233	1.069704793	187.7580893	4.305877
4790	176.6186	1.145361288	202.2921116	4.113954
4810	177.7131	1.206995944	214.4990479	3.951016
4830	178.8069	1.260001519	225.2969462	3.805474
4850	179.8998	1.313865732	236.3641756	3.654843
4870	180.9919	1.382489383	250.2193213	3.464043
4890	182.0831	1.485700684	270.5209143	3.179588
4910	183.1734	1.653510311	302.8790348	2.712322
4930	184.2628	1.936259283	356.7804682	1.883393
4950	185.3512	2.428352359	450.0980779	0

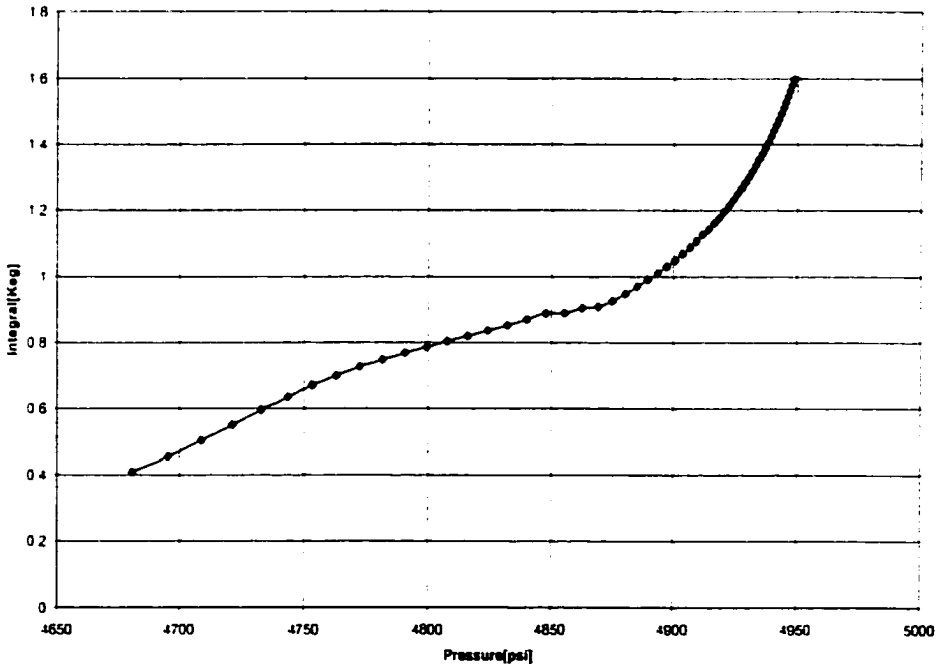


Fig. 8.38. Gas phase effective permeability Integral, (Eq.a Example-1)

Table 8.25. Water phase pseudopressure data

P	mP/Mw	Integral(kw)	mP	qw STB/D
4650	189.3454	0.443020274	83.88386	201.31
4670	190.0839	0.541023676	102.8399	191.832
4690	190.8217	0.649302819	123.9011	181 3014
4710	191.5587	0.762656808	146.0935	170 2051
4730	192.2949	0.874624744	168.1859	159.159
4750	193.0304	0.978679374	188.9149	148.7945
4770	193.7651	1.069704793	207.2715	139.6162
4790	194.499	1.145361288	222.7717	131.8661
4810	195.2322	1.206995944	235.6445	125.4297
4830	195.9646	1.260001519	246.9158	119.794
4850	196.6963	1.313865732	258.4325	114.0356
4870	197.4272	1.382489383	272.941	106.7814
4890	198.1573	1.485700684	294.4025	96.05067
4910	198.8867	1.653510311	328.8612	78.8213
4930	199.6153	1.936259283	386.507	49.9984
4950	200.3432	2.428352359	486.5038	0

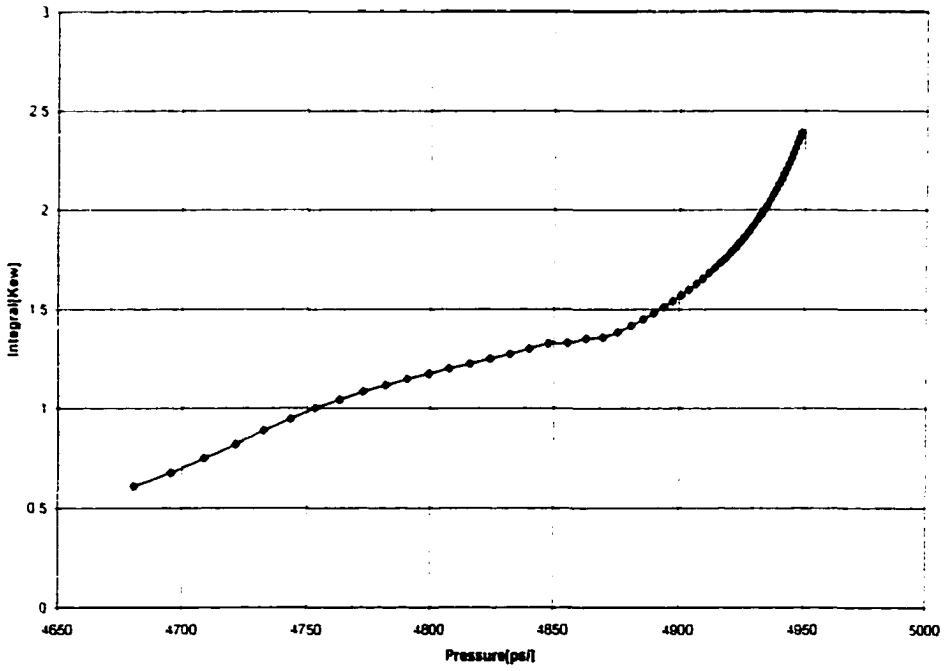


Fig. 8.39. Water phase effective permeability Integral, (Eq.b Example-1)

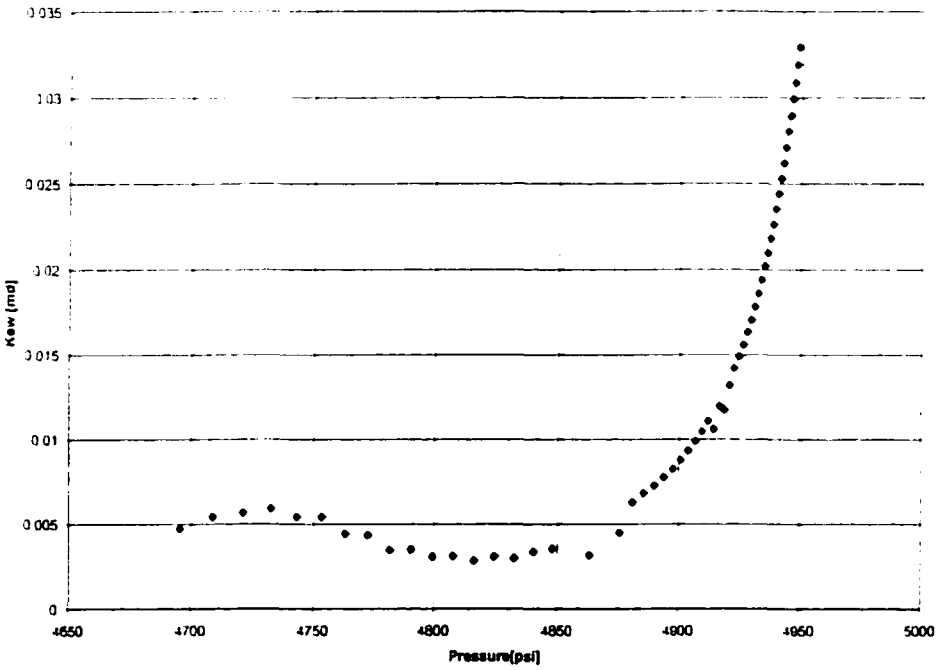


Fig. 8.40. Water phase effective permeability (Derivative of Eq.b Example-1)

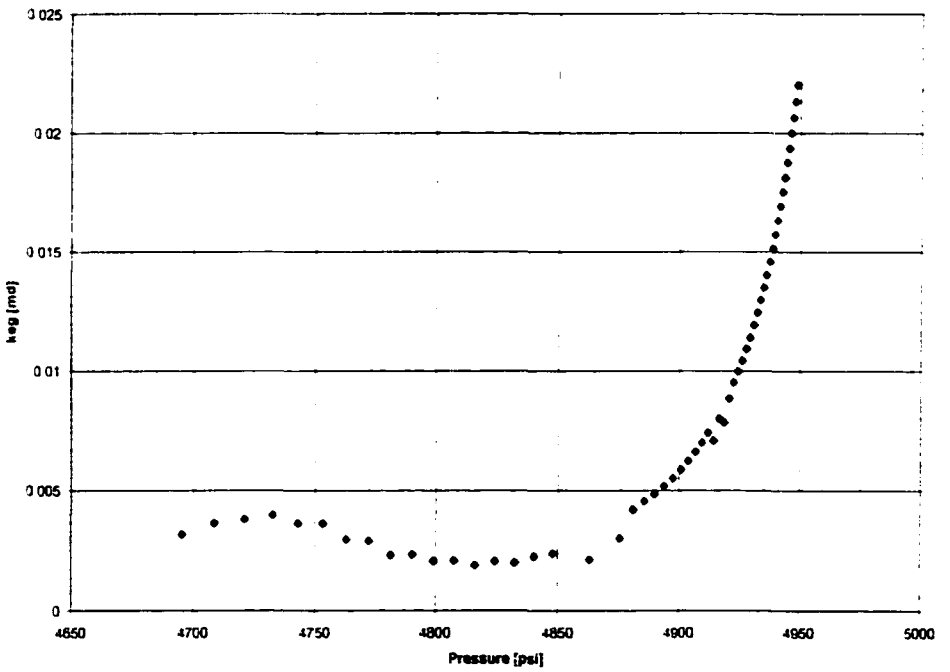


Fig. 8.41. Gas phase effective permeability (Derivative of Eq.a Example-1)

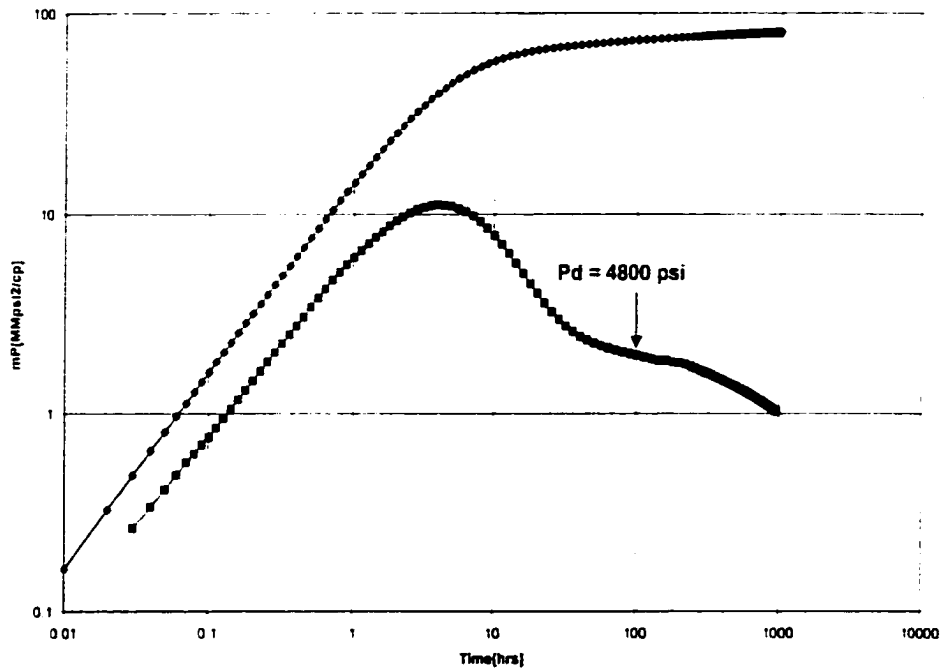


Fig.8.42. Pseudopressure and its derivative against time, Eq.490.

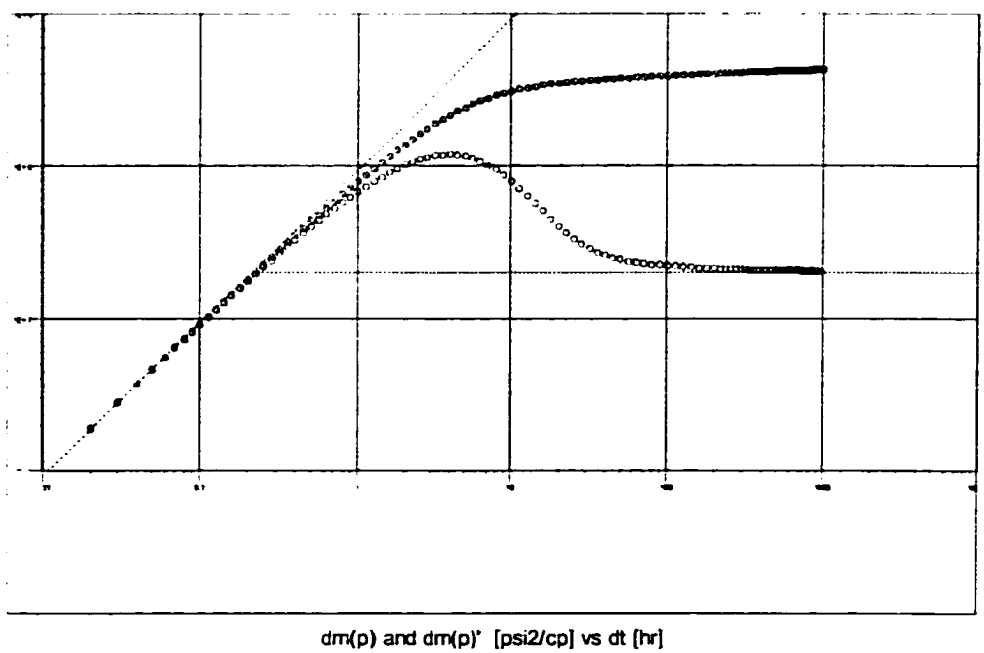


Fig.8.43. Pseudopressure and its derivative from Sapphire.

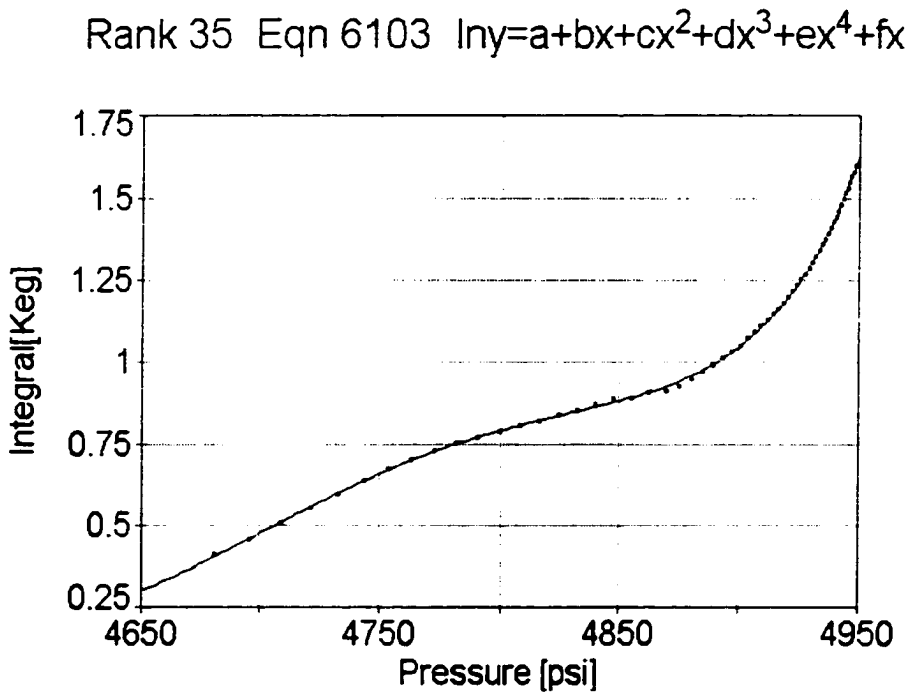


Fig. 8.44. Curve fit of Gas phase effective permeability Integral.

Table 8.26. Gas effective permeability integral.

Pressure	Integral[Keg]
4650	0.29762045799890937
4670	0.3634043918298419
4690	0.43596219600121575
4710	0.51181576975883678
4730	0.58665922703122982
4750	0.6561523280790823
4770	0.71689985846021637
4790	0.76735591174235665
4810	0.8084286250357622
4830	0.84372127405466752
4850	0.87956986766447234
4870	0.92526121796269346
4890	0.99405023518172253
4910	1.1060116957040951
4930	1.2948447155669481
4950	1.6238079244197225

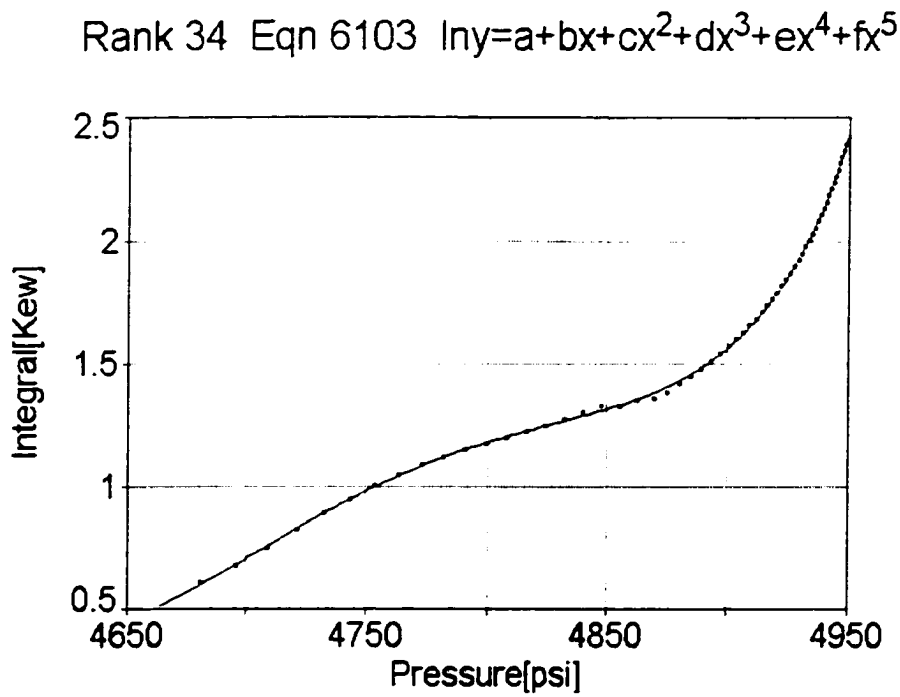


Fig. 8.45. Curve fit of Water phase effective permeability Integral.

Table 8.27. Water effective permeability integral.

Pressure	Integral[Kew]
4650	0.44302027417364041
4670	0.54102367599140588
4690	0.64930281931686321
4710	0.76265680812973728
4730	0.87462474391444535
4750	0.97867937420967451
4770	1.0697047931514044
4790	1.1453612878255373
4810	1.2069959437796109
4830	1.260001519200659
4850	1.3138657315396646
4870	1.3824893833407772
4890	1.4857006838184235
4910	1.6535103105320569
4930	1.9362592834488127
4950	2.428352358662414

Now converting the Pwf, production data into pseudopressure using Eq.4.90 this time with effective permeability terms, well performance is established. Again n and C were assumed.

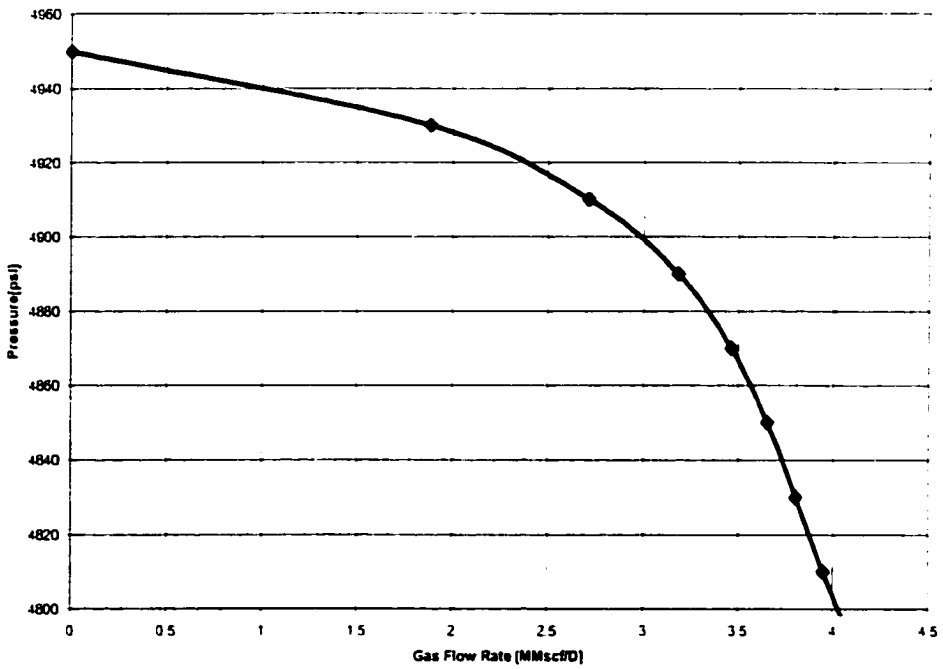


Fig. 8.46. Gas Phase IPR[n = 0.5, C = 0.05]

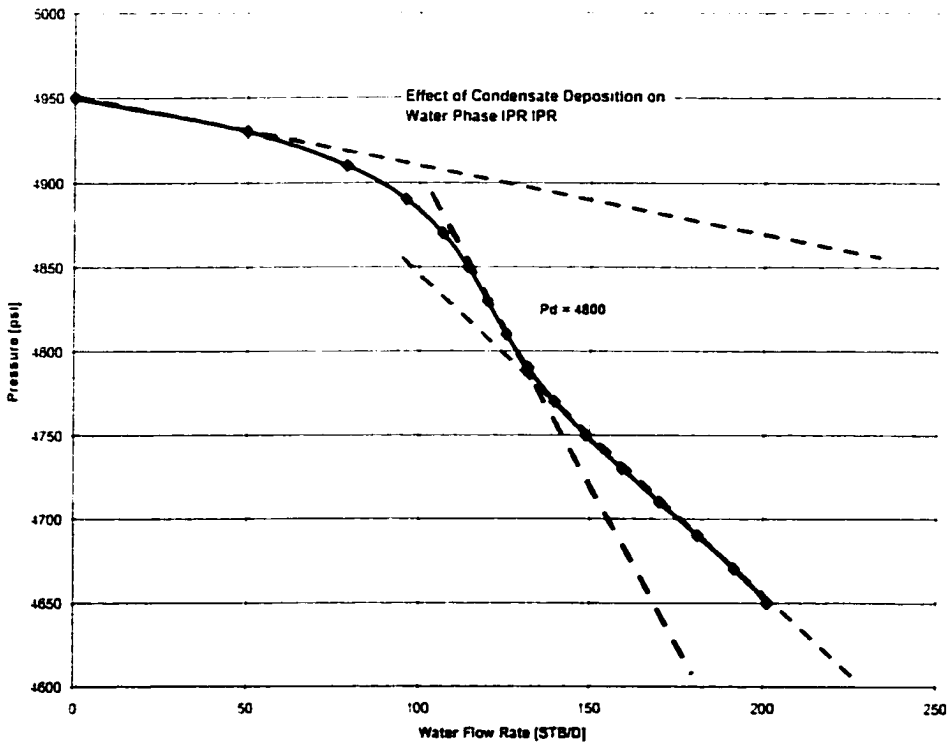


Fig. 8.47. Water phase IPR[n = 1, C = 0.5 Assumed values]

Example-3

Three Phase Horizontal Well

Table 8.28 Well and reservoir data.

Pi	3000	psi
GWR	10000	CF/STB
WGR	100	STB/MMscf
SG	0.7	
P_d	4800	psi
t_p	1000	hrs
C_r	3.00E-06	1/psi
T	200	F
GOR	20000	cf/STB
r_w	0.3	ft
L	1000	ft
C	0.1	STB/Psi
S	0	
Kh	30	md-ft
K	0.5	Md
q_g	5	MMcf/D
q_o	250	STB/D
q_w	500	STB/D
API	50	
h	60	Ft
Zw	30	Ft

Since reservoir pressure is greater than dew point pressure, only Region-3 exists.

Table 8.29. Pressure and pseudopressure for gas oil, and water phase.

		Gas		Oil		Water	
Time (hr)	Pressure (psia)	mP	t.dΔmP/dt	mP	t.dΔmP/dt	mP	t.dΔmP/dt
				MMpsi2/cp			
0	5200	224.2092		0.01504		165.4751	
0.01	5150.244	221.3834		0.015017		164.0621	
0.02	5143.958	221.0256		0.015004		163.8834	
0.03	5140.278	220.8159	0.517101	0.014994	2.36E-05	163.7787	0.258265
0.04	5137.665	220.6671	0.517486	0.014987	2.56E-05	163.7043	0.258433
0.05	5135.638	220.5515	0.517688	0.015	2.69E-05	163.6466	0.258515
0.06	5133.981	220.4571	0.517686	0.015	2.78E-05	163.5995	0.258499
0.07	5132.581	220.3773	0.517432	0.014972	2.84E-05	163.5597	0.258359

0.08	5131.37	220.3083	0.517004	0.014968	3.04E-05	163.5252	0.258134
0.09	5130.303	220.2475	0.516412	0.014964	3.09E-05	163.4948	0.257829
0.100982	5129.262	220.1881	0.515875	0.01496	3.23E-05	163.4652	0.257552
0.113303	5128.221	220.1288	0.515284	0.014957	3.27E-05	163.4355	0.257248
0.127128	5127.182	220.0695	0.515104	0.014953	3.27E-05	163.406	0.257149
0.14264	5126.142	220.0102	0.515384	0.014949	3.27E-05	163.3764	0.25728
0.160045	5125.101	219.9508	0.516694	0.014945	3.29E-05	163.3467	0.257925
0.179574	5124.055	219.8911	0.519309	0.014941	3.32E-05	163.3169	0.259222
0.201485	5123	219.8309	0.523753	0.014938	3.36E-05	163.2869	0.26143
0.22607	5121.932	219.77	0.530455	0.014934	3.42E-05	163.2565	0.264767
0.253654	5120.846	219.7081	0.539787	0.01493	3.5E-05	163.2255	0.269415
0.284605	5119.736	219.6447	0.552219	0.014925	3.6E-05	163.1939	0.27561
0.319332	5118.593	219.5795	0.567925	0.014921	3.72E-05	163.1614	0.283438
0.358296	5117.413	219.5121	0.587249	0.014917	3.86E-05	163.1277	0.293071
0.402015	5116.186	219.4421	0.610204	0.014912	4.03E-05	163.0928	0.304514
0.451069	5114.905	219.3689	0.63632	0.014907	4.22E-05	163.0563	0.317534
0.506107	5113.565	219.2925	0.666594	0.014902	4.43E-05	163.0181	0.332627
0.567862	5112.158	219.2121	0.700083	0.014897	4.67E-05	162.978	0.349322
0.637151	5110.674	219.1274	0.737592	0.014891	4.93E-05	162.9358	0.36802
0.714895	5109.108	219.0379	0.778728	0.014885	5.21E-05	162.8911	0.388525
0.802126	5107.452	218.9433	0.823215	0.014879	5.51E-05	162.8439	0.410699
0.9	5105.7	218.8432	0.870955	0.014872	5.83E-05	162.794	0.434492
1.009817	5103.846	218.7373	0.921832	0.014865	6.17E-05	162.7412	0.459846
1.133033	5101.883	218.6251	0.975732	0.014858	6.53E-05	162.6852	0.486703
1.271284	5099.806	218.5064	1.032534	0.01485	6.9E-05	162.626	0.515003
1.426404	5097.609	218.3808	1.092135	0.014841	7.29E-05	162.5634	0.544693
1.600451	5095.288	218.2481	1.154393	0.014832	7.7E-05	162.4972	0.575701
1.795736	5092.836	218.1078	1.219214	0.014823	8.12E-05	162.4272	0.607982
2.014849	5090.249	217.9598	1.286452	0.014813	8.56E-05	162.3534	0.641459
2.260698	5087.523	217.8039	1.356006	0.014803	9.01E-05	162.2757	0.676083
2.536545	5084.652	217.6396	1.427774	0.014792	9.48E-05	162.1938	0.711803
2.84605	5081.634	217.4668	1.501655	0.01478	9.95E-05	162.1077	0.748565
3.193321	5078.464	217.2853	1.577611	0.014768	0.000104	162.0172	0.786352
3.582965	5075.138	217.0948	1.655551	0.014756	0.000109	161.9222	0.825117
4.020152	5071.653	216.8951	1.735518	0.014743	0.000115	161.8227	0.864881
4.510685	5068.004	216.686	1.817179	0.014729	0.00012	161.7185	0.905475
5.061072	5064.188	216.4673	1.899279	0.014715	0.000125	161.6095	0.946276
5.678616	5060.209	216.2391	1.985138	0.0147	0.00013	161.4959	0.988935
6.371512	5056.053	216.0007	2.071692	0.014684	0.000136	161.3771	1.031925
7.148954	5051.717	215.7519	2.162599	0.014668	0.000142	161.2532	1.077068
8.021258	5047.195	215.4923	2.256263	0.014651	0.000148	161.1239	1.123566
9	5042.481	215.2216	2.352773	0.014633	0.000154	160.9891	1.171463
10.09817	5037.57	214.9395	2.452613	0.014614	0.00016	160.8487	1.221
11.33033	5032.454	214.6454	2.556049	0.014595	0.000167	160.7023	1.272305
12.71284	5027.125	214.339	2.66356	0.014575	0.000174	160.5498	1.325617
14.26404	5021.575	214.0197	2.775423	0.014554	0.000181	160.391	1.381071
16.00452	5015.794	213.6871	2.889415	0.014533	0.000189	160.2254	1.437559
17.95736	5009.784	213.341	3.010741	0.01451	0.000196	160.0533	1.49767
20.14849	5003.525	212.9805	3.135826	0.014486	0.000205	159.874	1.559621
22.60698	4997.001	212.6044	3.269421	0.014462	0.000213	159.687	1.625773

25.36545	4990.199	212.2122	3.410516	0.014436	0.000222	159.492	1.695621
28.4605	4983.105	211.8029	3.55897	0.01441	0.000232	159.2885	1.76909
31.93321	4975.705	211.3757	3.714905	0.014382	0.000242	159.0762	1.846239
35.82965	4967.982	210.9296	3.876004	0.014353	0.000252	158.8545	1.925912
40.20152	4959.933	210.4643	4.045257	0.014323	0.000263	158.6234	2.009591
45.10685	4951.542	209.979	4.22132	0.014291	0.000274	158.3823	2.096604
50.61072	4942.786	209.4722	4.404734	0.014258	0.000286	158.1307	2.187219
56.78616	4933.655	208.9434	4.596528	0.014224	0.000298	157.8681	2.281939
63.71512	4924.137	208.3917	4.793096	0.014188	0.000309	157.5943	2.378973
71.48954	4914.228	207.8169	4.988663	0.014151	0.000322	157.3091	2.475453
80.21258	4903.942	207.2199	5.192085	0.014113	0.000334	157.0129	2.575771
90	4893.257	206.5991	5.39176	0.014073	0.000346	156.7051	2.674169
100.9817	4882.173	205.9547	5.596824	0.014032	0.000358	156.3855	2.77518
113.3033	4870.694	205.2867	5.797234	0.013989	0.00037	156.0544	2.873825
127.1284	4858.84	204.5963	5.994521	0.013945	0.000381	155.7122	2.970866
142.6404	4846.62	203.884	6.187787	0.0139	0.000392	155.3593	3.065858
160.0451	4834.034	203.1496	6.375467	0.013854	0.000385	154.9955	3.158033
179.5736	4821.094	202.3939	6.550428	0.01381	0.00039	154.6213	3.243847
199.5736	4808.975	201.6856	8.694354	0.01377	0.000384	154.2706	3.320799
219.5736	4797.83	200.6864	6.659482	0.013733	0.000389	153.9478	3.387379
239.5736	4787.474	200.1094	8.433973	0.013698	0.000398	153.6478	3.443565
259.5736	4777.8	199.5697	6.733761	0.013666	0.000405	153.3673	3.498654
279.5736	4768.723	199.0626	6.813408	0.013635	0.000411	153.1041	3.537502
299.5736	4760.217	198.587	6.884624	0.013607	0.000416	152.8573	3.572099
319.5736	4752.215	198.139	6.947303	0.01358	0.00042	152.625	3.602372
339.5736	4744.629	197.7139	7.003903	0.013554	0.000425	152.4047	3.629601
359.5736	4737.417	197.3094	7.068936	0.013529	0.00043	152.1952	3.661298
379.5736	4730.545	196.9236	7.12783	0.013506	0.000434	151.9955	3.689896
399.5736	4723.982	196.5549	7.182381	0.013483	0.000437	151.8047	3.716317
419.5736	4717.7	196.2017	7.223027	0.013462	0.00044	151.622	3.735619
439.5736	4711.692	195.8635	7.260452	0.013441	0.000443	151.4472	3.753324
459.5736	4705.935	195.5393	7.295425	0.013421	0.000445	151.2797	3.769821
479.5736	4700.396	195.2272	7.327464	0.013402	0.000448	151.1184	3.784866
499.5736	4695.06	194.9263	7.365108	0.013384	0.00045	150.9631	3.802857
519.5736	4689.912	194.6358	7.400419	0.013366	0.000453	150.8131	3.819697
539.5736	4684.94	194.3551	7.433399	0.013349	0.000455	150.6683	3.835372
559.5736	4680.131	194.0834	7.464337	0.013332	0.000457	150.5281	3.850043
579.5736	4675.476	193.8202	7.49343	0.013316	0.000459	150.3925	3.863796
599.5736	4670.965	193.5651	7.520205	0.013301	0.00046	150.2609	3.876398
619.5736	4666.589	193.3175	7.537497	0.013285	0.000461	150.1334	3.884145
639.5736	4662.351	193.0775	7.554482	0.013271	0.000462	150.0097	3.891775
659.5736	4658.24	192.8447	7.569665	0.013257	0.000463	149.8898	3.898507
679.5736	4654.242	192.6181	7.585237	0.013243	0.000465	149.7731	3.905473
699.5736	4650.351	192.3975	7.606244	0.013229	0.000466	149.6596	3.915271
719.5736	4646.561	192.1825	7.626283	0.013216	0.000467	149.5489	3.924593
739.5736	4642.868	191.9729	7.645367	0.013203	0.000469	149.4411	3.933454
759.5736	4639.266	191.7684	7.663522	0.013191	0.00047	149.3359	3.941859
779.5736	4635.751	191.5688	7.680976	0.013178	0.000471	149.2333	3.949927
799.5736	4632.32	191.3738	7.697607	0.013166	0.000472	149.133	3.957595
819.5736	4628.967	191.1832	7.713672	0.013155	0.000473	149.0351	3.964993

839.5736	4625.69	190.9969	7.729091	0.013143	0.000474	148.9393	3.972077
859.5736	4622.485	190.8146	7.743896	0.013132	0.000475	148.8456	3.978869
879.5736	4619.35	190.6361	7.758129	0.013121	0.000475	148.754	3.985383
899.5736	4616.28	190.4614	7.764346	0.01311	0.000475	148.6642	3.987798
919.5736	4613.28	190.2905	7.769168	0.0131	0.000476	148.5765	3.989518
939.5736	4610.346	190.1234	7.77452	0.01309	0.000476	148.4907	3.991528
959.5736	4607.471	189.9596	7.778549	0.01308	0.000477	148.4066	3.992873

Table 8.30. Pressure and Effective permeability integral and effective permeability of oil, gas, and water phase.

P	Int[Ko]	Ko	Int.[Kg]	Kg	Int.[Kw]	Kw
0	43.3668	0	0.000958	1.17E-18	0.019527	0
200	44.22919	0.008666	0.000958	6.1E-09	0.019691	1.64E-06
400	46.86733	0.017842	0.000961	2.44E-08	0.020187	3.32E-06
600	51.43402	0.028037	0.000969	5.49E-08	0.021027	5.09E-06
800	58.18401	0.03976	0.000984	9.76E-08	0.022231	6.98E-06
1000	67.47389	0.053521	0.001009	1.52E-07	0.023829	9.03E-06
1200	79.76215	0.069829	0.001046	2.2E-07	0.025857	1.13E-05
1400	95.60918	0.089193	0.001098	2.99E-07	0.028361	1.38E-05
1600	115.6773	0.112124	0.001166	3.9E-07	0.031394	1.66E-05
1800	140.7305	0.13913	0.001254	4.94E-07	0.035017	1.97E-05
2000	171.635	0.170721	0.001365	6.1E-07	0.039301	2.32E-05
2200	209.3587	0.207407	0.001499	7.38E-07	0.044323	2.71E-05
2400	254.9713	0.249696	0.001661	8.78E-07	0.05017	3.15E-05
2600	309.6447	0.298099	0.001851	1.03E-06	0.056936	3.63E-05
2800	374.6523	0.353124	0.002074	1.2E-06	0.064724	4.17E-05
3000	451.3697	0.415281	0.00233	1.37E-06	0.073645	4.76E-05
3200	541.2743	0.48508	0.002624	1.56E-06	0.083817	5.42E-05
3400	645.9452	0.56303	0.002956	1.76E-06	0.095369	6.14E-05
3600	767.0637	0.649641	0.00333	1.98E-06	0.108436	6.94E-05
3800	906.4128	0.745421	0.003747	2.2E-06	0.123161	7.8E-05
4000	1065.877	0.85088	0.004211	2.44E-06	0.139696	8.75E-05
4200	1247.444	0.966529	0.004724	2.69E-06	0.158202	9.77E-05
4400	1453.202	1.092875	0.005288	2.95E-06	0.178847	0.000109
4600	1685.341	1.230429	0.005906	3.23E-06	0.201808	0.000121
4800	1946.155	1.379701	0.00658	3.51E-06	0.227269	0.000134
5000	2238.037	1.541198	0.007312		0.255424	0.000148
5200	2563.483	1.715432	0.008105		0.286474	0.000163

1. Using equation 4. 90, pressure test data is analyzed, ignoring the gas effective permeability term.

$$mP_{g1} = \int_{P_{wf}}^{P_i \geq P^*} k.k_g \left(\frac{R_{pgw}}{(R_{pgw} - R_{sgw})(\mu_g B_g)} \left(1 + R_{so} \left(\frac{1 - BR_o}{B - R_{so}} \right) \right) \right) dp$$

$$B = (R_{pgo} - R_{pwo} R_{sgw})$$

2. Using Eq.4.88 well test data is analyzed for water phase effective permeability

$$mP_w = \int_{P_{wf}}^{P^*} \frac{k.k_{rw}}{B_w.\mu_w} R_{pgw} dp$$

3. Using Eq.6.45, the gas and water phase effective permeability integrals are estimated.

$$\int_{P_{wf}}^{P} (k.k_{rg}(P)) dp = \frac{162.6}{\frac{dmP_g}{d\ln(t)}} \left(\frac{q_{g,meas}}{h} \right) \text{.....(c)}$$

$$\int_{P_{wf}}^{P} (k.k_{rw}(P)) dp = \frac{162.6}{\frac{dmP_g}{d\ln(t)}} \left(\frac{q_{g,meas}}{h} \right) \text{.....(d)}$$

$$\int_{P_{wf}}^{P} (k.k_{o}(P)) dp = \frac{162.6}{\frac{dmP_g}{d\ln(t)}} \left(\frac{q_{g,meas}}{h} \right) \text{.....(e)}$$

4. Now the production data (Pwf) is converted using equations in Step 1 and 2, this time with effective permeability integrals for both gas and water phase.
5. Establish the well performance.

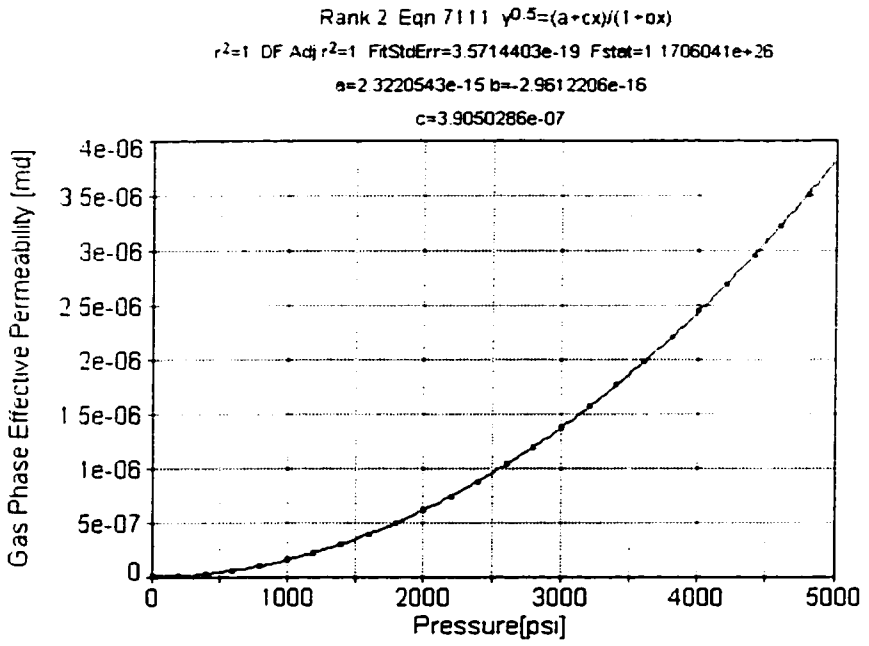


Fig.8.48. Gas phase effective permeability, derivative of Eq.c.

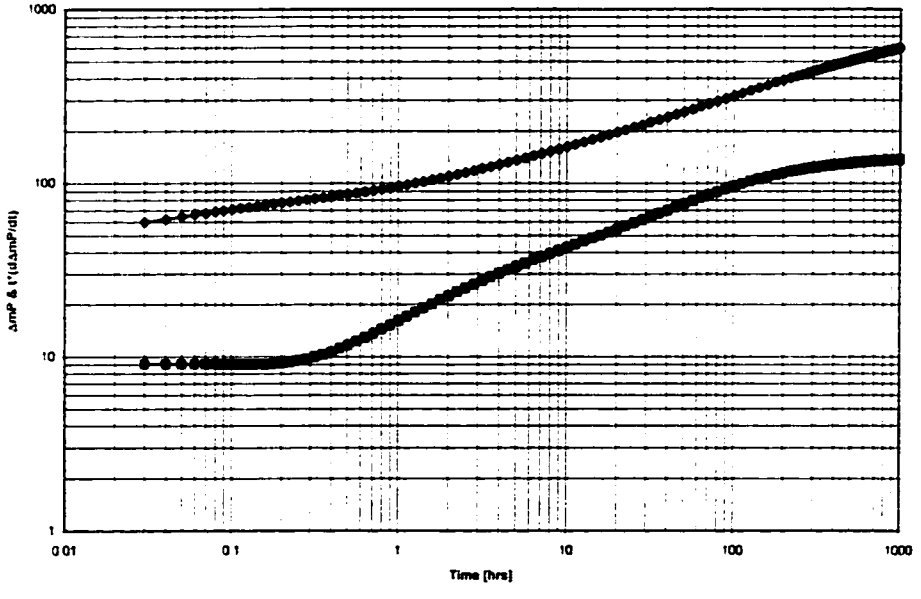


Fig.8.49. Pseudopressure and its derivative with new pseudopressure.

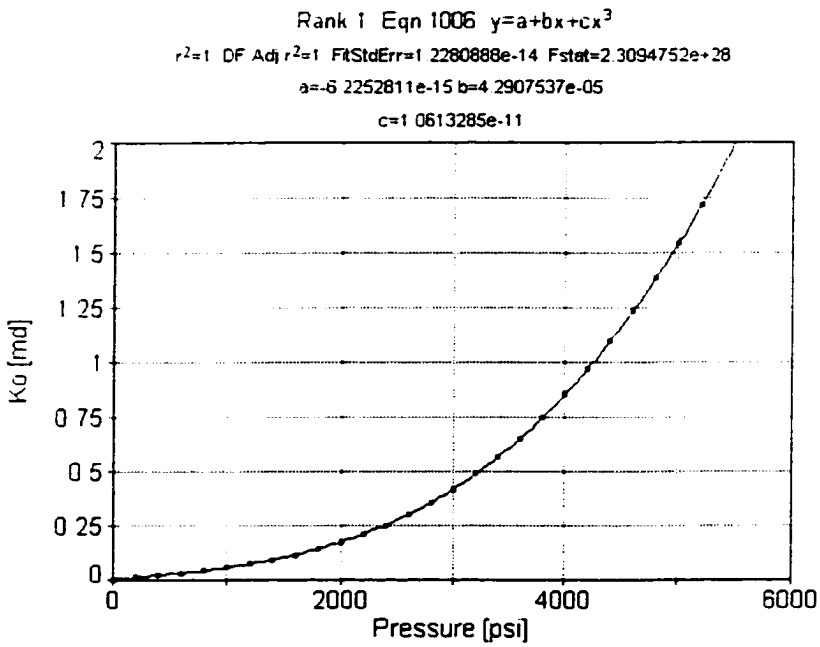


Fig.8.50 Oil phase effective permeability, derivative Eq.e.

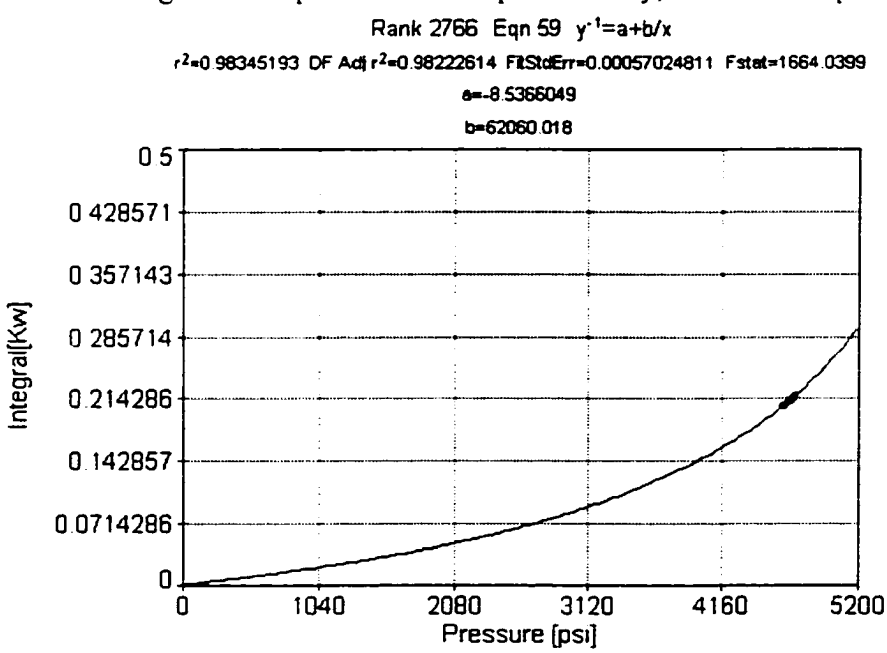


Fig.8.51. Water phase effective permeability integral, Eq.d.

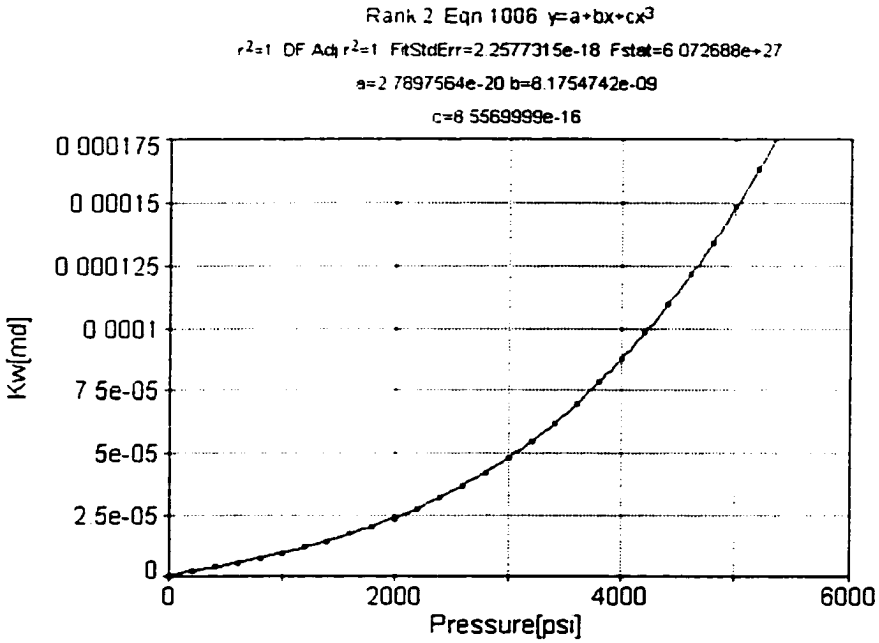


Fig.8.52. Water phase effective permeability, derivative Eq.d.

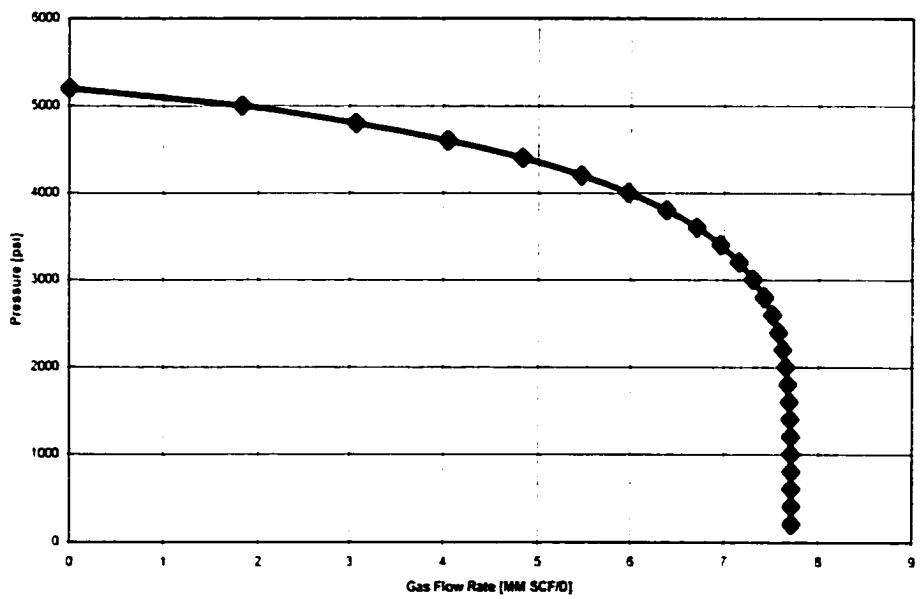


Fig.8.53. Gas Phase IPR against pressure.

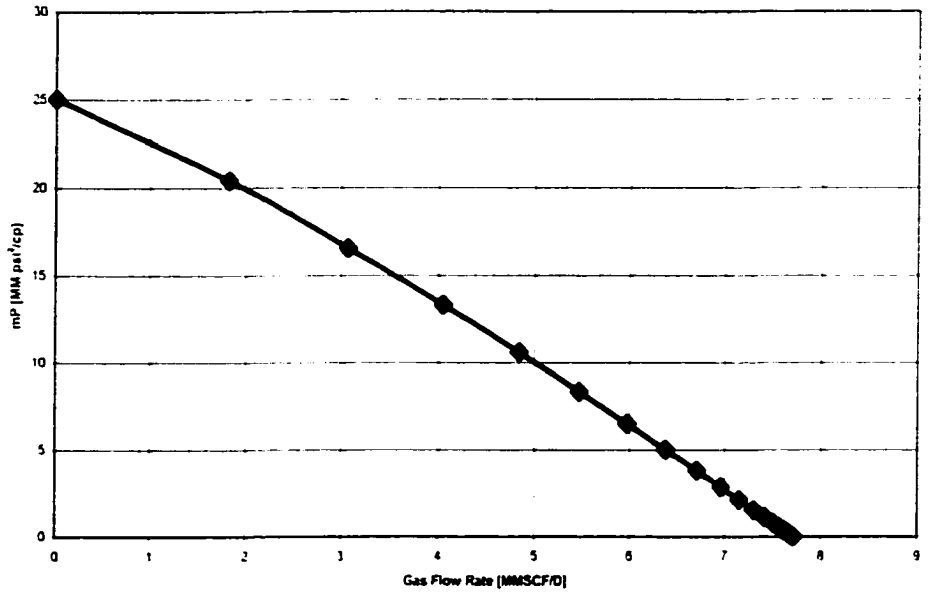


Fig.8.54. Gas Phase IPR against pseudopressure.

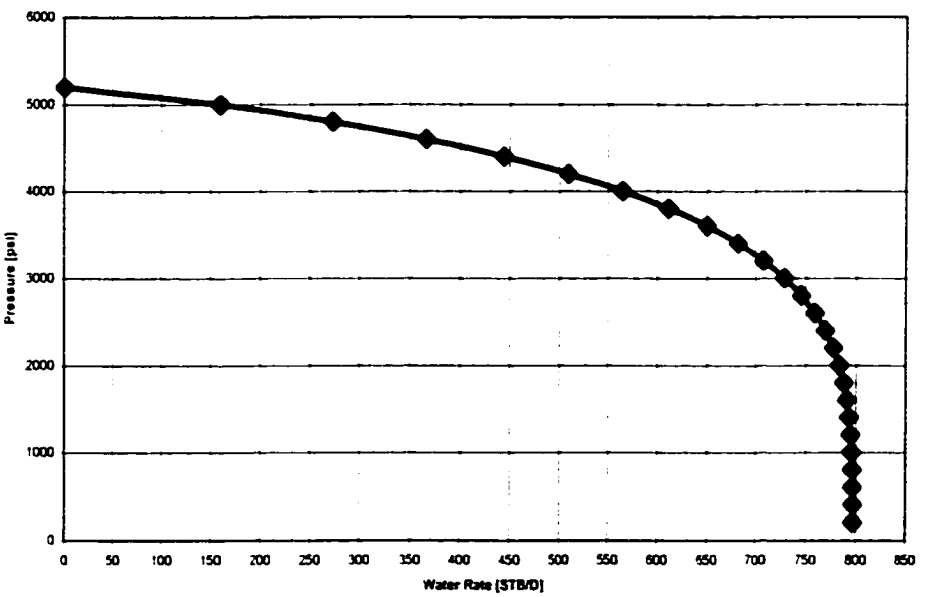


Fig.8.55. Water Phase IPR against pressure.

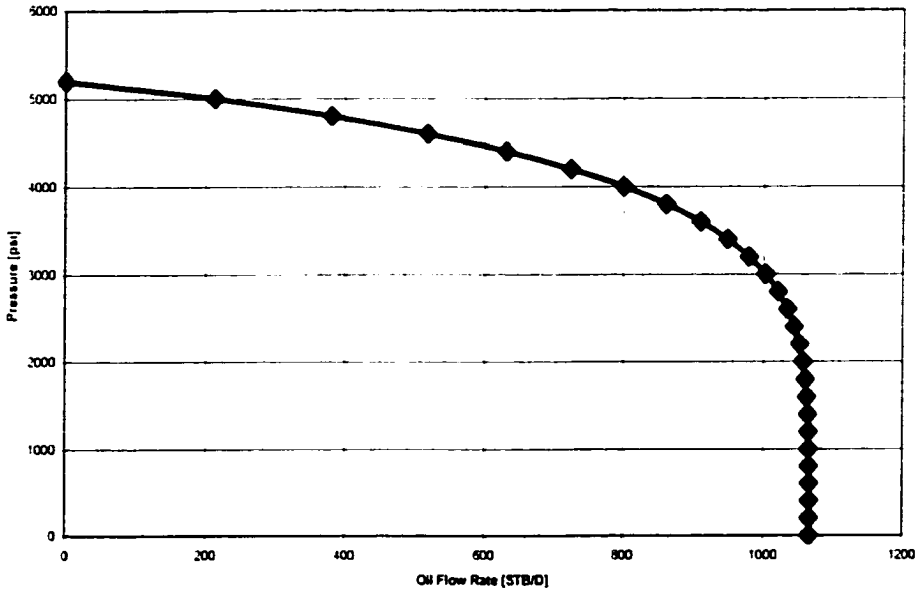


Fig.8.56. Oil Phase IPR against pressure.

TDS Example

Table 8.31. Well and Reservoir Data-(3 phase)

Pi	3000psi
GWR	10000CF/STB
WGR	100STB/MMscf
SG	0.7
P_d	4800psi
t_p	1000hrs
C_r	3.00E-06 1/psi
T	200F
GOR	20000cf/STB
r_w	0.3ft
L	1000ft
C	0.1STB/Psi
S	0
Kh	30md-ft
K	0.5md
q_g	5MMcf/D
q_o	250
q_w	500
API	50
h	60ft
Zw	30Ft
μ_g	0.00257 Cp
ϕ	0.1
h_x	1000ft
$\phi \mu_g C_r$	7.71E-10

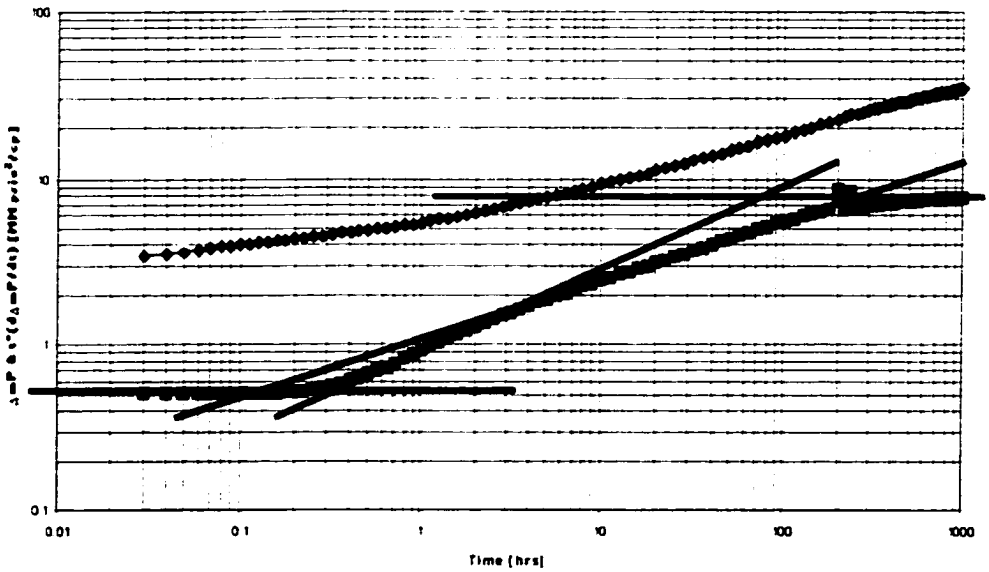


Fig.8.57. Log-log plot of pseudopressure and its derivative.

Characteristic points read from the log-log plot.

$(t*dmP/dt)_{ER}$	0.53×10^6
$(t*dm/dp)_{EL\text{-}1hr}$	0.95×10^6
$(t*dmP/dt)_{LR}$	8×10^6
$(t*dm/dp)_{LL\text{-}1hr}$	1.1×10^6
$ti_{ER\text{-}EL}$	0.33
$ti_{EL\text{-}LL}$	3.5
$ti_{LL\text{-}LR}$	260
$ti_{LR\text{-}EL}$	75

Gas Phase

Note: All the permeability values calculated are gas phase integral values of effective permeability in case of multi-phase systems and absolute permeability in case of single phase gas systems.

Using Eq.7.19

$$\sqrt{k_Y k_Z} = 70.6 \frac{q}{L\left(t \bullet \Delta mP'\right)_{ER}}$$

$$\sqrt{k_Y k_Z} = 70.6 \frac{5}{1000\ (0.53)} = 0.666$$

Eq. 7.26

$$\sqrt{k_Y} = \frac{1.016q\left(\frac{r_w}{r_{wa}}\right)}{\sqrt{(\phi\ \mu\ c_t)}h_Z\ L\ \left(t \bullet \Delta mP'\right)_{EL-1hr}}$$

$$\sqrt{k_Y} = \frac{1.016(5)\left(\frac{0.3}{0.3}\right)}{\sqrt{(7.71e-10)(60)(1000)(0.95)}} = 0.96$$

Eq.7.29

$$\sqrt{k_x k_y} = \frac{70.6q}{h_z\left(t \bullet \Delta mP'\right)_{LR}}$$

$$\sqrt{k_x k_y} = \frac{70.6(5)}{60(8)} = 0.735$$

Eq.7.50

$$\sqrt{k_Z} = 69.45\left(\sqrt{(\phi\ \mu\ c_t)}\right)\left(\frac{r_{wa}}{r_w}\right)\ (h_Z)\left(\frac{1}{\sqrt{t_i}}\right)_{ER-EL}$$

$$\sqrt{k_Z} = 69.45\left(\sqrt{(7.71E-10)}\right)\left(\frac{0.3}{0.3}\right)\ (60)\left(\frac{1}{\sqrt{0.33}}\right) = 0.201$$

Eq.7.52

$$\sqrt{k_X} = 69.45\left(\sqrt{(\phi\ \mu\ c_t)}\right)\left(\frac{r_{wa}}{r_w}\right)\ (L)\left(\frac{1}{\sqrt{t_i}}\right)_{LR-EL}$$

$$\sqrt{k_X} = 69.45\left(\sqrt{(7.71E-10)}\right)\left(\frac{0.3}{0.3}\right)\ (1000)\left(\frac{1}{\sqrt{0.33}}\right) = 0.201$$

Eq.7.55

$$\sqrt{k_X} = 69.45\left(\sqrt{(\phi\ \mu\ c_t)}\right)\left(\frac{r_{wa}}{r_w}\right)\ (h_X)\left(\frac{1}{\sqrt{t_i}}\right)_{LR-EL}$$

$$\sqrt{k_X} = 69.45\left(\sqrt{(7.71E-10)}\right)\left(\frac{0.3}{0.3}\right)\ (1000)\left(\frac{1}{\sqrt{75}}\right) = 0.222$$

Eq.7.56

$$\frac{(t \bullet \Delta mP)_{LR}}{(t \bullet \Delta mP)_{ER}} = \sqrt{\frac{k_Z}{k_X}}\left(\frac{L}{h_Z}\right)$$

$$h_Z = \left(\frac{0.201}{0.222}\right)\left(\frac{1000}{\left(\frac{8}{0.53}\right)}\right) = 59.9 \ Ft$$

Eq. 7.59

$$\frac{(t \bullet \Delta mP')_{ER}}{(t \bullet \Delta mP')_{LL-1hr}} = 69.45\frac{\sqrt{(\phi \ \mu \ c_t)}h_Z h_X}{\left(\frac{r_w}{r_{wa}}\right)L}\left(\sqrt{\frac{k_Y}{k_Z}}\right)$$

$$\left(\sqrt{\frac{k_Y}{k_Z}}\right) = 69.45\frac{\sqrt{(7.71E-10)}(60)(1000)}{\left(\frac{0.3}{0.3}\right)(1000)}\frac{1}{\frac{0.53}{1.1}} = 4.82$$

Eq. 7.60

$$\frac{(t \bullet \Delta mP')_{LR}}{(t \bullet \Delta mP')_{EL-1hr}} = 69.45\frac{\sqrt{(\phi \ \mu \ c_t)}L}{\left(\frac{r_w}{r_{wa}}\right)}\left(\frac{1}{\sqrt{k_x}}\right)$$

$$L = \frac{\frac{(t \bullet \Delta mP')_{LR}}{(t \bullet \Delta mP')_{EL-1hr}}}{69.45\frac{\sqrt{(\phi \ \mu \ c_t)}L}{\left(\frac{r_w}{r_{wa}}\right)}\left(\frac{1}{\sqrt{k_x}}\right)}$$

$$L = \frac{\frac{8}{0.95}}{69.45\frac{\sqrt{(7.71E-10)}(1000)}{\left(\frac{0.3}{0.3}\right)}\left(\frac{1}{0.222}\right)} = 972.4\,\text{Ft}$$

Chapter IX
Discussion of Figures

9.1 Chapter IV

Fig. 4.1 and Fig. 4.3: As the dew point pressure is reached, Region-2, the production gas oil ratio increases monotonically. As the P* (4300 psi) approaches, it dives and then begins to stabilize. This is a unique behavior and provides an opportunity to locate the P* as mentioned by Fevang and Whitson[5].

Fig. 4.2. As the P* approaches, 4300, the oil phase begins to develop. Since the oil relative permeability is initially very small, the gas to oil relative permeability ratio shows increasing behavior until the oil begins to move and has gained sufficient effective permeability.

Fig.4.4: Is the conceptual model of developing liquid phase in two phase systems.

Fig.4.5: Is the conceptual model of developing liquid phase in three phase systems.

Fig.4.6: Effective permeability behavior using free rate during the pressure transient data. It clearly shows the wellbore storage and skin effects on the effective permeability. Eq.4.42 and 4.43.

Fig.4.7: Pressure and pressure derivative profile that is needed to calculate the effective permeability in a multiphase environment. The derivative part, the radial flow portion, is needed to calculate effective permeability.

Fig.4.8: Effective permeability to oil in a multiphase environment. The wellbore storage and skin effects are at the beginning of the curve. Eq.4.42.

Fig.4.9: Effective permeability behavior against the time during a pressure transient test. This similar to pressure behavior with time.

Fig. 4.11: Gas effective permeability as a function pressure from well test analysis. Again skin factor and wellbore storage effects are apparent. Eq. 4.43

Fig.4.11 and 4.12: These figures show that effective permeability is not affected by the well surface rate. It tends to stabilize once the wellbore storage and skin effects are overcome.

Fig.4.13: Show the flow pattern during early radial and late radial flow regimes in a horizontal well during pressure transient test. These regimes are needed to calculate the effective permeability as a function of the pressure.

Fig.4.14: This figure is the pressure and pressure derivative response of a horizontal well. This example was simulated using Saphhire™ well test software. Simulation was done in order to project the early and late radial flow regimes. The late radial flow regime is used to calculate the effective permeability that is needed for the well performance.

Fig.4.15 shows the effect of the noflow upper and lower boundaries on the effective permeability curves.

Fig.4.16 is shows the effect of the upper and lower flow boundaries on the effective permeability curves.

Fig.4.17 is the pressure and pressure derivative of the horizontal well with projected late linear and late radial flow regimes.

Fig.4.18 is the oil effective permeability from a pressure test in a reservoir with upper and lower noflow boundaries. Once the boundary effects are over, the effective permeability stabilizes.

Fig.4.19 is the gas effective permeability profile from a horizontal well test with upper and lower noflow boundaries.

Fig. 4.20 and 4.21 show the effect of the well operating conditions (Varying rate) on the effective permeability. It is clear from these figures that effective permeability is not affected by the change in well operating conditions.

Fig. 4.22 through 4.25 are the effective permeability vs. pressure obtained from the late radial flow regime of horizontal well. The reservoir pressure was successively reduced to simulate the depletion and see how does the effective permeability behave with decreasing pressure. It is clear form the figures 4.22 through 4.25 that the effective permeability is heading towards zero value at reservoir pressure becomes zero. This is in accordance with the integral if the both limits of the effective permeability were zero.

Fig.4.26: Two phase oil phase pseudopressure profile estimated with Eq.4.74. consists of the effects of the vaporization and condensation in it. We see the effect of gas gravity immediately even at low pressure.

Fig. 4.27: The two phase water pseudopressure, Eq.4.76. The effect of gas gravity is not apparent at low pressure, however, at higher pressure we see clear impact of gas specific gravity on it.

Fig.4.28-4.32: The effect of changing producing gas oil ratio is clear on the pseudopressure at constant gas gravity.

Fig.4.34-38: Effect of producing gas oil ratio on two phase pseudopressure. The effect is more apparent at pressure greater than 3000 psi.

Fig.4.39: Effect of producing gas oil ratio on three phase pseudopressure at 200 °F, Eq.4.90. The effect is even clear at low pressure.

9.2 Chapter V

Fig.5.1 is the graphical representation of the well performance when dew point and P* are approached. Top line is the well performance of single phase gas well. The second line is the performance behavior due to dew point and denotes the beginning of the condensation. The third line is the well performance in the Region-1 after P* is reached. The increase in production is due to liquid mobility and the recovery in the form of liquid.

9.3 Chapter VIII

Fig.8.1 is the semi-log plot of shut-in test pressure vs. time. This plot is needed to recognize the well developed straight line. This portion will be needed to calculate effective permeability.

Fig.8.2 is the pseudopressure and its derivative against time. The radial portion, horizontal line, is needed to estimate the effective permeability as a function pressure.

Fig.8.3 is the gas effective permeability integral estimated from well test data. It is curve fitted to extrapolate it to zero pressure in Fig.8.4.

Fig.8.5 is the oil effective permeability integral estimated from well test data.

Fig.8.6 is the effect of 10% increase in GOR on the oil effective permeability integral. As we see the increase in GOR reduces the value of the integral by 9% in oil effective permeability as indicated by Table 8.8 and Fig. 8.7.

Fig.8.6 is the gas phase well performance established using Rawlins and Schelhardt[43] equation. The values of n and C were assumed.

Fig.8.8 is the effect of 10% increase in GOR on gas effective permeability. It is also clear from Table 8.8 that the 10% increase in GOR introduces an absolute error of 3% in gas effective permeability.

Fig.8.9: The effect of 10% increase in GOR on skin factor is investigated in this figure. The error in skin factor varies with pressure. It successively increases with increasing pressure.

Fig.8.10 is the gas phase IPR against pseudopressure and Fig.8.11, against pressure.

Fig.8.12 is the oil effective permeability integral extrapolated to zero pressure and Fig.8.13 is the generated with equation developed from Fig.8..12.

Fig.8.14 is the log-log plot pseudopressure and its derivative. The unexpected anomaly indicates the arrival of P* especially in this case.

Fig.8.15 and 16 are the oil phase IPRs against pseudopressure and pressure.

Fig.8.47: This figure is of special interest. Although the dew point pressure is 4800 psi, its impact on water production is felt much earlier. The upper dotted line is the water production trend if dew point pressure was not reached. After dew point pressure, water production declines sharply. Thus it is clear from Fig.8.47 that the condensation helps reduce water production. The second dotted line is the water production trend if P* was not reached. After P* is reached water trend picks up, stabilizes and shows linear decline. This behavior has never been discussed or explained in literature. Thus in three phase systems condensation helps reduce water production.

Fig.8.57 is a simulated well test in a horizontal well. The all four flow regimes are observed and used to calculated reservoir properties.

9.4 Appendix A

Fig.A1-A5 are the two phase gas pseudopressure calculated using Eq.4.93 with changing temperature. It is clear from these figures that at higher temperature the value of pseudopressure decreases.

Fig.A6-A8 is the effect of API gravity on the gas phase pseudopressure. It seems that the API gravity does not affect the pseudopressure much. We see little change in the values but it is not very apparent.

Fig.A9-A13 are the gas phase pseudopressure as a function of producing gas oil ratio. It is clear from these curves that the pseudopressure decreases with increasing gas oil ratio.

Fig. A-14-A19 are the oil phase pseudopressure. In these curves the temperature is changed progressively. It is clear form the curves that the value of pseudopressure decreases as the temperature increases.

Fig. A-20-A-23. In these curves the effect of API gravity is investigated. It is observed that the value of pseudopressure increases as the API gravity increases.

Fig. A-24-A-28 show the effect of the producing gas oil ratio on the oil phase pseudopressure. We see do not see any impact of producing gas oil ratio on the oil phase pseudopressure.

Fig. A-29-A-34. In these curves the behavior of gas phase pseudopressure in Regin-2 and Region-3 where only single phase gas is mobile is investigated by changing the temperature value. We see that the value of the gas phase pseudopressure decreases as the temperature increases. This behavior was also seen in Region-1, even though the definition of pseudopressure in Region-1 is different. Thus temperature affects in the same way in all the three regions.

9.5 Appendix B

Fig. B-1-B-5 are the gas phase pseudopressure in three phase reservoirs. The effect of temperature is investigated in these curves. It is clear that the with increasing temperature the value of pseudopressure decreases.

Fig. B-6-B-7. In these curves the oil phase pseudopressure is plotted by changing the value of the temperature. It is clear from these curves that the temperature does not affect the oil phase pseudopressure significantly.

Fig. B-8-B-9 show the water phase pseudopressure curves in Region-1. We see that the producing gas oil ratio affects the value of the water phase pseudopressure in three phase systems. This can be explained in the way that due to more amount of the liquid there is significant amount of dissolved gas in the system that travels with the liquid and affects water properties.

Fig. B-10-B-14 are the gas phase pseudopressure as a function of temperature in Region-2 and three. It is again clear that the value of the pseudopressure

decreases with increasing temperature in three phase environment as explained earlier.

Fig. B-15-B-16: The effect of producing gas oil ratio on three phase pseudopressure in Region-2 and Region-3 is investigated in these curves. We do not see any impact of GOR on the gas phase pseudopressure.

Fig. B-17-B-18 are the effect of producing gas water ratio on gas phase pseudopressure in three phase systems. The value of the pseudopressure does not change with change in gas water ratio. The possible explanation is that the water and oil phase are saturated with the gas since their volume is small as compared to the gas volume is such reservoirs which are primarily gas reservoirs. Thus any increase in either gas oil or gas water ratio does not affect the value of the pseudopressure.

Fig. B-19-B-20 are the water phase pseudopressure in Regin-2 and Region-3 in three phase systems. The effect of producing water gas ratio is investigated and it is clear that the water phase pseudopressure increases with increasing gas water ratio.

Chapter X

Summary, Conclusions, and Recommendations

10.1 Summary

A new method of establishing performance of vertical and horizontal wells completed in gas-condensate reservoirs has been developed. This method does not require relative permeability curves as a function of saturation instead pressure transient well test data is used to establish the effective permeability as a function of pressure, thereby eliminating the need of the relative permeability curves. Surface production data and the pressure transient data are then combined to forecast the well performance. Several new equations of effective permeability in two phase and three phase systems have been introduced that are estimated from the definitions of producing gas-oil, water-oil, and gas-water ratios for two and three phase systems. Also the new method allows to determine the loss in gas well deliverability mathematically after the condensate has begun to liquefy. Thus well efficiency and damage factor can now be calculated analytically. Also well testing equations have been redefined to estimate the effective permeability as a function of pressure in multiphase systems. *Tiab's Direct Synthesis (TDS)* technique of pressure transient analysis has also been applied to gas and gas-condensate systems.

Gas condensate reservoirs are primarily gas reservoirs containing some heavier hydrocarbons (C3-C5). With depletion, when dew point pressure is reached, these heavier hydrocarbons begin to condense and a liquid region develops. This liquid does not move until sufficient quantity has gathered and it becomes mobile. The pressure at this point is termed as P* and saturation as critical liquid saturation, S_{cl}. At this point on the flow is two phase in nature and follows the laws of multiphase flow. A gas condensate reservoir may observe three distinct regions in its life. Region-1: This region starts from the wellbore

and extends up to P*. Flow in this region is two-phase in nature. Rgion-2: It is spread from P* to Pd. The liquid is accumulating in this region but is not mobile yet. Region-3: This region occupies the area that is spread from Pd to the external boundary pressure, Pe. The flow in this region is single phase gas flow and laws of single phase real gas apply. The condensing liquid reduces the well's gas deliverability, the main production of such wells.

Gas condensate reservoirs go under two kinds of changes in their lifetime. The phase change and the physical properties change. Both the changes have been handled in this study using the pseudopressure function integral concept.

In three phase system accumulating condensate, along with gas phase production, reduces the water production, a very positive impact. Much of the gas phase that goes in the liquid phase is recovered in the form of the condensate. Also it was observed that the mobile liquid condensate cleans the formation. This impact was observed from the continuously decreasing skin factor that was estimated as a function of pressure, an impact never seen before.

To predict the well performance in multiphase producing environment relative permeability as a function of pressure is used which requires the prior knowledge of the saturation at all the times. Saturation is usually estimated from material balance and reservoir simulation. Also relative permeability curves have to be developed in the laboratory on core samples, an expensive and time consuming process. For individual operators who usually operate on minimum margins of profit, obtaining such data can be an economic challenge. In Oklahoma, regulatory bodies require every well to be tested once a year. Thus a valuable pressure transient data is available on yearly basis. Using that data to forecast well performance can have a profound economic impact on the oil and gas industry. Thus relative permeability curves as a function of saturation have been completely eliminated and it has been shown in this study

how to use pressure transient data to develop effective permeability as a function of pressure and then us it to forecast the well performance.

Also gas well testing equations of pressure drawdown and pressure buildup have been modified such that they provide the effective permeability as a function of pressure for both vertical and horizontal wells. TDS has been applied to gas and gas condensate horizontal wells. Finally several examples have been solved to show the use of the mathematical models developed.

If available, relative permeability curves can also be used. Effective permeability obtained from pressure tests may be preferred since it is the true representative of the dynamic response of the reservoir. The effective permeability of any phase can be estimated from any other phase production data during the pressure transient test. However, the most reliable fluid data must be used. In case of water phase production, it must be preferred since water is the most reliable phase. Its physical properties rarely change with pressure. Both the two-phase, oil and gas, and the three phase, oil, water, and gas, systems have been treated in this study. The new definitions of the pseudopressure for gas condensate systems have been introduced and their mathematical models have been developed for two and three phase gas condensate systems. The new models handle both the phase change and the physical properties change with pressure, the two main difficulties in analyzing gas condensate systems. Mathematically it has been shown that the total well productivity loss in gas condensate systems is the combination of the reservoir and wellbore geometry, formation damage non-Darcy flow, and the blockage due to condensate. Also the new definitions of pseudopressure for two and three phase gas condensate systems allow to analyze the pressure test data and estimate the effective permeability as a function of pressure and the skin factor as a function of pressure. TDS technique has been applied and the simple

algebraic form of equations has been obtained for the use of gas and, gas condensate horizontal wells.

It is recommended that a Masters thesis should be devoted to investigate the impact of near critical phase change on the effective permeability of each phase as a function of pressure. Tremendous amount of time, energy and financial resources has been devoted on the study of relative permeability as a function of saturation. Yet those models require a great deal of information in order to be able to use them. Thus it is recommended that the next few years here at OU should be devoted to study the effective permeability as a function of pressure and that can be obtained from pressure transient tests. Also the effect of stress on the effective permeability as a function of pressure can be investigated.

10.2 Conclusions

Following conclusions have been drawn from this study of production behavior of gas condensate wells.

1. A new method has been developed to estimate the effective permeability of each phase (gas, oil, and water) as a function of pressure from pressure transient test data, thereby eliminating the need for prior knowledge of relative permeability and absolute permeability that is required to establish the well performance.
2. If available, relative permeability curves can also be used. Effective permeability obtained from pressure tests may be preferred since it is the true representative of the dynamic response of the reservoir.
3. The effective permeability of any phase can be estimated from any other phase production during the pressure transient test. However, the most reliable fluid such as water data must be used since water properties rarely change with pressure.
4. In case of water phase production, it must be preferred since water is the most reliable phase. Its physical properties rarely change with pressure.
5. Both the two-phase, oil and gas, and the three phase, oil, water, and gas, systems have been treated in this study.
6. The new definitions of the pseudopressure for gas condensate systems have been introduced and their mathematical models have been developed for two and three phase gas condensate systems.
7. The new models handle both the phase change and the physical properties change with pressure, the two main difficulties in analyzing gas condensate systems.
8. Mathematically it has been shown that the total well productivity loss in gas condensate systems is the combination of the reservoir and wellbore

geometry, formation damage non-Darcy flow, and the blockage due to condensate.

9. Also the new definitions of pseudopressure for two and three phase gas condensate systems allow to analyze the pressure test data and estimate the effective permeability as a function of pressure and the skin factor as a function of pressure.
10. TDS technique has been applied and the simple algebraic form of equations has been obtained for the use of gas and, gas condensate horizontal wells.
11. Several examples have been solved to show the use of the methods developed.
12. In two phase systems an error of 10% in producing gas oil ratio introduces an error of 9% in oil effective permeability and 3% in gas effective permeability respectively.

10.3 Recommendations

1. A Masters thesis can be devoted to investigate the impact of near critical phase change on the effective permeability of each phase as a function of pressure.
2. Tremendous amount of time, energy and resources has been devoted on the study of relative permeability as a function of saturation. Yet those models require a great deal of information in order to be able to use them. Thus it is recommended that the next few years here at OU should be devoted to study the effective permeability as a function of pressure and that can be obtained from pressure transient tests.
3. Also the effect of stress on the effective permeability as a function of pressure can be studied.

Nomenclature

A = Horizontal well drainage area, sq.ft
B_o = Oil FVF, RB/STB
B_{gd} = Dry gas FVF CF/SCF
C_H = Geometric Factor for horizontal well
K_{ro} = Oil relative permeability
K_{rg} = Gas relative permeability
L = Length of horizontal well
Qg = Gas Flow Rate, scf/D
R_s = Solution GOR, SCF/STB
R_{sgw} = Solution Gas water ratio, SCF/STB
R_p = Producing GOR, SCG/STB (q_g/q_o)
R_{pgw} = Producing Gas water ratio, SCF/STB
R_{pow} = Producing oil water ratio, STB/STB
S = skin
S_R = Skin factor due to partial penetration
S_o = Oil saturation, fraction
S_g = Gas saturation, fraction
S_{OC} = Critical oil saturation, fraction
V_{roCCE} = Relative oil volume in constant composition experiment
V_{roCVD} = Relative oil volume in constant volume depletion experiment
Xe = a = Reservoir width, ft
Ye = b = Horizontal reservoir length, ft
mP = pseudo-pressure function, $psia^2/cp$
μ_o = Oil viscosity, cp
μ_g = Gas viscosity, cp

Subscripts

g = Gas
o = Oil
w = Water
r = relative
e = effective
z = in Z direction
x = in X direction
y = in y direction
cl = Condensate liquid
meas = Measured
i = intersection
1hr = One hour
w = wellbore (In well testing equations)
cor = Corrected
b = Bubble
d = Dew
trans = Transient
sp = Single phase
sp-trans = Single phase from transient test
wf = wellbore flowing
s = shut-in
1 = Region-1

2 = Region-1
3 = Region-1
g1.o = gas phase in Region-1 using oil effective permeability
g1.g = gas phase in Region-1 using gas effective permeability
o1.o = Oil phase in Region-1 using oil effective permeability
o1.g = Oil phase in Region-1 using gas effective permeability

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Appendix-A

Pseudopressure Function Figures [Two phase systems]

Effect of Temperature

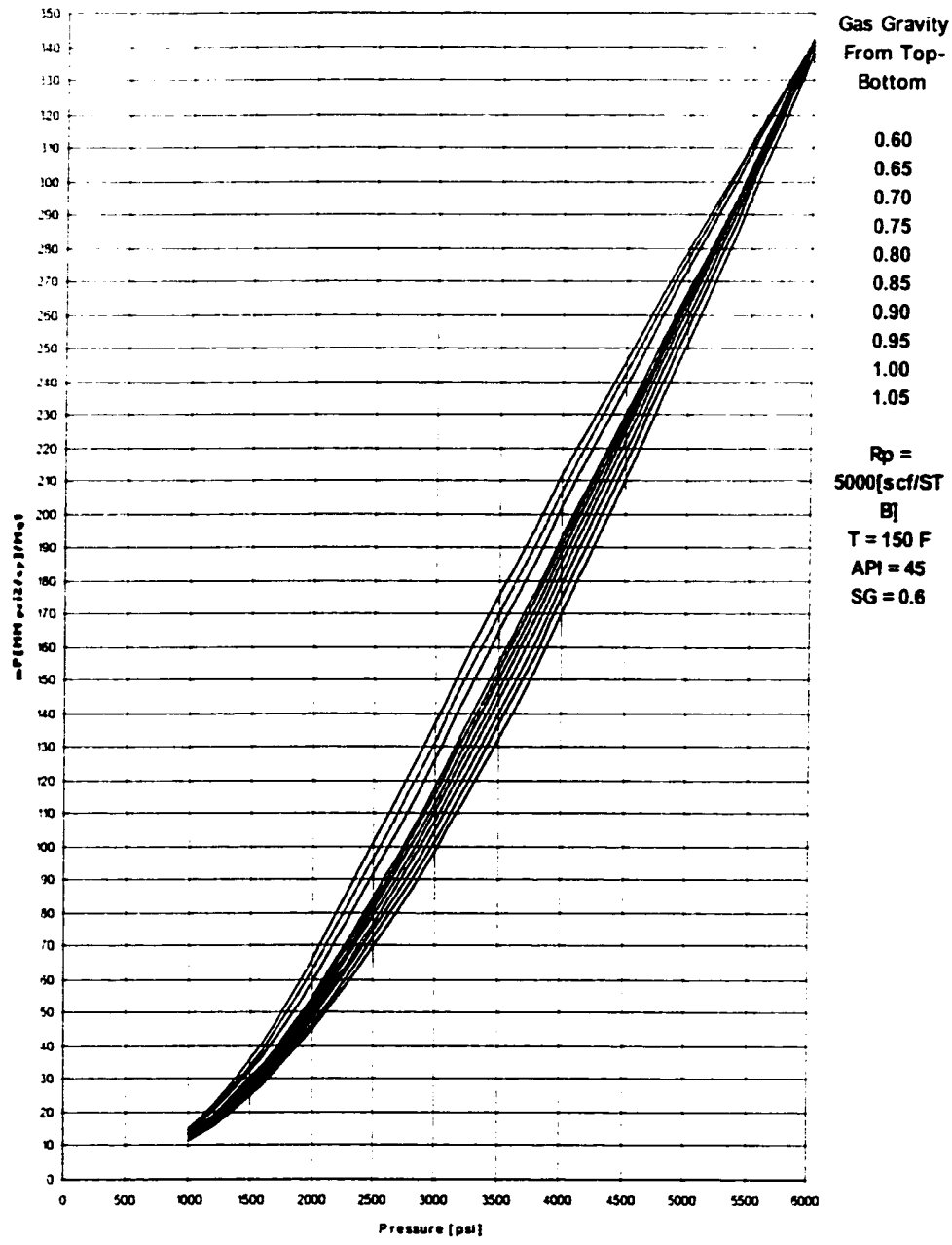

Fig.A-1Gas phase pseudopressure Region-1[Eq.4.93] [T = 150F]

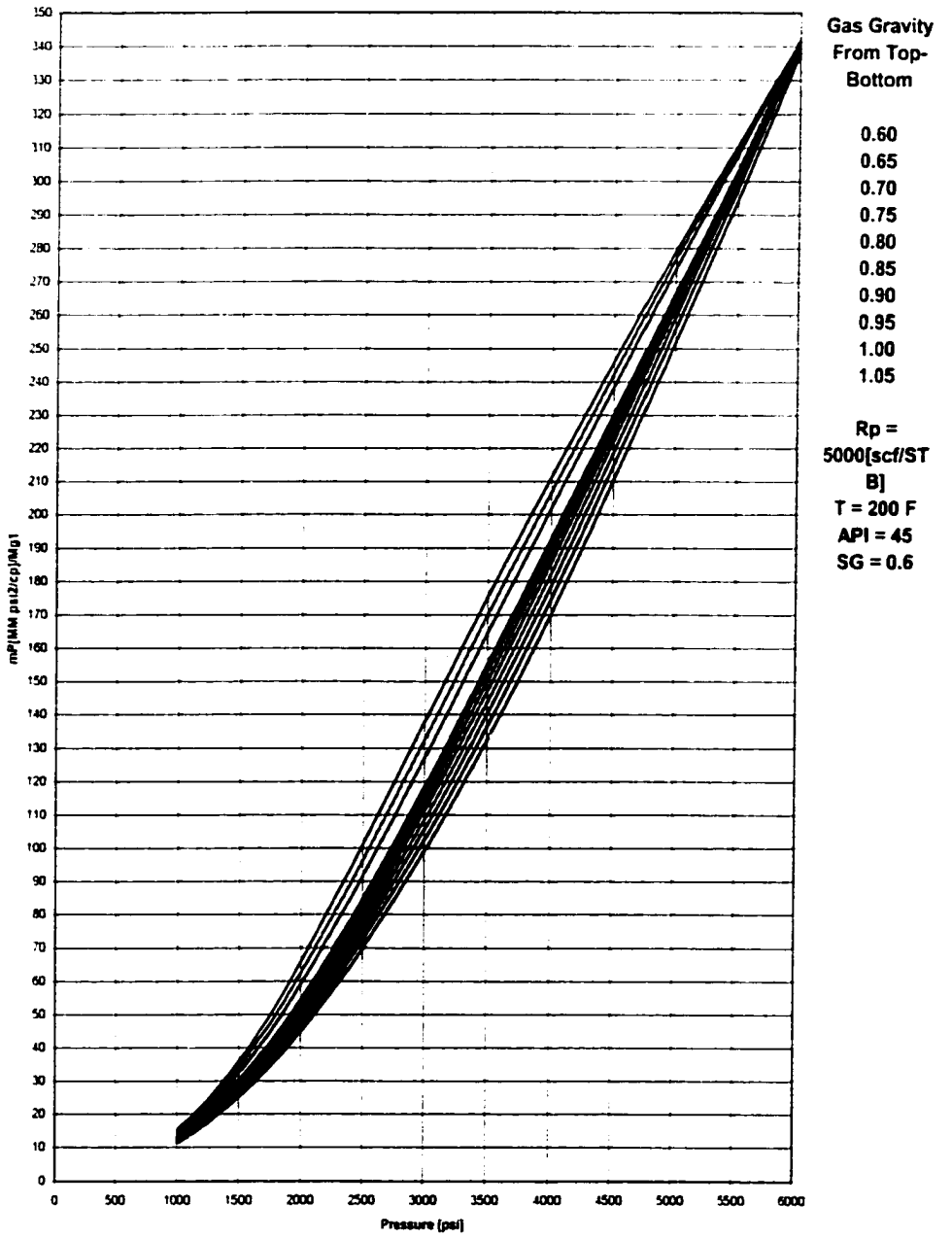

Fig.A-2 Gas phase pseudopressure Region-1[Eq.4.93] [T = 200F]

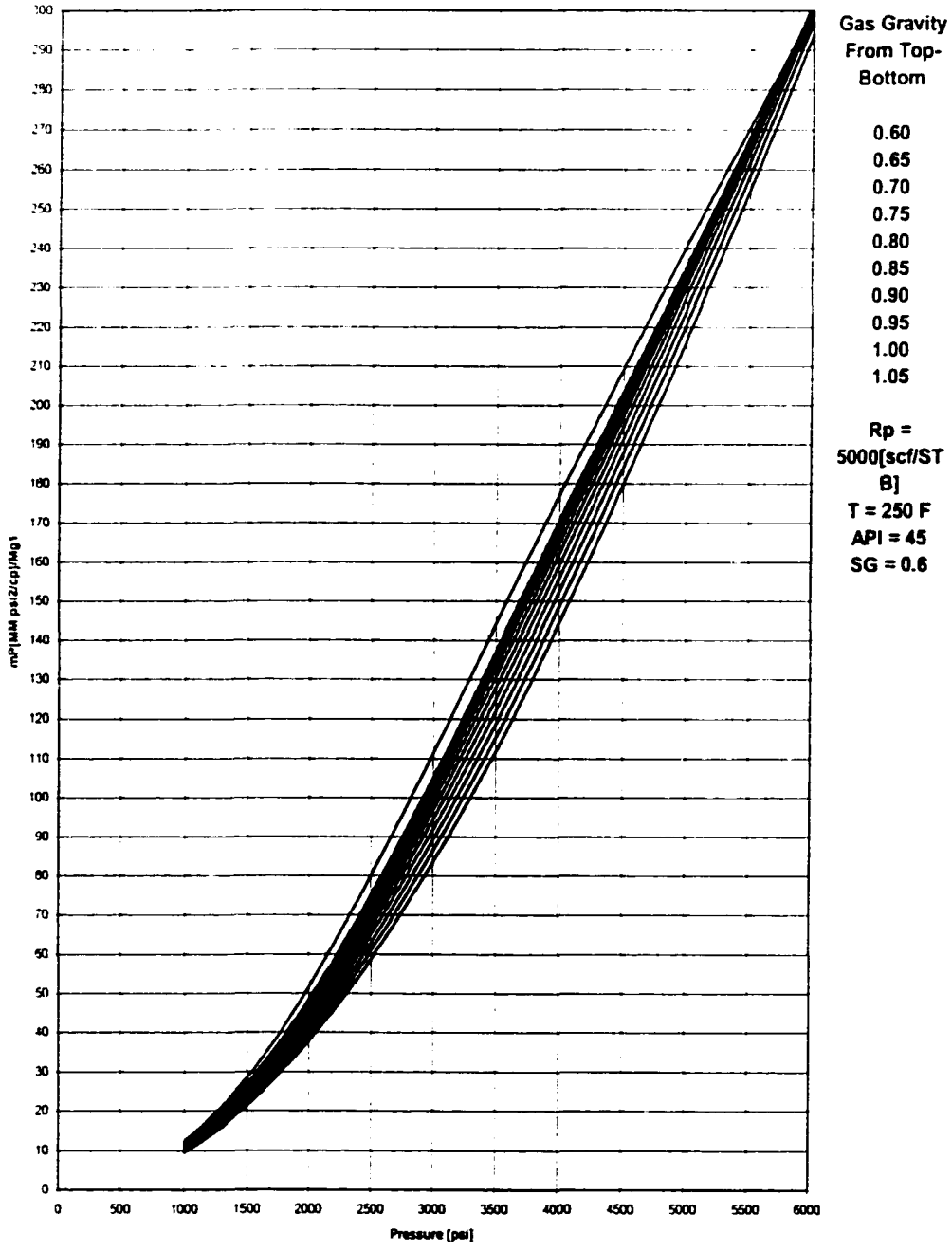

Fig.A-3 Gas phase pseudopressure Region-1[Eq.4.93] [T = 250F]

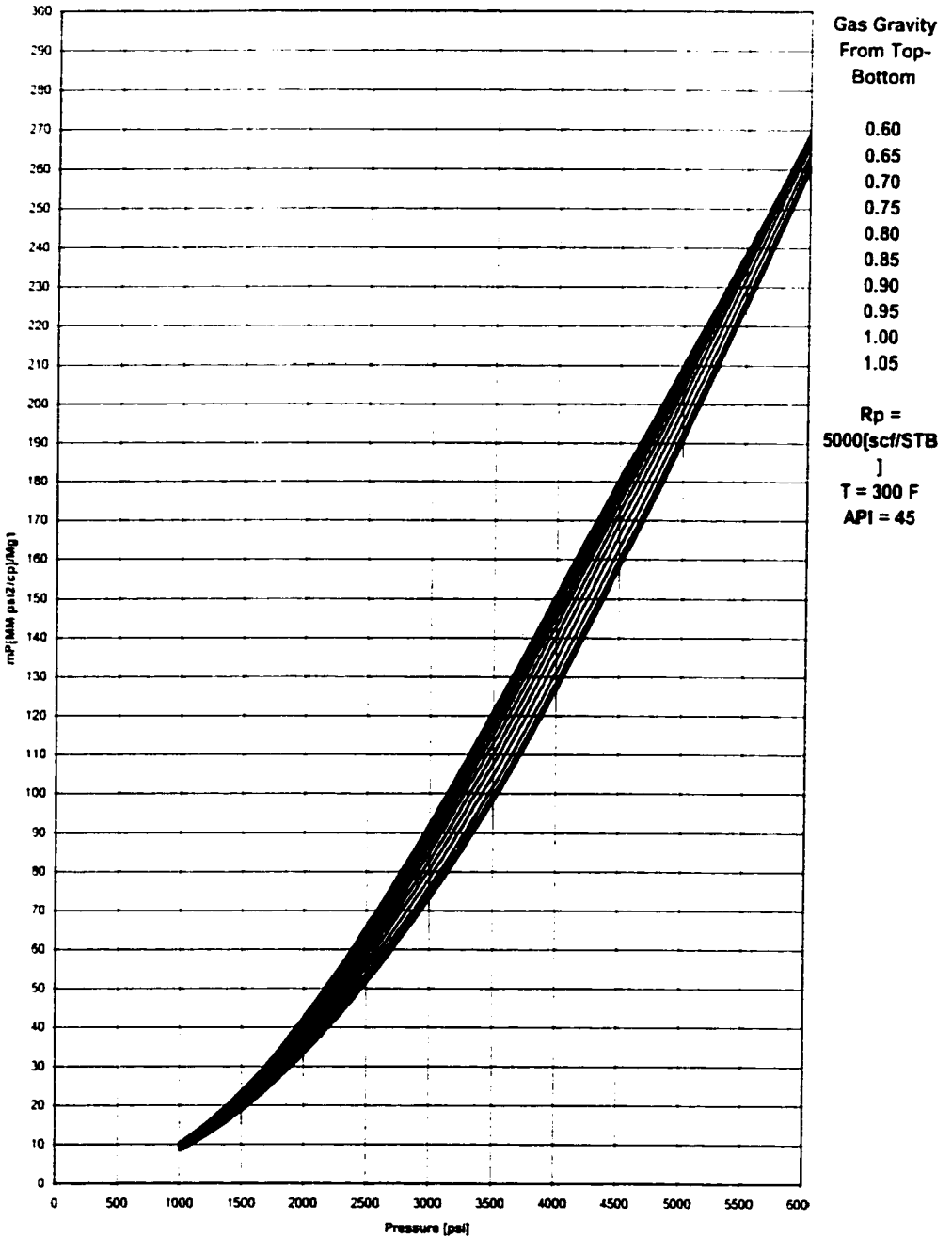

Fig.A-4 Gas phase pseudopressure Region-1[Eq.4.93] [T = 300F]

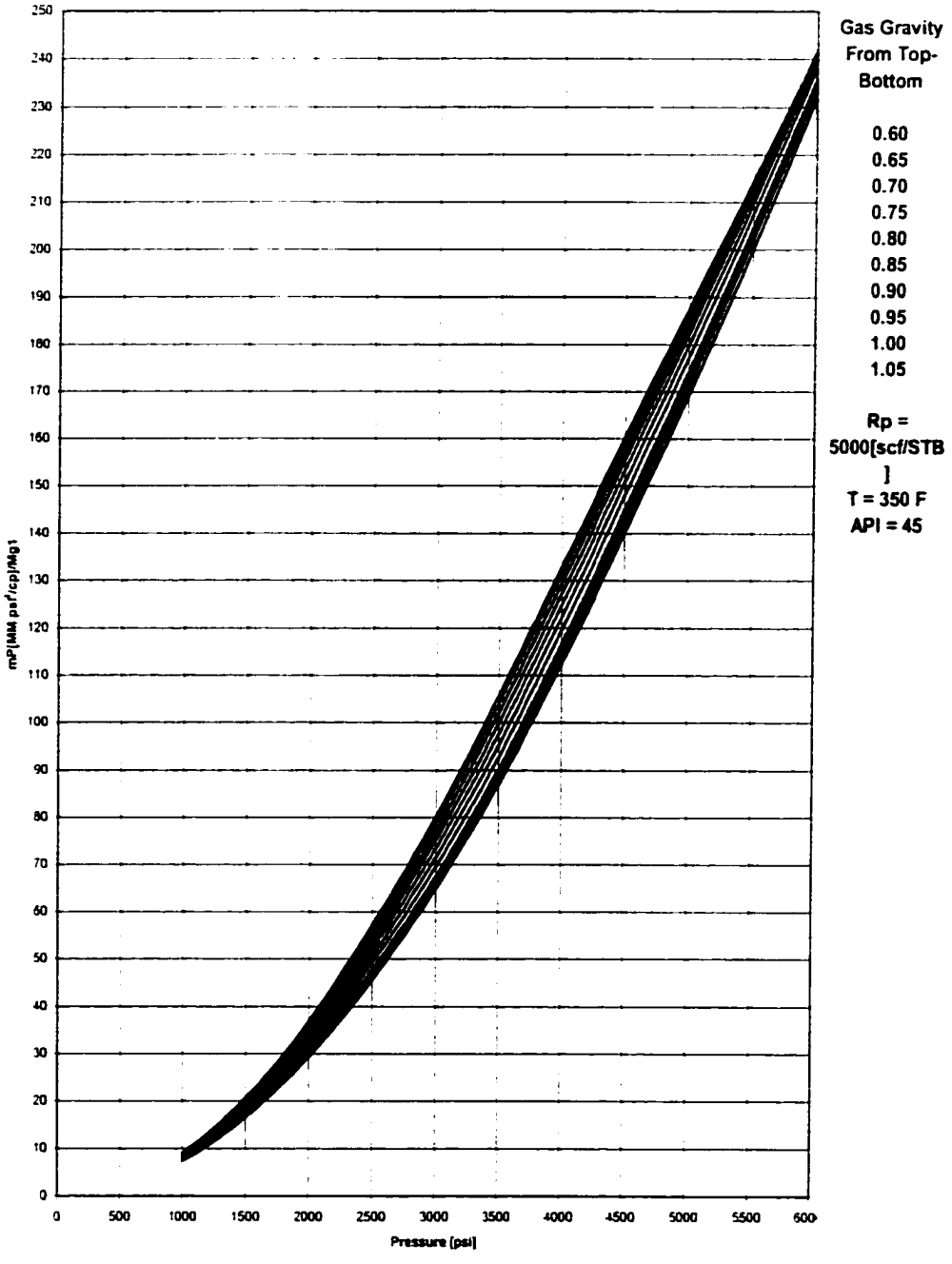

Fig.A-5 Gas phase pseudopressure Region-1[Eq.4.93] [T = 350F]

Effect of API Gravity

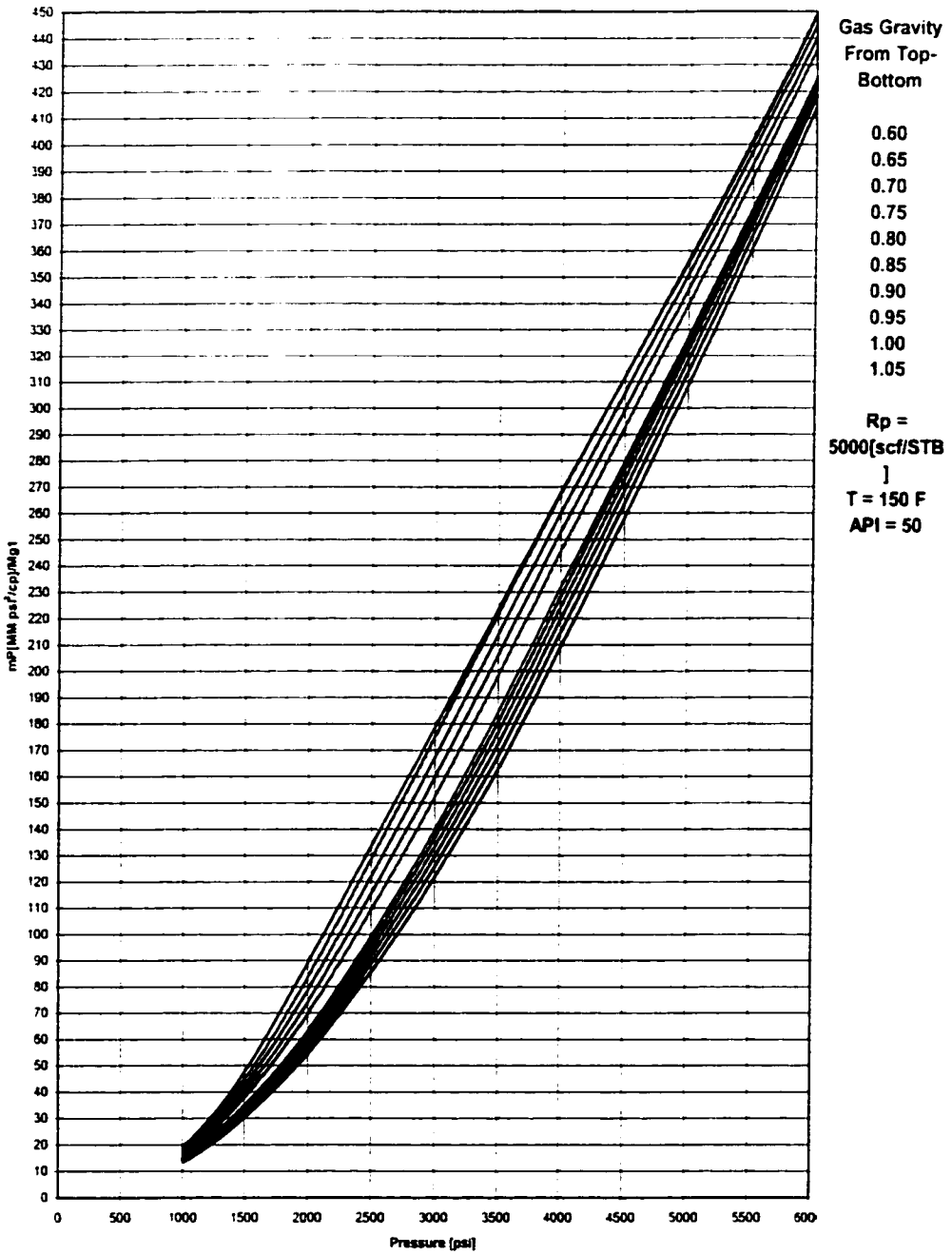

Fig.A-6 Gas phase pseudopressure Region-1[Eq.4.93] [API = 50]

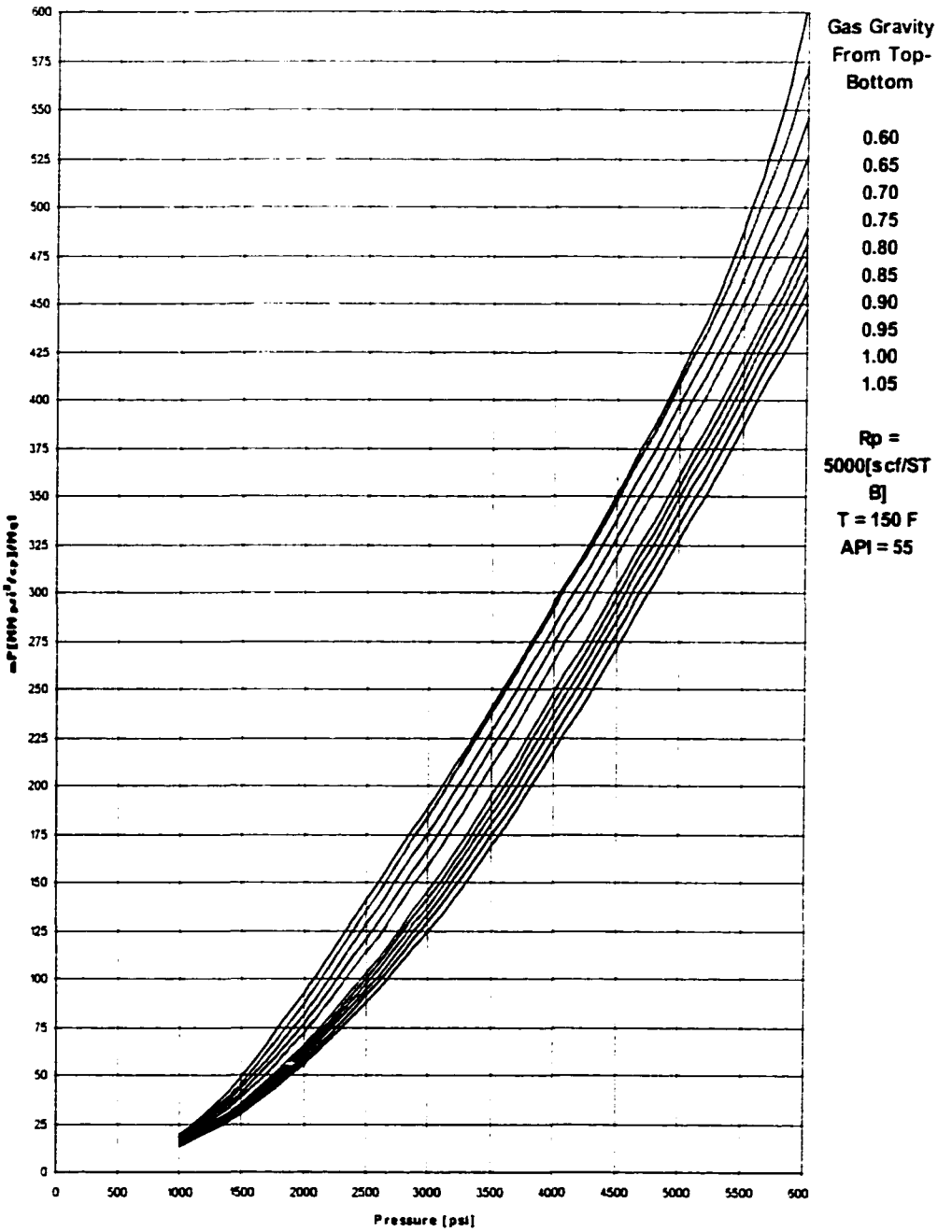

Fig.A-7 Gas phase pseudopressure Region-1[Eq.4.93] [API = 55]

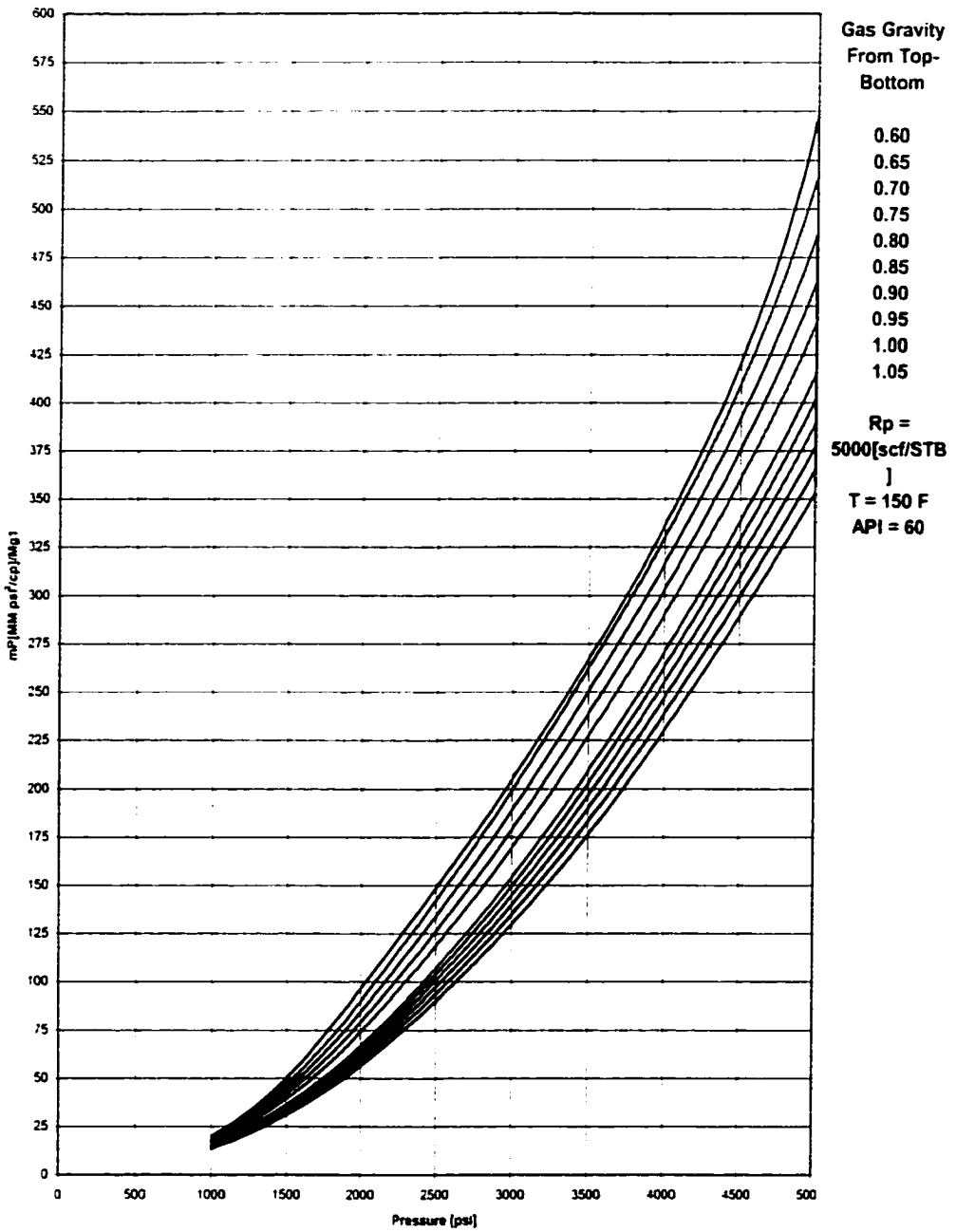

Fig.A-8 Gas phase pseudopressure Region-1[Eq.4.93] [API = 60]

Effect of Producing Gas Oil Ratio, Rp

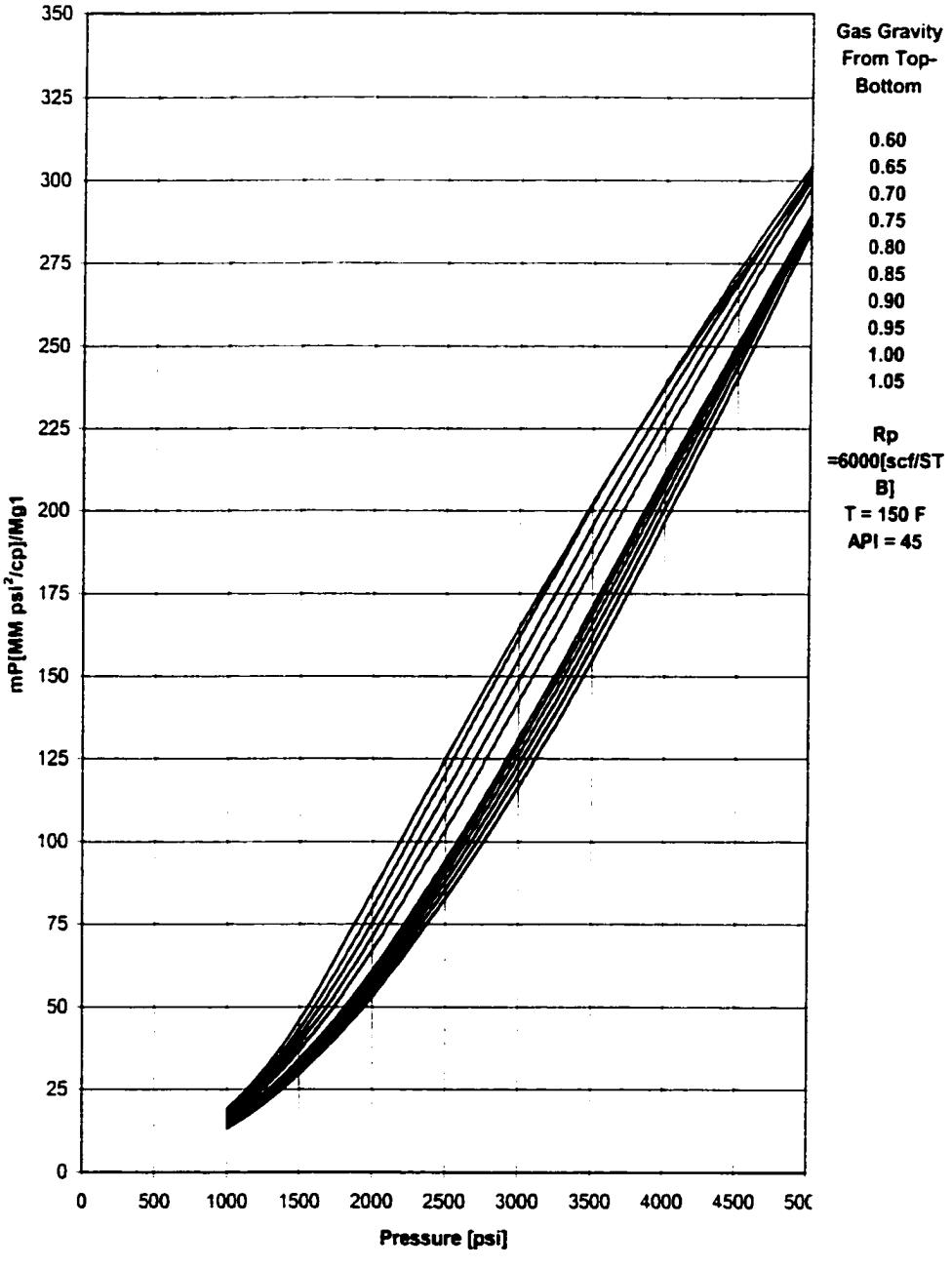

Fig.A-9 Gas phase pseudopressure Region-1[Eq.4.93] [Rp = 6000]

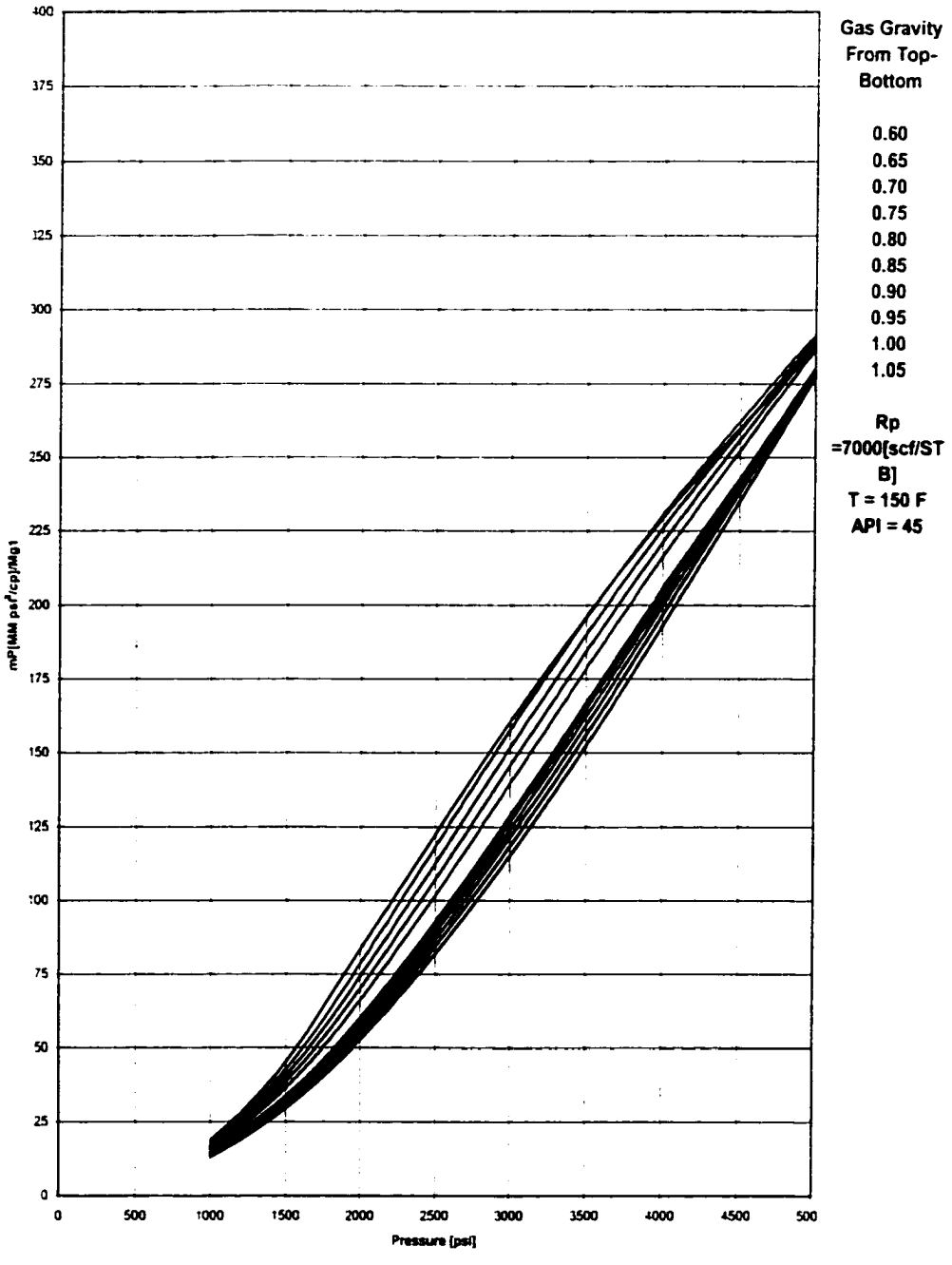

Fig.A-10 Gas phase pseudopressure Region-1[Eq.4.93] [Rp = 7000]

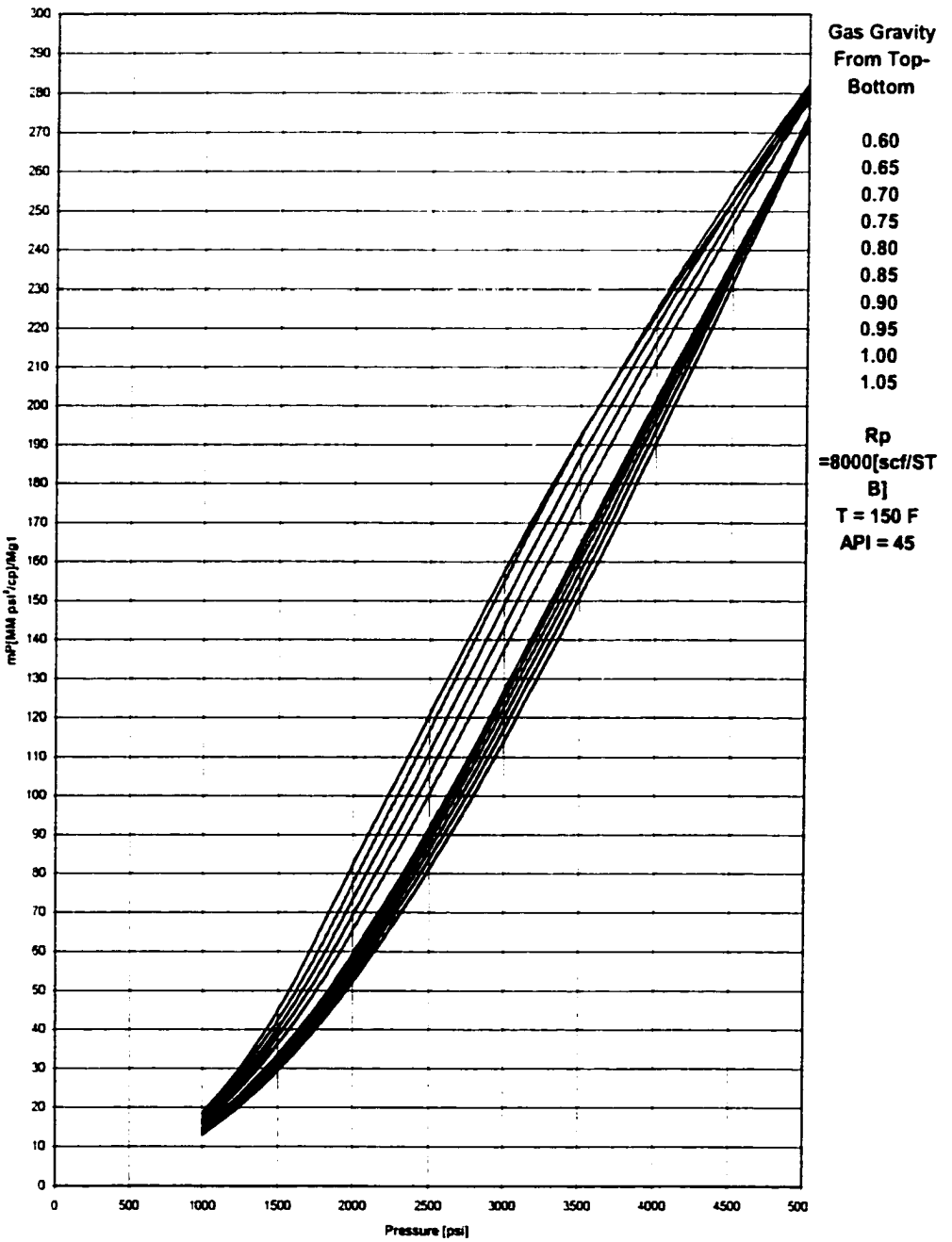

Fig.A-11 Gas phase pseudopressure Region-1[Eq.4.93] [Rp = 8000]

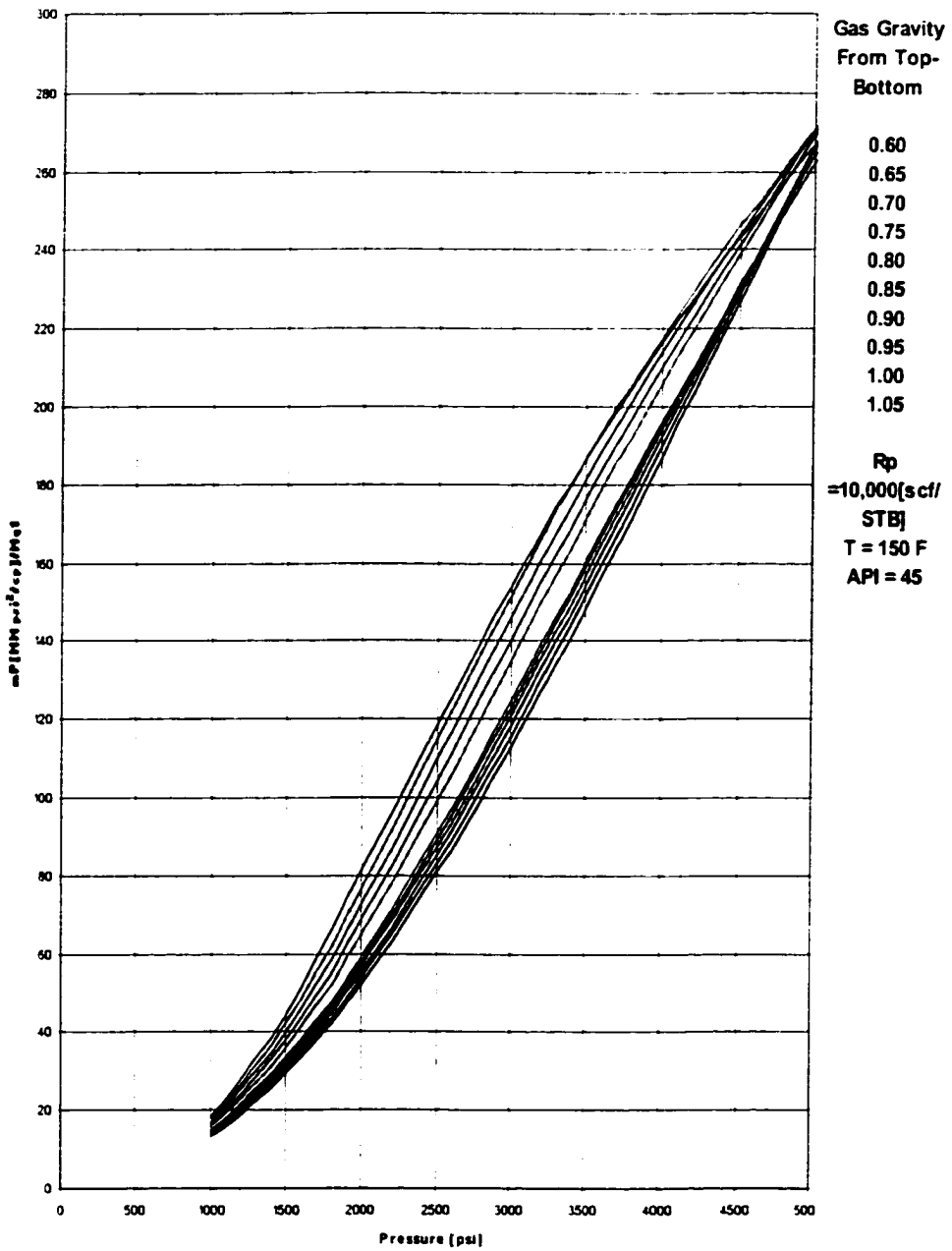

Fig.A-12 Gas phase pseudopressure Region-1[Eq.4.93] [Rp = 10,000]

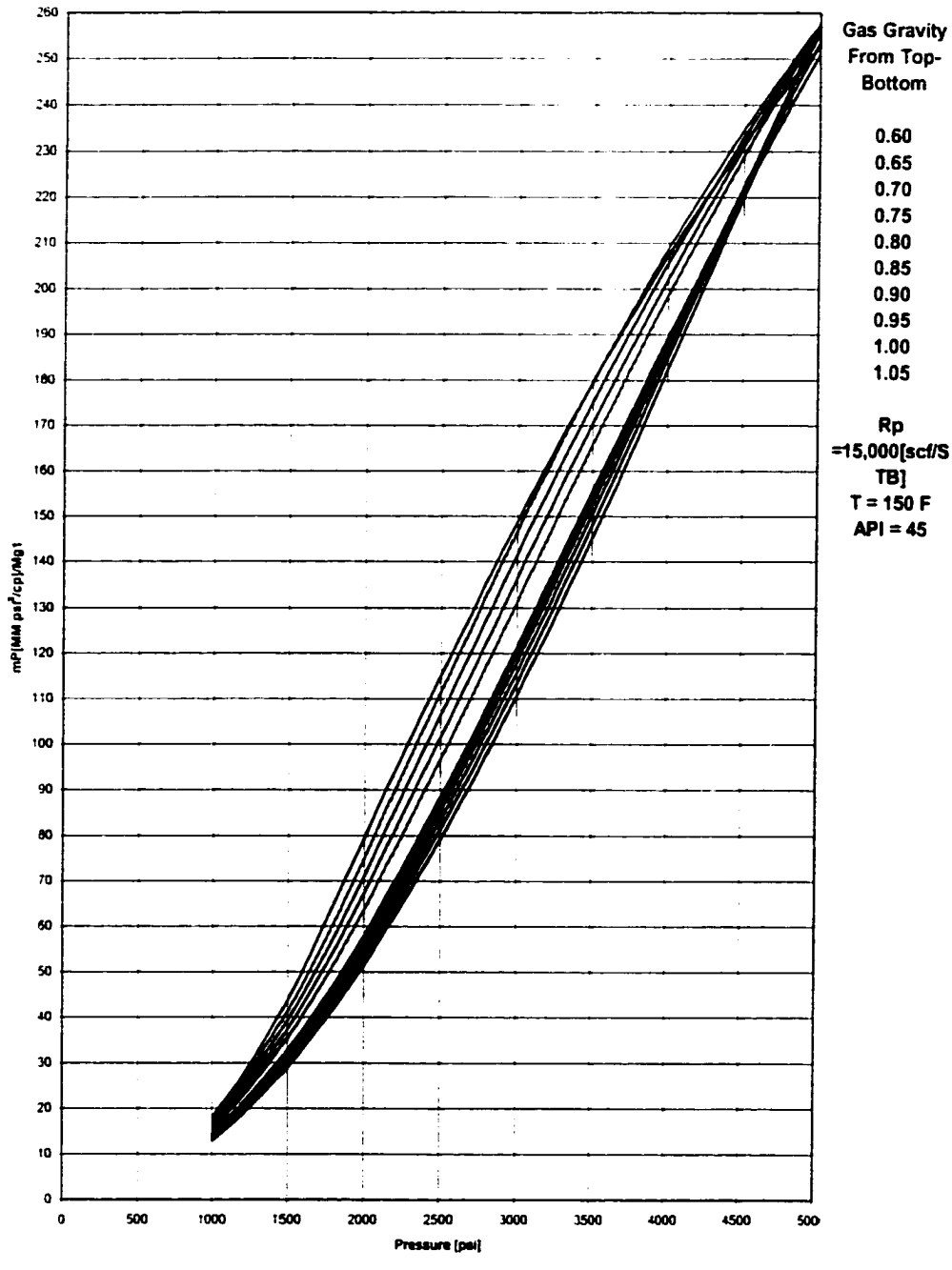

Fig.A-13 Gas phase pseudopressure Region-1[Eq.4.93] [Rp = 15,000]

Oil Phase Region-1

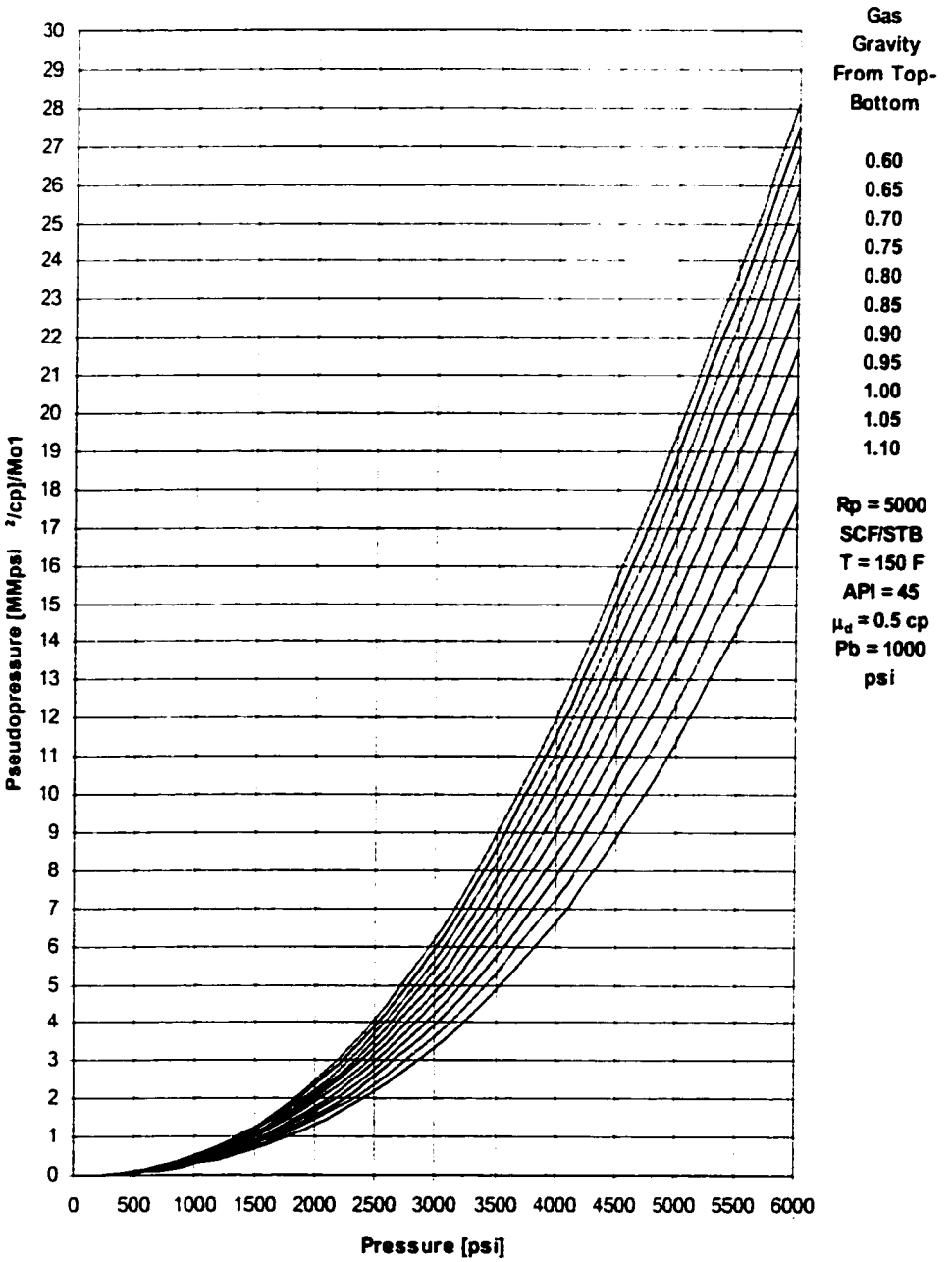

Fig.A-14 Oil phase pseudopressure Region-1[Eq.4.74] [T=150]

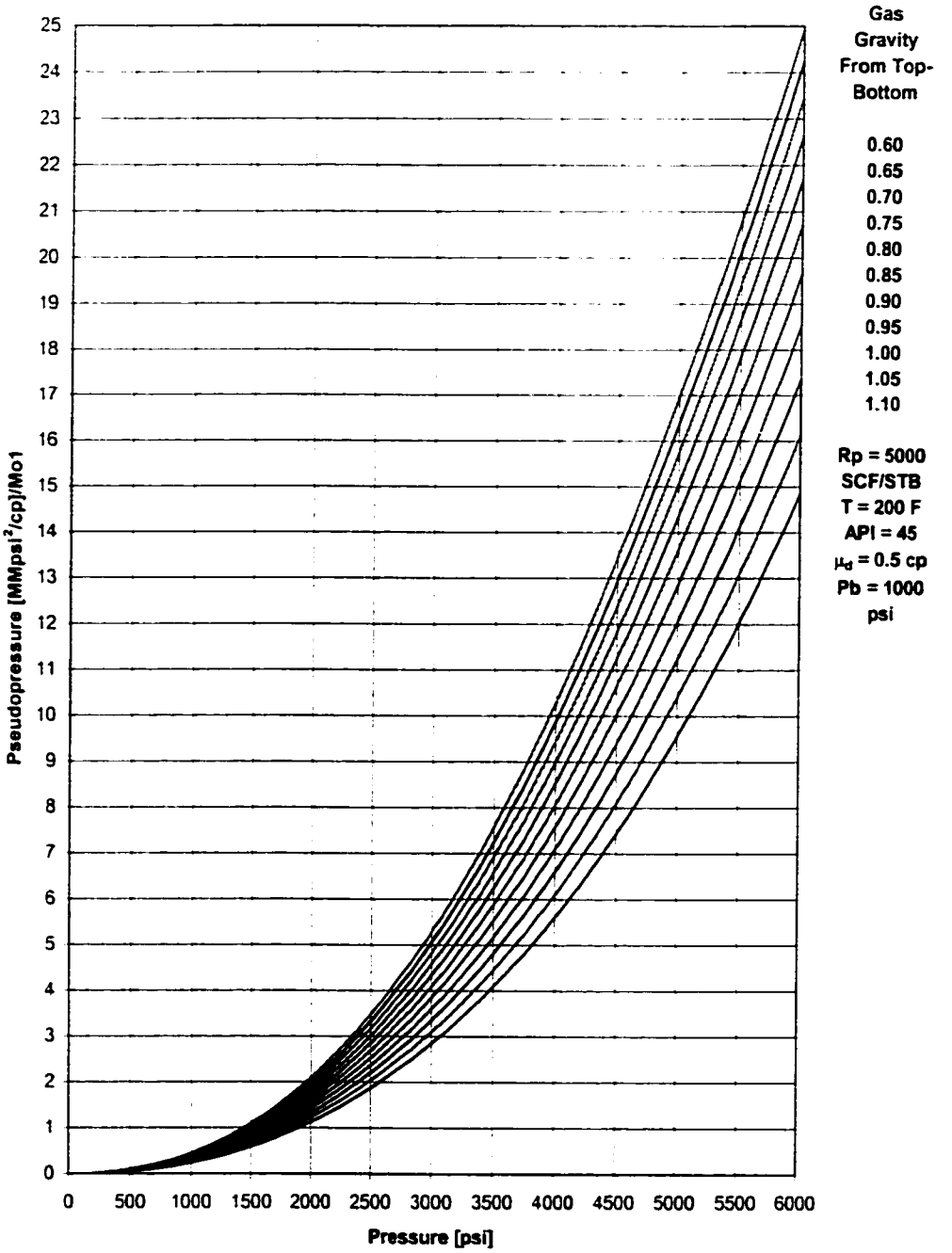

Fig.A-15 Oil phase pseudopressure Region-1[Eq.4.74] [T=200]

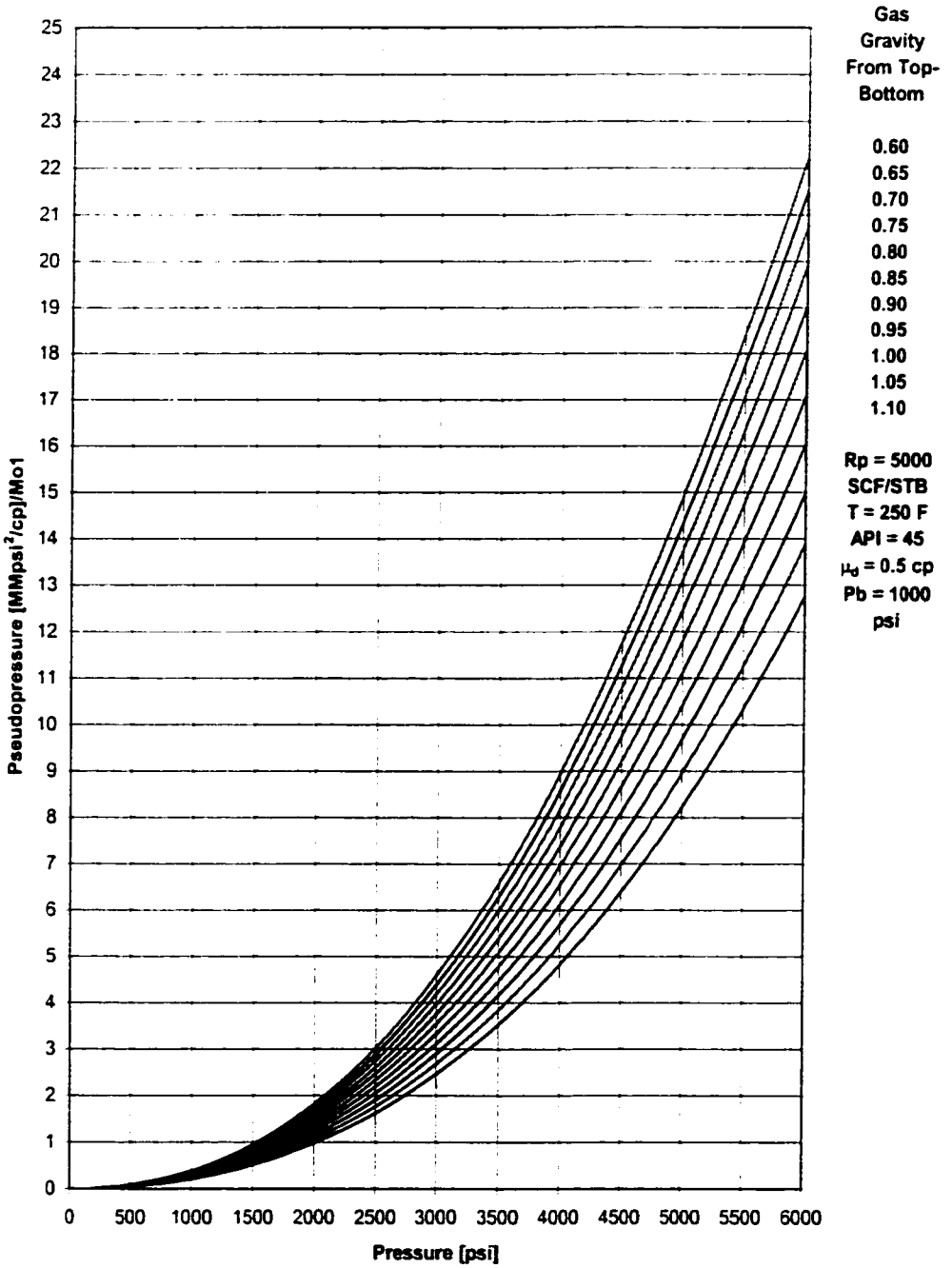

Fig.A-16 Oil phase pseudopressure Region-1[Eq.4.74] [T=250]

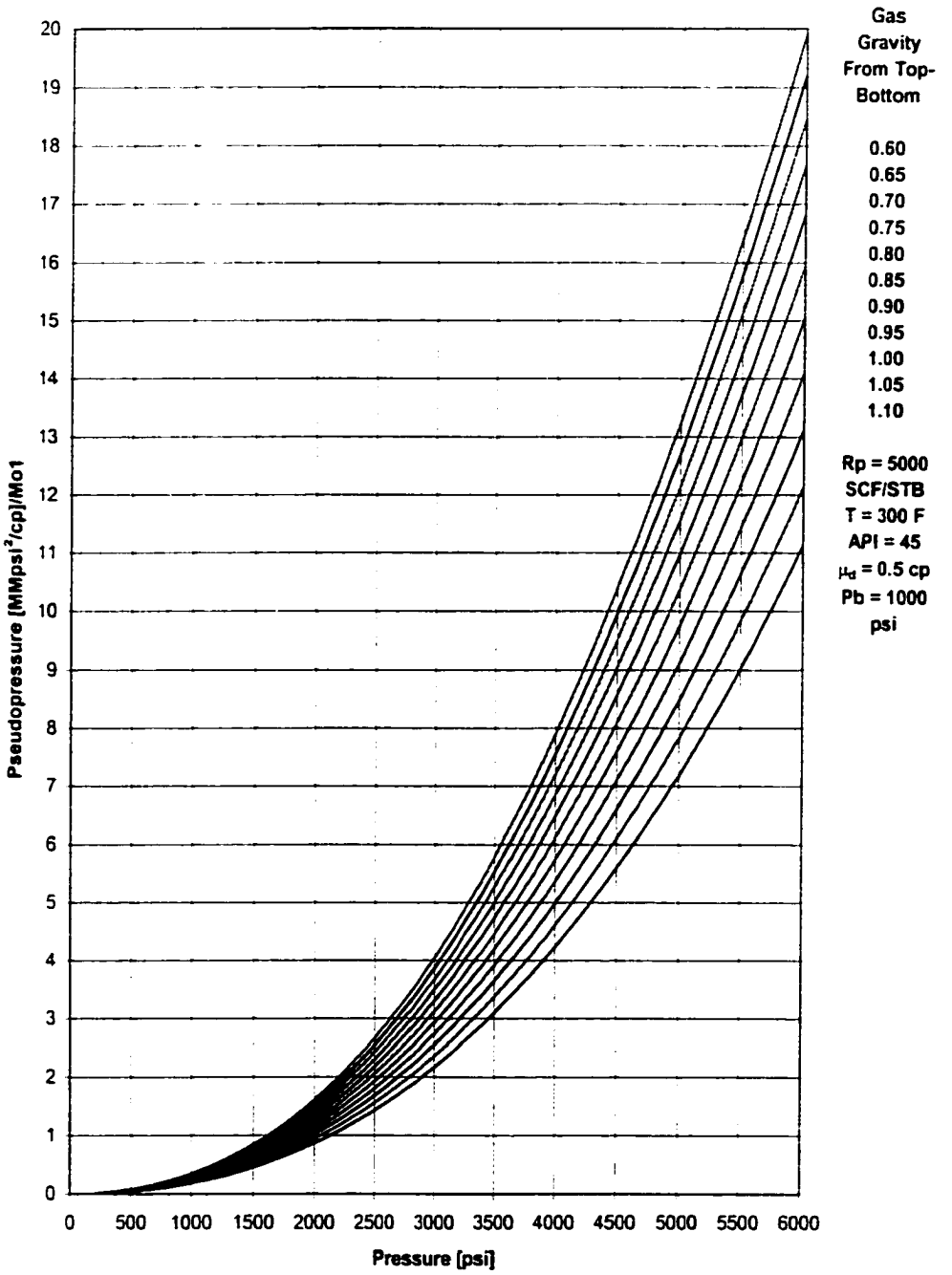

Fig.A-17 Oil phase pseudopressure Region-1[Eq.4.74] [T=300]

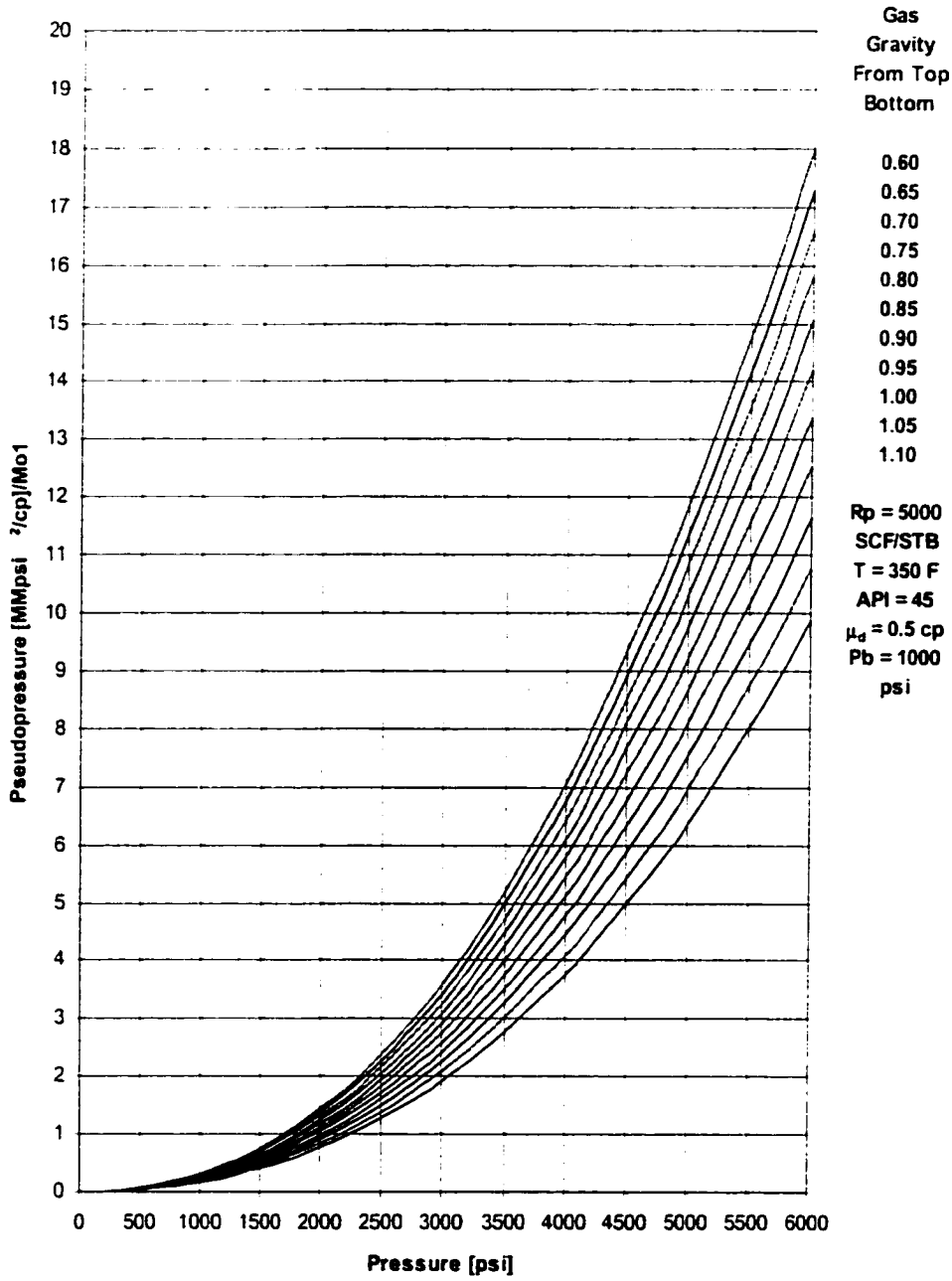

Fig.A-18 Oil phase pseudopressure Region-1[Eq.4.74] [T= 350]

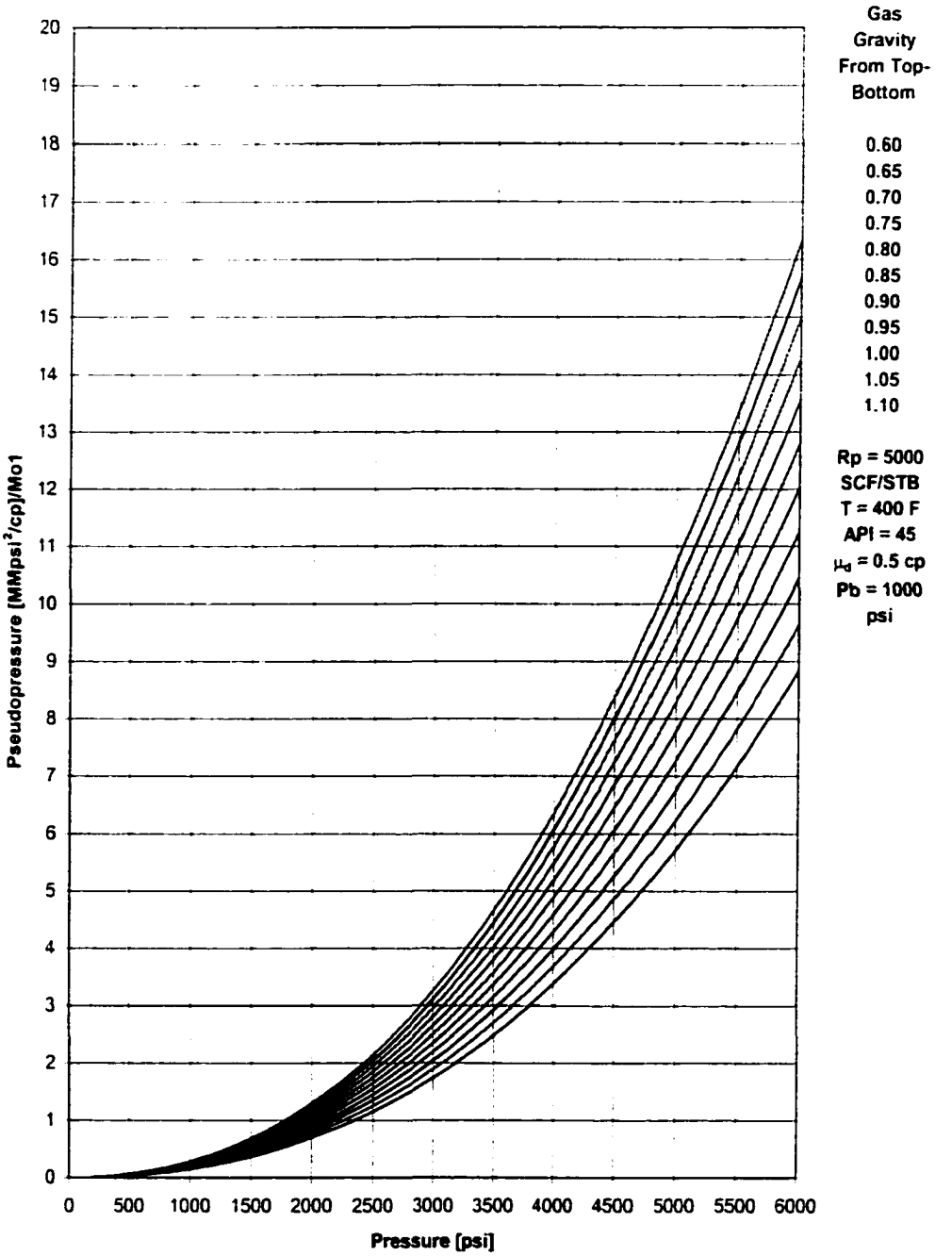

Fig.A-19 Oil phase pseudopressure Region-1[Eq.4.74] [T= 400]

Effect of API Gravity

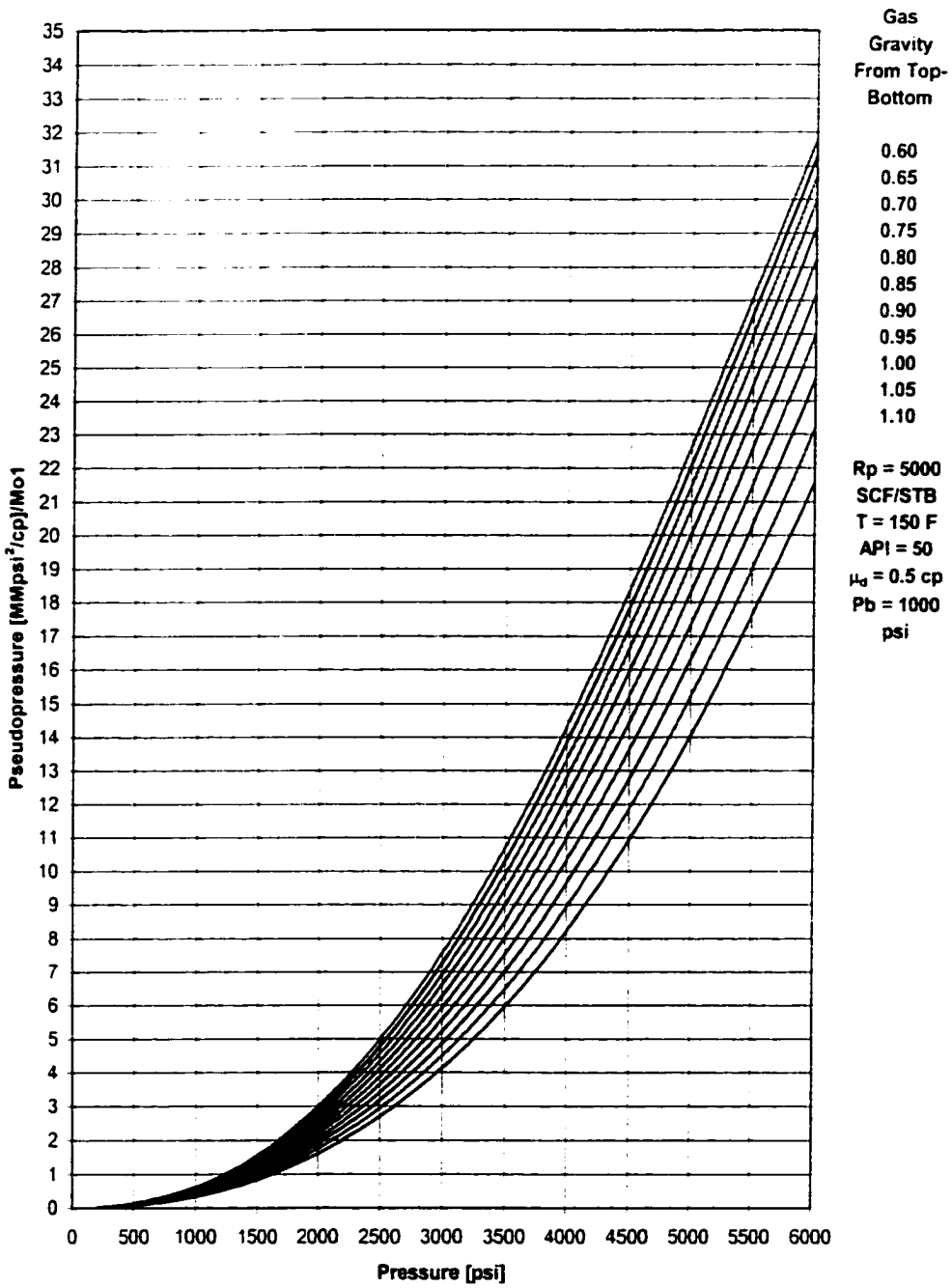

Fig.A-20 Oil phase pseudopressure Region-1[Eq.4.74] [API = 50]

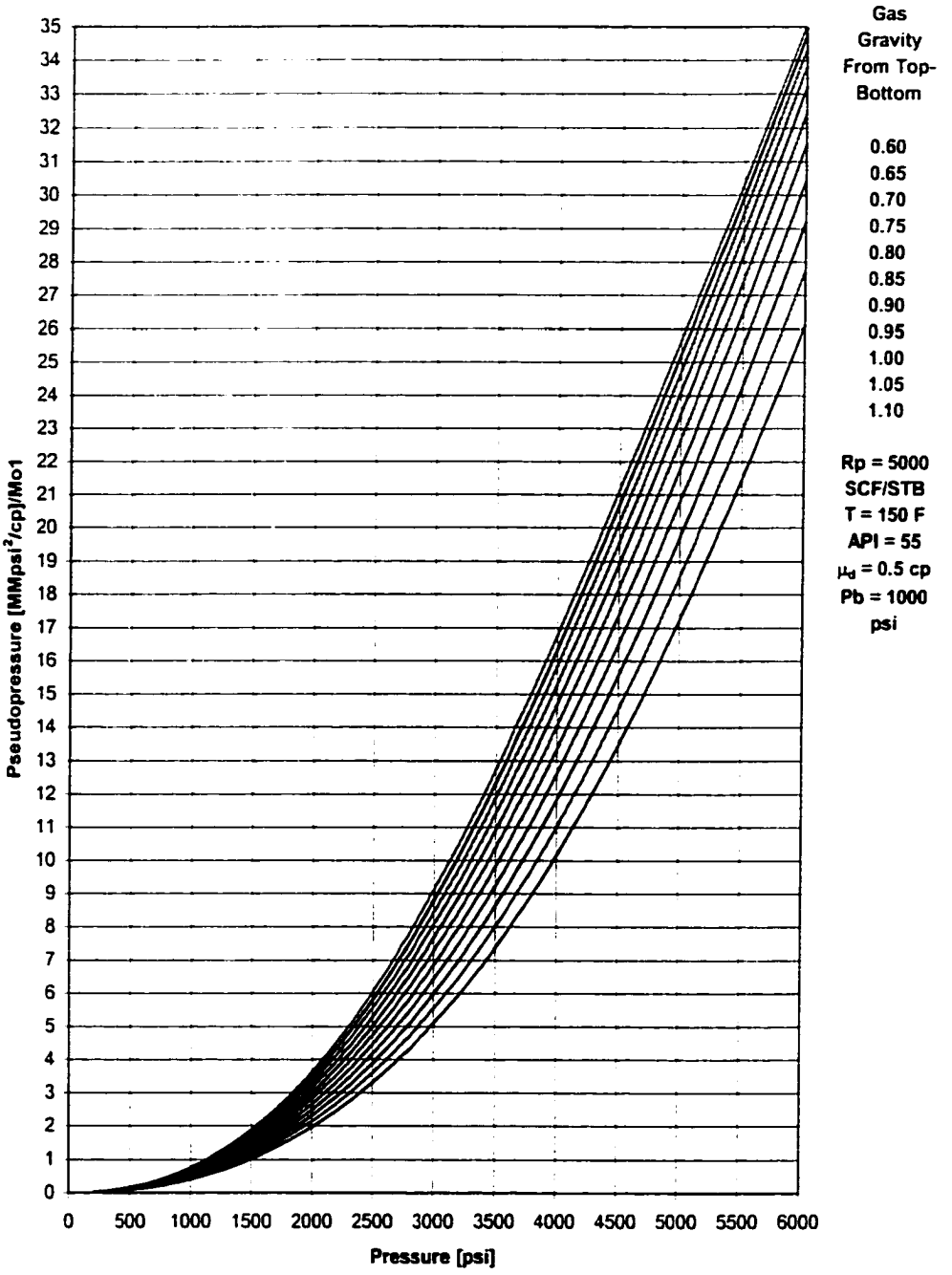

Fig.A-21 Oil phase pseudopressure Region-1[Eq.4.74] [API= 55]

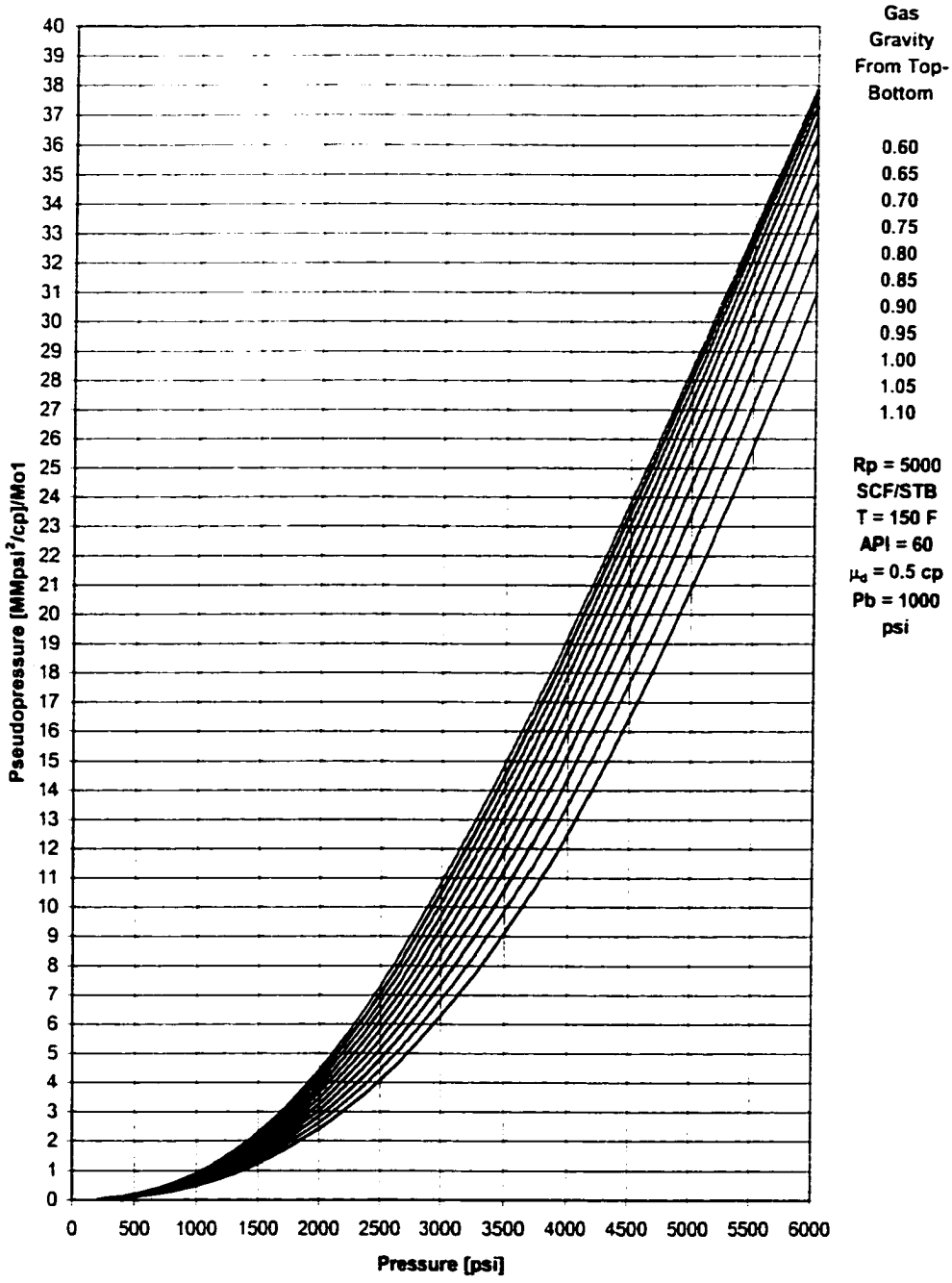

Fig.A-22 Oil phase pseudopressure Region-1[Eq.4.74] [API= 60]

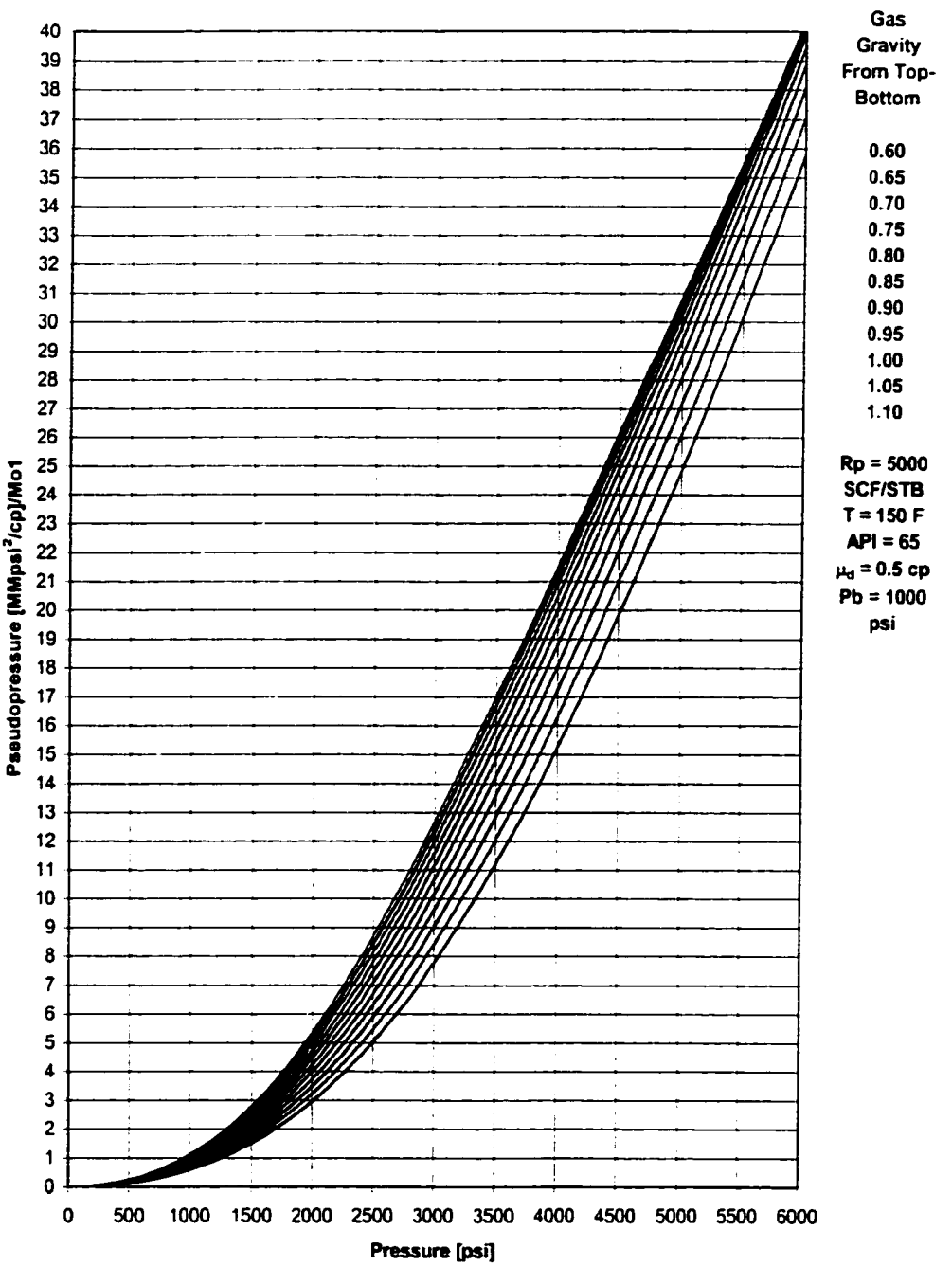

Fig.A-23 Oil phase pseudopressure Region-1[Eq.4.74] [API= 65]

Effect of Rp

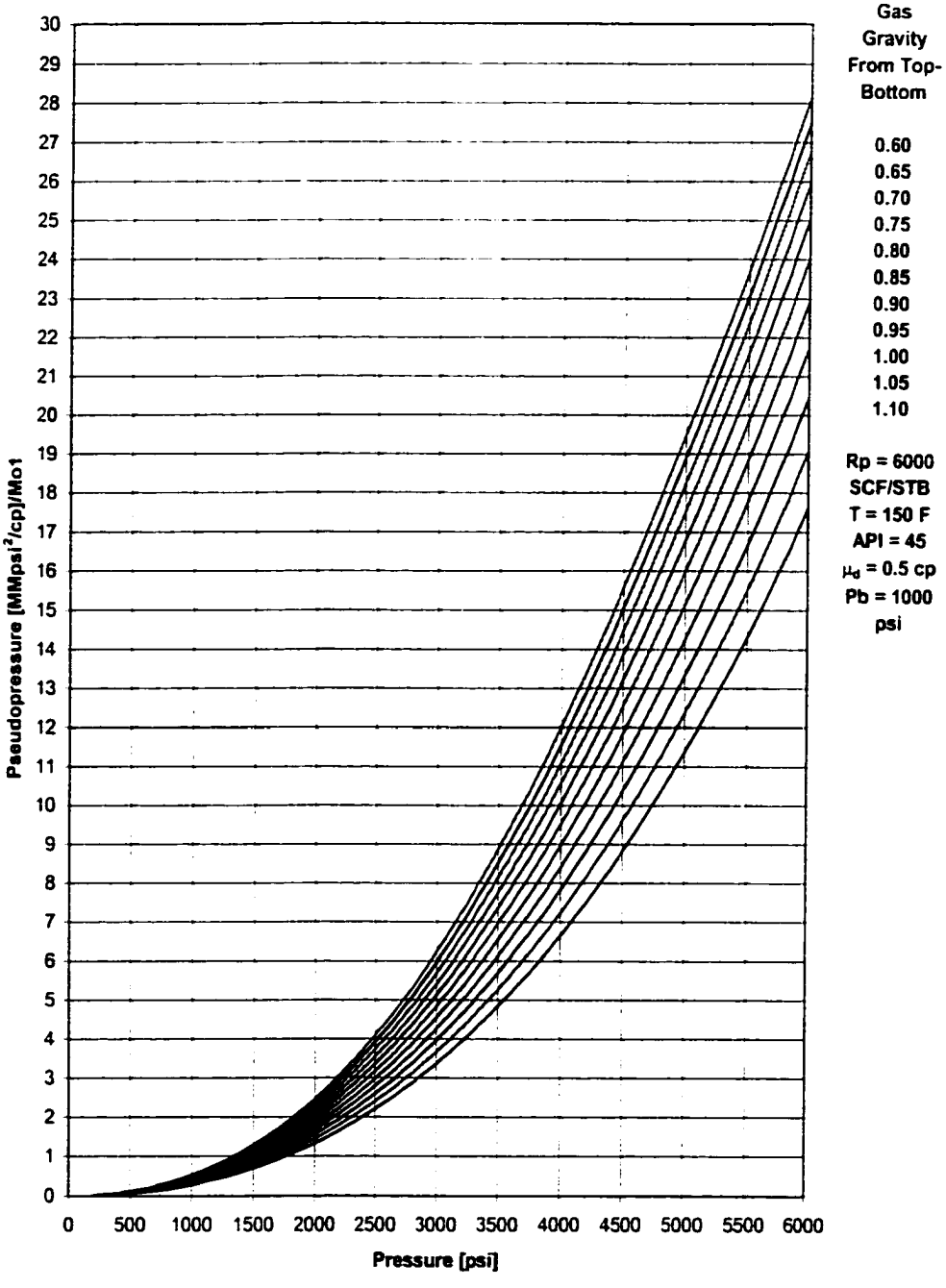

Fig.A-24 Oil phase pseudopressure Region-1[Eq.4.74] [Rp = 6,000]

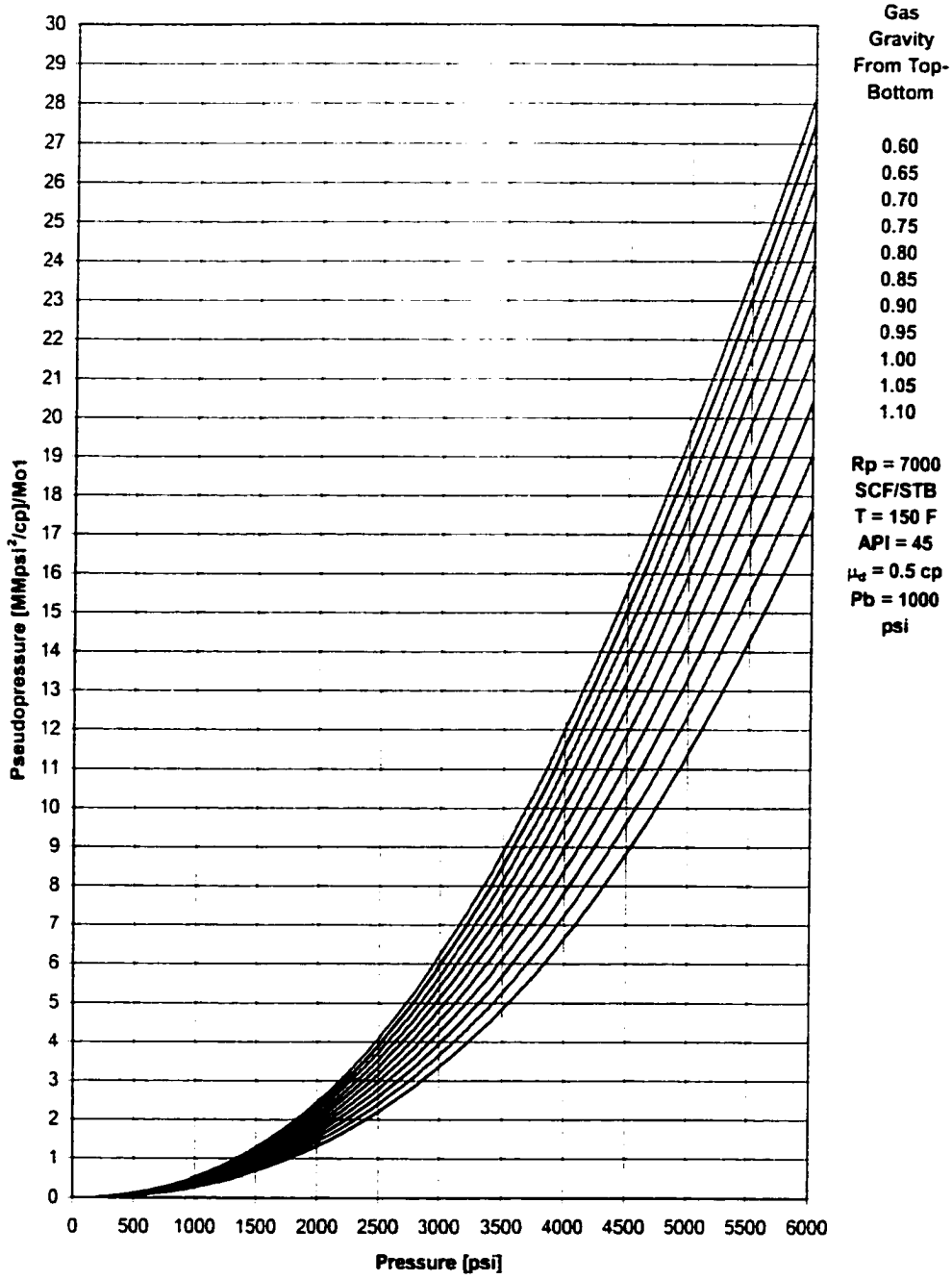

Fig.A-25 Oil phase pseudopressure Region-1[Eq.4.74] [Rp = 7,000]

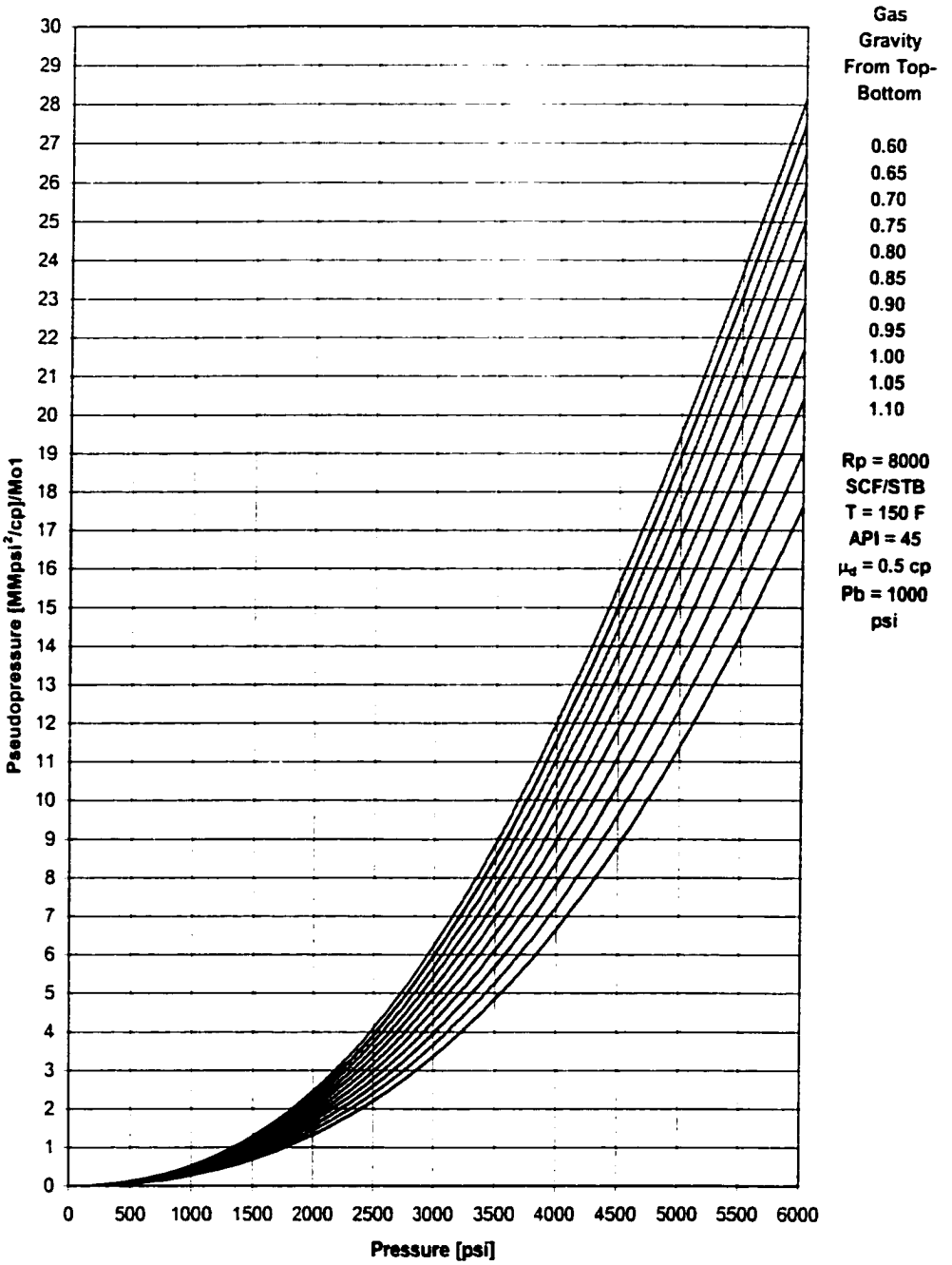

Fig.A-26 Oil phase pseudopressure Region-1[Eq.4.74] [Rp = 8,000]

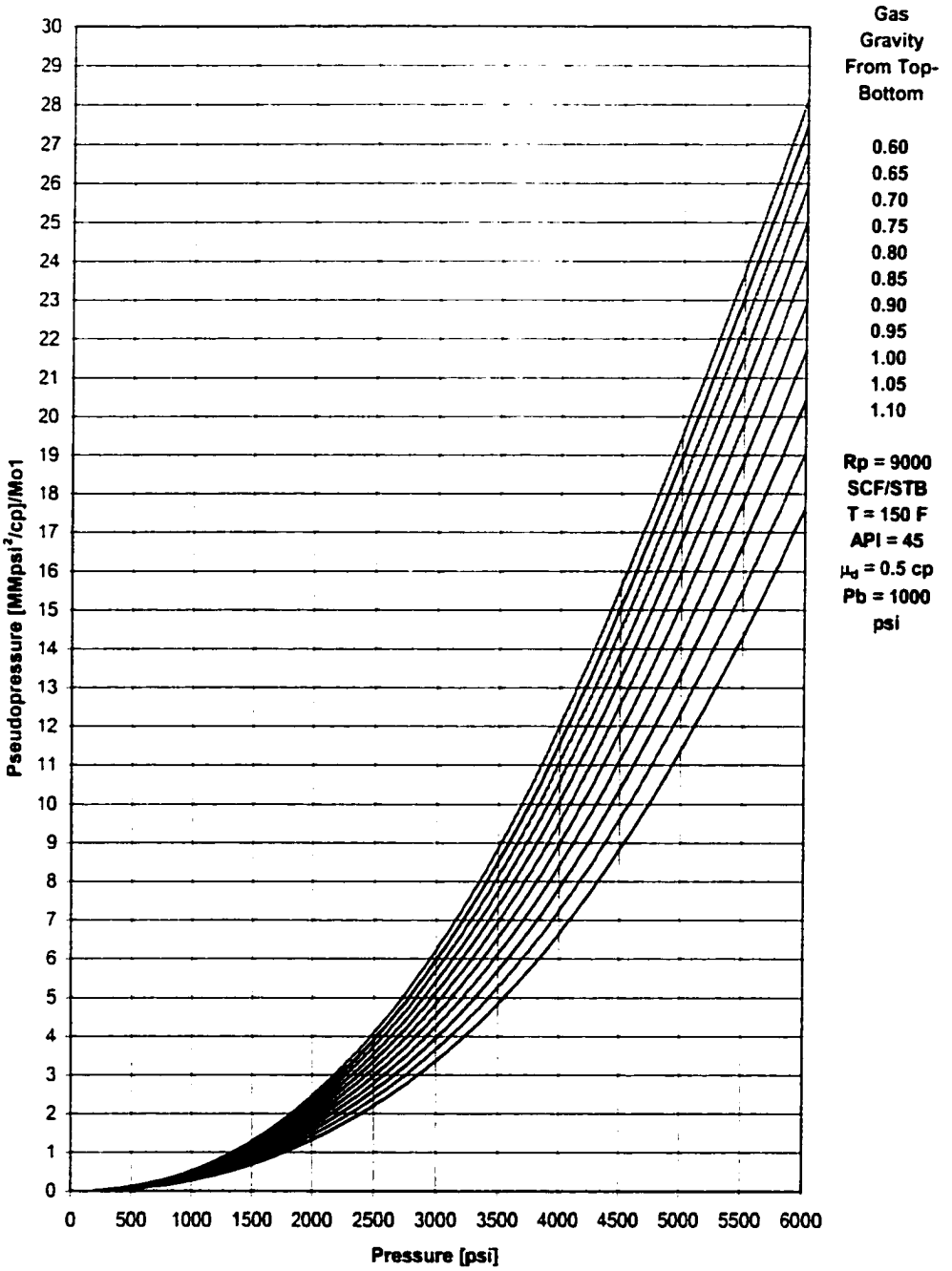

Fig.A-27 Oil phase pseudopressure Region-1[Eq.4.74] [Rp = 9,000]

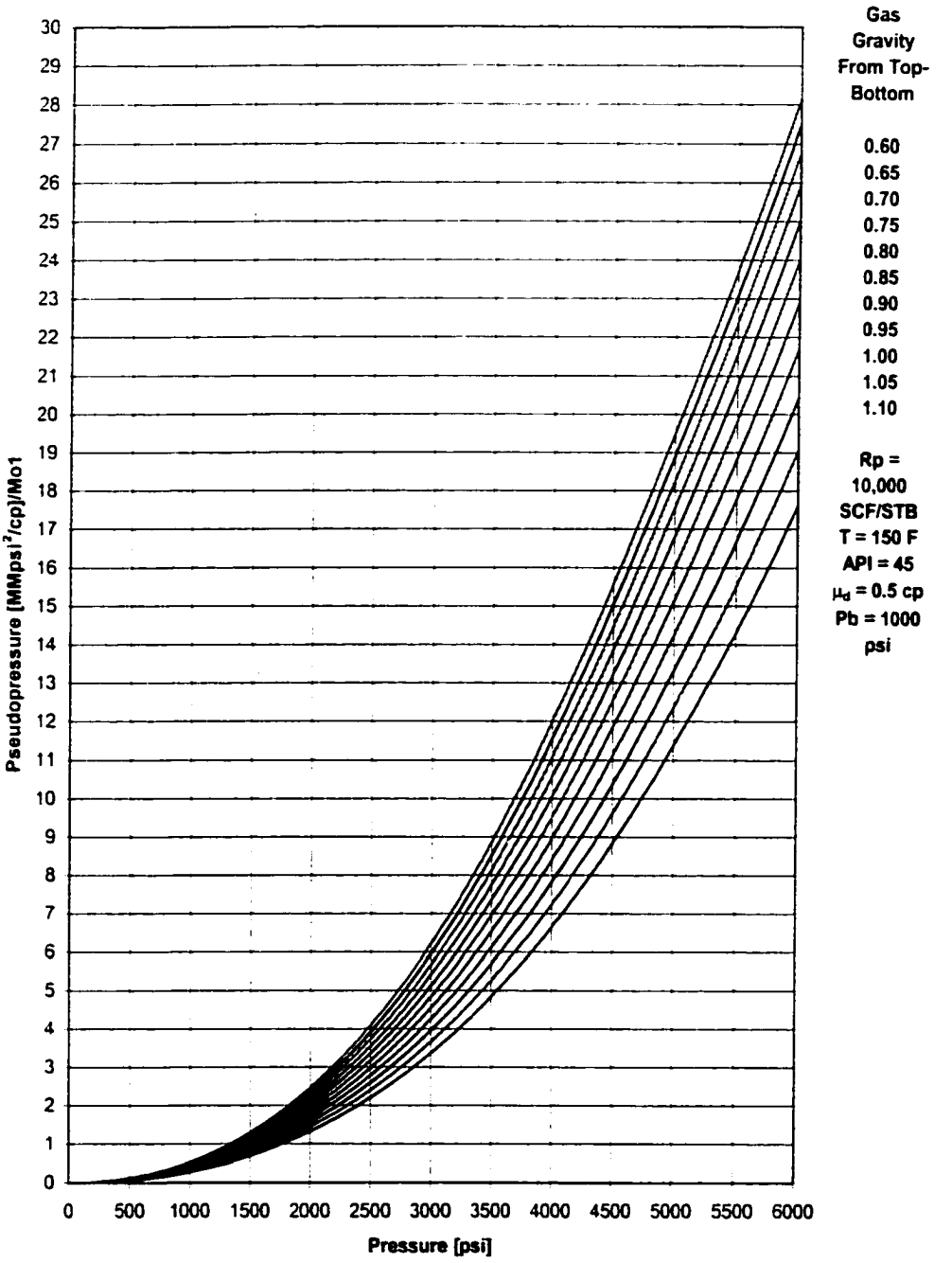

Fig.A-28 Oil phase pseudopressure Region-1[Eq.4.74] [Rp = 10,000]

Region-2 and Region-3: Gas Phase

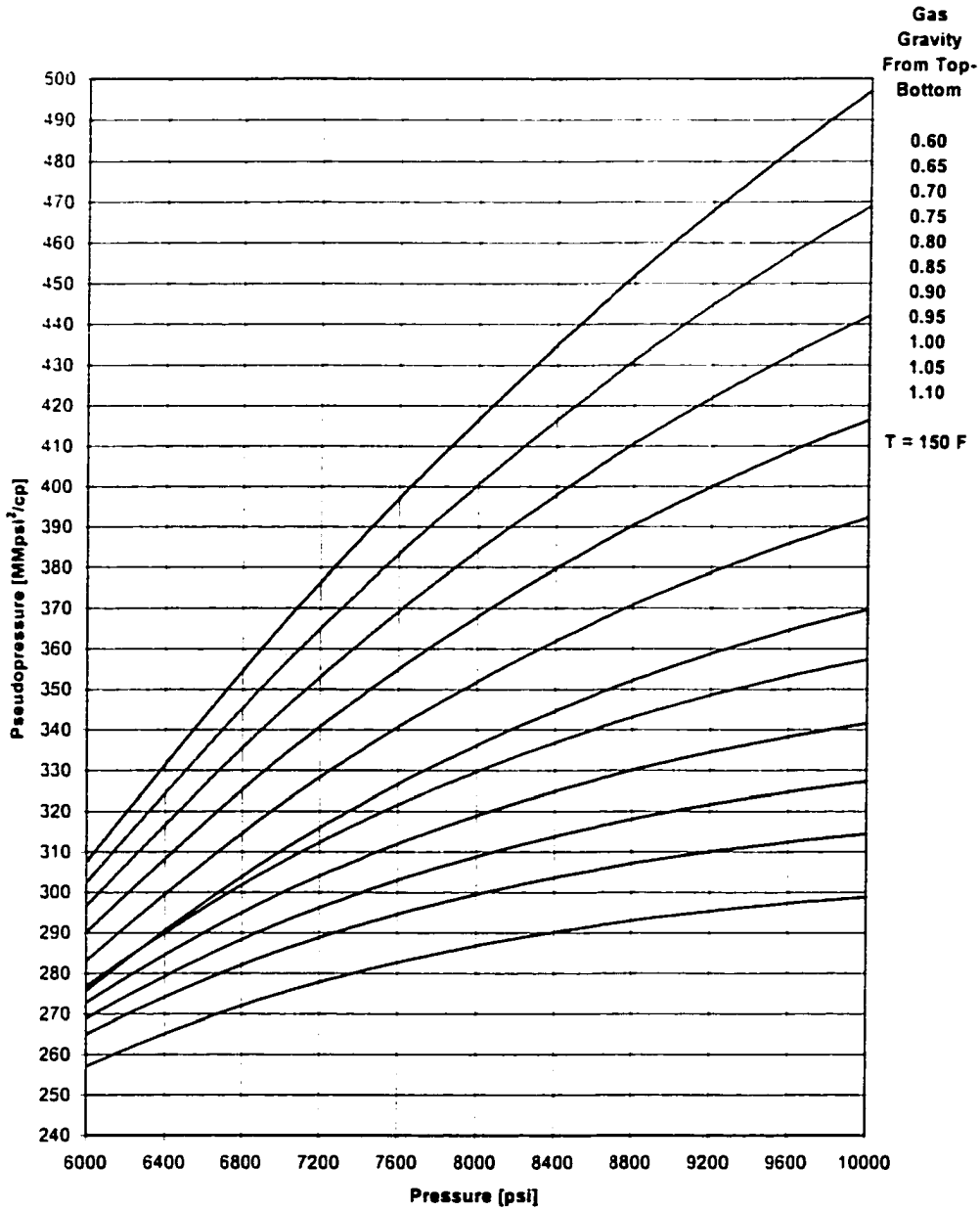

Fig.A-29 Gas phase pseudopressure Region-1[Eq.4.82] [T = 150]

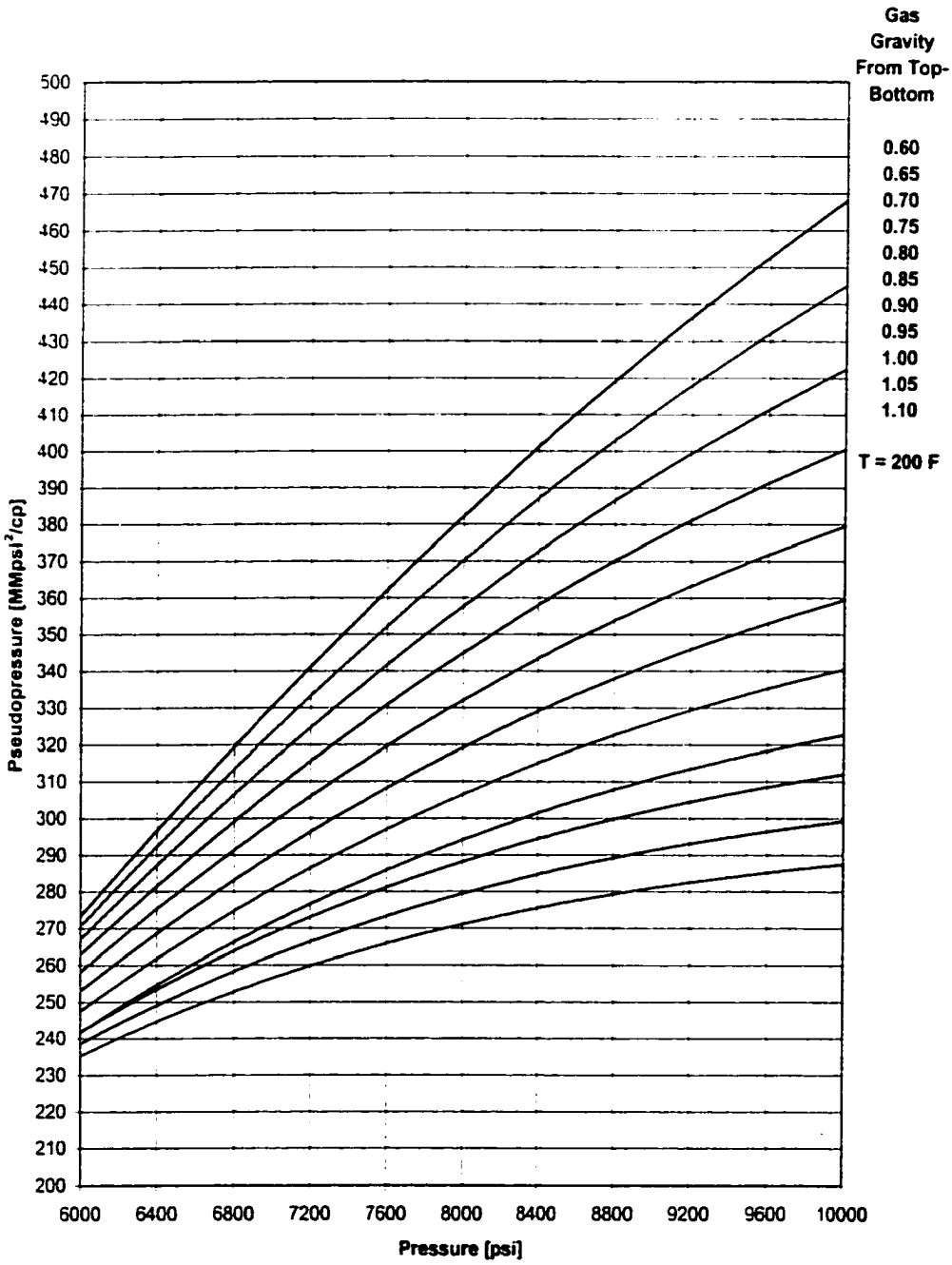

Fig.A-30 Gas phase pseudopressure Region-1[Eq.4.82] [T = 200]

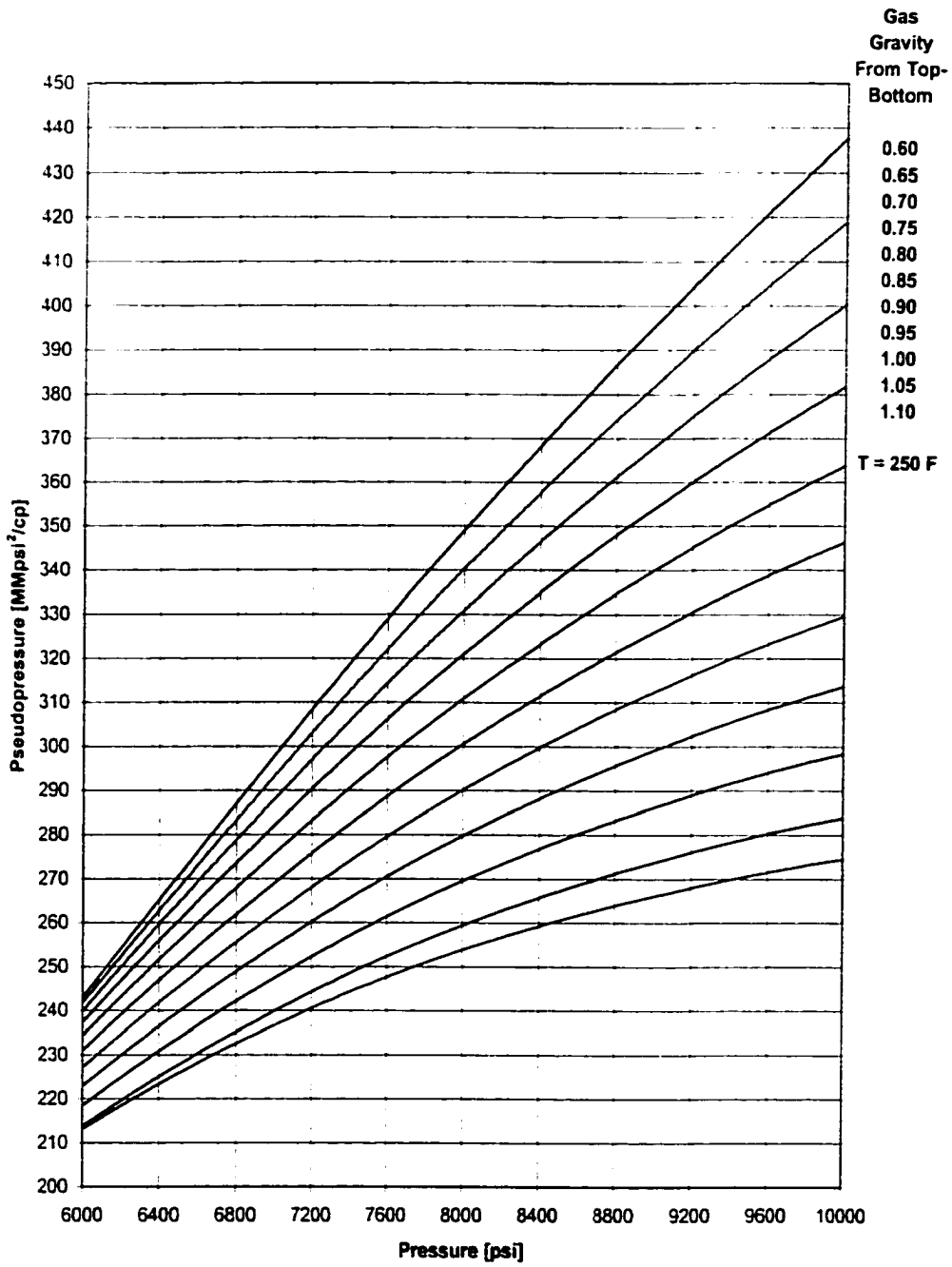

Fig.A-31 Gas phase pseudopressure Region-1[Eq.4.82] [T = 250]

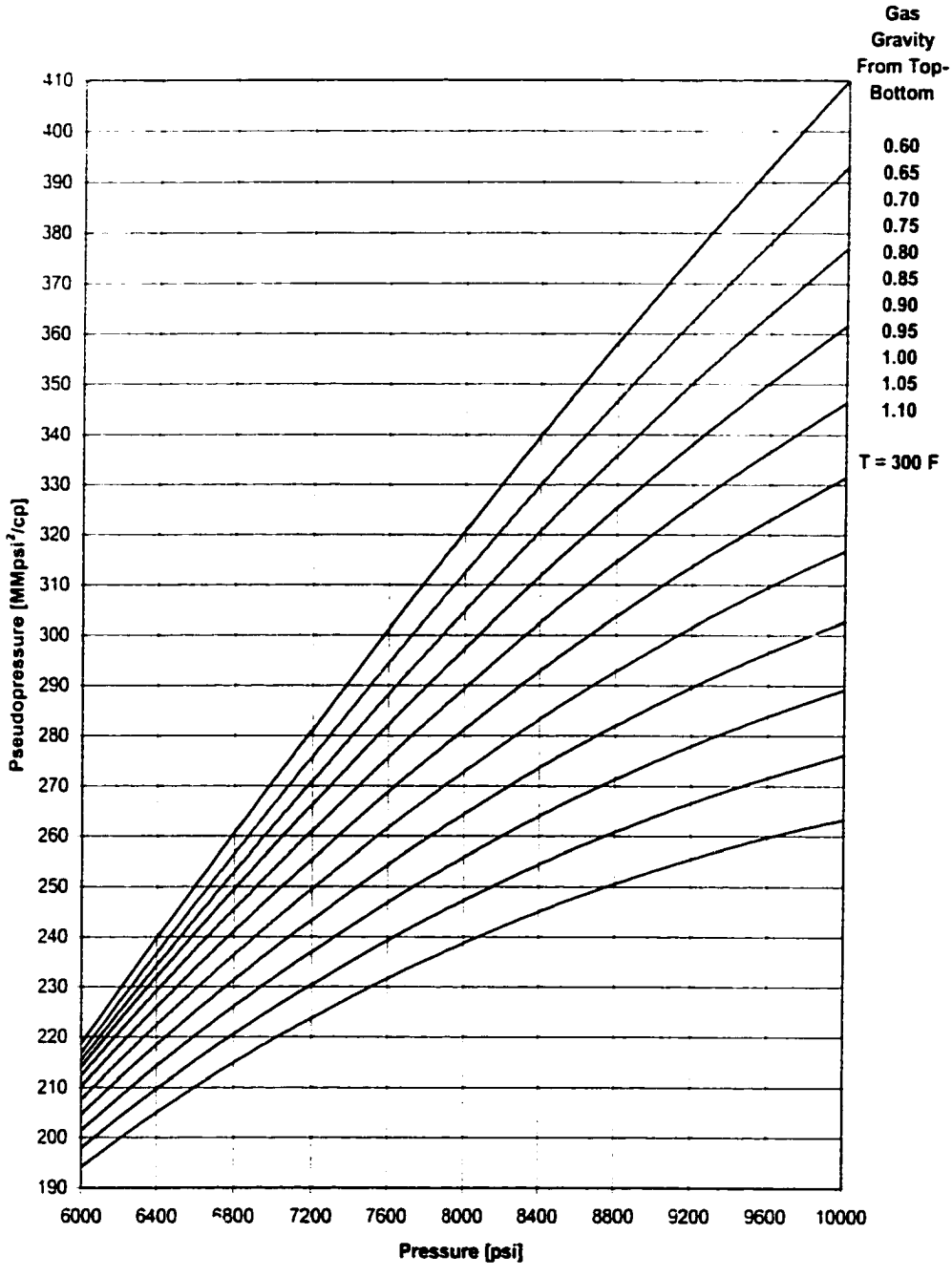

Fig.A-32 Gas phase pseudopressure Region-1[Eq.4.82] [T = 300]

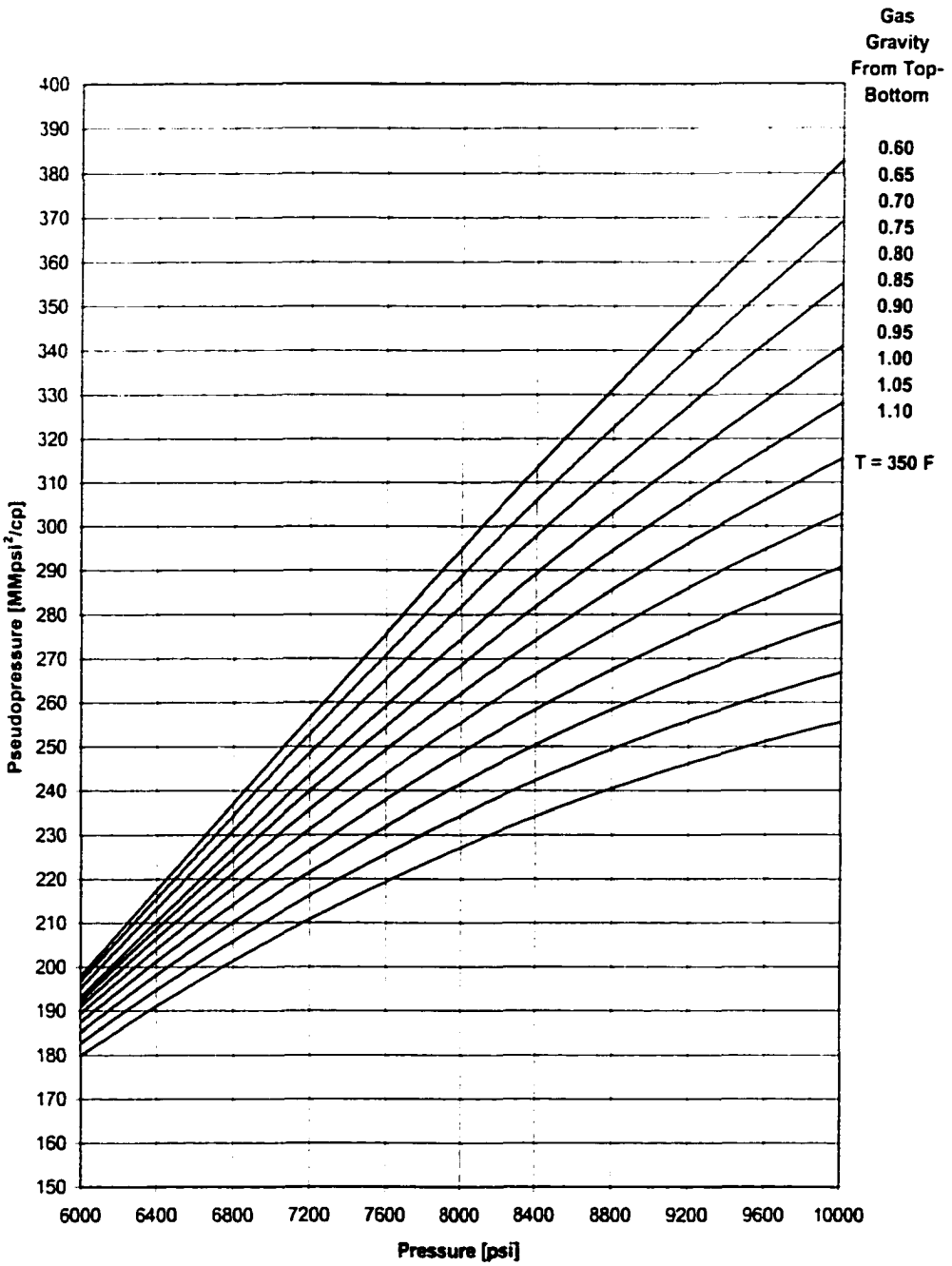

Fig.A-33 Gas phase pseudopressure Region-1[Eq.4.82] [T = 350]

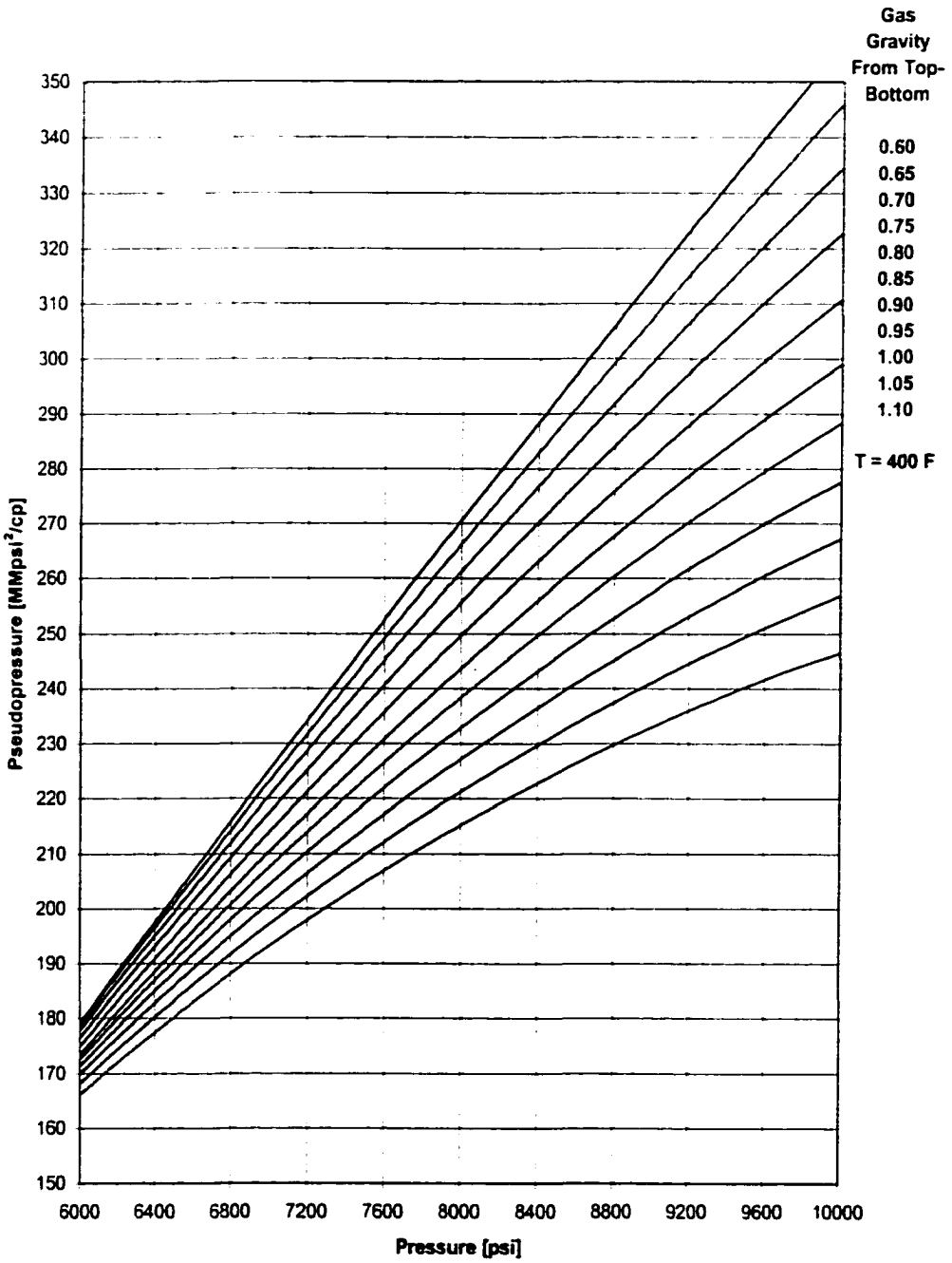

Fig.A-34 Gas phase pseudopressure Region-1[Eq.4.82] [T = 400]

Appendix B Three Phase Systems

Region-: Gas Phase Effect of Temperature

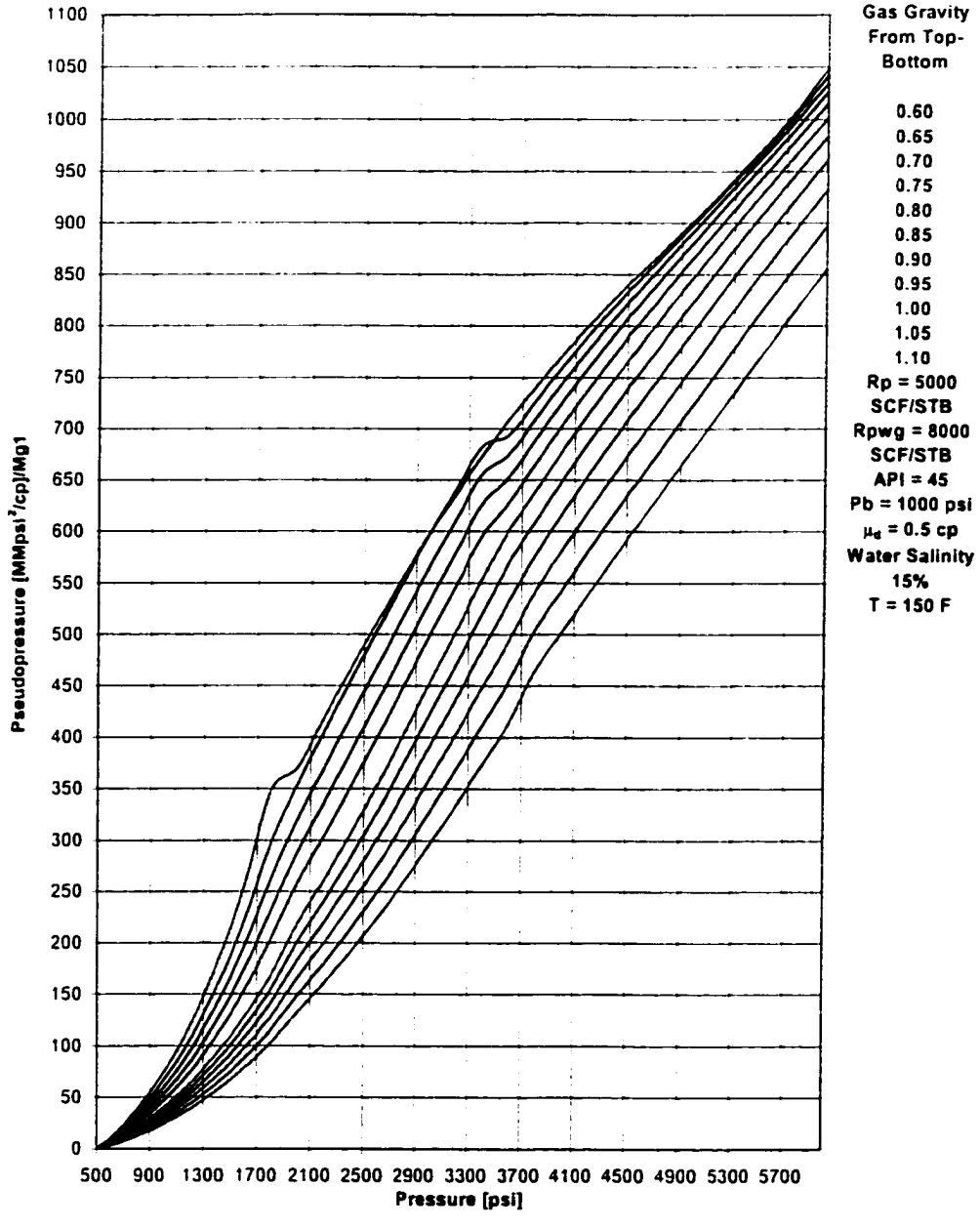

Fig.B-1 Gas phase pseudopressure Region-1[Eq.4.109b] [T = 150]

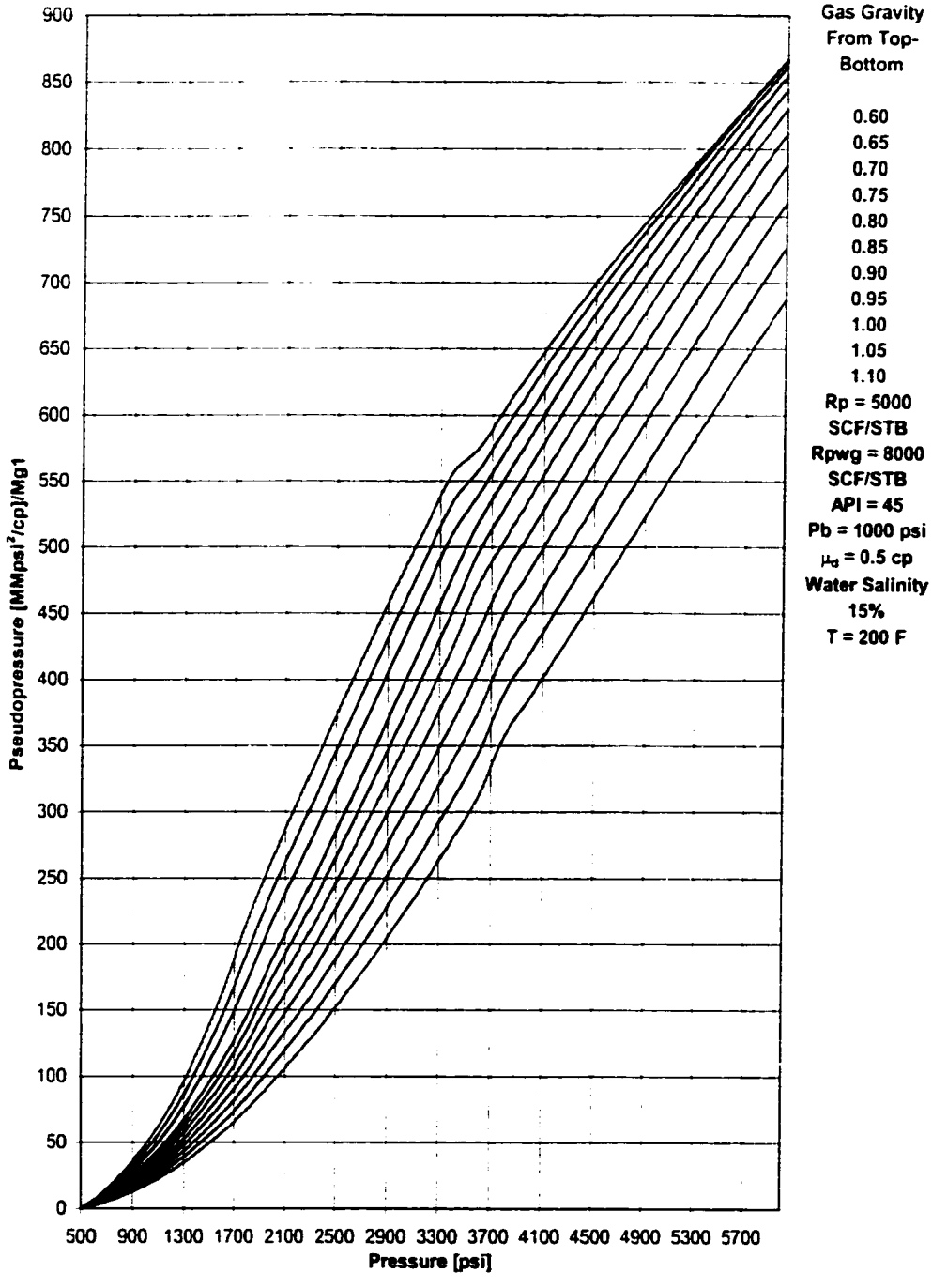

Fig.B-2 Gas phase pseudopressure Region-1[Eq.4.109b] [T = 200]

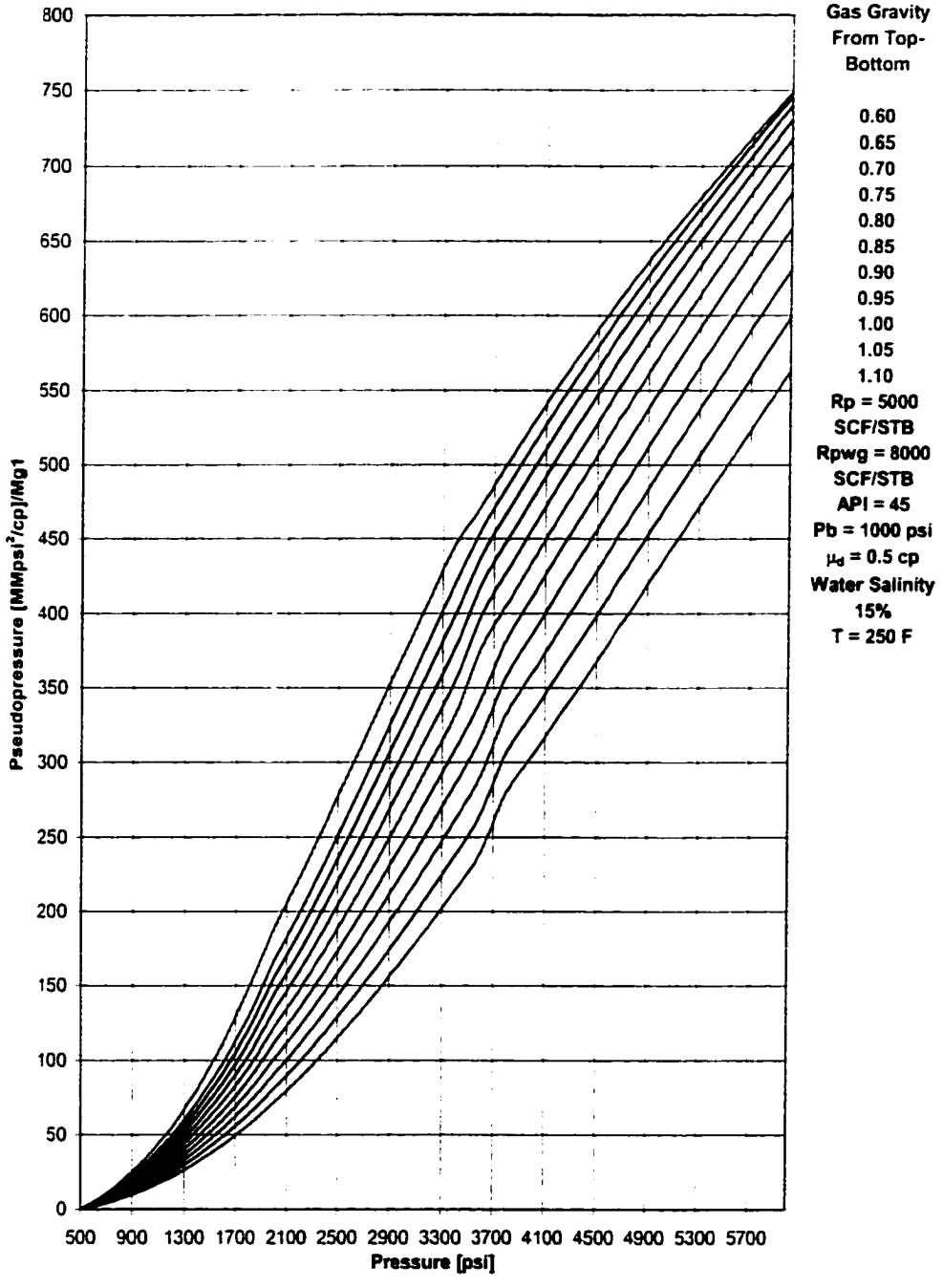

Fig.B-3 Gas phase pseudopressure Region-1[Eq.4.109b] [T = 250]

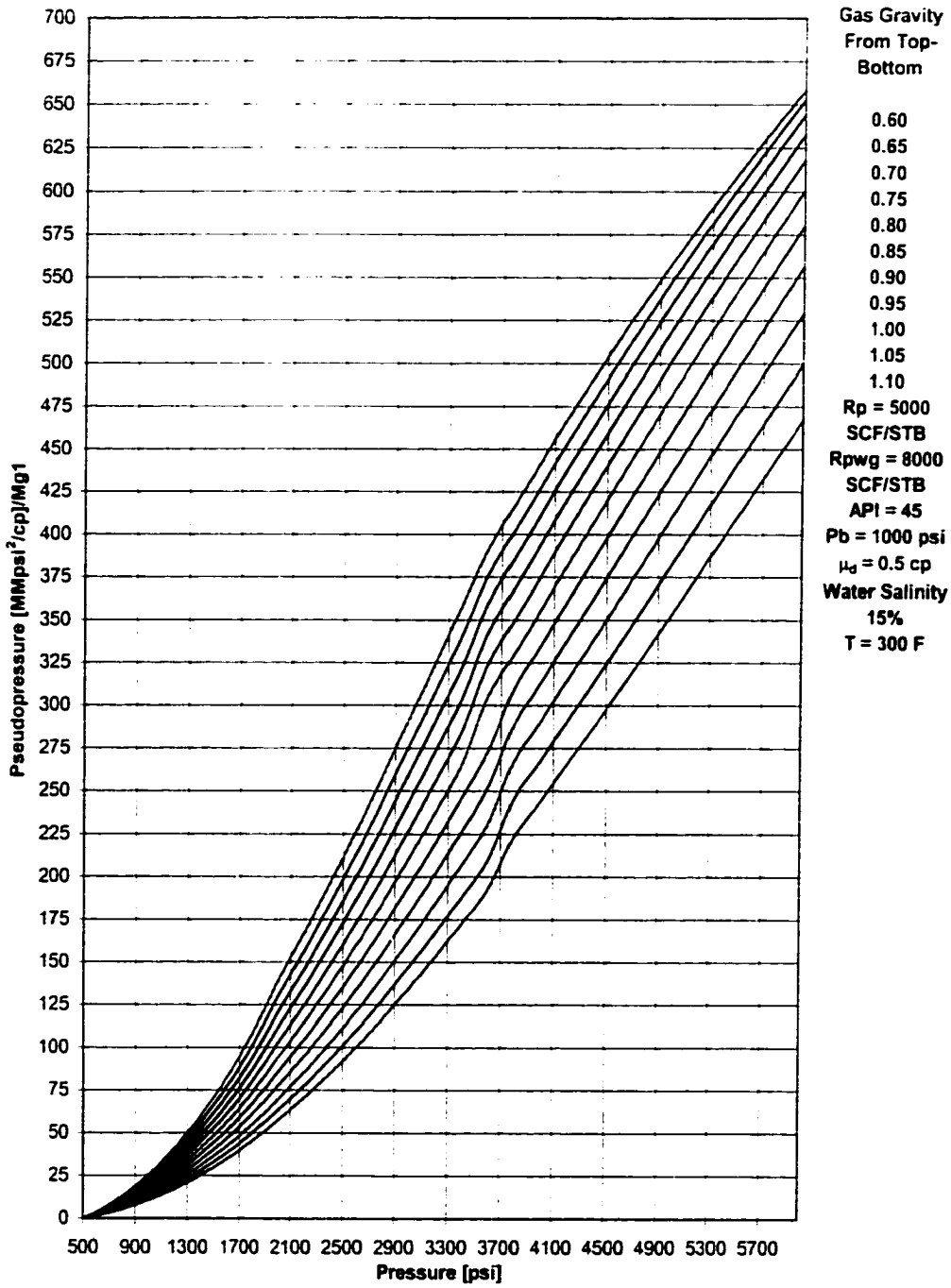

Fig.B-4 Gas phase pseudopressure Region-1[Eq.4.109b] [T = 300]

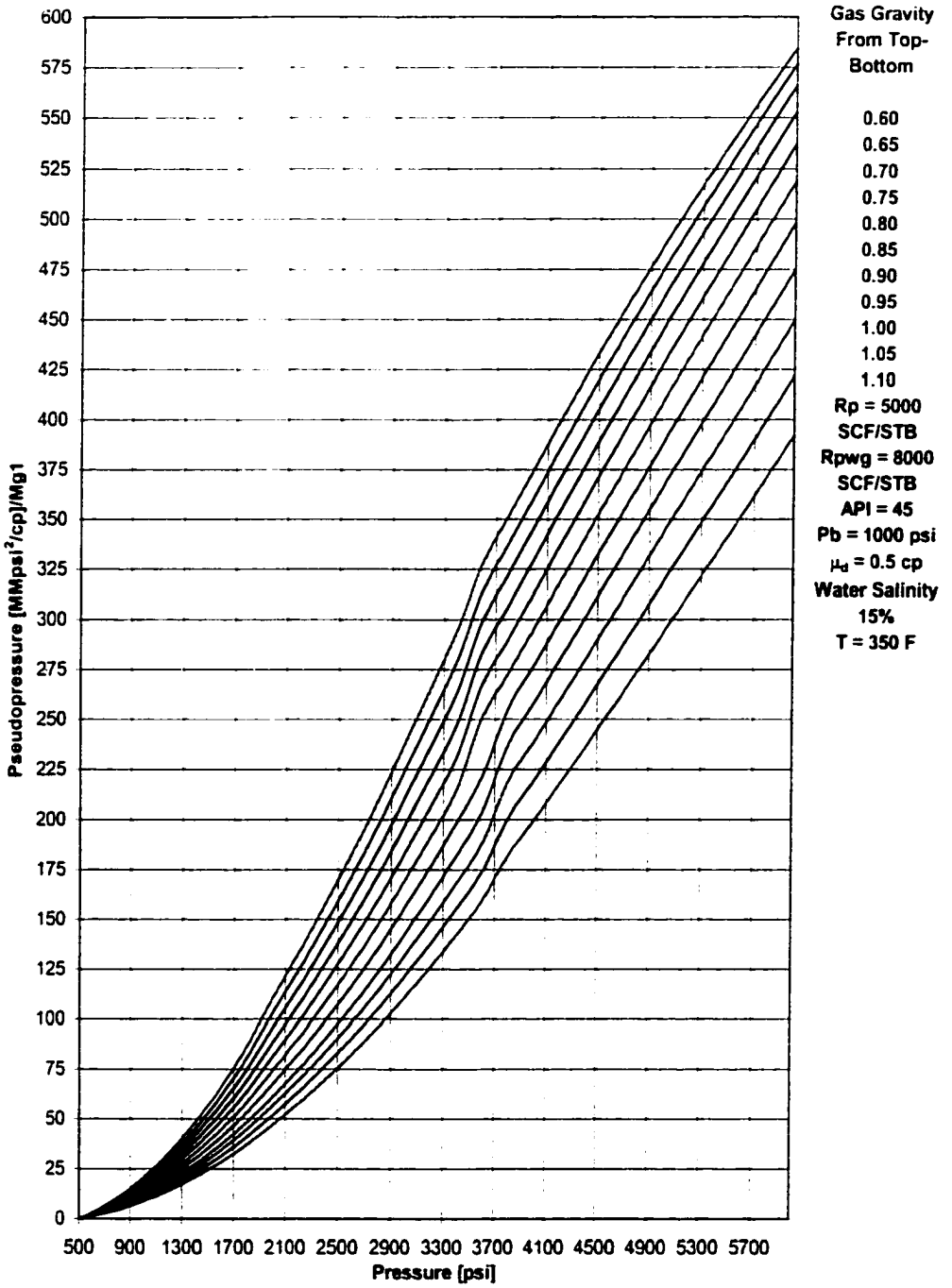

Fig.B-5 Gas phase pseudopressure Region-1[Eq.4.109b] [T = 350]

Region-1 oil phase

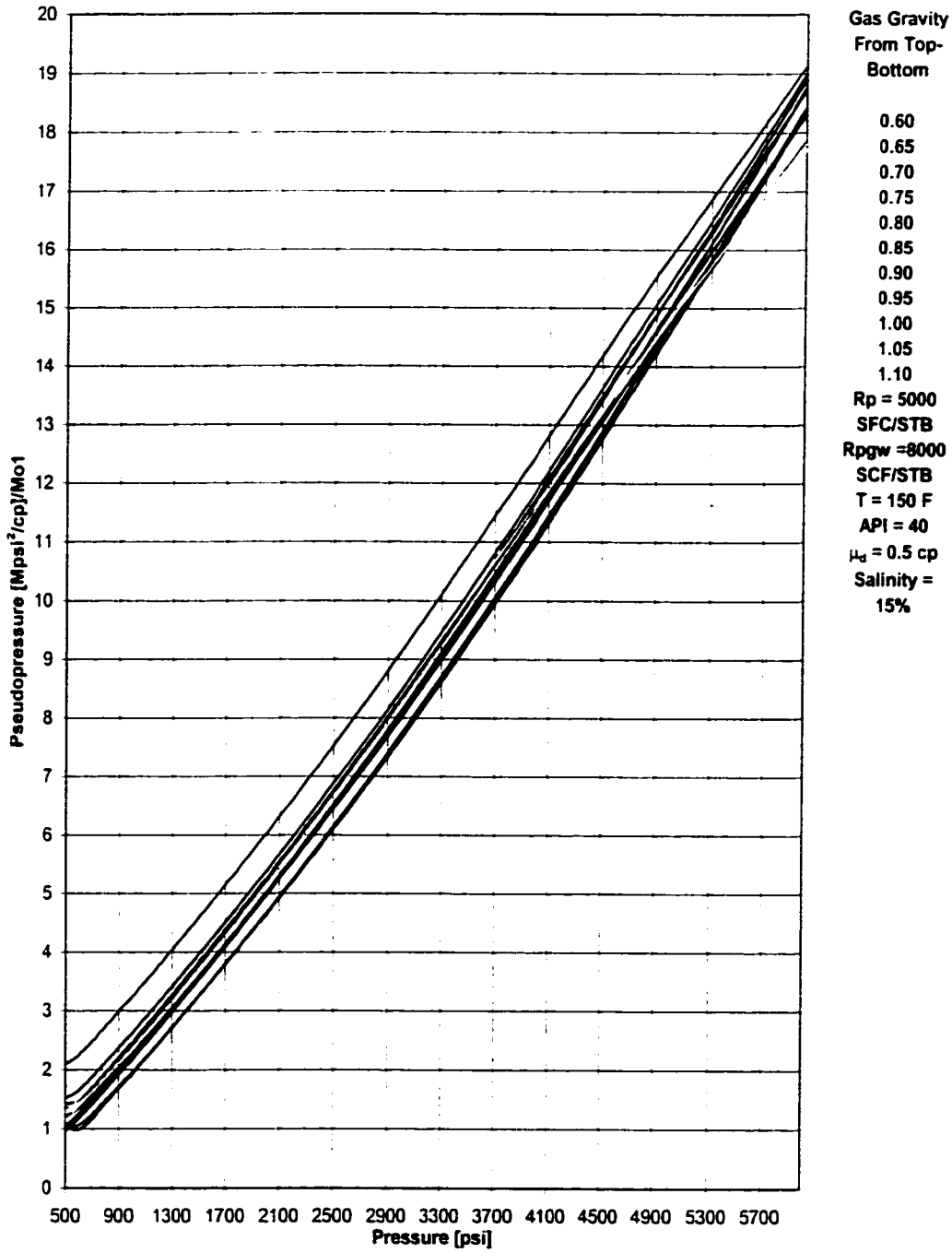

Fig.B-6 Oil phase pseudopressure Region-1[Eq.4.104] [T = 150]

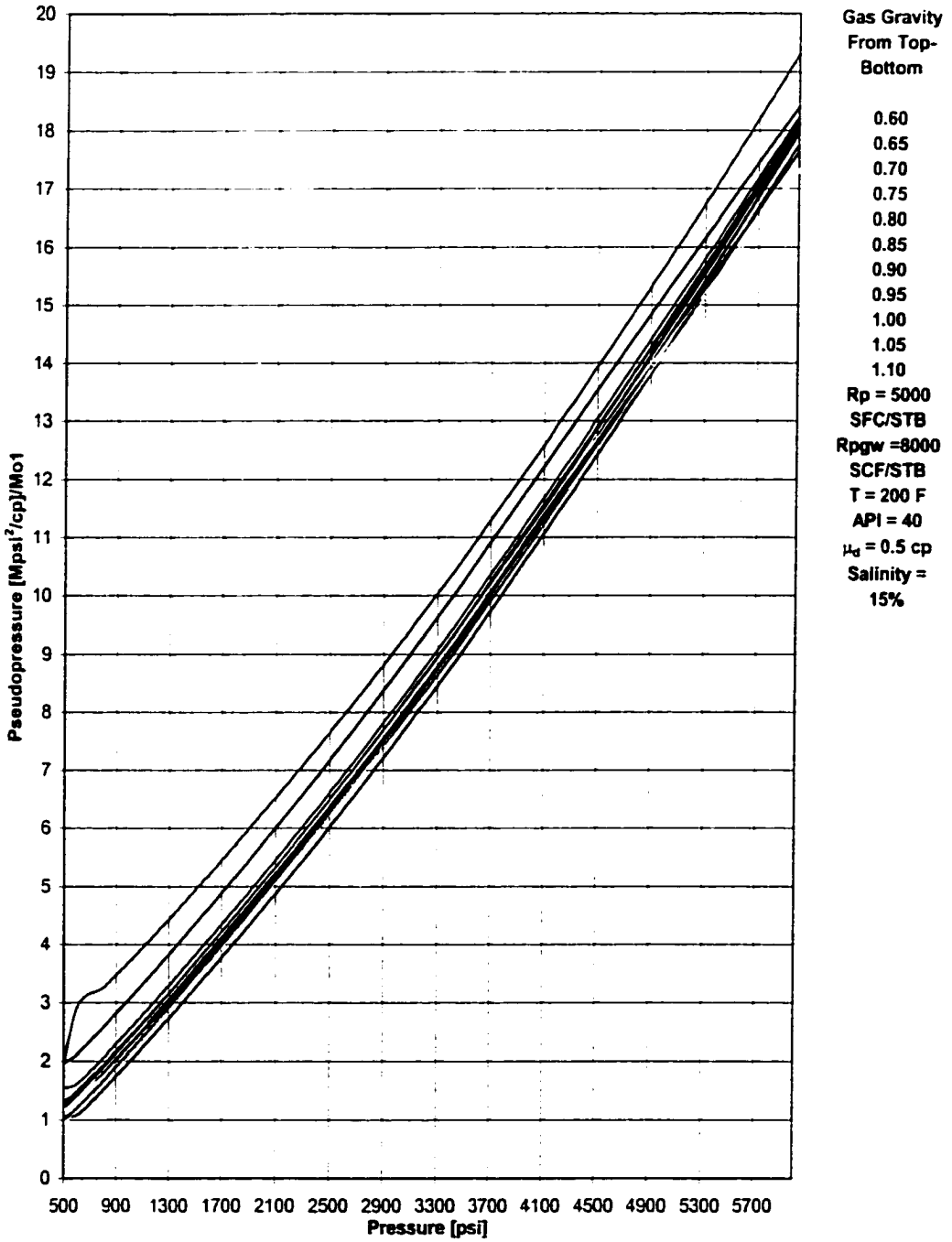

Fig.B-7 Oil phase pseudopressure Region-1[Eq.4.104] [T = 200]

Water phase, effect of Rpgw

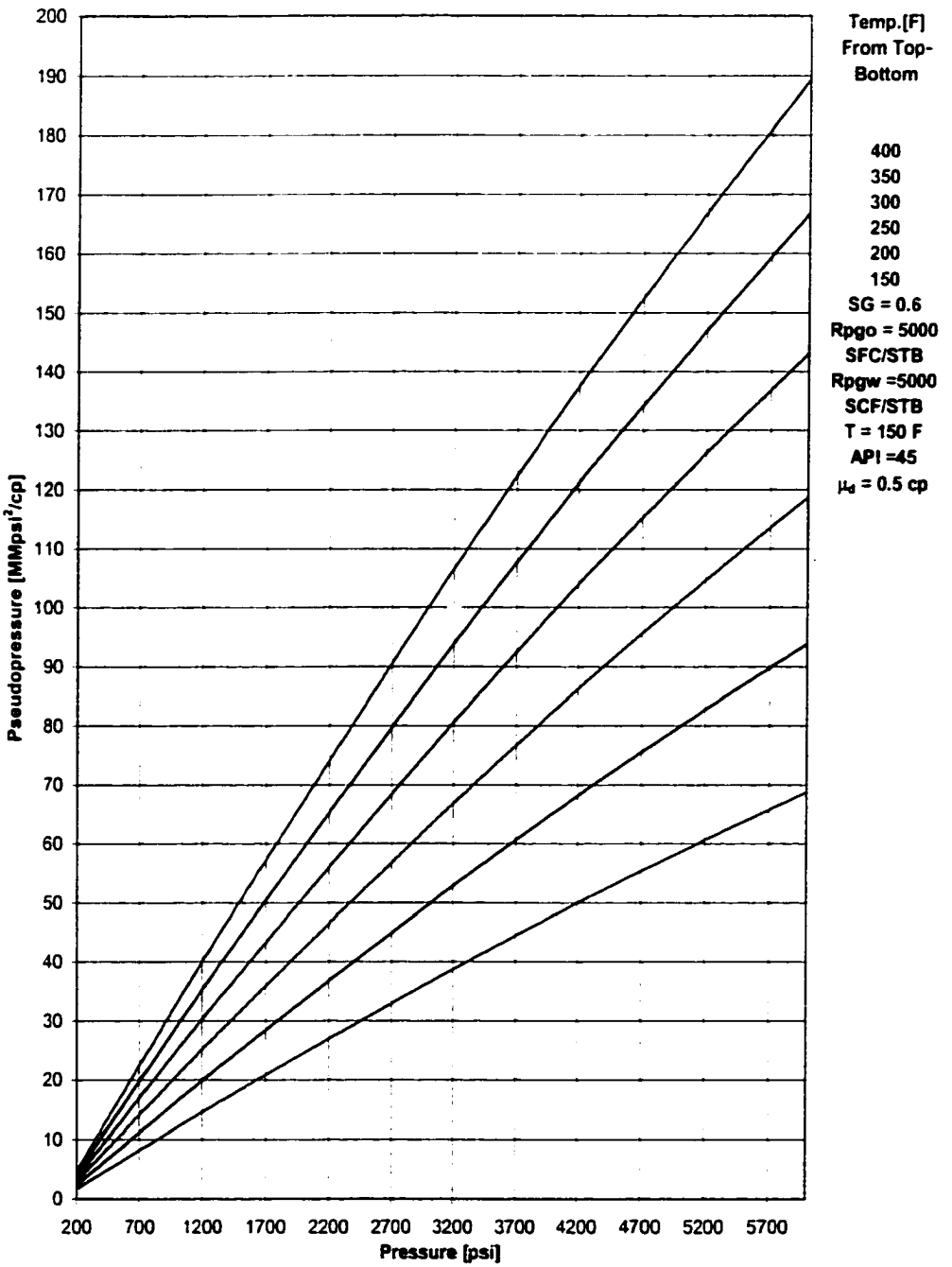

Fig.B-8 Water phase pseudopressure Region-1[Eq.4.79] [Rpgw = 5,000]

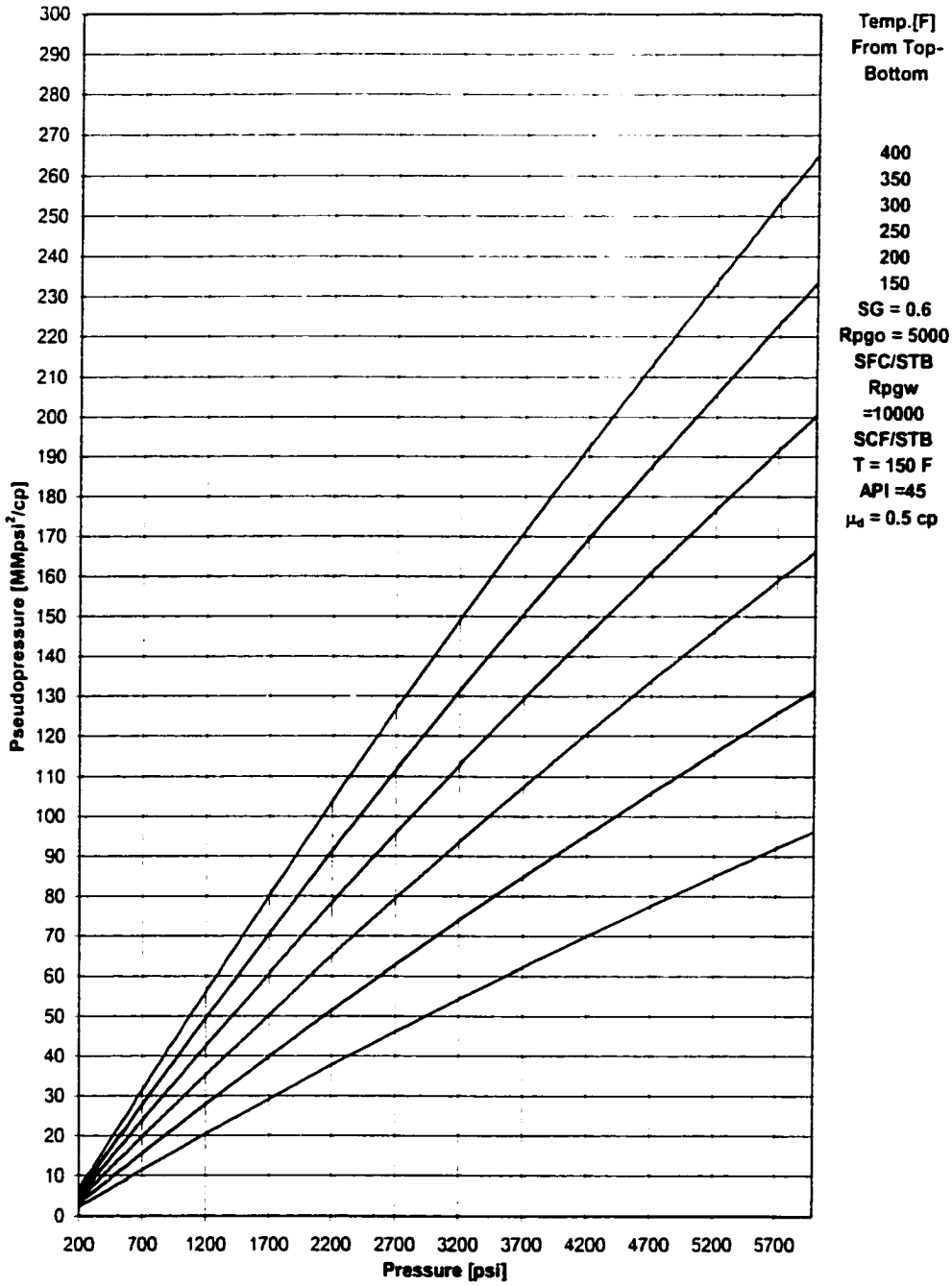

Fig.B-9 Water phase pseudopressure Region-1 [Eq.4.79] [Rpgw = 10,000]

Region-2 and Region-3

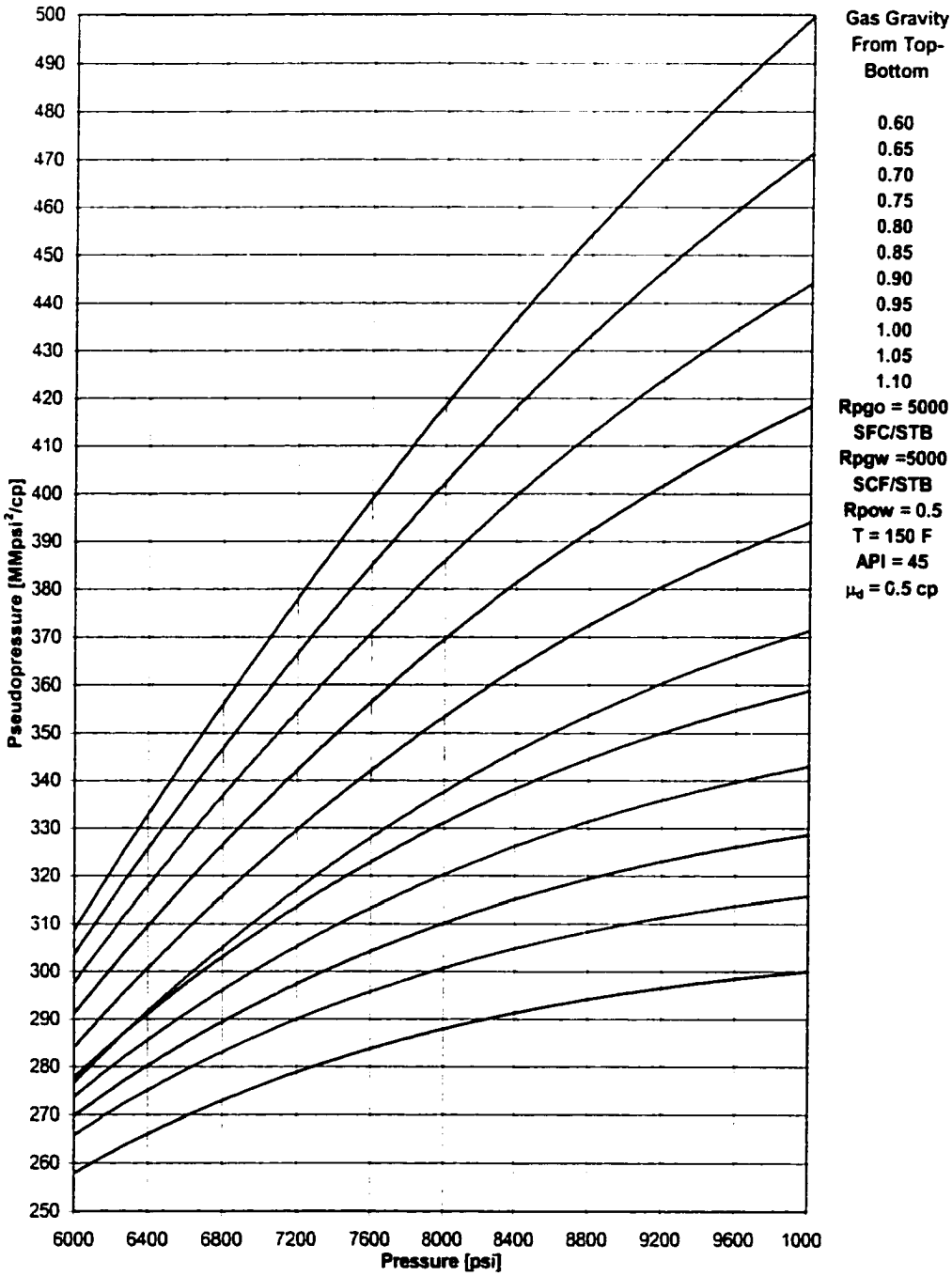

Fig.B-10 Gas phase pseudopressure Region-1[Eq.4.79] [T = 150]

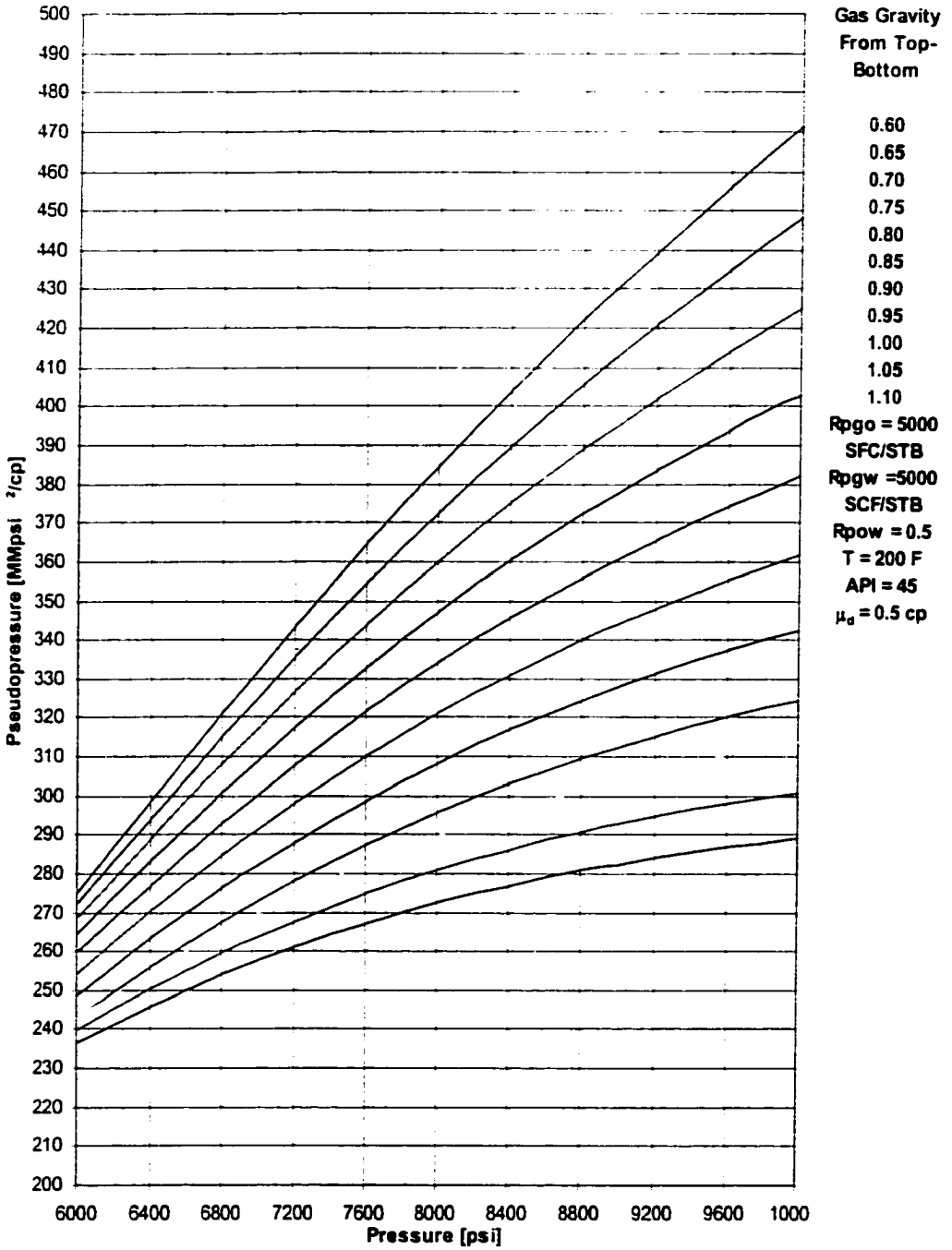

Fig.B-11 Gas phase pseudopressure Region-1[Eq.4.79] [T = 200]

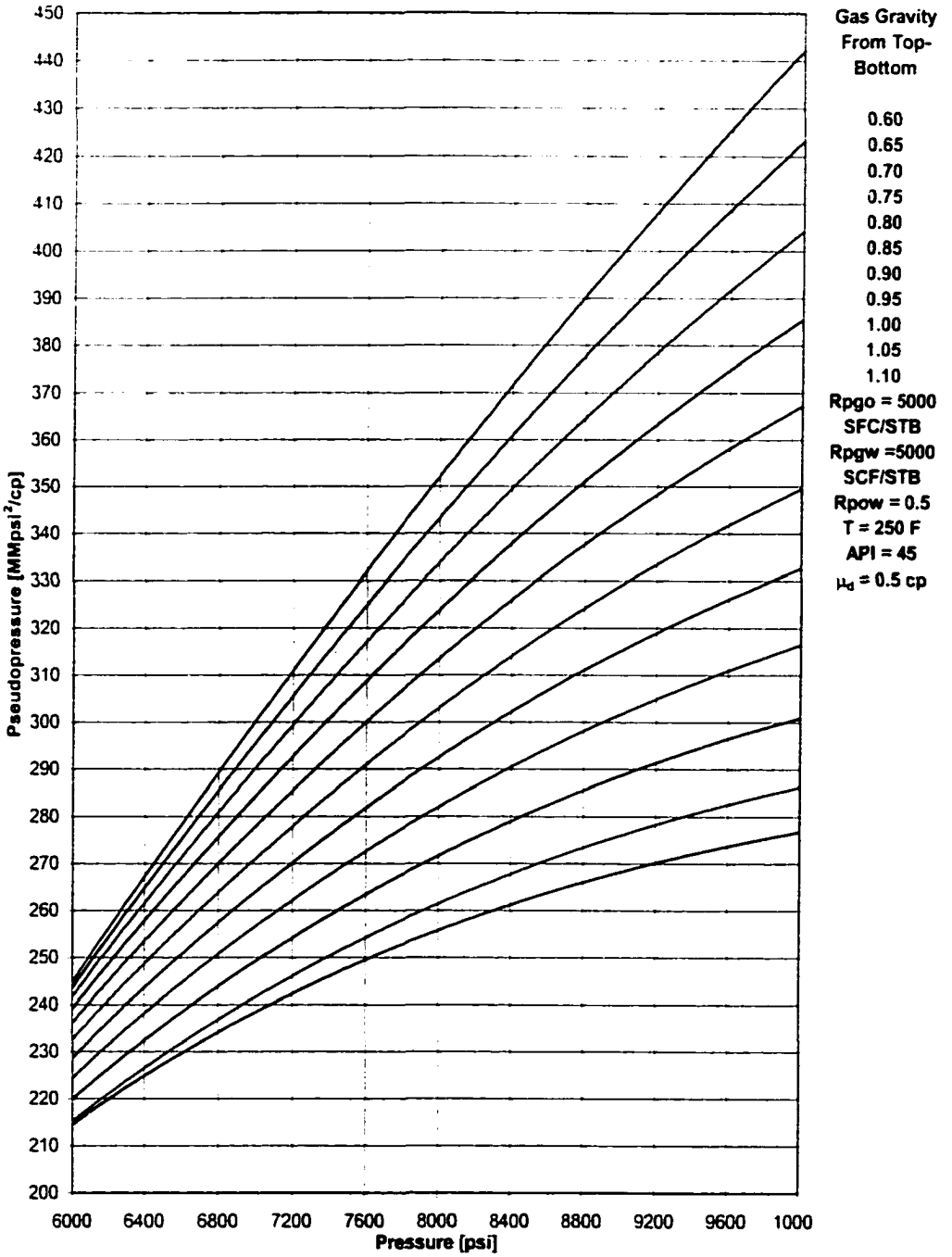

Fig.B-12 Gas phase pseudopressure Region-1[Eq.4.79] [T = 250]

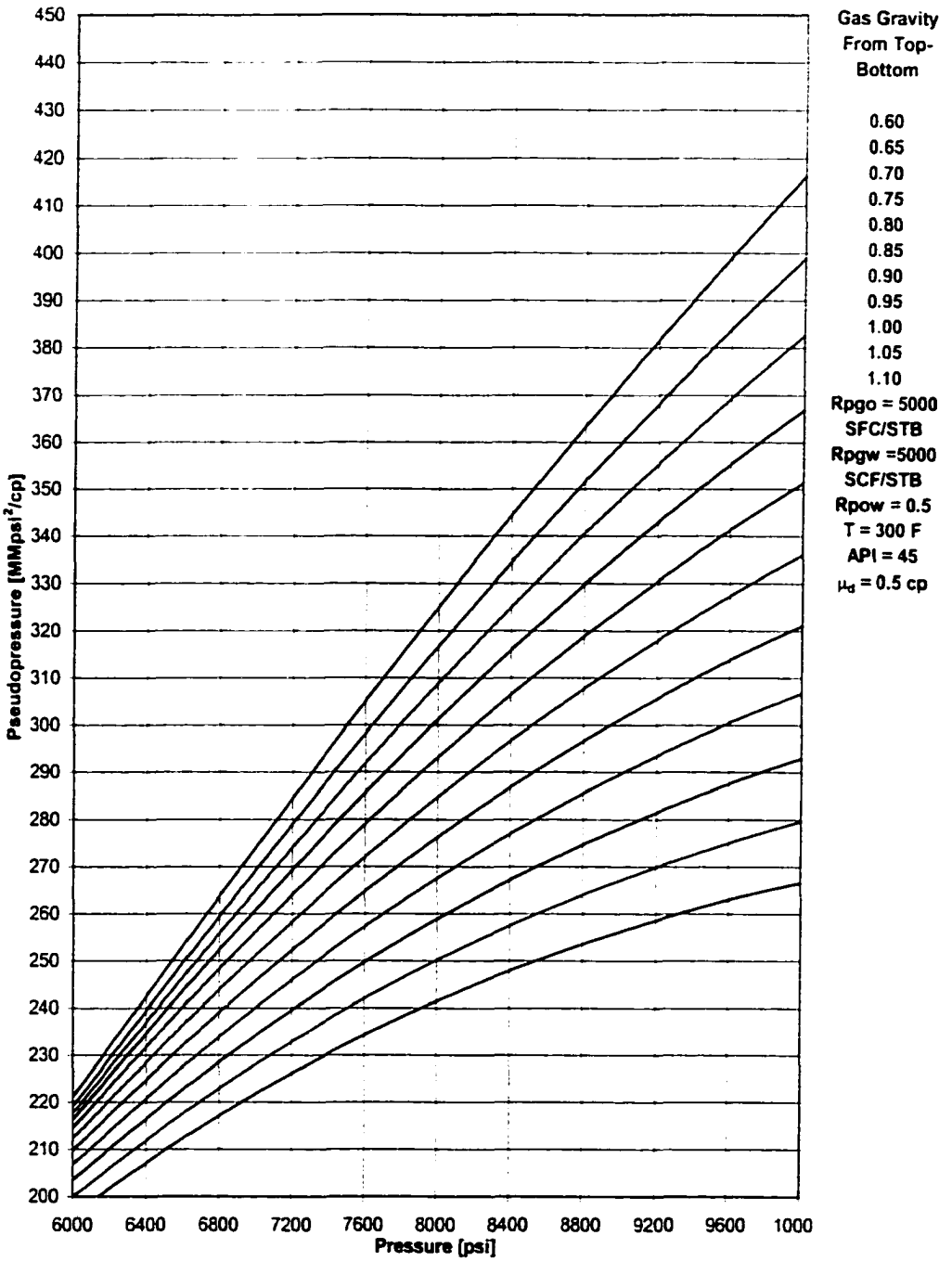

Fig.B-13 Gas phase pseudopressure Region-1[Eq.4.79] [T = 300]

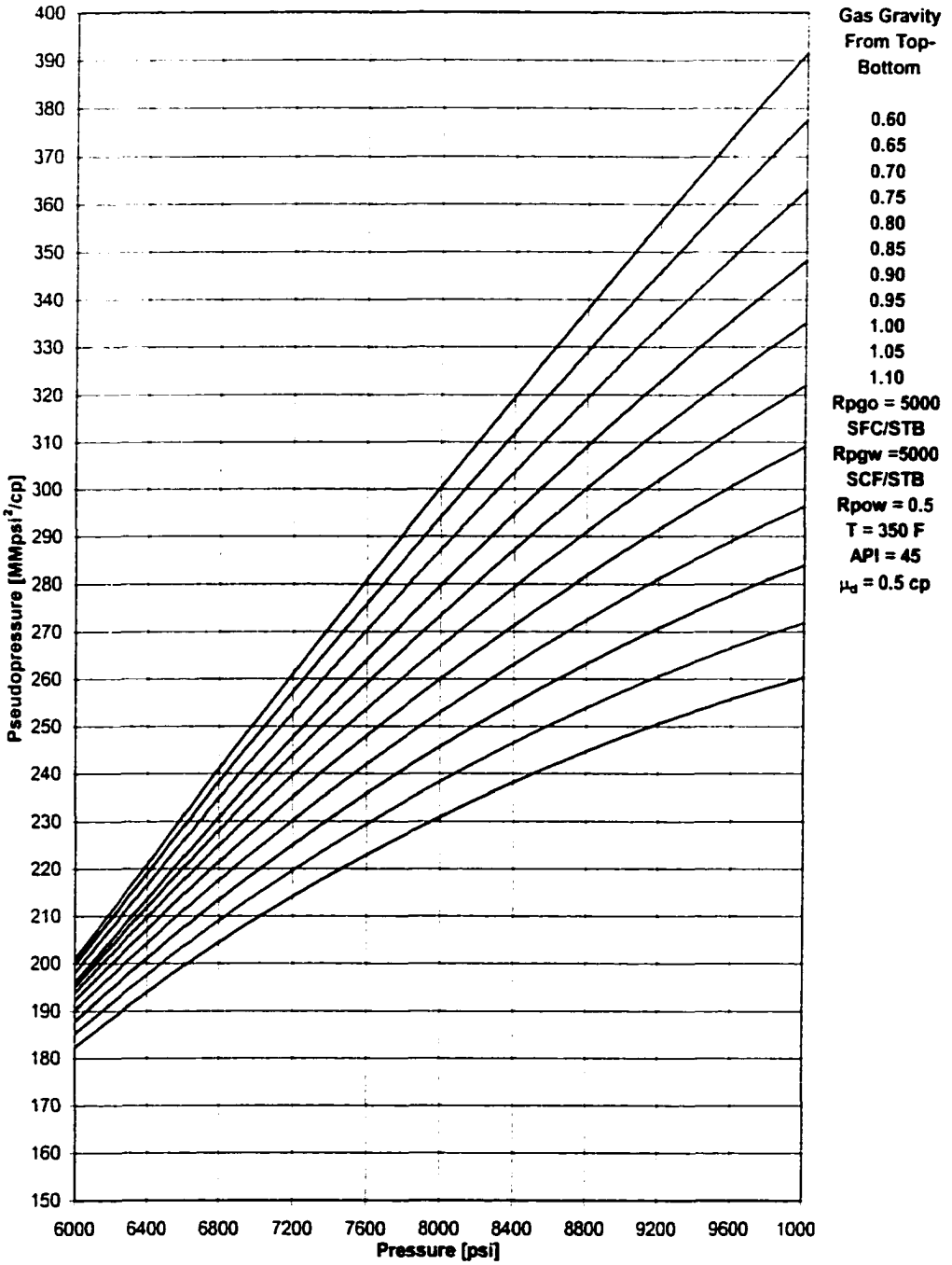

Fig.B-14 Gas phase pseudopressure Region-1[Eq.4.79] [T = 350]

Effect of Rp

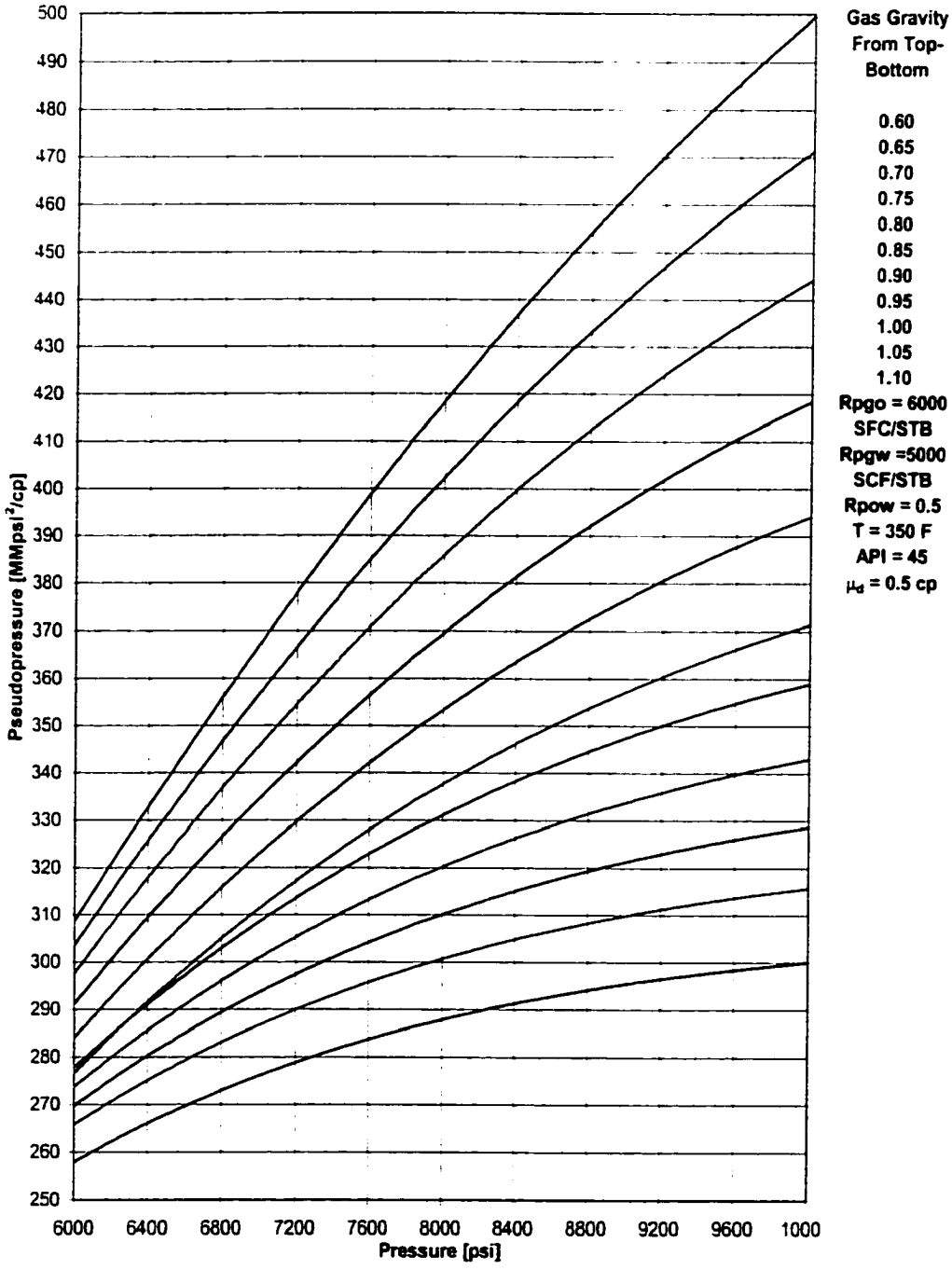

Fig.B-15 Gas phase pseudopressure Region-1[Eq.4.79] [Rp= 6,000]

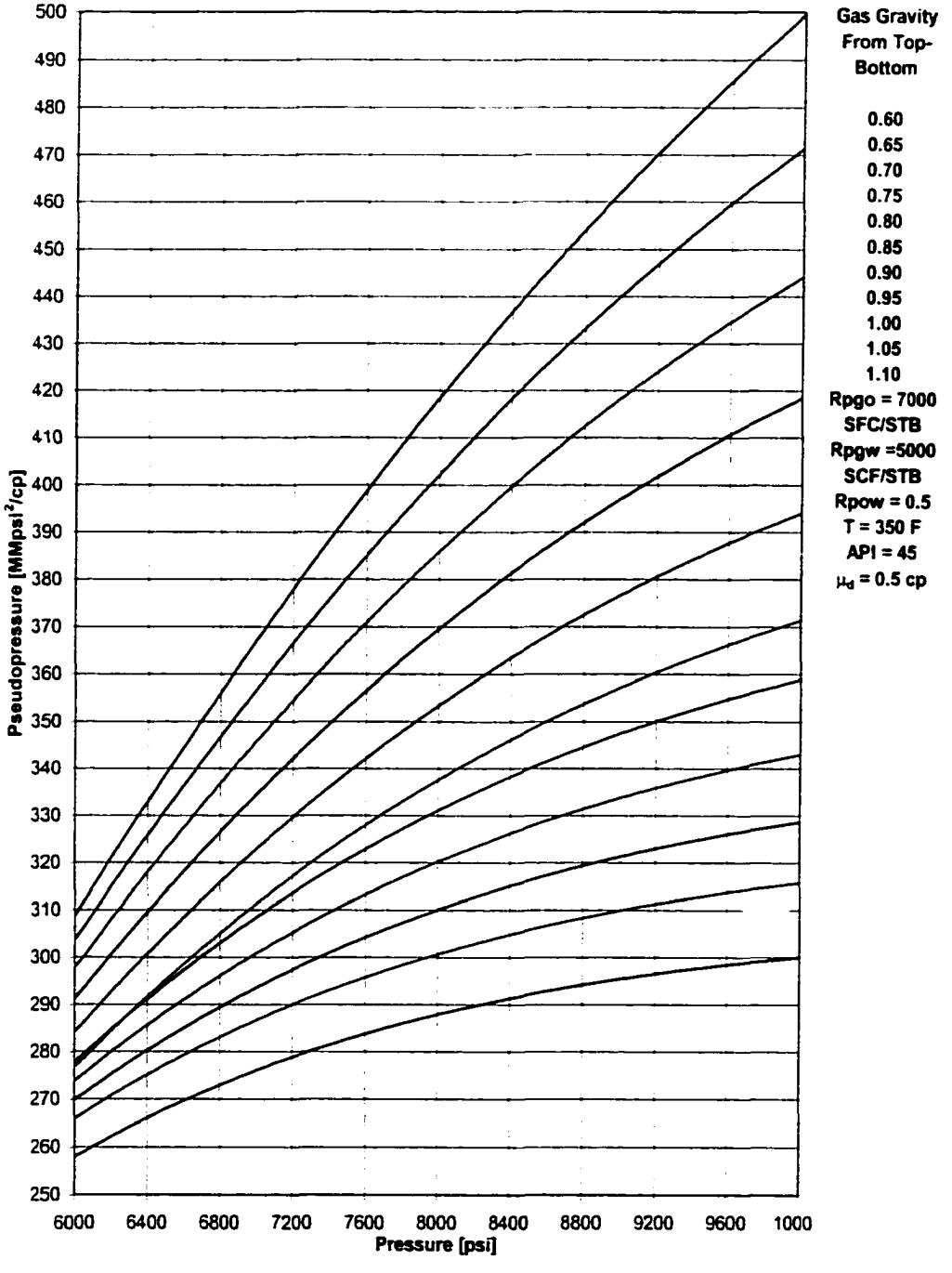

Fig.B-16 Gas phase pseudopressure Region-1[Eq.4.79] [Rp = 7,000]

Effect of Rpgw

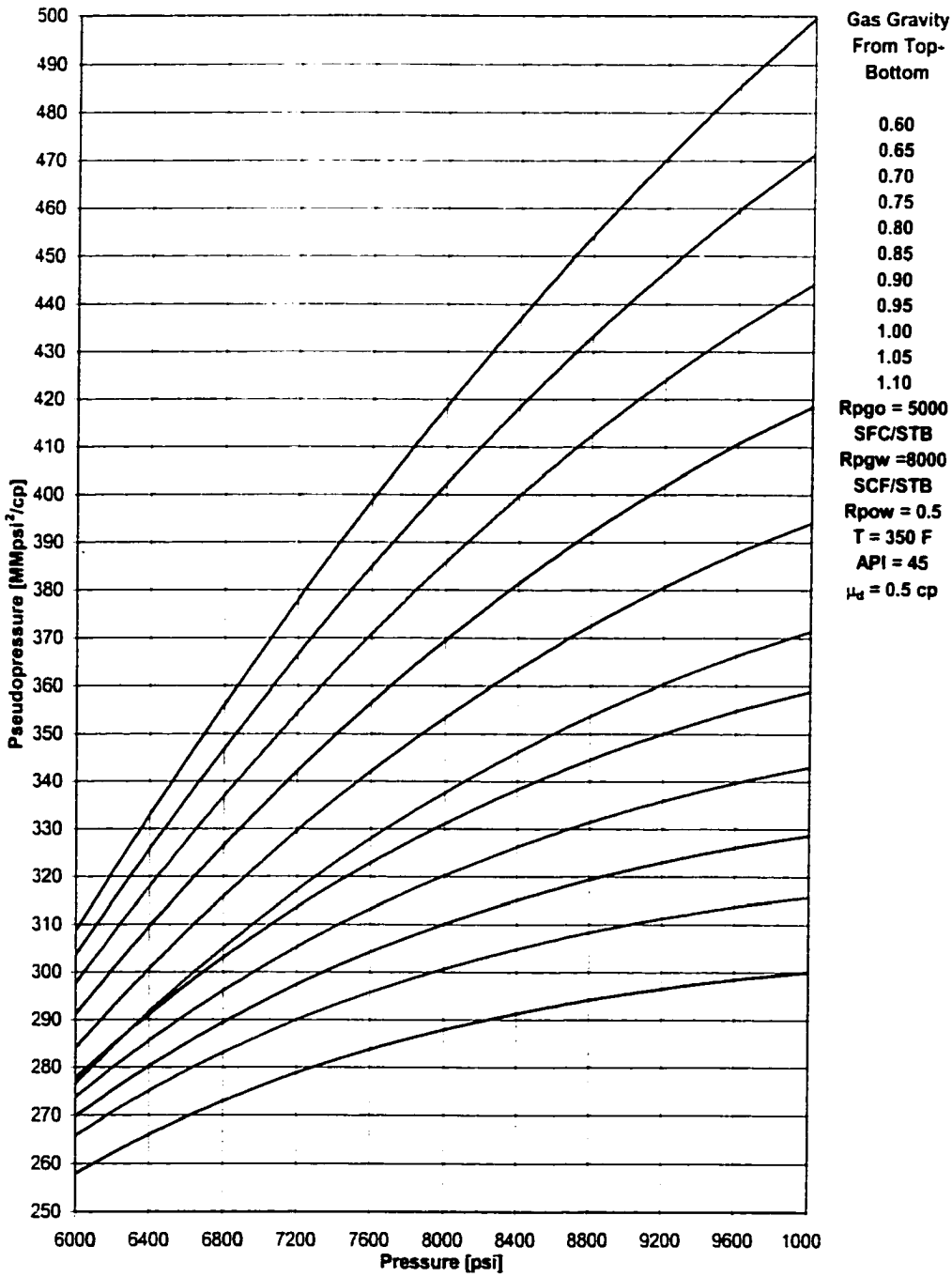

Fig.B-17 Gas phase pseudopressure Region-1[Eq.4.79] [Rpgw = 8,000]

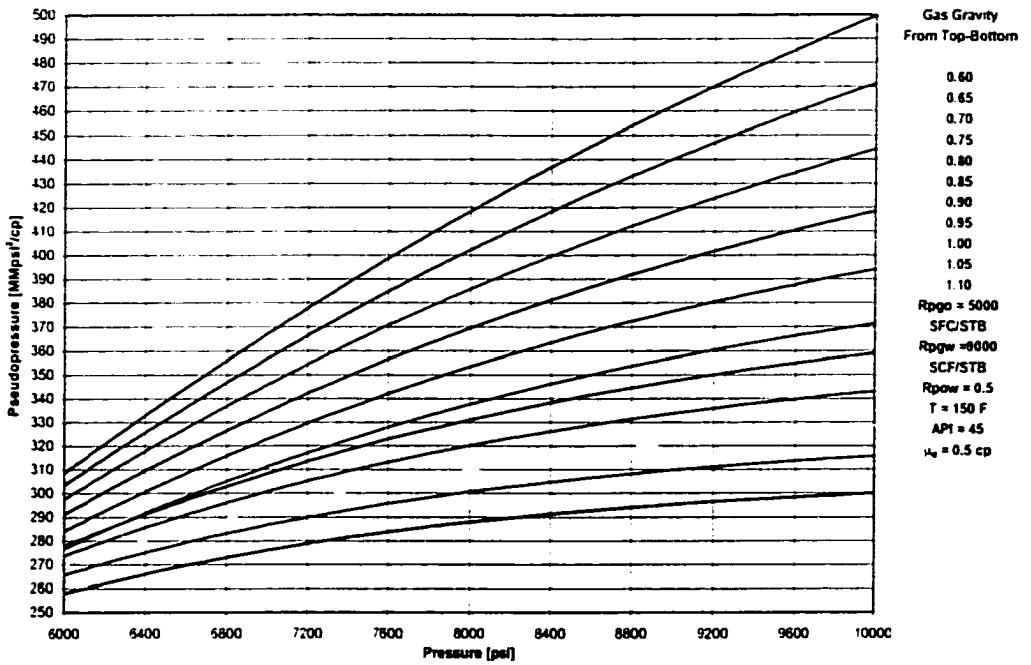

Fig.B-18 Gas phase pseudopressure Region-1[Eq.4.79] [Rpgw = 9,000]

Water Phase, effect of Rpgw

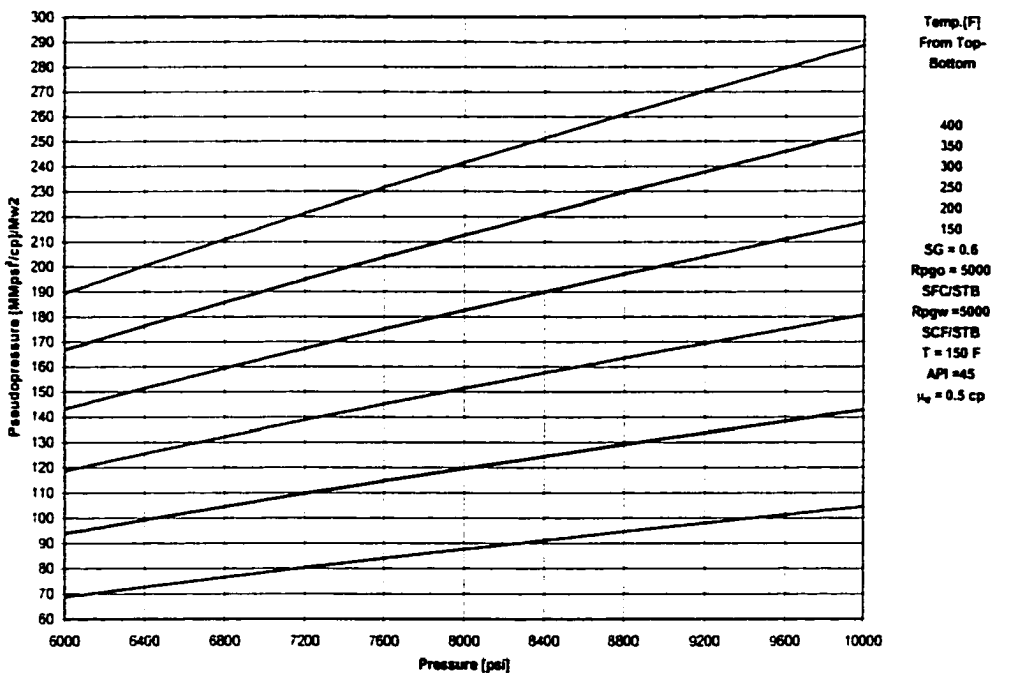

Fig.B-19 Water phase pseudopressure Region-1[Eq.4.79] [Rpgw = 5,000]

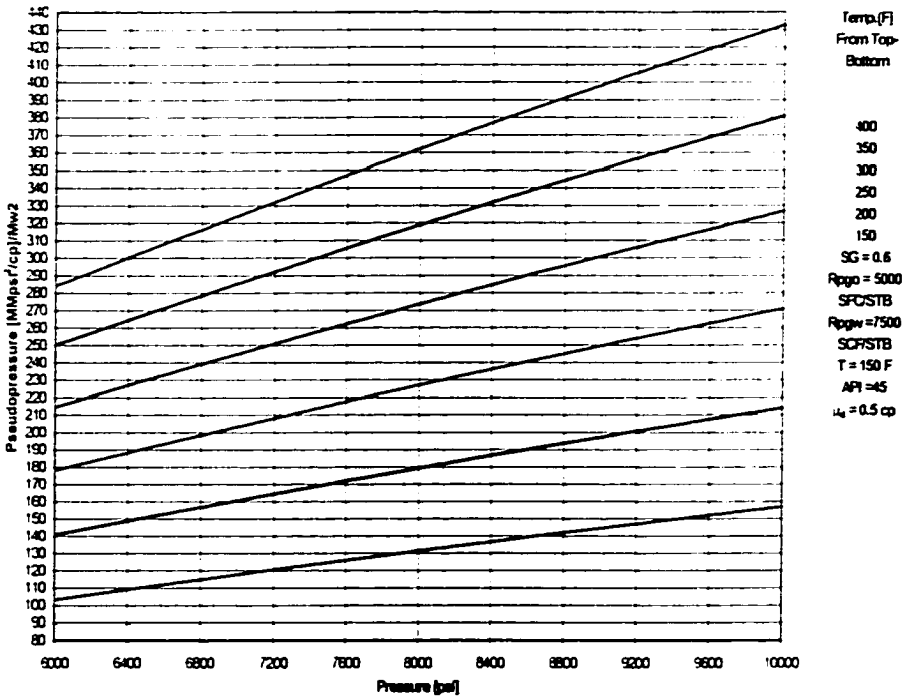

Fig.B-20 Gas phase pseudopressure Region-1[Rpgw = 7.500 Eq.4.79]

Appendix-C
Algorithm [Two Phase Region-1]

```
Sub mP()

Range("B2:IV5000").ClearContents

Dim IntPb As Integer
Dim SngTpr As Single
Dim SngPpr As Single
Dim IntT As Integer    'Temp R
Dim IntTf As Integer   'Temp F
Dim SngSg As Single    'Gas SG
Dim IntApi As Integer  'Oil API Gravity
Dim Sngn As Single     'Intermediate expn
Dim DblRso As Single
Dim iColumn As Integer, iRow As Integer

Dim SngBg As Single
Dim IntM As Integer
Dim SngTpc As Single
Dim SngPpc As Single
Dim IntRp As Long
Dim IntPd As Integer '-----Dew point Pressure---
Dim SngBgi  As Single
Dim SngSwc  As Single '-----Critical Water Saturation
Dim X As Integer

' Define gas Composition

Dim SngMolWt As Single
Dim DblmP1 As Double
Dim DblmP2 As Double
Dim DblmP3 As Double

Dim DblY1 As Double  ' Parameter to calculate LOV
Dim DblY2 As Double
Dim DblY3 As Double
Dim DblF As Double

Dim DblW1 As Double
Dim DblW2 As Double
'*****************Viscosity Parameter
 Dim SngX1 As Single
Dim SngX2 As Single
Dim SngX3 As Single
Dim SngX4 As Single
Dim SngVg As Single

'********Pressure
```

```
Dim DblPi As Double
Dim check As Integer
Dim IntPc As Integer '   Pc = P*

'*****************mP Parameters********
Dim DblJ1 As Double
Dim DblJ2 As Double
Dim DblJ3 As Double
Dim DblJ4 As Double
Dim DblJ5 As Double
Dim DblJ6 As Double
Dim DblBx As Double

Dim DblP As Double
Dim iRow1 As Integer

Dim IntPo As Integer
Dim DblD1 As Double
Dim DblD2 As Double
Dim IntStep As Integer
Dim iColumn2 As Integer
Dim IntX As Integer
Dim DblYi As Double

' Define Production Fluid Ratios

Dim DblRsgwf As Double  ' Solution Gas in fresh Water Ratio
Dim DblRsgw As Double   ' Solution Gas Water Ratio
Dim DblRpgw As Double   ' Producing Gas Water Ratio
Dim DblRpow As Double   ' Producing Oil Water Ratio
Dim DblRp As Double     ' Producing Gas Oil Ratio
Dim DblRpwo As Double
Dim DblRo As Double
Dim DblVd As Double
Dim DblVo1 As Double
Dim DblVo2 As Double
Dim DblVo As Double
Dim DblSgo As Double
Dim DblBo As Double

' Define Water Properties
Dim SngVw As Double ' Water Viscosity
Dim SngBw As Double
Dim DblKw As Double ' Water Effective Perm

Dim Dblmo As Double
Dim Dblmg As Double
Dim Dblmw As Double ' Water Effective Perm

Dim DblIo As Double
```

```
Dim DblIg As Double
Dim DblIw As Double

Dim DblS As Double ' Water Salinity

' Constants for Viscosity
Dim DblAw As Double
Dim DblB As Double
Dim DblTw As Double
Dim DblVw1 As Double  ' Water Viscosity at Atmospheric pressure

' Constants for Solution Gas fresh water ratio
Dim DblA5 As Double
Dim DblB5 As Double
Dim DblC5 As Double ' Constant in Solution Gas Water Ratio
'-------------------------------------------------------------------------
X = 2

iColumn = 13
Cells(4, 2) = "mP [0.6]"
Cells(5, 2) = "MMpsia^2/cp"
Cells(4, 3) = "mP [0.65]"
Cells(4, 4) = "mP [0.70]"
Cells(4, 5) = "mP [0.75]"
Cells(4, 6) = "mP [0.80]"
Cells(4, 7) = "mP [0.85]"
Cells(4, 8) = "mP [0.90]"

IntTf = InputBox("Enter The Reservoir Temperature[F]", "Condensates", 150) 'Cells(8, 3)
'Temp F
IntPb = InputBox("Enter The Bubble Point Pressure[psi]", "Condensates", 1000)
IntApi = InputBox("Enter The API of Condensate", "Condensates", 35)

DblRp = InputBox("Enter The Producing Gas Oil Ratio [SCF/STB]", "Condensates", 5000)

DblVd = InputBox("Enter The Dead Oil Viscosity [cp]", "Condensates", 0.5)
DblS = InputBox("Enter The Salinity [Weight %]", "Condensates", 0.15)
DblSgo = 141.5 / (131.5 + IntApi)

'*******************************
'Print Table'
'*******************************
Cells(4, 9) = "API"
Cells(4, 10) = IntApi
Cells(5, 9) = "Pb"
Cells(5, 10) = IntPb
Cells(6, 9) = "T[F]"
Cells(6, 10) = IntTf
Cells(7, 9) = "Rp[SCF/STB]"
Cells(7, 10) = DblRp
```

```
'------------------------------
For SngSg = 0.6 To 0.901 Step 0.05
If SngSg > 0.9 Then
SngSg = 0.9
End If

Cells(12, iColumn + 1) = SngSg

'---------- Pseudo Critical Temp. and Pressure for Ok Gases

SngTpc = 298.6 * SngSg + 181.89 ' Ok Gases
Cells(8, iColumn + 1).Value = SngTpc
SngPpc = -514.01 * (SngSg ^ 4) + 1788.2 * (SngSg ^ 3) - 2337.5 * (SngSg ^ 2) + 1305.3 *
(SngSg) + 415.07
Cells(9, iColumn + 1).Value = SngPpc

'**************Labels****************
Cells(8, iColumn) = "Tpc [R]= "
Cells(9, iColumn) = "Ppc [psi]= "
Cells(12, iColumn) = "S.G = "
Cells(14, iColumn) = "Tpr = "
Cells(16, iColumn) = "Res Temp [T]= "
Cells(16, iColumn + 1).Value = IntTf
IntT = IntTf + 460 ' Cells(8, 2)  'Temp R
Cells(17, iColumn) = "Res Temp [R]]= "
Cells(17, iColumn + 1).Value = IntT
Cells(19, iColumn) = "Mol.Wt.[Gas]= "

SngMolWt = SngSg * 28.9125
Cells(19, iColumn + 1) = SngMolWt

   Cells(4, iColumn + 3).Value = "Ppr"
   Cells(4, iColumn + 4).Value = "Z"
   Cells(4, iColumn + 5).Value = "Bg[bbl/scf]"
   Cells(4, iColumn + 6).Value = "Den[gm/cc]"
   Cells(4, iColumn + 7).Value = "Vis [cp]"
   Cells(4, iColumn + 8).Value = "P[psia]"
   Cells(4, iColumn + 9) = "mP"

'********************Reduced Temp Calculation*****************

SngTpr = IntT / SngTpc ' Cells(20, 2)
Cells(14, iColumn + 1).Value = SngTpr

'******************** Z, Viscosity, Bg**************************

DblAw = 109.574 - 8.40564 * DblS + 0.313314 * DblS ^ 2 + 0.00872213 * DblS ^ 3
DblB = -1.12166 + 0.0263951 * DblS - 0.000679461 * DblS ^ 2 - 5.47119 * E - 5 * DblS ^ 3 +
0.00000155586 * DblS ^ 4
DblVw1 = DblAw * IntTf ^ (DblB)
```

```
DblA5 = 8.15839 - 0.0612265 * IntTf + 0.000191663 * IntTf ^ 2 - 0.00000021654 * IntTf ^ 3
DblB5 = 0.0101021 - 0.0000744241 * IntTf + 0.000000305553 * IntTf ^ 2
DblC5 = (9.02505 - 0.130237 * IntTf + 0.000853425 * IntTf ^ 2 - 0.00000234122 * IntTf ^ 3 +
0.0000000237049 * IntTf ^ 4) * (-10 ^ -7)
DblD5 = (-0.0840655 * DblS * IntTf ^ (-0.285854))

For iRow1 = 7 To 5000 Step 1

IntPo = 0
DblmP2 = 0
DblD2 = 0

'----------Reservoir Pressure Input-----------------------------------------

DblP = Cells(iRow1, 1)   'Pressure  Values in column 4
If Cells(iRow1, 1) = Empty Then
GoTo 4500
End If

IntStep = 10

iRow = 6
check = 0
For DblPi = 150 To DblP * 2 Step IntStep
If DblPi > DblP Then
DblPi = DblP
check = 1
End If

'---------------------Rso-----------------------

DblRso = (DblPi ^ 1.1535) * (SngSg / 37.966) * (10 ^ (9.441 * IntApi / IntT))
DblRo = (-11.66 + 0.000000004706 * DblRso ^ 3 + 1.623 * (DblRso ^ 0.5) - (42.3815 / DblRso
^ 0.5)) / 1000000#
If DblRo < 0 Then
DblR0 = 0
End If
'---------------Water Formation Volume Factor---------------------------

SngBw = (1 + (-0.010001 + 0.000133391 * IntTf + 0.000000550654 * (IntTf ^ 2))) * (1 + (-
0.00000000195301 * DblPi * IntTf - 1.72834E-13 * IntTf * DblPi ^ 2 - 0.000000358922 *
DblPi - 0.000000000225341 * (DblPi ^ 2)))

DblFo = DblRso * ((SngSg / DblSgo) ^ 0.5) + 1.25 * IntTf
DblBo = 0.972 + 0.000147 * DblFo ^ 1.175

'----------------Water Viscosity--------------------
SngVw = (0.9994 + 0.000040295 * DblPi + 0.0000000031062 * DblPi ^ 2) * DblVw1
DblRsgwf = DblA5 + DblB5 * DblPi + DblC5 * DblPi ^ 2
DblRsgw = DblRsgwf * (10 ^ DblD5)
```

```
'Oil Viscosity
DblVo2 = 10 ^ (-0.000396 * DblRso)
DblVo1 = (0.1615 + 0.7024 * 10 ^ (-0.000583 * DblRso)) * DblVd ^ (0.172 + 0.7881 *
DblVo2)
DblVo = -0.032124 + 0.9289 * DblVo1 - 0.02865 * DblVo1 ^ 2

'---------- Reduced Pressure Calculation----------

SngPpr = DblPi / SngPpc 'Cells(24, 2)

'--- Module-3 Gas Compressibility(Z) Estimation Using Gopal Equations----------

Select Case SngPpr
    Case 0.2 To 1.2
        Select Case SngTpr
        Case 1.05 To 1.2
          SngZ = SngPpr * (1.6643 * SngTpr - 2.2114) - 0.367 * SngTpr + 1.4385
        Case 1.2 To 1.4
          SngZ = SngPpr * (0.5222 * SngTpr - 0.8511) - 0.0364 * SngTpr + 1.049
        Case 1.4 To 2
          SngZ = SngPpr * (0.1391 * SngTpr - 0.2988) + 0.0007 * SngTpr + 0.9969
        Case 2 To 3
          SngZ = SngPpr * (0.0295 * SngTpr - 0.0825) + 0.0009 * SngTpr + 0.9967
        End Select
Case 1.2 To 2.8
        Select Case SngTpr
          Case 1.05 To 1.2
        SngZ = SngPpr * (-1.357 * SngTpr + 1.4942) + 4.6315 * SngTpr - 4.7009
          Case 1.2 To 1.4
        SngZ = SngPpr * (0.1717 * SngTpr - 0.3232) + 0.5869 * SngTpr + 0.1229
           Case 1.4 To 2
        SngZ = SngPpr * (0.0984 * SngTpr - 0.2053) + 0.0621 * SngTpr + 0.858
          Case 2 To 3
        SngZ = SngPpr * (0.0211 * SngTpr - 0.0527) + 0.0127 * SngTpr + 0.9549
        End Select
Case 2.8 To 5.4
        Select Case SngTpr
          Case 1.05 To 1.2
        SngZ = SngPpr * (-0.3227 * SngTpr + 0.4752) + 1.8223 * SngTpr - 1.9036
          Case 1.2 To 1.4
        SngZ = SngPpr * (-0.2521 * SngTpr + 0.3872) + 1.6087 * SngTpr - 1.6635
          Case 1.4 To 2
        SngZ = SngPpr * (-0.0284 * SngTpr + 0.0625) + 0.4714 * SngTpr - 0.0011
          Case 2 To 3
        SngZ = SngPpr * (0.0041 * SngTpr + 0.0039) + 0.0607 * SngTpr + 0.7927
        End Select
Case 5.4 To 15
       Select Case SngTpr

         Case 1.05 To 3
```

```
            SngZ = SngPpr * ((0.711 + 3.66 * SngTpr) ^ -1.4667) - (1.637 / (0.319 * SngTpr +
0.522)) + 2.071

        End Select

'------------ Katz Z Correlation for P = 10,000 to 20,0000----------
Case 15 To 30
        Select Case SngTpr

          Case 1.35 To 1.5
             SngZ = SngTpr * ((0.053929 * SngPpr) + 0.282857)
          Case 1.500001 To 1.7
             SngZ = SngTpr * ((0.039125 * SngPpr) + 0.327563)
          Case 1.700001 To 1.9
             SngZ = SngTpr * ((0.031 * SngPpr) + 0.322889)
           Case 1.900001 To 2.1
             SngZ = SngTpr * ((0.02465 * SngPpr) + 0.32415)

           Case 2.100001 To 2.3
             SngZ = SngTpr * ((0.020045 * SngPpr) + 0.320591)

           Case 2.300001 To 2.5
             SngZ = SngTpr * ((0.18675 * SngPpr) + 0.30875)
           Case 2.500001 To 2.7
             SngZ = SngTpr * ((0.013962 * SngPpr) + 0.304577)
           Case 2.700001 To 3
              SngZ = SngTpr * ((0.011679 * SngPpr) + 0.298643)
        End Select
'------------
Case Else
SngZ = 1000000
End Select
'------------ Gas FVF----------
SngBg = 0.00504 * IntT * SngZ / DblPi  ' bbl/SCF

'--------- Gas Density = PM/RT    T[R], P{psia], M = Mixture Mol.Wt

Dim SngDen As Single
SngDen = (1.601846 * 10 ^ -2) * SngMolWt * DblPi / (10.732 * IntT) ' Cells(17, 2)

'---------- Estimation of Gas Viscosity by Lee-------

SngX1 = (9.4 + 0.02 * SngMolWt) * (IntT ^ 1.5) / (209 + 18 * SngMolWt + IntT)
SngX2 = 3.5 + 0.01 * SngMolWt + (986 / IntT)
SngX3 = 2.4 - 0.2 * SngX2
SngX4 = (SngDen ^ SngX3) * SngX2
SngVg = SngX1 * Exp(SngX4) * 10 ^ -4

DblKo = Dblmo * DblPi + DblIo
DblKg = Dblmg * DblPi + DblIg
DblKw = Dblmw * DblPi + DblIw
```

```
'*****************************************************

DblJ1 = (SngBg * SngVg)
DblJ2 = (DblBo * DblVo)
DblJ3 = (SngBw * SngVw)

'--------------------
DblGh = blRso * DblRo
If DblGh > 0.99 Then
DblGh = 0
Else
DblGh = DblGh
End If
DblJ4 = (1 - DblGh) * DblRp
DblJ5 = (DblRp - DblRso) * DblJ1

DblD1 = DblJ4 / DblJ5

'**DblD2 = Dbl1 at zero pressure = 0 initially

DblmP1 = ((((DblD1 + DblD2) * (DblPi - IntPo)) / 2) + DblmP2)

DblD2 = DblD1
DblmP2 = DblmP1

'*************************************
If check = 1 Then DblPi = DblP
IntPo = DblPi
If DblPi = DblP Then
GoTo 4000
End If

Next DblPi

4000

'********** iColumn = 1**********

' Print P, Ppr, Z, Bg, Den, Vis, Rso, Bo, LOV

'************************************************************

   Cells(iRow1, iColumn + 3).Value = SngPpr  ' = Column = 4
   Cells(iRow1, iColumn + 4).Value = SngZ  ' = Column = 5
   Cells(iRow1, iColumn + 5).Value = SngBg  ' = Column = 6
   Cells(iRow1, iColumn + 6).Value = SngDen ' = Column = 7
   Cells(iRow1, iColumn + 7).Value = SngVg  ' = Column = 8
   Cells(iRow1, iColumn + 8).Value = DblPi 'Print Pressure Twice
   Cells(iRow1, iColumn + 9) = DblmP2 / 1000000#
   Cells(iRow1, X) = DblmP2 / 1000000#
```

```
Next iRow1
4500
        X = X + 1
        iColumn = iColumn + 11
        Next SngSg
5000
Application.StatusBar = "Simulation is Complete, Resume Your Work"
MsgBoxEnd = MsgBox(" Simulation Was Successful", vbOKOnly, " End Of Simulation")
Application.StatusBar = "       "
End Sub
```

	mP [0.6]	mP [0.65]	mP [0.70]	mP [0.75]	mP [0.80]	mP [0.85]	mP [0.90]	API	35
Psia	MMpsia^2/cp							Pb	1000
								T[F]	150
150	0.2858097	0.292011	0.298148	0.30422	0.310229	0.31617	0.323973	Rp[SCF/STB]	5000
350	1.5654752	1.600823	1.635692	1.6700919	1.7040246	1.73749	1.790191		
550	3.8947749	3.987163	4.077939	4.1671257	4.2547223	4.34072	4.508062		
750	7.2929102	7.4741	7.65147	7.8250536	7.994827	8.16074	8.549011		
950	11.786172	12.09394	12.39582	12.688529	12.97353	13.2532	14.05301		
1150	17.349044	17.81851	18.27634	18.719241	19.148584	19.5667	20.95237		
1350	23.966235	24.6314	25.27707	25.89989	26.501095	27.0828	29.24122		
1550	31.630062	32.52547	33.39114	34.223609	35.023905	35.7939	38.94184		
1750	40.331255	41.49195	42.61006	43.681961	44.708391	45.6909	50.07875		
1950	50.109982	51.58531	53.01776	54.39297	55.688328	56.9469	62.78238		
2150	60.91835	62.7531	64.52213	66.210352	67.794676	69.3178	76.45353		
2350	72.514577	74.69579	76.78336	78.761696	80.607457	82.3633	90.66342		
2550	84.850482	87.358	89.73888	91.977267	94.049904	95.9997	105.3081		
2750	97.878613	100.6856	103.3279	105.78985	108.04859	110.148	120.2926		
2950	111.5524	114.6259	117.4918	120.13493	122.53356	124.733	135.5305		
3150	125.82629	129.1275	132.1737	134.95078	137.43848	139.683	150.9434		
3350	140.65583	144.141	147.3194	150.17858	152.70061	154.935	166.4606		
3550	155.99779	159.6184	162.8765	165.76244	168.26089	170.424	182.0187		
3750	172.02638	175.6859	178.9068	181.68259	184.00284	185.916	197.2014		
3950	188.54372	192.0858	195.1199	197.64585	199.65998	201.217	212.1034		
4150	205.20484	208.5579	211.3331	213.53775	215.17597	216.31	226.7338		
4350	221.97054	225.0634	227.5085	229.32226	230.51757	231.166	241.0669		
4550	238.80473	241.5666	243.6121	244.96766	245.65612	245.758	255.0825		
4750	255.67421	258.0354	259.6135	260.44615	260.56713	260.067	268.7642		
4950	272.54855	274.4407	275.4857	275.73352	275.22983	274.076	282.0998		
5150	289.39986	290.7561	291.2047	290.80884	289.62688	287.772	295.0804		
5350	306.20267	306.9581	306.7494	305.65417	303.74399	301.143	307.7		
5550	322.93378	323.0255	322.1014	320.2543	317.56962	314.184	319.9553		
5750	339.57209	338.9395	337.2447	334.59651	331.09474	326.888	331.8453		
5950	356.0985	354.6833	352.1654	348.67035	344.31255	339.253	343.3709		
6150	372.49575	370.2422	366.8519	362.46742	357.21828	351.278	354.535		
6350	388.74833	385.6033	381.2941	375.98121	369.80894	362.963	365.3418		
6550	404.84236	400.7553	395.4841	389.20687	382.0832	374.311	375.7968		
6750	420.76548	415.6886	409.4151	402.14112	394.04114	385.325	385.907		
6950	436.50673	430.3951	423.0821	414.78208	405.68413	396.009	395.6799		
7150	452.05652	444.8679	436.4813	427.1291	417.01473	406.37	405.124		
7350	467.40646	459.1015	449.6101	439.18267	428.03647	416.413	414.2488		
7550	482.54933	473.0913	462.467	450.94432	438.75383	426.146	423.0639		
7750	497.47901	486.8341	475.0516	462.4165	449.17204	435.577	431.5798		
7950	512.19035	500.3275	487.3643	473.60246	459.2971	444.715	439.8072		
8150	526.67915	513.5699	499.4063	484.50621	469.13558	453.568	447.7573		
8350	540.94209	526.5608	511.1799	495.13243	478.69463	462.146	455.4416		
8550	554.97666	539.3002	522.6876	505.48638	487.98188	470.458	462.8718		
8750	568.78109	551.789	533.9329	515.57388	497.00539	478.515	470.0599		

Algorithm [Two Phase Region-2 and Region-3]

```
Sub mP()

'----------Clear the Contents---------
Range("B2:IV5000").ClearContents

'*********************************************************************
'    Light Oil Properties are estimated using Modified AGIP Co-relations
'*********************************************************************
Dim IntPb As Integer
Dim SngTpr As Single
Dim SngPpr As Single
Dim IntT As Integer    'Temp R
Dim IntTf As Integer   'Temp F
Dim SngSg As Single    'Gas SG
Dim IntApi As Integer  'Oil API Gravity
Dim Sngn As Single     'Immediate expn
Dim DblRso As Single
Dim iColumn As Integer, iRow As Integer

Dim SngBg As Single
Dim IntM As Integer
Dim SngTpc As Single
Dim SngPpc As Single
Dim IntRp As Long
Dim IntPd As Integer  '-----Dew point Pressure---
Dim SngBgi As Single
Dim SngSwc As Single  '-----Critical Water Saturation
Dim X As Integer

' Define gas Composition

Dim SngMolWt As Single
Dim DblmP1 As Double
Dim DblmP2 As Double
Dim DblmP3 As Double

Dim DblY1 As Double  ' Parameter to calculate LOV
Dim DblY2 As Double
Dim DblY3 As Double
Dim DblF As Double

Dim DblW1 As Double
Dim DblW2 As Double
'*****************Viscosity Parameter
 Dim SngX1 As Single
Dim SngX2 As Single
Dim SngX3 As Single
Dim SngX4 As Single
Dim SngVg As Single
```

```
'********Pressure
Dim DblP1 As Double
Dim check As Integer
Dim IntPc As Integer '  Pc = P*
'****************mP Parameters********
Dim DblJ1 As Double
Dim DblJ2 As Double
Dim DblJ3 As Double
Dim DblJ4 As Double
Dim DblJ5 As Double
Dim DblJ6 As Double

Dim DblP As Double
Dim iRow1 As Integer

Dim IntPo As Integer
Dim DblD1 As Double
Dim DblD2 As Double
Dim IntStep As Integer
Dim iColumn2 As Integer
Dim IntX As Integer
Dim DblYi As Double

' Define Production Fluid Ratios

Dim DblRsgwf As Double  ' Solution Gas in fresh Water Ratio
Dim DblRsgw As Double   ' Solution Gas Water Ratio
Dim DblRpgw As Double   ' Producing Gas Water Ratio
Dim DblRpow As Double   ' Producing Oil Water Ratio
Dim DblRp As Double     ' Producing Gas Oil Ratio
Dim DblRpwo As Double   ' Producing water Oil Ratio
Dim DblRo As Double
Dim DblVd As Double
Dim DblVo1 As Double
Dim DblVo2 As Double
Dim DblVo As Double
Dim DblSgo As Double
Dim DblBo As Double

' Define Water Properties
Dim SngVw As Double ' Water Viscosity
Dim SngBw As Double
Dim DblKw As Double ' Water Effective Perm

Dim Dblmo As Double
Dim Dblmg As Double
Dim Dblmw As Double ' Water Effective Perm

Dim DblIo As Double
Dim DblIg As Double
```

```
Dim DblIw As Double

Dim DblS As Double ' Water Salinity

' Constants for Viscosity
Dim DblAw As Double
Dim DblB As Double
Dim DblTw As Double
Dim DblVw1 As Double  ' Water Viscosity at Atmospheric pressure

' Constants for Solution Gas fresh water ratio
Dim DblA5 As Double
Dim DblB5 As Double
Dim DblC5 As Double ' Constant in Solution Gas Water Ratio

'Dim DblBo As Double
'Dim DblVo As Double
'-------------------------------------------------------------------------
X = 2
iColumn = 13
Cells(4, 2) = "mP [0.6]"
Cells(4, 3) = "mP [0.65]"
Cells(4, 4) = "mP [0.70]"
Cells(4, 5) = "mP [0.75]"
Cells(4, 6) = "mP [0.80]"
Cells(4, 7) = "mP [0.85]"
Cells(4, 8) = "mP [0.90]"
Cells(4, 9) = "mP [0.95]"
Cells(4, 10) = "mP [1.00]"
Cells(4, 11) = "mP [1.05]"
Cells(4, 12) = "mP [1.10]"

IntTf = InputBox("Enter The Reservoir Temperature[F]", "Condensates", 150) 'Cells(8, 3)
'Temp F
IntPb = InputBox("Enter The Bubble Point Pressure[psi]", "Condensates", 1000)
IntApi = InputBox("Enter The API of Condensate", "Condensates", 45)

DblRp = InputBox("Enter The Producing Gas Oil Ratio [SCF/STB]", "Condensates", 10000)
DblRpgw = InputBox("Enter The Producing Gas Water Ratio [SCF/STB]", "Condensates",
5000)

DblRpow = DblRpgw / DblRp
DblRpwo = 1 / DblRpow

DblVd = InputBox("Enter The Dead Oil Viscosity [cp]", "Condensates", 0.5)
DblS = InputBox("Enter The Salinity [Weight %]", "Condensates", 0.15)

DblSgo = 141.5 / (131.5 + IntApi)

'**************************
```

```
For SngSg = 0.6 To 1.101 Step 0.05
If SngSg > 1.1 Then
SngSg = 1.1
End If

Cells(12, iColumn + 1) = SngSg

'---------- Pseudo Critical Temp. and Pressure for Ok Gases

SngTpc = 298.6 * SngSg + 181.89 ' Ok Gases
Cells(8, iColumn + 1).Value = SngTpc
SngPpc = -514.01 * (SngSg ^ 4) + 1788.2 * (SngSg ^ 3) - 2337.5 * (SngSg ^ 2) + 1305.3 *
(SngSg) + 415.07
Cells(9, iColumn + 1).Value = SngPpc

'**************Labels*****************

Cells(8, iColumn) = "Tpc [R]= ".
Cells(9, iColumn) = "Ppc [psi]= "
Cells(12, iColumn) = "S.G = "

Cells(14, iColumn) = "Tpr = "

Cells(16, iColumn) = "Res Temp [T]= "
Cells(16, iColumn + 1).Value = IntTf

IntT = IntTf + 460
Cells(17, iColumn) = "Res Temp [R]]= "
Cells(17, iColumn + 1).Value = IntT

Cells(19, iColumn) = "Mol.Wt.[Gas]= "

SngMolWt = SngSg * 28.9125
Cells(19, iColumn + 1) = SngMolWt

   Cells(4, iColumn + 3).Value = "Ppr"
   Cells(4, iColumn + 4).Value = "Z"
   Cells(4, iColumn + 5).Value = "Bg[bbl/scf]"
   Cells(4, iColumn + 6).Value = "Den[gm/cc]"
   Cells(4, iColumn + 7).Value = "Vis [cp]"
   Cells(4, iColumn + 8).Value = "P[psia]"
   Cells(4, iColumn + 9) = "mP"

' ----------Reduced Temp Calculation----------

SngTpr = IntT / SngTpc ' Cells(20, 2)
Cells(14, iColumn + 1).Value = SngTpr

'****************** Z, Viscosity, Bg**********************

DblAw = 109.574 - 8.40564 * DblS + 0.313314 * DblS ^ 2 + 0.00872213 * DblS ^ 3
```

```
DblB = -1.12166 + 0.0263951 * DblS - 0.000679461 * DblS ^ 2 - 5.47119 * e - 5 * DblS ^ 3 +
0.00000155586 * DblS ^ 4
DblVw1 = DblAw * IntTf ^ (DblB)

DblA5 = 8.15839 - 0.0612265 * IntTf + 0.000191663 * IntTf ^ 2 - 0.00000021654 * IntTf ^ 3
DblB5 = 0.0101021 - 0.0000744241 * IntTf + 0.000000305553 * IntTf ^ 2
DblC5 = (9.02505 - 0.130237 * IntTf + 0.000853425 * IntTf ^ 2 - 0.00000234122 * IntTf ^ 3 +
0.00000000237049 * IntTf ^ 4) * (-10 ^ -7)
DblD5 = (-0.0840655 * DblS * IntTf ^ (-0.285854))

For iRow1 = 7 To 5000 Step 1

IntPo = 0
DblmP2 = 0
DblD2 = 0

'---------Reservoir Pressure Input-----------------------------------------

DblP = Cells(iRow1, 1)  'Pressure  Values in column 4
If Cells(iRow1, 1) = Empty Then
GoTo 4500
End If

IntStep = 10

iRow = 6
check = 0
For DblPi = 150 To DblP * 2 Step IntStep
If DblPi > DblP Then
DblPi = DblP
check = 1
End If

'--------------------Rso-----------------------

DblRso = (DblPi ^ 1.1535) * (SngSg / 37.966) * (10 ^ (9.441 * IntApi / IntT))

DblRo = -11.66 + 0.000000004706 * DblRso ^ 3 + 1.623 * (DblRso ^ 0.5) - (42.3815 / DblRso
^ 0.5)

'---------------Water Formation Volume Factor----------------------------

SngBw = (1 + (-0.010001 + 0.000133391 * IntTf + 0.000000550654 * (IntTf ^ 2))) * (1 + (-
0.00000000195301 * DblPi * IntTf - 1.72834E-13 * IntTf * DblPi ^ 2 - 0.000000358922 *
DblPi - 0.000000000225341 * (DblPi ^ 2)))

DblFo = DblRso * ((SngSg / DblSgo) ^ 0.5) + 1.25 * IntTf
DblBo = 0.972 + 0.000147 * DblFo ^ 1.175
SngVw = (0.9994 + 0.000040295 * DblPi + 0.0000000031062 * DblPi ^ 2) * DblVw1
DblRsgwf = DblA5 + DblB5 * DblPi + DblC5 * DblPi ^ 2
DblRsgw = DblRsgwf * (10 ^ DblD5)
```

```
'Oil Viscosity
DblVo2 = 10 ^ (-0.000396 * DblRso)
DblVo1 = (0.1615 - 0.7024 * 10 ^ (-0.000583 * DblRso)) * DblVd ^ (0.172 + 0.7881 *
DblVo2)
DblVo = -0.032124 + 0.9289 * DblVo1 - 0.02865 * DblVo1 ^ 2


'---------- Reduced Pressure Calculation----------

SngPpr = DblPi / SngPpc 'Cells(24, 2)

'--- Module-3 Gas Compressibility(Z) Estimation Using Gopal Equations----------

Select Case SngPpr
    Case 0.2 To 1.2
        Select Case SngTpr
        Case 1.05 To 1.2
          SngZ = SngPpr * (1.6643 * SngTpr - 2.2114) - 0.367 * SngTpr + 1.4385
        Case 1.2 To 1.4
          SngZ = SngPpr * (0.5222 * SngTpr - 0.8511) - 0.0364 * SngTpr + 1.049
        Case 1.4 To 2
          SngZ = SngPpr * (0.1391 * SngTpr - 0.2988) + 0.0007 * SngTpr + 0.9969
        Case 2 To 3
          SngZ = SngPpr * (0.0295 * SngTpr - 0.0825) + 0.0009 * SngTpr + 0.9967
        End Select
Case 1.2 To 2.8
        Select Case SngTpr
          Case 1.05 To 1.2
        SngZ = SngPpr * (-1.357 * SngTpr + 1.4942) + 4.6315 * SngTpr - 4.7009
          Case 1.2 To 1.4
        SngZ = SngPpr * (0.1717 * SngTpr - 0.3232) + 0.5869 * SngTpr + 0.1229
           Case 1.4 To 2
        SngZ = SngPpr * (0.0984 * SngTpr - 0.2053) + 0.0621 * SngTpr + 0.858
          Case 2 To 3
        SngZ = SngPpr * (0.0211 * SngTpr - 0.0527) + 0.0127 * SngTpr + 0.9549
        End Select
Case 2.8 To 5.4
        Select Case SngTpr
          Case 1.05 To 1.2
        SngZ = SngPpr * (-0.3227 * SngTpr + 0.4752) + 1.8223 * SngTpr - 1.9036
          Case 1.2 To 1.4
        SngZ = SngPpr * (-0.2521 * SngTpr + 0.3872) + 1.6087 * SngTpr - 1.6635
          Case 1.4 To 2
        SngZ = SngPpr * (-0.0284 * SngTpr + 0.0625) + 0.4714 * SngTpr - 0.0011
          Case 2 To 3
        SngZ = SngPpr * (0.0041 * SngTpr + 0.0039) + 0.0607 * SngTpr + 0.7927
        End Select
Case 5.4 To 15
       Select Case SngTpr
```

```
        Case 1.05 To 3
            SngZ = SngPpr * ((0.711 + 3.66 * SngTpr) ^ -1.4667) - (1.637 / (0.319 * SngTpr +
0.522)) + 2.071

        End Select

'------------ Katz Z Correlation for P = 10,000 to 20,0000----------
Case 15 To 30
        Select Case SngTpr

          Case 1.35 To 1.5
             SngZ = SngTpr * ((0.053929 * SngPpr) + 0.282857)
          Case 1.500001 To 1.7
             SngZ = SngTpr * ((0.039125 * SngPpr) + 0.327563)
          Case 1.700001 To 1.9
             SngZ = SngTpr * ((0.031 * SngPpr) + 0.322889)
           Case 1.900001 To 2.1
             SngZ = SngTpr * ((0.02465 * SngPpr) + 0.32415)

           Case 2.100001 To 2.3
             SngZ = SngTpr * ((0.020045 * SngPpr) + 0.320591)

           Case 2.300001 To 2.5
             SngZ = SngTpr * ((0.18675 * SngPpr) + 0.30875)
           Case 2.500001 To 2.7
             SngZ = SngTpr * ((0.013962 * SngPpr) + 0.304577)
           Case 2.700001 To 3
              SngZ = SngTpr * ((0.011679 * SngPpr) + 0.298643)
        End Select
'------------
Case Else
SngZ = 1000000
End Select
'------------ Estimation of Gas FVF----------
SngBg = 0.00504 * IntT * SngZ / DblPi  ' bbl/SCF

'--------- Gas Density = PM/RT   T[R], P{psia], M = Mixture Mol.Wt

Dim SngDen As Single
SngDen = (1.601846 * 10 ^ -2) * SngMolWt * DblPi / (10.732 * IntT) ' Cells(17, 2)

'---------- Estimation of Gas Viscosity by Lee--------

SngX1 = (9.4 + 0.02 * SngMolWt) * (IntT ^ 1.5) / (209 + 18 * SngMolWt + IntT)
SngX2 = 3.5 + 0.01 * SngMolWt + (986 / IntT)
SngX3 = 2.4 - 0.2 * SngX2
SngX4 = (SngDen ^ SngX3) * SngX2
SngVg = SngX1 * Exp(SngX4) * 10 ^ -4

DblKo = Dblmo * DblPi + DblIo
DblKg = Dblmg * DblPi + DblIg
```

```
DblKw = Dblmw * DblPi + DblIw

'*******************************************************
DblJ1 = (SngBg * SngVg)
DblJ2 = (DblBo * DblVo)
DblJ3 = (SngBw * SngVw)

DblD1 = 1 / (DblJ1)

'***DblD2 = Dbl1 at zero pressure = 0 initially

DblmP1 = (((DblD1 + DblD2) * (DblPi - IntPo)) / 2) + DblmP2

DblD2 = DblD1
DblmP2 = DblmP1

'**************************************
If check = 1 Then DblPi = DblP
IntPo = DblPi
If DblPi = DblP Then
GoTo 4000
End If
Next DblPi

4000
'*********** iColumn = 1 ************

' Print P, Ppr, Z, Bg, Den, Vis, Rso, Bo, LOV

'*****************************************************************
   Cells(iRow1, iColumn + 3).Value = SngPpr  ' = Column = 4
   Cells(iRow1, iColumn + 4).Value = SngZ   ' = Column = 5
   Cells(iRow1, iColumn + 5).Value = SngBg  ' = Column = 6
   Cells(iRow1, iColumn + 6).Value = SngDen ' = Column = 7
   Cells(iRow1, iColumn + 7).Value = SngVg  ' = Column = 8
   Cells(iRow1, iColumn + 8).Value = DblPi 'Print Pressure Twice
   Cells(iRow1, iColumn + 9) = DblmP2 / 1000000#
   Cells(iRow1, X) = DblmP2 / 1000000#

Next iRow1
4500
        X = X + 1
        iColumn = iColumn + 11
        Next SngSg
5000
Application.StatusBar = "Simulation is Complete, Resume Your Work"
MsgBoxEnd = MsgBox(" Simulation Was Successful", vbOKOnly, " End Of Simulation")
Application.StatusBar = "       "
End Sub
```

P	mP [0.6]	mP [0.65]	mP [0.70]	mP [0.75]	mP [0.80]	mP [0.85]	mP [0.90]	API	35
Psia	MMpsia^2/cp							Pb	1000
								T[F]	150
8000	416.57	400.5009	384.206105	367.93086	351.86299	336.19297	329.735845	Rp[SCF/STB]	5000
8200	425.8829	408.6157	391.225058	373.9609	357.01101	340.56241	333.424252		
8400	434.9057	416.4337	397.948717	379.70358	361.88465	344.6741	336.873931		
8600	443.6412	423.9603	404.384543	385.16829	366.49482	348.54004	340.097609		
8800	452.0924	431.2009	410.540275	390.36452	370.85235	352.17203	343.107627		
9000	460.2632	438.1617	416.423872	395.30181	374.96797	355.58156	345.915913		
9200	468.1574	444.8488	422.043452	399.98972	378.85227	358.77986	348.533964		
9400	475.7798	451.2688	427.407246	404.43776	382.51563	361.77782	350.972831		
9600	483.1351	457.4286	432.523551	408.65536	385.96823	364.58599	353.243116		
9800	490.2284	463.3349	437.400692	412.65185	389.22001	367.21456	355.354964		
10000	497.0651	468.9949	442.046983	416.43641	392.28064	369.67112	357.33778		
10200	503.4966	474.3407	446.499185	420.17858	395.00741	371.94112	359.230442		
10400	509.2885	479.3363	450.768551	423.79668	397.54888	374.062	360.988374		
10600	514.8601	484.1165	454.831519	427.22067	399.93579	376.04233	362.620083		
10800	520.2171	488.6879	458.695859	430.45899	402.17622	377.89026	364.133645		
11000	525.3651	493.0576	462.369235	433.51992	404.27797	379.61361	365.536723		
11200	530.31	497.2321	465.859186	436.41151	406.2485	381.21983	366.836571		
11400	535.0574	501.2183	469.173113	439.14159	408.095	382.71601	368.040049		
11600	539.6133	505.0228	472.318262	441.71778	409.82436	384.1089	369.153636		
11800	543.9834	508.6521	475.301717	444.14743	411.44313	385.40491	370.18344		
12000	548.1734	512.1127	478.130386	446.43769	412.95763	386.61011	371.135218		
12200	552.1891	515.4109	480.810998	448.59544	414.37383	387.73027	372.014382		
12400	556.036	518.553	483.350095	450.62731	415.69748	388.77085	372.826023		
12600	559.7198	521.5449	485.754028	452.53972	416.934	389.73699	373.574917		
12800	563.246	524.3928	488.028953	454.3388	418.08859	390.63356	374.265544		
13000	566.62	527.1023	490.180829	456.03046	419.16616	391.46517	374.902101		
13200	569.8471	529.6792	492.215416	457.62039	420.17138	392.23613	375.488518		
13400	572.9326	532.1289	494.138277	459.114	421.10869	392.95052	376.028466		
13600	575.8815	534.4568	495.954778	460.5165	421.98228	393.61218	376.525378		
13800	578.699	536.668	497.670086	461.83287	422.79612	394.22472	376.982457		
14000	581.3898	538.7677	499.289177	463.06786	423.55397	394.79152	377.402691		
14200	583.9589	540.7607	500.816831	464.22599	424.25937	395.31575	377.788864		
14400	586.4108	542.6518	502.257641	465.3116	424.91569	395.8004	378.143568		
14600	588.7501	544.4454	503.616016	466.3288	425.52608	396.24825	378.469215		
14800	590.9812	546.146	504.89618	467.28151	426.09352	396.66192	378.768046		
15000	593.1085	547.7578	506.10218	468.17347	426.62082	397.04386	379.042146		
15200	595.1361	549.2851	507.237891	469.00821	427.11063	397.39634	379.293447		
15400	597.0681	550.7316	508.307016	469.7891	427.56542	397.72151	379.523744		
15600	598.9085	552.1012	509.313097	470.51933	427.98755	398.02135	379.734699		
15800	600.6609	553.3976	510.259512	471.20193	428.3792	398.29772	379.927853		
16000	602.3292	554.6243	511.149488	471.83976	428.74243	398.55236	380.104632		
16200	603.9168	555.7846	511.9861	472.43555	429.07919	398.78689	380.266356		
16400	605.4273	556.8818	512.772279	472.99184	429.39129	399.0028	380.414246		
16600	606.864	557.919	513.510817	473.51109	429.68042	399.2015	380.549428		

Algorithm [Three Phase Region-1]

```
Sub mP()
Range("B2:IV5000").ClearContents

'*****************************************************************

'    Light Oil Properties are estimated using Modified AGIP Co-relations

'*****************************************************************

Dim IntPb As Integer
Dim SngTpr As Single
Dim SngPpr As Single
Dim IntT As Integer    'Temp R
Dim IntTf As Integer   'Temp F
Dim SngSg As Single    'Gas SG
Dim IntApi As Integer  'Oil API Gravity
Dim Sngn As Single     'Immediate expn
Dim DblRso As Single
Dim iColumn As Integer, iRow As Integer

Dim SngBg As Single
Dim IntM As Integer
Dim SngTpc As Single
Dim SngPpc As Single
Dim IntRp As Long
Dim IntPd As Integer '-----Dew point Pressure---
Dim SngBgi  As Single
Dim SngSwc  As Single '-----Critical Water Saturation
Dim X As Integer

' Define gas Composition

Dim SngMolWt As Single
Dim DblmP1 As Double
Dim DblmP2 As Double
Dim DblmP3 As Double

Dim DblY1 As Double  ' Parameter to calculate LOV
Dim DblY2 As Double
Dim DblY3 As Double
Dim DblF As Double

Dim DblW1 As Double
Dim DblW2 As Double
'*****************Viscosity Parameter
 Dim SngX1 As Single
Dim SngX2 As Single
Dim SngX3 As Single
Dim SngX4 As Single
```

```
Dim SngVg As Single

'********Pressure
Dim DblP1 As Double
Dim check As Integer
Dim IntPc As Integer '  Pc = P*
'****************mP Parameters********
Dim DblJ1 As Double
Dim DblJ2 As Double
Dim DblJ3 As Double
Dim DblJ4 As Double
Dim DblJ5 As Double
Dim DblJ6 As Double
Dim DblBx As Double

Dim DblP As Double
Dim iRow1 As Integer

Dim IntPo As Integer
Dim DblD1 As Double
Dim DblD2 As Double
Dim IntStep As Integer
Dim iColumn2 As Integer
Dim IntX As Integer
Dim DblYi As Double

' Define Production Fluid Ratios

Dim DblRsgwf As Double  ' Solution Gas in fresh Water Ratio
Dim DblRsgw As Double   ' Solution Gas Water Ratio
Dim DblRpgw As Double   ' Producing Gas Water Ratio
Dim DblRpow As Double   ' Producing Oil Water Ratio
Dim DblRp As Double     ' Producing Gas Oil Ratio
Dim DblRpwo As Double
Dim DblRo As Double
Dim DblVd As Double
Dim DblVo1 As Double
Dim DblVo2 As Double
Dim DblVo As Double
Dim DblSgo As Double
Dim DblBo As Double

' Define Water Properties
Dim SngVw As Double ' Water Viscosity
Dim SngBw As Double
Dim DblKw As Double ' Water Effective Perm

Dim Dblmo As Double
Dim Dblmg As Double
Dim Dblmw As Double ' Water Effective Perm
```

```
Dim DblIo As Double
Dim DblIg As Double
Dim DblIw As Double

Dim DblS As Double ' Water Salinity

' Constants for Viscosity
Dim DblAw As Double
Dim DblB As Double
Dim DblTw As Double
Dim DblVw1 As Double  ' Water Viscosity at Atmospheric pressure

' Constants for Solution Gas fresh water ratio
Dim DblA5 As Double
Dim DblB5 As Double
Dim DblC5 As Double ' Constant in Solution Gas Water Ratio

'-------------------------------------------------------------------------

X = 2

iColumn = 13
Cells(4, 2) = "mP [0.6]"
Cells(5, 2) = "MMpsia^2/cp"
Cells(4, 3) = "mP [0.65]"
Cells(4, 4) = "mP [0.70]"
Cells(4, 5) = "mP [0.75]"
Cells(4, 6) = "mP [0.80]"
Cells(4, 7) = "mP [0.85]"
Cells(4, 8) = "mP [0.90]"

IntTf = InputBox("Enter The Reservoir Temperature[F]", "Condensates", 150) 'Cells(8, 3)
'Temp F
IntPb = InputBox("Enter The Bubble Point Pressure[psi]", "Condensates", 1000)
IntApi = InputBox("Enter The API of Condensate", "Condensates", 45)

DblRp = InputBox("Enter The Producing Gas Oil Ratio [SCF/STB]", "Condensates", 8000)
DblRpgw = InputBox("Enter The Producing Gas Water Ratio [SCF/STB]", "Condensates",
8000)
DblVd = InputBox("Enter The Dead Oil Viscosity [cp]", "Condensates", 0.5)
DblS = InputBox("Enter The Salinity [Weight %]", "Condensates", 0.15)

DblRpow = DblRpgw / DblRp
DblRpwo = 1 / DblRpow
DblSgo = 141.5 / (131.5 + IntApi)

'*****************************
'Print Table'
'*****************************
Cells(4, 9) = "API"
Cells(4, 10) = IntApi
```

```
Cells(5, 9) = "Pb"
Cells(5, 10) = IntPb
Cells(6, 9) = "T[F]"
Cells(6, 10) = IntTf

Cells(7, 9) = "Rp[SCF/STB]"
Cells(7, 10) = DblRp
Cells(8, 9) = "Rpgw[SCF/STB]"
Cells(8, 10) = DblRpgw
Cells(9, 9) = "Rpow[SCF/STB]"
Cells(9, 10) = DblRpow

'**************************

For SngSg = 0.6 To 0.901 Step 0.05
If SngSg > 0.9 Then
SngSg = 0.9
End If

Cells(12, iColumn + 1) = SngSg

'---------- Pseudo Critical Temp. and Pressure for Ok Gases

SngTpc = 298.6 * SngSg + 181.89 ' Ok Gases
Cells(8, iColumn + 1).Value = SngTpc
SngPpc = -514.01 * (SngSg ^ 4) + 1788.2 * (SngSg ^ 3) - 2337.5 * (SngSg ^ 2) + 1305.3 *
(SngSg) + 415.07
Cells(9, iColumn + 1).Value = SngPpc

'**************Labels****************

Cells(8, iColumn) = "Tpc [R]= "
Cells(9, iColumn) = "Ppc [psi]= "
Cells(12, iColumn) = "S.G = "

Cells(14, iColumn) = "Tpr = "
Cells(16, iColumn) = "Res Temp [T]= "
Cells(16, iColumn + 1).Value = IntTf

IntT = IntTf + 460 ' Cells(8, 2)  'Temp R
Cells(17, iColumn) = "Res Temp [R]]= "
Cells(17, iColumn + 1).Value = IntT
Cells(19, iColumn) = "Mol.Wt.[Gas]= "

SngMolWt = SngSg * 28.9125
Cells(19, iColumn + 1) = SngMolWt

   Cells(4, iColumn + 3).Value = "Ppr"
   Cells(4, iColumn + 4).Value = "Z"
   Cells(4, iColumn + 5).Value = "Bg[bbl/scf]"
   Cells(4, iColumn + 6).Value = "Den[gm/cc]"
```

```
    Cells(4, iColumn + 7).Value = "Vis [cp]"
    Cells(4, iColumn + 8).Value = "P[psia]"
    'Cells(4, iColumn + 13).Value = IntPo
    Cells(4, iColumn + 9) = "mP"

' ------------Reduced Temp Calculation-------------------------------

SngTpr = IntT / SngTpc ' Cells(20, 2)
Cells(14, iColumn + 1).Value = SngTpr

'******************** Z, Viscosity, Bg**************************

DblAw = 109.574 - 8.40564 * DblS + 0.313314 * DblS ^ 2 + 0.00872213 * DblS ^ 3
DblB = -1.12166 + 0.0263951 * DblS - 0.000679461 * DblS ^ 2 - 5.47119 * E - 5 * DblS ^ 3 +
0.00000155586 * DblS ^ 4
DblVw1 = DblAw * IntTf ^ (DblB)

DblA5 = 8.15839 - 0.0612265 * IntTf + 0.000191663 * IntTf ^ 2 - 0.00000021654 * IntTf ^ 3
DblB5 = 0.0101021 - 0.0000744241 * IntTf + 0.000000305553 * IntTf ^ 2
DblC5 = (9.02505 - 0.130237 * IntTf + 0.000853425 * IntTf ^ 2 - 0.00000234122 * IntTf ^ 3 +
0.00000000237049 * IntTf ^ 4) * (-10 ^ -7)
DblD5 = (-0.0840655 * DblS * IntTf ^ (-0.285854))

For iRow1 = 7 To 5000 Step 1

IntPo = 0
DblmP2 = 0
DblD2 = 0

'----------Reservoir Pressure Input-----------------------------------------

DblP = Cells(iRow1, 1)   'Pressure  Values in column 4
If Cells(iRow1, 1) = Empty Then
GoTo 4500
End If

IntStep = 10

iRow = 6
check = 0
For DblPi = 150 To DblP * 2 Step IntStep
If DblPi > DblP Then
DblPi = DblP
check = 1
End If

'--------------------Rso----------------------
DblRso = (DblPi ^ 1.1535) * (SngSg / 37.966) * (10 ^ (9.441 * IntApi / IntT))
DblRo = (-11.66 + 0.000000004706 * DblRso ^ 3 + 1.623 * (DblRso ^ 0.5) - (42.3815 / DblRso
^ 0.5)) / 1000000#
If DblRo < 0 Then
```

```
DblR0 = 0
End If
'----------Water Formation Volume Factor----------

SngBw = (1 + (-0.010001 + 0.000133391 * IntTf + 0.000000550654 * (IntTf ^ 2))) * (1 + (-
0.0000000195301 * DblPi * IntTf - 1.72834E-13 * IntTf * DblPi ^ 2 - 0.000000358922 *
DblPi - 0.00000000225341 * (DblPi ^ 2)))

DblFo = DblRso * ((SngSg / DblSgo) ^ 0.5) + 1.25 * IntTf
DblBo = 0.972 + 0.000147 * DblFo ^ 1.175

SngVw = (0.9994 + 0.000040295 * DblPi + 0.0000000031062 * DblPi ^ 2) * DblVw1
DblRsgwf = DblA5 + DblB5 * DblPi + DblC5 * DblPi ^ 2
DblRsgw = DblRsgwf * (10 ^ DblD5)

'Oil Viscosity
DblVo2 = 10 ^ (-0.000396 * DblRso)
DblVo1 = (0.1615 + 0.7024 * 10 ^ (-0.000583 * DblRso)) * DblVd ^ (0.172 + 0.7881 *
DblVo2)
DblVo = -0.032124 + 0.9289 * DblVo1 - 0.02865 * DblVo1 ^ 2

'---------- Reduced Pressure Calculation----------

SngPpr = DblPi / SngPpc 'Cells(24, 2)

'--- Module-3 Gas Compressibility(Z) Estimation Using Gopal Equations----------

Select Case SngPpr
    Case 0.2 To 1.2
        Select Case SngTpr
        Case 1.05 To 1.2
          SngZ = SngPpr * (1.6643 * SngTpr - 2.2114) - 0.367 * SngTpr + 1.4385
        Case 1.2 To 1.4
          SngZ = SngPpr * (0.5222 * SngTpr - 0.8511) - 0.0364 * SngTpr + 1.049
        Case 1.4 To 2
          SngZ = SngPpr * (0.1391 * SngTpr - 0.2988) + 0.0007 * SngTpr + 0.9969
        Case 2 To 3
          SngZ = SngPpr * (0.0295 * SngTpr - 0.0825) + 0.0009 * SngTpr + 0.9967
        End Select
Case 1.2 To 2.8
        Select Case SngTpr
          Case 1.05 To 1.2
        SngZ = SngPpr * (-1.357 * SngTpr + 1.4942) + 4.6315 * SngTpr - 4.7009
          Case 1.2 To 1.4
        SngZ = SngPpr * (0.1717 * SngTpr - 0.3232) + 0.5869 * SngTpr + 0.1229
           Case 1.4 To 2
        SngZ = SngPpr * (0.0984 * SngTpr - 0.2053) + 0.0621 * SngTpr + 0.858
          Case 2 To 3
        SngZ = SngPpr * (0.0211 * SngTpr - 0.0527) + 0.0127 * SngTpr + 0.9549
        End Select
Case 2.8 To 5.4
```

```
        Select Case SngTpr
          Case 1.05 To 1.2
        SngZ = SngPpr * (-0.3227 * SngTpr - 0.4752) + 1.8223 * SngTpr - 1.9036
          Case 1.2 To 1.4
        SngZ = SngPpr * (-0.2521 * SngTpr + 0.3872) + 1.6087 * SngTpr - 1.6635
          Case 1.4 To 2
        SngZ = SngPpr * (-0.0284 * SngTpr + 0.0625) + 0.4714 * SngTpr - 0.0011
          Case 2 To 3
        SngZ = SngPpr * (0.0041 * SngTpr + 0.0039) + 0.0607 * SngTpr + 0.7927
        End Select
Case 5.4 To 15
       Select Case SngTpr

         Case 1.05 To 3
            SngZ = SngPpr * ((0.711 + 3.66 * SngTpr) ^ -1.4667) - (1.637 / (0.319 * SngTpr +
0.522)) + 2.071

       End Select

'------------ Katz Z Correlation for P = 10,000 to 20,0000----------
Case 15 To 30
       Select Case SngTpr

         Case 1.35 To 1.5
            SngZ = SngTpr * ((0.053929 * SngPpr) + 0.282857)
         Case 1.500001 To 1.7
            SngZ = SngTpr * ((0.039125 * SngPpr) + 0.327563)
         Case 1.700001 To 1.9
            SngZ = SngTpr * ((0.031 * SngPpr) + 0.322889)
          Case 1.900001 To 2.1
            SngZ = SngTpr * ((0.02465 * SngPpr) + 0.32415)

          Case 2.100001 To 2.3
            SngZ = SngTpr * ((0.020045 * SngPpr) + 0.320591)

          Case 2.300001 To 2.5
            SngZ = SngTpr * ((0.18675 * SngPpr) + 0.30875)
          Case 2.500001 To 2.7
            SngZ = SngTpr * ((0.013962 * SngPpr) + 0.304577)
          Case 2.700001 To 3
             SngZ = SngTpr * ((0.011679 * SngPpr) + 0.298643)
       End Select
'------------
Case Else
SngZ = 1000000
End Select
'------------ Estimation of Gas FVF------------
SngBg = 0.00504 * IntT * SngZ / DblPi  'bbl/SCF

'-------- Gas Density = PM/RT    T[R], P{psia], M = Mixture Mol.Wt
```

```
Dim SngDen As Single
SngDen = (1.601846 * 10 ^ -2) * SngMolWt * DblPi / (10.732 * IntT)

'---------- Estimation of Gas Viscosity by Lee--------

SngX1 = (9.4 + 0.02 * SngMolWt) * (IntT ^ 1.5) / (209 + 18 * SngMolWt + IntT)
SngX2 = 3.5 + 0.01 * SngMolWt + (986 / IntT)
SngX3 = 2.4 - 0.2 * SngX2
SngX4 = (SngDen ^ SngX3) * SngX2
SngVg = SngX1 * Exp(SngX4) * 10 ^ -4

DblKo = Dblmo * DblPi + DblIo
DblKg = Dblmg * DblPi + DblIg
DblKw = Dblmw * DblPi + DblIw

'*********************************************************

DblJ1 = (SngBg * SngVg)
DblJ2 = (DblBo * DblVo)
DblJ3 = (SngBw * SngVw)

DblBx = (DblRp - DblRpwo * DblRsgw)
DblJ4 = DblRpgw / (DblRpgw - DblRsgw)
DblJ5 = 1 + (DblRso * (1 - DblBx * DblRo) / (DblBx - DblRso))

DblD1 = (DblJ4 * DblJ5) / DblJ1

'***DblD2 = Dbl1 at zero pressure = 0 initially

DblmP1 = ((((DblD1 + DblD2) * (DblPi - IntPo)) / 2) + DblmP2)

DblD2 = DblD1
DblmP2 = DblmP1

'************************************
If check = 1 Then DblPi = DblP
IntPo = DblPi
If DblPi = DblP Then
GoTo 4000
End If

Next DblPi

4000

'********** iColumn = 1*************

' Print P, Ppr, Z, Bg, Den, Vis, Rso, Bo, LOV

'*********************************************************************
```

```
    Cells(iRow1, iColumn + 3).Value = SngPpr  ' = Column = 4
    Cells(iRow1, iColumn + 4).Value = SngZ   ' = Column = 5
    Cells(iRow1, iColumn + 5).Value = SngBg  ' = Column = 6
    Cells(iRow1, iColumn + 6).Value = SngDen ' = Column = 7
    Cells(iRow1, iColumn + 7).Value = SngVg  ' = Column = 8
    Cells(iRow1, iColumn + 8).Value = DblPi 'Print Pressure Twice
    Cells(iRow1, iColumn + 9) = DblmP2 / 1000000#
    Cells(iRow1, X) = DblmP2 / 1000000#
Next iRow1
4500
        X = X + 1
        iColumn = iColumn + 11
        Next SngSg
5000
Application.StatusBar = "Simulation is Complete, Resume Your Work"
MsgBoxEnd = MsgBox(" Simulation Was Successful", vbOKOnly, " End Of Simulation")
Application.StatusBar = "       "
End Sub
```

	mP [0.6]	mP [0.65]	mP [0.70]	mP [0.75]	mP [0.80]	mP [0.85]	mP [0.90]	API	35
Psia	MMpsia^2/cp							Pb	1000
								T[F]	150
150	0.28562429	0.291792	0.297893	0.303928	0.309899	0.315804	0.323559	Rp[SCF/STB]	8000
350	1.56303455	1.598014	1.6325	1.6665	1.700018	1.733052	1.785246	Rpgw[SCF/STB]	8000
550	3.88302966	3.973766	4.062817	4.150207	4.235934	4.319991	4.48483	Rpow[SCF/STB]	1
750	7.25858793	7.435046	7.607467	7.775889	7.940293	8.10064	8.481034		
950	11.708594	12.00568	12.29636	12.57739	12.85023	13.11727	13.89699		
1150	17.1997117	17.64859	18.08483	18.5052	18.91109	19.30479	20.64856		
1350	23.7081141	24.33761	24.94587	25.52964	26.0902	26.62973	28.71088		
1550	31.2168895	32.05503	32.86062	33.63036	34.3654	35.06772	38.08463		
1750	39.706983	40.78082	41.80782	42.78457	43.71202	44.59195	48.77052		
1950	49.20675	50.55548	51.85448	53.08999	54.24064	55.34812	60.86762		
2150	59.6585187	61.31532	62.89702	64.38935	65.7707	67.08265	73.78202		
2350	70.817667	72.75938	74.59539	76.31121	77.88527	79.3594	87.09036		
2550	82.6279991	84.82371	86.87795	88.77636	90.49785	92.08492	100.6811		
2750	95.0342704	97.44591	99.6753	101.7087	103.526	105.1709	114.4527		
2950	107.982366	110.5653	112.9205	115.0354	116.8915	118.5342	128.3136		
3150	121.419447	124.1231	126.5492	128.6871	130.5204	132.0971	142.1811		
3350	135.294071	138.0626	140.4998	142.5978	144.3431	145.787	155.9813		
3550	149.556286	152.3289	154.7134	156.7051	158.2944	159.5365	169.6483		
3750	164.357009	167.0271	169.2346	170.9798	172.2592	173.1265	182.8123		
3950	179.503324	181.9112	183.7909	185.1501	185.9935	186.3822	195.5541		
4150	194.670547	196.7374	198.2111	199.1086	199.4432	199.285	207.8794		
4350	209.8174	211.4651	212.4566	212.819	212.5759	211.8066	219.7652		
4550	224.906024	226.0576	226.4927	226.2499	225.3638	223.9238	231.1935		
4750	239.901756	240.482	240.289	239.374	237.7835	235.6181	242.1506		
4950	254.772928	254.7083	253.8182	252.1676	249.8158	246.8746	252.6271		
5150	269.490671	268.7099	267.0568	264.6108	261.4448	257.6824	262.6168		
5350	284.028731	282.4631	279.9841	276.6867	272.6578	268.0333	272.1164		
5550	298.363297	295.9465	292.5821	288.3812	283.4451	277.9221	281.1256		
5750	312.472837	309.1416	304.8355	299.6828	293.7994	287.3461	289.6459		
5950	326.337946	322.0317	316.7313	310.5823	303.7158	296.3044	297.6812		
6150	339.9412	334.6024	328.2585	321.0729	313.1912	304.7985	305.2368		
6350	353.26702	346.8414	339.4083	331.1492	322.2246	312.8312	312.3196		
6550	366.301546	358.7378	350.1734	340.8079	330.8164	320.4068	318.9378		
6750	379.032516	370.2826	360.5483	350.0471	338.9686	327.531	325.1004		
6950	391.449153	381.4682	370.5289	358.8664	346.6842	334.2104	330.8176		
7150	403.542065	392.2885	380.1123	367.2665	353.9675	340.4527	336.1001		
7350	415.30314	402.7384	389.2971	375.2492	360.8238	346.2663	340.9594		
7550	426.725458	412.8142	398.0827	382.8175	367.2592	351.6604	345.4074		
7750	437.803205	422.5133	406.4698	389.9752	373.2805	356.6447	349.4563		
7950	448.531588	431.8339	414.4598	396.7266	378.8952	361.2294	353.1189		
8150	458.906767	440.7753	422.055	403.0772	384.1114	365.4251	356.4078		
8350	468.925781	449.3375	429.2583	409.0328	388.9376	369.2427	359.3361		
8550	478.586481	457.5211	436.0735	414.5998	393.3828	372.6934	361.9169		
8750	487.887471	465.3278	442.5047	419.7852	397.4562	375.7885	364.1631		

Algorithm [Three Phase Region-2&3]

```
Sub mP()

Range("B2:IV5000").ClearContents

'*********************************************************************
'    Light Oil Properties are estimated using Modified AGIP Co-relations
'*********************************************************************
Dim IntPb As Integer
Dim SngTpr As Single
Dim SngPpr As Single
Dim IntT As Integer    'Temp R
Dim IntTf As Integer   'Temp F
Dim SngSg As Single    'Gas SG
Dim IntApi As Integer  'Oil API Gravity
Dim Sngn As Single     'Immediate expn
Dim DblRso As Single
Dim iColumn As Integer, iRow As Integer

Dim SngBg As Single
Dim IntM As Integer
Dim SngTpc As Single
Dim SngPpc As Single
Dim IntRp As Long
Dim IntPd As Integer '-----Dew point Pressure---
Dim SngBgi  As Single
Dim SngSwc  As Single '-----Critical Water Saturation
Dim X As Integer

' Define gas Composition

Dim SngMolWt As Single
Dim DblmP1 As Double
Dim DblmP2 As Double
Dim DblmP3 As Double

Dim DblY1 As Double  ' Parameter to calculate LOV
Dim DblY2 As Double
Dim DblY3 As Double
Dim DblF As Double

Dim DblW1 As Double
Dim DblW2 As Double
'*****************Viscosity Parameter
 Dim SngX1 As Single
Dim SngX2 As Single
Dim SngX3 As Single
Dim SngX4 As Single
Dim SngVg As Single
```

```
'********Pressure
Dim DblPi As Double
Dim check As Integer
Dim IntPc As Integer '  Pc = P*
'****************mP Parameters********
Dim DblJ1 As Double
Dim DblJ2 As Double
Dim DblJ3 As Double
Dim DblJ4 As Double
Dim DblJ5 As Double
Dim DblJ6 As Double
Dim DblBx As Double

Dim DblP As Double
Dim iRow1 As Integer

Dim IntPo As Integer
Dim DblD1 As Double
Dim DblD2 As Double
Dim IntStep As Integer
Dim iColumn2 As Integer
Dim IntX As Integer
Dim DblYi As Double

' Define Production Fluid Ratios

Dim DblRsgwf As Double  ' Solution Gas in fresh Water Ratio
Dim DblRsgw As Double   ' Solution Gas Water Ratio
Dim DblRpgw As Double   ' Producing Gas Water Ratio
Dim DblRpow As Double   ' Producing Oil Water Ratio
Dim DblRp As Double     ' Producing Gas Oil Ratio
Dim DblRpwo As Double
Dim DblRo As Double
Dim DblVd As Double
Dim DblVo1 As Double
Dim DblVo2 As Double
Dim DblVo As Double
Dim DblSgo As Double
Dim DblBo As Double

' Define Water Properties
Dim SngVw As Double ' Water Viscosity
Dim SngBw As Double
Dim DblKw As Double ' Water Effective Perm

Dim Dblmo As Double
Dim Dblmg As Double
Dim Dblmw As Double ' Water Effective Perm

Dim DblIo As Double
Dim DblIg As Double
```

```
Dim DblIw As Double

Dim DblS As Double ' Water Salinity

' Constants for Viscosity
Dim DblAw As Double
Dim DblB As Double
Dim DblTw As Double
Dim DblVw1 As Double  ' Water Viscosity at Atmospheric pressure

'Constants for Solution Gas fresh water ratio
Dim DblA5 As Double
Dim DblB5 As Double
Dim DblC5 As Double ' Constant in Solution Gas Water Ratio

'------------------------------------------------------------------------

X = 2

iColumn = 13
Cells(4, 2) = "mP [0.6]"
Cells(5, 2) = "MMpsia^2/cp"
Cells(4, 3) = "mP [0.65]"
Cells(4, 4) = "mP [0.70]"
Cells(4, 5) = "mP [0.75]"
Cells(4, 6) = "mP [0.80]"
Cells(4, 7) = "mP [0.85]"
Cells(4, 8) = "mP [0.90]"

IntTf = InputBox("Enter The Reservoir Temperature[F]", "Condensates", 150) 'Cells(8, 3)
'Temp F
IntPb = InputBox("Enter The Bubble Point Pressure[psi]", "Condensates", 1000)
IntApi = InputBox("Enter The API of Condensate", "Condensates", 45)

DblRp = InputBox("Enter The Producing Gas Oil Ratio [SCF/STB]", "Condensates", 5000)
DblRpgw = InputBox("Enter The Producing Gas Water Ratio [SCF/STB]", "Condensates",
8000)

DblVd = InputBox("Enter The Dead Oil Viscosity [cp]", "Condensates", 0.5)
DblS = InputBox("Enter The Salinity [Weight %]", "Condensates", 0.15)

DblRpow = DblRpgw / DblRp
DblRpwo = 1 / DblRpow

DblSgo = 141.5 / (131.5 + IntApi)

'*******************************
'Print Table'
'*******************************
Cells(4, 9) = "API"
Cells(4, 10) = IntApi
```

```
Cells(5, 9) = "Pb"
Cells(5, 10) = IntPb
Cells(6, 9) = "T[F]"
Cells(6, 10) = IntTf

Cells(7, 9) = "Rp[SCF/STB]"
Cells(7, 10) = DblRp
Cells(8, 9) = "Rpgw[SCF/STB]"
Cells(8, 10) = DblRpgw
Cells(9, 9) = "Rpow[SCF/STB]"
Cells(9, 10) = DblRpow

'**************************

For SngSg = 0.6 To 0.901 Step 0.05
If SngSg > 0.9 Then
SngSg = 0.9
End If

Cells(12, iColumn + 1) = SngSg

'---------- Pseudo Critical Temp. and Pressure for Ok Gases

SngTpc = 298.6 * SngSg + 181.89 ' Ok Gases
Cells(8, iColumn + 1).Value = SngTpc
SngPpc = -514.01 * (SngSg ^ 4) + 1788.2 * (SngSg ^ 3) - 2337.5 * (SngSg ^ 2) + 1305.3 *
(SngSg) + 415.07
Cells(9, iColumn + 1).Value = SngPpc

'**************Labels****************

Cells(8, iColumn) = "Tpc [R]= "
Cells(9, iColumn) = "Ppc [psi]= "
Cells(12, iColumn) = "S.G = "

Cells(14, iColumn) = "Tpr = "

Cells(16, iColumn) = "Res Temp [T]= "
Cells(16, iColumn + 1).Value = IntTf

IntT = IntTf + 460 ' Cells(8, 2)  'Temp R
Cells(17, iColumn) = "Res Temp [R]]= "
Cells(17, iColumn + 1).Value = IntT

Cells(19, iColumn) = "Mol.Wt.[Gas]= "

SngMolWt = SngSg * 28.9125
Cells(19, iColumn + 1) = SngMolWt

   Cells(4, iColumn + 3).Value = "Ppr"
   Cells(4, iColumn + 4).Value = "Z"
```

```
    Cells(4, iColumn + 5).Value = "Bg[bbl/scf]"
    Cells(4, iColumn + 6).Value = "Den[gm/cc]"
    Cells(4, iColumn + 7).Value = "Vis [cp]"
    Cells(4, iColumn + 8).Value = "P[psia]"
    'Cells(4, iColumn + 13).Value = IntPo
    Cells(4, iColumn + 9) = "mP"

' ------------Reduced Temp Calculation-------------------------------

SngTpr = IntT / SngTpc ' Cells(20, 2)
Cells(14, iColumn + 1).Value = SngTpr

'******************** Z, Viscosity, Bg**************************

DblAw = 109.574 - 8.40564 * DblS + 0.313314 * DblS ^ 2 + 0.00872213 * DblS ^ 3
DblB = -1.12166 + 0.0263951 * DblS - 0.000679461 * DblS ^ 2 - 5.47119 * E - 5 * DblS ^ 3 +
0.00000155586 * DblS ^ 4
DblVw1 = DblAw * IntTf ^ (DblB)

DblA5 = 8.15839 - 0.0612265 * IntTf + 0.000191663 * IntTf ^ 2 - 0.00000021654 * IntTf ^ 3
DblB5 = 0.0101021 - 0.0000744241 * IntTf + 0.000000305553 * IntTf ^ 2
DblC5 = (9.02505 - 0.130237 * IntTf + 0.000853425 * IntTf ^ 2 - 0.00000234122 * IntTf ^ 3 +
0.00000000237049 * IntTf ^ 4) * (-10 ^ -7)
DblD5 = (-0.0840655 * DblS * IntTf ^ (-0.285854))

For iRow1 = 7 To 5000 Step 1

IntPo = 0
DblmP2 = 0
DblD2 = 0

'----------Reservoir Pressure Input-------------------------------------------

DblP = Cells(iRow1, 1)   'Pressure  Values in column 4
If Cells(iRow1, 1) = Empty Then
GoTo 4500
End If

IntStep = 10

iRow = 6
check = 0
For DblPi = 150 To DblP * 2 Step IntStep
If DblPi > DblP Then
DblPi = DblP
check = 1
End If

'-------------------Rso---------------------
DblRso = (DblPi ^ 1.1535) * (SngSg / 37.966) * (10 ^ (9.441 * IntApi / IntT))
```

```
DblRo = (-11.66 + 0.000000004706 * DblRso ^ 3 + 1.623 * (DblRso ^ 0.5) - (42.3815 / DblRso
^ 0.5)) / 1000000#
If DblRo < 0 Then
DblR0 = 0
End If
'----------Water Formation Volume Factor----------

SngBw = (1 + (-0.010001 + 0.000133391 * IntTf + 0.000000550654 * (IntTf ^ 2))) * (1 + (-
0.00000000195301 * DblPi * IntTf - 1.72834E-13 * IntTf * DblPi ^ 2 - 0.000000358922 *
DblPi - 0.000000000225341 * (DblPi ^ 2)))

DblFo = DblRso * ((SngSg / DblSgo) ^ 0.5) + 1.25 * IntTf
DblBo = 0.972 + 0.000147 * DblFo ^ 1.175


SngVw = (0.9994 + 0.000040295 * DblPi + 0.0000000031062 * DblPi ^ 2) * DblVw1
DblRsgwf = DblA5 + DblB5 * DblPi + DblC5 * DblPi ^ 2
DblRsgw = DblRsgwf * (10 ^ DblD5)

'Oil Viscosity
DblVo2 = 10 ^ (-0.000396 * DblRso)
DblVo1 = (0.1615 + 0.7024 * 10 ^ (-0.000583 * DblRso)) * DblVd ^ (0.172 + 0.7881 *
DblVo2)
DblVo = -0.032124 + 0.9289 * DblVo1 - 0.02865 * DblVo1 ^ 2


'---------- Reduced Pressure Calculation----------

SngPpr = DblPi / SngPpc 'Cells(24, 2)

'--- Module-3 Gas Compressibility(Z) Estimation Using Gopal Equations----------

Select Case SngPpr
    Case 0.2 To 1.2
        Select Case SngTpr
        Case 1.05 To 1.2
          SngZ = SngPpr * (1.6643 * SngTpr - 2.2114) - 0.367 * SngTpr + 1.4385
        Case 1.2 To 1.4
          SngZ = SngPpr * (0.5222 * SngTpr - 0.8511) - 0.0364 * SngTpr + 1.049
        Case 1.4 To 2
          SngZ = SngPpr * (0.1391 * SngTpr - 0.2988) + 0.0007 * SngTpr + 0.9969
        Case 2 To 3
          SngZ = SngPpr * (0.0295 * SngTpr - 0.0825) + 0.0009 * SngTpr + 0.9967
        End Select
Case 1.2 To 2.8
        Select Case SngTpr
          Case 1.05 To 1.2
        SngZ = SngPpr * (-1.357 * SngTpr + 1.4942) + 4.6315 * SngTpr - 4.7009
          Case 1.2 To 1.4
        SngZ = SngPpr * (0.1717 * SngTpr - 0.3232) + 0.5869 * SngTpr + 0.1229
           Case 1.4 To 2
```

```
        SngZ = SngPpr * (0.0984 * SngTpr - 0.2053) + 0.0621 * SngTpr + 0.858
          Case 2 To 3
        SngZ = SngPpr * (0.0211 * SngTpr - 0.0527) + 0.0127 * SngTpr + 0.9549
        End Select
Case 2.8 To 5.4
        Select Case SngTpr
          Case 1.05 To 1.2
        SngZ = SngPpr * (-0.3227 * SngTpr + 0.4752) + 1.8223 * SngTpr - 1.9036
          Case 1.2 To 1.4
        SngZ = SngPpr * (-0.2521 * SngTpr + 0.3872) + 1.6087 * SngTpr - 1.6635
          Case 1.4 To 2
        SngZ = SngPpr * (-0.0284 * SngTpr + 0.0625) + 0.4714 * SngTpr - 0.0011
          Case 2 To 3
        SngZ = SngPpr * (0.0041 * SngTpr + 0.0039) + 0.0607 * SngTpr + 0.7927
        End Select
Case 5.4 To 15
       Select Case SngTpr

         Case 1.05 To 3
            SngZ = SngPpr * ((0.711 + 3.66 * SngTpr) ^ -1.4667) - (1.637 / (0.319 * SngTpr +
0.522)) + 2.071

        End Select

'------------ Katz Z Correlation for P = 10.000 to 20.0000----------
Case 15 To 30
       Select Case SngTpr

         Case 1.35 To 1.5
            SngZ = SngTpr * ((0.053929 * SngPpr) + 0.282857)
         Case 1.500001 To 1.7
            SngZ = SngTpr * ((0.039125 * SngPpr) + 0.327563)
         Case 1.700001 To 1.9
            SngZ = SngTpr * ((0.031 * SngPpr) + 0.322889)
          Case 1.900001 To 2.1
            SngZ = SngTpr * ((0.02465 * SngPpr) + 0.32415)

          Case 2.100001 To 2.3
            SngZ = SngTpr * ((0.020045 * SngPpr) + 0.320591)

          Case 2.300001 To 2.5
            SngZ = SngTpr * ((0.18675 * SngPpr) + 0.30875)
          Case 2.500001 To 2.7
            SngZ = SngTpr * ((0.013962 * SngPpr) + 0.304577)
          Case 2.700001 To 3
             SngZ = SngTpr * ((0.011679 * SngPpr) + 0.298643)
        End Select
'-----------
Case Else
SngZ = 1000000
End Select
```

```
'---------- Estimation of Gas FVF----------
SngBg = 0.00504 * IntT * SngZ / DblPi  ' bbl/SCF

'--------- Gas Density = PM/RT    T[R], P[psia], M = Mixture Mol.Wt

Dim SngDen As Single
SngDen = (1.601846 * 10 ^ -2) * SngMolWt * DblPi / (10.732 * IntT) ' Cells(17, 2)

'---------- Estimation of Gas Viscosity by Lee--------

SngX1 = (9.4 + 0.02 * SngMolWt) * (IntT ^ 1.5) / (209 + 18 * SngMolWt + IntT)
SngX2 = 3.5 + 0.01 * SngMolWt + (986 / IntT)
SngX3 = 2.4 - 0.2 * SngX2
SngX4 = (SngDen ^ SngX3) * SngX2
SngVg = SngX1 * Exp(SngX4) * 10 ^ -4

DblKo = Dblmo * DblPi + DblIo
DblKg = Dblmg * DblPi + DblIg
DblKw = Dblmw * DblPi + DblIw

'*****************************************************

DblJ1 = (SngBg * SngVg)
DblJ2 = (DblBo * DblVo)
DblJ3 = (SngBw * SngVw)

DblJ4 = 1 + (DblRsgw / DblRpgw)
DblD1 = DblJ4 / DblJ1

'***DblD2 = Dbl1 at zero pressure = 0 initially

DblmP1 = ((((DblD1 + DblD2) * (DblPi - IntPo)) / 2) + DblmP2)

DblD2 = DblD1
DblmP2 = DblmP1

'************************************
If check = 1 Then DblPi = DblP
IntPo = DblPi
If DblPi = DblP Then
GoTo 4000
End If

Next DblPi

4000

'********** iColumn = 1**********

' Print P, Ppr, Z, Bg, Den, Vis, Rso, Bo, LOV
```

```
'*****************************************************************
   Cells(iRow1, iColumn + 3).Value = SngPpr  ' = Column = 4
   Cells(iRow1, iColumn + 4).Value = SngZ   ' = Column = 5
   Cells(iRow1, iColumn + 5).Value = SngBg  ' = Column = 6
   Cells(iRow1, iColumn + 6).Value = SngDen ' = Column = 7
   Cells(iRow1, iColumn + 7).Value = SngVg  ' = Column = 8
   Cells(iRow1, iColumn + 8).Value = DblPi 'Print Pressure Twice
   Cells(iRow1, iColumn + 9) = DblmP2 / 1000000#
   Cells(iRow1, X) = DblmP2 / 1000000#
Next iRow1
4500
        X = X + 1
        iColumn = iColumn + 11
        Next SngSg
5000
Application.StatusBar = "Simulation is Complete, Resume Your Work"
MsgBoxEnd = MsgBox(" Simulation Was Successful", vbOKOnly, " End Of Simulation")
Application.StatusBar = "      "
End Sub
```

P	mP [0.6]	mP [0.65]	mP [0.70]	mP [0.75]	mP [0.80]	mP [0.85]	mP [0.90]	API	35
Psia	MMpsia^2/cp							Pb	1000
								T[F]	150
3000	107.10485	109.3328	111.327	113.078	114.5715	115.853	124.9591		
3200	119.86175	122.1388	124.1358	125.846	127.2572	128.419	137.7194	Rpgw[SCF/STB]	8000
3400	132.9708	135.2395	137.1795	138.787	140.0541	141.033	150.3491	Rpow[SCF/STB]	1.6
3600	146.38395	148.5836	150.404	151.846	152.9046	153.636	162.7605		
3800	160.31947	162.3163	163.8683	164.982	165.6608	165.962	174.6266		
4000	174.38719	176.0596	177.2333	177.923	178.1396	177.948	186.0972		
4200	188.41825	189.694	190.4197	190.619	190.3124	189.572	197.1552		
4400	202.37709	203.186	203.3968	203.044	202.1564	200.817	207.7885		
4600	216.23173	216.5057	216.1381	215.174	213.6538	211.668	217.9897		
4800	229.95354	229.6273	228.6209	226.992	224.7907	222.118	227.7556		
5000	243.51696	242.5279	240.8262	238.482	235.5569	232.162	237.0861		
5200	256.89933	255.1881	252.7382	249.633	245.9456	241.797	245.9841		
5400	270.08065	267.5912	264.344	260.436	255.9525	251.024	254.4551		
5600	283.04338	279.7229	275.6332	270.885	265.5763	259.846	262.5063		
5800	295.77226	291.5715	286.5981	280.977	274.8174	268.268	270.1469		
6000	308.25414	303.1273	297.2329	290.71	283.6785	276.296	277.3874		
6200	320.47783	314.3828	307.5337	300.084	292.1635	283.939	284.2392		
6400	332.43391	325.332	317.4986	309.1	300.2782	291.205	290.7148		
6600	344.11461	335.9708	327.127	317.763	308.0291	298.105	296.8272		
6800	355.51368	346.2963	336.4196	326.076	315.424	304.649	302.59		
7000	366.62626	356.3072	345.3786	334.044	322.4715	310.849	308.017		
7200	377.44875	366.0032	354.0071	341.675	329.1807	316.716	313.1222		
7400	387.97871	375.3851	362.309	348.975	335.5615	322.263	317.9197		
7600	398.21475	384.4548	370.2892	355.951	341.624	327.502	322.4235		
7800	408.15645	393.2148	377.9533	362.612	347.3787	332.446	326.6475		
8000	417.80426	401.6685	385.3075	368.967	352.8363	337.106	330.6053		
8200	427.15939	409.8201	392.3583	375.025	358.0077	341.495	334.3105		
8400	436.22378	417.6742	399.1129	380.794	362.9038	345.626	337.776		
8600	445.00001	425.2358	405.5788	386.284	367.5355	349.51	341.0148		
8800	453.4912	432.5107	411.7636	391.505	371.9136	353.159	344.039		
9000	461.701	439.5047	417.6753	396.466	376.0489	356.585	346.8607		
9200	469.63348	446.2242	423.3221	401.176	379.952	359.798	349.4914		
9400	477.29312	452.6757	428.7121	405.646	383.6333	362.811	351.9422		
9600	484.68475	458.8659	433.8537	409.885	387.103	365.633	354.2237		
9800	491.81347	464.8017	438.7552	413.901	390.371	368.275	356.3461		
10000	498.68464	470.4902	443.4249	417.705	393.447	370.744	358.3389		
10200	505.14884	475.8632	447.8998	421.466	396.1877	373.025	360.2412		
10400	510.97049	480.8845	452.191	425.102	398.7422	375.157	362.0082		
10600	516.57092	485.6893	456.275	428.544	401.1414	377.148	363.6483		
10800	521.95579	490.2846	460.1595	431.799	403.3935	379.005	365.1698		
11000	527.13083	494.6772	463.8521	434.876	405.5063	380.738	366.5802		
11200	532.10182	498.8738	467.3605	437.783	407.4872	382.352	367.8869		
11400	536.87454	502.8812	470.6921	440.528	409.3436	383.856	369.0968		
11600	541.4548	506.706	473.8541	443.118	411.0822	385.257	370.2163		