# University of Alberta

A Depletion Strategy for Oil Production with a Secondary Recovery Option

by

Mustafa Oguztoreli

A thesis submitted to the Faculty of Graduate Studies and Research in partial fulfilment of the requirements for the degree of

Doctor of Philosophy
in
Engineering Management

Department of Mining Metallurgical
and Petroleum Engineering

Edmonton, Alberta
Fall, 1996

National Library of Canada

Acquisitions and Bibliographic Services Branch

395 Wellington Street
Ottawa, Ontario
K1A 0N4

Bibliothèque nationale du Canada

Direction des acquisitions et des services bibliographiques

395, rue Wellington
Ottawa (Ontario)
K1A 0N4

*Your file Votre référence*

*Our file Notre référence*

**The author has granted an irrevocable non-exclusive licence allowing the National Library of Canada to reproduce, loan, distribute or sell copies of his/her thesis by any means and in any form or format, making this thesis available to interested persons.**

**L'auteur a accordé une licence irrévocable et non exclusive permettant à la Bibliothèque nationale du Canada de reproduire, prêter, distribuer ou vendre des copies de sa thèse de quelque manière et sous quelque forme que ce soit pour mettre des exemplaires de cette thèse à la disposition des personnes intéressées.**

**The author retains ownership of the copyright in his/her thesis. Neither the thesis nor substantial extracts from it may be printed or otherwise reproduced without his/her permission.**

**L'auteur conserve la propriété du droit d'auteur qui protège sa thèse. Ni la thèse ni des extraits substantiels de celle-ci ne doivent être imprimés ou autrement reproduits sans son autorisation.**

ISBN 0-612-18089-1

Canada

## University of Alberta

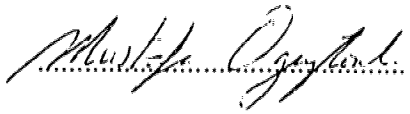
Library Release Form

| | |
|---|---|
| Name of Author: | Mustafa Oguztoreli |
| Title of Thesis: | A Depletion Strategy for Oil Production with a Secondary Recovery Option |
| Degree: | Doctor of Philosophy |

Year this Degree Granted: 1996

Permission is hereby granted to the University of Alberta to reproduce single copies of this thesis and to lend or sell such copies for private, scholarly, or scientific research purposes only.

The author reserves all other publication and other rights in association with the copyright in the thesis, and except as hereinbefore provided, neither the thesis nor any substantial portion thereof may be printed or otherwise reproduced in any material form whatever without the author's prior written permission.



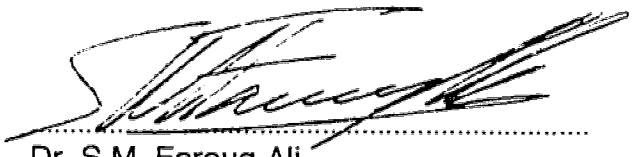
Mustafa Oguztoreli
121 Willow Way
Edmonton, Alberta
Canada T5T-1C9

Aug 29, 1996

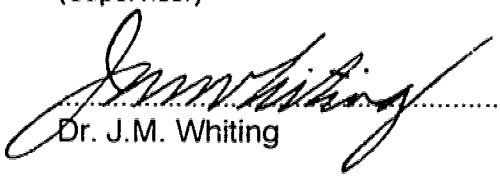
## University of Alberta

Faculty of Graduate Studies and Research

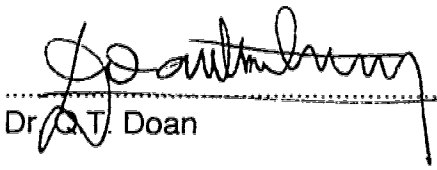
The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research for acceptance, a thesis entitled A Depletion Strategy for Oil Production with a Secondary Recovery Option submitted by Mustafa Oguztoreli in partial fulfilment of the requirements for the degree of Doctor of Philosophy in Engineering Management.



Dr. S.M. Farouq Ali
(Supervisor)

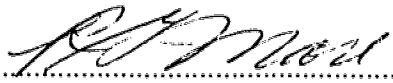


Dr. J.M. Whiting



Dr. Q.T. Doan

Dr. T. Daniel



Dr. R.G. Moore
(External Examiner)

Aug 27, 96

*To my mother Ceyda*
*and to the memory of my beloved sister Billur*

## Abstract

An oilfield usually has a secondary recovery stage for economically viable oil production over its producing life. The total inventory of recoverable oil will depend on the manner in which the reservoir is produced. The initiation of a secondary recovery stage at different times over the primary production life cycle may result in different ultimate recoveries. This work supplements a theoretical development for constructing optional-stage depletion strategies with a realistic application to the Chedderville Viking "A" Pool in Alberta. The particular field produces naturally under solution gas drive and is a good candidate for a pattern waterflood. Ultimate recovery and project economics depend on the depletion strategy that manages both natural depletion under primary production and pattern waterflooding under secondary recovery.

The reservoir is characterized with a black oil simulation model calibrated by matching historical production and pressure data. Primary operations adhere to regulatory constraints that limit monthly allowables for oil and gas production. A pattern waterflood is proposed and control policies established to meet design objectives. Secondary waterflood branches are forecast along a primary depletion path. A branched differential decision process using dynamic programming techniques is used to find investment and operating decision rules that maximize the modelled economic value of remaining operating alternatives over a strategic window.

The strategic model system examines the waterflood investment timing option. Nested primary and secondary operational modes for controlled production, suspended field-wide operations and early abandonment are also examined. The space of allowable operating pathways give considerable flexibility for decision making. The value of alternative recovery options depends on reservoir depletion paths and the probability structure of macro-economic scenarios. The analysis is restricted to situations where the macroeconomic oil price and cumulative oil production are sufficient state variables for decision-making. Oil price expectations assume an exogenous continuous random walk in volatile future price movements. An intertemporal equilibrium asset valuation model, based on oil futures price dynamics, is used to value production cash flows from alternative recovery paths in terms of macro-economic factors and field-specific costs. Uncertainty about future price gives a flexible decision process additional value over rigid production plans. The valuation method parallels derivative asset pricing models used in financial option analysis.

The model system depletion strategy is intended to guide oil producers to make better management decisions in their field operations. The strategy constitutes an optimal policy that is compiled as a schedule of price sensitive decision rules which apply at future depletion states, regardless of how the model operations were managed up to that point in time.

## Acknowledgements

The guidance, support and encouragement of Professor S.M. Farouq Ali, Professor D.G. Laughton and Professor J.M. Whiting is hereby acknowledged with gratitude. I would like to thank Professor Q.T. Doan for the provision of historical reservoir data and fruitful discussions on related reference material. I would also like to thank J.E. Faltinson for providing accurate cost correlations and shedding light on realistic production practices. A special thank-you to my father, Professor M.N. Oguztoreli, for his insightful inputs in control theory and provision of computer resources.

# Table of Contents


Chapter 1: Introduction ..... 1
- 1.1 Production Stages ..... 1
- 1.2 Secondary Recovery Option ..... 2
- 1.3 Objectives ..... 3
- 1.4 Guiding Philosophy ..... 4
- 1.5 Sources of Data ..... 6

Chapter 2: Reservoir Characterization ..... 7
- 2.1 Reservoir Description Process ..... 7
- 2.2 Reservoir Simulation ..... 8
- 2.3 State of Reservoir Information ..... 9
- 2.4 Geological and Geographic Data ..... 9
- 2.5 Perforation Zone Data ..... 10
- 2.6 Core and Well Log Data ..... 21
- 2.7 High-Permeability Channel ..... 55
- 2.8 Three-Dimensional Reservoir Model ..... 59
- 2.9 Pressure-Volume-Temperature Data ..... 76
- 2.10 Capillary Pressure Data ..... 93
- 2.11 Relative Permeability Data ..... 96
- 2.12 Initial Depletion State ..... 105

Chapter 3: Well Management System Model ..... 116
- 3.1 Well Model ..... 116
- 3.2 Surface Facility ..... 118
- 3.3 System Hydraulics ..... 119
- 3.4 Regulatory Rate Constraints ..... 123
- 3.5 Control Strategy ..... 126
- 3.6 Well Spacing ..... 128
- 3.7 Primary Control Policy ..... 129
- 3.8 Secondary Control Policy ..... 132

Chapter 4: History Match ..... 135
- 4.1 Historical Controls ..... 135
- 4.2 Simulation Controls ..... 135
- 4.3 Simulation Results ..... 136
- 4.4 Calibration Summary ..... 137

Chapter 5: Primary Forecast ..... 186
- 5.1 Primary Controls ..... 186
- 5.2 Primary Simulation ..... 187
- 5.3 Primary Summary ..... 189

Chapter 6: Secondary Forecast ..... 223
6.1 Waterflood Design ..... 223
6.2 Secondary Controls ..... 224
6.3 Waterflood Simulation ..... 225
6.4 Waterflood Design Summary ..... 226

Chapter 7: Reservoir Depletion Paths ..... 277
7.1 Path-Dependent Production Trees ..... 277
7.2 Operational Modes ..... 279
7.3 Near-State Variables ..... 281
7.4 Cumulative Production Tree ..... 283
7.5 Time-Averaged Production Rates ..... 284

Chapter 8: Depletion Strategy Model ..... 294
8.1 Strategic Decisions ..... 294
8.2 Strategy Duration ..... 294
8.3 Project Costs ..... 295
8.4 Cash Flow Model ..... 296
8.5 Oil Price Model ..... 299
8.6 Asset Valuation Model ..... 303
8.7 Action Regions ..... 309
8.8 Boundary Conditions ..... 312
8.9 Decision Model Summary ..... 319

Chapter 9: Depletion Strategy ..... 323
9.1 Dynamic Programming ..... 323
9.2 Model Results ..... 323
9.3 Recommended Action ..... 326
9.4 Model Limitations ..... 326

Chapter 10: Conclusion ..... 359

References ..... 361

Appendix A1: Black Oil Simulation Model ..... 364
A1.1 Reservoir Volume Elements ..... 364
A1.2 Volume Fractions ..... 366
A1.3 Capillary Pressures ..... 366
A1.4 Fluid Volumes ..... 366
A1.5 Conservation of Mass ..... 367
A1.6 Phase Potentials ..... 368
A1.7 Darcy Velocities ..... 368
A1.8 Oil Pressure Equation ..... 369
A1.9 Saturation Equations ..... 370
A1.10 Finite Difference Equations ..... 371

A1.11 Numerical Stability ..... 373

Appendix A2: Dynamic Programming Algorithm ..... 375
A2.1 Depletion-Time Grid Partition ..... 375
A2.2 Sweep Direction ..... 379
A2.3 Depletion Boundary Tracking ..... 380
A2.4 Price-Time Grid Partition ..... 382
A2.5 Finite Differences ..... 383

# List of Tables


| Table | | |
|---|---|---|
| 2.1(a) | Chedderville Viking "A" Well List Geographic Order (Oct-94) ..... | 11 |
| 2.1(b) | Chedderville Viking "A" Well List Historical Order (Oct-94) ..... | 12 |
| 2.2 | Core Data ..... | 24-26 |
| 2.3 | Core and Log Data Summary Data ..... | 54 |
| 2.4 | Reservoir Grid Dimensions ..... | 62 |
| 2.5 | Reservoir Grid Depth ..... | 63 |
| 2.6(a) | Horizontal Permeability $K_x$ ..... | 66 |
| 2.6(b) | Horizontal Permeability $K_y$ ..... | 67 |
| 2.6(c) | Vertical Permeability $K_z$ ..... | 68 |
| 2.6(d) | Reservoir Porosity $\phi$ ..... | 69 |
| 2.6(e) | Initial Water Saturation $S_w$ ..... | 70 |
| 2.7 | Gas Analysis (06-14-37-7W5) and Oil Analysis (08-13-37-8W5) ..... | 77 |
| 2.8 | Oil API and Gravity Measurements from Selected Wells ..... | 78 |
| 2.9 | Isothermal Gas Properties ..... | 81 |
| 2.10 | Isothermal Oil Properties ..... | 85 |
| 2.11 | Isothermal Water Properties ..... | 89 |
| 2.12 | Oil-Water Capillary Pressure ..... | 94 |
| 2.13 | Core Two-Phase Relative Permeabilities ..... | 97 |
| 2.14 | Three-Phase Relative Permeability Nomenclature ..... | 98 |
| 2.15 | Model Two-Phase Relative Permeabilities and Capillary Pressures ..... | 100 |
| 2.16 | Model Three-Phase Oil Relative Permeability $k_{ro}$ ..... | 104 |

| | | |
|---|---|---|
| 2.17 | Chedderville Viking "A" Pressure History (1-Oct-94) | 107 |
| 2.18(a) | Initial Equilibrium Pressure $p_o$ | 108 |
| 2.18(b) | Initial Oil Saturation $S_o$ | 109 |
| 2.18(c) | Initial Gas Saturation $S_g$ | 110 |
| 2.18(d) | Initial Bubble Point Pressure $p_b$ | 111 |
| 4.1 | Chedderville Viking "A" Production History (Oct-94) | 138-142 |
| 4.2 | Chedderville Viking "A" Production Match (Oct-94) | 143-147 |
| 6.1 | Proposed Waterflood Project | 227 |
| 7.1(a) | Cumulative Oil Production (MSTB) Milestone Times (days), $t_o(\mathcal{P}_1, \mathcal{P}_2)$ | 291 |
| 7.1(b) | Average Oil Rate (STB/day) between Cumulative Oil Milestones (MSTB), $Q_o(\mathcal{P}_1, \mathcal{P}_2)$ | 291 |
| 7.1(c) | Average Gas Rate (Mscf/day) between Cumulative Oil Milestones (MSTB), $Q_g(\mathcal{P}_1, \mathcal{P}_2)$ | 291 |
| 8.1 | Project Capital, Operating and Abandonment Costs | 297 |
| 8.2 | Oil and Gas Accounting for Cash Flow and Income Tax (Alberta) | 298 |
| 8.3 | Oil Price Volatility | 300 |
| 9.1(a) | Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=0) | 327 |
| 9.1(b) | Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=1 yr) | 328 |
| 9.1(c) | Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=2 yrs) | 329 |
| 9.1(d) | Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=4 yrs) | 330 |
| 9.1(e) | Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=8 yrs) | 331 |
| 9.1(f) | Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=12 yrs) | 332 |
| 9.1(g) | Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=16 yrs) | 333 |

9.1(h) Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=20 yrs) ..... 334

9.1(i) Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=24 yrs) ..... 335

9.1(j) Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=28 yrs) ..... 336

9.2(a) Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=0 yrs,$\mathcal{P}_1$=0 MSTB) ..... 337

9.2(b) Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=2 yrs,$\mathcal{P}_1$=0 MSTB) ..... 338

9.2(c) Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=4 yrs,$\mathcal{P}_1$=0 MSTB) ..... 339

9.2(d) Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=8 yrs,$\mathcal{P}_1$=0 MSTB) ..... 340

9.2(e) Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=12 yrs,$\mathcal{P}_1$=0 MSTB) ..... 341

9.2(f) Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=16 yrs,$\mathcal{P}_1$=0 MSTB) ..... 342

9.2(g) Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=20 yrs,$\mathcal{P}_1$=0 MSTB) ..... 343

9.2(h) Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=24 yrs,$\mathcal{P}_1$=0 MSTB) ..... 344

9.2(i) Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=28 yrs,$\mathcal{P}_1$=0 MSTB) ..... 345

9.3 Primary Economic Limit Abandonment Price $s_{1A}^*$ ($\mathcal{P}_1$,t) ($/bbl) ..... 346

9.4 Secondary Economic Limit Abandonment Price $s_{2A}^*$ ($\mathcal{P}_2$,t;$\mathcal{P}_1$) ($/bbl) ..... 347-354

# List of Figures


| Figure | | |
|---|---|---|
| 2.1 | Chedderville Viking "A" Well Location Map | 13 |
| 2.2 | Chedderville Viking "A" Grid (10 Acre) Overlay | 14 |
| 2.3(a) | Reservoir Thickness $\Delta z$ | 15 |
| 2.3(b) | Reservoir Thickness $\Delta z$ | 16 |
| 2.4(a) | Kelly Bushing Elevation Contours | 17 |
| 2.4(b) | Kelly Bushing Elevation Surface | 18 |
| 2.5(a) | Reservoir Top Subsea Depth | 19 |
| 2.5(b) | Reservoir Top Subsea Depth | 20 |
| 2.6(a) | Core Porosity $\phi$ Histogram | 27 |
| 2.6(b) | Core Porosity Histogram (Lognormal Segmentation) | 28 |
| 2.7(a) | Core Porosity Depth Trend | 29 |
| 2.7(b) | Core Porosity Top-to-Bottom Trend | 30 |
| 2.7(c) | Core Porosity East-West Trend | 31 |
| 2.7(d) | Core Porosity North-South Trend | 32 |
| 2.8(a) | Core Maximum Permeability $K_x$ Histogram | 33 |
| 2.8(b) | Core Maximum Permeability $K_x$ Histogram (Lognormal Segmentation) | 34 |
| 2.9(a) | Core Maximum Permeability $K_x$ vs Depth | 35 |
| 2.9(b) | Core Maximum Permeability $K_x$ Vertical Trend | 36 |
| 2.9(c) | Core Maximum Permeability $K_x$ East-West Trend | 37 |
| 2.9(d) | Core Maximum Permeability $K_x$ North-South Trend | 38 |
| 2.9(e) | Core Maximum Permeability $K_x$ vs Core Porosity $\phi$ | 39 |
| 2.10(a) | Core 90-Degree Permeability $K_y$ Histogram | 40 |
| 2.10(b) | Core 90-Degree Permeability $K_y$ Histogram (Lognormal Segmentation) | 41 |
| 2.11(a) | Core 90-Degree Permeability $K_y$ vs Depth | 42 |
| 2.11(b) | Core 90-Degree Permeability $K_y$ Vertical Trend | 43 |
| 2.11(c) | Core 90-Degree Permeability $K_y$ East-West Trend | 44 |
| 2.11(d) | Core 90-Degree Permeability $K_y$ North-South Trend | 45 |

2.11(e) Core 90-Degree Permeability $K_y$ vs Core Porosity $\phi$ ..... 46

2.12(a) Core Vertical Permeability $K_z$ Histogram ..... 47
2.12(b) Core Vertical Permeability $K_z$ Histogram (Lognormal Segmentation)..... 48

2.13(a) Core Vertical Permeability $K_z$ vs Depth ..... 49
2.13(b) Core Vertical Permeability $K_z$ Vertical Trend ..... 50
2.13(c) Core Vertical Permeability $K_z$ East-West Trend ..... 51
2.13(d) Core Vertical Permeability $K_z$ North-South Trend ..... 52
2.13(e) Core Vertical Permeability $K_z$ vs Core Porosity $\phi$ ..... 53

2.14(a) High Permeability Channel ..... 57
2.14(b) Channel Thickness $\Delta z$(k=1) ..... 58

2.15(a) Channel Grid Block Thickness $\Delta z$(k=1) ..... 60
2.15(b) Matrix Grid Block Thickness $\Delta z$(k=2) ..... 61

2.16(a) Reservoir Thickness $\Delta z$ ..... 64
2.16(b) Reservoir Subsea Depth ..... 65

2.17(a) Reservoir Permeability $K_x$ ..... 71
2.17(b) Reservoir Permeability $K_y$ ..... 72
2.17(c) Reservoir Permeability $K_z$ ..... 73
2.17(d) Reservoir Porosity $\phi$ ..... 74
2.17(e) Initial (Oct-87) Water Saturation $S_w$ ..... 75

2.18(a) Gas Deviation Z-Factor (08-13-37-8W5) ..... 82
2.18(b) Gas Formation Volume Factor $B_g$ (08-13-37-8W5) ..... 83
2.18(c) Gas Viscosity $\mu_g$ (08-13-37-8W5) ..... 84

2.19(a) Gas-Oil Solubility $R_{so}$ (08-13-37-8W5) ..... 86
2.19(b) Oil Formation Volume Factor $B_o$ (08-13-37-8W5) ..... 87
2.19(c) Oil Viscosity $\mu_o$ (08-13-37-8W5) ..... 88

2.20(a) Gas-Water Solubility $R_{sw}$ (08-13-37-8W5) ..... 90
2.20(b) Water Formation Volume Factor $B_w$ (08-13-37-8W5) ..... 91
2.20(c) Water Viscosity $\mu_w$ (08-13-37-8W5) ..... 92

2.21 Oil-Water Capillary Pressure $p_{cow}$ (08-17-37-7W5) ..... 95

2.22(a) 2-Phase Water and Water-Oil Relative Permeabilities ..... 101

| | | |
|---|---|---|
| 2.22(b) | 2-Phase Gas and Gas-Oil Relative Permeabilities | 102 |
| 2.22(c) | Model 3-Phase Oil Relative Permeabilities | 103 |
| 2.23(a) | Initial (Nov-87) Pressure $p_o$ | 112 |
| 2.23(b) | Initial (Nov-87) Oil Saturation $S_o$ | 113 |
| 2.23(c) | Initial (Nov-87) Gas Saturation $S_g$ | 114 |
| 2.23(d) | Initial (Nov-87) Bubble Point Pressure $p_b$ | 115 |
| 3.1 | Monthly Rate Limitations | 125 |
| 3.2 | Producing GOR Effects on Unfilled Oil Quota | 130 |
| 4.1(a) | Oil and Gas Production History Match (16-09-37-7W5) | 148 |
| 4.1(b) | Oil and Gas Production History Match (16-15-37-7W5) | 149 |
| 4.1(c) | Oil and Gas Production History Match (08-13-37-8W5) | 150 |
| 4.1(d) | Oil and Gas Production History Match (06-13-37-8W5) | 151 |
| 4.1(e) | Oil and Gas Production History Match (06-16-37-7W5) | 152 |
| 4.1(f) | Oil and Gas Production History Match (08-14-37-8W5) | 153 |
| 4.1(g) | Oil and Gas Production History Match (08-18-37-7W5) | 154 |
| 4.1(h) | Oil and Gas Production History Match (16-08-37-7W5) | 155 |
| 4.1(i) | Oil and Gas Production History Match (14-09-37-7W5) | 156 |
| 4.1(j) | Oil and Gas Production History Match (08-17-37-7W5) | 157 |
| 4.1(k) | Oil and Gas Production History Match (14-07-37-7W5) | 158 |
| 4.1(l) | Oil and Gas Production History Match (14-12-37-8W5) | 159 |
| 4.1(m) | Oil and Gas Production History Match (16-12-37-8W5) | 160 |
| 4.1(n) | Oil and Gas Production History Match (08-07-37-7W5) | 161 |
| 4.2(a) | Pressure History Match (16-09-37-7W5) | 162 |
| 4.2(b) | Pressure History Match (16-15-37-7W5) | 163 |
| 4.2(c) | Pressure History Match (08-13-37-8W5) | 164 |
| 4.2(d) | Pressure History Match (06-13-37-8W5) | 165 |
| 4.2(e) | Pressure History Match (06-16-37-7W5) | 166 |
| 4.2(f) | Pressure History Match (08-14-37-8W5) | 167 |
| 4.2(g) | Pressure History Match (08-18-37-7W5) | 168 |
| 4.2(h) | Pressure History Match (16-08-37-7W5) | 169 |
| 4.2(i) | Pressure History Match (14-09-37-7W5) | 170 |
| 4.2(j) | Pressure History Match (08-17-37-7W5) | 171 |
| 4.2(k) | Pressure History Match (14-07-37-7W5) | 172 |
| 4.2(l) | Pressure History Match (14-12-37-8W5) | 173 |
| 4.2(m) | Pressure History Match (16-12-37-8W5) | 174 |
| 4.2(n) | Pressure History Match (08-07-37-7W5) | 175 |
| 4.3(a) | Average Reservoir Pressure (Simulation) | 176 |
| 4.3(b) | Pool Cumulative Production History Match | 177 |
| 4.3(c) | Pool Cumulative Production History Match (Excluding 16-09-37-7W5 and 06-15-37-7W5) | 178 |

| | | |
|---|---|---|
| 4.4(a) | Pool Oil Production Rate (Simulation) | 179 |
| 4.4(b) | Pool Gas Production Rate (Simulation) | 180 |
| 4.5(a) | History Match (Oct-94) Pressure p | 181 |
| 4.5(b) | History Match (Oct-94) Water Saturation $S_w$ | 182 |
| 4.5(c) | History Match (Oct-94) Oil Saturation $S_o$ | 183 |
| 4.5(d) | History Match (Oct-94) Gas Saturation $S_g$ | 184 |
| 4.5(e) | History Match (Oct-94) Bubble Point $p_b$ | 185 |
| 5.1(a) | Primary Production Forecast (08-13-37-8W5) | 190 |
| 5.1(b) | Primary Production Forecast (06-13-37-8W5) | 191 |
| 5.1(c) | Primary Production Forecast (06-16-37-7W5) | 192 |
| 5.1(d) | Primary Production Forecast (08-14-37-8W5) | 193 |
| 5.1(e) | Primary Production Forecast (08-18-37-7W5) | 194 |
| 5.1(f) | Primary Production Forecast (16-08-37-7W5) | 195 |
| 5.1(g) | Primary Production Forecast (14-09-37-7W5) | 196 |
| 5.1(h) | Primary Production Forecast (08-17-37-7W5) | 197 |
| 5.1(i) | Primary Production Forecast (14-07-37-7W5) | 198 |
| 5.1(j) | Primary Production Forecast (14-12-37-8W5) | 199 |
| 5.1(k) | Primary Production Forecast (16-12-37-8W5) | 200 |
| 5.1(l) | Primary Production Forecast (08-07-37-7W5) | 201 |
| 5.2(a) | Primary Pressure Prediction (08-13-37-8W5) | 202 |
| 5.2(b) | Primary Pressure Prediction (06-13-37-8W5) | 203 |
| 5.2(c) | Primary Pressure Prediction (06-16-37-7W5) | 204 |
| 5.2(d) | Primary Pressure Prediction (08-14-37-8W5) | 205 |
| 5.2(e) | Primary Pressure Prediction (08-18-37-7W5) | 206 |
| 5.2(f) | Primary Pressure Prediction (16-08-37-7W5) | 207 |
| 5.2(g) | Primary Pressure Prediction (14-09-37-7W5) | 208 |
| 5.2(h) | Primary Pressure Prediction (08-17-37-7W5) | 209 |
| 5.2(i) | Primary Pressure Prediction (14-07-37-7W5) | 210 |
| 5.2(j) | Primary Pressure Prediction (14-12-37-8W5) | 211 |
| 5.2(k) | Primary Pressure Prediction (16-12-37-8W5) | 212 |
| 5.2(l) | Primary Pressure Prediction (08-07-37-7W5) | 213 |
| 5.3(a) | Primary Average Reservoir Pressure Prediction | 214 |
| 5.3(b) | Pool Cumulative Primary Production Prediction | 215 |
| 5.4(a) | Pool Primary Oil Production Rate Forecast | 216 |
| 5.4(b) | Pool Primary Gas Production Rate Forecast | 217 |
| 5.5(a) | Primary (Oct-07) Pressure p | 218 |
| 5.5(b) | Primary (Oct-07) Water Saturation $S_w$ | 219 |
| 5.5(c) | Primary (Oct-07) Oil Saturation $S_o$ | 220 |
| 5.5(d) | Primary (Oct-07) Gas Saturation $S_g$ | 221 |

5.5(e) Primary (Oct-07) Bubble Point Pressure $p_b$ ..... 222

6.1(a) Chedderville Viking "A" Infill Drilling Location Map ..... 228
6.1(b) Infill Drilling Grid (40-acre Spacing) ..... 229
6.1(c) 5-Spot Pattern Waterflood with Water-Barrier ..... 230

6.2(a) Waterflood Production Forecast (08-13-37-8W5) ..... 231
6.2(b) Waterflood Production Forecast (06-13-37-8W5) ..... 232
6.2(c) Waterflood Production Forecast (08-14-37-8W5) ..... 233
6.2(d) Waterflood Production Forecast (08-18-37-7W5) ..... 234
6.2(e) Waterflood Production Forecast (08-17-37-7W5) ..... 235
6.2(f) Waterflood Production Forecast (14-07-37-7W5) ..... 236
6.2(g) Waterflood Production Forecast (14-12-37-8W5) ..... 237
6.2(h) Waterflood Production Forecast (16-12-37-8W5) ..... 238
6.2(i) Waterflood Production Forecast (08-07-37-7W5) ..... 239
6.2(j) Waterflood Production Forecast (06-07-37-7W5) ..... 240
6.2(k) Waterflood Production Forecast (16-07-37-7W5) ..... 241
6.2(l) Waterflood Production Forecast (06-08-37-7W5) ..... 242
6.2(m) Waterflood Production Forecast (14-08-37-7W5) ..... 243
6.2(n) Waterflood Production Forecast (06-17-37-7W5) ..... 244
6.2(o) Waterflood Production Forecast (06-18-37-7W5) ..... 245
6.2(p) Waterflood Production Forecast (16-11-37-8W5) ..... 246
6.2(q) Waterflood Production Forecast (06-12-37-8W5) ..... 247
6.2(r) Waterflood Production Forecast (08-12-37-8W5) ..... 248

6.3(a) Waterflood Injection Forecast (06-16-37-7W5) ..... 249
6.3(b) Waterflood Injection Forecast (16-08-37-7W5) ..... 250
6.3(c) Waterflood Injection Forecast (10-07-37-7W5) ..... 251
6.3(d) Waterflood Injection Forecast (12-07-37-7W5) ..... 252
6.3(e) Waterflood Injection Forecast (10-08-37-7W5) ..... 253
6.3(f) Waterflood Injection Forecast (12-08-37-7W5) ..... 254
6.3(g) Waterflood Injection Forecast (04-16-37-7W5) ..... 255
6.3(h) Waterflood Injection Forecast (02-17-37-7W5) ..... 256
6.3(i) Waterflood Injection Forecast (04-17-37-7W5) ..... 257
6.3(j) Waterflood Injection Forecast (02-18-37-7W5) ..... 258
6.3(k) Waterflood Injection Forecast (04-18-37-7W5) ..... 259
6.3(l) Waterflood Injection Forecast (10-12-37-8W5) ..... 260
6.3(m) Waterflood Injection Forecast (12-12-37-8W5) ..... 261
6.3(n) Waterflood Injection Forecast (02-13-37-8W5) ..... 262
6.3(o) Waterflood Injection Forecast (04-13-37-8W5) ..... 263
6.3(p) Waterflood Injection Forecast (02-14-37-8W5) ..... 264

6.4(a) Waterflood Average Reservoir Pressure Prediction ..... 265
6.4(b) Pool Cumulative Waterflood Production Forecast ..... 266
6.4(c) Pool Cumulative Waterflood Injection Forecast ..... 267

| | | |
|---|---|---|
| 6.5(a) | Pool Waterflood Oil Production Rate Forecast | 268 |
| 6.5(b) | Pool Waterflood Gas Production Rate Forecast | 269 |
| 6.5(c) | Pool Waterflood Water Production Rate Forecast | 270 |
| 6.5(d) | Pool Waterflood Water Injection Forecast | 271 |
| 6.6(a) | Waterflood (Oct-07) Pressure p | 272 |
| 6.6(b) | Waterflood (Oct-07) Water Saturation $S_w$ | 273 |
| 6.6(c) | Waterflood (Oct-07) Oil Saturation $S_o$ | 274 |
| 6.6(d) | Waterflood (Oct-07) Gas Saturation $S_g$ | 275 |
| 6.6(e) | Waterflood (Oct-07) Bubble Point $p_b$ | 276 |
| 7.1 | Path Dependence of Production Forecast | 277 |
| 7.2 | Reservoir State Possibilities for Irreversible Mutually-Exclusive Decision Pathways | 278 |
| 7.3 | Path-Dependent Control and Bifurcation of Depletion Paths from Switching Operation Modes | 280 |
| 7.4 | Transient Deviation in Near-State Variables | 282 |
| 7.5 | Unique Depletion Path in ($\mathcal{P}$,t) Space | 283 |
| 7.6(a) | Cumulative Oil Branches | 286 |
| 7.6(b) | Cumulative Gas Branches | 287 |
| 7.6(c) | Cumulative Water Production Branches | 288 |
| 7.6(d) | Cumulative Water Injection Branches | 289 |
| 7.6(e) | Average Reservoir Pressure Branches | 290 |
| 7.7(a) | Average Pool Oil Rate between Cumulative Oil | 292 |
| 7.7(b) | Average Pool Gas Rate between Cumulative Oil | 293 |
| 8.1 | Strategic Decision Hierarchy for Operation and Investment | 295 |
| 8.2 | Average Monthly Spot Oil Price | 301 |
| 8.3 | Lognormal Oil Price Expectations ($\mu$=0) | 302 |
| 8.4 | Price-Sensitive Action Regions $\mathcal{R}_i(\Theta_i)$ in Price-Time-Depletion | 310 |
| 8.5 | Terminal Mandatory Abandonment Boundary Condition | 313 |
| 8.6 | Feasible Depletion Space at Discrete Primary Oil Milestones | 315 |

8.7 Decision Times Track Discrete Depletion Milestones ..... 315

8.8 Feasible Depletion Space at Discrete Decision Times ..... 316

9.1 Remaining Depletion Strategy Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ..... 355

9.2 Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ for Primary oil $\mathcal{P}_1$=0 MSTB ..... 356

9.3 Primary Economic Limit Abandonment Price $s_{1A}^*(\mathcal{P}_1,t)$ ..... 357

9.4 Secondary Economic Limit Abandonment Price $s_{2A}^*(\mathcal{P}_2,t;\mathcal{P}_1)$ for $\mathcal{P}_1$=0 ..... 358

A1.1 Reservoir Grid Coordinate System ..... 364

A1.1 Irregular Thickness Partition with Skewed Elements ..... 365

A2.1 Primary Depletion-Time $(\mathcal{P}_1,t)$ Grid with Temporal Boundary ..... 375

A2.2 Secondary Depletion-Time $(\mathcal{P}_2,t)$ Grid with Temporal Boundary ..... 376

A2.3 Feasible Depletion State Cumulative Time Mapping ..... 377

A2.4 Partial Intervals at Branch End-Points ..... 378

A2.5 Backward Sweep Direction with Depletion Boundary Tracking ..... 379

A2.6 Boundary Bracketing and Incremental Tracking ..... 381

A2.7 Price-Time (s,t) Grid with Regular and Asymptotic Steps ..... 382

A2.8 Price Difference Lattice ..... 385

A2.9 Depletion Boundary Difference Lattice ..... 385

A2.10 Suspended Depletion Boundary Value Time Difference ..... 386

A2.11 Non-Stationary Depletion State Difference Lattice ..... 387

A2.12 Stationary Depletion State Difference Lattice ..... 388

# Nomenclature

| | |
|---|---|
| $A_1$ | primary abandonment expense ($) |
| $A_2$ | secondary abandonment expense ($) |
| $A_g$ | Darcy gas transmissibility at the block boundaries |
| $A_o$ | Darcy oil transmissibility at the block boundaries |
| $A_w$ | Darcy water transmissibility at the block boundaries |
| $B_g$ | gas formation volume factor (reservoir $ft^3/scf$) |
| $B_o$ | oil formation volume factor (reservoir bbl/STB) |
| $B_w$ | water formation volume factor (reservoir bbl/STB) |
| c | marginal net convenience yield rate per dollar unit of commodity held in inventory |
| $c_t$ | total compressibility ($psi^{-1}$) |
| $c_r$ | rock compressibility ($psi^{-1}$) |
| $c_o$ | oil compressibility ($psi^{-1}$) |
| $c_w$ | water compressibility ($psi^{-1}$) |
| $c_g$ | gas compressibility ($psi^{-1}$) |
| C | marginal net convenience yield |
| $\mathcal{C}_1$ | active primary control policy |
| $\mathcal{C}_2$ | active secondary waterflood control policy |
| $Cf$ | before-tax cash flow ($/day) |
| dLN | lognormal probability density |
| dm | probability density measure for future price state |
| dY | instantaneous dollar return on the portfolio |
| $\mathcal{D}$ | depletion strategy |
| $\mathbf{e}_x$ | rectilinear coordinate unit vector in x-direction |
| $\mathbf{e}_y$ | rectilinear coordinate unit vector in y-direction |
| $\mathbf{e}_z$ | rectilinear coordinate unit vector in z-direction |
| $f_1$ | primary fixed costs ($/day) |
| $f_2$ | secondary fixed costs ($/day) |
| F | futures price |
| g | gravitational constant |
| GOR | base gas-oil ratio |
| $\overline{GOR}$ | producing gas-oil ratio |
| h | effective completion interval thickness (ft) |
| $k_{rg}$ | gas relative permeability |
| $k_{rgro}$ | gas relative permeability in gas-oil at residual oil saturation |
| $k_{ro}$ | oil relative permeability |
| $k_{rog}$ | oil relative permeability in gas-oil system |
| $k_{roiw}$ | oil relative permeability in water-oil at irreducible water saturation |
| $k_{row}$ | oil relative permeability in water-oil system |

| | |
|---|---|
| $k_{rw}$ | water relative permeability |
| $k_{rwro}$ | water relative permeability in water-oil at residual oil saturation |
| $K_{12}$ | lump sum waterflood capital cost ($) |
| $K_x$ | absolute permeability (md) in x-direction |
| | maximum core permeability (md) |
| $K_y$ | absolute permeability (md) in y-direction |
| | 90° core permeability (md) |
| $K_z$ | absolute permeability (md) in z-direction |
| | vertical core permeability (md) |
| $\bar{K}$ | rock permeability tensor (md) |
| $M_1$ | primary depletion state partition |
| $M_2$ | secondary depletion state partition |
| MRL | base maximum rate limitation (STB/day) |
| Mscf | 1000 scf |
| MSTB | 1000 STB |
| MW | molecular weight (lbs/lb-mole) |
| $n_g$ | saturation exponent for $k_{rg}$ |
| $n_{og}$ | saturation exponent for $k_{rog}$ |
| $n_{ow}$ | saturation exponent for $k_{row}$ |
| $n_w$ | saturation exponent for $k_{rw}$ |
| $N_{Courant}$ | Courant number |
| $N_s$ | price state partition |
| $N_x$ | reservoir grid partition in x-direction |
| $N_y$ | reservoir grid partition in y-direction |
| $N_z$ | reservoir grid partition in z-direction |
| $R_{so}$ | gas-oil solubility (scf/STB) |
| $R_{sw}$ | gas-water solubility (scf/STB) |
| p | reservoir fluid pressure (psia) |
| | grid block pressure (psia) |
| $p_b$ | bubble point pressure (psia) |
| $p_{cgo}$ | gas-oil capillary pressure (psia) |
| $p_{cow}$ | oil-water capillary pressure (psia) |
| $p_g$ | gas pressure (psia) |
| $p_o$ | oil pressure (psia) |
| $p_{pc}$ | pseudo-critical pressure (psia) |
| $p_w$ | water pressure (psia) |
| $p_{wf}$ | flowing bottomhole pressure (psia) |
| $p_{wh}$ | well head pressure (psia) |
| $p_{wf}^{min}$ | minimum oil production bottomhole pressure constraint (psia) |
| $p_{wf}^{max}$ | maximum water injection bottomhole pressure constraint (psia) |
| $\Delta p_f$ | friction loss pressure drop (psi) |
| $\Delta p_h$ | head loss pressure drop (psi) |

| | |
|---|---|
| $\Delta p_{ke}$ | inertial loss pressure drop (psi) |
| $\Delta p_{pump}$ | external pump work (psi) |
| $\mathcal{P}_1$ | pooled cumulative primary oil production (MSTB)<br>primary near-state variable<br>primary production milestone |
| $\Delta\mathcal{P}_1$ | cumulative primary oil interval (MSTB) |
| $\mathcal{P}_2$ | pooled cumulative secondary oil production (MSTB)<br>secondary near-state variable<br>secondary production milestone |
| $\Delta\mathcal{P}_2$ | cumulative secondary oil interval (MSTB) |
| PI | well productivity index |
| $q_g$ | gas mass concentration source/sink (lbs/ $ft^3$/day) |
| $q_o$ | oil mass concentration source/sink (lbs/ $ft^3$/day) |
| $q_w$ | water mass concentration source/sink (lbs/ $ft^3$/day) |
| $Q$ | pooled production rate |
| $Q_g$ | standard gas volumetric flow rate (Mscf/day) |
| $Q_o$ | standard oil volumetric flow rate (STB/day) |
| $\underline{Q_o}$ | time-averaged pooled oil production rate |
| $\overline{Q}_o$ | daily oil production rate (STB/day) |
| $Q_o^{max}$ | well maximum oil production rate capacity (STB/day) |
| $Q_w$ | standard water volumetric flow rate (STB/day) |
| $Q_w^{max}$ | well maximum water injection rate capacity (STB/day) |
| r | real risk-free interest rate |
| $r_w$ | wellbore radius (ft) |
| R | lumped royalty rate |
| $\mathcal{R}$ | reservoir state ($p, S_w, S_g$) |
| $\mathcal{R}_1$ | primary action region ($s,t,\mathcal{P}_1$) |
| $\mathcal{R}_{1A}$ | primary early abandonment mode action region ($s,t,\mathcal{P}_1$) |
| $\mathcal{R}_{1C}$ | primary control operating mode action region ($s,t,\mathcal{P}_1$) |
| $\mathcal{R}_{1S}$ | primary suspended operating mode action region ($s,t,\mathcal{P}_1$) |
| $\mathcal{R}_2$ | secondary action region ($s,t,\mathcal{P}_2;\mathcal{P}_1$) |
| $\mathcal{R}_{2A}$ | secondary early abandonment mode action region ($s,t,\mathcal{P}_2;\mathcal{P}_1$) |
| $\mathcal{R}_{2C}$ | secondary control operating mode action region ($s,t,\mathcal{P}_2;\mathcal{P}_1$) |
| $\mathcal{R}_{2S}$ | secondary suspended operating mode action region ($s,t,\mathcal{P}_2;\mathcal{P}_1$) |
| s | stochastic spot oil price ($/bbl) |
| $s_{12}^*$ | critical waterflood investment price ($/bbl) |
| $s_{1CS}^*$ | critical primary operating price boundary between active control and suspended operations ($/bbl) |

| | |
|---|---|
| $s_{1CA}^*$ | critical primary operating price boundary for irreversible early abandonment from active control ($/bbl) |
| $s_{1SA}^*$ | critical primary operating price boundary for irreversible early abandonment from suspended operations ($/bbl) |
| $s_{2CS}^*$ | critical secondary operating price boundary between active control and suspended operations ($/bbl) |
| $s_{2CA}^*$ | critical secondary operating price boundary for irreversible early abandonment from active control ($/bbl) |
| $s_{2SA}^*$ | critical secondary operating price boundary for irreversible early abandonment from suspended operations ($/bbl) |
| scf | standard cubic foot (1 atm, 60° F) |
| S | skin factor |
| $S^*$ | phase volumetric bulk concentration |
| $S_g$ | gas saturation |
| $S_g^*$ | normalized gas saturation |
| $S_{gc}$ | critical mobile gas saturation |
| $S_l$ | liquid saturation |
| $S_o$ | oil saturation |
| $S_o^*$ | normalized oil saturation |
| $S_{org}$ | residual oil saturation in gas-oil |
| $S_{orw}$ | residual oil saturation in water-oil |
| $S_w$ | water saturation |
| $S_w^*$ | normalized water saturation |
| $S_{wir}$ | irreducible connate water saturation |
| STB | stock tank barrel (1 atm, 60° F) |
| t | time (days) |
| $t_o$ | cumulative oil production time (days) |
| $\Delta t^n$ | time step (days) |
| $\Delta t_{produce}$ | monthly cycle production interval (days) |
| T | overall strategic plan duration (years)<br>termination time (years)<br>delivery time |
| T | temperature (° F) |
| $T_{pc}$ | pseudo-critical temperature (° F) |
| $T_x$ | block boundary transmissibility (x-direction) |
| $T_y$ | block boundary transmissibility (y-direction) |
| $T_z$ | block boundary transmissibility (z-direction) |
| u | continuously compounded rate of return on spot oil price |
| **u** | propagation velocity |
| $v_1$ | primary variable unit costs ($/STB) |
| $v_2$ | secondary variable unit costs ($/STB) |
| $\mathbf{v}_g$ | gas Darcy velocity reservoir volumetric flux (ft/day) |
| $\mathbf{v}_o$ | oil Darcy velocity reservoir volumetric flux (ft/day) |

| | |
|---|---|
| $\mathbf{v}_w$ | water Darcy velocity reservoir volumetric flux (ft/day) |
| $V_g$ | reservoir gas volume (reservoir $ft^3$) |
| $V_o$ | reservoir oil volume (reservoir bbl) |
| $V_{scg}$ | gas volume (scf) at standard conditions (1 atm, 60° F) |
| $V_{sco}$ | oil volume (STB) at standard conditions (1 atm, 60° F) |
| $V_{scw}$ | water volume (STB) at standard conditions (1 atm, 60° F) |
| $V_w$ | reservoir water volume (reservoir bbl) |
| $\Delta V_b$ | elemental bulk volume ($ft^3$) |
| $\mathcal{V}$ | remaining production value ($) |
| $\mathcal{V}_1$ | remaining primary value ($) |
| $\mathcal{V}_{1A}$ | remaining primary value for early abandonment ($) |
| $\mathcal{V}_{1C}$ | remaining primary value under control policy ($) |
| $\mathcal{V}_{1S}$ | remaining primary value under pooled suspension ($) |
| $\mathcal{V}_2$ | remaining secondary value ($) |
| $\mathcal{V}_{2A}$ | remaining secondary value for early abandonment ($) |
| $\mathcal{V}_{2C}$ | remaining secondary value under control policy ($) |
| $\mathcal{V}_{2S}$ | remaining secondary value under pooled suspension ($) |
| $\Delta\mathcal{V}_{12}$ | payoff from waterflood investment option ($) |
| $W_1$ | dollars invested in holding oil in inventory ($) |
| $W_2$ | dollars shorted in oil futures contracts ($) |
| $W_3$ | dollars borrowed at the risk free rate ($) |
| WI | well injectivity index |
| WOR | water-oil ratio |
| $\Delta x$ | grid block length (ft) |
| $\mathbf{x}$ | coordinate vector (x, y, z) |
| $\Delta\mathbf{x}$ | volume element ($ft^3$) |
| $\Delta\mathbf{x}_{ijk}$ | grid block volume element ($ft^3$) |
| $\Delta y$ | grid block width (ft) |
| z | gas deviation factor |
| z | depth (ft) |
| z=0 | sea level |
| $z_0$ | formation top depth (ft subsea) |
| $\Delta z$ | thickness (ft)<br>grid block thickness (ft)<br>mechanical perforation zone thickness (ft) |

Greek Symbols

| | |
|---|---|
| $\beta$ | instantaneous expected rate of return on the futures contract |
| $\beta_g$ | three-phase permeability gas function |
| $\beta_w$ | three-phase permeability water function |

| | |
|---|---|
| $\gamma$ | standard deviation in the rate of return on the futures contract |
| $\gamma_g$ | gas gravity (Air=1) |
| $\gamma_o$ | oil gravity (Fresh Water=1) |
| $\gamma_w$ | saline water gravity (Fresh Water=1) |
| $\Delta_s$ | oil price state difference operator |
| $\Delta_t$ | time difference operator |
| $\Delta_x$ | x-direction difference operator |
| $\Delta_y$ | y-direction difference operator |
| $\Delta_z$ | z-direction difference operator |
| $\Delta_1$ | primary depletion state difference operator |
| $\Delta_2$ | secondary depletion state difference operator |
| $\phi$ | rock porosity |
| $\Phi_g$ | gas potential (psi) |
| $\Phi_o$ | oil potential (psi) |
| $\Phi_w$ | water potential (psi) |
| $\lambda_g$ | gas mobility |
| $\lambda_o$ | oil mobility |
| $\lambda_w$ | water mobility |
| $\mu$ | mean rate of return on spot oil price market |
| $\mu_g$ | gas viscosity (cp) |
| $\mu_o$ | oil viscosity (cp) |
| $\mu_w$ | water viscosity (cp) |
| $\rho_g$ | gas density (lbs/ft$^3$) |
| $\rho_o$ | oil density (lbs/ft$^3$) |
| $\rho_{scg}$ | gas density (lbs/ft$^3$) at standard conditions (1 atm, 60° F) |
| $\rho_{sco}$ | oil density (lbs/ft$^3$) at standard conditions (1 atm, 60° F) |
| $\rho_{scw}$ | saline water density (lbs/ft$^3$) at standard conditions (1 atm, 60° F) |
| $\rho_w$ | saline water density (lbs/ft$^3$) |
| $\theta_{1A}$ | terminal primary early abandonment operating mode |
| $\theta_{1C}$ | active primary operating mode under control policy |
| $\theta_{1S}$ | passive primary operating mode pooled suspension |
| $\Theta_1$ | primary operations |
| $\theta_{2A}$ | terminal secondary early abandonment operating mode |
| $\theta_{2C}$ | active secondary operating mode under control policy |
| $\theta_{2S}$ | passive secondary operating mode pooled suspension |
| $\Theta_2$ | secondary operations |

| | |
|---|---|
| $\sigma$ | non-stochastic annual oil price volatility |
| $\tau$ | time |
| | time to maturity ($\tau$=T–t). |
| $\tau_o$ | time to fill monthly oil quota (days) |
| $\tau_g$ | time to fill monthly gas quota (days) |
| $d\zeta$ | normal random variable with variance dt |
| $\Delta\xi$ | characteristic length (ft) |

Subscripts and Superscripts

| | |
|---|---|
| A | early abandonment operating mode |
| C | active control operating mode |
| g | gas phase |
| i | discrete (x) coordinate index |
| | discrete oil price (s) state index |
| | operation stage index |
| j | discrete (y) coordinate index |
| k | discrete (z) coordinate index |
| m | operating mode index |
| $m_1$ | discrete ($\mathcal{P}_1$) primary depletion state index |
| $m_2$ | discrete ($\mathcal{P}_2$) secondary depletion state index |
| n | discrete (t) time index |
| o | oil phase |
| s | oil price |
| S | suspended pool operating mode |
| sc | standard conditions (1 atm, 60° F) |
| w | water phase |
| x | x-direction |
| y | y-direction |
| z | z-direction |
| 1 | primary |
| 2 | secondary |
| * | boundary indicator |

# Chapter 1: Introduction

## 1.1 Production Stages

An oilfield may have more than one stage of economically viable oil production over its producing life. The first, or primary, production stage uses the natural expansion energy within the reservoir to displace fluids towards producing wells. Primary production declines as the intrinsic supply of potential energy is converted into displacement work. Increasing ultimate oil recovery by the reservoir-scale introduction of extrinsic energy may become a viable option at some point over primary decline. The timing of investment and the implementation that follows can be critical for a depletion strategy whose objective is to maximize the overall project economics. When additional energy can no longer increase recovery in an economic manner, the oilfield will be abandoned.

In primary production, the sources of energy may come from fluid expansion, solution gas drive, water drive, gas cap drive, compaction drive or a combination of these natural depletion mechanisms. The reservoir may be stimulated at or near producing wells by mechanical, chemical, thermal or explosive means. Stimulation technologies, like acidizing and fracturing, attempt to increase well productivity by reducing bottleneck resistances to fluid flow. Artificial lift technologies may also supplement naturally flowing wells with the additional energy needed to pump fluids to the surface.

A depletion strategy may begin to develop as information about reservoir potential materializes in the early phase of primary production. Preferred recovery schemes, based on reservoir characteristics, fluid properties and reservoir state, may then be considered for the next stage of oil production. Various schemes have been developed to enhance oil recovery for different reservoir scenarios. These enhanced oil recovery (EOR) schemes are classified as secondary or tertiary technologies. Secondary recovery schemes, like pattern waterflooding, immiscible gas flooding and pressure maintenance by water or immiscible gas injection, supplement the natural expansion energy of the reservoir. Tertiary recovery schemes, like hydrocarbon miscible flooding, miscible $CO_2$ flooding, steamflooding and in situ combustion, introduce chemical or thermal energy into the reservoir system to reduce the viscous and interfacial forces that impede porous media flow. Each recovery scheme may have many variations which implement different flood patterns and operating practices. Each application will be unique and require customized engineering solutions to address the specific design problems.

## 1.2 Secondary Recovery Option

While most depletion strategies with enhanced recovery options have common economic objectives, their implementation will differ from case to case. This work has chosen to supplement the theoretical development for constructing optional-stage depletion strategies with a realistic application to a particular oilfield. The reservoir example used throughout this work is the Chedderville Viking "A" Pool located 160 km southwest of Edmonton, Alberta, Canada. This is a light oil pool in early primary production. The depletion strategy constructed for this pool considers an optional secondary recovery stage by pattern waterflood. Although the reservoir aspects of this study will be field specific, the production forecasting methodology and the economic decision model can be extended to most operations that consider an optional recovery stage.

Ultimate recovery from this particular reservoir will depend on the depletion strategy that manages both natural depletion under primary production and pattern waterflooding under secondary recovery. Factors that can be controlled by human intervention in primary production include the number, placement, timing and control of production wells. Well capabilities can be enhanced by stimulation to increase wellbore permeability and installation of artificial lift equipment to lower flowing bottomhole pressures. In secondary recovery, additional degrees of freedom will include the number, placement, timing and control of water injection wells. Production will depend on the multi-phase flow of oil, water and gas through the overall production system of porous reservoir media, subsurface equipment, vertical and directional tubings and casings, horizontal and inclined surface flow lines, and flow through any restrictions and chokes. Peak liquid production will be limited by reservoir productivity and the design capacity of the facilities for gathering, separating and treating produced fluids. Peak water injection will be limited by reservoir injectivity and the design capacity of the injection system and water source. Regulatory constraints may limit monthly oil and gas production and restrict minimum well spacing. Well workovers and installation of new equipment may interrupt production continuity.

The engineering design objective attempts to minimize pressure drops in each portion of the production system such that optimal flow conditions are achieved at maximum efficiency. The integrated system design between reservoir and surface facilities is highly complex and requires accurate relationships between flow rates and pressures. Economic criteria determines the scaling decisions that fix the number of wells and size the surface facilities accordingly. Economic criteria also determine the timing decisions for drilling new wells, adding new equipment, expanding existing facilities, implementing waterflood projects and abandoning field operations. Finally, economic criteria

determine the control decisions for daily and monthly production from individual wells, and collectively from the entire pool.

### 1.3 Objectives

The objective of the present work is to develop a methodology using reservoir simulation for constructing optional-stage depletion strategies that incorporate a probabilistic economic model for the timing valuation of recovery options. The tasks set forth are:

1) To approximate depletion state variables based on cumulative oil production and to define a feasible depletion space for primary and secondary operations.

2) To formulate a branched differential decision process model and use dynamic programming techniques to find investment and operating decision rules that maximize the modelled economic value of remaining operating alternatives over a strategic window. The time-dependent project value is to depend on the state of oil price, the state of depletion and the depletion strategy. An intertemporal equilibrium asset valuation model, based on oil futures price dynamics, is to be used to value production cash flows from alternative recovery paths in terms of macro-economic factors and field-specific costs. The decision model is to be based on probabilistic economic scenarios that examine nested primary and secondary operating modes for active control policy, pooled suspension and early abandonment. The dynamic programming algorithm is to track the feasible depletion state boundary constraint for decision times based on cumulative production milestones.

3) To develop a reservoir simulation tool with branched forecasting capabilities for an optional secondary recovery stage at discrete depletion states along the primary life cycle. A three-dimensional, three-phase black oil reservoir simulation tool is to be adapted to forecast waterflood branches in a production tree. A user-friendly simulation tool with dynamic memory allocation, keyword parsing and tree data structures is to be developed in a Microsoft Excel 5.0 workbook environment with program modules in Visual Basic. Tabular data, three-dimensional array data and structured well control schedules are to be organized in multiple worksheets of a common simulation workbook.

4) To develop a well management system for monthly oil and gas regulatory quotas and implement the system into the reservoir simulation tool. The model production rate regulator and accounting system is to be based on Alberta oil and gas monthly allowables where constrained production cycles for monthly gas production has precedence over monthly oil production.

5) To propose a primary control policy that adheres to regulatory constraints and a secondary control policy to meet waterflood design specifications. The control policies are to be based on heuristics that govern the individual rate specification for single well entities and collective rate specifications for blocks of wells.

6) To demonstrate the realistic application of the optional-stage depletion strategy methodology for the Chedderville Viking "A" Pool. In order to demonstrate the realistic application this work has chosen to :

a) characterize the reservoir for Chedderville Viking "A" using geostatistics
b) match historical production and pressure data
c) design a feasible waterflood project
d) propose a primary control policy that adheres to regulatory constraints
e) propose a secondary control policy to meet design objectives
f) forecast waterflood production branches along the primary life cycle
g) generate a model depletion strategy for Chedderville Viking "A"
h) analyze the investment timing option and determine the economic limit

## 1.4 Guiding Philosophy

The main factor effecting primary oil recovery is the natural depletion mechanism. The decision to continue with primary operations will depend on the expected value of remaining primary production forecasts. Production forecasts will depend on primary controls and expansion decisions. Waterflooding is a proven secondary technology to improve oil recovery. Solution gas drive reservoirs like Chedderville Viking "A" are good candidates for waterflooding. The decision to waterflood will depend on the expected payoff from predicted waterflood oil production. Waterflood prediction will depend on waterflood design and secondary control decisions.

An optimality criterion for waterflood design is somewhat evasive and the concept misleading. A truly optimal design would determine the number, placement, timing and control of wells to maximize expected project value in accordance with regulatory constraints and economic criteria. The design choice may not necessarily be unique, with different configurations and policies leading to the same project value. Different configurations may become more attractive as the probability structure of macro-economic scenarios unfold with time. The problem here is not to find an optimal design, but to find optimal decision rules for a particular design.

A waterflood strategy with a fixed pattern design may be tailored for a particular primary depletion state. The same waterflood may or may not perform as well for other primary depletion states. The design process concentrates on

refining performance for a unique primary depletion state at a particular point in time. The decision process defines rules for choosing the fixed design at different times over primary decline.

Secondary waterflood depletion paths branch from originating primary depletion states. The waterflood investment decision will compare the net value of initiating a secondary recovery stage with the remaining value of primary production. Waterflood stage recoveries may change with declining primary production. Economic evaluation should consider the timing impact of how these changes will affect the overall project value.

Before any informed decisions can be made to manage the reservoir economically, or plan for future operations, management personnel should know what it is they are trying to manage. They should acquire sufficient information about the reservoir characteristics through core samples, logs, well tests, fluid samples and accumulated production history to forecast the production capability of the entire pool. Reliability of the production forecast will depend on the analysis techniques used, validity of the data measured and availability of information.

A depletion strategy will emerge as reservoir characteristics and production capabilities are better understood. Design and operating decisions will be made to economically manage the reservoir and plan for future operations. Some decisions will react to changing economic conditions and unfolding physical events. Control strategies will establish guiding policies to improve existing operations and design future expansions.

Management personnel should have some measure of how effective their decisions will be and how they will attain the objectives set forth. They need to know what they can do and how to do it. Management personnel should be familiar with all aspects of their operation and have a system to facilitate decision-making. They should have some means to forecast performance of the overall production system and have the ability to test the outcomes from the decisions they can make.

Before a depletion strategy can be analyzed on the model system, the reservoir model should first be validated with historical data. The reservoir simulation tool has limitations that rest on the accuracy of the reservoir description, the bias of the underlying model and the discretization errors in numerical solution. The integrity of simulation results depends on the quality of production and pressure data, and the ability to calibrate the model accurately by history matching. Model rejection or acceptance will depend on the degree of fit. The degree of fit will depend on interacting performance criteria and will tend to be subjective in some cases.

## 1.5 Sources of Data

The data for Chedderville Viking "A" was provided by Canadian Hunter Exploration Ltd. of Calgary, Alberta, for the undergraduate Design Course, PET.E. 496, instructed by Dr. Q.T. Doan at the University of Alberta. The data package included:

- geological and geographic data
- well completions, perforation zones and stimulation treatments data
- core data and well log data
- PVT data
- capillary pressure data (Canadian Hunter Waterflood Design Study)[1]
- relative permeability data (Canadian Hunter Waterflood Design Study)
- monthly production data
- bottomhole pressure data (Energy Resources Conservation Board)
- maximum monthly rate limitations and gas-oil ratios
- well capital cost data

Supplementary data was obtained from GEOBASE, CD PUBCO Inc., Calgary, Alberta, to corroborate production histories and well data.

Typical operating costs for Alberta oilfields were obtained through direct consultation with the Alberta Department of Energy[2]. These included:

- fixed operating costs per well
- variable operating costs per barrel of oil produced
- water injection conversion costs
- well abandonment costs correlated with depth

Macro-economic data for representative average monthly oil prices were obtained from The Monthly Commodity Price Bulletin. Nominal risk-free interest and inflation rates were based on data from the Canadian Economic Observer (Nov 1994), Statistics Canada Catalogue No. 11-010 Monthly.

- Dubai, U.K. Brent and Alaska Average, SPOT, F.O.B. (1991-1994)
- Government of Canada 3-month Treasury Bills (1994)
- Consumer Price Index (1994)

---

1 Canadian Hunter Chedderville Waterflood Design Study, Hycal Energy Research Laboratories Ltd., Calgary, Oct 25, 1993.

2 Consultation with John E. Faltinson, Alberta Department of Energy.

# Chapter 2: Reservoir Characterization

## 2.1 Reservoir Description Process

Field data is sparse and irregular, with point estimates at a few wells dispersed over a relatively large reservoir domain. Average values can suffice to represent three-dimensional (3-D) macroscopic properties for reservoirs with small variations in sample data. Large variations and discontinuities must be resolved by refining reservoir attributes with a descriptive model. Different recovery schemes for different reservoir conditions will require different simulation models. Reservoir simulators are engineering tools used to forecast production for particular sets of production and reservoir criteria. The simulation model outlined in Appendix A1 describes the observed reservoir flow behaviour in Chedderville Viking "A" and can be used to predict future waterflood response. This model requires data filled on a block-centered grid. The modelling objective set forth is to sufficiently describe the reservoir with the simplest possible grid.

The actual variation in reservoir properties between point estimates is uncertain. The sample represents a single realization from a distribution of possible reservoir conditions. Rock attributes are randomly distributed at the microscopic scale, but may have certain trends at the macroscopic scale. The description process used to characterize the reservoir assumes macroscopic continuity within the reservoir domain bounded by known geological barriers.

The choice in grid size may be constrained by computational power. The areal partition selected in this work used a 10-acre (0.125 mile × 0.125 mile) grid overlay. Many data fill techniques are available to generate regular matrices from irregular data. Commercially available software, such as Spyglass® Transform, provides nearest neighbour, kernel smoothing, linear interpolation, weighted fill and kriging methods. Of these, kriging is preferred. Kriging uses a weighted calculation to minimize the statistical variance of the array according to their distance (Delhomme 1978). All data fill operations in the description process for Chedderville Viking "A" used Spyglass® Transform kriging with a spherical distribution function and the largest possible sample size per kriging pass. The original sample values were preserved and default settings were used for the kriging parameters of range, variance and nugget. The nugget parameter is the minimum variance value for unknown data values. Data manipulation and processing was performed with Microsoft Excel® 5.0 for organizing, tabulating, calculating and plotting numeric information. Customized mapping software was developed using Microsoft Visual Basic® modules in the Microsoft Excel® 5.0 environment.

Even with these tools, obtaining a representative reservoir description is more of an art than a science. The description process for each reservoir property is coupled with the description processes for all other reservoir properties, and is iterative in nature. The initial model may be adjusted and recast many times before an acceptable representation is attained through history matching production and pressure data (Mattax and Dalton, 1990). Manual history matching involves the recursive refinement of input data subject to the degree of fit between simulation output and historical performance measurements. The reservoir data presented in this chapter is the data input for the three-dimensional, three-phase black oil simulator. This chapter shows only the final results obtained over countless trials of iterative history matching, and outlines some of the problem-solving difficulties incurred.

## 2.2 Reservoir Simulation

Mattax and Dalton (1990) discuss a wide range of reservoir simulation topics and give a good overview of the subject. The reservoir simulation model used in this work describes simultaneous multiphase fluid flow of oil, water and gas in porous media to predict oil production from the reservoir (Farouq Ali 1980). The black oil reservoir model accounts for fluid and rock compressibility, gas-oil and gas-water solubilities, oil-water and gas-oil capillary pressures, three-phase relative permeabilities and variable bubble point pressures. The simulator can handle the non-linearities in fluid properties, heterogeneities in the reservoir, discontinuities in the geology and multi-well control. A well management system model allows for scheduling and regulation of wells under maximum monthly rate limitations and maximum gas-oil ratios. The well management system model is described in Chapter 3.

Reservoir simulators solve the nonlinear partial differential equations describing porous media flow using numerical finite-difference techniques. The material balance formulation using Darcy-continuity equations is outlined in Appendix A1. The formulation is based on the "Black Oil Applied Simulation Tool (BOAST)" developed in FORTRAN by Franchi *et al.* (1982). The model uses the implicit-pressure explicit-saturation (IMPES) sequential solution procedure (Sheldon *et al.* 1960, Stone and Garder 1961). This method solves the derived oil pressure equation implicitly and then determines phase saturations explicitly using calculated pressures. Finite-difference equations are solved using a direct method with symbolic D4-ordering (Oguztoreli 1984, Oguztoreli 1988). The actual simulator implementation used Microsoft Visual Basic modules in a Microsoft Excel 5.0 workbook. This software development environment was chosen for its user interface with built-in spreadsheet, charting and programming facilities. The simulator developed for this work has improved modifications in well management, state initialization, three-phase relative permeability, cubic spline interpolation, performance data accounting, branched

production trees and overall user interface. Tracking branched production possibilities on a data tree structure is the foundation for analyzing the timing impact of an optional waterflood stage.

The three-dimensional three-phase black oil reservoir simulator is capable of forecasting primary production and waterflood for most, but not all, reservoir conditions. In this simulation study, we must keep in mind that production forecasts become increasingly less reliable as projected further into the future, and should be interpreted as a quantitative guide, rather than the absolute rule.

## 2.3 State of Reservoir Information

The current state of primary production operations in the Chedderville Viking "A" pool is defined on the calendar date of October 1, 1994. The initial state, marked by the first production record from the pool, is defined on the calendar date of November 1, 1987. Reservoir data was extracted from the Canadian Hunter (1994) data package and GEOBASE (1993). This information can be grouped as:

- geological and geographic data
- well perforation zone data
- core data and well log data
- PVT data
- capillary pressure data
- relative permeability data
- bottomhole pressure data
- production data

## 2.4 Geological and Geographic Data

The Viking "A" pool in the Chedderville field is located 160 km southwest of Edmonton in the legal subdivisions of township 37, ranges 7 and 8, west of meridian 5. The hydrocarbon bearing deposit lies in the Viking Sandstone formation between overlying Shaftesbury Sea shales and underlying Joli Fou shales. The reservoir was initially classified as undersaturated with ordinary black oil. This is a light oil pool in early primary production with 19 wells drilled at the time of investigation (Oct 1994). These wells are listed in geographic and historical orders in Tables 2.1(a) and (b), respectively. Figure 2.1 shows the location of these wells with respect to their legal subdivisions. Reservoir boundaries are delineated by sandstone continuity and fluid transmissibility through pressure communication with adjacent media. A fault defines the western boundary which separates Viking "A" and Viking "S" pools. The oil-bearing deposit thins out at the northern edge and virtually vanishes at wells 14-18-37-7W5 and 04-22-37-7W5. The southern boundary isolates Viking "B"

and is marked by a sudden reduction in rock permeability to fluid transmission and by a thinning of pay zone.

## 2.5 Perforation Zone Data

Most of the well data was consistent between Canadian Hunter (1994) and GEOBASE (1993), however, discrepancies were evident in perforation zone depths. Depths are measured from kelly bushing elevations at the surface. Geological revisions in GEOBASE (1993) to the original perforation zone depths had been made to those wells directionally drilled at or near the subtle fault delineating the western pool boundary (Figure 2.1). Earlier estimates of the reservoir structure and associated oil in place had also been revised as new information concerning pressure communication was revealed through the addition of new wells to the pool. The revised perforation data from GEOBASE (1993) was used in this work. These perforation zones are assumed as net pay and their corresponding depths and thicknesses are listed in Tables 2.1(a) and 2.1(b).

Typically, a principal axis transformation aligns the areal coordinate system with core-maximum and core-90° permeability trends in the reservoir. These longitudinal and transverse permeability directions corresponds to the x-axis and y-axis, respectively. The longitudinal x-axis is assumed to coincide with the east-west length of the pool. The reservoir was delineated on a regular 64×24 10-acre areal grid overlay (Figure 2.2). Delineation was based on contour-thresholding a kriged reservoir thickness above 3.75 feet. A boundary mask was superimposed to reflect the discontinuity at the western fault and the segmentation of Viking "B". Kriged reservoir thickness was forced continuously to 0.5 feet at northern and southern edges to align east-west with abandoned dry-hole wells. Viking "C" was also segmented by forcing thickness continuity of 0.5 feet at the north-eastern corner of the grid. The grid boundary was fine-tuned manually with contour and surface plot visualization as shown in Figures 2.3(a) and 2.3(b), respectively. Fine-tuning adjustments were made to maintain region convexity, long boundary runs and smooth boundary transitions. A high ridge with a continuous east-west crest was forced over the mid-length of the reservoir, after feedback from pressure history matching indicated a larger deposit than initially interpolated. The final trimmed reservoir geometry fit on a 54×18 grid with an areal span of 6450 acres and an average thickness of $\Delta z$=16.8 feet. The resulting boundary was used to areally mask all other reservoir properties which were kriged without any forcing boundary constraints. Kelly bushing elevation contour and surface plots are shown in Figures 2.4(a) and (b). Contour and surface plots for the sub-sea depth of the reservoir top are shown in Figures 2.5(a) and (b). The pool has and east-west dip, from 4900 feet at the eastern edge to 5250 feet at the western boundary.

| | Chedderville Viking A Well Data Base | | | | | Spud Date | Flow Status | Core Sample | Kelly Bushing Elevation (ft) | Perf Top Depth KB (ft) | Perf Bottom Depth KB (ft) | Zone Thickness (ft) | Perf Top Depth Subsea (ft) | Perf Bottom Depth Subsea (ft) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Well | LSD | SEC | TWP | RGE | W | | | | | | | | | |
| 1 | 8 | 7 | 37 | 7 | 5 | 30-Nov-93 | Flowing/Pumping | YES | 3567.6 | 8684.4 | 8704.1 | 19.7 | 5116.8 | 5136.5 |
| 2 | 14 | 7 | 37 | 7 | 5 | 8-Jun-93 | Flowing/Pumping | YES | 3546.6 | 8668.0 | 8697.5 | 29.5 | 5121.4 | 5150.9 |
| 3 | 8 | 8 | 37 | 7 | 5 | 18-Oct-87 | Viking B | | 3575.5 | 8645.0 | 8658.1 | 13.1 | 5069.6 | 5082.7 |
| 4 | 16 | 8 | 37 | 7 | 5 | 18-Jul-92 | Flowing/Pumping | YES | 3530.5 | 8546.6 | 8582.7 | 36.1 | 5016.1 | 5052.2 |
| 5 | 8 | 9 | 37 | 7 | 5 | 18-Oct-87 | Abandoned | | 3533.1 | 8525.3 | 8526.9 | 1.6 | 4992.1 | 4993.8 |
| 6 | 14 | 9 | 37 | 7 | 5 | 8-Feb-86 | Flowing/Pumping | NO | 3524.3 | 8507.2 | 8517.1 | 9.8 | 4982.9 | 4992.8 |
| 7 | 16 | 9 | 37 | 7 | 5 | 15-Sep-87 | Flowing/Pumping | NO | 3556.8 | 8526.9 | 8540.0 | 13.1 | 4970.1 | 4983.3 |
| 8 | 6 | 14 | 37 | 7 | 5 | 22-Nov-87 | Capped Gas | YES | 3482.9 | 8366.1 | 8389.1 | 23.0 | 4883.2 | 4906.2 |
| 9 | 6 | 15 | 37 | 7 | 5 | 28-Nov-88 | Flowing/Pumping | YES | 3504.6 | 8425.2 | 8444.9 | 19.7 | 4920.6 | 4940.3 |
| 10 | 6 | 16 | 37 | 7 | 5 | 28-Jul-90 | Flowing/Pumping | NO | 3507.2 | 8431.8 | 8448.2 | 16.4 | 4924.5 | 4940.9 |
| 11 | 8 | 17 | 37 | 7 | 5 | 19-Feb-93 | Flowing/Pumping | YES | 3485.9 | 8507.2 | 8520.3 | 13.1 | 5021.3 | 5034.4 |
| 12 | 8 | 18 | 37 | 7 | 5 | 21-Feb-92 | Flowing/Pumping | NO | 3536.4 | 8615.5 | 8628.6 | 13.1 | 5079.1 | 5092.2 |
| 13 | 14 | 18 | 37 | 7 | 5 | 28-Nov-90 | Abandoned | | 3520.3 | 8663.1 | 8664.7 | 1.6 | 5142.7 | 5144.4 |
| 14 | 4 | 22 | 37 | 7 | 5 | 14-Mar-64 | Abandoned | | 3429.1 | 8376.0 | 8379.3 | 3.3 | 4946.9 | 4950.1 |
| 15 | 14 | 12 | 37 | 8 | 5 | 30-Jul-93 | Flowing/Pumping | NO | 3592.8 | 8838.6 | 8871.4 | 32.8 | 5245.7 | 5278.5 |
| 16 | 16 | 12 | 37 | 8 | 5 | 26-Aug-93 | Flowing/Pumping | NO | 3581.4 | 8736.9 | 8763.1 | 26.2 | 5155.5 | 5181.8 |
| 17 | 6 | 13 | 37 | 8 | 5 | 10-Mar-90 | Flowing/Pumping | YES | 3572.8 | 8779.5 | 8792.7 | 13.1 | 5206.7 | 5219.8 |
| 18 | 8 | 13 | 37 | 8 | 5 | 20-Dec-89 | Flowing/Pumping | NO | 3576.8 | 8733.6 | 8746.7 | 13.1 | 5156.8 | 5169.9 |
| 19 | 8 | 14 | 37 | 8 | 5 | 27-Sep-90 | Flowing/Pumping | YES | 3608.9 | 8851.7 | 8864.8 | 13.1 | 5242.8 | 5255.9 |

Table 2.1(a): Chedderville Viking "A" Well List Geographic Order (Oct-94)

| | Chedderville Viking A Well Data Base | | | | | Spud Date | Flow Status | Core Sample | Kelly Bushing Elevation (ft) | Perf Top Depth KB (ft) | Perf Bottom Depth KB (ft) | Zone Thickness (ft) | Perf Top Depth Subsea (ft) | Perf Bottom Depth Subsea (ft) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Well | LSD | SEC | TWP | RGE | W | | | | | | | | | |
| 14 | 4 | 22 | 37 | 7 | 5 | 14-Mar-64 | Abandoned | | 3429.1 | 8376.0 | 8379.3 | 3.3 | 4946.9 | 4950.1 |
| 6 | 14 | 9 | 37 | 7 | 5 | 8-Feb-86 | Flowing/Pumping | NO | 3524.3 | 8507.2 | 8517.1 | 9.8 | 4982.9 | 4992.8 |
| 7 | 16 | 9 | 37 | 7 | 5 | 15-Sep-87 | Flowing/Pumping | NO | 3556.8 | 8526.9 | 8540.0 | 13.1 | 4970.1 | 4983.3 |
| 3 | 8 | 8 | 37 | 7 | 5 | 18-Oct-87 | Viking B | | 3575.5 | 8645.0 | 8658.1 | 13.1 | 5069.6 | 5082.7 |
| 5 | 8 | 9 | 37 | 7 | 5 | 18-Oct-87 | Abandoned | | 3533.1 | 8525.3 | 8526.9 | 1.6 | 4992.1 | 4993.8 |
| 8 | 6 | 14 | 37 | 7 | 5 | 22-Nov-87 | Capped Gas | YES | 3482.9 | 8366.1 | 8389.1 | 23.0 | 4883.2 | 4906.2 |
| 9 | 6 | 15 | 37 | 7 | 5 | 28-Nov-88 | Flowing/Pumping | YES | 3504.6 | 8425.2 | 8444.9 | 19.7 | 4920.6 | 4940.3 |
| 18 | 8 | 13 | 37 | 8 | 5 | 20-Dec-89 | Flowing/Pumping | NO | 3576.8 | 8733.6 | 8746.7 | 13.1 | 5156.8 | 5169.9 |
| 17 | 6 | 13 | 37 | 8 | 5 | 10-Mar-90 | Flowing/Pumping | YES | 3572.8 | 8779.5 | 8792.7 | 13.1 | 5206.7 | 5219.8 |
| 10 | 6 | 16 | 37 | 7 | 5 | 28-Jul-90 | Flowing/Pumping | NO | 3507.2 | 8431.8 | 8448.2 | 16.4 | 4924.5 | 4940.9 |
| 19 | 8 | 14 | 37 | 8 | 5 | 27-Sep-90 | Flowing/Pumping | YES | 3608.9 | 8851.7 | 8864.8 | 13.1 | 5242.8 | 5255.9 |
| 13 | 14 | 18 | 37 | 7 | 5 | 28-Nov-90 | Abandoned | | 3520.3 | 8663.1 | 8664.7 | 1.6 | 5142.7 | 5144.4 |
| 12 | 8 | 18 | 37 | 7 | 5 | 21-Feb-92 | Flowing/Pumping | NO | 3536.4 | 8615.5 | 8628.6 | 13.1 | 5079.1 | 5092.2 |
| 4 | 16 | 8 | 37 | 7 | 5 | 18-Jul-92 | Flowing/Pumping | YES | 3530.5 | 8546.6 | 8582.7 | 36.1 | 5016.1 | 5052.2 |
| 11 | 8 | 17 | 37 | 7 | 5 | 19-Feb-93 | Flowing/Pumping | YES | 3485.9 | 8507.2 | 8520.3 | 13.1 | 5021.3 | 5034.4 |
| 2 | 14 | 7 | 37 | 7 | 5 | 8-Jun-93 | Flowing/Pumping | YES | 3546.6 | 8668.0 | 8697.5 | 29.5 | 5121.4 | 5150.9 |
| 15 | 14 | 12 | 37 | 8 | 5 | 30-Jul-93 | Flowing/Pumping | NO | 3592.8 | 8838.6 | 8871.4 | 32.8 | 5245.7 | 5278.5 |
| 16 | 16 | 12 | 37 | 8 | 5 | 26-Aug-93 | Flowing/Pumping | NO | 3581.4 | 8736.9 | 8763.1 | 26.2 | 5155.5 | 5181.8 |
| 1 | 8 | 7 | 37 | 7 | 5 | 30-Nov-93 | Flowing/Pumping | YES | 3567.6 | 8684.4 | 8704.1 | 19.7 | 5116.8 | 5136.5 |

Table 2.1(b): Chedderville Viking "A" Well List Historical Order (Oct-94)

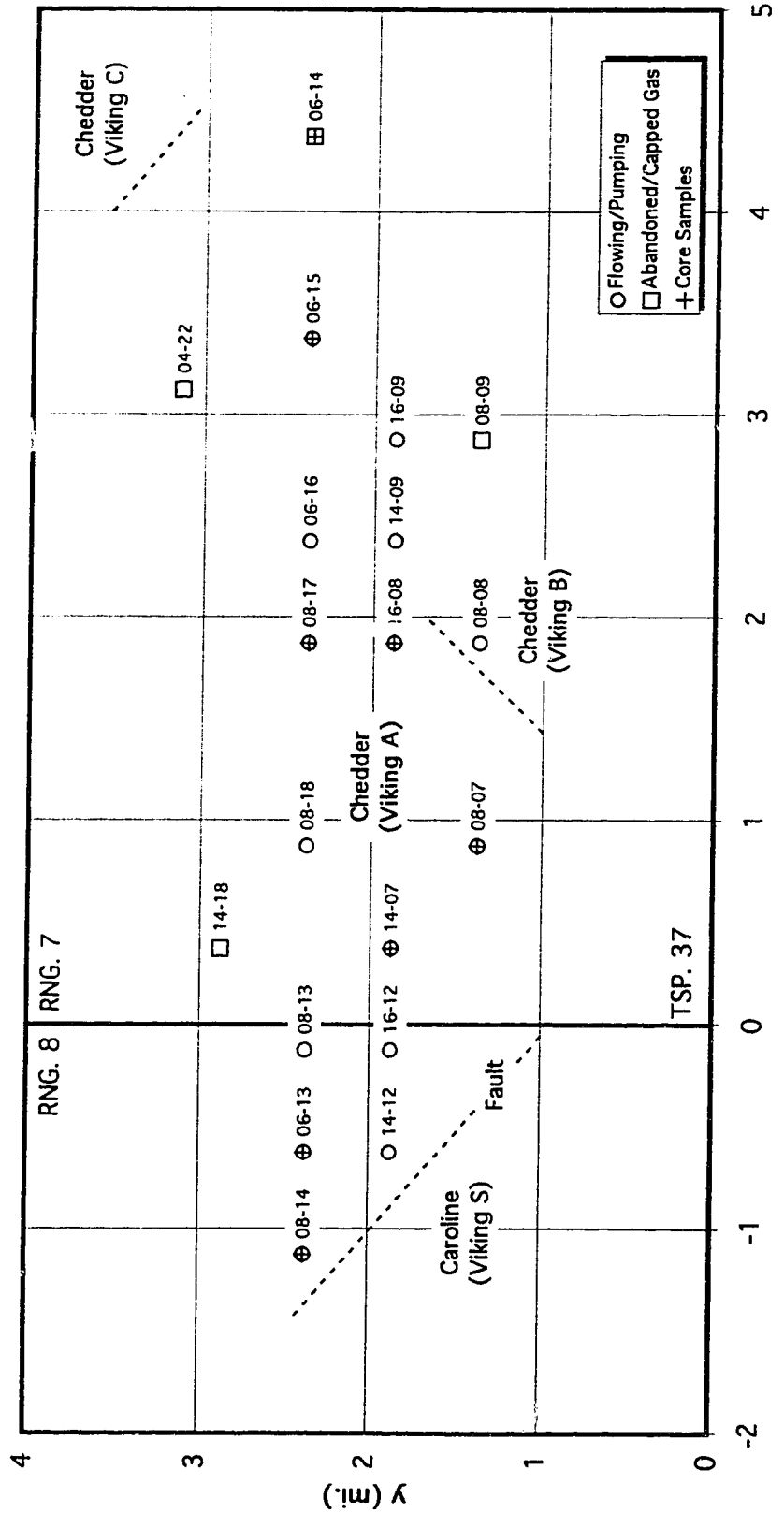



Figure 2.1: Chedderville Viking "A" Well Location Map

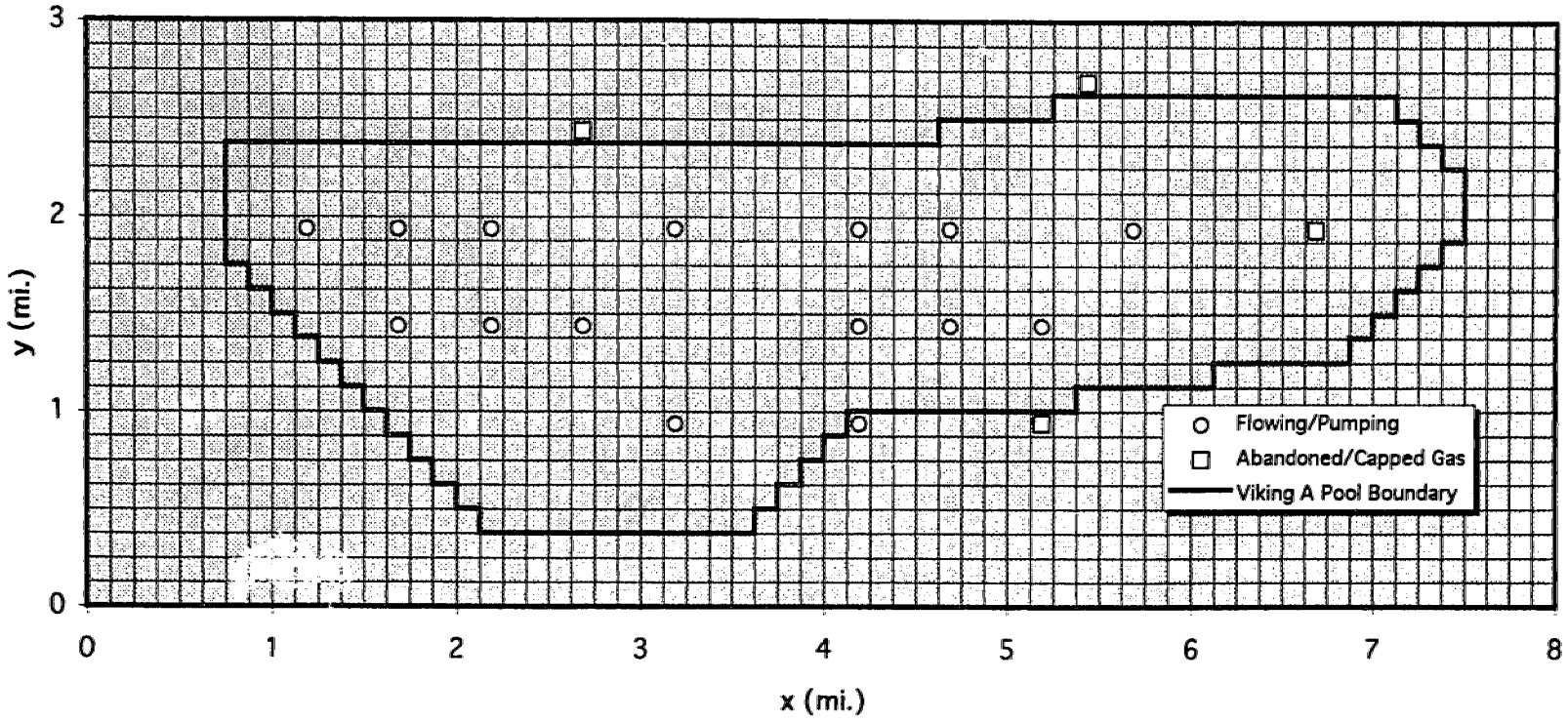



Figure 2.2: Chedderville Viking "A" Grid (10 Acre) Overlay

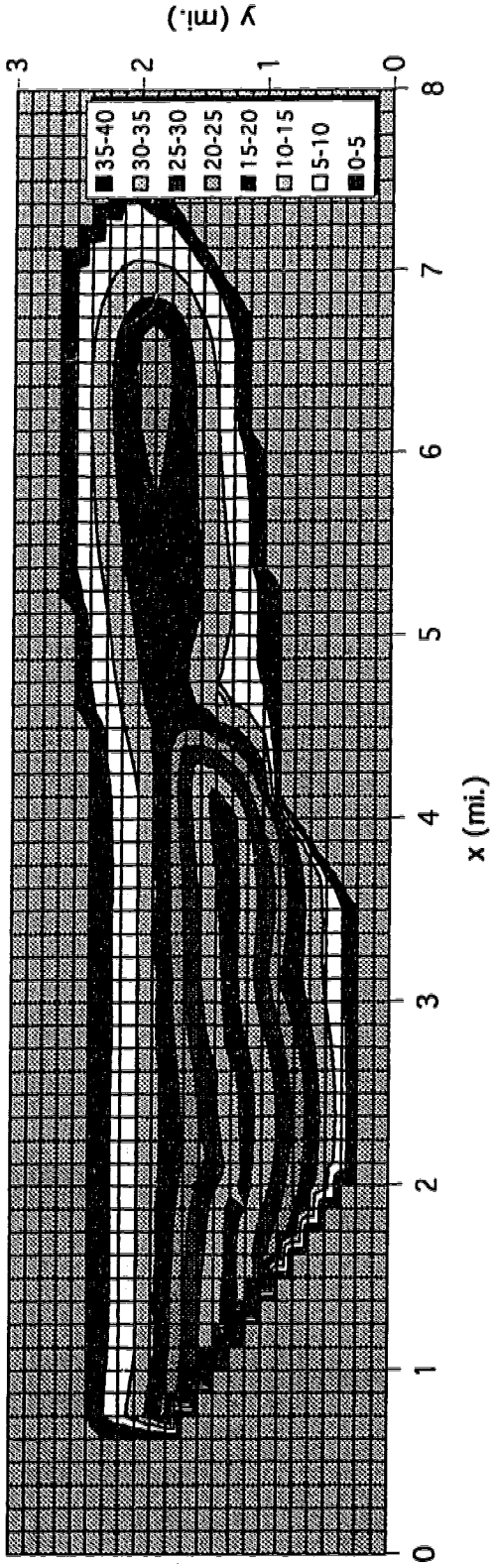



Figure 2.3(a): Reservoir Thickness Δz (ft)

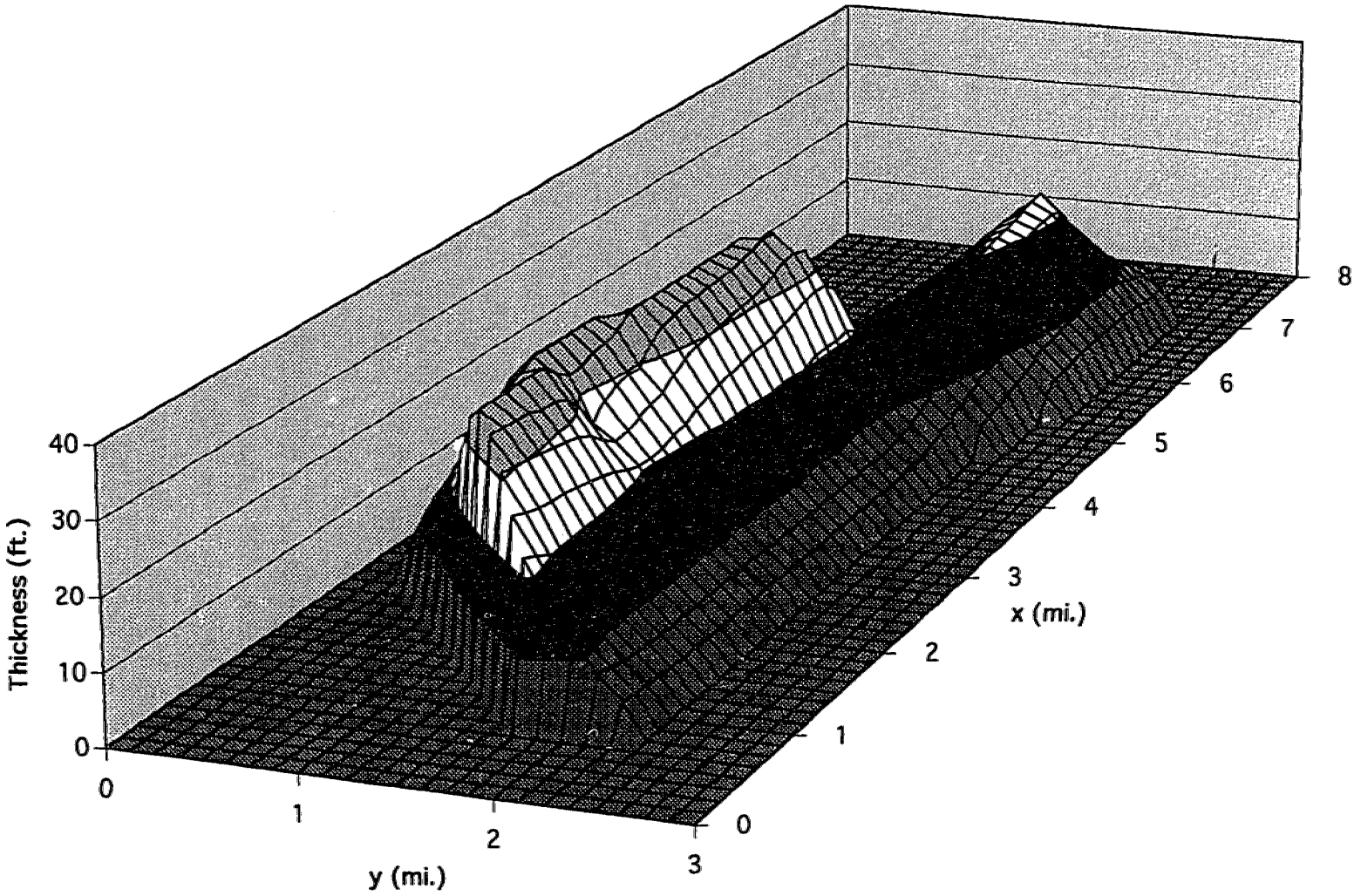



Figure 2.3(b): Reservoir Thickness $\Delta z$

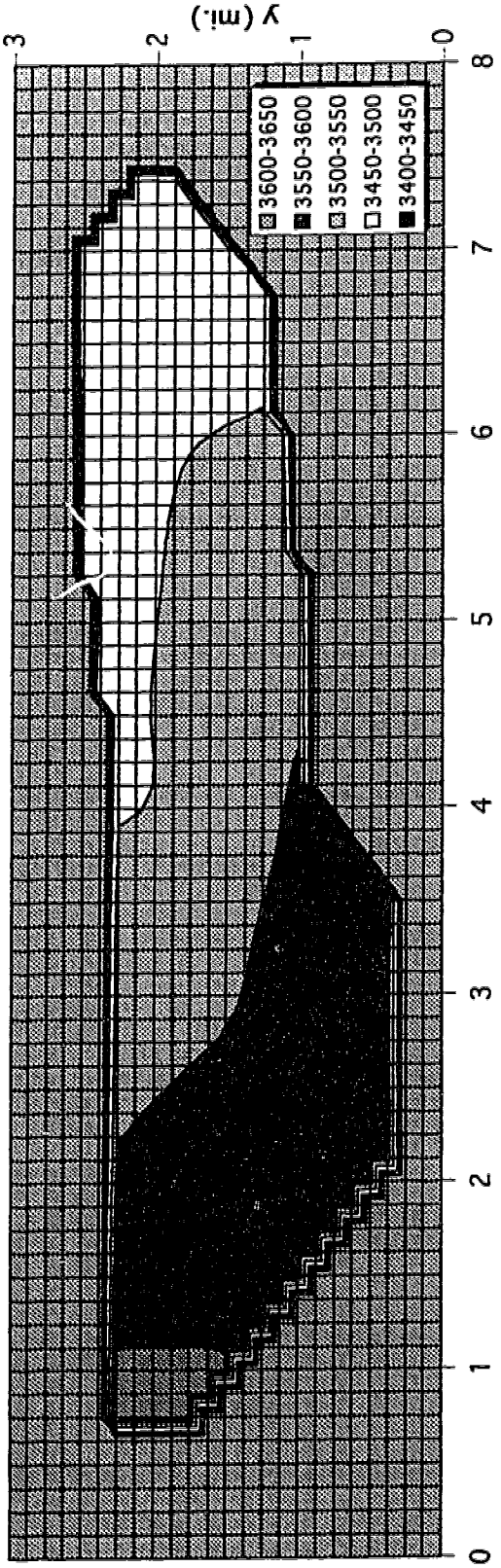



Figure 2.4(a): Kelly Bushing Elevation Contours (ft.)

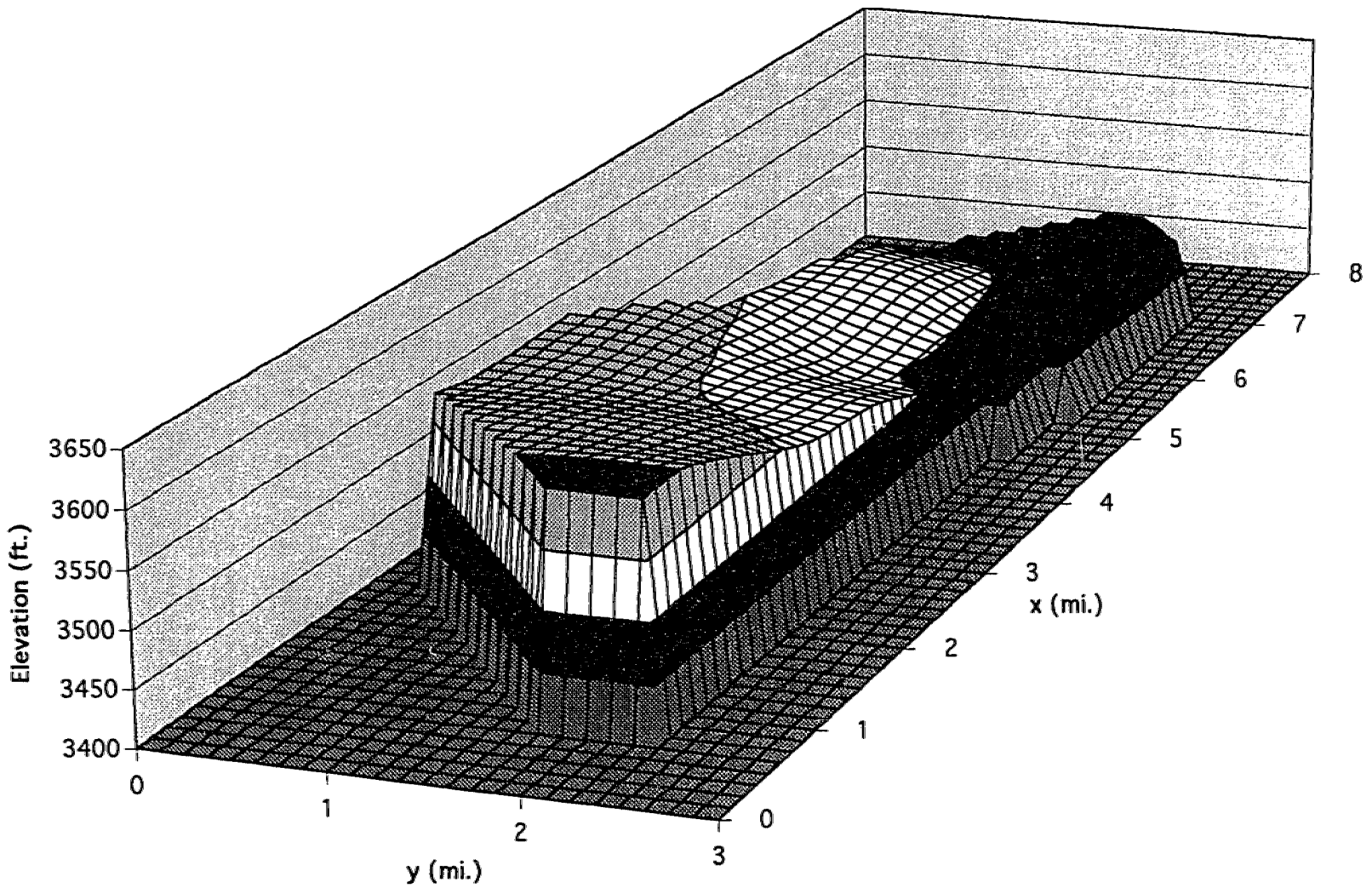



Figure 2.4(b): Kelly Bushing Elevation Surface

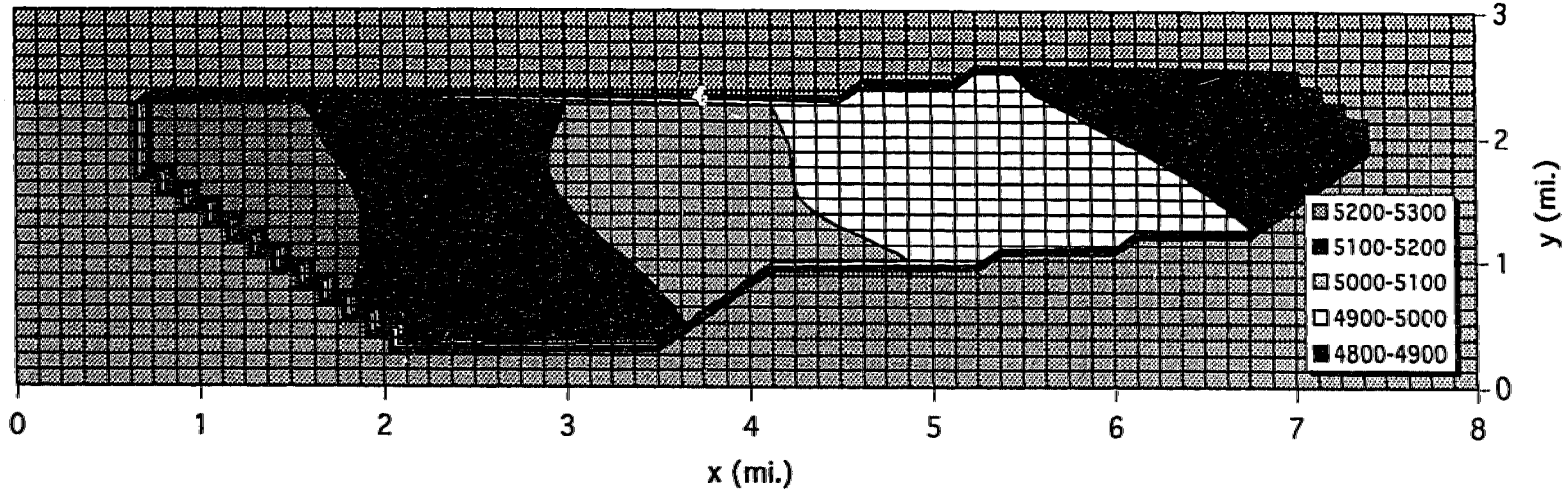



Figure 2.5(a): Reservoir Top Subsea Depth (ft)

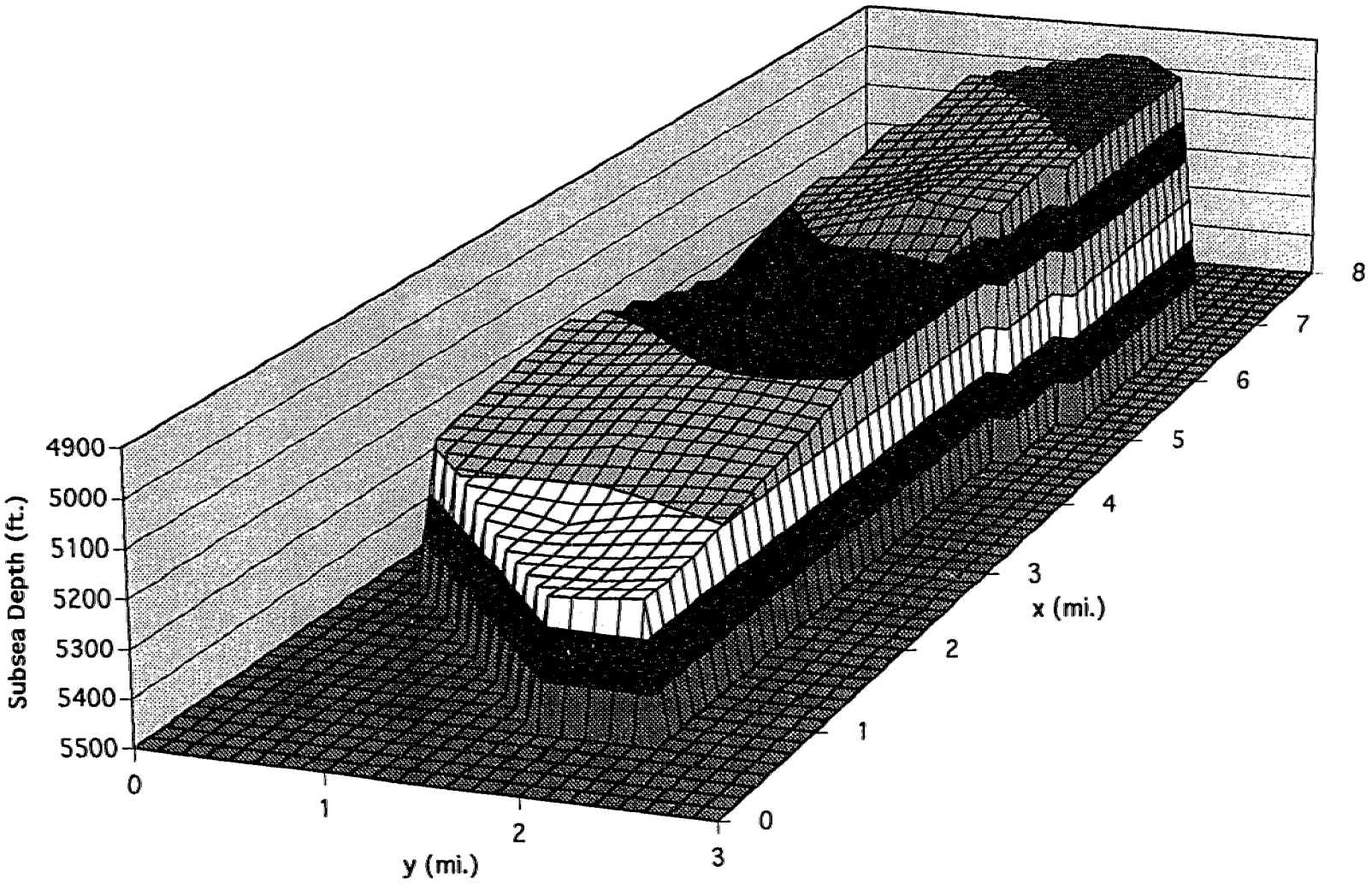



Figure 2.5(b): Reservoir Top Depth

## 2.6 Core and Well Log Data

Table 2.1(b) indicates wells with core samples taken from relevant perforation zones. The state of core data is incomplete with partial, or no, analysis performed on some perforation zones. The available core data for porosity and absolute permeability from eight wells are listed in Table 2.2. Thickness-weighted porosity averages and geometric log-mean permeabilities are calculated for each core sample.

Porosity is defined as the locally-averaged void volume-fraction of the rock matrix. Porosity histograms for individual core samples and for the aggregate are plotted in Figure 2.6(a). The aggregate sample indicates the presence of two populations with lognormal distributions. These populations are segmented in Figure 2.6(b) into major and minor components, with log mean porosities of $\phi$=6.4% and $\phi$=2.3%, respectively. The rock is a conglomerate. Porosity trends with respect to zone depth, top-to-bottom, east-west and north-south are shown in Figures 2.7(a)-(d). No marked trends with respect to depth and areal directions are distinguishable. Only the top-to-bottom distribution shows an increasing porosity trend.

Maximum core permeability histograms for individual core samples and for the aggregate are plotted in Figure 2.8(a). The aggregate sample indicates the presence of two populations with lognormal distributions. These populations are segmented in Figure 2.8(b) into major and minor components, with log mean maximum permeabilities of $K_x$=3.3 md and $K_x$=1220 md, respectively. The major component is attributable to the bulk of matrix rock and the minor component is interpreted as a high-permeability channel. Maximum permeability trends with respect to zone depth, top-to-bottom, east-west, north-south and core porosity are shown in Figures 2.9(a)-(e). The high-permeability channel seems to persist throughout the length of the reservoir and is concentrated in the northern sections. It seems to be limited to the top portion of the perforation zone and does not wane or wax with depth. Closer inspection of the original core data in Table 2.2 marked a 1.0-2.5 feet high-permeability zone within contiguous wells. Figure 2.9(e) shows the correlation between maximum core permeability and core porosity (correlation coefficient =0.243).

$$\log_{10} K_x = .223 + 8.09\phi \qquad (2.1)$$

Transverse 90° core permeability histograms for individual core samples and for the aggregate are plotted in Figure 2.10(a). The aggregate sample also indicates the presence of two populations with log-normal distributions. These populations are segmented in Figure 2.10(b) into major and minor components, with log mean 90° permeabilities of $K_y$=3.0 md and $K_y$=855 md, respectively.

Similarly, the major component is attributable to the bulk rock matrix and the minor component is interpreted as a high-permeability channel. Transverse 90° permeability trends with respect to zone depth, top-to-bottom, east-west, north-south and core porosity are shown in Figures 2.11(a)-(e). Transverse 90° permeability is highly correlated with maximum permeability (correlation coefficient=0.943).

$$\log_{10}K_y = -.035 + .848 \log_{10}K_x \tag{2.2}$$

Figure 2.11(e) shows the correlation between 90° core permeability and core porosity (correlation coefficient =0.374).

$$\log_{10}K_y = .0074 + 9.82\phi \tag{2.3}$$

Vertical core permeability histograms for individual core samples and for the aggregate are plotted in Figure 2.12(a). The aggregate sample is a single lognormal distribution with a log mean $K_z$=1.3 md, as shown in Figure 2.12(b). Vertical permeability trends with respect to zone depth, top-to-bottom, east-west, north-south and core porosity are shown in Figures 2.13(a)-(e). No distinct geographic or geological trends are distinguishable from these graphs. Vertical permeability is moderately correlated with maximum permeability (correlation coefficient=0.450).

$$\log_{10}K_z = -.14 + .32 \log_{10}K_x \tag{2.4}$$

Figure 2.13(e) shows the correlation between vertical core permeability and core porosity (correlation coefficient =0.544).

$$\log_{10}K_z = .583 + 11.83\phi \tag{2.5}$$

Ample log data and a petrophysical summary was provided by Canadian Hunter (1994). Proper interpretation could not be made with these logs because of missing scales on the sheets provided. Only the water saturations listed in the petrophysical summary were used in this work. Table 2.3 summarizes the core and log data. The bulk water fraction is included to correlate the irreducible water saturation $S_{wir}$ with porosity $\phi$ (Dewan, 1983, p276):

$$S_{wir} = \frac{0.0169}{\phi} \tag{2.6}$$

The rock compressibility coefficient[3] $c_r$ is calculated with Hall's porosity correlation (Ahmed, 1989, p236) using average core porosities:

$$c_r = 6.37 \times 10^{-6} \text{ psi}^{-1} \tag{2.7}$$

---

3 The overburden weight may cause compaction in the bulk rock as production of fluids create an imbalance in stresses. As the rock compensates the stress imbalance by compaction, internal fluids get squeezed to higher pressures causing production to decline at slower rates.

| Core Sample | 08-07-37-7W5 |
|---|---|
| Top (m) | 2653.92 |
| Bottom (m) | 2659.00 |
| KB (m) | 1087.40 |

| Depth (m) | Subsea Depth (m) | Subsea Depth (ft) | Thickness Δz (ft) | Porosity ϕ | $K_x$ Maximum (md) | $K_y$ 90 Degree (md) | $K_z$ Vertical (md) |
|---|---|---|---|---|---|---|---|
| 2653.92 | 1566.52 | 5139.50 | | | | | |
| 2654.09 | 1566.69 | 5140.06 | 0.56 | 2.70% | 1.25 | 1.12 | 0.02 |
| 2654.38 | 1566.98 | 5141.01 | 0.95 | 6.80% | 1.54 | 1.46 | 0.31 |
| 2654.62 | 1567.22 | 5141.80 | 0.79 | 2.30% | 1.42 | 0.75 | 0.19 |
| 2654.85 | 1567.45 | 5142.55 | 0.75 | 2.70% | 1.54 | 1.40 | 0.38 |
| 2655.09 | 1567.69 | 5143.34 | 0.79 | 1.10% | 1.29 | 1.16 | 0.16 |
| 2655.36 | 1567.96 | 5144.23 | 0.89 | 3.90% | 8.52 | 1.10 | 0.13 |
| 2655.65 | 1568.25 | 5145.18 | 0.95 | 5.30% | 29.20 | 26.10 | 2.22 |
| 2655.82 | 1568.42 | 5145.73 | 0.56 | 5.90% | 12.00 | 9.56 | 2.44 |
| 2656.32 | 1568.92 | 5147.38 | 1.64 | 6.40% | 3.40 | 2.86 | 1.13 |
| 2656.72 | 1569.32 | 5148.69 | 1.31 | 5.40% | 4.41 | 2.67 | 1.80 |
| 2657.11 | 1569.71 | 5149.97 | 1.28 | 3.60% | 2.16 | | |
| 2657.42 | 1570.02 | 5150.98 | 1.02 | 2.50% | 2.61 | 2.17 | 0.77 |
| 2657.79 | 1570.39 | 5152.20 | 1.21 | 1.70% | 0.41 | 0.35 | 0.13 |
| 2658.09 | 1570.69 | 5153.18 | 0.98 | 1.90% | 7.66 | 2.62 | 0.25 |
| 2658.45 | 1571.05 | 5154.36 | 1.18 | 2.90% | 0.15 | 0.11 | 0.01 |
| 2659.00 | 1571.60 | 5156.17 | 1.80 | 5.40% | 0.06 | 0.06 | 0.01 |
| ZONE | | | 16.67 | 4.05% | 1.94 | 1.31 | 0.23 |

| Core Sample | 14-07-37-7W5 |
|---|---|
| Top (m) | 2645.06 |
| Bottom (m) | 2653.51 |
| KB (m) | 1081.00 |

| Depth (m) | Subsea Depth (m) | Subsea Depth (ft) | Thickness Δz (ft) | Porosity ϕ | $K_x$ Maximum (md) | $K_y$ 90 Degree (md) | $K_z$ Vertical (md) |
|---|---|---|---|---|---|---|---|
| 2645.06 | 1564.06 | 5131.43 | | | | | |
| 2645.38 | 1564.38 | 5132.48 | 1.05 | 6.40% | 2.48 | 2.07 | 2.49 |
| 2645.49 | 1564.49 | 5132.84 | 0.36 | 7.50% | 1090.00 | 194.00 | 23.50 |
| 2645.73 | 1564.73 | 5133.63 | 0.79 | 6.70% | 3510.00 | | |
| 2645.93 | 1564.93 | 5134.28 | 0.66 | 1.90% | 2.47 | 2.47 | 0.63 |
| 2646.14 | 1565.14 | 5134.97 | 0.69 | 5.70% | 5.21 | | |
| 2646.60 | 1565.60 | 5136.48 | 1.51 | | | | |
| 2646.78 | 1565.78 | 5137.07 | 0.59 | 3.60% | 1.23 | 1.08 | 0.53 |
| 2647.05 | 1566.05 | 5137.96 | 0.89 | 5.40% | 3.93 | 3.38 | 1.97 |
| 2647.27 | 1566.27 | 5138.68 | 0.72 | 4.10% | 1.16 | 1.12 | 0.95 |
| 2647.43 | 1566.43 | 5139.21 | 0.52 | 5.60% | 3.63 | 3.62 | 3.60 |
| 2647.60 | 1566.60 | 5139.76 | 0.56 | 8.50% | 4.36 | 2.99 | 2.89 |
| 2647.83 | 1566.83 | 5140.52 | 0.75 | 7.70% | 4.29 | 3.32 | 3.29 |
| 2648.00 | 1567.00 | 5141.08 | 0.56 | 7.50% | 7.73 | 6.82 | 3.90 |
| 2648.26 | 1567.26 | 5141.93 | 0.85 | 11.30% | 3.53 | 3.51 | 3.47 |
| 2648.46 | 1567.46 | 5142.59 | 0.66 | 6.10% | 3.51 | 3.35 | 2.09 |
| 2648.60 | 1567.60 | 5143.04 | 0.46 | 7.10% | 3.45 | 3.07 | 2.26 |
| 2648.76 | 1567.76 | 5143.57 | 0.52 | 8.60% | 6.05 | 3.15 | 2.58 |
| 2648.94 | 1567.94 | 5144.16 | 0.59 | 5.90% | 2.14 | 1.94 | 1.89 |
| 2649.01 | 1568.01 | 5144.39 | 0.23 | 5.00% | 1.42 | 1.37 | 0.92 |
| 2649.31 | 1568.31 | 5145.37 | 0.98 | 6.90% | 4.26 | 3.24 | 2.08 |
| 2649.48 | 1568.48 | 5145.93 | 0.56 | 6.40% | 1.79 | 1.62 | 0.95 |
| 2649.72 | 1568.72 | 5146.72 | 0.79 | 6.50% | 9.18 | 6.26 | 7.44 |
| 2649.94 | 1568.94 | 5147.44 | 0.72 | 7.70% | 16.90 | 13.80 | 10.40 |
| 2650.11 | 1569.11 | 5148.00 | 0.56 | 7.50% | 6.49 | 6.13 | 4.14 |
| 2650.39 | 1569.39 | 5148.92 | 0.92 | 6.70% | 5.24 | 4.36 | 3.83 |
| 2650.65 | 1569.65 | 5149.77 | 0.85 | 4.90% | 2.04 | 1.29 | 0.94 |
| 2650.89 | 1569.89 | 5150.56 | 0.79 | 7.00% | 4.03 | 3.40 | 3.00 |
| 2651.10 | 1570.10 | 5151.25 | 0.69 | 8.80% | 12.60 | 9.09 | 4.37 |
| 2651.32 | 1570.32 | 5151.97 | 0.72 | 9.60% | 5.68 | 5.51 | 2.91 |
| 2651.51 | 1570.51 | 5152.59 | 0.62 | 8.10% | 8.62 | 7.36 | 4.53 |
| 2651.86 | 1570.86 | 5153.74 | 1.15 | 7.50% | 6.88 | 5.53 | 1.19 |
| 2652.11 | 1571.11 | 5154.56 | 0.82 | 7.40% | 2.46 | 2.10 | 1.96 |
| 2652.34 | 1571.34 | 5155.31 | 0.75 | 7.90% | 2.50 | 2.22 | 1.59 |
| 2652.71 | 1571.71 | 5156.53 | 1.21 | 7.60% | 5.94 | 5.03 | 4.73 |
| 2652.87 | 1571.87 | 5157.05 | 0.52 | 9.20% | 12.60 | 11.30 | 7.08 |
| 2653.04 | 1572.04 | 5157.61 | 0.56 | 10.70% | 7.32 | 7.20 | 5.56 |
| 2653.21 | 1572.21 | 5158.17 | 0.56 | 9.20% | 3.09 | 2.99 | 2.98 |
| 2653.32 | 1572.32 | 5158.53 | 0.36 | 8.70% | 4.06 | 3.31 | 3.14 |
| 2653.37 | 1572.37 | 5158.69 | 0.16 | 9.20% | 12.60 | 11.30 | 7.08 |
| 2653.51 | 1572.51 | 5159.15 | 0.46 | 6.30% | 3.81 | 1.59 | 0.60 |
| ZONE | | | 27.72 | 7.09% | 5.85 | 3.94 | 2.64 |

Table 2.2: Core Data

| Core Sample | 16-08-37-7W5 |
|---|---|
| Top (m) | 2608.00 |
| Bottom (m) | 2612.93 |
| KB (m) | 1076.10 |

| Depth (m) | Subsea Depth (m) | Subsea Depth (ft) | Thickness Δz (ft) | Porosity ϕ | $K_x$ Maximum (md) | $K_y$ 90 Degree (md) | $K_z$ Vertical (md) |
|---|---|---|---|---|---|---|---|
| 2608.00 | 1531.90 | 5025.92 | | | | | |
| 2608.67 | 1532.57 | 5028.12 | 2.20 | 7.70% | 4.80 | 4.67 | 0.89 |
| 2608.90 | 1532.80 | 5028.87 | 0.75 | 5.60% | 0.55 | 0.40 | 0.24 |
| 2609.44 | 1533.34 | 5030.64 | 1.77 | 4.00% | 2.24 | 2.23 | 1.33 |
| 2609.62 | 1533.52 | 5031.23 | 0.59 | 4.90% | 15.30 | 2.44 | 1.67 |
| 2610.19 | 1534.09 | 5033.10 | 1.87 | 4.70% | 2.65 | 2.03 | 0.49 |
| 2610.65 | 1534.55 | 5034.61 | 1.51 | 4.80% | 2.17 | 0.94 | 0.27 |
| 2610.93 | 1534.83 | 5035.53 | 0.92 | 5.60% | 3.85 | 1.96 | 0.66 |
| 2611.00 | 1534.90 | 5035.76 | 0.23 | 10.20% | 0.23 | | |
| 2611.44 | 1535.34 | 5037.20 | 1.44 | 6.60% | 0.81 | 0.73 | 0.31 |
| 2612.13 | 1536.03 | 5039.47 | 2.26 | 10.20% | | | |
| 2612.93 | 1536.83 | 5042.09 | 2.62 | 11.40% | 0.27 | | |
| ZONE | | | 16.17 | 7.25% | 1.59 | 1.51 | 0.58 |

| Core Sample | 06-14-37-7W5 |
|---|---|
| Top (m) | 2557.40 |
| Bottom (m) | 2561.20 |
| KB (m) | 1061.60 |

| Depth (m) | Subsea Depth (m) | Subsea Depth (ft) | Thickness Δz (ft) | Porosity ϕ | $K_x$ Maximum (md) | $K_y$ 90 Degree (md) | $K_z$ Vertical (md) |
|---|---|---|---|---|---|---|---|
| 2557.40 | 1495.80 | 4907.48 | | | | | |
| 2557.55 | 1495.95 | 4907.97 | 0.49 | 2.50% | 4.79 | 3.93 | 1.14 |
| 2557.90 | 1496.30 | 4909.12 | 1.15 | 2.30% | 11.80 | 8.61 | 1.28 |
| 2558.03 | 1496.43 | 4909.55 | 0.43 | 2.40% | 10.30 | 6.21 | 0.92 |
| 2558.29 | 1496.69 | 4910.40 | 0.85 | 2.00% | 1.97 | 1.84 | 0.88 |
| 2558.57 | 1496.97 | 4911.32 | 0.92 | 2.20% | 34.50 | 33.30 | 1.14 |
| 2558.89 | 1497.29 | 4912.37 | 1.05 | 2.80% | 39.90 | 29.10 | 0.90 |
| 2559.13 | 1497.53 | 4913.16 | 0.79 | 3.10% | 1.13 | 1.00 | 0.22 |
| 2559.40 | 1497.80 | 4914.04 | 0.89 | 9.50% | 1490.00 | 1220.00 | 12.90 |
| ZONE | | | 6.56 | 3.42% | 15.07 | 12.09 | 1.17 |

| Core Sample | 06-15-37-7W5 |
|---|---|
| Top (m) | 2573.17 |
| Bottom (m) | 2579.11 |
| KB (m) | 1068.20 |

| Depth (m) | Subsea Depth (m) | Subsea Depth (ft) | Thickness Δz (ft) | Porosity ϕ | $K_x$ Maximum (md) | $K_y$ 90 Degree (md) | $K_z$ Vertical (md) |
|---|---|---|---|---|---|---|---|
| 2573.17 | 1504.97 | 4937.57 | | | | | |
| 2573.40 | 1505.20 | 4938.32 | 0.75 | 3.90% | 3.34 | 1.59 | 0.54 |
| 2573.70 | 1505.50 | 4939.30 | 0.98 | 5.70% | 44.28 | 14.71 | 0.48 |
| 2574.06 | 1505.86 | 4940.49 | 1.18 | 3.20% | 1.91 | 1.61 | 0.50 |
| 2574.34 | 1506.14 | 4941.40 | 0.92 | 4.70% | 1275.62 | 510.00 | 0.10 |
| 2574.53 | 1506.33 | 4942.03 | 0.62 | 7.50% | 316.95 | 72.04 | 10.67 |
| 2574.83 | 1506.63 | 4943.01 | 0.98 | 2.20% | 0.93 | 0.84 | 0.32 |
| 2575.18 | 1506.98 | 4944.16 | 1.15 | 4.80% | 20.65 | 2.42 | 0.28 |
| 2575.56 | 1507.36 | 4945.41 | 1.25 | 5.20% | 3.37 | 2.44 | 0.32 |
| 2575.86 | 1507.66 | 4946.39 | 0.98 | 10.00% | 1261.88 | 1213.80 | 2.61 |
| 2576.20 | 1508.00 | 4947.51 | 1.12 | 5.80% | 5.30 | 4.34 | 1.58 |
| 2576.50 | 1508.30 | 4948.49 | 0.98 | 4.80% | 3.39 | 3.09 | 1.85 |
| 2576.82 | 1508.62 | 4949.54 | 1.05 | 3.00% | 1.39 | 1.35 | 0.62 |
| 2577.12 | 1508.92 | 4950.52 | 0.98 | 5.30% | 6.47 | 6.27 | 0.31 |
| 2577.32 | 1509.12 | 4951.18 | 0.66 | 3.80% | 0.53 | 0.46 | 0.38 |
| 2577.60 | 1509.40 | 4952.10 | 0.92 | 6.40% | 8.33 | 8.13 | 0.36 |
| 2577.90 | 1509.70 | 4953.08 | 0.98 | 9.30% | 38.47 | 35.86 | 9.93 |
| 2578.16 | 1509.96 | 4953.94 | 0.85 | 10.10% | 17.52 | 10.17 | 5.56 |
| 2578.30 | 1510.10 | 4954.40 | 0.46 | 9.30% | 0.32 | | |
| 2578.63 | 1510.43 | 4955.48 | 1.08 | 9.40% | 0.84 | 0.80 | 0.25 |
| 2578.81 | 1510.61 | 4956.07 | 0.59 | 13.30% | 2.43 | 2.22 | 1.26 |
| 2579.11 | 1510.91 | 4957.05 | 0.98 | 9.90% | 0.42 | 0.38 | 0.04 |
| ZONE | | | 19.49 | 6.32% | 7.27 | 5.58 | 0.69 |

Table 2.2: Core Data (Continued)

| Core Sample | 08-17-37-7W5 |
|---|---|
| Top (m) | 2598.55 |
| Bottom (m) | 2602.69 |
| KB (m) | 1062.50 |

| Depth (m) | Subsea Depth (m) | Subsea Depth (ft) | Thickness Δz (ft) | Porosity ϕ | $K_x$ Maximum (md) | $K_y$ 90 Degree (md) | $K_z$ Vertical (md) |
|---|---|---|---|---|---|---|---|
| 2598.55 | 1536.05 | 5039.53 | | | | | |
| 2598.83 | 1536.33 | 5040.45 | 0.92 | 2.40% | 1.53 | 1.29 | 0.47 |
| 2599.08 | 1536.58 | 5041.27 | 0.82 | 2.60% | 1.81 | 1.38 | 0.57 |
| 2599.37 | 1536.87 | 5042.22 | 0.95 | 1.80% | 1.01 | 0.80 | 0.45 |
| 2599.61 | 1537.11 | 5043.01 | 0.79 | 2.10% | 2.17 | 1.78 | 0.24 |
| 2600.05 | 1537.55 | 5044.46 | 1.44 | 7.10% | 3.55 | 2.97 | 2.23 |
| 2600.25 | 1537.75 | 5045.11 | 0.66 | 7.10% | 56.50 | 38.00 | 1.45 |
| 2600.66 | 1538.16 | 5046.46 | 1.35 | 7.90% | 1000.00 | 5.01 | 2.18 |
| 2600.85 | 1538.35 | 5047.08 | 0.62 | 6.60% | 1.96 | 1.55 | 3.65 |
| 2601.14 | 1538.64 | 5048.03 | 0.95 | 8.90% | 63.20 | 45.90 | 5.14 |
| 2601.33 | 1538.83 | 5048.65 | 0.62 | 5.50% | 2.56 | 2.37 | 1.58 |
| 2601.48 | 1538.98 | 5049.15 | 0.49 | 8.80% | 12.10 | 8.44 | 7.25 |
| 2601.73 | 1539.23 | 5049.97 | 0.82 | 6.30% | 3.45 | 3.16 | 3.30 |
| 2601.90 | 1539.40 | 5050.52 | 0.56 | 7.10% | 5.37 | 3.22 | 1.92 |
| 2602.20 | 1539.70 | 5051.51 | 0.98 | 2.20% | 8.55 | 7.41 | 7.86 |
| 2602.48 | 1539.98 | 5052.43 | 0.92 | 8.60% | 13.70 | 10.30 | 10.40 |
| 2602.69 | 1540.19 | 5053.12 | 0.69 | 5.50% | 1.93 | 1.46 | 0.39 |
| ZONE | | | 13.58 | 5.64% | 6.77 | 3.85 | 1.76 |

| Core Sample | 06-13-37-8W5 |
|---|---|
| Top (m) | 2683.50 |
| Bottom (m) | 2686.33 |
| KB (m) | 1089.00 |

| Depth (m) | Subsea Depth (m) | Subsea Depth (ft) | Thickness Δz (ft) | Porosity ϕ | $K_x$ Maximum (md) | $K_y$ 90 Degree (md) | $K_z$ Vertical (md) |
|---|---|---|---|---|---|---|---|
| 2683.50 | 1594.50 | 5231.30 | | | | | |
| 2683.64 | 1594.64 | 5231.76 | 0.46 | 1.80% | 3.53 | 1.86 | 0.29 |
| 2683.75 | 1594.75 | 5232.12 | 0.36 | 3.50% | 0.78 | | |
| 2683.87 | 1594.87 | 5232.51 | 0.39 | 5.70% | 1540.00 | 1090.00 | 2.83 |
| 2684.08 | 1595.08 | 5233.20 | 0.69 | 4.40% | 5.70 | 3.72 | 1.41 |
| 2684.17 | 1595.17 | 5233.50 | 0.30 | 4.00% | 0.60 | | |
| 2684.39 | 1595.39 | 5234.22 | 0.72 | 5.40% | 5.46 | 5.13 | 1.02 |
| 2684.60 | 1595.60 | 5234.91 | 0.69 | 5.70% | 4.85 | 4.56 | 2.68 |
| 2684.74 | 1595.74 | 5235.37 | 0.46 | 5.80% | 18.00 | | |
| 2685.01 | 1596.01 | 5236.25 | 0.89 | 8.90% | 1360.00 | 556.00 | 3.00 |
| 2685.16 | 1596.16 | 5236.75 | 0.49 | 6.30% | 27.00 | | |
| 2685.48 | 1596.48 | 5237.80 | 1.05 | 5.00% | 2.77 | 2.63 | 1.67 |
| 2685.51 | 1596.51 | 5237.89 | 0.10 | | | | |
| 2685.79 | 1596.79 | 5238.81 | 0.92 | 4.70% | 2.42 | 2.11 | 2.06 |
| 2685.89 | 1596.89 | 5239.14 | 0.33 | 2.90% | 1.03 | | |
| 2686.05 | 1597.05 | 5239.67 | 0.52 | 3.80% | 8.91 | 7.21 | 1.54 |
| 2686.17 | 1597.17 | 5240.06 | 0.39 | 4.40% | 0.65 | | |
| 2686.33 | 1597.33 | 5240.58 | 0.52 | 4.70% | 1.40 | 1.14 | 0.61 |
| ZONE | | | 9.28 | 5.09% | 6.64 | 9.23 | 1.41 |

| Core Sample | 08-14-37-8W5 |
|---|---|
| Top (m) | 2758.19 |
| Bottom (m) | 2760.56 |
| KB (m) | 1100.00 |

| Depth (m) | Subsea Depth (m) | Subsea Depth (ft) | Thickness Δz (ft) | Porosity ϕ | $K_x$ Maximum (md) | $K_y$ 90 Degree (md) | $K_z$ Vertical (md) |
|---|---|---|---|---|---|---|---|
| 2758.19 | 1658.19 | 5440.26 | | | | | |
| 2758.40 | 1658.40 | 5440.94 | 0.69 | 3.70% | 3.85 | 3.82 | 1.38 |
| 2758.75 | 1658.75 | 5442.09 | 1.15 | 4.60% | 2.51 | 2.51 | 2.34 |
| 2758.96 | 1658.96 | 5442.78 | 0.69 | 4.90% | 1.96 | 1.69 | 1.87 |
| 2759.32 | 1659.32 | 5443.96 | 1.18 | 5.60% | 4.64 | 4.34 | 3.80 |
| 2759.60 | 1659.60 | 5444.88 | 0.92 | 5.60% | 3.70 | 3.56 | 2.89 |
| 2759.86 | 1659.86 | 5445.73 | 0.85 | 6.30% | 1.97 | 1.96 | 0.88 |
| 2760.07 | 1660.07 | 5446.42 | 0.69 | 6.90% | 3.06 | 2.67 | 2.52 |
| 2760.26 | 1660.26 | 5447.05 | 0.62 | 6.10% | 1.08 | 1.03 | 0.76 |
| 2760.56 | 1660.56 | 5448.03 | 0.98 | 5.20% | 0.82 | 0.73 | 0.62 |
| ZONE | | | 7.78 | 5.40% | 2.29 | 2.15 | 1.60 |

**Table 2.2: Core Data (Continued)**

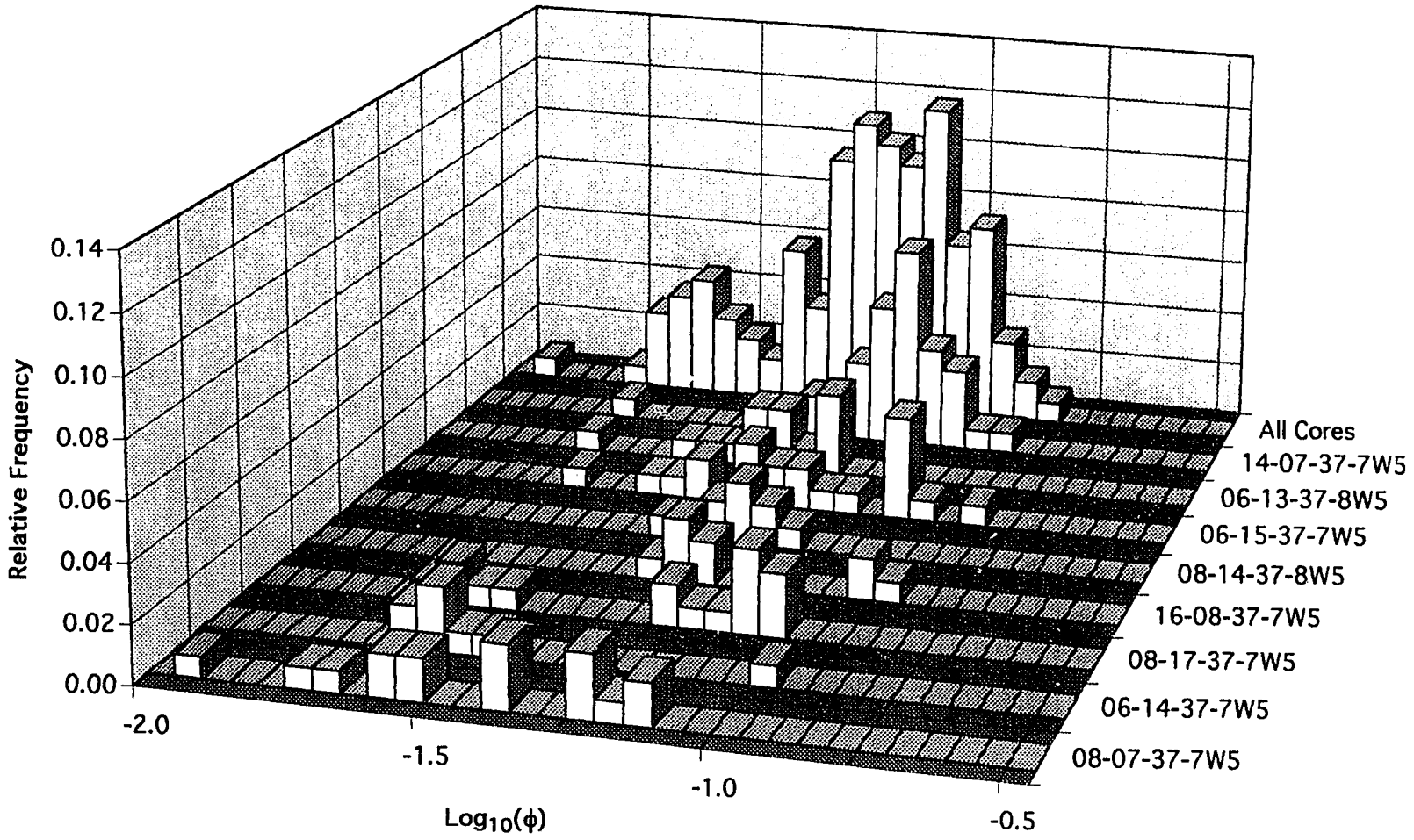



Figure 2.6(a): Core Porosity $\phi$ Histogram

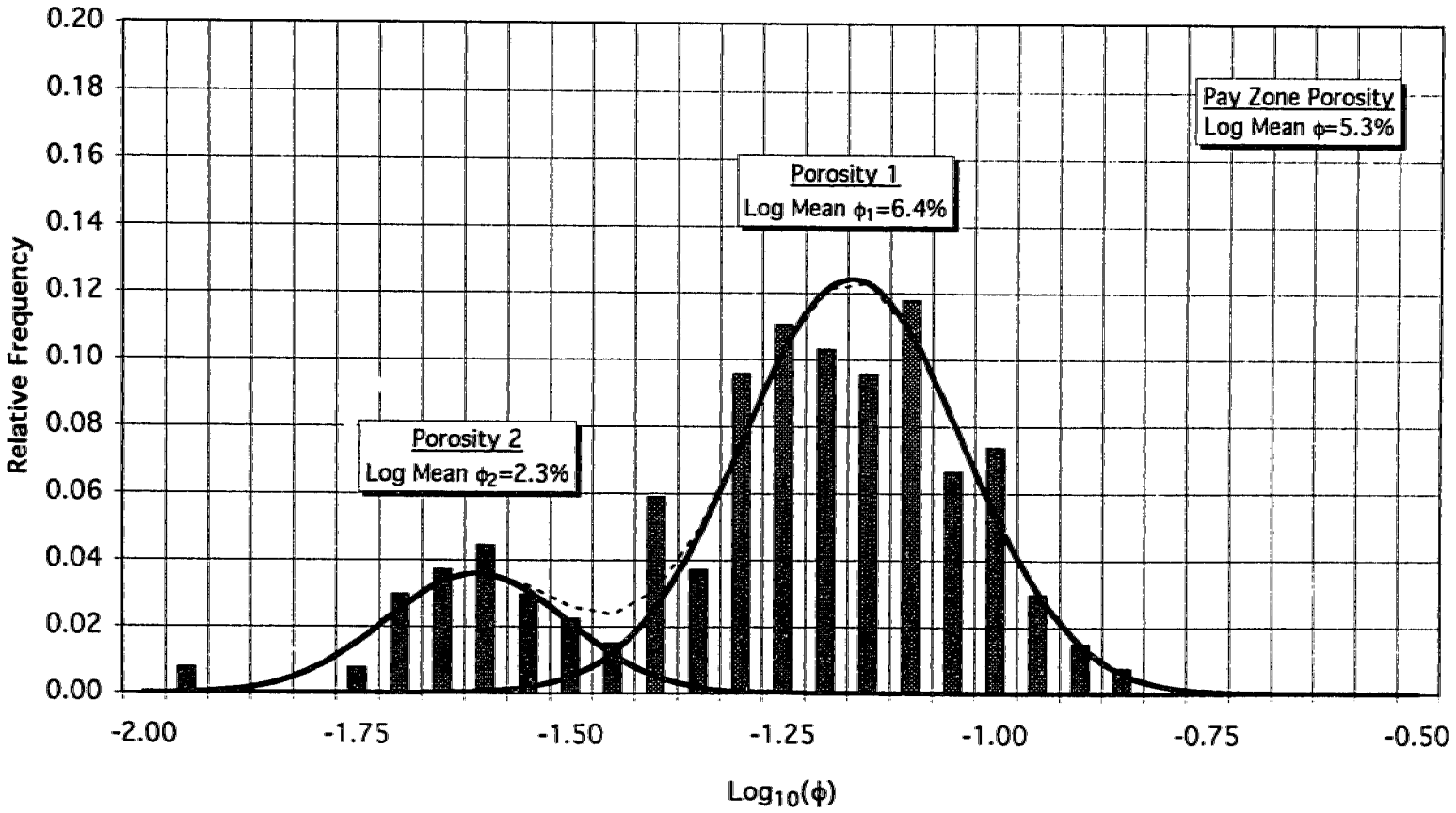



Figure 2.6(b): Core Porosity Histogram (Lognormal Segmentation)

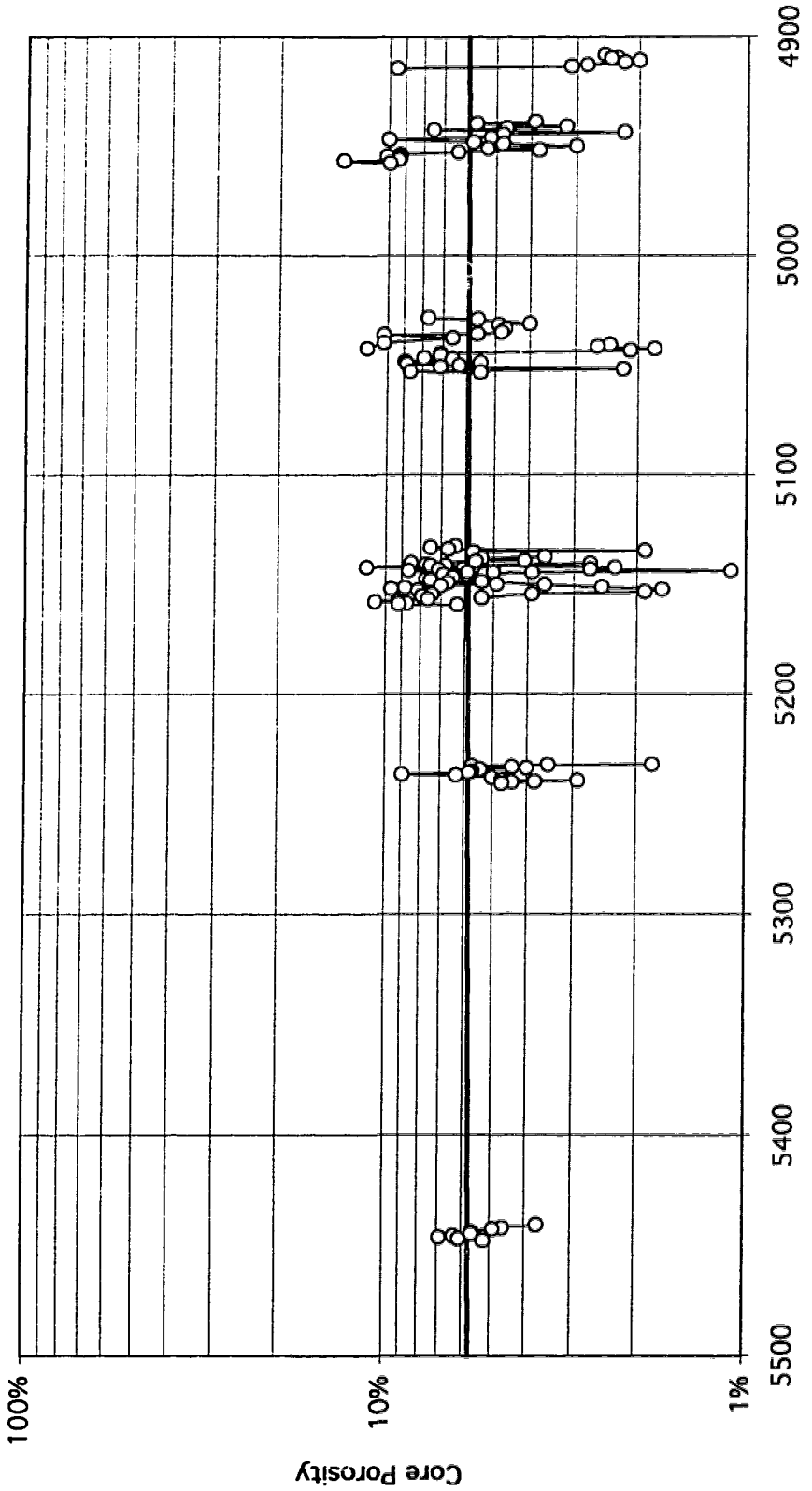



Figure 2.7(a): Core Porosity Depth Trend

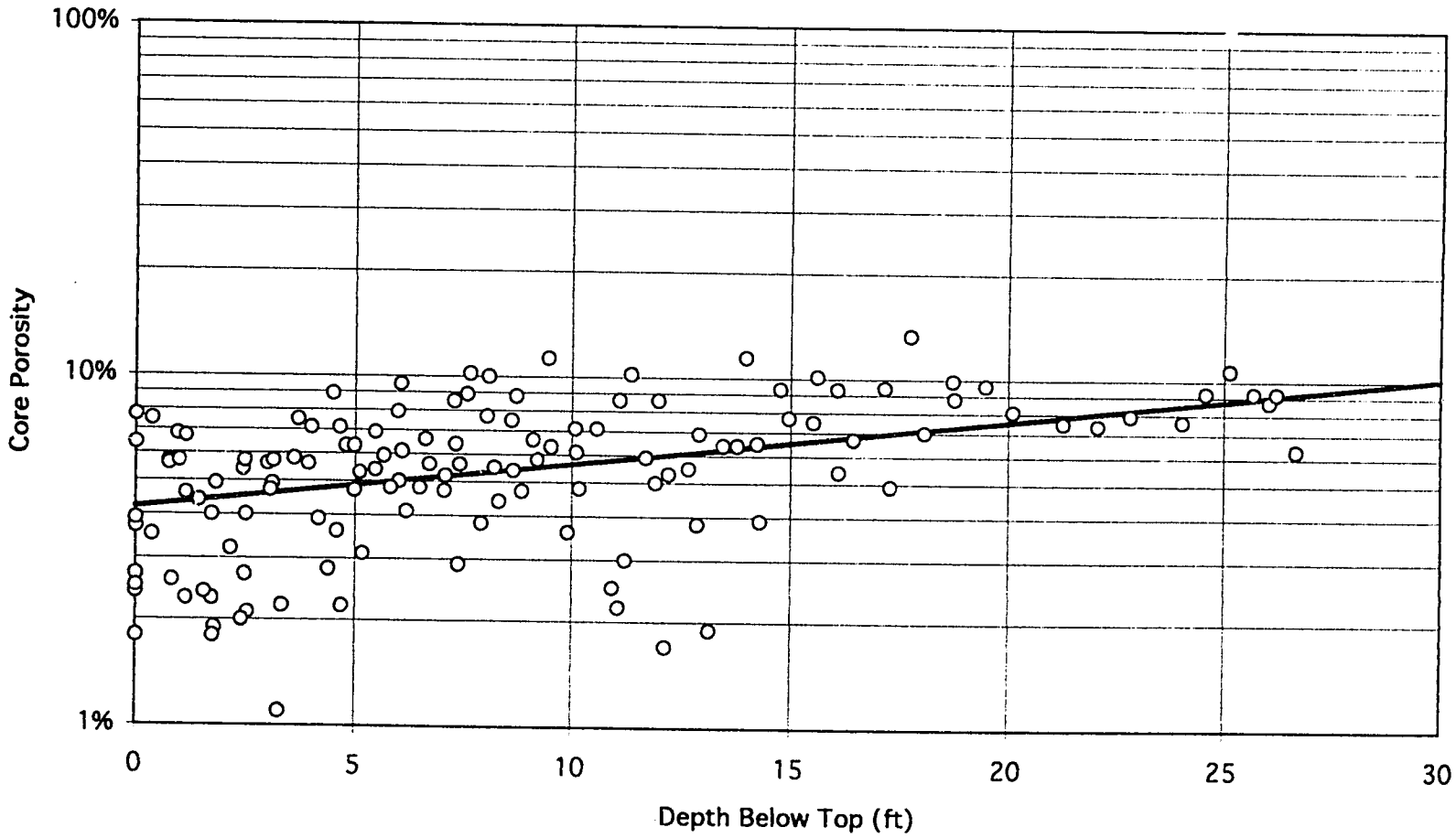



Figure 2.7(b): Core Porosity Top-to-Bottom Trend

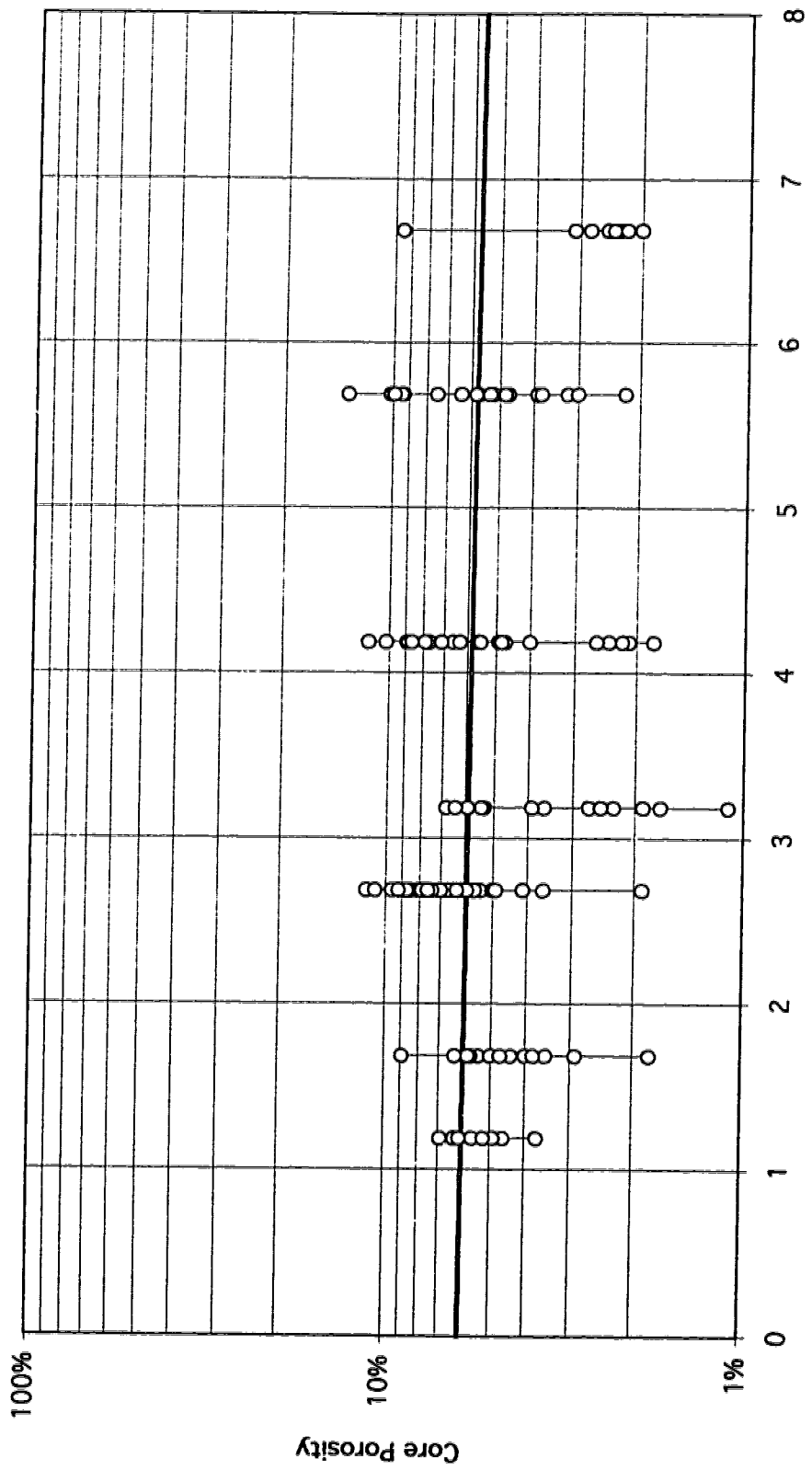



Figure 2.7(c): Core Porosity East-West Trend

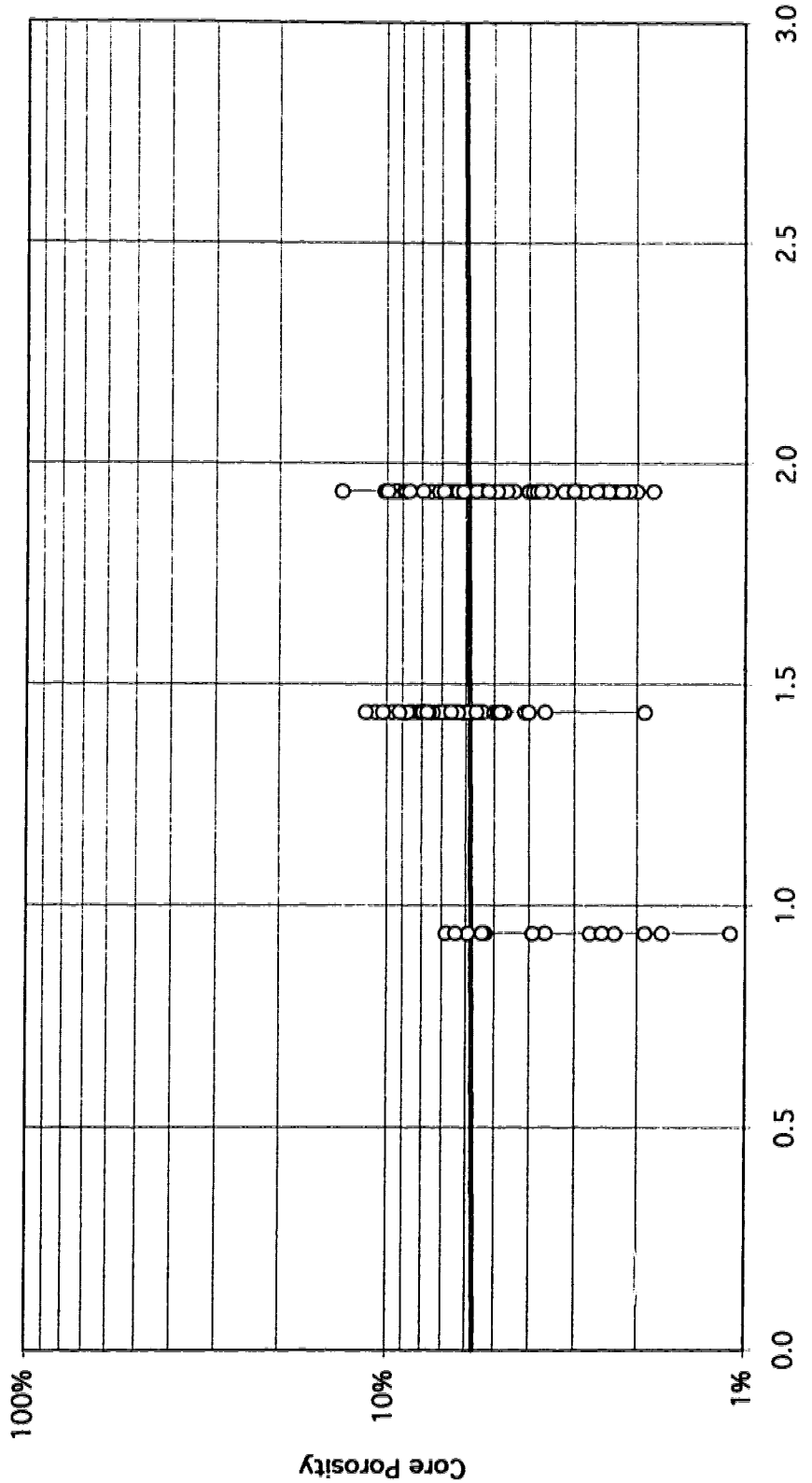



Figure 2.7(d): Core Porosity North-South Trend

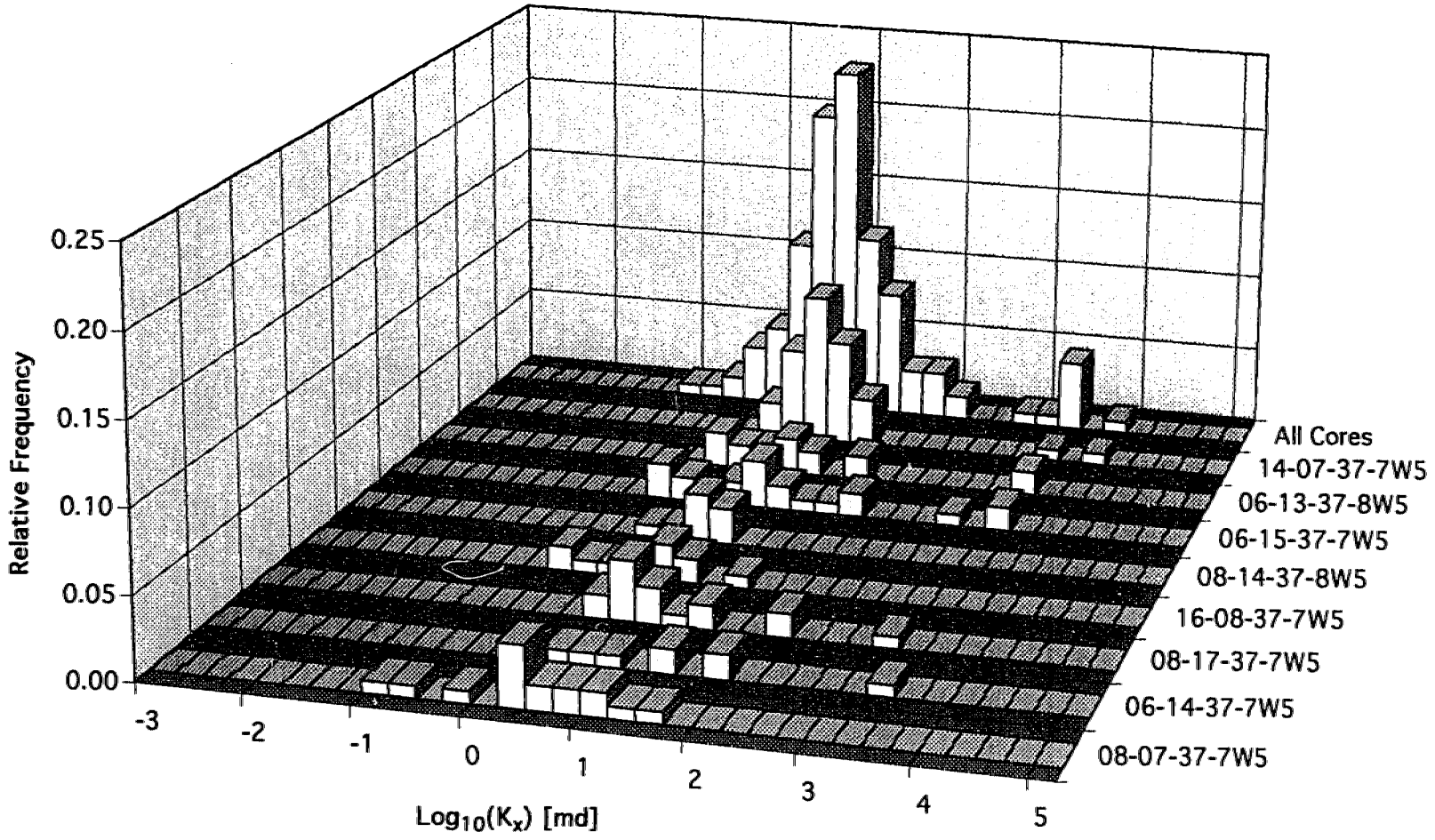



Figure 2.8(a): Core Maximum Permeability $K_x$ Histogram

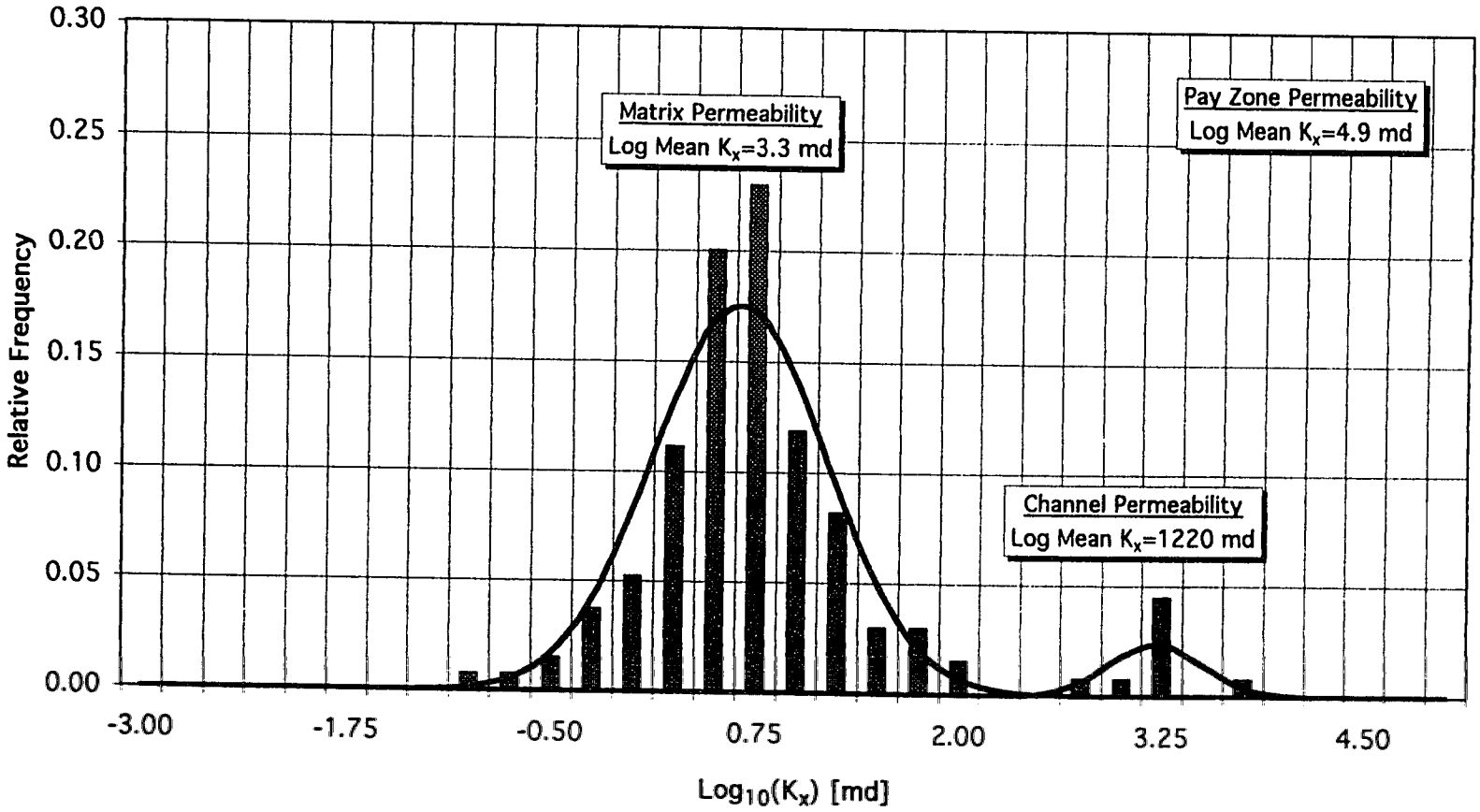



Figure 2.8(b): Core Maximum Permeability $K_x$ Histogram
(Lognormal Segmentation)

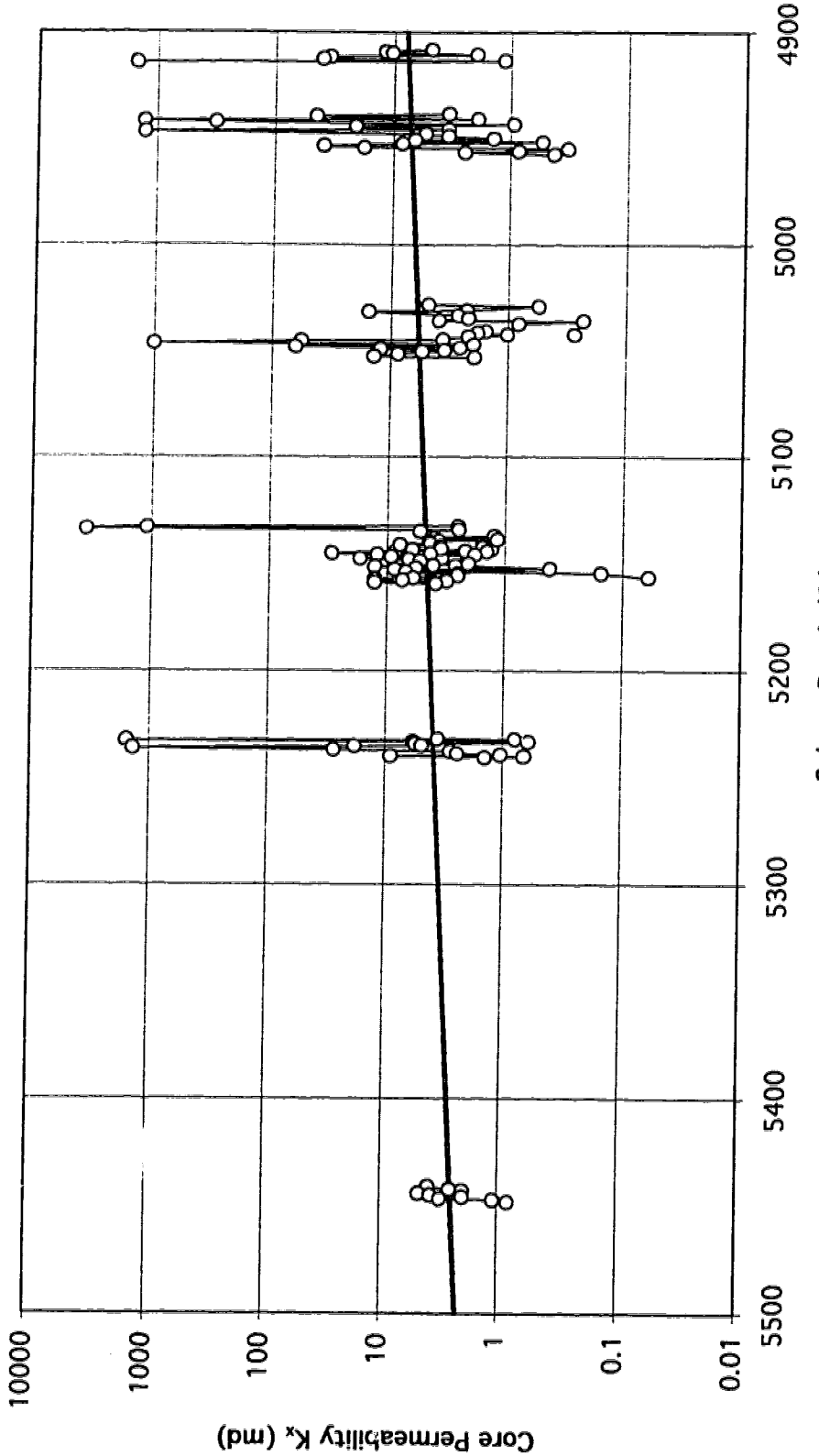



Figure 2.9(a): Core Maximum Permeability $K_x$ vs Depth

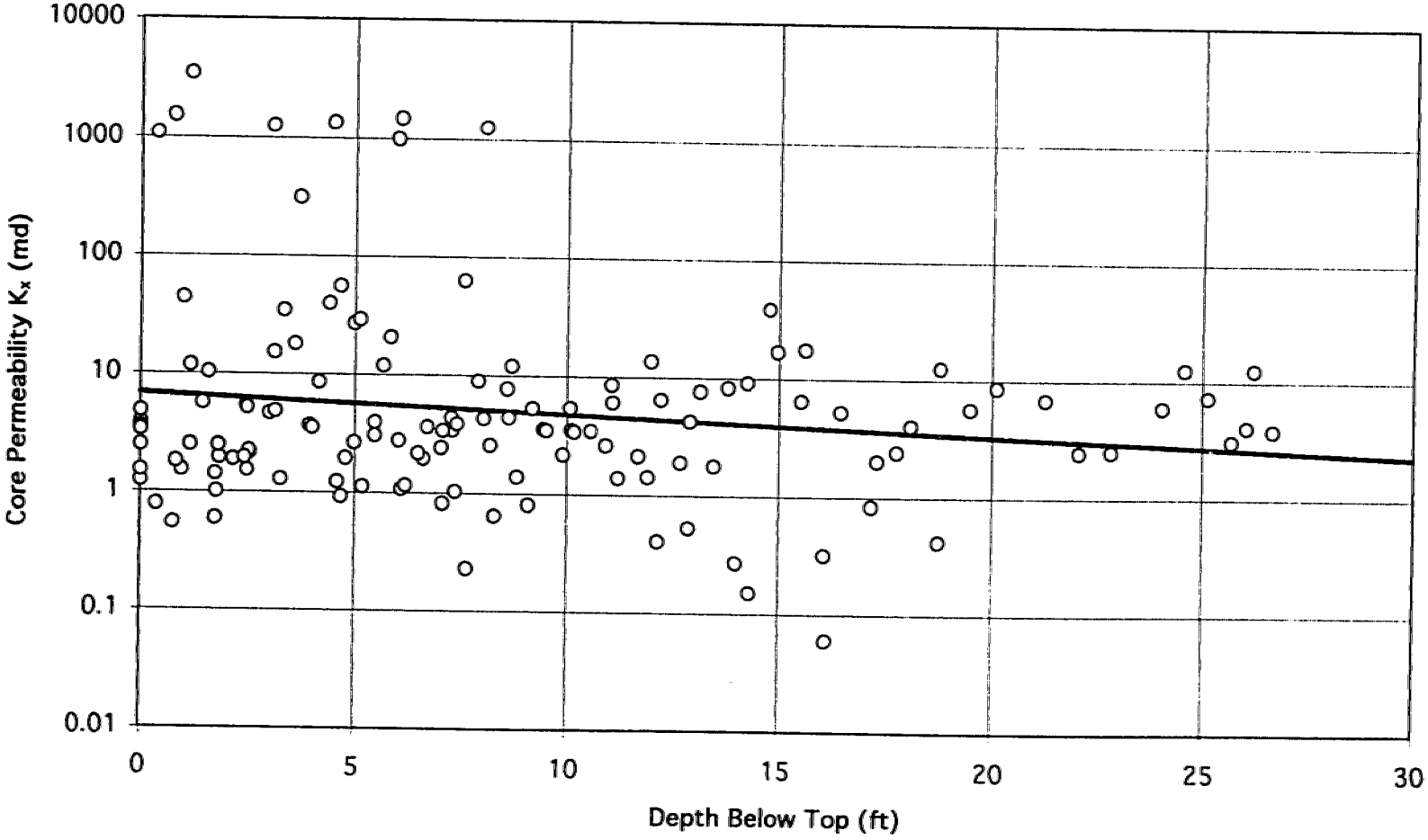



Figure 2.9(b): Core Maximum Permeability $K_x$ Vertical Trend

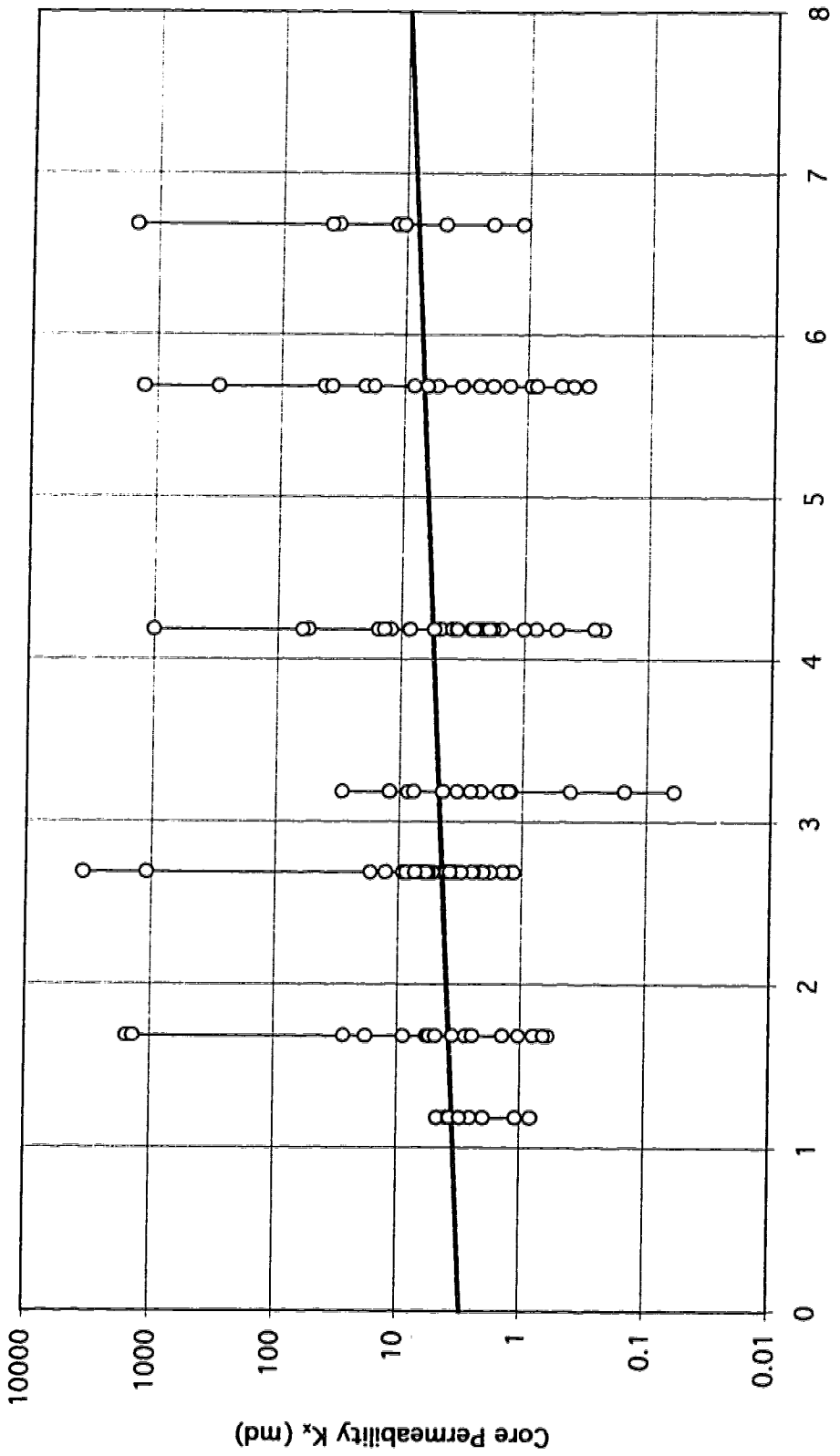



Figure 2.9(c): Core Maximum Permeability $K_x$ East-West Trend

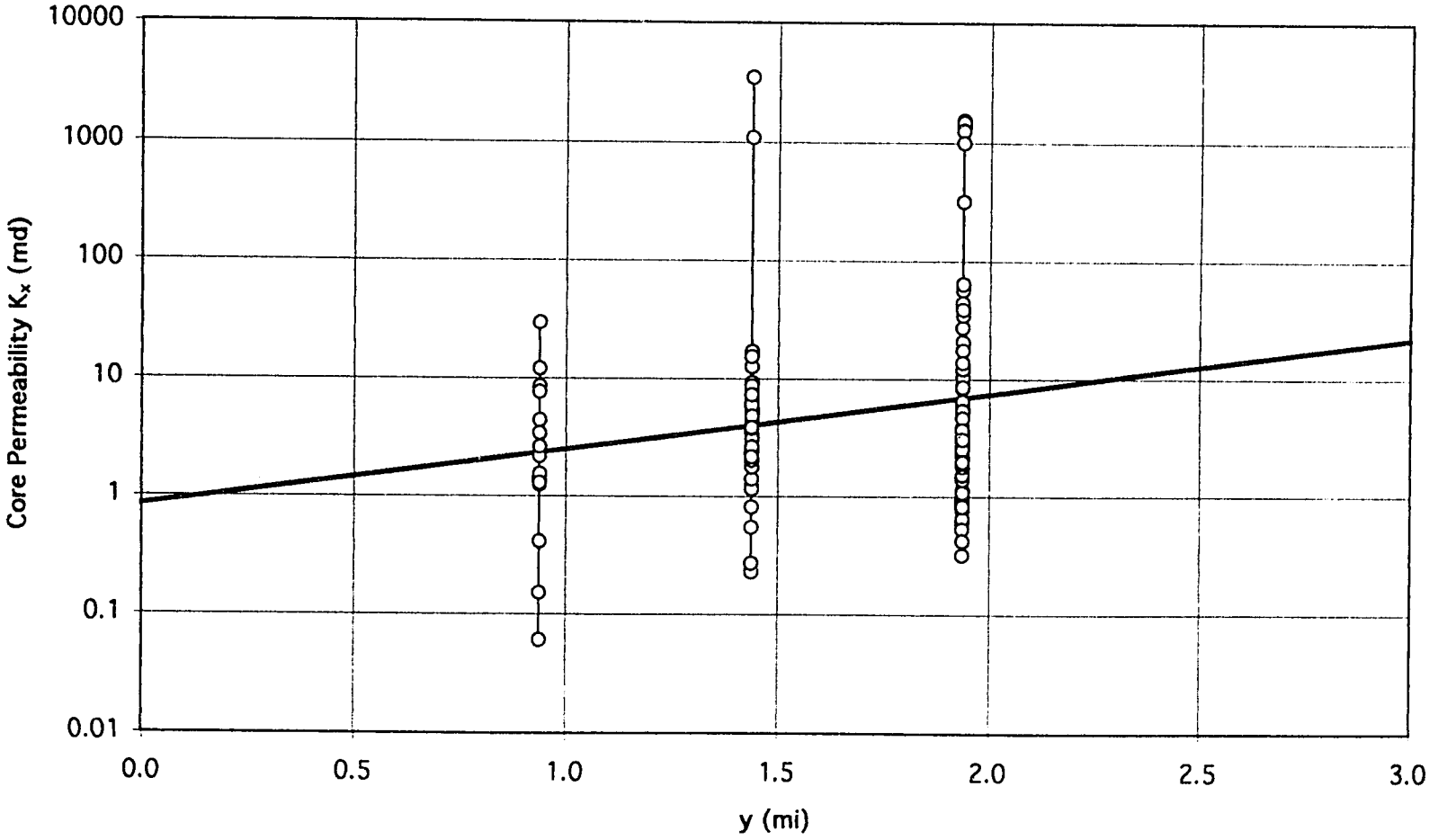



Figure 2.9(d): Core Maximum Permeability $K_x$ North-South Trend

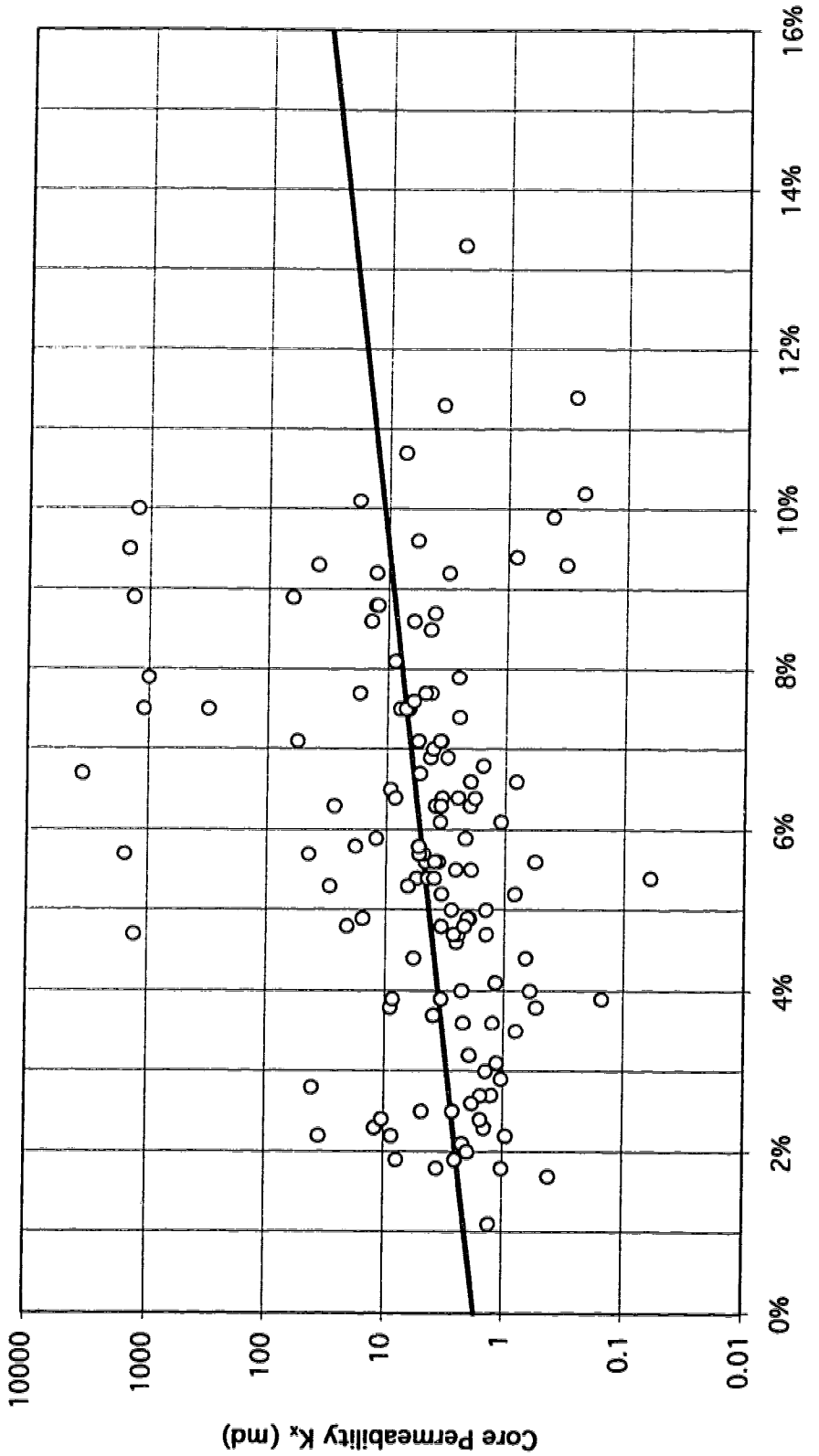



Figure 2.9(e): Core Maximum Permeability $K_x$ vs Core Porosity ϕ

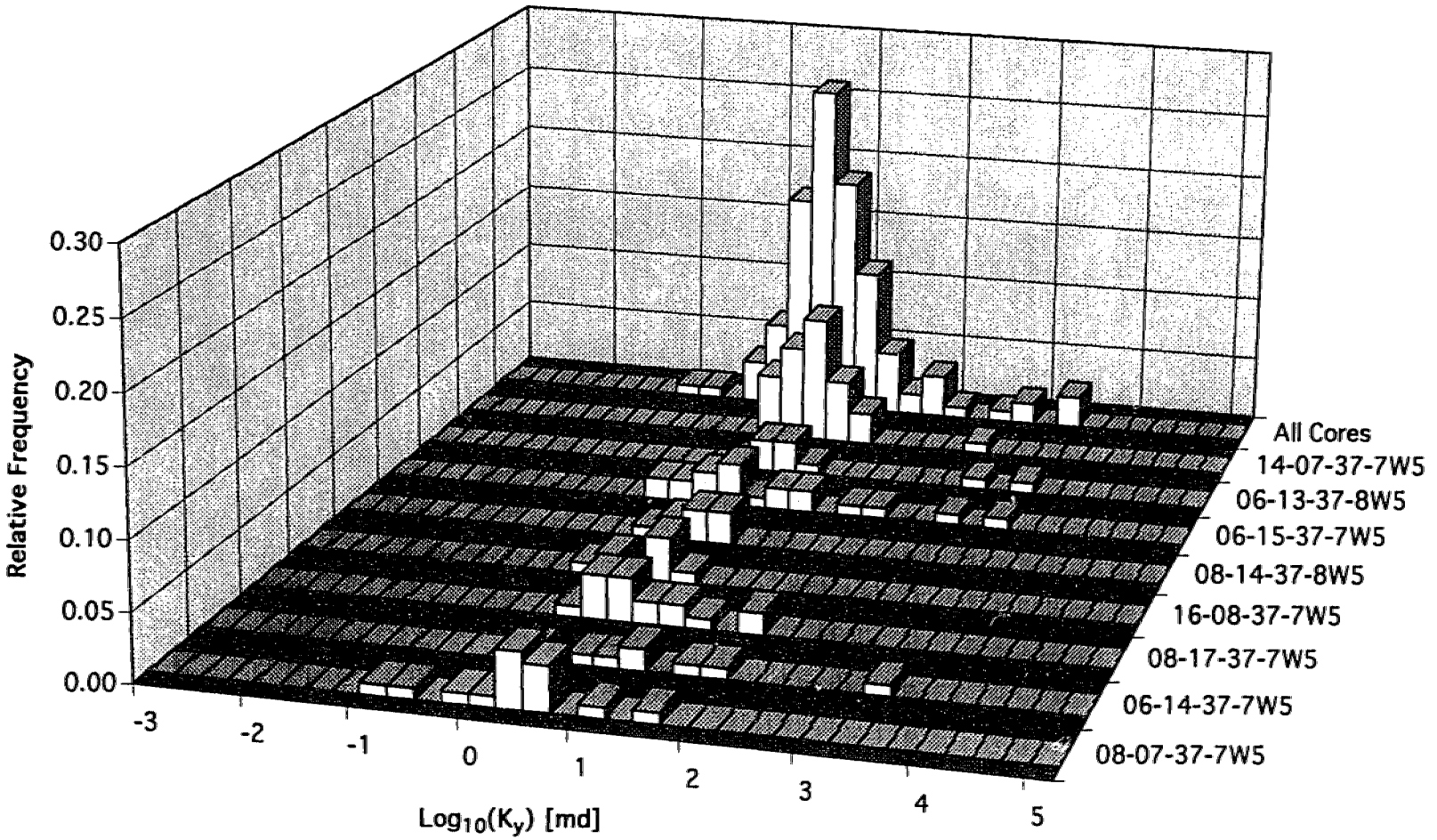



Figure 2.10(a): Core 90-Degree Permeability $K_y$ Histogram

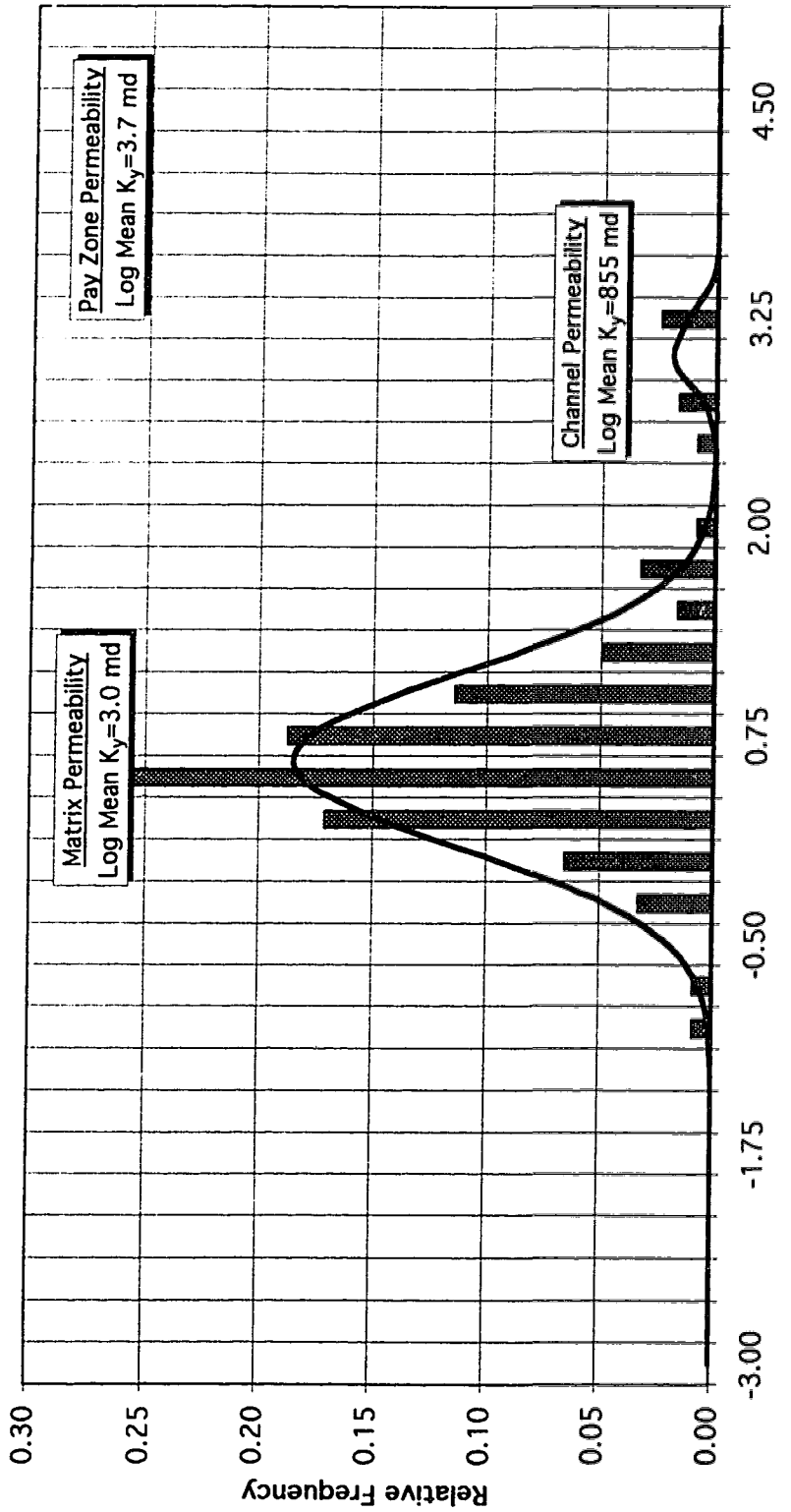



Figure 2.10(b): Core 90 Degree Permeability $K_y$ Histogram
(Lognormal Segmentation)

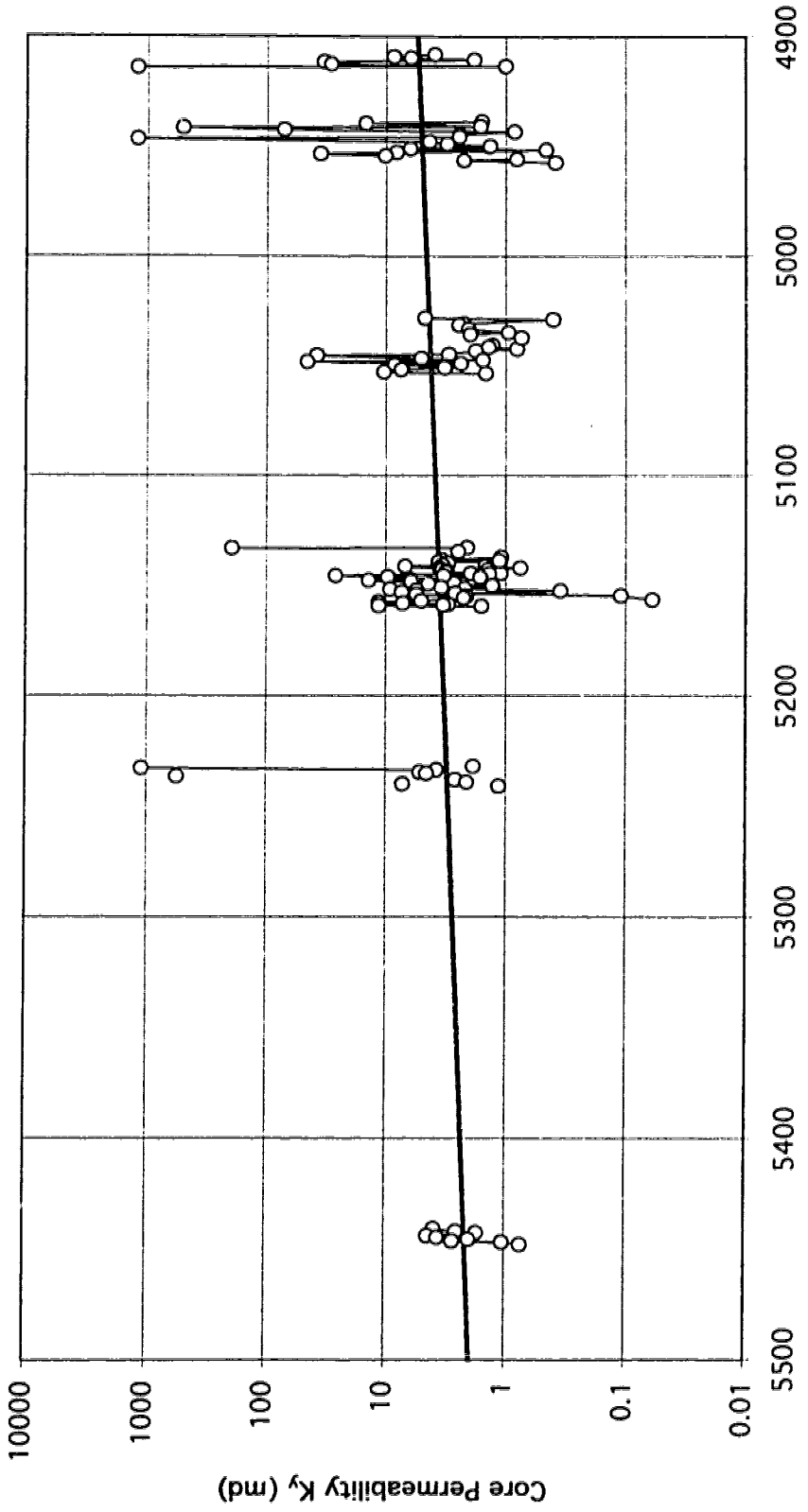



Figure 2.11(a): Core 90 Degree Permeability $K_y$ vs Depth

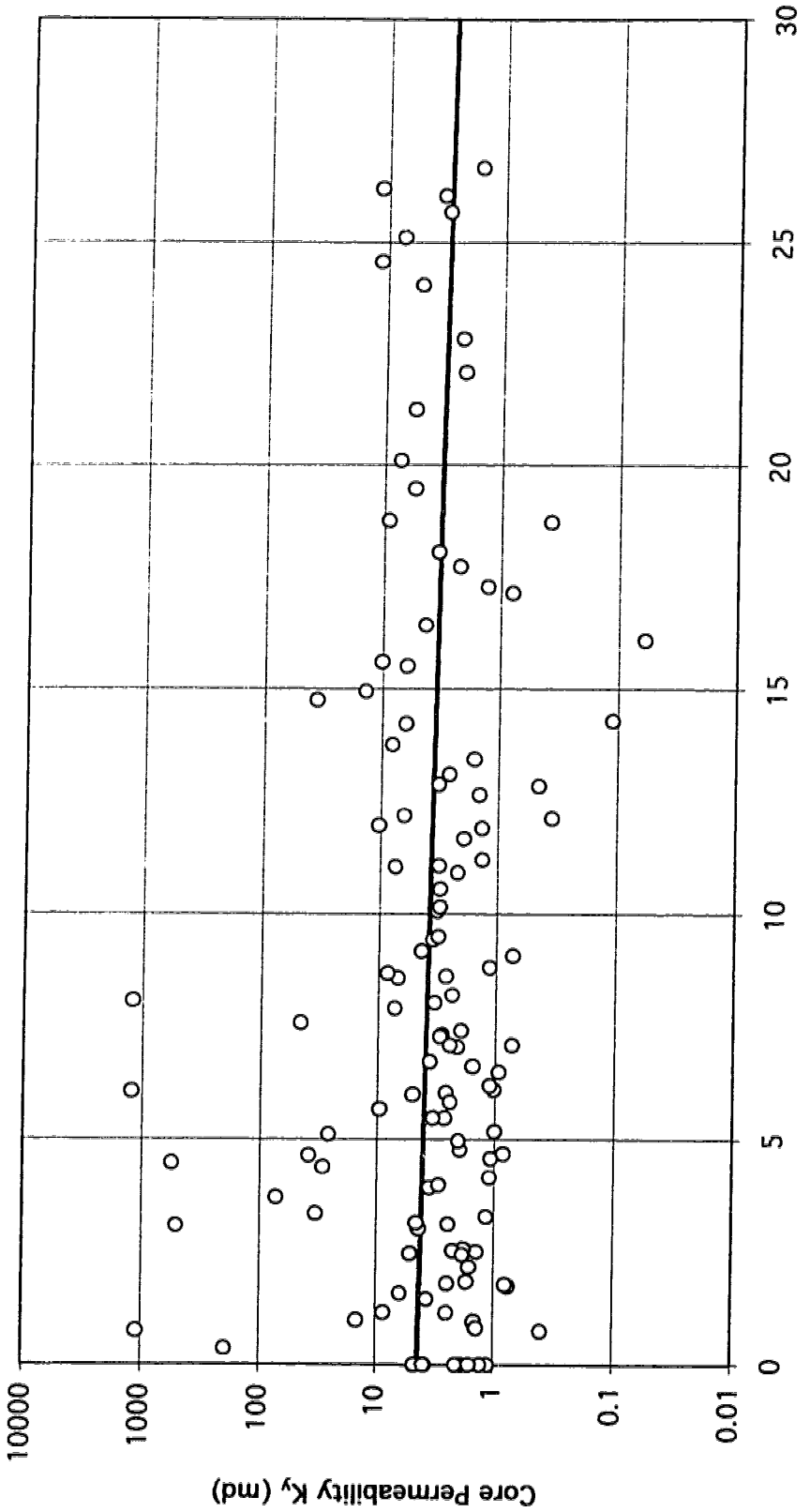



Figure 2.11(b): Core 90 Degree Permeability $K_y$ Vertical Trend

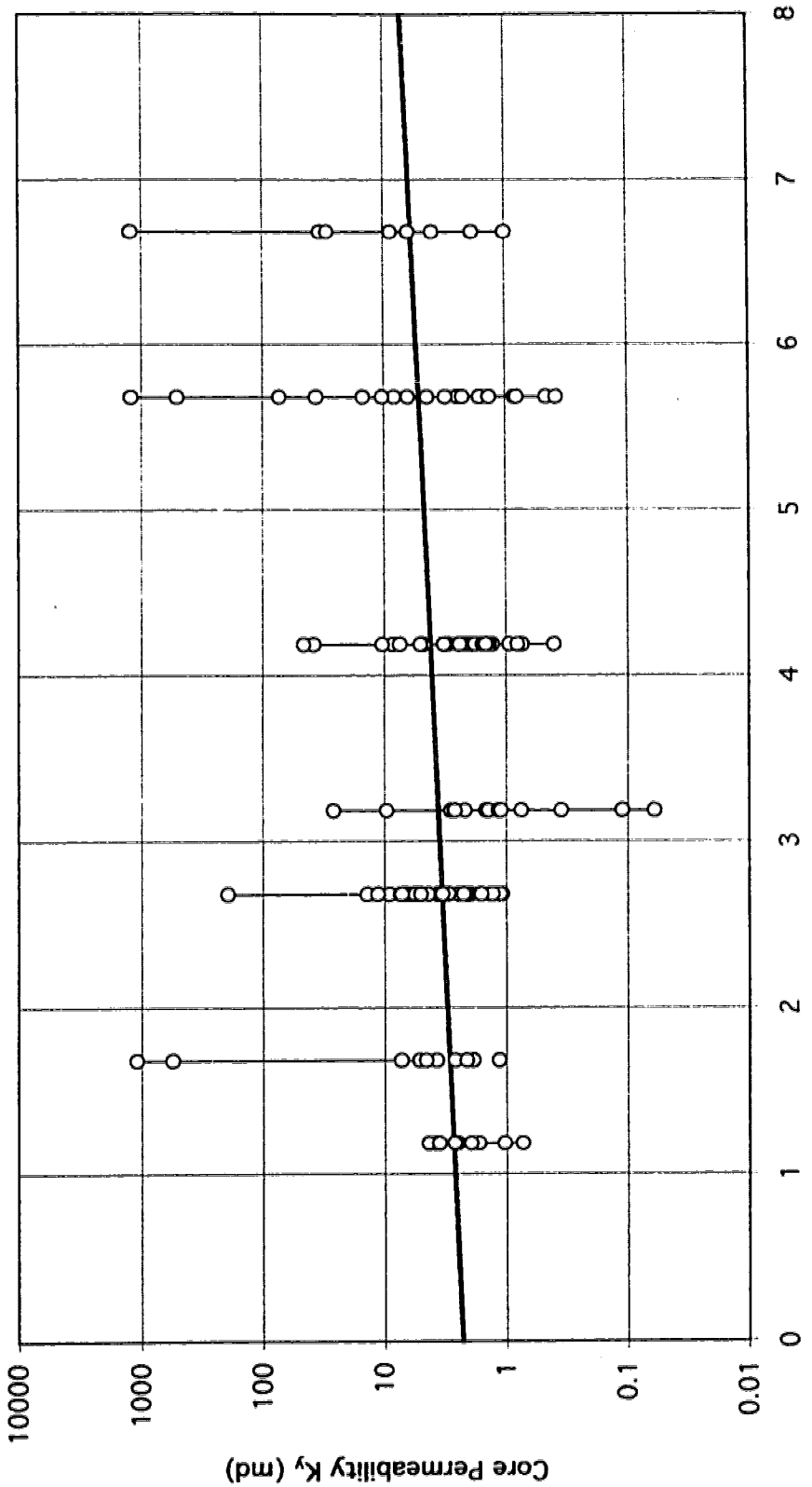



Figure 2.11(c): Core 90 Degree Permeability $K_y$ East-West Trend

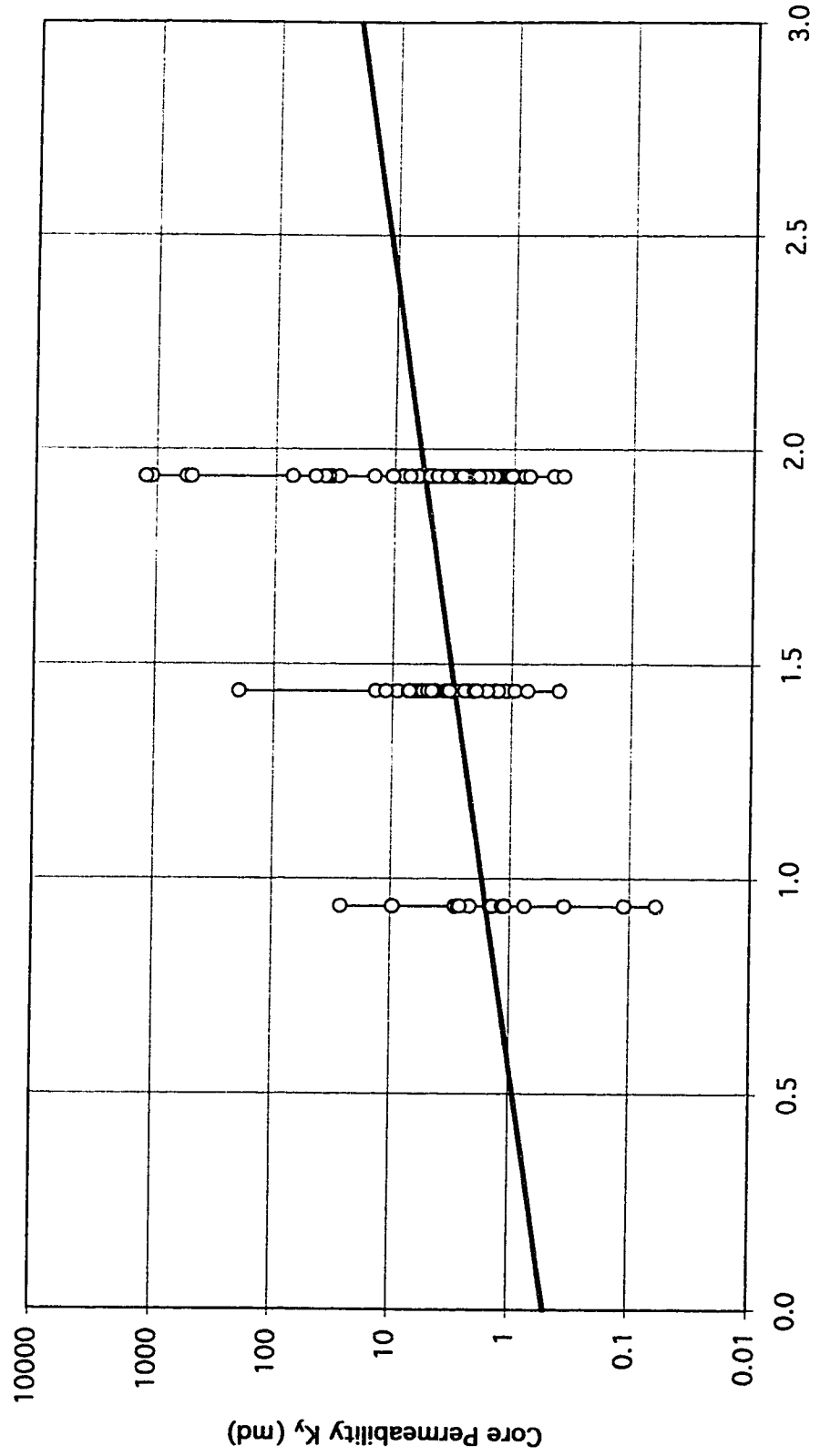



Figure 2.11(d): Core 90 Degree Permeability $K_y$ North-South Trend

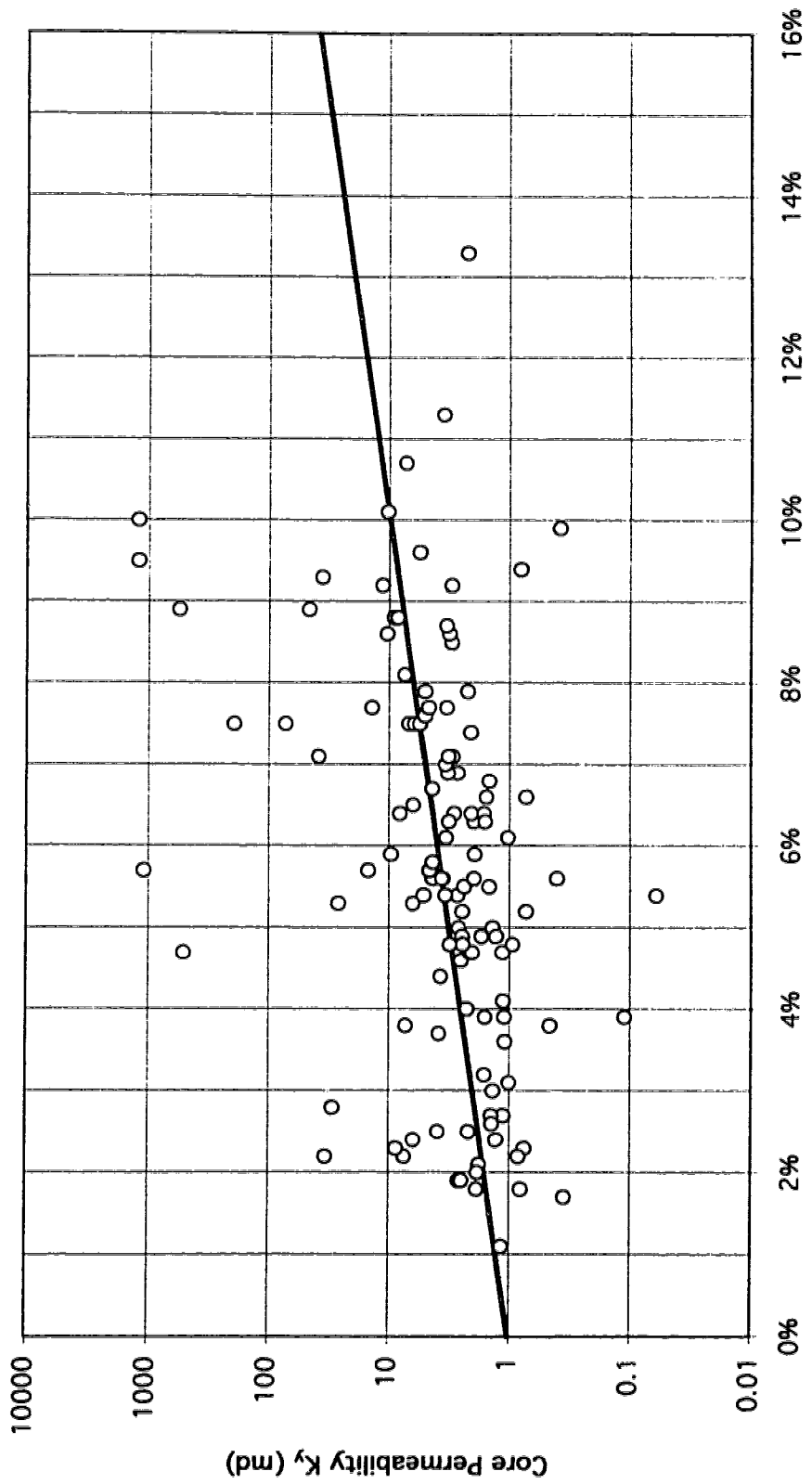



Figure 2.11(e): Core 90 Degree Permeability $K_y$ vs Core Porosity $\phi$

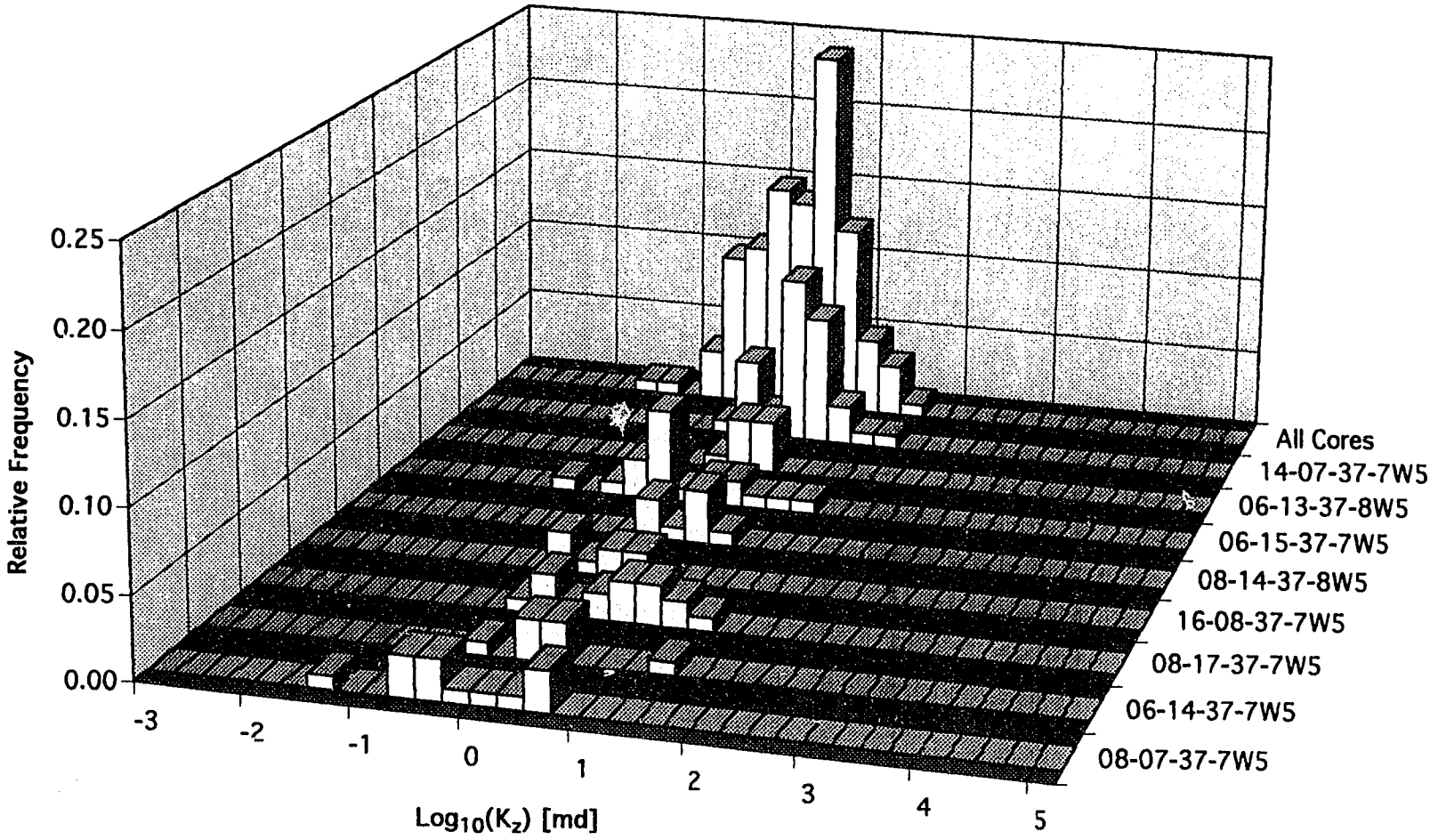



Figure 2.12(a): Core Vertical Permeability $K_z$ Histogram

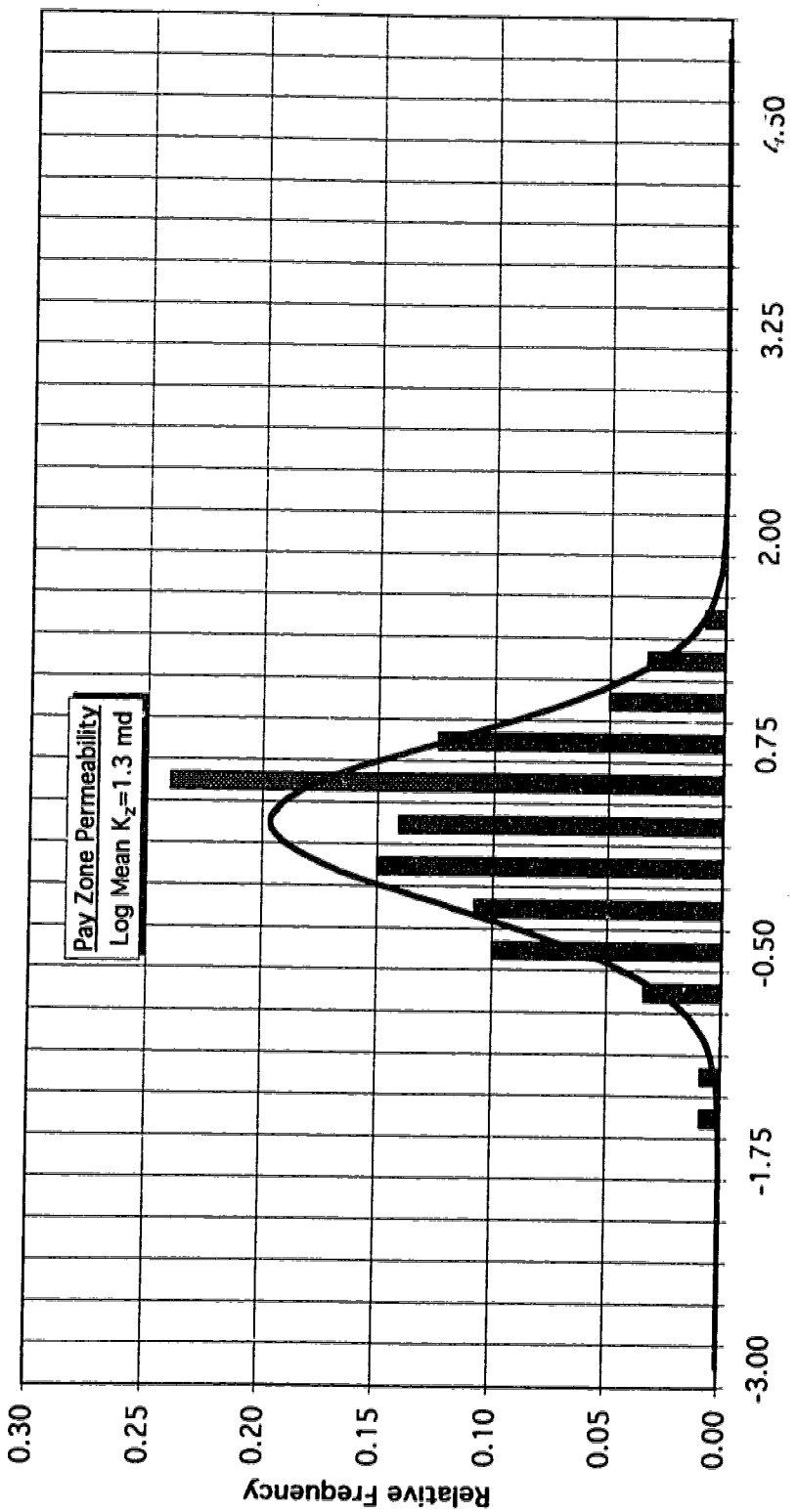



Figure 2.12(b): Core Vertical Permeability $K_z$ Histogram (Lognormal Segmentation)

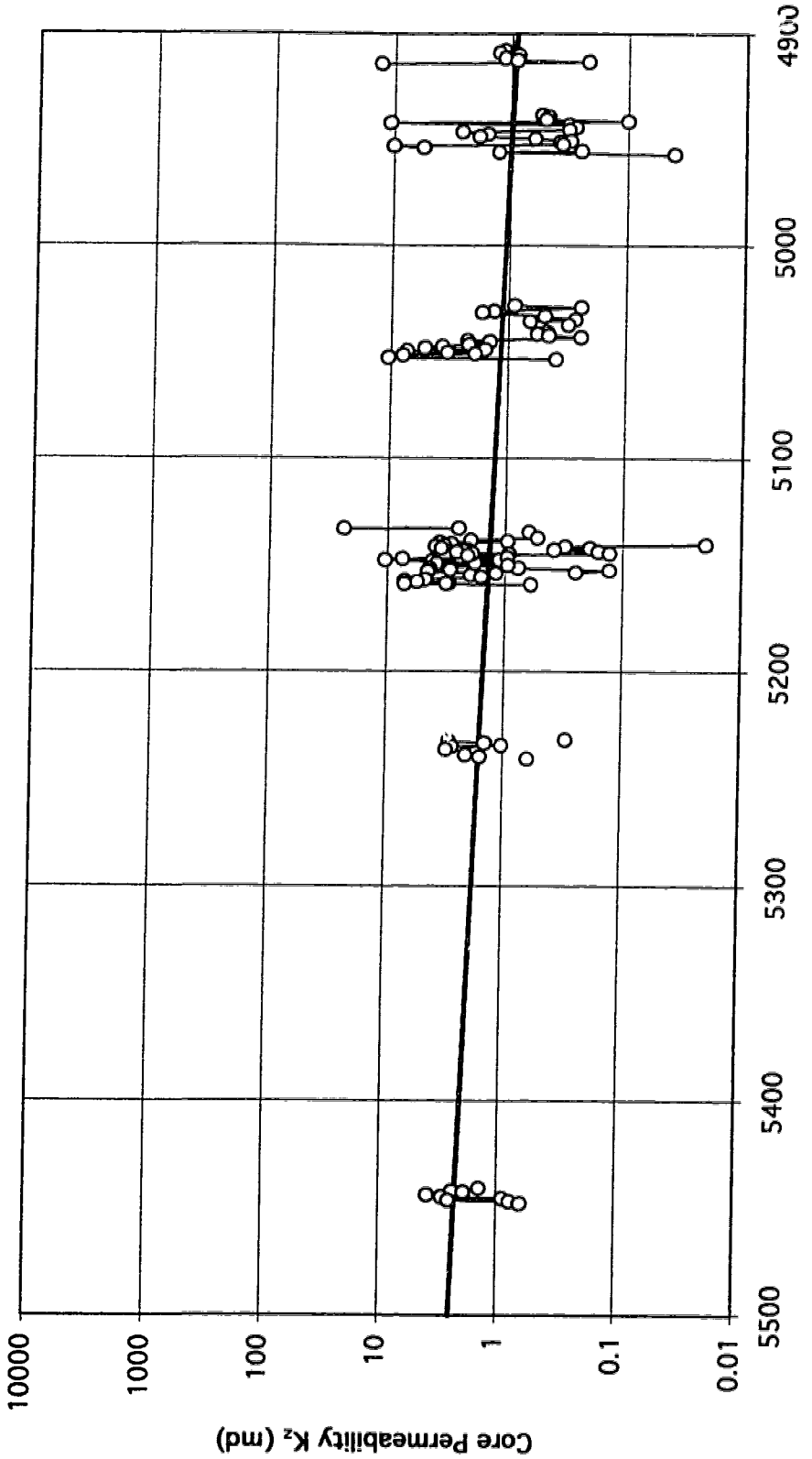



Figure 2.13(a): Core Vertical Permeability $K_z$ vs Depth

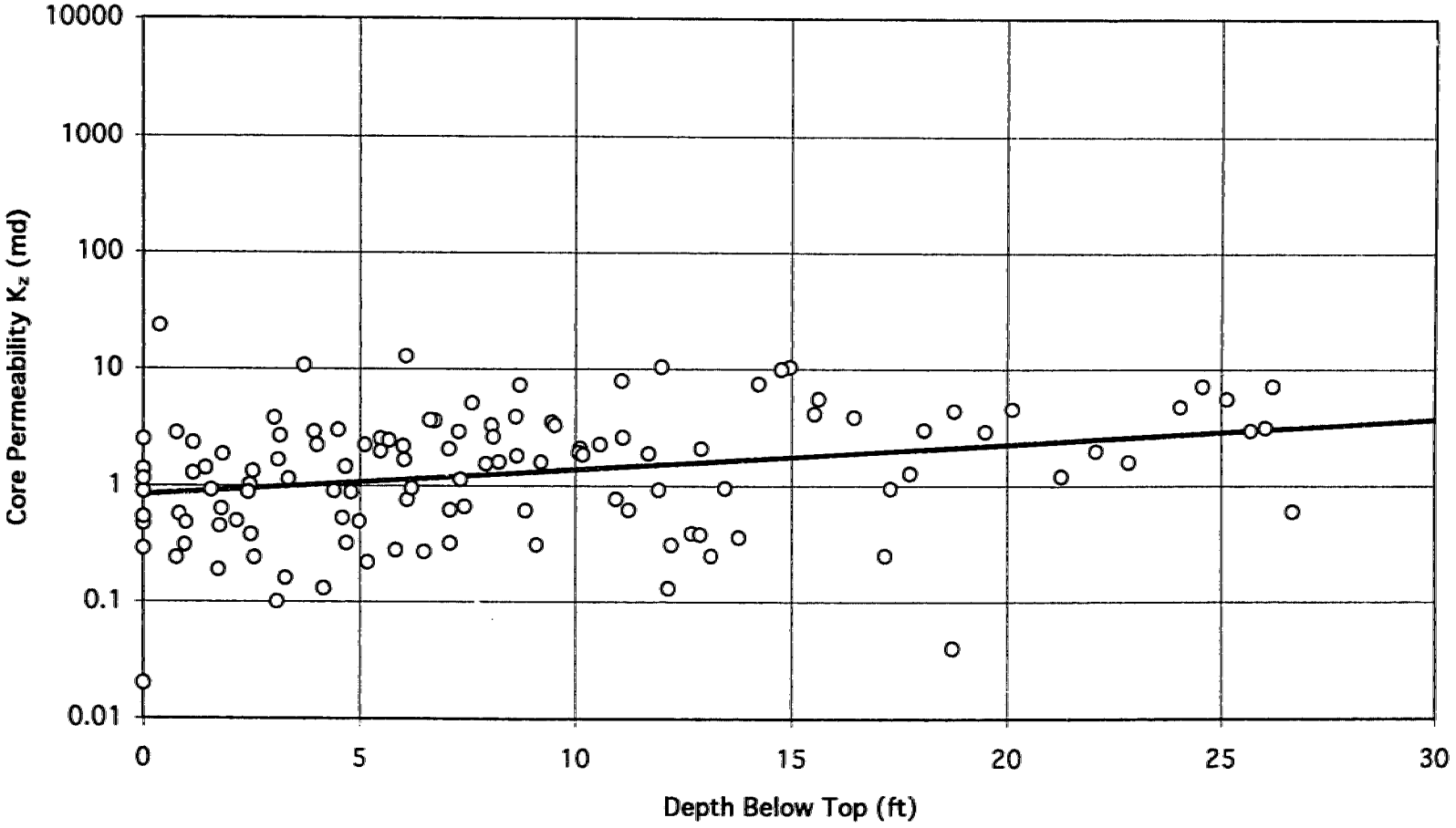



Figure 2.13(b): Core Vertical Permeability $K_z$ Vertical Trend

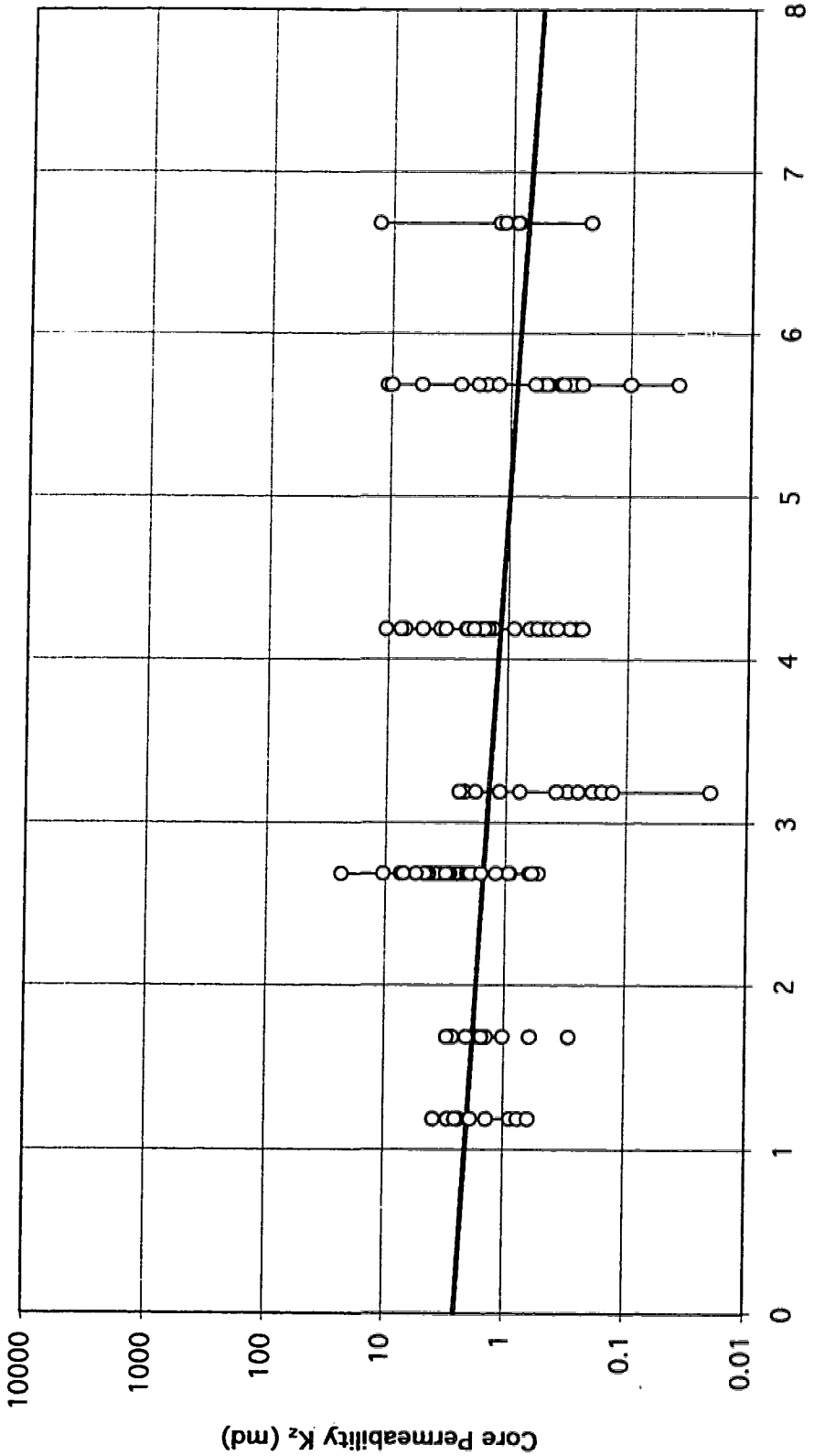



Figure 2.13(c): Core Vertical Permeability $K_z$ East-West Trend

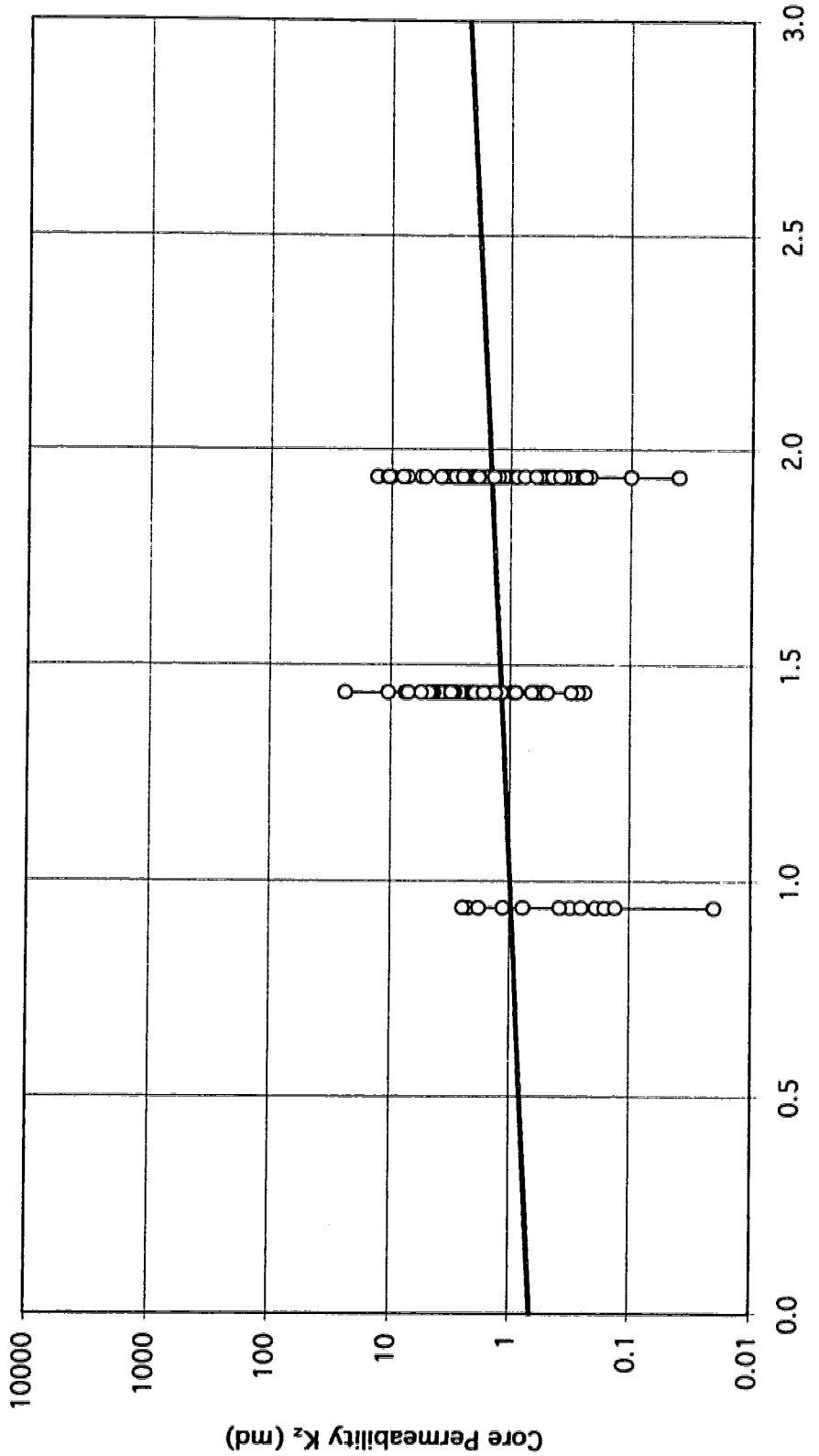



Figure 2.13(d): Core Vertical Permeability $K_z$ North-South Trend

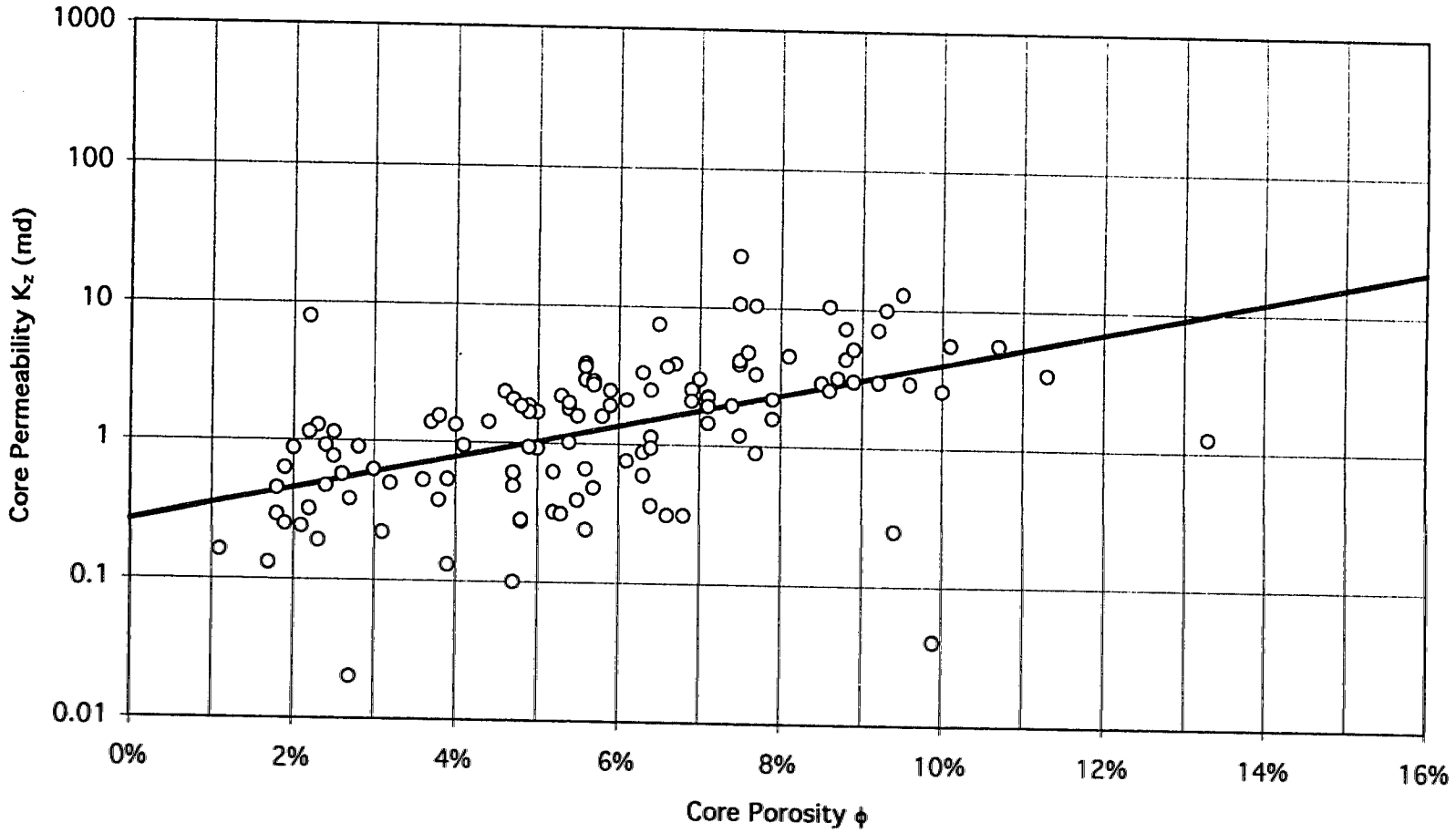



Figure 2.13(e): Core Vertical Permeability $K_z$ vs Core Porosity $\phi$

| | Chedderville Viking A Core Summary | | | | | Zone Thickness | Δz-weighted Porosity | Log-mean Permeability | Log-mean Permeability | Log-mean Permeability | Rock Compressibility | Water Saturation | Bulk Water Fraction |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Well | LSD | SEC | TWP | RGE | W | Δz (ft) | $\phi$ | Kx (md) | Ky (md) | Kz (md) | cr (1/psi) | Sw | $\phi S_w$ |
| 1 | 8 | 7 | 37 | 7 | 5 | 29.53 | 4.05% | 1.94 | 1.31 | 0.23 | 7.14e-06 | 32.0% | 0.0130 |
| 2 | 14 | 7 | 37 | 7 | 5 | 27.89 | 7.09% | 5.85 | 3.94 | 2.64 | 5.64e-06 | 23.7% | 0.0168 |
| 3 | 16 | 8 | 37 | 7 | 5 | 34.45 | 7.25% | 1.59 | 1.51 | 0.58 | 5.59e-06 | 33.8% | 0.0245 |
| 4 | 6 | 14 | 37 | 7 | 5 | 22.97 | 3.42% | 15.07 | 12.09 | 1.17 | 7.70e-06 | 41.8% | 0.0143 |
| 5 | 6 | 15 | 37 | 7 | 5 | 19.69 | 6.32% | 7.27 | 5.58 | 0.69 | 5.92e-06 | 27.5% | 0.0174 |
| 6 | 8 | 17 | 37 | 7 | 5 | 16.40 | 5.64% | 6.77 | 3.85 | 1.76 | 6.20e-06 | 28.7% | 0.0162 |
| 7 | 6 | 13 | 37 | 8 | 5 | 13.12 | 5.09% | 6.64 | 9.23 | 1.41 | 6.47e-06 | | |
| 8 | 8 | 14 | 37 | 8 | 5 | 18.04 | 5.40% | 2.29 | 2.15 | 1.60 | 6.31e-06 | 29.5% | 0.0159 |
| | | | | | Zone | 22.76 | 5.64% | 4.94 | 3.77 | 1.27 | 6.37e-06 | 28.4% | 0.0169 |

Permeability Averaging: Geometric Log Mean

Rock Compressibility Coefficient: Hall's porosity correlation (Ahmed, T., p236)

Water Saturation: Canadian Hunter Petrophysical Summary (Logs)

Bulk Water Averaging: Δz-weighted

Table 2.3: Core and Log Data Summary

## 2.7 High-Permeability Channel

The inclusion of the high-permeability channel in the reservoir model is paramount to history matching recorded bottomhole pressures and forecasting production accurately. The modelling of this channel is the critical link in the chain of reservoir characteristics. This is the vehicle by which pressure is maintained throughout the tight reservoir. Pressure communication within the channel media is prompt and local pressure gradients are equalized rapidly.

The initial reservoir model considered a two-dimensional (2-D) areal grid only, using average vertical reservoir properties. The high permeability zones were considered thin and insignificant. These were averaged in with the matrix. The result gave an unacceptable pressure history match, with predicted bottomhole pressures declining at phenomenally rapid rates. In the simulation, pressure fox holes grew rapidly in the tight porous media and historical production rates could not be sustained effectively. The drainage radii of producing wells was small. Fluid mobility was limited to these regions which collectively spanned a fraction of entire pool. The actual pressure decline history did not seem to be consistent with the 2-D reservoir model. Reasons were posed to be one of many:

- larger hydrocarbon deposit than assumed
- incorrect pressure initialization
- an unaccounted aquifer
- pressure communication with an adjacent pool
- pressure communication with other formations
- enhanced pressure communication within the pool

Most of the reasons were ruled out by the process of elimination through logic or simulation. The dimensions of the hydrocarbon deposit and the initial pressure had to be drastically manipulated in order to fit the pressure history. This was not acceptable and was therefore ruled out. The petrophysical data gave no evidence of an aquifer, and this too was ruled out. The only adjacent pool that could effect the reservoir pressure in the required manner was the Chedderville Viking "S" Caroline Pool (Figure 2.1). The fault separating Viking "A" from Caroline shifted the pools relative position by twisting and vertically translating the pools apart. The only communication between pools that could potentially take place was at an isolated seam on the south-western tip of Viking "A". This, however, could not account for the high pressure source needed for the history match, and was also ruled out. There was some evidence of pressure communication between the Viking "A" pool and a lower Mannville formation at a single well (14-09-37W5). This was deduced after an acceptable history match was attained and will be discussed at length later. Even though this presents certain complications in reservoir modelling, it does not account

for pressure maintenance on the reservoir scale. The final reason considered was that a high permeability channel, no matter how thin, could have a significant effect on the overall reservoir pressure response. The three-dimensional (3-D) reservoir model, with an upper layer representing the channel, seemed to work.

The 3-D reservoir model incorporating the high permeability channel considered a 2-layer system with a thin upper layer (k=1) appended on the initial 2-D 54×18 rock matrix grid (k=2). Computational constraints eliminated higher dimensional configurations. The high permeability channel was assumed to span all contiguous wells that had supported its existence with core data as shown in Figure 2.14(a). Furthermore, it was assumed that the partial analysis on core sample for 08-14-37-8W5 had missed channel identification, and was also grouped within the continuous convex region defining the channel domain. History matching results supported this assumption. The actual channel appears to be isolated in the top 6 feet of the perforation zone, running from a constant 1 feet thickness in the lower third of the reservoir and increasing to a maximum of 2.5 feet in the upper third, as shown in Figure 2.14(b). The two-layer model explicitly lumps the channel directly on top of the perforation zone[4]. The rock matrix layer is also characterized to implicitly account for both channel thickness and permeability through geometric averaging. This simple model is intended to capture the gross channel functionality while preserving well productivity to a single layer. Fluids will readily flow in the channel maintaining pressure communication throughout. Actual well inflow will be highly inter-dependent between channel and matrix flows. The relative vertical position of the channel with respect to the rock matrix is essential for successful waterflood operations. Water prefers to flow below the oil and along the bottom of the perforation zone. If the channel appeared on the bottom of the perforation zone, the injected water would preferentially flow along the bottom and effectively bypass the bulk of the oil deposit above.

---

4 It should be noted that this is the simplest reservoir model that describes the 3-D system, and that more rigorous models would try to place the channel in its correct vertical position.

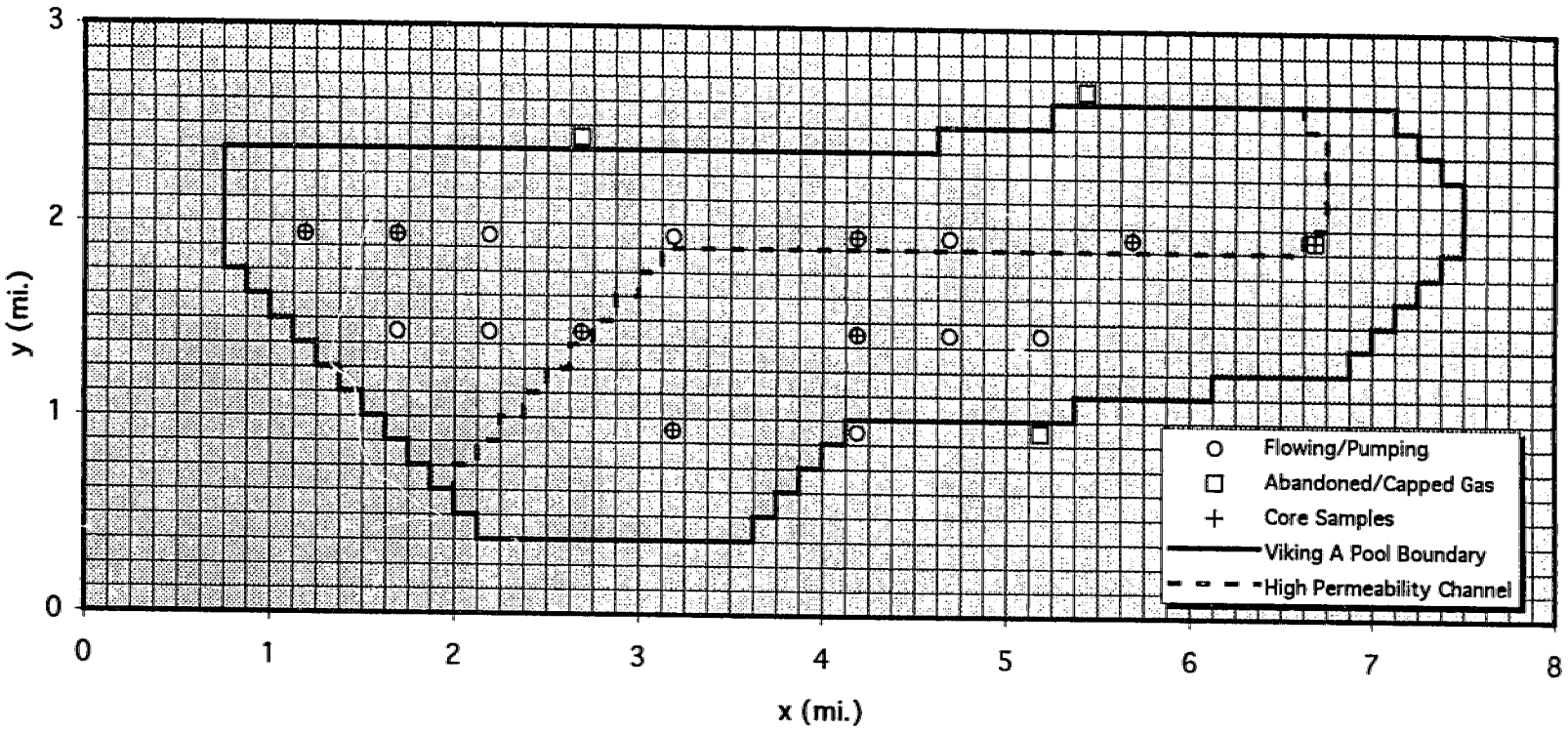



Figure 2.14 (a): High Permeability Channel

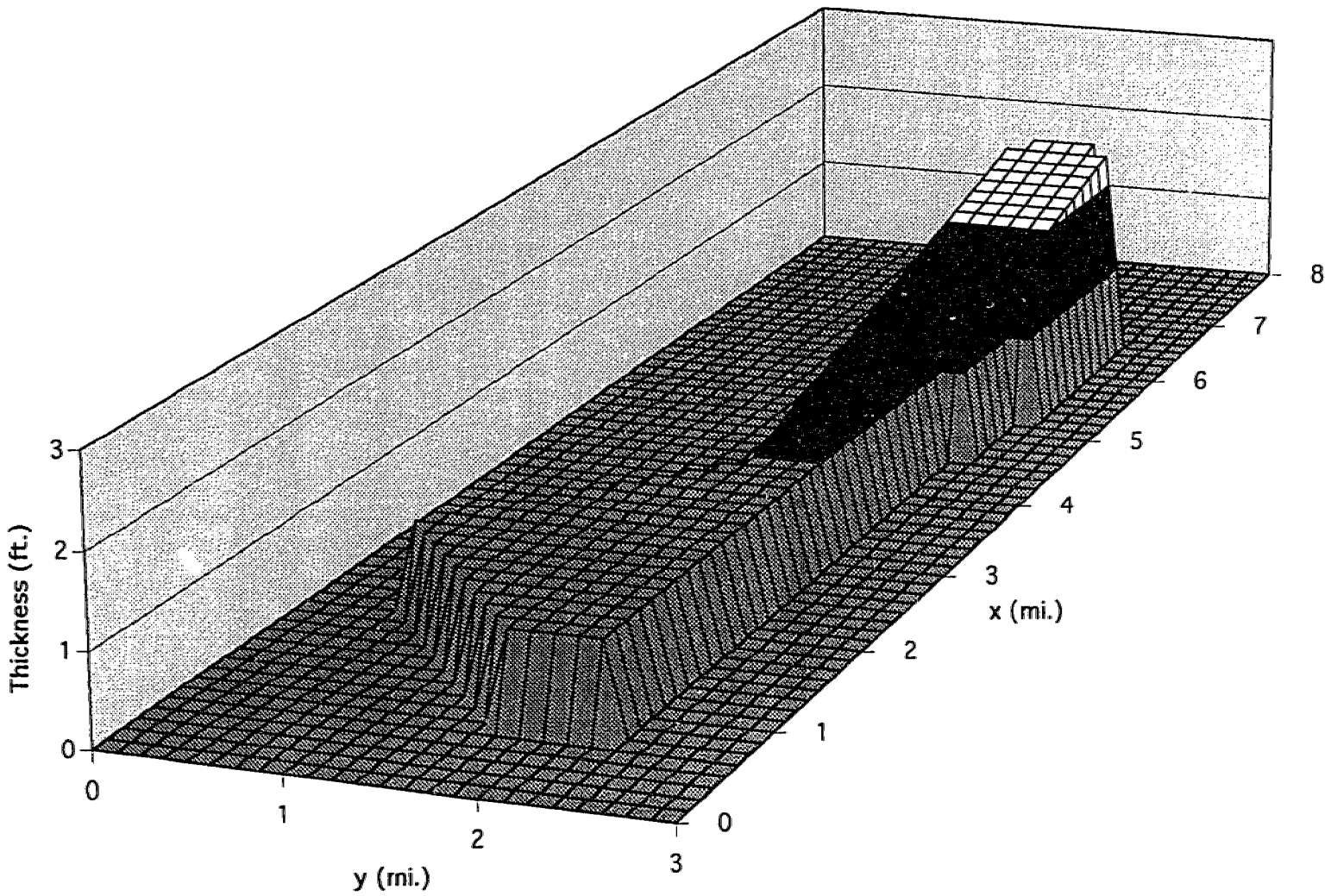



Figure 2.14(b): Channel Thickness Δz (k=1)

## 2.8 Three-Dimensional Reservoir Model

The 3-D reservoir geometry can be modelled by grid block volumes representing the channel (k=1) and matrix (k=2), as shown in Figures 2.15(a) and 2.15(b). The numeric values for layer thickness and layer depth are listed in Tables 2.4 and 2.5, respectively. Corresponding contour plot visualizations are presented in Figures 2.16(a) and 2.16(b).

Assigning values to the reservoir properties of porosity and absolute rock permeabilities was an iterative task governed by history matching. Channel layer (k=1) properties were assumed to be homogeneous. Log-mean values of $K_x$=1220 md and $K_y$=855 md were assigned to the horizontal channel permeability. The vertical channel permeability $K_z$ =5 md and porosity $\phi$=10% were estimated from core data. The bottom matrix layer (k=2) was segmented into two major rock types. A smooth transition was assumed to separate a homogeneous region situated below the high permeability channel from the other region some distance away. The procedure used the correlations established in Section 2.5 to inter-relate reservoir properties. Permeability $K_x$ was designated as the control parameter. $K_y$ and $K_z$ were correlated to $K_x$ using Eqn 2.2 and 2.4. Porosity $\phi$ was correlated to the vertical permeability $K_z$ using Eqn 2.5. The initial water saturation $S_w$ was assumed to be irreducible, and correlated to the porosity $\phi$ using Eqn 2.6. The history matched properties in the homogeneous zone below the channel were $K_x$=8.0 md, $K_y$=5.4 md, $K_z$=1.4 md, $\phi$=6.2% and $S_w$=27.5%. The other region was determined to be $K_x$=2.0 md, $K_y$=1.7 md, $K_z$=0.9 md, $\phi$=4.6% and $S_w$=37.3%. The transition region was determined patiently through trial and error. The resulting numeric assignment for $K_x$, $K_y$, $K_z$, $\phi$ and $S_w$ distributions are tabulated in Tables 2.6(a)-(e). Corresponding contour plot visualizations are presented in Figures 2.17(a)-(e). These values are representative of their statistical distributions (Section 2.5).

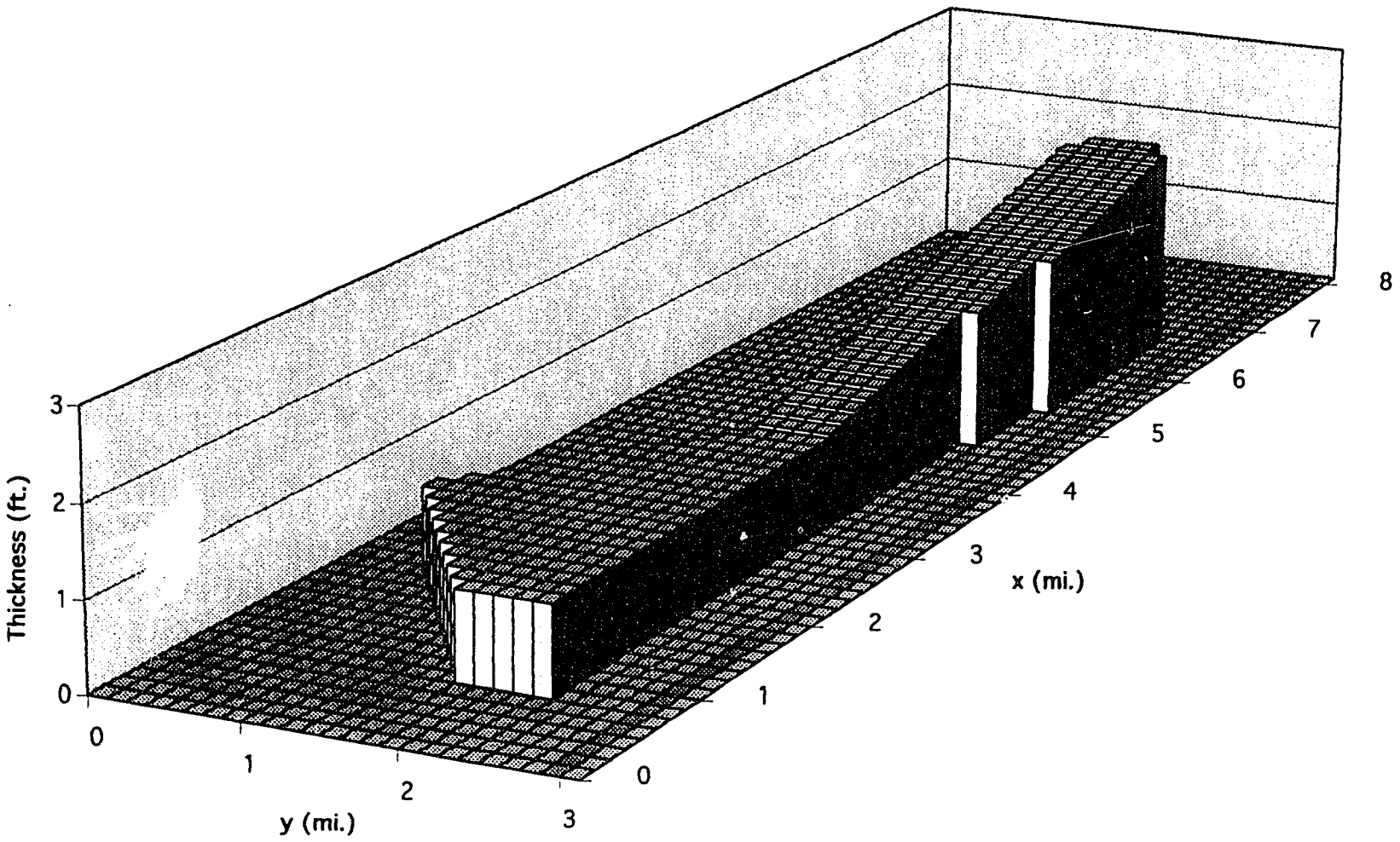



Figure 2.15(a): Channel Grid Block Thickness $\Delta z$ (k=1)

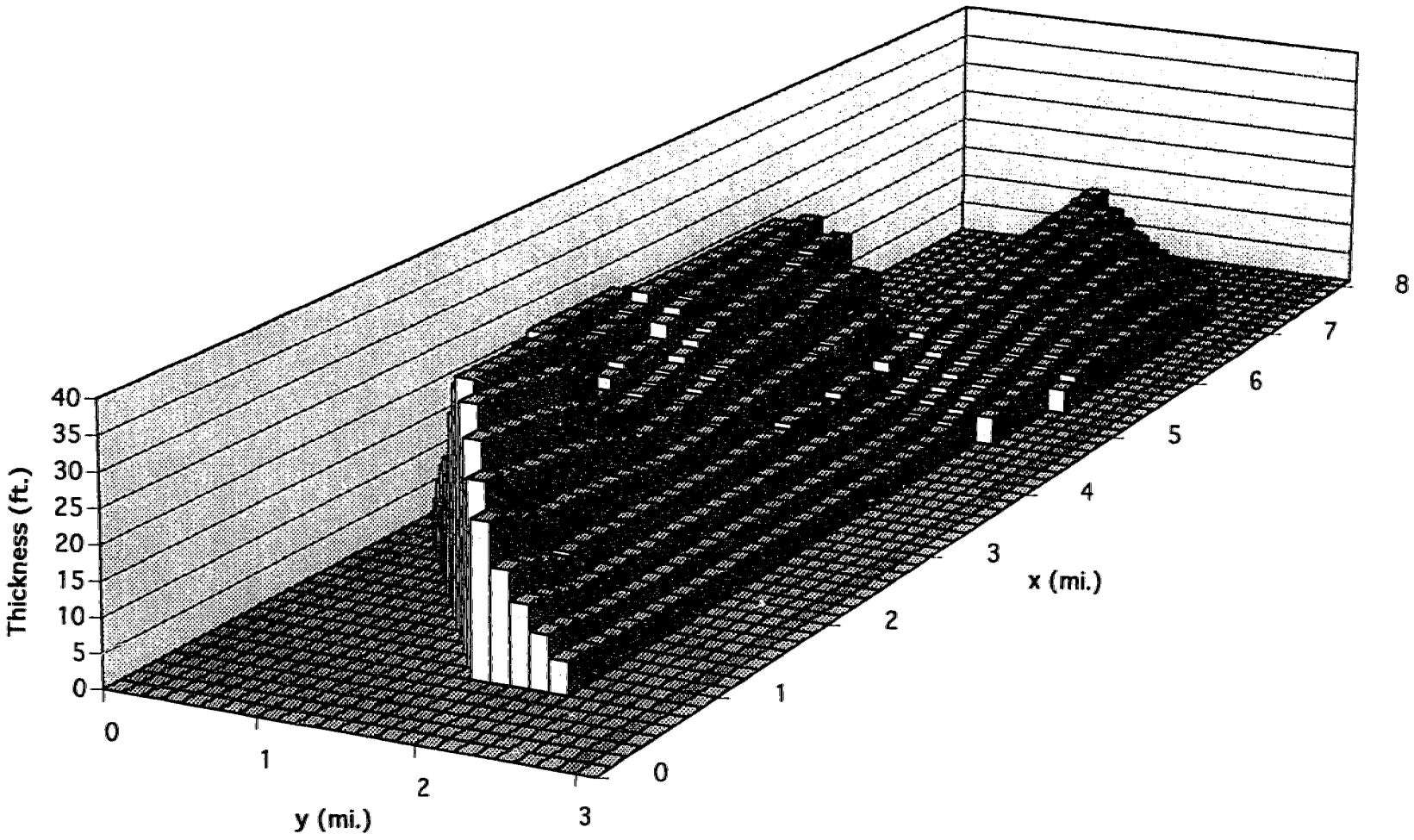



Figure 2.15(b): Matrix Grid Block Thickness $\Delta z$ (k=2)

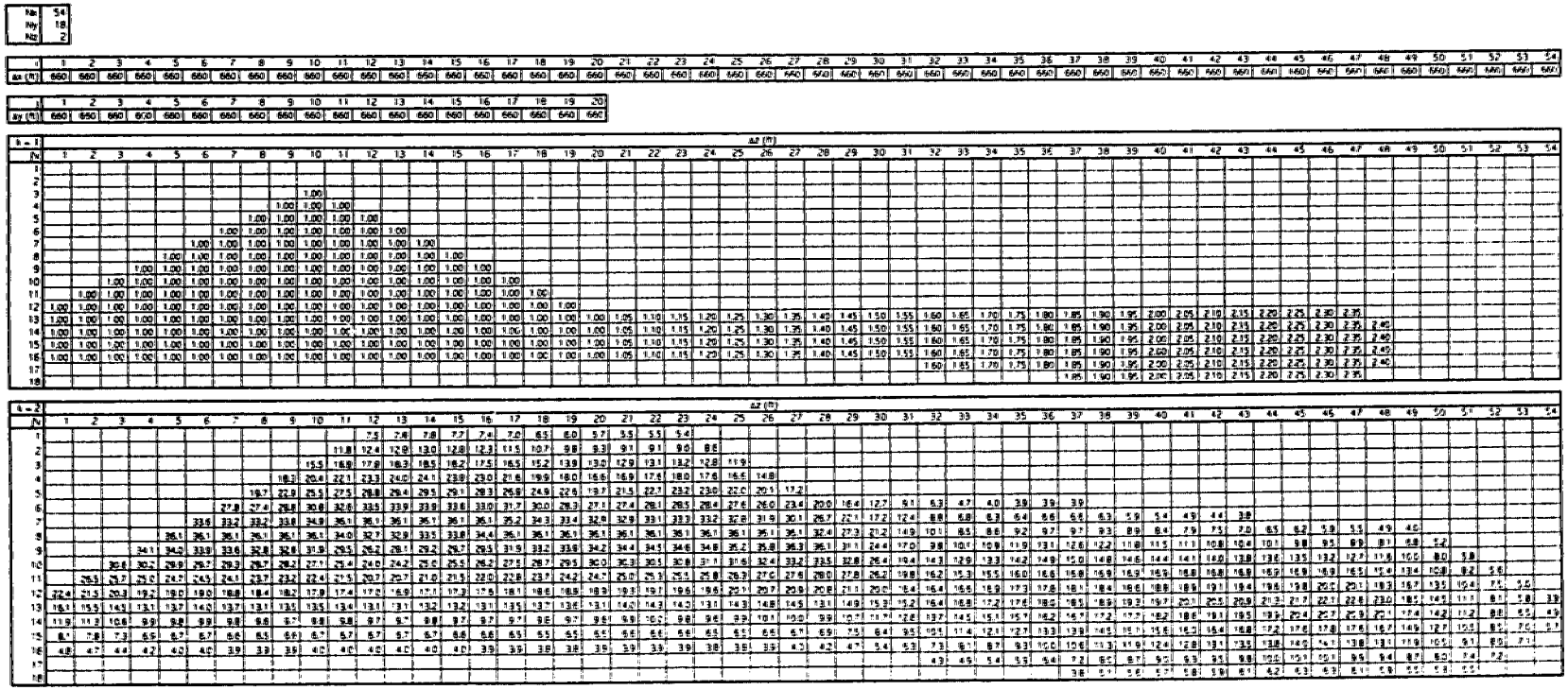


Table 2.4: Reservoir Grid Dimensions

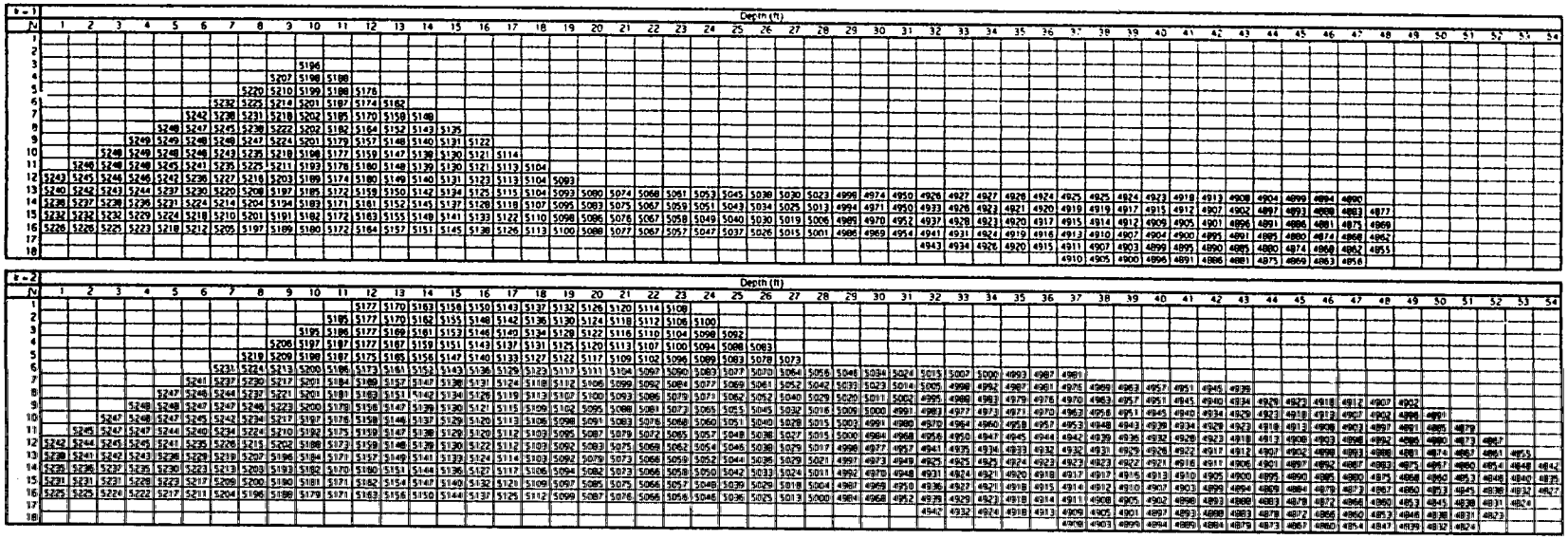


Table 2.5: Reservoir Grid Depth

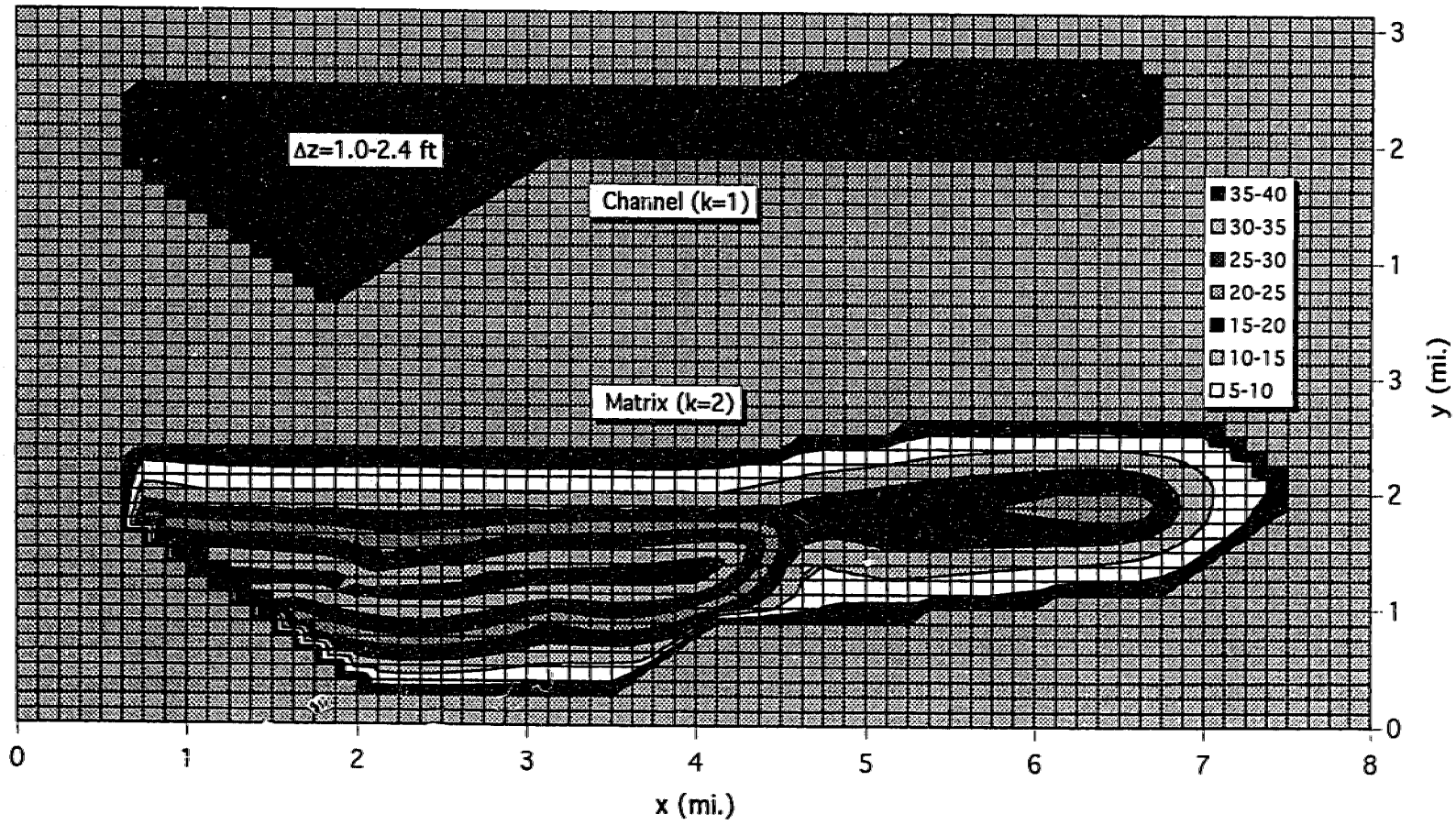



Figure 2.16(a): Reservoir Thickness Δz (ft)

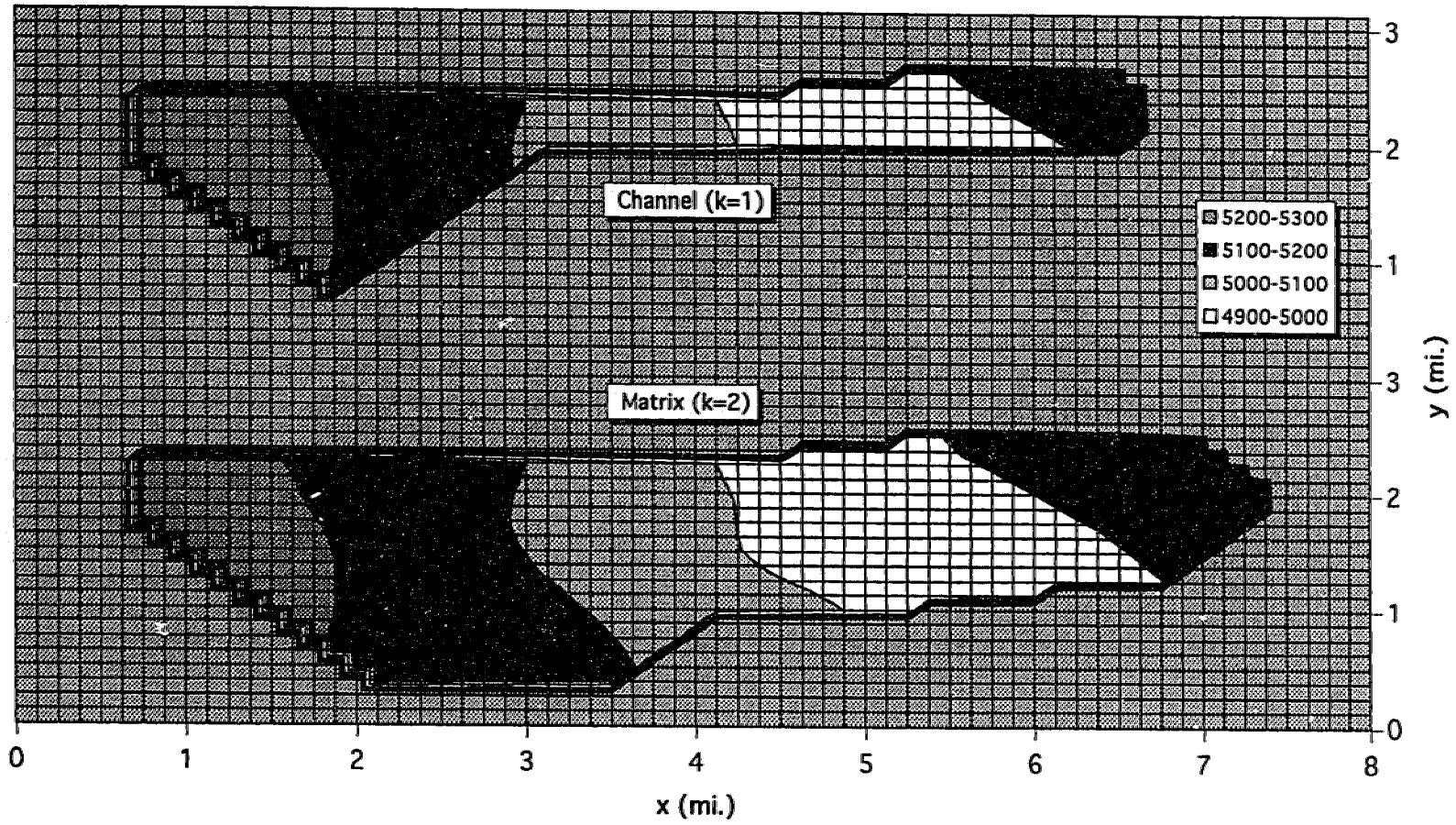



Figure 2.16(b): Reservoir Subsea Depth (ft)

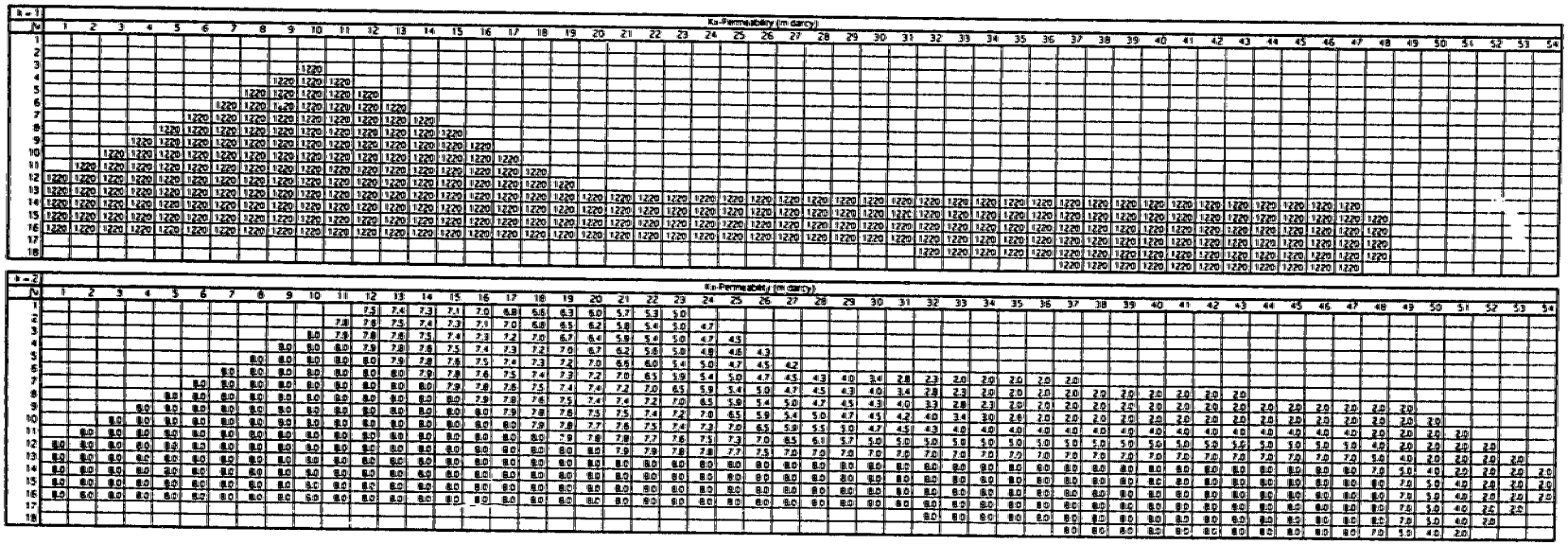


Table 2.6(a): Horizontal Permeability $K_x$

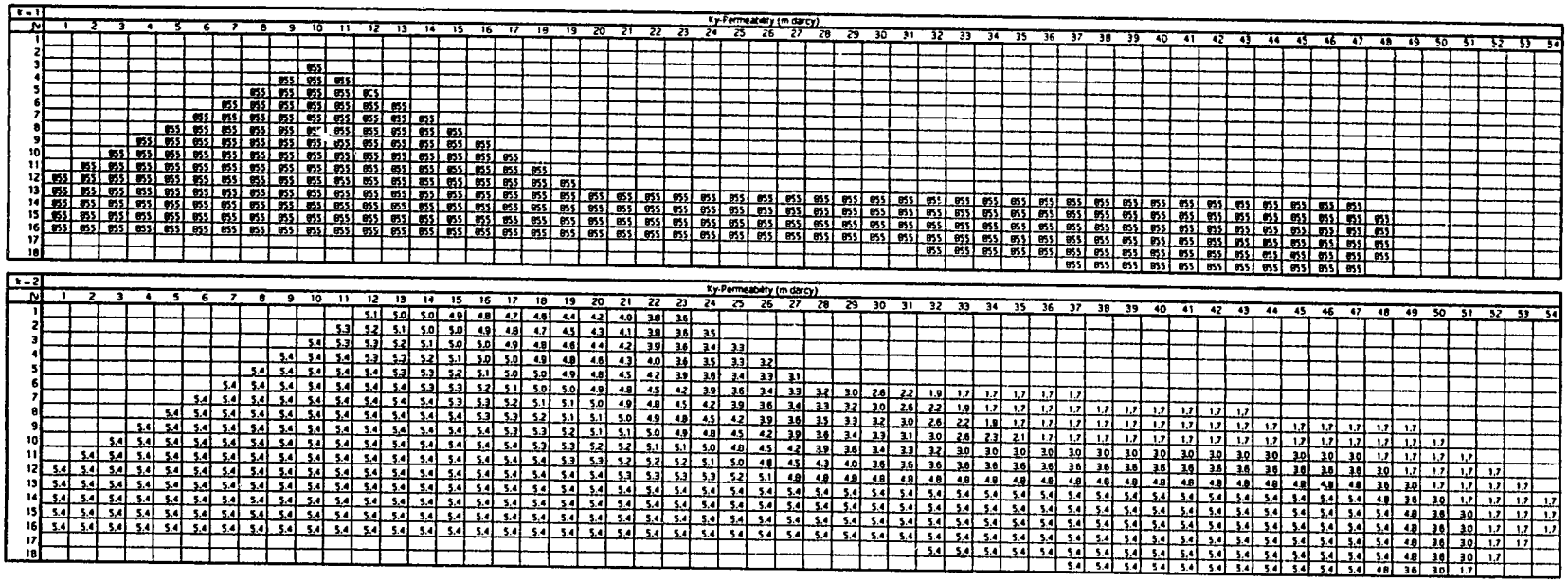



Table 2.6(b): Horizontal Permeability $K_y$

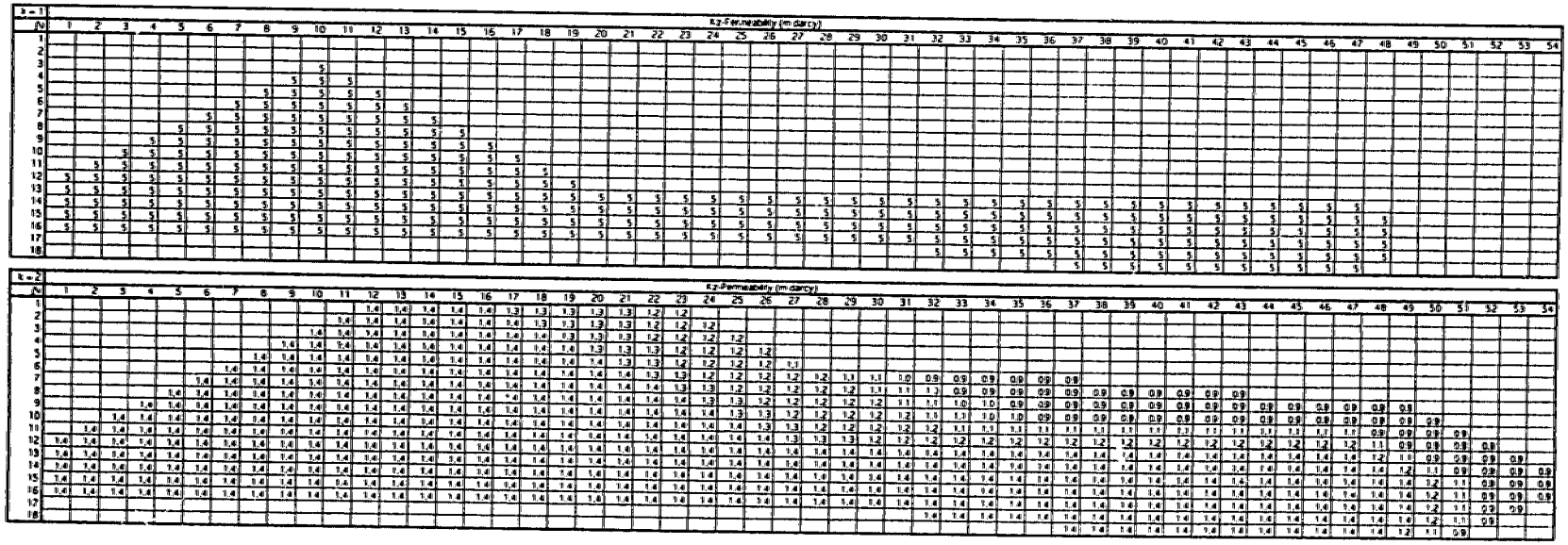


Table 2.6(c): Vertical Permeability $K_z$

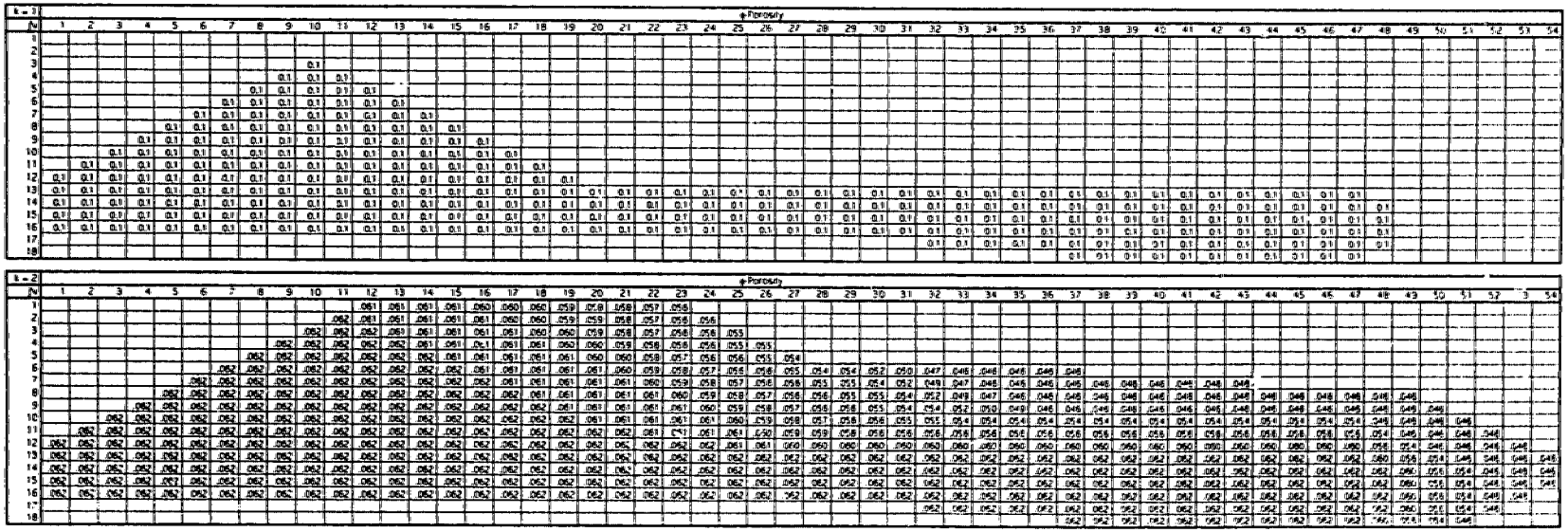


Table 2.6(d): Reservoir Porosity $\phi$

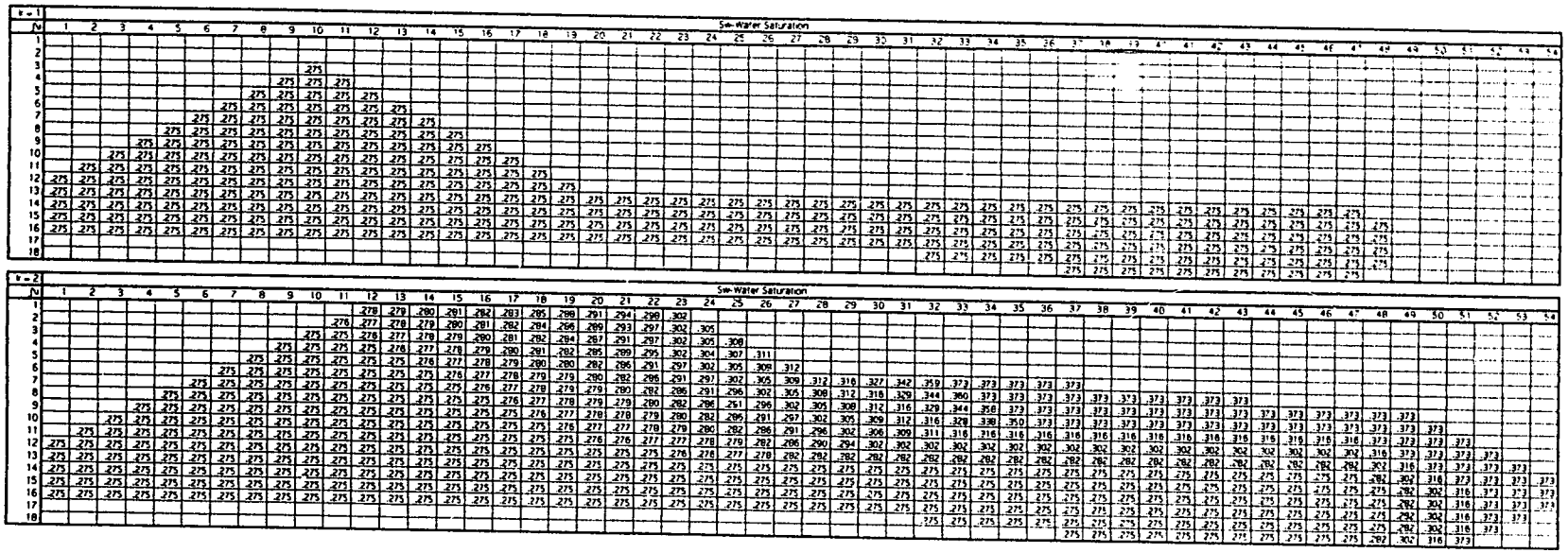



Table 2.6(e): Initial Water Saturation $S_w$

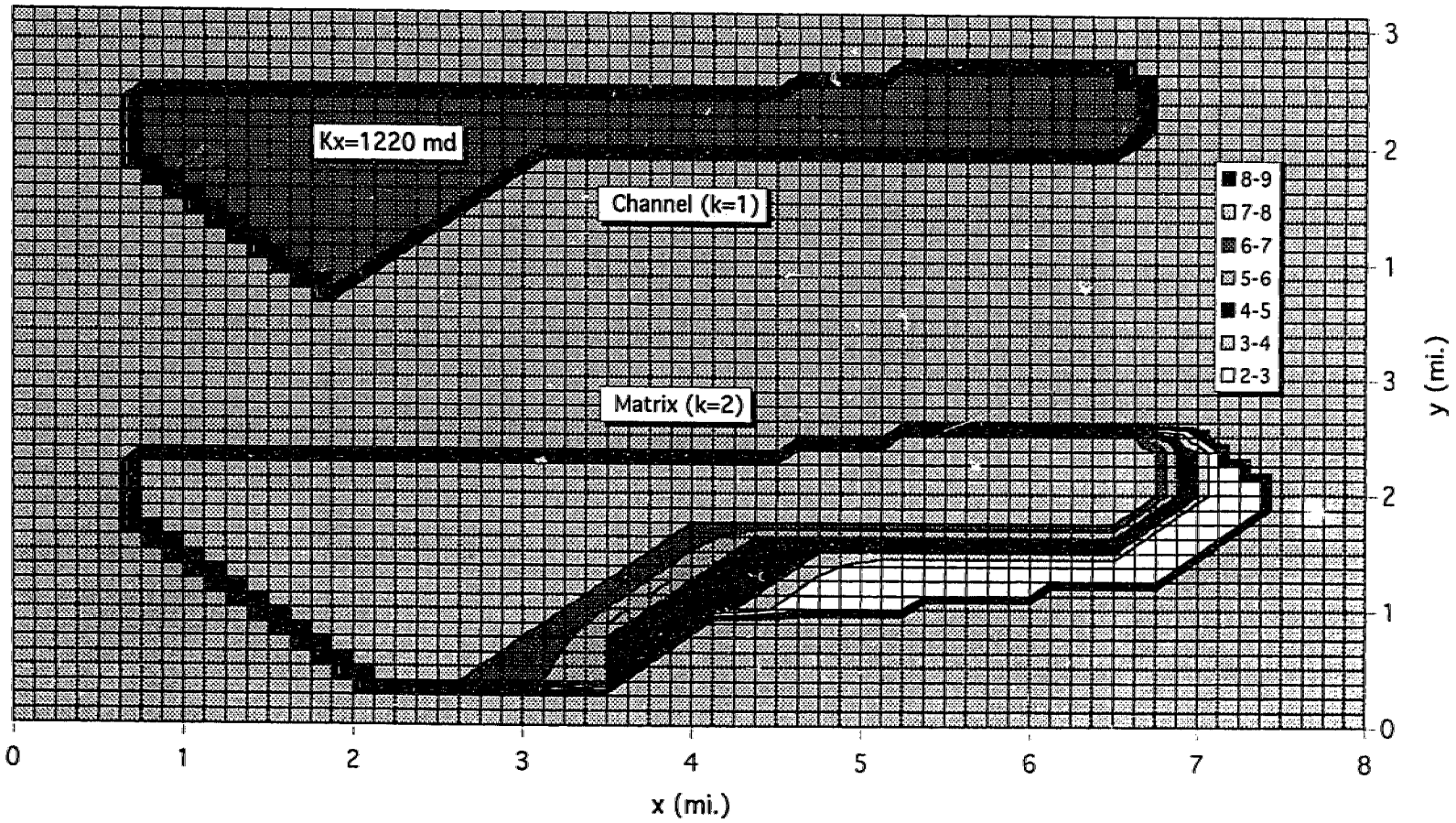



Figure 2.17(a): Reservoir Permeability Kx (md)

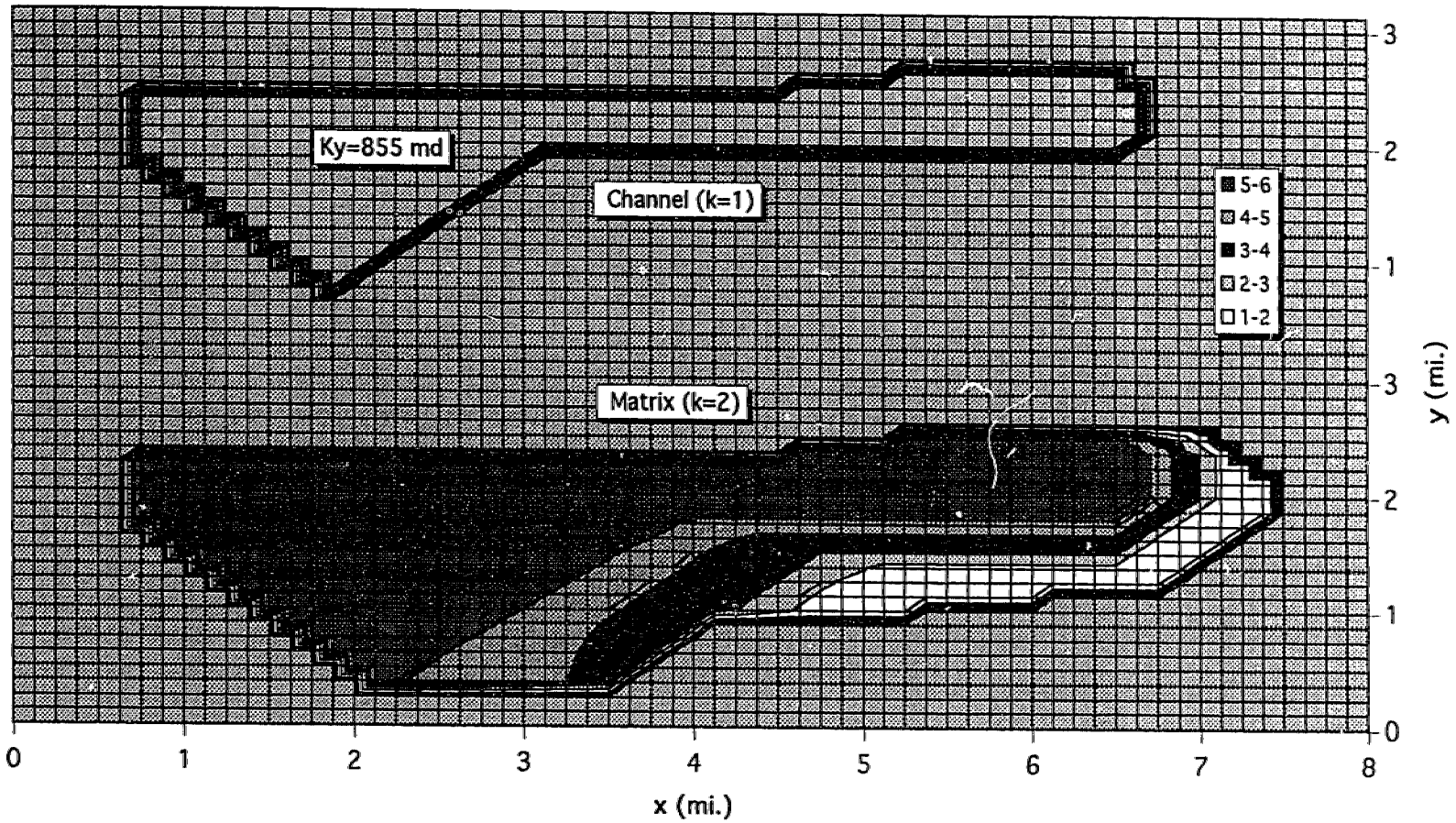



Figure 2.17(b): Reservoir Permeability Ky (md)

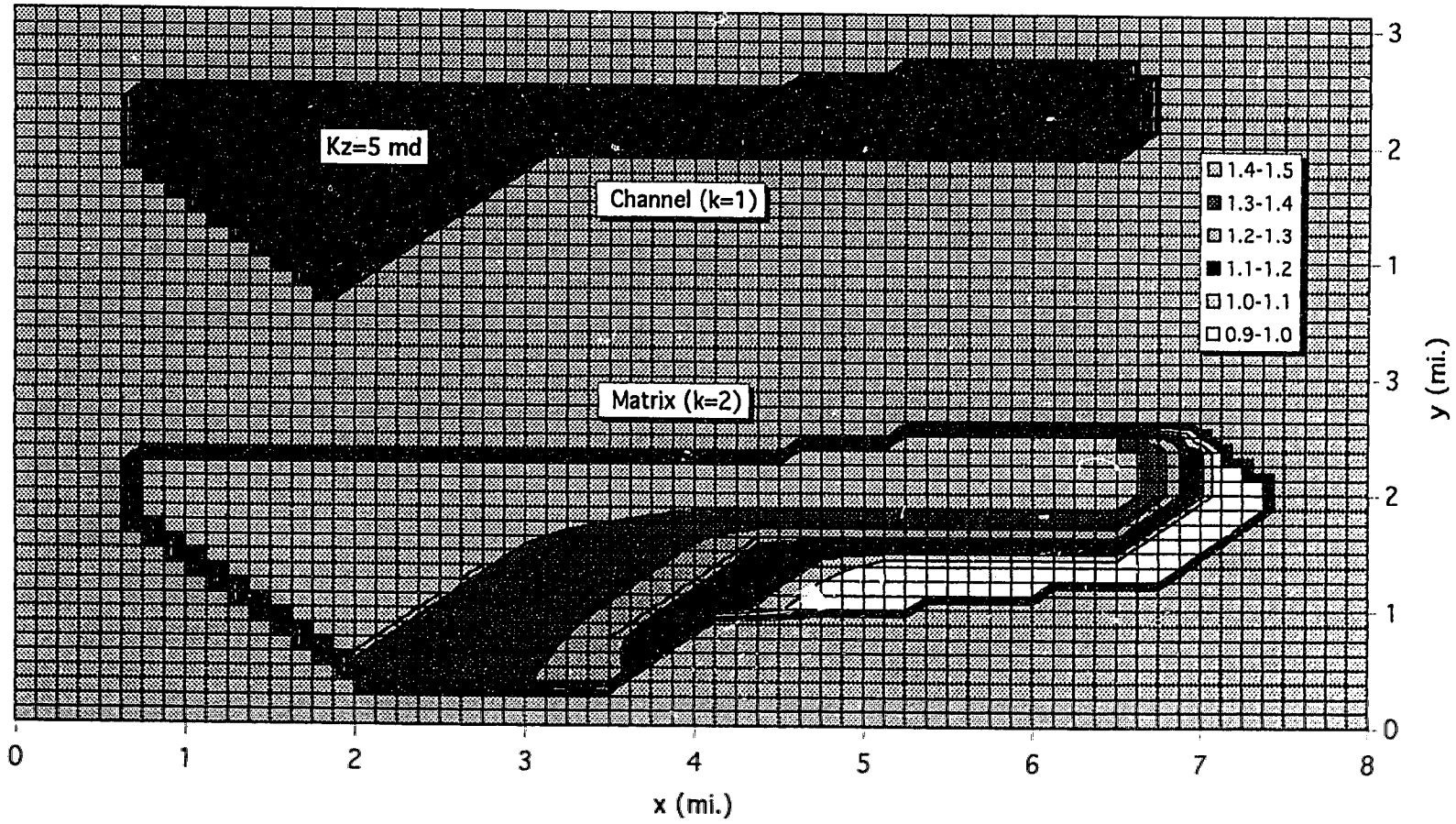



Figure 2.17(c): Reservoir Permeability Kz (md)

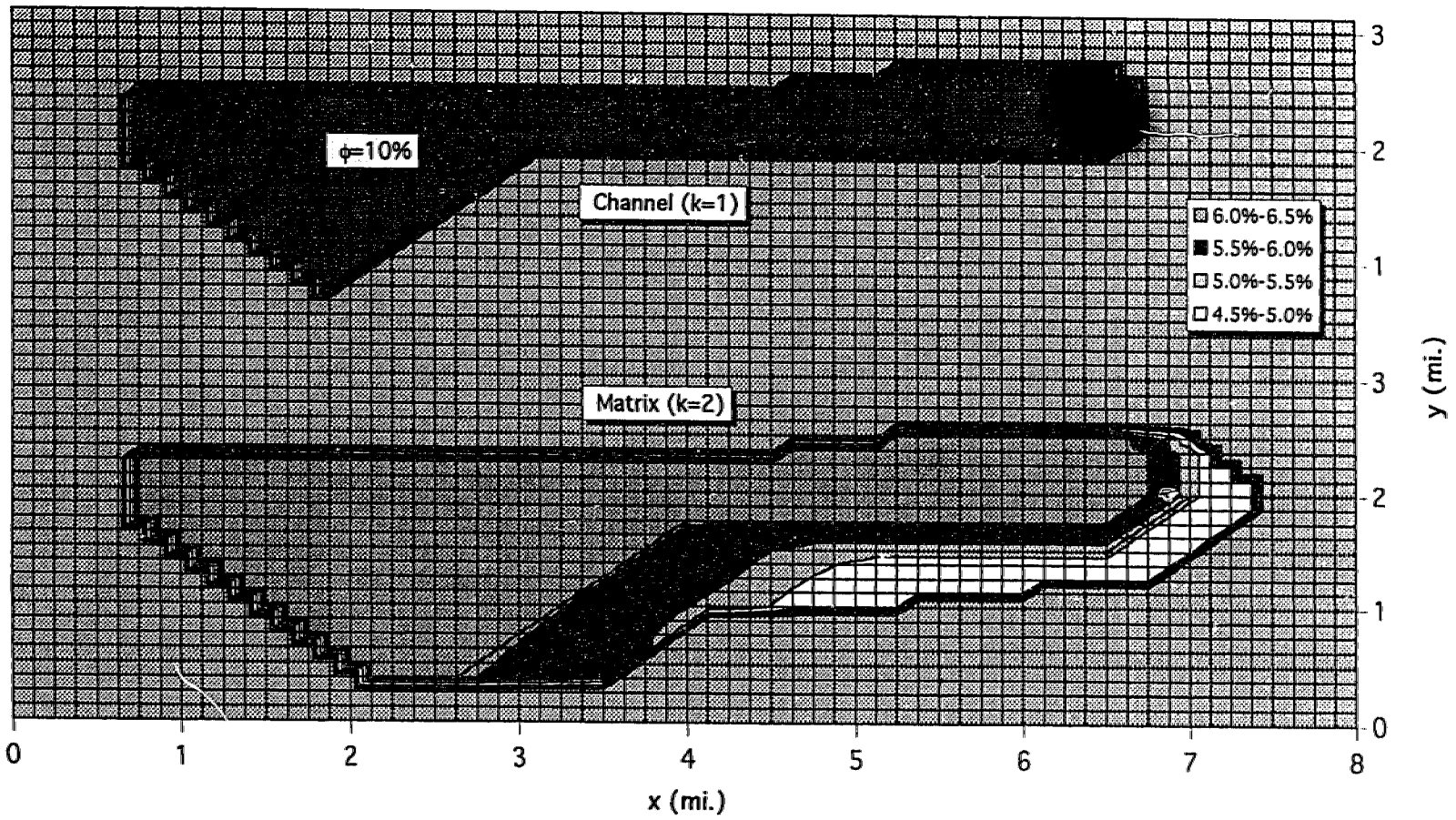



Figure 2.17(d): Reservoir Porosity $\phi$

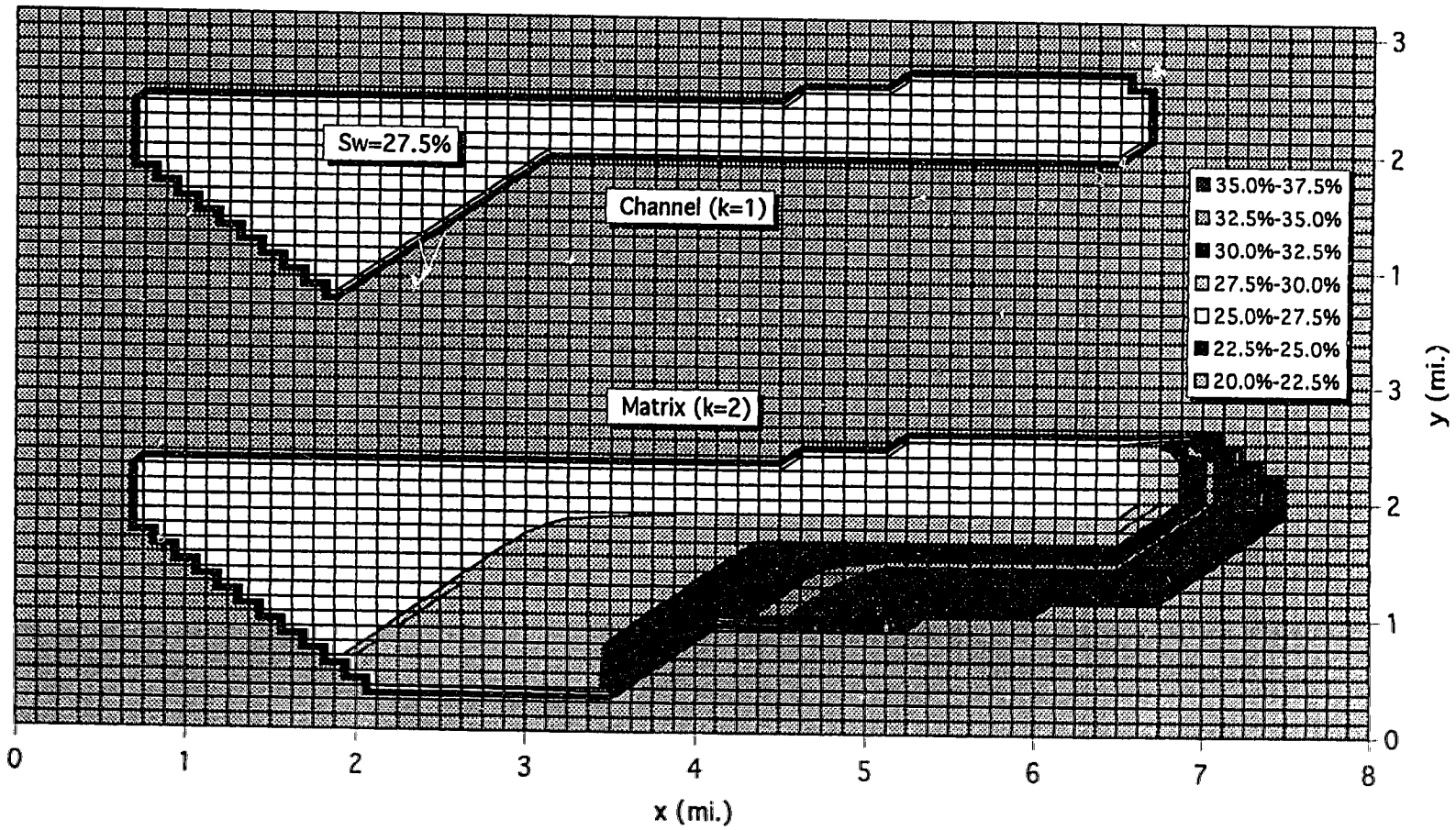



Figure 2.17(e): Initial (Oct-87) Water Saturation $S_w$

## 2.9 Pressure-Volume-Temperature Data

Oil is a liquid mixture containing many hydrocarbon fractions and inorganic compounds. Lighter fractions are more volatile and have lower boiling points than the heavier fractions. Lighter fractions tend to be in a free gaseous state at atmospheric pressure and room temperature. Table 2.7 lists the liquid and gas composition of Chedderville Viking "A" hydrocarbons at standard conditions (1 atm and 60° F) as provided by Canadian Hunter (1994). The gas was sampled from 06-14-37-7W5 located in a gas cap and the liquid was sampled down dip at 08-13-37-8W5. At typical reservoir pressures and temperatures, light fractions are soluble in the liquid mixture. The phase relationship[5] between liquid and vapour fractions depend on the composition, pressure and temperature. At thermodynamic equilibrium, each phase will have a unique composition of hydrocarbon fractions. Lighter fractions will concentrate in the vapour state and heavier fractions will concentrate in the liquid state. The liquid will be saturated with its ability to dissolve lighter fractions. As the pressure increases isothermally, the gaseous light fractions will dissolve more readily in the liquid mixture and the vapour fractions will decrease. At some critical pressure, all fractions will be in the liquid state. Above this critical pressure, the liquid will have an increased ability to dissolve more light fractions and will become undersaturated in the absence of a vapour fraction. The critical pressure at which the oil changes from undersaturated to saturated states is known as the bubble point pressure. This is the saturation pressure at which the first vapour bubble forms in the closed system. Black oil is a term used to characterize the liquid mixture as a single lumped component, with isothermal properties that depend on pressure only. Similarly, free gas refers to the lumped gaseous mixture, with isothermal properties that also depend on pressure only. Since the free gas is composed mostly of hydrocarbons, it will have a non-ideal gas compressibility factor. The solubility of gas in oil will depend on whether the system pressure is above or below the bubble point. The oil will have a compressibility factor that increases with solution gas, and therefore have different pressure dependence above and below the bubble point. Similarly, oil viscosity will also depend on the solution gas and have different pressure dependence for saturated and undersaturated states. Formation volume factors are used to relate the standard volume of a particular phase to the volume that results at reservoir pressure and temperature. For reservoir liquids of oil and formation water, the standard volume is one barrel of liquid at stock tank conditions (1 atm, 60° F). For free gas, the standard volume is one standard cubic foot (1 atm, 60° F). Oil and water formation volume factors will account for dissolved gas in solution. Gas solubilities are expressed in standard volumes of

---

5 Refer to Ahmed (1989) for a more comprehensive discussion on hydrocarbon phase behaviour.

| Gas Analysis | 06-14-37-7W5 | | | |
|---|---|---|---|---|
| Gas Component | Mole Fraction | Molecular Mass | Psuedo-Critical $p_{pc}$ (psia) | Psuedo-Critical $T_{pc}$ (degrees F) |
| N2 | 0.30% | 28.01 | 493.1 | -232.5 |
| CO2 | 0.90% | 44.01 | 1071.0 | 87.9 |
| C1 | 86.09% | 16.04 | 666.4 | -116.7 |
| C2 | 7.71% | 30.07 | 706.5 | 89.9 |
| C3 | 3.20% | 44.10 | 616.0 | 206.1 |
| IC4 | 0.40% | 58.12 | 527.9 | 274.5 |
| nC4 | 0.90% | 58.12 | 550.6 | 305.6 |
| IC5 | 0.20% | 72.15 | 490.4 | 369.1 |
| nC5 | 0.20% | 72.15 | 488.6 | 385.8 |
| C6 | 0.10% | 86.18 | 436.9 | 453.6 |
| Mixture | 100.00% | 19.15 | 671.9 | -82.5 |

Critical Constants: (Ahmed, T., Table 1.1, Figures 2.3-2.5)
Critical Constant Correction: Carr-Kobayashi-Burrows Method (Ahmed, T., p98)
Standard Conditions: 1 atm and 60 degrees F

| Liquid Analysis | 08-13-37-8W5 | | | | | |
|---|---|---|---|---|---|---|
| Liquid Component | Mole Fraction | Mass Fraction | Volume Fraction | Molecular Mass | Psuedo-Critical $p_{pc}$ (psia) | Psuedo-Critical $T_{pc}$ (degrees F) |
| N2 | 0.11% | 0.03% | 0.03% | 28.01 | 493.1 | -232.5 |
| CO2 | 0.70% | 0.33% | 0.28% | 44.01 | 1071.0 | 87.9 |
| C1 | 43.22% | 7.42% | 17.16% | 16.04 | 666.4 | -116.7 |
| C2 | 7.90% | 2.54% | 4.93% | 30.07 | 706.5 | 89.9 |
| C3 | 5.44% | 2.57% | 3.51% | 44.10 | 616.0 | 206.1 |
| IC4 | 1.09% | 0.68% | 0.84% | 58.12 | 527.9 | 274.5 |
| nC4 | 2.82% | 1.75% | 2.08% | 58.12 | 550.6 | 305.6 |
| IC5 | 1.31% | 1.01% | 1.13% | 72.15 | 490.4 | 369.1 |
| nC5 | 1.56% | 1.21% | 1.33% | 72.15 | 488.6 | 385.8 |
| C6 | 1.98% | 1.98% | 2.08% | 86.18 | 436.9 | 453.6 |
| C7+ | 33.87% | 80.48% | 66.63% | 222.50 | 300.0 | -200.0 |
| Mixture | 100.00% | 100.00% | 100.00% | 93.46 | 533.9 | -68.9 |

Critical Constants: (Ahmed, T., Table 1.1, Figures 2.3-2.5) C7+ from Hydrocarbon Liquid Analysis (Average Boiling Point = 215.3 C, 37.3 API)
Critical Constant Correction: Carr-Kobayashi-Burrows Method (Ahmed, T., p98)
Standard Conditions: 1 atm and 60 degrees F

| C7+ Liquid Analysis | 08-13-37-8W5 | |
|---|---|---|
| Component | Boiling Point C | Mole Fraction |
| Heptanes | 68.9 | 2.11% |
| Octanes | 98.3 | 2.25% |
| Nonanes | 125.6 | 2.06% |
| Decanes | 150.6 | 2.23% |
| Undecanes | 173.9 | 1.98% |
| Dodecanes | 196.1 | 1.73% |
| Tridecanes | 215.0 | 1.71% |
| Tetradecanes | 235.0 | 1.54% |
| Pentadecanes | 252.2 | 1.34% |
| Hexadecanes | 270.6 | 1.22% |
| Heptadecanes | 287.8 | 0.94% |
| Octadecanes | 302.8 | 1.06% |
| Nonadecanes | 317.2 | 0.94% |
| Eicosanes | 330.0 | 0.76% |
| Heneicosanes | 344.4 | 0.71% |
| Docosanes | 357.2 | 0.66% |
| Tricosanes | 369.4 | 0.56% |
| Tetracosanes | 380.0 | 0.51% |
| Pentacosanes | 391.1 | 0.46% |
| Hexacosanes | 401.7 | 0.36% |
| Heptacosanes | 412.2 | 0.35% |
| Octacosanes | 422.2 | 0.30% |
| Nonacosanes | 431.7 | 0.27% |
| Tricontanes Plus | 441.1 | 1.80% |
| Benzene | 80.0 | 0.14% |
| Toluene | 110.6 | 0.72% |
| Ethylbenzene, p+m-Xylene | 136.1 | 1.58% |
| o-Xylene | 144.4 | 0.76% |
| 1,2,4 Trimethylbenzene | 168.9 | 0.73% |
| Cyclopentane | 48.9 | 0.05% |
| Methylcyclopentane | 72.2 | 0.42% |
| Cyclohexane | 81.1 | 0.68% |
| Methylcyclohexane | 101.1 | 0.94% |
| Mixture | 215.3 | 33.87% |

Table 2.7 Gas Analysis (06-14-37-7W5) and Oil Analysis (08-13-37-8W5)

gas dissolved in standard volumes of liquid.

Mixture molecular weights (MW), pseudo-critical pressures ($p_{pc}$) and pseudo-critical temperatures ($T_{pc}$) were calculated for liquid from 08-13-37-8W5 (MW=93.5, $p_{pc}$=534 psia, $T_{pc}$=-69° F) and gas from 06-14-37-7W5 (MW=19.2, $p_{pc}$=672 psia, $T_{pc}$=-83° F) in Table 2.7 using molar-averaged critical constants (Ahmed, 1989, Table 1.1, Figures 2.3-2.5). Molar average boiling point (215.3° C) was calculated for the heavier liquid fractions (C7+) which correlated to 37.3 API gravity (MW=222.5, $p_{pc}$=300 psia, $T_{pc}$=-200° F). Mixture critical constant corrections for $N_2$ and $CO_2$ were performed using Carr-Kobayashi-Burrows method (Ahmed, 1989, p98). This analysis provides a basis for the range of hydrocarbons present in the gas cap and the oil deposit. Table 2.8 lists the gravity of oil sampled from different wells. No variation is observed in oil gravity.

| Well | API | Oil Gravity (Water=1) |
|---|---|---|
| 16-09-37-7W5 | 41.73 | 0.82 |
| 06-16-37-7W5 | 40.87 | 0.82 |
| 08-14-37-8W5 | 40.68 | 0.82 |
| 08-13-37-8W5 | 40.40 | 0.82 |

Table 2.8: Oil API and Gravity Measurements from Selected Wells

A Pressure-Volume-Temperature (PVT) laboratory analysis was provided by Canadian Hunter (1994) for the hydrocarbon fluids sampled from 08-13-37-8W5. The reported reservoir temperature was 185° F. The isothermal analysis included:

- oil and gas densities ($\rho_o$, $\rho_g$)
- gas deviation factor (z)
- oil and gas viscosities ($\mu_o$, $\mu_g$)
- oil and gas formation volume factors ($B_o$, $B_g$)
- solution gas-oil ratios ($R_{so}$)

The initial bubble point pressure for the liquid sample was measured at $p_b$=3002.7 psia. Both flash and differential vaporization analysis was performed on the sample. The analysis presented herein has further extrapolated gas and

saturated oil properties above the initial bubble point to cover a wider pressure range that includes possible waterflood repressurization hysteresis.

Properties of the liberated gas from the liquid sample were measured in the laboratory below the bubble point pressure. Table 2.9 tabulates both measured and extrapolated gas properties (differential vaporization). The liberated gas molecular weight ($MW_a$=23.3), pseudo-critical pressure ($p_{pc}$=660 psia) and pseudo-critical temperature ($T_{pc}$=-69° F) were fitted to extrapolate gas properties above the initial bubble point ($p_b$=3002.7 psia). The standard gas density and gas gravity were estimated at $\rho_{scg}$=0.0614 lbs/ft$^3$ and $\gamma_g$=0.805 (Air=1). The incremental gas deviation factor (z) was extrapolated using Hall-Yarborough method (Ahmed, 1989, p102-103, Dake, 1978, p19). The gas formation volume factor ($B_g$) was extrapolated using the non-ideal gas law with extrapolated gas deviation factors (Ahmed, 1989, p112, Dake, 1978, p45-50). The gas viscosity ($\mu_g$) was extrapolated using Lee-Gonzalez-Eakin correlation (Ahmed, 1989, p120). The original laboratory measurements with extrapolated values for z, $B_g$ and $\mu_g$ are plotted in Figures 2.18(a)-(c).

The measured oil API gravity was 40.4°. In this analysis, the oil was fitted with 41.5 API to extrapolate saturated oil behaviour above the initial bubble point in Table 2.10. The standard oil density and oil gravity were estimated at $\rho_{sco}$=51.06 lbs/ft$^3$ and $\gamma_o$=0.82 (Water=1). Undersaturated oil properties were measured in the laboratory above the initial bubble point pressure. The analysis presented herein approximates undersaturated oil behaviour using average slopes with respect to pressure. The values of these slopes for gas-oil solubility ($R_{so}$), oil formation volume factor ($B_o$) and oil viscosity ($\mu_o$) are:

$$\frac{\partial R_{so}}{\partial p} = 0 \quad , \quad \frac{\partial B_o}{\partial p} = -1.84 \times 10^{-5} \quad , \quad \frac{\partial \mu_o}{\partial p} = 5.17 \times 10^{-5} \qquad p \geq p_b$$

The saturated gas-oil solubility ($R_{so}$) was extrapolated above the initial bubble point using Vasquez-Beggs' correlation (Ahmed, 1989, p177-181). The saturated oil formation volume factor ($B_o$) was extrapolated using Vasquez-Beggs' compressibility coefficient correlation (Ahmed, 1989, p162). The saturated oil viscosity ($\mu_o$) was extrapolated using Beggs-Robinson Correlation (Ahmed, 1989, p210) with a 0.0416 cp correction to preserve continuity. The original laboratory measurements with extrapolated values for $R_{so}$, $B_o$ and $\mu_o$ are graphed in Figures 2.19(a)-(c). The undersaturated oil properties are characterized by a family of parallel lines stemming from possible bubble points

on the saturated oil curve. This reflects that the local bubble point pressure may vary as free gas is produced and that waterflood repressurization may create some hysteresis.

The solubility of gas in oil will depend on whether the reservoir pressure is above or below the bubble point pressure. When the reservoir pressure drops below the bubble point pressure, a free gas saturation will form. Oil will be saturated with dissolved gas. Saturated oil will behave differently from its undersaturated counterpart. The slope of oil properties with respect to pressure is discontinuous at the bubble point. When the free gas saturation exceeds the critical gas saturation, it will become mobile. Migration of free gas will change the local ratio of free gas to oil volumes. The change in vapour-liquid equilibrium will change the local saturation pressure (bubble point). The new bubble point can be estimated as the pressure which completely dissolves the local volumes of free and dissolved gas in the local volume of oil. An isobaric increase in free gas saturation will tend to shift the bubble point up, while an isobaric decrease in free gas saturation will tend to shift the bubble point down. Since the presence of free gas implies that the oil is locally saturated, the bubble point can be dynamically tracked using the saturated gas-oil solubility relationship with pressure. New bubble point pressures can be interpolated directly from Table 2.10. When primary production is in a global pressure decline below the original bubble point, the relevant range of saturated PVT data will not be affected by a bubble point that varies above system pressure. If however, the reservoir is repressured by waterflood, the initial bubble point will no longer apply for the anticipated transition from saturated to undersaturated regimes. The undersaturated oil property pressure dependence will shift along the saturated curve. This is the hysteresis in bubble point pressure that occurs when the reservoir is repressurized after free gas is produced.

Formation water PVT was estimated in Table 2.11 using the salinity (4.5%) reported in the Canadian Hunter Chedderville Waterflood Design Study (1993). The saline water gravity was approximated using 45000 ppm NaCl (Bateman, R.M., Table 16.2 p315). The standard water density and water gravity were estimated at $\rho_{scw}$=64.3 lbs/ft$^3$ and $\gamma_w$=1.03 (Fresh Water=1). Gas-water solubility ($R_{sw}$) was correlated to water salinity and gas properties using the Hewlett-Packard H.P.41C Petroleum Fluids PAC Manual, 1982 (Ahmed, 1989, p202) with linear extrapolation above 6014.7 psia. Saline water formation volume factor ($B_w$) was also correlated using the Hewlett-Packard H.P.41C Petroleum Fluids PAC Manual, 1982 (Ahmed, 1989, p203). Saline water viscosity ($\mu_w$) pressure dependence was obtained from Chesnut (unpublished), Shell Development Co. chart correlation (Matthews, 1967., p158). The correlated values for $R_{sw}$, $B_w$ and $\mu_w$ are shown in Figures 2.20(a)-(c).

| Gas Properties | 08-13-37-8W5 | | |
|---|---|---|---|
| Standard Gas Density $\rho_{gsc}$ (lbs/ft$^3$) | Gas Gravity $\gamma_g$ (Air=1) | | |
| 0.0614 | 0.805 | | |
| Temperature T (degrees F) | Psuedo-Critical $T_{pc}$ (degrees F) | Psuedo-Critical $p_{pc}$ (psia) | Molecular Weight $MW_a$ |
| 185 | -69 | 660 | 23.3 |
| Pressure p (psia) | Gas Deviation Factor Z | Gas FVF $B_g$ (rcf/scf) | Gas Viscosity $\mu_g$ (cp) |
| 14.7 | 1.000 | 1.245420 | 0.0101 |
| 314.7 | 0.937 | 0.054510 | 0.0123 |
| 614.7 | 0.913 | 0.027180 | 0.0132 |
| 914.7 | 0.893 | 0.017870 | 0.0140 |
| 1214.7 | 0.876 | 0.013200 | 0.0148 |
| 1514.7 | 0.863 | 0.010430 | 0.0157 |
| 1814.7 | 0.852 | 0.008590 | 0.0167 |
| 2114.7 | 0.844 | 0.007300 | 0.0178 |
| 2414.7 | 0.841 | 0.006370 | 0.0190 |
| 2714.7 | 0.844 | 0.005690 | 0.0205 |
| 3002.7 | 0.852 | 0.005175 | 0.0219 |
| 3114.7 | 0.856 | 0.005013 | 0.0224 |
| 3214.7 | 0.861 | 0.004881 | 0.0229 |
| 3514.7 | 0.876 | 0.004543 | 0.0243 |
| 4014.7 | 0.907 | 0.004121 | 0.0267 |
| 4514.7 | 0.945 | 0.003817 | 0.0291 |
| 5014.7 | 0.987 | 0.003587 | 0.0313 |
| 5514.7 | 1.031 | 0.003408 | 0.0334 |
| 6014.7 | 1.077 | 0.003264 | 0.0354 |
| 6514.7 | 1.124 | 0.003145 | 0.0374 |
| 7014.7 | 1.171 | 0.003045 | 0.0393 |
| 7514.7 | 1.219 | 0.002959 | 0.0411 |
| 8014.7 | 1.268 | 0.002885 | 0.0428 |
| 8514.7 | 1.317 | 0.002819 | 0.0445 |
| 9014.7 | 1.365 | 0.002761 | 0.0462 |

Critical Contants and Molecular Weight fitted to extrapolate gas properties above bubble point $p_b$=3002.7 psia

Z-Factor Extrapolation: Hall-Yarborough Method (Ahmed, T., p102-103, Dake, L.P., p19)

Gas FVF Extrapolation: (Ahmed, T., p112, Dake, L.P., p45-50)

Gas Viscosity Extrapolation: Lee-Gonzalez-Eakin Correlation (Ahmed, T., p120)

Standard Conditions: 1 atm and 60 degrees F

Table 2.9: Isothermal Gas Properties

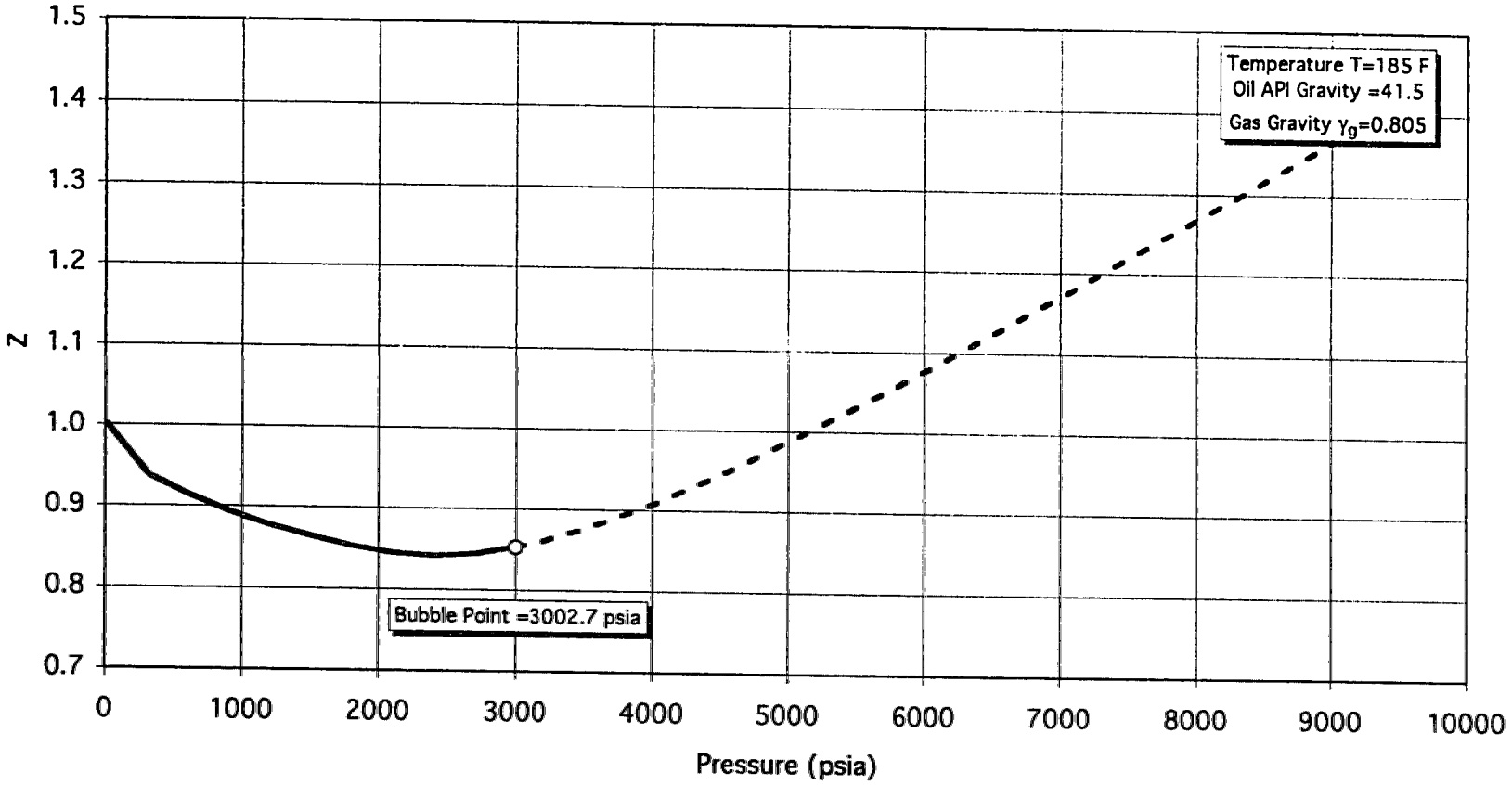



Figure 2.18(a): Gas Deviation Z-Factor (08-13-37-8W5)

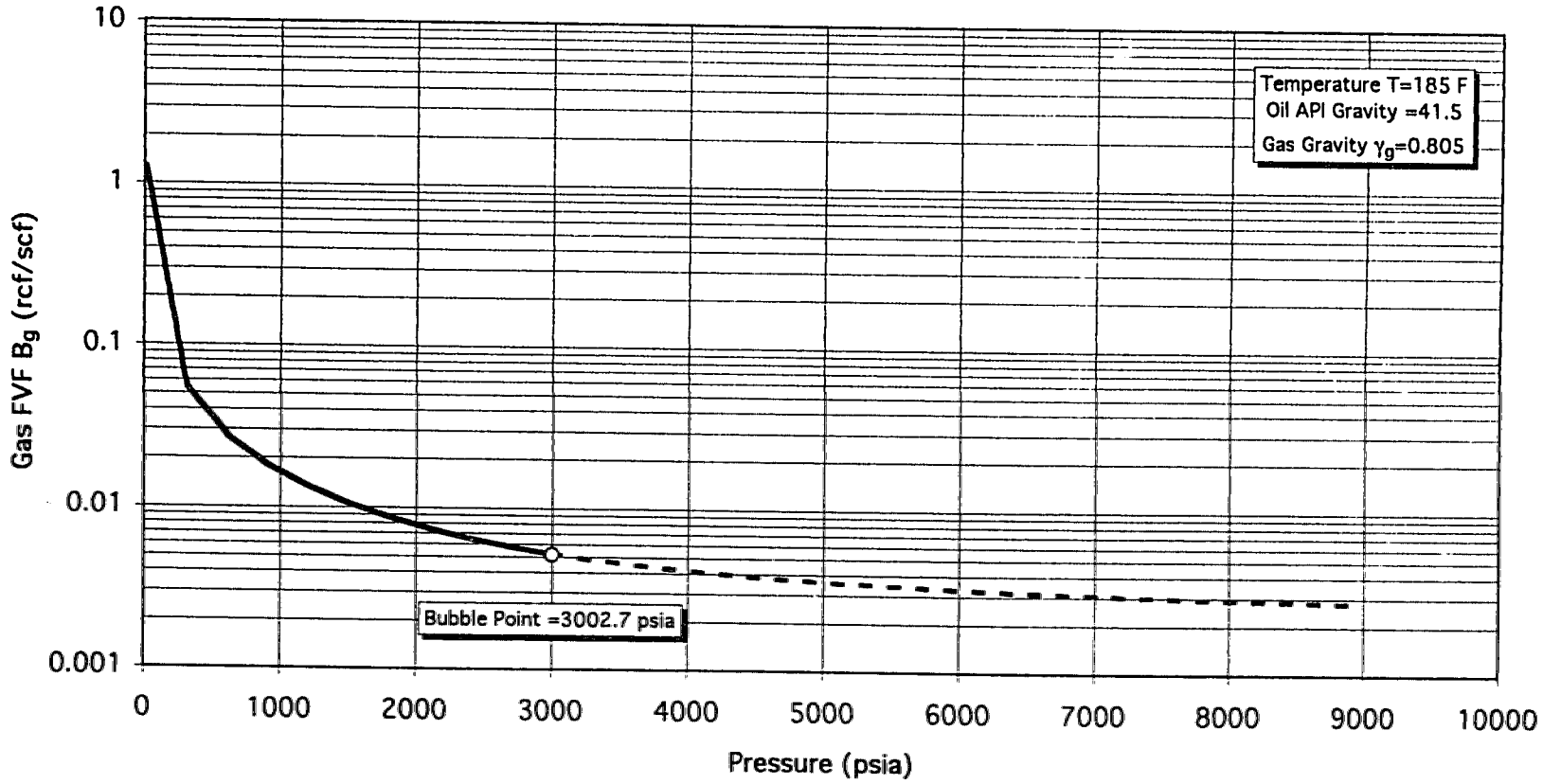



Figure 2.18(b): Gas Formation Volume Factor $B_g$ (08-13-37-8W5)

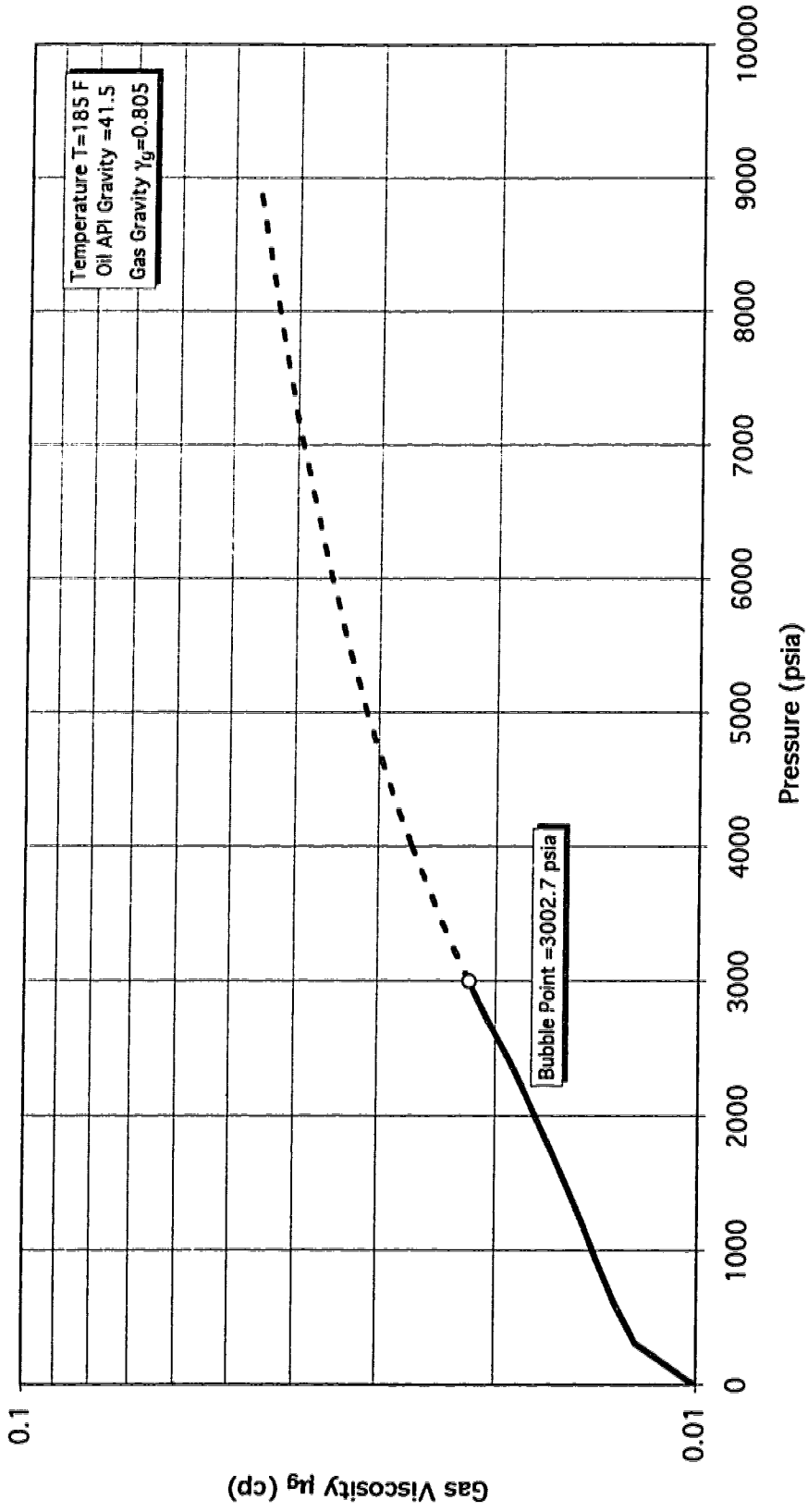



Figure 2.18(c): Gas Viscosity $\mu_g$ (08-13-37-8W5)

| Oil Properties | 08-13-37-8W5 | | |
|---|---|---|---|
| Standard Oil Density $\rho_{osc}$ (lbs/ft$^3$) | Oil Gravity $\gamma_o$ (Fresh Water=1) | | |
| 51.06 | 0.82 | | |
| Temperature T (Degrees F) | Gas Gravity $\gamma_g$ (Air=1) | Oil Gravity (API) | Initial Solution GOR $R_{so}$ (scf/STB) |
| 185 | 0.805 | 41.5 | 893 |
| | **Undersaturated Oil Property Slopes above Bubble Point** | | |
| Bubble Point Pressure $p_b$ (psia) | Gas-Oil Solubility $dR_{so}/dp$ (scf/STB/psi) | Oil FVF $dB_o/dp$ (RB/STB/psi) | Oil Viscosity $d\mu_o/dp$ (cp/psi) |
| 3002.7 | 0 | -1.84e-05 | 5.17e-05 |
| | **Saturated Oil Properties** | | |
| Pressure p (psia) | Gas-Oil Solubility $R_{so}$ (scf/STB) | Oil FVF $B_o$ (RB/STB) | Oil Viscosity $\mu_o$ (cp) |
| 14.7 | 0 | 1.0630 | 1.5460 |
| 314.7 | 162 | 1.1750 | 1.0540 |
| 614.7 | 242 | 1.2130 | 0.9210 |
| 914.7 | 317 | 1.2460 | 0.8010 |
| 1214.7 | 391 | 1.2780 | 0.6990 |
| 1514.7 | 470 | 1.3120 | 0.6290 |
| 1814.7 | 548 | 1.3450 | 0.5610 |
| 2114.7 | 630 | 1.3800 | 0.5120 |
| 2414.7 | 714 | 1.4160 | 0.4720 |
| 2714.7 | 803 | 1.4550 | 0.4420 |
| 3002.7 | 893 | 1.4960 | 0.4160 |
| 3114.7 | 934 | 1.5154 | 0.4169 |
| 3214.7 | 970 | 1.5324 | 0.4095 |
| 3514.7 | 1078 | 1.5840 | 0.3893 |
| 4014.7 | 1263 | 1.6717 | 0.3611 |
| 4514.7 | 1452 | 1.7615 | 0.3379 |
| 5014.7 | 1644 | 1.8532 | 0.3185 |
| 5514.7 | 1841 | 1.9466 | 0.3020 |
| 6014.7 | 2040 | 2.0416 | 0.2878 |
| 6514.7 | 2243 | 2.1381 | 0.2753 |
| 7014.7 | 2449 | 2.2360 | 0.2644 |
| 7514.7 | 2658 | 2.3352 | 0.2546 |
| 8014.7 | 2869 | 2.4356 | 0.2459 |
| 8514.7 | 3083 | 2.5372 | 0.2380 |
| 9014.7 | 3299 | 2.6400 | 0.2308 |

Oil Gravity: Fitted for extrapolation of saturated oil properties above bubble point $p_b$=3002.7 psia

Gas-Oil Solubility: Extrapolation using Vasquez-Beggs' correlation (Ahmed, T., p177-181)

Saturated Oil FVF: Extrapolation using Vasquez-Beggs' compressibility coefficient correlation (Ahmed, T., p162)

Undersaturated Oil FVF: Linear extrapolation using flash liberation slope

Saturated Oil Viscosity: Extrapolation using Beggs-Robinson Correlation (Ahmed, T., p210) with .0416 cp correction

Undersaturated Oil Viscosity: Linear extraploation

Standard Conditions: 1 atm and 60 degrees F

Table 2.10: Isothermal Oil Properties

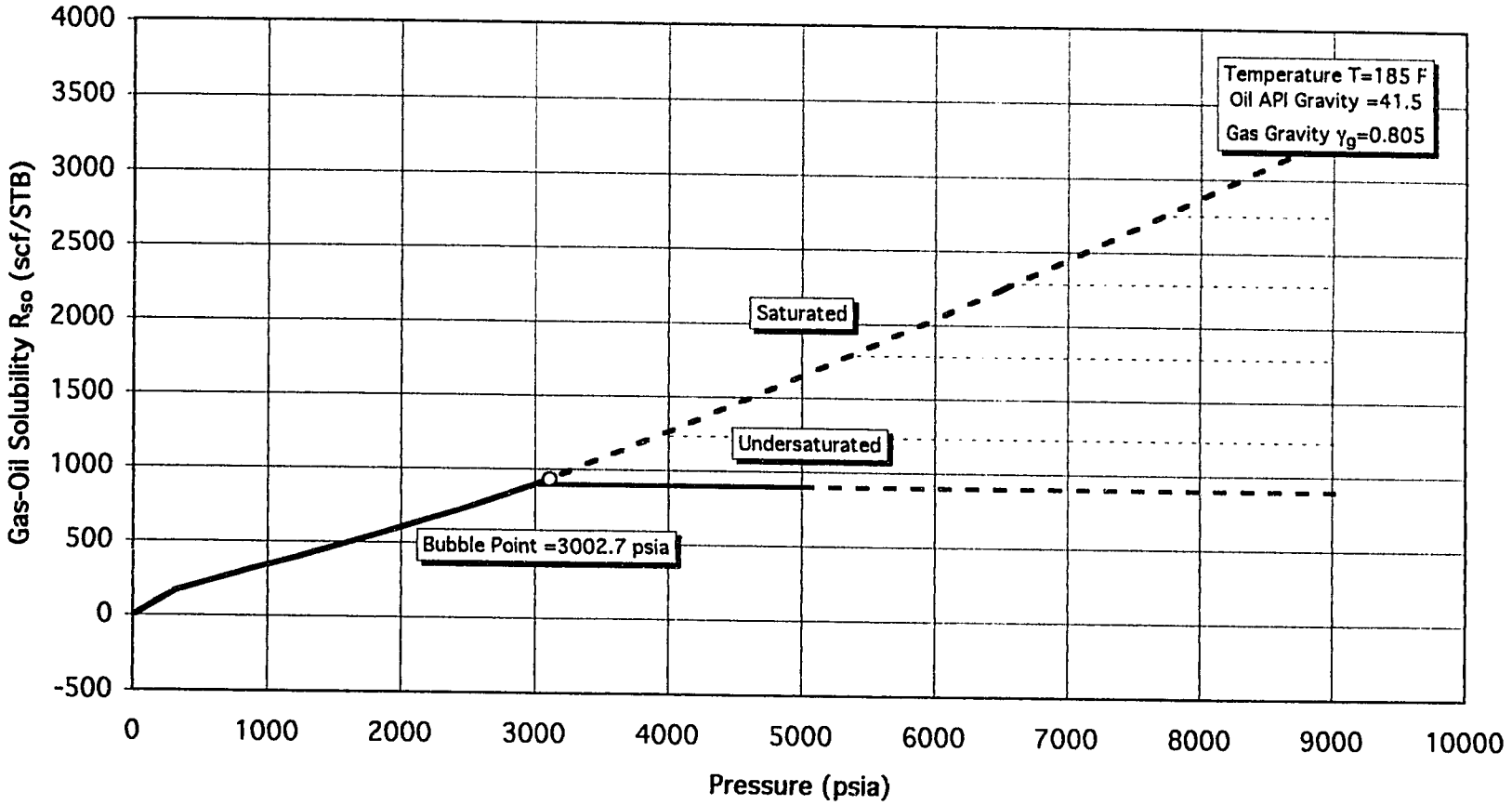



Figure 2.19(a): Gas-Oil Solubility $R_{so}$ (08-13-37-8W5)

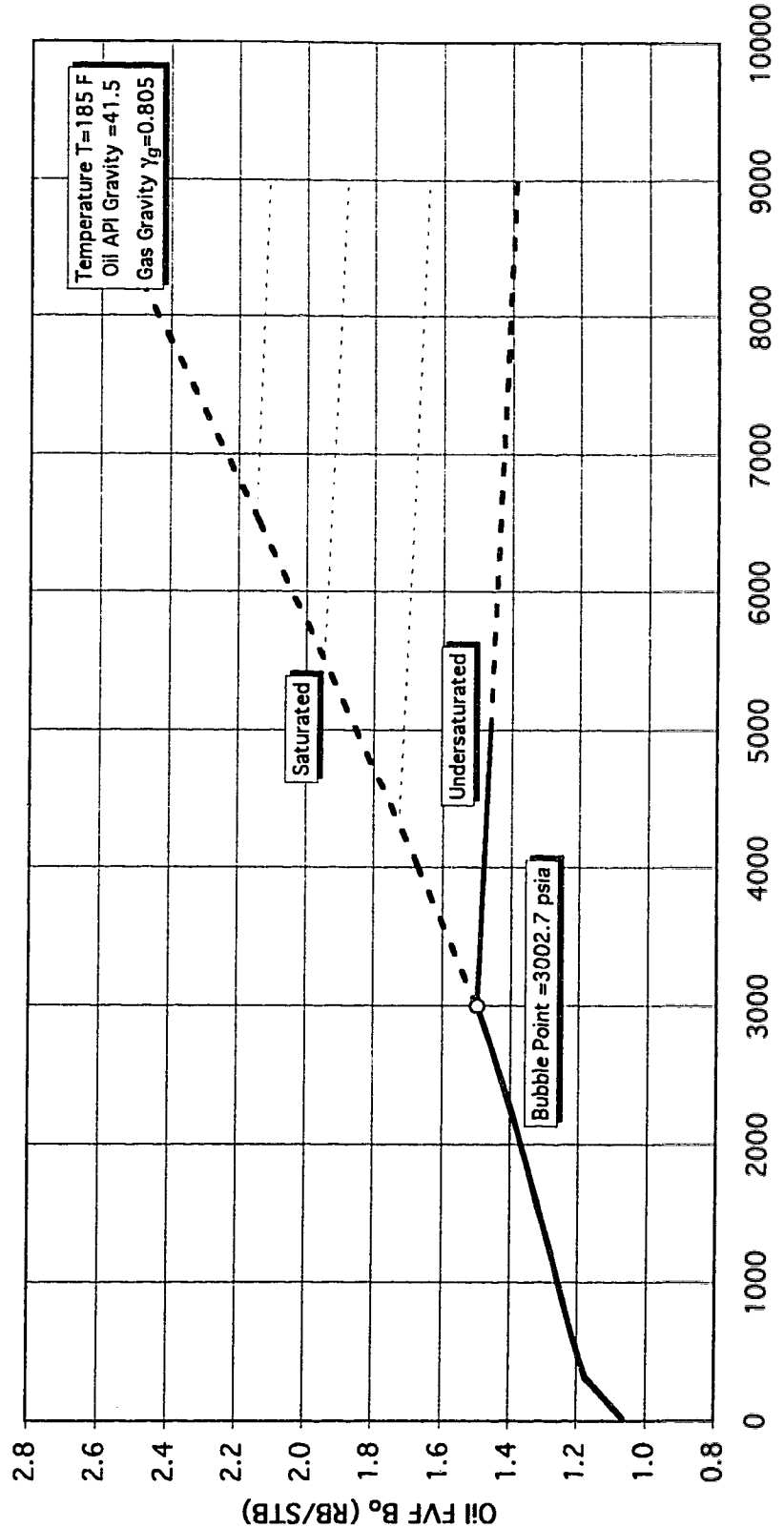



Figure 2.19(b): Oil Formation Volume Factor $B_o$ (08-13-37-8W5)

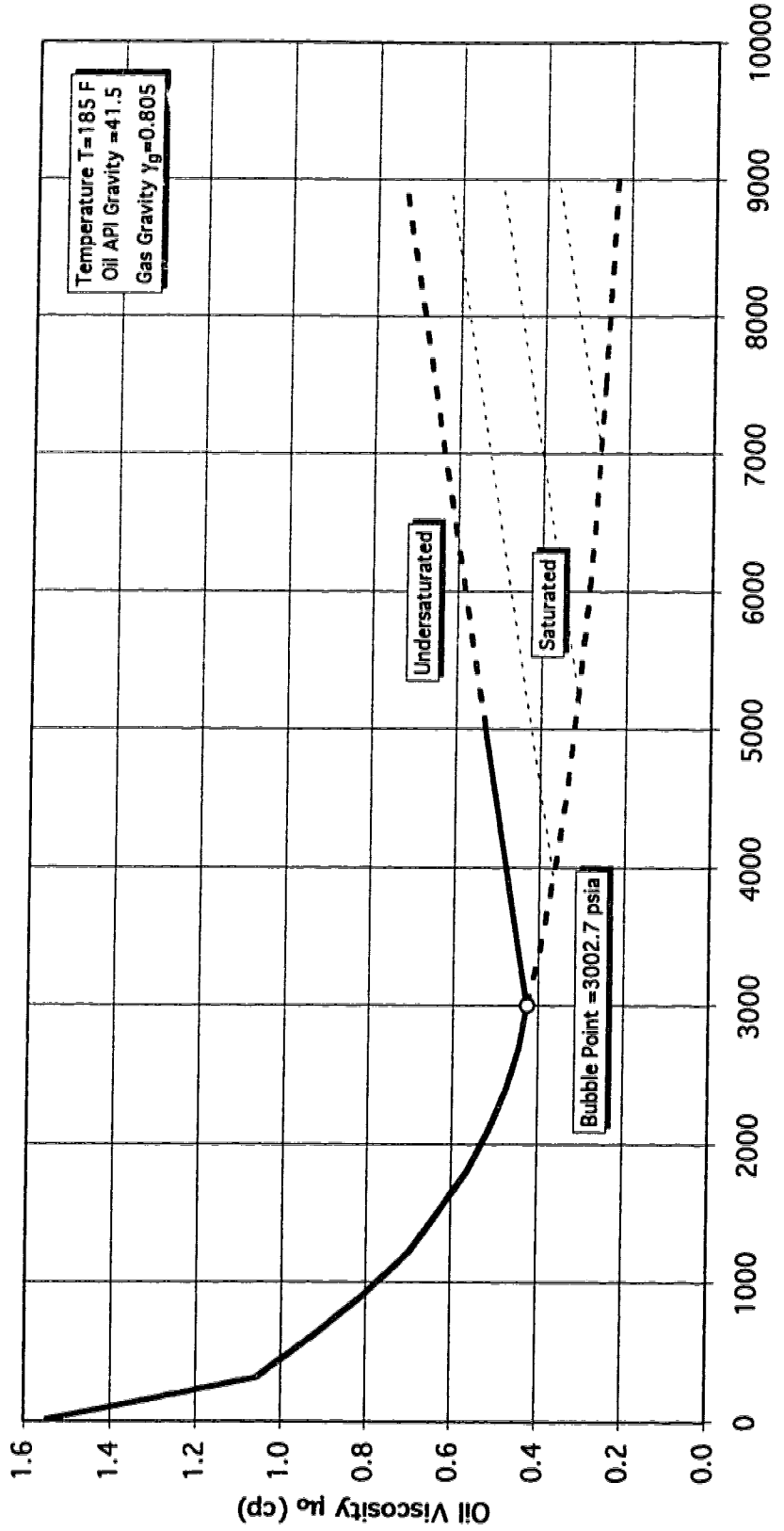



Figure 2.19(c): Oil Viscosity $\mu_o$ (08-13-37-8W5)

| Water Properties | 08-17-37-7W5 | | |
|---|---|---|---|
| Standard Water Density $\rho_{wsc}$ (lbs/ft$^3$) | Water Gravity $\gamma_w$ (Fresh Water=1) | | |
| 64.30 | 1.030 | | |
| Temperature T (Degrees F) | Gas Gravity $\gamma_g$ (Air=1) | Water Salinity | Water Viscosity $\mu_w$ (cp) @3114.7 psia |
| 185 | 0.805 | 4.5% | 0.370 |
| Pressure p (psia) | Gas-Water Solubility $R_{sw}$ (scf/STB) | Water FVF $B_w$ (RB/STB) | Water Viscosity $\mu_w$ (cp) |
| 14.7 | 1.6 | 1.0214 | 0.367 |
| 314.7 | 3.4 | 1.0209 | 0.367 |
| 614.7 | 5.0 | 1.0204 | 0.367 |
| 914.7 | 6.6 | 1.0199 | 0.368 |
| 1214.7 | 8.1 | 1.0195 | 0.368 |
| 1514.7 | 9.5 | 1.0190 | 0.368 |
| 1814.7 | 10.8 | 1.0186 | 0.368 |
| 2114.7 | 12.0 | 1.0181 | 0.369 |
| 2414.7 | 13.1 | 1.0177 | 0.369 |
| 2714.7 | 14.2 | 1.0172 | 0.369 |
| 3002.7 | 15.1 | 1.0168 | 0.370 |
| 3114.7 | 15.4 | 1.0166 | 0.370 |
| 3214.7 | 15.7 | 1.0165 | 0.370 |
| 3514.7 | 16.5 | 1.0161 | 0.370 |
| 4014.7 | 17.6 | 1.0153 | 0.371 |
| 4514.7 | 18.5 | 1.0146 | 0.372 |
| 5014.7 | 19.1 | 1.0139 | 0.373 |
| 5514.7 | 19.5 | 1.0133 | 0.373 |
| 6014.7 | 19.6 | 1.0126 | 0.374 |
| 6514.7 | 19.7 | 1.0119 | 0.376 |
| 7014.7 | 19.8 | 1.0113 | 0.377 |
| 7514.7 | 20.0 | 1.0106 | 0.378 |
| 8014.7 | 20.1 | 1.0100 | 0.379 |
| 8514.7 | 20.2 | 1.0094 | 0.381 |
| 9014.7 | 20.3 | 1.0087 | 0.383 |

Water Salinity: Canadian Hunter Chedderville Waterflood Design Study, Hycal Energy Research Laboratories Ltd., Calgary, Oct 25, 1993.

Saline Gas-Water Solubility: Hewlett-Packard H.P.41C Petroleum Fluids PAC Manual, 1982 (Ahmed, T., p202), Linear extrapolation above 6014.7 psia

Saline Water FVF: Hewlett-Packard H.P.41C Petroleum Fluids PAC Manual, 1982 (Ahmed, T., p203)

Saline Water Viscosity: Pressure dependence from Chesnut, unpublished, Shell Development Co. (Matthews, C.S., p158) chart correlation

Water Gravity: $\gamma_w$=1.03 for 45000 ppm NaCl (Table 16.2 Bateman, R.M., p315)

Standard Conditions: 1 atm and 60 degrees F

Table 2.11: Isothermal Water Properties

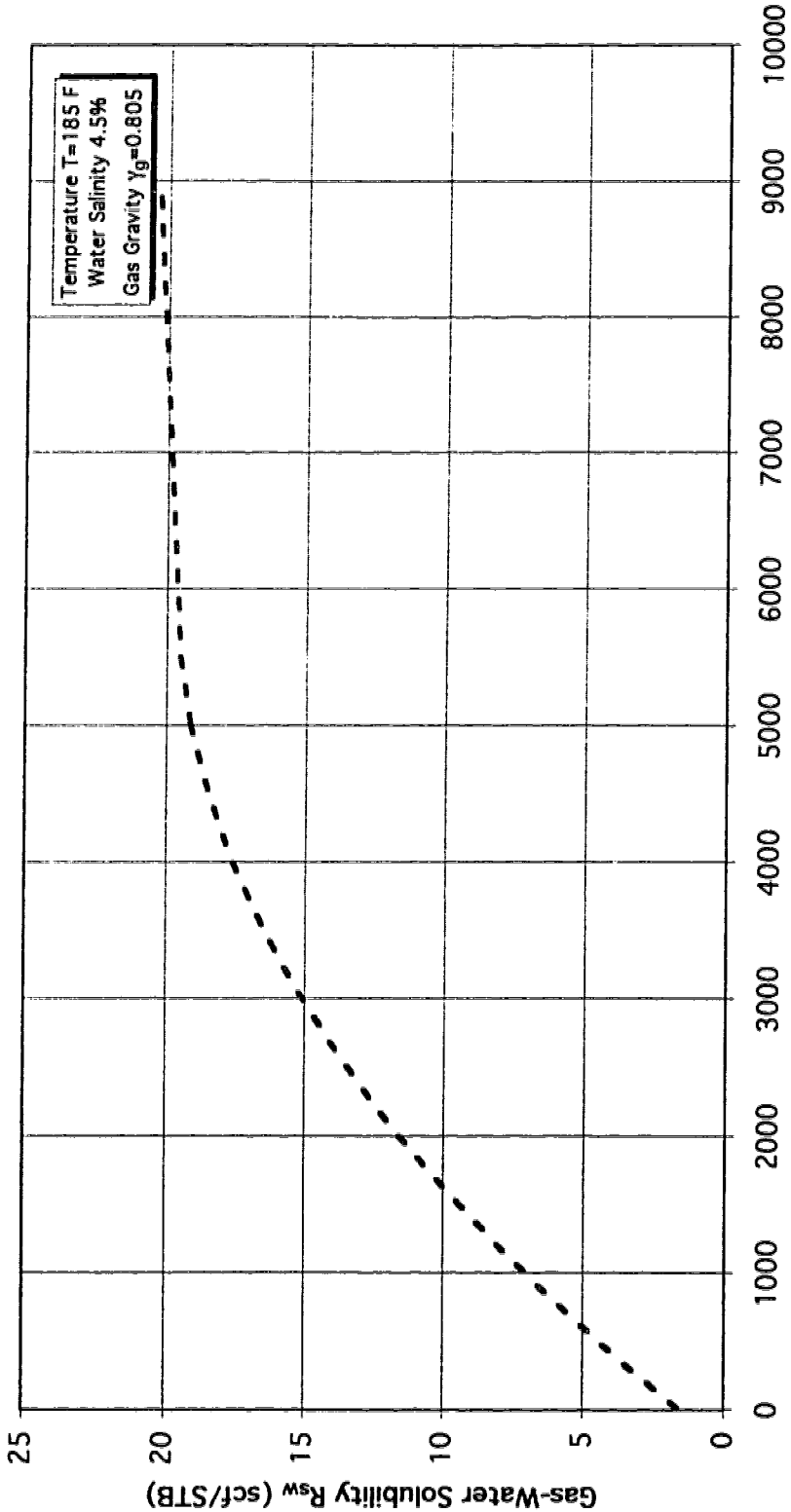



Figure 2.20(a): Gas-Water Solubility $R_{sw}$ (08-17-37-8W5)

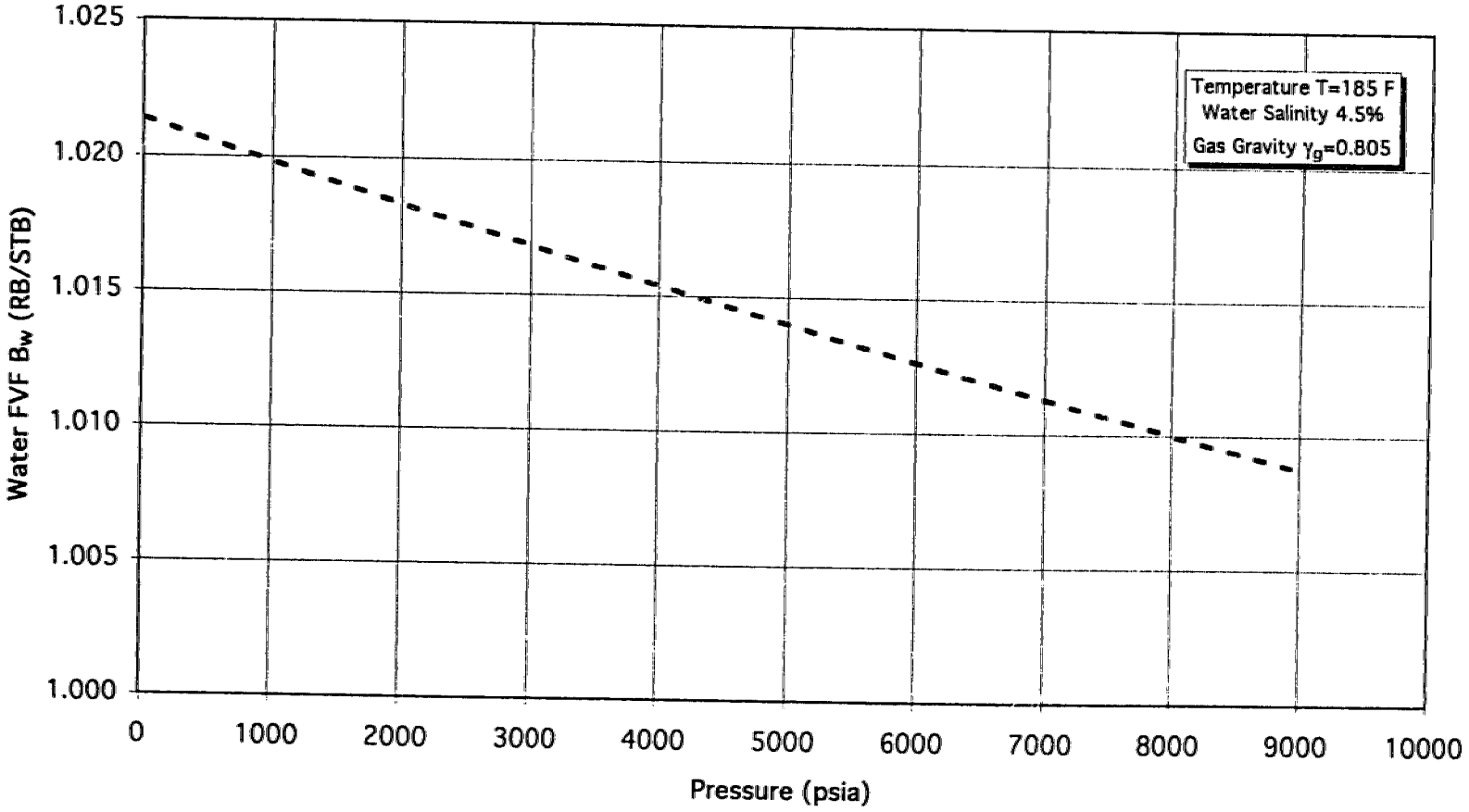



Figure 2.20(b): Water Formation Volume Factor $B_w$ (08-17-37-8W5)

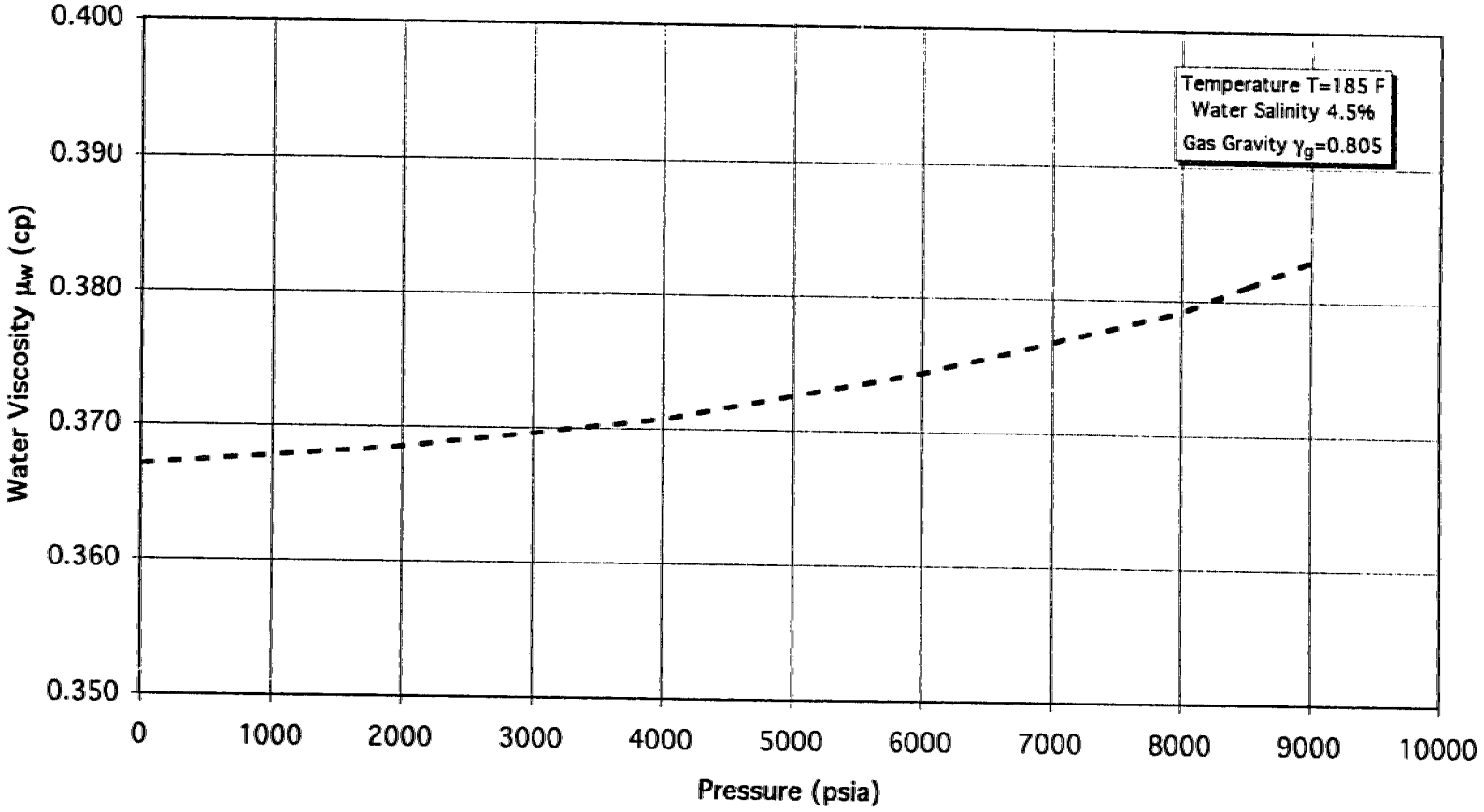



Figure 2.20(c): Water Viscosity $\mu_w$ (08-17-37-8W5)

## 2.10 Capillary Pressure Data

Fluids in porous media flow towards regions of lower potential. The fluid potential is the combined hydrodynamic and hydrostatic head. Generally, all three constituent phases of oil, water and free gas coexist in the porous reservoir. Each phase has its own potential. Phase potentials are interrelated by capillary pressures. Capillary pressures measure the difference between oil-water and oil-gas pressures caused by the interfacial tension between immiscible phases occupying distinct portions of the pore space. In the absence of capillary pressure, all three phases would be fully mixed. The oil-water and gas-oil capillary pressures ($P_{cow}$, $P_{cgo}$) are functions of water saturation and gas saturation, respectively. The oil-water capillary pressure ($P_{cow}$) decreases from an asymptotic limit at the irreducible water saturation (distinct simply-connected oil and water regions) to zero at high water saturation (oil fully dispersed in water). In contrast, the gas-oil capillary pressure ($P_{cgo}$) is small at low trapped gas saturations (gas fully dispersed in oil) and approaches an asymptotic limit at higher gas saturations (simply connected oil and gas regions).

Oil-water capillary pressure ($P_{cow}$) data was obtained from the Canadian Hunter Chedderville Waterflood Design Study (1993). Table 2.12 shows the analysis conducted on two core slices, 9B and 13B, sampled from 08-17-37-7W5. The rock was classified as neutral to moderately water-wet. The oil-water capillary pressure dependence on water saturations shows some hysteresis between imbibition and drainage curves (Figure 2.21). Core 9B was selected as the basis for the simulation model because its range of imbibition data seemed to be more consistent with the bulk of irreducible water estimates (Section 2.7) and relative permeability data (Section 2.11). The simulation model data extended the water range from $S_w$=27.5% (irreducible water) to $S_w$= 82.5% (residual oil). Gas-oil capillary pressure was not available and assumed to be negligible ($P_{cgo}$=0).

| Core: | 9B | Core: | 13B |
|---|---|---|---|
| Well | 08-17-37-7W5 | Well | 08-17-37-7W5 |
| Depth KB (ft) | 8535.1 | Depth KB (m) | 8536.3 |
| Air Kx (md) | 68 | Air Kx (md) | 15 |
| Porosity | 10.70% | Porosity | 8.20% |

| Moderately Water-Wet | | Neutral Wettability | |
|---|---|---|---|
| Sw | Pcow (psi) | Sw | Pcow (psi) |
| 29.40% | -0.29 | 34.70% | -0.26 |
| 44.50% | -0.81 | 40.50% | -0.73 |
| 55.30% | -2.50 | 46.30% | -2.22 |
| 59.60% | -5.11 | 49.20% | -4.54 |
| 68.20% | -11.48 | 52.00% | -10.21 |
| 72.30% | -20.41 | 55.90% | -18.16 |
| 72.30% | -27.00 | 55.90% | -24.02 |
| | | | |
| 71.20% | 0.29 | 54.90% | 0.26 |
| 68.20% | 0.81 | 54.00% | 0.73 |
| 59.70% | 2.50 | 50.10% | 2.22 |
| 49.10% | 5.11 | 46.30% | 4.54 |
| 40.60% | 11.48 | 42.40% | 10.21 |
| 30.00% | 20.41 | 38.50% | 18.16 |
| 28.00% | 27.00 | 38.50% | 24.02 |

| Sw | * Pcow (psi) |
|---|---|
| 27.50% | 27.00 |
| 30.00% | 20.41 |
| 32.50% | 18.18 |
| 35.00% | 15.95 |
| 37.50% | 13.71 |
| 40.00% | 11.48 |
| 42.50% | 9.66 |
| 45.00% | 7.84 |
| 47.50% | 6.02 |
| 50.00% | 4.82 |
| 52.50% | 4.24 |
| 55.00% | 3.66 |
| 57.50% | 3.08 |
| 60.00% | 2.50 |
| 62.50% | 2.02 |
| 65.00% | 1.53 |
| 67.50% | 1.05 |
| 70.00% | 0.55 |
| 72.50% | 0.20 |
| 75.00% | 0.01 |
| 77.50% | 0.00 |
| 80.00% | 0.00 |
| 82.50% | 0.00 |

Canadian Hunter Chedderville Waterflood Design Study, Hycal Energy Research Laboratories Ltd., Calgary, Oct 25, 1993.

*Core 9B Basis for Waterflood Model

## Table 2.12: Oil-Water Capillary Pressure

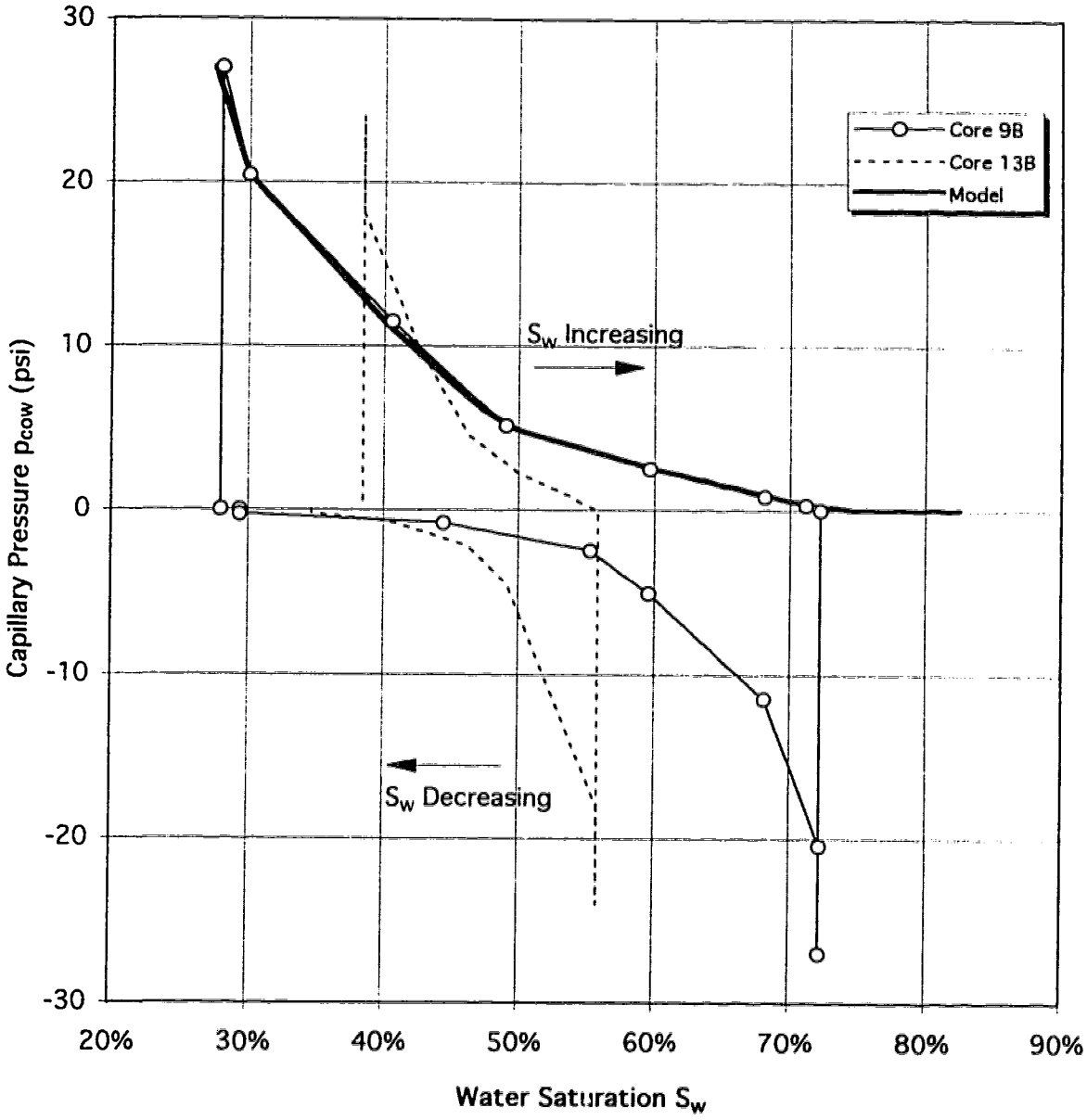



Figure 2.21: Oil-Water Capillary Pressure $p_{cow}$
(08-17-37-7W5)

## 2.11 Relative Permeability Data

The phase flow rate under a pressure gradient depends on the absolute rock permeability to fluid flow, the phase viscosity and the relative permeability of that particular phase. When the local reservoir pressure is above the bubble point, undersaturated oil will expand as it moves towards regions of lower pressure. When the pressure drops below the bubble point, dissolved gas will be released from the saturated oil as free gas. This highly compressible free gas will displace oil as it expands locally. As the pressure continues to drop, the evolution of free gas will saturate the surrounding porous media and become mobile as it accumulates to some critical level. Above this critical level, free gas will no longer be trapped locally and will move towards producing wells in its free and mobile state. The producing gas-oil ratio will increase as the mobile free gas flows to the surface along with the solution gas in oil. As the reservoir gas saturation increases, its relative mobility will increase and flow preferentially by impeding the flow of oil. Gas production will increase and oil production decrease, until the rate of free gas evolution drops below the rate of gas production.

Under waterflood pressure, injected water would start to expand and flow towards producing wells. An oil bank would form as it gets compressed ahead of the water front. The piston-like displacement efficiency would depend on the mobility ratio between water and oil (Willhite, 1990, p87-89). The producing oil rate would initially increase and remain relatively constant until the water front advances to the producing wells. As the reservoir water saturation increases, its relative mobility will increase and flow preferentially by impeding the flow of oil. Subsequent production after water breakthrough will have increasing water-oil ratios.

Phase mobilities are directly proportional to phase relative permeabilites and inversely proportional to phase viscosities. Three-phase relative permeabilities are difficult to measure and are typically calculated using two-phase oil-gas and oil-water data. Two-phase relative permeability data was obtained from Canadian Hunter Chedderville Waterflood Design Study (1993). Table 2.13 shows the analysis conducted on two core stacks, #1 and #2, sampled from 08-17-37-7W5. Stack#1 was selected as the basis for the simulation model because its range of data seemed to be more consistent with the bulk of irreducible water estimates (Section 2.7). The procedure described by Demetre(1993) was followed to calculate three-phase relative permeabilities ($k_{ro}$,$k_{rw}$,$k_{rg}$).

| Core: | Stack #1 |
|---|---|
| Well | 08-17-37-7W5 |
| Depth KB (ft) | 8535.0 |
| Kx (md) | 50.1 |
| Porosity | 10.10% |

| Sw | Krw | Kro | Sg | Krg | Krl@Sw=.467 |
|---|---|---|---|---|---|
| 39.90% | 0.00000 | 0.30140 | 0.00% | 0.00000 | 0.25090 |
| 42.00% | 0.00006 | 0.26600 | 0.60% | 0.00092 | 0.21570 |
| 44.20% | 0.00025 | 0.23330 | 1.20% | 0.00191 | 0.18390 |
| 46.30% | 0.00061 | 0.20300 | 1.90% | 0.00292 | 0.15540 |
| 48.40% | 0.00120 | 0.17500 | 2.50% | 0.00395 | 0.13000 |
| 50.50% | 0.00205 | 0.14980 | 3.10% | 0.00500 | 0.10760 |
| 52.70% | 0.00320 | 0.12670 | 3.70% | 0.00605 | 0.08786 |
| 54.80% | 0.00469 | 0.10590 | 4.30% | 0.00711 | 0.07072 |
| 56.90% | 0.00653 | 0.08727 | 5.00% | 0.00818 | 0.05598 |
| 59.00% | 0.00875 | 0.07073 | 5.60% | 0.00926 | 0.04344 |
| 61.20% | 0.01140 | 0.05620 | 6.20% | 0.01034 | 0.03295 |
| 63.30% | 0.01447 | 0.04362 | 6.80% | 0.01143 | 0.02430 |
| 65.40% | 0.01801 | 0.03288 | 7.40% | 0.01252 | 0.01734 |
| 67.50% | 0.02204 | 0.02390 | 8.10% | 0.01362 | 0.01186 |
| 69.70% | 0.02657 | 0.01657 | 8.70% | 0.01472 | 0.00770 |
| 71.80% | 0.03162 | 0.01078 | 9.30% | 0.01582 | 0.00467 |
| 73.90% | 0.03723 | 0.00641 | 9.90% | 0.01693 | 0.00258 |
| 76.00% | 0.04340 | 0.00332 | 10.50% | 0.01804 | 0.00126 |
| 78.20% | 0.05015 | 0.00136 | 11.20% | 0.01916 | 0.00051 |
| 80.30% | 0.05752 | 0.00034 | 11.80% | 0.02028 | 0.00016 |
| 82.40% | 0.06550 | 0.00000 | 12.40% | 0.02140 | 0.00000 |

| Core: | Stack #2 |
|---|---|
| Well | 08-17-37-7W5 |
| Depth KB (ft) | 8528.9 |
| Kx (md) | 1.47 |
| Porosity | 7.10% |

| Sw | Krw | Kro | Sg | Krg | Krl@Sw=.608 |
|---|---|---|---|---|---|
| 52.8% | 0.00000 | 0.15370 | 0.0% | 0.00000 | 0.12520 |
| 54.1% | 0.00359 | 0.13630 | 0.6% | 0.00071 | 0.11880 |
| 55.3% | 0.00748 | 0.12020 | 1.1% | 0.00148 | 0.11230 |
| 56.6% | 0.01149 | 0.10520 | 1.7% | 0.00228 | 0.10590 |
| 57.9% | 0.01558 | 0.09129 | 2.2% | 0.00309 | 0.09950 |
| 59.2% | 0.01973 | 0.07854 | 2.8% | 0.00391 | 0.09310 |
| 60.4% | 0.02394 | 0.06688 | 3.3% | 0.00475 | 0.08672 |
| 61.7% | 0.02818 | 0.05629 | 3.9% | 0.00559 | 0.08035 |
| 63.0% | 0.03246 | 0.04673 | 4.4% | 0.00644 | 0.07399 |
| 64.2% | 0.03678 | 0.03818 | 5.0% | 0.00730 | 0.06765 |
| 65.5% | 0.04112 | 0.03610 | 5.6% | 0.00816 | 0.06132 |
| 66.8% | 0.04549 | 0.02399 | 6.1% | 0.00902 | 0.05502 |
| 68.0% | 0.04988 | 0.01828 | 6.7% | 0.00990 | 0.04874 |
| 69.3% | 0.05430 | 0.01344 | 7.2% | 0.01077 | 0.04247 |
| 70.6% | 0.05873 | 0.00944 | 7.8% | 0.01165 | 0.03624 |
| 71.9% | 0.06319 | 0.00624 | 8.3% | 0.01253 | 0.03004 |
| 73.1% | 0.06766 | 0.00377 | 8.9% | 0.01342 | 0.02387 |
| 74.4% | 0.07215 | 0.00199 | 9.4% | 0.01431 | 0.01775 |
| 75.7% | 0.07665 | 0.00083 | 10.0% | 0.01520 | 0.01169 |
| 76.9% | 0.08117 | 0.00021 | 10.5% | 0.01610 | 0.00573 |
| 78.2% | 0.08570 | 0.00000 | 11.1% | 0.01700 | 0.00000 |

Canadian Hunter Chedderville Waterflood Design Study,
Hycal Energy Research Laboratories Ltd., Calgary, Oct 25, 1993.

Table 2.13: Core Two-Phase Relative Permeabilities

Three-phase relative permeabilities[6] are assumed to have a functional dependence on ($S_o$, $S_w$, $S_g$) as proposed in the probability models of Stone (1970, 1973).

$$k_{ro}=k_{ro}(S_w,S_g) \quad , \quad k_{rw}=k_{rw}(S_w) \quad , \quad k_{rg}=k_{rg}(S_g) \tag{2.8}$$

Two-phase relative permeability functions of water and gas saturations (Coats(1980), Aziz *et al.* (1987)) were used to fit laboratory data:

$$k_{rw}=k_{rwro}\left[\frac{S_w-S_{wir}}{1-S_{orw}-S_{wir}}\right]^{n_w} \qquad k_{rg}=k_{rgro}\left[\frac{S_g-S_{gc}}{1-S_{wir}-S_{org}-S_{gc}}\right]^{n_g}$$

$$k_{row}=k_{roiw}\left[\frac{1-S_{orw}-S_w}{1-S_{orw}-S_{wir}}\right]^{n_{ow}} \qquad k_{rog}=k_{roiw}\left[\frac{1-S_{wir}-S_{org}-S_g}{1-S_{wir}-S_{org}}\right]^{n_{og}} \tag{2.9}$$

| | | | |
|---|---|---|---|
| $S_w$ | water saturation | $S_g$ | gas saturation |
| $k_{rw}$ | water relative permeability | $k_{rg}$ | gas relative permeability |
| $k_{row}$ | oil relative permeability in water-oil | $k_{rog}$ | oil relative permeability in gas-oil |
| $S_{wir}$ | irreducible connate water saturation | $S_{gc}$ | critical mobile gas saturation |
| $S_{orw}$ | residual oil saturation in water-oil | $S_{org}$ | residual oil saturation in gas-oil |
| $k_{roiw}$ | oil relative permeability in water-oil at irreducible water saturation | | |
| $k_{rwro}$ | water relative permeability in water-oil at residual oil saturation | $k_{rgro}$ | gas relative permeability in gas-oil at residual oil saturation |
| $n_w$ | saturation exponent for $k_{rw}$ | $n_g$ | saturation exponent for $k_{rg}$ |
| $n_{ow}$ | saturation exponent for $k_{row}$ | $n_{og}$ | saturation exponent for $k_{rog}$ |

Table 2.14: Three-Phase Relative Permeability Nomenclature

6 Honarpour *et al.* (1986) provide a comprehensive discussion on relative permeability.

Three-phase oil relative permeability $k_{ro}$ in the water-gas-oil system was then calculated using the model proposed by Aziz and Settari (1979) :

$$k_{ro}(S_w,S_g) = k_{roiw} S_o^* \beta_w \beta_g \tag{2.10}$$

where,

$$\beta_g = \frac{1}{k_{roiw}(1-S_g^*)} k_{rog}(S_l) \qquad \beta_w = \frac{1}{k_{roiw}(1-S_w^*)} k_{row}(S_w)$$

$$S_l = 1 - S_g \qquad S_o^* = \frac{S_o - S_{orw}}{(1-S_{wir}-S_{orw})} \qquad S_o \geq S_{orw}$$

$$S_g^* = \frac{S_g}{(1-S_{wir}-S_{org})} \qquad S_w^* = \frac{S_w - S_{wir}}{(1-S_{wir}-S_{orw})} \qquad S_w \geq S_{wir} \tag{2.11}$$

The two-phase relative permeabilities for stack #1 were fitted using the procedure described above. The results were fine-tuned through the iterative process of history matching. The final results used in the simulation model are given in Table 2.15. A critical gas saturation $S_{gc}$=2.5% was needed to match gas production history. Two-phase relative permeabilities for the oil-water and oil-gas systems are graphed in Figures 2.22(a) and 2.22(b). Calculated three-phase oil relative permeability is tabulated as a function of $S_w$ and $S_g$ in Table 2.16 and plotted in Figure 2.22(c).

| | Irreducible Water | | Residual Oil (w) | | Residual Oil (g) | | Critical Gas |
|---|---|---|---|---|---|---|---|
| Saturation (Swir) | .2750 | Saturation (Sorw) | .1750 | Saturation (Sorg) | .2250 | Saturation (Sgc) | .0250 |
| Rel Perm (kroiw) | .6000 | Rel Perm (krwro) | .0650 | Rel Perm (krgro) | .0650 | | |

| | krw Exponent | krow Exponent | | | krg Exponent | krog Exponent | |
|---|---|---|---|---|---|---|---|
| | 3.500 | 2.500 | | | .725 | 4.000 | |
| Water Saturation (Sw) | Water Relative Permeability (krw) | Oil-Water Relative Permeability (krow) | Oil-Water Capillary Pressure (psi) | Gas Saturation (Sg) | Gas Relative Permeability (krg) | Oil-Gas Relative Permeability (krog) | Gas-Oil Capillary Pressure (psi) |
| 0.0% | .0000 | 1.0000 | .000 | 0.0% | .0000 | .6000 | .000 |
| 2.5% | .0000 | .9636 | .000 | 2.5% | .0000 | .4887 | .000 |
| 5.0% | .0000 | .9273 | .000 | 5.0% | .0077 | .3937 | .000 |
| 7.5% | .0000 | .8909 | .000 | 7.5% | .0127 | .3132 | .000 |
| 10.0% | .0000 | .8545 | .000 | 10.0% | .0171 | .2458 | .000 |
| 12.5% | .0000 | .8182 | .000 | 12.5% | .0210 | .1898 | .000 |
| 15.0% | .0000 | .7818 | .000 | 15.0% | .0247 | .1441 | .000 |
| 17.5% | .0000 | .7455 | .000 | 17.5% | .0282 | .1071 | .000 |
| 20.0% | .0000 | .7091 | .000 | 20.0% | .0315 | .0778 | .000 |
| 22.5% | .0000 | .6727 | .000 | 22.5% | .0347 | .0549 | .000 |
| 25.0% | .0000 | .6364 | 50.000 | 25.0% | .0378 | .0375 | .000 |
| 27.5% | .0000 | .6000 | 27.000 | 27.5% | .0408 | .0246 | .000 |
| 30.0% | .0000 | .5341 | 20.410 | 30.0% | .0437 | .0154 | .000 |
| 32.5% | .0000 | .4728 | 18.180 | 32.5% | .0466 | .0090 | .000 |
| 35.0% | .0001 | .4159 | 15.950 | 35.0% | .0494 | .0049 | .000 |
| 37.5% | .0002 | .3633 | 13.710 | 37.5% | .0521 | .0023 | .000 |
| 40.0% | .0004 | .3149 | 11.480 | 40.0% | .0548 | .0010 | .000 |
| 42.5% | .0007 | .2706 | 9.660 | 42.5% | .0574 | .0003 | .000 |
| 45.0% | .0012 | .2303 | 7.840 | 45.0% | .0600 | .0001 | .000 |
| 47.5% | .0019 | .1938 | 6.020 | 47.5% | .0625 | .0000 | .000 |
| 50.0% | .0028 | .1610 | 4.820 | 50.0% | .0650 | .0000 | .000 |
| 52.5% | .0041 | .1318 | 4.240 | 52.5% | .1117 | .0000 | .000 |
| 55.0% | .0057 | .1061 | 3.660 | 55.0% | .1585 | .0000 | .000 |
| 57.5% | .0078 | .0836 | 3.080 | 57.5% | .2052 | .0000 | .000 |
| 60.0% | .0103 | .0642 | 2.500 | 60.0% | .2520 | .0000 | .000 |
| 62.5% | .0134 | .0478 | 2.020 | 62.5% | .2987 | .0000 | .000 |
| 65.0% | .0170 | .0343 | 1.530 | 65.0% | .3455 | .0000 | .000 |
| 67.5% | .0213 | .0233 | 1.050 | 67.5% | .3923 | .0000 | .000 |
| 70.0% | .0264 | .0148 | .550 | 70.0% | .4390 | .0000 | .000 |
| 72.5% | .0322 | .0085 | .200 | 72.5% | .4858 | .0000 | .000 |
| 75.0% | .0389 | .0041 | .010 | 75.0% | .5325 | .0000 | .000 |
| 77.5% | .0466 | .0015 | .000 | 77.5% | .5792 | .0000 | .000 |
| 80.0% | .0552 | .0003 | .000 | 80.0% | .6260 | .0000 | .000 |
| 82.5% | .0650 | .0000 | .000 | 82.5% | .6727 | .0000 | .000 |
| 85.0% | .1986 | .0000 | .000 | 85.0% | .7195 | .0000 | .000 |
| 87.5% | .3321 | .0000 | .000 | 87.5% | .7663 | .0000 | .000 |
| 90.0% | .4657 | .0000 | .000 | 90.0% | .8130 | .0000 | .000 |
| 92.5% | .5993 | .0000 | .000 | 92.5% | .8598 | .0000 | .000 |
| 95.0% | .7329 | .0000 | .000 | 95.0% | .9065 | .0000 | .000 |
| 97.5% | .8664 | .0000 | .000 | 97.5% | .9533 | .0000 | .000 |
| 100.0% | 1.0000 | .0000 | .000 | 100.0% | 1.0000 | .0000 | .000 |

**Table 2.15: Model Two-Phase Relative Permeabilities and Capillary Pressures**

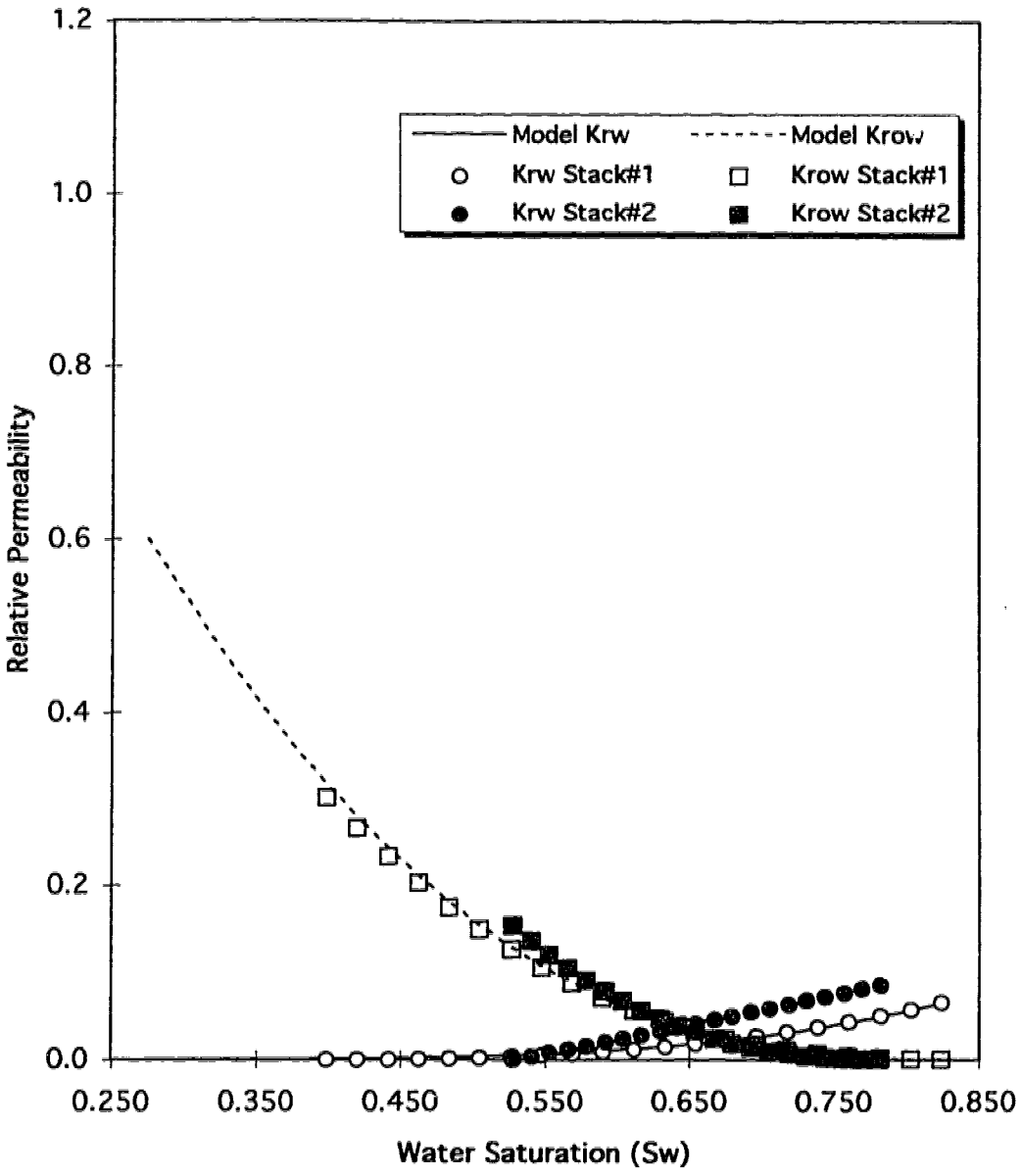



Figure 2.22(a): 2-Phase Water and Water-Oil Relative Permeabilities

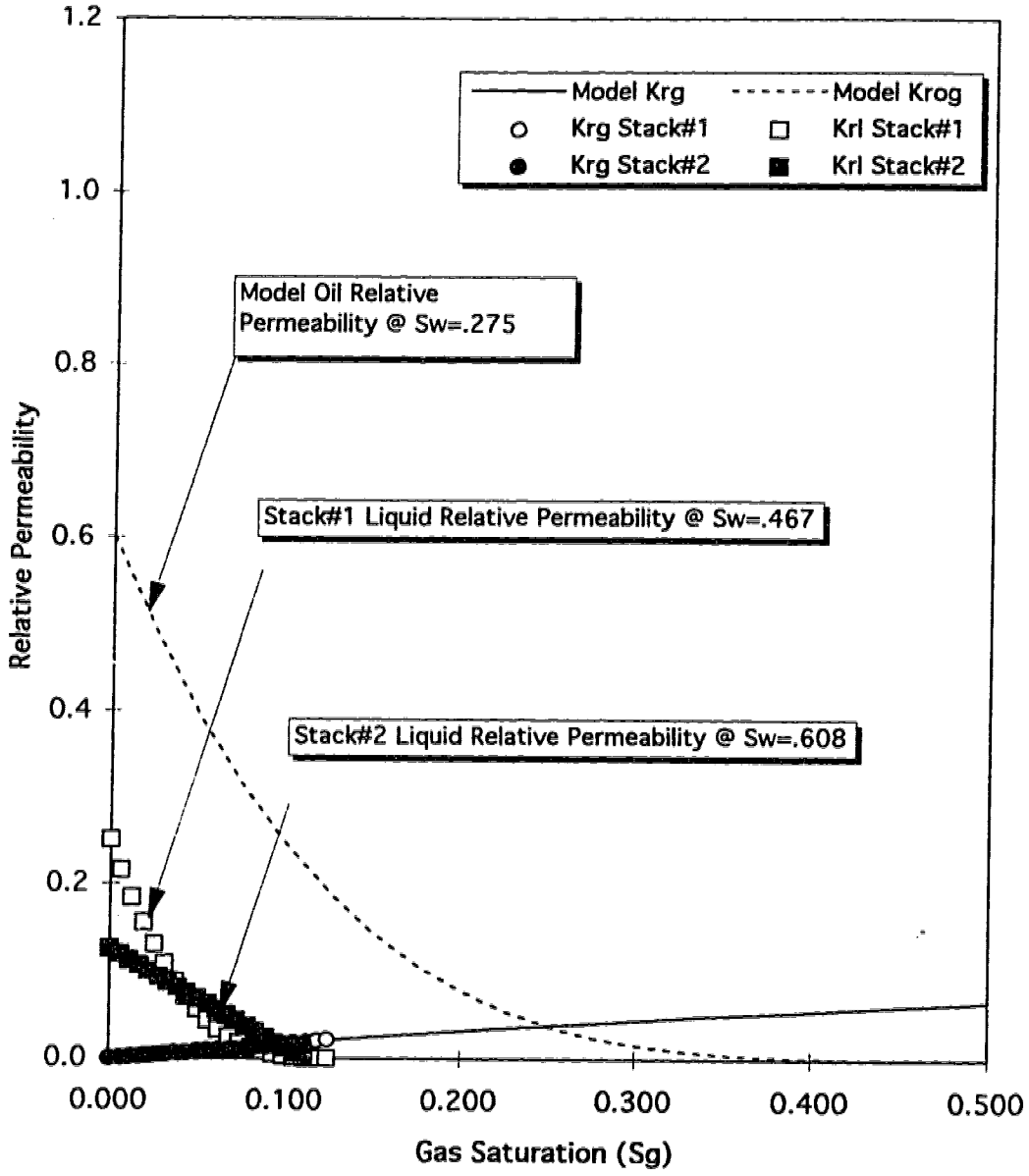



Figure 2.22(b): 2-Phase Gas and Gas-Oil Relative Permeabilities

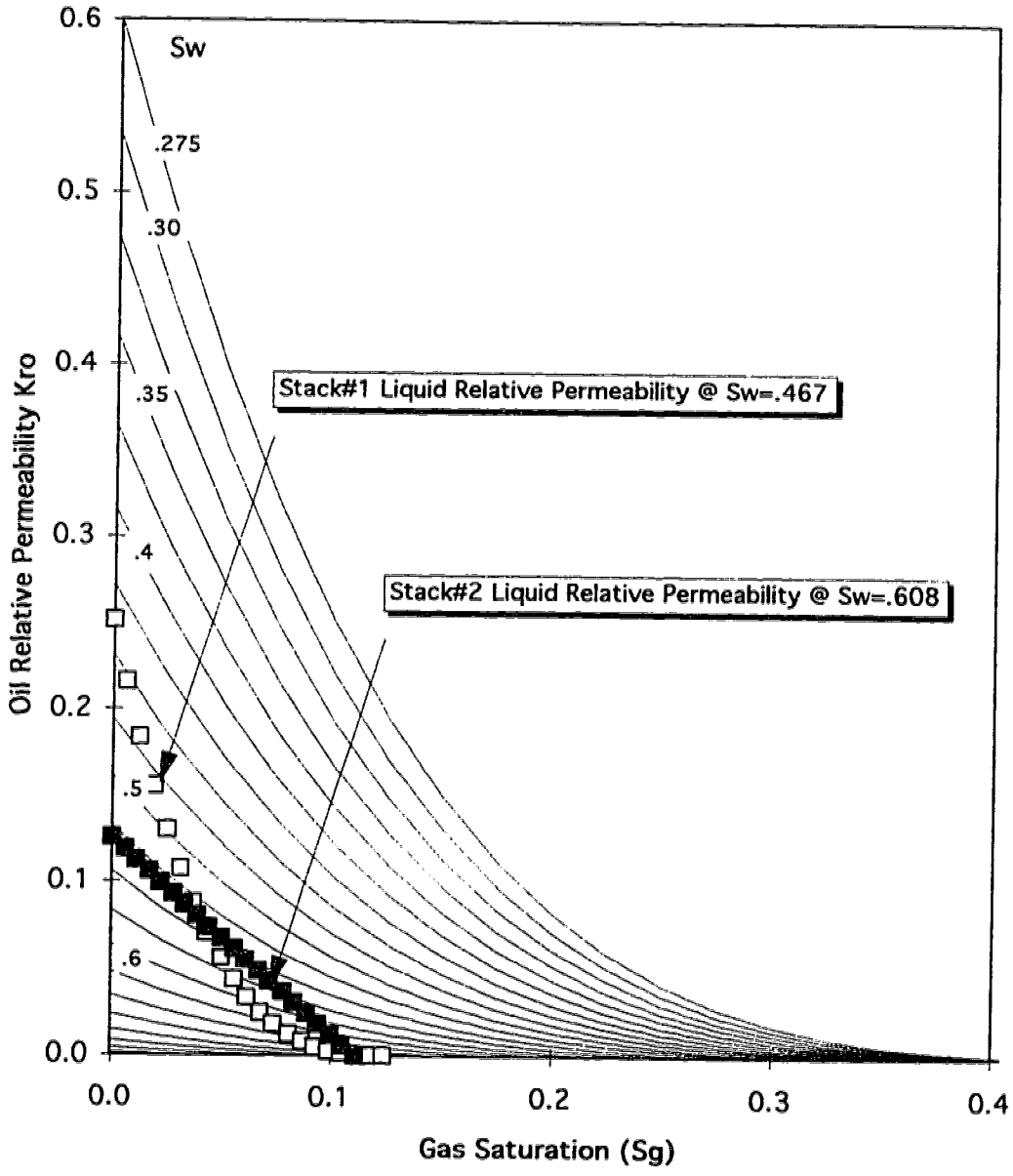



Figure 2.22(c): Model 3-Phase Oil Relative Permeabilities

| Sw\Sg | .000 | .025 | .050 | .075 | .100 | .125 | .150 | .175 | .200 | .225 | .250 | .275 | .300 | .325 | .350 | .375 | .400 | .425 | .450 | .475 | .500 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0.275 | .600 | .491 | .398 | .318 | .251 | .196 | .150 | .112 | .082 | .059 | .041 | .027 | .017 | .011 | .006 | .003 | .001 | .000 | .000 | .000 | |
| 0.300 | .534 | .436 | .352 | .281 | .221 | .172 | .131 | .098 | .071 | .051 | .035 | .023 | .015 | .009 | .005 | .002 | .001 | .000 | .000 | .000 | |
| 0.325 | .473 | .385 | .310 | .247 | .194 | .150 | .114 | .084 | .061 | .043 | .030 | .019 | .012 | .007 | .004 | .002 | .001 | .000 | .000 | .000 | |
| 0.350 | .416 | .338 | .271 | .215 | .168 | .129 | .098 | .072 | .052 | .036 | .025 | .016 | .010 | .006 | .003 | .001 | .001 | .000 | .000 | .000 | |
| 0.375 | .363 | .294 | .235 | .186 | .145 | .111 | .083 | .061 | .044 | .030 | .020 | .013 | .008 | .004 | .002 | .001 | .000 | .000 | .000 | .000 | |
| 0.400 | .315 | .254 | .203 | .159 | .123 | .094 | .070 | .051 | .036 | .025 | .016 | .010 | .006 | .003 | .002 | .001 | .000 | .000 | .000 | .000 | |
| 0.425 | .271 | .218 | .173 | .135 | .104 | .078 | .058 | .042 | .029 | .020 | .013 | .008 | .004 | .002 | .001 | .000 | .000 | .000 | .000 | .000 | |
| 0.450 | .230 | .184 | .146 | .113 | .086 | .065 | .047 | .034 | .023 | .015 | .010 | .006 | .003 | .001 | .000 | .000 | .000 | .000 | .000 | .000 | |
| 0.475 | .194 | .154 | .121 | .094 | .071 | .053 | .038 | .027 | .018 | .012 | .007 | .004 | .002 | .001 | .000 | .000 | .000 | .000 | .000 | .000 | |
| 0.500 | .161 | .127 | .099 | .076 | .057 | .042 | .030 | .020 | .013 | .008 | .005 | .002 | .001 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | |
| 0.525 | .132 | .104 | .080 | .061 | .045 | .032 | .023 | .015 | .009 | .005 | .003 | .001 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | |
| 0.550 | .106 | .083 | .063 | .047 | .035 | .024 | .017 | .011 | .006 | .003 | .001 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | |
| 0.575 | .084 | .064 | .049 | .036 | .026 | .018 | .011 | .007 | .004 | .001 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | |
| 0.600 | .064 | .049 | .036 | .026 | .018 | .012 | .007 | .004 | .002 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | |
| 0.625 | .048 | .036 | .026 | .018 | .012 | .008 | .004 | .002 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | | | |
| 0.650 | .034 | .025 | .018 | .012 | .008 | .004 | .002 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | | | | |
| 0.675 | .023 | .017 | .011 | .007 | .004 | .002 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | | | | | |
| 0.700 | .015 | .010 | .006 | .004 | .002 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | | | | | | |
| 0.725 | .008 | .005 | .003 | .001 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | | | | | | | | |
| 0.750 | .004 | .002 | .001 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | | | | | | | | |
| 0.775 | .001 | .001 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | | | | | | | | | |
| 0.800 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | | | | | | | | | | | |
| 0.825 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | .000 | | | | | | | | | | | | | |

Table 2.16: Model Three-Phase Oil Relative Permeability $K_{ro}$

## 2.12 Initial Depletion State

The reservoir depletion state is sufficiently described by the distributions of ($p$, $S_w$, $S_g$). The initial reservoir pressure state (1-Nov-87) was deduced from the current bottomhole pressure history (1-Oct-94) listed in Table 2.17. Pressure data from a bottomhole pool summary (ERCB) was sparse and scattered in both space and time. The data represented various states of depletion over seven years of production. Fourteen wells had been initiated at different times. The initialization procedure was based on the premise that the reservoir flow was originally at equilibrium (Franchi *et al.* 1982). Phase potential differences due to gravitational terms were assumed to be in balance and that no fluid migration was occurring under gravity-capillary equilibrium conditions. A reference pressure was estimated at an arbitrary depth (5300 feet subsea) selected below the deepest point in the reservoir southwest corner. There was no identifiable water-oil contact at this depth. The bulk of the reservoir was assumed to be initially undersaturated, with some upper portion saturated at a critical gas level. An initial bubble point pressure distribution was estimated. An undersaturated oil density distribution was calculated at the fixed reference pressure using estimated bubble point pressures. The calculated oil density reflected only the variation in bubble point with no variation[7] in actual pressure. A static head distribution was determined with respect to the reference depth using approximate densities. An equilibrium pressure distribution was then assigned to each grid block as the reference pressure offset by the local static head. The reference pressure was adjusted manually until an acceptable distribution was found to locally match early historical data at designated grid blocks. The reference pressure was initialized to 3350 psia. The initial pressure distribution is tabulated in Table 2.18(a) and plotted in Figure 2.23(a).

$$p^0_{ijk} = p_{ref} + \frac{1}{B_o}(\rho_{sco} + R_{so}\rho_{scg})(z_{ijk} - z_{ref})g \qquad (2.12)$$

The initial water saturation was assumed to be at the irreducible state (Table 2.6(e), Figure 2.17(e)). The initial gas saturation state was deduced by matching historical production data (Chapter 4). The first two wells in chronological producing order, 16-09-37-7W5 and 06-15-37-7W5, exhibited historical gas-oil ratios characteristic of saturated bottomhole conditions from the start. Gas production from these wells were much higher than that expected from dissovled gas alone. This fact suggested that a local free gas saturation was initially present. Producing gas-oil ratios for other wells were observed to cross over, from undersaturated to saturated behaviour, sequentially down the east-west dip of the pool. The bubble point pressure determines the local vapour-

---

7 This approximation linearized the equation.

liquid ratio between free gas and oil saturations. The initial bubble point pressure and the free gas saturation were both manually fit to match the oil and gas production data. A developing gas cap was assumed to be initially saturated at critical gas levels to maintain vertical pressure equilibrium. Initial gas cap boundaries were interpolated through trial and error to match the sequential crossovers observed in historical gas-oil ratios. The initial distributions for oil saturation, gas saturation and local bubble point pressure are tabulated in Tables 2.18(b)-(d) and plotted in Figures 2.23(b)-(d).

The matched bubble point distribution in Figure 2.23(d) indicates some disturbance in the center of the pool. Large temperature variations were also observed in historical log data. New information obtained after history match shed some light on this anomalous behaviour. There was evidence of pressure communication between the Viking "A" pool and a lower Mannville formation at a single well (14-09-37W5) located at the source of the disturbance. This well had apparently been producing from the lower formation for a number of years before it started producing from Viking "A". In fact, (14-09-37W5) was producing from the Mannville formation for about a year before the first well (16-09-37W5) started in Viking "A". Production from the Mannville zone was at extremely high initial gas rates, an order of magnitude larger than that observed in Viking "A". Production from the Mannville zone was shut in shortly after (14-09-37W5) started producing from Viking "A". The initial bubble point disturbance observed for Viking "A" was rationalized as a high pressure gas influx through the connecting hole from the zone below. The sustained high pressure gas source could potentially account for an up-dip gas migration in Viking "A" to form a gas cap, and a down-dip nonisothermal solution gas migration to lighten the crude oil. Lighter oils would be characterized by the higher bubble point pressures observed in the wake of migration.

The initial depletion state defined in this section is therefore not the true initial state, but a representative state that accounts for the cumulative effect of pressure communication with the lower formation.

| | 16-09-37-7W5 |
|---|---|
| Date | Pressure (psia) |
| 16-Nov-87 | 2506 |

| | 06-15-37-7W5 |
|---|---|
| Date | Pressure (psia) |
| 20-Feb-89 | 3024 |
| 14-Jul-89 | 2539 |
| 4-Jan-90 | 1922 |
| 23-Mar-90 | 2914 |
| 27-Jun-91 | 2789 |

| | 8-13-37-8W5 |
|---|---|
| Date | Pressure (psia) |
| 22-Mar-90 | 3154 |
| 25-Apr-90 | 3139 |
| 15-Jan-91 | 3098 |
| 10-Dec-91 | 2998 |
| 16-Mar-92 | 2904 |
| 19-Jan-93 | 2861 |

| | 6-13-37-8W5 |
|---|---|
| Date | Pressure (psia) |
| 29-Jan-91 | 3058 |

| | 06-16-37-7W5 |
|---|---|
| Date | Pressure (psia) |
| 7-Oct-90 | 3135 |
| 16-Apr-92 | 2957 |
| 19-Oct-92 | 2906 |
| 19-Jan-93 | 2911 |

| | 8-14-37-8W5 |
|---|---|
| Date | Pressure (psia) |
| 29-Sep-94 | 2550 |

Energy Resources Conservation Board
Bottom Hole Pressure Pool Summary

| | 08-18-37-7W5 |
|---|---|
| Date | Pressure (psia) |
| 14-Mar-92 | 2591 |
| 23-Apr-92 | 2982 |
| 12-Sep-92 | 2932 |

| | 16-08-37-7W5 |
|---|---|
| Date | Pressure (psia) |
| 3-Apr-93 | 2748 |

| | 14-09-37-7W5 |
|---|---|
| Date | Pressure (psia) |
| 27-Jan-93 | 2739 |

| | 08-17-37-7W5 |
|---|---|
| Date | Pressure (psia) |
| 2-Apr-93 | 2901 |

| | 14-07-37-7W5 |
|---|---|
| Date | Pressure (psia) |
| 27-Jul-93 | 2819 |

| | 14-12-37-8W5 |
|---|---|
| Date | Pressure (psia) |
| 8-Nov-94 | 2528 |

| | 16-12-37-8W5 |
|---|---|
| Date | Pressure (psia) |
| 10-Dec-93 | 2704 |
| 26-Jan-94 | 2663 |

| | 08-07-37-7W5 |
|---|---|
| Date | Pressure (psia) |
| 13-May-94 | 2627 |
| 6-Jun-94 | 2615 |

Table 2.17: Chedderville Viking "A" Pressure History (1-Oct-94)

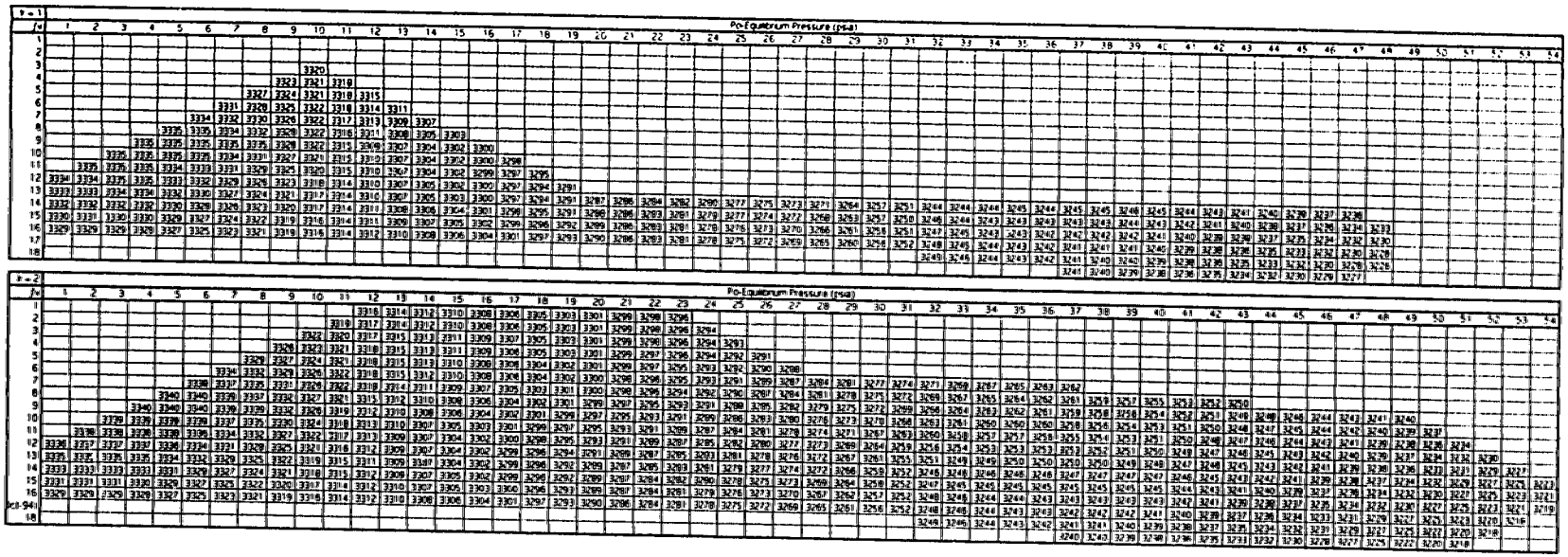


Table 2.18(a): Initial Equilibrium Pressure $p_o$

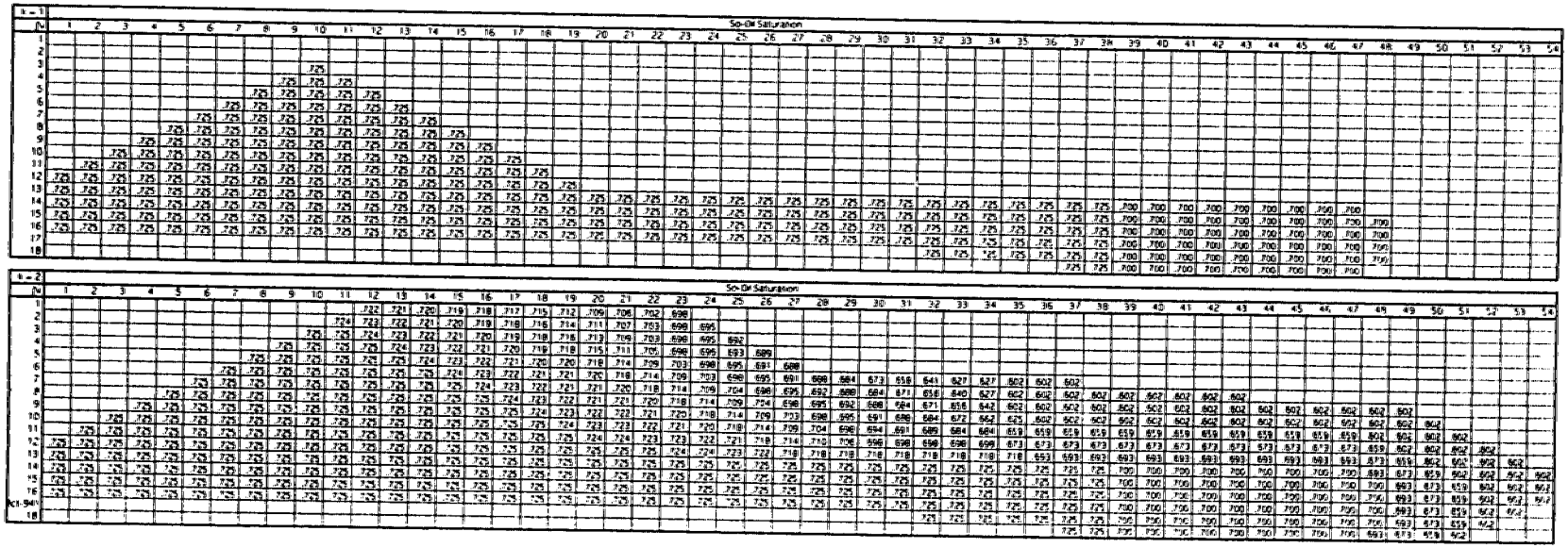


Table 2.18(b): Initial Oil Saturation $S_o$

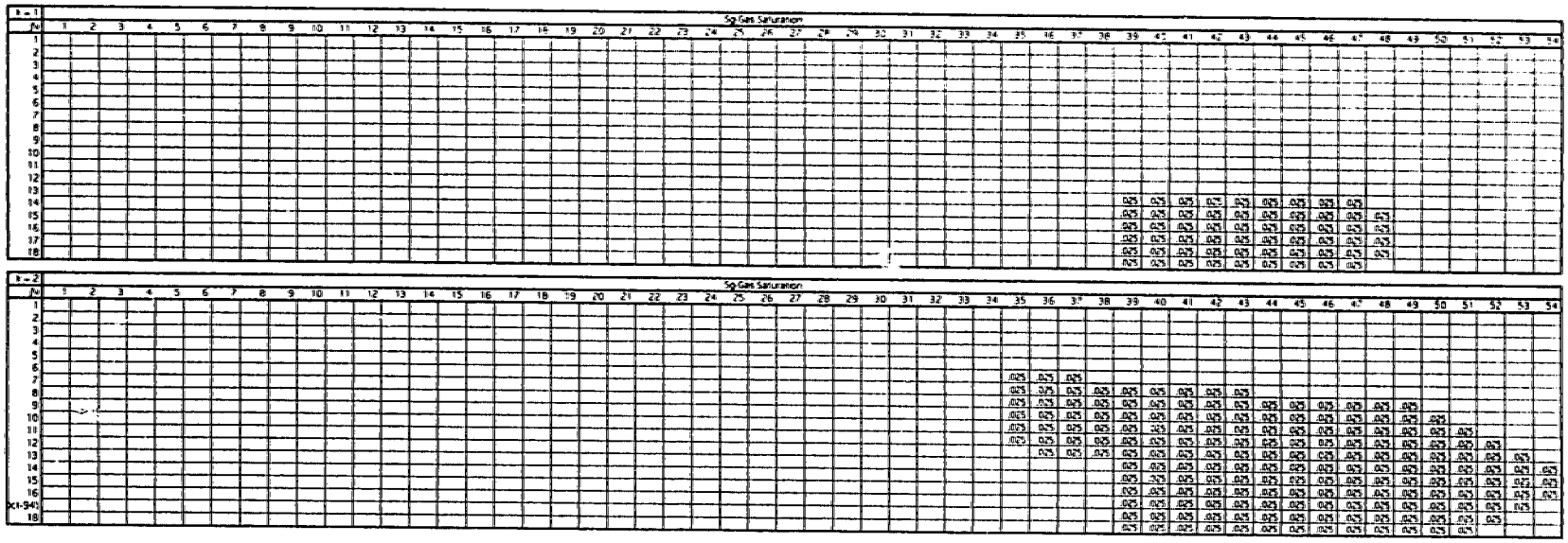


Table 2.18(c): Initial Gas Saturation $S_g$

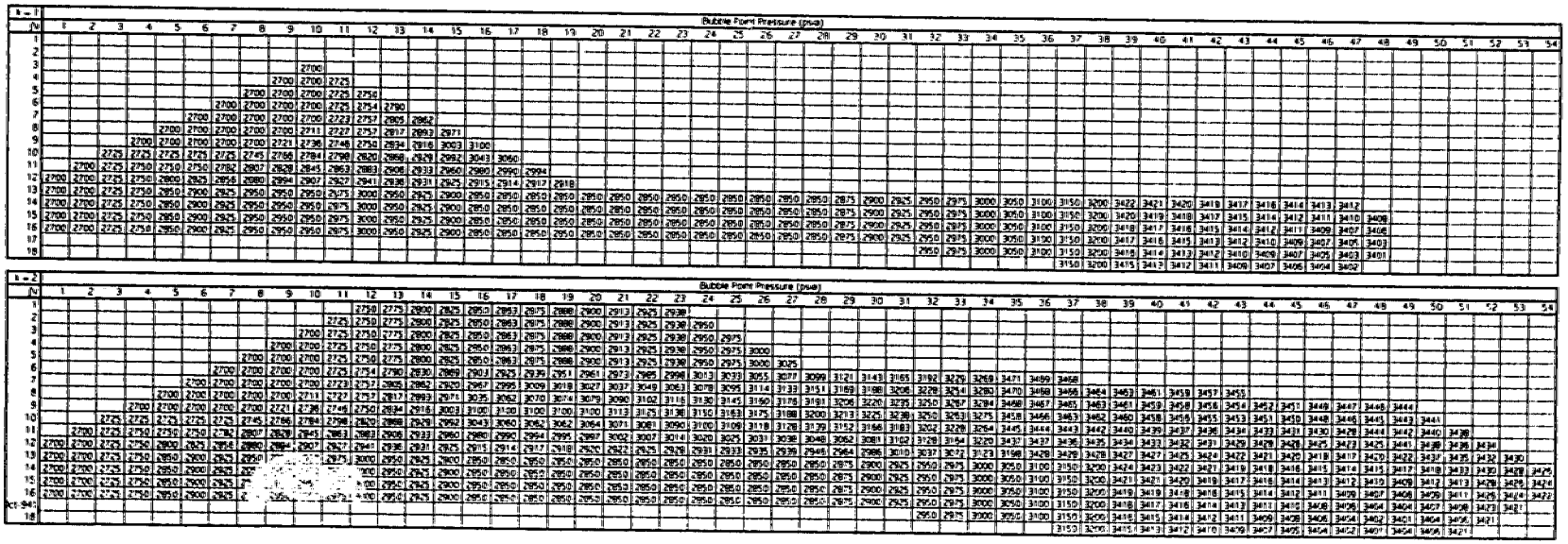


Table 2.18(d): Initial Bubble Point Pressure $p_b$

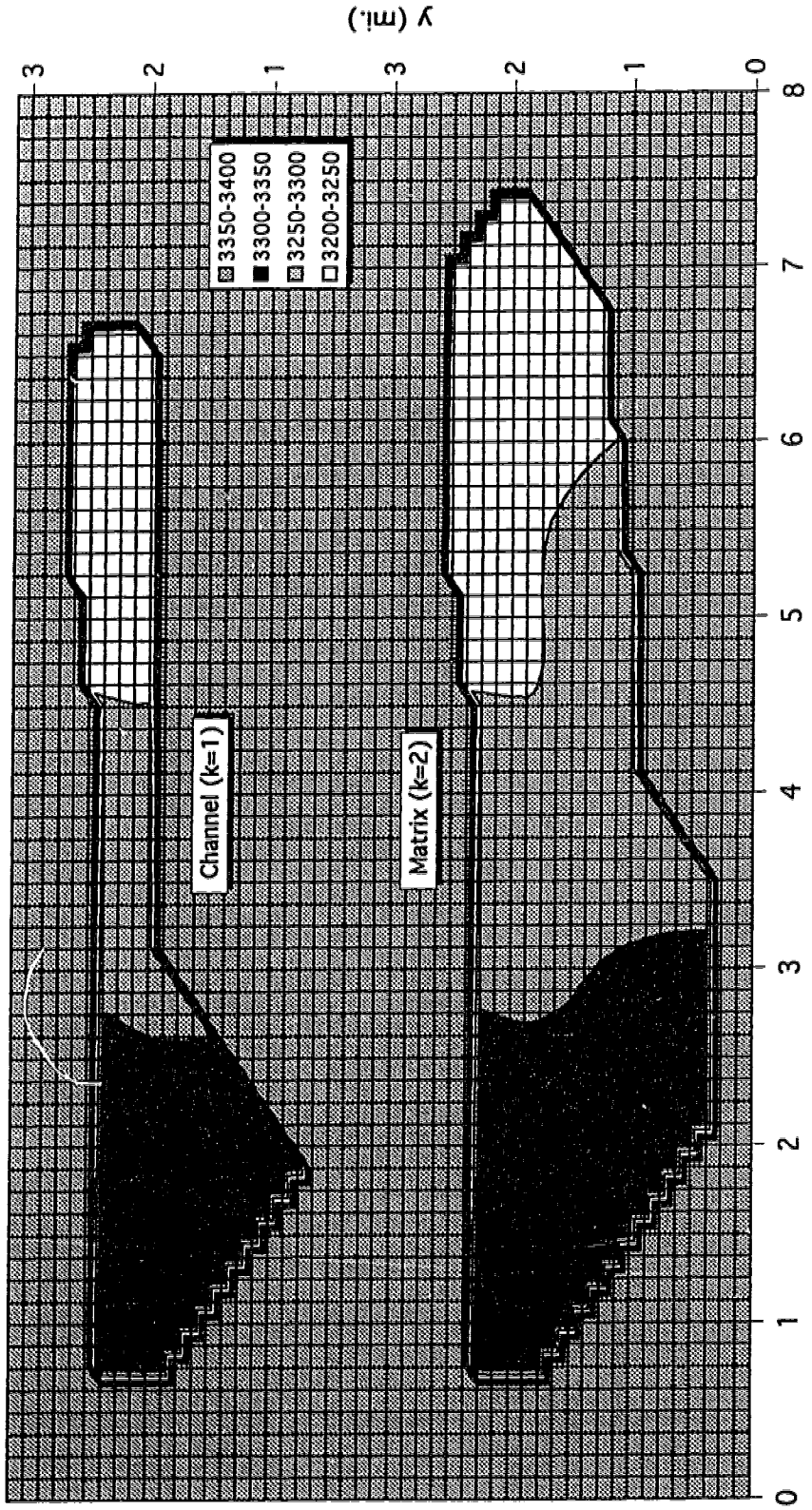



Figure 2.23(a): Initial (Nov-87) Pressure p (psia)

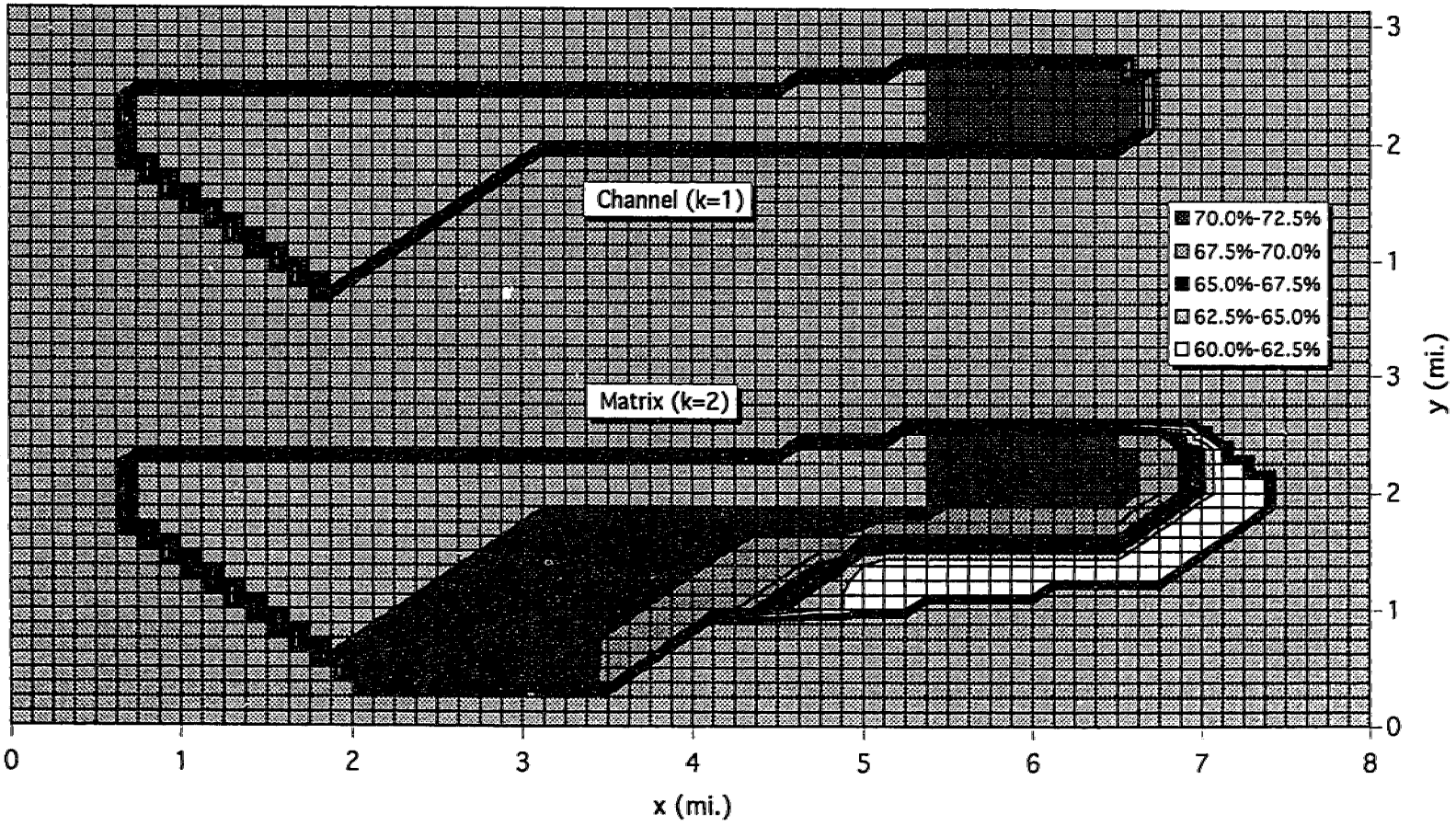



Figure 2.23(b): Initial (Nov-87) Oil Saturation $S_o$

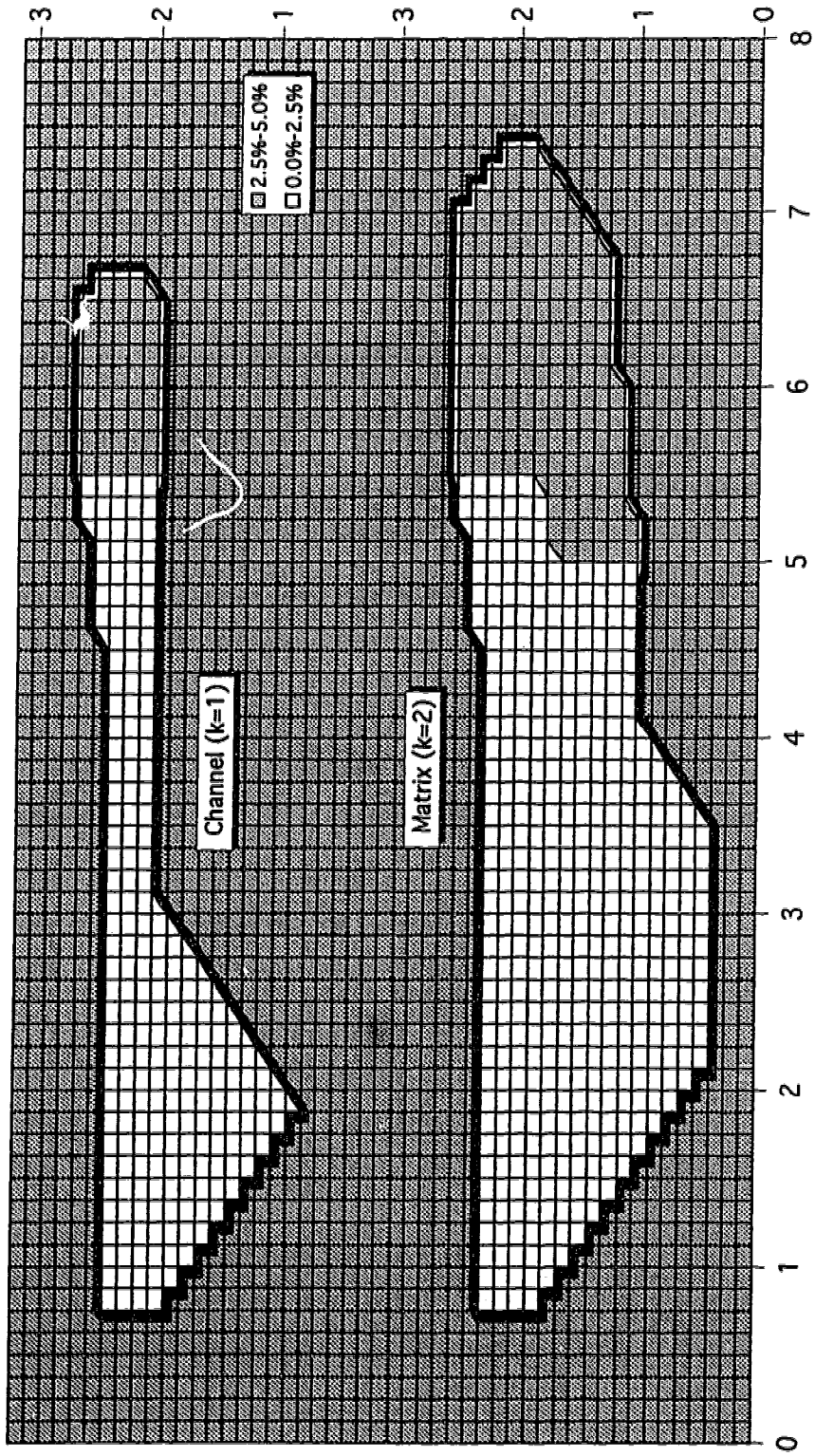



Figure 2.23(c): Initial (Nov-87) Gas Saturation $S_g$

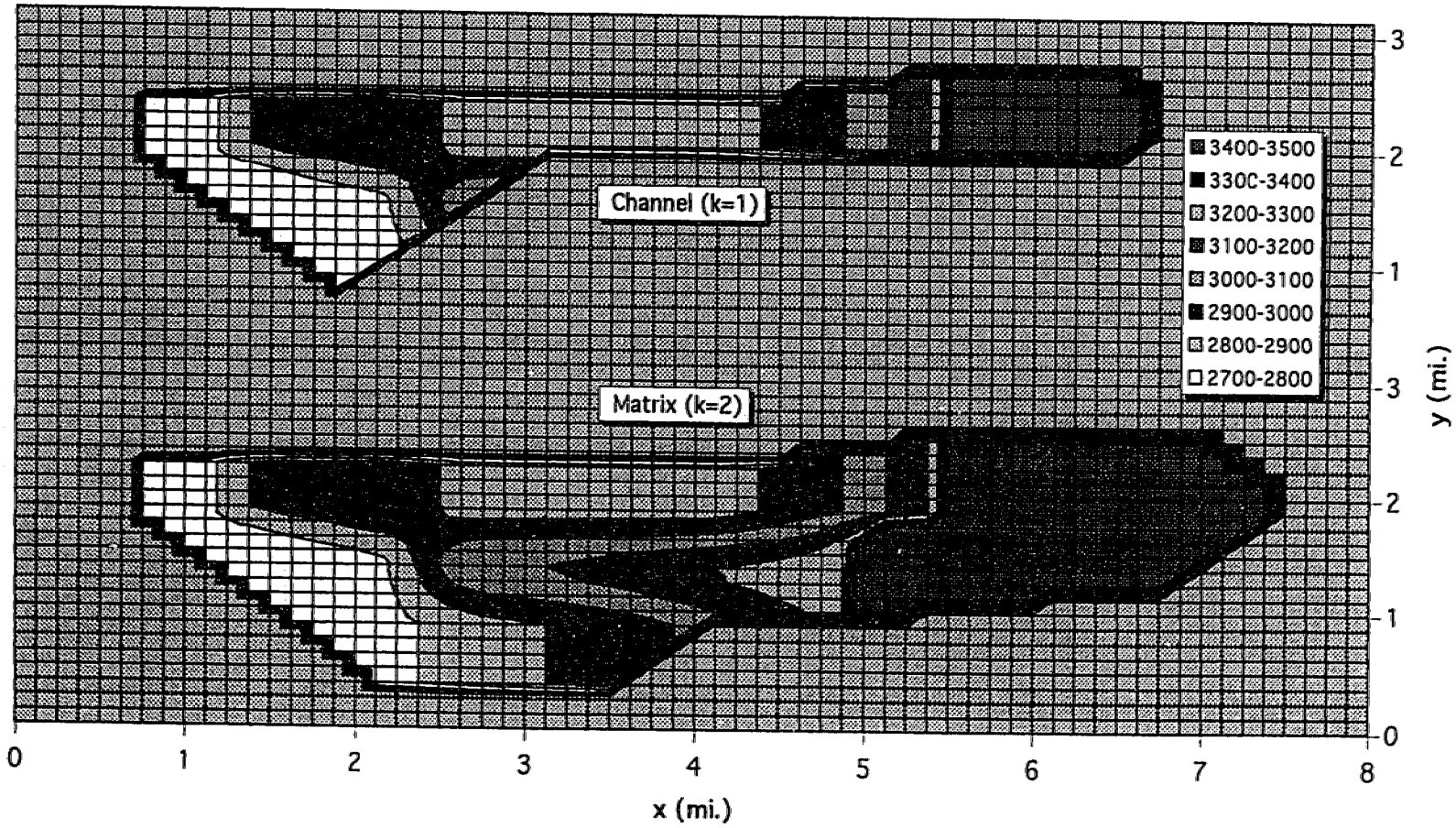



Figure 2.23(d): Initial (Nov-87) Bubble Point $p_b$ (psia)

# Chapter 3: Well Management System Model

## 3.1 Well Model

Production of reservoir fluids ($Q_o$, $Q_w$, $Q_g$) will cause the bottomhole pressure $p_{wf}(\mathbf{x})$ of flowing wells to drop below their static levels $p(\mathbf{x})$. This pressure drop will induce pressure gradients within the surrounding porous media. Transient pressure disturbances will propagate away from the flowing wells at a speed determined by the local reservoir characteristics and fluid properties. The intensity of the pressure disturbance will decrease with distance travelled and virtually vanish at some external drainage boundary. Some wells will coincide within the drainage radii of other wells and interference between pressure disturbances will take place. This interference will couple the pressure response between wells, such that changes in production at one well will effect the production in others. Unsteady flow will occur while the early transient propagates out to the external boundary. The pressure will be a function of both time and distance. The time between early and late transient arrivals at the external boundary will mark the period when transitional flow occurs. When the late transient reaches the external boundary, the system enclosed by the external boundary will behave like a tank (Donaldson *et al.* 1985). The flow will become pseudo-steady and the rate of pressure change will be independent of the location within the closed system. Well productivity will become a function of the average system pressure and stabilized inflow conditions will prevail.

The well productivity index (PI) relates standard flow rates ($Q_o$, $Q_w$, $Q_g$) with the pressure difference between external drainage boundary (p) and bottomhole pressure ($p_{wf}$). Analytical models have been proposed for various external boundary configurations considering unsteady, pseudo-steady, and steady-state flows. Peaceman (1978) used a single-phase steady-state radial flow model, relating well block pressures to flowing pressures at equivalent radii from block centers. The relationship has been extended to multi-phase flow using relative permeabilities.

$$Q_o(\mathbf{x}) = PI\frac{\lambda_o}{B_o}[p(\mathbf{x}) - p_{wf}(\mathbf{x})]$$

$$Q_w(\mathbf{x}) = PI\frac{\lambda_w}{B_w}[p(\mathbf{x}) - p_{wf}(\mathbf{x})]$$

$$Q_g(\mathbf{x}) = PI\left(\frac{\lambda_g}{B_g} + R_{so}\frac{\lambda_o}{B_o} + R_{sw}\frac{\lambda_w}{B_w}\right)[p(\mathbf{x}) - p_{wf}(\mathbf{x})] \qquad (3.1)$$

All well rates are explicitly, rather than implicitly, incorporated into the reservoir flow model described in Appendix A1. Grid block pressures are referenced at the contemporaneous reservoir state at time ($t^n$). Production from completion intervals are modeled as point sinks located in specific reservoir volume elements. Wells that penetrate multiple reservoir elements are approximated as a collection of point sinks. Injection wells are treated in the same manner as production wells. Total flows are distributed between grid blocks assigned to particular wells. For vertical wells, these blocks align vertically at different grid layers. Allocation of flow over multiple grid blocks depend on individual layer flow indexes. The layer production flow index (PI) has been estimated by Peaceman (1978) in terms of the areal grid block dimensions ($\Delta x$, $\Delta y$), wellbore radius ($r_w$), effective completion interval thickness (h), absolute permeability (K) and a skin factor (S):

$$PI(z;x,y) = \left. \frac{0.00708\, K\, h}{\ln\left(\frac{0.121\sqrt{\Delta x \Delta y}}{r_w}\right) + S} \right|_{(x,y,z)} \qquad (3.2)$$

The conversion factor in the numerator of Eqn (3.2) is consistent with the field units adopted in this work. All wells in the Chedderville Viking "A" pool are vertical. The wellbore radius ($r_w$) is approximated by the outer casing radius ($r_w$=5.5 inches) common to all well completion intervals. Wells fully penetrate the bottom layer of the two-layer reservoir model characterized in Section 2.8. The effective completion interval thickness (h) in the bottom layer is assumed to be the same as the mechanical perforation zone thickness ($\Delta z$). The absolute permeability (K) is assumed to be the local principal-axis maximum permeability ($K_x$). Skin effects are due to physical changes in the formation and restricted flow entry at the wellbore. The skin factor (S) accounts for the degree of well damage or stimulation, perforation effects, partial penetration effects, inclined wellbore effects and naturally occurring matrix fractures (Mattax and Dalton 1990). Positive skin factors (S>0) reflect the degree of flow restriction while negative skin factors (S<0) can be used to characterize a fractured or stimulated well. All wells in the Viking "A" pool have been initially stimulated by acidizing, and some wells by hydraulic fracturing. Therefore, skin effects are assumed to be negligible (S=0). A high-permeability top layer is incorporated in the simulation model to provide a channel mechanism for enhanced pressure communication within the reservoir. Only the gross channel functionality is modelled and well flow in this layer is assumed to be shut-in. The actual production from this thin zone is incorporated in the rock matrix layer below. The rock matrix layer implicitly accounts for both channel thickness and permeability through geometric averaging.

The well is a producer if the flowing bottomhole pressure is less than the reservoir pressure. There is no flow when the flowing bottomhole pressure is equal to the reservoir pressure and the well is assumed to be shut in at the static bottomhole pressure.

$$\begin{array}{ll} p > p_{wf} & \text{Production} \\ p = p_{wf} & \text{Shut in} \end{array} \qquad (3.3)$$

Similarly, the well is an injector if the flowing bottomhole pressure is greater than the reservoir pressure.

$$\begin{array}{ll} p < p_{wf} & \text{Injection} \\ p = p_{wf} & \text{Shut in} \end{array} \qquad (3.4)$$

Water injection rates are based on a layer well injectivity index (WI=PI) and total fluid mobilities (Franchi *et al.* 1982):

$$Q_w(\mathbf{x}) = WI \frac{(\lambda_o + \lambda_w + \lambda_g)}{B_w} [p_{wf}(\mathbf{x}) - p(\mathbf{x})] \qquad (3.5)$$

### 3.2 Surface Facility

Peak liquid production from the pool of wells will be limited by reservoir productivity and the design capacity of the facilities for gathering, separating and treating produced fluids. Separators are pressure vessels designed to separate multiphase fluids into constituent gaseous and liquid streams using flash vaporization. The number of flash separation stages will depend on feedstock composition, temperature and flowing pressures. The stock tank is one stage of separation. Stages are sized to operate most effectively under a narrow band of design pressures and temperatures. Facilities are sized according to the expectation of reservoir productivity and constraining economic criteria. Since pooled production changes with time, the optimum number of stages can also vary with time. In actual field practice, three stages are typically chosen (Chilingarian *et al.* 1986).

The CIM Petroleum Society Monograph No. 1 (1994) describes the risks associated with separator facility sizing. Ultimate reserves are established by an economic limit that depends on hydrocarbon price expectations, operating and capital costs, fiscal regimes and encumbrances such as royalties and net profit interests. Facility capital and operating costs have a direct impact on the ultimate reserves. A facility sized large enough to handle maximum production will have continued high operating costs when volumes decline. A large facility

operation may reach its economic limit earlier, with less reserves, than a smaller less-expensive operation that limits the production ceiling. The size of the facility determines the peak fluid production capacity of the entire operation. The ceiling on total fluid further constrains peak oil capacity, which declines with increasing levels of gas-oil and water-oil ratios. The circular argument in facility design can be resolved by staging modular satellites to handle increased production volumes. The economics of scale may be foregone in lieu of the benefits associated with timely expansion.

### 3.3 System Hydraulics

The stock tank fixes downstream pressure to atmospheric conditions. All upstream pressures, from bottomhole to the stock tank, must adjust to maintain production by overcoming the inertial, viscous, gravitational and interfacial forces that resist flow. A single-layer vertical well model is used to describe well flow behaviour at bottomhole conditions in the reservoir. System hydraulics couple bottomhole pressure to surface pressures through flow in tubings and casings, horizontal and inclined surface flow lines, and flow through restrictions and chokes (Chilingarian *et al.* 1986). Pressure drops will result in all stages from friction losses, changes in kinetic energy and hydrostatic head loss. Some stages may realize additional pressure drops from external work loss due to fluids driving a turbine. External work gains can also be introduced through pumps. The engineering design objective attempts to minimize pressure drops in each portion of the production system such that optimal flow conditions are achieved at maximum efficiency. The integrated system design between reservoir and surface facilities is highly complex and requires accurate relationships between flow rates and pressures.

Back pressures at different system stages are determined by pump and compressor capacities, and by downstream chokes and restrictions. Surface and bottomhole chokes are typically used to regulate flow. The multi-purpose function of the choke is to maintain set point flow rates; maintain sufficient back pressure to prevent sand entry; protect surface equipment; and prevent gas or water coning (Chilingarian *et al.* 1986). When choke flow is critical, changes in downstream pressure do not effect the flow rate or upstream pressure. Critical chokes essentially decouple the flow system at specific points.

In naturally flowing wells, the wellhead pressure ($p_{wh}$) typically regulates well outflow. Tubing and annulus performance relationships between flow rates and pressure depend on many factors including: temperature, gas-oil ratios, water cuts, fluid properties, interfacial surface tensions, inclination, depth, pipe diameter and pipe smoothness. Aziz *et al.* (1979) have generated gradient curves over a wide range of operating conditions. Hein (1982) gives a stepwise calculation for three-phase flow rates, pressure drops and gas holdup using

Beggs and Brill (1973) method. Calculations are based on multi-phase flow regimes that can occur over incremental segments that span the entire length of pipe. These flow regimes are:

- segregated (stratified, wavy and annular) flow
- intermittent (plug and slug) flow
- distributed (bubble or mist) flow
- single phase flow

Well-bore hydraulics can easily[8] be implemented into the reservoir simulator if the control variable is either the flowing bottomhole pressure or the flow rate. Three-phase fluid properties for viscosity, density, formation volume factors, gas solubility and interfacial surface tension should cover the complete range of pressures and temperatures that may occur over the length of the pipe. Pipe diameters, lengths, inclinations and wall smoothness should also be known. Flowing bottomhole pressures and well flow rates can be determined using Eqns (3.1)-(3.5) coupled with the reservoir flow model described in Appendix A1. Predicted bottomhole saturations can be used to calculate the free gas holdup at bottomhole conditions. With flow rates, bottomhole pressures and gas holdup calculated at each time step, the dynamic well head pressure response can then be predicted using Hein (1982) to explicitly calculate incremental flow regimes and corresponding pressure drops. If the well head pressure is the control variable, then the coupled system is somewhat more difficult[9] to solve for bottomhole pressure and flow rate response. This difficulty arises from the causality of incremental flow regimes. Flow rates must be known in advance to segment these flow regimes.

In pumping wells, artificial lift technologies are used to supplement natural flow with additional energy. The flowing bottomhole pressure ($p_{wf}$) can be related to the well head pressure ($p_{wh}$) through an energy or pressure balance:

$$p_{wf} = p_{wh} + \Delta p_h + \Delta p_f + \Delta p_{ke} - \Delta p_{pump} \qquad (3.6)$$

---

8 Results are not presented in this work to maintain scope. The author reports that trial attempts to implement wellbore hydraulics matched specific surface pressure data.

9 The author anticipates that an implicit solution with flow regime segmentation will be unstable and that an iterative shooting method with explicit pipe calculations should be considered.

Pressure drops are caused by head loss ($\Delta p_h$) resulting from fluid in the tubing, friction loss ($\Delta p_f$) resulting from irreversible work done, and inertial loss ($\Delta p_{ke}$) resulting from changes in kinetic energy. External pump work ($\Delta p_{pump}$) can induce a pressure gain in the flow field. For the pump to be effective, it must provide enough external energy to lift liquids to the surface and maintain the well head pressure set point designated by downstream surface operations. This simply implies that the pump will make up the difference between the natural energy within the reservoir, as determined by grid block pressure (p), and the energy required for separating fluids on the surface, as determined by the well head pressure ($p_{wh}$).

There are six mechanisms for artificially-induced fluid flow:

- centrifugal force
- volumetric displacement
- mechanical impulse
- momentum transfer
- electromagnetic force
- gravity

Pump designs in the petroleum industry are commonly based on the action of centrifugal force and volumetric displacement by mechanical means or by another fluid. Gas lift systems inject high pressure gas down tubing or casing eductors to lift well fluids by gas expansion, fluid column aeration and fluid displacement. Plunger lift systems use gas lift with a free travelling mechanical piston to separate lifted oil. Sucker-rod pumps use string-connected plunger-barrel devices that provide positive displacement on the upstroke. Subsurface hydraulic pumps are downhole devices powered by high-pressure fluids directed from the surface. Positive displacement piston pumps are driven by a hydraulic reciprocating subsurface engine. Jet pumps directly transfer momentum from the power fluid to the working fluid. Electric submersible pumps are multistage centrifugal devices.

The overall pump efficiency is determined by the ratio of useful hydraulic work performed to the input work required to operate the device (Chilingarian *et al.* 1986). The amount of useful work is the product of flow rate capacity with the pressure head differential between inlet and outlet ends. For the pump to operate efficiently at design capacity, its suction end should be within the fluid column below the producing level. Pumping will draw down static fluid levels. Fluid pump-off can occur if the drawdown rate exceeds the well inflow rate over a given period of time. A minimum fluid level above the pump placement is required for uninterrupted operation. The height of fluid flowing in the well depends directly on the flowing bottomhole pressure. Gas locking can also

occur when the intake pressure falls below the bubble point pressure. Cyclic loading of free gas and fluid slugs can lead to erratic behaviour and inevitably lead to shut down. The pump should be chosen in advance to match the inflow characteristics of the well. Operations should strictly adhere to a minimum flowing bottomhole pressure constraint, if remedial actions are to be avoided. Remedial actions could involve a well stimulation treatment to increase well productivity, pump modification or replacement, lowering pump setting depths or reducing the production rate with a surface choke. Excessive solids such as sand, scale and weighted mud debris require special attention. Pumps may have to operate below rated capacities to avoid entraining these solids.

The current state of primary production operations in the Chedderville Viking "A" pool is defined on the calendar date of October 1, 1994. At this time, some wells are flowing naturally into a satellite battery gathering system while others are being individually pumped. The simulation model assumes that all current and future production wells are fitted with downhole pumps, each capable of producing at a maximum capacity of 500 barrels per day with a minimum bottomhole pressure constraint of 800 psia.

$$\begin{aligned} Q_o &\leq Q_o^{max} = 500\ \text{STB/day} \\ p_{wf} &\geq p_{wf}^{min} = 800\ \text{psia} \end{aligned} \tag{3.7}$$

The maximum oil flow rate[10] was estimated as the global maximum observed over the entire pool of well production histories. The minimum bottomhole pressure constraint was determined through history matching production and pressure data under historical monthly-averaged flow rate specification. The assumption of pumping wells decouple reservoir flow from well-bore flow, such that the flowing bottomhole pressure becomes the control variable and the pump work becomes a slack variable. The overall production system can be sufficiently determined by the well model in Eqns (3.1)-(3.5), coupled with the reservoir flow model described in Appendix A1, under rate or flowing bottomhole pressure constraints. These production constraints are expressed for oil rate control as:

$$0 \leq Q_o \leq \min\left( Q_o^{max}, PI \frac{\lambda_o}{B_o} [p - p_{wf}^{min}] \right) \tag{3.8}$$

---

10 In retrospect, a more appropriate flow constraint would limit the maximum liquid production including water from future waterflood operations. The exclusion of water in the well maximum capacity constraint turned out to be innocuous under the additional constraints for flowing bottomhole pressure and water-oil ratios.

and for flowing bottomhole pressure control as:

$$\max\left(p_{wf}^{min}, p-\frac{B_o}{PI\,\lambda_o}Q_o^{max}\right) \le p_{wf} \le p \tag{3.9}$$

Peak water injection will be limited by reservoir injectivity and the design capacity of the injection system and water source. The simulation model assumes that all future water injection wells are each capable of injecting at a maximum design capacity of 800 barrels per day with a maximum bottomhole pressure constraint of 7000 psia.

$$\begin{aligned} Q_w &\le Q_w^{max} = 800\ \text{STB/day} \\ p_{wf} &\le p_{wf}^{max} = 7000\ \text{psia} \end{aligned} \tag{3.10}$$

The bottomhole pressure constraint was chosen to limit an assumed reservoir parting pressure. These waterflood constraints are expressed for water injection rate control as:

$$0 \le Q_w \le \min\left(Q_w^{max}, WI\frac{[\lambda_o+\lambda_w+\lambda_g]}{B_w}[p_{wf}^{max}-p]\right) \tag{3.11}$$

and for flowing bottomhole pressure control as:

$$p \le p_{wf} \le \min\left(p_{wf}^{max}, p+\frac{B_w}{WI\,(\lambda_o+\lambda_w+\lambda_g)}Q_w^{max}\right) \tag{3.12}$$

### 3.4 Regulatory Rate Constraints

Regulatory constraints may limit monthly oil and gas production. In Alberta, monthly allowables are assigned for each well, individually or in aggregate, by EUB, formerly known as the Energy Resources Conservation Board (ERCB). This government agency is empowered by provincial statutes to regulate responsible development and enforce penalties to discourage unauthorized overproduction. Production limits on specific pools, and enhanced recovery projects, are established by the Board's assessment of conservation, equity and environmental impact. The Allowables Handbook (ERCB) describes the accounting system for calculating monthly production allowables. The allowables system is structured on a base maximum rate limitation (MRL) that assigns the daily rate for a single well and a base gas-oil ratio (GOR). Both

bases are published in the MRL Order (ERCB) several days prior to the month in which it applies. For Chedderville Viking "A", the single well base MRL, and the base GOR, have remained constant for all wells, from the initial calendar date (1-Nov-1987) to the current date (1-Oct-1994).

$$\begin{aligned} \text{Base MRL} &= 88 \text{ STB/day} \\ \text{Base GOR} &= 1.129 \text{ Mscf/STB} \end{aligned} \tag{3.13}$$

Monthly base allowables are calculated on the basis of cumulative monthly production over the calendar days in a specific month.

$$\begin{aligned} \text{Base Oil Allowable} &= \text{Base MRL} \times \text{days in month} \\ \text{Net Gas Allowable} &= \text{Base GOR} \times \text{Base Oil Allowable} \end{aligned} \tag{3.14}$$

The intention of the net gas limitation is to maximize primary oil recovery by conserving solution gas and to discourage excessive flaring or waste. GOR penalty factors are introduced to limit the monthly net gas produced. Gas credits are awarded for GOR penalty relief when gas is gathered, or used as lease and battery fuel, rather than flared. The monthly net gas produced is calculated as the total monthly gas produced, less gas gathered, less gas used as lease or battery fuel. The net gas allowable is the amount of produced gas that can be flared on a monthly basis, without incurring a penalty. A produced GOR is calculated as:

$$\text{Produced GOR} = \frac{\text{Gas Produced} - \text{Gas Gathered}}{\text{Oil Produced}} \tag{3.15}$$

GOR penalty factors reduce the monthly oil allowable. No GOR penalty factors apply when the producing GOR is below base GOR, otherwise, the penalty factor decreases the base oil allowable proportionately with the excess of producing GOR over the base GOR. The adjusted MRL is referred to as the penalized MRL.

$$\text{Penalized MRL} = \frac{\text{Base GOR}}{\text{Produced GOR}} \text{ MRL} \tag{3.16}$$

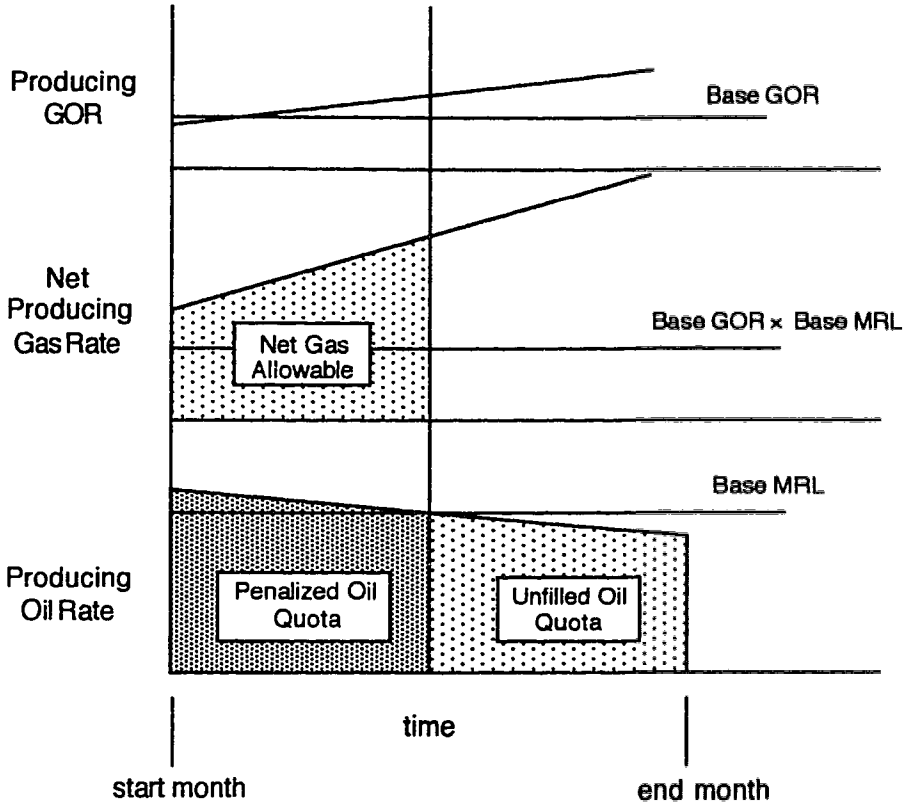



Figure 3.1: Monthly Rate Limitations

Figure 3.1 illustrates the effect of monthly rate limitations. In essence, the base allowable and base GOR set monthly quota ceilings[11] on cumulative oil and cumulative net (flared) gas that can be produced over monthly cycles. Gas production takes precedence and penalizes oil production if it reaches its quota ceiling first. When this occurs, the unfilled portion of the allowable oil quota is foregone for that month. The temptation to cheat and overproduce is quickly extinguished by the overproduction penalty structure. All penalties are payable in oil. A monthly overproduction pe[illegible] is assessed at 50% of the volume in

11 The current month's penalized MRL is calculated using the GOR penalty factor from the third preceding month. Other details involving off-target penalties are also involved. New wells have modified calculations over the first four months of production. These details essentially change the ceiling on monthly quotas by varying degrees. For simplicity, it is assumed that no off-target penalties apply and that the penalized MRL can be approximated using the current month's GOR penalty factor.

excess of 110% of the adjusted oil allowable. Monthly over- or under-production, and the monthly overproduction penalty, is added to a cumulative production status. A further 20% cumulative status penalty is assessed for each month that the overproduction status remains above 10% of the adjusted MRL for three consecutive months. This penalty also accumulates with the overproduction status. ERCB expects operators to retire[12] overproduction by reducing production levels below penalized MRL until the cumulative status reaches zero. Prolonged overproduction can lead to the well being shut in by law.

Base MRL and GOR can also be assigned to a block of wells in aggregate, and to enhanced oil recovery projects. The pooled production from the block of wells, and recovery projects, are subject to same overproduction penalty structure as described for a single well entity. Some operations can be assigned a good production practice standing, which is not governed by base allowables, but is subject to discretionary production without adversely affecting conservation.

### 3.5 Control Strategy

Ramirez (1987) gives a thorough treatment on the application of optimal control theory to enhanced oil recovery projects. He uses Pontryagin's Maximum Principle (Pontryagin *et al.* 1962) to solve a class of optimal control problems that determine control policies which extremize specific performance criterion. Performance criteria assume a deterministic economic model using net present value with discounted cash flows. Of particular interest in his book, is the discrete maximum principle applied to the same black oil simulation model described in Appendix A1. Mehos (1986) first formulated the implicit discrete necessary conditions for an adjoint costate model with transversality equations. Profit maximizing injection policies were found for simulated cases of a single five-spot pattern with water and carbon dioxide injection. State variables were defined as the contemporaneous ($p$, $S_o$, $S_g$) for each volume element in the reservoir grid. A control vector was defined in terms of the flowing bottomhole pressure ($p_{wf}$) for production grid blocks and injection rates ($Q_w$, $Q_g$) for injection grid blocks. The discrete costate model had the same finite difference form as the original state equations that describe multi-phase porous media flow. An iterative computational technique was used to solve the system of two-point boundary valued difference equations. State equations were integrated forward in time to forecast production. Costate equations were then

---

12 Suspended wells have no allowable but must carry forward over-production. Wells should retire overproduction before they can officially be suspended.

integrated backward in time in order to satisfy a terminal transversality boundary condition. An initial guess of optimal controls were recursively refined in a gradient direction determined by the costate equations. A single variable search along the gradient direction was used to find the maximum local improvement in the performance function.

The problem of interest in the present work incorporates a probabilistic economic model for the timing valuation of recovery options. Project value is modeled to depend on time, the state of oil price, the state of depletion and an implemented depletion strategy. The depletion strategy consists of waterflood design and investment timing decisions. It also facilitates control decisions in both primary and secondary operations under regulatory constraints. Waterflood response has a causal dependence on the primary depletion state. The branched differential decision process uses dynamic programming techniques, based on the principle of optimality (Bellman 1957), to find investment and operating decision rules that maximize project value. Branched production forecasts are calculated on the basis of the current primary configuration and a fixed waterflood design with heuristic control strategies. The waterflood design is refined manually to improve potential response at a fixed primary depletion state in a feasible waterflood window. Price sensitive investment decision rules are then found for the fixed waterflood design at different primary depletion states, and times, over the life of the project. Further implementation of the discrete maximum principle to iteratively determine nested optimal control policies in a branched decision process would be computationally prohibitive. The degrees of freedom would explode combinatorially!

The control policy adopted for the depletion strategy of Chedderville Viking "A" is based on a more heuristic approach with design-based decisions. This is not necessarily the best policy, but it does reflect actual field decisions. The model chooses not to overproduce under primary MRL regulation. All produced gas is flared rather than gathered. Primary operations assume that the current single well MRL and GOR will continue for another year. High gas-oil ratio producers are designated to be shut-in at the end of that year. The remaining wells are reclassified under a new block MRL status and reassigned with an aggregate primary MRL based on the sum total of original single well MRLs. The current single well GOR is applied to the new pooled aggregate. At this time, a ten year window for pattern waterflood is assumed to open up. This timing window corresponds to the admissible depletion states remaining in the twenty year life planned for primary production. Good production practice is assumed to apply for a twenty year pattern waterflood. The practice chooses to initially limit aggregate oil and gas production, and allow water injection to repressurize the reservoir above the bubble point pressure. Water injection is maintained at maximum admissible rates for the duration of the project.

Individual wells are regulated independently from a pooled aggregate while they operate above the bubble point pressure. Well workovers and installation of new equipment are assumed not to interrupt production continuity, and are implicitly scheduled over monthly production cycle downtimes.

### 3.6 Well Spacing

Many wells will produce from the same reservoir pool. As new wells are drilled and go online, they will be continually controlled at design rates and pressures to accommodate bottomhole conditions, downstream flow conditions and regulatory constraints. The placement and number of wells will have design criteria based on both economic and reservoir engineering foundations. In theory, a single well can drain all the moveable oil from a pool given a sufficiently large time. As the well is produced, the pressure gradient established in the reservoir will move out towards the physical boundaries. The production rate will decline proportionally with the decline in average reservoir pressure. Additional wells will accelerate both pooled production and the decline in average reservoir pressure. Pressure gradients from wells that are close together will generally interact sooner than those far apart. When well pressure gradients interact, the effective drainage area per coupled well will be reduced, and consequently, the oil recovered per coupled well will also be reduced. The design production well spacing should attempt to delay interaction between pressure gradients for as long as possible. Each additional well will provide a varying degree of acceleration to the pooled production revenue. Single well contributions to pooled production will generally diminish as the well spacing exceeds a critical density. The optimum number of wells can be determined by the net incremental value of oil recovered by adding each additional well. The expected incremental value will depend on cash flow forecasts based on predicted production, price models and well costs. This is not an easy problem to solve. Even if oil prices were known with certainty, and the reservoir was characterized exactly, the optimal placement, timing and subsequent control of wells using the discrete maximum principle (Mehos 1986, Ramirez 1987) would require a control vector whose dimension would be several factors of the grid partition. This could prove to be computationally prohibitive for a field-wide application.

In practice, regulations constrain the minimum well spacing to regular production spacing units on an areal grid. Initially, new wells are drilled to delineate reservoir boundaries according to the geological and geophysical expectations of oil rich zones. Infill drilling programs may attempt to tap the more productive zones first, as more information becomes available about reservoir structure, characteristics and trends. These programs will consider drilling blocks of infill wells according to the expected economic benefits.

## 3.7 Primary Control Policy

Wells may be independently, or collectively, toggled[13] on and off between maximum admissible rates established by well productivity and no-flow shut-in states. Monthly production cycles can be as short as a few days of continuous operation in order to adhere with the quotas established by regulatory authorities. Wells can also be regulated at intermediate rates for longer hours of monthly production to satisfy the same constraints. The choice in control may effect the long term recovery by effecting oil production in the short-term.

The choice between high rate (short pulse) and intermediate rate (longer bandwidth) production cycles may affect producing gas-oil ratios. This choice in control can affect the monthly cycle productivity by manipulating unfilled oil quotas. Figure 3.2 illustrates how the producing gas-oil ratio ($\overline{GOR}$) effects unfilled monthly oil quotas. When the oil production rate ($\overline{Q}_o$) is above the base MRL, the time to fill the monthly oil quota ($\tau_o$) will be less than the calendar days in the month. When the producing $\overline{GOR}$ is above the base GOR, the time for gas to fill its monthly quota ($\tau_g$), at a rate of $\overline{GOR} \times \overline{Q}_o$, will be less than the time ($\tau_o$) for oil.

$$\int_0^{\tau_o} \overline{Q}_o dt = MRL \times (month_{end} - month_{start})$$

$$\int_0^{\tau_g} \overline{GOR} \times \overline{Q}_o dt = GOR \times MRL \times (month_{end} - month_{start})$$

$$\Delta t_{produce} = \min(\tau_o, \tau_g) \qquad (3.17)$$

If the oil rate remains constant over the monthly production cycle, then the unfilled volume of the oil quota foregone will be $\overline{Q}_o \times (\tau_o - \tau_g)$. An optimal control policy, under regulatory MRL and GOR constraints, would attempt to minimize the producing gas-oil ratio, so that well productivity could fill the monthly oil quota up to its ceiling.

---

13 This is bang-bang control when switching between extremal control states.

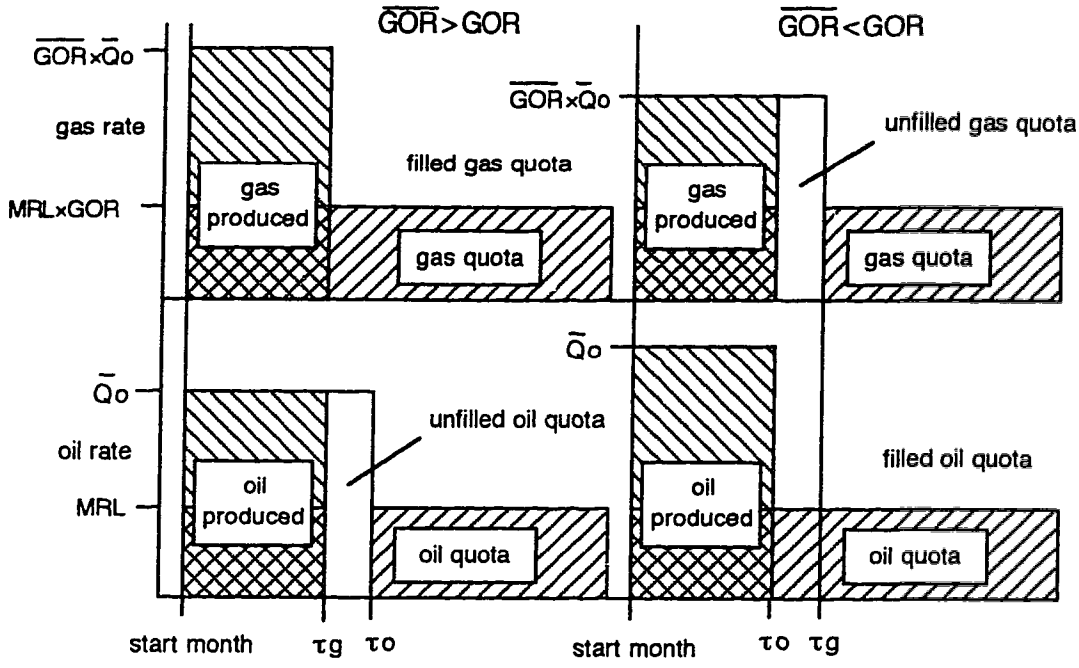



Figure 3.2: Producing GOR Effects on Unfilled Oil Quota

The producing gas-oil ratio depends on the reservoir state (p, $S_w$, $S_g$) in the well grid block.

$$\overline{GOR}\ (p,S_w,S_g) = R_{so} + R_{sw}\frac{\lambda_w B_o}{\lambda_o B_w} + \frac{\lambda_g B_o}{\lambda_o B_g} \qquad (3.18)$$

These states are coupled by the reservoir flow model described in Appendix A1. The producing gas-oil ratio will inevitably increase as free gas evolves from solution. Primary control under MRL regulation will only delay the inevitable. Independent control of single wells may inadvertently change the reservoir state for other wells. The system is coupled and the ensemble of wells should be orchestrated in unison.

When the producing gas-oil ratio is below the base GOR, the minimum set point rate should be chosen as the base MRL. The selection between maximum admissible or MRL set point rates is inconsequential as long as the cumulative monthly oil production meets the monthly allowable oil quota. If well productivity cannot sustain the MRL set point, then the control rate should be the maximum admissible rate under pumping or flowing conditions. Maintaining MRL or lower set point rates will ensure production continuity without toggling the well off.

Higher than MRL set point rates will lead to cyclic transitions between on and off states as allowable quotas are met. Monthly production bandwidths will get shorter as the rate increases. A limiting minimum bandwidth is determined by the maximum admissible rate. Long production intervals, with intermediate or low set point rates, may not necessarily be the best course of action. The inappropriate choice in rate control may prematurely fill the well block with a dominating free gas saturation.

The primary control policy proposed in this work is based on bubble point pressure hysteresis. The following causal argument assumes saturated oil conditions in the well block which is characteristic of higher producing gas-oil ratios. Well blocks are assumed to be outside of the gas cap. When the well starts its production cycle, the reservoir block pressure falls below its static level, and free gas differentially evolves from solution. Mobile free gas will be produced, along with dissolved gas in oil, at the set point rate. Free gas and reservoir liquids will flow from adjacent grid blocks under induced pressure gradients. In the absence of other wells, a pseudo-steady flow will quickly stabilize over an initial transitionary period[14]. The local free gas saturation will fall if the sustained gas production rate is greater than the combined rates of free gas evolution and migration from surrounding blocks. The local bubble point will drop and adjust to the new vapour-liquid ratio within the producing well block. When the well is shut at the end of its production cycle, the local grid block pressure will rise back to a new static level. Vapour-liquid equilibrium will be reached and free gas evolution will stop. Pressure gradients will diminish and gas migration will halt. The vapour-liquid ratio will remain at the new level established by the adjusted bubble point. For this tight reservoir, it is assumed that the rate of inter-block free gas migration, outside of the gas cap, is small with respect to the local rate of free gas evolution.

$$\left.\frac{\partial}{\partial t}\left(\phi\frac{R_{so}S_o}{B_o}\right)\right|_{ijk} >> \left.\nabla\cdot\bar{K}\cdot\left[\frac{\lambda_g}{B_g}\nabla(p + p_{cgo} - \rho_g g z)\right]\right|_{ijk} \qquad (3.19)$$

Bleeding gas at low set point rates will allow differential gas evolution to balance produced gas volumes, and thereby have little effect on the local bubble point.

$$\left.\Delta\left(\phi\frac{R_{so}S_o}{B_o}\Delta x\right)\right|_{ijk} \approx Q_g|_{ijk}\,\Delta t_{produce} \qquad (3.20)$$

---

14 This transitionary period (Dake 1978) was estimated at less than a day .

The next cycle will start at a lower static grid block pressure, and an increased gap between local bubble point and static grid block pressures will persist. Higher set point rates will cause larger pressure swings with shorter production bandwidths. Pressure swings will initially cause free gas to evolve from solution. If, for the same pressure swing, the gas production rate is higher than the gas evolution rate,

$$\Delta(\phi \frac{R_{so} S_o}{B_o} \Delta x)\Big|_{ijk} < Q_g|_{ijk} \Delta t_{produce} \qquad (3.21)$$

then the local vapour-liquid ratio will decrease. This can occur if production is more responsive to pressure than free gas evolution is to pressure. This implies that the local bubble point pressure for larger pressure swings will drop to lower levels than those resulting from smaller pressure swings. If a fixed volume of fluid is produced over comparable pressure swing cycles, then grid block pressures will be approximately the same after a stabilization period at the cycle end. Bubble point pressures, however, will lock onto different levels. The next cycle will start at a lower static grid block pressure and a lower local bubble point that corresponds to a reduction in the local gas-oil ratio. The gap between local bubble point and static grid block pressures will still persist, but will be less for larger pressure swings than for smaller ones. In this manner, a bang-bang control policy producing at the maximum admissible rate with short monthly pulses can delay higher producing gas-oil ratios.

The proposed primary control policy was tested with the simulation model for the first year of primary production forecasting. It did delay higher gas-oil ratios and was adopted throughout the remaining forecasts. An accounting system was used to regulate oil and gas production. Explicit time steps were set to coincide with individual well production cycles. Wells were toggled on and off between maximum admissible rates established by well productivity (Eqns 3.7-3.9) and no-flow shut-in states. Monthly production accounts were accumulated for each well to satisfy MRL and GOR regulatory constraints.

### 3.8 Secondary Control Policy

Primary operations assume that the current wells will continue to produce for another year with the exception of those in the developing gas cap. High gas-oil ratio producers are designated to be shut-in at the end of that year, and a ten year timing window for pattern waterflood is assumed to open up. The primary state of the reservoir over the waterflood timing window is assumed to be saturated with rising levels of free gas. Good production practice is assumed to apply for a twenty year pattern waterflood.

The practice chooses to initially limit aggregate oil and gas production, and allow water injection to repressurize the reservoir above the bubble point pressure. Water injection is maintained at maximum admissible rates for the duration of the project. If fluid production is not managed in the early phase of the waterflood, average reservoir pressures may continue to decline as a result of imbalances between water injection and fluid production rates. Declining pressures would free more gas from solution. Waterflood energy would then be expended on recompressing free gas instead of displacing an oil bank. This inefficiency would render the waterflood to be virtually ineffective. Oil mobility will decrease in the presence of increasing free gas and water saturations. In contrast, gas mobility will increase with increasing free gas and water mobility will increase with increasing water. The piston-like displacement efficiency of the waterflood sweep depends on the mobility ratio between water and oil (Willhite, 1990, p87-89). Under waterflood pressure, injected water would start to expand and flow towards producing wells. An oil bank would form as it gets compressed ahead of the water front. The leading oil would have a maximum mobility in the absence of free gas. This would occur at the bubble point pressure. Further compression above the bubble point would direct waterflood energy into accelerating the displacement process through heightened pressure gradients. The theoretical limit of waterflood efficiency would be determined by the residual oil saturation and the three-dimensional sweep in both vertical and horizontal directions.

The secondary control policy for Chedderville Viking "A" is based on these physical mechanisms and an implicit utility function specific to corporate demands. Waterflood injection capabilities are limited by the pattern design, well injectivities, design capacity of the injection system, surface water source and reservoir characteristics. A fixed waterflood design may exhibit fluctuations in water injection rates and pressures. Injection rates will initially drop as radial flow fronts from point sources interact with reservoir fluids in the surrounding porous media. Injection rates will then rise as water displaces or dissolves free gas and fills its pore space. Injection rates will continue to rise until water breaks through at adjacent producing wells. After water breakthrough, injection rates will fall as the reservoir floods out with increasing pressure. As high water-oil producers are shut in, underground water flows will be diverted towards other producing wells. The choice in water injection set point rates are assumed to be weakly subject to explicit operating costs. Injection operating costs are assumed to be implicitly lumped with overall production operating costs. The choice in waterflood injection rates, over the admissible range, are only based on advanced timing, or acceleration of the production revenue stream. Higher injection rates will hasten oil displacement and accelerate production revenues. Higher injection rates will also initiate earlier water breakthrough times and subsequent advances in rising water-oil ratios. The premise that production revenues should come sooner than later, fixes injection rate setpoints to those

maximum admissible for individual injection wells.

The choice in production rates is not as obvious as the choice in injection rates. One extreme would be to shut in all producers, until the reservoir is repressured above the bubble point, and then regulate production to maintain undersaturated bottomhole conditions. This strategy has flaws. Shutting in all producers will eliminate production revenues over the repressurization period, which may be measured in years. Water may also advance through the top high permeability channel and saturate the rock matrix below. This would interfere with the formation of an oil bank ahead of the water front when producing wells are open to flow. The other extreme would consider producing at maximum admissible rates under the good production practice umbrella. This, however, would prove to be a futile waterflood effort and lead to similar recoveries as observed in primary production.

The problem at hand is to choose production rates that balance corporate head office's demand for an uninterrupted revenue stream with a control policy that ensures repressurization without channelling water. The challenge was met with a compromise solution. All wells operating with saturated bottomhole conditions[15] were pooled into one control group, while the remaining wells were treated as single control entities. Single control entities were continuously produced at maximum admissible rates while local bottomhole conditions remained undersaturated. Single control entities were reclassified and demoted to the aggregate control group, when the entity's bottomhole condition switched from undersaturated to saturated. The aggregate control group was assigned an in-house MRL and GOR that satisfied both utility demands and repressurization objectives. The in-house MRL and GOR assignments were established on the basis of an implicit utility function. It was assumed that corporate head office would demand an initial waterflood revenue stream to be at least as much as that expected from continued primary production. The group was controlled in the same bang-bang manner described for primary control in Section 3.7. Wells that repressured above the bubble point were promoted to single control entity status and allowed to produce at maximum rates. Individual production wells were regulated over the course of waterflood, either independently or within a group, to attain the objectives set forth.

---

15 Local bottomhole conditions depend on whether the reservoir pressure is above or below the local bubble point in the well grid block.

# Chapter 4: History Match

## 4.1 Historical Controls

Historical controls for Chedderville Viking "A" may or may not have been based on a control strategy. These controls would have reacted to the actual conditions encountered during operation. The decisions would have been based on timely information about well particulars. This information would be confidential and not available to the general public. The following account of historical control is an interpretation deduced from historical production data listed in Table 4.1. Historical data indicates that decision-makers were using ad-hoc controls.

New wells have a grace period of four months before MRL regulation kicks in. Rates and monthly bandwidths were adjusted over this initial trial period to determine production response. Pumps were most likely installed in some wells. Most wells were initially operating at undersaturated bottom-hole conditions. Producing gas-oil ratios were below the base GOR. High gas-oil ratio wells were encountered in a developing gas cap. These wells were choked back to produce at lower oil rates so that gas production would stabilize within allowable limits. Reservoir pressures declined as more wells were produced. Jumps in producing gas-oil ratios signalled the sudden release of mobile free gas as bottomhole pressures dropped below local bubble point pressures. This occurred sequentially down the east-west dip of the pool. Daily oil rates were eventually set at intermediate levels with intermediate monthly bandwidths. Cyclic controls reacted to conditions encountered in the field. Stabilized gas rates were managed while monthly oil production declined. Historical data highly correlates monthly gas production with the net gas allowable, indicating that produced gas was flared and not gathered. Historical data also highly correlates monthly oil production with the net oil allowable, indicating that decision makers adhered to MRL regulations. The observed decline in oil production is interpreted as a consequence of the control choices made to satisfy regulatory constraints and not the decreased well capabilities associated with reservoir pressure decline. It is conjectured that maximum admissible rates are above current producing levels and that physical production ceilings will remain higher for some time before the actual pressure decline becomes the limiting factor.

## 4.2 Simulation Controls

A base time step was fixed at ten days to ensure numerical stability. The instantaneous set point oil rate for each well was fixed at historical monthly averages for set point durations fixed at historical monthly hours of operation.

Consecutive time steps were determined using an accounting system. Explicit time steps were set to coincide with individual well production cycles. All producing wells were turned on and monthly production counters set to zero at the beginning of each monthly cycle. Consecutive time steps were marked by the minimum between the base time step, remaining time for the monthly accounting cycle and the remaining durations over all wells. Gas produced by individual wells over each time step was accumulated in corresponding counters. Relevant wells were toggled off and the next step initiated. Cycle-averaged gas rates were calculated for each well by dividing accumulated monthly gas by the hours of production. Cycle-averaged gas rates were recorded for the current month at the end of the monthly cycle. Calendar time was used for each month. Instantaneous aggregate pool production rates and average reservoir pressure were recorded at each time step. Instantaneous bottomhole pressures for each well were also recorded at each time step.

## 4.3 Simulation Results

Table 4.2 lists the final results for simulator matched gas production, for the given schedule of monthly oil rates and hours of operation, obtained at the end of the iterative modelling process undertaken for this project. Figures 4.1(a)-(n) show the fit between historical gas production data and simulation matched results for 14 individual wells in chronological order. The second well 06-15-37-7W5 in the developing gas cap could not be fit with this model and was toggled off midway through the simulation. Most gas matches were adequate to good. Diverging results for 14-09-37-7W5 and neighbouring wells in 1993 were attributed to the pressure disturbance that occurred when the lower Mannville perforation zone was shut in. Figures 4.2(a)-(n) show the fit between historical pressure data and simulation predicted results for instantaneous reservoir pressure and flowing bottomhole pressure. The second well 06-15-37-7W5 pressures could not be fit with this model, but the remaining wells showed good matches. The bottomhole pressure spikes represents the cyclic response to bang-bang rate controls.

Figure 4.3(a) shows a general decline in average reservoir pressure starting in 1990. Figure 4.3(b) shows the cumulative gas production match for the entire pool. Large initial deviation is a result of the poor fit for 06-15-37-7W5. Figure 4.3(c) shows are good fit when the first two wells in the developing gas cap are excluded. Figure 4.4(a) shows the simulated instantaneous pooled oil production rate from the reservoir. Pooled monthly production cycles correspond to the sum of individual well cycles at different rates and different duration bandwidths. Figure 4.4(b) shows similar behaviour for pooled instantaneous gas production rates. The actual instantaneous oil and gas rate behaviour may or may not resemble simulated results. Bottomhole pressures were probably the set point control and oil production rates were allowed to

vary over production cycles. The assumption that individual production cycles started at the beginning of each month and were sustained for a single band may also affect the shape of these curves. These details could not be verified with the information made publicly available.

Figures 4.5(a)-(e) show the simulated current reservoir depletion state at the end of the history match period. The central pressure disturbance is highly visible in Figure 4.5(a). No changes are observed in the water saturation distribution in Figure 4.5(b), which is to be expected for a reservoir with no initially mobile water zone. Figures 4.5(c)-(e) show the oil saturation, gas saturation and bubble point pressure distributions. The initial gas cap is observed to have grown, with a new free gas zone beginning to develop in the thickest portion of the lower reservoir.

## 4.4 Calibration Summary

The reservoir description and black oil simulation model gave a reasonable match for the overall pool performance. Wells in the vicinity of gas cap and central pressure disturbance could not be adequately modelled throughout the historical seven year period. These wells were 06-15-37-7W5, 14-09-37-7W5 and 16-09-37-7W5. The remaining eleven wells showed satisfactory to good fits for both pressure and gas production. These wells are located in the oil rich zone which is designated for pattern waterflood. The history match validated the model to an acceptable degree. The model is assumed to provide reliable forecasts for future production in the lower portion of the reservoir.

| | Well Battery | 16-09-37-7W5 16-09-37-7W5 | | SINGLE | | Well Battery | 05-15-37-7W5 06-15-37-7W5 | | SINGLE | | Well Battery | 08-13-37-8W5 06-13-37-8W5 | | SATELLITE | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Casing | Depth (ft) | Dia (in) | Wt (lb/ft$^3$) | | Casing | Depth (ft) | Dia (in) | Wt (lb/ft$^3$) | | Casing | Depth (ft) | Dia (in) | Wt (lb/ft$^3$) | |
| | Surface | 1337.6 | 8.6 | 2.23 | | Surface | 1325.5 | 9.6 | 3.35 | | Surface | 1379.6 | 9.6 | 3.35 | |
| | Prod | 8759.8 | 5.5 | 2.23 | | Prod | 8579.4 | 5.5 | 2.23 | | Prod | 9186.4 | 5.5 | 2.23 | |
| Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | |
| Oct-87 | | | | | Oct-87 | | | | | Oct-87 | | | | | |
| Nov-87 | 477 | 38.2 | 34.8 | 0.0 | Nov-87 | | | | | Nov-87 | | | | | |
| Dec-87 | 525 | 21.3 | 54.1 | 0.0 | Dec-87 | | | | | Dec-87 | | | | | |
| Jan-88 | 269 | 36.4 | 22.8 | 0.0 | Jan-88 | | | | | Jan-88 | | | | | |
| Feb-88 | 696 | 29.9 | 66.2 | 0.0 | Feb-88 | | | | | Feb-88 | | | | | |
| Mar-88 | 744 | 18.1 | 38.2 | 0.0 | Mar-88 | | | | | Mar-88 | | | | | |
| Apr-88 | 480 | 29.1 | 35.8 | 0.0 | Apr-88 | | | | | Apr-88 | | | | | |
| May-88 | 579 | 25.2 | 39.2 | 0.0 | May-88 | | | | | May-88 | | | | | |
| Jun-88 | 705 | 15.8 | 34.9 | 0.0 | Jun-88 | | | | | Jun-88 | | | | | |
| Jul-88 | 722 | 26.0 | 38.7 | 0.0 | Jul-88 | | | | | Jul-88 | | | | | |
| Aug-88 | 739 | 18.1 | 36.4 | 0.0 | Aug-88 | | | | | Aug-88 | | | | | |
| Sep-88 | 588 | 20.4 | 39.5 | 0.0 | Sep-88 | | | | | Sep-88 | | | | | |
| Oct-88 | 728 | 18.7 | 33.6 | 0.0 | Oct-88 | | | | | Oct-88 | | | | | |
| Nov-88 | 720 | 17.5 | 31.5 | 0.0 | Nov-88 | | | | | Nov-88 | | | | | |
| Dec-88 | 568 | 22.5 | 31.8 | 0.0 | Dec-88 | | | | | Dec-88 | | | | | |
| Jan-89 | 740 | 18.8 | 28.8 | 0.0 | Jan-89 | | | | | Jan-89 | | | | | |
| Feb-89 | 648 | 17.8 | 28.4 | 0.0 | Feb-89 | | | | | Feb-89 | | | | | |
| Mar-89 | 528 | 19.6 | 28.1 | 0.0 | Mar-89 | 636 | 102.6 | 314.5 | 0.0 | Mar-89 | | | | | |
| Apr-89 | 432 | 26.4 | 33.9 | 0.0 | Apr-89 | 676 | 71.6 | 345.4 | 0.0 | Apr-89 | | | | | |
| May-89 | 553 | 25.2 | 28.1 | 0.0 | May-89 | 735 | 53.6 | 331.7 | 0.0 | May-89 | | | | | |
| Jun-89 | 711 | 18.3 | 26.8 | 0.0 | Jun-89 | 720 | 49.2 | 299.1 | 0.0 | Jun-89 | | | | | |
| Jul-89 | 744 | 17.4 | 26.9 | 0.0 | Jul-89 | 185 | 49.4 | 345.8 | 0.0 | Jul-89 | | | | | |
| Aug-89 | 744 | 15.9 | 25.5 | 0.0 | Aug-89 | 288 | 33.3 | 314.1 | 0.0 | Aug-89 | | | | | |
| Sep-89 | 720 | 20.1 | 28.6 | 0.0 | Sep-89 | 240 | 42.5 | 321.2 | 0.0 | Sep-89 | | | | | |
| Oct-89 | 525 | 16.9 | 40.3 | 0.0 | Oct-89 | 176 | 58.7 | 365.0 | 0.0 | Oct-89 | | | | | |
| Nov-89 | 720 | 17.5 | 23.7 | 0.0 | Nov-89 | 108 | 65.0 | 364.4 | 0.0 | Nov-89 | | | | | |
| Dec-89 | 744 | 15.6 | 27.3 | 0.0 | Dec-89 | 139 | 63.3 | 329.7 | 0.0 | Dec-89 | | | | | |
| Jan-90 | 744 | 15.0 | 26.2 | 0.0 | Jan-90 | 173 | 67.3 | 429.9 | 0.0 | Jan-90 | | | | | |
| Feb-90 | 672 | 16.1 | 24.1 | 0.0 | Feb-90 | 189 | 64.0 | 382.2 | 0.0 | Feb-90 | | | | | |
| Mar-90 | 744 | 16.2 | 25.1 | 0.0 | Mar-90 | 155 | 86.7 | 441.3 | 0.0 | Mar-90 | 125 | 408.6 | 265.8 | 12.3 | |
| Apr-90 | 720 | 14.8 | 25.4 | 0.0 | Apr-90 | 142 | 71.0 | 456.5 | 0.0 | Apr-90 | 45 | 390.5 | 274.5 | 0.0 | |
| May-90 | 744 | 14.7 | 25.9 | 0.0 | May-90 | 144 | 83.3 | 411.1 | 0.0 | May-90 | 575 | 352.0 | 282.7 | 0.1 | |
| Jun-90 | 720 | 15.0 | 26.3 | 0.0 | Jun-90 | 234 | 57.2 | 364.4 | 0.0 | Jun-90 | 400 | 367.1 | 300.9 | 0.0 | |
| Jul-90 | 432 | 18.7 | 22.7 | 0.0 | Jul-90 | 160 | 72.9 | 415.8 | 0.0 | Jul-90 | 54 | 359.8 | 293.4 | 0.3 | |
| Aug-90 | 744 | 18.7 | 26.3 | 0.0 | Aug-90 | 282 | 53.4 | 425.3 | 0.0 | Aug-90 | 168 | 357.2 | 292.6 | 0.7 | |
| Sep-90 | 720 | 16.7 | 26.6 | 0.0 | Sep-90 | 143 | 73.2 | 418.8 | 0.0 | Sep-90 | 189 | 361.6 | 291.2 | 0.1 | |
| Oct-90 | 720 | 16.3 | 24.0 | 0.0 | Oct-90 | 166 | 79.3 | 398.6 | 0.0 | Oct-90 | 188 | 364.2 | 286.8 | 0.1 | |
| Nov-90 | 720 | 18.0 | 29.5 | 0.0 | Nov-90 | 117 | 70.9 | 326.9 | 0.0 | Nov-90 | 204 | 343.4 | 276.9 | 0.1 | |
| Dec-90 | 639 | 17.4 | 26.9 | 0.0 | Dec-90 | 120 | 97.5 | 337.9 | 0.0 | Dec-90 | 192 | 355.8 | 292.8 | 0.1 | |
| Jan-91 | 744 | 16.5 | 27.6 | 0.0 | Jan-91 | 142 | 99.1 | 323.4 | 0.0 | Jan-91 | 192 | 352.3 | 292.8 | 3.4 | |
| Feb-91 | 672 | 18.2 | 22.9 | 0.0 | Feb-91 | 186 | 84.1 | 308.4 | 0.0 | Feb-91 | 172 | 354.5 | 286.3 | 0.1 | |
| Mar-91 | 710 | 16.3 | 25.2 | 0.0 | Mar-91 | 262 | 79.6 | 263.0 | 0.0 | Mar-91 | 163 | 342.1 | 281.7 | 0.1 | |
| Apr-91 | 615 | 17.5 | 24.4 | 0.0 | Apr-91 | 286 | 73.0 | 276.4 | 0.0 | Apr-91 | 192 | 339.1 | 273.3 | 0.1 | |
| May-91 | 744 | 16.7 | 25.4 | 0.0 | May-91 | 264 | 72.6 | 282.4 | 0.0 | May-91 | 201 | 341.4 | 283.5 | 0.1 | |
| Jun-91 | 720 | 15.9 | 26.0 | 0.0 | Jun-91 | 288 | 74.9 | 263.5 | 0.0 | Jun-91 | 192 | 348.1 | 286.6 | 0.8 | |
| Jul-91 | 744 | 15.5 | 25.1 | 0.0 | Jul-91 | 264 | 74.0 | 285.6 | 0.0 | Jul-91 | 207 | 334.3 | 288.1 | 0.1 | |
| Aug-91 | 744 | 14.2 | 22.8 | 0.0 | Aug-91 | 240 | 76.7 | 226.1 | 0.0 | Aug-91 | 192 | 359.7 | 290.2 | 0.1 | |
| Sep-91 | 720 | 14.7 | 22.4 | 0.0 | Sep-91 | 260 | 73.0 | 235.6 | 0.0 | Sep-91 | 209 | 323.0 | 286.5 | 0.1 | |
| Oct-91 | 744 | 12.8 | 20.7 | 0.0 | Oct-91 | 240 | 67.4 | 248.8 | 0.0 | Oct-91 | 207 | 330.7 | 264.8 | 0.1 | |
| Nov-91 | 720 | 13.0 | 20.7 | 0.0 | Nov-91 | 334 | 75.9 | 226.0 | 0.0 | Nov-91 | 187 | 362.0 | 291.5 | 0.1 | |
| Dec-91 | 432 | 12.4 | 23.1 | 0.6 | Dec-91 | 336 | 68.3 | 230.0 | 0.0 | Dec-91 | 188 | 366.1 | 291.8 | 0.1 | |
| Jan-92 | 744 | 12.0 | 22.5 | 0.0 | Jan-92 | 291 | 69.3 | 250.3 | 0.0 | Jan-92 | 192 | 354.7 | 301.2 | 0.1 | |
| Feb-92 | 696 | 20.3 | 27.2 | 0.0 | Feb-92 | 265 | 72.6 | 205.4 | 0.0 | Feb-92 | 144 | 341.0 | 291.1 | 0.1 | |
| Mar-92 | 744 | 20.1 | 28.6 | 0.0 | Mar-92 | 359 | 60.6 | 188.2 | 0.0 | Mar-92 | 208 | 325.1 | 274.4 | 0.1 | |
| Apr-92 | 720 | 19.2 | 30.3 | 0.0 | Apr-92 | 336 | 56.7 | 231.7 | 0.0 | Apr-92 | 192 | 343.1 | 288.8 | 0.1 | |
| May-92 | 744 | 19.1 | 32.4 | 0.0 | May-92 | 480 | 51.8 | 213.7 | 0.0 | May-92 | 187 | 360.7 | 309.3 | 0.1 | |
| Jun-92 | 720 | 18.5 | 35.1 | 0.0 | Jun-92 | 466 | 47.0 | 192.3 | 0.0 | Jun-92 | 176 | 375.8 | 310.3 | 0.1 | |
| Jul-92 | 744 | 18.5 | 31.8 | 0.0 | Jul-92 | 312 | 55.8 | 276.0 | 0.0 | Jul-92 | 181 | 375.0 | 314.9 | 0.1 | |
| Aug-92 | 744 | 17.7 | 29.3 | 0.0 | Aug-92 | 265 | 66.0 | 320.5 | 0.0 | Aug-92 | 185 | 364.7 | 323.2 | 0.1 | |
| Sep-92 | 720 | 16.9 | 29.8 | 0.0 | Sep-92 | 240 | 71.7 | 295.0 | 0.0 | Sep-92 | 178 | 371.7 | 329.7 | 0.1 | |
| Oct-92 | 744 | 16.2 | 29.4 | 0.0 | Oct-92 | 205 | 71.5 | 244.8 | 7.1 | Oct-92 | 182 | 374.4 | 339.3 | 0.1 | |
| Nov-92 | 720 | 16.3 | 28.4 | 0.0 | Nov-92 | 166 | 83.8 | 218.6 | 0.0 | Nov-92 | 240 | 273.0 | 231.8 | 0.0 | |
| Dec-92 | 744 | 15.2 | 28.4 | 0.0 | Dec-92 | 208 | 81.2 | 204.0 | 0.0 | Dec-92 | 335 | 192.0 | 152.3 | 0.0 | |
| Jan-93 | 744 | 15.1 | 31.4 | 0.0 | Jan-93 | 290 | 70.9 | 196.2 | 0.0 | Jan-93 | 273 | 241.8 | 136.4 | 0.0 | |
| Feb-93 | 672 | 14.7 | 59.2 | 0.1 | Feb-93 | 334 | 60.2 | 129.8 | 0.0 | Feb-93 | 322 | 192.5 | 168.2 | 0.0 | |
| Mar-93 | 744 | 14.4 | 57.5 | 0.0 | Mar-93 | 191 | 120.1 | 75.4 | 0.0 | Mar-93 | 364 | 188.8 | 194.7 | 0.0 | |
| Apr-93 | 720 | 13.0 | 49.0 | 0.0 | Apr-93 | 106 | 287.9 | 559.3 | 0.0 | Apr-93 | 375 | 172.5 | 173.8 | 0.0 | |
| May-93 | 744 | 9.6 | 49.9 | 0.0 | May-93 | 77 | 85.7 | 498.9 | 0.0 | May-93 | 456 | 165.0 | 187.7 | 0.0 | |
| Jun-93 | 720 | 11.9 | 53.7 | 0.0 | Jun-93 | 696 | 42.0 | 24.0 | 0.0 | Jun-93 | 401 | 169.6 | 223.0 | 0.0 | |
| Jul-93 | 744 | 12.0 | 52.8 | 0.0 | Jul-93 | 672 | 17.4 | 15.2 | 0.0 | Jul-93 | 398 | 154.4 | 217.7 | 0.0 | |
| Aug-93 | 666 | 11.1 | 58.3 | 0.0 | Aug-93 | 552 | 20.3 | 46.3 | 0.0 | Aug-93 | 257 | 265.6 | 331.8 | 0.0 | |
| Sep-93 | 720 | 9.2 | 51.9 | 0.0 | Sep-93 | 648 | 49.1 | 35.2 | 0.0 | Sep-93 | 228 | 284.2 | 377.4 | 0.0 | |
| Oct-93 | 576 | 7.2 | 58.4 | 0.0 | Oct-93 | 744 | 60.1 | | 0.0 | Oct-93 | 271 | 252.0 | 302.4 | 0.0 | |
| Nov-93 | 720 | 5.9 | 49.1 | 0.0 | Nov-93 | 312 | 30.1 | 1.3 | 4.4 | Nov-93 | 257 | 248.3 | 410.0 | 0.0 | |
| Dec-93 | 744 | 8.1 | 47.8 | 0.0 | Dec-93 | 13 | 164.9 | 19.7 | 0.0 | Dec-93 | 312 | 173.5 | 348.1 | 0.0 | |
| Jan-94 | 744 | 7.3 | 48.1 | 0.0 | Jan-94 | 4 | 769.9 | | 0.0 | Jan-94 | 372 | 148.1 | 409.0 | 0.0 | |
| Feb-94 | 607 | 8.0 | 56.2 | 0.0 | Feb-94 | 13 | 932.5 | | 0.0 | Feb-94 | 241 | 151.8 | 442.5 | 0.0 | |
| Mar-94 | 724 | 7.3 | 51.8 | 0.0 | Mar-94 | 25 | 372.5 | | 0.0 | Mar-94 | 270 | 134.6 | 435.4 | 0.0 | |
| Apr-94 | 720 | 6.8 | 50.4 | 0.0 | Apr-94 | 23 | 327.5 | | 0.0 | Apr-94 | 198 | 132.0 | 433.7 | 0.0 | |
| May-94 | 744 | 6.4 | 49.1 | 0.0 | May-94 | 14 | 576.8 | | 0.0 | May-94 | 239 | 109.3 | 616.6 | 0.0 | |
| Jun-94 | 720 | 6.5 | 46.6 | 0.0 | Jun-94 | 17 | 547.9 | | 0.0 | Jun-94 | 128 | 177.1 | 727.4 | 0.0 | |
| Jul-94 | 528 | 6.0 | 52.0 | 0.4 | Jul-94 | 23 | 533.6 | | 0.0 | Jul-94 | 239 | 92.6 | 686.1 | 0.0 | |
| Aug-94 | 504 | 9.2 | 54.6 | 0.0 | Aug-94 | 23 | 517.8 | | 0.0 | Aug-94 | 120 | 104.2 | 619.0 | 0.0 | |
| Sep-94 | 24 | 196.2 | 1519.2 | 0.0 | Sep-94 | 22 | 532.4 | | 0.0 | Sep-94 | 164 | 105.0 | 584.3 | 0.0 | |
| MRL = 88 STB/d GOR = 1,129 Mscf/STB | | | | | MRL = 88 STB/d GOR = 1,129 Mscf/STB | | | | | MRL = 88 STB/d GOR = 1,129 Mscf/STB | | | | | |

**Table 4.1: Chedderville Viking "A" Production History (Oct-94)**

| | Well Battery | 06-13-37-8W5 | | SATELLITE |
|---|---|---|---|---|
| | Casing | Depth (ft) | Dia (in) | Wt (lb/ft) |
| | Surface | 1364 5 | 9 6 | 3 35 |
| | Prod | 8999 3 | 5 5 | 2 23 |
| Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | |
| Nov-87 | | | | |
| Dec-87 | | | | |
| Jan-88 | | | | |
| Feb-88 | | | | |
| Mar-88 | | | | |
| Apr-88 | | | | |
| May-88 | | | | |
| Jun-88 | | | | |
| Jul-88 | | | | |
| Aug-88 | | | | |
| Sep-88 | | | | |
| Oct-88 | | | | |
| Nov-88 | | | | |
| Dec-88 | | | | |
| Jan-89 | | | | |
| Feb-89 | | | | |
| Mar-89 | | | | |
| Apr-89 | | | | |
| May-89 | | | | |
| Jun-89 | | | | |
| Jul-89 | | | | |
| Aug-89 | | | | |
| Sep-89 | | | | |
| Oct-89 | | | | |
| Nov-89 | | | | |
| Dec-89 | | | | |
| Jan-90 | | | | |
| Feb-90 | | | | |
| Mar-90 | | | | |
| Apr-90 | | | | |
| May-90 | | | | |
| Jun-90 | | | | |
| Jul-90 | | | | |
| Aug-90 | 744 | 127 7 | 103 0 | 0 0 |
| Sep-90 | 528 | 160 4 | 128 1 | 0 0 |
| Oct-90 | 744 | 222 2 | 172 7 | 0 0 |
| Nov-90 | 120 | 173 6 | 117 1 | 0 0 |
| Dec-90 | 672 | 122 3 | 78 6 | 0 0 |
| Jan-91 | 336 | 173 0 | 121 2 | 0 0 |
| Feb-91 | 408 | 138 4 | 113 6 | 0 0 |
| Mar-91 | 288 | 224 5 | 180 1 | 0 0 |
| Apr-91 | 312 | 226 6 | 169 6 | 0 0 |
| May-91 | 264 | 222 4 | 163 9 | 0 0 |
| Jun-91 | 312 | 225 0 | 160 5 | 0 0 |
| Jul-91 | 288 | 235 1 | 176 3 | 0 0 |
| Aug-91 | 240 | 249 4 | 178 5 | 0 0 |
| Sep-91 | 312 | 212 5 | 162 5 | 0 0 |
| Oct-91 | 288 | 235 7 | 180 7 | 0 0 |
| Nov-91 | 264 | 249 7 | 183 6 | 0 0 |
| Dec-91 | 240 | 280 4 | 209 8 | 0 0 |
| Jan-92 | 240 | 295 9 | 225 4 | 0 0 |
| Feb-92 | 216 | 274 2 | 220 8 | 0 0 |
| Mar-92 | 240 | 288 3 | 219 7 | 0 0 |
| Apr-92 | 264 | 249 1 | 183 9 | 0 0 |
| May-92 | 288 | 234 1 | 179 8 | 0 0 |
| Jun-92 | 264 | 248 6 | 201 4 | 0 0 |
| Jul-92 | 504 | 132 1 | 105 1 | 0 0 |
| Aug-92 | 480 | 140 3 | 90 2 | 0 0 |
| Sep-92 | 264 | 245 2 | 180 4 | 0 0 |
| Oct-92 | 336 | 200 8 | 140 0 | 0 0 |
| Nov-92 | 408 | 163 9 | 110 2 | 0 0 |
| Dec-92 | 336 | 230 3 | 111 9 | 0 0 |
| Jan-93 | 344 | 192 5 | 77 3 | 0 0 |
| Feb-93 | 241 | 217 9 | 91 9 | 0 0 |
| Mar-93 | 306 | 207 9 | 131 4 | 0 0 |
| Apr-93 | 311 | 218 4 | 160 5 | 0 0 |
| May-93 | 313 | 237 6 | 189 7 | 0 0 |
| Jun-93 | 344 | 218 4 | 150 8 | 0 0 |
| Jul-93 | 337 | 211 8 | 142 0 | 0 0 |
| Aug-93 | 318 | 207 9 | 139 6 | 0 0 |
| Sep-93 | 292 | 210 0 | 150 8 | 0 0 |
| Oct-93 | 238 | 219 7 | 212 6 | 0 0 |
| Nov-93 | 308 | 210 1 | 226 8 | 0 0 |
| Dec-93 | 306 | 207 9 | 226 1 | 0 0 |
| Jan-94 | 310 | 211 1 | 222 6 | 0 0 |
| Feb-94 | 276 | 211 1 | 287 0 | 0 0 |
| Mar-94 | 312 | 207 1 | 253 4 | 0 0 |
| Apr-94 | 308 | 209 5 | 248 4 | 0 0 |
| May-94 | 276 | 202 8 | 289 6 | 0 0 |
| Jun-94 | 294 | 209 3 | 295 7 | 0 0 |
| Jul-94 | 326 | 158 3 | 285 3 | 0 0 |
| Aug-94 | 271 | 185 9 | 380 4 | 0 0 |
| Sep-94 | 333 | 175 2 | 372 7 | 0 0 |

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

| | Well Battery | 06-18-37-7W5 | | SATELLITE |
|---|---|---|---|---|
| | Casing | Depth (ft) | Dia (in) | Wt (lb/ft) |
| | Surface | 1351 7 | 9 6 | 3 35 |
| | Prod | 8694 2 | 5 5 | 2 23 |
| Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | |
| Nov-87 | | | | |
| Dec-87 | | | | |
| Jan-88 | | | | |
| Feb-88 | | | | |
| Mar-88 | | | | |
| Apr-88 | | | | |
| May-88 | | | | |
| Jun-88 | | | | |
| Jul-88 | | | | |
| Aug-88 | | | | |
| Sep-88 | | | | |
| Oct-88 | | | | |
| Nov-88 | | | | |
| Dec-88 | | | | |
| Jan-89 | | | | |
| Feb-89 | | | | |
| Mar-89 | | | | |
| Apr-89 | | | | |
| May-89 | | | | |
| Jun-89 | | | | |
| Jul-89 | | | | |
| Aug-89 | | | | |
| Sep-89 | | | | |
| Oct-89 | | | | |
| Nov-89 | | | | |
| Dec-89 | | | | |
| Jan-90 | | | | |
| Feb-90 | | | | |
| Mar-90 | | | | |
| Apr-90 | | | | |
| May-90 | | | | |
| Jun-90 | | | | |
| Jul-90 | | | | |
| Aug-90 | | | | |
| Sep-90 | | | | |
| Oct-90 | 63 | 491 1 | 223 1 | 86 0 |
| Nov-90 | 621 | 290 1 | 230 5 | 0 1 |
| Dec-90 | 583 | 291 6 | 370 1 | 0 0 |
| Jan-91 | | | | |
| Feb-91 | 213 | 268 3 | 200 0 | 0 1 |
| Mar-91 | 234 | 270 7 | 231 2 | 0 1 |
| Apr-91 | 244 | 254 8 | 215 1 | 0 1 |
| May-91 | 236 | 266 4 | 182 7 | 0 1 |
| Jun-91 | 231 | 266 1 | 202 5 | 0 1 |
| Jul-91 | 238 | 262 9 | 204 4 | 0 1 |
| Aug-91 | 264 | 237 9 | 211 4 | 0 1 |
| Sep-91 | 262 | 237 5 | 215 6 | 0 1 |
| Oct-91 | 264 | 238 6 | 231 4 | 0 1 |
| Nov-91 | 237 | 257 7 | 230 4 | 0 1 |
| Dec-91 | 262 | 237 7 | 225 3 | 0 1 |
| Jan-92 | 261 | 239 5 | 259 1 | 0 1 |
| Feb-92 | 266 | 236 1 | 312 6 | 0 1 |
| Mar-92 | 285 | 229 8 | 349 1 | 0 1 |
| Apr-92 | 245 | 251 0 | 296 6 | 0 2 |
| May-92 | 237 | 223 2 | 313 4 | 0 1 |
| Jun-92 | 178 | 239 5 | 316 3 | 0 1 |
| Jul-92 | 193 | 251 1 | 297 9 | 0 1 |
| Aug-92 | 215 | 237 2 | 299 1 | 0 1 |
| Sep-92 | 210 | 246 2 | 350 5 | 0 1 |
| Oct-92 | 289 | 207 2 | 458 1 | 0 1 |
| Nov-92 | 360 | 154 7 | 359 0 | 0 0 |
| Dec-92 | 240 | 225 7 | 381 9 | 0 0 |
| Jan-93 | 111 | 282 2 | 365 3 | 0 0 |
| Feb-93 | 110 | 273 5 | 348 5 | 0 0 |
| Mar-93 | 183 | 239 5 | 364 5 | 0 0 |
| Apr-93 | 223 | 216 1 | 431 3 | 0 0 |
| May-93 | 312 | 174 9 | 456 2 | 0 0 |
| Jun-93 | 303 | 158 3 | 430 4 | 0 0 |
| Jul-93 | 264 | 139 3 | 509 2 | 0 0 |
| Aug-93 | 179 | 153 6 | 453 0 | 0 0 |
| Sep-93 | 154 | 149 1 | 469 6 | 0 0 |
| Oct-93 | 117 | 151 8 | 404 8 | 0 0 |
| Nov-93 | 126 | 169 5 | 440 1 | 0 0 |
| Dec-93 | 160 | 144 2 | 463 2 | 0 0 |
| Jan-94 | 177 | 152 9 | 502 5 | 0 0 |
| Feb-94 | 167 | 150 5 | 414 2 | 0 0 |
| Mar-94 | 189 | 121 6 | 465 6 | 0 0 |
| Apr-94 | 192 | 113 5 | 471 6 | 0 0 |
| May-94 | 233 | 118 7 | 469 8 | 0 0 |
| Jun-94 | 163 | 124 7 | 482 9 | 0 0 |
| Jul-94 | 150 | 121 8 | 453 8 | 0 0 |
| Aug-94 | 133 | 140 4 | 406 7 | 0 0 |
| Sep-94 | 127 | 133 6 | 398 4 | 0 0 |

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

| | Well Battery | 08-14-37-8W5 | | SATELLITE |
|---|---|---|---|---|
| | Casing | Depth (ft) | Dia (in) | Wt (lb/ft) |
| | Surface | 1404 2 | 9 6 | 3 35 |
| | Prod | 9225 7 | 5 5 | 2 23 |
| Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | |
| Nov-87 | | | | |
| Dec-87 | | | | |
| Jan-88 | | | | |
| Feb-88 | | | | |
| Mar-88 | | | | |
| Apr-88 | | | | |
| May-88 | | | | |
| Jun-88 | | | | |
| Jul-88 | | | | |
| Aug-88 | | | | |
| Sep-88 | | | | |
| Oct-88 | | | | |
| Nov-88 | | | | |
| Dec-88 | | | | |
| Jan-89 | | | | |
| Feb-89 | | | | |
| Mar-89 | | | | |
| Apr-89 | | | | |
| May-89 | | | | |
| Jun-89 | | | | |
| Jul-89 | | | | |
| Aug-89 | | | | |
| Sep-89 | | | | |
| Oct-89 | | | | |
| Nov-89 | | | | |
| Dec-89 | | | | |
| Jan-90 | | | | |
| Feb-90 | | | | |
| Mar-90 | | | | |
| Apr-90 | | | | |
| May-90 | | | | |
| Jun-90 | | | | |
| Jul-90 | | | | |
| Aug-90 | | | | |
| Sep-90 | | | | |
| Oct-90 | | | | |
| Nov-90 | | | | |
| Dec-90 | | | | |
| Jan-91 | | | | |
| Feb-91 | 600 | 192 3 | 128 8 | 0 0 |
| Mar-91 | 744 | 167 5 | 116 8 | 0 0 |
| Apr-91 | 720 | 153 6 | 118 3 | 0 0 |
| May-91 | | | | |
| Jun-91 | 384 | 168 5 | 130 4 | 0 0 |
| Jul-91 | 744 | 88 6 | 64 1 | 0 0 |
| Aug-91 | 264 | 241 2 | 181 0 | 0 0 |
| Sep-91 | 336 | 195 4 | 143 8 | 0 0 |
| Oct-91 | 312 | 214 4 | 157 8 | 0 0 |
| Nov-91 | 288 | 211 4 | 151 1 | 0 0 |
| Dec-91 | 240 | 258 6 | 204 1 | 0 0 |
| Jan-92 | 240 | 272 6 | 194 2 | 0 0 |
| Feb-92 | 216 | 286 8 | 206 3 | 0 0 |
| Mar-92 | 264 | 243 4 | 199 4 | 0 0 |
| Apr-92 | 240 | 271 7 | 202 1 | 0 0 |
| May-92 | 240 | 268 5 | 176 4 | 0 0 |
| Jun-92 | 240 | 273 1 | 180 0 | 0 0 |
| Jul-92 | 312 | 208 8 | 133 8 | 0 0 |
| Aug-92 | 504 | 129 1 | 76 1 | 0 0 |
| Sep-92 | 312 | 170 6 | 118 8 | 0 0 |
| Oct-92 | 288 | 228 7 | 156 9 | 0 0 |
| Nov-92 | 288 | 229 8 | 144 4 | 0 0 |
| Dec-92 | 258 | 307 4 | 129 8 | 0 0 |
| Jan-93 | 221 | 295 1 | 148 0 | 0 0 |
| Feb-93 | 381 | 134 3 | 71 1 | 0 0 |
| Mar-93 | 384 | 173 3 | 99 8 | 0 0 |
| Apr-93 | 300 | 227 8 | 114 1 | 0 0 |
| May-93 | 388 | 183 5 | 115 2 | 0 0 |
| Jun-93 | 402 | 171 3 | 114 4 | 0 0 |
| Jul-93 | 351 | 182 7 | 126 7 | 0 0 |
| Aug-93 | 372 | 175 9 | 121 4 | 0 0 |
| Sep-93 | 362 | 173 5 | 120 5 | 0 0 |
| Oct-93 | 381 | 179 2 | 159 4 | 0 0 |
| Nov-93 | 357 | 179 5 | 164 9 | 0 0 |
| Dec-93 | 357 | 178 4 | 162 5 | 0 0 |
| Jan-94 | 402 | 163 9 | 149 2 | 0 0 |
| Feb-94 | 362 | 161 9 | 161 7 | 0 0 |
| Mar-94 | 330 | 196 3 | 176 3 | 0 0 |
| Apr-94 | 362 | 171 7 | 163 6 | 0 0 |
| May-94 | 396 | 169 7 | 165 4 | 0 0 |
| Jun-94 | 404 | 156 6 | 148 9 | 0 0 |
| Jul-94 | 377 | 165 4 | 181 2 | 0 0 |
| Aug-94 | 392 | 163 8 | 184 9 | 0 0 |
| Sep-94 | 385 | 163 2 | 198 7 | 0 0 |

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

**Table 4.1: Production History (Continued)**

| | Well Battery | 06-18-37-7W5 06-18-37-7W5 | | SATELLITE |
|---|---|---|---|---|
| | Casing | Depth (ft) | Dia (in) | Wt (lb/ft³) |
| | Surface | 1353 7 | 9 6 | 3 35 |
| | Prod | 8776 2 | 5 5 | 2 23 |
| Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | |
| Nov-87 | | | | |
| Dec-87 | | | | |
| Jan-88 | | | | |
| Feb-88 | | | | |
| Mar-88 | | | | |
| Apr-88 | | | | |
| May-88 | | | | |
| Jun-88 | | | | |
| Jul-88 | | | | |
| Aug-88 | | | | |
| Sep-88 | | | | |
| Oct-88 | | | | |
| Nov-88 | | | | |
| Dec-88 | | | | |
| Jan-89 | | | | |
| Feb-89 | | | | |
| Mar-89 | | | | |
| Apr-89 | | | | |
| May-89 | | | | |
| Jun-89 | | | | |
| Jul-89 | | | | |
| Aug-89 | | | | |
| Sep-89 | | | | |
| Oct-89 | | | | |
| Nov-89 | | | | |
| Dec-89 | | | | |
| Jan-90 | | | | |
| Feb-90 | | | | |
| Mar-90 | | | | |
| Apr-90 | | | | |
| May-90 | | | | |
| Jun-90 | | | | |
| Jul-90 | | | | |
| Aug-90 | | | | |
| Sep-90 | | | | |
| Oct-90 | | | | |
| Nov-90 | | | | |
| Dec-90 | | | | |
| Jan-91 | | | | |
| Feb-91 | | | | |
| Mar-91 | | | | |
| Apr-91 | | | | |
| May-91 | | | | |
| Jun-91 | | | | |
| Jul-91 | | | | |
| Aug-91 | | | | |
| Sep-91 | | | | |
| Oct-91 | | | | |
| Nov-91 | | | | |
| Dec-91 | | | | |
| Jan-92 | | | | |
| Feb-92 | | | | |
| Mar-92 | 93 | 130 8 | 299 5 | 0 0 |
| Apr-92 | | | | |
| May-92 | | | | |
| Jun-92 | | | | |
| Jul-92 | 738 | 110 7 | 123 2 | 0 0 |
| Aug-92 | 720 | 101 7 | 134 2 | 0 0 |
| Sep-92 | | | | |
| Oct-92 | 617 | 75 2 | 57 6 | 0 0 |
| Nov-92 | 720 | 35 8 | 19 9 | 0 0 |
| Dec-92 | 164 | 50 6 | 57 1 | 0 0 |
| Jan-93 | 493 | 120 7 | 99 3 | 0 0 |
| Feb-93 | 538 | 110 6 | 85 3 | 0 0 |
| Mar-93 | 579 | 123 5 | 110 9 | 0 0 |
| Apr-93 | 516 | 130 3 | 96 9 | 0 0 |
| May-93 | 580 | 122 5 | 110 6 | 0 0 |
| Jun-93 | 474 | 119 6 | 105 7 | 0 0 |
| Jul-93 | 570 | 121 5 | 120 3 | 0 0 |
| Aug-93 | 578 | 118 5 | 106 7 | 0 0 |
| Sep-93 | 588 | 110 7 | 101 7 | 0 0 |
| Oct-93 | 624 | 110 4 | 99 2 | 0 0 |
| Nov-93 | 487 | 107 1 | 103 9 | 0 0 |
| Dec-93 | 474 | 135 9 | 131 2 | 0 0 |
| Jan-94 | 463 | 140 4 | 134 1 | 0 0 |
| Feb-94 | 465 | 127 0 | 142 9 | 0 0 |
| Mar-94 | 587 | 112 0 | 127 8 | 0 0 |
| Apr-94 | 537 | 119 6 | 132 0 | 0 0 |
| May-94 | 600 | 120 0 | 162 3 | 0 0 |
| Jun-94 | 607 | 108 9 | 153 4 | 0 0 |
| Jul-94 | 655 | 100 6 | 168 7 | 0 0 |
| Aug-94 | 546 | 95 9 | 193 0 | 0 0 |
| Sep-94 | 474 | 94 2 | 200 0 | 0 0 |

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

| | Well Battery | 16-08-37-7W5 06-18-37-7W5 | | SATELLITE |
|---|---|---|---|---|
| | Casing | Depth (ft) | Dia (in) | Wt (lb/ft³) |
| | Surface | 1120 4 | 8 6 | 2 23 |
| | Prod | 8684 4 | 5 5 | 2 23 |
| Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | |
| Nov-87 | | | | |
| Dec-87 | | | | |
| Jan-88 | | | | |
| Feb-88 | | | | |
| Mar-88 | | | | |
| Apr-88 | | | | |
| May-88 | | | | |
| Jun-88 | | | | |
| Jul-88 | | | | |
| Aug-88 | | | | |
| Sep-88 | | | | |
| Oct-88 | | | | |
| Nov-88 | | | | |
| Dec-88 | | | | |
| Jan-89 | | | | |
| Feb-89 | | | | |
| Mar-89 | | | | |
| Apr-89 | | | | |
| May-89 | | | | |
| Jun-89 | | | | |
| Jul-89 | | | | |
| Aug-89 | | | | |
| Sep-89 | | | | |
| Oct-89 | | | | |
| Nov-89 | | | | |
| Dec-89 | | | | |
| Jan-90 | | | | |
| Feb-90 | | | | |
| Mar-90 | | | | |
| Apr-90 | | | | |
| May-90 | | | | |
| Jun-90 | | | | |
| Jul-90 | | | | |
| Aug-90 | | | | |
| Sep-90 | | | | |
| Oct-90 | | | | |
| Nov-90 | | | | |
| Dec-90 | | | | |
| Jan-91 | | | | |
| Feb-91 | | | | |
| Mar-91 | | | | |
| Apr-91 | | | | |
| May-91 | | | | |
| Jun-91 | | | | |
| Jul-91 | | | | |
| Aug-91 | | | | |
| Sep-91 | | | | |
| Oct-91 | | | | |
| Nov-91 | | | | |
| Dec-91 | | | | |
| Jan-92 | | | | |
| Feb-92 | | | | |
| Mar-92 | | | | |
| Apr-92 | | | | |
| May-92 | | | | |
| Jun-92 | | | | |
| Jul-92 | | | | |
| Aug-92 | 24 | | | 3 8 |
| Sep-92 | 483 | 203 5 | 457 5 | 0 0 |
| Oct-92 | 334 | 271 9 | 296 1 | 0 0 |
| Nov-92 | 382 | 236 1 | 264 3 | 0 0 |
| Dec-92 | 363 | 231 4 | 204 9 | 0 0 |
| Jan-93 | 262 | 239 6 | 268 5 | 0 0 |
| Feb-93 | 337 | 184 4 | 253 5 | 0 0 |
| Mar-93 | 250 | 250 5 | 256 2 | 0 0 |
| Apr-93 | 220 | 264 8 | 316 4 | 0 0 |
| May-93 | 167 | 355 5 | 315 2 | 0 0 |
| Jun-93 | 266 | 229 1 | 278 9 | 0 0 |
| Jul-93 | 246 | 249 6 | 292 6 | 0 0 |
| Aug-93 | 291 | 226 1 | 271 1 | 0 0 |
| Sep-93 | 213 | 182 2 | 270 0 | 0 0 |
| Oct-93 | 309 | 197 0 | 304 4 | 0 0 |
| Nov-93 | 261 | 226 1 | 355 4 | 0 0 |
| Dec-93 | 744 | 63 8 | 130 4 | 0 0 |
| Jan-94 | 193 | 230 1 | 399 5 | 0 0 |
| Feb-94 | 191 | 207 6 | 384 4 | 0 0 |
| Mar-94 | 216 | 157 2 | 350 2 | 0 0 |
| Apr-94 | 192 | 226 8 | 458 3 | 0 0 |
| May-94 | 192 | 183 3 | 386 0 | 0 0 |
| Jun-94 | 231 | 118 6 | 476 8 | 0 0 |
| Jul-94 | 264 | 134 5 | 668 9 | 0 0 |
| Aug-94 | 480 | 52 0 | 594 4 | 0 0 |
| Sep-94 | 112 | 160 1 | 455 6 | 0 0 |

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

| | Well Battery | 14-09-37-7W5 14-09-37-7W5 | | SINGLE |
|---|---|---|---|---|
| | Casing | Depth (ft) | Dia (in) | Wt (lb/ft³) |
| | Surface | 1482 9 | 9 6 | 3 35 |
| | Prod | 11154 9 | 7 0 | 2 23 |
| Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | |
| Nov-87 | | | | |
| Dec-87 | | | | |
| Jan-88 | | | | |
| Feb-88 | | | | |
| Mar-88 | | | | |
| Apr-88 | | | | |
| May-88 | | | | |
| Jun-88 | | | | |
| Jul-88 | | | | |
| Aug-88 | | | | |
| Sep-88 | | | | |
| Oct-88 | | | | |
| Nov-88 | | | | |
| Dec-88 | | | | |
| Jan-89 | | | | |
| Feb-89 | | | | |
| Mar-89 | | | | |
| Apr-89 | | | | |
| May-89 | | | | |
| Jun-89 | | | | |
| Jul-89 | | | | |
| Aug-89 | | | | |
| Sep-89 | | | | |
| Oct-89 | | | | |
| Nov-89 | | | | |
| Dec-89 | | | | |
| Jan-90 | | | | |
| Feb-90 | | | | |
| Mar-90 | | | | |
| Apr-90 | | | | |
| May-90 | | | | |
| Jun-90 | | | | |
| Jul-90 | | | | |
| Aug-90 | | | | |
| Sep-90 | | | | |
| Oct-90 | | | | |
| Nov-90 | | | | |
| Dec-90 | | | | |
| Jan-91 | | | | |
| Feb-91 | | | | |
| Mar-91 | | | | |
| Apr-91 | | | | |
| May-91 | | | | |
| Jun-91 | | | | |
| Jul-91 | | | | |
| Aug-91 | | | | |
| Sep-91 | | | | |
| Oct-91 | | | | |
| Nov-91 | | | | |
| Dec-91 | | | | |
| Jan-92 | | | | |
| Feb-92 | | | | |
| Mar-92 | | | | |
| Apr-92 | | | | |
| May-92 | | | | |
| Jun-92 | | | | |
| Jul-92 | | | | |
| Aug-92 | | | | |
| Sep-92 | | | | |
| Oct-92 | | | | |
| Nov-92 | | | | |
| Dec-92 | | | | |
| Jan-93 | | | | |
| Feb-93 | 487 | 91 2 | 124 9 | 0 0 |
| Mar-93 | 648 | 54 9 | 128 1 | 0 0 |
| Apr-93 | 720 | 43 4 | 104 4 | 0 0 |
| May-93 | 744 | 38 8 | 83 4 | 0 0 |
| Jun-93 | 720 | 37 0 | 80 9 | 0 0 |
| Jul-93 | 744 | 35 7 | 75 2 | 0 0 |
| Aug-93 | 744 | 35 1 | 82 0 | 0 0 |
| Sep-93 | 672 | 31 7 | 92 6 | 0 0 |
| Oct-93 | 744 | 28 9 | 102 6 | 0 0 |
| Nov-93 | 720 | 27 2 | 116 1 | 0 0 |
| Dec-93 | 744 | 26 7 | 128 5 | 0 0 |
| Jan-94 | 720 | 27 5 | 151 2 | 0 0 |
| Feb-94 | 568 | 24 2 | 135 9 | 0 0 |
| Mar-94 | 744 | 22 8 | 144 1 | 0 0 |
| Apr-94 | 698 | 21 1 | 146 9 | 0 0 |
| May-94 | 744 | 21 2 | 157 6 | 0 0 |
| Jun-94 | 480 | 38 6 | 194 5 | 0 0 |
| Jul-94 | 288 | 42 7 | 197 3 | 0 0 |
| Aug-94 | 264 | 36 0 | 133 5 | 0 0 |
| Sep-94 | 312 | 24 6 | 187 4 | 0 0 |

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

**Table 4.1: Production History (Continued)**

| | Well | 08-17-37-7W5 | | | | Well | 14-07-37-7W5 | | | | Well | 14-12-37-8W5 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Battery | 08-18-37-7W5 | | | SATELLITE | Battery | 08-18-37-7W5 | | | SATELLITE | Battery | 06-13-37-8W5 | | | SATELLITE |
| | Casing | Depth (ft) | Dia (in) | Wt (lb/ft) | | Casing | Depth (ft) | Dia (in) | Wt (lb/ft) | | Casing | Depth (ft) | Dia (in) | Wt (lb/ft) | |
| | Surface | 1151 6 | 8 6 | 2 23 | | Surface | 1177 8 | 8 6 | 2 23 | | Surface | 1349 1 | 9 6 | 3 35 | |
| | Prod | 8667 3 | 5 5 | 2 23 | | Prod | 8822 2 | 5 5 | 2 23 | | Prod | 9012 1 | 5 5 | 2 23 | |
| Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | |
| Oct-87 | | | | | Oct-87 | | | | | Oct-87 | | | | | |
| Nov-87 | | | | | Nov-87 | | | | | Nov-87 | | | | | |
| Dec-87 | | | | | Dec-87 | | | | | Dec-87 | | | | | |
| Jan-88 | | | | | Jan-88 | | | | | Jan-88 | | | | | |
| Feb-88 | | | | | Feb-88 | | | | | Feb-88 | | | | | |
| Mar-88 | | | | | Mar-88 | | | | | Mar-88 | | | | | |
| Apr-88 | | | | | Apr-88 | | | | | Apr-88 | | | | | |
| May-88 | | | | | May-88 | | | | | May-88 | | | | | |
| Jun-88 | | | | | Jun-88 | | | | | Jun-88 | | | | | |
| Jul-88 | | | | | Jul-88 | | | | | Jul-88 | | | | | |
| Aug-88 | | | | | Aug-88 | | | | | Aug-88 | | | | | |
| Sep-88 | | | | | Sep-88 | | | | | Sep-88 | | | | | |
| Oct-88 | | | | | Oct-88 | | | | | Oct-88 | | | | | |
| Nov-88 | | | | | Nov-88 | | | | | Nov-88 | | | | | |
| Dec-88 | | | | | Dec-88 | | | | | Dec-88 | | | | | |
| Jan-89 | | | | | Jan-89 | | | | | Jan-89 | | | | | |
| Feb-89 | | | | | Feb-89 | | | | | Feb-89 | | | | | |
| Mar-89 | | | | | Mar-89 | | | | | Mar-89 | | | | | |
| Apr-89 | | | | | Apr-89 | | | | | Apr-89 | | | | | |
| May-89 | | | | | May-89 | | | | | May-89 | | | | | |
| Jun-89 | | | | | Jun-89 | | | | | Jun-89 | | | | | |
| Jul-89 | | | | | Jul-89 | | | | | Jul-89 | | | | | |
| Aug-89 | | | | | Aug-89 | | | | | Aug-89 | | | | | |
| Sep-89 | | | | | Sep-89 | | | | | Sep-89 | | | | | |
| Oct-89 | | | | | Oct-89 | | | | | Oct-89 | | | | | |
| Nov-89 | | | | | Nov-89 | | | | | Nov-89 | | | | | |
| Dec-89 | | | | | Dec-89 | | | | | Dec-89 | | | | | |
| Jan-90 | | | | | Jan-90 | | | | | Jan-90 | | | | | |
| Feb-90 | | | | | Feb-90 | | | | | Feb-90 | | | | | |
| Mar-90 | | | | | Mar-90 | | | | | Mar-90 | | | | | |
| Apr-90 | | | | | Apr-90 | | | | | Apr-90 | | | | | |
| May-90 | | | | | May-90 | | | | | May-90 | | | | | |
| Jun-90 | | | | | Jun-90 | | | | | Jun-90 | | | | | |
| Jul-90 | | | | | Jul-90 | | | | | Jul-90 | | | | | |
| Aug-90 | | | | | Aug-90 | | | | | Aug-90 | | | | | |
| Sep-90 | | | | | Sep-90 | | | | | Sep-90 | | | | | |
| Oct-90 | | | | | Oct-90 | | | | | Oct-90 | | | | | |
| Nov-90 | | | | | Nov-90 | | | | | Nov-90 | | | | | |
| Dec-90 | | | | | Dec-90 | | | | | Dec-90 | | | | | |
| Jan-91 | | | | | Jan-91 | | | | | Jan-91 | | | | | |
| Feb-91 | | | | | Feb-91 | | | | | Feb-91 | | | | | |
| Mar-91 | | | | | Mar-91 | | | | | Mar-91 | | | | | |
| Apr-91 | | | | | Apr-91 | | | | | Apr-91 | | | | | |
| May-91 | | | | | May-91 | | | | | May-91 | | | | | |
| Jun-91 | | | | | Jun-91 | | | | | Jun-91 | | | | | |
| Jul-91 | | | | | Jul-91 | | | | | Jul-91 | | | | | |
| Aug-91 | | | | | Aug-91 | | | | | Aug-91 | | | | | |
| Sep-91 | | | | | Sep-91 | | | | | Sep-91 | | | | | |
| Oct-91 | | | | | Oct-91 | | | | | Oct-91 | | | | | |
| Nov-91 | | | | | Nov-91 | | | | | Nov-91 | | | | | |
| Dec-91 | | | | | Dec-91 | | | | | Dec-91 | | | | | |
| Jan-92 | | | | | Jan-92 | | | | | Jan-92 | | | | | |
| Feb-92 | | | | | Feb-92 | | | | | Feb-92 | | | | | |
| Mar-92 | | | | | Mar-92 | | | | | Mar-92 | | | | | |
| Apr-92 | | | | | Apr-92 | | | | | Apr-92 | | | | | |
| May-92 | | | | | May-92 | | | | | May-92 | | | | | |
| Jun-92 | | | | | Jun-92 | | | | | Jun-92 | | | | | |
| Jul-92 | | | | | Jul-92 | | | | | Jul-92 | | | | | |
| Aug-92 | | | | | Aug-92 | | | | | Aug-92 | | | | | |
| Sep-92 | | | | | Sep-92 | | | | | Sep-92 | | | | | |
| Oct-92 | | | | | Oct-92 | | | | | Oct-92 | | | | | |
| Nov-92 | | | | | Nov-92 | | | | | Nov-92 | | | | | |
| Dec-92 | | | | | Dec-92 | | | | | Dec-92 | | | | | |
| Jan-93 | | | | | Jan-93 | | | | | Jan-93 | | | | | |
| Feb-93 | | | | | Feb-93 | | | | | Feb-93 | | | | | |
| Mar-93 | 12 | 561 1 | 631 8 | 16 4 | Mar-93 | | | | | Mar-93 | | | | | |
| Apr-93 | 472 | 499 1 | 403 2 | 0 0 | Apr-93 | | | | | Apr-93 | | | | | |
| May-93 | | | | | May-93 | | | | | May-93 | | | | | |
| Jun-93 | 238 | 524 7 | 463 5 | 0 0 | Jun-93 | 72 | 191 2 | | 0 0 | Jun-93 | | | | | |
| Jul-93 | 118 | 538 3 | 476 5 | 0 0 | Jul-93 | 465 | 389 0 | 428 0 | 0 0 | Jul-93 | | | | | |
| Aug-93 | 119 | 527 0 | 468 2 | 0 0 | Aug-93 | 474 | 380 5 | 467 1 | 0 0 | Aug-93 | | | | | |
| Sep-93 | 116 | 526 1 | 466 3 | 0 0 | Sep-93 | | | | | Sep-93 | 335 | 303 5 | 181 6 | 5 3 | |
| Oct-93 | 120 | 526 0 | 501 2 | 0 0 | Oct-93 | | | | | Oct-93 | 744 | 132 6 | 86 6 | 1 3 | |
| Nov-93 | 126 | 488 7 | 524 0 | 0 0 | Nov-93 | 189 | 355 4 | 515 6 | 0 0 | Nov-93 | 597 | 146 9 | 102 2 | 2 8 | |
| Dec-93 | 271 | 235 1 | 259 3 | 0 0 | Dec-93 | 227 | 281 5 | 543 0 | 0 0 | Dec-93 | 528 | 130 5 | 98 2 | 0 0 | |
| Jan-94 | 290 | 222 7 | 288 5 | 0 0 | Jan-94 | 307 | 216 2 | 374 3 | 0 0 | Jan-94 | 528 | 134 8 | 103 1 | 0 0 | |
| Feb-94 | 324 | 184 9 | 325 8 | 0 0 | Feb-94 | 293 | 196 6 | 389 9 | 0 0 | Feb-94 | 457 | 132 0 | 95 7 | 0 0 | |
| Mar-94 | 401 | 161 6 | 347 8 | 0 0 | Mar-94 | 206 | 190 0 | 381 7 | 0 0 | Mar-94 | 541 | 126 7 | 92 4 | 0 0 | |
| Apr-94 | 377 | 148 1 | 362 0 | 0 0 | Apr-94 | 234 | 180 1 | 383 0 | 0 0 | Apr-94 | 499 | 122 9 | 82 6 | 0 0 | |
| May-94 | 286 | 151 3 | 371 4 | 0 0 | May-94 | 198 | 174 4 | 423 8 | 0 0 | May-94 | 575 | 117 9 | 85 0 | 0 0 | |
| Jun-94 | 236 | 149 4 | 377 2 | 0 0 | Jun-94 | 222 | 161 1 | 432 9 | 0 0 | Jun-94 | 577 | 114 6 | 83 0 | 0 0 | |
| Jul-94 | 211 | 148 8 | 384 3 | 0 0 | Jul-94 | 217 | 160 2 | 407 1 | 0 0 | Jul-94 | 587 | 111 7 | 74 6 | 0 0 | |
| Aug-94 | 192 | 155 6 | 393 1 | 0 0 | Aug-94 | 193 | 154 7 | 406 9 | 0 0 | Aug-94 | 616 | 105 3 | 74 6 | 0 0 | |
| Sep-94 | 167 | 161 0 | 387 2 | 0 0 | Sep-94 | 169 | 143 7 | 411 3 | 0 0 | Sep-94 | 413 | 83 4 | 64 6 | 0 0 | |

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

**Table 4.1: Production History (Continued)**

| | Well | 16-12-37-8W5 | | | SATELLITE | | Well | 08-07-37-7W5 | | | SATELLITE | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Battery | 06-13-37-8W5 | | | | | Battery | 08-18-37-7W5 | | | | | | | | | |
| | Casing | Depth (ft) | Dia (in) | Wt (lb/ft³) | | | Casing | Depth (ft) | Dia (in) | Wt (lb/ft³) | | | | | | | |
| | Surface | 1299 7 | 9 6 | 3 35 | | | Surface | 1079 4 | 8 6 | 2 23 | | | | | | | |
| | Prod | 8933 7 | 5 5 | 2 23 | | | Prod | 8864 8 | 5 5 | 2 23 | | | Cumulative Pool Production | | | | |
| Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | Date | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | Date | Oil MSTB | Gas MMscf | Water MSTB | Wells Producing |
| Oct-87 | | | | | Oct-87 | | | | | Oct-87 | | | | |
| Nov-87 | | | | | Nov-87 | | | | | Nov-87 | 0 8 | 0 7 | 0 0 | 1 |
| Dec-87 | | | | | Dec-87 | | | | | Dec-87 | 1 2 | 1 9 | 0 0 | 1 |
| Jan-88 | | | | | Jan-88 | | | | | Jan-88 | 1 7 | 2 2 | 0 0 | 1 |
| Feb-88 | | | | | Feb-88 | | | | | Feb-88 | 2 4 | 4 1 | 0 0 | 1 |
| Mar-88 | | | | | Mar-88 | | | | | Mar-88 | 3 0 | 5 3 | 0 0 | 1 |
| Apr-88 | | | | | Apr-88 | | | | | Apr-88 | 3 5 | 6 0 | 0 0 | 1 |
| May-88 | | | | | May-88 | | | | | May-88 | 4 1 | 6 9 | 0 0 | 1 |
| Jun-88 | | | | | Jun-88 | | | | | Jun-88 | 4 6 | 7 9 | 0 0 | 1 |
| Jul-88 | | | | | Jul-88 | | | | | Jul-88 | 5 2 | 9 1 | 0 0 | 1 |
| Aug-88 | | | | | Aug-88 | | | | | Aug-88 | 5 7 | 10 2 | 0 0 | 1 |
| Sep-88 | | | | | Sep-88 | | | | | Sep-88 | 6 2 | 11 2 | 0 0 | 1 |
| Oct-88 | | | | | Oct-88 | | | | | Oct-88 | 6 8 | 12 2 | 0 0 | 1 |
| Nov-88 | | | | | Nov-88 | | | | | Nov-88 | 7 3 | 13 2 | 0 0 | 1 |
| Dec-88 | | | | | Dec-88 | | | | | Dec-88 | 7 8 | 13 9 | 0 0 | 1 |
| Jan-89 | | | | | Jan-89 | | | | | Jan-89 | 8 4 | 14 8 | 0 0 | 1 |
| Feb-89 | | | | | Feb-89 | | | | | Feb-89 | 8 9 | 15 6 | 0 0 | 1 |
| Mar-89 | | | | | Mar-89 | | | | | Mar-89 | 12 0 | 24 5 | 0 0 | 2 |
| Apr-89 | | | | | Apr-89 | | | | | Apr-89 | 14 6 | 34 9 | 0 0 | 2 |
| May-89 | | | | | May-89 | | | | | May-89 | 16 8 | 45 7 | 0 0 | 2 |
| Jun-89 | | | | | Jun-89 | | | | | Jun-89 | 18 8 | 55 4 | 0 0 | 2 |
| Jul-89 | | | | | Jul-89 | | | | | Jul-89 | 19 7 | 58 9 | 0 0 | 2 |
| Aug-89 | | | | | Aug-89 | | | | | Aug-89 | 20 6 | 63 5 | 0 0 | 2 |
| Sep-89 | | | | | Sep-89 | | | | | Sep-89 | 21 6 | 67 6 | 0 0 | 2 |
| Oct-89 | | | | | Oct-89 | | | | | Oct-89 | 22 4 | 71 1 | 0 0 | 2 |
| Nov-89 | | | | | Nov-89 | | | | | Nov-89 | 23 3 | 73 5 | 0 0 | 2 |
| Dec-89 | | | | | Dec-89 | | | | | Dec-89 | 24 1 | 76 2 | 0 0 | 2 |
| Jan-90 | | | | | Jan-90 | | | | | Jan-90 | 25 1 | 80 1 | 0 0 | 2 |
| Feb-90 | | | | | Feb-90 | | | | | Feb-90 | 26 0 | 83 8 | 0 0 | 2 |
| Mar-90 | | | | | Mar-90 | | | | | Mar-90 | 29 2 | 88 8 | 0 1 | 3 |
| Apr-90 | | | | | Apr-90 | | | | | Apr-90 | 30 8 | 92 8 | 0 1 | 3 |
| May-90 | | | | | May-90 | | | | | May-90 | 40 2 | 102 9 | 0 1 | 3 |
| Jun-90 | | | | | Jun-90 | | | | | Jun-90 | 47 3 | 112 2 | 0 1 | 3 |
| Jul-90 | | | | | Jul-90 | | | | | Jul-90 | 49 0 | 116 1 | 0 1 | 3 |
| Aug-90 | | | | | Aug-90 | | | | | Aug-90 | 56 6 | 127 1 | 0 1 | 4 |
| Sep-90 | | | | | Sep-90 | | | | | Sep-90 | 63 9 | 135 5 | 0 1 | 4 |
| Oct-90 | | | | | Oct-90 | | | | | Oct-90 | 76 0 | 147 3 | 0 3 | 5 |
| Nov-90 | | | | | Nov-90 | | | | | Nov-90 | 88 2 | 158 7 | 0 3 | 5 |
| Dec-90 | | | | | Dec-90 | | | | | Dec-90 | 102 5 | 174 6 | 0 3 | 5 |
| Jan-91 | | | | | Jan-91 | | | | | Jan-91 | 108 9 | 181 4 | 0 3 | 4 |
| Feb-91 | | | | | Feb-91 | | | | | Feb-91 | 122 1 | 193 2 | 0 3 | 6 |
| Mar-91 | | | | | Mar-91 | | | | | Mar-91 | 136 3 | 206 7 | 0 3 | 6 |
| Apr-91 | | | | | Apr-91 | | | | | Apr-91 | 150 4 | 220 8 | 0 3 | 6 |
| May-91 | | | | | May-91 | | | | | May-91 | 159 7 | 230 6 | 0 3 | 5 |
| Jun-91 | | | | | Jun-91 | | | | | Jun-91 | 172 0 | 243 0 | 0 3 | 6 |
| Jul-91 | | | | | Jul-91 | | | | | Jul-91 | 184 4 | 255 5 | 0 3 | 6 |
| Aug-91 | | | | | Aug-91 | | | | | Aug-91 | 196 2 | 266 9 | 0 3 | 6 |
| Sep-91 | | | | | Sep-91 | | | | | Sep-91 | 208 3 | 279 1 | 0 3 | 6 |
| Oct-91 | | | | | Oct-91 | | | | | Oct-91 | 220 5 | 291 5 | 0 3 | 6 |
| Nov-91 | | | | | Nov-91 | | | | | Nov-91 | 232 6 | 303 6 | 0 3 | 6 |
| Dec-91 | | | | | Dec-91 | | | | | Dec-91 | 244 6 | 316 1 | 0 4 | 6 |
| Jan-92 | | | | | Jan-92 | | | | | Jan-92 | 257 0 | 329 3 | 0 4 | 6 |
| Feb-92 | | | | | Feb-92 | | | | | Feb-92 | 268 1 | 341 4 | 0 4 | 6 |
| Mar-92 | | | | | Mar-92 | | | | | Mar-92 | 281 1 | 357 2 | 0 4 | 7 |
| Apr-92 | | | | | Apr-92 | | | | | Apr-92 | 293 2 | 371 7 | 0 4 | 6 |
| May-92 | | | | | May-92 | | | | | May-92 | 305 4 | 386 4 | 0 4 | 6 |
| Jun-92 | | | | | Jun-92 | | | | | Jun-92 | 316 8 | 399 8 | 0 4 | 6 |
| Jul-92 | | | | | Jul-92 | | | | | Jul-92 | 331 9 | 416 9 | 0 4 | 7 |
| Aug-92 | | | | | Aug-92 | | | | | Aug-92 | 346 7 | 434 0 | 0 4 | 8 |
| Sep-92 | | | | | Sep-92 | | | | | Sep-92 | 361 8 | 456 1 | 0 4 | 7 |
| Oct-92 | | | | | Oct-92 | | | | | Oct-92 | 379 5 | 476 5 | 0 5 | 8 |
| Nov-92 | | | | | Nov-92 | | | | | Nov-92 | 396 0 | 495 0 | 0 5 | 8 |
| Dec-92 | | | | | Dec-92 | | | | | Dec-92 | 412 5 | 510 0 | 0 5 | 8 |
| Jan-93 | | | | | Jan-93 | | | | | Jan-93 | 428 4 | 524 0 | 0 5 | 8 |
| Feb-93 | | | | | Feb-93 | | | | | Feb-93 | 444 8 | 541 4 | 0 5 | 9 |
| Mar-93 | | | | | Mar-93 | | | | | Mar-93 | 463 6 | 561 9 | 0 5 | 10 |
| Apr-93 | | | | | Apr-93 | | | | | Apr-93 | 492 0 | 592 1 | 0 5 | 10 |
| May-93 | | | | | May-93 | | | | | May-93 | 510 7 | 616 6 | 0 5 | 9 |
| Jun-93 | | | | | Jun-93 | | | | | Jun-93 | 534 9 | 644 3 | 0 5 | 11 |
| Jul-93 | | | | | Jul-93 | | | | | Jul-93 | 562 2 | 678 3 | 0 5 | 11 |
| Aug-93 | | | | | Aug-93 | | | | | Aug-93 | 589 3 | 711 6 | 0 5 | 11 |
| Sep-93 | | | | | Sep-93 | | | | | Sep-93 | 611 7 | 736 6 | 0 5 | 11 |
| Oct-93 | 185 | 593 1 | 67 2 | 3 6 | Oct-93 | | | | | Oct-93 | 639 9 | 763 4 | 0 6 | 12 |
| Nov-93 | 624 | 421 0 | 336 7 | 0 0 | Nov-93 | | | | | Nov-93 | 674 8 | 804 5 | 0 7 | 13 |
| Dec-93 | | | | | Dec-93 | | | | | Dec-93 | 697 4 | 839 8 | 0 7 | 12 |
| Jan-94 | | | | | Jan-94 | | | | | Jan-94 | 720 4 | 877 6 | 0 7 | 12 |
| Feb-94 | 215 | 401 6 | 386 3 | 0 0 | Feb-94 | | | | | Feb-94 | 744 2 | 915 5 | 0 7 | 13 |
| Mar-94 | 168 | 379 3 | 404 6 | 0 0 | Mar-94 | | | | | Mar-94 | 767 3 | 956 0 | 0 7 | 13 |
| Apr-94 | 120 | 397 4 | 396 8 | 0 0 | Apr-94 | 24 | 562 9 | 408 2 | 0 0 | Apr-94 | 789 4 | 995 0 | 0 7 | 14 |
| May-94 | 144 | 407 8 | 518 2 | 0 0 | May-94 | 158 | 370 5 | 259 3 | 0 0 | May-94 | 813 4 | 1040 1 | 0 7 | 14 |
| Jun-94 | 120 | 396 5 | 379 1 | 0 4 | Jun-94 | 560 | 305 6 | 212 4 | 0 0 | Jun-94 | 840 4 | 1083 7 | 0 7 | 14 |
| Jul-94 | 120 | 451 6 | 584 9 | 0 0 | Jul-94 | 576 | 239 3 | 233 1 | 0 0 | Jul-94 | 865 7 | 1132 9 | 0 7 | 14 |
| Aug-94 | 168 | 382 9 | 637 4 | 0 0 | Aug-94 | 240 | 271 2 | 213 3 | 0 0 | Aug-94 | 886 6 | 1179 4 | 0 7 | 14 |
| Sep-94 | 168 | 379 8 | 709 4 | 0 1 | Sep-94 | 264 | 242 3 | 221 0 | 0 0 | Sep-94 | 905 6 | 1218 0 | 0 7 | 14 |

MRL = 88 STB/d
GOR = 1,129 Mscf/STB

MRL = 88 STB/d
GOR = 1,129 Mscf/STB

**Table 4.1: Production History (Continued)**

| Date | Well | 16-9-37-7W5 | | | Date | Well | 6-15-37-7W5 | | | Date | Well | 8-19-37-8W5 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | | Oct-87 | | | | | Oct-87 | | | | |
| Nov-87 | 477 | 38.2 | 50.8 | 0.0 | Nov-87 | | | | | Nov-87 | | | | |
| Dec-87 | 528 | 21.2 | 45.2 | 0.0 | Dec-87 | | | | | Dec-87 | | | | |
| Jan-88 | 288 | 36.9 | 79.5 | 0.0 | Jan-88 | | | | | Jan-88 | | | | |
| Feb-88 | 696 | 25.9 | 54.7 | 0.0 | Feb-88 | | | | | Feb-88 | | | | |
| Mar-88 | 744 | 18.1 | 42.6 | 0.0 | Mar-88 | | | | | Mar-88 | | | | |
| Apr-88 | 480 | 25.1 | 56.7 | 0.0 | Apr-88 | | | | | Apr-88 | | | | |
| May-88 | 579 | 25.2 | 49.5 | 0.0 | May-88 | | | | | May-88 | | | | |
| Jun-88 | 705 | 15.8 | 27.1 | 0.0 | Jun-88 | | | | | Jun-88 | | | | |
| Jul-88 | 722 | 20.0 | 31.9 | 0.0 | Jul-88 | | | | | Jul-88 | | | | |
| Aug-88 | 739 | 18.1 | 29.0 | 0.0 | Aug-88 | | | | | Aug-88 | | | | |
| Sep-88 | 588 | 20.4 | 32.8 | 0.0 | Sep-88 | | | | | Sep-88 | | | | |
| Oct-88 | 728 | 18.7 | 27.8 | 0.0 | Oct-88 | | | | | Oct-88 | | | | |
| Nov-88 | 720 | 17.3 | 26.1 | 0.0 | Nov-88 | | | | | Nov-88 | | | | |
| Dec-88 | 568 | 22.5 | 35.5 | 0.0 | Dec-88 | | | | | Dec-88 | | | | |
| Jan-89 | 740 | 18.8 | 28.0 | 0.0 | Jan-89 | | | | | Jan-89 | | | | |
| Feb-89 | 648 | 17.8 | 27.7 | 0.0 | Feb-89 | | | | | Feb-89 | | | | |
| Mar-89 | 528 | 19.6 | 30.5 | 0.0 | Mar-89 | 636 | 102.6 | 107.0 | 0.0 | Mar-89 | | | | |
| Apr-89 | 432 | 28.4 | 40.0 | 0.0 | Apr-89 | 676 | 71.6 | 75.4 | 0.0 | Apr-89 | | | | |
| May-89 | 552 | 25.2 | 35.9 | 0.0 | May-89 | 735 | 53.6 | 56.5 | 0.0 | May-89 | | | | |
| Jun-89 | 711 | 18.3 | 26.6 | 0.0 | Jun-89 | 720 | 49.2 | 52.4 | 0.0 | Jun-89 | | | | |
| Jul-89 | 744 | 17.4 | 26.6 | 0.0 | Jul-89 | 185 | 49.4 | 53.8 | 0.0 | Jul-89 | | | | |
| Aug-89 | 744 | 15.9 | 24.3 | 0.0 | Aug-89 | 288 | 33.3 | 33.0 | 0.0 | Aug-89 | | | | |
| Sep-89 | 720 | 20.1 | 31.2 | 0.0 | Sep-89 | 240 | 42.5 | 41.2 | 0.0 | Sep-89 | | | | |
| Oct-89 | 525 | 16.9 | 27.7 | 0.0 | Oct-89 | 176 | 58.7 | 56.9 | 0.0 | Oct-89 | | | | |
| Nov-89 | 720 | 17.5 | 23.7 | 0.0 | Nov-89 | 108 | 65.0 | 63.0 | 0.0 | Nov-89 | | | | |
| Dec-89 | 744 | 15.8 | 22.3 | 0.0 | Dec-89 | 120 | 63.3 | 61.3 | 0.0 | Dec-89 | | | | |
| Jan-90 | 744 | 15.0 | 20.9 | 0.0 | Jan-90 | 173 | 67.3 | 65.2 | 0.0 | Jan-90 | | | | |
| Feb-90 | 672 | 16.1 | 22.3 | 0.0 | Feb-90 | 189 | 64.0 | 61.9 | 0.0 | Feb-90 | | | | |
| Mar-90 | 744 | 16.2 | 22.9 | 0.0 | Mar-90 | 155 | 86.7 | 83.7 | 0.0 | Mar-90 | 125 | 408.6 | 384.6 | 0.0 |
| Apr-90 | 720 | 14.8 | 20.9 | 0.0 | Apr-90 | 142 | 71.0 | 68.4 | 0.0 | Apr-90 | 45 | 390.5 | 348.5 | 0.0 |
| May-90 | 744 | 14.7 | 20.2 | 0.0 | May-90 | 144 | 83.3 | 80.5 | 0.0 | May-90 | 575 | 352.0 | 314.1 | 0.0 |
| Jun-90 | 720 | 15.0 | 20.4 | 0.0 | Jun-90 | 234 | 57.2 | 55.5 | 0.0 | Jun-90 | 400 | 367.1 | 327.6 | 0.0 |
| Jul-90 | 432 | 18.7 | 26.1 | 0.0 | Jul-90 | 160 | 72.9 | 74.7 | 0.0 | Jul-90 | 54 | 359.8 | 321.1 | 0.0 |
| Aug-90 | 744 | 18.7 | 23.1 | 0.0 | Aug-90 | 282 | 53.4 | 60.2 | 0.0 | Aug-90 | 168 | 357.2 | 318.7 | 0.0 |
| Sep-90 | 720 | 16.7 | 23.9 | 0.0 | Sep-90 | 143 | 73.2 | 87.7 | 0.0 | Sep-90 | 189 | 361.6 | 322.7 | 0.0 |
| Oct-90 | 720 | 16.3 | 24.3 | 0.0 | Oct-90 | 168 | 79.3 | 101.8 | 0.0 | Oct-90 | 188 | 364.2 | 325.0 | 0.0 |
| Nov-90 | 720 | 18.0 | 27.3 | 0.0 | Nov-90 | 117 | 70.9 | 94.6 | 0.0 | Nov-90 | 204 | 343.4 | 306.3 | 0.0 |
| Dec-90 | 639 | 17.4 | 27.6 | 0.0 | Dec-90 | 120 | 97.5 | 132.3 | 0.0 | Dec-90 | 192 | 355.8 | 317.3 | 0.0 |
| Jan-91 | 744 | 18.5 | 27.8 | 0.0 | Jan-91 | 142 | 99.1 | 137.4 | 0.0 | Jan-91 | 192 | 352.3 | 313.2 | 0.0 |
| Feb-91 | 672 | 18.2 | 29.2 | 0.0 | Feb-91 | 166 | 84.1 | 116.9 | 0.0 | Feb-91 | 172 | 354.5 | 314.3 | 0.0 |
| Mar-91 | 710 | 16.3 | 26.4 | 0.0 | Mar-91 | 262 | 79.6 | 116.5 | 0.0 | Mar-91 | 168 | 342.1 | 301.7 | 0.0 |
| Apr-91 | 615 | 17.5 | 27.3 | 0.0 | Apr-91 | 286 | 73.0 | 113.4 | 0.0 | Apr-91 | 192 | 339.1 | 296.6 | 0.0 |
| May-91 | 744 | 16.7 | 24.4 | 0.0 | May-91 | 264 | 72.6 | 118.2 | 0.0 | May-91 | 201 | 341.4 | 295.4 | 0.0 |
| Jun-91 | 720 | 15.9 | 24.0 | 0.0 | Jun-91 | 288 | 74.9 | 128.0 | 0.0 | Jun-91 | 192 | 348.1 | 297.9 | 0.0 |
| Jul-91 | 744 | 15.5 | 23.6 | 0.0 | Jul-91 | 264 | 74.0 | 132.4 | 0.0 | Jul-91 | 207 | 334.3 | 283.5 | 0.0 |
| Aug-91 | 744 | 14.2 | 21.4 | 0.0 | Aug-91 | 240 | 76.7 | 141.2 | 0.0 | Aug-91 | 192 | 359.7 | 302.7 | 0.0 |
| Sep-91 | 720 | 14.2 | 21.0 | 0.0 | Sep-91 | 260 | 73.0 | 138.6 | 0.0 | Sep-91 | 209 | 323.0 | 269.3 | 0.0 |
| Oct-91 | 744 | 12.8 | 18.6 | 0.0 | Oct-91 | 240 | 67.4 | 131.8 | 0.0 | Oct-91 | 207 | 330.7 | 274.2 | 0.0 |
| Nov-91 | 720 | 13.0 | 18.5 | 0.0 | Nov-91 | 334 | 75.9 | 157.2 | 0.0 | Nov-91 | 187 | 352.0 | 298.3 | 0.0 |
| Dec-91 | 432 | 12.4 | 17.7 | 0.0 | Dec-91 | 336 | 68.3 | 151.2 | 0.0 | Dec-91 | 188 | 356.1 | 299.3 | 0.0 |
| Jan-92 | 744 | 12.0 | 14.3 | 0.0 | Jan-92 | 291 | 69.3 | 159.6 | 0.0 | Jan-92 | 192 | 354.7 | 287.9 | 0.0 |
| Feb-92 | 696 | 20.3 | 29.6 | 0.0 | Feb-92 | 265 | 72.6 | 173.9 | 0.0 | Feb-92 | 144 | 341.0 | 275.3 | 0.0 |
| Mar-92 | 744 | 20.1 | 37.6 | 0.0 | Mar-92 | 359 | 60.6 | 153.5 | 0.0 | Mar-92 | 208 | 325.1 | 261.3 | 0.0 |
| Apr-92 | 720 | 19.2 | 40.2 | 0.0 | Apr-92 | 336 | 56.7 | 148.0 | 0.0 | Apr-92 | 192 | 343.1 | 275.9 | 0.0 |
| May-92 | 744 | 19.1 | 41.7 | 0.0 | May-92 | 480 | 51.8 | 141.1 | 0.0 | May-92 | 187 | 360.7 | 288.3 | 0.0 |
| Jun-92 | 720 | 18.5 | 40.8 | 0.0 | Jun-92 | 466 | 47.0 | 135.7 | 0.0 | Jun-92 | 176 | 375.8 | 298.3 | 0.0 |
| Jul-92 | 744 | 18.5 | 40.3 | 0.0 | Jul-92 | 312 | 55.8 | 167.0 | 0.0 | Jul-92 | 181 | 375.0 | 295.6 | 0.0 |
| Aug-92 | 744 | 17.7 | 37.7 | 0.0 | Aug-92 | 265 | 66.0 | 200.2 | 0.0 | Aug-92 | 185 | 364.7 | 286.1 | 0.0 |
| Sep-92 | 720 | 16.9 | 34.8 | 0.0 | Sep-92 | 240 | 71.7 | 222.3 | 0.0 | Sep-92 | 178 | 371.7 | 290.2 | 0.0 |
| Oct-92 | 744 | 16.2 | 32.1 | 0.0 | Oct-92 | 205 | 71.5 | 225.1 | 0.0 | Oct-92 | 182 | 374.4 | 290.8 | 0.0 |
| Nov-92 | 720 | 16.3 | 31.4 | 0.0 | Nov-92 | 166 | 83.8 | 264.6 | 0.0 | Nov-92 | 240 | 273.0 | 211.1 | 0.0 |
| Dec-92 | 744 | 15.2 | 28.7 | 0.0 | Dec-92 | 208 | 81.2 | 264.7 | 0.0 | Dec-92 | 335 | 192.0 | 148.5 | 0.0 |
| Jan-93 | 744 | 15.1 | 28.0 | 0.0 | Jan-93 | 290 | 70.9 | 244.9 | 0.0 | Jan-93 | 278 | 241.8 | 199.1 | 0.0 |
| Feb-93 | 672 | 14.7 | 27.2 | 0.0 | Feb-93 | 334 | 60.2 | 214.5 | 0.0 | Feb-93 | 322 | 192.5 | 177.2 | 0.0 |
| Mar-93 | 744 | 14.4 | 26.7 | 0.0 | Mar-93 | | | | | Mar-93 | 364 | 188.8 | 204.8 | 0.0 |
| Apr-93 | 720 | 13.0 | 24.0 | 0.0 | Apr-93 | | | | | Apr-93 | 375 | 172.5 | 176.8 | 0.0 |
| May-93 | 744 | 9.6 | 16.9 | 0.0 | May-93 | | | | | May-93 | 456 | 165.0 | 204.2 | 0.0 |
| Jun-93 | 720 | 11.9 | 20.3 | 0.0 | Jun-93 | | | | | Jun-93 | 401 | 169.6 | 222.3 | 0.0 |
| Jul-93 | 744 | 12.0 | 21.3 | 0.0 | Jul-93 | | | | | Jul-93 | 398 | 154.4 | 207.0 | 0.0 |
| Aug-93 | 666 | 11.1 | 20.4 | 0.0 | Aug-93 | | | | | Aug-93 | 257 | 265.6 | 400.9 | 0.0 |
| Sep-93 | 720 | 9.2 | 16.5 | 0.0 | Sep-93 | | | | | Sep-93 | 228 | 284.2 | 455.2 | 0.0 |
| Oct-93 | 576 | 7.2 | 12.7 | 0.0 | Oct-93 | | | | | Oct-93 | 271 | 252.0 | 407.8 | 0.0 |
| Nov-93 | 720 | 5.9 | 9.5 | 0.0 | Nov-93 | | | | | Nov-93 | 257 | 248.3 | 385.2 | 0.0 |
| Dec-93 | 744 | 8.1 | 13.4 | 0.0 | Dec-93 | | | | | Dec-93 | 312 | 178.5 | 302.2 | 0.0 |
| Jan-94 | 744 | 7.3 | 12.7 | 0.0 | Jan-94 | | | | | Jan-94 | 372 | 148.1 | 266.9 | 0.0 |
| Feb-94 | 607 | 8.0 | 14.5 | 0.0 | Feb-94 | | | | | Feb-94 | 241 | 151.8 | 288.4 | 0.0 |
| Mar-94 | 724 | 7.3 | 13.5 | 0.0 | Mar-94 | | | | | Mar-94 | 270 | 134.6 | 279.6 | 0.0 |
| Apr-94 | 720 | 6.8 | 12.9 | 0.0 | Apr-94 | | | | | Apr-94 | 198 | 132.0 | 286.8 | 0.0 |
| May-94 | 744 | 6.4 | 12.4 | 0.0 | May-94 | | | | | May-94 | 239 | 109.3 | 234.9 | 0.0 |
| Jun-94 | 720 | 6.5 | 12.8 | 0.0 | Jun-94 | | | | | Jun-94 | 128 | 177.1 | 367.4 | 0.0 |
| Jul-94 | 528 | 6.0 | 12.0 | 0.0 | Jul-94 | | | | | Jul-94 | 239 | 92.6 | 187.4 | 0.0 |
| Aug-94 | 504 | 9.2 | 18.3 | 0.0 | Aug-94 | | | | | Aug-94 | 120 | 104.2 | 224.6 | 0.0 |
| Sep-94 | | | | | Sep-94 | | | | | Sep-94 | 164 | 105.0 | 239.7 | 0.0 |
| MRL = 88 STB/d<br>GOR = 1.129 Mscf/STB | | | | | MRL = 88 STB/d<br>GOR = 1.129 Mscf/STB | | | | | MRL = 88 STB/d<br>GOR = 1.129 Mscf/STB | | | | |

Table 4.2: Chedderville Viking "A" Production Match (Oct-94)

| Date | Well | 6-13-37-8W5 | | | Date | Well | 6-16-37-7W5 | | | Date | Well | 8-14-37-8W5 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | | Oct-87 | | | | | Oct-87 | | | | |
| Nov-87 | | | | | Nov-87 | | | | | Nov-87 | | | | |
| Dec-87 | | | | | Dec-87 | | | | | Dec-87 | | | | |
| Jan-88 | | | | | Jan-88 | | | | | Jan-88 | | | | |
| Feb-88 | | | | | Feb-88 | | | | | Feb-88 | | | | |
| Mar-88 | | | | | Mar-88 | | | | | Mar-88 | | | | |
| Apr-88 | | | | | Apr-88 | | | | | Apr-88 | | | | |
| May-88 | | | | | May-88 | | | | | May-88 | | | | |
| Jun-88 | | | | | Jun-88 | | | | | Jun-88 | | | | |
| Jul-88 | | | | | Jul-88 | | | | | Jul-88 | | | | |
| Aug-88 | | | | | Aug-88 | | | | | Aug-88 | | | | |
| Sep-88 | | | | | Sep-88 | | | | | Sep-88 | | | | |
| Oct-88 | | | | | Oct-88 | | | | | Oct-88 | | | | |
| Nov-88 | | | | | Nov-88 | | | | | Nov-88 | | | | |
| Dec-88 | | | | | Dec-88 | | | | | Dec-88 | | | | |
| Jan-89 | | | | | Jan-89 | | | | | Jan-89 | | | | |
| Feb-89 | | | | | Feb-89 | | | | | Feb-89 | | | | |
| Mar-89 | | | | | Mar-89 | | | | | Mar-89 | | | | |
| Apr-89 | | | | | Apr-89 | | | | | Apr-89 | | | | |
| May-89 | | | | | May-89 | | | | | May-89 | | | | |
| Jun-89 | | | | | Jun-89 | | | | | Jun-89 | | | | |
| Jul-89 | | | | | Jul-89 | | | | | Jul-89 | | | | |
| Aug-89 | | | | | Aug-89 | | | | | Aug-89 | | | | |
| Sep-89 | | | | | Sep-89 | | | | | Sep-89 | | | | |
| Oct-89 | | | | | Oct-89 | | | | | Oct-89 | | | | |
| Nov-89 | | | | | Nov-89 | | | | | Nov-89 | | | | |
| Dec-89 | | | | | Dec-89 | | | | | Dec-89 | | | | |
| Jan-90 | | | | | Jan-90 | | | | | Jan-90 | | | | |
| Feb-90 | | | | | Feb-90 | | | | | Feb-90 | | | | |
| Mar-90 | | | | | Mar-90 | | | | | Mar-90 | | | | |
| Apr-90 | | | | | Apr-90 | | | | | Apr-90 | | | | |
| May-90 | | | | | May-90 | | | | | May-90 | | | | |
| Jun-90 | | | | | Jun-90 | | | | | Jun-90 | | | | |
| Jul-90 | | | | | Jul-90 | | | | | Jul-90 | | | | |
| Aug-90 | 744 | 127.7 | 111.9 | 0.0 | Aug-90 | | | | | Aug-90 | | | | |
| Sep-90 | 528 | 160.4 | 140.6 | 0.0 | Sep-90 | | | | | Sep-90 | | | | |
| Oct-90 | 744 | 222.2 | 194.8 | 0.0 | Oct-90 | 63 | 491.1 | 430.5 | 0.0 | Oct-90 | | | | |
| Nov-90 | 120 | 173.6 | 152.2 | 0.0 | Nov-90 | 621 | 290.1 | 254.3 | 0.0 | Nov-90 | | | | |
| Dec-90 | 672 | 122.3 | 107.2 | 0.0 | Dec-90 | 589 | 291.6 | 255.6 | 0.0 | Dec-90 | | | | |
| Jan-91 | 336 | 173.0 | 151.6 | 0.0 | Jan-91 | | | | | Jan-91 | | | | |
| Feb-91 | 408 | 138.4 | 121.3 | 0.0 | Feb-91 | 213 | 268.3 | 235.2 | 0.0 | Feb-91 | 600 | 192.3 | 156.5 | 0.0 |
| Mar-91 | 288 | 224.5 | 196.8 | 0.0 | Mar-91 | 234 | 270.7 | 237.3 | 0.0 | Mar-91 | 744 | 167.5 | 136.3 | 0.0 |
| Apr-91 | 312 | 226.6 | 198.8 | 0.0 | Apr-91 | 244 | 254.9 | 223.3 | 0.0 | Apr-91 | 720 | 153.6 | 125.0 | 0.0 |
| May-91 | 264 | 222.4 | 192.1 | 0.0 | May-91 | 236 | 266.4 | 233.5 | 0.0 | May-91 | | | | |
| Jun-91 | 312 | 225.0 | 192.3 | 0.0 | Jun-91 | 231 | 266.1 | 233.2 | 0.0 | Jun-91 | 384 | 168.5 | 137.1 | 0.0 |
| Jul-91 | 288 | 235.0 | 199.7 | 0.0 | Jul-91 | 238 | 262.9 | 230.4 | 0.0 | Jul-91 | 744 | 88.6 | 72.1 | 0.0 |
| Aug-91 | 240 | 249.4 | 210.3 | 0.0 | Aug-91 | 264 | 237.9 | 208.5 | 0.0 | Aug-91 | 264 | 241.2 | 196.3 | 0.0 |
| Sep-91 | 312 | 212.5 | 177.3 | 0.0 | Sep-91 | 262 | 237.5 | 208.3 | 0.0 | Sep-91 | 336 | 195.2 | 158.9 | 0.0 |
| Oct-91 | 288 | 235.7 | 195.4 | 0.0 | Oct-91 | 264 | 238.6 | 209.0 | 0.0 | Oct-91 | 312 | 214.4 | 174.5 | 0.0 |
| Nov-91 | 264 | 249.7 | 205.4 | 0.0 | Nov-91 | 237 | 257.7 | 225.2 | 0.0 | Nov-91 | 288 | 211.4 | 172.0 | 0.0 |
| Dec-91 | 240 | 280.4 | 228.9 | 0.0 | Dec-91 | 262 | 237.7 | 207.1 | 0.0 | Dec-91 | 240 | 258.6 | 209.9 | 0.0 |
| Jan-92 | 240 | 295.9 | 239.4 | 0.0 | Jan-92 | 261 | 239.5 | 208.2 | 0.0 | Jan-92 | 240 | 272.6 | 219.9 | 0.0 |
| Feb-92 | 216 | 274.2 | 219.9 | 0.0 | Feb-92 | 266 | 236.1 | 204.9 | 0.0 | Feb-92 | 216 | 286.8 | 229.3 | 0.0 |
| Mar-92 | 240 | 288.3 | 229.9 | 0.0 | Mar-92 | 285 | 220.8 | 192.3 | 0.0 | Mar-92 | 264 | 243.4 | 193.7 | 0.0 |
| Apr-92 | 264 | 249.1 | 198.5 | 0.0 | Apr-92 | 245 | 251.0 | 220.8 | 0.0 | Apr-92 | 240 | 271.7 | 216.2 | 0.0 |
| May-92 | 288 | 234.1 | 185.6 | 0.0 | May-92 | 237 | 223.2 | 196.0 | 0.0 | May-92 | 240 | 268.5 | 212.2 | 0.0 |
| Jun-92 | 264 | 248.6 | 196.3 | 0.0 | Jun-92 | 178 | 239.5 | 211.5 | 0.0 | Jun-92 | 240 | 273.1 | 214.4 | 0.0 |
| Jul-92 | 504 | 132.1 | 104.1 | 0.0 | Jul-92 | 193 | 251.1 | 229.7 | 0.0 | Jul-92 | 312 | 208.8 | 163.5 | 0.0 |
| Aug-92 | 480 | 140.3 | 110.6 | 0.0 | Aug-92 | 215 | 237.2 | 306.9 | 0.0 | Aug-92 | 504 | 129.1 | 101.1 | 0.0 |
| Sep-92 | 264 | 245.2 | 192.3 | 0.0 | Sep-92 | 210 | 246.2 | 498.1 | 0.0 | Sep-92 | 312 | 170.6 | 133.5 | 0.0 |
| Oct-92 | 336 | 200.8 | 156.8 | 0.0 | Oct-92 | 289 | 207.2 | 503.9 | 0.0 | Oct-92 | 288 | 228.7 | 178.5 | 0.0 |
| Nov-92 | 408 | 163.9 | 128.0 | 0.0 | Nov-92 | 360 | 154.7 | 363.3 | 0.0 | Nov-92 | 288 | 229.8 | 178.9 | 0.0 |
| Dec-92 | 334 | 230.3 | 178.8 | 0.0 | Dec-92 | 240 | 225.7 | 472.2 | 0.0 | Dec-92 | 258 | 307.4 | 237.6 | 0.0 |
| Jan-93 | 344 | 192.5 | 149.3 | 0.0 | Jan-93 | 111 | 282.2 | 521.1 | 0.0 | Jan-93 | 221 | 295.1 | 227.0 | 0.0 |
| Feb-93 | 241 | 217.9 | 168.7 | 0.0 | Feb-93 | 110 | 273.5 | 486.2 | 0.0 | Feb-93 | 281 | 134.3 | 104.0 | 0.0 |
| Mar-93 | 306 | 207.9 | 160.1 | 0.0 | Mar-93 | 183 | 239.5 | 507.8 | 0.0 | Mar-93 | 394 | 178.3 | 138.9 | 0.0 |
| Apr-93 | 311 | 218.4 | 168.1 | 0.0 | Apr-93 | 223 | 216.1 | 528.0 | 0.0 | Apr-93 | 350 | 227.8 | 175.7 | 0.0 |
| May-93 | 313 | 237.6 | 182.7 | 0.0 | May-93 | 312 | 174.9 | 445.0 | 0.0 | May-93 | 888 | 183.5 | 141.6 | 0.0 |
| Jun-93 | 344 | 218.4 | 168.7 | 0.0 | Jun-93 | 308 | 158.9 | 387.1 | 0.0 | Jun-93 | 402 | 171.3 | 132.3 | 0.0 |
| Jul-93 | 337 | 211.8 | 170.9 | 0.0 | Jul-93 | 264 | 189.9 | 387.2 | 0.0 | Jul-93 | 351 | 182.7 | 140.9 | 0.0 |
| Aug-93 | 318 | 207.9 | 183.6 | 0.0 | Aug-93 | 179 | 158.6 | 366.9 | 0.0 | Aug-93 | 372 | 175.9 | 135.4 | 0.0 |
| Sep-93 | 292 | 210.0 | 195.1 | 0.0 | Sep-93 | 154 | 149.1 | 356.0 | 0.0 | Sep-93 | 362 | 173.5 | 134.7 | 0.0 |
| Oct-93 | 238 | 219.7 | 203.9 | 0.0 | Oct-93 | 117 | 151.8 | 360.9 | 0.0 | Oct-93 | 381 | 179.2 | 146.7 | 0.0 |
| Nov-93 | 308 | 210.1 | 210.0 | 0.0 | Nov-93 | 126 | 169.5 | 410.5 | 0.0 | Nov-93 | 357 | 179.5 | 151.9 | 0.0 |
| Dec-93 | 306 | 207.9 | 218.8 | 0.0 | Dec-93 | 160 | 144.2 | 382.1 | 0.0 | Dec-93 | 357 | 178.4 | 152.4 | 0.0 |
| Jan-94 | 310 | 211.1 | 210.4 | 0.0 | Jan-94 | 177 | 152.9 | 441.7 | 0.0 | Jan-94 | 402 | 163.9 | 139.9 | 0.0 |
| Feb-94 | 276 | 211.1 | 250.9 | 0.0 | Feb-94 | 167 | 150.5 | 495.3 | 0.0 | Feb-94 | 362 | 161.9 | 138.3 | 0.0 |
| Mar-94 | 312 | 207.1 | 268.8 | 0.0 | Mar-94 | 189 | 121.6 | 446.7 | 0.0 | Mar-94 | 330 | 196.3 | 178.3 | 0.0 |
| Apr-94 | 308 | 209.4 | 287.1 | 0.0 | Apr-94 | 192 | 113.5 | 445.7 | 0.0 | Apr-94 | 362 | 171.7 | 147.1 | 0.0 |
| May-94 | 276 | 202.8 | 251.6 | 0.0 | May-94 | 233 | 118.7 | 472.6 | 0.0 | May-94 | 396 | 169.7 | 132.2 | 0.0 |
| Jun-94 | 294 | 209.3 | 247.3 | 0.0 | Jun-94 | 163 | 124.7 | 475.2 | 0.0 | Jun-94 | 404 | 156.5 | 118.0 | 0.0 |
| Jul-94 | 326 | 158.3 | 225.4 | 0.0 | Jul-94 | 150 | 121.8 | 452.6 | 0.0 | Jul-94 | 377 | 165.4 | 141.7 | 0.0 |
| Aug-94 | 271 | 185.9 | 306.9 | 0.0 | Aug-94 | 133 | 140.4 | 556.9 | 0.0 | Aug-94 | 392 | 163.8 | 154.2 | 0.0 |
| Sep-94 | 333 | 175.2 | 294.5 | 0.0 | Sep-94 | 127 | 133.6 | 566.2 | 0.0 | Sep-94 | 385 | 163.2 | 156.0 | 0.0 |

MRL = 88 STB/d
GOR = 1,129 Mscf/STB

MRL = 88 STB/d
GOR = 1,129 Mscf/STB

MRL = 88 STB/d
GOR = 1,129 Mscf/STB

Table 4.2: Production Match (Continued)

| Date | Well | 8-18-37-7W5 | | | Date | Well | 16-8-37-7W5 | | | Date | Well | 14-9-37-7W5 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | | Oct-87 | | | | | Oct-87 | | | | |
| Nov-87 | | | | | Nov-87 | | | | | Nov-87 | | | | |
| Dec-87 | | | | | Dec-87 | | | | | Dec-87 | | | | |
| Jan-88 | | | | | Jan-88 | | | | | Jan-88 | | | | |
| Feb-88 | | | | | Feb-88 | | | | | Feb-88 | | | | |
| Mar-88 | | | | | Mar-88 | | | | | Mar-88 | | | | |
| Apr-88 | | | | | Apr-88 | | | | | Apr-88 | | | | |
| May-88 | | | | | May-88 | | | | | May-88 | | | | |
| Jun-88 | | | | | Jun-88 | | | | | Jun-88 | | | | |
| Jul-88 | | | | | Jul-88 | | | | | Jul-88 | | | | |
| Aug-88 | | | | | Aug-88 | | | | | Aug-88 | | | | |
| Sep-88 | | | | | Sep-88 | | | | | Sep-88 | | | | |
| Oct-88 | | | | | Oct-88 | | | | | Oct-88 | | | | |
| Nov-88 | | | | | Nov-88 | | | | | Nov-88 | | | | |
| Dec-88 | | | | | Dec-88 | | | | | Dec-88 | | | | |
| Jan-89 | | | | | Jan-89 | | | | | Jan-89 | | | | |
| Feb-89 | | | | | Feb-89 | | | | | Feb-89 | | | | |
| Mar-89 | | | | | Mar-89 | | | | | Mar-89 | | | | |
| Apr-89 | | | | | Apr-89 | | | | | Apr-89 | | | | |
| May-89 | | | | | May-89 | | | | | May-89 | | | | |
| Jun-89 | | | | | Jun-89 | | | | | Jun-89 | | | | |
| Jul-89 | | | | | Jul-89 | | | | | Jul-89 | | | | |
| Aug-89 | | | | | Aug-89 | | | | | Aug-89 | | | | |
| Sep-89 | | | | | Sep-89 | | | | | Sep-89 | | | | |
| Oct-89 | | | | | Oct-89 | | | | | Oct-89 | | | | |
| Nov-89 | | | | | Nov-89 | | | | | Nov-89 | | | | |
| Dec-89 | | | | | Dec-89 | | | | | Dec-89 | | | | |
| Jan-90 | | | | | Jan-90 | | | | | Jan-90 | | | | |
| Feb-90 | | | | | Feb-90 | | | | | Feb-90 | | | | |
| Mar-90 | | | | | Mar-90 | | | | | Mar-90 | | | | |
| Apr-90 | | | | | Apr-90 | | | | | Apr-90 | | | | |
| May-90 | | | | | May-90 | | | | | May-90 | | | | |
| Jun-90 | | | | | Jun-90 | | | | | Jun-90 | | | | |
| Jul-90 | | | | | Jul-90 | | | | | Jul-90 | | | | |
| Aug-90 | | | | | Aug-90 | | | | | Aug-90 | | | | |
| Sep-90 | | | | | Sep-90 | | | | | Sep-90 | | | | |
| Oct-90 | | | | | Oct-90 | | | | | Oct-90 | | | | |
| Nov-90 | | | | | Nov-90 | | | | | Nov-90 | | | | |
| Dec-90 | | | | | Dec-90 | | | | | Dec-90 | | | | |
| Jan-91 | | | | | Jan-91 | | | | | Jan-91 | | | | |
| Feb-91 | | | | | Feb-91 | | | | | Feb-91 | | | | |
| Mar-91 | | | | | Mar-91 | | | | | Mar-91 | | | | |
| Apr-91 | | | | | Apr-91 | | | | | Apr-91 | | | | |
| May-91 | | | | | May-91 | | | | | May-91 | | | | |
| Jun-91 | | | | | Jun-91 | | | | | Jun-91 | | | | |
| Jul-91 | | | | | Jul-91 | | | | | Jul-91 | | | | |
| Aug-91 | | | | | Aug-91 | | | | | Aug-91 | | | | |
| Sep-91 | | | | | Sep-91 | | | | | Sep-91 | | | | |
| Oct-91 | | | | | Oct-91 | | | | | Oct-91 | | | | |
| Nov-91 | | | | | Nov-91 | | | | | Nov-91 | | | | |
| Dec-91 | | | | | Dec-91 | | | | | Dec-91 | | | | |
| Jan-92 | | | | | Jan-92 | | | | | Jan-92 | | | | |
| Feb-92 | | | | | Feb-92 | | | | | Feb-92 | | | | |
| Mar-92 | 93 | 130.8 | 110.5 | 0.0 | Mar-92 | | | | | Mar-92 | | | | |
| Apr-92 | | | | | Apr-92 | | | | | Apr-92 | | | | |
| May-92 | | | | | May-92 | | | | | May-92 | | | | |
| Jun-92 | | | | | Jun-92 | | | | | Jun-92 | | | | |
| Jul-92 | 738 | 110.7 | 92.7 | 0.0 | Jul-92 | | | | | Jul-92 | | | | |
| Aug-92 | 720 | 101.7 | 84.4 | 0.0 | Aug-92 | | | | | Aug-92 | | | | |
| Sep-92 | | | | | Sep-92 | 483 | 203.5 | 253.1 | 0.0 | Sep-92 | | | | |
| Oct-92 | 617 | 75.2 | 62.7 | 0.0 | Oct-92 | 334 | 271.9 | 456.2 | 0.0 | Oct-92 | | | | |
| Nov-92 | 720 | 35.8 | 29.8 | 0.0 | Nov-92 | 382 | 236.1 | 384.1 | 0.0 | Nov-92 | | | | |
| Dec-92 | 164 | 50.6 | 42.1 | 0.0 | Dec-92 | 363 | 231.4 | 366.7 | 0.0 | Dec-92 | | | | |
| Jan-93 | 493 | 120.7 | 99.4 | 0.0 | Jan-93 | 262 | 289.6 | 339.1 | 0.0 | Jan-93 | | | | |
| Feb-93 | 538 | 110.0 | 90.1 | 0.0 | Feb-93 | 337 | 184.4 | 210.9 | 0.0 | Feb-93 | 487 | 91.2 | 163.7 | 0.0 |
| Mar-93 | 579 | 123.5 | 100.5 | 0.0 | Mar-93 | 250 | 250.5 | 259.9 | 0.0 | Mar-93 | 648 | 54.9 | 124.5 | 0.0 |
| Apr-93 | 516 | 130.3 | 105.4 | 0.0 | Apr-93 | 220 | 264.8 | 274.7 | 0.0 | Apr-93 | 720 | 43.4 | 92.1 | 0.0 |
| May-93 | 580 | 122.5 | 98.3 | 0.0 | May-93 | 167 | 355.5 | 402.2 | 0.0 | May-93 | 744 | 38.8 | 77.1 | 0.0 |
| Jun-93 | 474 | 119.6 | 95.6 | 0.0 | Jun-93 | 266 | 229.1 | 276.0 | 0.0 | Jun-93 | 720 | 37.0 | 69.0 | 0.0 |
| Jul-93 | 570 | 121.5 | 96.7 | 0.0 | Jul-93 | 246 | 249.6 | 333.3 | 0.0 | Jul-93 | 744 | 35.7 | 65.5 | 0.0 |
| Aug-93 | 578 | 118.5 | 97.8 | 0.0 | Aug-93 | 291 | 226.1 | 336.0 | 0.0 | Aug-93 | 744 | 35.1 | 66.0 | 0.0 |
| Sep-93 | 588 | 110.7 | 96.8 | 0.0 | Sep-93 | 213 | 182.2 | 268.1 | 0.0 | Sep-93 | 672 | 31.7 | 60.8 | 0.0 |
| Oct-93 | 624 | 110.4 | 101.5 | 0.0 | Oct-93 | 309 | 197.0 | 297.3 | 0.0 | Oct-93 | 744 | 28.9 | 53.0 | 0.0 |
| Nov-93 | 487 | 107.1 | 99.7 | 0.0 | Nov-93 | 261 | 226.1 | 365.9 | 0.0 | Nov-93 | 720 | 27.2 | 50.8 | 0.0 |
| Dec-93 | 474 | 135.9 | 186.8 | 0.0 | Dec-93 | 744 | 63.8 | 97.2 | 0.0 | Dec-93 | 744 | 26.7 | 51.0 | 0.0 |
| Jan-94 | 463 | 140.4 | 151.0 | 0.0 | Jan-94 | 193 | 230.1 | 372.0 | 0.0 | Jan-94 | 720 | 27.5 | 54.9 | 0.0 |
| Feb-94 | 465 | 127.0 | 150.5 | 0.0 | Feb-94 | 191 | 207.6 | 317.3 | 0.0 | Feb-94 | 568 | 24.2 | 48.7 | 0.0 |
| Mar-94 | 582 | 112.0 | 149.8 | 0.0 | Mar-94 | 216 | 157.2 | 243.0 | 0.0 | Mar-94 | 744 | 22.8 | 43.2 | 0.0 |
| Apr-94 | 537 | 119.6 | 180.3 | 0.0 | Apr-94 | 192 | 226.8 | 357.1 | 0.0 | Apr-94 | 688 | 21.1 | 41.8 | 0.0 |
| May-94 | 600 | 120.0 | 186.8 | 0.0 | May-94 | 192 | 183.3 | 278.4 | 0.0 | May-94 | 744 | 21.2 | 41.6 | 0.0 |
| Jun-94 | 607 | 108.9 | 181.4 | 0.0 | Jun-94 | 231 | 118.6 | 145.1 | 0.0 | Jun-94 | 480 | 38.6 | 82.5 | 0.0 |
| Jul-94 | 655 | 100.6 | 183.4 | 0.0 | Jul-94 | 264 | 134.5 | 161.9 | 0.0 | Jul-94 | 288 | 42.7 | 91.1 | 0.0 |
| Aug-94 | 546 | 95.9 | 185.0 | 0.0 | Aug-94 | 480 | 52.0 | 68.2 | 0.0 | Aug-94 | 264 | 36.0 | 66.7 | 0.0 |
| Sep-94 | 474 | 94.2 | 176.5 | 0.0 | Sep-94 | 112 | 160.1 | 195.5 | 0.0 | Sep-94 | 312 | 24.6 | 39.6 | 0.0 |

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

Table 4.2: Production Match (Continued)

| Date | Well | 8-17-37-7W5 | | | Date | Well | 14-7-37-7W5 | | | Date | Well | 14-12-37-8W5 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d |
| Oct-87 | | | | | Oct-87 | | | | | Oct-87 | | | | |
| Nov-87 | | | | | Nov-87 | | | | | Nov-87 | | | | |
| Dec-87 | | | | | Dec-87 | | | | | Dec-87 | | | | |
| Jan-88 | | | | | Jan-88 | | | | | Jan-88 | | | | |
| Feb-88 | | | | | Feb-88 | | | | | Feb-88 | | | | |
| Mar-88 | | | | | Mar-88 | | | | | Mar-88 | | | | |
| Apr-88 | | | | | Apr-88 | | | | | Apr-88 | | | | |
| May-88 | | | | | May-88 | | | | | May-88 | | | | |
| Jun-88 | | | | | Jun-88 | | | | | Jun-88 | | | | |
| Jul-88 | | | | | Jul-88 | | | | | Jul-88 | | | | |
| Aug-88 | | | | | Aug-88 | | | | | Aug-88 | | | | |
| Sep-88 | | | | | Sep-88 | | | | | Sep-88 | | | | |
| Oct-88 | | | | | Oct-88 | | | | | Oct-88 | | | | |
| Nov-88 | | | | | Nov-88 | | | | | Nov-88 | | | | |
| Dec-88 | | | | | Dec-88 | | | | | Dec-88 | | | | |
| Jan-89 | | | | | Jan-89 | | | | | Jan-89 | | | | |
| Feb-89 | | | | | Feb-89 | | | | | Feb-89 | | | | |
| Mar-89 | | | | | Mar-89 | | | | | Mar-89 | | | | |
| Apr-89 | | | | | Apr-89 | | | | | Apr-89 | | | | |
| May-89 | | | | | May-89 | | | | | May-89 | | | | |
| Jun-89 | | | | | Jun-89 | | | | | Jun-89 | | | | |
| Jul-89 | | | | | Jul-89 | | | | | Jul-89 | | | | |
| Aug-89 | | | | | Aug-89 | | | | | Aug-89 | | | | |
| Sep-89 | | | | | Sep-89 | | | | | Sep-89 | | | | |
| Oct-89 | | | | | Oct-89 | | | | | Oct-89 | | | | |
| Nov-89 | | | | | Nov-89 | | | | | Nov-89 | | | | |
| Dec-89 | | | | | Dec-89 | | | | | Dec-89 | | | | |
| Jan-90 | | | | | Jan-90 | | | | | Jan-90 | | | | |
| Feb-90 | | | | | Feb-90 | | | | | Feb-90 | | | | |
| Mar-90 | | | | | Mar-90 | | | | | Mar-90 | | | | |
| Apr-90 | | | | | Apr-90 | | | | | Apr-90 | | | | |
| May-90 | | | | | May-90 | | | | | May-90 | | | | |
| Jun-90 | | | | | Jun-90 | | | | | Jun-90 | | | | |
| Jul-90 | | | | | Jul-90 | | | | | Jul-90 | | | | |
| Aug-90 | | | | | Aug-90 | | | | | Aug-90 | | | | |
| Sep-90 | | | | | Sep-90 | | | | | Sep-90 | | | | |
| Oct-90 | | | | | Oct-90 | | | | | Oct-90 | | | | |
| Nov-90 | | | | | Nov-90 | | | | | Nov-90 | | | | |
| Dec-90 | | | | | Dec-90 | | | | | Dec-90 | | | | |
| Jan-91 | | | | | Jan-91 | | | | | Jan-91 | | | | |
| Feb-91 | | | | | Feb-91 | | | | | Feb-91 | | | | |
| Mar-91 | | | | | Mar-91 | | | | | Mar-91 | | | | |
| Apr-91 | | | | | Apr-91 | | | | | Apr-91 | | | | |
| May-91 | | | | | May-91 | | | | | May-91 | | | | |
| Jun-91 | | | | | Jun-91 | | | | | Jun-91 | | | | |
| Jul-91 | | | | | Jul-91 | | | | | Jul-91 | | | | |
| Aug-91 | | | | | Aug-91 | | | | | Aug-91 | | | | |
| Sep-91 | | | | | Sep-91 | | | | | Sep-91 | | | | |
| Oct-91 | | | | | Oct-91 | | | | | Oct-91 | | | | |
| Nov-91 | | | | | Nov-91 | | | | | Nov-91 | | | | |
| Dec-91 | | | | | Dec-91 | | | | | Dec-91 | | | | |
| Jan-92 | | | | | Jan-92 | | | | | Jan-92 | | | | |
| Feb-92 | | | | | Feb-92 | | | | | Feb-92 | | | | |
| Mar-92 | | | | | Mar-92 | | | | | Mar-92 | | | | |
| Apr-92 | | | | | Apr-92 | | | | | Apr-92 | | | | |
| May-92 | | | | | May-92 | | | | | May-92 | | | | |
| Jun-92 | | | | | Jun-92 | | | | | Jun-92 | | | | |
| Jul-92 | | | | | Jul-92 | | | | | Jul-92 | | | | |
| Aug-92 | | | | | Aug-92 | | | | | Aug-92 | | | | |
| Sep-92 | | | | | Sep-92 | | | | | Sep-92 | | | | |
| Oct-92 | | | | | Oct-92 | | | | | Oct-92 | | | | |
| Nov-92 | | | | | Nov-92 | | | | | Nov-92 | | | | |
| Dec-92 | | | | | Dec-92 | | | | | Dec-92 | | | | |
| Jan-93 | | | | | Jan-93 | | | | | Jan-93 | | | | |
| Feb-93 | | | | | Feb-93 | | | | | Feb-93 | | | | |
| Mar-93 | 12 | 561.1 | 474.1 | 0.0 | Mar-93 | | | | | Mar-93 | | | | |
| Apr-93 | 472 | 499.1 | 397.5 | 0.0 | Apr-93 | | | | | Apr-93 | | | | |
| May-93 | | | | | May-93 | | | | | May-93 | | | | |
| Jun-93 | 238 | 524.7 | 418.9 | 0.0 | Jun-93 | 72 | 191.2 | 173.1 | 0.0 | Jun-93 | | | | |
| Jul-93 | 118 | 538.3 | 442.9 | 0.0 | Jul-93 | 465 | 389.0 | 556.7 | 0.0 | Jul-93 | | | | |
| Aug-93 | 119 | 527.0 | 434.1 | 0.0 | Aug-93 | 474 | 380.5 | 746.6 | 0.0 | Aug-93 | | | | |
| Sep-93 | 116 | 526.1 | 433.1 | 0.0 | Sep-93 | | | | | Sep-93 | 333 | 303.5 | 237.7 | 0.0 |
| Oct-93 | 120 | 526.0 | 437.4 | 0.0 | Oct-93 | | | | | Oct-93 | 744 | 132.6 | 103.5 | 0.0 |
| Nov-93 | 126 | 488.7 | 499.1 | 0.0 | Nov-93 | 189 | 355.4 | 478.6 | 0.0 | Nov-93 | 597 | 146.9 | 113.4 | 0.0 |
| Dec-93 | 271 | 235.1 | 588.8 | 0.0 | Dec-93 | 227 | 281.5 | 481.7 | 0.0 | Dec-93 | 528 | 130.5 | 100.5 | 0.0 |
| Jan-94 | 290 | 222.7 | 484.7 | 0.0 | Jan-94 | 307 | 216.2 | 430.9 | 0.0 | Jan-94 | 528 | 134.8 | 103.5 | 0.0 |
| Feb-94 | 324 | 194.9 | 384.0 | 0.0 | Feb-94 | 293 | 196.6 | 440.1 | 0.0 | Feb-94 | 437 | 132.0 | 101.1 | 0.0 |
| Mar-94 | 401 | 161.6 | 325.9 | 0.0 | Mar-94 | 206 | 190.0 | 438.5 | 0.0 | Mar-94 | 541 | 126.2 | 96.2 | 0.0 |
| Apr-94 | 377 | 148.1 | 303.5 | 0.0 | Apr-94 | 284 | 180.1 | 431.7 | 0.0 | Apr-94 | 499 | 122.9 | 93.3 | 0.0 |
| May-94 | 286 | 151.3 | 293.7 | 0.0 | May-94 | 198 | 174.4 | 404.8 | 0.0 | May-94 | 575 | 117.9 | 89.1 | 0.0 |
| Jun-94 | 236 | 149.4 | 268.7 | 0.0 | Jun-94 | 222 | 161.1 | 337.7 | 0.0 | Jun-94 | 577 | 114.6 | 86.2 | 0.0 |
| Jul-94 | 211 | 148.8 | 277.5 | 0.0 | Jul-94 | 217 | 160.2 | 333.9 | 0.0 | Jul-94 | 587 | 111.7 | 83.8 | 0.0 |
| Aug-94 | 192 | 155.6 | 321.1 | 0.0 | Aug-94 | 193 | 154.7 | 331.1 | 0.0 | Aug-94 | 610 | 108.3 | 77.7 | 0.0 |
| Sep-94 | 167 | 161.0 | 340.5 | 0.0 | Sep-94 | 169 | 143.7 | 300.3 | 0.0 | Sep-94 | 413 | 83.4 | 62.3 | 0.0 |
| MRL = 88 STB/d | | | | | MRL = 88 STB/d | | | | | MRL = 88 STB/d | | | | |
| GOR = 1.129 Mscf/STB | | | | | GOR = 1.129 Mscf/STB | | | | | GOR = 1.129 Mscf/STB | | | | |

Table 4.2: Production Match (Continued)

| Date | Well | 16-12-37-8W5 | | | Date | Well | 8-7-37-7W5 | | | Cumulative Pool Production | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | | Prod hrs | Oil STB/d | Gas Mscf/d | Water STB/d | Date | Oil MSTB | Gas MMscf | Water MSTB | Wells Producing |
| Oct-87 | | | | | Oct-87 | | | | | Oct-87 | | | | |
| Nov-87 | | | | | Nov-87 | | | | | Nov-87 | 0.8 | 1.0 | 0.0 | 1 |
| Dec-87 | | | | | Dec-87 | | | | | Dec-87 | 1.2 | 2.0 | 0.0 | 1 |
| Jan-88 | | | | | Jan-88 | | | | | Jan-88 | 1.7 | 3.0 | 0.0 | 1 |
| Feb-88 | | | | | Feb-88 | | | | | Feb-88 | 2.4 | 4.5 | 0.0 | 1 |
| Mar-88 | | | | | Mar-88 | | | | | Mar-88 | 3.0 | 5.9 | 0.0 | 1 |
| Apr-88 | | | | | Apr-88 | | | | | Apr-88 | 3.5 | 7.0 | 0.0 | 1 |
| May-88 | | | | | May-88 | | | | | May-88 | 4.1 | 8.2 | 0.0 | 1 |
| Jun-88 | | | | | Jun-88 | | | | | Jun-88 | 4.6 | 9.0 | 0.0 | 1 |
| Jul-88 | | | | | Jul-88 | | | | | Jul-88 | 5.2 | 9.9 | 0.0 | 1 |
| Aug-88 | | | | | Aug-88 | | | | | Aug-88 | 5.7 | 10.8 | 0.0 | 1 |
| Sep-88 | | | | | Sep-88 | | | | | Sep-88 | 6.2 | 11.6 | 0.0 | 1 |
| Oct-88 | | | | | Oct-88 | | | | | Oct-88 | 6.8 | 12.5 | 0.0 | 1 |
| Nov-88 | | | | | Nov-88 | | | | | Nov-88 | 7.3 | 13.3 | 0.0 | 1 |
| Dec-88 | | | | | Dec-88 | | | | | Dec-88 | 7.8 | 14.1 | 0.0 | 1 |
| Jan-89 | | | | | Jan-89 | | | | | Jan-89 | 8.4 | 15.0 | 0.0 | 1 |
| Feb-89 | | | | | Feb-89 | | | | | Feb-89 | 8.9 | 15.7 | 0.0 | 1 |
| Mar-89 | | | | | Mar-89 | | | | | Mar-89 | 12.0 | 19.2 | 0.0 | 2 |
| Apr-89 | | | | | Apr-89 | | | | | Apr-89 | 14.6 | 22.1 | 0.0 | 2 |
| May-89 | | | | | May-89 | | | | | May-89 | 16.8 | 24.6 | 0.0 | 2 |
| Jun-89 | | | | | Jun-89 | | | | | Jun-89 | 18.8 | 27.0 | 0.0 | 2 |
| Jul-89 | | | | | Jul-89 | | | | | Jul-89 | 19.7 | 28.2 | 0.0 | 2 |
| Aug-89 | | | | | Aug-89 | | | | | Aug-89 | 20.6 | 29.4 | 0.0 | 2 |
| Sep-89 | | | | | Sep-89 | | | | | Sep-89 | 21.7 | 30.7 | 0.0 | 2 |
| Oct-89 | | | | | Oct-89 | | | | | Oct-89 | 22.5 | 31.7 | 0.0 | 2 |
| Nov-89 | | | | | Nov-89 | | | | | Nov-89 | 23.3 | 32.7 | 0.0 | 2 |
| Dec-89 | | | | | Dec-89 | | | | | Dec-89 | 24.1 | 33.8 | 0.0 | 2 |
| Jan-90 | | | | | Jan-90 | | | | | Jan-90 | 25.1 | 34.9 | 0.0 | 2 |
| Feb-90 | | | | | Feb-90 | | | | | Feb-90 | 26.0 | 36.0 | 0.0 | 2 |
| Mar-90 | | | | | Mar-90 | | | | | Mar-90 | 29.2 | 39.2 | 0.0 | 3 |
| Apr-90 | | | | | Apr-90 | | | | | Apr-90 | 30.8 | 40.9 | 0.0 | 3 |
| May-90 | | | | | May-90 | | | | | May-90 | 40.2 | 49.5 | 0.0 | 3 |
| Jun-90 | | | | | Jun-90 | | | | | Jun-90 | 47.3 | 56.1 | 0.0 | 3 |
| Jul-90 | | | | | Jul-90 | | | | | Jul-90 | 49.0 | 57.8 | 0.0 | 3 |
| Aug-90 | | | | | Aug-90 | | | | | Aug-90 | 56.6 | 64.9 | 0.0 | 4 |
| Sep-90 | | | | | Sep-90 | | | | | Sep-90 | 63.9 | 71.8 | 0.0 | 4 |
| Oct-90 | | | | | Oct-90 | | | | | Oct-90 | 76.0 | 82.9 | 0.0 | 5 |
| Nov-90 | | | | | Nov-90 | | | | | Nov-90 | 88.2 | 94.2 | 0.0 | 5 |
| Dec-90 | | | | | Dec-90 | | | | | Dec-90 | 102.5 | 107.3 | 0.0 | 5 |
| Jan-91 | | | | | Jan-91 | | | | | Jan-91 | 108.9 | 113.6 | 0.0 | 4 |
| Feb-91 | | | | | Feb-91 | | | | | Feb-91 | 122.1 | 125.6 | 0.0 | 6 |
| Mar-91 | | | | | Mar-91 | | | | | Mar-91 | 136.3 | 138.6 | 0.0 | 6 |
| Apr-91 | | | | | Apr-91 | | | | | Apr-91 | 150.5 | 151.6 | 0.0 | 6 |
| May-91 | | | | | May-91 | | | | | May-91 | 159.7 | 160.5 | 0.0 | 5 |
| Jun-91 | | | | | Jun-91 | | | | | Jun-91 | 172.0 | 172.1 | 0.0 | 6 |
| Jul-91 | | | | | Jul-91 | | | | | Jul-91 | 184.4 | 183.6 | 0.0 | 6 |
| Aug-91 | | | | | Aug-91 | | | | | Aug-91 | 196.2 | 194.7 | 0.0 | 6 |
| Sep-91 | | | | | Sep-91 | | | | | Sep-91 | 208.4 | 206.0 | 0.0 | 6 |
| Oct-91 | | | | | Oct-91 | | | | | Oct-91 | 220.5 | 217.1 | 0.0 | 6 |
| Nov-91 | | | | | Nov-91 | | | | | Nov-91 | 232.6 | 228.8 | 0.0 | 6 |
| Dec-91 | | | | | Dec-91 | | | | | Dec-91 | 244.6 | 240.2 | 0.0 | 6 |
| Jan-92 | | | | | Jan-92 | | | | | Jan-92 | 257.0 | 251.7 | 0.0 | 6 |
| Feb-92 | | | | | Feb-92 | | | | | Feb-92 | 268.1 | 262.5 | 0.0 | 6 |
| Mar-92 | | | | | Mar-92 | | | | | Mar-92 | 281.1 | 275.3 | 0.0 | 7 |
| Apr-92 | | | | | Apr-92 | | | | | Apr-92 | 293.3 | 287.4 | 0.0 | 6 |
| May-92 | | | | | May-92 | | | | | May-92 | 305.4 | 300.1 | 0.0 | 6 |
| Jun-92 | | | | | Jun-92 | | | | | Jun-92 | 316.9 | 312.0 | 0.0 | 6 |
| Jul-92 | | | | | Jul-92 | | | | | Jul-92 | 331.9 | 326.7 | 0.0 | 7 |
| Aug-92 | | | | | Aug-92 | | | | | Aug-92 | 346.7 | 341.9 | 0.0 | 7 |
| Sep-92 | | | | | Sep-92 | | | | | Sep-92 | 361.8 | 360.6 | 0.0 | 7 |
| Oct-92 | | | | | Oct-92 | | | | | Oct-92 | 379.6 | 384.1 | 0.0 | 8 |
| Nov-92 | | | | | Nov-92 | | | | | Nov-92 | 396.0 | 405.7 | 0.0 | 8 |
| Dec-92 | | | | | Dec-92 | | | | | Dec-92 | 412.5 | 426.6 | 0.0 | 8 |
| Jan-93 | | | | | Jan-93 | | | | | Jan-93 | 428.5 | 445.1 | 0.0 | 8 |
| Feb-93 | | | | | Feb-93 | | | | | Feb-93 | 444.8 | 465.1 | 0.0 | 9 |
| Mar-93 | | | | | Mar-93 | | | | | Mar-93 | 462.7 | 485.7 | 0.0 | 9 |
| Apr-93 | | | | | Apr-93 | | | | | Apr-93 | 489.8 | 518.9 | 0.0 | 9 |
| May-93 | | | | | May-93 | | | | | May-93 | 508.2 | 536.3 | 0.0 | 8 |
| Jun-93 | | | | | Jun-93 | | | | | Jun-93 | 531.2 | 561.8 | 0.0 | 10 |
| Jul-93 | | | | | Jul-93 | | | | | Jul-93 | 558.0 | 594.8 | 0.0 | 10 |
| Aug-93 | | | | | Aug-93 | | | | | Aug-93 | 584.6 | 632.8 | 0.0 | 10 |
| Sep-93 | | | | | Sep-93 | | | | | Sep-93 | 605.7 | 655.7 | 0.0 | 10 |
| Oct-93 | 185 | 593.1 | 494.8 | 0.0 | Oct-93 | | | | | Oct-93 | 632.1 | 684.0 | 0.0 | 11 |
| Nov-93 | 624 | 421.0 | 495.5 | 0.0 | Nov-93 | | | | | Nov-93 | 666.6 | 725.1 | 0.0 | 12 |
| Dec-93 | | | | | Dec-93 | | | | | Dec-93 | 689.1 | 757.8 | 0.0 | 11 |
| Jan-94 | | | | | Jan-94 | | | | | Jan-94 | 712.0 | 791.8 | 0.0 | 11 |
| Feb-94 | 215 | 401.6 | 382.9 | 0.0 | Feb-94 | | | | | Feb-94 | 735.2 | 825.9 | 0.0 | 12 |
| Mar-94 | 168 | 379.3 | 432.1 | 0.0 | Mar-94 | | | | | Mar-94 | 758.0 | 860.4 | 0.0 | 12 |
| Apr-94 | 120 | 397.4 | 501.6 | 0.0 | Apr-94 | 24 | 562.9 | 479.1 | 0.0 | Apr-94 | 779.8 | 894.6 | 0.0 | 13 |
| May-94 | 144 | 407.8 | 532.7 | 0.0 | May-94 | 158 | 370.5 | 306.4 | 0.0 | May-94 | 803.4 | 929.4 | 0.0 | 13 |
| Jun-94 | 120 | 396.5 | 410.8 | 0.0 | Jun-94 | 560 | 305.6 | 212.5 | 0.0 | Jun-94 | 830.1 | 962.5 | 0.0 | 13 |
| Jul-94 | 120 | 451.6 | 402.2 | 0.0 | Jul-94 | 576 | 289.3 | 167.3 | 0.0 | Jul-94 | 854.9 | 994.2 | 0.0 | 13 |
| Aug-94 | 168 | 382.9 | 484.5 | 0.0 | Aug-94 | 240 | 271.2 | 202.1 | 0.0 | Aug-94 | 875.3 | 1023.6 | 0.0 | 13 |
| Sep-94 | 168 | 379.8 | 520.9 | 0.0 | Sep-94 | 264 | 242.3 | 165.7 | 0.0 | Sep-94 | 893.6 | 1050.7 | 0.0 | 12 |

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

MRL = 88 STB/d
GOR = 1.129 Mscf/STB

Table 4.2: Production Match (Continued)

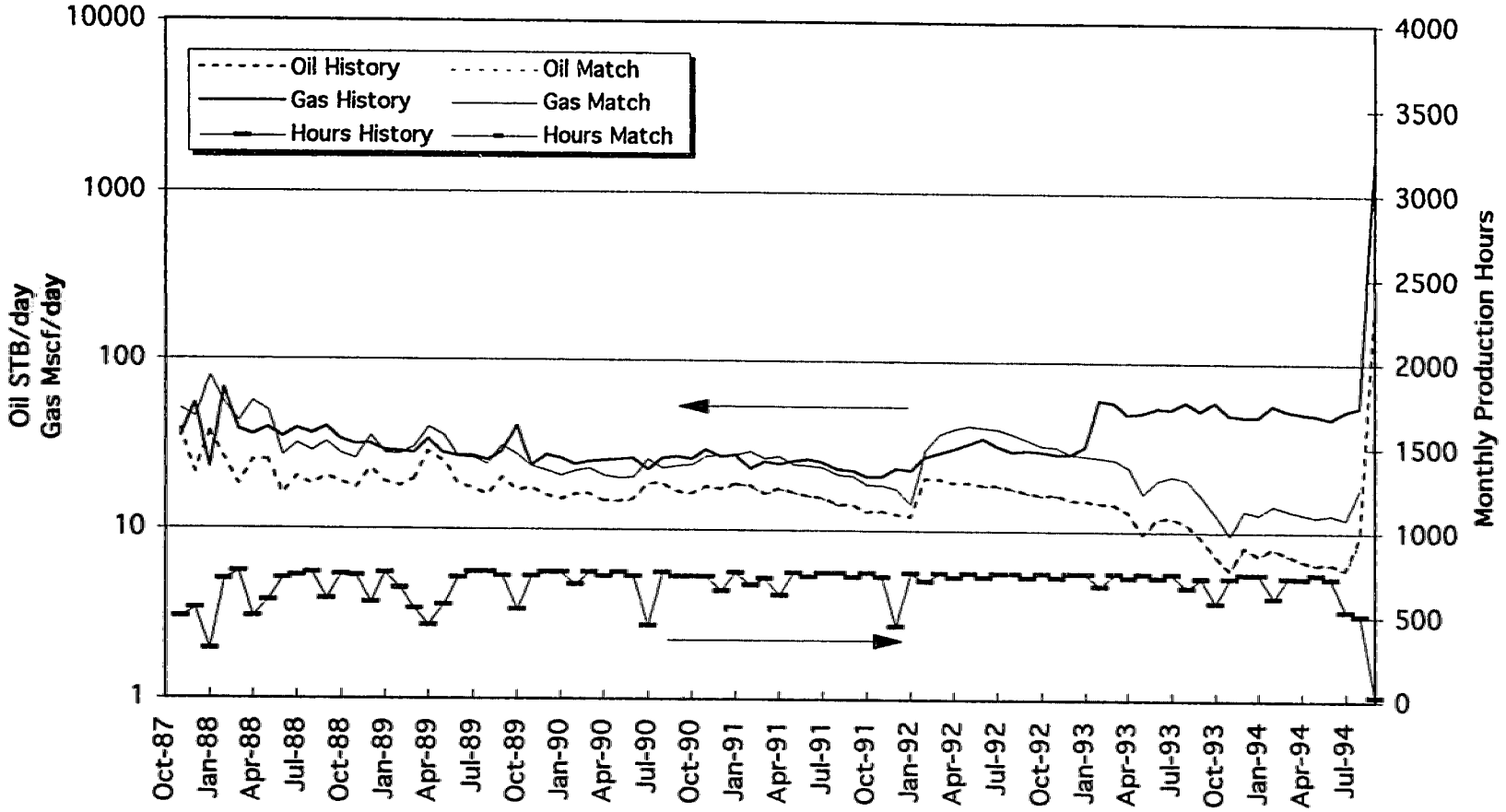



Figure 4.1(a): Oil and Gas Production History Match (16-09-37-7W5)

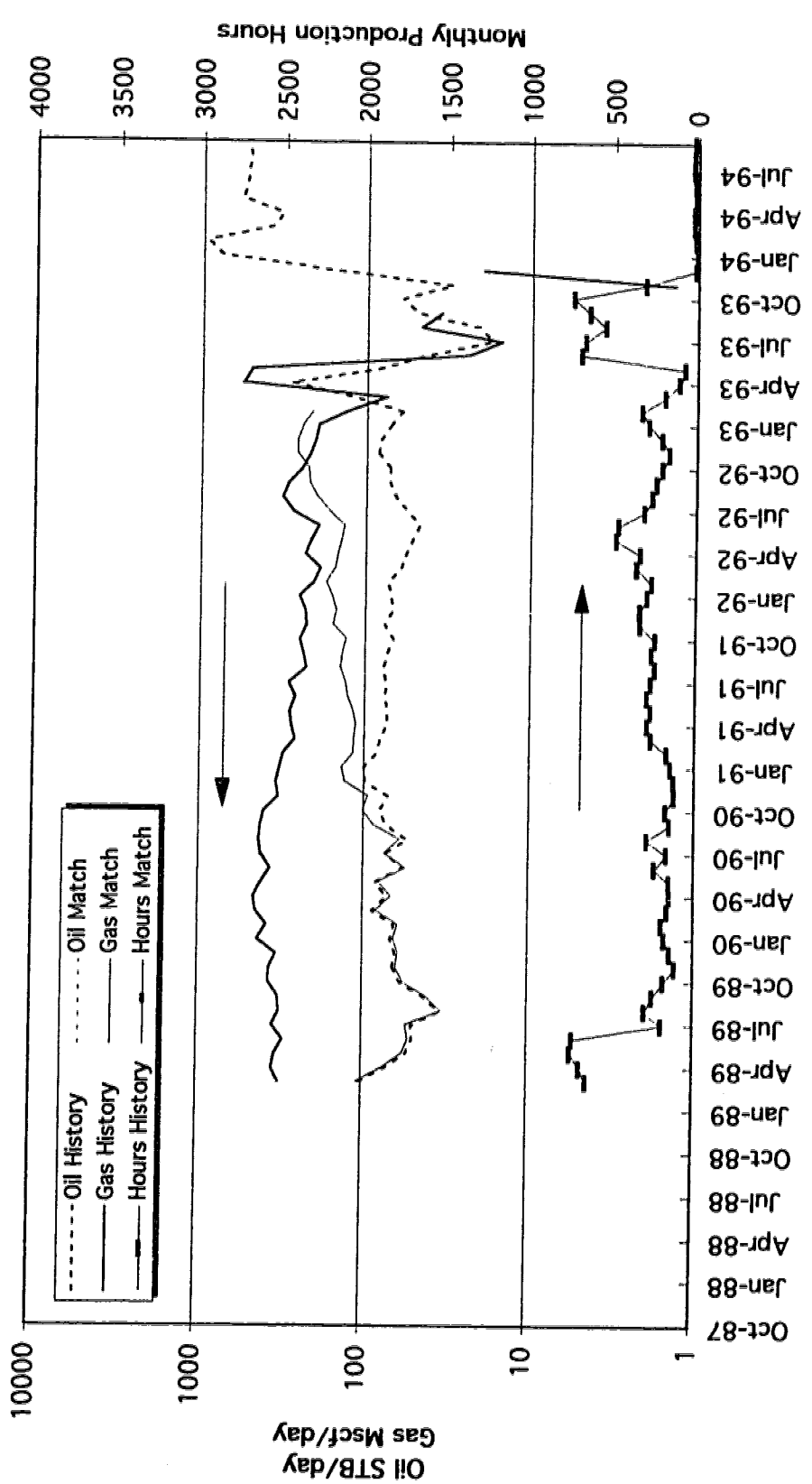



Figure 4.1(b): Oil and Gas Production History Match (06-15-37-7W5)

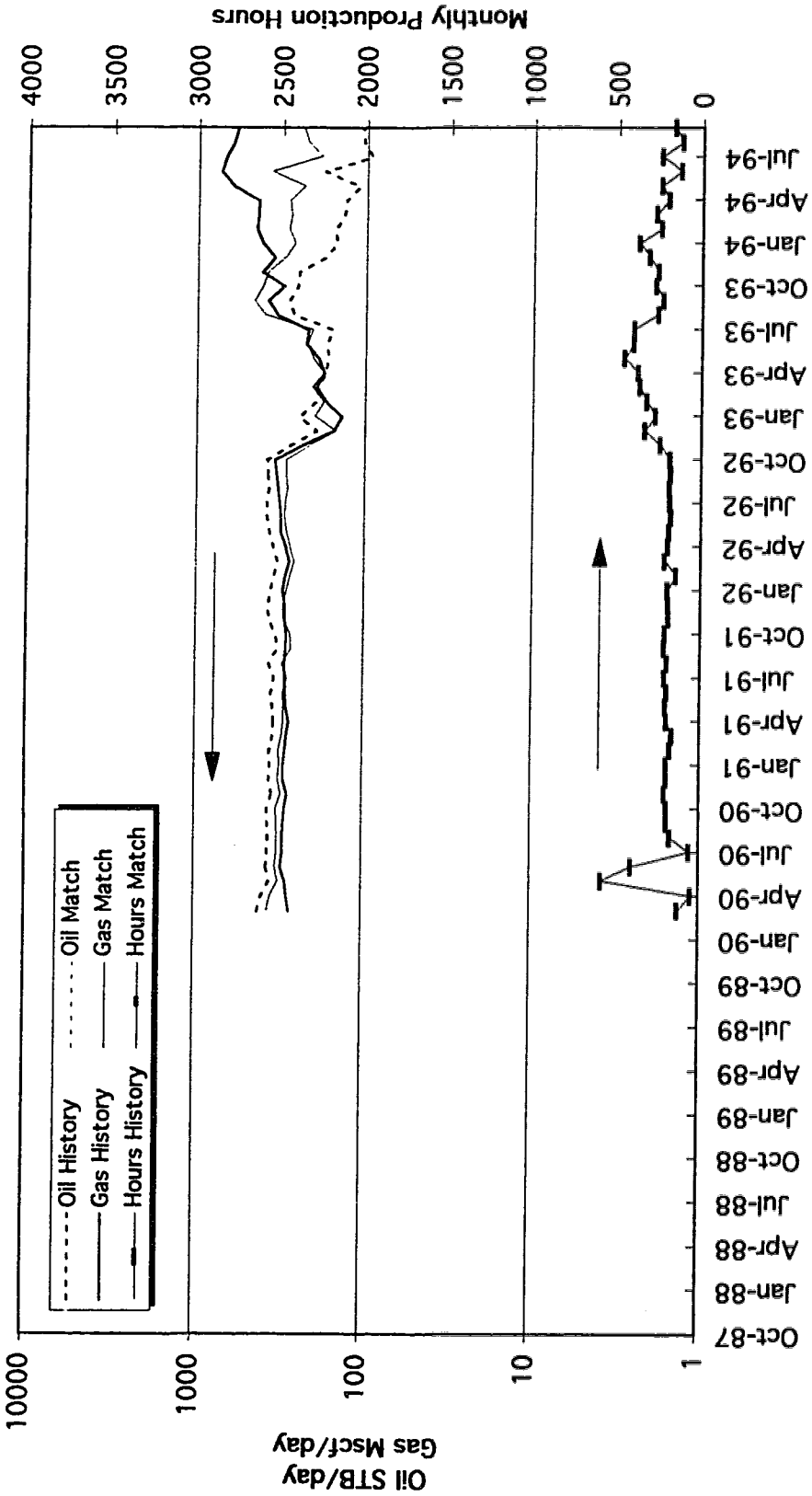



Figure 4.1(c): Oil and Gas Production History Match (08-13-37-8W5)

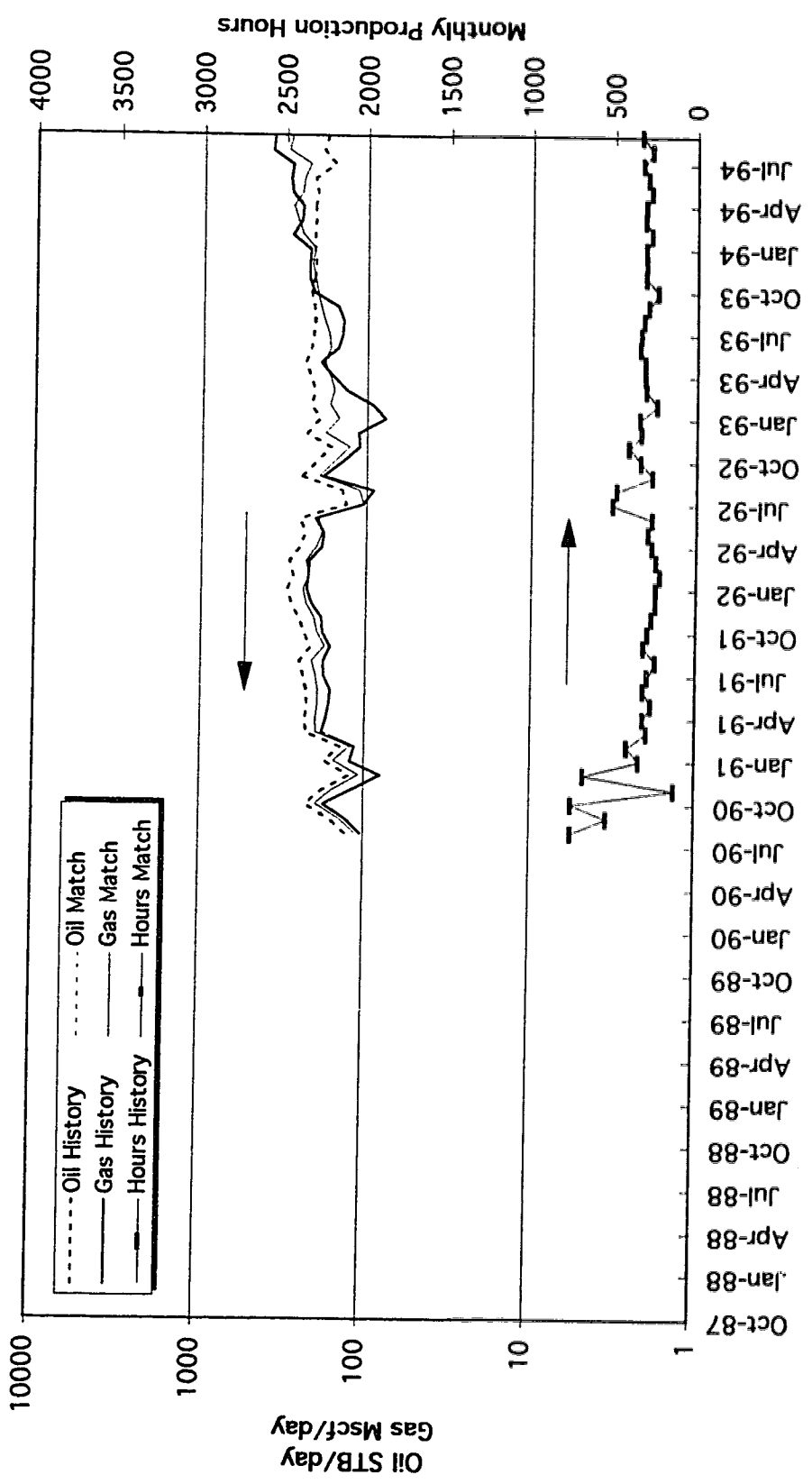



Figure 4.1(d): Oil and Gas Production History Match (06-13-37-8W5)

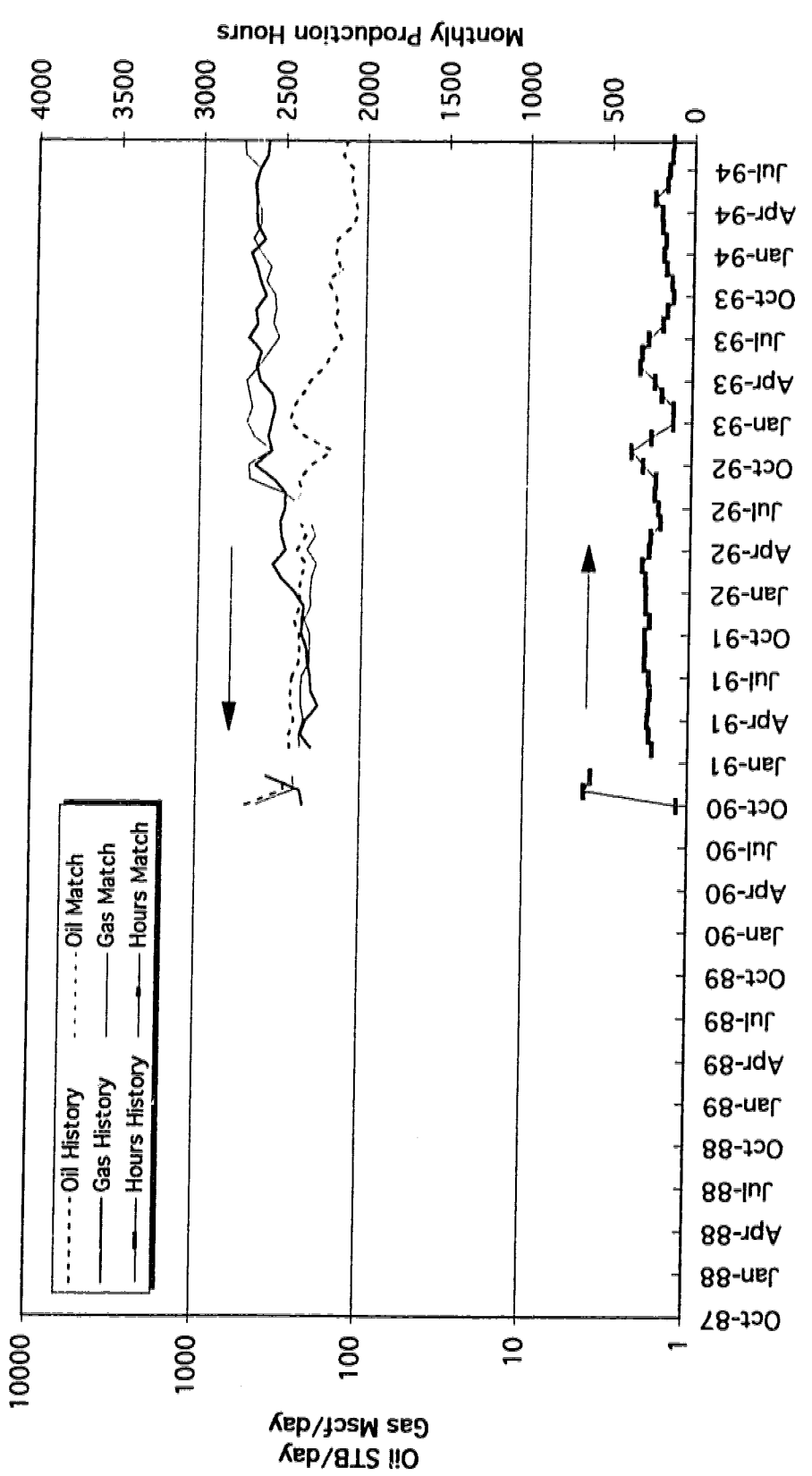



Figure 4.1(e): Oil and Gas Production History Match (06-16-37-7W5)

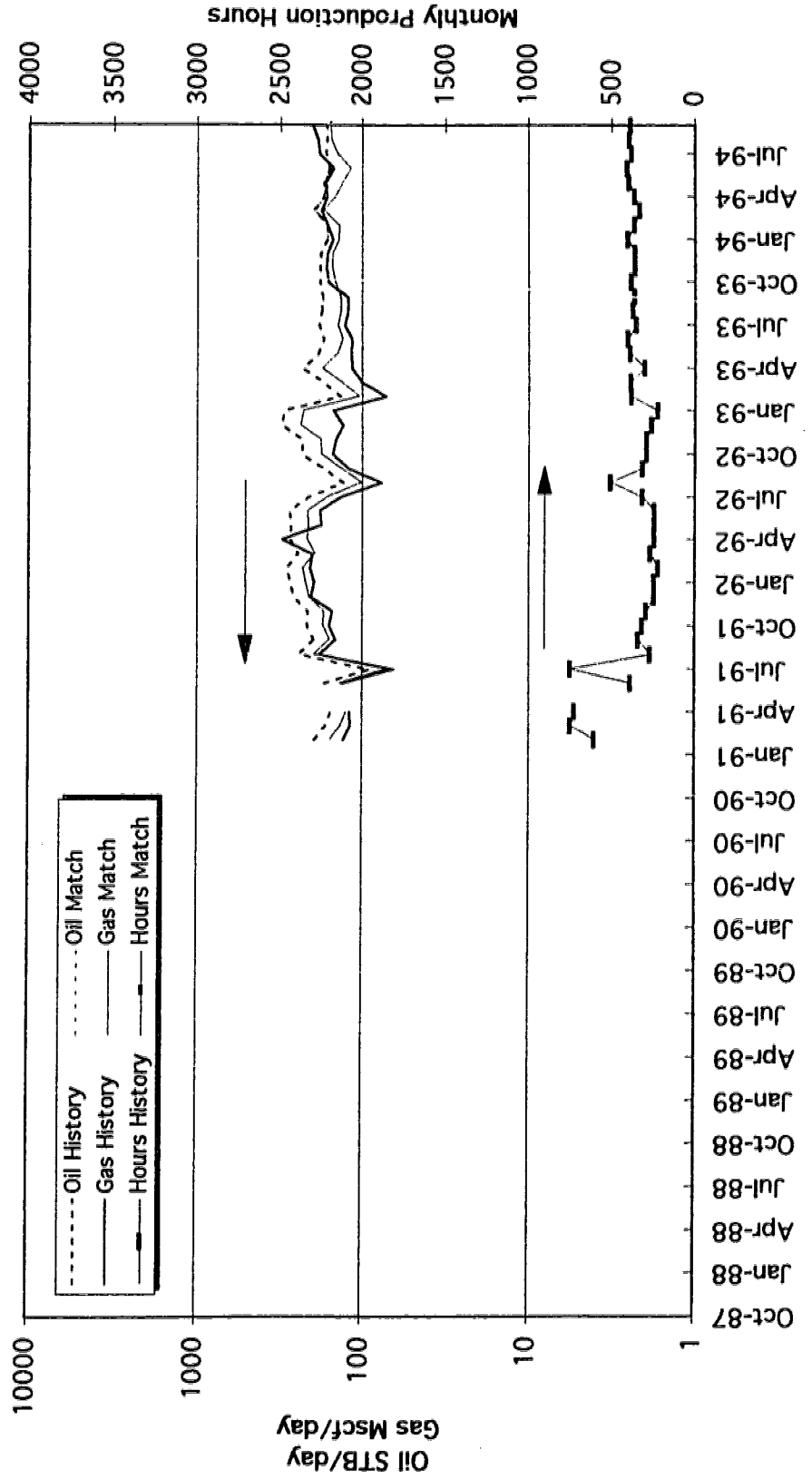



Figure 4.1(f): Oil and Gas Production History Match (08-14-37-8W5)

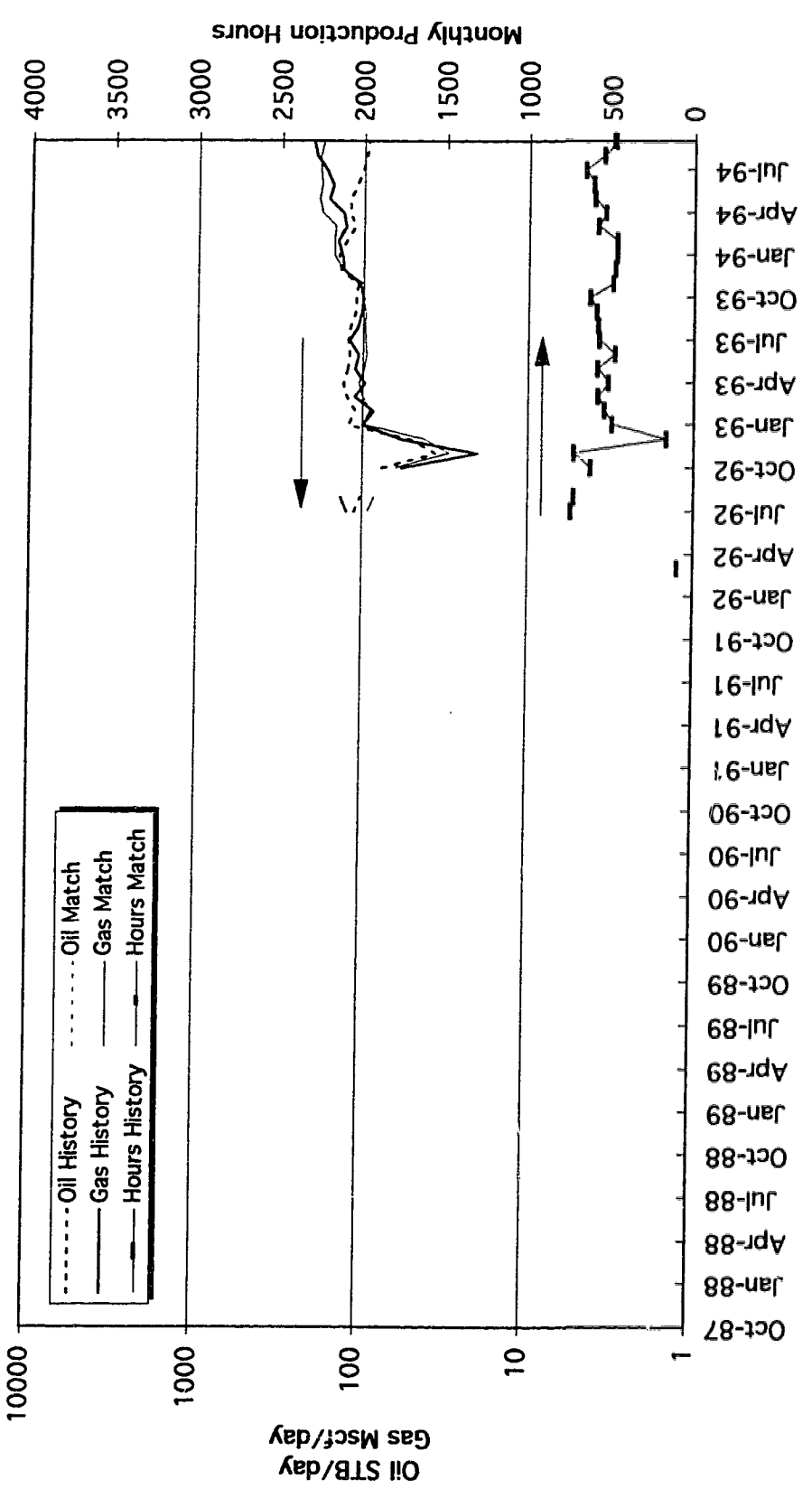



Figure 4.1(g): Oil and Gas Production History Match (08-18-37-7W5)

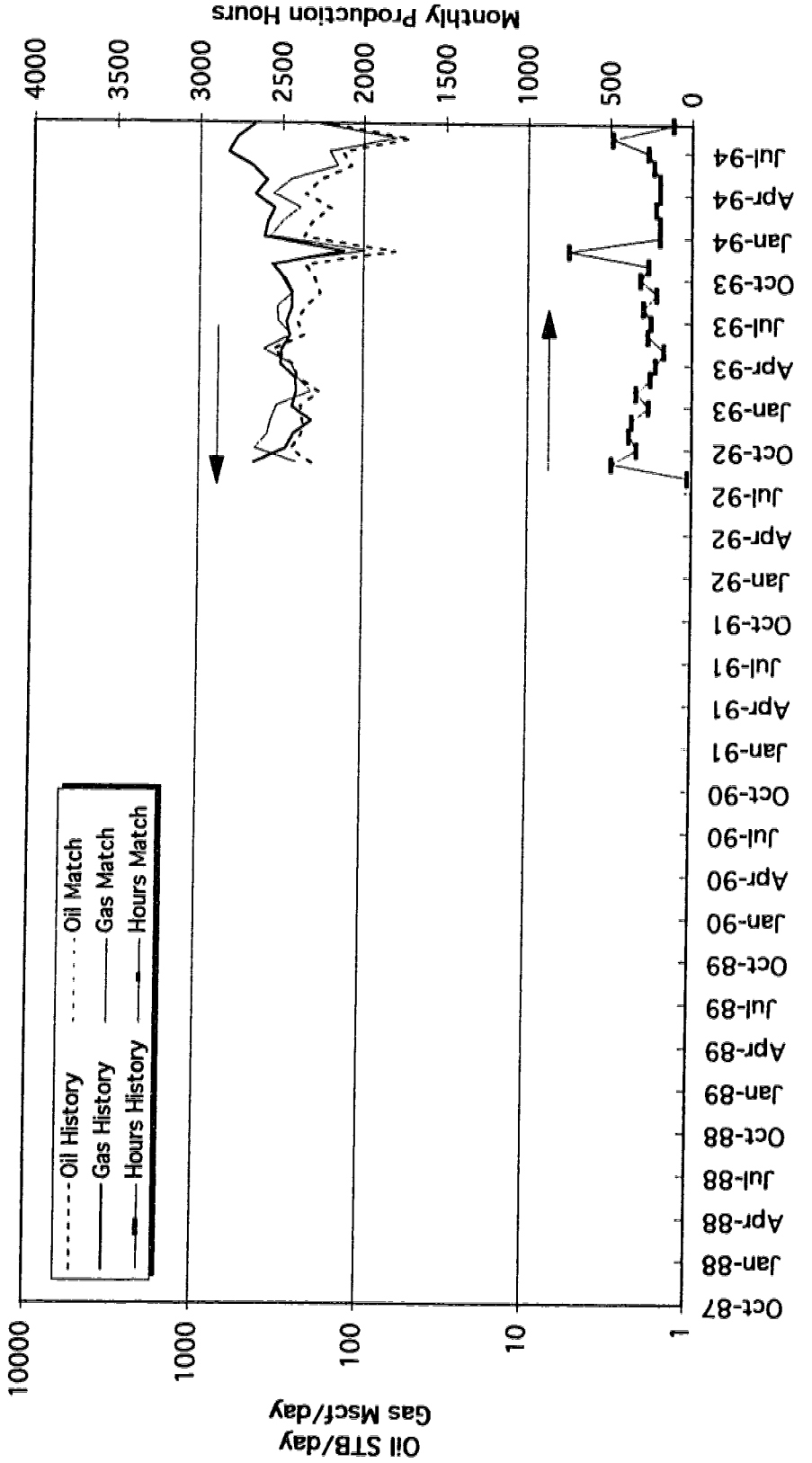



Figure 4.1(h): Oil and Gas Production History Match (16-08-37-7W5)

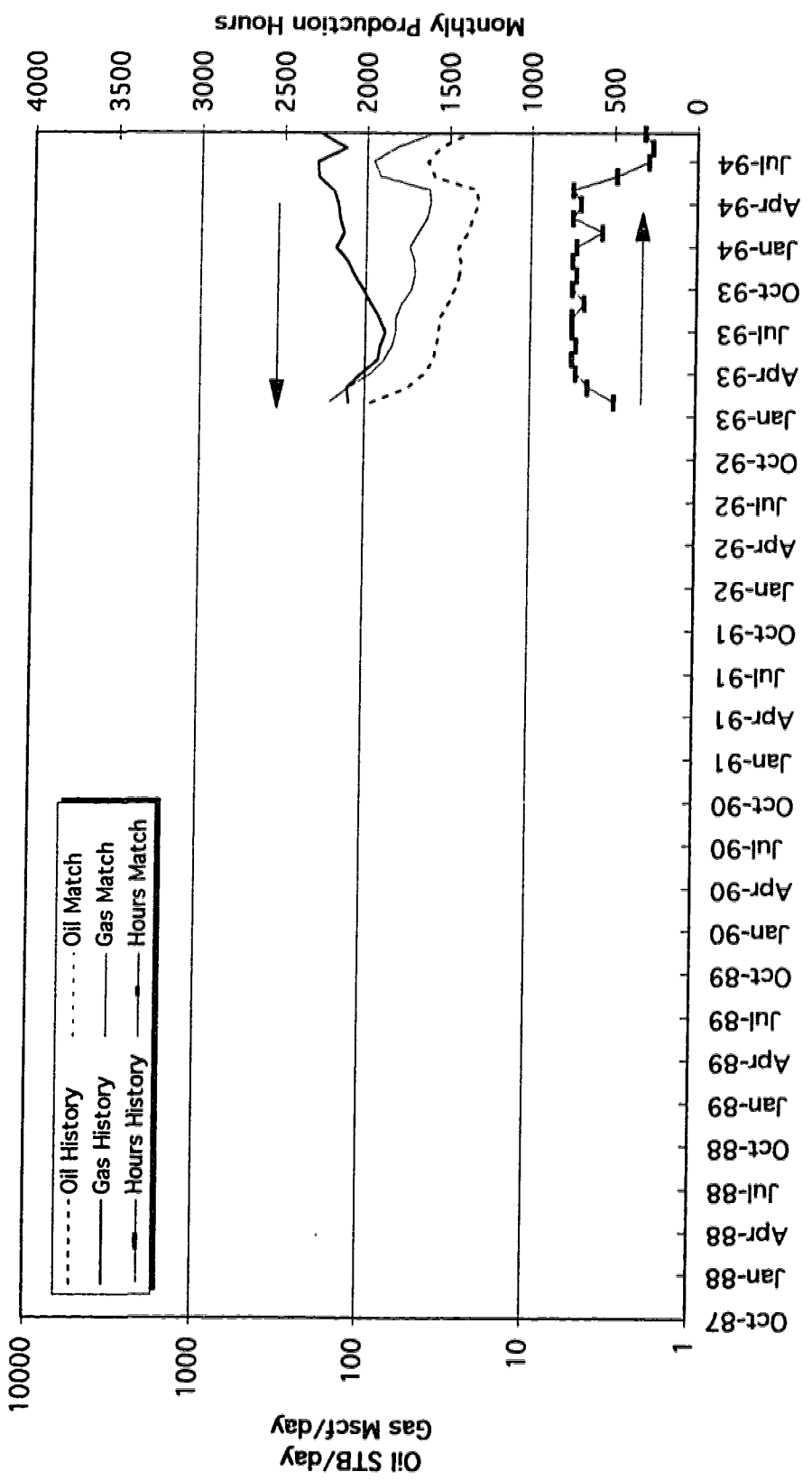



Figure 4.1(i): Oil and Gas Production History Match (14-09-37-7W5)

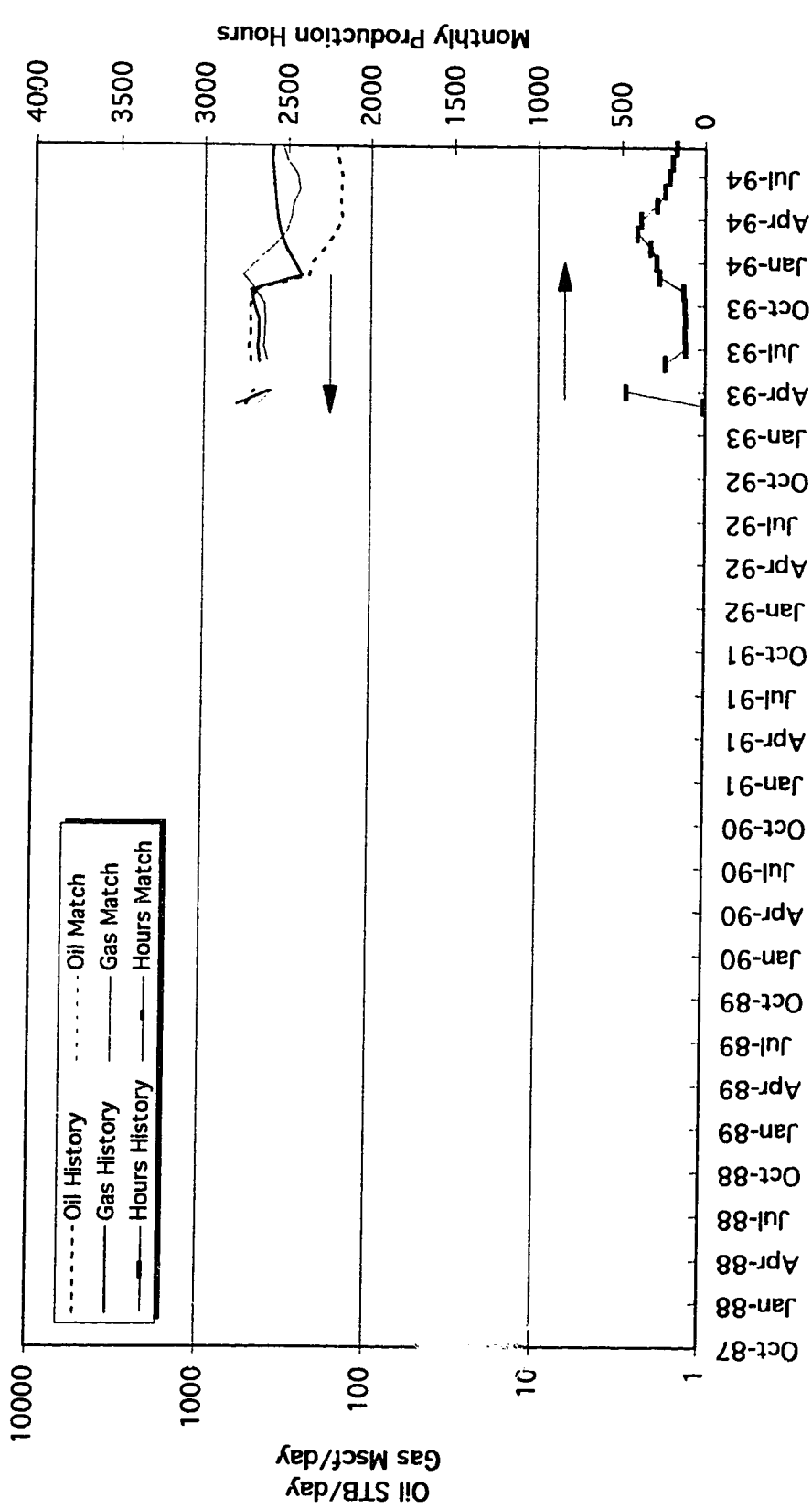



Figure 4.1(i): Oil and Gas Production History Match (08-17-37-7W5)

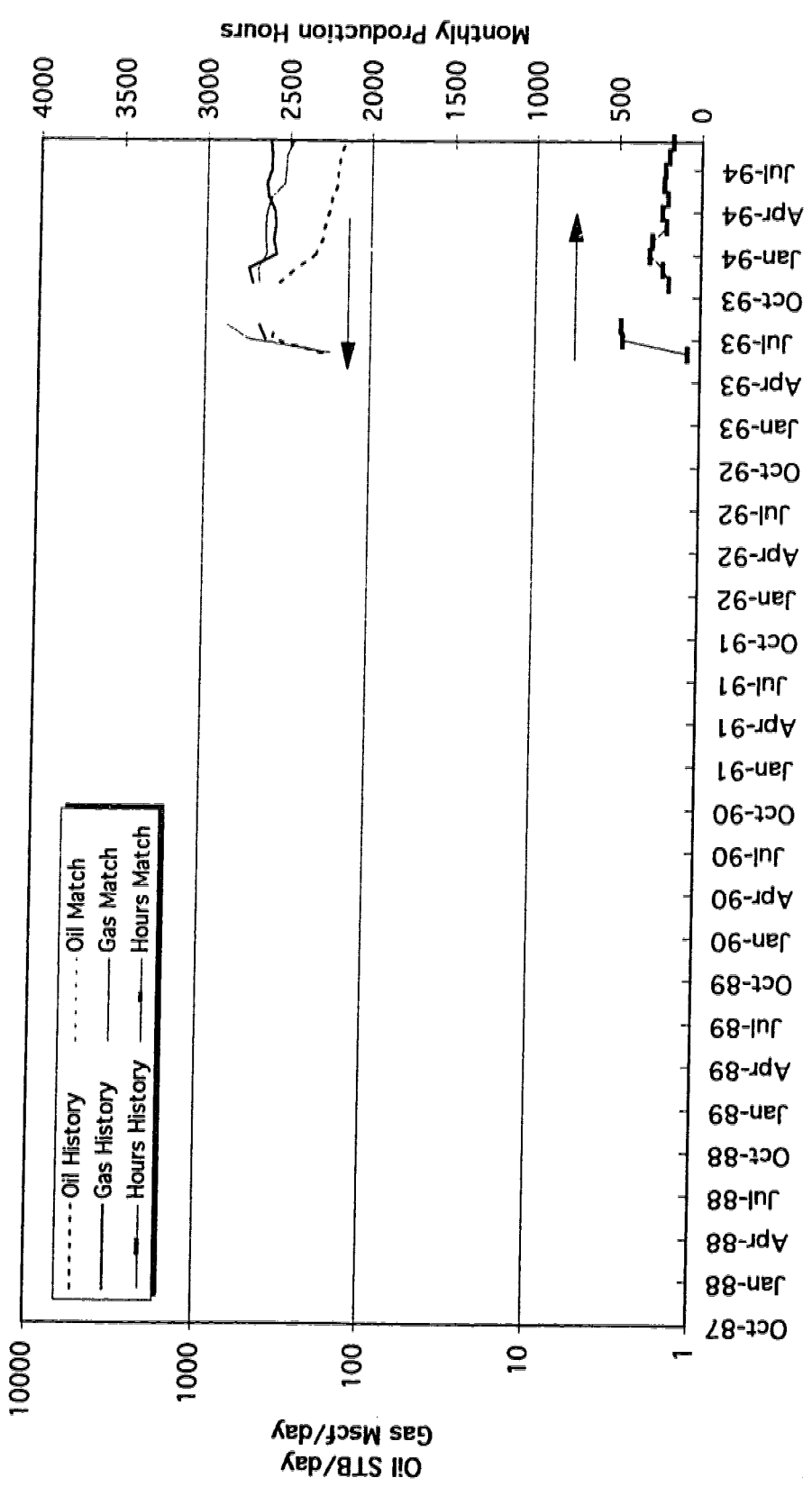



Figure 4.1(k): Oil and Gas Production History Match (14-07-37-7W5)

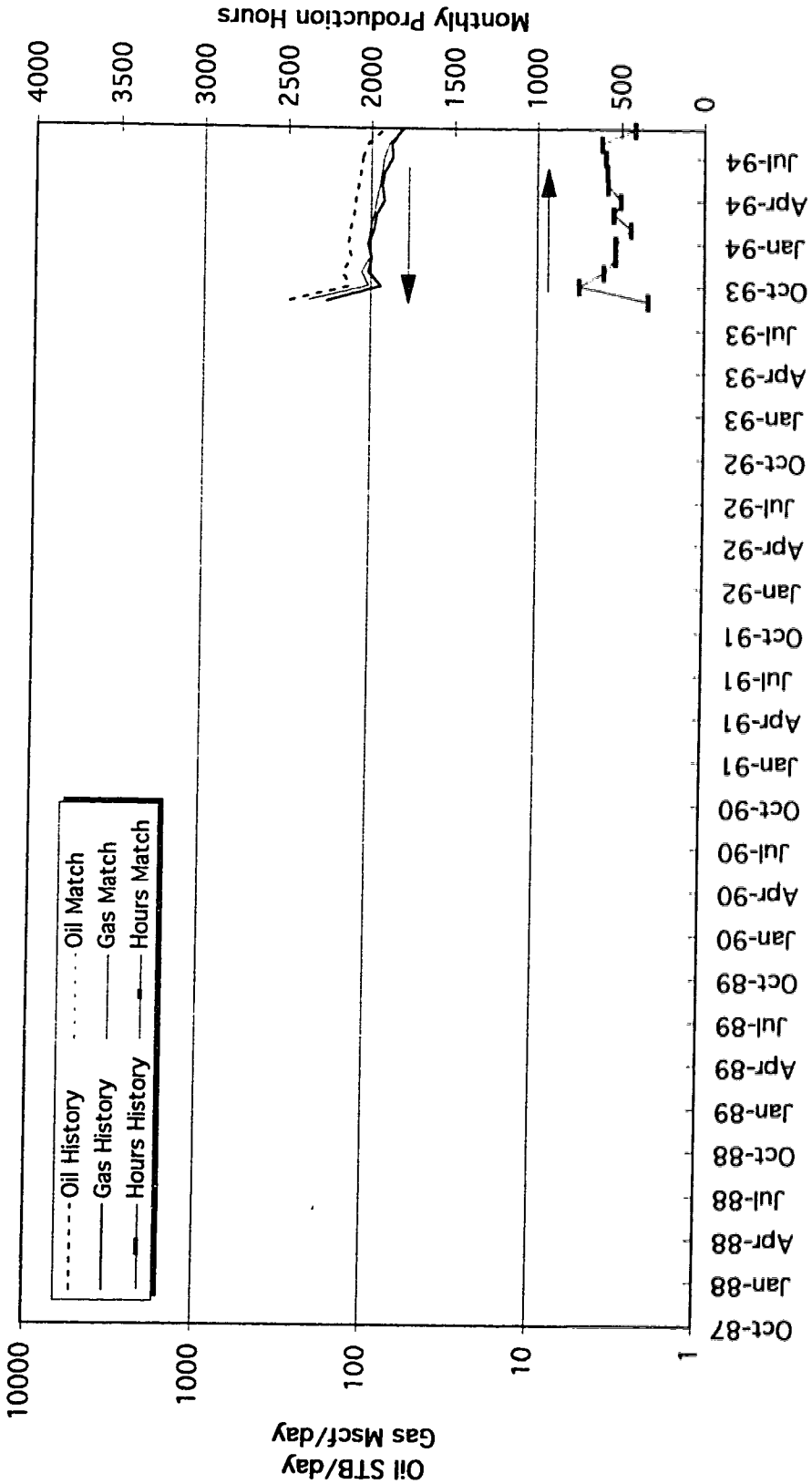



Figure 4.1(I): Oil and Gas Production History Match (14-12-37-8W5)

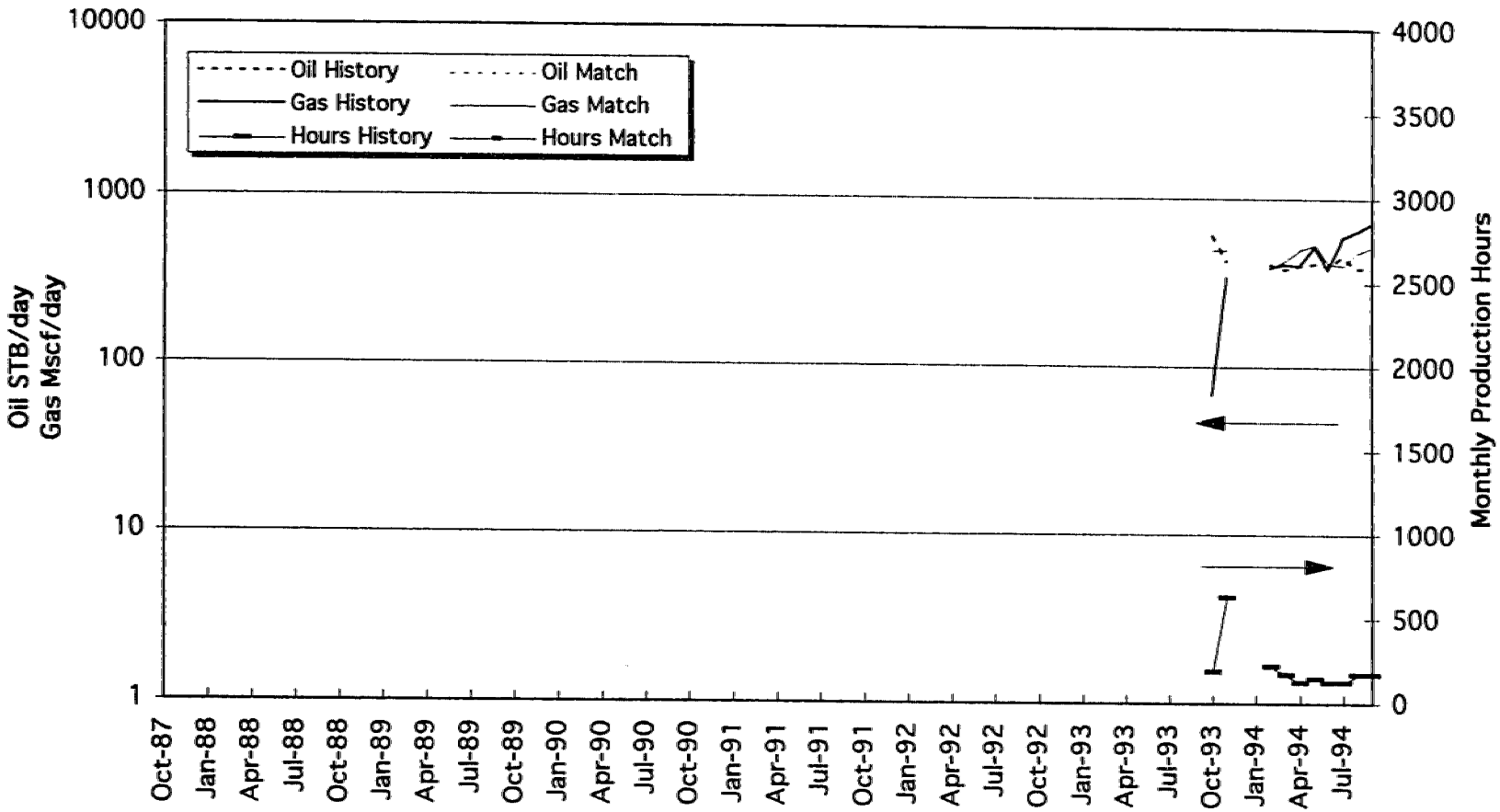



Figure 4.1(m): Oil and Gas Production History Match (16-12-37-8W5)

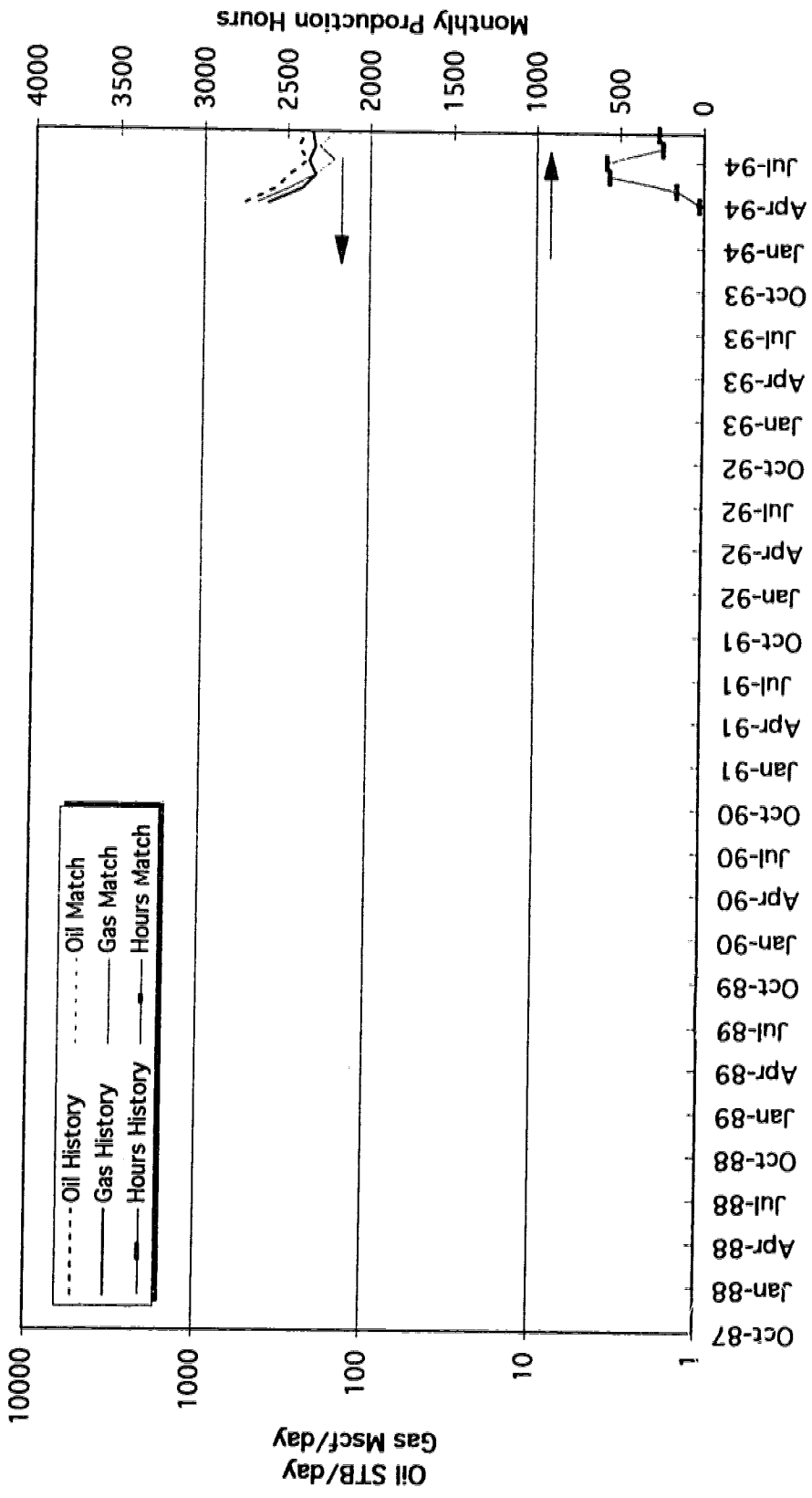



Figure 4.1(n): Oil and Gas Production History Match (08-07-37-7W5)

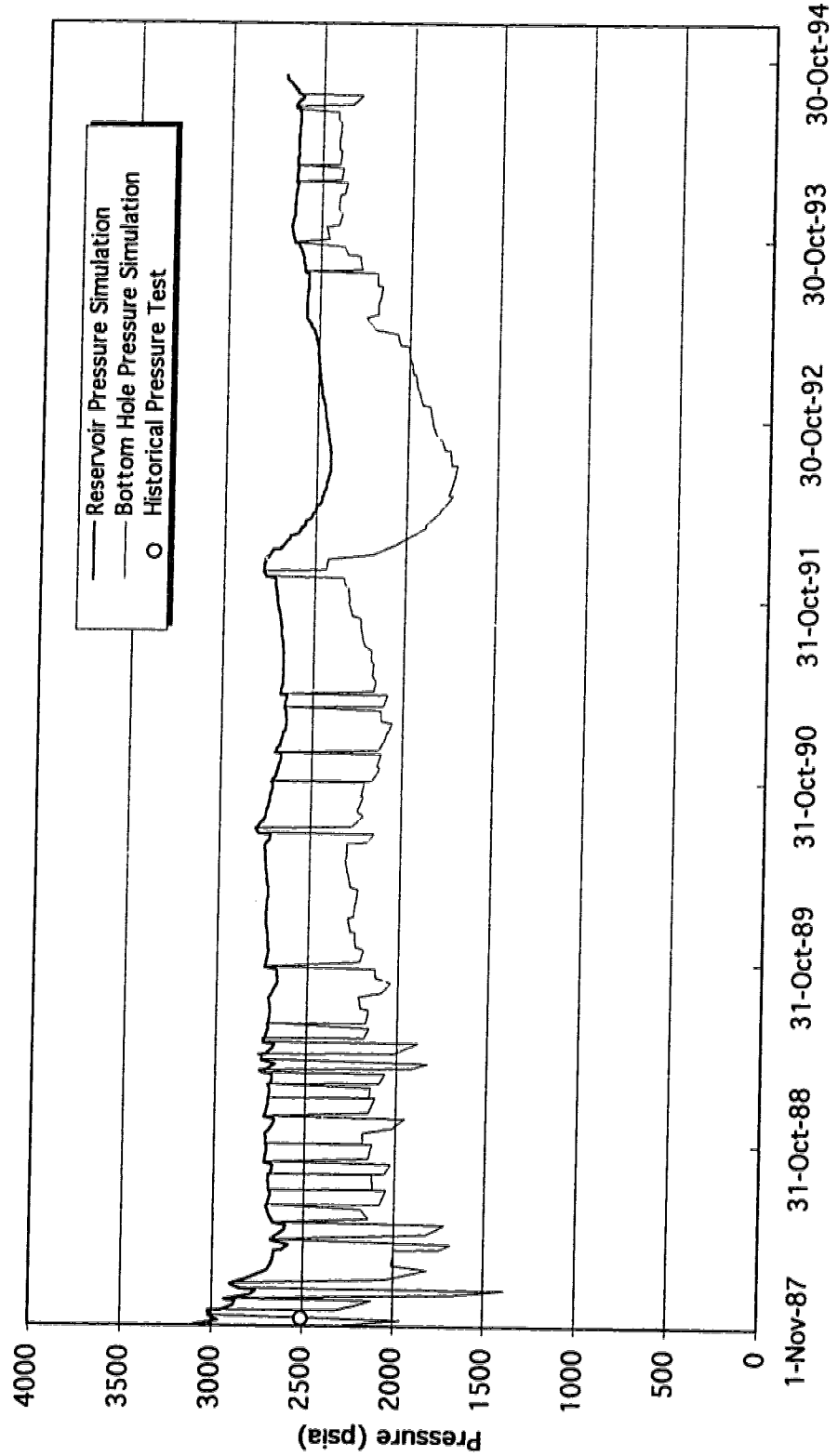



Figure 4.2(a): Pressure History Match (16-09-37-7W5)

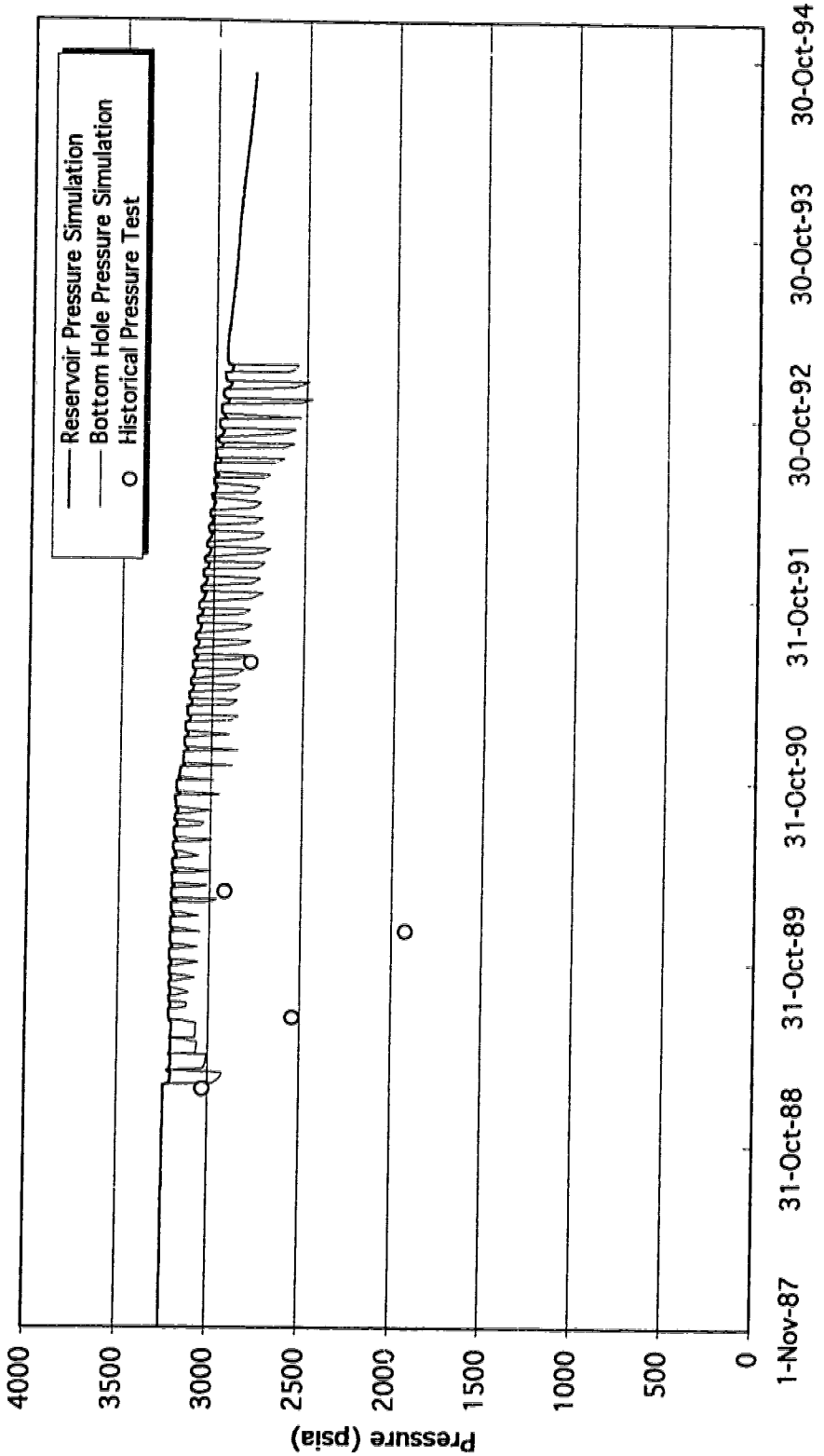



Figure 4.2(b): Pressure History Match (06-15-37-7W5)

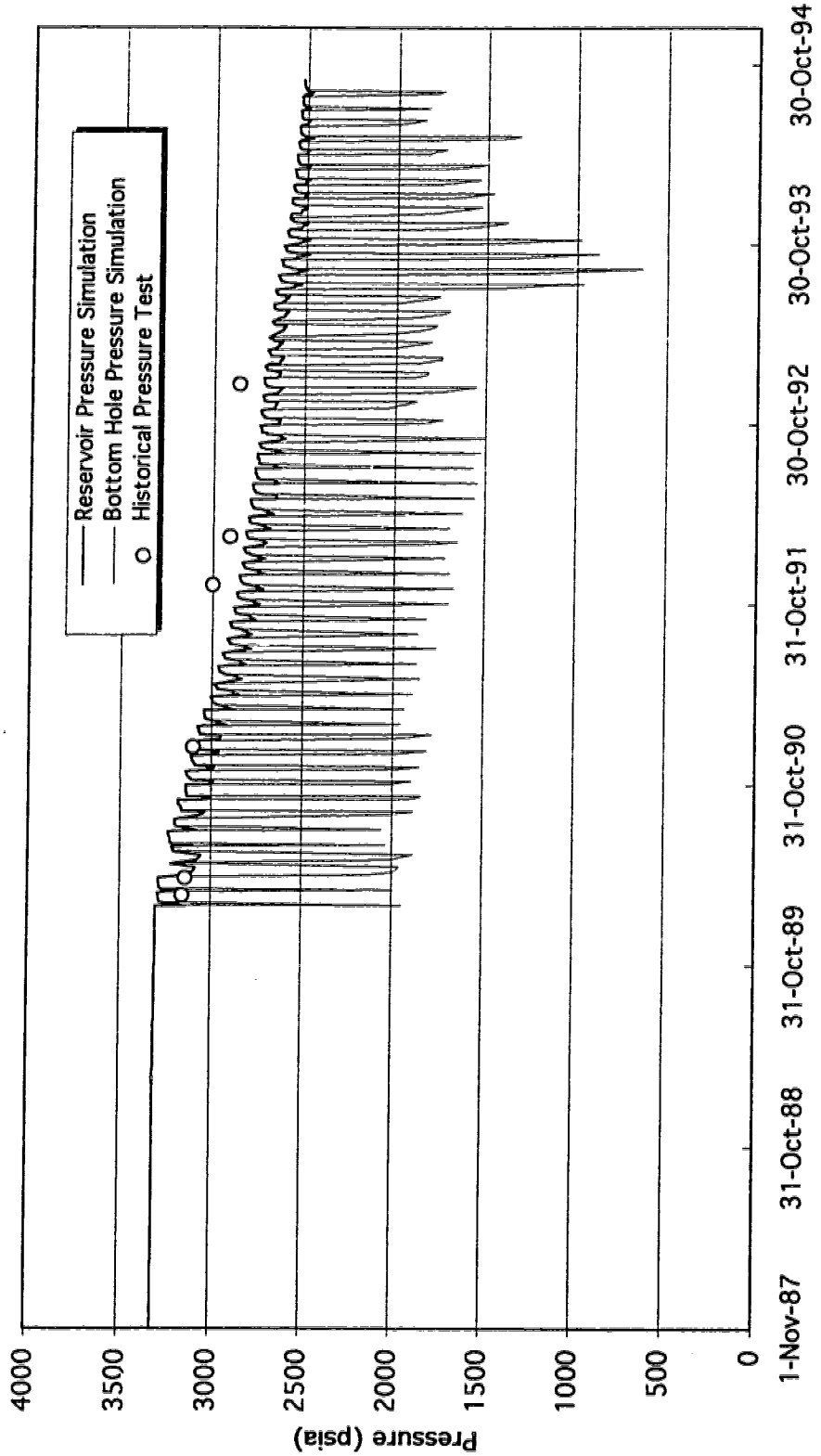



Figure 4.2(c): Pressure History Match (08-13-37-8W5)

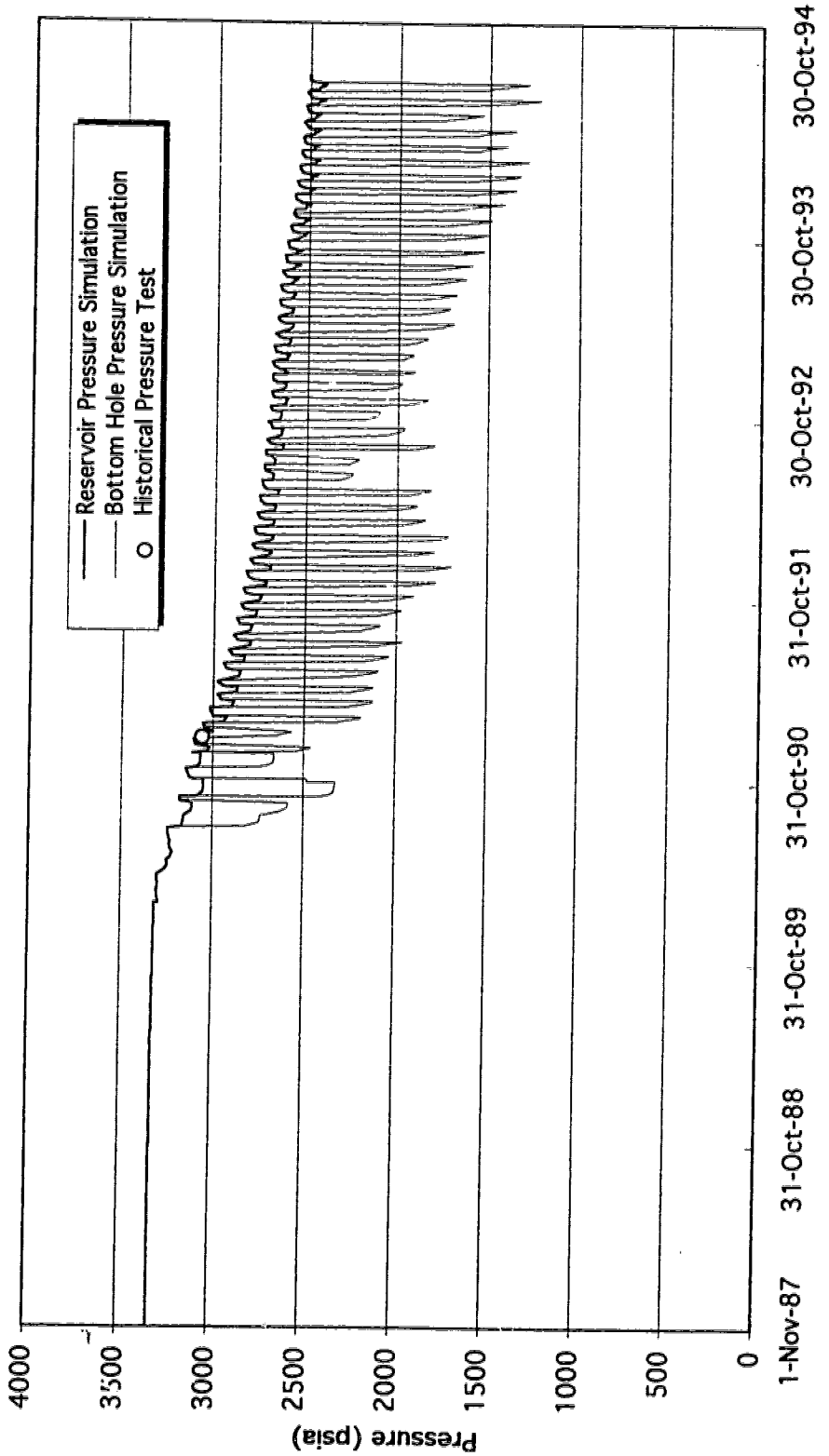



Figure 4.2(d): Pressure History Match (06-13-37-8W5)

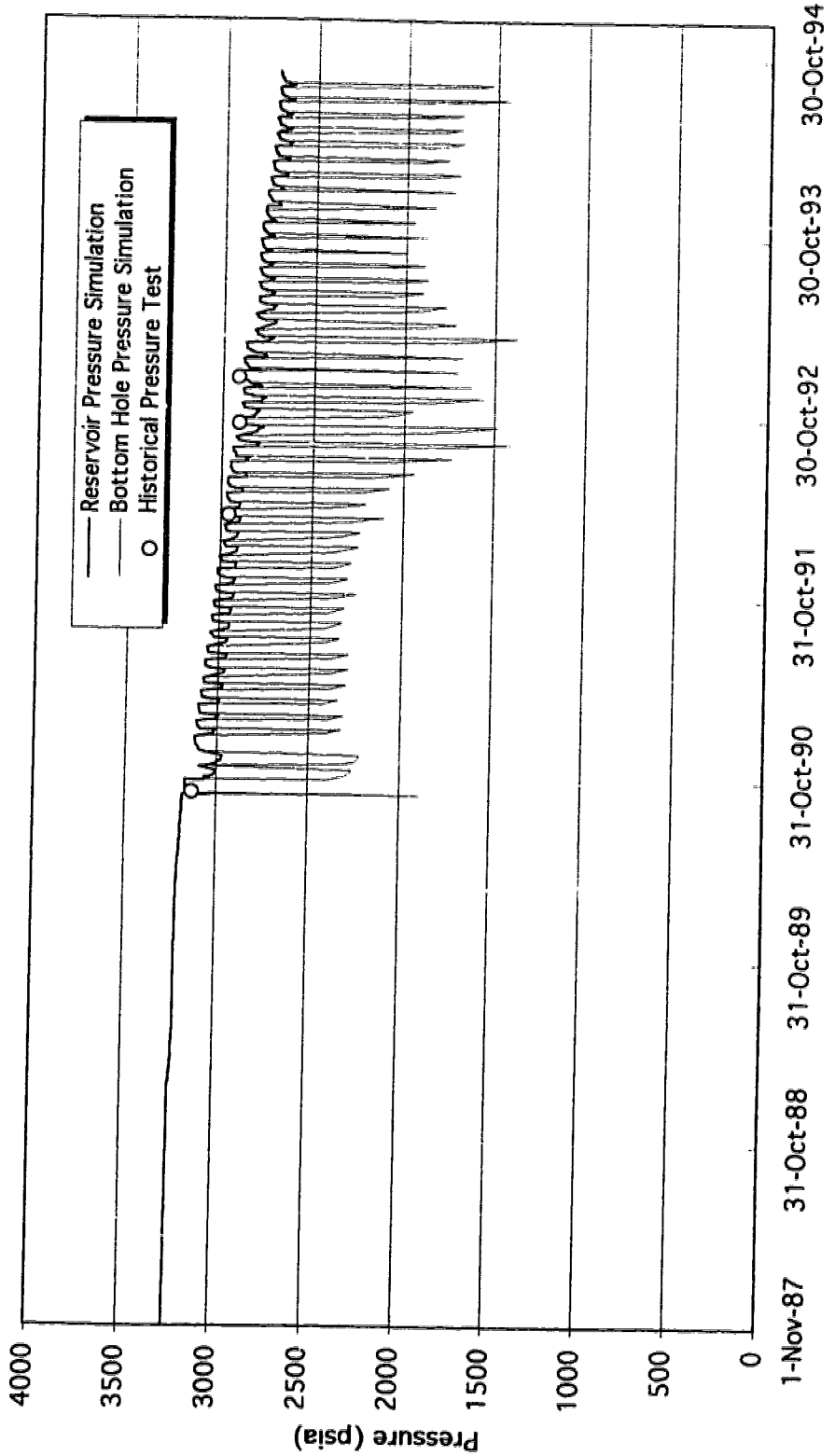



Figure 4.2(e): Pressure History Match (06-16-37-7W5)

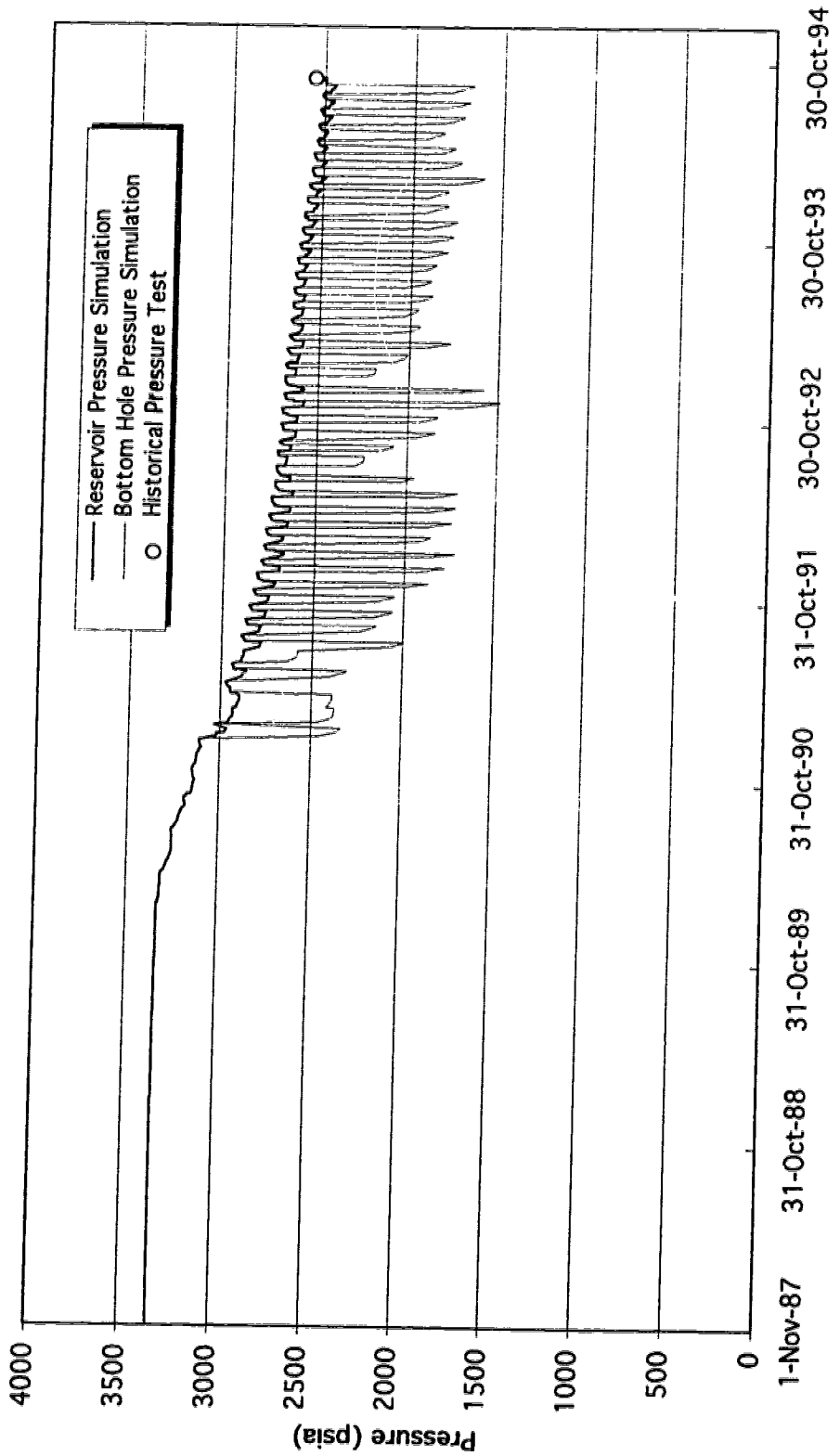



Figure 4.2(f): Pressure History Match (08-14-37-8W5)

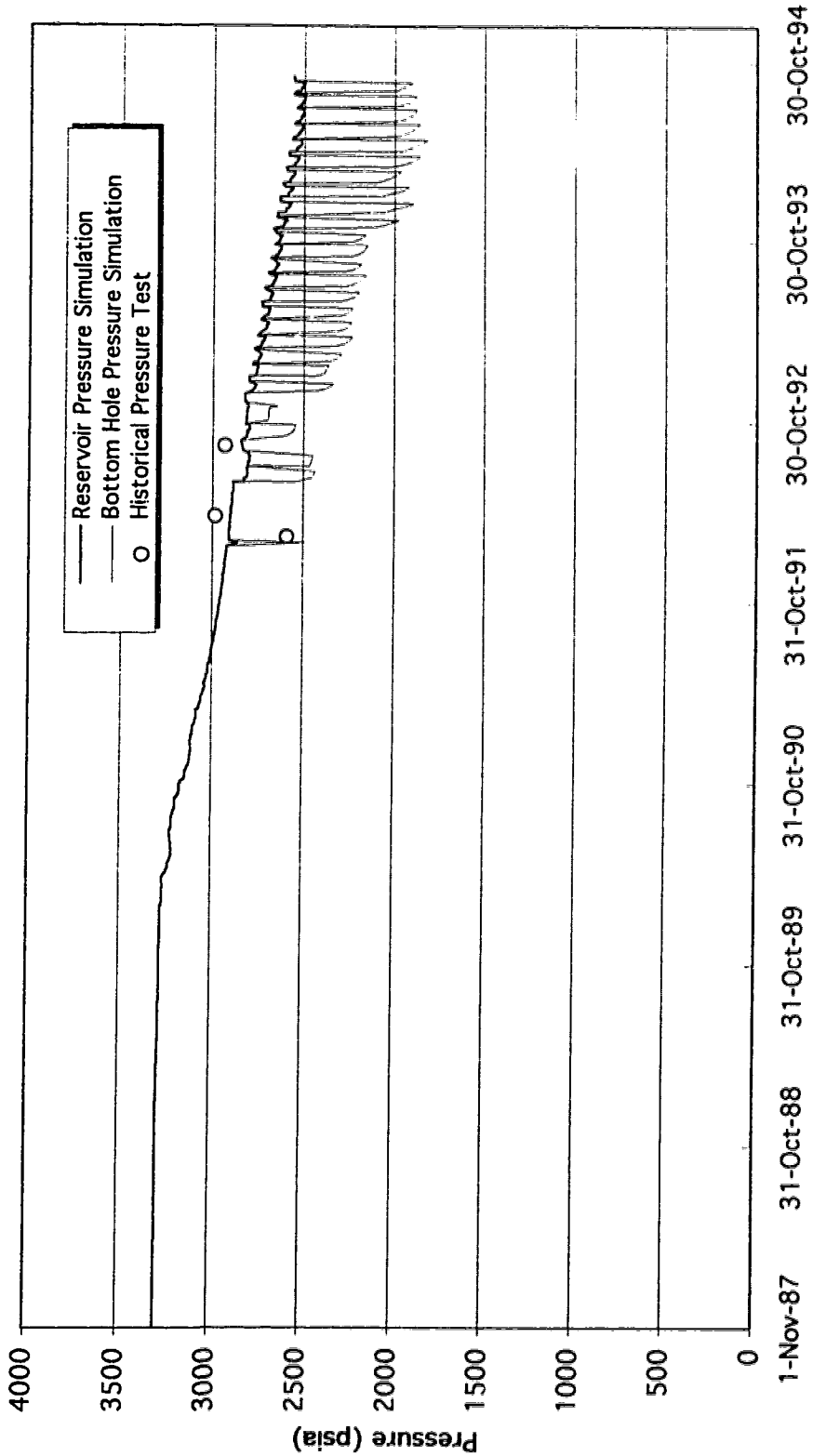



Figure 4.2(g): Pressure History Match (08-18-37-7W5)

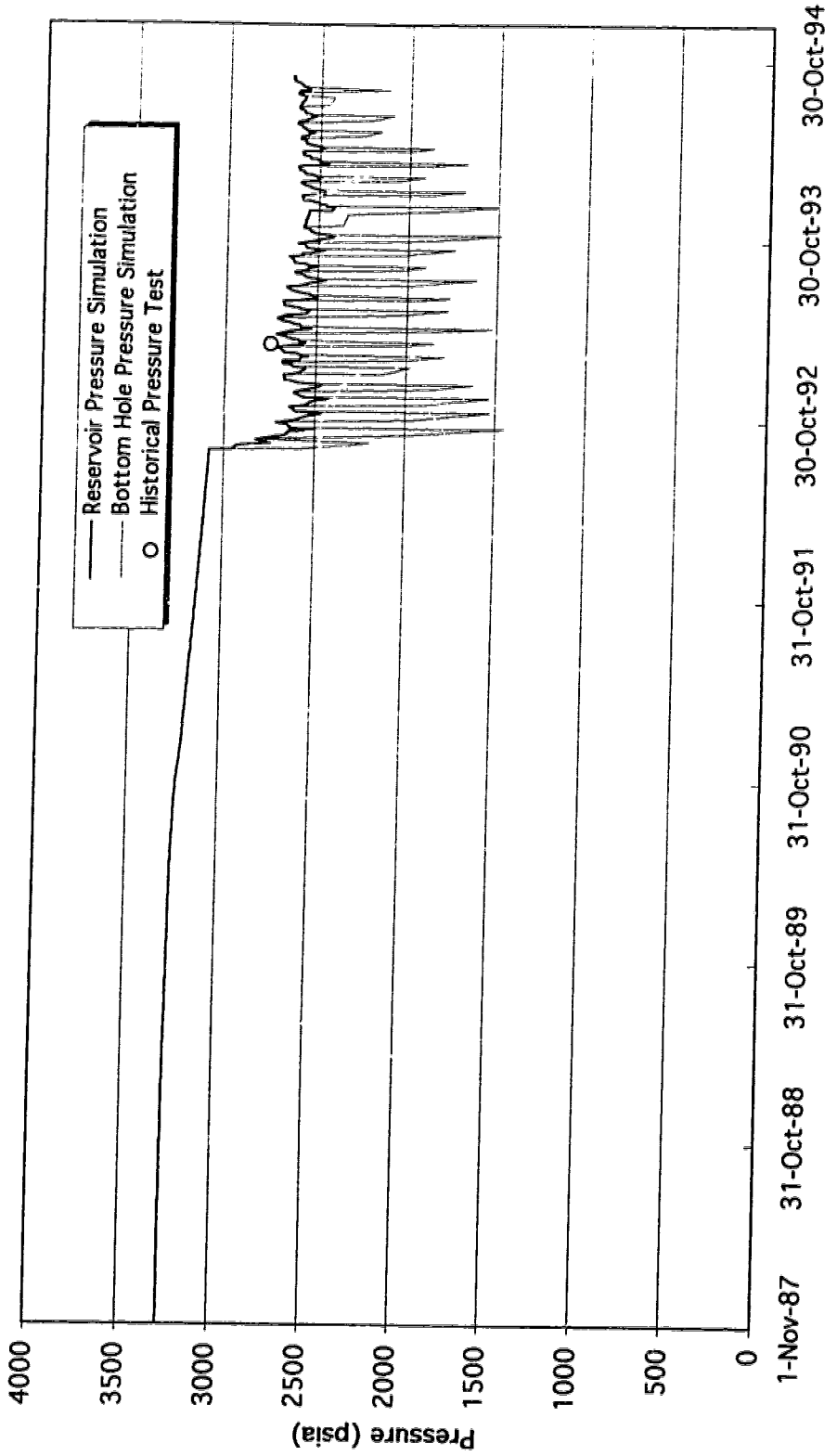



Figure 4.2(h): Pressure History Match (16-08-37-7W5)

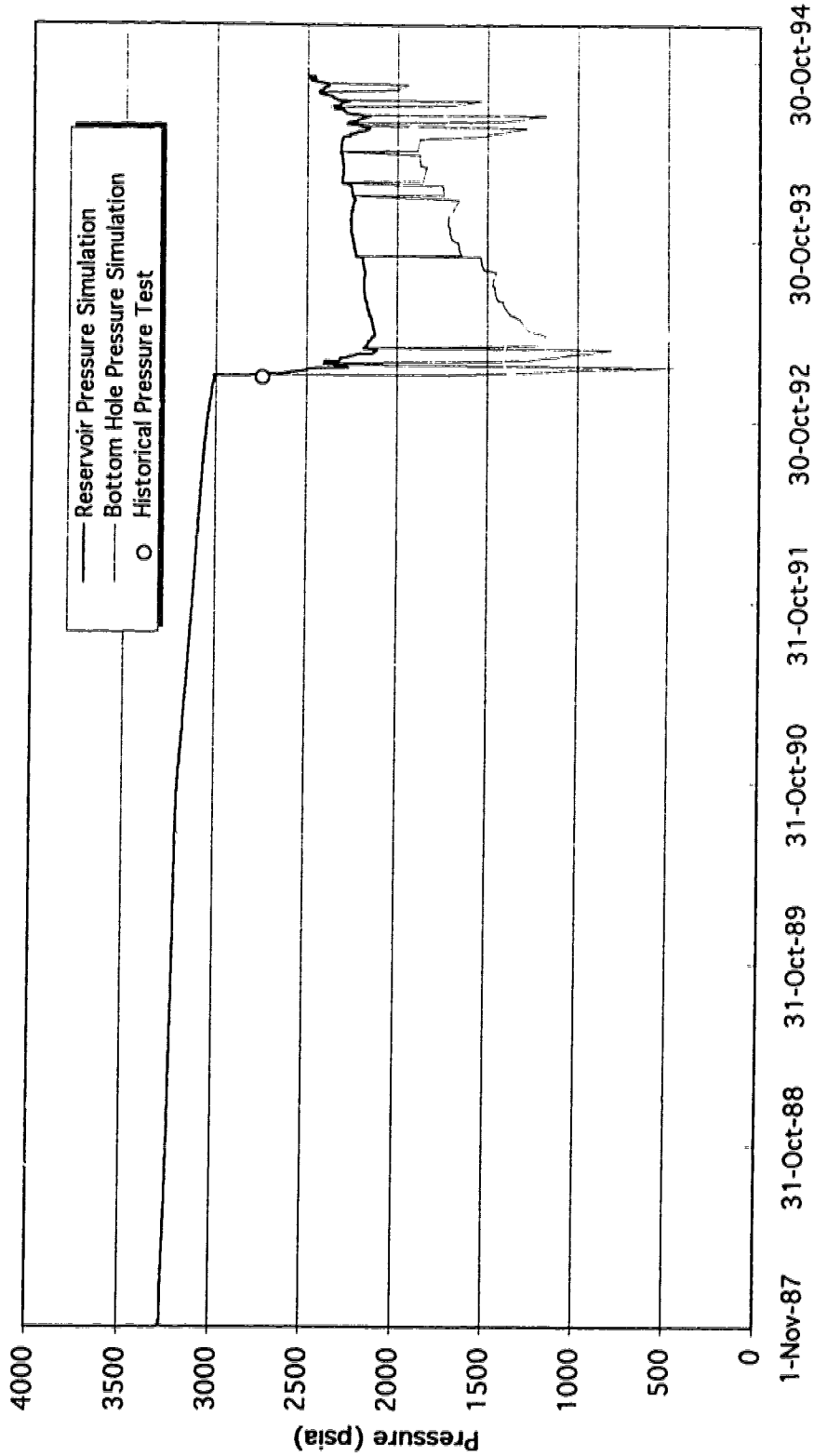



Figure 4.2(i): Pressure History Match (14-09-37-7W5)

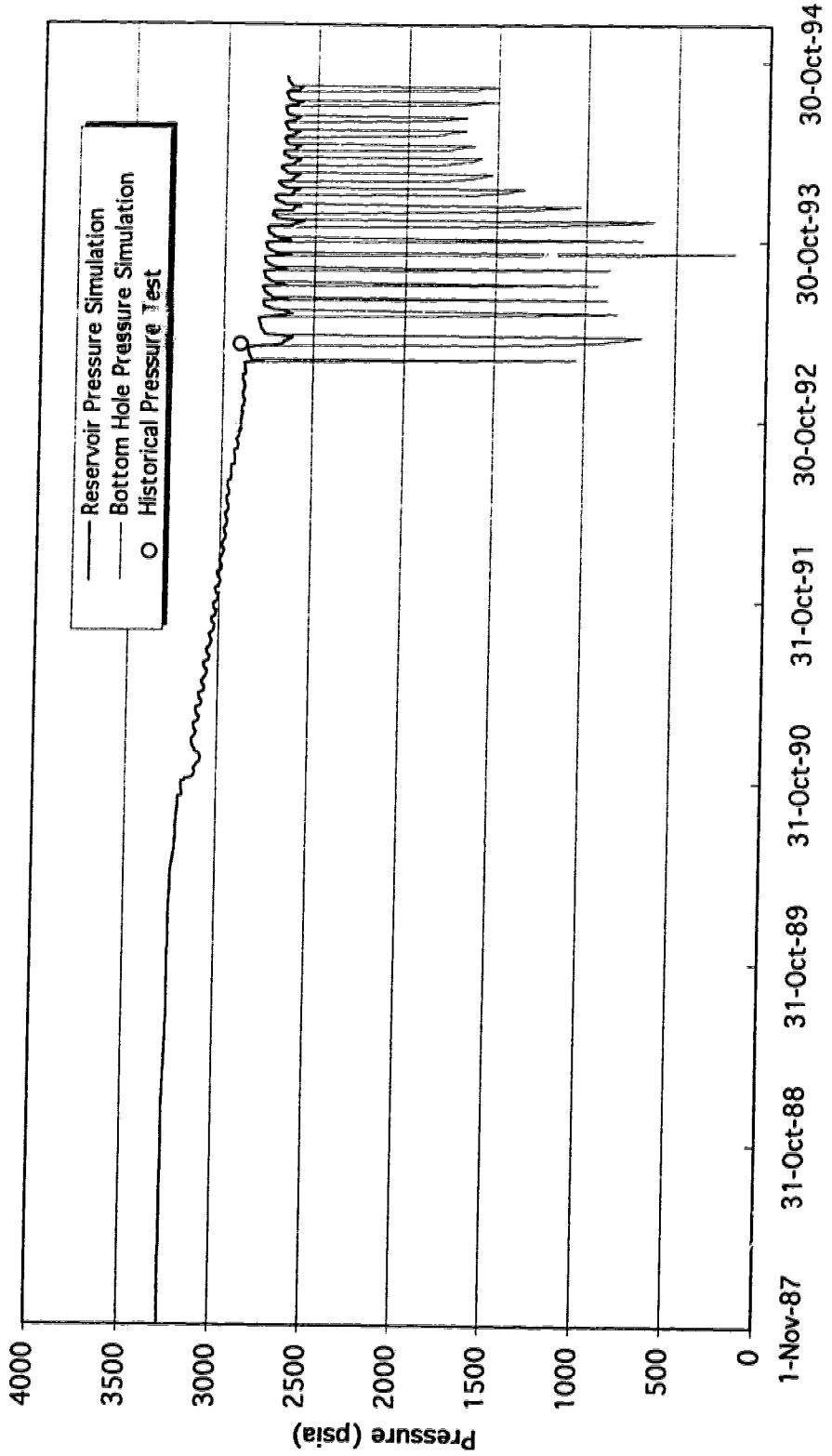



Figure 4.2(i): Pressure History Match (08-17-37-7W5)

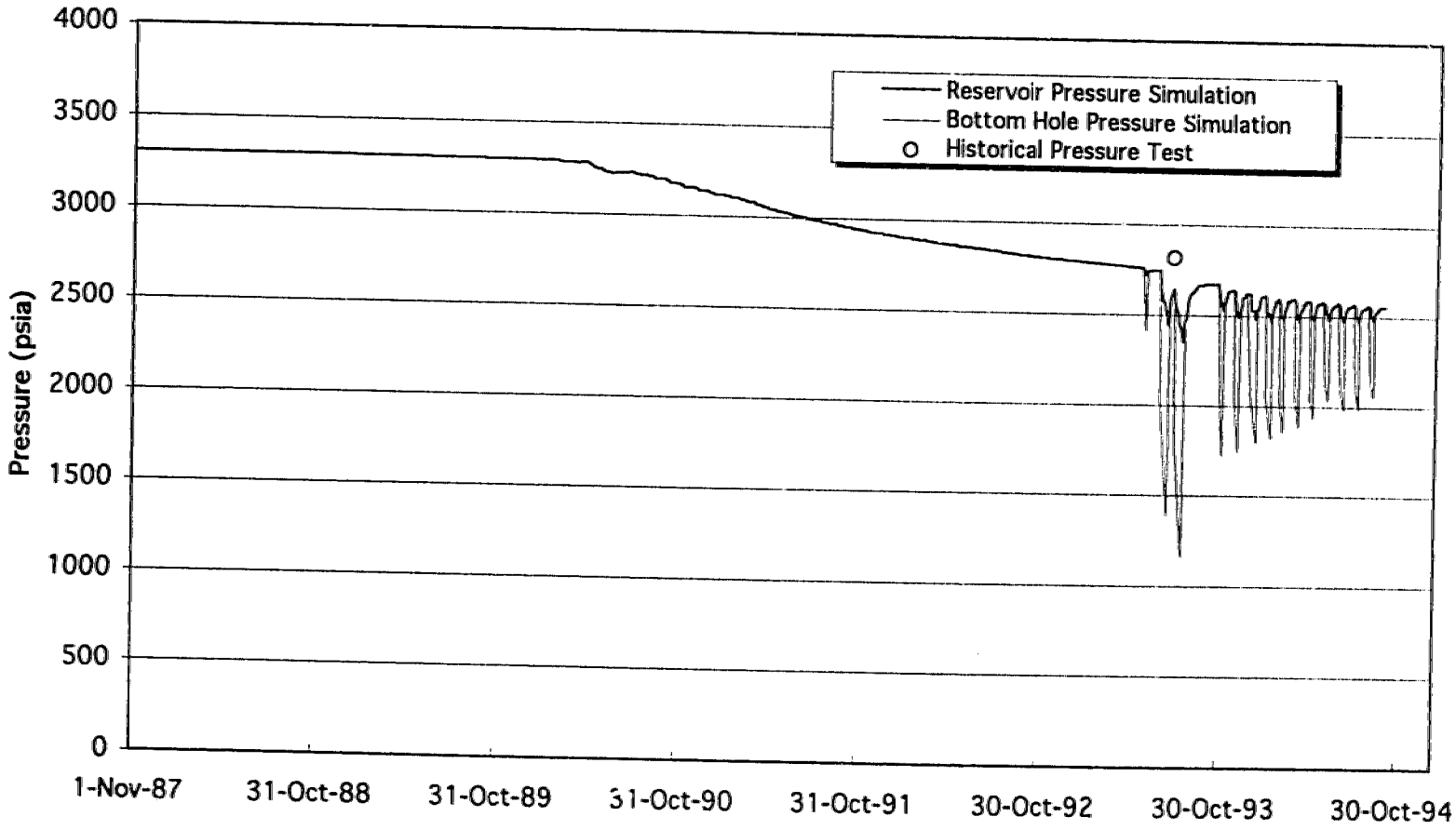



Figure 4.2(k): Pressure History Match (14-07-37-7W5)

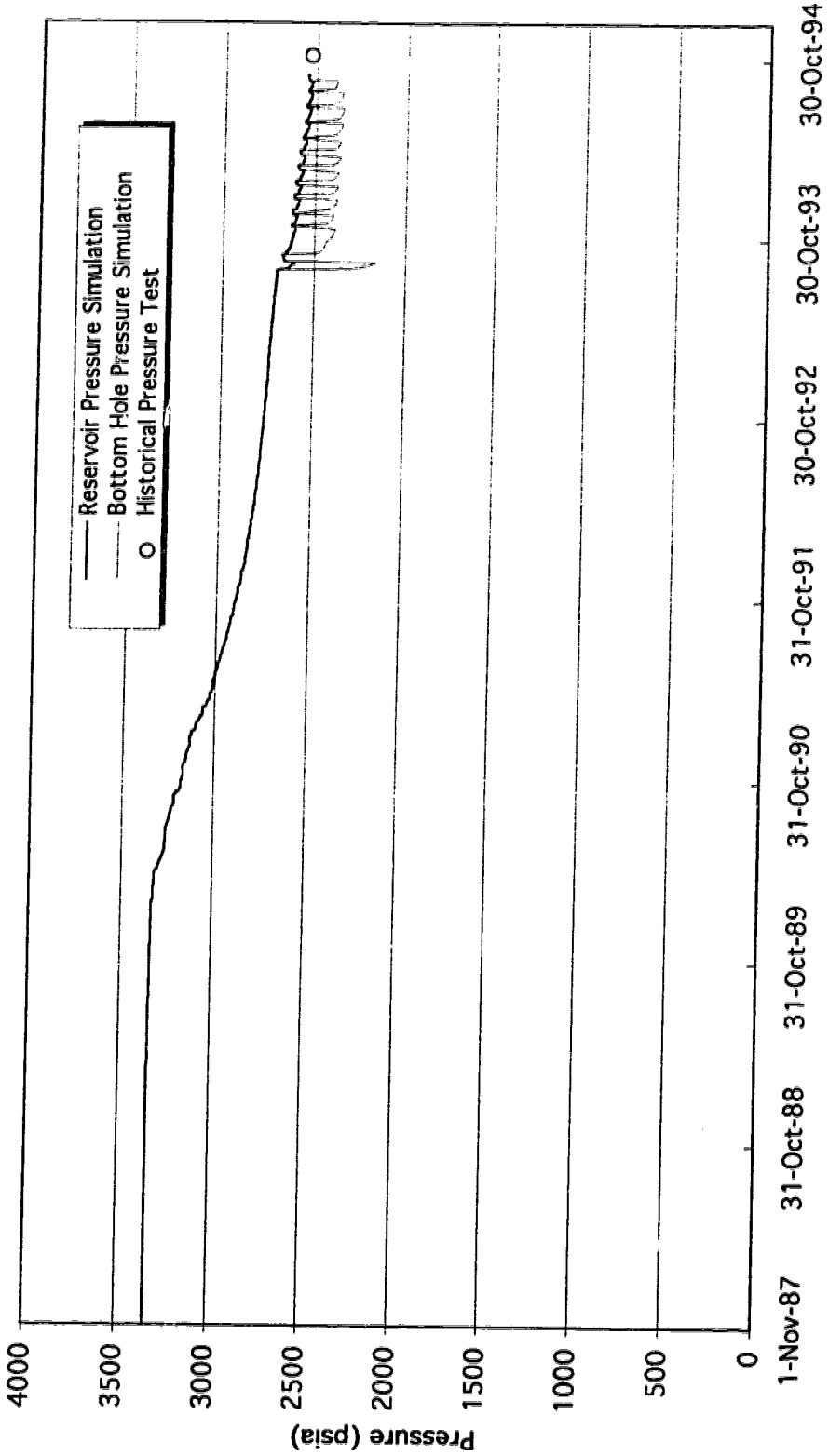



Figure 4.2(l): Pressure History Match (14-12-37-8W5)

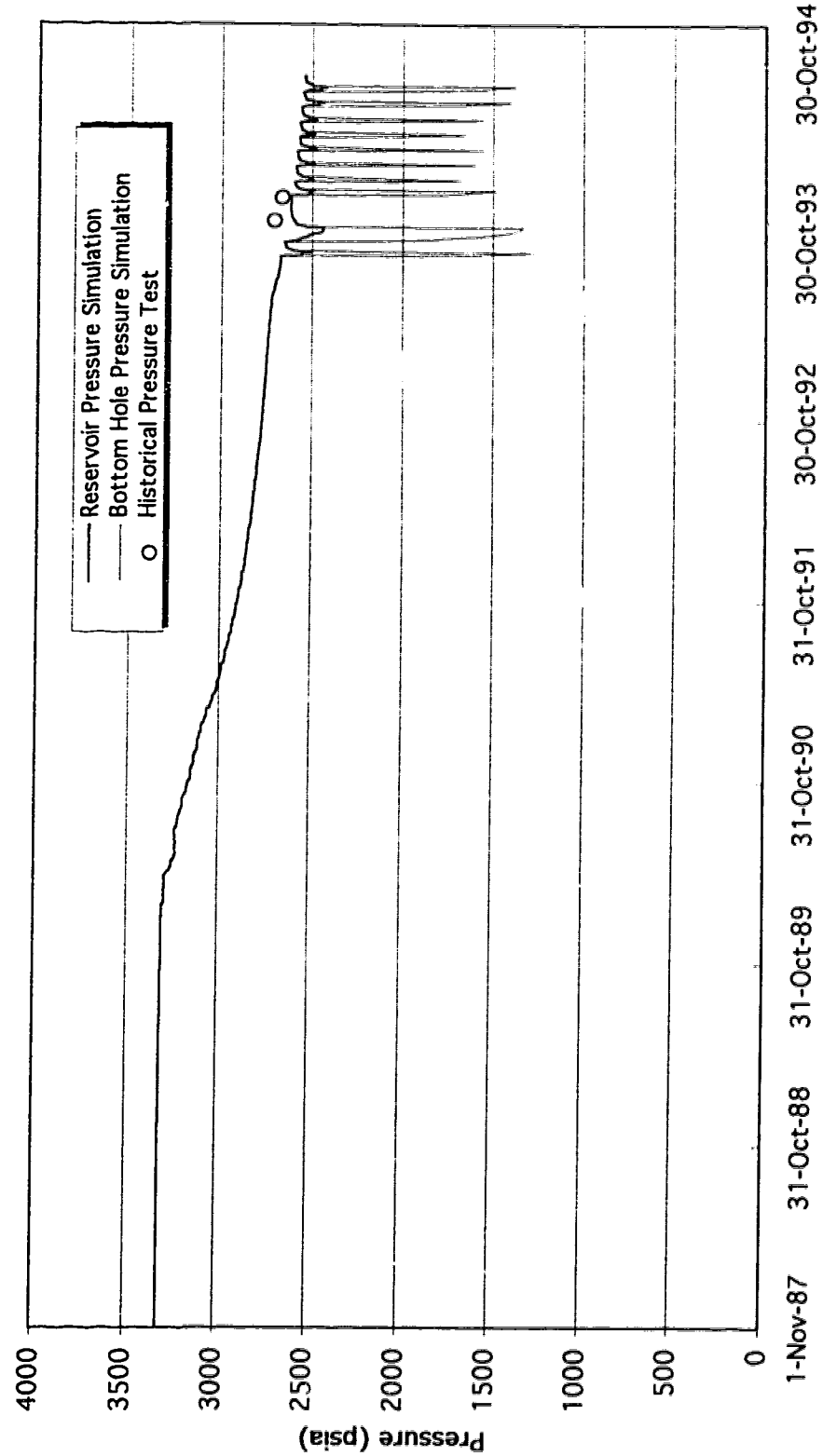



Figure 4.2(m): Pressure History Match (16-12-37-8W5)

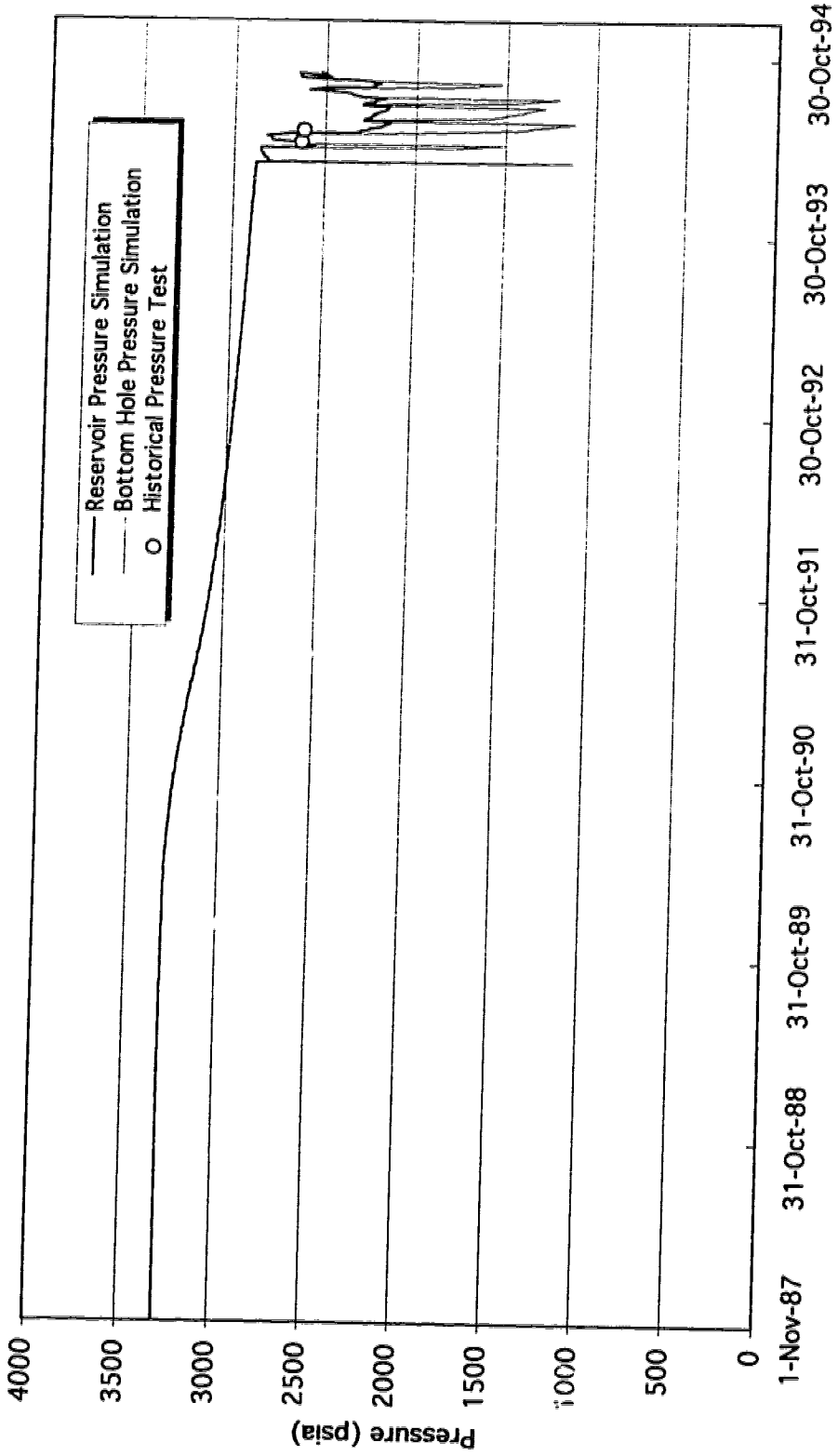



Figure 4.2(n): Pressure History Match (08-07-37-7W5)

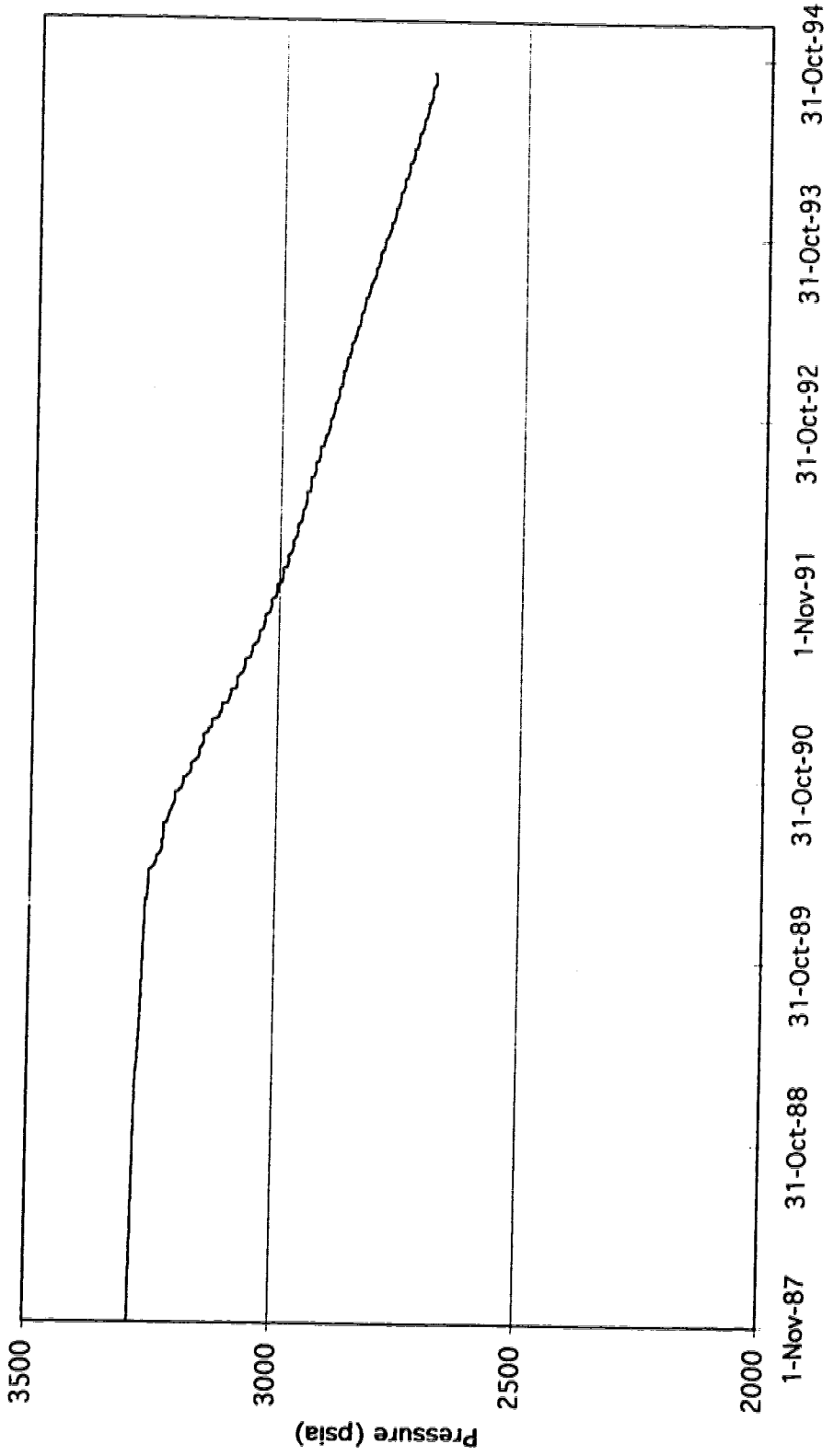



Figure 4.3(a): Average Reservoir Pressure (Simulation)

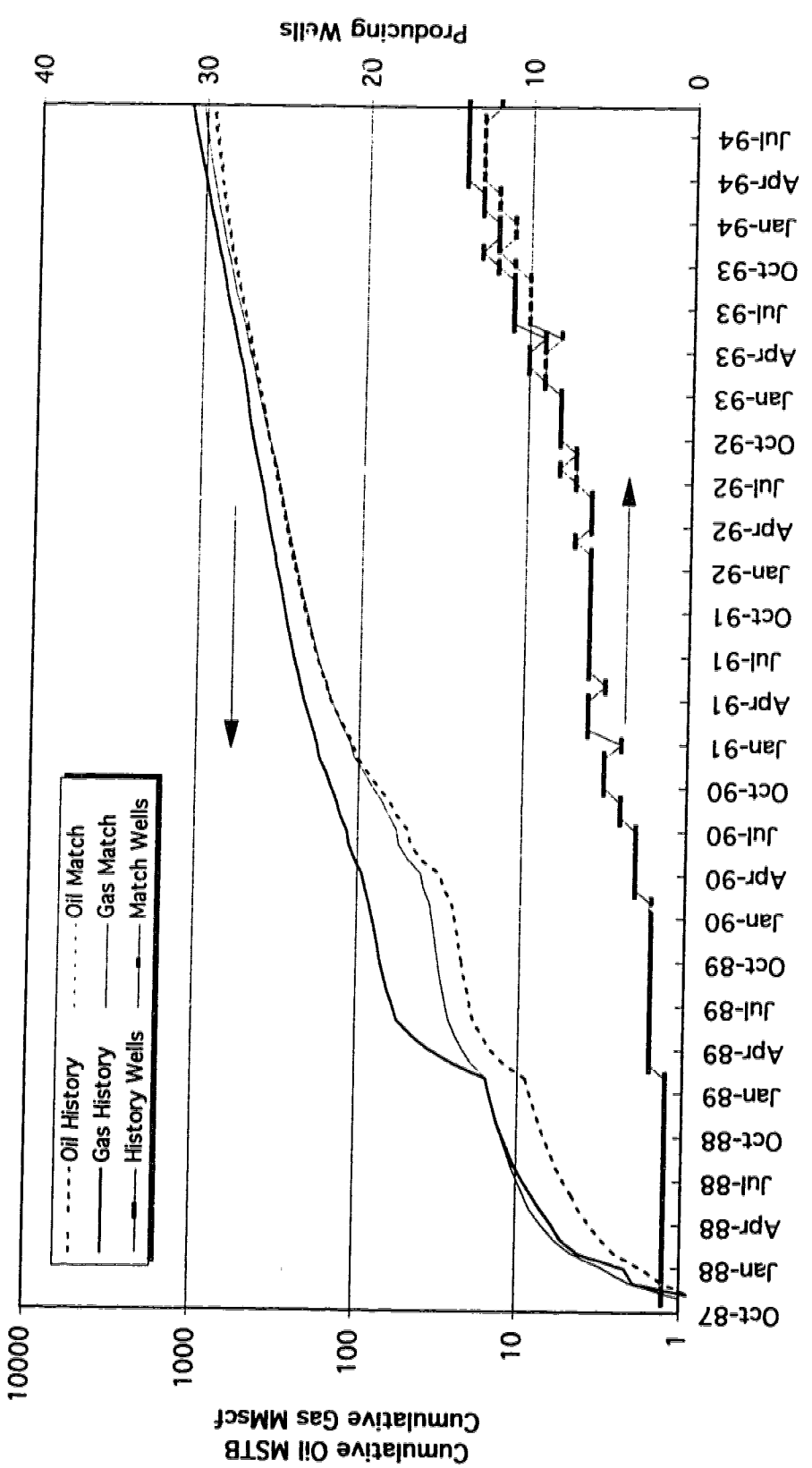



Figure 4.3(b): Pool Cumulative Production History Match

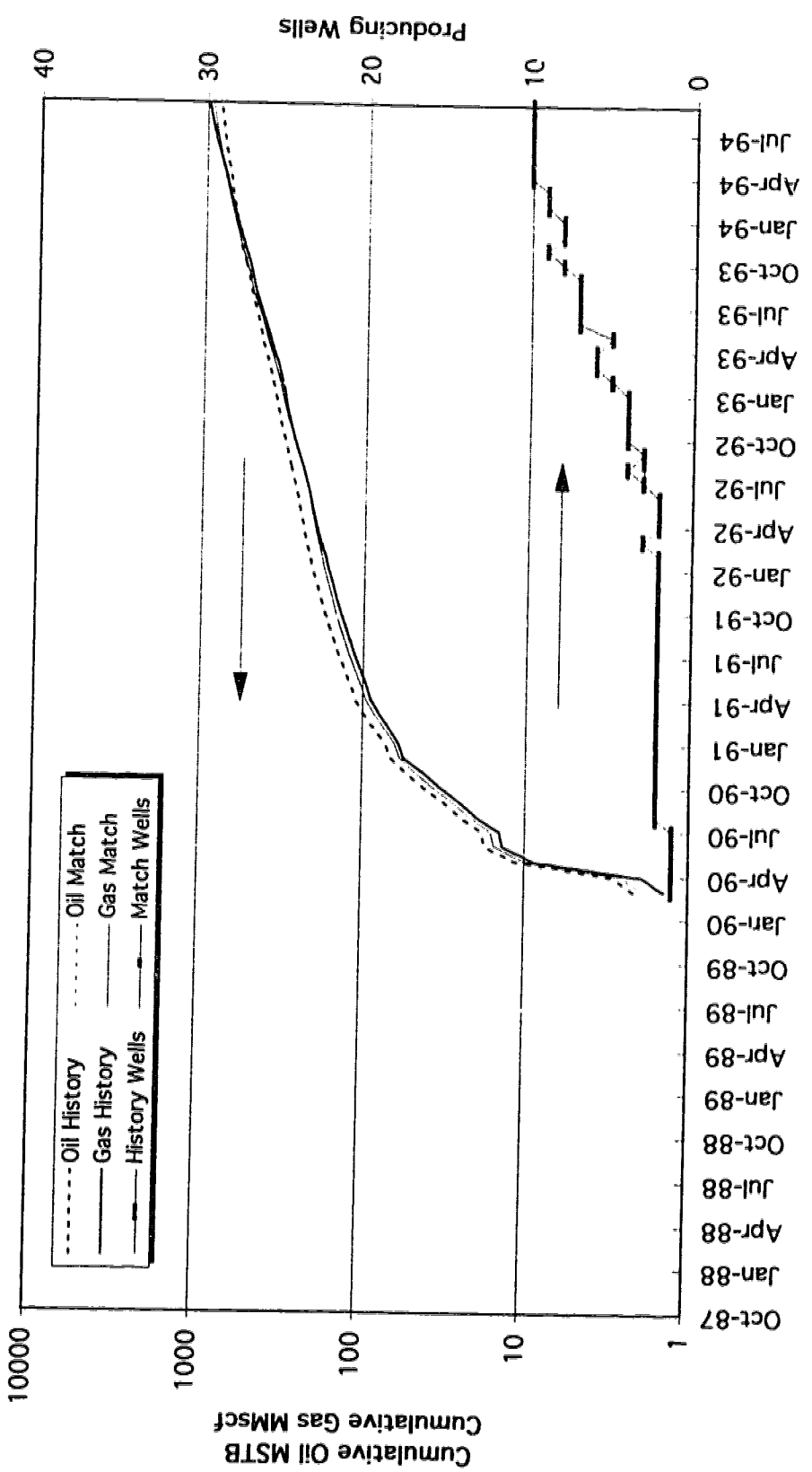



Figure 4.3(c): Pool Cumulative Production History Match
(Excluding 16-09-37-7W5 and 06-15-37-7W5)

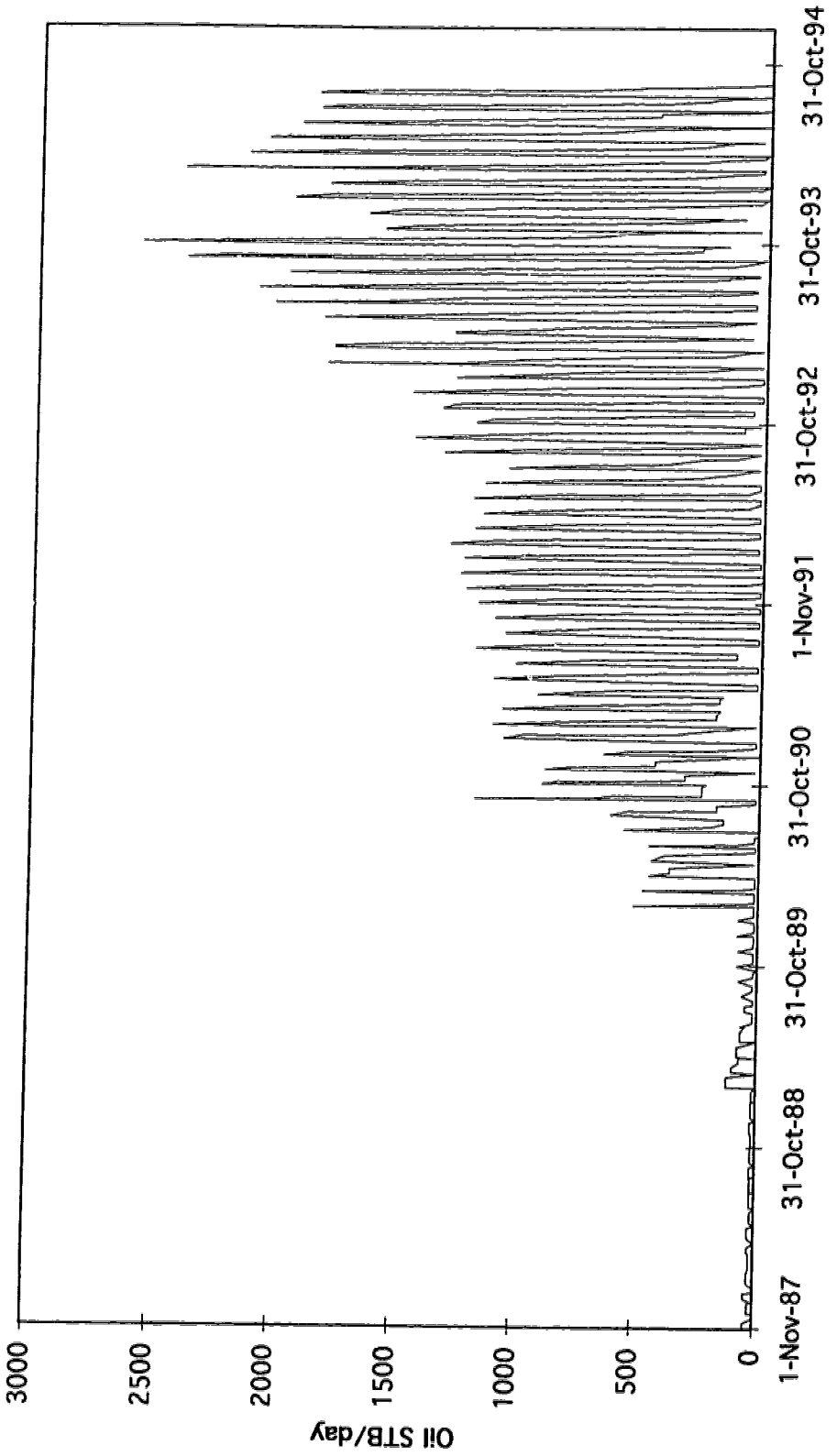



Figure 4.4(a): Pool Oil Production Rate (Simulation)

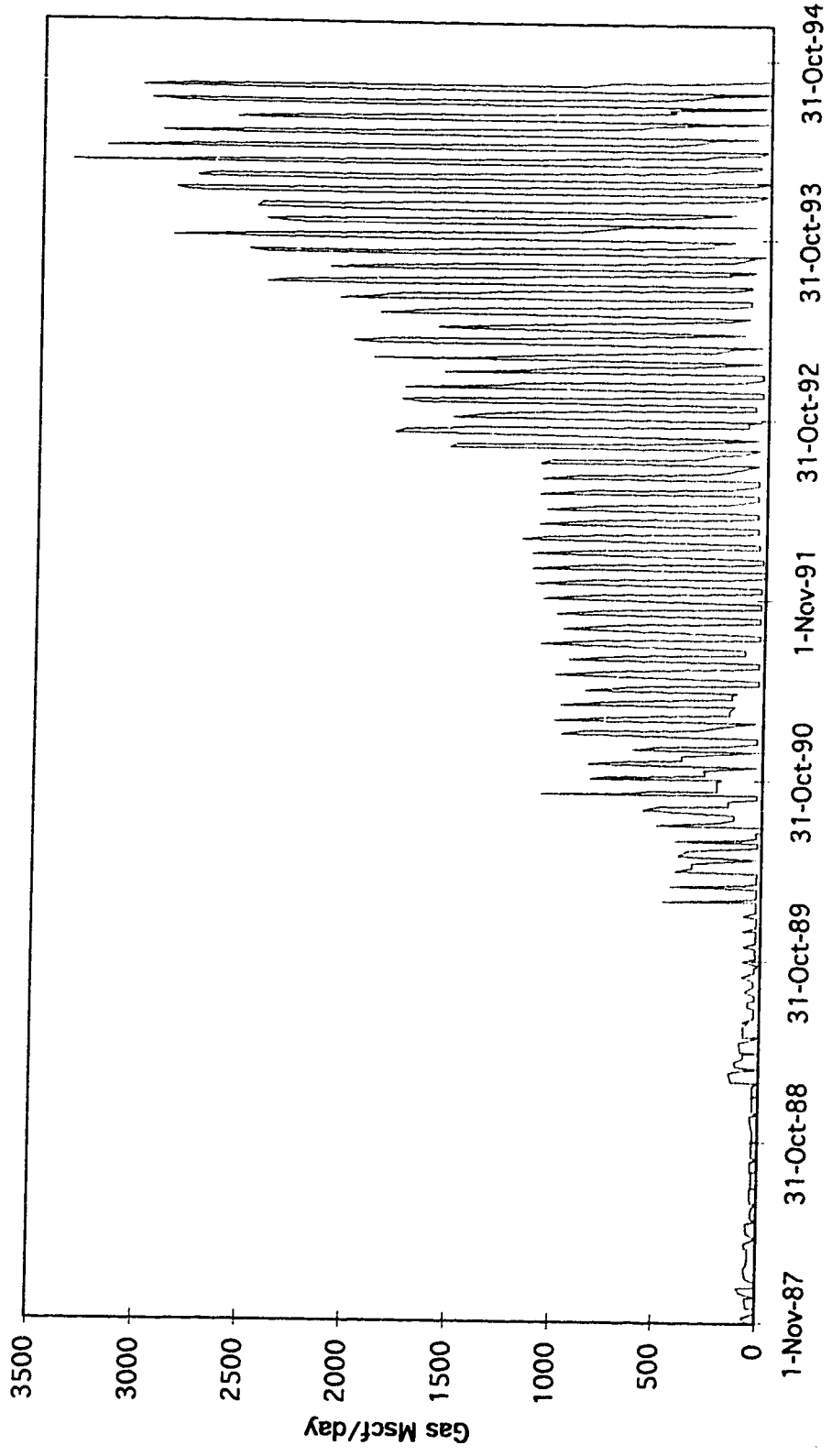



Figure 4.4(b): Pool Gas Production Rate (Simulation)

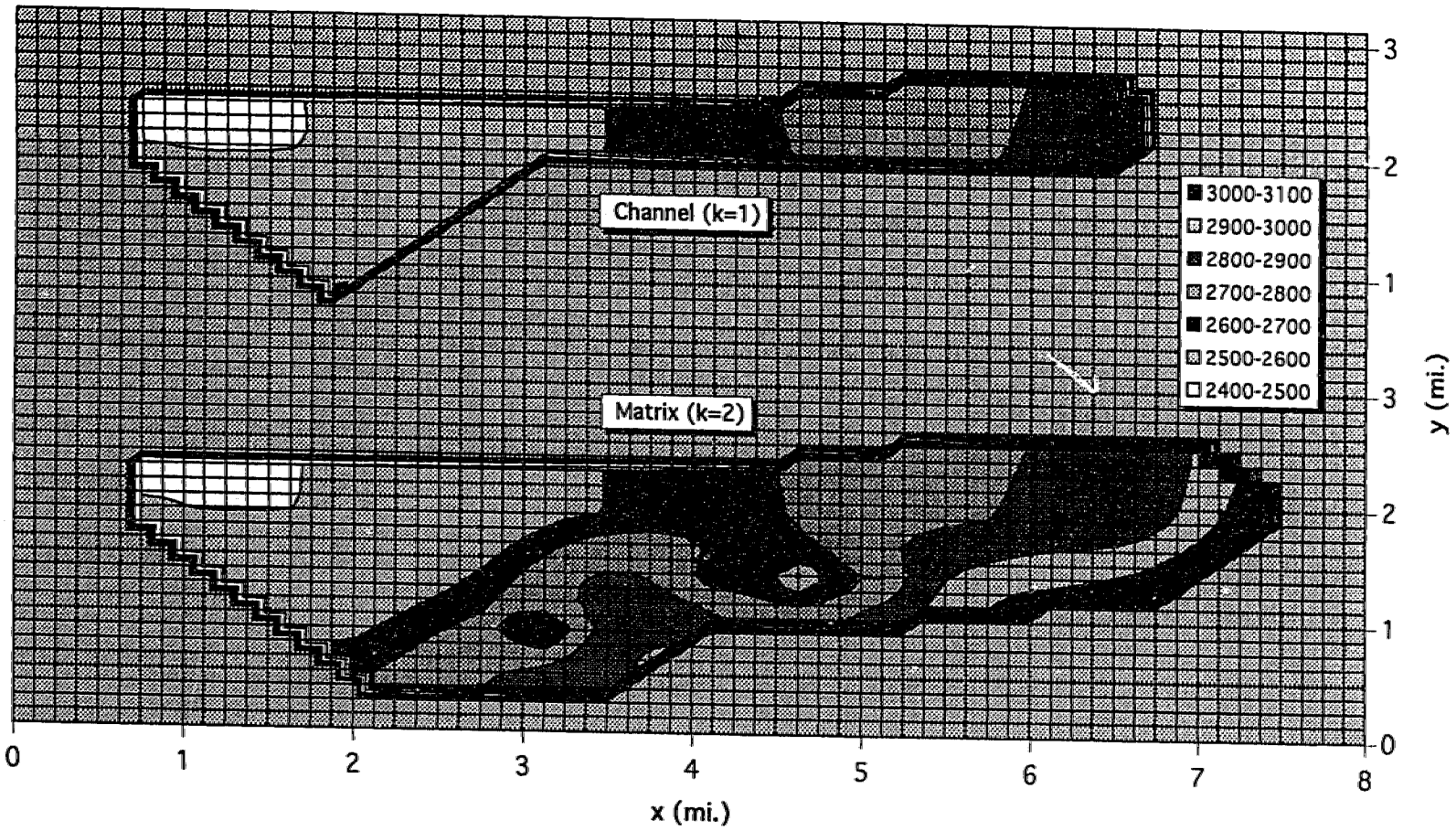



Figure 4.5(a): History Match (Oct-94) Pressure p (psia)

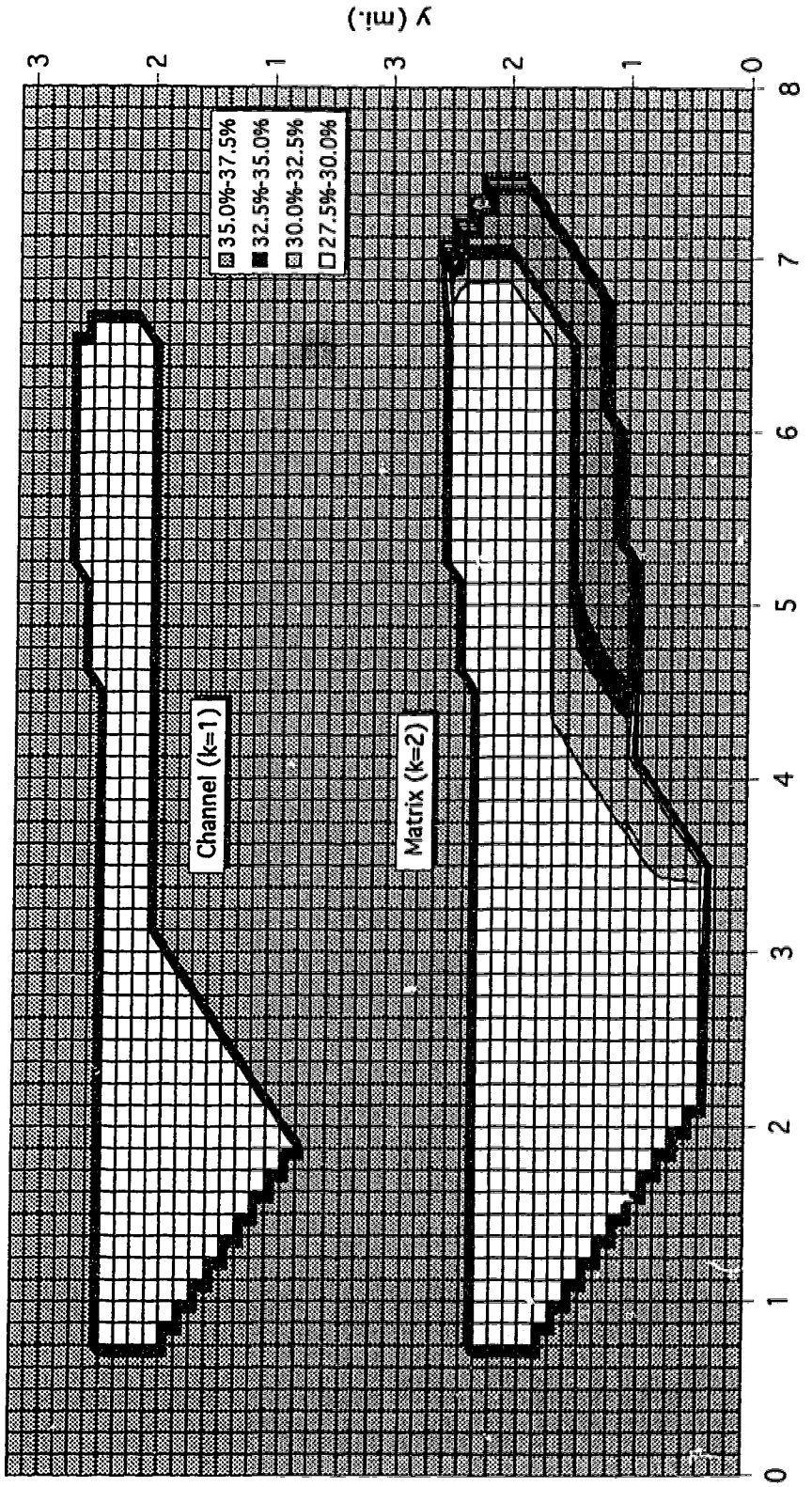



Figure 4.5(b): History Match (Oct-94) Water Saturation $S_w$

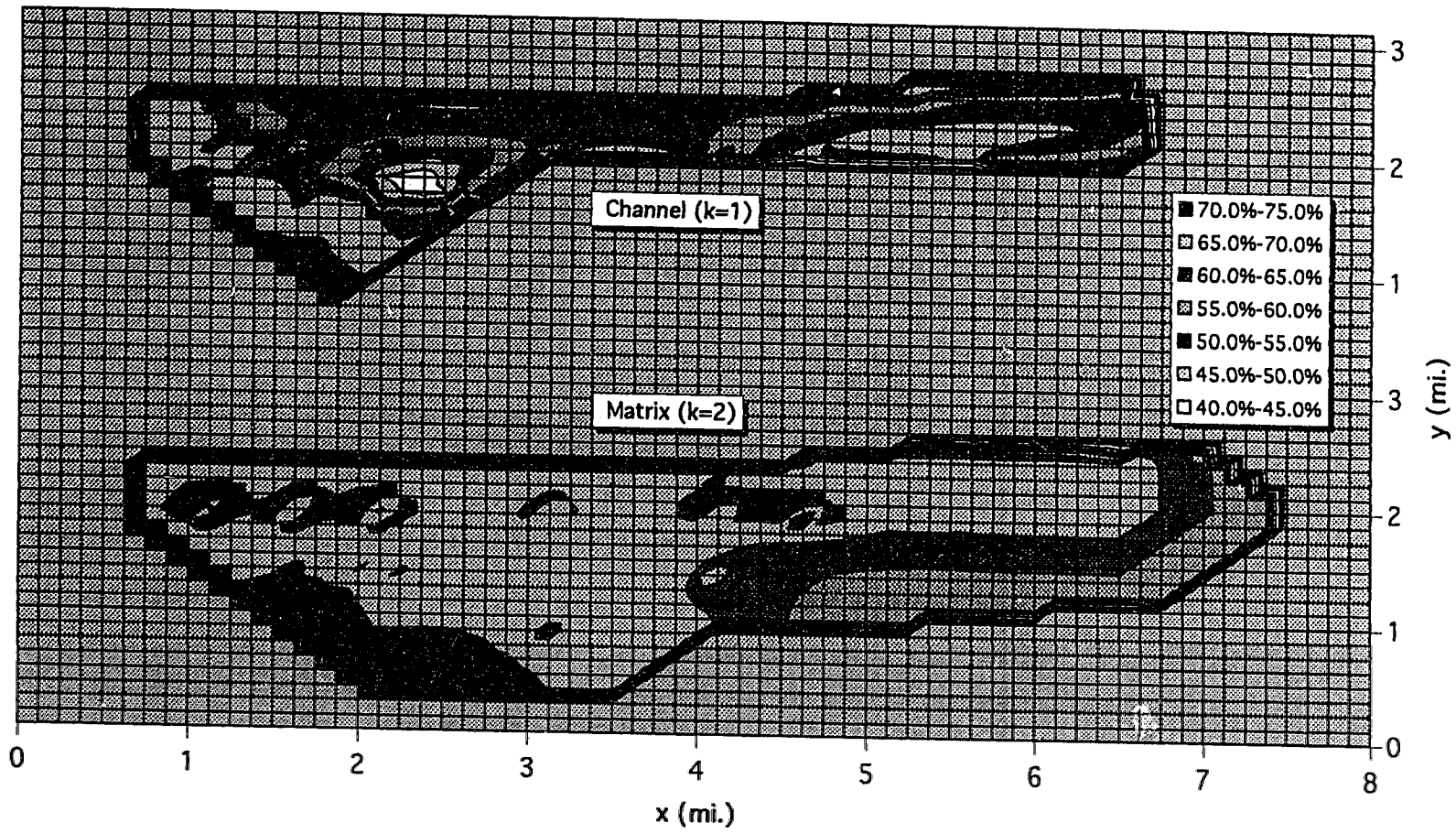



Figure 4.5(c): History Match (Oct-94) Oil Saturation $S_o$

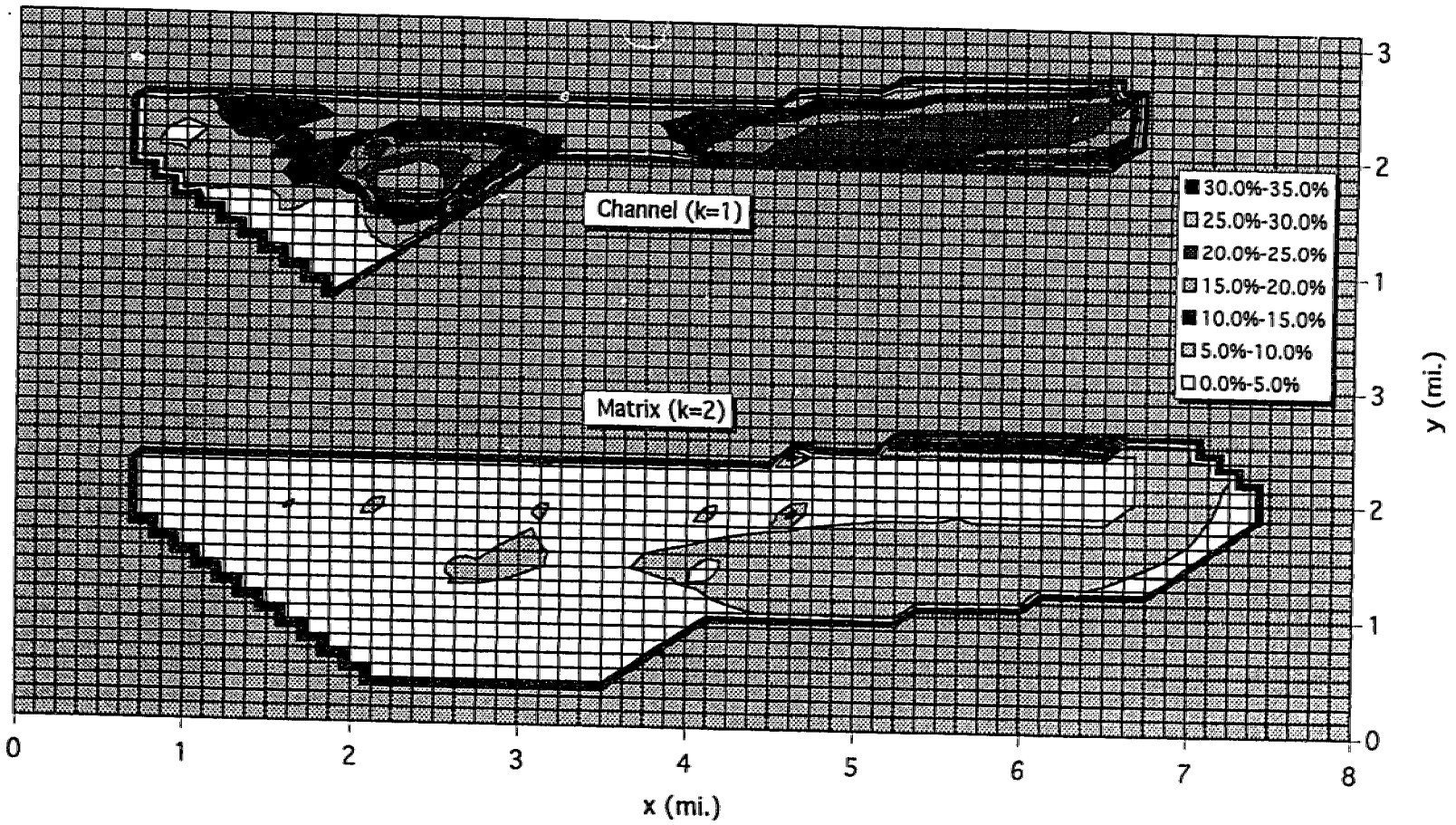



Figure 4.5(d): History Match (Oct-94) Gas Saturation $S_g$

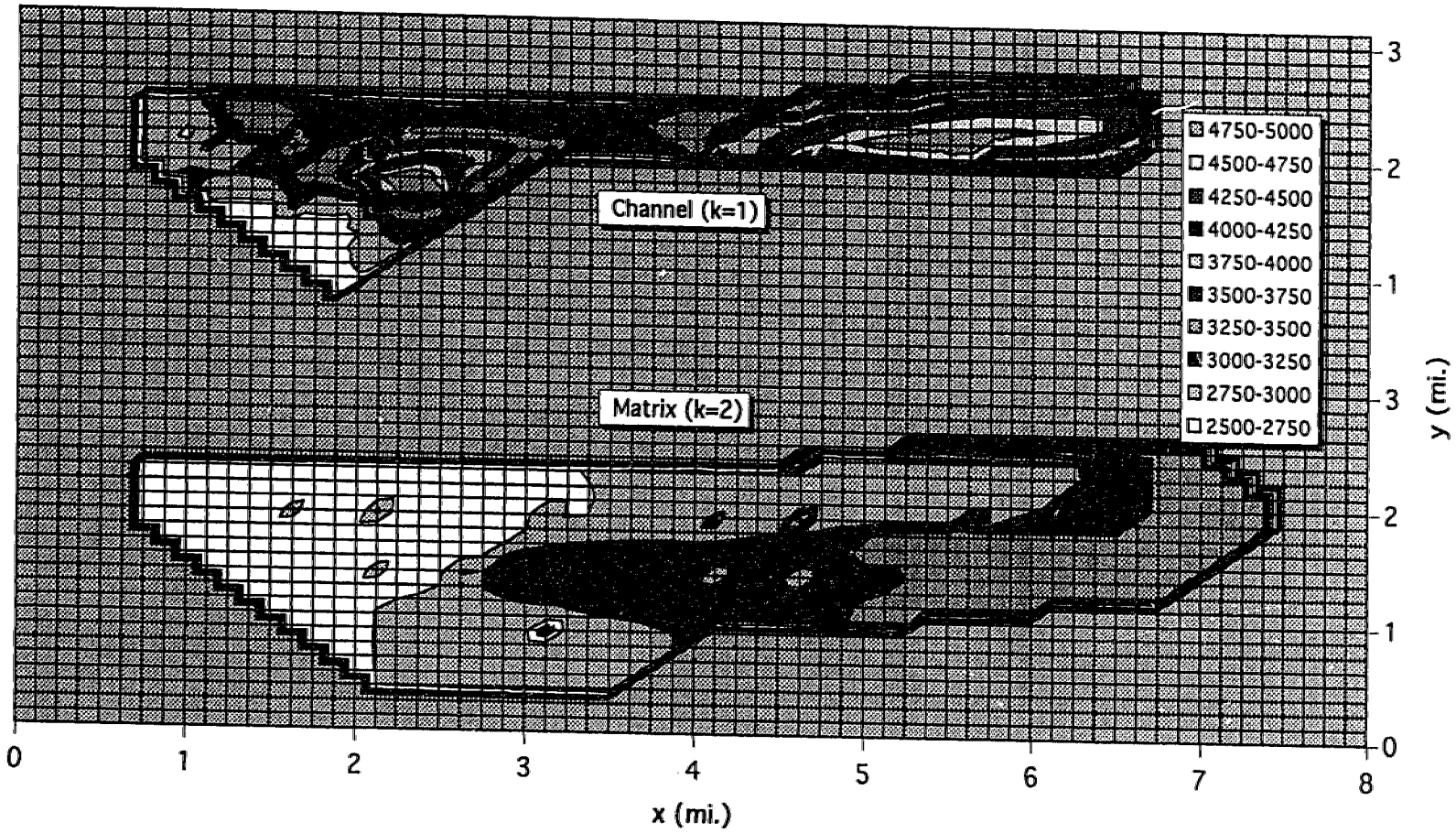



Figure 4.5(e): History Match (Oct-94) Bubble Point $p_b$ (psia)

# Chapter 5: Primary Forecast

## 5.1 Primary Controls

Wells 06-15-37-7W5 and 16-09-37-7W5 in the developing gas cap are excluded from the forecast and designated as shut in. No new wells are scheduled for primary operations. The model chooses not to overproduce under primary MRL regulations. All produced gas is flared rather than gathered. Primary operations assume that the current single well MRL and GOR will continue for another year. The high gas-oil ratio producer 14-09-37-7W5 at the source of the pressure disturbance is scheduled to be shut-in at the end of that year. The remaining wells are then reclassified under a new block MRL status and reassigned with an aggregate primary MRL=1320 STB/day. The pooled aggregate MRL is based on the sum total of original[16] single well MRLs. The current single well GOR is applied to the new pooled aggregate (GOR=1.129 Mscf/STB). Individual producers are designated to be permanently shut in if the oil rates fall below 10 STB/day or the gas-oil ratio rises above 50 Mscf/STB. Primary production is scheduled to terminate after 13 years of simulated time which completes a 20 year recovery life on 1-Oct-2007.

An accounting system was used to regulate oil and gas production. This system implemented the primary control policy described in Section 3.7. Explicit time steps were set to coincide with individual well production cycles. Wells were toggled on and off between maximum admissible rates established by well productivity (Eqns 3.7-3.9) and no-flow shut-in states. Monthly production accounts were accumulated for each well to satisfy single well MRL=88 STB/day and GOR=1.129 Mscf/STB regulatory constraints. All producing wells were turned on and monthly production counters set to zero at the beginning of each monthly cycle. Automatic time step control used a Courant number ($N_{Courant}$=.25) and bounded base time steps between 5-10 days to ensure numerical stability. Maximum changes over each timestep for reservoir pressure and phase saturation was limited to 1000 psi and 10%, respectively. Remaining oil and gas production quota bandwidths (Eqn 3.17) for individual wells were estimated at each step using the explicit well model. The minimum remaining bandwidth was selected from all wells for the new time step. Gas quotas had precedence over oil quotas and wells were toggled off accordingly. Consecutive time steps were marked by the minimum between the base time step, remaining time for the monthly accounting cycle and the remaining

---

16 The aggregate MRL also includes the isolated producer 08-08-37-7W5 in Chedderville Viking "B". The model assumes that the low-rate producer is effectively shut in and does not interact with Viking "A" wells.

durations over all wells. Gas produced by individual wells over each time step was accumulated in corresponding counters. Relevant wells were toggled off and the next step initiated. Each well tracked different monthly production hours. Cycle-averaged oil, gas and water rates were calculated for each well by dividing accumulated monthly production accounts by the corresponding hours of production. Cycle-averaged production rates were recorded for the current month at the end of the monthly cycle. Calendar time was used for each month. Instantaneous aggregate pool production rates and average reservoir pressure were recorded at each time step. Instantaneous bottomhole pressures for each well were also recorded at each time step. The actual simulation time[17] on the available hardware grew proportionately with an overwhelming number of time steps when all production wells were online and tracked separately. A simplification was considered for the pooled production constraint which became effective after the first year of primary production forecasting. This simplification used the same accounting system to calculate one monthly lumped cycle for all pooled wells, with explicit timing based on aggregate maximum admissible production rates. Relevant wells were simultaneously, and collectively, toggled on and off, once a month. Individual producers were permanently shut in when oil production rates fell below 10 STB/day or the gas-oil ratio exceeded 50 Mscf/STB. The aggregate production quota remained constant so that production slack from shut-in wells were redistributed to those wells still in operation.

## 5.2 Primary Simulation

Figures 5.1(a)-(l) shows monthly production forecasts for the twelve wells appointed for primary operation. Most wells continue to produce below rated pump capacity (500 STB/day). Production is limited by the flowing bottomhole pressure constraint. Figure 5.1(g) shows the scheduled shut in of 14-09-37-7W5 at the end of first year. This well was producing continuously without bang-bang control at the time of shut in (Oct-95). The change from single well MRL to block MRL (Oct-95) is observed to shift cycle-averaged production rates and hours of operation. The block MRL reclassification with aggregate control change-over leads to a global increase and redistribution of production quotas within the pool. Most wells react with a sudden jump to longer hours of monthly operation. Some wells react with short-lived increases in oil production as a result of

---

17 Actual reservoir simulation time on a Power Macintosh 6100/60 for the branched production forecast was one hundred hours of continuous CPU time. The final simulation run was performed on a Power Macintosh 8500/120 using forty hours of dedicated CPU time. These run-times correspond to the pooled accounting simplification which gave an overall time reduction factor by at least five.

transient pressure disturbances. Figure 5.1(l) shows a decrease in production hours for 08-07-37-7W5 with a sustained increase in daily oil rates. Gas production in most wells is observed to peak within two to three years and rapidly decline thereafter. Wells represented in Figures 5.1(a),(b) and (d) are shut in prematurely (Oct-02) as a result of oil rates falling below the 10 STB/day cutoff. The reallocation of production slack to remaining wells are marked by longer production hours. The increase in production triggers a gas-oil ratio crossover from undersaturated to saturated bottomhole conditions for 08-07-37-7W5 as shown in Figure 5.1(l). Figures 5.2(a)-(l) shows the predicted response in instantaneous bottomhole pressures. The flowing bottomhole pressure spikes represents the cyclic response to bang-bang rate controls. The flowing bottomhole pressures reach the set point floor ($p_{wf}$=800 psia). Most wells exhibit a linear decline trend in static bottomhole pressure. Figure 5.2(g) shows the increase in static pressure as gradual fluid influx from tight porous media stabilize pressure gradients about 14-09-37-7W5.

Figure 5.3(a) shows a linear decline trend in average reservoir pressure. Figure 5.3(b) shows the cumulative oil and gas production predicted for the entire pool. Cumulative gas increases linearly while cumulative oil increases asymptotically. Figures 5.4(a) and (b) show the predicted instantaneous pooled oil and gas production rates, respectively. Pooled monthly production cycles over the first year correspond to sum total of individual well cycles at different rates and different duration bandwidths. Pooled cycles over the remaining years correspond to the sum total of individual well cycles with the same duration but different rates. The change-over in MRL and aggregate control (Oct-95) effects the decline trend in daily pooled oil rate. The decrease in pooled gas rate is a direct result of shutting in low oil producers (Oct-02). The decrease in pooled oil rate (Oct-02) is a result of the gas-oil ratio crossover of 08-07-37-7W5.

Figures 5.5(a)-(e) show the predicted reservoir depletion state at the end of the planned primary period (Oct-07). Pressures are distributed between 1200-1900 psia in Figure 5.5(a). No changes are observed in the water saturation distribution in Figure 5.5(b). Figures 5.5(c)-(e) show the oil saturation, gas saturation and bubble point pressure distributions. Large amounts of saturated oil still remain in the matrix rock. The gas cap has expanded throughout the reservoir. The bubble point variation is large over the whole reservoir, especially between upper and lower layers. Accumulation of free gas migrating from the lower to upper layers has dominated the high permeability channel with lighter ends of the hydrocarbon mixture (high bubble point). Continued production, migration and evolution of free gas from the bottom layer has lowered local bubble point pressures leaving heavy ends.

## 5.3 Primary Summary

Primary depletion forecasted large amounts of remaining oil in place at the end of the planned primary life. The current state of operation had historically recovered 0.89 MMSTB over seven years of production. The original oil in place was estimated as 25.4 MMSTB in the reservoir model. Predicted remaining recovery was 1.05 MMSTB to give a forecasted primary recovery factor of 7.7%. Low primary recovery factors 5%-15% are characteristic of solution gas drive from Alberta light to medium density oil pools (CIM Petroleum Society Monograph No. 1 1994). The low primary oil recovery forecasted for this solution gas drive reservoir justifies the consideration of secondary recovery schemes for pressure maintenance by water injection or a pattern waterflood.

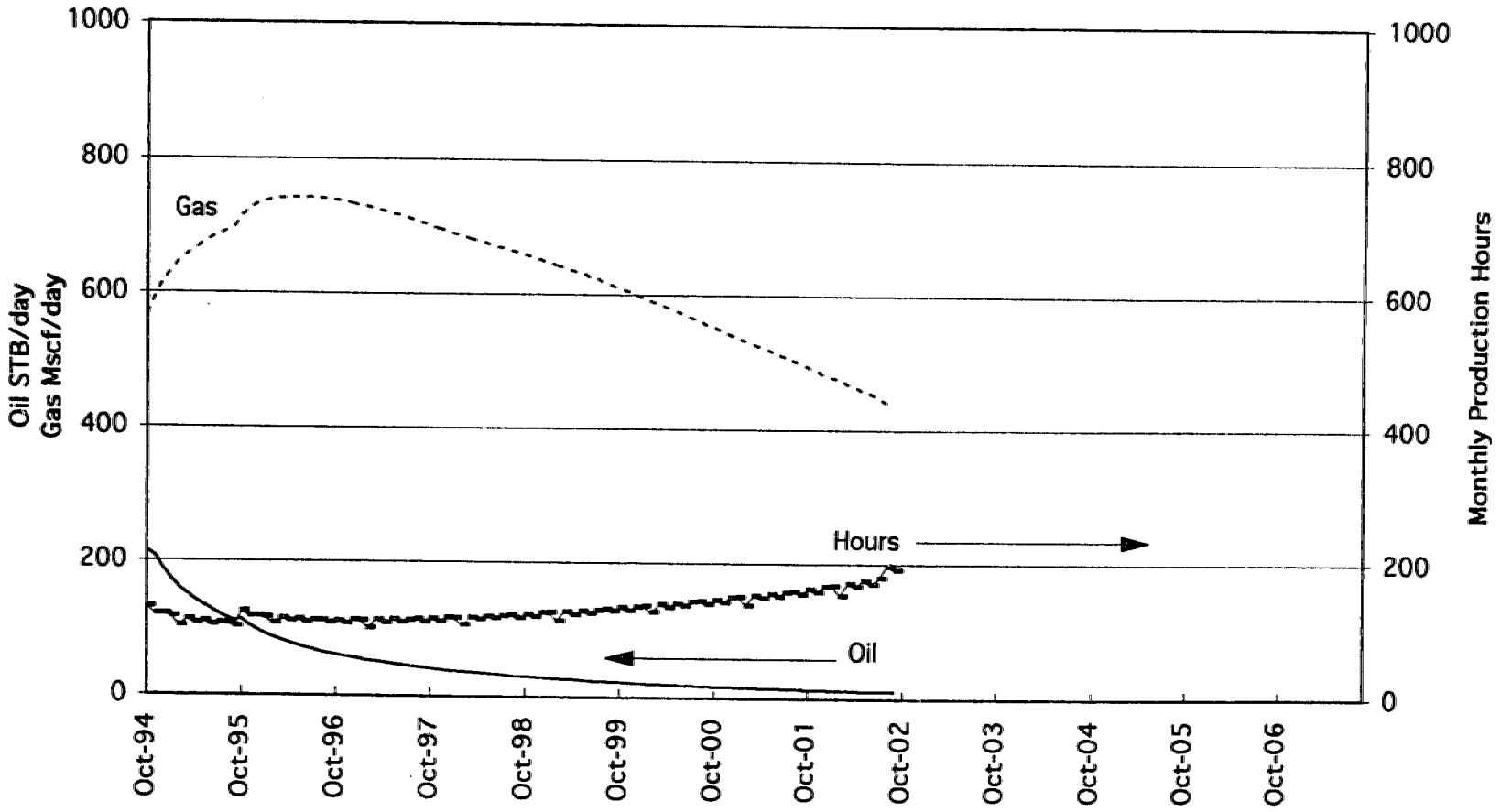



Figure 5.1(a): Primary Production Forecast (08-13-37-8W5)

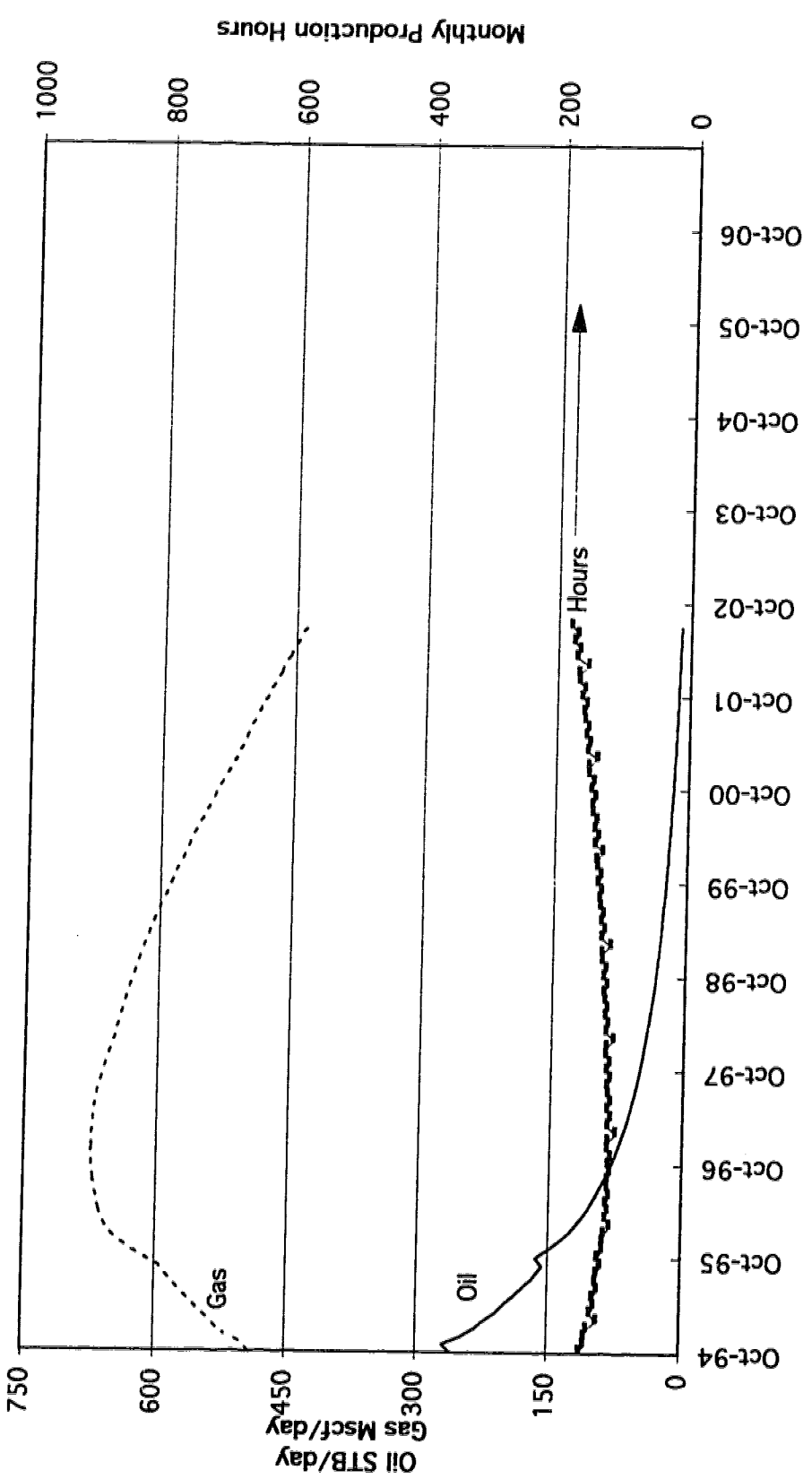



Figure 5.1(b): Primary Production Forecast (06-13-37-8W5)

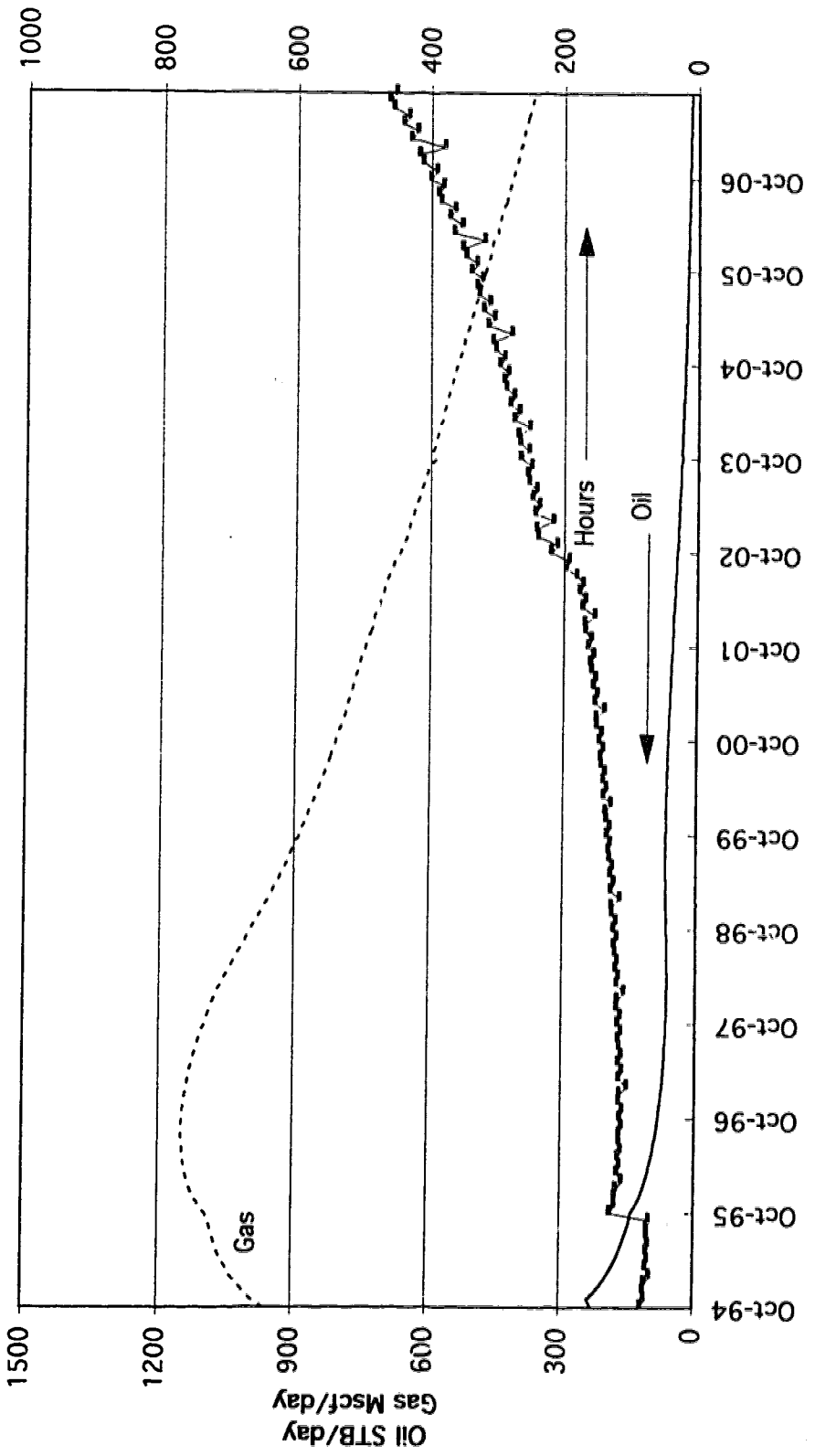



Figure 5.1(c): Primary Production Forecast (06-16-37-7W5)

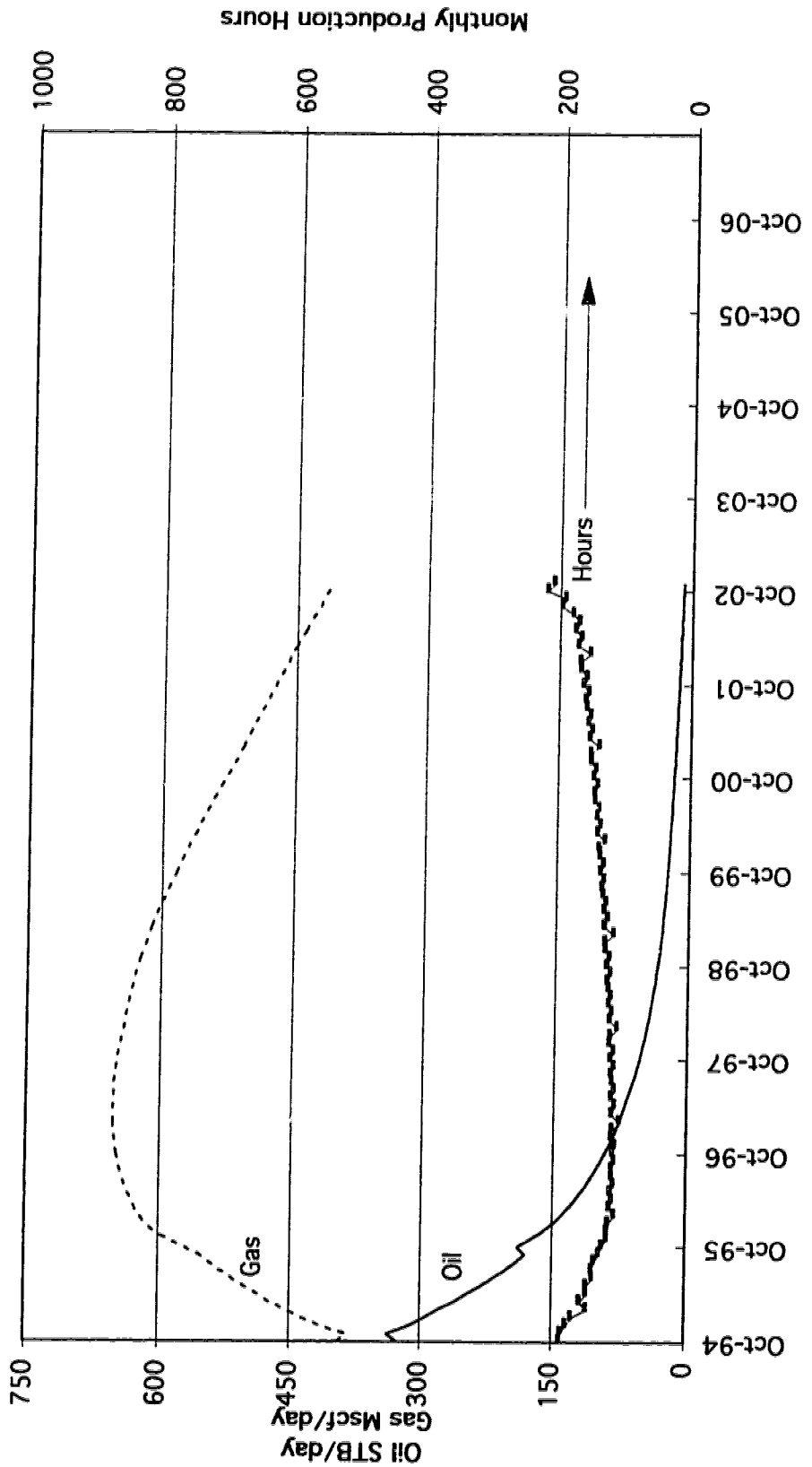



Figure 5.1(d): Primary Production Forecast (08-14-37-8W5)

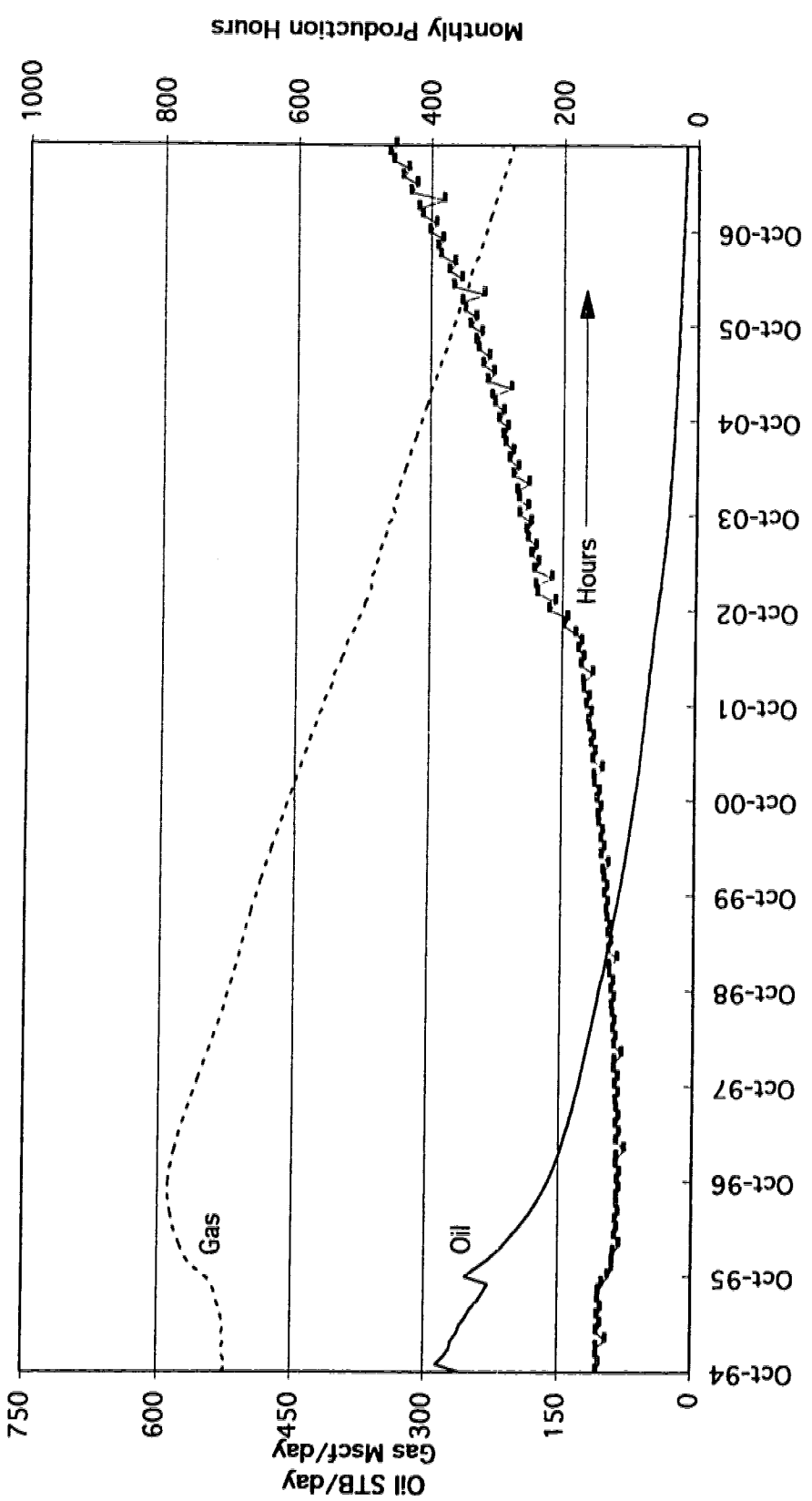



Figure 5.1(e): Primary Production Forecast (08-18-37-7W5)

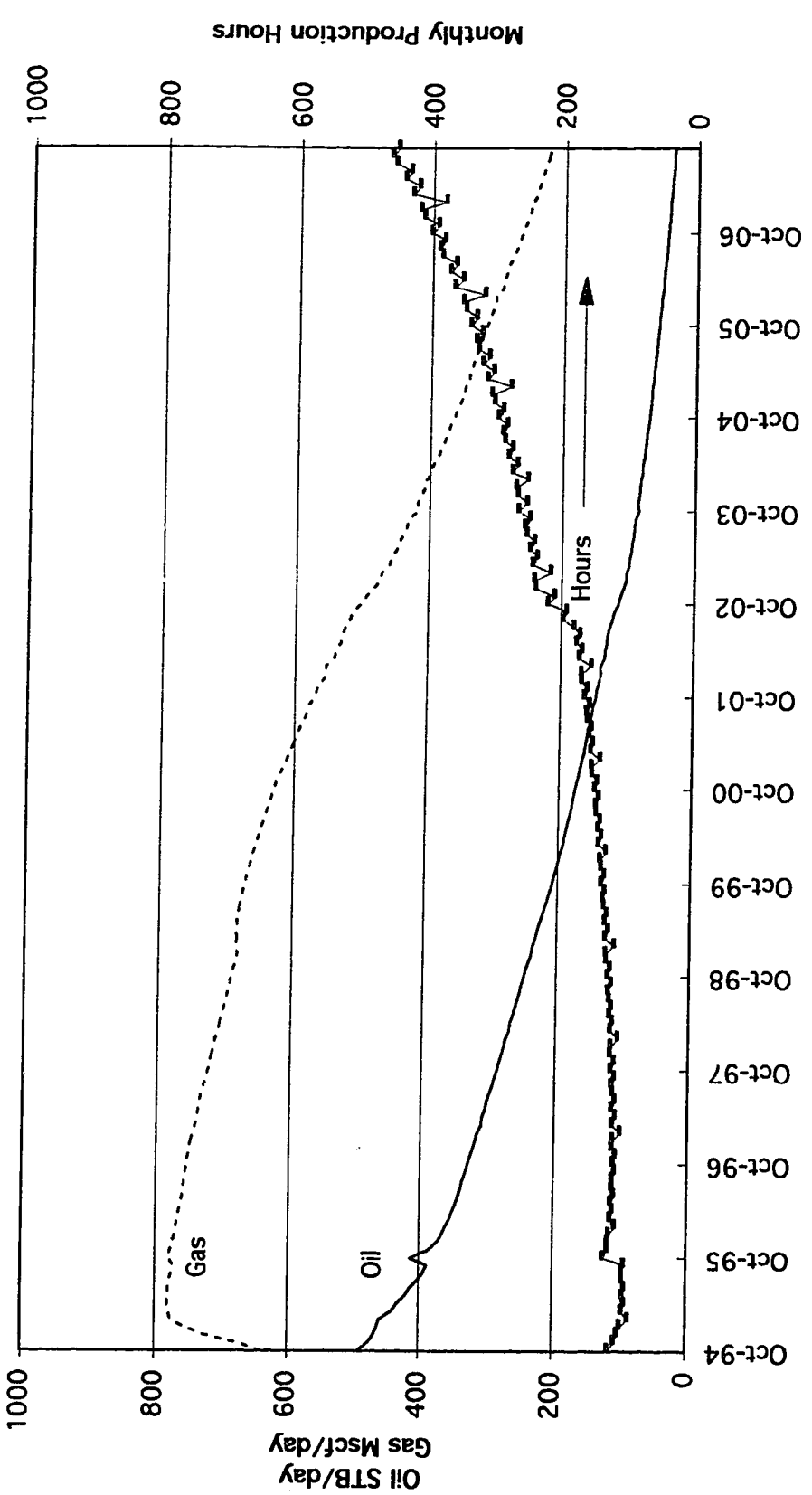



Figure 5.1(f): Primary Production Forecast (16-08-37-7W5)

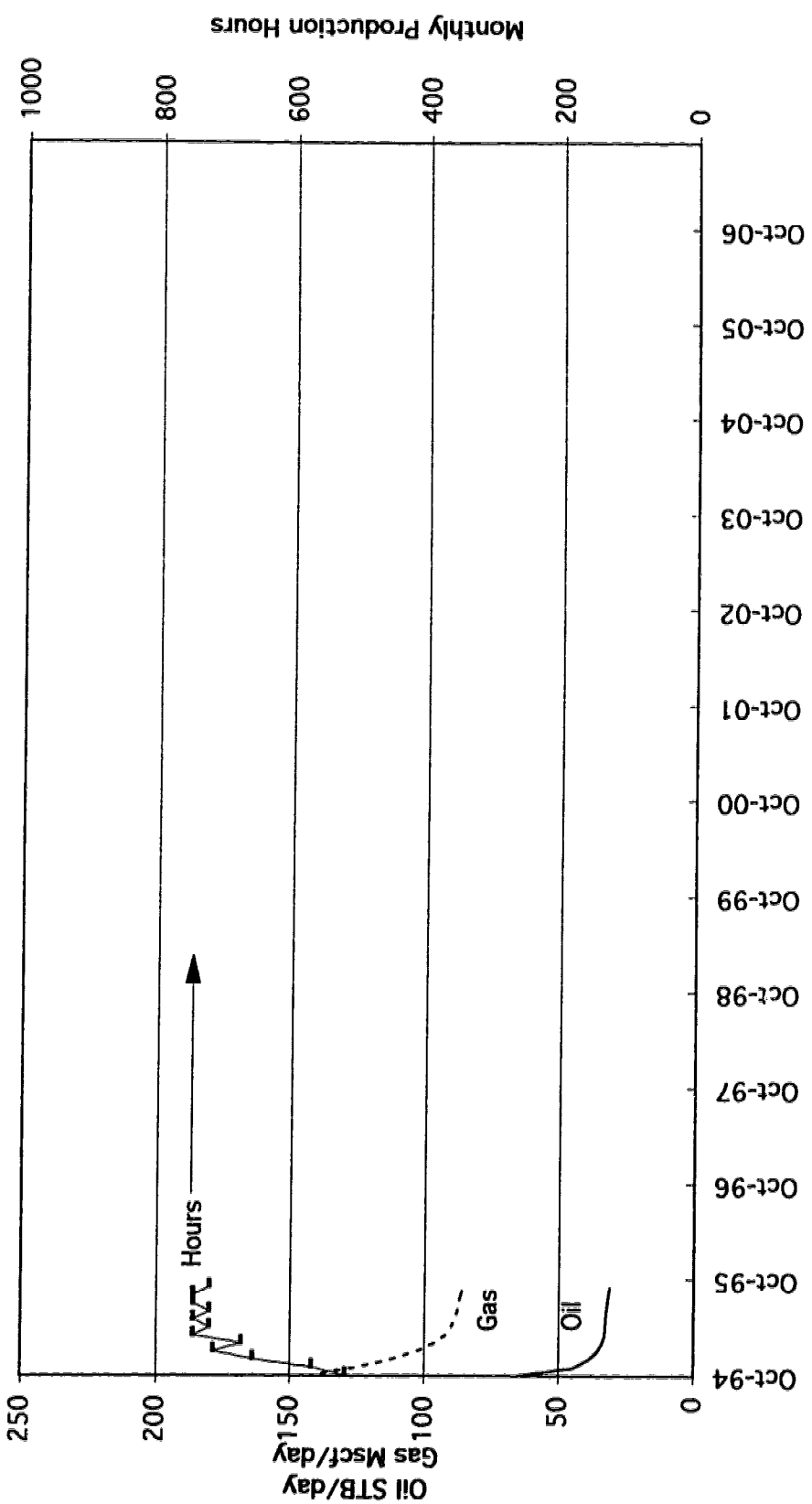



Figure 5.1(g): Primary Production Forecast (14-09-37-7W5)

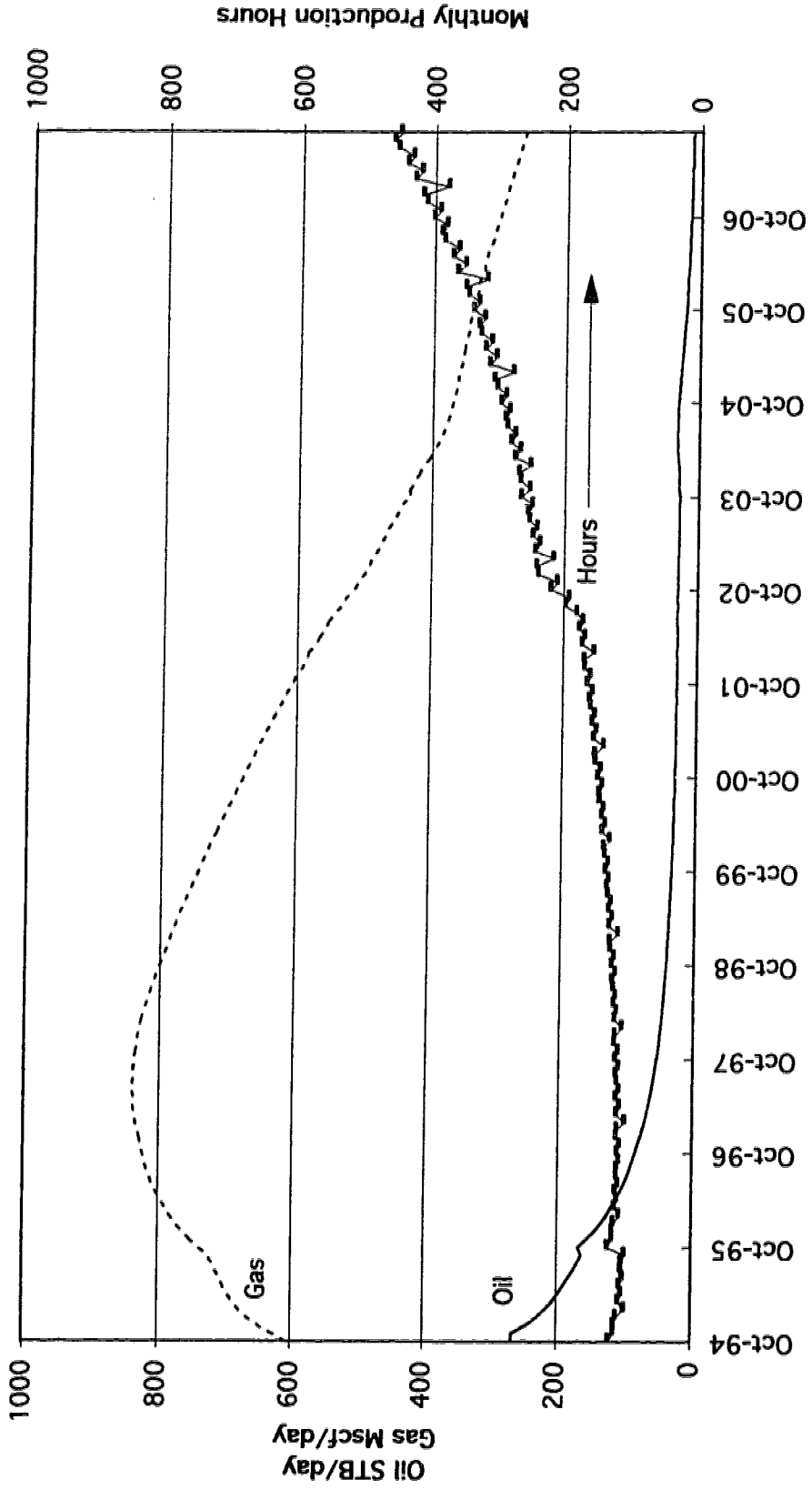



Figure 5.1(h): Primary Production Forecast (08-17-37-7W5)

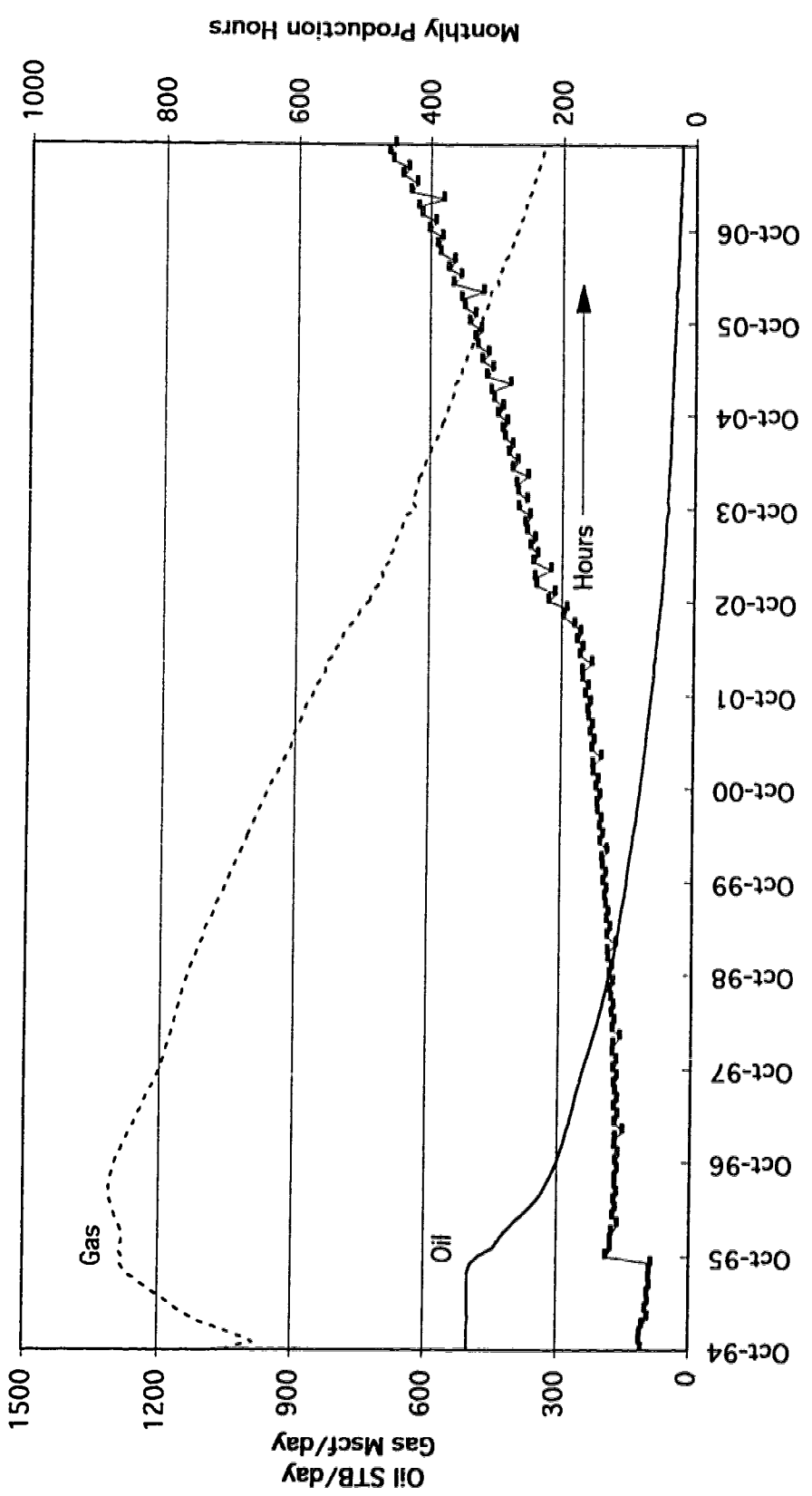



Figure 5.1(i): Primary Production Forecast (14-07-37-7W5)

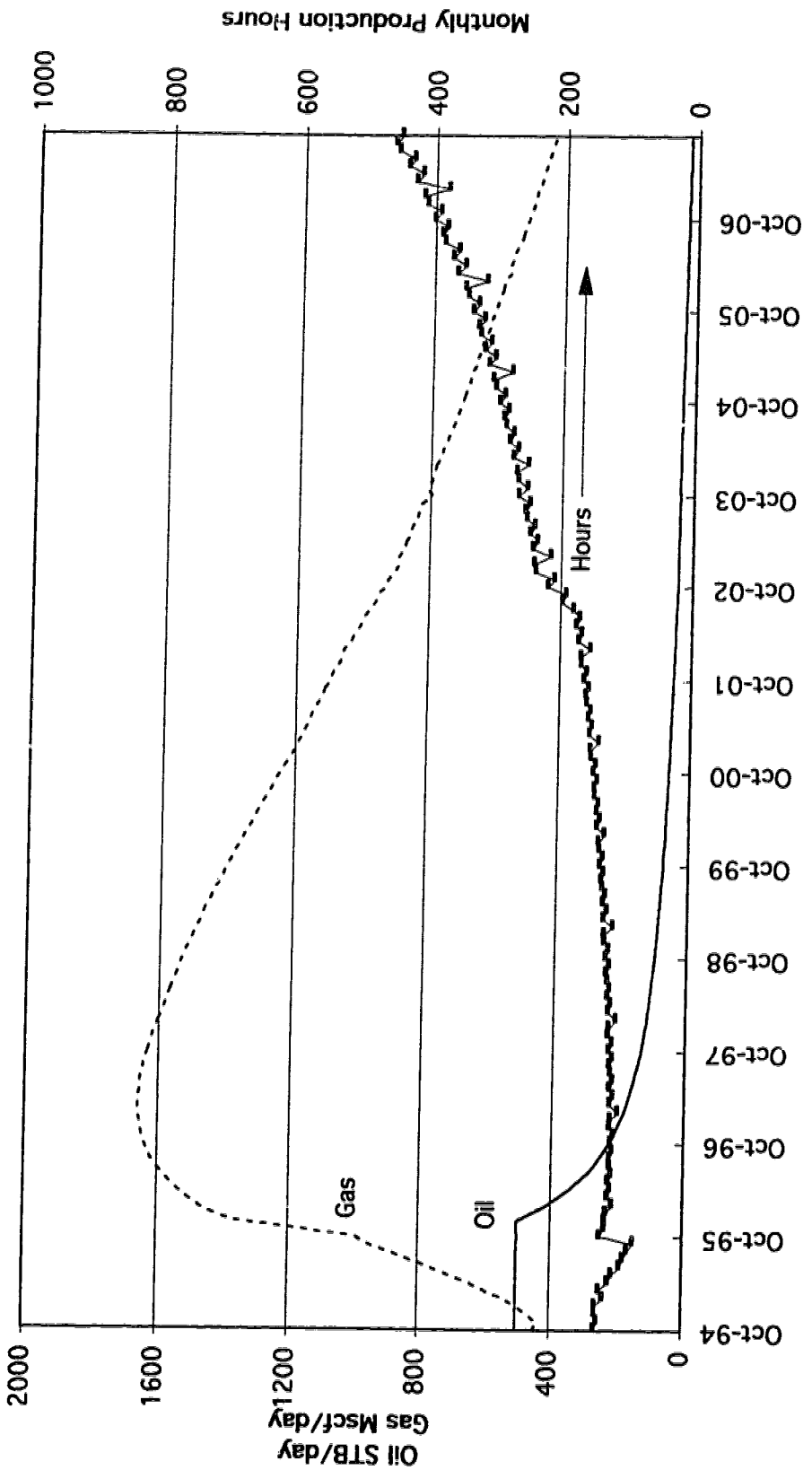



Figure 5.1(i): Primary Production Forecast (14-12-37-8W5)

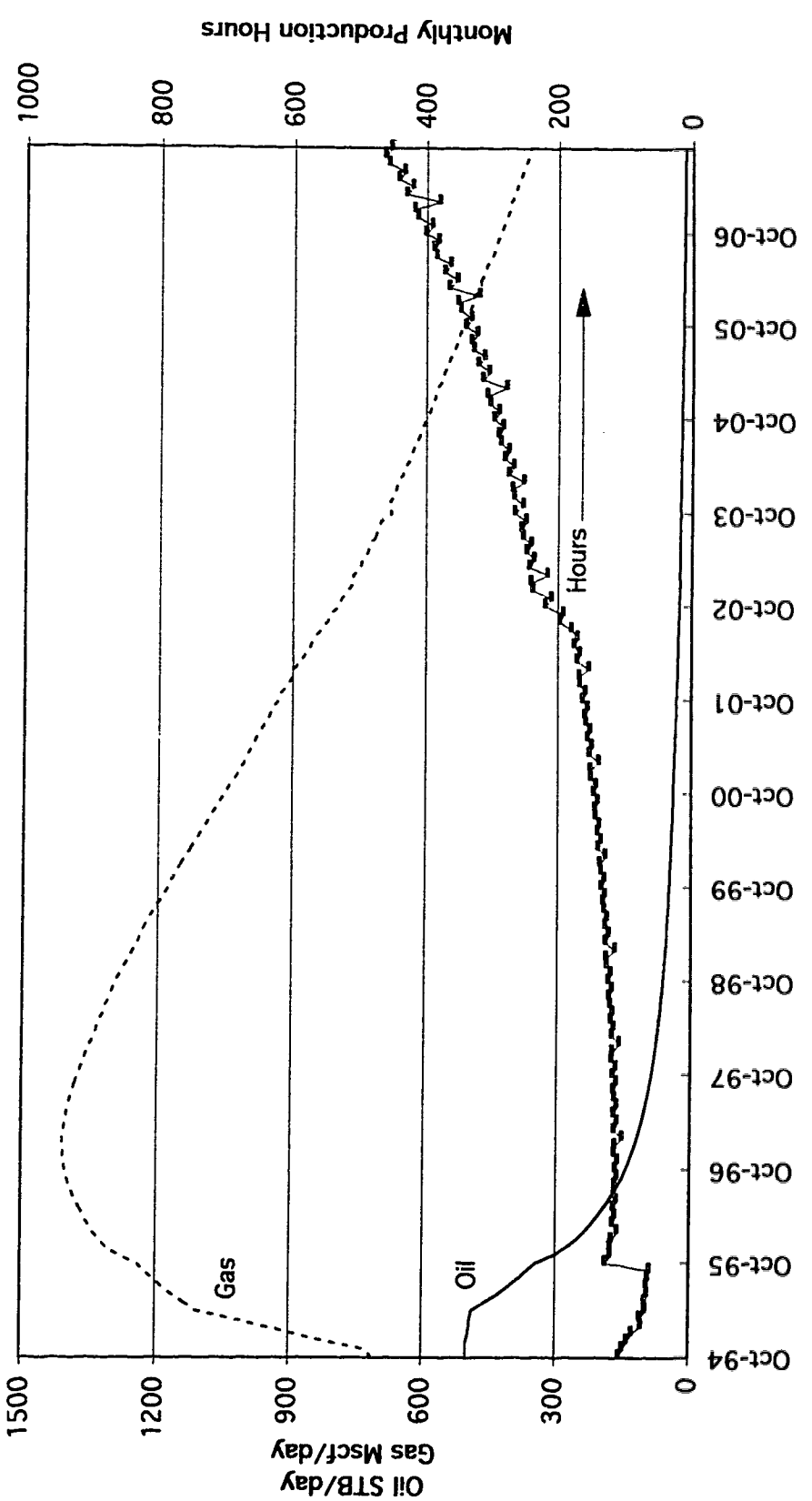



Figure 5.1(k): Primary Production Forecast (16-12-37-8W5)

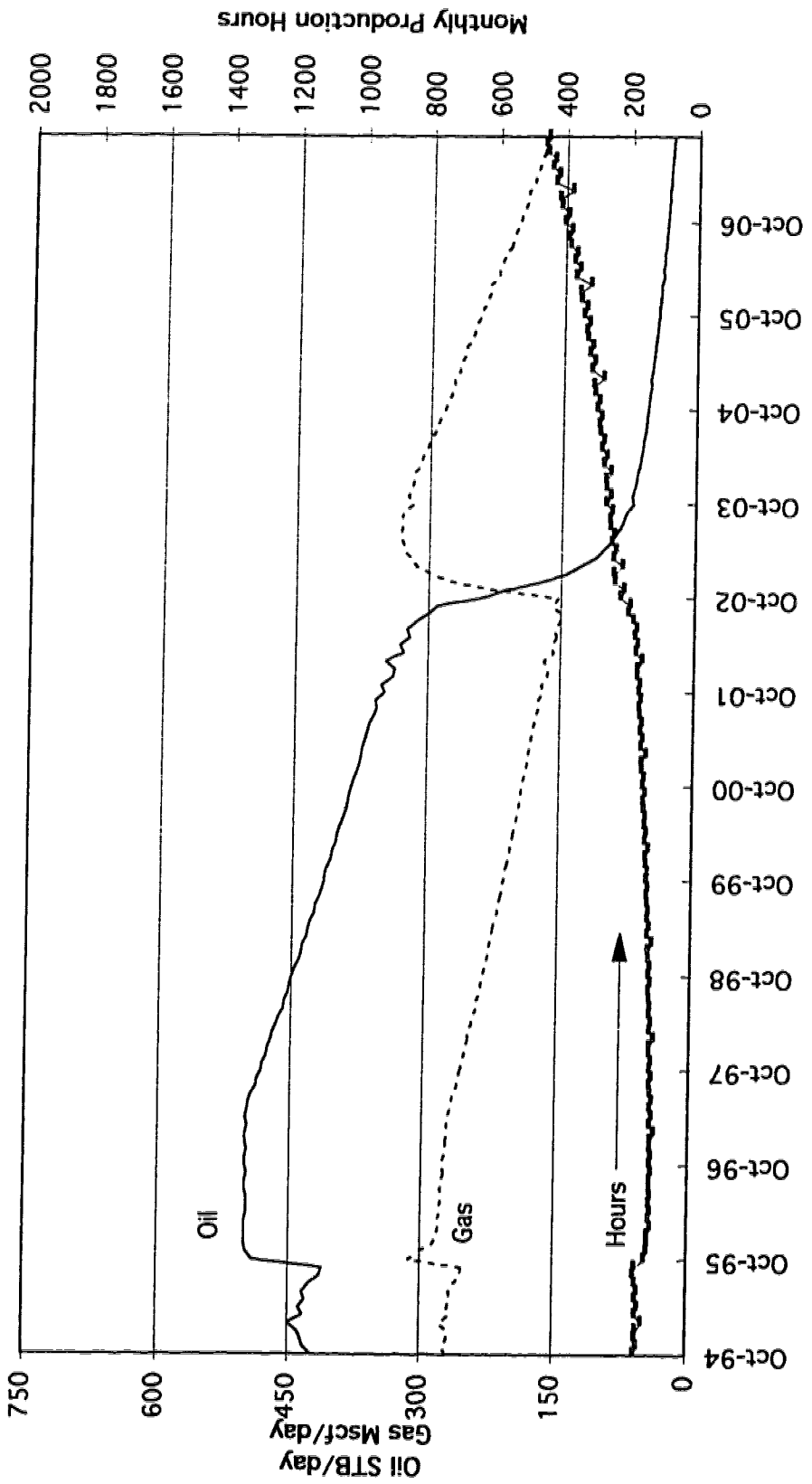



Figure 5.1(I): Primary Production Forecast (08-07-37-7W5)

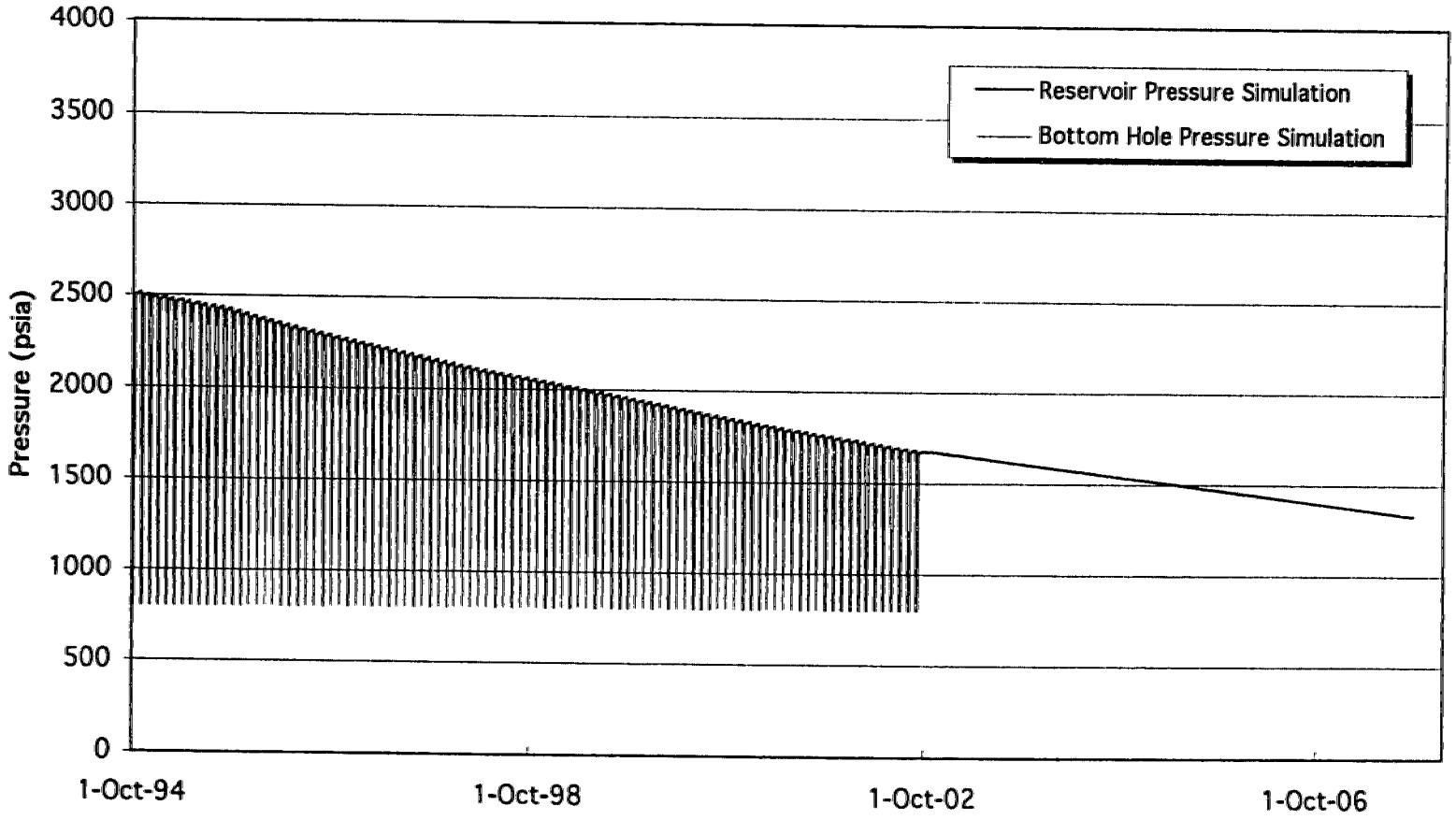



Figure 5.2(a): Primary Pressure Prediction (08-13-37-8W5)

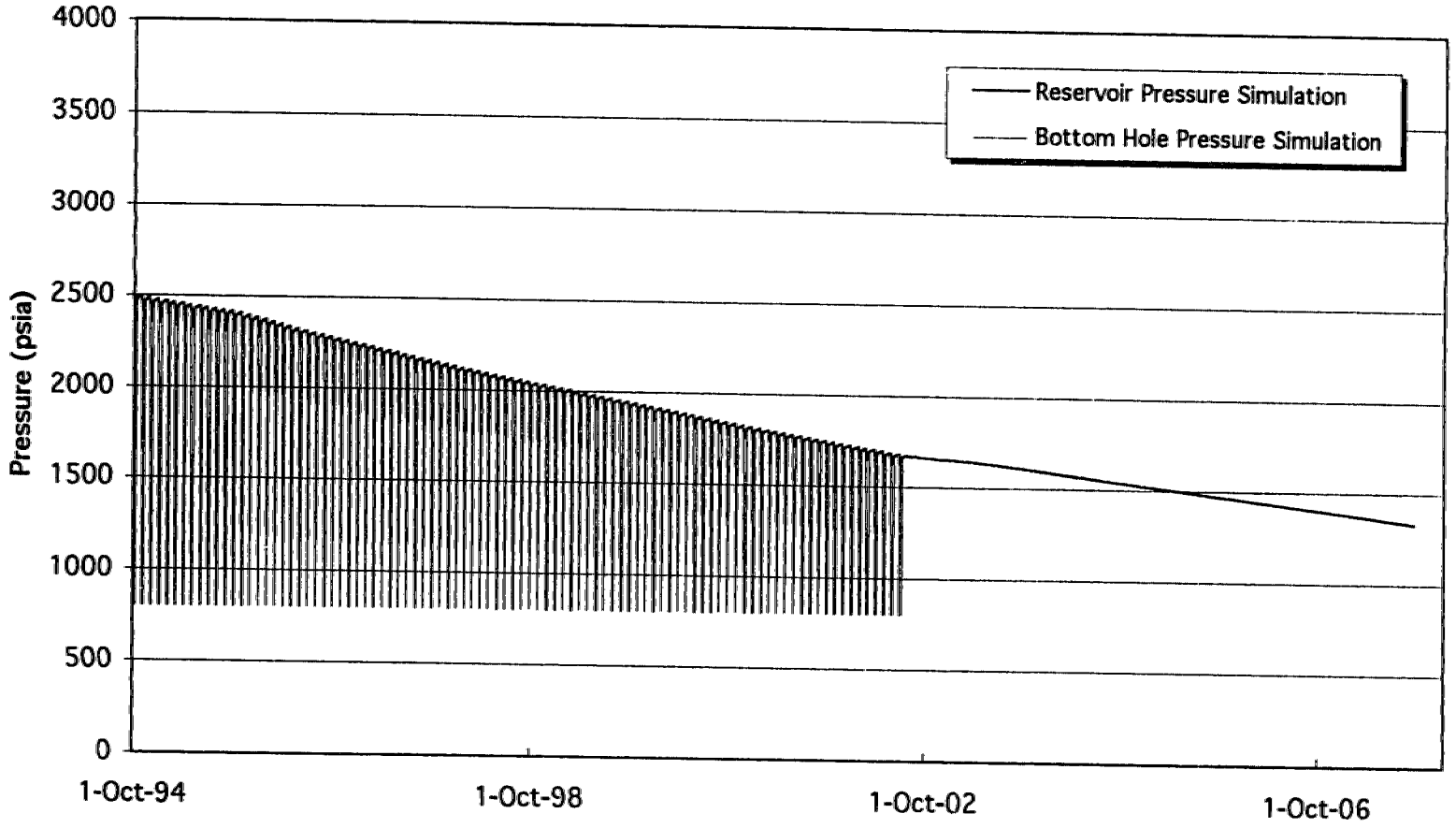



Figure 5.2(b): Primary Pressure Prediction (06-13-37-8W5)

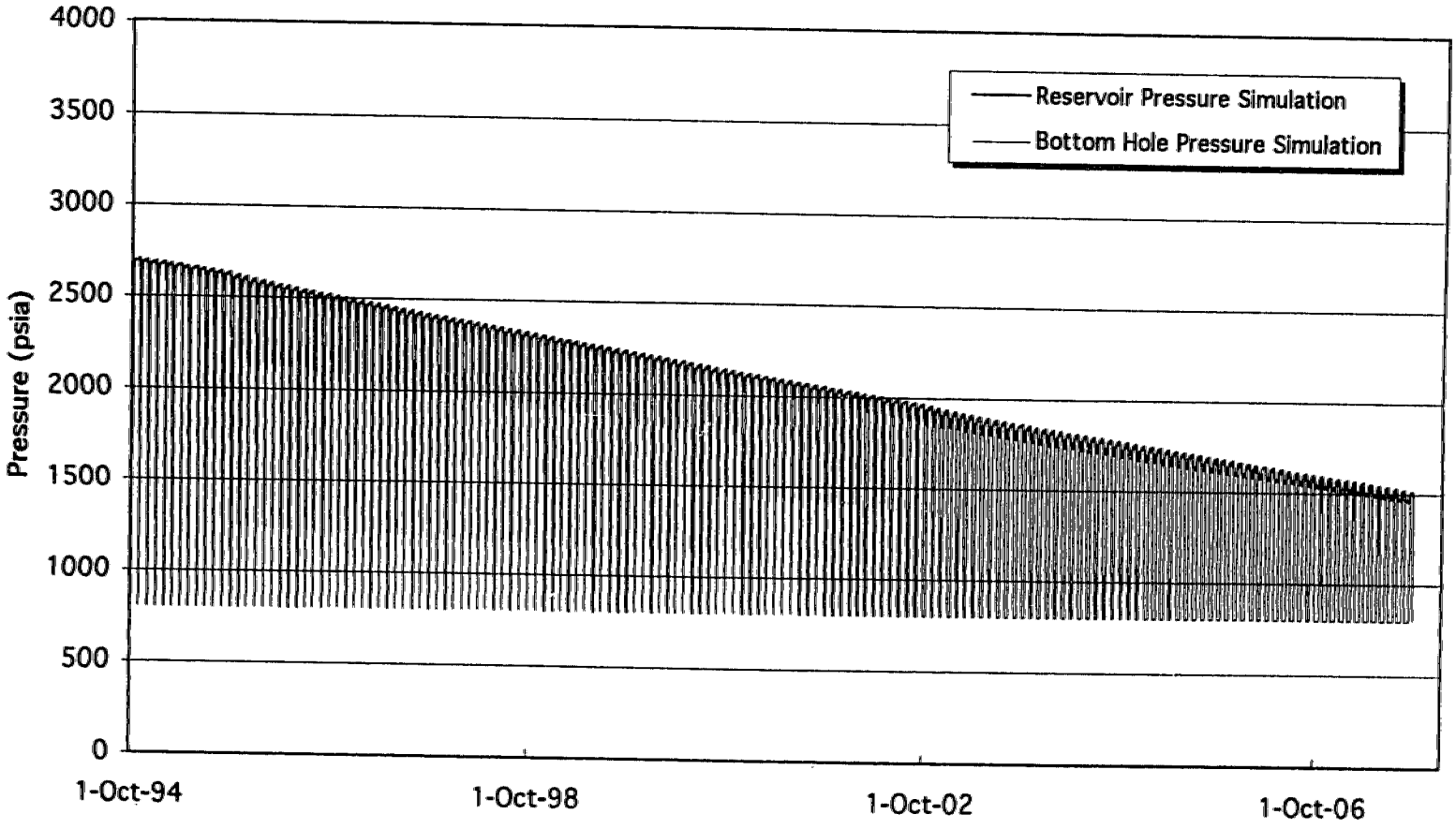



Figure 5.2(c): Primary Pressure Prediction (06-16-37-7W5)

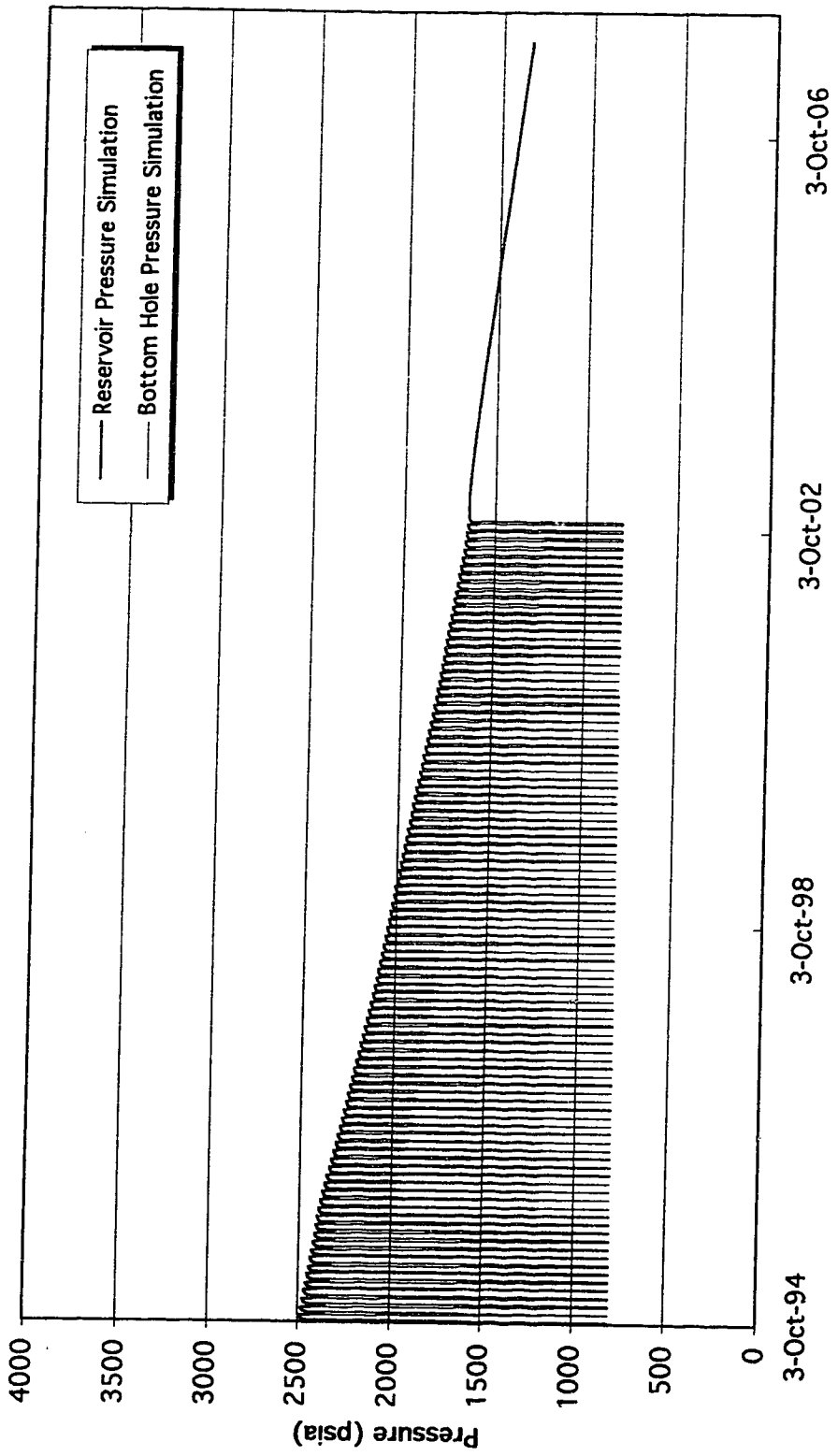



Figure 5.2(d): Primary Pressure Prediction (08-14-37-8W5)

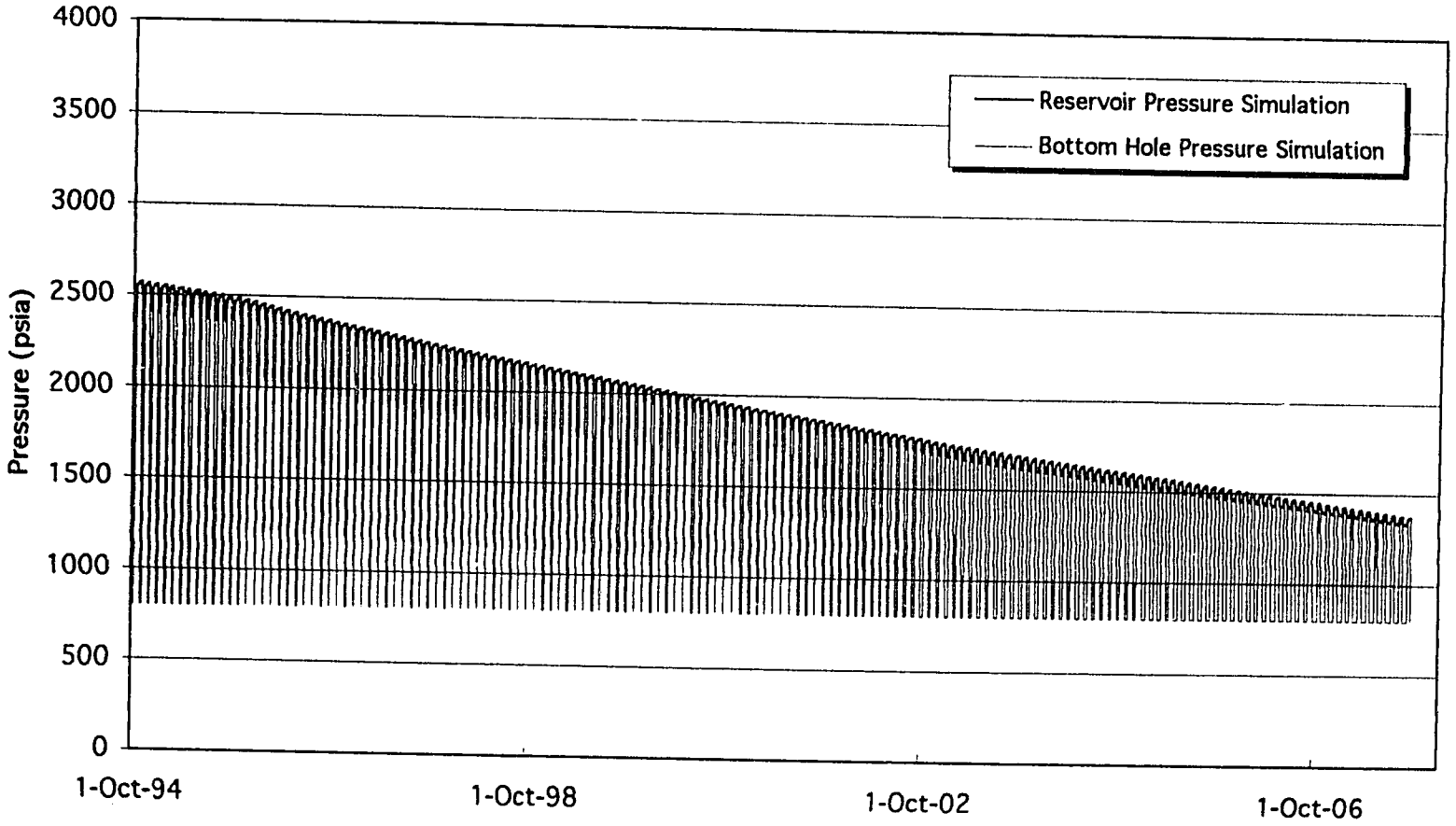



Figure 5.2(e): Primary Pressure Prediction (08-18-37-7W5)

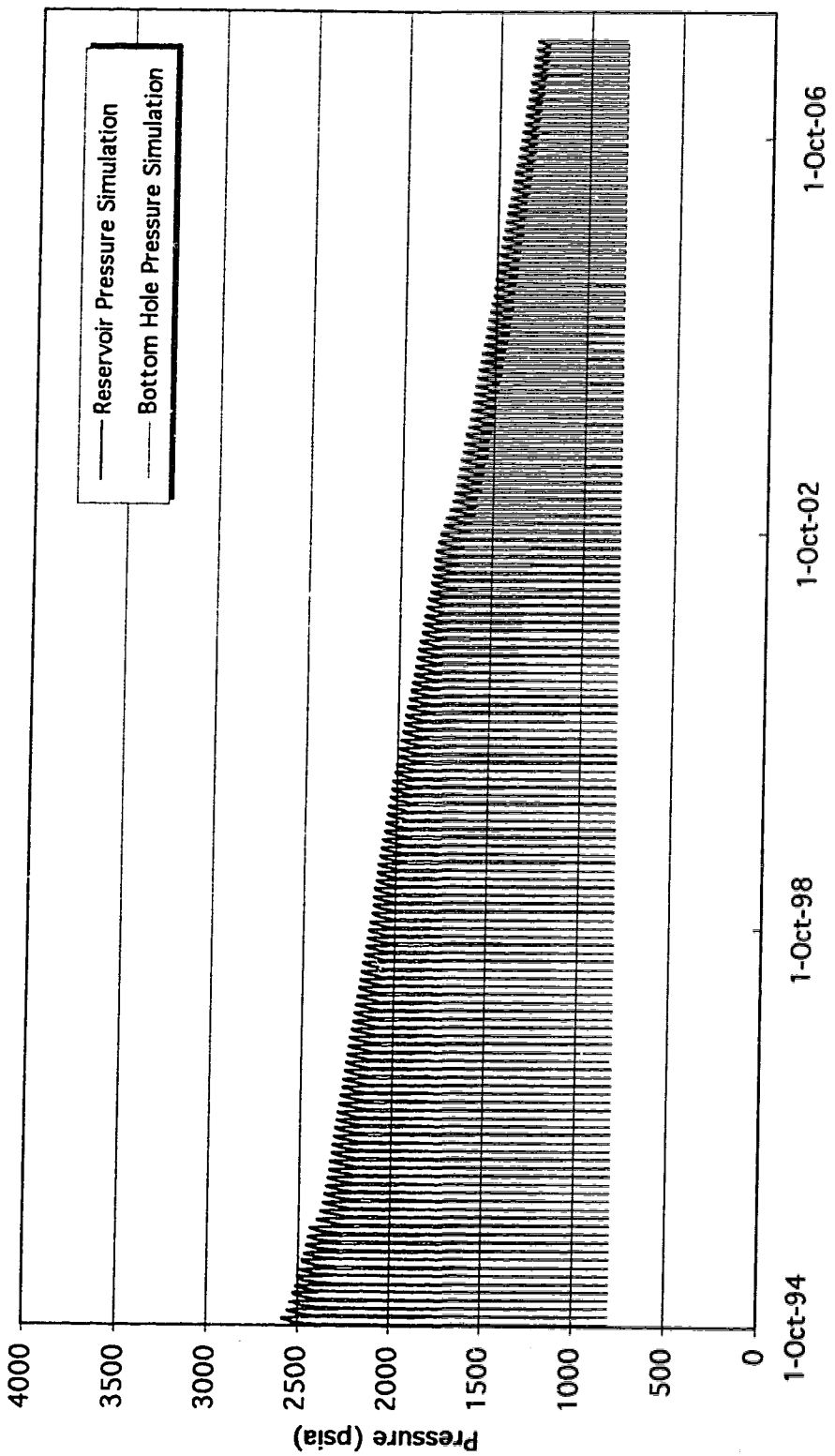



Figure 5.2(f): Primary Pressure Prediction (16-08-37-7W5)

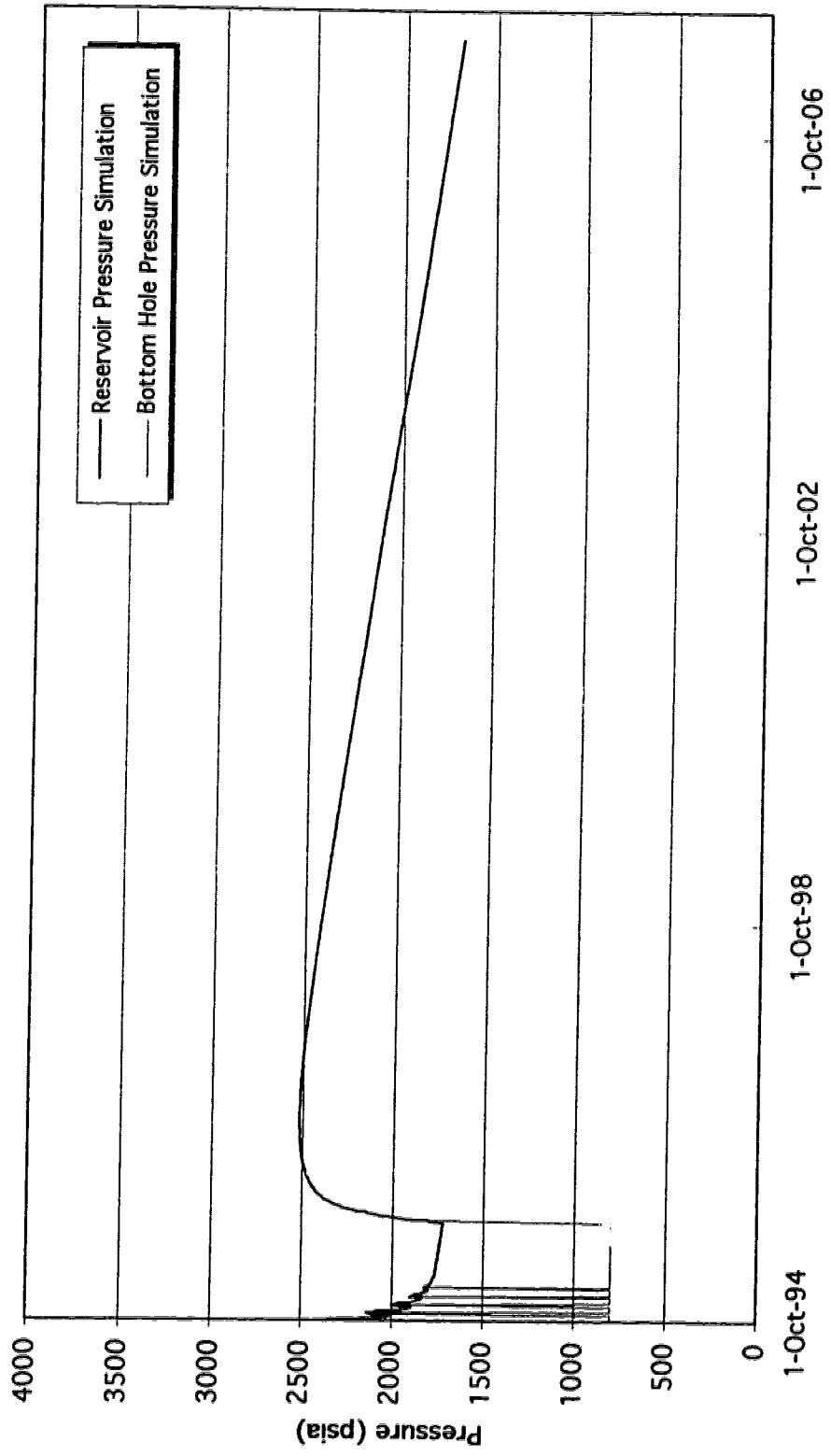



Figure 5.2(g): Primary Pressure Prediction (14-09-37-7W5)

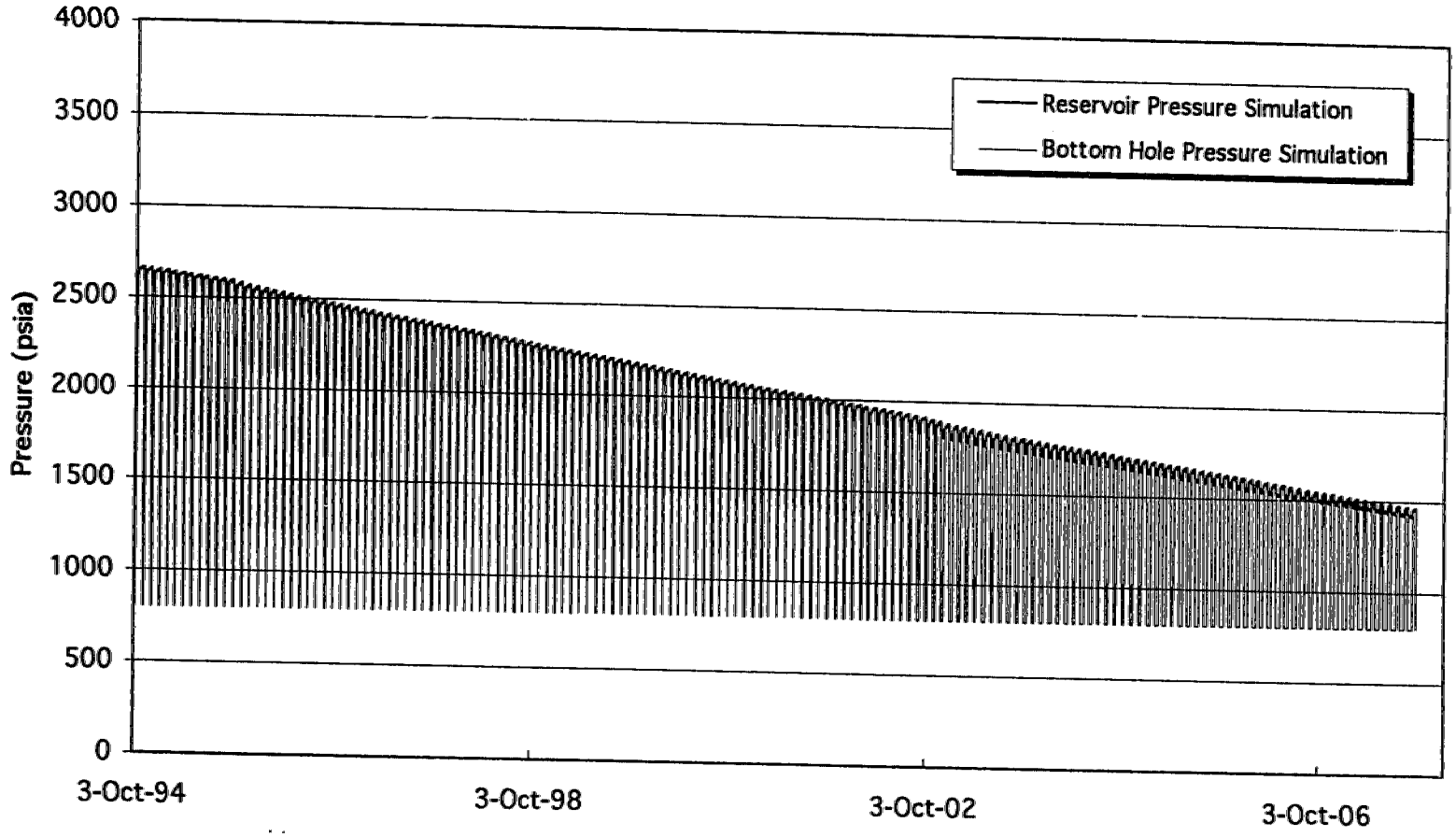



Figure 5.2(h): Primary Pressure Prediction (08-17-37-7W5)

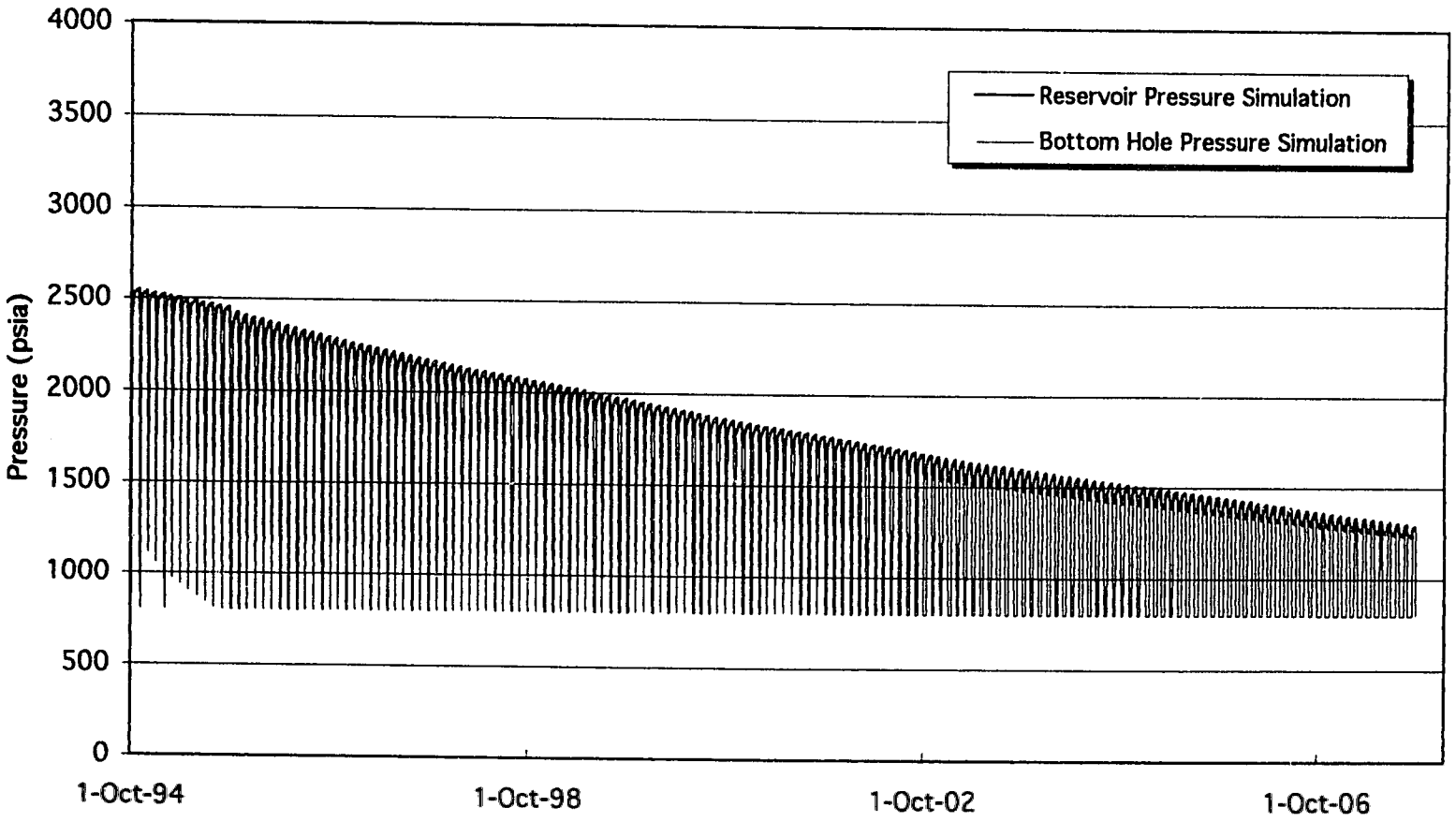



Figure 5.2(i): Primary Pressure Prediction (14-07-37-7W5)

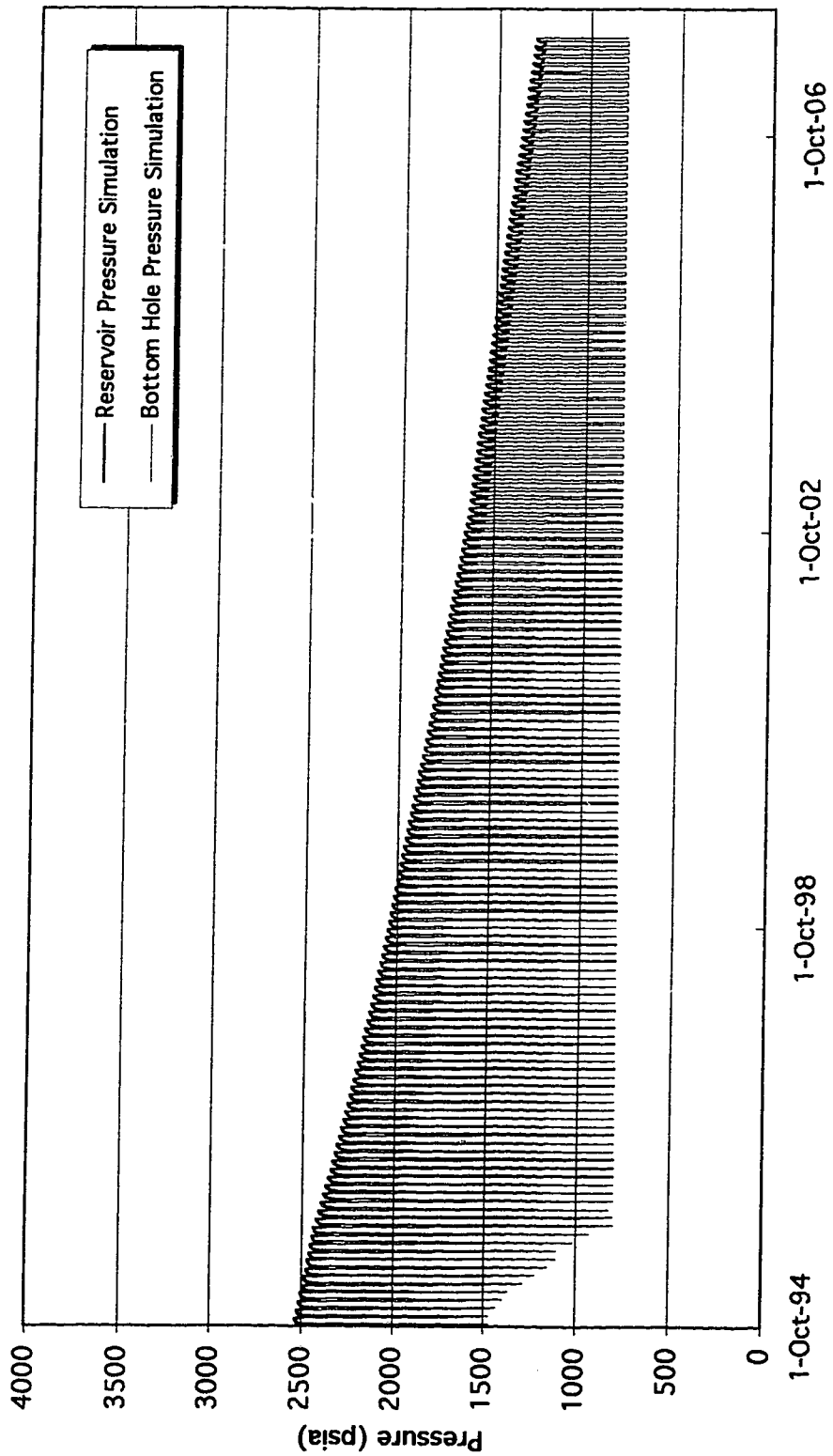



Figure 5.2(i): Primary Pressure Prediction (14-12-37-8W5)

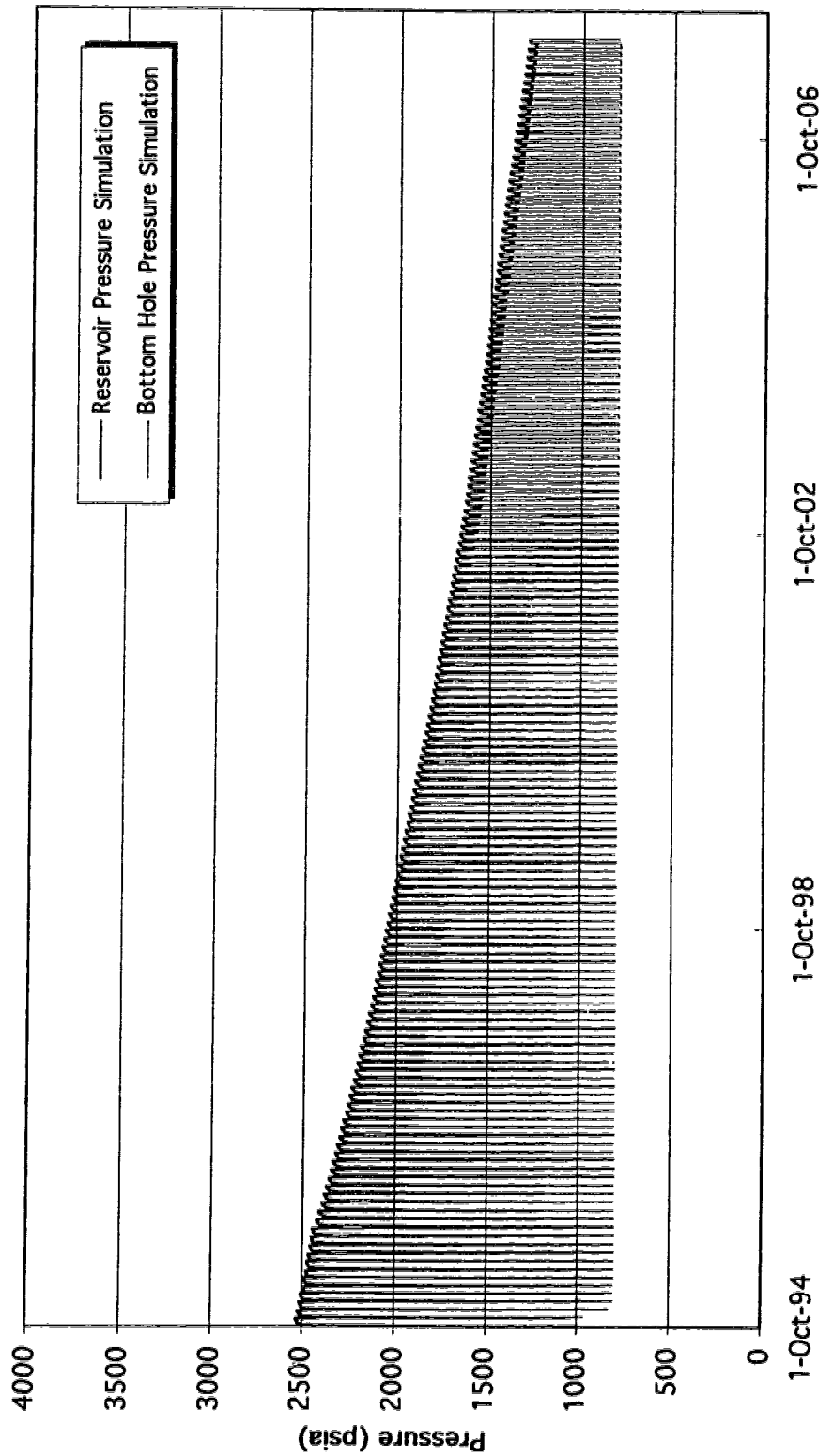



Figure 5.2(k): Primary Pressure Prediction (16-12-37-8W5)

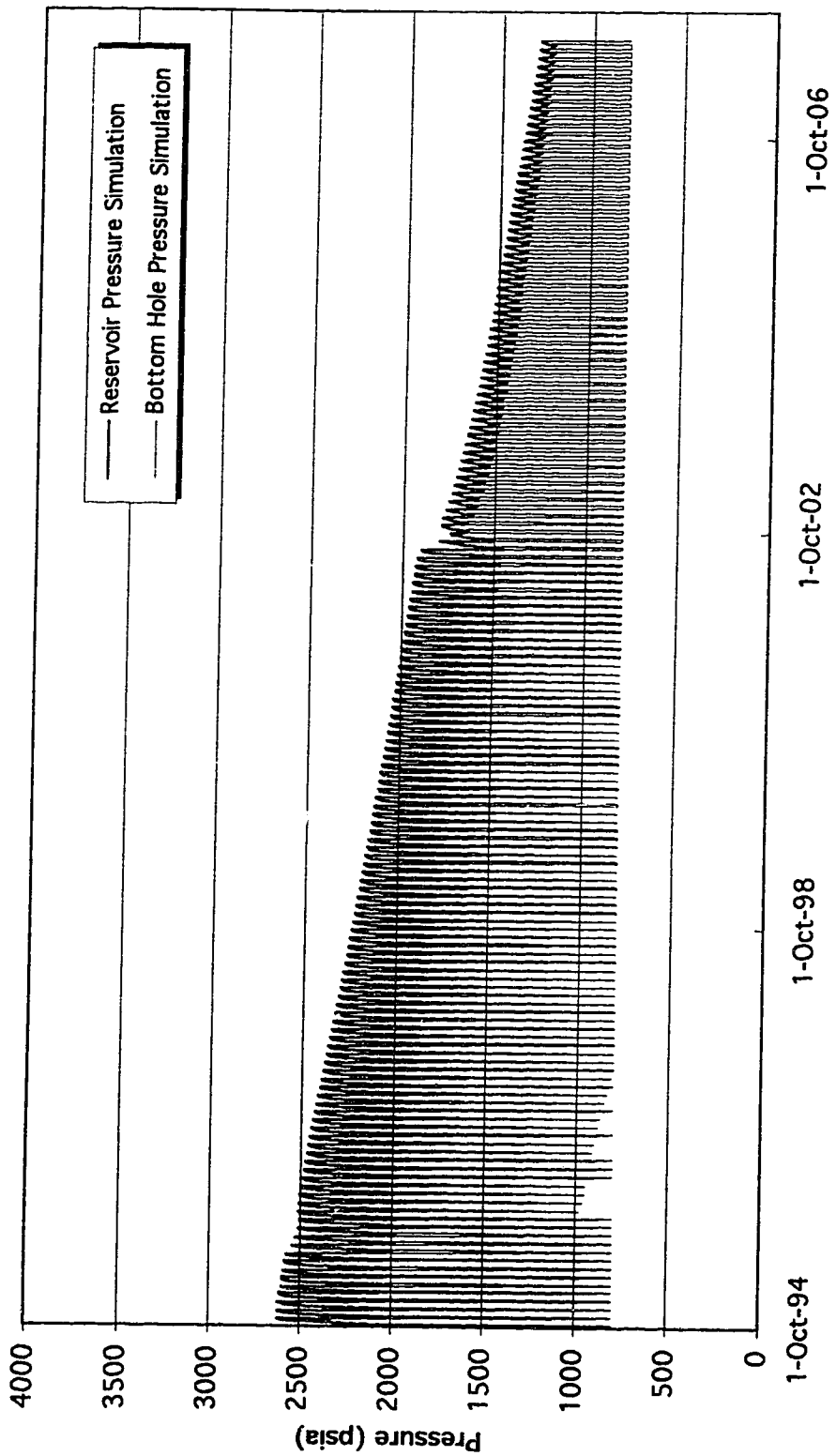



Figure 5.2(I): Primary Pressure Prediction (08-07-37-7W5)

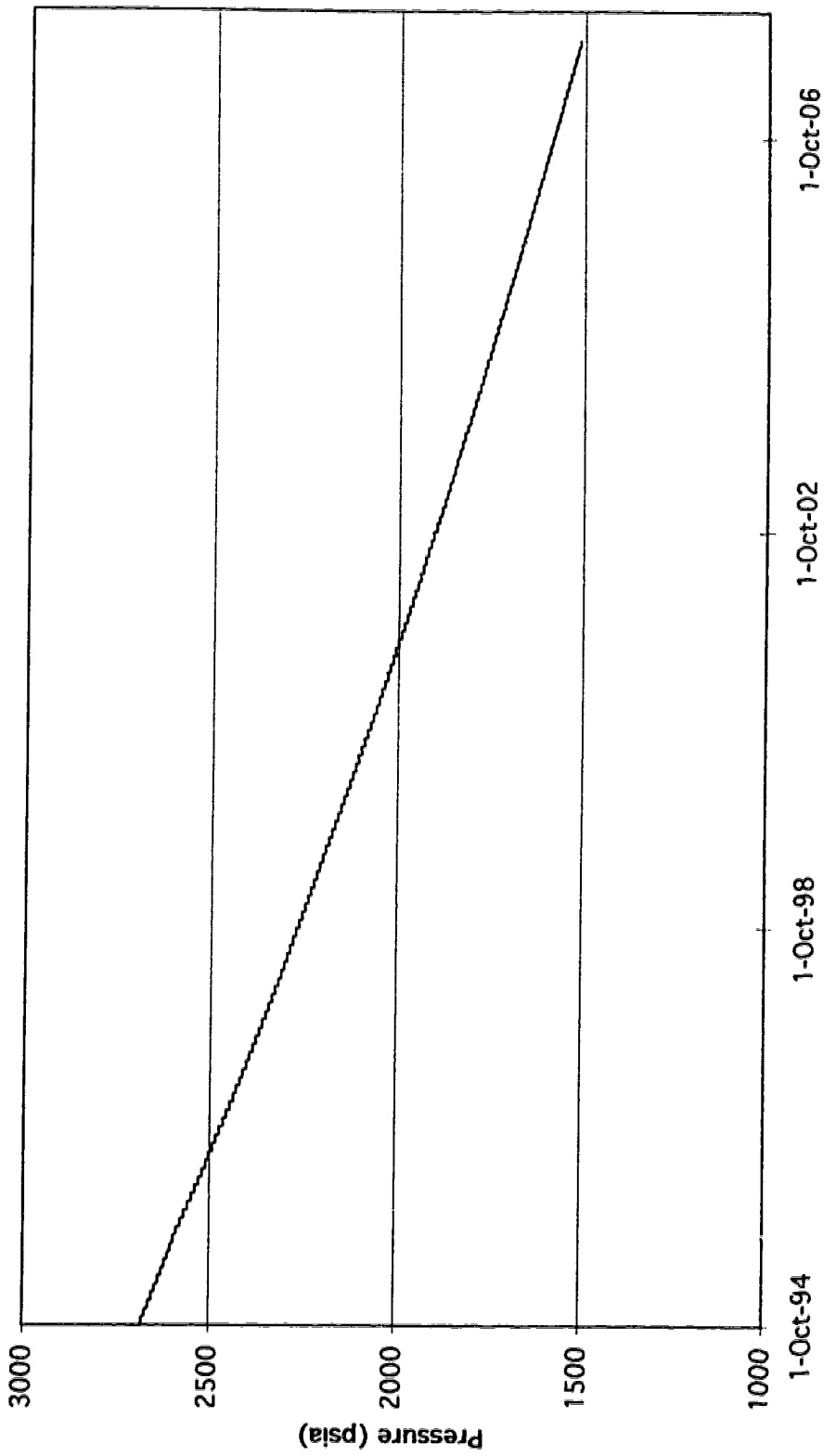



Figure 5.3(a): Primary Average Reservoir Pressure Prediction

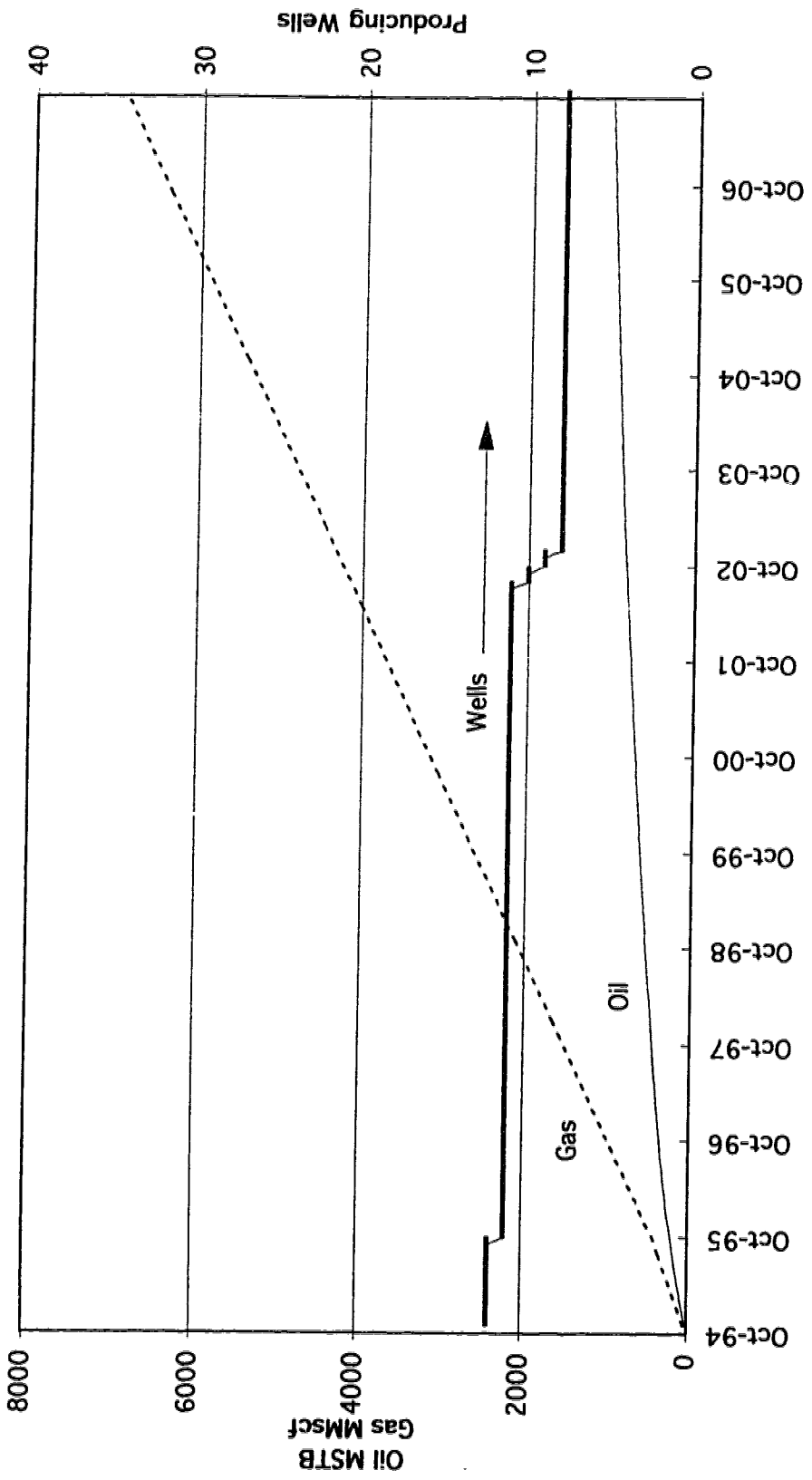



Figure 5.3(b): Pool Cumulative Primary Production Prediction

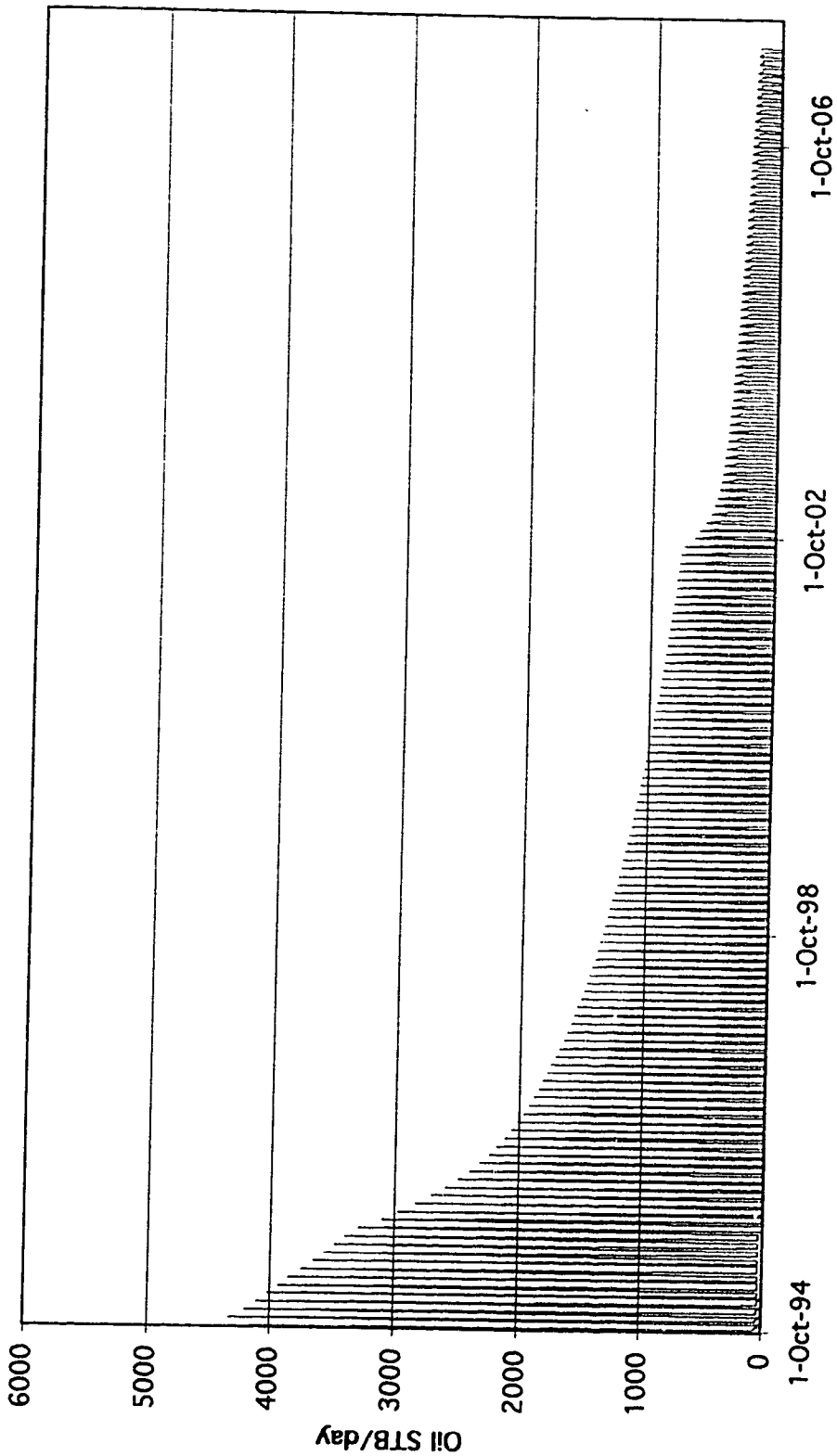



Figure 5.4(a): Pool Primary Oil Production Rate Forecast

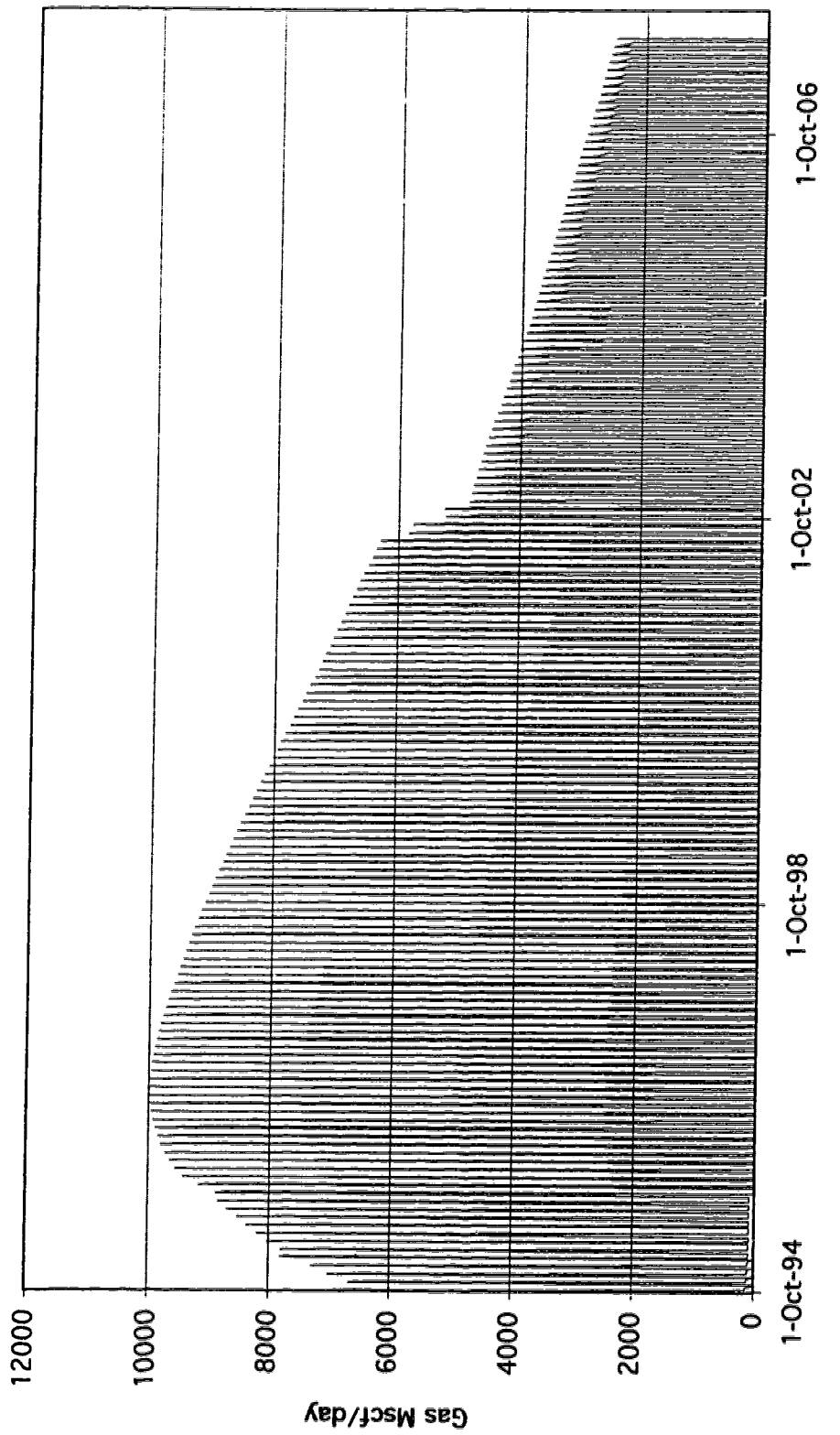



Figure 5.4(b): Pool Primary Gas Production Rate Forecast

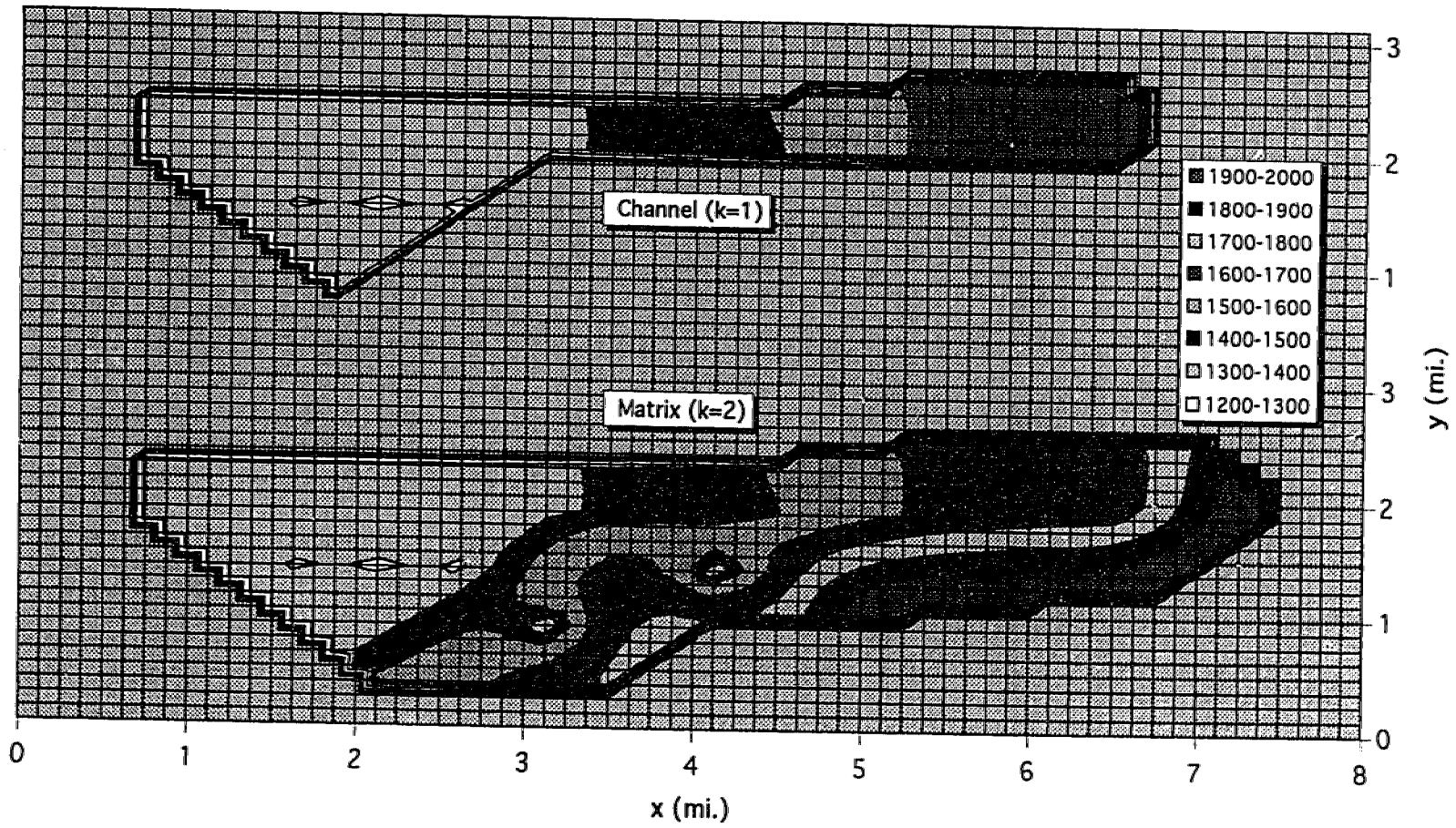



Figure 5.5(a): Primary (Oct-07) Pressure p (psia)

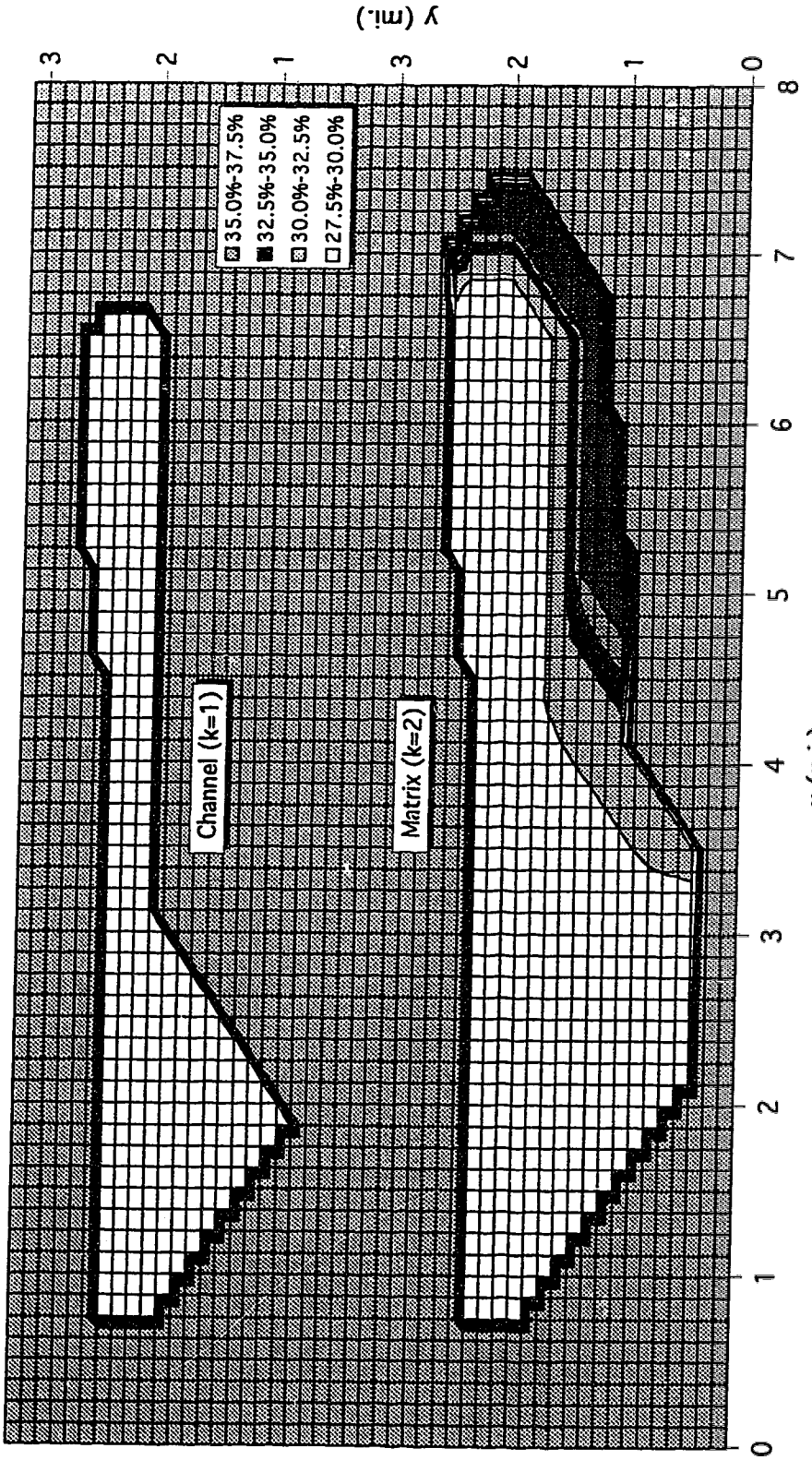



Figure 5.5(b): Primary (Oct-07) Water Saturation $S_w$

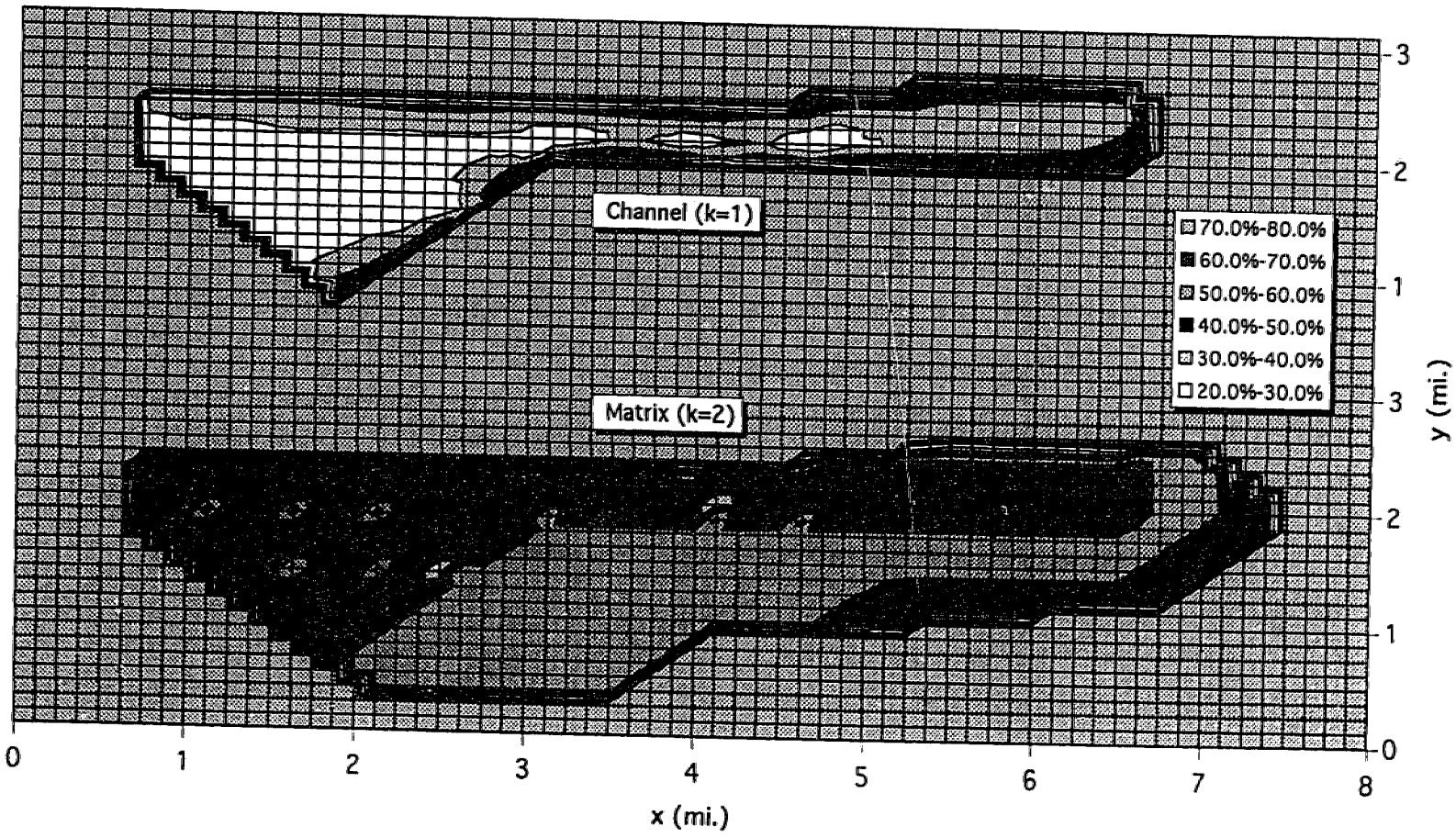



Figure 5.5(c): Primary (Oct-07) Oil Saturation $S_o$

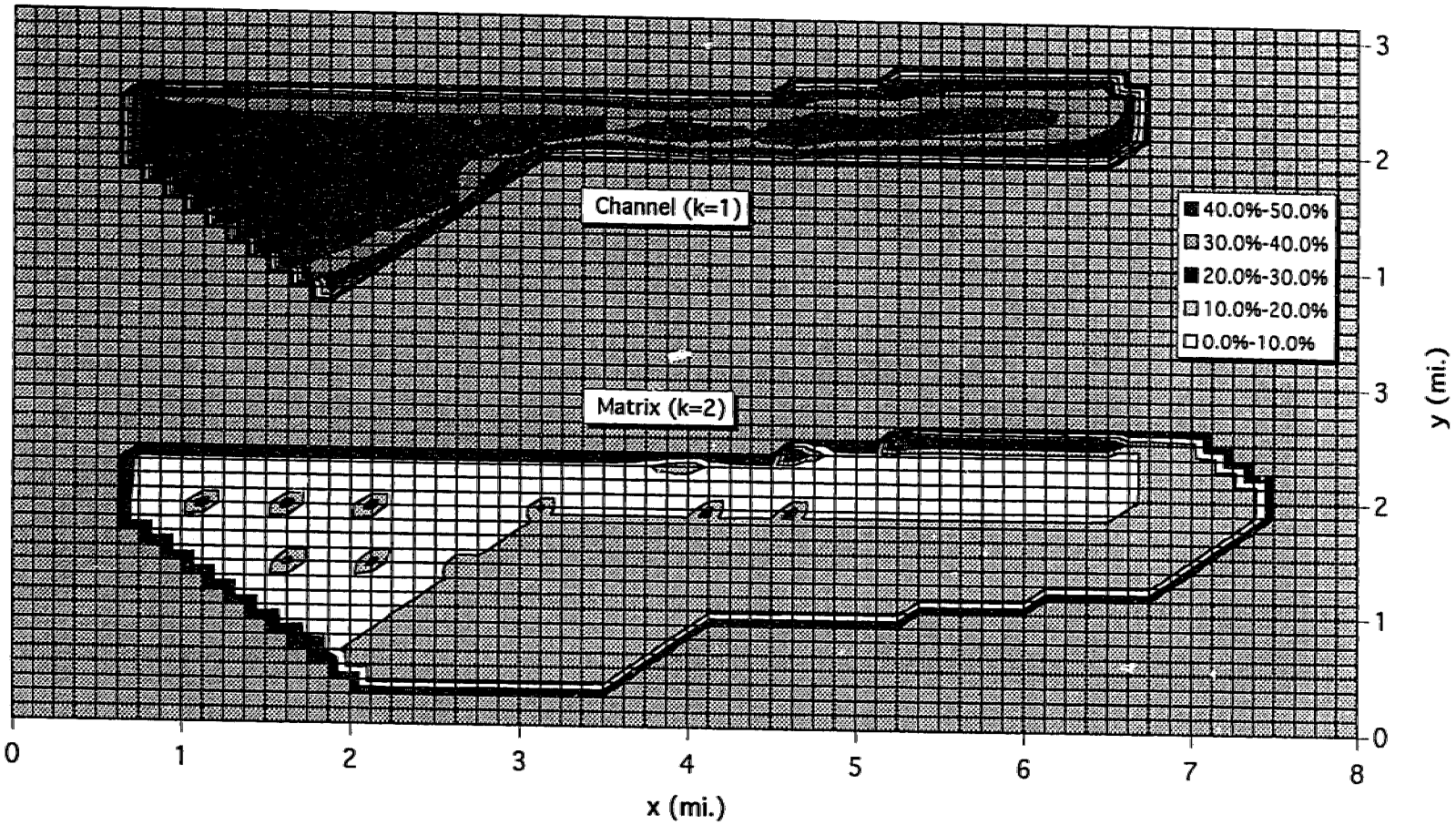



Figure 5.5(d): Primary (Oct-07) Gas Saturation $S_g$

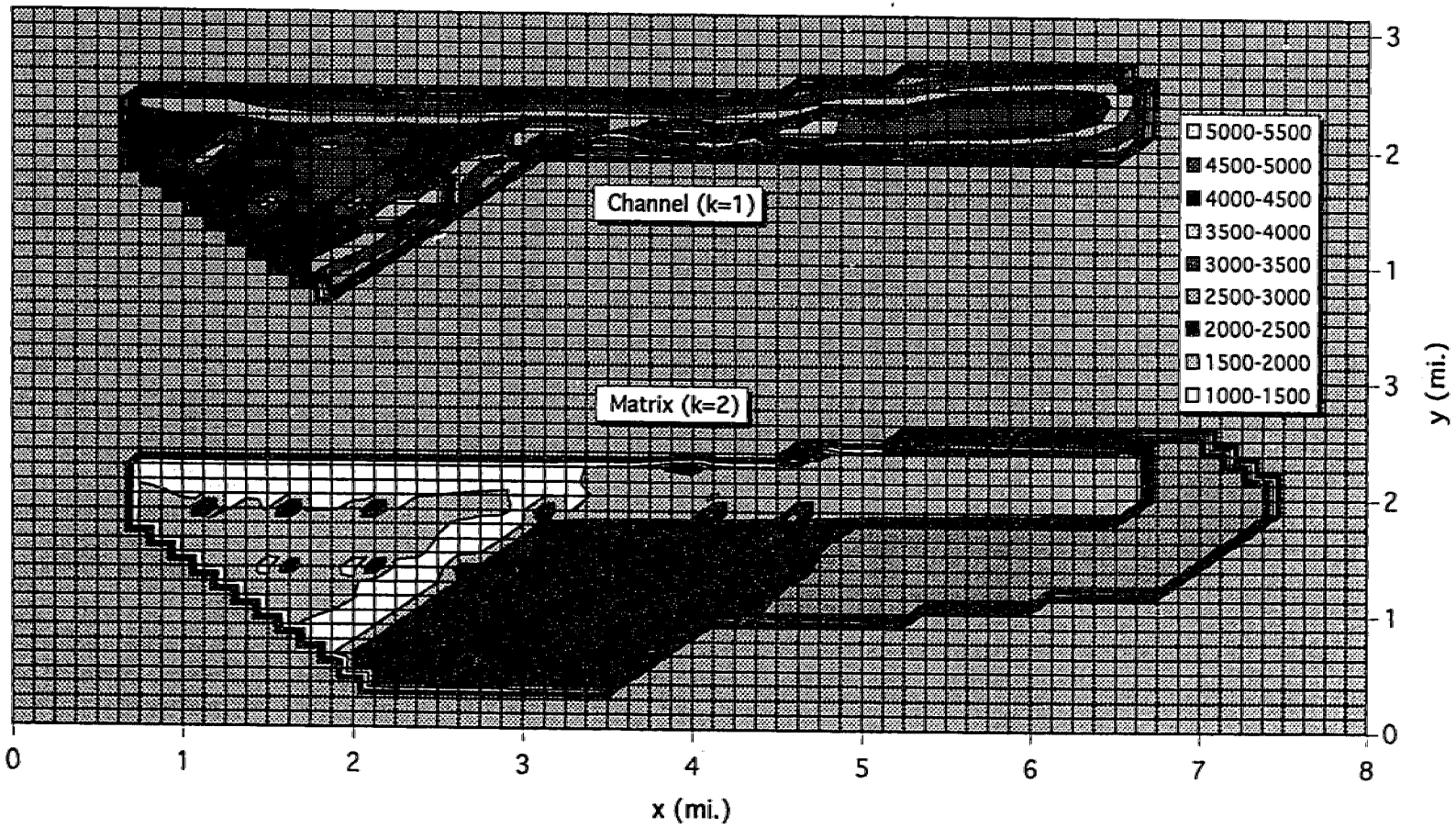



Figure 5.5(e): Primary (Oct-07) Bubble Point Pressure $p_b$ (psia)

# Chapter 6: Secondary Forecast

## 6.1 Waterflood Design

Waterflood design depends on the flood scheme. Schemes are classified by the main direction of displacement in either vertical or horizontal planes. A combination of vertical and horizontal processes can apply in dipping reservoirs. Vertical schemes inject water into wells completed at the bottom of the formation and produce oil from wells completed at the top. Horizontal schemes inject water into a pattern of wells and produce oil from wells completed in between. Commonly used patterns include:

- five-spot
- inverted nine-spot
- line drive
- peripheral

Some strategies will flood all pattern spacing units simultaneously. This requires a lump sum capital expense to drill and equip all wells in advance. Other strategies may stage the waterflood by sequentially flooding an emerging pattern in a predetermined sweep direction. Producers that flood out can be converted to injectors in adjacent pattern spacing units. The main advantage of the staged waterflood strategy is that capital is expensed in time with expanding operations. The main disadvantage is that production revenues are delayed over an extended project duration.

Waterflooding is an irreversible process. Once water communication is established between injectors and producers, water will preferentially flow through the pattern spacing unit. Existing producers will gradually flood out after water breaks through. Further pattern refinement through infill drilling may be inefficient. In some cases, infill drilling has been effective with pattern inversion. The pattern spacing and coverage must therefore be fixed at design time.

Waterflood response has a dependence on the primary depletion state. A waterflood strategy with a fixed pattern design is tailored to a particular primary depletion state at a particular point in time. The same waterflood may or may not perform as well for other primary depletion states. The decision process defines rules for choosing the fixed design at different times over primary decline.

A ten year timing window for pattern waterflood is assumed to open up within one year (1-Oct-95). This timing window corresponds to the admissible depletion states remaining in the twenty year life planned for primary production. The waterflood design is refined manually to improve potential

response at the earliest feasible depletion state (1-Oct-95). Good production practice is assumed to apply for a twenty year pattern waterflood.

A five-spot pattern waterflood is chosen with a 40-acre spacing based on the minimum allowed by regulation. Simultaneous operation is selected to expedite the project. The proposed 34 well waterflood project with 23 infill wells are listed in Table 6.1 and mapped geographically in Figure 6.1(a). Figure 6.1(b) shows the 40-acre infill well spacing on the 10-acre reservoir grid overlay. Assignment of injectors and producers in the five-spot pattern are shown in Figure 6.1(c). A water barrier is placed on the eastern edge of the project to isolate the waterflood from the gas cap. The purpose of the barrier is to eliminate gas interference from the gas cap and maintain pressure in the project. The gas will be cut off at the high permeability channel pass.

Alternating rows of production and injection wells make up the five spot pattern. The number of wells were varied and the pattern shifted areally over the reservoir domain to obtain the best sweep of the oil rich zone. The placement of additional wells on the north and south boundary of the project had little effect on project recovery and were not included. Production wells on the north and south peripheral rows drained thinning boundary pay zones. Water displaced oil from the two injection rows placed between production rows. This configuration with 16 injectors and 18 producers gave a reduced set of wells to efficiently sweep the zone in an acceptable length of time.

## 6.2 Secondary Controls

The model waterflood is scheduled to start on 1-Oct-1995 and terminate at the end of a planned 20 year life on 1-Oct-2015. Only the wells in the design waterflood project are assumed to be in operation. Individual producers are designated to be permanently shut in if the oil rates fall below 10 STB/day or the water-oil ratio exceeds 20 STB/STB.

The secondary control policy described in Section 3.8 was implemented. Good production practice chooses to initially limit aggregate oil and gas production, and allow water injection to repressurize the reservoir above the bubble point pressure. Water injection was continuously maintained at maximum admissible rates (Eqns 3.10-12) over the duration of the project. All wells operating with saturated bottomhole conditions were pooled into one control group, while the remaining wells were treated as single control entities. These were continuously produced at maximum admissible rates (Eqns 3.7-3.9) while corresponding local bottomhole conditions remained above the bubble point pressure. Single control entities were reclassified and demoted to the aggregate control group, when the bottomhole condition switched from undersaturated to saturated states. An accounting system similar to that

described for pooled primary control in Section 5.1 was used to regulate oil and gas production from the control group. In-house MRL and GOR assignments were established on the basis of an implicit utility function. It was assumed that corporate head office would demand an initial waterflood revenue stream to be at least as much as that expected from continued primary production. The base GOR=1.129 Mscf/STB that applied for primary operations was chosen for the aggregate control group. An aggregate MRL=1600 STB/day for the control group was determined by waterflood forecasting through trial and error. These values provided a repressurization policy which met undersaturated objectives within 1-6 years and provided initial waterflood revenues that satisfied the revenue utility demand. A single lumped production cycle was determined by the aggregate maximum admissible oil and gas production rates. In house gas quotas had precedence over oil quotas. Relevant wells were simultaneously, and collectively, toggled on and off while assigned to the control group. Wells that repressured above the bubble point were promoted to single control entity status and allowed to produce at maximum rates. Individual production wells were regulated over the course of waterflood, either independently or within a group, to attain the objectives set forth.

Monthly production accounts were accumulated for each well. Each well in the control group tracked the same monthly production hours. Cycle-averaged oil, gas and water rates were calculated for each well by dividing accumulated monthly production accounts by the corresponding hours of production. Cycle-averaged production rates were recorded for the current month at the end of the monthly cycle. Calendar time was used for each month. Instantaneous aggregate pool production rates and average reservoir pressure were recorded at each time step. Instantaneous bottomhole pressures for each well were also recorded at each time step.

## 6.3 Waterflood Simulation

Figures 6.2(a)-(r) shows monthly production forecasts for the eighteen production wells. Half the wells start producing at maximum pump capacity. Some wells exhibit cyclic switching from bang-bang control to continuous control as bottomhole conditions oscillate about the bubble point pressure. Individual well repressurization objectives are met within 1-6 years and water breakthroughs occur within 3-15 years. Monthly cycle bandwidths in production hours increase as production rates decline. Some wells flood out early and are permanently shut in.

Figures 6.3(a)-(p) shows monthly water injection forecasts for the sixteen injection wells. Injection rates initially drop as radial flow fronts interact with reservoir fluids. Injection rates then rise as water displaces or dissolves free gas and fills its pore space. Injection rates continue to rise until water breaks

through at adjacent producing wells. Injection rates fall after water breakthrough and the reservoir floods out with increasing pressure. Underground water flows are diverted towards other producing wells as high water-oil producers are shut in.

Figure 6.4(a) shows an increasing trend in average reservoir pressure as it exceeds bubble point pressures. Figure 6.4(b) shows the cumulative oil, gas and water production predicted for the entire pool. Seven production wells have flooded out. Figure 6.4(c) shows the cumulative water injection predicted for the entire pool. Figures 6.5(a)-(c) show the predicted instantaneous pooled oil gas and water production rates, respectively. Pooled cycles correspond to the sum total of individual well cycles, some operating continuously and others under bang-bang control. The envelopes for pooled oil and gas rate display typical waterflood response. The pooled water production rate drops stepwise as producers flood out and are shut in. Figure 6.5(d) shows predicted instantaneous pooled water injection rates. The pooled water injection rate also shows a typical waterflood response.

Figures 6.6(a)-(e) show the predicted reservoir depletion state after twelve years of waterflooding (Oct-07). This time coincides with the end of the planned primary period. The reservoir is highly repressurized except for a low pressure gas zone persisting at the southern boundary as shown in Figures 6.6(a)and(d). This area is adjacent to the Viking "B" pool and has low permeability. The gas cap has been compressed back into solution. Figure 6.6(b) shows high water saturations distributed over the waterflood project region. Most of the region has flooded out. A few remaining wells are experiencing water breakthrough. The water barrier has effectively isolated the project region. Figure 6.6(c) shows that the region flooded out is at residual oil saturation (17.5%). High oil saturations remain in thin boundary edges and in the region occupied by the receding gas. The bubble point pressure distribution in Figure 6.6(e) shows that the remaining oil in the waterflood region has become more concentrated in heavier ends.

## 6.4 Waterflood Design Summary

Waterflood depletion forecasted large amounts of oil recovered over the planned waterflood life. The current state of operation had historically recovered 0.89 MMSTB over seven years of primay production (1-Oct-94). Another 0.21 MMSTB was forecast for one year of continued primary operation (1-Oct-95). The original oil in place was estimated as 25.4 MMSTB in the reservoir model. Predicted waterflood recovery was 9.8 MMSTB to give a forecasted secondary recovery factor of 38.6% and a total recovery factor of 42.8%. Cumulative water injected was 24.2 MMSTB and cumulative water produced was 6.6 MMSTB. The expectation of high secondary recovery for the proposed waterflood design justifies an economic evaluation with option timing analysis.

| | Chedderville Viking A<br>Proposed Waterflood with Infill Wells | | | | | |
|---|---|---|---|---|---|---|
| Well | LSD | SEC | TWP | RGE | W | STATUS |
| 1 | 6 | 7 | 37 | 7 | 5 | INFILL |
| 2 | 10 | 7 | 37 | 7 | 5 | INFILL |
| 3 | 12 | 7 | 37 | 7 | 5 | INFILL |
| 4 | 16 | 7 | 37 | 7 | 5 | INFILL |
| 5 | 6 | 8 | 37 | 7 | 5 | INFILL |
| 6 | 10 | 8 | 37 | 7 | 5 | INFILL |
| 7 | 12 | 8 | 37 | 7 | 5 | INFILL |
| 8 | 14 | 8 | 37 | 7 | 5 | INFILL |
| 9 | 4 | 16 | 37 | 7 | 5 | INFILL |
| 10 | 2 | 17 | 37 | 7 | 5 | INFILL |
| 11 | 4 | 17 | 37 | 7 | 5 | INFILL |
| 12 | 6 | 17 | 37 | 7 | 5 | INFILL |
| 13 | 2 | 18 | 37 | 7 | 5 | INFILL |
| 14 | 4 | 18 | 37 | 7 | 5 | INFILL |
| 15 | 6 | 18 | 37 | 7 | 5 | INFILL |
| 16 | 16 | 11 | 37 | 8 | 5 | INFILL |
| 17 | 6 | 12 | 37 | 8 | 5 | INFILL |
| 18 | 8 | 12 | 37 | 8 | 5 | INFILL |
| 19 | 10 | 12 | 37 | 8 | 5 | INFILL |
| 20 | 12 | 12 | 37 | 8 | 5 | INFILL |
| 21 | 2 | 13 | 37 | 8 | 5 | INFILL |
| 22 | 4 | 13 | 37 | 8 | 5 | INFILL |
| 23 | 2 | 14 | 37 | 8 | 5 | INFILL |
| 1 | 6 | 7 | 37 | 7 | 5 | PRODUCTION |
| 2 | 8 | 7 | 37 | 7 | 5 | PRODUCTION |
| 3 | 14 | 7 | 37 | 7 | 5 | PRODUCTION |
| 4 | 16 | 7 | 37 | 7 | 5 | PRODUCTION |
| 5 | 6 | 8 | 37 | 7 | 5 | PRODUCTION |
| 6 | 14 | 8 | 37 | 7 | 5 | PRODUCTION |
| 7 | 6 | 17 | 37 | 7 | 5 | PRODUCTION |
| 8 | 8 | 17 | 37 | 7 | 5 | PRODUCTION |
| 9 | 6 | 18 | 37 | 7 | 5 | PRODUCTION |
| 10 | 8 | 18 | 37 | 7 | 5 | PRODUCTION |
| 11 | 16 | 11 | 37 | 8 | 5 | PRODUCTION |
| 12 | 6 | 12 | 37 | 8 | 5 | PRODUCTION |
| 13 | 8 | 12 | 37 | 8 | 5 | PRODUCTION |
| 14 | 14 | 12 | 37 | 8 | 5 | PRODUCTION |
| 15 | 16 | 12 | 37 | 8 | 5 | PRODUCTION |
| 16 | 6 | 13 | 37 | 8 | 5 | PRODUCTION |
| 17 | 8 | 13 | 37 | 8 | 5 | PRODUCTION |
| 18 | 8 | 14 | 37 | 8 | 5 | PRODUCTION |
| 19 | 10 | 7 | 37 | 7 | 5 | INJECTION |
| 20 | 12 | 7 | 37 | 7 | 5 | INJECTION |
| 21 | 10 | 8 | 37 | 7 | 5 | INJECTION |
| 22 | 12 | 8 | 37 | 7 | 5 | INJECTION |
| 23 | 16 | 8 | 37 | 7 | 5 | INJECTION |
| 24 | 4 | 16 | 37 | 7 | 5 | INJECTION |
| 25 | 6 | 16 | 37 | 7 | 5 | INJECTION |
| 26 | 2 | 17 | 37 | 7 | 5 | INJECTION |
| 27 | 4 | 17 | 37 | 7 | 5 | INJECTION |
| 28 | 2 | 18 | 37 | 7 | 5 | INJECTION |
| 29 | 4 | 18 | 37 | 7 | 5 | INJECTION |
| 30 | 10 | 12 | 37 | 8 | 5 | INJECTION |
| 31 | 12 | 12 | 37 | 8 | 5 | INJECTION |
| 32 | 2 | 13 | 37 | 8 | 5 | INJECTION |
| 33 | 4 | 13 | 37 | 8 | 5 | INJECTION |
| 34 | 2 | 14 | 37 | 8 | 5 | INJECTION |

Table 6.1: Proposed Waterflood Project

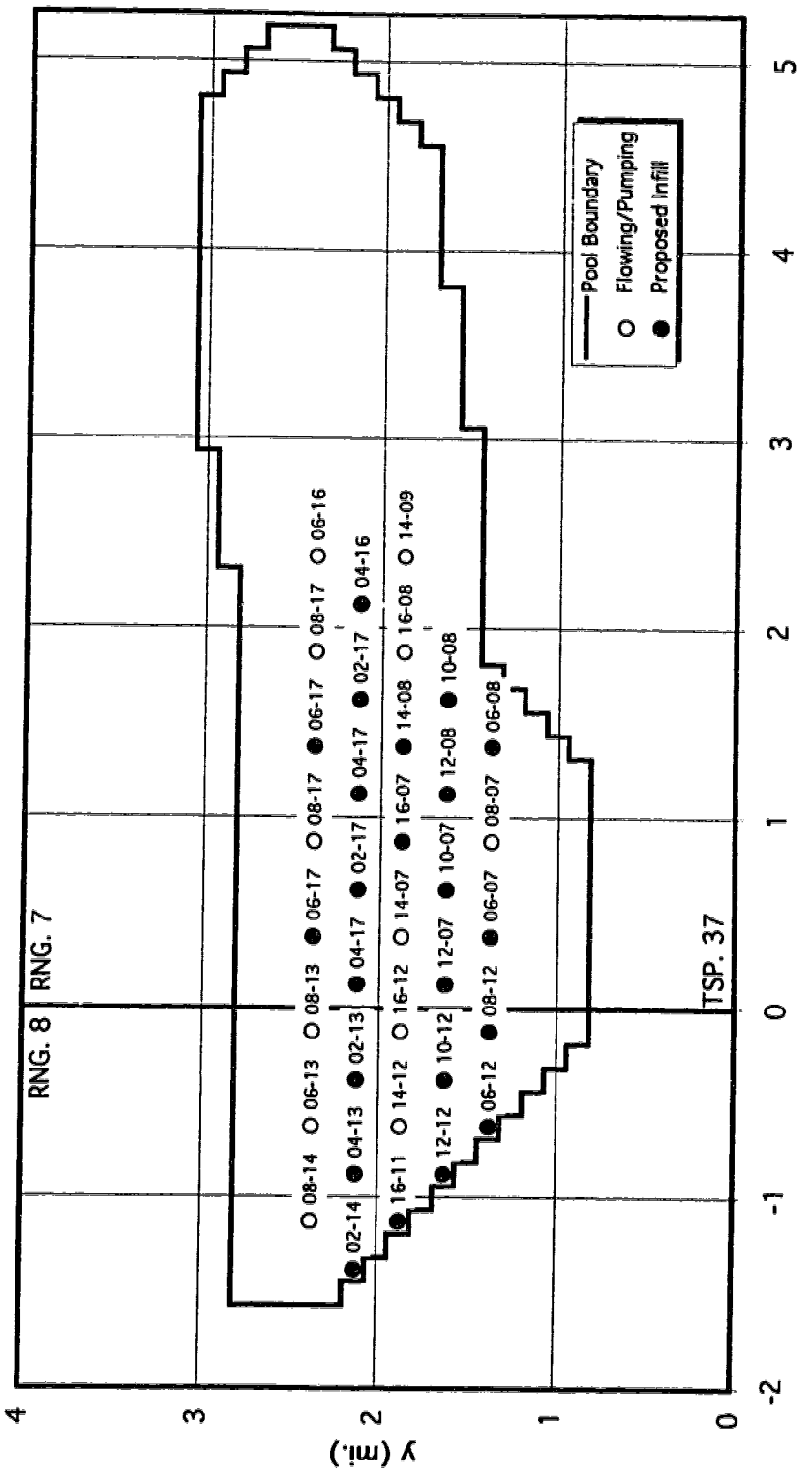



Figure 6.1(a): Chedderville Viking "A" Infill Drilling Location Map

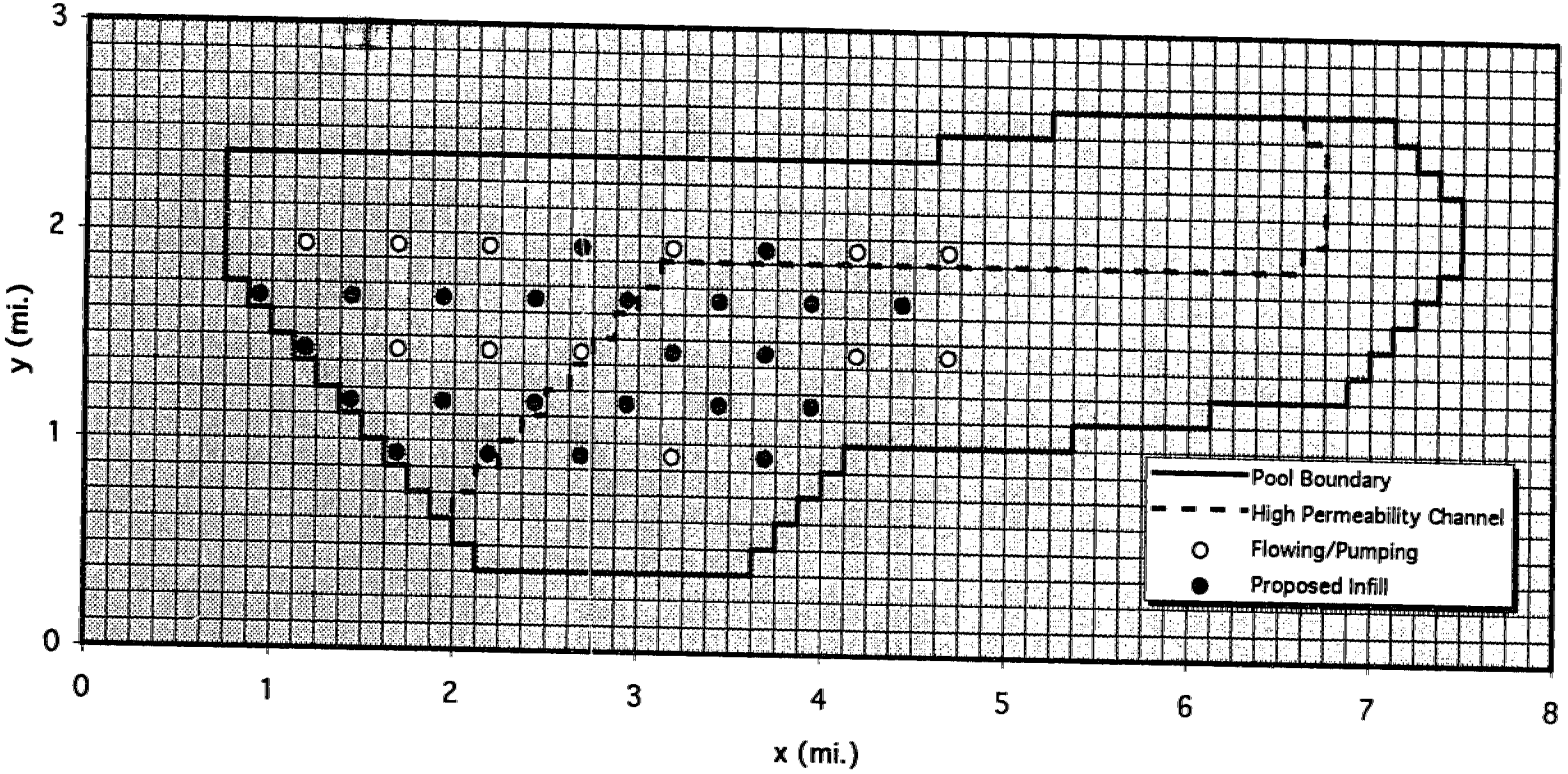



Figure 6.1(b): Infill Drilling Grid (40-acre Spacing)

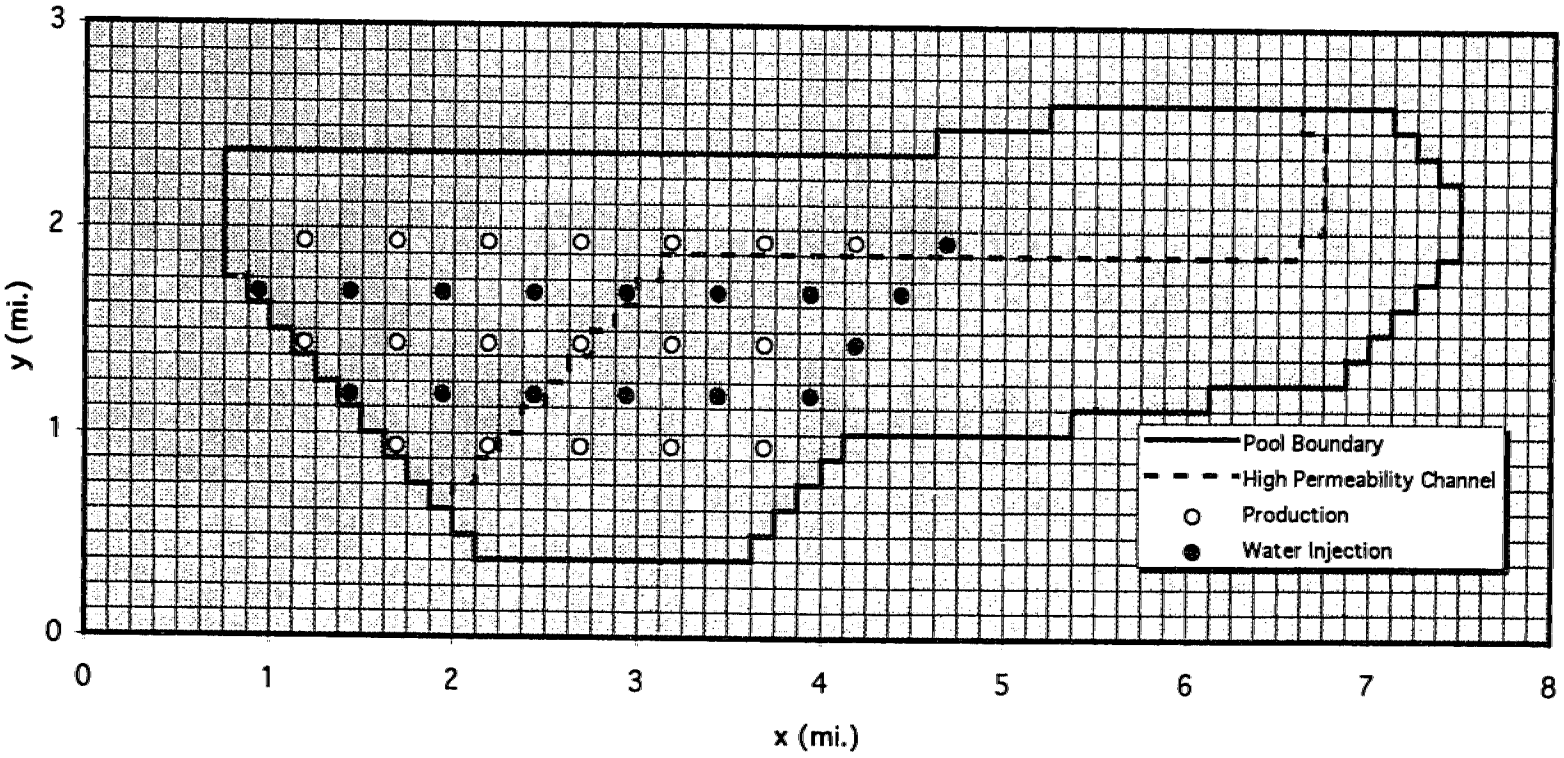



Figure 6.1(c): 5-Spot Pattern Waterflood with Water-Barrier

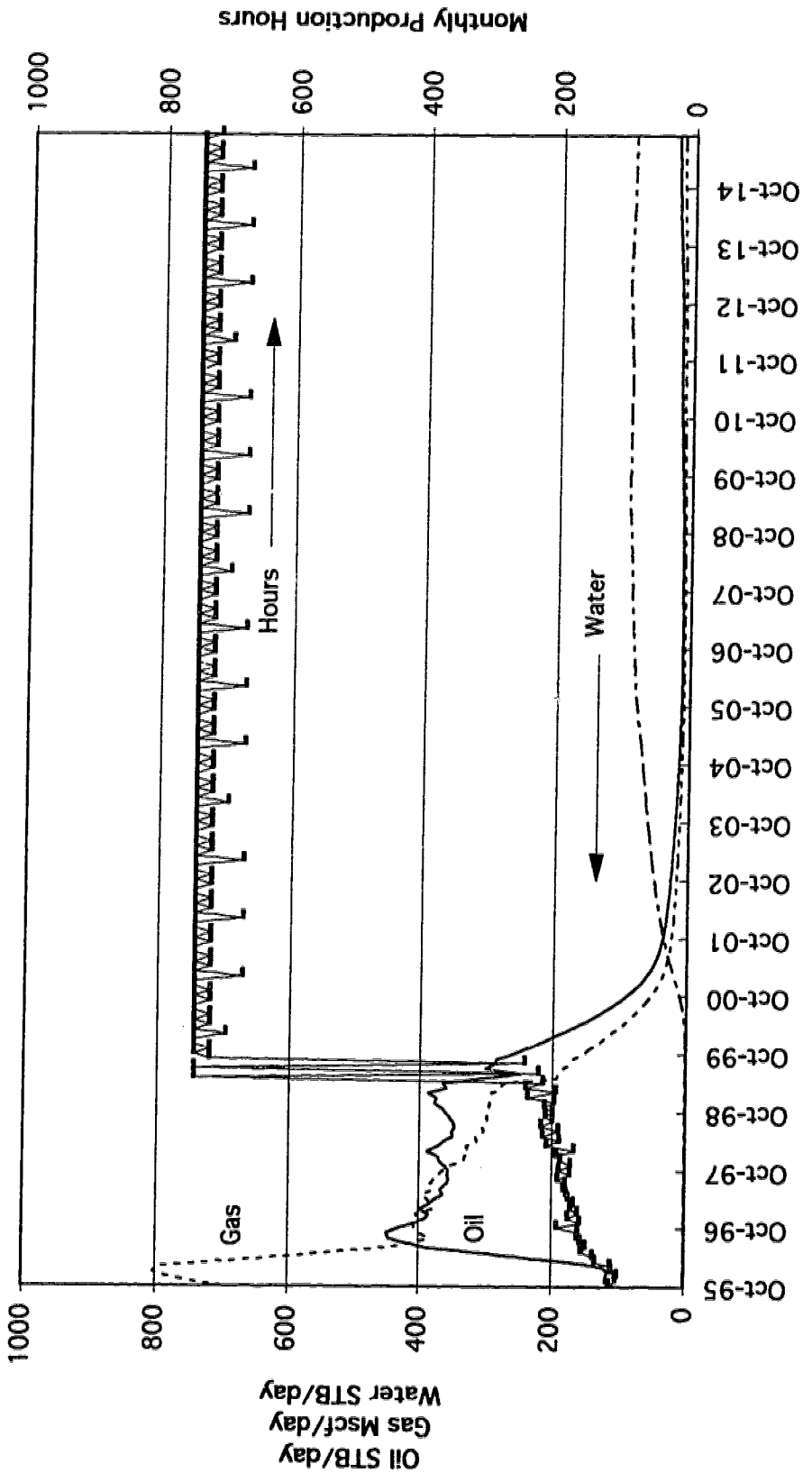



Figure 6.2(a): Waterflood Production Forecast (08-13-37-8W5)

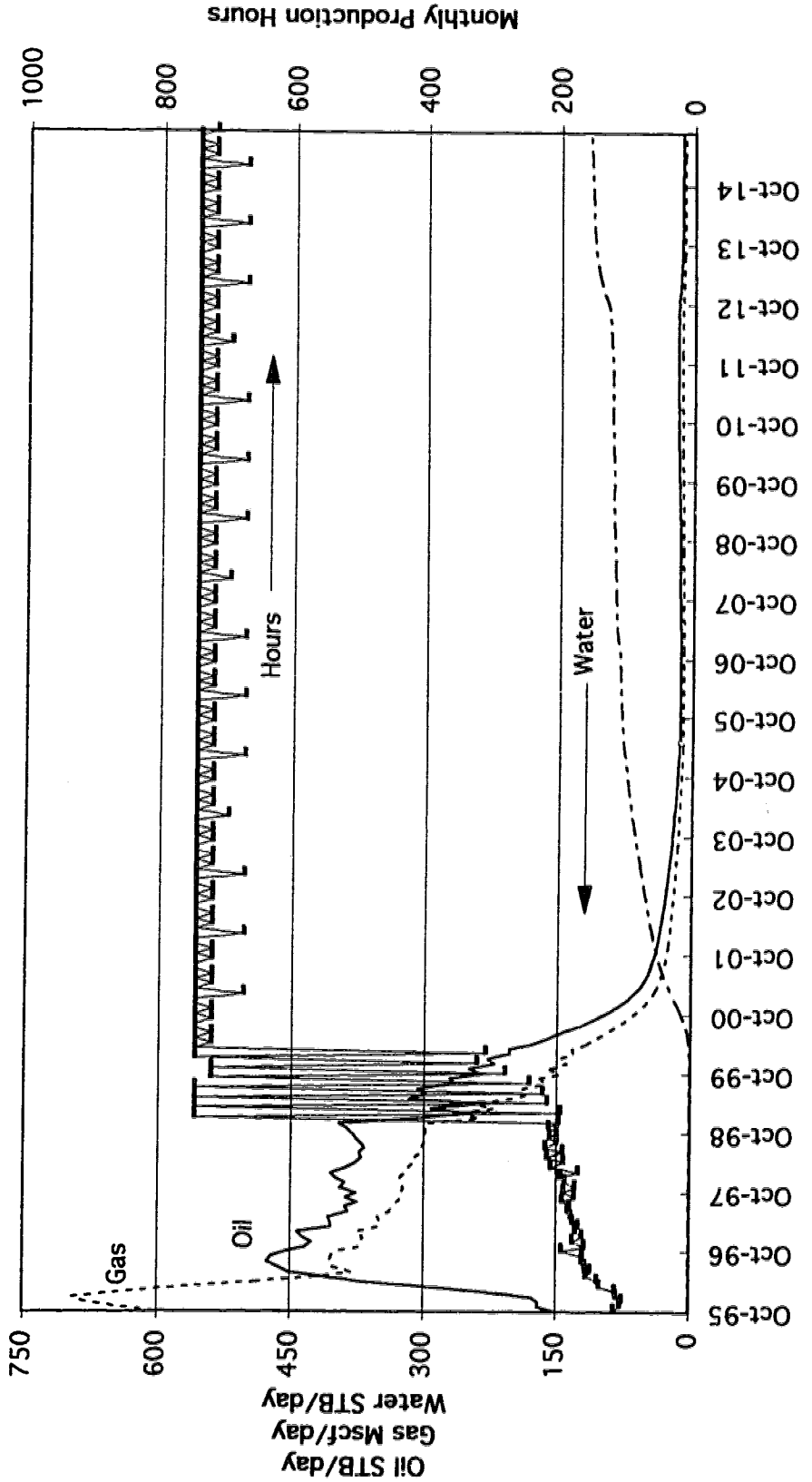



Figure 6.2(b): Waterflood Production Forecast (06-13-37-8W5)

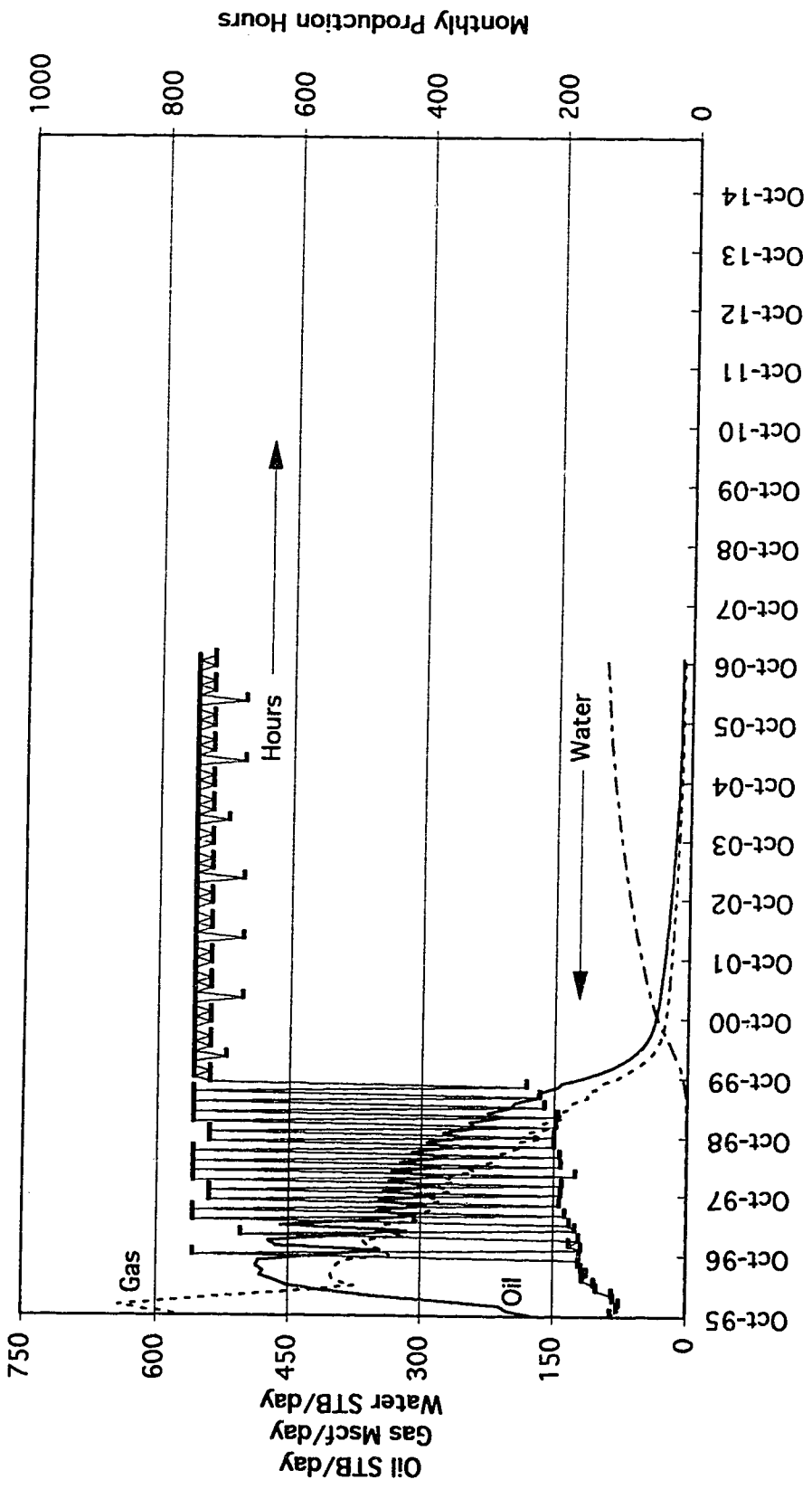



Figure 6.2(c): Waterflood Production Forecast (08-14-37-8W5)

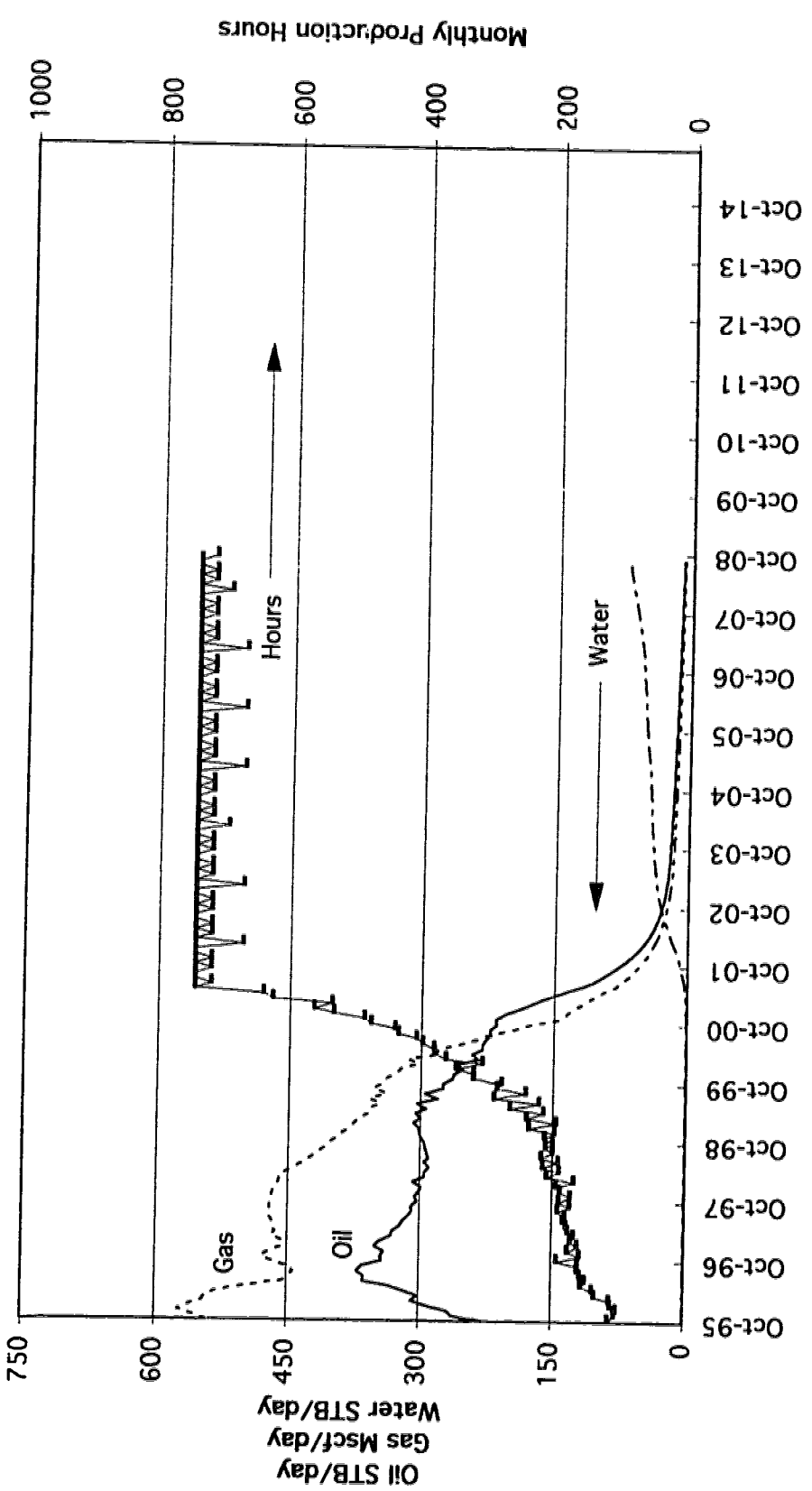



Figure 6.2(d): Waterflood Production Forecast (08-18-37-7W5)

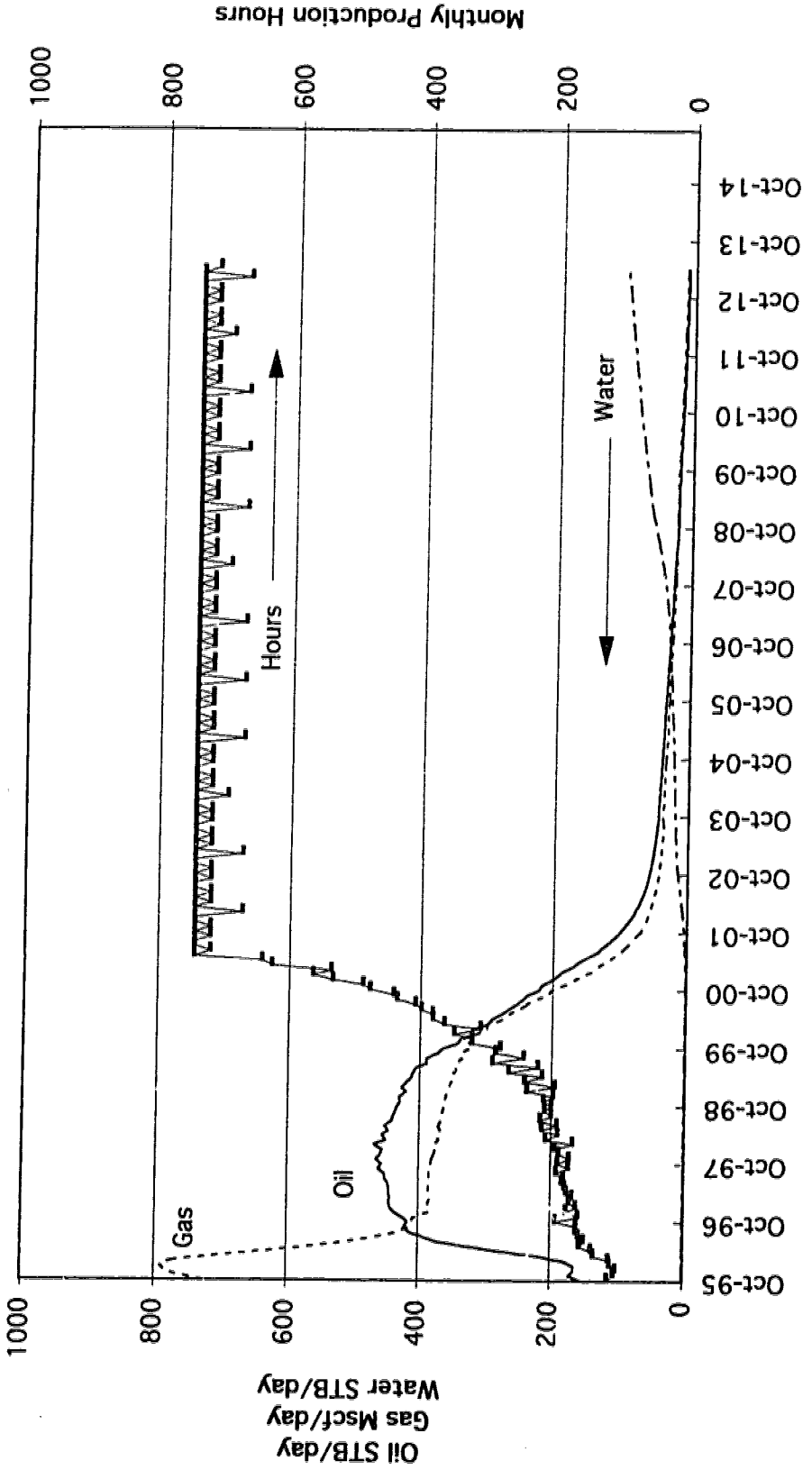



Figure 6.2(e): Waterflood Production Forecast (08-17-37-7W5)

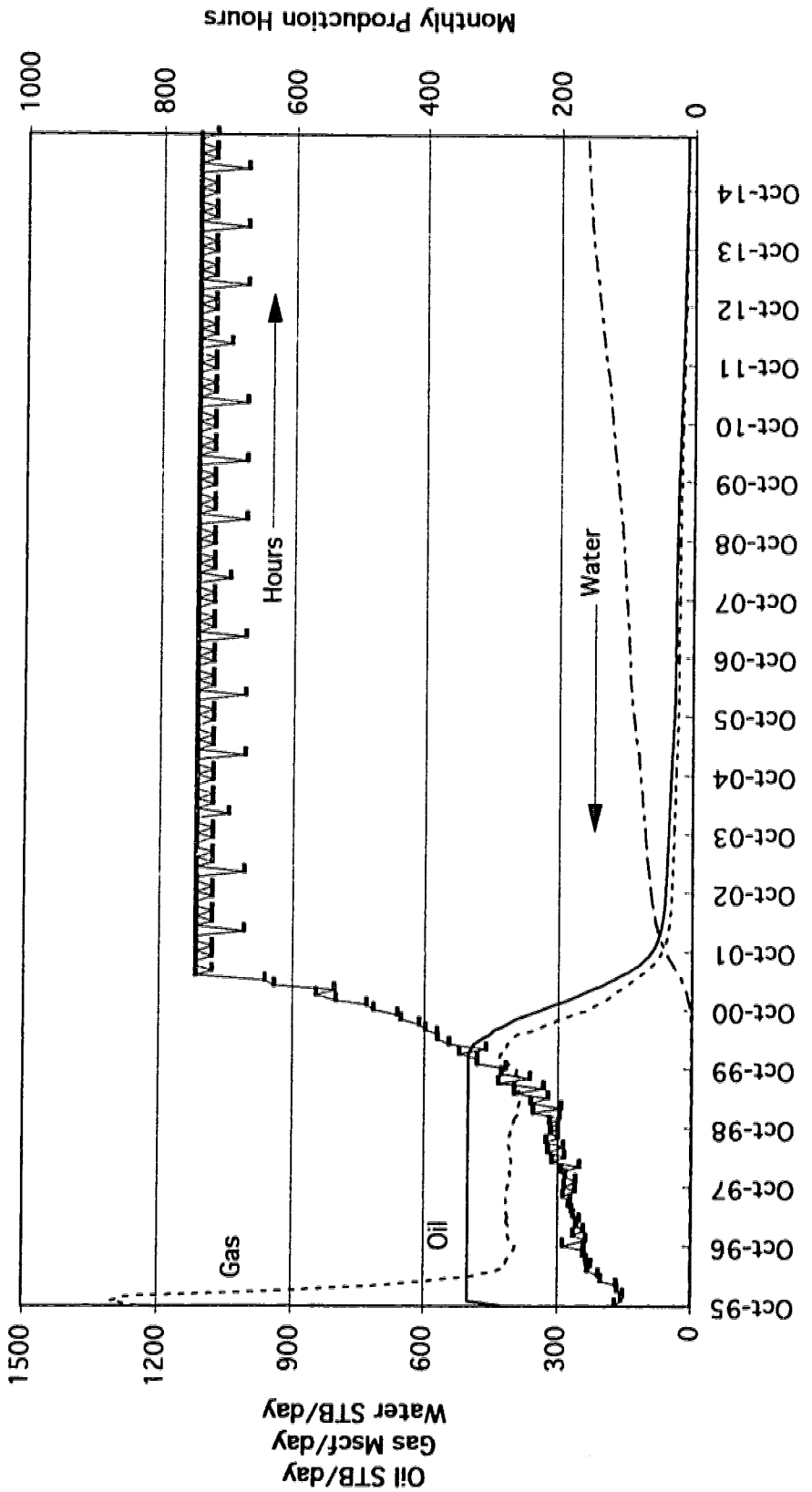



Figure 6.2(f): Waterflood Production Forecast (14-07-37-7W5)

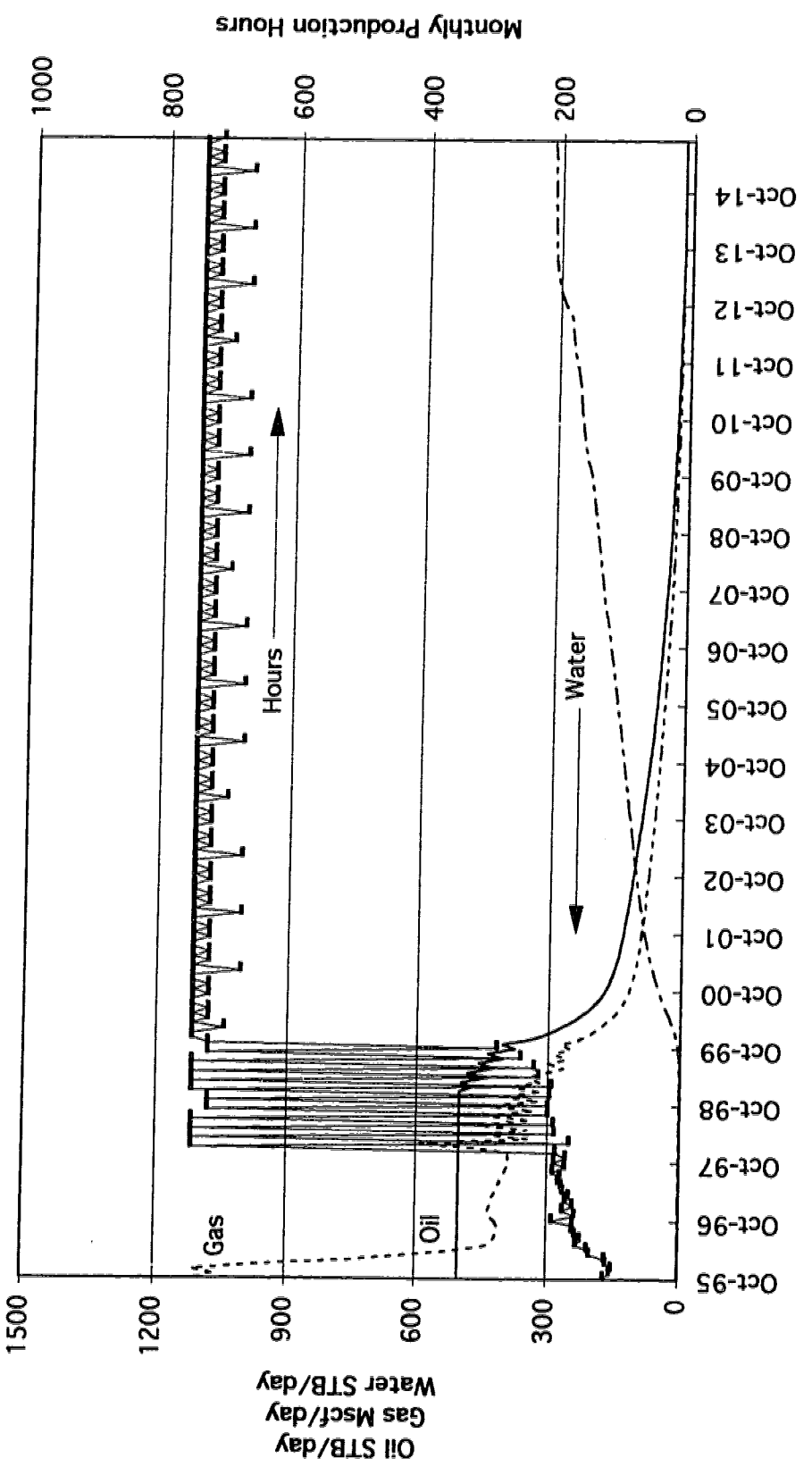



Figure 6.2(g): Waterflood Production Forecast (14-12-37-8W5)

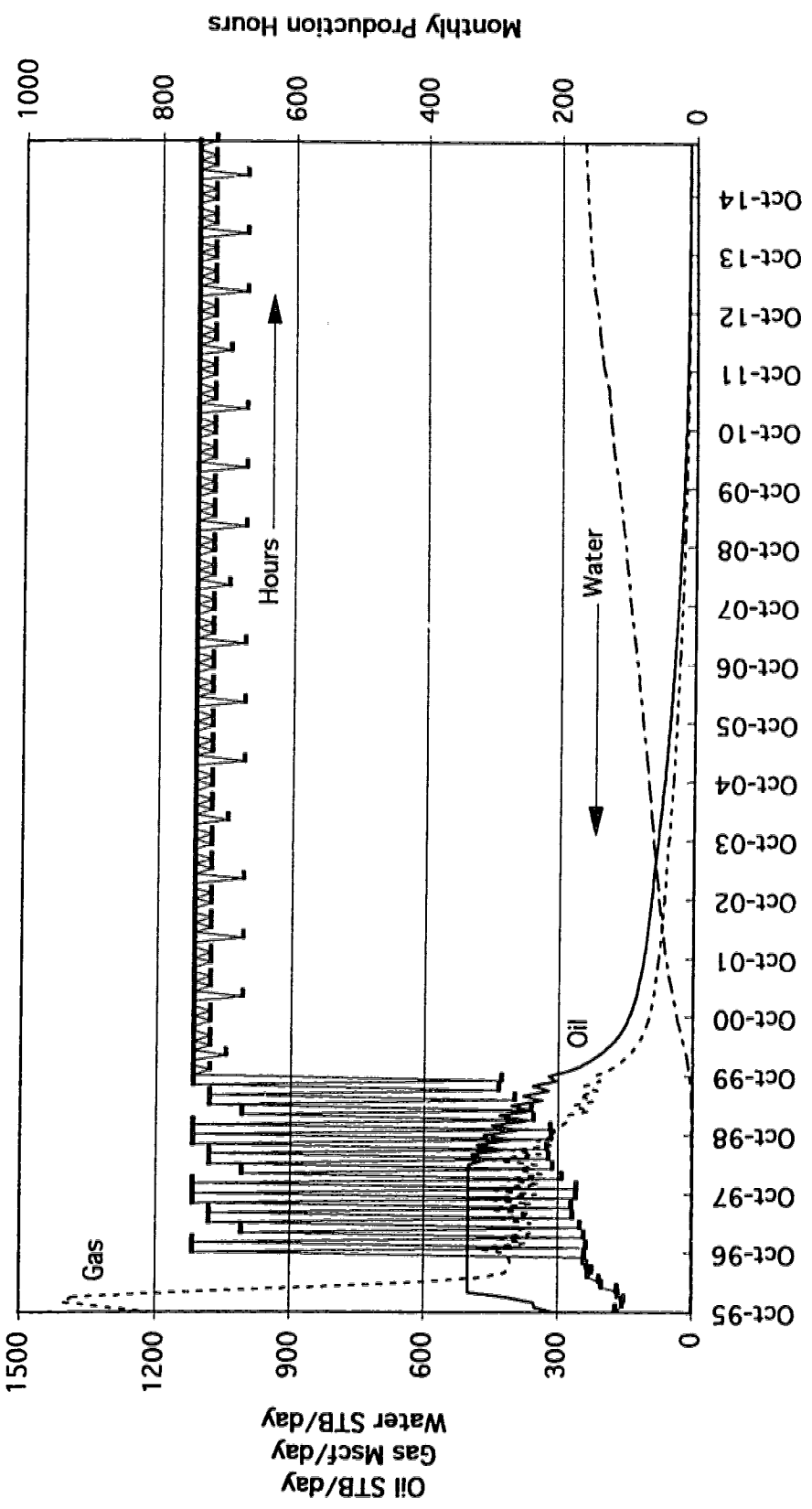



Figure 6.2(h): Waterflood Production Forecast (16-12-37-8W5)

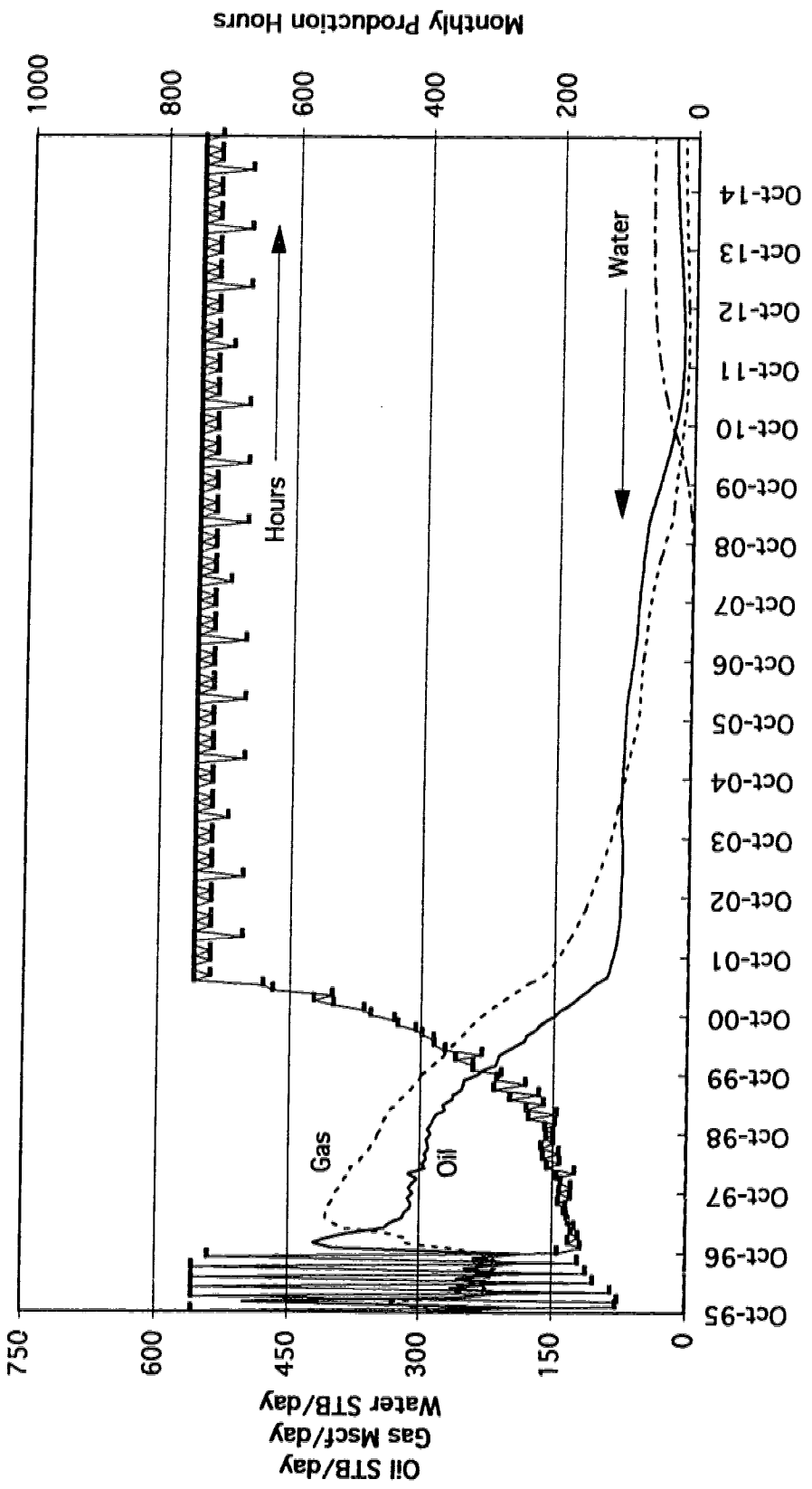



Figure 6.2(i): Waterflood Production Forecast (08-07-37-7W5)

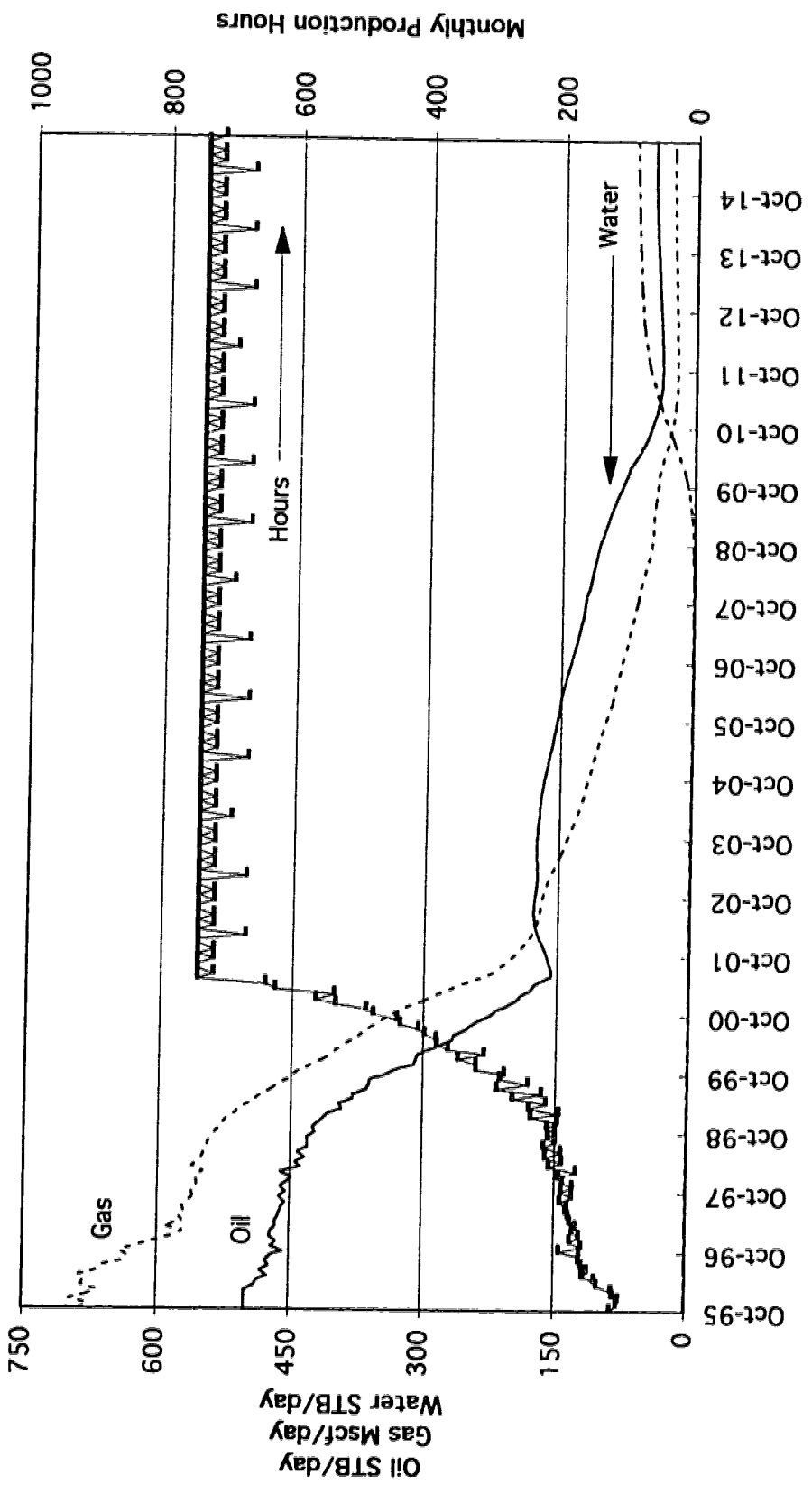



Figure 6.2(i): Waterflood Production Forecast (06-07-37-7W5)

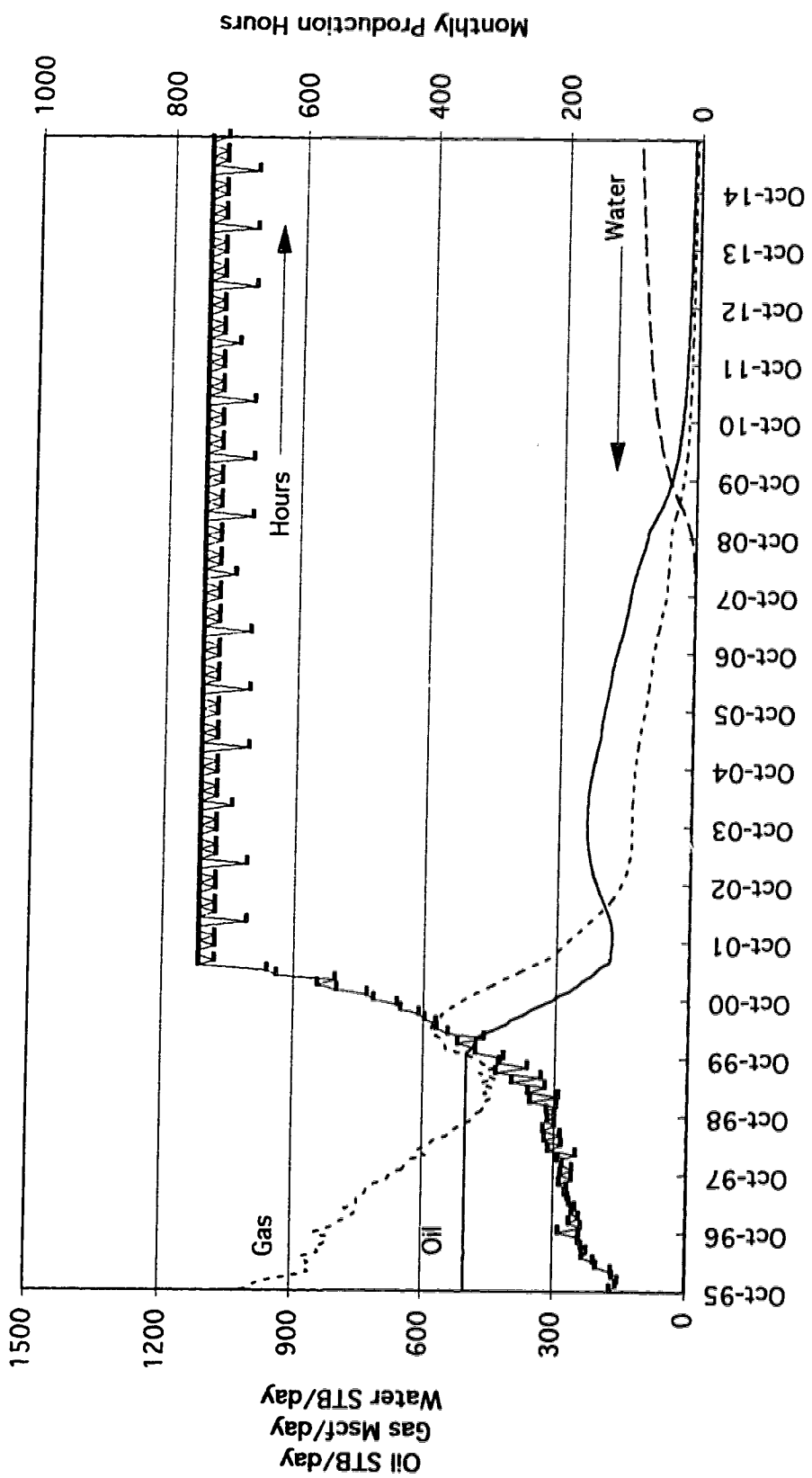



Figure 6.2(k): Waterflood Production Forecast (16-07-37-7W5)

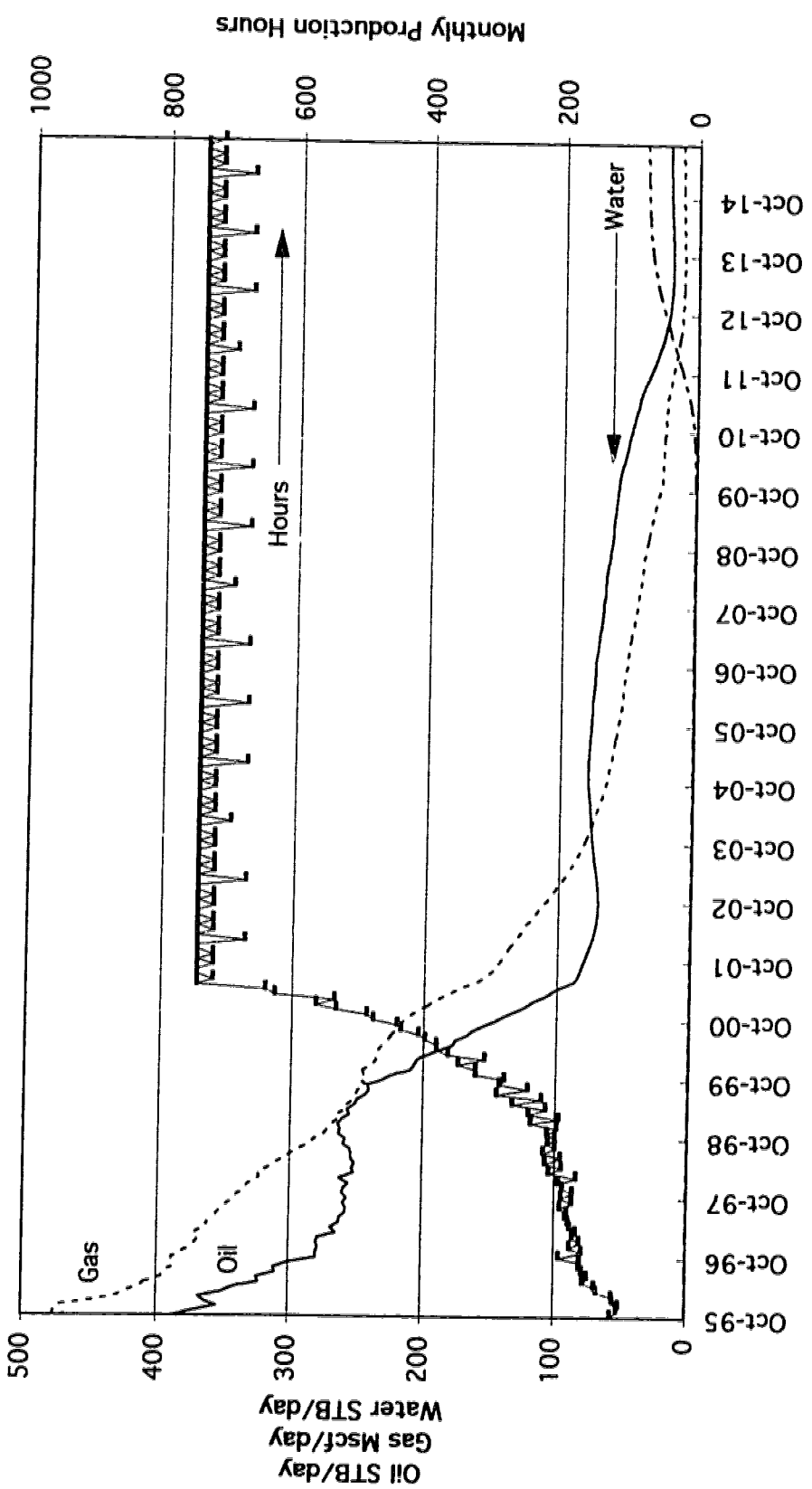



Figure 6.2(I): Waterflood Production Forecast (06-08-37-7W5)

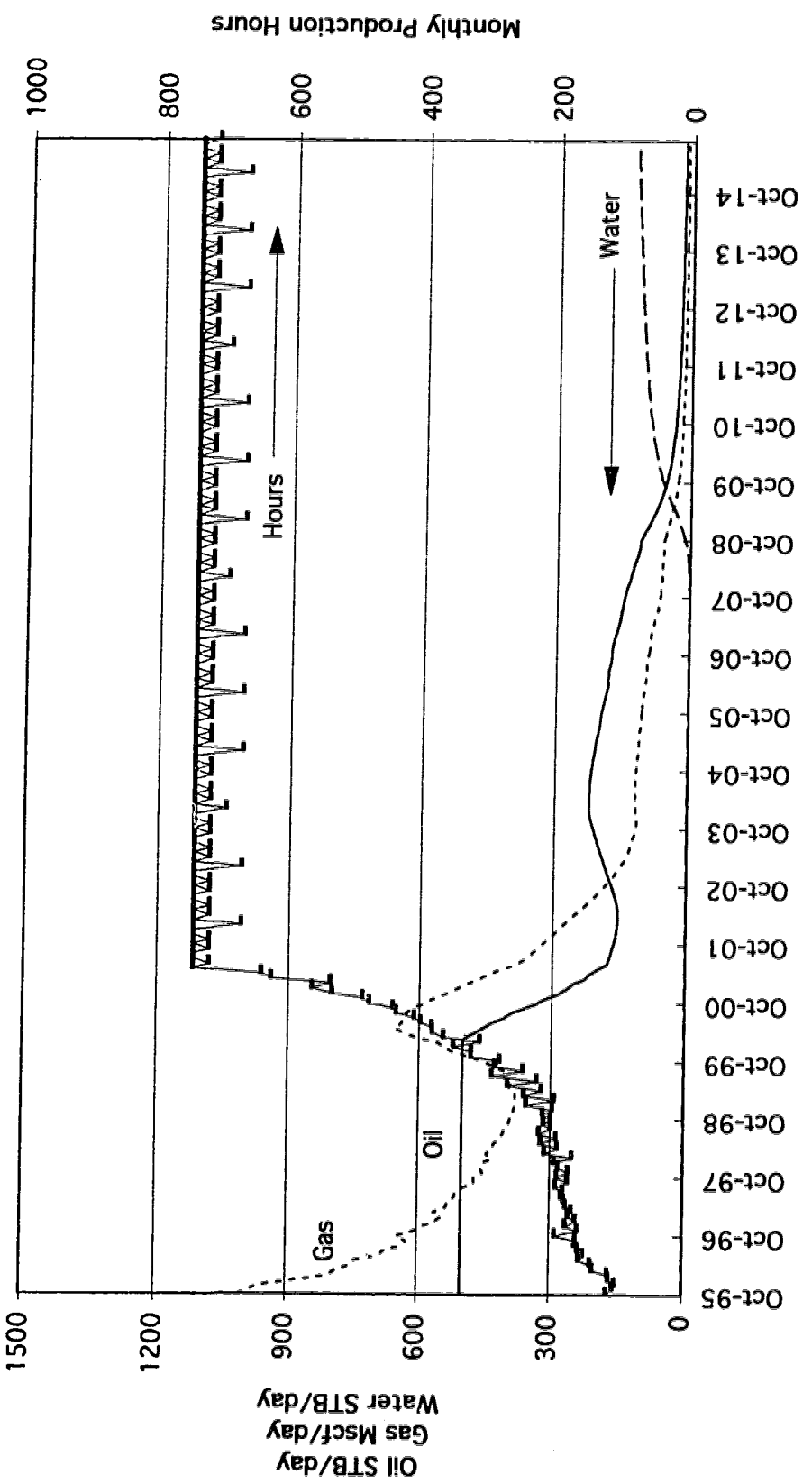



Figure 6.2(m): Waterflood Production Forecast (14-08-37-7W5)

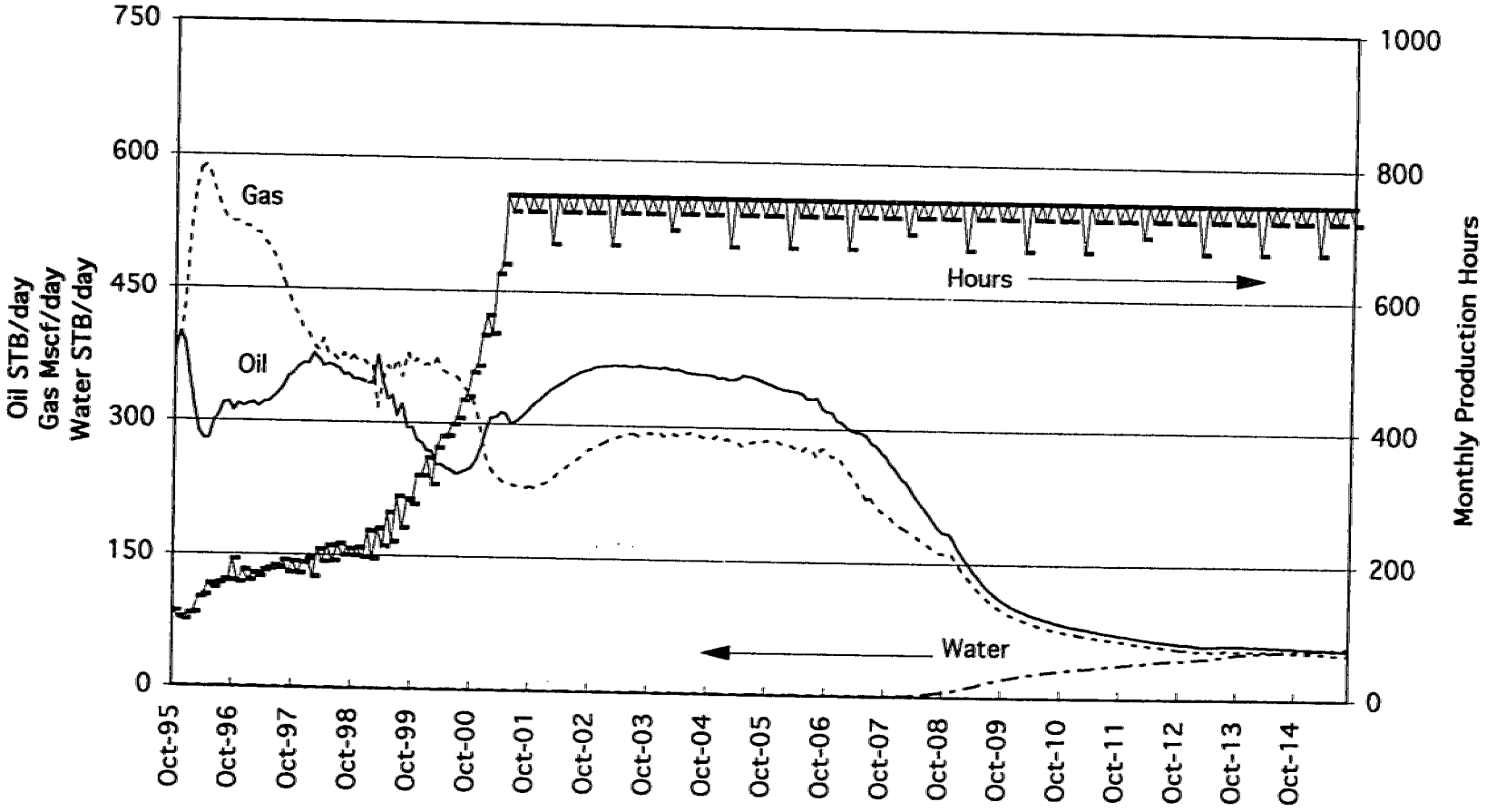



Figure 6.2(n): Waterflood Production Forecast (06-17-37-7W5)

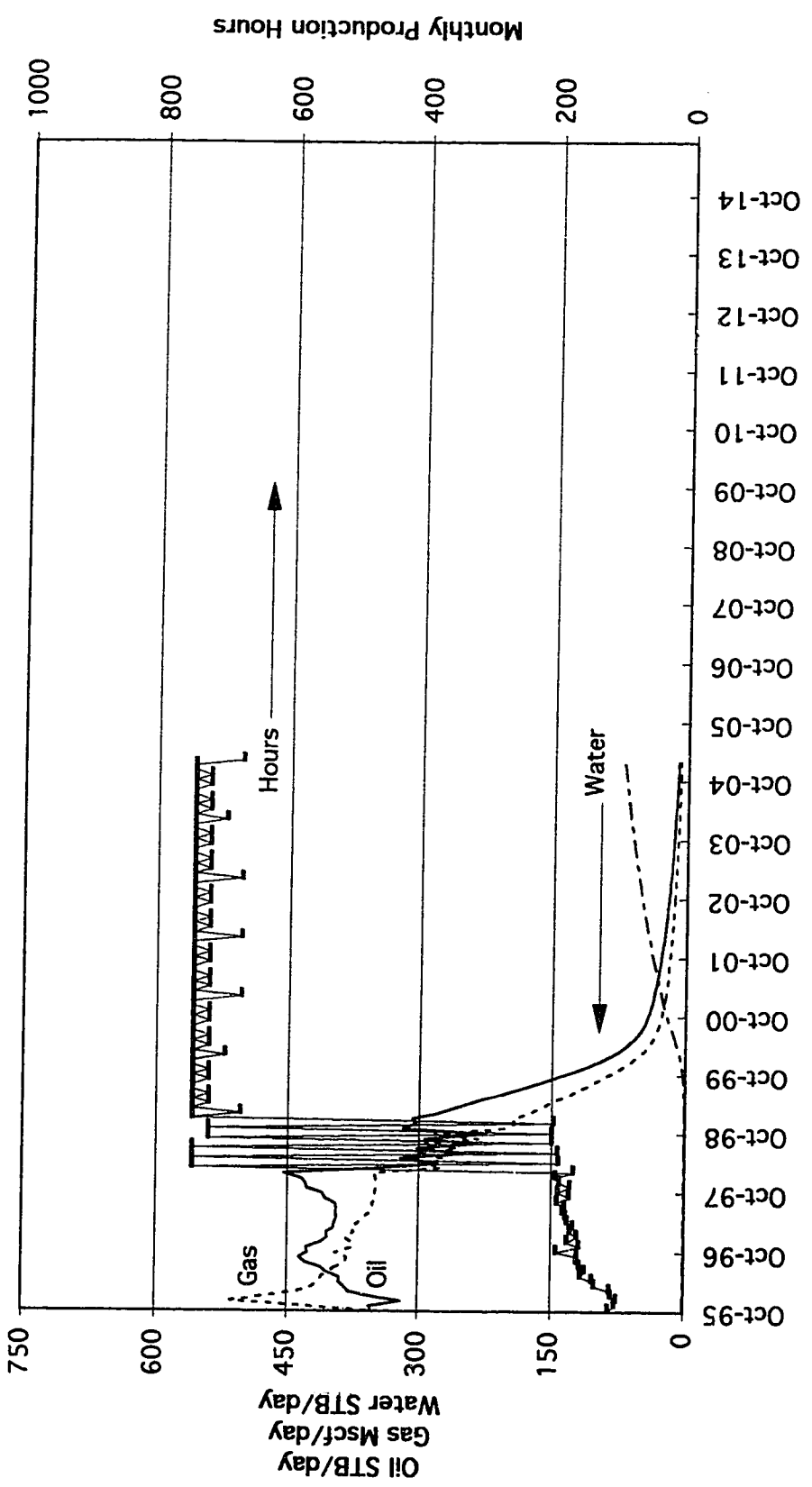



Figure 6.2(o): Waterflood Production Forecast (06-18-37-7W5)

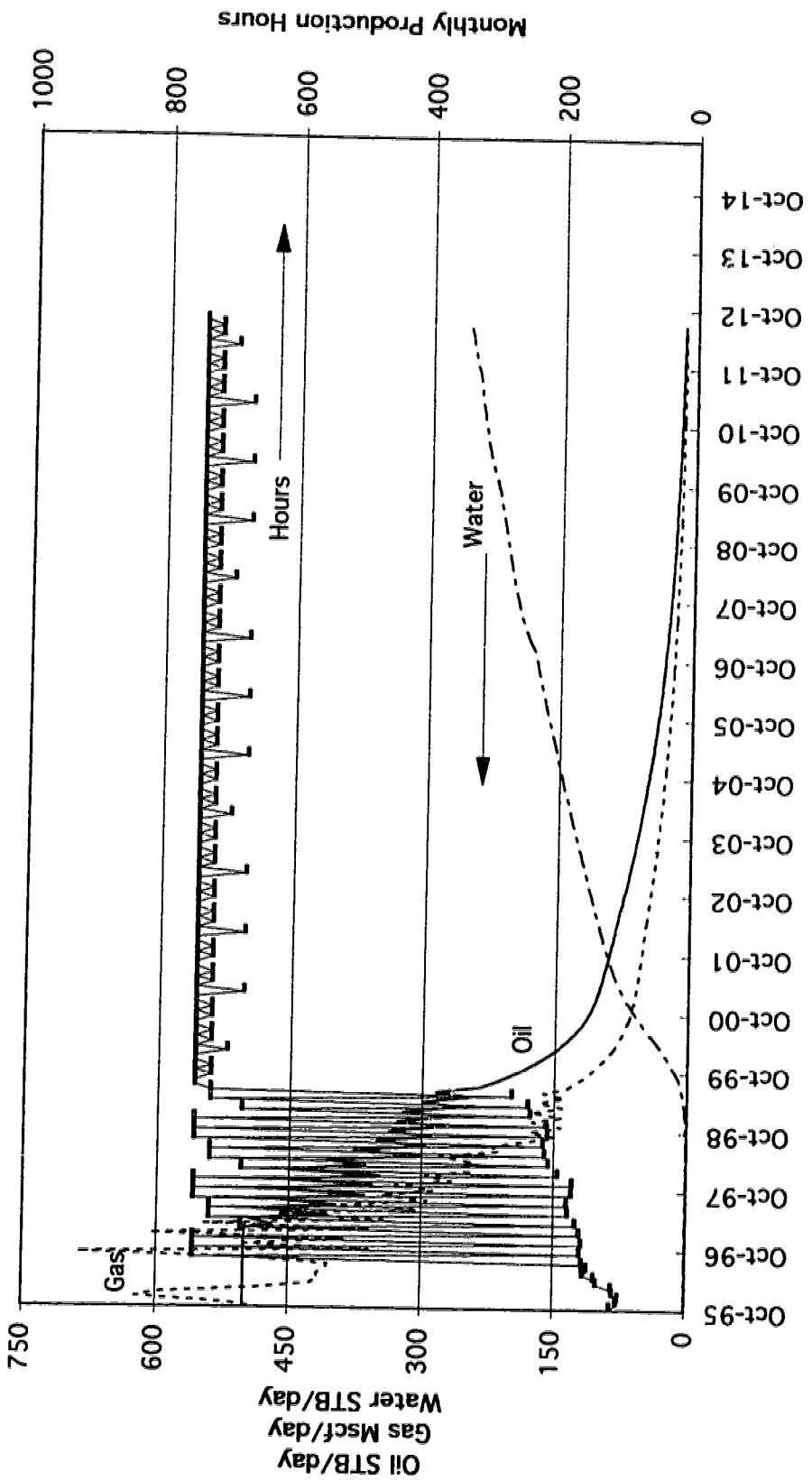



Figure 6.2(p): Waterflood Production Forecast (16-11-37-8W5)

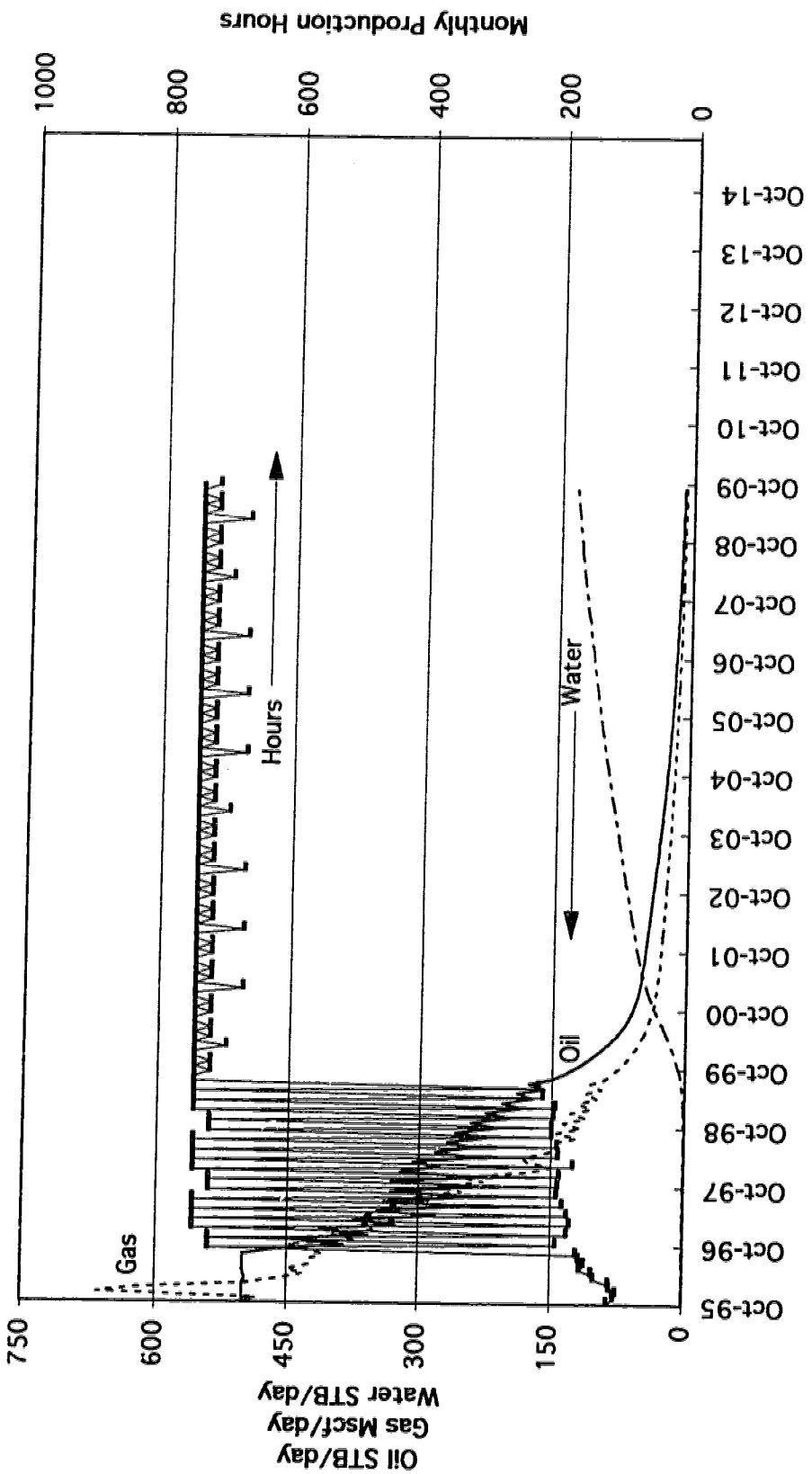



Figure 6.2(g): Waterflood Production Forecast (06-12-37-8W5)

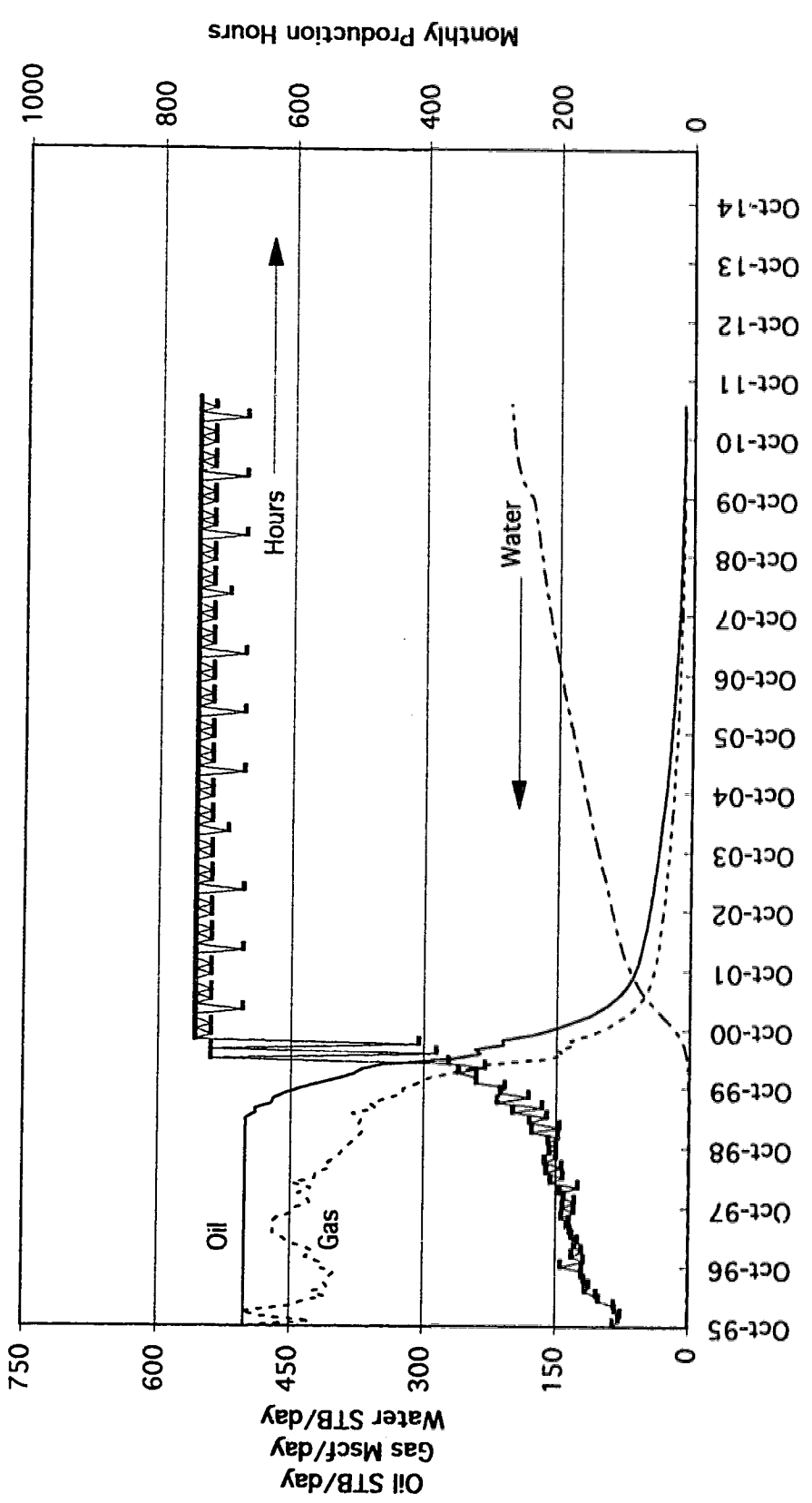



Figure 6.2(r): Waterflood Production Forecast (08-12-37-8W5)

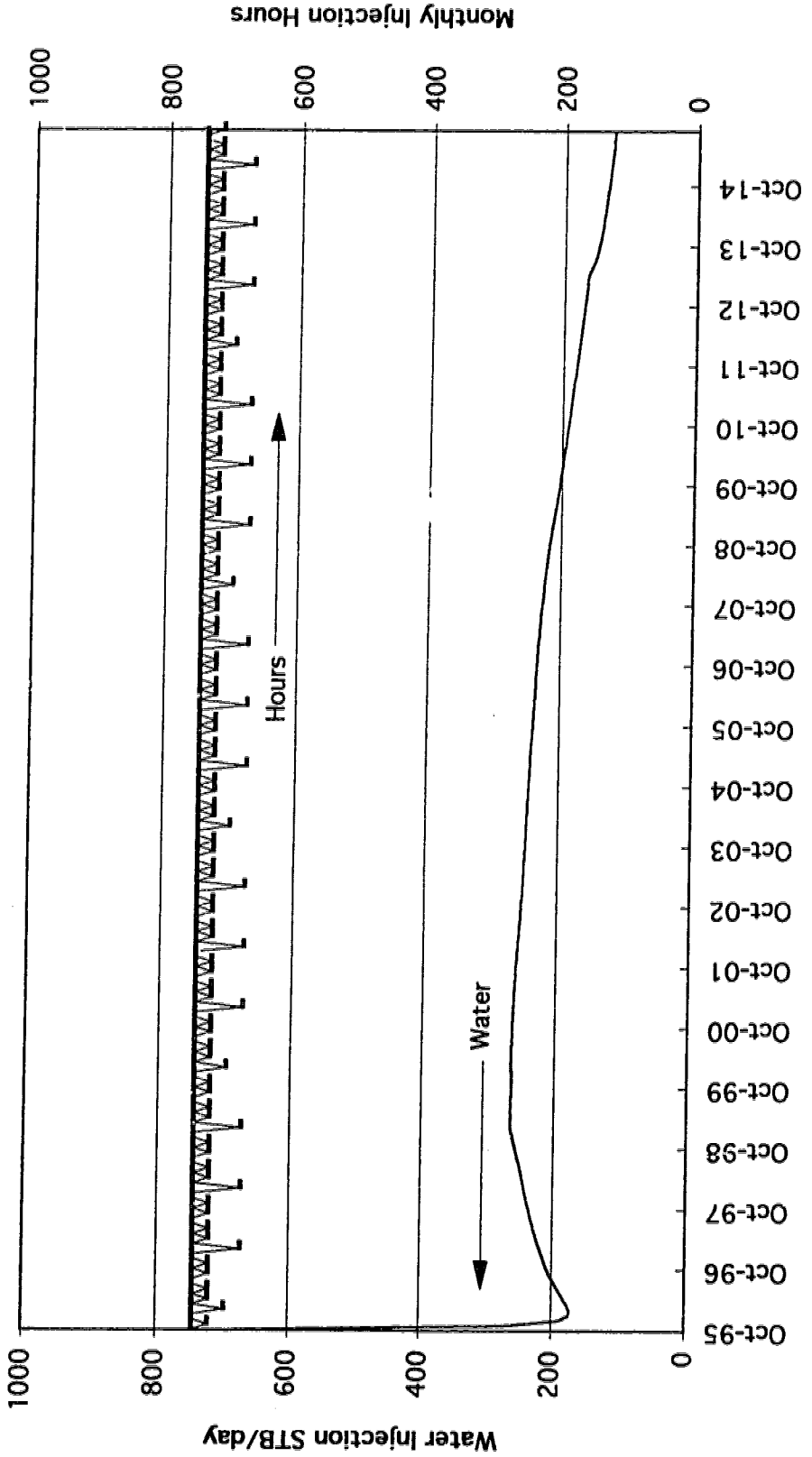



Figure 6.3(a): Waterflood Injection Forecast (06-16-37-7W5)

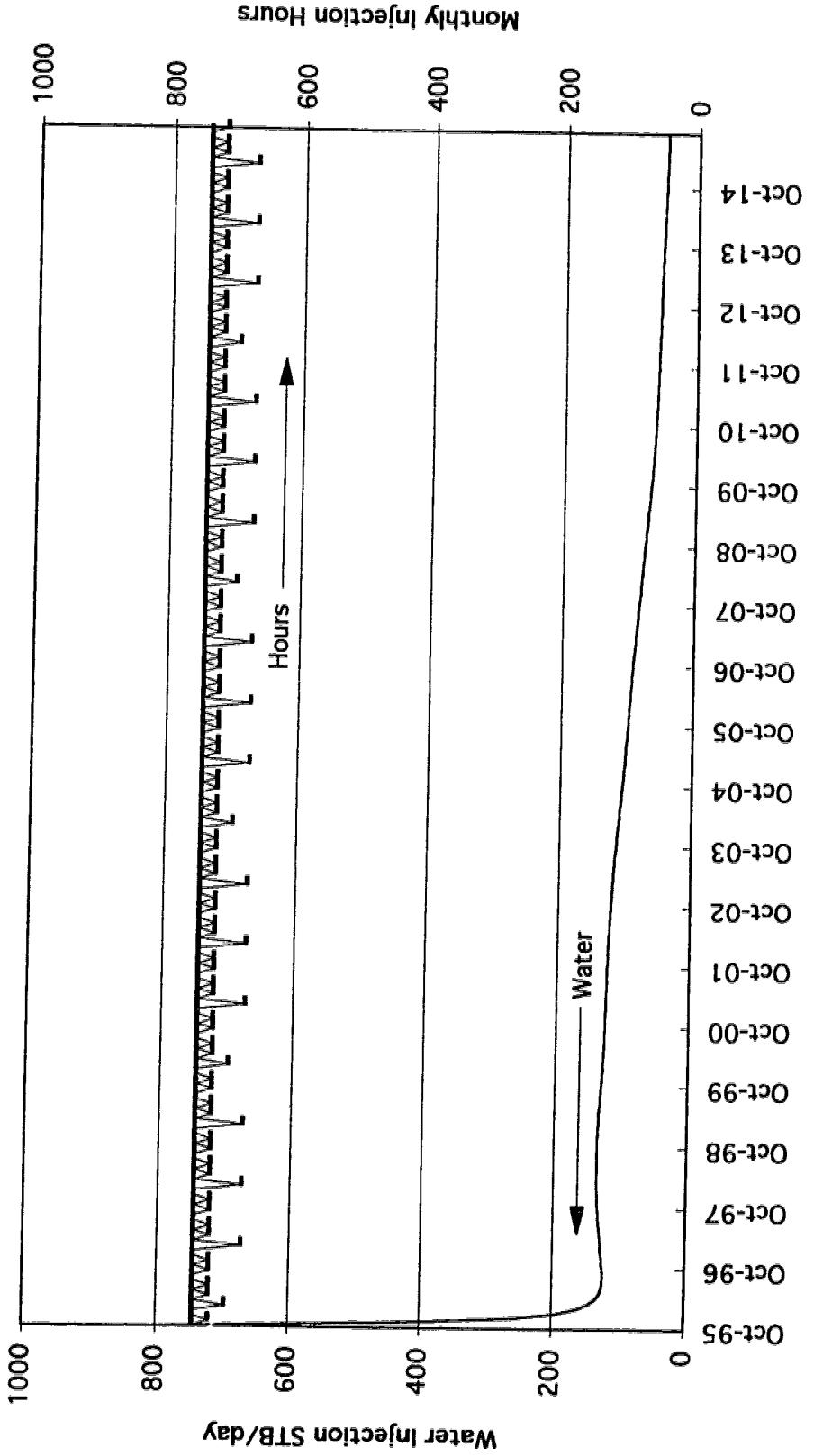



Figure 6.3(b): Waterflood Injection Forecast (16-08-37-7W5)

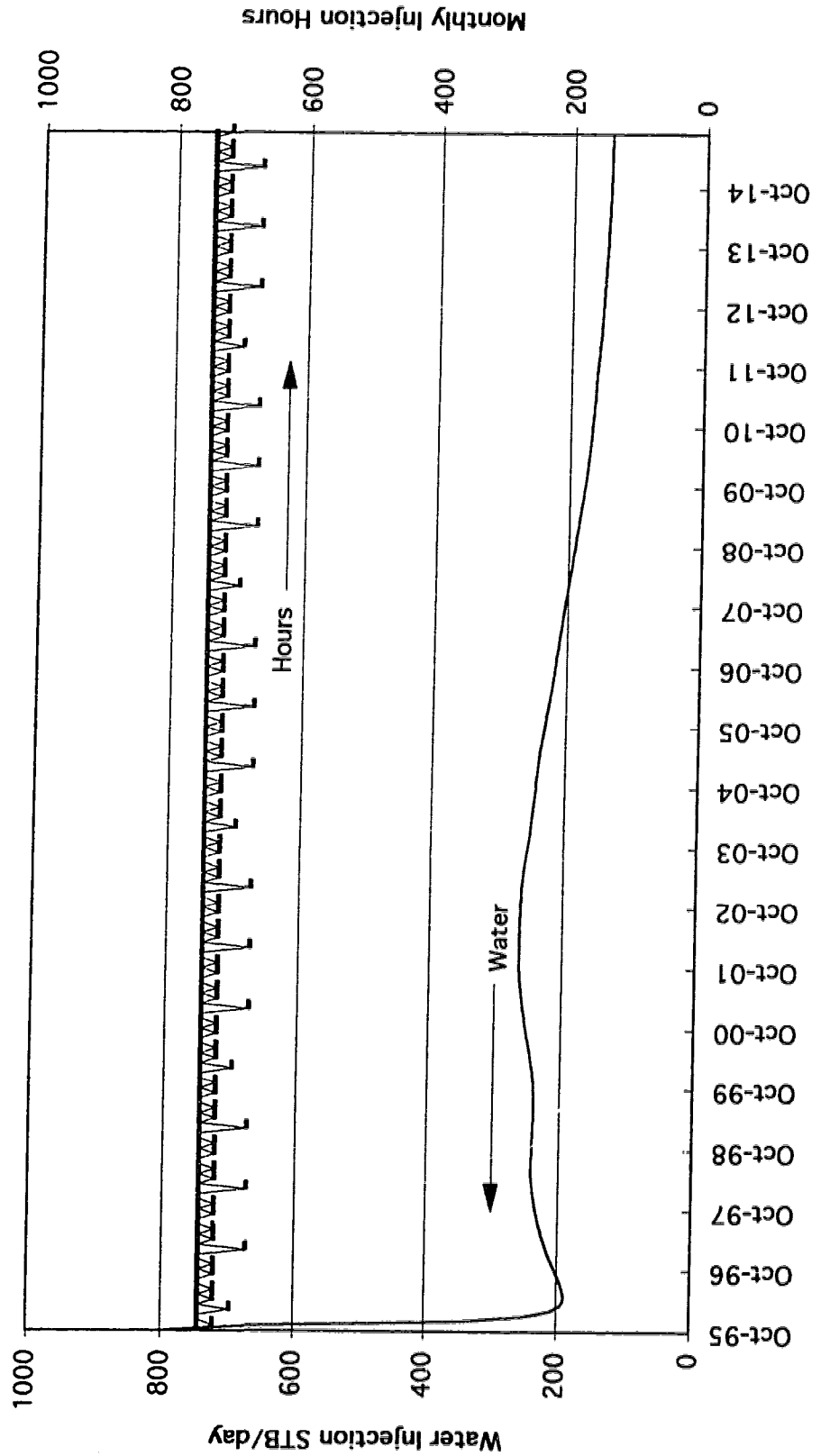



Figure 6.3(c): Waterflood Injection Forecast (10-7-37-7W5)

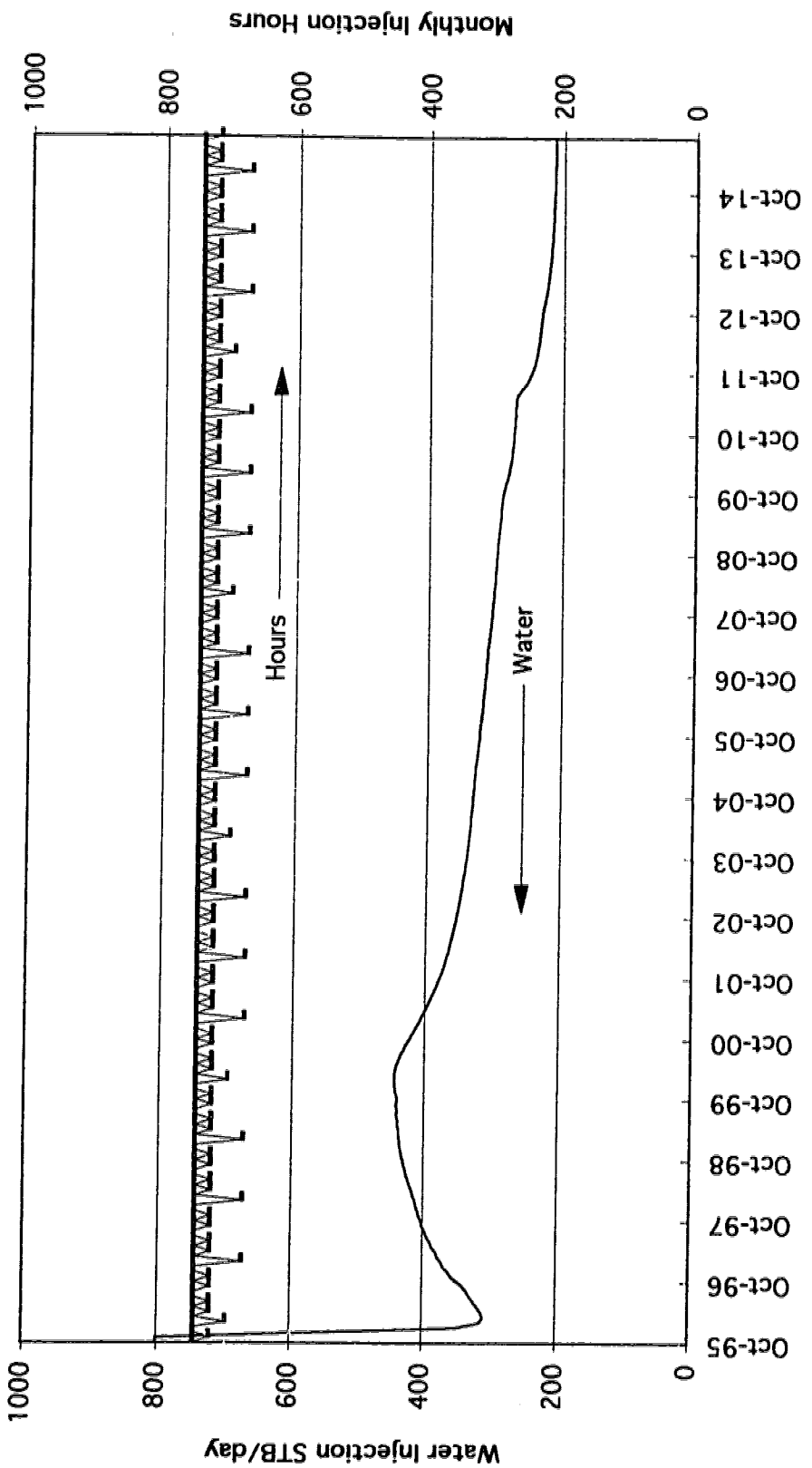



Figure 6.3(d): Waterflood Injection Forecast (12-07-37-7W5)

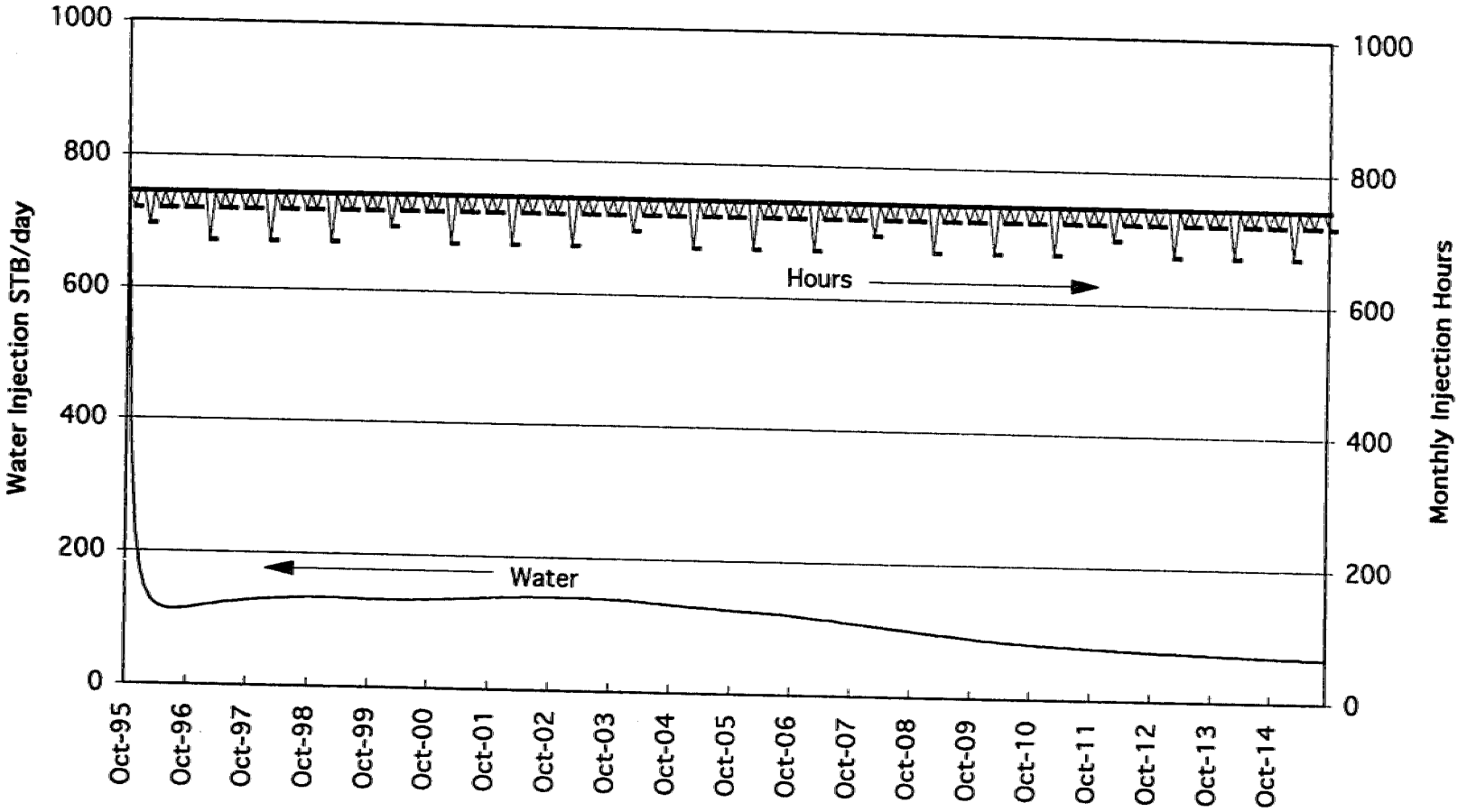



Figure 6.3(e): Waterflood Injection Forecast (10-08-37-7W5)

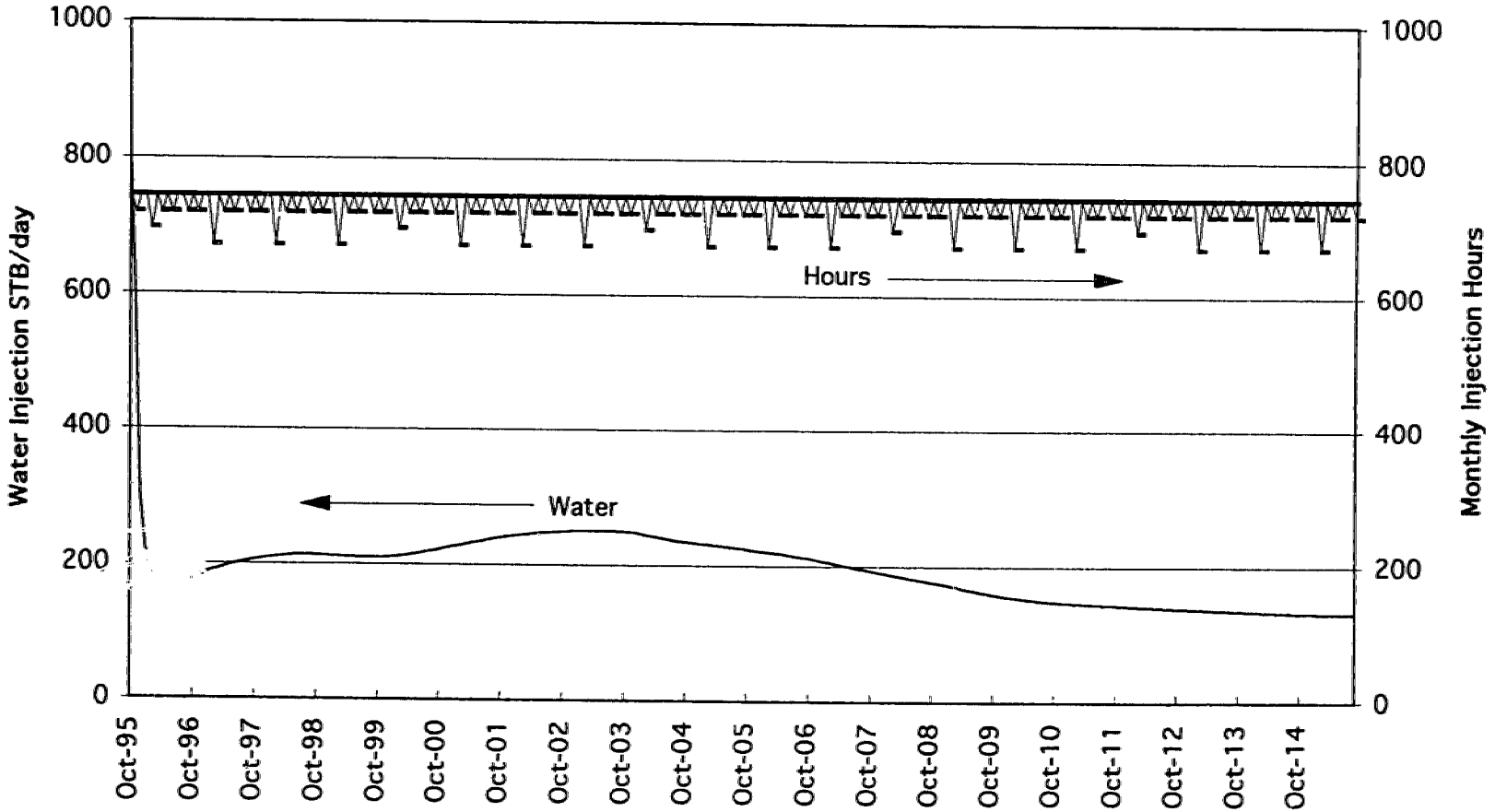



Figure 6.3(f): Waterflood Injection Forecast (12-08-37-7W5)

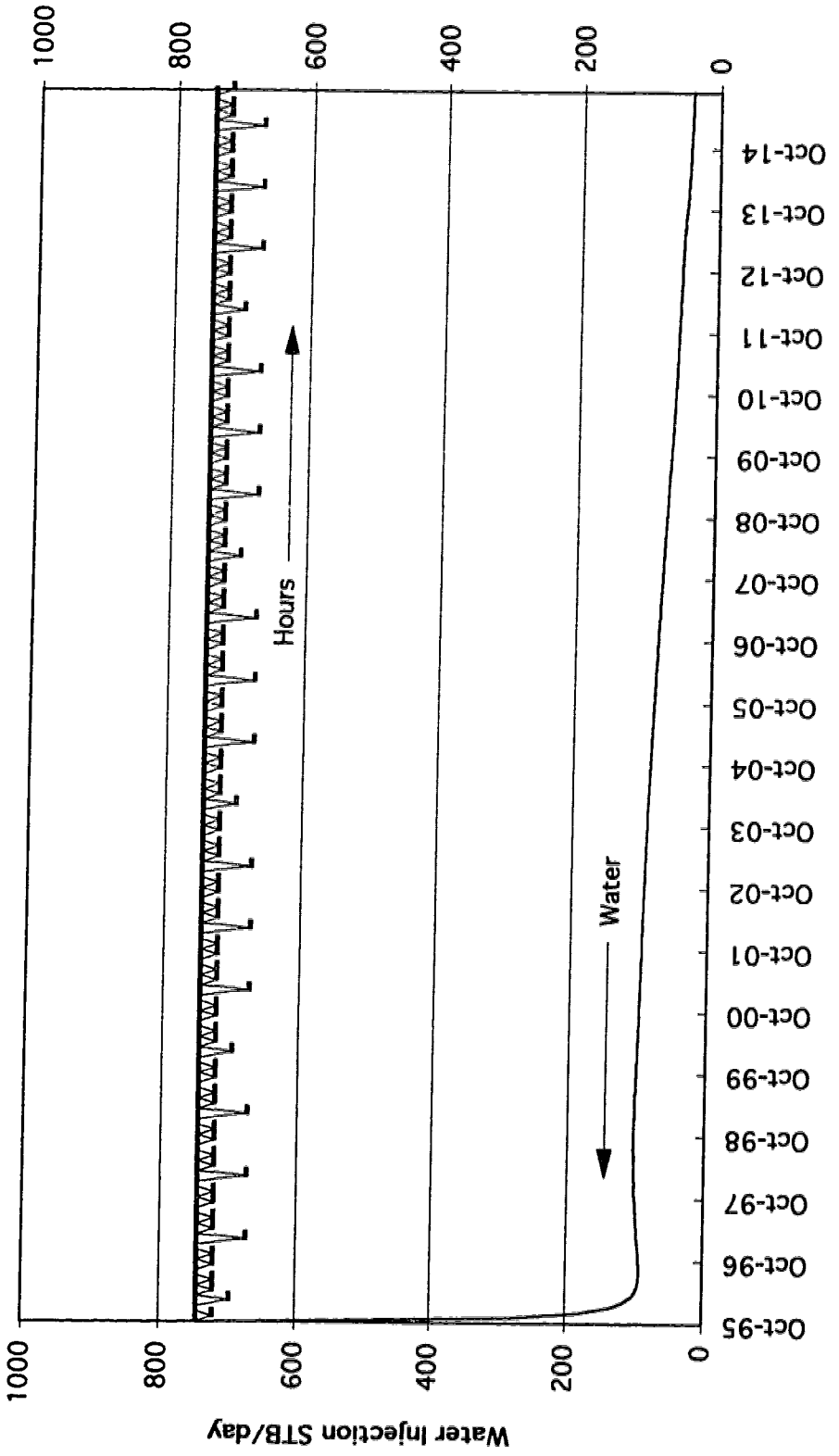



Figure 6.3(g): Waterflood Injection Forecast (04-16-37-7W5)

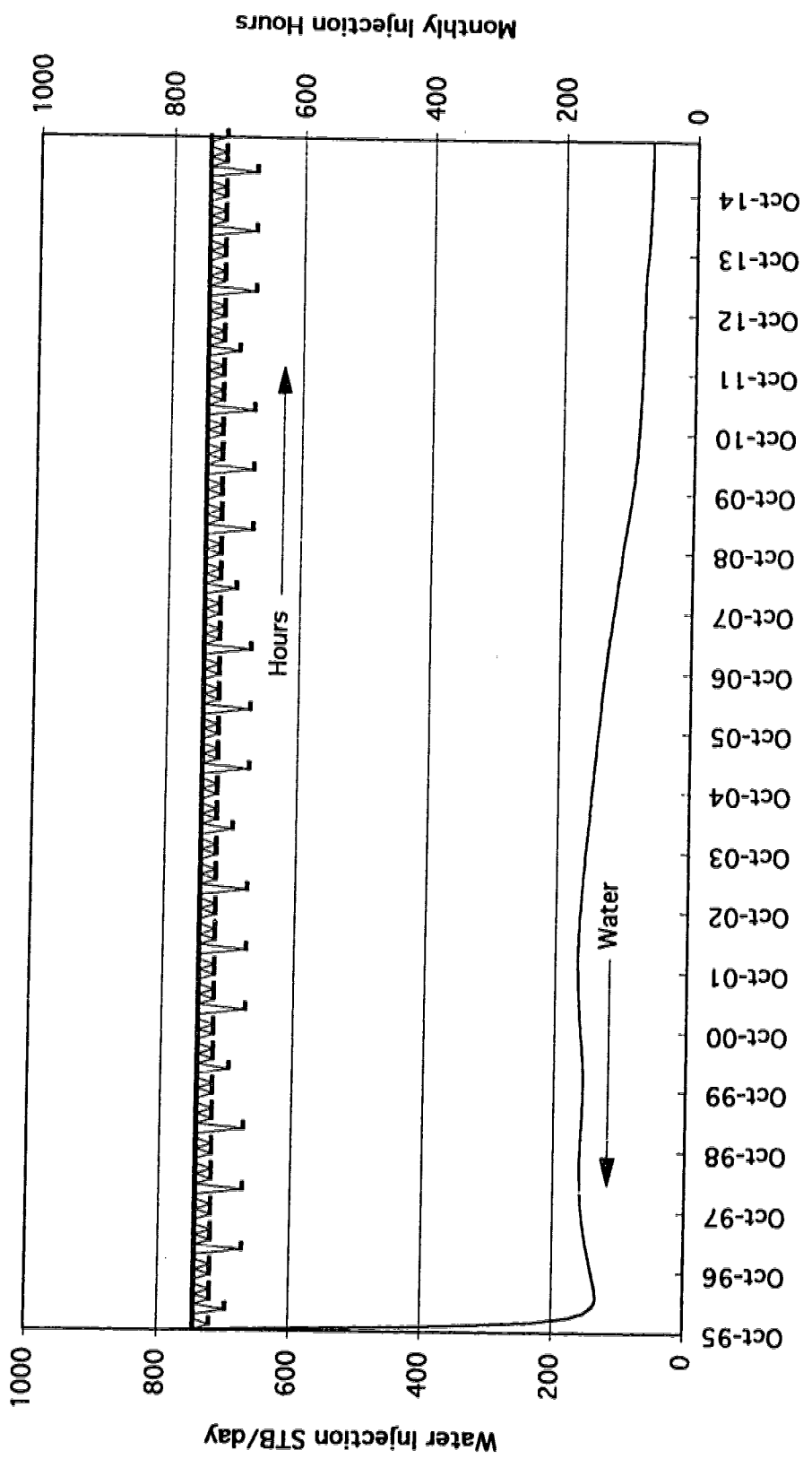



Figure 6.3(h): Waterflood Injection Forecast (02-17-37-7W5)

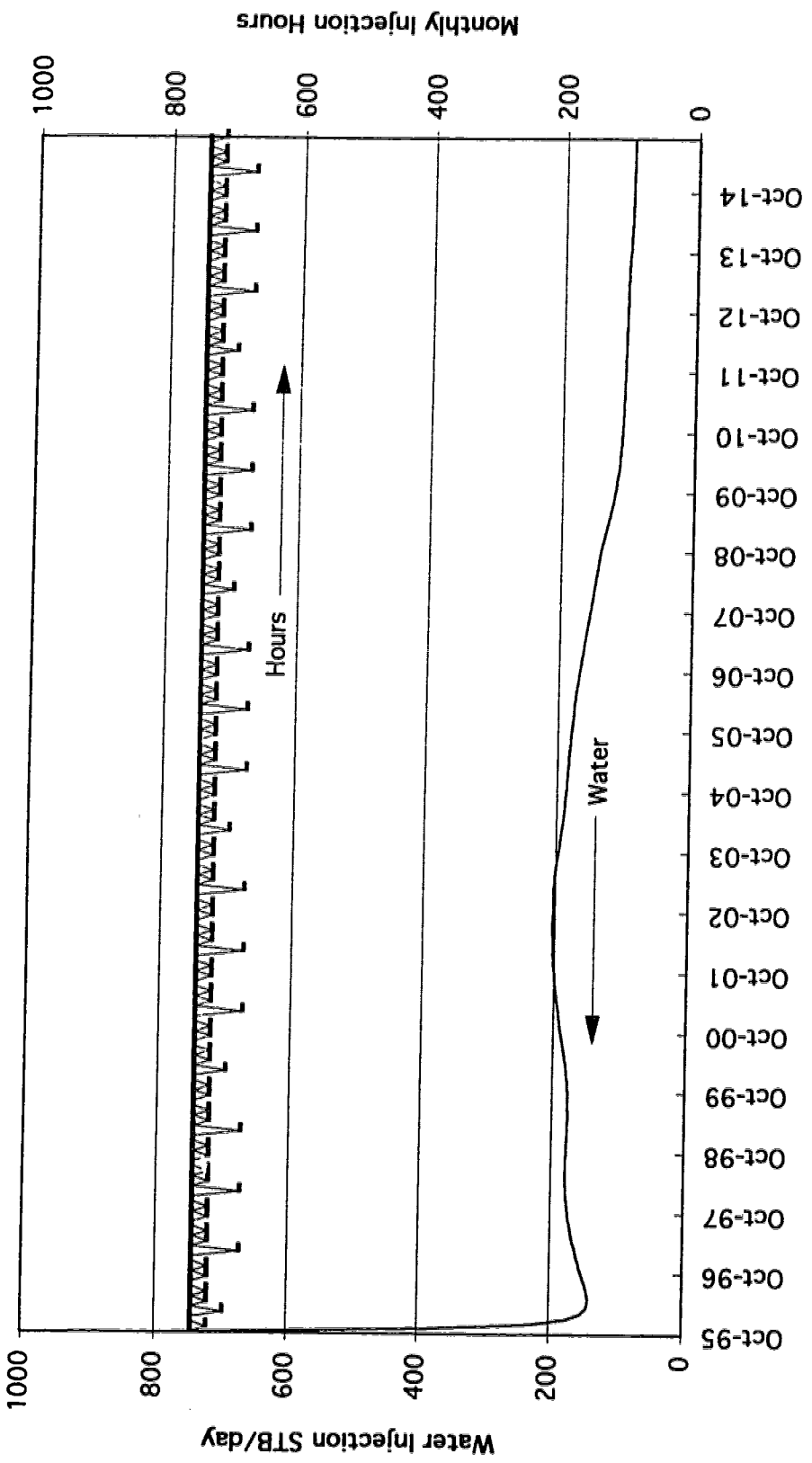



Figure 6.3(i): Waterflood Injection Forecast (04-17-37-7W5)

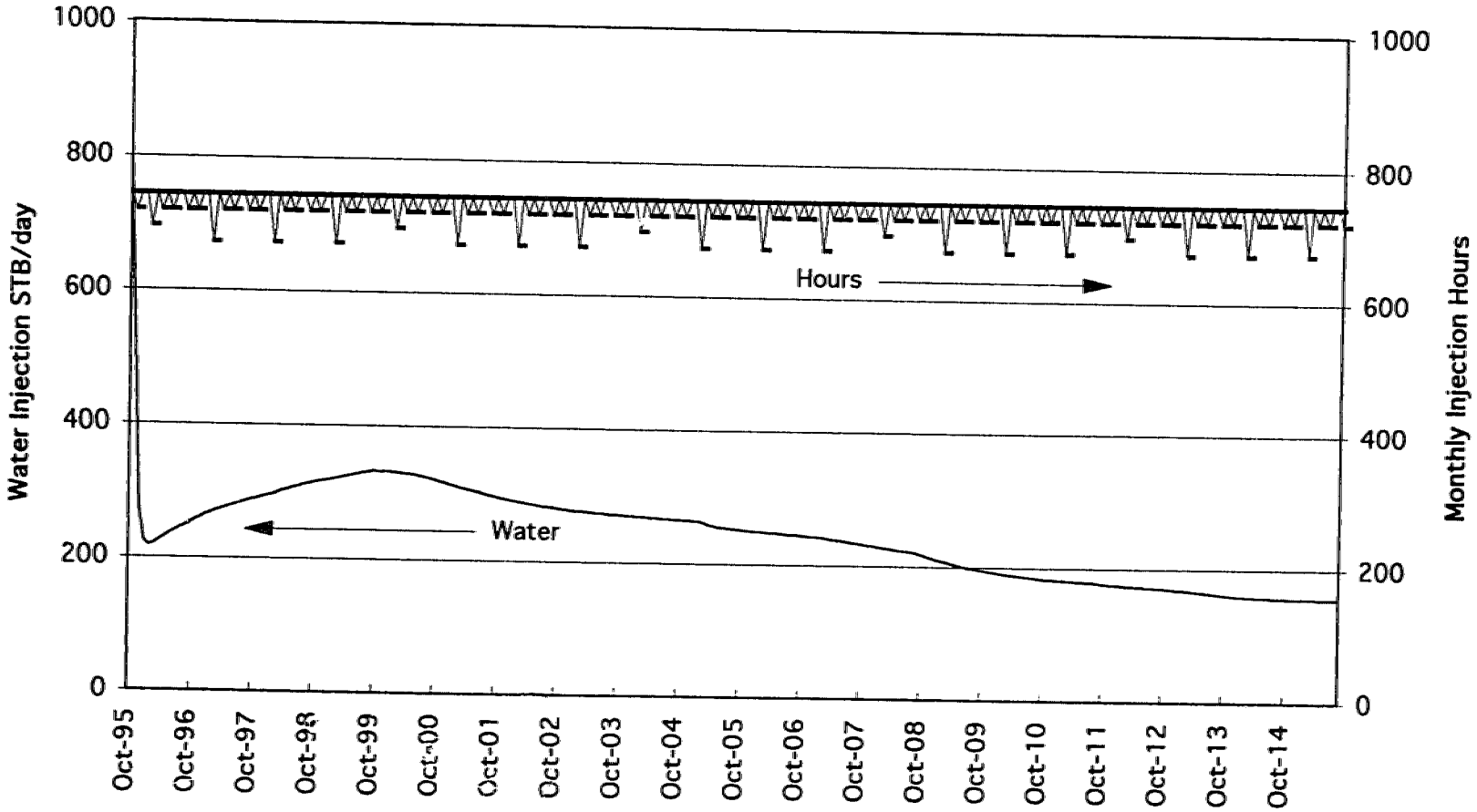



Figure 6.3(j): Waterflood Injection Forecast (02-18-37-7W5)

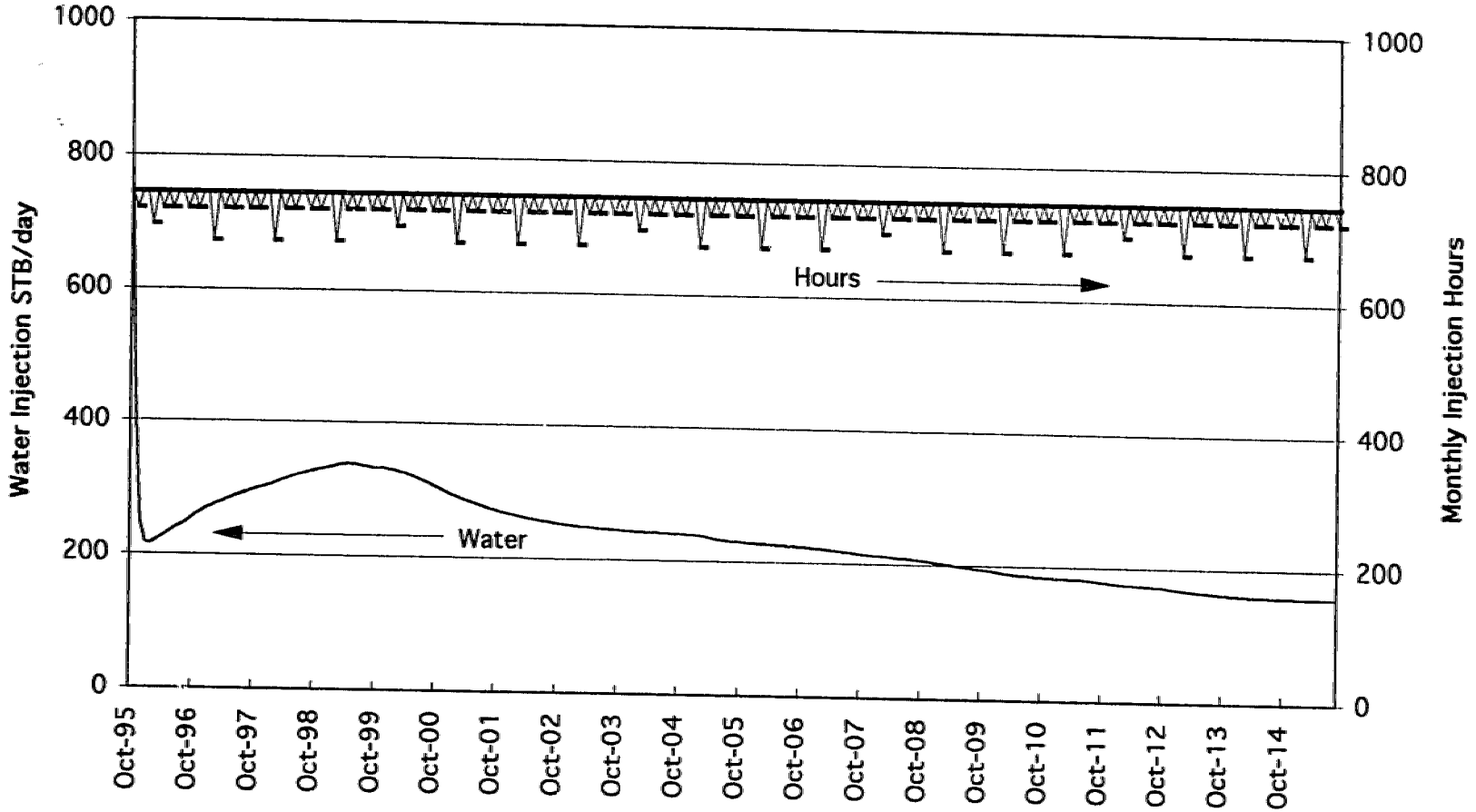



Figure 6.3(k): Waterflood Injection Forecast (04-18-37-7W5)

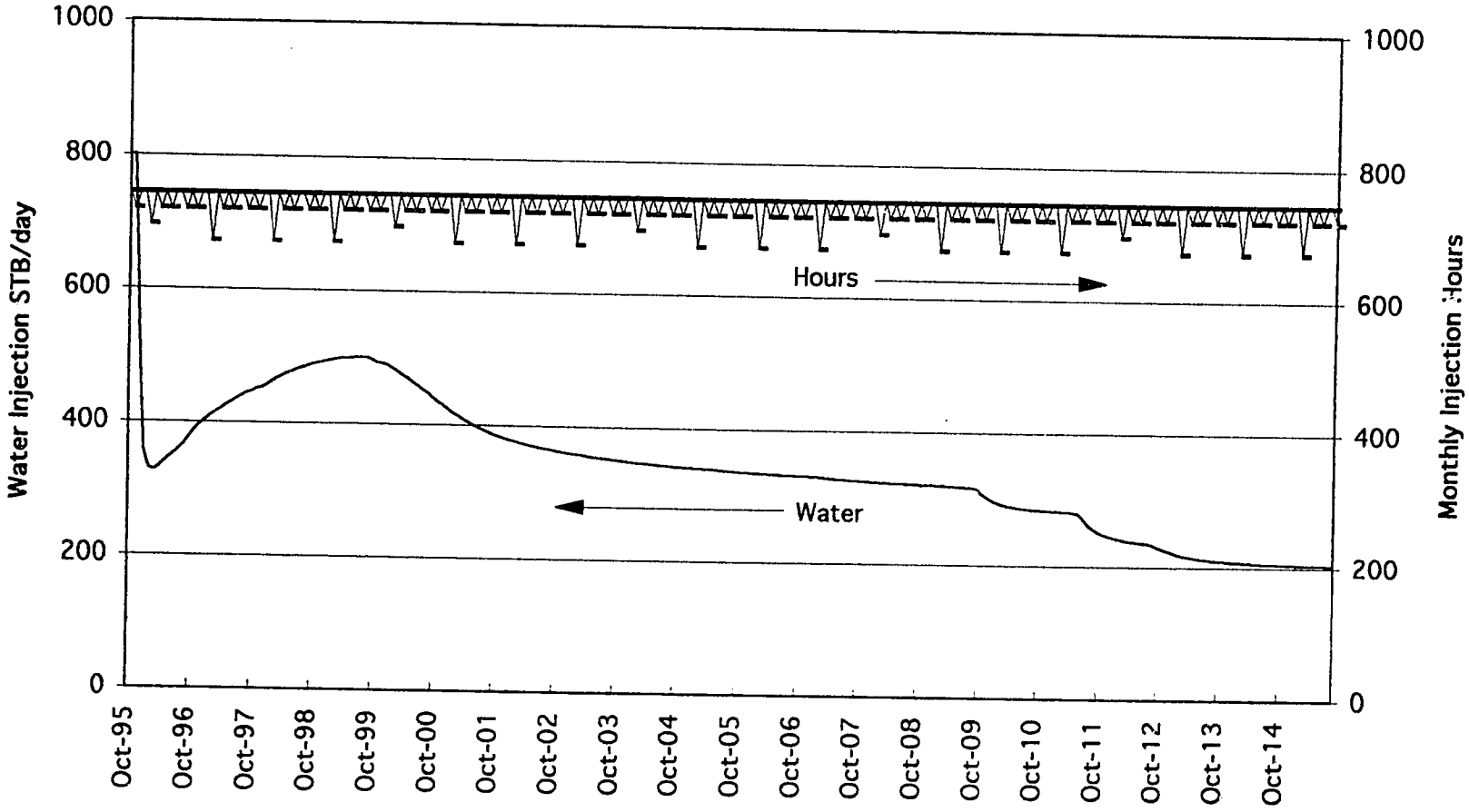



Figure 6.3(I): Waterflood Injection Forecast (10-12-37-8W5)

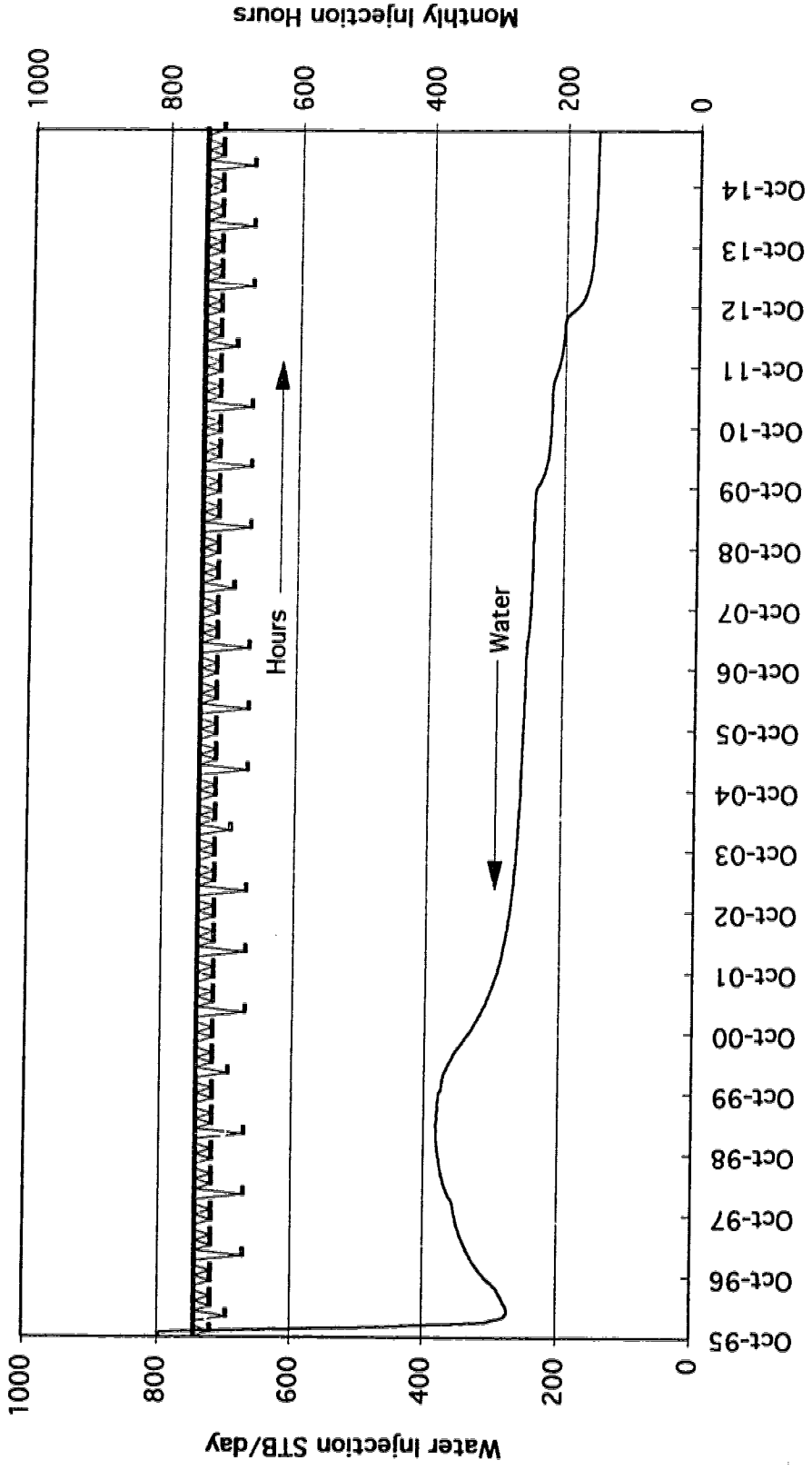



Figure 6.3(m): Waterflood Injection Forecast (12-12-37-8W5)

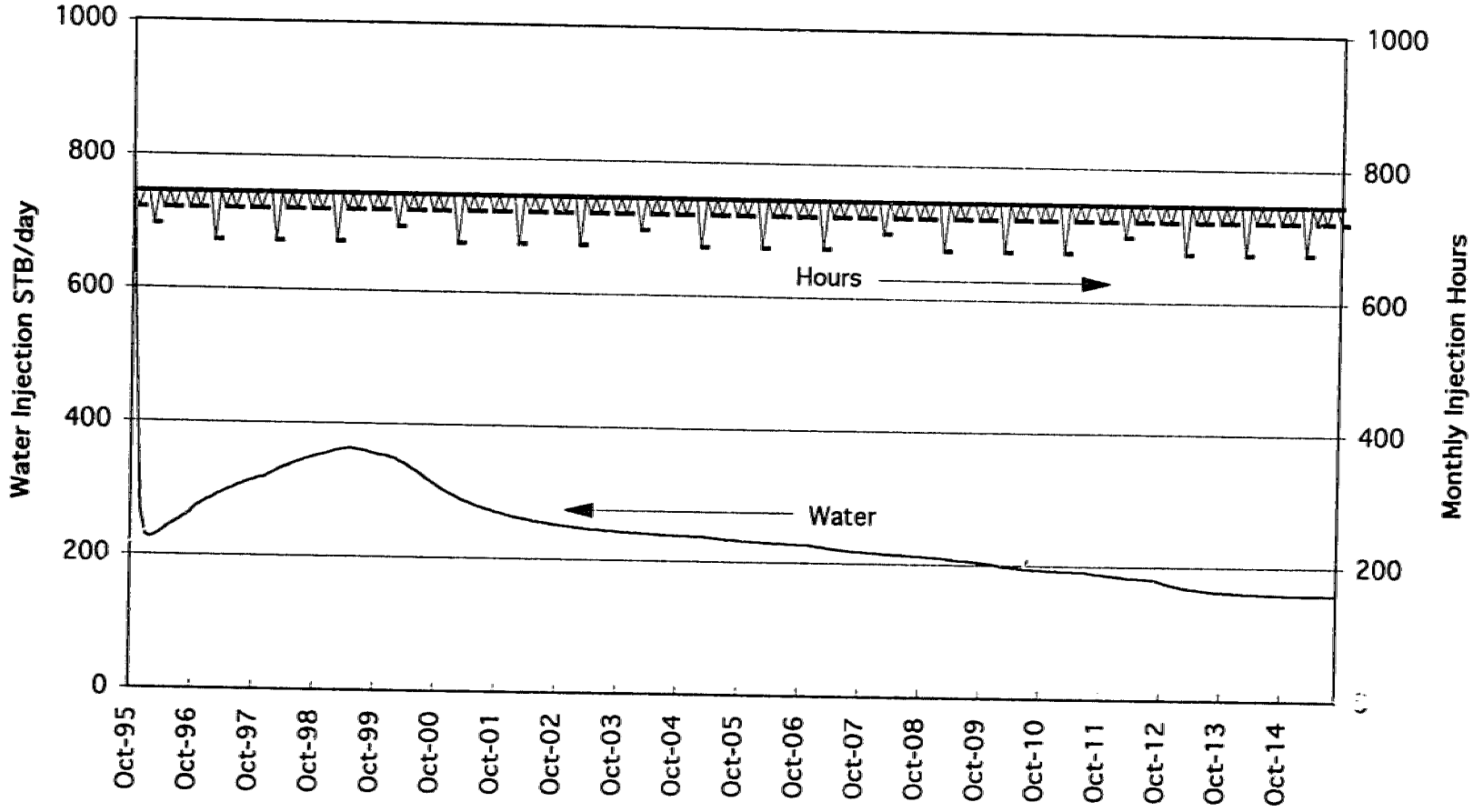



Figure 6.3(n): Waterflood Injection Forecast (02-13-37-8W5)

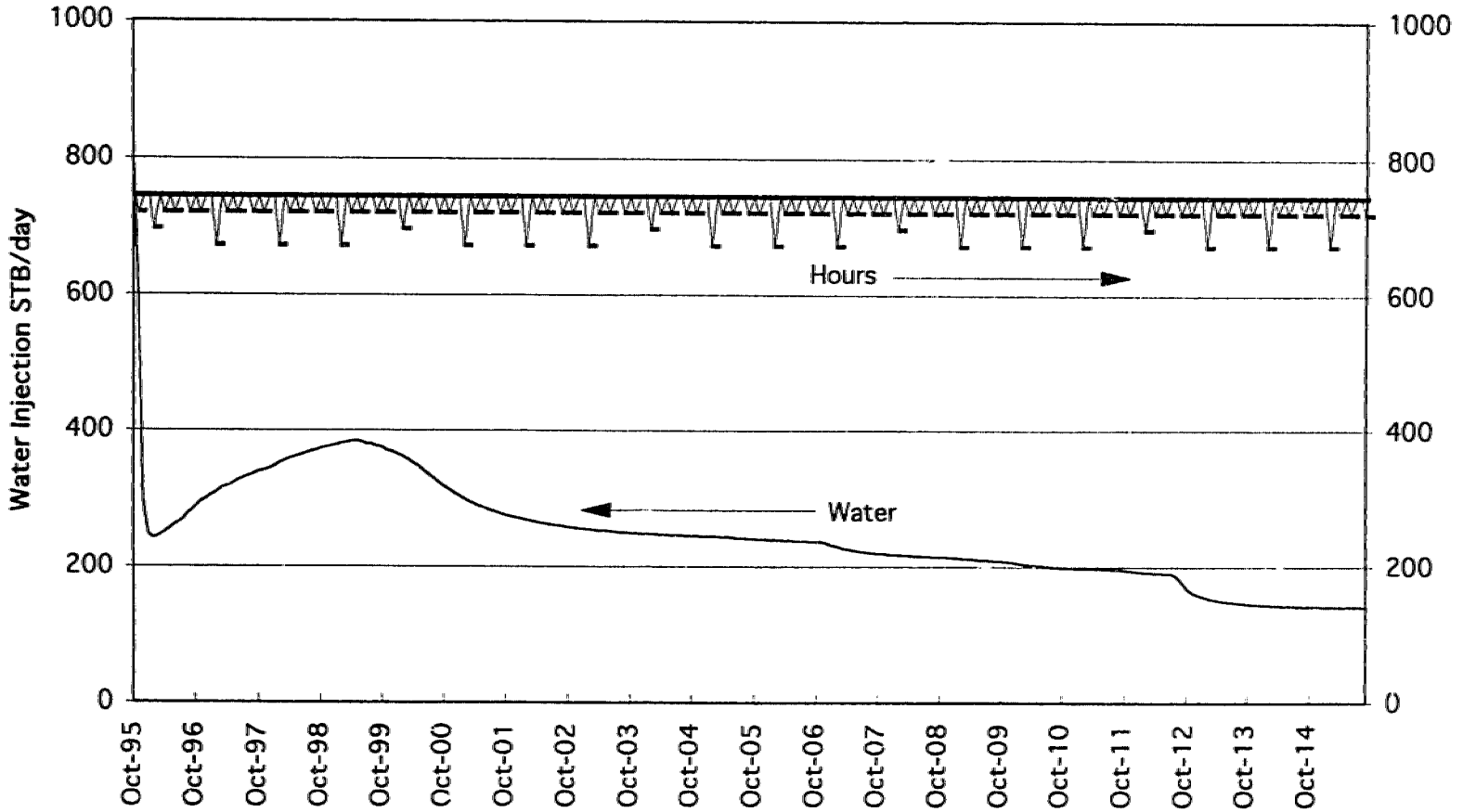



Figure 6.3(o): Waterflood Injection Forecast (04-13-37-8W5)

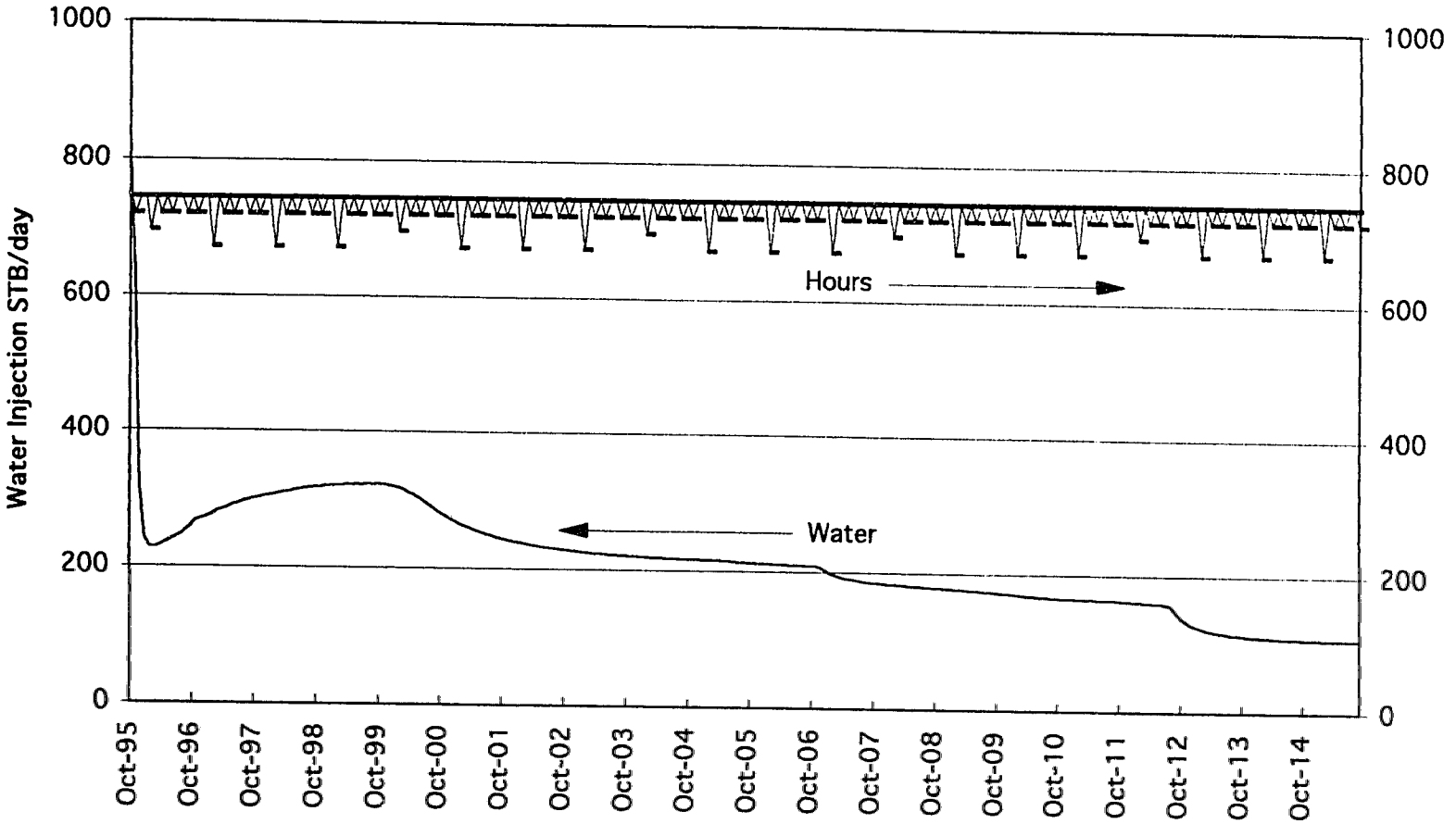



Figure 6.3(p): Waterflood Injection Forecast (02-14-37-8W5)

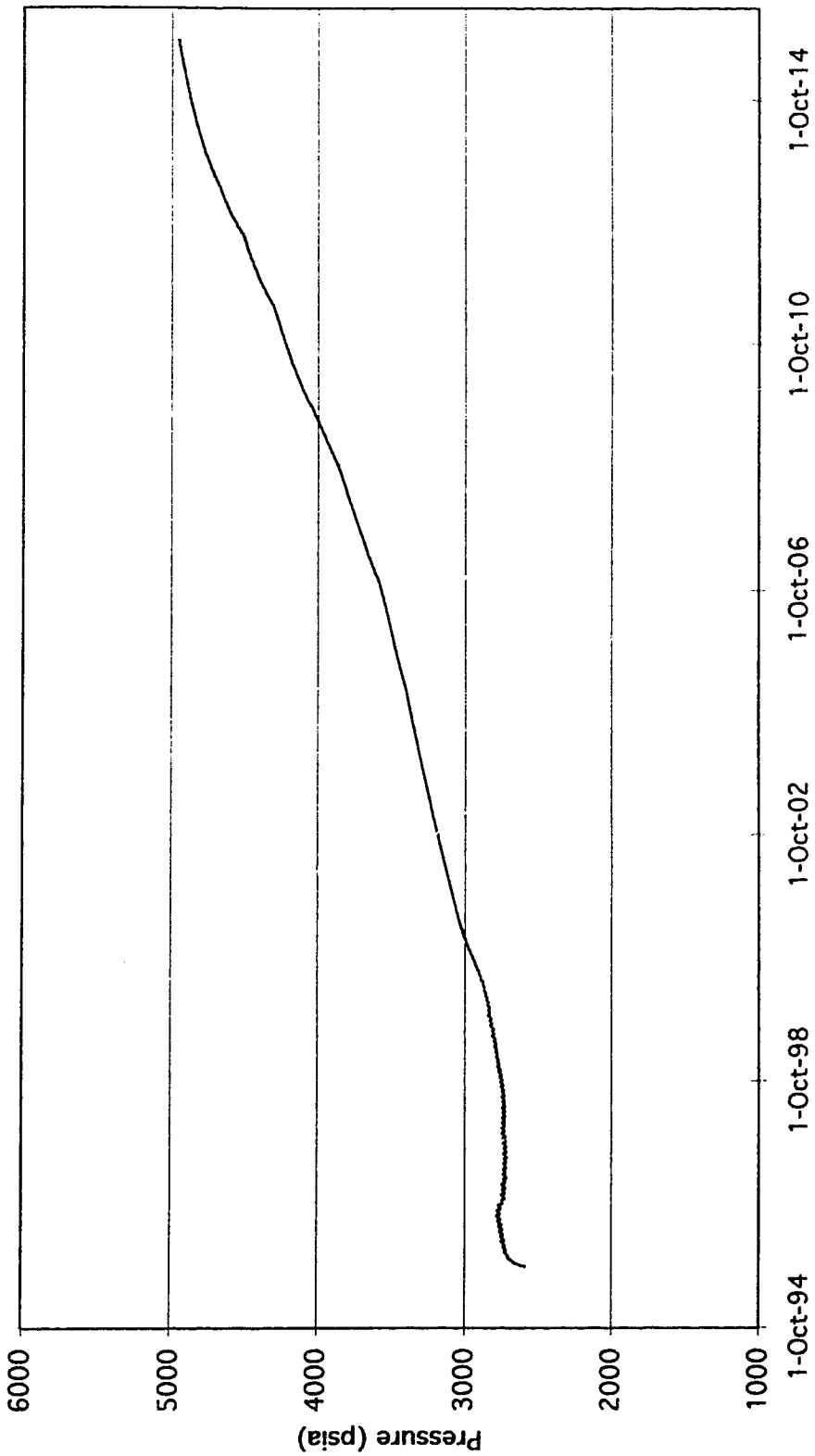



Figure 6.4(a): Waterflood Average Reservoir Pressure Prediction

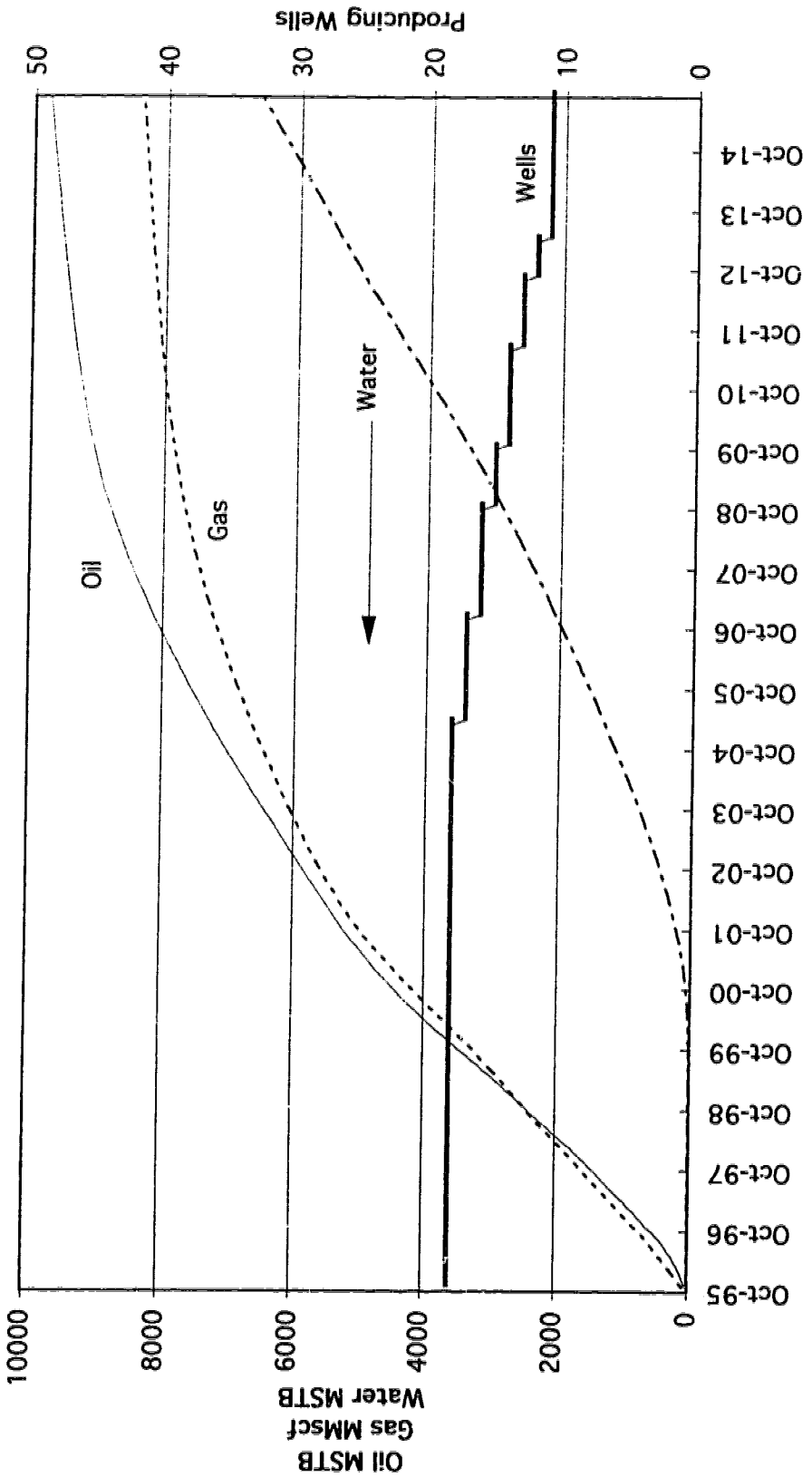



Figure 6.4(b): Pool Cumulative Waterflood Production Forecast

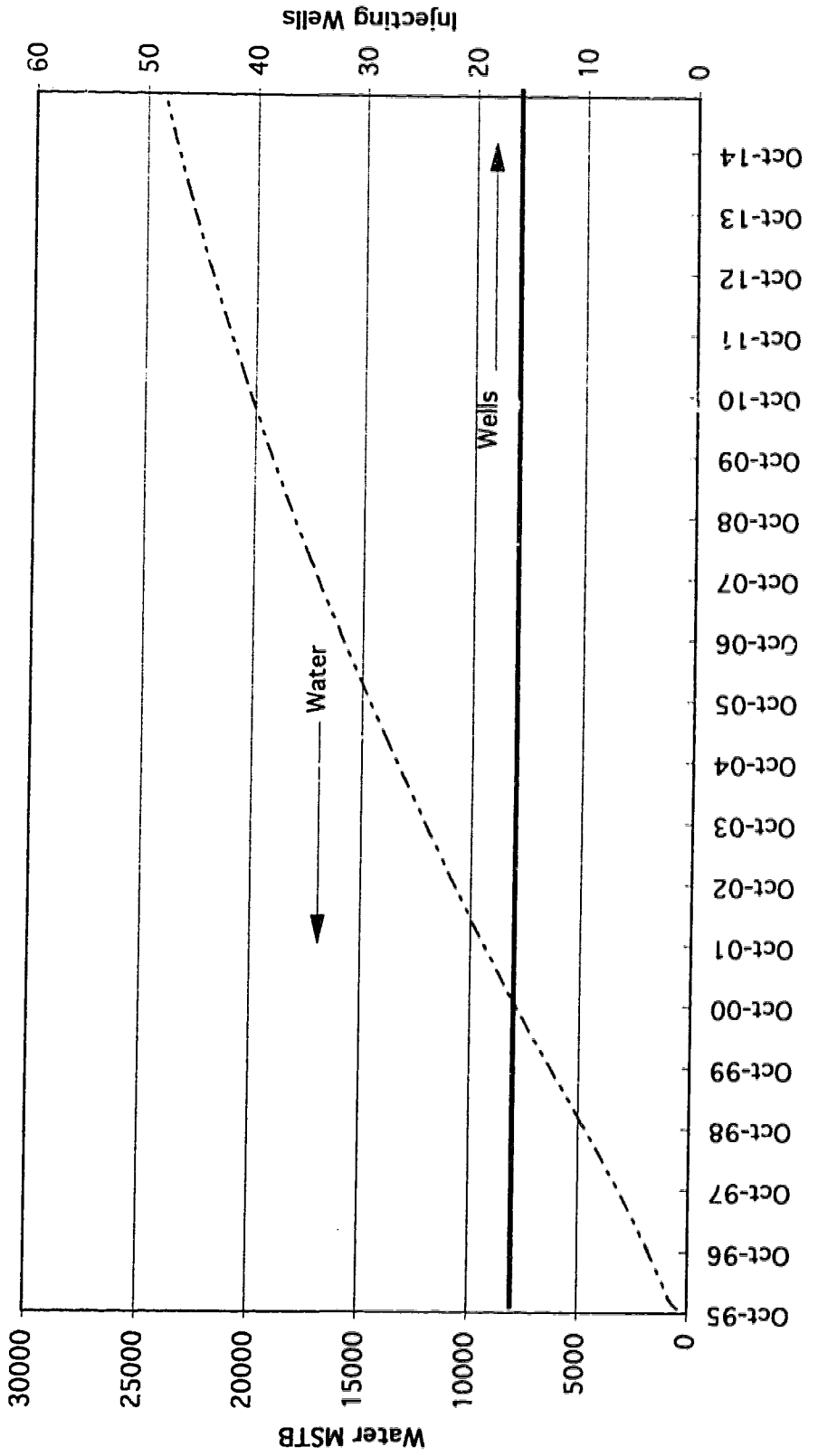



Figure 6.4(c): Pool Cumulative Waterflood Injection Forecast

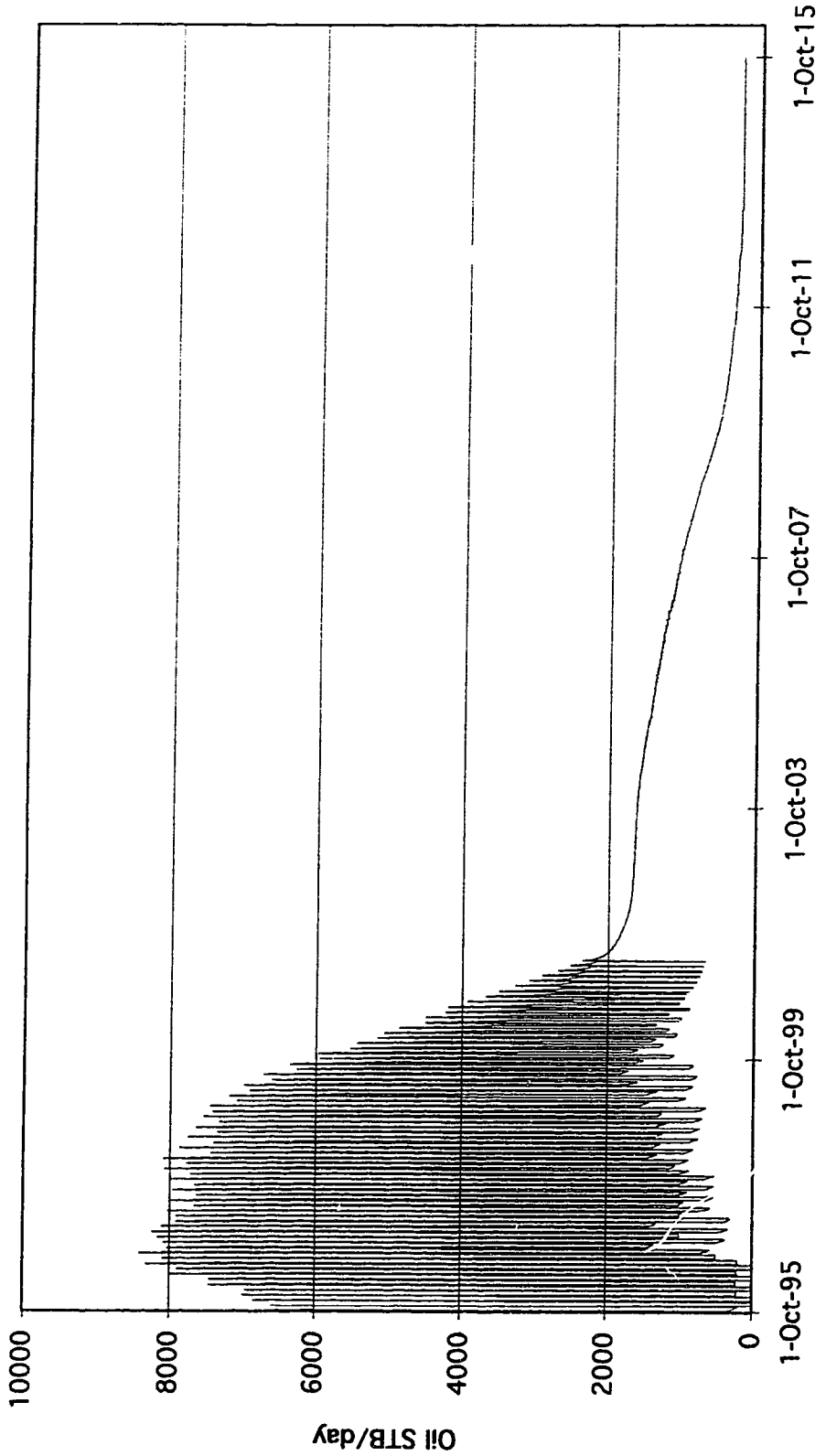



Figure 6.5(a): Pool Waterflood Oil Production Rate Forecast

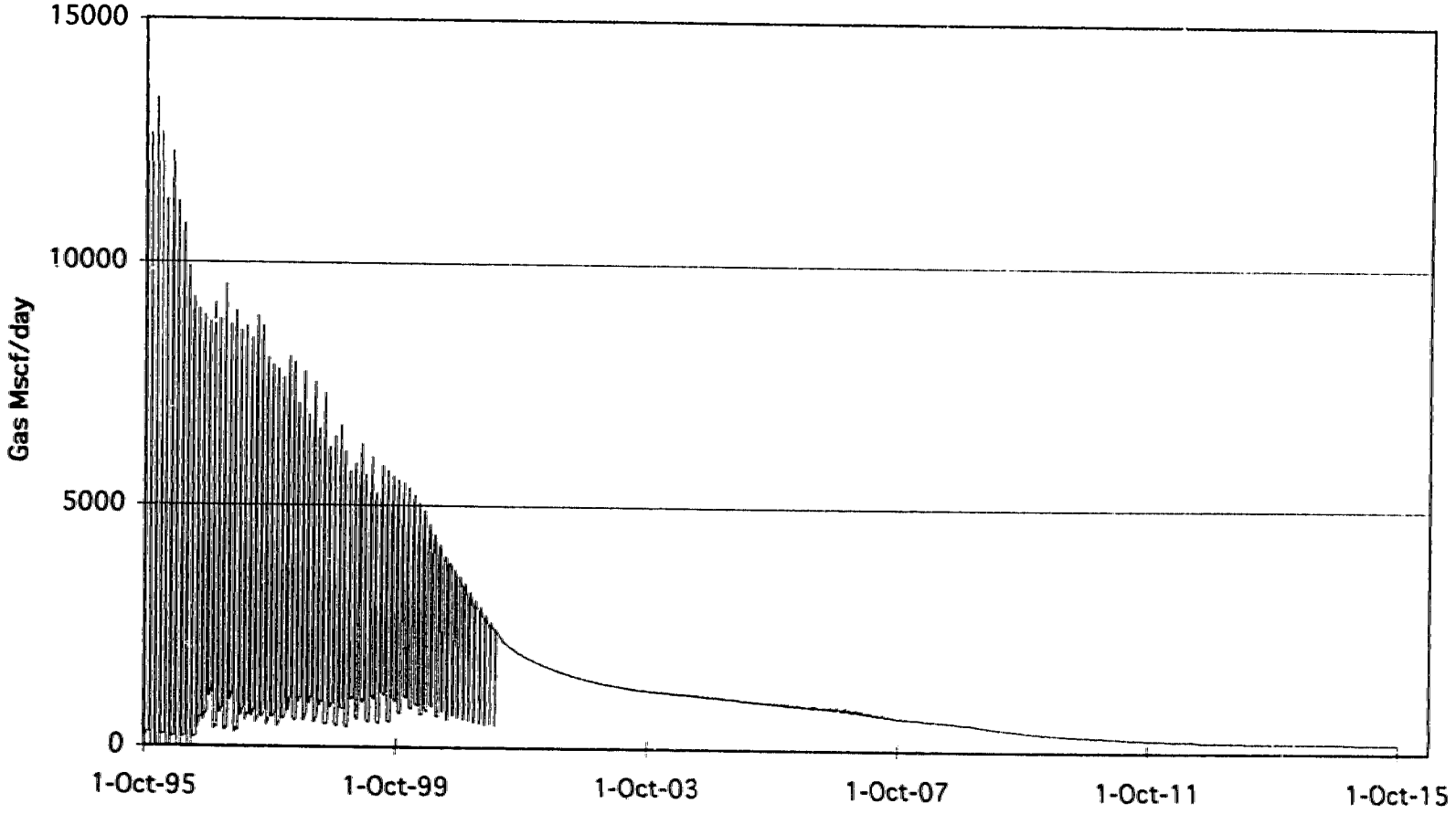



Figure 6.5(b): Pool Waterflood Gas Production Rate Forecast

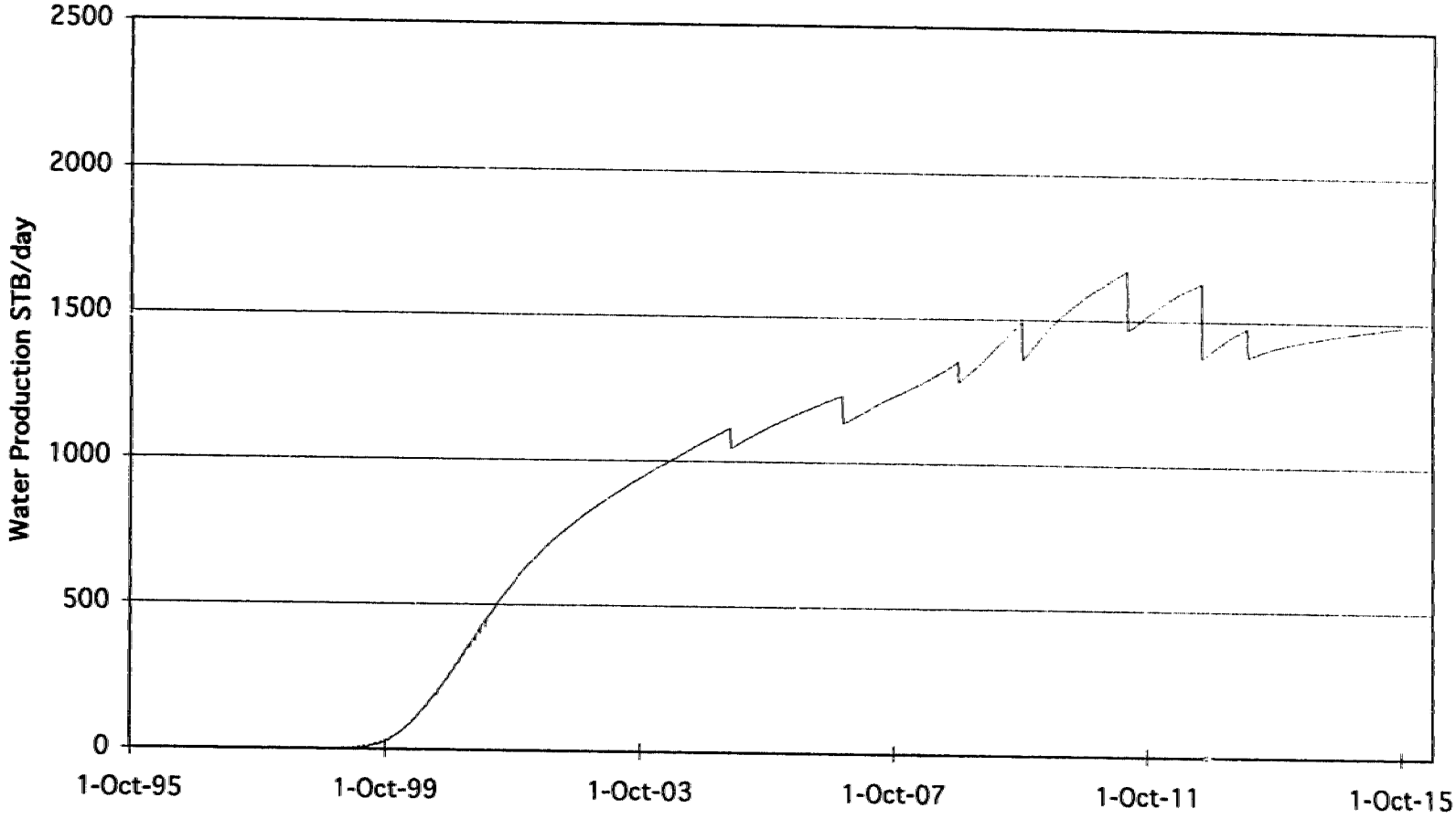



Figure 6.5(c): Pool Waterflood Water Production Rate Forecast

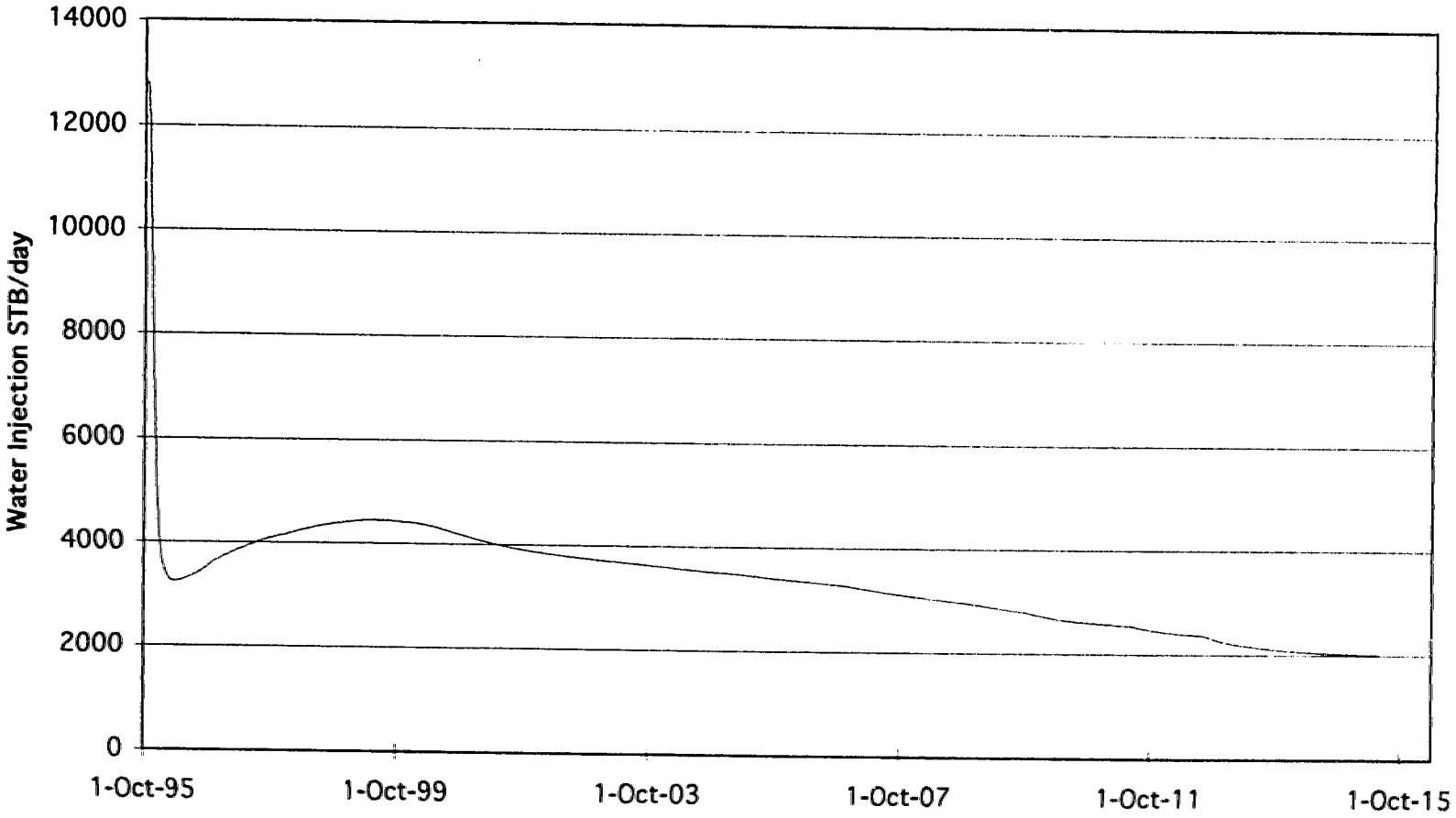



Figure 6.5(d): Pool Waterflood Water Injection Forecast

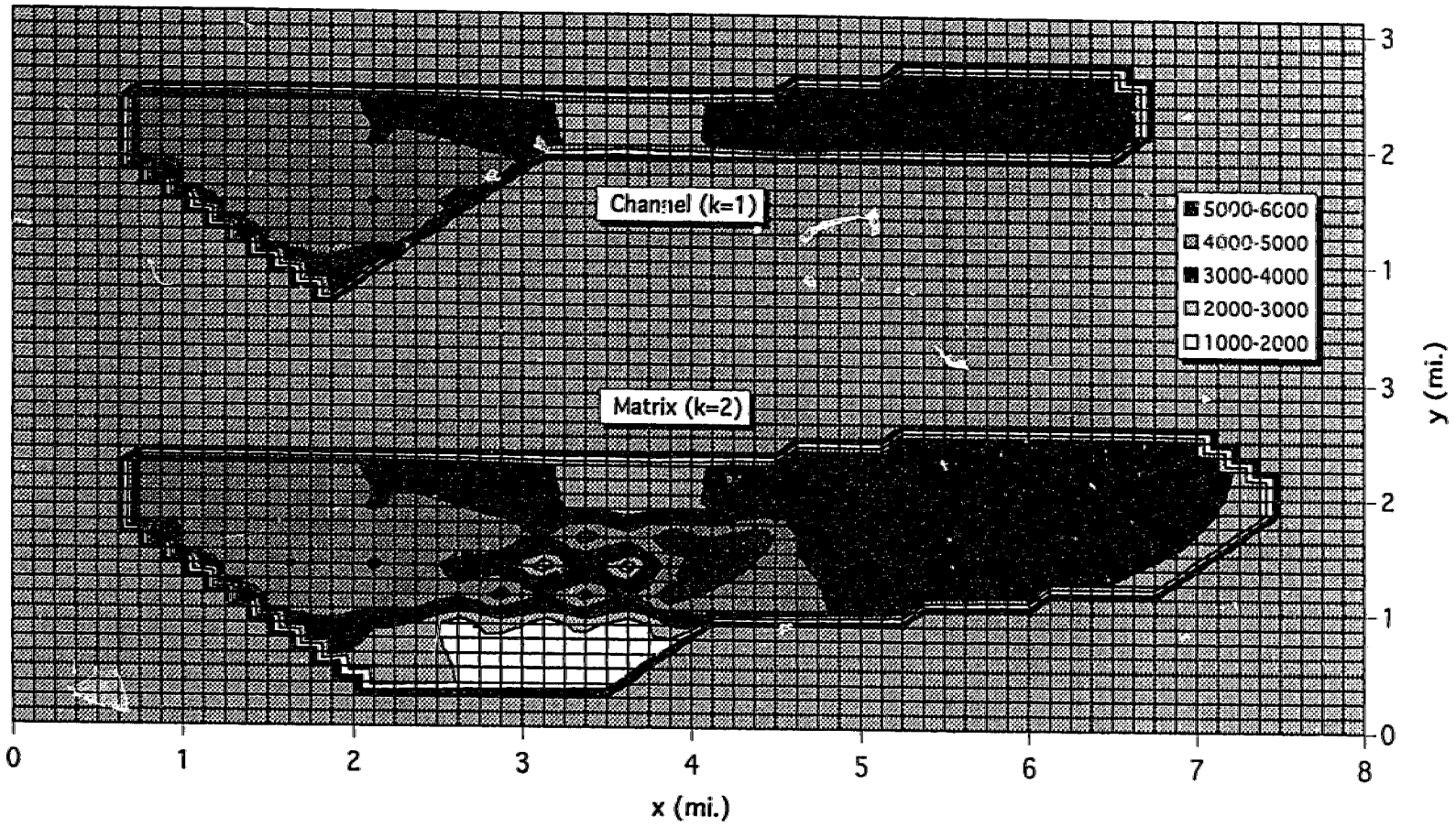



Figure 6.6(a): Waterflood (Oct-07) Pressure p (psia)

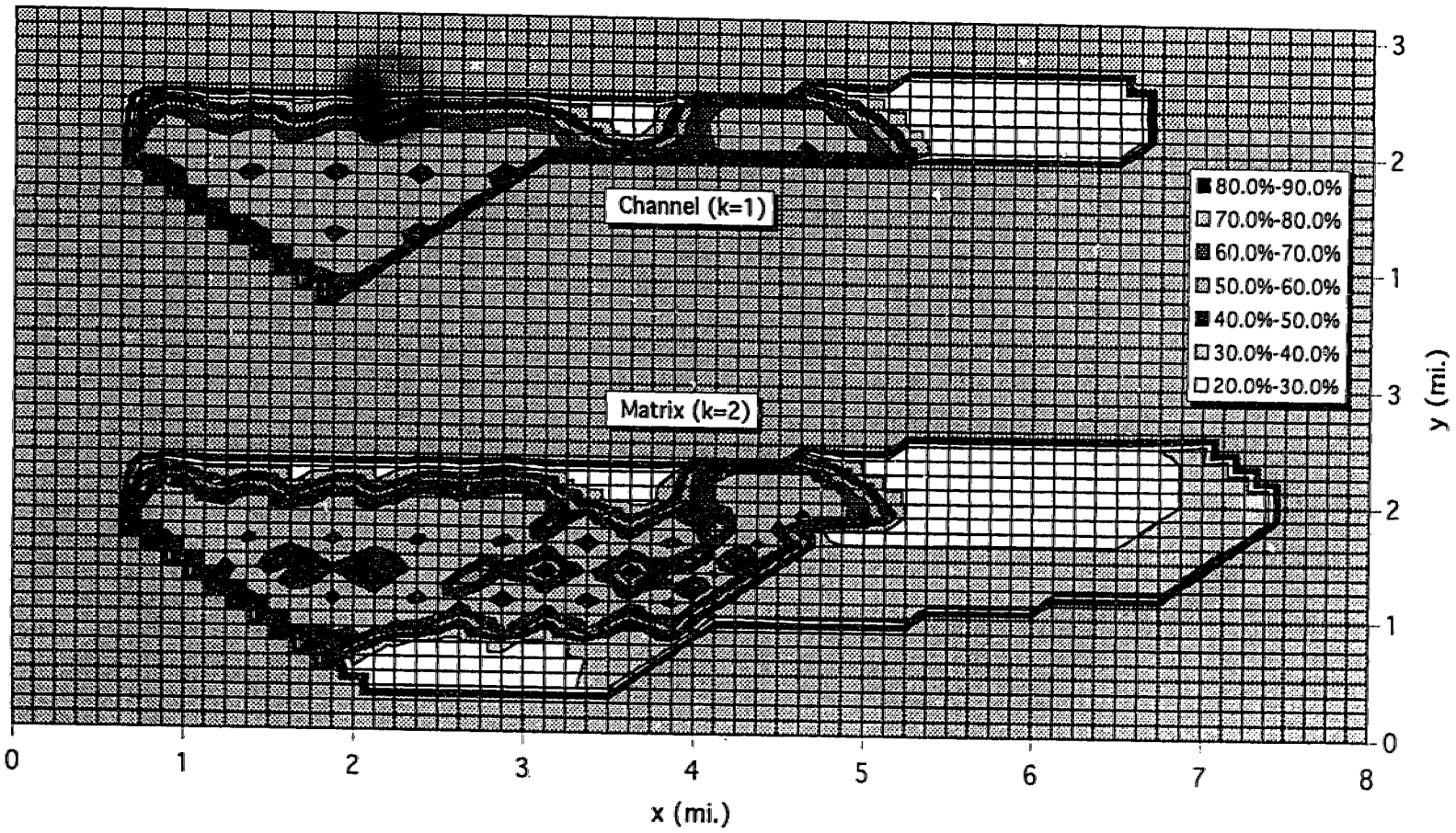



Figure 6.6(b): Waterflood (Oct-07) Water Saturation $S_w$

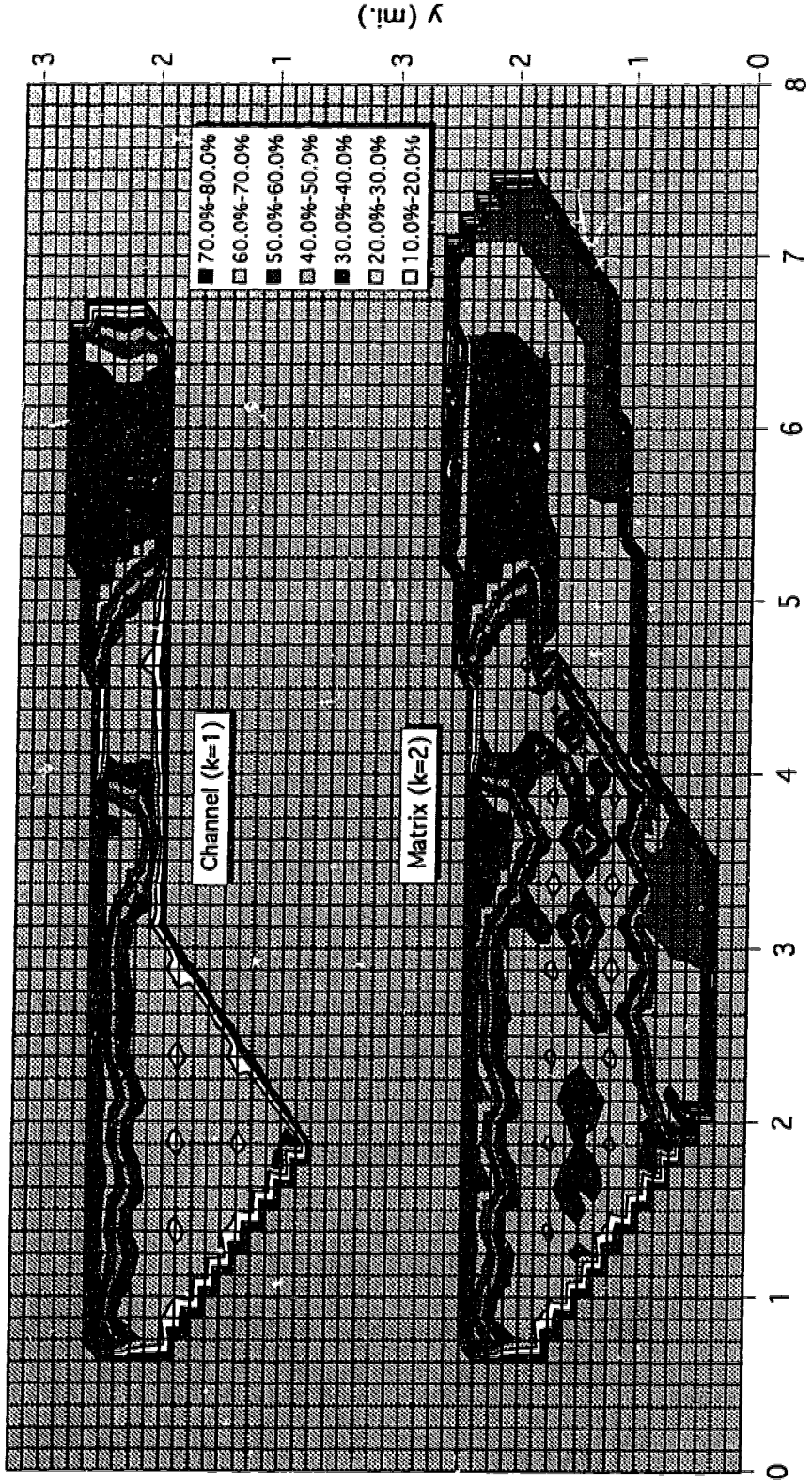



Figure 6.6(c): Waterflood (Oct-07) Oil Saturation $S_o$

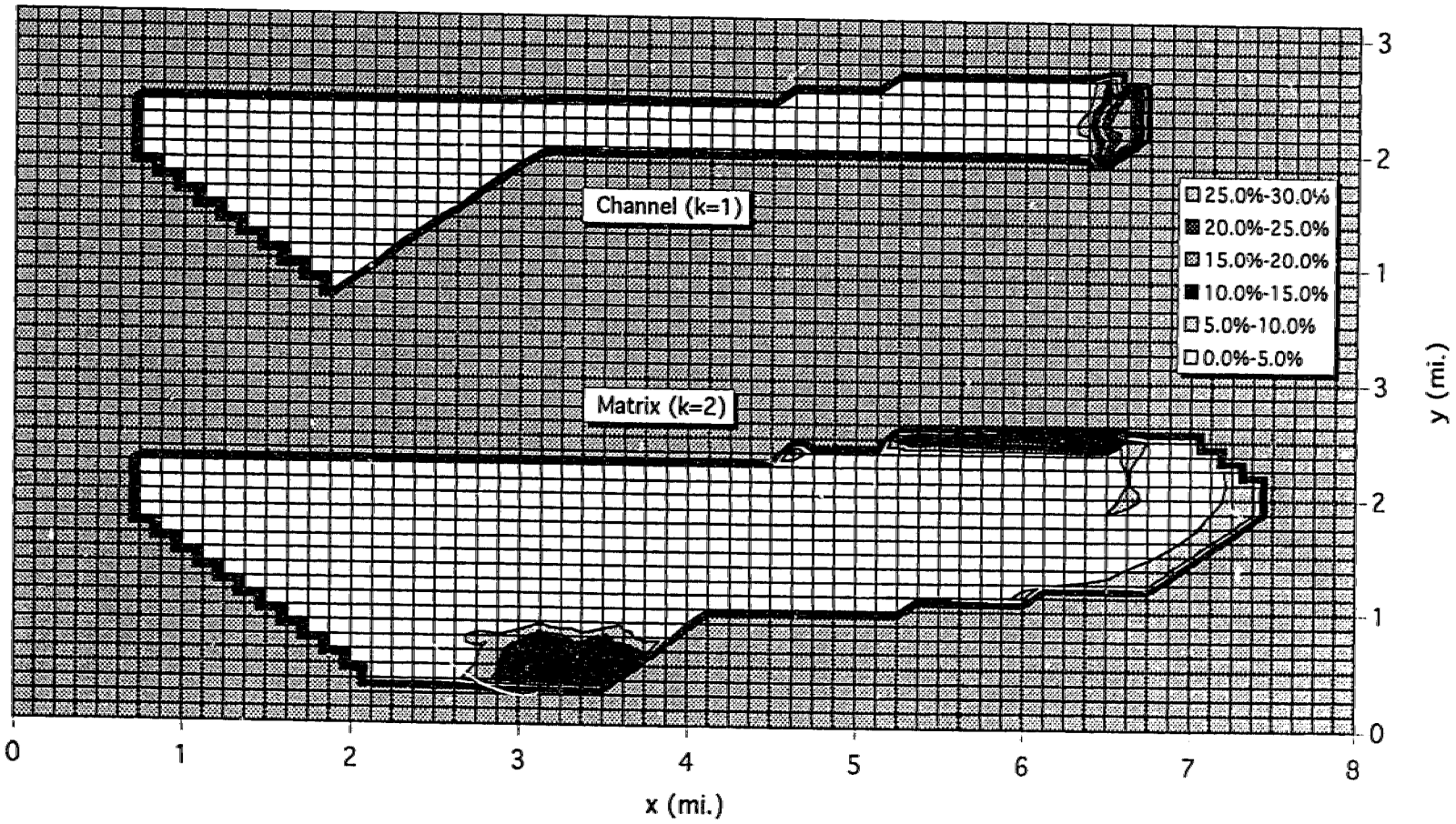



Figure 6.6(d): Waterflood (Oct-07) Gas Saturation $S_g$

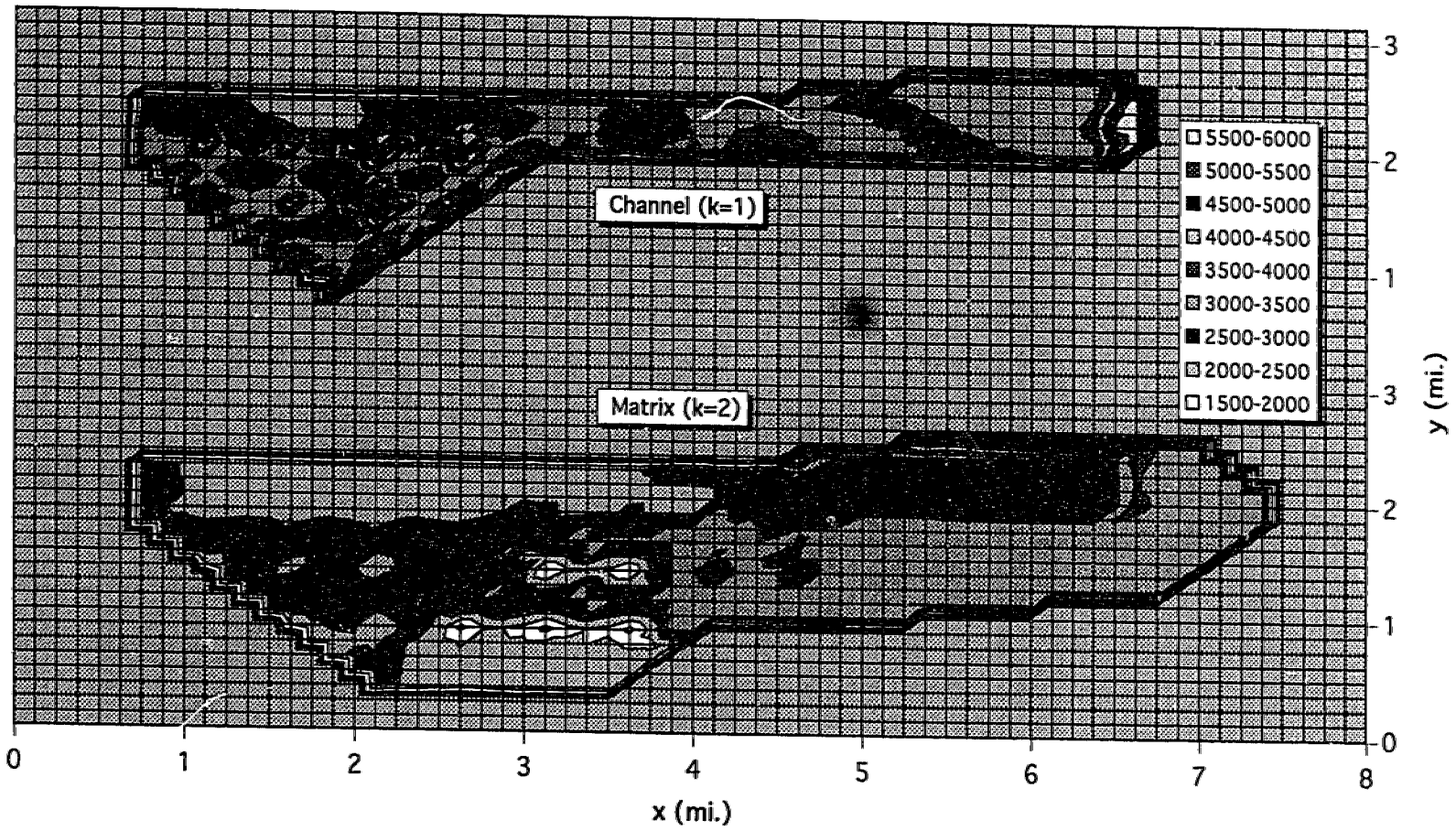



Figure 6.6(e): Waterflood (Oct-07) Bubble Point $p_b$ (psia)

# Chapter 7: Reservoir Depletion Paths

## 7.1 Path-Dependent Production Trees

Production forecasts for secondary recovery will depend on the originating reservoir state of primary operations and the control policy (Figure 7.1). Discrete timing response is represented by production branches on a forecast tree.

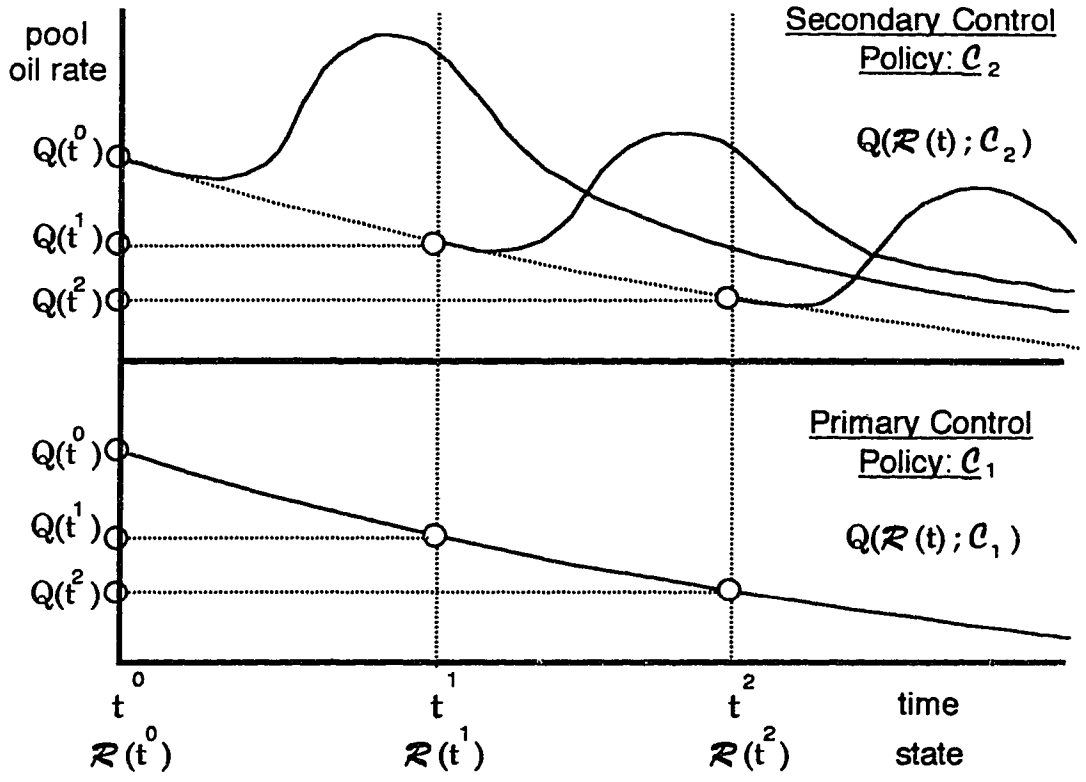



Figure 7.1: Path Dependence of Production Forecast

Project evaluation will be based on cash flow projections for the entire pool. Operating and investment timing decisions will choose between mutually exclusive production alternatives. Cash flows will depend on the contemporaneous pooled production rate Q(t).

$$Q(t) = \sum_{\text{Producers}} Q(t) \qquad (7.1)$$

The pooled oil production rate $Q_o(t)$ will depend on the reservoir state $\mathcal{R}(t)$ and the control policy $\mathcal{C}$. The reservoir state $\mathcal{R}(t)$ is determined by the state variables $(p, S_w, S_g)$ which are distributed in both space and time. The active control policy will depend on the reservoir state and the recovery stage: $\mathcal{C}_1$ for primary control and $\mathcal{C}_2$ for secondary waterflood control. Controls will be distributed in time at particular points in the reservoir space. Continuous forecasting of path-dependent secondary recovery is virtually intractable. Consequently, decision pathways are confined to discrete secondary timing options only (Figure 7.2).

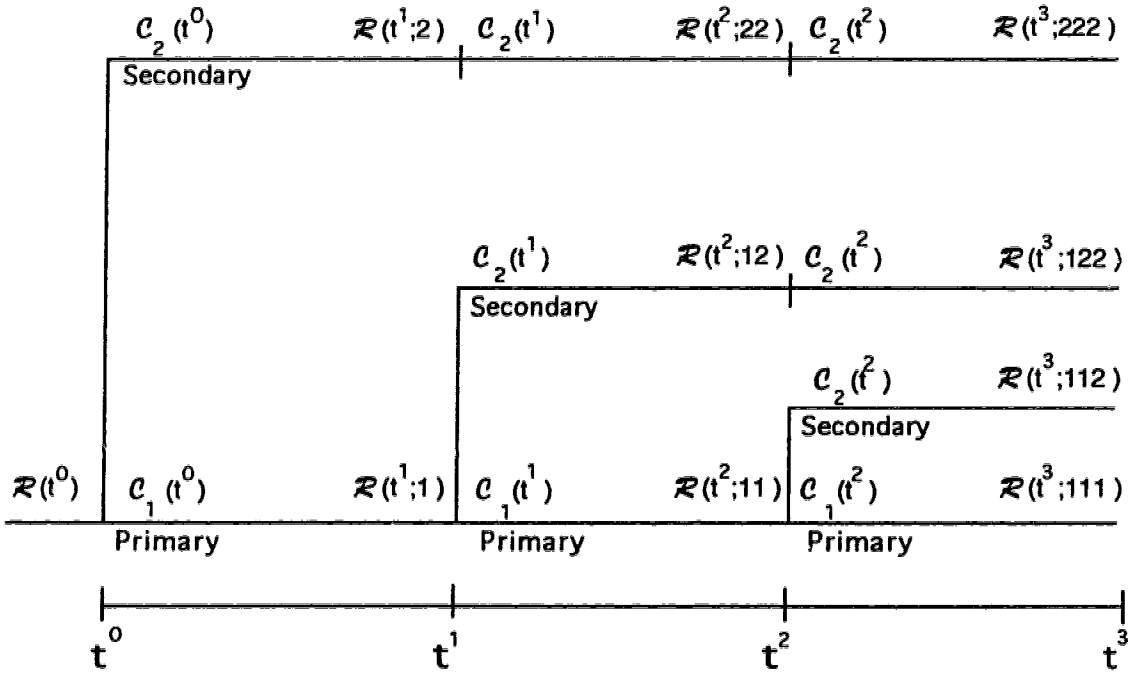



Figure 7.2: Reservoir State Possibilities for Irreversible Mutually-Exclusive Decision Pathways.

## 7.2 Operational Modes

Operational modes will depend on the probability structure of macro-economic scenarios. The model system considers an early abandonment option and temporary suspensions of pooled production[18]. Three modes of operation will apply for each recovery stage:

- production under active control policy
- temporary suspension of pooled field-wide production
- early abandonment

These operational modes are context sensitive to the contemporaneous recovery stage. Primary and secondary recovery stages will have their own operating policies that establish decision rules for switching between operational modes.

If the early abandonment option is exercised, then the overall project will be terminated and all wells will be permanently shut in. This is a terminal mode that prunes all future branches and sets the production rate $Q(t)=0$ for all future time. Early abandonment may result from a contemporaneous shift in the economic limit due to low oil price expectations.

All operating wells will be collectively shut in if the contemporaneous recovery stage is suspended. The pooled production rate is $Q(t)=0$ while in suspended mode. This mode can occur when the contemporaneous oil price dips below a critical price level and the compounded value of fixed costs is less than the abandonment expense. Suspension is a reversible mode. The operation can switch back and forth between active production and pooled suspension modes. Because of the transient nature in the physical mechanisms governing porous media flow, the reservoir will change state along two different depletion pathways in response to the two control possibilities under active or suspended production modes. This implies that when the price changes state about the critical level, bifurcation in future control becomes path dependent on past actions (Figure 7.3). Bifurcation in reservoir depletion paths on each transition about the critical switching price cascades future control, investment and abandonment decisions into a infinite myriad of combinatorial instances.

---

18 A more rigorous analysis would consider the suspension policy for individual wells. This would involve a combinatorial exploration over an increased space of depletion state transitions. This is beyond the computational capacity of the present model with the available hardware.

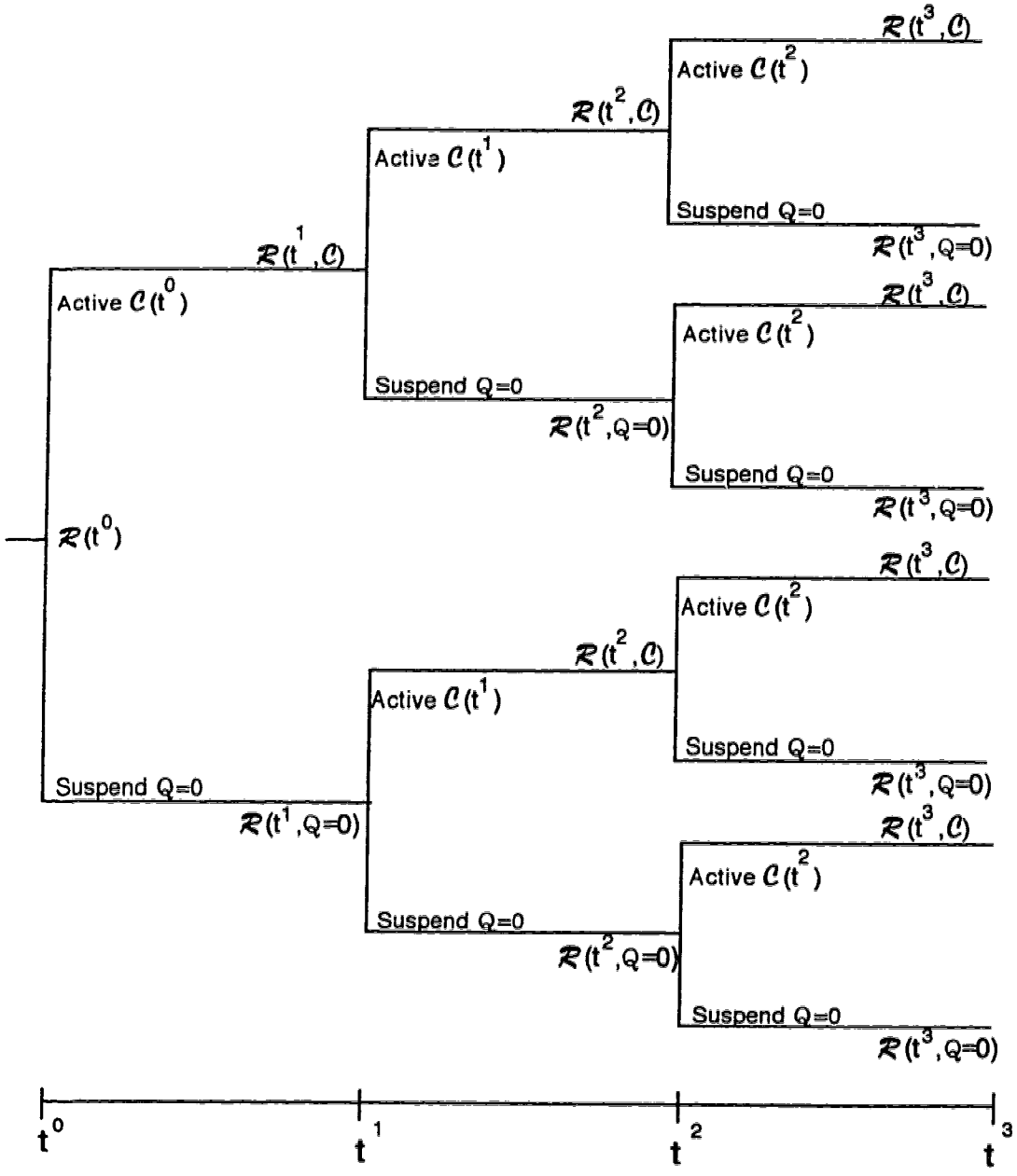



Figure 7.3: Path-Dependent Control and Bifurcation of Depletion Paths from Switching Operation Modes

## 7.3 Near-State Variables

Reservoir depletion paths determine oil production from the pool. These paths are not only functions of time, but also functions of the nested operating and control policies that depend on the reservoir depletion state. The dimension of reservoir state variables and bifurcating depletion paths complicate the deterministic measurement for contemporaneous production response and the prediction of future production rates. The model system deals with this problem by approximating the true reservoir state with near-state variables. Primary and secondary near-state variables ($\mathcal{P}_1$, $\mathcal{P}_2$) are defined as the cumulative pooled oil production from respective recovery stages.

$$\mathcal{P}_1(t) = \int_{t^0}^{t} Q_o(\tau)d\tau = \sum_{\substack{\text{primary}\\ \text{producers}}} \int_{t^0}^{t} Q_o(\tau)d\tau \qquad \text{Primary Production}$$

$$\mathcal{P}_2(t) = \int_{t^0}^{t} Q_o(\tau)d\tau = \sum_{\substack{\text{secondary}\\ \text{producers}}} \int_{t^0}^{t} Q_o(\tau)d\tau \qquad \text{Secondary Production} \qquad (7.2)$$

The model assumes that primary production rates under active control policy and suspended pool operational modes can be uniquely determined as a function of the pooled cumulative primary oil production ($\mathcal{P}_1$). Furthermore, for a particular originating primary near-state ($\mathcal{P}_1$), waterflood production rates along secondary branches can be determined uniquely by the pooled cumulative secondary oil production ($\mathcal{P}_2$).

$$\begin{aligned} Q &= Q(\mathcal{P}_1) && \text{Primary Production} \\ Q &= Q(\mathcal{P}_2 ; \mathcal{P}_1) && \text{Secondary Production} \end{aligned} \qquad (7.3)$$

The argument behind this premise is based on decline curve analysis. For a particular recovery stage with a given well configuration and active control policy, the active depletion state will follow a unique path in time. Production rates that can be determined as unique functions of time, can be equivalently expressed in terms of cumulative oil production. If production were to stop suddenly, then all flowing bottomhole pressures would stabilize towards static levels. In the absence of large gravitational and interfacial forces, static pressures would reach equilibrium after a short stabilization period. If production were to resume back to the same active controls as before, then bottomhole pressures would continue with the same active trend after an initial transient response. Production rates would pick up where they left off. If the transient response is negligible, then suspension would only shift the active

production rate curve by the suspension period (Figure 7.4). The suspension period is filtered out when rate is expressed in terms of cumulative oil. The actively-controlled and suspended rate functions become virtually identical in terms of cumulative oil, except for transient deviations from suspension events. With this near-state transformation, bifurcating depletion paths essentially lead to the same production rates.

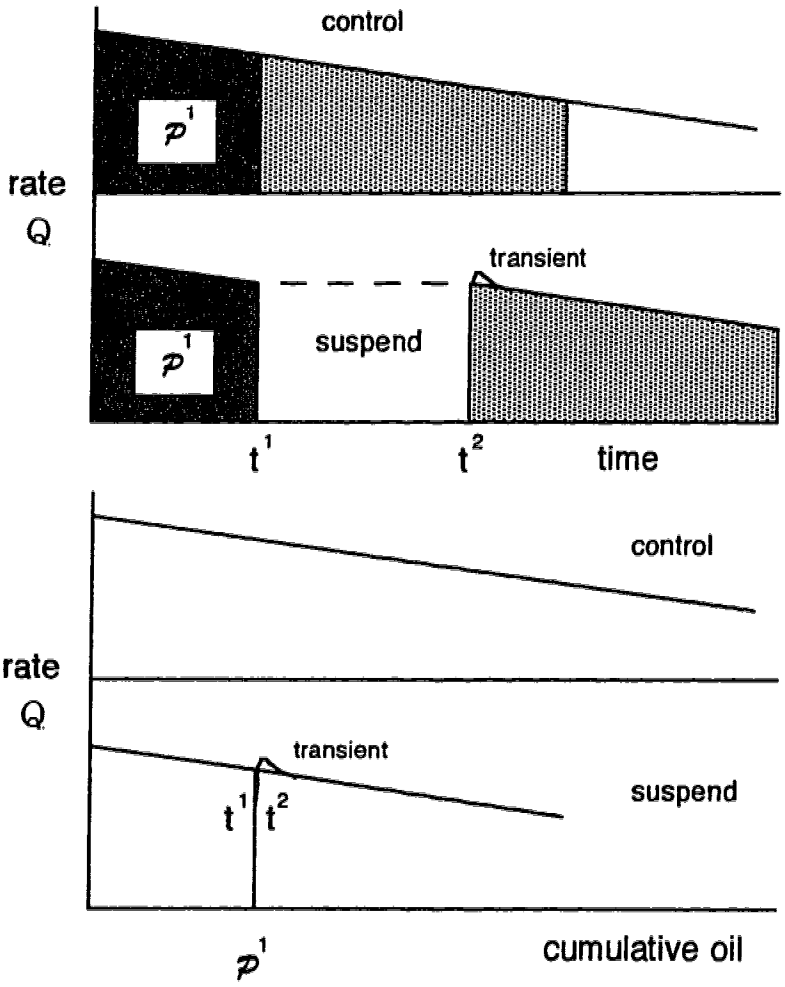



Figure 7.4: Transient Deviation in Near-State Variables

The near-state concept assumes that the suspension period is large with respect to the monthly bang-bang control policy. Transient effects will show some divergence between temporarily suspended operations and those without suspension in the time domain. These differences are smoothed out upon integration in the cumulative oil production domain.

Unique depletion paths can be traced in the feasible region of ($\mathcal{P}$, t) space as shown in Figure 7.5. The feasible depletion region is bounded by the cumulative oil production limit as determined by a sustained active control policy. Depletion path segments that are constant correspond to suspended modes of operation. Path segments that run along directions of increasing cumulative production ($\mathcal{P}$) correspond to operations under active control policy.

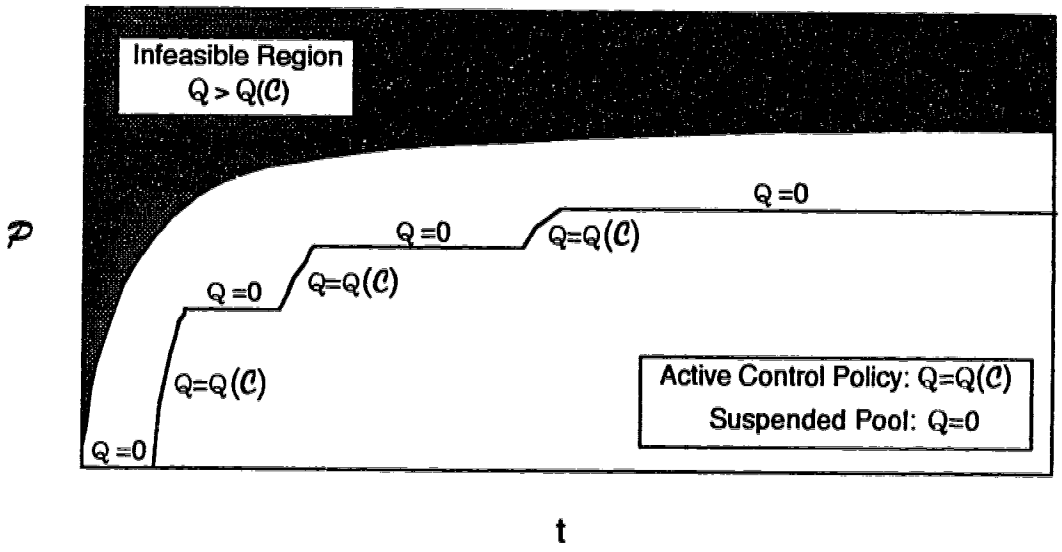



Figure 7.5: Unique Depletion Path in ($\mathcal{P}$,t) Space

## 7.4 Cumulative Production Tree

Cumulative oil intervals of equal volume are used to partition the ($\mathcal{P}_1$, $\mathcal{P}_2$) domain. Figure 7.6(a) shows the cumulative oil production tree. Five secondary waterflood branches, labelled (A) through (E), are forecast at 200 MSTB primary oil intervals starting from 1-Oct-95. All cumulative forecasts measure total production from the starting reference date. The ultimate primary oil recovery remaining is forecasted at 843 MSTB. Cumulative secondary oil decreases with waterflood delay, as indicated by total recoveries posted at the end of each consecutive branch. A maximum remaining waterflood recovery of 9.7 MMSTB is predicted for the earliest time and a minimum of 8.7 MMSTB is predicted for the latest time. Figure 7.6(b) shows the forecasted cumulative gas production tree. Cumulative gas increases significantly with waterflood delay. Figure 7.6(c) and (d) shows the forecasted cumulative water production and injection trees. Both cumulative water production and cumulative water injection peak at

branch (D). Figure 7.6(e) shows the average reservoir pressure tree with predicted primary pressure decline and waterflood repressurization branches.

## 7.5 Time-Averaged Production Rates

Investment and operating decisions depend on cash flow projections. Cash flow depends on production rate. Decisions may be continuously polled along depletion branches or made at discrete decision times. Decisions can also be made at cumulative oil production milestones. Production rates representative of daily operations may have large fluctuating cycles as seen in Figure 5.4(a) and 6.5(a). These short-term oscillations can lead to misleading results from an economic evaluation. Time-averaging will smooth rates over periods of time more representative of the decision process. These periods are chosen to coincide with the cumulative oil partition. Time-averaged production rates can be determined from the incremental slope along depletion pathways:

$$Q_o = \frac{d\mathcal{P}}{dt} \qquad \text{Active Control Policy}$$

$$Q_o = 0 \qquad \text{Suspended Pool} \tag{7.4}$$

Table 7.1(a) tabulates the cumulative time ($t_o$) for oil production to reach its cumulative milestone partition under the active control policy. The ($M_1 \times M_2$) partition has $M_1$=9 intervals of $\Delta\mathcal{P}_1$=100 MSTB along the primary branch and a maximum of $M_2$=20 intervals of $\Delta\mathcal{P}_2$=500 MSTB along secondary branches. Cumulative oil times have been interpolated between simulated secondary branches to provide higher resolution. Table 7.1(b) tabulates the average oil rate ($Q_o$) between cumulative oil intervals ($\Delta\mathcal{P}_1, \Delta\mathcal{P}_2$). The oil rate posted at each milestone is the average rate measured from the previous milestone. For example, an average oil rate $Q_o(\mathcal{P}_1=0, \mathcal{P}_2=500)$=1363 STB/day over $t_o(0,500)$=367 days produces $\Delta\mathcal{P}_2$ =500 MSTB of secondary oil in the earliest waterflood branch.

$$Q_o(\mathcal{P}_1^{m_1}, 0) = \frac{[\mathcal{P}_1^{m_1} - \mathcal{P}_1^{m_1-1}]}{[t_o(\mathcal{P}_1^{m_1}, 0) - t_o(\mathcal{P}_1^{m_1-1}, 0)]} \qquad ; m_1 = 1,2,\ldots,M_1 - 1$$

$$Q_o(\mathcal{P}_1^{m_1}, \mathcal{P}_2^{m_2}) = \frac{[\mathcal{P}_2^{m_2} - \mathcal{P}_2^{m_2-1}]}{[t_o(\mathcal{P}_1^{m_1}, \mathcal{P}_2^{m_2}) - t_o(\mathcal{P}_1^{m_1}, \mathcal{P}_2^{m_2-1})]} \; ; \; m_2 = 1,2,\ldots,M_2^{m_1} - 1 \tag{7.5}$$

Branch endpoints track partial intervals. The product of average rate at the branch endpoint and the time interval from the previous milestone gives the remaining cumulative oil recoverable along that branch.

$$\Delta\mathcal{P}_1^{M_1} = Q_o(\mathcal{P}_1^{M_1},0)\times[t_o(\mathcal{P}_1^{M_1},0) - t_o(\mathcal{P}_1^{M_1-1},0)]$$

$$\Delta\mathcal{P}_2^{m_1^{M_2}} = Q_o(\mathcal{P}_1^{m_1}, \mathcal{P}_2^{m_1^{M_2}})\times[t_o(\mathcal{P}_1^{m_1},\mathcal{P}_2^{m_1^{M_2}}) - t_o(\mathcal{P}_1^{m_1},\mathcal{P}_2^{m_1^{M_2}-1})] \qquad (7.6)$$

Table 7.2(c) tabulates the average gas rate for the cumulative oil partition. Gas rates are calculated in the same manner using cumulative gas production forecasts. Figure 7.7(a) and (b) show the time-averaged oil and gas production rates for primary and secondary branches in the production tree.

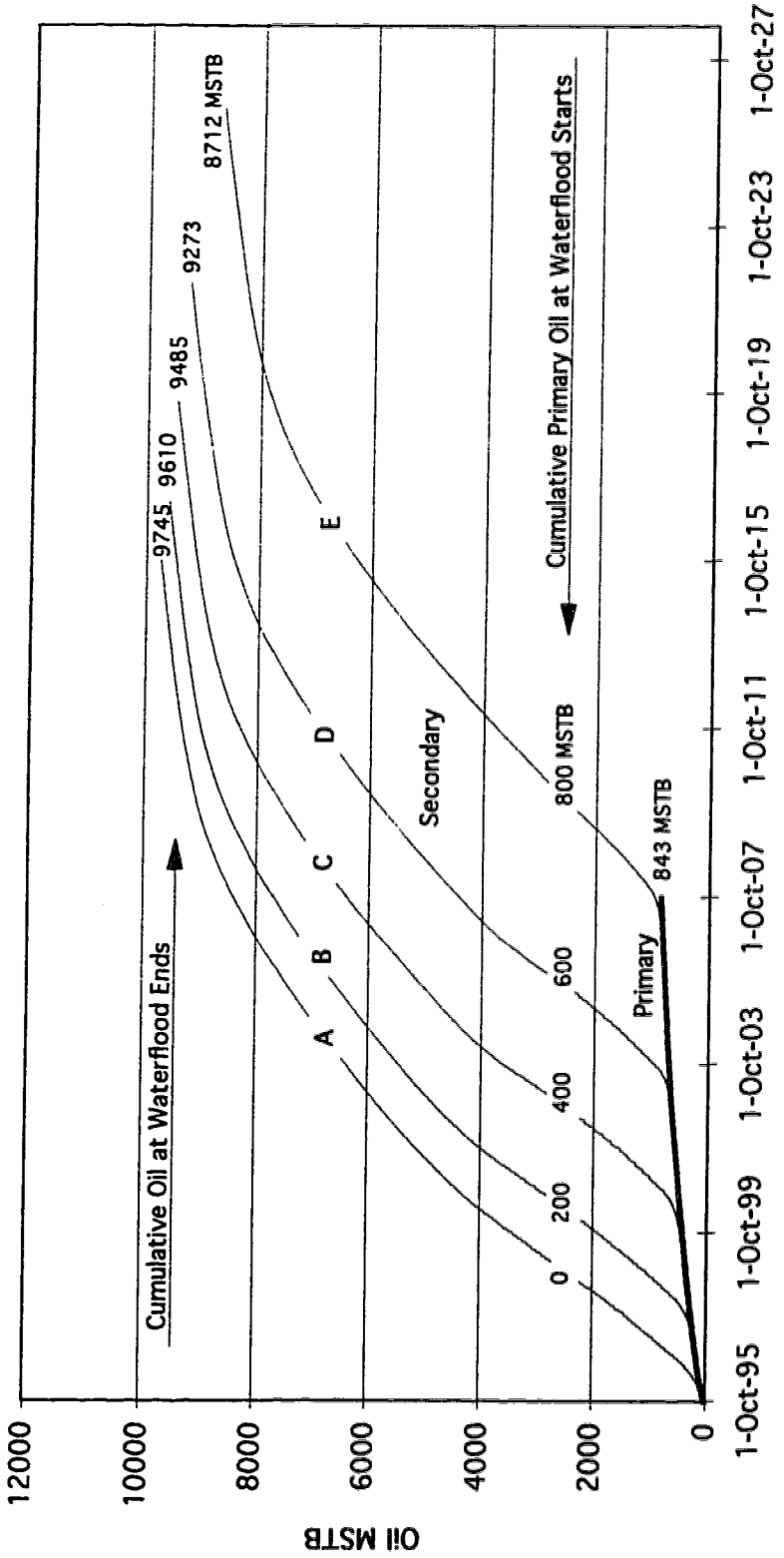



Figure 7.6(a): Cumulative Oil Branches

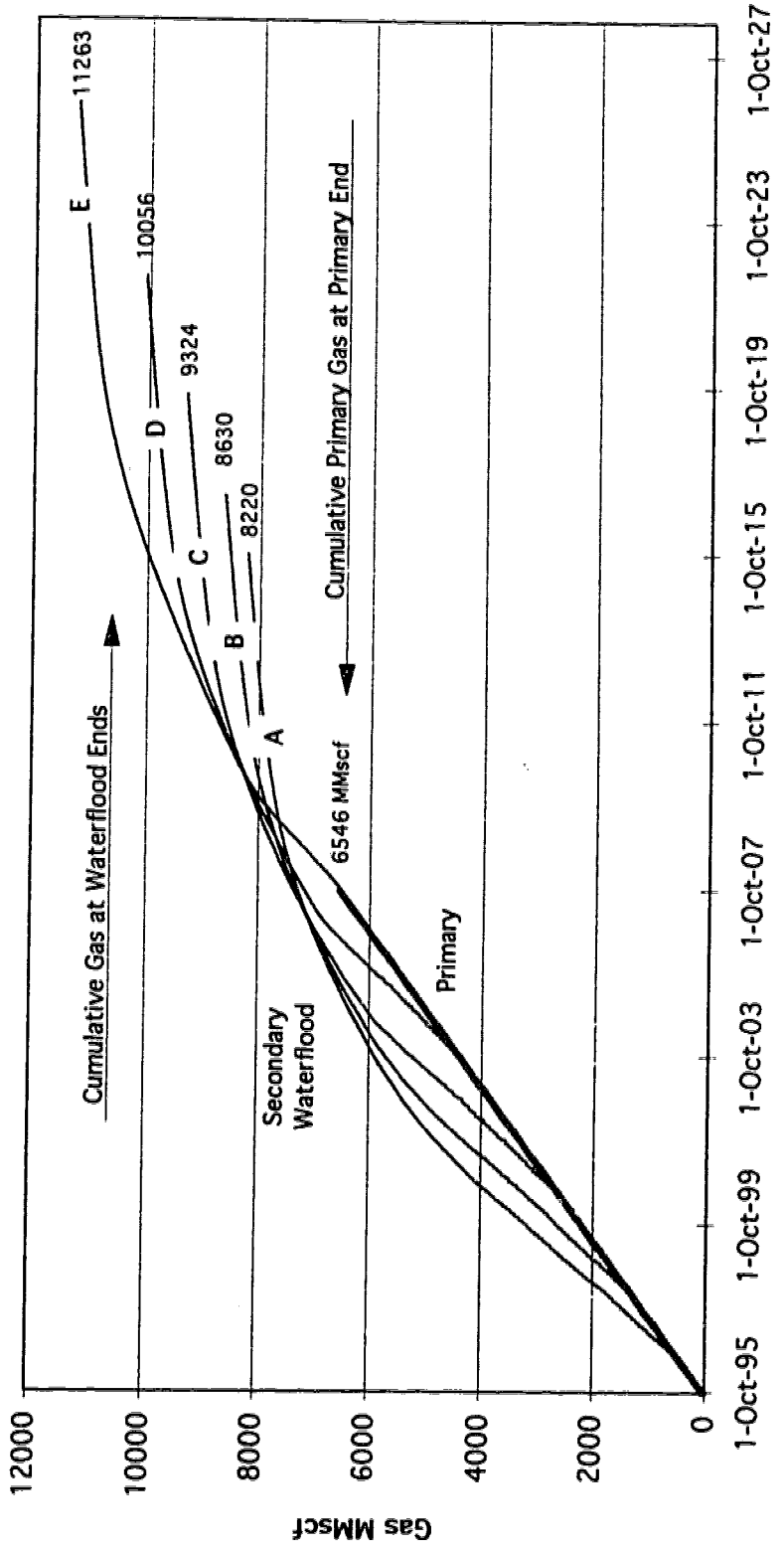



Figure 7.6(b): Cumulative Gas Branches

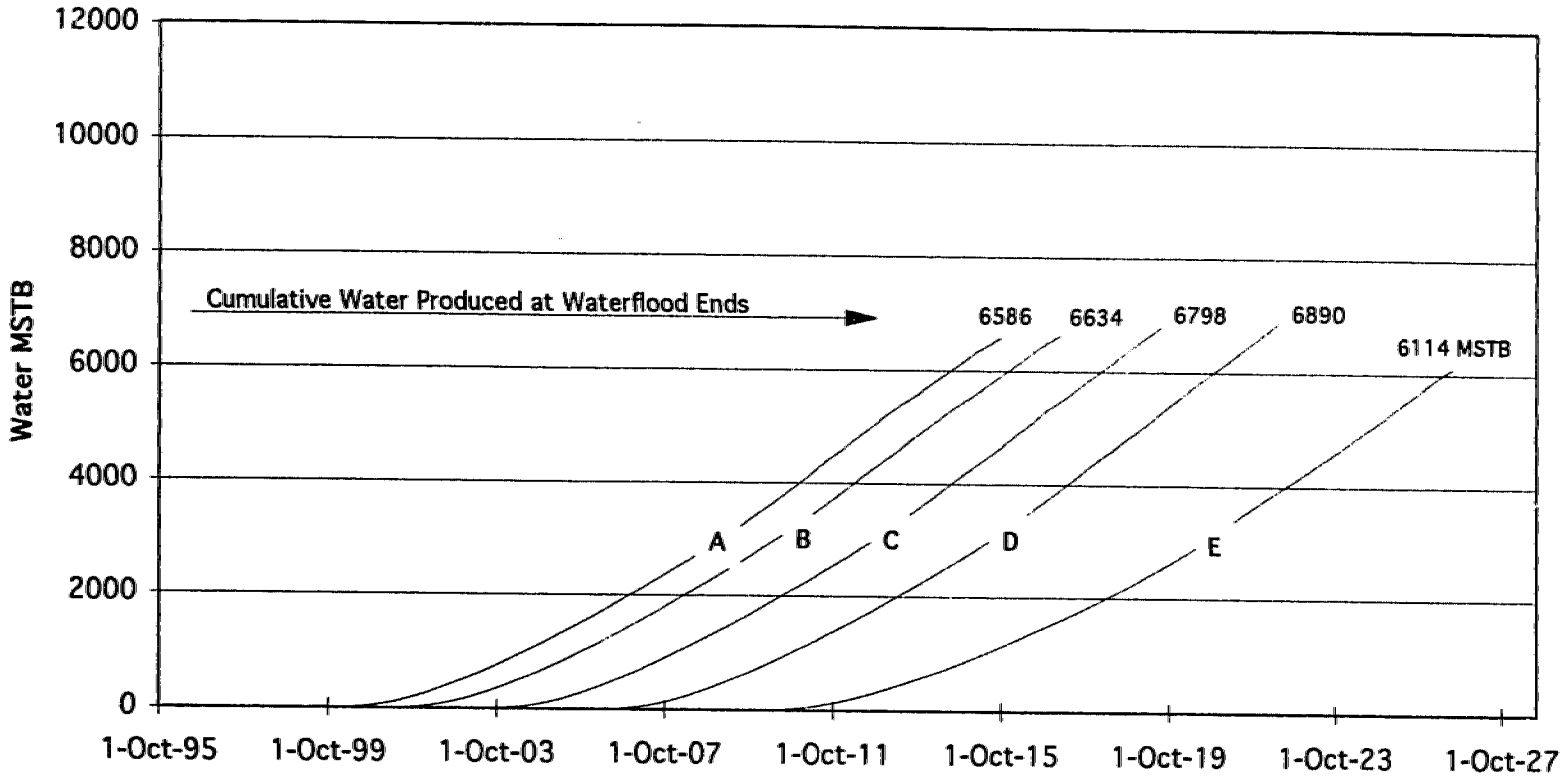



Figure 7.6(c): Cumulative Water Production Branches

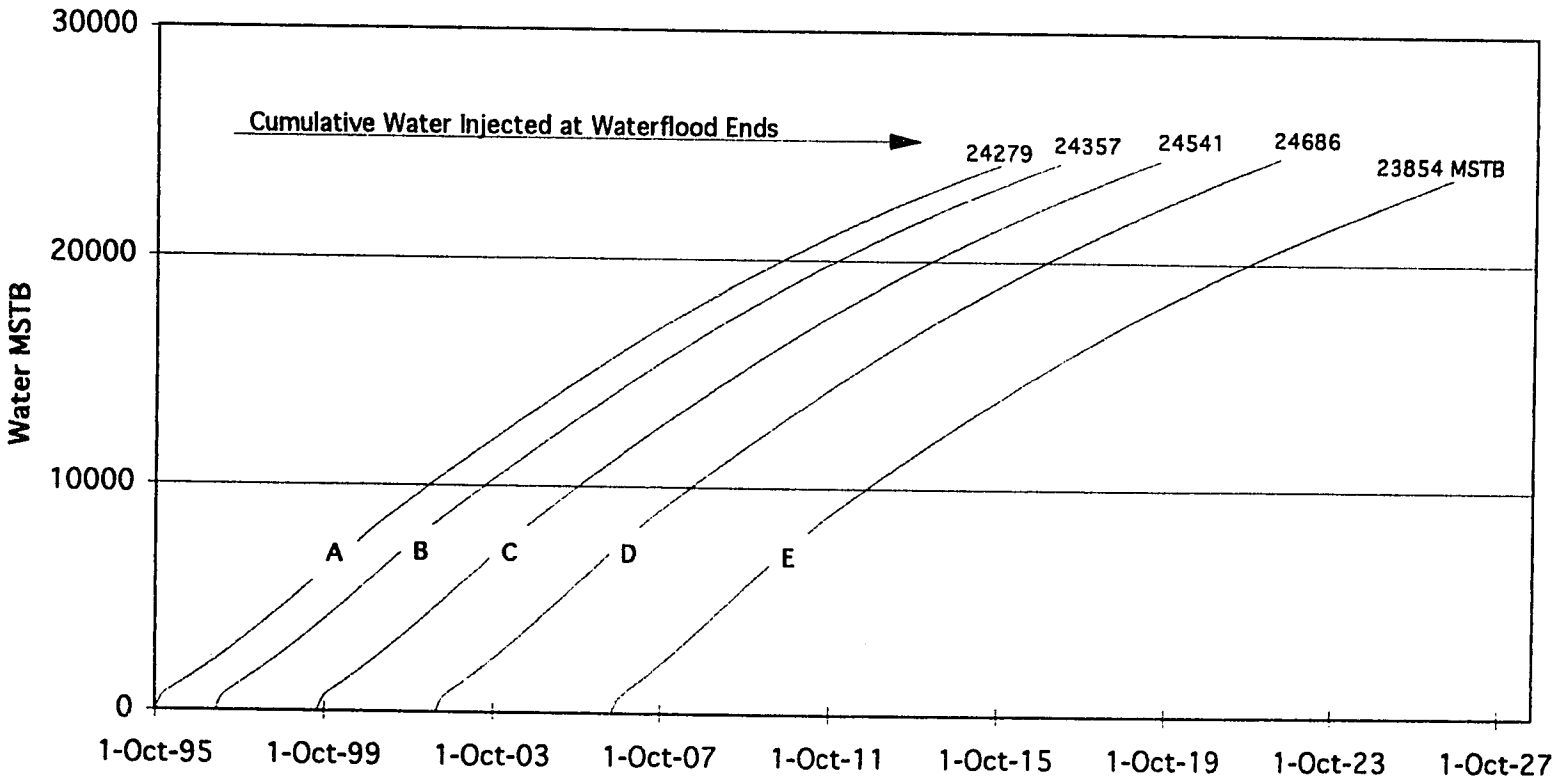



Figure 7.6(d): Cumulative Water Injection Branches

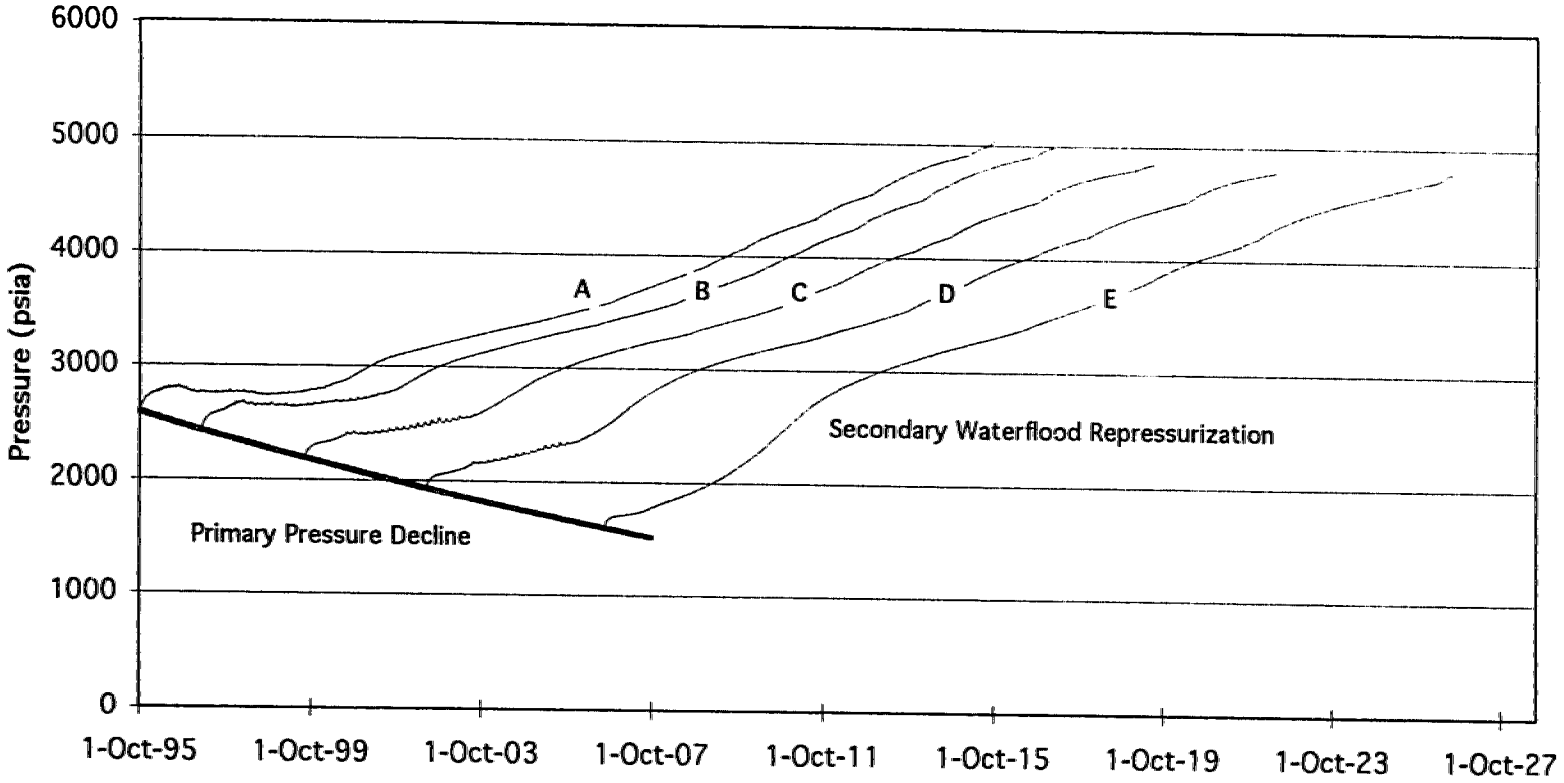



Figure 7.6(e): Average Reservoir Pressure Branches

| $p_1 \backslash p_2$ | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 367 | 565 | 768 | 949 | 1128 | 1301 | 1478 | 1666 | 1872 | 2120 | 2385 | 2676 | 2981 | 3299 | 3642 | 4022 | 4467 | 5078 | 6356 | 7306 |
| 100 | 245 | 607 | 811 | 1016 | 1200 | 1379 | 1549 | 1725 | 1913 | 2132 | 2385 | 2660 | 2955 | 3262 | 3587 | 3940 | 4337 | 4817 | 5585 | 6960 | 7519 |
| 200 | 521 | 950 | 1162 | 1371 | 1559 | 1738 | 1903 | 2077 | 2267 | 2504 | 2785 | 3053 | 3353 | 3664 | 3998 | 4366 | 4786 | 5317 | 6308 | 7823 | 0 |
| 300 | 843 | 1401 | 1615 | 1828 | 2016 | 2194 | 2354 | 2533 | 2739 | 2989 | 3258 | 3544 | 3841 | 4155 | 4500 | 4883 | 5335 | 5997 | 7292 | 8245 | 0 |
| 400 | 1201 | 1890 | 2104 | 2323 | 2512 | 2688 | 2844 | 3024 | 3251 | 3515 | 3799 | 4076 | 4371 | 4683 | 5044 | 5444 | 5931 | 6734 | 8359 | 8703 | 0 |
| 500 | 1593 | 2414 | 2641 | 2855 | 3040 | 3213 | 3385 | 3590 | 3831 | 4099 | 4378 | 4668 | 4973 | 5304 | 5673 | 6106 | 6711 | 7838 | 9195 | 0 | 0 |
| 600 | 2017 | 2993 | 3234 | 3443 | 3625 | 3795 | 3964 | 4213 | 4475 | 4746 | 5027 | 5323 | 5646 | 5998 | 6370 | 6839 | 7575 | 9061 | 9741 | 0 | 0 |
| 700 | 2469 | 3690 | 3938 | 4158 | 4365 | 4571 | 4791 | 5036 | 5303 | 5583 | 5875 | 6186 | 6524 | 6902 | 7364 | 8103 | 9167 | 10398 | 0 | 0 | 0 |
| 800 | 2947 | 4407 | 4665 | 5100 | 5340 | 5562 | 5854 | 6119 | 6394 | 6684 | 6992 | 7322 | 7686 | 8105 | 8672 | 9767 | 11263 | 0 | 0 | 0 | 0 |
| 843 | 3363 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Table 7.1(a): Cumulative Oil Production (MSTB) Milestone Times (days), $t_o(p_1,p_2)$.

| $p_1 \backslash p_2$ | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 1363 | 2513 | 2470 | 2754 | 2501 | 2391 | 2817 | 2666 | 2424 | 2013 | 1685 | 1713 | 1641 | 1572 | 1456 | 1315 | 1124 | 619 | 392 | 256 |
| 100 | 466 | 1274 | 2451 | 2434 | 2718 | 2796 | 2949 | 2838 | 2653 | 2284 | 1975 | 1822 | 1696 | 1626 | 1541 | 1415 | 1260 | 1041 | 651 | 364 | 197 |
| 200 | 926 | 1155 | 2301 | 2384 | 2404 | 2753 | 3036 | 2670 | 2334 | 2109 | 1814 | 1739 | 1606 | 1505 | 1497 | 1360 | 1190 | 942 | 505 | 275 | 0 |
| 300 | 1397 | 1092 | 2338 | 2343 | 2659 | 2816 | 3110 | 2797 | 2432 | 2000 | 1858 | 1751 | 1681 | 1591 | 1451 | 1305 | 1106 | 756 | 386 | 271 | 0 |
| 400 | 1914 | 1010 | 2314 | 2301 | 2649 | 2647 | 3165 | 2723 | 2245 | 1893 | 1800 | 1783 | 1697 | 1577 | 1493 | 1251 | 1026 | 622 | 308 | 251 | 0 |
| 500 | 2493 | 960 | 2196 | 2343 | 2698 | 2888 | 2910 | 2433 | 2074 | 1871 | 1790 | 1727 | 1637 | 1512 | 1353 | 1155 | 826 | 444 | 288 | 0 | 0 |
| 600 | 3144 | 895 | 2179 | 2330 | 2754 | 2834 | 2848 | 2176 | 1918 | 1847 | 1772 | 1645 | 1557 | 1447 | 1302 | 1066 | 679 | 330 | 254 | 0 | 0 |
| 700 | 3879 | 858 | 2016 | 2270 | 2419 | 2430 | 2270 | 2040 | 1869 | 1792 | 1710 | 1608 | 1479 | 1323 | 1083 | 676 | 470 | 282 | 0 | 0 | 0 |
| 800 | 4713 | 799 | 1933 | 2125 | 2046 | 1961 | 1914 | 1695 | 1615 | 1724 | 1627 | 1512 | 1366 | 1191 | 936 | 457 | 276 | 0 | 0 | 0 | 0 |
| 843 | 5116 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Table 7.1(b): Average Oil Rate (STB/day) between Cumulative Oil Milestones (MSTB), $Q_o(p_1,p_2)$.

| $p_1 \backslash p_2$ | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 1643 | 2434 | 2244 | 2364 | 2407 | 2431 | 2343 | 2360 | 2359 | 2002 | 1650 | 1499 | 1274 | 1132 | 1020 | 907 | 751 | 545 | 282 | 192 |
| 100 | 155 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 200 | 351 | 1522 | 3253 | 2139 | 2337 | 2141 | 2385 | 2312 | 2402 | 2052 | 1456 | 1505 | 1243 | 1142 | 1045 | 939 | 804 | 609 | 345 | 203 | 0 |
| 300 | 1275 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 400 | 1591 | 1121 | 2247 | 2211 | 2337 | 2218 | 2423 | 2247 | 2337 | 1505 | 1214 | 1192 | 1111 | 1115 | 993 | 794 | 729 | 545 | 215 | 174 | 0 |
| 500 | 1935 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 600 | 2327 | 1007 | 2246 | 2036 | 2145 | 2332 | 2335 | 1668 | 1242 | 1185 | 1054 | 1019 | 934 | 835 | 751 | 534 | 331 | 209 | 162 | 0 | 0 |
| 700 | 2769 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 800 | 3267 | 1587 | 1906 | 1826 | 1745 | 1663 | 1571 | 1340 | 1261 | 1353 | 1257 | 1143 | 1003 | 828 | 643 | 443 | 243 | 159 | 0 | 0 | 0 |
| 843 | 3616 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Table 7.1(c): Average Gas Rate (Mscf/day) between Cumulative Oil Milestones (MSTB), $Q_g(p_1,p_2)$.

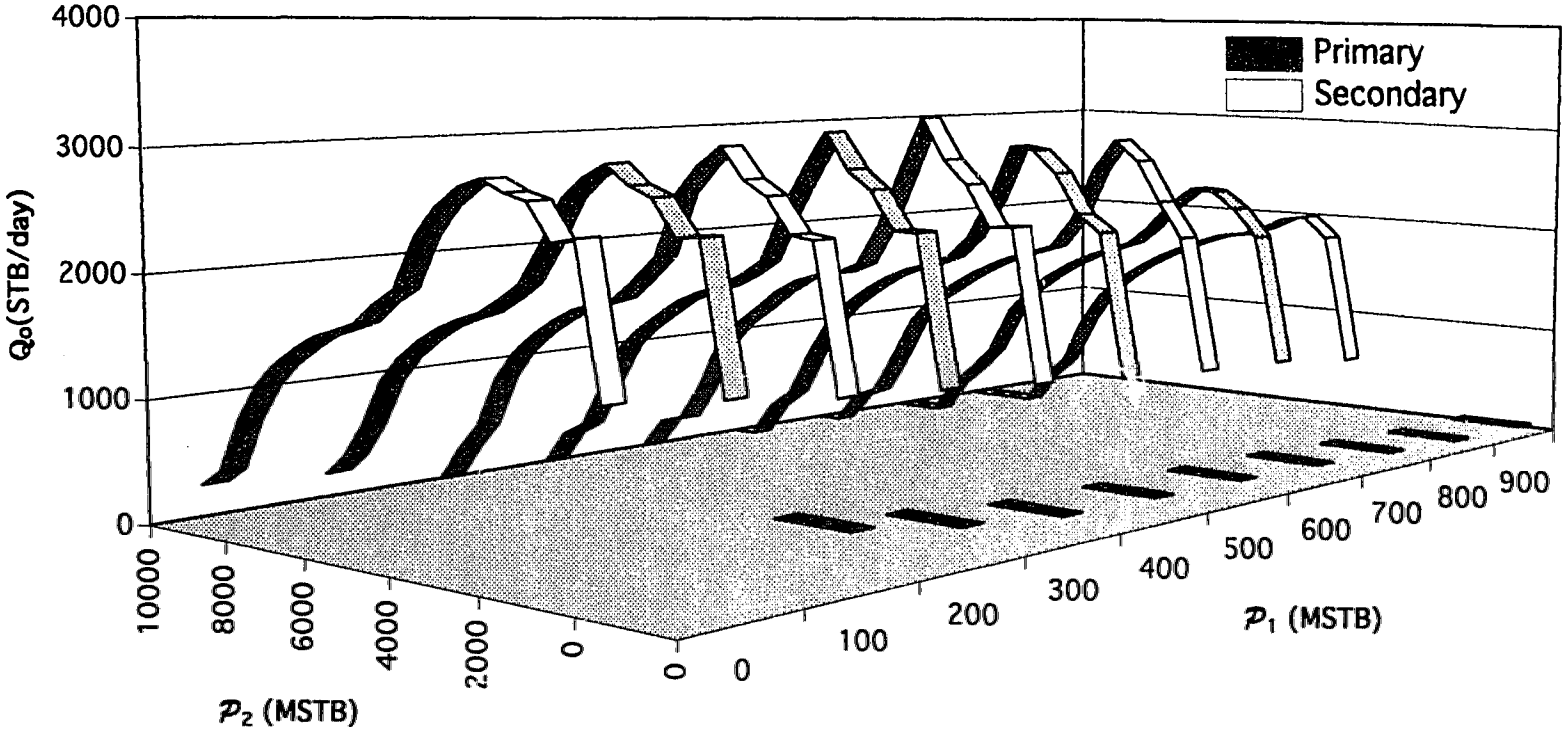



Figure 7.7(a): Average Pool Oil Rate between Cumulative Oil

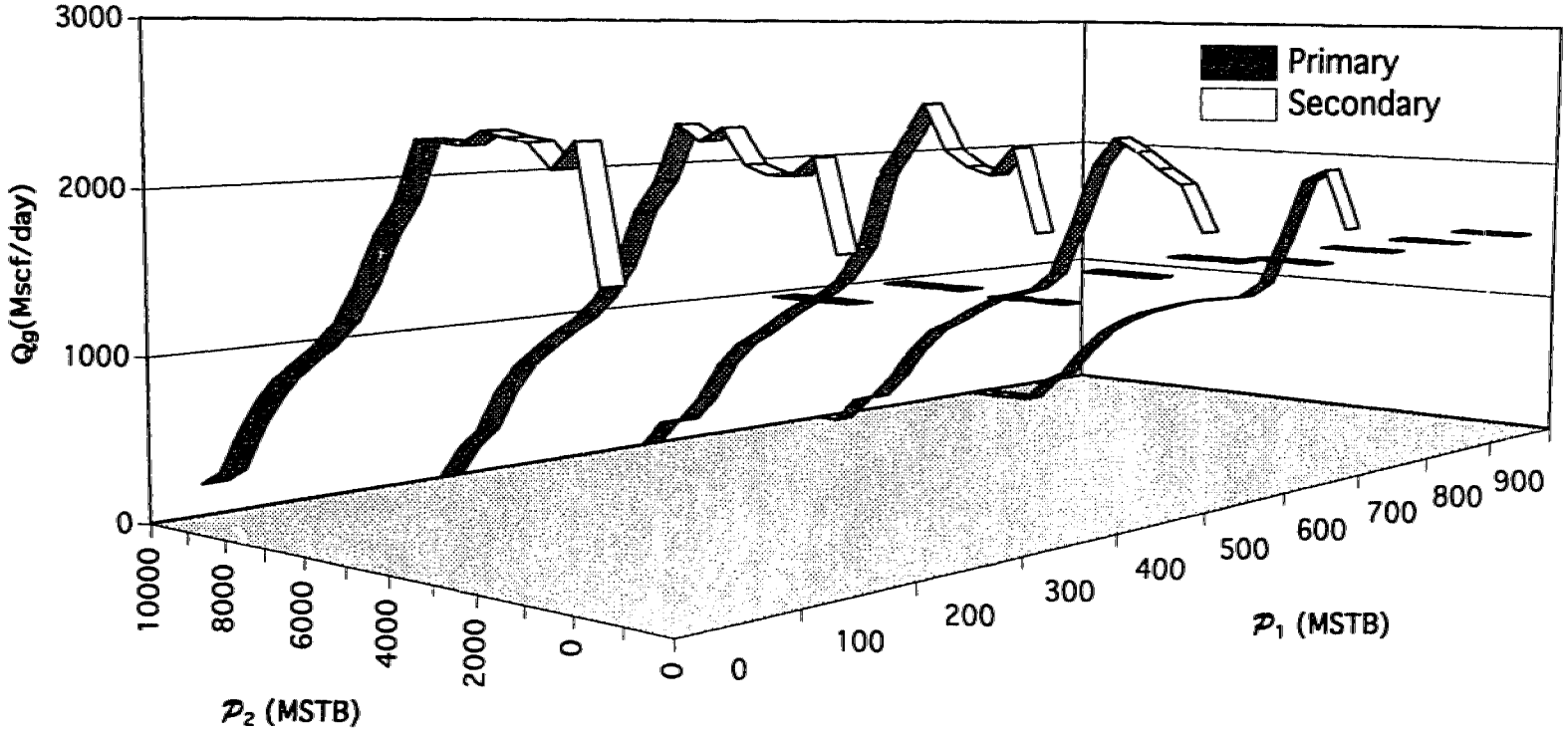



Figure 7.7(b): Average Pool Gas Rate between Cumulative Oil

# Chapter 8: Depletion Strategy Model

## 8.1 Strategic Decisions

The depletion strategy ($\mathcal{D}$) establishes price-sensitive decision rules to maximize production value over the space of allowable operating choices. The optimization problem is formulated to maximize operations value contingent on the investment timing decision for a design secondary recovery project.

Production value ($\mathcal{V}$) of remaining operating alternatives over the producing life cycle ($0 \le t \le T$) depends exogenously on the contemporaneous spot price of oil, s(t). Remaining production value also depends on the contemporaneous depletion state, as represented by cumulative oil production ($\mathcal{P}_1$, $\mathcal{P}_2$), and the depletion strategy ($\mathcal{D}$) followed in producing the reservoir.

$$\mathcal{V} = \mathcal{V}(s,t,\mathcal{P}_1, \mathcal{P}_2; \mathcal{D}) \tag{8.1}$$

The depletion strategy ($\mathcal{D}$) involves price-sensitive investment decisions for choosing between alternative depletion paths. Primary and secondary paths have separate operating policies ($\Theta_1,\Theta_2$) with context sensitive decision rules to choose between three mutually exclusive modes of operation (Figure 8.1). The three modes of primary and secondary operation ($\theta_{1m},\theta_{2m}$; m=C,S,A) are active control, pool suspension and early abandonment as described in Section 7.2. Active production modes ($\theta_{1C},\theta_{2C}$) for primary and secondary stages operate under the corresponding control policy ($\mathcal{C}_1,\mathcal{C}_2$) established to meet design objectives subject to regulatory constraints. Passive production modes ($\theta_{1S},\theta_{2S}$) suspend field operations ($Q_1=0,Q_2=0$). Terminal production modes ($\theta_{1A},\theta_{2A}$) abandon the operation early.

## 8.2 Strategy Duration

The depletion strategy ($\mathcal{D}$) for Chedderville Viking "A" will apply over a fixed duration strategic window ($0 \le t \le T$) that spans a complete set of producing life possibilities. The earliest time in the feasible waterflood timing window establishes the start time (t=0) on the calendar date 1-Oct-95. Primary production is planned to terminate at the end of twelve years under the primary control policy ($\theta_{1C}$). A design waterflood is planned for a twenty year secondary life cycle under control ($\theta_{2C}$) over primary depletion states ($\mathcal{P}_1$) in a ten year

timing window. The depletion state will not change while primary operations are suspended ($\theta_{1S}$). If primary operations are temporarily suspended, then the calendar time of the waterflood window will be extended by the suspension period. The design waterflood could potentially start at any time ($0 \le t \le T$). The depletion strategy fixes the overall decision policy duration (T=32 years) to coincide with consecutive primary and secondary life cycles. This fixed duration allows some slack time for the depletion strategy. The actual duration may be less if the project is abandoned early.

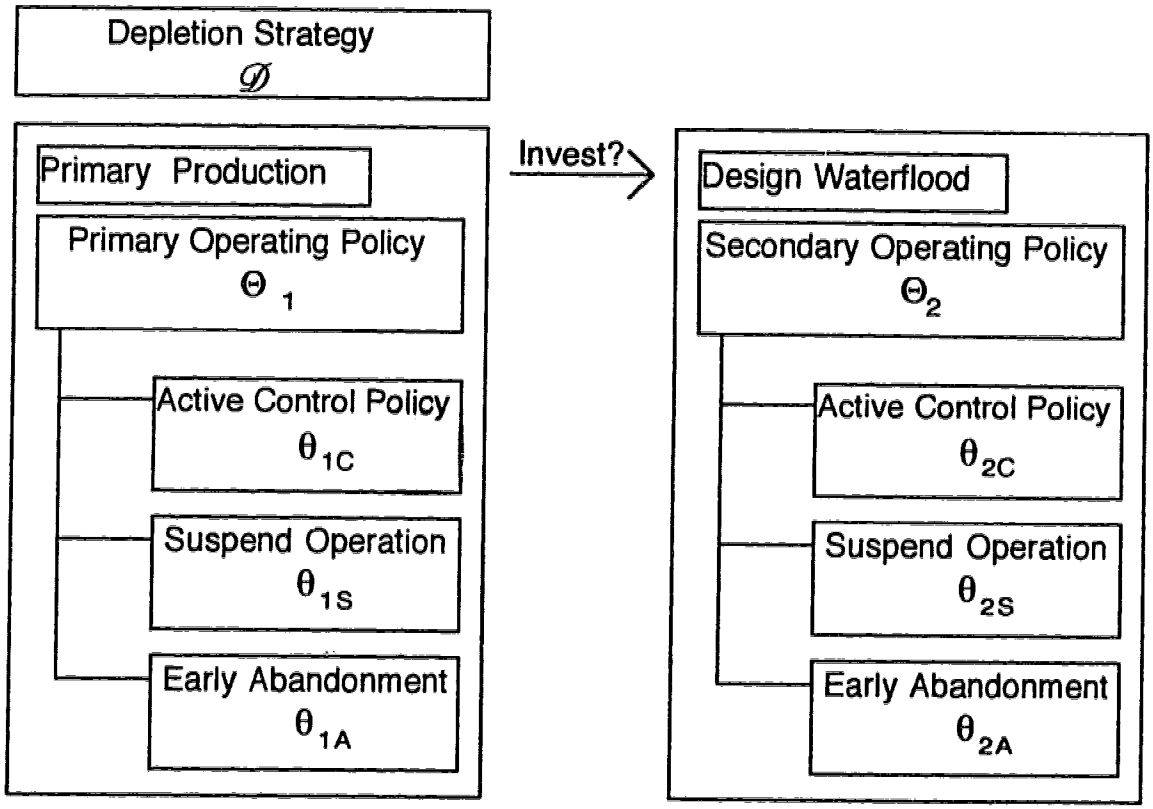



Figure 8.1: Strategic Decision Hierarchy for Operations and Investment

## 8.3 Project Costs

The operation is assumed to have exhausted economic reserves by the end of the strategic window. A lump sum mandatory abandonment expense must be incurred at the terminal time. The abandonment expense ($A_1$,$A_2$) depends on the contemporaneous recovery stage at the time of termination (t=T). A lump

sum capital cost ($K_{12}$) must be sunk to implement the design waterflood. The investment decision to shift from primary to secondary recovery stages is irreversible and mutually exclusive. The operation of each recovery stage has an associated cost schedule for fixed costs ($f_1$,$f_2$) and variable unit costs ($v_1$,$v_2$). Typical operating costs for Alberta oilfields were obtained through direct consultation with the Alberta Department of Energy[19]. These included:

- average fixed operating costs per well
- average variable operating costs per barrel of oil produced
- water injection conversion costs
- well abandonment costs correlated with depth

The mean abandonment cost per well is correlated to the depth (z) in meters:

$$A = 16871 - 4.8393\,z + 0.009267\,z^2 + 0.0000002\,z^3 \qquad (8.2)$$

The historical capital cost for new wells in the Viking "A" pool was $1.2 million. Capital, operating and abandonment costs for each recovery stage are listed in Table 8.1. The waterflood capital cost is estimated at $32.4 million, fixed costs at $100/day/well and variable costs at $2/STB oil. All gas is to be flared and not gathered, so that no benefits or costs are associated with gas production.

## 8.4 Cash Flow Model

Cash flow and income tax accounting calculations are shown in Table 8.2 (CIM Petroleum Society Monograph No. 1, 1994). The model will use a simplified before-tax cash flow ($Cf$) calculation that depends on continuous production revenues, operating costs and a single lumped royalty rate. Gross revenue projections will come directly from oil production forecasts (Q) and the oil price (s). Model royalties will be paid out at a fixed royalty rate percentage (R=23%) of gross revenues. Cash flow before tax ($Cf$) will depend on the recovery stage ($\Theta_i$).

$$Cf(s,t,Q_i\,;\Theta_i) = [(1-R)\,s(t) - v_i]\,Q_i - f_i \qquad (8.3)$$

---

19 Consultation with John E. Faltinson, Alberta Department of Energy.

| Primary Production Costs | Unit Cost per Well | Number of Wells | $Amount |
|---|---|---|---|
| Infill Drilling | $1,200,000 | 0 | $0 |
| **Total Capital Cost** | | | **$0** |
| Abandon Wells @ 8600 ft Depth | $71,500 | 14 | $1,001,000 |
| **Field Abandonment Cost** | | | **$1,001,000** |
| Fixed Monthly Operating Cost | $3,000 | 14 | $42,000 |
| **Total Fixed Montly Operating Cost** | | | **$42,000** |

Variable Operating Cost = $2.00/STB Oil + $0.80/Mscf Gas Gathered

| Waterflood Project Costs | Unit Cost per Well | Number of Wells | $Amount |
|---|---|---|---|
| Infill Drilling | $1,200,000 | 23 | $27,600,000 |
| Conversion to Water Injection | $300,000 | 16 | $4,800,000 |
| **Total Capital Cost** | | | **$32,400,000** |
| Abandon Wells @ 8600 ft Depth | $71,500 | 37 | $2,645,500 |
| **Field Abandonment Cost** | | | **$2,645,500** |
| Fixed Montly Operating Cost | $3,000 | 37 | $111,000 |
| **Total Fixed Monthly Operating Cost** | | | **$111,000** |

Variable Operating Cost = $2.00/STB Oil + $0.80/Mscf Gas Gathered

Table 8.1: Project Capital, Operating and Abandonment Costs

| | Income Tax | Earned Depletion | Resource Allowance | Cash Flow |
|---|---|---|---|---|
| **Gross Revenue** | | | | |
| Working Interest | + | + | + | + |
| Production Royalty | + | + | + | + |
| Deemed Income | + | + | + | |
| **Expenses** | | | | |
| Crown Royalty | | | | - |
| Mineral Tax | | | | - |
| Production Royalty | - | - | - | - |
| Lease Operating | - | - | - | - |
| Crown Lease Rentals | - | | | - |
| CCA - Production | - | - | - | |
| G&A - Production | - | - | - | - |
| CEDOE | | | - | - |
| **Adjusted Resource Profits (ARP)** | | | Σ | |
| Resource Allowance (25% of ARP) | - | - | | |
| Resource Royalty Income | + | + | | + |
| Resource Royalty Expense | - | - | | - |
| CCA-Other-Resource Profit | - | | | |
| G&A-Other | - | - | | - |
| Interest | - | - | | - |
| COGPE | - | - | | |
| CDE | - | - | | |
| CEE | - | - | | |
| Resource Profits (RP) | | Σ | | |
| Earned Depletion (25% of RP) | - | | | |
| Other | | | | |
| Foreign Income | + | | | + |
| Foreign Expense | - | | | - |
| Nonproduction Income | + | | | + |
| Nonproduction Expense | - | | | - |
| Net Income for Tax Purpose | Σ | | | |
| Cash Flow before Income Tax | | | | Σ |

Table 8.2 : Oil and Gas Accounting for Cash Flow and Income Tax (Alberta)

## 8.5 Oil Price Model

The spot price s(t) at the current time ($t=t^0$) is known with certainty. The spot price at any future time ($t^0<t\leq T$) will be in some state of uncertainty. Asset valuation will depend on the price model used to forecast future spot oil prices. Discounted cash flow methods assume a price model where the future spot price can be forecast with certainty. Modern asset pricing methods assume a stochastic price model that explicitly accounts for this uncertainty. The price model used in this work assumes a continuous stochastic Gauss-Wiener process where future oil price expectations depend on the current oil price state and a non-stochastic oil price volatility.

Volatility estimates are based on the historical average monthly spot oil prices[20] listed in Table 8.3 and plotted in Figure 8.2. The price volatility ($\sigma$) is a measure of the variation in the proportional change in price over time (Hull 1991). The rate of proportional change in price is the rate of return in the spot market. The expected rate of return, is the rate of growth in the mean price trend ($\mu$). The expected trend and annual volatility ($\sigma$) can be approximated with statistical point estimates. The continuously compounded rate of return ($u^n$),

$$u^n = \ln\left(\frac{s^n}{s^{n-1}}\right) \tag{8.4}$$

is calculated using price states ($s^n$) sampled at regular intervals $\{t^n=n\Delta t;\ n=0,1,...N\}$ over the time period ($t^0\leq t^n\leq t^N$). The time interval $\Delta t$ is measured in years. The mean rate of return ($\mu$) is estimated by the arithmetic average, $\overline{u}$ :

$$\overline{u} = \frac{1}{N}\sum_{n=0}^{N} u^n \tag{8.5}$$

Standard deviation in the rate of return ($\sigma\sqrt{\Delta t}$) is estimated by the sample statistic, $s\sqrt{\Delta t}$ :

$$s\sqrt{\Delta t} = \sqrt{\frac{1}{N-1}\sum_{n=0}^{N}(u^n-\overline{u})^2} \tag{8.6}$$

---

20 Dubai, U.K. Brent and Alaska Average, SPOT, F.O.B. (1991-1994) from The Monthly Commodity Price Bulletin.

| Month | Monthly Average* Oil Price ($US/bbl) | Monthly Average Return (%) |
|---|---|---|
| Jan-91 | $21.25 | |
| Feb-91 | $16.68 | -24.21% |
| Mar-91 | $17.05 | 2.19% |
| Apr-91 | $17.50 | 2.61% |
| May-91 | $17.68 | 1.02% |
| Jun-91 | $17.03 | -3.75% |
| Jul-91 | $18.01 | 5.60% |
| Aug-91 | $18.24 | 1.27% |
| Sep-91 | $19.14 | 4.82% |
| Oct-91 | $20.43 | 6.52% |
| Nov-91 | $19.68 | -3.74% |
| Dec-91 | $16.72 | -16.30% |
| Jan-92 | $16.38 | -2.05% |
| Feb-92 | $16.68 | 1.81% |
| Mar-92 | $16.52 | -0.96% |
| Apr-92 | $17.82 | 7.57% |
| May-92 | $18.70 | 4.82% |
| Jun-92 | $20.23 | 7.86% |
| Jul-92 | $19.47 | -3.83% |
| Aug-92 | $18.77 | -3.66% |
| Sep-92 | $19.20 | 2.27% |
| Oct-92 | $19.33 | 0.67% |
| Nov-92 | $18.22 | -5.91% |
| Dec-92 | $17.26 | -5.41% |
| Jan-93 | $16.38 | -5.23% |
| Feb-93 | $17.45 | 6.33% |
| Mar-93 | $17.78 | 1.87% |
| Apr-93 | $17.80 | 0.11% |
| May-93 | $17.52 | -1.59% |
| Jun-93 | $16.80 | -4.20% |
| Jul-93 | $15.72 | -6.64% |
| Aug-93 | $15.88 | 1.01% |
| Sep-93 | $15.27 | -3.92% |
| Oct-93 | $15.82 | 3.54% |
| Nov-93 | $14.50 | -8.71% |
| Dec-93 | $12.65 | -13.65% |
| Jan-94 | $13.49 | 6.43% |
| Feb-94 | $13.36 | -0.97% |
| Mar-94 | $13.35 | -0.07% |
| Apr-94 | $14.84 | 10.58% |
| May-94 | $16.09 | 8.09% |
| Jun-94 | $16.54 | 2.76% |
| Jul-94 | $17.37 | 4.90% |
| Aug-94 | $16.51 | -5.08% |
| Sep-94 | $15.66 | -5.29% |
| | Annual Price Volatility | 23.33% |
| | Standard Error | 2.49% |

* Dubai, U.K. Brent and Alaska Average, SPOT, F.O.B. (Monthly Commodity Price Bulletin)

Table 8.3: Oil Price Volatility

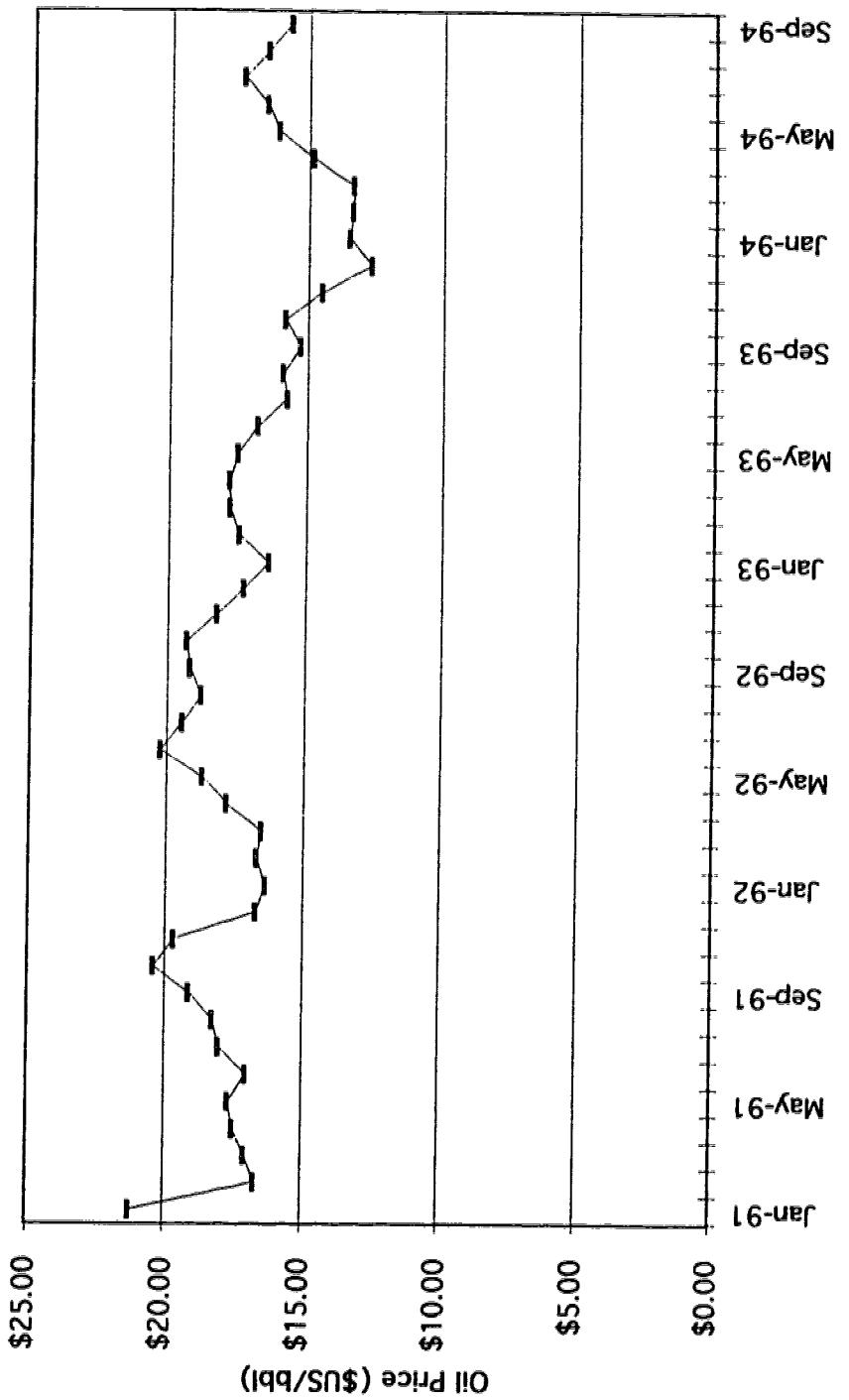



Figure 8.2: Average Monthly Spot Oil Price

The estimated annual volatility ($\sigma$=23.3%) has a standard error of 2.5%. Volatility time dependence is not considered here and assumed to be constant throughout the depletion strategy. The effects of the U.S. exchange rate on Canadian oil price volatility are not considered here.

The rate of return on the spot oil price is modelled as an exogenous continuous stochastic standard Gauss-Wiener process (Merton 1973):

$$\frac{ds}{s} = \mu dt + \sigma d\zeta \qquad (8.7)$$

where $d\zeta(t)$ is a normal random variable with variance dt; s(t) is the spot oil price at time t; $\mu(t)$ is the expectation of the continuously compounded rate of return on the spot market; and $\sigma(t)$ is the non-stochastic standard deviation in the rate of return. The solution of this differential random walk process is a lognormal distribution for the future spot price (Samuelson 1965).

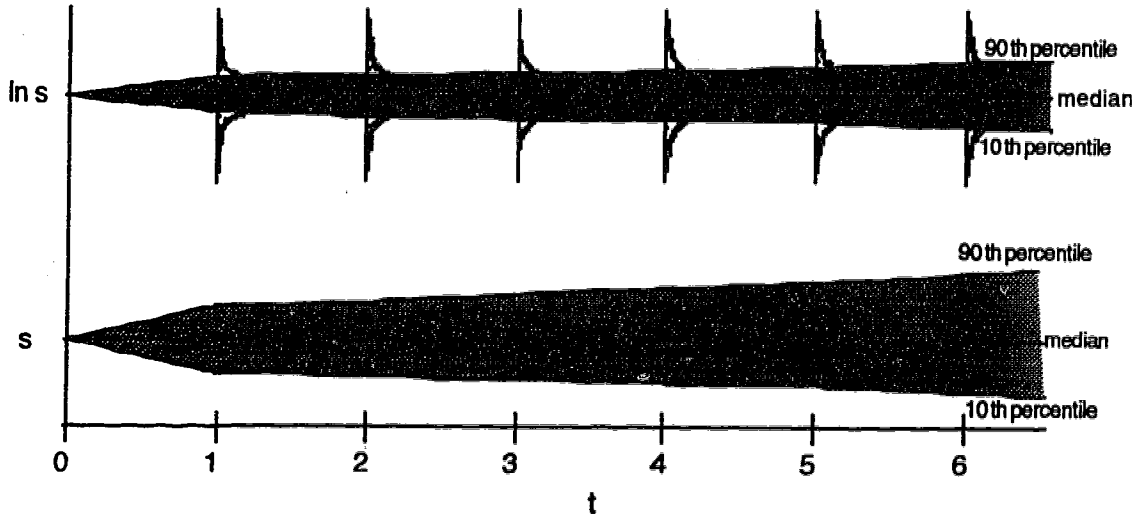



Figure 8.3: Lognormal Oil Price Expectations ($\mu$=0)

The probability density measure (dm) for future price states $s(\tau)$ at time $\tau$, given the price state s(t) at an earlier time t,

$$dm(\tau, s(\tau) \mid t, s(t)) = dLN[s(\tau) ; s(t)e^{\mu(\tau-t)}, \sigma^2(\tau-t)] \qquad (8.8)$$

has a lognormal distribution dLN[s;E,$\sigma^2$] in the spot price (s) with expectation (E) and associated variance ($\sigma^2$):

$$dLN[\, s(\tau);\, s(t)e^{\mu(\tau-t)},\, \sigma^2(\tau-t)] = \frac{1}{\sigma\sqrt{2\pi(\tau-t)}}\, e^{-\left[\frac{\ln\frac{s(\tau)}{s(t)}+\mu(\tau-t)}{\sigma\sqrt{2(\tau-t)}}\right]^2} ds(\tau) \qquad (8.9)$$

The evolution of price state distributions are illustrated in Figure 8.3. The price distributions represent a continuous state of price uncertainty at future times. The variance of these distributions grow proportionally with time.

## 8.6 Asset Valuation Model

The asset valuation model assumes that production can be sold forward on the futures market, and that the production asset value can be replicated by a self-financing portfolio of commodity futures and risk free assets. Dynamic equilibrium models for the futures price (Samuelson 1965, Merton 1973) and asset value (Brennan and Schwartz 1985) are formulated by finding hedge ratios that eliminate the stochastic returns from the self-financing portfolios.

Holding oil in inventory will have additional benefits over holding other commodities strictly for investment (Hull 1991). These benefits include the ability to profit from temporary local shortages and the ability to keep an industrial process running (Brennan and Schwartz 1985). The flow of benefits that accrue from ownership provide a convenience yield to the owner. The convenience yield will vary between different inventory holders. Inventories in equilibrium will be held by those that have the highest convenience yield for a marginal unit of inventory, net of storage costs. If positive amounts are held in inventory, and competition among storers ensure a unique marginal net convenience yield, then the yield will vary inversely with the amount of oil held in inventory. The benefits that accrue from ownership will increase with shortages and decrease with gluts. The net convenience yield will correlate positively with the spot oil price. The marginal net convenience yield (C) in this model is assumed to be directly proportional to the spot price (s).

$$C(S,t) = c\, s(t) \qquad (8.10)$$

The net marginal convenience yield rate per dollar unit of commodity held in inventory (c=5%) is assumed to be 2% higher than the real risk-free interest rate (r=3%). Nominal risk-free interest and inflation rates are based on 90-day

treasury bills and the consumer price index[21] (1994). Term structure is not considered.

The futures price is assumed to be the theoretical forward price, which implies that the following assumptions (Cox *et al.*, 1981) hold throughout this formulation:

- the risk free rate is known with certainty
- borrowing rates are the same as the risk-free interest rate
- all trading profits are subject to the same tax rate
- transaction costs are negligible
- arbitrage opportunities disappear as soon as they arise, so that no arbitrage opportunities persist for any length of time

The contemporaneous futures price (F) for delivery at time (T) is a function of the stochastic spot price (s) and the time to maturity ($\tau$=T–t).

$$F = F(s,\tau) \tag{8.11}$$

Ito's lemma eliminates explicit dependence on the stochastic variable, $d\zeta$, and relates the total change in the futures price to the partial changes with respect to time and the contemporaneous spot price:

$$dF = (\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 F}{\partial s^2} - \frac{\partial F}{\partial \tau})dt + \frac{\partial F}{\partial s}ds \tag{8.12}$$

A Gauss Wiener process for the futures price is obtained using Ito's lemma (8.12) in conjunction with the instantaneous return on the spot price (8.7):

$$\frac{dF}{F} = \beta dt + \gamma d\zeta \tag{8.13}$$

where $\beta$ is instantaneous expected rate of return on the futures contract:

$$\beta = F^{-1}[\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 F}{\partial s^2} + \mu s \frac{\partial F}{\partial s} - \frac{\partial F}{\partial \tau}] \tag{8.14}$$

---

21 Government of Canada 3-month treasury bills and consumer price index were obtained from Canadian Economic Observer (Nov 1994), Statistics Canada Catalogue No. 11-010 Monthly.

and $\gamma$ is standard deviation in the rate of return on the futures contract:

$$\gamma = F^{-1}[\sigma s \frac{\partial F}{\partial s}] \tag{8.15}$$

The no arbitrage assumption implies that a self-financing portfolio can be replicated with a long position in oil, a short position in oil futures contracts and funds borrowed at the risk free rate. This portfolio has $W_1$ (instantaneous) dollars invested in holding oil in inventory, $W_2$ dollars shorted in oil futures contracts and $W_3$ dollars borrowed at the risk free rate. Entering a futures contract involves no receipt or outlay of funds and borrowing is used to finance the long position in oil, such that the aggregate investment in the portfolio is zero ($W_1$-$W_3$=0). A self-financing portfolio requires zero investment and provides a zero expected return. The instantaneous return on the portfolio (dY), including the convenience yield, is a stochastic differential process:

$$dY = W_1(\frac{ds}{s} + cdt) - W_2\frac{dF}{F} - W_3 rdt \tag{8.16}$$

Substitution of Gauss Wiener processes for spot and futures prices, (8.7) and (8.13), gives:

$$dY = [W_1\sigma - W_2\gamma]d\zeta + [W_1(\mu + c - r) - W_2\beta]dt \tag{8.17}$$

A hedge ratio, or the proportion of dollar amounts invested between futures ($W_2$) and the commodity ($W_1$) are chosen so that the instantaneous return is non-stochastic.

$$W_2 = \frac{\sigma}{\gamma}W_1 = F[s\frac{\partial F}{\partial s}]^{-1}W_1 \tag{8.18}$$

The expected return on the portfolio must also be zero:

$$(\mu + c - r)W_1 - \beta W_2 = 0 \tag{8.19}$$

Substituting for $W_1$, $W_2$, and $\beta$ from (8.14), (8.18) and (8.19):

$$(\mu + c - r) - [s\frac{\partial F}{\partial s}]^{-1}\{\frac{1}{2}\sigma^2 s^2\frac{\partial^2 F}{\partial s^2} + \mu s\frac{\partial F}{\partial s} - \frac{\partial F}{\partial \tau}\} = 0 \tag{8.20}$$

leads to a deterministic nonstationary second-order partial differential equation for the futures price (Samuelson 1965, Merton 1973):

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 F}{\partial s^2} + (r-c)s\frac{\partial F}{\partial s} - \frac{\partial F}{\partial \tau} = 0 \tag{8.21}$$

An analytical solution is obtained when the convenience yield is proportional to the spot price. The terminal condition that the futures price must converge to the spot price at maturity, gives:

$$F(s,0) = s \rightarrow F(s,\tau) = se^{(r-c)\tau} \tag{8.22}$$

This implies that the spot price (s) is a sufficient statistic to determine the futures price $F(s,\tau)$. For a given depletion strategy ($\mathcal{D}$), the instantaneous production value $\mathcal{V}(s,t,\mathcal{P}_1, \mathcal{P}_2;\mathcal{D})$ is a function of the contemporaneous spot price (s), time (t) and the depletion state ($\mathcal{P}_1$, $\mathcal{P}_2$). Ito's lemma eliminates explicit dependence on the stochastic variable, $d\zeta$, and relates the change in production value to the partial changes with respect to time, spot price and depletion state:

$$d\mathcal{V} = \frac{\partial \mathcal{V}}{\partial s}ds + \{\frac{\partial \mathcal{V}}{\partial t} + \frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2}\}dt + \frac{\partial \mathcal{V}}{\partial \mathcal{P}_1}d\mathcal{P}_1 + \frac{\partial \mathcal{V}}{\partial \mathcal{P}_2}d\mathcal{P}_2 \tag{8.23}$$

Production can be sold forward through futures contracts. A self-financing portfolio is replicated with $W_1$ dollars invested in a long position in oil production with asset value $\mathcal{V}$, $W_2$ dollars shorted in oil futures and $W_3$ dollars borrowed at the risk free rate (r). Entering the futures contract involves no receipt or outlay of funds and borrowing is used to finance the long position on oil production ($W_1$=$W_3$). A self-financing portfolio requires zero investment and provides a zero expected return. The instantaneous dollar return on the portfolio, dY, including the cash flows from production ($\mathcal{C}f$) is:

$$dY = W_1(\frac{d\mathcal{V}}{\mathcal{V}} + \frac{\mathcal{C}f}{\mathcal{V}}dt) - W_2\frac{dF}{F} - W_3 r dt \tag{8.24}$$

Using Ito's lemma (8.23) and substituting for the futures price, (8.13) and (8.21), yields:

$$dY = \frac{W_1}{\mathcal{V}}\{[\mathcal{C}f + \frac{\partial \mathcal{V}}{\partial t} + \frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2}]dt + \frac{\partial \mathcal{V}}{\partial s}ds + \frac{\partial \mathcal{V}}{\partial \mathcal{P}_1}d\mathcal{P}_1 + \frac{\partial \mathcal{V}}{\partial \mathcal{P}_2}d\mathcal{P}_2\}$$
$$- \frac{W_2}{F}[(c-r)s\frac{\partial F}{\partial s}dt + \frac{\partial F}{\partial s}ds] - W_3 r dt \tag{8.25}$$

Rearranging terms with ($W_1$=$W_3$) gives:

$$dY = \{\frac{1}{\mathcal{V}}[\mathcal{C}f + \frac{\partial \mathcal{V}}{\partial t} + \frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2}] - \frac{W_2}{FW_1}(c-r)s\frac{\partial F}{\partial s} - r\}dt$$
$$+ \{\frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_1}\frac{d\mathcal{P}_1}{dt} + \frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_2}\frac{d\mathcal{P}_2}{dt}\}dt$$
$$+ [\frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial s} - \frac{W_2}{FW_1}\frac{\partial F}{\partial s}]ds \tag{8.26}$$

The instantaneous return on the portfolio is a differential stochastic process. A hedge ratio, or the proportion of dollar amounts invested in oil futures, $W_2$, is chosen so that the instantaneous return is non-stochastic.

$$W_2 = \frac{F}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial s}[\frac{\partial F}{\partial s}]^{-1} W_1 \tag{8.27}$$

The expected return on the portfolio must also be zero:

$$\{\frac{1}{\mathcal{V}}[\mathcal{C}f + \frac{\partial \mathcal{V}}{\partial t} + \frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2}] - \frac{W_2}{FW_1}(c-r)s\frac{\partial F}{\partial s} - r\}$$
$$+ \{\frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_1}\frac{d\mathcal{P}_1}{dt} + \frac{1}{\mathcal{V}}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_2}\frac{d\mathcal{P}_2}{dt}\} = 0 \tag{8.28}$$

Using the definition of near-state variables ($\mathcal{P}_1$, $\mathcal{P}_2$) in Section (7.3):

$$\frac{d\mathcal{P}_1}{dt} = Q_{o_1}(t,\mathcal{P}_1;\Theta_1)$$

$$\frac{d\mathcal{P}_2}{dt} = Q_{o_2}(t,\mathcal{P}_2;\mathcal{P}_1,\Theta_2) \tag{8.29}$$

and Eqn (8.27), leads to a deterministic nonstationary second-order partial differential equation for production value in the price-time-depletion state domain (Brennan and Schwartz 1985).

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}}{\partial s^2} - (c-r)s\frac{\partial \mathcal{V}}{\partial s} + Q_{o_1}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_1} + Q_{o_2}\frac{\partial \mathcal{V}}{\partial \mathcal{P}_2} + \frac{\partial \mathcal{V}}{\partial t} - r\mathcal{V} + Cf = 0 \tag{8.30}$$

The spot oil price state is a sufficient economic statistic to determine production value. The model describes the dynamics of a continuous diffusion process for the asset value $\mathcal{V}(s,t,\mathcal{P}_1, \mathcal{P}_2;\mathcal{D})$ of a depletion strategy ($\mathcal{D}$) over a semi-infinite continuum of price states within a feasible depletion state domain.

The first-order temporal and depletion terms represents the accumulation of value along the depletion path. Production value can concentrate locally in the price domain through a transient response or operating decision. The sign of this term suggests that the diffusion process is flowing backwards in time, so that current production value responds to future events.

The first-order price term represents drift in the growth rate trend for production value. Value grows faster at higher prices, higher net convenience yield rates and lower interest rates. The zero-order term represents the time value of money. Value is continuously compounded at the risk-free interest rate. The source term generates value for the process at a rate equal to the continuous cash flow.

The second-order price term represents value dispersion over price states. Production values disperse across the price domain as the uncertainty grows about forecasting future events further ahead in time. Value will disperse more rapidly at higher prices and higher volatilities. Values concentrate as time approaches maturity of a future event and contemporaneous expectations become more certain about a forthcoming price state. This term gives the optional stage in a flexible decision process additional waiting time value. Expected payoffs may have second-order price dependencies that manifest as changes in slope at critical price-sensitive decision boundaries. If the expected

payoff from a decision has second-order dependence on the price state, then the waiting value of the payoff will disperse back in time and provide additional value to earlier stages of the decision process.

In the special case where no price risk is associated with cash flows and forward prices are known with certainty ($\sigma \rightarrow 0$), the modern asset pricing model reduces to a discounted cash flow (DCF) formulation.

## 8.7 Action Regions

Mutually exclusive operating policies ($\Theta_1, \Theta_2$) will exhibit different remaining production values ($\mathcal{V}$) at different times (t), oil prices (s) and depletion states ($\mathcal{P}_1, \mathcal{P}_2$). The domain ($s,t,\mathcal{P}_1,\mathcal{P}_2$) is segmented into time-dependent price regions ($\mathcal{R}$) over the feasible depletion range. Primary and secondary operations will have preferred action regions ($\mathcal{R}_1, \mathcal{R}_2$) in the price-time-depletion domain (Figure 8.4). Production values within these respective regions are defined as:

$$\begin{aligned} \mathcal{V}_1 &= \mathcal{V}_1(s,t,\mathcal{P}_1; \Theta_1) && (s, t, \mathcal{P}_1) \in \mathcal{R}_1 \\ \mathcal{V}_2 &= \mathcal{V}_2(s,t, \mathcal{P}_2; \mathcal{P}_1, \Theta_2) && (s, t, \mathcal{P}_2; \mathcal{P}_1) \in \mathcal{R}_2 \end{aligned} \qquad (8.31)$$

The critical price boundary ($s_{12}^*$) that separates these actions regions will determine the price-sensitive investment decision rules for waterflood initiation.

$$s_{12}^* = s_{12}^*(t,\mathcal{P}_1) \qquad (8.32)$$

Primary production value ($\mathcal{V}_1$) depends on the primary depletion state ($\mathcal{P}_1$) and primary operating policy ($\Theta_1$). Secondary production value ($\mathcal{V}_2$) under the secondary operating policy ($\Theta_2$) depends functionally on the secondary depletion state ($\mathcal{P}_2$) and parametrically on the originating primary depletion state ($\mathcal{P}_1$). Each operational stage ($\Theta_i$) is further subdivided into operational modes ($\theta_{iC}, \theta_{iS}, \theta_{iA}$) for active control, pool suspension and early abandonment. Operating modes ($\theta_{iC}, \theta_{iS}, \theta_{iA}$) will have preferred action regions ($\mathcal{R}_{iC}, \mathcal{R}_{iS}, \mathcal{R}_{iA}$) in the price-time-depletion domain. The production value in these regions are defined as:

$$\begin{aligned} \mathcal{V}_{1m} &= \mathcal{V}_{1m}(s,t,\mathcal{P}_1; \theta_{1m}) && (s, t, \mathcal{P}_1) \in \mathcal{R}_{1m} && , m=C,S,A \\ \mathcal{V}_{2m} &= \mathcal{V}_{2m}(s,t, \mathcal{P}_2; \mathcal{P}_1, \theta_{2m}) && (s, t, \mathcal{P}_2; \mathcal{P}_1) \in \mathcal{R}_{2m} && , m=C,S,A \end{aligned} \qquad (8.33)$$

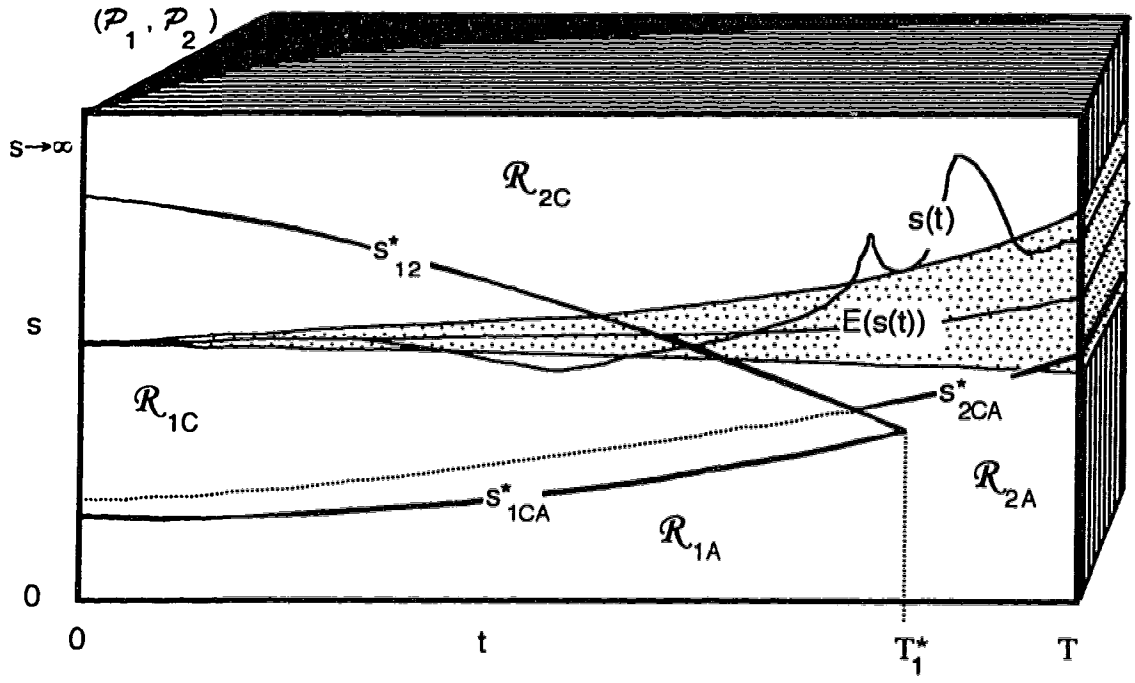



Figure 8.4: Price-Sensitive Action Regions $\mathcal{R}(\Theta_i)$ in Price-Time-Depletion

Critical price boundaries ($s_{iCS}^*, s_{iCA}^*, s_{iSA}^*$) separate operating regions from each other. These boundaries determine the price-sensitive decision rules for reversibly switching between active control and suspended operations ($s_{iCS}^*$), irreversible early abandonment from active control ($s_{iCA}^*$) and irreversible early abandonment from suspended operations ($s_{iSA}^*$).

$$
\begin{aligned}
s^*_{1CS} &= s^*_{1CS}(t,\mathcal{P}_1) \\
s^*_{1CA} &= s^*_{1CA}(t,\mathcal{P}_1) \\
s^*_{1SA} &= s^*_{1SA}(t,\mathcal{P}_1) \\
s^*_{2CS} &= s^*_{2CS}(t,\mathcal{P}_2;\mathcal{P}_1) \\
s^*_{2CA} &= s^*_{2CA}(t,\mathcal{P}_2;\mathcal{P}_1) \\
s^*_{2SA} &= s^*_{2SA}(t,\mathcal{P}_2;\mathcal{P}_1)
\end{aligned}
\qquad (8.34)
$$

The value-maximizing operating policy for a particular recovery scheme ($\Theta_i$) will have price-sensitive control decisions for the oil production rate ($Q_i$). Non-terminal operating decisions will choose between active control ($\theta_{iC}$) and pool suspension ($\theta_{iS}$).

$$\begin{aligned} Q_1(s,t,\mathcal{P}_1) &= Q_1(\mathcal{P}_1;\mathcal{C}_1) && (s,t,\mathcal{P}_1)\in\mathcal{R}_{1C} \\ &= 0 && (s,t,\mathcal{P}_1)\in\mathcal{R}_{1S} \\ Q_2(s,t,\mathcal{P}_2;\mathcal{P}_1) &= Q_2(\mathcal{P}_2;\mathcal{C}_2,\mathcal{P}_1) && (s,t,\mathcal{P}_2;\mathcal{P}_1)\in\mathcal{R}_{2C} \\ &= 0 && (s,t,\mathcal{P}_2;\mathcal{P}_1)\in\mathcal{R}_{2S} \end{aligned} \tag{8.35}$$

Active control modes ($\theta_{iC}$) will have a production rates determined by the design control policy:

$$\begin{aligned} Q_{1C} &= Q_{o_1}(\mathcal{P}_1;\mathcal{C}_1) \\ Q_{2C} &= Q_{o_2}(\mathcal{P}_2;\mathcal{P}_1,\mathcal{C}_2) \end{aligned} \tag{8.36}$$

with associated cash flows:

$$\mathcal{C}f_{iC}(s,t,Q_{iC}) = [(1-R)\,s(t) - v_i]\,Q_{iC} - f_i \quad i=1,2 \tag{8.37}$$

Dynamic value in active control regions ($\mathcal{R}_{iC}$, i=1,2) will be governed by:

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}_{iC}}{\partial s^2} - (c-r)s\frac{\partial \mathcal{V}_{iC}}{\partial s} + Q_{o_{iC}}\frac{\partial \mathcal{V}_{iC}}{\partial \mathcal{P}_i} + \frac{\partial \mathcal{V}_{iC}}{\partial t} - r\mathcal{V}_{iC} + \mathcal{C}f_{iC} = 0 \tag{8.38}$$

No production will occur during pool suspension modes ($\theta_{iS}$). Associated cash flows will only incur fixed operating costs.

$$Q_{iS} = 0 \qquad \mathcal{C}f_{iS}(t) = -f_i \qquad i=1,2 \tag{8.39}$$

Dynamic value in suspended mode regions ($\mathcal{R}_{iS}$, i=1,2) will be governed by:

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}_{iS}}{\partial s^2} - (c-r)s\frac{\partial \mathcal{V}_{iS}}{\partial s} + \frac{\partial \mathcal{V}_{iS}}{\partial t} - r\mathcal{V}_{iS} + \mathcal{C}f_{iS} = 0 \tag{8.40}$$

Early abandonment ($\theta_{iA}$) is a terminating mode of operation that will establish the economic limit. Economic reserves will be exhausted and no more production will occur. The operation will have a negative value at the time of abandonment from incurring a lump sum mandatory abandonment expense ($A_i$). Remaining static value in early abandonment regions ($\mathcal{R}_{iA}$, i=1,2) is constant.

$$\mathcal{V}_{iA} = -A_i \tag{8.41}$$

## 8.8 Boundary Conditions

The critical price boundaries determine the operating and investment decision rules. These critical boundaries are found by maximizing the overall production asset value of the entire depletion strategy. Conditions at certain boundaries must be defined to determine particular asset values. Boundary conditions for production value are specified for:

- asymptotic price limit
- price origin
- terminal time
- primary and secondary depletion state feasible boundaries
- critical irreversible investment price boundary
- critical primary and secondary irreversible abandonment boundaries
- critical primary and secondary reversible suspension boundaries

An asymptotic limit will bound growth in the dynamic value of the non-terminal action regions that exist at higher prices.

$$\frac{\partial^2 \mathcal{V}_{im}}{\partial s^2} = o\left(\frac{1}{s^2}\right) \text{ as } s \to \infty \quad \text{for all } \mathcal{R}_{im} \{i = 1,2; m = C,S\} \tag{8.42}$$

The valuation model exhibits an absorbing state at zero price (s=0). The cash flow model implies that operating costs will still be incurred in the absence of production revenues. The valuation model at the price origin degenerates into a differential equation independent of the price state. Value dynamics at the price origin will depend on time and depletion states, only.

$$\mathcal{V}_{1m}(0,t,\mathcal{P}_1;\theta_{1m}) = \mathcal{V}_{1m}(t,\mathcal{P}_1;\theta_{1m}) \qquad (0,t,\mathcal{P}_1) \in \mathcal{R}_{1m} \quad , m=C,S$$
$$\mathcal{V}_{2m}(0,t,\mathcal{P}_2;\mathcal{P}_1,\theta_{2m}) = \mathcal{V}_{2m}(t,\mathcal{P}_2;\mathcal{P}_1,\theta_{2m}) \qquad (0,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2m} \quad , m=C,S \tag{8.43}$$

The primary action region ($\mathcal{R}_1$) will exist up to a time, $T_1^* \leq T$, at which point primary operations ($\Theta_1$) will terminate, either through mandatory abandonment (t=T), early abandonment ($\theta_{iA}$), or by irreversibly switching to secondary operations, ($\Theta_2$). Operations that exist at the end of the strategic plan duration (t=T), will have a negative terminal value from incurring a lump sum mandatory abandonment expense ($A_i$).

$$\mathcal{V}_i(s,T,\mathcal{P}_1,\mathcal{P}_2;\{\Theta_i \mid \mathcal{R}_i \text{ exists at } t=T\}) = -A_i \tag{8.44}$$

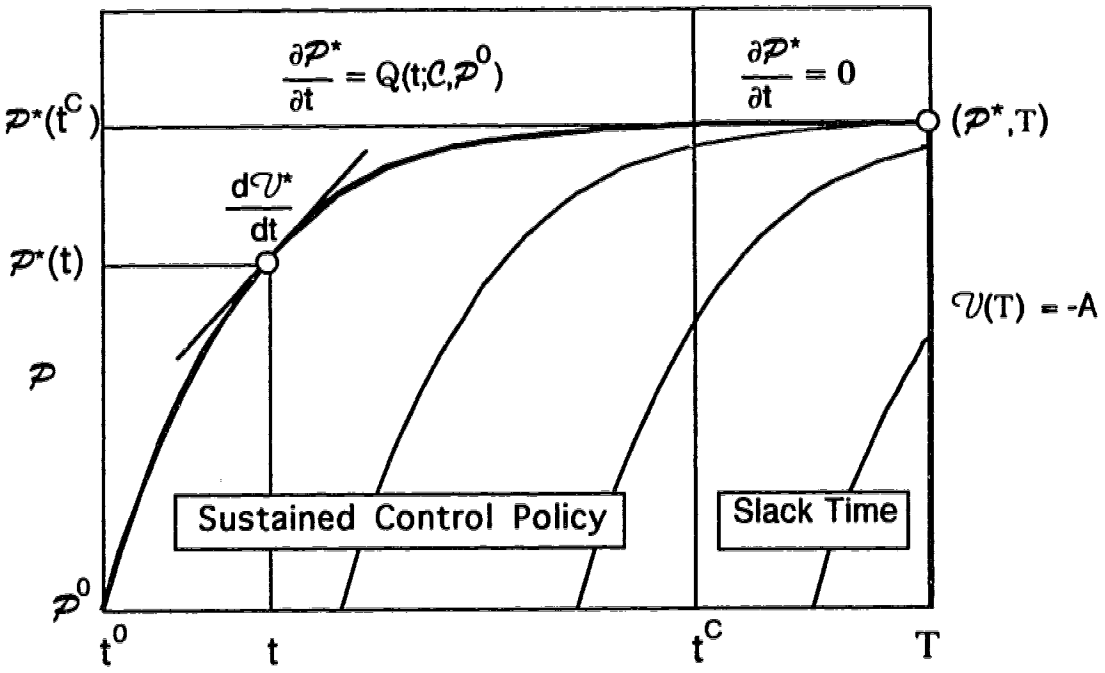



Figure 8.5: Terminal Mandatory Abandonment Boundary Condition

Action regions will have corresponding terminal conditions:

$$\begin{aligned} &\mathcal{V}_{1m}(s,T,\mathcal{P}_1;\theta_{1m}) = -A_1 \quad \text{if } (s,T,\mathcal{P}_1) \in \mathcal{R}_{1m} \quad , m=C,S,A \\ &\mathcal{V}_{2m}(s,T,\mathcal{P}_2;\mathcal{P}_1,\theta_{2m}) = -A_2 \quad \text{if } (s,T,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2m} \quad , m=C,S,A \end{aligned} \tag{8.45}$$

All depletion path possibilities will be truncated at the terminal time (t=T). The terminal condition applies at branch endpoints of primary and secondary

depletion state feasible boundaries. By definition, the feasible boundary is the maximum limit under sustained active control with no suspension possibilities. The time derivative along any active control path including the boundary path is:

$$\left.\frac{d\mathcal{V}_1}{dt}\right|_{Control} = \frac{\partial \mathcal{V}_1}{\partial t} + Q_{o1}(\mathcal{P}_1; \mathcal{C}_1)\frac{\partial \mathcal{V}_1}{\partial \mathcal{P}_1}$$

$$\left.\frac{d\mathcal{V}_2}{dt}\right|_{Control} = \frac{\partial \mathcal{V}_2}{\partial t} + Q_{o2}(\mathcal{P}_2; \mathcal{C}_2, \mathcal{P}_1)\frac{\partial \mathcal{V}_2}{\partial \mathcal{P}_2} \qquad (8.46)$$

The time derivative along the boundary path (*) with the terminal abandonment condition define the primary and secondary constrained depletion boundary conditions (Figure 8.5).

$$\left.\frac{d\mathcal{V}_1}{dt}\right|^* = \left.\frac{\partial \mathcal{V}_1}{\partial t}\right|^* + Q_{o1}(\mathcal{P}_1^*(t))\left.\frac{\partial \mathcal{V}_1}{\partial \mathcal{P}_1}\right|^* \qquad \mathcal{V}_1(s,T)\Big|^* = -A_1$$

$$\left.\frac{d\mathcal{V}_2}{dt}\right|^* = \left.\frac{\partial \mathcal{V}_2}{\partial t}\right|^* + Q_{o2}(\mathcal{P}_2^*(t;\mathcal{P}_1))\left.\frac{\partial \mathcal{V}_2}{\partial \mathcal{P}_2}\right|^* \qquad \mathcal{V}_2(s,T;\mathcal{P}_1)\Big|^* = -A_2$$

(8.47)

Critical price boundaries are prices at which the depletion strategy is indifferent between alternative choices. The structure of these critical boundaries will depend on how the decision-making process polls progressive performance and forecasts future expectations. Performance can be continuously polled or measured at discrete events. Discrete events can be marked by either the passage of time or by incremental production.

Continuous forecasting of path-dependent secondary recovery was deemed as virtually intractable in Section 7.1 and decision pathways were restricted to discrete investment timing options at selected primary depletion milestones (Figure 8.6). This implies that even if performance could be polled continuously, investment decisions must still be based on discrete primary production milestones that evolve continuously with time. In essence, decisions are made at discrete depletion states that are continuously tracked in time (Figure 8.7).

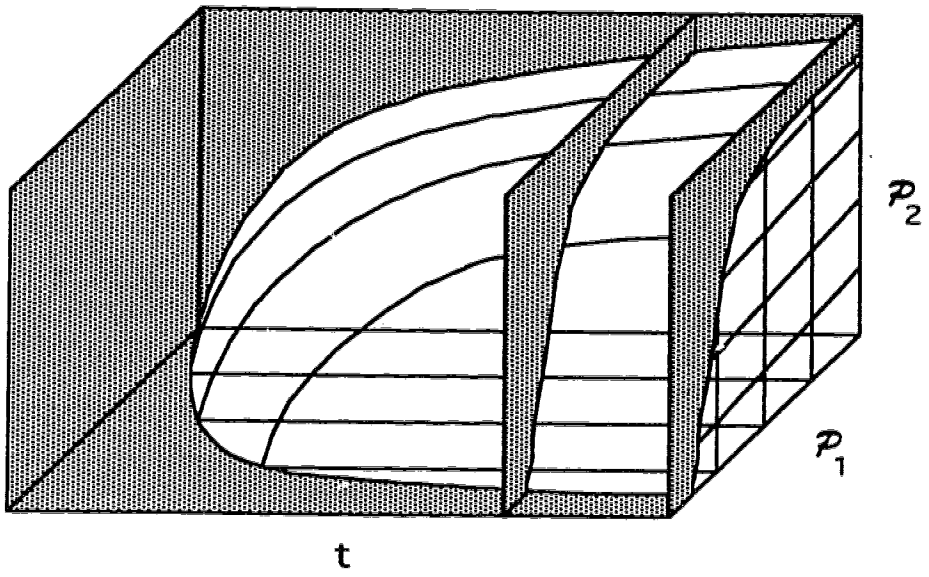



Figure 8.6: Feasible Depletion Space at Discrete Primary Oil Milestones

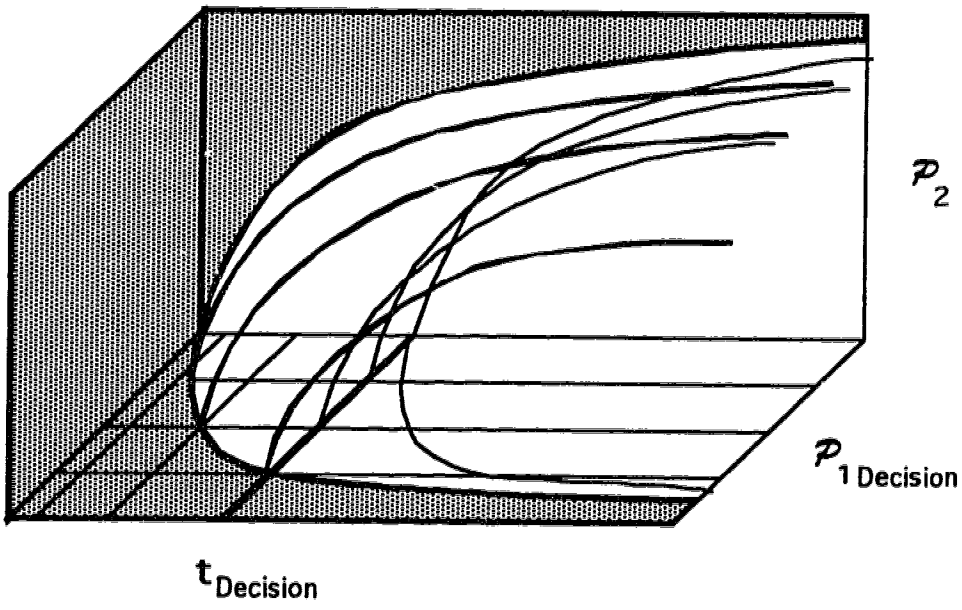



Figure 8.7: Decision Times Track Discrete Depletion Milestones

This means that time interval between discrete decisions can vary as production rates change. Decision times are chosen not to exceed quarterly intervals. This also means that the secondary recovery option cannot be exercised at transitional depletion states between primary production milestones. Hence, the model investment decision process is limited to a wait-and-see approach in the depletion state-time domain (Figure 8.8).

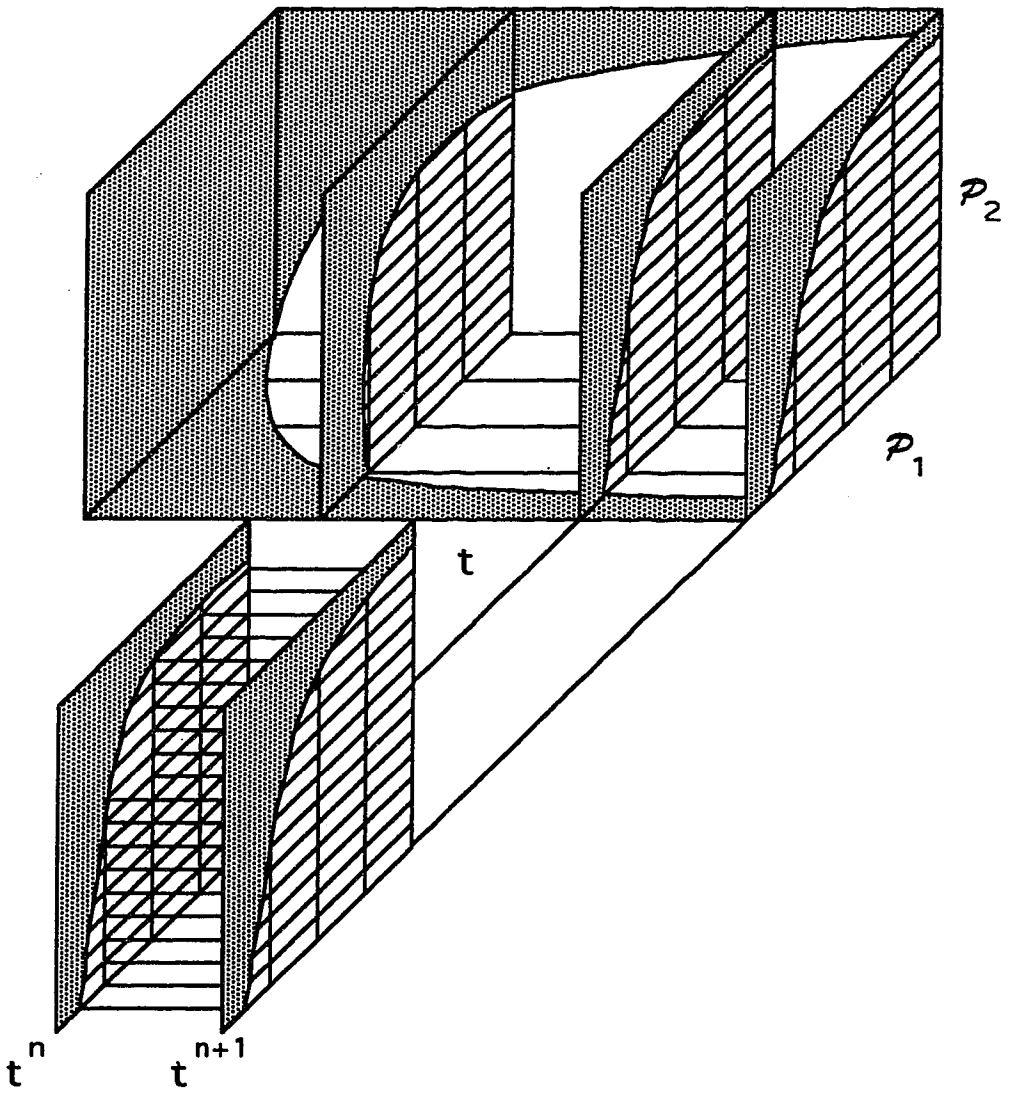



Figure 8.8: Feasible Depletion Space at Discrete Decision Times

The irreversible investment decision to choose secondary operations ($\Theta_2$) while in primary operations ($\Theta_1$) will depend on the relative values at the oil price and primary depletion state at the time of decision. If the expected value from initiating waterflood $\mathcal{V}_2(s,t,\mathcal{P}_2=0;\Theta_2,\mathcal{P}_1)$, net of capital investment ($K_{12}$), is greater than the remaining value of the originating primary production policy $\mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1)$, then a value-maximizing investment action will shift from primary ($\mathcal{R}_1$) to secondary operations ($\mathcal{R}_2$). The remaining production value of either pathway depends on the contemporaneous reservoir state of the originating primary recovery stage in progress. This state depends on the historical depletion path followed up to the time the investment decision is made. The value of a particular alternative depends on the remaining depletion pathways and price state possibilities that follow. If the investment decision is made, then production controls applicable to the new secondary policy determine depletion pathways. If the investment decision is not made, controls for the originating primary policy remain in place. The irreversible, mutually-exclusive investment timing decision will not affect the remaining production values distinct to the respective actions. This implies that the critical price can be determined with certainty. The discrete formulation ensures no dispersion in remaining production value between mutually exclusive alternatives by placing them on separate branched pathways. The expected production value at a particular point in time from cash flow streams along remaining depletion pathways in one region will not distort the expected production value from the other.

$$\mathcal{V}_1(s=s^*_{12},t,\mathcal{P}_1;\Theta_1) = \mathcal{V}_2(s=s^*_{12},t,\mathcal{P}_2=0;\Theta_2,\mathcal{P}_1) - K_{12} \qquad (8.48)$$
$$\text{where } s^*_{12}(t,\mathcal{P}_1) = \mathcal{R}_1 \cap \mathcal{R}_2$$

The payoff ($\Delta\mathcal{V}_{12}$) from the waterflood investment option will be the value added from secondary recovery:

$$\Delta\mathcal{V}_{12} = \max\left[0, \mathcal{V}_2(s,t,\mathcal{P}_2=0;\mathcal{P}_1,\Theta_2) - K_{12} - \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1)\right] \qquad (8.49)$$

The payoff is a function of the contemporaneous spot price at decision time. The payoff increases as waterflood value, net of the capital investment, rises above the primary production value. Investment action will only proceed if the net payoff is positive and value can be added by waterflood.

$$\begin{aligned} &\mathcal{V}_2(s,t,\mathcal{P}_2=0;\mathcal{P}_1,\Theta_2) - K_{12} > \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) \quad \rightarrow \{(s,t,\mathcal{P}_1,\mathcal{P}_2)\in\mathcal{R}_2\} \\ &\mathcal{V}_2(s,t,\mathcal{P}_2=0;\mathcal{P}_1,\Theta_2) - K_{12} \leq \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) \quad \rightarrow \{(s,t,\mathcal{P}_1,\mathcal{P}_2)\in\mathcal{R}_1\} \end{aligned} \qquad (8.50)$$

The price boundary between regions is the critical investment price ($s_{12}^*$) at which the payoff is indifferent to either alternative. Primary and secondary action regions will have nested value-maximizing sub-regions for the three mutually-exclusive operational modes of active control (C), pooled suspension (S) and early abandonment (A). Critical price boundaries reflect indifference between alternative choices. The three-way choice between two reversible modes (C,S) and one terminal mode (A) leads to three nested critical price boundaries: C-S, C-A and S-A.

$$\begin{aligned}
&\mathcal{V}_{1C}(s^*_{1CS},t,\mathcal{P}_1) = \mathcal{V}_{1S}(s^*_{1CS},t,\mathcal{P}_1) && s^*_{1CS}(t,\mathcal{P}_1) = \mathcal{R}_{1C} \cap \mathcal{R}_{1S}\\
&\mathcal{V}_{1C}(s^*_{1CA},t,\mathcal{P}_1) = -A_1 && s^*_{1CA}(t,\mathcal{P}_1) = \mathcal{R}_{1C} \cap \mathcal{R}_{1A}\\
&\mathcal{V}_{1S}(s^*_{1SA},t,\mathcal{P}_1) = -A_1 && s^*_{1SA}(t,\mathcal{P}_1) = \mathcal{R}_{1S} \cap \mathcal{R}_{1A}\\
&\mathcal{V}_{2C}(s^*_{2CS},t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2S}(s^*_{2CS},t,\mathcal{P}_2;\mathcal{P}_1) && s^*_{2CS}(t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{R}_{2C} \cap \mathcal{R}_{2S}\\
&\mathcal{V}_{2C}(s^*_{2CA},t,\mathcal{P}_2;\mathcal{P}_1) = -A_2 && s^*_{2CA}(t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{R}_{2C} \cap \mathcal{R}_{2A}\\
&\mathcal{V}_{2S}(s^*_{2SA},t,\mathcal{P}_2;\mathcal{P}_1) = -A_2 && s^*_{2SA}(t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{R}_{2S} \cap \mathcal{R}_{2A}
\end{aligned} \tag{8.51}$$

Action sub-regions are chosen to maximize value over remaining decision pathways that stem from contemporaneous operation under one of the three alternative operating modes. Remaining primary value is,

$$\mathcal{V}_1(s,t,\mathcal{P}_1) = \max\{\mathcal{V}_{1C}(s,t,\mathcal{P}_1), \mathcal{V}_{1S}(s,t,\mathcal{P}_1), -A_1\} \tag{8.52}$$

with nested primary operating action regions:

$$\left.\begin{aligned}
\Theta_1(s,t,\mathcal{P}_1) &= C \quad \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = \mathcal{V}_{1C}(s,t,\mathcal{P}_1)\\
&= S \quad \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = \mathcal{V}_{1S}(s,t,\mathcal{P}_1)\\
&= A \quad \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = -A_1
\end{aligned}\right] \tag{8.53}$$

Remaining secondary value is,

$$\mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \max\{\mathcal{V}_{2C}(s,t,\mathcal{P}_2;\mathcal{P}_1), \mathcal{V}_{2S}(s,t,\mathcal{P}_2;\mathcal{P}_1), -A_2\} \tag{8.54}$$

with nested secondary operating action regions:

$$\left.\begin{aligned}\Theta_2(s,t,\mathcal{P}_2;\mathcal{P}_1) &= C \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2C}(s,t,\mathcal{P}_2;\mathcal{P}_1)\\ &= S \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2S}(s,t,\mathcal{P}_2;\mathcal{P}_1)\\ &= A \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = -A_2\end{aligned}\right] \tag{8.55}$$

## 8.9 Decision Model Summary

The mathematical decision model for maximizing the modelled economic value ($\mathcal{V}$) of remaining operating alternatives over a strategic window is summarized below:

- Depletion Strategy Objective

$$\max \mathcal{V}(s,t,\mathcal{P}_1,\mathcal{P}_2;\mathcal{D})$$

$$s \geq 0$$

$$0 \leq t \leq T$$

$$0 \leq \mathcal{P}_1 \leq \overset{*}{\mathcal{P}}_1(t)$$

$$0 \leq \mathcal{P}_2 \leq \overset{*}{\mathcal{P}}_2(t;\mathcal{P}_1)$$

- Primary and Secondary Segmentation

$$\begin{aligned}\mathcal{V}(s,t,\mathcal{P}_1,\mathcal{P}_2;\mathcal{D}) &= \mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) && \text{if } (s,t,\mathcal{P}_1) \in \mathcal{R}_1\\ &= \mathcal{V}_2(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1) && \text{if } (s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_2\end{aligned}$$

$$\begin{aligned}\mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) &= \mathcal{V}_{1C}(s,t,\mathcal{P}_1;\theta_{1C}) && \text{if } (s,t,\mathcal{P}_1) \in \mathcal{R}_{1C}\\ &= \mathcal{V}_{1S}(s,t,\mathcal{P}_1;\theta_{1S}) && \text{if } (s,t,\mathcal{P}_1) \in \mathcal{R}_{1S}\\ &= \mathcal{V}_{1A}(s,t,\mathcal{P}_1;\theta_{1A}) && \text{if } (s,t,\mathcal{P}_1) \in \mathcal{R}_{1A}\end{aligned}$$

$$\begin{aligned}\mathcal{V}_2(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1) &= \mathcal{V}_{2C}(s,t,\mathcal{P}_2;\theta_{2C},\mathcal{P}_1) && \text{if } (s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2C}\\ &= \mathcal{V}_{2S}(s,t,\mathcal{P}_2;\theta_{2S},\mathcal{P}_1) && \text{if } (s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2S}\\ &= \mathcal{V}_{2A}(s,t,\mathcal{P}_2;\theta_{2A},\mathcal{P}_1) && \text{if } (s,t,\mathcal{P}_2;\mathcal{P}_1) \in \mathcal{R}_{2A}\end{aligned}$$

- Production Control Policy Subject to Regulatory Constraints

$$Q_{1C} = Q_{o_1}(\mathcal{P}_1; \mathcal{C}_1)$$

$$Q_{2C} = Q_{o_2}(\mathcal{P}_2; \mathcal{P}_1, \mathcal{C}_2)$$

- Before Tax Cash Flow Model (i=1,2)

$$\mathcal{C}f_{iC}(s,t,Q_{iC}) = [(1-R)\,s(t) - v_i]\,Q_{iC} - f_i$$
$$\mathcal{C}f_{iS}(t) = -f_i$$

- Active Control Mode (C) Dynamic Value (i=1,2)

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}_{iC}}{\partial s^2} - (c-r)s\frac{\partial \mathcal{V}_{iC}}{\partial s} + Q_{o_{iC}}\frac{\partial \mathcal{V}_{iC}}{\partial \mathcal{P}_i} + \frac{\partial \mathcal{V}_{iC}}{\partial t} - r\mathcal{V}_{iC} + \mathcal{C}f_{iC} = 0$$

- Pooled Suspension Mode (S) Dynamic Value (i=1,2)

$$\frac{1}{2}\sigma^2 s^2 \frac{\partial^2 \mathcal{V}_{iS}}{\partial s^2} - (c-r)s\frac{\partial \mathcal{V}_{iS}}{\partial s} + \frac{\partial \mathcal{V}_{iS}}{\partial t} - r\mathcal{V}_{iS} + \mathcal{C}f_{iS} = 0$$

- Early Abandonment Mode (A) Static Value (i=1,2)

$$\mathcal{V}_{iA} = -A_i$$

- Price Origin Boundary Condition (m=C,S)

$$\mathcal{V}_{1m}(0,t,\mathcal{P}_1; \theta_{1m}) = \mathcal{V}_{1m}(t,\mathcal{P}_1; \theta_{1m})$$
$$\mathcal{V}_{2m}(0,t,\mathcal{P}_2; \mathcal{P}_1, \theta_{2m}) = \mathcal{V}_{2m}(t,\mathcal{P}_2; \mathcal{P}_1, \theta_{2m})$$

- Asymptotic Price Boundary Condition (i=1,2; m=C,S)

$$\frac{\partial^2 \mathcal{V}_{im}}{\partial s^2} = O\left(\frac{1}{s^2}\right) \text{ as } s \to \infty$$

- Terminal Boundary Condition (m=C,S)

$$\mathcal{V}_{1m}(s,t=T,\mathcal{P}_1) = -A_1$$
$$\mathcal{V}_{2m}(s,t=T,\mathcal{P}_2;\mathcal{P}_1) = -A_2$$

- Depletion Boundary Constraint

$$\left.\frac{d\mathcal{V}_1}{dt}\right|^* = \left.\frac{\partial \mathcal{V}_1}{\partial t}\right|^* + Q_{o_1}(\mathcal{P}_1^*(t))\left.\frac{\partial \mathcal{V}_1}{\partial \mathcal{P}_1}\right|^*$$

$$\left.\frac{d\mathcal{V}_2}{dt}\right|^* = \left.\frac{\partial \mathcal{V}_2}{\partial t}\right|^* + Q_{o_2}(\mathcal{P}_2^*(t;\mathcal{P}_1))\left.\frac{\partial \mathcal{V}_2}{\partial \mathcal{P}_2}\right|^*$$

- Nested Critical Operating Price Boundary Conditions

$$\mathcal{V}_{1C}(s^*_{1CS},t,\mathcal{P}_1) = \mathcal{V}_{1S}(s^*_{1CS},t,\mathcal{P}_1) \qquad s^*_{1CS}(t,\mathcal{P}_1) = \mathcal{R}_{1C}\cap\mathcal{R}_{1S}$$
$$\mathcal{V}_{1C}(s^*_{1CA},t,\mathcal{P}_1) = -A_1 \qquad s^*_{1CA}(t,\mathcal{P}_1) = \mathcal{R}_{1C}\cap\mathcal{R}_{1A}$$
$$\mathcal{V}_{1S}(s^*_{1SA},t,\mathcal{P}_1) = -A_1 \qquad s^*_{1SA}(t,\mathcal{P}_1) = \mathcal{R}_{1S}\cap\mathcal{R}_{1A}$$
$$\mathcal{V}_{2C}(s^*_{2CS},t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2S}(s^*_{2CS},t,\mathcal{P}_2;\mathcal{P}_1) \qquad s^*_{2CS}(t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{R}_{2C}\cap\mathcal{R}_{2S}$$
$$\mathcal{V}_{2C}(s^*_{2CA},t,\mathcal{P}_2;\mathcal{P}_1) = -A_2 \qquad s^*_{2CA}(t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{R}_{2C}\cap\mathcal{R}_{2A}$$
$$\mathcal{V}_{2S}(s^*_{2SA},t,\mathcal{P}_2;\mathcal{P}_1) = -A_2 \qquad s^*_{2SA}(t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{R}_{2S}\cap\mathcal{R}_{2A}$$

- Nested Primary (i=1) Operating Decisions

$$\mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1) = \max[\mathcal{V}_{1C}(s,t,\mathcal{P}_1;\theta_{1C}),\mathcal{V}_{1S}(s,t,\mathcal{P}_1;\theta_{1S}),-A_1]$$

$$s\geq 0;\ (t,\mathcal{P}_1)\in\{(t,\mathcal{P}_1)_{Decision}\mid 0\leq t\leq T;\ 0\leq\mathcal{P}_1\leq\mathcal{P}_1^*(t)\}$$

$$\left.\begin{aligned}\Theta_1(s,t,\mathcal{P}_1) &= C \quad \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = \mathcal{V}_{1C}(s,t,\mathcal{P}_1)\\ &= S \quad \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = \mathcal{V}_{1S}(s,t,\mathcal{P}_1)\\ &= A \quad \text{if } \mathcal{V}_1(s,t,\mathcal{P}_1) = -A_1\end{aligned}\right]$$

- Nested Secondary (i=2) Operating Decisions

$$\mathcal{V}_2(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1) = \max\left[\mathcal{V}_{2C}(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1),\mathcal{V}_{2S}(s,t,\mathcal{P}_2;\Theta_2,\mathcal{P}_1),-A_2\right]$$

$$s \geq 0\ ;\ (t,\mathcal{P}_1) \in \{(t,\mathcal{P}_1)_{Decision} \mid 0 \leq t \leq T\ ;\ 0 \leq \mathcal{P}_1 \leq \mathcal{P}_1^*(t)\}$$

$$\mathcal{P}_2 \in \{(\mathcal{P}_2)_{Decision} \mid 0 \leq \mathcal{P}_2 \leq \mathcal{P}_2^*(t;\mathcal{P}_1)\}$$

$$\left.\begin{aligned}\Theta_2(s,t,\mathcal{P}_2;\mathcal{P}_1) &= C \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2C}(s,t,\mathcal{P}_2;\mathcal{P}_1)\\ &= S \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = \mathcal{V}_{2S}(s,t,\mathcal{P}_2;\mathcal{P}_1)\\ &= A \quad \text{if } \mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1) = -A_2\end{aligned}\right]$$

- Critical Investment Price Boundary Condition

$$\mathcal{V}_1(s = s_{12}^*, t, \mathcal{P}_1;\Theta_1) = \mathcal{V}_2(s = s_{12}^*, t, \mathcal{P}_2 = 0;\Theta_2, \mathcal{P}_1) - K_{12}$$

where $s_{12}^*(t,\mathcal{P}_1) = \mathcal{R}_1 \cap \mathcal{R}_2$

- Investment Timing Decision

$$\max\left[\mathcal{V}_1(s,t,\mathcal{P}_1;\Theta_1),\mathcal{V}_2(s,t,\mathcal{P}_2 = 0;\Theta_2,\mathcal{P}_1) - K_{12}\right]$$

$$s \geq 0\ ;\ (t,\mathcal{P}_1) \in \{(t,\mathcal{P}_1)_{Decision} \mid 0 \leq t \leq T\ ;\ 0 \leq \mathcal{P}_1 \leq \mathcal{P}_1^*(t)\}$$

$$\rightarrow \max \mathcal{V}(s,t,\mathcal{P}_1,\mathcal{P}_2;\mathcal{D})$$

# Chapter 9: Depletion Strategy

## 9.1 Dynamic Programming

The effect of any initial choice of allowable actions in $\mathscr{D}$ will convert the reservoir state $(\mathscr{P}_1, \mathscr{P}_2)^n$ at time $(t^n)$, over the time interval $[t^n, t^n+\Delta t]$, into a new state $(\mathscr{P}_1, \mathscr{P}_2)^{n+1}$ at time $(t^n+\Delta t)$, by way of the differential equations governing the reservoir dynamic response under the control policy that satisfies regulatory constraints. Over the same period, the price state $(s^n)$ will change to $(s^{n+1})$, by way of the exogenous continuous random walk model for volatile future price movements. Whatever the initial choice of action is over $[t^n, t^n+\Delta t]$, an optimization problem of precisely the same form as the original will apply over the remaining interval $[t^n+\Delta t, T]$, with the only difference being that $(s, \mathscr{P}_1, \mathscr{P}_2)^n$ is replaced by $(s, \mathscr{P}_1, \mathscr{P}_2)^{n+1}$.

$$\max \mathscr{V}(s,t,\mathscr{P}_1, \mathscr{P}_2; \mathscr{D}) \tag{9.1}$$

The principle of optimality (Bellman, 1957) states:

"An optimal policy has the property that whatever the initial state and initial decision are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision."

For the multi-step policy to be optimal, it must be optimal at each step. A numerical algorithm based on finite-difference dynamic programming methods with critical boundary tracking procedures is presented in Appendix A2. The dynamic programming procedure marches from known terminal states, back in time and depletion, to the initial decision point. Price-sensitive value-maximizing actions are tracked in the feasible depletion space at discrete decision times.

## 9.2 Model Results

The depletion strategy for the optional waterflood design proposed for Chedderville Viking "A" was constructed with decision times not exceeding quarterly intervals at discrete primary and secondary depletion state cumulative oil production milestones. The expected median of future oil prices are the same as the current oil price ($20/bbl). The annual price volatility is set at 23.3%. The real risk-free interest rate is held constant at 3% and the convenience yield rate at 5%. Table 9.1(a)-(j) tabulates the schedules of price-

sensitive decision rules for waterflood investment action while under primary operations. These schedules are listed for future times, measured in years, from the start of the strategic depletion plan (Oct-1-95) which is one year in the future from the current time (Oct-1-94). Action regions and remaining project value are tabulated as functions of the feasible primary depletion state and contemporaneous spot oil price at selected times. Figure 9.1 plots the remaining value at selected times as functions of the primary depletion state and spot oil price. Remaining values decrease with time and depletion state and increase with oil price.

Table 9.1(a) indicates that the value-maximizing action at the beginning of the plan (Oct-1-95) is to invest in the waterflood if oil prices are above $13/bbl and to abandon operations if oil prices drop below $6/bbl. The expected net contemporaneous value of the waterflood is $40.7 million for a $32.4 million capital outlay on Oct-1-95 if the contemporaneous oil price is $20/bbl. The sustained primary depletion boundary path develops over the 12 year primary production life cycle (Tables 9.1(a)-(d)). Waterflood investment decisions are made at discrete primary production milestones and primary operations are assumed to prevail over transitionary depletion states marked by the leading edge of the primary depletion path ($\mathcal{P}_1=\mathcal{P}_1^*$). The critical investment price remains steady at $13/bbl over the first 4 years (Table 9.1(d)) and rises slowly to $15/bbl by the end of feasible waterflood window ($\mathcal{P}_1$=800 MSTB) over 12 years of primary production (Table 9.1(f)). The critical investment price increases steadily over remaining futures times (t >12 years) as the proposed 20 year waterflood duration is truncated short at the terminal 32 year strategic window (Tables 9.1(f)-(j)). If primary operations are in progress at the end of 24 years, then the secondary option with 8 years of waterflood is still the better choice at the expected median oil price of $20/bbl (Table 9.1(i)). After 28 years, the secondary option with less than 4 years of waterflood cannot deliver the additional value to warrant investment at $20/bbl (Table 9.1(j)). The transient effects of the finite duration depletion strategy become pronounced after 24 years with returns diminishing as waterfloods are truncated (Figure 9.1).

The depletion strategy has price-sensitive decision rules for secondary operations that stem from waterflood initiation at discrete primary depletion states. The full package of 32 annual decision rules for all primary launch points ($\leq$9) constitutes over 200 individual tables. Only selected times for the initial primary launch point ($\mathcal{P}_1$=0) will be shown here, since this is the one most likely to be implemented from the start. Net secondary values at primary launch points that exceed the critical investment floor are explicit in the primary schedules. Table 9.2(a)-(i) tabulates the schedules of price-sensitive decision rules for secondary operations if waterflood is initiated from the current primary depletion

state ($\mathcal{P}_1$=0). Action regions and remaining gross secondary value are tabulated as functions of the feasible secondary depletion state and contemporaneous spot oil price at selected times. Figure 9.2 plots the remaining secondary value at selected times as functions of the secondary depletion state and spot oil price. Remaining values decrease with time and depletion state and increase with oil price. Table 9.2(a) indicates that the current economic limit abandonment price is about $5/bbl. Pooled suspension is sub-optimal so that no price regions appear. Remaining secondary value decreases rapidly with increasing cumulative secondary production (Figure 9.2).The same transient effects of the finite duration depletion strategy become pronounced after 24 years with returns diminishing as waterfloods are truncated. It should be noted that the investment regions in the primary schedules are only based on starting secondary values as indicated by the trailing edge of individual dune-like profiles. The economic limit abandonment price increases with secondary depletion. The economic limit is above the expected median oil price ($20/bbl) before the end of the planned waterflood life ($\mathcal{P}_2$=9500 MSTB) as shown in Table 9.2(g). This implies that the planned waterflood may be cut short by a couple of years and abandoned early if the contemporaneous oil price is below $21/bbl at t=18 years.

Primary values ($\mathcal{V}_1$) include long positions in a waterflood call option and an early abandonment put option, while secondary values ($\mathcal{V}_2$) include only the put option on early abandonment. The dune-like profiles represented in Figures 9.1 and 9.2 are extensions of the hockey-stick payoff functions in the price domain that are familiar to financial options. The downside risk in both primary and secondary operations are hedged using a protective put strategy (Hull 1991) which is the combination of a long position in the production asset and a long position in an early abandonment American put option. The put option is only exercised if the payoff from early abandonment is greater than the payoff from continued operations. The waterflood call option is only exercised if the payoff from waterflood is greater than the payoff from continued primary operations.

The price at which the early abandonment put option is exercised is the price that determines the economic limit of the operation. Table 9.3 tabulates the primary economic limit annually for different stages of primary depletion. Figure 9.3 plots these critical abandonment prices as functions of time and primary depletion state. The primary economic limit increases with depletion state. The economic limit for sustained primary production over the full strategic window is below the expected median oil price ($20/bbl). Table 9.4 tabulates the secondary economic limit annually for different stages of secondary depletion for all admissible primary launch states. The evolution of the feasible depletion boundary can be seen over consecutive years. Highlighted cells that

have no numeric value represent out-of-range prices. It should be noted that leading cells in the depletion front do not necessarily coincide with the depletion partition and may represent partial intervals. Economic limits generally increase with increasing depletion. However, secondary cash flows are generally lower over an initial waterflood period which also diminish with waterflood timing delay. The incremental value over the initial period may be subject to net cash outflow before benefits can be realized further down the depletion path. The economic limit will therefore be higher initially to reflect lower secondary output and potential decreases in incremental value. The general trend picks up after initially low output. Transient effects become apparent only in the last two years of the strategic plan. Figure 9.4 plots critical abandonment prices as functions of time and secondary depletion state for the initial primary launch point ($\mathcal{P}_1$=0). The economic waterflood life may be cut short by a couple of years if the oil price stays about the expected median oil price ($20/bbl).

The pooled suspension operating mode does not exist in this depletion strategy. This implies that the active control and early abandonment regions totally mask the sub-optimal suspended pool operating choice. The compound interest on the abandonment expense is much less than the annuity of fixed costs. Fixed costs would have to come down an order of magnitude before the option to suspend production becomes more cost-effective than early abandonment.

## 9.3 Recommended Action

The recommended action for Chedderville Viking "A" is facilitate a detailed waterflood design based on the proposed model and implement a revised depletion strategy as soon as possible. Accelerated pilot studies may be needed to verify model predictions for waterflood response. The strategic plan for remaining production possibilities should be revised periodically as new information emerges from continued production.

## 9.4 Model Limitations

The decision model is based on a probability structure of macro-economic scenarios that assume a random walk in volatile price movements. This assumption is reasonable in the absence of oil price shocks. Reversion models should be used to describe price behaviour for scenarios that include these events.

| t=0 yrs | Primary | Secondary | Abandon |
|---|---|---|---|
| Oil Prices ($/bbl) | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | |
| | 0 | | |
| $0 | -$1.0 | | |
| $1 | -$1.0 | | |
| $2 | -$1.0 | | |
| $3 | -$1.0 | | |
| $4 | -$1.0 | | |
| $5 | -$1.0 | | |
| $6 | -$1.0 | | |
| $7 | -$0.9 | | |
| $8 | -$0.9 | | |
| $9 | -$0.7 | | |
| $10 | -$0.6 | | |
| $11 | -$0.4 | | |
| $12 | -$0.1 | | |
| $13 | $3.7 | | |
| $14 | $8.9 | | |
| $15 | $14.2 | | |
| $16 | $19.5 | | |
| $17 | $24.7 | | |
| $18 | $30.0 | | |
| $19 | $35.3 | | |
| $20 | $40.7 | | |
| $21 | $46.1 | | |
| $22 | $51.5 | | |
| $23 | $56.9 | | |
| $24 | $62.4 | | |
| $25 | $67.8 | | |
| $26 | $73.2 | | |
| $27 | $78.7 | | |
| $28 | $84.1 | | |
| $29 | $89.6 | | |
| $30 | $95.1 | | |
| $31 | $100.6 | | |
| $32 | $106.0 | | |
| $33 | $111.6 | | |
| $34 | $117.1 | | |
| $35 | $122.6 | | |
| $36 | $128.1 | | |
| $37 | $133.6 | | |
| $38 | $139.1 | | |
| $39 | $144.6 | | |
| $40 | $150.1 | | |

Table 9.1(a): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=0)

| t=1 yrs | Primary | Secondary | Abandon |
|---|---|---|---|
| Oil Price | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | |
| s ($/bbl) | 0 | 100 | 149 |
| $0 | -$1.0 | -$1.0 | -$1.0 |
| $1 | -$1.0 | -$1.0 | -$1.0 |
| $2 | -$1.0 | -$1.0 | -$1.0 |
| $3 | -$1.0 | -$1.0 | -$1.0 |
| $4 | -$1.0 | -$1.0 | -$1.0 |
| $5 | -$1.0 | -$1.0 | -$1.0 |
| $6 | -$1.0 | -$1.0 | -$1.0 |
| $7 | -$1.0 | -$1.0 | -$1.0 |
| $8 | -$0.9 | -$1.0 | -$1.0 |
| $9 | -$0.7 | -$0.9 | -$1.0 |
| $10 | -$0.6 | -$0.8 | -$0.9 |
| $11 | -$0.4 | -$0.7 | -$0.8 |
| $12 | -$0.1 | -$0.5 | -$0.6 |
| $13 | $3.3 | $2.5 | $1.2 |
| $14 | $8.5 | $7.7 | $6.1 |
| $15 | $13.8 | $12.9 | $11.0 |
| $16 | $19.0 | $18.1 | $16.0 |
| $17 | $24.2 | $23.3 | $21.1 |
| $18 | $29.4 | $28.5 | $26.2 |
| $19 | $34.7 | $33.7 | $31.3 |
| $20 | $40.0 | $38.9 | $36.3 |
| $21 | $45.4 | $44.2 | $41.4 |
| $22 | $50.8 | $49.5 | $46.5 |
| $23 | $56.1 | $54.9 | $51.6 |
| $24 | $61.5 | $60.2 | $56.7 |
| $25 | $66.9 | $65.6 | $61.8 |
| $26 | $72.3 | $71.0 | $67.0 |
| $27 | $77.7 | $76.3 | $72.1 |
| $28 | $83.1 | $81.7 | $77.3 |
| $29 | $88.6 | $87.1 | $82.5 |
| $30 | $94.0 | $92.4 | $87.7 |
| $31 | $99.4 | $97.8 | $92.9 |
| $32 | $104.9 | $103.2 | $98.1 |
| $33 | $110.4 | $108.5 | $103.3 |
| $34 | $115.8 | $113.9 | $108.5 |
| $35 | $121.3 | $119.3 | $113.7 |
| $36 | $126.7 | $124.7 | $119.0 |
| $37 | $132.2 | $130.1 | $124.2 |
| $38 | $137.7 | $135.4 | $129.4 |
| $39 | $143.1 | $140.8 | $134.6 |
| $40 | $148.6 | $146.2 | $139.9 |

Table 9.1(b): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\varnothing)$ ($million) and Action Regions (t=1 yr)

| t=2 yrs | Primary | Secondary | Abandon | | |
|---|---|---|---|---|---|
| Oil Price | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | | | |
| s ($/bbl) | 0 | 100 | 200 | 250 | |
| $0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | |
| $1 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | |
| $2 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | |
| $3 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | |
| $4 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | |
| $5 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | |
| $6 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | |
| $7 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | |
| $8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | |
| $9 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | |
| $10 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | |
| $11 | -$0.4 | -$0.7 | -$0.9 | -$0.9 | |
| $12 | -$0.1 | -$0.5 | -$0.7 | -$0.8 | |
| $13 | $3.2 | $2.2 | $1.4 | $0.1 | |
| $14 | $8.4 | $7.4 | $6.3 | $4.7 | |
| $15 | $13.6 | $12.5 | $11.3 | $9.5 | |
| $16 | $18.8 | $17.7 | $16.4 | $14.4 | |
| $17 | $24.0 | $22.9 | $21.5 | $19.2 | |
| $18 | $29.3 | $28.0 | $26.6 | $24.1 | |
| $19 | $34.5 | $33.2 | $31.8 | $29.0 | |
| $20 | $39.8 | $38.5 | $36.9 | $33.9 | |
| $21 | $45.2 | $43.7 | $42.1 | $38.8 | |
| $22 | $50.5 | $49.0 | $47.2 | $43.8 | |
| $23 | $55.9 | $54.3 | $52.3 | $48.8 | |
| $24 | $61.2 | $59.6 | $57.5 | $53.8 | |
| $25 | $66.6 | $64.9 | $62.7 | $58.8 | |
| $26 | $72.0 | $70.3 | $67.8 | $63.8 | |
| $27 | $77.4 | $75.6 | $73.0 | $68.9 | |
| $28 | $82.8 | $80.9 | $78.3 | $73.9 | |
| $29 | $88.2 | $86.3 | $83.5 | $79.0 | |
| $30 | $93.6 | $91.6 | $88.7 | $84.0 | |
| $31 | $99.1 | $97.0 | $94.0 | $89.1 | |
| $32 | $104.5 | $102.3 | $99.3 | $94.2 | |
| $33 | $109.9 | $107.6 | $104.5 | $99.2 | |
| $34 | $115.4 | $113.0 | $109.8 | $104.3 | |
| $35 | $120.8 | $118.3 | $115.1 | $109.4 | |
| $36 | $126.3 | $123.7 | $120.4 | $114.5 | |
| $37 | $131.7 | $129.0 | $125.6 | $119.6 | |
| $38 | $137.2 | $134.4 | $130.9 | $124.7 | |
| $39 | $142.6 | $139.7 | $136.2 | $129.8 | |
| $40 | $148.1 | $145.1 | $141.4 | $134.8 | |

Table 9.1(c): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=2 yrs)

| t=4 yrs | Primary | Secondary | Abandon | | | |
|---|---|---|---|---|---|---|
| Oil Price | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | | | | |
| s ($/bbl) | 0 | 100 | 200 | 300 | 400 | 412 |
| $0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $1 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $2 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $3 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $4 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $5 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $6 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $7 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $9 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $10 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $11 | -$0.4 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 |
| $12 | -$0.1 | -$0.5 | -$0.8 | -$0.9 | -$0.9 | -$0.9 |
| $13 | $3.1 | $2.1 | $1.0 | $0.1 | -$0.5 | -$0.8 |
| $14 | $8.3 | $7.2 | $5.9 | $5.0 | $4.3 | $1.5 |
| $15 | $13.5 | $12.4 | $10.9 | $9.9 | $9.2 | $5.9 |
| $16 | $18.7 | $17.5 | $15.9 | $14.8 | $14.1 | $10.3 |
| $17 | $23.9 | $22.7 | $21.0 | $19.7 | $19.0 | $14.8 |
| $18 | $29.1 | $27.8 | $26.1 | $24.7 | $23.9 | $19.4 |
| $19 | $34.4 | $33.0 | $31.2 | $29.6 | $28.8 | $23.9 |
| $20 | $39.7 | $38.2 | $36.3 | $34.6 | $33.7 | $28.6 |
| $21 | $45.0 | $43.4 | $41.4 | $39.6 | $38.6 | $33.2 |
| $22 | $50.3 | $48.7 | $46.5 | $44.7 | $43.5 | $37.8 |
| $23 | $55.7 | $54.0 | $51.6 | $49.7 | $48.4 | $42.4 |
| $24 | $61.0 | $59.3 | $56.7 | $54.8 | $53.4 | $47.1 |
| $25 | $66.4 | $64.6 | $61.8 | $59.9 | $58.4 | $51.7 |
| $26 | $71.7 | $69.9 | $67.0 | $65.0 | $63.4 | $56.4 |
| $27 | $77.1 | $75.2 | $72.1 | $70.1 | $68.4 | $61.1 |
| $28 | $82.5 | $80.5 | $77.3 | $75.2 | $73.5 | $65.8 |
| $29 | $87.9 | $85.8 | $82.5 | $80.3 | $78.6 | $70.5 |
| $30 | $93.3 | $91.1 | $87.7 | $85.4 | $83.6 | $75.2 |
| $31 | $98.7 | $96.5 | $92.9 | $90.5 | $88.7 | $79.9 |
| $32 | $104.2 | $101.8 | $98.1 | $95.7 | $93.8 | $84.7 |
| $33 | $109.6 | $107.1 | $103.3 | $100.8 | $98.9 | $89.4 |
| $34 | $115.0 | $112.4 | $108.6 | $106.0 | $103.9 | $94.1 |
| $35 | $120.4 | $117.7 | $113.8 | $111.1 | $109.0 | $98.9 |
| $36 | $125.9 | $123.1 | $119.0 | $116.3 | $114.1 | $103.6 |
| $37 | $131.3 | $128.4 | $124.2 | $121.4 | $119.2 | $108.4 |
| $38 | $136.7 | $133.7 | $129.5 | $126.6 | $124.3 | $113.1 |
| $39 | $142.1 | $139.1 | $134.7 | $131.7 | $129.4 | $117.8 |
| $40 | $147.6 | $144.4 | $139.9 | $136.8 | $134.4 | $122.6 |

Table 9.1(d): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=4 yrs)

| t=8 yrs | Primary | Secondary | Abandon | | | | | |
|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | | | | | | |
| s ($/bbl) | 0 | 100 | 200 | 300 | 400 | 500 | 600 | 672 |
| $0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $1 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $2 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $3 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $4 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $5 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $6 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $7 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $9 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $10 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $11 | -$0.4 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $12 | -$0.1 | -$0.5 | -$0.8 | -$0.9 | -$0.9 | -$1.0 | -$1.0 | -$1.0 |
| $13 | $3.1 | $2.1 | $0.9 | $0.0 | -$0.8 | -$0.9 | -$1.0 | -$1.0 |
| $14 | $8.3 | $7.2 | $5.9 | $4.8 | $3.7 | $2.3 | $1.1 | -$1.0 |
| $15 | $13.5 | $12.3 | $10.8 | $9.7 | $8.5 | $6.9 | $5.7 | $2.2 |
| $16 | $18.7 | $17.5 | $15.8 | $14.6 | $13.4 | $11.5 | $10.2 | $6.5 |
| $17 | $23.9 | $22.6 | $20.9 | $19.5 | $18.2 | $16.2 | $14.8 | $10.8 |
| $18 | $29.1 | $27.8 | $25.9 | $24.4 | $23.0 | $20.9 | $19.3 | $15.2 |
| $19 | $34.3 | $32.9 | $31.0 | $29.3 | $27.9 | $25.7 | $23.9 | $19.5 |
| $20 | $39.6 | $38.1 | $36.1 | $34.3 | $32.7 | $30.4 | $28.5 | $23.9 |
| $21 | $44.9 | $43.4 | $41.2 | $39.3 | $37.5 | $35.2 | $33.1 | $28.3 |
| $22 | $50.3 | $48.6 | $46.3 | $44.3 | $42.4 | $39.9 | $37.7 | $32.8 |
| $23 | $55.6 | $53.9 | $51.4 | $49.3 | $47.3 | $44.7 | $42.4 | $37.2 |
| $24 | $60.9 | $59.1 | $56.5 | $54.3 | $52.2 | $49.5 | $47.1 | $41.6 |
| $25 | $66.3 | $64.4 | $61.6 | $59.4 | $57.1 | $54.3 | $51.8 | $46.0 |
| $26 | $71.6 | $69.7 | $66.7 | $64.4 | $62.1 | $59.2 | $56.5 | $50.4 |
| $27 | $77.0 | $75.0 | $71.9 | $69.5 | $67.0 | $64.0 | $61.3 | $54.9 |
| $28 | $82.4 | $80.3 | $77.0 | $74.6 | $72.0 | $68.9 | $66.0 | $59.3 |
| $29 | $87.8 | $85.6 | $82.2 | $79.6 | $77.0 | $73.7 | $70.7 | $63.8 |
| $30 | $93.2 | $90.9 | $87.4 | $84.7 | $81.9 | $78.6 | $75.5 | $68.3 |
| $31 | $98.6 | $96.2 | $92.6 | $89.8 | $86.9 | $83.5 | $80.3 | $72.8 |
| $32 | $104.0 | $101.5 | $97.7 | $94.9 | $91.9 | $88.4 | $85.0 | $77.3 |
| $33 | $109.4 | $106.8 | $102.9 | $100.0 | $96.9 | $93.2 | $89.8 | $81.8 |
| $34 | $114.8 | $112.1 | $108.1 | $105.1 | $101.9 | $98.1 | $94.6 | $86.3 |
| $35 | $120.2 | $117.4 | $113.3 | $110.2 | $106.9 | $103.0 | $99.3 | $90.8 |
| $36 | $125.6 | $122.7 | $118.5 | $115.3 | $111.9 | $107.9 | $104.1 | $95.3 |
| $37 | $131.0 | $128.0 | $123.7 | $120.4 | $116.9 | $112.8 | $108.9 | $99.8 |
| $38 | $136.4 | $133.3 | $128.9 | $125.5 | $121.9 | $117.6 | $113.7 | $104.4 |
| $39 | $141.8 | $138.7 | $134.1 | $130.6 | $126.9 | $122.5 | $118.4 | $108.9 |
| $40 | $147.2 | $144.0 | $139.3 | $135.7 | $131.9 | $127.4 | $123.2 | $113.4 |

Table 9.1(e): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=8 yrs)

| t=12 yrs | Primary | Secondary | Abandon | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | | | | | | | | |
| s ($/bbl) | 0 | 100 | 200 | 300 | 400 | 500 | 600 | 700 | 800 | 843 |
| $0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $1 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $2 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $3 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $4 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $5 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $6 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $7 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $9 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $10 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $11 | -$0.4 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $12 | -$0.1 | -$0.5 | -$0.8 | -$0.9 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $13 | $3.1 | $2.1 | $0.9 | $0.0 | -$0.8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $14 | $8.3 | $7.2 | $5.9 | $4.8 | $3.7 | $2.2 | $0.8 | -$1.0 | -$1.0 | -$1.0 |
| $15 | $13.5 | $12.3 | $10.8 | $9.7 | $8.5 | $6.8 | $5.3 | $2.3 | -$0.4 | -$1.0 |
| $16 | $18.6 | $17.4 | $15.8 | $14.6 | $13.3 | $11.4 | $9.9 | $6.6 | $3.7 | -$1.0 |
| $17 | $23.8 | $22.6 | $20.8 | $19.4 | $18.1 | $16.1 | $14.4 | $11.0 | $7.7 | -$1.0 |
| $18 | $29.1 | $27.7 | $25.9 | $24.3 | $23.0 | $20.8 | $18.9 | $15.4 | $11.9 | -$1.0 |
| $19 | $34.3 | $32.9 | $31.0 | $29.3 | $27.8 | $25.5 | $23.5 | $19.7 | $16.0 | -$1.0 |
| $20 | $39.6 | $38.1 | $36.0 | $34.2 | $32.6 | $30.2 | $28.0 | $24.1 | $20.1 | -$1.0 |
| $21 | $44.9 | $43.3 | $41.1 | $39.2 | $37.4 | $35.0 | $32.6 | $28.5 | $24.3 | -$1.0 |
| $22 | $50.2 | $48.5 | $46.2 | $44.2 | $42.3 | $39.7 | $37.2 | $33.0 | $28.5 | -$1.0 |
| $23 | $55.5 | $53.7 | $51.3 | $49.2 | $47.1 | $44.5 | $41.8 | $37.4 | $32.6 | -$1.0 |
| $24 | $60.8 | $59.0 | $56.3 | $54.2 | $52.0 | $49.2 | $46.4 | $41.8 | $36.8 | -$1.0 |
| $25 | $66.1 | $64.2 | $61.4 | $59.2 | $56.9 | $54.0 | $51.1 | $46.2 | $41.0 | -$1.0 |
| $26 | $71.5 | $69.5 | $66.5 | $64.2 | $61.8 | $58.8 | $55.8 | $50.6 | $45.2 | -$1.0 |
| $27 | $76.8 | $74.8 | $71.7 | $69.3 | $66.8 | $63.6 | $60.4 | $55.1 | $49.4 | -$1.0 |
| $28 | $82.1 | $80.0 | $76.8 | $74.3 | $71.7 | $68.4 | $65.1 | $59.6 | $53.6 | -$1.0 |
| $29 | $87.5 | $85.3 | $81.9 | $79.3 | $76.6 | $73.2 | $69.8 | $64.0 | $57.9 | -$1.0 |
| $30 | $92.9 | $90.5 | $87.1 | $84.4 | $81.6 | $78.1 | $74.5 | $68.5 | $62.1 | -$1.0 |
| $31 | $98.2 | $95.8 | $92.2 | $89.4 | $86.5 | $82.9 | $79.1 | $73.0 | $66.4 | -$1.0 |
| $32 | $103.6 | $101.1 | $97.4 | $94.5 | $91.5 | $87.7 | $83.8 | $77.5 | $70.7 | -$1.0 |
| $33 | $109.0 | $106.3 | $102.5 | $99.6 | $96.4 | $92.5 | $88.5 | $82.0 | $74.9 | -$1.0 |
| $34 | $114.3 | $111.6 | $107.7 | $104.6 | $101.4 | $97.3 | $93.2 | $86.4 | $79.2 | -$1.0 |
| $35 | $119.7 | $116.9 | $112.8 | $109.7 | $106.3 | $102.2 | $97.9 | $90.9 | $83.5 | -$1.0 |
| $36 | $125.1 | $122.1 | $118.0 | $114.7 | $111.3 | $107.0 | $102.6 | $95.4 | $87.7 | -$1.0 |
| $37 | $130.4 | $127.4 | $123.1 | $119.8 | $116.2 | $111.8 | $107.3 | $99.9 | $92.0 | -$1.0 |
| $38 | $135.8 | $132.7 | $128.3 | $124.8 | $121.2 | $116.6 | $112.0 | $104.4 | $96.3 | -$1.0 |
| $39 | $141.2 | $138.0 | $133.4 | $129.9 | $126.1 | $121.4 | $116.7 | $108.8 | $100.5 | -$1.0 |
| $40 | $146.5 | $143.3 | $138.6 | $135.0 | $131.1 | $126.3 | $121.4 | $113.3 | $104.8 | -$1.0 |

Table 9.1(f): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=12 yrs)

| t=16 yrs | Primary | Secondary | Abandon | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | | | | | | | | |
| s ($/bbl) | 0 | 100 | 200 | 300 | 400 | 500 | 600 | 700 | 800 | 843 |
| $0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $1 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $2 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $3 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $4 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $5 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $6 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $7 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $9 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $10 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $11 | -$0.4 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $12 | -$0.1 | -$0.5 | -$0.8 | -$0.9 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $13 | $3.0 | $2.0 | $0.8 | -$0.2 | -$0.8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $14 | $8.1 | $7.0 | $5.7 | $4.7 | $3.6 | $2.1 | $0.7 | -$1.0 | -$1.0 | -$1.0 |
| $15 | $13.2 | $12.1 | $10.6 | $9.5 | $8.3 | $6.6 | $5.1 | $2.1 | -$1.0 | -$1.0 |
| $16 | $18.4 | $17.2 | $15.6 | $14.3 | $13.1 | $11.2 | $9.6 | $6.4 | $2.9 | -$1.0 |
| $17 | $23.5 | $22.2 | $20.5 | $19.1 | $17.8 | $15.8 | $14.1 | $10.6 | $6.9 | -$1.0 |
| $18 | $28.7 | $27.3 | $25.5 | $24.0 | $22.6 | $20.5 | $18.6 | $14.9 | $10.9 | -$1.0 |
| $19 | $33.8 | $32.4 | $30.5 | $28.8 | $27.3 | $25.1 | $23.0 | $19.2 | $14.9 | -$1.0 |
| $20 | $39.0 | $37.5 | $35.5 | $33.7 | $32.1 | $29.8 | $27.5 | $23.5 | $18.9 | -$1.0 |
| $21 | $44.3 | $42.6 | $40.5 | $38.6 | $36.9 | $34.4 | $32.0 | $27.8 | $22.9 | -$1.0 |
| $22 | $49.5 | $47.8 | $45.5 | $43.5 | $41.6 | $39.1 | $36.6 | $32.1 | $27.0 | -$1.0 |
| $23 | $54.7 | $52.9 | $50.5 | $48.4 | $46.4 | $43.7 | $41.1 | $36.4 | $31.0 | -$1.0 |
| $24 | $59.9 | $58.1 | $55.4 | $53.3 | $51.2 | $48.4 | $45.6 | $40.8 | $35.0 | -$1.0 |
| $25 | $65.1 | $63.2 | $60.5 | $58.3 | $56.0 | $53.1 | $50.2 | $45.1 | $39.1 | -$1.0 |
| $26 | $70.4 | $68.3 | $65.5 | $63.2 | $60.9 | $57.8 | $54.7 | $49.4 | $43.1 | -$1.0 |
| $27 | $75.6 | $73.5 | $70.5 | $68.1 | $65.7 | $62.5 | $59.3 | $53.7 | $47.2 | -$1.0 |
| $28 | $80.8 | $78.6 | $75.5 | $73.0 | $70.5 | $67.2 | $63.9 | $58.1 | $51.3 | -$1.0 |
| $29 | $86.1 | $83.8 | $80.5 | $78.0 | $75.3 | $71.9 | $68.4 | $62.4 | $55.3 | -$1.0 |
| $30 | $91.3 | $88.9 | $85.6 | $82.9 | $80.2 | $76.6 | $73.0 | $66.8 | $59.4 | -$1.0 |
| $31 | $96.6 | $94.1 | $90.6 | $87.8 | $85.0 | $81.3 | $77.6 | $71.1 | $63.5 | -$1.0 |
| $32 | $101.8 | $99.2 | $95.6 | $92.8 | $89.8 | $86.0 | $82.1 | $75.4 | $67.6 | -$1.0 |
| $33 | $107.1 | $104.4 | $100.7 | $97.7 | $94.7 | $90.7 | $86.7 | $79.8 | $71.6 | -$1.0 |
| $34 | $112.3 | $109.5 | $105.7 | $102.6 | $99.5 | $95.4 | $91.3 | $84.1 | $75.7 | -$1.0 |
| $35 | $117.5 | $114.7 | $110.7 | $107.6 | $104.3 | $100.1 | $95.8 | $88.4 | $79.8 | -$1.0 |
| $36 | $122.8 | $119.8 | $115.7 | $112.5 | $109.2 | $104.8 | $100.4 | $92.8 | $83.9 | -$1.0 |
| $37 | $128.0 | $125.0 | $120.8 | $117.4 | $114.0 | $109.5 | $105.0 | $97.1 | $87.9 | -$1.0 |
| $38 | $133.3 | $130.1 | $125.8 | $122.4 | $118.8 | $114.2 | $109.5 | $101.5 | $92.0 | -$1.0 |
| $39 | $138.5 | $135.3 | $130.8 | $127.3 | $123.6 | $118.9 | $114.1 | $105.8 | $96.1 | -$1.0 |
| $40 | $143.8 | $140.4 | $135.9 | $132.2 | $128.5 | $123.6 | $118.7 | $110.1 | $100.1 | -$1.0 |

Table 9.1(g): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=16 yrs)

| t=20 yrs | Primary | Secondary | Abandon | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | | | | | | | | |
| s ($/bbl) | 0 | 100 | 200 | 300 | 400 | 500 | 600 | 700 | 800 | 843 |
| $0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $1 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $2 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $3 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $4 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $5 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $6 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $7 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $9 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $10 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $11 | -$0.4 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $12 | -$0.1 | -$0.5 | -$0.8 | -$0.9 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $13 | $1.8 | $0.9 | -$0.3 | -$0.7 | -$0.8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $14 | $6.7 | $5.7 | $4.4 | $3.4 | $2.3 | $0.9 | -$0.5 | -$1.0 | -$1.0 | -$1.0 |
| $15 | $11.5 | $10.5 | $9.0 | $8.0 | $6.8 | $5.2 | $3.7 | $0.8 | -$1.0 | -$1.0 |
| $16 | $16.4 | $15.2 | $13.7 | $12.5 | $11.3 | $9.6 | $7.9 | $4.8 | $1.2 | -$1.0 |
| $17 | $21.3 | $20.0 | $18.4 | $17.1 | $15.8 | $13.9 | $12.1 | $8.8 | $4.9 | -$1.0 |
| $18 | $26.1 | $24.8 | $23.0 | $21.6 | $20.2 | $18.3 | $16.3 | $12.8 | $8.6 | -$1.0 |
| $19 | $31.0 | $29.6 | $27.7 | $26.2 | $24.7 | $22.6 | $20.5 | $16.8 | $12.4 | -$1.0 |
| $20 | $35.9 | $34.4 | $32.4 | $30.8 | $29.2 | $27.0 | $24.7 | $20.8 | $16.1 | -$1.0 |
| $21 | $40.8 | $39.2 | $37.0 | $35.4 | $33.7 | $31.3 | $29.0 | $24.8 | $19.8 | -$1.0 |
| $22 | $45.6 | $44.0 | $41.7 | $40.0 | $38.2 | $35.7 | $33.2 | $28.8 | $23.5 | -$1.0 |
| $23 | $50.5 | $48.8 | $46.4 | $44.6 | $42.6 | $40.1 | $37.4 | $32.8 | $27.2 | -$1.0 |
| $24 | $55.4 | $53.6 | $51.1 | $49.1 | $47.1 | $44.4 | $41.6 | $36.8 | $31.0 | -$1.0 |
| $25 | $60.3 | $58.4 | $55.7 | $53.7 | $51.6 | $48.8 | $45.9 | $40.8 | $34.7 | -$1.0 |
| $26 | $65.2 | $63.1 | $60.4 | $58.3 | $56.1 | $53.1 | $50.1 | $44.8 | $38.4 | -$1.0 |
| $27 | $70.0 | $67.9 | $65.1 | $62.9 | $60.6 | $57.5 | $54.3 | $48.8 | $42.2 | -$1.0 |
| $28 | $74.9 | $72.7 | $69.8 | $67.5 | $65.1 | $61.9 | $58.6 | $52.8 | $45.9 | -$1.0 |
| $29 | $79.8 | $77.5 | $74.4 | $72.1 | $69.6 | $66.2 | $62.8 | $56.8 | $49.6 | -$1.0 |
| $30 | $84.7 | $82.3 | $79.1 | $76.7 | $74.1 | $70.6 | $67.0 | $60.8 | $53.4 | -$1.0 |
| $31 | $89.6 | $87.1 | $83.8 | $81.3 | $78.6 | $75.0 | $71.3 | $64.8 | $57.1 | -$1.0 |
| $32 | $94.4 | $91.9 | $88.5 | $85.8 | $83.1 | $79.3 | $75.5 | $68.8 | $60.8 | -$1.0 |
| $33 | $99.3 | $96.7 | $93.1 | $90.4 | $87.6 | $83.7 | $79.7 | $72.8 | $64.5 | -$1.0 |
| $34 | $104.2 | $101.5 | $97.8 | $95.0 | $92.1 | $88.1 | $84.0 | $76.8 | $68.3 | -$1.0 |
| $35 | $109.1 | $106.3 | $102.5 | $99.6 | $96.6 | $92.4 | $88.2 | $80.8 | $72.0 | -$1.0 |
| $36 | $114.0 | $111.1 | $107.2 | $104.2 | $101.0 | $96.8 | $92.4 | $84.8 | $75.7 | -$1.0 |
| $37 | $118.9 | $115.9 | $111.9 | $108.8 | $105.5 | $101.2 | $96.7 | $88.8 | $79.5 | -$1.0 |
| $38 | $123.7 | $120.7 | $116.5 | $113.4 | $110.0 | $105.5 | $100.9 | $92.8 | $83.2 | -$1.0 |
| $39 | $128.6 | $125.5 | $121.2 | $118.0 | $114.5 | $109.9 | $105.2 | $96.8 | $86.9 | -$1.0 |
| $40 | $133.5 | $130.3 | $125.9 | $122.6 | $119.0 | $114.2 | $109.4 | $100.8 | $90.7 | -$1.0 |

Table 9.1(h): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=20 yrs)

| t=24 yrs | Primary | Secondary | Abandon | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | | | | | | | | |
| s ($/bbl) | 0 | 100 | 200 | 300 | 400 | 500 | 600 | 700 | 800 | 843 |
| $0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $1 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $2 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $3 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $4 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $5 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $6 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $7 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $9 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $10 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $11 | -$0.4 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $12 | -$0.1 | -$0.5 | -$0.8 | -$0.9 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $13 | $0.2 | -$0.2 | -$0.5 | -$0.7 | -$0.8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $14 | $0.9 | $0.1 | -$0.3 | -$0.5 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $15 | $4.9 | $4.0 | $2.6 | $1.6 | $0.5 | -$0.8 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $16 | $8.9 | $7.9 | $6.4 | $5.4 | $4.2 | $2.7 | $0.9 | -$1.0 | -$1.0 | -$1.0 |
| $17 | $13.0 | $11.8 | $10.2 | $9.1 | $7.8 | $6.2 | $4.4 | $1.4 | -$1.0 | -$1.0 |
| $18 | $17.0 | $15.8 | $14.1 | $12.9 | $11.5 | $9.7 | $7.8 | $4.6 | $0.4 | -$1.0 |
| $19 | $21.0 | $19.7 | $17.9 | $16.6 | $15.1 | $13.3 | $11.2 | $7.9 | $3.3 | -$1.0 |
| $20 | $25.0 | $23.7 | $21.7 | $20.4 | $18.8 | $16.8 | $14.6 | $11.1 | $6.2 | -$1.0 |
| $21 | $29.0 | $27.6 | $25.5 | $24.1 | $22.5 | $20.4 | $18.0 | $14.3 | $9.2 | -$1.0 |
| $22 | $33.0 | $31.5 | $29.4 | $27.9 | $26.1 | $23.9 | $21.4 | $17.5 | $12.1 | -$1.0 |
| $23 | $37.0 | $35.5 | $33.2 | $31.6 | $29.8 | $27.4 | $24.8 | $20.7 | $15.0 | -$1.0 |
| $24 | $41.1 | $39.4 | $37.0 | $35.4 | $33.4 | $31.0 | $28.2 | $23.9 | $17.9 | -$1.0 |
| $25 | $45.1 | $43.3 | $40.8 | $39.1 | $37.1 | $34.5 | $31.7 | $27.1 | $20.9 | -$1.0 |
| $26 | $49.1 | $47.3 | $44.7 | $42.9 | $40.7 | $38.1 | $35.1 | $30.3 | $23.8 | -$1.0 |
| $27 | $53.1 | $51.2 | $48.5 | $46.6 | $44.4 | $41.6 | $38.5 | $33.5 | $26.7 | -$1.0 |
| $28 | $57.1 | $55.2 | $52.3 | $50.4 | $48.1 | $45.1 | $41.9 | $36.7 | $29.6 | -$1.0 |
| $29 | $61.1 | $59.1 | $56.1 | $54.1 | $51.7 | $48.7 | $45.3 | $39.9 | $32.6 | -$1.0 |
| $30 | $65.2 | $63.0 | $60.0 | $57.9 | $55.4 | $52.2 | $48.7 | $43.1 | $35.5 | -$1.0 |
| $31 | $69.2 | $67.0 | $63.8 | $61.6 | $59.0 | $55.8 | $52.1 | $46.3 | $38.4 | -$1.0 |
| $32 | $73.2 | $70.9 | $67.6 | $65.4 | $62.7 | $59.3 | $55.5 | $49.6 | $41.3 | -$1.0 |
| $33 | $77.2 | $74.9 | $71.5 | $69.1 | $66.3 | $62.9 | $59.0 | $52.8 | $44.3 | -$1.0 |
| $34 | $81.2 | $78.8 | $75.3 | $72.9 | $70.0 | $66.4 | $62.4 | $56.0 | $47.2 | -$1.0 |
| $35 | $85.2 | $82.7 | $79.1 | $76.6 | $73.7 | $69.9 | $65.8 | $59.2 | $50.1 | -$1.0 |
| $36 | $89.2 | $86.7 | $82.9 | $80.4 | $77.3 | $73.5 | $69.2 | $62.4 | $53.1 | -$1.0 |
| $37 | $93.3 | $90.6 | $86.8 | $84.1 | $81.0 | $77.0 | $72.6 | $65.6 | $56.0 | -$1.0 |
| $38 | $97.3 | $94.5 | $90.6 | $87.9 | $84.6 | $80.6 | $76.0 | $68.8 | $58.9 | -$1.0 |
| $39 | $101.3 | $98.5 | $94.4 | $91.6 | $88.3 | $84.1 | $79.4 | $72.0 | $61.8 | -$1.0 |
| $40 | $105.3 | $102.4 | $98.2 | $95.4 | $91.9 | $87.6 | $82.9 | $75.2 | $64.8 | -$1.0 |

Table 9.1(i): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=24 yrs)

| t=28 yrs | Primary | Secondary | Abandon | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Primary Oil $\mathcal{P}_1$ (MSTB) | | | | | | | | | |
| s ($/bbl) | 0 | 100 | 200 | 300 | 400 | 500 | 600 | 700 | 800 | 843 |
| $0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $1 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $2 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $3 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $4 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $5 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $6 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $7 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $9 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $10 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $11 | -$0.4 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $12 | -$0.1 | -$0.5 | -$0.8 | -$0.9 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $13 | $0.1 | -$0.3 | -$0.6 | -$0.7 | -$0.8 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $14 | $0.4 | -$0.1 | -$0.4 | -$0.6 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $15 | $0.7 | $0.2 | -$0.2 | -$0.4 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | -$1.0 | -$1.0 |
| $16 | $1.0 | $0.4 | $0.0 | -$0.2 | -$0.4 | -$0.7 | -$0.9 | -$1.0 | -$1.0 | -$1.0 |
| $17 | $1.3 | $0.7 | $0.2 | $0.0 | -$0.3 | -$0.6 | -$0.8 | -$1.0 | -$1.0 | -$1.0 |
| $18 | $1.5 | $0.9 | $0.4 | $0.2 | -$0.1 | -$0.4 | -$0.8 | -$1.0 | -$1.0 | -$1.0 |
| $19 | $1.8 | $1.1 | $0.7 | $0.4 | $0.0 | -$0.3 | -$0.7 | -$0.9 | -$1.0 | -$1.0 |
| $20 | $2.1 | $1.4 | $0.9 | $0.6 | $0.2 | -$0.2 | -$0.6 | -$0.9 | -$1.0 | -$1.0 |
| $21 | $2.9 | $1.7 | $1.1 | $0.7 | $0.4 | $0.0 | -$0.5 | -$0.8 | -$0.9 | -$1.0 |
| $22 | $5.2 | $4.0 | $2.1 | $0.9 | $0.6 | $0.1 | -$0.3 | -$0.7 | -$0.9 | -$1.0 |
| $23 | $7.6 | $6.2 | $4.2 | $3.0 | $1.5 | $0.3 | -$0.2 | -$0.6 | -$0.9 | -$1.0 |
| $24 | $9.9 | $8.5 | $6.4 | $5.1 | $3.5 | $1.7 | -$0.1 | -$0.6 | -$0.8 | -$1.0 |
| $25 | $12.2 | $10.8 | $8.6 | $7.2 | $5.5 | $3.7 | $1.6 | -$0.5 | -$0.8 | -$1.0 |
| $26 | $14.6 | $13.0 | $10.8 | $9.3 | $7.6 | $5.6 | $3.4 | -$0.1 | -$0.8 | -$1.0 |
| $27 | $16.9 | $15.3 | $12.9 | $11.5 | $9.6 | $7.6 | $5.3 | $1.6 | -$0.7 | -$1.0 |
| $28 | $19.3 | $17.6 | $15.1 | $13.6 | $11.7 | $9.5 | $7.1 | $3.3 | -$0.7 | -$1.0 |
| $29 | $21.6 | $19.9 | $17.3 | $15.7 | $13.7 | $11.5 | $9.0 | $5.0 | -$0.3 | -$1.0 |
| $30 | $23.9 | $22.1 | $19.5 | $17.8 | $15.7 | $13.4 | $10.9 | $6.7 | $1.2 | -$1.0 |
| $31 | $26.3 | $24.4 | $21.6 | $19.9 | $17.8 | $15.4 | $12.7 | $8.4 | $2.7 | -$1.0 |
| $32 | $28.6 | $26.7 | $23.8 | $22.0 | $19.8 | $17.3 | $14.6 | $10.1 | $4.2 | -$1.0 |
| $33 | $30.9 | $28.9 | $26.0 | $24.1 | $21.8 | $19.3 | $16.4 | $11.8 | $5.7 | -$1.0 |
| $34 | $33.3 | $31.2 | $28.1 | $26.2 | $23.9 | $21.2 | $18.3 | $13.5 | $7.2 | -$1.0 |
| $35 | $35.6 | $33.5 | $30.3 | $28.4 | $25.9 | $23.2 | $20.2 | $15.2 | $8.7 | -$1.0 |
| $36 | $37.9 | $35.7 | $32.5 | $30.5 | $27.9 | $25.1 | $22.0 | $17.0 | $10.2 | -$1.0 |
| $37 | $40.3 | $38.0 | $34.7 | $32.6 | $30.0 | $27.1 | $23.9 | $18.7 | $11.7 | -$1.0 |
| $38 | $42.6 | $40.3 | $36.8 | $34.7 | $32.0 | $29.0 | $25.7 | $20.4 | $13.2 | -$1.0 |
| $39 | $45.0 | $42.6 | $39.0 | $36.8 | $34.1 | $31.0 | $27.6 | $22.1 | $14.7 | -$1.0 |
| $40 | $47.3 | $44.8 | $41.2 | $38.9 | $36.1 | $33.0 | $29.4 | $23.8 | $16.2 | -$1.0 |

Table 9.1(j): Remaining Value $\mathcal{V}(s,\mathcal{P}_1,t;\mathcal{D})$ ($million) and Action Regions (t=28 yrs)

| t=0 yrs | Produce | Abandon |
|---|---|---|
| Oil Price s ($/bbl) | Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB | |
| | 0 | |
| $0 | -12.6 | |
| $1 | -12.6 | |
| $2 | -12.6 | |
| $3 | -12.6 | |
| $4 | -12.6 | |
| $5 | -$1.8 | |
| $6 | $1.5 | |
| $7 | $5.7 | |
| $8 | $10.4 | |
| $9 | $15.4 | |
| $10 | $20.4 | |
| $11 | $25.6 | |
| $12 | $30.8 | |
| $13 | $36.1 | |
| $14 | $41.3 | |
| $15 | $46.6 | |
| $16 | $51.9 | |
| $17 | $57.1 | |
| $18 | $62.4 | |
| $19 | $67.7 | |
| $20 | $73.1 | |
| $21 | $78.5 | |
| $22 | $83.9 | |
| $23 | $89.3 | |
| $24 | $94.8 | |
| $25 | $100.2 | |
| $26 | $105.6 | |
| $27 | $111.1 | |
| $28 | $116.5 | |
| $29 | $122.0 | |
| $30 | $127.5 | |
| $31 | $133.0 | |
| $32 | $138.4 | |
| $33 | $144.0 | |
| $34 | $149.5 | |
| $35 | $155.0 | |
| $36 | $160.5 | |
| $37 | $166.0 | |
| $38 | $171.5 | |
| $39 | $177.0 | |
| $40 | $182.5 | |

Table 9.2(a): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=0 yrs, $\mathcal{P}_1$=0 MSTB)

| t=2 yrs | Produce | | | |
|---|---|---|---|---|
| Oil Price | Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB | | | |
| s ($/bbl) | 0 | 500 | 1000 | 1408 |
| $0 | [illegible] | [illegible] | [illegible] | -12.6 |
| $1 | [illegible] | [illegible] | [illegible] | -12.6 |
| $2 | [illegible] | [illegible] | -12.6 | -12.6 |
| $3 | [illegible] | [illegible] | -12.6 | -12.6 |
| $4 | [illegible] | [illegible] | -12.6 | -12.6 |
| $5 | -$1.8 | -$1.2 | -$1.3 | -$1.3 |
| $6 | $1.5 | $2.0 | $1.7 | $1.5 |
| $7 | $5.6 | $6.1 | $5.6 | $5.2 |
| $8 | $10.2 | $10.6 | $9.9 | $9.4 |
| $9 | $15.1 | $15.4 | $14.5 | $13.8 |
| $10 | $20.1 | $20.3 | $19.1 | $18.3 |
| $11 | $25.2 | $25.3 | $23.9 | $22.9 |
| $12 | $30.4 | $30.4 | $28.7 | $27.6 |
| $13 | $35.6 | $35.5 | $33.6 | $32.2 |
| $14 | $40.8 | $40.5 | $38.4 | $36.9 |
| $15 | $46.0 | $45.6 | $43.3 | $41.6 |
| $16 | $51.2 | $50.7 | $48.1 | $46.3 |
| $17 | $56.4 | $55.8 | $53.0 | $51.0 |
| $18 | $61.7 | $61.0 | $57.9 | $55.7 |
| $19 | $66.9 | $66.1 | $62.8 | $60.5 |
| $20 | $72.2 | $71.3 | $67.8 | $65.3 |
| $21 | $77.6 | $76.6 | $72.8 | $70.2 |
| $22 | $82.9 | $81.8 | $77.9 | $75.0 |
| $23 | $88.3 | $87.1 | $82.9 | $79.9 |
| $24 | $93.6 | $92.4 | $87.9 | $84.8 |
| $25 | $99.0 | $97.6 | $93.0 | $89.7 |
| $26 | $104.4 | $102.9 | $98.0 | $94.6 |
| $27 | $109.8 | $108.2 | $103.1 | $99.5 |
| $28 | $115.2 | $113.5 | $108.2 | $104.4 |
| $29 | $120.6 | $118.8 | $113.3 | $109.3 |
| $30 | $126.0 | $124.2 | $118.4 | $114.2 |
| $31 | $131.5 | $129.5 | $123.5 | $119.2 |
| $32 | $136.9 | $134.8 | $128.6 | $124.1 |
| $33 | $142.3 | $140.2 | $133.7 | $129.1 |
| $34 | $147.8 | $145.5 | $138.8 | $134.0 |
| $35 | $153.2 | $150.9 | $143.9 | $139.0 |
| $36 | $158.7 | $156.2 | $149.1 | $144.0 |
| $37 | $164.1 | $161.6 | $154.2 | $148.9 |
| $38 | $169.6 | $166.9 | $159.3 | $153.9 |
| $39 | $175.0 | $172.3 | $164.4 | $158.8 |
| $40 | $180.5 | $177.6 | $169.5 | $163.8 |

Table 9.2(b): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=2 yrs, $\mathcal{P}_1$=0 MSTB)

| t=4 yrs | Produce | Abandon | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Oil Prices ($/bbl) | Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB | | | | | | | |
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3451 |
| $0 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $1 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $2 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $3 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $4 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $5 | -$1.8 | -$1.2 | -$1.3 | -$1.3 | -$1.5 | $1.7 | -$2.0 | $2.2 |
| $6 | $1.5 | $2.0 | $1.7 | $1.4 | $0.9 | $0.5 | $0.0 | -$0.5 |
| $7 | $5.6 | $6.0 | $5.5 | $5.0 | $4.3 | $3.6 | $2.8 | $2.2 |
| $8 | $10.2 | $10.8 | $9.8 | $9.0 | $8.1 | $7.1 | $6.1 | $5.2 |
| $9 | $15.1 | $15.3 | $14.3 | $13.3 | $12.1 | $10.9 | $9.6 | $8.5 |
| $10 | $20.1 | $20.2 | $19.0 | $17.7 | $16.3 | $14.8 | $13.2 | $11.9 |
| $11 | $25.2 | $25.2 | $23.7 | $22.3 | $20.5 | $18.8 | $16.9 | $15.4 |
| $12 | $30.3 | $30.3 | $28.5 | $26.8 | $24.8 | $22.8 | $20.6 | $18.9 |
| $13 | $35.5 | $35.3 | $33.4 | $31.4 | $29.1 | $26.8 | $24.4 | $22.4 |
| $14 | $40.7 | $40.4 | $38.2 | $36.0 | $33.5 | $30.9 | $28.1 | $25.9 |
| $15 | $45.9 | $45.5 | $43.0 | $40.5 | $37.8 | $34.9 | $31.9 | $29.4 |
| $16 | $51.1 | $50.5 | $47.8 | $45.1 | $42.1 | $38.9 | $35.7 | $33.0 |
| $17 | $56.3 | $55.6 | $52.7 | $49.7 | $46.4 | $43.0 | $39.4 | $36.5 |
| $18 | $61.5 | $60.7 | $57.6 | $54.4 | $50.8 | $47.1 | $43.3 | $40.1 |
| $19 | $66.8 | $65.9 | $62.5 | $59.0 | $55.2 | $51.3 | $47.2 | $43.8 |
| $20 | $72.1 | $71.1 | $67.4 | $63.8 | $59.7 | $55.5 | $51.1 | $47.5 |
| $21 | $77.4 | $76.3 | $72.4 | $68.5 | $64.2 | $59.7 | $55.1 | $51.2 |
| $22 | $82.7 | $81.5 | $77.4 | $73.3 | $68.7 | $64.0 | $59.0 | $55.0 |
| $23 | $88.1 | $86.8 | $82.4 | $78.0 | $73.2 | $68.2 | $63.0 | $58.7 |
| $24 | $93.4 | $92.0 | $87.4 | $82.8 | $77.7 | $72.4 | $67.0 | $62.5 |
| $25 | $98.8 | $97.3 | $92.4 | $87.6 | $82.2 | $76.7 | $70.9 | $66.2 |
| $26 | $104.1 | $102.5 | $97.5 | $92.4 | $86.7 | $80.9 | $74.9 | $70.0 |
| $27 | $109.5 | $107.8 | $102.5 | $97.2 | $91.3 | $85.2 | $78.9 | $73.7 |
| $28 | $114.9 | $113.1 | $107.5 | $102.0 | $95.8 | $89.5 | $82.9 | $77.5 |
| $29 | $120.3 | $118.4 | $112.6 | $106.8 | $100.4 | $93.8 | $87.0 | $81.3 |
| $30 | $125.7 | $123.7 | $117.7 | $111.6 | $105.0 | $98.1 | $91.0 | $85.2 |
| $31 | $131.1 | $129.0 | $122.8 | $116.5 | $109.6 | $102.4 | $95.0 | $89.0 |
| $32 | $136.6 | $134.3 | $127.8 | $121.3 | $114.1 | $106.8 | $99.1 | $92.8 |
| $33 | $142.0 | $139.6 | $132.9 | $126.2 | $118.7 | $111.1 | $103.2 | $96.6 |
| $34 | $147.4 | $144.9 | $138.0 | $131.0 | $123.3 | $115.4 | $107.2 | $100.5 |
| $35 | $152.8 | $150.3 | $143.1 | $135.9 | $127.9 | $119.7 | $111.3 | $104.3 |
| $36 | $158.3 | $155.6 | $148.2 | $140.7 | $132.5 | $124.1 | $115.3 | $108.1 |
| $37 | $163.7 | $160.9 | $153.3 | $145.6 | $137.1 | $128.4 | $119.4 | $111.9 |
| $38 | $169.1 | $166.2 | $158.4 | $150.4 | $141.7 | $132.7 | $123.4 | $115.8 |
| $39 | $174.5 | $171.5 | $163.4 | $155.3 | $146.3 | $137.1 | $127.5 | $119.6 |
| $40 | $180.0 | $176.9 | $168.5 | $160.1 | $150.9 | $141.4 | $131.5 | $123.4 |

Table 9.2(c): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=4 yrs, $\mathcal{P}_1$=0 MSTB)

| t=8 yrs | Produce | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB | | | | | | | | | | | | | |
| s ($/bbl) | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6404 |
| $0 | | | | | | | | | | | | | | |
| $1 | | | | | | | | | | | | | | |
| $2 | | | | | | | | | | | | | | |
| $3 | | | | | | | | | | | | | | |
| $4 | | | | | | | | | | | | | | |
| $5 | -$1.8 | -$1.2 | -$1.3 | -$1.3 | -$1.5 | -$1.7 | -$2.0 | -$2.2 | -$2.4 | -$2.6 | -$2.8 | | | |
| $6 | $1.5 | $2.0 | $1.7 | $1.4 | $0.9 | $0.5 | -$0.1 | -$0.6 | -$1.1 | -$1.5 | -$1.8 | -$2.1 | -$2.3 | -$2.4 |
| $7 | $5.6 | $6.0 | $5.5 | $5.0 | $4.3 | $3.5 | $2.8 | $2.0 | $1.2 | $0.5 | -$0.1 | -$0.6 | -$1.0 | -$1.3 |
| $8 | $10.2 | $10.6 | $9.8 | $9.0 | $8.1 | $7.1 | $6.0 | $4.9 | $3.9 | $2.9 | $2.1 | $1.3 | $0.6 | $0.1 |
| $9 | $15.1 | $15.3 | $14.3 | $13.3 | $12.1 | $10.8 | $9.5 | $8.1 | $6.8 | $5.5 | $4.4 | $3.3 | $2.3 | $1.6 |
| $10 | $20.1 | $20.2 | $19.0 | $17.7 | $16.2 | $14.7 | $13.1 | $11.4 | $9.8 | $8.2 | $6.8 | $5.5 | $4.2 | $3.3 |
| $11 | $25.2 | $25.2 | $23.7 | $22.2 | $20.4 | $18.6 | $16.7 | $14.8 | $12.9 | $11.0 | $9.3 | $7.7 | $6.2 | $5.1 |
| $12 | $30.3 | $30.2 | $28.5 | $26.7 | $24.7 | $22.6 | $20.4 | $18.2 | $16.0 | $13.8 | $11.9 | $10.0 | $8.2 | $6.8 |
| $13 | $35.5 | $35.3 | $33.3 | $31.3 | $29.0 | $26.6 | $24.2 | $21.6 | $19.1 | $16.7 | $14.4 | $12.2 | $10.1 | $8.6 |
| $14 | $40.7 | $40.3 | $38.1 | $35.9 | $33.3 | $30.7 | $27.9 | $25.1 | $22.3 | $19.5 | $17.0 | $14.5 | $12.1 | $10.3 |
| $15 | $45.9 | $45.4 | $42.9 | $40.4 | $37.6 | $34.7 | $31.6 | $28.5 | $25.4 | $22.4 | $19.6 | $16.8 | $14.1 | $12.1 |
| $16 | $51.1 | $50.5 | $47.8 | $45.0 | $41.9 | $38.7 | $35.4 | $31.9 | $28.6 | $25.2 | $22.1 | $19.1 | $16.1 | $13.9 |
| $17 | $56.3 | $55.6 | $52.6 | $49.6 | $46.2 | $42.8 | $39.1 | $35.4 | $31.7 | $28.1 | $24.8 | $21.5 | $18.2 | $15.8 |
| $18 | $61.5 | $60.7 | $57.5 | $54.2 | $50.6 | $46.9 | $42.9 | $39.0 | $35.0 | $31.1 | $27.5 | $23.9 | $20.4 | $17.8 |
| $19 | $66.7 | $65.8 | $62.4 | $58.9 | $55.0 | $51.0 | $46.8 | $42.5 | $38.3 | $34.1 | $30.2 | $26.4 | $22.6 | $19.8 |
| $20 | $72.0 | $71.0 | $67.3 | $63.6 | $59.4 | $55.1 | $50.7 | $46.1 | $41.6 | $37.1 | $33.0 | $28.9 | $24.9 | $21.8 |
| $21 | $77.3 | $76.2 | $72.3 | $68.3 | $63.8 | $59.3 | $54.6 | $49.7 | $44.9 | $40.2 | $35.7 | $31.4 | $27.1 | $23.9 |
| $22 | $82.7 | $81.4 | $77.2 | $73.0 | $68.4 | $63.5 | $58.5 | $53.4 | $48.3 | $43.2 | $38.5 | $33.9 | $29.3 | $25.9 |
| $23 | $88.0 | $86.6 | $82.2 | $77.8 | $72.8 | $67.7 | $62.4 | $57.0 | $51.6 | $46.3 | $41.3 | $36.4 | $31.6 | $27.9 |
| $24 | $93.3 | $91.9 | $87.2 | $82.5 | $77.3 | $71.9 | $66.3 | $60.7 | $55.0 | $49.4 | $44.1 | $38.9 | $33.8 | $30.0 |
| $25 | $98.7 | $97.1 | $92.2 | $87.3 | $81.8 | $76.2 | $70.3 | $64.3 | $58.3 | $52.5 | $46.9 | $41.4 | $36.1 | $32.1 |
| $26 | $104.0 | $102.3 | $97.2 | $92.0 | $86.3 | $80.4 | $74.2 | $68.0 | $61.7 | $55.6 | $49.8 | $44.0 | $38.4 | $34.1 |
| $27 | $109.4 | $107.6 | $102.3 | $96.8 | $90.8 | $84.7 | $78.2 | $71.7 | $65.1 | $58.7 | $52.8 | $46.6 | $40.7 | $36.3 |
| $28 | $114.8 | $112.9 | $107.3 | $101.6 | $95.4 | $88.9 | $82.2 | $75.4 | $68.5 | $61.8 | $55.5 | $49.2 | $43.0 | $38.4 |
| $29 | $120.2 | $118.2 | $112.3 | $106.4 | $99.9 | $93.2 | $86.2 | $79.1 | $72.0 | $64.9 | $58.3 | $51.8 | $45.4 | $40.5 |
| $30 | $125.6 | $123.4 | $117.4 | $111.2 | $104.5 | $97.5 | $90.2 | $82.8 | $75.4 | $68.1 | $61.2 | $54.4 | $47.7 | $42.7 |
| $31 | $131.0 | $128.7 | $122.4 | $116.0 | $109.0 | $101.7 | $94.2 | $86.5 | $78.8 | $71.2 | $64.1 | $57.0 | $50.0 | $44.8 |
| $32 | $136.4 | $134.0 | $127.5 | $120.9 | $113.6 | $106.0 | $98.2 | $90.2 | $82.3 | $74.4 | $67.0 | $59.8 | $52.4 | $46.9 |
| $33 | $141.8 | $139.3 | $132.6 | $125.7 | $118.1 | $110.3 | $102.2 | $93.8 | $85.7 | $77.5 | $69.9 | $62.2 | $54.7 | $49.1 |
| $34 | $147.2 | $144.6 | $137.6 | $130.5 | $122.7 | $114.6 | $106.2 | $97.7 | $89.1 | $80.7 | $72.7 | $64.8 | $57.1 | $51.2 |
| $35 | $152.6 | $149.9 | $142.7 | $135.3 | $127.2 | $118.9 | $110.2 | $101.4 | $92.6 | $83.8 | $75.6 | $67.4 | $59.4 | $53.3 |
| $36 | $158.0 | $155.2 | $147.7 | $140.1 | $131.8 | $123.2 | $114.2 | $105.1 | $96.0 | $87.0 | $78.5 | $70.0 | $61.7 | $55.5 |
| $37 | $163.4 | $160.5 | $152.8 | $145.0 | $136.4 | $127.5 | $118.2 | $108.8 | $99.4 | $90.2 | $81.4 | $72.6 | $64.1 | $57.6 |
| $38 | $168.8 | $165.8 | $157.9 | $149.8 | $140.9 | $131.8 | $122.2 | $112.6 | $102.9 | $93.3 | $84.3 | $75.2 | $66.4 | $59.8 |
| $39 | $174.2 | $171.1 | $162.9 | $154.6 | $145.5 | $136.0 | $126.2 | $116.3 | $106.3 | $96.5 | $87.1 | $77.9 | $68.7 | $61.9 |
| $40 | $179.6 | $176.5 | $168.0 | $159.4 | $150.1 | $140.3 | $130.2 | $120.0 | $109.7 | $99.6 | $90.0 | $80.5 | $71.1 | $64.0 |

Table 9.2(d): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=8 yrs, $\mathcal{P}_1$=0 MSTB)

| t=12 yrs | Produce | Abandon | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB | | | | | | | | | | | | | | | | | |
| s ($/bbl) | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8405 |
| $0 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $1 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $2 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $3 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $4 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $5 | -$1.8 | -$1.2 | -$1.3 | -$1.3 | -$1.5 | -$1.7 | -$2.0 | -$2.2 | -$2.4 | -$2.6 | -$2.8 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 | -$12.6 |
| $6 | $1.5 | $2.0 | $1.7 | $1.4 | $0.9 | $0.5 | -$0.1 | -$0.6 | -$1.1 | -$1.5 | -$1.8 | -$2.1 | -$2.3 | -$2.4 | -$2.8 | -$12.6 | -$12.6 | -$12.6 |
| $7 | $5.6 | $6.0 | $5.5 | $5.0 | $4.3 | $3.5 | $2.8 | $2.0 | $1.2 | $0.5 | -$0.1 | -$0.6 | -$1.0 | -$1.5 | -$1.9 | -$2.3 | -$2.5 | $2.6 |
| $8 | $10.2 | $10.6 | $9.8 | $9.0 | $8.1 | $7.1 | $6.0 | $4.9 | $3.9 | $2.9 | $2.1 | $1.3 | $0.5 | -$0.2 | -$0.9 | -$1.6 | -$2.2 | -$2.5 |
| $9 | $15.1 | $15.3 | $14.3 | $13.3 | $12.1 | $10.8 | $9.5 | $8.1 | $6.8 | $5.5 | $4.4 | $3.3 | $2.3 | $1.2 | $0.2 | -$0.8 | -$1.7 | -$2.2 |
| $10 | $20.1 | $20.2 | $19.0 | $17.7 | $16.2 | $14.7 | $13.0 | $11.4 | $9.8 | $8.2 | $6.8 | $5.4 | $4.1 | $2.8 | $1.5 | $0.2 | -$1.0 | -$1.8 |
| $11 | $25.2 | $25.2 | $23.7 | $22.2 | $20.4 | $18.6 | $16.7 | $14.8 | $12.8 | $11.0 | $9.3 | $7.7 | $6.1 | $4.5 | $2.9 | $1.3 | -$0.3 | -$1.3 |
| $12 | $30.3 | $30.2 | $28.5 | $26.7 | $24.7 | $22.6 | $20.4 | $18.2 | $16.0 | $13.8 | $11.8 | $9.9 | $8.0 | $6.1 | $4.2 | $2.3 | $0.4 | -$0.9 |
| $13 | $35.5 | $35.3 | $33.3 | $31.3 | $29.0 | $26.6 | $24.1 | $21.8 | $19.1 | $16.6 | $14.4 | $12.2 | $10.0 | $7.8 | $5.6 | $3.3 | $1.1 | -$0.5 |
| $14 | $40.7 | $40.3 | $38.1 | $35.8 | $33.3 | $30.7 | $27.9 | $25.1 | $22.2 | $19.5 | $17.0 | $14.4 | $12.0 | $9.5 | $6.9 | $4.3 | $1.8 | $0.0 |
| $15 | $45.9 | $45.4 | $42.9 | $40.4 | $37.6 | $34.7 | $31.6 | $28.5 | $25.4 | $22.3 | $19.5 | $16.7 | $13.9 | $11.1 | $8.3 | $5.4 | $2.5 | $0.5 |
| $16 | $51.0 | $50.5 | $47.8 | $45.0 | $41.9 | $38.7 | $35.3 | $31.9 | $28.5 | $25.2 | $22.1 | $19.0 | $16.0 | $12.9 | $9.7 | $6.5 | $3.4 | $1.1 |
| $17 | $56.2 | $55.5 | $52.8 | $49.6 | $46.2 | $42.8 | $39.1 | $35.4 | $31.7 | $28.1 | $24.7 | $21.3 | $18.0 | $14.7 | $11.2 | $7.8 | $4.4 | $1.9 |
| $18 | $61.5 | $60.7 | $57.5 | $54.2 | $50.6 | $46.8 | $42.9 | $38.9 | $35.0 | $31.0 | $27.4 | $23.7 | $20.2 | $16.5 | $12.8 | $9.1 | $5.3 | $2.6 |
| $19 | $66.7 | $65.8 | $62.4 | $58.9 | $55.0 | $51.0 | $46.8 | $42.5 | $38.2 | $34.0 | $30.1 | $26.2 | $22.3 | $18.4 | $14.4 | $10.3 | $6.3 | $3.4 |
| $20 | $72.0 | $71.0 | $67.3 | $63.6 | $59.4 | $55.1 | $50.6 | $46.1 | $41.5 | $37.1 | $32.8 | $28.6 | $24.5 | $20.3 | $16.0 | $11.6 | $7.3 | $4.1 |
| $21 | $77.3 | $76.1 | $72.2 | $68.3 | $63.9 | $59.3 | $54.5 | $49.7 | $44.9 | $40.1 | $35.6 | $31.1 | $26.7 | $22.2 | $17.6 | $12.9 | $8.3 | $4.9 |
| $22 | $82.6 | $81.3 | $77.2 | $73.0 | $68.3 | $63.5 | $58.4 | $53.3 | $48.2 | $43.1 | $38.4 | $33.6 | $28.9 | $24.1 | $19.2 | $14.3 | $9.3 | $5.7 |
| $23 | $87.9 | $86.6 | $82.2 | $77.7 | $72.8 | $67.7 | $62.4 | $56.9 | $51.5 | $46.2 | $41.1 | $36.1 | $31.1 | $26.0 | $20.8 | $15.6 | $10.4 | $6.5 |
| $24 | $93.2 | $91.8 | $87.2 | $82.5 | $77.3 | $71.9 | $66.3 | $60.6 | $54.9 | $49.2 | $43.9 | $38.6 | $33.3 | $28.0 | $22.5 | $17.0 | $11.4 | $7.3 |
| $25 | $98.5 | $97.0 | $92.1 | $87.2 | $81.8 | $76.1 | $70.2 | $64.2 | $58.2 | $52.3 | $46.7 | $41.1 | $35.6 | $30.0 | $24.2 | $18.4 | $12.5 | $8.2 |
| $26 | $103.9 | $102.2 | $97.1 | $92.0 | $86.2 | $80.3 | $74.1 | $67.9 | $61.6 | $55.4 | $49.5 | $43.7 | $37.9 | $31.9 | $25.9 | $19.8 | $13.7 | $9.1 |
| $27 | $109.2 | $107.5 | $102.1 | $96.7 | $90.7 | $84.6 | $78.1 | $71.6 | $65.0 | $58.5 | $52.4 | $46.2 | $40.1 | $33.9 | $27.6 | $21.2 | $14.8 | $10.0 |
| $28 | $114.5 | $112.7 | $107.2 | $101.5 | $95.3 | $88.8 | $82.1 | $75.2 | $68.4 | $61.6 | $55.2 | $48.8 | $42.4 | $35.8 | $29.3 | $22.6 | $15.9 | $10.9 |
| $29 | $119.9 | $118.0 | $112.2 | $106.3 | $99.8 | $93.1 | $86.0 | $78.9 | $71.8 | $64.7 | $58.1 | $51.4 | $44.7 | $37.9 | $31.0 | $24.0 | $17.0 | $11.7 |
| $30 | $125.3 | $123.2 | $117.2 | $111.1 | $104.3 | $97.3 | $90.0 | $82.6 | $75.2 | $67.9 | $60.9 | $53.9 | $47.0 | $40.0 | $32.7 | $25.5 | $18.1 | $12.6 |
| $31 | $130.6 | $128.5 | $122.2 | $115.9 | $108.8 | $101.6 | $94.0 | $86.3 | $78.6 | $71.0 | $63.8 | $56.5 | $49.3 | $42.0 | $34.5 | $26.9 | $19.3 | $13.5 |
| $32 | $136.0 | $133.8 | $127.3 | $120.7 | $113.4 | $105.8 | $98.0 | $90.0 | $82.0 | $74.1 | $66.6 | $59.1 | $51.6 | $44.0 | $36.2 | $28.3 | $20.4 | $14.4 |
| $33 | $141.4 | $139.0 | $132.3 | $125.5 | $117.9 | $110.1 | $102.0 | $93.7 | $85.4 | $77.3 | $69.5 | $61.7 | $53.9 | $46.0 | $37.9 | $29.7 | $21.5 | $15.3 |
| $34 | $146.7 | $144.3 | $137.3 | $130.3 | $122.5 | $114.4 | $106.0 | $97.4 | $88.9 | $80.4 | $72.3 | $64.2 | $56.2 | $48.0 | $39.6 | $31.2 | $22.6 | $16.2 |
| $35 | $152.1 | $149.6 | $142.4 | $135.0 | $127.0 | $118.6 | $109.9 | $101.1 | $92.3 | $83.5 | $75.2 | $66.8 | $58.5 | $50.0 | $41.4 | $32.6 | $23.8 | $17.1 |
| $36 | $157.5 | $154.9 | $147.4 | $139.8 | $131.5 | $122.9 | $113.9 | $104.8 | $95.7 | $86.6 | $78.0 | $69.4 | $60.8 | $52.1 | $43.1 | $34.0 | $24.9 | $18.0 |
| $37 | $162.8 | $160.1 | $152.4 | $144.6 | $136.1 | $127.2 | $117.9 | $108.5 | $99.1 | $89.8 | $80.9 | $72.0 | $63.1 | $54.1 | $44.8 | $35.4 | $26.0 | $18.9 |
| $38 | $168.2 | $165.4 | $157.5 | $149.4 | $140.6 | $131.4 | $121.9 | $112.2 | $102.5 | $92.9 | $83.8 | $74.6 | $65.4 | $56.1 | $46.5 | $36.9 | $27.1 | $19.8 |
| $39 | $173.6 | $170.7 | $162.5 | $154.2 | $145.1 | $135.7 | $125.9 | $115.9 | $105.9 | $96.0 | $86.6 | $77.1 | $67.7 | $58.1 | $48.3 | $38.3 | $28.3 | $20.7 |
| $40 | $178.9 | $175.9 | $167.6 | $159.0 | $149.7 | $140.0 | $129.9 | $119.7 | $109.4 | $99.2 | $89.5 | $79.7 | $70.0 | $60.1 | $50.0 | $39.7 | $29.4 | $21.6 |

Table 9.2(e): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=12 yrs, $\mathcal{P}_1$=0 MSTB)

| t=16 yrs | Produce | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB | | | | | | | | | | | | | | | | | | | |
| s ($/bbl) | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9300 |
| $0 | | | | | | | | | | | | | | | | | | | | |
| $1 | | | | | | | | | | | | | | | | | | | | |
| $2 | | | | | | | | | | | | | | | | | | | | |
| $3 | | | | | | | | | | | | | | | | | | | | |
| $4 | | | | | | | | | | | | | | | | | | | | |
| $5 | -$1.8 | -$1.2 | -$1.3 | -$1.3 | -$1.5 | -$1.7 | -$2.0 | -$2.2 | -$2.4 | -$2.6 | -$2.6 | | | | | | | | | |
| $6 | $1.5 | $2.0 | $1.7 | $1.4 | $0.9 | $0.5 | -$0.1 | -$0.6 | -$1.1 | -$1.5 | -$1.8 | -$2.1 | -$2.3 | -$2.4 | -$2.6 | | | | | |
| $7 | $5.6 | $6.0 | $5.5 | $5.0 | $4.3 | $3.5 | $2.8 | $2.0 | $1.2 | $0.5 | -$0.1 | -$0.6 | -$1.0 | -$1.5 | -$1.9 | -$2.3 | -$2.5 | | | |
| $8 | $10.2 | $10.6 | $9.8 | $9.0 | $8.1 | $7.1 | $6.0 | $4.9 | $3.8 | $2.9 | $2.1 | $1.3 | $0.5 | -$0.2 | -$0.9 | -$1.6 | -$2.2 | | | |
| $9 | $15.1 | $15.3 | $14.3 | $13.3 | $12.1 | $10.8 | $9.5 | $8.1 | $6.8 | $5.5 | $4.4 | $3.3 | $2.3 | $1.2 | $0.2 | -$0.8 | -$1.7 | -$2.4 | | |
| $10 | $20.1 | $20.2 | $19.0 | $17.7 | $16.2 | $14.7 | $13.0 | $11.4 | $9.8 | $8.2 | $6.8 | $5.4 | $4.1 | $2.8 | $1.5 | $0.2 | -$1.0 | -$2.1 | | |
| $11 | $25.1 | $25.2 | $23.7 | $22.2 | $20.4 | $18.6 | $16.7 | $14.8 | $12.8 | $11.0 | $9.3 | $7.7 | $6.1 | $4.5 | $2.9 | $1.3 | -$0.3 | -$1.7 | | |
| $12 | $30.2 | $30.2 | $28.5 | $26.7 | $24.7 | $22.6 | $20.4 | $18.2 | $16.0 | $13.8 | $11.8 | $9.9 | $8.0 | $6.1 | $4.2 | $2.3 | $0.4 | -$1.4 | | |
| $13 | $35.4 | $35.2 | $33.2 | $31.3 | $29.0 | $26.6 | $24.1 | $21.6 | $19.1 | $16.6 | $14.4 | $12.2 | $10.0 | $7.8 | $5.6 | $3.3 | $1.1 | -$1.0 | | |
| $14 | $40.5 | $40.2 | $38.0 | $35.8 | $33.3 | $30.6 | $27.9 | $25.0 | $22.2 | $19.5 | $16.9 | $14.4 | $12.0 | $9.5 | $6.9 | $4.3 | $1.8 | -$0.7 | | |
| $15 | $45.6 | $45.3 | $42.8 | $40.4 | $37.6 | $34.6 | $31.6 | $28.5 | $25.4 | $22.3 | $19.5 | $16.7 | $13.9 | $11.1 | $8.3 | $5.4 | $2.5 | -$0.2 | -$2.5 | -$2.5 |
| $16 | $50.8 | $50.3 | $47.6 | $44.9 | $41.8 | $38.7 | $35.3 | $31.9 | $28.5 | $25.2 | $22.1 | $19.0 | $15.9 | $12.9 | $9.7 | $6.5 | $3.4 | $0.3 | -$2.3 | -$2.4 |
| $17 | $55.9 | $55.4 | $52.5 | $49.5 | $46.2 | $42.7 | $39.1 | $35.4 | $31.7 | $28.1 | $24.7 | $21.3 | $18.0 | $14.8 | $11.2 | $7.7 | $4.3 | $0.9 | -$2.0 | -$2.3 |
| $18 | $61.1 | $60.4 | $57.3 | $54.1 | $50.5 | $46.8 | $42.9 | $38.9 | $34.9 | $31.0 | $27.4 | $23.7 | $20.1 | $16.5 | $12.8 | $9.0 | $5.2 | $1.5 | -$1.6 | -$2.1 |
| $19 | $66.2 | $65.5 | $62.2 | $58.7 | $54.9 | $50.9 | $46.7 | $42.5 | $38.2 | $34.0 | $30.1 | $26.2 | $22.3 | $18.4 | $14.3 | $10.3 | $6.2 | $2.2 | -$1.3 | -$2.0 |
| $20 | $71.4 | $70.7 | $67.1 | $63.4 | $59.3 | $55.0 | $50.6 | $46.0 | $41.5 | $37.0 | $32.8 | $28.6 | $24.5 | $20.3 | $15.9 | $11.5 | $7.2 | $2.8 | -$1.0 | -$1.8 |
| $21 | $76.7 | $75.8 | $72.0 | $68.1 | $63.7 | $59.2 | $54.4 | $49.6 | $44.8 | $40.0 | $35.6 | $31.1 | $26.7 | $22.1 | $17.5 | $12.8 | $8.1 | $3.5 | -$0.6 | -$1.6 |
| $22 | $81.9 | $80.9 | $76.9 | $72.7 | $68.1 | $63.3 | $58.3 | $53.2 | $48.1 | $43.1 | $38.3 | $33.6 | $28.9 | $24.1 | $19.1 | $14.1 | $9.1 | $4.2 | -$0.2 | -$1.4 |
| $23 | $87.1 | $86.1 | $81.8 | $77.4 | $72.5 | $67.5 | $62.2 | $56.8 | $51.4 | $46.1 | $41.1 | $36.0 | $31.1 | $26.0 | $20.8 | $15.5 | $10.2 | $4.9 | $0.2 | -$1.1 |
| $24 | $92.3 | $91.2 | $86.7 | $82.1 | $77.0 | $71.6 | $68.1 | $60.4 | $54.7 | $49.1 | $43.8 | $38.5 | $33.3 | $27.9 | $22.4 | $16.8 | $11.2 | $5.7 | $0.6 | -$0.8 |
| $25 | $97.5 | $96.4 | $91.6 | $86.8 | $81.4 | $75.8 | $70.0 | $64.0 | $58.1 | $52.2 | $46.6 | $41.0 | $35.5 | $29.9 | $24.1 | $18.2 | $12.3 | $6.4 | $1.1 | -$0.4 |
| $26 | $102.8 | $101.5 | $96.6 | $91.5 | $85.9 | $80.0 | $73.9 | $67.7 | $61.4 | $55.3 | $49.4 | $43.6 | $37.8 | $31.8 | $25.7 | $19.6 | $13.4 | $7.2 | $1.6 | -$0.1 |
| $27 | $108.0 | $106.7 | $101.5 | $96.2 | $90.3 | $84.2 | $77.8 | $71.3 | $64.8 | $58.3 | $52.2 | $46.1 | $40.0 | $33.8 | $27.4 | $21.0 | $14.4 | $8.0 | $2.0 | $0.2 |
| $28 | $113.2 | $111.8 | $106.4 | $100.8 | $94.8 | $88.4 | $81.7 | $74.9 | $68.1 | $61.4 | $55.0 | $48.6 | $42.3 | $35.8 | $29.1 | $22.4 | $15.5 | $8.8 | $2.5 | $0.5 |
| $29 | $118.5 | $117.0 | $111.4 | $105.6 | $99.2 | $92.6 | $85.7 | $78.6 | $71.5 | $64.5 | $57.9 | $51.2 | $44.6 | $37.8 | $30.8 | $23.8 | $16.6 | $9.5 | $3.0 | $0.8 |
| $30 | $123.7 | $122.2 | $116.3 | $110.4 | $103.7 | $96.8 | $89.6 | $82.3 | $74.9 | $67.6 | $60.7 | $53.7 | $46.8 | $39.8 | $32.5 | $25.2 | $17.7 | $10.3 | $3.4 | $1.1 |
| $31 | $129.0 | $127.4 | $121.3 | $115.1 | $108.2 | $101.0 | $93.5 | $85.9 | $78.3 | $70.7 | $63.5 | $56.3 | $49.1 | $41.8 | $34.2 | $26.6 | $18.8 | $11.1 | $3.9 | $1.4 |
| $32 | $134.2 | $132.5 | $126.2 | $119.8 | $112.7 | $105.2 | $97.5 | $89.6 | $81.6 | $73.8 | $66.3 | $58.9 | $51.4 | $43.8 | $35.9 | $28.0 | $19.9 | $11.9 | $4.4 | $1.8 |
| $33 | $139.5 | $137.7 | $131.2 | $124.5 | $117.1 | $109.4 | $101.4 | $93.2 | $85.0 | $76.9 | $69.2 | $61.4 | $53.7 | $45.8 | $37.6 | $29.4 | $21.0 | $12.7 | $4.9 | $2.1 |
| $34 | $144.7 | $142.9 | $136.1 | $129.2 | $121.6 | $113.6 | $105.3 | $96.9 | $88.4 | $80.0 | $72.0 | $64.0 | $56.0 | $47.8 | $39.4 | $30.8 | $22.1 | $13.5 | $5.3 | $2.4 |
| $35 | $149.9 | $148.1 | $141.1 | $134.0 | $126.1 | $117.8 | $109.3 | $100.5 | $91.8 | $83.1 | $74.8 | $66.5 | $58.2 | $49.8 | $41.1 | $32.2 | $23.2 | $14.2 | $5.8 | $2.7 |
| $36 | $155.2 | $153.2 | $146.0 | $138.7 | $130.5 | $122.1 | $113.2 | $104.2 | $95.1 | $86.2 | $77.6 | $69.1 | $60.5 | $51.8 | $42.8 | $33.6 | $24.3 | $15.0 | $6.3 | $3.0 |
| $37 | $160.4 | $158.4 | $151.0 | $143.4 | $135.0 | $126.3 | $117.1 | $107.8 | $98.5 | $89.3 | $80.5 | $71.6 | $62.8 | $53.8 | $44.5 | $35.0 | $25.4 | $15.8 | $6.7 | $3.3 |
| $38 | $165.7 | $163.6 | $155.9 | $148.1 | $139.5 | $130.5 | $121.1 | $111.5 | $101.8 | $92.4 | $83.3 | $74.2 | $65.1 | $55.8 | $46.2 | $36.4 | $26.5 | $16.6 | $7.2 | $3.6 |
| $39 | $170.9 | $168.7 | $160.9 | $152.9 | $144.0 | $134.7 | $125.0 | $115.2 | $105.3 | $95.5 | $86.1 | $76.7 | $67.3 | $57.7 | $47.9 | $37.8 | $27.6 | $17.4 | $7.7 | $3.9 |
| $40 | $176.2 | $173.9 | $165.8 | $157.6 | $148.4 | $138.9 | $128.9 | $118.8 | $108.6 | $98.6 | $88.9 | $79.3 | $69.6 | $59.7 | $49.6 | $39.2 | $28.7 | $18.2 | $8.2 | $4.3 |

Table 9.2(f): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=16 yrs, $\mathcal{P}_1$=0 MSTB)

| t=20 yrs | Produce | Abandon | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Prices ($/bbl) | Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB | | | | | | | | | | | | | | | | | | | | |
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 9745 |
| $0 | | | | | | | | | | | | | | | | | | | | | |
| $1 | | | | | | | | | | | | | | | | | | | | | |
| $2 | | | | | | | | | | | | | | | | | | | | | |
| $3 | | | | | | | | | | | | | | | | | | | | | |
| $4 | | | | | | | | | | | | | | | | | | | | | |
| $5 | -$1.8 | -$1.2 | -$1.3 | -$1.3 | -$1.5 | -$1.7 | -$2.0 | -$2.2 | -$2.4 | -$2.6 | -$2.8 | | | | | | | | | | |
| $6 | $1.5 | $2.0 | $1.7 | $1.4 | $0.9 | $0.5 | -$0.1 | -$0.6 | -$1.1 | -$1.5 | -$1.8 | -$2.1 | -$2.3 | -$2.4 | -$2.8 | | | | | | |
| $7 | $5.6 | $6.0 | $5.5 | $5.0 | $4.8 | $3.5 | $2.8 | $2.0 | $1.2 | $0.5 | -$0.1 | -$0.6 | -$1.0 | -$1.5 | -$1.9 | -$2.3 | -$2.5 | | | | |
| $8 | $10.1 | $10.5 | $9.8 | $9.0 | $8.1 | $7.1 | $6.0 | $4.9 | $3.9 | $2.9 | $2.1 | $1.3 | $0.5 | -$0.2 | -$0.9 | -$1.6 | -$2.2 | | | | |
| $9 | $14.9 | $15.2 | $14.2 | $13.2 | $12.1 | $10.8 | $9.5 | $8.1 | $6.7 | $5.5 | $4.3 | $3.3 | $2.3 | $1.2 | $0.2 | -$0.8 | -$1.7 | -$2.4 | | | |
| $10 | $19.7 | $20.0 | $18.8 | $17.6 | $16.1 | $14.6 | $13.0 | $11.4 | $9.7 | $8.2 | $6.8 | $5.4 | $4.1 | $2.8 | $1.5 | $0.2 | -$1.0 | -$2.1 | | | |
| $11 | $24.5 | $24.8 | $23.4 | $22.0 | $20.3 | $18.5 | $16.6 | $14.7 | $12.8 | $10.9 | $9.3 | $7.6 | $6.1 | $4.5 | $2.9 | $1.2 | -$0.3 | -$1.7 | | | |
| $12 | $29.4 | $29.6 | $28.0 | $26.4 | $24.5 | $22.4 | $20.3 | $18.1 | $15.9 | $13.8 | $11.8 | $9.9 | $8.0 | $6.1 | $4.2 | $2.3 | $0.4 | -$1.4 | | | |
| $13 | $34.2 | $34.5 | $32.7 | $30.8 | $28.7 | $26.4 | $23.9 | $21.5 | $19.0 | $16.6 | $14.3 | $12.1 | $10.0 | $7.8 | $5.5 | $3.3 | $1.1 | -$1.0 | | | |
| $14 | $39.1 | $39.3 | $37.3 | $35.3 | $32.8 | $30.3 | $27.8 | $24.8 | $22.1 | $19.4 | $16.9 | $14.4 | $11.9 | $9.5 | $6.9 | $4.3 | $1.8 | -$0.7 | | | |
| $15 | $43.9 | $44.2 | $42.0 | $39.7 | $37.0 | $34.2 | $31.3 | $28.2 | $25.2 | $22.2 | $19.4 | $16.6 | $13.9 | $11.1 | $8.3 | $5.4 | $2.5 | -$0.2 | -$2.5 | | |
| $16 | $48.8 | $49.0 | $46.6 | $44.1 | $41.2 | $38.2 | $34.9 | $31.6 | $28.3 | $25.0 | $22.0 | $18.9 | $15.9 | $12.8 | $9.7 | $6.5 | $3.4 | $0.3 | -$2.3 | | |
| $17 | $53.7 | $53.9 | $51.3 | $48.6 | $45.4 | $42.1 | $38.6 | $35.0 | $31.4 | $27.9 | $24.6 | $21.3 | $18.0 | $14.6 | $11.2 | $7.7 | $4.3 | $0.9 | -$2.0 | | |
| $18 | $58.5 | $58.7 | $55.9 | $53.0 | $49.7 | $46.1 | $42.3 | $38.5 | $34.6 | $30.8 | $27.2 | $23.6 | $20.1 | $16.5 | $12.7 | $9.0 | $5.2 | $1.5 | -$1.7 | | |
| $19 | $63.4 | $63.6 | $60.8 | $57.5 | $53.9 | $50.1 | $46.1 | $42.0 | $37.8 | $33.7 | $29.9 | $26.0 | $22.2 | $18.3 | $14.3 | $10.2 | $6.2 | $2.2 | -$1.3 | | |
| $20 | $68.3 | $68.5 | $65.3 | $62.0 | $58.1 | $54.1 | $49.8 | $45.4 | $41.0 | $36.7 | $32.6 | $28.4 | $24.4 | $20.2 | $15.9 | $11.5 | $7.1 | $2.8 | -$1.0 | | |
| $21 | $73.2 | $73.3 | $70.0 | $66.5 | $62.4 | $58.1 | $53.6 | $48.9 | $44.2 | $39.6 | $35.3 | $30.9 | $26.5 | $22.0 | $17.4 | $12.8 | $8.1 | $3.5 | -$0.7 | -$2.6 | |
| $22 | $78.0 | $78.2 | $74.7 | $71.0 | $66.7 | $62.1 | $57.3 | $52.4 | $47.5 | $42.6 | $37.9 | $33.3 | $28.7 | $23.9 | $19.0 | $14.1 | $9.1 | $4.2 | -$0.3 | -$2.5 | |
| $23 | $82.9 | $83.1 | $79.3 | $75.4 | $70.9 | $66.1 | $61.1 | $55.9 | $50.7 | $45.5 | $40.6 | $35.7 | $30.8 | $25.8 | $20.6 | $15.4 | $10.1 | $4.9 | $0.1 | -$2.3 | |
| $24 | $87.8 | $88.0 | $84.0 | $79.9 | $75.2 | $70.2 | $64.8 | $59.4 | $53.9 | $48.5 | $43.3 | $38.2 | $33.0 | $27.7 | $22.3 | $16.7 | $11.1 | $5.6 | $0.5 | -$2.2 | |
| $25 | $92.7 | $92.9 | $88.7 | $84.4 | $79.4 | $74.2 | $68.6 | $62.9 | $57.1 | $51.4 | $46.0 | $40.6 | $35.2 | $29.6 | $23.9 | $18.1 | $12.2 | $6.4 | $1.0 | -$2.0 | |
| $26 | $97.6 | $97.7 | $93.4 | $88.9 | $83.7 | $78.2 | $72.4 | $66.4 | $60.4 | $54.4 | $48.8 | $43.1 | $37.4 | $31.6 | $25.8 | $19.4 | $13.3 | $7.1 | $1.4 | -$1.8 | |
| $27 | $102.4 | $102.6 | $98.1 | $93.4 | $88.0 | $82.2 | $76.1 | $69.9 | $63.6 | $57.4 | $51.5 | $45.5 | $39.6 | $33.5 | $27.2 | $20.8 | $14.3 | $7.9 | $1.9 | -$1.7 | |
| $28 | $107.3 | $107.5 | $102.8 | $97.9 | $92.2 | $86.2 | $79.9 | $73.4 | $66.9 | $60.4 | $54.2 | $48.0 | $41.8 | $35.4 | $28.9 | $22.2 | $15.4 | $8.6 | $2.3 | -$1.5 | |
| $29 | $112.2 | $112.4 | $107.5 | $102.4 | $96.5 | $90.3 | $83.7 | $76.9 | $70.1 | $63.4 | $57.0 | $50.5 | $44.0 | $37.4 | $30.5 | $23.5 | $16.5 | $9.4 | $2.8 | -$1.3 | |
| $30 | $117.1 | $117.3 | $112.2 | $106.9 | $100.8 | $94.3 | $87.5 | $80.4 | $73.4 | $66.3 | $59.7 | $53.0 | $46.2 | $39.3 | $32.2 | $24.9 | $17.5 | $10.2 | $3.3 | -$1.2 | |
| $31 | $122.0 | $122.2 | $116.9 | $111.4 | $105.0 | $98.3 | $91.2 | $84.0 | $76.6 | $69.3 | $62.4 | $55.4 | $48.5 | $41.3 | $33.9 | $26.3 | $18.6 | $10.9 | $3.7 | -$1.0 | |
| $32 | $126.8 | $127.0 | $121.6 | $115.9 | $109.3 | $102.4 | $95.0 | $87.5 | $79.9 | $72.3 | $65.2 | $57.9 | $50.7 | $43.2 | $35.5 | $27.7 | $19.7 | $11.7 | $4.2 | -$0.8 | |
| $33 | $131.7 | $131.9 | $126.3 | $120.4 | $113.6 | $106.4 | $98.8 | $91.0 | $83.1 | $75.3 | $67.9 | $60.4 | $52.9 | $45.2 | $37.2 | $29.0 | $20.8 | $12.5 | $4.6 | -$0.7 | |
| $34 | $136.6 | $136.8 | $131.0 | $124.9 | $117.9 | $110.4 | $102.6 | $94.5 | $86.4 | $78.3 | $70.6 | $62.9 | $55.1 | $47.1 | $38.8 | $30.4 | $21.8 | $13.2 | $5.1 | -$0.5 | |
| $35 | $141.5 | $141.7 | $135.7 | $129.4 | $122.1 | $114.5 | $106.3 | $98.0 | $89.6 | $81.3 | $73.3 | $65.3 | $57.3 | $49.0 | $40.5 | $31.8 | $22.9 | $14.0 | $5.5 | -$0.3 | |
| $36 | $146.4 | $146.6 | $140.4 | $133.9 | $126.4 | $118.5 | $110.1 | $101.5 | $92.9 | $84.2 | $76.1 | $67.8 | $59.5 | $51.0 | $42.2 | $33.1 | $24.0 | $14.8 | $6.0 | -$0.2 | |
| $37 | $151.3 | $151.5 | $145.1 | $138.4 | $130.7 | $122.5 | $113.9 | $105.0 | $96.1 | $87.2 | $78.8 | $70.3 | $61.7 | $52.9 | $43.8 | $34.5 | $25.0 | $15.5 | $6.5 | $0.0 | |
| $38 | $156.1 | $156.4 | $149.8 | $142.9 | $134.9 | $126.5 | $117.6 | $108.5 | $99.3 | $90.2 | $81.5 | $72.8 | $64.0 | $54.9 | $45.5 | $35.9 | $26.1 | $16.3 | $6.9 | $0.2 | |
| $39 | $161.0 | $161.2 | $154.5 | $147.4 | $139.2 | $130.6 | $121.4 | $112.1 | $102.6 | $93.2 | $84.3 | $75.2 | $66.2 | $56.8 | $47.2 | $37.3 | $27.2 | $17.1 | $7.4 | $0.3 | |
| $40 | $165.9 | $166.1 | $159.1 | $151.9 | $143.5 | $134.6 | $125.2 | $115.6 | $105.8 | $96.2 | $87.0 | $77.7 | $68.4 | $58.8 | $48.8 | $38.6 | $28.3 | $17.8 | $7.8 | $0.5 | |

Table 9.2(g): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=20 yrs, $\mathcal{P}_1$=0 MSTB)

| t=24 yrs | Produce | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB | | | | | | | | | | | | | | | | | | | |
| s ($/bbl) | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 9745 |
| $0 | | | | | | | | | | | | | | | | | | | | | |
| $1 | | | | | | | | | | | | | | | | | | | | | |
| $2 | | | | | | | | | | | | | | | | | | | | | |
| $3 | | | | | | | | | | | | | | | | | | | | | |
| $4 | | | | | | | | | | | | | | | | | | | | | |
| $5 | -$1.8 | -$1.2 | -$1.3 | -$1.3 | -$1.5 | -$1.7 | -$2.0 | -$2.2 | -$2.4 | -$2.6 | -$2.8 | | | | | | | | | | |
| $6 | $1.4 | $2.0 | $1.7 | $1.4 | $0.9 | $0.5 | -$0.1 | -$0.6 | -$1.1 | -$1.5 | -$1.8 | -$2.1 | -$2.3 | -$2.4 | -$2.6 | | | | | | |
| $7 | $5.2 | $5.8 | $5.3 | $4.8 | $4.2 | $3.5 | $2.7 | $1.9 | $1.2 | $0.5 | -$0.1 | -$0.6 | -$1.1 | -$1.5 | -$1.9 | -$2.3 | -$2.5 | | | | |
| $8 | $9.2 | $9.9 | $9.3 | $8.6 | $7.8 | $6.9 | $5.8 | $4.8 | $3.8 | $2.8 | $2.0 | $1.2 | $0.5 | -$0.2 | -$0.9 | -$1.6 | -$2.2 | | | | |
| $9 | $13.2 | $14.0 | $13.3 | $12.5 | $11.4 | $10.3 | $9.1 | $7.8 | $6.5 | $5.3 | $4.3 | $3.2 | $2.2 | $1.2 | $0.2 | -$0.8 | -$1.7 | -$2.4 | | | |
| $10 | $17.2 | $18.2 | $17.3 | $16.3 | $15.1 | $13.8 | $12.3 | $10.8 | $9.3 | $7.9 | $6.6 | $5.3 | $4.1 | $2.8 | $1.5 | $0.2 | -$1.0 | -$2.1 | | | |
| $11 | $21.3 | $22.3 | $21.3 | $20.2 | $18.8 | $17.3 | $15.6 | $13.9 | $12.2 | $10.5 | $9.0 | $7.4 | $5.9 | $4.4 | $2.8 | $1.2 | -$0.3 | -$1.7 | | | |
| $12 | $25.3 | $26.4 | $25.3 | $24.1 | $22.5 | $20.8 | $18.9 | $17.0 | $15.0 | $13.1 | $11.3 | $9.6 | $7.8 | $6.0 | $4.1 | $2.3 | $0.4 | -$1.4 | | | |
| $13 | $29.3 | $30.6 | $29.3 | $27.9 | $26.2 | $24.3 | $22.2 | $20.0 | $17.8 | $15.7 | $13.7 | $11.7 | $9.7 | $7.6 | $5.5 | $3.3 | $1.1 | -$1.0 | | | |
| $14 | $33.3 | $34.7 | $33.3 | $31.8 | $29.9 | $27.8 | $25.5 | $23.1 | $20.7 | $18.3 | $16.1 | $13.9 | $11.6 | $9.3 | $6.8 | $4.3 | $1.8 | -$0.7 | | | |
| $15 | $37.3 | $38.8 | $37.3 | $35.7 | $33.6 | $31.3 | $28.8 | $26.2 | $23.5 | $20.9 | $18.5 | $16.0 | $13.5 | $10.9 | $8.1 | $5.3 | $2.5 | -$0.2 | -$2.5 | | |
| $16 | $41.3 | $42.9 | $41.3 | $39.5 | $37.3 | $34.8 | $32.1 | $29.2 | $26.4 | $23.5 | $20.9 | $18.2 | $15.4 | $12.6 | $9.5 | $6.4 | $3.3 | $0.3 | -$2.3 | | |
| $17 | $45.4 | $47.1 | $45.3 | $43.4 | $41.0 | $38.3 | $35.4 | $32.3 | $29.2 | $26.1 | $23.3 | $20.4 | $17.4 | $14.3 | $11.0 | $7.6 | $4.2 | $0.9 | -$2.0 | | |
| $18 | $49.4 | $51.2 | $49.3 | $47.3 | $44.6 | $41.8 | $38.7 | $35.4 | $32.1 | $28.8 | $25.7 | $22.6 | $19.4 | $16.0 | $12.5 | $8.8 | $5.1 | $1.5 | -$1.7 | | |
| $19 | $53.4 | $55.3 | $53.3 | $51.1 | $48.3 | $45.3 | $42.0 | $38.5 | $34.9 | $31.4 | $28.2 | $24.8 | $21.4 | $17.8 | $14.0 | $10.0 | $6.0 | $2.1 | -$1.4 | | |
| $20 | $57.4 | $59.5 | $57.3 | $55.0 | $52.0 | $48.8 | $45.3 | $41.6 | $37.8 | $34.1 | $30.6 | $27.0 | $23.4 | $19.5 | $15.4 | $11.2 | $7.0 | $2.7 | -$1.1 | | |
| $21 | $61.4 | $63.6 | $61.3 | $58.9 | $55.7 | $52.3 | $48.6 | $44.6 | $40.7 | $36.7 | $33.0 | $29.3 | $25.4 | $21.3 | $16.9 | $12.5 | $7.9 | $3.4 | -$0.7 | -$2.6 | |
| $22 | $65.4 | $67.7 | $65.3 | $62.7 | $59.4 | $55.8 | $51.9 | $47.7 | $43.5 | $39.4 | $35.5 | $31.5 | $27.4 | $23.0 | $18.4 | $13.7 | $8.8 | $4.0 | -$0.4 | -$2.5 | |
| $23 | $69.4 | $71.9 | $69.3 | $66.6 | $63.1 | $59.3 | $55.2 | $50.8 | $46.4 | $42.0 | $37.9 | $33.7 | $29.4 | $24.8 | $19.9 | $14.9 | $9.8 | $4.7 | $0.0 | -$2.3 | |
| $24 | $73.5 | $76.0 | $73.3 | $70.5 | $66.8 | $62.8 | $58.5 | $53.9 | $49.3 | $44.7 | $40.4 | $35.9 | $31.4 | $26.6 | $21.5 | $16.2 | $10.8 | $5.4 | $0.1 | -$2.2 | |
| $25 | $77.5 | $80.1 | $77.3 | $74.4 | $70.5 | $66.4 | $61.8 | $57.0 | $52.1 | $47.3 | $42.8 | $38.2 | $33.4 | $28.4 | $23.0 | $17.4 | $11.8 | $6.1 | $0.8 | -$2.0 | |
| $26 | $81.5 | $84.3 | $81.3 | $78.2 | $74.2 | $69.9 | $65.1 | $60.1 | $55.0 | $50.0 | $45.3 | $40.4 | $35.4 | $30.1 | $24.5 | $18.7 | $12.8 | $6.8 | $1.3 | -$1.8 | |
| $27 | $85.5 | $88.4 | $85.3 | $82.1 | $77.9 | $73.4 | $68.4 | $63.2 | $57.9 | $52.6 | $47.7 | $42.6 | $37.4 | $31.9 | $26.1 | $20.0 | $13.8 | $7.5 | $1.7 | -$1.7 | |
| $28 | $89.5 | $92.5 | $89.3 | $86.0 | $81.6 | $76.9 | $71.7 | $66.3 | $60.7 | $55.3 | $50.2 | $44.9 | $39.5 | $33.7 | $27.8 | $21.3 | $14.7 | $8.2 | $2.1 | -$1.5 | |
| $29 | $93.5 | $96.7 | $93.3 | $89.8 | $85.3 | $80.4 | $75.0 | $69.3 | $63.6 | $57.9 | $52.6 | $47.1 | $41.5 | $35.5 | $29.1 | $22.5 | $15.7 | $8.9 | $2.5 | -$1.3 | |
| $30 | $97.6 | $100.8 | $97.3 | $93.7 | $89.0 | $83.9 | $78.3 | $72.4 | $66.5 | $60.6 | $55.1 | $49.3 | $43.5 | $37.3 | $30.7 | $23.8 | $16.7 | $9.6 | $3.0 | -$1.2 | |
| $31 | $101.6 | $104.9 | $101.4 | $97.6 | $92.7 | $87.4 | $81.6 | $75.5 | $69.4 | $63.2 | $57.5 | $51.6 | $45.5 | $39.0 | $32.2 | $25.1 | $17.7 | $10.3 | $3.4 | -$1.0 | |
| $32 | $105.6 | $109.1 | $105.4 | $101.4 | $96.4 | $90.9 | $84.9 | $78.6 | $72.2 | $65.9 | $60.0 | $53.8 | $47.5 | $40.8 | $33.7 | $26.3 | $18.7 | $11.0 | $3.8 | -$0.9 | |
| $33 | $109.6 | $113.2 | $109.4 | $105.3 | $100.1 | $94.4 | $88.2 | $81.7 | $75.1 | $68.5 | $62.4 | $56.0 | $49.5 | $42.6 | $35.3 | $27.6 | $19.7 | $11.8 | $4.2 | -$0.7 | |
| $34 | $113.6 | $117.3 | $113.4 | $109.2 | $103.8 | $97.9 | $91.5 | $84.8 | $78.0 | $71.2 | $64.8 | $58.3 | $51.6 | $44.4 | $36.8 | $28.9 | $20.7 | $12.5 | $4.6 | -$0.5 | |
| $35 | $117.6 | $121.4 | $117.4 | $113.1 | $107.5 | $101.5 | $94.8 | $87.9 | $80.8 | $73.8 | $67.3 | $60.5 | $53.6 | $46.2 | $38.3 | $30.1 | $21.7 | $13.2 | $5.1 | -$0.4 | |
| $36 | $121.6 | $125.6 | $121.4 | $116.9 | $111.2 | $105.0 | $98.1 | $91.0 | $83.7 | $76.5 | $69.7 | $62.8 | $55.6 | $48.0 | $39.8 | $31.4 | $22.7 | $13.9 | $5.5 | -$0.2 | |
| $37 | $125.7 | $129.7 | $125.4 | $120.8 | $114.9 | $108.5 | $101.4 | $94.1 | $86.6 | $79.1 | $72.2 | $65.0 | $57.6 | $49.7 | $41.4 | $32.7 | $23.7 | $14.6 | $5.9 | $0.0 | |
| $38 | $129.7 | $133.8 | $129.4 | $124.7 | $118.6 | $112.0 | $104.7 | $97.1 | $89.4 | $81.8 | $74.6 | $67.2 | $59.6 | $51.5 | $42.9 | $33.9 | $24.7 | $15.3 | $6.3 | $0.1 | |
| $39 | $133.7 | $138.0 | $133.4 | $128.5 | $122.3 | $115.5 | $108.0 | $100.2 | $92.3 | $84.4 | $77.1 | $69.5 | $61.6 | $53.3 | $44.4 | $35.2 | $25.7 | $16.0 | $6.8 | $0.3 | |
| $40 | $137.7 | $142.1 | $137.4 | $132.4 | $126.0 | $119.0 | $111.3 | $103.3 | $95.2 | $87.1 | $79.5 | $71.7 | $63.7 | $55.1 | $46.0 | $36.5 | $26.7 | $16.7 | $7.2 | $0.4 | |

Table 9.2(h): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=24 yrs, $\mathcal{P}_1$=0 MSTB)

| t=28 yrs | Produce | Abandon | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oil Price | Cumulative Secondary Oil $\mathcal{P}_2$ (MSTB) for Primary Oil $\mathcal{P}_1$=0 MSTB | | | | | | | | | | | | | | | | | | | | |
| s ($/bbl) | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 9745 |
| $0 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 |
| $1 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 |
| $2 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 |
| $3 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 |
| $4 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 |
| $5 | -$2.0 | -$1.3 | -$1.3 | -$1.4 | -$1.5 | -$1.7 | -$2.0 | -$2.2 | -$2.4 | -$2.6 | -$2.8 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 |
| $6 | $0.3 | $1.3 | $1.2 | $1.0 | $0.7 | $0.3 | -$0.2 | -$0.7 | -$1.1 | -$1.6 | -$1.8 | -$2.1 | -$2.3 | -$2.4 | -$2.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 | -12.6 |
| $7 | $2.6 | $3.9 | $3.8 | $3.6 | $3.1 | $2.6 | $2.0 | $1.3 | $0.7 | $0.1 | -$0.3 | -$0.8 | -$1.1 | -$1.5 | -$1.9 | -$2.3 | -$2.6 | -12.6 | -12.6 | -12.6 | -12.6 |
| $8 | $4.8 | $6.6 | $6.4 | $6.1 | $5.6 | $4.9 | $4.1 | $3.3 | $2.6 | $1.8 | $1.3 | $0.7 | $0.2 | -$0.4 | -$1.0 | -$1.6 | -$2.2 | -12.6 | -12.6 | -12.6 | -12.6 |
| $9 | $7.3 | $9.2 | $9.0 | $8.7 | $8.0 | $7.2 | $6.3 | $5.4 | $4.4 | $3.6 | $2.9 | $2.2 | $1.6 | $0.9 | $0.0 | -$0.8 | -$1.7 | -$2.4 | -12.6 | -12.6 | -12.6 |
| $10 | $9.6 | $11.9 | $11.6 | $11.2 | $10.5 | $9.6 | $8.5 | $7.4 | $6.3 | $5.3 | $4.5 | $3.8 | $3.0 | $7.1 | $1.1 | $0.0 | -$1.1 | -$2.1 | -12.6 | -12.6 | -12.6 |
| $11 | $11.9 | $14.5 | $14.2 | $13.8 | $12.9 | $11.9 | $10.7 | $9.4 | $8.2 | $7.0 | $6.2 | $5.3 | $4.4 | $3.4 | $2.2 | $0.9 | -$0.4 | -$1.8 | -12.6 | -12.6 | -12.6 |
| $12 | $14.3 | $17.2 | $16.8 | $16.3 | $15.4 | $14.2 | $12.8 | $11.5 | $10.1 | $8.8 | $7.8 | $6.8 | $5.8 | $4.7 | $3.3 | $1.8 | $0.2 | -$1.4 | -12.6 | -12.6 | -12.6 |
| $13 | $16.6 | $19.8 | $19.4 | $18.9 | $17.8 | $16.5 | $15.0 | $13.5 | $12.0 | $10.5 | $9.4 | $8.3 | $7.2 | $6.0 | $4.4 | $2.7 | $0.8 | -$1.1 | -12.6 | -12.6 | -12.6 |
| $14 | $18.9 | $22.4 | $22.0 | $21.5 | $20.3 | $18.8 | $17.2 | $15.5 | $13.8 | $12.3 | $11.1 | $9.9 | $8.7 | $7.2 | $5.5 | $3.6 | $1.4 | -$0.8 | -12.6 | -12.6 | -12.6 |
| $15 | $21.3 | $25.1 | $24.8 | $24.0 | $22.7 | $21.2 | $19.4 | $17.5 | $15.7 | $14.0 | $12.7 | $11.4 | $10.1 | $8.5 | $6.6 | $4.5 | $2.1 | -$0.4 | -$2.5 | -12.6 | -12.6 |
| $16 | $23.6 | $27.7 | $27.3 | $26.6 | $25.2 | $23.5 | $21.6 | $19.6 | $17.6 | $15.8 | $14.4 | $12.9 | $11.5 | $9.8 | $7.7 | $5.4 | $2.8 | $0.1 | -$2.3 | -12.6 | -12.6 |
| $17 | $26.0 | $30.4 | $29.9 | $29.1 | $27.6 | $25.8 | $23.7 | $21.6 | $19.5 | $17.5 | $16.0 | $14.5 | $12.9 | $11.1 | $8.9 | $6.4 | $3.6 | $0.6 | -$2.1 | -12.6 | -12.6 |
| $18 | $28.3 | $33.0 | $32.5 | $31.7 | $30.1 | $28.1 | $25.9 | $23.6 | $21.4 | $19.2 | $17.6 | $16.0 | $14.3 | $12.4 | $10.0 | $7.3 | $4.3 | $1.1 | -$1.8 | -12.6 | -12.6 |
| $19 | $30.6 | $35.7 | $35.1 | $34.2 | $32.5 | $30.5 | $28.1 | $25.7 | $23.2 | $21.0 | $19.3 | $17.5 | $15.8 | $13.7 | $11.1 | $8.3 | $5.0 | $1.6 | -$1.6 | -12.6 | -12.6 |
| $20 | $33.0 | $38.3 | $37.7 | $36.8 | $35.0 | $32.8 | $30.3 | $27.7 | $25.1 | $22.7 | $20.9 | $19.1 | $17.2 | $15.0 | $12.3 | $9.2 | $5.8 | $2.1 | -$1.3 | -12.6 | -12.6 |
| $21 | $35.3 | $40.9 | $40.3 | $39.3 | $37.4 | $35.1 | $32.5 | $29.7 | $27.0 | $24.5 | $22.5 | $20.6 | $18.6 | $16.3 | $13.4 | $10.2 | $6.5 | $2.6 | -$1.1 | -$2.6 | -12.6 |
| $22 | $37.6 | $43.6 | $42.9 | $41.9 | $39.8 | $37.4 | $34.6 | $31.7 | $28.9 | $26.2 | $24.2 | $22.1 | $20.0 | $17.5 | $14.5 | $11.1 | $7.2 | $3.1 | -$0.8 | -$2.5 | -12.6 |
| $23 | $40.0 | $46.2 | $45.5 | $44.4 | $42.3 | $39.8 | $36.8 | $33.8 | $30.8 | $28.0 | $25.8 | $23.6 | $21.4 | $18.8 | $15.7 | $12.1 | $8.0 | $3.6 | -$0.5 | -$2.3 | -12.6 |
| $24 | $42.3 | $48.9 | $48.1 | $47.0 | $44.7 | $42.1 | $39.0 | $35.8 | $32.6 | $29.7 | $27.5 | $25.2 | $22.9 | $20.1 | $16.8 | $13.0 | $8.8 | $4.2 | -$0.2 | -$2.2 | -12.6 |
| $25 | $44.6 | $51.5 | $50.7 | $49.6 | $47.2 | $44.4 | $41.2 | $37.8 | $34.5 | $31.5 | $29.1 | $26.7 | $24.3 | $21.4 | $18.0 | $14.0 | $9.5 | $4.7 | $0.2 | -$2.1 | -12.6 |
| $26 | $47.0 | $54.2 | $53.3 | $52.1 | $49.6 | $46.7 | $43.4 | $39.9 | $36.4 | $33.2 | $30.7 | $28.2 | $25.7 | $22.7 | $19.1 | $14.9 | $10.3 | $5.2 | $0.5 | -$1.9 | -12.6 |
| $27 | $49.3 | $56.8 | $55.9 | $54.7 | $52.1 | $49.1 | $45.5 | $41.9 | $38.3 | $34.9 | $32.4 | $29.8 | $27.1 | $24.0 | $20.2 | $15.9 | $11.0 | $5.8 | $0.8 | -$1.8 | -12.6 |
| $28 | $51.7 | $59.5 | $58.6 | $57.2 | $54.5 | $51.4 | $47.7 | $43.9 | $40.2 | $36.7 | $34.0 | $31.3 | $28.6 | $25.3 | $21.4 | $16.9 | $11.8 | $6.3 | $1.1 | -$1.6 | -12.6 |
| $29 | $54.0 | $62.1 | $61.2 | $59.8 | $57.0 | $53.7 | $49.9 | $45.9 | $42.0 | $38.4 | $35.7 | $32.8 | $30.0 | $26.6 | $22.5 | $17.8 | $12.5 | $6.8 | $1.4 | -$1.5 | -12.6 |
| $30 | $56.3 | $64.7 | $63.8 | $62.3 | $59.4 | $56.0 | $52.1 | $48.0 | $43.9 | $40.2 | $37.3 | $34.4 | $31.4 | $27.9 | $23.8 | $18.8 | $13.3 | $7.4 | $1.7 | -$1.4 | -12.6 |
| $31 | $58.7 | $67.4 | $66.4 | $64.9 | $61.9 | $58.4 | $54.2 | $50.0 | $45.8 | $41.9 | $38.9 | $35.9 | $32.8 | $29.2 | $24.8 | $19.7 | $14.0 | $7.9 | $2.0 | -$1.2 | -12.6 |
| $32 | $61.0 | $70.0 | $69.0 | $67.4 | $64.3 | $60.7 | $56.4 | $52.0 | $47.7 | $43.7 | $40.6 | $37.4 | $34.2 | $30.5 | $25.9 | $20.7 | $14.8 | $8.4 | $2.3 | -$1.1 | -12.6 |
| $33 | $63.3 | $72.7 | $71.6 | $70.0 | $66.8 | $63.0 | $58.6 | $54.1 | $49.6 | $45.4 | $42.2 | $38.9 | $35.7 | $31.8 | $27.1 | $21.6 | $15.5 | $9.0 | $2.6 | -$0.9 | -12.6 |
| $34 | $65.7 | $75.3 | $74.2 | $72.5 | $69.2 | $65.3 | $60.8 | $56.1 | $51.5 | $47.1 | $43.8 | $40.5 | $37.1 | $33.1 | $28.2 | $22.6 | $16.3 | $9.5 | $2.9 | -$0.8 | -12.6 |
| $35 | $68.0 | $78.0 | $76.8 | $75.1 | $71.7 | $67.6 | $63.0 | $58.1 | $53.3 | $48.9 | $45.5 | $42.0 | $38.5 | $34.4 | $29.3 | $23.6 | $17.1 | $10.0 | $3.2 | -$0.7 | -12.6 |
| $36 | $70.3 | $80.6 | $79.4 | $77.7 | $74.1 | $70.0 | $65.1 | $60.1 | $55.2 | $50.6 | $47.1 | $43.5 | $39.9 | $35.6 | $30.5 | $24.5 | $17.8 | $10.6 | $3.6 | -$0.5 | -12.6 |
| $37 | $72.7 | $83.3 | $82.0 | $80.2 | $76.6 | $72.3 | $67.3 | $62.2 | $57.1 | $52.4 | $48.8 | $45.1 | $41.4 | $36.9 | $31.6 | $25.5 | $18.6 | $11.1 | $3.9 | -$0.4 | -12.6 |
| $38 | $75.0 | $85.9 | $84.6 | $82.8 | $79.0 | $74.6 | $69.5 | $64.2 | $59.0 | $54.1 | $50.4 | $46.6 | $42.8 | $38.2 | $32.7 | $26.4 | $19.3 | $11.6 | $4.2 | -$0.2 | -12.6 |
| $39 | $77.4 | $88.5 | $87.2 | $85.3 | $81.5 | $76.9 | $71.7 | $66.2 | $60.9 | $55.9 | $52.0 | $48.1 | $44.2 | $39.5 | $33.9 | $27.4 | $20.1 | $12.2 | $4.5 | -$0.1 | -12.6 |
| $40 | $79.7 | $91.2 | $89.8 | $87.9 | $83.9 | $79.3 | $73.9 | $68.3 | $62.7 | $57.6 | $53.7 | $49.7 | $45.6 | $40.8 | $35.0 | $28.3 | $20.8 | $12.7 | $4.8 | $0.0 | -12.6 |

Table 9.2(i): Remaining Secondary Value $\mathcal{V}_2(s,\mathcal{P}_2,t;\mathcal{P}_1,\Theta_2)$ ($million) and Action Regions (t=28 yrs, $\mathcal{P}_1$=0 MSTB)

| Primary Oil $\mathcal{P}_1$ (MSTB) | time t (yrs) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| 0 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 |
| 100 | | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 |
| 200 | | $7.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 |
| 300 | | | $9.75 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 |
| 400 | | | | $10.25 | $10.75 | $10.75 | $10.75 | $11.00 | $11.00 | $10.75 | $10.75 | $10.75 | $10.75 | $11.00 | $11.00 | $11.00 |
| 500 | | | | | $10.75 | $11.00 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 |
| 600 | | | | | | | $11.75 | $13.25 | $13.25 | $13.25 | $13.25 | $13.25 | $13.25 | $13.25 | $13.25 | $13.25 |
| 700 | | | | | | | | $13.75 | $13.75 | $13.75 | $14.00 | $14.00 | $14.00 | $14.00 | $14.00 | $14.00 |
| 800 | | | | | | | | | | $14.75 | $14.50 | $14.50 | $14.50 | $14.75 | $14.75 | $14.75 |
| 900 | | | | | | | | | | | | $18.00 | | | | |

| Primary Oil $\mathcal{P}_1$ (MSTB) | time t (yrs) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 |
| 0 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 | $6.25 |
| 100 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 | $7.75 |
| 200 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 | $9.75 |
| 300 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 | $10.25 |
| 400 | $10.75 | $10.75 | $10.75 | $11.00 | $11.00 | $11.00 | $11.00 | $11.00 | $10.75 | $11.00 | $10.75 | $10.75 | $10.75 | $10.75 | $10.75 | $10.75 |
| 500 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 | $11.75 |
| 600 | $13.25 | $13.25 | $13.25 | $13.50 | $13.50 | $13.75 | $13.75 | $14.00 | $14.00 | $14.00 | $14.00 | $14.00 | $14.00 | $14.00 | $14.00 | $14.00 |
| 700 | $14.00 | $14.00 | $14.00 | $14.25 | $14.25 | $14.50 | $14.75 | $15.25 | $16.00 | $17.00 | $17.50 | $17.50 | $17.50 | $17.50 | $17.50 | $17.50 |
| 800 | $14.75 | $14.75 | $14.75 | $15.00 | $15.25 | $15.50 | $15.75 | $16.50 | $17.25 | $18.00 | $18.00 | $18.00 | $18.00 | $18.00 | $18.00 | $18.00 |
| 900 | | | | | | | | | | | | | | | | |

Table 9.3: Primary Economic Limit Abandonment Price $s_{1A}(\mathcal{P}_1,t)$ ($/bbl)

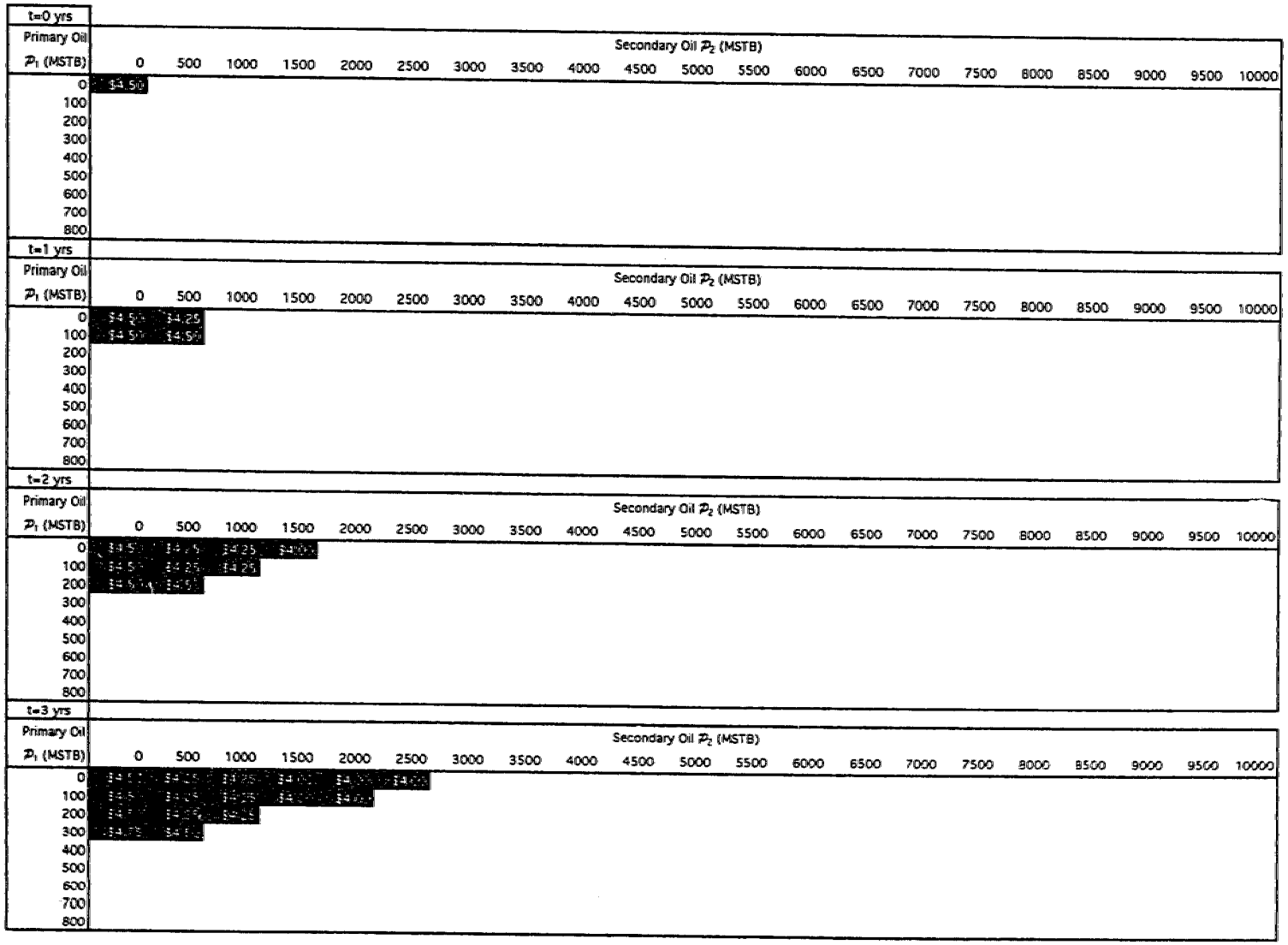
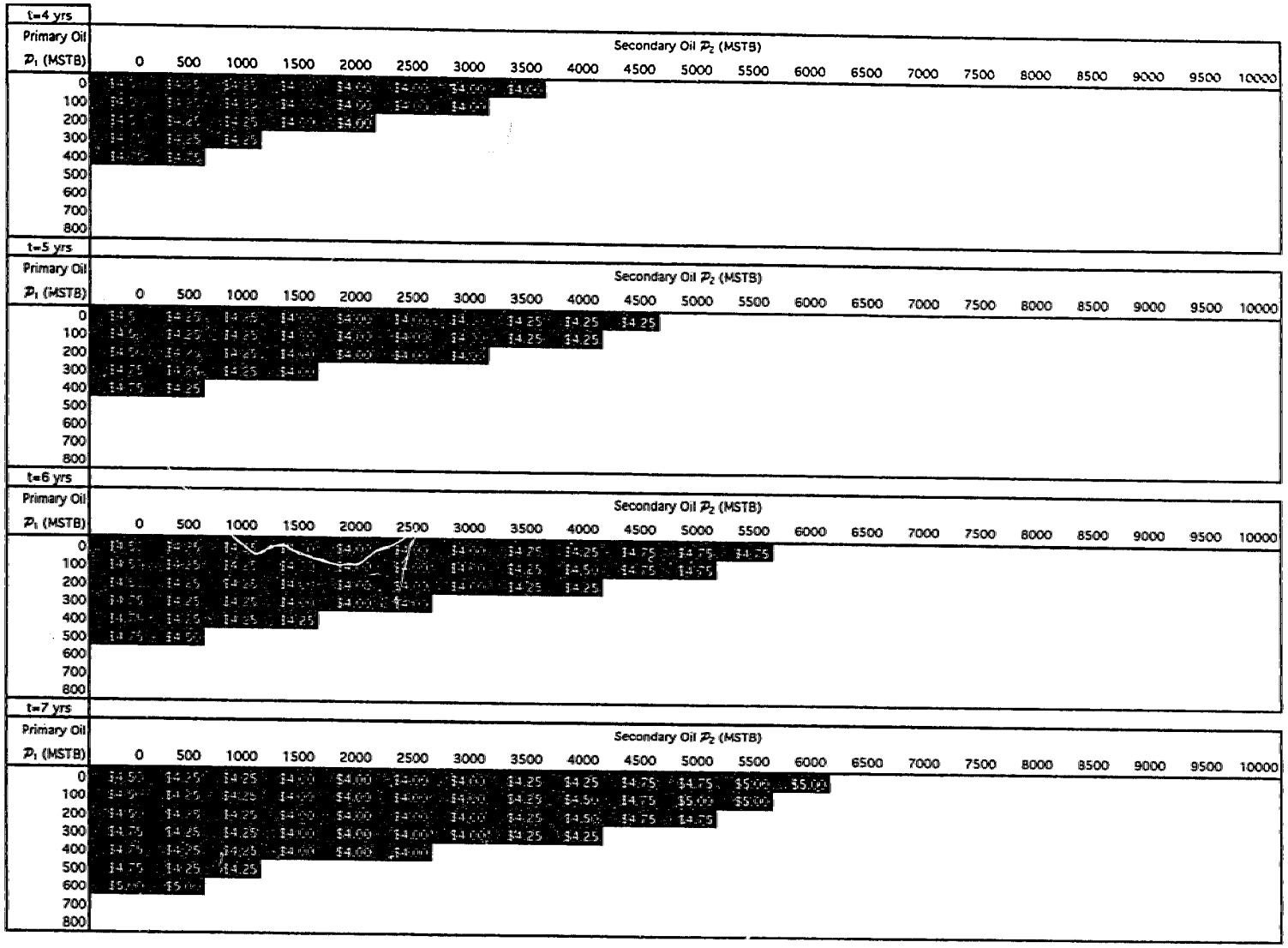



Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl)



t=4 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=5 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

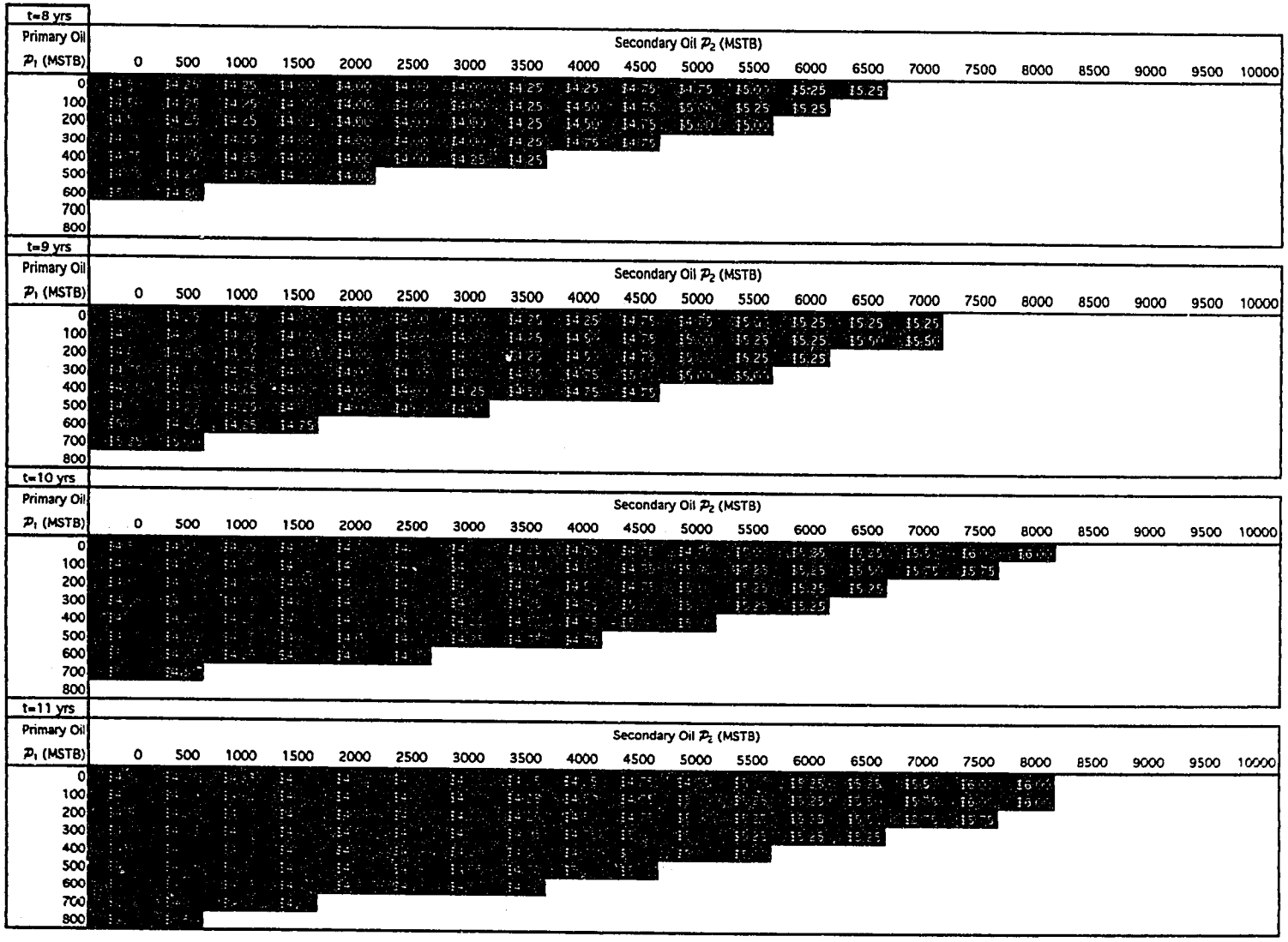
t=6 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=7 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)



t=8 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=9 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

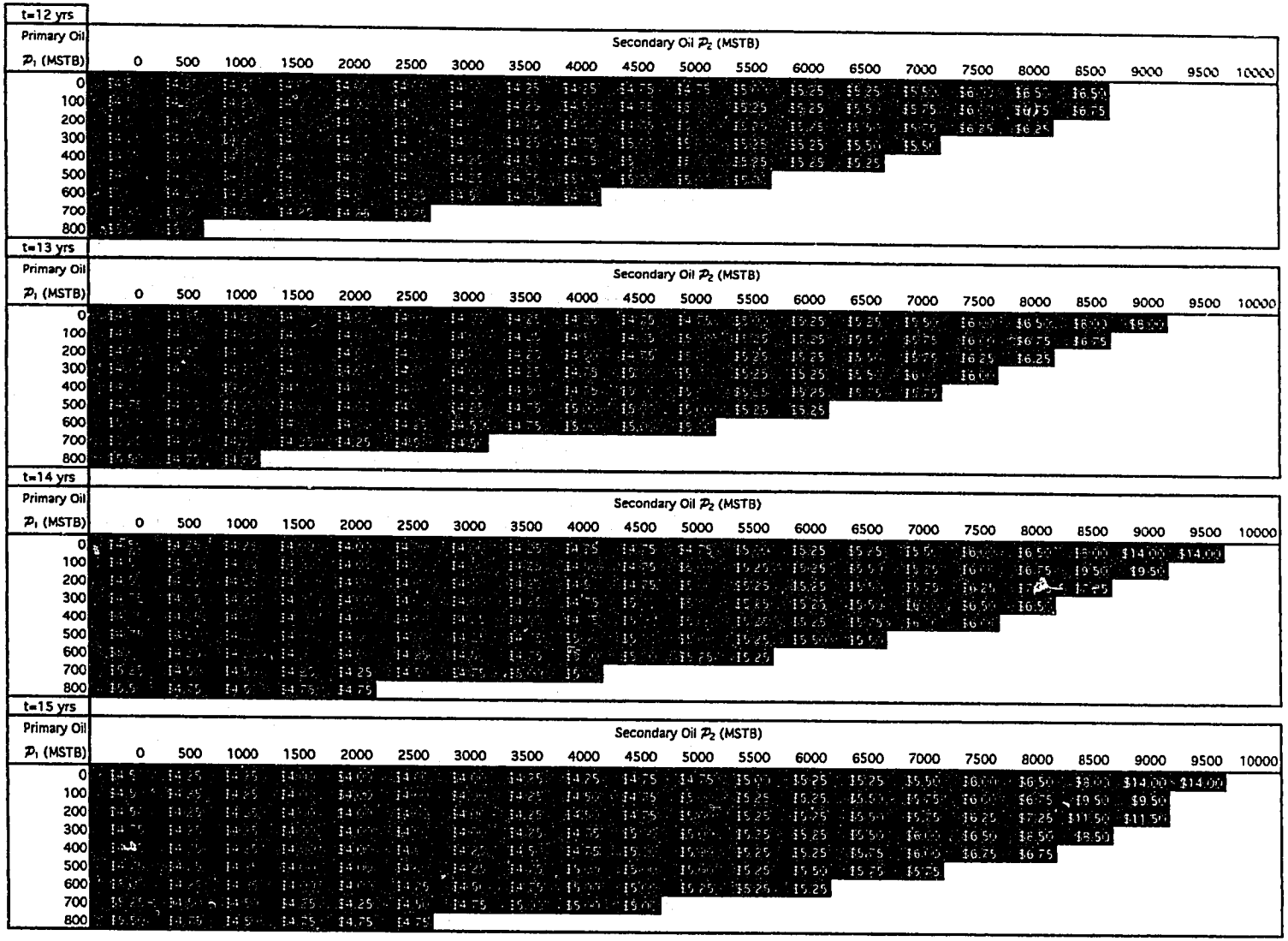
t=10 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=11 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)



t=12 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | $6.50 | | | |
| 100 | | | | | | | | | | | | | | | | | | $6.75 | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=13 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | $9.50 | | |
| 100 | | | | | | | | | | | | | | | | | | $6.75 | | | |
| 200 | | | | | | | | | | | | | | | | | | $6.25 | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=14 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | $14.00 | $14.00 | |
| 100 | | | | | | | | | | | | | | | | | | $9.50 | $9.50 | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=15 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | $14.00 | $14.00 | |
| 100 | | | | | | | | | | | | | | | | | | $9.50 | $9.50 | | |
| 200 | | | | | | | | | | | | | | | | | $7.25 | $11.50 | $11.50 | | |
| 300 | | | | | | | | | | | | | | | | | | $8.50 | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)

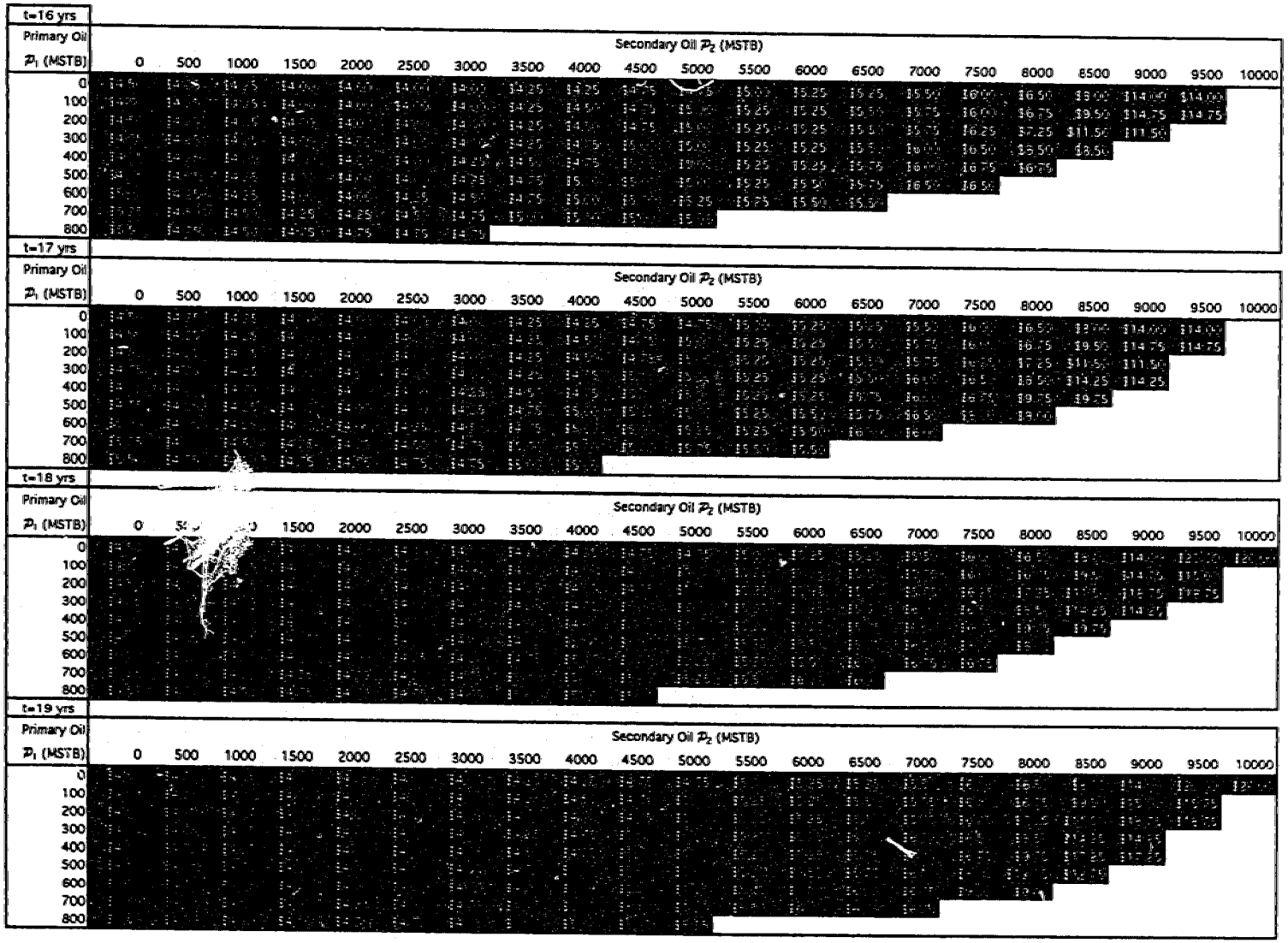
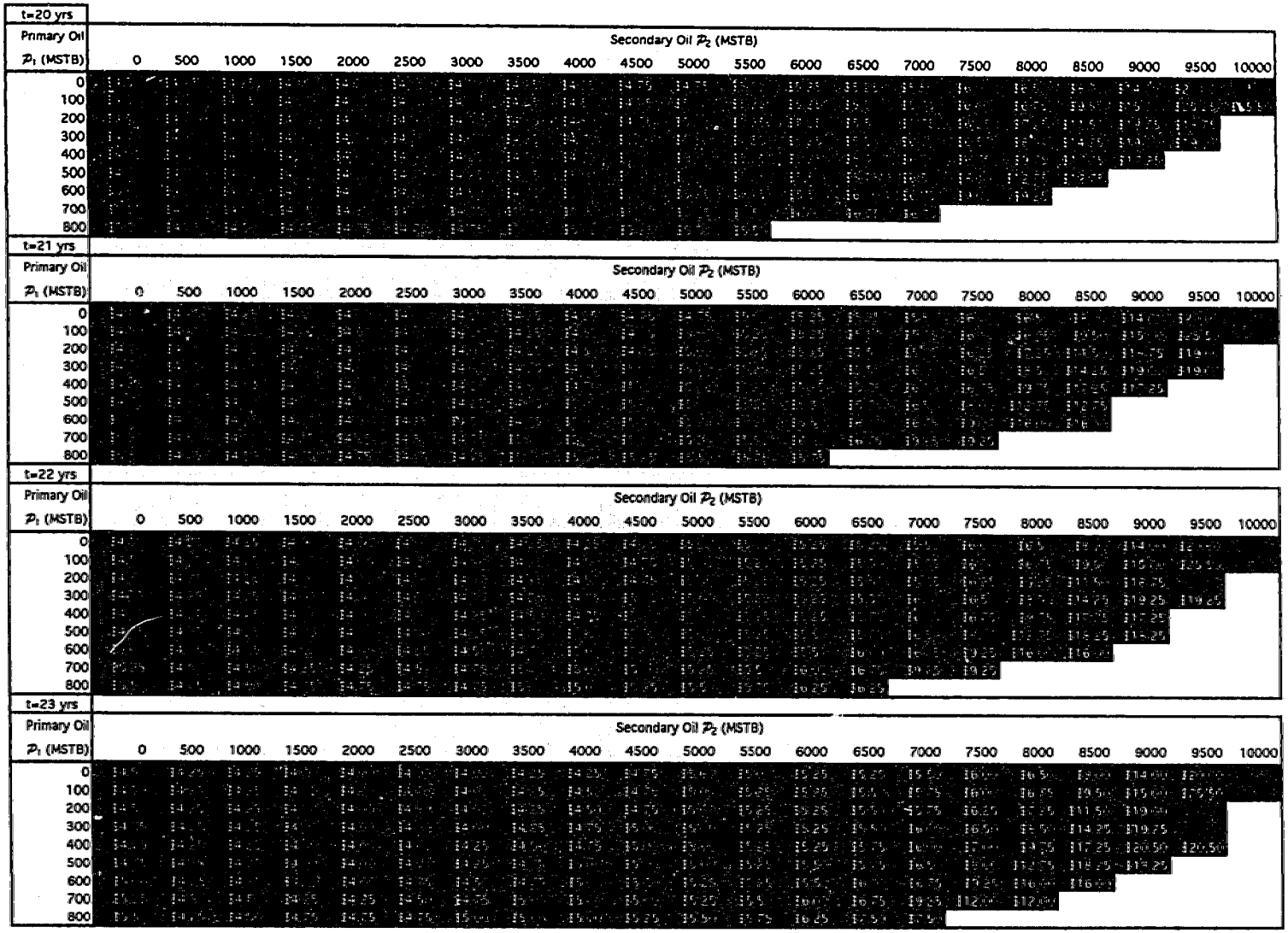


Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)



| t=20 yrs | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Primary Oil $\mathcal{P}_1$ (MSTB) | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

| t=21 yrs | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Primary Oil $\mathcal{P}_1$ (MSTB) | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

| t=22 yrs | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Primary Oil $\mathcal{P}_1$ (MSTB) | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

| t=23 yrs | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Primary Oil $\mathcal{P}_1$ (MSTB) | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)

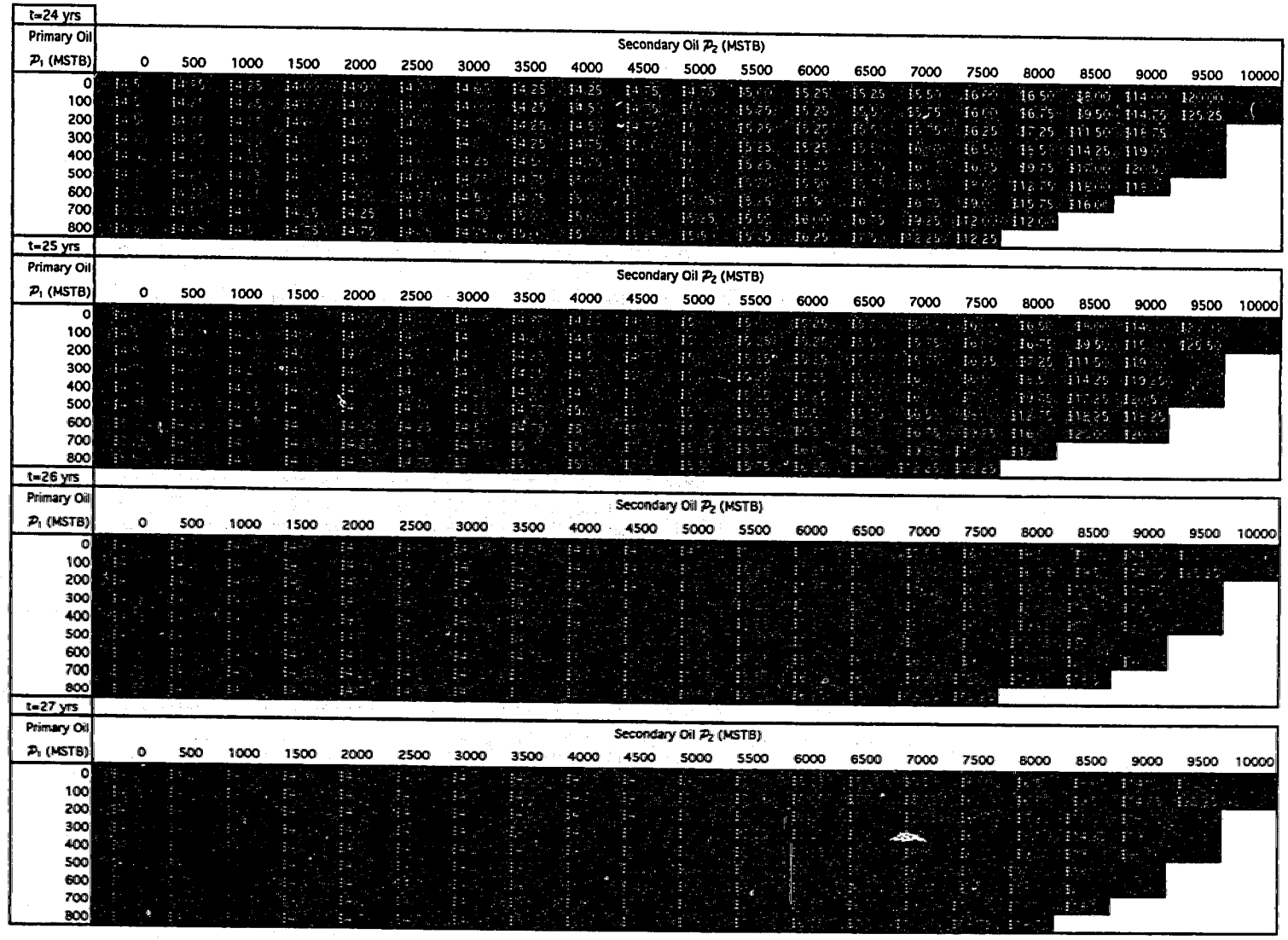
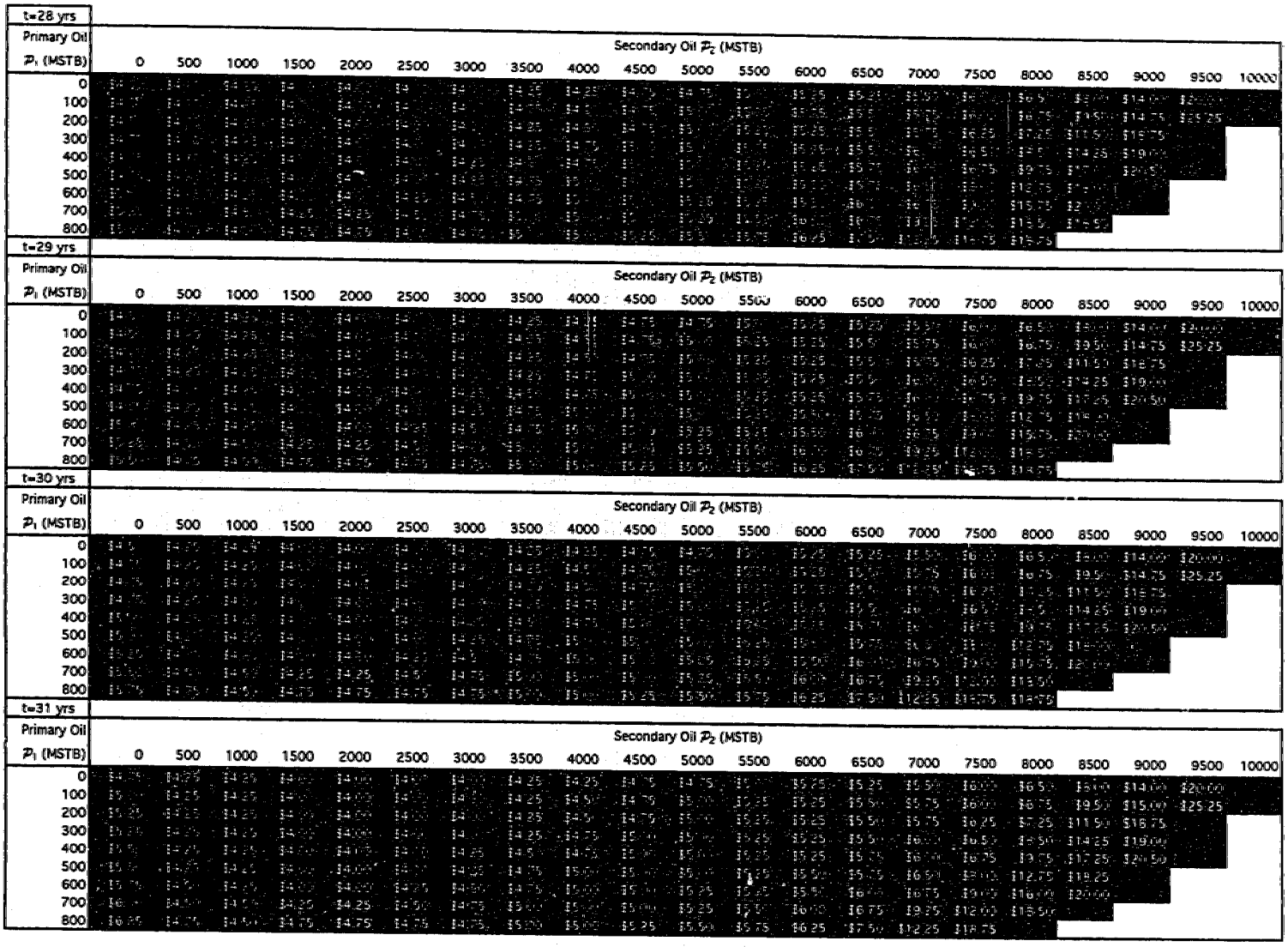



Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)



t=28 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=29 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=30 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

t=31 yrs

| Primary Oil $\mathcal{P}_1$ (MSTB) | Secondary Oil $\mathcal{P}_2$ (MSTB) | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | 500 | 1000 | 1500 | 2000 | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 | 5500 | 6000 | 6500 | 7000 | 7500 | 8000 | 8500 | 9000 | 9500 | 10000 |
| 0 | | | | | | | | | | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | | | | | | | | | | |
| 300 | | | | | | | | | | | | | | | | | | | | | |
| 400 | | | | | | | | | | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | | | | | | | | | | |
| 600 | | | | | | | | | | | | | | | | | | | | | |
| 700 | | | | | | | | | | | | | | | | | | | | | |
| 800 | | | | | | | | | | | | | | | | | | | | | |

Table 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(\mathcal{P}_2,t;\mathcal{P}_1)$ ($/bbl) (continued)

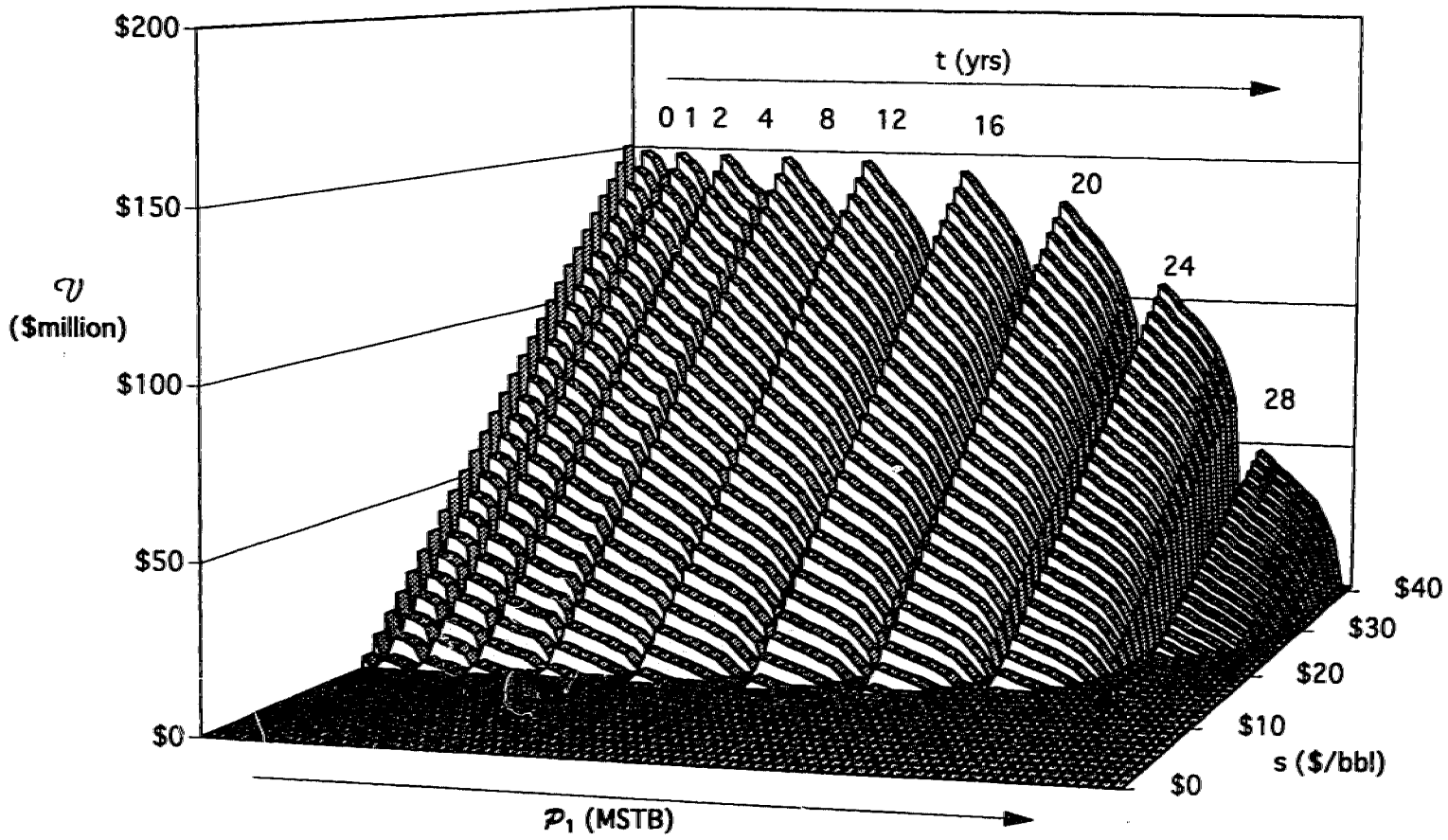



Figure 9.1: Remaining Depletion Strategy Value $\mathcal{V}(s,t,\mathcal{P}_1;\mathcal{D})$

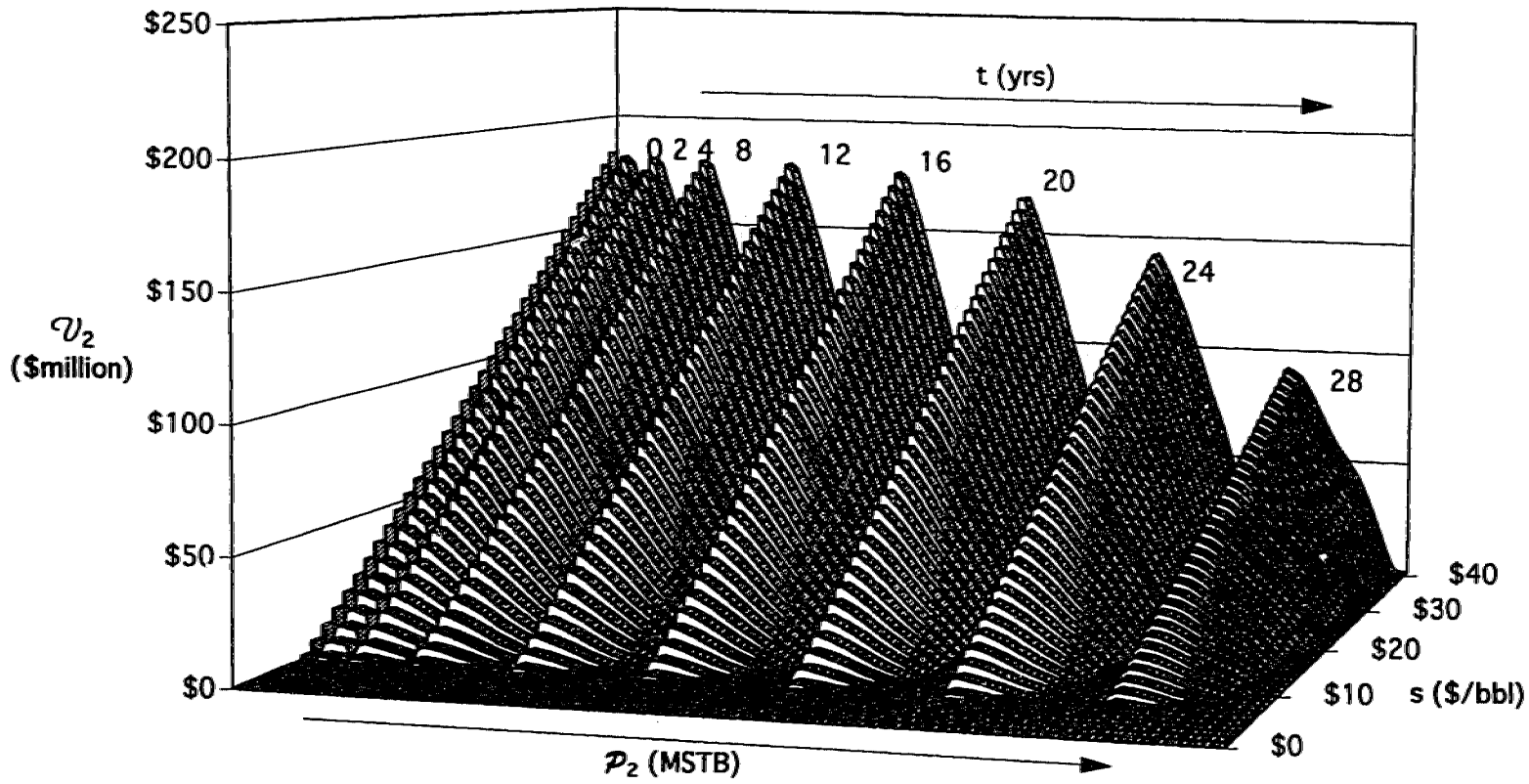



Figure 9.2: Remaining Secondary Value $\mathcal{V}_2(s,t,\mathcal{P}_2;\mathcal{P}_1,\Theta_2)$ for Primary Oil $\mathcal{P}_1$=0 MSTB

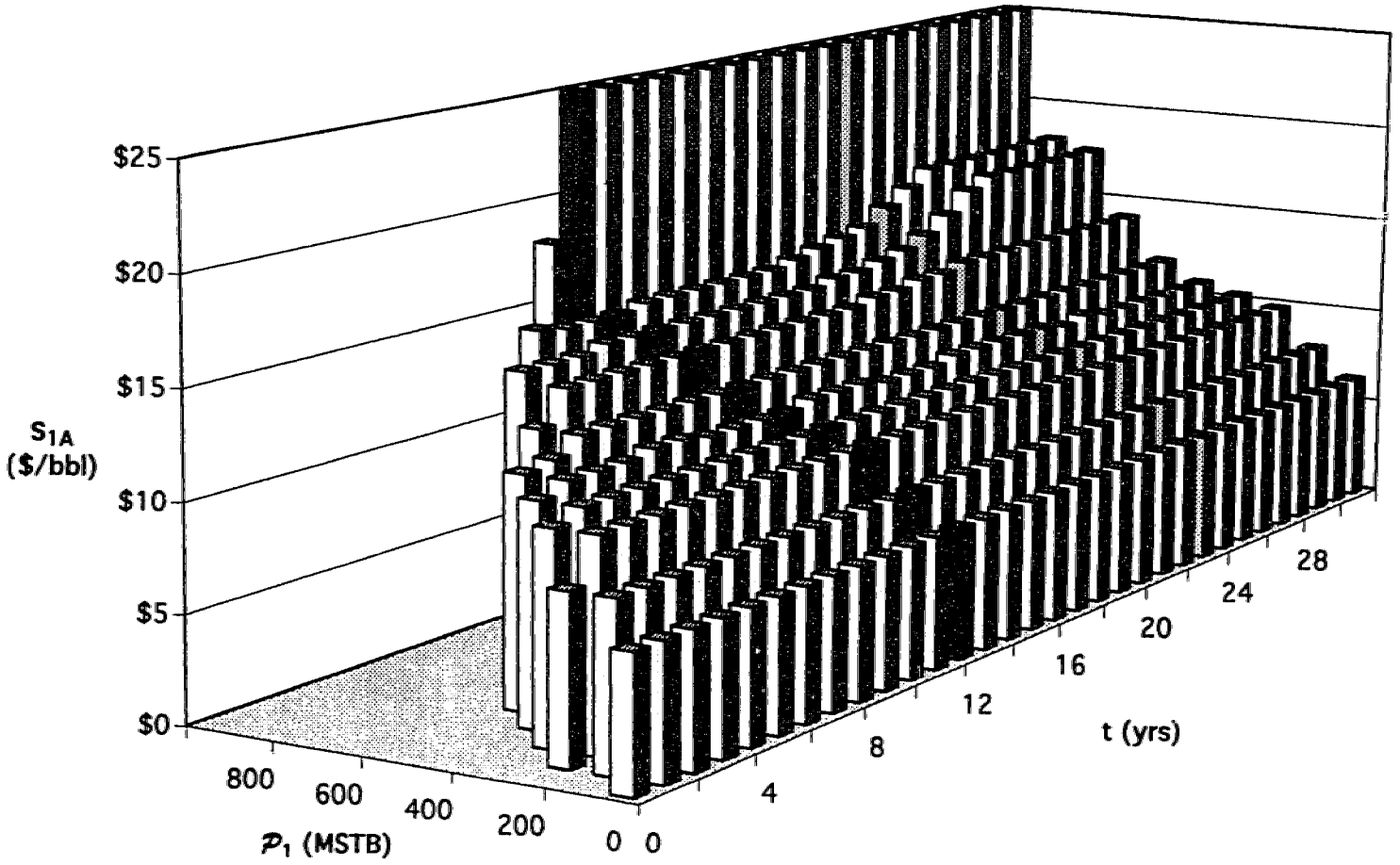



Figure 9.3: Primary Economic Limit Abandonment Price $s_{1A}(t,\mathcal{P}_1)$

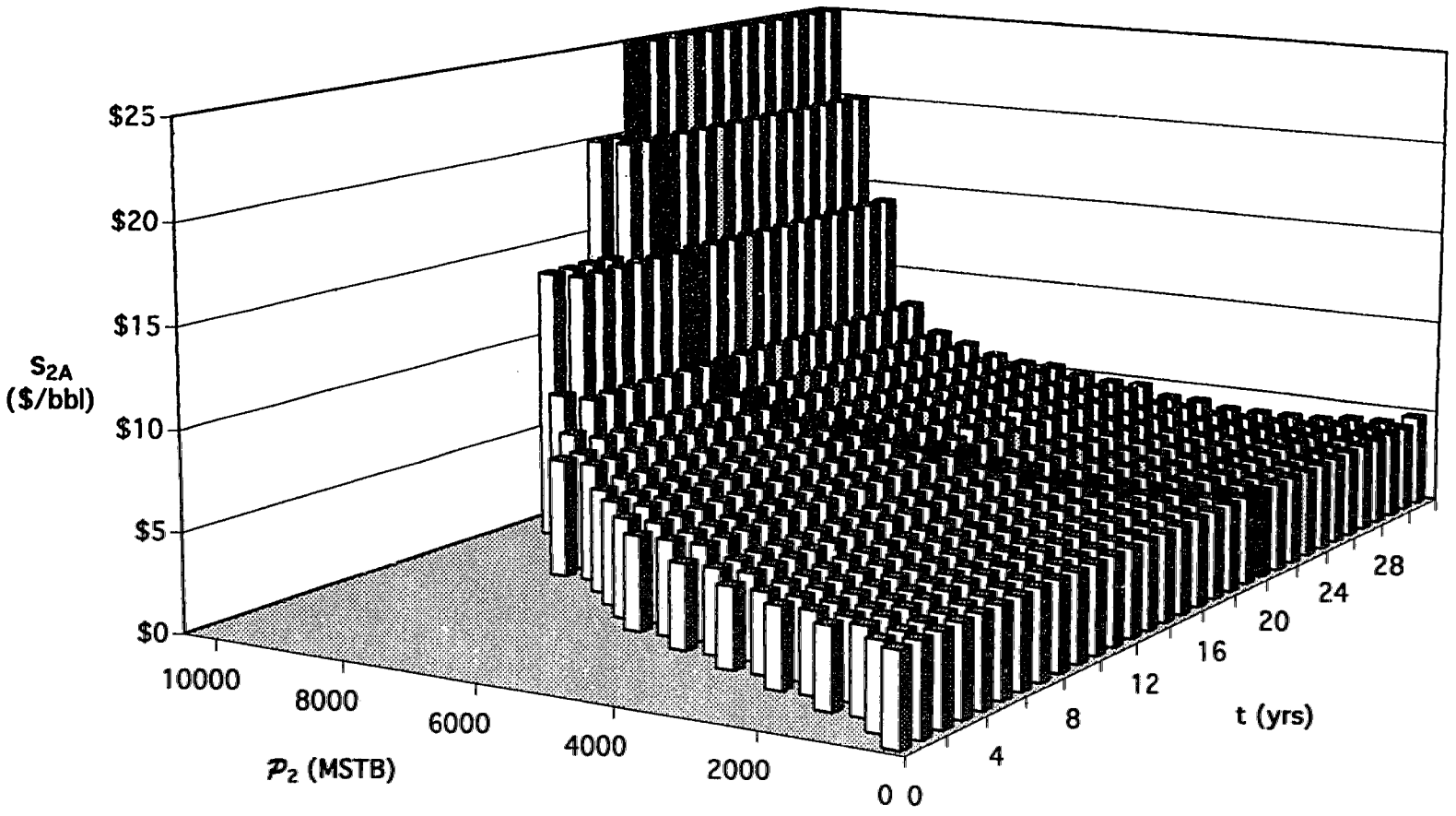



Figure 9.4: Secondary Economic Limit Abandonment Price $s_{2A}(t,\mathcal{P}_2;\mathcal{P}_1)$ for $\mathcal{P}_1=0$

# Chapter 10: Conclusion

A methodology has been presented for constructing optional-stage depletion strategies that incorporate a probabilistic economic model for the timing valuation of secondary recovery options. A branched differential decision process using dynamic programming techniques was used to find investment and operating decision rules that maximized the modelled economic value of remaining operating alternatives over a strategic window.

A depletion strategy was constructed for the implementation of an optional waterflood design in the Chedderville Viking "A" pool. The strategy constituted an optimal policy that was compiled as a schedule of price sensitive decision rules to apply at future depletion states, regardless of how model operations are managed up to that point in time. Regulatory constraints limited monthly oil and gas primary production. The model system examined the waterflood investment timing option. The economic limit for early abandonment options were also determined. Modelled economic value depended on the remaining reservoir depletion paths and the probability structure of macro-economic scenarios. The oil price and cumulative oil production were sufficient state variables for decision-making. Oil price expectations assumed an exogenous continuous random walk in volatile future price movements. An intertemporal equilibrium asset valuation model, based on oil futures price dynamics, was used to value production cash flows from alternative recovery paths in terms of macro-economic factors and field-specific costs.

This investigation presents the following contributions to petroleum engineering management:

1) Depletion state variables based on cumulative oil production were approximated and a feasible depletion space for primary and secondary operations defined.

2) The decision model based on probabilistic economic scenarios examined nested primary and secondary operating modes for active control policy, pooled suspension and early abandonment. A dynamic programming algorithm tracked the feasible depletion state boundary constraint for decision times based on cumulative production milestones.

3) A reservoir simulation tool was developed with branched forecasting capabilities for an optional secondary recovery stage at discrete depletion states along the primary life cycle.

4) A well management system for monthly oil and gas regulatory quotas was implemented into the reservoir simulation tool.

5) A primary control policy that adhered to regulatory constraints and a secondary control policy that met waterflood design specifications were proposed.

6) The optional-stage depletion strategy methodology was demonstrated with the realistic application for the Chedderville Viking "A" Pool. The demonstration included:

a) reservoir characterization of Chedderville Viking "A" using geostatistics
b) history matching production and pressure data
c) feasible waterflood project design
d) primary control policy that adheres to regulatory constraints
e) secondary control policy to meet waterflood design objectives
f) branched waterflood production forecasts along the primary life cycle
g) model depletion strategy generated for Chedderville Viking "A"
h) investment timing option analysis and economic limit determination

# References

Ahmed, T (1989): *Hydrocarbon Phase Behaviour*, Contributions in Petroleum Geology and Engineering Volume 7, Gulf Publishing Company, Houston, Texas, 1989.

Aziz, K. and Settari, A. (1979): *Petroleum Reservoir Simulation*, Applied Science Publishers, London, 1979.

Aziz, K., Eickmeier, J.R., Fogarasi, M. and Gregory, G.A. (1979): *Gradient Curves for Well Analysis and Design*, CIM Special Volume 20, 1979, The Canadian Institute of Mining and Metallurgy.

Aziz, K., Ramesh, A.B. and Woo, P.T. (1987): "Fourth SPE Comparative Solution Project: Comparison of Steam Injection Simulators", *J. Pet. Tech.* (December 1987), 1576-1584.

Bateman, R.M. (1985): *Open-Hole Log Analysis and Formation Evaluation*, International Human Resources Development Corporation, Boston, 1985.

Beggs, H.D. and Brill, J.P. (1973): "A Study of Two-Phase Flow in Inclined Pipes", *JPT* (May 1973) 607-17; *Trans.*, AIME, 255.

Bellman, R. (1957): *Dynamic Programming*, Princeton University Press, Princeton, New Jersey, 1957.

Brennan, M.J. and E.S Schwartz (1985): "Evaluating Natural Resource Investments", *Journal of Business* 58 (1985) 135-157.

Chilingarian, G.V., Robertson Jr., J.O. and Kumar, S. (1987): *Surface Operations in Production, I* , Developments in Petroleum Science 19A ,Elsevier Science Publishers B.V., Amsterdam, The Netherlands.

CIM Petroleum Society Monograph No. 1 (1994): *Determination of Oil and Gas Reserves*, The Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum, Calgary Section, 1994.

Coats, K.H. (1980): "In-Situ Combustion Model", *Soc. Pet. Eng. J.* (December 1980), 534-554.

Cox, J.C., J.E. Ingersoll, Jr., and S.A.Ross (1981): "The Relation between Forward Prices and Futures Prices", Journal of Financial Economics, 9 (1981), pp 321-346.

Dake, L.P. (1978): *Fundamentals of Reservoir Engineering*, Developments in Petroleum Science 8, Elsevier Science Publishers B.V., Amsterdam, The Netherlands, 1978.

Delhomme, J.P. (1978): "Kriging in the Hydrosciences", *Advances in Water Resources* (1978) 1, No. 5, 251-66.

Demetre, G. P. (1993):*Contiguous Hypergrid in Steam Injection Simulation*, Ph.D. Thesis, University of Alberta, 1993.

Dewan, J.T. (1983): *Essentials of Modern Open-Hole Log Interpretation*, PennWell Publishing Company, Tulsa, Oklahoma, 1983.

Farouq Ali, S.M. (1980): *Elements of Reservoir Modelling*, University of Alberta, 1980.

Franchi, J.R., K.J. Harpole and S.W. Bujnowski (1982): *BOAST: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool (Version 1.1* Volume 1, U.S. Department of Energy, 1982 (DOE/BC/10033-3 Distribution Category UC-92a.

Hein, M. (1982): "3P flow analyzer", *Oil & Gas Journal*, Aug 9, 1982 OGJ REPORT, 132-138.

Honarpour, M., Koederitz, L. and Harvey, A.H. (1986): *Relative Permeability of Petroleum Reservoirs*, CRC Press Inc. Boca Raton, Florida,1986.

Hull, J (1991): *Introduction to Futures and Options Markets*, Prentice-Hall Inc., Englewood Cliffs, New Jersey, 1991.

Matthews,C.S. and Russell, D.G. (1967): *Pressure Buildup and Flow Tests in Wells* , Society of Petroleum Engineers of AIME, 1967.

Mattax, C.C. and Dalton, R.L. (1990): *Reservoir Simulation*, Monograph Volume 13, Henry L. Doherty Series, Society of Petroleum Engineers, Richardson TX, 1990.

Mehos, G.J. (1986): *Optimal Control Policies for Carbon Dioxide Miscible Flooding Enhanced Oil Recovery*, Ph.D. Thesis, University of Colorado (1986).

Merton, R.C. (1973): "A Rational Theory of Option Pricing", *Bell Journal of Economics and Management Science* 4 (1973) 141-183.

Oguztoreli, M. (1984):*A Mathematical Approach to the Solvent Leaching of Tar Sands*, M.Sc. Thesis, University of Alberta, 1984.

Oguztoreli, M. (1988): "The Symbolic D4 Method for Reservoir Simulation", Petroleum Society of CIM, Paper No. 88-39-02 (13 pages), presented at the 39-th Annual Technical Meeting of the Petroleum Society of CIM, Calgary, Alberta, June 12-16, 1988.

Pontryagin, L.S., Boltyanskii, R.V., Gamkrelidze, R.V., Mischenko, E.F. (1962): *The Mathematical Theory of Optimal Processes*, Wiley, New York (1962).

Press, W.H., Flannery, B.P., Teukolsky, S.A. and Vetterling, W.T. (1986): *Numerical Recipes ,The Art of Scientific Computing*, Cambridge University Press, 1986.

Ramirez, W.F. (1987): *Application of Optimal Control Theory to Enhanced Oil Recovery*, Developments in Petroleum Science 21, Elsevier Science Publishers B.V., Amsterdam, The Netherlands.

Samuelson, P.A. (1965): "Rational Theory of Warrant Pricing", *Industrial Management Review*, (1965) 6 Spring, 3-31.

Sheldon, J.W., Harris, C.D., and Bavly, D. (1960): "A Method for General Reservoir Behaviour on Digital Computers", paper SPE 1521-G presented at the 1960 SPE Annual Meeting, Denver, Oct. 2-5.

Slider, H.C. (1983): *Worldwide Practical Petroleum Reservoir Engineering Methods* , PennWell Publishing Company, Tulsa, Oklahoma, 1983.

Stone, H.L. and Garder, A.O. Jr. (1961): "Analysis of Gas-Cap or Dissolved Gas Drive Reservoirs", *SPEJ* (June 1961) 92-104; *Trans.*, AIME, 222.

Stone, H.L. (1970): "Estimation of Three-Phase Relative Permeability", *J. Pet. Tech.*, 2, 214, 1970.

Stone, H.L. (1973): "Estimation of Three-Phase Relative Permeability and Residual Oil Data", *J. of Can. Pet. Technol.*, 12, 53, 1973.

Willhite, G.P. (1990): *Waterflooding*, SPE Textbook Series Vol. 3, Society of Petroleum Engineers, Richardson TX, 1990.

# Appendix A1: Black Oil Simulation Model

This formulation is based on the "Black Oil Applied Simulation Tool (BOAST)" developed by Franchi *et al.* (1982).

## A1.1 Reservoir Volume Elements

A principle axis transformation aligns the areal coordinate system with core permeability trends. The longitudinal maximum and transverse 90° permeability directions corresponds to the rectilinear x- and y-axis, respectively. The vertical z-axis is in the direction of increasing depth. Rectilinear coordinate unit vectors ($\mathbf{e}_x$, $\mathbf{e}_y$, $\mathbf{e}_z$) define (x, y, z) directions. Vector $\mathbf{x}$=(x, y, z) defines the location of a volume element ($\Delta\mathbf{x}$) within the porous reservoir domain.

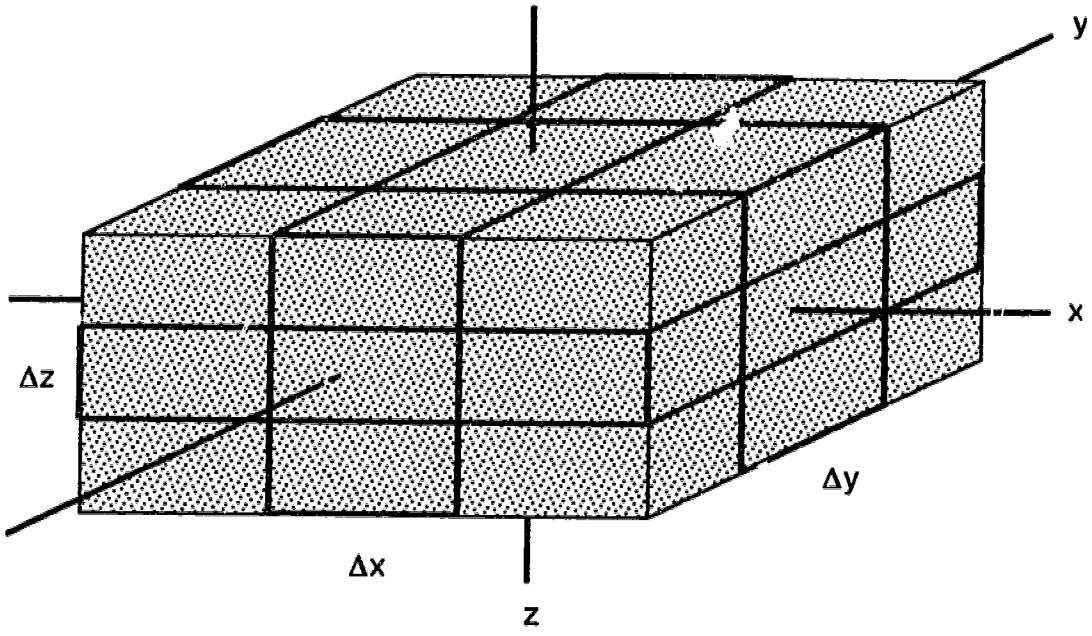



Figure A1.1: Reservoir Grid Coordinate System

The rock matrix is partitioned on a block-centered grid into ($N_x$, $N_y$, $N_z$) intervals of dimension ($\Delta x$, $\Delta y$ ,$\Delta z$). Areal grid block boundaries map directly onto a discrete coordinate mesh on the x-y plane.

$$x_i = x_{i-1} + \Delta x_i \qquad i = 1,2,\ldots,N_x$$
$$y_j = y_{j-1} + \Delta y_j \qquad j = 1,2,\ldots,N_y \qquad \text{(A1.1)}$$

The formation top depth $z_0(x,y)$ is measured from the reference areal coordinate system at sea level (z=0). The thickness partition is generally a function of the specific volume element $\Delta z(x,y,z)$. The depth of a specific volume element is determined recursively from the location of the volume element above.

$$z_k(x,y) = z_{k-1}(x,y) + \Delta z_k(x,y) \qquad k = 1,2,\ldots,N_z \tag{A1.2}$$

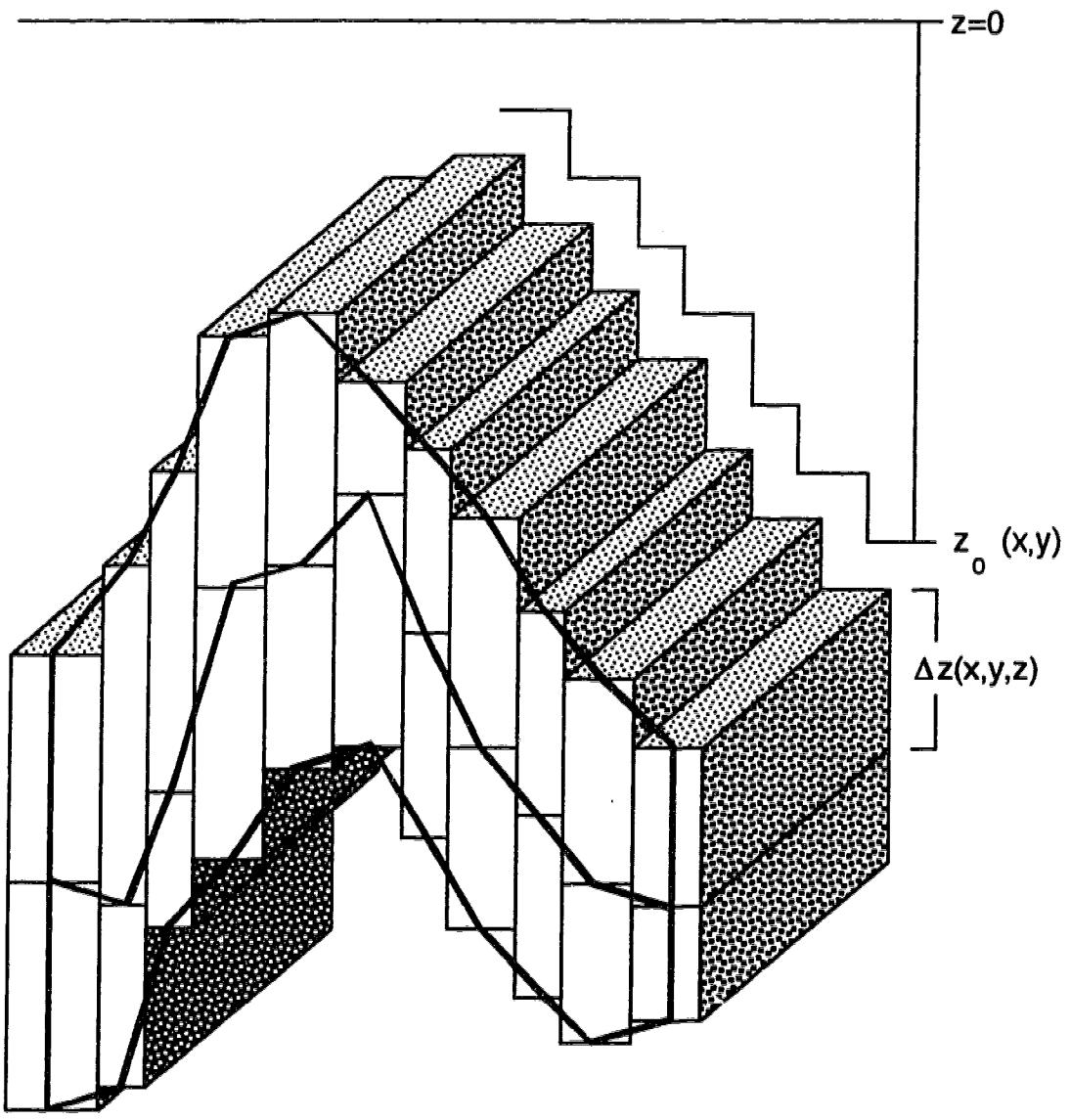



Figure A1.2: Irregular Thickness Partition with Skewed Elements

The irregular grid partition in the z-direction may result in skewed volume elements. Skewness occurs when connected faces of adjacent elements are located at different depths. Elemental bulk volumes ($\Delta V_b=\Delta \mathbf{x}$) are defined in terms of discrete elemental dimensions ($\Delta x_i$, $\Delta y_j$ ,$\Delta z_{ijk}$).

$$\Delta V_b = \Delta x_i \, \Delta y_j \, \Delta z_{ijk} \tag{A1.3}$$

## A1.2 Volume Fractions

Reservoir porosity ($\phi$) is defined as the locally-averaged void volume-fraction of the rock matrix. Rock compressibility ($c_r$) is assumed to be a function of the reservoir pressure (p).

$$\frac{\partial \phi}{\partial p} = c_r(p) \tag{A1.4}$$

Phase saturations ($S_o$, $S_w$, $S_g$) are defined as locally-averaged rock void volume-fractions occupied by the respective phases of oil water and gas.

$$S_o + S_w + S_g = 1 \tag{A1.5}$$

## A1.3 Capillary Pressures

Each phase can occupy a distinct portion of the pore space, with the formation of oil-water and gas-oil interfacial boundaries. The surface tension at these boundaries create a capillary pressure difference between the distinct phase pressures ($p_o$, $p_w$, $p_g$). The reservoir fluid pressure (p) is typically in terms of the oil pressure ($p_o$=p). Oil-water and gas-oil capillary pressures ($p_{cow}$, $p_{cgo}$) are functions of water and gas saturations, respectively.

$$\begin{aligned} p_{cow}(S_w) &= p_o - p_w \\ p_{cgo}(S_g) &= p_g - p_o \end{aligned} \tag{A1.6}$$

## A1.4 Fluid Volumes

Reservoir fluid volumes ($V_o$, $V_w$, $V_g$) are converted into a standard fluid volumes ($V_{sco}$, $V_{scw}$, $V_{scg}$) by formation volume factors ($B_o$, $B_w$, $B_g$). Formation volume factors have units of reservoir fluid volume per unit standard fluid

volume. Isothermal reservoir volumes depend on reservoir pressure (p). The Standard volume is one barrel at stock tank conditions (1 atm, 60° F) for oil and formation water. The gas standard volume is one standard cubic foot (1 atm, 60° F).

$$B_o = \frac{V_o(p)}{V_{sco}} \qquad B_w = \frac{V_w(p)}{V_{scw}} \qquad B_g = \frac{V_g(p)}{V_{scg}} \tag{A1.7}$$

Gas can either flow in its free form, or flow as a dissolved component with oil and water. The reservoir liquid volumes ($V_o$, $V_w$) will include dissolved gas. The volume of dissolved gas depends on its solubility. Gas solubilities ($R_{so}$, $R_{sw}$) are expressed in standard volumes of gas dissolved in standard volumes of liquid. Isothermal gas solubilities are functions of pressure.

$$R_{so} = R_{so}(p) \qquad R_{sw} = R_{sw}(p) \tag{A1.8}$$

## A1.5 Conservation of Mass

The phase velocity ($\mathbf{v}_o$, $\mathbf{v}_w$, $\mathbf{v}_g$) is defined as the reservoir volumetric flux. Standard densities ($\rho_{sco}$, $\rho_{scw}$, $\rho_{scg}$) relate standard volumes to mass. Mass is conserved for each phase. The rate of mass accumulation in a volume element must equal the combined rates of net mass influx from adjacent elements and mass source introduced from within. Mass concentration sources ($q_o$, $q_w$, $q_g$) are defined in terms of fluid mass rates per unit reservoir volume. Conservation of mass equations are determined using Gauss's divergence theorem over individual volume elements. The system of partial differential equations in differential vector form are:

$$-\nabla\cdot\frac{\mathbf{v}_o}{B_o} - \frac{q_o}{\rho_{sco}} = \frac{\partial}{\partial t}\left(\phi\frac{S_o}{B_o}\right)$$

$$-\nabla\cdot\frac{\mathbf{v}_w}{B_w} - \frac{q_w}{\rho_{scw}} = \frac{\partial}{\partial t}\left(\phi\frac{S_w}{B_w}\right)$$

$$-\nabla\cdot\left(\frac{\mathbf{v}_g}{B_g}+\frac{R_{so}\mathbf{v}_o}{B_o}+\frac{R_{sw}\mathbf{v}_w}{B_w}\right) - \frac{q_g}{\rho_{scg}} = \frac{\partial}{\partial t}\left[\phi\left(\frac{S_g}{B_g}+\frac{R_{so}S_o}{B_o}+\frac{R_{sw}S_w}{B_w}\right)\right] \tag{A1.9}$$

Wells provide fluid sources and sinks into reservoir volume elements at specific locations $\{\mathbf{x}_{ijk}\}$. Production wells are negative sinks and injection wells are positive sources. Well flows are in terms of a standard volumetric flow rates ($Q_o$, $Q_w$, $Q_g$). The appropriate mass concentration source terms ($q_o$, $q_w$, $q_g$) distribute point flows over the physical volume of the reservoir element ($\Delta\mathbf{x}$).

$$Q_o = \frac{q_o(\mathbf{x})}{\rho_{sco}}\Delta\mathbf{x}$$

$$Q_w = \frac{q_w(\mathbf{x})}{\rho_{scw}}\Delta\mathbf{x}$$

$$Q_g = \frac{q_g(\mathbf{x})}{\rho_{scg}}\Delta\mathbf{x} \qquad \text{(A1.10)}$$

## A1.6 Phase Potentials

Phase potentials ($\Phi_o$, $\Phi_w$, $\Phi_g$) are defined as sum of hydrodynamic pressures and hydrostatic heads at depth (z).

$$\Phi_o = p_o + \rho_o g z$$

$$\Phi_w = p_w + \rho_w g z$$

$$\Phi_g = p_g + \rho_g g z \qquad \text{(A1.11)}$$

## A1.7 Darcy Velocities

Darcy's equation relates the fluid flux to the potential gradient. The resistance to flow is determined by the rock permeability ($\tilde{K}$), a dyadic tensor of rank two.

$$\mathbf{v}_o = -\tilde{K} \cdot \lambda_o \nabla \Phi_o$$

$$\mathbf{v}_w = -\tilde{K} \cdot \lambda_w \nabla \Phi_w$$

$$\mathbf{v}_g = -\tilde{K} \cdot \lambda_g \nabla \Phi_g \qquad \text{(A1.12)}$$

The rock permeability ($\tilde{K}$) tensor accounts for the anisotropic nature of the reservoir pore structure, where a potential gradient can produce component flows in different directions. A principle axis transformation diagonalizes the

tensor matrix into longitudinal, transverse and vertical permeability components ($K_x$, $K_y$, $K_z$) to align with directions of the coordinate unit vectors ($\mathbf{e}_x$, $\mathbf{e}_y$, $\mathbf{e}_z$).

$$\begin{aligned}
\mathbf{v}_o &= -\lambda_o\left[K_x\frac{\partial}{\partial x}\mathbf{e}_x + K_y\frac{\partial}{\partial y}\mathbf{e}_y + K_z\frac{\partial}{\partial z}\mathbf{e}_z\right]\Phi_o \\
\mathbf{v}_w &= -\lambda_w\left[K_x\frac{\partial}{\partial x}\mathbf{e}_x + K_y\frac{\partial}{\partial y}\mathbf{e}_y + K_z\frac{\partial}{\partial z}\mathbf{e}_z\right]\Phi_w \\
\mathbf{v}_g &= -\lambda_g\left[K_x\frac{\partial}{\partial x}\mathbf{e}_x + K_y\frac{\partial}{\partial y}\mathbf{e}_y + K_z\frac{\partial}{\partial z}\mathbf{e}_z\right]\Phi_g
\end{aligned} \tag{A1.13}$$

The phase mobilities ($\lambda_o$, $\lambda_w$, $\lambda_g$) are the ratios of the phase relative permeabilities ($k_{ro}$, $k_{rw}$, $k_{rg}$) to phase viscosities ($\mu_o$, $\mu_w$, $\mu_g$). Isothermal phase viscosities depend on pressure (p). Oil and water viscosities account for the effects of dissolved gas in solution. Three-phase relative permeabilities are assumed to have a functional dependence on ($S_o$, $S_w$, $S_g$) as proposed in the probability models of Stone (1970, 1973).

$$\lambda_o = \frac{k_{ro}(S_w, S_g)}{\mu_o(p)} \qquad \lambda_w = \frac{k_{rw}(S_w)}{\mu_w(p)} \qquad \lambda_g = \frac{k_{rg}(S_g)}{\mu_g(p)} \tag{A1.14}$$

## A1.8 Oil Pressure Equation

The oil pressure equation is derived by eliminating phase saturations using the identity (A1.5), the Darcy-continuity equations (A1.9-A1.13) and the capillary pressures (A1.6). Isothermal formation volume factors (A1.7), gas solubilities (A1.8) and porosity (A1.4) are functions of pressure only. Time derivatives in (A1.9) can be expanded using the chain rule. Phase compressibility coefficients ($c_o$, $c_w$, $c_g$) are defined in terms of reservoir phase volumes.

$$\begin{aligned}
c_o &= -\frac{1}{B_o}\frac{\partial B_o}{\partial p} + \frac{B_g}{B_o}\frac{\partial R_{so}}{\partial p} \\
c_w &= -\frac{1}{B_w}\frac{\partial B_w}{\partial p} + \frac{B_g}{B_w}\frac{\partial R_{sw}}{\partial p} \\
c_g &= -\frac{1}{B_g}\frac{\partial B_g}{\partial p}
\end{aligned} \tag{A1.15}$$

The total compressibility coefficient ($c_t$) is the sum of component coefficients:

$$c_t = c_r + c_o S_o + c_w S_w + c_g S_g \tag{A1.16}$$

The oil pressure equation in differential form becomes:

$$\begin{aligned}
\phi c_t \frac{\partial p}{\partial t} = {} & (B_o - R_{so} B_g)[\nabla \cdot \tilde{K} \cdot \frac{\lambda_o}{B_o} \nabla (p - \rho_o g z) - \frac{q_o}{\rho_{sco}}] \\
& + (B_w - R_{sw} B_g)[\nabla \cdot \tilde{K} \cdot [\frac{\lambda_w}{B_w} \nabla (p - \rho_w g z) - \frac{\lambda_w}{B_w} \nabla p_{cow}] - \frac{q_w}{\rho_{scw}}] \\
& + B_g [\nabla \cdot \tilde{K} \cdot [(\frac{\lambda_g}{B_g} + \frac{R_{so}\lambda_o}{B_o} + \frac{R_{sw}\lambda_w}{B_w}) \nabla p - \frac{R_{so}\lambda_o}{B_o} \nabla (\rho_o g z) \\
& + \frac{\lambda_g}{B_g} \nabla (p_{cgo} - \rho_g g z) - \frac{R_{sw}\lambda_w}{B_w} \nabla (p_{cow} + \rho_w g z)] - \frac{q_g}{\rho_{scg}}]
\end{aligned} \tag{A1.17}$$

The pressure equation has no explicit time derivatives of saturation.

## A1.9 Saturation Equations

Oil and water saturations are determined directly from the Darcy-continuity equations (A1.9)-(A1.13) :

$$\begin{aligned}
\frac{\partial}{\partial t}(\phi \frac{S_o}{B_o}) &= \nabla \cdot \tilde{K} \cdot \frac{\lambda_o}{B_o} \nabla (p - \rho_o g z) - \frac{q_o}{\rho_{sco}} \\
\frac{\partial}{\partial t}(\phi \frac{S_w}{B_w}) &= \nabla \cdot \tilde{K} \cdot \frac{\lambda_w}{B_w} \nabla (p - \rho_w g z) - \nabla \cdot \tilde{K} \cdot \frac{\lambda_w}{B_w} \nabla p_{cow} - \frac{q_w}{\rho_{scw}}
\end{aligned} \tag{A1.18}$$

and the gas saturation from the identity (A1.5).

$$S_g = 1 - S_o - S_w \tag{A1.19}$$

## A1.10 Finite Difference Equations

The system of partial differential equations (A1.17)-(A1.19) at time $t^n$ are spatially integrated over grid block volume elements $\Delta x_{ijk}$ and temporally integrated over a time step $\Delta t$. Block boundary transmissibilities ($T_x$,$T_y$,$T_z$) are defined between grid block (i,j,k) and corresponding adjacent blocks (i-1,j,k), (i,j-1,k) and (i,j,k-1) as:

$$T_{x_{i-\frac{1}{2},j,k}} = \frac{2(K_{x_{i,j,k}} \Delta y_{i,j,k} \Delta z_{i,j,k})(K_{x_{i-1,j,k}} \Delta y_{i-1,j,k} \Delta z_{i-1,j,k})}{K_{x_{i,j,k}} \Delta x_{i-1,j,k} + K_{x_{i-1,j,k}} \Delta x_{i,j,k}}$$

$$T_{y_{i,j-\frac{1}{2},k}} = \frac{2(K_{y_{i,j,k}} \Delta x_{i,j,k} \Delta z_{i,j,k})(K_{y_{i,j-1,k}} \Delta x_{i,j-1,k} \Delta z_{i,j-1,k})}{K_{y_{i,j,k}} \Delta y_{i,j-1,k} + K_{y_{i,j-1,k}} \Delta y_{i,j,k}}$$

$$T_{z_{i,j,k-\frac{1}{2}}} = \frac{2(K_{z_{i,j,k}} \Delta x_{i,j,k} \Delta y_{i,j,k})(K_{z_{i,j,k-1}} \Delta x_{i,j,k-1} \Delta y_{i,j,k-1})}{K_{z_{i,j,k}} \Delta z_{i,j,k-1} + K_{z_{i,j,k-1}} \Delta z_{i,j,k}} \qquad \text{(A1.20)}$$

The Darcy phase transmissibilities ($A_o$,$A_w$,$A_g$) at the block boundaries are calculated using upstream-weighted relative permeability and arithmetic mean values for viscosity and formation volume factor.

$$A_{o_{x\,i-\frac{1}{2},j,k}} = \frac{k_{ro}}{\mu_o B_o} T_{x_{i-\frac{1}{2},j,k}} \quad A_{w_{x\,i-\frac{1}{2},j,k}} = \frac{k_{rw}}{\mu_w B_w} T_{x_{i-\frac{1}{2},j,k}} \quad A_{g_{x\,i-\frac{1}{2},j,k}} = \frac{k_{rg}}{\mu_g B_g} T_{x_{i-\frac{1}{2},j,k}}$$

$$A_{o_{y\,i,j-\frac{1}{2},k}} = \frac{k_{ro}}{\mu_o B_o} T_{y_{i,j-\frac{1}{2},k}} \quad A_{w_{y\,i,j-\frac{1}{2},k}} = \frac{k_{rw}}{\mu_w B_w} T_{y_{i,j-\frac{1}{2},k}} \quad A_{g_{y\,i,j-\frac{1}{2},k}} = \frac{k_{rg}}{\mu_g B_g} T_{y_{i,j-\frac{1}{2},k}}$$

$$A_{o_{z\,i,j,k-\frac{1}{2}}} = \frac{k_{ro}}{\mu_o B_o} T_{z_{i,j,k-\frac{1}{2}}} \quad A_{w_{z\,i,j,k-\frac{1}{2}}} = \frac{k_{rw}}{\mu_w B_w} T_{z_{i,j,k-\frac{1}{2}}} \quad A_{g_{z\,i,j,k-\frac{1}{2}}} = \frac{k_{rg}}{\mu_g B_g} T_{z_{i,j,k-\frac{1}{2}}}$$

(A1.21)

Central-difference operators ($\Delta_x,\Delta_y,\Delta_z$) are used to approximate the differential vector operator ($\nabla$). Gauss's divergence theorem applied over the volume element $\Delta\mathbf{x}_{ijk}$ gives:

$$\iiint_{\Delta\mathbf{x}_{ijk}} \left(\nabla\cdot\tilde{K}\cdot\frac{\lambda_o}{B_o}\nabla p\right) d\mathbf{x} = \Delta A_o \Delta p = \Delta_x A_{o_x}\Delta_x p + \Delta_y A_{o_y}\Delta_y p + \Delta_z A_{o_z}\Delta_z p$$

$$\iiint_{\Delta\mathbf{x}_{ijk}} \left(\nabla\cdot\tilde{K}\cdot\frac{\lambda_w}{B_w}\nabla p\right) d\mathbf{x} = \Delta A_w \Delta p = \Delta_x A_{w_x}\Delta_x p + \Delta_y A_{w_y}\Delta_y p + \Delta_z A_{w_z}\Delta_z p$$

$$\iiint_{\Delta\mathbf{x}_{ijk}} \left(\nabla\cdot\tilde{K}\cdot\frac{\lambda_g}{B_g}\nabla p\right) d\mathbf{x} = \Delta A_g \Delta p = \Delta_x A_{g_x}\Delta_x p + \Delta_y A_{g_y}\Delta_y p + \Delta_z A_{g_z}\Delta_z p \qquad \text{(A1.22)}$$

where

$$\Delta_x A_{o_x}\Delta_x p = A_{o_{x\,i+\frac{1}{2},j,k}}(p_{i+1,j,k}-p_{i,j,k}) - A_{o_{x\,i-\frac{1}{2},j,k}}(p_{i,j,k}-p_{i-1,j,k})$$

$$\Delta_x A_{o_y}\Delta_x p = A_{o_{y\,i,j+\frac{1}{2},k}}(p_{i,j+1,k}-p_{i,j,k}) - A_{o_{y\,i,j-\frac{1}{2},k}}(p_{i,j,k}-p_{i,j-1,k})$$

$$\Delta_x A_{o_z}\Delta_x p = A_{o_{z\,i,j,k+\frac{1}{2}}}(p_{i,j,k+1}-p_{i,j,k}) - A_{o_{z\,i,j,k-\frac{1}{2}}}(p_{i,j,k}-p_{i,j,k-1}) \qquad \text{(A1.23)}$$

Using this notation with explicit sources and sinks, the oil equation becomes:

$$\left[\Delta A_o^n \Delta(p^{n+1}-\rho_o^n gz) - Q_o^n\right]_{i,j,k} = \frac{1}{\Delta t}\left[\left(\frac{\phi S_o}{B_o}\right)^{n+1} - \left(\frac{\phi S_o}{B_o}\right)^n\right]_{i,j,k} \Delta V_{b_{i,j,k}} \qquad \text{(A1.24)}$$

the water equation becomes:

$$\left[\Delta A_w^n \Delta(p^{n+1}-\rho_w^n gz - p_{cow}^n) - Q_w^n\right]_{i,j,k} = \frac{1}{\Delta t}\left[\left(\frac{\phi S_w}{B_w}\right)^{n+1} - \left(\frac{\phi S_w}{B_w}\right)^n\right]_{i,j,k} \Delta V_{b_{i,j,k}}$$

(A1.25)

and the pressure equation becomes:

$$\frac{1}{\Delta t}\left[\phi^n c_t^n (p^{n+1} - p^n)\right]_{i,j,k} \Delta V_{b_{i,j,k}} = (B_o^n - B_g^n R_{so}^n)_{i,j,k}\left[\Delta A_o^n \Delta(p^{n+1} - \rho_o^n gz) - Q_o^n\right]_{i,j,k}$$
$$+ (B_w^n - B_g^n R_{sw}^n)_{i,j,k}\left[\Delta A_w^n \Delta(p^{n+1} - \rho_w^n gz - p_{cow}^n) - Q_w^n\right]_{i,j,k}$$
$$+ (B_g^n)_{i,j,k}\left[\begin{array}{c}\Delta A_g^n \Delta(p^{n+1} - \rho_g^n gz + p_{cgo}^n) + \Delta R_{so}^n A_o^n \Delta(p^{n+1} - \rho_o^n gz) \\ + \Delta R_{sw}^n A_w^n \Delta(p^{n+1} - \rho_w^n gz - p_{cow}^n) - Q_g^n\end{array}\right]_{i,j,k} \quad \text{(A1.26)}$$

The pressure equation can be rearranged to a standard difference form:

$$Z_{i,j,k} p_{i,j,k-1}^{n+1} + B_{i,j,k} p_{i,j-1,k}^{n+1} + D_{i,j,k} p_{i-1,j,k}^{n+1} + E_{i,j,k} p_{i,j,k}^{n+1}$$
$$+ F_{i,j,k} p_{i+1,j,k}^{n+1} + H_{i,j,k} p_{i,j+1,k}^{n+1} + S_{i,j,k} p_{i,j,k+1}^{n+1} = Q_{i,j,k}^n \quad \text{(A1.27)}$$

The hepta-diagonal system is solved algebraicly using a direct method with symbolic D4-ordering (Oguztoreli 1984, Oguztoreli 1988).

### A1.11 Numerical Stability

The finite difference equations are implicitly solved for the pressure distribution at forward times ($t^{n+1}$) using known phase saturations at time ($t^n$). Phase saturations are then explicitly determined using forward pressure distributions. Equations implicit in pressure will be stable for any time step size. However, oscillatory and divergent behaviour of explicit saturations will limit the step size. Franchi *et al.* (1982) do not discuss numerical stability. Mattax and Dalton (1990) briefly address this topic and grid orientation effects.

The step size must ensure that no more than one grid block pore volume throughput can occur over any timestep. Stability criteria for flux conservative equations are generally Courant conditions (Courant-Friedrichs-Lewy stability criterion):

$$\frac{|u|\Delta t}{\Delta \xi} \leq N_{Courant} \quad \text{(A1.28)}$$

where $\Delta\xi$ is a characteristic length and **u** is the velocity. The Courant number is typically less than one. A courant condition can be established for each phase, of which the minimum time step is chosen. Oil and water saturation equations can be expressed in the form:

$$\frac{\partial S^*}{\partial t} = -\nabla \cdot (\mathbf{u} S^*) \tag{A1.29}$$

where $S^*$ is the phase volumetric bulk concentration and **u** is its propagation velocity. A gas saturation equation can also be defined in the same form. The Courant number in three dimensions is $N_{Courant}=3^{-0.5}=0.58$ (Press *et al.* 1986). Propagation velocities can be approximated by explicit Darcy phase velocities divided by phase volumetric bulk concentrations. Source terms can be treated in the same manner. A problem with inherent instability was used as a test case. Stability was obtained for $N_{Courant}=0.25$.

Other factors may also affect the stability in simulation. Numerical solution will always has some degree of local oscillation, and will be heightened by the presence of free gas. The sum total of phase saturations is fixed so that free gas can be calculated directly from oil and water saturations. An overshoot in combined oil and water saturations will typically clip and redistribute the error. This clip may create a local transient error that could propagate with time or die out if time steps are small. A danger exists when undershoot in combined oil and water saturations persist to form numerical free gas. Numerical free gas coupled with bubble point tracking can lead to spurious numerical free gas production above the bubble point. A minuscule amount of numerical free gas in an undersaturated grid block can shift the true bubble point to a level above the contemporaneous reservoir pressure. This can be problematic when waterflood has repressurized the reservoir above the bubble point and a free gas zone grows from numerical bubble point hysteresis. Checks must be in place to zero free gas saturation above the bubble point and redistribute the undershoot between oil and water. Bubble point tracking should not be active above the bubble point. This is not a typical problem and may not happen in most cases. Care must be taken whenever new techniques are applied to existing methods.

# Appendix A2: Dynamic Programming Algorithm

The numerical algorithm is based on finite-difference dynamic programming methods with critical boundary tracking procedures.

## A2.1 Depletion-Time Grid Partition

Time is partitioned into discrete decision time steps $\Delta t^n$. Decision times ($t^n$) are chosen not to exceed quarterly intervals ($\Delta t^n \leq 91.3125$ days) over 32 years of strategic planning.

$$t^n = t^{n+1} - \Delta t^n \tag{A2.1}$$

Discrete primary depletion states ($\mathcal{P}_1^{m1}$) are calculated over ($M_1=9$) primary cumulative oil production steps ($\Delta\mathcal{P}_1=100$ MSTB). Figure A2.1 shows the primary depletion state-time grid partition.

$$\mathcal{P}_1^{m_1} = m_1 \Delta\mathcal{P}_1 \qquad m_1=0,1,\ldots,M_1 \tag{A2.2}$$

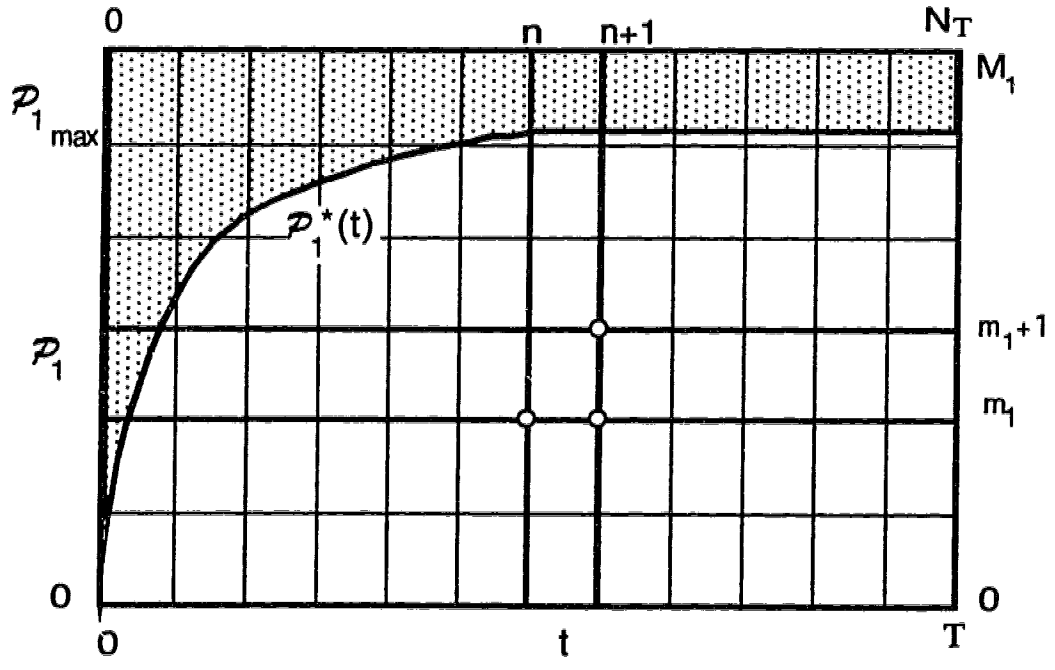



Figure A2.1: Primary Depletion-Time ($\mathcal{P}_1$,t) Grid with Temporal Boundary

The stationary grid partition tracks a time-dependent feasible primary depletion boundary. The maximum grid primary depletion state ($\mathcal{P}_1^{M1}$=900 MSTB) covers the feasible cumulative oil production range under sustained primary control $\mathcal{P}_1^*(T)$=843 MSTB.

Discrete secondary depletion states ($\mathcal{P}_2^{m2}$) are calculated over ($M_2$=20) secondary cumulative oil production steps ($\Delta\mathcal{P}_2$=500 MSTB). Figure A2.2 shows the secondary depletion state-time grid partition.

$$\mathcal{P}_2^{m_2} = m_2 \Delta\mathcal{P}_2 \qquad m_2=0,1,\ldots,M_2 \tag{A2.3}$$

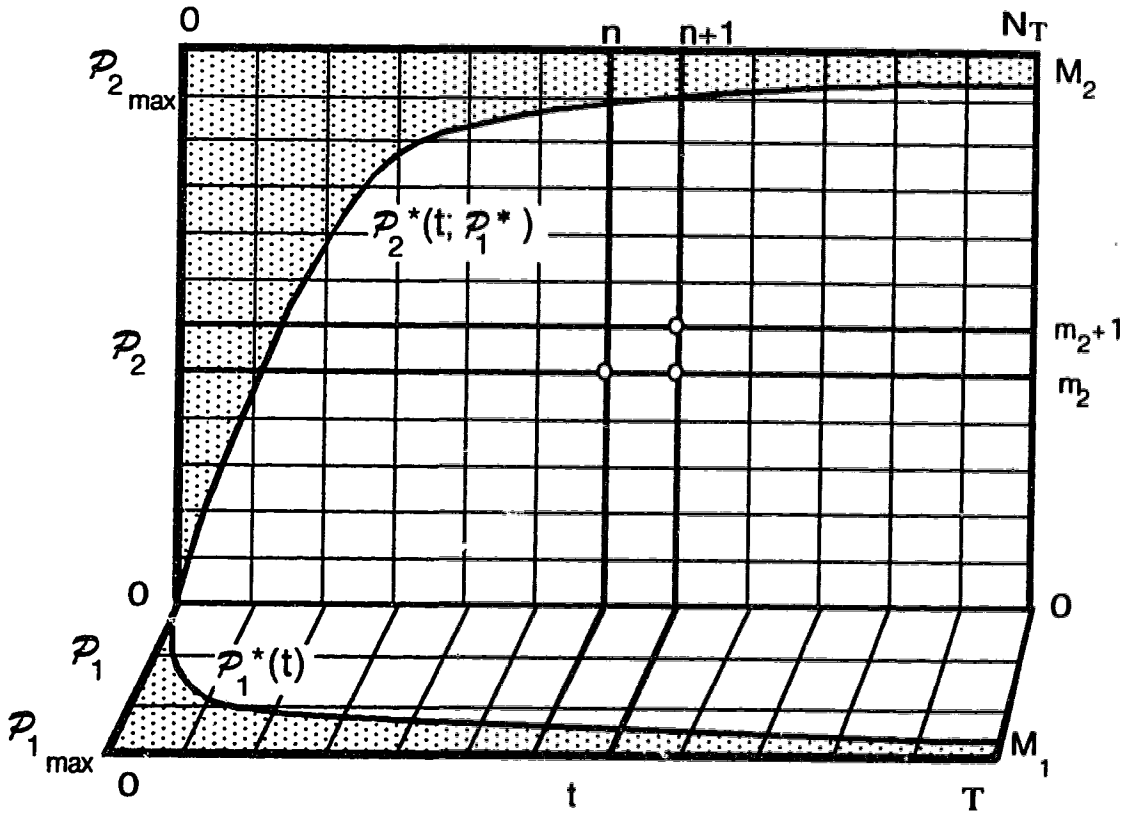



Figure A2.2: Secondary Depletion-Time ($\mathcal{P}_2$,t) Grid with Temporal Boundary

The stationary grid partition tracks a time-dependent secondary depletion boundary. The maximum grid secondary depletion state ($\mathcal{P}_2^{M2}$=10,000 MSTB)

covers the feasible cumulative oil production range under sustained secondary control, $\mathcal{P}_2^*(T;\mathcal{P}_1=0) = 9745$ MSTB. The $(\mathcal{P}_1,\mathcal{P}_2,t)$ grid partition encapsulates the space of all feasible depletion paths.

Section 7.5 discusses production rate time-averaging over cumulative oil production milestones. Table 7.1(a) tabulates cumulative time ($t_o$) for cumulative oil production to reach the milestone partition under the active control. The $(M_1 \times M_2)$ path-dependent table of cumulative production times $t_o(m_1,m_2)$ maps the feasible depletion region in $(\mathcal{P}_1,\mathcal{P}_2,t)$ space as shown in Figure A2.3. The table is directional along the primary branch $(m_1,0)$ and along secondary branches $(m_1,m_2)$. Branch endpoints $(M_1,M_2^{m_1})$ track partial cumulative production intervals $(\Delta\mathcal{P}_1,\Delta\mathcal{P}_2)$ that map off mesh centers $(m_1,m_2)$.

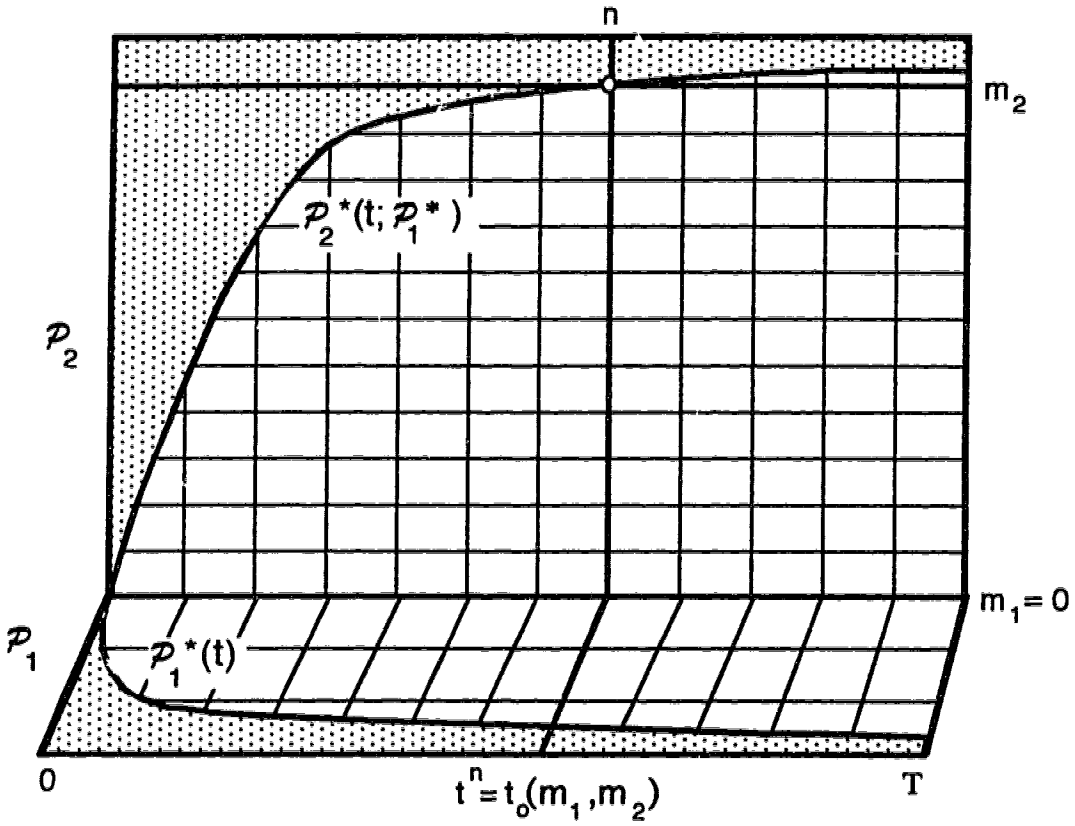



Figure A2.3: Feasible Depletion State Cumulative Time Mapping

$$\mathcal{P}_1^*(t_o(m_1,0)) = \mathcal{P}_1^{m_1} \qquad m_1 = 0,1,\ldots,M_1 - 1$$

$$\mathcal{P}_2^*(t_o(m_1,m_2)) = \mathcal{P}_2^{m_2} \qquad m_2 = 0,1,\ldots,M_2^{m_1} - 1 \tag{A2.4}$$

Discrete times $t^n < t_o(m_1,m_2)$ are infeasible. Table 7.1(b) tabulates the average oil rate ($Q_o$) between cumulative oil intervals ($\Delta\mathcal{P}_1,\Delta\mathcal{P}_2$). The oil rate posted at each milestone is the average rate measured from the previous milestone.

$$Q_o(m_1,0) = \frac{[\mathcal{P}_1^{m_1} - \mathcal{P}_1^{m_1-1}]}{[t_o(m_1,0) - t_o(m_1-1,0)]} \qquad ; m_1 = 1,2,\ldots,M_1 - 1$$

$$Q_o(m_1,m_2) = \frac{[\mathcal{P}_2^{m_2} - \mathcal{P}_2^{m_2-1}]}{[t_o(m_1,m_2) - t_o(m_1,m_2-1)]} \; ; \; m_2 = 1,2,\ldots,M_2^{m_1} - 1 \tag{A2.5}$$

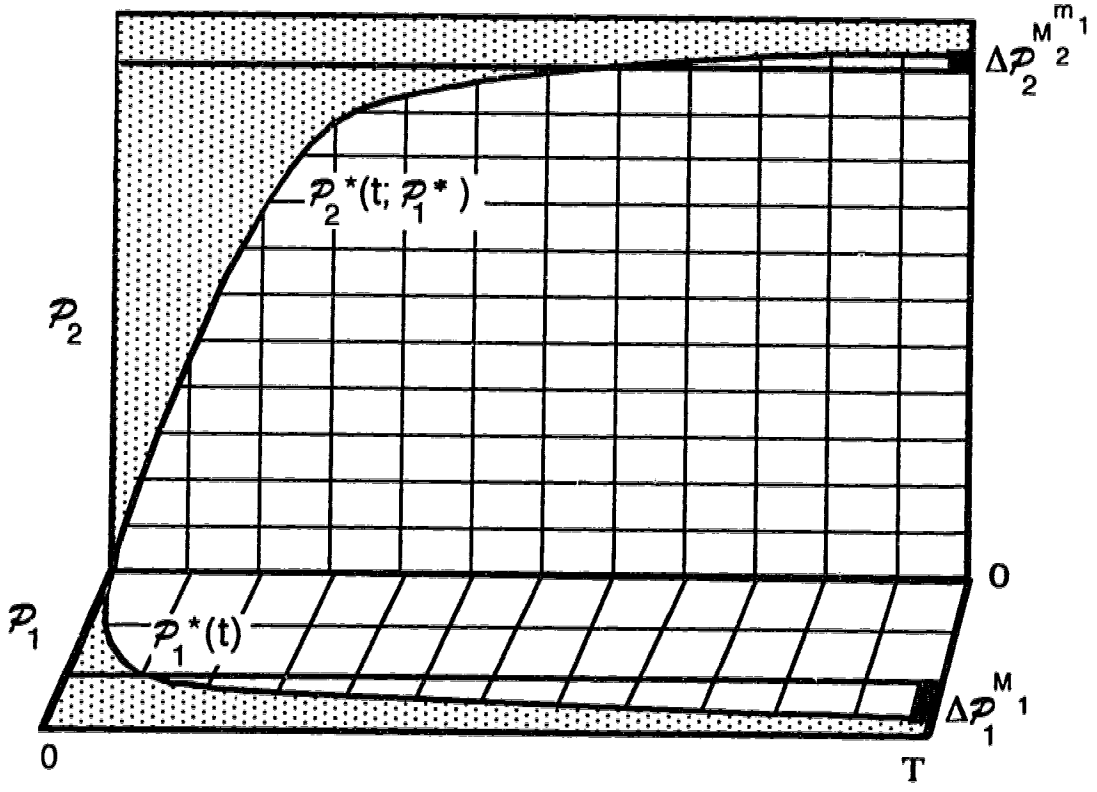



Figure A2.4: Partial Intervals at Branch End-Points

The product of average rate at the branch endpoint and the time interval from the previous milestone gives the remaining cumulative oil recoverable along that branch. Partial intervals at branch endpoints are illustrated in Figure A2.4.

$$\Delta\mathcal{P}_1^{M_1} = Q_o(M_1,0)[t_o(M_1,0) - t_o(M_1-1,0)]$$

$$\Delta\mathcal{P}_2^{M_2^{m_1}} = Q_o(m_1, M_2^{m_1})\,[t_o(m_1, M_2^{m_1}) - t_o(m_1, M_2^{m_1}-1)] \qquad \text{(A2.6)}$$

## A2.2 Sweep Direction

A forward pass with the black oil reservoir simulator forecasts future production possibilities in the depletion strategy. The contemporaneous reservoir state at each decision node depends on the sequence of past actions.

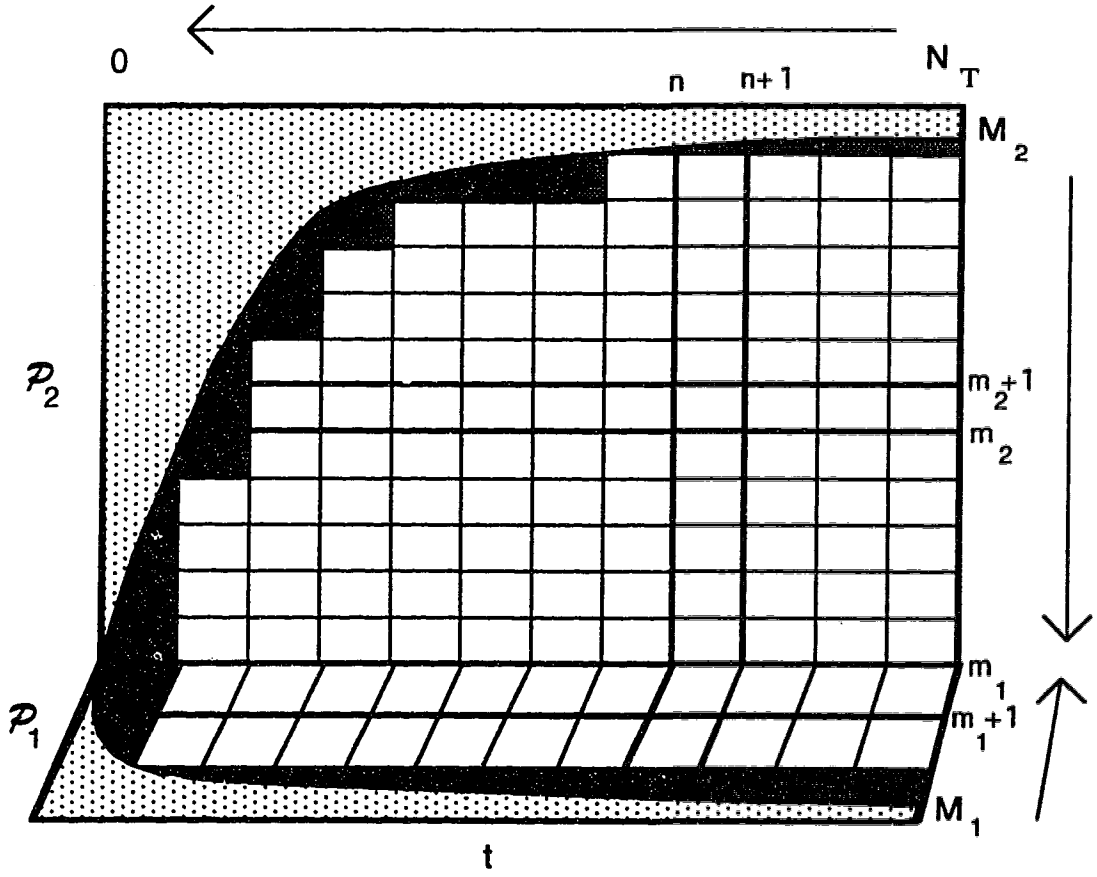



Figure A2.5: Backward Sweep Direction with Depletion Boundary Tracking

Dynamic programming is applied in a step-wise backward pass from terminal states to recursively find value-maximizing decision rules. The time step must be less than the minimum time interval between consecutive production milestones,

$$\Delta t < \min\{\Delta_1 t_o(m_1,0), \Delta_2 t_o(m_1,m_2); \text{over } (M_1 \times M_2)\} \tag{A2.7}$$

The depletion state difference operator along primary and secondary branches are defined by backward difference operators.

$$\begin{aligned} \Delta_1 t_o(m_1,0) &= t_o(m_1,0) - t_o(m_1-1,0) \\ \Delta_2 t_o(m_1,m_2) &= t_o(m_1,m_2) - t_o(m_1,m_2-1) \end{aligned} \tag{A2.8}$$

## A2.3 Depletion Boundary Tracking

Contemporaneous branch endpoints are tracked on the stationary depletion grid (Figure A2.5). The nonstationary grid is represented by the internal depletion nodes on the regular stationary grid with an irregular moving endpoint at the feasible boundary. As time levels go back in time from $t^{n+1}$ to $t^n$, the irregular endpoint interval shrinks until it crosses over to the next stationary depletion node. A tracking algorithm uses the $(M_1 \times M_2)$ cumulative production time $t_o(m_1,m_2)$ to determine the location of endpoints on the regular grid partition. Endpoints are bracketed by $(M_1^n, M_1^{n+1})$ for primary and $(M_2^{m_1,n}, M_2^{m_1,n+1})$ for secondary depletion boundaries (Figure A2.6).

$$\begin{aligned} t_o(M_1^n,0) &\le t^n < t_o(M_1^n+1,0) \\ t_o(M_1^{n+1},0) &\le t^{n+1} < t_o(M_1^{n+1}+1,0) \\ t_o(m_1,M_2^{m_1,n}) &\le t^n < t_o(m_1,M_2^{m_1,n}+1) \\ t_o(m_1,M_2^{m_1,n+1}) &\le t^{n+1} < t_o(m_1,M_2^{m_1,n+1}+1) \end{aligned} \tag{A2.9}$$

Time steps are chosen to ensure that discrete depletion milestones are not missed as the boundary path crosses over to the next stationary depletion node.

$$t^n \ge \max_{m_1}[t_o(M_1^n,0), t_o(m_1,M_2^{m_1,n})] \;;\; M_1^{n+1} - M_1^n \le 1 \;;\; M_2^{m_1,n+1} - M_2^{m_1,n} \le 1 \tag{A2.10}$$

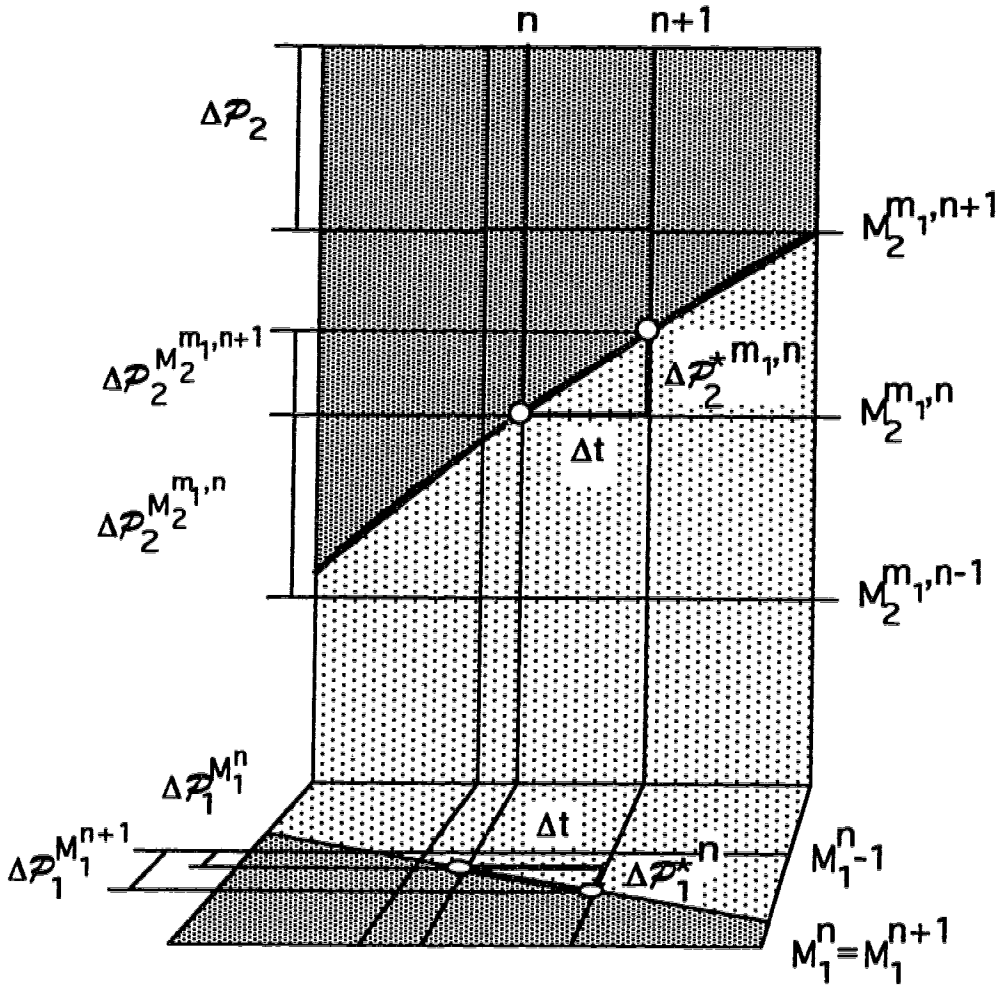



Figure A2.6: Boundary Bracketing and Incremental Tracking

Endpoint intervals are calculated using average oil production rates $Q_o(m_1,m_2)$ associated with the stationary grid.

$$\Delta\mathcal{P}_1^{M_1^n} = Q_o(M_1^n,0)\,[t^n - t_o(M_1^n-1,0)]$$

$$\Delta\mathcal{P}_1^{M_1^{n+1}} = Q_o(M_1^{n+1},0)\,[t^{n+1} - t_o(M_1^{n+1}-1,0)]$$

$$\Delta\mathcal{P}_2^{M_2^{m_1,n}} = Q_o(m_1,M_2^{m_1,n})\,[t^n - t_o(m_1,M_2^{m_1,n}-1)]$$

$$\Delta\mathcal{P}_2^{M_2^{m_1,n+1}} = Q_o(m_1,M_2^{m_1,n+1})\,[t^{n+1} - t_o(m_1,M_2^{m_1,n+1}-1)] \qquad \text{(A2.11)}$$

Incremental oil production along depletion boundaries ($\Delta\mathcal{P}_1^{*n}, \Delta\mathcal{P}_2^{*m_1,n}$) is calculated over the time step $\Delta t$.

$$\Delta\mathcal{P}_1^{*n} = \Delta\mathcal{P}_1^{M_1^{n+1}} - \Delta\mathcal{P}_1^{M_1^{n}} + \Delta\mathcal{P}_1(M_1^{n+1} - M_1^{n})$$

$$\Delta\mathcal{P}_2^{*m_1,n} = \Delta\mathcal{P}_2^{M_2^{m_1,n+1}} - \Delta\mathcal{P}_2^{M_2^{m_1,n}} + \Delta\mathcal{P}_2(M_2^{m_1,n+1} - M_2^{m_1,n}) \qquad \text{(A2.12)}$$

## A2.4 Price-Time Grid Partition

Price is partitioned with regular and asymptotic price steps. Figure A2.7 shows the price-time grid partition. Discrete prices ($s_i$) are calculated over $N_s$=320 price steps. The price range between \$0-\$60/bbl is partitioned into $Ns_{regular}$=240 regular price steps ($\Delta s$=\$0.25/bbl).

$$s_i = i\,\Delta s \qquad i=0,1,\ldots,Ns_{regular} \qquad \text{(A2.13)}$$

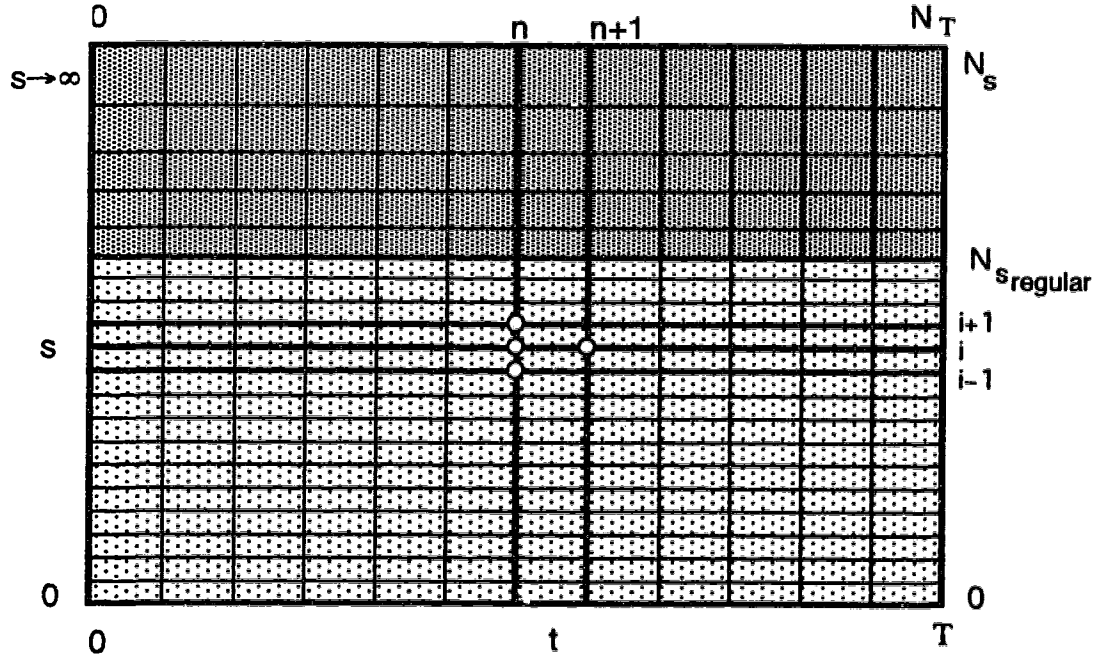



Figure A2.7: Price-Time (s,t) Grid with Regular and Asymptotic Steps

Asymptotic prices are calculated recursively using an expansion factor (=1.1),

$$s_{i+1} = 1.1\, s_i \qquad i=Ns_{regular}+1,\ldots,N_s \qquad \text{(A2.14)}$$

The maximum price state ($s_{max}$=\$122,904/bbl) approximates the limit ($s \to \infty$).

### A2.5 Finite Differences

Primary and secondary values ($\mathcal{V}_1, \mathcal{V}_2$) are initialized to their corresponding terminal abandonment values over all price and depletion states at time $t^{N_T} = T$. Feasible depletion boundary endpoints are determined at the terminal time.

$$\mathcal{V}_1^{N_T}(i,m_1) = -A_1 \qquad ;i=0,1,\ldots,N_s;\ m_1=0,1,\ldots,M_1^{N_T}$$

$$\mathcal{V}_2^{N_T}(i,m_1,m_2^{m_1}) = -A_2 \quad ;i=0,1,\ldots,N_s;\ m_1=0,1,\ldots,M_1^{N_T};\ m_2^{m_1}=0,1,\ldots,M_2^{m_1,N_T}$$

(A2.15)

Operating modes ($\theta$=C,S,A) are also initialized to their corresponding terminal abandonment values.

$$\mathcal{V}_{1\theta}^{N_T}(i,m_1) = -A_1 \qquad ;i=0,1,\ldots,N_s;\ m_1=0,1,\ldots,M_1^{N_T}$$

$$\mathcal{V}_{2\theta}^{N_T}(i,m_1,m_2^{m_1}) = -A_2 \quad ;i=0,1,\ldots,N_s;\ m_1=0,1,\ldots,M_1^{N_T};\ m_2^{m_1}=0,1,\ldots,M_2^{m_1,N_T}$$

(A2.16)

The terminal action for both primary and secondary operations ($\Theta_1, \Theta_2$) is the abandonment mode ($\theta$=A).

$$\Theta_1^{N_T}(i,m_1) = A \qquad ;i=0,1,\ldots,N_s;\ m_1=0,1,\ldots,M_1^{N_T}$$

$$\Theta_2^{N_T}(i,m_1,m_2^{m_1}) = A \quad ;i=0,1,\ldots,N_s;\ m_1=0,1,\ldots,M_1^{N_T};\ m_2^{m_1}=0,1,\ldots,M_2^{m_1,N_T}$$

(A2.17)

Primary and secondary action-values are known at the future time level $t^{n+1}$. Feasible depletion boundary endpoints are determined for time level $t^n$. A primary loop sweeps from $m_1$=$M_1^n$ down to 0. Nested secondary loops sweep from $m_2$=$M_2^{m_1,n}$ down to 0.

Dynamic values for operating modes ($\mathcal{V}_{2C}$,$\mathcal{V}_{2S}$; i=0,1,...,$N_s$) are determined sequentially for all feasible depletion states at time $t^n$. No production occurs in the suspended mode ($\theta_{2S}$). Comparisons are made at each decision step between operating choices ($\theta_2$=C,S,A), and the value-maximizing action selected. The maximum operation value $\mathcal{V}_2$=max($\mathcal{V}_{2C}$,$\mathcal{V}_{2S}$,$\mathcal{V}_{2A}$) then becomes the new basis for calculating dynamic operating values ($\mathcal{V}_{2C}$,$\mathcal{V}_{2S}$) at the previous decision step. The differential equations in Eqns (8.38) and (8.39) are discretized at lattice points ($i,n,m_1,m_2^{m_1}$) using finite difference operators for price ($\Delta_s$), time ($\Delta_t$) and secondary depletion state ($\Delta_2$).

$$\left[\frac{1}{2}\sigma^2 s^2\frac{\Delta_s{}^2\mathcal{V}_{2C}}{\Delta s^2} - (c-r)s\frac{\Delta_s\mathcal{V}_{2C}}{\Delta s} - r\mathcal{V}_{2C} + Cf_{2C} + Q_{o_{2C}}\frac{\Delta_2\mathcal{V}_{2C}}{\Delta\mathcal{P}_2} + \frac{\Delta_t\mathcal{V}_{2C}}{\Delta t}\right]_i^{n,m_1,m_2} = 0$$

$$\left[\frac{1}{2}\sigma^2 s^2\frac{\Delta_s{}^2\mathcal{V}_{2S}}{\Delta s^2} - (c-r)s\frac{\Delta_s\mathcal{V}_{2S}}{\Delta s} - r\mathcal{V}_{2S} + Cf_{2S} + \frac{\Delta_t\mathcal{V}_{2S}}{\Delta t}\right]_i^{n,m_1,m_2} = 0 \qquad \text{(A2.18)}$$

Price differences ($\Delta_s$) are calculated on a 3-point lattice (Figure A2.8). First order backward differences are chosen for stability.

$$\left.\frac{\Delta_s\mathcal{V}_{2\theta}}{\Delta s}\right|_i^{n,m_1,m_2} = \left[\frac{\mathcal{V}_{2\theta_i} - \mathcal{V}_{2\theta_{i-1}}}{s_i - s_{i-1}}\right]^{n,m_1,m_2}$$

$$\left.\frac{\Delta_s^2\mathcal{V}_{2\theta}}{\Delta s^2}\right|_i^{n,m_1,m_2} = \frac{2}{s_{i+1}-s_{i-1}}\left[\frac{\mathcal{V}_{2\theta_{i+1}} - \mathcal{V}_{2\theta_i}}{s_{i+1}-s_i} - \frac{\mathcal{V}_{2\theta_i} - \mathcal{V}_{2\theta_{i-1}}}{s_i - s_{i-1}}\right]^{n,m_1,m_2} \qquad \text{(A2.19)}$$

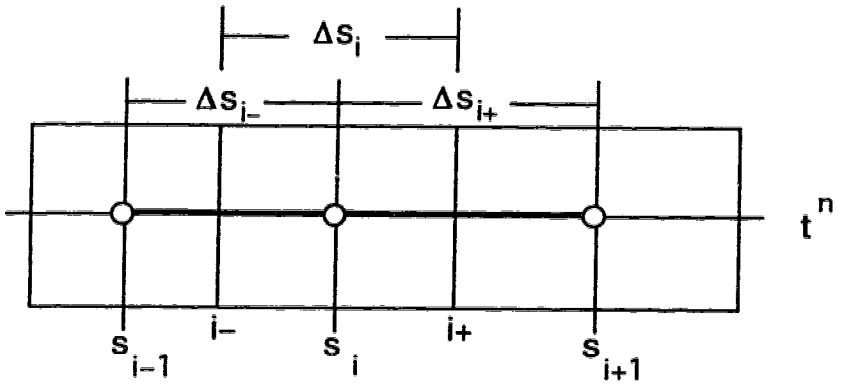



Figure A2.8: Price Difference Lattice

First and second-order price terms in Eqn. (A2.18) vanish at the price origin (i=0). The second order difference term vanishes at the asymptotic limit ($i=N_s$).

$$\left.\frac{\Delta_s^2 \mathcal{V}_{2\theta}}{\Delta s^2}\right|_{N_s}^{n,m_1,m_2} = 0 \qquad \text{(A2.20)}$$

Forward differences are used for depletion paths.

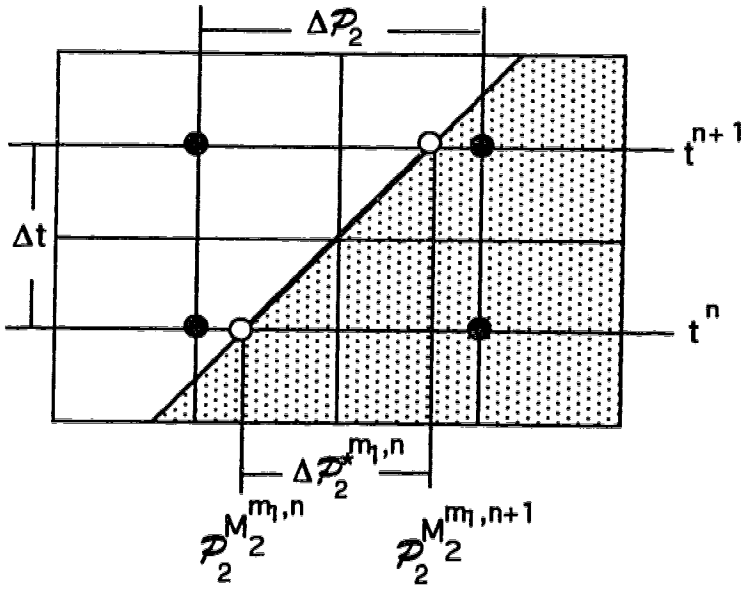



Figure A2.9: Depletion Boundary Difference Lattice

Difference operations on internal stationary lattice points are handled differently from nonstationary depletion boundary points. Depletion paths can either have positive slopes with increasing cumulative production along actively controlled segments or remain constant along suspended path segments. Actively controlled production value along the depletion boundary is first calculated at $M_2^{m_1,n}$ from known values at $M_2^{m_1,n+1}$. The combined partial derivatives with respect to time and depletion state reduce to the time derivative along the boundary depletion path (Figure A2.9).

$$\left[ Q_{o_{2C}} \frac{\Delta_2 \mathcal{V}_{2C}}{\Delta \mathcal{P}_2} + \frac{\Delta_t \mathcal{V}_{2C}}{\Delta t} \right]_i^{n,m_1,M_2^{n,m_1}} = \left[ \frac{\Delta \mathcal{P}_2^*}{\Delta t} \frac{\Delta_2^* \mathcal{V}_{2C}}{\Delta \mathcal{P}_2^*} \right]_i^{n,m_1,M_2^{n,m_1}}$$

$$= \left[ \frac{\mathcal{V}_{2C}^{n+1,m_1,M_2^{n+1,m_1}} - \mathcal{V}_{2C}^{n,m_1,M_2^{n,m_1}}}{t^{n+1} - t^n} \right]_i \qquad \text{(A2.21)}$$

A simplifying assumption is used to approximate time differences for suspended production value at the feasible boundary.

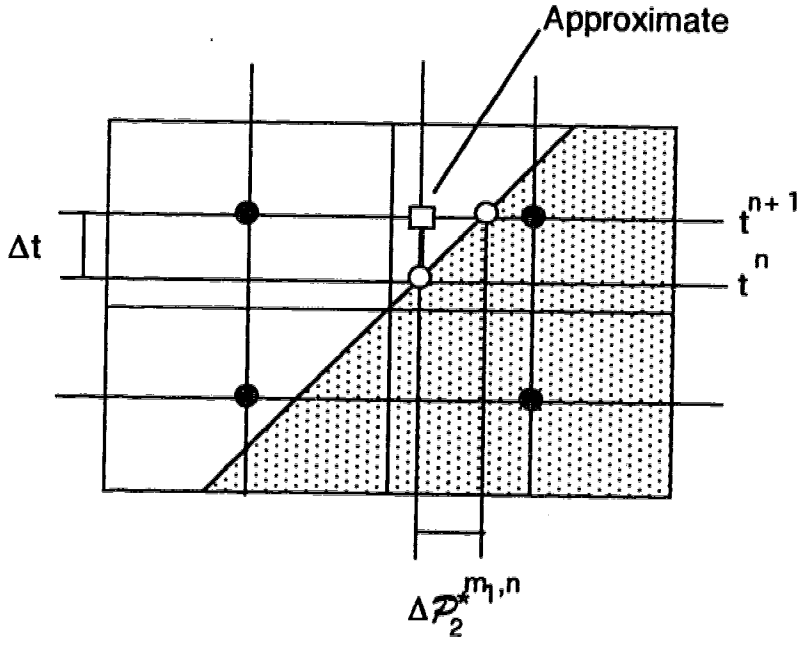



Figure A2.10: Suspended Depletion Boundary Value Time Difference

Boundary nodes $M_2^{m_1,n}$ that do not coincide with the discrete depletion partition must either use interpolated values at $t^{n+1}$ or have an intermediate depletion partition that coincides with $M_2^{m_1,n}$ (Figure A2.10). An intermediate depletion partition would need to run from the terminal time to the contemporaneous calculation node. The need for additional partitions will grow rapidly with the incremental changes in depletion boundary. The partition needed to resolve the suspended production value over all depletion boundaries will be in the order of the total time steps. This high resolution approach is computationally prohibitive with memory requirements being several orders of magnitude larger than the present partition. Furthermore, the finer partition demands more secondary branch forecasts along transitional primary depletion states. The computational algorithm described here adopts a simplifying approximation for suspended production value along the depletion boundary. Linear interpolation between adjacent nodes on the same depletion line is not used since irreversible actions at previous depletion states may divert the decision process along other pathways. One choice is to approximate the transient changes in suspended production value forward along the actively controlled depletion boundary. If time steps are selected small enough, the error in the zero-order approximation will be bounded.

$$\left[\frac{\Delta_t \mathcal{V}_{2S}}{\Delta t}\right]_i^{n,m_1,M_2^{n,m_1}} = \left[\frac{\mathcal{V}_{2S}^{n+1,m_1,M_2^{n+1,m_1}} - \mathcal{V}_{2S}^{n,m_1,M_2^{n,m_1}}}{t^{n+1} - t^n}\right]_i \qquad \text{(A2.22)}$$

A non-stationary 3-point difference lattice is used for boundary adjacent depletion grid points (Figure A2.11). Depletion state difference operators at time $t^n$ are calculated on the basis of forward values along depletion paths at $t^{n+1}$.

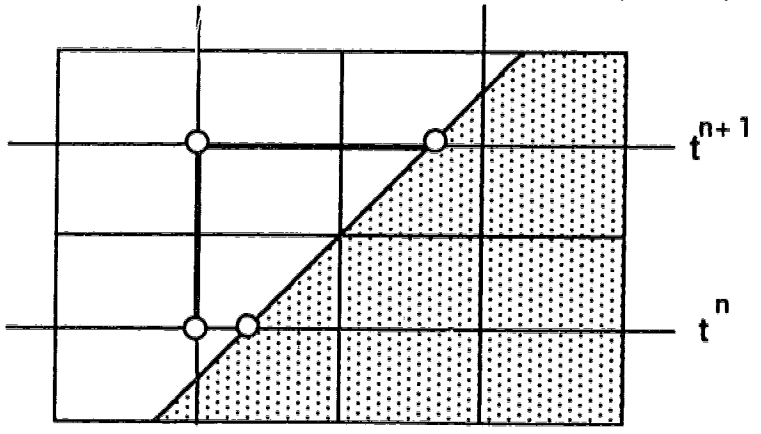



Figure A2.11: Non-Stationary Depletion State Difference Lattice

$$\left.\frac{\Delta_t \mathcal{V}_{2\theta}}{\Delta t}\right|_i^{n,m_1,M_2^{n,m_1}-1} = \left[\frac{\mathcal{V}_{2\theta}^{n+1} - \mathcal{V}_{2\theta}^{n}}{t^{n+1} - t^{n}}\right]_i^{m_1,M_2^{n,m_1}-1}$$

$$\left.\frac{\Delta_2 \mathcal{V}_{2C}}{\Delta \mathcal{P}_2}\right|_i^{n,m_1,M_2^{n,m_1}-1} = \left[\frac{\mathcal{V}_{2C}^{M_2^{n+1,m_1}} - \mathcal{V}_{2C}^{M_2^{n+1,m_1}-1}}{\mathcal{P}_2^{M_2^{n,m_1}} - \mathcal{P}_2^{M_2^{n,m_1}-1}}\right]_i^{n+1,m_1} \qquad \text{(A2.23)}$$

A stationary 3-point difference lattice is used for internal depletion grid points (Figure A2.12).

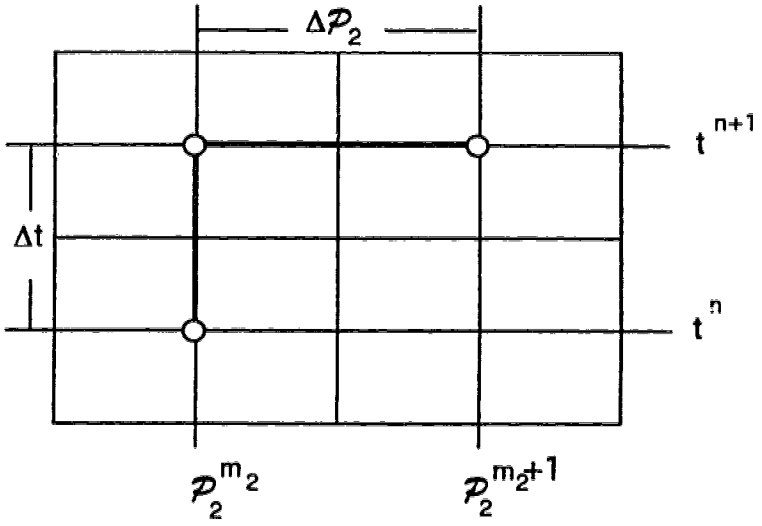



Figure A2.12: Stationary Depletion Difference Lattice

$$\left.\frac{\Delta_t \mathcal{V}_{2\theta}}{\Delta t}\right|_i^{n,m_1,m_2} = \left[\frac{\mathcal{V}_{2\theta}^{n+1} - \mathcal{V}_{2\theta}^{n}}{t^{n+1} - t^{n}}\right]_i^{m_1,m_2}$$

$$\left.\frac{\Delta_2 \mathcal{V}_{2C}}{\Delta \mathcal{P}_2}\right|_i^{n,m_1,m_2} = \left[\frac{\mathcal{V}_{2C}^{m_2+1} - \mathcal{V}_{2C}^{m_2}}{\mathcal{P}_2^{m_2+1} - \mathcal{P}_2^{m_2}}\right]_i^{n+1,m_1} \qquad \text{(A2.24)}$$

Independent finite-difference equations for ($\mathcal{V}_{2C}$,$\mathcal{V}_{2S}$) are solved implicitly for all price states at ($n,m_1,m_2^{m_1}$) using a tri-diagonal algorithm.

$$A_{2C_i}\mathcal{V}_{2C_{i-1}}^{n,m_1,m_2} + B_{2C_i}\mathcal{V}_{2C_i}^{n,m_1,m_2} + C_{2C_i}\mathcal{V}_{2C_{i+1}}^{n,m_1,m_2} = D_{2C_i}$$

$$A_{2S_i}\mathcal{V}_{2S_{i-1}}^{n,m_1,m_2} + B_{2S_i}\mathcal{V}_{2S_i}^{n,m_1,m_2} + C_{2S_i}\mathcal{V}_{2S_{i+1}}^{n,m_1,m_2} = D_{2S_i} \qquad \text{(A2.25)}$$

Value-maximizing actions for secondary operations $\mathcal{V}_2=\max(\mathcal{V}_{2C},\mathcal{V}_{2S},\mathcal{V}_{2A})$ are determined at each price state (i).

$$\left.\begin{aligned}
\mathcal{V}_2^n(i,m_1,m_2^{m_1}) &= \max\{\mathcal{V}_{2C}^n(i,m_1,m_2^{m_1}),\mathcal{V}_{2S}^n(i,m_1,m_2^{m_1}),-A_2\}\\
\Theta_2^n(i,m_1,m_2^{m_1}) &= C \quad \text{if } \mathcal{V}_2^n(i,m_1,m_2^{m_1}) = \mathcal{V}_{2C}^n(i,m_1,m_2^{m_1})\\
&= S \quad \text{if } \mathcal{V}_2^n(i,m_1,m_2^{m_1}) = \mathcal{V}_{2S}^n(i,m_1,m_2^{m_1})\\
&= A \quad \text{if } \mathcal{V}_2^n(i,m_1,m_2^{m_1}) = -A_2
\end{aligned}\right\}; i=0,1,\ldots,N_s \qquad \text{(A2.26)}$$

Secondary operation values are calculated over all price states ($i=0,1,\ldots,N_s$) for feasible secondary depletion states ($m_2=0,1,\ldots,M_2^{n,m_1}$) from feasible primary depletion states ($m_1=0,1,\ldots,M_1^n$) at the contemporaneous time level ($t^n$) from pre-established secondary values ($\mathcal{V}_2$) at the future time level ($t^{n+1}$).

For $m_1 = M_1^n,\ldots,1,0$

For $m_2^{m_1} = M_2^{n,m_1},\ldots,1,0$

Solve $\{\mathcal{V}_{2C}^n(i,m_1,m_2^{m_1}),\mathcal{V}_{2S}^n(i,m_1,m_2^{m_1}); i=0,1,\ldots,N_s\}$

$$\left.\begin{aligned}
&\mathcal{V}_2^n(i,m_1,m_2^{m_1}) = \max\{\mathcal{V}_{2C}^n(i,m_1,m_2^{m_1}),\mathcal{V}_{2S}^n(i,m_1,m_2^{m_1}),-A_2\}\\
&\text{Map Actions: } \Theta_2^n(i,m_1,m_2^{m_1}) = (C,S,A)
\end{aligned}\right\} i=0,1,\ldots,N_s$$

Next $m_2^{m_1}$

Next $m_1$

The backward sweep direction ensures that unknown values can be determined from pre-calculated values. The maximized secondary value at the contemporaneous decision step becomes the new basis for calculating dynamic operating values $(\mathcal{V}_{2C},\mathcal{V}_{2S})^{n+1}=\mathcal{V}_2^n$ at the previous decision step.

Similarly, dynamic values for primary operating modes $(\mathcal{V}_{1C},\mathcal{V}_{1S};i=0,1,\ldots,N_s)$ are determined sequentially for all feasible depletion states at time $t^n$. No production occurs in the suspended mode $(\theta_{1S})$. Comparisons are made at each decision step between operating choices $(\theta_1=C,S,A)$ and the value-maximizing action selected $\mathcal{V}_1=\max(\mathcal{V}_{1C},\mathcal{V}_{1S},\mathcal{V}_{1A})$. The remaining primary operation value is then compared with the initiating waterflood value net of capital investment, $\mathcal{V}=\max(\mathcal{V}_1,\mathcal{V}_2-K_{12})$. The maximized value at the contemporaneous decision step becomes the new basis for calculating dynamic operating values $(\mathcal{V}_{1C},\mathcal{V}_{1S})^{n+1}=\mathcal{V}^n$ at the previous decision step. The differential equations are discretized at lattice points $(i,n,m_1)$ using finite difference operators for price $(\Delta_s)$, time $(\Delta_t)$ and primary depletion state $(\Delta_1)$.

$$\left[\frac{1}{2}\sigma^2 s^2\frac{\Delta_s{}^2\mathcal{V}_{1C}}{\Delta s^2}-(c-r)s\frac{\Delta_s\mathcal{V}_{1C}}{\Delta s}-r\mathcal{V}_{1C}+Cf_{1C}+Q_{o_{1C}}\frac{\Delta_1\mathcal{V}_{1C}}{\Delta\mathcal{P}_1}+\frac{\Delta_t\mathcal{V}_{1C}}{\Delta t}\right]_i^{n,m_1}=0$$

$$\left[\frac{1}{2}\sigma^2 s^2\frac{\Delta_s{}^2\mathcal{V}_{1S}}{\Delta s^2}-(c-r)s\frac{\Delta_s\mathcal{V}_{1S}}{\Delta s}-r\mathcal{V}_{1S}+Cf_{1S}+\frac{\Delta_t\mathcal{V}_{1S}}{\Delta t}\right]_i^{n,m_1}=0 \qquad \text{(A2.27)}$$

Independent finite-difference equations for $(\mathcal{V}_{1C},\mathcal{V}_{1S})$ are found in the same manner as described for secondary operations. These are solved implicitly for all price states at $(n,m_1)$ using a tri-diagonal algorithm.

$$A_{1C_i}\mathcal{V}_{1C_{i-1}}^{n,m_1}+B_{1C_i}\mathcal{V}_{1C_i}^{n,m_1}+C_{1C_i}\mathcal{V}_{1C_{i+1}}^{n,m_1}=D_{1C_i}$$

$$A_{1S_i}\mathcal{V}_{1S_{i-1}}^{n,m_1}+B_{1S_i}\mathcal{V}_{1S_i}^{n,m_1}+C_{1S_i}\mathcal{V}_{1S_{i+1}}^{n,m_1}=D_{1S_i} \qquad \text{(A2.28)}$$

Value-maximizing primary actions are determined at each price state (i).

$$\left.\begin{aligned} \mathcal{V}_1^n(i,m_1) &= \max\{\mathcal{V}_{1C}^n(i,m_1), \mathcal{V}_{1S}^n(i,m_1), -A_1\} \\ \Theta_1^n(i,m_1) &= C \quad \text{if} \quad \mathcal{V}_1^n(i,m_1) = \mathcal{V}_{1C}^n(i,m_1) \\ &= S \quad \text{if} \quad \mathcal{V}_1^n(i,m_1) = \mathcal{V}_{1S}^n(i,m_1) \\ &= A \quad \text{if} \quad \mathcal{V}_1^n(i,m_1) = -A_1 \end{aligned}\right\}; i = 0,1,\ldots,N_s \tag{A2.29}$$

Secondary values, net of capital investment at waterflood initiation states ($m_2$=0), are compared with primary operating values at all primary states ($m_1$=0,1,...,$M_1^n$).

$$\left.\begin{aligned} \mathcal{V}^n(i,m_1) &= \max\{\mathcal{V}_2^n(i,m_1,0) - K_{12}, \mathcal{V}_1^n(i,m_1) \\ \mathcal{D}^n(i,m_1) &= \Theta_1^n \quad \text{if} \quad \mathcal{V}^n(i,m_1) = \mathcal{V}_1^n(i,m_1) \\ &= \Theta_2^n \quad \text{if} \quad \mathcal{V}^n(i,m_1) = \mathcal{V}_2^n(i,m_1,0) - K_{12} \end{aligned}\right\}; i = 0,1,\ldots,N_s \tag{A2.30}$$

Remaining depletion strategy values are calculated over all price states (i=0,1,...,$N_s$) for feasible primary depletion states ($m_1$=0,1,...,$M_1^n$) at the contemporaneous time level ($t^n$) from pre-established primary values ($\mathcal{V}$) at the future time level ($t^{n+1}$).

For $m_1 = M_1^n,\ldots,1,0$

Solve $\{\mathcal{V}_{1C}^n(i,m_1), \mathcal{V}_{1S}^n(i,m_1); i = 0,1,\ldots,N_s\}$

$$\left.\begin{aligned} &\mathcal{V}_1^n(i,m_1) = \max\{\mathcal{V}_{1C}^n(i,m_1), \mathcal{V}_{1S}^n(i,m_1), -A_1\} \\ &\text{Map Actions: } \Theta_1^n(i,m_1) = (C,S,A) \end{aligned}\right\} i = 0,1,\ldots,N_s$$

$$\left.\begin{aligned} &\mathcal{V}^n(i,m_1) = \max\{\mathcal{V}_2^n(i,m_1,0) - K_{12}, \mathcal{V}_1^n(i,m_1)\} \\ &\text{Map Actions: } \mathcal{D}^n(i,m_1) = (\Theta_1^n, \Theta_2^n) \end{aligned}\right\} i = 0,1,\ldots,N_s$$

Next $m_1$