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Well Test Analysis and Reservoir Modeling of Geopressured-Geothermal Systems

**Includes Topical Reports on Analyses for:
Pleasant Bayou Well No. 2
Gladys McCall Well No. 1**

**T. D. Riney
L. A. Owusu**

Final Report

**Submitted to:
Lawrence Berkeley Laboratory
U. S. Department of Energy**

**Work Performed Under:
LBL Subcontract 4584310
U. S. DOE Contract DE-AC03-76SF00098**

February 1993

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Table of Contents

Section	Page
List of Figures	v
List of Tables	ix
1. Introduction	1-1
2. Method of Analysis	2-1
3. Pleasant Bayou	3-1
3.1 Graphical Analysis of Pressure Transient Data	3-1
3.2 Automated Inversion of Pressure Transient Data	3-2
3.3 Long-term Buildup Response	3-5
4. Gladys McCall	4-1
4.1 Final Diagnostic Test	4-2
4.2 Automated Inversion of Pressure Transient Data	4-3
5. Conclusions and Discussion	5-1
6. References	6-1
Appendices	
A. Depletion and Recovery Behavior of the Gladys McCall Geopressured Geothermal Reservoir	A-1
B. Pleasant Bayou Geopressured-Geothermal Reservoir Analysis—October 1991	B-1
C. Gladys McCall Geopressured Reservoir Analysis—June 1987	C-1

List of Figures

Figure	Page
1.1 Updated comparison of simulated pressure buildup history (curve) and data (points) measured during long-term shutin test at Gladys McCall Well No.1. Datum level is 15,100 ft. Model is described in Appendix A.	1-3
1.2. Updated comparison of simulated 1988–1993 test history (curve) and data (points); data include bottomhole measurements and values estimated from wellhead recordings at Pleasant Bayou Well No.2. Datum level is 14,600 ft. Model is as described in Appendix B except horizontal permeabilities in two low-porosity layers (remote volume) were set at $k_1/4$ rather than $k_1/7$	1-4
3.1. Bottomhole pressure buildup data from the 84-hr and 70-hr bottomhole tests of Pleasant Bayou Well No.2. Vertical displacement reflects changes in the skin factor (s).	3-3
3.2a. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2a. RLT with $kh = 3.665$ D-m.	3-9
3.2b. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2b. MRT with $kh = 3.665$ D-m.	3-11
3.2c. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2c. 65-hr test with $kh = 3.665$ D-m.	3-13
3.2d. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2d. 62-hr test with $kh = 3.665$ D-m.	3-15

Figure	Page
3.2e. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2e. 84-hr test with $kh = 3.665$ D-m.	3-17
3.2f. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2f. 70-hr test with $kh = 3.665$ D-m.	3-19
3.3a. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3a. RLT with kh a free parameter.	3-21
3.3b. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3b. MRT with kh a free parameter.	3-23
3.3c. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3c. 65-hr test with kh a free parameter.	3-25
3.3d. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3d. 62-hr test with kh a free parameter.	3-27
3.3e. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3e. 84-hr test with kh a free parameter.	3-29
3.3f. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3f. 7-hr test with kh a free parameter.	3-31

Figure	Page
3.4a. Specification of input data for Pleasant Bayou hydrostatic pressure calculation for September 15, 1992.	3-33
3.4b. Computed results for Pleasant Bayou hydrostatic pressure calculation for September 15, 1992.	3-34
3.5a. Specification of input data for Pleasant Bayou hydrostatic pressure calculation for September 24, 1992.	3-35
3.5b. Computed results for Pleasant Bayou hydrostatic pressure calculation for September 15, 1992.	3-36
3.6. Use of simultaneous early-time BHP and WHP measurements in Pleasant Bayou Well No.2 to estimate late-time shutin values of ΔP_{wb} from 14,600 ft to surface	3-38
3.7. Estimated bottomhole pressure recovery in Pleasant Bayou Well No. 2 during long-term buildup test. Datum level is 14,600 ft.	3-39
3.8. Plot of Series 3 (kh fixed) INVERT results for Pleasant Bayou Long-Term Test through January 1, 1993. Calculation is for a homogeneous model with three linear boundaries and correspond to the input data in Table 3.5.	3-41
4.1. Bottomhole pressure transient data from 1983 RLT and 1991 FDT at the Gladys McCall well. Vertical displacement reflects change in the skin factor (s).	4-4
4.2a. Plots of Series 3 [$(\phi C_h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2a. RLT with $(\phi C_h)_1 = 1.472$ cm/MPa.	4-9
4.2b. Plots of Series 3 [$(\phi C_h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2b. 79-hr test with $(\phi C_h)_1 = 1.472$ cm/MPa.	4-11
4.2c. Plots of Series 3 [$(\phi C_h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2c. 92-hr test with $(\phi C_h)_1 = 1.472$ cm/MPa.	4-13

Figure	Page
4.2d. Plots of Series 3 [$(\phi C_h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2d. MRT with $(\phi C_h)_1 = 1.472$ cm/MPa.	4-15
4.2e. Plots of Series 3 [$(\phi C_h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2e. FDT with $(\phi C_h)_1 = 1.472$ cm/MPa.	4-17
4.3a. Plots of Series 4 [$(\phi C_h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3a. RLT with $(\phi C_h)_1$ a free parameter.	4-19
4.3b. Plots of Series 4 [$(\phi C_h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3b. 79-hr test with $(\phi C_h)_1$ a free parameter.	4-21
4.3c. Plots of Series 4 [$(\phi C_h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3c. 92-hr test with $(\phi C_h)_1$ a free parameter.	4-23
4.3d. Plots of Series 4 [$(\phi C_h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3d. MRT with $(\phi C_h)_1$ a free parameter.	4-25
4.3e. Plots of Series 4 [$(\phi C_h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3e. FDT with $(\phi C_h)_1$ a free parameter.	4-27

List of Tables

Table	Page
2.1 Mathematical models currently included in INVERT's library. Each model can include up to four reservoir boundaries; each boundary may be either a no-flow barrier or maintain a constant hydrostatic pressure ("leaky").	2-3
3.1. Summary of inversion calculations for Pleasant Bayou pressure transient welltest data. Cases include models with single linear boundary (X_a) and models with three linear boundaries ($X_a, Y_c = Y_d = 4330$ m).	3-6
3.2a. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2a. RLT with $kh = 3.665$ D-m.	3-8
3.2b. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2b. MRT with $kh = 3.665$ D-m.	3-10
3.2c. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2c. 65-hr test with $kh = 3.665$ D-m.	3-12
3.2d. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2d. 62-hr test with $kh = 3.665$ D-m.	3-14
3.2e. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2e. 84-hr test with $kh = 3.665$ D-m.	3-16

Table	Page
3.2f. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2f. 70-hr test with $kh = 3.665$ D-m.	3-18
3.3a. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3a. RLT with kh a free parameter.	3-20
3.3b. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3b. MRT with kh a free parameter.	3-22
3.3c. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3c. 65-hr test with kh a free parameter.	3-24
3.3d. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3d. 62-hr test with kh a free parameter.	3-26
3.3e. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3e. 84-hr test with kh a free parameter.	3-28
3.3f. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3f. 70-hr test with kh a free parameter.	3-30
3.4. Measured P/T gradients recorded in Pleasant Bayou test well during downhole logs on September 1 and September 24, 1992.	3-32

List of Tables

Table	Page
3.5. Report of Series 3 (kh fixed) INVERT results for Pleasant Bayou Long-Term Test through January 1, 1993. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.8.	3-40
4.1. Summary of inversion calculations for Gladys McCall pressure transient welltest data. Cases include Composite Model with no boundaries (infinite) and Composite Model with two linear boundaries ($Y_c = Y_d = 648.34$ m).	4-7
4.2a. Reports of Series 3 [$(\phi C_f h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2a. RLT with $(\phi C_f h)_1 = 1.472$ cm/MPa.	4-8
4.2b. Reports of Series 3 [$(\phi C_f h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2b. 79-hr test with $(\phi C_f h)_1 = 1.472$ cm/MPa.	4-10
4.2c. Reports of Series 3 [$(\phi C_f h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2c. 92-hr test with $(\phi C_f h)_1 = 1.472$ cm/MPa.	12
4.2d. Reports of Series 3 [$(\phi C_f h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2d. MRT test with $(\phi C_f h)_1 = 1.472$ cm/MPa.	4-14
4.2e. Reports of Series 3 [$(\phi C_f h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2e. FDT with $(\phi C_f h)_1 = 1.472$ cm/MPa.	4-16
4.3a. Reports of Series 4 [$(\phi C_f h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3a. RLT with $(\phi C_f h)_1$ a free parameter.	4-18

Table	Page
4.3b. Reports of Series 4 ($(\phi C_i h)_1$ free) INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3b. 79-hr test with $(\phi C_i h)_1$ a free parameter.	4-20
4.3c. Reports of Series 4 ($(\phi C_i h)_1$ free) INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3c. 92-hr test with $(\phi C_i h)_1$ a free parameter.	4-22
4.3d. Reports of Series 4 ($(\phi C_i h)_1$ free) INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3d. MRT test with $(\phi C_i h)_1$ a free parameter.	4-24
4.3e. Reports of Series 4 ($(\phi C_i h)_1$ free) INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3e. FDT with $(\phi C_i h)_1$ a free parameter.	4-26

1 Introduction

Many sedimentary basins contain formations with pore fluids at higher than hydrostatic pressures (vertical fluid-pressure gradients greater than about 0.465 psi/ft); these formations are called geopressured. The geopressured strata are comprised of under-compacted clays (or shales) and sandstones with interstitial fluids bearing most of the overburden pressure. The pore pressure is generally well in excess of hydrostatic, and the fluids are saline, hot, and contain dissolved methane. Thus, the fluids contain energy in three forms; thermal energy, hydraulic (or pressure) energy, and chemical energy with the methane.

Among geopressured basins in the United States, the northern Gulf of Mexico basin has been most extensively investigated. As part of its program to define the magnitude and recoverability of the geopressured-geothermal energy resource, the U.S. Department of Energy (DOE) has tested five deep research wells in the Texas-Louisiana Gulf Coast region:

- (1) Pleasant Bayou Well No. 2, Brazoria County, Texas.
- (2) Amoco Fee Well No. 1, Sweet Lake Field, Cameron Parish, Louisiana.
- (3) L.R. Sweezy Well No. 1, Parcperdue Field, Vermilion Parish, Louisiana.
- (4) Gladys McCall Well No. 1, Cameron Parish, Louisiana.
- (5) Willis Hulin Well No. 1, Vermilion Parish, Louisiana.

The first four were both drilled and tested by DOE, whereas the Hulin well was a gas producer taken over from industry and re-completed in preparation for possible long-term testing.

Testing of the Amoco Fee and Sweezy wells has been completed, and the wells subsequently plugged and abandoned. Technical reports describing analyses of data from the Amoco Fee (Garg, 1982) and Sweezy (Garg and Riney, 1984) research wells were prepared for DOE by S-Cubed. Results of the Sweezy well testing were also analyzed recently by Lai, *et al.* (1991). Data from flow testing the Hulin well (November 1989–January 1990) were also analyzed and a preliminary reservoir model developed (Riney, 1991a). DOE has decided not to reopen the well for long-term testing; Hulin is scheduled to be plugged and abandoned during 1993.

One of the objectives of the DOE program has been to investigate the pressure maintenance mechanisms that operate within the reservoirs tested by the research wells. The Parcperdue reservoir was selected because of its well-defined geology and volume so that the testing could be completed within one year. Depletion testing by the Sweezy well had to be terminated, however, when excess sand was produced from the unconsolidated formation. The Amoco Fee well exhibited a much larger than anticipated pressure-drawdown during short-term flow testing. Analysis of the downhole pressure data indicated that the well penetrated a zone of relatively high per-

meability but flow was constrained by either low permeability or geologic structure away from the well. The Hulin well was accepted for testing by DOE since it penetrates the deepest known Gulf Coast geopressured-geothermal reservoir. Preliminary flow testing, however, indicated that the near-well permeability of the selected formation is rather low (~15–25 md) and that the pore volume in hydraulic communication with the well may be only about 180 million barrels.

Selection of the Pleasant Bayou and Gladys McCall well sites was based on geologic work at the University of Texas at Austin and Louisiana State University that identified localized regions where thick, high-pressure, high-temperature sandstone masses existed as a result of isolation by growth faults, salt movement, facies boundaries, or other factors. These geologic studies (Bebout, *et al.*, 1978; Bebout, *et al.*, 1982; Bebout 1982; Brunheld 1984) successfully identified the Pleasant Bayou and Gladys McCall prospects as large volume aquifers that would likely be producible for extended periods at high flow rates. The long-term depletion and recovery test histories of the Pleasant Bayou and Gladys McCall research wells have indeed defined impressively large geopressured-geothermal reservoirs.

Gladys McCall Well No. 1 was flow tested from 1983 to 1987, underwent long-term pressure recovery testing from October 1987 to October 1991, and was re-entered for final diagnostic testing during October–November 1991. Diagnostic testing was undertaken to help resolve questions that arose during the analysis of the data from the eight-year depletion/recovery testing. The bottomhole pressure was logged for the final time on June 17, 1992. A rather complete

summary of the synthesis, correlation and analysis of the 1983–1990 depletion/recovery test history has recently been published (Riney, 1991b) and is included in this report as Appendix A. Figure 1.1 (an update of Figure 9 in Appendix A) includes the final pressure buildup datum in the comparison of the data with the reservoir simulation model presented in Appendix A. Analysis of the flow test data from the diagnostic testing of Gladys McCall Well No. 1 in conjunction with a reexamination of the full suite of bottomhole pressure transient data sets is presented in this report.

Preliminary flow testing (phase 0) of Pleasant Bayou Well No. 2 took place during 1979, reservoir limits testing during 1980 (phase 1), and long-term testing (phase 2) during 1981–1983. The well experienced numerous mechanical problems during phase 2, including wireline and fishing tool loss; testing was suspended in May 1983. The well was recompleted and long-term production testing resumed in May 1988 and continued until September 12, 1992 when it was shutin for long-term pressure recovery testing. A rather complete summary of the synthesis, correlation and analysis of the test data through October 1991 has just been published (Riney, 1992) and is included in this report as Appendix B. An update of the reservoir simulation model presented in Appendix B has been made for comparison with the full 1988–1992 test history; Figure 1.2 (an update of Figure 9 in Appendix B) shows the total pressure history comparison. Two new pressure transient tests of Pleasant Bayou Well No. 2 were conducted during 1992. Analysis of these data together with reanalysis of the earlier bottomhole pressure transient tests of the well are presented in this report.

Figure 1.1. Updated comparison of simulated pressure buildup history (curve) and data (points) measured during long-term shutin test at Gladys McCall Well No.1. Datum level is 15,100 ft. Model is described in Appendix A.

Figure 1.2. Updated comparison of simulated 1988–1993 test history (curve) and data (points); data include bottomhole measurements and values estimated from wellhead recordings at Pleasant Bayou Well No.2. Datum level is 14,600 ft. Model is as described in Appendix B except horizontal permeabilities in two low-porosity layers (remote volume) were set at $k_h/4$ rather than $k_h/7$.

2 Method of Analysis

A numerical reservoir simulator was used in our earlier work as a tool for integrating and synthesizing the diverse data sets available for the Gladys McCall (Appendix A) and Pleasant Bayou (Appendix B) geopressed reservoir systems. The simulator allows incorporation of the geological informations, formation and fluid properties data from laboratory tests, and data obtained from pressure transient and production testing of wells. Because of the lack of detailed geologic information at Gladys McCall, the reservoir simulation model used a simple reservoir configuration as a framework for integrating the available data sets. In contrast with the situation at Gladys McCall, the geological information for the C-zone tested at Pleasant Bayou is extensive and the reservoir simulation model used a configuration based on geological studies at UTA's Bureau of Economic Geology (see Appendix B).

Knowledge concerning the permeability structure of a geopressed system and the locations of the major "effective connection zones" between the near-well (proximal) region of the reservoir and remote regions of the reservoir are required input in a simulation model. Near-well permeability structure is best estimated from pressure transient tests. Since there is but a single test well at both Gladys McCall and Pleasant Bayou, the permeability structure away from the test well and the location of effective connection zones between the proximal and remote regions necessarily require iterative history-matching simulations.

The models described in Appendices A and B are based on such an approach.

Interpretation of pressure transient data constitutes an inverse problem. A mathematical model is used to relate pressure changes to flow rate history, and to infer formation parameters. (It is implicitly assumed here that the "mathematical model" is representative of the physical process operating within the reservoir such that "model parameters" are identical with "formation parameters"). Traditional methods for pressure transient data interpretation rely almost exclusively upon graphical representations of mathematical models. A comprehensive review of standard graphical techniques may be found in monographs by Matthews and Russell (1967) and Earlougher (1977); a graphical method has been applied in interpreting data from the Gladys McCall (Appendix A) and Pleasant Bayou (Appendix B) test wells. Recently, several software programs have been developed to aid in the interpretation of pressure transient data. These computer programs make it possible to speed up traditional graphical techniques.

An important breakthrough in pressure transient analysis recently resulted with the development of nonlinear regression for specific mathematical models. Automated methods of inversion of pressure transient data, including flow rate variations, have been developed and incorporated in advanced software packages (see *e.g.*, Horne, 1990). The

packages permit automated inversion of data using mathematical models for which there exist analytical time domain solutions, or models with analytical solutions in the Laplace space ("semi-analytical solutions"). There exist numerous such analytical or semi-analytical solutions; a convenient compilation is given by Streltsova (1988).

Ramey (1992) has discussed the advantages of automated inversion of pressure transient data compared with traditional graphical techniques. He presents a number of examples to demonstrate that the computer-aided inversion method permits a quantum jump in the accuracy of the interpretation of well test data.

Recently, the INVERT software package was developed at S-Cubed for automated inversion of pressure transient data (Owusu and Garg, 1992); INVERT is especially designed for interpreting data from multi-well interference testing of geothermal reservoir systems. The INVERT software program consists of roughly 40 Fortran routines for calculating the wells' pressure responses, and

routines for performing the nonlinear least squares inversion for model parameters (given the test data). Table 2.1 lists the seven mathematical models now in the program's library; other models are being added. Each model permits up to four linear boundaries to be treated.

The availability of the INVERT software has allowed us to reanalyze the complete suite of pressure transient data sets from the Gladys McCall and Pleasant Bayou test wells. The objective is to analyze the full pressure response curve for each of the tests, rather than the early-time portion of the data analyzed previously by a graphical method, to see if more complete information can be determined regarding the permeability structure of the two reservoirs. The mathematical models (Table 2.1) used in the analyses are the "Single Porosity-Finite Wellbore" (Homogeneous Model) and "Composite System" (Composite Model) models. Each of these two models was used with from one to four linear boundaries in an effort to best fit the pressure transient data sets.

Table 2.1. Mathematical models currently included in INVERT's library. Each model can include up to four reservoir boundaries; each boundary may be either a no-flow barrier or maintain a constant hydrostatic pressure ("leaky").

1. Single Porosity (Finite Wellbore)	infinite: $kh, \phi c_i h, C, s, P_i, \alpha$ circular boundary: $kh, \phi c_i h, C, s, P_i, \alpha, r_e$ linear boundary: $kh, \phi c_i h, C, s, P_i, X_a, X_b, Y_c, Y_d$
2. Double Porosity (Warren and Root)	infinite: $kh, \phi c_i h, C, s, \omega, \lambda, P_i, \alpha$ circular boundary: $kh, \phi c_i h, C, s, \omega, \lambda, P_i, \alpha, r_e$ linear boundary: $kh, \phi c_i h, C, s, \omega, \lambda, P_i, X_a, X_b, Y_c, Y_d$
3. Double Porosity (Gradient Flow)	infinite: $kh, \phi c_i h, C, s, \omega, \lambda, P_i, \alpha$ circular boundary: $kh, \phi c_i h, C, s, \omega, \lambda, P_i, \alpha, r_e$ linear boundary: $kh, \phi c_i h, C, s, \omega, \lambda, P_i, X_a, X_b, Y_c, Y_d$
4. Double Porosity (Hantush)	infinite: $kh, \phi c_i h, C, s, \omega, \lambda, P_i, \alpha$ circular boundary: $kh, \phi c_i h, C, s, \omega, \lambda, P_i, \alpha, r_e$ linear boundary: $kh, \phi c_i h, C, s, \omega, \lambda, P_i, X_a, X_b, Y_c, Y_d$
5. Composite System	infinite: $(kh)_1, (\phi c_i h)_1, C, s, \delta, \gamma, r_c, P_i, \alpha$ circular boundary: $(kh)_1, (\phi c_i h)_1, C, s, \delta, \gamma, r_c, P_i, \alpha, r_e$ linear boundary: $(kh)_1, (\phi c_i h)_1, C, s, \delta, \gamma, r_c, P_i, \alpha, X_a, X_b, Y_c, Y_d$
6. Single Porosity (Line Source)	infinite: $kh, \phi c_i h, P_i, \alpha$ linear boundary: $kh, \phi c_i h, P_i, \alpha, X_a, X_b, Y_c, Y_d$
7. Point Source	infinite: $k, \phi c_i, P_i, \alpha$ linear boundary: $k, \phi c_i, P_i, \alpha, X_a, X_b, Y_c, Y_d$

Nomenclature

C	Wellbore storage
kh	permeability-thickness product
k_x	horizontal permeability
k_z	vertical permeability
r_c	radius of discontinuity boundary in composite model
r_e	radius of outer boundary
s	skin
P_i	initial pressure
X_a	distance between left boundary and observation point
X_b	distance between right boundary and observation point
Y_c	distance between top or front boundary and observation point
Y_d	distance between bottom or back boundary and observation point
α	pressure drift parameter
δ	$(kh/\mu)_2/(kh/\mu)_1$ in composite model
γ	$(\phi c_i h)_2/(\phi c_i h)_1$ in composite model
λ	interporosity flow parameter
$\phi c_i h$	storativity
ω	storativity ratio

3 Pleasant Bayou

There have been seven periods during the history of the Pleasant Bayou test well when downhole pressure/temperature transient measurements were recorded. Garg (1980) reported the results from the preliminary (phase 0) measurements. The six tests during the long-term testing are as follows:

1. Sept. 15, 1980 to Dec. 15, 1980
Reservoir limits test
(drawdown/buildup)
2. May 26, 1988 to June 1, 1988
Multi-rate test after recompletion
(drawdown/buildup)
3. May 15, 1989 to May 18, 1989
65-hr test
(buildup only)
4. May 13, 1991 to May 16, 1991
62-hr test
(buildup only)
5. April 28, 1992 to May 2, 1992
84-hr test
(drawdown/buildup)
6. Sept. 12, 1992 to Sept. 15, 1992
70-hr test
(buildup only)

The buildup since shutting the well on September 12, 1992 is continuing at the present time, but only intermittent downhole P/T logs are in the test plan.

A traditional graphical method was employed earlier in a simultaneous analysis of the pressure transient data from the first four of the six tests. Figure 3 of Appendix B compares the data plots ($\Delta p/\Delta q$ vs $\log \Delta t$) for the first four tests; all data are closely approximated (prior to the onset of the effects of previous flow rate changes and reservoir boundaries) by lines of the common slope $m' = 3.83 \times 10^{-3}$ psi/stb/d. The vertical displacements between the parallel lines in the figure reflect changes in the value of the skin factor (near wellbore flow resistance) operative at the time of the tests. The essentially constant slopes indicate that the permeability-thickness product of the perforated sandstone remained unchanged at $kh = \sim 12,024$ md-ft.

The last two of the tests listed were made during 1992. We will first analyze the data using the graphical method of Appendix B and then re-examine all six data sets using an inversion method which considers the full pressure-time series rather than just the constant slope portion. Analysis of the buildup response during the ongoing long-term test (LTT) is also given; the analysis is based on values of bottomhole pressure recovery estimated from pressures recorded at the wellhead.

3.1 GRAPHICAL ANALYSIS OF PRESSURE TRANSIENT DATA

On March 13, 1992 the Pleasant Bayou test well was shutin and the reservoir allowed

to recover in preparation for a bottomhole pressure transient test. On April 28 a pressure/temperature gauge was set at a depth of 14,600 ft in the shutin well and allowed to stabilize to bottomhole conditions (recorded P/T values were 10,180.8 psia, 305.0°F). The pressure was still recovering slowly from the four-year production testing prior to the March 13, 1992 shutin. The well was opened at 19:03:00 on April 28 and transient P/T values were recorded in the flowing well until malfunctioning of the recording system was detected at 23:30 on April 28. Production was continued at a rate of $q = \sim 11,353$ stb/d while the first gauge was brought to the surface and replaced by a second gauge which was again set at a depth of 14,600 ft. By 19:00 on April 29 the second gauge had been in place long enough to stabilize. Just prior to the well being shutin at 20:05:00 on April 29, flowing P/T values at the datum level (14,600 ft) were measured as

$$p_{wf} = 9902 \text{ psia} \quad T_{wf} = 305^\circ\text{F}.$$

Pressure buildup was recorded until 07:00 on May 2 when the second gauge was started up the hole from the 14,600 ft datum level.

Examination of the drawdown data reveals that the original gauge had already begun to drift within ~ 0.3 hr from the start of the flow on April 28. Only the data from the second gauge will be analyzed; *i.e.*, only ~ 55 hours of the 84-hr test (covering the buildup response) provided useful data.

On September 4, 1992 the flow rate of the Pleasant Bayou well was decreased from $\sim 22,750$ stb/d to a stable flow rate of $q = 10,615$ stb/d in preparation for a final pressure buildup test. On September 11 a pressure

gauge was lowered in the flowing well, set at 14,600 ft and allowed to stabilize. Just prior to the well being shutin at 09:08:26 on September 12, the recorded P/T values were

$$P_{wf} = 9582 \text{ psia} \quad T_{wf} = 305^\circ\text{F}.$$

The bottomhole pressure recovery was recorded until 07:16 on September 15 (70-hr buildup test) when the gauge was pulled out of the hole.

Figure 3.1 shows semilog plots of $\Delta p/\Delta q$ vs Δt for the 84-hr and 70-hr buildup tests. Both curves are closely approximated by a line of slope $m' = 3.65 \times 10^{-3}$ psi/stb/d as shown there. This slope is very close to the lines of common slope ($m' = 3.65 \times 10^{-3}$ psi/stb/d) that were found to match all the data from the other four bottomhole pressure transient tests (see Figure 6 and Table 1 in Appendix B). The essentially constant slopes indicate that the permeability-thickness product of the perforated sandstone (thickness $h = 60$ ft = 18.29 m) is essentially unchanged since 1980, *i.e.*,

$$kh = \sim 12,024 \text{ md-ft (3.665 D-m)}.$$

3.2 AUTOMATED INVERSION OF PRESSURE TRANSIENT DATA

Preliminary calculations with INVERT were made using the "Single Porosity-Finite Wellbore" (Homogeneous Model) and "Composite System" (Composite Model) models listed in Table 2.1. It became clear that the Composite Model was not applicable to the Pleasant Bayou data. As discussed in Appendix B, the C-zone of the Pleasant Bayou fault block is massive and reservoir simulation history matching calculations employ a homogeneous model for the proximal

Figure 3.1. Bottomhole pressure buildup data from the 84-hr and 70-hr bottomhole tests of Pleasant Bayou Well No.2. Vertical displacement reflects changes in the skin factor (s).

reservoir formation. The bulk of the INVERT calculations for the pressure transient data were made using the Homogeneous Model with linear faults present. The parameters occurring in this model are as follows:

$kh, \phi C_l h, C, s, P_i, X_a, X_b, X_c, X_d$
(Nomenclature defined in Table 2.1).

In the present single-well application, the last four parameters denote the distances from the test well to linear boundaries (if present in the model) to the left (X_a), right (X_b), top (X_c) and bottom (X_d). Since the remote Pleasant Bayou reservoir configuration (see Figure 3 in Appendix B) is more complex than the homogeneous rectangular model in the inversion calculations, the model can only match the pressure history of the Pleasant Bayou test well for a restricted time period. For orientation purposes, X_a may be considered to correspond to F1 in the Pleasant Bayou reservoir configuration (see Figure 3 in Appendix B). When employed in the inversion calculations, X_c and X_d are taken to correspond to the major growth faults which form lateral boundaries to the Pleasant Bayou fault block (see Figure 1 in Appendix B). X_b was generally not employed in the mathematical model, *i.e.*, the model is assumed to have no effective boundary to the northeast over the duration of the pressure transient data set being analyzed. (Trial calculations in which X_b was introduced as a hydrostatic pressure boundary, to represent a "leaky fault", failed to yield good matches to the pressure transient data).

In applying INVERT it is required to provide the flow rate history as well as the pressure transient data set of interest. Since earlier rate changes also affect the pressure transient response of the test well, the flow rate

history employed in the inversion calculations should closely approximate the actual test history for a significant period preceding the rate change of primary interest. In some cases, the need to carry out the inversion calculation over an extended flow-rate history is in conflict with the inability of the idealized mathematical model to represent the actual reservoir response except for a limited time. As a practical matter this results in the inversion calculation yielding an "effective initial pressure" rather than a true value. Both the Reservoir Limits Test (RLT) and Multi-Rate Test (MRT) were started from static reservoir conditions. The duration of the 90-day RLT was sufficiently long that the idealized model yields a value of P_i that is only an "effective initial pressure". The duration of the MRT, however, is so short that only the nearest boundary has a significant effect. P_i is not a free parameter; it is fixed at the measured stable pre-test value.

At the present time INVERT does not include treatment of a rate-dependent skin factor (s). As demonstrated in the data analysis in Appendix B, the value of s varies with episodal sand production and changes in the near-well pore pressure during the test history of the well. The flow rate of Pleasant Bayou Well No. 2 was varied during the drawdown portions of both the RLT and MRT. Since the mathematical models employed by INVERT treat skin as a constant, we chose to analyze only the buildup portions of the RLT and MRT pressure transient data.

The following input parameters were kept fixed at the values used in the graphical pressure transient analysis presented in Appendix B: $r_w = 8.89 \times 10^{-2}$ m (0.2917 ft), $h = 18.29$ m (60 ft), $\phi = 0.18$, $\mu = 2.7 \times 10^{-4}$

Pa-s (0.27 cp), $C_i = 7.01 \times 10^{-10}$ Pa-1 (4.83×10^{-6} psi⁻¹). The formation storativity was therefore fixed at

$$\phi C_i h = 2.3076 \times 10^{-9} \text{ m/Pa.}$$

Two series of inversion calculations were made using a single boundary at a distance X_a (free parameter) from the test well; in the first series kh was fixed at the value estimated by the graphical analyses, *i.e.*, $kh = 3.665$ D-m. In the second series kh was treated as a free parameter. An additional two series of inversion calculations were made using three boundaries; in these X_a was a free parameter but the top and bottom boundaries were fixed to correspond to the reservoir simulation configuration (Figure 3 in Appendix B),

$$Y_c = Y_d = 4330 \text{ m.}$$

In the third series kh was again fixed at $kh = 3.665$ D-m; in the fourth series kh was a free parameter. The results of all four series are summarized in Table 3.1.

Comparison of the results of Series 1 with Series 3 and the results of Series 2 with Series 4 (Table 3.1) shows that the introduction of boundaries at Y_c and Y_d makes no significant difference in the inversion calculations except for the RLT; the chief difference between corresponding RLT inversions is the value for X_a that is calculated. Reports summarizing all the inversion calculational results for three boundaries are given in Tables 3.2a-f (Series 3) and Tables 3.3a-f (Series 4). The associated plots comparing the results of the inversion calculations with the pressure transient data are also shown in Figures 3.2a-f (Series 3) and Figures 3.3a-f (Series 4).

The plots for the Series 3 and Series 4 inversion calculations demonstrate excellent agreement with the pressure transient data for all cases. Comparison of the reports for corresponding inversions for Series 3 and Series 4 shows that the Standard Error for the former is larger than the latter series; this is a consequence of kh being an additional free parameter in Series 4. Comparison of the Correlation Matrix for each Series 4 case shows a high negative correlation between values calculated for parameters kh and X_a ; a large negative correlation between kh and X_a implies that an increase (or decrease) in kh when accompanied by a corresponding increase (or decrease) in X_a will give essentially the same result.

The durations of the pressure transient tests other than the RLT are too small for the distance from the well to the nearest boundary (X_a) to be definitely determined by the data inversion. Based on the results of the inversion calculations, of the bottomhole pressure transient data set, the best estimates for kh and X_a would appear to be $kh = 3.665$ D-m and $X_a = 869$ m. The associated value of the skin factor ($s = +4.42$ at the time on the RLT) varied throughout the history of the Pleasant Bayou test well, but the value of kh remained essentially constant.

3.3 LONG-TERM BUILDUP RESPONSE

At the conclusion of the 70-hr buildup test on September 15, 1992, P/T gradient measurements were recorded during stops made every 1,000 ft as the tool was raised to the surface. On September 24, 1992 a different

Table 3.1. Summary of inversion calculations for Pleasant Bayou pressure transient welltest data. Cases include models with single linear boundary (X_a) and models with three linear boundaries ($X_a, Y_c = Y_d = 4330$ m).

Test	kh Fixed Value			kh Free Parameter		
	kh (D-m)	s	X_a (m)	kh (D-m)	s	X_a (m)
One Linear Fault: X_a (Free Parameter)						
	Series 1			Series 2		
RLT	3.665	+4.43	1140	4.034	+5.57	756
MRT	3.665	+2.36	572	3.701	+2.45	553
65-hr	3.665	-1.11	672	4.169	-0.29	414
62-hr	3.665	-1.66	618	3.880	-1.36	498
84-hr	3.665	-2.10	411	3.666	-2.10	411
70-hr	3.665	-1.85	453	4.247	-1.09	269
Three Linear Faults: X_a (Free Parameters), $Y_c = Y_d = 4330$ m						
	Series 3			Series 4		
RLT	3.665	+4.42	869	4.039	+5.57	597
MRT	3.665	+2.36	572	3.701	+2.45	553
65-hr	3.665	-1.07	675	4.164	-0.40	399
62-hr	3.665	-1.66	616	3.887	-1.35	494
84-hr	3.665	-2.10	419	3.632	-2.15	430
70-hr	3.665	-1.85	442	4.244	-1.10	262

P/T gauge was lowered in the test well, stable values recorded at 14,600 ft, and P/T gradient measurements again recorded as the gauge was pulled out of the hole. The test plan called for additional P/T gradient logs to be made to allow accurate calculation of bottomhole pressure buildup (from continuously recorded wellhead pressures) during the long-term shutin test. Budget constraints apparently now preclude additional P/T logs.

The use of different gauges for the September 15 and 24 measurements, and other uncertainties in the test procedures employed, have recently been discussed by Randolph, *et al.*, (IGT's Pleasant Bayou Report for the week of September 24–30, 1992). To evaluate the effect of these sources of error in the P/T data, the measured $T(z)$ values and the equation-of-state for brine-methane mixtures (see Pritchett, 1985) have been used to estimate BHP values from values of WHP recorded to date during the final long-term shutin test of the Pleasant Bayou well, *i.e.*,

$$\text{BHP} \sim \text{WHP} + g \times \int \rho(T, P) dz$$

Table 3.4 lists the P/T gradient data recorded on September 15 and 24, 1992. The prescribed wellbore fluid conditions the hydrostatic pressure calculations are based on the $T(z)$ measurements and the following assumed composition of the reservoir fluid (same as assumed in Appendix B):

H ₂ O:	0.87733
CH ₄ :	0.00267
NaCl:	0.12000

Figures 3.4a and 3.4b show, respectively, the specified input data and the results of the hydrostatic pressure calculations for the September 15, 1992 case. Figures 3.5a and 3.5b present corresponding information for the

September 24, 1992 case. The relatively high temperatures recorded at 5,000 ft (1524 m) reflect the heating of the shallow aquifer used for reinjection of the hot processed brine. The unstable region noted in the graphs refer to the presence of a vapor phase calculated as existing from the surface to the indicated depths. Under stable conditions the free gas would actually rise to the top of the wellbore; the specified $T(z)$ data and fluid composition are inconsistent with stable conditions. However, in each case the calculated volume fraction of the vapor phase is very small and does not significantly affect the calculated pressure gradient.

The calculation for September 15, 1992 used IGT's measured value of WHP = 227.94 bars (3,306 psia) and gave BHP = 684.18 bars (9,923 psia) at the depth of 4,450.1 m (14,600 ft); the pressure recorded at 14,600 ft just prior to raising the tool on September 15 was 682.72 bars (9,902 psia). The calculation for September 24, 1992 used IGT's measured value of WHP = 230.49 bars (3,343 psia) and gave BHP = 689.66 bars (10,003 psia) at 4,450.1 m (14,600 ft); the pressure recorded at 14,600 ft just prior to pulling out of the hole on September 24 was 687.75 bars (9,975 psia). The agreement between the measured and calculated values for BHP are within the accuracy expected for isolated bottomhole data.

The calculated wellbore pressure drop (BHP-WHP) increased from 456.24 bars on September 15 to 459.17 bars on September 24; the corresponding increase in the measured pressure drop was from 454.78 bars to 457.26 bars. The increase in (BHP-WHP) results from the higher density of the wellbore fluid as it cooled between September 15 and September 24. It would be highly desirable to have additional P/T gradient measurements since

Continued on page 3-37

Table 3.2a. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2a.

3.2a. RLT with kh = 3.665 D-m.

REGRESSION RESULTS: RLT Series 3, kh Fixed

HmgMod:L3(C_t , kh, Y_c , Y_d fixed)

1	Initial Pressure, bar	=	7.6800E+02	±	1.1263E-01
2	Permeability-Thickness, Darcy-m	=	3.6650E+00	±	0.0000E+00
3	Storage Coefficient, m/Pa	=	2.3076E-09	±	0.0000E+00
4	Skin	=	4.4216E+00	±	5.8441E-02
5	Wellbore Storage, m ³ /Pa	=	8.5564E-08	±	7.0933E-09
9	X_a , m	=	8.6850E+02	±	4.7994E+01
11	Y_c , m	=	4.3300E+03	±	0.0000E+00
12	Y_d , m	=	4.3300E+03	±	0.0000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 6.473364E+00

STANDARD ERROR (bar) = 2.652596E-01

Correlation Matrix

1.0000	-0.1027	-0.0617	-0.8217
-0.1027	1.0000	0.1127	0.3900
-0.0617	0.1127	1.0000	0.2347
-0.8217	0.3900	0.2347	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)	Time(hrs)	Rate(kg/s)
0.0000	5.0565	359.5000	29.1261
0.5000	9.8268	363.1700	36.3957
1.0000	11.3495	439.0000	35.4632
3.3330	12.8783	444.5000	29.8825
125.6700	0.0	516.5000	27.2632
128.0000	18.6851	540.5000	25.2443
128.7500	20.9622	1084.035*	0.0

*Shutin for RLT Buildup ($Q_0 = 542,937$ stb)

3.2a. RLT with $kh = 3.665$ D-m.

Figure 3.2a. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2a.

Table 3.2b. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2b.

3.2b. MRT with kh = 3.665 D-m.

REGRESSION RESULTS: MRT Series 3, kh Fixed

HmgMod:L3 (P_o , C_t , kh fixed)

1	Initial Pressure, bar	=	7.57010E+02 ± 0.00000E+00
2	Permeability-Thickness, Darcy-m	=	3.66500E+00 ± 0.00000E+00
3	Storage Coefficient, m/Pa	=	2.30760E-09 ± 0.00000E+00
4	Skin	=	2.35688E+00 ± 2.64638E-02
5	Wellbore Storage, m ³ /Pa	=	5.54117E-08 ± 2.36025E-09
9	X_a , m	=	5.72428E+02 ± 8.14227E+00
11	Y_c , m	=	4.33000E+03 ± 0.00000E+00
12	Y_d , m	=	4.33000E+03 ± 0.00000E+00
(for 95% confidence interval)			

CHISQ (bar**2) = 4.200214E-01

STANDARD ERROR (bar) = 8.165174E-02

Correlation Matrix

1.0000	0.0036	0.4508
0.0036	1.0000	0.2473
0.4508	0.2473	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	9.797
11.5100	14.803
23.5040	23.469
29.7730	22.957
54.2730	18.875
82.5720*	0.000

*Shutin for RLT Buildup ($Q = 31,944$ stb)

3.2b. MRT with $kh = 3.665$ D-m.

Figure 3.2b. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2b.

Table 3.2c. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2c.

3.2c. 65-hr test with kh = 3.665 D-m.

REGRESSION RESULTS: 65-hr Series 3, kh Fixed

HmgMod:L3 (C_t , kh, Y_c , Y_d fixed)

1	Initial Pressure, bar	=	7.44174E+02	±	3.29452E-01
2	Permeability-Thickness, Darcy-m	=	3.66500E+00	±	0.00000E+00
3	Storage Coefficient, m/Pa	=	2.30760E-09	±	0.00000E+00
4	Skin	=	-1.06863E+00	±	8.19160E-02
5	Wellbore Storage, m ³ /Pa	=	1.89758E-07	±	3.08721E-08
9	X_a , m	=	6.74871E+02	±	8.57823E+01
11	Y_c , m	=	4.33000E+03	±	0.00000E+00
12	Y_d , m	=	4.33000E+03	±	0.00000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 1.548994E+01

STANDARD ERROR (bar) = 3.769741E-01

Correlation Matrix

1.0000	-0.1137	-0.0821	-0.9699
-0.1137	1.0000	-0.0588	0.2025
-0.0821	-0.0588	1.0000	0.1467
-0.9699	0.2025	0.1467	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	34.0000
8047.4400	24.4212
8472.0067*	0.0

*Shutin for 65-hr Buildup ($Q = 5,913,404$ stb)

3.2c. 65-hr test with $kh = 3.665$ D-m.

Figure 3.2c. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2c.

Table 3.2d. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2d.

3.2d. 62-hr test with kh = 3.665 D-m.

REGRESSION RESULTS: 62-hr Series 3, kh Fixed

HmgMod:L3 (C_t , kh, Y_c , Y_d fixed)

1	Initial Pressure, bar	=	7.27866E+02 ± 2.28617E-01
2	Permeability-Thickness, Darcy-m	=	3.66500E+00 ± 0.00000E+00
3	Storage Coefficient, m/Pa	=	2.30760E-09 ± 0.00000E+00
4	Skin	=	-1.65798E+00 ± 6.64612E-02
5	Wellbore Storage, m ³ /Pa	=	2.21886E-07 ± 4.31600E-08
9	X_a , m	=	6.16450E+02 ± 5.97750E+01
11	Y_c , m	=	4.33000E+03 ± 0.00000E+00
12	Y_d , m	=	4.33000E+03 ± 0.00000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 1.797938E+01

STANDARD ERROR (bar) = 3.676729E-01

Correlation Matrix

1.0000	-0.1747	-0.1162	-0.9442
-0.1747	1.0000	0.0717	0.3259
-0.1162	0.0717	1.0000	0.2186
-0.9442	0.3259	0.2186	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	29.7870
25553.1900	35.4793
25663.4400	24.1738
25953.5000*	0.0

*Shutin for 62-hr Buildup ($Q = 16,077,111$ stb)

3.2d. 62-hr test with $kh = 3.665$ D-m.

Figure 3.2d. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2d.

Table 3.2e. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2e.

3.2e. 84-hr test with kh = 3.665 D-m.

REGRESSION RESULTS: 84-hr Series 3, kh Fixed

HmgMod:L3 (C_t , kh, Y_c , Y_d fixed)

1	Initial Pressure, bar	=	7.23175E+02 ± 1.56013E-02
2	Permeability-Thickness, Darcy-m	=	3.66500E+00 ± 0.00000E+00
3	Storage Coefficient, m/Pa	=	2.30760E-09 ± 0.00000E+00
4	Skin	=	-2.10195E+00 ± 1.31921E-02
5	Wellbore Storage, m ³ /Pa	=	8.06117E-12 ± 3.99512E-08
9	X_a , m	=	4.19112E+02 ± 4.98459E+00
11	Y_c , m	=	4.33000E+03 ± 0.00000E+00
12	Y_d , m	=	4.33000E+03 ± 0.00000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 9.284344E+01

STANDARD ERROR (bar) = 5.135755E-01

Correlation Matrix

1.0000	-0.1087	-0.0958	-0.8597
-0.1087	1.0000	0.1212	0.2665
-0.0958	0.1212	1.0000	0.2477
-0.8597	0.2665	0.2477	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	32.2924
32272.4400	43.4965
32668.4400	24.2051
33260.4400	0.0000
34379.4900	22.7021
34404.52333333*	0.0000

*Shutin for Buildup part of 84-hr Test ($Q = 22,369,881$ stb)

3.2e. 84-hr test with $kh = 3.665$ D-m.

Figure 3.2e. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2e.

Table 3.2f. Reports of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.2f.

3.2f. 70-hr test with kh = 3.665 D-m.

REGRESSION RESULTS: 70-hr Series 3, kh Fixed

HmgMod:L3 (C_t , kh, Y_C , Y_D fixed)

1	Initial Pressure, bar	=	7.3760E+02	±	1.2457E-01
2	Permeability-Thickness, Darcy-m	=	3.6650E+00	±	0.0000E+00
3	Storage Coefficient, m/Pa	=	2.3076E-09	±	0.0000E+00
4	Skin	=	-1.8537E+00	±	4.6869E-02
5	Wellbore Storage, m ³ /Pa	=	2.0735E-07	±	2.4898E-08
9	X_a , m	=	4.4240E+02	±	2.4642E+01
11	Y_C , m	=	4.3300E+03	±	0.0000E+00
12	Y_D , m	=	4.3300E+03	±	0.0000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 2.417863E+00

STANDARD ERROR (bar) = 1.648241E-01

Correlation Matrix

1.0000	-0.1191	-0.1043	-0.9439
-0.1191	1.0000	0.0293	0.2501
-0.1043	0.0293	1.0000	0.2208
-0.9439	0.2501	0.2208	1.0000

Flow Rate Input Data

Time (hrs)	Rate (kg/s)
0.0000	32.2924
32272.4400	43.4965
32668.4400	24.2051
33260.4400	0.0000
34379.4900	22.7021
34404.54	0.0000
34476.574	45.522
37470.5567	21.240
37657.5817*	0.000

*Shutin for 70-hr Buildup ($Q = 25,290,659$)

690

3.2f. 70-hr test with $kh = 3.665$ D-m.

Figure 3.2f. Plots of Series 3 (kh fixed) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.2f.

Table 3.3a. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3a.

3.3a. RLT with kh a free parameter.

REGRESSION RESULTS: RLT Series 4, kh Fixed

HmgMod:L3(C_t , Y_c , Y_d fixed)

1	Initial Pressure, bar	=	7.6776E+02	±	1.2929E-01
2	Permeability-Thickness, Darcy-m	=	4.0386E+00	±	1.3615E-01
3	Storage Coefficient, m/Pa	=	2.3076E-09	±	0.0000E+00
4	Skin	=	5.5706E+00	±	4.1965E-01
5	Wellbore Storage, m ³ /Pa	=	9.6911E-08	±	6.4675E-09
9	X_a , m	=	5.9722E+02	±	8.4060E+01
11	Y_c , m	=	4.3300E+03	±	0.0000E+00
12	Y_d , m	=	4.3300E+03	±	0.0000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 4.499302E+00

STANDARD ERROR (bar) = 2.211458E-01

Correlation Matrix

1.0000	-0.7661	-0.7663	-0.4493	0.5547
-0.7661	1.0000	0.9914	0.5537	-0.9408
-0.7663	0.9914	1.0000	0.5601	-0.9139
-0.4493	0.5537	0.5601	1.0000	-0.4512
0.5547	-0.9408	-0.9139	-0.4512	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)	Time(hrs)	Rate(kg/s)
0.0000	5.0565	359.5000	29.1261
0.5000	9.8268	363.1700	36.3957
1.0000	11.3495	439.0000	35.4632
3.3330	12.8783	444.5000	29.8825
125.6700	0.0	516.5000	27.2632
128.0000	18.6851	540.5000	25.2443
128.7500	20.9622	1084.035*	0.0

*Shutin for RLT Buildup ($Q_0 = 542,937$ stb)

3.3a. RLT with kh a free parameter.

Figure 3.3a. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3a.

Table 3.3b. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3b.

3.3b. MRT with kh a free parameter.

REGRESSION RESULTS: MRT Series 4, kh Fixed

HmgMod:L3 (P_o , C_t , kh fixed)

1	Initial Pressure, bar	=	7.57010E+02 ± 0.00000E+00
2	Permeability-Thickness, Darcy-m	=	3.70112E+00 ± 4.81814E-02
3	Storage Coefficient, m/Pa	=	2.30760E-09 ± 0.00000E+00
4	Skin	=	2.44511E+00 ± 1.19956E-01
5	Wellbore Storage, m ³ /Pa	=	5.63344E-08 ± 2.64052E-09
9	X_a , m	=	5.53434E+02 ± 2.73040E+01
11	Y_c , m	=	4.33000E+03 ± 0.00000E+00
12	Y_d , m	=	4.33000E+03 ± 0.00000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 4.044273E-01

STANDARD ERROR (bar) = 8.012167E-02

Correlation Matrix

1.0000	0.9753	0.4797	-0.9578
0.9753	1.0000	0.4681	-0.9052
0.4797	0.4681	1.0000	-0.3974
-0.9578	-0.9052	-0.3974	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	9.797
11.5100	14.803
23.5040	23.469
29.7730	22.957
54.2730	18.875
82.5720*	0.000

*Shutin for RLT Buildup ($Q = 31,944$ stb)

3.3b. MRT with kh a free parameter.

Figure 3.3b. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3b.

Table 3.3c. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3c.

3.3c. 65-hr test with kh a free parameter.

REGRESSION RESULTS: 65-hr Series 4, kh Fixed

HmgMod:L3 (C_t , Y_c , Y_d fixed)

1	Initial Pressure, bar	=	7.42222E+02 ± 1.01903E+00
2	Permeability-Thickness, Darcy-m	=	4.16437E+00 ± 2.41519E-01
3	Storage Coefficient, m/Pa	=	2.30760E-09 ± 0.00000E+00
4	Skin	=	-3.96573E-01 ± 3.74845E-01
5	Wellbore Storage, m ³ /Pa	=	2.38033E-07 ± 3.57404E-08
9	X_a , m	=	3.98721E+02 ± 8.55889E+01
11	Y_c , m	=	4.33000E+03 ± 0.00000E+00
12	Y_d , m	=	4.33000E+03 ± 0.00000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 1.132083E+01

STANDARD ERROR (bar) = 3.222744E-01

Correlation Matrix

1.0000	-0.9845	-0.9616	-0.5756	0.8285
-0.9845	1.0000	0.9724	0.5744	-0.9089
-0.9616	0.9724	1.0000	0.5430	-0.8581
-0.5756	0.5744	0.5430	1.0000	-0.4593
0.8285	-0.9089	-0.8581	-0.4593	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	34.0000
8047.4400	24.4212
8472.0067*	0.0

*Shutin for 65-hr Buildup ($Q = 5,913,404$ stb)

3.3c. 65-hr test with kh a free parameter.

Figure 3.3c. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3c.

Table 3.3d. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3d.

3.3d. 62-hr test with kh a free parameter.

REGRESSION RESULTS: 62-hr Series 4, kh Fixed

HmgMod:L3 (C_t , Y_C , Y_d fixed)

1	Initial Pressure, bar	=	7.26592E+02 ± 1.13401E+00
2	Permeability-Thickness, Darcy-m	=	3.88698E+00 ± 1.95950E-01
3	Storage Coefficient, m/Pa	=	2.30760E-09 ± 0.00000E+00
4	Skin	=	-1.34850E+00 ± 2.80089E-01
5	Wellbore Storage, m ³ /Pa	=	2.55618E-07 ± 5.08303E-08
9	X_a , m	=	4.94136E+02 ± 9.76624E+01
11	Y_C , m	=	4.33000E+03 ± 0.00000E+00
12	Y_d , m	=	4.33000E+03 ± 0.00000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 1.722322E+01

STANDARD ERROR (bar) = 3.598582E-01

Correlation Matrix

1.0000	-0.9878	-0.9625	-0.5749	0.8305
-0.9878	1.0000	0.9684	0.5692	-0.9025
-0.9625	0.9684	1.0000	0.5632	-0.8363
-0.5749	0.5692	0.5632	1.0000	-0.4323
0.8305	-0.9025	-0.8363	-0.4323	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	29.7870
25553.1900	35.4793
25663.4400	24.1738
25953.5000*	0.0

*Shutin for 62-hr Buildup ($Q = 16,077,111$ stb)

3.3d. 62-hr test with kh a free parameter.

Figure 3.3d. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3d.

Table 3.3e. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3e.

3.3e. 84-hr test with kh a free parameter.

REGRESSION RESULTS: 84-hr Series 4, kh Fixed

HmgMod:L3 (C_t , Y_c , Y_d fixed)

1	Initial Pressure, bar	=	7.23370E+02 ± 2.65135E-01
2	Permeability-Thickness, Darcy-m	=	3.63151E+00 ± 4.53705E-02
3	Storage Coefficient, m/Pa	=	2.30760E-09 ± 0.00000E+00
4	Skin	=	-2.14547E+00 ± 6.75898E-02
5	Wellbore Storage, m ³ /Pa	=	1.68539E-11 ± 6.17334E-08
9	X_a , m	=	4.30031E+02 ± 1.14550E+01
11	Y_c , m	=	4.33000E+03 ± 0.00000E+00
12	Y_d , m	=	4.33000E+03 ± 0.00000E+00

(for 95% confidence interval)

CHISQ (bar**2) = 9.236065E+01

STANDARD ERROR (bar) = 5.122384E-01

Correlation Matrix

1.0000	-0.9980	-0.9790	-0.7445	0.8536
-0.9980	1.0000	0.9796	0.7419	-0.8810
-0.9790	0.9796	1.0000	0.7427	-0.8383
-0.7445	0.7419	0.7427	1.0000	-0.5767
0.8536	-0.8810	-0.8383	-0.5767	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	32.2924
32272.4400	43.4965
32668.4400	24.2051
33260.4400	0.0000
34379.4900	22.7021
34404.52333333*	0.0000

*Shutin for Buildup part of 84-hr Test ($Q = 22,369,881$ stb)

3.3e. 84-hr test with kh a free parameter.

Figure 3.3e. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3e.

Table 3.3f. Reports of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculatons are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.3f.

3.3f. 70-hr test with kh a free parameter.

REGRESSION RESULTS: 70-hr Series 4, kh Fixed

HmgMod:L3 (C_t , kh, Y_c , Y_d fixed)

1	Initial Pressure, bar	=	7.3173E+02	±	9.7297E-01
2	Permeability-Thickness, Darcy-m	=	4.2443E+00	±	1.0464E-01
3	Storage Coefficient, m/Pa	=	2.3076E-09	±	0.0000E+00
4	Skin	=	-1.0966E+00	±	1.3665E-01
5	Wellbore Storage, m ³ /Pa	=	2.9064E-07	±	1.7869E-08
9	X_a , m	=	2.6155E+02	±	2.3700E+01
11	Y_c , m	=	4.3300E+03	±	0.0000E+00
12	Y_d , m	=	4.3300E+03	±	0.0000E+00
(for 95% confidence interval)					

CHISQ (bar**2) = 8.383301E-01

STANDARD ERROR (bar) = 9.705380E-02

Correlation Matrix

1.0000	-0.9987	-0.9709	-0.6314	0.9247
-0.9987	1.0000	0.9708	0.6287	-0.9408
-0.9709	0.9708	1.0000	0.6067	-0.8872
-0.6314	0.6287	0.6067	1.0000	-0.5224
0.9247	-0.9408	-0.8872	-0.5224	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	32.2924
32272.4400	43.4965
32668.4400	24.2051
33260.4400	0.0000
34379.4900	22.7021
34404.54	0.0000
34476.574	45.522
37470.5567	21.240
37657.5817*	0.000

*Shutin for 70-hr Buildup ($Q = 25,290,659$)

3.3f. 70-hr test with kh a free parameter.

Figure 3.3f. Plots of Series 4 (kh free) INVERT results for Pleasant Bayou pressure transient tests. Calculations are for a homogeneous model with three boundaries and correspond to the input data listed in Table 3.3f.

Table 3.4. Measured P/T gradients recorded in Pleasant Bayou test well during downhole logs on September 1 and September 24, 1992.

Depth (m)	September 15, 1992		September 24, 1992	
	Pressure (bars)	Temperature (°C)	Pressure (bars)	Temperature (°C)
12.50	—	—	232.2	29.7
152.40	243.6	98.1	—	—
304.80	259.2	93.2	263.2	77.9
609.60	290.8	93.3	294.7	79.9
914.40	322.4	95.1	326.2	82.5
1219.20	354.0	95.4	357.9	84.1
1524.00	385.9	104.2	389.5	93.3
1828.80	416.9	100.9	421.1	89.4
2133.60	448.6	110.6	452.4	100.3
2438.40	479.8	120.8	483.9	112.3
2734.20	510.8	124.8	515.1	118.4
3048.00	541.7	131.3	546.1	126.5
3352.80	572.5	137.9	577.1	134.1
3657.60	603.2	142.2	607.9	139.5
3962.40	633.9	144.8	638.7	143.4
4267.20	664.5	149.6	669.4	149.1
4450.08	682.7	151.7	687.7	151.9

Figure 3.4a. Specification of input data for Pleasant Bayou hydrostatic pressure calculation for September 15, 1992.

Figure 3.4b. Computed results for Pleasant Bayou hydrostatic pressure calculation for September 15, 1992.

Figure 3.5a. Specification of input data for Pleasant Bayou hydrostatic pressure calculation for September 24, 1992.

Figure 3.5b. Computed results for Pleasant Bayou hydrostatic pressure calculation for September 15, 1992.

the wellbore temperature will slowly decrease further as the long-term shutin test continues. In the absence of such data we hypothesize that (BHP-WHP) is approaching $\Delta\bar{P}$ exponentially with increasing time, *i.e.*,

$$\text{BHP} - \text{WHP} = \Delta\bar{P} + p * \exp(-\Delta t/\tau)$$

A semi-log plot of (BHP-WHP) versus shutin time, Δt , is indeed approximated by a straight line for

$$\Delta\bar{P} = 6,634 \text{ psi (457.40 bars)}$$

as is shown in Figure 3.6. Estimates for (BHP-WHP) from Figure 3.6 have been added to the recorded WHP, at corresponding values of Δt , to approximate the long-term test (LTT) of the

pressure recovery of the Pleasant Bayou reservoir. The results are shown in Figure 3.7.

The estimated LTT pressure values (Figure 3.7) have been appended to the 70-hr downhole pressure buildup data at the same datum level and INVERT applied to the complete data set through January 1, 1993. The results are comparable to those obtained for the 70-hr test (see Table 3.1). The report summarizing the inversion for Series 3 ($k_h = 3.665 \text{ D-m}$ and $Y_c = Y_d$) is shown in Table 3.5; the associated plot comparing the LTT data with the Homogeneous Model inversion calculation is given in Figure 3.8. The computed distance to the nearest boundary (X_d) is closer to the values computed from all the downhole tests since 1980 than it is to the value computed from the 1980 RLT data.

Figure 3.6. Use of simultaneous early-time BHP and WHP measurements in Pleasant Bayou Well No.2 to estimate late-time shutin values of ΔP_{wb} from 14,600 ft to surface.

Figure 3.7. Estimated bottomhole pressure recovery in Pleasant Bayou Well No. 2 during long-term buildup test. Datum level is 14,600 ft.

Table 3.5. Report of Series 3 (kh fixed) INVERT results for Pleasant Bayou Long-Term Test through January 1, 1993. Calculations are for a homogeneous model with three boundaries and correspond to the plot in Figure 3.8.

REGRESSION RESULTS: LTT Series 3, kh Fixed

HmgMod:L3(kh, C_t , Y_c , Y_d fixed)

1	Initial Pressure, bar	=	7.3755E+02	±	6.8300E-02
2	Permeability-Thickness, Darcy-m	=	3.6650E+00	±	0.0000E+00
3	Storage Coefficient, m/Pa	=	2.3076E-09	±	0.0000E+00
4	Skin	=	-1.8486E+00	±	6.1896E-02
5	Wellbore Storage, m ³ /Pa	=	2.0957E-07	±	3.2843E-08
9	X_a , m	=	4.5245E+02	±	1.7488E+01
11	Y_c , m	=	4.3300E+03	±	0.0000E+00
12	Y_d , m	=	4.3300E+03	±	0.0000E+00
(for 95% confidence interval)					

CHISQ (bar**2) = 6.424474E+00

STANDARD ERROR (bar) = 2.206134E-01

Correlation Matrix

1.0000	-0.0746	-0.0652	-0.7807
-0.0746	1.0000	0.0173	0.3180
-0.0652	0.0173	1.0000	0.2813
-0.7807	0.3180	0.2813	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	32.2924
32272.4400	43.4965
32668.4400	24.2051
33260.4400	0.0000
34379.4900	22.7021
34404.54	0.0000
34476.574	45.522
37470.5567	21.240
37657.5817*	0.000

*Shutin for 70-hr Buildup and LLT ($Q = 25,290,659$ stb)

Figure 3.8. Plot of Series 3 (kh fixed) INVERT results for Pleasant Bayou Long-Term Test through January 1, 1993. Calculation is for a homogeneous model with three linear boundaries and correspond to the input data in Table 3.5.

4 Gladys McCall

There have been six periods during the history of the Gladys McCall test well when downhole pressure/temperature transient measurements were recorded. Pritchett and Riney (1985) reported the results of the short-term flow test of sand zone 9 (15,508–15,636 ft) from March 21 to April 14, 1983. The five tests during the long-term testing of sand 8 (15,158–15,490 ft) are as follows:

1. October 7, 1983 to November 30, 1983
Reservoir limits test
(drawdown/buildup)
2. April 9, 1985 to April 12, 1985
79-hr test
(buildup only)
3. January 23, 1986 to January 27, 1986
92-hr test
(buildup only)
4. October 25, 1987 to November 3, 1987
Multi-rate test
(drawdown/buildup)
5. October 10, 1991 to October 16, 1991
Final diagnostic test
(drawdown/buildup)

The well was shut on October 29, 1987 and the pressure transient measurements continued until the bottomhole gauge was removed on November 3, 1987 at the conclusion of the multi-rate portion of the Long Term Test (LTT). The well remained shut until October 1991 and the pressure recovery was monitored by isolated bottomhole pressure/

temperature measurements made at increasing time intervals between logs. The well was reentered in October 1991 in preparation for the Final Diagnostic Test (FDT) undertaken by DOE to help resolve questions that arose during the analysis of the test data from the eight year depletion and recovery of the Gladys McCall reservoir.

A traditional graphical method was employed earlier in a simultaneous analysis of the pressure transient data from the first four of the five tests. Figure 4 of Appendix A compares the data plots ($\Delta p/\Delta q$ vs $\log \Delta t$) for the 79-hr, 92-hr and multi-rate tests. All were considered to be reasonably approximated (prior to the onset of the effects of earlier flow rate changes and reservoir boundaries) by lines with the common slope $m' = 1.75 \times 10^{-3}$ psi/sep b/d. Analogous plots for the drawdown and buildup portions of the RLT show that both early time semilog plots are approximated by straight lines with the common slope $m' = 1.13 \times 10^{-3}$ psi/sep b/d. An increase in m' implies a corresponding decrease in the kh value from the time of the original 1983 RLT (kh = 44,090 md-ft) to a value of kh = 28,340 md-ft at the time of the 79-hr (1985), 92-hr (1986) and MRT (1987).

Our earlier modeling work (see Appendix A) attributed the reduction in kh to partial plugging of sand zone 8 during an aborted downhole scale inhibitor pill injection episode in May 1985, prior to the 79-hr bottomhole pressure transient test. A rather complete discussion of the surface pressure data recordings following the episode has been

presented (Riney, 1988); that paper is included here as Appendix C for completeness. The basis for the hypothesized plugging and subsequent partial cleaning out of a fraction of the precipitates in the pores is presented along with pertinent surface data (Figure 2 in Appendix C). The hypothesized plugging in conjunction with a shale stringer known to be located near the center of the sand (see Figure 2 in Appendix A) would explain the kh reduction.

4.1 FINAL DIAGNOSTIC TEST

During October 1991 the Gladys McCall well was flowed twice as part of the Final Diagnostic Test. On October 1 flow was started to clean out the well and to perform a spinner survey to determine the fluid entry distribution across the perforated interval of sand zone 8. The spinner log was run on October 2 with the well producing at a constant rate of ~4800 stb/d.* Total production during the October 1–2 test period was 5954 stb. The second flow was from October 10 to 14 to obtain downhole pressure transient data to determine the kh value following the four-year shutin period (October 1987 to October 1991). The total production during the four day constant-rate (5958 stb/d) drawdown test of October 10–14 was 23,850 stb.

Interpretation of the spinner log data (Randolph, *et al.*, 1991) provides the following estimates for the percent of flow entering the wellbore in each of the indicated intervals of sand zone 8 (15,158–15,490 ft):

15,150–15,200	19.5%
15,200–15,250	18.0%
15,250–15,300	20.3%
15,300–15,350	5.3%
15,350–15,400	15.9%
Below 15,400	21.0%

The results indicate that at the time of the measurement (October 2, 1991) there was communication between the formation and the wellbore both above and below the shale stringer located near the middle of sand 8 (Figure 2 in Appendix A).

A Panex P/T gauge was lowered to 15,160 ft in the cleaned out, shutin well on October 9, 1991 and allowed to stabilize overnight. The stable values recorded at 15,160 ft were

$$P = 12,096 \text{ psia} \quad T = 294.4^{\circ}\text{F.}$$

The well was opened to flow at 10:57:24 on October 10 and flowed at a steady rate of 5958 stb/d until shutin at 11:01:37 on October 14, 1991. Bottomhole pressure and temperature were recorded during the ~96 hours of drawdown and for ~46 hours of buildup subsequent to shutin. At the time of shutin the values recorded at 15,160 ft while the well was flowing were

$$P = 11,981 \text{ psia} \quad T = 294.4^{\circ}\text{F.}$$

Attempts to monitor the pressure buildup by isolated bottomhole P/T logs were made on October 19 (11:25), October 31 (15:44) and

* In Appendix A flow rates are given in separator barrels per day (sep b/d) as reported by the well operator at that time. Here we present the FDT flow rates in standard barrels per day (stb/d) as reported by IGT. The corresponding formation factors are $B = 0.984 \text{ res b/sep b}$ and $B_o = 1.043 \text{ res b/std b}$ ($B_f = B/B_o = 0.944 \text{ std b/sep b}$). Flow rates for the other tests are kept in sep b/d.

November 4 (13:59). Under normal field conditions errors in gauge placement can introduce error of about 25 psi. Since the contractor (M.L. Cooke) replaced the wireline prior to the last two logs, recorded depths for these measurements are highly suspect; the recordings reported for pressure at 15,160 ft on October 31 (12,109 psia) and November 4 (12,114 psia) are larger than the stable pressure measured at that depth prior to starting the drawdown test. It is likely that the new cable stretched under the wellbore conditions. In any case, the isolated P/T log recordings are considered useless for analysis purposes.

Figure 4.1 shows semilog plots of $\Delta p/\Delta q$ vs Δt for the drawdown and buildup portions for both the 1983 RLT and the 1991 FDT. It is apparent that these data plots approximate straight lines of about the same slope $m' = 1.19 \times 10^{-3}$ psi/~/(stb/d). Comparison with the data plots in Figure 4 of Appendix A show that this slope is much smaller than the common slope of the lines used to approximate the data from the three intervening tests: 79-hr (1985), 92-hr (1986) and MRT (1987). According to the traditional graphical method of pressure transient analysis, the reduction in kh during the course of the production testing had apparently been reversed by the time of the FDT.

4.2 AUTOMATED INVERSION OF PRESSURE TRANSIENT DATA

The spinner test has shown that sand zone 8 is in communication with the wellbore above and below the shale stringer as of October 1991. Since there is no known mechanism for the presumed plugging of the formation (see Figure 2 in Appendix A) to have been removed during the long-term shutin test (November 1987–October 1991), the data from all five pressure transient tests have been reanalyzed using the data inversion

package INVERT. All data were corrected to a common datum level of 15,100 ft.

One purpose of the INVERT calculations is to examine the possibility that the decrease in kh is a reflection of nonlinear reservoir formation behavior at Gladys McCall. Nonlinear rock formation response might arise from overpressure hydraulic fracturing during the original drilling of the well or during the subsequent injection of scale inhibitor pills. Nonlinear formation behavior could also result from changes in the effective stress as the pore fluid pressure is lowered during depletion and increased during recovery periods. In either case it is reasonable to assume that any nonlinear effects are largest near the wellbore (See discussion of the skin factor variations in Appendix A). Moreover, the pressure excursions during each of the relatively brief bottomhole pressure transient tests are small compared to the pressure changes during the total depletion/recovery phases of the Gladys McCall test history. This makes it reasonable to analyze the bottomhole pressure transient data using linear response solution methods even though the long-term depletion/recovery behavior might exhibit nonlinear response.

A second purpose of the INVERT calculations is to provide an objective mathematical process for evaluating the kh values for each of the pressure transient tests. As pointed out by Ramey (1992), the use of two graphical methods to analyze the same well-test data often yields different answers. Computer-aided interpretation helps with the nonuniqueness problem; many possible models can be tested and statistical measures used to select the best fit of the models tested.

Preliminary calculations with INVERT were made using the "Single Porosity-Finite Wellbore" (Homogeneous Model) and "Composite System" (Composite Model) models

Figure 4.1. Bottomhole pressure transient data from 1983 RLT and 1991 FDT at the Gladys McCall well. Vertical displacement reflects change in the skin factor (s).

listed in Table 2.1. For the Homogeneous Model it was not possible to get satisfactory matches to the data sets regardless of the number of linear boundaries selected even though both impermeable and leaky (constant pressure) boundaries were tried. This is consistent with our experience in the reservoir simulation history-matching calculations described in Appendix A. To match the pressure transient data a model was employed in which sand 8 is assumed to be a narrow strip, lying between two parallel impermeable boundaries, and the permeability away from the well was assumed to decrease by a factor of seven from the near-well value. Although the model assumed in those calculations (see Figure 7 in Appendix A) was somewhat arbitrary and non-unique, the simulations demonstrated that the effective kh product of the Gladys McCall formation must decrease dramatically away from the well in order to match the test data. This requirement can be met using a Composite Model for the INVERT calculations.

During the 1987 MRT (the shutin portion of the MRT comprises the early part of the LTT) the original ("old") gauge was observed to drift and was replaced by a "new" gauge during the bottomhole pressure transient measurements. In Appendix A the old gauge data were "adjusted for drift" and the "corrected" values plotted (Figure 4 of Appendix A) as "LTT-Drawdown"; the buildup recordings using the new gauge are plotted there as "LTT-Buildup". Our attempts to match both these drawdown and buildup sets of data using INVERT proved fruitless. The corrected LTT-Drawdown data are not compatible with the LTT-Buildup data measured with the new gauge. We now conclude that the "corrected" old gauge data are corrupted and have chosen to consider the LTT-Buildup (MRT data) as the only valid data available.

Preliminary regression calculations with INVERT demonstrated that reasonably good matches to the valid data from each of the five pressure transient tests could be obtained using a Composite Model (with discontinuity in formation properties at radial distance R_d) and no boundaries. Subsequent calculations employed two parallel impermeable boundaries to further improve the results. The parameters occurring in the model are as follows:

$(kh)_1, (\phi C_l h)_1, C, s, P_p, (kh)_2, (\phi C_l h)_2, Y_c, Y_d$
(nomenclature in Table 2.1).

Note, for these Gladys McCall calculations, INVERT was modified to directly use the formation properties in the outer region $[(kh)_2, (\phi C_l h)_2]$ as calculational parameters, rather than the ratios γ and δ listed in Table 2.1. This allowed the inversion calculations to be made for the five pressure transient tests while holding the formation parameters fixed. If any nonlinear formation response occurred during the test history of the Gladys McCall well, the effect would likely be confined to a near-wellbore region; any changes in the properties in the far-field should be negligible.

In the present single-well application, the parameters Y_c and Y_d denote the distances from the test well to linear boundaries (if present in the model) to the top (Y_c) and bottom (Y_d). For orientation purposes they may be considered as east-west faults corresponding to the direction of the major growth faults mapped at Gladys McCall (see Figure 1 in Appendix A). However, it must be emphasized that the models employed in the INVERT calculations are not meant to approximate actual reservoir geology, nor are the far-field ($R > R_d$) reservoir properties meant to approximate the actual values. The far-field properties and the dimensions R_d, Y_c and Y_d are chosen such that

the model mimics the effects of the actual far-field reservoir on the near-field response so that the pressure transient data can be used to evaluate the near-field reservoir properties.

The following input parameters were kept fixed at the values used in the graphical pressure transient analysis presented in Appendix A: $r_w = 8.89 \times 10^{-2}$ m (0.2917 ft), $\mu = 3.1 \times 10^{-4}$ Pa-s (0.31 cp) and $\rho = 1030.50$ kg/m³. The base case calculations used the values $\phi = 0.16$, $C_i = 9.094 \times 10^{-10}$ Pa⁻¹ (6.27 $\times 10^{-6}$ psi⁻¹) employed in Appendix A and the value $kh = 13.439$ D-m (44,090 md-ft), estimated there from the RLT data, as near-well input parameters in INVERT.

Two series of inversion calculations were made using the Composite Model with no linear boundaries: in Series 1 the value of $(\phi C_i h)_1$ was fixed at the value used in the graphical analysis, *i.e.*, $(\phi C_i h)_1 = 1.4724 \times 10^{-8}$ m/Pa. The RLT base calculation in Series 1 used $(kh)_1 = 13.439$ D-m and arrived at values of R_d , $(\phi C_i h)_2$ and $(kh)_2$ by regression that provides the best match to the data for the infinite Composite Model. The other four pressure transient data sets in Series 1 were made keeping these far-field properties $[(\phi C_i h)_2, (kh)_2]$ fixed; the values of $(kh)_1$, s , C , and R_d were treated as free parameters in the calculations. As discussed in Section 3 of this report, the "effective initial pressure" (P_i) is also considered a free parameter in the INVERT calculations for tests (79-hr, 92-hr and MRT) where previous flow rate changes and boundary effects preclude the Composite Model from matching the full test history.

In Series 2 the near-well storage coefficient, $(\phi C_i h)_1$, was made a free parameter also, and the INVERT calculations were

repeated for each of the five pressure transient tests. The results for Series 1 and 2 are summarized in Table 4.1.

An additional two series of INVERT calculations were made using two parallel boundaries (Y_c and Y_d). The RLT base case calculation in Series 3 fixed the values of $(\phi C_i h)_1 = 1.4724 \times 10^{-8}$ m/Pa and $kh = 13.439$ D-m and arrived at values of R_d , $(\phi C_i h)_2$, $(kh)_2$, Y_c and Y_d by regression that represent the best solution for the Composite Model with two linear boundaries. During the regression the parameters Y_c and Y_d evolved to equal values. INVERT calculations for the other four data sets in Series 3 were made keeping the far-field properties $[(\phi C_i h)_2, (kh)_2]$ and boundary distances $[Y_c, Y_d]$ fixed; the values of $(kh)_1$, s , C and R_d were free parameters in these calculations during the regression calculations. The "effective initial pressure" was again considered a free parameter for the regression calculations for the 79-hr, 92-hr and MRT data sets.

In Series 4 the near-well storage coefficient, $(\phi C_i h)_1$, was also treated as a free parameter. The results for Series 3 and 4 are summarized in Table 4.1 together with the results for Series 1 and 2.

In each of the five cases the match to the pressure data is much better when the two linear boundaries are included (Series 3 and 4). Reports are given in Tables 4.2a-e (Series 3) and Tables 4.3a-e (Series 4) that summarize the results of the INVERT calculations for these series. The associated plots, comparing the results of the regression calculations with the pressure transient data for each of the five tests are presented in Figures 4.2a-e (Series 3) and Figures 4.3a-e (Series 4). The agreement

between the Composite Model solution and the pressure transient data is excellent in each case for both Series 3 and Series 4.

Comparison of Series 3 and 4 results shows that treating $(\phi C_r h)_1$ as a free parameter in Series 4 had little effect for the RLT, 79-hr and 92-hr tests. The regressions for Series 4 gave larger values for $(\phi C_r h)_1$ than the corresponding Series 3 calculations in the case of the MRT and FDT data sets. Since the use of the additional free parameter in Series 4 does not significantly improve the regression results, the Series 3 calculations for a fixed

value $[(\phi C_r h)_1 = 1.47239 \times 10^{-8} \text{ m/Pa}]$ are preferred.

In summary, we now believe that there was a decrease in the near-well kh value only at the time of the 79-hr (1985) and 92-hr (1986) tests. By the time of the MRT (1987), the value of kh had already recovered to its value at the time of the RLT (1983). That is, we believe that the partial plugging of sand 8 during May 1985 had been effectively removed by the flowing brine prior to the start of the 1987 shutin for the LTT.

Table 4.1. Summary of inversion calculations for Gladys McCall pressure transient welltest data. Cases include Composite Model with no boundaries (infinite) and Composite Model with two linear boundaries ($Y_c = Y_d = 648.34 \text{ m}$).

Test	$(\phi C_r h)_1$ Fixed Value			$(\phi C_r h)_1$ Free Parameter		
	$(kh)_1$ (D-m)	$(\phi C_r h)_1$ (cm/Mpa)	R_d (m)	$(kh)_1$ (D-m)	$(\phi C_r h)_1$ (cm/Mpa)	R_d (m)
No Linear Boundaries: $(kh)_2$ and $(\phi C_r h)_2$ Fixed Values						
	Series 1			Series 2		
RLT	13.44	1.472	593	13.38	1.752	562
79-hr	7.41	1.472	638	7.93	0.995	658
92-hr	8.90	1.472	577	9.55	1.237	577
MRT	11.30	1.472	558	11.57	1.303	559
FDT	11.16	1.472	537	11.32	1.451	539
Two Linear Boundaries: Y_c, Y_d , and $(\phi C_r h)_2$ Fixed Values						
	Series 3			Series 4		
RLT	13.44	1.472	503	13.44	1.488	502
79-hr	7.69	1.472	501	7.69	1.472	501
92-hr	8.86	1.472	499	8.86	1.479	499
MRT	13.03	1.472	427	11.99	1.948	427
FDT	12.96	1.472	464	12.49	1.973	420

Table 4.2a. Reports of Series 3 $[(\phi C_h)_1 \text{ fixed}]$ INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2a.

4.2a. RLT with $(\phi C_h)_1 = 1.472 \text{ cm/MPa}$.

REGRESSION RESULTS: RLT Series 3, $(\phi C_h)_1$ Fixed

CmgMod:L2 (P_o , kh, C_t fixed)

1	Initial Pressure, bar	=	8.8143E+02	±	0.0000E+00
2	Permeability-Thickness, Darcy-m	=	1.3439E+01	±	0.0000E+00
3	Storage Coefficient, m/Pa	=	1.4724E-08	±	0.0000E+00
4	Skin	=	2.4618E+00	±	5.0406E-02
5	Wellbore Storage, m ³ /Pa	=	8.9231E-07	±	6.4836E-08
11	Y_c , m	=	6.4834E+02	±	3.8869E+09
12	Y_d , m	=	6.4834E+02	±	3.8869E+09
13	Radius at Discontinuity, m	=	5.0259E+02	±	3.6941E+00
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	±	4.4167E-02
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	±	9.6760E-10

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 7.591747E+00

STANDARD ERROR (bar) = 1.983317E-01

Correlation Matrix

1.0000	0.2592	0.0000	0.0000	-0.0377	0.2659	0.1289
0.2592	1.0000	0.0000	0.0000	-0.0156	0.0549	0.0837
0.0000	0.0000	1.0000	-1.0000	0.0000	0.0000	0.0000
0.0000	0.0000	-1.0000	1.0000	0.0000	0.0000	0.0000
-0.0377	-0.0156	0.0000	0.0000	1.0000	-0.0508	-0.1148
0.2659	0.0549	0.0000	0.0000	-0.0508	1.0000	-0.5733
0.1289	0.0837	0.0000	0.0000	-0.1148	-0.5733	1.0000

Flow Rate Input Data

Time (hrs)	Rate (kg/s)
0.000000E+00	26.03
0.505520E+03*	0.

*Shutin for RLT Buildup ($Q = 297,783 \text{ bbls}$)

a. RLT with $(\phi C_p h)_1 = 1.472 \text{ cm/MPa}$.

Figure 4.2a. Plots of Series 3 [$(\phi C_p h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2a.

Table 4.2b. Reports of Series 3 $[(\phi C_t h)_1 \text{ fixed}]$ INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2b.

4.2b. 79-hr test with $(\phi C_t h)_1 = 1.472 \text{ cm/MPa}$.

REGRESSION RESULTS: 79-hr Series 3, $(\phi C_t h)_1$ Fixed

CmpMod:L2 $[(\phi C_t h)_1, Y_C, Y_d, (\phi C_t h)_2, kh_2 \text{ fixed}]$

1	Initial Pressure, bar	=	8.8269E+02	±	3.0485E-01
2	Permeability-Thickness, Darcy-m	=	7.6942E+00	±	4.5743E-01
3	Storage Coefficient, m/Pa	=	1.4724E-08	±	0.0000E+00
4	Skin	=	7.0136E+00	±	8.4804E-01
5	Wellbore Storage, m ³ /Pa	=	1.3097E-07	±	2.4292E-08
11	Y_C , m	=	6.4834E+02	±	0.0000E+00
12	Y_d , m	=	6.4834E+02	±	0.0000E+00
13	Radius at Discontinuity, m	=	5.0138E+02	±	1.2414E+00
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	±	0.0000E+00
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	±	0.0000E+00

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 2.915903E+01

STANDARD ERROR (bar) = 5.569583E-01

Correlation Matrix

1.0000	-0.7823	-0.7338	-0.5733	-0.6639
-0.7823	1.0000	0.9675	0.4336	0.2892
-0.7338	0.9675	1.0000	0.4026	0.3040
-0.5733	0.4336	0.4026	1.0000	0.7144
-0.6639	0.2892	0.3040	0.7144	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.	26.0300
505.5000	0.0000
1316.9200	27.8560
12529.0000	27.6010
13043.2500	0.0000
13049.1700	28.3800
13186.7700*	0.0000

*Shutin for 79-hr Buildup ($Q = 7,788,221 \text{ bbls}$)

b. 79-hr test with $(\phi C_h)_1 = 1.472 \text{ cm/MPa}$.

Figure 4.2b. Plots of Series 3 [$(\phi C_h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2b.

Table 4.2c. Reports of Series 3 $[(\phi C_h)_1 \text{ fixed}]$ INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2c.

4.2c. 92-hr test with $(\phi C_h)_1 = 1.472 \text{ cm/MPa}$.

REGRESSION RESULTS: 92-hr Series 3, $(\phi C_h)_1$ Fixed

CmpMod: L2 $[(\phi C_h)_1, Y_C, Y_d, (\phi C_h)_2, kh_2 \text{ fixed}]$

1	Initial Pressure, bar	=	8.8113E+02	± 1.6535E-01
2	Permeability-Thickness, Darcy-m	=	8.8576E+00	± 3.5536E-01
3	Storage Coefficient, m/Pa	=	1.4724E-08	± 0.0000E+00
4	Skin	=	5.6429E+00	± 5.3487E-01
5	Wellbore Storage, m ³ /Pa	=	3.2442E-07	± 2.5456E-08
11	Y_C , m	=	6.4834E+02	± 0.0000E+00
12	Y_d , m	=	6.4834E+02	± 0.0000E+00
13	Radius at Discontinuity, m	=	4.9872E+02	± 1.6334E-01
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	± 0.0000E+00
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	± 0.0000E+00

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 1.817309E+00

STANDARD ERROR (bar) = 1.906468E-01

Correlation Matrix

1.0000	-0.8795	-0.7915	-0.1987	-0.0880
-0.8795	1.0000	0.9668	0.4074	-0.1574
-0.7915	0.9668	1.0000	0.3668	-0.1951
-0.1987	0.4074	0.3668	1.0000	-0.4099
-0.0880	-0.1574	-0.1951	-0.4099	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.00	25.612
13413.92	41.957
19659.25	43.060
19709.75	0.00
19736.50	19.24
20134.50*	0.00

*Shutin for 92-hr Buildup ($Q = 13,951,336 \text{ bbls}$)

c. 92-hr test with $(\phi C_h)_1 = 1.472 \text{ cm/MPa}$.

Figure 4.2c. Plots of Series 3 $[(\phi C_h)_1 \text{ fixed}]$ INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2c.

Table 4.2d. Reports of Series 3 $[(\phi C_t h)_1 \text{ fixed}]$ INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2d.

4.2d. MRT test with $(\phi C_t h)_1 = 1.472 \text{ cm/MPa}$.

REGRESSION RESULTS: MRT Series 3, $(\phi C_t h)_1$ Fixed

CmpMod: L2 $[(\phi C_t h)_1, Y_c, Y_d, (\phi C_t h)_2, kh_2 \text{ fixed}]$

1	Initial Pressure, bar	=	8.6571E+02	± 2.2236E-01
2	Permeability-Thickness, Darcy-m	=	1.3030E+01	± 1.3817E+00
3	Storage Coefficient, m/Pa	=	1.4724E-08	± 0.0000E+00
4	Skin	=	7.8909E+00	± 1.5806E+00
5	Wellbore Storage, m ³ /Pa	=	7.7977E-07	± 5.7119E-08
11	Y_c , m	=	6.4834E+02	± 0.0000E+00
12	Y_d , m	=	6.4834E+02	± 0.0000E+00
13	Radius at Discontinuity, m	=	4.2717E+02	± 1.1318E+00
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	± 0.0000E+00
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	± 0.0000E+00

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 3.541944E+00

STANDARD ERROR (bar) = 2.144744E-01

Correlation Matrix

1.0000	-0.5636	-0.5440	-0.1980	-0.7861
-0.5636	1.0000	0.9904	0.4260	0.0066
-0.5440	0.9904	1.0000	0.3679	0.0055
-0.1980	0.4260	0.3679	1.0000	-0.0002
-0.7861	0.0066	0.0055	-0.0002	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.0000	35.6667
31658.0000	18.0026
35484.0389	27.6600
35496.7333	22.8660
35502.8472	18.2844
35598.8050*	0.0000

*Shutin for MRT Buildup ($Q = 27,182,151 \text{ bbls}$)

d. MRT with $(\phi C_p h)_1 = 1.472 \text{ cm/MPa}$.

Figure 4.2d. Plots of Series 3 [$(\phi C_p h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2d.

Table 4.2e. Reports of Series 3 $[(\phi C_t h)_1 \text{ fixed}]$ INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.2e.

4.2e. FDT with $(\phi C_t h)_1 = 1.472 \text{ cm/MPa}$.

REGRESSION RESULTS: FDT Series 3, $(\phi C_t h)_1$ Fixed

CmpMod: L2 $[(P_o, (\phi C_t h)_1, Y_c, Y_d, (\phi C_t h)_2, kh_2 \text{ fixed})]$

1	Initial Pressure, bar	=	8.3211E+02	± 0.0000E+00
2	Permeability-Thickness, Darcy-m	=	1.2958E+01	± 3.3703E-01
3	Storage Coefficient, m/Pa	=	1.4724E-08	± 0.0000E+00
4	Skin	=	5.5243E+00	± 3.4465E-01
5	Wellbore Storage, m ³ /Pa	=	7.9924E-07	± 2.8786E-07
11	Y_c , m	=	6.4834E+02	± 0.0000E+00
12	Y_d , m	=	6.4834E+02	± 0.0000E+00
13	Radius at Discontinuity, m	=	4.6448E+02	± 7.1153E-01
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	± 0.0000E+00
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	± 0.0000E+00

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 2.662200E-01

STANDARD ERROR (bar) = 4.241207E-02

Correlation Matrix

1.0000	0.9975	0.5760	-0.0493
0.9975	1.0000	0.5817	-0.0526
0.5760	0.5817	1.0000	-0.0285
-0.0493	-0.0526	-0.0285	1.0000

Flow Rate Input Data

Time (hrs)	Rate (kg/s)
0.000000E+00	11.30
0.960710E+02*	0.

*Shutin for FDT Buildup ($Q_1 = 27,182,151 \text{ bbls}$)

e. FDT with $(\phi C_h)_1 = 1.472 \text{ cm/MPa}$.

Figure 4.2e. Plots of Series 3 [$(\phi C_h)_1$ fixed] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.2e.

Table 4.3a. Reports of Series 4 $[(\phi C_t h)_1 \text{ free}]$ INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3a.

4.3a. RLT with $(\phi C_t h)_1$ a free parameter.

REGRESSION RESULTS: RLT Series 4, $(\phi C_t h)_1$ Free

CmgMod:L2 $[Y_C, Y_d, (\phi C_t h)_2, kh_2 \text{ fixed}]$

1	Initial Pressure, bar	=	8.8143E+02	±	0.0000E+00
2	Permeability-Thickness, Darcy-m	=	1.3439E+01	±	0.0000E+00
3	Storage Coefficient, m/Pa	=	1.4879E-08	±	3.2896E-10
4	Skin	=	2.4786E+00	±	5.4289E-02
5	Wellbore Storage, m ³ /Pa	=	8.9819E-07	±	6.4216E-08
11	Y_C , m	=	6.4834E+02	±	0.0000E+00
12	Y_d , m	=	6.4834E+02	±	0.0000E+00
13	Radius at Discontinuity, m	=	5.0185E+02	±	2.4693E+00
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	±	0.0000E+00
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	±	0.0000E+00

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 7.566694E+00

STANDARD ERROR (bar) = 1.980042E-01

Correlation Matrix

1.0000	0.5601	0.1547	-0.8341
0.5601	1.0000	0.2668	-0.4002
0.1547	0.2668	1.0000	-0.0719
-0.8341	-0.4002	-0.0719	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.000000E+00	26.03
0.505520E+03*	0.

*Shutin for RLT Buildup ($Q = 297,783$ bbls)

a. RLT with $(\phi C_p h)_1$ a free parameter.

Figure 4.3a. Plots of Series 4 [$(\phi C_p h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3a.

Table 4.3b. Reports of Series 4 ($(\phi C_p h)_1$ free) INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3b.

4.3b. 79-hr test with $(\phi C_p h)_1$ a free parameter.

REGRESSION RESULTS: 79-hr Series 3, $(\phi C_p h)_1$ Free

CmpMod: L2 [Y_c , Y_d , kh_2 , $(\phi C_p h)_2$ fixed]

1	Initial Pressure, bar	=	8.8269E+02	±	3.3249E-01
2	Permeability-Thickness, Darcy-m	=	7.6942E+00	±	5.9886E-01
3	Storage Coefficient, m/Pa	=	1.4724E-08	±	2.8791E-09
4	Skin	=	7.0136E+00	±	1.0071E+00
5	Wellbore Storage, m ³ /Pa	=	1.3097E-07	±	2.4904E-08
11	Y_c , m	=	6.4834E+02	±	0.0000E+00
12	Y_d , m	=	6.4834E+02	±	0.0000E+00
13	Radius at Discontinuity, m	=	5.0138E+02	±	1.2567E+00
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	±	0.0000E+00
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	±	0.0000E+00

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 2.915903E+01

STANDARD ERROR (bar) = 5.569583E-01

Correlation Matrix

1.0000	-0.3062	-0.3871	-0.3671	-0.4433	-0.5638
-0.3062	1.0000	-0.6403	0.9699	0.4512	0.2941
-0.3871	-0.6403	1.0000	-0.5319	-0.1944	-0.1146
-0.3671	0.9699	-0.5319	1.0000	0.4378	0.3167
-0.4433	0.4512	-0.1944	0.4378	1.0000	0.7185
-0.5638	0.2941	-0.1146	0.3167	0.7185	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.	26.0300
505.5000	0.0000
1316.9200	27.8560
12529.0000	27.6010
13043.2500	0.0000
13049.1700	28.3800
13186.7700*	0.0000

*Shutin for 79-hr Buildup ($Q = 7,788,221$ bbls)

b. 79-hr test with $(\phi C_i h)_1$ a free parameter.

Figure 4.3b. Plots of Series 4 $[(\phi C_i h)_1 \text{ free}]$ INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3b.

Table 4.3c. Reports of Series 4 ($(\phi C_t h)_1$ free) INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3c.

4.3c. 92-hr test with $(\phi C_t h)_1$ a free parameter.

REGRESSION RESULTS: 92-hr Series 4, $(\phi C_t h)_1$ Free

CmpMod: L2 [$(Y_c, Y_d, (\phi C_t h)_2, kh_2$ fixed]

1	Initial Pressure, bar	=	8.8114E+02	±	2.8775E-01
2	Permeability-Thickness, Darcy-m	=	8.8605E+00	±	3.9906E-01
3	Storage Coefficient, m/Pa	=	1.4785E-08	±	2.0860E-09
4	Skin	=	5.6422E+00	±	6.1899E-01
5	Wellbore Storage, m ³ /Pa	=	3.2379E-07	±	2.6289E-08
11	Y_c , m	=	6.4834E+02	±	0.0000E+00
12	Y_d , m	=	6.4834E+02	±	0.0000E+00
13	Radius at Discontinuity, m	=	4.9865E+02	±	1.6727E-01
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	±	0.0000E+00
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	±	0.0000E+00

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 1.815668E+00

STANDARD ERROR (bar) = 1.924953E-01

Correlation Matrix

1.0000	-0.1384	0.8089	-0.0359	-0.0272	-0.0886
-0.1384	1.0000	0.4116	0.9693	0.4137	-0.1622
0.8089	0.4116	1.0000	0.4637	0.1102	-0.0457
-0.0359	0.9693	0.4637	1.0000	0.3676	-0.1964
-0.0272	0.4137	0.1102	0.3676	1.0000	-0.4080
-0.0886	-0.1622	-0.0457	-0.1964	-0.4080	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.00	25.612
13413.92	41.957
19659.25	43.060
19709.75	0.00
19736.50	19.24
20134.50*	0.00

*Shutin for 92-hr Buildup ($Q = 13,951,336$ bbls)

c. 92-hr test with $(\phi C_p h)_1$ a free parameter.

Figure 4.3c. Plots of Series 4 [$(\phi C_p h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3c.

Table 4.3d. Reports of Series 4 ($(\phi C_t h)_1$ free) INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3d.

4.3d. MRT test with $(\phi C_t h)_1$ a free parameter.

REGRESSION RESULTS: MRT Series 4, $(\phi C_t h)_1$ Free

CmpMod: L2 [Y_C , Y_d , kh_2 , $(\phi C_t h)_2$ fixed]

1	Initial Pressure, bar	=	8.6626E+02	±	1.2021E+00
2	Permeability-Thickness, Darcy-m	=	1.1987E+01	±	1.1366E+00
3	Storage Coefficient, m/Pa	=	1.9482E-08	±	2.5694E-09
4	Skin	=	6.9111E+00	±	1.2690E+00
5	Wellbore Storage, m ³ /Pa	=	7.6664E-07	±	5.2753E-08
11	Y_C , m	=	6.4834E+02	±	0.0000E+00
12	Y_d , m	=	6.4834E+02	±	0.0000E+00
13	Radius at Discontinuity, m	=	4.2742E+02	±	7.4350E+00
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	±	0.0000E+00
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	±	0.0000E+00

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 3.104856E+00

STANDARD ERROR (bar) = 2.008054E-01

Correlation Matrix

1.0000	-0.3016	0.2988	-0.2762	-0.0954	-0.9592
-0.3016	1.0000	-0.4169	0.9869	0.4328	0.1102
0.2988	-0.4169	1.0000	-0.3492	-0.1258	-0.0390
-0.2762	0.9869	-0.3492	1.0000	0.3752	0.1028
-0.0954	0.4328	-0.1258	0.3752	1.0000	0.0302
-0.9592	0.1102	-0.0390	0.1028	0.0302	1.0000

Flow Rate Input Data

Time (hrs)	Rate (kg/s)
0.0000	35.6667
31658.0000	18.0026
35484.0389	27.6600
35496.7333	22.8660
35502.8472	18.2844
35598.8050*	0.0000

*Shutin for MRT Buildup ($Q = 27,182,151$ bbls)

d. MRT with $(\phi C_p h)_1$ a free parameter.

Figure 4.3d. Plots of Series 4 [$(\phi C_p h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3d.

Table 4.3e. Reports of Series 4 ($(\phi C h)_1$ free) INVERT results for Gladys McCall pressure transient tests. Calculations are for Composite Model with two linear boundaries; results correspond to plot in Figure 4.3e.

4.3e. FDT with $(\phi C h)_1$ a free parameter.

REGRESSION RESULTS: FDT Series 4, $(\phi C h)_1$ Fixed

CmpMod: L2 [P_o , Y_c , Y_d , $(\phi C h)_1$, kh2 fixed]

1	Initial Pressure, bar	=	8.3211E+02	±	0.0000E+00
2	Permeability-Thickness, Darcy-m	=	1.2487E+01	±	4.5445E-01
3	Storage Coefficient, m/Pa	=	1.9727E-08	±	2.7098E-10
4	Skin	=	5.2169E+00	±	4.5334E-01
5	Wellbore Storage, m ³ /Pa	=	6.5143E-07	±	3.7138E-07
11	Y_c , m	=	6.4834E+02	±	0.0000E+00
12	Y_d , m	=	6.4834E+02	±	0.0000E+00
13	Radius at Discontinuity, m	=	4.1974E+02	±	1.1316E+00
14	Permeability-Thickness #2, Darcy-m	=	5.6305E-01	±	0.0000E+00
15	Storage Coefficient #2, m/Pa	=	1.4905E-08	±	0.0000E+00

(for 95% confidence interval)

SUM SQUARE ERRORS (bar**2) = 2.188842E-01

STANDARD ERROR (bar) = 3.845708E-02

Correlation Matrix

1.0000	-0.7643	0.9986	0.6633	0.1300
-0.7643	1.0000	-0.7478	-0.3837	-0.2041
0.9986	-0.7478	1.0000	0.6721	0.1207
0.6633	-0.3837	0.6721	1.0000	0.0464
0.1300	-0.2041	0.1207	0.0464	1.0000

Flow Rate Input Data

Time(hrs)	Rate(kg/s)
0.000000E+00	11.30
0.960710E+02*	0.

*Shutin for FDT Buildup ($Q_1 = 23,850$ bbls)

e. FDT test with $(\phi C_h)_1$ a free parameter.

Figure 4.3e. Plots of Series 4 [$(\phi C_h)_1$ free] INVERT results for Gladys McCall pressure transient tests. Calculations are for a Composite Model with two boundaries and correspond to the input data listed in Table 4.3e.

5 Conclusions and Discussion

Automated inversion of pressure transient data from the Pleasant Bayou and Gladys McCall geopressured test wells has allowed the resolution of several outstanding questions concerning the two reservoirs. The added accuracy of the interpretation of the various data sets from each well provides convincing evidence that the formation response of each of the reservoirs behaved in an essentially linear fashion throughout its multi-year depletion/recovery test history. The only exception was in the immediate vicinity of the sandface; the skin factor in each of the wells varies during the course of its test history (see Appendices for detailed discussions of the variations and the likely causes of the variations for each well).

- a) The six bottomhole pressure transient tests of Pleasant Bayou Well No.2 over a twelve year period (1980–1992) yield estimates for the permeability-thickness product that are in excellent agreement ($kh = 3.665 \text{ D-m}$).

Inversion of the 45-day buildup portion of the 1980 RLT yields an estimate of $X_a = 869 \text{ m}$ as the distance from the well to the nearest boundary. The inversion of the data from the other five tests, of much shorter duration, yield estimates in the range $X_a = 427\text{--}503 \text{ m}$. The RLT estimate would normally be given much more credence. The failure, repair and resetting of the gauge after the first ten days of the start of the buildup test, however, may have affected the RLT data.

Calculations are employed to estimate bottomhole pressures from surface recordings subsequent to removal of the bottomhole gauge following the 1992 70-hr buildup test. These estimated values were combined with the 70-hr data to form the 111-day (from September 12, 1992 through January 1, 1993) LTT buildup test data set. The LTT data were inverted to yield an estimate of $X_a = 452 \text{ m}$. Since this is in agreement with the range of estimates from the five short-term bottomhole test, we believe the range $X_a = 427\text{--}503 \text{ m}$ to represent the best estimate for the distance from the well to the nearest boundary.

The simulation model presented in Appendix B used $L1 = 990 \text{ m}$ (Figure 3 in Appendix B) as the distance from the test well to the nearest boundary. The simulation model could probably be improved using a smaller value for $L1$. The actual location of the boundary to the south of the well is not known from the available geological information.

- b) The five bottomhole pressure transient tests of Gladys McCall Well No.2 over an eight-year period (1983–1991) yield estimates for the permeability-thickness product that differ significantly from each other. The differences, however, can be explained by the partial plugging of the near-well formation during an aborted attempt to inject a scale-inhibitor pill in May 1985, followed by subsequent

scouring out the pill precipitates by the flowing fluid during the May 1985–August 1987 production testing. The partial plugging of the near-well formation in conjunction with a known shale stringer that prevents vertical communication in sand 8 (Figure 2 in Appendix A) would reduce the apparent value of kh to about sixty percent of the original RLT value of 13.44 D-m. Inversion of the 79-hr (1985) and 92-hr (1986) buildup tests yield kh estimates of 7.69 and 8.86 D-m, respectively. Inversions of the valid MRT (1987) and FDT (1991) pressure transient data yield estimates very near the original RLT value.

The reinterpretation of the MRT data represents a correction of our earlier conclusion (in Appendix A); we now believe that the data from the first and second gauges employed during the MRT are incompatible. Data from the first (“old”) gauge during the drawdown portion of the MRT could not be adequately corrected for the observed drift in the recorded data. Only the second (“new”) gauge data are considered reliable and inversion of the buildup data it recorded yields the estimate for kh that is in agreement with estimates obtained from inversion of the RLT and FDT pressure transient data.

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A Depletion and Recovery Behavior of the Gladys McCall Geopressured Geothermal Reservoir

Depletion and Recovery Behavior of the Gladys McCall Geopressured Geothermal Reservoir

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Abstract *Many sedimentary basins throughout the world contain sealed fault blocks in which the pore fluids are at higher pressures and temperatures than normal as a consequence of their depositional environment. The U.S. Department of Energy has drilled, completed, and tested four deep research wells in selected geopressured geothermal prospects in the Texas-Louisiana Gulf Coast region to evaluate the recoverability of the thermal, hydraulic, and chemical (methane) energy in this potential energy resource. The wells are expensive and the specific energy of the fluids is relatively small, but the total recoverable energy from a single well can be extremely large. Long-term testing of the Gladys McCall No. 1 research well, located in Cameron Parish, Louisiana, U.S.A., has defined an impressively large geopressured geothermal reservoir. An integrated analysis of the test data is presented, and a numerical model is constructed that matches the available data for the 6.5-year test history of the well.*

Keywords geothermal energy, geopressured resource, reservoir engineering

Introduction

Many sedimentary basins contain formations with pore fluids at higher than hydrostatic pressures (vertical fluid-pressure gradients greater than about 0.465 psi/ft); these formations are called geopressured. The geopressured strata are comprised of under-compacted clays (or shales) and sandstones with the interstitial fluids bearing most of the overburden pressure. The pore pressure is generally well in excess of hydrostatic, and the fluids are saline, hot, and contain dissolved methane. Thus, the fluid contains energy in three forms; thermal energy, hydraulic (or pressure) energy, and chemical energy associated with the methane.

Among geopressured basins in the United States, the northern Gulf of Mexico basin has been most extensively investigated. A review of the estimates of the energy recoverable from the Gulf Coast region has been presented by Garg, Riney, and Wallace (1985). As part of its program to define the magnitude and recoverability of the geopressured-geothermal energy resource, the U.S. Department of Energy (DOE) has drilled and tested four deep research wells in the Texas-Louisiana Gulf Coast region:

- (1) Pleasant Bayou Well No. 2, Brazoria County, Texas.
- (2) Amoco Fee Well No. 1, Sweet Lake Field, Cameron Parish, Louisiana.
- (3) L. R. Sweezy Well No. 1, Parcperdue Field, Vermilion Parish, Louisiana.
- (4) Gladys McCall Well No. 1, Cameron Parish, Louisiana.

Testing of the Amoco Fee and L. R. Sweezy wells has been completed, and the wells have been plugged and abandoned. Long-term production testing of the Pleasant Bayou

well is still in progress. Reservoir pressure recovery is currently (May 1990) being monitored in the Gladys McCall well following long-term production testing of the well.

One of the objectives of the DOE program is to investigate the pressure maintenance mechanisms that operate within the reservoirs tested by the design wells. The Parcperdue reservoir was selected because of its well-defined geology and volume so that the testing could be completed within one year. Depletion testing had to be terminated, however, when excessive sand was produced from the unconsolidated formation. The Amoco Fee well exhibited a much larger than anticipated pressure-drawdown during short-term flow testing. Analysis of the downhole pressure data indicated that the well penetrated a zone of relatively high permeability but flow was constrained by either low permeability or geologic structure away from the well.

Selection of the Pleasant Bayou and the Gladys McCall well sites was based on research at the University of Texas at Austin and Louisiana State University that identified localized regions where thick, high-pressure, high-temperature sandstone masses existed as a result of isolation by growth faults, salt movement, facies boundaries, or other factors. These geologic studies (Bebout, Loucks, and Gregory 1978; Bebout 1982; Brunheld 1984) successfully identified the Pleasant Bayou and Gladys McCall prospects as large volume aquifers that could be produced for extended periods at high flow rates.

The Gladys McCall geopressured prospect lies at the western edge of the Rockefeller Wildlife Refuge about 55 miles southeast of Lake Charles in Cameron Parish, Louisiana. Preliminary studies of the geology and structure of the area were conducted by D. G. Bebout (1982) and Brunheld (1984) based on well logs from the subject well and five nearby deep wells. The approximate locations of the three major growth faults considered to control the structure of the prospect are shown at 15,500 feet in Figure 1; the east-west length of the fault block could not be determined from available information.

Recently, John (1988) reviewed the geology of the Gladys McCall prospect. Although no new geological information was available to better establish reservoir boundaries, production flow testing had established that the Gladys McCall test was drawing from a large reservoir. John's model for the depositional origin of the geopressured sand section penetrated by the Gladys McCall test well considers the entire section to be a genetic unit generated within the same channel system, consisting of interconnected channel and point bar sandstones deposited through time. When the sand supply was interrupted, shale may have been deposited locally, but the laterally extensive channel and point bar sands may still be interconnected within the genetic system. Consequently, John (1988) suggests that the whole thickness of the sand section, though appearing on the electric log as possibly different and separated sandstones, may behave as a single sand body, allowing fluid communication at shale breaks during brine production.

Gladys McCall Test Data

Gladys McCall Well No. 1 was spudded on May 27, 1981, drilled to a total depth of 16,510 ft, and plugged back to 15,831 ft. A 7-in. diameter casing string was cemented from the surface to 15,958 ft, and the well was completed with 5-in. diameter production tubing. Technadril-Fenix and Scisson (1982) managed the drilling, completion, and testing of the well until October 1985; Eaton Operating Company took over management of the well for DOE at that time. The stratigraphic section seen in the borehole consists of alternating massive sandstones and thin shales. There are approximately 1150 ft net of sand in the target Miocene sand within the 14,412 ft to 16,320 ft interval penetrated by the test well. Eleven sequentially number sand zones separated by shale breaks at the

Figure 1. Major growth faults within lower Miocene section at depth (15,500 feet) between sand zones 8 and 9 with locations of Gladys McCall No. 1 and nearby deep wells. Geologic map adapted from Technadril-Fenix and Scisson (1982).

wellbore were identified from log analysis by Technadril-Fenix and Scisson (1982). Over two-thirds of the net sand is contained in three of the eleven sand zones (nos. 2, 8, and 9). Only sands 8 and 9 have been perforated.

Sand zone 9, from 15,508 ft to 15,636 ft, was flowed from March 21, 1983, to April 14, 1983. After gas separation, the brine produced was injected into a nearby disposal well. A Panex downhole pressure/temperature gauge positioned at 15,460 ft recorded the pretest reservoir pressure of 12,911 psia and temperature of 298 °F. Because of the rapid pressure drawdown in the well, sand zone 9 was sealed off with a plug set at ~15,500 ft in preparation for testing sand zone 8.

The 7-in. casing was perforated to test sand zone 8, from 15,158 ft to 15,490 ft (sand thickness $h = 332$ ft). A Panex pressure/temperature gauge was fixed at a depth of 15,100 ft to record the initial pressure and temperature: $P_i = 12,784$ psia and $T_i = 289.2$ °F. Production started on October 7, 1983, and the test well produced over 27.3×10^6 sep bbl of brine (measured at the brine/gas separator conditions) from October 7, 1983 ($t = 0$) through October 29, 1987 ($t = 1483$ days) when the well was shut in for a long-term pressure build up test still underway (May 1990). The produced fluid was remarkably free of sand and fines over its entire production history.

Laboratory tests (Kelkar et al., 1982) under bench conditions on well-consolidated core samples from the test well gave average values for porosity and permeability of $\phi \sim 0.168$ and $k \sim 83$ md, respectively. Under simulated reservoir conditions they reported permeabilities ($k \sim 1$ to 17 md) that are much smaller than implied by actual

field measurements at the test well ($k \sim 133$ md). Kelkar et al. also reported values for the uniaxial compaction coefficient ($C_m \sim 2 \times 10^{-7} \text{ psi}^{-1}$) that are very low and inconsistent with values ($C_m \sim 8 \times 10^{-7} \text{ psi}^{-1}$) deduced from their measurements for bulk compressibility and Poisson's ratio. The corresponding values for the total formation compressibility would be $C_T = 4.0 \times 10^{-6} \text{ psi}^{-1}$ and $C_T = 7.7 \times 10^{-6} \text{ psi}^{-1}$. Because of these ambiguities, we will use a value of $C_T = 6.27 \times 10^{-6} \text{ psi}^{-1}$ based on correlations for consolidated sandstone (Earlougher 1977).

Studies by the Rice University brine research group showed that fluids produced from sand zones 8 and 9 are essentially identical. Weatherly Laboratories, Inc. reported the following properties of fluid samples recombined to approximate reservoir conditions (sand zone 8): brine compressibility $C_w \sim 2.76 \times 10^{-6} \text{ psi}^{-1}$, dynamic viscosity $\mu \sim 0.31$ cp, and bubble pressure ~ 9200 psia. The average gas-to-water ratio for the total gas production from the test well is GWR ~ 30.15 SCF/STB ($\text{ft}^3 \text{ bbl}^{-1}$ at 14.67 psia, 60.33°F). Average salinity of the brine is $\sim 97,800$ mg/l.

Although production from sand zone no. 8 by Gladys McCall Well No. 1 included numerous rate changes since initiation of the Reservoir Limits Test (RLT) on October 7, 1983 ($t = 0$), the production history may be divided into two major phases. Except for relatively short time intervals (following decreases in the flow rate), the bottomhole pressure generally decreased from the time the RLT was initiated up to April 21, 1987 ($t = 1292$ days). This period of over 3.5 years will be called the depletion phase of the reservoir response. The flow rate during the depletion phase was over 30,000 sep b/d part of the time and averaged $\sim 19,600$ sep b/d.

Starting on April 21, 1987, the flow rate of the well was lowered in four steps over a four-week period and then held at $q \sim 9800$ sep b/d until the initiation of the multi-rate flowing portion of the Long Term Test (LTT) on October 24, 1987. The well was shut on October 29 ($t = 1483$ days) in order to monitor the pressure recovery during the buildup portion of the LTT. The pressure generally increased during the 191-day period of reduced flow rate ($\sim 10,040$ sep b/d from April 21 to October 29, 1987) and has continued to increase since shut in. This total period of about 3.0 years from April 21, 1987, to the present will be called the recovery phase of the reservoir response.

An earlier article (Riney 1988) presented an analysis of the test data available at the end of the depletion phase. A conceptual model of the reservoir was constructed that depends on cross-flow at shale breaks from sands overlying sand zone 8 for the observed pressure maintenance, and a reservoir simulation model based on the cross-flow concept was developed. The present article presents analysis of the more complete data now available. This includes reanalysis of the depletion phase data in conjunction with the analysis of the new data from the recovery phase of the testing of the Gladys McCall Well No. 1. Modification of the reservoir simulation model described in the earlier article is necessary to provide a satisfactory match to the integrated data sets comprised of both the depletion and recovery phases of the test history.

Method of Analysis

The data analysis is complicated by the fact that the well initially experienced severe calcite scaling within the production tubing. Costly and time consuming acid treatments were employed on four occasions to remove the scale. Control of scaling of the well tubulars was then attempted by injecting into the formation a chemical mixture (mostly phosphonate) designed to inhibit the precipitation of calcium carbonate from the brine. The first attempt to inject the phosphonate "pill" into sand zone 8 in November 1984

($t \sim 418$ days) was aborted when the incremental injection pressure exceeded 600 psi. The pill flowback contained solid precipitates, and formation plugging was suspected at the time (Durrett 1985). This appeared to be confirmed when it was not possible to lower the test tool below 15,158 feet when the well was next logged on April 13, 1985. The second attempt to inject a scale inhibitor pill in May 1985 ($t \sim 594$ days) was also aborted. Successful pill injections were accomplished during June 1985 ($t \sim 628$ days) and February 1986 ($t \sim 851$ days). The success of the scale inhibitor pills has been crucial to the success of the geopressured test well program (Tomson, Matty, and Durrett 1985). Analysis of the Gladys McCall production data has revealed, however, that even successful injections cause an increase in the apparent skin factor, causing an increase in the near-wellbore pressure loss (Riney 1988).

There have been four periods during the 6.5 years of sand zone 8 test history when downhole pressure transient tests have been performed:

- (1) October 1983 to December 1983; reservoir limits test (drawdown/buildup)
- (2) April 1985; 79-hr test (buildup only)
- (3) January 1986; 92-hr test (buildup only)
- (4) October 1987 to present; long-term test (drawdown/buildup).

The first three tests were conducted during the depletion phase, and the results were described by Riney (1988). The LTT is composed of measurements that were continuously recorded over a multi-rate drawdown and early buildup portion of the test, augmented by measurements made while logging downhole pressure/temperature values, at increasingly longer time intervals between logs, from November 1987 to the present.

Both the 79-hr and 92-hr tests were found to infer a near-well transmissivity (kh) equal to about half the value measured during the original RLT (Riney 1988). This reduction in transmissivities was attributed to the presumed plugging of about half the thickness in sand zone 8 in combination with a shale stringer (vertical flow barrier) identified from well logs at 15,365 ft to 15,369 ft (Fig. 2). At the time of the 92-hr

Figure 2. Schematic showing location of the shale stringer in sand zone 8 and depth in feet of presumed plug reported at time of 79-hr test.

test, however, the well was again logged and the tool reached wellbottom without detecting any obstruction. It was hypothesized that the plugging within the formation remains since there is no flow below the shale stringer to flush the precipitates from the pores. Parametric reservoir simulation studies were performed to estimate the effective distance (ℓ) that the shale stringer extends laterally from the wellbore. It was found that a vertical flow barrier for a distance $\ell \sim 657$ ft (200 m) provided a good match to the downhole pressure transient data recorded before and after the presumed plugging (Riney 1988).

In preparation for the LTT, a Panex pressure/temperature gauge was lowered in Gladys McCall Well No. 1 on October 24, 1987 ($t = 1478$ days) and set at a depth of 14,650 ft with the well producing brine at ~ 9950 sep b/d. At 01:17:00 on October 25, the flow rate was increased to $\sim 15,050$ sep b/d. At 13:58:40 on October 25 the rate was decreased to $\sim 12,440$ sep b/d, and at 20:05:30 on October 25 the rate was lowered to ~ 9950 sep b/d. On October 26 it became apparent that the measured downhole pressure values were drifting with time. The original ("old") downhole Panex gauge was pulled out and a "new" Panex pressure/temperature was set at 14,650 feet at 22:00:00 on October 26. The flow continued at ~ 9950 sep b/d until the well was shut in at 20:02:10 on October 29, 1987 ($t = 35,598.8$ h). The buildup pressure was monitored continuously until 07:00:00 on November 5, 1987, when the new gauge was pulled. The subsequent pressure recovery has been monitored by isolated bottomhole pressure and temperature measurements made with increasing time intervals between logs.

Detailed analysis of the LTT pressure data revealed a drift of 3.62 psi/hr in the recordings of the old gauge. For analysis purposes the LTT data were further corrected to the depth of 15,100 feet at which measurements were made in the three previous bottomhole tests. The corrected old gauge data points are plotted with the new gauge data in Figure 3. The discontinuity reflects errors in the corrections for the old gauge data in some combination with differences in the calibrations and downhole positioning of the two gauges.

Except for these four bottomhole pressure transient tests, the Gladys McCall reservoir response must necessarily be inferred from wellhead recordings. The wellhead pressure measurements are related to the reservoir response as follows.

$$p_{WH} = p_{BH} - \Delta p_{wb} = p_i - \Delta p_{res} - \Delta p_{sk} - \Delta p_{wb} \quad (1)$$

Here the pressure drop in the wellbore (i.e., within the production string) is the sum of frictional and hydrostatic pressure losses ($\Delta p_{wb} = \Delta p_{fric} + \Delta p_{hydr}$); p_i is the initial reservoir pressure, Δp_{res} the pressure drop in the reservoir in the absence of a skin effect ($s = 0$), and Δp_{sk} the pressure drop due to the skin effect ($s > 0$). Relating the wellhead measurements to the characteristics of the geopressured reservoir involves calculations for subsurface pressure losses (Δp_{wb} , Δp_{sk} , Δp_{res}).

During the evaluation of the total available data set from Gladys McCall Well No. 1 we have

- (1) Performed simultaneous analysis of the pressure transient data from the four isolated downhole tests. The revised values for the near-well formation properties are used in reservoir simulation computations to calculate Δp_{res} .
- (2) Evaluated the wellhead pressure data available just prior to and immediately after planned shut in periods during the depletion phase to estimate Δp_{sk} .
- (3) Recalibrated the wellbore flow model to improve the calculations for Δp_{wb} and,

Figure 3. Data points are for LTT bottomhole measurements corrected to 15,100 feet. Old gauge data also corrected for drift. Curve is the simulated history. Test time referenced to $t_0 = 35,470$ hr (on October 25, 1987).

consequently, improve earlier estimates to bottomhole pressures during the depletion phase.

These results will be described in the following sections.

Simultaneous Analysis of Pressure Test Data

The reservoir analysis is simplified by the relatively low gas content. Preliminary parametric simulations were made that maximized the credible effects of any free gas that might evolve within the formation under Gladys McCall conditions; the studies show that the gas in the formation would be confined to a very small zone at the sandface. Parametric simulations assessing the effects of irreversible rock compaction and stress-dependent permeability were also conducted (Riney 1986). These simulations indicated that any associated nonlinear effects at Gladys McCall would likely occur only in the neighborhood of the wellbore. Such local effects would be reflected as variations in the apparent value of the skin factors when using linear methods of analysis.

Consider a well with radius r_w flowing under semi-steady state conditions at rate q for an equivalent production period t_p . If there is a step rate change (Δq) at time t_p , the associated sandface pressure change at time $t_p + \Delta t$ ($\Delta p = p_{w|t_p+\Delta t} - p_{w|t_p}$) is approximated by (in oilfield units; see Earlougher 1977)

$$\frac{\Delta p}{\Delta q} = m' \left(\log \Delta t + \log \frac{k}{\phi \mu C_T r_w^2} - 3.23 + 0.87 s \right) \quad (2)$$

where $m' = 162.6 \mu B/kh$. The formation factor (B) is required to convert separator barrels to reservoir barrels. If we assume the fluid viscosity (μ), formation porosity (ϕ), and total compressibility (C_T) are known, a semi-logarithmic plot of pressure transient data can be used to estimate the values of transmissivity (kh) and skin factor (s). The slope m' yields kh and the intercept at $\Delta t = 1$ hr yields s ,

$$s = 1.151 \left\{ \frac{1}{m'} \left[\frac{\Delta p}{\Delta q} \right]_{1\text{hr}} - \log \frac{k}{\phi \mu C_T r_w^2} + 3.23 \right\} \quad (3)$$

Figure 4 compares plots of $\Delta p/\Delta q$ versus $\log \Delta t$ for the 79-hr (April 9–12, 1985) and 92-hr (January 23–27, 1986) buildup tests with plots for two steps of the LTT (October 24, 1987–present). The plot for the first step (rate change from 9950 to 15,050 sep b/d) of the multi-rate drawdown portion of the LTT is closely approximated by a line of the same slope ($m' = 1.75 \times 10^{-3}$ psi/sep b/d) as lines approximating the 79-h and 92-h tests. The rate was maintained at 15,050 sep b/d for 12.68 h. The next two step-rate changes did not provide useful data for analysis because of the short time (step 2) and a gauge failure (step 3). The plot for the fourth step, the early part of the buildup portion of the LTT (started on October 29, 1987), is also closely approximated by a line of the same slope ($m' = 1.75 \times 10^{-3}$ psi/sep b/d). The slow rise times for the two portions of the LTT shown in Figure 4 appear to be associated with the time taken to complete the flow-rate changes.

Analogous plots for the drawdown (October 7–28, 1983) and buildup (October 28–November 30, 1983) portions of the RLT show that both early time semilog plots are approximated by straight lines of slope $m' = 1.13 \times 10^{-3}$ psi/sep b/d.

In the previous simultaneous analysis, the same values for the input parameters were employed as were used in the separate analyses made at the time of each of the downhole pressure transient tests (Riney 1988): $r_w = 0.2917$ ft, $h = 332$ ft, $\phi = 0.16$, $\mu = 0.31$ cp, $C_T = 6.27 \times 10^{-6}$, $B = 0.984$. The flow rate changes, and the flowing pressures (at 15,100 ft) just prior to the rate changes are listed in Table 1. The values for the formation transmissivity (kh) calculated from the slopes (m') in the semilog plots are also listed. The drawdown and buildup portions of the initial RLT imply a transmissivity of $\sim 44,090$ md-ft; all subsequent pressure transient tests imply a transmissivity of $\sim 28,340$ md-ft. Assuming $h = 332$ ft, the pressure transient data taken without further information would imply a reduction in near-well permeability from an initial value of $k = 133$ md to $k = 85$ md.

Table 1 also lists the values of $\Delta p/\Delta q|_{1\text{hr}}$ read from the straight line approximations to the semilog plots (e.g., Fig. 4). Equation 3 yields the corresponding estimates for the skin factor (s) at the time of each of the six downhole pressure transient tests. The estimate for the drawdown portion of the LTT is enclosed in parentheses in Table 1, since any vertical displacement of the $\Delta p/\Delta q$ curve (Fig. 4) that might be present after correcting for the linear drift in the old gauge pressure values would affect the estimate for s .

Figure 4. Bottomhole pressure transient data from 79-hr buildup test, 92-hr buildup test, one step of the LTT multi-rate drawdown, and the early portion of the LTT buildup. Datum level is 15,100 ft.

From Equations 2 we see that the pressure drop due to the skin effect changes with Δq according to $\delta p_s = m'(0.87s)\delta q$, or

$$\delta p_s = \frac{141.2 \delta q \mu B}{kh} s \quad (4)$$

We note that the discrepancy between the skin factor estimates for the two steps of the LTT ($\delta s = 4.68 - 2.97 = 1.71$) would correspond to a constant error in the corrected old gauge pressure values of

$$\delta p_o < \frac{141.2(5100)(0.31)(0.984)(1.71)}{28,340} \sim 13 \text{ psi}$$

Since an error of this size is possible in our correction for the drift in the pressure values

Table 1

Summary of Results of Simultaneous Analysis of Bottomhole Pressure Transient Measurements for Gladys McCall Sand Zone 8.
Long-Term Test Measurements at 14,650 Feet Were Corrected to a Common 15,100 Feet Datum Level

	Reservoir Limits Test				Long-Term Test	
	Drawdown	Buildup	79-Hour Buildup	92-Hour Buildup	Drawdown	Buildup
Date of measurement	Oct 07, '83	Oct 28, '83	April 09, '85	Jan 23, '86	Oct 25, '87	Oct 29, '89
Test days, d	0	21	550	839	1,479	1,483
Q , 10^3 sep b	0	298	7,788	13,951	27,131	27,182
$[p_w]_{0-}$, psia	12,784	12,418	10,855	10,267	10,068	10,074
Δq , sep b/d	14,162	14,162	15,438	10,470	5,100	9,950
$[\Delta p/\Delta q]_{hr} \times 10^3$, psi/sep b/d	9.55	9.78	23.9	18.8	18.1	15.5
$m' \times 10^3$, psi/~/(sep b/d)	1.13	1.13	1.75	1.75	1.75	1.75
kh , md-ft	44,090	44,090	28,340	28,340	28,340	28,340
s	2.28	2.51	8.49	5.11	(4.68)	2.97

measured with the old gauge, the skin factor based on the early buildup data ($s = 2.97$) is the preferred estimate at the time of the LTT.

Evaluation of Skin Factor Variations

There have been numerous times during the depletion testing of Gladys McCall Well No. 1 when the production tubing was free of scaling and the well had flowed at a constant rate for a sustained period prior to a planned shut in. On 21 occasions recordings of the wellhead pressure were made on a continuous basis just prior to and immediately after shut in. These data can be evaluated to estimate Δp_{sk} (and thus the apparent value of s) at those times. For this purpose we set $\Delta t = 3 \text{ m} = 0.05 \text{ hr}$ in Equation 2 and solve for s to obtain

$$s = 1.151 \left\{ \frac{1}{m'} \left[\frac{\Delta p}{\Delta q} \right]_{3m} - \log \frac{k(0.05)}{\phi \mu C_T r_w^2} + 3.23 \right\} \quad (5)$$

The choice of $\Delta t = 3 \text{ m}$ is made since it has been found to be long enough for wellbore storage effects to be small, and short enough for thermal changes to be negligible.

When the well is shut, $\Delta p_{wb} = \Delta p_{hydr}$. The values of Δp_{hydr} have been estimated (at the 15,100-ft datum level) from simultaneous wellhead and bottomhole P/T measurements made at the times of the RLT and 79-hr shut-in tests. The sandface shut-in pressures $p_{ws}]_{3m}$ are calculated based on the approximation $p_{ws}]_{3m} = pWH]_{3m} + \Delta p_{hydr}$. Estimates for the sandface flowing pressures just prior to shut-in are based in Equation 1, $p_{wf}]_{\Delta t=0-} = pWH]_{\Delta t=0-} + \Delta p_{wb}$, with the values Δp_{wb} calculated using the recalibrated model for wellbore flow (see next section).

Using Equation 5 with $r_w = 0.2917 \text{ ft}$, $h - h' = 207 \text{ ft}$ (see Fig. 2), $\phi = 0.16$, $\mu = 0.31 \text{ cp}$, $C_T = 6.27 \cdot 10^{-6} \text{ psi}^{-1}$, and the values calculated for $\Delta p = p_{ws}]_{3m} - p_{wf}]_{\Delta t=0-}$ (with $m' = 1.75 \cdot 10^{-3} \text{ psi/sep b/d}$ from Table 1), the estimates for the skin factor (s) are obtained for the 21 shut-in times. The results are plotted in Figure 5 against the corresponding values of the bottomhole (15,100-ft datum level) pressure drop from the initial reservoir pressure of 12,784 psi. Also plotted are the estimates for s given in Table 1 from the reevaluation of the downhole pressure transient test data.

The apparent skin factor values displayed in Figure 5 may be related to times at which scale inhibitor pills were injected.

October 1983 At the time of the original RLT the downhole measurement indicate a skin factor of $s = 2.28$ to 2.5 .

November 1984 First aborted attempt to inject pill; plugging a part of formation thickness near wellbore by precipitates suspected. Large increase in s value.

April 1985 At the time of the 79-hr buildup test, analysis of downhole measurements indicate a skin factor of $s = 8.49$. Hypothesized skin decrease subsequent to November 1984 pill is indicated by dashed curve approaching the 79-h data point in Figure 5.

May 1985 Second aborted pill injection causes large increase in skin factor value. Analysis of surface pressure data indicates that the large value of s subsequently decreases with continuous production; decrease attributed to partial flushing of precipitates from pores by flowing brine (see Riney 1988).

June 1985 First successful pill injection; analysis of surface pressures again indicates an associated large increase in apparent skin factor observed along with

Figure 5. Apparent skin factor (s) values displayed as function of pore pressure decrease (from $P_i = 12,784$ psia) in the neighborhood of the Gladys McCall Well No. 1 wellbore.

subsequent decrease (Riney 1988). The decrease in the value of s is indicated by the dashed curve approaching trend line A in Figure 5.

July 1985–January 1986 As bottomhole pressure continues to decrease the apparent skin factor allows trend line A as shown. The skin factor $s = 5.11$ determined at the time of the 92-hr buildup test falls on trend line A.

February 1986 Second successful pill injection; associated increase in apparent skin factor.

February 1986–October 1987 The apparent skin factor subsequently decreases with flow as indicated by the dashed curve approaching trend line B in Figure 5. As bottom pressure continues to change, the apparent value of s follows trend line B. The value $s = 2.97$ determined at the time of the LTT shutin also falls on trend line B.

The fact that the estimate s values approximate the trend lines A and B in Figure 5 between times that pills were injected implies that the skin factor depends on the bot-

tomhole pressure. Based on parametric calculations performed to examine the possible effects of free gas evolution and nonlinear formation response (preceding section), the latter mechanism seems a more plausible cause for the pressure dependence. The effective stress at the sandface increases as the bottomhole pressure decreases.

In summary, it appears that there are at least three mechanisms contributing to the variations of the skin factor s :

- (1) Abrupt increases in s associated with scale inhibitor pill injections, followed by subsequent slow decrease in s by partial removal of precipitates.
- (2) An apparent increase in s associated with a partial penetration effect caused by reduction of the horizontal communication with the wellbore due to plugging of the formation after November 1984.
- (3) An increase associated with an increase in the effective stress on the formation adjacent to the wellbore.

Recalibration of Wellbore Model

The wellbore flow model (Pritchett 1985) calculates the steady flow in a geothermal well producing under stable conditions. Starting with specified bottomhole conditions, the program integrates up the well to predict the wellhead conditions. The frictional effects in the wellbore are treated using a correlation by Dukler, Wicks, and Cleveland (1964); the effects of tubing roughness are included through a relative roughness parameter (R). Heat loss by combined conduction and convection to a porous water-saturated medium is treated by an approximate analytical solutions and its magnitude is controlled by a heat transfer coefficient (U). Both R and U are empirical parameters.

The wellbore model uses an equation-of-state for brine/methane mixtures to calculate the properties of the geopressured fluid as it rises in the productions tubing. The equation-of-state incorporates recent data concerning the compressibility of liquid brines (Osif 1984) and measurements of methane solubility in hot brines reported by Price et al. (1981). The mass fraction composition employed to represent the Gladys McCall brine is as follows:

$$\text{H}_2\text{O} : 0.901479, \quad \text{CH}_4 : 0.003481, \quad \text{NaCl} : 0.092340$$

This choice yields a bubble point of 9200 psia for a temperature of 289.2°F, in agreement with tests performed on reconstituted Gladys McCall sand zone 8 fluids by Weatherly Laboratories, Inc. The selected composition corresponds to $\text{GWR} = 30.70$ SCF/STB, which closely approximates the total gas-to-water ratio produced from Gladys McCall Well No. 1.

Available stable downhole flowing pressure and temperature measurements in Gladys McCall Well No. 1 since October 7, 1983 (test day 0) must be used to calibrate the wellbore model. Unfortunately, the only P/T profile data were measured on April 18, 1985 (test day 549) just prior to the 79-h shut in test. Since the production tubing was badly scaled at that time, the available profile data are corrupted.

During the RLT (test day 21), a stable "full-stream" temperature of 280°F was recorded at the wellhead, while the temperature of the fluid leaving the separator was 275°F. Since full-stream values were not reported after January 1985, wellhead temperatures at the other times (79-hr, 92-hr, and LTT) are estimated by adding 5°F to the temperatures recorded for the fluid leaving the first stage separator. The durations of

step 2 ($q = 15,050$ sep b/d) and step 3 ($q = 12,440$ sep b/d) of the multi-rate drawdown test prior to the start of the long-term shut in test were too short for stable temperatures to be attained.

Based on the reevaluation of the total pressure/temperature data available, it is apparent that the sand zone 8 temperature is higher than the value of 289.2°F measured at the time of the RLT. The P/T data are best matched with the wellbore model recalibrated using the earlier mass fraction composition, reservoir temperature $T_o = 297.0^\circ\text{F}$, and the following values for the empirical parameters: $U = 7.0 \text{ Wm}^{-2} \text{ }^\circ\text{C}^{-1}$, $R = 0.090 \text{ mm}$.

The new calibration has been used to estimate the pressure drop in the wellbore for a specified flow rate and pressure at the datum level, 15,100 ft. The value of Δp_{hydr} decreases with increasing q since the fluid is less dense as it has less time to cool in the wellbore at higher rates; the value of Δp_{fric} , however, rapidly increases as q increases. The total pressure drop (Δp_{wb}) decreases with increasing q for $q < \sim 3000$ sep b/d and then increases rapidly with q . For a fixed value of q , Δp_{wb} decreases with a decreasing value for the datum pressure; since more gas evolves in the wellbore at the lower datum pressure, the wellbore fluid is less dense. The decrease is ~ 125 psi as the datum pressure decreases from 12,000 to 8000 psia.

The change in datum pressure has negligible effect on the wellhead temperatures predicted by the wellbore model; the flow rate does have a significant effect. Figure 6 compares the results of the recalibrated model predictions for the wellhead temperature with the data available at times of sustained stable flow rate over the production history of the test well. The datum pressure at 15,100 ft was fixed at 10,000 psia. The agreement is quite good. Because of the limited P/T profile data available and lack of downhole pressure data for high flow rates, however, the calibration and associated wellbore model predictions (and consequently the estimated bottomhole pressure data points in Fig. 8) are subject to error during periods of the depletion phase when flow rates were sustained at $q \sim 20,000$ to $30,000$ sep b/d.

Implications of Integrated Analysis

The significant implication of the simultaneous analysis of the four pressure transient tests is the fact that the LTT infers a near-well formation transmissivity unchanged from the values inferred by the 79-hr and 92-hr data. It is interesting to note that the reduction in the kh product from the RLT values ($28,340/44,090 = 0.64$) is close to the hypothesized reduction in the sand thickness in horizontal communication with the wellbore ($207/332 = 0.62$) at the time of the 79-hr test (Fig. 2).

Actual obstruction within the borehole has not been observed in later downhole probes at Gladys McCall. It is plausible that brine flow cleaned out the borehole obstruction observed on April 13, 1985; scouring action appears to have occurred subsequent to each of the four pill injections (two successful and two unsuccessful attempts). After each pill injection there was a large increase in the apparent skin factor, but the magnitude of the skin effect subsequently decreased, presumably from the cleansing action of the flowing fluid. This effect might not occur in a completely plugged horizon as there is no flow; horizontal communication with the wellbore apparently has remained reduced to $\sim 64\%$ of its original value.

The variations in kh in Table 1 would be difficult to explain in terms of nonlinear rock formation behavior. Any decrease in kh would likely start at the sandface (lowest pressure/highest effective stress) and move outward as the reservoir depleted. The radial

Figure 6. Stable Gladys McCall wellhead temperatures recorded during 1983–1987 (data points) at indicated flow rates compared with recalibrated wellbore model calculations (curve).

propagation of the nonlinear effect would imply a monotonically increasing apparent skin factor in association with a decreasing value for the apparent kh product (Riney 1986). It is difficult to envision a decrease in kh to 64% of the original value after producing 6.8×10^6 sep b and then no further change upon producing an additional 19.4×10^6 sep b. The only significant nonlinear formation response apparent from the Gladys McCall test well data is in the immediate vicinity of the wellbore as reflected in the dependence of the skin factor on the effective stress change (Fig. 5).

Since all other downhole pressure transient measurements are consistent, it is reasonable to question the measurements made at the time of the RLT. Were the actual flow rates only ~62% of the values reported? This is not credible since the stable full-stream temperature (280°F) recorded at the surface during RLT drawdown is consistent with the flow rate reported (Fig. 6). Also, the pressure drop measured in the wellbore from 15,100 ft to the surface is consistent with the reported flow rate.

Since nonlinear formation response and measurement error do not seem plausible, the pressure transient data available from the Gladys McCall Well No. 1 are best ex-

Figure 7. Vertical section (upper) and planar (lower) views of model for Gladys McCall reservoir based on concept that cross-flow from overlying/underlying sands sustain pressure in sand zone 8 (k_i = horizontal permeabilities in sand zone 8; l = 200 m).

plained by the presumed partial plugging of the sand formation in conjunction with the presence of a thin shale stringer in sand zone 8.

Reservoir Simulation Model

Figure 7 shows a schematic of the geopressured reservoir simulation model (which employs SI metric units) used to match the integrated data sets composed of the full test history of sand zone 8. The configuration, symmetrical across a north-south plane through the test well, is basically the same as employed in the earlier article (Riney 1988) except the total volume is enlarged by removing the earlier assumption that the flow barriers F1 and F2 form the southern and northern boundaries of the reservoir. The distances of F1 (240 m) and F2 (400 m) from the test well are based on the analysis of the downhole pressure data from the RLT (Riney 1988). The distance ($\ell = 200$ m) that the shale stringer near the middle of sand zone 8 extends from the well is based on reservoir simulation calculations described in an earlier section. The present model assumes 62% of the thickness of sand zone 8 is above the shale stringer (Fig. 2); the earlier model used 50%.

In the new model, F1 and F2 are assumed to be internal sealing faults that do not extend as far as the east-west boundaries of the reservoir. They are assumed to form horizontal flow barriers for the same distance from the test well as the major shale break at the top of sand zone 8 forms a vertical flow barrier. The north-south dimensions of the reservoir drained by the test well are assumed to extend for 2440 m as shown. The east-west dimensions and the upper and lower boundaries in Figure 7, however, are unchanged from the earlier model. The thickness of 390 m approximates the net sand in the Miocene sand/shale sequence penetrated by the test well. The north-south and east-west dimensions roughly approximate the fault block dimensions mapped in Figure 1.

The thickness of sand zone 8 is approximated by 100 m as in the earlier model. The near-well horizontal permeability is chosen to be $k_1 = 134$ md (1.33×10^{-13} m²) to preserve the value of $kh = 44,090$ md-ft estimated from the RLT data. The more distant horizontal permeability in sand zone 8 is assumed to be $k_2 = 2 \times 10^{-14}$ m² as in the earlier model; this permeability value is also used for the reservoir southern and northern extensions beyond faults F1 and F2 (i.e., $k_4 = 2 \times 10^{-14}$ m²). The effective horizontal permeability in the regions of the reservoir beyond the east and west ends of the faults was varied in a series of simulations; the best history match was obtained using $k_3 = 5 \times 10^{-15}$ m². The total compressibility ($C_T = 9.1 \times 10^{-4}$ MPa⁻¹ [6.27×10^{-6} psi⁻¹]) and porosity ($\phi = 0.16$) throughout the extended sand zone 8 volume are the same as in the earlier model. The reservoir brine properties were also unchanged: $\mu = 0.31 \times 10^{-4}$ Pa $\cdot$ s (0.31 cp), $\rho = 1030.5$ kg/m³.

The 290-m thick upper layer in the model represents overlying/underlying sands that contribute to the pressure support of sand zone 8 by fluid cross-flow at shale breaks. Both the horizontal and vertical effective permeabilities in this layer and the vertical permeability in sand zone 8 are all assumed to be 2×10^{-16} m². The total compressibility is the same as in sand zone 8, but the porosity was reduced to $\phi = 0.12$ in this "remote volume" to provide the best history match.

It should be emphasized that the actual reservoir properties away from the test well are not known and our choices represent "effective values" that provide a good match to the integrated depletion and recovery phases of Gladys McCall Well No. 1.

In simulating the production history of the well, the numerous rate changes were closely approximated. The values of the skin factor (s) determined from the wellhead

pressures in Figure 5 were employed in the simulation. At $t = 418$ days (November 28, 1984), plugging by the first aborted pill injection of the portion of sand zone 8 below the shale stringer is assumed; flow into the wellbore thereafter is restricted to the upper 207 ft (Fig. 2) so that the near-well apparent transmissivity is reduced to $kh = 28,340$ md-ft. Figure 8 compares the simulated sandface pressure at the datum level (15,100 ft) with bottomhole values estimated from wellhead recordings during periods of stable production. The simulated sandface pressure agrees equally well with bottomhole values estimated from wellhead recordings just after planned shut ins ($[p_{ws}]_{sm}$). There is also good agreement through the simulated transition from the depletion phase to the recovery phase during the four-week period starting on April 21, 1987. The simulated sandface pressures during the multi-rate flowing portion of the LTT and the shut-in portion of the LTT are compared with the bottomhole data (corrected to the datum level) in Figures 3 and 9, respectively.

Discussion

Nonlinear reservoir response mechanisms have not been detected at Gladys McCall except possibly as a skin effect in the vicinity of the wellbore. Nevertheless, nonlinear processes (e.g., irreversible formation compaction, shale water influx, leaky boundaries, formation creep, etc.) might be present and have affected long-term pressure maintenance but be too subtle to be apparent in the test data from a single well in a poorly defined reservoir. This would be in contrast with the experience at the Parcedue geopressed reservoir where robust nonlinear effects were manifested from the early short-term testing of the L. R. Sweezy well.

A simple reservoir configuration (Fig. 7) has been used as a framework for constructing a linear model to match the integrated data base available for Gladys McCall. The reservoir boundaries were chosen such that total fault block volume roughly approximates the dimensions suggested by the limited geological information and the near-field reservoir properties are based on data from the test well. The configuration used is only one of many alternatives, however, and is not particularly constrained by the geological data. The unknown far-field reservoir properties were varied in a series of parametric calculations to arrive at values that provide a good match to the available test data. The quality of the history match obtained during the transition from the depletion to the recovery phase was sensitive to the parameters that control the hydrologic connection to the remote volumes of the reservoir. The value chosen for the effective porosity in the reservoir volume representing the overlying/underlying stands affects the quality of the history match during the recovery phase.

The good match that the simulation model provides with the integrated data base does not imply that the selected configuration approximates the actual reservoir geology or that the far-field reservoir properties approximate the actual values. It only suggests that the depletion and recovery behavior of the real system is similar to that of the model selected. This non-uniqueness problem cannot be resolved in the absence of more definitive information defining the geology and reservoir properties away from the Gladys McCall test well.

The connected pore volume of the linear (but heterogeneous) reservoir model used to match the integrated Gladys McCall data is

$$V_p = 10,000(2440)[(0.16)(100) + (0.12)(290)] = 1.24 \times 10^9 \text{ m}^3 (7.8 \times 10^9 \text{ bbl})$$

Figure 8. Simulated sandface pressure history (curve) compared with values (points) estimated from flowing wellhead recordings of Gladys McCall Well No. 1. Datum level is 15,100 ft.

Since estimates for distances made from well test analysis depend on the square root of C_T , all lateral dimensions employed in the model would need to be increased by $\sim 20\%$ if $C_T = 4.0 \times 10^{-6} \text{ psi}^{-1}$ were used, or decreased by $\sim 10\%$ if $C_T = 7.7 \times 10^{-6} \text{ psi}^{-1}$ were used, rather than $C_T = 6.27 \times 10^{-6} \text{ psi}^{-1}$. These dimensions would also lie within the uncertainty of the known geology of the Gladys McCall fault block.

In contrast with the situation at Gladys McCall, the geological information for the geopressured C-zone being tested by the Pleasant Bayou research well is extensive. Considerable deep-well data and broad-based geological work has defined the boundaries and internal structure of the reservoir and estimated the connected pore volume to be between 6.2 and 6.6×10^9 bbl (Hamlin and Tyler 1988). Long-term production testing of the Pleasant Bayou well, now in progress, will provide a basis for comparing geopressured reservoir volume estimates based on extensive geological data as opposed to estimates based on actual depletion behavior of the reservoir. These results may provide further insight for interpreting the Gladys McCall test data.

Figure 9. Simulated pressure buildup history (curve) compared with bottomhole pressure data (points) measured during long-term shut in test still underway at Gladys McCall Well No. 1. Datum level is 15,100 feet.

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Appendix

B Pleasant Bayou Geopressured- Geothermal Reservoir Analysis—October 1991

Pleasant Bayou Geopressured-Geothermal Reservoir Analysis—October 1991

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Many sedimentary basins contain formations with pore fluids at pressures higher than hydrostatic value; these formations are called geopressured. The pore pressure is generally well in excess of hydrostatic and the fluids are saline, hot, and contain dissolved methane. The U.S. Department of Energy (DOE) has drilled and tested deep wells in the Texas-Louisiana Gulf Coast region to evaluate the geopressured-geothermal resource. Geological information for the Pleasant Bayou geopressured resource in southeast Texas is most extensive among the reservoirs tested. Testing of the DOE well (Pleasant Bayou No. 2) was conducted during 1979–1983; testing resumed in May 1988. A numerical simulator is employed to synthesize and integrate the geological information, formation rock and fluid properties data from laboratory tests, and well data from the earlier (1979–1983) and the ongoing testing (1988–1991) of the well. A reservoir simulation model has been constructed which provides a detailed match to the well test history to date.

Introduction

The Pleasant Bayou fault block lies astride the boundary between Brazoria and Galveston Counties along the Texas Gulf Coast, about 64 km (40 m) south of Houston. It was selected for testing under the U.S. Department of Energy (DOE) program to evaluate the nation's geopressured geothermal energy resource based on geological work conducted at the Texas Bureau of Economic Geology (BEG) by Bebout et al. (1978). Pleasant Bayou well No. 1 was drilled in 1978 and plugged back and completed as a brine disposal well because of hole instability problems. The test well, Pleasant Bayou well No. 2, was offset 152 m (500 ft) from the No. 1 well, drilled to a depth of 5029 m (16,500 ft) and completed during 1979.

Well No. 2 has 0.178-m (7-in.) casing which is perforated across the thickness of 18.3 m (60 ft) comprising the main reservoir sandstone (4463.5–4481.8 m) (14,644–14,704 ft) within the lower Frio Formation C-zone; the total thickness of the C-zone at the wellbore is composed of 38.1 m (125 ft) of sandstone and 33.2 m (109 ft) of mudstone. The test well was completed with 0.140-m (5.5-in.) production tubing from 4253 m (13,952 ft) to the surface. After gas separation, the brine produced from the test well is injected into a shallow aquifer using well No. 1 recompleted as a disposal well.

Preliminary testing (phase 0) of well No. 2 took place during 1979, reservoir limits testing during 1980 (phase 1), and long-term testing (phase 2) was conducted during 1981–1983. The test well experienced severe calcite scaling on the inner surface of the production tubing and numerous mechanical problems during phase 2, including wireline and fishing tool loss. Testing

was suspended in May 1983 when the 0.140 m (5.5-in) production tubing parted at 1593 m (5225 ft) (Rodgers, 1982).

Eaton Operating Co. subsequently took over the operation of the Pleasant Bayou facility for DOE with the Institute of Gas Technology (IGT) responsible for surface production measurements. Both the production well (No. 2) and the injection well (No. 1) were successfully cleaned out and the 0.140-m (5.5-in) tubing replaced during 1987. The wireline and tool lost during the earlier testing was pushed below the production perforations before recompleting well No. 2.

The produced brine is principally a sodium chloride with substantial concentrations of calcium and ions such as potassium and magnesium; the salinity is 130,000 ppm total dissolved solids, corresponding to a mass fraction of $S=0.12$. Solution gases produced are mainly methane (~ 85 percent) and heavier hydrocarbons (~ 5 percent) with significant quantities of carbon dioxide (~ 10 percent). The concentrated brine and presence of carbon dioxide under high temperature and pressure gave rise to problems of scaling in the tubular goods and surface equipment experienced in 1981–1983.

Prior to flow testing the recompleted production well, a phosphonate scale inhibitor "pill" was injected into the formation on April 18, 1988. The design of the phosphonate solution scale-inhibitor pill for Pleasant Bayou was based on work performed by Tomson et al. (1985). A second inhibitor pill was injected on November 19, 1989 after producing in excess of $1.2 \times 10^6 \text{ m}^3$ (7.7×10^6 bbls) of brine. Cumulative production during 1988–1991 (Oct) is in excess of $3.0 \times 10^6 \text{ m}^3$ (19×10^6 bbls), with no downhole scaling.

This paper describes the use of a numerical reservoir simulator as a tool for integrating and synthesizing the diverse data sets available for the Pleasant Bayou fault block, each of which describes some aspect of the geopressured-geothermal reservoir and/or its response to fluid production. The available

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Fig. 2 Southwest-northeast cross section showing details of sandstone and mudstone interbedding down the long axis of the fault block (Hamlin and Tyler, 1988)

growth faults forming major lateral boundaries for the Pleasant Bayou fault block are well established, except for the southern boundary; no deep control wells penetrate the C-zone in a large area south of the Pleasant Bayou No. 2 well. Numerous smaller faults within the block probably occur, but only those identified from well and seismic data are shown in Fig. 1. Porosity pinch-out possibly in conjunction with smaller internal faults is considered by Hamlin and Tyler (1988) to form the southern boundary of the fault block. They fix the southern boundary at 4.8 km (3 mi) south of the test well for purposes of reservoir volume calculations, since the southern area was bypassed by the major sand-depositing channel systems.

The lateral continuity of the perforated interval of the test well and its communication with the other C-zone sandstones were traced by correlating interbedded mudstones. Figure 2 reproduces a southwest-northeast cross section of the C-zone; Hamlin and Tyler found that only the upper and basal mudstones are continuous throughout the Pleasant Bayou fault block. They form the upper and lower boundaries of the reservoir, which can be subdivided into three units: the lower, middle (main perforated zone) and upper sandstone. Figure 2 illustrates multiple thick sandstones in the Danbury salt-withdrawal basin, the three units at the test well, the single massive sandstone at Chocolate Bayou, and thinly interbedded stones and mudstones to the northeast. Hamlin and Tyler (1988) conclude that the Chocolate Bayou area is an important region of vertical communication within the reservoir.

By constructing other cross sections similar to Fig. 2, Hamlin and Tyler delineated the sandstone and mudstone distributions for the entire C-zone reservoir. They assume that thicker sandstones are mostly composed of distributed channel-fill and channel-mouth bar deposits that have porosities (~ 0.18) similar to the perforated interval in the test well. Thinner sandstones are considered to have lower porosities, (~ 0.09). Hamlin and Tyler (1988) estimate that total C-zone sandstone pore volume is $1.3 \times 10^9 \text{ m}^3$ ($8.3 \times 10^9 \text{ bbls}$) and that 75 to 80 percent of this is interconnected, i.e., the effective pore volume is $V_p = 9.8$ to $10.4 \times 10^8 \text{ m}^3$ (6.2 to $6.6 \times 10^9 \text{ bbls}$). They suggest a simple rectangular configuration (Fig. 3) as a reasonable approximation to the geometry, volume and porosity distribution for the C-zone reservoir. The boundaries of the configuration represent average reservoir length, width, thickness and horizontal porosity layers approximate the geometry of the major reservoir sandstones. The model configuration (BEG1) consists of a main high-porosity ($\phi_1 = 0.18$) reservoir sand sandwiched between two low-porosity ($\phi_2 = 0.09$) layers which represent thinner, more isolated sandstones comprising the "remote volume" of the reservoir. In Fig. 3 we have superimposed the approximate locations of three internal faults in the main reservoir sand (denoted by F1, F2 and F3) identified in Fig. 1 on the basis of seismic and control well data.

Fig. 3 Reservoir simulation model geometry based on BEG1 model

The geologically based configuration does not provide information regarding formation compressibility and transmissivity, fluid properties, or the major "effective connection zones" between the remote volume layers and the main reservoir layer. The consolidated geological information presented by Hamlin and Tyler (1988), however, provide a framework within which the reservoir simulation model will be synthesized using various data sets available.

Production History

There have been five periods during the history of the Pleasant Bayou test well when downhole pressure/temperature transient measurements have been made. Results from the preliminary short-term (phase 0) testing were reported by Garg (1980). The four tests during long-term testing are as follows:

1 September 15, 1980 to December 15, 1980	Reservoir limits test (drawdown/buildup)
2 May 26, 1988 to June 1, 1988	Multi-rate test (drawdown/buildup)
3 May 15, 1989 to May 18, 1989	65-hr test (buildup test)
4 May 13, 1991 to May 16, 1991	62-hr test (buildup test)

The 90-day reservoir limits test (RLT) at the start of the initial long-term testing of the well consisted of a 45-day multi-rate drawdown followed by a 45-day pressure buildup test. These 1980 (phase 1) data are the only downhole test of sufficient duration to define the distance to a reservoir boundary (Garg et al., 1981).

A Panex P/T gage set at 4438 m (14,560 ft) recorded stable values of 76.642 MPa (11,116 psia) and 152.2 C (306 F) prior to opening the well for the RLT. The flow rate variations, (Rodgers, 1982, Vol. 2) during the RLT included four periods of stable flow during the drawdown phase (A: $\sim 1.184 \times 10^{-2} \text{ m}^3/\text{s}$ (6,436 stb/d); B: $\sim 1.928 \times 10^{-2} \text{ m}^3/\text{s}$ (10,476 stb/d); C: $\sim 3.346 \times 10^{-2} \text{ m}^3/\text{s}$ (18,184 stb/d); D: $\sim 2.322 \times 10^{-2} \text{ m}^3/\text{s}$ (12,616 stb/d)). Flow rates are given at standard oilfield pressure/temperature conditions of 101.325 kPa (14.696 psia) and 15.56 C (60 F). The well was flowing at a steady rate of $\sim 2.322 \times 10^{-2} \text{ m}^3/\text{s}$ (12,616 stb/d) when shut in on October 31, 1980 for the buildup portion of the RLT. During November 8–10, the Panex gage failed and was removed, repaired and reset at 4438 m (14,560 ft) as indicated in Fig. 4 (at $t = 54$ –56 days). The brief transients in the data points are associated with adjustments in the choke setting at times when the stepped flow rates were changed.

Although the well was produced at $\sim 3.68 \times 10^{-2} \text{ m}^3/\text{s}$ (20,000 bbl/d) for a total production of $\sim 5.9 \times 10^5 \text{ m}^3$ ($3.7 \times 10^6 \text{ bbl}$) during 1981–1983 (phase 2), no successful downhole meas-

Fig. 1 Structure map on the top of the C-zone (Hamlin and Tyler, 1988). Numbers on contours denote depths below sea level of 3960 m (13,000 ft), 4270 m (14,000 ft) and 4570 m (15,000 ft).

data sets will never be complete enough to uniquely define the required input parameters in the reservoir simulation model. Construction of the model requires performance of a series of parametric calculations in which the input parameters are varied within their ranges of uncertainty to match the production history of the test well. Since the data base is continuously being expanded and updated, the model development is a dynamic process and the reservoir simulation model will necessarily evolve as more complete information becomes available.

BEG Configuration

In preparation for the new phase of long-term production testing of the No. 2 well that began in May 1988, BEG (Hamlin and Tyler, 1988) reviewed previous geological studies of the Pleasant Bayou area and extended the research by focusing on the C-zone reservoir. Figure 1 shows the revised structure map on top of the C-zone. Locations of deep control wells and the Pleasant Bayou test well (No. 2) are also shown. Large

Nomenclature

B_o = formation volume fraction	p_{wf} = flowing pressure at sandface	Δq = change in volumetric flow rate
C_m = uniaxial rock compressibility	p_{ws} = shutin pressure at sandface	r_w = wellbore radius
C_{pm} = uniaxial pore volume compressibility	p_{BH} = bottomhole pressure	R = wellbore roughness parameter
C_T = total uniaxial compressibility	p_{WH} = wellhead pressure	s = skin factor
C_w = fluid compressibility	P_i = stable bottomhole pressure measurement	S = fluid salinity, mass fraction
h = formation thickness	P_o = original reservoir pressure	t = time during flow test
k = formation permeability	Δp = pressure drop at sandface caused by rate change Δq	t_p = time when flow rate changed
k_H = horizontal permeability	Δp_{fric} = frictional loss of pressure in wellbore	Δt = time since flow rate changed
k_v = vertical permeability	Δp_{hydr} = hydrostatic head in wellbore	V_p = pore volume of reservoir
K = wellbore heat transfer parameter	Δp_{wb} = total pressure drop in wellbore	μ = fluid viscosity
L_i = distances ($i = 1, \dots, 6$) defining reservoir model geometry	Q = cumulative volume of fluid produced	ρ = fluid density
m' = slope of linear portion of $\Delta p/\Delta q$ versus $\log t$ plot		ϕ = effective formation porosity, fraction

datum level of 4450 m (14,600 ft) hereafter. The measured reservoir conditions at the start of the 1980 reservoir limits test become (at 4450 m (14,600 ft) datum)

$$P_o = 76.766 \text{ MPa (11,134 psia)} \quad T_o = 152.2 \text{ C (306 F)}$$

The pressure would need to be reduced to $-44.1 \text{ MPa (6400 psia)}$ for free methane gas to evolve from the reservoir brine. However, carbon-dioxide and other gas components present in the brine might cause free gas to evolve at higher pressures.

Prior to the 1988 MRT a stable pressure of $73.670 \text{ MPa (10,685 psia)}$ was measured at $4252 \text{ m (13,950 ft)}$; the temperature measurements were in error. Since flowing temperatures measured at $4450 \text{ m (14,600 ft)}$ prior to the 1989 65-hr and 1991 62-hr shutin tests are in good agreement with the 1980 measurement, reservoir conditions at the start of the MRT are assumed to be (at $4450 \text{ m (14,600 ft)}$ datum)

$$P_i = 75.691 \text{ MPa (10,978 psia)} \quad T_i = 152.2 \text{ C (306 F)}$$

The corresponding equation-of-state varies for the dynamic viscosity (μ), formation factor (B_o) and compressibility (C_w) of the reservoir fluid are as follows: $\mu = 2.7 \times 10^{-4} \text{ Pa-s (0.27 cp)}$, $B_o = 1.049 \text{ res vol/std vol}$, $C_w = 3.70 \times 10^{-10} \text{ Pa}^{-1} (2.55 \times 10^{-6} \text{ psi}^{-1})$.

The total compressibility of the reservoir formation is the sum of the uniaxial pore volume compressibility (C_{pm}) and fluid compressibility (C_w), or $C_T = C_{pm} + C_w = \phi^{-1} C_m + C_w$. Here $C_m = \phi C_{pm}$ is the uniaxial formation compressibility. A representative value for the coefficient C_m has been estimated from UTA rock mechanics tests on Pleasant Bayou reservoir cores (Fahrenthold and Gray, 1985) to be $C_m \sim 4.3$ to $8.7 \times 10^{-11} \text{ Pa}^{-1} (3 \text{ to } 6 \times 10^{-7} \text{ psi}^{-1})$. Using $C_w = 3.70 \times 10^{-10} \text{ Pa}^{-1} (2.55 \times 10^{-6} \text{ psi}^{-1})$ and $\phi = 0.18$, these values for C_m imply $C_T = 6.1\text{--}8.5 \times 10^{-10} \text{ Pa}^{-1} (4.2\text{--}5.9 \times 10^{-6} \text{ psi}^{-1})$ for the C-zone reservoir sand. We use $C_T = 7.01 \times 10^{-10} \text{ Pa}^{-1} (4.83 \times 10^{-6} \text{ psi}^{-1})$.

Wellbore Calculations

The wellbore flow model (Pritchett, 1985) calculates the steady flow in a geothermal well. Frictional effects in the wellbore are treated and the effects of tubing roughness are included through a relative roughness parameter (R) which occurs as a model input parameter. Heat loss by combined conduction and convection from a porous water-saturated medium is treated by an approximate analytical solution; its magnitude is controlled by the well geometry and the effective formation conductivity (K). The model calculates the properties of the geopressured fluid as it rises in the production tubing.

Available downhole flowing pressure and temperature measurements in the recompleted test well have been used to arrive at the following values for the empirical parameters: $K = 1.05 \text{ Wm}^{-2} \text{ C}^{-1}$, $R = 0.12 \text{ mm}$. The calibrated wellbore model was used to estimate the surface temperature and pressure drop ($\Delta p_{wb} = \Delta p_{hydr} + \Delta p_{fric}$) in the wellbore for specified flow rate and P/T values at the datum level of $4450 \text{ m (14,600 ft)}$. Estimates of bottomhole pressures ($p_{BH} = p_{wH} + \Delta p_{wb}$) at times of sustained flow at a constant rate are shown in Fig. 5 together with the downhole data. The corresponding estimates for the surface temperature are in good agreement with wellhead data (see Riney, 1991a, for more details).

Because of the limited downhole P/T gradient data available, however, the calibration and associated wellbore model predictions (and consequently the bottomhole pressure values estimated from wellhead recordings) are subject to error during periods of high flow rates. An increase from the selected value of $R = 0.12 \text{ mm}$ to $R = 0.21 \text{ mm}$ would increase the calculated value of Δp_{wb} by less than $-0.35 \text{ MPa (50 psi)}$ at the maximum calibration flow rate $2.246 \times 10^{-2} \text{ m}^3/\text{s (12,205 stb/d)}$, but would predict a value $-1.1 \text{ MPa (160 psi)}$ higher at $4.42 \times 10^{-2} \text{ m}^3/\text{s (24,000 stb/d)}$. The estimated value of the flowing

Fig. 6 Bottomhole pressure transient data from buildup portion of 1980 RLT, first step of the MRT drawdown, buildup after the MRT, 65-hr buildup test, and 62-hr buildup test of well No. 2. Datum level is $4450 \text{ m (14,600 ft)}$.

bottomhole pressure based on wellhead recordings would be correspondingly higher.

Pressure Transient Data

The reservoir analysis is simplified by the relatively low gas content; any free gas that might evolve within the Pleasant Bayou reservoir formation would be confined to a very small zone at the sandface. Parametric simulations assessing the effects of irreversible rock compaction and stress-dependent permeability indicated that any associated nonlinear effects at Pleasant Bayou would also occur only in the neighborhood of the wellbore. Such local effects would be reflected as variations in the apparent value of the skin factor (s).

Consider a well flowing under steady conditions at rate q for an equivalent production period t_p . If there is a step rate change at time t_p , the sandface pressure change ($\Delta p = p_{ws}(t_p + \Delta t) - p_{ws}(t_p)$) is approximated by (in SI MKS units; see Streletsova, 1988)

$$\Delta p / \Delta q = m' [\log \Delta t + \log(k / \phi \mu C_T r_w^2) + 0.351 + 0.87 s]$$

where $m' = 0.183 \mu B_o / kh$. Set $\Delta t = 1 \text{ s}$ and solve for s to obtain

$$s = 1.151 [(1/m') (\Delta p / \Delta q)_{1s} - \log(k / \phi \mu C_T r_w^2) - 0.351]$$

Figure 6 compares the data plots ($\Delta p / \Delta q$ versus $\log \Delta t$) for the buildup portion of the RLT, the 65-hr buildup test, and the 62-hr buildup test similar plots for two steps of the MRT. The plot for the first step (rate change from 0 to $9.009 \times 10^{-3} \text{ m}^3/\text{s (4896 stb/d)}$ on May 27, 1988) of the drawdown portion of the MRT reflects adjustments made to establish a stable flow rate, but thereafter is closely approximated by a line of the same slope ($m' = 1.43 \times 10^7 \text{ Pa/m}^3 - \text{s (3.83} \times 10^{-3} \text{ psi/stb/d)}$) as lines approximating the buildup tests. The plot for the early part of the buildup portion of the MRT (rate change from $1.736 \times 10^{-2} \text{ m}^3/\text{s (9433 stb/d)}$ to 0 on May 30, 1988) approximates a line of the same slope. Vertical displacements between the lines reflect changes in the value of s operative at the time of the tests. The constant slopes indicate that the permeability of the formation away from the sandface is unchanged since 1980.

In the foregoing analysis, the input parameters employed were: $r_w = 8.891 \times 10^{-2} \text{ m (0.2917 ft)}$, $h = 18.3 \text{ m (60 ft)}$, $\phi = 0.18$, $\mu = 2.7 \times 10^{-4} \text{ Pa-s (0.27 cp)}$, $C_T = 7.01 \times 10^{-10} \text{ Pa}^{-1} (4.83 \times 10^{-6} \text{ psi}^{-1})$, $B_o = 1.049$. The formation kh product corresponding to m' is

Fig. 4 Data points are for 1980 RLT bottomhole measurements corrected to 4450 m (14,600 ft) datum. Curve is the simulated history.

urements were made and the available wellhead recordings are of no diagnostic value because of severe scaling in the production tubing and surface equipment. Total production during 1979–1983 (phases 0, 1 and 2) was $Q_1 \sim 7.2 \times 10^5 \text{ m}^3$ ($4.5 \times 10^6 \text{ bbl}$).

A Panex pressure/temperature gage was lowered in the re-completed test well on May 26, 1988 (test day 0) and set at a depth of 4252 m (13,950 ft) for the multi-rate test (MRT). After equilibrating overnight, stable values of 73.670 MPa (10,685 psia) and 145.4 °C (293.7 °F) were recorded; the well was opened on May 27, 1988 ($t = 0.0 \text{ hr}$). Some adjustments in flow rate were required before a steady value was attained; an average rate $\sim 9.009 \times 10^{-3} \text{ m}^3/\text{s}$ (4896 stb/d) was produced during the initial step of the MRT. On May 28 ($t = 30 \text{ hr}$) the pressure readings of the original downhole gage began to drift; on May 29 ($t \sim 52 \text{ hr}$) it failed completely and was replaced by a new Panex gage (Fig. 5). The test well was flowing at a steady rate of $\sim 1.736 \times 10^{-2} \text{ m}^3/\text{s}$ (9433 stb/d) when shutin on May 30, 1988 ($t = 82.572 \text{ hr}$) for the buildup portion of the MRT.

On June 20–21, 1988 (test day 25–26 in Fig. 5) there was production of a large amount of sand when the flow rate was increased stepwise to flow rates up to $\sim 4.60 \times 10^{-2} \text{ m}^3/\text{s}$ (25,000 stb/d). There was dramatic drop in the surface pressure after the sand production. The rate was subsequently held below $\sim 3.68 \times 10^{-2} \text{ m}^3/\text{s}$ (20,000 stb/d) with no further significant sand production. The rate generally declined to $\sim 3.20 \times 10^{-2} \text{ m}^3/\text{s}$ (17,400 stb/d) when it was reduced to a stable rate of $\sim 2.246 \times 10^{-2} \text{ m}^3/\text{s}$ (12,205 stb/d) on April 27, 1989, in preparation for the 65-hr shutin test.

On May 15, 1989 (test day 354 in Fig. 5) a Panex P/T gage was lowered in the well flowing at $\sim 2.246 \times 10^{-2} \text{ m}^3/\text{s}$ (12,205 stb/d) and set at 4450 m (14,600 ft). Equilibrated values of 69.534 MPa (10,085 psia) and 153.2 °C (307.7 °F) were recorded just prior to shutting the well on May 15, 1989 ($t = 353.0 \text{ days}$) for the 65-hr buildup test.

Subsequent to the 62-hr pressure buildup test, the test well was produced at $\sim 2.94 \times 10^{-2} \text{ m}^3/\text{s}$ (16,000 stb/d) until it was shutin on November 16, 1989 in preparation for the second scale inhibitor pill injection. Production resumed on November 24 and continued to May 30, 1990, when the test well was shutin to allow evaluation of the disposal well.

During June 1989–May 1990 the rate was maintained at $\sim 2.94 \times 10^{-2} \text{ m}^3/\text{s}$ (16,000 stb/d) to provide the brine inlet

Fig. 5 Composite pressure data (points) from 1988–1991 production of test well. Curve is the simulated history at 4450 m (14,600 ft).

pressure needed for flow operation of the Hybrid Power System for electric power generation (Campbell and Hattar, 1991). Production was resumed on July 27, 1990 (test day 792) and the rate was increased from $\sim 2.94 \times 10^{-2} \text{ m}^3/\text{s}$ (16,000 stb/d) in four stages until a flow rate of $\sim 4.42 \times 10^{-2} \text{ m}^3/\text{s}$ (24,000 stb/d) was attained on October 16, 1990 (test day 873). A slug of about 0.06 m^3 (2 ft³) of sand was produced on October 28 (test day 885); the production rate was subsequently reduced and maintained at $\sim 2.21 \times 10^{-2} \text{ m}^3/\text{s}$ (12,000 stb/d) to allow installation of sand detection equipment. Over a three-month period starting on February 28, 1991 (test day 1008) the flow rate was again slowly increased in steps until $\sim 4.42 \times 10^{-2} \text{ m}^3/\text{s}$ (24,000 stb/d) was attained. On April 27, 1991 (test day 1066), less than 0.03 m^3 (1 ft³) of sand was produced; the rate was quickly reduced.

On May 13, 1991 (test day 1082) a Panex gage was lowered in the well flowing at $q \sim 2.234 \times 10^{-2} \text{ m}^3/\text{s}$ (12,142 stb/d) and set at 4450 m (14,600 ft). Equilibrated values of 67.548 MPa (9797 psia) and 152.1 °C (305.7 °F) were recorded just prior to shutting the well on May 13, 1991 ($t = 1081.4 \text{ days}$) for the 62-hr buildup test. The well was reopened on May 16 and flowed at $\sim 4.34 \times 10^{-2} \text{ m}^3/\text{s}$ (23,600 stb/d) until July 27, 1991 (test day 1157) when it was shutin for safety certification of surface equipment. Flow was resumed on August 8, 1991 (test day 1167). The flow rate at present (Oct. 1991) is $\sim 4.42 \times 10^{-2} \text{ m}^3/\text{s}$ (24,000 stb/d).

During the 1988–1991 production testing to date (Oct. 1991), Pleasant Bayou Well No. 2 has produced an additional volume of $\sim 3.0 \times 10^6 \text{ m}^3$ ($19 \times 10^6 \text{ bbl}$).

Fluid and Formation Properties

An equation-of-state package for water/sodium chloride/methane mixtures (Pritchett, 1985) is used to calculate the properties of the reservoir fluid. For reservoir conditions measured at 4438 m (14,560 ft) at the start of the 1980 RLT (76.642 MPa, 152.2 °C) (11,116 psia, 306 °F), a fully saturated liquid brine, according to the equation-of-state, would correspond to a gas-to-water ratio at standard conditions of $5.71 \text{ m}^3/\text{m}^3$ (31.7 scf/stb). Since the actual measured value is gwr $\sim 4.32 \text{ m}^3/\text{m}^3$ (24 scf/stb), the reservoir is assumed to be initially undersaturated.

The mass fraction composition employed is as follows: H₂O: 0.87733, CH₄: 0.00267, NaCl: 0.12000. This choice yields gwr = $4.32 \text{ m}^3/\text{m}^3$ (24.0 scf/stb). We choose to use a common

Preliminary Reservoir Simulations

The BEG1 reservoir configuration (Fig. 3) has a pore volume of $1.27 \times 10^9 \text{ m}^3$ ($8.0 \times 10^9 \text{ bbls}$) comprised of the main reservoir sand $8.4 \times 10^8 \text{ m}^3$ ($5.3 \times 10^9 \text{ bbls}$) and the remote volume $4.3 \times 10^8 \text{ m}^3$ ($2.7 \times 10^9 \text{ bbls}$). Since both the stable pressure data and the geological studies imply a total connected pore volume of 9.8 to $10.4 \times 10^8 \text{ m}^3$ (6.2 to $6.6 \times 10^9 \text{ bbls}$), portions of the reservoir configuration are presumably not hydrologically connected to the test well. Fluid flow within the interconnected reservoir pore volume is controlled by internal hydrological barriers and major permeable zones that cannot be completely defined. Dimensional parameters L1 through L5 (Fig. 3) correspond to these uncertainties and preliminary reservoir simulation calculations were performed to estimate their effective values. The simulations were performed for both the 1980 RLT and the 1988–1991 production histories.

Since the thickness of the main reservoir sand of BEG1 is $h = 21.3 \text{ m}$ (70 ft), we take $k_1 = 1.70 \times 10^{-13} \text{ m}^2$ (172 md) to preserve the value of the near-well kh product determined from the pressure transient data analysis. The vertical permeability and far-field horizontal permeabilities were varied in the preliminary reservoir simulations. The total formation compressibility ($C_T = 7.01 \times 10^{-10} \text{ Pa}^{-1}$ ($4.83 \times 10^{-6} \text{ psi}^{-1}$)) and brine properties ($\mu = 2.7 \times 10^{-4} \text{ Pa-s}$ (0.27 cp), $\rho = 1036.8 \text{ kg/m}^3$) were the same throughout the reservoir volume.

Most of the simulations were performed assuming the presence of vertical communication between the main reservoir sand and remote layers towards the northeastern end of the reservoir (over lengths L4 and/or L5), but assuming that the pore volume of the main reservoir sand southwest of F1 (Fig. 3) is isolated from hydrologic communication with the test well; this corresponds to a connected pore volume of $V_p = 9.7 \times 10^8 \text{ m}^3$ ($6.1 \times 10^9 \text{ bbls}$). In some cases the calculations were repeated with vertical communication between the layers permitted to the southwest of F1 (along with vertical communication over L4 and/or L5). This allowed the entire pore volume of the BEG1 configuration to be in communication with the test well (i.e., $V_p = 1.27 \times 10^9 \text{ m}^3$ ($8.0 \times 10^9 \text{ bbls}$)). The effect on the simulated history through October 1991 was small (see Riney, 1991a for more details). It may be necessary to refine the assumed distribution of the connected pore volume as the depletion testing continues.

History Matching Simulation

Iterative parametric history-matching simulations established the following estimates for the dimensional parameters L1 through L6 illustrated in Fig. 3: L1 = 990 m (3248 ft), L2 = 5380 m (3.34 mi), L3 = 1420 m (0.88 mi), L4 = 100 m (328 ft), L5 = 7154 m (4.45 mi). The distance L1 from the test well to the sealing fault F1 is based primarily on analysis of the 1980 RLT pressure transient data. L2 approximates the distance from F1 to the mapped faults F2 and F3 shown in Fig. 1; L3 approximates the gap between the ends of faults F2 and F3 in the main reservoir sand. L4 and L5 approximate the distances from F2/F3, to the southwest and northeast, respectively, of the 3960 m (13,000 ft) contour on the structure map (Fig. 1). Vertical communication among the three sandstone units is permitted in this region which represents the single massive sandstone at Chocolate Bayou.

The reservoir simulation model used to match the test well history to date uses a horizontal permeability of $k_1 = 1.70 \times 10^{-13} \text{ m}^2$ (172 md) for the main reservoir sand ($h = 21.3 \text{ m}$ (70 ft)) lying between sealing fault F1 and faults F2/F3; this preserves the near-well transmissivity determined from the pressure transient data. The horizontal permeability in the region of the main reservoir sand southwest of F1 was set to $k_1/4 = 4.24 \times 10^{-14} \text{ m}^2$ (43 md), but the calculations are independent of its value since the region is hydrologically isolated ($V_p = 9.7 \times 10^8 \text{ m}^3$ ($6.1 \times 10^9 \text{ bbls}$)). The calculations

Fig. 8 Comparison of simulated 1988–1991 production history (curve) with May 1991 62-hr buildup data (points) at 4450 m (14,600 ft)

are insensitive to the horizontal permeability to the northeast of F2/F3; it was set at k_1 for simplicity. The horizontal permeabilities in the two low-porosity layers (remote volume) of the model were set at $k_1/7$.

The vertical permeability in each of the three layers was set at one-tenth of its value for the horizontal permeability ($k_v = k_H/10$). Since vertical communication in the Chocolate Bayou area is allowed over a very large area (L4 and L5 in Fig. 3), the simulated results are not sensitive to the k_v values. However, they are sensitive to the distance (L2–L4) from the test well to the area of vertical communication through the otherwise impermeable shales separating the main reservoir sand from the overlying/underlying low-porosity layers.

In simulating the detailed test history of the 1980 RLT and the 1988 MRT, the skin factor (s) at each step was varied according to the downhole pressure transient analysis (first trend line in Fig. 7). This relation was assumed to hold up to the time of the abrupt decrease in s associated with sand production on June 20–21, 1988. Subsequent to that time, its value was held constant at $s = +0.56$ for the remainder of the 1988–1990 simulated production history of the Pleasant Bayou test well.

The model was employed for a detailed history matching simulation of the Pleasant Bayou test well. Comparison with the 1980 RLT data is given in Fig. 4. The semi-log plot in Fig. 5 compares the detailed simulation with the 1988 MRT data and the full 1988–1991 production test history. The data points in Fig. 5 include the downhole measurements from the 1988 MRT, the 1989 65-hr test, the 1991 62-hr test and the bottom-hole pressure values estimated from surface recordings. Figure 8 presents a detailed comparison with the 1991 62-hr test. Agreement is excellent during buildup tests (when the skin factor has no effect). The linear plot in Fig. 9 presents a more detailed comparison of the simulated test history with the bottom-hole pressure values estimated from the wellhead recordings. The relatively small discrepancies at the lower sandface pressures could be further reduced if the values of s implied by the two more recent trend lines in Fig. 7 were used in the simulation. They were not since the variations in s implied from wellhead data are considered tenuous.

Discussion

The close agreement between the estimates for the connected

Table 1 Summary of simultaneous analysis of bottomhole pressure transient measurements for Pleasant Bayou well No. 2. The MRT and RLT data are corrected to 4450 m (14,600 ft) datum level

	Multi-Rate Test		65-Hour Buildup	62-Hour Buildup	RLT
	Drawdown	Buildup			Buildup
Date of Measurement	May 27, '88	May 30, '88	May 15, '89	May 13, '91	Oct 31, '90
Test Days, d	1	4	354	1082	461
$Q, 10^3 \text{ m}^3$ ($Q, 10^3 \text{ stb}$)	0	5.073 (31.94)	940.1 (5,913)	—	86.2 (~542)
$(p_{wf})_{0-}, 10^6 \text{ Pa}$ ($(p_{wf})_{0-}, \text{psia}$)	75.691 (10,978)	72.905 (10,574)	69.534 (10,085)	67.548 (9,797)	71.747 (10,406)
$\Delta q \times 10^3, \text{ m}^3/\text{s}$ ($\Delta q, \text{ stb}/\text{d}$)	9.009 (4,896)	17.36 (9,433)	22.46 (12,205)	22.34 (12,142)	23.22 (12,616)
$m' \times 10^{-7}, \frac{\text{Pa}}{\text{m}^3}$ ($m' \times 10^7, \frac{\text{psi}}{\text{stb}}$)	1.43 (3.83)	1.43 (3.83)	1.43 (3.83)	1.43 (3.83)	1.43 (3.83)
$kh \times 10^{12}, \text{ m}^2$ ($kh, \text{ md-ft}$)	3.62 (12,024)	3.62 (12,024)	3.62 (12,024)	3.62 (12,024)	3.62 (12,024)
s	-0.13	-2.24	-1.09	-1.86	-4.59

$$kh = 0.183 \mu B_o / m' = 3.62 \times 10^{-12} \text{ m}^2 (12,024 \text{ md-ft})$$

These values for the input parameters were also used in the foregoing equation to calculate the values of the skin factor listed in Table 1.

Skin Factor Variations

There have been times during the 1988–1991 testing when Pleasant Bayou well No. 2 had flowed at a constant rate for a sustained period prior to a planned shutin. Recordings of the wellhead pressure just prior to and immediately after shutin can be used to estimate the value of the skin factor at those times. For this purpose we set $\Delta t = 180 \text{ s}$ in the foregoing equation for $\Delta p / \Delta q$ and solve for s to obtain

$$s = 1.151 [(1/m')(\Delta p / \Delta q)_{180 \text{ s}} - \log(k(180) / \phi \mu C_T r_w^2) - 0.351]$$

The choice of $\Delta t = 180 \text{ s}$ has been found to be long enough for wellbore storage effects to be small, and short enough for thermal changes to be negligible.

When the well is shut $\Delta p_{wb} = \Delta p_{hydr}$. The value of $\Delta p_{hydr} = 44.54 \text{ MPa}$ (6460 psi) has been estimated (at the 4450 m (14,600 ft) datum level) from simultaneous wellhead and bottomhole pressure measurements made during the MRT, 65-hr, and 62-hr shutin tests. The sandface shutin pressures $[p_{ws}]_{180 \text{ s}}$ are calculated using the approximation $[p_{ws}]_{180 \text{ s}} = [p_{wh}]_{180 \text{ s}} + \Delta p_{hydr}$. Estimates for the sandface flowing pressures just prior to shutin are given by $[p_{wf}]_{\Delta t=0-} = [p_{wh}]_{\Delta t=0-} + \Delta p_{wb}$, with the values Δp_{wb} calculated using the calibrated wellbore model.

Using the foregoing equation for s , with the values calculated for $\Delta p = [p_{ws}]_{180 \text{ s}} - [p_{wf}]_{\Delta t=0-}$ (with $m' = 1.43 \times 10^7 \text{ Pa/m}^3 \cdot \text{s}$ ($3.83 \times 10^{-3} \text{ psi/stb} \cdot \text{d}$) and $kh = 3.62 \times 10^{-12} \text{ m}^2$ (12,024 md-ft)), estimates for the skin factor are obtained at the corresponding shutin times. These estimates from wellhead pressure recordings and estimates for s based on the simultaneous analysis of the downhole pressure data (Table 1) are plotted in Fig. 7 against the drop in the bottomhole pressure from its original value ($P_o = 76.766 \text{ MPa}$ (11,134 psia)) at the 4450 m (14,600 ft) datum. Also plotted are estimates for s based on the 1980 RLT (Garg et al., 1981).

The estimated values of s from the 1980 RLT data (from three drawdown steps A, B, C and the buildup) and estimates based on the 1988 MRT data are approximated by a single trend line. The apparent drop in the estimated s values between May 30 (MRT buildup) and August 31, 1988 is believed to be associated with the production of a large amount of sand on June 20–21, 1988. Subsequent to the sand production, the

Fig. 7 Estimated skin factor (s) values for well No. 2 displayed as function of pore pressure decrease from $P_o = 76.766 \text{ MPa}$ (11,134 psia)

estimated values of s are approximated by a second line parallel to the earlier trend line (Fig. 7) until October 1990. After production of about 0.06 m^3 (2 ft³) of sand on October 28, 1990, there was also an abrupt reduction in the skin factor. The third trend line in Fig. 7 is followed thereafter. The flow resistance at the sandface is apparently reduced by enlarging and/or cleaning out sand from plugged perforations. Any reduction in s associated with the smaller production of sand on April 27, 1991 is too small to be clearly established.

The trend lines in Fig. 7 appear to indicate that the skin factor depends on bottomhole pressure. The effective stress at the sandface increases as the bottomhole pressure decreases. Inference that s depends on the bottomhole pressure must be considered tenuous, however, since evaluation of Δp_{wb} (and hence associated s estimates) from surface data is subject to significant error at high flow rates as discussed in the foregoing.

In summary, at least three mechanisms might be contributing to the apparent variations of the skin-factor s : 1) an increase associated with an increase in the effective stress on the formation in the neighborhood of the wellbore; 2) an abrupt decrease in s associated with sand production on June 20–21, 1988 and October 28, 1990; and 3) possible creation of a very small gas bubble within the near-wellbore formation. There is no evidence of an increase in the skin-factor associated with the injection of phosphonate scale inhibitor pills on April 18, 1988 and November 19, 1989. This is contrary to the experience at the Gladys McCall geopressured test well (Riney, 1991b).

Reservoir Volume Estimate

The measured drop in the stable reservoir pressure (at 4450 m (14,600 ft) datum) between September 16, 1980 and May 27, 1988 was $\Delta p = P_o - P_i = 76.766 - 75.691 = 1.075 \text{ MPa}$ (156 psi). This value, the corresponding fluid production Q_i , and the formation properties assumed for the Pleasant Bayou reservoir can be used to estimate the connected pore volume drained by the test well, $V_p = Q_i B / C_T \Delta p \sim 1.00 \times 10^9 \text{ m}^3$ ($6.26 \times 10^9 \text{ bbl}$). This value is remarkably close to the estimate of $V_p = 9.8$ to $10.4 \times 10^8 \text{ m}^3$ (6.2 to $6.6 \times 10^9 \text{ bbl}$) based on the geological studies of Hamlin and Tyler (1988). The agreement is to some extent fortuitous given the inherent errors in downhole pressure measurements.

Fig. 9 Comparison of simulated 1988-1991 production history (curve) with flowing bottom-hole (points) estimated from wellhead values (4450 m (14,600 ft) datum)

pore volume given by the geological studies and the stable pressure measurements has provided a sound basis for modeling the Pleasant Bayou reservoir. The BEG1 geological configuration in conjunction with the well test data has permitted the construction of the reservoir simulation model to proceed in a logical sequence as the well test history evolved. This is in sharp contrast to the situation at Gladys McCall, where no geological information is available for determining the reservoir connected pore volume or for locating reservoir boundaries (Riney, 1990).

With continued long-term production testing it should be possible to distinguish between the reservoir models which equally well match the test history through Oct. 1991. It is anticipated that revisions in the permeability distributions assumed in the remote region of the reservoir model may be required. It remains to be seen if the Pleasant Bayou geopressured reservoir will exhibit nonlinear formation response as the pore pressure decreases (and the effective stress on the formation rock increases).

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Appendix

C Gladys McCall Geopressured Reservoir Analysis— June 1987

Gladys McCall Geopressured Reservoir Analysis—June 1987

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The Gladys McCall geopressured reservoir consists of an interbedded sequence of relatively thick sands and thin shales. The lateral extent of the reservoir is not well defined. Gladys McCall Well No. 1 produced approximately 4.0×10^6 m³ (25×10^6 barrels) of brine from Sand Zone No. 8 from October 7, 1983 through May 1987. Analysis of the flow data from the well has led to the development of a conceptual model of the reservoir, which depends on cross-flow from sands overlying/underlying Sand Zone No. 8 for the observed pressure maintenance. The fluid source is remote from the well in the sense that the fluid from the neighboring sands must flow a long distance to find a vertical pathway around the intervening shale stringers in order to recharge Sand Zone No. 8. A reservoir simulation model based on the conceptual model provides an excellent match to the detailed downhole pressure buildup measurements made during the original Reservoir Limits Test and two subsequent short-term buildup tests. The model has also been employed to match the production history of the Gladys McCall No. 1 well and to predict future reservoir response. Nevertheless, the reservoir model employed is not unique and alternate models for pressure maintenance are also being investigated.

Introduction

As part of its Geopressured-Geothermal Program, the U.S. Department of Energy (DOE) drilled, completed and is testing the Gladys McCall No. 1 well located in Cameron Parish, Louisiana. Objectives of the test program include demonstration of the technological and economical feasibility of recovery of thermal energy and natural gas from geopressured-geothermal fluids and generation of data to define the nature and size of the reservoir, characterization of the fluids produced, confirmation of the adequacy of the test well and surface facilities design, and control of the associated scaling/corrosion problems.

The geologic interpretation of the Gladys McCall prospect is based solely on well logs from the subject well and five nearby deep wells. The geologic structure of the prospect is considered to be controlled by three major faults; the east-west length of the fault block cannot be determined from available information.

The Gladys McCall No. 1 test well was spudded on May 27, 1981, drilled to a total depth of 5032 m (16,510 ft), and plugged back to 4825 m (15,831 ft). A 178-mm (7-in.) casing string (run as a liner) was cemented from the surface to 4864 m (15,958 ft), and the well was completed with 127-mm (5-in.) production tubing. The stratigraphic section seen in the borehole consists of alternating massive sandstones and thin shales. There are approximately 335 m (1100 ft) net of sand in the target Miocene sand in the 4393 m (14,412 ft) to 4834 m (15,860 ft) interval penetrated by the test well. Over two-thirds

of the potential productivity appears to be contained in three massive sand zones (Nos. 2, 8 and 9). To date only Sands 8 and 9 have been perforated.

Laboratory tests (Kelkar and colleagues, 1982) gave average values for porosity and permeability of 0.168 and 82×10^3 μm^2 (83 md), respectively. The formation rock was found to be quite stiff; a typical uniaxial compaction coefficient reported was 2.9×10^{-5} MPa⁻¹ (0.2×10^{-6} psi⁻¹). Since this value appears to be unrealistically small, we use a value for total formation compressibility ($C_T = 9.09 \times 10^{-4}$ MPa⁻¹ (6.27×10^{-6} psi⁻¹)) based on correlations for consolidated sandstone (Earlougher, 1977).

Brine chemistry studies by Rice University have shown that fluids produced from Sand Zones Nos. 8 and 9 are essentially identical. Weatherly Laboratories, Inc. reported the following properties of fluid samples recombined to approximate reservoir conditions (Sand Zone No. 8): brine compressibility $\sim 4.0 \times 10^{-4}$ MPa⁻¹ (2.76×10^{-6} psi⁻¹), dynamic viscosity $\sim 3.1 \times 10^{-4}$ Pa-s (0.31 cp), and bubble pressure ~ 63 MPa (9200 psia). Tests on Sand Zone No. 8 showed that the recovered gas increases from 0.172 to 0.223 kmol/m³ (22.9 to 29.7 SCF/STB) as the separator pressure is reduced from 6.89 MPa (1000 psig) to 1.72 MPa (250 psig). The incremental gas production of 0.051 kmol/m³ (~ 6.8 SCF/STB), however, contains a large fraction of CO₂. The average for the total gas production from the well is ~ 0.227 kmol/m³ (30.15 SCF/STB). Average salinity of the brine is 97,800 mg/L.

Sand Zone No. 9, from 4727 m (15,508 ft) to 4766 m (15,636 ft), was flowed from March 21, 1983 to April 14, 1983. A Panex downhole pressure/temperature gage positioned at 4712 m (15,460 ft) recorded the pretest reservoir pressure of 89.02 MPa (12,911 psia) and temperature of 148°C (298°F).

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Downhole values were recorded intermittently during the subsequent drawdown/buildup test. Because of the apparently limited volume of Sand Zone No. 9, it was sealed off with a plug set at ~ 4724 m (15,500 ft) in preparation for testing Sand Zone No. 8.

The 178-mm (7-in.) casing was perforated from 4,621 m (15,160 ft) to 4715 m (15,470 ft) to test Sand Zone No. 8. A Panex pressure/temperature gage was fixed at a depth of 4602 m (15,100 ft) to record stable conditions: $P_i = 88.14$ MPa (12,784 psia) and $T_i = 143^\circ\text{C}$ (289°F). Production started on October 7, 1983, and the drawdown phase of the Reservoir Limits Test (RLT) of Sand Zone No. 8 continued for 21 days (total flow $Q = 4.74 \times 10^4$ m³ at separator conditions (2.98 $\times 10^5$ sep bbl); $t_p = 505.5$ hr). Transient pressure data were recorded at 4602 (15,100 ft) during the drawdown and subsequent buildup phases of the test. There were no large variations in flow rates during the drawdown period, the average flow rate at separator conditions over the full drawdown period was $q = 2253$ sep m³/d (14,170 sep bbl/day).

Testing of Sand Zone No. 8 has continued from October 7, 1983 ($t=0$) to the present time. An integrated reservoir diagnostic test program initiated on April 13, 1987 ($t = 1285$ days) is expected to continue until early 1989.

An earlier paper (Pritchett and Riney, 1985) presented analysis of the Gladys McCall test data and a reservoir simulation model that matched the data for the first year. This paper will present the data pertinent to reservoir response that has accumulated over the past three years and describe the associated evolution of the reservoir model. An excellent history match to the data available through June 1987 for Sand Zone No. 8 is obtained using an updated reservoir simulation model.

Gladys McCall Test Data

Testing of Sand Zone No. 8 by production from the Gladys McCall No. 1 well was initiated on October 7, 1983 ($t = 0$ days). At various times the production has been controlled by either setting the choke to attain a desired flow rate, or leaving the choke open to maximize the flow while maintaining the first stage separator pressure at a constant value. The surface pressure measurements are related to the reservoir response as follows:

$$\begin{aligned} p_{\text{sep}} &= p_{\text{WH}} - \Delta p_{\text{srf}} \\ p_{\text{WH}} &= p_{\text{BH}} - \Delta p_{\text{wb}} \\ &= p_i - \Delta p_{\text{res}} - \Delta p_{\text{sk}} - \Delta p_{\text{wb}} \end{aligned}$$

where

- p_i = initial reservoir pressure,
- Δp_{res} = pressure drop in the reservoir in the absence of skin ($s=0$),
- Δp_{sk} = pressure drop due to skin,
- Δp_{wb} = pressure drop in the wellbore (i.e., within the production tubing string),
- Δp_{srf} = pressure drop in the surface piping (i.e., from the well head to the first stage separator).

Relating the surface pressure measurements to the characteristics of the geopressed reservoir involves calculations for subsurface pressure losses (Δp_{wb} , Δp_{sk} , Δp_{res}).

Bottomhole pressure measurements provide data necessary for separate evaluation of the subsurface pressure losses. To date, bottomhole pressure/temperature measurements have been made at 4602 m (15,100 ft) during three periods:

October 1983 to	Reservoir limits test
December 1983	(drawdown/buildup)
April 1985	79-hr test (buildup only)
January 1986	92-hr test (buildup only).

Under the current ongoing integrated test plan, the well will be flowed until late in 1987, and, when shutin (at $t \sim 1480$ days), a long-term buildup test will be performed that will include bottomhole p/T measurements.

Figure 1 presents a summary of the production history of the Gladys McCall No. 1 well from Sand Zone No. 8 from the start of the Reservoir Limits Test (RLT) through the end of the 92-hr test ($t=0$ to ~ 855 days). The well was subsequently produced at the maximum rate possible while holding the first stage separator pressure constant, $p_{\text{sep}} \sim 6.89$ MPa (1000 psia), for most of the period from $t \sim 855$ to 1285 days. The ongoing integrated test plan for the well was started on April 13, 1987 ($t = 1285$ days).

The well initially experienced severe calcite scaling within the production tubing. When the scale was present, the reduction in tubing diameter made calculations of the wellbore pressure drop (Δp_{wb}) unreliable. Acid treatments were employed on four occasions to remove the scale. After two earlier attempts in November 1984 ($t \sim 418$ days) and May 1985 ($t \sim 594$ days) to inhibit scaling by injection of phosphonate into the formation were aborted, successful "pill" injections were accomplished during June 1985 ($t \sim 628$ days) and February 1986 ($t \sim 851$ days). The tubing has apparently remained scale-free since the first successful pill injection.

The success of the scale inhibitor pill (designed by Dr. Mason Tomson, Rice University) has been crucial to the success of the geopressed test well program. Analysis of the production data has revealed, however, that even successful injections cause an increase of the apparent skin factor, corresponding to an increase in the near-wellbore pressure loss, Δp_s .

In November 1984 ($t \sim 418$ days) the well was shut for approximately 57 hr for the first attempt to inject an inhibitor pill. Although the production rate both before and after shutin was ~ 2380 m³/d (15,000 bbl/day), the surface pressure after the well was reopened was actually less than just prior to shutin. Since the reservoir pressure certainly recovered significantly during the 57-hr shutin period, the inhibitor injected is presumed to have caused an increase in the near-wellbore pressure loss, $\Delta(\Delta p_s) > 0$. The pill injection attempt was aborted when the incremental injection pressure exceeded 4.14 MPa (600 psi). The pill flowback contained solid precipitates and formation plugging was suspected at the time.

The data from the second pill injection attempt (also unsuccessful) more clearly demonstrates an apparently associated increase in the skin factor (Fig. 2). In May 1985 ($t \sim 594$ days), the well was shut for approximately 120 hr, while an attempt was made to inject an inhibitor pill. Although the production rate both before and after shutin was ~ 2460 m³/d (15,500 bbl/day), the surface pressure after the well was reopened was ~ 1.38 MPa (200 psi) less than just prior to shutin. Over the next month the surface pressure actually increased even while drawdown continued at ~ 2460 m³/d (15,500 bbl/day). We presume that the flow of the brine through the formation cleaned out a fraction of the precipitates in the pores thereby recovering the near-wellbore permeability to some extent.

Analysis of the data also indicates an apparent increase in the skin factor at the time of the two successful pill injections.

The downhole pressure data measured during the 92-hr buildup test of January 1986 are in excellent agreement with the data from the 79-hr test of April 1985. However, both infer a near-well reservoir transmissivity (kH) equal to about half the value measured during the reservoir limits test of November 1983. We attribute this reduction in transmissivity to the plugging of about half the perforations in Sand Zone No. 8 that we believe occurred during the November 1984 ($t \sim 418$ days) attempt to inject a scale inhibitor pill (Riney, 1986a). In conjunction with a shale stringer, identified from well logs

Fig. 1 Gladys McCall well production history through February 6, 1986

Fig. 2 Flowing wellhead pressures (recorded at surface tubing of Gladys McCall No. 1 well) at 7:00 a.m. of indicated days

Fig. 3 Comparison of calculated shut-in bottomhole pressure with values estimated from instantaneous wellhead pressure measurements

(by Dr. Myron H. Dorfman of the University of Texas at Austin) at a depth of 4683 m (15,365 ft) to 4684 m (15,369 ft), plugging of the lower half of Sand Zone No. 8 would effectively reduce the sand thickness in direct communication with the wellbore from 101 m (332 ft) at the time of the reservoir limits test, to the upper 63 m (207 ft) at the time of the 79-hr test ($t \sim 550$ days).

Wellhead pressure recordings have been used to estimate bottomhole values immediately after brief shut-ins ("instantaneous shut-in pressures" at $\Delta t \sim 60$ to 180 s) throughout the production history of Gladys McCall Well No. 1. When the well is shut

$$\Delta p_{wb} = \Delta p_{fric} + \Delta p_{hydr} - \Delta p_{hydr}$$

and

$$p_{BH}|_{\Delta t=0+} = p_{WH}|_{\Delta t=0+} + \Delta p_{hydr}$$

The value of $\Delta t = 60$ to 180 s has been found to be long enough for wellbore storage effects to be small, and short enough that thermal effects are negligible (Pritchett and Riney, 1985). Fur-

Fig. 4 Comparison of calculated flowing bottomhole pressures with values estimated from flowing wellhead pressure measurements. Predicted values are also shown under the assumption that the flow rate is maintained at $q = 1590 \text{ sep m}^3/\text{d}$ (10,000 sep bbl/day).

ther, bottomhole flowing pressures have been estimated from the wellhead recordings during steady flow-rate production periods when the wellbore is free of scaling by calculating Δp_{wb} from a wellbore flow simulator

$$p_{BH}|_{t_p} = p_{WH} + \Delta p_{wb}$$

The calculated values of Δp_{wb} are believed to be reliable since the time of the first successful scale-inhibitor pill injection ($t \sim 628$ days). The wellbore model has been calibrated using flowing wellhead and bottomhole data recorded during the RLT and 92-hr test. (The wellbore was scaled at the time of the 79-hr test.)

The data points displayed in Fig. 3 are the instantaneous bottomhole shut-in pressures, $p_{BH}|_{\Delta t=0+}$, estimated from the corresponding wellhead pressure measurements. The data points in Fig. 4 are flowing bottomhole pressures, $p_{BH}|_{t_p}$, estimated from corresponding wellhead measurements using the calibrated wellbore model.

Fig. 5 Conceptual model of reservoir produced by well from Sand Zone No. 8

Fig. 6 Model for Gladys McCall reservoir based on assumption that pressure maintenance due to crossflow from overlying/underlying sands ($k_1 = 158 \times 10^{-3} \mu\text{m}^2$ (160 md); $k_2 = 197 \times 10^{-3} \mu\text{m}^2$ (20 md); $l = 200 \text{ m}$)

Reservoir Model and Simulated History Match

Figure 5 shows the conceptual model that has evolved of the reservoir produced by Sand Zone No. 8. The thin shale layers separating the massive sand zones at the Gladys McCall borehole are assumed to pinch out away from the well. It is assumed that cross-flow from sands overlying/underlying Sand Zone No. 8 is the major cause of the observed pressure reservoir maintenance. The corresponding simulation model for the Gladys McCall reservoir includes a shale stringer that has been identified near the middle of Sand Zone No. 8 (Fig. 6). Since the shallower sands can only supply recharge to Sand Zone No. 8 by inflow beyond the confining overlying shale layer, the model is numerically equivalent to the simulation model shown in Fig. 7. The dimensions in Fig. 6 correspond to Fig. 7 with $L = 4000 \text{ m}$. The distances from the well to the two nearest boundaries and the near-well formation permeability are estimated from analysis of the RLT downhole pressure data (Pritchett and Riney, 1985). This model with elastic rock properties and recharge from a *remote* reservoir volume provides matches both to the measured and the inferred (from wellhead measurements) bottomhole pressure data over the production history up to the present time.

We note that value of the skin factor used in the simulation update was changed from an initial value of $s = +4.3$ to a value of $+8.9$ at the time of the first aborted pill when the lower half of the sand was plugged ($t \sim 418$ days). There were no further changes made in the reservoir model; the flow rate was merely updated with time in accordance with the production history and the skin factor adjusted at the times of the four (two unsuccessful and two successful) pill injections. A value of $s = +17$ has been employed in the simulation since

Fig. 7 Numerical equivalent model used in Gladys McCall reservoir production history-match simulation ($L = 4000 \text{ m}$; $k_1 = 158 \times 10^{-3} \mu\text{m}^2$ (160 md); $k_2 = 19.7 \times 10^{-3} \mu\text{m}^2$ (20 md); $l = 200 \text{ m}$)

Fig. 8 Comparison of bottomhole pressures calculated with simulation model and values measured during drawdown/buildup portions of reservoir limits test

the second successful pill injection during February 1986 (i.e., $t > \sim 851$ days).

The complex history-matching curve that closely approximates the two sets of estimated bottomhole pressure data sets in Figs. 3 and 4 is calculated using the reservoir simulation model described in the foregoing. The predicted bottomhole pressures during and beyond the 140-day period when the well is expected to flow at $q \sim 1590 \text{ sep m}^3/\text{d}$ (10,000 sep bbls/day) is also shown in the two figures.

The agreement of the simulated history with the downhole pressure transient measurements during the reservoir limits test (Fig. 8), the 79-hr buildup test (Fig. 9) and the 92-hr buildup (Fig. 10) is also excellent.

It seems worthwhile here to review the evolution of the estimates made for the reservoir volume from the time the production of Sand Zone No. 8 was initiated for the reservoir limits test on October 7, 1983 ($t = 0$ days).

1 At the conclusion of the buildup period following the RLT, the connected pore volume was estimated to be

$$V_p = \phi V > \sim 6.8 \times 10^7 \text{ m}^3 (0.43 \times 10^9 \text{ bbl}) \text{ at } t = 54 \text{ days}$$

This corresponds to $L = 0$ in Fig. 7.

2 To match the instantaneous shutin pressure data available from production testing through September 4, 1984, it was found necessary to hypothesize an additional *remote* reservoir volume (Pritchett and Riney, 1985). The RLT was apparently too short in duration for the remote volume to have significantly affected the pressure at the well. Simulations cor-

Fig. 9 Comparison of bottomhole pressures calculated with simulation model and values measured during 79-hr buildup test

responding to configurations with various values of L were performed. All simulations with $L \geq 1500$ m were found to match the data (available at that time) equally well. The revised estimate for the connected pore-volume was therefore assumed to be

$$V_p = \phi V \sim 1.94 \times 10^8 \text{ m}^3 (1.22 \times 10^9 \text{ bbl}) \text{ at } t = 333 \text{ days}$$

3 With further time of production, the predicted bottomhole pressure simulations using different values of $L > 1500$ diverge as the effect of the remote reservoir volume becomes more important. By August 5, 1985 it was apparent that the instantaneous shutin pressure values were no longer matched by the reservoir volume corresponding to $L = 1500$ m. Simulation of the production history through August 5, 1985 was found to be closely matched using the reservoir volume represented by $L = 4000$ (Riney, 1986a). The connected pore volume was therefore estimated to be

$$V_p = \phi V \sim 4.0 \times 10^8 \text{ m}^3 (2.5 \times 10^9 \text{ bbl}) \text{ at } t = 668 \text{ days}$$

All simulations since August 5, 1985 have assumed this reservoir volume (including the history-matching simulation shown in Figs. 3 and 4). The equivalent reservoir dimensions are shown in Fig. 6.

Discussion

Five geopressed design wells have been drilled, completed and tested under the DOE Geopressed-Geothermal Program. Sufficient data are available during the depletion phase of the production tests of two of these (L. R. Sweezy and Gladys McCall wells) to conclude that unanticipated reservoir drive mechanisms are operative; in both cases the reservoir pressure is maintained at a higher value than expected. An objective of the DOE program is to determine which mechanism(s) is responsible for the observed pressure maintenance.

Models that match the downhole pressure measurement and the observed reservoir depletion behavior might possibly be devised based on any one of the following reservoir drive mechanisms:

- 1 stress-dependent rock formation compressibility,
- 2 long-term formation creep,
- 3 cross-flow from overlying/underlying sands,
- 4 shale-water recharge,
- 5 leakage across boundary faults, and
- 6 free gas evolution.

It is not possible to determine the dominant mechanism on the basis of test data from a single well.

Fig. 10 Comparison of bottomhole pressures calculated with simulation model and values measured during 92-hr buildup test

It should be emphasized that geopressed reservoirs differ widely as do normally pressured reservoirs. It may be that the dominant drive mechanism will differ from one reservoir to another. For example, the small geopressed reservoir produced by the Sweezy well is sandwiched between two massive shale zones which suggest shale-water recharge as a viable drive mechanism. The Gladys McCall reservoir consists of an interbedded sequence of relatively thick sands and thin shales; the individual shales probably do not extend large lateral distances before pinching out. At this time, cross-flow from overlying/underlying sands is believed to be the predominant reservoir drive mechanism rather than shale-dewatering.

In a related study (Riney, 1986b), a series of parametric reservoir simulation calculations were performed to determine the range of reservoir parameters and test conditions under which irreversible rock compaction might be an important mechanism for sustaining reservoir pressure. The associated effect of stress-dependent permeability was also evaluated. The range of input parameters were based on information supplied by the University of Texas at Austin (UTA) rock mechanics group (Drs. E. P. Farenthold and K. E. Gray) based on laboratory tests on core sample from geopressed formations. The simulations show that the effect on reservoir response increases with formation compressibility and decreases with formation transmissivity. When the compressibility and transmissivity values believed appropriate for Sand Zone No. 8 of the Gladys McCall reservoir are used in the simulation, however, all effects of irreversible rock compaction were found to be insignificant.

The evolution of free gas has from time-to-time been suggested as a mechanism for reservoir pressure maintenance at Gladys McCall (because of the associated increase in the compressibility) and a possible explanation for the apparent increase in the skin factor (because of relative permeability effects associated with the creation of a gas bubble near the wellbore). To evaluate these possibilities, parametric reservoir simulations were made using Gladys McCall reservoir conditions (unsaturated case) and a comparison case in which the initial methane content was increased to the bubble point (saturated case). Even for cases that maximize the credible effects for the Gladys McCall reservoir conditions, any free gas would be confined to the immediate neighborhood of the wellbore. This would appear as an added skin effect but would not result in an apparent skin anywhere near as large as $s_d \sim 17$.

The ongoing integrated test program for the Gladys McCall well will provide crucial information to help distinguish between the candidate reservoir drive mechanisms. The behavior of the reservoir during the pressure recovery phase subsequent

to its long-term production will be studied. Information to calculate the skin factor and to determine if the formation has been partially plugged will also be obtained. Pressure measurements in several sands overlying Sand Zone No. 8 are also planned as part of the integrated test program.

The parametric calculations (described in the foregoing) have eliminated 1 (irreversible rock compaction) and 6 (free gas evolution) as major mechanisms for Gladys McCall pressure maintenance. Measurements of pressures in overlying sands planned as part of the integrated test program will either confirm or discredit 3 (cross-flow) as the dominant mechanism. If cross-flow is discredited but the linear (reversible) model described earlier also matches the long-term buildup data (subsequent to closing the well late in 1987), a closed reservoir of large lateral extent would be confirmed. If the model does not match the long-term buildup measurements, history-matching calculations should allow differentiation between recharge from leaky boundaries as opposed to pressure maintenance by sources distributed throughout the reservoir volume (formation creep or shale-water recharge).

Simulation studies alone may not allow us to distinguish between 2 (long-term formation creep) and 4 (shale-water recharge). Since the shale layers are thin the time required for recharge will be relatively fast. Rock mechanics measurements are underway at UTA to determine the time constants govern-

ing Gladys McCall formation creep response. This information could be used in reservoir simulation studies to differentiate between these two mechanisms.

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