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Reservoir Potential of Thin-Bedded Turbidites: Prospect Tahoe

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Abstract

Geological/Petrophysical modeling, production testing and pressure transient analysis have demonstrated that thin-bedded turbidites can be very productive and have large connected volumes at Prospect Tahoe. This offshore Alabama field (water depth = 1,500 ft) occurs as a northwest-southeast trending turbidite channel/levee complex and is predominantly a gas reservoir with a thin oil rim. There is a relatively large volume of geological and engineering data for this thin-bedded turbidite deposit. In addition to a 3-D seismic survey, there are seven exploratory penetrations (three with whole core), a production test, and PVT analyses from several samples. The hydrocarbon accumulation exhibits a proven hydrocarbon column height in excess of 700 feet over an area greater than 4,000 acres. The reservoir depth at Tahoe is about 10,000 feet subsea, and initial reservoir pressure is about 5,000 psia.

A 100 foot cored interval was completed and production tested, attaining a stabilized rate of 29 MMCFPD for three days. The subsequent five-day downhole shut-in exhibited persistent radial flow, indicating permeability-thickness of 1,700 md-ft and a connected area in excess of 520 acres. In the production test interval, over 1,400 individual beds were identified from whole core. The average sand bed thickness is less than 0.5 inches, and no sand bed exceeds three inches in thickness.

This interdisciplinary study demonstrated that thin-bedded turbidites can be successfully tested, be very productive, and have large connected volumes. This work may have analog application elsewhere.

Introduction

Prospect Tahoe is an oil and gas accumulation located 90 miles south of Mobile, Alabama in the Gulf of Mexico, as illustrated in Figure 1. The prospect is situated on Viosca Knoll Blocks 783 and 827 in water depths ranging from 1,200 to 1,600 feet. This paper focuses on a Miocene sand that has been penetrated by exploratory drilling at depths ranging from -9,683 to -10,412 feet subsea. The maximum net hydrocarbon pay encountered by the seven exploratory penetrations on the prospect is 131 feet of gas within a 290-foot gross thickness interval comprised of alternating thin sands and shales. A gas column height in excess of 500 feet is interpreted to occur above a 200-foot oil rim.

In addition to the well logs for the seven penetrations on the prospect, 273 feet of whole core was obtained from three wells, and a 3-D seismic survey was shot to help delineate structure and identify areal extent of the hydrocarbons. Well OCS-G 6886 No. 4 Sidetrack was completed in a 100 foot interval where whole core was available, and was production tested to evaluate the productivity of the thinly bedded turbidite sands.

Geological Setting and Depositional Model

The hydrocarbon bearing sand is interpreted to be part of a turbidite channel-levee system of Miocene Age. Repeated pulses of sediment originated from the northwest and flowed for many miles along ribbon-like channels to the southeast. The orientation of the interpreted turbidite channel is superimposed on a structure map in Figure 2 which shows the well penetrations and illustrates the major faulting and approximate hydrocarbon contacts for the sand. The larger turbidite flows are believed to have deposited thin overbank sand layers well beyond the margins of the turbidite channel. The main channel is interpreted to be less than ½ mile wide while the thinly bedded overbank sand layers are believed to extend two to three miles on either side of the channel axis.

The seismic expression of the sand near the gas bearing test well is illustrated by a deconvolved 3-D seismic profile in Figure 3. As the objective sand/shale package approaches its maximum thickness of 300 vertical feet the seismic response changes from a single left kicking event to a double left kicking event. The presence of oil and gas in the sand increases the acoustic impedance contrast between the bounding shales and the reservoir sands, resulting in a seismic anomaly in areas with good quality pay.

A stratigraphic cross section through four of the wells on the prospect is shown in Figure 4. The base of the thinly layered sand/shale levee deposits is above the more massive sands and channel fill near the channel axis.

The main development targets at Prospect Tahoe are the thinly bedded overbank sands that seem to have good lateral continuity and may contain in excess of 90% of the estimated gas reserves. Individual sand units within the levees have depositional dips of less than two degrees and generally range in thickness from a fraction of an inch up to about three inches based on whole core recovery. The total number of individual sand units within the 300-foot thick levee sequence is estimated to exceed 3,000 at the test well.

The hydrocarbon accumulations are interpreted to occur on a faulted anticlinal structure, situated above an unpenetrated salt feature. The main reservoir is estimated to have a gas column that exceeds 500 vertical feet and an oil column of approximately 200 feet based on well control and a 3-D seismic survey. Neither a gas-oil contact nor a water level has been penetrated by well control in the tested reservoir.

A smaller, more oil prone accumulation with a significantly higher oil-water contact was penetrated to the northwest of the main reservoir area. The two penetrated reservoirs on the prospect are interpreted to be separated by faulting, although stratigraphic seals at the channel margins may play a role in trapping and separating the hydrocarbon accumulations. Whether or not the channel margins of this turbidite system are seals to hydrocarbon migration and production cannot be conclusively determined with the data presently available at Prospect Tahoe.

Petrophysical Properties

The seven exploratory well penetrations have a base logging suite consisting of induction, density, neutron, acoustic and sidewall samples. Several formation fluid and pressure samples were acquired in addition to the whole core.

The intrinsic petrophysical properties of the sand in this thin-bedded reservoir are difficult to extract solely from standard wireline data. This is due to the inherent vertical and horizontal resolution capabilities of these tools. Thus, an unconventional approach was used to integrate direct measurements from stressed whole core plugs with higher resolution wireline tools (e.g., dipmeters). The log shapes are generally serrate in appearance reflecting the highly laminated nature of the rock (Figure 5a). Reservoir quality is relatively high with stressed porosities ranging from 23 to 30 percent and horizontal stressed brine permeabilities ranging from about ten to several hundred millidarcies. Stressed core data were correlated with conventional wireline data to estimate porosity and permeability as a function of formation composition, texture, and bed thickness.

Over 1400 individual sand/silt beds were identified in 100 feet of whole core with average bed thicknesses of approximately 0.5 inches. In general, the bedding contacts are subparallel to parallel but may be wavy to lenticular in appearance. The basal contact is usually very sharp with a general upward gradational transition from sand to silty shale (Figure 5b,c).

The rock is characterized by alternating layers of sand or silt with silty shale or mudstones. It ranges from unconsolidated to slightly consolidated. Compositionally, the reservoir rock is quartz rich, feldspathic to sublithic with varying amounts of clays. In addition, a slight diagenetic overprint has been identified in several of the individual reservoir beds, mainly in the form of calcite cementation. However, little reduction in reservoir quality can be attributed to this diagenetic overprint. Grain size ranges from upper very fine sand (125 microns) to coarse silts (62.5 microns) and in general the rock is poor to very poorly sorted (Figure 5d).

Production Test Design

A production test was considered with the goals of proving productivity and estimating continuity. The rock-fluid system at Prospect Tahoe makes a production test especially difficult to design, execute, and analyze. Complicating factors include: permeability variation from under ten to several hundred millidarcies; condensate content of about 35 bbl/MMscf; the three-dimensional seismic survey was interpreted to indicate a fault near enough to the well to affect the test; and bed terminations might further complicate interpretation. These concerns and complications motivated design work to ensure that a test of reasonable duration could be expected to achieve the objectives of estimating minimum connected volume and proving the productivity of the thin-bedded channel-levee facies.

Normally, estimates of the formation properties are made (based on available core, log, flow, or analog data), and these estimates are used in design equations based on analytic solutions to the linearized radial diffusivity equation.[1] These equations predict the time to the beginning of the radial flow regime, the time of onset of boundary effects, etc. These times are then used to specify the required durations for the flowing and shut-in periods.

These equations were not considered adequate for the complex geology and fluids at Tahoe. Therefore, numerical reservoir simulators were used to generate the response functions. After generating a particular response, the pressure data were analyzed to see if the desired parameters could be extracted from the buildup data. If reasonable estimates could be obtained, the test design was deemed technically feasible for that set of assumed properties, geometry, and flow schedule.

Design Simulations

All of the simulation models had some of the same features. Layer porosity and permeability were estimated by correlation with bed thickness. The bed thickness is available either from digitized core photographs or from microresistivity logs. The fluid description was based on a wireline-retrieved fluid sample from Tahoe No. 4. The sample indicated a well stream gravity of 0.73, condensate content of 35 bbl/MMscf, and provided compositional data used for single phase, volatile oil, and equation of state modeling. Where needed, multiphase pressure traverses were calculated for 3½-inch nominal tubing. The shales were considered to be impermeable to hydrocarbons due to the capillary entry pressure of 500 psi, which would not be approached in any layer during the production test. Other properties of interest are given in Table 1.

Several simulators have been used to examine aspects of the test design. The models were needed to address layering, reservoir boundaries, phase behavior, and well inflow/outflow.

A high-resolution single-phase R-Z model was used to represent the sand-shale sequences explicitly, using up to 256 layers. Transmissibility barriers ensured that no gas could flow through the shale, even as the compressibility of the shale and associated water provided pressure support. Several geological and simulation models were used to examine different facies and completion intervals. These models demonstrated that the various facies as identified from core and log respond very differently to pressure transients, as shown in Figure 6. Thus, the test interval should be chosen to minimize mixing of these different facies.

Next, a three-dimensional single-phase model was used to study the effects of variable bed length explicitly. This model was limited to 32 layers. The bed lengths were drawn from a binomial distribution with a mean length of 1,900 feet based on outcrop studies and statistical modeling available at the time. Additional data and analysis have led to the conclusion that this estimate of bed length is probably pessimistic. This model was also used to assess the effects of nearby faults. Examination of the buildup behavior of this model indicated that the complexities caused by variable bed length and faults were largely ended by about 5-7 days of shut in. After that time, a conservative estimate of connected pore volume could be obtained by material balance, using the final observed pressure as a lower limit on average reservoir pressure.

Then, 32-layer two-dimensional R-Z buildup studies using an extended black oil simulator (BOSIM) included a more realistic representation of phase behavior and multiphase flow in the reservoir. A volatile oil representation was used to model mass transfer between the gas and oleic phases. In this and the following model, the layering model honored the distribution of bed thicknesses by discretizing the core-derived distribution from the test well. Equal percent increments in probability were used to set the bounds on the thickness classes included in each layer. This lumping into "pseudolayers" is possible due to the no cross-flow assumption. The effects of shale compressibility were incorporated using an augmented water compressibility:

$$\tilde{c}_w = c_w + \frac{\phi_{sh}(c_{sh} + c_w)V_{sh}}{\phi\, S_w(1-V_{sh})} \qquad (1)$$

Over the limited pressure range encountered in a production test, the compressibility could be considered to be constant for purposes of material balance but not pressure transient analysis. The reduction of the layer count did reduce the complexity of the pressure response relative to the more geologically detailed single-phase model, above. Also, as discussed below, a volatile oil model cannot represent some aspects of condensate phase behavior, especially near the well. This may result in significant differences, vis-à-vis an equation of state simulator, in predicting flowing wellbore pressure (as shown in Figure 7). The predictions of buildup response are adequate except for skin effect.

Finally, an equation of state simulator was used to model the drawdown behavior, using five pseudo-components to represent the gas-condensate system. The predictions of drawdown were important: (1) to determine whether the well could saturate the facilities with only the cored interval perforated; (2) to ensure that, for reasonable skin factors, the drawdown would be within guidelines for a gravel-packed completion; and (3) to formulate methods to estimate the bottomhole drawdown and skin factor from parameters that could be obtained at the surface during flowing periods.

A set of design charts was prepared from the results of the simulations. An example, which shows nominal impairment contoured on a cross-plot of flowing tubing head pressure and gas rate, is included as Figure 8. The skin is termed nominal because it is composed of actual wellbore damage, differences in kh between predicted and actual, wellbore fluid load, and condensate dropout. For the simulations, but not the data, it is the true skin. Also shown on Figure 8 are observations from various phases of the test; these will be discussed in the Monitoring section of this paper.

Results Of Design Study

1. The completion should be confined to the cored interval only to minimize the complexity of the buildup response and maximize confidence in estimates of permeability-thickness and net thickness. The cored interval comprised 100 of the 270 gross feet in the pay interval. Posttest pressure measurements were specified to detect out-of-zone communication, if it occurred.

2. For reasonable skin effects, rates of up to 30 MMscf/day could be obtained from the cored interval only with near wellbore drawdown of less than 1500 psi.

3. Even with stratification, bed terminations, and faults the connected pore volume could be calculated with reasonable accuracy using a material balance estimate—if the shut-in period were sufficiently long, about 5 to 7 days. The last recorded shut-in pressure can be used as a minimum value for the average reservoir pressure. This simple and conservative approach is a virtually failsafe method to obtain a lower bound on connected pore volume.

4. Design charts to monitor well inflow were prepared. These charts required only flowing tubing head pressure and gas rate to estimate nominal well impairment.

5. Accurate pressure data during various phases of the test were vital. Therefore, the downhole tools were designed to include two sets of three strain gauges with surface readout capability and a carrier containing three quartz crystal and one bourdon-tube gauge, integrated with a bottomhole shut-in valve and annular sample chamber.

6. An additional flow and shut-in cycle was recommended prior to the final shut in. This test was designed to ensure that a good estimate of kh and skin could be obtained, to aid in analysis and to support a stimulation treatment if needed. The early shut in would minimize possible complications due to differential depletion among layers of contrasting permeability.

Test Monitoring

The production test can be divided into four phases: Phase 1, prior to failure of the first gravel pack; Phase 2, between the installation of a new pack and the foamed acid treatment; Phase 3, comprised of the extended flow and shut-in periods; and Phase 4, the posttest pressure measurements. Phases 1-3 each had two buildups that could be analyzed with confidence; most of these buildups were obtained during short shut-ins for operational reasons.

Figure 8 shows the flowing tubing head pressure and gas rate for all three phases of the production test. Several points should be noted: (1) there is a very large decrease in nominal impairment at about the time sand was produced to the surface (end of Phase 1); (2) the well was cleaning up slowly during Phase 2; and (3) the foamed acid job improved the inflow significantly. In the extended flow period, the well flowed at a stabilized rate of 28.8 MMscf/day with over 900 bbl/day of associated condensate. The well was then shut in for a 5½ day buildup.

The responsibilities of the on-site reservoir engineers included: programming the pressure recorders, overseeing fluid sampling, recommending times to begin and end shut-in periods, ensuring that proper shut-in procedures were followed, supervising the interrogation of the downhole gauges via wireline, and providing on-site analysis.

The ability to retrieve data from the gauges during the test proved useful. The interrogation was used to verify that the gauge was working properly. Also, data retrieved after the pre-acid buildup was analyzed to show a high degree of impairment ($S>30$). The skin was used to justify a foamed acid treatment, which reduced the skin to eight.

The bottomhole shut-in valve allowed the gauge interrogating tool to be run with no surface pressure and improved the data quality of the buildups on which it was used.

At the end of the test, a series of pressure measurements were taken within the pay interval but outside the perforated interval. There was considerable noise in these data due to rig motion. The data were averaged and reconciled with a pretest quartz crystal measurement (at the top of the tested interval) and an open-hole wireline pressure measurement (below the tested interval). The measurements indicate that there was no communication below zone and possible communication above zone, as shown in Figure 9. Since the above-zone data are especially noisy, this indication of communication is not conclusive. Nonetheless, all volume and permeability estimates were discounted to allow for the possibility of out-of-zone communication.

Production Test Analysis

The estimates of permeability-thickness (kh) and skin are straightforward and reliable. Real gas potential and a time superposition group were used in all analyses. Each buildup test indicated an increase in kh over the previous tests, with the exception of the last test when kh was stable. As shown in Table 2, estimated kh increased from about 600 md-ft to over 1,700 md-ft. This effect is ascribed to gradual opening of additional layers due to cleaning out perforations or removing water blockage. Such a trend is unusual, but the consistency of the trend and the high quality of the data (see Figure 10, the pre-acid Horner plot) indicate that the effect is real.

The final value of 35 md (Table 2) compares reasonably well with the predicted value of 46 md used in the design simulations, but may still reflect an overestimation of reservoir thickness. The final skin of 8-10 may be due to near-well damage or condensate dropout. Also, the well was still cleaning up. For the well geometry and the expected low vertical permeability, analytic solutions and simulations demonstrate that no partial penetration skin should be apparent. The damage could have been caused by high fluid losses, plugging of the prepacked gravel pack screen, mixing of sand and silts in the perforated interval, or poor perforation cleaning.

An early seismic interpretation placed a fault just south of the No. 4 Sidetrack well. The high-quality radial flow data (Figure 10, the pre-acid test; Figure 11, the final test) do not indicate a fault near the test well. A subsequent seismic review also eliminates the fault.

The complex geometry and heterogeneous properties of the reservoir would lead one to expect a correspondingly complex test response. Remarkably, the Horner plot of the extended buildup reveals an effectively homogeneous radial flow regime that persisted for the entire 127 hours of the buildup (see Figure 11). This indicated that radius of investigation formulae could be used. The method of images was used to investigate different formulae for radius of investigation—for single and multiple intersecting boundaries, the rock and fluid properties at Prospect Tahoe, and the actual flowing and shut-in schedule. A boundary was considered detectable when the deviation of the calculated results from the semilog line was 10 times the average deviation of the observed pressure about the semilog trend. These calculations showed departures generally occurred shortly after the time predicted by Hurst's formula,[2]

$$r_i = 0.0429\sqrt{\frac{kt}{\phi \mu c_t}} \tag{2}$$

Therefore, this formula should tend to underpredict the radius of investigation for this test. Using Equation 2, the most likely connected area was estimated to be 520 acres. This most likely area was obtained by a Monte Carlo analysis in which the petrophysical properties were sampled from triangular, uniform, or normal distributions; the uncertainty in net thickness was also included.

Conclusions

The cost of deepwater operations and the ambitious goals for this test motivated extensive design, monitoring, and analysis. The design work demonstrated the feasibility of determining reservoir properties and estimating minimum connected volume. Using detailed geological models, we were able to obtain good prior estimates to use in design work and increase the confidence in the viability of the test. Operationally acceptable flow and shut-in periods were specified. Equation of state drawdown simulation provided methods to monitor well impairment and clean-up.

The analysis for kh and skin was straightforward due to the unusually high quality of many of the data sets. The final estimates for skin and kh are 10 and 1,700 md-ft, respectively. The connected pore volume estimated from a radius of investigation formula yields a drainage area of at least 520 acres.

Acknowledgments

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Nomenclature

c_{sh} = shale pore compressibility, psi^{-1}
c_t = total compressibility, psi^{-1}
c_w = water compressibility, psi^{-1}
$\tilde{c}_w$ = augmented water compressibility, psi^{-1}
k = average permeability, md
r_i = radius of investigation, ft
S_w = water saturation in sand
t = time, hrs
V_{sh} = shale fraction of gross section
μ = fluid viscosity, cp
ϕ = average sand porosity
ϕ_{sh} = shale porosity

References

1. Earlougher, R. C., Jr. (1977), Advances in Well Test Analysis, Mon. Vol. 5, Soc. Pet. Eng., AIME, pp. 58-69.

2. Hurst, W. (1978), Advances in Petroleum Engineering, PennWell Publishing Company, Tulsa, OK, pp. 313-321.

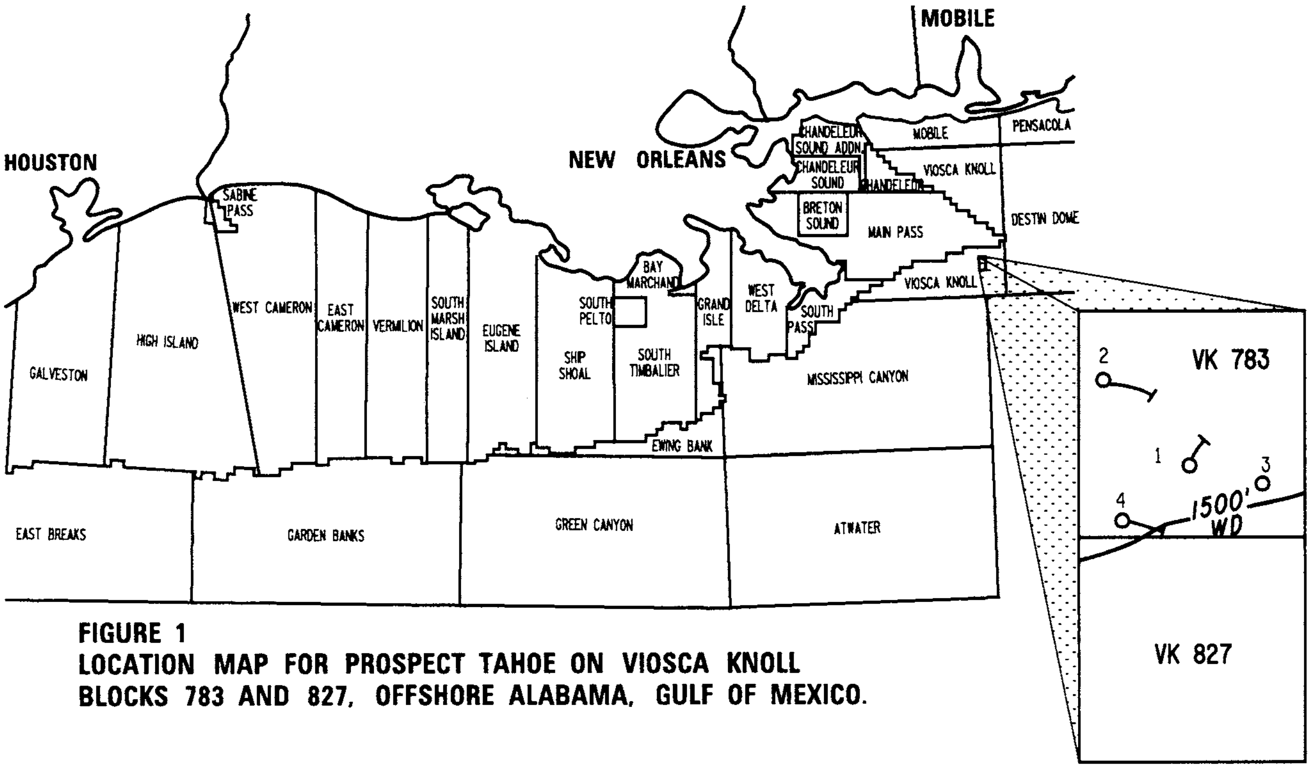


FIGURE 1
LOCATION MAP FOR PROSPECT TAHOE ON VIOSCA KNOLL
BLOCKS 783 AND 827, OFFSHORE ALABAMA, GULF OF MEXICO.

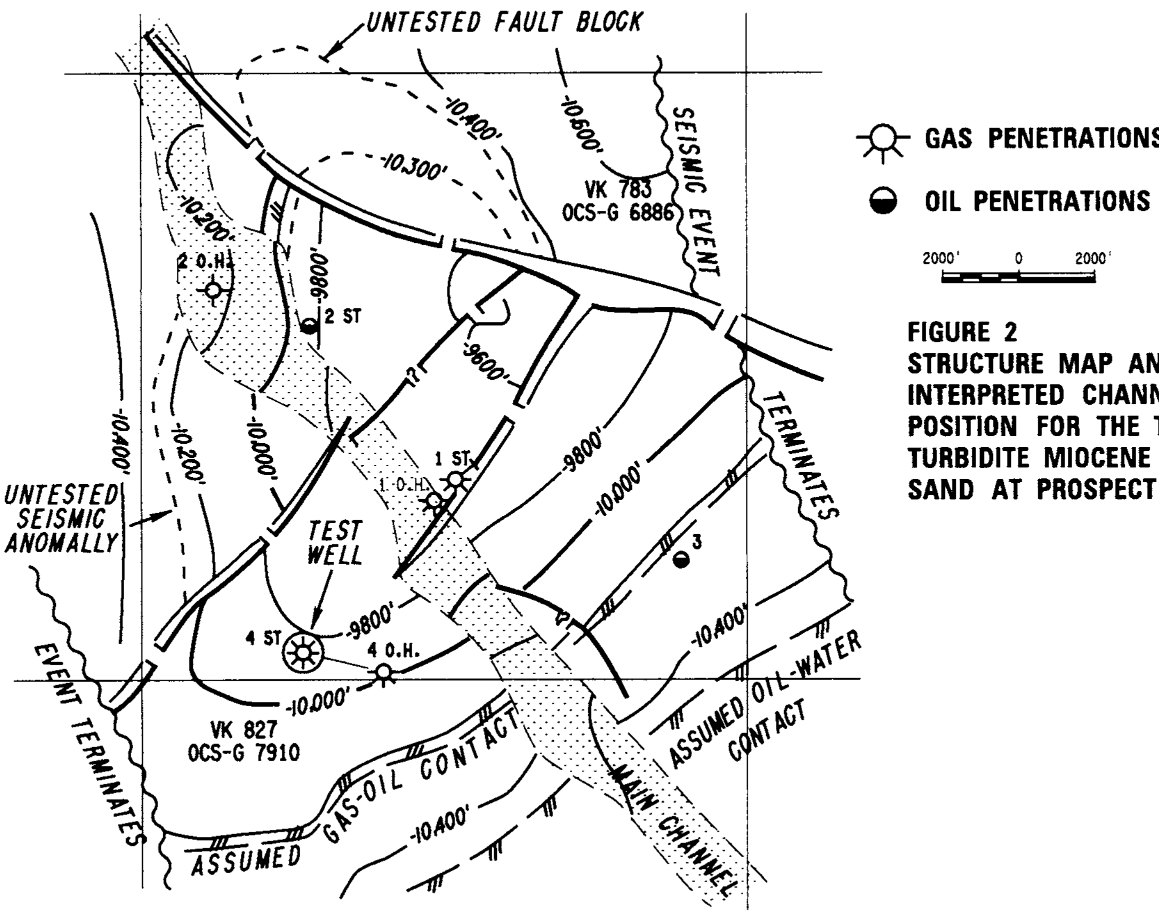


FIGURE 2
STRUCTURE MAP AND INTERPRETED CHANNEL POSITION FOR THE TESTED TURBIDITE MIOCENE AGE SAND AT PROSPECT TAHOE

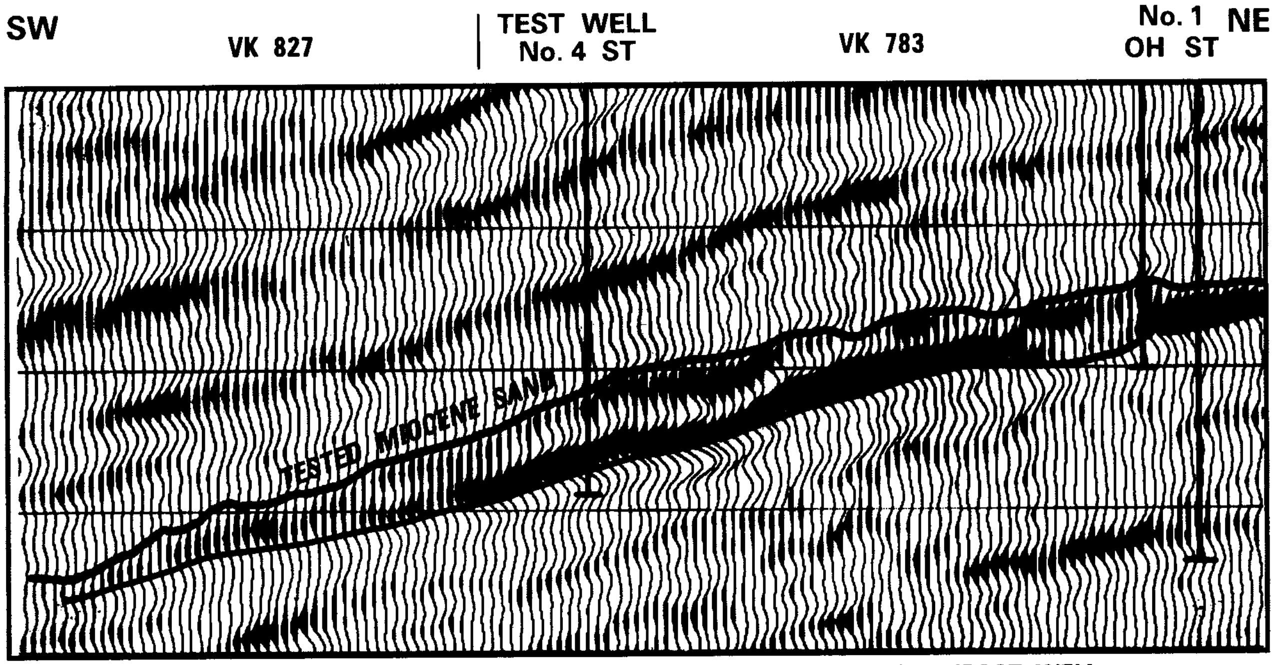
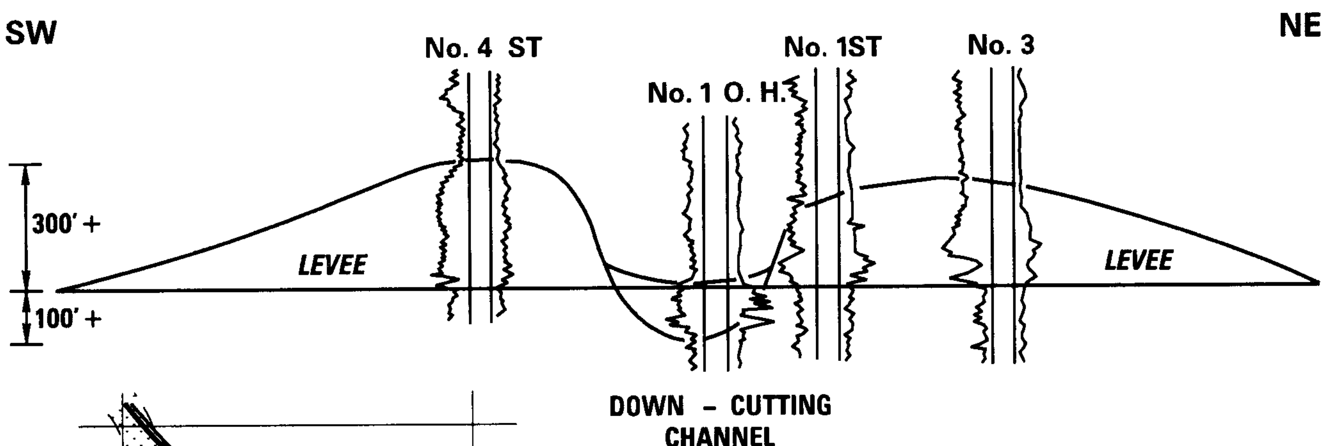


FIGURE 3: SEISMIC PROFILE THROUGH THE TESTED No. 4 SIDETRACT WELL WHERE THE 290-FOOT GROSS SECTION OF THINLY BEDDED TURBIDITE SANDS IS EXPRESSED SEISMICALLY AS A DOUBLE, LEFT KICKING EVENT.



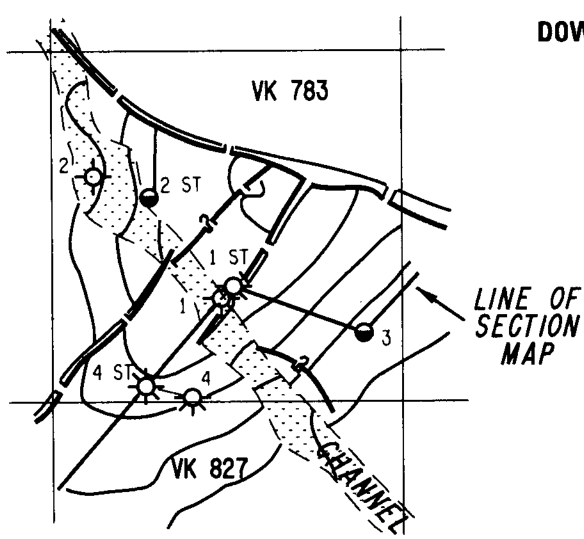
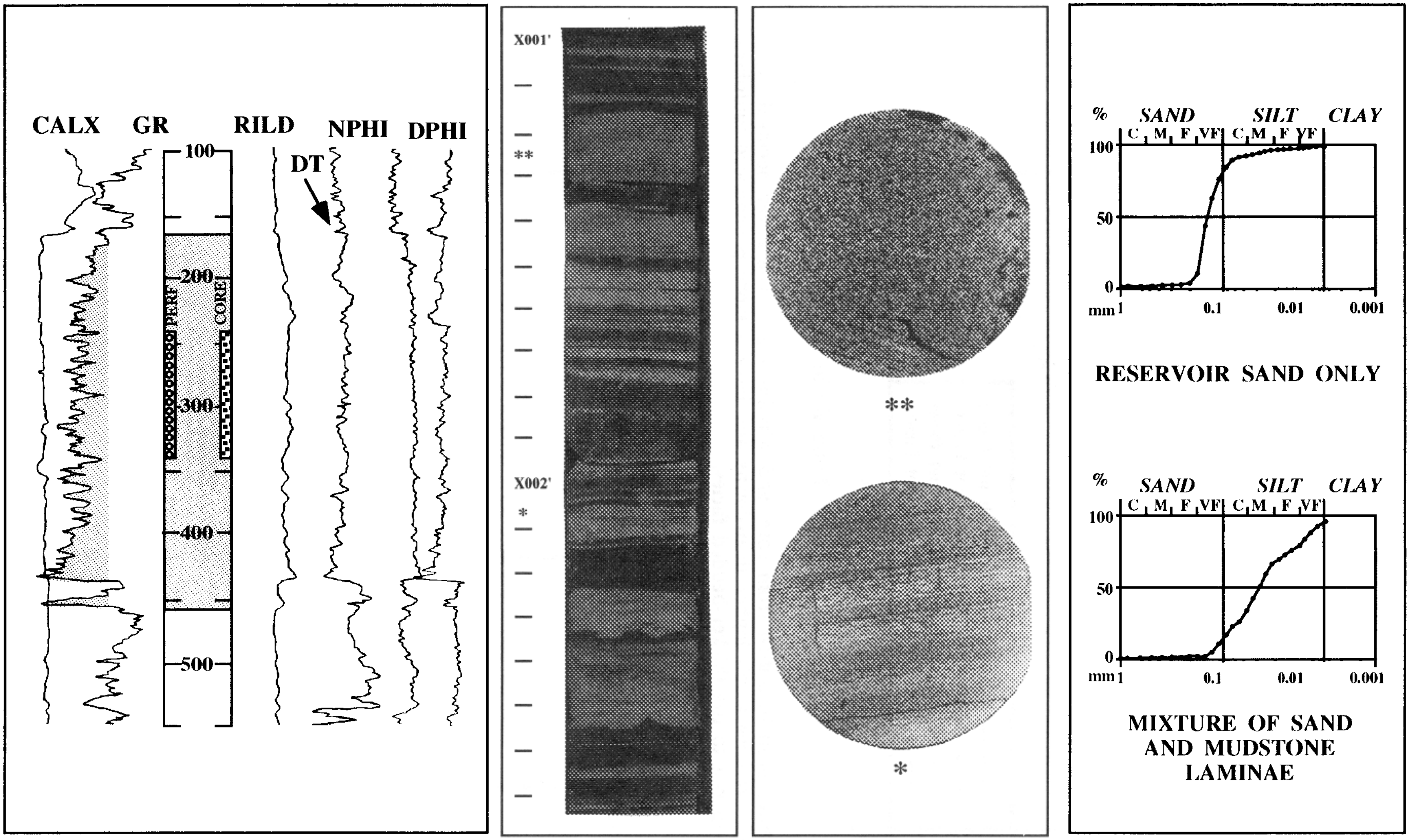


FIGURE 4
STRATIGRAPHIC CROSS SECTION THROUGH THE TESTED No. 4 SIDETRACT WELL AT PROSPECT TAHOE (after R. S. BARNARD)



(a) Wireline Logs and Tested Interval Location

(b) Core Photograph

(c) Thin Sections

(d) Grain Size Distributions

FIGURE 5: THIS CORE AND TEST INTERVAL ARE IN A FINELY LAMINATED PORTION NEAR THE CENTER OF THE RESERVOIR. ANALYSIS OF THIN SECTION AND SIEVE DATA SHOWED THAT EVEN THE VERY THIN SAND LAMINAE CONTAIN REASONABLY GOOD QUALITY RESERVOIR ROCK.

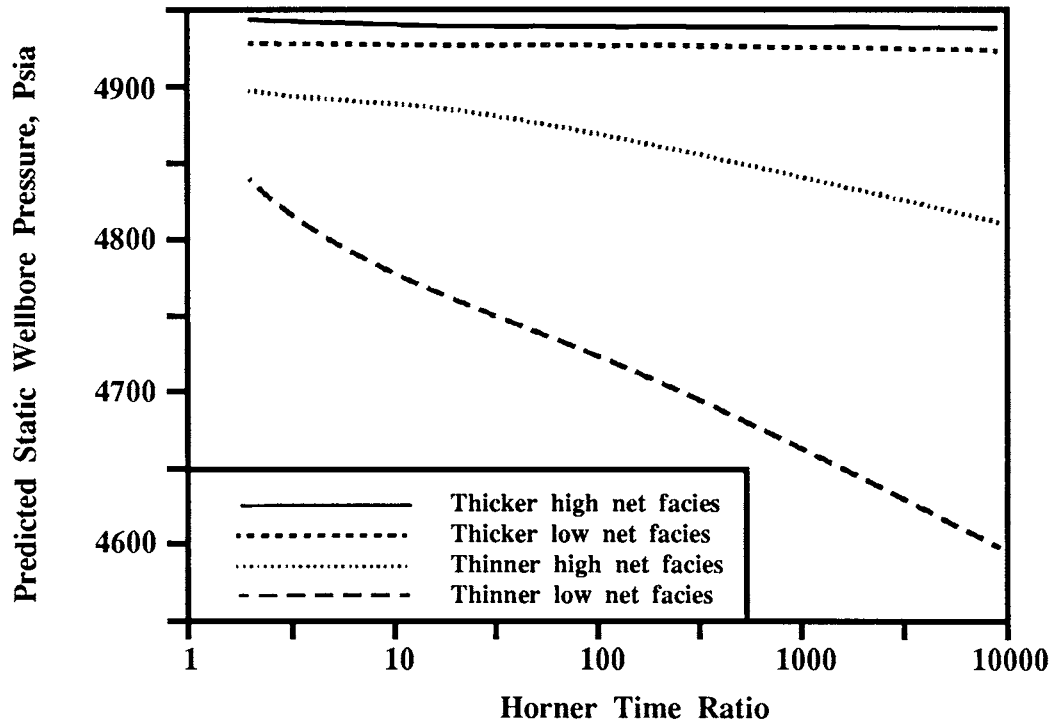


FIG. 6 Four facies have been identified from core and wireline logs. The lower permeability thin bed facies require much higher drawdowns and have a more pronounced multilayer response compared to the thicker-bedded facies.

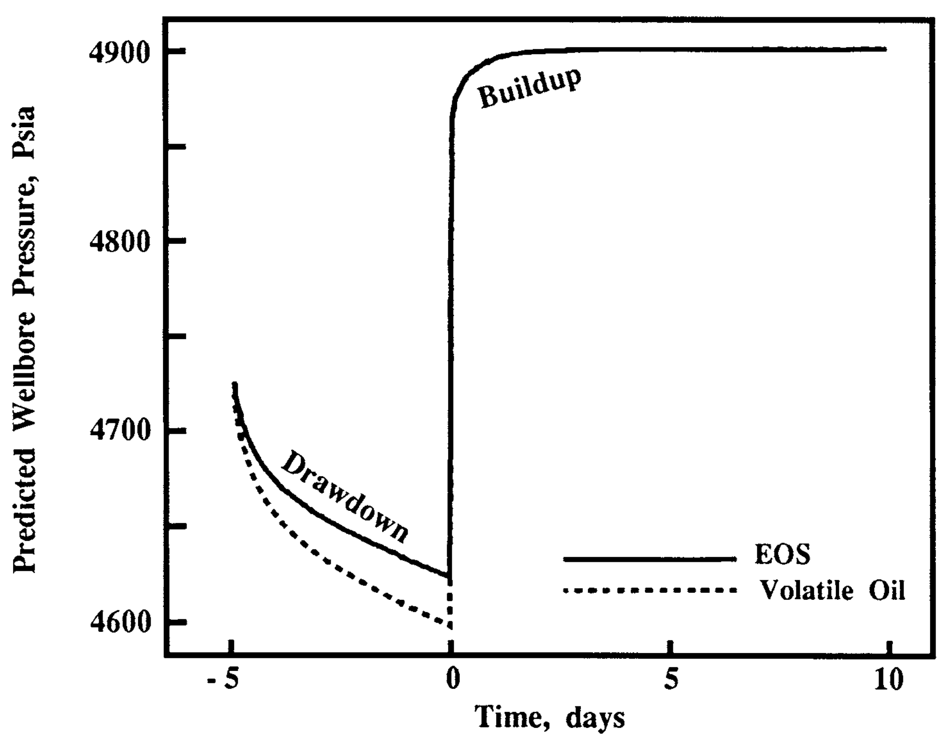


FIG. 7 The volatile oil model does not accurately model phase behavior in the high-throughput near-well region. Compared to the more rigorous equation of state model, the volatile oil model predicts a higher skin due to condensate dropout.

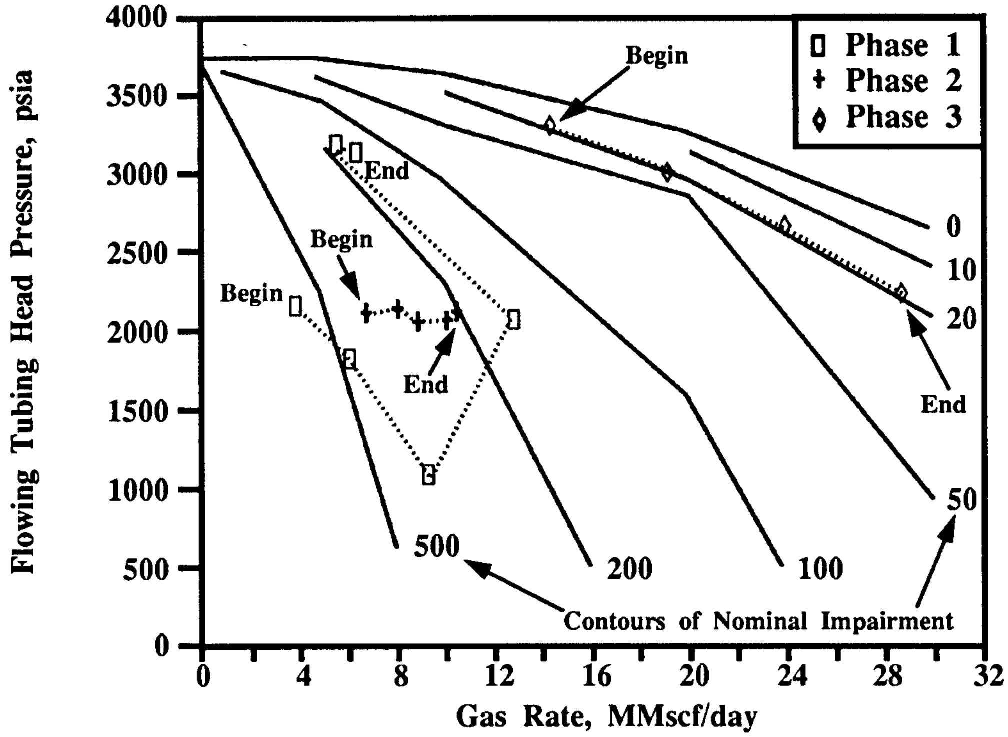


FIG. 8 Equation of state simulations were coupled with multiphase pipe flow models to develop relations for tubing head pressure versus gas rate; various skin values were assumed. Observations from the production test are also plotted, showing reasonable agreement with predictions and test results.

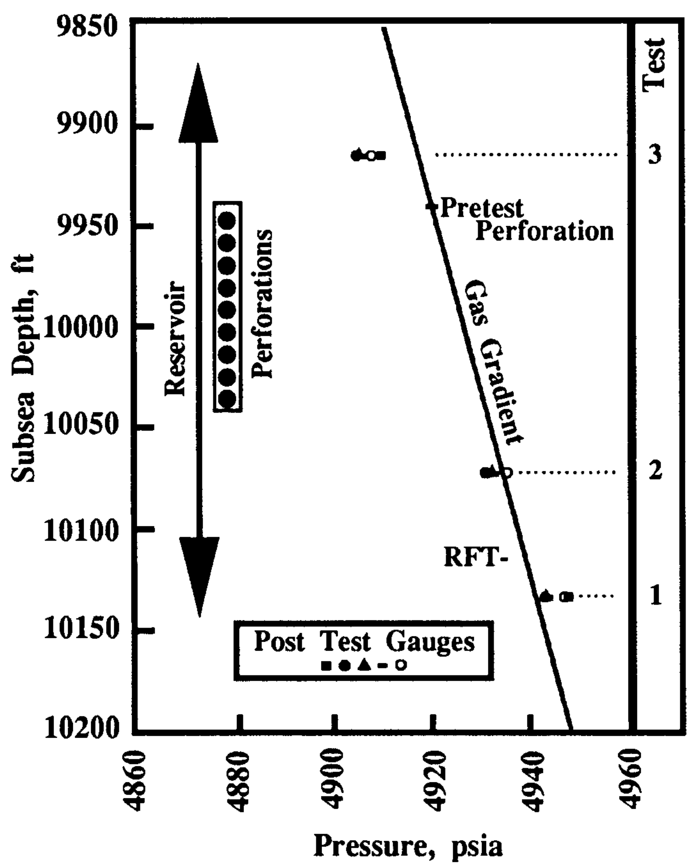


FIG. 9 After the test, short intervals above and below the test interval were perforated and their pressure measured. This depth-pressure plot indicates no significant depletion below the test interval, and possible leakage from above the completed interval.

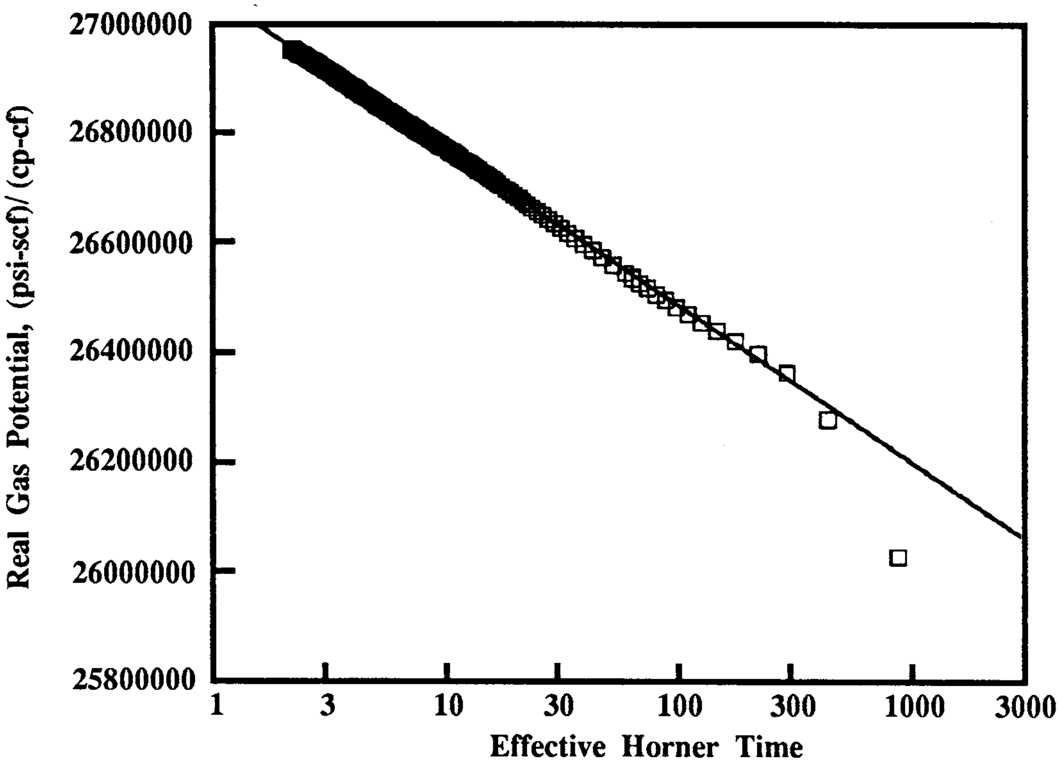


FIG. 10 This buildup (Test 2.3 in Table 2) was obtained before the extended flow. Storage ended within several minutes, and the radial flow line persisted throughout the 24 hour test. Horner analysis indicated a permeability-thickness of 1060 and a skin of 35.

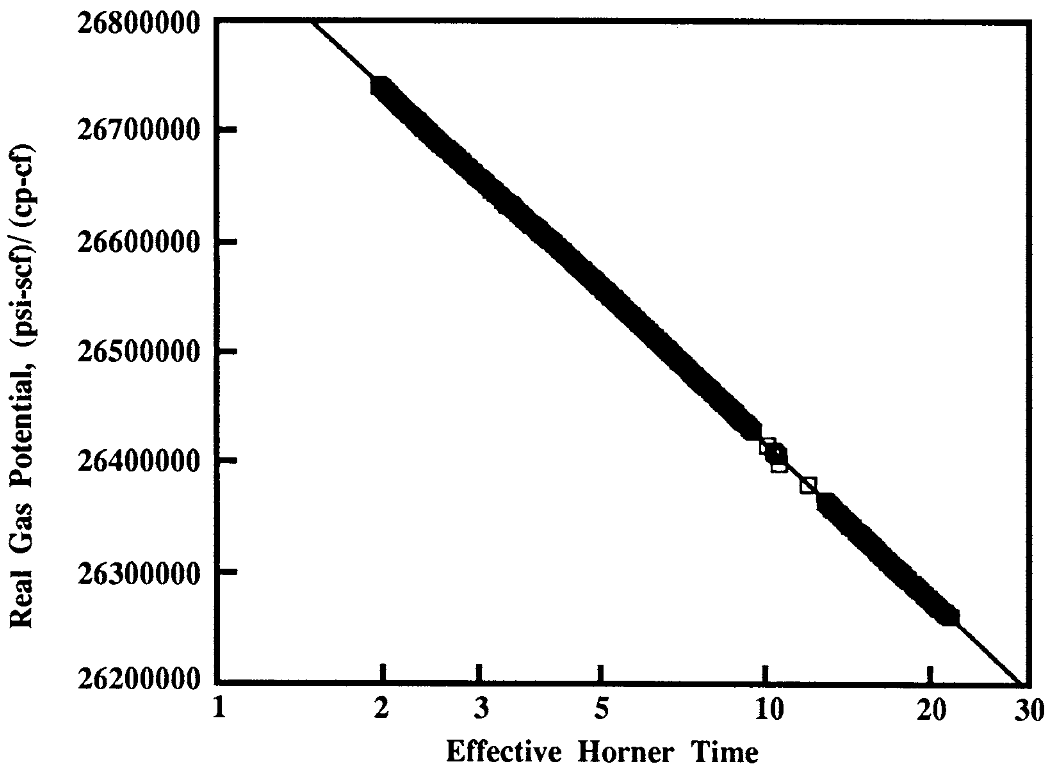


FIG. 11 The final buildup (Test 3.2 in Table 2) lasted 127 hrs and is entirely apparent radial flow. The root mean square deviation form the semilog straight line is well under 0.1 psi.

TABLE 1

Reservoir Properties

Wet Gas Viscosity, cp	0.032
Wet Gas Formation Volume Factor, bbl/Mscf	0.69
Wet Gas Compressibility, E-6/psi	110
Sand Pore Compressibility, E-6/psi	5
Shale Pore Compressibility, E-6/psi	15
Water Compressibility, E-6/psi	2.9
Average Sand Porosity, fraction	.27
Average Shale Porosity, fraction	0.12
Average Water Saturation, fraction	0.26
Prior Average Permeability, md	46
Gross Test Interval Thickness, ft	100
Net Test Interval Thickness, ft	49

TABLE 2

Results of Radial Flow Analysis

Test # Phase.Shutin	kh md-ft	k md	Skin	Flow Efficiency
1.1	525	10	9	0.39
1.4	676	13	12	0.47
2.2	806	16	34	0.18
2.3	1,061	20	35	0.18
3.1	1,706	35	8	0.49
3.2	1,709	35	10	0.47