Analysis of a Drillstem Buildup Test in an Oolitic Limestone Interval of the Scott 4-3 Well, Finney County, Kansas

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Abstract

A drillstem test in an interval of the Scott 4-3 gas well in Finney County, Kansas, was analysed to test the potential connection between a water-bearing nonproductive zone in the well and the adjacent Stewart field oil reservoir. Analyses of drillstem pressure measurements when combined with detailed geologic analysis yield an improved picture of the reservoir framework near the tested well. Horner plots of a porous water-bearing oolitic limestone interval in the well permitted estimates of permeability and static reservoir pressure, and provided insights into the reservoir geometry. Based upon an analysis of Horner buildup curves, the permeable oolitic limestone bed does not appear to be connected to the Stewart Field.

Understanding the degree of connection between the aquifer and the oil reservoir is important when constructing predictive reservoir models of Stewart Field. All significant water-yielding beds that might be connected need to be accounted for.

Introduction

Stewart Field is a sandstone oil reservoir located in Finney County, Kansas (Figure 1). The producing sandstone is Lower Pennsylvanian in age and was deposited within a paleovalley which was incised (during a lowstand in sealevel) into underlying Mississippian age oolitic grainstone (Figure 2). The valley is variable in depth of incisement throughout the field area. The thickness of siliciclastics, which comprise the valley-fill, is closely associated with the paleotopographic relief. Siliciclastics were deposited in a fluvial to estuarine environment during an episode of stillstand through a longer rise in sealevel. These rocks range from 60 feet thick on the west end to 10 feet thick in the east, where they eventually lap out updip (KGS/TORP 1992).

Stewart Field is the site of a joint project between the United States Department of Energy, Tertiary Oil Recovery Project, Kansas Geological Survey, and a partnership of Kansas independent oil operators. As such it will be the site of several demonstration projects highlighting different oil recovery procedures that will rely upon highly detailed reservoir analyses and simulations (modelling), if they are to succeed.

Background Information

During the first few months of 1994, petroleum engineers associated with the Tertiary Oil Recovery Project (TORP) at the University of Kansas evaluated the central portion of the

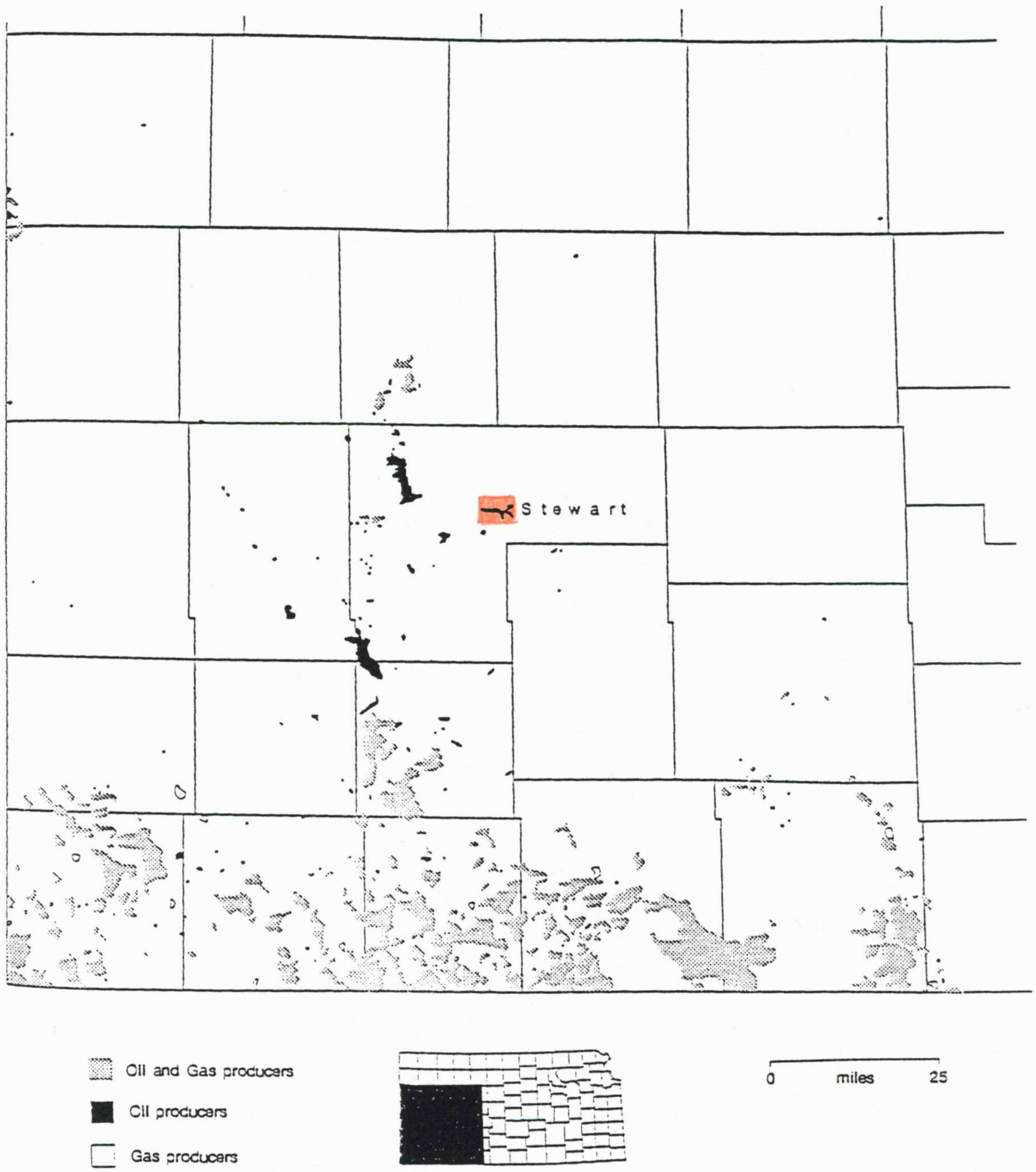


figure 1

Oil and Gas fields from Lower Pennsylvanian Morrow Sandstones in Western Kansas.

Study Area

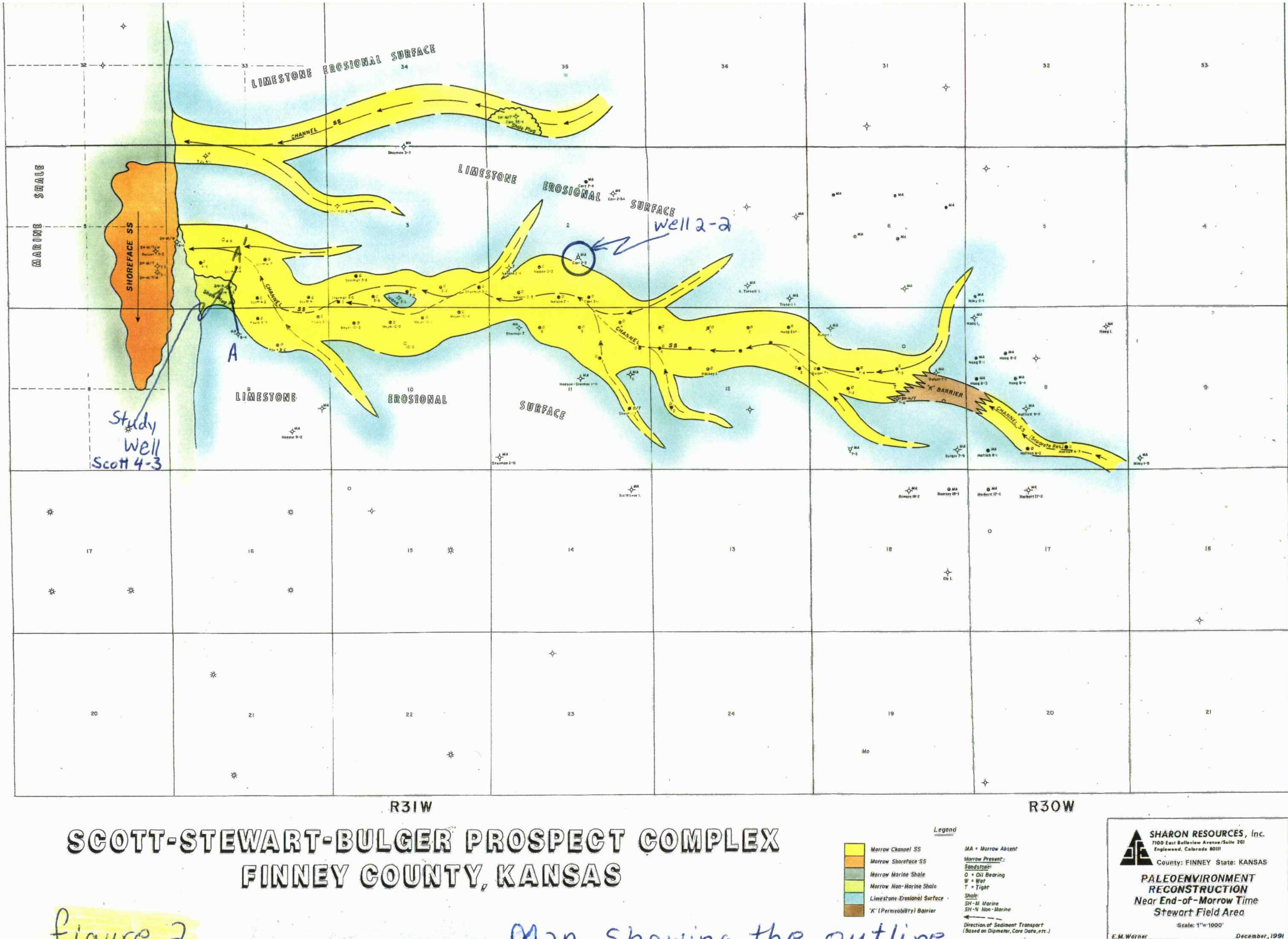


figure 2 Map showing the outline of the Stewart Field Oil Reservoir, the location of a previously studied well (2-2), and the location of cross section (A-A').

Stewart Field (quartz sandstone interval) through use of a predictive fluid flow reservoir simulation. An unexplained source of pressure support was recognized in the central portion of the field which appears to have facilitated oil production. The engineers in conjunction with geologists on the project suggested that the reservoir sandstone might be in communication with the underlying, mostly water-bearing, St. Louis Limestone. Hydraulic fracturing stimulation operations were carried out at all producing wells in the field in 1991 and may have caused the two zones to be in contact. Since they had no reason to believe that the field contained adjacent oil recharge intervals of a different lithology, the main body of their initial model was dominated by the siliciclastic reservoir interval (shown in yellow in figure 2) with a minor contribution from underlying limestone to account for the reservoir pressure support.

During the history matching stage of the reservoir simulation it became obvious that the reservoir model was not able to attain the large volume of oil which had been produced in the north-central portion of the field. In order to attain a production match, the engineers felt that it was necessary to increase the reservoir volume by fifty percent along the northern border of the reservoir, essentially extending the valley wall northward. This extended portion of the reservoir was assigned a low value of permeability and was incorporated into the simulation to act as a recharge area for oil produced.

In order to ascertain whether significant reservoir volumes existed in the north central portion of the field, investigators at the Kansas Geological Survey (KGS) analyzed well logs and reviewed records of well tests from wells near the northern border of the field. They also reviewed records from wells which were outside the prescribed confines of the field. Analysis of Well 2-2 (figure 2) revealed the presence of thin oil-filled permeable beds that were truncated against the northern valley wall along the northern border of the field. Because of the limited well control in that region of the field it appeared to the original operators of the well that the oil-saturated footage in the well (approximately four feet thick) was quartz sandstone on the far edge of the producing zone. The operators drew their isopach of sandstone thickness to include this well, placing the zero sandstone line slightly north of the well. Well log analysis of this northern well revealed that the oil-saturated interval in the well was actually oolitic limestone. A drill stem test in the well showed that the oil saturated interval contained the same pressure as in the original Stewart Field reservoir, suggesting that the beds may have a limited connection to the reservoir. Analyses of other nearby wells to the north and east revealed that the oolitic limestone bed was present along much of the north central edge of the paleovalley, and extended far outside the confines of the paleovalley. This oolitic limestone bed was truncated and exposed when the valley was incised through it during a fall in relative sealevel. Reservoir quality quartz sandstone in Stewart Field was later deposited in this valley and probably resides locally in contact with the oolite along reaches of the valley wall.

Discovery of the permeable oil-saturated beds lent credence to the conclusion that additional reservoir volume needed to be incorporated in the reservoir simulation. Their discovery also advanced the possibility that additional truncated, porous beds may exist in communication with the reservoir in other areas of the field.

The presence of these peripheral beds outside the valley and in communication with the reservoir sandstone has significant implications: if they are oil saturated they might provide more oil than originally calculated, but if they contain no oil they could provide varying amounts of salt water during production. In either case they complicate predictive modelling in the area.

Study Objective

The goal of this project is to determine whether thin beds of oolitic limestone similar to those found on the north-central border of the field are in hydraulic communication with reservoir sandstone on the western edge of the field (figure 2). This was accomplished by utilizing pressure buildup profiles obtained during drillstem testing in the Scott 4-3 well. Because of the excessive water production from wells in the field in this vicinity, this area was suggested as a potential zone of water recharge.

Lithology

The Scott 4-3 was drilled at the southwest margin of the field (location shown in figure 2). The well was drillstem tested in the same interval where sandstone is present in adjacent wells within Stewart Field. Not all of the section tested contained permeable rock. Detailed lithologic interpretations (figure 3) were made by analyzing geophysical wireline logs (porosity, gamma ray, and photoelectric logs) from the well. These analyses reveal the presence of porous oolitic limestone. However, porosity logs reveal that only 5 feet of the tested interval (from 4760 to 4807 feet) contains rocks with enough porosity to have contributed substantial fluid to the borehole during the relatively short drillstem test period.

Drillstem Testing

Drillstem (DST) pressure tests are conducted in order to measure reservoir pressure, allow the petroleum engineer to estimate the reservoir quality of producing horizons, and to determine reservoir geometry and continuity. As shown in figure 4, the DST tool consists of a series of packers, valves, and pressure recorders which are attached to the drill string and lowered downhole to test the zone of interest. Figure 4a shows the sequence of operations used during the test period. A pressure survey, utilizing this sequence of operations at the Scott 4-3, is shown in figure 5. Four distinct test periods can be discerned from this plot:

Detailed lithologic column

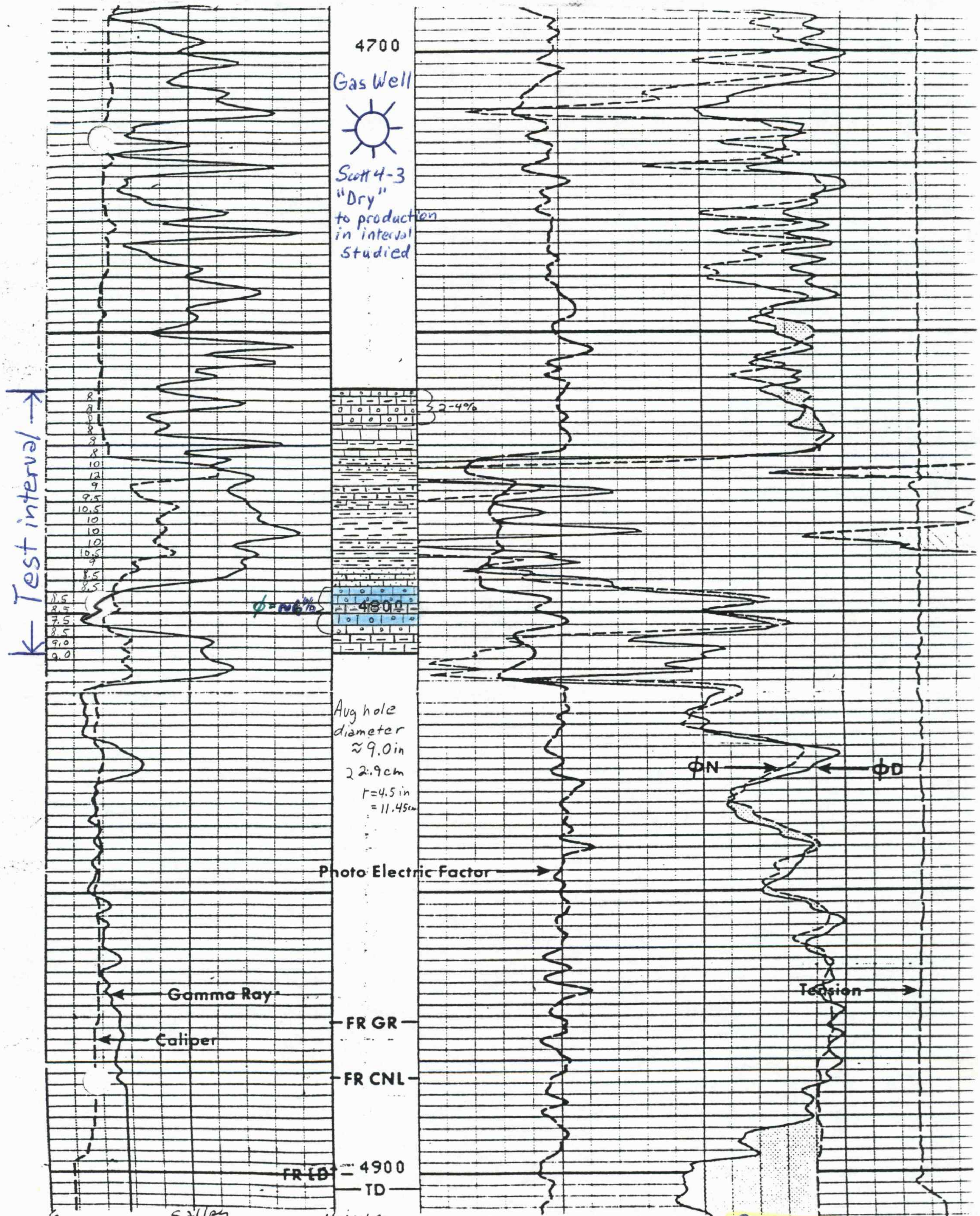


figure 3

limestone

Sandy limestone

interbedded shale and limestone

sandstone

shaly sandstone

Zone of interest Oolitic Limestone with ϕ=~6%;

a.

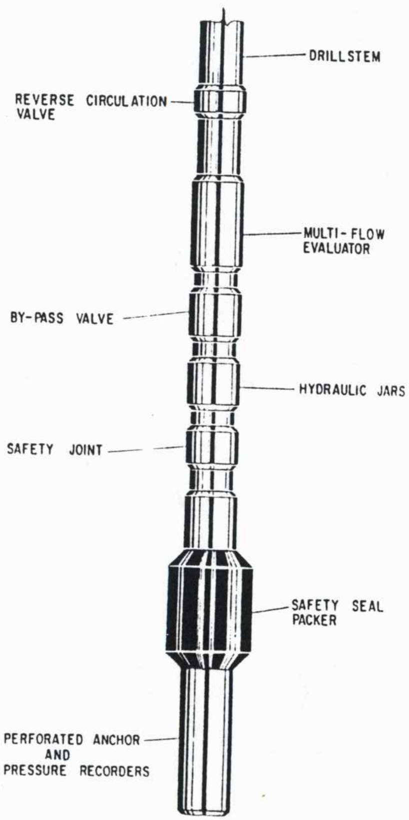
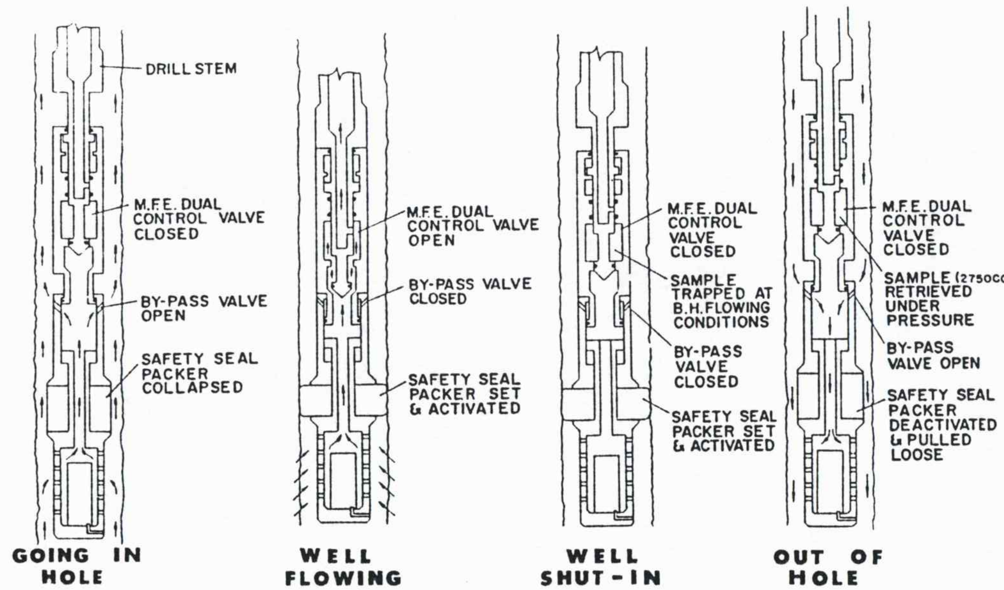


Diagram of currently operational DST tool. (After McAlister, Nutter and Lebourg.[2])

b.



Sequence of operations for MFE tool. (After McAlister, Nutter and Lebourg.[2])

from Matthews and Russell (1967)

Figure 4

Drillstem test tools and operations

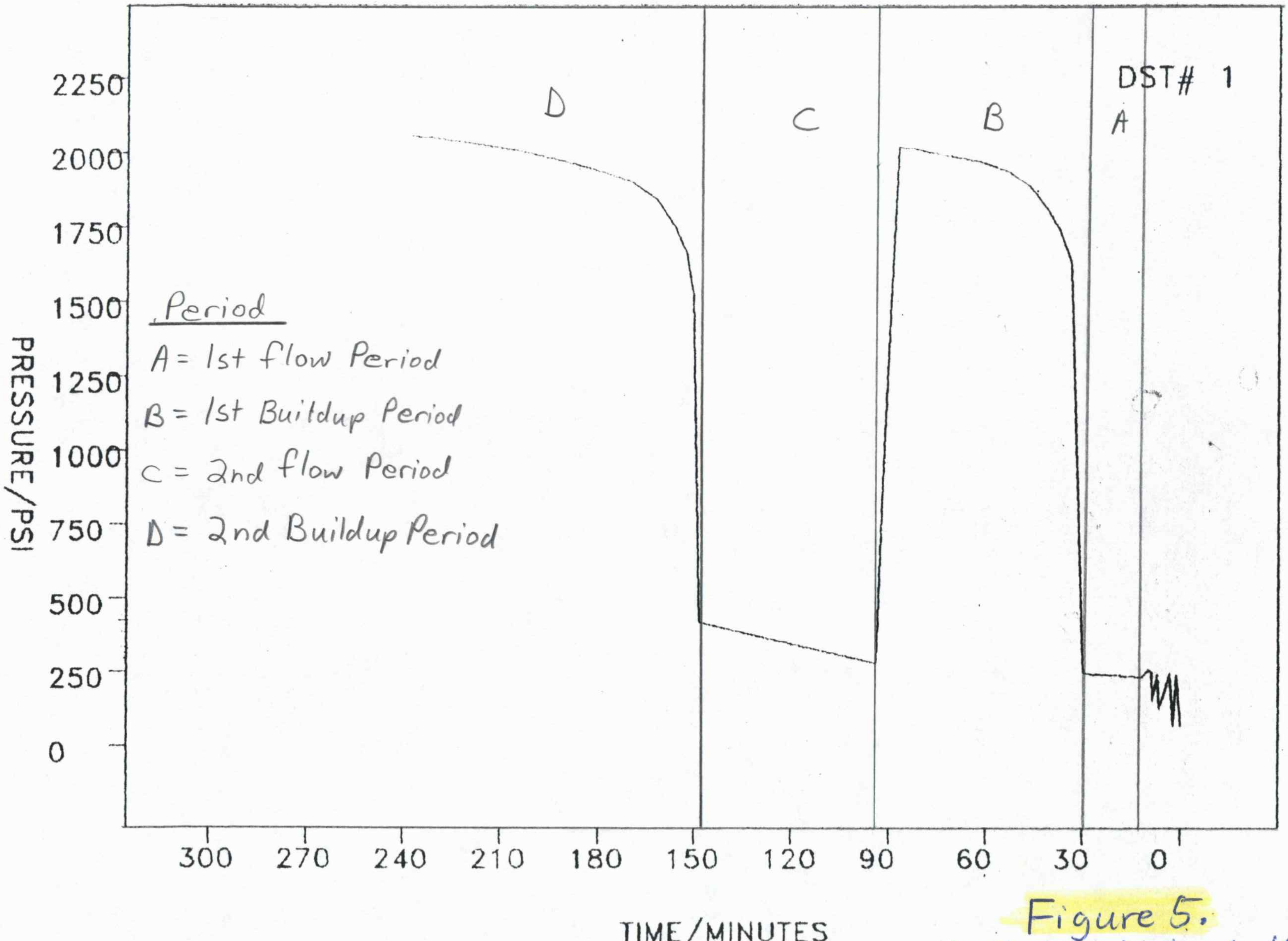


Figure 5.
Drillstem test at the Scott 4-3.

1. Period A is a period of flow which is used primarily for the purpose of allowing the formation pressure to equalize back to static reservoir pressure in the near wellbore mud filtrate-invaded zone. It is designed to relieve the over-pressured conditions which are inherent in drilling with a mud column, and allow the formation to return to its initial state.
2. Period B is a period of pressure buildup. After this period it is possible to obtain a good estimate of static reservoir pressure. This interval of the test represents the best estimate of the reservoir parameters at near-equilibrium conditions (Horner 1951).
3. Period C is one of flow in which the engineer is able to estimate the near well bore flow rate.
4. Period D is the second buildup period which generally runs for a longer period that the first. A longer flow period allows for the best possible calculation of reservoir permeability (Matthews and Russell 1967) because the reservoir achieves a more steady late-stage slope.

Using data obtained during this test it is possible to obtain estimates of pressure, permeability, and fluid ratios within the reservoir. The test also allows the investigator to determine the extent of the reservoir by checking for pressure interference effects caused by nearby impermeable boundaries, natural fractures, and flowing wells (figure 6).

Horner Plots

Semi-log plots of pressure versus Horner time (t / t') are

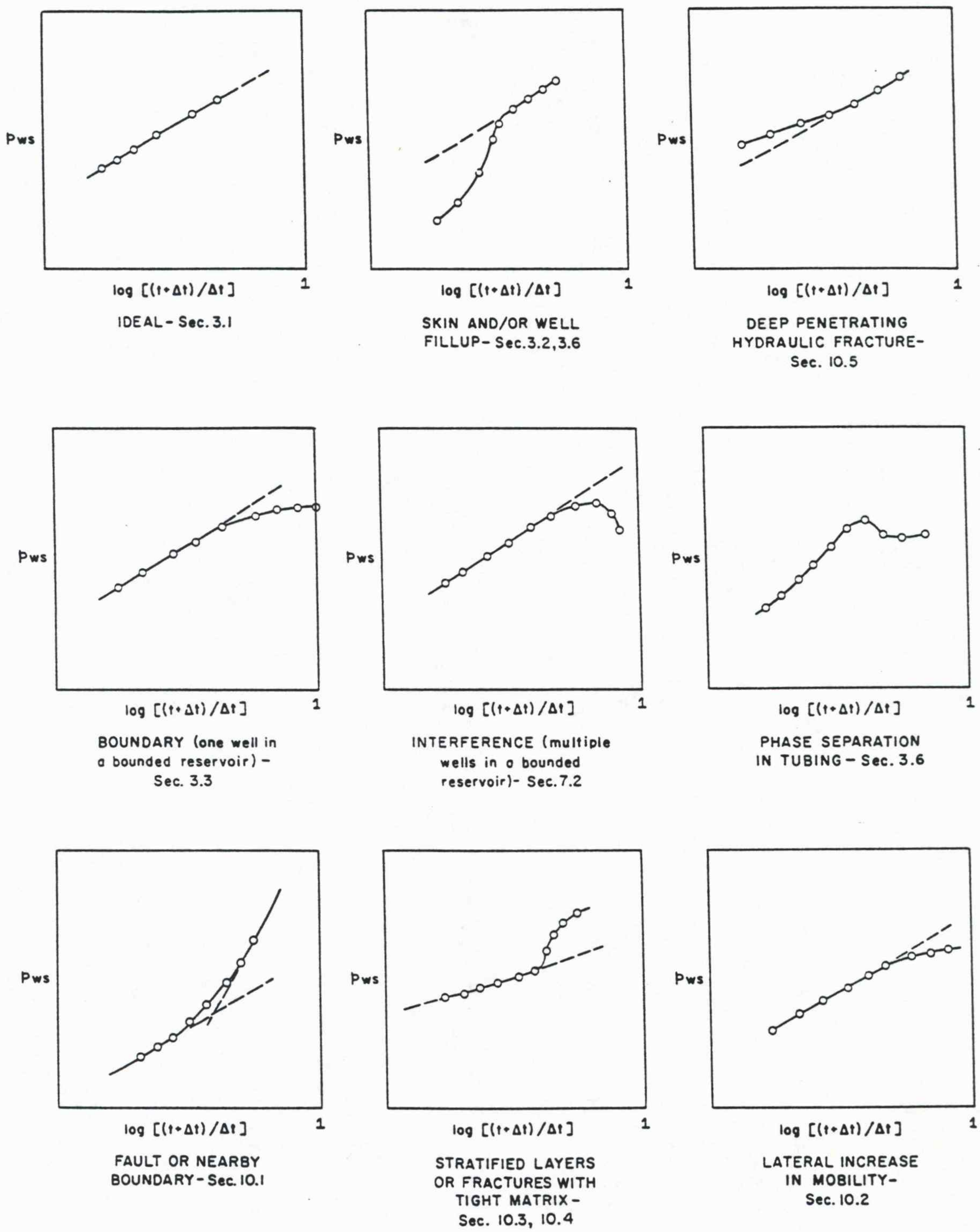


Figure 6. Example buildup curves.

from Matthews and Russell (1967)

shown in figure 7a and b. In these plots, t is the time since the beginning of the test and t' is the time since the well was shut-in for pressure build-up. Flow calculations are based on the slope (m), therefore test completion to a linear rate of pressure change is important for determining accurate permeability (Matthews and Russell, 1967). An estimate of permeability in 5 foot of oolitic limestone (figure 3; 4795 to 4802 feet minus 2 feet of shaly limestone in the center of the zone) from the tested interval, is shown in Calculation 1. This estimate was obtained by utilizing the final slope of pressure over 1 log cycle on figure 7a.

By fitting a straight line to the slope of the curve (in this case to the final slope) and extrapolating to the point where Horner time equals unity (or 1 on the semi-log plot), it is possible to obtain an estimate of the static or initial pressure (P_i) in the reservoir. The pressure (P_i) within the oolitic limestone of the Scott 4-3 is 2100 psi, as estimated from an average of the two buildup curves (figures 7a and 7b).

Parameters Used for Analysis

Viscosity

The viscosity of the produced fluid was not measured at the completion of the test. Approximately 30 percent of the produced fluid was composed of water and the other 70 percent is described as "mud". Though the viscosity of the drilling mud was measured by the well logging company prior to a logging run, this is not an accurate estimate for use in buildup

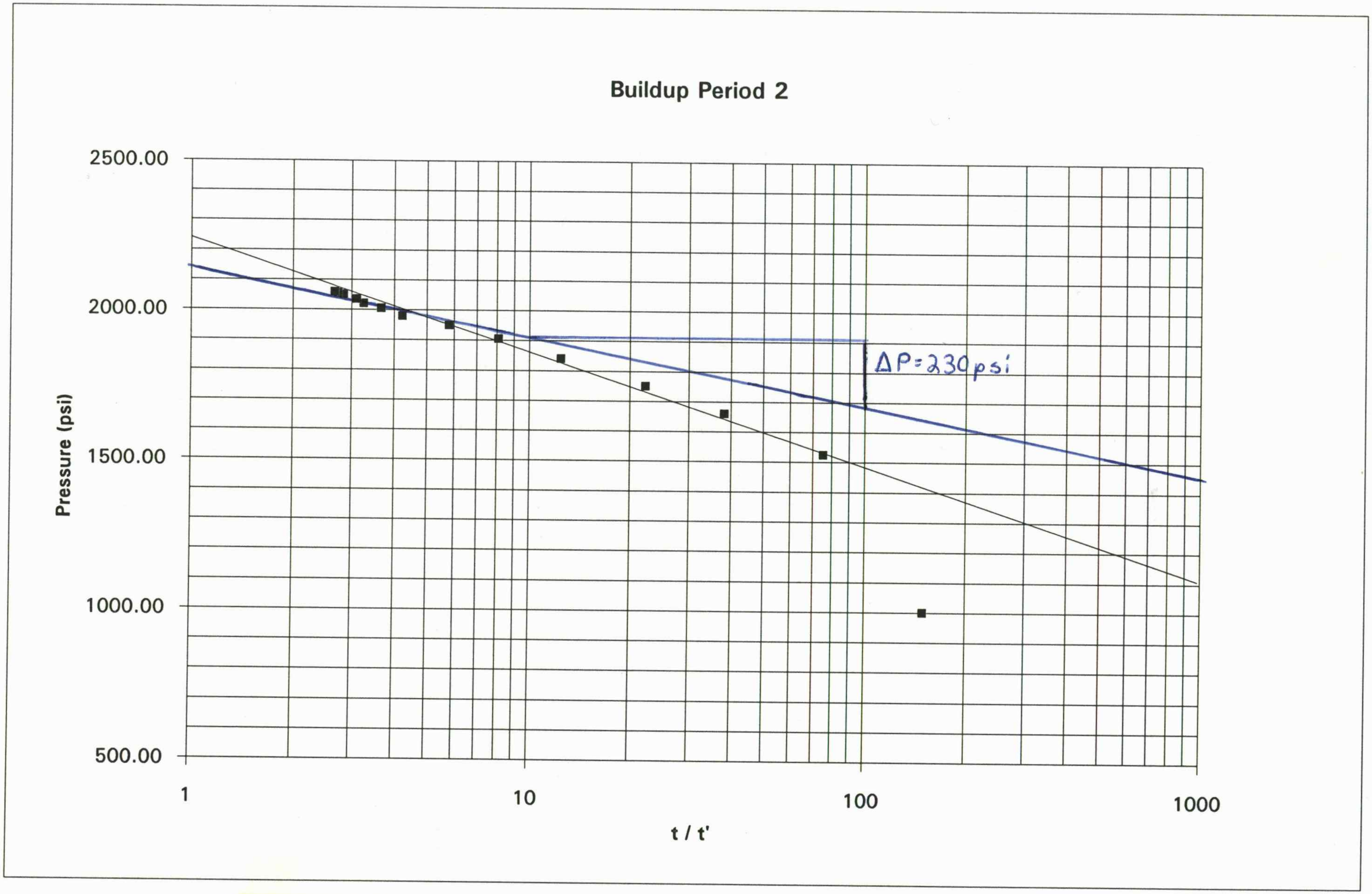


Figure 7a. A pressure buildup plot during Buildup Period 2 (Period D, Figure 5). The slope over 1 log cycle is 230psi/cycle

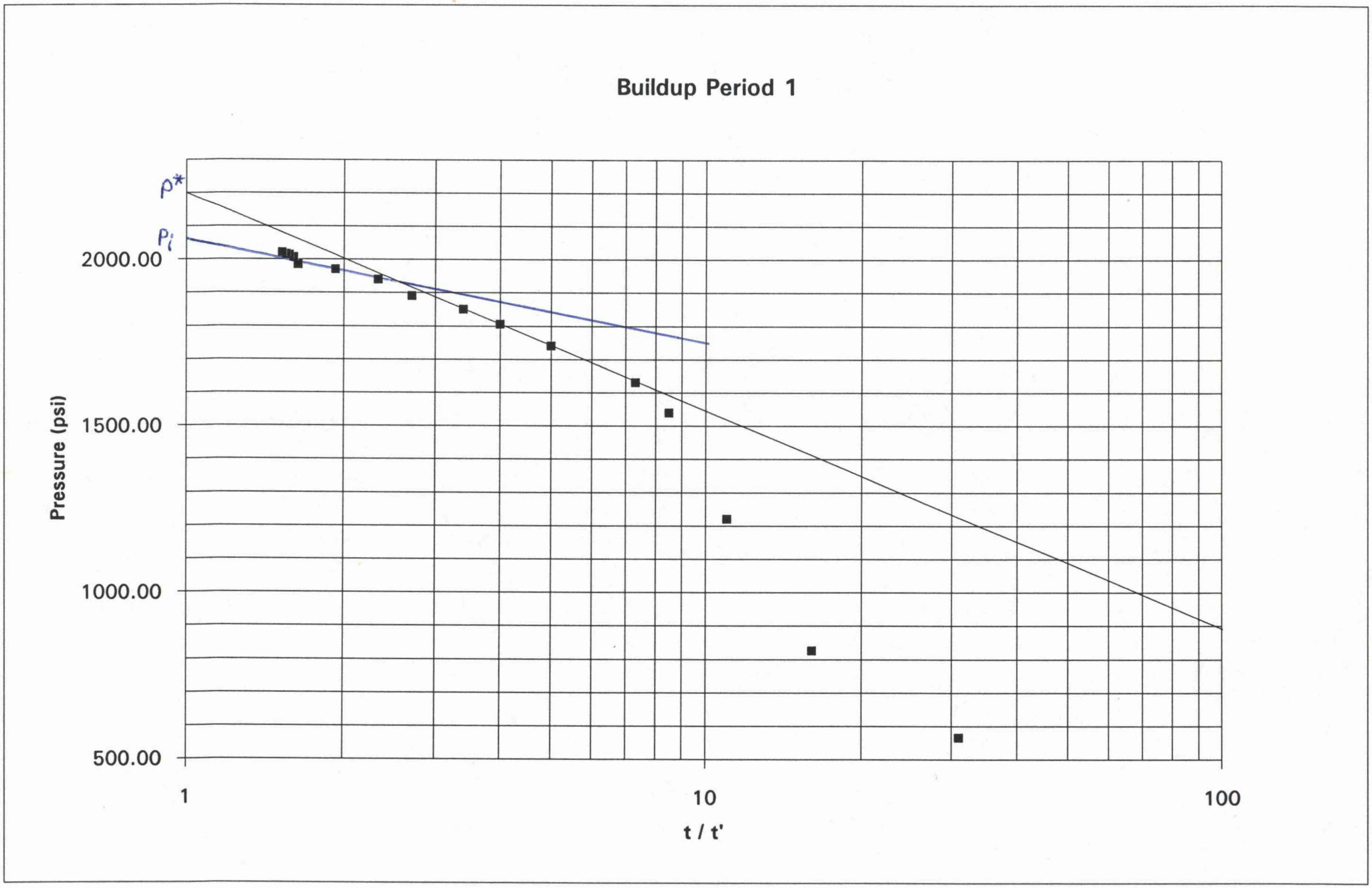


Figure 7b Horner Plot of Buildup Period 1.
Note the location of Pi (static reservoir pressure)

Calculation 1

An analysis of buildup (period 2) to obtain a permeability (k) estimate of an oolitic zone (from 4795 to 4802 feet minus 2 feet of shaly limestone from the center of the zone).

$$k \frac{m}{\mu} = 2.3 \frac{Q}{4\pi \Delta P} \log\left(\frac{t}{t'}\right)$$

where ΔP = change in pressure over 1 log cycle

$= 230$ psi or 1.59×10^{6} Pa

Q = flow rate $= 81.5 \frac{bbls}{day}$ or $1.50 \times 10^{-4} \frac{m^3}{s}$

μ = viscosity of produced fluid

$\simeq 1$ cp or 1.002×10^{-3} Pa·s

$m = 5$ ft or 1.52 m

$$k \frac{m}{\mu} = 2.3 \frac{1.50 \times 10^{-4} \frac{m^3}{s}}{(4\pi)(1.59 \times 10^{6} N/m^2)}$$

$$k \frac{m}{\mu} = 1.73 \times 10^{-11} \frac{m^5}{N \cdot s}$$

$$k = \left(1.73 \times 10^{-11} \frac{m^5}{N \cdot s}\right) \frac{1.002 \times 10^{-3} \frac{N \cdot s}{m^2}}{1.52 \, m}$$

$$k = 1.14 \times 10^{-14} m^2$$

$k = 0.012$ darcys or $\boxed{\text{12 millidarcies}}$

Estimates of k as high as 50 millidarcies are possible based upon other reasonable estimates of the viscosity of the produced fluid (ie. 1-4 cp).

pressure analysis since much (if not all) of the drilling fluid produced was actually mud filtrate. Because the "mud" portion of the produced fluid is probably composed substantially of filtrate, the viscosity of the produced fluid is estimated to be 1.0 centipoise (1 cp), slightly more than the viscosity of water at 20°C. The viscosity of a fluid is proportional to its mobility in a porous and permeable media. The higher the estimated value of viscosity the higher the permeability value. Thus, calculations using a viscosity estimate of 1 cp will represent a low estimate of permeability.

Flow Rate (Q)

This parameter was evaluated by the service company in charge of running and analyzing the drillstem test and is estimated from the amount of fluid received during Flow Period C (figure 5). Because we did not have an accurate record of the amount of fluid produced during this period, we chose to use their estimate of 81.5 barrels of fluid per day.

Analysis Of Pressure Buildup Data

In an infinite reservoir system, semi-log plots of wellbore pressure versus Horner time (figure 8) have a straight line slope.

In reservoirs which have only one boundary (figure 9), the buildup pressure curve shows an additive pressure effect leading to a doubling of slope with time owing to the addition of twice as much pressure through time. This type of effect can be modeled mathematically if we place the well in an

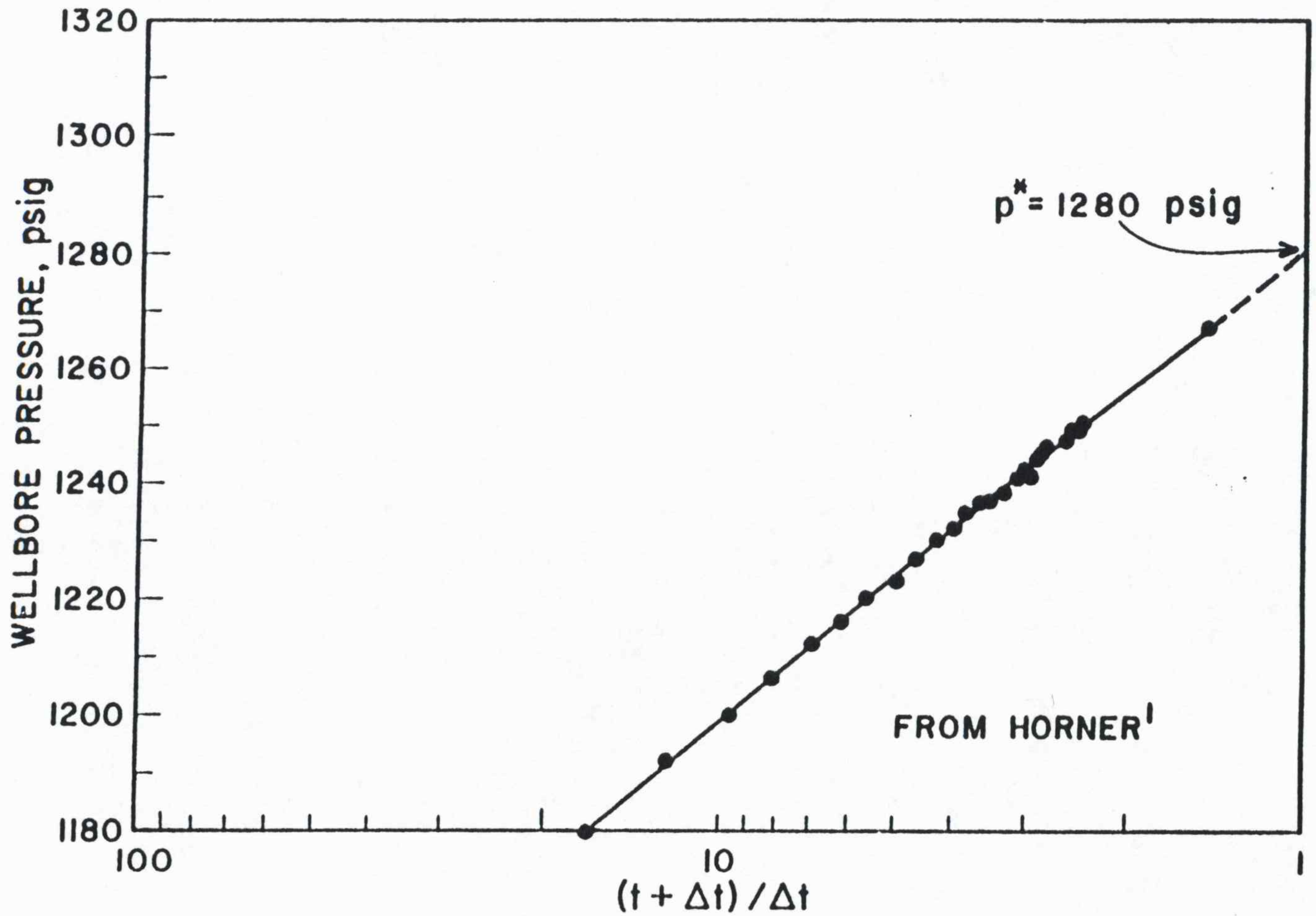


Figure 8. **Pressure buildup in a nearly ideal reservoir.**

after Matthews and Russell (1967)

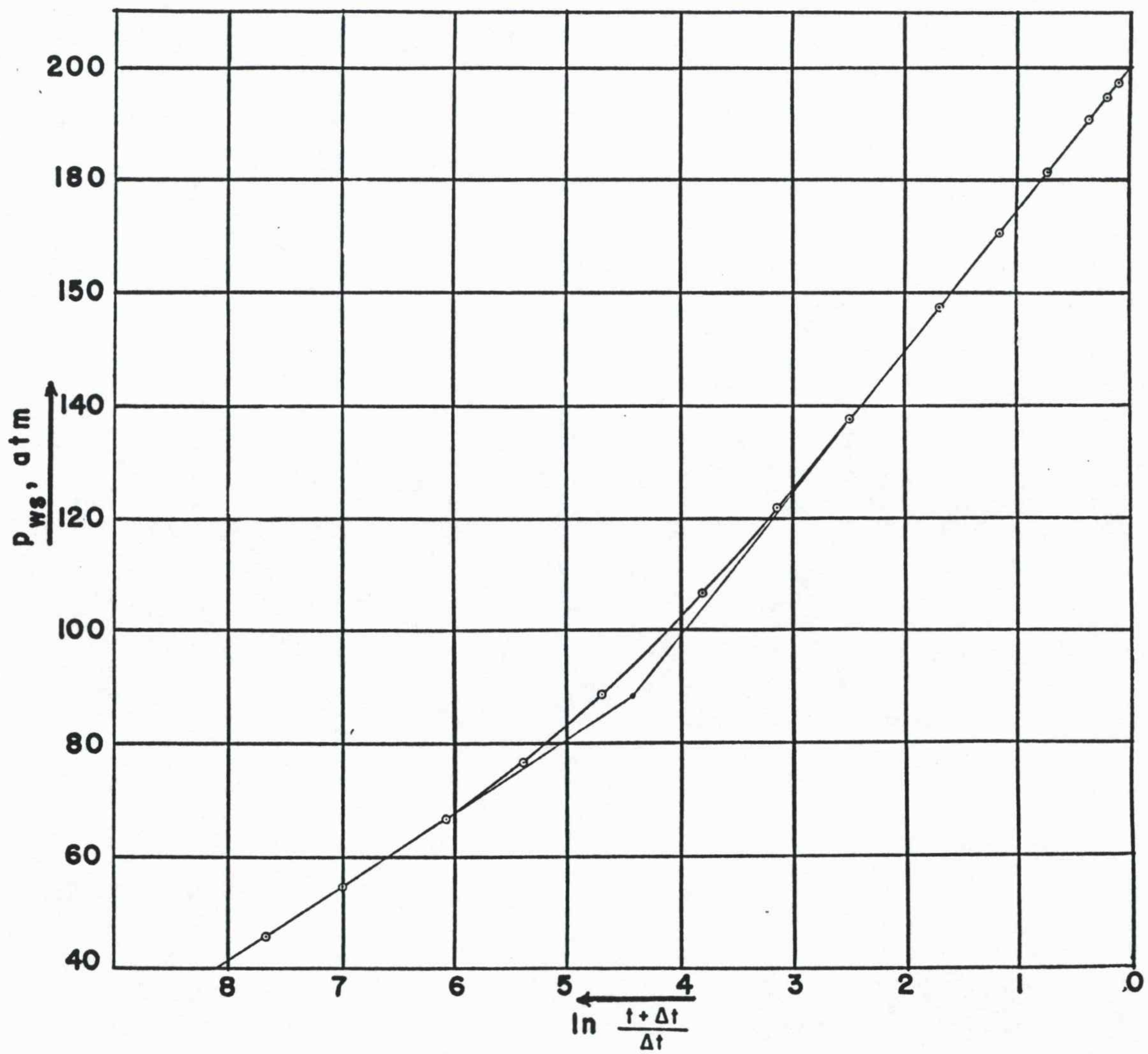


Figure 9. Illustration of the theoretical case of a linear barrier fault. (After Horner.[7])

unbounded system and add an image well which provides the same amount of pressure during buildup.

Figure 10 shows a plot of a well which was tested within a finite reservoir (cylindrical boundary). The plot shows a downward deflection from the apparent static pressure curve over time. This type of curve is developed when additive effects of pressure buildup due to an "infinite" number of image wells cause the reservoir pressure to buildup at a much higher rate (from the start of the test) than it would if it were in a infinite reservoir with no boundaries (Matthews and Russell 1967). As the test is continued, the buildup curve levels off, approaching asymptotically the actual reservoir pressure (P_i). It is not advisable to attempt to calculate the distance to any specific boundary since an infinite number of boundaries have affected the buildup curve and their exact contributions cannot be determined (Matthews and Russell 1967).

A Horner plot of the first buildup period (figure 11) shows a deflection in slope which is characteristic of a well which is developed within a finite reservoir with an outer cylindrical boundary. At the time of this pressure test there were no producing wells in the immediate area of the Scott 4-3, thus there is no potential for interference from nearby pumping wells. In addition, wells which were drillstem tested in the Stewart Field, at or shortly before the time of the Scott 4-3 test yield pressures of 800 psi, considerably lower than the 2100 psi measured in the Scott 4-3.

The presence of this well within a totally enclosed system

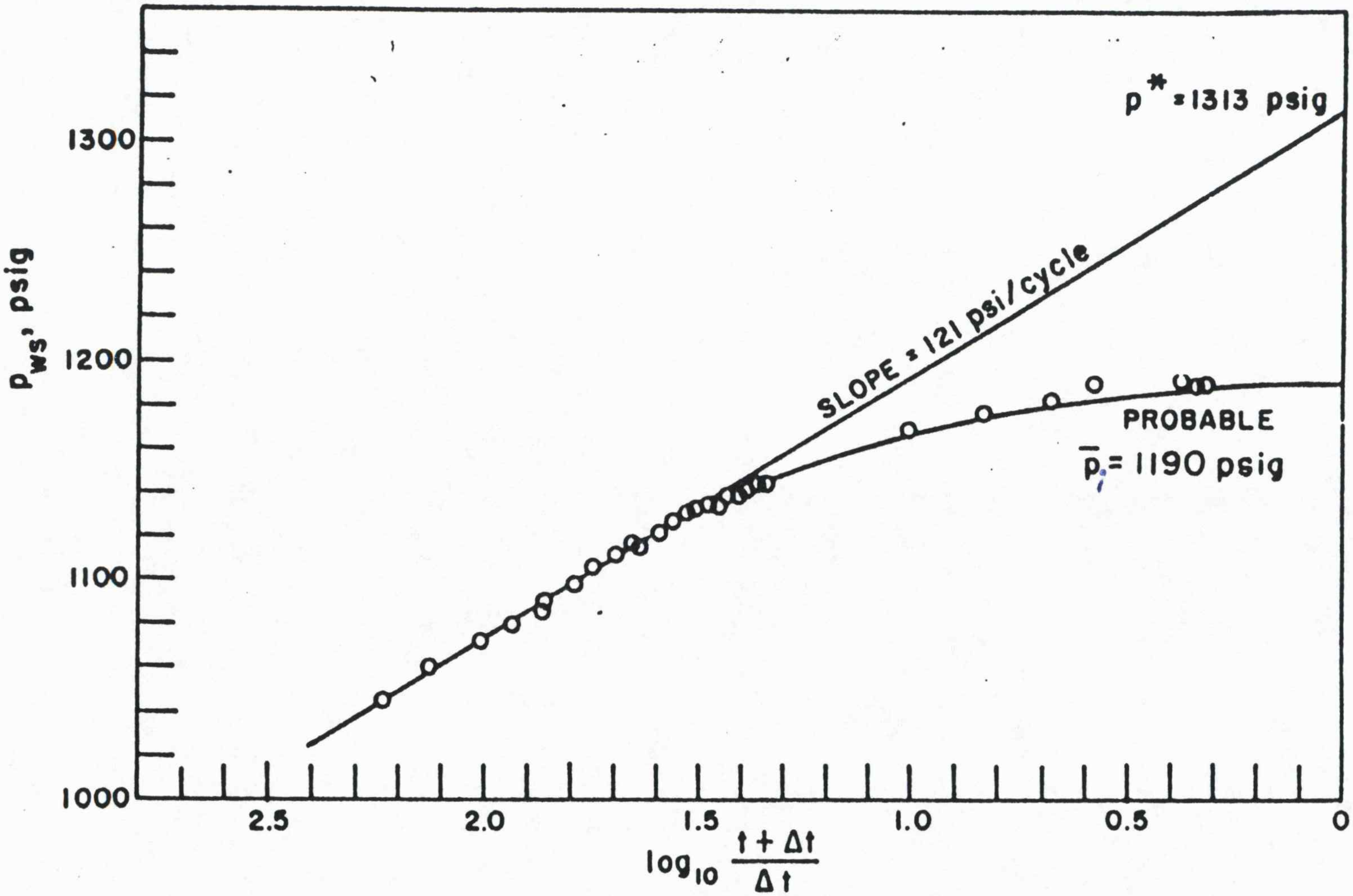


Figure 10. **Observed pressure buildup curve in well in finite reservoir.**

from Matthews and Russell (1967)

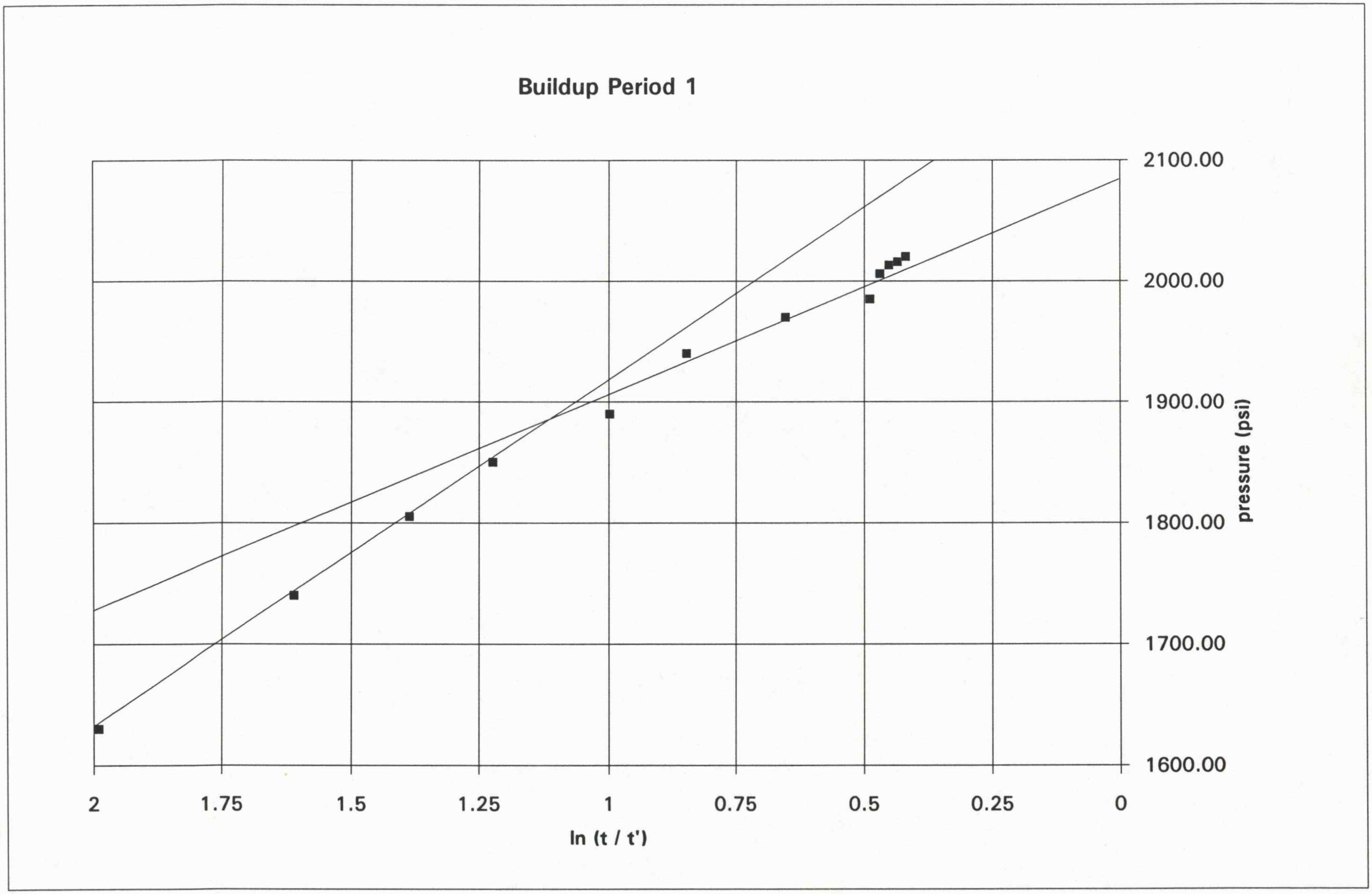
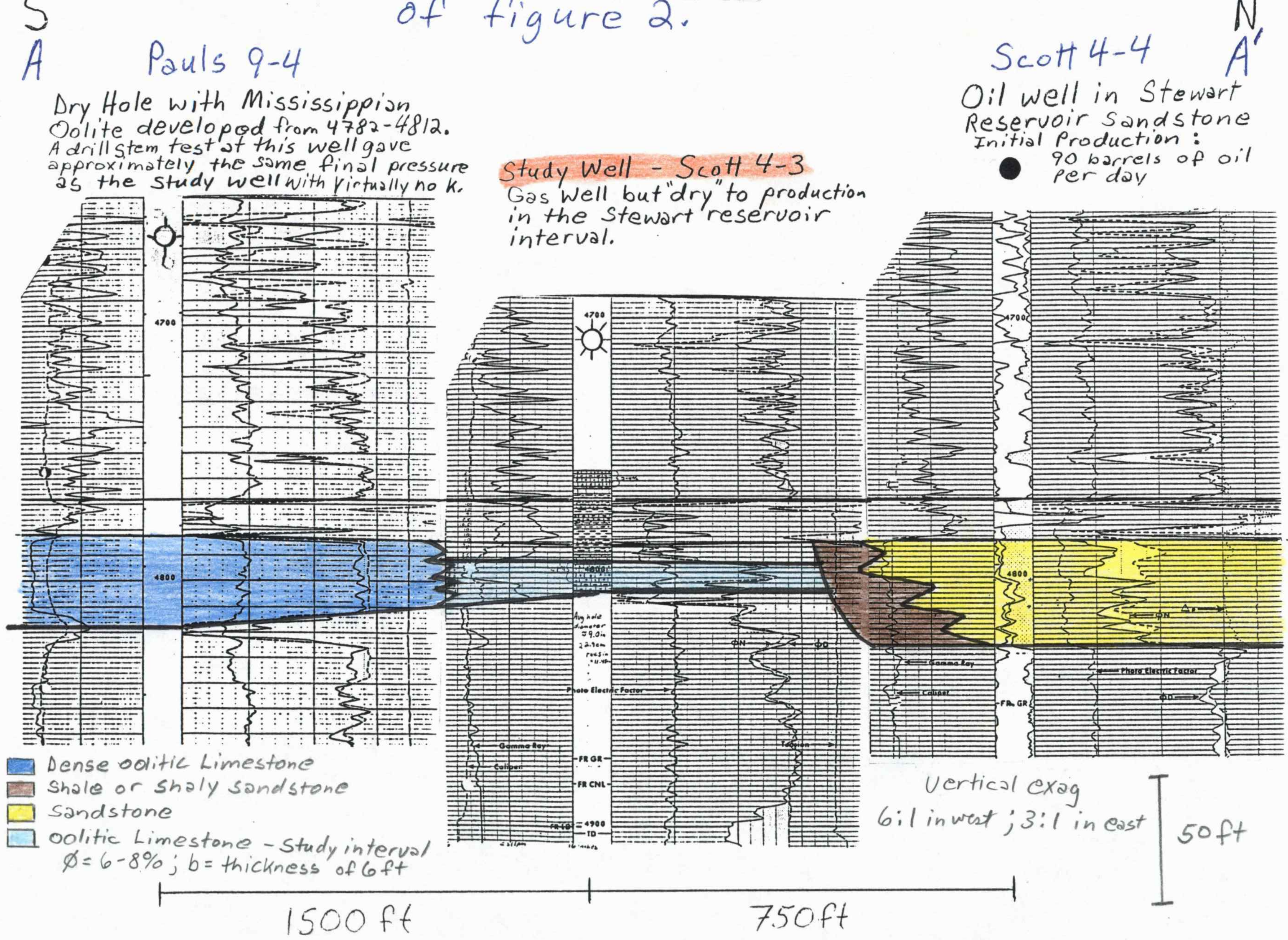


Figure 11. Horner plot of Buildup Period 1. Consistent with development in a reservoir with an outer cylindrical boundary.

can be explained by looking at the reservoir in a geological context. Several geologic observations allow for the assessment of complete confinement. As can be seen in figure 2, the well is bounded on the north and northeast by the Stewart Field incised valley. Siliciclastics in the valley-fill interval include clean quartz sandstone, silty sandstone, and shale. Because of the nature of fluvial and estuarine deposition, sandstone bodies are not always in communication, separated from one another by shale and shaly sandstone, and the sandstone is compartmentalized. This type of heterogeneity makes possible the interpretation that the oolite body is isolated from the main body of the field by a shale or shaly sandstone bed which does not allow their direct communication. It can be seen from the map in figure 2, that the exact location and nature of the boundary are not known.

A cross section (figure 12) which runs from south to north (from the oolite into the main body of Stewart Field), demonstrates that although the oolite body thickens to the south and west, it becomes less porous and permeable away from the incised valley. A drill stem test conducted in the Pauls 9-4, the southern well in the cross section, revealed that the same amount of reservoir pressure was present within the oolite as in the Scott 4-3. However, only a minimal amount of fluid was obtained during flow (15 feet, representing only 0.15 barrels of fluid in a 90 minute flow period) suggesting that negligible permeability exists within the interval. The porosity well logs which were run in this well suggest that

Figure 12. Cross section A to A'. The location of the section is shown on the left side of figure 2.



less than 2 percent porosity is present, contrasting with an average of 6 percent porosity in oolite from the Scott 4-3. In the cross section a porosity "pinchout" has been drawn between these two wells. Thus, Scott 4-3 appears to be isolated with respect to fluid flow from surrounding areas.

Conclusions

Detailed geologic analyses in combination with pressure test data in the Scott 4-3 gas well have allowed assessment of an area where a potential water recharge area was thought to exist in the Stewart field reservoir. Analyses of an oolitic limestone interval ("dry" to production), laterally adjacent to production in the Stewart field sandstone reservoir interval, reveal the existence of a highly permeable and porous limestone unit that is not in communication with the oil reservoir. Pressure values attained during the buildup test are considerably higher than previous pressure measurements made in the Stewart Field suggesting that the oolite and the sandstone reservoir were never in contact. Pressure buildup curves obtained during a drillstem pressure test of the oolite show that it is bounded on all sides by impermeable units. This observation is corroborated by geologic analyses of an adjacent well to the south, and is tempered by the knowledge that impermeable lithologies, which may provide a lateral seal to communication, are common along fluvial and estuarine valleys of the present day.

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		Flow Period 1		Flow Period 2				
step	time	t / t+dt	pressure	time	t / t+dt	pressure	t / t'	
1	4.75	0.950	1630.00	1.00	1.629	1525.00	1.00	1525.00
2	7.50	0.692	1740.00	3.00	1.342	1660.00	3.00	1660.00
3	10.00	0.563	1805.00	6.00	1.084	1750.00	6.00	1750.00
4	12.50	0.485	1850.00	12.00	0.875	1840.00	12.00	1840.00
5	17.50	0.437	1890.00	20.00	0.689	1905.00	20.00	1905.00
6	22.50	0.353	1940.00	30.00	0.563	1950.00	30.00	1950.00
7	32.50	0.287	1970.00	45.00	0.479	1980.00	45.00	1980.00
8	47.50	0.246	1985.00	55.00	0.425	2005.00	55.00	2005.00
9	50.00	0.204	2006.00	65.00	0.381	2020.00	65.00	2020.00
10	52.50	0.192	2013.00	70.00	0.347	2035.00	70.00	2035.00
11	55.00	0.186	2016.00	80.00	0.324	2050.00	80.00	2050.00
12	57.50	0.178	2020.00	85.00	0.312	2055.00	85.00	2055.00
13				88.00	0.302	2058.00	88.00	2058.00

4.75	1630.00
7.50	1740.00
10.00	1805.00
12.50	1850.00
17.50	1890.00
22.50	1940.00
32.50	1970.00
47.50	1985.00
50.00	2006.00
52.50	2013.00
55.00	2016.00
57.50	2020.00

Appendix A.

Data used for buildup analysis.

	Flow Period 1						Flow Period 2			
	time of recovery	log(t+dt/dt	pressure	t / t'			time of recovery	t / t+dt	pressure	t / t'
30.00	0.00		250.00		250.00	149.00	0.00		415.00	
31.00	1.00		565.00	31.00	565.00	150.00	1.00		1000.00	150.00
32.00	2.00		825.00	16.00	825.00	151.00	2.00	1.629	1525.00	75.50
33.00	3.00		1220.00	11.00	1220.00	153.00	4.00	1.342	1660.00	38.25
34.00	4.00		1540.00	8.50	1540.00	156.00	7.00	1.084	1750.00	22.29
34.75	4.75	0.950	1630.00	7.32	1630.00	162.00	13.00	0.875	1840.00	12.46
37.50	7.50	0.692	1740.00	5.00	1740.00	170.00	21.00	0.689	1905.00	8.10
40.00	10.00	0.563	1805.00	4.00	1805.00	180.00	31.00	0.563	1950.00	5.81
42.50	12.50	0.485	1850.00	3.40	1850.00	195.00	46.00	0.479	1980.00	4.24
47.50	17.50	0.437	1890.00	2.71	1890.00	205.00	56.00	0.425	2005.00	3.66
52.50	22.50	0.353	1940.00	2.33	1940.00	215.00	66.00	0.381	2020.00	3.26
62.50	32.50	0.287	1970.00	1.92	1970.00	220.00	71.00	0.347	2035.00	3.10
77.50	47.50	0.246	1985.00	1.63	1985.00	230.00	81.00	0.324	2050.00	2.84
80.00	50.00	0.204	2006.00	1.60	2006.00	235.00	86.00	0.312	2055.00	2.73
82.50	52.50	0.192	2013.00	1.57	2013.00	238.00	89.00	0.302	2058.00	2.67
85.00	55.00	0.186	2016.00	1.55	2016.00					
87.50	57.50	0.178	2020.00	1.52	2020.00					

Appendix A (cont.)

		Period 1				
	ln t / t'	pressure	log t / t'	pressure	t / t'	pressure
415.00		250.00		250.00		250.00
1000.00	3.433987	565.00	1.491362	565.00		565.00
1525.00	2.772589	825.00	1.20412	825.00		825.00
1660.00	2.397895	1220.00	1.041393	1220.00		1220.00
1750.00	2.140066	1540.00	0.929419	1540.00		1540.00
1840.00	1.990035	1630.00	0.864261	1630.00	0.14	1630.00
1905.00	1.609438	1740.00	0.69897	1740.00	0.20	1740.00
1950.00	1.386294	1805.00	0.60206	1805.00	0.25	1805.00
1980.00	1.223775	1850.00	0.531479	1850.00	0.29	1850.00
2005.00	0.998529	1890.00	0.433656	1890.00	0.37	1890.00
2020.00	0.847298	1940.00	0.367977	1940.00	0.43	1940.00
2035.00	0.653926	1970.00	0.283997	1970.00	0.52	1970.00
2050.00	0.489548	1985.00	0.212608	1985.00	0.61	1985.00
2055.00	0.470004	2006.00	0.20412	2006.00	0.63	2006.00
2058.00	0.451985	2013.00	0.196295	2013.00	0.64	2013.00
	0.435318	2016.00	0.189056	2016.00	0.65	2016.00
	0.419854	2020.00	0.18234	2020.00	0.66	2020.00

Appendix A (cont.)