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ENGINEERING PARAMETERS USED IN GEOPRESSURED GEOTHERMAL FAIRWAY EVALUATION AND TEST-WELL SITE LOCATION, FRIO FORMATION, TEXAS GULF COAST*

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ABSTRACT

Adequate deliverability of fluids from reservoirs with temperatures higher than 300°F is a key factor in evaluating geopressured geothermal resources. In the Austin Bayou Prospect, Brazoria County, Texas, permeability is difficult to evaluate before wells are drilled and tested. However, this report discusses how reservoir pressure decline and high temperature reduce permeability.

The history of gas-condensate production from geopressured reservoirs in the Chocolate Bayou field, located near the Austin Bayou Prospect, shows that deliverability of hydrocarbons is high in the early life of the reservoirs but drops sharply as pressure declines. Average geothermal gradient is 1.8°F per hundred feet and reservoir pressure gradients lie between 0.465 and 0.98 psia per foot for depths below 10,000 feet. Salinities vary from 40,000

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to 80,000 ppm and methane content may range from 25 to 45 cubic feet per barrel for formation waters commonly found in the Chocolate Bayou field. The effective gas permeabilities determined from production flow tests are estimated to range from 1 to 6 millidarcys and absolute permeabilities lie between 2 and 10 millidarcys.

More than 10 billion barrels of water inferred to occur in place in the prospective sandstone reservoirs of the Austin Bayou prospect contain potentially 1,733 MW-years of electrical energy and 400 billion cubic feet of methane in solution.

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INTRODUCTION

Extensive studies are being made by the Bureau of Economic Geology and the Department of Petroleum Engineering, The University of Texas at Austin, to evaluate the potential of producing geothermal energy from the geopressured Tertiary sandstones along the Texas Gulf Coast. The objective of these studies is to locate prospective reservoirs with a volume of 3 cubic miles or more, minimum permeability of 20 millidarcys, and fluid temperatures of at least 300°F. A general survey indicated that three formations--the Frio, Vicksburg, and Wilcox--have potential to meet these specifications. A recent study of the Frio geothermal fairways (Bebout, in press) shows the presence of a geothermal prospect, in the Brazoria fairway (fig. 1)

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* This paper is a portion of the Bureau of Economic Geology publication by Bebout and others (in press), "Frio Sandstone Reservoirs in the Deep Subsurface Along the Texas Gulf Coast--Their Potential for the Production of Geopressured Geothermal Energy."

located in Brazoria and Galveston Counties. A prospective geothermal well site has been located within the Austin Bayou Prospect located in the Brazoria fairway in a syncline between the Chocolate Bayou field on the northeast and the Danbury dome on the southwest (fig. 2).

A successful geothermal well should produce methane-saturated water at a rate of 20,000 to 40,000 barrels per day. The thermal and physical energy will be used to operate turbines to produce electricity at the site, and the methane will be removed and routinely processed as natural gas. The salinity of the water is expected to be too high to use on the surface for agricultural purposes and probably will have to be reinjected through disposal wells into a shallower reservoir.

Since subsurface engineering data are not available in the immediate vicinity of the proposed test-well site, estimates of pertinent engineering parameters such as porosity, permeability, salinity, temperature, and bottom-hole pressure were obtained from existing oil and gas wells in Brazoria County. Engineering and production data (supplied by Phillips Petroleum Company) for wells in the Chocolate Bayou field were particularly useful for estimating the in situ permeability and long-range deliverability of these geopressured hydrocarbon-producing reservoirs.

Water produced from the geothermal well is expected to have a salinity of 20,000 to 80,000 ppm total dissolved solids and to be

saturated with methane (40 to 50 cubic feet per barrel of water). The initial bottom-hole pressure will be greater than 10,000 psi. Predictions of decline in bottom-hole flowing pressures as a function of time and the effect of reinjection of produced water into the producing formation on flow rates and cumulative production of water and methane are reported from results of reservoir simulation tests performed by others (Knapp and Elemo, personal communication; Garg and others, 1977).

FORMATION TEMPERATURES AND PRESSURES

BRAZORIA COUNTY, TEXAS

Geothermal gradients along the Gulf Coast are known to range from about 1.4 to 2.4°F per hundred feet. In Brazoria County, the geothermal gradient is about 1.8°F per hundred feet as indicated by bottom-hole temperatures measured just prior to production flow tests for a number of wells at depths ranging from 8,500 feet to 18,000 feet (fig. 3). Subsurface temperatures of 250 and 300°F are found at depths of about 11,000 feet and 13,800 feet, respectively. Wells must be drilled to more than 16,000 feet to find temperatures near 350°F. The measured bottom-hole temperatures are higher than those obtained from well logs that are corrected to approximate equilibrium temperatures according to the relation developed by Kehle (1971).

$$T_E = T_L - 8.819 \times 10^{-12} D^3 - 2.143 \times 10^{-8} D^2 + 4.375 \times 10^3 D - 1.018 \quad (1)$$

where

T_E = equilibrium temperature, ^oF

T_L = bottom-hole temperature from well logs, ^oF, and

D = depth, feet.

A plot of temperature corrections from Kehle's relationship for depths from 7,000 to 20,000 feet shows a maximum correction of 32.9^{o}F at a depth of 13,000 feet (fig. 4). The correction diminishes to 7.4^{o}F at 20,000 feet, 25.5^{o}F at 7,000 feet and becomes zero near the surface.

In Brazoria County, the computed equilibrium temperatures underestimate the measured bottom-hole temperatures by 6° to 20° (fig. 3). Better agreement is observed as the depth increases. The geothermal gradient established by least-squares fit is 1.98^{o}F per 100 feet for equilibrium temperatures from well logs compared to 1.8^{o}F per 100 feet for measured bottom-hole temperatures. The observed discrepancies are not surprising. The empirical relationship developed by Kehle (1971) is based on a statistical study of many wells over a wide area along the Gulf Coast and will not always agree with temperatures in local areas.

Reservoir-fluid pressure controls the primary driving forces that produce the geothermal water and, thus, is an important aspect of geopressured aquifers. The effective overburden stress on the reservoir rock is controlled by fluid pressure; as reservoir pressures decline, the increase in effective overburden stress will cause changes in fluid storage volume (porosity), fluid transmissibility (permeability) and may lead to dewatering of adjacent shales. Shear stresses induced by nonuniform deformation of the overburden may cause fracturing and instability of subsurface formations, especially in the vicinity of fault zones. Subsidence at the surface may cause damage to structures, equipment, and the general environment. Aquifers in the Chocolate Bayou field are commonly geopressured below a depth of about 10,000 feet (fig. 5). Geopressure gradients lie between 0.465 and 0.98 psia per foot.

SALINITY AND METHANE CONTENT

SALINITY OF FORMATION WATERS

(Chocolate Bayou field, Brazoria County, Texas)

Salinity variations observed in formation waters depend on the history of water movement in the reservoir and are influenced by the following processes (Fowler, 1970).

1. Selective retention of ions by compacting shales acting as membranes may dilute original formation waters as reservoir pressures decline.

2. Dilution may also be caused by condensation of water vapor from gas that is being produced and usually occurs when gas-water ratios are high.
3. Increases in salinity may occur in a reservoir when more saline waters break through from adjacent aquifers. Entry of water from other aquifers can occur when permeability barriers break down as a result of pressure decline in the reservoir. If the waters from adjacent aquifers are fresher than the reservoir water, the salinity of the produced water decreases.

After considering the aforementioned processes Fowler (1970) observes that the typical pattern of salinity variation in the Chocolate Bayou field is one of dilution over a period of time. However, the history of salinity variations in the area is complex and exceptions to the above observation are known to occur.

Fowler (personal communication) selected salinities that he believed were typical of the connate waters of a number of formations at depths ranging from 8,600 to 12,833 feet. These salinities average about 40,000 ppm at depths of 8,600 to 10,000 feet then increase sharply to values ranging from 50,000 to 87,000 ppm at depths of 11,000 to 12,800 feet (fig. 6). The observed increase in salinity with depth in the geopressured formations of the Chocolate Bayou field is at variance with the strong dilution of salinity noted by Schmidt

(1973) in the geopressured zone of the Manchester field, Calcasieu Parish, Louisiana (fig. 7). These variations in salinity between different fields in different locations may not be unusual.

The solubility of methane in formation water is influenced by pressure, temperature, and salinity; at constant temperature, it increases as a function of pressure as shown by the experimental data (fig. 8) of Culberson and McKetta (1951). At constant pressure, the solubility first decreases slowly then increases rapidly as the temperature rises. Increasing salinity reduces the methane solubility at different rates depending on the temperature (fig. 9) as shown by Dodson and Standing (1944). For salinities up to 40,000 ppm, the rate of reduction decreases as the temperature rises. By using the data of Dodson and Standing (1944) and Culberson and McKetta (1951), the solubility of methane is estimated (fig. 10) for a bottom-hole pressure of 10,000 psia, salinities exceeding 40,000 ppm, and a temperature of 300°F. A linear extrapolation of curves is also drawn for temperatures of 100°, 200° and 250°F to a salinity of 100,000 ppm. The curve for 300°F is estimated and extrapolated to 100,000 ppm also. Brill and Beggs (1975) show that at a salinity of 300,000 ppm the aqueous solubility of natural gas is reduced to 20 to 30 percent of its solubility in pure water in the temperature range from about 90° to 250°F (fig. 11).

Although the solubility of methane decreases as salinity rises, an increase in temperature in the geopressured zone (fig. 6) causes

a small net increase in solubility despite the higher salinity. For example, in the hydropressured zone at a depth of 9,600 feet, the temperature is about 225°F, the salinity is 40,000 ppm, and the solubility of methane from figure 10 is about 29 standard cubic feet per barrel of water. In the geopressured zone at a depth of 12,500 feet, the salinity has increased to about 70,000 ppm, but the temperature has also increased to 275°F and the solubility of methane rises to 33 standard cubic feet per barrel of water.

POROSITY AND PERMEABILITY--CORE ANALYSIS

Laboratory measurements of porosity and permeability are often made on conventional cores at atmospheric conditions. These analyses of unconfined cores give more reliable permeability values than analyses for sidewall cores because they are damaged less by recovery techniques and, therefore, are more representative of the formation rock in situ. An example is the porosity-permeability relationships for both unconfined cores and sidewall cores for a well located in Nueces County (fig. 12). The porosities and permeabilities of the sidewall cores are substantially higher than those of conventional cores.

Permeability data from unconfined specimens may be satisfactory for predicting the deliverability of shallow reservoirs. However, as the depth of the reservoir increases and the reservoir pressure declines, the reduction of permeability caused by the effective overburden pressure and temperature becomes increasingly significant.

Therefore, permeability data from unconfined cores can be expected to overestimate the deliverability of deep geopressured geothermal reservoirs.

Alterations of permeability, porosity, and elastic deformation properties caused by pressure and heat can have a substantial influence on the bulk volume, pore-fluid volume, and deliverability of a reservoir. Therefore, it is important to understand the reasons for discrepancies that exist between porosities and permeabilities measured on unconfined cores and those measured on sandstone reservoirs in situ.

The effective overburden pressure on a reservoir is the difference between the total overburden pressure and the internal reservoir-fluid pressure. When both overburden pressure and reservoir-fluid pressure are varied, only the difference between the two has a significant influence on the dynamic physical properties of the reservoir rock. In a highly geopressured reservoir, the effective overburden pressure will be relatively small when production is first started, but will increase in direct proportion to the decline in reservoir-fluid pressure over the producing life of the reservoir. The reduction in permeability associated with increases in the effective overburden pressure is especially important to the permeability and long-range deliverability of a geopressured reservoir.

Thermal effects on permeability depend on the nature of the pore fluid. Casse and Ramey (1976) found that the oil permeability

of oil-saturated Berea sandstone was relatively insensitive to heat and that the absolute permeability to gas was independent of temperature. In water-saturated Berea sandstone however, the aqueous permeability was sensitive to temperature because of the combined influence of thermal expansion of grains into pores and pore throats, mechanical stresses caused by differential expansion of different minerals along different crystallographic axes, and fluid-rock surface interactions. The determination of absolute permeability to water can be seriously affected by the swelling of certain types of clay particles, such as montmorillonite. However, increasing the salinity of water tends to reduce the swelling potential of the clays. The role of heat in deactivating the swelling potential of clays (Grim, 1962) is a phenomenon that might be detectable in deep reservoirs that have been exposed to high temperatures. In a flowing water well, clay particles can be dislodged from the rock, obstruct or plug flow channels, and reduce the permeability. Likewise, gas that has been released from solution in a pressure-reduced reservoir will decrease the effective permeability to water in the same manner.

Empirical relationships show that permeability normally increases as the porosity increases. The type of porosity has an influence on permeability; for example, isolated pore spaces (vugs) that are not interconnected with flow channels, microcracks in cement, pores within kaolinite clay, and pore fillings do not contribute to the effective permeability.

Permeability values found for unconfined cores from geopressured formations for two wells in Brazoria County range from less than 0.1 millidarcy for cores with low porosities of less than 15 percent to several hundred millidarcys in the porosity range from 20 to 30 percent (fig. 13). In the No. 1 Houston "JJ" well (fig. 13) the initial effective overburden pressure was 3,870 psi at a depth of 15,244 feet (just above the cored interval). The value of the effective overburden pressure is based on a bottom-hole pressure of 11,375 psi recorded in 1965 (fig. 23). A bottom-hole temperature of 321°F was recorded at the same time. One year later (in 1966) a bottom-hole pressure of 5,600 psi was measured at the same depth. Hence, during this 12-month period, the reservoir pressure declined by 5,775 psi, and the effective overburden pressure increased from 3,870 to 9,644 psi. Although incomplete information is available on the effect of overburden pressure and temperature on gas and liquid permeabilities, Casse and Ramey (1976) show that the absolute permeability to water in Berea sandstone (fig. 14) decreased by more than 30 percent when subjected to a confining pressure of 4,000 psi at a temperature of 300°F. These pressure and temperature conditions are roughly the same as those described above that existed in the No. 1 Houston "JJ" well when production was started in 1965. The additional reduction in permeability, caused by pressure decline and the resulting buildup of the effective overburden pressure to 9,644 psi, cannot be determined from figure 14. If the trend of the relationship in

figure 14 is extrapolated, however, the total reduction in permeability will probably exceed 50 percent. The data of McLatchie and others (1958) show that rocks with low permeability are more sensitive to changes in the effective overburden pressure than rocks with high permeability (fig. 15). Reductions in permeability approach 90 percent when low-permeability rocks are subjected to effective overburden pressures of 5,000 psi or more.

Even if a 50-percent reduction of the core-analysis permeabilities (fig. 13) is allowed to account for the effective overburden pressures observed in deep geopressured reservoirs, the resultant permeabilities remain much higher than those obtained from production flow tests. For example, a comparison of original and late-time performance curves (fig. 16) indicates that a much greater reduction of permeability occurs in the reservoir that was originally highly geopressured for (1) a highly geopressured reservoir, the "S" sandstone in the Phillips No. 1 Houston "FF" and (2) a slightly geopressured reservoir, the upper Weiting sandstone in the Phillips No. 1 Rekdahl. Curves for the No. 1 Houston "FF" show that the flow rate q increased substantially at a constant value of the pressure drawdown parameter $\bar{P}^2 - P_{wf}^2 / \mu Z$ during the production time interval between the original and late flow tests. Similar curves for the Rekdahl show that q changed little, but increased somewhat, for a constant value of the pressure drawdown parameter. The angle between the original and late-time performance curves

should give a qualitative estimate of how much the Kh product diminished during the production-time interval. In this example, the largest reduction in the Kh product predictably occurs in the highly geopressured reservoir. Quantitative methods for calculating permeability from well-production tests are discussed in detail in the next section.

PERMEABILITY--WELL-PRODUCTION FLOW TESTS

Many of the sandstones producing gas and condensate in the Chocolate Bayou field have pay thicknesses from 10 to 30 feet. Methods used for evaluating gas permeability from pressure buildup data and for converting gas permeability to absolute permeability are explained in this section. A method for computing permeability and skin factor from absolute open-flow-potential tests (AOFPT) is also discussed. Agreement between permeabilities obtained from pressure buildup tests and from AOFPT does not always occur as shown by comparative data for several wells located in the Chocolate Bayou field (table 1). Permeability values from pressure-buildup data range from 1.6 to 16.5 millidarcys and those from AOFPT vary from 1.4 to 131 millidarcys. The general quality and scatter of data from AOFPT for gas wells in Brazoria County make the validity of these permeabilities seem questionable. The general performance characteristics of gas wells suggest that a conservative interpretation of permeability data should be made. Hence, the effective permea-

bilities are estimated to range from 2 to about 10 millidarcys. These permeability data are for relatively tight, thin gas-bearing reservoirs, and the thicker and more porous reservoirs in the Austin Bayou Prospect are expected to have higher permeabilities.

PRESSURE-BUILDUP ANALYSIS

The effective permeability of a reservoir can be estimated from the rise in bottom-hole pressure when a producing well is shut in. The method is valuable because the effective permeability is based on the actual performance of a well and represents the average reservoir properties of a major portion of the drainage area rather than the limited area around the well bore. Excessive pressure drop in the vicinity of the well bore (skin effect) detracts from the producing capability of the well. This skin effect is often the result of damages sustained by drilling, production, and completion practices and probably extends a distance of less than 20 feet from the well. The method for evaluating effective permeability involves equations which define the buildup characteristics for the shut-in well as functions of time, the production rate before shut in, the radius of drainage of the well, the compressibility and viscosity of the reservoir fluid, and the porosity and permeability of the drainage area.

The method of Horner (1951) involves plotting the buildup of

reservoir pressure P_r^2 as a function of a time ratio, ($T + \Delta t$ / Δt), where T is the length of the producing time before shut in, and Δt is the shut-in period of time. A semilog plot of this pressure buildup data should result in a straight line with slope M that is inversely proportional to the mean formation permeability as indicated by the relation:

$$Kh = \frac{1637\ T_r\ q\ \mu\ Z}{M} \qquad (2)$$

Equations for the skin factor (S) and estimated damage ratio (EDR) also use slope M.

$$S = 1.151 \left[\frac{P_r^2\ 1hr - P_{wf}^2}{M} - \text{Log} \frac{q\ T_r\ Z\ P_r}{1.033\ Mh\ \phi r_w^2} \right] \qquad (3)$$

$$EDR = \frac{\overline{P}_r^2 - P_{wf}^2}{M\ (\text{Log}\ T + 2.65)} \qquad (4)$$

where

K	=	permeability (md)
h	=	pay thickness (feet)
T_r	=	formation temperature (^oR)
q	=	gas-flow rate (MCFPD)

μ = viscosity of gas (cp)

Z = gas deviation factor

$\bar{P}_r$ = reservoir pressure (psig)

P_{wf} = formation flowing pressure in wellbore (psig)

ϕ = fractional porosity

r_w = wellbore radius (feet)

T = flow period (minutes, or hours), and

Δt = shut-in period (minutes, or hours).

As an example, a pressure buildup plot for the No. 1 Gardiner, Chocolate Bayou field, Brazoria County, gives a slope $M = 0.58 \times 10^6$ psig per cycle (fig. 17). The effective permeability for this well was computed to be 5.2 millidarcys, and the EDR was 1.3. Values of formation parameters used for these calculations are as follows.

Flow time (T)	60 minutes
Flow rate (q)	1,765 MCFPD
Depth of producing sand	11,779 feet
Sand thickness (h)	25 feet
Bottom-hole temperature	260°F
Gravity of gas	0.654
Viscosity of gas (μ)	0.03 cp
Gas deviation factor (Z)	1.21
Reservoir pressure (P_r)	7,575 psig
Formation flowing pressure in well bore (P_{wf})	7,347 psig

MULTIPOINT OPEN-FLOW POTENTIAL TESTS

An important source of flow data is from absolute open-flow potential tests (AOFPT), sometimes called four-point open-flow tests. The AOFPT are a series of measurements of flowing bottom-hole pressures made with the well flowing at different rates. The Railroad Commission of Texas requires that AOFPT be made in gas wells; the results aid in determining the allowable flow rate. The data can be used to determine the Kh product and skin factor by analytical procedures described by Odeh and Jones (1965). Usefulness of the technique depends highly on the accuracy of the pressure measurements. The Kh product and skin factor are determined from:

$$Kh = \frac{28{,}958\ \mu_g\ B_g}{m'} \tag{5}$$

$$S = 1.151 \left[\frac{b'}{m'} - \log \frac{k_g}{\phi\ \mu_g\ c_g\ r_w^2} + 3.23 \right] \tag{6}$$

where

μ_g = viscosity of gas (cp)

k_g = permeability to gas (md)

ϕ = fractional porosity

c_g = compressibility of gas (psi^{-1})

r_w = radius of well (ft)

B_g = formation volume factor

m' is the slope and b' is the intercept of a plot of $\frac{Pi - Pwf}{qn}$

versus $$\sum_{j=1}^{n} \left(\frac{q_j - q_{j-1}}{q_n} \right) \log (t_n - t_{j-1}).$$

Details of calculations required in the analysis of multipoint open-flow potential test data are given by Matthews and Russell (1967). Results from AOFPT analysis of data for the Phillips No. 1 Gardiner show a permeability of 1.4 millidarcys and a skin factor of -2 (fig. 18). These results agree fairly well with those from pressure buildup data given earlier where K is 5.2 millidarcys, and S is 3.

CALCULATION OF ABSOLUTE PERMEABILITY

The absolute permeability is determined by flow tests on rocks that are fully saturated by a single fluid. The presence of other fluids within the rock reduces the ability of the first fluid to flow. This reduced permeability is called the effective permeability to the first fluid. Relative permeability is the ratio of the effective permeability to the absolute permeability and varies from 0 to 1. The relative permeability is influenced by the portion of the pore volume occupied by each fluid and by how the fluids are

distributed and segregated within the rock. Segregation is a function of saturation levels and the wetting characteristics of the rock and the respective fluids. Most reservoir rocks are considered to be water wet because they were laid down originally in a water environment. Where gas and water are the predominant reservoir fluids, gas is the nonwetting phase, and, of course, water is the wetting phase.

The effective gas permeability (K_g) determined from pressure buildup tests was estimated to lie between 1 and 6 millidarcys for wells in the Chocolate Bayou field. The relative permeability to the nonwetting phase (K_{rn}) was calculated from the relationship below (Rose, 1949).

$$K_{rn} = \frac{16\rho^2_n \, (\rho_n - \rho_{nm})^3 \, (1-\Psi_w-\rho_{nm})}{\left[2\rho^2_n(2-2\Psi_w-3\rho_{nm}) + 3\rho_n\rho_{nm}\,(3\rho_{nm}-2+2\Psi_w) + \rho_{nm}(1-\Psi_w)(4-4\Psi_w-5\rho_{nm})\right]^2} \quad (7)$$

where

K_{rn} = K_{rg} = relative permeability to gas

ρ = fluid saturation

Ψ = immobile phase saturation

n = nonwetting phase

w = wetting phase, and

m = minimum saturation values attained under dynamic flow conditions.

It is assumed that the immobile wetting phase saturation Ψ_w is 30 percent, and ρ_n is 60 percent since some water production (about 10 percent) is observed. The value of 0.18 for ρ_{nm} is based on a gas-recovery efficiency of 70 percent assumed for Gulf Coast wells, that is, $\rho_{nm} = (1-0.7)\ (.6) = 0.18$. The numerical evaluation of K_{rg} in equation (7) gives a value of 0.66.

The absolute permeability $K = \frac{K_g}{K_{rg}}$, hence $K_1 = \frac{1}{0.66} = 1.5$ md,

and $K_2 = \frac{6}{0.66} = 9.1$ md where K_1 and K_2 are low and high values of absolute permeability based on the range of effective gas permeabilities determined from production flow tests.

PERMEABILITY--RESERVOIR FLUID DELIVERABILITY

The geopressured reservoir selected for testing is assumed to have enough porosity to contain the volume of water required for long-range requirements of the geothermal project. Adequate porosity (about 20 percent) was an important consideration in selecting the prospective geothermal test-well site. However, permeability is the most critical factor affecting fluid-production rates.

The rate of flow of water from a reservoir is controlled by parameters in the following equation.

$$q = \frac{Kh\,(\bar{P} - P_w)}{141.2\,\mu\,B\,(\ln r_e/r_w - .75 + S)} \qquad (8)$$

where

q	=	flow rate (bbl/day)
K	=	permeability (md)
h	=	formation thickness (ft)
$\bar{P}$	=	reservoir pressure (psi)
P_w	=	bottom-hole flowing pressure (psi)
μ	=	viscosity of formation water (cp)
B	=	formation volume factor
r_w	=	radius of reservoir (ft)
r_e	=	radius of well (ft), and
S	=	skin factor

If the low permeabilities (2 to 10 millidarcys) found in gas-producing reservoirs in Brazoria County are also typical of water-producing reservoirs, then the formation thickness must be increased substantially to obtain adequate water-flow rates. Actually the thick water-bearing sandstones in the Austin Bayou Prospect are expected to have better permeability characteristics than the thin gas-bearing sandstones. However, it is not possible to make a quantitative evaluation of the permeability of these water-bearing sandstones until a well is drilled and suitable production tests

are made. The possibility exists for increasing the producing capacity of deep reservoirs by a factor of 1 to 1 1/2 using currently available hydraulic fracturing technology and propping materials. The expected development of stronger propping agents in the near future may result in increasing the flow rates by a factor of 2 1/2 to 3 (Podio and others, 1976).

Estimates of sandstone thickness required to produce 20,000 and 40,000 barrels of water per day are 191 and 383 feet, respectively, if a permeability of 10 millidarcys and a drawdown pressure of 2,000 psi is assumed (fig. 19). Thickness requirements decrease as permeability and drawdown pressure increases as shown by the simplified relationships in the following equations obtained from equation (8) after assumptions for reservoir parameters are made.

for $q = 20{,}000$ B/D,

$$h = \frac{3.828 \times 10^6}{K\,(\Delta P)} \tag{9}$$

for $q = 40{,}000$ B/D

$$h = \frac{7.656 \times 10^6}{K\,(\Delta P)} \tag{10}$$

where

formation-water viscosity (μ) at 300°F = 0.2 cp

formation-volume factor (B) = 1.0

radius of reservoir (r_e) = 930 ft

radius of well bore (r_w) = 0.5 ft

skin factor (S) = 0, and

formation thickness (h), permeability (K), and pressure drawdown ($\bar{P} - P_w$) are variables.

RESERVOIR PRESSURE DECLINE AND HYDROCARBON PRODUCTION HISTORIES

Pressure decline and hydrocarbon production behavior of geopressured reservoirs in the Gulf Coast area depend on many complex interacting factors. These factors include the intrinsic physical properties of the reservoir rock, the geological environment, location of faults, dynamic driving forces acting on fluids, well completion techniques, economics, and management policies. The list could be expanded to include virtually every phase of petroleum technology. Here, it is sufficient to state that the behavior of each reservoir is often unique and unpredictable in detail. Normal trends of well performance, however, can be predicted for gas-condensate production from geopressured reservoirs. Typically, deliverability is high during the early life of these wells, then drops sharply when semi-steady-state conditions are achieved. Deliverability is reduced greatly over the life of the wells as reservoir pressures decline, although many wells are still producing after 10 or 12 years.

Most wells that were drilled in Brazoria County produced gas and condensate, a few produced oil, and, of course, many were dry holes as far as hydrocarbon production was concerned.

Pressure decline and production curves for several wells are discussed in the following section. Wells were selected to illustrate the diverse behavior of reservoirs near the Austin Bayou Prospect (fig. 20).

THE PHILLIPS NO. 1 GARDINER, SOUTH CHOCOLATE BAYOU FIELD, BRAZORIA COUNTY, TEXAS

This well was drilled in 1964 to a total depth of 13,500 feet and produced gas and oil from a 14-foot interval (11,772 to 11,786 feet) in the lower Weiting sandstone. The early history of the well showed a rapid decline in bottom-hole pressure from 7,589 to 4,823 psia in less than 12 months (fig. 21). The original geopressure gradient (0.644 psi/ft) declined to the hydropressure gradient level (0.465 psi/ft) in less than 10 months. The initial bottom-hole temperature of 260°F declined somewhat for the first few months, then increased to a maximum value of 263°F before declining gradually back to 260°F after a period of 28 months.

The annual gas and oil production peaked during the early life of the well at 1,644 MMCF and 167,000 barrels respectively (fig. 22). The well produced for only 4 months in 1964, hence low production values are recorded for that year. After 16 months, the annual gas and oil production declined to 33 MMCF and 91,700 barrels, respectively. At this point, the well was reclassified from a gas well to an oil well by the Railroad Commission of Texas. Thereafter, production from the well was recorded as casinghead gas and oil. Currently, after 12 years, the well is producing at an annual rate of about 20 MMCF of casinghead gas and 2,250 barrels of oil.

THE PHILLIPS NO. 1 HOUSTON "JJ", SOUTH CHOCOLATE BAYOU FIELD, BRAZORIA COUNTY, TEXAS

This well was drilled to a total depth of 17,020 feet and was completed in 1965 as a gas producer. Production was from the "S" sandstone through perforations in the depth interval of 15,187 to 15,332 feet. The bottom-hole temperature was 321°F at 15,244 feet. The bottom-hole pressure at a depth of 15,244 feet decreased from the initial 11,375 psia to 5,599 psia during the first year (fig. 23). The well was producing 95 percent salt water and the bottom-hole pressure was 4,272 psia 4.5 years later. The initial geopressure gradient of 0.746 psi/ft declined to the hydropressure gradient level (0.465 psi/ft) in a period of 6 months and reached a value of 0.28 psi/ft when the well went to salt water. In 1970 the well was recompleted into the lower Weiting sandstone and produced gas and condensate from perforations in the depth interval of 14,613 to 14,741 feet (fig. 24).

The initial gas and condensate production from the "S" sandstone was 2,259 MMCF and 32,523 barrels respectively during the year 1965. In 1967 the well produced 290 MMCF of gas and 173 barrels of condensate. Production increased again before the well went to salt water in 1970 (fig. 24). Production from the lower Weiting sandstone continued for 3 years until the well died in 1973 and was plugged and abandoned in 1974.

THE PHILLIPS NO. 1 HOUSTON "FF", SOUTH CHOCOLATE BAYOU FIELD, BRAZORIA COUNTY, TEXAS

The No. 1 Houston "FF" was drilled to a total depth of 17,201 feet; the well was completed in 1964. The Patrick sandstone was tested in the depth interval 16,776 to 16,870 feet. The bottom-hole temperature was 338°F, and the bottom-hole pressure was 10,095 psia at a depth of 16,700 feet. Apparently the production test was unsuccessful because no production from the Patrick sandstone was recorded.

The initial production was from the "S" sandstone from the depth interval of 15,238 to 15,386 feet. Reservoir temperature was 318°F and the 24-hour shut-in pressure was 12,273 psia at a depth of 15,293 feet. A few weeks later the temperature was 326°F when measured at a depth of 15,312 feet after a shut-in period of 48 hours. Thereafter the temperature decreased over a period of several months and stabilized and remained constant at 322°F for several years (fig. 25).

Bottom-hole pressures measured at a depth of 15,293 feet in the "S" sandstone declined in a period of about 17 months from 12,273 psia in August 1964 to 5,215 psia in January 1966 (fig. 25). At this time much of the driving force provided by the gas compressibility had been expended; thereafter pressures declined at a much slower rate and finally stabilized at about 3,000 psia from 1971 to 1973.

The maximum annual gas production from the "S" sandstone was 2,342 MMCF in 1965 and declined to about 66 MMCF in 1973. Production from this well was increased dramatically in 1974 by perforating the sandstone interval from 13,788 to 13,824 feet (fig. 26). In 1976, production was down again, and the Banfield sandstone (depth unspecified) was perforated in an effort to increase production.

A plot of bottom-hole pressures, corrected for gas compressibility Z versus cumulative production from the "S" sandstone fails to give a straight line relationship (fig. 27). The volume of original gas in place G can be calculated when a linear relationship exists, but in this example, G is estimated by extrapolation of the curve to a zero value of P/Z.

THE GENERAL CRUDE OIL CO., NO. 3 HOUSTON FARMS DEV. CO., SOUTH CHOCOLATE BAYOU FIELD, BRAZORIA COUNTY, TEXAS

This well was completed in December 1960 to a total depth of 13,472 feet and produced gas and condensate from the 8-foot-thick Frio "P" sandstone in the depth interval 12,510 to 12,518 feet. Production did not begin until July 1964 (fig. 28). In 1965, the annual production was 791 MMCF of gas and 35,728 barrels of condensate. The production decline curves are not as steep as most of the wells described previously and are also relatively free of rapid fluctuations over the 12 years of production history. The well was still producing in 1976 at annual rates of about 122 MMCF of gas and 1,350

barrels of condensate. Bottom-hole pressure and temperature values of 9,087 psi and 275°F, respectively, were recorded in 1961 at a depth of 12,505 feet. In summary, this thin sandstone produced over 12 billion cubic feet of gas and about 190,000 barrels of condensate over a period of 12.5 years.

THE PHILLIPS NO. 2 HOUSTON "M", CHOCOLATE BAYOU FIELD, BRAZORIA COUNTY, TEXAS

The Houston "M" No. 2 had a relatively weak production history caused partly by the close proximity of a fault which restricted the area of drainage. The well was completed in September 1956, and produced gas and condensate from the Rycade sandstone between 11,396 and 11,404 feet. Production curves and well-log responses through the production zone are shown in figure 29. After producing for 7 years and 4 months, the well was shut in during 1964 and plugged in 1965.

PERDICTED RESERVOIR PERFORMANCE

Geological analysis indicates that the proposed test well in the Austin Bayou Prospect will drain many sandstone units in an area of about 16 square miles. The total thickness of these sandstones is 840 feet and is the sum of all sandstone units indicated by the interpolated spontaneous-potential log of the test well for zones A, B, C, D, E, and F (fig. 30). An average porosity of 20 percent or more is predicted

for 250 feet of the total sandstone; the remaining 560 feet has a porosity that varies between 5 and 20 percent and average 15 percent. The total bulk volume of all sandstone units is 360 billion cubic feet, and the total pore volume is 60 billion cubic feet. If all pore space is filled with water, the aquifer will contain more than 10 billion barrels of water; if the water contains 40 cubic feet of methane per barrel, as discussed previously, then the total gas resource should be 426 billion cubic feet in place.

House and others (1975) estimate the potential electrical energy of deep (16,000 feet) geopressured geothermal reservoirs at 300°F to be 49.1×10^{-11} MW-yr. per pound of reservoir water in place. Based on this estimate, the total electrical energy potential of water contained by reservoirs in the Austin Bayou Prospect is 1,733 MW-yrs. To obtain the available electrical energy, the in-place potential must be multiplied by a recovery factor, which is the fraction of in-place water that can be produced at the surface. The recovery factor depends on a number of variables such as reservoir driving forces, rock and fluid compressibilities, shale water influx, changes in reservoir characteristics as a function of pressure decline, effects of free gas and gas in solution, production rate, production method, and possible reinjection of produced water into the producing formations. Many of these variables can be evaluated only after appropriate production tests are made and adequate depletion history is available.

Simulation studies of geopressured reservoirs have been made by Garg and others (1977). They have concluded that without reinjection only 10 percent of the in-place methane will be produced (fig. 31). The total fluid flow rate and methane flow rate will decrease rapidly by this method (figs. 32 and 33), but there will be little decline in fluid temperature (fig. 34).

On the other hand, if a substantial portion of the water is reinjected into the producing reservoir to maintain reservoir pressure and fluid flow rates, more than 90 percent of the gas can be extracted. Using the reinjection method, higher reservoir pressure and fluid flow rates can be maintained for a longer period of time. The total fluid flow rate will increase slightly after 20 years (fig. 32), but the methane flow rate will continue to decline as a result of dilution by injected water (fig. 33). The reservoir simulation model of Garg and others predicts that fluid temperatures will remain relatively constant at about 300°F for 15 to 20 years with reinjection and will then begin to decline to less than 200°F after 55 years (fig. 34). The excess surface water over that which can be reinjected is estimated to peak after 8 years of production at 94 million barrels per well pair (fig. 35). The amount of excess water declines to a break-even point in 39 years, after which time there will be a water deficit.

The relationship between the water flow rate and sandstone thickness (fig. 36) for the test well (fig. 30) has been computed from

equation (8) assuming 5 to 25 millidarcys permeability and a constant drawdown pressure of 1,000 psi. Other values of parameters in the equation are:

Viscosity of formation water (μ)	=	0.2 cp at 300°F
Formation volume factor (B)	=	1.0
Radius of reservoir (r_e)	=	10,560 feet
Radius of production tubing (r_w)	=	0.458 feet
Skin factor (S)	=	0

If all the sandstone units in the test well (840 feet) are perforated, adequate flow rate is possible with permeability as low as 5 millidarcys and a drawdown pressure of 1,000 psi (fig. 36). If the drawdown pressure is doubled, the flow rate is also doubled with the other parameters remaining constant. If the permeability of any sandstone unit or zone is known, then the flow rate can be determined from figure 36. For example, if the 230 feet of sandstone in zone E is produced at a drawdown pressure of 1,000 psi and assumed permeability of 15 millidarcys, 13,140 barrels per day would be produced.

Dewatering of shales may have a significant influence on the maintenance of reservoir pressure while zone E is produced. Pressure-decline curves based on a reservoir simulation model (Knapp and Elemo, personal communication) show that the bottom-hole flowing pressure will decrease by 2,138 psi in 20 years when only the sandstone compressibi-

lity is taken into account (fig. 37). However the pressure will decrease by only 848 psi when the maximum possible shale-dewatering effects are added. The maximum shale dewatering effect is based on a model which disseminates the shale uniformly through the sandstone. A more realistic model, which concentrates the shale in layers which approximate the sand-shale sequence in zone E, is expected to produce a pressure decline curve which lies between the curves shown in fig. 37.

Reservoir parameters used in the simulation program to produce the data in fig. 37 are the following.

Single well drainage area	16 square miles
Depth	15,300-15,900 feet
Initial bottom-hole pressure	10,318 psi
Bottom-hole drawdown pressure	1,000 psi
Fluid flow rate	13,140 B/D
Water salinity	45,000 ppm
Temperature	325°F
Sandstone	
Thickness	230 feet
Porosity	20 percent
Permeability (horizontal)	15 md
Bulk compressibility	1.21×10^{-5} psi^{-1}
Shale	
Thickness	310 feet
Porosity	16.5 percent
Permeability (horizontal)	0
Bulk compressibility	2×10^{-5} psi^{-1}

SUMMARY

The effective gas permeabilities determined from production flow tests are estimated to range from 1 to 6 millidarcys and absolute permeabilities lie between 2 and 10 millidarcys for selected wells in the Chocolate Bayou field, Brazoria County, Texas. In a reservoir with a drainage radius of 930 feet, a permeability of 10 millidarcys, a sandstone thickness of 383 feet, and a drawdown pressure of 2,000 psia, a flow rate of 40,000 barrels of water per day can be achieved. Salinity of this water will range from 40,000 to 80,000 ppm, and methane content may range from 25 to 45 cubic feet per barrel. The average geothermal gradient is 1.8°F per hundred feet and reservoir fluid pressures lie between 0.465 and 0.98 psia per foot for depths below 10,000 feet in the Chocolate Bayou field.

A prospective geothermal test-well site has been located within the Austin Bayou Prospect, Brazoria fairway, which should have a total of 800 to 900 feet of sandstone in the depth interval from 14,000 to 16,500 feet. At least 250 feet of the sandstone should have porosities of 20 percent or more and permeabilities up to 20 millidarcys. The temperature at the top of the sandstone section should be 300°F. Water produced at a rate of 20,000 to 40,000 barrels per day will probably be injected into shallow sandstone reservoirs. Simulation studies, however, indicate that only 10 percent of the total methane in place can be extracted unless the produced water is reinjected into the producing reservoir.

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Table 1.

Examples of effective permeabilities and skin factors computed from flow tests made early in life of wells in Chocolate Bayou field, Brazoria County, Texas

Well Name	Perforated Zone	BHP psia	H feet	BHP Buildup			AOFPT (4-pt. tests)		
				Kh md-ft	K md	S	Kh md-ft	K md	S
Houston "FF" #1	15,239-15,384	12,420	29	113	3.9	0	1,430*	49 *	65
Houston "X" #1	12,099-12,110	8,623	10	128	12.8**	3	12	1.2	- 5
Banfield #1	10,540-10,550	5,630	10	165	16.5	11	31	3.1	0
Gardiner #1	11,772-11,786	7,575	25	130	5.2	3	34	1.4	- 2
Houston "W" #1	12,089-12,108	5,730	14	-	-	-	1,840	131	49
Rekdahl #1	11,376-11,397	5,290	8	14	1.7	8	225*	28 *	14
Houston "EE" #1	14,641-14,724	12,422	12	-	-	-	18*	1.5	- 2
Millington #1	11,015-11,022	4,515	25	40	1.6	2.8	-	-	-
Houston "M" #2	11,396-11,404	2,572	8	-	-	-	20	2.5	-

*Scatter of data makes analysis questionable.
**Insufficient data make analysis questionable.

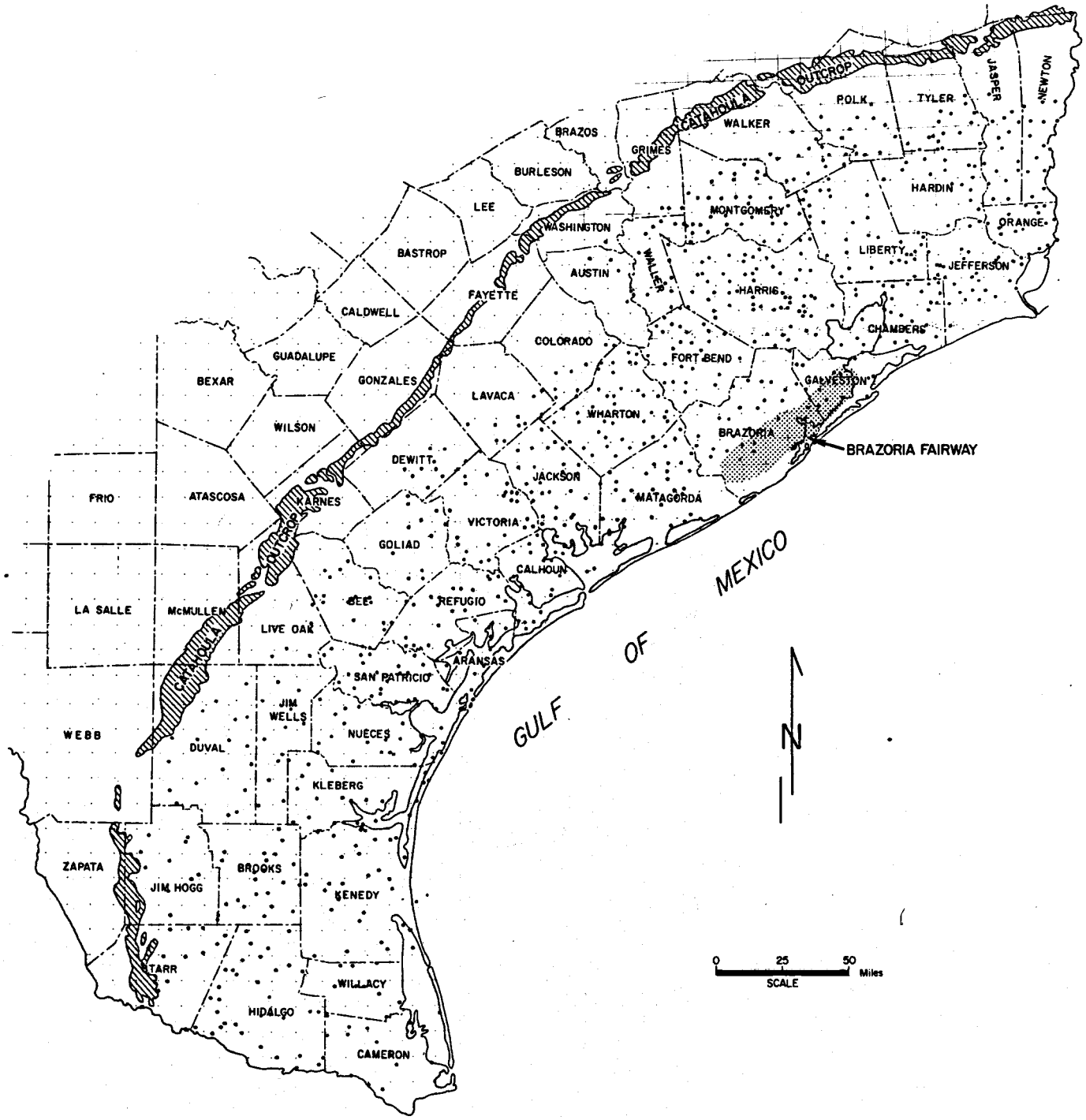

Figure 1 Location of Brazoria Fairway

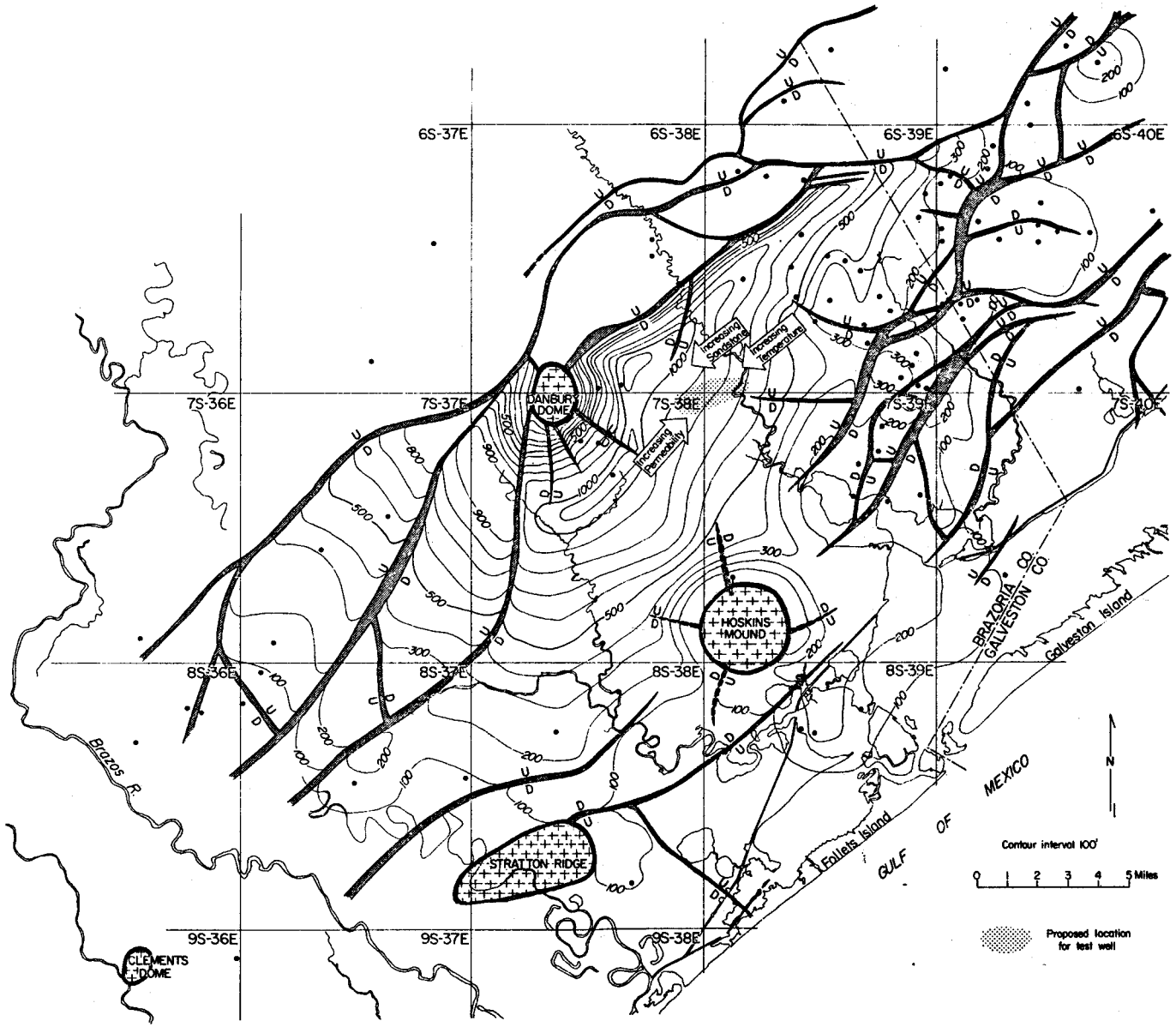

Figure 2 Total net sand and location of test-well site, Austin Bayou Prospect, Brazoria County, Texas.

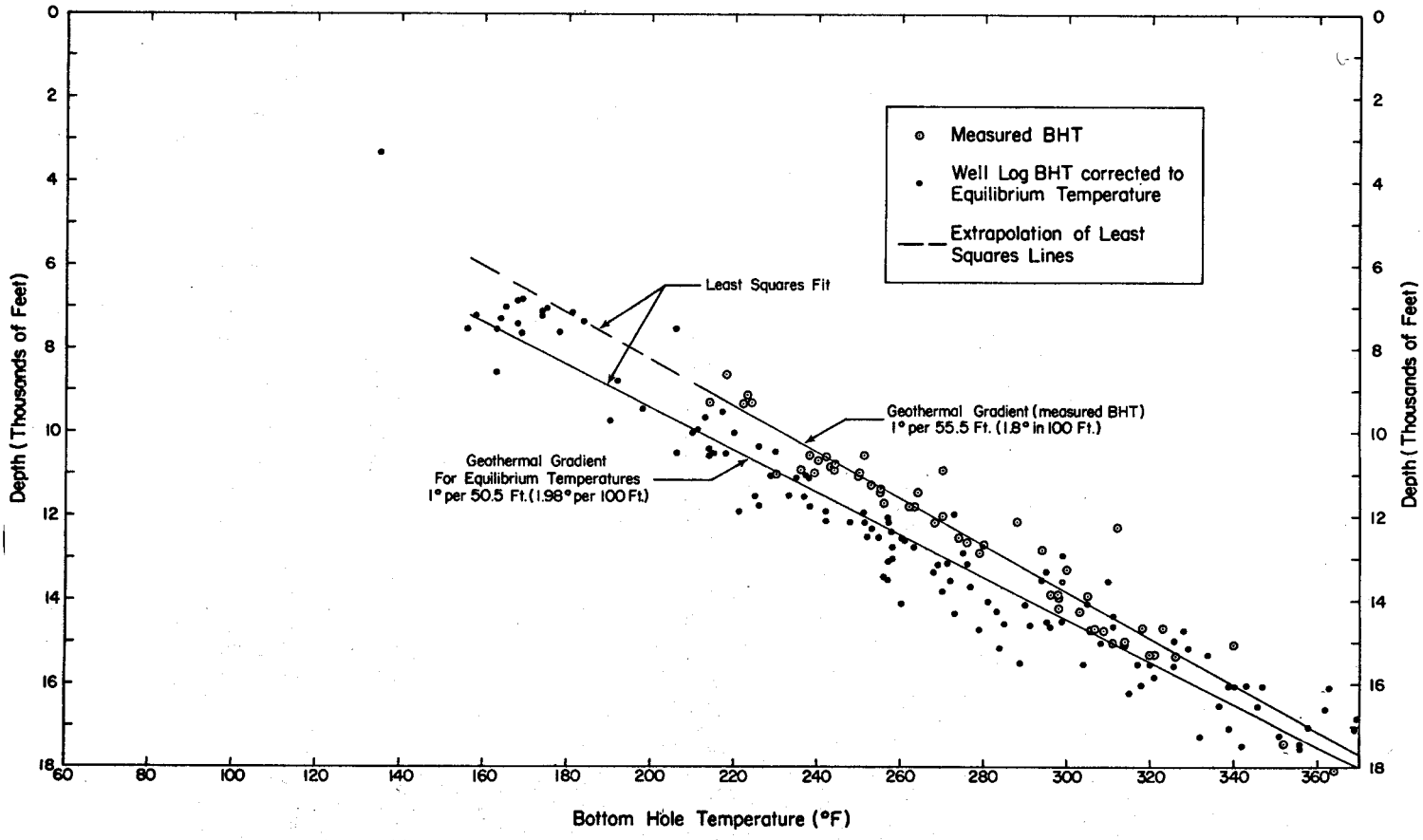

Figure 3: Comparison between measured bottom-hole temperatures and equilibrium temperatures calculated from well logs (Brazoria County, Texas).

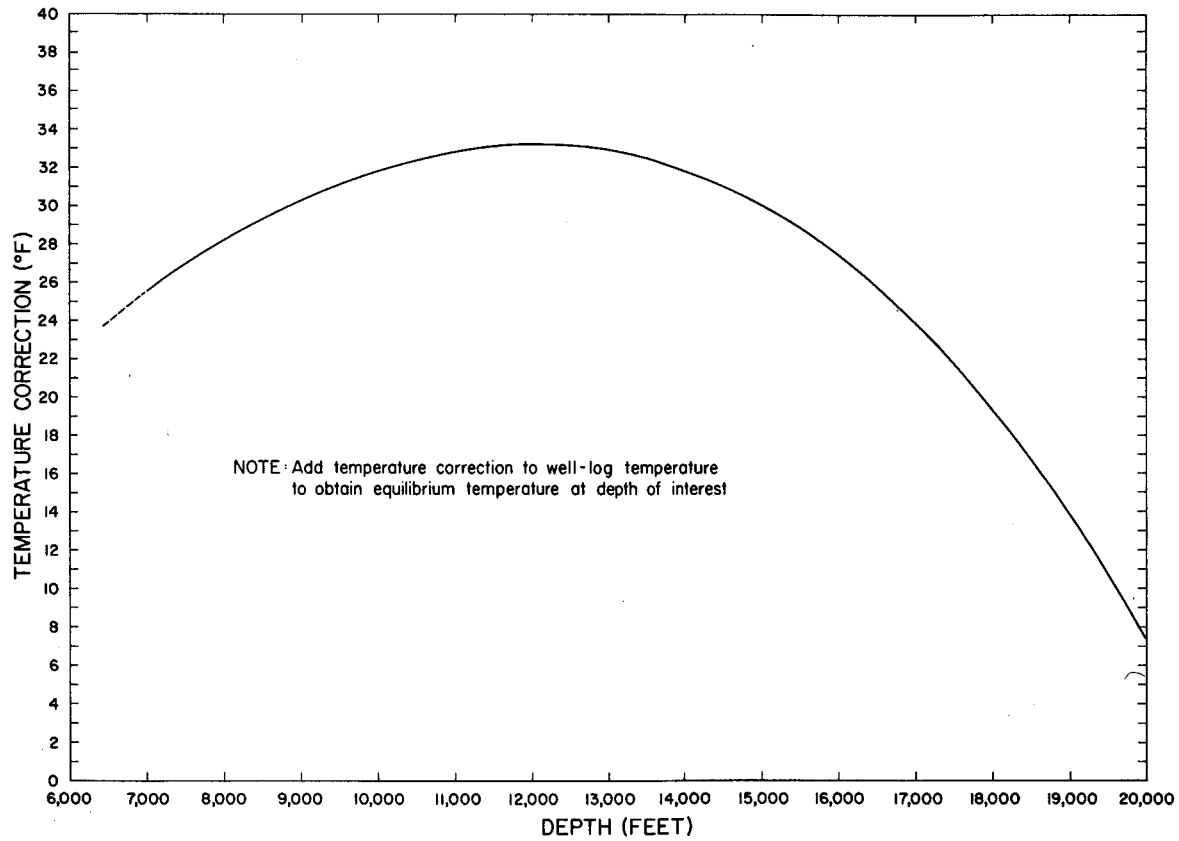

Figure 4 Temperature corrections as a function of depth for adjusting well-log temperatures to approximate equilibrium temperatures.

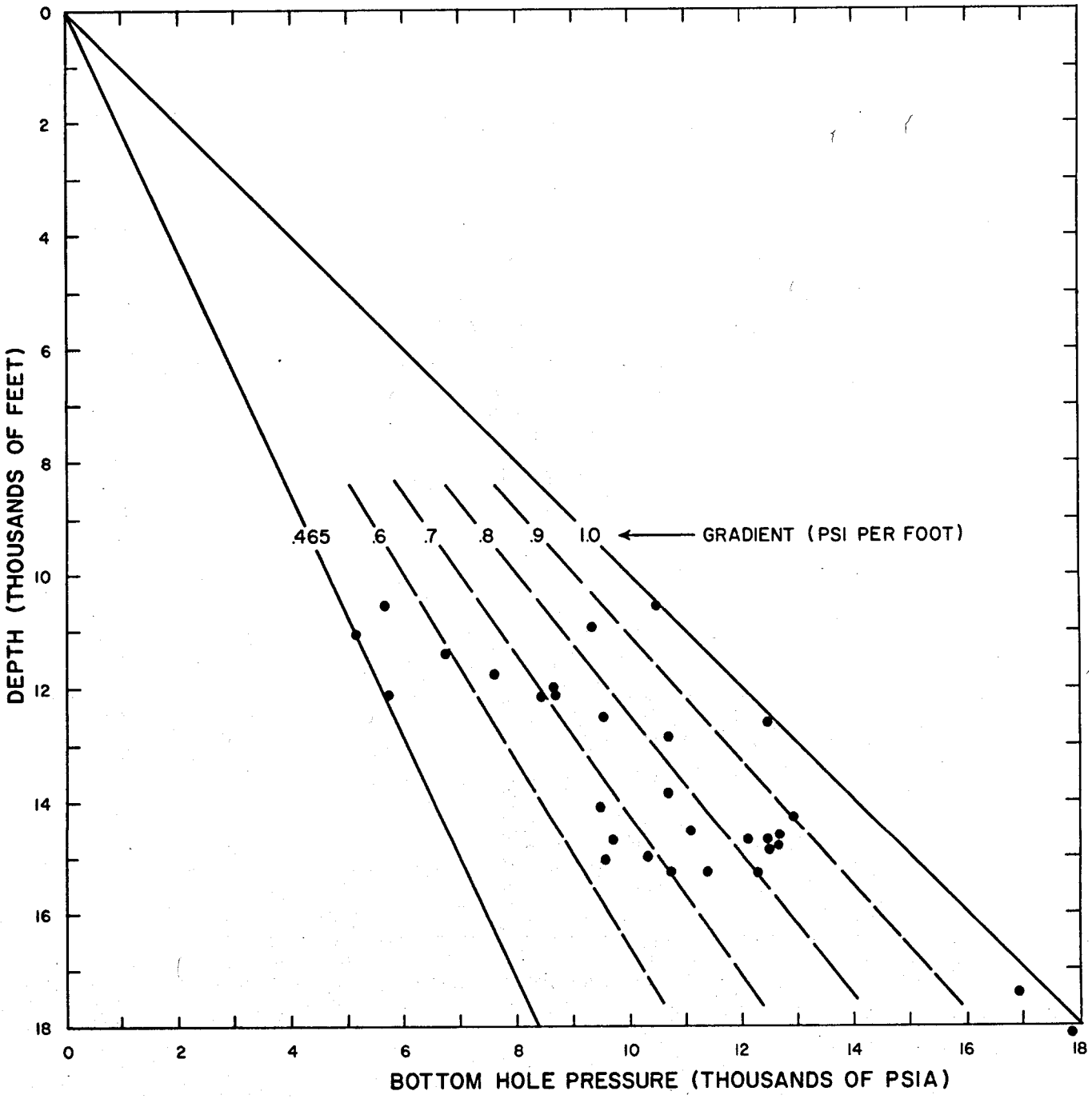

Figure 5 Static bottom-hole pressures versus depth for a number of wells in Chocolate Bayou Field, Brazoria County, Texas.

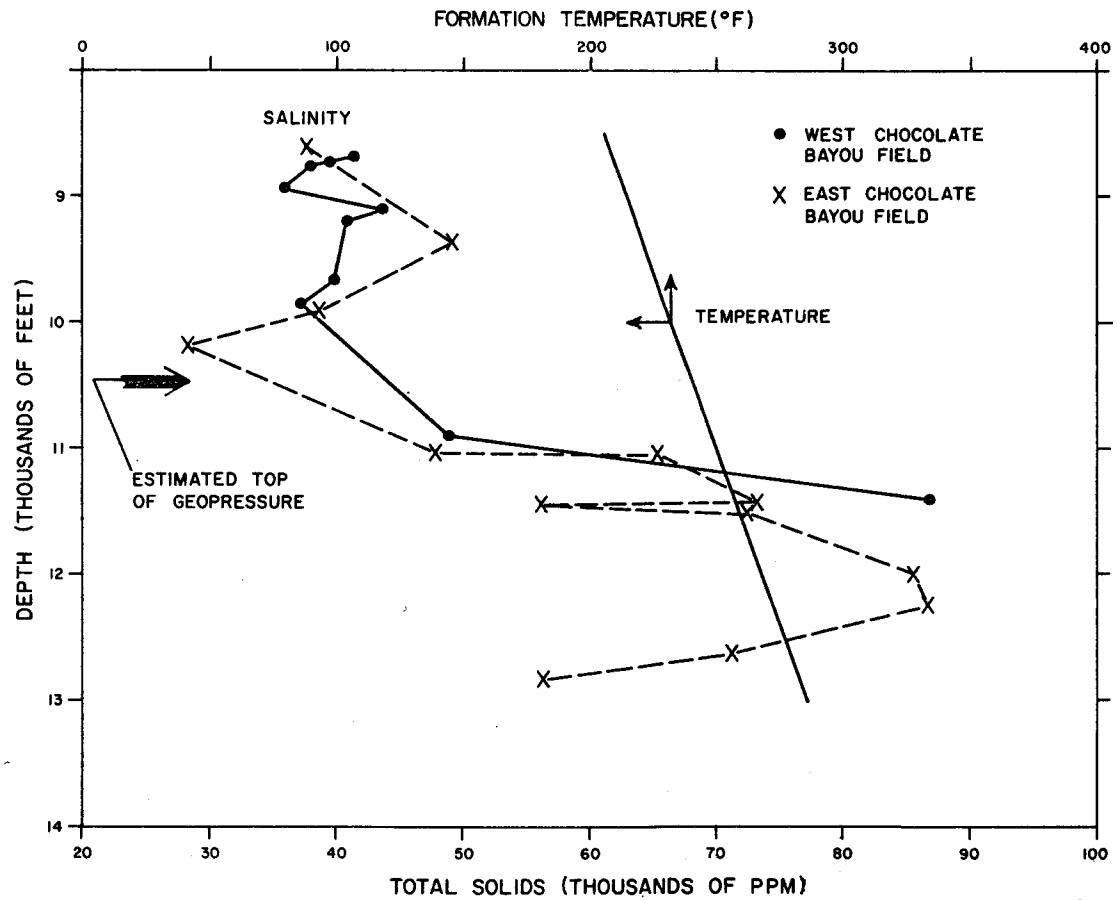

Figure 6 Salinity and temperature of formation waters from Chocolate Bayou Field, Brazoria County, Texas.

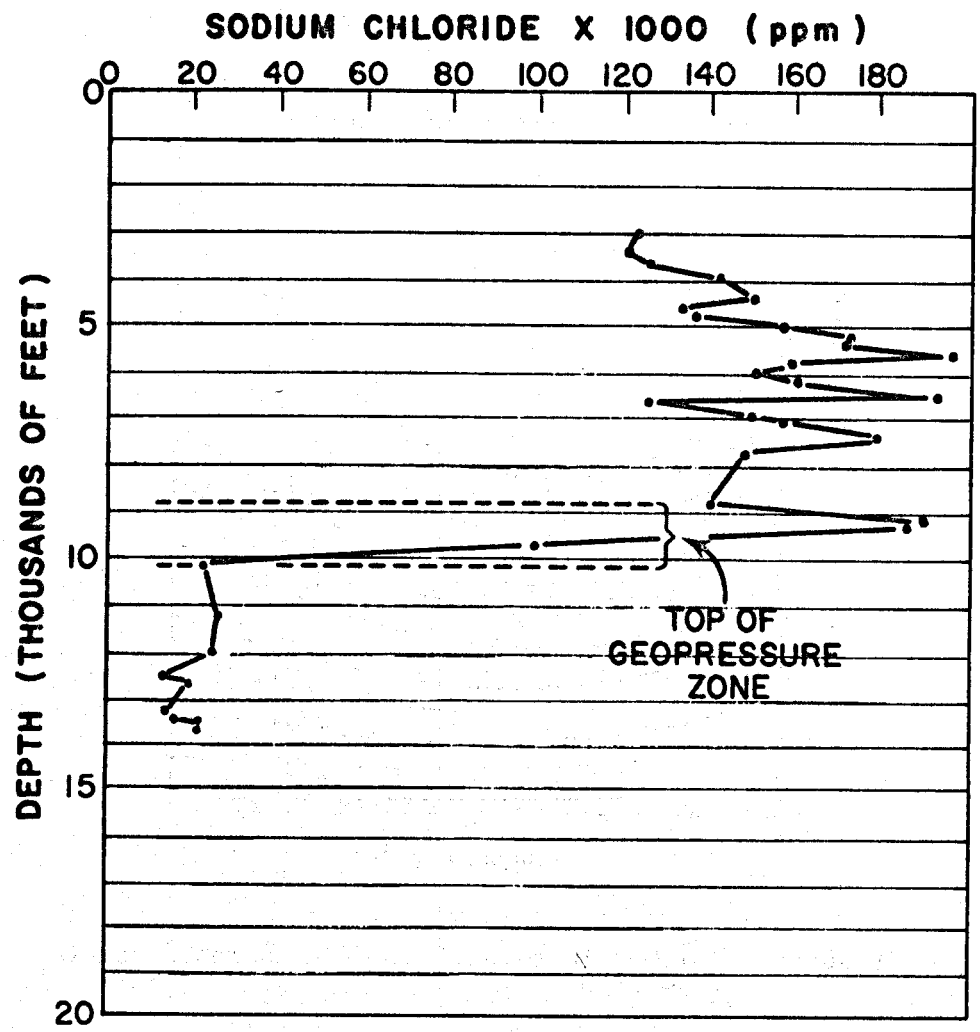

Figure 7 Change in formation water salinity with depth related to the occurrence of the geopressured zone, Manchester Field, Calcasieu Parish, Louisiana (after Schmidt, 1973).

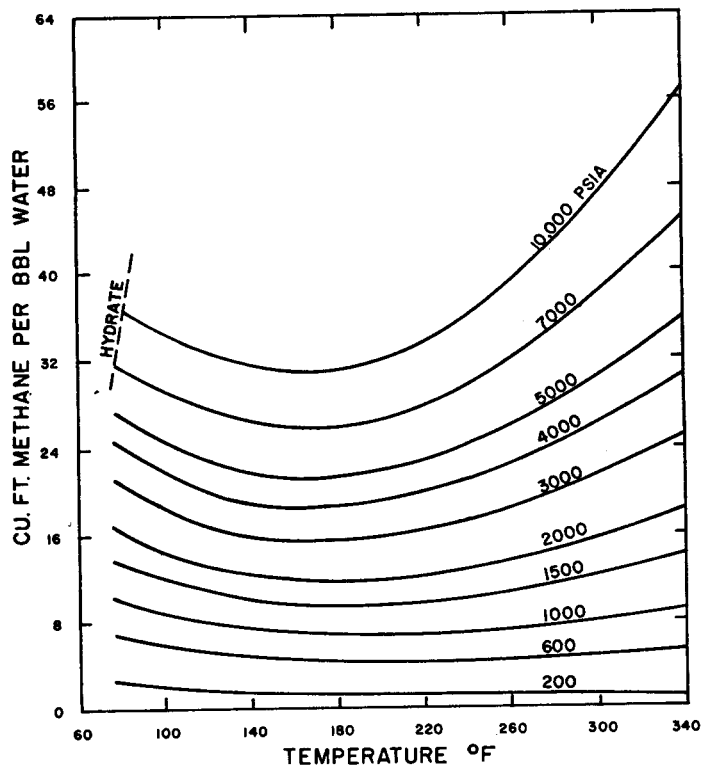

Figure 8 Volumetric solubility of methane in water (after Culberson and McKetta, 1951).

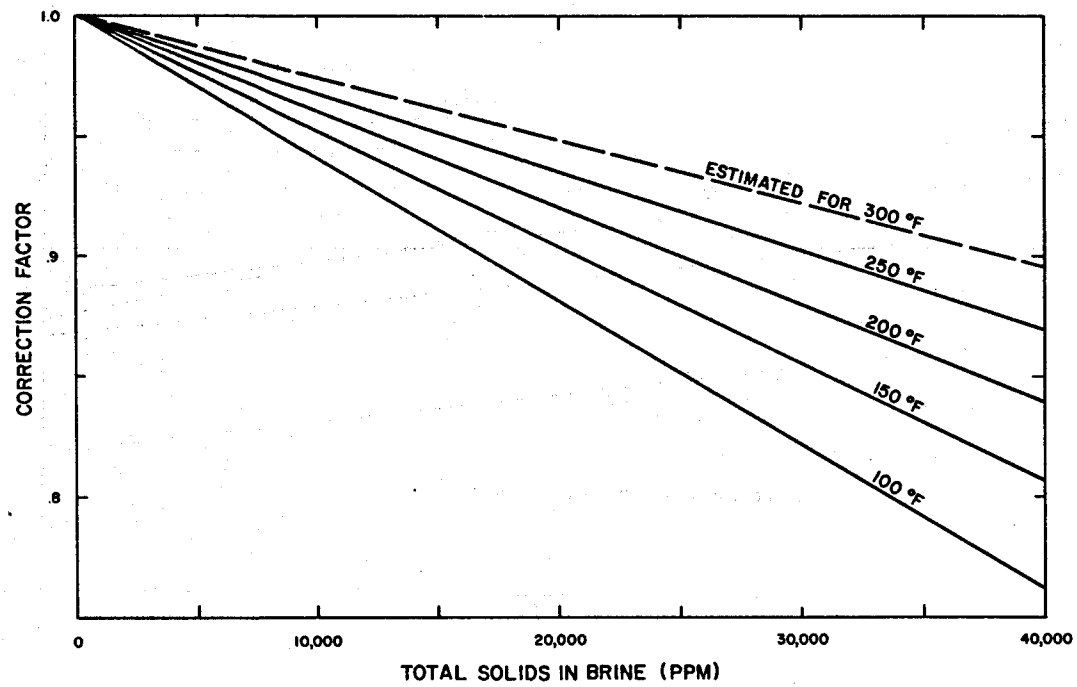

Figure 9 Solubility correction factor for salinity of formation water (after Dodson and Standing, 1944).

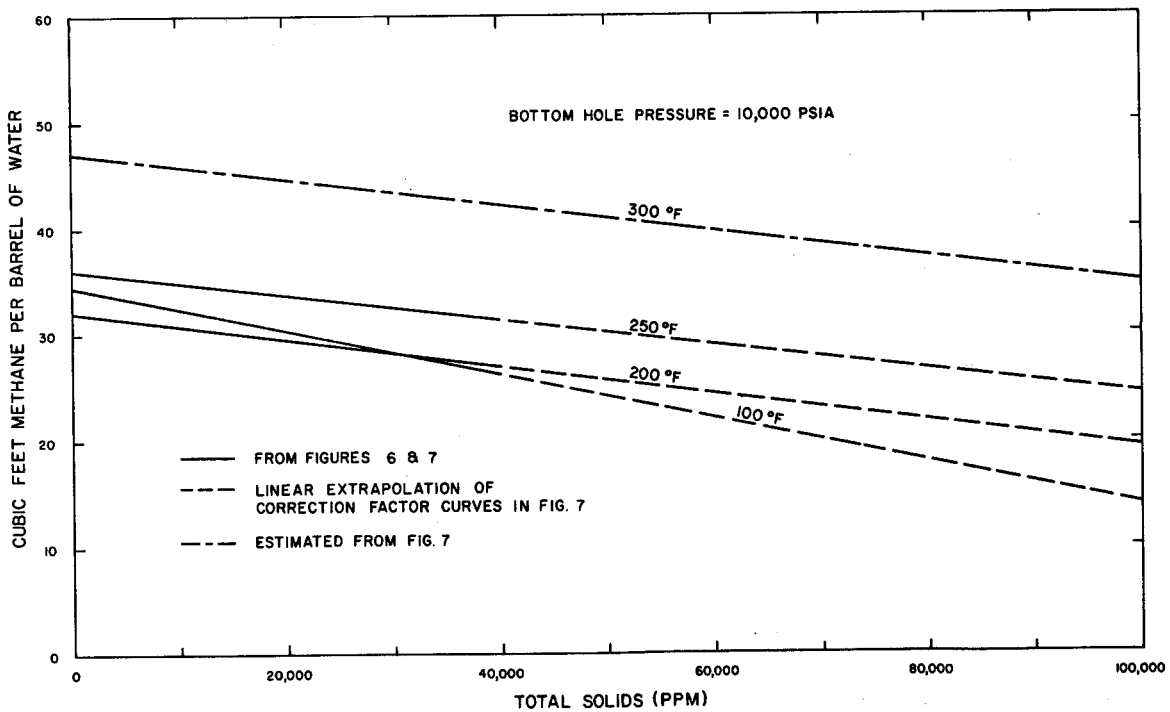

Figure 10 Effect of salinity and temperature on solubility of methane in water at constant pressure of 10,000 psi.

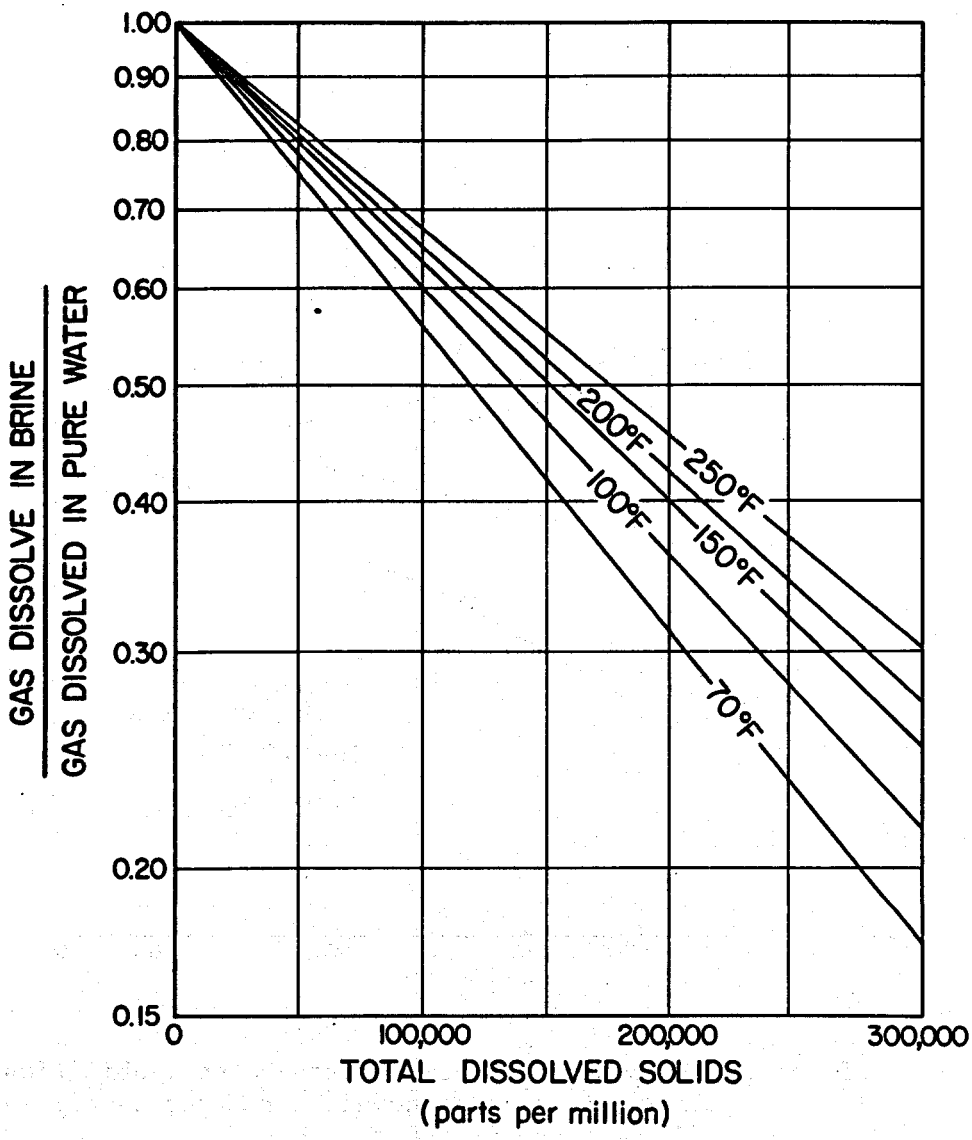

Figure 11 Effect of salinity on the amount of gas in solution when brine is fully saturated with gas (after Brill, 1975).

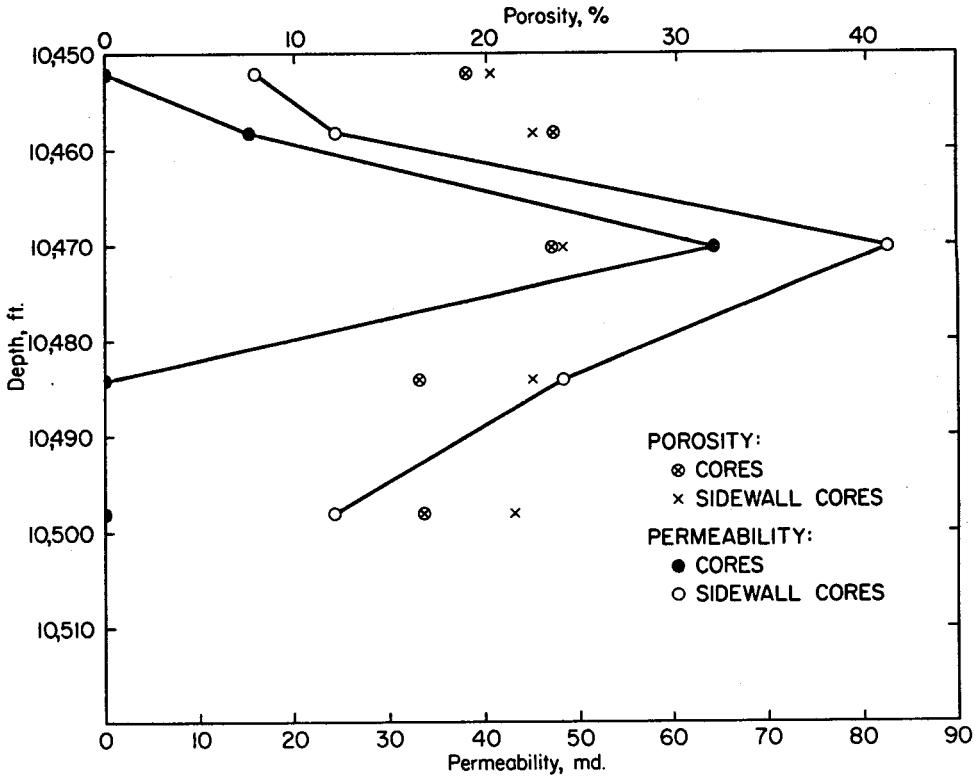

Figure 12 Comparison of porosities and permeabilities from cores and sidewall cores for a well in Nueces County, Texas.

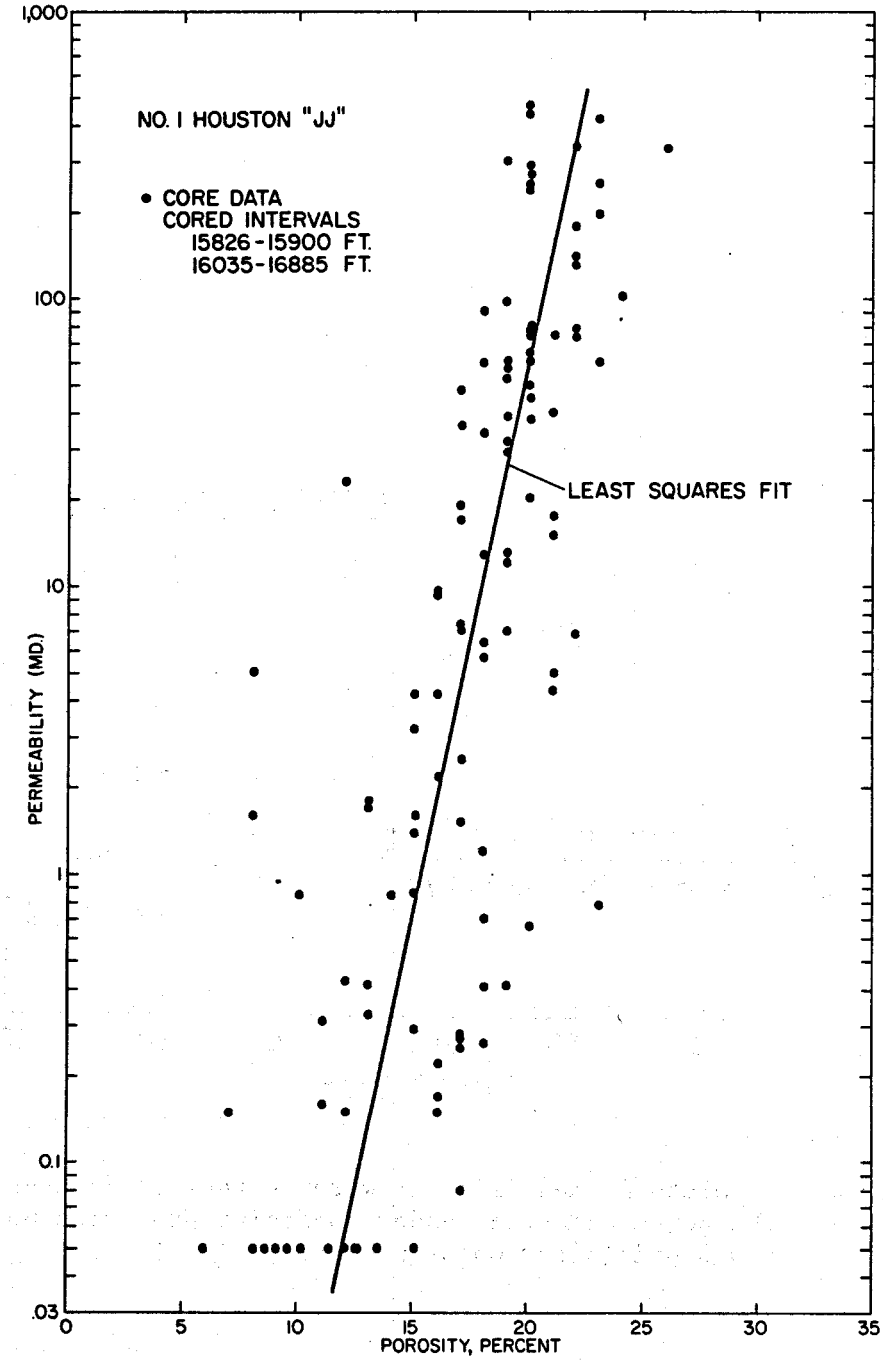

Figure 13 Porosity-permeability relationship from core measurements made at atmospheric pressure for the Phillips No. 1 Houston "JJ", Chocolate Bayou Field, Brazoria County, Texas.

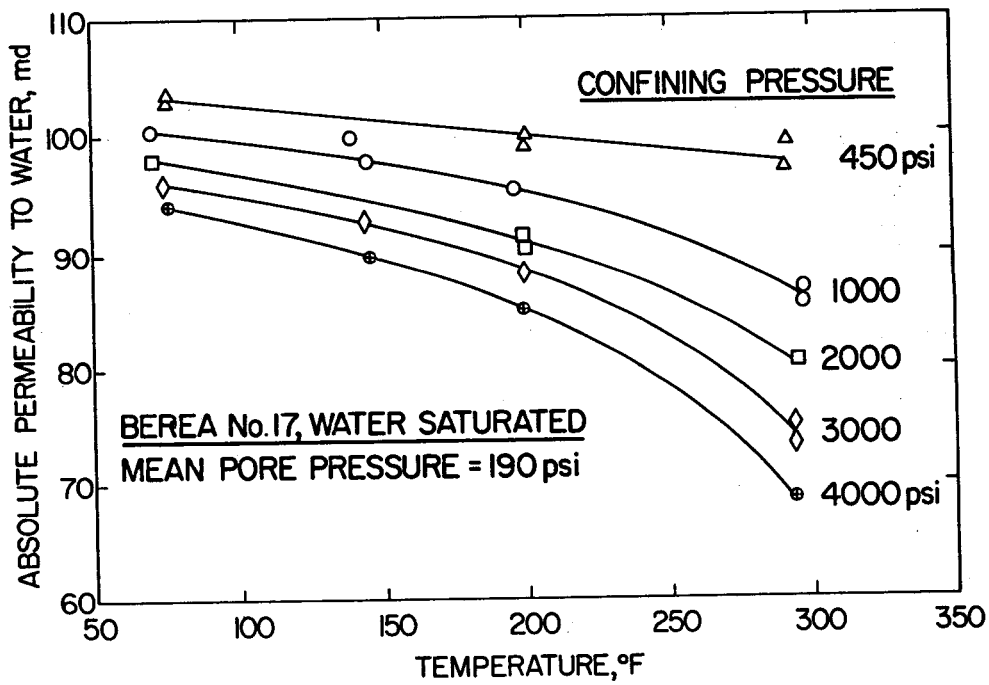

Figure 14 Absolute permeability to water versus temperature for the Berea Sandstone under confining pressures up to 4,000 psi (after Casse and Ramey, 1976).

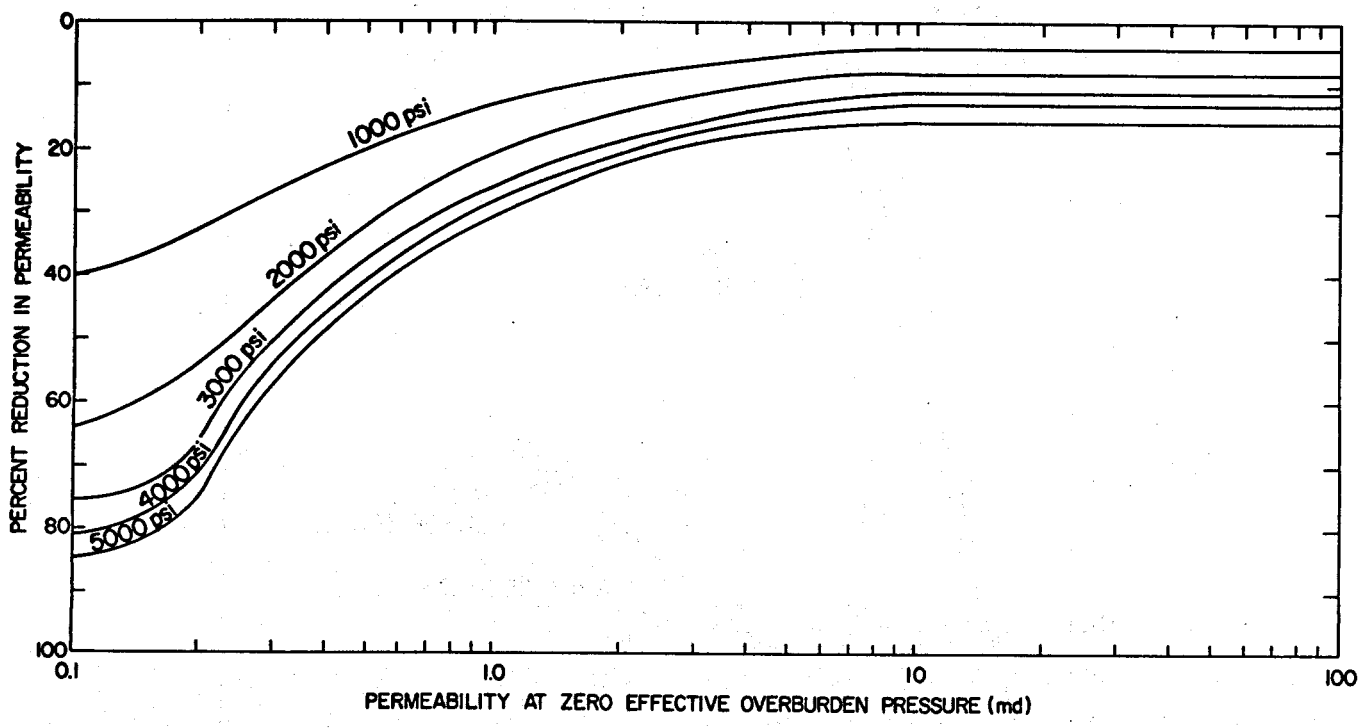

Figure 15 Reduction in oil permeability versus effective overburden pressure (after McLatchie, et al., 1958).

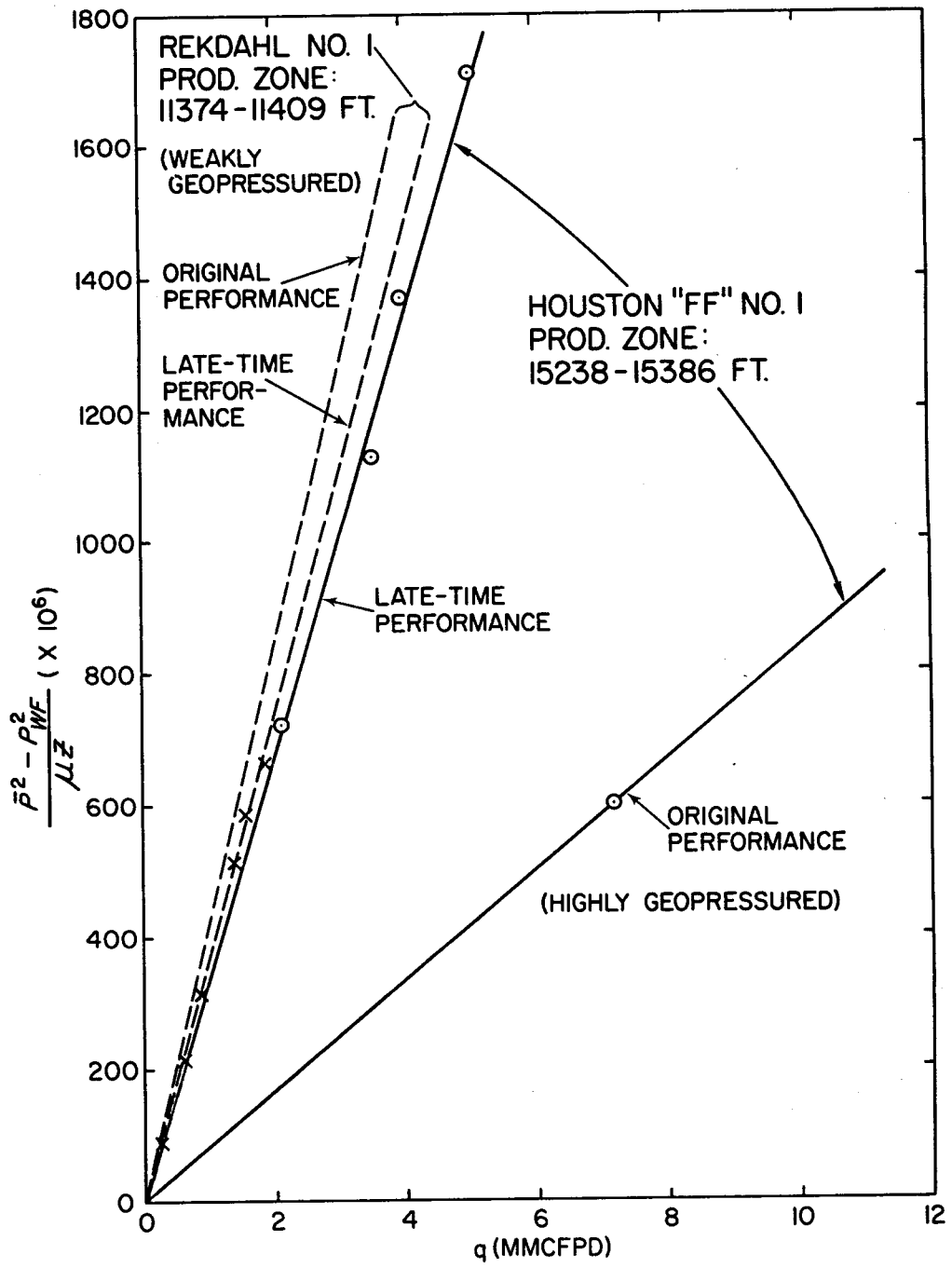

Figure 16 Comparison of original and late-time performance curves for highly geopressured and slightly geopressured reservoirs in Chocolate Bayou Field, Brazoria County, Texas (after Farina, 1976).

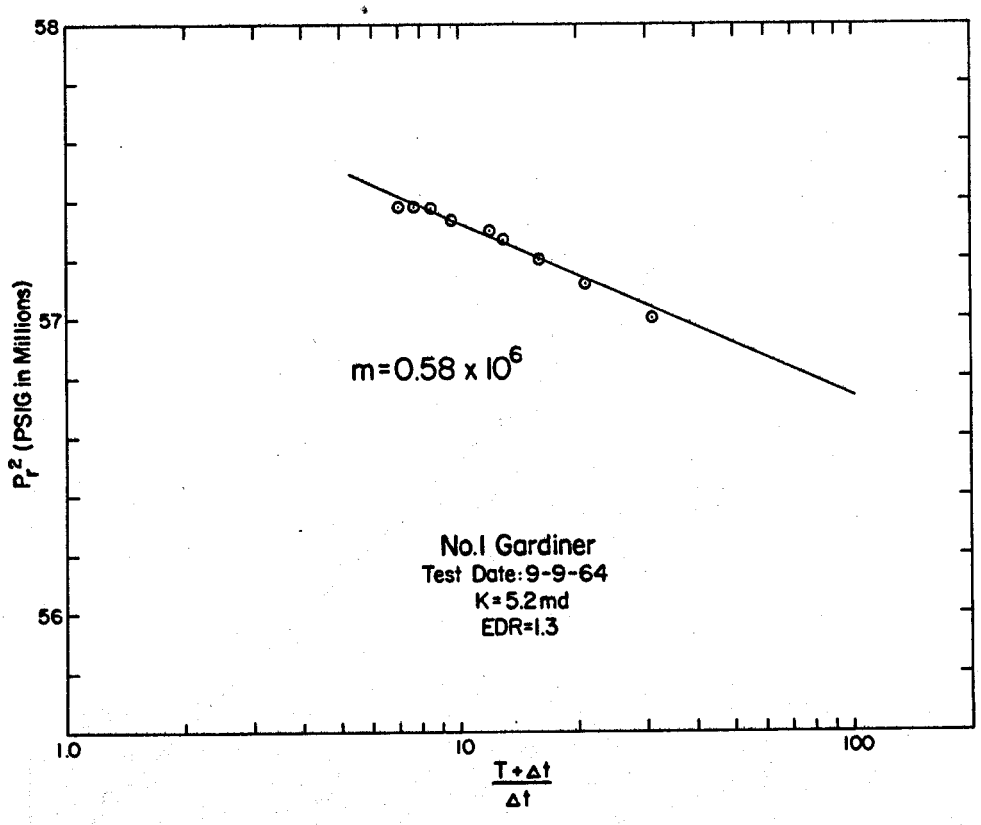

Figure 17 Pressure buildup for gas producing from lower Weiting sandstones, Phillips No. 1 Gardiner, Chocolate Bayou Field, Brazoria County, Texas.

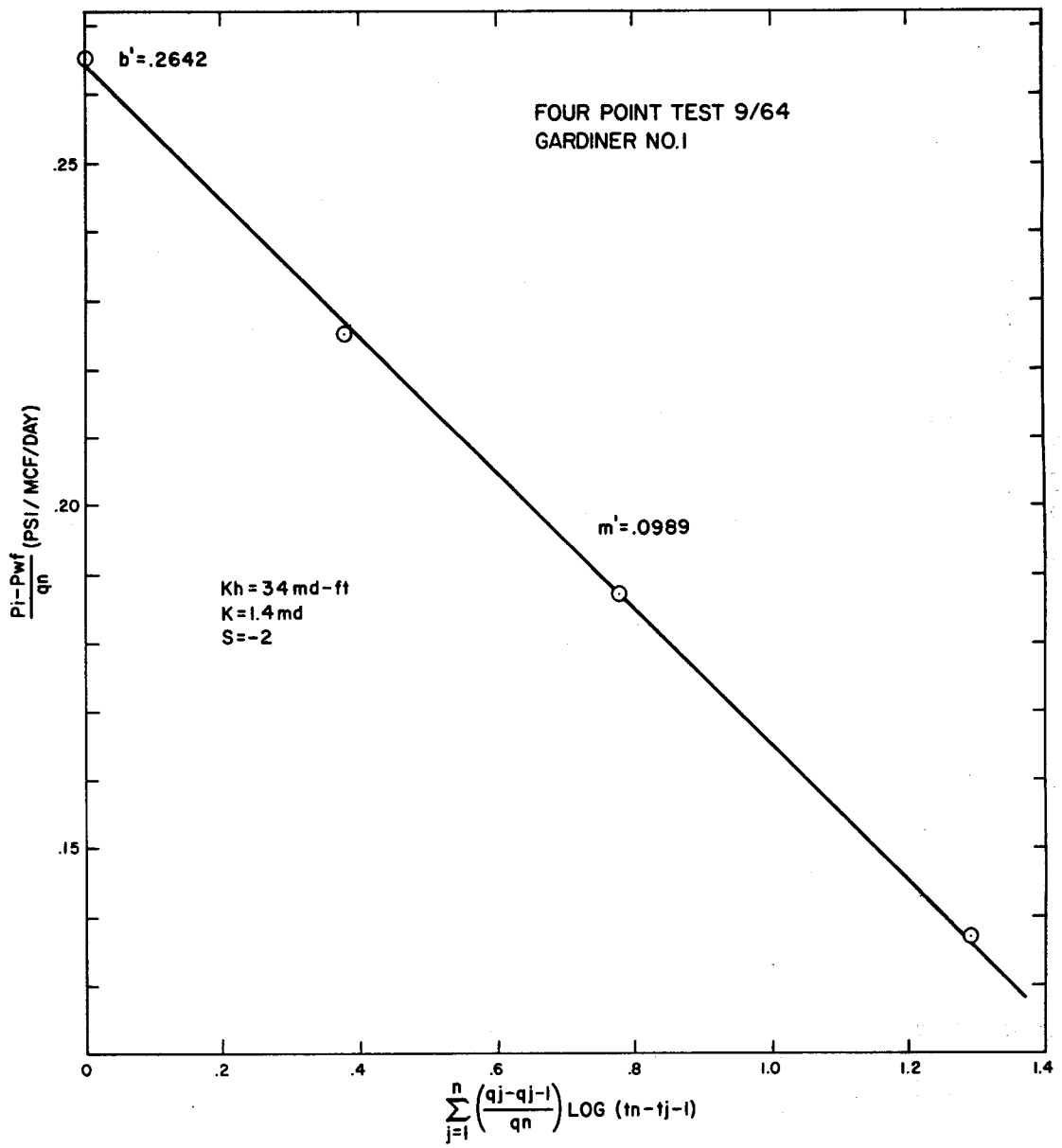

Figure 18 Data from open-flow potential tests used to calculate Kh and S for Phillips No. 1 Gardiner, Chocolate Bayou Field, Brazoria County, Texas.

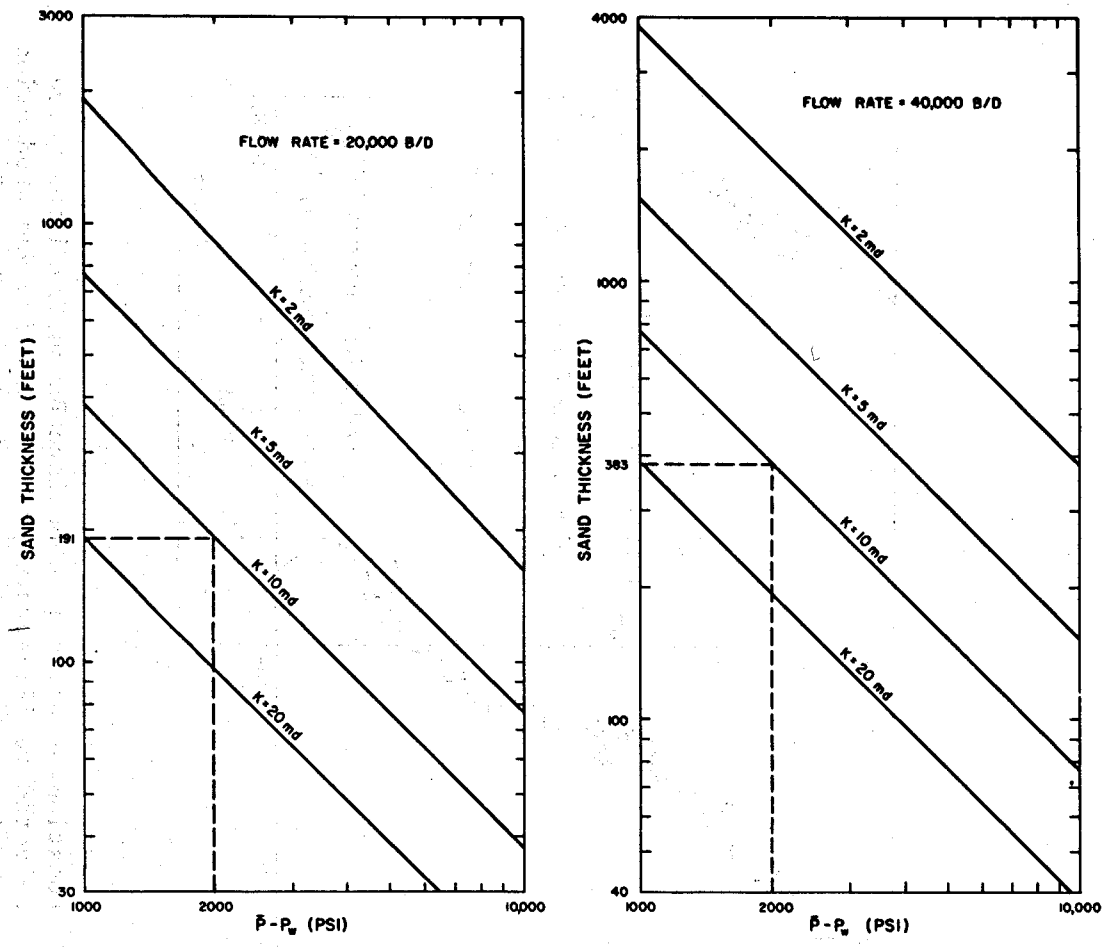

Figure 19 Sand thickness required to produce (a) 20,000 and (b) 40,000 barrels of water per day as a function of drawdown pressure for permeabilities from 2 to 20 millidarcys.

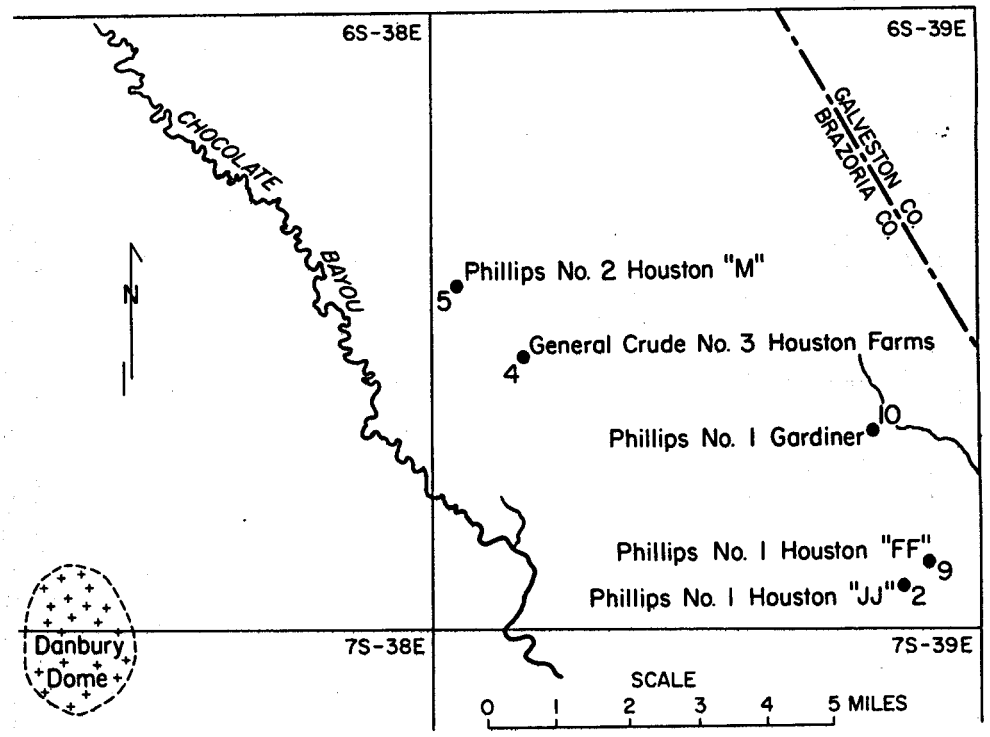

Figure 20 Location of wells in Chocolate Bayou Field that were selected to illustrate pressure decline and production behavior of reservoirs near the Austin Bayou Prospect.

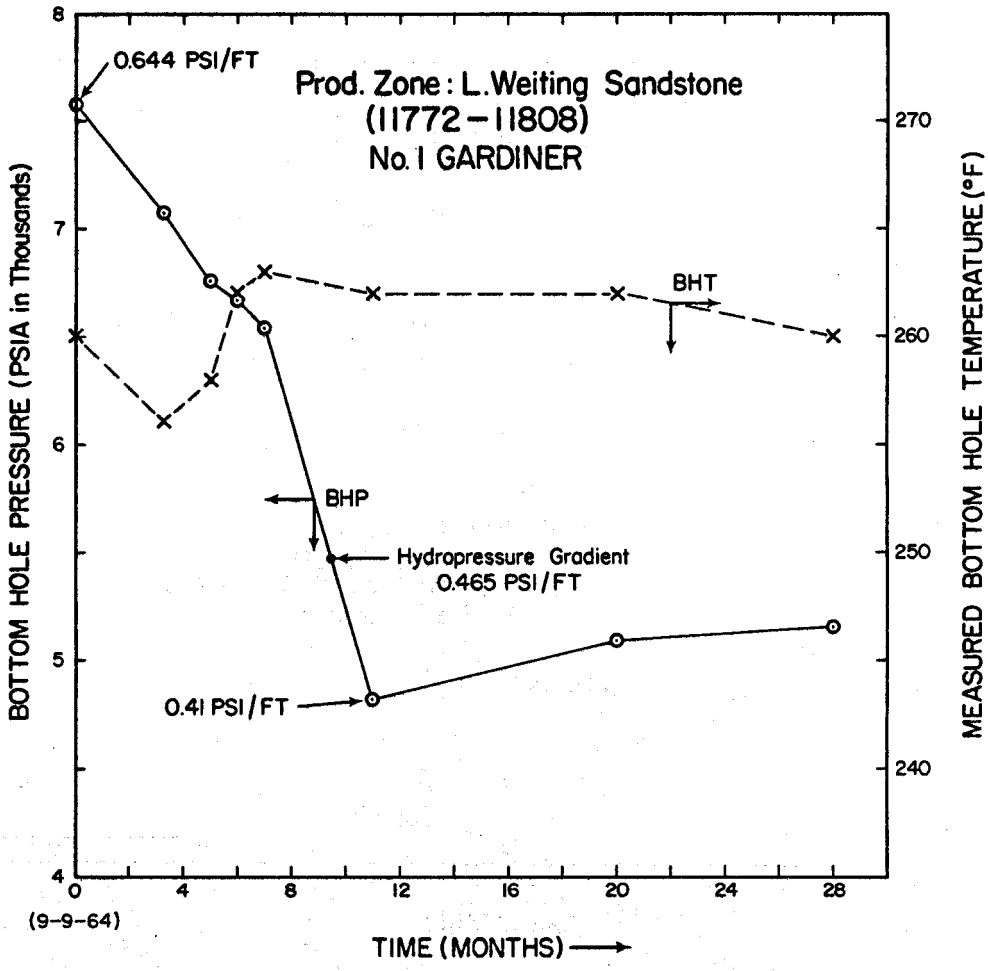

Figure 21 Early history of bottom-hole pressures and temperatures in the Phillips No. 1 Gardiner, Chocolate Bayou Field, Brazoria County, Texas.

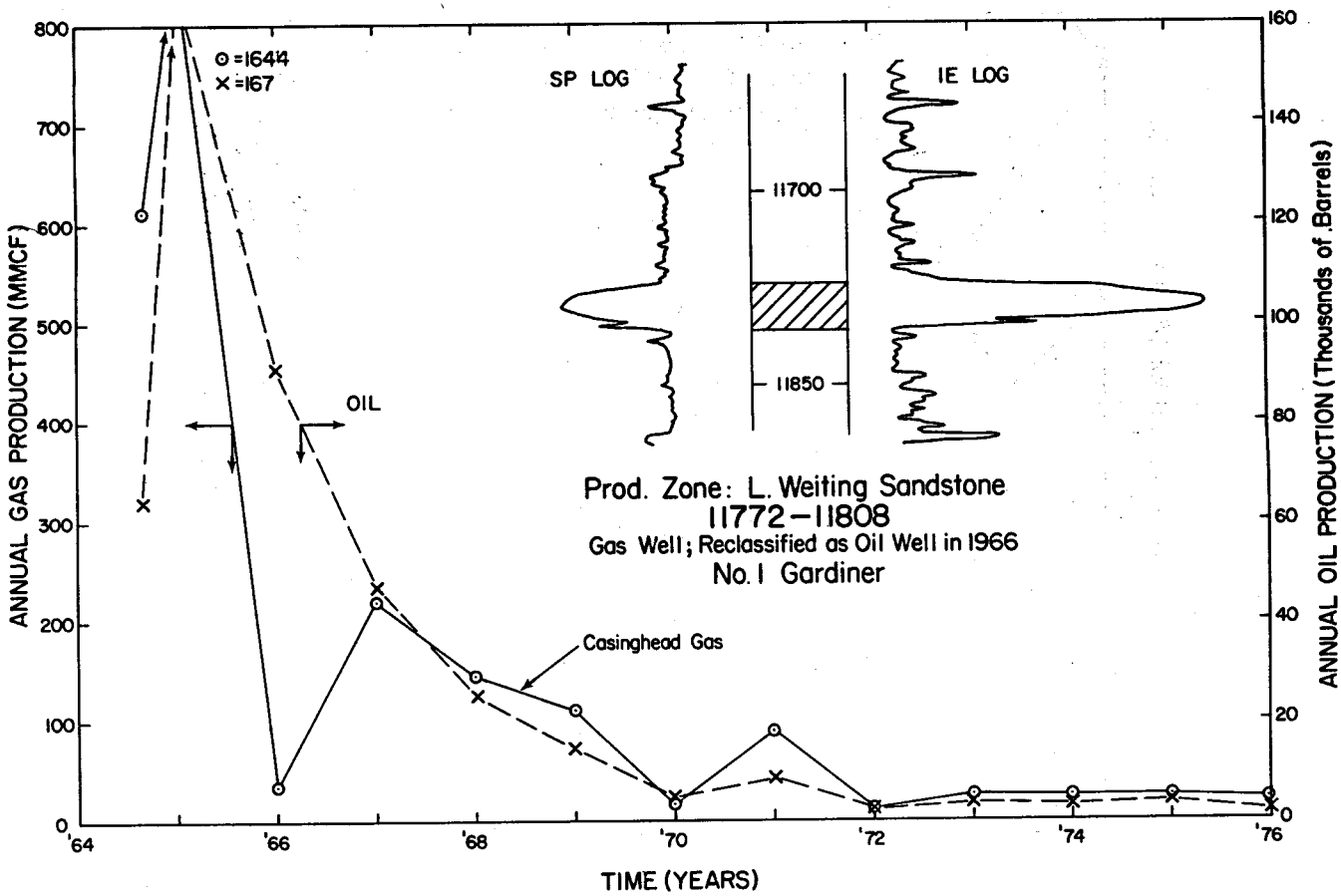

Figure 22 Production history of the Phillips No. 1 Gardiner, Chocolate Bayou Field, Brazoria County, Texas.

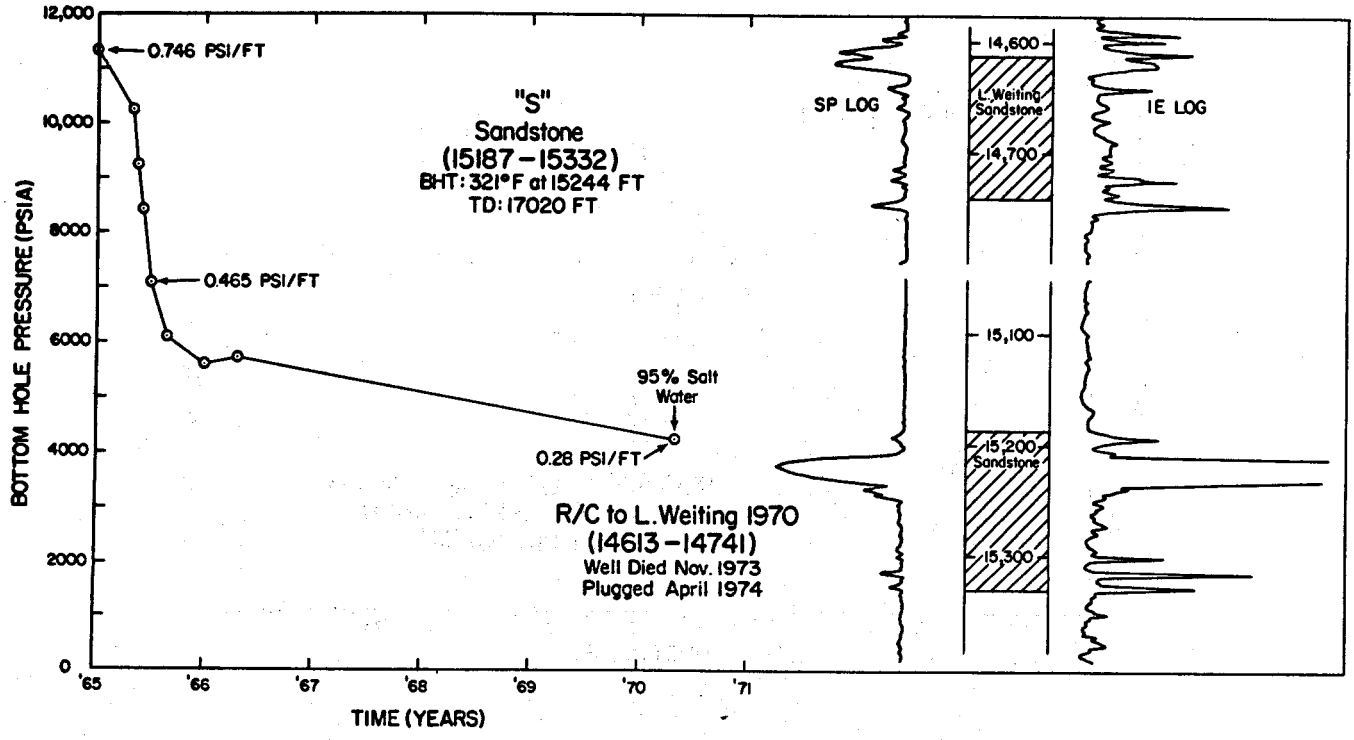

Figure 23 History of decline in bottom-hole pressure for the No. 1 Houston "JJ", Chocolate Bayou Field, Brazoria County, Texas.

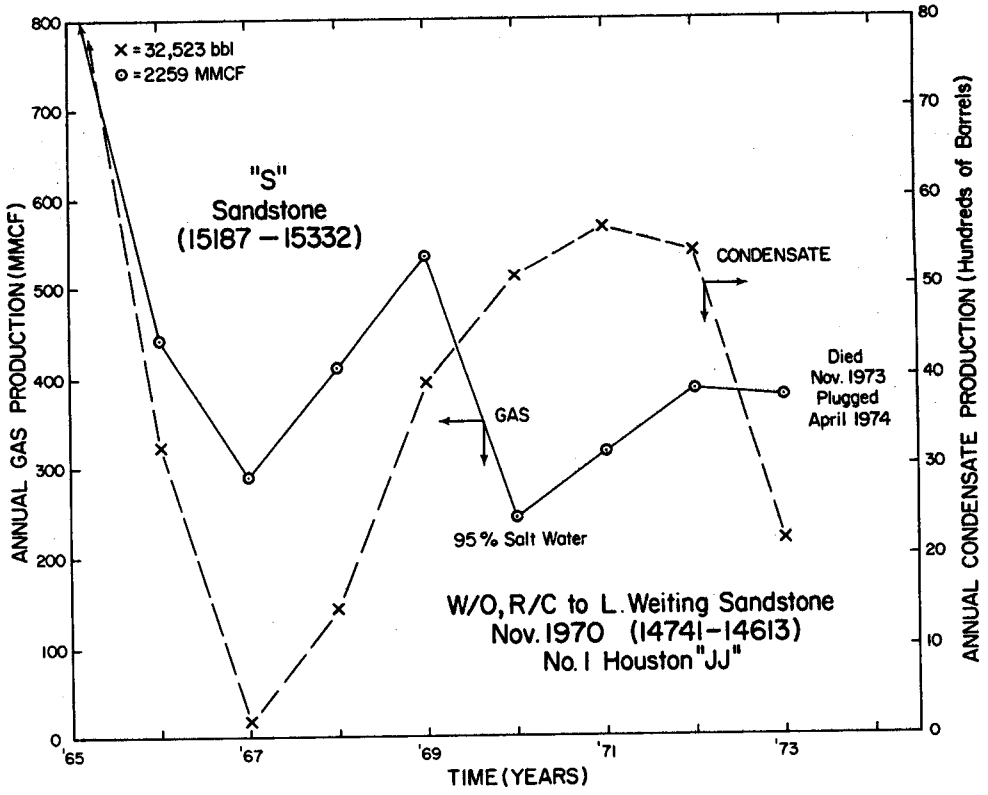

Figure 24 Production history of the Phillips No. 1 Houston "JJ", Chocolate Bayou Field, Brazoria County, Texas.

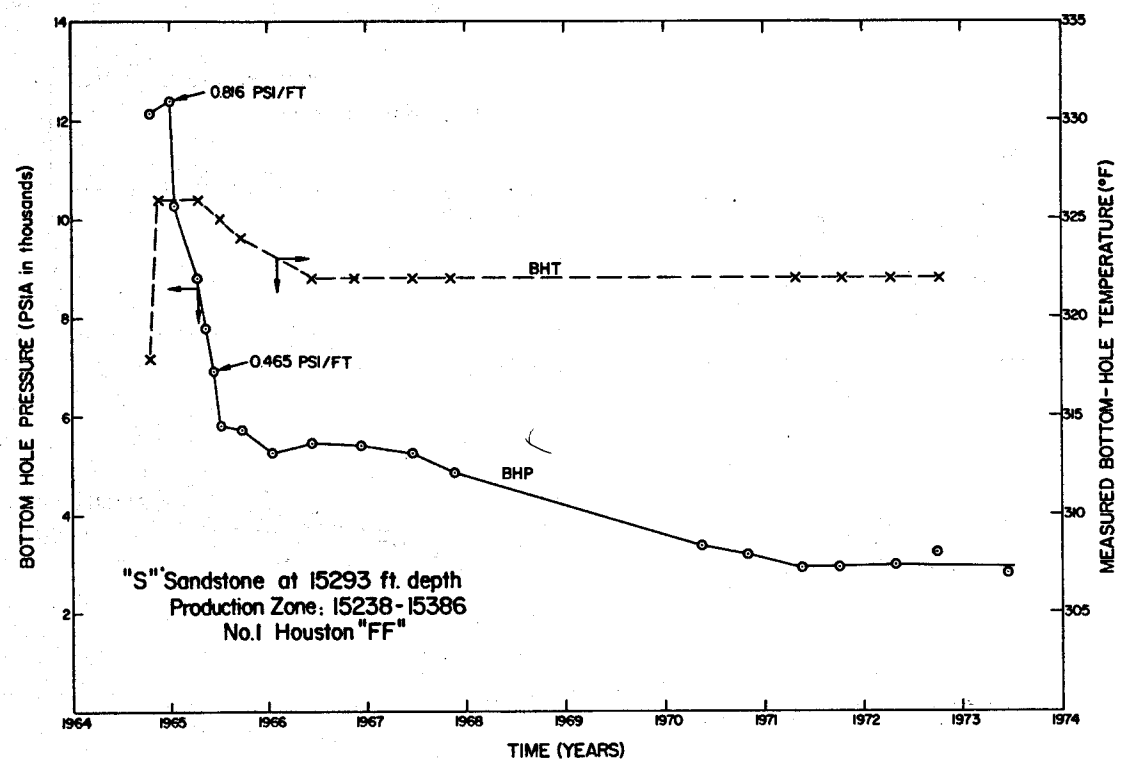

Figure 25 History of decline in bottom-hole pressure and temperature for the Phillips No. 1 Houston "FF", Chocolate Bayou Field, Brazoria County, Texas.

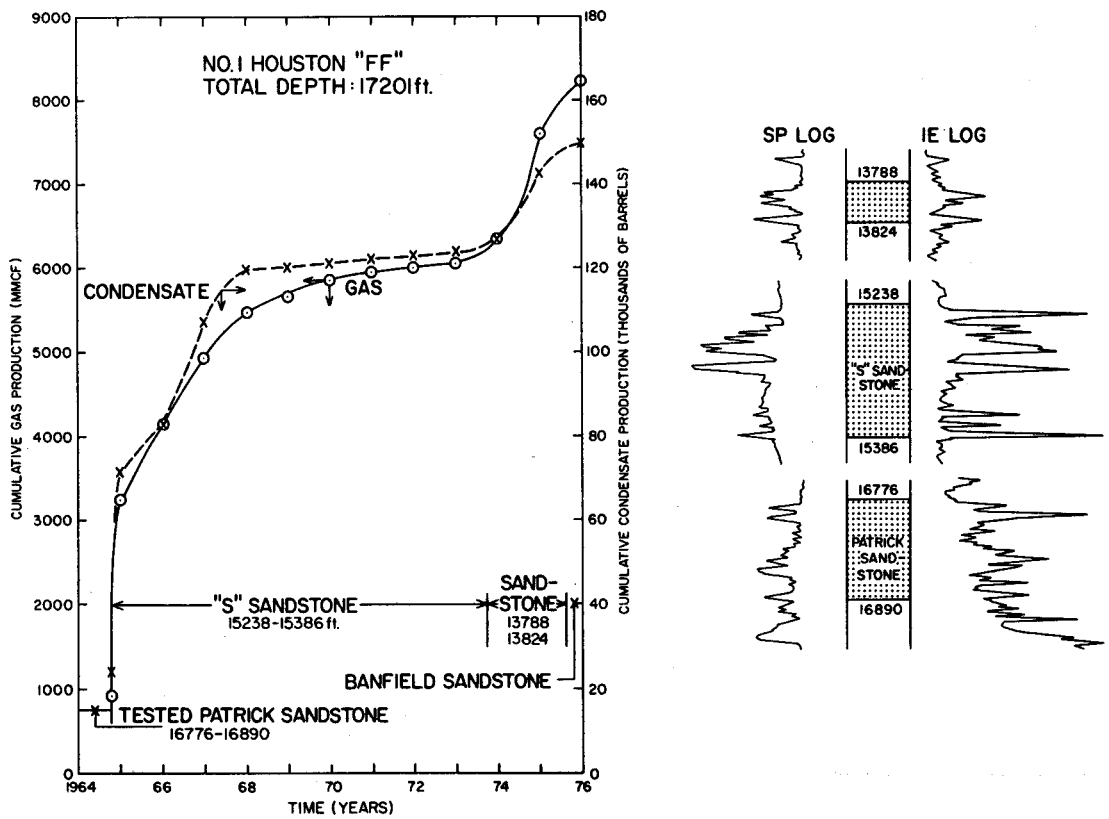

Figure 26 Production history of the Phillips No. 1 Houston "FF", Chocolate Bayou Field, Brazoria County, Texas.

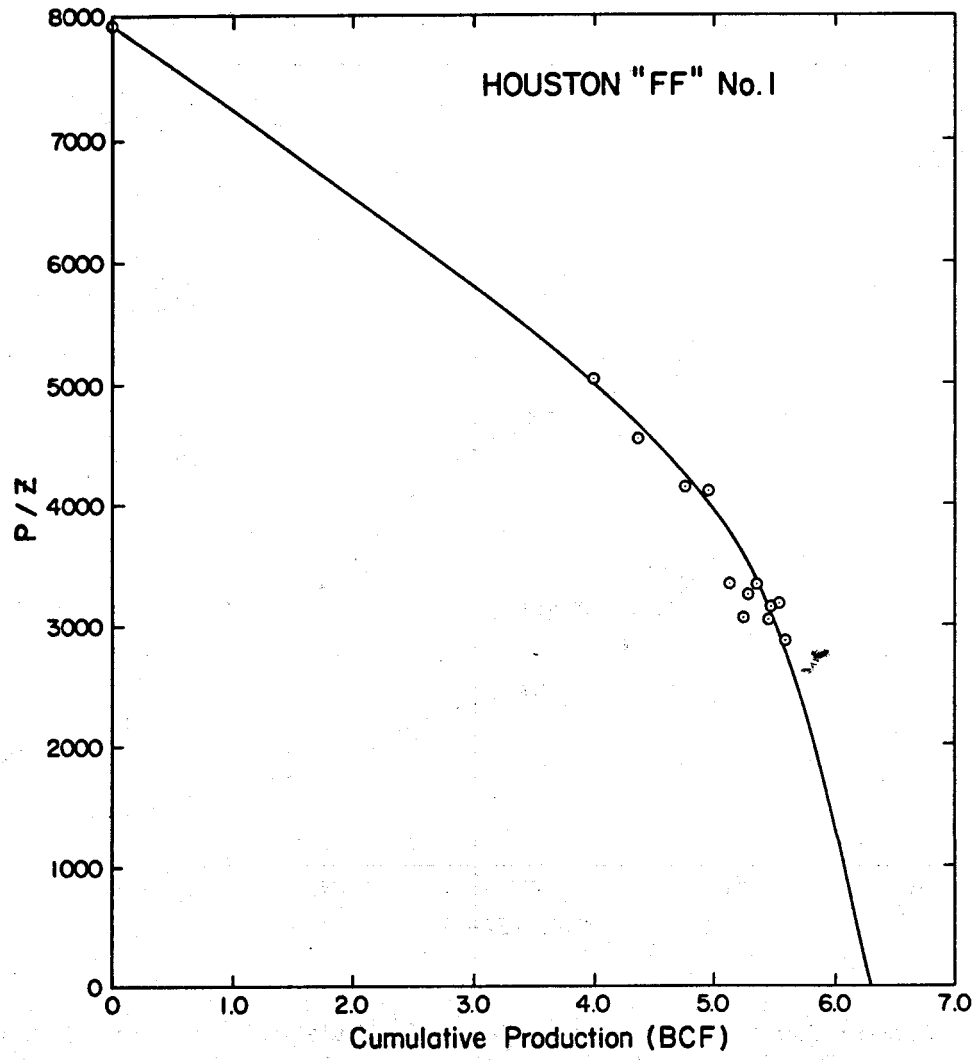

Figure 27 P/Z versus cumulative production from the "S" sandstone, Phillips No. 1 Houston "FF", Chocolate Bayou Field, Brazoria County, Texas (after Farina, 1976).

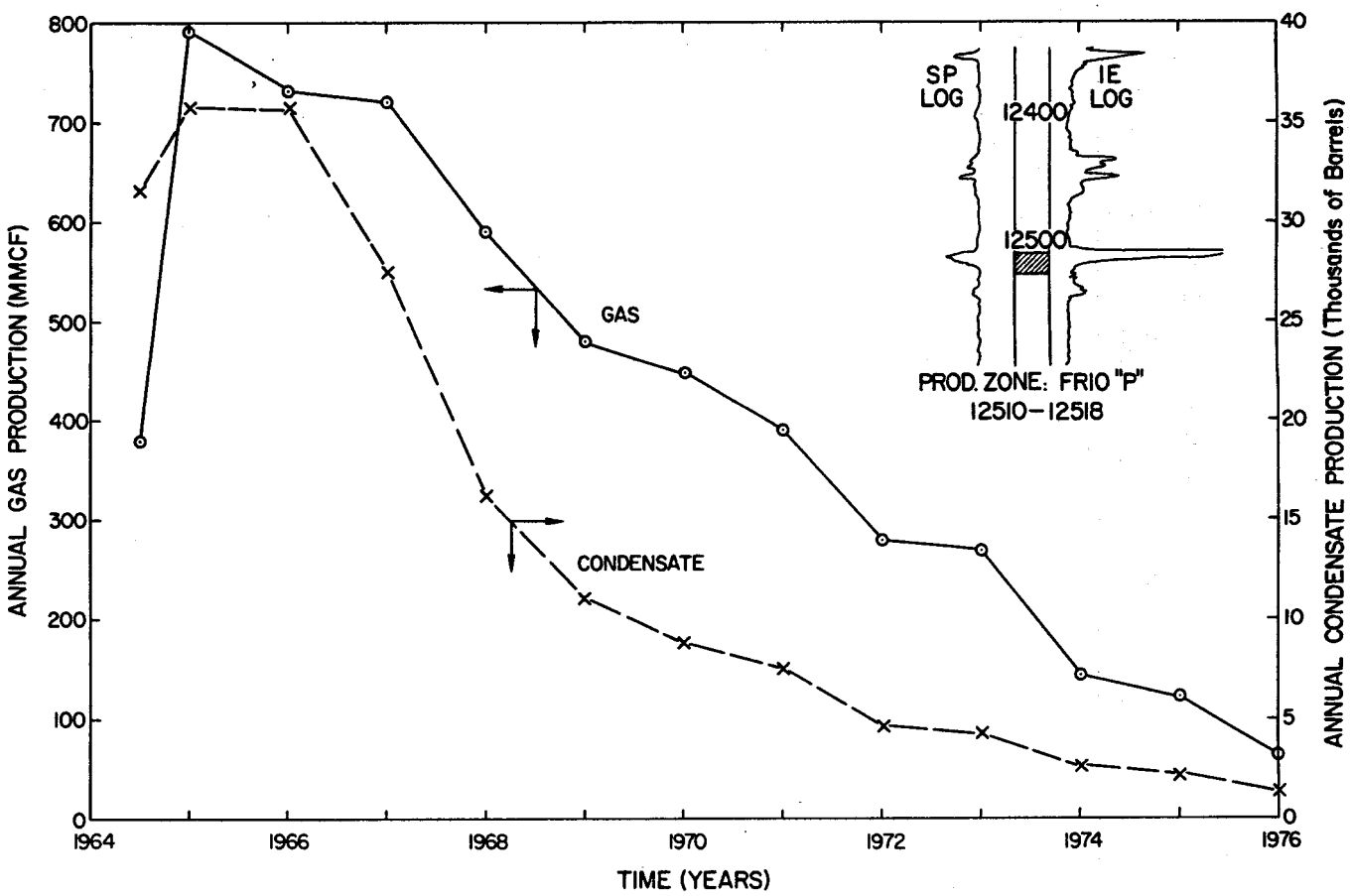

Figure 28 Production history of the General Crude Oil Co., No. 3 Houston Farms Development Company, Chocolate Bayou Field, Brazoria County, Texas.

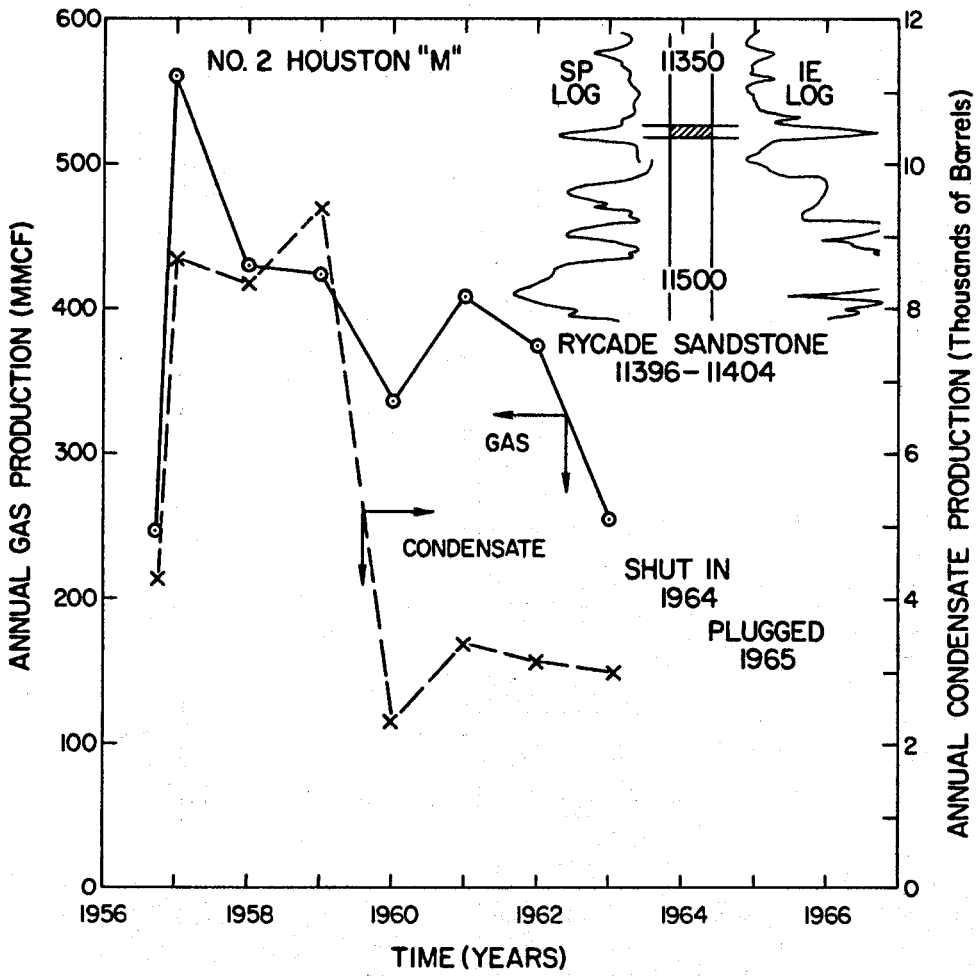

Figure 29 Production history of the Phillips No. 2, Houston "M", Chocolate Bayou Field, Brazoria County, Texas.

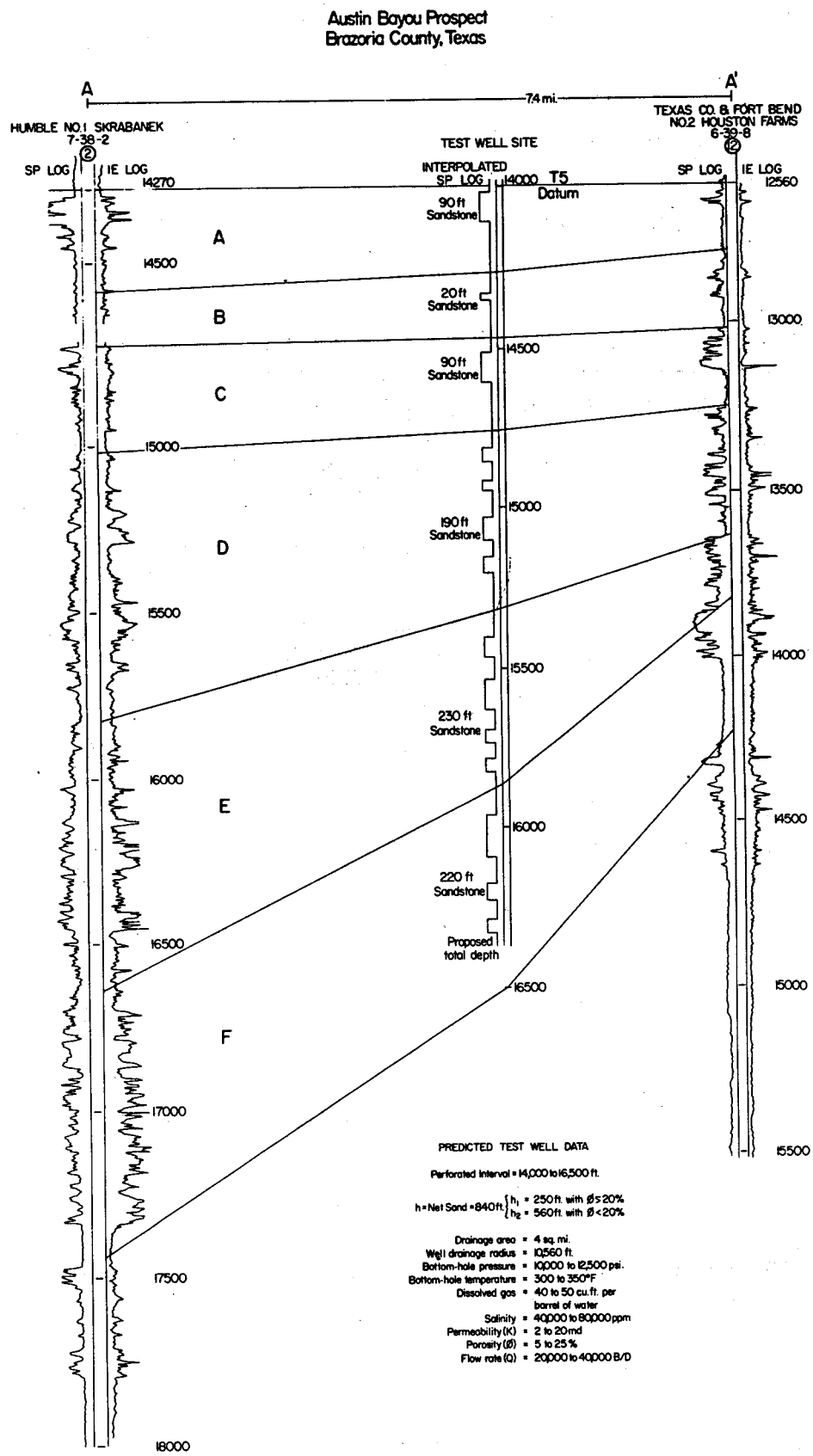

Figure 30 Expected sandstone distribution from an SP Log created for the test well site by interpolation from existing control wells.

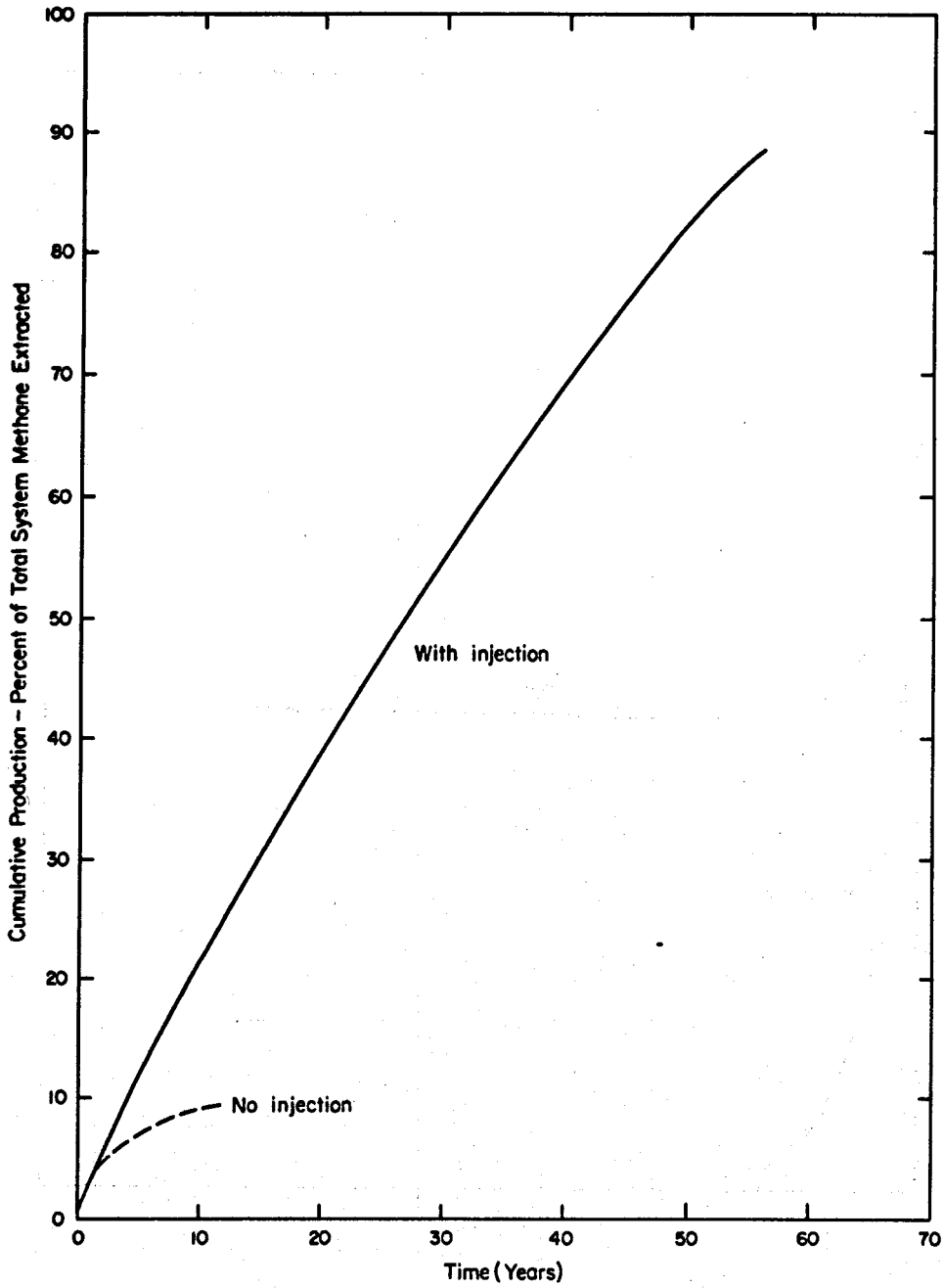

Figure 31 Cumulative methane production (after Garg, Pritchett, Rice, and Riney, 1977).

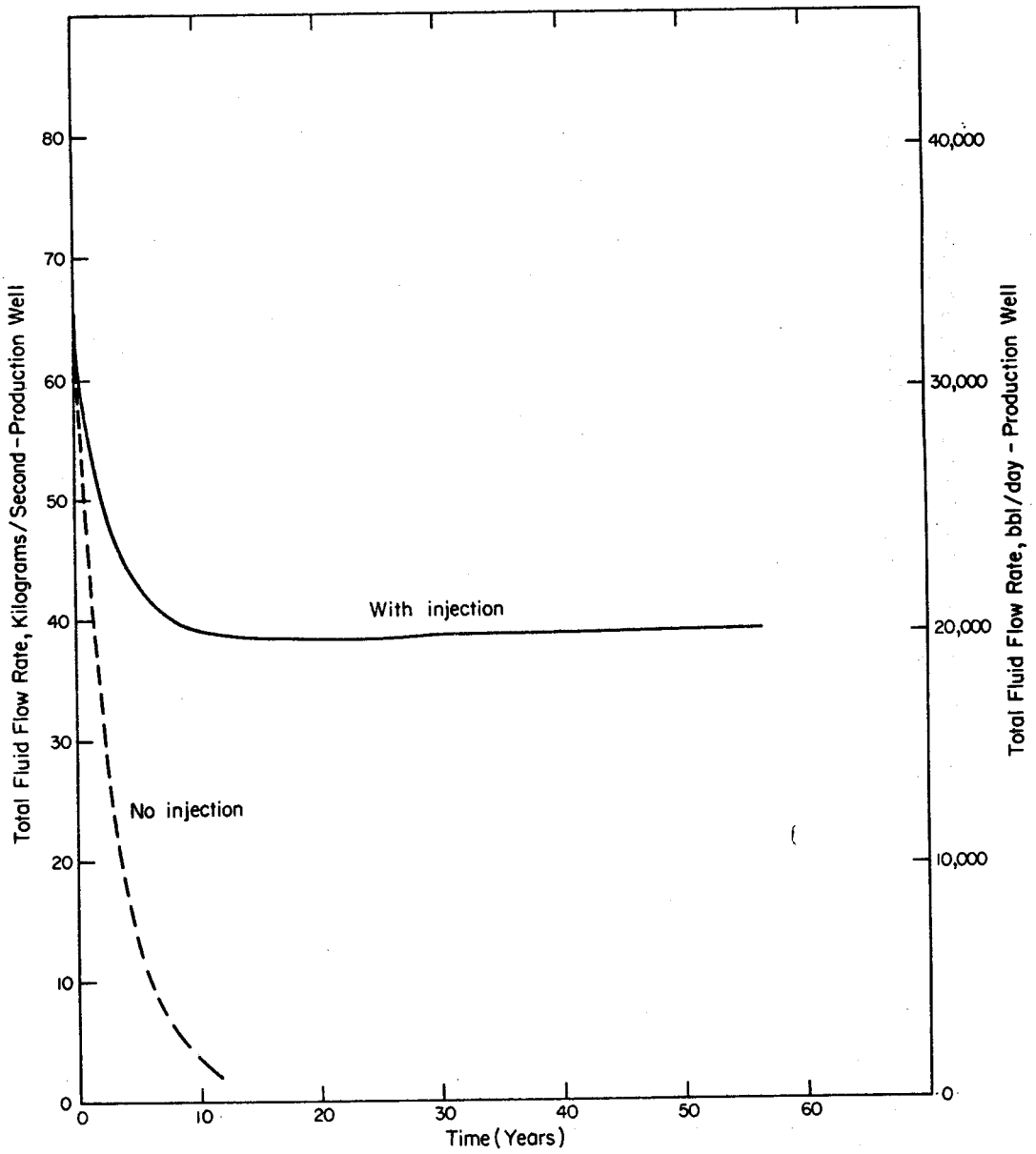

Figure 32 Total flow rate versus time per well, water plus methane (after Garg, Pritchett, Rice, and Riney, 1977).

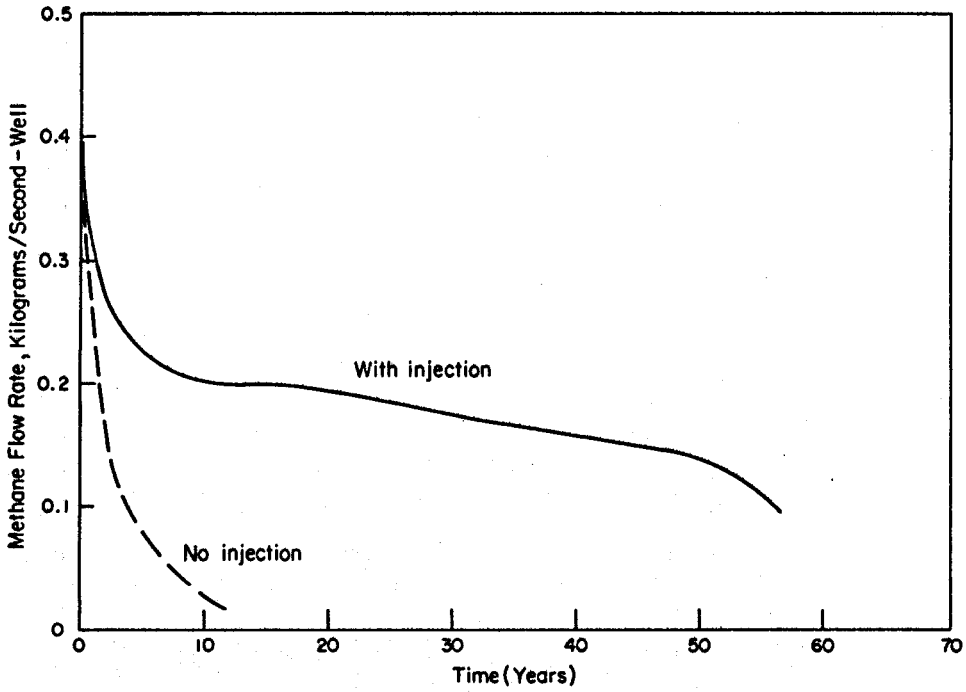

Figure 33 Methane flow rate per well versus time (after Garg, Pritchett, Rice, and Riney, 1977).

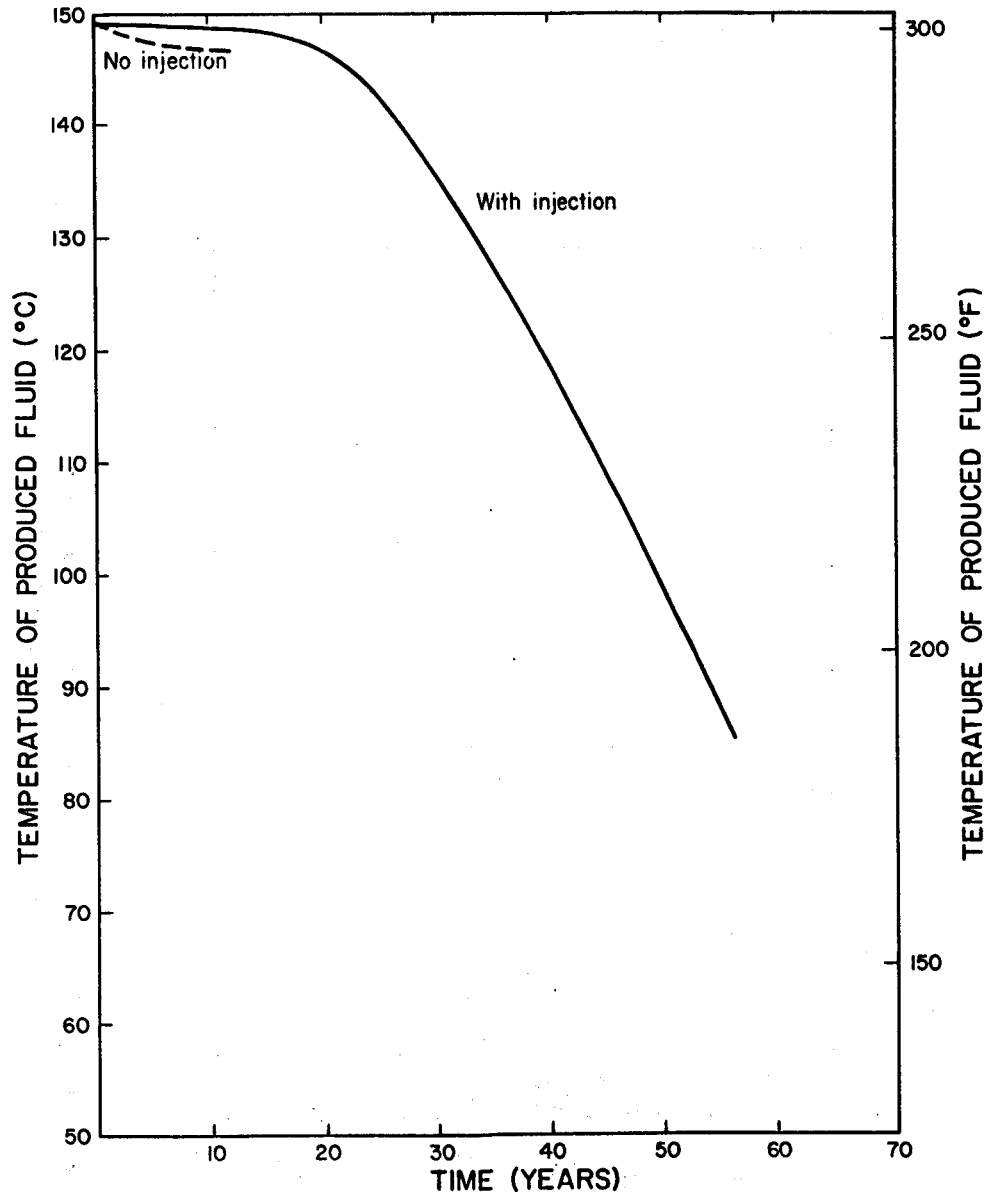

Figure 34 Temperature of produced field (after Garg, Pritchett, Rice, and Riney, 1977).

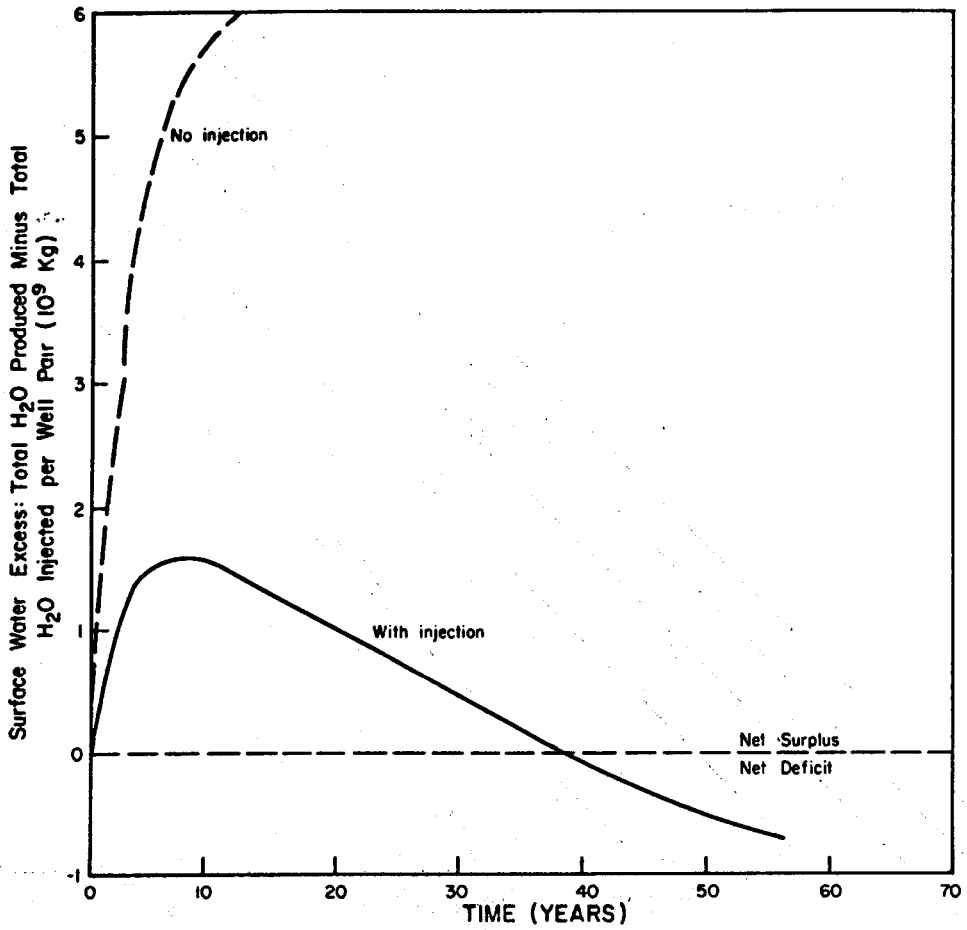

Figure 35 Surface water excess inventory per well pair versus time (after Garg, Pritchett, Rice, and Riney, 1977).

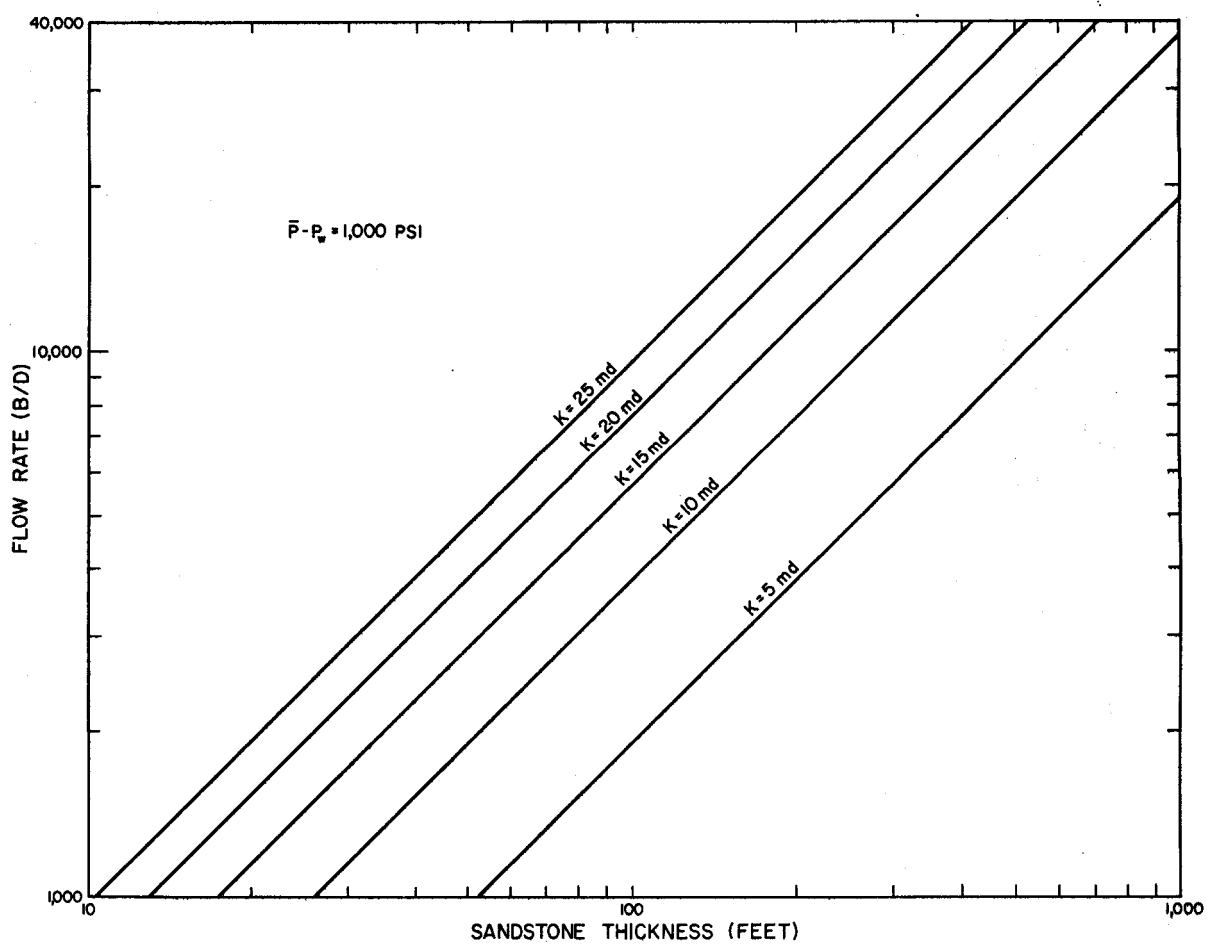

Figure 36 Flow rate of water as a function of sandstone thickness for different permeabilities and for a constant drawdown pressure of 1000 psi.

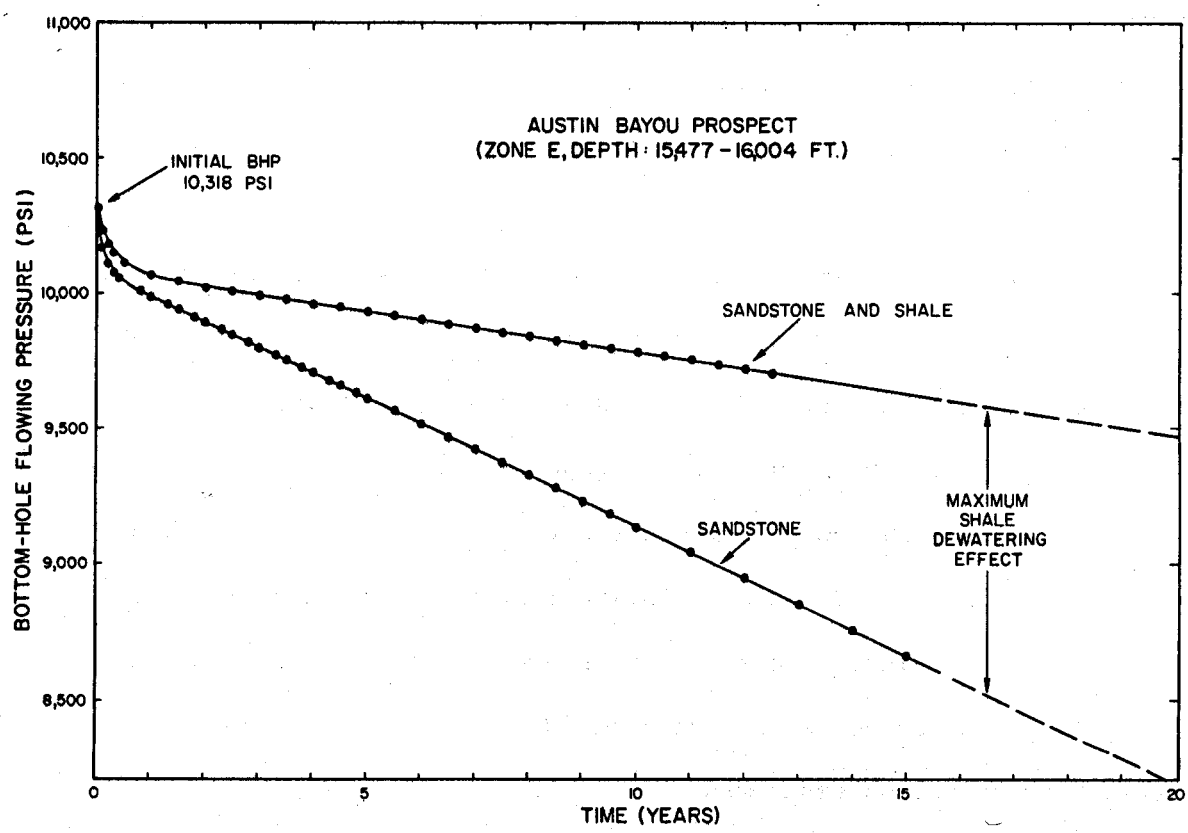

Figure 37 Predicted bottom-hole flowing pressure versus time (after Knapp and Elemo, 1977).