Analysis of the Kansas Hugoton Infill-Drilling Program

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Summary. This paper uses official deliverability tests and production histories to compare the performances of infill wells and companion original wells drilled in the Kansas Hugoton field. In addition, the performance of one of the five Mesa replacement test wells drilled in 1977 in the Kansas Hugoton is reviewed. Pitfalls in the use of official deliverability and wellhead shut-in pressure differences between infill wells and companion original wells to indicate additional gas in place (GIP) are presented. Analysis of the performance of the first 659 infill wells has found no evidence of additional GIP.

Introduction

We examined more than 12 years of performance data from a five-replacement-well program in the Kansas Hugoton and evaluated the results of the Kansas Hugoton infill-drilling program started in 1987. This work focuses on the pressure, deliverability, and rate-vs.-time relationship between two wells on a 640-acre section with respect to any GIP additions made by the second well.

In 1977, Mesa undertook a five-replacement-well test program to determine if increased reserves and improved deliverability could be obtained by drilling an additional well on each of the five 640-acre-spacing units. One aspect of the five-replacement-well study is that the original wells were shut in for nearly 10 years and wellhead observation pressures recorded monthly while the replacement wells were produced. The observed pressures, combined with pressure and flowmeter data taken on each of the four no-crossflow layers in the productive interval, provide a unique look at the performance relationship between two wells on the same 640-acre-spacing unit. We found no evidence that the replacement wells encountered any gas that was not already being drained by the original wells.

This paper also examines the performance data of the first 659 infill wells placed on production in the Kansas Hugoton. In April 1986, the Kansas Corporation Commission (KCC) amended its basic proration order[1] for the Kansas Hugoton gas field to permit a second optional well to be drilled on all basic acreage units larger than 480 acres. The KCC based its decision to allow infill wells on the premise that these wells would recover an additional 3.5 to 5.0 Tscf of gas that could not be recovered by existing wells. Data used in our analysis include the official deliverability test data and monthly allowable and production history for each infill and companion original well. Results indicate that infill wells have not encountered or indicated additional GIP. This conclusion is supported by companion papers on the Guymon-Hugoton field.[2-4]

The performance of the five replacement wells compared with the companion original wells illustrates the rate and pressure-vs.-time relationship of a well pair on 640-acre-spacing units in the Kansas Hugoton. Results obtained from the five-well program provide a more complete understanding of infill-well performance in the Kansas Hugoton and other similar layered no-crossflow reservoirs.

History

The Hugoton field is the largest gas accumulation in the Lower 48 states, covering about 6,500 sq. miles in three states. Approximately two-thirds of the field lies in southwest Kansas on all or portions of nine counties (**Fig. 1**). In Nov. 1989, there were 4,853 producing gas wells in the Kansas Hugoton, including 659 infill wells. Cumulative production from the Kansas Hugoton through Dec. 1989 totaled more than 20 Tscf, with an estimated remaining GIP of about 10 Tscf.

The Kansas Hugoton field was discovered in 1922; most of the wells were drilled in the 1940's and early 1950's on 640-acre units.[5,6] The early wells were completed open hole; later, slotted liners were run over the openhole interval to avoid cave-in problems. By 1938, operators were treating the whole productive interval with HCl. In the late 1940's, many operators found that maximum deliverability could be obtained by setting casing through the pay zones and selectively perforating and acidizing each zone.[7-9] By the early 1960's, the primary method of stimulation was hydraulic fracturing.

Geology

The Lower Permian section across southwestern Kansas and the Oklahoma and Texas panhandles was deposited in cyclical sequences on a shallow marine carbonate ramp.[2,10] Each cycle consists of laterally continuous anhydritic carbonates and fine-grained clastics capped and separated by shaley redbeds and paleosols. The Chase group is the major gas pay within the Hugoton field and is subdivided primarily into carbonate units and interlayered shaly units. The carbonate units, including (from the botintervals with different porosity/permeability relationships.

5. Routine core data have shown that there can be significant variation in porosity/permeability relationships between formations, within what are considered to be uniform sands, between wells in the same area of a field, and between the oil and water zones.

6. Oil-based drilling mud can significantly alter reservoir wettability and affect measurements of relative permeability and ROS.

Nomenclature

k = permeability, md
k_r = relative permeability
k_o = oil effective permeability, md
k_{ro} = oil relative permeability
k_{rw} = water relative permeability
P_c = capillary pressure, psi
S_{wi} = initial (low) water saturation
ϕ = porosity

Acknowledgments

We thank Shell U.K. E&P for participating in several of the special core analysis programs discussed, for providing the core material and reservoir fluids required in laboratory tests, and for granting permission to publish the paper. A special note of thanks to our colleagues at Exxon Production Research Co., who conducted the special core analysis tests described.

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SI Metric Conversion Factors

ft	× 3.048*	E−01	=	m
°F	(°F−32)/1.8		=	°C
mile	× 1.609 344*	E+00	=	km
psi	× 6.894 757	E+00	=	kPa

*Conversion factor is exact.

Provenance

Original SPE manuscript, **The Use of Routine and Special Core Analysis in Characterizing Brent Group Reservoirs, U.K. North Sea,** received for review Oct. 16, 1988. Revised manuscript received March 3, 1992. Paper accepted for publication March 17, 1992. Paper (SPE 18386) first presented at the 1988 SPE European Petroleum Conference held in London, Oct. 16-19.

JPT

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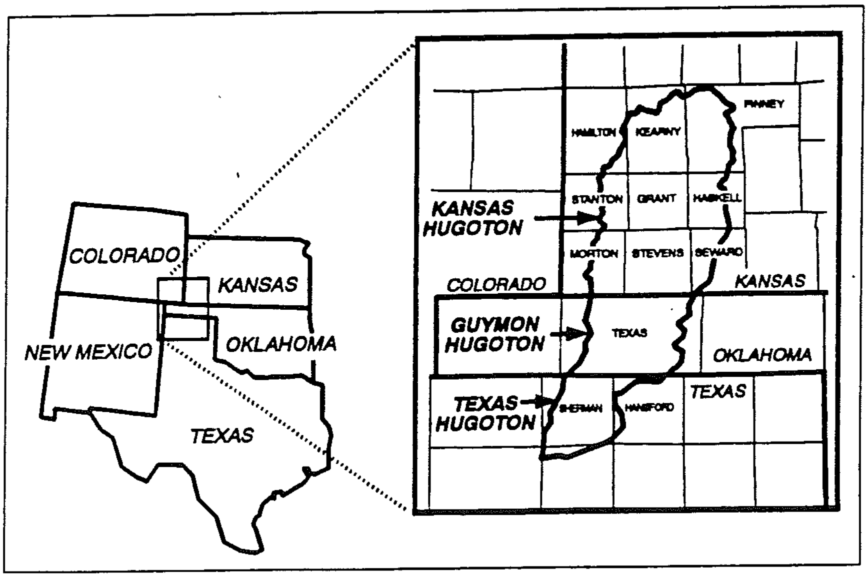

Fig. 1—Kansas Hugoton field location map.

"Results obtained from the five-well program provide a more complete understanding of infill-well performance in the Kansas Hugoton and other similar layered no-crossflow reservoirs."

tom up) the Upper and Lower Fort Riley, Winfield, Krider, and Herington limestones and dolomites, constitute the potential reservoir intervals within the Kansas Hugoton field. These reservoir intervals are separated by sealing shaly units, including the Oketo, Holmesville, Gage, Odell, and Paddock shales. The reservoir and shaly nonreservoir units exhibit characteristic log signatures recognizable throughout the field. Regional north-south and east-west cross sections (**Figs. 2 and 3**), developed from cross sections by Clausing,[11] illustrate the lateral continuity of the reservoir layers and shaly barrier units across the field. Additional information on the geological features in Oklahoma's Guymon-Hugoton field can be found in Ref. 2.

Five-Replacement-Well Study

In 1977, Mesa drilled and completed five replacement wells in the Kansas Hugoton field to determine the performance of replacement wells in relation to original wells.[12,13] Specifically, the operator was interested in determining if increased reserves and deliverability could be achieved with the replacement wells by (1) encountering undrained pay stringers within the Chase group, (2) encountering a higher reservoir pressure in a different part of the 640-acre section, and (3) improving stimulation procedures by selectively perforating and controlling hydraulic fracture treatments. Cross sections generated by the operator indicated laterally continuous producing zones with little discontinuity between wells. From individual-layer pressure and flowmeter data, the operator concluded that the Krider, Winfield, and Upper and Lower Fort Riley zones are separate and distinct producing horizons within the Chase formation, having different reservoir pressures and depleting at different rates. From flowmeter tests, wellbore backflow was found to occur between zones when a well was shut in, further evidence of differential depletion—i.e., a no-crossflow layered reservoir system. The operator found that commingled wellhead shut-in pressures on these wells reflect the pressure in the layer with the lowest reservoir shut-in pressure. One unique aspect of the replacement-well study was that the original wells were shut in for almost 10 years and monthly wellhead shut-in pressures taken and reported to the KCC. The initial wellhead shut-in pressure of the replacement wells averaged 14.4 psi higher than the original wells' 72-hour shut-in pressure at that time. Initial calculated official 72-hour deliverability for the replacement wells averaged 753 Mscf/D/well higher than the latest deliverability of the original wells. No conclusions about any additional GIP were offered in Mesa's original work.[12]

The first of the five replacement wells drilled was the Gano No. A1 located in Sec. 20 T29S R37W in Grant County, KS. Because this was the only replacement well with complete individual-layer pressure buildups and flowmeter test results, its performance is presented in detail.

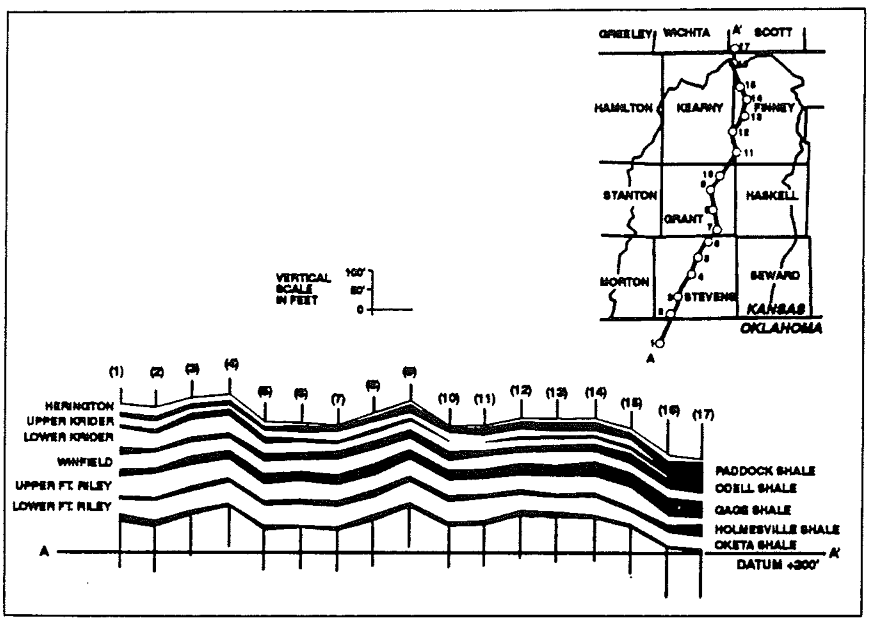

Fig. 2—East-west cross section through the Kansas Hugoton (after Clausing[11]).

Gano No. 1, Original Well. The Gano No. 1 was drilled on Aug. 28, 1951, by Hugoton Producing Co. and completed open hole in the Krider, Winfield, and Upper and Lower Fort Riley layers with a slotted liner. The entire openhole interval was acidized. Initial wellhead shut-in pressure was 434 psia with an absolute open-flow potential (AOFP) of 33,000 Mscf/D. In 1969, Mesa purchased the Gano No. 1 and restimulated the well in 1970 with 150,000 lbm of sand and 150,000 gals of water, resulting in a four-fold increase in productivity. When the well was shut in as an observation well on April 13, 1977, the cumulative production was about 6 Bscf.

Gano No. A1, Replacement Well. The Gano No. A1 reached a total depth of 2,960

"One unique aspect of the replacement-well study was that the original wells were shut in for almost 10 years and monthly wellhead shut-in pressures taken. . ."

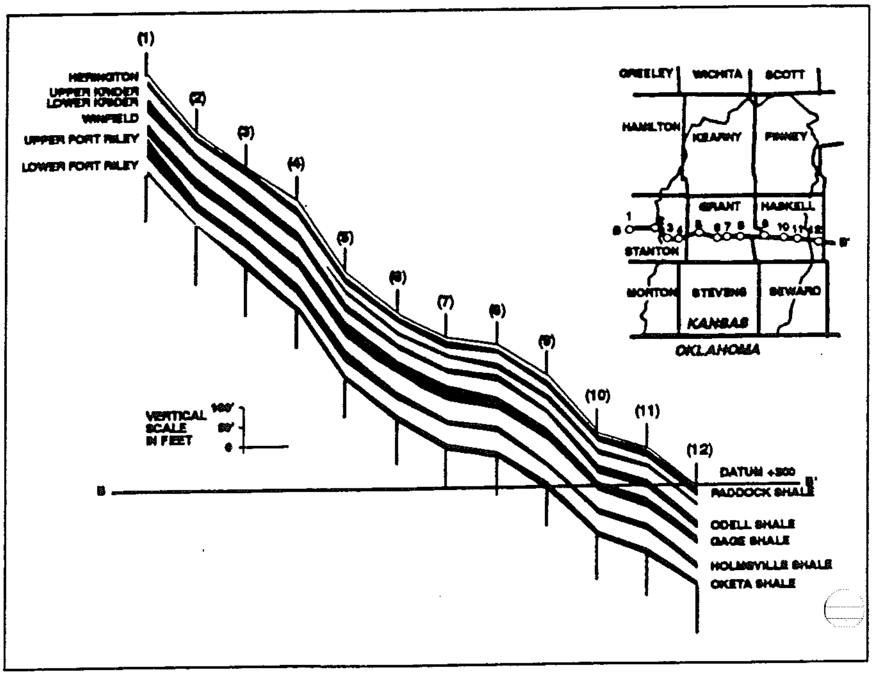

Fig. 3—North-south cross section through the Kansas Hugoton (after Clausing[11]).

ft on April 7, 1977, with 7-in. casing cemented through all the productive intervals. Each layer was separately acidized, flowed to clean up, and then shut in for a pressure-buildup test. After each layer had been individually perforated, acidized, and tested, a final commingled pressure buildup was run. All four layers were then sand fractured with 200,000 gals of gelled water and 200,000 lbm of sand.

Fig. 4 presents permeabilities and bottomhole pressures (BHP's) from the individual-layer pressure-buildup tests and log-calculated porosities for the Gano No. A1. The individual-layer buildup test results clearly indicate that each layer has a different pressure and permeability. The most permeable layer, Krider, has the lowest pressure, 188 psia; the least permeable layer, Lower Fort Riley, has the highest pressure, 284 psia. The greatest amount of depletion has occurred in the more permeable layer(s). The commingled buildup pressure of 190 psia reflects the pressure in the low-pressure, more-permeable Krider layer. During the commingled buildup, the operator indicated[12] that wellbore backflow was occurring from the higher-pressure, lower-permeability layers to the low-pressure, high-permeability layer during the test.

To assess the contribution of flow from each layer and to confirm that wellbore backflow between layers was occurring during shut in, the operator ran a differential temperature log and flowmeter survey on the Gano No. A1. Production was stabilized at 1,200 Mscf/D for 7 days before the survey with a final p_{whf} of 158.4 psia. Fig. 4 shows flow rates from each layer. The Krider contributed 47% of the total flow, while the Lower Fort Riley contributed only 2%. This survey also showed that, during shut in at the surface, the lower two layers, the Upper and Lower Fort Riley, continued to produce gas into the wellbore, backflowing into the upper two layers, the Winfield and the Krider.

Fig. 5 is a plot of p_{whs} vs. G_p with a wellhead backpressure curve and a location plat for the Gano lease. The distance between the two wells on this section is 2,150 ft. The shift to the right in the backpressure curve for the original well (solid circles) corresponds to a sand fracture restimulation performed in 1970. The backpressure curve for the replacement well (open circles) lies slightly to the right of that of the original well after restimulation, indicating only slightly better stimulation results in this

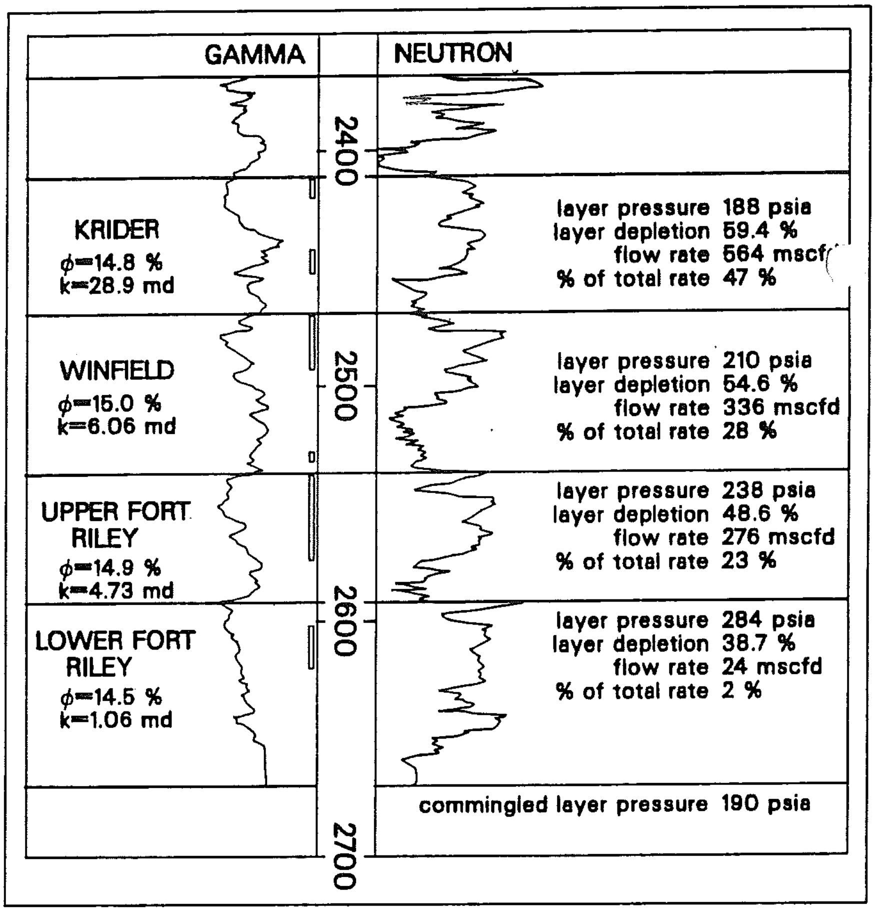

Fig. 4—Type log for the Gano No. A1 with individual-layer pressures and flow rates (after Carnes[12]).

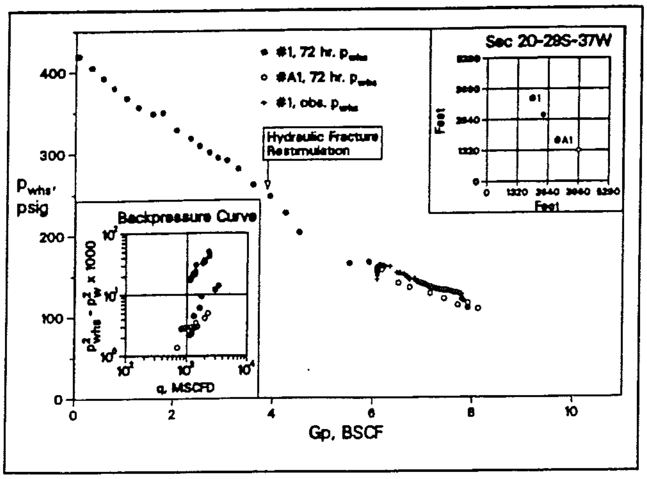

Fig. 5—Wellhead shut-in pressure vs. cumulative production with a wellhead backpressure curve and a location plat for the Gano lease.

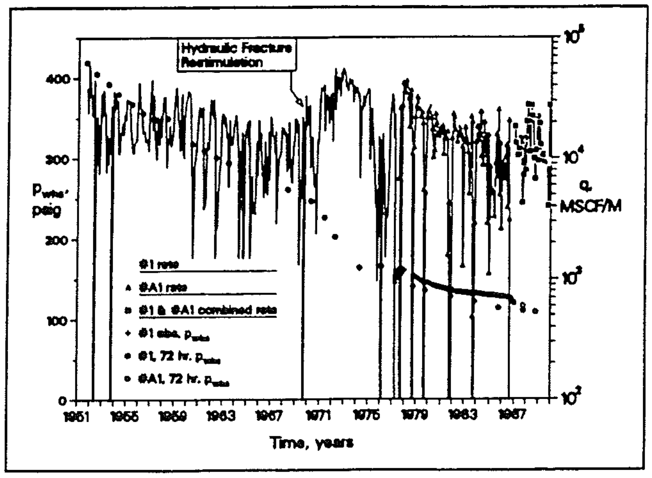

Fig. 6—Wellhead shut-in pressure and monthly rate vs. time for the Gano lease.

replacement well. If the original well had not been restimulated, there would have been an "apparent" dramatic (stimulation or higher-areal-layer pressure-rate contribution) benefit attributed solely to the replacement well or an equivalent infill well. The p_{whs} vs. G_p curve has several apparent slope changes, making it difficult to extrapolate to a GIP properly. The producing rate and/or shut-in duration before the official deliverability test and the no-crossflow layered nature of the reservoir all play important roles in interpreting and evaluating the p_{whs} vs. G_p curve.

The sand fracture restimulation conducted in 1970 on the original well substantially increased the official deliverability, resulting in a much higher allowable for this well. The increased downward slope represented by the p_{whs} points taken after the fracture job appear to indicate a decrease in remaining GIP for this well. The change in slope of the p_{whs} vs. G_p curve after the fracture job in Fig. 5 is primarily caused by the change in the production rate due to the increased allowables resulting from the restimulation and does not reflect a change in the drainage volume for this well.

Another important consideration in evaluating the shape of the p_{whs} vs. G_p curve is the effect of any large rate changes, including extended shut-ins, before the official deliverability test. The production rate was decreased before the 1976 official deliverability test, and the well was shut in during the month immediately before the official test. The effect of rate and "rest period" can be seen more clearly in the rate and pressure vs. time plot of **Fig. 6**. The resulting p_{whs} in 1976 is clearly higher than that of the previous test in 1974. In the Kansas Hugoton, an official deliverability test consists of a 72-hour flow followed by a 72-hour shut-in. The rate and flowing pressure are recorded at the end of the flow period and the p_{whs} at the end of the shut-in. Resting a well before an official deliverability test will allow the 72-hour p_{whs} to build up to a higher pressure than if the well had been producing before the test. The wellbore backflow from the high-pressure layer(s) to the low-pressure layer(s) that occurs during shut-in also causes the well to build up to a higher pressure. (In the Kansas Hugoton, p_{whs} is an important factor in the calculation of allowables. For a given well, the higher the p_{whs}, the higher the allowable.)

Taking into account the expected curvature of the p_{whs} vs. G_p curve in a layered no-crossflow reservoir with contrasting layer properties and the effect of the rate and shut-in periods on the shape of this same curve (see Figs. 5 and 6), we can conclude that the replacement well is producing from the same drainage area as the original well. The p_{whs} for the replacement well falls on the p_{whs} trend started by the original well (Fig. 5).

Observation-Well Pressures. Fig. 7 is a plot of p_{whs} and monthly rate vs. time since 1977 for the Gano lease. The solid and open circles represent the 72-hour p_{whs} for the original (Gano No. 1) and replacement (Gano No. A1) wells, respectively. The triangles with the dashed line represent the replacement well (Gano No. A1) rates, while the solid line represents the monthly rates for the original well (Gano No. 1). The plus symbol denotes the observation wellhead shut-in pressures taken on the original well (Gano No. 1). The first observation pressure is 144.7 psig and was taken after

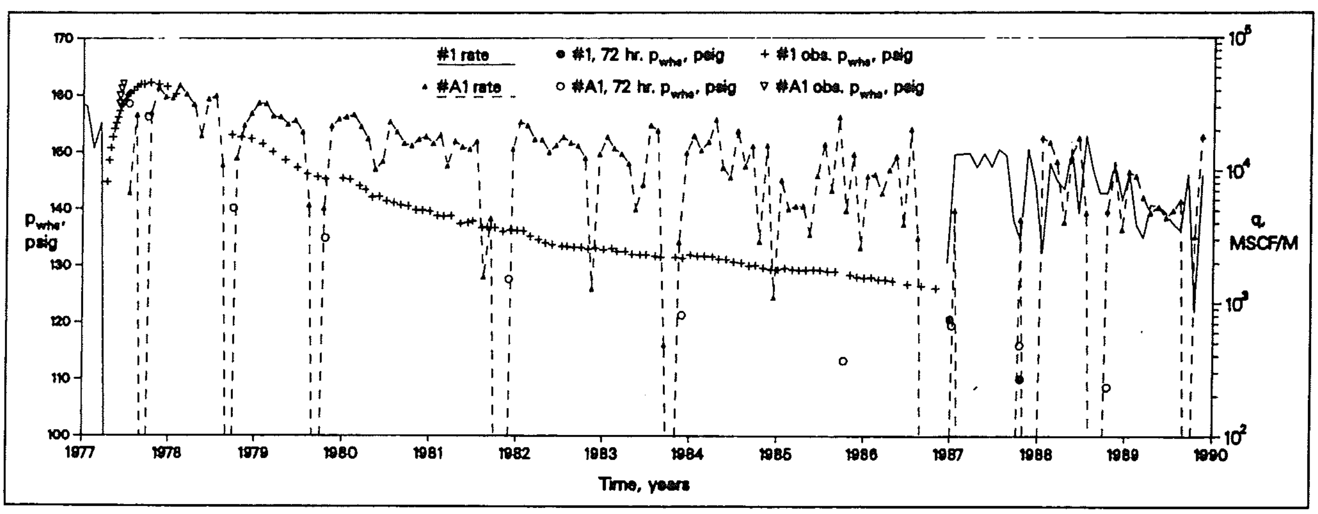

Fig. 7—Wellhead shut-in pressure and monthly rate vs. time since 1977 for the Gano lease.

TABLE 1—EFFECT OF LAYERING ON DEPLETION AND TIME TO ABANDONMENT RATE
(p_i = 463 psia. B_{gi} = 31.98 scf/res ft^3. μ_2 = 0.01045 cp. T = 550°R. r_w = 0.2539 ft)

Comments	Parameter	Krider	Winfield	Upper Fort Riley	Lower Fort Riley	Total
	k, md	21.8	12.6	5.4	0.53	
	h, ft	34	28	42	26	130
	kh, md-ft	741	353	227	14	1,335
	ϕ	0.148	0.150	0.149	0.128	
	S_w	0.235	0.285	0.312	0.308	
	G_i, MMscf	3,432	2,676	3,840	2,052	12,000
	$\bar{p}$, psia (1977)*	188	210	238	284	
	G_p/G_i	0.610	0.563	0.503	0.402	
	G_r, MMscf	1,284	1,123	1,830	1,178	5,415
One producing well per section, each layer produced separately to an abandonment rate of 10 Mscf	$(q_{gi})_{max}$, Mscf/D	889	528	436	38	1,795
	t_a, years	60	63	91	108	
	G_p/G_i, fraction	0.96	0.94	0.92	0.69	
One producing well per section, commingled well	t_a, years	162	162	162	162	
	q_{layer}, Mscf/D	0.72	0.90	2.70	5.68	10.0
	G_p/G_i, fraction	0.99	0.98	0.96	0.77	0.94
	$\bar{p}_{layer}$, psia	5	10	20	112	
Two producing wells per section, each layer produced separately to an abandonment rate of 20 Mscf	$(q_{gi})_{max}$, Mscf/D	1,968	1,169	965	83	3,950
	t_a, years**	43	44	58	67	
	G_p/G_i, fraction	0.96	0.94	0.92	0.71	
Two producing wells per section, commingled production	t_a, years	92	92	92	92	
	q_{layer}, Mscf/D	1.4	1.8	5.3	11.5	20.0
	G_p/G_i, fraction	0.99	0.98	0.96	0.77	0.94
	$\bar{p}_{layer}$, psia	5	10	20	112	

*Pressure distribution of layers at time = 27 years (1977).
**t_a = total producing life, including the first 27 years of commingled production.

the well had been shut in for 1 week. Wellhead shut-in pressures taken on the replacement well (Gano No. A1) for several weeks after the sand fracture, while the well was waiting for an official deliverability test, are denoted by inverted triangles. Note that through time, before the start of production from the replacement well, the observation-well (Gano No. 1) pressure builds up to the pressure of the replacement well (Gano No. A1). This indicates that before any production from the replacement well, the pressure in the most permeable layer is basically the same between these two wells.

Once the replacement well begins to produce, the subsequent 72-hour p_{whs} from the official deliverability tests falls below the observation-well pressures. The difference between the first observation-well pressure on the original well and the first pressure on the replacement well is 10 psi. Approximately 1 year later, at the time of the official deliverability test for the replacement well, the pressure difference between the two wells is 12.9 psi. Although the absolute pressure difference is basically the same, the pressures for the two wells have traded positions. The wellhead shut-in pressure of the original well is now higher than that of the replacement well. This indicates that the pressure difference is simply a reflection of the pressure gradient between the two wells in the most permeable layer when one well is shut in and the other producing. Ref. 14 attempts to confirm this conclusion by use of the steady-state radial flow equation in a bounded system.

Another interesting point in Fig. 7 relates to the effect of resting the original well on the observation-well pressures. In 1978, 1979, 1981, and 1983, the replacement well was "rested" for about 1 month before the official deliverability test. The slope of the observation-well pressures flattens out after each of these rest periods. This subtle change in slope indicates pressure communication between these two wells in the most permeable layer.

In late 1986, Mesa applied for the transfer of allowables from the five replacement wells back to the five original wells that were designated as pressure observation wells. The replacement wells then were shut in until they could be brought back on production as infill wells. The replacement well (Gano No. A1) was shut in during Sept. 1986 and the original well (Gano No. 1) began producing again in Dec. 1986. In Jan. 1988, the replacement well was placed back into production as an infill well. The p_{whs} for both wells at the start of 1987, after several months of no production from either well, are nearly identical. Note in Fig. 7 that the second 1987 p_{whs} for the original well falls back into the pressure trend of the replacement well while it was producing.

An analysis of the Mesa replacement-well program demonstrates that the replacement well and the original well are in pressure communication and the pressure difference between the two wells is caused by the pressure gradient in the most permeable layer. We found no evidence that the replacement well encountered any gas that was not already being drained by the original well. The same conclusion can be drawn from the performance of the other four replacement wells in Mesa's study.[14]

Effect of Layering on Depletion and Abandonment

In this section, we use the simple rate/time and cumulative-time equations of Ref. 15 to illustrate the effect of no crossflow on individual-layer pressure depletion and time to abandonment for the Gano No. A1. Calculations were made assuming equal skins for all layers (−5) and adjusting the permeability for each layer to be in proportion to the rates obtained from the flowmeter survey. Water saturations for each layer are calculated from the layer GIP estimates provided in Ref. 13 with log-derived porosity and thickness and a 640-acre drainage area. **Table 1** gives the calculated depletion times and layer abandonment pressures for the Gano No. 1 assuming wide-open production starting in 1977 at a limiting flowing BHP of 0 psia. The equations used to calculate the time to an abandonment rate and layer pressures at abandonment are summarized in the Appendix. Produced separately, the Krider, Winfield, and Upper and Lower Fort Riley layers take a total of 60, 63, 91, and 108 years, respectively, to reach an abandonment rate of 10 Mscf/D. Commingled production against 0-psia flowing BHP takes 162 years to reach the 10-Mscf/D abandonment rate. The time to an abandonment rate of 10 Mscf/D is almost double the time to the same abandonment rate for the Buf No. 1 well calculations given in Ref. 4. These much longer calculated times are primarily caused by the addition of a fourth productive layer in the Kansas portion of the Hugoton field. The calculated layer abandonment pressures for the Krider, Winfield, and Up-

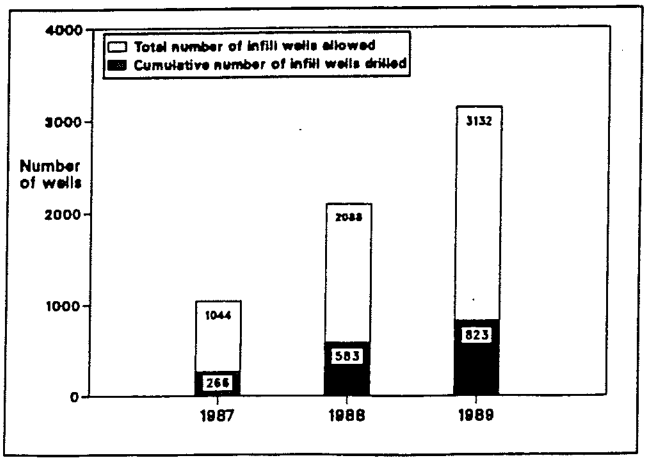

Fig. 8—Actual number of infill wells drilled compared to the total number of wells allowed.

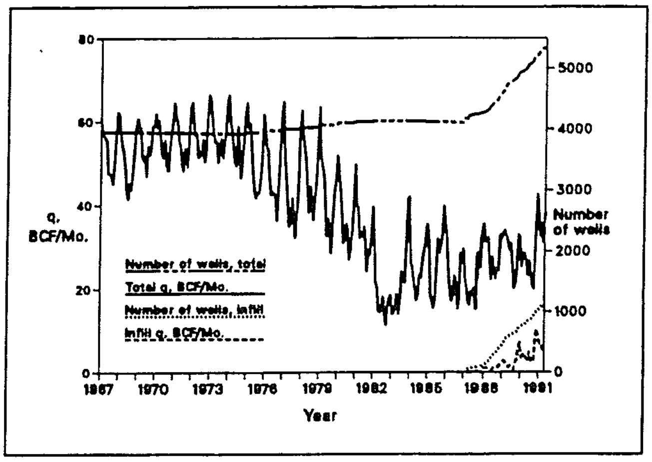

Fig. 9—Historical production and well count for the Kansas Hugoton since 1967.

per Fort Riley are 5, 10, and 20 psia, respectively, while the abandonment pressure for the Lower Fort Riley is 112 psia.

Table 1 also presents the effect of layering on depletion and time to an abandonment rate when there are two wells per section (each well assigned a 320-acre drainage area). The second well is drilled when the layer pressure distribution is identical to that measured in 1977 on the Gano No. A1. The abandonment rate now becomes 20 Mscf/D because there are two wells producing in this section. Both wells are assumed to produce wide open starting in 1977. The remaining time to an abandonment rate of 20 Mscf/D for each layer is reduced by half, while the layer pressure at abandonment does not change compared with the single-well case. The fractional recoveries for the one- and two-well cases are identical at an abandonment rate of 10 Mscf/D per well. The infill well will accelerate production, but the recovery does not change to the same per-well abandonment rate.

Using the method to calculate time to an abandonment rate and layer abandonment pressures, we can conclude for the Kansas Hugoton that a very long producing life can be expected and infill wells produced to the same per-well abandonment rate as the original wells do not add incremental reserves.

Infill Drilling Order

Cities Service Oil & Gas Corp. (now OXY U.S.A.) filed an application with the KCC on July 31, 1984, requesting that an optional well be permitted on each basic proration unit[1] of 640 acres in the Kansas Hugoton. A hearing on the application, in which 110 witnesses testified, began on July 29, 1985, and ended on Dec. 5, 1985.

In April 1986, the KCC amended the proration order for the Kansas Hugoton to permit a second optional well. Starting in 1987, the KCC ordered that the infill drilling be phased in over a 4-year period to avoid a boom/bust race to drill the infill wells. Each operator would be permitted to drill a maximum of one-quarter of its infill locations each year, with any undrilled infill locations carried forward to the next year.

Data Analysis

Infill-Drilling Activity. The infill wells analyzed in this study are the 659 wells that were assigned allowables and listed in the Nov. 1989 monthly Kansas Hugoton field report. Infill drilling in the Kansas Hugoton began in 1987, with 260 wells being spudded in the first year compared with the 1,044 allowed by the KCC. Fig. 8 compares the actual number of infill wells drilled to the total number of infill wells allowed by year. As of the end of 1989, only 823 infill wells of the 3,132 allowed (26%) had been drilled. The overall infill-drilling activity progressed at a significantly slower pace than was allowed by the KCC.

Fig. 9 presents the Kansas Hugoton monthly production and well count since 1967 for both the infill and original wells. The gas market curtailment is evident in this plot by the rate decline in the early 1980's. The production from the infill wells has not had an appreciable effect on the total production from the field. In fact, the increase in demand for gas from the Kansas Hugoton between 1987 and 1988 had a greater impact on total field production than the infill wells.

Infill Well Initial Wellhead Shut-In Pressures. Fig. 10 presents a cumulative frequency and frequency distribution histogram of the initial shut-in wellhead pressures,

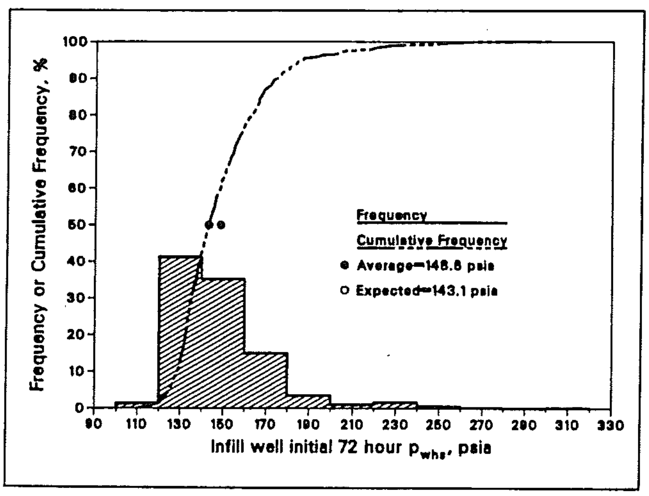

Fig. 10—Infill-well initial wellhead shut-in pressure histogram.

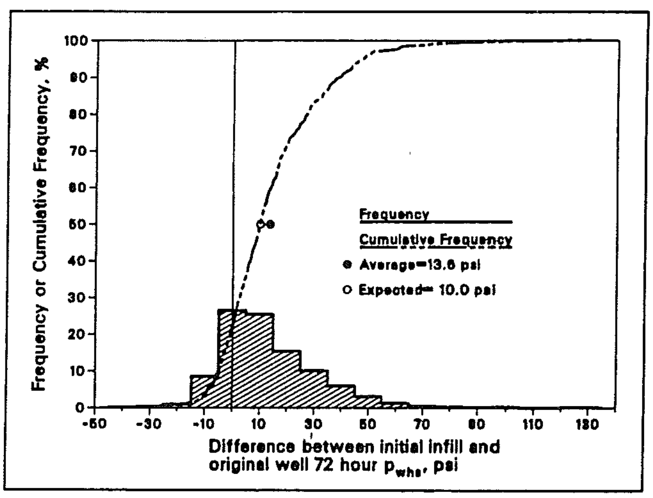

Fig. 11—Histogram of the difference between initial infill and original wellhead shut-in pressures.

"For the Kansas Hugoton, we can conclude that a long producing life can be expected and that infill wells produced to the same abandonment rate as the original wells will not add any incremental reserves."

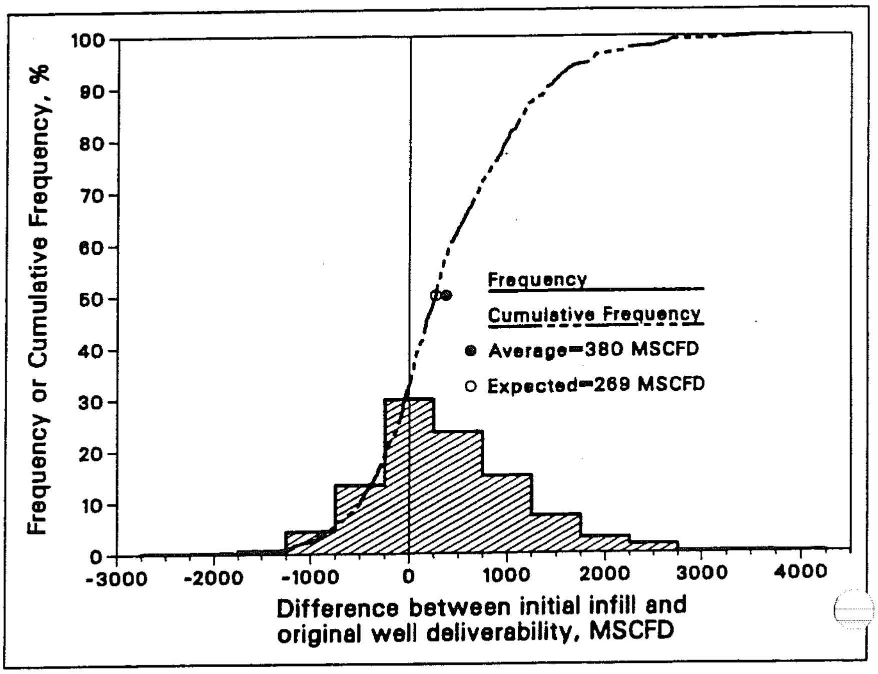

Fig. 12—Histogram of the difference between initial infill- and original-well official deliverability.

p_{iwhs}, encountered by the infill wells between Jan. 1987 and Nov. 1989. The $\bar{p}_{iwhs}$ is 148.8 psia, with an expected value of 143.1 psia. The expected value accounts for skewness in the data. Note the skewness in the upper end of the distribution in Fig. 10. The $\bar{p}_{iwhs}$ of 148.8 psia is significantly lower than the original field discovery pressure of about 450 psia.[1] This average reduction in initial pressure of more than 300 psi in the infill wells drilled in the Kansas Hugoton is evidence that the existing wells have drained gas from the reservoir in the areas of every new infill well.

Infill p_{iwhs} is generally a function of well location and the permeability of the low-pressure layer. The lower pressures are found in the more productive areas of the field and the higher pressures are found on the edges of the field. The fact that no infill well encountered the initial discovery pressure of 450 psia in the Kansas Hugoton indicates lateral continuity of the more permeable productive layers and that the existing wells have drained significant volumes of gas from these layers in the areas of every new infill well.

Difference Between Initial Infill and Original Wellhead Shut-In Pressure. In this section, we compare the difference between the p_{iwhs} of the infill well and the original well p_{whs} or Δp_{iwhs}. The average elapsed time between the initial infill-well official deliverability test and the companion test for the original well was 8½ months. **Fig. 11** presents the cumulative frequency and frequency distribution histogram for Δp_{iwhs}. The average difference is 13.6 psi, with an expected value of 10.0 psi. Almost one-quarter of the infill wells had a p_{iwhs} that was lower than the p_{whs} for the original well, mainly as a result of test time differences. Some of the original wells had been shut in for a significant period of time before their official deliverability tests, while the companion infill wells were being flowed to clean up before their official deliverability tests. This combination of events would cause the p_{iwhs} for the infill well to be lower than the p_{whs} for the companion original well.

Because the p_{whs} typically reflects the pressure of the most permeable layer, the pressure differences are basically a function of the permeability variations in the most permeable layer across the field. Because the p_{iwhs} for the infill wells are much lower than the field discovery pressure, the infill wells must be tapping into the existing drainage area of the original well. For gas to flow within this drainage area to the original well, a pressure drop must exist from the drainage area boundary to the original well.

An infill well drilled anywhere within this drainage area should have a higher p_{iwhs} because of the pressure sink at the original well. Claims have been made that the higher pressures observed in the infill wells compared with those for the original wells indicate that the original wells were not effectively and efficiently draining all the existing gas reserves and that infill drilling has increased ultimate recoverable reserves. The average initial Δp_{whs} of 13.6 psi between the infill and original wells is simply a reflection of the pressure gradient toward the original well in the most permeable layer and reflects no additional GIP found by the infill well.

The fact that in a no-crossflow layered reservoir the 72-hour wellhead shut-in pressure generally reflects the pressure in the low-pressure, high-permeability layer does not diminish its value as a meaningful reservoir parameter. Fetkovich *et al.*[4,15] showed that the 72-hour wellhead shut-in pressure reflects the performance of all layers. The contribution from the other layers is evident in the relationship between the wellhead shut-in pressure and the cumulative production. The 72-hour wellhead shut-in pressures and the cumulative production would be much lower had the other layers not contributed.

Infill-Well Official Deliverability. Initial official deliverabilities observed in the infill wells that were higher than those for the original wells also have been interpreted as a reflection of an increase in GIP. The higher official deliverabilities found in infill wells, however, cannot be used as a reliable indication that the infill wells are encountering additional GIP. The official deliverability of each well in the Kansas Hugoton is determined by conducting a one-point 72-hour deliverability test. The official deliverability, D, is calculated by

$$D=q[(p_{whs}^2-p_d^2)/(p_{whs}^2-p_w^2)]^{0.85}. \quad \ldots(1)$$

The deliverability standard pressure, p_d, is equal to 70% of $\bar{p}_{whs}$ for all the wells tested in the Kansas Hugoton in the previous year. **Fig. 12** presents the difference in infill- and original-well official deliverabilities used in the determination of well allowables. If the p_{whs} for either the original well or the infill well is less than p_d, then the well has a zero deliverability and is assigned a minimum allowable of 65 Mscf/D. The initial deliverability for the average infill well is 380 Mscf/D higher than for the original well. However, official deliverability is not an accurate measure of the difference between infill- and original-well performance because the field average standard deliverability pressure is involved. For example, the initial test for the Wagner 1-2 (infill well), located in Sec. 20 T24S R35W, on April 13, 1988, had a p_{whs} of 93.6 psig and flowed 253 Mscf/D at a flowing pressure, p_{whf}, of 85.4 psig. With the 1987 standard deliverability pressure, p_d, of 102.3 psig, use of Eq. 1 results in an official deliverability of zero for the Wagner 1-2. The official deliverability is simply a measure of relative productive capacities against a standard deliverability pressure and is a number used for assigning allowables. The higher p_{iwhs} at the infill well caused by the pressure sink at the original well becomes a factor in the calculated official deliverability.

We can illustrate the effect of a higher p_{whs} on a calculated official deliverability by using the official test data for a typical infill well as an example. **Fig. 13** is a wellhead backpressure curve for the Nafzinger No. 1 (original well) and the Nafzinger No. 2-2 (infill well) located in Sec. 2 T29S R37W. The initial difference in p_{whs} for these two wells is 16.7 psi, which corresponds to a 92-Mscf/D difference in official deliverability. The official deliverability for each well is marked graphically on the plot. The difference in these official deliverabilities is a result of the 16.7-psi higher p_{iwhs} for the infill well. The Nafzinger No. 2-2 was tested 15 months later on Jan. 10, 1989, with a p_{whs} of 122.9 psig, corresponding to a 16.4-psi wellhead shut-in pressure drop over that period. The average pressure drop for the field during the same period was only 7.4 psi. The subsequent official deliverability calculated from the second test was 288 Mscf/D lower than the first test, while the rate for the second test was only 2 Mscf/D lower than that of the first.

The higher official deliverabilities in the infill wells are generally temporary and are caused by the higher initial wellhead shut-in pressure observed in the infill wells.

A better method to compare well or completion performance between the infill and original wells is to use the AOFP calculation corrected to the 1989 average field p_{whs}. This calculation puts all the wells on the same pressure basis and removes the effect of testing time between original- and infill-well tests. This method presents a better comparison of current well productivities and demonstrates the effectiveness of infill-well completion and stimulation techniques relative to those used on the original wells.

$$q_{\mathrm{AOFP},c}=q[(\bar{p}_{whs}^2-14.4^2)/(p_{whs}^2-p_w^2)]^{0.85}, \quad \ldots\ldots\ldots\ldots\ldots (2)$$

where $q_{\mathrm{AOFP},c}$ is the calculated AOFP at the field $\bar{p}_{whs}$ for 1989 (147.6 psia). With this method, the corrected AOFP for the infill well in Fig. 13 is 1,715 Mscf/D less than the corrected AOFP for the original well. The ratio of the corrected AOFP's for this infill well to that of the original well is about 0.64. This indicates that the stimulation and/or completion procedures for this infill well were not as effective as those of the original well.

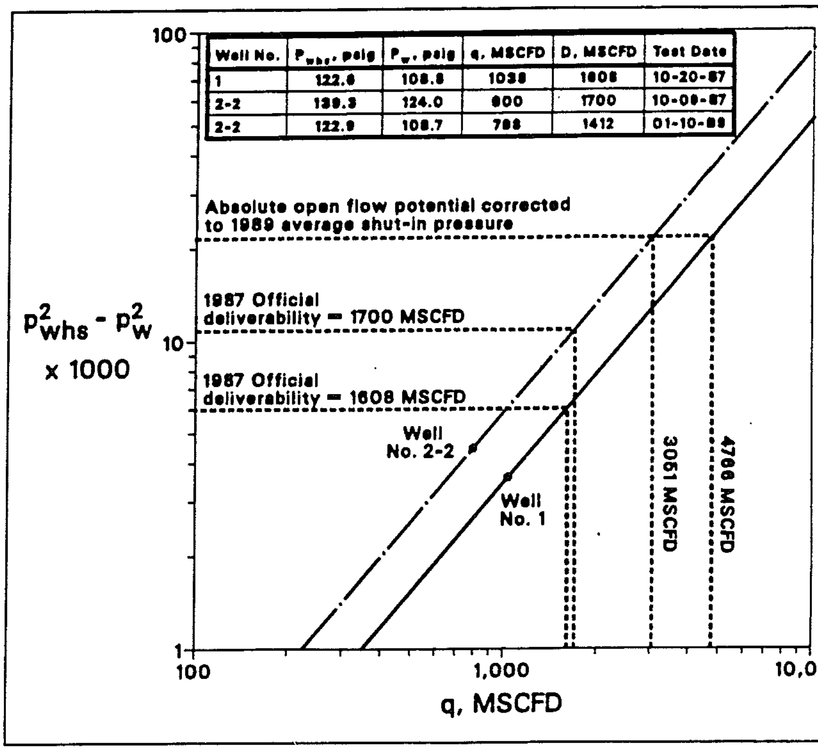

Fig. 13—Wellhead backpressure curve for the Nafzinger No. 1 and No. 2-2.

Corrected AOFP Comparison. The average infill well has a corrected AOFP of 457 Mscf/D less than that of the original well. On average, this indicates poorer stimulation results in the infill wells compared with the original wells. (At the time of the original well stimulation, all layer pressures were equal.) **Fig. 14** compares the corrected AOFP's by use of a ratio of the corrected AOFP's for the infill and original wells. The average ratio is 1.1, with a most probable value of 0.85. This ratio is a direct measure of the difference between the completion performance of a typical infill-well and original-well pair. Fig. 14 indicates that more than 60% of the infill wells have corrected AOFP's that are less than the original well. Because the infill wells were generally stimulated with a water-based treatment, the infill wells may have experienced some degree of cleaning up over time. This possibility was investigated by calculating the ratio of corrected AOFP between the first and second official deliverability tests for the 261 infill wells with more than one test. The average ratio was 1.08 with a most probable ratio of 1.04, indicating an average increase in productivity of 8% between the first and second tests. Although a slight increase in productivity is observed in the infill wells over time because of clean-up effects, this increase has no appreciable effects on the results of this study. Fig. 14 also shows that the performance of some of the infill wells is dramatically better than the companion original well. Investigation of these cases found that either the original well was not properly stimulated or restimulated in the early 1960's or the original well was suffering from mechanical integrity problems. Albeit the calculated official deliverabilities for the infill wells averaged 380 Mscf/D greater than those for the original wells, the corrected AOFP, which represents a better comparison of well performance, averaged 457 Mscf/D less than those of the original wells.

Infill- vs. Original-Well Allowables. Through the beginning of 1989, the presence of the infill well did not add significantly to the volumes of gas allowed to be produced from the infilled proration units. By Nov. 1989, the infill wells accounted for an overall incremental allowable of about 12% from the infilled proration units. Because the infill wells are only allowed to produce a fraction of their capacity, some operators appear to be overproducing their wells, which may accelerate revenue to help defray the cost of the infill well. Once a nonminimum well becomes overproduced by six times its basic monthly allowable, the KCC shuts the well in until the overproduction is worked off. For example, in Jan. 1989, 102 (24.5%) of the 417 infill wells at that time were overproduced to the point where the KCC shut them in, while only 16 (3.8%) of the 417 companion original wells were shut in by the KCC.

Cumulative frequency and frequency distribution plots were generated of the difference between the current allowable for the infilled proration units and the allowable for that proration unit had the infill well never been drilled. Distributions of this difference were generated for each month from May 1987 through Nov. 1989. For the first 11 months of 1989, the average infilled prora-

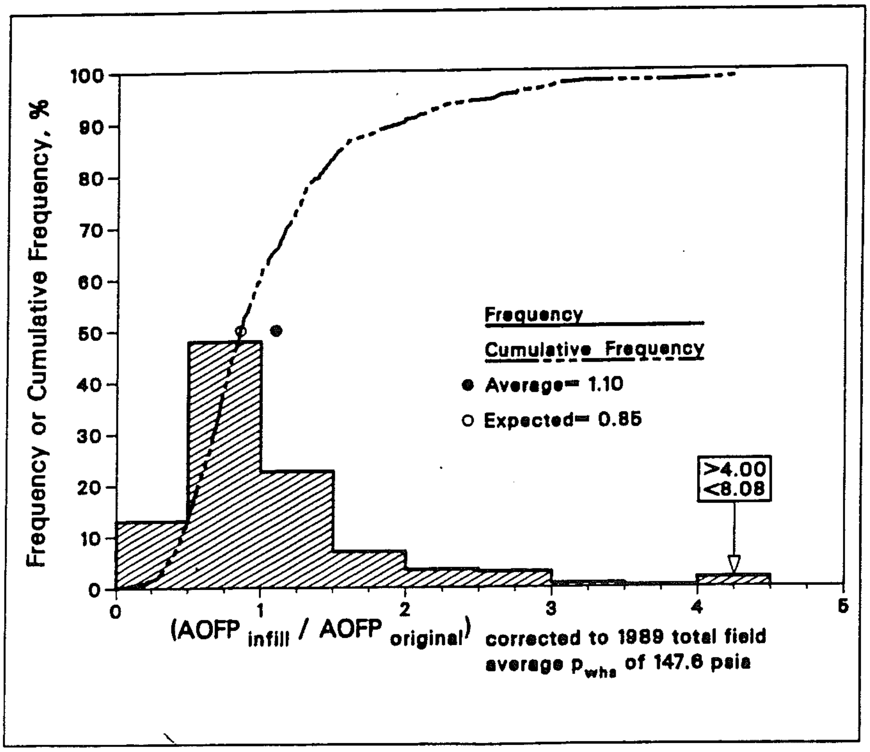

Fig. 14—Histogram of the ratio of corrected AOFP.

tion unit had an increase in allowable of only 36 Mscf/D as a result of the presence of the infill well. For this same period, 35% of the infilled proration units actually lost allowable because of the infill well.

Further information on the performance of the infill wells with respect to the original wells by operator and by county can be found in Ref. 16.

Conclusions

1. An analysis of the Mesa replacement-well program demonstrates that the replacement well and original well are in pressure communication and the pressure difference between each set of original and replacement wells is caused by the pressure gradient in the most permeable layer(s) between the two wells. We found no evidence that the replacement well encountered any gas that was not already being drained by the original well.

2. A simple method can be used to calculate time to an abandonment rate and layer abandonment pressures for a layered, no-crossflow reservoir such as the Kansas Hugoton. These calculations can be made for any number of layers and wells within a drainage area. For the Kansas Hugoton, we can conclude that a long producing life can be expected and that infill wells produced to the same abandonment rate as the original wells will not add any incremental reserves.

3. Our analysis of the infill- and companion original-well performance data in the Kansas Hugoton, showed no evidence that the infill wells found any additional GIP.

4. The infill wells have an average initial wellhead shut-in pressure of 148.8 psia with no infill well encountering the initial discovery pressure of 450 psia. The magnitude of this average reduction in pressure indicates lateral continuity of the more permeable productive layers and that the existing wells have drained significant volumes of gas from these layers in the areas of every new infill well.

5. The average infill well's initial wellhead shut-in pressure is 13.6 psi higher than the average corresponding wellhead shut-in pressure for the original well. This pressure difference does not reflect additional GIP but is a result of the pressure gradient in the most permeable layer(s) toward the original well.

6. The higher initial official deliverabilities found in the infill wells over the original wells cannot be used as an indication that the infill wells are encountering additional GIP. To compare well performance between the infill and corresponding original well better, a calculation may be made of the AOFP corrected to the 1989 field-average shut-in pressure of 147.6 psia. This calculation puts all the wells on the same shut-in-pressure basis. Although the calculated official deliverabilities for the infill wells average 380 Mscf/D greater than that for the original wells, the corrected AOFP's, which represent a better comparison, averaged 476 Mscf/D less than those for the original wells. On average, this indicates poorer stimulation results in the infill wells than in the original wells, possibly because of layer pressure differences.

7. During the first 11 months of 1989, the average infilled proration unit had an increase in allowable of 36 Mscf/D as a result of the presence of the infill well. For the same period, 35% of the infilled proration units actually lost allowable because of the infill well.

8. Through 1989, only 26% of the infill wells allowed by the KCC have been drilled. The overall infill drilling activity has progressed at a significantly slower pace than was permitted by the KCC.

Nomenclature

B_{gi} = gas FVF, scf/res ft^3
D = official deliverability (Eq. 1), Mscf/D
G_i = initial GIP, Bscf
G_p = cumulative gas production, Bscf
G_r = remaining GIP, Bscf
h = thickness, ft
k = effective permeability, md
n = number of layers
p = pressure, psia
$\bar{p}$ = average field shut-in pressure, psia
p_d = deliverability standard pressure, psia
p_w = working wellhead pressure at rate q, psia
q = observed producing rate at end of 72 hours, Mscf/D
$q(t)$ = surface flow rate at time t, Mscf/D
$(q_{gi})_{max}$ = initial surface rate of flow from stabilized curve at p_w=0, Mscf/D
q_a = abandonment flow rate, Mscf/D
$q_{AOFP,c}$ = AOFP at the field $\bar{p}_{whs}$
r_e = external boundary radius, ft
r_w = wellbore radius, ft
s = skin factor, dimensionless
S_w = water saturation, fraction
t_a = time to abandonment rate, years
T = reservoir temperature, °R
z = gas compressibility factor, dimensionless
μ = viscosity, cp
ϕ = porosity, fraction of bulk volume

Subscripts

f = flowing
g = gas
i = initial
n = layer number
s = shut-in
wh = wellhead

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Appendix—Equation Summary

Rate/time equation:

$$q(t)=\frac{(q_{gi})_{\max}}{\left\{\left[\frac{(q_{gi})_{\max}}{G_i}\right]t+1\right\}^2} \quad \text{(A-1)}$$

Rate/time equation for four layers:

$$q(t)=\sum_{n=1}^{4}\frac{(q_{gi})_{\max}}{\left\{\left[\frac{(q_{gi})_{\max}}{G_i}\right]t+1\right\}^2} \quad \text{(A-2)}$$

$q_{\max}$ equation, pseudosteady state:

$$(q_{gi})_{\max}=\frac{kh\bar{p}^2}{1424\bar{\mu}\bar{z}T\left[\ln\left(\frac{0.472r_e}{r_w}\right)+s\right]} \quad \text{(A-3)}$$

Material-balance equations:

$$G_p/G_i=1-\left(\frac{p/z}{p_i/z_i}\right) \quad \text{(A-4)}$$

$$\text{and } G_p=\pi r_e^2 B_{gi}\sum_{n=1}^{4}\phi_n(1-S_{wn})\left(\frac{G_p}{G_i}\right)_n \quad \text{(A-5)}$$

Time to abandonment rate, q_a:

$$t_a=\frac{\sqrt{\frac{(q_{gi})_{\max}}{q_a}}-1}{\left[\frac{(q_{gi})_{\max}}{G_i}\right]} \quad \text{(A-6)}$$

Fractional recovery for each layer at abandonment:

$$(G_p/G_i)_a=1-\frac{1}{\left[\frac{(q_{gi})_{\max}}{G_i}\right]t_a+1} \quad \text{(A-7)}$$

SI Metric Conversion Factors

acre	× 4.046 873	E−01	=	ha
cp	× 1.0	E−03	=	Pa·s
ft	× 3.048*	E−01	=	m
ft³	× 2.831 685	E−02	=	m³
°R	°R/1.8		=	K
gal	× 3.785 412	E−03	=	m³
in.	× 2.54*	E+00	=	cm
lbm	× 4.535 924	E−01	=	kg
md	× 9.869 233	E−04	=	μm²
psi	× 6.894 757	E+00	=	kPa
sq.mile	× 2.589 988	E+00	=	km²

*Conversion factor is exact.

Provenance

Original SPE Manuscript, **Analysis of Kansas Hugoton Infill Drilling: Part II—12-Year Performance History of Five Replacement Wells** received for review Sept. 2, 1990. Revised manuscript received Aug. 30, 1991. Paper accepted for publication Jan. 17, 1992. Paper (SPE 20779) first presented at the 1990 SPE Annual Technical Conference and Exhibition held in New Orleans, Sept. 23-26.

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Wilcox Formation Evaluation: Improved Procedures for Tight-Gas-Sand Evaluation

D.J. Lewis, SPE, and **J.D. Perrin,** SPE, BP Exploration Inc.

Summary. Risks in tight-gas-sand evaluation are reduced by defining relationships between pore geometry and critical water saturations. These results are integrated with log interpretation to derive an estimated *kh* that compares favorably with a true *kh* from production tests. These procedures are potentially applicable for evaluating other complex reservoirs.

Introduction

Tight gas sands, such as those common in the Lower Wilcox formation of Texas, are routinely difficult to identify accurately as candidates for testing, completion, or abandonment. Several factors contribute to this difficulty.

1. Porosity and permeability are controlled by complex and variable diagenesis that leads to a poor correlation between porosity and permeability.
2. A dual-porosity system is present, where depositional and diagenetic clays, along with grain and cement dissolution, create isolated macro- and micropores that do not contribute to flow.
3. Pore-lining clays are present and variable, and although they can preserve porosity and permeability by limiting quartz overgrowths, they also can completely fill pore throats. Clay types and their positions within the pore structure are not quantifiable from log responses.
4. Critical water saturation is difficult to establish because the heterogeneity of rock types causes extreme variability in critical water saturations. This leads to some productive rock types having water saturations approximately equal to other rock types that are at residual gas saturation.
5. Wilcox formation water resistivity, R_w, frequently varies from zone to zone and is difficult to determine petrophysically, especially in wells with oil-based mud. Obtaining R_w from porosity logs is difficult because a 100% wet zone is seldom available for the calculation.
6. Completions are difficult and variable because the pore system is fragile and easily damaged by drilling and completion fluids.

Producing Behavior, Theory, and Definitions

Wilcox formation gas production is controlled primarily by the pore geometry and the amount of water present. This production behavior assumes no retrograde condensate dropout in the reservoir and is characterized by two main factors: increasing water saturation significantly decreases effective permeability and relative permeability behavior changes as a function of pore geometry.

Relative permeability behavior changes with the amount of water present in the producing pores. Multiple types of pore geometries can isolate water from main flow paths and reduce the amount of water available to flow.

Understanding the differences between laboratory-measured unstressed and stressed air permeabilities and the actual effective permeability of a reservoir fluid is key to distinguishing nonproductive from productive intervals. In tight-gas-sand formations, permeability must be measured at in-situ conditions, including elevated confining pressure, pore pressure, and water saturation.[1-4]

We define absolute permeability, k_K, as the gas permeability, k_g, of the dry rock ($S_{we}=0$) at in-situ effective stress conditions (overburden minus pore pressure). Effective permeability is the k_g at in-situ conditions. Relative permeability is the ratio of effective to absolute permeability.

Methodology

A comprehensive approach that addressed complex formation characteristics was required to improve evaluation of tight gas sands. To develop the procedures, we established commercial criteria, measured core properties, measured pore geometry from core and cuttings, developed a k_a estimator from pore geometry and a k_K estimator from k_a, defined k_g/k_K type curves, and developed a type-curve estimator from pore geometry.

First, we developed commercial production criteria by examining well production characteristics. The criteria were calculated from pressure buildup data and four-point production tests that provided the minimum *kh* required for both successful nonstimulated and stimulated completions.[5] Second, rock properties were measured from core plugs. We measured unstressed and stressed dry porosity and permeability, as well as mercury-injection capillary pressure and drainage non-steady-state pulse-decay permeability. We took thin-sections from each plug and used image analysis to collect pore geometry and compositional characteristics.

RATE-TIME EQUATION SUMMARY

Øivind Fevang
September 9, 1991
After
C.H. Whitson
May, 1991

DIMENSIONLESS VARIABLES

$$t_D = \frac{0.00634kt}{\varphi \mu c_{pss} r_{wa}^2}$$

$$r_{wa} = r_w e^{-s}$$

$$c_{pss} \equiv \frac{Q_i/Q}{p_i - p_{wf}}(1-b)$$

Oil: $$q_D = \frac{141.2\mu_o B_o}{kh(p_i - p_{wf})} q_o$$

General Gas: $$q_D = \frac{T}{0.703kh(m(p_i) - m(p_{wf}))} q_g$$

Low-Pressure Gas: $$q_D = \frac{\mu Z T}{0.703kh(p_i^2 - p_{wf}^2)} q_g$$

$$m(p) = 2\int_{p_o}^{p} \frac{p}{\mu Z} dp$$

$$Q_D = \int_0^{t_D} q_D dt_D$$

$$Q_D = \left(\frac{q_D}{q}\right)\left(\frac{t_D}{t}\right) Q_p \quad ; \quad Q_p = N_p \text{ or } G_p$$

$$\frac{Q_i}{Q} = \frac{N_i}{N} = \frac{G_i}{G} = \text{Ultimate Recovery} = c_{pss}(p_i - p_{wf})$$

PSEUDOSTEADY STATE CONSTANTS A & B

Fetkovich:

$$A = \frac{1}{\ln(\frac{r_e}{r_{wa}}) - 0.5}$$

$$B = \frac{2A}{(\frac{r_e}{r_{wa}})^2 - 1}$$

Golan-Whitson:

$$A = \frac{1}{\ln(\frac{r_e}{r_{wa}}) - 0.75 + 0.736(\frac{r_e}{r_{wa}})^{-0.644}}$$

$$B = \frac{2}{(\frac{r_e}{r_{wa}})^2 \left[\ln(\frac{r_e}{r_{wa}}) - 0.75 + 0.66(\frac{r_e}{r_{wa}})^{-1}\right]}$$

DIMENSIONLESS TIME TO PSEUDOSTEADY STATE

Standard Definition:

$$t_{Dpss} = 0.1\pi(\frac{r_e}{r_{wa}})^2$$

Golan-Whitson:

$$t_{Dpss} = 0.177(\frac{r_e}{r_{wa}})^2 - 0.234(\frac{r_e}{r_{wa}})$$

INFINITE-ACTING DIMENSIONLESS RATE

Edwardson, et al.

$t_D < 200$:

$$q_D = \frac{26.7544 + 43.5537\sqrt{t_D} + 13.3813 t_D + 0.492949 t_D^{1.5}}{47.4210\sqrt{t_D} + 35.5372 t_D + 2.60967 t_D^{1.5}}$$

$t_D \geq 200$:

$$q_D = \frac{3.90086 + 2.02623 t_D (\ln t_D - 1)}{t_D (\ln t_D)^2}$$

INFINITE-ACTING DIMENSIONLESS CUMULATIVE

Edwardson, et al.

$t_D < 200$:

$$Q_D = \frac{1.12838\sqrt{t_D} + 1.19328 t_D + 0.269872 t_D^{1.5} + 0.00855294 t_D^2}{1 + 0.616599\sqrt{t_D} + 0.0413008 t_D}$$

$t_D \geq 200$:

$$Q_D = \frac{-4.29881 + 2.02566 t_D}{\ln t_D}$$

PSEUDOSTEADY STATE DIMENSIONLESS RATE

Arps

Exponential (b=0): $q_D = Ae^{-Bt_D}$

Hyperbolic (0<b<1): $q_D = \dfrac{A}{(1+bBt_D)^{1/b}}$

Harmonic (b=1): $q_D = \dfrac{A}{1+Bt_D}$

PSEUDOSTEADY STATE DIMENSIONLESS CUMULATIVES

Arps

Exponential:

$$Q_D = \frac{A}{B}(1-e^{-Bt_D})$$

$$Q_{Di} = \frac{A}{B} = 0.5[(r_e/r_{wa})^2-1] \quad \text{as } t\rightarrow\infty \text{ and } q\rightarrow 0$$

Hyperbolic:

$$Q_D = \frac{A}{B(1-b)}\left[1-(bBt_D+1)^{1-1/b}\right]$$

$$Q_{Di} = \frac{A}{B(1-b)} = \frac{0.5[(r_e/r_{wa})^2-1]}{1-b} \quad \text{as } t\rightarrow\infty \text{ and } q\rightarrow 0$$

ORIGINAL ARPS PSEUDOSTEADY STATE RATE EQUATIONS

Exponential (b=0): $q = q_i e^{-D_i t}$

Hyperbolic (0<b<1): $q = \dfrac{q_i}{(1+bD_i t)^{1/b}}$

Harmonic (b=1): $q = \dfrac{q_i}{(1+D_i t)}$

$$D_i = \frac{q_i}{Q_i}\frac{1}{(1-b)} \quad ; \quad Q_i = N_i \text{ or } G_i$$

ORIGINAL ARPS PSEUDOSTEADY STATE CUMULATIVE EQUATIONS

Arps

Exponential:

$$Q_p = N_p \text{ or } G_p = \frac{q_i}{D_i}(1-e^{-D_i t})$$

Hyperbolic:

$$Q_p = N_p \text{ or } G_p = \frac{q_i}{D_i(1-b)}[1-(D_i bt+1)^{(1-1/b)}]$$

FETKOVICH PSEUDOSTEADY STATE UNIT DIMENSIONLESS RATE

Exponential (b=0): $q_{Dd} = e^{-t_{Dd}}$

Hyperbolic (0<b<1): $q_{Dd} = \dfrac{1}{(1+bt_{Dd})^{1/b}}$

Harmonic (b=1): $q_{Dd} = \dfrac{1}{1+t_{Dd}}$

$$q_{Dd} = \frac{q_D}{A} = \frac{q}{q_i}$$

$$t_{Dd} = Bt_D = D_i t$$

FETKOVICH PSEUDOSTEADY STATE UNIT DIMENSIONLESS CUMULATIVES

Exponential:

$$Q_{Dd} = 1 - e^{-t_{Dd}}$$

$$Q_{Ddi} = 1 \quad \text{as } t \to \infty \text{ and } q \to 0$$

Hyperbolic:

$$Q_{Dd} = \frac{1}{1-b}\left[1-(bt_{Dd}+1)^{(1-1/b)}\right]$$

$$Q_{Ddi} = \frac{1}{1-b} \quad \text{as } t \to \infty \text{ and } q \to 0$$

$$Q_{Dd} = \int_0^{t_{Dd}} q_{Dd}\, dt_{Dd}$$

$$Q_{Dd} = \frac{B}{A} Q_D = \left(\frac{B}{A}\right)\left(\frac{q_D}{q}\right)\left(\frac{t_D}{t} Q_p\right)$$

$$Q_{Dd} = \frac{Q_p}{q_i} D_i$$

where $Q_p = N_p$ or G_p

ARPS PSEUDOSTEADY STATE CONSTANTS q_i & D_i

$$\underline{\text{General}}: \; q_i = \frac{q}{q_D} A$$

$$\underline{\text{Oil}}: \; q_{oi} = \frac{kh(p_i - p_{wf})}{141.2 \mu_o B_o} A$$

$$\underline{\text{General Gas}}: \; q_{gi} = \frac{0.703 kh \left[m(p_i) - m(p_{wf}) \right]}{T} A$$

$$\underline{\text{Low-Pressure Gas}}: \; q_{gi} = \frac{0.703 kh (p_i^2 - p_{wf}^2)}{T \mu_g Z} A$$

$$D_i = \frac{0.00634 k}{\phi \mu_i c_{ti} r_{wa}^2} B = \frac{t_D}{t} B$$

or

$$D_i = \frac{1}{(1-b)} \left(\frac{q_i}{Q_i} \right) = \frac{1}{(1-b)} \left(\frac{q_{oi}}{N_i} \right) = \frac{1}{(1-b)} \left(\frac{q_i}{G_i} \right)$$

effective

INSTANTANEOUS DECLINE CONSTANT d_i

$$d_i \equiv \left|\frac{d\ln q}{dt}\right| = \text{slope on semilog plot}$$

$$d_i = \frac{D_i}{1+bD_it} = d_i(t) \quad \text{for } b>0$$

$$d_i = D_i \text{ for } b=0$$

PERCENTAGE DECLINE CONSTANT $d_{\%}$

$$d_{\%} \equiv 100\frac{(q_1-q_2)}{q_1}\frac{1}{(t_2-t_1)}$$

$$\text{With } q = q_i e^{-D_it} \;;\; \frac{q_2}{q_1} = e^{-D_i(t_2-t_1)}$$

$$\text{then } d_{\%} = \frac{100}{t_2-t_1}(1-e^{-D_i(t_2-t_1)})$$

$$\text{but } e^{\varepsilon} \approx 1+\varepsilon$$

$$\text{so } d_{\%} \approx \frac{100}{t_2-t_1}(1-(1-D_i(t_2-t_1))$$

$$d_{\%} \approx 100D_i \text{ for } b=0$$

$$d_{\%} \approx 100d_i \text{ for } b>0$$

NOMENCLATURE

A = constant in dimensionless rate equation
b = Arps decline exponent
B = constant in dimensionless rate equation
B_o = oil formation volume factor, bbl/STB
c_t = effective total compressibility, 1/psi
= $c_f+c_{wi}S_w+c_{gi}S_g+c_{oi}S_o$ for infinite-acting (same as in well test analysis);
= cumulative total compressibility from material balance for pseudosteady state
d_i = slope of semilog rate-time plot, cycle/day
$d_{\%}$ = percentage decline rate, percentage
D_i = Arps decline time constant, 1/day
h = net pay thickness, ft
k = permeability, md
$m(p)$ = gas pseudopressure function, $psia^2/cp$
p_i = initial (average) reservoir pressure at start of decline, psia
p_{wf} = constant wellbore flowing pressure, psia
p_R = average reservoir pressure at any time after start of decline, psia
q = rate, q_o(STB/D) or q_g(scf/D)
q_i = initial pseudosteady state rate at start of decline, q_{oi}(STB/D) or q_{gi}(scf/D)
q_D = dimensionless rate
q_{Dd} = unit dimensionless rate
Q = initial hydrocarbon in place, N(STB) or G(scf)
Q_p = cumulative produced hydrocarbon, N_p(STB) or G_p(scf)
Q_i = initial producible hydrocarbon from start of decline, N_i(STB) or G_i(scf)
Q_D = dimensionless cumulative hydrocarbon produced
Q_{Di} = initial dimensionless producible hydrocarbon from start of decline
Q_{Dd} = unit dimensionless cumulative hydrocarbon produced
Q_{Ddi} = initial unit dimensionless producible hydrocarbon from start of decline
r_e = outer ("external") drainage radius, ft
r_w = actual wellbore radius, ft
r_{wa} = apparent wellbore radius (same as r_w'), $r_{wa}=f(r_w,s)$, ft

Nomenclature (continued)

t = time, days
t_D = dimensionless time
t_{Dd} = unit dimensionless time
T = reservoir temperature, °R
Z_g = gas compressibility factor

ϕ = porosity, fraction
μ = viscosity, cp

Subscripts
i = initial from start of decline
pss = pseudosteady state

MAY 14, 1993

TANANGER

TO: MIKE VIENOT FAX NO. 04 69 11 24

RE: RESERVOIR COURSE - STAVANGER, MIKE FETKOVIC

FIRST: WOULD BE AN ~~GOOD~~ EXCELLENT IDEA TO VIDEO TAPE IT.
ITS ONE OF FORD GRIGGS objectives ~~WANTS IT DONE ANY WAY~~!!!

COURSE CONTENT

DAY 1. FULL DAY ON RATE TIME DECLINE

- HISTORICAL BACKGROUND OF RATE-TIME ANALYSIS.
- GAS WELL RATE-TIME, Cum-Time and Rate Cum ~~DERIVED~~ EQUATIO IDENTICAL IN FORM to Arps equations. Results in physical meaning for q_i, D_i and exponent b. Can all be calculated rigorously without any rate time performance data at all.

- As above except now for oil wells.
- Concept that b value reflects reservoir drive or recovery efficiency.
- Development of the Fetkovich Type Curve and the concepts of superpositio
- Field Examples with detailed discussion of each.

DAY 2. FULL DAY ON DEPLETION PERFORMANCE of Layered Reservoirs Without Crossflow.

- Red Cave Field Rate Time Performance Producing at a Constant Wellbore Pressure
- Oklahoma Hugoton Field Model Study of Layered Non-Crossflow Reservoir Producing at a Constant Rate. History Match and Predictio

• End of Day 2. Pass out SPE Papers to Read for next day on layered performance behavior.

Day 3. How to Identify Layered No-Crossflow Reservoirs from Historical Performance Data.

- Geological Considerations that imply Layered No-Crossflow Reservoir Behavior
- Discuss Papers read the previous evening on layered behaviour.
- Work example problem(s).
  1) Gas Well Problem
  2) Oil Well Problem with Infill Drilling

10/28/91

SGR One-Day Short Course Attendees List
DAY ONE - October 29, 1991

1. Arco Oil and Gas
Mr. M. J. Tarrillion
P.O. Box 1346
Houston, TX 77251

2. Arco Oil and Gas
Mr. Greg Ernster
P.O. Box 1346
Houston, TX 77251

3. Arkla Exploration
Mr. Floyd D. Hamm
5100 Westheimer, Suite 400
Houston, TX 77056

4. Arkla Exploration Company
Mr. Orville R. Berg
P.O. Box 21734
Shreveport, LA 71151

5. Baird Petrophysical International, Inc.
Mr. Ralph W. Baird
1784 W. Sam Houston Pkwy. N.
Houston, TX 77043

6. Banner Petroleum
Mr. Floyd Adcock
3000 Post Oak Blvd., Suite 1600
Houston, TX 77056

7. Bass Enterprises Production Company
Mr. Larry Wilson Hoover
201 Main Street, Suite 2900
Fort Worth, TX 76102

8. Buttes Resources Company
Mr. Ed Van Dike
3040 Post Oak Blvd., Suite 300
Houston, TX 77056-6509

9. Chevron U.S.A., Inc.
Mr. B. R. Koehler
P.O. Box 36366
Houston, TX 77236

10. Chevron U.S.A., Inc.
Mr. M. C. Caraballo
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11. Chevron USA
Ms. Kathleen Castillo
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Houston, TX 77236

12. Consultant
Mr. John Farina
3214 Spring Gardens
Springwood, TX 77339

13. Core Laboratories
Mr. Robert Y. Fu
5295 Hollister Rd.
Houston, TX 77040

14. Department of Energy/METC
Mr. Hugh Guthrie
P.O. Box 880
Morgantown, WV 26507-0880

15. Energy Development Corporation
Mr. Ian Smith
1000 Louisiana, Suite 2900
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16. Enron Oil & Gas
Mr. Larry D. Vinson
1400 Smith, EB 2039
Houston, TX 77002

17. Exxon Co., USA
Mr. Wesley W. Diehl
Greenspoint 3, 233 Benmar
Houston, TX 77060

18. Exxon Company U.S.A.
Onshore Exploration Division
Mr. G. J. Moir
P.O. Box 4778
Houston, TX 77210-4778

10/28/91

SGR One-Day Short Course Attendees List
DAY ONE - October 29, 1991

19. Gas Research Institute
Dr. Myron Gottlieb
8600 West Bryn Mawr Avenue
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20. IHRDC
Dr. M. A. (Al) Rogers
10777 Westheimer, Suite 1080
Houston, TX 77042

21. Inland Gas Corporation
Mr. Nick Snyder
1770 St. James Place
Houston, TX 77056

22. JFS Production Co., Inc.
Mr. John F. Simpson
4515 Bryn Mawr Lane
Houston, TX 77027

23. Kerr McGee Corporation
Mr. Aaron Reyna
P.O. Box 25861
Oklahoma City, OK 73125

24. Marathon Oil Co.
Mr. Richard D. Rosencrans
P.O. Box 3128
Houston, TX 77253

25. McKenzie Petroleum Company
Mr. R. Bonner Sears
7880 San Felipe Road, Suite 100
Houston, TX 77063

26. Nomeco Oil & Gas Company
Mr. Stan Idziak
P.O. Box 1150
Jackson, MI 49204

27. Oil and Gas Journal
Mr. A. D. Koen
3050 Post Oak Blvd., Suite 200
Houston, TX 77056

28. Oryx Energy Co.
Mr. Michael L. Elliott
P.O. Box 830936
Richardson, TX 75083-0936

29. Oryx Energy Co.
Mr. Robert A. Skopec
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30. Oxy USA
Mr. Jack Klotz
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Midland, TX 79710

31. Pennzoil Exploration and Production Co.
Mr. Barney Gary
Pennzoil Place, P.O. Box 2967
Houston, TX 77252-2967

32. Pennzoil Exploration and Production Co.
Mr. Perry Lawrence
Pennzoil Place, P.O. Box 2967
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33. Phillips Petroleum
Mr. Michael Lamar
P.O. Box 1967
Houston, TX 77251-1967

34. Phillips Petroleum
Mr. Eric A. Weiss
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Houston, TX 77251-1967

35. Phillips Petroleum
Mr. Gary M. Guerrieri
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Houston, TX 77251-1967

36. Phillips Petroleum
Mr. Paul Robertson
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37. Preston Oil Company
Mr. Scott Laurent
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SGR One-Day Short Course Attendees List
DAY ONE - October 29, 1991

38. Preston Oil Company
Mr. Joe Eubanks
1717 Woodstead Court
The Woodlands, TX 77387

39. Rio Petroleum, Inc.
Mr. Barrett W. Pierce
2805 West 15 Street
Amarillo, TX 79102

40. Schlumberger
Mr. Thomas H. Fett
370 Lantana
Corpus Christi, TX 78408

41. Schlumberger
Mr. Jim Tucker
5005 Mitchelldale, Suite 280
Houston, TX 77092

42. Tenneco Gas
Mr. Joseph J. Hocker
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Houston, TX 77252-2511

43. Tenneco Gas
Mr. G. Mike Morgan
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44. Texaco
Mr. Andrew R. Thomas
3901 Briarpark
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45. Texaco
Mr. William R. Almon
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46. Texaco Inc., E&P Technology Dept.
Ms. Janet B. Thornburg
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47. Texas Crude
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48. Union Pacific Resources
Mr. Mark A. Conrad
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Fort Worth, TX 76132

49. Walter Exploration, Inc.
Mr. Brian Walter
6116 N. Central Exp., #313
Dallas, TX 75206

10/28/91

SGR One-Day Short Course Attendees List
DAY TWO - October 30, 1991

1. Arco Oil & Gas Co.
Mr. Steve Earle
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Houston, TX 77079

2. Arco Oil & Gas Co.
Mr. Gary Lenz
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Houston, TX 77079

3. Bar-Mac
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Brenham, TX 77833

4. Bar-Mac
Mr. Ross Mocyzgemba
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Brenham, TX 77833

5. Chevron
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6. Choctaw II Oil & Gas, Ltd.
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7. Conoco
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8. Consultant
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10. Cox & Perkins Exploration, Inc.
Mr. Mark A. West
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Houston, TX 77057

11. Cox & Perkins Exploration, Inc.
Mr. Mark D. McCuen
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12. CXY Energy, Inc.
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13. Enron
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Houston, TX 77251-1188

14. EST
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15. Gas Research Inst.
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16. Gas Research Institute
Mr. Harvey Haines
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17. Gas Research Institute
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18. Halliburton Geophysical Services
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19. Halliburton Reservoir Services
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20. J. M. Huber Corp.
Mr. Don Lanman
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SGR One-Day Short Course Attendees List
DAY TWO - October 30, 1991

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22. Oryx Energy Company
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23. Phillips Petroleum
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24. Phillips Petroleum
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Bellaire, TX 77401-2901

25. Phillips Petroleum
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29. Plains Petroleum Company
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30. Plains Resources
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31. Quintana Petroleum Corp.
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32. Rose Energy Corporation
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33. Shell
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34. Shell Western E&P, Inc.
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35. Shell Western E&P, Inc.
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P.O. Box 576
Houston, TX 77079

36. Shell Western E&P, Inc.
Mr. Chandler T. Wilhelm
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37. Southwest Research Inst.
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38. Swift Energy
Mr. Julian Chahin
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39. Tenneco Gas-Houston
Mr. Kyle Sawyer
1010 Milam, Suite 2453A
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40. Tenneco Gas-Houston
Mr. Dennis Dutton
1010 Milam, Suite 2405A
Houston, TX 77002

SGR One-Day Short Course Attendees List
DAY TWO - October 30, 1991

41. Tenneco Gas-Houston
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42. Texaco, Inc.
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43. Transco Energy
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44. Union Pacific Resources
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45. Union Pacific Resources Co.
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46. Union Pacific Resources Co.
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47. Unocal
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48. Virginia Indonesia Co.
Mr. Gary A. Bajgier
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49. Wilcox Oil and Gas Co.
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Americana Bldg., 811 Dallas, Suite 927
Houston, TX 77002

50. Wilcox Oil and Gas, Inc.
Mr. Mitchell Anderson
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51. Willrich Oil & Gas Corporation
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Reservoir Pressure Data Used To Justify Infill Drilling in a Low Permeability Reservoir

Elbert F. Davis, SPE-AIME, Continental Oil Co.
James C. Shepler, SPE-AIME, Continental Oil Co.

Introduction

Engineers and conservation officials in the various oil and gas producing states have been concerned for some time with the efficient development of our oil and gas resources through optimum well spacing. Usually this concern has centered on justifying wider spacing than is authorized by the various state oil and gas regulatory agencies. Surely each reader of this paper knows of a field, or fields, where engineers, through the presentation of sound engineering principles and data, have succeeded in obtaining wider spacing rules to develop oil and gas reservoirs more efficiently and economically and to make maximum profits. In recent years the case for wider spacing has been recognized by most regulatory agencies; for example, in Texas in 1965, the Statewide Spacing Rule for oil wells was changed from 20 acres to 40 acres. In general, this has been a wise decision; however, it is still the responsibility of the engineer to evaluate each developing field to determine the optimum spacing for that field.

The Sacatosa (San Miguel-1 sand) field, which initially was developed on 40-acre spacing, represents a case in which infill drilling on 20-acre spacing was justified by the use of reservoir pressure data. Development of the Sacatosa field has generated considerable interest, particularly in Southwest Texas, not only because of its size, but also because of the challenge it has presented to the engineering and production people to extract efficiently and economically the petroleum hydrocarbons from this shallow, low-permeability oil reservoir.

Location and Geology

The Sacatosa (San Miguel-1 sand) field, henceforth referred to as the Sacatosa field, is in Maverick County in Southwest Texas and is approximately 20 miles from the Rio Grande River or Mexican border (Fig. 1). Locally the field is more generally known as the Chittim field, because most of the San Miguel-1 sand, development is on Continental Oil Co.'s lease on the N. J. Chittim ranch.

Fig. 2 is a structure map of the San Miguel-1 sand, which shows that the formation dip is to the southeast and varies from 140 to 200 ft/mile. Minor faulting occurs in the field with the fault traversing Sec. 42, providing closure for a small, isolated gas cap around Well 42-7.

Although not shown in Fig. 2, the San Miguel-1 sand pinches out updip against the Chittim arch, thereby forming a stratigraphic trap for the accumulation of oil. The present productive limits of the Sacatosa field are defined by an oil-water contact on the east and southeast, or downdip, side of the field and by permeability and sand thickness that decrease on all other sides of the field.

Geologically, the San Miguel-1 sand is generally considered a member of the Upper Taylor formation in the Gulf Series of the Cretaceous system of Mesozoic Age.

The initial development spacing for a field may or may not be the optimum spacing, depending upon the reservoir and producing characteristics and upon the development economics of that particular field. Reservoir pressure data can be helpful in determining the best pattern.

Reservoir Characteristics

The San Miguel-1 sand reservoir acts as an initially saturated, solution-gas-drive reservoir, whose original bubble-point pressure was equal to the original formation pressure. Although an oil-water contact exists on the east (or downdip) side of the reservoir, the aquifer is inactive for all practical purposes.

The average porosity of the San Miguel-1 sand is approximately 24 percent and the average horizontal air permeability is approximately 3.6 md. However, production characteristics and computer matching indicate the average oil permeability to be about 0.4 to 0.5 md (Table 1). Although shallow, with completions varying from 1,140 to 1,775 ft, this reservoir does not produce a low gravity crude oil. The gravity of oil through the LACT unit averages 37.2° API. Figs. 3 and 4 graphically show other oil and gas data for this reservoir.

Initial Development History

After preliminary exploratory work the initial drilling took place in the spring of 1956, when 14 stratigraphic test holes were drilled on the Chittim lease. Four of these stratigraphic tests helped define the San Miguel-1 sand reservoir, which at that time was not considered to have any commercial significance.

On Dec. 5, 1956, the discovery well, Chittim No. 37-6 (Fig. 2), was completed by setting casing on top of the San Miguel-1 sand, under-reaming the open-hole section, and gravel packing. The initial production test was 4 BOPD by pump. In Aug., 1958, the well was shot with 150 qt nitroglycerin, resulting in an 8-BOPD well. This first San Miguel-1 sand producer certainly could not be considered exciting, but as a matter of interest, Well 37-6 is still producing 4 to 5 BOPD, with a cumulative production of 18,500 bbl of oil as of June 1, 1968.

In May and June, 1957, two more wells, Nos. 37-10 and 37-11 (east and south offsets to Well 37-6) were completed in the San Miguel-1 sand by single plane perforating and fracturing. The initial potentials of these two wells, after recovery of load oil, were 58 BOPD and 60 BOPD, flowing. The apparent success of these two wells was very encouraging, but development proceeded cautiously, with over a year's observation time elapsing before additional wells were drilled. Then, between Nov., 1958, and March, 1959, six wells were drilled across the field for areal evaluation of the reservoir (Fig. 2). All were successful completions except Well 100-1, which encountered a very poor San Miguel-1 sand section caused by a serpentine plug intrusion.

Based on the reservoir and production data obtained from the drilling and completion of these first nine wells, full-scale development of the field on 40-acre spacing began in the fall of 1959, and continued until mid-1961. At the conclusion of 40-acre development, we had drilled 279 wells in the field and had developed approximately 11,000 productive acres. Although various completion techniques were evaluated in the field, the standard completion was to single-plane perforate and to fracture with 60,000 gal lease crude containing 90,000 lb sand.

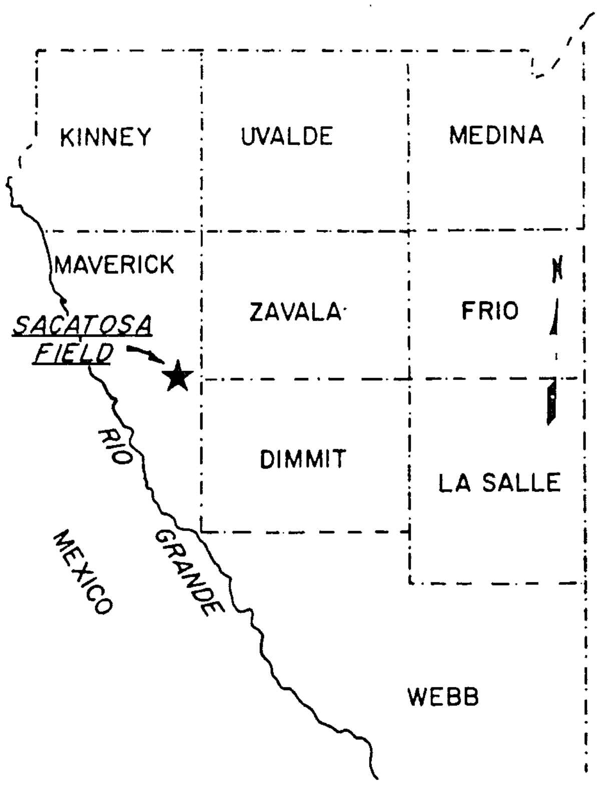

Fig. 1—Location map of Sacatosa field, Maverick County, Tex.

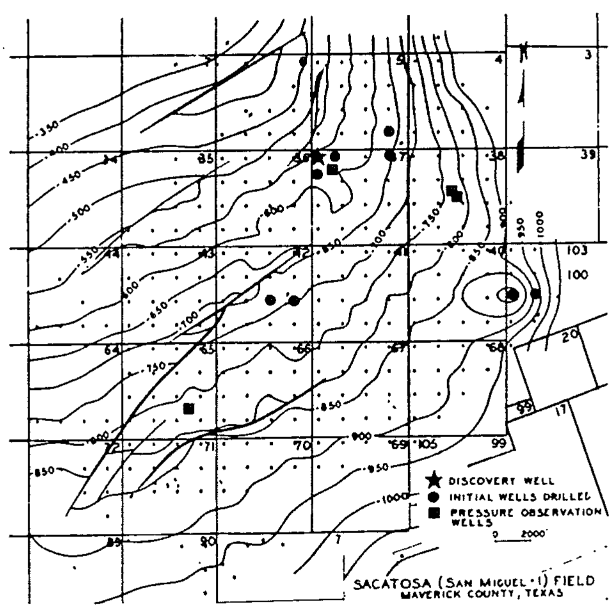

Fig. 2—Sacatosa field after 40-acre development.

Included in this well total are four pressure observation wells, illustrated in Fig. 2. Three of these wells were drilled on 20-acre spacing. These were perforated, but not fractured, swabbed down to create a differential pressure into the wellbore, and then shut in. The 5-acre pressure observation well, located midway between a producing well and a 20-acre pressure observation well, was completed the same way in June, 1963. These pressure observation wells were continuously monitored to detect any pressure decline associated with depletion of the reservoir on 40-acre spacing.

Fig. 5 shows a typical open-hole electric log, which in this case is for Well 37-7. The top of the San Miguel-1 sand is at 1,370 ft. The well was single-plane perforated at 1,388 ft and fractured with 52,000 gal lease crude containing 90,000 lb of 20-40 mesh sand. After recovery of load oil, the well flowed at a rate of 62 BOPD.

Fig. 6 shows the production decline curve for this same Well 37-7, which is typical for wells in the field. At the present time Well 37-7 is producing 10 to 12 BOPD and has a cumulative production of over 38,000 bbl of oil.

Further Evaluation

After the initial field development ceased, we continued to collect data on the behavior of the four pressure observation wells, on pressure buildup and drawdown tests, and on production and well tests. We also obtained additional research reports on reservoir rock and fluid properties.

TABLE 1—COMPUTER CALCULATED OIL PERMEABILITIES AND RESULTS OF MATCHING CALCULATIONS

Section	k_o (md)	h (ft)	kh (md-ft)
4	0.26	24	6.24
5	0.36	20	7.20
6	0.032	20	0.64
35	0.028	20	0.56
36	0.56	21	11.76
37	0.725	24	17.40
38	0.56	24	13.44
40	0.335	28	9.38
41	0.41	23	9.43
42	0.60	22	13.20
43	0.27	22	5.94
64	0.20	12	2.40
65	0.40	16	6.40
66	0.20	20	4.00
67	0.23	26	5.98
68	0.35	28	9.80
69	0.13	25	3.25
70	0.125	20	2.50
71	0.17	16	2.72
72	0.22	13	2.86
100	1.05	24	25.20

k_o = absolute permeability to oil at 45 percent water saturation and zero gas saturation

ϕ = 24 percent

B_o = 1.1135 to 1.1332 depending upon depth and pressure

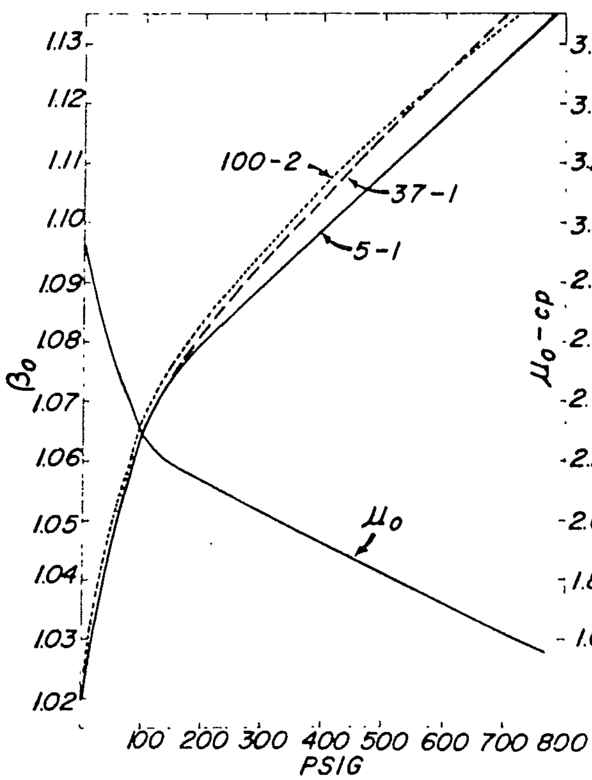

Fig. 3—Reservoir fluid properties (oil).

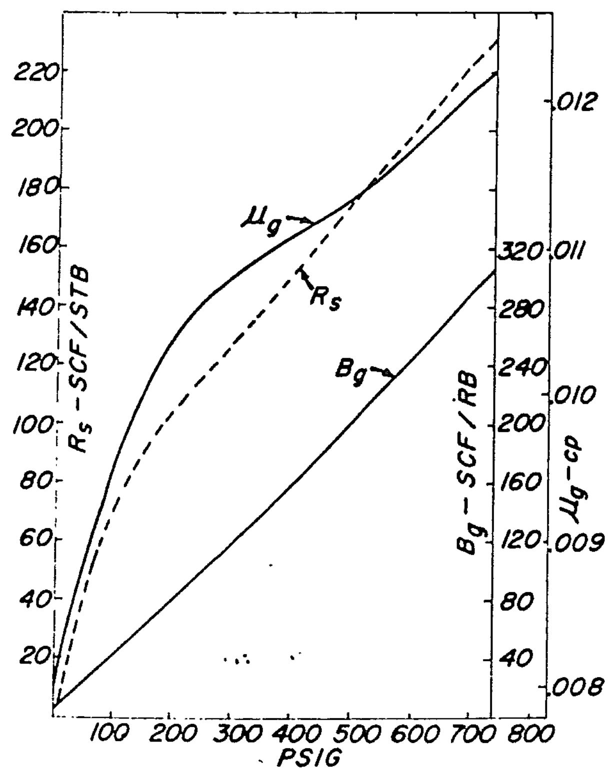

Fig. 4—Reservoir fluid properties (gas).

around the well. Reservoir fluid properties (B_o, B_g, u_o, u_g, R_s) are assumed to be a function of pressure in the model, and relative oil and gas permeabilities are included as a function of total liquid saturation. Reservoir properties of thickness, porosity and water saturation are constant in each computer run. Several computer runs were made varying the formation permeability, fracture length and fracture permeability until a match was obtained between the field buildup and drawdown data, and production performance.

To see an example of matched performance, refer to Fig. 8, which shows the computer predicted pressure performance of pressure observation Well 37-17 as a dashed line, and the actual measured pressure performance as a solid line. It can be seen that good agreement was obtained between the predicted and actual performance.

Fig. 9 shows two curves. The upper curve is the calculated pressure distribution curve from producing Well 38-4, through pressure observation Well 38-18, located 467 ft from Well 38-4, and then to pressure observation Well 38-17, located 933 ft from Well 38-4. On the basis of the measured pressures in the three wells, we assumed that this calculated curve matched reservoir distributions in this entire area. Note that the point of the measured bottom-hole pressure in Well 38-18 lies practically on the calculated curve, while the point of the measured bottom-hole pressure in Well 38-17 lies a little below the calculated curve.

The lower curve is a volume curve related to radial distance away from producing Well 38-4. By relating the two curves, we can see that 86.5 percent of the pressure drop occurs at a distance of 467 ft from the producing wellbore, but includes only 25 percent of the actual volume out to a 20-acre location 933 ft away. These curves were for conditions as they existed in March, 1964, when Well 38-4 was producing at a rate of 11 BOPD and had produced 21,876 bbl of oil.

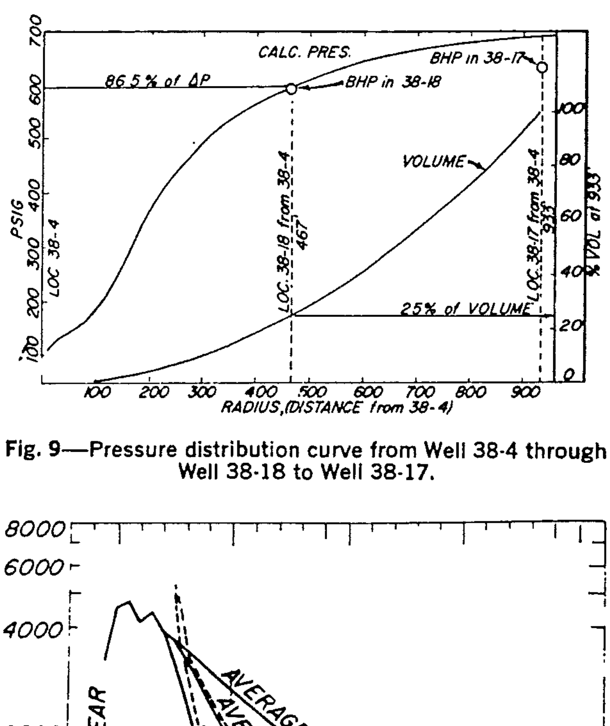

Fig. 9—Pressure distribution curve from Well 38-4 through Well 38-18 to Well 38-17.

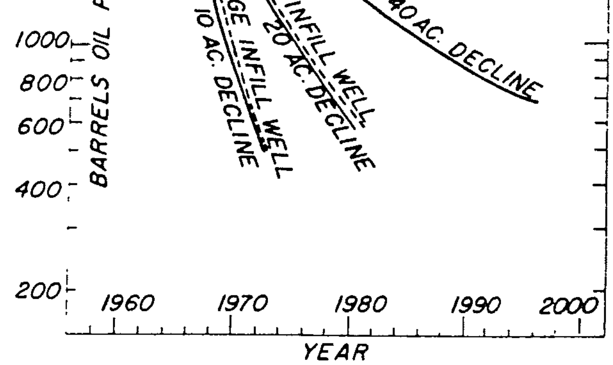

Fig. 10—Predicted well performance for an average well in Sec. 37 for 40-, 20- and 10-acre development.

The entire production matching and subsequent production predictions were based on the concept of an average well per section (except for four irregular-shaped sections on the east side of the field). For example, the uppermost solid curve in Fig. 10 represents the past performance of an average 40-acre well in Sec. 37, which was matched, and then predicts its future producing rate. The middle dashed curve represents the predicted performance of a new well drilled on 20-acre spacing, and the middle solid curve represents the new, or changed, performance of the original 40-acre well due to production from the new 20-acre well. The lowest set of curves represents, in the same manner, a new 10-acre well and the changed performance of the original well.

After a similar set of average well performance curves had been obtained for each section of the field, it became a simple matter of multiplying each average well performance curve by the number of wells per section to predict section performance. An economic evaluation was then made, by sections, for each development program (40-acre, 20-acre and 10-acre well spacing). It became immediately apparent that the combination of accelerated production rate and increased recovery from development on 10-acre spacing, when compared with 20-acre development, was not economically feasible, so further investigation was confined to evaluating infill drilling and development on 20-acre spacing.

The economic analysis of infill drilling on 20-acre spacing indicated that at least 12 sections of the field should be developed on this closer spacing. However, before making the large investment required to infill drill, we decided to drill eight 20-acre wells across the field to check further the reservoir pressure (Fig. 11). (Five stepout wells drilled at this same time are also shown in this figure.)

Each of these eight wells was perforated, but not fractured, swabbed down to create a differential pressure towards the wellbore, and then shut in to determine the reservoir pressure at that particular 20-acre location. Fig. 12 shows the predicted and actual pressures obtained on three of these wells. The predicted pressures and the measured, stabilized pressures are

in close agreement. Similar results also were obtained on the other five wells, indicating that original, or near-original, pressures could be expected at newly drilled 20-acre locations.

After these eight 20-acre wells had served their usefulness as pressure data wells, they were fractured and placed on production to compare their actual productivities with the predicted performance of average, new, 20-acre wells. Fig. 13 is a plot of BOPD vs cumulative production for one of these wells, No. 37-18. The dashed line is the predicted-production performance curve, and the solid line is the actual production, flowing and then pumping, from May, 1965, to June, 1968. Actual production compares favorably with the predicted production rate. It should be pointed out that at the time this curve was used to help prove reliability of the prediction method, only that portion of the curve to approximately 5,000 bbl cumulative production was available. However, it was considered sufficient to show that actual production was as good as, or better than, that which had been predicted and used in the economic evaluation. For comparison, similar curves were prepared for the other 20-acre wells that were produced, and

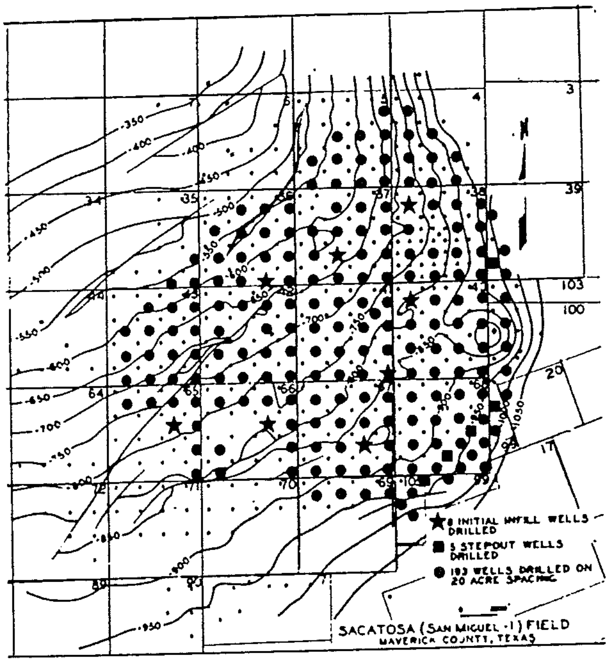

Fig. 11—Sacatosa field after 20-acre development.

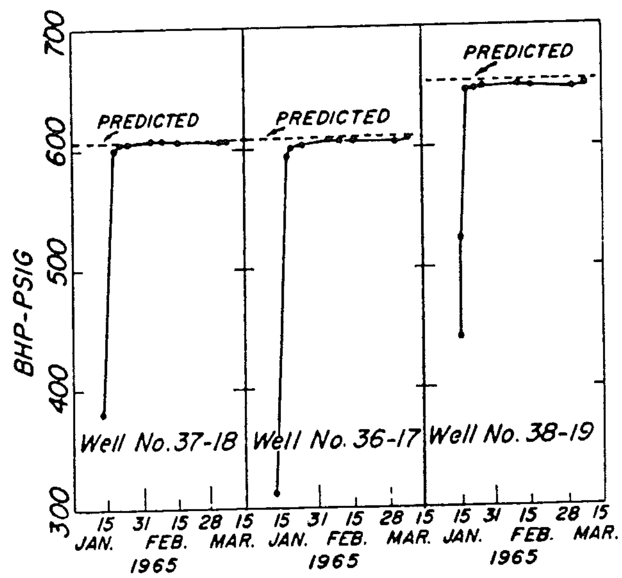

Fig. 12—Predicted and actual initial bottom-hole pressures in 20-acre Wells 36-17, 37-18 and 38-19.

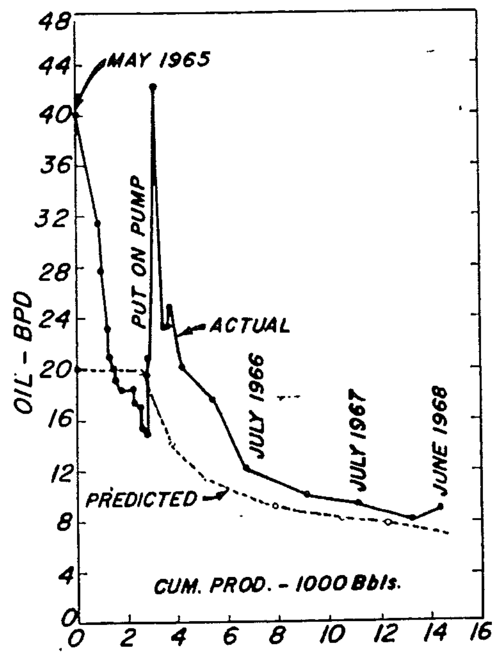

Fig. 13—Predicted and actual production performance of Chittim No. 37-18.

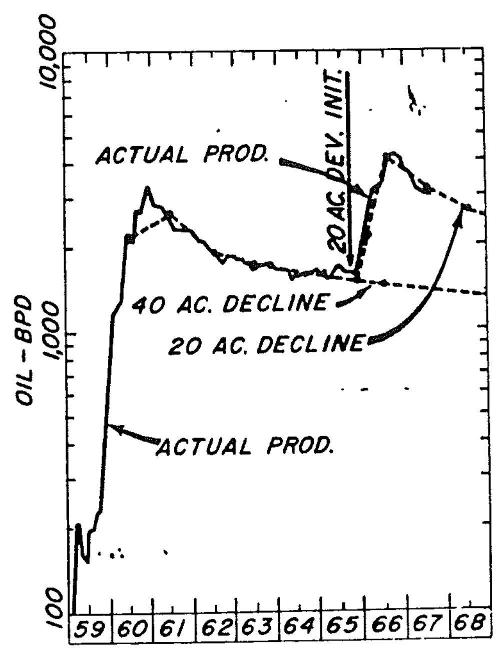

Fig. 14—Predicted and actual production performance of the Sacatosa field on 40- and 20-acre development.

all showed favorable matches between actual and predicted production rates.

On the basis of this additional pressure and production data showing that the predictive method was essentially correct, management approved the development of the major portion of the field on 20-acre spacing. Development drilling was commenced on Oct. 6, 1965, and when it was completed on Nov. 1, 1966, an additional 193 wells had been drilled. Part of this drilling was step-out drilling on the southeast flank of the field, where one dry hole was drilled (Well 99-2). The three original pressure observation wells (Nos. 37-17, 38-17 and 65-17), having served their purpose, were also converted to producers. The total field development at this time can be seen in Fig. 11.

Total field performance can be seen in Fig. 14 (Continental-operated wells). The initial solid line represents actual field production performance on 40-acre spacing up to Nov., 1965; the predicted future performance on 40-acre spacing is represented by the lower dashed curve (based on data as of Jan. 1, 1964). Cumulative production from Continental-operated wells at that time was 3,148,000 bbl of oil.

The upper dashed curve represents the predicted field production due to infill drilling and development on 20-acre spacing; and the solid line, after Nov., 1965, represents actual field production performance resulting from the infill drilling. A very good match exists between actual and predicted performance. Cumulative production from Continental-operated wells, through June, 1968, approximates 7,360,000 bbl of oil. Additional recovery due to the infill drilling, as of July 1, 1968, is estimated to be approximately 1,700,000 bbl. The estimated ultimate increase in primary recovery, due to the infill drilling, was originally expected to exceed 14 percent. This may prove to be too low.

Conclusions

The initial development spacing pattern for a field may or may not be the optimum well spacing for that specific field, because optimum well spacing depends upon the reservoir and producing characteristics, as well as upon the development economics of that field. The field dealt with here was initially developed on relatively wide spacing, which provided an opportunity to evaluate this spacing pattern to determine if it or an alternate spacing pattern was the optimum for that field.

Acknowledgments

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Read Carefully

Infill Drilling To Increase Reserves—Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois

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Summary

Evaluation of reservoir discontinuity has been used by industry to estimate potential oil recovery to be realized from infill drilling. That this method may underestimate the additional recovery potential is shown by continuity evaluation in a west Texas carbonate reservoir, as infill drilling progressed from 40-acre (162×10^3-m^2) wells to 20-acre (81×10^3-m^2) wells and eventually to 10-acre (40.5×10^3-m^2) wells.

Actual production history from infill drilling in nine fields, including carbonate and sandstone reservoirs, shows that additional oil recovery was realized by improving reservoir continuity with increased well density.

Introduction

One objective of an orderly field-development program is to determine the maximum well spacing that will effectively drain oil and gas reserves. While wide spacing has proved effective in many oilfield applications, there are a growing number of examples where infill drilling, combined with water-injection pattern modifications, has provided substantial additional oil reserves. This paper deals with such fields: Means, Fullerton, Robertson, IAB (Menielle Penn), Howard Glasscock, Dorward, and Sand Hills fields in west Texas, Hewitt field in southern Oklahoma, and Loudon field in Illinois. The paper will quantify the contribution to current production and the additional reserves attributable to this action, using data available through Oct. 1981. Infill drilling has continued in most of these fields. Also revealed by infill drilling is the fact that the west Texas carbonate reservoirs are more stratified, and porous stringers are more discontinuous than revealed by initial studies.

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Background

The theoretical concepts indicating that infill drilling will increase reservoir continuity and improve waterflood pattern conformance in heterogeneous west Texas carbonate reservoirs were researched and published in the early 1970's by Ghauri,[1] Ghauri *et al.*,[2] Stiles,[3] George,[4] and Driscoll.[5]

Detailed field studies recommending infill-drilling and waterflood-pattern modifications were made for the Means, Fullerton, and Robertson fields by Stiles and George.[3,4] Unpublished studies were made for the other reservoirs prior to infill drilling.

Borrowed from a previous work by George and Stiles,[4] Fig. 1 is a type cross section in the Fullerton Clearfork reservoir that illustrates the concept of "continuity," the percentage of pay in a well that is continuous to another well. The two original Wells A and B are 40-acre (162×10^3-m^2) locations, and the center well is an infill location 660 ft (201.2 m) from either original well. Note the discontinuous nature of the porosity stringers and that correlation before the infill well was drilled would have been considerably different than it is after the infill well was drilled. The increase in net pay in the infill well, especially in the upper part of the Clearfork formation, illustrates the fact that the more wells that are drilled, the more highly stratified, discontinuous, and complex a given west Texas carbonate reservoir is found to be. This fact leads to a conservative evaluation of the potential increased recovery from an infill well.

Considerations in Infill Drilling

A progression of continuity improvement was revealed by infill drilling in the Means San Andres field. Fig. 2 is a statistical plot of continuous pay vs. horizontal distance

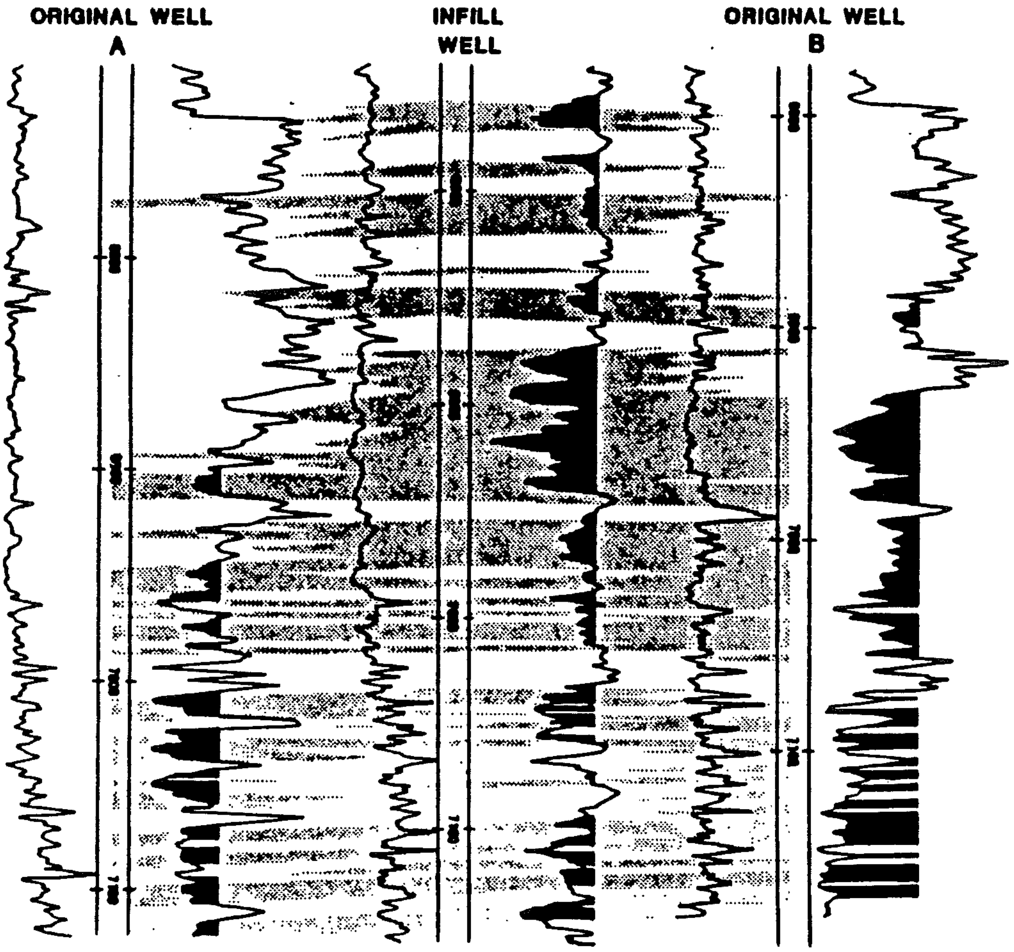

Fig. 1—Type cross section—Fullerton Clearfork reservoir (adapted from Ref. 4).

between wells for an area at Means that has been infill drilled to 10-acre (40.5×10^3-m^2) density. This technique was used by Shell Oil Co.[6] and was discussed by Stiles[3] in a previous paper. The top curve, made prior to infill drilling, shows the increase in apparent continuity between wells with increasing well density. Subsequent curves, made after infill drilling, show the pay development to be more discontinuous than would have been predicted. As shown by the upper curve, based on 40-acre (162×10^3-m^2) wells alone, an increase in continuity of 3% would be expected as spacing decreased from 20 acres (81×10^3m^2) to 10 acres (40.5×10^3 m^2). The second curve, after 20-acre (81×10^3-m^2) wells were drilled, shows that with only 40-acre (162×10^3-m^2) and 20-acre (81×10^3-m^2) wells, an increase in continuity of 4% would be anticipated as spacing decreased from 20 acres (81×10^3 m^2) to 10 acres (40.5×10^3 m^2). The analysis including the 10-acre (40.5×10^3-m^2) wells, shown by the lower line, indicates an apparent 14% improvement in continuity. The absolute values obtained for this particular area of the field are not necessarily typical of what would be expected throughout the field but do illustrate the concept of progressive increase in continuity with closer well spacing.

The complexity of stringerization is even more obvious after Fig. 3 is examined. This is a cross section

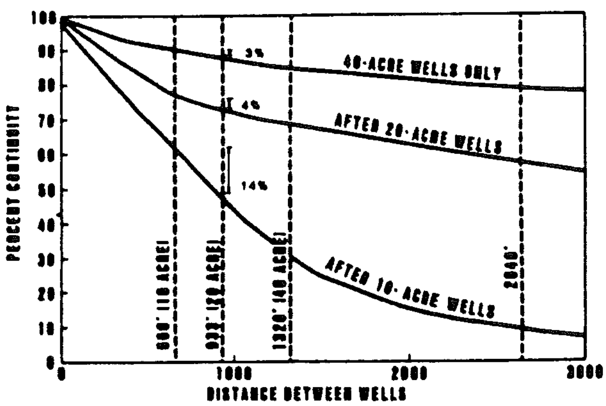

Fig. 2—Continuity progression—Means San Andres Unit.

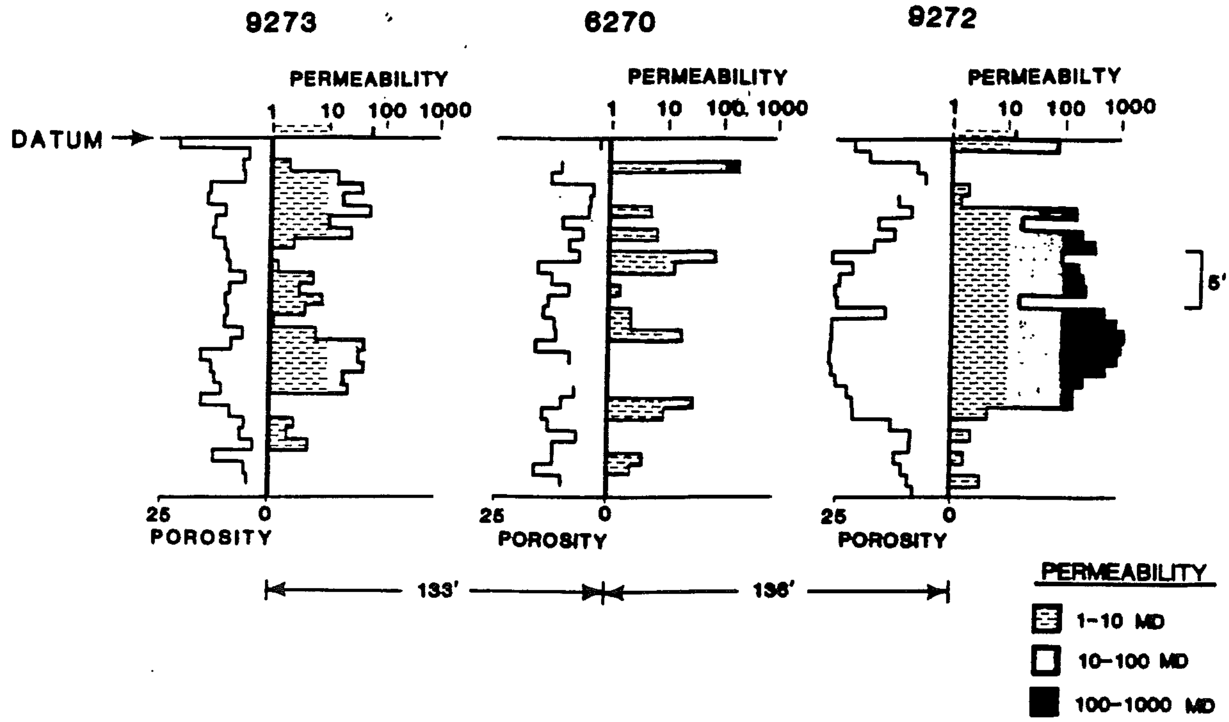

Fig. 3—Porosity and permeability variations—Means tertiary pilot.

through three wells in a tertiary pilot in the Means San Andres reservoir. The wells are located approximately 150 ft (45.7 m) apart, and core porosity and permeability have been correlated over the same stratigraphic interval. Porosity is plotted to the left and permeability is plotted on a log scale to the right. The pay intervals are relatively continuous between wells, but the porosity variations are significant in an individual stringer between wells. Permeability variations are even more severe. With injected fluids taking the path of least resistance, this plot serves to illustrate why, even in stringers that are continuous between wells, recovery may be lower than anticipated.

In a previous paper,[3] it was stated that a pay interval must meet the following three requirements for waterflooding.

1. It must be continuous and reasonably homogeneous between an injection well and the offset producing wells.
2. It must be injection supported.
3. It must be effectively completed in the offset producing well.

In many west Texas Permian carbonate reservoirs there may be 50 or more individual pay stringers. Only rarely will all the stringers be effectively completed in a specific well. When a pay stringer is not effectively completed in a given well, a partial pattern exists for that stringer, and recovery will be less than for a complete pattern. These considerations were used to evaluate infill drilling and pattern modifications in several fields.

Infill Drilling Results

Major infill drilling programs were implemented in nine fields in west Texas, Oklahoma, and Illinois. These fields include dolomite, limestone, and sandstone reservoirs with porosities varying from 4 to 21% and with average permeabilities varying from 0.65 to about 184 md. Two of the fields are still on primary production, the other seven are waterflood fields. A detailed discussion of each of these fields follows.

Means San Andres Unit

One of the first fields studied was the Means San Andres reservoir in Andrews County, TX. Production is from a depth of 4,400 ft (1341 m). The San Andres is over 1,400 ft (427 m) thick, but only the upper 200 to 300 ft (61 to 91 m) is productive at Means. It is predominantly dolomite with minor shale and anhydrite. Average porosity and permeability are 9% and 20 md, respectively. Oil viscosity was 6 cp (6 mPa·s) at initial reservoir conditions. The reservoir was discovered in 1934 and drilled to 40-acre (162×10^3-m^2) spacing. Waterflooding began in 1963 with a peripheral pattern, which was expanded to a three-to-one line drive in 1970. Following a detailed reservoir study in 1975, a large-scale infill-drilling and pattern-modification program was begun. By the 1981 study cutoff date, 141 twenty-acre (81×10^3-m^2) and 16 ten-acre (40.5×10^3-m^2) infill wells had been drilled. During this period the pattern was gradually changed, generally to an 80-acre (324×10^3-m^2) inverted nine-spot.

Actual production from the 40-acre (162×10^3-m^2) wells is shown by the lower line in Fig. 4. Production from the total unit is shown by the upper line. The area between these lines is wellbore oil production from the infill wells. The area between the dashed line and actual 40-acre (162×10^3-m^2) well production is interference oil. Increased recovery resulting from infill drilling is that production represented by the area between the dashed line and the total unit production. The infill wells account for 68% of the unit daily production.

Increased recovery is calculated to be 15.4 million bbl (2.4×10^6 m^3) oil, or 66% of the total oil produced by the infill wells. The unit was divided into 40-acre (162×10^3-m^2) tracts and the original oil in place (OOIP) was calculated volumetrically for each of these tracts.[4] Additional recovery was calculated for each infill well, and as to be expected, the recoveries varied widely. In general, the additional recovery for the 20-acre (81×10^3-m^2) infill wells ranged from 5 to 8% OOIP in the 40-acre (162×10^3-m^2) tract in which the infill well was drilled.

In a smaller area in the Means field sixteen 10-acre (40.5×10^3-m^2) wells were drilled in two pilot areas in 1979 and 1980. Fig. 5 shows the impact of the 10-acre (40.5×10^3-m^2) infills on the production in the pilot areas. Decline-curve analysis indicates that additional recovery from the 10-acre (40.5×10^3-m^2) infills will be 1.2 million bbl (1.9×10^5 m^3) oil, or 67% of the wellbore recovery. Additional recovery from the 10-acre (40.5×10^3-m^2) infill wells is estimated to vary from 2 to 5% OOIP in the 40-acre (162×10^3-m^2) tract in which the infill well was drilled.

Fullerton Field

The Fullerton Clearfork Unit, also located in Andrews County, TX, produces from the Permian Clearfork and Wichita formations, which are predominantly dolomite interbedded with limestone, anhydrite, and shale. Production is from an average depth of 7,000 ft (2134 m), and the reservoir averages 10% porosity and 3-md permeability. At initial reservoir conditions, the oil viscosity was 0.75 cp (0.75 mPa·s).

Fullerton was discovered in 1942 and was originally developed on 40-acre (162×10^3-m^2) spacing. The Fullerton Clearfork Unit has been under water injection since 1961. The original pattern used in the largest portion of the field, the North dome, was a three-to-one line drive, with the injectors oriented north-south. The original north-south injection rows are shown in Fig. 6. Note the 80 acres (324×10^3 m^2) outlined by the dashed line. An 80-acre (324×10^3-m^2) tract in this position will be discussed further.

Based on the recommendations of a 1973 study reported by Stiles,[3] a program later called the Phase I Infill Program was initiated. Under this program, the wells shown by the solid dots in Fig. 6 were drilled as infill producers, and half the adjacent row producers were converted to injection wells as shown by the solid triangles. Sixty-one Phase I wells were drilled. At the conclusion of the Phase I drilling in 1976, the average production of the Phase I wells was 88 B/D (14 m^3/d) oil with a 46% water cut. Average production for the offset wells was about half, or 46 B/D (7.3 m^3/d) oil, with a 68% water cut. The fact that these infill wells performed better than the offsets indicated that additional pay was being opened up, which in turn implied that less than all the pay was being flooded.

An 80-acre (324×10^3-m^2) tract, outlined in Fig. 6, has been enlarged and is shown in Fig. 7. The original north-south injection row is to the left and the black dot to the right fixes the location of the 61 Phase I wells. The

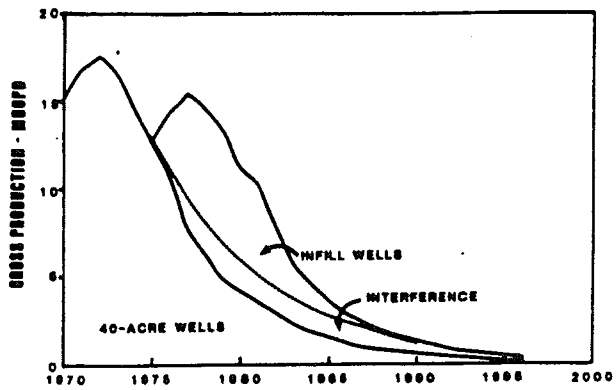

Fig. 4—Production datagraph—Means San Andres Unit.

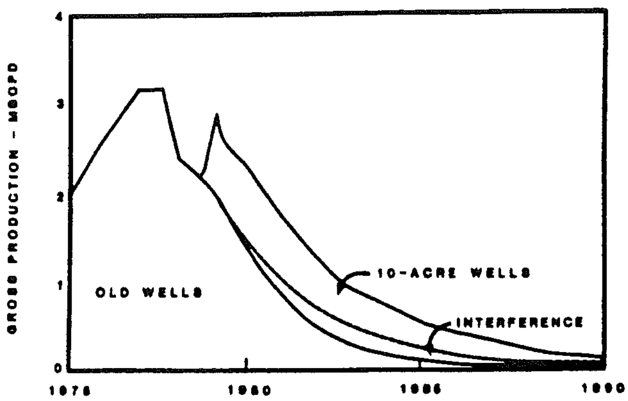

Fig. 5—Production datagraph—10-acre pilot, Means San Andres Unit.

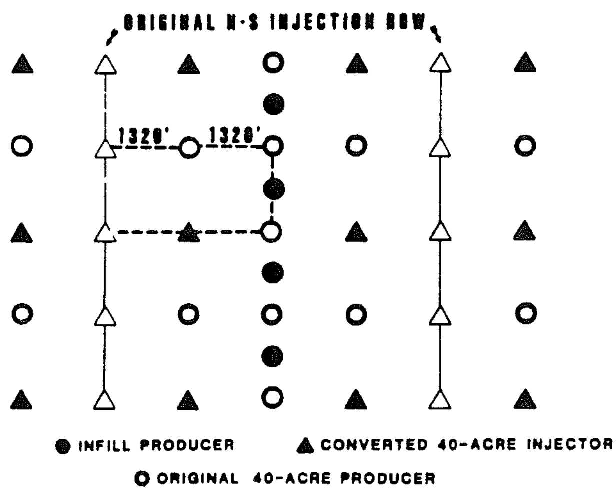

Fig. 6—Phase 1 infill drilling—Fullerton Clearfork Unit.

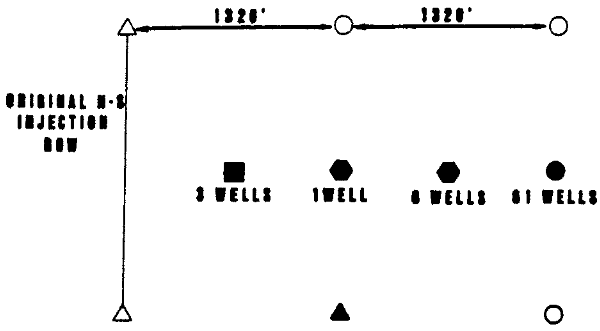

Fig. 7—Pilot infill drilling—Fullerton Clearfork Unit.

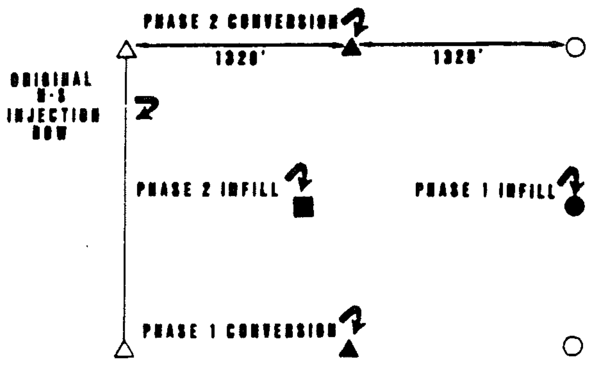

Fig. 8—Phase 2 infill drilling—Fullerton Clearfork Unit.

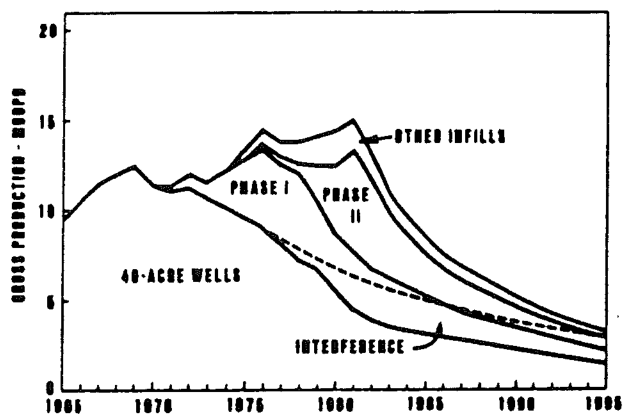

Fig. 9—Production datagraph—Fullerton Clearfork Unit

solid triangle shows the location of the Phase I injection conversion. Prior to the Phase I program, seven wells had been drilled between 1970 and 1972 in the positions shown by the hexagons. These wells had average initial potentials of 221 B/D (35.1 m^3/d) oil, and in July 1976 they were producing an average of 92 B/D (14.6 m^3/d) oil and 70% water. Their offset wells were producing an average of 26 B/D (4.1 m^3/d) oil. The performance of the Phase I wells and the seven earlier wells suggested that additional recovery might be obtained if wells were drilled anywhere within the pattern. In 1976, three wells were drilled in the position shown by the square. They produced an average of 115 B/D (18.3 m^3/d) oil with a 74% water cut. Four of the six direct offsets to these wells had been shut in from 4 to 9 years earlier as uneconomical to produce. One was a produeer testing 1 B/D (0.16 m^3/d) oil and 500 B/D (79.5 m^3/d) water. The sixth was an injector that had been converted in 1975 while producing 38 B/D (6 m^3/d) oil.

As a result of these 10 pilot wells, a 151-well Phase II infill drilling program at Fullerton was undertaken. Phase II wells have been drilled in the position shown by the square in Fig. 8. Wells in the position captioned "Phase II Conversion" are being converted to injection as part of the Phase II program. Of the 171 wells in this conversion location, 111 were watered out by 1976. Most others were producing at very low rates. It can be concluded that Phase II wells are mostly additional recovery. The production contribution from these infill drilling programs can be seen in Fig. 9. This datagraph shows the impact of the Phase I, Phase II, and other infill wells. These wells account for 71% of the unit's current production and will result in additional recovery of 24.6 million bbl (3.9×10^6 m^3) oil. Fifty-six percent of the wellbore reserves are increased recovery and will average about 97,000 bbl (15.4×10^3 m^3) per infill well.

Robertson Field

The Robertson Clearfork Unit in Gaines County, TX, produces from the Permian Glorieta, Upper Clearfork, and Lower Clearfork formations, at an average depth of 6,500 ft (1981 m). The reservoir is about 1,400 ft (427 m) thick with actual net pay of about 200 to 300 ft (61 to 91 m), broken vertically into as many as 50 to 60 separate porosity stringers in any given well: Fig. 10, a cross section between two 40-acre (162×10^3-m^2) wells, better illustrates the extreme stringerization. The reservoir rock is predominantly dolomite with anhydrite and shale. Porosity averages 6.3% and permeability averages 0.65 md. Oil viscosity at reservoir conditions is 1.2 cp (1.2 mPa·s). Beginning in 1942, the area was drilled on 40-acre (162×10^3-m^2) locations. In 1969, the unit was formed for waterflooding. From 1976 through 1980, 107 infill wells were drilled on 20-acre (81×10^3-m^2) spacing. A 10-acre (40.5×10^3-m^2) drilling program has begun with 31 wells completed through Oct. 1981.

The contribution of the 20-acre (81×10^3-m^2) and 10-acre (40.5×10^3-m^2) wells is shown in Fig. 11. The dashed line represents the expected production from the 40-acre (162×10^3-m^2) wells had there been no infills. Infill wells provide 73% of the current production. They are expected to add additional reserves of 10.7 million bbl (1.7×10^6 m^3). Increased recovery represents 79% of the wellbore reserves and is about 73,000 bbl (11.6×10^3 m^3) per well.

IAB Field

The IAB (Menielle Penn) field is located in Coke County, TX. The Menielle Penn reservoir produces from a depth of 5,800 ft (1768 m) and is a coarse skeletal limestone buildup with an average of 7% porosity and 27-md permeability. The oil viscosity at initial reservoir conditions was only 0.2 cp (0.2 mPa·s) at IAB. The reservoir was discovered in 1958 and was drilled initially on 80-acre (324×10^3-m^2) spacing. Waterflooding began in 1962 with an initial pattern which was essentially a three-to-one line drive. Fig. 12 is the production datagraph showing the impact from a 17-well 40-acre (162×10^3-m^2) infill drilling program that began in 1978. The dashed line is an extrapolation of what the 80-acre (324×10^3-m^2) wells would have done if the infill wells had not been drilled. The lower solid line shows the actual and forecasted performance of the old wells. This analysis shows that the infill wells will increase the field's reserves by 1.7 million bbl (2.7×10^6 m^3). This represents additional recovery of 100,000 bbl (1.59×10^5 m^3) per well, which is 58% of the wellbore reserves and 4% of OOIP in the affected area.

Howard-Glasscock Field

The Douthit Unit, located in Howard and Sterling Counties, TX, was formed for waterflooding the Permian Seven Rivers reservoir in the Howard-Glasscock field. The reservoir is approximately 1,400 ft (427 m) deep and is a sandstone with a porosity of 18% and a permeability of 44 md. In this reservoir, the oil viscosity of 9.4 cp (9.4 mPa·s) is relatively high for west Texas reservoirs. Development of the Seven Rivers reservoir in this area began in 1957, and it was originally drilled on 40-acre (162×10^3-m^2) locations. Waterflooding began in 1968 with a peripheral injection pattern. Ten-acre (40.5×10^3-m^2) development began in 1976, and, by the 1981 study cutoff date, 52 infill wells had been drilled. The production datagraph, Fig. 13, shows the additional production from the infills along with production from the older wells. The infill wells account for 75% of the current production, and wellbore production is 88% additional recovery. Total additional recovery of 1.0 million bbl (1.59×10^6 m^3) is expected.

Dorward Field

The Dorward field is located in Scurry and Garza Counties, TX. Production is commingled from the Permian San Angelo and San Andres formations at average depths of 2,350 and 2,100 ft (716 and 640 m), respectively. The San Angelo formation is mostly dolomite interbedded with shale and sandstone. The San Andres consists of dolomite, anhydrite, and shale. Apparent porosity for the San Angelo and San Andres are 15 and 13.5%, respectively. Actual porosities are probably less because of the presence of gypsum, which causes optimistic measurements of porosities in cores and logs. Average permeability is about 3 md in both reservoirs. In the San Angelo, the oil viscosity is 1.9 cp (1.9 mPa·s) while in the San Andres, it is 3.2 cp (3.2 mPa·s).

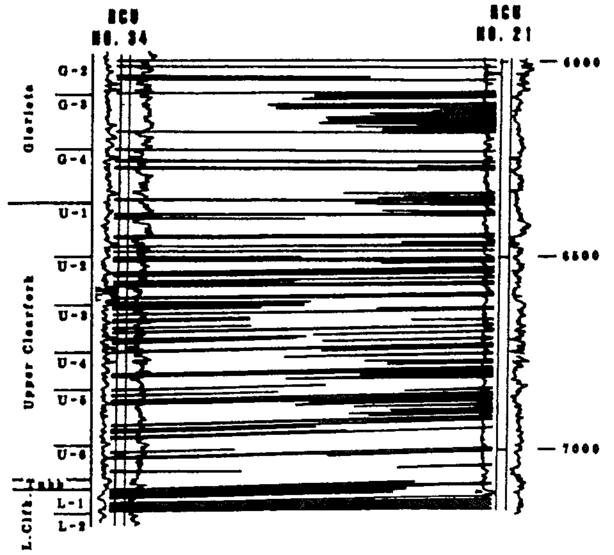

Fig. 10—Cross section—Robertson Clearfork Unit.

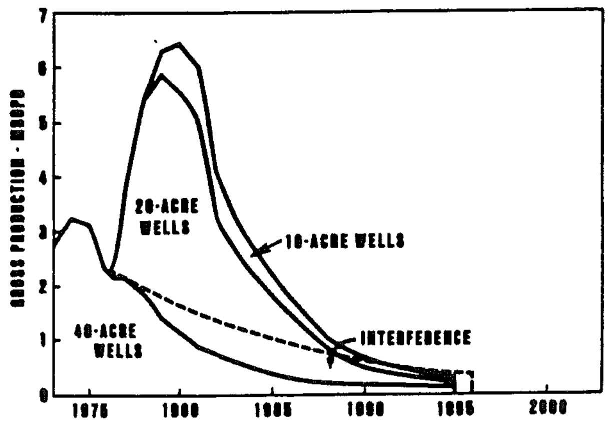

Fig. 11—Production datagraph—Robertson Clearfork Unit.

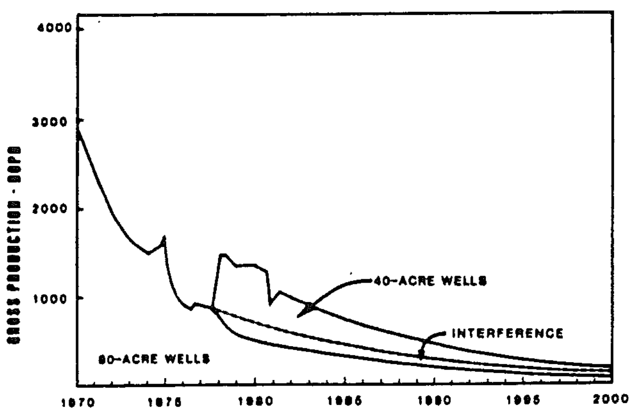

Fig. 12—Production datagraph—IAB (Menielle Penn) field.

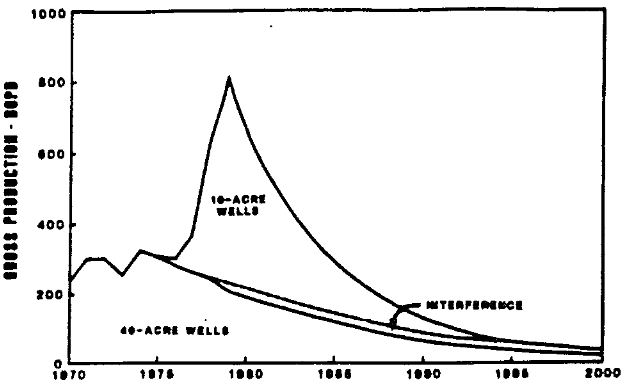

Fig. 13—Production datagraph—Douthit Unit, Howard-Glasscock field.

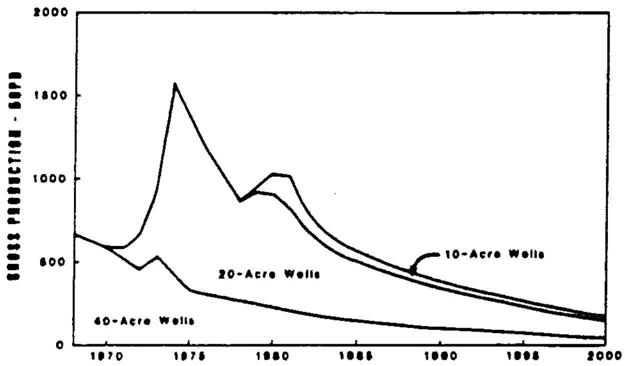

Fig. 14—Production datagraph—Dorward field.

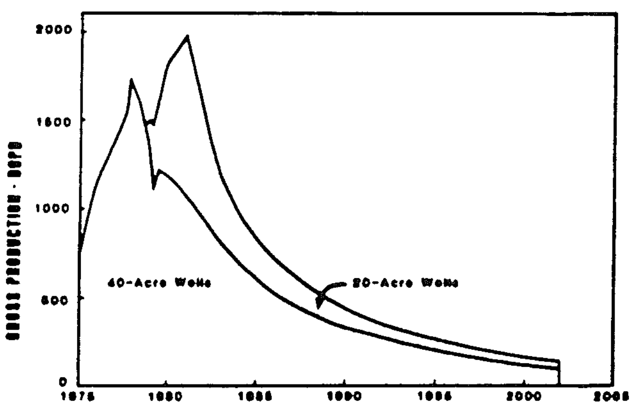

Fig. 15—Production datagraph—Sand Hills area.

The field was discovered in 1950 and drilled on 40-acre (162×10^3-m^2) spacing. Although waterflooding began in 1958 in a portion of the field, most of the field has been and is currently producing primary oil by dissolved-gas drive. Peripheral and 80-acre (324×10^3-m^2) five-spot patterns were tried. Early water breakthrough, caused by directional permeability and severe stratification, discouraged expansion of waterflooding to other areas.

Infill drilling began in 1971. At that time, 149 wells on 40-acre (162×10^3-m^2) spacing had been drilled. An average of 49,400 bbl (7850 m^3) oil per well had been accumulated, and production had declined to an average of 4.8 B/D (0.76 m^3/d) oil per well for the 107 wells still producing at that time. From 1971 through 1980, there were 123 twenty-acre (81×10^3-m^2) infill wells drilled. Ten-acre (40.5×10^3-m^2) drilling began in 1979, and 17 wells had been drilled by the end of 1980. Fig. 14 shows the results.

Because production was nearing the economic limit when infill drilling began, essentially all production from the infill wells is considered increased recovery. The infill wells will provide additional recovery of 4.6 million bbl (7.3×10^5 m^3) of oil or 33,000 bbl (5244 m^3) per well. The field is now being studied for further 10-acre (40.5×10^3-m^2) development and to determine if waterflooding is feasible with increased well density.

Sand Hills

Infill drilling in the Sand Hills area of Crane County, TX has been concentrated in the Sand Hills (Tubb and McKnight) fields. The Tubb reservoir produces from the Permian Lower Clearfork formation at a depth of 4,250 ft (1295 m) and is anhydritic dolomite with a minor amount of limestone. Average porosity and permeability are 4% and 12 md, respectively. Oil viscosity in the Tubb is 1.5 cp (1.5 mPa·s) at initial reservoir conditions. The McKnight reservoir produces from the Permian Lower San Andres at a depth of 3,200 ft (975 m) and is also mostly anhydritic dolomite. In this reservoir, average porosity and permeability are 5% and 1.3 md, respectively. In the McKnight reservoir, the oil viscosity is 1.0 cp (1.0 mPa·s). Gross productive interval is approximately 400 ft (122 m) in the Tubb and 350 ft (107 m) in the McKnight. Both reservoirs are highly stringerized with indications of poor reservoir continuity. They are both productive throughout the area of interest.

The Sand Hills (Tubb) field was discovered in 1931 and was generally developed on 40-acre (162×10^3-m^2) spacing. In the area of interest, most of the Tubb 40-acre (162×10^3-m^2) drilling was between 1936 and 1941. Development of the McKnight reservoir did not begin until 1955. McKnight development was erratic, depending largely on recompletions from the depleting Tubb reservoir; however, there was some drilling along with the workovers. Most of the 40-acre (162×10^3-m^2) McKnight activity was from 1955 to 1965 and later during the 1970's.

A 20-acre (81×10^3-m^2) infill program was begun in 1979. By the 1981 cutoff date, 56 infill wells had been drilled, with most of them being dually completed in both reservoirs. As expected, these wells found stringers that were pressure depleted but also found stringers that

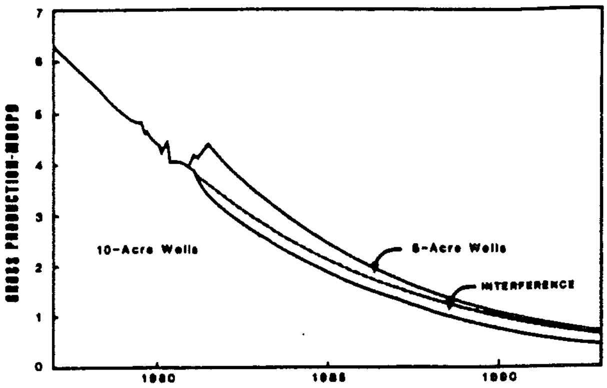

Fig. 16—Production datagraph—Hewitt Unit, Hewitt field (OK).

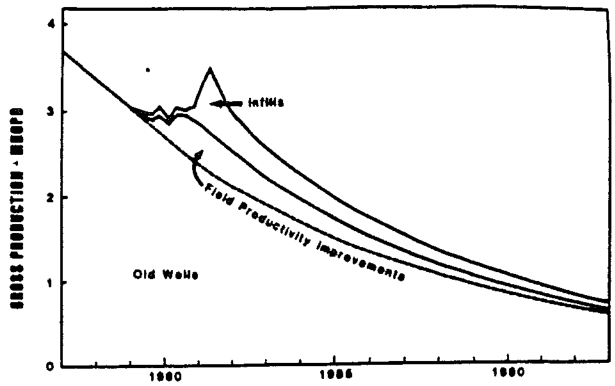

Fig. 17—Production datagraph—Loudon field (IL).

were only partially depleted or had not been penetrated by other wells. Forty-acre (162×10^3-m^2) development had continued until the time when the 20-acre (81×10^3-m^2) infill program began. Thus, a substantial amount of total production was flush production from recently drilled wells. Production from the older 40-acre (162×10^3-m^2) locations, those drilled before 1975, was 5.5 B/D (0.87 m^3/d) oil from the McKnight and 5.3 B/D (0.84 m^3/d) oil from the Tubb. Remaining reserves from these wells were about 9,000 bbl (1431 m^3) per well.

Fig. 15 shows both the performance of the 20-acre (81×10^3-m^2) infills and offset 40-acre (162×10^3-m^2) wells, including the recently drilled ones. During 1981, the infills produced 45% of the total production. Performance to date indicates they will ultimately produce 1.6 million bbl (2.5×10^5 m^3) of additional oil or 28,400 bbl (4516 m^3) per well. This recovery compares favorably with the estimated remaining 9,000 bbl (1430 m^3) per well from the older 40-acre (162×10^3-m^2) wells. Because of the extreme lenticularity of these reservoirs and difficulty in obtaining reliable porosity data, good values for OOIP are not available.

Hewitt Field

The Hewitt field, located in Carter County, OK, was discovered in 1919. Production is from 22 Pennsylvanian Hoxbar and Deese sand intervals, with a gross thickness of over 1,500 ft (457 m). The many sand intervals are separated by shale zones. Average depth to the top of the first pay interval is about 2,000 ft (610 m). The sands have an average porosity of 21% and an average permeability of 184 md. Oil viscosity in this reservoir is 8.7 cp (8.7 mPa·s). In the area of infill drilling, the original spacing was 2.5 acres (10×10^3-m^2). After the field was unitized for secondary recovery operations, many of the old wells were plugged and the field was redrilled on 10-acre (40.5×10^3-m^2) spacing. A fieldwide 20-acre (81×10^3-m^2) five-spot water injection project was begun.[7] Fifteen five-acre (20×10^3-m^2) infills have been drilled and their impact is shown in Fig. 16. The infills account for 23% of current unit production. Our analysis indicates about 60% of the wellbore reserves will be increased recovery and will total about 400,000 bbl (6.4×10^4 m^3) from the 15 wells.

The performance of the best well of these infills is a good example of the erratic nature of the porosity development and fluid-flow characteristics of this reservoir. This well potentialed for 414 B/D (65.8 m^3/d) oil with a 50% water cut, although one offset was producing 44 B/D (7.0 m^3/d) oil with a 96% water cut, and the other was producing only 7 B/D (1.1 m^3/d) oil with a 99% water cut. Overall project water cut is 97%. This type of result was obtained in a reservoir that was developed on 2.5-acre (10×10^3-m^2) spacing with a 20-acre (81×10^3-m^2) five-spot pattern.

Loudon Field

The Loudon field, discovered in 1937, is located in Fayette and Effingham Counties, IL, and produces from four Mississippian sandstones, the Weiler, Paint Creek, Bethel, and Aux Vases, at an average depth of 1,500 ft (457 m). Average porosity is 19%, and average permeability is about 100 md. The oil viscosity is 5 cp (5 mPa·s). The northern half of the field was drilled on 20-acre (81×10^3-m^2) spacing in a sunflower pattern. The southern half of the field was drilled on 10-acre (40.5×10^3-m^2) spacing. Waterflooding began in the early 1950;s, with the north half of the field on a 70-acre (283×10^3-m^2) nine-spot pattern and the south half on a 20-acre (81×10^3-m^2) five-spot pattern. Subsequently, injection wells were drilled in 10-acre (40.5×10^3-m^2) "dead" spots that are characteristic of the sunflower pattern, thus creating 10-acre (40.5×10^3-m^2) five-spot patterns. Producing water cut is now 98%.

Beginning in 1979, 50 infill wells have been drilled in the 20-acre (81×10^3-m^2) development area. These infills were drilled at the intersection of a line between 20-acre (81×10^3-m^2) producing wells and a line connecting offset injection wells. This is a dead area in the flood pattern, and it was thought that these areas had been inadequately flooded. Initial production ranged from 131 B/D (20.8 m^3/d) oil to 3.4 B/D (0.54 m^3/d) oil, with the average being 25 B/D (4.0 m^3/d) oil. Offsets were producing less than 4 B/D (0.6 m^3/d) oil average prior to the drilling of the infill wells. Fig. 17 shows the impact of drilling these 50 infills. At the time of analysis these wells were producing about 600 B/D (95.4 m^3/d) oil or 18% of total field production.

Because of their location and the stage of depletion of the field, essentially all production from these wells is considered increased recovery. These infills are expected to increase oil reserves by 970,000 bbl (1.5×10^5 m^3).

Conclusions

The conclusions formulated from this infill drilling study are as follows.

1. Infill drilling in nine fields has resulted in per-well-recovery improvements that are attractive under current economic conditions.
2. Increased oil recovery from the drilling of 870 infill wells in 9 fields ranges from 56% to 100% of their wellbore production.
3. Total additional reserves from these wells will be 60.8 million bbl (9.7×10^6 m^3) oil.
4. Continuity calculations made after infill drilling indicated the pay zones to be more discontinuous than when calculations were made before infill drilling.
5. The experience in these nine fields indicates that the ultimate well density in any given field can be determined only after several years of field performance provide sufficient information on reservoir continuity and recovery efficiencies.

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SI Metric Conversion Factors

acre	× 4.046 873	E+03	= m^2
bbl	× 1.589 873	E−01	= m^3
ft	× 3.048*	E−01	= m

*Conversion factor is exact.

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