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Analysis of Kansas Hugoton Infill Drilling: Part I—Total Field Results

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ABSTRACT

This paper compares the performance of infill wells drilled in the Kansas Hugoton to the companion original wells - regionally, by operator, and the field as a whole, using official deliverability tests and production history. We present the pitfalls of using official deliverability and wellhead shut-in pressure differences between the infill wells and the companion original wells as indications of additional gas-in-place and suggest more reliable methods of interpreting infill well performance. The results of the first 659 infill wells drilled in the Kansas Hugoton reveal that the infill wells have not found any evidence of additional gas-in-place.

INTRODUCTION

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 greater than 480 acres. The KCC based their decision to allow infill wells on the premise that these wells would recover an additional 3.5 to 5.0 trillion cubic feet (TCF) of gas that could not be recovered by the existing wells.

This paper is a study of the data publicly available through November 1989 for the first 659 infill wells put on production. The data analyzed include the official deliverability tests and the monthly allowable and production history for each infill and companion original well. The results of this study indicate that the infill wells have not encountered nor indicate additional gas-in-place. This conclusion is also supported by the companion papers on the Guymon-Hugoton[2,3,4] and Part II[5] of this work.

References and illustrations at end of paper.

HISTORY

The Hugoton Field is the largest gas accumulation in the lower 48 states covering approximately 6500 square miles in three states. Approximately two-thirds of the field lies in southwest Kansas on all or portions of 11 counties (see Fig. 1). As of November 1989, there were 4853 producing gas wells in the Kansas Hugoton including 659 infill wells. Cumulative production from the Kansas portion of the field through December 1989 totaled over 20 TCF, with an estimated remaining gas-in-place of approximately 10 TCF.

The Kansas Hugoton discovery well[6] was Defenders Petroleum Company's Boles No. 1, Sec. 3, T35S, R34W, completed in December 1922, three miles west of Liberal, Kansas, with an open flow potential of ~ 1 MMSCFD. Development of the field was delayed until 1930 when the first major pipeline was completed in the area. By the end of 1930, seventy-five wells had been drilled in southwest Stevens County.[7] The majority of the remaining wells were drilled in the 1940s and early 1950s on 640-acre units.

The early wells in the field were completed open hole with casing to the top of the productive interval. In many wells, slotted liners were run over the open hole interval to avoid cave-in problems. In an attempt to increase the open flow capacities, operators began to treat the whole productive interval with HCl, with the typical treatment being 8,000 gallons. This became common practice by 1938. In the late 1940s, it was established that maximum deliverability could be obtained by setting casing through the pay zones and selectively perforating and acidizing each zone.[8,9,10] In 1947, the very first hydraulic fracturing operation was conducted on the Klepper No. 1 in the Kansas Hugoton using a gasoline-based napalm gel fracturing fluid.[11] By the early 1960s, the primary method of stimulation was hydraulic fracturing using large volumes of low-cost, water-based fluid pumped at high rates with 1 ppg of river sand. Many successful restimulation workovers were conducted on the older wells during this time.[12]

GEOLOGY

The Lower Permian section across the Texas and Oklahoma Panhandles and southwestern Kansas was deposited in cyclical sequences on a shallow marine carbonate ramp.[2,13] 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 into primarily carbonate units and interlayered shaley units. The carbonate units, including the Upper and Lower Ft. Riley, Winfield, Krider, and Herington Limestones and Dolomites, constitute the potential reservoir intervals within the Hugoton field. These reservoir intervals are separated by shaley units, including the Oketo, Holmesville, Gage, Odell, and Paddock Shales. Based on individual layer pressure data and flowmeter data on five replacement wells in the Kansas Hugoton, Carnes[15] concluded that the Krider, Winfield, Upper Fort Riley and Lower Fort Riley are separate and distinct producing horizons within the Chase formation, having different pressures and depleting at different rates. The reservoir and shaley nonreservoir units exhibit characteristic log signatures recognizable throughout the field. Regional north-south and east-west cross-sections, as demonstrated in Figs. 2 and 3, developed from logs by Clausing,[14] illustrate the lateral continuity of the reservoir layers and shaley barrier units across the field. Additional information on the geological features in Oklahoma can be found in Ref. 2.

INFILL DRILLING ORDER

Cities Service Oil and Gas Corporation (now OXY USA) 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 Cities application began on July 29, 1985, and ended on December 5, 1985, before the KCC. One hundred ten witnesses testified.

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 in order to avoid a boom-bust race to drill the infill wells. Each operator would be permitted to drill a maximum of one-quarter of their infill locations each year with a carry forward of the number of undrilled infill locations from the previous year. In addition, during the four-year phase-in, the original well would have an acreage factor of 0.7 and the infill well an acreage factor of 0.3. During the fifth year, the acreage factors become 0.6 and 0.4 respectively for the original and infill well. Starting in the sixth year, each well will receive an acreage factor of 0.5. The KCC decided that this acreage factor schedule would protect correlative rights during the phase-in period.

ANALYSIS OF DATA

Infill Drilling Activity

The infill wells analyzed in this study are the 659 wells that were assigned allowables and listed in the November 1989 Monthly Kansas Hugoton Field report. The data analyzed in this study include all of the official deliverability test data (72 hr flows and shut-ins) published by the KCC through November 1989 and the monthly production and allowables for each well up to November 1989.

Infill drilling in the Kansas Hugoton began in 1987 with 260 wells being spudded in the first year compared to the 1044 allowed by the KCC. Figure 4 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 3132 allowed (26%) have been drilled. The overall infill drilling activity has progressed at a significantly slower pace than was allowed by the KCC.

Fig. 5 summarizes the infill activity through November 1989 by operator as a percentage of their allotment. The number of infill wells for each operator is listed next to the operator name on the x-axis of Fig. 5. Mesa has been, by far, the most active, having drilled one-third of all the infill wells in the field representing over 91% of their allotment of infill wells. The two largest operators, Mobil with 691 wells and Amoco with 810 wells prior to the start of infill drilling, have drilled only 5% and 7% respectively of their allotment of infill wells. Although Santa Fe and Arco each had less than 100 wells prior to the start of infill drilling, on a percentage basis they each have been quite active, drilling 76% and 79% respectively of their allotment of infill wells.

Fig. 6 is a map of the Kansas Hugoton with a summary of the infill well locations by operator. Most of the infill wells are located in Grant County (258 infill wells) and Stevens County (158 infill wells). It appears that some of the operators such as Amoco, Mobil, OXY USA, Anadarko, and Plains have spread out their infill well locations over their whole properties. Out of the 659 infill wells, approximately 79 (12%) of the wells were unsuccessful deep tests that were plugged back and completed in the Chase.

The Kansas Hugoton monthly production and wellcount since 1967 for both the infill and original wells are presented in Fig. 7. The gas market curtailment can be seen in this plot as evidenced by the rate decline in the early 1980s. The production from the infill wells has not had an appreciable effect upon the total production from the field. In fact, the increase in demand for gas from the Kansas Hugoton between 1987 and 1988 has had a greater impact on total field production than the infill wells.

Infill Well Initial Wellhead Shut-In Pressures

A cumulative frequency and a frequency distribution histogram of the initial shut-in wellhead pressures encountered by the infill wells between January

1987 and November 1989 is presented in Fig. 8. The average initial wellhead shut-in pressure is 148.8 psia with a most probable value of 143.1 psia. The most probable value accounts for skewness in the data. Note the skewness in the upper end of the distribution in Fig. 8. The average initial wellhead shut-in pressure of 148.8 psia is significantly lower than the original field discovery pressure of approximately 450 psia.[1] This average reduction in initial pressure of over 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.

In a layered, no-crossflow reservoir with contrasting layer properties such as the Kansas Hugoton, the shut-in wellhead pressure reflects the pressure of the lowest pressure zone open to the wellbore. This behavior was observed by Carnes[15] in the Kansas Hugoton while conducting an in-depth study of five replacement wells. Using a two-layer radial reservoir model, Fetkovich et al.[16] demonstrated that the commingled shut-in pressures in a two layer, no crossflow system follow the pressure in the more permeable layer assuming equal skins on each layer. Although the wellhead shut-in pressure typically reflects the pressure in the most permeable layer, the cumulative production from the well reflects production from <u>all layers</u> although each layer is depleting at a different rate. Using a simple analytical approach, Part II[5] presents in detail the basic pressure-rate-time relationship between each of the layers for a typical Kansas Hugoton well. The shape of the wellhead shut-in pressure vs. G_p plot can reflect the volume of the more permeable layer. The rate of take also affects the shape of the wellhead shut-in pressure vs. G_p curve. When the field produces wide open from the start, the wellhead shut-in pressure vs. G_p curve basically follows that of the most permeable layer assuming equal skins on all layers. On the other hand when the rate of take approaches zero, all of the layers deplete at the same rate and the wellhead shut-in pressure vs. G_p plot results in a straight line. Actual production for each well is bounded by these two limiting cases. Reference 4 presents additional detailed information relating to the factors influencing the shape of the wellhead shut-in pressure vs. G_p curve.

The average and most probable initial infill wellhead shut-in pressure for each operator is presented in Fig. 9. The number of infill wells for each operator is listed next to the operator name. The 1989 field average shut-in pressure of 147.6 psia is included on Fig. 9 as a reference point. Mesa, Mobil, and Anadarko have drilled a majority of their wells in the most productive area of the field resulting in their average infill wellhead shut-in pressures being lower than the field average. The rest of the operators have drilled many of their wells on the lower permeability edges of the field causing their average wellhead shut-in pressures to be higher than the average.

Fig. 10 is a bar plot of the average and most probable initial infill wellhead shut-in pressures by county with the number of infill wells in each county posted next to the county name. Grant, Stevens, Kearny, and portions of Morton counties, located in the more productive areas of the field have initial wellhead shut-in pressures very close to or below the 1989 field average wellhead shut-in pressure of 147.6 psia. The other five counties, Finney, Seward, Haskell, Stanton, and Hamilton, all have average and most probable initial infill wellhead shut-in pressures greater than the 1989 field average of 147.6 psia because they are typically on the edges of the field.

The initial infill wellhead shut-in pressures are generally a function of the location of the infill well. 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 is an indication of 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.

<u>Difference Between Initial Infill and Original Wellhead Shut-In Pressure</u>

In this section we compare the difference between the initial infill wellhead shut-in pressure and the original well wellhead shut-in pressure. This pressure difference is infill wellhead shut-in pressure minus original well wellhead shut-in pressure. Since the infill and original wells are not always tested at the same time, we used the test for the original well that was closest in time to the initial test for the infill well. The average elapsed time between the initial infill well official deliverability test and the companion test for the original well was 8½ months. Figure 11 is a cumulative frequency and a frequency distribution histogram of the difference in wellhead shut-in pressure between the infill and original well. The average difference is 13.6 psi with a most probable value of 10.0 psi. Almost one-quarter of the infill wells had an initial wellhead shut-in pressure that was <u>lower</u> than the wellhead shut-in pressure for the original well.

The average and most probable difference between infill and original well wellhead shut-in pressures for each operator is presented in Figure 12. The averages range from 1.8 psi (Santa Fe) to 27.5 psi (Kansas Nat). Fig. 13 presents the difference in wellhead shut-in pressure between the infill and original well by county. The highest pressure differences are in Stanton Co. (36.4 psi) and the lowest in Morton Co. (7.2 psi).

Since the wellhead shut-in pressure typically reflects the pressure of the most permeable layer, these pressure difference variations are basically a function of the permeability variations in the most permeable layer across the field. Since the initial wellhead shut-in pressures 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. In order 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 initial wellhead shut-in pressure due to the pressure sink at the original well. Claims have been made that the higher pressures observed in the infill wells compared to 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 difference in wellhead shut-in pressure of 13.6 psi between the infill and original wells. The initial difference is simply a reflection of the pressure gradient toward the original well in the most permeable layer.

In 1977, Mesa conducted a five-well replacement well program,[15] which provides information on the behavior of the pressure gradient between an infill well and the corresponding original well. In Mesa's study, the original wells were disconnected and used as pressure observation wells. Mesa collected almost 10 years of monthly wellhead shut-in pressures on these five observation wells. Part II of this paper[5] presents an updated interpretation of the results of the Mesa five well study. Fig. 14 is a plot of wellhead shut-in pressure vs. cumulative production for one of the original and replacement well pairs in Mesa's study. The initial wellhead shut-in pressure for the replacement well is higher than the corresponding wellhead shut-in pressure for the original well due to the pressure gradient created by flow to the original well. However, once the replacement well begins to produce, the subsequent wellhead shut-in pressures plot on the trend of the wellhead shut-in pressures for the original well. Also, during the same time period, the monthly observation pressures for the original well increase and follow the trend started by the replacement well. The exchange of positions on the pressure trends for these two wells is due to a pressure gradient caused by flow toward the producing well in the most permeable layer. This demonstrates that the higher initial wellhead shut-in pressure of 14.4 psi observed in the five replacement wells and the higher initial wellhead shut-in pressure of 13.6 psi observed in the infill wells does not by itself reflect any additional gas-in-place and is due only to the pressure gradient in the most permeable layer encountered by the replacement well at some distance away from the original well.

Infill Well Official Deliverability

The higher initial official deliverabilities observed in the infill wells when compared to the original wells have been interpreted as reflecting an increase in ultimate recoverable reserves. In the text that follows, we will demonstrate that the higher official deliverabilities found in the infill wells over the original wells cannot be reliably used as an indication that the infill wells are encountering additional gas-in-place. The official deliverability of each well in the Kansas Hugoton is determined by conducting a one point deliverability test. The official deliverability, D, is calculated using the following equation:

$$D = R\left[\frac{P^2 - P_d^{\,2}}{P^2 - P_w^{\,2}}\right]^{.85} \qquad (1)$$

where:
- D = official deliverability, Mscf/day
- R = observed producing rate at the end of 72 hours, Mscf/day
- P = 72-hour wellhead shut-in pressure, psia
- P_w = working wellhead pressure at rate R, psia
- P_d = deliverability standard pressure, psia

The deliverability standard pressure, P_d, is equal to seventy percent of the average wellhead shut-in pressure of all the wells tested in the Kansas Hugoton that year. Fig. 15 presents the difference in infill and original well official deliverabilities (as defined by Eq. 1) used in the determination of well allowables. If the wellhead shut-in pressure for either the original well or the infill well is less than the standard deliverability pressure, then the well has a zero deliverability and a minimum allowable of 65 Mscf/day is assigned to the well. The initial official deliverability for the average infill well is 380 Mscf/day higher than that for the original well with a most probable official deliverability of 269 Mscf/day higher for the infill well. However, as demonstrated in the following discussion, official deliverability is not an accurate measure of the difference between infill and original well performance. For example, the initial test for the Wagner 1-2 (infill well) on 4/13/88 located in Sec. 20 T24S R35W had a wellhead shut-in pressure of 93.6 psig and flowed 253 Mscf/day at a pressure of 85.4 psig. Using Eq. 1, with the 1987 standard deliverability pressure of 102.3 psig, results in an official deliverability of <u>zero</u> for the Wagner 1-2 when the well actually flowed 253 Mscf/day at a pressure of 85.4 psig. The official deliverability is simply a measure of relative productive capacities and a number used for assigning allowables. The higher initial wellhead shut-in pressure at the infill well due to the pressure sink at the original well is a factor in the official deliverability equation.

The effect of higher shut-in pressure on official deliverability can be shown using the official test data for a typical infill well as an example, and a more reliable method of presenting well performance will therefore be introduced. Fig. 16 is a wellhead backpressure curve for the Nafzinger #1 (original well) and the Nafzinger #2-2 (infill well) located in Sec. 2 T29S R37W. The solid curve represents the official 1988 test "backpressure" curve for the original well; the chain-dotted curve represents the infill well. The initial difference in shut-in pressure for these two wells is 16.7 psi which corresponds to a 92 Mscf/day 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 initial wellhead shut-in pressure for the infill well. The Nafzinger 2-2 was tested 15 months later on 1/10/89 with a wellhead shut-in pressure of 122.9 psig, corresponding to a 16.4 psi drop over that time 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/day lower than the first test while the test rate for the second test was only 2 Mscf/day lower than that of the first.

The higher official deliverabilities in the infill wells are generally temporary and are caused by higher initial wellhead shut-in pressure observed in the infill wells when compared to the original wells. We have already demonstrated that the higher initial wellhead shut-in pressure at the infill wells is a result of the pressure gradient, and as such any increase in official deliverability found in the infill wells over the original wells caused by this higher initial wellhead shut-in pressure at the infill well does not reflect additional gas-in-place. This effect is demonstrated by the historical official deliverabilities of the five replacement well leases in Mesa's study. Fig. 17 is a plot of official deliverability vs. time for the wells in Mesa's study. The big increase in official deliverability observed in 1969 is a result of hydraulic fracture restimulations conducted on the original wells. The first official deliverability tests for the five replacement wells indicate a 55% increase in official deliverability. After several years, the official deliverability for these five replacement wells falls back onto the trend started by the five original wells. This demonstrates that the higher official deliverabilities found in any new well in the Hugoton caused by the pressure gradient will be temporary.

A better method to compare well performance between the infill and original well, designed to avoid the impact of pressure gradients, is to use the AOFP calculation corrected to the 1989 average field shut-in pressure of 147.6 psia (Eq. 2). This calculation puts all of the wells on the same pressure basis. This method also 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.

$$\text{corrected AOFP} = R \left[\frac{p_{avg}^2 - 14.4^2}{p^2 - p_w^2} \right]^{0.85} \qquad (2)$$

Where the corrected AOFP, Mscf/day, is the calculated absolute open flow potential at the field average shut-in pressure (p_{avg}) for 1989 equal to 147.6 psia. R, P, and P_w are defined as before. Using this method, the corrected AOFP for the infill well in Figure 16 is 1715 Mscf/day less than the corrected AOFP for the original well. The ratio of the corrected AOFP's for the infill well to that of the original well is approximately 0.64. This indicates that the stimulation and/or completion procedures for this infill well were not as effective as those used on the original well.

Corrected AOFP Comparison

The average infill well has a corrected AOFP of 457 Mscf/day less than that of the original well. On average, this indicates poorer stimulation results in the infill wells compared to the original wells. Figure 18 compares the corrected AOFP's by using a ratio of corrected AOFP for the infill well to the corrected AOFP for the original well. The average ratio is 1.1 with a most probable value of 0.85. The upper skewness in this distribution is the cause of the difference between the average and most probable values. This ratio is a direct measure of the difference between the performance of a typical infill well and the original well. Fig. 18 indicates that over 60% of the infill wells have corrected AOFP's less than the original well. Since the infill wells were generally stimulated with a water-based treatment, the infill wells could experience some degree of cleaning up over time as they unload the injected frac water. This effect 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 due to clean-up effects, this increase has no appreciable effects upon the results of this study. Although the calculated official deliverabilities for the infill well averaged 380 Mscf/day greater than that for the original well, the corrected AOFP, which represents a better comparison, averaged 457 Mscf/day <u>less</u> than that for the original well.

The ratio of corrected AOFP used in Figure 18 is presented by operator in Fig. 19. Arco, Union Pacific, and the other operators have ratios greater than 1.75. The most likely reason for the infill wells appearing to be so much better than the original well is that the original wells had poorer stimulation results. The results for the remaining operators range from ratios of 1.18 (OXY) to 0.77 (Anadarko). Since Anadarko has such a low average, it may be an indication of less than optimum stimulation results on the infill wells or better initial completion results.

Fig. 20 shows the ratio of corrected AOFP between the infill and original wells by county. The counties on the north and some of the edges of the field including Kearny, Finney, Haskell, Stanton, and Hamilton Counties all have ratios greater than 1.28. This indicates on average that in these counties the original wells had poor stimulation results. It is possible that many of these original wells on the edges of the field were not restimulated in the early 1960s. The average in the remaining counties ranges from .89 to 1.08.

Infill Well Allowables vs. Original Well Allowables

Fig. 21 is a plot of allowable vs. time for the original wells, infill wells, the sum of the infill and original wells, and for the original well had the infill well not been drilled. The original well allowable divided by seventy percent gives us the original well allowable had the infill well not been drilled. The well count vs. time is on the offset y-axis of Fig. 21. 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 November 1989, the infill wells accounted for an overall incremental allowable of approximately 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 non-minimum well becomes overproduced by 6 times its basic monthly allowable, the KCC shuts the well in until the overproduction is worked off. For example, in January 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 starting in May 1977 through November 1989. For the first 11 months of 1989, the average infilled proration unit had an increase in allowable of only 36 Mscf/day due to the presence of the infill well. For this same period, 35% of the infilled proration units actually lost allowable because of the infill well.

CONCLUSIONS

After studying the results of the 659 infill wells given allowables by the KCC through November 1989 we have the following conclusions:

1. Based on our engineering analysis of the infill and companion original well performance data in the Kansas Hugoton, we conclude that no evidence of additional gas-in-place was found.

2. 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 is an indication of 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.

3. The average infill well's initial wellhead shut-in pressure is 13.6 psi higher than the average corresponding shut-in pressure of the original well. We believe this pressure difference does not reflect additional gas-in-place but is a result of the pressure gradient in the most permeable layer toward the original well.

4. The higher initial official deliverabilities found in the infill wells over the original wells cannot be reliably used as an indication that the infill wells are encountering additional gas-in-place. To better compare performance between the infill and corresponding original well, a calculation may be made of the absolute open flow potential corrected to 1989 field average shut-in pressure of 147.6 psia. This calculation puts all the wells on the same pressure basis, removing the effect of the pressure gradient. Although the calculated official deliverabilities for the infill wells average 380 Mscf/day greater than that for the original well, the corrected AOFP, which represents a better comparison, averaged 476 Mscf/day less than that for the original well. On average, this indicates poorer stimulation results in the infill wells compared to the original wells.

5. During the first 11 months of 1989, the average infilled proration unit had an increase in allowable of 36 Mscf/day due to the presence of the infill well. For the same period, 35% of the infilled proration units actually lost allowable because of the infill well.

6. During the month of November 1989, the allowable of the infill units was approximately 12% greater than the allowable of the proration unit if the infill well had never been drilled.

7. 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 allowed by the Kansas Corporation Commission.

NOMENCLATURE

AOFP = absolute open flow potential, Mscf/day
D = official deliverability, Mscf/day
P = 72-hour wellhead shut-in pressure, psia
P_{avg} = average field shut-in pressure, psia
P_d = deliverability standard pressure, psia
P_w = working wellhead pressure at ratio R, psia
R = observed producing rate at the end of 72 hours, Mscf/day

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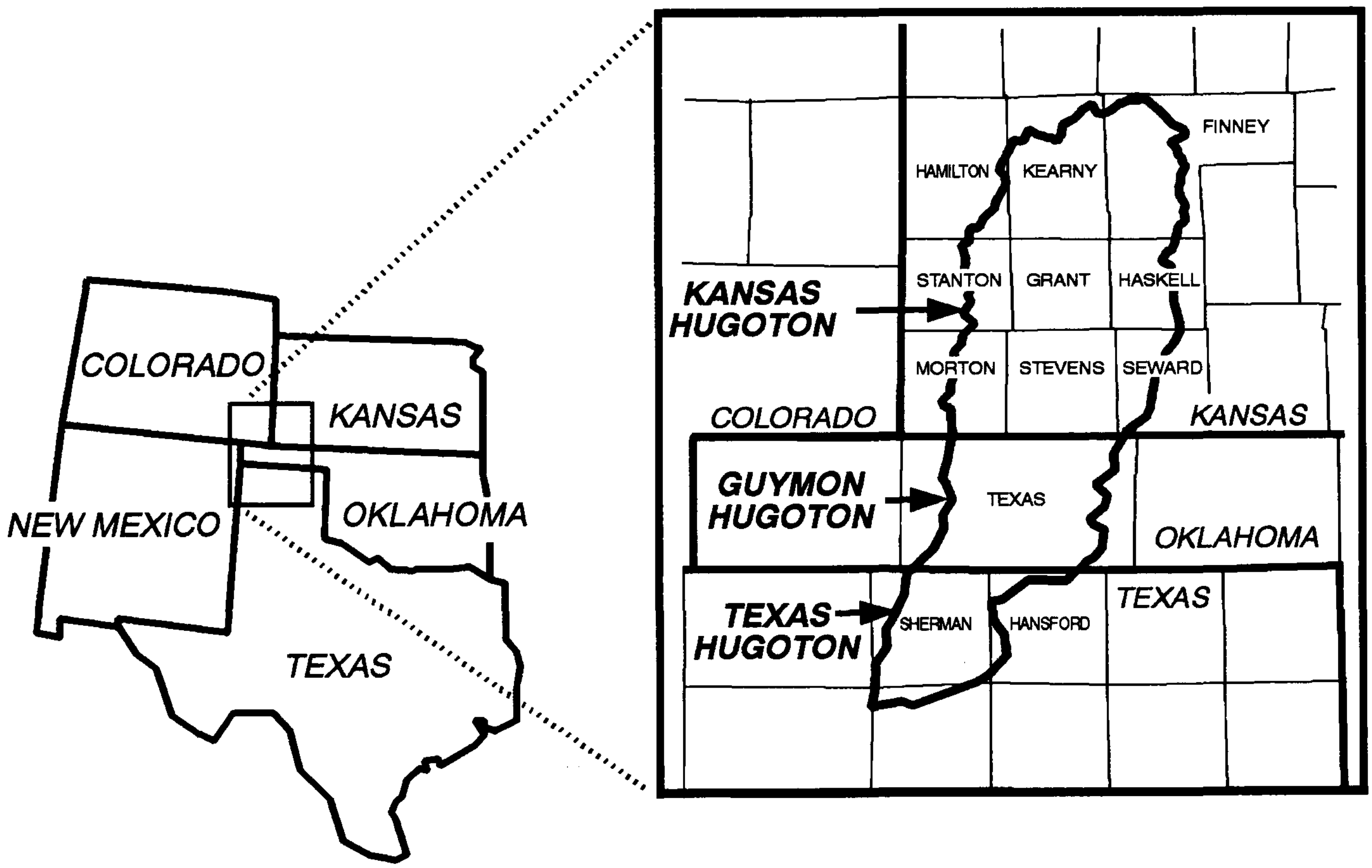

Fig. 1—Kansas Hugoton location map.

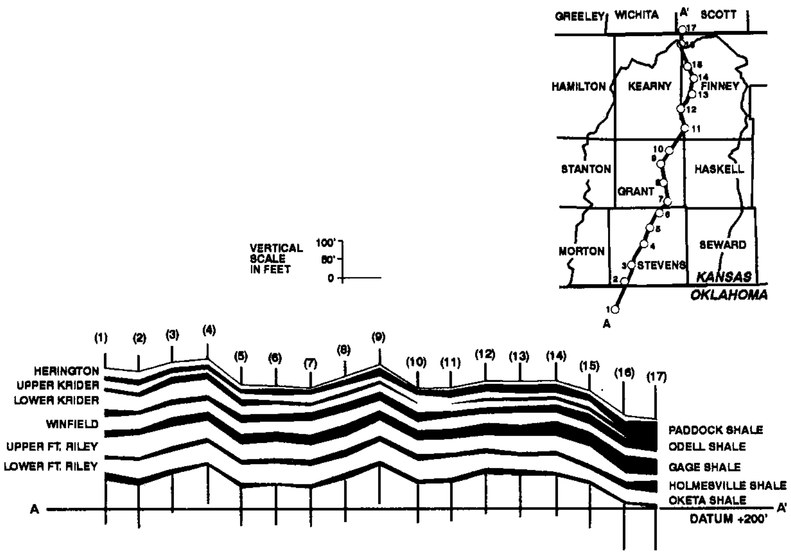

Fig. 2—East-west cross section through the Kansas Hugoton.

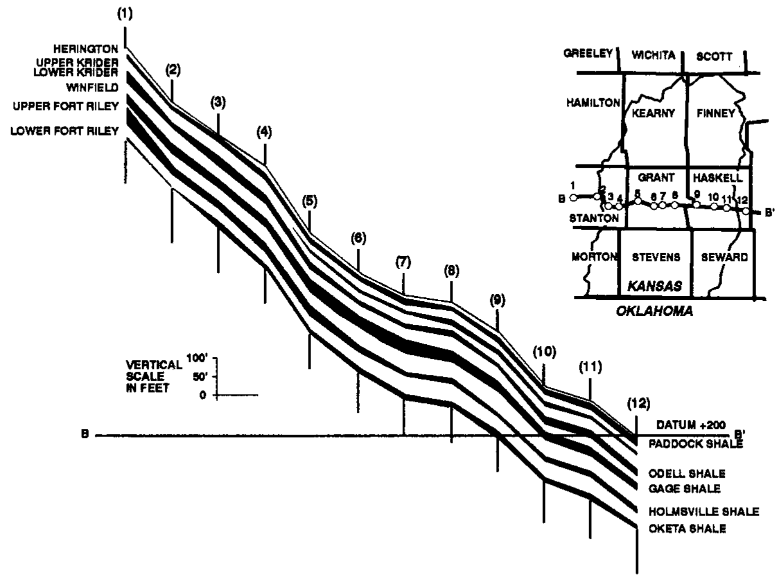

Fig. 3—North-south cross section through the Kansas Hugoton.

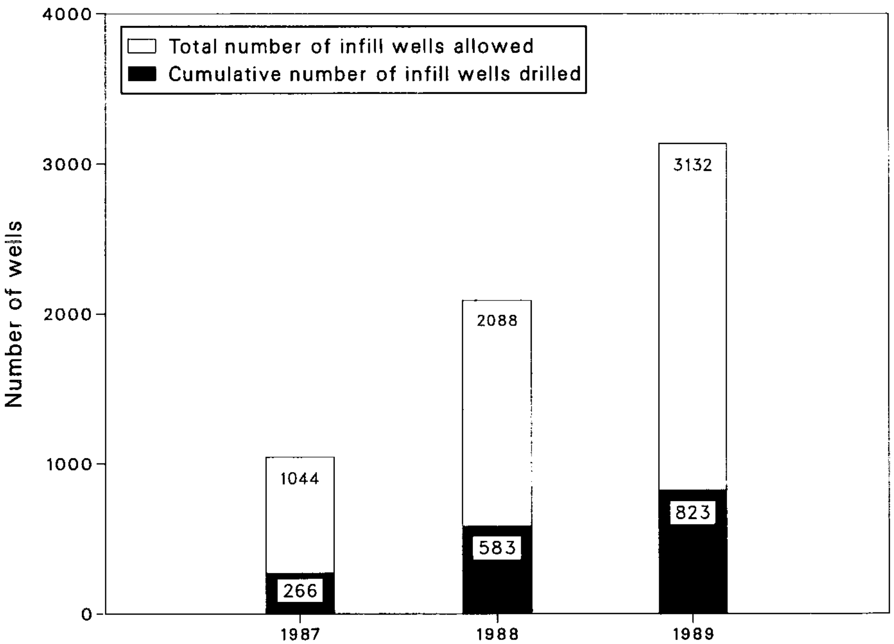

Fig. 4—Actual number of infill wells drilled compared with the total number of wells allowed.

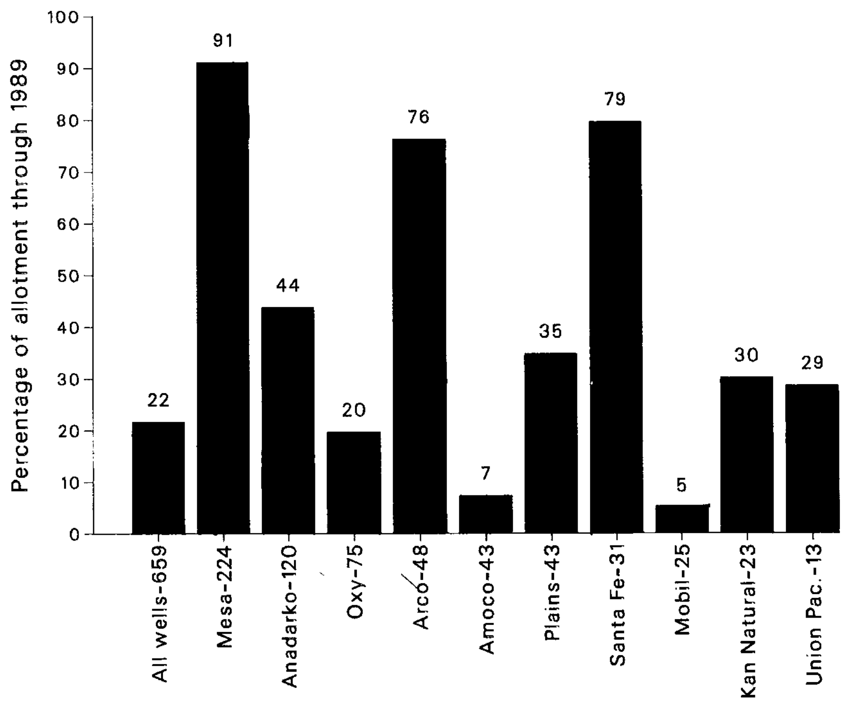

Fig. 5—Infill activity by operator.

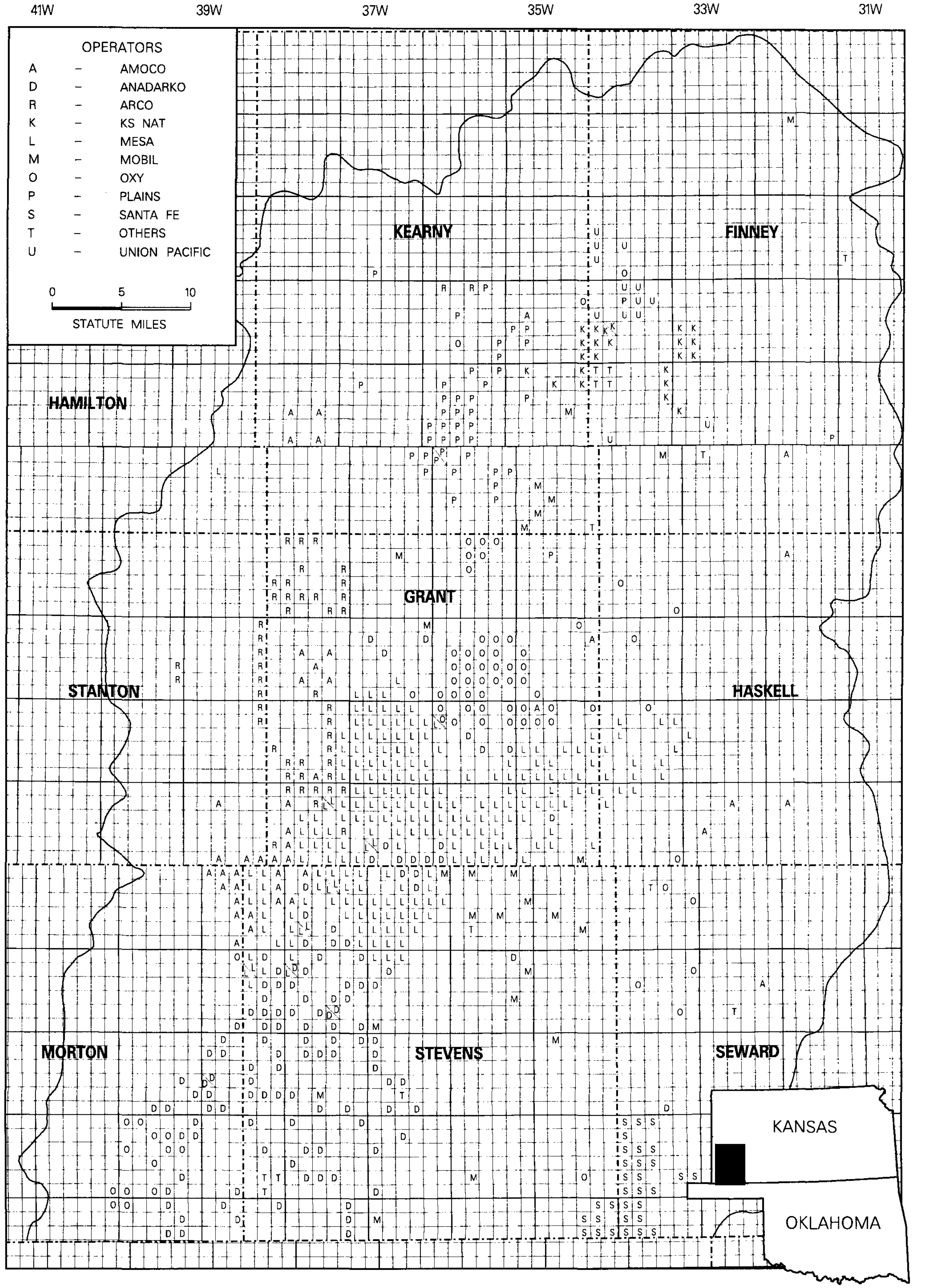

Fig. 6—Kansas Hugoton infill well locations.

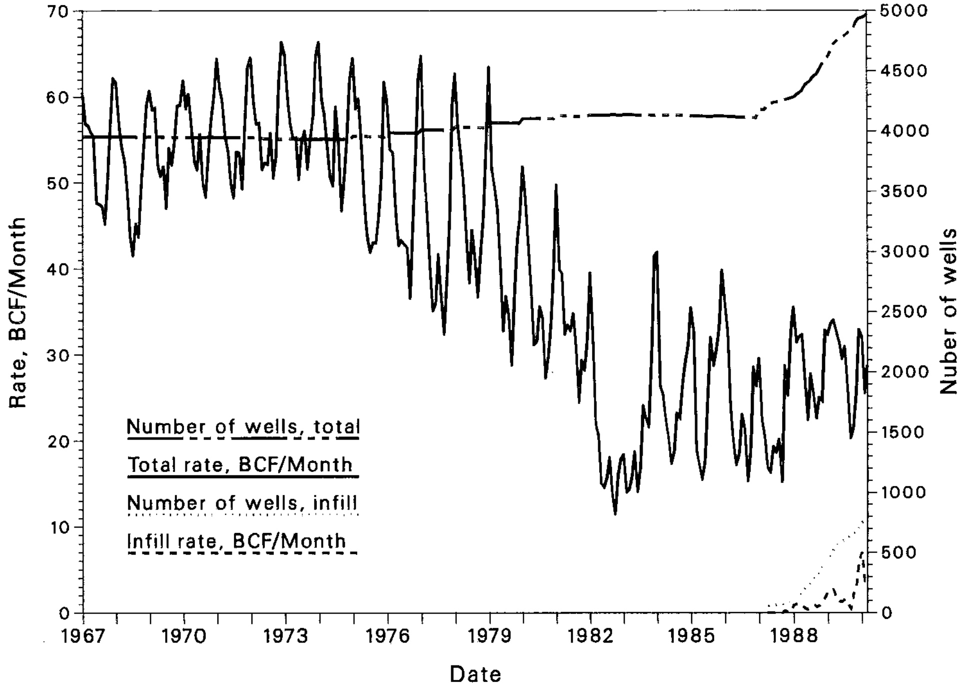

Fig. 7—Historical production and well count since 1967.

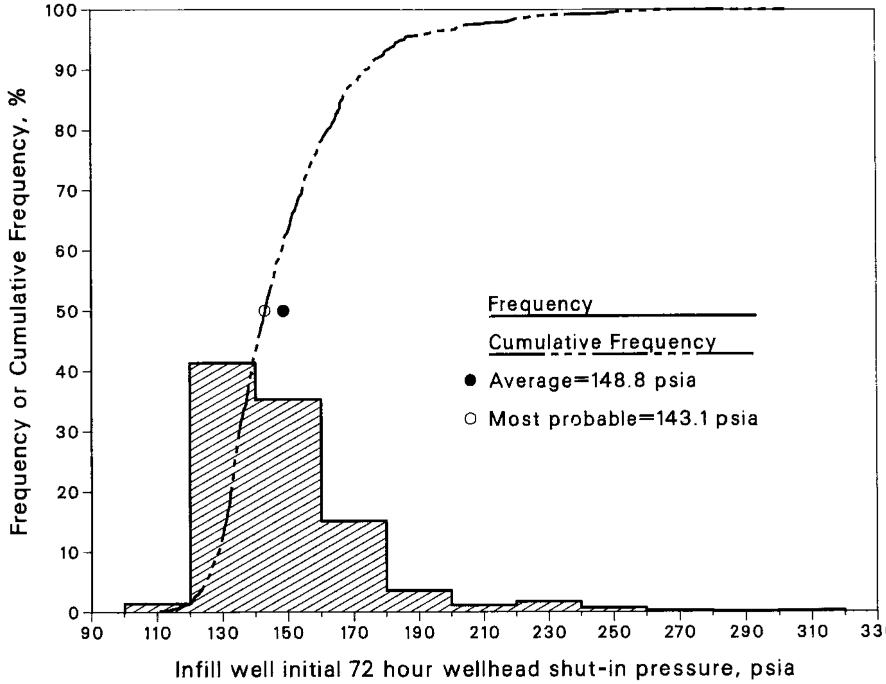

Fig. 8—Infill well initial wellhead shut-in pressure histogram.

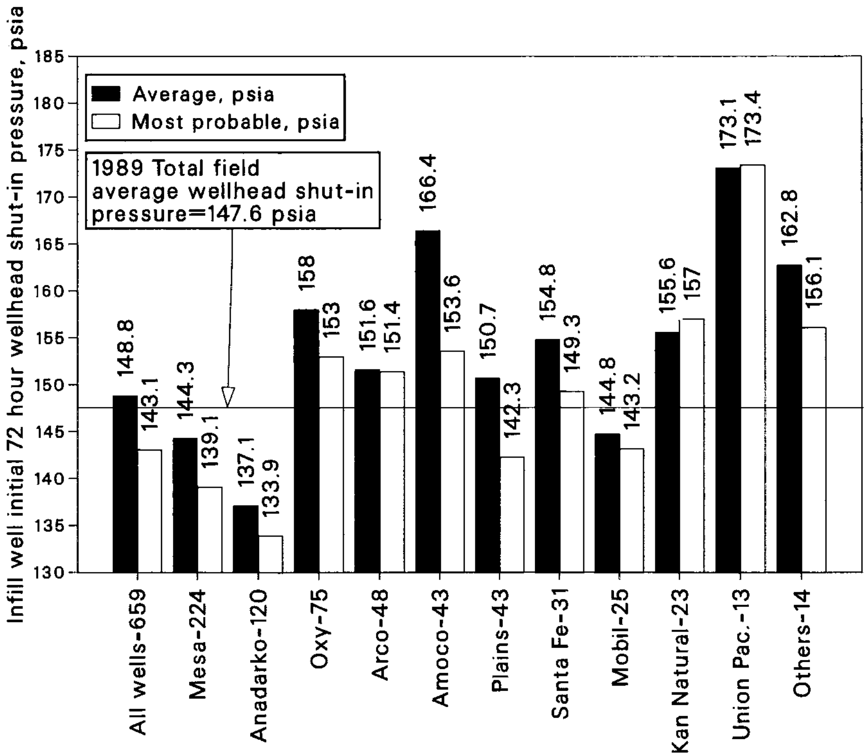

Fig. 9—Initial infill wellhead shut-in pressures by operator.

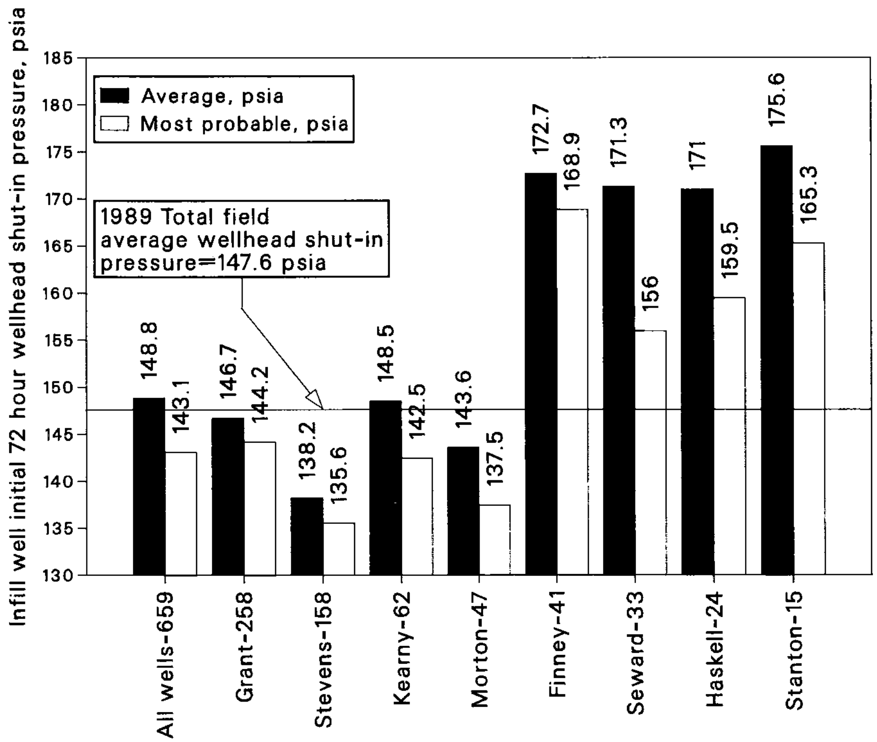

Fig. 10—Initial infill wellhead shut-in pressures by county.

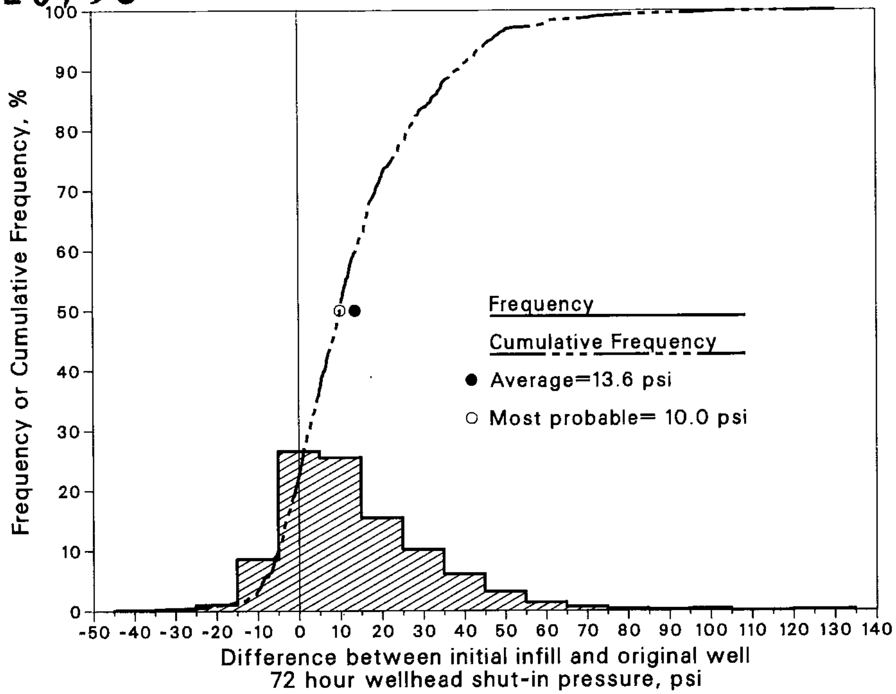

Fig. 11—Histogram of the differences between initial infill and original wellhead shut-in pressures.

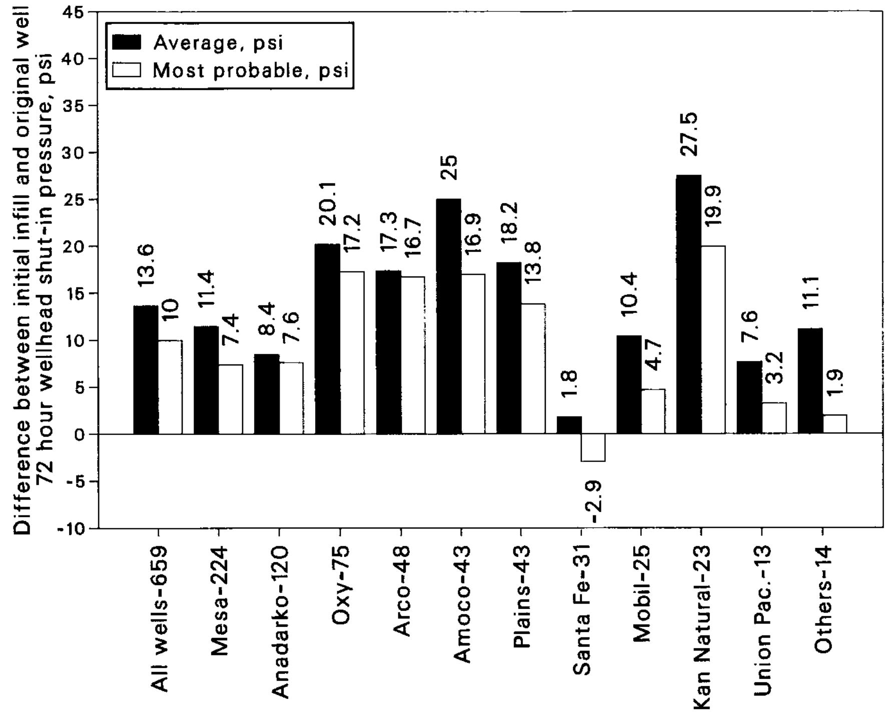

Fig. 12—Difference between initial infill and original wellhead shut-in pressure by operator.

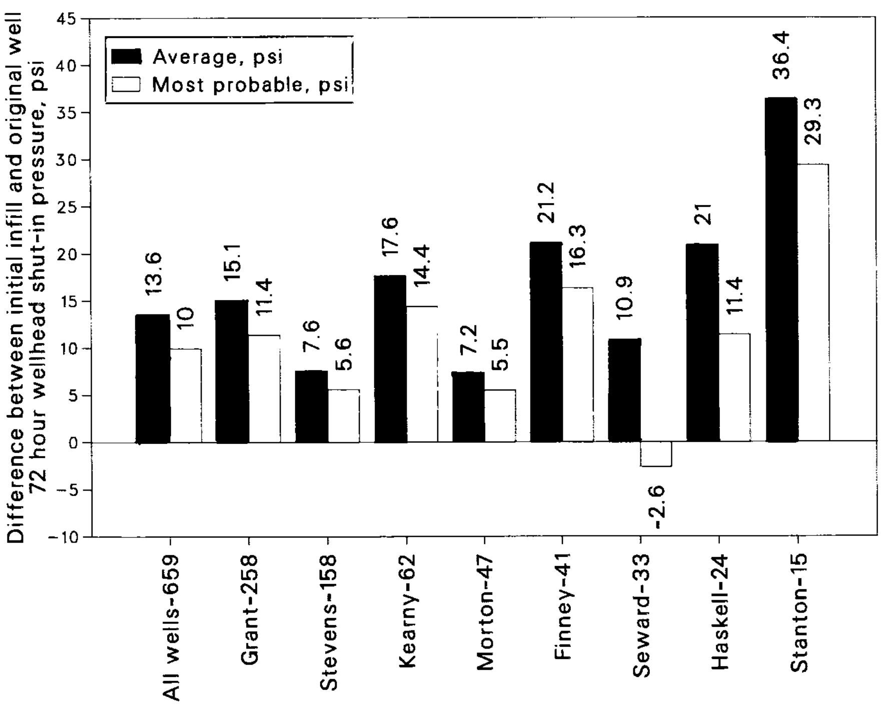

Fig. 13—Difference between initial infill and original wellhead shut-in pressure by county.

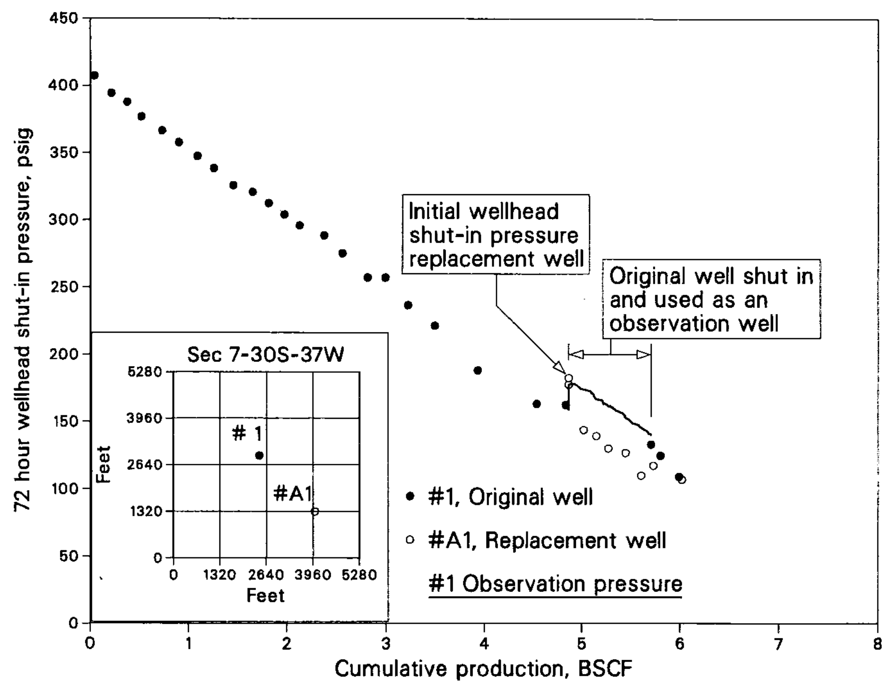

Fig. 14—Wellhead shut-in pressure vs. cumulative production for one of Mesa's original and replacement well pairs.

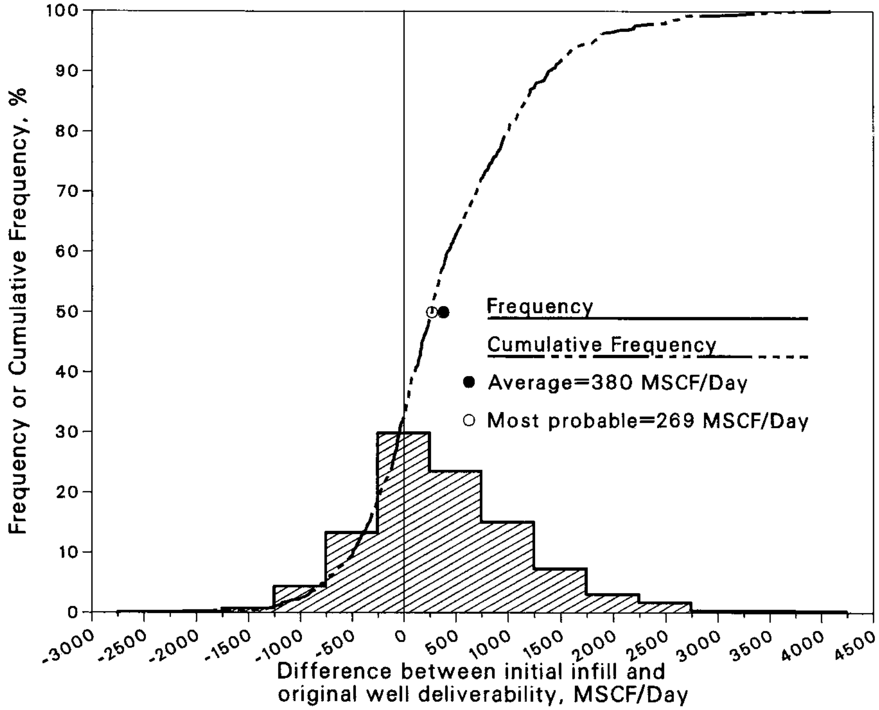

Fig. 15—Histogram of the difference between initial infill and original well official deliverabilities.

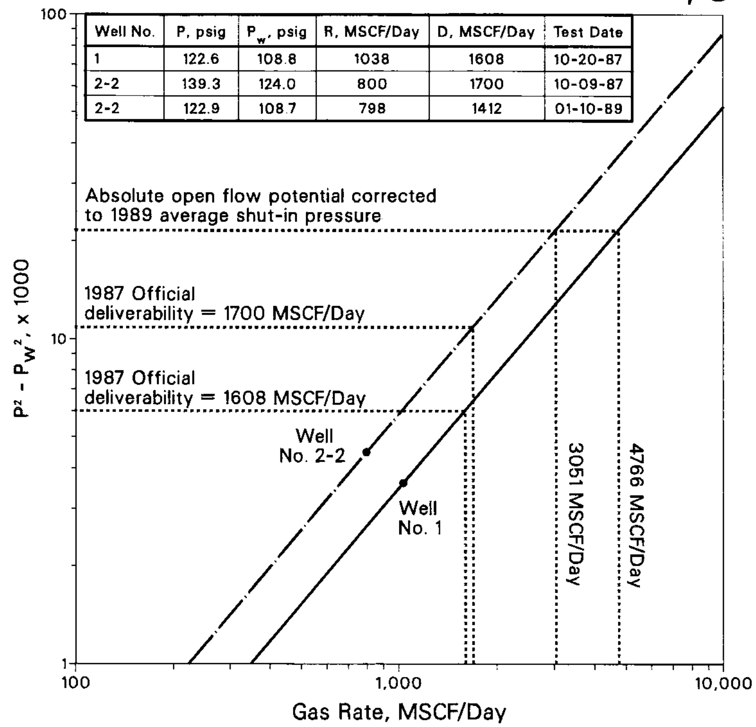

Fig. 16—Wellhead backpressure curve for the Nafzinger No. 1 and No. 2-2.

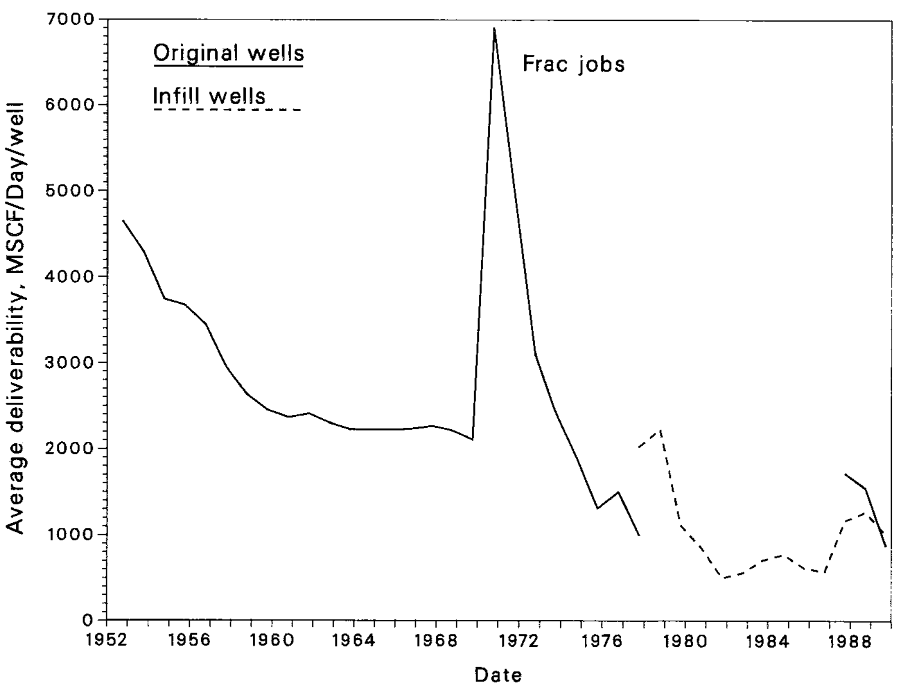

Fig. 17—Historical official deliverability for the wells in Mesa's five-well replacement well study area.

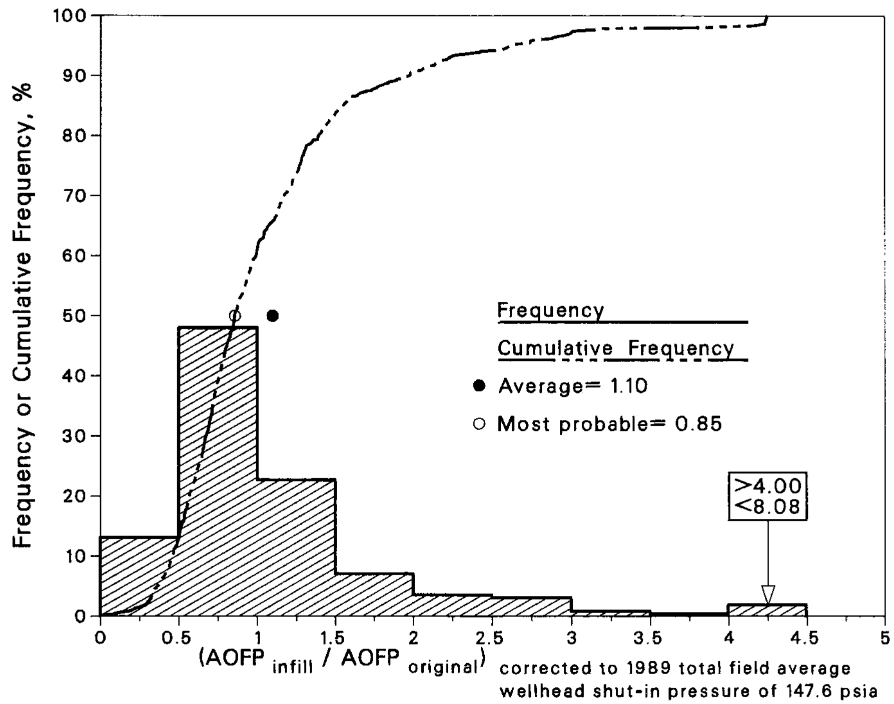

Fig. 18—Histogram of the ratio of corrected AOFP.

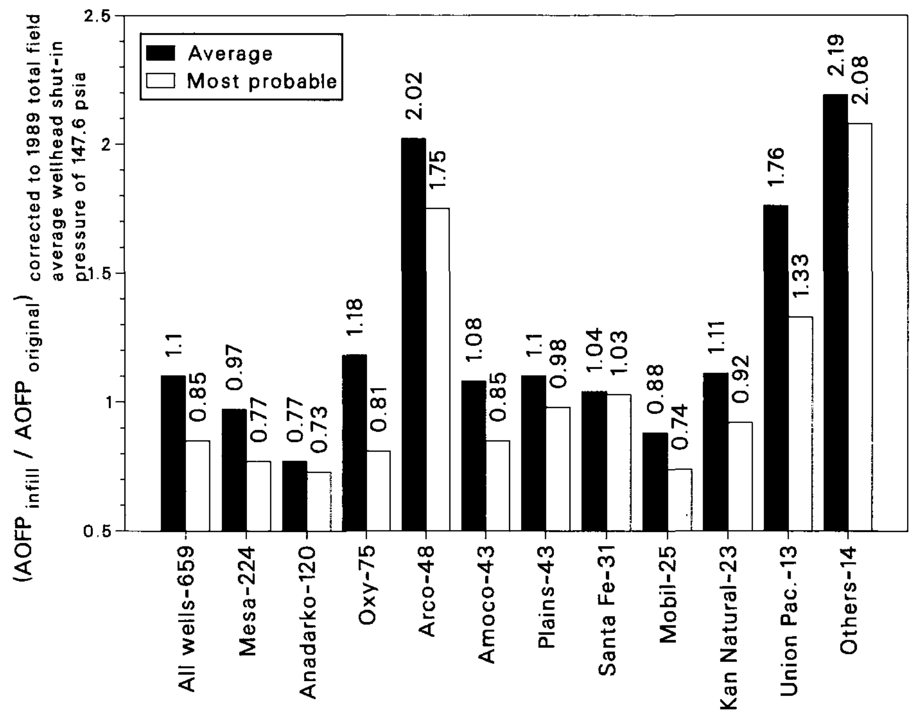

Fig. 19—Ratio of corrected AOFP by operator.

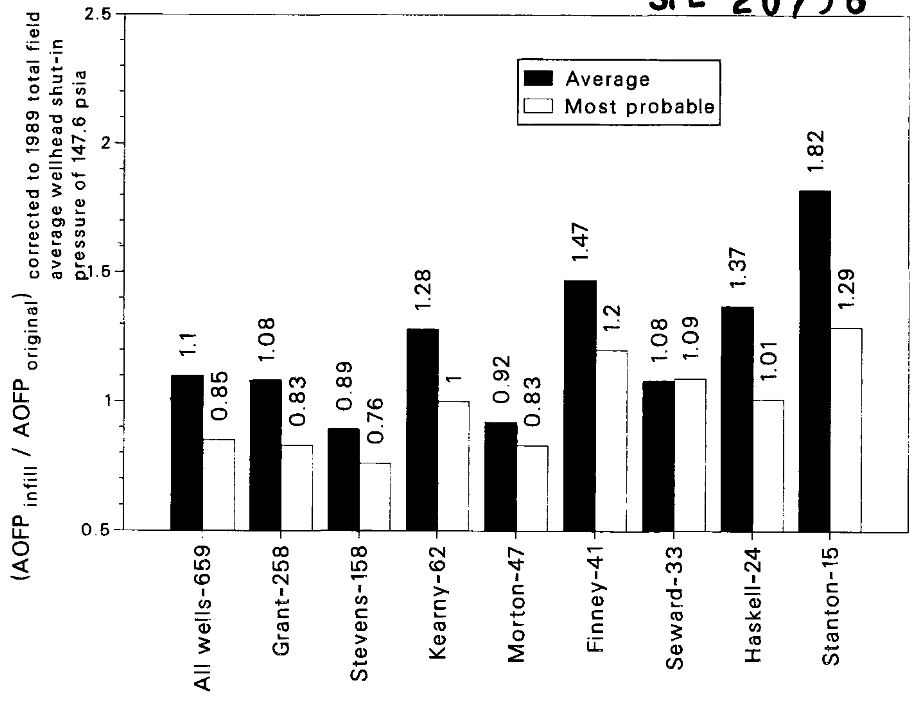

Fig. 20—Ratio of corrected AOFP by county.

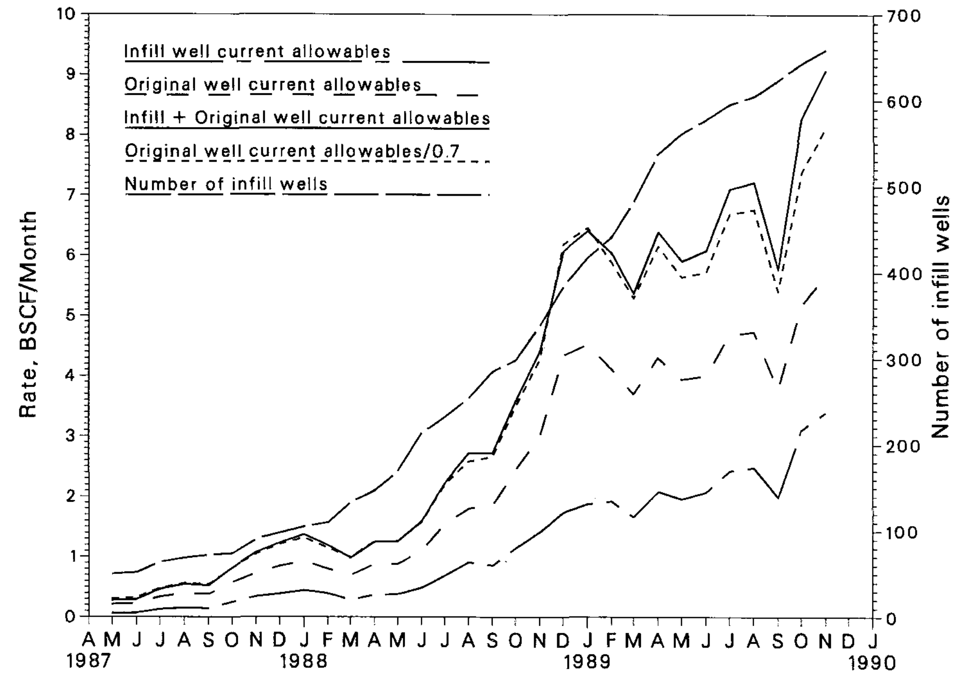

Fig. 21—Infill well allowables compared with original well allowables.