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Using a Multilayer Reservoir Model To Describe a Hydraulically Fractured, Low-Permeability Shale Reservoir

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ABSTRACT

This paper summarizes the development and application of a multi-layer reservoir description for the Gas Research Institute (GRI) Comprehensive Study Well 2 (CSW2), which is completed in the Devonian Shales and located in Calhoun Co., WV. We determined that a two-layer reservoir description best describes the complex reservoir and hydraulic fracture system of the CSW2. This reservoir description, determined using a numerical simulator, matched all the data collected, including pre- and post-fracture flow/buildup tests, multi-layer communication tests, individual-layer injection/falloff tests and pre- and post-fracture production data.

The results of this study indicate that a multi-layer reservoir description provides better estimates of post-fracture performance compared to a more conventional, single-layer reservoir description. This result also explains previous, optimistic estimates of post-fracture well performance which were based on single-layer interpretations of pre-fracture test data. This paper reviews and discusses briefly the many diagnostic tests performed on the CSW2, but focuses on the history match analysis and results determined with a two-layer reservoir model. The testing and analysis approach presented in this paper can be applied generally to other tight formations.

INTRODUCTION

The Devonian Shales of the eastern U.S. are a significant source of domestic U.S. natural gas. The complex storage and production mechanisms of the Shales have been studied extensively. In mid-1987, GRI initiated a multi-year research effort on several highly-instrumented study wells in the Devonian Shales of the Appalachian Basin.[1-3] These wells, called Comprehensive Study Wells (CSW's), were drilled and studied in cooperation with Appalachian Basin operators. Extensive data were collected and special experiments were conducted on these wells in addition to the operator's normal operations. The objectives of the CSW program were (1) to develop a better understanding of the geologic controls on production, (2) to refine previously developed formation evaluation tools for selecting completion intervals, and (3) to improve reservoir description and stimulation practices in the Devonian Shales.

In the CSW program, we first began evaluating the Devonian Shales using simple, single-layer reservoir models until, as this paper demonstrates, the need to develop more complex models become evident. Now, it appears the large intervals completed in the Shales cannot generally be analyzed or classified as an equivalent single-layer system; they are much more complex.[3,6,8-10] In the CSW2, the post-fracture production performance was much less than we predicted using a single-layer reservoir and fracture description based on pre-fracture well test analysis results and the fracture treatment design. Our initial post-fracture well test analysis results indicated a short, 28-ft, infinite-conductivity hydraulic fracture, using a single-layer reservoir description.[6] Because of these results, several post-stimulation diagnostic tests were performed to evaluate the location and geometry of the propped hydraulic fracture, to provide a more detailed reservoir description, and to determine the cause of the less-than-predicted post-fracture well performance.

The purpose of this paper is to present our CSW2 reservoir description based on results obtained using a two-layer reservoir model to history match all the numerous field data collected. Our analysis results indicate an unusual and complex hydraulic fracture geometry which intersects more than one "pay" layer, but only communicates with the wellbore in one layer. A more detailed discussion of our results can be found in Reference 6. The testing

References and illustrations at end of paper.

and analysis approach presented in this paper can be applied to other tight and/or layered formations, including tight gas sands and shales.

CSW2 WELL HISTORY

Sterling Drilling and Production Company drilled the CSW2, located in Calhoun County, WV, to a total depth of 4,550 ft in October 1987. **Fig. 1** shows the CSW2 location in relation to the other GRI CSW's. Numerous open and cased hole data were collected and analyzed from the CSW2.[4-7] Log analysis results, coupled with wellsite geochemistry, mud log shows, borehole television, and temperature surveys identified several potentially productive Shale intervals. The Devonian Shales in the CSW2 area consist primarily of gray and black shales with abundant interspersed siltstones.[4]

A 335-ft gross interval in the Upper Devonian Undivided and the Lower Huron was perforated in March 1988. **Fig. 2** is a wellbore schematic showing the perforated intervals. The perforations were broken down with 202,000 scf of nitrogen to achieve pre-fracture flow. A pre-fracture well test was performed on the total perforated interval following the breakdown. We analyzed these test data and determined a reservoir description, predicted future performance, and designed a hydraulic fracture treatment assuming a single-layer model.[6] The fracture treatment design was also based on stress test analysis results which indicated that fracture height would not be contained (radial height growth) due to the lack of high stress barriers above or below the pay interval.[6-10]

The perforated interval was hydraulically fractured in May 1988 using a 65- to 75-quality CO_2 foam (85,000 gal) carrying 252,000 lb of 20/40 mesh sand. The majority of the treatment was pumped at sand concentrations of 6 to 7 lb/gal, much higher than typically pumped in this area. CO_2 foam was selected as the fracturing fluid based on regained permeability tests conducted on core samples.[4]

Since the fracture treatment, the CSW2 has produced intermittently. A post-fracture well test was performed 60 days after the fracture treatment. The analysis results indicated a permeability-thickness product of 1.97 md-ft and a short fracture half-length of 28 ft, assuming a single-layer reservoir model. In addition, the post-fracture performance was much less than predicted. Results of an earlier, related study indicated a layered reservoir description might be more appropriate than an equivalent single-layer description.[8,9] Therefore, a series of diagnostic tests were initiated in March 1990 to determine the location and geometry of the hydraulic fracture and to evaluate the reservoir in more detail than was done in previous pre-fracture studies.

POST-FRACTURE DIAGNOSTIC TESTS

The CSW2 post-fracture diagnostic tests included zone isolation/communication tests, individual-zone nitrogen injection/falloff tests, individual-zone and total-well flow/buildup tests, and a microseismic logging experiment. The diagnostic tests were performed from March through September 1990. The results of the microseismic logging experiment and a discussion of the qualitative observations from the other diagnostic tests have been presented previously.[6,7] In this section, we briefly summarize the post-fracture diagnostic tests performed in CSW2 and our qualitative observations from the tests. **Table 1** summarizes the diagnostic tests which were performed.

Zone Isolation Tests

We conducted zone isolation tests in March 1990 to establish a production profile of the well by perforation interval. A tubing and packer assembly was used to isolate each perforated interval. The three intervals were tested for two hours each, flowing both the tubing and annulus. **Table 2** summarizes the post-fracture isolation test results and compares these rates to those of a pre-fracture spinner survey. The zone isolation rates are two hour, transient rates. We initially used this distribution of the flow rates to make a qualitative judgement of the relative effectiveness of the fracture treatment in each zone. All three perforated intervals (3,552 to 3,680 ft) appear to be stimulated by the hydraulic fracture treatment, based on post-fracture rate increases. However, the distribution of gas production changed as a result of the fracture treatment.

Communication Tests

Inter-zone communication tests were conducted after the zone isolation tests in March 1990 to evaluate the extent of communication, at the wellbore, between perforated intervals due to the propped hydraulic fracture. A packer and bridge plug arrangement was used to isolate individual perforated intervals in the wellbore, and the three perforated intervals in **Fig. 2** were each tested. Memory pressure gauges were installed at the surface, below the bridge plug, and in the tubing-tailpipe below the packer assembly. For each test, the annulus above the packer was flowed for approximately one day against atmospheric pressure with the tubing shut-in, monitoring the tubing for communication.

The results indicated the lower two perforated intervals are in communication at the wellbore. The cement bond log and cement evaluation tool indicate excellent bond in the interval between 3,580 to 3,623 ft. No communication was indicated between the upper perforated interval (3,345 to 3,379 ft) and the middle perforated interval (3,552 to 3,580 ft). From these test results, we inferred that there was a hydraulic fracture connecting the two lower perforated intervals (3,552 to 3,580 ft and 3,623 to 3,680 ft) and that this fracture was not in communication with the upper perforated interval (3,345 to 3,379 ft) at the wellbore. Hereafter, we refer to the upper perforated interval as the upper zone and to the middle and lower perforated intervals collectively as the lower zone.

Nitrogen Injection/Falloff Tests

A nitrogen injection/falloff test was performed in April 1990 on the lower zone because the earlier communication test indicated the two sets of perforations within this interval were in communication at the wellbore. A second test was performed on the upper zone. The objectives of these tests were to estimate the existence and size of the propped hydraulic fracture[8,9] and to gather additional information about the reservoir. To perform the tests, nitrogen was injected through tubing set on a packer in three stages to pre-determined design levels of approximately 900 psi, 1,200 psi, and 1,500 psi (below fracturing pressure) to pressurize the formation around the wellbore. A downhole shut-off tool was used to shut-in the well after each injection cycle, to reduce wellbore storage effects, and to allow us to closely monitor the pressure falloff with a bottomhole, surface readout quartz pressure gauge. The nitrogen injection/falloff test analysis results indicate an infinite-conductivity hydraulic fracture in communication with the wellbore in the lower zone, and no infinite-conductivity fracture in communication with the wellbore in the upper zone. We inferred these results because much more nitrogen was injected into the lower zone and the falloff data exhibited a half-slope (linear flow) in only the lower-zone test.[6,7-9]

Flow/Buildup Tests

From May through August 1990, we performed flow/buildup well tests individually on the lower and upper zones, and on the total perforated interval. Each well test consisted of a 14-day controlled-rate flow period against atmospheric pressure, followed by a 14-day buildup test. Tubing, packer, and a bridge plug were used to isolate intervals for each test. The objective of these tests was to determine reservoir and completion properties in more detail than possible from the pre-fracture and first post-fracture well tests performed in 1988 on the total perforated interval. As we will show, these three well tests proved to be essential in our study, enabling us to determine a hydraulic fracture and two-layer reservoir description for the CSW2.

Our qualitative well test analysis results were similar to our nitrogen injection/falloff results and indicate there is a infinite-conductivity hydraulic fracture in the lower zone, but no fracture at the wellbore in the upper zone. **Fig. 3** is a semilog plot of pressure buildup data for all three tests. The shape of the pressure buildup data are similar in the lower- and total-zone well tests (hydraulically fractured),[9] but the shape of the upper-zone data is different, indicating radial flow followed by heterogeneous behavior late in the test. These data were key to our ability to determine that the CSW2 can be described as a two-layer reservoir with a complex hydraulic fracture geometry.

We attempted to analyze each test using conventional, single-layer analysis techniques. Our analysis efforts indicated that history matching would be required to provide a consistent reservoir/hydraulic fracture description. The well test data also indicate the lower and upper zones are in communication, but not near the wellbore. This was an important observation, because the earlier communication tests did not indicate the upper and lower zones were in communication. **Fig. 4** illustrates this point by showing the pressures measured from the annulus (upper zone) and lower zone during the lower-zone well test. The upper and lower zones appear to be in communication, but away from the wellbore. We will discuss these results in more detail later in this paper.

Microseismic Test

The final post-stimulation diagnostic test on CSW2 in 1990 was a microseismic logging survey. Our analysis results are presented in Reference 7. The microseismic data analysis is unique in that it can detect the presence of a hydraulic fracture if it angles away from the wellbore. We inferred, from the microseismic analysis results, that the top portion of the fracture might penetrate the upper zone away from the wellbore. The nitrogen injection-/falloff tests and the flow/buildup tests did not indicate a hydraulic fracture at the wellbore in the upper zone.

Summary of Qualitative Post-Fracture Test Evaluation

Our qualitative observations from the post-fracture diagnostic tests are summarized below:

1. There is an infinite-conductivity fracture at the wellbore in the lower zone;

2. There is not an infinite-conductivity fracture at the wellbore in the upper zone;

3. The upper and lower zones are in communication, but at some distance from the wellbore; and

4. The hydraulic fracture in the lower zone might communicate with the upper zone at some distance away from the wellbore.

THEORETICAL EVALUATION OF TWO-LAYER MODEL

The purpose of this section is to present the results of a theoretical evaluation of a two-layer reservoir model with a complex hydraulic fracture geometry to evaluate the data collected in CSW2. We believed that we would ultimately need to history match the rates and pressures from the post-fracture diagnostic tests to characterize the CSW2 reservoir/fracture system and forecast well performance accurately. Before history matching actual data, however, we evaluated several possible reservoir/hydraulic fracture configurations to determine which model might yield pressure data similar in shape to the measured post-fracture test data. We could then choose an appropriate reservoir/fracture model to use in our final, quantitative CSW2 history match analysis. The qualitative model evaluation results presented in this section indicate a two-layer model with a hydraulic fracture in the lower zone, communicating into the upper zone away from the wellbore, yields similar pressure responses to those observed in the three CSW2 flow/buildup tests.

Simulation of Buildup Tests

We investigated three possible two-layer reservoir models to simulate the three buildup tests. We used a finite-difference reservoir simulator for this evaluation.[11] **Fig. 5** shows these three models, which we refer to as Models 1, 2, and 3. There are actually three layers in Models 1, 2, and 3. The very-low permeability middle layer (10^{-8} md) represents the unperforated interval from 3,380 to 3,551 ft in CSW2. On the basis of log analysis results,[5] this is not a net pay interval, but we modeled the total interval since the hydraulic fracture might have grown through all, or part of this interval. There is no inter-layer crossflow in Models 1,2, and 3 except through the hydraulic fracture.

Table 3 shows the reservoir properties assumed in our theoretical model evaluation, which are similar to actual CSW2 properties.[6] Model 1 contains a 100-ft hydraulic fracture through both upper and lower zones, and the hydraulic fracture is in communication with both zones at the wellbore. Model 2 has separate 100-ft hydraulic fractures in each layer, which are not in communication with each other. Model 3 has a 100-ft hydraulic fracture in the lower zone communicating with the upper zone away from the wellbore. There is not a hydraulic fracture at the wellbore in the upper zone in Model 3. The 100-ft fracture half-length was chosen based on preliminary history match results of the CSW2 fracture treatment pressure data.[6]

We simulated the buildup tests in a manner similar to the actual tests performed on CSW2. Our simulated pressure buildup results using Models 1 and 2 indicate similar, stimulated (hydraulically fractured) behavior for all three buildup tests. This result was expected since there is a fracture in both layers. This observation indicates that Models 1 and 2 do not adequately describe the buildup test behavior observed in the three CSW2 buildup tests.

The simulated pressure buildup data from Model 3 shows similar pressure buildup responses to that exhibited by CSW2. **Fig. 6** shows the simulated pressure buildup data from Model 3 compared to the actual data collected in CSW2 as a log-log plot of adjusted pressure change[12,13] versus equivalent adjusted time.[12-14] As with the CSW2 data, the simulated Model 3 buildup data from the lower zone are almost identical to the total interval data. This indicates that the hydraulically-fractured interval dominates the pressure response from the total-interval and lower-zone tests. The simulated upper zone data exhibits wellbore storage followed by radial flow behavior with heterogeneous or bounded behavior late in the test, also similar to that observed in the CSW2 data. On the basis of these similar pressure responses to CSW2, and the qualitative results of the communication tests, nitrogen injection/falloff tests, and microseismic experiment analysis, we chose a model similar to Model 3 for use in our final, quantitative history match.

Evaluation of Conventional Buildup Analysis Methods

Before attempting to history match the CSW2 data with a Model 3 reservoir/hydraulic fracture description, we analyzed the simulated pressure buildup data from Model 3 using conventional semilog and type curve analysis techniques.[15] The purpose of this analysis was to evaluate if reservoir and completion properties (kh, skin factor, and/or fracture half-length, L_f) could be determined from the simulated Model 3 pressure buildup data using conventional homogeneous, single-layer well test theory.

We first analyzed the simulated pressure buildup data from the Model 3 lower-zone test. We determined the correct permeability-thickness product, kh, using both the Barker-Ramey type curve[16] and linear flow analysis.[17] The calculated fracture half-length of 151 ft was too long, however, compared to the simulated half-length of 100 ft. This occurs because gas from the upper zone is produced, through the hydraulic fracture, down into the lower zone during the flow period. Recall that the upper zone is in communication with the lower zone through the hydraulic fracture in Model 3. The effect of the additional upper zone gas and upper zone fracture area on our analysis results is a calculated fracture half-length that is too long.

We also analyzed the simulated upper zone buildup data. Our upper zone analysis results indicated that we cannot determine the correct kh or skin factor. The analysis yielded a permeability which is too low compared to the simulated permeability. We believe this is due to fracture crossflow between the two layers during the flow period, similar to that observed in the lower-zone test. Our conventional analysis also resulted in a calculated negative skin factor, although Model 3 had a skin factor of 0 in the upper zone.

Finally, we analyzed the total-interval buildup data. Our results indicate we can determine the total kh of the simulated system, but that our calculated fracture half-length will be too small. The simulated data from Model 3 used a 30-day pressure buildup period, and we obtained sufficient data to reach pseudoradial flow and to determine kh correctly using both semilog and type curve analysis. In CSW2, however, the shut-in was only 14 days, and the actual data have not apparently reached the pseudoradial flow regime.

Summary of Theoretical Evaluation

In summary, we evaluated three theoretical, two-layer models containing hydraulic fractures to determine which model yielded pressure data similar qualitatively to the data observed in the three buildup tests in CSW2. Our results indicate that a two-layer reservoir description with a hydraulic fracture in the lower zone, extending up into the upper zone, (away from the wellbore in the upper zone), provides similar pressure responses to those observed in CSW2. This Model 3 reservoir/hydraulic fracture description is consistent with our qualitative analysis results from the other post-fracture diagnostic tests. We also determined that the simulated pressure data from the Model 3 lower zone can be analyzed using conventional, single-layer well test theory to calculate the correct lower zone kh. The fracture half-length calculated, however, will be too long. Based on our theoretical model evaluation results, we used the Model 3 geometry as a starting point in our quantitative CSW2 history match, which is discussed in the next section.

HISTORY MATCH ANALYSIS

This section discusses our two-layer history match analysis of the rate and pressure data from the three flow/buildup tests performed on CSW2. A two-layer reservoir description similar to Model 3 was used to determine a history match which describes the current deliverability of CSW2. This two-layer model was necessary to describe the hydraulic fracture geometry exhibited by the post-fracture diagnostic tests. We used a finite-difference reservoir simulator[11] to perform the history match analysis.

We first analyzed the lower-zone pressure buildup test to estimate kh and to approximate the fracture half-length, L_f. Our theoretical analyses results indicated we could calculate the correct lower-zone kh and an upper limit for fracture half-length using conventional, homogeneous, single-layer well test theory. **Fig. 7** shows the lower-zone pressure buildup data matched using a Barker-Ramey type curve.[16] Part of the pressure data shown in **Fig. 7** fall on a half-slope line, which is characteristic of linear flow from the formation into an infinite-conductivity hydraulic fracture.[17] The earliest pressure data are distorted by wellbore storage. **Fig. 8** is a plot of pressure change versus the square-root-of-time-function for linear flow analysis of the lower zone buildup test. The linear flow analysis yields the same fracture half-length as our type curve analysis, supporting our type curve interpretation. We calculated a kh of 0.42 md-ft and a fracture half-length of 164 ft for the lower zone. This fracture half-length is probably too long, based on the simulated Model 3 results discussed previously.

We determined reservoir property estimates for our initial two-layer CSW2 model as follows. The two layers correspond to the upper and lower zone in CSW2. We used log analysis results[5] to develop a porosity-net pay thickness profile. We estimated the upper-layer kh by subtracting the lower-zone kh of 0.42 md-ft (determined above) from the total-well kh determined from our previous post-fracture well test analysis results (1.97 md-ft). Initial reservoir pressure was obtained from the pre-fracture well test analysis.[6]

To perform our history match, we first simulated a production period based on the actual CSW2 history prior to the diagnostic tests. There were long periods after the 1988 fracture treatment when the well was cleaning up and in which we were uncertain of the exact production rates and flowing pressures. We used our best judgement to simulate these unknown periods. In our CSW2 history match, we placed an infinite-conductivity hydraulic fracture in the lower zone, communicating into the upper zone away from the wellbore in the upper zone. The variables in our history match were (1) fracture half-length, (2) distance from the wellbore that the hydraulic fracture intersects the upper zone, (3) areal extent of the upper zone, and (4) upper-zone permeability-thickness product. We varied the above parameters until a reasonable history match of all three well tests was obtained. We held the lower-zone kh constant at 0.42 md-ft.

Fig. 9 is a schematic of the model we used to obtain our best history match of the data from all three well tests performed on CSW2. **Fig. 10** is a semilog plot of our matches of the three pressure buildup tests. The most important reservoir properties used in our final two-layer model are summarized in **Table 4**. The reservoir description includes a thin, high-permeability upper zone and a thicker, low-permeability lower zone. Note we show three layers in our final model, but the middle layer has very low permeability (10^{-8} md). There is also no inter-layer crossflow except through the infinite-conductivity hydraulic fracture.

Important features of this model are (1) the kh distribution, which determines the productivity increase due to the hydraulic fracture, (2) a 100-ft infinite-conductivity hydraulic fracture in the lower zone that communicates with the upper zone 50 ft away from the wellbore, (3) a high-permeability feature at the wellbore in the upper zone connecting with the infinite-conductivity hydraulic fracture (modeled as a low-conductivity hydraulic fracture with a dimensionless fracture conductivity, C_r of 3.8), and (4) a reduced upper zone area. The final CSW2 model is not unique, but it matches the three flow/buildup tests reasonably well. Admittedly, the matches are not perfect, especially for the lower-zone and total-interval data. However, this description also predicts, with surprising accuracy, other observed test data from CSW2, as discussed in the next section.

We reduced the upper-zone areal extent from 160 acres to 90 acres to match the late-time observed pressure data in the upper-zone buildup test. If we had used 160 acres, the simulated data would exhibit a much sharper pressure increase after 150 hours, resulting in higher pressures over the last portion of the test. We could have probably also matched the upper-zone data by reducing the upper-zone initial reservoir pressure relative to the lower-zone reservoir pressure, but we did not investigate this possibility. A limited areal extent in a high-permeability interval in a multi-layer reservoir is not unreasonable.[18,19]

Our analysis indicates that the pressure response caused by the hydraulic fracture in the lower zone dominates the total-interval pressure buildup response. In the total-interval test, we do not observe the unusual upper-zone buildup response, unless the upper zone is tested separately. This illustrates the difficulty in analyzing post-stimulation well test data in multi-layer reservoirs that are perforated and stimulated over large gross intervals. A hydraulic fracture can penetrate a layer away from the wellbore and go undetected in isolated tests of that layer.

Our history match analysis also substantiates that there is no communication between the lower and upper zones near the wellbore. The communication between the zones occurs at some distance (50 ft in our model) from the wellbore. If there were communication between the two zones close to the wellbore, the upper-zone buildup would take on the characteristic shape of the lower-zone buildup (hydraulically fractured). We are uncertain of the exact distance from the wellbore where the lower-zone hydraulic fracture intersects the upper zone, but 50 ft provides a good match of the upper-zone pressure buildup data. It is not important that we determine the exact distance, but it is important that the infinite-conductivity fracture is some distance from the wellbore.

The high-permeability feature near the wellbore in **Fig. 9** was required for the upper zone to produce the rates observed during the upper-zone test and to match the buildup data. The high-permeability feature could be a fault and/or a natural-fracture system, or a low-conductivity hydraulic fracture. Natural fractures and/or a fault have been reported[4] in the upper zone. In addition, the upper zone could not produce the observed rates without gas feeding in from another source, and we believe this source is through the hydraulic fracture from the lower zone.

Fig. 11 is a schematic diagram illustrating two possible hydraulic fracture configurations to explain speculatively our CSW2 history match model. The inclined fracture shown in the left portion of **Fig. 11** might be possible if most of the treatment went into the lower perforated interval and grew at an angle from the wellbore. Natural fractures observed in CSW2[4,5] trend approximately 11° from vertical (including wellbore deviation). If a hydraulic fracture grew at an 11° angle from vertical at the midpoint of the lower zone, it would be approximately 49 ft from the wellbore at the mid-point in the upper zone. Shown in the right portion of **Fig. 11** is a theoretical example where proppant settling occurred, causing poor or no communication at the wellbore with the infinite-conductivity hydraulic fracture. Sand settling may have occurred in the upper zone due to poor proppant transport. Foam systems are complex, with short half-lives; it is conceivable that sand settled out of the upper zone near the wellbore either during the treatment or before the fracture closed.

To summarize, the two-layer reservoir model developed for CSW2 yielded reasonable matches of all three flow/buildup tests. A single-layer reservoir description with a hydraulic fracture cannot be used to model the well test data. We do not believe the above model is unique, but as we show in the following section, it replicates *all* the post-fracture diagnostic test data, the pre-stimulation well test data, and the pre- and post-fracture production data from CSW2.

VALIDATION OF TWO-LAYER RESERVOIR/FRACTURE MODEL

Several data comparisons were made to validate the two-layer reservoir/fracture description determined for CSW2 in the previous section. We used the two-layer model to simulate the post-fracture diagnostic tests, the pre-fracture well test, and post-fracture production data. The objective of these validation runs was to test the CSW2 model by comparing the actual data obtained in these other tests to simulated data. We did not history match the data or alter the two-layer CSW2 model during these validation runs.

Fig. 12 compares simulated and observed annulus pressures (upper zone) recorded during the May 1990 lower-zone well test. During the lower-zone well test, the upper zone (annulus) was shut-in and isolated in the wellbore from the lower zone via a packer. **Fig. 12** illustrates that there is communication away from the wellbore between the upper and lower zones. **Fig. 12** shows that our simulated pressures are in good agreement with the observed pressure data, validating our model.

Figs. 13 and **14** show the simulated and observed pressures from the lower-zone and upper-zone nitrogen injection/falloff tests. The pressure data are in excellent agreement. CSW2 produced into the sales lines from June 1989 through March 1990 and from November 1990 through April 1991. **Fig. 15** shows our simulated production compared to the observed, showing acceptable agreement. Similar comparisons were achieved for all the post-fracture diagnostic test data.[6] We also used our two-layer CSW2 model, without a hydraulic fracture, to simulate the pre-fracture well test data. **Fig. 16** compares the simulated and observed flow/buildup test data. These results show that we were also able to reproduce pre-fracture well test data using the two-layer model, providing further validation.

We made performance projections for CSW2 using both our original single-layer reservoir description[6] for CSW2 and our final two-layer model. We forecasted performance with a 100-ft fracture half-length in both cases. The primary objective of these runs is to illustrate that performance projections using a single-layer model are optimistic compared to those obtained from a two-layer model, assuming the same gas-in-place, total thickness, and total kh. **Fig. 17** shows rate and cumulative performance projections for the single-layer and two-layer models, both with 100-ft fracture half-lengths. Predictions with the single-layer model are 106% higher than those with the two-layer model.

To summarize, we used our two-layer CSW2 reservoir/fracture model to reproduce pressure and rate data obtained from all the post-fracture field diagnostic tests. It also replicated the post-fracture production and pre-fracture well test data. We believe the simulation results are quite good, thus verifying our two-layer CSW2 model that includes a complex hydraulic fracture geometry. In addition, the two-layer model yields more reasonable future performance forecasts than our single-layer model.

CONCLUSIONS

On the basis of our evaluation of the post-fracture diagnostic tests and other data from the CSW2, we have drawn the following conclusions.

1. A two-layer reservoir model with a hydraulic fracture reasonably describes *all* the data collected on the CSW2, including pre-fracture flow/buildup tests, and post-fracture isolation, communication, nitrogen injection/falloff, flow/buildup, and microseismic tests, and production data.
2. The propped, infinite-conductivity hydraulic fracture in CSW2 communicates with the lower zone (both perforated intervals) at the wellbore and with the upper zone away from the wellbore (~ 50 ft away).
3. Conventional well test analysis of a zone with an infinite-conductivity hydraulic fracture that communicates with other zones away from the wellbore will yield a reasonable estimate of the tested zone kh and an optimistic estimate of fracture half-length.
4. Conventional well test analysis of a zone which is intersected by an infinite-conductivity vertical fracture, away from the wellbore, will yield radial, unstimulated behavior at early times and heterogeneous behavior at late times.
5. Short-term tests, such as the CSW2 isolation/communication and nitrogen injection/falloff tests, are not reliable for determining inter-layer communication via a propped hydraulic fracture away from the wellbore. However, the longer flow/buildup tests and/or microseismic logging surveys can detect the inter-layer communication.
6. The fracture treatment increased deliverability in the CSW2. However, our two-layer model results in more realistic future performance predictions than our earlier single-layer model.

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NOMENCLATURE

Symbol	Description
C_r	Dimensionless fracture conductivity, $\frac{wk_f}{\pi kL_f}$
h	Thickness, ft
k	Permeability, md
k_f	Fracture permeability, md

L_f	Fracture half-length, ft
s, s'	Skin factor, dimensionless
w	Fracture width, ft
wk_f	Fracture conductivity, md-ft

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TABLE 1

SUMMARY OF CSW2 POST-FRACTURE DIAGNOSTIC TESTS

Date	Test	Perforated Interval(s)
March 1990	Zone Isolation	All
March 1990	Communication	All
April 1990	Nitrogen Injection/Falloff	3,345 to 3,379 ft 3,552 to 3,680 ft
May 1990	Flow/Buildup	3,552 to 3,680 ft
June 1990	Flow/Buildup	3,345 to 3,379 ft
July/August 1990	Flow/Buildup	3,345 to 3,680 ft
September 1990	Microseismic	All

TABLE 2

COMPARISON OF PRE-FRACTURE SPINNER SURVEY AND POST-FRACTURE ISOLATION TEST RESULTS

Zone	Pre-Fracture Spinner Rate (Mscf/D)	Pre-Fracture % Total	Post-Fracture Zone Test Rate (Mscf/D)	Post-Fracture % Total
3,345 to 3,379 ft	6.0	70.6	11.8	35.6
3,552 to 3,580 ft	1.5	17.6	4.9	14.8
3,623 to 3,680 ft	1.0	11.8	16.4	49.6
TOTAL	8.5	100.0	33.1	100.0

TABLE 3

RESERVOIR PROPERTIES ASSUMED FOR THEORETICAL MODEL EVALUATION

Reservoir Pressure, psia	570
Reservoir Temperature, °F	100
Gas Gravity (air = 1.0)	0.7
Total Net Pay Thickness, ft	42
Total Permeability-Thickness, md-ft	2.5
Upper Zone Properties	
Net Pay Thickness, ft	6
Permeability, md	0.333
Permeability-Thickness, md-ft	2.0
Gas Porosity, fraction	0.027
Lower Zone Properties	
Net Pay Thickness, ft	36
Permeability, md	0.0139
Permeability-Thickness, md-ft	0.5
Gas Porosity, fraction	0.027

TABLE 4

RESERVOIR PROPERTIES FOR FINAL CSW2 MODEL

Reservoir Pressure, psia	570
Reservoir Temperature, °F	100
Gas Gravity (air = 1.0)	0.7
Total Net Pay Thickness, ft	47
Total Permeability-Thickness, md-ft	2.02
Upper Zone Properties	
Net Pay Thickness, ft	6
Permeability, md	0.267
Permeability-Thickness Product, md-ft	1.60
Gas Porosity, fraction	0.032
Lower Zone Properties	
Net Pay Thickness, ft	41
Permeability, md	0.010
Permeability-Thickness, md-ft	0.42
Gas Porosity, fraction	0.029

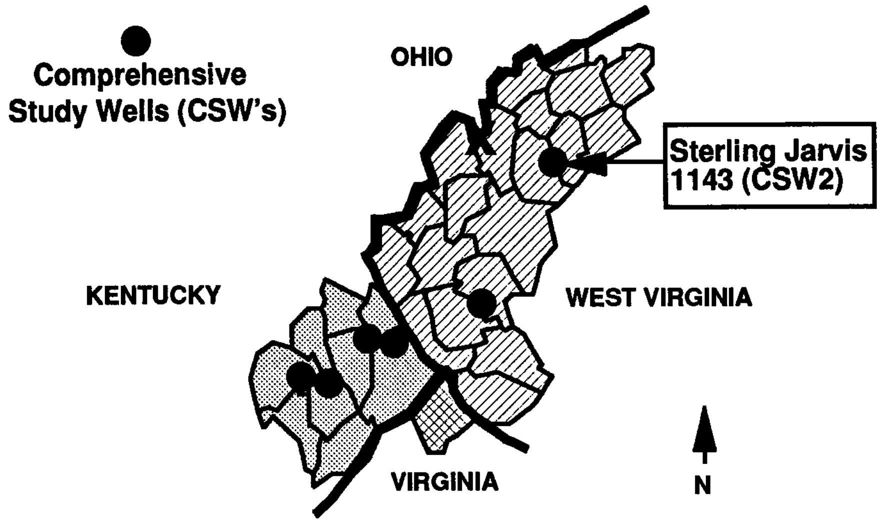

Fig. 1 - Location of Jarvis 1143 (CSW2) and other Comprehensive Study Wells.

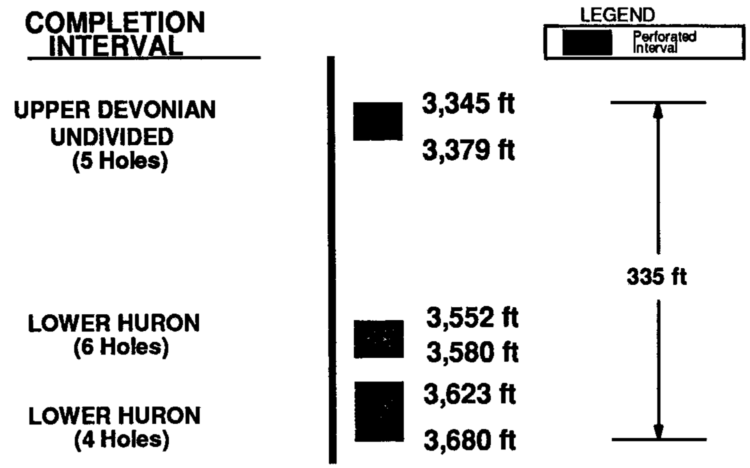

Fig. 2 - Completion intervals in the CSW2.

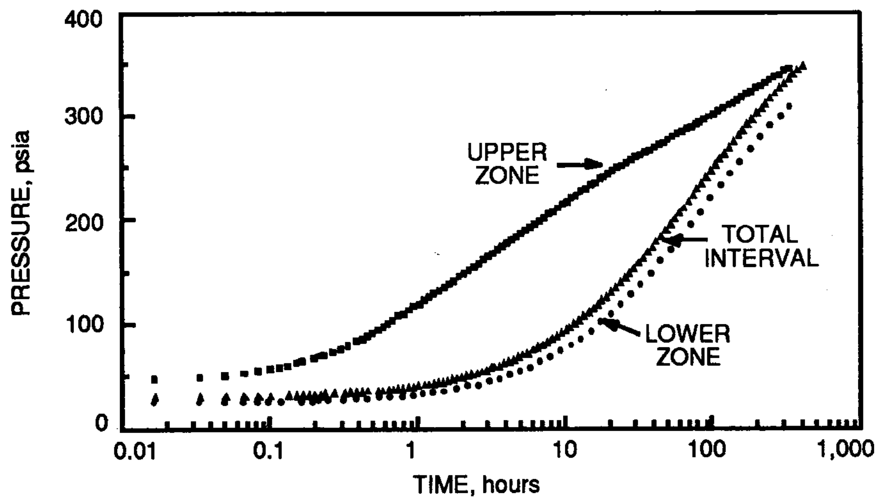

Fig. 3 - Pressure buildup data collected during the three well tests performed on CSW2 in 1990.

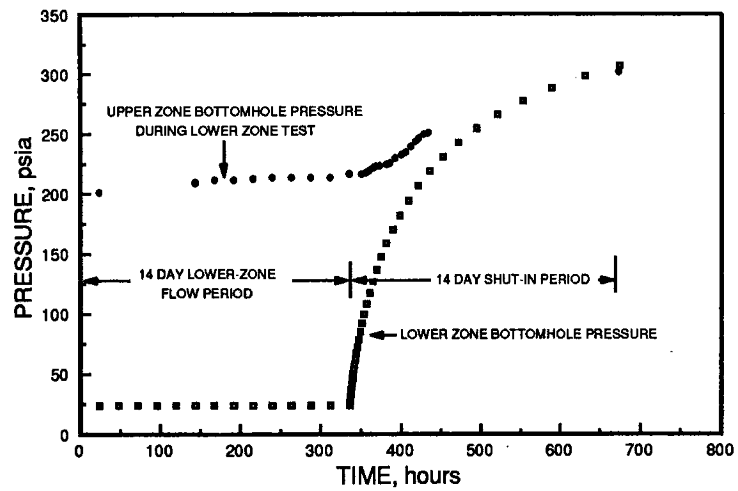

Fig. 4 - Pressure data from lower and upper zones during lower zone well test on CSW2.

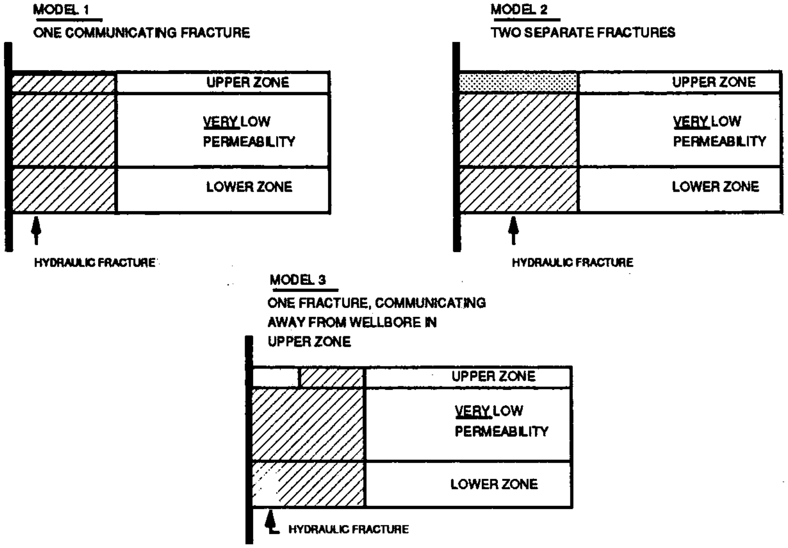

Fig. 5 - Three theoretical models used to investigate the shape of the CSW2 pressure buildup data from the lower zone, upper zone, and total interval.

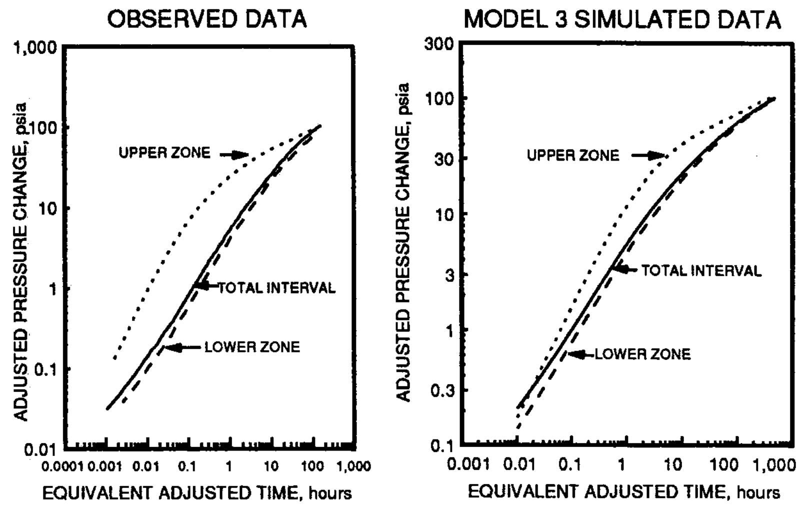

Fig. 6 - Comparison of CSW2 and Model 3 simulated pressure buildup data from the lower zone, upper zone, and total interval.

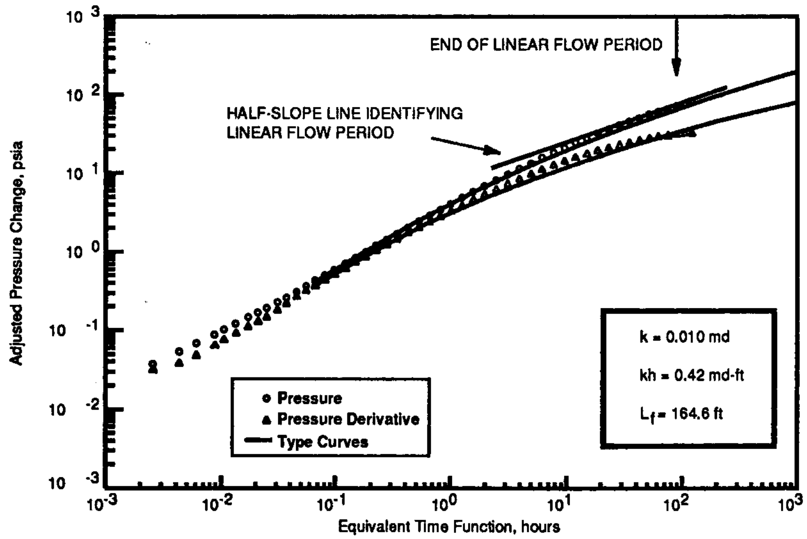

Fig. 7 - Analysis of the lower zone pressure buildup data from CSW2 using the Barker-Ramey type curve.

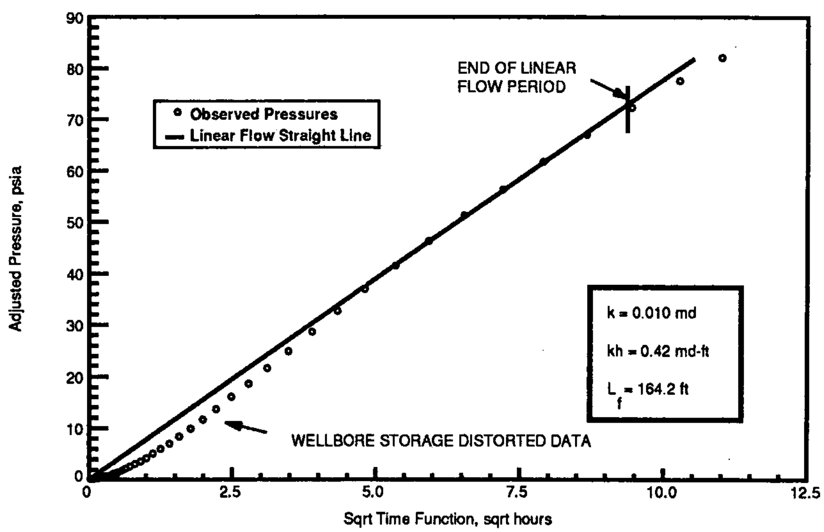

Fig. 8 - Linear flow analysis of CSW2 pressure data from lower zone buildup.

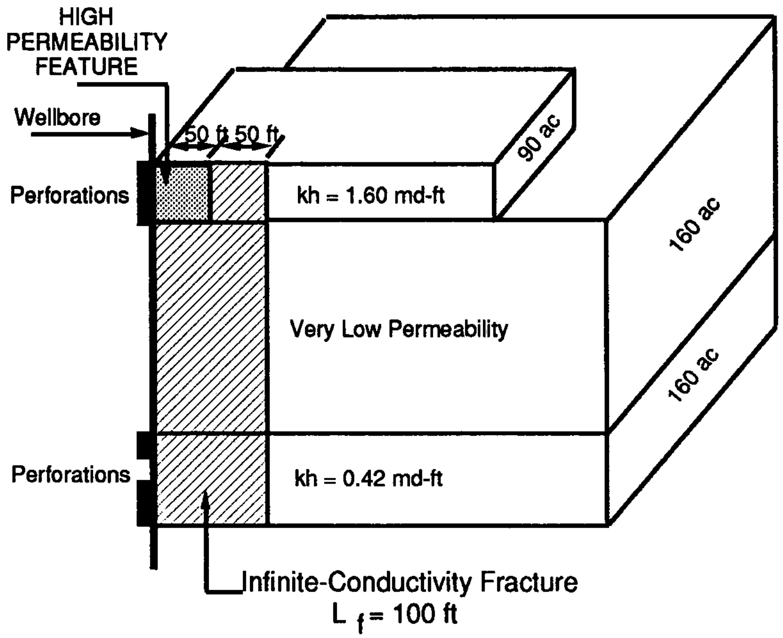

Fig. 9 - Schematic of final reservoir and hydraulic fracture description used to match the post-fracture diagnostic data collected on CSW2.

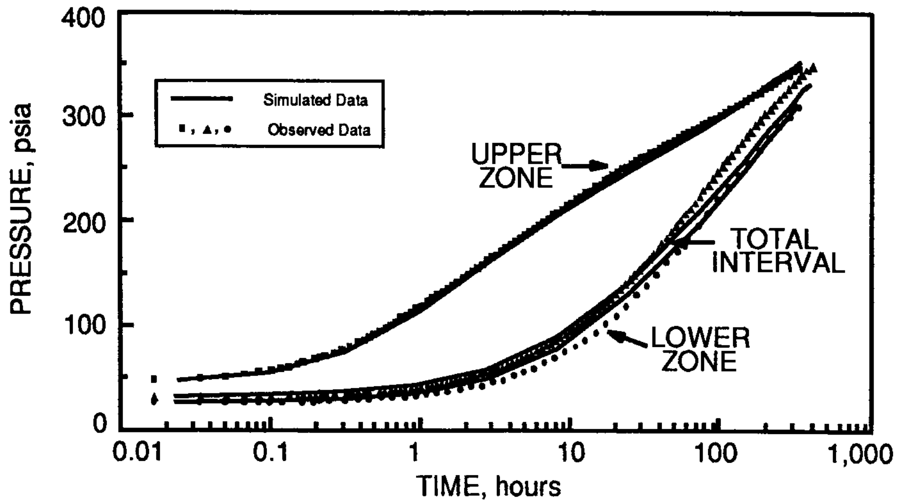

Fig. 10 - History match results for the three buildup tests performed on CSW2.

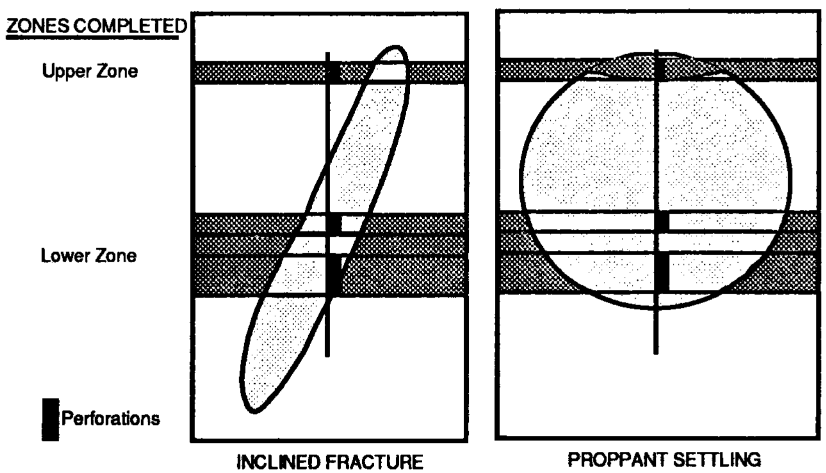

Fig. 11 - Possible hydraulic fracture geometries suggested from analysis of the post-fracture diagnostic data collected on CSW2.

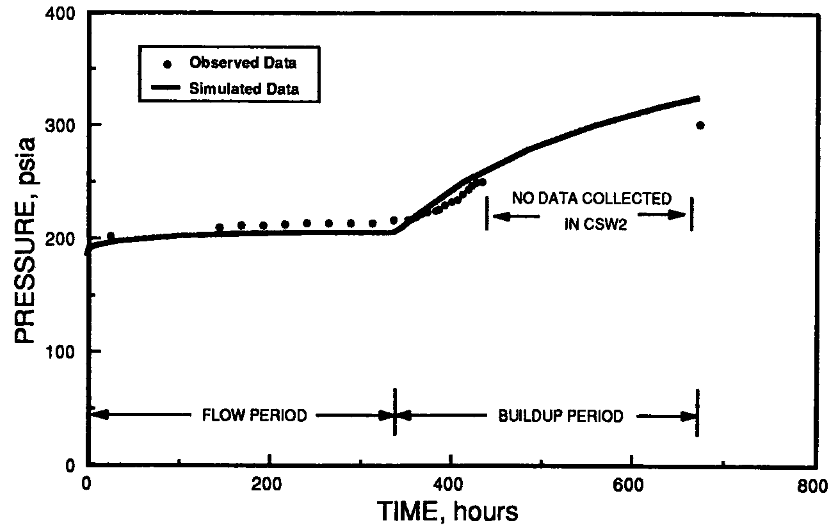

Fig. 12 - Comparison of simulated pressures from the CSW2 model to the observed data for the upper zone during the lower zone well test.

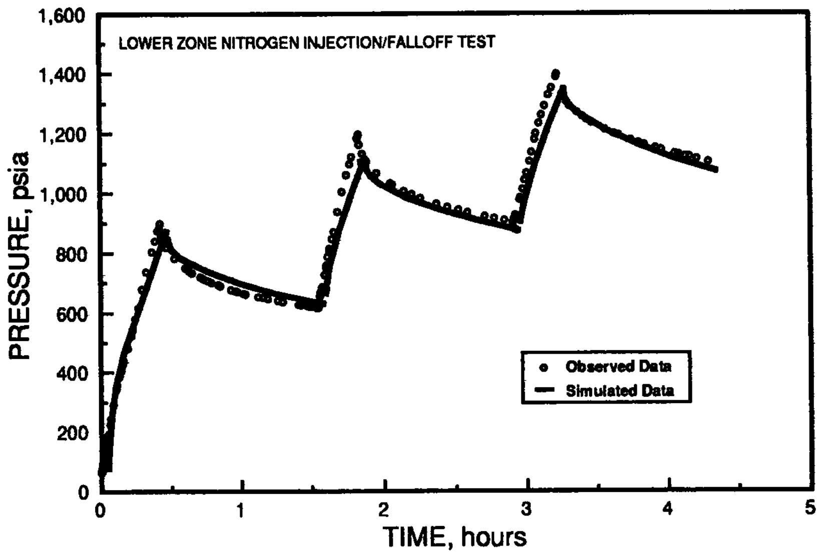

Fig. 13 - Comparison of simulated and observed pressure data from the lower zone nitrogen injection/falloff test.

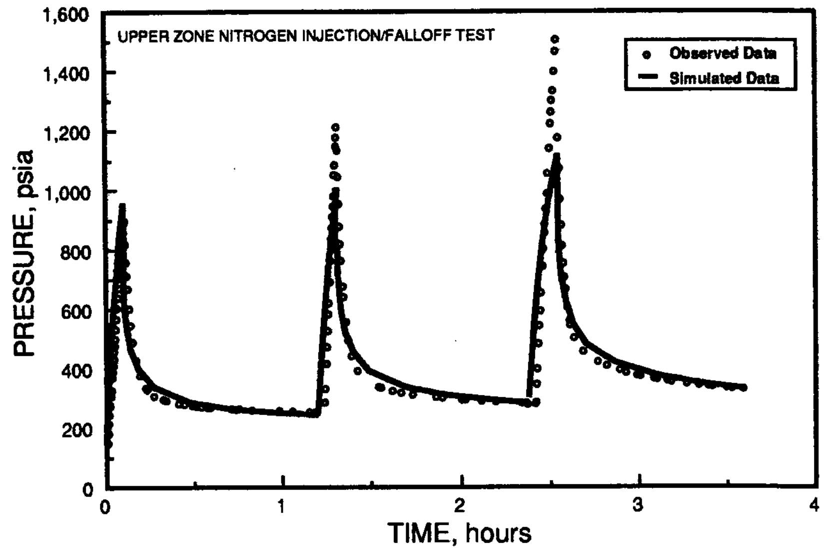

Fig. 14 - Comparison of simulated and observed pressure data from the upper zone nitrogen injection/falloff test.

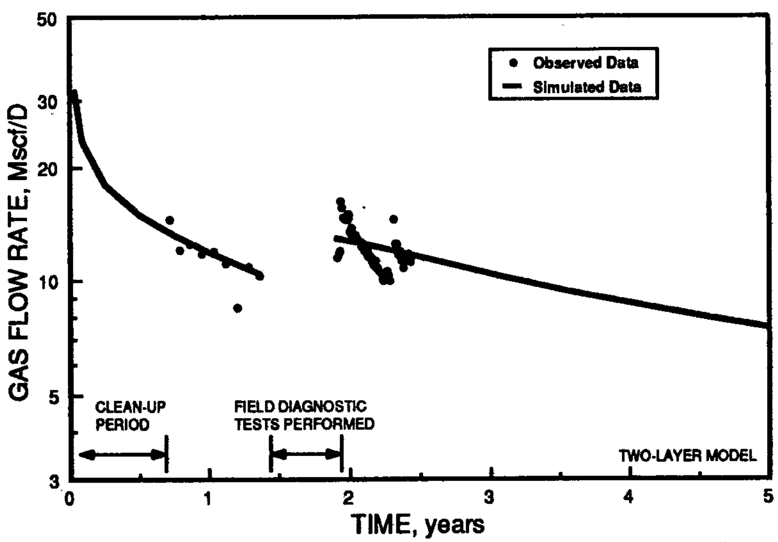

Fig. 15 - Comparison of simulated and observed production data from CSW2.

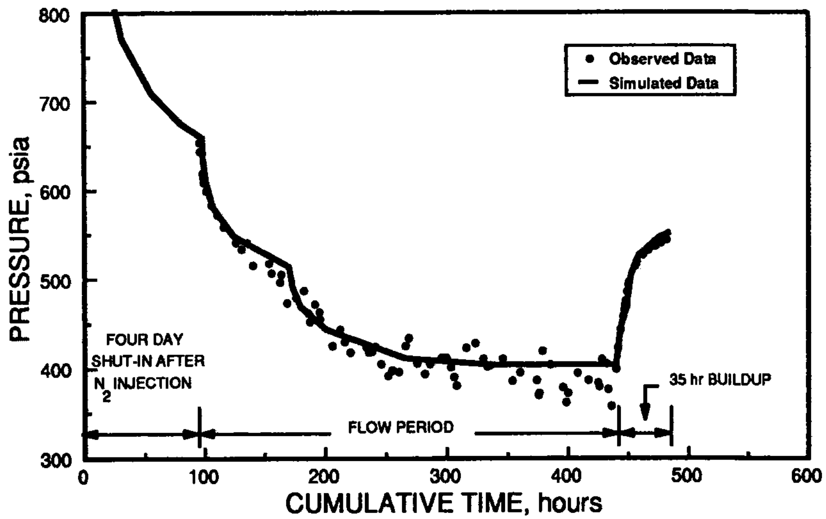

Fig. 16 - Comparison of simulated and observed pre-stimulation well test data.

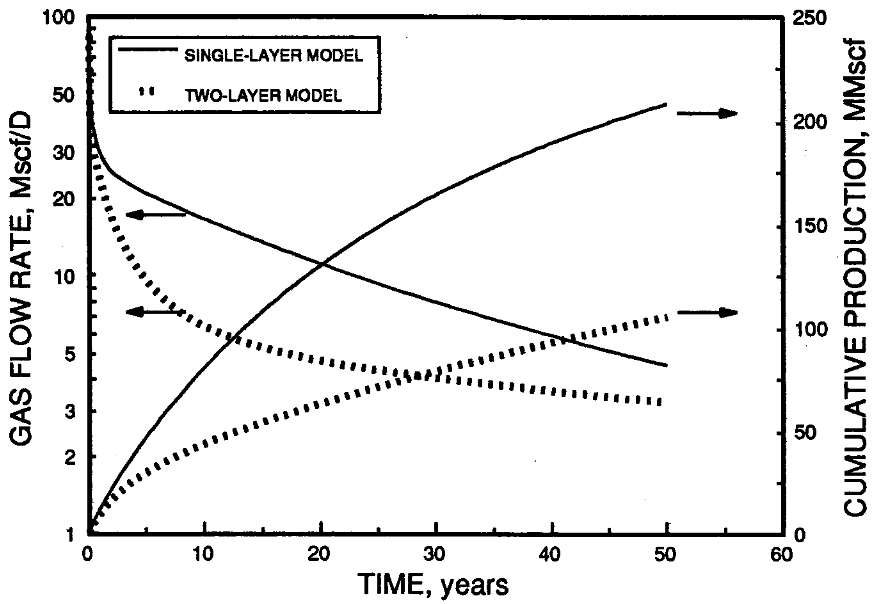

Fig. 17 - Performance projections for CSW2 using single- and two-layer models with a 100-ft fracture half-length.