EVALUATION OF A HYDRAULIC FRACTURE OPTIMIZATION PROCESS IN THE DEAN FORMATION IN MIDLAND COUNTY, TEXAS

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ABSTRACT:

This paper discusses a case history of a hydraulic fracture optimization and evaluation process conducted on four Dean formation wells in the Spraberry Trend Field of Midland County, Texas.

The first topic of discussion focuses on the basic steps of the optimization process. This systematic process review will show how the fracture stimulation treatments were designed to provide an optimum economic return based on simulated production results. These designs used reservoir data that was carefully collected by the most up to date technological tools and methods available. Present economic factors including a best estimate on the time value of money, were also used. A state-of-the-art fracturing simulator combined these parameters to formulate the optimized fracture treatments. These resulting Dean treatments were designed to yield optimum economic value over a targeted time period.

The second major discussion will focus on the evaluation of these treatments. This evaluation study will be based upon the actual average production history of these four Dean wells versus the simulated production obtained from the design model. This evaluation comparison clearly shows that actual production to date is very close to the production simulated by the model. The study also reveals that production from this fracture stimulated Dean reservoir can be accurately modeled and, therefore, successfully optimized on an economic value basis.

These four optimized Dean wells will also be compared on a production history basis to six previously completed Dean/Wolfcamp wells. The optimized Dean wells are completed only in one relatively small section of the Dean formation. The Dean/Wolfcamp wells are completed over much-larger intervals of the Dean formation and in extensive portions of the Wolfcamp formation. Fracturing stimulation treatments were done in these Dean/Wolfcamp wells but an optimization attempt has not been made. Most of the wells were completed with two separate fracture treatments per well. The comparison study of these four Dean and six Dean/Wolfcamp wells shows that the average cumulative production of these two differently completed well types is very similar. Although the cumulative production is similar, this study shows that the four optimized Dean wells are clearly more efficient on a production per perforated foot basis.They are also shallower and were each completed with only one fracturing stimulation treatment. All of these factors indicate that the four optimized Dean wells are providing a better value to date than their six Dean/Wolfcamp predecessors.

INTRODUCTION:

The Dean formation is located stratigraphically below the Spraberry formation and above the Wolfcamp formation. It is a dirty sandstone of Permian age and is considered to be water sensitive. This case study will focus on ten Dean and Dean/Wolfcamp wells drilled and completed from October, 1986 through February, 1988. They are all in the Spraberry Trend Field of Midland County, Texas within a 5 mile radius of each other, and are located 30 miles Southeast of Midland near Spraberry as shown in Figure 1.

The four optimized wells were completed exclusively in the Dean formation using the fracture stimulation treatment optimization process. The criteria considered in determining the optimum size of the treatments were as follows:

1. Optimize the reservoir deliverability. This is accomplished by a careful determination of factors such as formation porosity, permeability, net pay interval and reservoir pressure.
2. Maximize the proppant penetration. The fracture height, length, proppant concentration and proppant conductivity are valuable data for this aspect of the optimization process.
3. Optimize the pumping parameters through correct fluid selection, fluid viscosity and pump rate.
4. Minimize the treatment cost. Do not over-design parameters such as excessive rate, fluid type and proppant type.
5. Maximize economic returns of the well by determining and utilizing the optimum treatment. Economics should be based on presently known hydrocarbon prices and a best estimate of the future time value of money.

All of these criteria were integrated together and run through a state-of-the-art computer simulator to determine the optimum fracture stimulation treatment. This process was conducted for each of these four Dean wells, and the treatments were executed according to the design.

FRACTURE OPTIMIZATION:

Well Data:

Table 1 shows the average well data used for the optimized Dean stimulation design in detail. The source where the well data originated is also summarized in Table 1. As stated in the introduction, each parameter listed plays a very important part in the success of the design. As an example, the gross fracture height was determined to be approximately 300 ft. by the use of a fracture height determination log. Without the use of this tool, the fracture design based on penetration would be largely unreliable. The proppant conductivity data is based upon values determined by long-term closure and relative fluid damage to the proppant as reported by an independent testing lab. The lab conducted these tests for a consortium consisting of several operators and service companies throughout the industry. Prior to the work conducted by this consortium, the results obtained by an optimization process would generally be overestimated. This is due to findings that proppant conductivities are actually less than estimated from prior data. This was found to be due to conductivity decreases resulting from long term closure and proppant pack damage caused by fracturing fluids.

Fracture Modeling:

All of the well data was run through a computerized design simulator. This simulator calculates the fracture Net Present Value for each fracture over a range of treatment designs needed to produce each fracture half-length respectively. The Net Present Value of a treatment is determined by using the following equation

$$\text{Fracture NPV} = \text{Discounted Well Revenue - Treatment Cost} \qquad (1)$$

The net present values were calculated for a wide range of fracture half-lengths for a one, two and three year time period to determine the optimum fracture length. The NPV data output is displayed in tabular form in Table 2 and graphically in Figure 3.

As a result of this simulation, the optimum treatment was determined for each of the four Dean wells. From this data, the optimum frac length of 600 ft. was chosen using the two year NPV values. Table 3 shows the simulator output values used for the fracturing fluid volume and corresponding proppant volume to obtain this 600 ft. radius propped fracture.

This data indicates an optimum average job size for the previously listed well data to consist of approximately 160,000 gallons of fluid and 500,000 pounds of sand. The volumes actually used on the four subject wells are summarized in Table 4. These volumes would yield an average fracture half-length of approximately 576 ft. The fracture height used in the simulation was based on mechanical properties logs run on each of the wells. The log run on one of these wells is shown in Figure 2. The fracture simulator seams to verify the fracture height picked from the log. This is shown in Figure 4 and Figure 5 which represent net fracture pressure profiles simulated for the average treatment volume. Figure 2 shows an initial gross fracture height of approximately 200 ft. bounded by two 600 psi stress barriers. The simulated net pressure needed to overcome these barriers would occur approximately 50 min. into the job. This is shown in Figure 4. At this point, the fracture will increase in height to approximately 300 ft. and pumping operations will continue under confined height conditions until shutdown. The simulator predicts that the final net pressure at shutdown should be approximately 400 psi as shown in Figure 5.

The simulator used all of the previous data and fracturing parameters to compute an estimated average propped fracture conductivity of 136 md-ft over the estimated 576 ft. fracture half-length. Other parameters computed include a created fracture width of 0.54 in., an average propped width of 0.14 in. and an average proppant concentration in the fracture of 1.27 lbs./sq.ft.

EVALUATION:

Optimized Dean Wells' Simulated Versus Actual Production:

The simulated production decline is shown in Figure 6 along with the actual average production decline from the four optimized Dean wells. The comparison is based on the production time period available to date. An analysis of the plots clearly indicates that the simulator modeled the production rate decline in a very accurate manner. The actual average production decline of the four optimized Dean wells deviates only a small amount from the simulated values.

The simulated cumulative production is plotted in Figure 7 along with the actual average cumulative production for the available data gathering time period. As can be seen by comparing the plots of the two parameters, the actual average production is slightly lower than predicted but is within 8 percent of the targeted production. These production evaluation results indicate clearly that the optimization process was successful.

Optimized Dean Wells Compared To Previous Dean/Wolfcamp Wells:

The previous six Dean/Wolfcamp wells were completed using various sizes of fracture treatments in both the Dean and Wolfcamp formations. These wells are found in the same field and area outlined in Figure 1 as the four optimized Dean wells. Treatments conducted on these wells are summarized in Table 5. As shown in the table, the Wolfcamp formation is located below the Dean formation. These six Dean/Wolfcamp wells were completed over very large intervals in both the Dean and the Wolfcamp formations. This makes a direct comparison difficult, but some viable conclusions can still be drawn. The average optimized Dean well has produced 13,100 bbls. of oil in a 450 day period. Over the same period, the average Dean/Wolfcamp well produced 12,800 bbls. of oil. Figure 8 shows the 450 day cumulative production from each of the ten wells studied. This graph indicates that there is a predictable pattern of production in the four optimized Dean wells, but there is not a predictable pattern evident in the six Dean/Wolfcamp wells. Also, the average optimized Dean well produced it's 13,100 bbls. out of a perforated interval of only 145 feet. In the average Dean/Wolfcamp well, the 12,800 bbls. was produced over a 648 ft. interval. These intervals are listed in Table 4 and Table 5. The average optimized Dean well is 8,800 ft. deep and was fracture stimulated in one stage consisting of an average of 160,000 gal. and 500,000 lbs. of proppant. The average Dean/Wolfcamp well is 9,250 ft. deep and was fracture stimulated using two separate treatments consisting of an average total of 157,000 gal. and 300,000 lbs. of proppant.

Figure 9 shows a comparison of the 450-day-total cumulative-average production per perforated foot of interval. This is shown for each of the optimized wells and each of the previous wells. A pattern of improved production from the optimized Dean intervals is indicated. Again, the optimized fracs were placed only in the Dean and in a very selective manner. In contrast, the previous wells were fracture treated over larger intervals with a variety of treatment techniques. A further evaluation can be made by plotting the cumulative average production on a well type basis per perforated foot of interval as shown in Figure 10. In this comparison, the four optimized Dean fractures that were concentrated in the selective part of the Dean are substantially out-performing those over larger intervals in the previous six Dean/Wolfcamp wells. Figure 10 also shows a plot of the total cumulative average production per perforated foot of the six previous wells if all of their production is originating from the Dean perforations. This theoretical case does not allocate any production from the Wolfcamp perforations. Although the production per foot improves with this situation, the results are far short of those obtained by the optimized fracture production of the four optimized Dean wells.

The preceding production evaluation of the four optimized Dean wells compared to the six Dean/Wolfcamp wells indicates the optimized Dean wells are yielding superior value due to the following:

1. The optimized Dean wells are shallower and thus less expensive to drill and complete.

2. Each of the four optimized wells had only one fracture stimulation treatment. Four out of six Dean/Wolfcamp wells had two fracture stimulation treatments.

3. Cumulative total production results from the four optimized Dean wells are predictable and are very consistent between wells. The cumulative production results are very erratic and unpredictable in the six Dean/Wolfcamp wells.

4. Even though the total average production is similar between the two types of wells, the four optimized Dean wells are clearly out-performing the Dean/Wolfcamp wells on a production per ft. of perforated interval basis.

CONCLUSIONS:

1. Fracturing treatments in the Dean formation can be successfully optimized to achieve optimum economic value. This is confirmed by the evaluation of production results of the four optimized Dean wells. The production of these optimized wells was very close to simulated amounts.
2. The four optimized Dean wells are out-performing the previous Dean/Wolfcamp wells based on production per perforated foot of interval.
3. The four optimized Dean wells are showing a better overall value to date because they are shallower and were completed in a single interval with only one fracture stimulation treatment. The six Dean/Wolfcamp wells are deeper and were completed with an average of two fracture stimulation treatments per well.
4. Analysis indicates potential economic benefits could be obtained by a thorough systematic fracture optimization of each productive interval. This should be done in both the Dean and the Wolfcamp formations in these wells or future wells.
5. Current computer simulators will provide the operator with accurate results when all of the correct reservoir parameters are used.

REFERENCES:

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2. Nolte, K.G., Smith, M.B.: "Interpretation of Fracturing Pressures,", JPT, 1981.
3. Nolte, K.G.: "Application of Fracture Design Based on Pressure Analysis,", SPE Production Engineering, February 1988.
4. "1987 Stim-Lab, Inc. Consortium Final Report On The Investigation Of The Effects Of Fracturing Fluids Upon The Conductivity Of Proppants".

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Table 1
Data Used in Optimization Process and Acquisition Source

RESERVOIR INFORMATION		
Data	Value	Acquisition Source
Reservoir Permeability	0.05 md.	Operator Via Buildup
Formation Producing Thickness	50 ft.	Porosity Log
Reservoir Porosity	7%	Porosity Log
Reservoir Temperature	148 deg. F	Open Hole Log
Initial Reservoir Pressure	2,400 psi	Operator Via Buildup
Oil API Gravity	38.9	Operator
Gas Specific Gravity	0.89	Operator
Reservoir Oil Saturation	40%	Operator Via Open Hole Log
Reservoir Water Saturation	50%	Operator Via Open Hole Log
Well Spacing	160 acres	Operator
WELL PRODUCING AND PLUMBING		
Data	Value	Acquisition Source
Well Producing Type	Pumping	Operator
Tubing Outside Diameter	2.875	Operator
Tubing Inside Diameter	2.441 in.	Operator
Tubing Length Measured Depth	8,600 ft.	Operator
Measured Depth To Mid-Perforation	8,703	Operator
Est. Bottom-Hole Producing Pressure	100 psi	Operator
Casing Inside Diameter	4.89	Operator
Number Of Perforations	40	Operator
Perforation Diameter	0.3875	Operator
Producing Water Cut	40%	Operator
FRACTURE MECHANICS		
Data	Value	Acquisition Source
Fracture Geometry Model	Perkins And Kern	Data Frac
Formation Ave. Young's Modulus	5,500,000 psi	Frac Ht. Log (See Fig. 2)
Formation Poisson's Ratio	0.21	Frac Ht. Log (See Fig. 2)
Formation Fracture Gradient	0.6 psi/ft.	Breakdown
Fracture Leakoff Height	250 ft.	Porosity Log
Fracture Gross Height	332 ft.	Frac Ht. Log (See Fig. 2)
In-Situ Leakoff Coefficient	0.0012 ft./sq.rt. of min.	Data Frac
Spurt Loss Coefficient	2.5 gal./100 sq.ft.	Lab Data

PROPPANT DATA		
Data	Value	Acquisition Source
Proppant Type	20/40 Northern sand	Operator
Proppant Specific Gravity	2.65	Supplier And Lab Data
Proppant Diameter	0.0248 in.	Supplier And Lab Data
Proppant Unit Cost	$0.089/lb.	Pumping Service Co.
Long Term Stress Prop. Perm.	42,000 md.	Independent Lab Data
Prop. Pack Damage Factor	0.30 Retained Perm.	Independent Lab Data
Minimum Horizontal Stress	5,200 psi	Breakdown
FRACTURING FLUID DATA		
Data	Value	Acquisition Source
Fluid Type	Diesel In Water Polymer Emulsion	Operator
N-Prime	0.44	Pumping Service Lab
K-Prime	0.1112	Pumping Service Lab
Fluid Cost	$0.21/gal. (Not Incl. Diesel)	Pumping Service Co.
OPERATIONAL CONSTRAINTS		
Data	Value	Acquisition Source
Pump Rate	35 bpm	Operator
Treatment Through	Casing	Operator
Max. Prop. Concentration	9 ppa	Operator
ECONOMIC DATA		
Data	Value	Acquisition Source
Horsepower Unit Cost	$3.00/hhp	Pumping Service Co.
Miscellaneous Cost	$6,500.00/Treatment	Pumping Service Co.
Present Value Discount Rate	10%	Estimate
Oil Unit Revenue	$16.00/bbl	Estimate

Table 2
NPV Data Output

Propped Xf (ft.)	1 Yr. NPV ($)	2 Yr. NPV ($)	3 Yr. NPV($) ($)
100	31,200	59,100	79,200
200	50,252	93,500	127,100
300	62,000	117,600	159,800
400	66,500	133,400	183,600
500	65,100	142,300	200,000
600	58,800	144,900	209,400
700	48,400	142,300	212,700
800	34,400	134,900	210,600
900	17,800	124,200	204,700
1,000	-	110,203	195,100

Table 3
NPV Simulated Material Volumes

Propped Xf (ft.)	Fluid Volume (gal.)	Proppant Volume (lbs.)
100	11,700	45,500
200	31,400	115,700
300	57,100	199,700
400	88,000	294,000
500	123,600	397,500
600	163,900	508,200
700	208,500	625,500
800	257,200	748,800
900	310,100	877,500
1,000	367,000	1,011,000

Table 4
Actual Optimized Dean Fracture Treatments

Well	Perforated Interval Depth (ft.)	Perforated Total (ft.)	Formation	Fracturing Fluid Volume (gal.)	Proppant Volume (lbs.)
A	8,645 - 8,739	94	Dean	171,000	500,000
B	8,581 - 8,746	165	Dean	185,000	501,000
C	8,652 - 8,805	153	Dean	160,500	415,000
D	8,517 - 8,683	166	Dean	188,000	509,000

Table 5
Previous Dean/Wolfcamp Fracture Treatments

Well	Perforated Interval Depth (ft.)	Perforated Total (ft.)	Formation	Fracturing Fluid Volume (gal.)	Proppant Volume (lbs.)
1	8,525 - 8,853	328	Dean	115,000	242,000
2	9,090 - 9,342	252	Wolfcamp	66,000	109,000
	8,471 - 8,947	476	Dean	115,000	242,000
3	8,787 - 8,998	211	Wolfcamp	20,000	Gelled Acid
	8,434 - 8,638	204	Dean	90,000	109,000
4	8,738 - 9,131	393	Wolfcamp	100,000	162,000
	8,424 - 8,675	251	Dean	117,500	242,000
5	8,546 - 9,471	925	Dean/Wolfcamp	120,000	258,000
6	8,942 - 9,443	501	Wolfcamp	120,000	220,000
	8,547 - 8,896	349	Dean	81,000	238,000

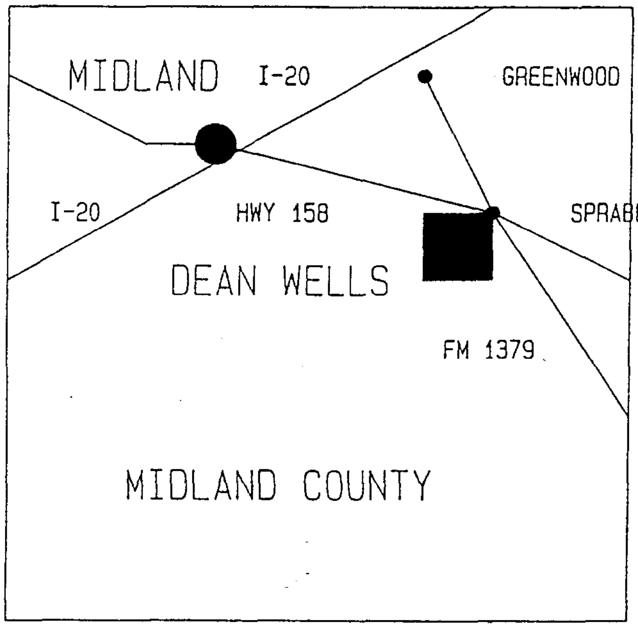
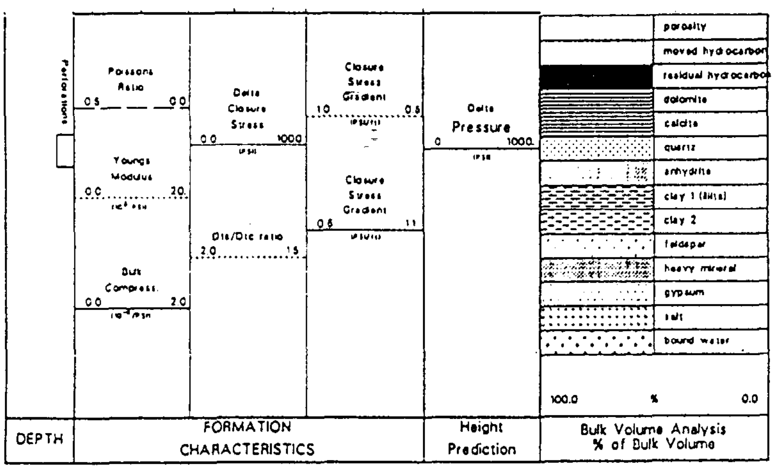


Figure 1 - Location of subject wells



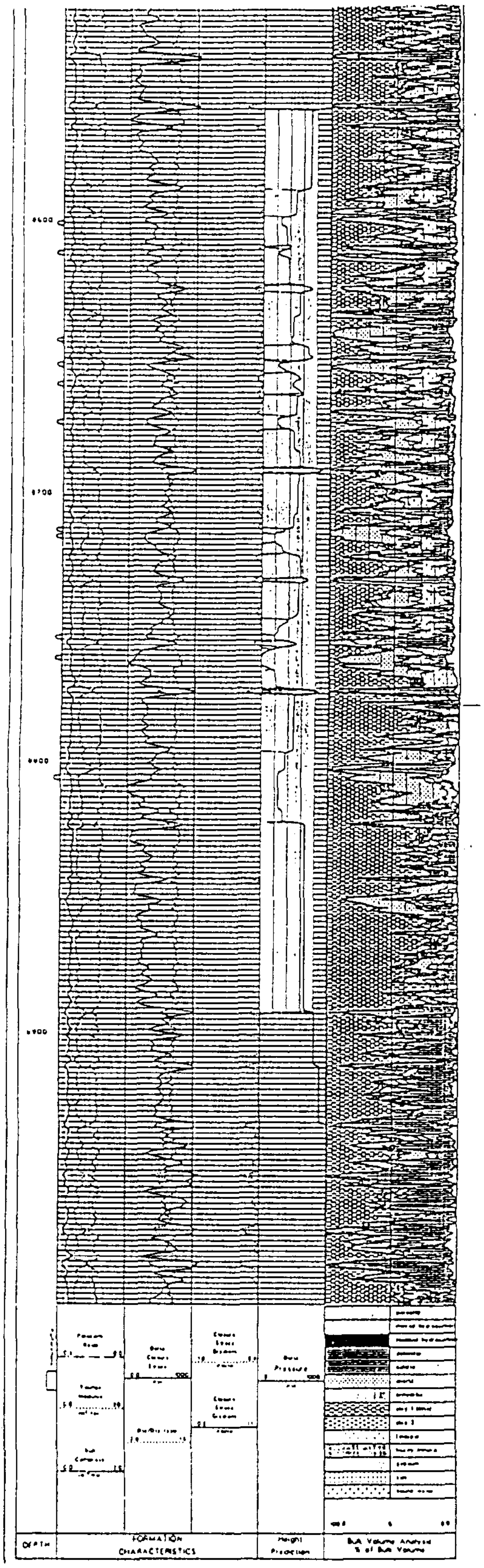


Figure 2 - Fracture height and formation characteristics log

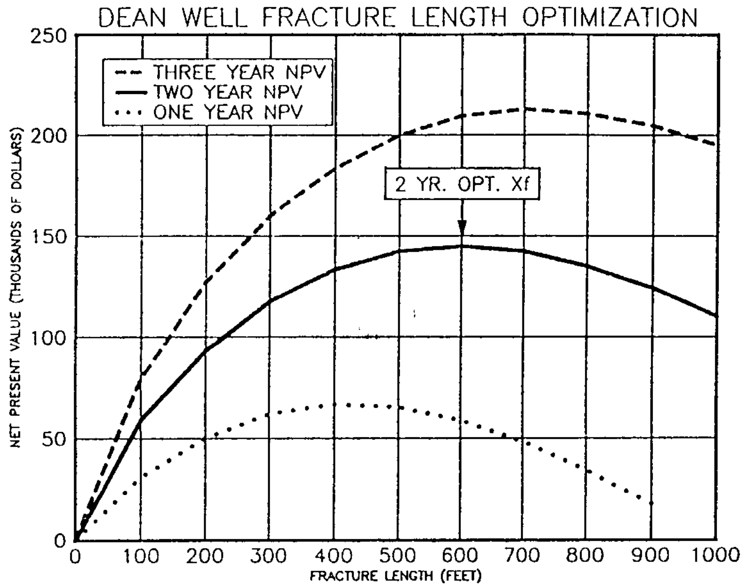


Figure 3 - Net Present Value plot

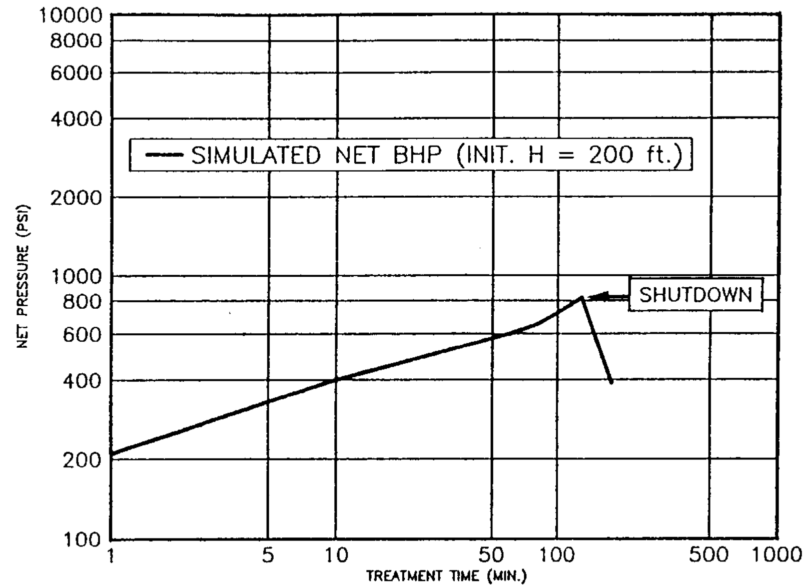


Figure 4 - Simulated early confined frac height

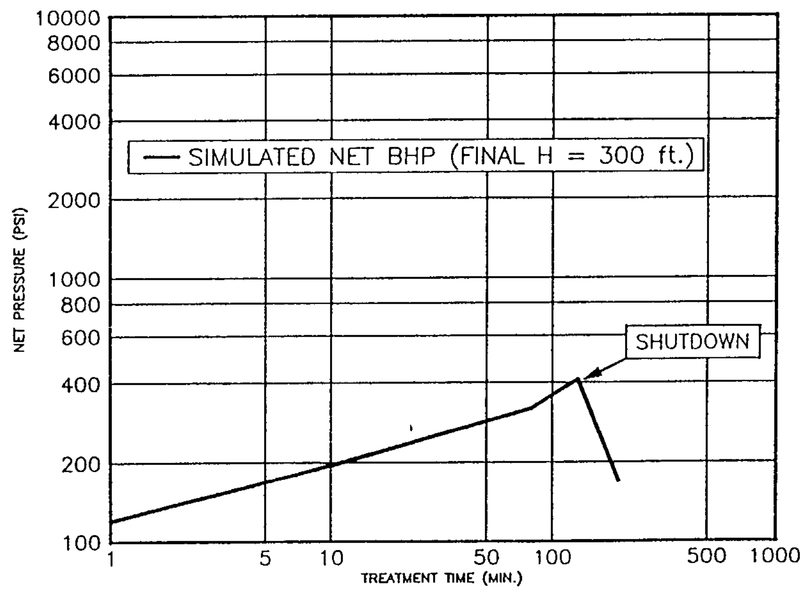


Figure 5 - Simulated final frac height

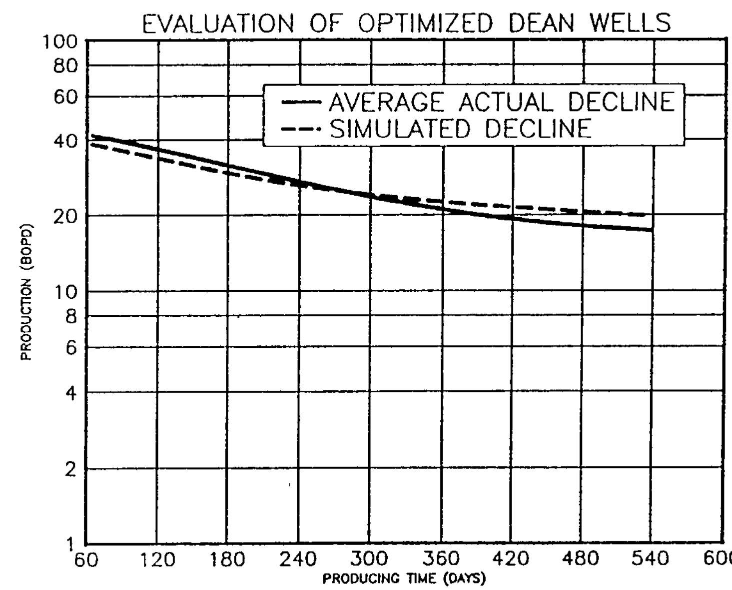


Figure 6 - Simulated vs. actual decline of the four Dean wells

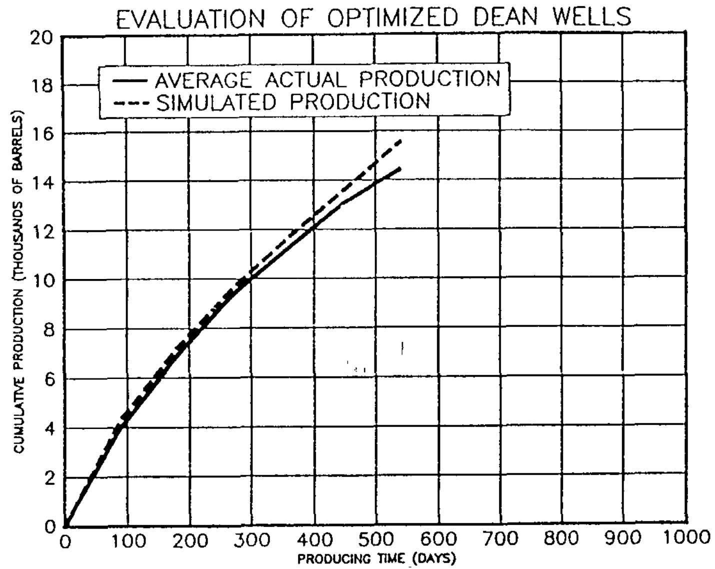


Figure 7 - Simulated vs. actual production of the four Dean wells

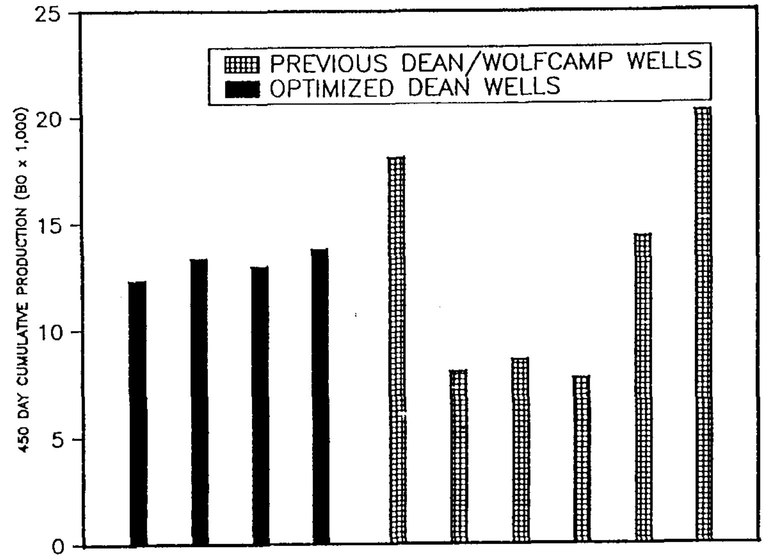


Figure 8 - Total cumulative production of each well

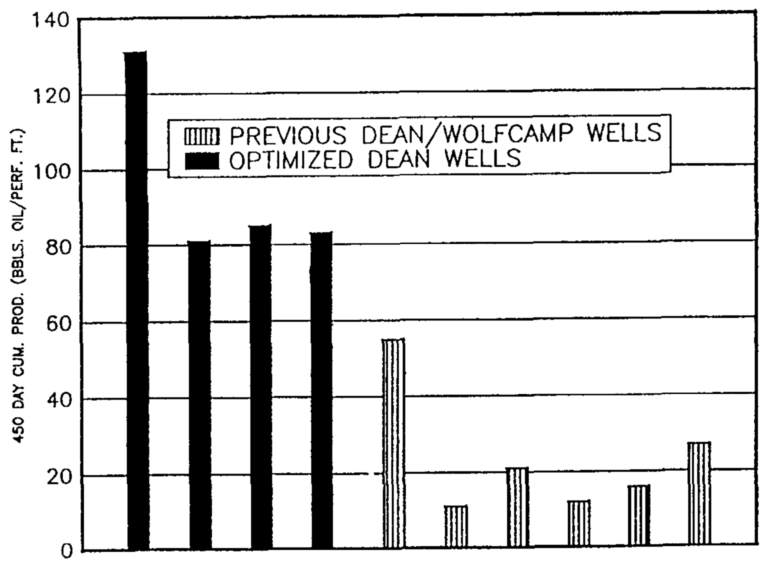


Figure 9 - Evaluation of each well's performance

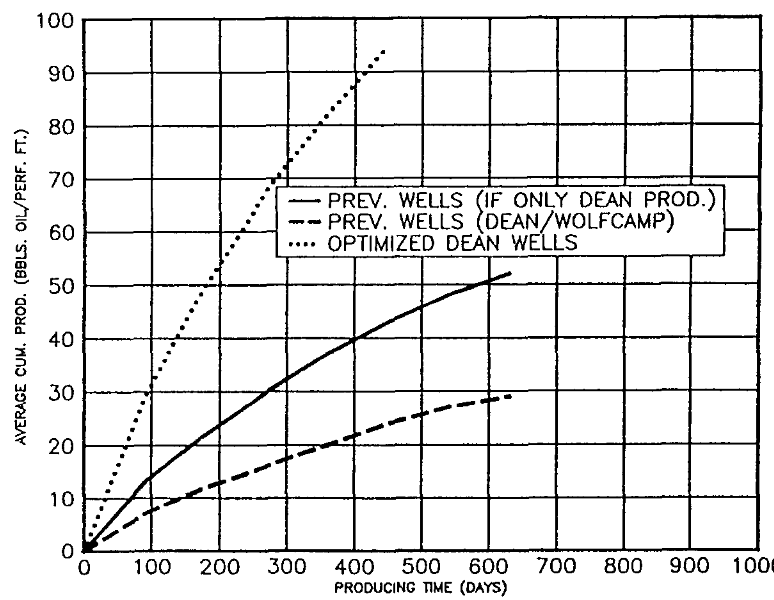


Figure 10 - Evaluation of average well performance