OPTIMIZING HYDROCARBON PRODUCTION THROUGH HORIZONTAL DRILLING AND STIMULATION: TEXACO VACUUM GLORIETA WEST UNIT

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Introduction:

The Glorieta, Upper Paddock, and Lower Paddock formations were unitized in the Vacuum Field (S.E. New Mexico) by Texaco in 1992 creating the Vacuum Glorieta West Unit. A technical committee made up of working interest owners was formed to determine operational matters for the newly formed unit. The technical committee determined that the Upper and Lower Paddock intervals contained the more prolific productive capacity and provided the most suitable median for waterflooding. Consequently, unit wide water injection in those intervals commenced late that same year. Almost immediately water breakthrough occurred in the northern area of the field and in selective areas of the southern portion of the field. Unit production showed an immediate increase in unit water production accompanied by an actual decrease in unit oil production at the commencement of the waterflood. From this point forward the water/oil ratio (WOR) became the major driver of economic limit for the VGWU. It was not until the first quarter of 1994 that the Vacuum Glorieta Unit saw its first positive response to injected water, considerably after the anticipated timeframe.

Geology (within the Unitized Interval):

Glorieta (~5900'): The lithology in the Glorieta interval consists of a micro-porous sandy dolomite. This interval is extremely tight with high water saturation. However, the water is tightly bound to the sand grains and is thus immobile. Consequently, due to the low permeability, this zone is unable to deliver economically commercial volumes of hydrocarbons.

Upper Paddock (~6000'): This interval ranges in thickness from 10' to 40'. The lithology consists of a highly porous (16%) and permeable (5 md) Limestone interval. This interval has demonstrated the most favorable response to injected water and is therefore the most prolific hydrocarbon producing interval during secondary operations.

Lower Paddock (~6100'): The Lower Paddock Dolomite interval consists of high perm streaks along with a network of natural fractures lending to outstanding primary production. Unfortunately, the very mechanisms that made primary production strong contribute to poor waterflooding medium. The natural fractures within the rock tend to thief injection water out of zone, while the high perm streaks tend to cycle injection water through the area without energizing the formation or displacing hydrocarbons. Water injection into this interval has proved to be ineffective and wasteful.

Both the Upper and Lower Paddock intervals are perforated in the producing and injecting wells. Given that the Lower Paddock Dolomite contains the path of least resistance, the majority of injection water flows into the least effective flood interval. Operationally, Texaco's challenge is to determine the most effective way to divert injection water from the Lower Paddock interval to the more lucrative Upper Paddock Limestone interval in the most prudent and cost effective manner.

Techniques Utilized for Water Control:

Many different techniques and strategies have been utilized in an attempt to control water production in this field. Texaco implemented a pilot polymer study utilizing the MARCIT** gel technology in late 1995 and early 1996. The study yielded varied results; moderate success in producing wells and negligible success in injection wells. Texaco also attempted water control through mechanical means with CIBP's, cement squeezes, and cement plugs. In most cases, mechanical measures proved ineffective due to poor cement integrity behind pipe between the Upper and Lower Paddock interval.

** MARCIT is a trademark of Marathon Oil Company

Apparently the perforating and numerous acid treatments performed through this interval had deteriorated any zonal isolation in the cement sheath.

Finally, in 1997, Texaco drilled a horizontal lateral that kicked off in the Glorieta interval and extended only through the Upper Paddock Limestone. The lateral was kicked off approximately 100' above the old perforations in an area that demonstrated good cement integrity behind pipe. By targeting the oil productive Upper Paddock zone, Texaco could avoid high volume water production from the Lower Paddock formation. The horizontal test well proved to be an extremely effective technique for water control and hydrocarbon enhancement. In lieu of the success, Texaco drilled an additional seven horizontal laterals in a similar manner.

Well Construction:

Each of the eight horizontal laterals was drilled from an existing vertical wellbore. The vertical perfs were abandoned by setting a bridge plug in the casing. A mechanical whipstock was set approximately 100 feet above the targeted zone and a casing window milled. The lateral was drilled with the build section in the Glorieta zone and the horizontal portion extending through the Upper Paddock Limestone. A 4-3/4" drill bit with a fresh water mud system was utilized to drill each horizontal interval which ranged in length from 900' to 1900'. The laterals were left as open-hole completions.

Stimulation Technique:

After completion, the wells were immediately put on production without stimulation. Of the eight wells drilled, only one showed high initial water production. The other seven showed low water production with declining oil production, making these wells candidates for stimulation.

The decision was made to stimulate the VGWU horizontal wells utilizing a method that would minimize water production and adequately stimulate the narrow oil bearing Upper Paddock. With bottom water in the Lower Paddock, it was imperative that acid was diverted away from existing natural fractures and into the matrix porosity.

The DSP FoamMAT* acidizing technique was selected to provide effective stimulation with proper zone coverage. Coiled tubing (1 ½") was used to place the acid along the different treatment interval. The coiled tubing contained an internal electric line (monocable), which allowed the use of the DSP* (Downhole Sensor Package) tool. The FoamMAT procedure is designed to achieve treatment fluid diversion by generating and maintaining a stable foam in any thief zones. The result is that acid is diverted away from natural fractures or high permeability zones and into damaged or tighter portions of the matrix, which truly require stimulation. The DSP tool provides real-time bottomhole temperature (BHT) and pressure (BHP) data that is used to adjust the foam stages. Since the nozzle is located above the DSP tool, a temperature increase indicates that cooler treatment fluid is no longer being accepted by the zone just acidized below the tool. As more foam is pumped, the bottomhole pressure starts to increase. This indicates diversion away from any permeable zones anywhere in the hole. Without real time bottom-hole data, quantifying diversion from surface pressures is highly inaccurate due to changing hydrostatic and friction pressures.

One of the key points behind using foam as a diverter was that it is completely non-damaging to the formation. The same cannot be said for most other diverters commonly employed. Because of the nature of the surfactants used, the foam is more stable in a water-wet environment over an oil zone. This allows preferential diversion of the acid into oil zones.

Stimulation Procedure

First the CT was run in hole to TD. If fill was anticipated, a dummy run with a conventional nozzle on the end of the coiled tubing was run to TD prior to the DSP treatment. Fill could not be circulated off bottom since the DSP tool is located below the nozzle on the CT bottom hole assembly. In two cases, a mutual solvent pre-flush was circulated across the open-hole lateral once at TD. This was intended to clean the near-wellbore region of any hydrocarbon, better insuring foam stability. The pre-flush was only used on wells with high initial water cuts.

The next step was to foam the annulus. Since these wells had low reservoir pressures, they would not support a full column of fluid to surface. Rather than having a partially full annulus, a continuous-phase stable foam was circulated to

* FoamMAT and DSP are trademarks of Schlumberger

surface. Then the annulus was closed and a foam stage was injected into the formation. This was intended to divert the upcoming acid stages from any natural fractures or other high permeability conduits to bottom water.

The first acid stage was pumped once the DSP tool indicated diversion. The sequence was then to pull up-hole while injecting acid over a 100-ft interval. Then, with the nozzle stationary at the top of the interval, a pad stage was injected into the matrix. The dual purposes of the pad were to water wet and saturate the near-wellbore matrix with surfactant, which were required for foam stability. Next nitrified foam was injected until the DSP tool indicated diversion, usually equaling one to two acid volumes. The foam volumes were specific to each well and varied within each well between intervals. This is where the DSP tool enabled Texaco to vary the pump schedule as required until diversion was obtained.

After the last acid stage was pumped at the heel of the well the coiled tubing was again run to TD. This was done to remove any fill that may have sloughed into the open-hole and also to commence lifting fluid in the well with nitrogen. The coiled tubing was retracted, and the unit rigged down, leaving the well flowing until dead. Texaco then ran ESP equipment to artificially lift the fluid from the reservoir.

Treatment Results:

The individual responses for each of the eight wells in the project are tabulated in **Table 1**. The initial production was taken just prior to stimulation. Post-stimulation results were taken as soon as the load water was removed and was generally in the first two to three days of production.

Oil Production:

The average initial production increase was 379% or 481 BOPD. The individual production responses are displayed in **Figs. 1** and **2**. After 30 days, the average production increase was 84% or 107 BOPD. The only well that had less production after 30 days than prior to the stimulation was VGWU 89. This well was on a sharp decline prior to the treatment and was drilled largely out of zone.

It was difficult to determine how much acid should be used to treat the laterals. Wells VGWU 70 and 88 were treated with 10 gal/ft of acid. All others were treated with 20 gal/ft. Fig. 1 illustrates two distinct groups of wells; those with initial production greater than 100 BOPD and those with less. The wells with initial production greater than 100 BOPD were VGWU 115, 88 and 103. VGWU 88 had the highest pre-stimulation production rate but did not obtain the highest stimulated oil rate. This well was only treated with 10 gal/ft of acid. The wells treated with 20 gal/ft of acid (VGWU 115 and 103) had higher initial stimulated production (Fig. 2).

The data from the other five wells does not maintain this trend. Although the VGWU 70 was treated with less acid, its stimulated production falls in the middle of this group, both in terms of BOPD and production increase. Of the five wells in this group, two wells performed better and two worse than the VGWU 70.

Two points can be drawn from this. First, the highest production increases did result in wells treated with 20 gal/ft of acid. Second, more work needs to be done here to truly optimize the acid volume. In some wells (like the VGWU 70) less acid may be required to dissolve the damage than in other wells. Pressure buildup tests performed before and after stimulation would probably be required to determine if the damage was completely removed or not.

In terms of the 30-day production, all of the wells fell off sharply. This is most likely because of inadequate injection support from offset injection wells. Currently injection support comes from vertical wells completed in both the Upper and Lower Paddock zones. Injection profiles have demonstrated that most of the water is injected into the Lower Paddock.

Water Production:

Water production increased in all of the wells stimulated. On average, water production increased by 539 BWPD or 196% after stimulation. After thirty days the average increase was 471 BWPD or 171%. This information is portrayed in **Fig. 3**. Note: Initial post-stimulation water production on the VGWU 70 was estimated. The actual well tests show lower water production after stimulation than before (see the production plot). This is possible but is most likely a test meter error. Since the water production jumps up sharply nine days later, a value of 1200 BWPD has been extrapolated back from later water production data.

From the data in **Table 1**, the average water cut before the acid treatment was 68%. The average post-stimulation water cut was 57% and the 30-day water cut averaged 76%. Of the eight wells treated, only one well (VGWU 114) had a higher water cut initially after the stimulation. On this treatment, there was direct communication with a nearby vertical wellbore during the first half of the treatment. This resulted in no control of acid placement during this part of the treatment until the vertical well was shut in at surface. This complete lack of diversion would most certainly have caused acid placement to be concentrated in some areas of the wellbore over others, resulting in high conductivity channels to the bottom water. Since the vertical well was perforated in both the Upper and Lower Paddock zones and had high water production, this is probably the source of much of the water production in the horizontal well.

By disregarding results from VGWU 114, the water cut data becomes even more favorable. The initial average water cut is 68%, the average post-stimulation water cut drops to 54% and the 30-day average water cut is 74%. The important point is that every well (except VGWU 114) had lower water cut initially after stimulation than prior to the treatment.

On two of the wells with high water cuts (>85%), a mutual solvent pre-flush was circulated across the lateral. **Table 2** compares the production results with and without a pre-flush. In both cases when a pre-flush was used, the water cut initially after stimulation was substantially lower. Thirty days later the water cut was still less than before stimulation.

In the wells treated without a pre-flush, four of the six wells had lower post-stimulation water cuts. Keep in mind that the VGWU 114 encountered treatment difficulties that could be responsible for the higher water cut. On the high water cut well in this group (VGWU 89), the water cut after the stimulation was not significantly lower than before. In this example, using a pre-flush made a larger reduction in water cut in high water cut wells. Water cuts after 30 days also suggest that using a pre-flush does a better job of keeping water production down in high water cut wells. When a pre-flush was not used, only half of the wells had lower water cuts than before.

VGWU 70 and 88 were only treated with 10 gal/ft of acid. This was done in an attempt to keep acid penetration to a minimum to avoid water production. In the case of the VGWU 88, the water cut was initially 6% lower after stimulation but climbed to 13% higher after 30 days. The VGWU 70 was also treated with a solvent pre-flush. Its water cut was lower at both time intervals after treatment. These preliminary results indicate that treating with less acid will not necessarily suppress the water cut, although it may help. Using a pre-flush, in contrast, dropped the water cut regardless of the acid volume.

Conclusions

The combination of horizontal drilling with DSP FoamMAT acid stimulation technology has consistently proven to be the most effective means for controlling water production and enhancing oil production on the Vacuum Glorieta West Unit. The average water/oil ratio (WOR) from the eight wells prior to horizontal drilling and treatment was approximately 19.5. Data taken from the same wells sixty days after the drilling and treatment shows an average WOR of 4.1, demonstrating a dramatic improvement. The impact of this result is very significant in that it extends the economic life of the VGWU by reducing the economic limit of hydrocarbon production in the field.

Placement of the acid within the open hole lateral is as important as accurate placement of the actual lateral was during drilling. Combined production data from all wells in the drilling package indicates that the DSP FoamMAT technique increased oil production by 379% while only increasing water production by only 196%. The post-treatment water cut was less after stimulation than before in seven of the eight wells. This data suggests that the DSP FoamMAT treatment preferentially stimulates oil productive zones over water productive zones.

The horizontal drilling package at the VGWU has been a technical and economic success. Subsequent to this drilling package, Texaco has utilized the same process to enhance water injection within the field with solid success. Based on the data presented in this paper, Texaco has begun a field-wide implementation of horizontal drilling and DSP FoamMAT stimulation practice to further reduce WOR and drive down the economic limit of the field.

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Table 1 - Treatment Summary

Well (VGWU)	Treatment Date	Length Treated (ft)	Acid gal	Acid gal/ft	Initial BOPD	Initial BWPD	Initial Water Cut	Post-Stim BOPD	% chg	Post-Stim BWPD	% chg	Post-Stim Water Cut	30-Day BOPD	% chg	30-Day BWPD	% chg	30-Day Water Cut
86	22-Aug-97	1,200	24k	20	81	253	76%	608	651%	828	227%	58%	228	181%	624	147%	73%
118	6-Nov-97	1,200	24k	20	2	18	90%	394	19600%	635	3428%	62%	124	6100%	529	2839%	81%
114	16-Dec-97	1,500	30k	20	94	239	72%	276	194%	1174	391%	81%	161	71%	1100	360%	87%
70	5-Jan-98	1,300	13k	10	67	448	87%	358	434%	1200	168%	77%	174	160%	997	123%	85%
89	13-Jan-98	1,400	28k	20	52	496	91%	148	185%	1259	154%	89%	42	-19%	1340	170%	97%
115	15-Jan-98	1,400	28k	20	211	265	56%	1071	408%	413	56%	28%	390	85%	366	38%	48%
88	21-Jan-98	1,100	11k	10	395	381	49%	1000	153%	756	98%	43%	527	33%	847	122%	62%
103	18-Feb-98	900	18k	20	114	99	46%	1007	783%	243	145%	19%	222	95%	164	66%	42%
	Average:				127	275	68%	608	379%	814	196%	57%	234	84%	746	171%	76%
Total:					1016	2199		4862		6508			1868		5967		

Table 2 - Comparison of Water Cuts with Respect to Treatment Type

	Acid gal/ft	Initial BWPD	Water Cut	Post-Stimulation BWPD	Water Cut	chg	30-Day BWPD	Water Cut	chg
Wells treated with a pre-flush:									
118	20	18	90%	635	62%	-28%	529	81%	-9%
70	10	448	87%	1200	77%	-10%	997	85%	-2%
Wells not treated with a pre-flush:									
86	20	253	76%	828	58%	-18%	624	73%	-3%
114	20	239	72%	1174	81%	9%	1100	87%	15%
89	20	496	91%	1259	89%	-2%	1340	97%	6%
115	20	265	56%	413	28%	-28%	366	48%	-8%
88	10	381	49%	756	43%	-6%	847	62%	13%
103	20	99	46%	243	19%	-27%	164	42%	-4%

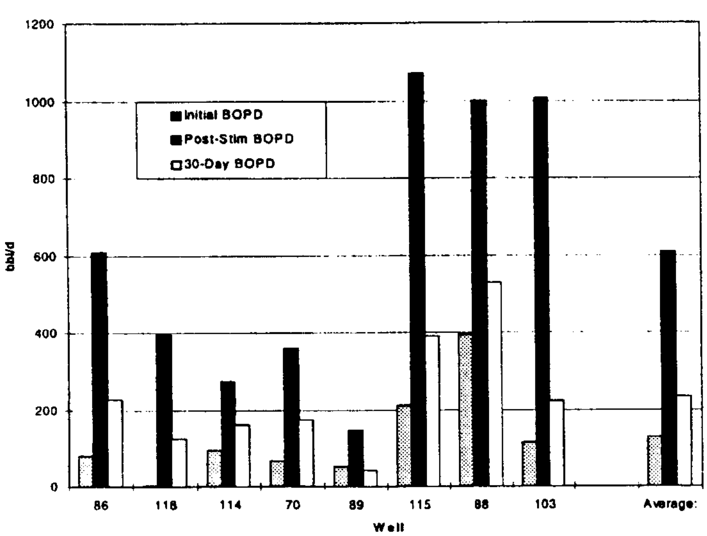

Figure 1 - Oil Production

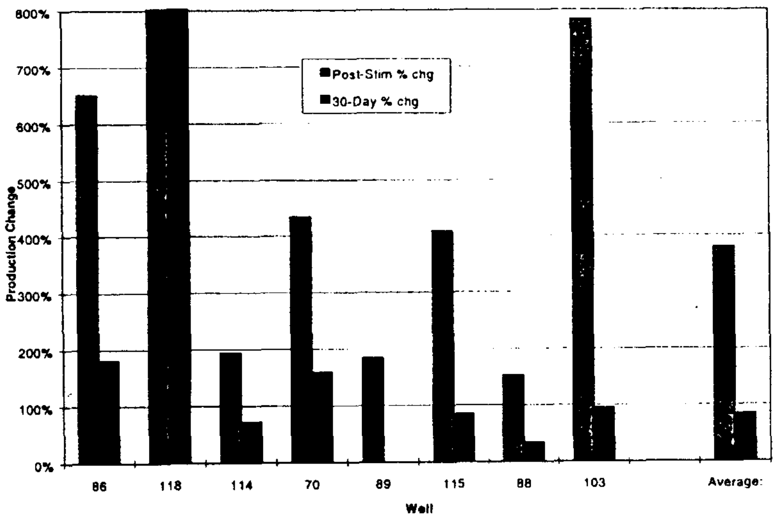

Figure 2 - Oil Production Increase

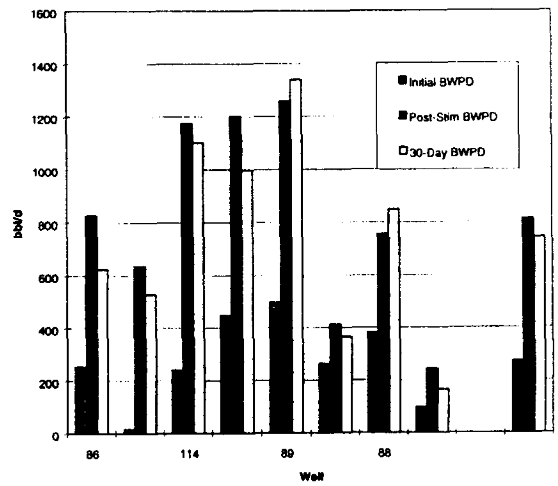

Figure 3 - Water Production

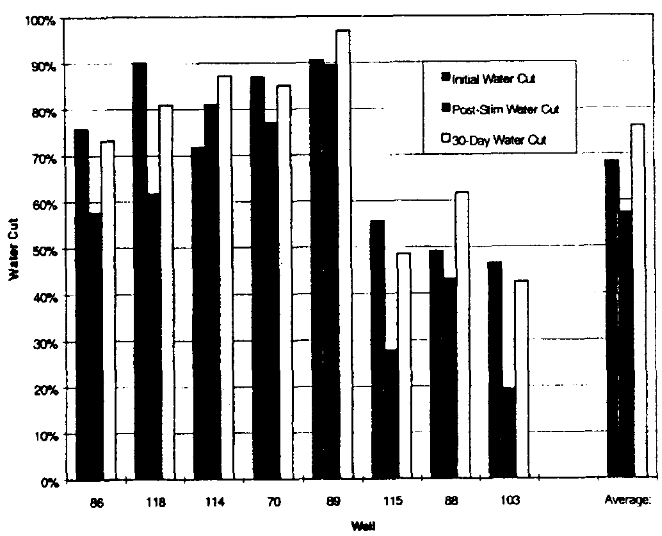

Figure 4 - Water Cut