Nitrogen Gas and Sand: A New Technique for Stimulation of Devonian Shale

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Summary

A process has been developed and demonstrated in 17 field tests in which sand proppant is added to a nitrogen gas stimulation treatment. Excepting minor problems with five treatments, all recent applications have been operationally successful. The early production results from two offset wells show decline curve improvement from the nitrogen-gas/sand treatment. Theories based on observed data from well treatments have been developed.

Displacement of proppant without the use of water or other liquids is a significant advantage both environmentally and economically. Additionally, the process causes no formation damage, and the well cleanup is rapid. The current major disadvantage is the small amounts of proppant displaced, although improved process design already has shown an increase in sand quantities. A wide variety of stimulation conditions involving flow rates, total nitrogen, number of perforations, and well depths have been tried.

Introduction

The use of nitrogen gas alone as a stimulation treatment has been practiced since 1978. Preliminary investigations into the specifics of this process have been published by several authors.[1,2] Nitrogen gas has been the most widely used stimulation treatment on the Devonian shale for several reasons.

The advantages of using nitrogen gas on the shale are as follows.

1. Nitrogen gas, being inert, is nondamaging to the shale. Problems with clay swelling, clay migration, or oil and water emulsions are eliminated.

2. Nitrogen gas stimulated wells will clean up quickly in most cases. Controlled cleanup will cause minimal permeability damage from fractured formation fines moving to the wellbore.

3. There is no liquid invasion of the microfractures in the shale, thus preventing possible reduction of the long-term productivity of the well.

4. The cost for a nitrogen gas treatment is usually less than for other stimulation methods, which allows a quicker return on invested capital.

These advantages provide a strong case for nitrogen gas stimulation; however, there is one disadvantage that has caused limited acceptance of the technique by some.

The lack of any type proppant being used with a nitrogen gas stimulation treatment has provided the strongest argument against it. The contention that fracture conductivity cannot be maintained without proppant is well known. Production results showing rapid decline curves are given as corroboration to the lack of fracture conductivity after the nitrogen gas fracture. It has been demonstrated that some natural propping does occur under certain conditions.[1] However, any additional placement of a proppant would improve the expected results from a nitrogen gas fracture. This placement of proppant and the process description thereof are the main concerns of this paper.

The three main considerations when adding proppant to a nitrogen gas fracture are (1) proppant transport capability of nitrogen gas; (2) created fracture geometry capacity to accept proppant; and (3) a method to add proppant to a high-velocity nitrogen gas stream under pressure. The approach selected to investigate these considerations was to perform an experimental treatment on a gas well completed in a shale interval. Before this treatment, preliminary testing was used to determine proppant transport ability of nitrogen gas.

The test was set up as shown in Fig. 1. Nitrogen gas was pumped down the 2⅜-in. [6.0-cm] tubing at velocities ranging from 27 to 120 ft/sec [8.23 to 36.58 m/s] and out the three perforations. Then, 20/40-mesh sand was added to the nitrogen gas stream at the various nitrogen rates. The sand was transported out the perforations at all rates. At 27 ft/sec [8.23 m/s], sand was transported out the bottom perforation only. At 120 ft/sec [36.58 m/s], sand was carried out all three perforations. Visual inspection inside the tubing after pumping stopped showed minimal sand left inside the tubing below the bottom perforation. From this test, it was concluded that nitrogen gas could be used to transport proppant and, if a created fracture was wide enough, the proppant could be displaced into it.

The test to determine the creation of adequate fracture width was designed to be an experimental treatment on a well completed in a gas-bearing shale. The treatment was simply to pump a pad of nitrogen gas followed by more nitrogen gas carrying 20/40-mesh sand. Total job size was 1,700 bbl [270.3 m^3], with 60% being pad and 40% carrying sand at an average concentration of 0.3 lbm/gal [0.14 kg/m^3]. Maximum rate achieved was 20 bbl/min [3.2 m^3/s]. The pressure averaged 3,500 psi

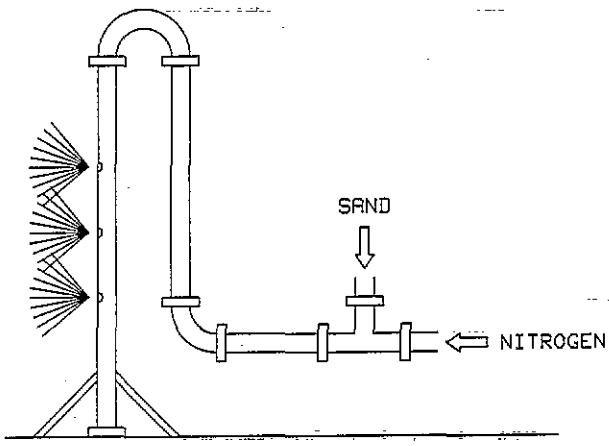

Fig. 1—Yard test.

[24.1 MPa] throughout the job, with no increase when the first grains of sand entered the fracture. Flowback afterward to clean up the well brought back very little sand. The success of this treatment supported the notion that proppant could indeed be added to a nitrogen gas stimulation treatment. Further investigation was warranted, which necessitated the proper surface equipment to do the job.

A truck-mounted, prototype blender was built to add sand to the nitrogen gas being pumped downhole. The purpose of this blender was to fill the gap between the first completely experimental setup and projected, specialized equipment in the future. All stimulations to date have used this prototype blender. The blender is a pressure vessel that can be manifolded to the wellhead to inject the sand (see Fig. 2). The original design has been modified as a result of observations made during the 17 well treatments to date. In essence, each job performed so far has been experimental, and the data gathered have been analyzed to enhance equipment performance and process design. Coupled with this field experimentation, laboratory simulations were begun to enable visualization of the sand transport mechanism.

The laboratory studies involved both the use of computer modeling and construction of a physical model to observe the behavior of sand being transported by a gas. Computer modeling was done by entering variables determined from results of nitrogen-gas/sand fracture jobs previously performed. The direction taken was to develop a method to design future treatments in terms of rate, total nitrogen gas, and total sand to be used. The physical model provided information used to alter the treatment design. Even more significant, the model confirmed suppositions made from field observations about the actual wellbore sand transport mechanisms of nitrogen gas. In essence, the laboratory studies provided confirmation that the process would work and established a basis for evaluation of the nitrogen-gas/sand treatment.

Evaluation of results from nitrogen-gas/sand treatments are to date incomplete. Paucity of production data from the treated wells is the primary reason. The current natural gas surplus has prevented wells from being turned into the line once they are cleaned up. Secondarily, the number of wells treated is not great enough to provide a valid comparison. The normal scatter in shale well production figures requires at least 100 wells for evaluation of treatment success. However, as will be discussed later, some production figures are available to support the nitrogen-gas/sand method being superior to a nitrogen-gas-only treatment.

Proppant Transport Mechanism

Model Study. To demonstrate qualitatively and to understand better what transport mechanisms were occurring in the fracture during pumping, an acrylic model of a fracture and wellbore was constructed, as shown in Fig. 3.

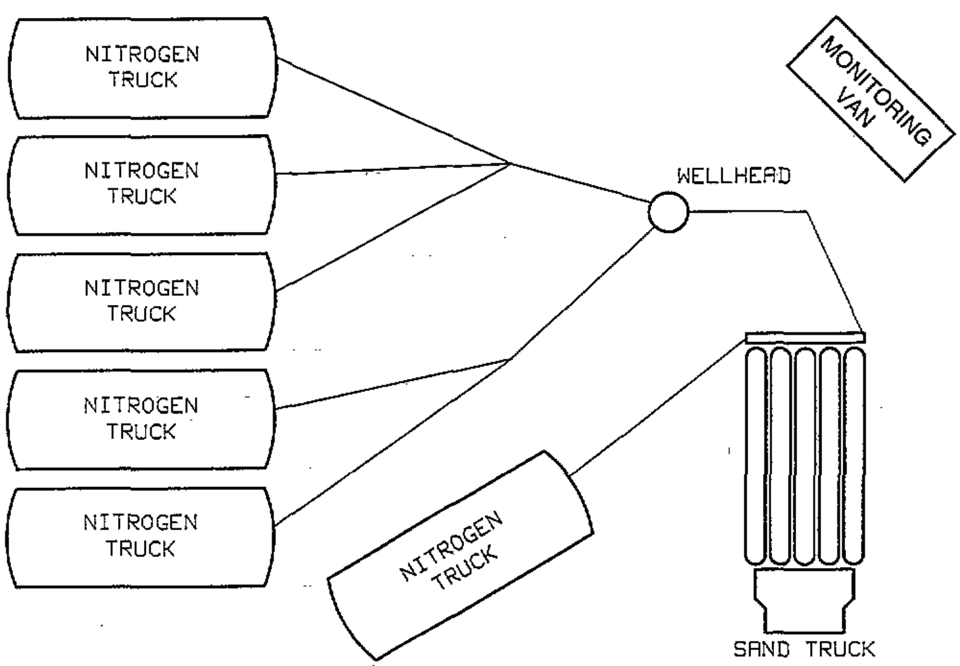

Fig. 2—Location layout.

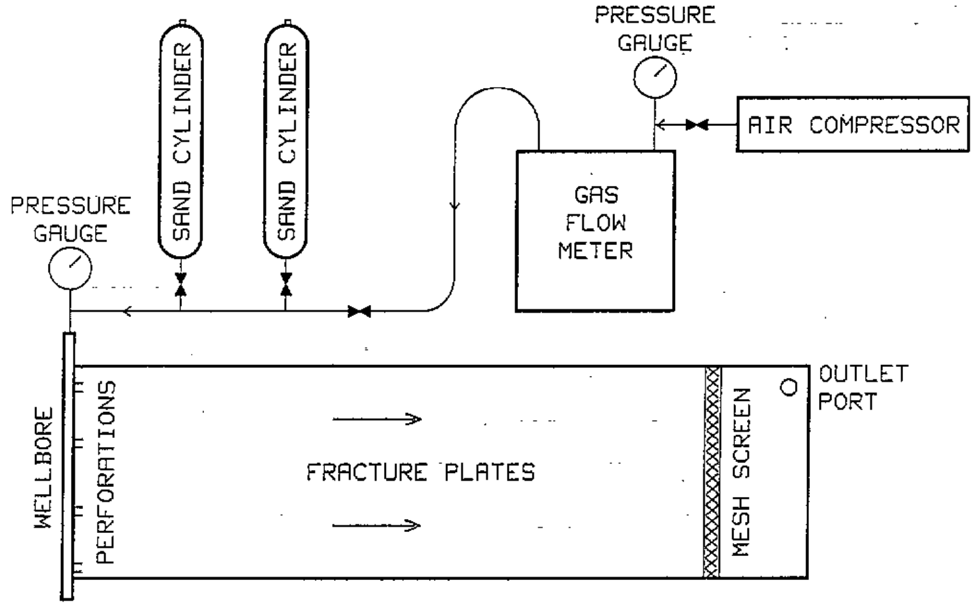

Fig. 3—Acrylic fracture model.

Two acrylic plates, approximately 2×7 ft [0.61×2.13 m], were spaced ¼ in. [0.64 cm] apart to simulate the fracture walls and width. Acrylic casing with a 1$\frac{1}{16}$-in. [4.01-cm] ID was used to represent the wellbore. Four perforations connected the wellbore to the fracture. In some tests, a wire mesh screen was placed between the plates to act as a bridging point in the fracture.

To simulate surface equipment, two cylindrical pressure vessels were filled with 40/70-mesh sand and then sealed to prevent leakage. Valves were installed at the bottom outlet connections to control the mass flow rate of sand into the gas stream. Air, provided by a compressor, was used to carry sand through the system. The air compressor was capable of producing flow rates of up to 20 scf/min [0.57 m^3/min], resulting in gas velocities up to approximately 7 ft/sec [2.1 m/s] between the plates, 48 ft/sec [14.6 m/s] down the wellbore (casing), and 85 ft/sec [25.9 m/s] through the perforations. Comparable velocities for actual fracture jobs were approximately 7.5 ft/sec [2.3 m/s] in the fractures, 60 ft/sec [18.3 m/s] down the casing, and 300 ft/sec [91.4 m/s] through the perforations. Gas velocities in the model were lower than actual cases because of pressure limits on the apparatus and because lower velocities showed more pronounced bank for the limited length of the plates.

In this configuration, several tests were made to observe the characteristics and location of the proppant bank. Various gas and proppant flow rates were used. Equilibrium velocity, defined by Babcock *et al.*[3] as "the velocity necessary to maintain the propping agents suspended in the fracturing fluid," was achieved in a number of these tests. It was concluded that the proppant banked or deposited in one of two ways.

First, if the fracture height was greater than the equilibrium height, then the proppant deposited near the wellbore until the height of the bank exceeded the equilibrium bank height (Fig. 4). Proppant then was transported toward the tip of the fracture, where a greater open height caused the velocity to decrease and proppant to deposit. In cases where the mesh screen was used, proppant bridged off and very quickly screened out the fracture tip. Second, if the fracture height was less than the equilibrium height (Fig. 5), proppant was transported immediately toward the fracture tip, where it again quickly bridged off. These two basic transport mechanisms dominated the test runs. However, because of the high velocity of the gas at the perforations, a more complex mechanism for transport existed near the wellbore. By intentionally blocking various combinations of perforations on the model, the effect of perforation geometry and perforation gas velocities on the bank location could be observed.

With all four perforations open, proppant would fill the wellbore (casing) quickly until it reached the lowest open perforation. The bank then formed at a distance away from the wellbore equal to the trajectory distance. As the bank grew, proppant moved back toward the wellbore until the bank covered and plugged the perforation. Proppant then filled the wellbore up to the next open perforation, and the process was repeated until equilibrium velocity in the fracture was achieved.

When half the perforations were intentionally blocked to increase gas velocity at the wellbore, a similar bank shape was generated. However, in this configuration, the bank formed away from the wellbore, and only minimal proppant was deposited near the perforations (Fig. 6). There also was an absence of proppant movement toward the wellbore, which prevented plugging of the perforations. As a result, minimal proppant was deposited in the casing. As anticipated, it was concluded from these tests that higher perforation gas velocities moved proppant away from the wellbore and resulted in reduced fracture conductivity near the wellbore.

Another important observation was that during all the tests, once the proppant containers were emptied, any further pumping of gas tended only to erode the bank in the fracture; i.e., overflushing would push the sand in the fracture back away from the wellbore. It was deduced, therefore, that overflushing should be avoided to prevent conductivity reductions in the fracture near the wellbore.

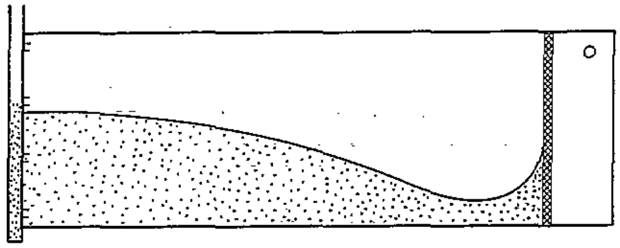

Fig. 4—Bank shape for case of fracture height greater than equilibrium height.

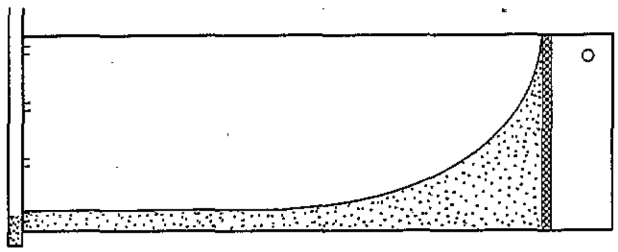

Fig. 5—Bank shape for case of fracture height less than equilibrium height.

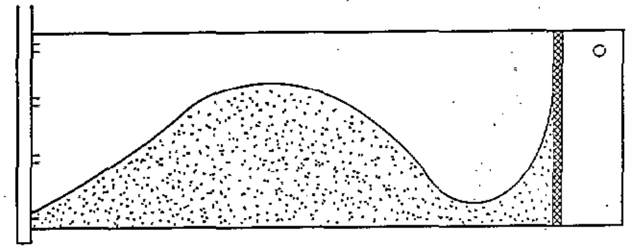

Fig. 6—Bank shape for case of high perforation velocity.

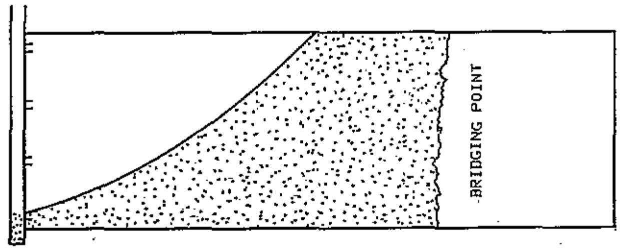

Fig. 7—Probably shape of proppant bank in fracture, actual case.

TABLE 1—RECOMMENDATIONS FOR TREATMENT OF 100 FT OF DEVONIAN SHALE

Perforated interval, ft	10 to 100
Perforation size, in.	0.39
Perforation number	30
Rat-hole below bottom perforation, ft	10 or less
Volume of nitrogen gas, bbl	900
Pump rate, bbl/min	50
Nitrogen pad volume, % of total volume	30 to 50
Amount of sand, lbm	10,000

Conclusions. By looking at the similarities between field cases and model tests, a theoretical mechanism for downhole proppant transport can be formulated.

Proppant is deposited in the rat-hole until the level reaches the lower perforations. At this point, all subsequent proppant enters the fracture. However, because equilibrium velocity in the fracture is easily achieved, proppant is transported quickly toward the tip of the fracture. Because of the narrowing of fracture width, proppant begins to bridge off. As proppant is packed toward the wellbore, the result is a slow increase in surface treating pressure.

The shape of the resulting proppant bank in the fracture is shown in Fig. 7. Note that most of the bank is away from the wellbore. Consequently, this fracture will tend to close near the wellbore under in-situ stresses and give a lower conductivity at the wellbore. Ideally, the largest portion of the bank should be nearest the wellbore. However, conductivity will still be greater than that of a simple nitrogen fracture under the same in-situ stress, injection pressure and rate, and reservoir conditions.

Treatment Procedure

The principal application of the nitrogen-gas/sand process to date has been on the Devonian shale, with select perforation intervals distributed over the typical 3,000-ft [914-m] shale interval. Each well requires a custom fracture design for gas/sand displacement. The geometry created by the pay zone thickness, spacing between pay zones, and the perforation pattern most likely will be different for every well. For best results with gas/sand, both the created fracture geometry and the wellbore aerodynamic flow pattern need to be incorporated in the fracture design. Both these variables can be controlled somewhat by perforation pattern design while, at the same time, opening the wellbore to the highest priority pay zones. These controllable, independent variables, along with injection pressure, flow rates, and gas/sand ratio, provide the opportunity for process optimization based on the primary dependent variable of interest (i.e., the proppant distribution along the fracture). Sand size selection also provides some options. To increase proppant penetration and transport efficiency, a smaller-mesh proppant can be used.

The recommended treatment procedure for a nitrogen-gas/sand stimulation treatment includes the guidelines listed in Table 1.

The typical equipment hookup to the well is shown in Figs. 2 and 8. Of special note is Fig. 8, showing the wellhead configuration. This design was adopted to prevent erosion of tubulars from high-rate flows of gas and sand by injecting sand into the high-rate gas after it "turns the corner" into the wellhead.

The sequence of events for the treatment consists of a perforation breakdown followed by the nitrogen pad, then by the sand and nitrogen, then by nitrogen flush. Fig. 9 is the surface-treating pressure chart from a representative job. Item A is the perforation breakdown where hydrochloric acid had been spotted in the casing (previously swabbed dry) across the perforations and pressure applied. Once the breakdown occurred, maximum pumping rate was established to pump the nitrogen pad. At Item B, the rate was decreased by 20% and sand injection started. Maximum sand concentration was 0.4 lbm/gal [0.2 kg/m^3]. The pressure began to increase at Item C. The increase in pressure was because of the progressive sandout of the perforations, since there was no change

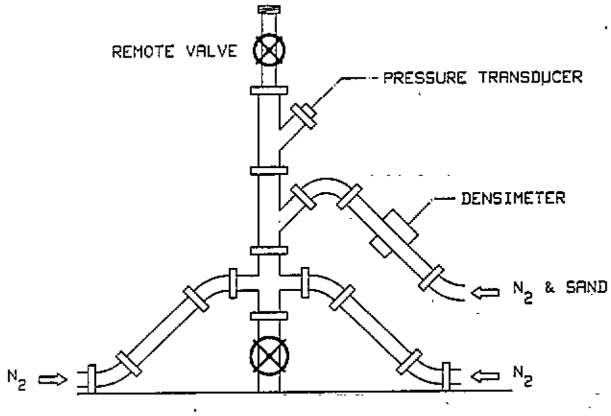

Fig. 8—Wellhead hookup.

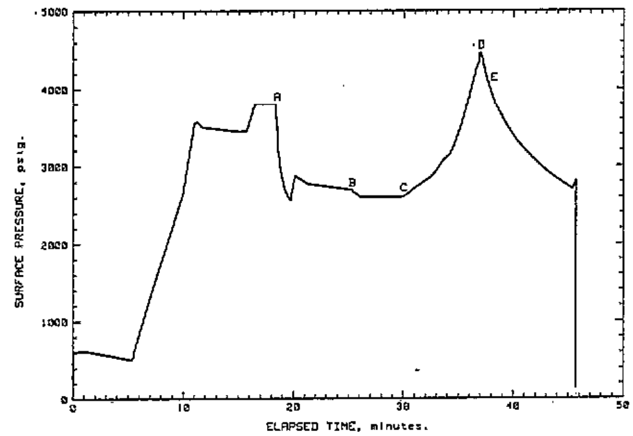

Fig. 9—Surface pressure behavior of treatment.

made in the pump rate. The treatment is self-diverting as some perforations sand up and others break down and begin taking treatment, thus eliminating any need for perforation sealer balls. At Item D, sand injection was stopped and a small volume of flush was pumped. Item E shows the shutdown and final shut-in pressure. Total pump time on this job was 19 minutes. Since the interval treated was short, the amounts of nitrogen and sand were decreased accordingly.

Data and Results

Table 2 contains some of the pertinent information on each nitrogen-gas/sand treatment performed to date. In addition to this information, some notes on the jobs are as follows.

Job 2. No sand was put into the fracture because of equipment problems.

Job 4. The design of this job was to place only 1,000 lbm [454 kg] of proppant in the fracture. No attempt was made to place maximum sand in the fracture.

Job 6. Premature sandout was caused by a concentrated slug of sand. The job was halted and the well was flowed back several times to remove the sand slug. After the slug was removed, the job proceeded as designed.

Job 8. This well was completed in two zones, with the top zone being treated with nitrogen-gas/sand. The upper zone was expected to produce oil.

Job 9. This well also was drilled for oil production. No oil was produced at the perforated interval, so plans are being made for recompletion.

Job 13. This is Well Goose Creek (G.C.) 1, which will be discussed later.

Jobs 16 and 17. These are the two stages of Well G.C. 2's treatment, which also will be discussed later.

Studies of stimulation jobs in which nitrogen was the sole transporting agent for the proppant resulted in the following observations and conclusion. First, in jobs with short rat-holes (less than 10 ft [3 m]), very little proppant could be found in the casing, and only 2 to 3 cu ft [0.05 to 0.08 m^3] of proppant was produced when the wells were flowed back. Since approximately 3,000 to 5,000 lbm [1361 to 2268 kg] of 20/40-mesh sand were pumped in these cases, indications are that most of the sand was placed in the fracture. Second, if a longer rat-hole existed, then proppant was deposited in the casing until the level of the proppant reached approximately the level of the lower perforations, depending on the nitrogen injection rate. All proppant then would enter the fracture.

TABLE 2—JOB DATA FOR ALL WELLS TREATED TO DATE

Job Number	Job Date	Well Location (County)	Formation Name	Treatment Volume (bbl)	Treatment Rate (bbl/min)	Proppant Type	Proppant Amount in Fracture (lbm)
1	May 1983	Ritchie, WV	Gordon sand	670	30	20/40 sand	1,300
2	May 1983	Roane, WV	Devonian shale	1,220	61	20/40 sand	0
3	May 1983	Boone, WV	Devonian shale	1,830	61	20/40 sand	2,800
4	May 1983	Noble, OH	Cow run sand	500	10	20/40 sand	1,100
5	May 1983	Jackson, WV	Devonian shale	1,450	57	20/40 sand	3,800
6	May 1983	Washington, OH	Devonian shale	1,630	52	20/40 sand	3,000
7	May 1983	Meigs, OH	Devonian shale	1,140	26	20/40 sand	2,800
8	June 1983	Ritchie, WV	sand	780	49	20/40 sand	3,100
9	Aug. 1983	Ritchie, WV	Devonian shale	1,290	57	40/60 sand	3,800
10	Aug. 1983	Ritchie, WV	Devonian shale	3,640	92	20/40 sand	5,200
11	Aug. 1983	Ritchie, WV	Devonian shale	630	36	20/40 sand	2,500
12	Aug. 1983	Second stage of No. 11	Devonian shale	780	46	20/40 sand	5,100
13	Aug. 1983	Ritchie, WV	Devonian shale	2,260	50	20/40 sand	5,400
14	Sept. 1983	Wirt, WV	Devonian shale	837	40	20/40 sand	300
15	Sept. 1983	Ritchie, WV	Devonian shale	800	33	20/40 sand	2,000
16	Sept. 1983	Ritchie, WV	Devonian shale	1,000	50	20/40 sand	0
17	Sept. 1983	Second stage of No. 16	Devonian shale	1,250	50	20/40 sand	0

TABLE 3—PRODUCTION DATA ON WELLS TREATED TO DATE

Job Number	Initial Production After Cleanup	Production After 1 Month	Production After 6 Months
1	20 Mscf/D open flow	shut-in	intermittent
2	200 Mscf/D open flow	shut-in	50 Mscf/D
3	660 Mscf/D open flow	shut-in	80 Mscf/D
4	10 Mscf/D open flow	shut-in	unavailable
5	180 Mscf/D open flow	shut-in	30 Mscf/D
6	30 Mscf/D open flow	20 Mscf/D in line	unavailable
7	60 Mscf/D open flow	56 Mscf/D in line	intermittent
8	? (two-zone completion)	unavailable	unavailable
9	30 Mscf/D in line	30 Mscf/D in line	well recompleted
10	325 BOPD in line	90 BOPD	5 BOPD
	40 Mscf/D in line	20 Mscf/D in line	10 Mscf/D in line
11	70 Mscf/D in line	shut-in	30 Mscf/D in line
	700 psig on 32/64 choke		
12	commingled with Job 11, above		
13	10 BOPD	28 BOPD	19 BOPD
14	30 Mscf/D open flow	shut-in	shut-in
15	5 BOPD	4 BOPD	3 BOPD
16	4 BOPD	8 BOPD	2 BOPD
17	commingled with Job 16, above		

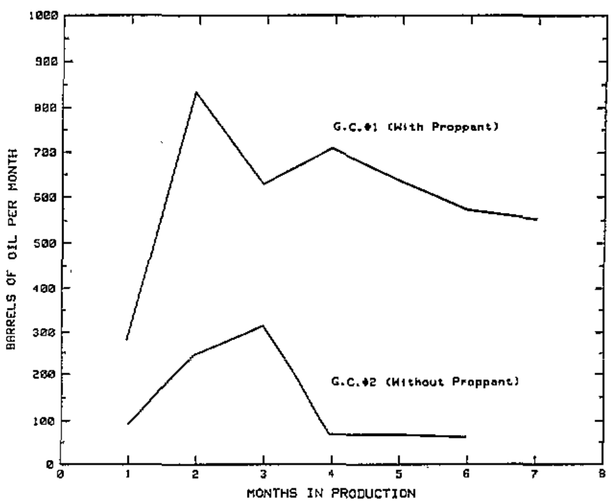

Fig. 10—Comparative production data.

Third, in jobs that screened out, surface pressure rise was not instantaneous, indicating a blockage out in the fracture rather than at the perforations. Taking these three observations into consideration, it appeared that proppant transport was efficient enough to place proppant in the fracture and effectively move it away from the wellbore.

In conjunction with Table 2, Table 3 and Fig. 10 contain production data from the wells treated with nitrogen gas and sand. Any evaluation of these results should consider the unconventionality of Devonian shale. Production from the shale is dominated by natural and created fracture systems.[4] A comparison between two offset wells may not be possible simply because they did not intersect into the same localized natural fracture system. To be statistically significant, a large population of perhaps 100 wells or more with similar reservoir conditions would be needed. Such data are not yet available.

Table 3 lists three categories of production results: initial, 1 month, and 6 months. The initial production figures are complete, but the more significant 1-month and 6-month columns show many shut-ins and unavailable data. Comparison of only initial flow data for various fracture processes (i.e., liquid-foam/sand, gas only, gas/sand) would not be very meaningful and could give erroneous expectations for long-term cumulative production. Obviously, the liquid-foam-based methods may require several months of well cleanup before maximum production is reached and true decline occurs. The initial flows with just nitrogen and no proppant in the fracture to create a pressure drop, on the contrary, would be much larger than gas/sand or liquid-foam/sand processes. Such large initial flow data would be grossly misrepresentative if, after the well is flowed back, the fractures close either partly or completely.

Fig. 10 does present some data that will allow a comparison between the nitrogen-gas/sand treatment and a nitrogen-gas-only treatment. Well G.C. 1 (Job 13) was treated with nitrogen gas and sand, whereas Well G.C. 2 (Jobs 16 and 17) was treated with nitrogen only. (Equipment problems prevented the originally intended gas/sand treatment.)

These two wells are offsets intersecting into the same localized natural fracture system. The logs, reservoir pressures, perforated intervals, and treatment volumes and rates for both wells will correlate closely. However, Fig. 10 shows the monthly oil production for these two wells to be quite far apart. Well G.C. 1 produces much better than Well G.C. 2. Well G.C. 1 had 5,400 lbm [2450 kg] of 20/40-mesh sand placed in the fracture during the stimulation treatment, whereas no sand was put into Well G.C. 2. Placement of the proppant in the fracture evidently resulted in a higher fracture conductivity in Well G.C. 1 than in Well G.C. 2, and resulted in increased oil production.

Conclusions

In this paper, we have described the evolution of a new method for stimulating Devonian shale wells. This process involves pumping nitrogen gas to create fractures in the shale and then placing proppant into those fractures with gas. This process was conceived as an alternative to other stimulation methods that have not yielded the desired results.

An approach combining laboratory and field data was used to investigate the nitrogen-gas/sand process. Results of the investigation are as follows:

1. Proppant can be added to a high-velocity nitrogen gas stream using presently available equipment with some modification.

2. Nitrogen gas will create a fracture wide enough to accept 20/40-mesh proppant.

3. Nitrogen gas will transport 20/40-mesh proppant efficiently into the fracture and move it effectively away from the wellbore.

4. Production information to date is not sufficient enough to be significant. However, data from two similar wells show the nitrogen-gas/sand treatment to be superior to a nitrogen-gas-only treatment.

Field data are rapidly accumulating. Theoretical and experimental studies are continuing.

Acknowledgments

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SI Metric Conversion Factors

bbl	× 1.589 873	E−01	=	m^3
cu ft	× 2.831 685	E−02	=	m^3
ft	× 3.048*	E−01	=	m
in.	× 2.54*	E+00	=	cm
lbm	× 4.535 924	E−01	=	kg
psi	× 6.894 757	E+00	=	kPa

*Conversion factor is exact.

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