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By
K-H. Frohne

Date Published – April 1977

Morgantown Energy Research Center
Morgantown, West Virginia

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by

K-H. Frohne[1]

ABSTRACT

This report describes a large-scale foam fracturing operation performed on a Devonian Shale well in Jackson County, W. Va. Here the Energy Research and Development Administration (ERDA) in cooperation with Consolidated Gas Supply Corp. (CGSC) conducted a foam frac using 973 bbl. water, 2160 MSCF nitrogen, and 155,000 lbs sand proppant. The gross perforated formation interval is 3238-3629 ft. in W. L. Pinnel No. 12041 near Cottageville, Jackson County. The frac test was conducted to help evaluate the effectiveness of foam fracturing in the low-pressure water-sensitive Devonian Shale of the Appalachian Basin.

The report details the frac job and the well clean-up period with field problems encountered. Also described is the post-frac logging program run to define created vertical fracture extent and gas influx into the well bore.

A post-frac deliverability test performed on the well is described. The well was found to have an absolute open flow potential of 173 MSCFD.

An 804 hour pressure buildup test run on the well after the flow test indicated a static reservoir pressure of 564 psia, a well capacity of 3.42 md-ft, and an induced fracture half-length of 1155 ft.

INTRODUCTION

The present natural gas shortage and associated supply problems in this country are pushing both the energy industry and government into developing new sources and improving known but currently marginal gas-producing areas. One such marginal area is the Devonian Shale formation of the Appalachian Basin, which holds huge in-place resources of natural gas but which, because of its very low permeability, results mostly in very poor gas wells.

The Morgantown Energy Research Center (MERC/ERDA) is involved in an on-going research program into well stimulation research in the Devonian Shale, and this report describes a phase of this research. The report details a large-scale foam fracturing demonstration conducted on Consolidated Gas Supply Corp. W. L. Pinnel No. 12041 in Jackson County, West Virginia. This demonstration was performed to help evaluate the effectiveness of novel fracturing techniques such as foam in the water-sensitive Devonian Shale. Figure 1. shows Jackson Co. and the location of the well.

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1 Petroleum Engineer

FOAM FRACTURING DEMONSTRATION PROGRAM:

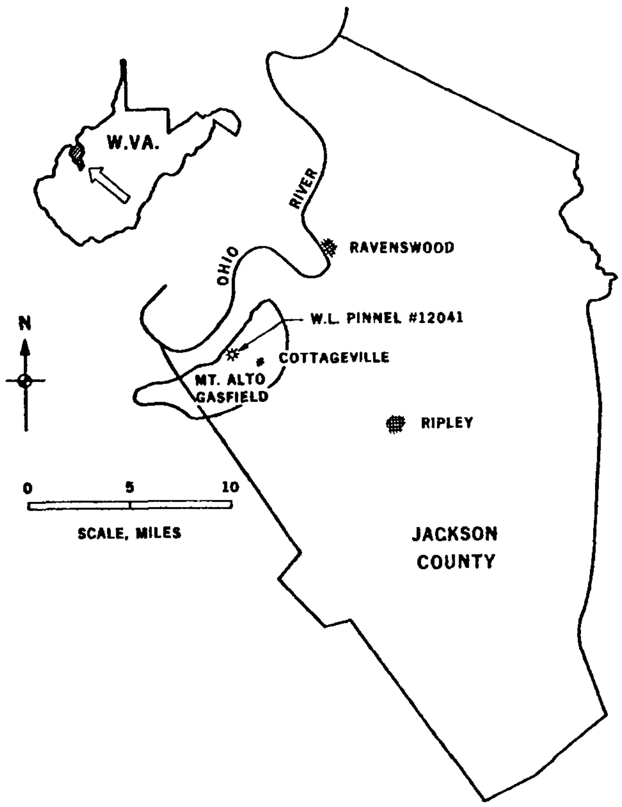

Figure 1 - Well Location W. L. Pinnell #12041

Foam Fracturing Design Considerations

The foam fracturing design for the W. L. Pinnel No. 12041 test was based primarily on what we have learned in past foam frac experiments by MERC in Kentucky and Ohio. The Devonian Shale is water sensitive and has low reservoir pressure and gas flow rates, and thus does not usually flow back frac water effectively. For these reasons we are investigating high-stability foam as a fracturing fluid, because it only contains 25% water by volume and the other 75% volume of nitrogen serves to blow back a large part of the frac water quickly.

We have also learned that foam stability is a critical part of fracture job design. Too much foaming agent will over-stabilize the foam and prevent it from breaking down promptly in the created fracture. This results in the fluid coming back about the way it was pumped in, carrying a lot of frac proppant out with it and damaging the created fracture system. In severe cases of over-stability the foam does not break down at all, releases no nitrogen gas to drive itself out, and thus remains in the fracture as a foam block. When such a block exists, well production is usually nil.

At the other end of the stability range is under-stabilized foam. Here the foam can break down into gas and water during the pumping operation, resulting in a proppant screen-out either in the fracture or in the well bore. Sometimes a screen-out can be repaired by immediate blow-back of the well, but often the job must be abandoned.

In our past work we have found that in the Devonian Shale a foaming agent concentration of 2 - 5 gallons of agent per 1,000 gallons of water is effective in giving the proper foam stability. As back up for the Jackson County design we had an independent laboratory conduct a stability screening test on some Shale core samples, and they recommended an optimum concentration of 2 gallons of Howcosuds foamer (or equivalent) per thousand gallons. A useable concentration range of 2 - 5 gallons was evident, from the screening test and since Consolidated Gas personnel were concerned about stability and the length of pumping time of the proposed job, we recommended 5 gal/1,000 to be used. Other frac fluid and reservoir parameters used in the treatment are listed in Tables 1 and 2. The information listed in these tables was supplied to the fracturing subcontractors, Halliburton Services and to Aircowell (nitrogen supplier) in the form of a request for bid for the foam fracturing service.

Since the 32 casing perforations were spaced over a gross interval of 391 ft., it was decided to use a diverting agent to improve frac coverage over the interval. After discussions with Halliburton we made plans to triple-stage the job with 3 injections of TLC-80, a flaked Benzoic acid product. This blocking agent is designed to temporarily seal off open performations in order to force open new ones. After some residence time of a few hours the agent is designed to go into solution with frac or formation water and to reopen the perforations.

Well Perforation and Breakdown

In December 1975 Consolidated Gas perforated W. L. Pinnel No. 12041 with 32 holes (0.41 in. dia.) spaced over the 3238-3629 ft. interval. Figure 2 shows the GR-Density log over the zone of interest. The well was then shut in until January 19, 1976, when Halliburton set up on location to break down the perforations. The cased hole (4 1/2 in. pipe) was filled with 12 barrels (bbl.) of 15% acid (HCL) and 47.5 bbl. of 7.5% acid at 0 psi surface pressure. Breakdown of the formation occurred during fill-up, and an additional 12 bbl. b.c. acid siphoned into the well. The acid pump was shut down and the well siphoned until shut in.

Acid pumping was resumed at 16 barrels/minute (BPM) and 300 psi, and 50 perforation balls (7/8 in. dia.) were injected. Balling action occurred and surface pressure rose to 1600 psi while pumping at 12 BPM, indicating some open perforations. Another 57 bbl. acid was injected at 1600 psi and 12 BPM, indicating a constant number of open holes.

On shut-in, the well surface pressure immediately fell to 0 psi, and echo-soundings were taken to establish a fluid

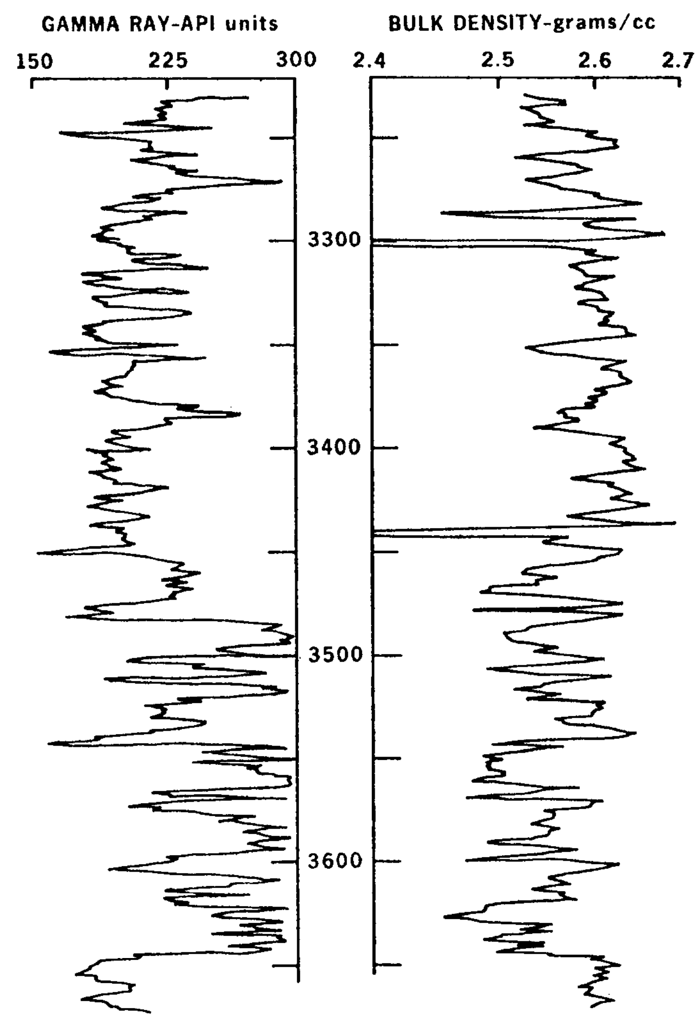

Figure 2 - W. L. Pinnel #12041 Completion Zone Well Log

Table 1 - Technical Job Specifications, Fracturing Service

Basic Job Parameters:	
Pumping rate, foam	20 BPM
Pad volume, foam	15,000 gal.
Treatment volume, foam	148,000 gal.
Flush volume, foam	5,000 gal.
Sand	155,000 lbs.
Fracturing Design Parameters:	
Formation pressure	195 psi
Formation temperature	80°F
Foam quality	75
BHTP	1980 psi
Casing	4 1/2 in.
Foam viscosity, pipe	58 cp.
Friction loss, pipe	10.4 psi/100 ft.
KCl concentration, water	2%
Foaming agent concentration, water	5 gal/1000 gal.
Materials and Equipment Required:	
Cementer	as required
Pumper	as required
Blender	as required
Foaming agent	200 gal.
KCl	8,400 lbs.
Sand, 20/40 mesh	155,000 lbs.
Chemical diverter	2,000 lbs.
Acid, 15% HCl	4,000 gal.
Acid inhibitor	as required
Acid Pump	as required
Ball injector	1 unit
Perforation balls, 7/8 in. dia.	75

Table 2 - Technical Job Specifications, Nitrogen Service

Basic Job Parameters:	
Injection rate, foam	20 BPM
Injection rate, nitrogen	10,720 SCFM
Foam quality	75
BHTP	1,980 psi
Formation temperature	80°F
Pipe	4 1/2 in.
Materials and Equipment Required:	
Nitrogen gas	2,200 MSCF
N_2 pumper	as required
N_2 transporter	as required
N_2 vaporizer	as required

level. The three echometer shots indicated the fluid level to be at 330 ft. Halliburton then rigged down, and a bailer was run into the well. The driller tagged fluid at about 300 ft. 30 minutes after the initial shut-in. Based on the approximated 300 ft. fluid level and the fact that a few perforations were open, a fracturing treating pressure of 1400 psi was estimated for this well. This number was used to fine-tune nitrogen demand for the foam frac.

Breakdown acid was swabbed from the well the remainder of January 19 and 20, at which time the well bore was free of liquids. During swabbing, 15 perf balls were recovered from the well. None showed seating marks characteristic of seated balls.

By the evening of January 20 Halliburton had spotted their frac equipment on location, and Aircowell had assembled the nitrogen equipment at their Ripley depot.

Foam Fracturing Operation

At 4 AM January 21, Halliburton jetted the frac tanks to pre-heat the water and to mix the 2% KCL and 0.5% Ca Cl_2 as required for the foam frac. By 10:30 AM all Halliburton and Aircowell equipment was set up on location and injection lines had been pressure tested. Figure 3 shows the equipment schematic for the fracturing operation. At the recommendation of Halliburton and CGSC the foaming agent concentration was increased from the original design of 5 gal/1000 gal., to 7 gal/1000 this heavier concentration was used throughout the frac job.

The actual fracturing was initiated at 10:49 AM. A pad of 380 bbl of 75 quality foam was pumped in at 1,000 psi surface pressure. Nitrogen rate was held at a constant 9000 standard cubic feet/minute (SCFM) at 100°F for the entire job, while the water rate varied from 4.5 - 5.7 BPM, averaging 5.1 BPM or 20.4 BPM foam. After the foam pad, 20/40 mesh sand was added to the foam stream at 0.5 pounds /gallon (ppg) (2.0 ppg at blender) for 240 bbl foam. Sand was then raised to 1.0 ppg (4.0 ppg at blender) for 240 bbl. and

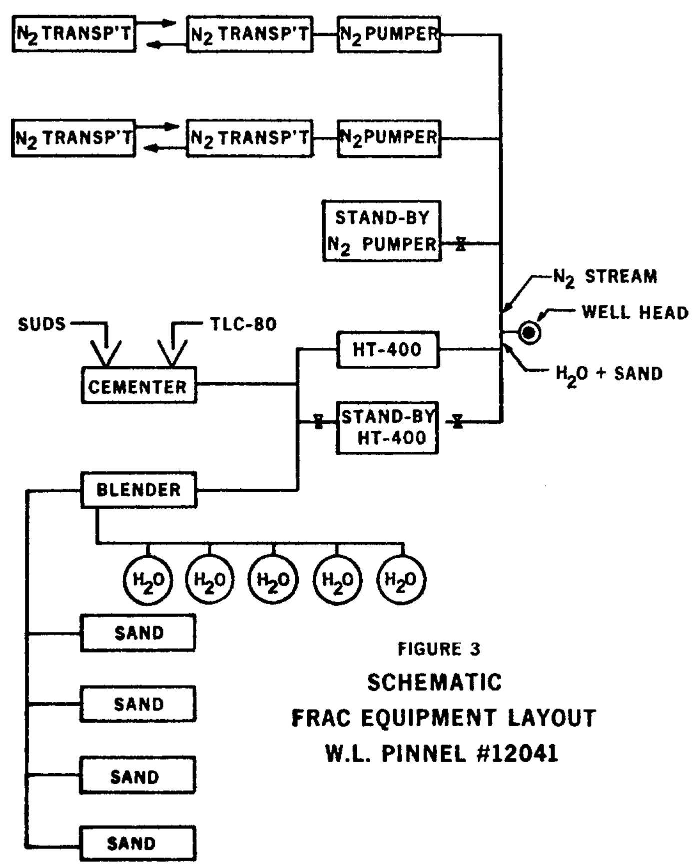

Figure 3 - Schematic Frac Equipment Layout
W. L. Pinnel #12041

raised again to 1.5 ppg (6.0 ppg at blender) for 360 bbl. to complete the first stage. Surface pressure rose gradually from 1000 psi initially to 1175 psi at the end of the stage.

A slug of 500 lb. TLC-80 diverter, pre-mixed in gelled water, was pumped into the foam stream by the cementer. Difficulty was experienced in pumping the viscous slug due to N_2 gas trapped in the cementer manifold, and 100 bbl. foam was needed to put the diverter away. Surface pressure rose to 1350 psi, indicating some blocking of perforations.

The second stage was started with 200 bbl. foam at 0.5 ppg sand. Surface pressure dropped back to 1200 psi, indicating additional perforations opening up. Sand was increased to 1.0 ppg for 240 bbl. foam and increased to 1.5 ppg for 360 bbl. to complete stage 2.

Another TLC-80 slug was pumped by the cementer. Despite all efforts, vapor locking occurred again and 160 bbl. foam was needed to put the slug away. Pressure rose back to 1350 psi.

The third stage was started with 0.5 ppg sand in 140 bbl. foam with pressure dropping back to 1325 psi. Sand was increased to 1.0 ppg for 240 bbl. and pressure fell to 1300 psi. Sand at 1.5 ppg in 380 bbl. foam finished the third stage.

The final slug of 700 lb TLC-80 was dumped dry directly into the blender and was quickly put away in 56 bbl. foam as pressure rose to 1400 psi.

Stage 4 was started with 240 bbl. foam and 0.5 ppg. sand, while the pressure stayed at 1400 psi. Sand was increased to 1.0 ppg in 120 bbl., and pressure fell to 1325 psi. Sand was increased to 1.5 ppg for the final 268 bbl. foam to finish the stage. Final pressure was 1300 psi.

During the second half of each stage, Birdwell, a geophysical logging company, was introducing radio-tracer frac beads at the blender. These beads are made of a plastic material irradiated with Iridium 192 and are designed to smear off in the perforations and the created fractures. Four liters of beads were put away during the frac job. A flush of 20 bbl. foam followed by 41 bbl. water completed the job. The flush pressure fell from 1300 psi initially to a final 200 psi. This drop was due mostly to the weight of water now in the casing. The frac job was completed at 3:01 PM, lasting 4 hours and 11 minutes. Totals of 973 bbl. water, 2160 MSCF nitrogen, and 155000 lb. 20/40 mesh sand were pumped into the Devonian Shale. After pump shut-down, pressure immediately fell to 0 psi. and Halliburton and Aircowell uncoupled and moved off location.

Foam Fracturing Flowback

After frac equipment had been cleared off location, a Halliburton control head and dual choke manifold rated for 25000 psi working pressure was installed on the well head. Exhaust lines from the chokes were routed to the mud pit, and at 4:30 PM, about 1 1/2 hours after frac job completion, the well was opened for flowback. The head manifold held 2 positive bean chokes with ceramic inserts that could be operated singly or in parallel. Flow was started through a single 1/8 in. choke, and by 5:30 PM a one in. stream of wet foam and fine sand was going into the mud pit. Choke size was increased to 3/16 in. at 6:15 and sand flow increased. At 6:30

the choke was cut back to 1/8 and the well was making stiff foam and some sand. During the night the choke was tended by a Halliburton technician and a rig crewman. Chokes were gradually increased to 1/2 in. overnight, with increasing production of finely crushed sand. (No whole grains were found in a sand sample.) Choke size was then reduced to 3/16 in order to reduce sand production.

At 8 AM on January 22, the well was producing wet gray foam and heavy amounts of crushed sand through the 3/16 choke. The choke was then increased to 1/4 making foam with heavy sand and grey formation fines. By 10:30 AM the sand was cleaner but still crushed, and by 11:30 AM sand returns were reduced. ERDA personnel left the job site at that time to return to Morgantown. The well flowback was continued by the Halliburton choke tender and CGSC personnel.

After a total of 20 hours on line (about 12:30 PM, January 22, 1976,) the choke body was cut out by sand erosion, spraying foam and sand onto the rig floor. The well head valve was shut in to control the well, but was found to leak slightly. A second 4 1/2 inch valve was stacked on top of the leaking valve, but the new valve also leaked. Another valve (new) was found and replaced the second valve on the well head, finally permitting a complete shut-in of the well. Another Halliburton control head was installed and flowback was resumed at 8:50 AM on January 24. Repairs had taken 44 hours with the well off production.

The well was opened through a 1/8 choke, blowing dry gas through 1/8, 3/16, 1/2, and 3/8 inch chokes until 7 PM. The well then began surging foam and water until 8 PM. At that time it started flowing soapy water at an estimated 20 - 30 bbl./hour for about 24 hours, or until 8 PM on January 25. Very little sand was produced during this time. Flowing pressure had been constant at about 825 psi until the water flow started, and then dropped steadily at 4 psi/hour during the flow period to a final 10 psi. The well was on the 3/8 choke during the entire water flow period.

During the evening of January 27, the control head was removed from the well and a sand line was run into the well. Sand was tagged at 3625 ft. The lowest perforation was at 3629 ft., and essentially the entire fractured interval was sand free. A pitot tube test indicated an open flow of 150 MCFD, probably mostly nitrogen. The service rig started swabbing water from the well the evening of January 27 and continued until the well was dry. About 30 ft. of sand was bailed from the well to form a pocket.

Post Fracturing Well Logging

Well swabbing was continued intermittently as needed to dry up the well until February 5. At that time Birdwell ran wellbore sibilation and spinner surveys and a gamma ray log over the fractured interval. The sibilation and spinner surveys are designed to detect gas entering the wellbore, sibilation by detecting noise and the spinner by metering the gas flow. The GR was run to log for the radiation of the frac beads spotted during the fracturing operation. Figure 4 shows these three logs along with the location of casing perforations and the created vertical fracture height interpreted from the GR. As can be seen, all perforations seem to have been fractured, including the two isolated sets in the upper zone. Total indicated frac height is 159 ft. It can also be seen that vertical fracture extension beyond the perforated intervals rises up to 24 ft. above the perfs, but never more than 2 ft. below.

The quantitative spinner survey showed that 97% of gas production is coming from the 3270-3374 ft. interval. The sibilation survey's microphone was dead over most of the gas interval and only began to perform at 3310 ft., logging up. Sibilation microphones are highly sensitive to water, and the tool was probably temporarily disabled by a water film.

After the post-frac logging program the well was shut-in to build up to a stabilized pressure, to be followed by a deliverability test.

Well Deliverability Test

On March 8, 1976, the well surface pressure had risen to a pseudo-stabilized 521 psig. At this time the pressure was only rising a fraction of a psi per day and was considered stabilized sufficiently for purposes of flow-testing. Figure 5 shows the well head and deliverability test equipment used in our flow test. All equipment was set up, and the test, a modified isochronal test 1/ 2/, was started at 10:00 AM, March 9. The well was produced through a critical flow prover for four 1-hour periods separated by 1-hour shut-ins. The well was flowed at increasing rates of 395, 664, 1298, and 2636 MSCFD. Table 3 shows the composition analysis, specific gravity, and heating value of the gas produced during the test. The table is a composite of 3 samples taken over the flow test interval. Table 4 shows the detailed data recorded during the modified isochronal test.

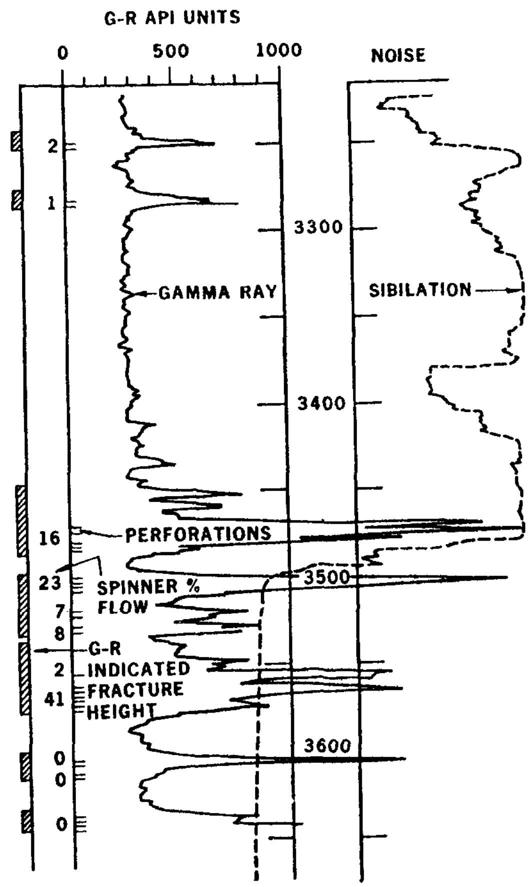

Figure 4 - W. L. Pinnel #12041 Post-Fracturing Log

At the conclusion of the fourth 1-hour flow period, the well was drawn down to stabilization using the 0.625 inch orifice plate. At about 8 PM a 0.250 plate was inserted in the prover, and the well was approaching stabilization. At 10 PM the well stabilized at 102 psig surface pressure at a calculated flow rate of 160.5 MSCFD, and held that pressure until 2 AM on March 10, a stabilized rate over 4 hours. This was considered satisfactory to establish the stabilized rate point on the modified isochronal test plot, Figure 6.

From Figure 6 we obtain the well deliverability under any gathering system line pressure. The absolute open flow potential of the well is 173 MSCFD, and the well should deliver about 168 MSCF into the 80 psig

Cottageville field gathering system.

Pressure Buildup Test

The well was then shut-in after the stabilized flow rate for a long-term pressure buildup test. Since the well has not produced any water since frac clean-up, we have confidence in obtaining a good buildup.

The well remained shut in for a total of 804 hours. During the last 200 hours of the test the bottom-hole pressure leveled off at 564 psia, which is considered to be the static reservoir pressure of the shale surrounding the well.

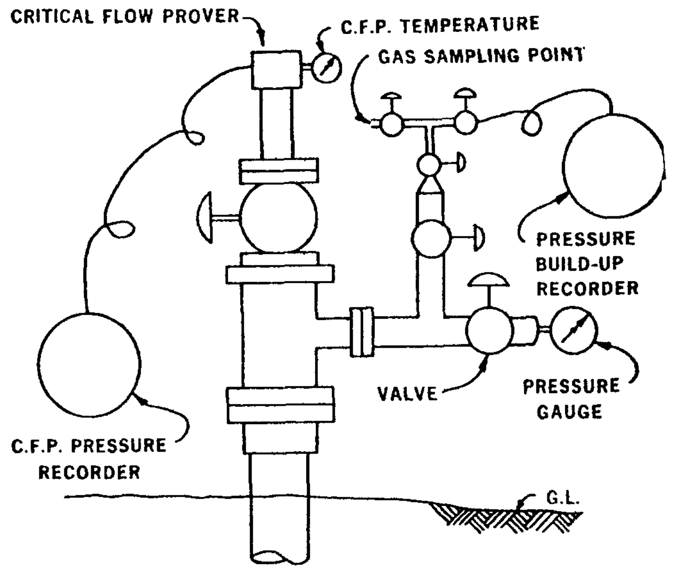

Figure 5 - Well Head & Test Assembly

The buildup data have been used to calculate well capacity and fracture length for well #12041, utilizing Raghavan's approach to pressure analysis in fractured wells.

As a first step, surface-recorded buildup data were converted to bottom-hole conditions by the empirical relationship:

$$P_{bh} = P_s \, e^{(GL/53.34 \, \bar{T})} \qquad (1)$$

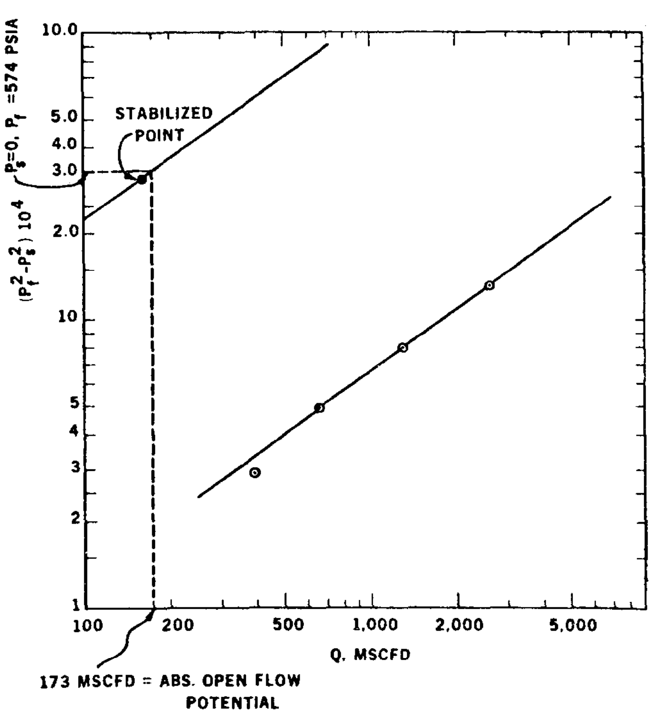

Figure 6 - Modified Isochronal Flow Test

where P_{bh} = bottom-hole pressure, psia
P_s = surface pressure, psia
G = gas gravity, 0.71
$\bar{T}$ = average gas column temperature, 547°R
L = length of casing to perforation center, 3550 ft.

The resulting bottom-hole pressures were then plotted against the log of shut-in time (figure 7), and against the square root of time (figure 8). Also plotted on log-log paper was the pressure difference (bottom-hole pressure at any given time minus the pressure at the instant of shut-in) against shut-in time (figure 9). As described in detail in reference 4, the straight line portion of figure 9 is thought to represent linear gas flow toward the induced fracture face. As shown in the figure, the straight line lasts about 15 hours into the buildup period. This period, when plotted on cartesian paper (figure 8), can then be used to

Table 3 - Gas Composition (Well Test)

Constituent	Concentration, %
hydrogen	0.16*
oxygen	0.59
nitrogen	12.63
methane	71.68
ethane	9.43
carbon dioxide	0.17
propane	4.20
iso-butane	0.25
butane	0.80

*average values for 3 samples

Specific gravity of gas is 0.71

Heat value of gas is 1201 BTU/MCF

Table 4 - Modified Isochronal Flow Test Data

Flow No.	Time	Temp.	PSIG	Plate	Coefficient	Flow Rate
	10:00 am	36.5°F	509 psig			
	10:15	37	500			
1	10:30	37	494	0.187	14.47	394.6 MCFD
	10:45	37	490			
	11:00 am	37.5	486			
Shut in						
	12:00	37	486			
	12:15		475			
	12:30	36	465	0.250	25.86	664.1
	12:45		456.5			
	1:00 pm	35	448.5			
Shut in						
	2:00 pm	36	453.5			
	2:15		429			
3	2:30	36	410	0.375	56.58	1297.7
	2:45		393			
	3:00 pm	36.5	378			
Shut in						
	4:00 pm	35	391			
	4:15		326			
4	4:30	36	285	0.625	154.0	2635.9
	4:45		252			
	5:00 pm	37	222			
Draw down to stabilization						
Stabilization						
10:00 pm-2:00 am		38°F	102 psig	0.250	25.86	160.5 MCFD

estimate the induced fracture length. The same straight line can also be used to determine the correct slope of the semi-log plot (figure 7), by doubling the figure 9 pressure difference at 15 hours and then finding the corresponding time (2 times 110 psi = 220 psi, which corresponds to about 60 hours). The proper straight line of the semi-log plot then begins at about 60 hours.

After determining the proper line portions for figures 7 and 8 and the corresponding slopes m=358 psi/cyc and m' = 33.17 psi/hr, a few more reservoir parameters must be calculated in order to complete the pressure analysis. These values were obtained by applying established correlation techniques to known data from well logs, pressure buildup test, modified isochronal test, and the gas analysis (Table 3). The obtained values are listed in Table 5.

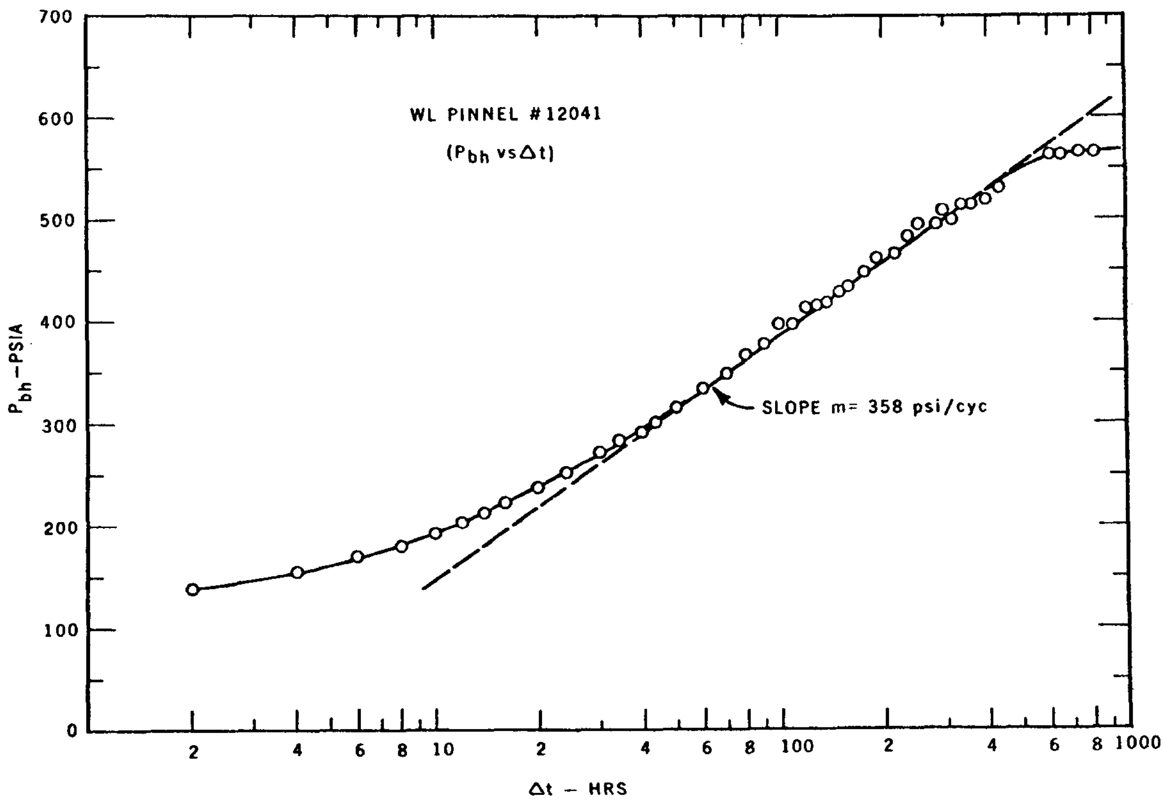

Figure 7 — Pressure Buildup Data, Semi-Log Plot

Table 5 - Reservoir Parameters

Parameter	Value
Reservoir temperature, T_{bh}	546°R
Static reservoir pressure, P_r	564 psia
Fracture height, h	159 ft.
Stabilized flow rate, Q_g	158 mcfd
Gas formation volume factor, B_g	0.025 cf/scf
Gas compressibility factor, Z	0.91
Gas viscosity, μ_g	0.014 cp
Formation system compressibility, c_t	11×10^{-6} psi $^{-1}$

Using some of these values and the relationship: [6]

$$K_g h = \frac{818\ Q_g\ \mu_g\ T_{bh}\ Z}{m\ P_r} \qquad (2)$$

where m is the slope of the bottom-hole pressure vs the log of shut-in time plot (figure 7).

or $$k_g h = \frac{818(158)(0.014)(546)(0.91)}{358(564)}$$

$k_g h = \underline{\underline{3.42 \text{ md-ft}}}$, well capacity

$k_g = \underline{\underline{0.92 \text{ md}}}$, permeability to gas

Also some Table 5 values and the slope m' from the plot of bottom-hole pressure vs the time can be used in the following equation to estimate induced fracture length: [4]

$$L = \frac{0.39}{m'} \quad \frac{Q_g\ B_g\ m}{\phi\ h\ c_t} \qquad (3)$$

where Q_g is the gas flow rate in barrels/day and L is the fracture half-length in feet.

or $$L = \frac{0.319}{33.17}\ \frac{28164(0.025)(358)}{0.01(159)(11\text{x}10^{-6})}$$

$L = \underline{\underline{1155 \text{ ft per wing}}}$

This gives an estimated total fracture length of about 2300 ft.

CONCLUSIONS

Foam fracturing shows promise as a good well stimulation technique in the Devonian Shale of the Appalachian Basin. The fact that the foam only contains 25% water by volume gives foam much better clean-up and formation damage characteristics than conventional water fracs.

The primary conclusion of this report is that the design of proper foam frac treatments is critical in planning proper stability for the foam. Laboratory tests on core samples and frac fluids are important and should be used to plan the concentration of foaming agent. It is clear that the 7

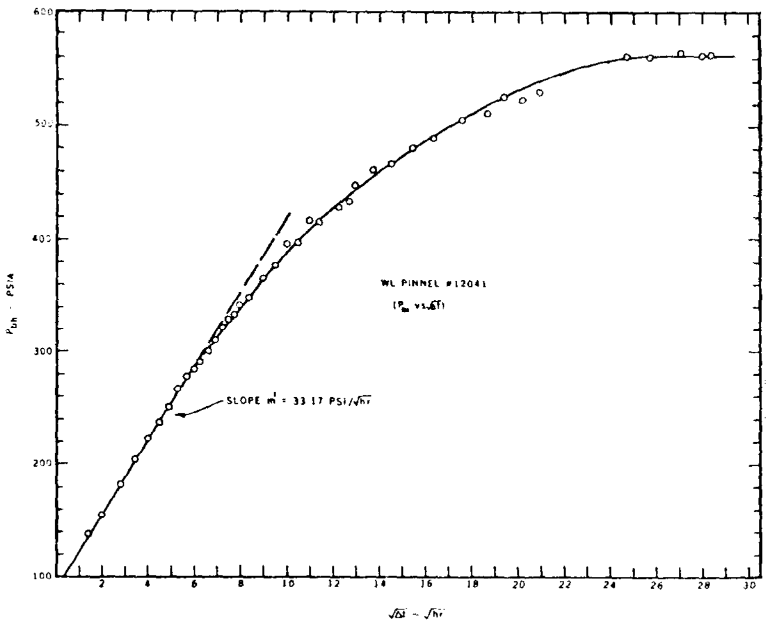

Figure 8 - Pressure Buildup Data, Cartesian Plot.

gallons soap concentration/1000 gallons water was too high, and should have been closer to the 2-3 gallon optimum recommended by the lab tests. The over-stabilized foam did not break into nitrogen gas and water in the fracture, dropping out the sand to prop the fracture, but instead came back as foam during the early clean-up period. This resulted in an estimated 15-20 sacks of frac sand coming back and cutting out the 25000 psi control head and choke assembly, and potentially could have ruined the entire foam frac job. Fortunately the 2 days lost in repairing the damaged well head gave the foam time to break down to salvage the well. We cannot determine if W. L. Pinnel 12041 would have been a better well if the proper foam stability had been employed.

It can also be concluded that the so-called modified isochronal test can be used to successfully measure the deliverability of Devonian Shale wells, which often exhibit low productivity and extremely long stabilization times. Absolute open flow potential of the well is calculated to be 173 mcfd.

The long-term pressure buildup test conducted on well #12041 indicates the well capacity to be 3.42 md-ft and the formation permeability to be 0.021 md, or 21 microodarcy. Estimated fracture half-length is 1155 ft., giving a total foam-induced fracture length of 2310 ft.

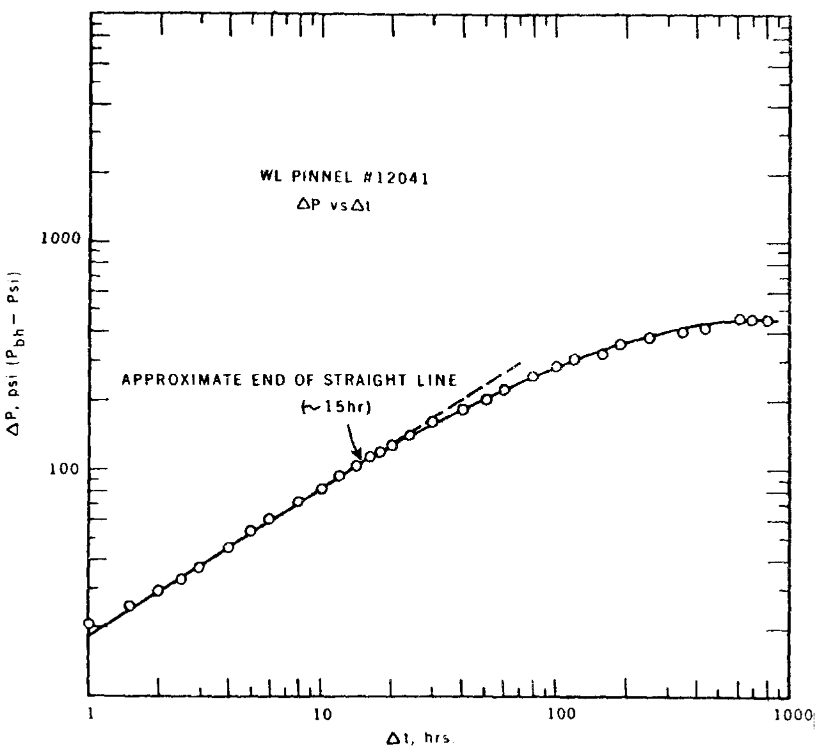

Figure 9 - Pressure Buildup Data, Log Log Plot.

ACKNOWLEDGEMENTS

The author wishes to acknowledge the assistance and cooperation of Consolidated Gas Supply Corporation in making their well available for this fracturing test.

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