Pre-Formed Stable Foam: The New Approach to Big Hole Drilling and Slim-Hole High-Pressure Cleanouts

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INTRODUCTION

A paper titled "Stable Foam Lowers Production, Drilling and Remedial Costs" was presented at the 17th Southwestern Petroleum Short Course in April 1970 which discussed the general concepts of pre-formed stable foam, equipment requirements and its use as a drilling, cleanout and remedial fluid.

This paper has been prepared to report on some of the results that have been achieved on previously reported work and to review some of the significant new developments and applications in the use of pre-formed stable foam as a circulating fluid. Some of these results and achievements are:

1. Foam recompletion costs 30 percent less and has produced 33 percent more oil than new wells drilled in with clay-base mud.
2. Near-gauge surface holes have been drilled in permafrost where conventional fluids cause excessive hole enlargement. Increased penetration rates have lowered costs about $15,000 per well.
3. Surface hole and top hole drilling in West Texas were successful where air drilling failed due to wet formations, and drilling costs were reduced from $19 per foot to $6 per foot.
4. Hard rock porous formations have been drilled and evaluated without the formation damage caused by overblancing drilling fluids.
5. Computer program permits analysis of circulating pressures where gas, foam, or liquids are used.
6. The combination of improved hydraulic snubbing equipment or reeled pipe with pre-

TABLE 1

COMPARISON OF FOAM RECOMPLETIONS VS. NEW WELLS COSTS
KERN RIVER FIELD, CALIFORNIA

	FOAM RECOMPLETIONS			NEW WELLS			FOAM RECOMPLETION
PROPERTY	NO. WELLS	TOTAL COST	AV. COST/WELL	NO. WELLS	TOTAL COST	AV. COST/WELL	% SAVING
A	41	453,150	11,052	22	350,979	15,953	31%
B	9	135,681	15,075	3	49,054	16,351	8%
C	10	138,171	13,817	17	341,918	20,112	31%
D	8	105,437	13,179	-	-	-	-
	68	832,439	12,241	42	741,951	17,665	30%

Indicated Savings 68 x $5,424 = $368,832

Possible Savings on Abandonment 68 x $2,000 = $136,000

COMPARISON OF FOAM RECOMPLETIONS VS. NEW WELLS PRODUCTION

PROPERTY	NO. WELLS	CUM. PROD. 1st 24 Mo. Bbls.	AV. CUM. PROD/WELL Bbls.	NO. WELLS	CUM. PROD. 1st 24 Mo. Bbls.	AV. CUM. PROD/WELL Bbls.	FOAM RECOMPLETION % GAIN
In 10 Pattern Steam Drive	21	484,432	23,068	10	172,976	17,297	+33

Value of Improved Production in 10 Pattern Steam Drive
5,771 Bbls./Well x 21 Wells x $2.00/Bbl. = $240,382

formed stable foam has created a whole new dimension in well servicing where costs can be reduced, safety improved, formation damage eliminated and ecology preserved.

PRE-FORMED STABLE FOAM RECOMPLETION VS. NEW WELLS

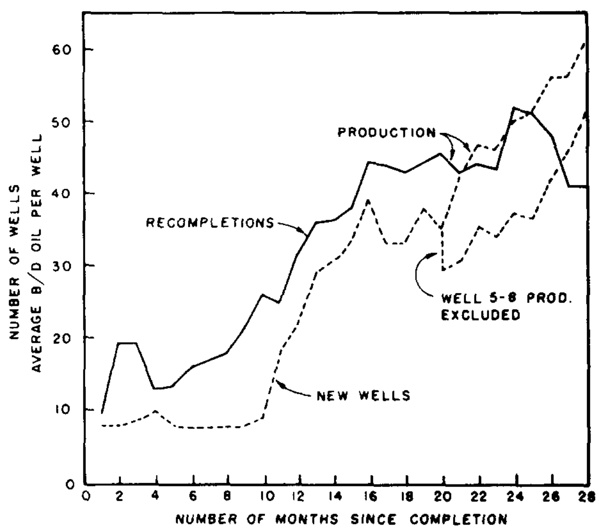
The wells drilled in the late 1800's and early 1900's in California's low gravity oil fields were generally completed with liners having large perforations or slots which were adequate and desirable for primary production. However, these large perforations allow little or no sand control and excessive sand production becomes a major problem when the crude oil's viscosity is lowered in place by steam injection. One solution to the problem was to drill replacement wells equipped with fine mesh slotted liners. This required abandoning the old wells which could be very costly—averaging about $2000 per well. A more economic solution was to pull the old liners using the thermal assist technique discussed in the previous short course[1] and drill in a new fine mesh slotted liner with pre-formed stable foam.

Table 1 compares the cost and production of 68 wells recompleted with foam and 42 new wells completed with clay-base mud. As indicated, $368,832 was saved by not having to replace the 68 old wells with new wells and an additional $136,000 was saved by not having to abandon the old wells.

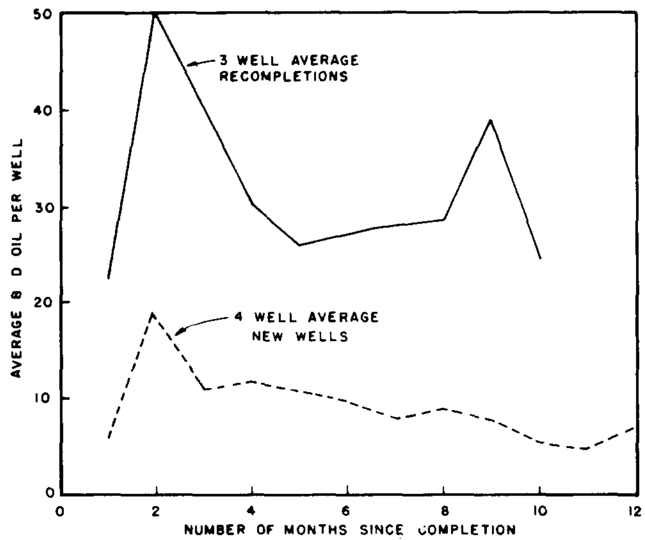
The average cumulative production for the first 24 months compares 21 foam-recompleted wells and 10 new wells in a steam-drive section of the Kern River Field where the thermal and energy levels were fairly uniform. The foam-recompleted wells averaged 5771 more BOPW which increased income by $240,382.

Figure 1 is a plot of the average daily production of foam-recompleted wells vs. new wells. In the previous paper presented in April 1970[1], it was estimated from limited data that formation damage resulting from the use of clay-base drilling fluids could be removed by steam drive in 10 to 12 months. However, additional production history indicates that much more time is required, probably 20 to 24 months, before continuous steam injection can effectively remove the clay-base drilling fluid formation damage.

A similar study was made of new wells and foam recompletions in a field on the Westside of the San Joaquin Valley in California. Figure 2 is a plot of the average daily production after the first steam cycle. The cost of recompleting an old well with stable foam was 26 percent less than the cost of drilling a new well. However, the most significant factor was the first 10 months' production after steaming. The foam-recompleted wells averaged a total oil production of 8301 BPW while the new wells made only 2827 BPW. Recent new wells completed with pre-formed stable foam in these low pressured, low gravity reservoirs have shown excellent initial production responses to cyclic steam stimulation.



FOAM RECOMPLETIONS AND NEW WELLS
KERN RIVER – SAN JOAQUIN VALLEY – CALIFORNIA
FIGURE 1

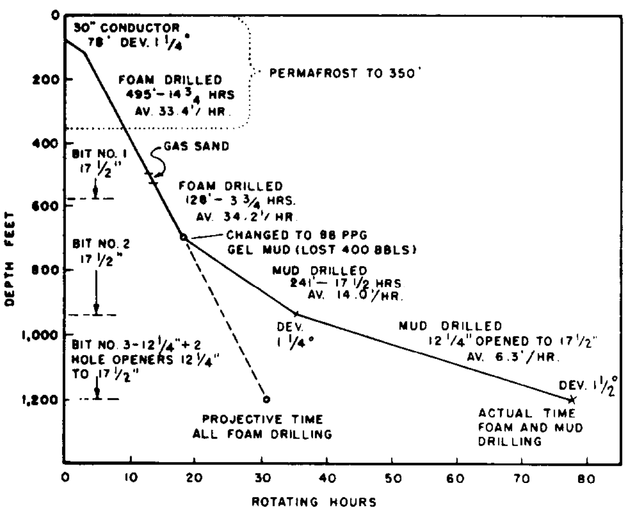


FOAM RECOMPLETIONS AND NEW WELLS
WESTSIDE - SAN JOAQUIN VALLEY - CALIFORNIA
FIGURE 2

PRE-FORMED STABLE FOAM PERMAFROST DRILLING

Laboratory tests and field trials of pre-formed stable foam at elevated temperatures proved that higher bottomhole circulating temperatures could be realized than if raw steam were used as the circulating fluid. It was concluded from these experiments that stable foam has a low heat capacity and is a poor conductor of heat. It was decided that the thermal properties of pre-formed stable foam should be investigated in the low temperature ranges for use as a drilling fluid to drill large diameter holes in permafrost for surface casing. Laboratory tests with simulated permafrost cores were conducted with encouraging results.

The first cold foam field trial was conducted by Chevron Standard Ltd. in the Canadian Arctic in January, 1971 with outstanding results.[2,3,4] Figure 3 is a plot of drilling times achieved with pre-formed stable foam and lightweight mud. Full-size 17-½ in. hole was drilled with pre-formed stable foam at penetration rates up to three times faster and no hole deviation problems were encountered. Hole caliper logs indicated no significant washed-out sections through the permafrost.



PRE - FORMED STABLE FOAM DRILLING
VS
MUD DRILLING
YUKON TERRITORY, CANADA

FIGURE 3

While taking a deviation survey at 699 ft, formation gas unloaded the foam from the annulus and was detected at the blooie line. For safety, the gas was flared at the blooie line 150 ft from the rig. A check valve installed high in the drill string prevented back flow and the rotating head diverted all returns out the blooie line. Apparently the pre-formed stable foam entrapped all produced formation gas while circulating, but there was sufficient formation pressure for the gas to unload the well after circulation was stopped.

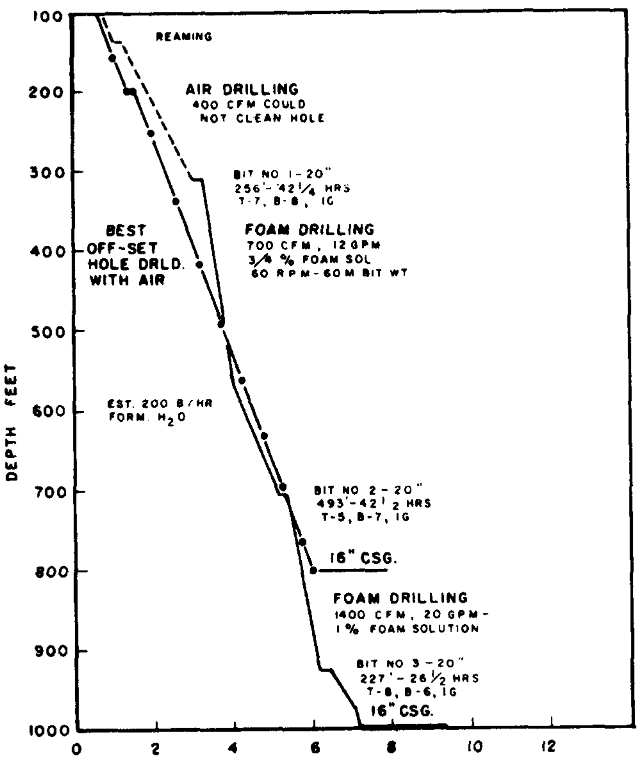
This is an excellent example of the safety that can be realized by using pre-formed stable foam. However, since equipment was not available on this first field trial, either for safely round-tripping the bit or for detecting formation gas in the returns, it was decided to kill the well with mud before drilling ahead. The hazard potential of encountering shallow gas sands was further emphasized when 400 bbls of 8.8 ppg mud was lost before circulation could be established.

Serious surface pipe problems have developed in some of the completed North Slope wells. It is believed casing collapse has been caused by refreezing of water-base mud left in the annulus between the permafrost and the 20-in. casing. Diligent efforts have been made to completely displace this mud with either cement or oil pack fluids. However, these viscous fluids tend to channel through the washed-out areas, leaving freezable fluids in the annulus. Pre-formed stable foam drilling should provide an excellent solution to this problem. A hole drilled through permafrost with pre-formed stable foam should be near-gauge, and the denser fluids, such as cement or oil pack fluid, should give more nearly a 100 percent displacement. Laboratory tests indicate that even water will float pre-formed stable foam out of large bulbs efficiently.[3]

Pre-formed stable foam should not present any ecological problems since it is composed of a large volume of air with a small amount of fresh water and a very small percentage of biodegradable surfactant.

WEST TEXAS TOP HOLE DRILLING

Figure 4 compares pre-formed stable foam drilling rates vs. the best air drilling rates in 20-in. surface hole in Pecos County, Texas. This well was spudded with air, but it soon became evident that 4000 SCFM of air could not develop enough annular velocity to efficiently clean 20-in. hole. Pre-formed stable foam drilling was started with 700 SCFM air and 12 GPM foam solution. The hole cleaned up quickly which permitted drilling ahead to 1000 ft in record time. After cementing 16-in. surface casing at 1000 ft, an attempt was made to drill a 14-¾-in. hole with air, but the formation was too wet to permit effective hole cleaning. Pre-formed stable foam was then used to drill to 5800 ft in a record 24 days. In this area, the best previous lightweight brine mud drilling time to 5800 ft was 53 days. (See Fig. 5). At this point pre-formed stable foam drilling was discontinued due to excessive fill after trips.



PRE - FORMED STABLE FOAM DRILLING

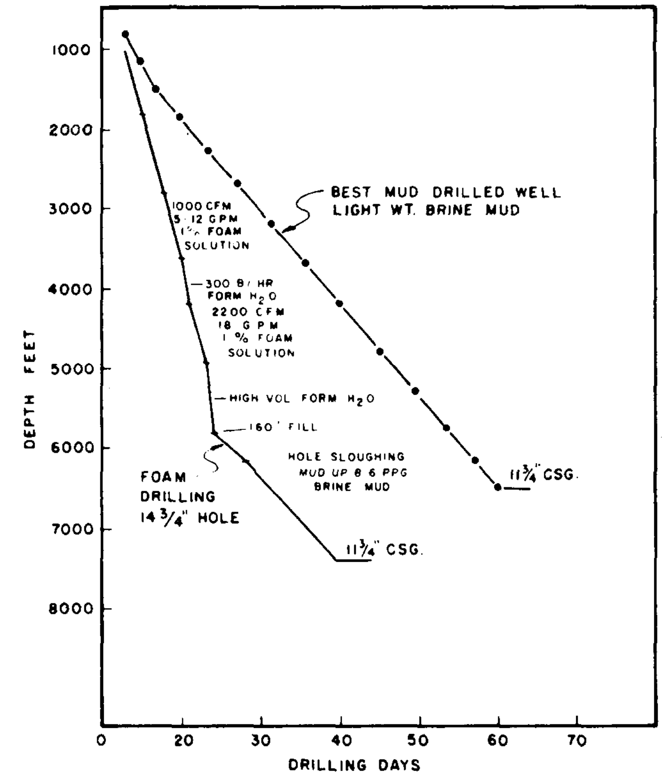
vs

AIR DRILLING

PECOS COUNTY, TEXAS

FIGURE 4

This well was drilled with fresh water foam which reacted with water-sensitive shales causing severe hole enlargement. Since the drilling of this well, more stable salt-water foamers have been developed along with certain foam additives which should solve this hole enlargement problem and permit pre-formed stable foam drilling to greater depths to take advantage of these outstanding penetration rates. Drilling with pre-formed stable foam in the interval



PRE - FORMED STABLE FOAM DRILLING

vs

MUD DRILLING

PECOS COUNTY, TEXAS

FIGURE 5

from 1000 ft to 5800 ft reduced the drilling cost from $19 per foot for mud drilling to $6 per foot. The use of pre-formed stable foam for drilling in this well resulted in an over-all savings of $75,000.

HARD ROCK PRODUCING ZONE DRILLING

Pre-formed stable foam has been used to drill into limestone and dolomite reservoirs in Colorado with penetration rates up to four times faster than mud drilling while permitting instantaneous porosity evaluation. Normally, wells drilled with lightweight muds lose circulation when porosity is encountered, which then requires massive acid treatment to permit evaluation. A recent pre-formed stable foam drilled well came in for 650 BOPD without acid treatment.

A fractured cherty shale producing zone in Santa Maria, California has been drilled with pre-formed stable foam increasing penetration rates up to five times while using only one-fourth as many bits as the best well drilled with clay-base drilling fluid. Here, too, drilling with muds causes severe formation damage which must be removed with massive acid treatments to achieve production.

The pre-formed stable foam completed wells were producing oil while being drilled and came in immediately after completion without acid treatment.

IMPROVED HYDRAULIC SNUBBING UNITS

Pre-formed stable foam was first used in conjunction with a hydraulic snubbing unit for remedial work on an artificial island off the coast of California in November, 1968.[4] This initial work indicated that several improvements in the snubbing equipment would be required before efficient well servicing could be accomplished. The improvements incorporated into the hydraulic snubbing units to facilitate complete well servicing were: new tubular aluminum mast designed for 1000-lb hook loads; a rotating head assembly was added to permit rotation of the work string for drilling cement plugs and hard sand fill; the unit was reunitized into 10,000-lb packages for faster rig-up and to permit offshore platform on and off loading with existing cranes; a larger hydraulic power unit was added to increase pulling capacity to 140,000 lbs; larger hydraulic cylinders were installed to permit handling 3-½-in. OD tubing; and a large diameter lubricator was designed to be held in the snubber pipe rams to permit the running of wireline tools and packers through the unit.

ONSHORE SNUBBING WORK

Improved hydraulic snubbing equipment has been used on 10 onshore wells. Six jobs involved the circulation of pre-formed stable foam to remove sand and debris from wells to depths of 11,466 ft, annular clearances as low as 0.051 in., and injection pressures to 2500 psi. Sliding sleeves were actuated and gas lift valves were installed in one well which was so deviated that wireline tools were ineffective.

Tubing was changed out in three gas wells where maximum casing pressure was 1500 psi. Previous tubing changes using conventional well servicing equipment required killing fluids which resulted in severe damage to gas sand permeability and loss of commercial production.

The first use of pre-formed stable foam with the improved hydraulic snubbing equipment was on a newly completed dual zone well, (Fig. 7—Well A), which had developed a packer leak. The well was killed with calcium chloride water to pull and repair the packer. After recompletion it was found that the lower oil zone would not flow even after swabbing, rocking, and blowing with gas.

One-inch tubing was snubbed into a 2-⅜-in. tubing against 300 psi wellhead pressure. Pre-formed stable foam circulation was established with gas from the upper zone at a rate of 80 SCFM and 15 GPM foam solution at 2100 psi injection pressure. A total of 63 ft of sand and mud was cleaned out along with calcium chloride killing fluid. After cleanout the circulating pressure was 575 psi with 57 SCFM gas and 6 GPM foam solution, but the bottom zone was still too badly damaged to flow.

Acid was pumped down the tubing annulus to remove the formation damage caused by the killing fluid. An attempt was made to unload the spent acid by injecting gas down the 1-in. tubing string at rates up to 880 MCFD but only 10 to 15 bbl of fluid could be unloaded.

Pre-formed stable foam circulation was established with 74 SCFM gas and 15 GPM foam solution at 2425 psi, recovering acid, salt water, and oil. Foam circulation was continued for 20 hr to thoroughly clean the well. After clean-up the stable foam rates were 39 SCFM gas with 6 GPM foam solution at 480 psi with abundant oil in the returns. Foam circulation was discontinued and the well continued to flow with an initial production rate of 377 BOPD and 512 MCFD gas at 500 psi. The total cost of this 92-hr job, including acid, was $10,500.

OFFSHORE REMEDIAL WORK

The improved hydraulic snubbing unit with a pre-formed stable foam circulating system was used on 24 jobs on two offshore platforms. Work strings of ¾-in. and 1-in. pipe were run inside of 2-⅜ and 2-⅞-in. tubing. Pre-formed stable foam was circulated while removing sand, mud and cement; milling-up stuck gas lift valves and wireline tools; fishing and washing over stuck bailers; cleaning out after perforating and unloading spent acid. Gas lift gas was used to generate the pre-formed stable foam. Injection pressures ranged from 650 to 1800 psi at depths of 3030 to 9200 ft. The total cost of the 105 days of work on these 24 jobs was $140,000, including all marine transportation. The newly unitized snubbing equipment can be transported in one trip by a small work boat and off-loaded at the platform with available cranes. In contrast, the marine transportation and crane service required to round-trip a conventional workover rig and circulating system costs approximately $155,000.

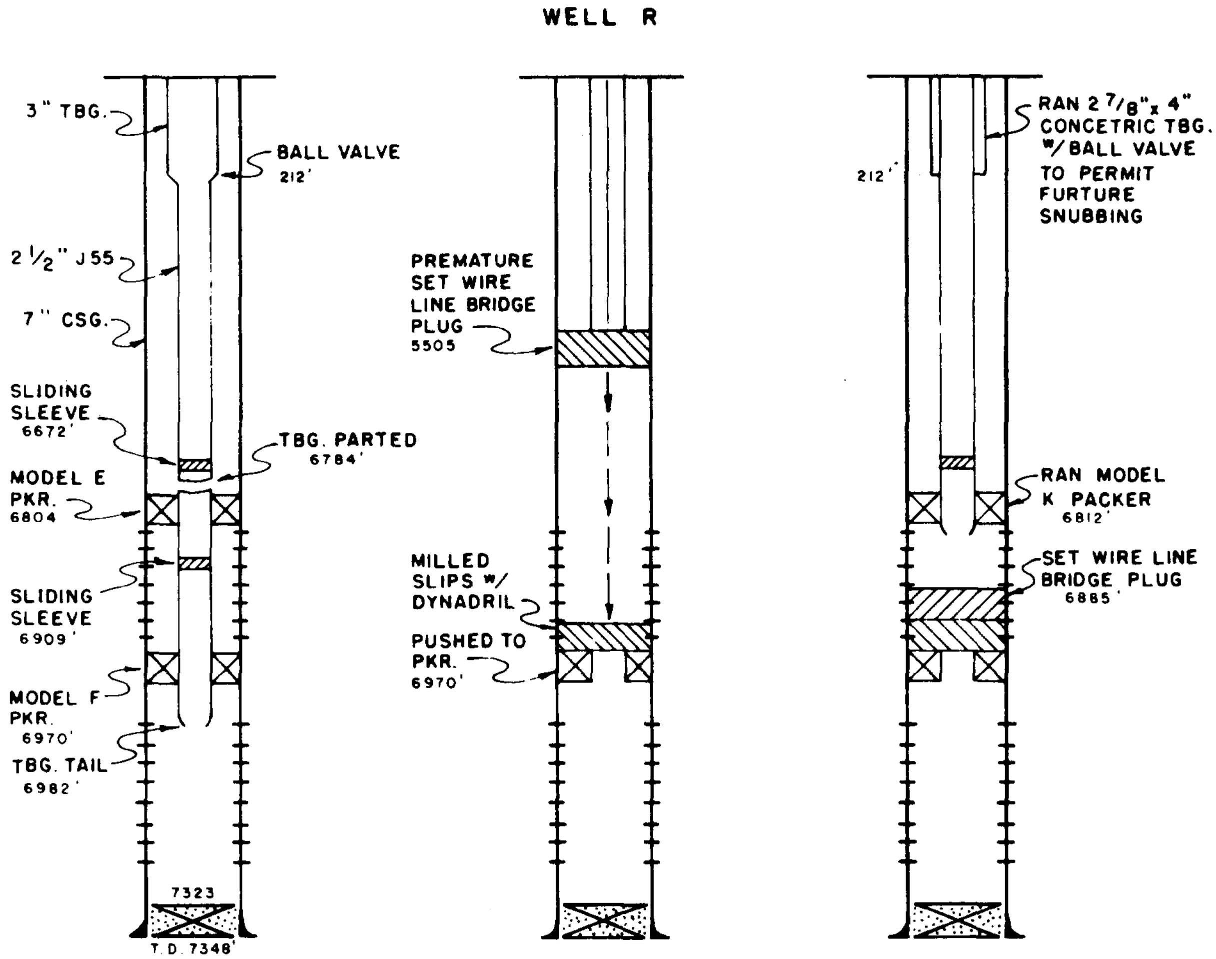
The production recovered by servicing these 24 wells was 613 BOPD and 1688 MCFD gas which could not have been realized at this time because permits for using conventional hoisting equipment could not be obtained.

OFFSHORE RECOMPLETIONS

Two supposedly simple recompletion jobs developed unexpected problems after work began which points up the versatility of the improved hydraulic snubbing units. These wells initially were to be a simple recompletion involving pulling the tubing string, running bridge plugs to abandon the lower intervals, and rerunning the tubing for perforation of a new zone with thru-tubing guns.

Well P

After the snubbing equipment was rigged up over the hole it was found that the packers could not be pulled within the tensile strength of the 2-⅞-in. J-55 tubing string. Tubing was cut above the top packer with a chemical cutter and the J-55 tubing was pulled. A fishing string with overshot, bumper sub, hydraulic jars, three 4-¾-in. drill collars and an accelerator was run on 2-⅞-in. N-80 tubing. The fish was engaged and jarred up to 100,000 lb without avail. A more powerful hydraulic power unit was installed which permitted jarring up to 125,000 lb and pulling to 135,000 lb, but the packers still could not



OFFSHORE RECOMPLETION WORK

FIGURE 6

be pulled. A free point indicator was run and a chemical cut made between packers. The fishing tools, top packer seal assembly, three sliding sleeve valves, and two gas lift mandrels were recovered. The lower intervals were abandoned.

The 2-⅞-in. J-55 production string was rerun with gas lift mandrels, sliding sleeves and seal assembly and landed in the top packer. A 4 x 2-⅞-in. concentric tubing ball valve assembly of new design was run on the top of the production string to permit future snubbing without killing the well. Previous ball valve assemblies with a ¼-in. external hydraulic line required killing the top portion of the well for removal before snubbing operations could be started. This complete workover job cost $25,500 and took 13 daylight tours.

Well R (Fig. 6)

While trying to unseat the packers, the tubing parted at a sliding sleeve valve. Fishing tools consisting of overshot, bumper sub, hydraulic jars, and drill collars were run on N-80 2-⅞-in. tubing. The fish was engaged and jarred free at 100,000 lb. The fish was pulled recovering the retrievable packer and lower seal assembly.

A 7-in. bridge plug was run on wire line and accidentally set 1400 ft above the programmed depth. Retrieving tools were run on 2-⅞-in. tubing but the bridge plug could not be released or moved and only the setting tool was recovered.

A circulating pump and tank were moved onto the platform and filled with sea water. A 6-in. concaved mill was run on a 5-in. straight hole Dyna-Drill with float sub, two junk subs, and one 4-½-in. drill collar with stabilizer on 2-⅞-in. N-80 tubing.

After milling for 1-½ hours circulating sea water, the bridge plug dropped down the hole and circulation was immediately lost. The bridge plug was pushed down the hole with the Dyna-Drill to the bottom packer.

Pre-formed stable foam could have been used to run the Dyna-Drill since it is a positive displacement type mud motor. However, in this well the lower zone was to be abandoned so lost circulation was not critical.

After a casing scraper run, a second bridge plug was set at the desired depth and the production string with sliding sleeves, gas-lift mandrels, and production packer was landed.

This work required 31 daylight tours and cost $50,000.

The last offshore work done with conventional hoisting and circulation equipment on these platforms was in 1968. One comparable job, involving killing with salt water, circulating to remove gas, packer milling with a Dyna-Drill and perforating extended over twenty 24-hr days at a cost of $77,000, including a prorated marine transportation cost of only $6769.

ELK HILLS PACKER SNUBBING PROGRAM

Hydraulic snubbing equipment was used at the Elk Hills Naval Petroleum Reserve No. 1 to pull tubing and rerun with packers in 184 wells without killing the wells.[6] An additional 33 wells were serviced with snubbing equipment but required killing with salt water because of the type of existing wellhead equipment or for well logging. The density of killing fluids used in these wells was carefully designed to provide a maximum 100 psi overbalance. However, even with this close control of killing fluid density, an average of 28 bbl of salt water was lost in 14 of the 28 wells killed. Killing the wells with salt water cost on an average $850 more per well than snubbing under pressure.

SAFETY

The improved hydraulic snubbing units have an outstanding safety record—over 259 jobs without a blowout or lost time accident.

Probably, part of this safety record is due to the redundancy of BOP equipment available when a snubbing unit is used. Generally, and particularly offshore, the snubber is rigged up on top of a full BOP stack, including GK-Hydril bag, double pipe rams, and complete shut-off rams. Since the snubbing equipment includes two pipe rams and a stripper, there are at least five annular closing devices on the well. The BOP stack and snubber stack have independent hydraulic power systems.

Another factor which contributes to safety is that pre-formed stable foam can be circulated from the well head through a high pressure trap into existing production facilities for separation into gas, liquid, and solids, and disposal through the gathering system.

Working with wells under pressure requires that personnel plan carefully and proceed with a caution that contributes to safety.

REELED TUBING WORK

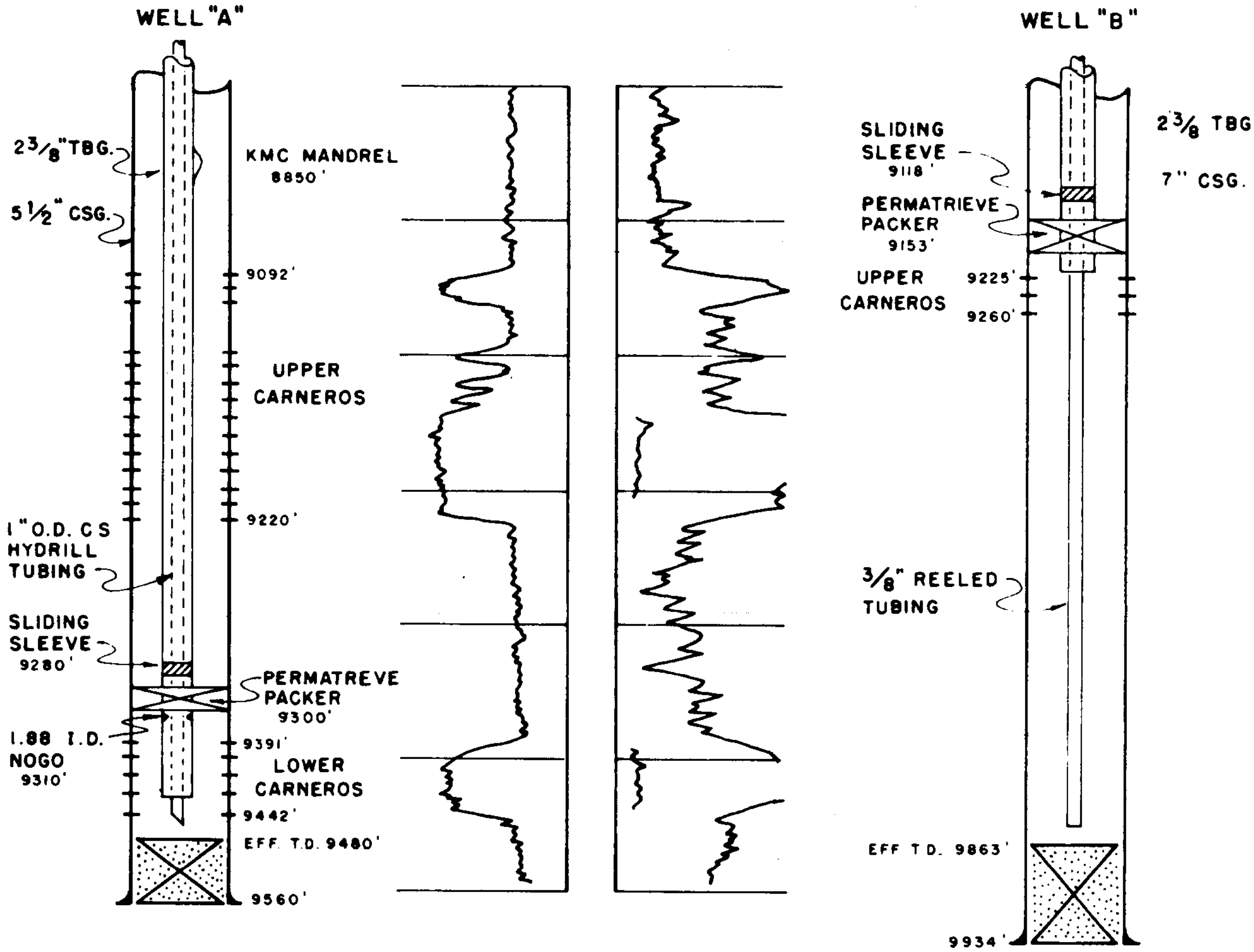
The combination of reeled tubing with pre-formed stable foam as a circulating fluid has developed into a useful tool for specific applications. Previous attempts to unload fluids such as spent acid, salt water and oil from low pressured wells with high rates of nitrogen were unsuccessful. At these high nitrogen rates, the hydrostatic head of lifted fluid plus annular friction exceeded bottomhole formation pressure and fluid was pushed back into the formation so only a small slug could be unloaded before gas breakthrough. When nitrogen rate was reduced, the lower velocity would not carry fluids.

Well B

Figure 7 is an excellent example of how the combination of reeled tubing and pre-formed stable foam can permit well stimulation without killing the well and causing further formation damage. Well B is a single zone completion in the upper high GOR sand in the same field as Well A.

After several years, the production had declined to 37 BOPD and 748 MCFD at 480 psi. Build-up tests indicated severe formation damage, but a potential of 2100 MCFD at 1200 psi.

Acid was pumped down the annulus between ¾-in. reeled tubing and the 2-⅜-in. production string. Pre-formed stable foam circulation was established at 3500 ft with 100 SCFM nitrogen and 4 GPM foam solution at 1000 psi. Acid-cut foam surfaced in 23 minutes. Reeled tubing



PRE-FORMED STABLE FOAM STIMULATION WORK

FIGURE 7

was run at 40 to 60 FPM while maintaining constant foam circulation with 150 SCFM nitrogen and 4 GPM foam solution. At 8480 ft, a maximum injection pressure of 3330 psi was reached and the well started to come in. Annulus back pressure of 300 psi was maintained for well control and injection pressure dropped to 1750 psi at 9860 ft. As the well unloaded, back pressure was increased to 550 psi and the injection pressure dropped to 1400 psi.

After a total of 5 hr of foam injection, the pH of the returns increased to 7.0, indicating complete acid recovery. The initial production was 1900 MCFD at 1150 psi, indicating excellent formation damage removal. Total cost of the job was $5507, including acid, reeled pipe unit, and 75,000 SCF of nitrogen.

Another well in the same field had loaded up and died while producing to a 500 psi separator. After lower pressure surface facilities were installed, ¾-in. reeled tubing was run inside the 2-⅜-in. tubing and circulation was established with pre-formed stable foam in 15 minutes. Reeled tubing was run at 40-60 FPM to 7800 ft while maintaining continuous foam circulation. The well unloaded and began to flow. Foam circulation was stopped and the reeled tubing was withdrawn from the well.

Initial production was 220 BOPD and 250 MCFD gas at 300 psi. The total cost of this safe and effective method of unloading a dead well was $2141, including 26,000 SCF of nitrogen.

The maximum nitrogen injection pressure used for forming pre-formed stable foam in the field has been 3800 psi, and 10,000 psi during a controlled test in the shop area.

FOAM CIRCULATION ANALYSIS

A computer program has been developed by Chevron Oil Field Research Company which can analyze a circulation system to determine injection pressures, bottomhole circulating pressures, foam quality and lifting ability—plus annular velocity and circulating times at various gas and foam solution rates and annular back pressures.

The program considers liquid and gas entry from the formations, foam temperature gradient, penetration rate and formation solids density. Deviation effects of directional holes and the excess tubing on reeled pipe jobs are also taken into account. This program has proved successful in design of gas volume and pressure requirements to get maximum hole-cleaning ability with foam. With appropriate wellhead and back pressure controlling equipment, foam circulating systems can be designed to maintain specific bottomhole circulating pressures.

While this program was designed primarily to handle stable foam, it can be used to analyze the circulation of gas, liquid, or any combination of gas and liqud.

LICENSING

Licenses under patent rights and technical information to use pre-formed stable foam are granted by Chevron Research Company, the research and development subsidiary of the Standard Oil Company of California. The following companies have been licensed:

Licensees	Major Operating Area
Sierra Production Service	Central California
Lunn Production Service	Central California
California Production Service	Southern California
Border Drilling Company	Central Canada
Pool Company	West Texas & Wyoming
Skinner Drilling Company	Trinidad
Servicios Hydrocarb	Trinidad & Venezuela
Baker Oil Tools	California & Gulf Coast
Halliburton (Otis Engineering)	California & Gulf Coast
Air Drilling Services	Canada, Rocky Mountain Area & Alaska
Foam Circulation, Inc.	West Texas
NOWSCO	California & Gulf Coast

CONCLUSIONS

1. The use of pre-formed stable foam as the circulating fluid for drilling and re-completing wells in low pressured reservoirs has reduced costs up to 30 percent and increased the oil productivity over 33 percent because formation damage has been minimized.
2. The use of pre-formed stable foam circulating fluids in top hole drilling has achieved penetration rates equal to air drilling rates and three to five times greater than low density mud rates for significant drilling cost savings.
3. Near-gauge, straight holes have been drilled through permafrost formations with cold pre-formed stable foam at penetration rates up to three times greater than mud drilling rates, which resulted in a savings of $15,000 per well.
4. The combination of an improved hydraulic snubbing unit with pre-formed stable foam circulating fluids offers a whole new approach to well servicing operations while reducing operating costs and preventing or minimizing formation damage which results in improved productivity.
5. The portability of hydraulic snubbing units is an important cost saving feature, particularly offshore.
6. Hydraulic snubbing equipment was used on 259 recent jobs in California without a single lost-time accident, blowout, or environmental pollution.
7. The use of hydraulic snubbing equipment presents a safe method of performing remedial and recompletion work on gas wells without killing them with a fluid.
8. Reeled tubing units have been used with the pre-formed stable foam process to unload solids, spent acids and fluids from wells economically and safely while preventing formation damage.
9. The use of the computer program for analyzing the circulating system is extremely helpful in predetermining equipment requirements and injection rates and pressures to achieve a controlled bottom-hole circulating pressure.
10. It is believed there is no limit to the depth or pressure at which pre-formed stable foam can be used. However, the high pressure equipment presently available in the field imposes a 10,000 psi maximum pressure limitation.

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