DRILLING TO THE WOLFCAMP, STRAWN AND FUSSELMAN FORMATIONS-
GLASSCOCK COUNTY, TEXAS - A CASE HISTORY *

James T. Laumbach & Dan L. Whiteman

Exxon Company, U.S.A.

ABSTRACT

This paper presents a case history of the methods used by Exxon Co., U.S.A. to drill the St. Lawrence Field in Glasscock County, Texas. Lightweight oil base mud was used to combat salt and lost circulation, while brine water weighted with hematite was used to drill an abnormally pressured section. Two-stage and tack-and-squeeze cementing were used to place cement across lost circulation zones. The lightweight oil base mud was technically successful, yet proved uneconomical. In contrast, the hematite was cost effective as a weighting material. The tack-and-squeeze method proved to be the most successful method of cementing.

INTRODUCTION

The St. Lawrence Field is located approximately 8 miles southwest of Garden City, Texas. The discovery well for the field spudded in May, 1983. The primary objective was the Fusselman at 10,640', while secondary objectives were the Strawn at 9730' and the Wolfcamp at 7815'.

Drilling the Strawn requires 10.3 ppg to 11.0 ppg mud. However, a 2500' lost circulation zone from 5200' - 7700' and a salt zone from 1200' - 3100' lie above the Strawn. Furthermore, the corrosive San Andres formation from 3100' - 5200' needs to be covered with cement to prevent H_2S corrosion of production casing.

Initially, there were two feasible mud and casing programs. The first alternative was to drill out from under surface casing with a light weight oil base mud through the salt section and lost returns zone before setting intermediate casing. The second alternative was to drill out from under surface casing with brine water through the salt section and then set pipe. After setting the casing across the salt section, it was possible to drill the lost returns zone with fresh water without washing out the hole or increasing the mud weight by picking up chlorides from exposed formations. Figure 1 is a schematic showing both alternatives.

This paper describes the various casing, mud, and cementing programs used to resolve these drilling and cementing problems.

***SPE 14426 presented at the 1985 Fall Meeting of the SPE, Las Vegas, Nevada.**

CASING DESIGN

Discovery Well

The discovery well was drilled as a Fusselman well with three strings of casing designed: 13-3/8" surface casing set at 450', 8-5/8" intermediate casing set into the San Andres at 3200' and 5-1/2" production casing set through the Fusselman at 10,800'. This is a typical design for a well of this type in the Permian Basin.

While drilling the production hole of the discovery well at 9886' with 9.1 ppg fresh water mud, the well began to flow. The normally tight Strawn formation was developed and productive. The well could not be easily killed due to lost returns zones up the hole. Eventually, 7" flush joint casing was run across the zone and a 5-7/8" hole drilled to TD. The Strawn proved commercial and field development started.

Four String Casing Design

To reduce costs, two alternate casing designs were developed. The first design included four strings. This design would set 13-3/8" surface casing at 450' for fresh water protection. A 12-1/4" hole would then be drilled to 3200' with a saturated brine water system and 9-5/8" casing set. An 8-1/2" hole would then be drilled through the lost circulation zones in the intermediate hole and 7" casing set. At this point, the mud system could be weighted up as required and the 6" production hole drilled and a 4-1/2" production liner set.

This design had several advantages: 1) the mud system was low cost and familiar to the drilling crews; 2) it was a safe system for drilling into the over pressured Strawn formation. The disadvantages were the high cost of casing and the high dry hole cost due to three strings being required prior to drilling the productive interval.

Three String Casing Design

The second design included three strings. The system would set 9-5/8" surface casing at 1100' for fresh water protection and well control. An 8-1/2" hole would then be drilled from 1100' to 8050' and 7" casing set. At this point, as with the four string design, the production hole would be drilled with weighted brine water mud and a 4-1/2" production liner set.

The difficulty with the second system was drilling the 8-1/2" intermediate hole. Salt from 1200' to 3100' and lost circulation zones from 5200' to 7700' would both be exposed. A mud system would have to be used which would not wash out the salt sections increasing the mud weight and would also be light enough in weight to not lose returns in these sections. The only system that could accomplish both objectives was a light weight oil base system (7.8 - 8.3 ppg). Due to the reduced casing cost of this design, the higher mud cost of this system appeared economical.

LIGHTWEIGHT OIL BASE MUD

An unweighted, relaxed fluid loss, oil base system was built and displaced into the surface casing prior to drilling out on one of the initial development wells. It was felt that a low viscosity relaxed system would keep the penetration rate comparable to a fresh water system. See Figure 2 for mud properties at displacement and after drilling the interval.

Results

Several unanticipated difficulties occurred with this system. Lost returns at weights as low as 8.3 ppg, and water flows were encountered. A water wet solids problem also resulted. This made it almost impossible to screen solids at the shale shaker because of constant blinding of the screens. Additions of emulsifiers at the shaker helped but would not cure the water wet solids problem. Screen size on the shakers was increased to 20 mesh to keep the mud in the system. Hydrocyclones were able to keep solids in the acceptable range but mud weight could not be kept as low as needed without costly dilution.

The higher cost of the oil mud offset the additional cost of casing in the four string design and indicated the oil mud was uneconomical. A total of six wells were drilled with oil mud in the intermediate hole and improvements were made. Oil mud was displaced at 3100' after drilling the salt with a brine water system. Also, reduced emphasis was placed on the shale shaker and hydro cyclones and a centrifuge was allowed to do the majority of solids removal. With these changes economics were improved but never reduced to the point of competing with the four string casing design which is now used.

One additional idea, not tried, was a reformulation of the oil mud to a reduced fluid loss system with a higher percentage of emulsifiers. This system would reduce the water wet solids problem which was so costly to the relaxed fluid loss system.

Conclusion

Light weight oil base mud proved uneconomical as attempted. With further development the system could be improved. However, the four string casing design is the best alternative due to drilling crew inexperience with light weight oil base muds, the high expense if problems occur and the current reduced cost of tubulars.

HEMATITE

Hematite was successfully used as a weighting material in the production hole to obtain mud weights of 10.4 - 11.3 ppg. Cut brine water was used to drill within approximately 300 feet of the abnormally pressured Strawn and then displaced with 10.0 ppg brine water. The hematite was then added to the 10.0 ppg brine water system to obtain the necessary mud weight.

This material is used instead of barite to obtain meaningful lithology density logs. The lithology density log measures the bulk density and photoelectric absorption (Pe) of the formation. The Pe curve reflects the average atomic number of the formation. This is helpful in interpretation of complex lithology. Most formations have a Pe number of 3 to 6. Barite has a Pe number of 267 which distorts the formation Pe curve. Hematite has no adverse effect on the Pe curve because its Pe number is 3 to 5. In the past, hematite has caused pump wear due to abrasion and burned motor bearings from excessive dust. The first problem was lessened by using a finer grind. The latter problem was solved by changing air filters frequently and venting hematite dust to the pits rather than the air.

None of the drilling contractors reported increased pump wear in the nine wells hematite has been used in to date. This experience is probably due to the improvements mentioned, the medium weight of the mud (10.4 - 11.3 ppg), and that the mud is used for only a week per well.

CEMENTING

Objectives

There were three objectives when cementing the 7" intermediate casing at 8,050'. (1) A strong shoe was required to drill into the abnormally pressured Strawn formation. (2) Cement had to be placed across the San Andres formation due to H_2S corrosion. (3) Because the Leonard and Spraberry formations were potential salvage zones, cement also had to be placed across these two zones.

Possible Solutions

The most significant problem was placing cement across the Leonard and Spraberry formations. Lost returns were often encountered while drilling with mud weights of 9.0 ppg or less. There were three alternatives: 1) a conventional multi-stage cement job; 2) a foam cement job; 3) a tack-and-squeeze cement job. The tack-and-squeeze involves a standard cement job followed by a bradenhead squeeze - pumping cement down the 9-5/8" x 7" annulus and forcing the mud into the formation.

Foam cement was ruled out because of recent problems on other Exxon wells. A multi-stage was attempted first because it was less expensive than the tack-and-squeeze. Since a two-stage cement job had a reasonable chance of success, a three-stage job did not appear to be worth the additional expense.

Two-Stage

Proper placement of the stage tool is critical for successful two-stage cement jobs. The stage tool was placed at 5400', just above the most severe lost circulation zone. With this placement, a hydrostatic pressure of 9.9 ppg equivalent would be applied at the base of the Spraberry after the first stage, and a 10.3 ppg equivalent would be applied across the stage tool at the completion of the second stage. The first stage lead slurry was a 12.4 ppg lightweight cement and the tail was Class H mixed at 15.6 ppg. The second stage consisted of 12.1 ppg lightweight cement. As planned, the first stage tail would reach 7500' and the first stage lead would rise slightly above the stage tool. The second stage was planned to reach 2700'.

The results of the two stage cementing were mixed. Of the eight attempts, only on two wells was the top of cement inside the 9-5/8" intermediate casing at 3200'. These two wells had cement circulated off the stage tool, so there was a solid sheath of cement from the shoe to top of cement. Of the six wells that failed to bring cement inside the 9-5/8" casing, only on one well, did lost returns occur on the first stage. Lost returns occurred during the last 20 bbls of displacement. After opening the stage tool, returns were regained for one hour and then lost and never regained. Cement was only brought to 4800' or 600' above the stage tool. The lost returns usually occurred on the second stage toward the end of displacement. At the point of lost returns, the hydrostatic load had exceeded the formation integrity.

Two objectives had been met: we had a strong shoe and, with one exception, we placed cement across the Leonard and Spraberry formations. However, the success rate was only 25% for placing cement across the corrosive San Andres. The decision was made to try a tack-and-squeeze job on a well that encountered lost returns while drilling at 6200'.

Tack-and-Squeeze

The tack-and-squeeze cement job involves a conventional cement job followed later by a bradenhead squeeze pumped down the 9-5/8" x 7" annulus. A schematic is provided in Figure 3.

The first tack job was planned to reach 6200' because the formation below 6200' would not support the additional hydrostatic head of cement above 6200' and if the tack cement reached 6200', the worst lost returns zone would have cement across it prior to pumping the squeeze cement.

By running a temperature survey the top of cement for the tack job was observed at 6300' which was close to the objective. The temperature survey is plotted in Figure 4. The slope of the line representing the displaced mud is $0.95^{o}/100$ ft. The line representing top of cement then kicked out to $4.3^{o}/100$ ft.

The squeeze cement - Class C mixed at 14.8 ppg with 2% $CaCl_2$ - was then pumped. After pumping the squeeze cement, the well went on a vacuum. Temperature surveys were run in an effort to find the top and bottom of the squeeze cement. Top of cement was 1350' and the bottom of cement was at 5200'. Figure 5 has the temperature survey taken after the squeeze. Top of cement can be found at the change from a slope of $0.53^{o}/100$ ft to $3.5^{o}/100$ ft. It was concluded that cement was setting up below that due to the sharply increasing and decreasing temperature. Most importantly, below the cement the gradient reverted to a smooth slope of $1.00^{o}/100$ ft. This is virtually identical to the $0.95^{o}/100$ ft slope of the displaced mud after the tack job. From this similarity, it was concluded that there was an 1100' gap between the tack-and-squeeze cements. However, this first tack-and-squeeze was ruled a success since the two most important objectives had been met.

This same technique was attempted on the next four wells with mixed results. The bottom of the squeeze cement had reached the top of the tack cement as shown by the temperature surveys. This was concluded because there were no similar temperature gradients below a sharply increasing and decreasing line as mentioned above.

The temperature surveys failed to show a conclusive top of squeeze cement. One reason was that a 65:35 pozzolan cement mixed with 6% gel was pumped. This was done in an effort to cut squeeze cementing costs. It had less heat of hydration than the Class C neat, so there was never a good temperature anomaly. On two wells, temperature surveys were run at 4 hour intervals beginning 8 hours after the squeeze was pumped in an effort to find the maximum heat of hydration and an improved temperature anomaly. Maximum heat of hydration occurred at 12 hours, yet the temperature anomaly never improved.

Since the temperature surveys failed to provide a conclusive top of squeeze cement, another inexpensive method was needed. Most of the wells went on vacuum toward the completion of the squeeze so the cement had fallen some distance from the surface. This distance could be determined by filling the backside and measuring the volume of fluid required. By re-examining the temperature surveys and comparing the calculated top of cement with the temperature survey, calculated top of cement was confirmed by an anomaly on the temperature survey.

On the four wells that had tack cement brought up to an average of 5300', the squeeze cement reached the tack cement as verified by the temperature surveys. Based on this, future squeeze jobs would probably meet tack cement if they were brought to approximately 5300'. At this point, temperature surveys were no longer run.

Conclusion

The tack-and-squeeze was more successful than the two stage method of cementing the intermediate 7" casing. To determine the top of cement on the tack job, temperature surveys worked well. However, temperature surveys were not able to determine the top of cement of the squeeze cement conclusively, so the volume of fluid to fill up the backside was measured. Finally, the temperature surveys decisively showed that the squeeze cement had reached the tack cement.

CONCLUSION

During the development of the St. Lawrence Field in Glasscock County, Texas several unique techniques were used to reduce well cost. Lightweight oil base mud was used to combat salt and lost circulation. The oil base mud was technically feasible, but proved uneconomical.

Hematite was used to weight brine water mud when drilling the abnormally pressured Strawn. The hematite was cost effective and increased the effectiveness of the lithology density logs. In addition, no apparent wear to rig equipment was experienced.

Both two-stage and tack-and-squeeze cementing techniques were used to place cement across lost circulation zones and corrosive water flows. Tack-and-squeeze cementing proved to be the most effective method.

ACKNOWLEDGEMENTS

The authors thank Exxon Company, U.S.A. for permission to publish this paper.

REFERENCES

Dewan, John T. Essentials of Modern Open-Hole Log Interpretation, Penn Well, Oklahoma, 1983, page 217.

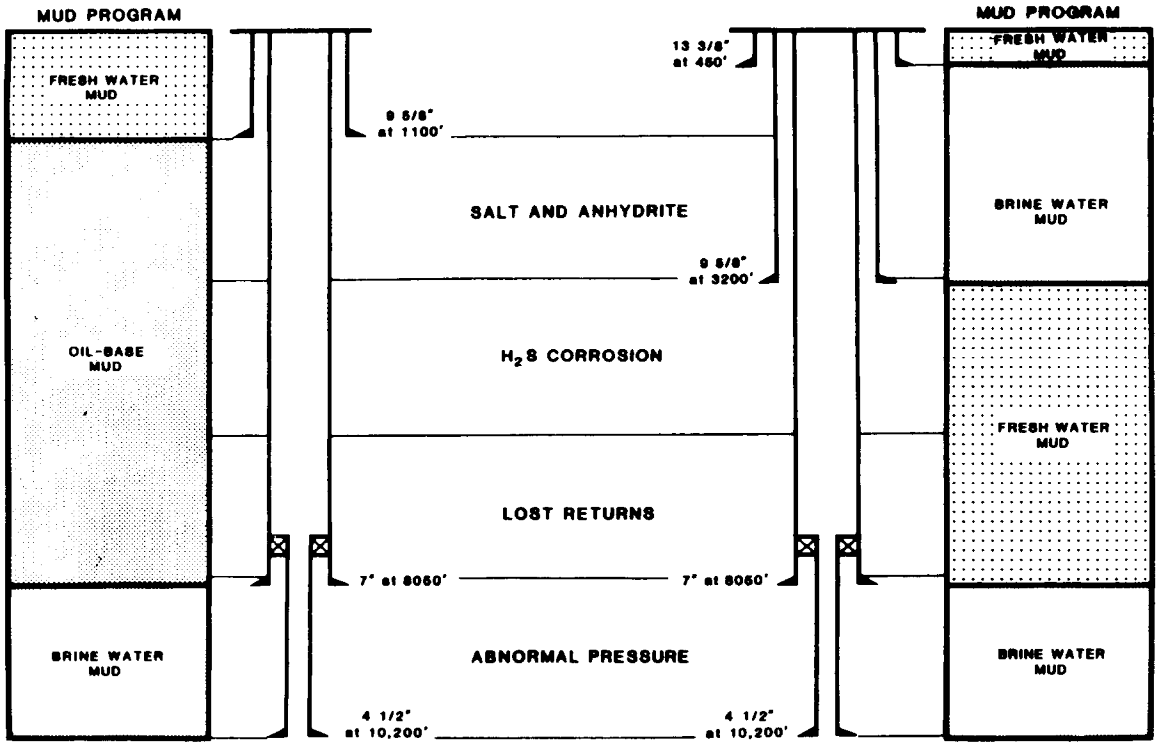

Figure 1—Alternative mud and casing programs

	PROPERTIES AT DISPLACEMENT	PROPERTIES AFTER DRILLING INTERVAL
WT - PPG	7.9	8.8
FV	44	57
PV	6	12
YP	6	9
GELS	3/6	7/9
HTHP WL	19	36.2 13 CC FREE WATER
SOLIDS	2%	5%
WATER	16%	29%
OIL	82%	66%
O/W	84/16	69/31
CL^-	281,000	150,000

Figure 2—Oil mud properties

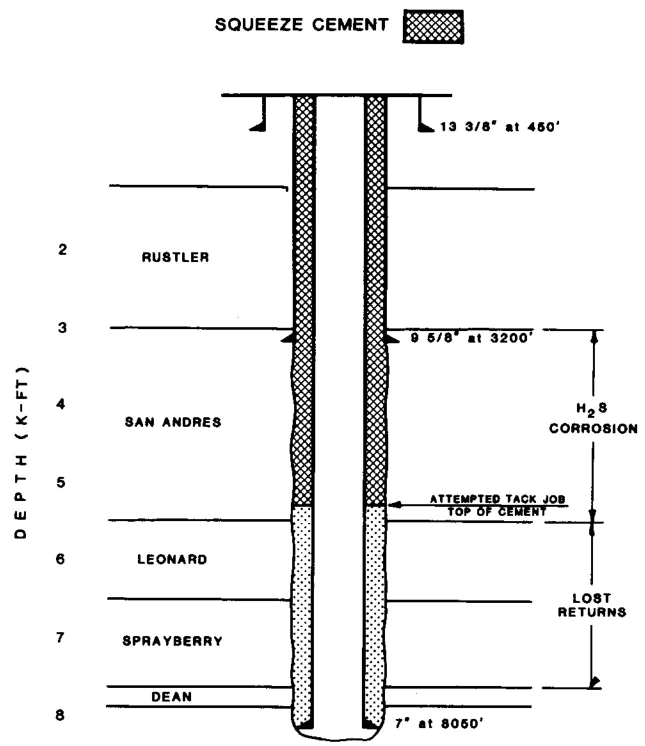

Figure 3—Tack and squeeze cement placement

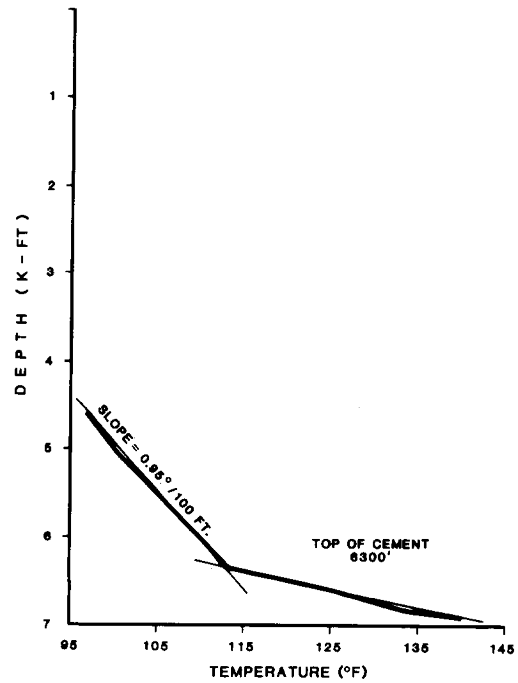

Figure 4 - Top of cement after tack job (temperature survey)

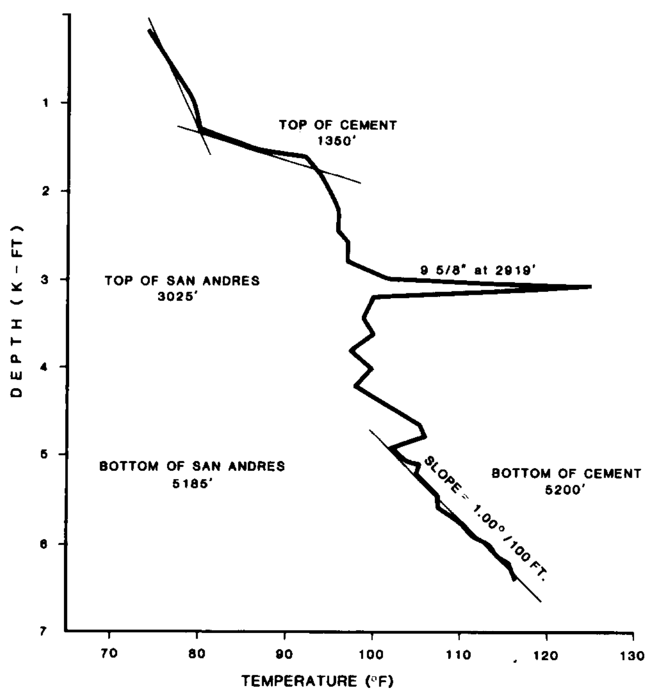

Figure 5—Top of cement after squeeze job (temperature survey)