

UNITED STATES PATENT AND TRADEMARK OFFICE

BEFORE THE PATENT TRIAL AND APPEAL BOARD

WEATHERFORD U.S., L.P.,
Petitioner,

v.

HALLIBURTON ENERGY SERVICES, INC.,
Patent Owner.

Case No. IPR2024-00990
U.S. Patent No. 11,333,007

**DECLARATION OF CHRISTINE DIEDRICH OF THE SOCIETY
OF PETROLEUM ENGINEERS IN SUPPORT OF
WEATHERFORD U.S., L.P.'S PETITION FOR
INTER PARTES REVIEW OF U.S. PATENT NO. 11,333,007**

I, Christine Diedrich hereby declare as follows:

1. My name is Christine Diedrich. I am over the age of twenty-one years, of sound mind, and capable of making the statements set forth in this Declaration. I am competent to testify about the matters set forth herein. All the facts and statements contained herein are within my personal knowledge and/or within my field of expertise, and they are true and correct to the best of my knowledge.

2. I have been employed by the Society of Petroleum Engineers (“SPE”) since July 2023 as the Director of Multimedia Publishing. In that role, my responsibilities include overseeing the production and publication of SPE publications. Through my role I have become familiar with and have personal knowledge of SPE’s forms of publication, distribution of articles, and systems for accessing such content.

3. SPE is the largest individual-member organization serving managers, engineers, scientists, and other professionals worldwide in the upstream segment of the oil and gas industry. SPE focuses on disseminating information regarding practices and technology in the oilfield industry. In addition to sponsoring conferences, SPE publishes one flagship peer-reviewed journal, *SPE Journal*. SPE also publishes several magazines in the oilfield industry.

4. SPE collects and makes publicly available papers presented at the various conferences it sponsors. For conference papers, SPE distributes hardcopy

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5. SPE Paper SPE-64410-MS, a true and correct copy of which is attached hereto as Exhibit A, is an SPE Paper entitled, *Design and Execution of a 3000-ft Horizontal Gravel-Packed Completion (A Kazakhstan Case History)*, presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition on October 16-18, 2000 in Brisbane, Australia. SPE is a sponsor of the SPE Asia Pacific Oil and Gas

Conference and Exhibition. Since that conference on October 16-18, 2000, SPE Paper SPE-64410-MS has been publicly available to anyone interested in purchasing a copy through the online sources provided by SPE discussed above.

6. SPE Paper SPE-155129-MS, a true and correct copy of which is attached hereto as Exhibit B, is an SPE Paper entitled, *The Evolution of Complete Designs Using Alternate Path (Shunt-Tubes) Technology*, presented at the SPE Oil and Gas India Conference and Exhibition on March 28-30, 2012 in Mumbai, India. SPE is a sponsor of the SPE Oil and Gas India Conference and Exhibition. Since that conference on March 28-30, 2012, SPE Paper SPE-155129-MS has been publicly available to anyone interested in purchasing a copy through the online sources provided by SPE discussed above.

7. SPE Paper SPE-22796-MS, a true and correct copy of which is attached hereto as Exhibit C, is an SPE Paper entitled, *Alternate Path Gravel Packing*, presented at the 66th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers on October 6-9, 1991 in Dallas, Texas. SPE is a sponsor of the Society of Petroleum Engineers Conference and Exhibition. Since that conference on October 6-9, 1991, SPE Paper SPE-22796-MS has been publicly available to anyone interested in purchasing a copy through SPE directly and later through the online sources provided by SPE discussed above.

8. SPE Paper SPE-86532-MS, a true and correct copy of which is attached hereto as Exhibit D, is an SPE Paper entitled, *Alternate Path Completions: A Critical Review and Lessons learned From Case Histories with Recommended Practices for Deepwater Applications*, presented at the SPE International Symposium and Exhibition on Formation Damage Control on February 18-20, 2004 in Lafayette, Louisiana. SPE is a sponsor of the SPE International Symposium and Exhibition. Since that conference on February 18-20, 2004, SPE Paper SPE-86532-MS has been publicly available to anyone interested in purchasing a copy through the online sources provided by SPE discussed above.

9. SPE Paper SPE-135102-MS, a true and correct copy of which is attached hereto as Exhibit E is an SPE Paper entitled, *Extending Openhole Gravel Packing Capability: Initial Field Installation of Internal Shunt Alternate Path Technology*, presented at the SPE Annual Technical Conference and Exhibition on September 19-22, 2010 in Florence, Italy. SPE is a sponsor of the SPE Annual Technical Conference and Exhibition. Since that conference on September 19-22, 2010, SPE Paper SPE-135102-MS has been publicly available to anyone interested in purchasing a copy through the online sources provided by SPE discussed above.

10. IPTC Paper IPTC-12549-MS, a true and correct copy of which is attached hereto as Exhibit F, is an IPTC Paper entitled, *Unlocking the Limits of Extreme Length in Alternate Path Gravel Packing*, presented at the International

Petroleum Technology Conference (“IPTC”) on December 3-5, 2008 in Kuala Lumpur, Malaysia. SPE is a sponsor of the IPTC. Since that conference on December 3-5, 2008, IPTC Paper IPTC-12549-MS has been publicly available to anyone interested in purchasing a copy through online sources provided by SPE discussed above.

11. SPE Paper SPE-39433-MS, a true and correct copy of which is attached hereto as Exhibit G, is an SPE Paper entitled, *Case History in Achieving High Rate Producers in Sub Sea Gravel Packed Completions*, presented at the 1998 SPE International Symposium on Formation Damage Control on February 18-19, 1998 in Lafayette, Louisiana. SPE is a sponsor of the SPE International Symposium on Formation Damage Control. Since that conference on February 18-19, 1998, SPE Paper SPE-39433-MS has been publicly available to anyone interested in purchasing a copy through SPE directly and later through the online sources provided by SPE discussed above.

12. SPE Paper SPE-110460-MS, a true and correct copy of which is attached hereto as Exhibit H, is an SPE Paper entitled, *Openhole Gravel Packing with Zonal Isolation*, presented at the 2007 SPE Annual Technical Conference and Exhibition on November 11-14, 2007 in Anaheim, California. SPE is a sponsor of the SPE Annual Technical Conference and Exhibition. Since that conference on November 11-14, 2007, SPE Paper SPE-110460-MS has been publicly available to

anyone interested in purchasing a copy through the online sources provided by SPE discussed above.

13. SPE Paper SPE-169440-MS, a true and correct copy of which is attached hereto as Exhibit I, is an SPE Paper entitled, *Design and Validation of an Improved Shunt Tube System*, was presented at SPE Latin America and Caribbean Petroleum Engineering Conference on May 21-23, 2014 in Maracaibo, Venezuela. (See Exhibit J). SPE is a sponsor of the SPE Latin America and Caribbean Petroleum Engineering Conference. Since that conference on May 21-23, 2014, SPE Paper SPE-169440-MS has been publicly available to anyone interested in purchasing a copy through the online sources provided by SPE discussed above.

14. Onepetro.org search results for and the abstract of SPE Paper SPE-169440 are attached as Exhibit J to this Declaration. These search results and abstract provide the exact date and location information for when and where SPE Paper SPE-169440 was presented.

15. SPE Paper SPE-38640-MS, a true and correct copy of which is attached hereto as Exhibit K, is an SPE Paper entitled, *Gravel Packing Horizontal Wellbores with Leak-Off Using Shunts*, presented at the 1997 SPE Annual Technical Conference and Exhibition on October 5-8, 1997 in San Antonio, Texas. SPE is a sponsor of the SPE Annual Technical Conference and Exhibition. Since that conference on October 5-8, 1997, SPE Paper SPE-38640-MS has been publicly

available to anyone interested in purchasing a copy through SPE directly and later through the online sources provided by SPE discussed above.

16. SPE Paper SPE-27359-PA, a true and correct copy of which is attached hereto as Exhibit L, is an SPE Paper entitled, *Completion and Production Results From Alternate-Path Gravel-Packed Wells*, presented at the 1994 SPE Formation Damage Control Symposium on February 7-10, 1994 in Lafayette, Louisiana. SPE is a sponsor of the SPE Formation Damage Control Symposium. Since that conference on February 7-10, 1994, SPE Paper SPE-27359-PA has been publicly available to anyone interested in purchasing a copy through SPE directly and later through the online sources provided by SPE discussed above.

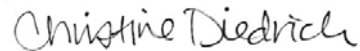
17. SPE Paper SPE-530-PA, a true and correct copy of which is attached hereto as Exhibit M, is an SPE Paper entitled, *A New Development in Completion Methods—The Limited Entry Technique*, presented at the SPE Rocky Mountain Regional Meeting on May 27-28, 1963 in Denver, Colorado. SPE is a sponsor of the SPE Rocky Mountain Regional Meeting. Since that conference on May 27-28, 1963, SPE Paper SPE-530-PA has been publicly available to anyone interested in purchasing a copy through SPE directly and later through the online sources provided by SPE discussed above.

18. SPE Paper SPE-58743-MS, a true and correct copy of which is attached hereto as Exhibit N, is an SPE Paper entitled, *Successful Application of Oil-*

based Drilling Fluids in Subsea Horizontal, Gravel-Packed Wells in West Africa, presented at the SPE International Symposium on Formation Damage Control on February 23-24, 2000 in Lafayette, Louisiana. Since that conference on February 23-24, 2000, SPE Paper SPE-58743-MS has been publicly available to anyone interested in purchasing a copy through the online sources provided by SPE discussed above.

I hereby declare that all statements made herein of my own knowledge are true, and that all statements made on information and belief are believed to be true and that such statements are made with the knowledge that willful false statements and the like are punishable by fine or imprisonment, or both, under Section 1001 of Title 18 of the United States Code.

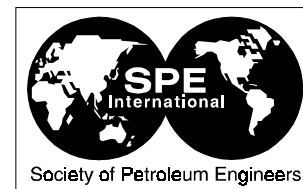
Dated: May 24, 2024



Christine Diedrich

Director, Multimedia & Publishing

EXHIBIT A



SPE 64410

Design and Execution of a 3000-ft Horizontal Gravel-Packed Completion (A Kazakhstan Case History)

Raymond Tibbles/Schlumberger, Elton Blessen/Texaco, Xiang Qian/Schlumberger, Bill Steven/Texaco, Carlos Pardo/Texaco, Gary Hurst/Schlumberger, Randall Kubota/Texaco, Peter Mysko/M-I Drilling Fluids

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This paper was prepared for presentation at the SPE Asia Pacific Oil and Gas Conference and Exhibition held in Brisbane, Australia, 16–18 October 2000.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of the Society of Petroleum Engineers is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of where and by whom the paper was presented. Write Librarian, SPE, P.O. Box 833836, Richardson, TX 75083-3836, U.S.A., fax 01-972-952-9435.

Abstract

This paper discusses the planning, design and successful execution of the first horizontal gravel pack in Texaco's remote North Buzachi field. Well NB4Z, located on land in Kazakhstan, presented extreme challenges that greatly affected the planning of the completion process.

Example of the challenges include the following:

- The combination of a 3000-ft-long openhole lateral section in a shallow reservoir meant that the screen would be over 1000 ft into the openhole before the gravel-pack packer was connected on the rig floor.
- The location had a limited supply of water for completion operations. Disposal of water was also a problem.
- The shallow reservoir made the screen placement problematic and made the torque and drag calculation much more critical.
- Because of the limited number of evaluation wells, everything had to work correctly the first time; i.e., there were no learning curve opportunities.

All aspects of the gravel-pack design are discussed (drilling fluid selection, torque and drag calculations, screen selection, selection of gravel-pack method, and pumping design). The successful executions of various completion phases are compared with the initial designs, and postcompletion well production is discussed.

This horizontal completion set several records. Among them are records for the longest slurry pack, the longest horizontal

well to be gravel packed without washpipe and the longest gravel pack using shunt screen technology. The design took an existing technology, enhanced it and stretched its application to a new limit, in the process obtaining a successful result.

Introduction

Horizontal gravel-packed completions are rapidly becoming a standard technique for high-rate oil and gas wells. Although various sand-control techniques have been applied in areas having significant completion infrastructure (personnel, operations base and local experience), this project shows how the technology can be successfully applied in a remote location with severe logistical and operational constraints.

Texaco is the operator of the North Buzachi field with a 65% interest in the field; Nimir holds 35% interest. The field contains approximately 2 billion barrels of undeveloped discovered reserve oil. The reservoir consists of shallow unconsolidated sandstone, producing relatively viscous 19°API crude oil. Well NB4Z is one of two horizontal wells drilled in the reservoir to date.

Working Environment

The field's remote location presents a major logistical challenge for well planning. Located 300 km north of the nearest city, Aktau, in the western part of Kazakhstan, (Figure 1), there is very little to no support for conventional oilfield services. Most equipment and material are imported, with delivery times ranging from three to four months.

A yearly temperature variation of –30° to 130°F adds to the difficult operating environment. The gravel-pack operation was performed in an outdoor temperature of 130°F, which complicated fluid handling and chemical mixing. The operation was executed with several different crew nationalities. This required extensive well site planning and communications required the assistance of translators.



Figure 1: Map of the area

Completion Design

Well NB4Z is essentially an exploration well designed for production. With a limited amount of formation, production and drilling data, decisions were made on the completion design before the 1999 drilling program began so that equipment could be selected, manufactured and shipped. The associated risks and unknowns were identified and then managed with the selection of equipment, services and field operations. The completion design started with the planning of the drilling program in the reservoir and finished with the well being available for production and reservoir data-gathering in the next year.

Reservoir Drill-In Fluid Design and Selection

The objectives of the fluid design were to provide a water-based drill-in fluid that would

- provide wellbore stability to successfully drill the 3000-ft horizontal section with no hole problems
- provide an “engineered” filter cake to reduce subsurface losses, especially while running the shunt screens
- minimize formation damage
- prevent or minimize damage to the screen
- ensure compatibility with all completion fluids
- facilitate optimum reservoir production
- exceed environmental standards for the region.

A water-based calcium carbonate-polymer-starch drill-in fluid was selected as providing the best drilling characteristics and minimizing potential damage to both formation and screen.

The key to the drill-in fluid system is the engineered filter cake, which provides a thin external barrier that protects the reservoir during drilling and running of screens. Pin-holes

through the filter cake will be generated with reservoir pressure drawdown, thus providing optimum production.

The system is composed of three major components:

- modified starch providing fluid loss control and low-end rheology
- biopolymer for viscosity and secondary fluid loss control
- a log linear designed carbonate for fluid loss control through optimum bridging.

The fluid was tailored to the actual reservoir requirements by adding glycol, a lubricant, and calcium carbonate. Glycols inhibit clays, and calcium carbonate addresses the formation permeability. The lubricant reduces torque and drag during drilling and running of the screen.

Horizontal Gravel-Pack Design

The first step in designing a horizontal gravel pack is selecting the method of placing the gravel. Water packing and shunt tube packing were considered. The shunt tube packing was selected based on ease of operation, logistics and water requirements (Table 1). Water packing consists of placing the gravel in an alpha-beta wave sequence using a low-viscosity carrier fluid (typically brine) at a low concentration of gravel (typically 0.5 to 1 ppa). Figure 2 depicts the typical packing sequence for a horizontal water pack. The numbers represent the progression of the settled or packed gravel front.

Shunt tube packing consists of placing the gravel in viscosified slurry at concentrations ranging from 6 to 8 ppa. Figure 3 depicts the theoretical packing sequence for the shunt treatment. Generally, shunt tube packing progresses from the heel of the well to the toe, as indicated by the numbers in Figure 3.

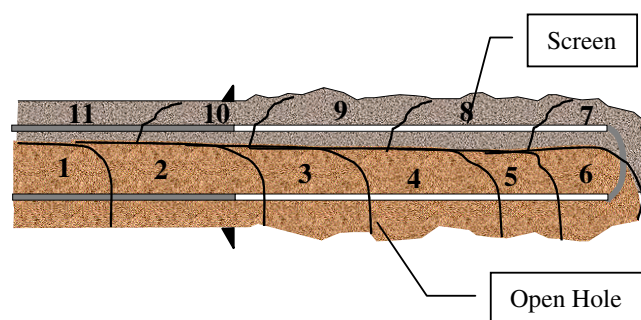


Figure 2: Water Packing Sequence

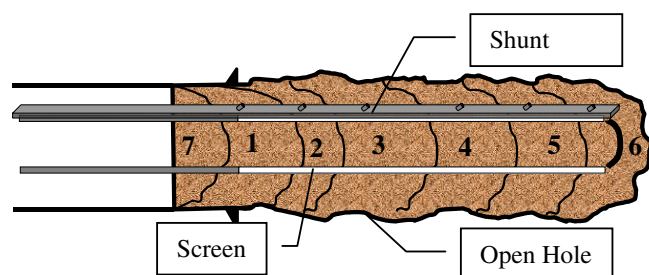


Figure 3: Shunt Tube Packing Sequence

For this 3000-ft gravel pack in an 8½-in. openhole, the theoretical gravel requirement was about 85000 lbm. Table 1 compares some of the salient features of the two gravel-packing methods.

The time required to run both types of gravel pack was analyzed and assessed. If washpipe is not used with the shunt tube packing (an option not available for water packing), then the total completion time is less when using the shunt completion.

When fluid volume is an issue, the shunt tube packing requires between 10 to 20% of the fluid required in a water pack treatment.

	Unit	Water packing	Shunt packing
Gravel volume (20% excess)	lbm	102000	102000
Screen running time	hr	6.5	15
Washpipe running and pulling time	hr	8	0
Gravel pumping time	hr	14	3
Total completion time	hr	28.5	18
Gravel concentration	ppa	0.5	6
Fluid volume for gravel	bbl	4857	405

Table 1: Comparison of Water Pack to Shunt Tube Pack

After selecting the technique, the completion hardware (principally the screen) and the pumping design were optimized. Since the 3000-ft lateral section of this well was much longer than the previous 1100 ft shunt screen record, a new screen design was introduced to

- improve the efficiency of the packing system
- reduce the makeup time for the screens.
- allow the treatment to be pumped at a higher rate

The new screen design consisted of two large transport tubes that branched off on each joint of screen to feed the packing tubes (Figure 4). This design reduced the number of shunt connections required between screen joints by 50%. In

addition, it significantly reduced the potential for fluid loss (slurry dehydration).

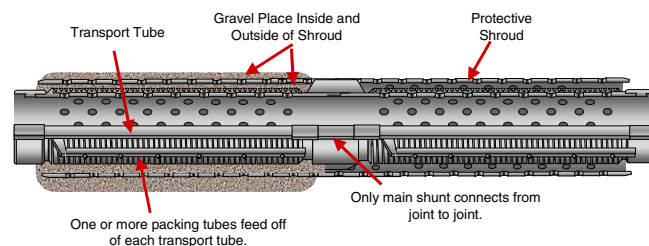


Figure 4: Transport Tube Screen Design

Torque and Drag Simulation

A major consideration in the planning of a highly deviated or horizontal well is the effective transmission of energy to the bottomhole assembly. A primary hindrance to this transmission is simple friction. The axial element of friction, drag, is the component that obstructs the transmission of work string weight to the assembly. The rotational component of the rotating friction, torque, is of paramount importance in the gravel-pack and screen completion design and must be within the limits of the threads and packer. Proprietary torque and drag software was used throughout the planning stage. The torque and drag analysis

- computes the expected friction losses along the work string and screen assembly while tripping in the hole
- selects the best path through analysis of the effects of profile changes on friction losses
- optimizes the work string design to produce the best combination of drill collars and HWDP to enable the screen to be pushed to bottom
- investigates the possibility of buckling the screen or blank pipe while pushing the screen assembly, indicating the maximum assembly that can run in a particular well
- produces charts for rig supervisors of tensile, surface loads and torque, demonstrating loads transmitted to the packer, screen and blank pipe.

The shallow TVD (491 m) and 880-m-long horizontal openhole lateral raised a concern of insufficient weight to push the screens into the openhole if the openhole friction factor was higher than expected. An openhole friction factor could not be attributed to the system because there was no database on running screen with this mud system for this particular field. As there were no data on which to model the field friction factor, assumptions were made based on North Sea experiences; i.e., 0.22 as the casing friction factor and 0.4 as the openhole friction factor for water-based mud.

Based on the simulation (Fig. 5), 5-in. heavyweight drillpipe was selected as the sole landing string. Two 5 1/2-in. 17-lbm conventional blank pipes were inserted between the packer assembly and shunted blank pipe to increase the buckling resistance of the screen bottomhole assembly.

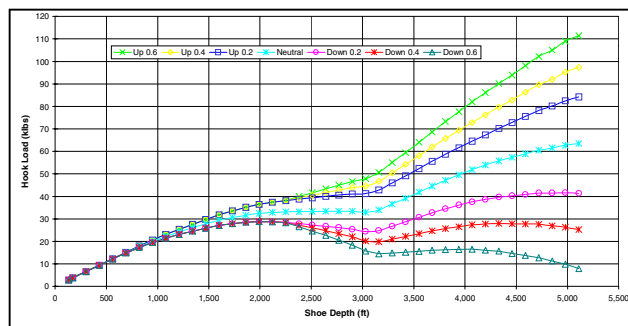


Figure 5: Torque and Drag Analysis

Drilling of the 8-1/2-in. Reservoir Section

The drill-in fluid system was built on the following formulation:

Calcium chloride brine to 10.8 ppg	
0.8 ppb	Polymer
5.0 ppb	Starch
30.0 ppb	Log linear carbonate
12.5 ppb	Coarse carbonate
0.4 ppb	Antifoam agent
3% vol/vol	Glycol
2% vol/vol	Lubricant

With the 9 5/8-in. shoe set at 683 m, drill-in fluid was displaced into the well. The section was drilled in three days to a total depth of 1562 m with no hole problems.

The mud density range was 11.0–11.3 ppg with the density derived primarily from calcium chloride brine. Good hole cleaning was achieved with a yield point of about 20 lbm/100 ft². The 6 and 3 rpm readings were 8 and 7, respectively. The spurt loss of the fluid was negligible, <0.5 mL with the fluid loss never exceeding 3 mL. The filter cake remained thin, pliable and elastic. The filter-cake composition and carbonate bridging contributed to zero subsurface drilling losses. At 818 m, a formation oil content of 2% was noted within the liquid mud fraction. At total depth, this oil content increased to 6%. The combination of formation oil, glycol and lubricant provided excellent lubricity with no torque or drag problems. The drill-in fluid remained in the horizontal openhole for six days, providing hole stability during the period required to drill the wellbore and run the shunt screen completion. Three wiper trips were made to establish wellbore conditions. No fill was ever encountered and hole conditions were good.

During the final wiper trip, brine was built using Volga water (total hardness = 160–340 mg/L and chlorides at 2000–3000 mg/L) and calcium chloride to a density of 1.32 sg (150 ppb calcium chloride to 0.88 bbl of water for one finished barrel). Sand-control batch mixer and tanks were used for brine mixing. A twin-pod cartridge unit and DE filter press were hooked within the system for brine filtration.

The openhole section was displaced to a solids-free drill-in fluid. Viscosity was achieved with 1-ppb polymer additions. Lubricant, at 2% by volume, was also added to provide lubricity and reduce friction coefficient while running the shunt screen. Rheological properties of the fluid were as follows:

$$600 - 33 \quad 300 - 22 \quad 100 - 12 \quad PV - 11 \quad YP - 11$$

The cased hole section was displaced to a filtered (<20 NTUs) calcium chloride brine.

Shunt Screen Installation

The special features of the shunt screen required several additional steps in making up the shunt screen connection in comparison to standard screen. These additional steps are alignment of the shunt tubes, installation of the jumper tubes and installation of the protective cover at the connection. The equipment used to run the screen is depicted in Figure 6. To improve the efficiency of the screen makeup, a “timed” thread was developed specifically for this application. This new SLHT-S thread was a shouldering thread that ensured proper alignment of the shunt tubes. During this operation 97 out of 100 screen joints lined up perfectly. The screen make-up and running speed averaged 6 joint per hour.

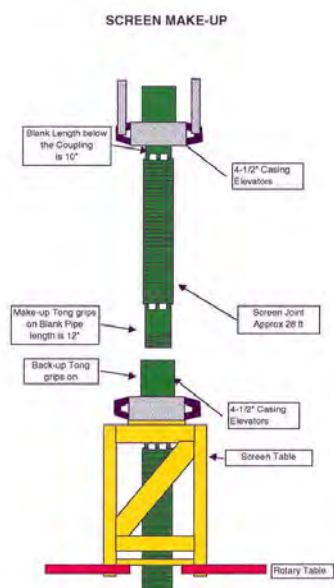


Figure 6: Screen Makeup Schematic

Gravel Pack

The gravel-packing operation was performed as planned with a complete annular pack achieved.

Figure 7 summarized the placement of the equipment used for the pumping operation. Equipment for the gravel-pack operation included

- one 850-hhp pumper skid for fracturing
- one pump truck
- one continuous mix blender
- one 2 x50 bbl batch mixer
- three fracturing tanks
- one rig tank.

Figure 8 contains the pumping chart from the gravel pack. The significant events highlighted on the chart are;

- Gravel arrives at the bottom of the well
- The annulus packs off and slurry flows through the shunt tubes
- Wet sand causes mixing problems, and the pump rate is reduced to allow the blender to keep up.
- Final screenout occurs at the end of the treatment.

The pressure increase from Point B until the final screenout at Point D was due mainly to the friction pressure of the slurry in the shunt tubes. Although the surface pressure was high enough to imply that the formation fracturing pressure was exceeded, fracturing did not occur as there was no loss of circulation throughout the operation. Figure 9 shows a

diagram of where gravel is placed and where pressure can build. Because the gravel pack was performed in circulation, and there was no washpipe, an annular bridge formed at the “top” of the screen and the gravel pack progressed from heel to toe. After the bridge formed, all pressure at Point P₀ was trapped in the area above the bridge (blank and casing annulus). For fracturing to occur, both pressure (above fracture pressure to initiate the fracture) and rate are needed to propagate the fracture.

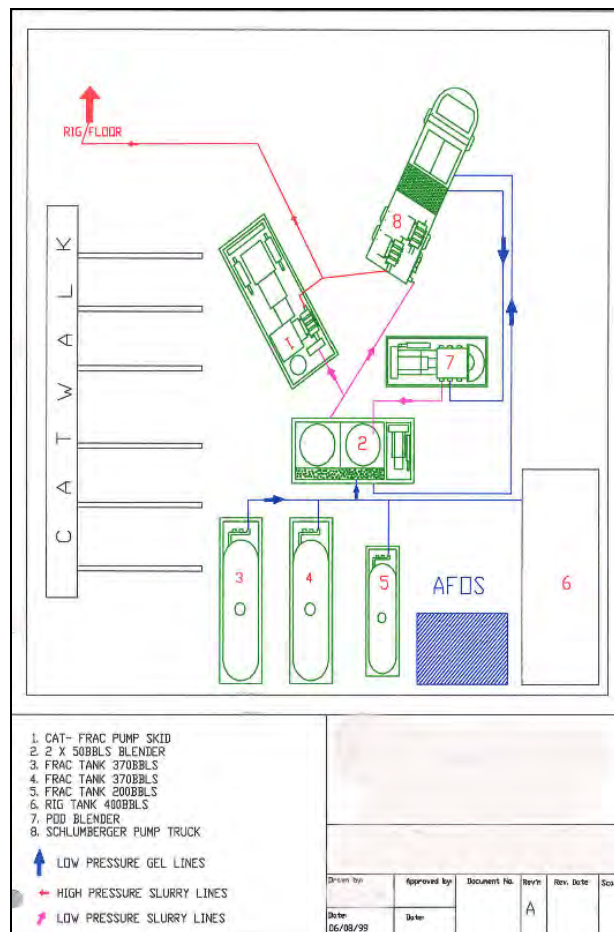


Figure 7: Surface Equipment Layout

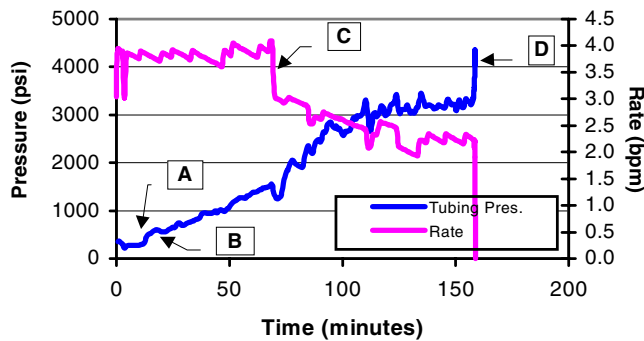


Figure 8: Gravel Pack Pumping Chart

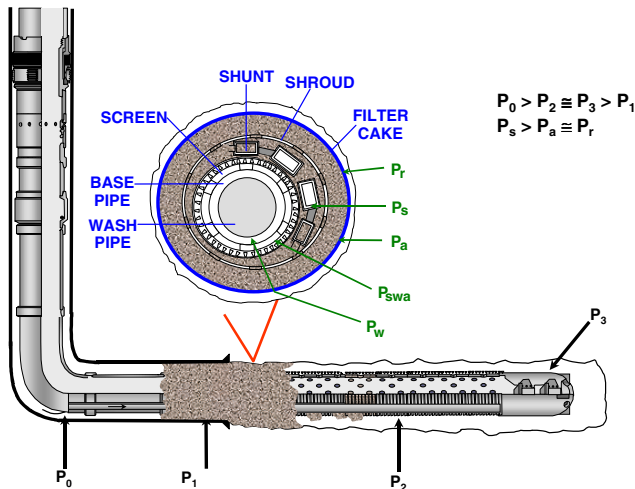


Figure 9: Pressures During Gravel Packing

Figure 10 was constructed using Darcy's linear flow equation to calculate the rates and pressures for various pack heights in the 4½-in. blank/9 5/8-in. annulus. The viscosity used in the calculation was 50 cp, which was 50% of the measured viscosity on location. Figure 10 illustrates that as little as a 2-ft pack will limit both rate and pressure seen by the openhole section.

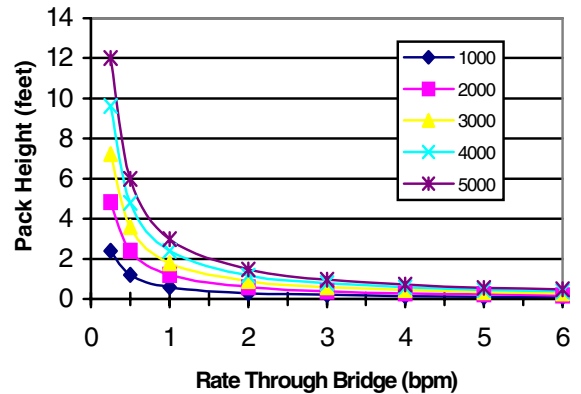


Figure 10: Linear Flow of Gel Through Packed Gravel

The theory of PressureDuring Gravel Packing was tested in a surface experiment. In this test, 2000 ft of a single-transport packing shunt tube arrangement was placed in a 2000-ft slotted plastic pipe. This simulated the worst leakoff condition in the openhole section. Similar gravel and fluids were used in the test and the field. The burst pressure of the plastic pipe was less than 100 psi. Figure 11 is the pressure chart from the test. Note that at the end of the gravel-packing operation, a shunt entry pressure of over 1400 psi was observed. The field results proved the theory and experiment correct; pressure is not transmitted through the packed gravel in the blank-casing annulus.

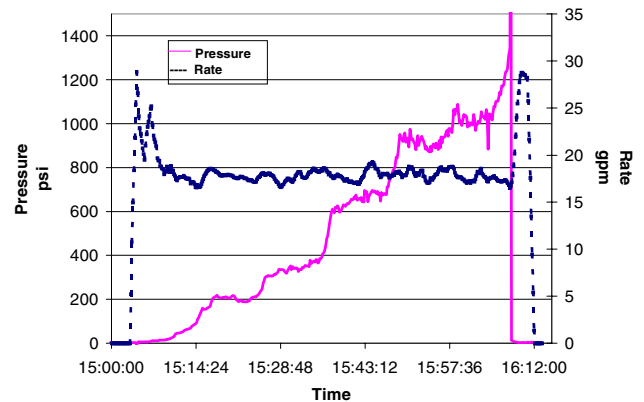


Figure 11: 2000-ft Surface Test of Shunt Packing

Results

Table 2 summarizes the production rates from the wells completed by Texaco. The initial oil production rate for the gravel packed horizontal well was a little over twice the rate of comparable vertical completions.

Well Number	Completion Type	1st Month Production	
		Oil Rate (bopd)	Water Rate (bwpd)
1	Vertical	521	2
2	Vertical	580	0
3	Horizontal Perforated Liner	321	0
4	Horizontal GP	1257	34

Table 2: Production Performance

Conclusions

The purpose of this well design and completion was to determine if economic production could be obtained from a horizontal completion given the reservoir conditions. It was also necessary to evaluate the potential of applying new technology in a remote location. The results were:

1. The gravel-packed horizontal well initially produced at twice the rate as the vertical wells.
2. The drill-in fluid performed as expected and the torque and drag predictions were close to actual recorded data.
3. Shunt technology allowed successful execution of a long horizontal gravel pack in this remote area having a limited water supply.
4. Using the shunts, an extended gravel pack could be performed without washpipe, which saved a significant amount of rig time.
5. The new timed thread allowed the shunts to be perfectly aligned each time, which reduced the total makeup time seen on earlier jobs.
6. A complete gravel pack was achieved on this well with 33% excess gravel over the theoretical volume being placed.

The shunt screen completion demonstrated that an existing technology could be enhanced and successfully implemented in a logistical difficult location. The success factors were: commitment of skilled people, detailed pre-job planning, excellent field execution, and communications at all levels.

Acknowledgments

The authors thank the management of Texaco, Schlumberger and MI for permission to publish this paper. In addition we thank the personnel with US Filter and Hunting, whose engineering expertise was instrumental in the design of the shunt screens. Last, but certainly not least, we thank the service crews who kept a positive attitude while overcoming challenging working conditions.

References

- ¹ Penberthy, W. L. Jr., Bickham, K. L., Nguyen, H. T., and Paulley, T. A., "Gravel Placement in Horizontal

Wells", SPE 31147, Proceedings SPE Formation Damage Symposium, Lafayette, La., Feb 14-15, 1996, pp 741-751.

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³ Bryant, D. W., and Jones, L. G., "Completion and Production Results from Alternate Path Gravel Packed Wells", SPE 27359, Presented at SPE Formation Damage Symposium, Lafayette La, 1994

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EXHIBIT B



SPE 155129

The Evolution of Completion Designs Using Alternate Path (Shunt-Tubes) Technology

Shahryar Saebi, Schlumberger

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Abstract

Alternate Path^{*} (shunt-tubes) technology has been available to the petroleum industry for well more than a decade. Its applications have expanded over time around the world ranging from single-zone cased-hole gravel packs to multizone gravel packs or frac packs and openhole gravel packs. The recent advances have expanded applicability from specialty gravel packing to a general, all-purpose technology with huge benefits. Its flexibility permits use in extremely challenging environments, allowing completions previously considered difficult or impossible.

Development of multizone packers (cup type or swellable) has helped to push the envelope for Alternate Path technology both for cased-hole and openhole applications. This technology has enabled operators to not only perform multizone gravel-pack and frac-pack completions, but also provide solutions for gravel packing in exceptional conditions such as gravel packing a new zone in presence of open perforations in the zone above, isolating unwanted zones while completing new intervals, or gravel packing in exceptional well geometry.

This paper provides a review of the recent unique completions using a shunt-tube system to overcome complicated well completion challenges and expand the limits of using this technology further.

Introduction

The shunt-tube technology was developed to bypass any annular blocking that can occur during the completion process for various reasons. This technique uses screens with steel rectangular tubes (also called shunt tubes) welded onto them. These tubes have nozzles that allow the slurry to exit out of the tubes and into the annulus once the blocked annular section is bypassed (Bryant and Jones 1994). The shunt tube comes in two dimensions depending on the required pumping rate to perform the operation: small tube (0.5- × 1.0-in. OD; 0.31- × 0.81-in. ID) or large tube (0.75- × 1.5-in. OD; 0.56- × 1.31-in. ID). The eccentric design of the tubes to the body of the screen and blank pipe allows for minimizing the external diameter (Hurst et al. 2004) (**Fig. 1**).

One of the main accessories of this system is the multizone (MZ) packer that is used to allow for completing multiple zones in a single trip. With a single pumping stage, the MZ packer saves significant rig time and eliminates the use of fluid-loss-control pills that are typically required in dual-trip or multitrip completion operations (**Fig. 2**).

^{*} Mark of ExxonMobil; technology licensed exclusively to Schlumberger

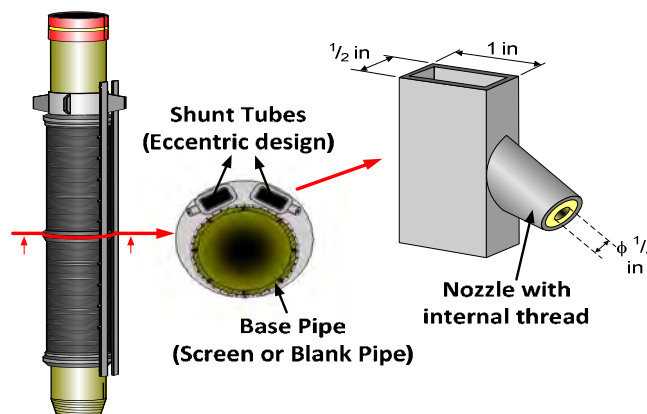


Fig. 1—Shunt-tube configurations and dimensions.

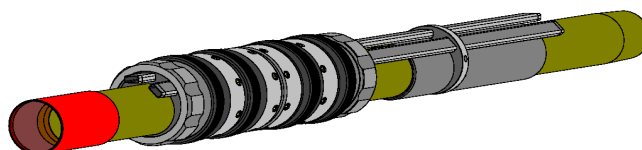


Fig. 2—MZ (cup type) packer allows flexibility in gravel packing separate zones simultaneously.

The MZ packer is a cup-type packer with shunts in the cup/base pipe annulus. The upper zone is packed conventionally, while the lower zone is packed by diverting the slurry through the shunts and bypassing the cup packer. Because the cup packer is only 6-ft long, it can isolate multiple sand bodies separated by relatively thin shale sections, whereas conventional stacked completions require a minimum of 15- to 20-ft spacing (Hurst et al. 2004). The MZ packer provides isolation of the casing/screen annulus (in a blank section); thus, an internal isolation would also be needed to selectively produce or isolate each zone. In this case, this internal isolation is achieved by placing a tail pipe with a sliding sleeve and isolation seal assembly inside the screen across each zone. This arrangement allows flexibility in terms of shutting off zones that are producing undesired fluids (water or gas). The same configuration can also be used to selectively produce each zone one at a time.

We will review a number of the recent unique completions that have used shunt-tube system to overcome complicated well completion challenges.

Gravel Packing the Lower Zone in the Presence of Existing Perforations in the Upper Zone

The conventional alternative consists of squeezing and sealing off the existing perforations, perforating the lower zone, gravel packing the lower zone, temporarily plugging the completed zone, perforating the upper zone, cleaning up the wellbore and retrieving the temporary plug, running the gravel pack assembly, and gravel packing the upper zone. This requires significantly more time and more mechanical elements to perform, thereby creating higher risk and possibility of failures (Fig. 3).

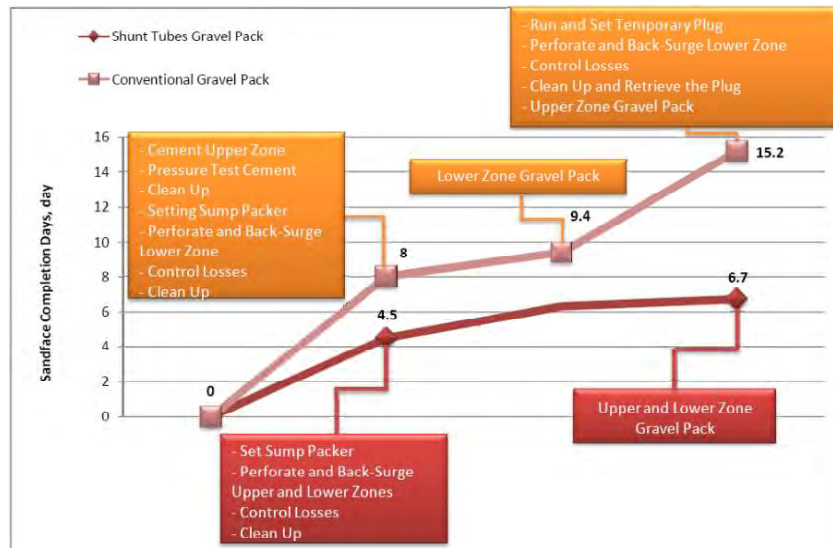


Fig. 3—Completion time for shunt tube could be less than half that for conventional methods.

To address the challenging requirements of the project, a combination of two completion techniques were implemented. Shunt-tube technology provides alternate slurry pathways that bypass the bridges to ensure 100% packing efficiency. A concentric completion system provides a circulation flow path during gravel placement, fluid-loss control after gravel placement, and selectivity during production. Fig. 4 shows the completion schematic of the candidate well.

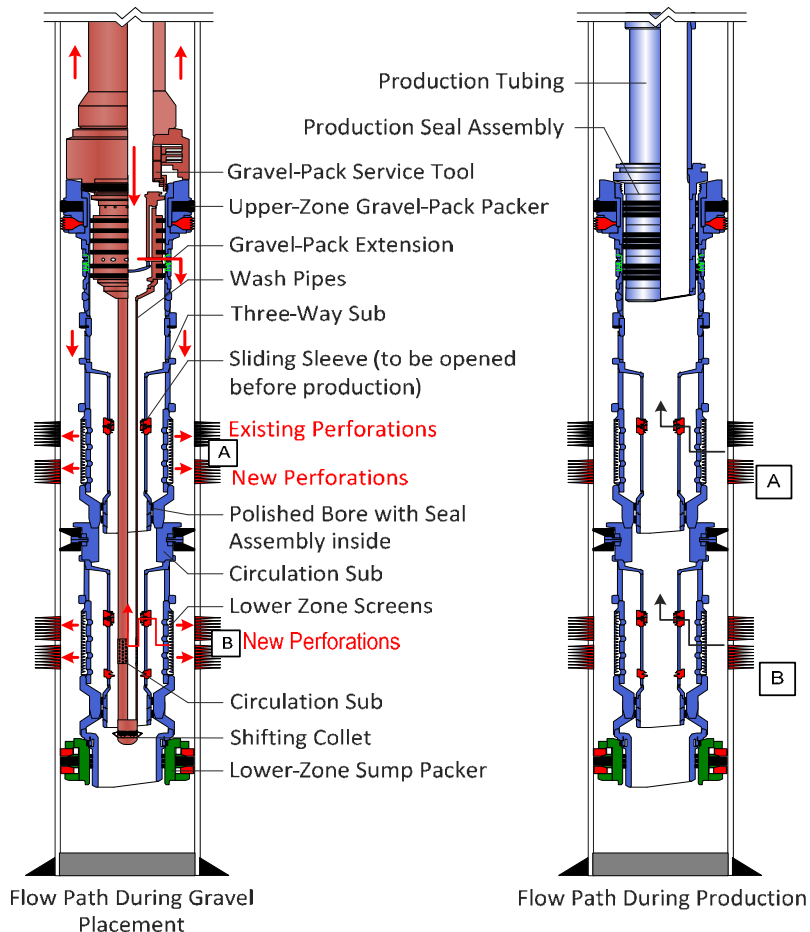


Fig. 4—Sandface completion design incorporating both shunt-tube technology and a concentric completion system ensured optimal completion of two zones, A and B.

Two zones (A and B) were completed in the target well. The target zones were gravel packed in one run using the shunt-tube technique combined with a three-way sub concentric completion system equipped with a 2 7/8-in. inner string and sliding sleeve door (SSD) for each zone. Also, polished bore receptacles were placed above the MZ packer to accommodate the isolation seal assembly and to provide internal isolation between the inner string and screens.

Gravel Packing 950 ft of Gross Perforated Interval with 600-ft Shale Section Between the Zones in a Single Pumping Operation

Three zones (A, B, and C) were completed in the target well (**Fig. 5**). Zones B and C were gravel packed in one run using the shunt-tube technique combined with a three-way sub concentric completion system equipped with a 2 7/8-in. inner string and SSDs for each zone.

Zone A was completed and gravel packed in a separate run using the shunt-tubes system as well because the gross interval of the zone reached 775 ft, and conventional gravel-pack methods would probably not be effective. Because the B and C zones were mechanically isolated by SSDs, no additional isolation plug was required during gravel packing treatment of zone A.

The upper completion with a seal assembly was then run and landed in the lower zone multiseal assembly (LZMSA) below Zone A. This configuration allowed production from zone A through the annular space between the screens and the long string into the short production string.

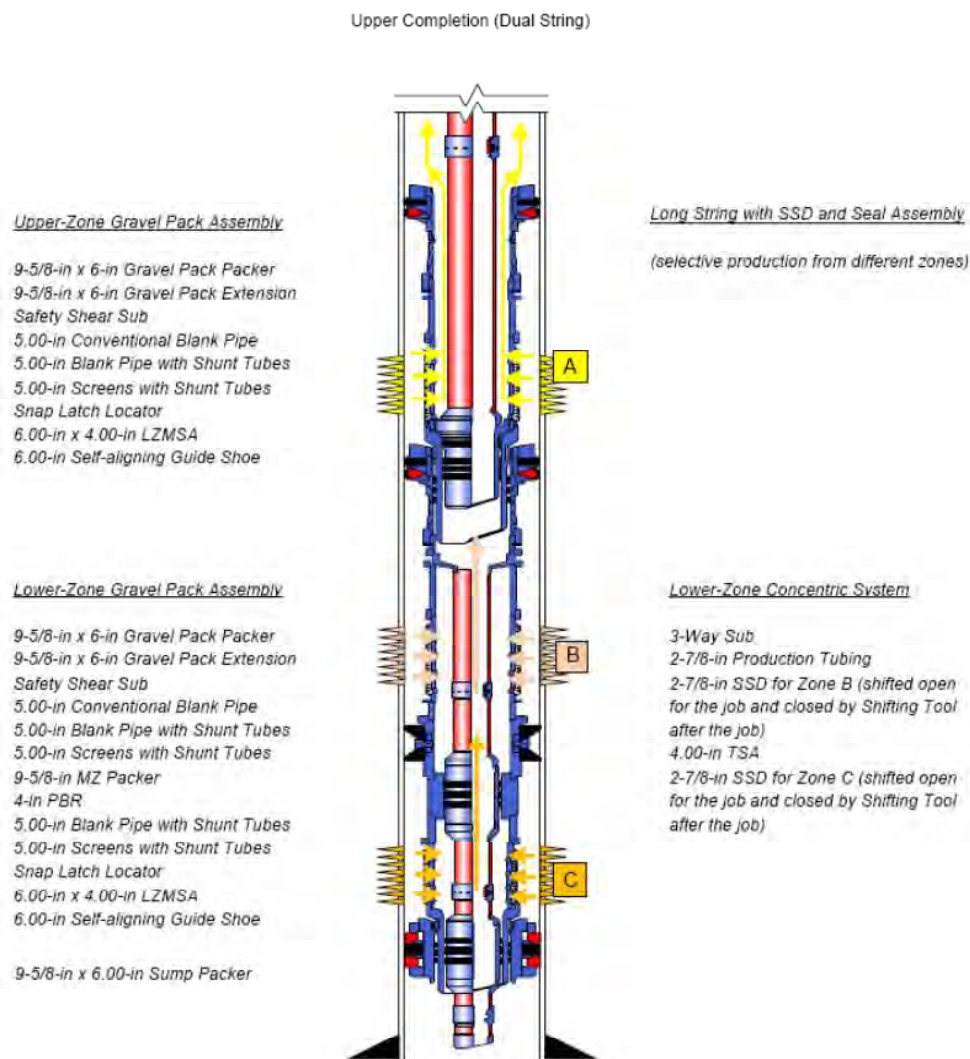


Fig. 5—Completion schematic.

Considering the long distance between the B and C zones (602 ft) and the length of each interval, 136 ft and 212 ft, respectively, the most suitable shunt-tubes configuration had to be selected to achieve the operational objectives. The proposed options are shown in (Fig. 6).

Option A. The shunt tubes are connected all the way to the bottom of assembly and all of the nozzles are open on the screens. This is a standard configuration for this type of application. The disadvantage of such a design is coping with the high-friction pressure through the long length of shunt tubes of the blank pipes below the MZ packer and also the possibility of early dehydration of the slurry in the shunts.

Option B. The shunt tubes are open ended below the MZ packer and all of the nozzles are open. The main advantage of this configuration is less friction pressure through the shunts. After packing the upper zone (conventionally or through the shunts), the shunt tubes below the MZ packer are activated, and the slurry begins to flow below the MZ packer. Because the shunts are open ended, the slurry will flow through the blank-casing annulus, which requires significantly less friction pressure for flow. The lower zone will be packed conventionally, and then by activation of the shunts on the lower zone screens (if required). The disadvantage of this approach is the possibility of crossflow between the zones through the shunt tubes during production.

Option C. The shunt tubes are connected all the way to the bottom and the nozzles of one of the upper zone shunts are plugged. In this configuration, one tube is dedicated to zone C (lower zone) and the second shunt is open to bypass the bridges on both the upper and lower zones. In such a design, the crossflow through the tubes during production is negligible but we still need to cope with possible high-friction pressure during the pumping operation. Using this configuration will also eliminate the possibility of early dehydration of the slurry in the shunt tube that is dedicated to zone C.

Considering all the advantages and disadvantages of the different configurations, option C was selected as the most suitable alternative for the application.

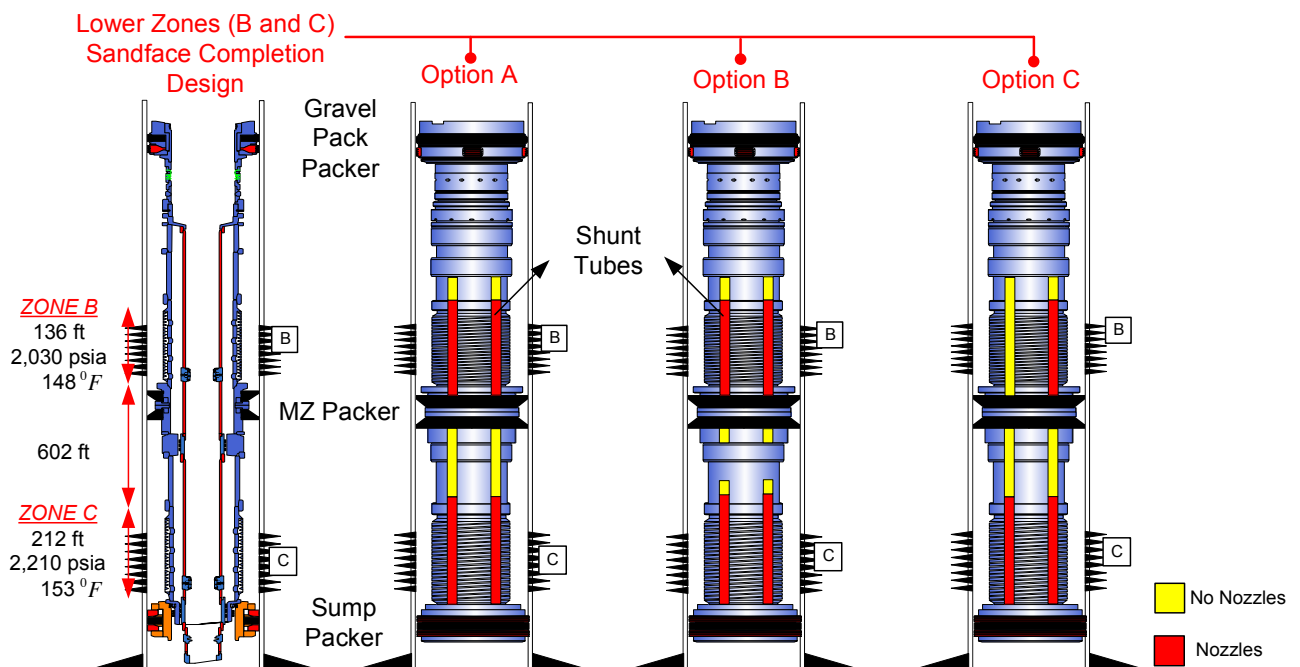


Fig. 6—Proposed completion configurations.

The customized sand-control system was successfully installed and achieved the operational objectives. Thus far, seven wells have been gravel packed using the shunt-tube system and concentric completion technique in this project.

Gravel Packing the Lower Zone and Abandoning the Upper Zone using Sandface Completion

The objective of the workover plan for the candidate well was to abandon the lower gravel-packed zone, isolate the upper gravel-packed zone, and perform a gravel pack in the middle zone. To access the reservoir section for the middle zone, both 7-in. and 9 5/8-in. casings had to be perforated. Due to the uncertainty of filling up the annular space between the two casings with gravel, the decision was made to perforate the 7-in. casing above and below the zone of interest, set a cement retainer

just above the lower perforations, and circulate cement slurry through the annular space between the two casings to fill up the void space between the two casings. The operation was continued by perforating the zone of interest through both casings and cement sheaths and performing gravel pack (**Figs. 7 and 8**).

The other requirement was to isolate the upper zone prior to gravel packing the middle zone. Instead of spending rig time to squeeze off and isolate the upper gravel-packed zone, the sandface completion design was modified to accommodate for this requirement. The upper zone was isolated by setting two MZ packers above and below the zone. The middle zone was gravel packed through shunt tubes that were extended all the way from above the top MZ packer to below the lower MZ packer. Since no nozzles are installed on the shunt tubes of the blank pipes between the two MZ packers, there is no leakoff to the upper zone while gravel packing the middle zone.

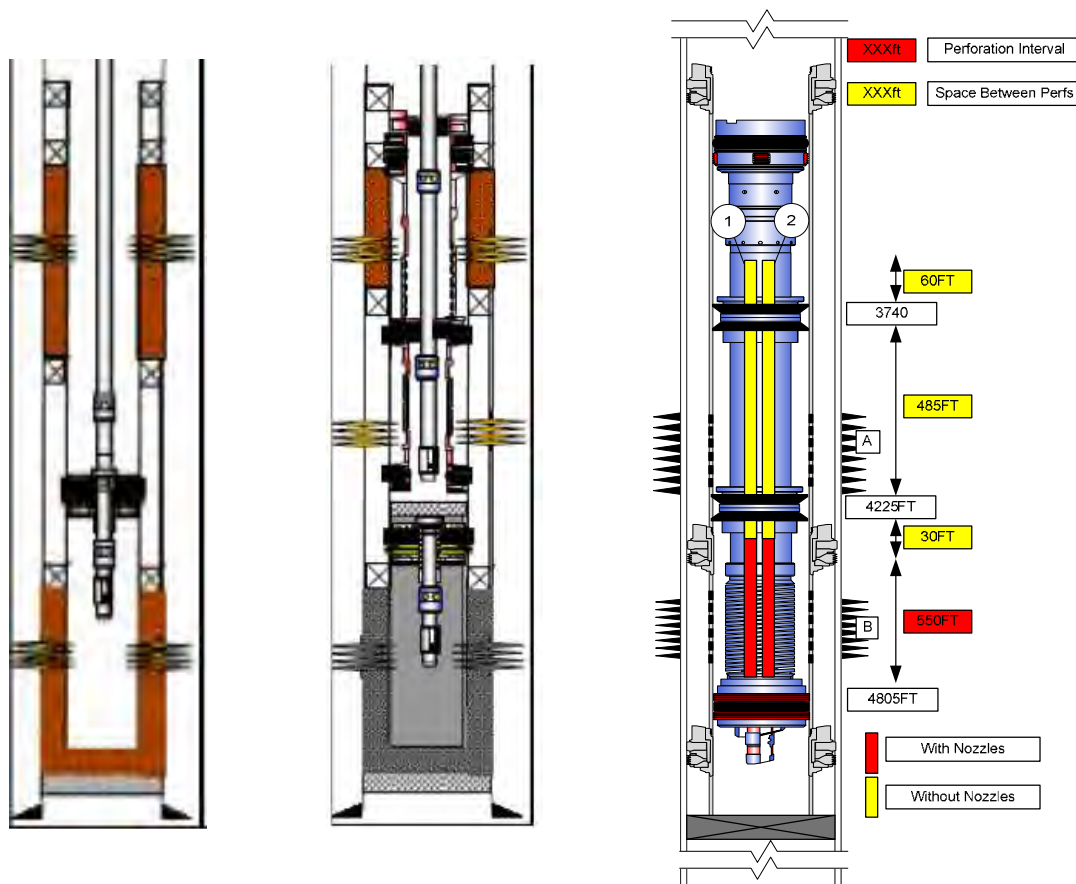


Fig. 7—Existing and proposed completion configurations.

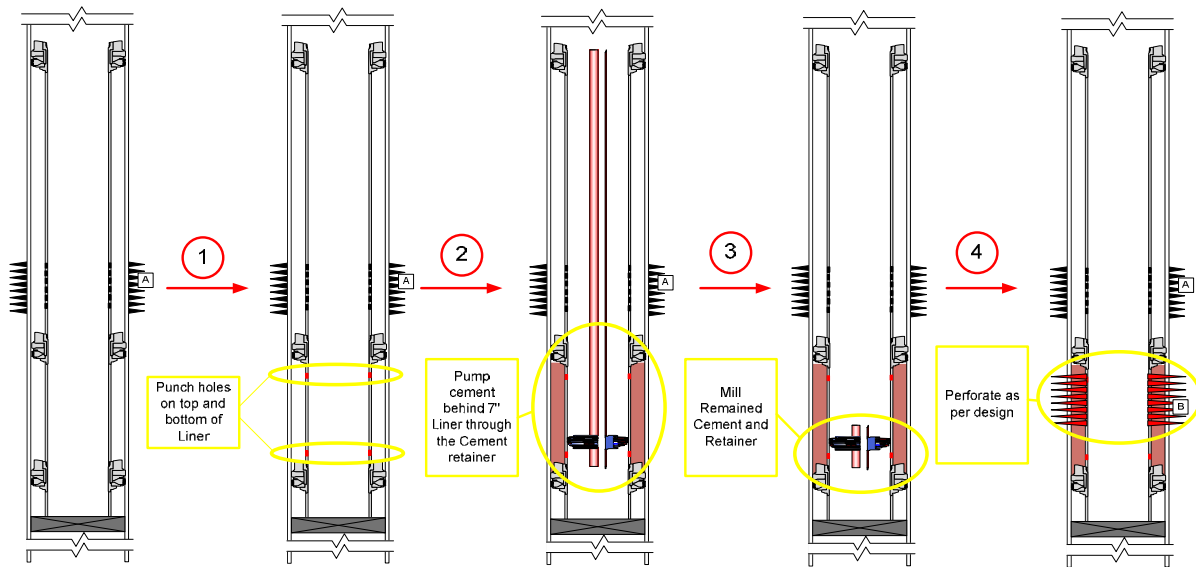


Fig. 8—Well preparation steps prior to completion.

Openhole Gravel Packing in Exceptional Well Geometry—Uphill Heel-to-Toe Packing

This technique has been used to gravel pack two fishhook wells with deviations of 126 and 131°, respectively, up to date. The fishhook wells concept has been initiated to develop near-offshore reservoirs from land locations (Sulaiman et al. 2011). The objectives of the completions were:

- Achieve a complete annular pack
- Provide the capability for zonal isolation
- Maintain bottomhole pressures below the fracturing pressure
- Deliver a low skin completion

For this application, screens with four shunt tubes (2 Transport Tubes × 2 Packing Tubes) were used.

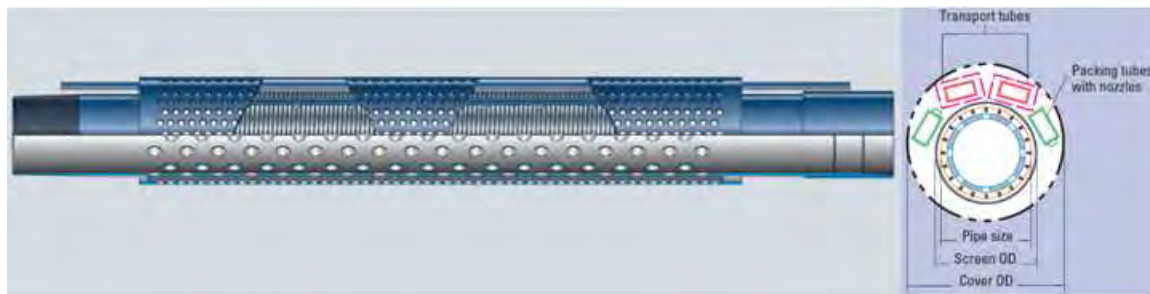


Fig. 9—2 Transport tubes × 2 Packing tubes screen.

A front end engineering design was initiated as a starting point for an in-depth discussion of the precompletion using the screen with shunt tubes. Several challenges were identified, with solutions proposed using both existing proven technologies and new technologies and innovative ideas that were to be applied for the first time (Sulaiman et al. 2011).

TABLE 1 – CHALLENGES AND SOLUTIONS		
	Technical Challenge	Proposed Solution
1	Ensure 100% annular pack at 120 to 130° deviations	Screen with shunt tubes
2	Setting of packer with ball in “upside down” position	Lighter density ball for setting packer
3	Packer setting ball falling back into belly section	Ball retainer at ball seat
4	Initiate heel to toe uphill packing	Use APS packer between screen and X-over ports as well as diverter valves at various locations on the washpipe.
5	Prevent pack sliding downhill during uphill gravel packing	Use APS packer between screen and X-over ports and encourage heel-to-toe packing.
6	Achieve zonal segmentation of precompletion	APS packer (oil swellable packer with shunt tubes)
7	Ensure zonal segmentation with oil swellable packers	Preswelling of APS packer prior to gravel packing
8	Minimize preswelling time of APS oil swellable packer	Design and use of fast-swell elastomer
9	Minimize preswelling time of APS oil swellable packer	Use clean solids-free elastomer swelling fluid\
10	Ensure 100% annular pack at blank sections	Design and use quasi APS blanks
11	Avoid exceeding fracture pressure at shoe during GP	Diverter valves in the washpipe string
12	Avoid exceeding fracture pressure at shoe during GP	Low-friction carrier fluid – VES
13	Ensure low skin at sandface	Solids-free carrier fluid – VES
14	Ensure low skin at sandface	Effective filtercake-removing agent
15	Design a gravel-pack simulator for uphill heel-to-toe packing	Purpose-built simulator

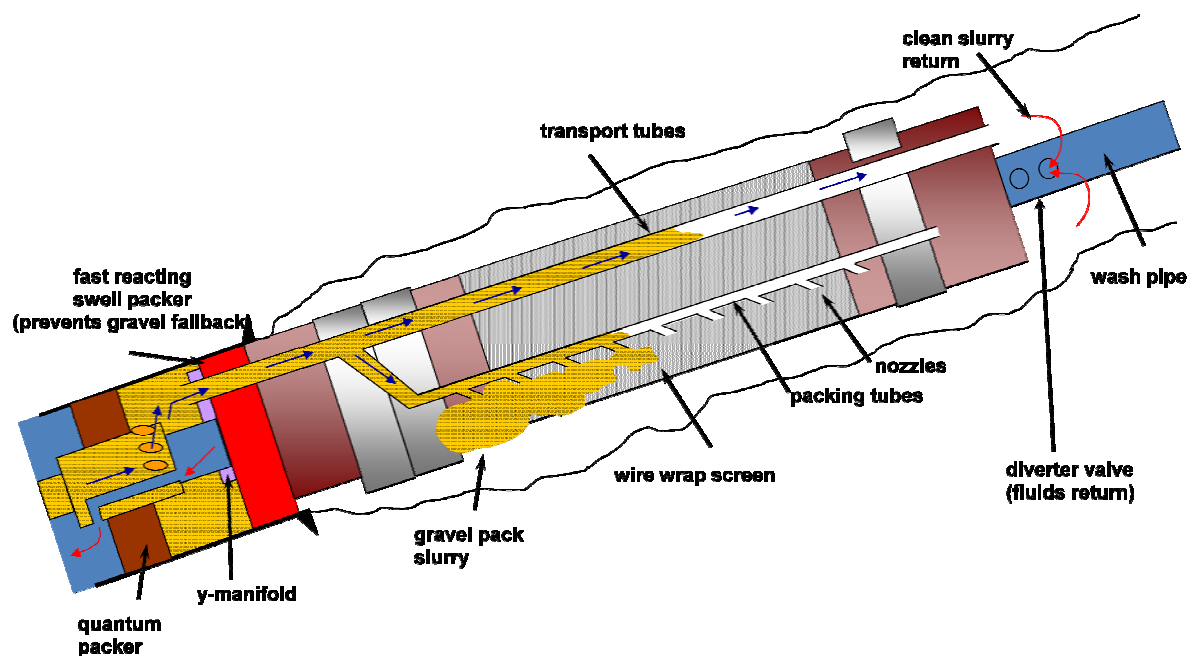


Fig. 10—Uphill gravel-packing process.

Conclusions

A series of exceptional well completions have been performed recently using Alternate Path (shunt-tubes) screens and accessories. The innovative approach taken to address the challenges imposed by each well completion design provided great value to the operation and could also be used as lessons learned for future similar applications.

Acknowledgments

The author wishes to thank Schlumberger management for the permission to publish this paper.

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SI Metric Conversion Factors

bbl	×	1.589 E-01	=	m ³
ft	×	3.048 E-01	=	m
cp	×	1.0 E-03	=	Pa.s
gal	×	3.785 E-03	=	m ³
in.	×	2.54 E+00	=	cm
lbm	×	4.535 E-01	=	kg
psi	×	6.894 E+00	=	kPa

EXHIBIT C

SPE 22796

Alternate Path Gravel Packing

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ABSTRACT

A new and superior gravel packing method called ALLPAK™, for alternate path gravel packing, is reported here. It has been found that gravel packing problems associated with formation of sand bridges in the annulus outside the screen can be eliminated by adding alternate flow paths for slurry flow. The alternate paths are provided by perforated shunts or secondary piping placed in the annulus, usually by attaching the tubes to the screen. Laboratory gravel pack simulator tests indicate that essentially complete annulus packs can always be obtained, even in cases where current methods provide very poor pack efficiencies. This paper describes the laboratory experiments and field tests which verify the advantages from this new concept.

SUMMARY

A new completion method is described which solves the classical problem of sand bridging in conventional gravel packing. Provision of properly designed alternate slurry flow paths, through shunts or secondary piping placed in the annulus, eliminates almost all of the voids seen with common gravel packing procedures. The results from laboratory testing done on a 30-ft full-scale gravel pack simulator indicate 95-100% gravel pack efficiencies as compared to 65-80% obtained with conventional procedures, where both efficiencies are estimated by visual observations. In addition to providing superior gravel packs, the new method, called ALLPAK™, for alternate path gravel packing, also permits wider ranges in slurry rheology and pumping rates. Field test results from U.S. Gulf Coast offshore wells validate and extend the laboratory observations.

References and illustrations at end of paper.

INTRODUCTION

The classical problem in gravel packing occurs when premature sand bridges form in the annulus between the sand retainer screen and the casing wall, for an incasing gravel pack, or the formation, for an open-hole gravel pack. The bridges usually form either at the top of the screen or adjacent to zones of higher permeability. Once a bridge forms, slurry flow past that point ceases, leaving an incomplete pack below the bridge.

Many mechanical variations for gravel packing apparatus have been developed or proposed for avoiding sand bridging¹⁻¹⁴, and a large body of literature exists reporting studies of the effects of gravel packing variables such as fluid rheology, pumping rates, sand density and concentration, etc. However, major problems still exist, especially where long intervals and/or highly deviated wells are involved.

This work describes apparatus and methodology for alternate path gravel packing which can eliminate bridging problems.¹⁵ The key to the new approach is the addition of alternate paths for slurry flow adjacent to the screen. These could either be inside or outside the screen, although the mechanical assembly is much simpler if the alternate paths are placed in the annulus. The alternate paths consist of small separate tubes or pipes attached to the screen and perforated with small holes every few feet. Slurry can either be injected directly into the tubes, or the tubes can be left open at the top of the annulus to act only as shunts.

Currently, our preferred arrangement is the shunt configuration because this permits running screens and placing gravel packs with little change from conventional equipment and procedures. Figures 1 and 2 illustrate the concept. Ultimately, injecting the slurry

directly into the tubes may prove to be the preferred arrangement because this would provide a more orderly, controllable, and predictable process.

LABORATORY TESTS

A series of tests were run on Baker Sand Control's 6.2 in. ID gravel pack simulator shown in Figures 3 and 4, using a 2 7/8" wire wrapped screen. The 18-ft perforated length simulates 12 shots/ft, with each 0.7 in. I.D. perforation backed by a 2.5 in. long 0.7 in. I.D. tube packed with 20/40 mesh sand to simulate the formation.

The simulator can vary in inclination between 0 and 90°, but most of the runs were made in a horizontal position to provide the most difficult packing conditions. Pertinent results are summarized in Table 1.

The first set of experiments listed in Table 1 were the initial experiments made in an attempt to verify the alternate path concept. The base case was previously known to provide incomplete packing and was repeated here for comparison purposes. Although the shunt runs were relatively successful, the packing mechanics were haphazard with slurry running in and out of shunt holes almost at random. From this it was surmised that the shunt holes were too large and that there were too many holes.

In the second set of experiments, the goal was to investigate the use of 36# XC/1000 gal. clarified gel rather than 40# HEC/1000 gal. and to improve shunt hole designs. The two base cases were run to provide comparisons for both squeeze and circulation positions. As an afterthought, one run was made using water as a carrier fluid with approximately the same results. The use of 0.75" I.D. tubes rather than 0.824" I.D. occurred because the 0.824" tubes were not immediately available. The small size variation did not alter results in any noticeable way.

The final set of experiments were made after a field apparatus design was tentatively identified. Rectangular shunts were chosen in order to maximize the clearance in the annulus while still retaining substantial shunt tube cross sectional area for slurry delivery. The squeeze-circulation experiment was chosen as a standard in order to simulate use of a differential valve. Four shunts set at right angles were chosen to assure that two shunts would always be at the top of the apparatus. The runs with 40/60 sand were made to study the effects of settling on the packing mechanism. The smaller holes were investigated to find how small the holes can be with minimal possibility of plugging.

A separate set of tests were run where up to 300 ft long shunt tubes were laid out on pavement and slurry was injected directly into the tubes. From these tests, it was found that the XC gel and 40/60 sand can be delivered several hundred feet at shunt flow rates of less than 0.2 bbls/min.

DISCUSSION OF LABORATORY RESULTS

For every sand size, hole angle, and slurry density relative to completion fluid density, gel rheology, and shunt design, there is a minimum shunt fluid slurry velocity, and hence pumping rate, required to pack a given length of interval. For the sake of practicality, experimentation has been concentrated on finding combinations that work, rather than investigating all options.

From the first set of experiments, it was found that numerous relatively large shunt holes produce a disorderly packing mechanism. We believe that such a mechanism would fail when packing long intervals.

The second set of experiments proved the value of the shunts. With uniform leak-off from the perforations, a squeeze pack produces better results. However, in later experiments, not reported here, poor packing resulted with squeeze packs when long intervals had no perforations leak-off.

The final set of reported experiments was performed to provide data for designing field tests. The rectangular tubes were chosen strictly for mechanical design advantages. Smaller shunt holes, 36# XC/1000 gal. clarified gel, and 40/60 sand were chosen primarily as a result of the long shunt tube tests. The last laboratory tests were intended to verify the general shunt design and to investigate the effects of longer shunt hole spacing. Visually, the tests with 4 ft spacings initially appeared to have the same complete annulus packs as found with smaller spacings. However, upon back-flushing with water, some slight sand movement and voidage occurred estimated at 5%.

It is probable that all packs would be improved with higher pressure differentials. The 100 psi limit in the experimental apparatus is quite low for dehydrating a gel pack, especially with 4 ft spacing between the pressure application points provided by the shunt holes. Although the field designs have been based on the outdoor long tube experiments, an interesting and helpful phenomenon occurs inside the simulator which makes these designs quite conservative. Too many holes obviously will provide too much leak-off from the shunts and reduce shunt fluid velocities. However, as the upstream holes are covered with sand, a major amount of the flow is diverted to downstream holes, with the result that the shunts are active over a longer distance inside the casing than they are when no casing is present. The length which can be treated is unknown at present since the simulator studies are so limited in length, but should be well in excess of the 300 ft test length in the outdoor tests.

One difficulty in developing detailed design information is that determining the mix between annular flow and shunt flow is beyond current engineering theoretical prediction capabilities, especially since the mix is dependent on geology. However, this dilemma is neatly avoided by using slurries where the sand settles slowly. In

that case, those periods of time when the shunt flow velocity is low do not result in shunt plugging because the sand is once again transported as soon as the shunt flow velocity recovers.

FIELD TESTS

Two U.S. Gulf Coast offshore wells were chosen for the first field tests. Each well provided a specific challenge for the new method. Well #1 was only inclined at 45° from vertical but had two productive zones separated by more than 50 feet of shale. The upper 18-ft perforated zone was much more permeable than the lower 9 ft zone, and the lower zone's estimated reserves were too small to justify a separate completion. Well #2 was inclined at 64° and had 190 feet of perforations in a 220-ft zone of highly variable quality.

The ALLPAK™ design for Well #1 included three joints of 2 3/8 inch screen with four half inch by one inch rectangular shunts attached and perforated every three feet with 3/32 inch holes. One joint of blank pipe with blank shunts was placed above the top of the screen. The connectors between individual screen joints are key elements in obtaining shunt fluid transmission continuity. Figure 5 provides an external view of the connectors. An internal O-ring assembly at each end of each connector assures a good pressure seal. Failure of a seal ends a shunt's effectiveness below that location. A connector is attached to the end of each shunt tube and the short length of shunt tube between the two end connectors allows for adjustment to slightly variable shunt and screen combinations. Additional installation time required to run an ALLPAK™ assembly has been about 15 minutes per joint. Most of the extra time is associated with making the connections.

Well #1 was initially packed at 3.5 bbls/min with 8 lbs/gal 40/60 sand, and a 40 cp, nearly Newtonian fluid. A lower tattle tale and 300 psi differential valve were used. Since the packing pressure was at approximately the fracture gradient, fracturing apparently occurred and a second batch of slurry was required. The second batch was pumped at approximately 1.5 bbls/min and a 2500 psi sand-off was soon achieved. The total amount of sand placed behind the pipe was approximately 0.65 cu ft/ft of perforated interval, much above the 0.2 to 0.25 normally expected for a superior gravel pack. It is currently speculated that the shunts facilitate fracturing along the entire perforated length when the fracture gradient is exceeded. Work is underway to exploit this advantage.

Figure 6 shows a silicon activation gravel pack log for Well #1. Although a standard analysis indicates some possible small voids, this is misleading, since no known mechanism exists to provide voids at and slightly above the very top of the upper screen. The most likely situation is that the added steel of the shunt tubes and normal statistical variations in silicon activation logs account for the occasional log interpretations of deviations from 100% packing efficiency. In addition, the shunt tube stand-off

from the screen is not uniform and occasionally a shunt will lie directly against the screen. This also will tend to cause variation in the silicon activation log. The vertical line on the log indicates the position of the almost certainly packed zone at the top of the screen. In all probability, the annulus was completely packed.

The apparatus design for Well #2 varied primarily in that two of the shunts had 3/32 inch holes at 5-ft intervals over the entire length and the other two had holes every 5 feet only over the bottom 100 feet of the perforated interval. Holes were offset so that at least one hole occurred every 2.5 feet across the pay zone. This design followed long tube experiments which showed that unperforated shunts provide excellent slurry transport along the unperforated length.

Well #2 was packed with the same methodology used for Well #1, except that 36 #XC/ 1000 gal. clarified gel was used as the carrier fluid. It was felt that the high inclination angle and excessive length required a longer sand settling time than was needed for Well #1. No problems were encountered either in running the screen or pumping the slurry for Well #2. One noteworthy occurrence was that approximately 10 minutes after the slurry reached the crossover, a rapid 300 psi pressure rise was observed. At that point, the pump rate was dropped to 2.25 bbls/min and the pumping pressure stabilized at approximately the initial value. Pumping continued at this rate and pressure for another 8 minutes, at which time pumping pressure began to rise again, with a high pressure (2600 psi) sand-off occurring 3 minutes later. It is speculated that the first pressure rise indicated formation of a complete annulus bridge near the top of the completion interval, and the later somewhat steady rise indicated dehydration of the pack for this relatively viscous carrier fluid.

Figure 7 shows a silicon activation gravel pack log covering the top 145 feet of the 220-ft screen. The previous comments regarding packing efficiency once again apply. The logging tool wouldn't slide below this level and was not forced lower for fear of retrieval problems. Once again, within our evaluation capability, the pack appears to be complete over the logged interval. Approximately 0.24 cu ft of sand was placed per foot of perforated interval.

Both test wells were put on production and flowed efficiently with little drawdown. As a result of these successful completions, reserves not otherwise available were added for Well #1 and the cost of breaking the zone into two completions was saved for Well #2. Following these excellent test results, the new procedure was adopted as a standard operation. Six more zones have since been completed with packing results similar to the test wells.

CONCLUSIONS

1. The ALLPAK™ gravel packing method eliminates bridges and voids which occur with current practices.

2. The prototype system has successfully packed over 200 feet of interval and is adequate for packing intervals up to 300 feet or more at any deviation angle.
3. The apparatus is compatible with current technology and can provide insurance whenever potential problems are anticipated.
4. The apparatus apparently enhances fracturing along the wellbore, raising the possibility of low rate fracturing over extended vertical intervals. This would provide superior productivity over longer completion lifetimes.

ACKNOWLEDGMENTS

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TABLE 1

Summary of ALLPAK™ Testing on Gravel Pack Simulator

Test	No. of Shunts (-)	Comments	Pack Type (-)	Shunt Size (in)	Hole Size (in)	Hole Density	Pack Efficiency (-)
1	0	w	circulation				75
2	2	w	circulation	0.824	3/16	2 per 1'	90
3	2	w	squeeze	0.824	3/16	2 per 1'	100
4	0	x	circulation				80
5	0		squeeze				70
6	2		circulation	0.75	1/8	1 per 1'	90
7	2		squeeze	0.75	1/8	1 per 1'	100
8	2	w	circulation	0.824	1/8	1 per 2'	95
9	2	x	circulation	0.824	1/8	1 per 2'	95
10	2	y	circulation	0.824	1/8	1 per 2'	95
11	0	z	sque-circ				65
12	4		circulation	1X0.5	3/32	1 per 2'	95
13	4		circulation	1X0.5	3/32	1 per 2'	98
14	4		sque-circ	1X0.5	3/32	1 per 2'	98
15	4	x,z	sque-circ	1X0.5	3/32	1 per 2'	99
16	4	z	circulation	1X0.5	1/16	1 per 4'	95
17	4	z	sque-circ	1X0.5	1/16	1 per 4'	95

Comments: w - Run with 40#/1000 gal HEC gel
 x - Run repeated with same result
 y - Run with water and 4#/gal sand concentration
 z - Run with 40/60 sand

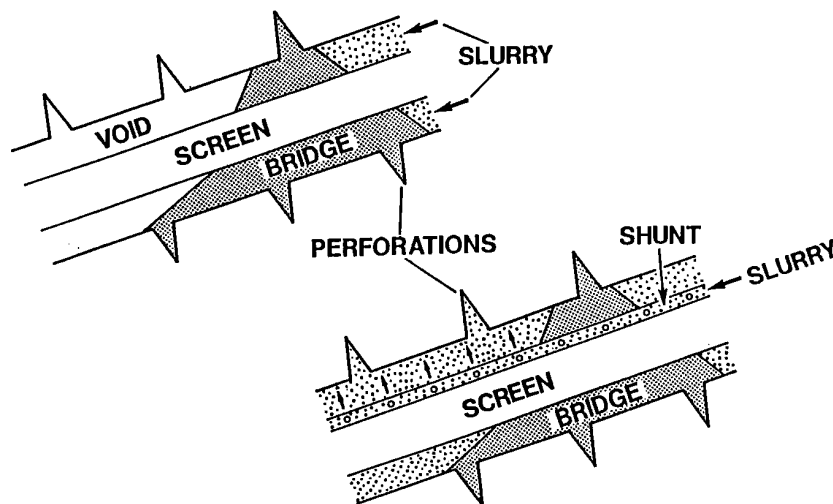


Figure 1 ALLPAK™ (Alternate Path Gravel Pack) Mechanism

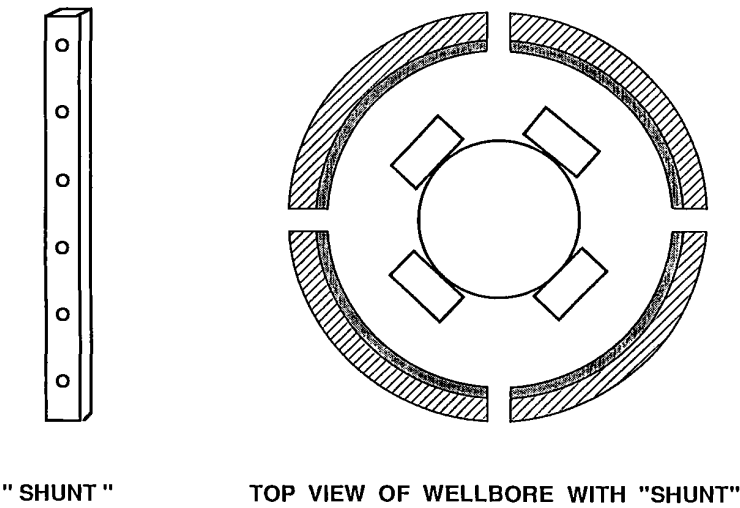


Figure 2 Schematic of ALLPAK™ Assembly

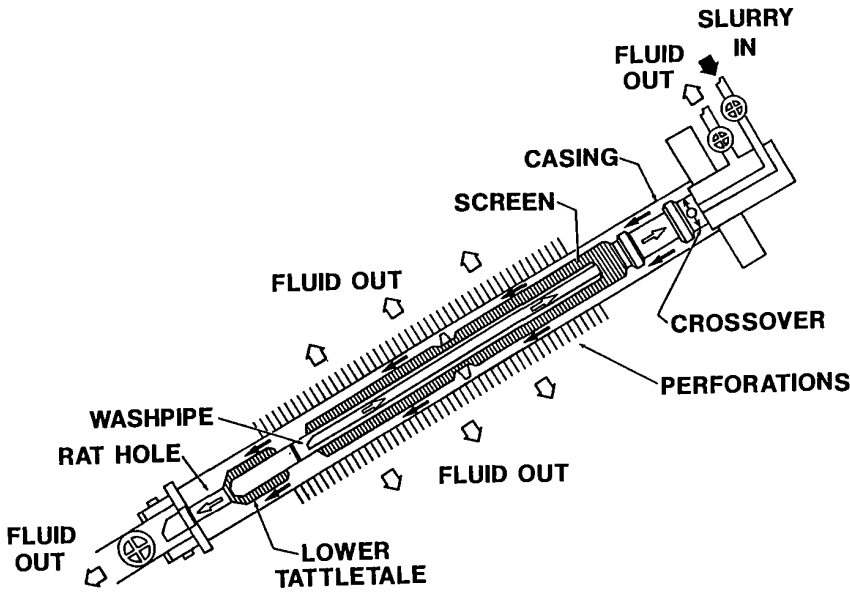


Figure 3 Schematic of Gravel Pack Simulator

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SPE 22796

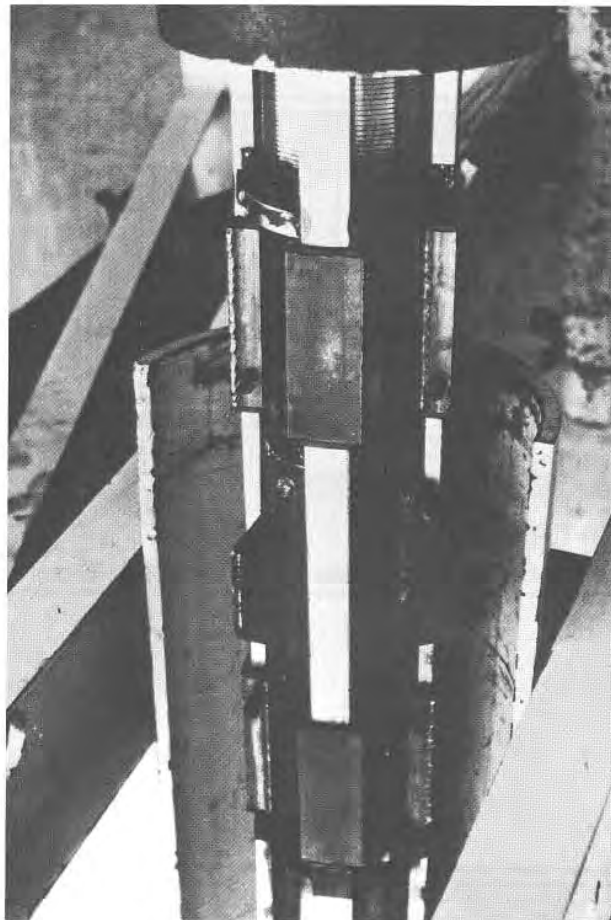


Figure 5 Field Type Shunt Connectors

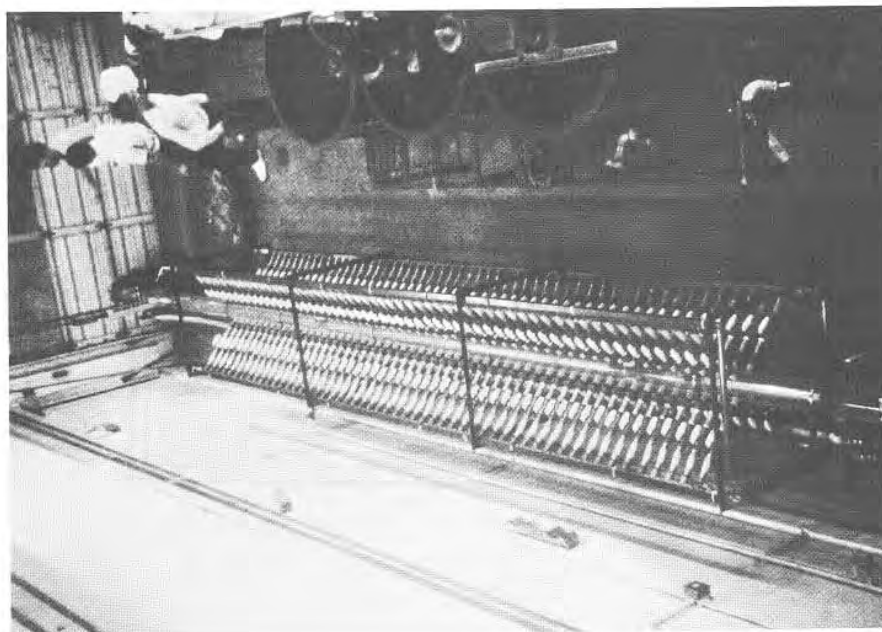


Figure 4 Gravel Pack Simulator

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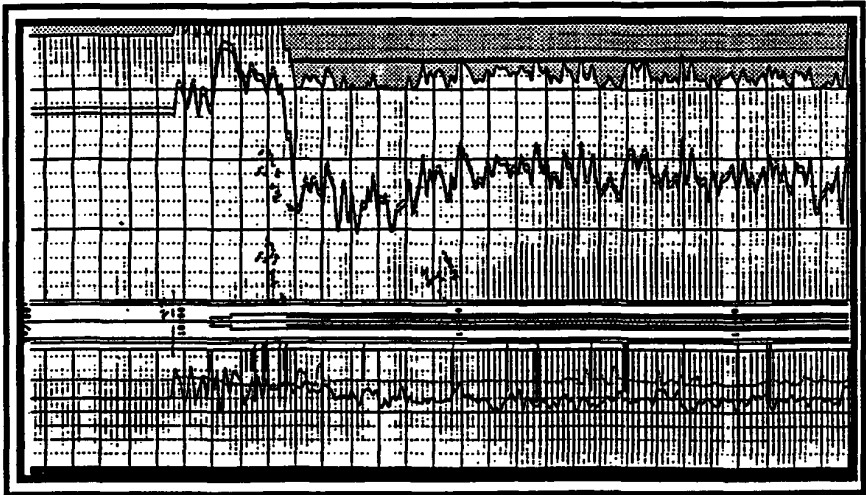


Figure 7 Well #2 with ALLPAK™

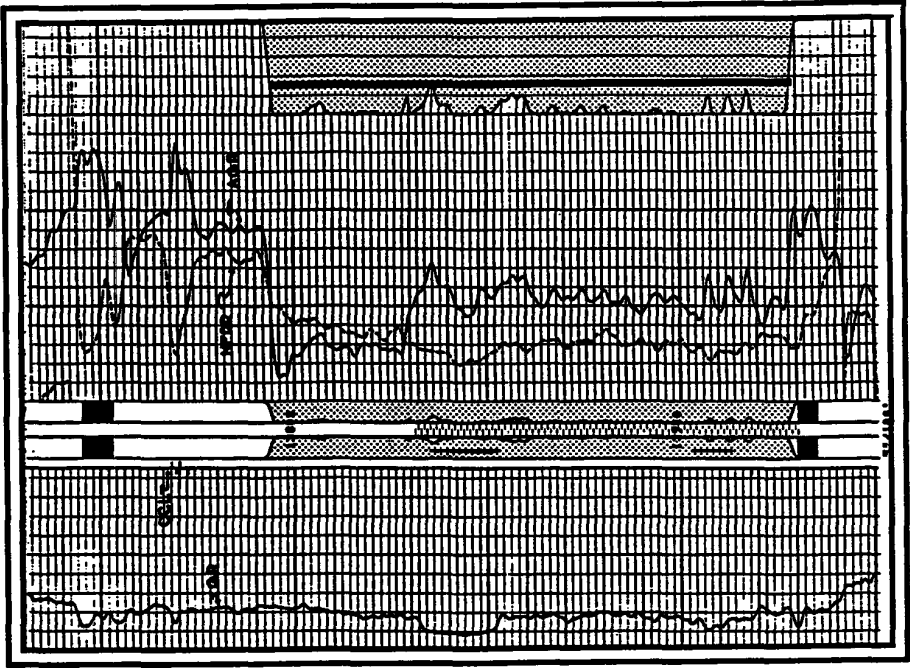


Figure 6 Well #1 with ALLPAK™

EXHIBIT D



SPE 86532

Alternate Path Completions: A Critical Review and Lessons Learned From Case Histories With Recommended Practices for Deepwater Applications

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Abstract

Since its introduction, over 700 alternate path sand control completions have been implemented around the world ranging from single zone cased hole gravel-packs to multi-zone frac-packs and fibre optic (DTS) enabled open hole horizontal completions. Over the last six years, the alternate path system has been field proven to provide high reliability in achieving complete packs as well as additional features allowing simultaneous cake cleanup, shale bypass and other contingencies that enable “doing it right the first time” in deep-water/subsea completions where interventions tend to be economically and logistically prohibitive.

This paper provides a critical review of those completions, capturing both successes and failures, along with the lessons learned in their design, execution and evaluation in relation to completion efficiency in sanding reservoirs. Furthermore, it details future development work and enablers that will allow the use of alternate path technology as the mainstay of intelligent well solutions, geometrical design improvements to provide optimal aspect ratios in the wellbore and its applicability in conjunction with water packing.

Introduction

Alternate Path is a technique that was developed to bypass any annular blocking that may occur during the completion process due to various reasons. Its original design consisted of steel rectangular tubes (also called shunt tubes) welded on screens, where the tubes had holes for exit of the slurry out of the tubes and into the annulus once the blocked annular

section is bypassed. This original design was intended primarily for use in cased-hole gravel packs. As such, this design (tubes with relatively small flow area and with holes drilled on) was sufficient for the pump rates, slurry volumes and the interval lengths that are commonly encountered in those applications. During the last six years, various improvements were made to the original design to address the specific needs for a variety of applications as discussed in the next section.

Although the initial applications of the alternate path technique have been directed towards improvement of gravel placement in cased holes, its current applications in frac-packing and open-hole horizontal gravel packing significantly outnumber cased hole gravel pack applications, in line with higher popularity of frac-packs and open hole gravel packs as reliable sand control techniques that yield high-productivities, particularly in deep-water/subsea environments. Thus, the review will focus primarily on alternate path case histories in these two areas, although examples of cased hole gravel packs will also be included for completeness.

The paper is organized as follows. First, we summarize the evolution of the alternate path system, highlighting the reasons for each improvement along with the benefits and potential disadvantages or limitations. We then continue with a discussion of the cased-hole followed by open-hole applications of the alternate path, providing some statistical information, along with a brief review of representative case histories as well as lessons learned for each application and some key considerations to ensure successful applications in the future. This is followed by a summary of further improvements that are currently being worked on. Finally we draw conclusions.

Evolution of the Alternate Path System

Optimization of Hole Size

The first improvement involved the optimization of the hole diameter on the shunt tubes. A series of yard tests were conducted with various hole diameters (3/32-in to 1/4-in) using gravels from 40/60 to 12/20 U.S. mesh. These tests indicated that bridging could occur when the hole diameter to mean gravel diameter ratio is less than approximately 5, preventing exit of the slurry out of the shunt tubes. Noting that the ratio of the largest to average grain diameter for each U.S. mesh gravel is approximately 1.3, this rule corresponds to 4 for the hole size to largest gravel size ratio. Thus, it is more

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conservative than the conventional bridging rules that have been established based on single size particles,¹ and based on rules developed for flowing conditioned mud systems through wire-wrap screens.² On the other hand, if the holes are made too large, then leakoff through these holes (into either the base-pipe/wash-pipe annulus or into the formation) becomes excessive, dehydrating the slurry and resulting in gradual increase of gravel concentration downstream of the shunt tubes, and an eventual screen-out within the shunts; thus, the need for optimization of the hole size.

Nozzles replaced the holes on the shunt tubes in current alternate path screens as discussed below, although the findings mentioned above are valid and used in the nozzle design.

Introduction of Larger Tubes

The second extension of the alternate path evolved along with the popularity of frac-packing as well as long open hole horizontal gravel packs as sand control techniques. The original shunt tube design with 0.5x1.0-in external (0.31x0.81-in internal) dimensions did not provide sufficient flow area for the pump rates that are typically used in frac-pack applications, resulting in high frictional pressure drops through the shunt tubes.

Similarly, long open hole horizontal gravel packs may limit the pump rates due to increased frictional pressure losses. In both cases, the limitation is the burst pressure of the shunt tubes, which is currently 5,000 psi.

The tube dimensions were modified to 0.75x1.5-in external (0.56x1.31-in internal), yielding 3 times the flow area of the original design and reducing friction pressures over the rates of interest by approximately an order of magnitude, for long horizontal gravel packs. This of course was at the expense of a reduced base pipe diameter, which in many instances does not impact well productivity in either frac-packed or gravel-packed horizontal completions, although this should be verified through reservoir simulators that couple friction in the wellbore with the pressure drop through the reservoir.

Holes to Nozzles with Tungsten Carbide Inserts

The third improvement was the replacement of holes with nozzles with tungsten carbide inserts. This modification was a result of earlier experiments conducted with the original shunt tube design. In these experiments, shunt tubes with 30-ft length containing 22 holes of 1/8-in diameter were used with the end of the shunt tube blocked, forcing all the slurry through the holes. An 80-lb/1,000-gal HEC solution with 2.0-ppa 40/60-U.S. mesh gravel was injected at 2.0 bbls/min. The key observations can be summarized as follows:

1. Holes closer to the inlet section of the shunt erode very quickly, as most of the flow occurs through these holes, and
2. As those holes elongate (increased flow area) with further erosion, all of the slurry flow occurs through the first several holes,
3. After 5 mins (10-bbls) of slurry injection, the first hole had already elongated to 0.4-in, growing to 0.6 and 0.8-in after 10 and 20 minutes, respectively.

Based on these results, as the holes become larger due to erosion, the leakoff rates would be increasing, with the same result as in use of large holes to begin with; i.e., increased gravel concentration and bridging within the shunt tubes.

In order to eliminate this concern, the holes were replaced with nozzles with tungsten carbide inserts. **Figure 1** shows some of the results for erosion testes where nozzles with and without Tungsten Carbide inserts were submitted to extreme slurry velocities.

Based on the hole-size optimization tests, combined with the nozzle design as well as additional experiments for confirmation, the recommended nozzle diameters for commonly used gravel sizes are given in **Table 1**. Note that gravel sizes up to and including 16/30 U.S. mesh can be used with 1/4-in nozzles, while 3/8-in would be required for 12/18 U.S. mesh, with a nozzle length of 5/8-in in both cases.

Note also that an additional advantage of the nozzles is reduced leakoff due to a small-diameter linear flow cell packed with gravel, once the annulus in that section is packed, further minimizing the risk of bridging in the shunts due to increased gravel concentration downstream of the shunts.

Introduction of Packing & Transport Tube Design

Even with the nozzle design, gravel packing of long horizontal completions may be difficult due to leakoff through the packed nozzles and thus the increased gravel concentration downstream leading to screenout in the shunt tubes. Following calculations, rather simplistic but instructive, illustrate how simply using shunt tubes with nozzles can lead to a failure due to bridging in the shunt tubes.

Figure 2 shows the rheology profile of a typical viscoelastic surfactant fluid used in open hole gravel pack applications with the alternate path technique. As seen, the rheology profile follows the Carreau model, exhibiting low-shear and high-shear plateaus, with a high-shear Newtonian plateau of 40 to 50 cp for this particular fluid formulation. The value of the high-shear plateau as well as the shear rate value at which it is observed depends on various parameters, including VES type and concentration, brine type and density, and temperature. As the shear rates in the packed nozzles are for the most part in the region where the high-shear Newtonian plateau is observed, we shall use 40 cp for the fluid viscosity, for illustration purposes. Using a lower viscosity will further strengthen our arguments.

Consider an interval of 2,000 ft, that will be gravel packed with 2 transport tubes at 4-bbls/min using 5.0 ppa VES slurry, with the transport tubes having 5 nozzles (1/4-in diameter) per shunt joint and each joint being 30-ft in length. Assume further that a bridge formed at ~1,000 ft from the heel and the first 1,000-ft section was subsequently gravel packed. Considering 1-psi/ft of friction pressure at 2-bbls/min per transport tube, and assuming that the decrease in friction pressure due to reduced flow rate in the shunts as a result of carrier fluid leakoff through the nozzles will be balanced by the increase in friction pressure due to increased gravel concentration due to leakoff, the total leakoff rate can be shown to reach the value where all gravel particles have grain-to-grain contact (i.e., bridging inside the transport tube) at ~1,000-ft.

Consider now the packing and transport tube arrangement shown in **Figure 3**, with 5 nozzles of 1/4-in diameter, first nozzle on the packing tube 1.5-ft away from the branching point of the transport tube. Considering the same example as above, with the same assumptions, it can be shown that the leakoff rate at the same 1,000-ft point would be reduced by more than an order of magnitude, thus no risk of bridging inside the transport tubes due to leakoff.

The advantages of the packing/transport tube arrangement include reduced friction through the use of larger tubes for transport, reduced leakoff through the use of smaller packing tubes that branch of the transport tubes, and reduced make up time due to lower number of connections between screen joints. These in turn yield longer distances to be packed in horizontal completions.

Leakoff Tubes

For gravel to be deposited in a given area, the slurry must dehydrate through leakoff either into the formation or into base-pipe/wash-pipe annulus. In open hole gravel packs, where there is a competent filtercake, appreciable leakoff can occur only into the base-pipe/wash-pipe annulus. Thus, at the connection area of the screen joints, the only way the gravel packing can proceed is if the fluid can leakoff through the deposited gravel pack and into the subsequent base-pipe/wash-pipe annulus.

The time it takes to pack the joint section will be a function of the pressure, pack permeability, fluid rheological parameters, annular area, and the length of the connection area. The latter can vary from ~ 3.5 to 5.5 ft in horizontal applications where premium threads are used. In order to ensure rapid packing of the connections, the leak-off tube concept was introduced. A small shunt tube with slots on it is currently being used as the leakoff tube to speed up the slurry dehydration (**Figure 4**). Note that in cased and perforated wells leakoff occurs externally and thus leakoff tubes are not needed.

Concentric versus Eccentric Design

One disadvantage of the alternate path system is the reduced base-pipe diameter due to presence of the shunt tubes. When the tubes are placed concentrically around a screen of fixed base-pipe diameter, the external dimensions become larger compared to when the tubes are placed eccentrically (**Figure 5**).

The key advantage of the eccentric design is the increased base-pipe size, allowing, for example, 5.5-in base pipe in an 8.5-in open hole. The disadvantage of the eccentric design is that the gravel pack thickness is lower on one side compared to the other.

Timed Premium Threads for Connections

Many horizontal applications, reservoirs with compaction problems and most deep-water environments require premium threads, to eliminate potential separation of screen joints during either installation or production (due to compaction). In addition, since there is no control over the circumferential

alignment from one joint to the next with the standard connections (leading to non-aligned shunts which could not be connected with jumper tubes), a timed premium thread was developed to torque the connection and align the shunt tubes simultaneously.

Manifold Design

In long horizontal completions, due to large number of joints and the jumper tube connections needed at each joint of screen, additional costs are incurred because of increased rig time. A manifold system was thus developed (**Figure 6**) to eliminate jumper connections and reduce rig time. With this design, the outer shroud and the inner base pipe are connected simultaneously, with the annular area between the outer and the inner strings creating a manifold. Although effective in reducing screen make up (thus rig) time; with the existing design, this system is limited to 4.5-in base pipe for 8.5-in open-hole applications. In addition, its heavy weight and cost of manufacturing are areas that need improvements for this design to be an attractive option for long horizontal completions.

Concentric Entrance

For horizontal gravel packs utilizing the eccentric design, another improvement of the alternate path system was the introduction of the concentric entrance, also known as Y-manifold, pictured in **Figure 7**. This design ensures that there is at least one transport tube in the top section of the horizontal well, providing a path for continuation of the gravel pack job in cases where long shut down periods may result in gravel settling and thus blocking of the entry to the shunt tubes, should the shunts end up on the low side.

Multi-Zone (MZ) Isolation Design

The MZ (multi-zone) packer, in **Picture 8**, was developed to allow for multiple zones to be completed in a single trip, with a single pumping stage, thereby saving significant rig time as well as eliminating the use of fluid loss control pills that are typically required in two or multi-trip completion operations. The MZ packer is a cup type packer with shunts in the cup/base-pipe annulus.

The upper zone is packed conventionally, while the lower zone is packed by diversion of the slurry through the shunts bypassing the cup packer. Because the cup-packer assembly is only 6-ft in length, it allows isolation in multiple sand bodies separated by relatively thin shale sections. This is compared to conventional stacked completions that require a minimum of 15 to 20 ft spacing.

This technique can be (and has been) used for frac-packing multiple zones, gravel packing multiple zones as well as frac-packing one zone and gravel-packing the other in one trip and one pumping operation. Fracturing or gravel packing of each individual zone is dictated by the rate of slurry diverted into each zone, which in turn is controlled by the frictional pressure drops within the shunts delivering slurry into each zone. For a given fluid composition and gravel concentration, friction and thus the pressure applied to each zone can be

controlled through the shunt tube dimensions (diameter and length) as well as the nozzle diameter and frequency.

The cup packer provides isolation of the casing/screen annulus (in a blank section), and thus an internal isolation would also be needed in order to selectively produce or isolate each zone. In many instances, this internal isolation is achieved by placing a sliding sleeve inside the screen across each zone. This allows for flexibility in terms of shutting off zones that are producing undesired fluids (water or gas). The same configuration can also be used to selectively produce each zone one at a time. Alternatively, an isolation string can be run to the lower of two zones below a production packer, and two tubing strings can be run above the production packer to simultaneously and selectively produce two zones.

There are two versions of the MZ-packer. The first one does not allow for a positive isolation, as there is hydraulic communication between the zones through the shunt tubes. In this case, limiting the production of undesired fluids relies purely on the linear flow cell created by the packed shunt tubes, which can reduce water production substantially as simple calculations using Darcy's law would indicate. The second version of the MZ-packer incorporates isolation valves to provide a positive isolation of the packed shunt tubes. These valves are actuated using a collet mounted to the wash-pipe. Driving the collet through the shifting sleeve in the down-hole direction opens the valve, while pulling it up through the shifting sleeve closes the valve.

Alternate Path with Fiber Optics

In line with the recent developments in downhole monitoring technology, a new alternate path screen was designed to allow for the installation of fiber optics in horizontal wells. In this design, the conventional alternate path protective shroud is dimpled (**Figure 9**) to allow the placement of a dual control line flat pack for post-job deployment of fiber optics for real time downhole temperature monitoring. This system, in its open hole version, was field tested recently, while its cased hole version is currently being developed.

Cased Hole Applications

Cased-hole alternate path applications account for approximately 86% of the worldwide job count to date (since 1996), totaling 624, with most of the applications in the Gulf of Mexico. Recent trends indicate an increasing acceptance of the alternate path technique in deepwater environments, in frac-packing longer intervals (over 200-ft of perforations) and wellbores with deviations above 70°.

Of the 624 cased-hole applications, 191 were conventional gravel packs, 163 were various applications of the multi-zone packer technology, and 270 frac-packs.

Multi-zone packer applications consisted of 19 frac-packs (4 with more than one multi-zone packers) and 144 gravel packs (9 with a multi-zone packers incorporating isolation valve).

Table 2 shows the screen lengths versus job count for cased hole frac-pack applications of alternate path. The kh varies in

the frac-pack applications varied up to 120,000 md-ft, and the fluids were crosslinked guar and viscoelastic surfactants in 90 and 10% of the cases, respectively. Well types range from oil or gas producers to water injectors.

Several variations of the technology are field proven, some of which are documented in the literature:

- Single and multi zone sand control,³⁻⁸
- Multi-zone sand control with zonal isolation (i.e., using the Multi-zone packer as isolation device),⁹
- Single-trip perforating and sand control treatment in single or multiple zones (with the Multi-zone packer),¹⁰⁻¹³
- Single-trip gravel packing and production,^{10, 12}

Case Histories

The case histories below are used to illustrate the versatility of the alternate path technology, illustrating some of the completion scenarios listed above.

Case history 1: Single Trip Perforating and Frac-Pack Treatment in 322-ft Gas Producer (Far East)

The completion of this gas well was described earlier by Burton et al.¹³ In this case, effective sand control was achieved with a 10 to 15% increased dry gas production versus initial projections (110 to 115 MMSCFD compared to 100 MMSCFD).

The deviation across the productive interval was 50° and the gross perforated length was 322-ft (284-ft net) with 18 spf underbalanced. Two large shunt tubes were used, eccentrically positioned on the screens.

In this application, 48% of the treatment (27,100 lbs of proppant) was pumped through the shunt tubes, at 12 bbls/min with 8-ppa slurry. This example illustrates the versatility of the alternate path system and how it can be of critical value in some completions.

Case history 2: Frac-Pack Treatment in a Deep-Water Gas Producer (Gulf of Mexico)

This gas well was successfully completed in the Gulf of Mexico in a challenging environment. This application was on a well with a measured depth of 15,144-ft, with a perforated interval of 230-ft at an inclination of 72°, a reservoir pressure and temperature of 7,612-psi and 220°F at a water-depth of 3,500-ft. The kh of this formation was 118, 000 md-ft.

Two large (transport) tubes were mounted on a 4.5-in base pipe screen. 180,000 lbs of 20/40 proppant were placed with 30-lbs/1,000 gal of cross-linked guar fluid (over 700 lbs per foot of perforation) at an initial pump rate of 40 bbls/min, which was reduced to 25 and 10-bbls/min upon indication of slurry diversion into the shunts. 24% of the total proppant was pumped through the shunts. This completion resulted in a near-zero skin with a sand free production of 80 MMSCFD.

Case history 3: Multi-Zone Gravel Pack (South America)

The alternate path multi-zone technology enabled optimization of reserves exploitation in several fields, where traditional selective completions (i.e., multiple trips for hardware installation and multiple pumping jobs) wouldn't be economically viable. These applications involve gravel packing multiple productive zones with a single tools-run followed by a single pumping stage.

The Dacion field case study is a representative example of this approach.⁹ Cost reduction associated with the elimination of completion trips as well as the optimization of the expected post-completion workover had a significant impact on the project economics of this field development. One of the case histories reported by Marshall et al.⁹ describes application of this technology to a well with three zones that are separated by thin shale sections, allowing zonal isolation which could not have been achieved with conventional stacked completions.

Case history 4: Frac-Pack Treatment in a Deep-Water Water-Injector (West Africa)

The subject well was completed with a 9.625-in. casing set at 12,000-ft measured depth, perforated nearly balanced with a 0.7-in perforation diameter and 12 spf. The perforated interval was 328-ft (measured) over a 166-ft zone (vertical). The single-trip perforating and packing technique could not be used due to lack of a rat hole. After perforating a crosslinked HEC fluid loss control pill was spotted to control losses during the trip. After running the completion assembly, which included 350-ft of alternate path screens, with two large tubes (0.75 by 1.5-inch) eccentrically placed on 5-in. base pipe, to TD, and setting the packer, an acid treatment was performed to break the fluid loss control pill. This was followed by a mini-frac. A 27-lb/1,000-gal borate crosslinked guar with an aggressive breaker schedule was used in the main treatment, with an initial pump rate of 35 bbls/min. 103,000-lbs of 20/40 ceramic proppant was placed below the crossover as per design. The reservoir pressure and temperature were 3,300-psi and 194°F, respectively, and the average permeability of the formation was 200 md. The resulting injectivity index in this completion was 26.3 bwpd/psi, with a skin of -1.4.

Lessons Learned and Recommendations

The high flow rates and large slurry volumes associated with frac-pack jobs introduce certain challenges to the alternate path technology, due to high velocities in the shunt tubes as well as the nozzles. The consequences of these flow conditions can be categorized as potential erosion, collapse, or burst, although the latter two are extremely unlikely in frac-packing applications. This is because there is always a hydraulic communication through the nozzles, which prevents exceeding the burst pressure limit, and use of shunted blanks of proper length minimizes the risk of exceeding collapse limit. Additional cased-hole specific concerns are related to the applications of multi-zone packer as discussed below.

The first, and crucial, learning is that the nozzles on each shunt tube attached to a screen (when using the eccentric design) must point outwards to avoid high velocity proppant hitting the other shunt tube. If this happens, the shunt tube will be eroded by the slurry, in addition to deflecting part of the flow to erode the screen jacket inducing loss of sand control. This effect was observed in a frac-pack job. After the treatment, the service tool and the wash-pipe were pulled out of the hole, and wash-pipe was visibly eroded and ruptured. After this observation, the screens were washed over and fished. Surface inspections of the retrieved screens confirmed erosion of one of the shunt tubes and the screen jacket in areas adjacent to the eroded shunt tube, due to improper nozzle positioning.

Erosion of the shunt tubes can also be induced by high flow rates through the shunts. Based on experiments conducted with shunt tubes, it was determined that erosion of the tubes themselves is not a concern as long as the flow rate is kept at or below 8 bbls/min and 2 bbls/min per tube for the large and small tubes, respectively. Above these rates, erosion becomes a function of total slurry volume passed through the tube. When/if an annular bridge forms, an increased fraction of the slurry diverts into the shunt tubes, as the resistance to flow increases due to continued packing above the bridge, resulting in a change in the slope of pressure versus time plot due to higher friction in the shunts. Cases where the slope becomes large ($>> 1$) indicate potential wellbore screenout. In such cases, the injection rate should be reduced to the rates given above.

In long shunted blank sections, where the tubes do not have nozzles, or when the tubes dedicated (i.e., without nozzles) to the lower zone in multi-zone completions are long, special attention must be given to the design. In such cases, due to large frictional losses in the tube (high rates and lengths) and full hydraulic communication in the annulus, the risk of exceeding the collapse pressure of the tubes must carefully be considered. This has been identified as the most plausible reason for a failure in a multi-zone frac-pack application. The collapse pressure of the large shunt tubes is 2,200 psi.

In the early designs of the multi-zone packer, difficulties were experienced while passing the elastomer cups through restrictions, such as the wellhead. This necessitated grinding the cups down on the rig floor, resulting in additional rig time. This was subsequently addressed by adding a beveled gaugering below the lower elastomer cup.

Open Hole Applications

Open-hole alternate path applications account for approximately 14% of the worldwide job count from 1996 to date, totaling 101, while they accounted for approximately 30% of the total job count in 2003. In 92% of the open-hole applications, visco-elastic surfactant fluids were used, while the rest with 2 exceptions were gravel packed with an HEC fluid, the latter mostly in dry gas wells. 80 of the 101 applications were with open-hole section at an angle greater than 80°. In this paper, we will define horizontal as being greater than 80°.

Of the 80 horizontals, 7 were completed with the manifold design, while the remainder was with the eccentric design. Approximately 46% of the horizontal completions were in wells drilled with oil-based fluids, and 35% of those drilled with water-based fluids were gravel packed using the simultaneous gravel packing and cake cleanup technique, incorporating enzyme, chelating agent solution or both in the carrier fluid for filtercake cleanup. **Table 3** shows the screen lengths versus job count for open-hole applications of the alternate path.

The alternate path technique is an alternative approach to water-packing in cases where the latter historically had relatively high rates of incomplete packing, as well as in high-risk areas where remediation can be prohibitively expensive.¹⁴ The alternate path applications in open holes included:

- Conventional open hole gravel packs (using a wash pipe and in circulation mode),¹⁵
- Conventional open hole gravel pack in circulation mode but without wash-pipe,¹⁶
- Open hole gravel pack above frac pressure,¹⁷
- Partial cake cleanup prior to gravel packing a water injector,
- Open hole gravel pack with full losses in circulating position,¹⁸
- Open hole gravel packs with filtercake cleanup chemistry incorporated into the gravel packing fluid,¹⁹⁻²³
- Open hole gravel pack in squeeze position, below²⁴ and above frac pressure with¹⁷ and without²² filtercake cleanup chemicals in the carrier fluid,
- Open hole frac-pack,²⁵
- Open hole gravel packing of two sands separated by a long (530-ft) shale break,²³
- OHGP in wells drilled with OBM using water-based¹⁸ and oil-based²⁶ carrier fluids

In open-hole completions, rapid dehydration of the slurry through high leakoff rates into either the formation or the screen, as well as localized hole-collapse or excessive swelling in highly reactive shale sections can cause a premature screenout in the absence of shunt tubes.

High leakoff into the formation may occur due to various reasons including filtercake liftoff, filtercake erosion, inclusion of filtercake cleanup chemicals in the gravel pack carrier fluid, and exceeding the fracturing pressure of the reservoir. Filtercake liftoff occurs when an underbalance is encountered, for example during tool manipulations, and if the fluid in the wellbore is a solids-free fluid, and thus there is no material to reestablish the filtercake. Tool systems that provide hydraulic communication between the upper-hole and the open-hole, throughout the completion process, minimize this risk and should always be considered as an integral part of any open-hole completion. For environments with a small operational window for fracturing, valves that divert flow into the wash pipe at preselected positions can be utilized to provide a short cut for returns and thus minimize the risk of building excessive pressure (thus fracturing) during the beta-wave of a water-packing treatment.

Thus, although two of the problems historically encountered in water-packing have, to some extent, been

addressed, the others still remain as issues of concern for a successful outcome of water-packing treatments. Filtercake erosion, evidenced as a gradual loss of returns, does occur in some instances. A well-documented case is an application discussed by Gilchrist et al.²⁷ where a synthetic/oil-based reservoir drilling was followed by water-packing. Note that although cake erosion is more of a concern in wells drilled with S/OB fluids, it is also observed in water-based drilling environments. Unpublished experimental work²⁸ demonstrated that internal cakes formed by properly designed reservoir drilling fluids (RDF) can alone be sufficient to control losses into the formation, regardless of the fluid type (S/OB or WB). Considering that a properly designed RDF limits the invasion of solids into the formation to a few grain-diameters, it is postulated that cases where gradual reduction in return rates leads to a premature screenout in water-packing are formations with low compressive strengths. In such cases, erosion of a few layers of formation sand (similar to but more severe than wash-outs during drilling due to absence of cake forming materials during gravel packing) would lead to increased losses due to removal of the internal cake as well as the external cake.

Another potential reason for premature termination of the alpha-wave is the incorporation of filtercake cleanup chemicals into the carrier fluid (brine). This has been demonstrated through laboratory experiments by Brady et al. to be a risky technique for water-packing, where they proposed an alternative approach of using a post-gravel-pack circulation tool to spot cleanup chemicals immediately after water-packing.²⁹ Note that the simultaneous gravel packing and cake cleanup technique proposed in conjunction with the alternate path technique³⁰⁻³² has been applied in an appreciable portion (~ 35%) of the open hole gravel packs in wells drilled with water-based fluids.

Localized hole-collapse and reactive shale sections continue to be challenges for the application of water-packing technique in open-holes, where alternate path provides assurance. Although the shunt technique can provide this assurance for complete packing (e.g., bypass of collapsed, sloughed shale bridges, swelled shales, etc.) as well as minimizing risk of shale mixing with gravel due to lower velocities compared to water packing, the risk of shale mixing with gravel would still be present when gravel packing with water-based fluids unless some precautions are taken. There are at least two ways of handling this, if a water-based fluid (e.g., VES) is used for gravel packing:

1. Do not use wash pipe at all: This would ensure gravel packing from heel to toe including the shale sections. Main disadvantages of this approach would be: (a) Alternate Path is the only path, as gravel packing would be through the shunt tubes from the beginning to the end (see case history highlighted below), (b) No wash down capability, (c) No downhole gauges, and (d) Does not allow for displacements after RIH with screens, (e) Does not allow spotting of cleanup chemicals immediately after gravel packing. Main advantages are: (a) No extended exposure of shale sections to water base fluids as packing will proceed from heel to toe and shale sections can also be packed with screen across those sections, (b) Don't have to deal with losses while pulling the wash pipe

should losses occur, (c) Lower cost (rig time savings and rental), (d) No risk of stuck wash pipe.

2. Use a wash-pipe with holes across shale sections: Compared to no wash-pipe at all, this option would allow downhole gauges while ensuring bridging across the shales and subsequent packing of the shale section as well as downstream of the shales through the shunts. This would isolate the shale sections, and prevent mixing of shales with gravel.

An alternative approach in reactive shale environments would be to use a synthetic/oil-based (S/OB) carrier fluid, if reservoir drilling is performed with a S/OB fluid. Such an approach has recently been successfully implemented on a high-rate gas well, incorporating filtercake cleanup chemicals into the carrier fluid after drilling with a reversible S/OB-RDF.²⁶

Below are several case histories highlighting some of the unique applications of the alternate path technique in open-hole completions.

Case History 1: Open-Hole Gravel-Packing without Wash-Pipe (Kazakhstan)

The subject well was in a remote location, 300-km away from the nearest city, presenting a major logistical challenge.¹⁶ In addition, the 3,000-ft horizontal open hole combined with shallow reservoir meant that the screens would be 1,000-ft into the open hole before the gravel-pack packer was connected on the rig floor. The location had a limited water supply for completion operations, and the field economics necessitated that everything be working correctly the first time.

The open-hole section was drilled with an RDF consisting of CaCO_3 , Biopolymer and Starch. Subsequently, the open hole was displaced to a solids-free RDF and the cased hole to filtered brine, screens were run to TD and the packer set. As indicated by an increase in slope of pressure versus time plot, an annular bridge formed shortly after slurry arrival to the open hole, and the packing continued through the shunt tubes. Note that the packing with alternate path technique proceeds from heel to toe in high-leakoff conditions (either into the formation or into the base pipe (in the absence of a wash pipe) as demonstrated through yard testing. This well was gravel packed using a viscoelastic surfactant fluid, with 33% excess gravel based on gauge hole (no caliper log), using less than 10% of the brine volume that would have been needed for water packing. Production from this well, 1,250 bopd with an associated 35 bwpd, three times the production obtained from an offset well completed with a slotted liner.³³

Case History 2: Open-Hole Gravel Packing above Frac Pressure (Gulf of Mexico)

A 277-ft of open hole was drilled horizontally (85 to 90°) using an RDF consisting of CaCO_3 , Biopolymer and Starch.¹⁷ At TD, open hole was displaced to a solids-free RDF and the cased hole to a KCl brine. After running the screens in hole, setting and testing the packer, the slurry consisting of a viscoelastic surfactant solution and 8 ppa 40/60 resieved sand was spotted to within 5 bbls of the service tool, before shifting the tool to squeeze position. After pumping a significant portion of the slurry in squeeze, the rate was reduced and the

service tool was shifted to circulating position to achieve final screenout at 6,000 psi. Amount of gravel placed below the crossover tool was greater than 150% of the volume around the screens and the blank pipe.

The carrier fluid in this application also contained an enzyme for starch removal and a chelating agent solution for CaCO_3 dissolution. Initial production from this well was 12 MMSCFD, with a near zero skin. After a year, the well was still producing at 2.5 MMSCFD with an associated 2,300 bwpd sand-free.

Case History 3: Open-Hole Gravel-Packing in Oil-Based Mud Environment (West Africa)

The paper by Chambers et al.¹⁸ described the very first successful applications of gravel packing wells drilled with oil-based fluids. These wells were displaced to a solids-free viscous fluid in the open hole and a completion-brine in the cased hole, prior to running in hole with shrouded alternate path screens. After the screens were at TD, packer was set and tested, and the gravel pack treatment consisting of a viscoelastic surfactant carrier fluid and 30/50 ceramic-gravel was spotted in the work string in reverse position. The treatment was pumped with the tool in circulating position. In two of the three wells, significant losses were observed, although all three wells were completely packed. Resulting production rates were in excess of 10,000 bopd with a lower drawdown than all the previous horizontal wells drilled with water-based reservoir drilling fluids. In fact, the normalized PI's from these wells were up to three times higher than those obtained with previous practices, which included post-gravel-pack acid treatments.

Case History 4: Open-Hole Frac-Packing (Indonesia)

This was the first and only reported frac-pack application in an open-hole environment, to our knowledge.²⁵ A well in a very challenging high kh (~100,000 md-ft) formation in a low frac gradient environment with a very low reservoir pressure was almost going to be lost. Very high losses were experienced during drilling, the presence of a high-pressure, reactive shale section above the sand necessitated running a 7-inch casing prematurely, in order to isolate that section. Furthermore, collapse of the shale section resulted in setting the casing above the target exposing 70-ft of shales. Although the original intent was a cased-hole frac-pack, the events that occurred during drilling as well as completion attempts led to a change of direction towards open-hole frac-packing.

In this application, a multi-zone packer was utilized below the gravel-pack packer in order to bypass the exposed shale section through large shunt tubes without holes, forcing all the slurry into the shunts. The driver for this approach was prevention of shale mixing with the proppant (and the resulting poor fracture conductivity). Approximately 22,000 lbs of 20/40 ceramic proppant was placed below crossover ports. The open-hole interval was 224-ft, with a 47-ft of net target sand, at 70° inclination. The gross production rate from this well was 2,000bfpd, with a net in excess of 500 bopd, well beyond expectations. Note that high water cuts are typical of the wells in this area, regardless of the completion type. The

resulting PI compares very favorably to both cased hole frac-packs and open-hole horizontal gravel packs, particularly considering the excessive losses experienced while drilling this well.

Case History 5: Simultaneous Gravel-Packing and Cake-Cleanup of Two Sands Separated by a Long Shale Section (Deep-Water North Sea)

This is the longest open-hole gravel packing application with the alternate path technique to date. The subject well penetrated through two sand bodies separated by a 530-ft shale section, with a total open-hole length of 3,075-ft. The open-hole section was drilled with a CaCO_3 /Biopolymer/Starch RDF and gravel packed with a viscoelastic surfactant fluid containing an enzyme and a chelating agent solution, using a 30/50 ceramic proppant which was slowly ramped from 2 to 6 ppa in order to provide a smooth transition from pad to slurry properties. As detailed elsewhere,²³ this well was completely packed based on an average 8.63-in hole (nominal hole: 8.5-inch). With an initial production rate of 20,500 STB/D and an estimated skin of zero, the sand-free cumulative production from this well was 2.1 MMSTB as of mid-October, 2003.

Case History 6: Open-Hole Gravel Packs in High-Rate Gas-Wells (Trinidad)

The southeastern Trinidad gas basin has proven to be a challenging environment for sand control. During the development of these fields, standalone screen, frac-pack and cased-hole gravel pack completions have each been implemented with mixed success. Open-hole gravel-pack completions have provided the most effective solution in achieving life-of-well sand control integrity for new wells. After using the water-packing technique initially, the alternate-path technique was introduced for open-hole gravel packing in Trinidad, increasing the ability to achieve successful sand control treatments. Highlighted below are two of these case histories.

The first well was relatively shallow (5,310-ft TVD), with 10.75-in casing set at 90° in the target sand at 6,952-ft MD. The 1,667-ft open-hole was drilled and underreamed to 9.5-in with a 9.8-ppg water-based (biopolymer, starch, carbonate) RDF. The open-hole section was displaced to a solids-free RDF and the casing to brine prior to running the screens in hole. Open hole was displaced to brine prior to setting the packer. The carrier fluid used in this application consisted of an HEC solution with an oxidizer as the internal breaker. After pumping all the premixed HEC fluid, there was no screenout and approximately half of the gravel that was supposed to have been pumped was still in the silo. There was a problem with the surface mixing/monitoring system and as a result the gravel concentration in the slurry was half the targeted value. At this point, two alternative approaches could be taken: either reverse out the slurry in the work string, mix more HEC and proceed with pumping, or continue gravel packing with brine using lower gravel concentration (0.5 to 1.0 ppa). The second option was implemented, and the well was gravel packed successfully. The initial mechanical skin of approximately 20 had reduced down to a final skin of about 3.9 over a period of

several weeks (~ 4 to 6 weeks), with an initial production rate of 180 MMSCFD.

The second well was deeper (9,650-ft TVD), with 10.75-in casing set at 12,294-ft MD. The 507-ft, 9.5-in open-hole section was drilled with a 9.2-ppg water-based RDF of similar composition as in the first well. Again, the open-hole was displaced to a solids-free WB-RDF, the cased hole to brine prior to running in hole with screens, and the open hole displaced to brine prior to setting the packer. This well was gravel packed successfully, using a 9.2-ppg HEC as the carrier fluid, with an internal breaker. A post-gravel-pack cleanup treatment consisting of a chelating agent solution and an enzyme was spotted into the open hole, prior to pulling the service tool and wash-pipe out of the hole, using a post-gravel-pack circulation tool. This well resulted in a mechanical skin of 1 with an initial rate of 247 MMSCFD.

These results appear to indicate that the post-gravel-pack filtercake cleanup treatments in these *high-rate-gas wells* only accelerate filtercake cleanup that eventually occurs over a several-week (4 to 6 weeks) time period through flow back. It should be noted that many of these wells are either tubing limited or constrained by erosional velocity limitations of surface flow lines. Skin variations in the range of 1 to 4 results in a negligible change in production rates.

Lessons Learned & Recommendations

Typically longer hole lengths in open hole completions introduce certain challenges in designing gravel-packing treatments with the alternate path technique. In addition to the collapse considerations as discussed earlier, the burst pressure limitations of the shunts must be kept in mind, which can impose an upper limit for treatment rates once the slurry diverts into the shunts. While lower rates address this concern, they may create concerns as to gravel settling in the vertical and inclined sections of the work string, which imposes a lower rate limit for the treatment. In addition to settling, collapse and burst considerations, paying utmost attention to the fluid compatibility issues is critical to the success of gravel packing with the alternate path technique.

Gravel suspension characteristics of the carrier fluids for the alternate path technique has been identified as a key consideration since the early development of the concept. Poor suspension can lead to:

1. Gravel settling in work string: This has been identified as the reason for failure on three occasions. In one case, a new viscoelastic surfactant fluid was in field trial stages. This application was in a four-well gas development in the North Sea. In one of the applications, a rubber seal in the chiksan lines on the rig floor had blown, resulting in a 10-minute shutdown period. As detailed by Campbell et al.,¹⁵ post-job analyses through yard and laboratory testing indicated that this particular VES fluid had temporarily lost its visco-elasticity after passing through the pumping equipment, and the rehealing of the fluid (recovering viscoelasticity) was time dependent, taking longer at low temperatures. This loss of viscoelasticity resulted in settling of the gravel in the work string and bridging at the

crossover ports, yielding an incomplete pack on this well. An additive was subsequently identified to address this problem.²¹ Similar settling related problems have been identified in two other occasions as the reason for incomplete packing. In both of these cases, a shutdown had occurred as a result of either a surface leak or inability to feed gravel to the fluid due to wet-sand, and the shut down period was in excess of tolerable time period based on sand settling test results.

2. Gravel settling in the shunt tubes: Prior to diversion of the slurry into the shunts, a relatively small fraction of the slurry flows in the shunts as the flow is shared between the annulus and the shunt tubes based on relative friction pressures in each section. If the gravel settles in the shunt tubes, as more of the flow is diverted into the shunts, higher velocities will result in picking up the settled gravel and thus increased gravel concentrations in the slurry or pushing the bed downstream. This can result in bridging within the shunts, causing a premature screenout. Another mechanism that can lead to bridging in the shunt tubes is leakoff through the ports in sections that are already packed. This can lead to increased gravel concentrations downstream and eventual bridging in the shunts, thus a premature screenout. This has been addressed through the development of the packing and transport tube arrangement, which minimizes leakoff.
3. Gravel settling in shunted blank area: On one occasion, a shut down occurred and the slurry was reversed out of the hole after a portion of the slurry was below the cross over port. During the shunt down period, the gravel had settled above the entrance of the shunts, which were lying on the lower side of the casing. This resulted in development of the concentric entrance design.

Another issue that must be kept in mind in alternate path gravel packing treatments is the burst pressure limit of the shunt tubes, which is 5,000 psi. High friction in long intervals can necessitate reduction in flow rates in order to stay below this limit. This is one of the reasons why viscoelastic surfactant fluids are preferred in alternate path applications, as these fluids are lowest friction systems available in the industry as evidenced through their extensive use in fracturing applications through coiled tubing. Note that even with higher friction fluid systems, rate reduction can lead to complete packing without exceeding the burst limit of the shunts, when fluids with excellent sand suspension characteristics are used.²⁶

Fluid-fluid compatibilities are very critical to successful outcome of alternate path applications. The fluid trains involved in the treatment must be carefully evaluated for the entire completion process. For example, most commonly used VES fluids are sensitive to mutual solvents. In one application, a mutual solvent used for flushing the lines was left in the lines, and lack of communication between various service companies led to water-like VES slurry with 5 ppa gravel being pumped downhole, and an immediate screen-out at the

service tool as indicated by down hole gauges at the top of the screen. Other considerations include high-density brines or oil-based fluids in the wellbore. In such cases, VES formulations that are either insensitive to high-density brines or less sensitive to oil-based fluids should be used.

Future Applications

Current work for extending alternate path applications focus on gravel packing with brines as well as gravel packing with VES fluids in oil-based fluid environments. Extensive testing both in the laboratory and large-scale models indicate that some VES formulations are less sensitive to oil-based fluids contamination. Although these fluids lose their viscosities over time periods of interest in putting the well on production, they tolerate contamination within the time periods of gravel packing. The driver for this approach is the elimination of the requirement for displacement to water-based fluids prior to running the alternate path screens in the hole (and thus a predrilled liner run) when VES fluids will be used for gravel packing due to their unmatched retained permeability characteristics in areas where compatibility with the crude oil has been demonstrated.

Another area that is being worked on is the ability to gravel pack with the alternate path using brines. This involves modifications in shunt tube design. This approach is expected to be ready for field-testing early 2005.

Conclusions

Alternate path technique has evolved significantly since its introduction over eight years ago. With over 700 treatments, this technique is field proven for both cased (624 treatments) and open-hole (101 treatments) applications. Multizone packer applications of alternate path allow exploitation of otherwise uneconomic reserves through a single-trip completion of multiple zones. Alternate path also enhances applicability of frac-packing technique to longer intervals and offers additional assurance for complete gravel packing of open holes in challenging environments.

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Figure 1 – Shunt tube nozzles after erosion tests showing nozzles with (right) and without (left) Tungsten Carbide inserts.

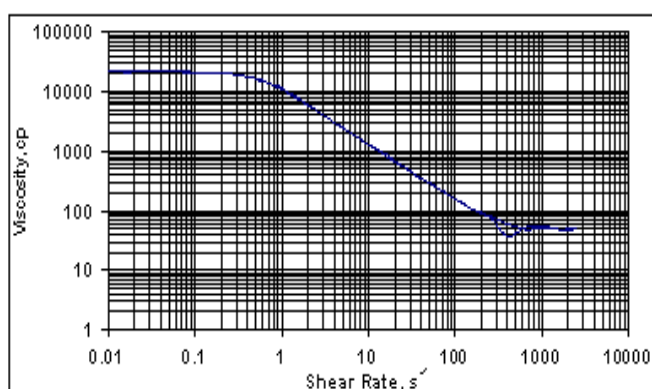


Figure 2 - Rheology profile of a VES fluid: 7.5% VES-HT in 9.8-ppg CaCl_2 brine, 170°F.

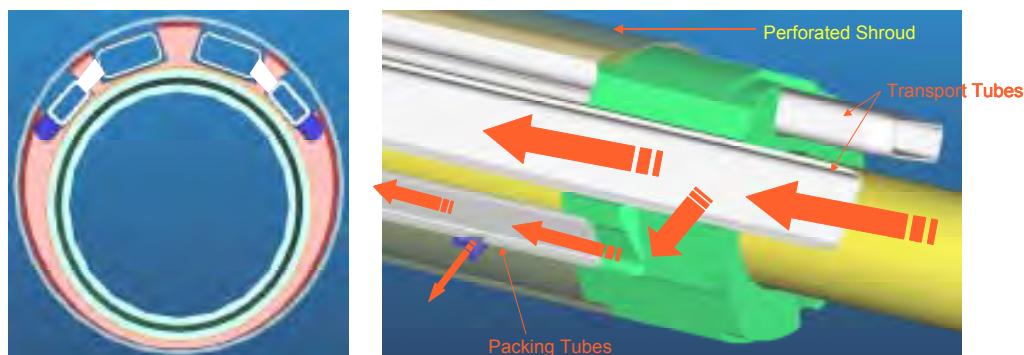


Figure 3 – Transport and Packing tube arrangement. Cross-sectional view (left) and flow pattern schematic (right).

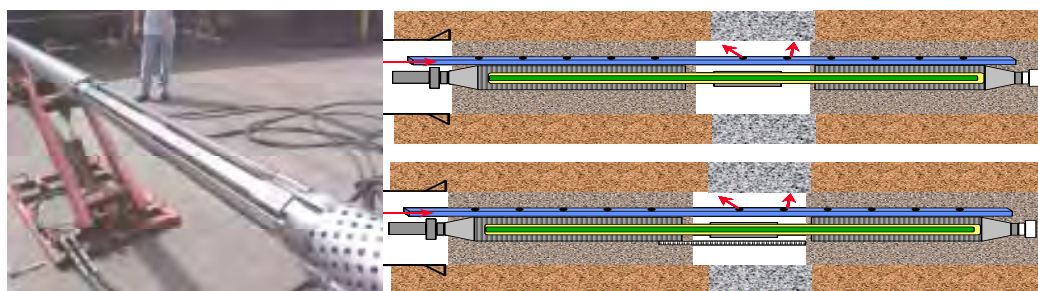


Figure 4 – Leak-off tube action (right) providing a pathway for fluid flow from blank area to screen jacket and installation photo (left).

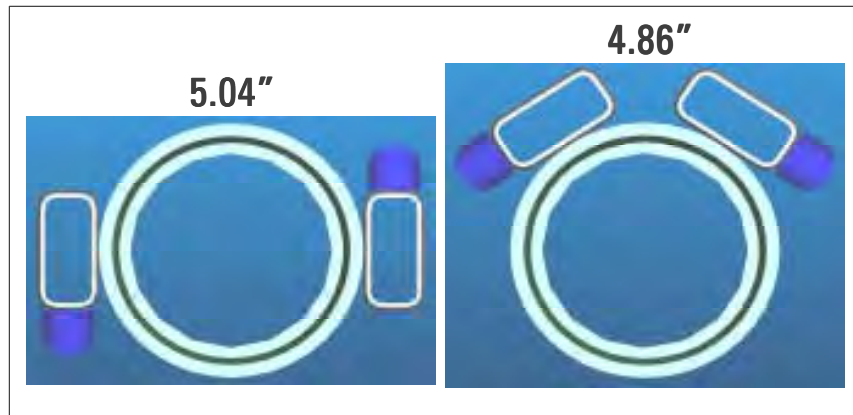


Figure 5 – Example of outer diameter reduction with eccentric design (right) versus concentric design (left).

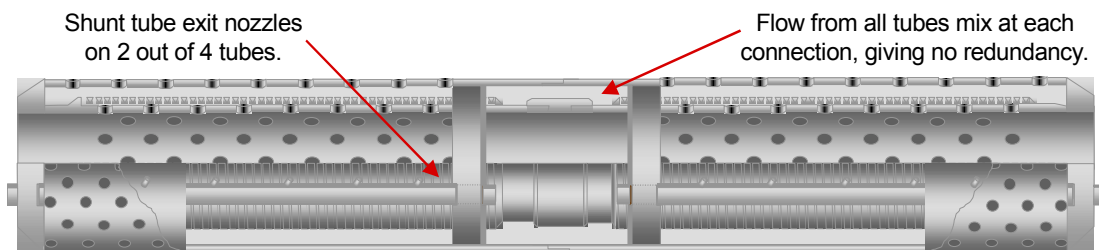


Figure 6 – Manifold connection schematic.

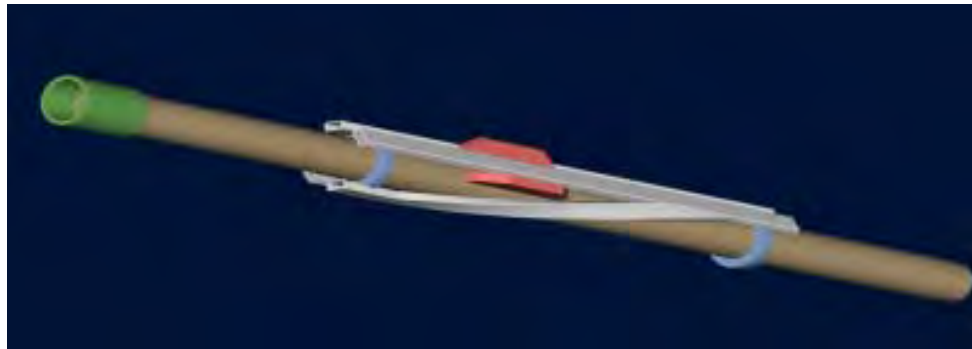


Figure 7 – Concentric Entrance (Y-manifold).



Figure 8 – Multi-zone packer. Note the beveled gauge ring close to the pin end.

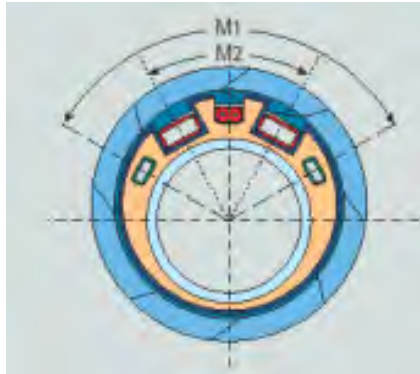


Figure 9 – Cross sectional representation of Alternate Path screens with a dimpled shroud for control line twin flat pack installation (in red) and later deployment of fiber optics.

Gravel U.S. Mesh	¼-in Nozzles		3/8-in Nozzles	
	Nozzle-to-Mean Gravel Diameter Ratio	Nozzle-to-Largest Gravel Diameter Ratio	Nozzle-to-Mean Gravel Diameter Ratio	Nozzle-to-Largest Gravel Diameter Ratio
40/60	19.0	15.1	28.4	22.7
20/40	10.1	7.6	15.1	11.3
16/30	7.3	5.5	10.9	8.3
12/18	4.9	3.9	7.3	5.9
8/12	3.1	2.6	4.7	3.8

Table 1 - Nozzle Diameter versus Gravel Mesh Size.

Screen Length (ft)	Job Count
< 100	107
100 – 200	105
200 - 300	34
> 300	24

Table 2 - Screen Lengths in Cased-Hole Frac-Pack Applications of Alternate Path.

Screen Length (ft)	Job Count
> 2,000	7
1,500 - 2,000	5
1,000 - 1,500	15
500 - 1,000	35
< 500	39

Table 3 - Screen Lengths in Open Hole Applications of Alternate Path.

EXHIBIT E



SPE 135102

Extending Openhole Gravel Packing Capability: Initial Field Installation of Internal Shunt Alternate Path Technology

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Abstract

High angle, openhole completions are often selected to maximize production and reserve capture from several non-homogeneous sand packages in a single wellbore. Many times, the wells will require some form of sand control. Standalone screen applications may often times be the most cost effective and simplest form of sand control, but the formation characteristics may dictate that a gravel pack is necessary. Circulating water packs, alpha-beta gravel packs, have been used worldwide, but may be challenged to achieve a complete gravel pack in certain applications. Alternate Path[®] technology (APT), using the current eccentric two by two (2x2) shunt system, has proven to be extremely reliable in completely packing the openhole annulus and delivering high rate, failure free openhole completions.

Although routinely deployed, the current eccentric 2x2 APT screens have both technical and operational limitations. These limitations may include:

- Maximum shunt system working pressure of 3,000 psi which limits the packable length to ~3,200 ft pumping at 5 barrels per minute (bpm)
- Risk of plugging with two independent shunt tubes extending the length of the completion
- Complexity of rig site connection make-up as oriented connections and cross-coupling jumper tubes are required
- Deployment exposure dictates that an outer shroud must be incorporated in openhole applications to protect the shunt tubes

In order to overcome some of these limitations, while preserving all of the benefits of Alternate Path technology, a new generation of gravel pack screens was developed and successfully run utilizing Internal Shunt Alternate Path Technology (ISAPT). ISAPT extends openhole packable length, increases shunt tube redundancy across the entire interval, improves rig site installation efficiency, reduces deployment exposure, and provides a platform to incorporate specially designed shunt packers to provide true openhole zonal isolation.

This paper will discuss the key differences between the new ISAPT gravel pack screens and the current eccentric 2x2 APT screens as well as validation of key objectives from the first field installation.

Background

High rate, high capacity, long-life wells are essential for the long-term economic success of deepwater developments. Due to the high cost of performing remedial workovers, a reliable form of sand control is desirable. Additionally, applications for longer completion lengths and high angle completions are increasing as the cost to develop deepwater plays continue to rise. In summary, there is a need to produce more hydrocarbons from fewer wells.

When gravel packs are required for sand control, the operator has two options for gravel packing high angle completions, the alpha-beta technique or gravel packing with APT. Alpha-beta gravel packing is used in high angle wellbores and relies on an alpha wave, controlled by fluid velocity, to deposit a gravel bed on the low side of the openhole. Fluid returns are required to ensure a full gravel pack in the annulus as the beta wave packs from the toe back to the heel. Many operating environments do not have sufficient frac margin to allow the beta wave to fully pack back to the heel. In long interval or heterogeneous reservoirs, additional monitoring and control features/programs have been used to achieve the goal of a complete gravel pack, but they also increase the complexity in both completions tools and operations (Pedroso 2005, Pedroso 2008), which are not desirable under rising cost, more remote, or more challenging well conditions. Some operators are satisfied with simply covering the screens. There is evidence that simply covering the screens is not sufficient and could lead to early screen failures. Localized, high permeability streaks may flush away the thin layer of sand covering the top of the gravel pack screens, resulting in direct impingement of formation sand on the screen. Formation sand may also mix with the gravel in a loose pack to reduce the permeability of the annular pack. Potential sanding and reduced permeability risks are not acceptable in high rate, high cost wells when only a few wells are drilled to develop a resource. Alternate Path technology was developed to consistently deliver fully packed, highly productive, and reliable wellbores.

Evolution of Alternate Path Technology

Single Shunt Tube Design - The original shunt tube design includes a continuous ported shunt tube mounted on the outside of a jacketed screen (**Fig. 1**). The shunt tube provides an alternate path for the slurry to bypass any premature bridge that may form in the annulus. The shunt tube remains inactive until the top of the screen is covered with gravel, then slurry is diverted through the shunt tubes to bypass any bridge and gravel packing continues until the annulus is fully packed. This design seemed to work well for relatively short intervals (< 100 ft); however, laboratory testing (Jones 1997) identified the potential to plug the shunt tubes in lengths > 100 ft as gravel concentration increased throughout the shunt tubes due to fluid leaking off through the ports.

Staggered Shunt Tube Design - In an attempt to gravel pack longer intervals, multiple shunt tubes were placed on the outside of the screens and portions of the ports were plugged off in the shunt tubes to allow packing further along the wellbore (**Fig. 2**). The concept would be for each shunt tube to pack a segment length of < 100 ft along the wellbore. If three shunt tubes were used, shunt tube A would have ports only along the top 80 ft, shunt tube B would be responsible for the next 80 ft and shunt tube C the next. This approach had its limitations with the number of shunt tubes that could be placed on the outside of the screens without sacrificing too much of the base pipe diameter. Even with four shunt tubes installed, the overall length one could gravel pack would be less than 400 ft.

Eccentric 2x2 Design - As industry pushed into deepwater developments in the mid 1990's, long openhole completions became more popular, maximizing oil recovery from fewer wells. The current eccentric 2x2 Alternate Path system was designed to ensure complete gravel packs beyond the 400-ft limitation of the previously described system. The eccentric 2x2 system has two types of shunt tubes attached externally to standard screen hardware, (non-ported) transport tubes and (ported) packing tubes. Transport tubes form a continuous conduit along the entire length of the completion and deliver fluid to packing tubes that branch at the top of each screen joint (**Fig. 3**). Packing tubes contain nozzles spaced approximately every 6 ft to deliver gravel slurry to the annulus. After exiting the nozzles, the slurry packs the nearby annulus or continues to pack down the annulus until another bridge is reached. Once the annulus is packed alongside the packing tube, slurry continues down the transport tube until another region of unpacked annulus is encountered. Since shunt packing progresses from top down, leakoff to the formation is minimized and the risk of prematurely plugging the transport tubes is significantly reduced. The rectangular-shaped tubes and an eccentric cross-sectional screen design as shown in Fig. 3 minimize the effective outside diameter of the assembly. An outer shroud covers the entire assembly, providing shunt tube protection during openhole installation.

The eccentric 2x2 system requires the use of timed connections on the screen base pipe to line up the shunt tubes of the two screen joints about to be made up. Once the connection is made, cross coupling jumper tubes are installed to form the continuous conduit from one screen joint to the next screen joint. A shroud is later placed around the connection for protection. The complexity of the connection slows the running of the screen joints at the rig site.

The eccentric 2x2 system has been used to gravel pack wells up to lengths of 3,200 ft in hole angles up to 93° and across hundreds of ft of shale with great success (**Fig. 4**) (Yeh 2008; Jones 1999; Bryant 1995; Tibbles 2000; Hurst 2004; Wilson 2004; Powers 2006; Whaley 2007). However, requirements for longer openhole gravel packs are ever increasing as environments become more challenging. The 3,200-ft limitation is due to the friction pressure associated with pumping through shunt tubes along the entire openhole interval. In-house best practices limit the shunt friction pressure to 3,000 psi to maintain reliability in the shunt packing system.

As the industry continues to drill longer extended reach wells, completing the wells may reveal additional challenges. Historically, short, openhole completions may intersect one or two pay intervals. The long openhole completions associated with many extended reach wells may intersect up to five or six pay intervals. The eccentric 2x2 system is ideal for completing the entire interval, given the length limitation mentioned above; providing unwanted water and gas are not encountered. The lack of zonal isolation capability can begin to minimize the initial benefits of the fully gravel packed openhole completion. Due to these situations and the potential limitations of the eccentric 2x2 design, an alternative solution was required.

ISAPT - A new and enhanced screen design has been developed and qualified (Barry 2007) to further extend the technical limits in Alternate Path gravel packing. The new design is an extension of field proven technology. The ISAPT screens incorporate nine round shunt tubes, six transport tubes and three packing tubes, protected by the wire wrap (**Fig. 5**). The wire wrap is applied using direct wrap screen technology (Moen 2001). The transport tubes are non-ported and run continuous throughout the length of each joint. The packing tubes are closed at the bottom of the screen joint and contain nozzle rings spaced approximately 6 ft apart. At each nozzle ring, 3 discharge nozzles are phased 120 degrees. At the top of each joint of screen, a manifold is present where slurry from the transport tubes of the previous joint is redistributed and can flow into any of the transport or packing tubes of the next joint of screen (**Fig. 6**). The transport tubes and packing tubes are no longer paired together as in the previous eccentric 2x2 design. This coaxial manifold increases shunt redundancy and further reduces the risk of shunt plugging, thereby increasing the probability of a successful gravel pack over the entire length of a completion. This feature is particularly important in completion intervals requiring prolonged gravel packing and allows the bypassing of any localized plugging in a transport tube that may occur when extending gravel pack lengths.

The coaxial manifold not only reduces the risk of plugging a single shunt tube over the length of a completion, but it also simplifies field make-up by eliminating the timed connections and cross coupling jumper tubes of the eccentric 2x2 design. The connection is based on a standard premium connection with a concentric outer sleeve. The connection design facilitates easy rig floor make-up similar to conventional tubing handling operations.

By migrating from rectangular shunt tubes to round shunt tubes, the working pressure of the shunt system increases from 3,000 to 6,500 psi. The shunt system of the new ISAPT screens has been tested to 10,000 psi. With the increase in working pressure, a length of 5,000 ft can now be packed at a rate of 4.5 bpm extending the length limit by more than 50%.

Internal shunt openhole packers, currently under development, will take advantage of the new ISAPT concentric screen design to provide zonal isolation. The openhole packers will be set prior to gravel packing, thereby providing a hydraulic and mechanical seal to the borehole before any gravel can be placed around the element. During pumping operations, once gravel covers the top of the screens, slurry is diverted into the shunt tubes, tightly packing the openhole above the packer, then passes through the packer and continues to pack below the packer via the shunt tubes. Internal shunt openhole packers enable gravel pack completions to gain the current flexibility of standalone screen (SAS) applications by providing future zonal isolation of unwanted fluids with the reliability of a gravel pack completion.

Initial Field Installation

After the completion of an extensive testing and qualification program for the ISAPT screens, the following objectives were set for the first field installation:

- Verify ease of the new screen handling / make-up equipment during field installation of the ISAPT screens
- Assess ISAPT screen make-up times and compare to that of the eccentric 2x2 APT screens
- Verify drag estimates for running a completion equipped with ISAPT screens
- Assure full gravel pack placement using the new ISAPT screens
- Verify shunt tube friction of the ISAPT screens and compare to eccentric 2x2 system field data and ISAPT qualification tests

The operator has extensive experience installing openhole gravel packs around the world, especially in West Africa developments. One such development, offshore Angola, provides excellent case histories with continuous improvements. Angola Block 15 is located approximately 90 miles off of the northwest coast of Angola. The KSJ-103 ST2 well was selected for the first installation of the new ISAPT gravel pack screens. This well is part of the Kizomba B Development and was a sidetrack from an existing wellbore on Tension Leg Platform 'B' (TLP-B). With the 9 $\frac{5}{8}$ -in. production casing set at 11,313 ft, the 9 $\frac{5}{8}$ -in. hole section was drilled to a total depth (TD) of 13,659 ft with an inclination between 85 and 90°. The openhole interval consisted of 144 ft of 12 $\frac{1}{4}$ -in. hole below the 9 $\frac{5}{8}$ -in. casing shoe, 1,962 ft of 9 $\frac{5}{8}$ -in. hole, and 240 ft of 8 $\frac{1}{2}$ -in. hole to TD. Since a large interval of shale was encountered in the bottom section of the well and the hole inclination was nearly horizontal, a decision was made to install screens

just below the base of the bottom sand at 13,298 ft rather than TD. The lower completion consisted of 54 joints of ISAPT gravel pack screen, two joints of shunted blank and one top joint.

One drawback of the current eccentric 2x2 design is related to the complexity of the rig site connection make-up given the need for oriented connections and the requirement to install cross coupling jumper tubes and shroud. This complexity slows the make-up and running speed of the screens to an average of approximately five joints per hour. The coaxial manifold system of the ISAPT screens eliminates these issues and significantly improves the overall make-up times for shunted screens. This design enhancement required a change in the handling and make-up equipment for the ISAPT screens. Due to the shape of the coaxial manifold system, a conventional bowl and slip arrangement could not be utilized to support the ISAPT screens while hanging in the rotary; therefore, a clam-styled landing spear was designed and tested. Additionally, a load collar was developed to place around a specially designed groove below the outer sleeve of the coaxial manifold to allow the screens to be picked up with conventional elevators. This same load collar is then temporarily used to support the weight of the screens when placed on the landing spear in the rotary.

A single joint compensator was used for each joint to ensure the pin was carefully stabbed into the coupling while not damaging the seal face of the coaxial manifold. Once the joint was successfully stabbed, the connection was made up hand tight with a strap wrench prior to using conventional power tongs and manual backup tongs to make-up to the final torque. The assembled screen sections were then picked up off the landing spear and the load collar on the lower screen section was removed (and subsequently installed on the next available joint of screen waiting on the pipe conveyor). The landing spear was opened and the assembly was lowered through the rotary. As the top of the assembly neared the rotary, the landing spear was closed and the assembly was slowly lowered until the load collar engaged the top of the landing spear. The process was repeated until all of the screens and blanks were run. All of the special running and handling equipment performed as expected.

A total of 57 connections were made up while running the ISAPT screen assembly and a peak run time of 10 joints per hour was obtained. This make-up time is consistent with make-up times of conventional tubing and is a significant improvement over the five joints per hour average for the eccentric 2x2 design. Each joint was successfully made up and no screen joints were laid down due to handling or make-up issues. The peak running time validated the assumption of improved rig site efficiency with the ISAPT design by the elimination of the timed connections and cross coupling jumper tubes of the eccentric 2x2 design.

The design of the ISAPT screens inherently makes the assembly more rigid which could make it more difficult to run to TD on long and highly deviated wells. While the ISAPT screens were successfully being run to the desired depth on 5½-in. drillpipe, pickup and slack-off weights were periodically recorded and plotted versus a range of expected values. A simulation with an overall cased hole friction factor of 0.20 and openhole friction factor of 0.25 was determined to best represent the actual value (**Fig. 7**). This combination of friction factors was found to be comparable to completions utilizing the eccentric 2x2 design on similar wells drilled from the TLP-B.

After successfully running the lower completion to the predetermined depth, the gravel pack packer was set and the well was prepared for gravel packing. The NAFpacSM process (Hecker 2004) was used to gravel pack the well. The open hole was swept with gravel pack gel by placing the fluid into the annulus, shifting the service tool into the gravel packing position and pumping down the casing annulus, through the wash pipe, up the open hole by screen annulus, and into the drillpipe. The service tool was shifted back to the reverse position and the drillpipe was reversed out. While still in the reverse position, 5.1 ppa (pounds of proppant added per gallon) slurry was spotted to the gravel pack service tool and the tool was shifted to the weight down position. The gravel pack pumps were brought back online at 5 bpm with full returns.

After pumping approximately 18,300 lb of proppant below the crossover tool, slurry was diverted through the shunt tubes resulting in a pump pressure increase of 217 psi (**Fig. 8**). **Fig. 9** shows the pressure increase of 217 psi on the bundle carrier reading drillpipe pressure, located one stand above the service tool. In deepwater environments, the production casing shoe is typically set off the bottom of the drilled hole for ease of space out. The productive interval is later drilled, but the larger rathole remains under the casing shoe, typically 15 to 35 ft in length. During normal gravel packing operations with a viscous fluid, the openhole by the screen annulus is gravel packed, toe to the heel, and the larger rathole is typically not fully packed. With APT, slurry is diverted into the shunt tubes after the screens are covered inside the production casing,. The 30 to 65 ft of annular space between the screen and casing are typically tightly packed, so the first exit port for the slurry, once it passes through the shunted blank joints and top screen joints, is immediately below the production casing shoe in the larger rathole. The sharp increase in pressure due to pumping through the shunt tubes will decrease slightly at this point as the slurry exits the shunt tubes. The sharp increase in pressure is used to calculate a shunt friction pressure gradient by dividing the initial pressure increase (217 psi) by the length of

shunt tubes from the top of the shunted blank to the casing shoe (135 ft). The shunt friction gradient of 1.6 psi/ft at 5 bpm from the KSJ-103 ST2 compares favorably with the friction numbers seen during pre-job modeling and full scale testing. An additional $\pm 33,000$ lb of proppant were pumped through the shunts, accounting for 64% of the gravel pack job, until a screenout was achieved.

The shunt friction pressure gradient can be used to track the progression of packing through the shunt tubes during the job. **Fig. 10** shows the drillpipe pressure at the bundle carrier increasing with time after slurry enters the shunt tubes. The observed pressure differential divided by the shunt friction results in the packing location. The pressure increase seen in KSJ-103 ST2 suggests the slurry was delivered to the end of the screens prior to screening out. Knowing that slurry was delivered to the bottom of the gravel pack assembly through the shunt tubes and the amount of gravel placed below the service tool equaled the calculated openhole volume required to pack the completion interval, one can feel confident the annular space was fully packed.

Conclusions

The performance of the ISAPT screens and handling equipment met or exceeded all key objectives established prior to the first installation on the KSJ-103 ST2 well. The fit for purpose screen handling equipment performed as expected and the rig crew (with minimal training) was able to demonstrate peak running times comparable to running conventional tubing. The drag profile for running the ISAPT screens experienced similar cased hole and openhole friction factors as the eccentric 2x2 design. The entire completion interval was completely packed after diverting into the shunt tubes. Future ISAPT installations of up to 5,000 ft should be achievable since the actual shunt friction factor replicated laboratory measurements and calculated values.

Utilizing a structured approach, additional ISAPT project objectives will be implemented and evaluated on subsequent wells throughout the operator's worldwide portfolio. Some potential applications being evaluated include:

- Extreme length openhole gravel packs requiring complete gravel packs
- Long interval openhole gravel packs needing zonal isolation
- Stacked pay targets that will require isolation of encountered water or gas intervals
- Multizone openhole completions (frac upper interval, gravel pack lower intervals)

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Figures

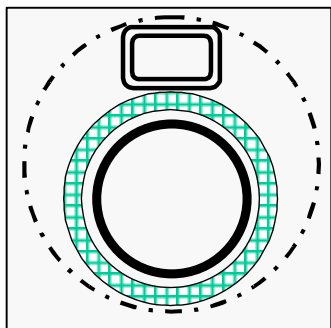


Fig. 1—Single shunt tube design.

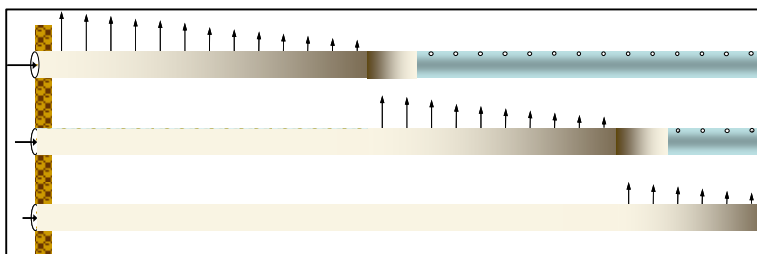


Fig. 2—Staggered shunt tube design.

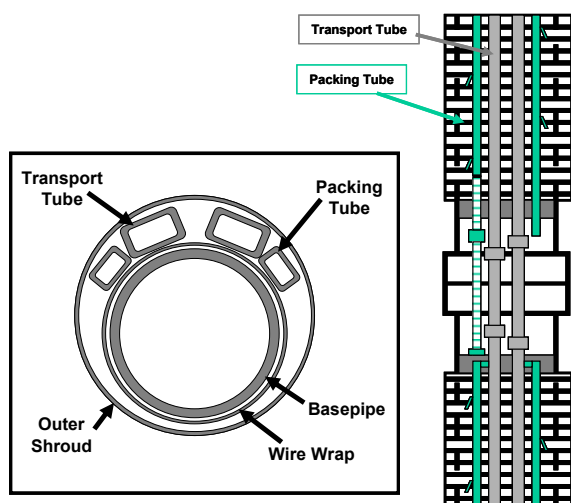


Fig. 3—Eccentric 2x2 design.

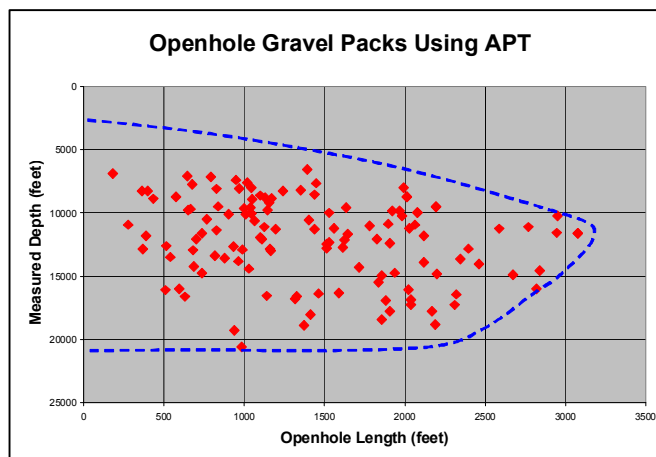


Fig. 4—Openhole gravel pack lengths of APT completions.

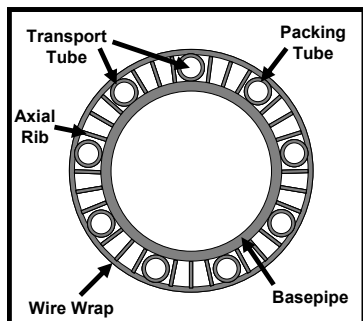


Fig. 5—Cross-Section of ISAPT

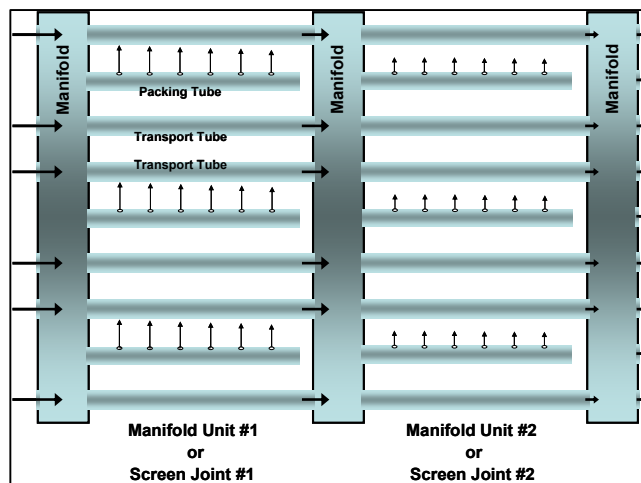


Fig. 6—ISAPT design, multiple-shunt manifold system.

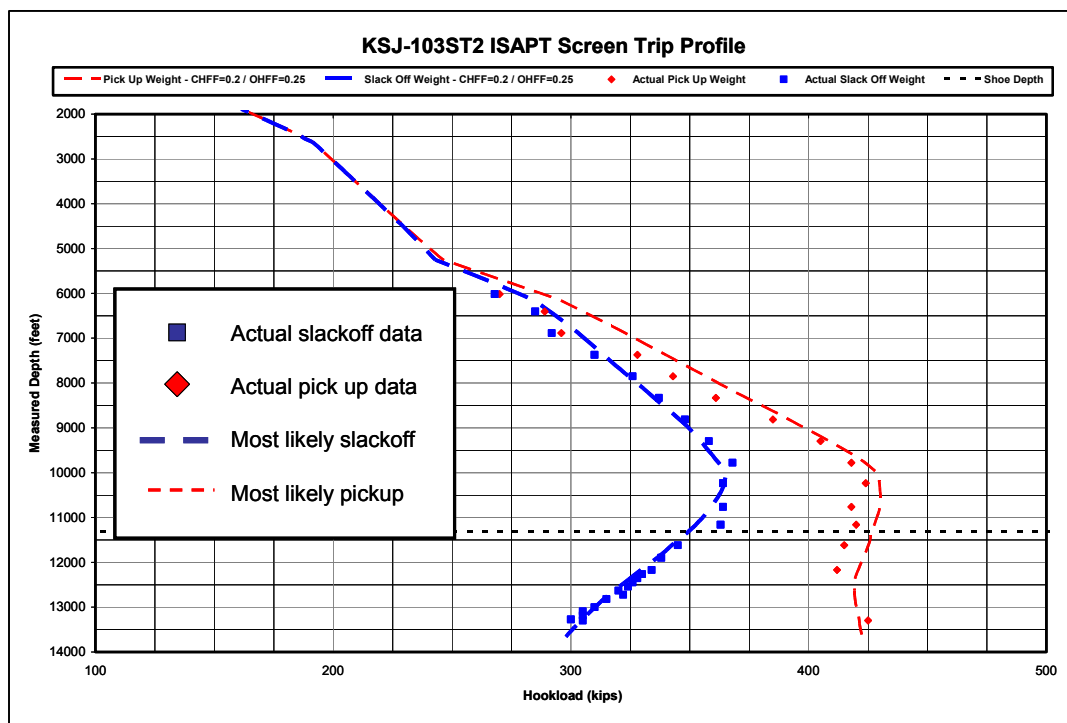


Fig. 7—ISAPT screen trip profile, actual pickup and slackoff data matches predicted numbers.

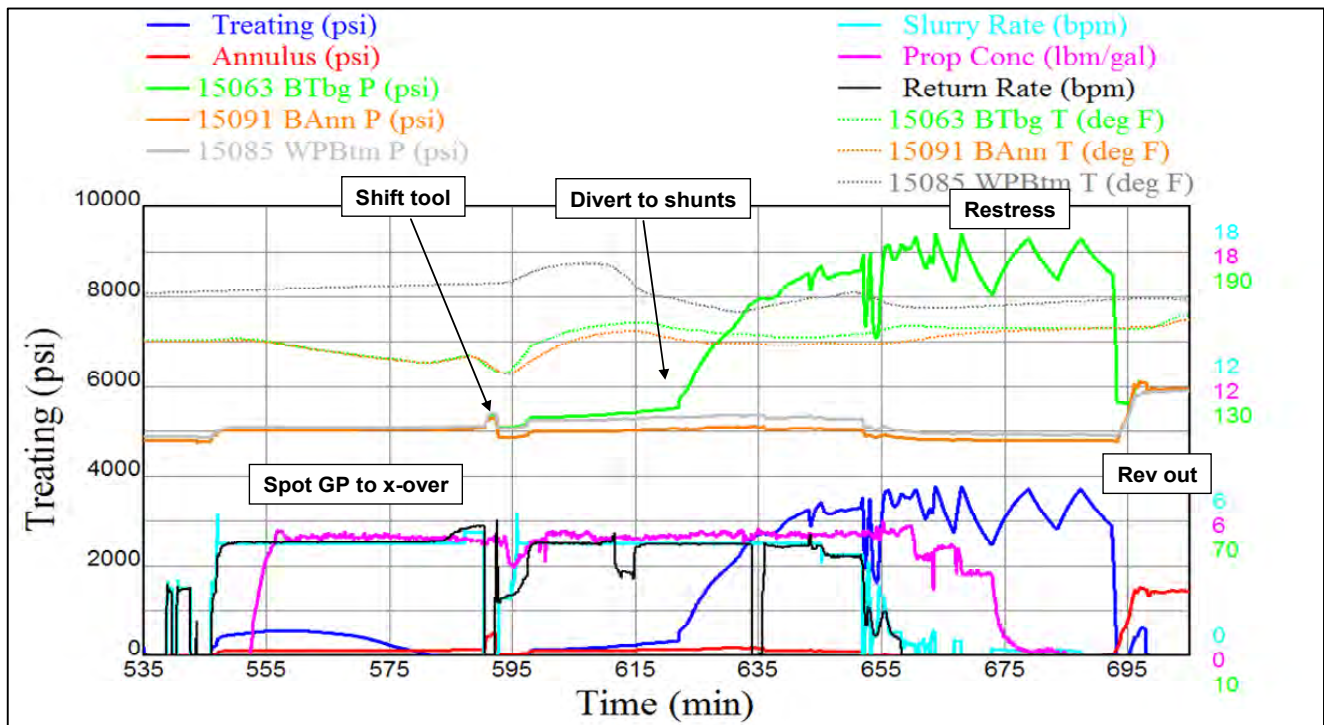


Fig. 8—KSJ103 ST2 pressure and pumping curves from initial ISAPT gravel pack.

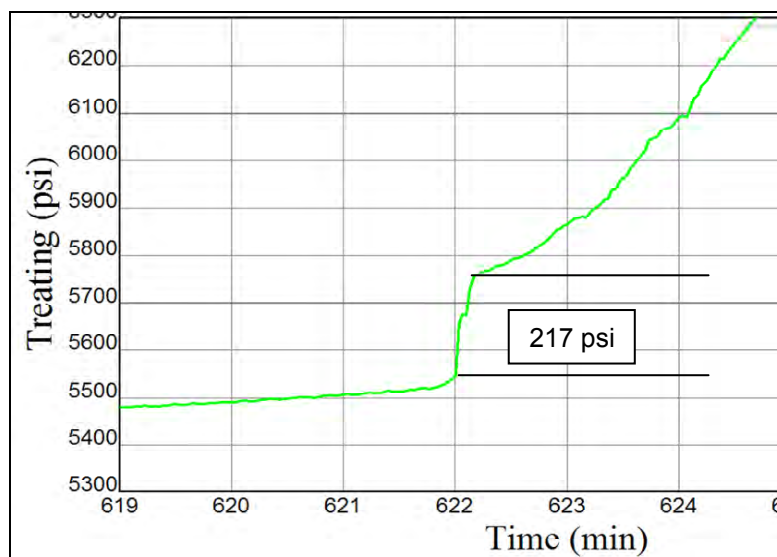


Fig. 9—Pressure increase due to shunt diversion.

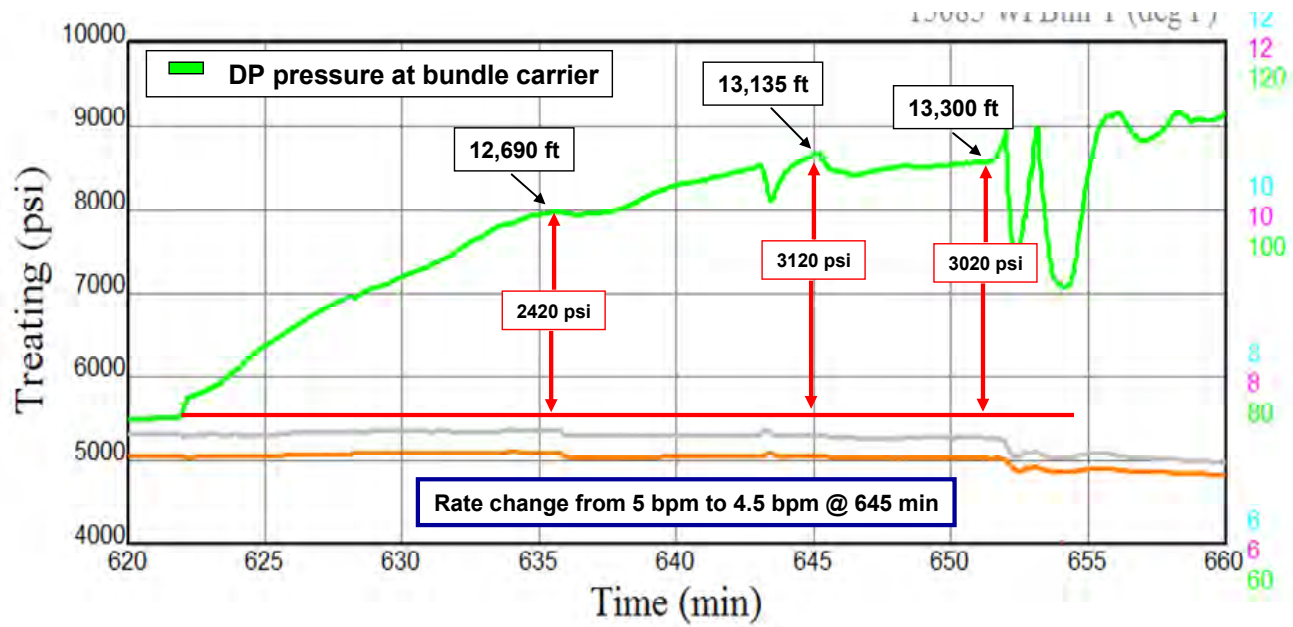


Fig. 10—KSJ103 ST2 progression of shunt tube packing.

EXHIBIT F

IPTC 12549

Unlocking the Limits of Extreme Length in Alternate Path Gravel Packing

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Abstract

Alternate Path® technology (APT) is a field-proven gravel packing technique for multi-zone, long interval, or horizontal wells. This technique has enabled the successful completion of more than 70 deepwater wells in West Africa. Recent APT technology advancements continue to improve completion design options and significantly extend the gravel pack length.

In challenging well environments (e.g., deepwater, extended reach drilling), conventional gravel packing methods are often terminated prematurely due to sand bridging in the wellbore, resulting in incomplete gravel packing and decreased protection from sand ingress. APT provides alternate flow paths around a sand bridge by diverting the slurry (gravel + carrier fluid) through shunt tubes. The slurry is delivered to the annular voids through distributed nozzles in the shunt tubes until a complete pack is placed in the wellbore.

This paper reviews the fundamental Alternate Path design concept and discusses recent improvements resulting from detailed studies of fluid hydraulics, including flow through the shunts, nozzles, and gravel pack. Original designs used single- or multiple-ported shunt tubes, which limited the diverting distance of the slurry and thus the overall packing length. The modern shunt manifold design enables sustained self-diverting transport over much longer production intervals (~ 5000 ft) without the need of a downhole monitor or control loop. This unique self-diverting capability distinguishes APT from all other gravel packing methods in its simplicity and reliability, particularly in challenging well environments.

The ability to extend APT gravel packs to significantly longer lengths provides greater flexibility in reservoir depletion planning by creating more robust completion designs to meet demanding production requirements. As application opportunities continue to expand, and as APT is integrated with other emerging completion technologies, in-depth understanding of shunt design and fluid hydraulics is essential to successful field implementation.

Introduction

Oil and gas production from weakly consolidated or unconsolidated reservoirs has been increasingly challenging. These challenges, which include deep-water, extended reach, high pressure/temperature, long intervals, high rate, and remote locations, raise both complexity and cost in drilling and completions, demanding fewer wells for an economical field development. While subsequent workovers may no longer be a viable option, the long-term reliability of sand control completions is becoming a major focus.

Drilling fewer development wells necessitates maximizing reservoir contact to capture various pay intervals and establish higher production rates from each well. One strategy is to penetrate reservoirs with extreme length wells. Combined with zonal isolation, extreme length wells provide greater flexibility for both reservoir and production management. When sand control is needed, an openhole gravel pack has been recognized to be a reliable and long-lasting completion for long interval, high rate wells.

Gravel packing for sand control involves pumping slurry (gravel + carrier fluid) into a wellbore annulus. The carrier fluid leaks off into the reservoir formation or screen and deposits the high permeability gravel in the annulus. In conventional gravel packing, premature sand bridges are often formed in the annulus due to low frac gradients, high permeability streaks, or shale instability. These bridges block the annular flow path, cease gravel packing, and result in an incomplete pack below the sand bridges. An incomplete gravel pack of any degree is known to impose high sanding potential after the well is put into production.

Alternate Path technology (APT), since introduced almost two decades ago, has become a field-proven gravel packing technique for multi-zone, long interval, or horizontal wells. APT provides alternate flow paths, named shunt tubes, to the primary annular path in the wellbore. Shunt tubes remain inactive until the annulus is blocked during the gravel pack operation. APT diverts flow through the shunt tubes and by-passes any blockage, such as a premature sand bridge, to continue gravel packing. As shown in Figure 1, shunt tubes divert slurry through distributed portholes to fill annular voids until a complete pack is placed.

APT was first field tested in the early 1990s^{1,2,3}. The early success was extended to long openhole applications in the late 1990s⁴. Along with the introduction of running gravel pack screen in nonaqueous fluid in 2002, APT began to be routinely applied for sand control in the deepwater fields in offshore Angola⁵. To date, more than 70 deepwater wells, with lengths up to 2,800 ft, have been successfully gravel packed using APT in West Africa. Gravel packing of long openhole intervals by APT has been consistently successful.

This paper reviews APT development and discusses design evolution along with shunt tube hydraulics. Both previous learning and understanding of fundamentals in APT are crucial to extend gravel packing to extreme lengths, 5000 ft or greater. Integrated with other emerging technologies, APT provides a field proven platform to extend sand control to extreme lengths.

Early Design for Long Intervals

During initial APT development, the characteristics of the gravel carrier fluid were identified to be critical for effective shunt flow diversion. A desirable fluid delivers good gravel suspension and low friction loss in the shunt tubes. A xanthan-based polymer was tested and showed satisfactory performance in both the laboratory and field. This gel system has since been used to establish the target fluid rheology (Figure 2) for Alternate Path gravel packing. In field operations, the target viscosity is applied under downhole conditions.

Since introduced nearly two decades ago, the design of shunt tubes has been evolving through many stages. One early attempt to pack longer intervals was a successive slurry diversion in a continuous, ported shunt tube as shown in Figure 3. However, feasibility of this design was soon negated by laboratory testing⁴, which identified an undesirable plugging tendency when using a continuous ported shunt. The plugging is primarily due to increasing gravel concentration and decreasing velocity. As the slurry enters the shunt tube, the high axial momentum of gravel resists the change of direction to comply with the pressure gradient at the porthole exit. Testing verified that the gravel concentration exiting the leading portholes proved to be less than the inlet slurry concentration. The concentration increased rapidly, however, further down the shunt tube at the subsequent portholes. In fact, for a 5 ppa (pound of gravel per gallon of fluid added) inlet slurry, a broad range of exit slurry concentrations was observed, ranging from 0.49 ppa at the 1st porthole to 17.3 ppa at the 8th porthole. In addition, the decreasing velocity caused by the fluid loss along the shunt length further aggravated the pack-off or plugging potential of the highly concentrated slurry.

In a horizontal ported shunt tube, shunt plugging was observed when the ratio of porthole diameter to gravel diameter was 7 or less (Figure 4a). The fluid diversion length was limited to about 100 ft. The resulting pack-off was insensitive to any attempt of increasing rate or pressure, and permanently deactivated the shunt diversion function.

Larger portholes, ratio 10 or greater, were found to facilitate the discharge of concentrated slurry and prevent plugging in a horizontal ported shunt tube. This criterion is greater than the suggested ratio of 6 from the experiments of particle-transport through perforations in a vertical casing⁶.

Although larger portholes could prevent plugging by a concentrated slurry, a different shunt plugging mechanism was observed after the annulus was packed as shown in Figure 4b. The large portholes allow excessive fluid leakoff through the surrounding annular pack (resulting in ever increasing slurry concentrations) and deposit gravel inward from the inner porthole face. The internal pack eventually grows large enough to block shunt flow.

Higher pressure and rate extends the fluid diversion distance in the shunt tubes. However, any fluctuation in slurry flow rate may induce instantaneous, irreversible plugging (Figure 4a or 4b) in a single shunt tube. High pressure alone does not prevent the shunt tube from plugging. Another design parameter affecting shunt diversion is porthole spacing. Although longer porthole spacing could increase the diversion distance, laboratory testing found that shunt packing becomes more challenging when porthole spacing is greater than 8-10 ft.

As the successive packing mechanism (Figure 3) in a single shunt tube is limited by shunt plugging, multiple shunt tubes with selective portholes were used in an attempt to increase the packing length. One design considered, shown in Figure 5, allocates the slurry diversion in three shunt tubes with staggered portholes. Each shunt diverts the slurry over one of three consecutive intervals. Any plugging phenomena in Figures 4a and 4b is isolated in each individual shunt tube. Compared to a single shunt design, the selective porthole design extends the shunt packing length or reduces the pressure/rate for the same packing length. The shunt tubes with selective portholes were successfully applied in the field during the 1990s for completion intervals up to several hundreds of feet³. In high angle openhole wells, the residual mud bed could block the portholes positioned on the low side of the screen and demands redundant shunt design. The shunt redundancy limits the number of staggered porthole intervals and therefore, the total diversion distance.

Other improvements to reduce plugging potential included lower gravel concentration, low-density gravel, and angled shunt porthole or nozzle segments. These concepts were laboratory tested and subsequently applied in the field to 500-1000 ft intervals⁴.

Up to this point, shunt plugging resulted in a paradox in the shunt design for extended intervals (> 1000 ft). Portholes, either too large or too small would both cause potential plugging in a single shunt longer than approximately 100 ft. Multiple shunts with selective portholes increase the packing length to several hundreds of feet, depending upon the number of shunt tubes able to be fit into a wellbore. The limitations for both large and small shunt portholes appeared to constrain slurry diversion or gravel packing length.

Shunt Manifold System

The manifold concept⁷ was developed to resolve the above paradox. The concept was to differentiate shunt slurry transport from shunt packing as shown in Figure 6a. The shunt manifold incorporates a continuous non-ported shunt tube to transport the slurry and a non-continuous, ported packing tube on each joint used to discharge the slurry. Shunt packing over one screen joint length (~ 30-40') has been well studied and proven in laboratory testing. The packing tube has a closed end to make the flow from shunt ports more uniform (see later discussion of Figure 7). The slurry exiting from the shunt ports either packs the adjacent annulus or travels down the annulus similar to conventional gravel packing. After a section of the annulus is packed, any subsequent plugging (Figure 6b) in a packing tube will not impact slurry transport through the transport shunt tube to the next unpacked interval. The slurry transport and shunt packing repeats until the entire wellbore is packed.

As an annular section is packed, gravel may accumulate in a packing tube and progress toward the manifold. This gravel accumulation rapidly increases flow resistance in the packing tube and diverts almost all slurry in the manifold to the transport tube. Additionally, turbulent flow in the manifold prevents any permanent gravel pack accumulation beyond the packing tube inlet.

The shunt manifold provides an innovative and simple solution to extend the gravel packing length beyond the previous limits of several hundred feet as shown in Figures 4-5. The transport/packing shunt design is field-proven and has been instrumental in successfully gravel packing hundreds of wells with intervals up to ~3000' openhole length^{5, 8-12}.

Gravel Packing in Extreme Lengths (5000 ft or Longer)

Going forward, gravel packing in extreme lengths will increase the chance of annular blockage from a required isolation packer, premature sand bridge, or local hole collapse due to reservoir heterogeneity or wellbore tortuosity. Not only are higher working pressures demanded at extreme lengths, but the working duration of shunt tubes is prolonged as well. As a result, the potential for shunt plugging rises, therefore further examination and design upgrades of the existing shunt system were needed.

Single Shunt Hydraulics

Figures 7 & 8 contain three examples of 1 bpm slurry flow through a single ported shunt. The selected slurry is composed of 4 ppa 30/50 mesh gravel in 8.34 ppg xanthan-based gel (Figure 2). The shunt tube has a 16 mm ID with 6 mm portholes every 6 ft. The analytical calculation of shunt hydraulics is based on both material and momentum balances with the flow through portholes treated as nozzle flow.

Case A shows that flow diversion using a single, continuous shunt could reach a maximum of 80 ft. That is, all inlet flow is diverted out of the portholes even if the shunt end is open ended. Since the size ratio of porthole to gravel is about 10, shunt plugging by gravel concentration gradient is not expected. The flow of slurry exiting from the portholes decreases along the length of the shunt tube. Case B is a 40 ft open-end shunt. About one-half of the inlet flow passes directly through the shunt without being diverted through portholes. Similar to Case A, the flow from the portholes decreases toward the shunt end. Case C is a 40 ft closed-end shunt. Compared to Case B, both porthole flow and pressure are higher but remain more uniform. The increase in pressure at the closed-end and the flow out of the last porthole is a result of the Bernoulli Effect. The characteristics of Case C promotes uniform shunt packing across the 40 ft interval, minimizing the amount of slurry passing by any packed porthole and avoiding the potential plugging mechanism described in Figure 4b.

Multiple-Shunt Manifold System for Extreme Length

To extend Alternate Path technology to extreme lengths, the number of shunt tubes was increased in the manifold system, forcing a re-examination of the shunt size and porthole spacing. Figure 9 shows an example of a multiple-shunt manifold system for gravel packing extreme lengths¹³. Two consecutive manifold units are shown, with each unit representing the configuration of one screen joint. Each manifold unit is designed to direct slurry into nine shunt tubes. Six of the shunts are non-ported transport tubes that are continuous to the next manifold unit. The remaining three shunts are ported packing tubes for gravel discharge. The packing tubes are closed-end and are not connected to the next manifold. Figure 10 is a cross-sectional view of the nine-shunt tubes. Round shunt tubes were chosen to increase the mechanical strength and pressure integrity required for extreme length gravel packing.

The transport and packing tubes are not specifically paired as in the original shunt manifold design. The multiple-shunt manifold design allows more flexible slurry diversion, capable of bypassing any local blockage in the shunt tube. Slurry entering a manifold can freely flow to any of three packing tubes or any of six transport tubes to continue Alternate Path gravel packing. The flow independence among shunt tubes overcomes the potential of any occasional shunt plugging that may occur in extreme length packing. The three packing tubes are positioned symmetrically so that the circumferential orientation during installation does not affect shunt packing. In a horizontal wellbore, at least one or two of the packing tubes are at elevated positions and away from the residual cuttings or mud bed.

The number and size of shunt tubes must be within the acceptable range of the friction pressure loss and the overall dimensions of the screen assembly. In the example system in Figure 9, the friction loss was determined experimentally (Figure 11) with the same slurry used to generate Figures 7 & 8. Analytical solutions were used to extrapolate the test data for friction loss under different conditions. The friction in three packing tubes is higher than in six transport tubes plus the manifold. The friction loss in transport tubes and manifold limits the overall distance of shunt diversion. If friction loss through the packing tubes is too high, the slurry diversion would cause shunt packing to occur over a long interval, weakening the local shunt packing and increasing the potential of incomplete gravel pack. If the friction in packing tubes is too low, high fluid leakoff may continue even after the packing tubes are fully packed (Figure 4b). Excessive fluid leakoff could then result in inadvertently bridging off the manifold and prematurely ending the gravel pack process. The packing tubes must therefore be designed to allow robust shunt packing as well as sufficiently low fluid leakoff when packed with gravel.

Previous gravel pack tests indicated that slurry exiting from a single shunt porthole could successfully pack up to an 8-10 ft annular void. Additional laboratory tests confirmed that shunt tubes with 6 ft porthole spacing fully packed an annulus in a 10" ID fixture. The 6 ft porthole spacing in Figure 9 utilizes six portholes to pack one screen joint (40 ft) interval.

Figure 12 presents calculated flow profiles of 5 bpm slurry diversion in the multiple-shunt manifold system incorporating six transport tubes and three packing tubes. The majority of the inlet slurry is diverted out through the packing tubes in the first (54%) and the second (27%) units below an annular blockage. The average flow exiting a single porthole is approximately 6 gpm in the first unit and 3 gpm in the second unit.

Recall from Figures 7 & 8 that the closed-end packing tubes produce a rather even flow from the portholes. The portholes are designed to be oriented in a tangential direction, as the circumferential flow is expected to be less erosive to the wellbore. Although the packing tubes are more resistant to flow than the transport tubes (Figure 11), they receive more slurry from the

manifold due to their direct connection to the annulus. The flow allocated to the transport tubes will be split again at the next manifold. Less than 20% of the inlet flow is diverted to the third manifold unit and beyond. Depending on the downhole leakoff conditions, the slurry exiting out of the packing tubes may pack the immediate annular space or move down the annulus. In any flow scenario, the diversion through the first and the second units continues until the associated annulus is packed. The packed annulus then becomes a new annular blockage and the shunt diversion is moved to the next manifold unit with partially or unpacked annulus, as shown in Figure 13. In a horizontal well, if one packing tube is buried in the mud bed and deactivated, the flow diversion will be in only two packing tubes in the manifold unit. As such, the shunt hydraulics in Figure 12 would be altered.

Due to prolonged shunt diversion and higher pressure in extreme length applications, leakoff through a packed packing tube (Figure 14) may be excessive and could allow gravel accumulation in the manifold. In order to reduce the leakoff rate, the distance between the manifold and the first porthole needs to be increased. However, this distance must be within the acceptable range of porthole spacing for shunt packing, e.g., 6 ft in the example of Figure 9. Figure 14 indicates a significant difference in fluid leakoff rate between a 1 ft and a 6 ft packed shunt tubes. The packed length between the manifold and the first porthole is crucial to a sustained self-diversion of slurry through shunt tubes in extreme length.

The leakoff effect is further explained by an example of gravel packing a 5,000 ft horizontal well with the multiple-shunt manifold system. Assuming the entire 5,000 ft interval is packed except for a void at the toe end of the well, the slurry is diverted through 5,000 ft long transport tubes. As the slurry passes each manifold, some fluid (gel) leaks off and is lost through the packing tubes into the annulus and screen. Higher pressure in the manifolds near the heel induces more leakoff and results in an elevated slurry concentration. Higher pump rate helps to prevent a gravel pack from accumulating inside the manifold due to the turbulence effect. Figure 15 shows the predicted pressure, rate, and gravel concentration profile in the shunt tubes over the 5,000 ft interval. The gravel concentration is increased from 4 ppa at the heel to 9 ppa at the toe. Approximately 3 bpm (vs. 5 bpm at the heel) eventually gets down to the toe to fill the void. Transporting 5 bpm slurry at the heel through the shunt tubes to the toe void requires 5,300 psi. Burst strength of shunt tubes must therefore be capable of accommodating this high hydraulic pressure.

The multiple-shunt manifold system in Figures 9-15 provides an example of using 4 ppa 30/50 mesh gravel in 8.34 ppg xanthan-based gel. The shunt design should be re-evaluated upon any changes in gravel, fluid, or wellbore size, especially in extreme length applications.

Shunt design for extreme length gravel packing utilizes unique non-Newtonian gel properties to enable sustained slurry diversion through the shunt tubes. Compared to water, a Newtonian fluid, the gel used during typical Alternate Path gravel packing operations (in Figure 2) yields lower friction loss through shunt tubes, comparable friction loss through nozzles, and higher friction loss when leaking off through gravel pack. These gel properties strongly influence the design of multiple-shunt manifold system. Additional improvement under extreme conditions may be gained by reverse engineering the desired shunt hydraulics to define the required gel properties.

The multiple-shunt manifold in Figures 9-10 has been successfully developed, qualified, and prototype tested¹³. More complicated shunt arrangements than Figure 9 are possible, e.g., further cascaded transport and packing tubes. Any sizable improvement, however, may be limited by wellbore dimensions, friction loss, manufacturing complexity, and overall cost.

Alternate Path - A Distinguishing Technology

Alternate Path technology provides a unique mechanical and hydraulic design capable of self-diverting and self-regulating flow until a complete gravel pack is consistently achieved, even under hostile, extreme length conditions.

Without a shunt manifold system, complicated monitoring and control devices may be needed to regulate flow through shunt tubes, portholes, screen, or washpipe. For example, to ensure a complete pack, the slurry flow paths could be shut off to a packed annulus and turned open to unpacked intervals when predetermined pressure limits are exceeded. This may be achieved by installing fiber optics, pressure sensors, control lines, and / or control valve hardware. The implementation would be sensitive to or limited by instrument reliability, data interpretation, response time, and further complicated by the required resolution. Such control mechanism likely becomes arduous or not operationally viable in the environments of extreme completion length, increasing zonal isolation, complex reservoir layering/heterogeneity, hostile environments, or remote location.

A multiple-shunt manifold system automatically bypasses any blockage (premature sand bridge, zonal isolation, packed shunt, etc.) and delivers slurry to any unpacked intervals. The self-diverting, self sustaining capacity of this system is solely driven by downhole hydraulics through the novel mechanical design of shunt tubes. No extra downhole hardware is

necessary other than those currently used in conventional gravel packing operations (e.g., pressure / temperature gauges). The simple but forgiving temperament is readily adapting to, rather than controlling, any intricate downhole conditions in gravel packing extreme lengths. This unique design and operating philosophy clearly distinguishes Alternate Path technology from all other openhole gravel packing techniques.

Emerging Opportunities

Unlocking the limits of extreme lengths by Alternate Path gravel packing provides additional opportunities in drilling, completion, and production. It has the potential to:

- Reduce well count
- Extend drilling to explore additional pays after a non-reservoir penetration
- Maximize reservoir contact
- Link stacked reservoirs or compartments
- Capture isolated by-passed reserves
- Expand gravel pack sand control in extreme length and hostile environments

The distinguishing Alternate Path technology is based on a self-activated, passive control nature without the need for complex downhole instrumentation hardware. This simple and reliable completion design provides a field-proven platform to launch other emerging technologies, e.g., zonal isolation, inflow control device (ICD), and intelligent wells. These devices increase flexibility of well production profile as well as reservoir depletion planning. The resulting benefits include isolating undesirable sections of the payzone, controlling water/gas breakthrough, allocating multi-zone production, managing reservoir drainage, and enhancing reserve recovery.

Continued evolution of APT as a future platform for sand control in extreme length completions will be built on assimilating fundamental shunt hydraulics, laboratory testing, field experience, and collaboration with service suppliers. These are essential to achieving successful engineering design, tool delivery, and field installation.

Conclusions

- The unique self-diverting capability distinguishes Alternate Path technology from other methods in its simplicity and reliability without the need for downhole monitoring and control hardware for gravel packing extreme lengths.
- Alternate Path technology with an improved multiple-shunt manifold design, unlocks the limits in gravel packing extreme lengths of 5,000 ft and beyond.
- Multiple-shunt manifold design is built upon a thorough understanding of previous experience and learning as well as a detailed fluid hydraulics study.
- Multiple-shunt manifold design increases slurry diverting flexibility, provides robust shunt packing, and sustains self-diverting capability over an extreme length.
- Alternate Path technology in extreme lengths continues to evolve via integration with other emerging completion technologies and is envisioned to be a platform to future openhole sand control capabilities.

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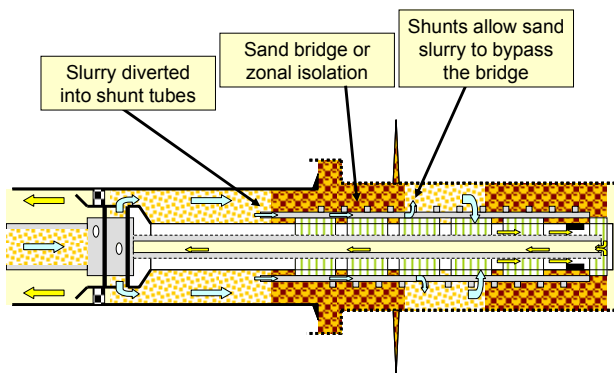


Figure 1 Alternate Path gravel packing with shunt tubes

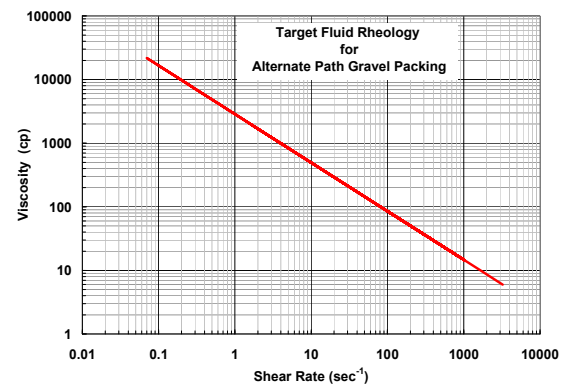


Figure 2 Target fluid rheology for Alternate Path gravel packing

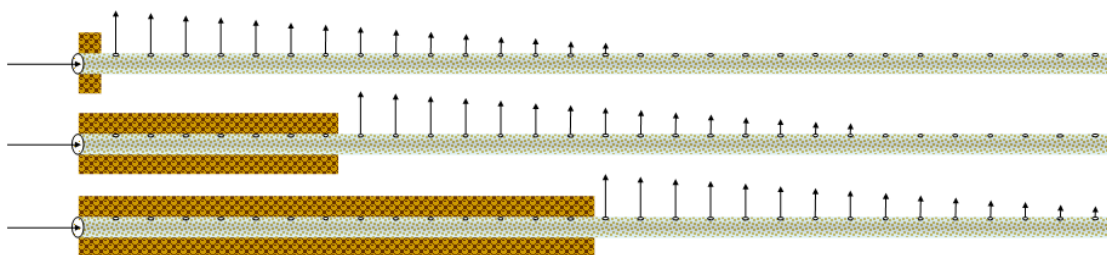


Figure 3 An early attempt of successive gravel packing proven not feasible

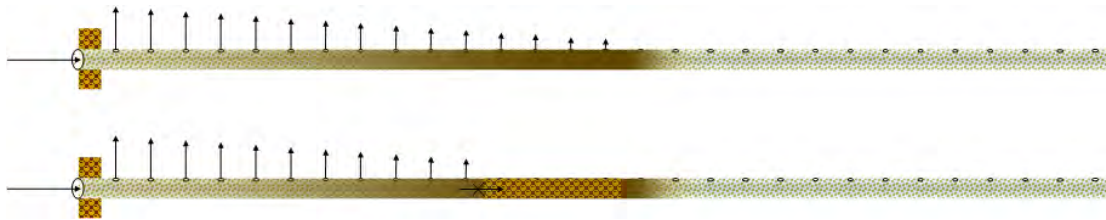


Figure 4a Single shunt plugging mechanism with small shunt portholes

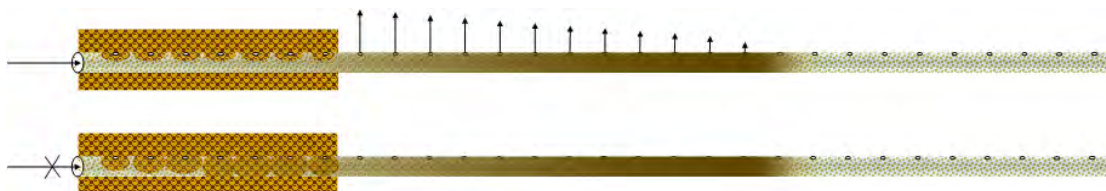


Figure 4b Single shunt plugging mechanism with large shunt portholes

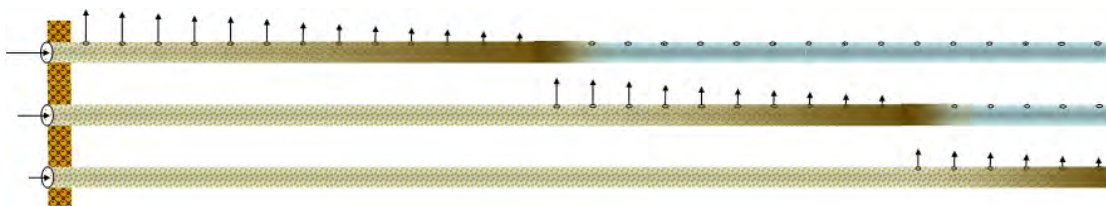


Figure 5 Multiple shunts with selective and staggered portholes

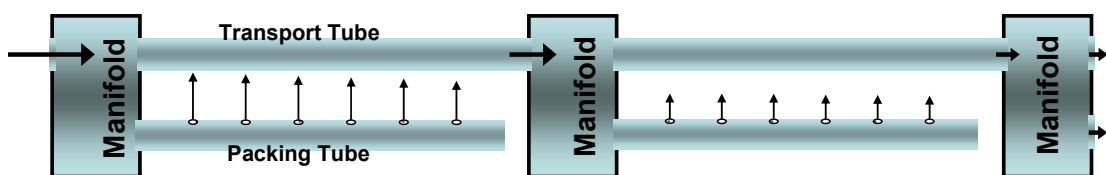
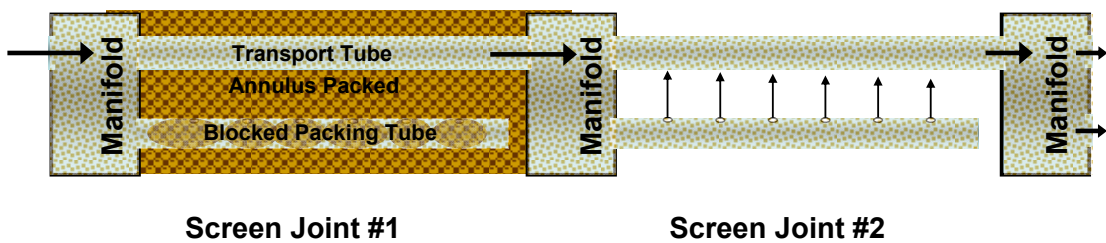


Figure 6a Shunt manifold system



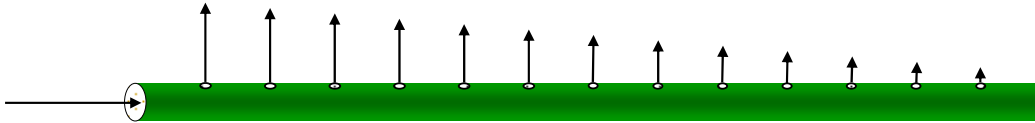
Screen Joint #1

Screen Joint #2

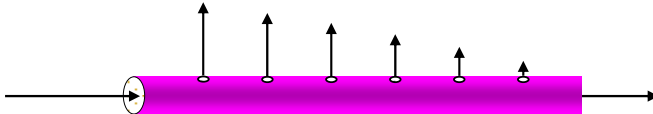
Figure 6b Shunt manifold system bypassing shunt plugging

1 bpm slurry flow through a 16 mm ID shunt tube with 6 ft porthole spacing

Case A Open-End Shunt with 6 mm Portholes over 80 ft Interval



Case B Open-End Shunt with 6 mm Portholes over 40 ft Interval



Case C Closed-End Shunt with 6 mm Portholes over 40 ft Interval

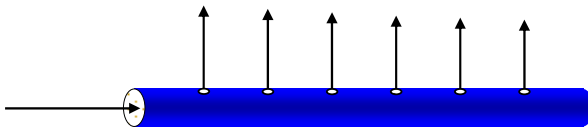


Figure 7 Flow diversion in a single shunt

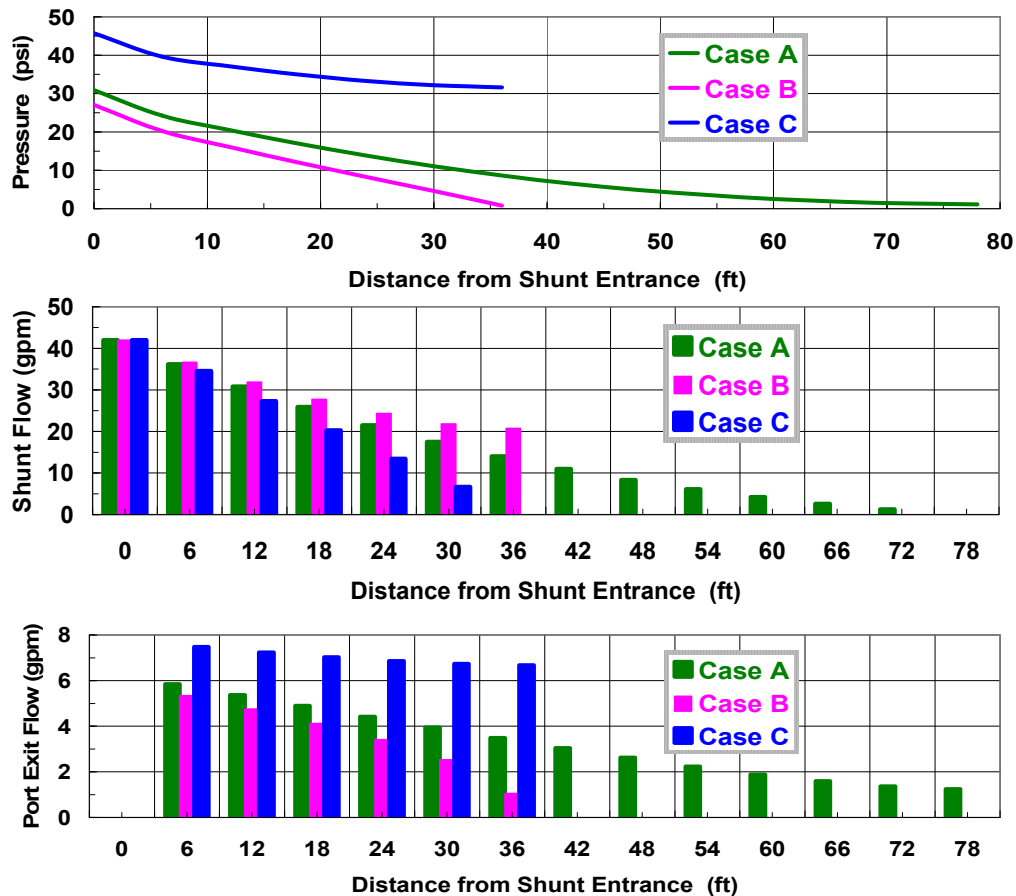


Figure 8 Single shunt hydraulics

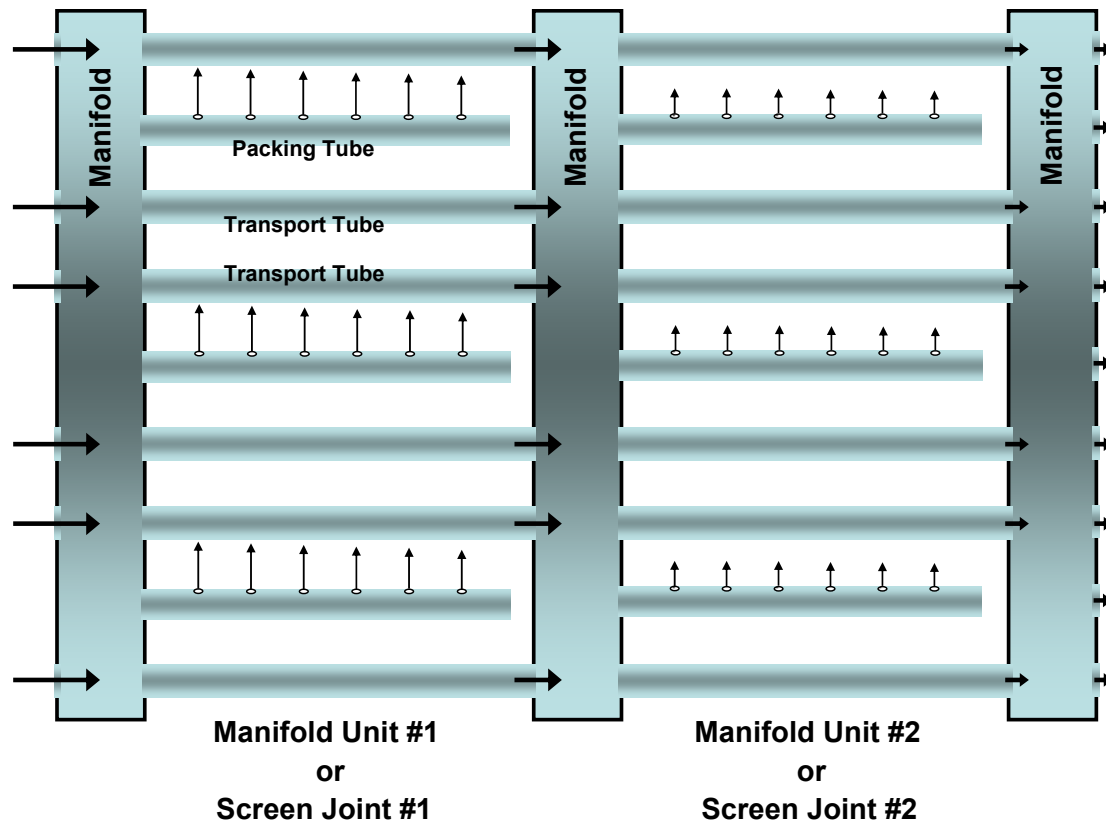


Figure 9 Multiple-shunt manifold system for gravel packing extreme length

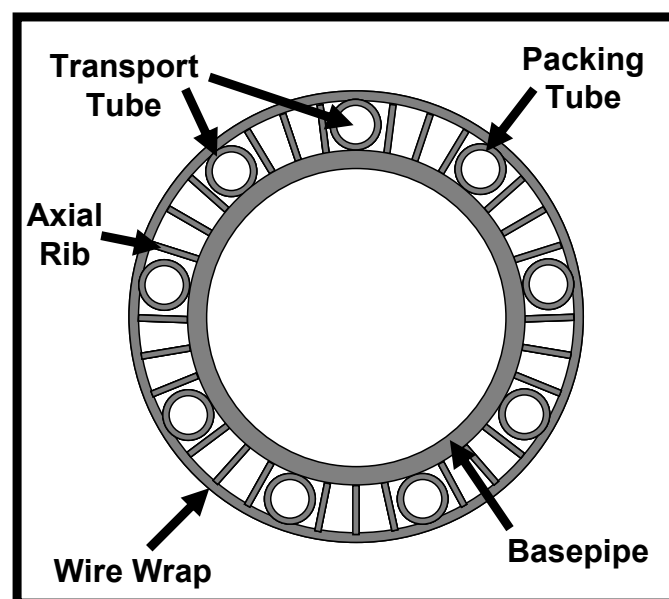


Figure 10 Cross-section of multiple-shunt manifold system

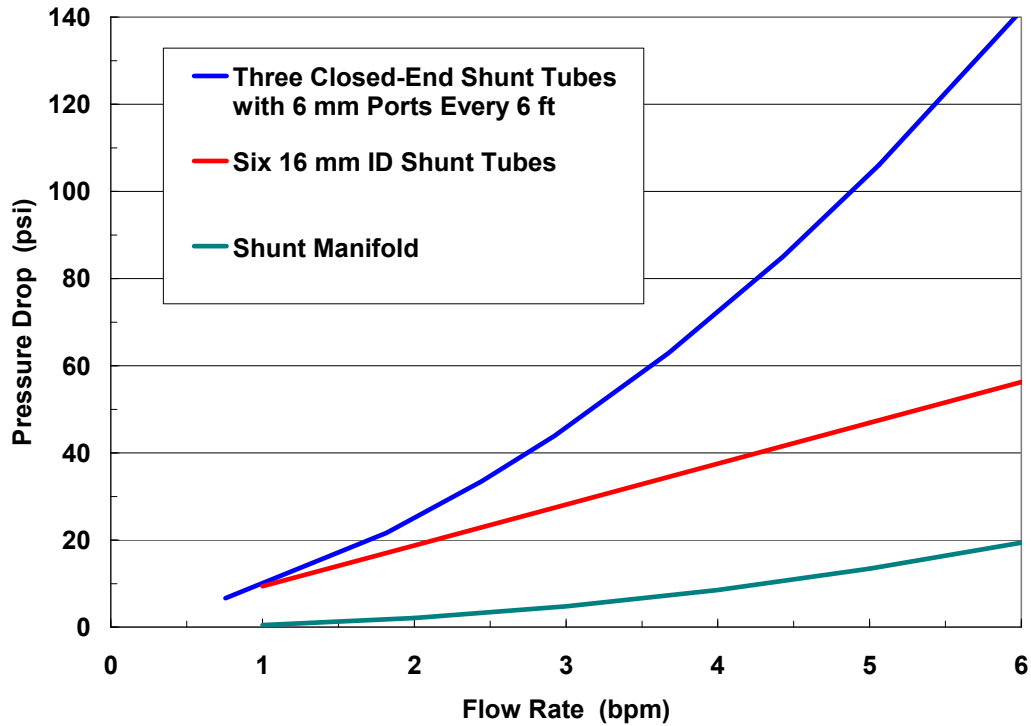


Figure 11 Friction loss in multiple-shunt manifold system

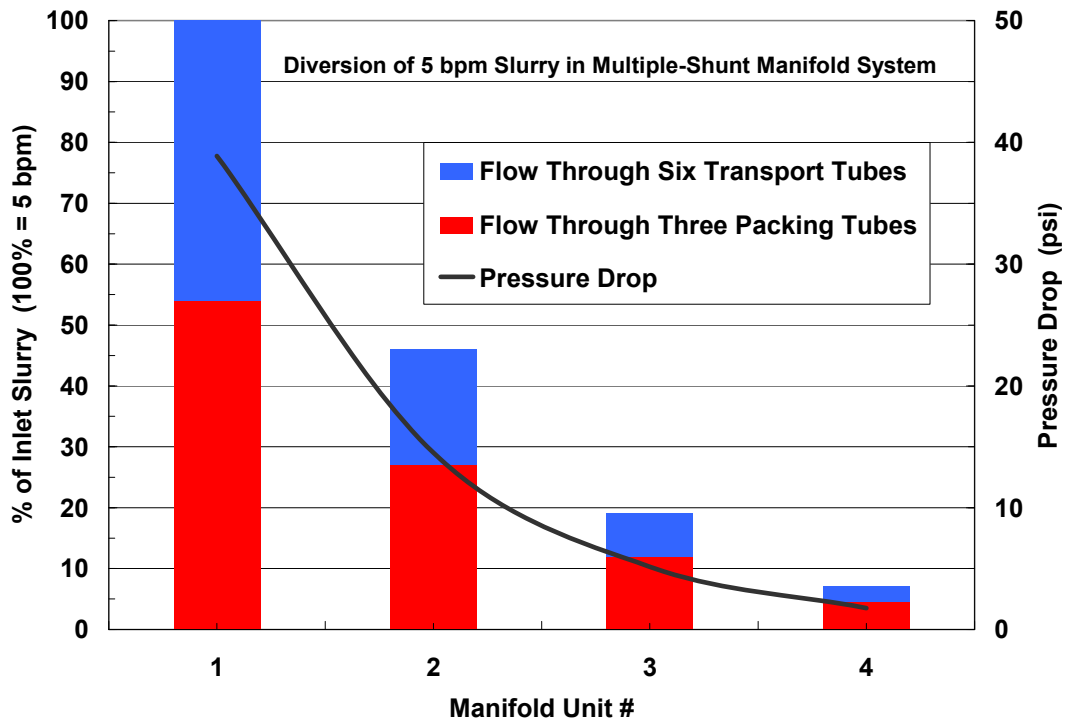


Figure 12 Flow diversion profiles in multiple-shunt manifold system

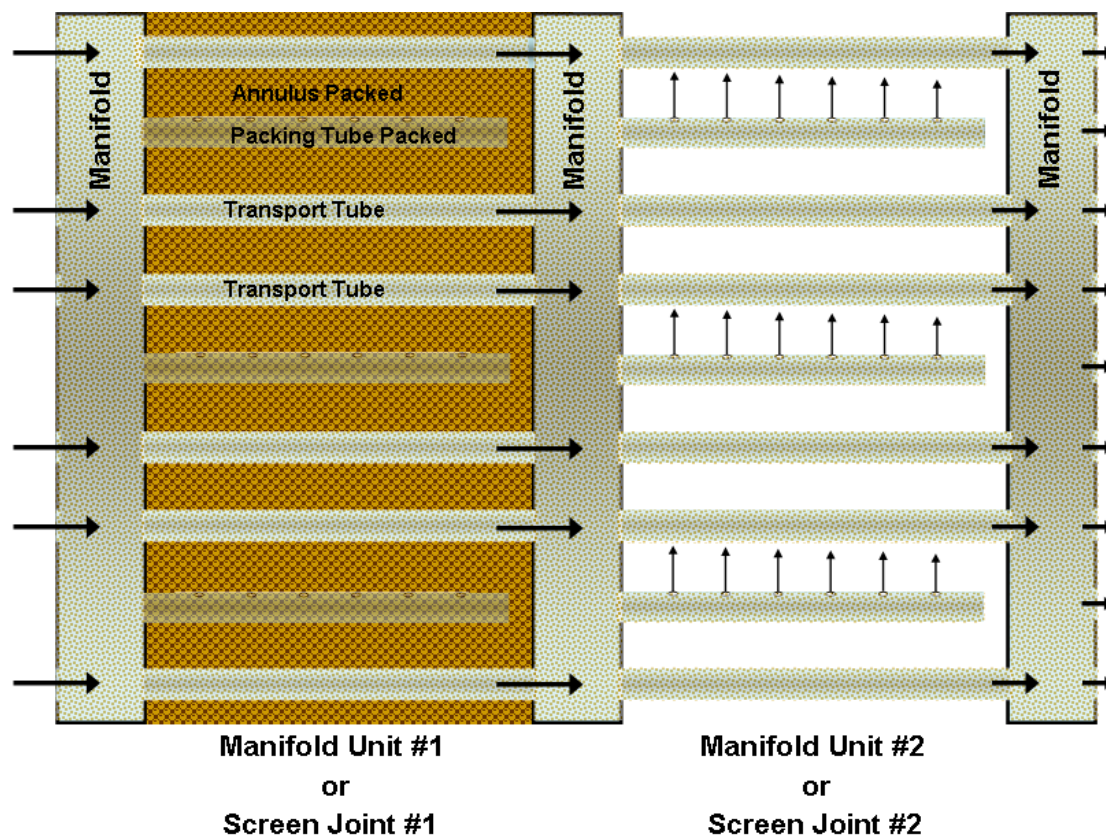


Figure 13 Self-Diversion in multiple-shunt manifold system

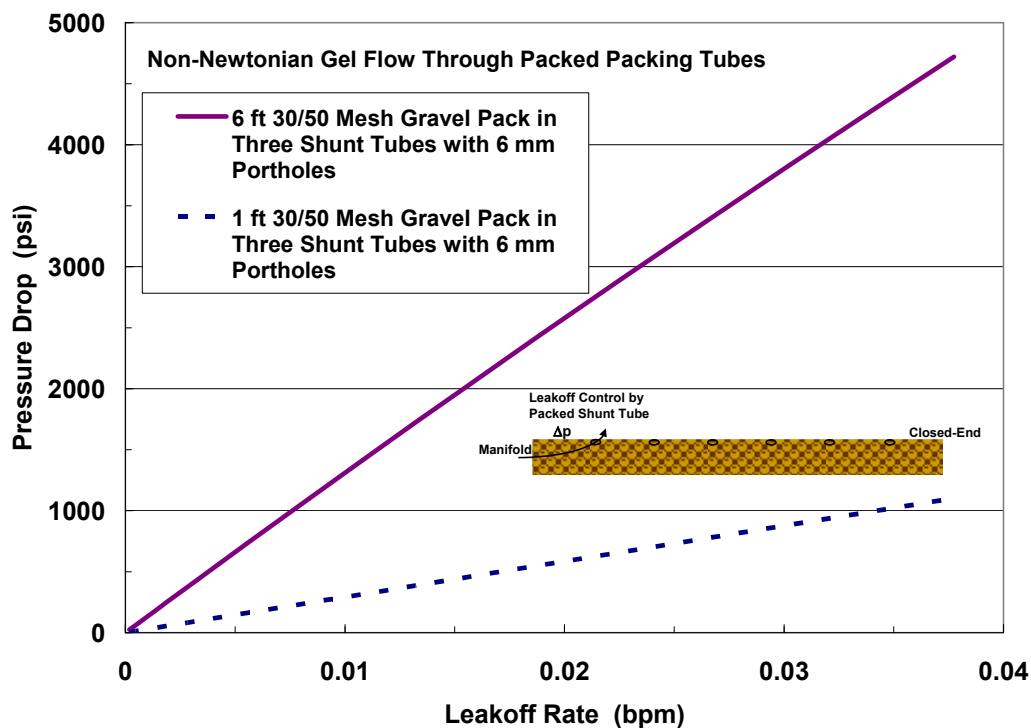


Figure 14 Leakoff through packed shunt tube

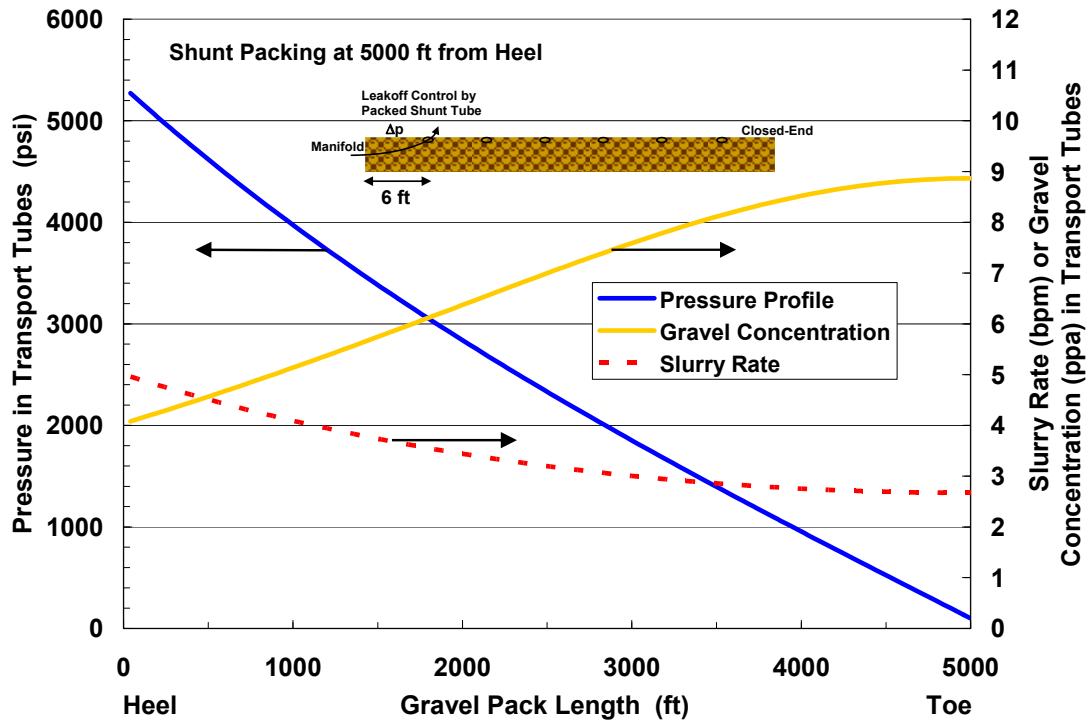


Figure 15 Gravel packing 5,000 ft with multiple-shunt manifold system

EXHIBIT G



SPE 39433

Case History in Achieving High Rate Producers in Sub Sea Gravel Packed Completions

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Abstract

The Zafiro Field, offshore Equatorial Guinea, was developed as a fast track project with production coming onstream in August, 1996 to an FPSO, less than two years from the field discovery. Downhole gauges with surface readout on the FPSO gave continual monitoring of well performance during early production from the field. These subsea wells, which required sand control, were targeted to produce at rates of 8000 bopd. Early wells made this target with Productivity Indices (PI's) of 6 to 33 bopd/psi. However the data also showed high post completion skin damage when compared to skins measured immediately after TCP operations. This real time data allowed continual improvements to be made in completion designs. This paper is a case history of these design changes which more than doubled PI's, yielding producers capable of 14,000 bopd. Design changes included a move to openhole completions where possible, new screen configurations, fluid studies for optimizing gelled fluids to transport sand in high angle and horizontal openhole completions, filter cake removal in openhole completions, and acid stimulation.

Introduction

The Zafiro Field is located in west Africa approximately 40 miles offshore Equatorial Guinea (Fig. 1) in water depths ranging from 425 to 2000 feet. The discovery well, Zafiro 1, was tested in March 1995 by Mobil (75%) and partner United Meridian Corporation (25%). The field is being developed on a fast track basis with subsea wells tied in to a Floating Production, Storage, and Offtake vessel (FPSO). First pro-

duction was brought onstream 25th August, 1996. Field production exceeded 90,000 bopd in November, 1997.

The discovery well penetrated 119 net feet of highly permeable clean oil bearing sands in the Intra Qua Iboe formation. Bottomhole pressure of 2488 psia was recorded at a datum of -5225 feet subsea; static bottomhole temperature was recorded to be 170 ° F.

Subsequent wells showed the reservoir to be highly stratified with permeability thickness varying considerably from well to well.

Wells were targeted to make 8000 bopd each. A sonic sand detector was used to assist in determining a maximum sand free rate from the Pliocene age sand. Flow tests during rig work showed that maximum sand free rates were too low to meet the targeted 8000 bopd per well without gravel packing to control sand production.

Early Design

Early wells were vertical, cased with 9-5/8" production casing throughout the pay intervals. Wells were shot with tubing conveyed 7" OD guns against an open choke, 500 psi underbalanced, at 12 shots per foot.

With the exception of the first two Zafiro gravel packs, perforations were not washed. Instead the wells were flowed continually after gun detonation for three or more hours to clean up perforation tunnels. Pre-gravel pack flow tests at ~ 2000 bopd followed by a pressure buildup, yielded slightly negative skin values and indicated this method of cleanup was effective.

Early wells used gravel packing equipment and materials readily available in west Africa, namely 8 gauge stainless wirewrapped screen and 40/60 sand with HEC as the carrying fluid. HEC was also used as loss circulation material (LCM) when fluid losses were encountered. Shunts attached to the wirewrapped screens to give an alternate path for transporting sand were introduced after the first two gravel packs. Sand stratification coupled with gross length of completion intervals, greater than 100 feet, were the major factors in having wirewrapped screens with shunts to minimize voids in the pack.^{1,2}

Downhole gauges with surface readout onboard the FPSO were run on all wells to obtain real time data as the wells were produced or shut in. Not only did the downhole gauges serve as a means to solve reservoir management issues³, it allowed early analysis of the completion design and the ability to respond quickly to any changes deemed necessary.

Early Results

When the early Zafiro wells came onstream in August and September of 1996, all Zafiro wells (No's 1-4) were capable of making the 8000 bopd target. Downhole gauges run with the completion gave the opportunity for well performance to be monitored early-on and design changes made accordingly. It was observed that skin damage was higher than desired, ranging from 13 to 23. Although skins of > 20 are common in the industry^{4,5}, it was felt these skins could be reduced.

Much discussion centered around the pros and cons to change procedures back to washing perforations versus whether or not to omit HEC from the system. HEC as documented by others⁶ could be damaging to the formation. The skin of + 23 on Zafiro 1 where perforations were washed prior to gravel packing hinted that HEC was part of the problem.

Fluids Testing on Zafiro Cores

Fluids testing with both carrying fluids and LCM was initiated on Zafiro cores to determine their effects on the Zafiro formation. Return permeabilities using HEC, a viscoelastic surfactant-based fluid (VSBF), NaCl, and CaCO₃ with a bio-polymer pill were conducted at the Mobil lab.

It was found in the fluids study (Table 1) that as a carrying fluid, both NaCl and VSBF gave the highest return permeabilities (73% to 77%) at static bottomhole temperatures. HEC with breaker exhibited only a 33 % return permeability.

As a loss circulation material, CaCO₃ with the bio-polymer pill exhibited only 19% return permeability, increasing only to 48% after 7-1/2% HCl acid was introduced. The VSBF, although viscous, has high leakoff properties and is not designed to control loss circulation. It was therefore decided to incorporate a flapper valve into the gravel pack bottomhole assembly when feasible to minimize fluid loss to the formation after gravel packing. It was also decided to minimize the amount of HEC pill that is spotted when losses were severe enough to require a loss circulation pill after perforating or should the flapper valve fail after gravel packing.

Other Considerations Leading to New Design

During a TCP operation in the Opalo 2 well, a low order detonation occurred with 7" OD guns in the hole. Fishing attempts were unsuccessful and the well was redrilled.

It was decided to no longer run 7" OD guns due to

associated mechanical risks. There were no 6" OD guns available at the time of completion and consequently 4-1/2" guns were used to perforate this 55 degree well.

HEC was not used as a carrying fluid and a flapper valve was incorporated so that no HEC was spotted after the gravel pack. Yet this well experienced extremely high skin (+70). Analysis indicated that the smaller gun, laying on the low side of the 9-5/8" casing, did not effectively perforate the upper side of the 9-5/8" and the smaller hole sizes did not allow enough 40/60 sand to be put away during gravel packing. The majority of the skin is attributed to convergence of flow on the low side of the well resulting from this inefficient perforation job. The results of Opalo 2 pointed to the need to omit perforations when possible, i.e., design for openhole gravel pack completions.

New Design Parameters and Potential Problems

New design parameters called for openhole completions when possible. Also since some of the sands were less than twenty feet thick, higher angle wells, even horizontal, were preferred to expose more sand to the wellbore. A minimum 500 feet of horizontal section in the Zafiro sand was desired. Applying nodal analysis using existing tubular sizes, the horizontal length began to reach diminishing returns at 1200 feet. Design for the first horizontal openhole completion was 500 feet.

Due to expected longevity of the wells, coupled with the high cost of subsea well intervention, prepacked screens were not considered. Plugging and subsequent production losses attributed to prepack screens over time⁷ was considered when making this decision. It was decided that the high angle and horizontal wells would need to be gravel packed. Prepacked screens would be available but used only as backup should mechanical or hole problems warrant their use.

It has been known that horizontal wells could be successfully gravel packed with a high rate water pack.⁸ However, due to pit volume limitations on the rig, it was desired to use a non-damaging viscous slurry pack. Previous fluids testing indicated the VSBF had enough viscosity to carry sand at Zafiro bottomhole treating temperatures and at pump rates < 5 BPM.

Shunt tubes would need to be used to eliminate voids but would need protection when running the bottomhole assembly to bottom. A special shrouded screen (Fig. 2) was developed to achieve this protection. Basically a typical 8 gauge stainless steel screen wrapped on 4" base pipe, fitted with four shunt tubes was built and inserted into a 7" OD perforated shroud then welded in place. The 7" OD outer shroud not only served as protection when running in hole, it provided centralization of the screen and standoff from the openhole wall. This standoff allowed for more gravel pack sand to be placed between the screen and formation. It also minimized any plugging tendencies from filter cake embed-

ding in the screen when running the screen on the low side of the openhole.

Use of oil base mud has been very successful in drilling the Zafiro wells. Fluids tests run with oil base mud in a gravel pack simulator indicated plugging would be a problem if the openhole were left with the oil base mud filtrate in place prior to gravel packing.

It was decided that for horizontal wells, a 12-1/4" pilot hole would be drilled using MWD to verify that the targeted sand had been encountered. A string of 9-5/8" casing would be set above the target zone, the oil base mud system would be swapped out to a drill-in fluid more compatible with gravel packing, and the horizontal section drilled.

Testing was done on a water base gelled drill-in system using CaCO_3 as the bridging material. This system was found to form a very thin filter cake (~ 1/8") with a low lift-off pressure (42 psig).

A post gravel pack acid job consisting of ~ 20 gal/ft of 7-1/2% HCL with iron sequestering agent and clay stabilizer, spotted with coil tubing, would be required to effectively dissolve and remove the CaCO_3 filter cake and pass through the gravel pack.⁹ Stress strain analysis on Zafiro cores had indicated that hole collapse may result if the openhole was acidized prior to gravel packing.

Surface testing was conducted using shunts in a horizontal mode with gravel transported via a gelled system (Fig. 3). Early results were pessimistic, but it was found that low density gravel would achieve a gravel pack. Further testing showed that after changing hole sizes in the shunts and optimizing the hole spacing successful results could be achieved with regular gravel. Results of the testing have indicated that 2000 feet or longer horizontal wells can be gravel packed with gelled system when the proper hole sizes in the shunts are used.¹⁰

Field Results With New Design Criteria

Openhole Horizontal Completions. Three horizontal openhole completions have been drilled, completed and put onstream to date. All three wells used the water based gelled CaCO_3 drill-in fluid, the VSBF carrying fluid, low density (S.G. = 1.7) artificial 40/60 sand, and shrouded shunted screen bottomhole assembly with flapper. These three wells, even though drilled in areas of the field that exhibited lower permeability thickness, are producing in excess of 10,000 bopd each with less than 500 psi drawdown. A typical drawing of the downhole configuration can be seen in Figure 4.

Zafiro 5: 508 ft. This near horizontal has 508 feet of 8-1/2" openhole beginning with 82 degrees and tapering off to 75 degrees, chasing a 30 feet thick sand that was dipping downward at 10 to 12 degrees. The well was completed and put onstream in February, 1997. The initial slurry was pumped at 1.5 to 5 bbls per minute, using 25% excess low density

sand over the calculated volume required. A screenout was not obtained. A top job was performed with no problems and a total of 64% excess sand was pumped. The post acid job was spotted with coil tubing from the toe to heel then squeezed into the formation.

This well has produced up to 12,000 bopd and is produced on a regular basis at 10,000 bopd. The initial post gravel pack PI of the well is 47.3 with a horizontal skin of 3.0. The horizontal permeability thickness, k_{ph} , is 35,000 md-ft.

Zafiro 10: 855 ft. This horizontal openhole section (908 ft) was drilled at 81 to 91 degrees. A 992 feet shrouded screen assembly was run into the well. Sluffing shales prevented getting the assembly to bottom; 855 feet of the assembly was run into the openhole section with the remaining screen in the 9-5/8". The well was gravel packed with low density sand with 43% excess sand being pumped. The well produces in excess of 10,000 bopd with an initial post gravel pack PI of 68.1. The measured k_{ph} is only 11,400 md-ft and horizontal skin is 0.3.

Zafiro 13: 611 ft. This horizontal openhole section was drilled at 87 degrees. Again sluffing shales prevented getting to bottom with the bottomhole screen assembly. 611 feet of the 1000 feet assembly was run in the openhole section. The well was gravel packed with 75% excess low density sand. The well exhibited an initial post gravel pack PI of 23.3 and produces 10,000 bopd. The measured k_{ph} is 37,000 md-ft and horizontal skin is 3.8.

Openhole Near Vertical Completions. Near vertical openhole completions differed from the horizontal wells in that the entire section was drilled with oil base mud. The pay section was next under-reamed using a water base gelled system. CaCO_3 was used only if loss circulation was encountered during under-reaming. When CaCO_3 was used, a post gravel pack acid job using 7-1/2% HCL, 25 to 50 gal/ft was administered. The same gelled system without CaCO_3 was used for cleanout sweeps during under-reaming operations. Regular sand was used in the gravel packing. One or two joints of shrouded screen were used in the bottomhole assembly to act as a centralizer; regular screens with shunts were used throughout the remainder of the assembly.

Zafiro 11: 235 ft straight openhole. This well had 9-5/8" set in a highly stratified section of the Zafiro sand with the cleanest part of the sand near the bottom of the hole. Shale sluffing was encountered during under-reaming to 14-3/4". Difficulty in keeping the hole clean during trips with drill pipe gave justification to the running of a prepacked screen. Indeed, only 10% of the sand had been put away before a screenout occurred during the gravel pack operation. The

well produced at an initial rate of 9500 bopd with an initial post gravel pack PI of 28.1 and a kh of 140,000 md-ft. Skin damage of 12.9 in this high permeability well can be partially attributed to the plugging of the prepacked screen. The well produces at approximately 10,000 bopd.

Opalo 3: 78 feet of 14 degree openhole. Opalo 3 had 9-5/8" set immediately above the clean sand and no shale sluffing problems were encountered during under-reaming. The well was gravel packed with 23% excess sand. This well which had a measured kh of 37,500 md-ft, had an initial post gravel pack PI of 87.7. Skin damage was 1.3. The well produces around 10,000 bopd but has been beaned up to produce near 14,000 bopd for a short period of time.

Opalo East 1: 158 feet straight openhole. This well has yet to be tied in to the FPSO. It was gravel packed upon drilling in order to conduct multi-rate testing and bottomhole sampling for full evaluation. The well was under-reamed to 14-3/4" using water base gelled system with CaCO₃ viscous sweeps during the operation. Post gravel pack PI for this high permeability well (kh of 233,000 md-ft) was 61.7. Skin damage was 11.4. However, the well was not acidized since the well was suspended pending flowline installation.

Topacio 3: 60 feet of near vertical hole. Shale sluffing problems arose in Topacio 3 as 9-5/8" was set well above the clean part of sand. The original 8-1/2" hole was cemented and a new 8-1/2" hole sidetracked just below the 9-5/8" shoe. Since shale sluffing problems increase with time, it was decided not to under-ream the new 8-1/2" hole. The well was gravel packed with 84 % excess sand. The initial post gravel pack PI was 22.8. The measured kh was 46,000 md-ft. Skin damage was 5.2.

Observations

One yardstick commonly used to determine how efficient a well completion to be is the Productivity Index (PI). However, since PI's are effected by kh and skin, PI's alone in non-homogeneous reservoirs can be deceiving. For this reason, both PI's and PI/Kh, bopd/psi/darcy-ft, were compared for the Zafiro completions (Figs. 5 and 6).

Conclusions

1. Openhole gravel packed completions can yield higher producibility than cased hole gravel packed wells.
2. Fluids studies on field cores can pay dividends by aiding in the selection of optimal fluids used during completions.
3. Several hundred feet of horizontal openhole can be successfully gravel packed using viscoelastic surfactant-based fluids in conjunction with shunted screens.
4. Use of shunted screens and viscoelastic surfactant-based fluids minimize pit volume requirements on the rig for long interval jobs.

5. Gravel packing high angle and horizontal wells is superior to running prepacked screens when long life completions are desired.

6. Minimizing fluid loss to the formation, either during post perforating or post gravel pack operations aids in minimizing skin damage.

7. Additional fluids testing and other work to prevent shale sluffing is required for Zafiro completions.

Acknowledgments

The authors would like to thank the Mobil drilling supervisors Will Billings, James Menard, Keith Renard, and Bob Simon for their field support. In addition, the authors would like to thank the staff of Mobil E&P Technology, Dowell Schlumberger, US Filter/Johnson Screens, and Lloyd Jones & Associates.

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Table 1-Return Permeability Tests of Carrying Fluids and LCM Pills Run on Zafiro Cores at BHT

Type Fluid	Return Permeability Thru Core
NaCl	73%
3% KCL & NaCl	76%
CaCO ₃ Biopolymer Pill	19%
CaCO ₃ Biopolymer Pill followed by 7-1/2% HCL	48%
Viscoelastic Surfactant-based fluid	77%
HEC without breaker	28%
HEC with breaker	33%

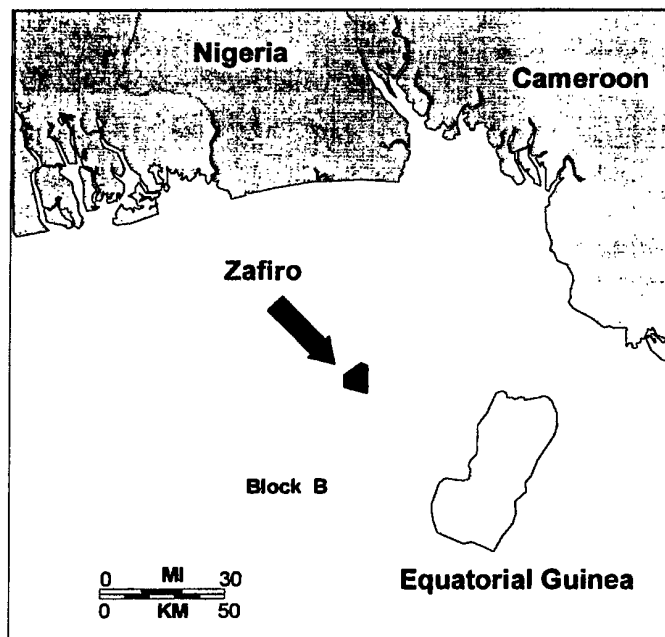


Fig 1- Map of the Zafiro Field

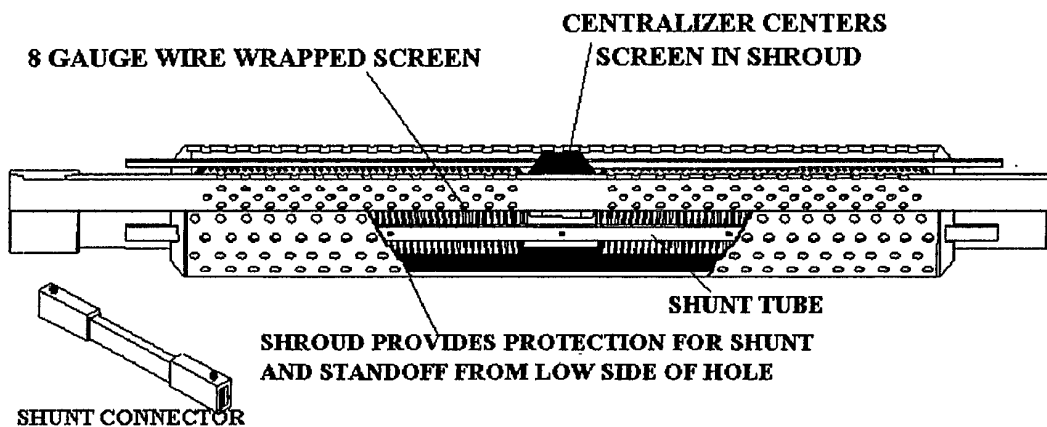


Fig. 2- Shrouded screen with shunt tubes



Fig. 3 -Surface tests performed with shunts in horizontal mode and slotted plastic pipe used as the formation with high leak-off. Flowed into the the liner and then down the shunt tube. Resulted in 500 ft completely packed with one shunt.

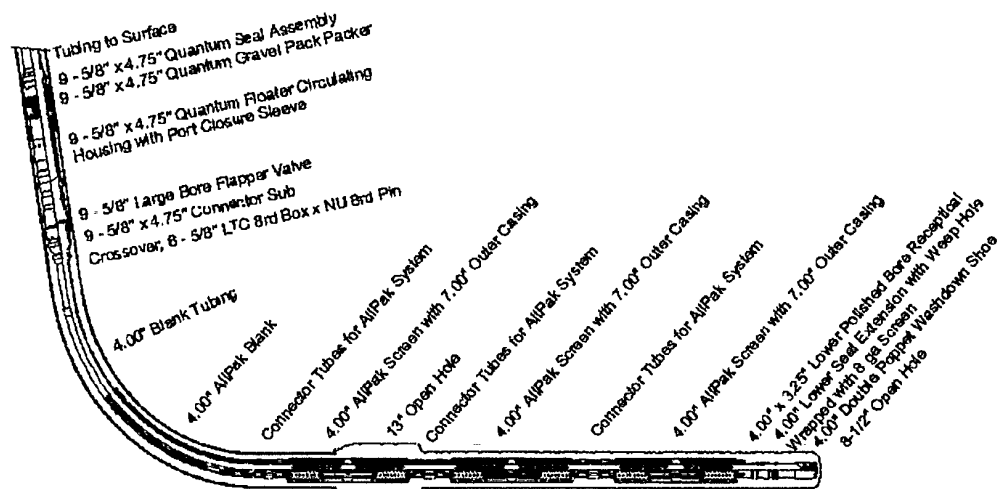


Fig. 4 - Typical Mobil Equatorial Guinea Openhole Gravel Pack Bottomhole Assembly

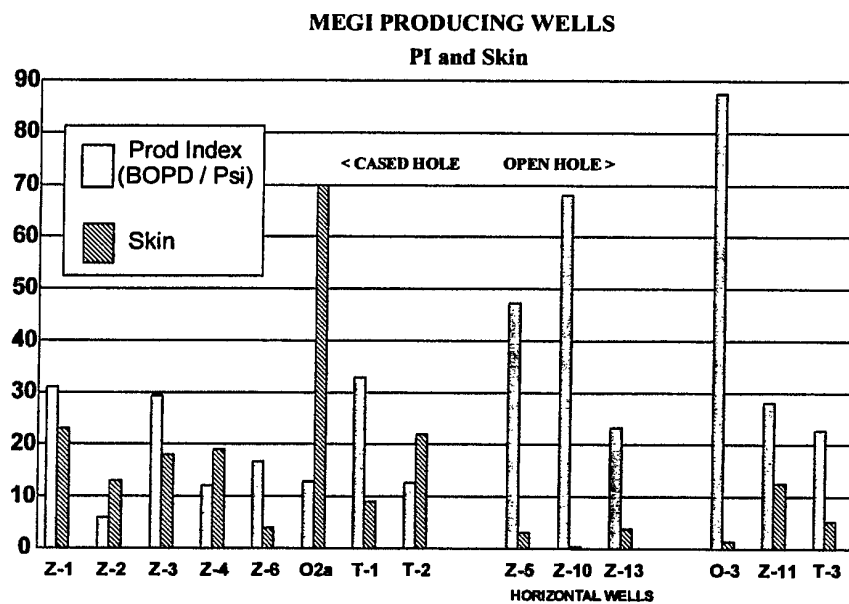


Fig. 5- Productivity Index and Skin for MEGI Producing Wells

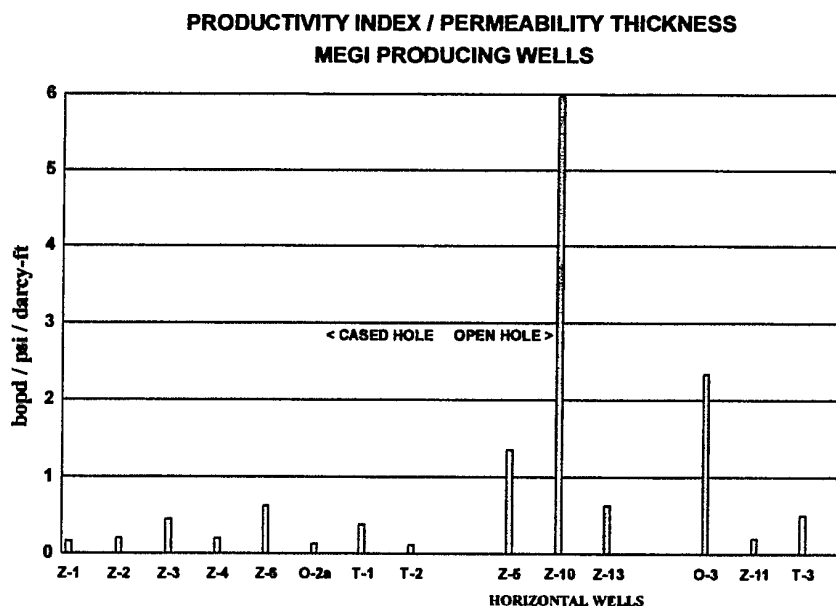


Fig. 6 - Productivity Index/Permeability Thickness for MEGI Producing Wells

EXHIBIT H



SPE 110460

Openhole Gravel Packing With Zonal Isolation

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Abstract

Many current deepwater and high rate wells are being completed in an openhole environment as openhole completions provide the greatest opportunity to maximize reservoir flow potential. Current technology, however, lacks the subsurface control necessary to effectively manage the reservoir in situations where sand control is required. ExxonMobil is pioneering technologies to model well performance more accurately and to provide subsurface control during completion and production operations. The first hardware developments within this initiative build on the success of Alternate Path[®] and NAFFacSM gravel packing technologies and address water or gas breakthrough in openhole, multi-zone gravel pack completions. ExxonMobil affiliates collaborated with third party suppliers to design and qualify new hardware to facilitate zonal isolation, extend gravel pack reach, and simplify rig site operations. This process included engineering design, component testing, and full-scale prototype evaluation. First application of this technology is targeted for early 2008.

This paper discusses newly developed sand control screen hardware that is enabling technology to perform openhole gravel packs with true zonal isolation. The equipment provides the ability to seal off bottom water, selectively complete or gravel pack targeted intervals, perform a stacked openhole completion, or isolate a gas/water-bearing sand following production. Application of the technology is expected to extend well life and ultimately increase volumes and reserves capture.

Background

Continued economic success in remote or deepwater environments requires delivery of high rate, high capacity, and long-life wells. In these developments, it is often necessary to drill and complete high angle wells, penetrating multiple pay

intervals and incorporate sand control technologies. Reservoir conditions, wellbore geometry, and production performance expectations can all introduce significant cost and complexity that frequently limit application of traditional cased hole sand control techniques. Openhole gravel pack completions are now commonly installed to connect multiple payzones over long intervals and improve well productivity.

Because openhole completions have no perforation tunnels, formation fluids can converge on the wellbore radially from 360 degrees, thus eliminating the additional pressure drop associated with converging flow and then linear flow through gravel filled perforation tunnels. The reduced pressure drop, associated with an openhole sand control completion, virtually guarantees that it will be more productive than an unstimulated, cased hole gravel pack in the same formation. Operationally, openhole techniques eliminate the need for costly cementing, perforating, and clean-up operations, the complexity of stacked completions, and in some areas an additional casing string or liner. The downside, however, is that openhole completions do not have the same level of installation flexibility and subsurface control to manage geologic and reservoir uncertainty versus traditional cased hole gravel pack techniques. Operators are particularly challenged in their ability to manage fluid inflow along the wellbore in openhole completions, including avoidance of watered-out or depleted zones during installation and shutting off unwanted water and gas during production.

Stand Alone Screens

Recent advances have introduced a number of effective hardware options for use in openhole stand alone screen (or screen-only) applications. Openhole zonal isolation packers and inflow control devices (i.e., downhole chokes) can be installed to regain some of the subsurface control lost in openhole completions. In the Chayvo development off the coast of Sakhalin Island, a combination of these relatively new technologies is being utilized to: (1) maintain a desired production profile, (2) mitigate the potential for sand production, and (3) maintain zonal isolation between various reservoir facies. In this development, screens are run across weak intervals to minimize the potential for sand production. Inflow control devices are added in high permeability intervals to delay the breakthrough of gas and/or water and enhance production from the lower permeability intervals. Pre-drilled liner is run across competent intervals that exhibit a low probability of sand production, and swellable packers are run

to isolate the various zones. This completion design meets all completion objectives, resulted in significant cost savings (~50 percent), and improved operational performance versus the original cased and perforated field completion design.¹

Openhole stand alone screen applications are best suited for high-angle completions in reservoirs with high permeability and well-sorted sands. The use of stand alone screens under other conditions, however, can result in screen plugging, poor productivity, or even sand control failure. If poorly sorted and unconsolidated formations are encountered, gravel packing is often deemed necessary.

Circulating Water Packs

Operators and service companies are beginning to report application of subsurface control technologies, similar to those used in standalone screens, in high-angle circulating water packs (alpha-beta).^{2,3} Alpha-beta gravel packing is used in wellbores with inclinations greater than ~60 degrees and relies on an alpha wave, controlled by fluid velocity, to deposit a gravel bed or dune on the low side of the wellbore. Fluid returns are essential for successful placement of gravel using this technique. Once the alpha wave reaches the toe of the well, a beta wave forms, packing the remaining wellbore from the toe of the well back towards the heel as fluid leaks off into the screen. Wellbore sections are left unpacked or "jumped," if fluid leakoff is not available. It is therefore possible to intentionally form a partial void in the gravel pack, creating the space necessary to set an openhole zonal isolation packer after gravel packing.² Packers add subsurface control to openhole completions by providing near-term and long-term isolation capabilities. A limitation with this circulating water pack technique is the difficulty eliminating the alpha wave from forming adjacent to the packer, leaving a high permeability gravel channel susceptible to gas or water bypass behind the packer element. Similar problems exist in low angle circulating water packs where gravity settling will result in gravel filling the void space adjacent to the packer. This would render zonal isolation ineffective as undesirable water or gas fluids can easily pass through the high permeability gravel.

Alternate Path Gravel Packing

Alternate Path gravel packing is an open or cased hole method applied at all well inclinations that minimizes the risk of an incomplete pack. This technique uses shunt tubes, a secondary packing system, to completely fill voids after the initial screen out. Two types of shunt tubes comprise this system, transport and packing, and attach externally to standard screen hardware. Transport tubes form a continuous conduit along the entire length of the completion and deliver fluid to packing tubes that branch off at the top of each screen joint. Packing tubes contain nozzles spaced approximately every 6 ft to deliver gravel slurry to the annulus. Typical systems use a "two-by-two" design, with two transport tubes and two packing tubes on each joint. The rectangular-shaped tubes and an eccentric cross-sectional screen design shown in **Fig. 1** minimize the effective outside diameter of the assembly. In openhole applications, an outer shroud covers

the entire assembly, providing shunt tube protection during installation.

An Alternate Path gravel pack is pumped using viscous slurry designed to transport gravel to the bottom of the well. Packing occurs from the toe of the well back towards the heel as fluid leaks off into the screen by base pipe annulus. A sand bridge may form in the annulus if fluid leakoff to formation fractures or high permeability sands becomes excessive. Packing continues until gravel covers the top of the gravel pack screens and an initial screen out occurs. With conventional techniques, gravel packing terminates upon screen out, leaving voids beneath the premature sand bridge. With Alternate Path technology, packing continues as slurry diverts into the transport shunt tubes and distributes to the unpacked or under-packed intervals through the packing tubes. After all intervals have been completely packed, pressure increases sharply again, signaling full screen out and a complete pack.^{4,5,6} In practice, an entire interval can be successfully packed through the shunt tube system. A 100-percent success rate using NAFpac, a variation of the Alternate Path gravel packing technique used when drilling with nonaqueous fluid, has been reported for Angola Block 15 in the completion of long, openhole gravel packs.⁷

Although routinely deployed and extremely successful, Alternate Path screens currently available for openhole applications have a number of inherent technical and operational limitations. These limitations include:

- Packable length of ~3,200 ft dictated by the pressure capacity and frictional pressure drop associated with the shunt system
- Challenges associated with incorporating openhole zonal isolation packers into the screen assembly due to the eccentric screen design
- Complexity of connection make-up (oriented connections and cross-coupling jumper tubes are required)
- Deployment exposure (outer shroud is required in openhole applications to protect the shunt tubes)

Many environments utilizing Alternate Path openhole gravel packs can benefit from improved subsurface control. While a zonal isolation packer (non-expandable, cup type with shunt bypass) has been designed for cased hole Alternate Path gravel packing applications, effective tools for openhole applications are not available.^{8,9} The eccentric design of the "two-by-two" Alternate Path system limits the ability to incorporate a concentric openhole packer that can be set prior to gravel packing, seal openhole geometries, and provide necessary pressure integrity.

New Alternate Path Screen Design

Continuous expansion and integration of Alternate Path technology with other evolving completion technologies is needed to accommodate the more challenging openhole completion environments of the future.

Internal Shunt Alternate Path technology is a new, enhanced design that has been developed and qualified to mitigate existing limitations and broadly expand the capabilities of current Alternate Path technology.

- The mechanical and hydraulic design of both the screen and the shunt tube system facilitates openhole gravel packing in wells with openhole intervals up to 5,000 ft in length.
- The product is concentric in design which provides the opportunity to incorporate specially designed external isolation shunt packers set prior to gravel packing to provide true zonal isolation while still achieving a complete gravel pack in an openhole completion.
- Unique connections between screen joints facilitate rapid and effective field make-up eliminating the need for both oriented connections and cross-coupling jumper tubes.
- Robust mechanical design eliminates the need for an outer protective shroud.

In order to create an operable shunt system, a number of challenges were identified and resolved:

- Sufficient flow capability, pressure integrity, and erosion resistance of the internal shunt system
- Exit nozzles at appropriate spacing along the length of the screen
- Flow manifold to divert fluid between packing tubes and transport tubes
- Design that enables simple handling and rig floor make-up

Sand Control

Internal Shunt Alternate Path screen incorporates direct wrap sand screen technology where the wrap wire is applied directly on the basepipe.¹⁰ Direct wrap techniques were modified to produce sand control screens with high (20+ mm) axial ribs on 5-1/2-in base pipe to create sufficient offset to facilitate installation of round shunt tubes under the wire wrap (i.e., "internal shunt") shown in **Fig. 2**. This technique results in a mechanically robust, concentric screen that eliminates the need for an outer protective shroud and facilitates interface with openhole packers. The 7.76-in OD of the internal shunt screen is comparable to the 7.65-in OD of the currently available Alternate Path screen.

Connection

The connection between screen joints is based on a standard premium coupling, as shown in **Fig. 3**. A concentric outer sleeve installed outside this coupling during manufacturing provides an annular conduit, or manifold, to transport shunted fluid flow between screen joints. This connection design facilitates simple rig floor make-up similar to conventional tubing handling operations. In contrast to the existing Alternate Path technology, there is no need to orient or align shunt tubes.

Shunt System

Nine round shunt tubes are integrated into the screen design, six tubes for joint-to-joint slurry transport and three tubes with exit nozzles for the gravel packing operation. Round shunt tubes provide a higher burst capacity than the rectangular tubes of the existing design, resulting in higher shunt system pressure capacity and longer packable length. Access to all transport and packing tubes is at the top of each joint in the manifold section. Smooth, machined profiles in the manifold were optimized by extensive laboratory testing and computational fluid dynamics (CFD) analyses to reduce shunt system pressure loss. Nozzle rings are spaced along the length of the joint and house three nozzles per ring (at 120 degrees apart) to allow for discharge of sand slurry from the packing tubes.

Qualification Testing

Significant testing was conducted on both components and full-scale prototypes to verify screen functionality. Tests targeted flow capacity, erosion, pressure integrity, mechanical integrity, gravel packing, and rig handling. At the conclusion of qualification testing, the Internal Shunt Alternate Path screens met or exceeded all design requirements.

Flow Capacity

Initial tests were run to determine the size and number of round shunt tubes required to fully pack a 5,000 ft openhole section at a rate of 4 - 5 bbl/min through the shunt tubes. Base gel, of known rheology suitable for Alternate Path gravel packing, was pumped through 100-ft lengths of various sized round shunt tubes to determine the friction loss through each tube. Six 20mm x 16mm (OD X ID) shunt tubes yielded frictional response comparable to the two 1.5 x 0.75-in transport tubes in the current "two-by-two" Alternate Path system. Although larger shunt tubes reduce the pressure drop and thus the pressure requirements for the Internal Shunt Alternate Path screens, the screens become too large for the desired application.

Erosion

A physical model was built to determine erosion effects of pumping ceramic proppant through the manifold located at each screen connection. The slurry was pumped at the proposed field pumping rates of 5 bbl/min. The manifold inlets and outlets were misaligned to represent the worst case field scenario when two screen joints are coupled together. One hundred fifty-two thousand (152,000) lbs of 30/50 ceramic proppant, the amount of proppant required to fully pack 5,000 ft of 9-7/8 in openhole by screen annulus with 50 percent excess, were pumped at 2-4 PPA (pounds of proppant added) and 5 bbl/min through the system. No erosion was observed in the manifold, but an unacceptable pressure drop through the manifold was measured. CFD models were calibrated using the experimental data from the physical test and used to optimize the manifold redesign. Based on results of the modeling, the length of the manifold was extended and subsequent testing revealed a 50 percent reduction in pressure drop. One hundred twenty-seven thousand (127,000) lbs of 30/50 ceramic proppant was pumped through the redesigned

system at 4 PPA and 4-5 bbl/min to verify no erosion concerns with the new design.

While packing through the shunt tubes, gravel is deposited around the screens through the packing tubes. A test was developed to determine the erosional effects of pumping slurry through the nozzles. The physical model, consisting of a single packing tube with six nozzles, simulated pumping the entire gravel pack through the top two to three joints of shunted screen at 5 bbl/min with one of the three nozzles at each nozzle ring plugged. Thirty-eight thousand six hundred (38,600) lbs of 30/50 ceramic proppant were pumped through the apparatus. Flow rate and proppant concentration were measured through each nozzle. The tungsten carbide nozzles showed minimal erosion. Photographs of the nozzles from the erosion test are shown in **Fig. 4**.

Pressure Integrity

Throughout all the physical testing, friction pressure drops were measured through the shunt system and manifold section in order to establish a baseline friction pressure through each joint of Internal Shunt Alternate Path screen. The final friction pressure associated with pumping through each joint of screen, including the redesigned manifold, is shown in **Fig. 5**.

At 4 bbl/min, 6,000 psi would be required to pump through the entire 5,000 ft of shunt tubes, therefore, the pressure integrity of the shunt system must be rated higher than 6,000 psi. Individual shunt tubes welded to an end ring were designed and pressure tested to 10,000 psi. The manifold seals required a specially designed seal stack to withstand the 10,000 psi test. The entire system was pressure tested to 10,000 psi at ambient temperatures and 180°F. Six thousand five hundred (6,500) psi was held at 170°F for a period of eight hours simulating the pumping of an entire gravel pack job through the shunt tubes.

Mechanical Integrity

Burst and collapse testing of the sand control screen was required to evaluate the behavior of the new, higher axial rib wires (support structure for the wrap wire). A burst condition exists when an inside the screen fluid loss pill is placed in an overbalanced condition during a completion or workover operation. Burst tests were performed on samples of 9-gauge, Internal Shunt Alternate Path screen. Strain gauges were placed along the length of the assembly. The screen was installed in a test fixture and a carbonate pill was placed inside the screen. Pressure was applied to the inside of the screen until excessive strain was observed in the wire wrap. Final burst pressures exceeded 2,400 psi, and upon examination of the screens, no gaps larger than 12-gauge were found in the samples. Sand control was maintained in all cases, and the pill remained intact at the end of each test.

While a true collapse condition where the screen is completely plugged is unlikely, the screens were tested to ensure the top screen joint could withstand the elevated pressures while pumping through the shunt system and at the time of final screen out. Collapse testing was performed by placing a ¼-in

thick layer of 30/50 ceramic proppant around the circumference of a 9-gauge, Internal Shunt Alternate Path screen sample. The proppant was held in place with an impermeable barrier adhered to the sample. The screen sample was placed inside a test fixture, and pressure was applied to the outside of the screen. Initial collapse test results led to an end ring modification and increase in the number of axial wires from 18 to 27. Final testing after incorporating all of the enhancements yielded a collapse pressure of 5,785 psi. Collapse resulted in a screen indentation, but sand control was maintained. Finite Element Analysis (FEA) was conducted to validate the physical testing and to specify mechanical property requirements for shunt tubes and wrap wire.

Gravel Packing

A horizontal test fixture (10-in ID) was used to test the packing functionality of the Internal Shunt Alternate Path screens. The prototype consisted of two screen joints (11.3 and 14.5 ft respectively) made up together with a manifold section. Each screen joint contained two nozzle rings with one of the three nozzles in each nozzle ring intentionally plugged. The uphole end of the test fixture was blocked, simulating either a sand bridge or an openhole packer, forcing all the slurry through the shunt tubes. The slurry consisted of base gel with 4 PPA 30/50 ceramic proppant. Rates were limited to 1 bbl/min during the test due to test fixture pressure constraints at the time of screen out.

Gravel pack tests were run using the prototype screens, both with and without 3-1/2-in washpipe inside the basepipe. As shown in **Fig. 6**, a 100-percent gravel pack was achieved. Fluid was then flowed back through the gravel pack at a rate of 15.7 gal/min through the 25.8 ft of screen, equivalent to 25,000 B/D through 1,200-ft screen. The gravel pack remained intact, leaving no exposed screen.

Rig Handling

Full length prototype joints of Internal Shunt Alternate Path screen were taken to a rig site, shown in **Fig. 7**, to evaluate the ease of handling and make-up of the screen joints with 140,000 lbs of buoyed weight below the screen joints. After a safety briefing and a short equipment orientation, the rig crew, who had previously never seen the screens, ran the screens at a rate of 12 joints per hour, compared to the typical five joints per hour rate for the current "two-by-two" Alternate Path system. One test joint of the screen was axially loaded to 408,000 lbs, simulating 5,000 ft of screen with 230,000 lbs of overpull. A post-test slot size inspection indicated less than 0.5-gauge change in slot width.

Application Opportunities

To grasp some of the potential for Internal Shunt Alternate Path technology, a few application opportunities and associated benefits will be briefly discussed.

Opportunity 1: Isolating Bottom Water

When bottom water is encountered during the drilling phase, few operationally attractive and cost effective mitigation options are available. The operator can attempt to set an openhole plug (cement or openhole packer) to isolate the zone.

Alternatively, the operator could choose to plug and abandon the openhole interval and then, with better geologic control, drill a sidetrack with the intent to avoid penetration of the water zone. Regardless of the technique chosen, the required remedial action takes significant time and results in substantial added cost.

With Internal Shunt Alternate Path technology, the openhole can be drilled through the entire payzone until the bottom water is encountered, thus maximizing the productive reservoir interval. The Internal Shunt Alternate Path screens are run with an openhole isolation packer spaced out and located in a low permeability zone above the water contact (identified using the openhole log). After mechanically setting the isolation packer, gravel packing commences and all productive intervals are fully packed above the water zone.

As shown in **Fig. 8**, Internal Shunt Alternate Path technology allows the operator to:

- Drill the entire reservoir section
- Respond efficiently to geologic uncertainties
- Eliminate costly plug back or sidetrack operations

Opportunity 2: Isolating Mid-Zone Water / Gas

With current technology, mitigation options to isolate mid-zone water or gas are quite limited. An operator could decide to complete the well as drilled and accept the constrained hydrocarbon production rates associated with the production of the undesirable fluid (water and/or gas). Alternatively, the well could be plugged back and redrilled to just above the identified water/gas zone. Although the undesirable fluid could be avoided, this technique is only partially effective as substantial hydrocarbon reserves from deeper horizons may be permanently lost.

After drilling the well, the undesirable gas or water zone can be identified on the openhole log. Shown in **Fig. 9**, Internal Shunt Alternate Path technology sand control screens, along with isolation packers and specially designed shunted blank pipe, can be configured and run to straddle the water / gas bearing intervals with the packers set in low permeability shale zones. After mechanically setting the packers, gravel packing operations commence packing the top zone first, skipping the blank section, and then fully packing the lower zone through shunt tubes.

Note that such a completion with true zonal isolation can only be achieved with Alternate Path technology, which is able to pack across any obstruction in the wellbore, be it natural (premature sand bridge in the annulus or collapse of formation around the screen) or intentional (installation of external isolation packers).

The cost savings and reservoir recovery potential associated with this technology is substantial. The Internal Shunt Alternate Path screens and isolation packer assembly:

- Eliminates costly sidetrack or plug back operations
- Facilitates aggressive drill well planning which can maximize reservoir recovery potential from every wellbore

- Enhances long-term production performance and wellbore reliability by delivering a complete gravel pack across all payzones

Opportunity 3: Isolating Gas / Water Breakthrough

Openhole, multi-zone completions are especially susceptible to premature water or gas breakthrough. This is particularly pertinent in developments where injector - producer pairs are installed to maximize reservoir recovery. When breakthrough occurs, production performance can be impaired significantly. Often, the breakthrough occurs in discrete, high permeability stringers that if properly isolated, could enable the well to be returned to its desired production rate.

Internal Shunt Alternate Path technology screens with zonal isolation packers that are pre-installed at strategic, low permeability intervals in the wellbore make it possible to effectively isolate water or gas breakthrough zones that may evolve over the course of routine production (**Fig. 10**). Straddle isolation tools are installed through intervention workover operations across problematic zones resulting in true isolation of the undesirable fluid (gas or water).

Opportunity 4: Stacked Pay, Openhole Gravel Packing

Completions in stacked pay applications, such as the Gulf of Mexico, have typically been managed by leveraging cased hole completion techniques, such as frac pack, high rate water pack, or slurry pack. If the number of pay intervals and / or the distance between target zones is large, the operator is often driven to complete each zone separately. Wellbore diameter, casing size, cementing, perforating effectiveness, and fluid loss during the completion phase, all have significant implications on the eventual production performance and long-term reliability of the well.

Internal Shunt Alternate Path screens with external isolation packers can be used to complete the entire well in a single operation. The internal shunt screens, along with shunted blank pipe and isolation packers, are spaced out as necessary to isolate each payzone interval and/or straddle zones containing undesirable water or gas. After mechanically setting the packer, gravel packing commences with the top payzone packing first. The slurry jumps across each blank section, while fully packing all screened sections below in a single pumping operation. The resulting completion is shown in **Fig. 11**.

In stacked pay applications the Internal Shunt Alternate Path technology screens with isolation packers:

- Eliminates the need for casing and cementing operations
- Eliminates the need for perforating, surging, and cleanout operations
- Eliminates the need for repeated pumping operations for each of the stacked intervals
- Improves productivity by decreasing the pressure drop through the completion
- Can be run in any hole deviation

- Can save 12 to 15 days of rig time for a typical three-zone stacked pay completion

Conclusions

New screen technology has been developed and qualified to facilitate openhole gravel packing with true zonal isolation. Internal Shunt Alternate Path hardware enables new application opportunities through improved operational performance and subsurface control. Project objectives were achieved and have resulted in enhanced Alternate Path screen functionality which:

- Adds zonal isolation capability in an openhole gravel pack to seal off bottom water, isolate a zone, and/or leave an unpacked section
- Adds selective gravel packing capability of specified intervals in stacked pay applications
- Extends gravel pack reach from ~3200 to 5000 ft
- Reduces connection make-up time and complexity
- Eliminates the screen's outer protective shroud

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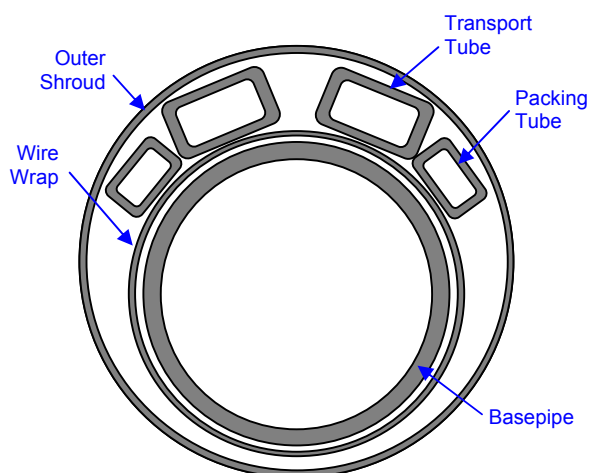


Fig. 1. Alternate Path "Two-by-Two" Screen Cross-Section

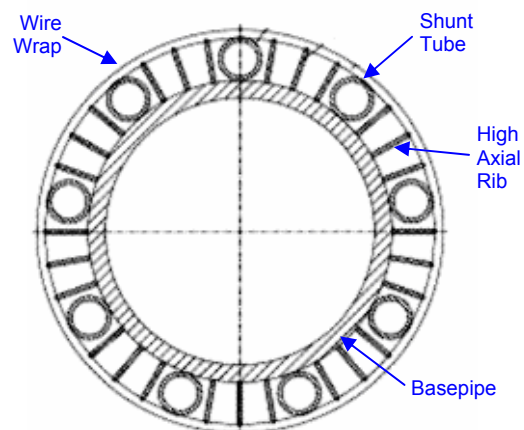


Fig. 2. Internal Shunt Alternate Path Screen Cross-Section



Fig. 3. Shunt System Manifold Box-End (without outer sleeve)

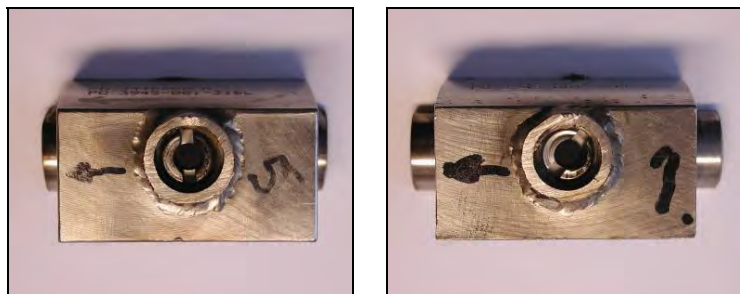
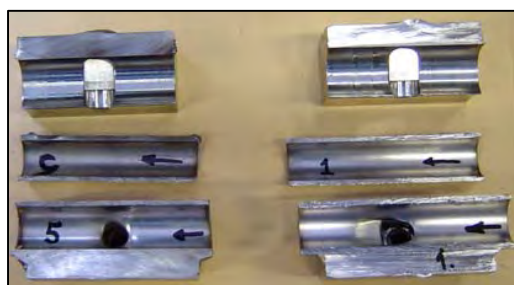


Fig. 4. Nozzle Erosion Test Results

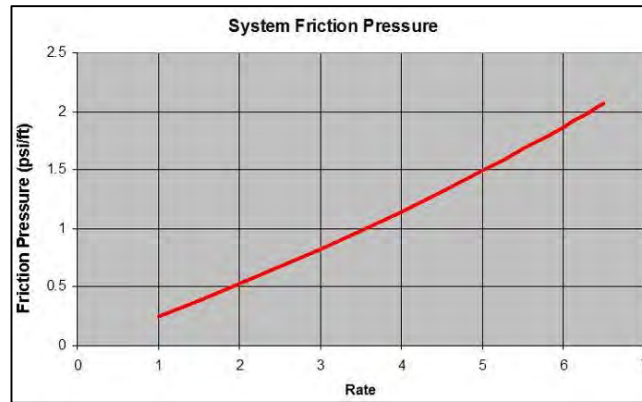


Fig. 5. Shunt System Friction Pressure

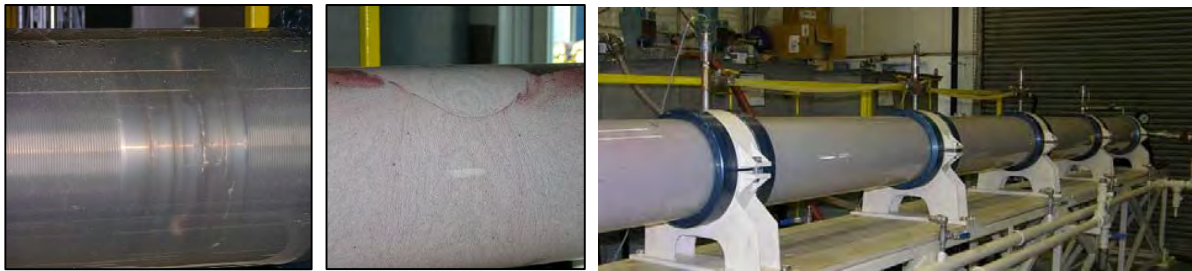


Fig. 6. Gravel Pack Qualification



Fig. 7. Rig Handling Qualification

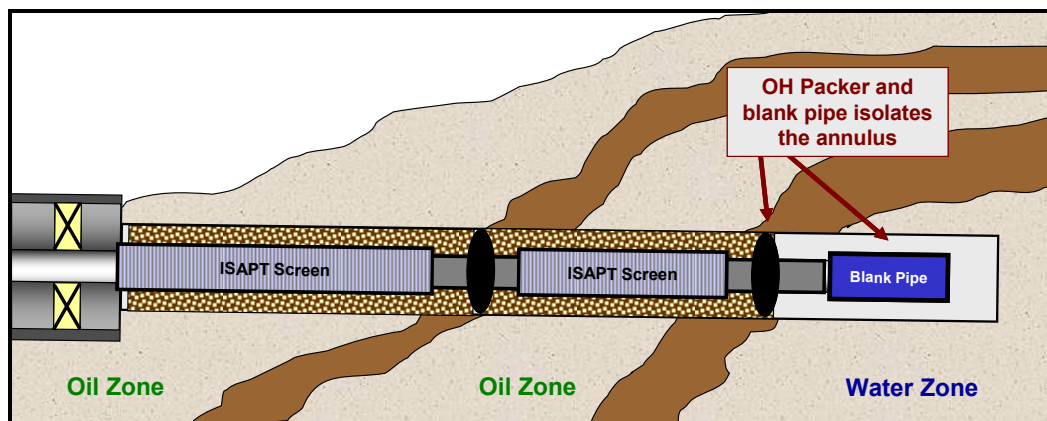


Fig. 8. Opportunity 1: Isolating Bottom Water

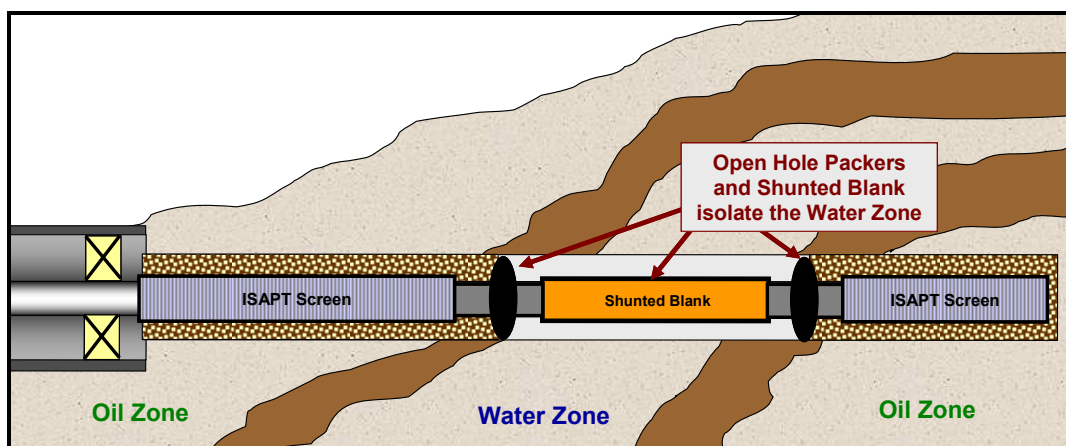


Fig. 9. Opportunity 2: Isolating Mid-Zone Water / Gas

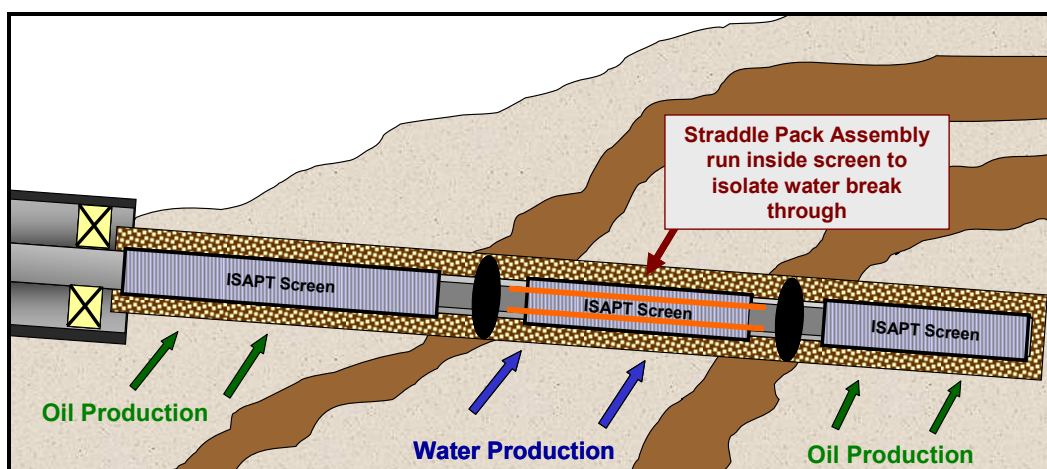


Fig. 10. Opportunity 3: Isolating Gas / Water Breakthrough

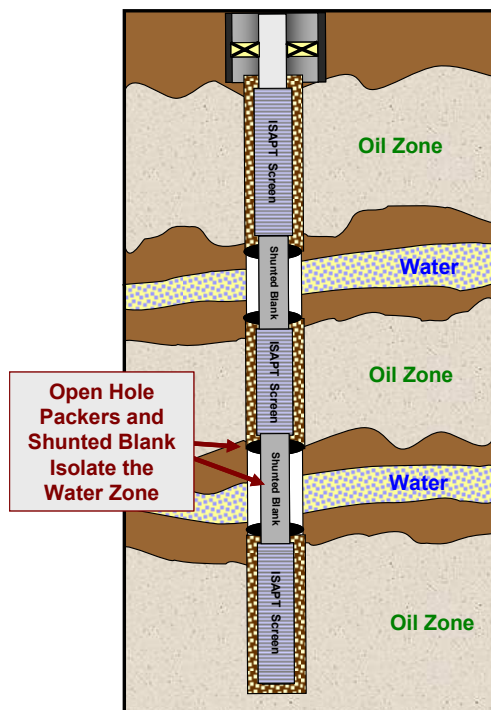


Fig. 11. Opportunity 4: Stacked Pay, Openhole Gravel Packing

EXHIBIT I



SPE-169440-MS

Design and Validation of an Improved Shunt Tube System

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Abstract

Shunt tube technology to mitigate premature bridging in the annulus while pumping slurry has been used successfully in the oilfield for over two decades to assure complete gravel placement. The systems have been applied in a variety of scenarios including single and multizone completions, cased and openhole completions, and both gravel and frac-pac applications. By deploying a screen system empowered with the slurry bypass mechanisms of a shunt system, an operator usually experienced greater job reliability, a reduced possibility of pack failure, and maximized production.

This paper discusses an improved version of the traditional shunt tube system that has recently been developed by a major engineering and service company to enhance sand screens for gravel packing in long production intervals. The system was designed primarily for gravel packing in horizontal wells and is a system with two larger transport tubes and two smaller packing tubes, all mounted to standard sand screens in an eccentric design. A new seal design improves sealing capability between the joints of screen. By the optimization of the attachment of the tubes to each other, to the rings mounting the system to the screen, and to the sealing fittings at the transport tube ends, the design significantly enhances system capabilities.

Computer flow modeling was used to improve erosion resistance and lower pressure loss by reducing friction at tube connection flow transitions. Extensive test programs to ensure equipment integrity, including torque, tension, and compression capability of major components were used. The system can be assembled more quickly due to the shroud covering the joint connection being an integral component of the screen with no bulky clamshell hinges or pins to be assembled.

The improved pressure sealing, erosion resistance, ruggedness, improved rig assembly times, and system qualification will be presented in the paper.

Introduction

As the industry moves into a time that challenges operators to push the limits of discovery and extraction, treating unconsolidated reservoirs and producing the oil and gas has become increasingly difficult. As operations move into deepwater, HPHT environments, extended reach wells with long intervals can be complex, costly, and challenging, especially when sand exclusion techniques are required. As the horizontal wellbore penetrations into these reservoirs become longer, the field proven technique of utilizing shunt tube equipped screens that provide alternative paths for the gravel pack placement is increasingly called on as the completion method of choice (Hurst et. al, 2004; Bryant and Jones, 1995).

The shunt tube systems that have been developed and now refined address the classic problems in gravel packed completions (Colwart et. al, 2009). While used in a variety of scenarios, shunt systems tend to have more recognized value in long openhole horizontal completions and deviated wells due to the increased problems deploying the pack, as premature annuli bridging, voids, and thief zones are all working against success. By utilizing secondary pathways for slurry deposition by attaching specific tubing (shunts) configurations to the sandface completion, an improved shunt tube packing sequence can lead to improved gravel pack placement (Tibbles et. al, 2000). As service companies work with operators to deliver shunt completion hardware that is fit-for-purpose, the industry continues to document how these systems are beneficial in achieving higher percentages of gravel placement and greater well productivities in wells in which they are deployed (Bryant and Jones, 1995; Jones et. al, 1997). Design improvements to the traditional shunt systems have been considered for some time, and the execution of a research and development program to address these improvements is discussed below.

Basis of Design

The main basis of design for the new system was to keep it functionally the same as existing industry-proven designs, in order to enjoy the empirical evidence of years of successful application of shunt tube gravel-packing technology. In this context, “functionally the same” was considered to be achieved if the flow areas for gravel packing slurry were essentially the same, the branching of flow to secondary tubes (packing tubes) from the primary flow tubes (transport tubes) was done in approximately the same manner, and the location and size of exit ports for flow to exit from the packing tubes were essentially the same. The mounting of the shunt tube system to each sand screen joint was designed in a common eccentric configuration, with the transport tubes brought into alignment at each joint connection via the use of an “oriented” premium thread. With this principle, extensive testing was not necessary to prove the ability to pack in various real-world conditions of deviation, leak-off, annular flow path blockages, and length of interval.

In certain parts of the design (i.e., for the jumper tubes across connections), it was determined that round tubes instead of the common industry design of rectangular tubes would be better. This choice led to a decrease in the amount of flow area in certain parts of the new design. For these parts, analyses were made to verify that although the flow areas were less, the friction pressure loss for these parts were essentially identical to those for the rectangular tube designs, owing to the nature of friction pressure loss in round tubes versus rectangular tubes.

Within the constraint of keeping the design functionally the same as proven designs, several enhancements were made to operational features. These enhancements were targeted primarily at decreasing the time required to assemble joints of shunted screen on the rig and also improving some features of reliability of the shunted screens. In general, all features were designed with the intention to equal or improve on industry standards for speed and reliability.

Improvements

Assembly Speed

Multiple features were used to shorten assembly time. These include a “snap” locking assembly of the jumper tubes that span each connection as well as using an integral shroud to cover each connection after the jumper tubes have been installed.

A design using “snap” c-rings was developed to attach the tubes that span the connections (jumper tubes) between shunted sand screen joints.

- In Figure 1 the snap rings compress as the male end fitting of each jumper tube is inserted by hand into the female end fitting at the ends of the transport tubes at either end of each joint. The snap rings expand into grooves in the female connector upon reaching the proper insertion depth. Small

hand tools are not necessary for assembly of these tubes. The jumper tubes telescope to accommodate small length variation across each connection.

Note: For the contingency of required disassembly of the system, a c-ring compression tool is required to disengage the snap ring at each end fitting as the jumper tubes are removed.

- A sliding shroud, integral to the design, was also developed to shorten the handling time which would be required to wrap a separate “clamshell” style shroud around the connection and secure it closed. The sliding shroud comes to the rig site in place over the lower end of each screen joint. Prior to lifting each joint to the rig v-door (and not directly part of the rig-floor assembly timeline), a handling tool is clamped around the sliding shroud to lock it in place relative to the underlying screen shroud, and to provide a convenient way to grip and control the shroud.

When the jumper tube connections for each joint are complete (normally two are used), a release lever on the handling tool is pressed to allow the sliding shroud to slide down and over the connection area. A large “snap” c- ring is compressed under the sliding shroud, and when the shroud is in the proper position the snap ring expands into a locking recess inside the upper end of the sliding shroud, thus locking it into place. [Figures 2 and 3](#) illustrate the improved assembly process.

Reliability

Features added to enhance reliability include the round jumper tubes and the cast fittings at the jumper tube connections. It is notable that in all the testing done on the new shunt tube system, a seal or mechanical failure of the new round jumper tube and cast fitting connection system did not occur.

Due to uneven bending and “squeeze” on o-rings that seal fittings in non-round shapes, rectangular tube fittings are prone to leaks. Also, due to variations in make-up of the oriented thread at each connection, rectangular tubes are subject to a rotational offset in addition to a lateral offset when the tubes of successive joints do not align perfectly. This phenomenon leads to uneven seal squeeze and is thought to cause more leaks. Consequently, it was decided early in the development of the new shunt tube system that round tubes would be used at the jumper tubes to connect the tube system across joint connections.

The new shunt tube system uses cast fittings at each end of the transport tubes (see [Figures 1 – 3](#) and [Figure 4](#)). These fittings are attached to the transport tubes in the manufacturing process, and are female connections on both box and pin ends, with the sealing surfaces and locking grooves inside the fittings well protected from damage during shipping. On the box end of each joint, the cast fittings also incorporate the hydraulic “branch” to the packing tubes for that joint, with the packing tubes being welded to the fittings rather than directly to the transport tubes. This design enables more reliable welded connections between the packing tubes and the cast fittings than is possible if the relatively thin-walled packing tubes were welded directly to the relatively thin-walled transport tubes.

Also, the reduction in manual processes required on the rig floor should lead to improvement in reliability of the new system.

This shunt tube system utilizes 2 x 2, eccentric configuration. This configuration of the shunt system is used across the industry and has well known flow characteristics. This shunt tube system is using the same size, the same geometry of the transport and packing tubing, the same exit port spacing and arrangement (shown in [Figure 5](#)).

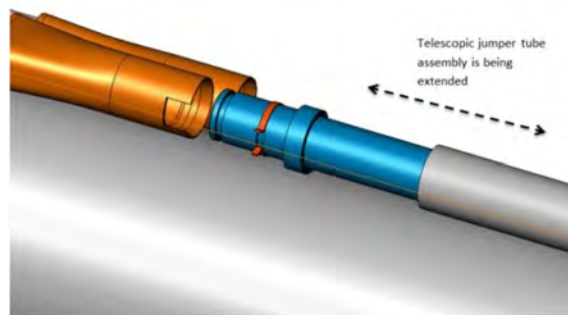


Figure 1—snap rings compressed

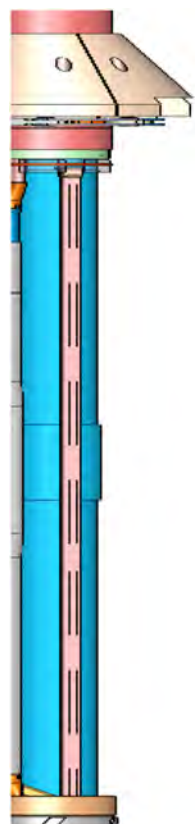


Figure 2—Sliding shroud with handling tool before sliding the shroud over a joint connection while the jumper tubes are already in place.



Figure 4—Cast End Fitting for Box End of Transport tubes and Packing Tubes

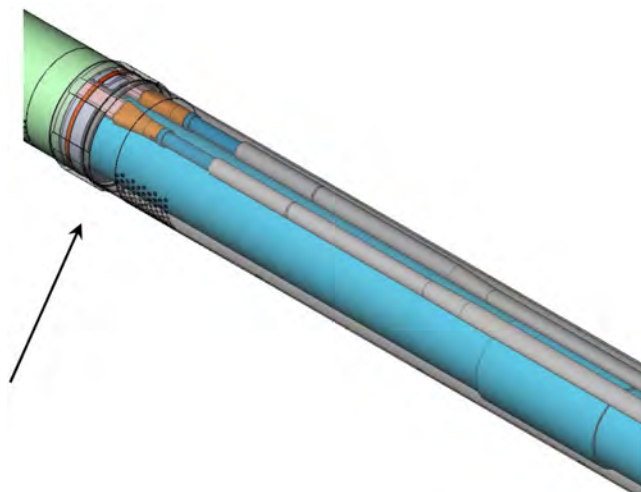


Figure 3—A large locking ring holds the sliding shroud in the proper position during run-in-hole(RIH).

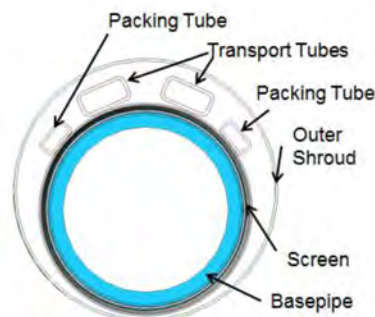


Figure 5—Cross section of shunt tube system

The shunt tube system is very similar to currently available shunt systems on the market; however, this system brings multiple design changes which contribute to increased reliability, faster rig installation, and eliminates the danger of small tools and parts falling into the well during system installation.

The design improvements include:

- Substitutions of the rectangular shape of the seal with round shape of the seal
- Elimination of the connection weld between the shunt tubing weldments and base pipe weldment support rings
- Use of erosion resistant material in erosion sensitive areas of the shunt system
- Tool-less jumper tubing connection
- Elimination of the use of fasteners for the leak off tubing securing the joint connection area
- Replacement of the clamp type shroud over the joint connection area with sliding type of shroud

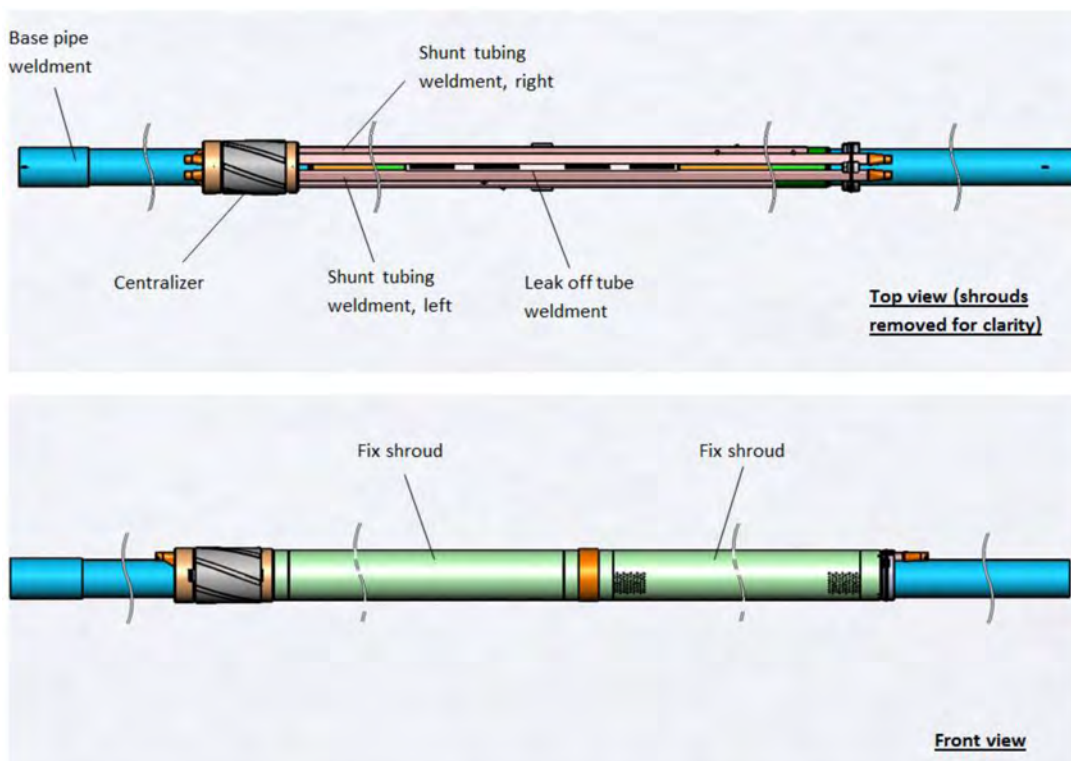


Figure 6—Main components of shunt tube system joint

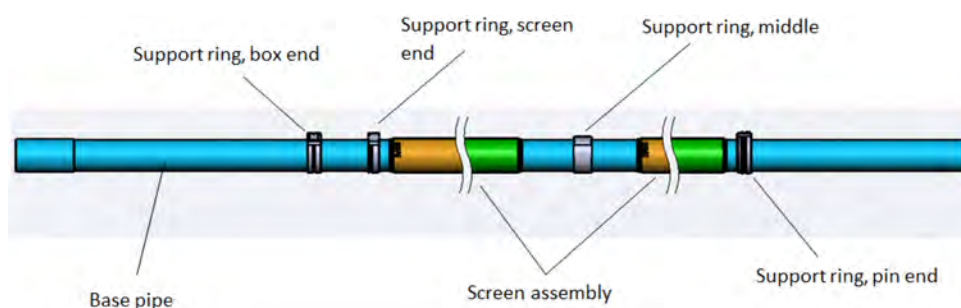


Figure 7—Base pipe weldment with its components

- Replacement the clamp type of centralizer with solid/rigid type of centralizer

The shunt tube system joint generally consists of the following sub-assemblies and components (Figures 6–9):

Notes on the shunt system construction

The outer (fixed) shroud holds the shunt tubing weldments and leak off tube weldment in place. It is welded to the base pipe support rings. It protects all the components and makes the joint smoother. The shroud is perforated.

A solid or rigid type of the centralizer is used. The centralizer is installed during manufacturing but can be replaced prior to system installation on the rig floor. The centralizer is secured into its operating position with centralizer support rings and snap rings (see Figure 10).

Individual joints connection (see Figure 11):

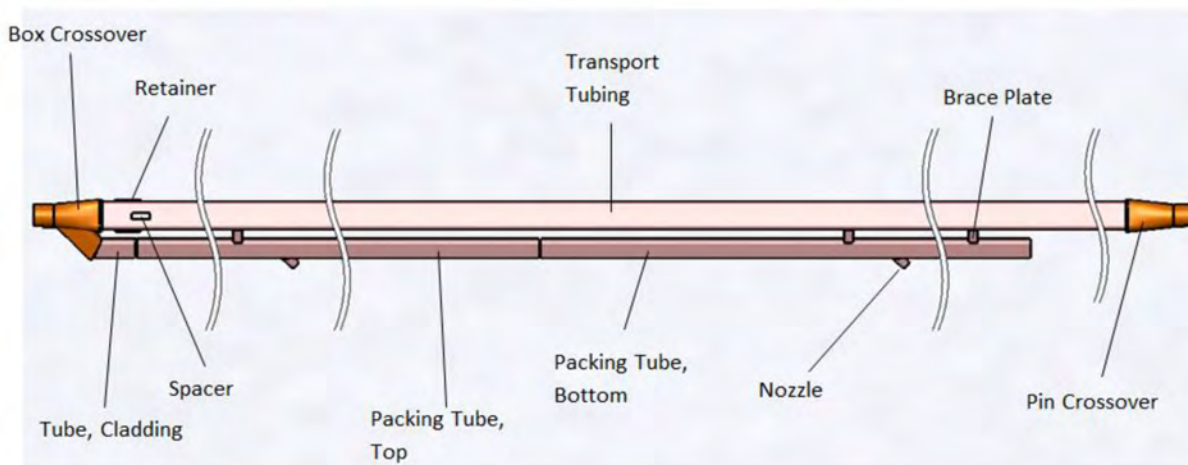


Figure 8—Shunt system tubing weldment with its components



Figure 9—Box end crossover, internally-cladded Packing Tube, and Pin end crossover

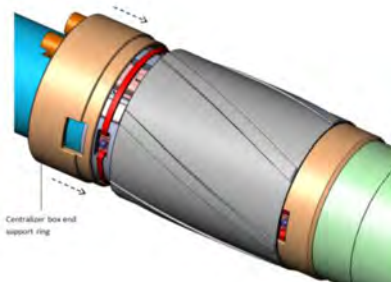


Figure 10—Installation of the centralizer

After the joint thread is made up, the jumper tubes and leak-off tube are installed, and the integral sliding shroud is moved down from its shipping position on the upper joint to its run-in position over the connection area.

Leak off tube The leak off tube helps to dehydrate the connection area during the gravel packing operation. There are no fasteners used to secure it into its operating position. Only the geometry features are locking the leak off tube into place. The lower end of the tube slides under the bottom joint centralizer, all the way to the screen section (see Figure 12). The upper end of the tube hooks into the supporting ring groove and is locked in when the sliding shroud is activated (see Figure 13).

EXECUTION OF THE DESIGN—DEVELOPMENT AND TESTING

The new shunt system physical performance was validated through an extensive suite of testing. The testing included:

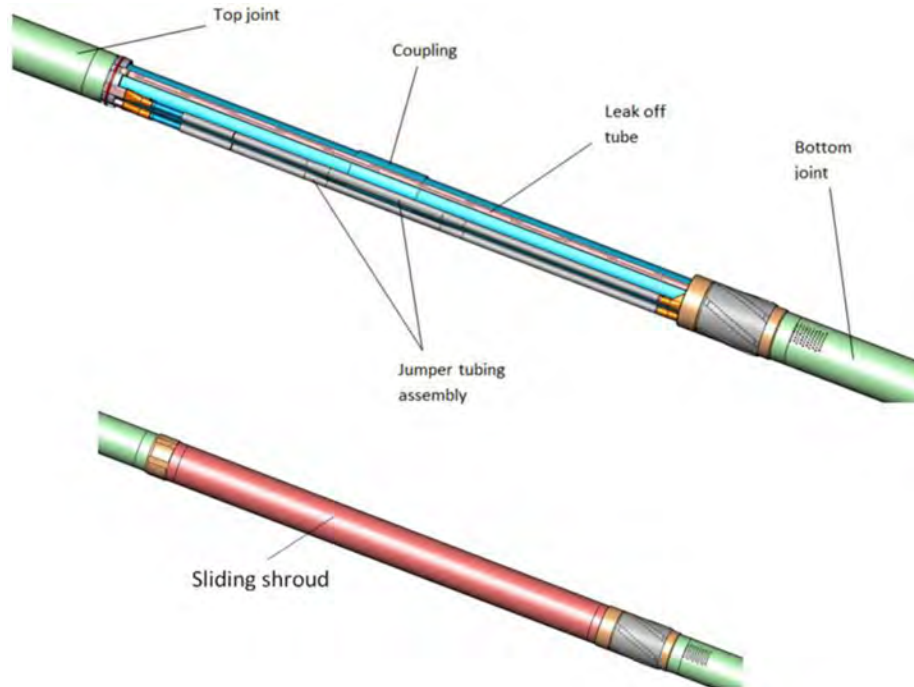


Figure 11—Joint connection components

- Outer (fixed) shroud tension test
- Outer (fixed) shroud torque test
- Dog Leg (bending) test
- Shunt tubing burst pressure test
- Shunt tubing collapse pressure test
- Centralizer radial load test
- Centralizer axial load test
- Jumper tubing connection tensile test
- Shunt tubing erosion test

The test protocol and results for each of these tests will be described.

Additionally, a shunt system flow (gravel packing) test was performed multiple times. The design of the flow paths and slurry exit ports of the new shunt system was intentionally made to match existing systems so as to rely on the considerable history of success in gravel packing with such shunt systems, so these were actually demonstrations rather than tests.

Since no aspect of this testing was expected to (or did) approach the mechanical limits of the new shunt system, it is considered outside the scope of this paper.

Also, an analysis was done on the flow pattern in the jumper tube component of the new shunt tube

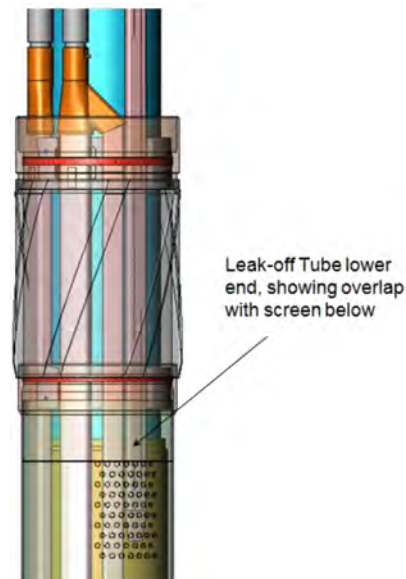


Figure 12—The leak off tube lower end placed under the centralizer

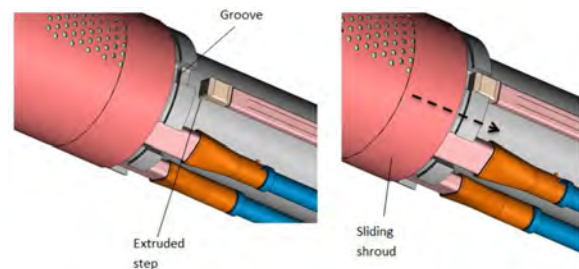


Figure 13—Securing the top end of the leak off tube into its operating position

system because these tubes differ from existing shunt tube systems in that they are round rather than rectangular.

- CFD simulation of the jumper tube section of the shunt system The results of this CFD simulation will be described.



Figure 14—The fixed shroud tension test sample placed into a test bay with a loading frame.

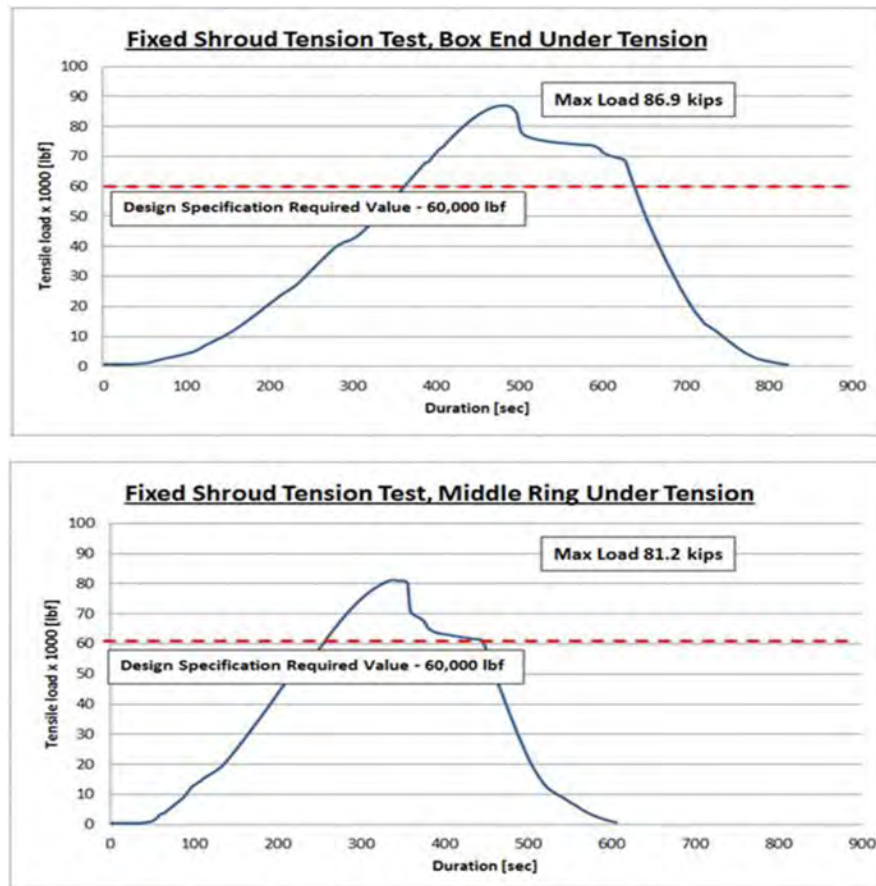


Figure 15—Fixed shroud tension test data recording sample.

Outer Shroud Tension Test The outer, fixed shroud over the shunt tube system (and the sand screen filter media underlying it) was tested for strength of attachment to the base pipe with respect to tension. A half-joint of shunt screen was constructed to mimic an actual joint upper half (upper half provides less weld), but without the shunt tubes and filter media actually installed; only the support rings, to which the shunt tubes would be mounted, and the outer shroud were actually attached (welded) to the base pipe. It was felt that the omission of the shunt tubes was allowable because their omission would tend to weaken the structure, hence creating a conservative test.

For the tension test, a testing ring was welded to the outer shroud of the half-joint of shunt screen at the middle of the outer shroud, and the test sample then mounted in a test bay with a loading ram (see Figure 14).

A tension load was applied to the half-joint of shunted screen multiple times, with increasing load until the test sample yielded plastically. An output chart typical of the results of this testing is shown in Figure 15.

A rating of 60,000 lbf, the goal rating for the product, was assigned to the new shunt tube system as a result of this testing, as the chart values indicated no plastic deformation within a factor of 1.4 of the plastic yield results.

Outer Shroud Torque Test A half-joint sample was prepared similarly to that for the tension testing, and the sample placed in a torque machine capable of applying torque to the welded testing ring (see Figure 16).

Again, a load was applied several times until plastic yielding of the sample. A typical load chart for this testing is seen in Figure 17.

The goal rating for torque was only 5000 ft-lb, but as indicated in the chart, plastic yield did not occur until above 10,000 ft-lb applied, comfortably supporting the 5000 ft-lb rating.



Figure 16—Outer shroud torque test setup.

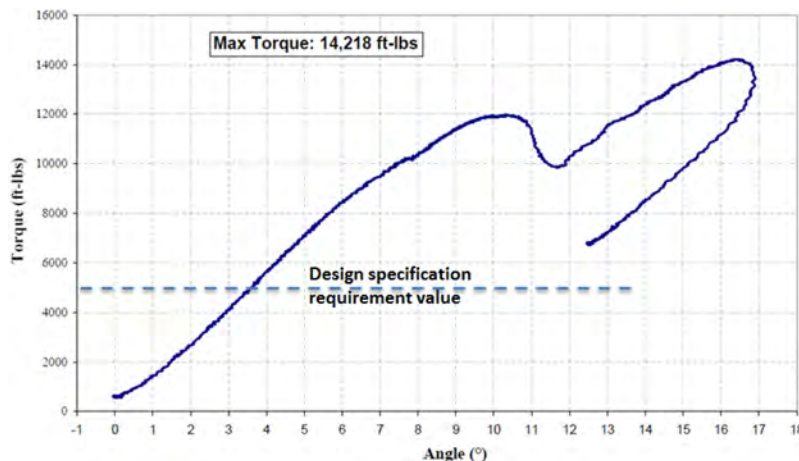


Figure 17—Fixed shroud torque test data recording sample.

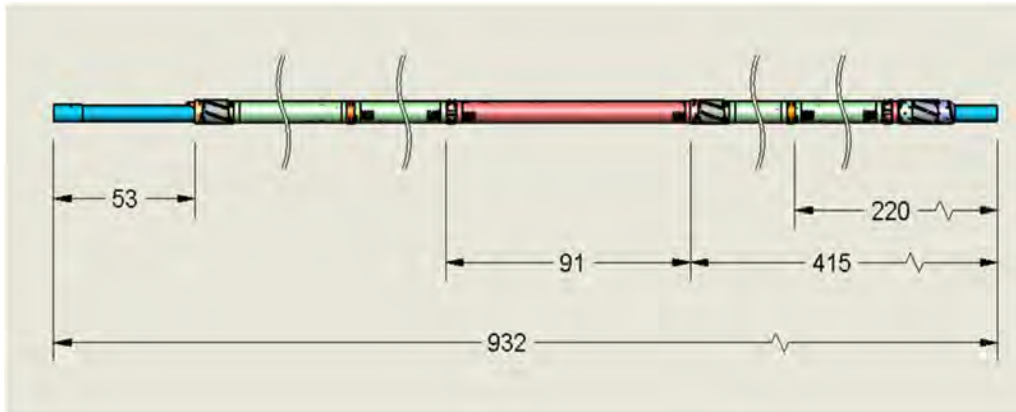


Figure 18—The test sample (assembly of two individual joint) used for dog leg (bending) test.



Figure 19—The dog leg (bending) test setup is shown on this image.

Dog Leg (Bending) Test The objective of this test was to verify that all components are able to maintain functionality during and after the completion is run into its operating position. Two full joints were assembled (see Figure 18).

The test sample was placed into the test fixture which simulated the transition of the vertical section of the well into the horizontal section of the well (see Figure 19). The curve rate of the casing was 15 deg / 100 feet. The box end of the sample assembly was connected to the ram. The ram provided reciprocal movement with a stroke of eight feet and a velocity of 2 feet per minute. The duration of the test simulated running the screen in the curve for a distance of 2000 feet.

The test sample was inspected before and after the test. All components retained their structural integrity and full functionality.

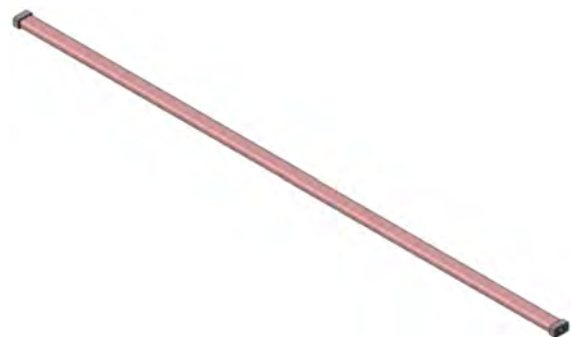


Figure 20—Stand-alone tubing used as a sample for burst pressure test.

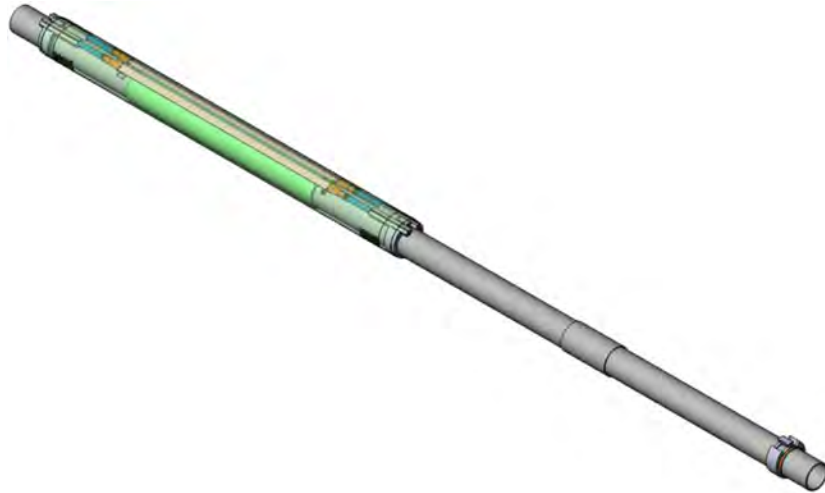


Figure 21—Image showing the complete section of the joint used as a sample for burst pressure test.



Figure 22—Image showing burst pressure test setup

Shunt Tubing Pressure Test The objective of this test was to determine the burst pressure rating of the shunt system. Multiple variations of test samples were subjected to this test. For example, tests were performed on stand-alone shunt tubing (see Figure 20) and on complete sections of the joint assembly with screen and outer (fixed) shroud (see Figure 21), as these components were expected to affect the free movement of the tubing, and constraining this free movement was expected to also affect the burst pressure performance. It was determined from the testing that although there was considerable variation in the failure point in burst for the samples, this variation did not associate with whether the tubes were tested in a stand-alone condition or in a complete assembly condition.

The test was performed with water at ambient temperature with the test sample placed into the test cell (see Figure 22). The pressure was gradually increased. Data collected in the test are shown in Figure 23.

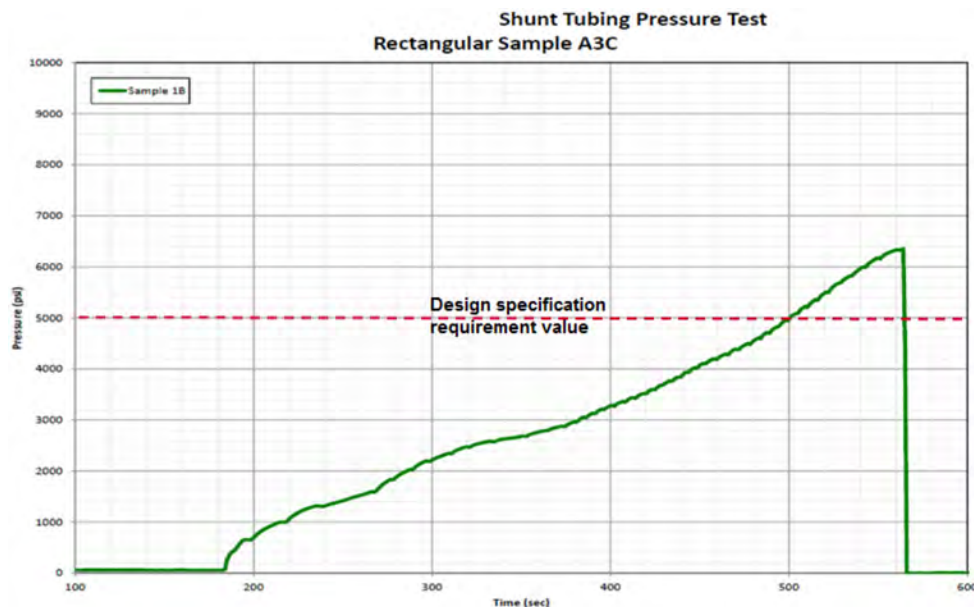


Figure 23—Image showing typical test data recording.

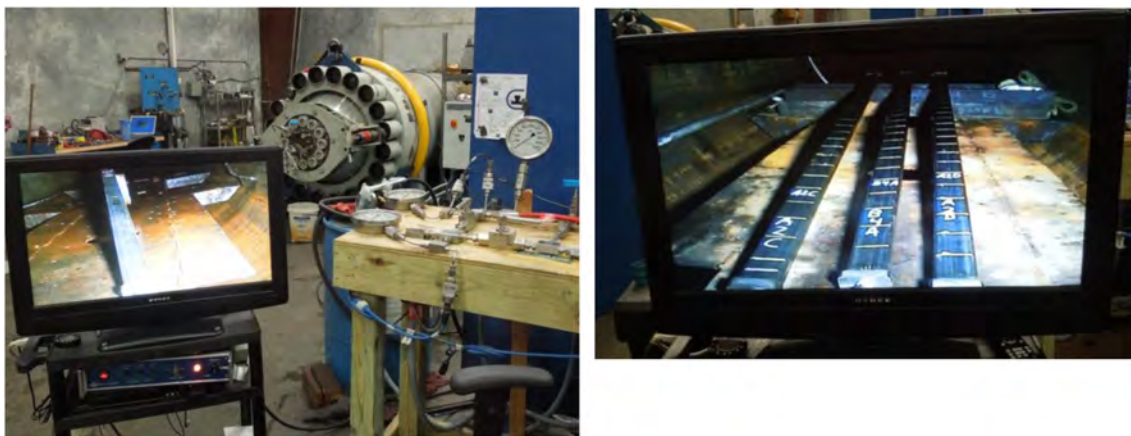


Figure 24—Image showing collapse pressure test setup

Although a sample tube failed below 5000 psi in this burst testing, it was determined after the test that this sample was defective in manufacture, and consequently that test was discounted. The overall testing substantiated the goal rating of 5000 psi burst pressure. However, a 1.33 safety factor was judged to be advisable for a working burst pressure for the tube system in order to allow for variations in the manufacturing of the tubes.

Shunt Tubing Collapse Test The objective of this test was to determine the collapse rating of the shunt system. Multiple test samples were subjected to this test. Test samples were identical to those used as a stand-alone tubing for burst pressure testing. Since

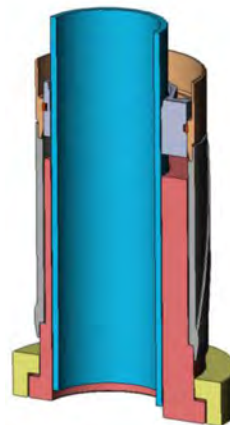


Figure 25—Image showing the test fixture for centralizer axial test.

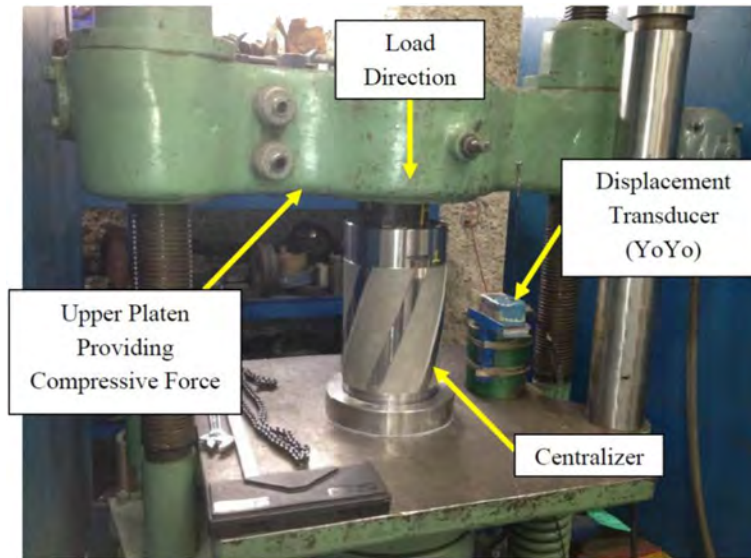


Figure 26—Image showing the centralizer axial test setup.

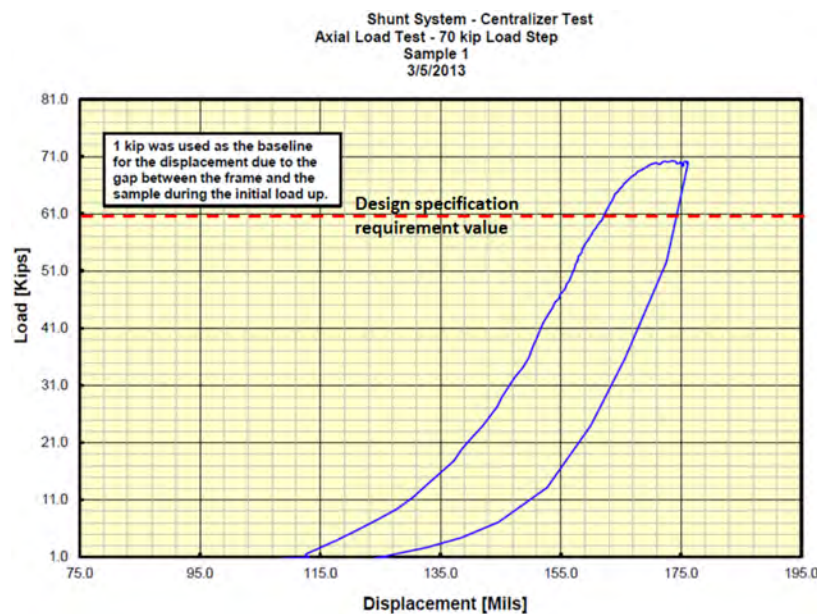


Figure 27—Data recording plot of centralizer axial load test.

no variation was expected whether the tubes were tested in a stand-alone condition or as part of a complete assembly, only the stand-alone condition was tested.

The test samples were placed into the test vessel, which was filled with water. The inside surface of the test samples were open to communicate with the atmosphere. The test was conducted at ambient temperature. During the test, the pressure inside the test vessel was slowly increased until the collapse of the test sample (see Figure 24).

All samples collapsed between 2450 and 2575 psi which satisfied the specification requirement of 2000 psi.

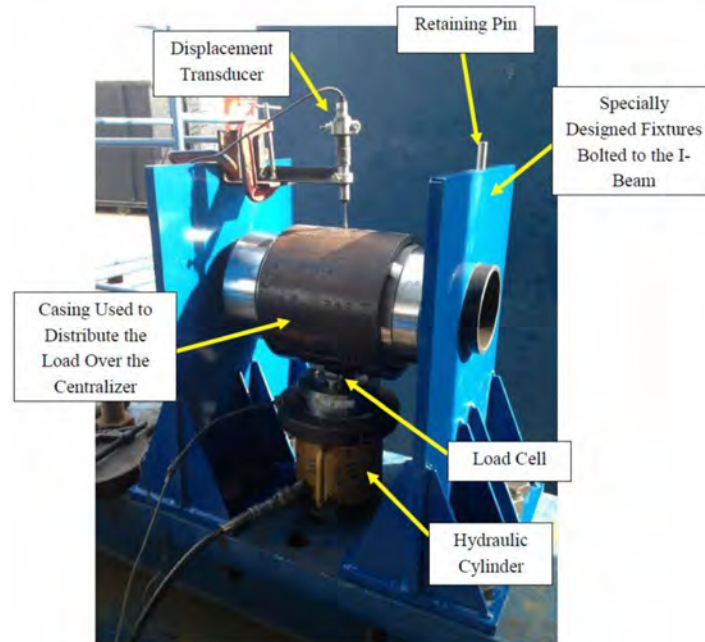


Figure 28—Centralizer radial load test setup.

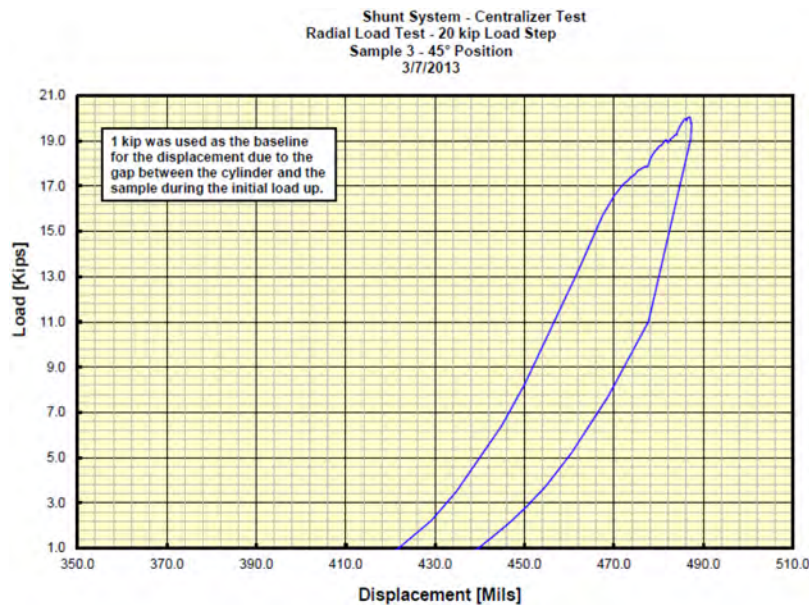


Figure 29—Data recording plot of the centralizer radial load test.

Centralizer Axial Load Test The objective of this test was to determine the maximum allowable centralizer axial load in the event that a centralizer was to stick while running the screen assembly. The test fixture is illustrated in Figure 25.

The test fixture was placed into the load frame (see Figure 26), and the test was performed at ambient temperature. From the initial base line load of 5000 lbf, the load was increased in 5000 lbf increments and held steady for 30 seconds at each load value (see Figure 27). Then the load was released and the centralizer was inspected for its structural integrity and functionality. If the centralizer passed, the load was increased and this was repeated until inspection discovered a failure.

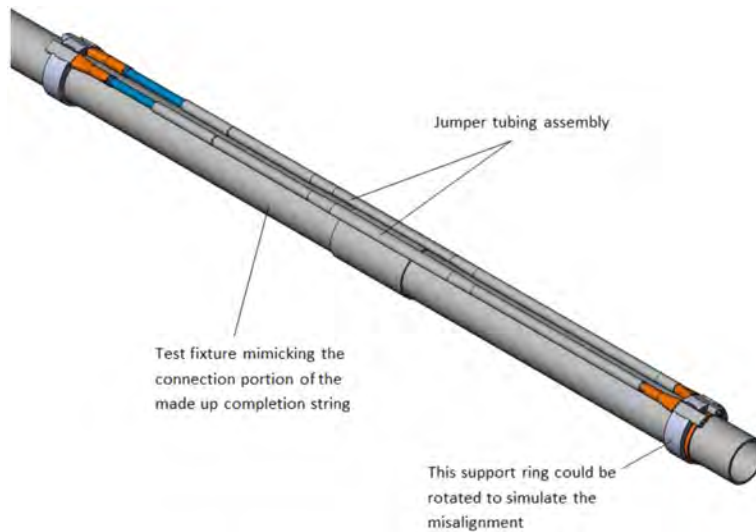


Figure 30—Jumper tube burst pressure test (sliding shroud not shown for clarity).



Figure 31—Test setup for the jumper tube burst pressure test, showing the test when sliding shroud was not used.

The testing substantiated a centralizer axial load rating of 60, 000 lbf.

Centralizer Radial Load Test The objective of the test was to determine the maximum centralizer radial load capacity. Like in the previous test, the centralizer was a part of the test fixture assembly which was mimicking the actual service condition of the centralizer when mounted on a joint assembly (see Figure 28).

The test procedure during this test was identical to the test procedure for the centralizer axial load test (see Figure 29 for an example of the recorded data).

The testing substantiated a centralizer radial load rating of 20, 000 lbf.

Jumper Tubing Burst Pressure Test The objective of this test was to determine the burst pressure rating of the jumper tube system. Samples were tested in aligned and misaligned positions, with and without the sliding shroud which is used to cover the jumper tubes and the connection area after the jumper tubes are installed (see Figure 30). Like in the case of the shunt tube system burst pressure test,

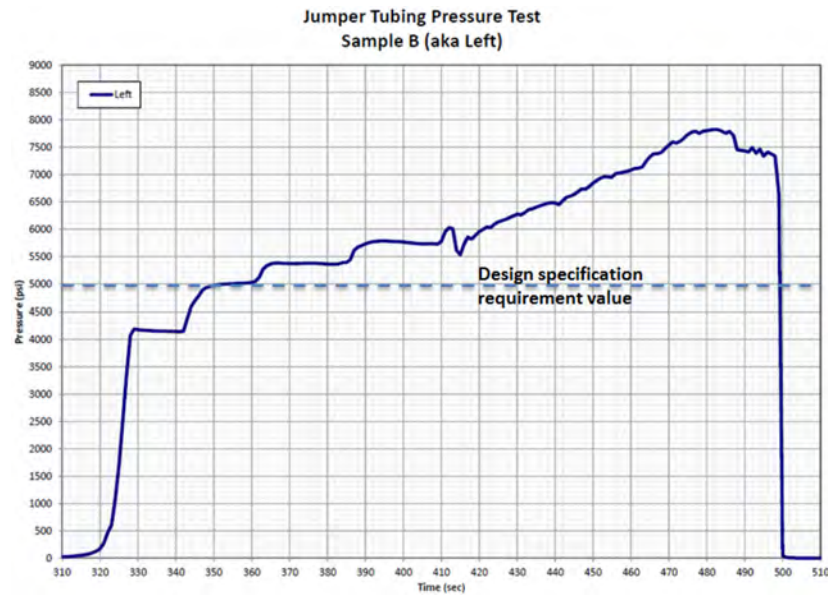


Figure 32—Example of jumper tube burst pressure test data

test samples were placed on a test fixture that mimicked the actual working condition of the jumper tube system (see Figure 31).

All jumper tube system testing failures were above 5000 psi, easily supporting the shunt tube system pressure rating of 5000 psi (see Figure 32).

Jumper tubing connection tensile test The objective of the test was to determine the tensile strength of the jumper tubing connection. The test sample, which was mimicking the jumper tubing connection, was placed into the load frame (see Figure 33). The load was slowly increased until the failure of the connection. The load and displacement was recorded through the duration of the test (see Figure 34).

Although the ultimate tensile failure of the jumper tube connection system was above 5000 lbf, some deformation of the locking rings was noted at about 700 lbf, so that is the assigned tensile rating for this component. It should be noted that this component does not have a tensile load due to pressure in the shunt system, so this value well exceeds the functional requirement.

Shunt system connection region CFD analysis

One of the signature features of the above described shunt system, is the use of round shaped jumper tubes. To ensure that this cross section transition would not result in an increased pressure drop, a CFD analysis was performed.



Figure 33—Setup for the jumper tubing connection tensile test.

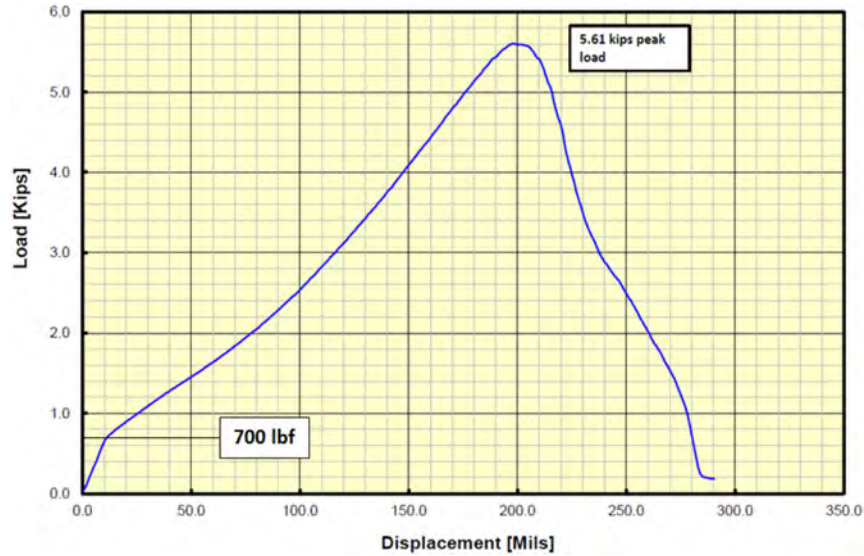


Figure 34—Example of jumper tube connection test data

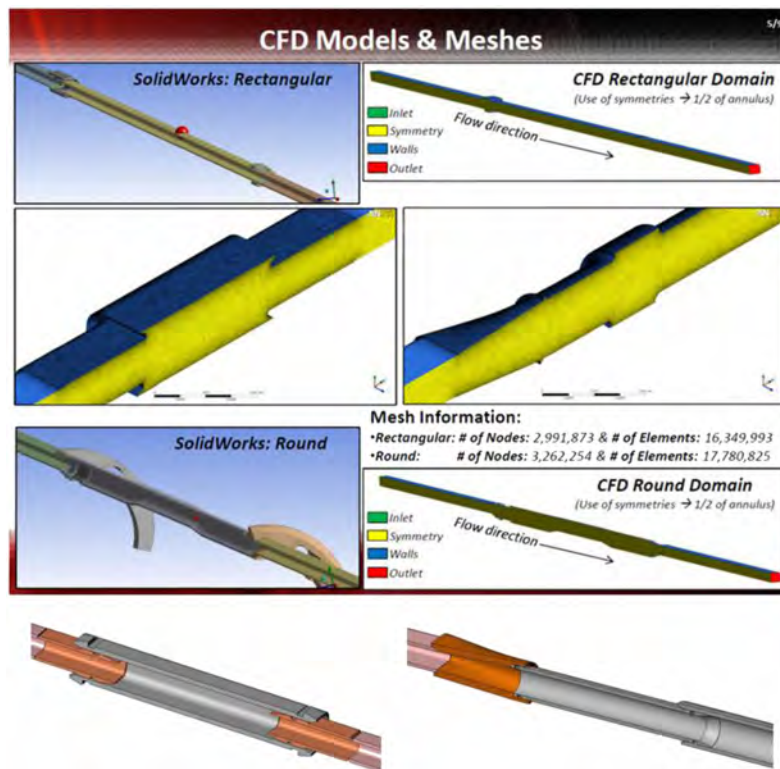


Figure 35—Models used for CFD analysis.

During this analysis, the flow characteristics of the above described shunt system was compared with the flow characteristics of a shunt system using rectangular tubes only (see Figures 35 and 36).

CFD analysis indicates that round jumper tubing does not result in increased pressure drop.

Shunt Tubing Erosion Tests

Main (transport) shunt tube erosion test Testing was done to make sure that all components of the shunt tube system would maintain functionality through the duration of the gravel packing operation. The

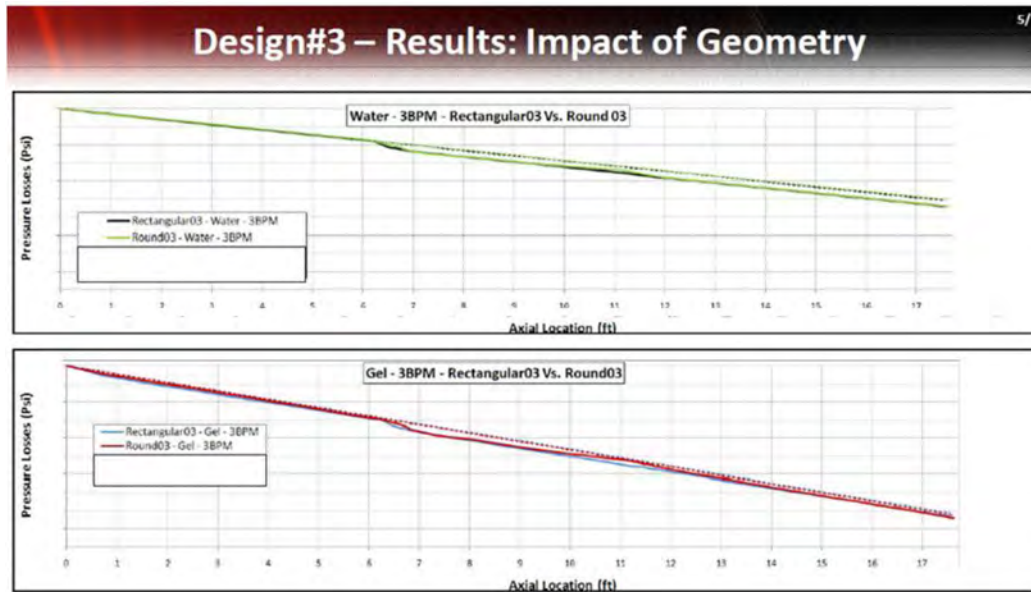


Figure 36—Image showing the flow characteristics of the connection region for rectangular and round jumper tube.



Figure 37—Image showing the typical erosion test setup.

components of the test samples were the jumper tube assembly, the packing tube connection (the casting carrying flow branched off from the transport tube to the packing tube) and the shunt system exit port.

Flow was blocked from exiting through the branched tube or exit port so that all flow was forced through the transport tube at maximum velocity (see Figure 37 for test setup).

A slurry of 20-40 gravel pack sand, suspended in a premium guar-based gravel pack carrier fluid, (36#/1000gal polymer loading) was pumped through a “half” tube system of one jumper tube and one main shunt tube with branched packing tube at 3 BPM, to simulate pumping at 6 BPM through a full, “2



Figure 38—Image showing the test sample for main shunt tube erosion test.

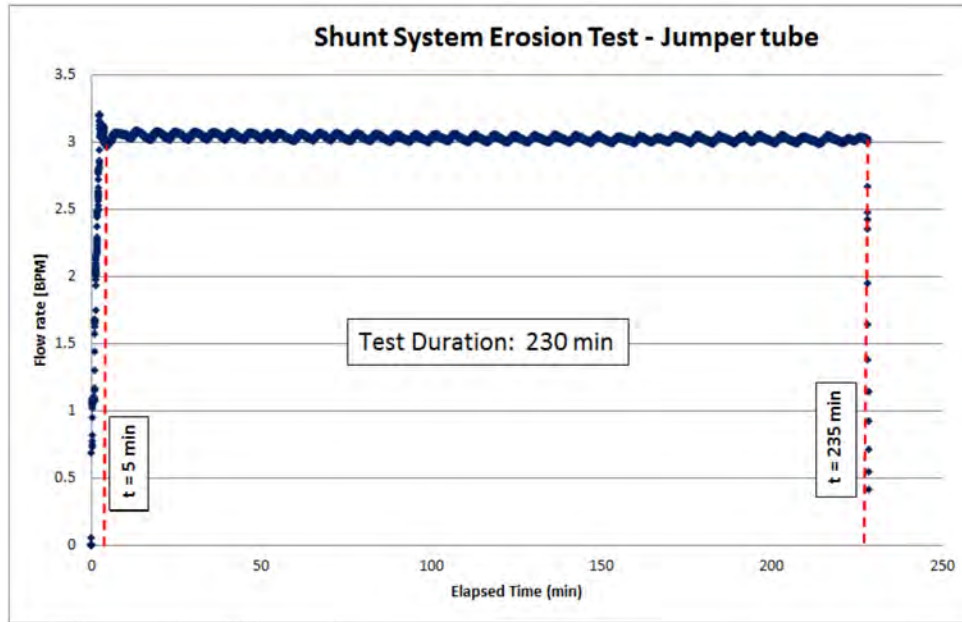


Figure 39—Transport and jumper tube erosion test data plot.

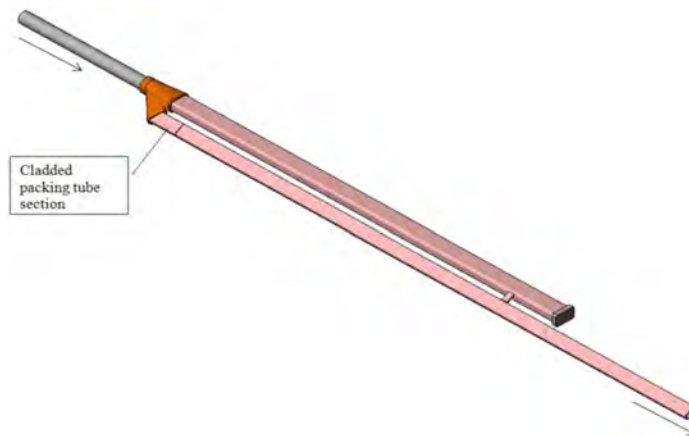


Figure 41—Image showing the test sample used for branched region erosion test.

x 2" tube system. Pumping was continued until 100, 000 lb of proppant passed through the system. After the test, all components were still functioning with no leaks observed (see Figures 38 and 39).

Packing tube and exit port erosion test In order to examine the resistance to erosion of the branched packing tubes and exit ports, separate testing was done with a test assembly similar to that used for testing the transport tubes, but with the transport tube flow blocked off downstream from the branched connection, and with the packing tube flow blocked at the exit port (see Figure 41) and flow blocked off downstream from the exit port (Figure 42).

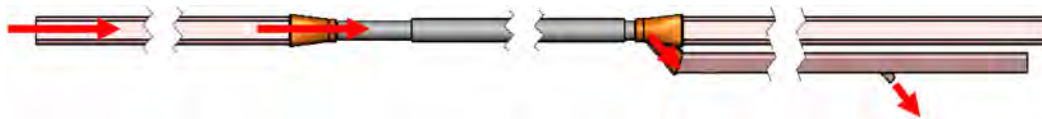


Figure 42—Image showing the test sample used for exit port erosion test.

Entry section of the packing tube The same carrier fluid, proppant (sand), and proppant loading was used for this test. The flow rate also was the same, 3 BPM. Two versions of the design were tested. The first one was without a clad entry section of the packing tube and the second was with a clad entry section of the packing tube.

The test sample without the clad entry section failed after 4 minutes (transporting about 2000 lb of proppant through only one packing tube, or about twice the amount of proppant expected to normally be required to pack around a full screen joint,) and the test sample with clad entry section failed after 8 minutes (transporting about 4000 lb of proppant, or four times the amount that could normally be required).

Exit port The same carrier fluid, proppant (sand), and proppant loading was used for this test. The maximum pressure rating of the system was reached at a pump rate less than the maximum for the system; the approximate rate before failing the assembly with erosion was 1.6 BPM. Failure of the exit port, as indicated by erosion through the wall area of any part of the branched cast connection, packing tube, or exit port, was always after at least 2500 lb of proppant had passed through the test sample. Considering that the packed proppant volume around a full joint of 5.5-in. base pipe shunted screen in 9.5-in. open hole is about 1000 lb, and that there are usually ten or more exit ports on each shunted screen joint, each exit port of an actual shunted screen is nominally required to pack about 100 lb of proppant, and that would be expected to occur at much less velocity than the flow induced in this test setup. Consequently, the erosion results were considered to be much better than required for surviving conceivable gravel packing scenarios.

Conclusions

Leveraging the traditional slurry bypass mechanisms of a 2 x 2 shunt system, the screen system that has been discussed followed a novel approach to joint to joint seal efficiency, optimized tube attachment protocol leading to a quick assembly, and validated the overall robustness of this new platform with an industry leading test matrix. While functionally similar to past systems, the assembly speed of the tubes is significantly reduced through the use of the “snap” locking assembly. The integral sliding shroud that is then deployed to protect the junction continues to build on the theme with additional reduced time. The enhanced reliability of the round jumper tube seal design and the incorporation of a fit-for-purpose cast fitting design serve to enhance the tube system. Eliminating the need for hand tools and fasteners to make the tube connections, while bolstering the erosional resistance of the system through strategic geometric design, the system offers a more efficient shunt system. With all of the new design elements coming into play, the extensive test protocol in the areas of mechanical loading, hydraulic loading, and erosional fatigue was critical for evaluation of the system. Looking into the performance of the protective shroud and the centralizer system with tests simulating run in hole loading scenarios, in addition to a system dog-leg fatigue test, proved the robustness of the system mechanical performance as a whole. Similarly, the hydraulic testing with clean fluid for various burst and collapse scenarios of the shunt tubing, jumper tubing, and connections coupled with the solids laden erosional testing of the same, validated the fluid transport robustness the system requires. In conclusion, the system presented above stayed true to the functionality of a proven base design, while utilizing design optimizations validated on a solid platform of robust testing methods. In so doing, the industry is offered an improved approach to a shunt system for reliable gravel packing operations.

Acknowledgement

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Abstract

Shunt tube technology to mitigate premature bridging in the annulus while pumping slurry has been used successfully in the oilfield for over two decades to assure complete gravel placement. The systems have been applied in a variety of scenarios including single and multizone completions, cased and openhole completions, and both gravel and frac-pac applications. By deploying a screen system empowered with the slurry bypass mechanisms of a shunt system, an operator usually experienced greater job reliability, a reduced possibility of pack failure, and maximized production.

This paper discusses an improved version of the traditional shunt tube system that has recently been developed by a major engineering and service company to enhance sand screens for gravel packing in long production intervals. The system was designed primarily for gravel packing in horizontal wells and is a system with two larger transport tubes and two smaller packing tubes, all mounted to standard sand screens in an eccentric design. A new seal design improves sealing capability between the joints of screen. By the optimization of the attachment of the tubes to each other, to the rings mounting the system to the screen, and to the sealing fittings at the transport tube ends, the design significantly enhances system capabilities.

Computer flow modeling was used to improve erosion resistance and lower pressure loss by reducing friction at tube connection flow transitions. Extensive test programs to ensure equipment integrity, including torque, tension, and compression capability of major components were used. The system can be assembled more quickly due to the shroud covering the joint connection being an integral component of the screen with no bulky clamshell hinges or pins to be assembled.

The improved pressure sealing, erosion resistance, ruggedness, improved rig assembly times, and system qualification will be presented in the paper.

Keywords: Screen Selection, shunt system, exit port, assembly, drilling operation, completion, tube system, Directional Drilling, jumper tube, shroud

Subjects: Drilling Operations, Directional drilling, Screen selection, Sand Control, Completion Operations

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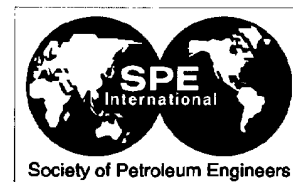
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EXHIBIT K



SPE 38640



Gravel Packing Horizontal Wellbores with Leak-Off Using Shunts

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Abstract

Because of the abnormal length of most horizontal wellbores, they present an exceptional challenge for gravel packing. Previously, the only way to gravel pack a long horizontal wellbore in a permeable formation was to seal off the wellbore from the formation to such an extent that substantial circulation could be maintained during the entire packing operation. While this approach has shown limited success, it necessitates the removal of the filter cake after the job is completed, which can be both difficult and expensive.

In this paper, equipment and procedures are described which allow gravel packing of long cased or open hole horizontal wellbores using alternate path shunts, without requiring circulation. The design methodology, procedures and evaluation have been developed with information obtained from studies using a series of physical wellbore simulators ranging from 150 to 500 feet in length. The simulators are described and results from the simulator studies are presented. Two case histories are included. The advantages of the new methodology are that it permits removal of the filter cake before or during the gravel packing operation and allows modest fracturing while packing, if desired.

SUMMARY

The pumping techniques and apparatus used in alternate path gravel packing have been extended here to allow gravel packing of long, open hole horizontal wellbores with or without substantial leak-off. Modest fracturing is possible, if

desired. The major pumping change is the use of gels that suspend the proppant during the entire job. The major apparatus changes are the use of larger exit ports from the shunts and use of a shroud over the screen and shunts to act as both a protector and centralizer.

The pumping and apparatus design changes are based on results of experiments performed with wellbore simulators ranging from 150 to 500 feet in length. Description of the experiments and results are provided below.

Two case history of the first field applications are presented. Total solids placement was 150% of the calculated annular volume of the 500-foot horizontal wellbore, suggesting that some modest fracturing took place. Productivity index for the well was 21, resulting in a production rate of 12,000 bbl/day from a formation with modest permeability thickness.

INTRODUCTION

Gravel packing of horizontal wellbores in unconsolidated formations is appealing because a tight gravel pack stabilizes the formation face. This will prevent movement of formation sand to the sand screen and permit use of a normal screen, which won't be plugged by the few fines that move through the gravel pack.

While gravel packing in cased horizontal wellbores has been used in places like the North Sea since 1991, Open hole horizontal well gravel packing has been difficult to accomplish because fluid leak-off along the horizontal interval dehydrates the slurry, leading to early annulus bridging and sand-out with long unpacked intervals. Numerous studies (1-14) have explained and documented the weaknesses and strengths of using either gels with good carrying capabilities or low viscosity fluids, such as water, for high angle and horizontal well gravel packing.

Horizontal water packing requires enough fluid velocity to maintain turbulent flow along the top of the wellbore to move the sand downstream. With leak-off, as soon

as enough fluid is lost so that turbulence can no longer be maintained the forward packing process (alpha wave) is halted. At this point the pack builds backward into the gap at the top of the hole until a completed pack reaches above the top of the screen. With substantial leakoff, such as at a fracture or high permeability location, the completed pack may be extremely short. Beyond that there is no pack at all (Figure 1 and Figure 2).



Figure 1: Water Packing Alpha Wave



Figure 2: Water Packing Beta Wave

Viscous gels will deliver solids over a much longer interval than water if leak-off is present. But the inevitable occurrence of a bridge in the annulus near top of the completion still severely limits the length of the pack. A bridge also prevents squeezing the slurry to remove excess gel from the portion of the completion below the bridge where slurry has penetrated (see Figure 3). The result is a poorly consolidated pack beyond the bridge. Therefore, until now the only method for producing acceptable long horizontal gravel packs has been to seal off the wellbore from the formation so tightly that the carrier fluid (usually water) is kept available for solids transport (14) and circulation is maintained. Fracturing must be avoided at all cost in such an operation. Even if successful, sealing off the wellbore necessitates removal of the seal after gravel packing, which can be difficult and expensive. The equipment and methodology described

below eliminate the need to maintain a seal while gravel packing a horizontal wellbore, and simultaneously permit fracturing if desired.

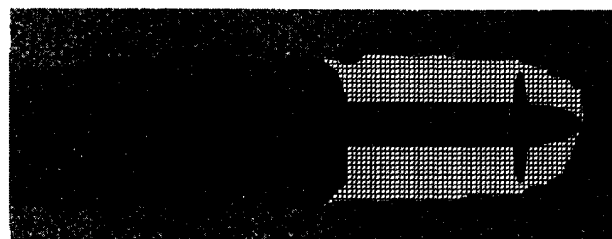


Figure 3: Conventional Gel Pack

Use of shunts attached to the screen to provide alternate paths for slurry flow in ordinary gravel packing or frac-packing has been previously described. (15-17). The primary attribute of the shunts is the capability to deliver gel slurry and associated hydraulic pressure past any bridges that form in the annulus outside the screen. This allows full application of squeeze pressure all along the completion length, resulting in complete packing, more fracturing, and very tight packs. The technology is adapted here to long horizontal open hole intervals by adjusting shunt exit port design to eliminate internal slurry concentration, by using low damaging fluids with good carrying capacity at low shear rates, and by protecting and centralizing the shunt screen with a perforated shroud. The required design and operating parameters for field use were established using experimental results from wellbore simulators ranging from 150 to 500 feet in length.

SIMULATION

It has been previously established that shunt packing of void spaces in the annulus is mostly independent of whether leak-off occurs through the screen or through the perforations, and that the squeeze position can always be used if desired (16). It is also known that each shunt operates independently of the others, in the sense that each can be used to pack an individual segment of the annulus by beginning the shunt ports, in an individual shunt, at the top of the segment it is to service. Accordingly, the simulators were constructed for rapid turnaround and minimum expense by using a single one half by one inch shunt inside a three inch O.D. plastic casing

Test Number	Fluid	Nozzle Opening	Shunts	Sand Size	Proppant	Density lb/gal	Length Packed	Model Length
1	40 lb Xanthan	N/A	0	20/40	Ottawa	5	25	150
2	60 lb Guar	1/8"	1	20/40	Ottawa	5	40	150
3	40 lb Xanthan	1/8"	1	20/40	Ottawa	5	90	150
4	2.5% VES*	1/8"	1	40/60	Low Dens	10*	250	250
5	1.5% VES	1/8"	1	40/60	Ottawa	8	120	250
6	1.5% VES	1/4"	1	40/60	Ottawa	8	500	500
7	0.5% VES	1/4"	1	40/60	Ottawa	8	160	500
8	1.5% VES	1/4"	1	20/40	Ottawa	8	250	250

Table 1 : Simulation Results

* A different VES formulation than the other tests presented 740

* Equivalent sand concentration

with 120 ten thousandth slots (10 gauge) per foot to provide leak-off. All tests were horizontal and in a squeeze mode with a cap at the end of the slotted liner.

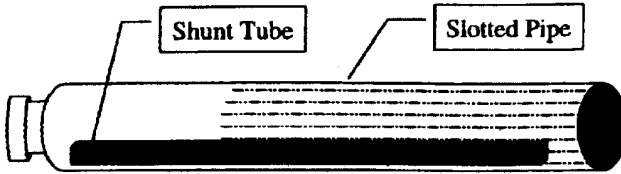
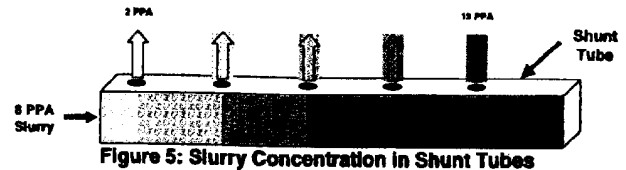


Figure 4: Test Fixture Setup

The shunts contained exit ports at 5-foot intervals lined with tungsten carbide inserts to prevent erosion problems. The ports were either an eighth inch diameter and a quarter inch long or a quarter inch diameter and five eighths inch long. Figure 4 shows the general arrangement and a short length of shunt. The slurry would enter through a connection on the left once in the blank section it can flow either down the casing or through the shunt tube. Run number 1 was performed without a shunt tube in the simulator. Enough blank with shunt and blank pipe was installed above the slotted liner to assure that the top bridge would not build above the shunt entry. Slurries of 4 to 8 lbs/gal of 40/60 sand, 20/40 sand, and 40/60 low density gravel substitute were pumped in a variety of carrier fluids into the annulus at 20 gallons per minute. The rate was normally reduced at the very end of the run in order to keep the pressure below the maximum for as long as possible. The various experiments and results are listed in Table 1. Significant findings were:

1. The carrier fluid must suspend the particles during the pumping period.
2. Sand grains do not turn the corner easily into small shunt ports, resulting in slurry concentration inside the shunt to an extent which limits the packing distance.
3. The large shunt ports are highly effective in preventing internal slurry concentration.
4. High viscosity and low solids concentrations extend the packing length.
5. Low-density particles follow the fluid better, thus extending packing length.

The great length of the simulators allowed study of effects that are not easily recognized in a shorter apparatus. Figure 5 graphically illustrates the problem of internal slurry concentration in the shunts when particle density is much higher than fluid density. Although this problem was known to exist prior to these studies, the magnitude of the problem was not fully understood. Likewise, the absolute necessity to avoid particle settling during the pumping phase was not appreciated until rapid shunt plugging was observed with linear carrier fluids in simulator runs 1 and 2. Neither effect is nearly as significant in wells with a deviation less than 50 degrees.



From simulator run 4 it was established that each shunt with 1/8 inch ports could pack at least 250 ft when using low density gravel substitute. The use of 1/8-inch ports was a necessity for the first well because those were the only shunt screens readily available at the location. Since the maximum length of the horizontal segment in the first well was to be less than 1000 ft and four shunts were attached to the screen, this result indicated the job could proceed.

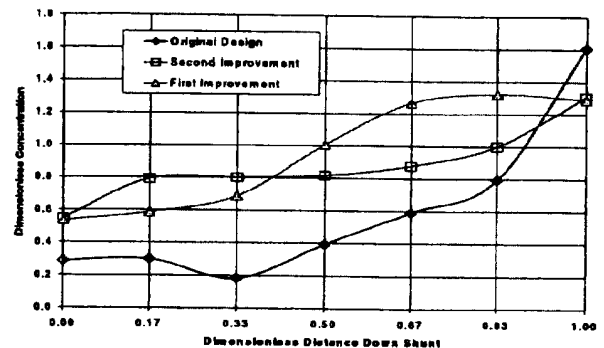


Figure 6: Plot of Concentration in Shunts

From simulator run 6 it has been established that the use of large ports extends the maximum packing length to at least 2000-ft with sand. Figure 6 illustrates how modifying the size and shape of the exit ports affects the concentration of the slurry leaving the ports. Pumping 8 PPA slurry down a shunt tube and measuring the concentration of the slurry leaving through various ports generated this data. If the shunt is passing through a gravel packed region, these slurry concentration phenomena will be greatly reduced. Angled ports extending into the shunt flow stream, as shown in Figure 8 reduce the tendency of the slurry to concentrate inside the shunt and thus extend the packing length. A design of this type may be required to extend the packing distance to the very long intervals of 3000 ft or more. Figure 7 shows the pressure record while packing. Annulus sand-off is clearly indicated at point A. Packing through the shunt then commences and proceeds until point B, when the pack reaches the end of the simulator. Pressure rises linearly during this period as the pack is extended farther and farther along the simulator. A short period of squeezing the pack follows until point C, at which time a sand-out occurs where no more space is available for packing in the annulus. This result is an important commercial milestone because of the availability and low price of sand. Results from run 8 indicate that 20/40 sand is a viable option in some cases. However, it must be

recognized that fluid requirements are more stringent for this option.

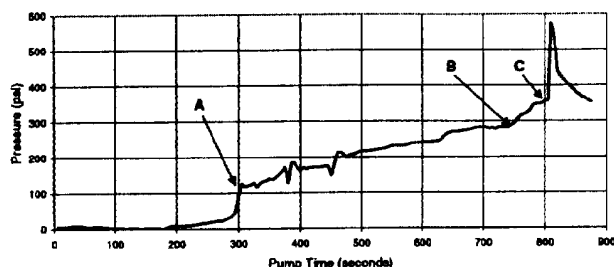


Figure 7: Simulator Pressure History

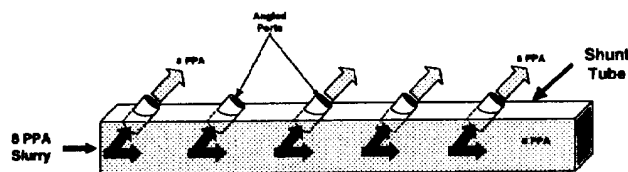


Figure 8: Shunt with Angled Ports

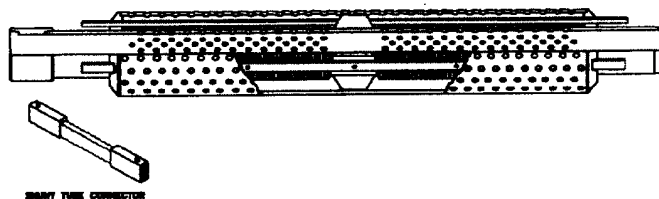


Figure 9: Shunt Tube Screen Design

Open Hole Screen Design

It was felt that the shunts needed thorough protection for running into open holes. Adding a perforated casing shroud over each screen joint to act as both a protector and centralizer provided this. An adapter at each end of every screen joint supports both the screen and the shunts, as shown in Figure 9. Connections are then made in the valleys between each screen joint. Gravel packing takes place through the multitude of holes in the shroud.

Case Histories

Early results in this field without the shunt tubes produced wells with PI's from 8 to 19 with post gravel pack skins from 9 to 23 and very high draw down pressures. The shunt tube technology was introduced simultaneously with a change in the gravel pack fluid, switch to open hole, and increased pay. The result of all these changes was an increase in the PI's, with a reduction in skin and draw down pressures. Case histories from three separate horizontal wells are presented in this section. Some of the data common for both wells are:

- The horizontal sections were drilled with a water based drill-in fluid.
- Low density gravel substitute (SG 1.7) was used.
- A visco-elastic surfactant was used as the carrier fluid.
- A gravel concentration of 5 PPA (lbs per gallon added) was used. This gravel concentration is equivalent to about 8 PPA of sand.
- CaCO_3 Fluid Loss control agent was used before running in with the screen.
- Both wells were packed in the squeeze position with the choke $\frac{1}{4}$ open.

Case 1: 508 ft

This 508 foot $8\frac{1}{2}$ inch open hole was drilled with from 75 to 82° deviation. The formation net height was measured from logs to be about 30 feet. This was the first open hole completion that used the new open hole shunt tube system. A drawing of the completion can be found in Figure 11. The well was drilled in January of 1997. The initial pumping sequence used 20% excess in gravel. A screen-out was not obtained. At this point, additional slurry was mixed and pumped until a screen-out was obtained. A total of 50% excess was placed. The total amount of low density gravel substitute placed was 15,600 lbs (equivalent to about 25,000 lbs of sand) No returns were observed until well into the job and only $\frac{1}{4}$ returns were then observed. This large excess of gravel with little or no returns and a relatively high surface pressure could be an indication that some fracturing occurred. The initial production from this well was measured at 12,000 bopd with a PI of 21 and a horizontal skin of 1. So far the PI has remained constant even with a decline in the reservoir pressure.

Case 2: 617 ft of Open Hole

This second well was drilled with a 1000-foot open hole section with between 85 and 90° of deviation. The formation net height in this well was 18 feet. Because of hole problems, only 617 feet of horizontal shunt screen made it into the open hole section. The other 383 feet of screen remained in the cased section of the well. During the pumping operation, 17% excess low density gravel substitute was placed. The initial PI from the well was measured at 23 with a horizontal skin of slightly less than 4. Figure 12 contains a drawing of the completion.

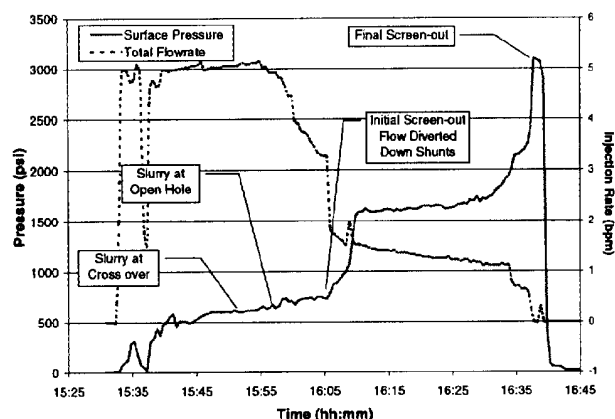


Figure 10: Well 2 Pumping Data

Figure 10 contains the surface pressure chart from this well. Note the similarity between this chart and the pressure chart obtained from the surface simulator in Figure 6. From Figure 10 it is clear that the shunt tubes became operational about 32 minutes into the gravel pack. After accounting for the material reversed out, 21,000 lbs of low density gravel substitute was placed (equivalent to 33,600 lbs of sand). Approximately 40 % of the total gravel pack was pumped through the shunt tubes. About 57% of the gravel placed in the open hole section was pumped through the shunt tubes. Since this gravel pack was performed with 8 ppa equivalent slurry, the actual slurry pumping time and fluid used in the slurry was reduced to 1/8 of that required for a water pack. While CaCO_3 was used to control losses during the running of the screen, it was not necessary to obtain 80 to 90% returns (or complete formation shut-off) in order to get a good gravel pack.

Case 3: 1000 ft of Open Hole

The third well was also drilled with a 1000 foot open hole section with a 90° deviation. During the first run, only 350 feet of screen could be pushed into the open hole. The string was pulled and rerun to bottom with 5 1/2 inch drill pipe. This example showed that the screen could be pulled if required. After the completion was landed, the gravel pack was pumped as per Figure 13. The batch of gravel did not result in a screen out. A second batch of 65 bbls of slurry was pumped approximately 2 hours later. The 37,000 lbs of light weight gravel placed was 35% excess. A screen out was obtained at the end of this second injection. The PI from this third well was measured at 60. This was the highest PI to date.

Conclusions

The following conclusions can be drawn from the work performed so far:

- The shunt tubes enable slurry pack techniques to be

used in long horizontal open hole intervals. This has been shown in both surface tests and field case histories.

- The protective shroud around the shunt tubes centralizes the screen, which insures that gravel is placed around the entire screen. Conventional water packing would normally leave the bottom of the screen exposed to the formation.
- The use of the shunt tubes reduces both fluid requirements and pumping times. This should translate into significant rig time savings.
- Production rates from these gravel packed wells are much better than the equivalent vertical wells.
- While the current well tests were only performed in open hole sections up to 1000 feet, intervals as long as 2000 feet can be performed with the current technology.
- Modifications in the shunt tube design should increase the maximum gravel pack length to the 5000-foot range.

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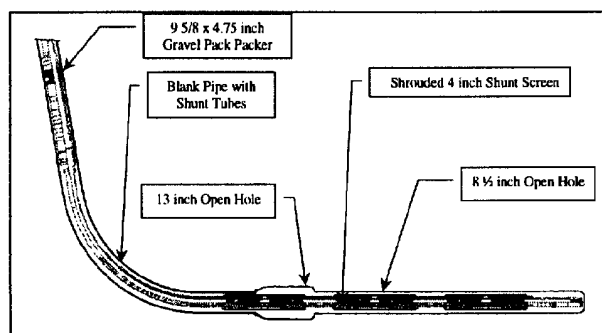


Figure 11: Case History 1 Completion Diagram

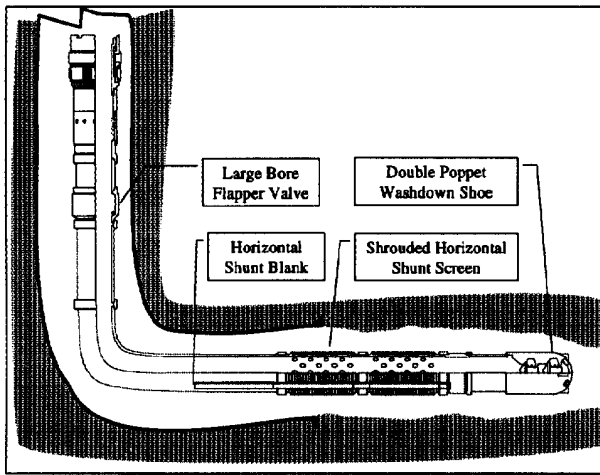


Figure 12: Case History 2 Completion Diagram

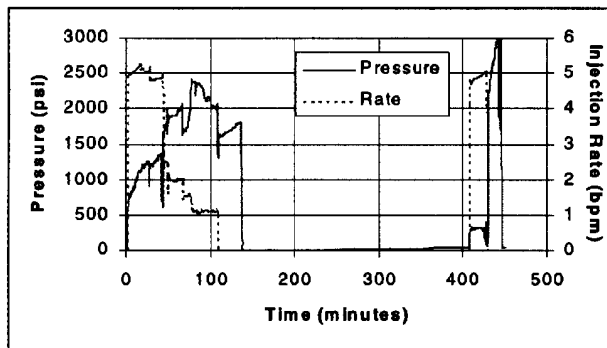


Figure 13: Case History 3 Surface Data

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EXHIBIT L

Completion and Production Results From Alternate-Path Gravel-Packed Wells

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Summary

A successful gravel pack requires two things: perforations packed with gravel-pack sand and a completely packed annulus. Failure to obtain either one can result in low productivity and/or a sand-producing gravel pack. Alternate-path gravel packing ensures that the annulus will be completely packed and that all perforations taking fluid will be packed with gravel-pack sand. Alternate-path gravel packing has provided long and highly productive completions without any sand production.

This paper presents completion data and production results from 39 wells completed with the alternate-path gravel-pack technique. The completion data include completion length, net perforations, carrier fluid, sand placement outside casing, workover fluid, and return rate during packing. Production results include qualitative discussion of all completions with quantitative results, including permeability-thickness product and skin on select completions.

Introduction

By the end of 1992, ALLPAKSM (alternate-path gravel packing) completion technology^{1,2} had been used in 43 completions. Included are an oil well reportedly tested at more than 40,000 BOPD by Statoil in offshore Norway, and a gas well tested at more than 70 MMcf/D by Mobil in the Gulf of Mexico. Experience with the new technology is related along with a description of insights and modifications growing out of these applications.

Alternate-path gravel packing uses bypass tubes, or shunts, attached to the screen. The shunts are perforated with small holes at various locations along the screen (Fig. 1). Although slurry can be injected directly into the bypass tubes, the preferred approach has been to leave the tubes open at the top of the annulus to act only as shunts. In a normal gravel-packing operation, the shunts have little impact until a sand bridge forms in the annulus. Then the shunts activate, carrying the slurry through that bridge and any others that subsequently form, ultimately completing the pack (Fig. 1). High well productivity and longevity result from the efficient placement of pack sand in the perforation tunnels accompanied by complete annulus packs.

In laboratory gravel-pack simulator experiments, the shunts have been shown to improve packs with all currently used carrier fluids, including water. Logic suggests that the best results should be obtained with high-quality gels. Because no special pumping requirements have been delineated, many different pumping procedures and carrier fluids have been used in field applications, which are described later.

The ability to pack extremely long pay intervals, highly deviated wellbores, and/or separate pay zones of highly variable permeability provides new engineering opportunities and challenges. Production at higher rates from fewer wells can be considered. Simultaneous production from multiple zones is feasible, with possible wireline water shutoff in selected zones. Separate prepacking operations are probably no longer required, and the need for perforations washing can be re-examined.

The packing operation itself can be changed to use the advantages offered by the shunts better. Squeeze packing or severely restricting returns no longer risks incomplete packs resulting from bridging and appears to be a preferred procedure. High-pressure pumping

with the shunts in place appears to enhance the probabilities for frac-packing as long as the screen/washpipe annulus is small enough to limit flow through that path.

Gravel-Packing Mechanisms

Optimum uses of alternate-path gravel packing ultimately require a thorough knowledge of the various flow mechanisms provided by the shunts. Sand transport is dominated by one of the following mechanisms³⁻¹²: (1) viscous fluid flow, as in packing with a carrier fluid like xanthan (XC) gel, where the sand does not settle and is carried to and deposited at locations where fluid exits from the casing/screen annulus; (2) velocity and gravity, as in packing with water, where sand is transported downward by gravity and laterally by turbulent fluid flow; or (3) some combination of these two mechanisms.

Packing With Viscous Fluids. In packing with viscous carrier fluids, the pack forms outward from the screen as the carrier fluid exits through the screen into the screen/washpipe annulus and inward from nodes that form in and around each perforation that takes fluid. At a high-leakoff location without the shunts, these accumulations will eventually join to form a complete bridge in the casing/screen annulus, preventing further slurry flow to any point below the bridge. The incomplete pack below the bridge remains until a repair process or gravity causes the gravel in the annulus to move down and fill the void. Regardless of how the annular void is eliminated, the perforations in that area are not packed with gravel-pack sand. In a circulation mode, the pack above the bridge is completed as gel leaks off through the screen and flows through the screen/washpipe annulus and the open casing/screen annulus below the bridge to the washpipe entrance or into the perforations taking fluid in or below the bridge. In a squeeze mode, the pack above the bridge is completed as gel leaks off through the screen and flows through the screen/washpipe annulus to any perforations taking fluid. In either case, when the pack reaches the top of the screen, the fluid-leak-off path through the screen is no longer available and a high-pressure sandout occurs.

Obviously, the leakoff paths provided by perforations can have a high flow resistance, and the perforations may be poorly packed unless low-flow-resistance leakoff paths, such as the washpipe, are closed. Consequently, without shunts, the circulation mode normally produces better annulus packs, and the squeeze mode packs the perforations better. Prepacking offers the chance to gain the advantages of both packing modes but at the expense and inconvenience of adding another operational step without guaranteed elimination of voids.

When a shunt or shunts are present, the higher packing pressure that occurs above a newly formed bridge activates one or more shunts. Slurry then preferentially flows through the shunts. When the slurry reaches the open-shunt portholes, it exits back into the casing/screen annulus and packing below the bridge continues much as before (Fig. 1). Most shunts are designed with very small holes so that slurry will exit from 10 to 40 holes simultaneously. Whenever a pack forms in the annulus over one or more shunt holes, the small size of the holes restricts leakoff to such a negligible amount that the slurry is diverted to uncovered shunt holes farther downstream. Fig. 1 illustrates the various flow paths available to the slurry and carrier fluids when shunts are used.

Premature internal plugging of the shunts has not been a problem with gels in field applications to date. The shunts normally pack off at high pressures from the bottom up after the annulus is completely packed. The packoff usually occurs below 0.25 bbl/min. However, laboratory studies have shown that premature plugging can occur

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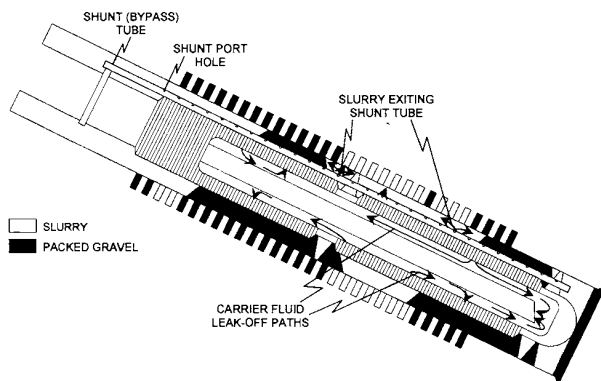


Fig. 1—Gravel-pack mechanisms with shunt bypass tubes.

inside the shunts if the exit ports are too large and allow too much leakoff or if too much packing takes place through a short section of a shunt. Excessive packing through a short shunt section can occur if there is no pack buildup adjacent to that section because of limited leakoff from the annulus. The shunt ports can be eroded to a much larger size, destroying the effectiveness of the shunt and eventually allowing internal bridge formation. Internal bridges can also form because of a natural separation process that occurs inside a shunt, where a certain fraction of the sand particles bypasses the small shunt holes while the gel exits. Eventually the slurry becomes too concentrated to pump through the shunt. Both premature shunt-plugging mechanisms can be eliminated with modest mechanical improvements, but they have not been considered necessary yet.

Because prematurely formed bridges in the casing/screen annulus are bypassed by slurry flow through the shunts, holding back pressure in a squeeze mode or limiting returns during packing is no longer counterproductive to annular pack quality. In fact, limiting returns is the preferred procedure because it eliminates the need for a separate prepacking operation. However, to take full advantage of this potential, it is necessary to recognize that complete annulus packing with shunts requires only modest leakoff capacity. Gel leaked off by packing associated with any shunt port can flow through the screen/washpipe annulus either down or up to any location where leakoff at a lower pressure occurs. To obtain high localized pressures for packing low-permeability perforations or for frac-packing, it is necessary either to use a small screen/washpipe annulus or to limit leakoff through the packed perforations. Because the latter can be counterproductive, the use of a small screen/washpipe annulus seems to be preferred. If frac-packing is desired, more viscous carrier fluids provide obvious advantages.

Packing With Low-Viscosity Fluids. When compared with gel slurry packing, packing with water or other low-viscosity carrier fluids provides both advantages and disadvantages. In a nearly vertical hole, the sand is carried downward both by fluid movement and by gravity, and the pack builds upward from the bottom of the hole. Regardless of the completion length, the annulus will usually be packed completely provided there is no high-permeability stringer at the top of the perforations. There may be enough leakoff into each perforation to provide sufficient velocity for packing perforations if only a few perforations are present. As the number of perforations increases, the amount of fluid available for leakoff into each perforation is reduced, and perforation packing efficiency declines. Field studies that graphically illustrate this situation have been presented.^{12,13}

As hole deviation increases, there are marked tendencies for gravity to enhance packing of low-side perforations and for high-side perforations to remain open and capable of taking excessive quantities of fluid. Nonetheless, annulus packing will usually be complete until the hole angle reaches about 60°. At hole angles above 60°, a settled bed forms along the bottom of the casing and sand is carried toward the bottom of the hole by turbulent flow in a channel along the top of the sand bed. The thickness of the sand bed at any location depends on the amount of carrier fluid flowing through the annulus

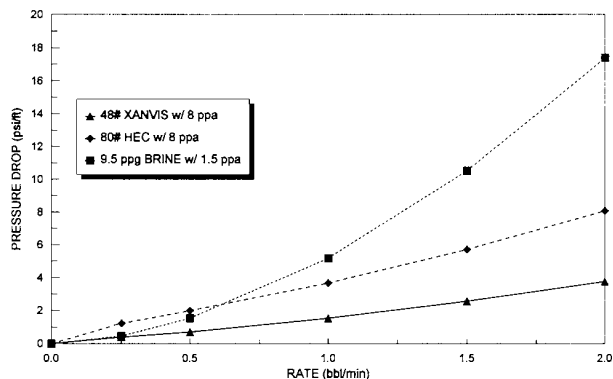


Fig. 2—Pressure drop as a function of slurry rate through a single shunt tube with three different slurries.

at that point. As carrier fluid is lost to the formation and to the screen/washpipe annulus, the sand bed becomes thicker. The pack will continue to build toward the bottom of the hole as long as enough fluid is available to maintain the critical carrying velocity along a narrow channel at the top of the bed. At the location along the completion where leakoff has taken too much carrier fluid, the sand bed reaches the upper casing wall and a bridge forms. The pack above this location is completed as sand is deposited along the upper channel and the associated carrier fluid exits through the pack into the screen/washpipe annulus.

The length of a more or less horizontal completion that can be packed with a low-viscosity carrier fluid therefore primarily depends on leakoff. If no leakoff is present, the distance appears essentially infinite. If leakoff is high, the distance can be very short, on the order of a few tens of feet. The screen/washpipe annulus can be kept small enough to limit flow and leakoff into the screen/washpipe annulus. But, a large number of perforations into a highly permeable formation will take enough fluid to limit pack length severely unless perforation leakoff is controlled. The pack length can be extended by using low sand concentrations, which has become common practice. The low sand concentration provides extra fluid for leakoff, preventing the critical velocity from being reached in the upper channel.

Shunts can be used to extend pack length and efficiency for low-viscosity carriers as well as for gels. Packing improvements will always be obtained with the shunts. However, there are some noteworthy differences. Any shunt with its entrance buried in a sand bed becomes inoperative, and this fact must be considered when designing the shunt arrangements. In a truly horizontal hole, the amount of sand entering a high-side shunt is negligible, but shunts located on the low side may take enough sand to form a bridge near their entrances. A simple rupture disk arrangement would eliminate this possibility but has not been used as yet. Leakoff from shunt port-holes to a packed annulus is considerably greater with low-viscosity fluids and limits the number of possibly effective shunt holes. It is much more difficult for the sand to exit upward from a shunt with low-viscosity carriers, which increases the likelihood of internal bridging in the top-side shunts if the shunt holes are in the top shunt wall. Therefore, shunt holes are better placed in the sides of the shunts for horizontal wellbores, raising the possibility that a carelessly drilled shunt hole might direct the slurry against the screen, which could erode the screen. The result of these differences is that optimum shunt designs are different for low-viscosity carriers. The total interval length that can be packed with a low-viscosity carrier fluid with shunts is greater than that without shunts but less than that with shunts and gel carriers.

In addition to the different mechanisms, the rheology plays a large part in the performance of the shunt tube. As Fig. 2 shows, the pressure drop through a single tube at 0.75 bbl/min for low-viscosity carrier fluid is greater than that of hydroxyethylcellulose (HEC) or clarified xanthan gum (XANVIS™). The greater the rate through the tube, the greater the pressure-loss differences between low-viscosity and gelled carrier fluids. Based on the previous discussion, all

TABLE 1—ALLPAK COMPLETIONS

Completion	Screen Length (ft)	Net Perforations (ft)	Average Angle (degree)	Gravel Outside Casing (ft ³ /ft)	Workover Fluid Density (lbm/gal)	Gravel Size	Carrier Fluid	Returns (%)	Number of Tubes	Allpak Design	Hole Spacing (ft)
1	236	194	60	0.24	14.3	40/60	Xanvis	10	4	Dual	4
2	100	27	46	0.65	16.2	40/60	14.5 HP	36	4	Single	3
3	257	62	28	0.10	15.9	40/60	Xanvis	54	4	Dual	4
4	109	83	62	0.17	10.0	40/60	Permpac	?	4	Single	4
5	109	83	62	0.17	10.0	40/60	Permpac	0	4	Single	4
6	182	172	45	0.08	9.3	40/60	Xanvis	87	4	Dual	5
7	32	22	43	0.22	9.3	40/60	Xanvis	85	4	Single	3
8	101	44	6	1.52	16.2	40/60	14.7 HEC	?	4	Single	4
9	53	30	8	1.27	16.2	40/60	Permpac	?	4	Single	3
10	77	62	16	0.25	9.4	40/60	Xanvis	55	4	Single	4
11	188	115	3	0.14	9.4	40/60	Xanvis	50	4	Dual	4
12	42	20	0	0.38	8.7	40/60	Xanvis	44	4	Single	3
13	57	32	46	0.18	9.5	40/60	Permpac	0	2	Single	3
14	55	25	46	0.16	9.5	40/60	Permpac	0	2	Single	3
15	55	30	46	0.22	9.5	40/60	Permpac	0	2	Single	3
16	87	49	46	0.24	9.5	40/60	Permpac	40	2	Single	3
I 17	58	50	28	0.40	11.6	50/70	Permpac	5	4	Single	3
N 18	58	48	28	1.21	11.0	50/70	Permpac	35	4	Single	3
N 19	81	64	30	0.56	13.3	50/70	Permpac	25	3	Single	3
N 20	63	33	20	0.34	8.8	40/60	Xanvis	35	4	Single	3
N 21	57	36	38	0.25	8.6	50/70	Permpac	20	4	Single	3
22	27	14	38	0.37	9.5	50/70	Permpac	40	4	Single	3
23	61	50	21	0.20	12.9	40/60	Xanvis	25	2	Single	3
24	58	40	20	0.38	16.0	40/60	Xanvis	25	2	Single	3
25	107	90	2	0.21	14.7	40/60	11.0 HEC	0	1	Single	4
N 26	106	86	3	0.02	8.5	40/60	8.4 HEC	0	3	Single	4
27	30	19	41	0.61	9.3	40/60	Permpac	0	3	Single	3
28	53	31	41	0.81	9.8	40/60	Permpac	0	3	Single	3
29	68	52	21	0.07	13.3	40/60	8.4 HEC	0	1	Single	3
30	68	52	21	0.44	13.3	40/60	8.4 HEC	0	1	Single	3
31	36	20	20	0.78	9.5	40/60	8.4 HEC	0	1	Single	2
32	115	99	26	0.23	12.9	40/60	8.4 HEC	0	1	Single	4
33	42	27	30	0.41	9.6	40/60	8.4 HEC	0	1	Single	3
NI 34	109	94	19	0.71	14.5	40/60	8.4 HEC	0	4	Single	4
35	38	20	44	0.97	10.9	40/60	Xanvis	0	2	Single	2
36	246	210	54	0.20	10.9	40/60	Xanvis	25	3	Single	4
37	259	252	36	0.01	11.4	40/60	Xanvis	25	1	Single	4
N 38	90	72	46	0.37	16.5	50/70	8.4 HEC	0	2	Single	3
N 39	176	160	2	0.74	14.0	50/70	11.0 HEC	5	3	Single	4
Average				0.42							
Weighted Average				0.32							

N—Perforations were not washed.
I—Injected directly into the shunt tubes.

Mobil's ALLPAK completions have been done with gelled carrier fluid.

Completion Data

Table 1 gives available completion data as of early 1993. In addition to these, Statoil has reportedly used alternate-path technology for gravel-pack lengths of up to 480 ft and at deviation angles up to 75°. Gravel-pack logs were run on seven of the completions reported here. All indicated complete annulus packs. Considering the exceptional ability of the shunts to pack the annulus, this result was expected. Today, gravel-pack logs are run only if the volumetric calculations indicate insufficient sand to fill the annulus. All the ALLPAK completions are producing sand-free.

The average of 0.42 ft³/ft and a weighted average of 0.32 ft³/ft of gravel placed outside the casing are comparatively good (Fig. 3). Historically, Mobil has placed an average of about 0.10 to 0.15 ft³ of gravel/ft of perforated interval using similar packing techniques without shunts. Placement volumes of greater than 0.5 ft³/ft are believed to have resulted from the development of small fractures.

Reasons for low placement are not fully understood. They could be the result of very poor formation leakoff, as in Completion 6; extremely high formation leakoff over a small portion of the perforated interval, as in Completion 26; or a small volume outside the casing that is filled with gravel, as in Completion 37. As with all the completions in Table 1, these completions performed equal to or greater than the rate calculated by system analysis. Also, there are no reports of productivity decline with age for the ALLPAK completions. Because of the excellent productivity results obtained with ALLPAK, there is a reluctance to accept the expense and trouble associated with taking the downhole measurements required to determine permeability thickness and skin in a substantial number of wells.

Early completions were done with a tell-tale screen with a differential valve to move into the upper circulating position to finish the annulus pack. When it was recognized that any bridges that formed prematurely were easily bypassed with the shunts, backpressure was applied to restrict returns in an attempt to obtain more sand outside the casing. Fig. 4 shows the pump pressure, rate in, and rate out

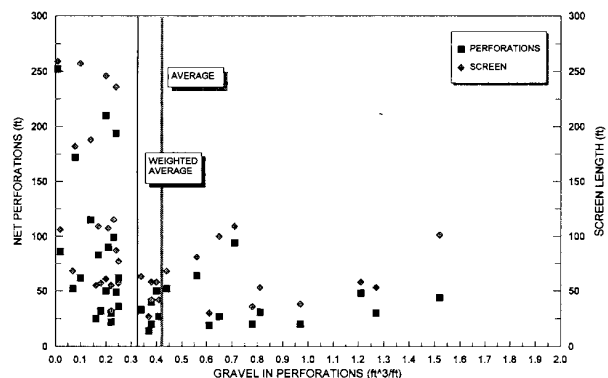


Fig. 3—Gravel in perforations as a function of the net perforations and screen length.

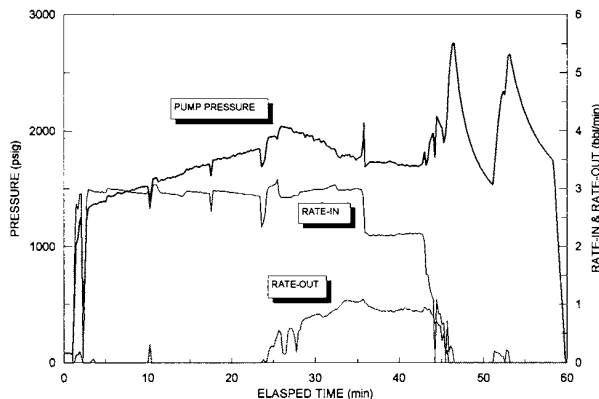


Fig. 4—Pump pressure, rate in, and rate out as functions of time for Completion 1.

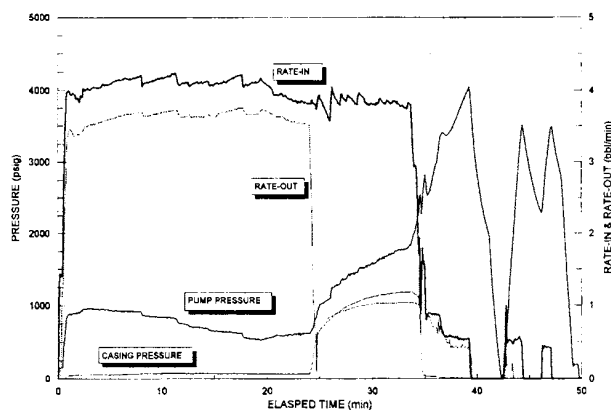


Fig. 5—Casing pressure, pump pressure, rate in, and rate out as functions of time for Completion 36.

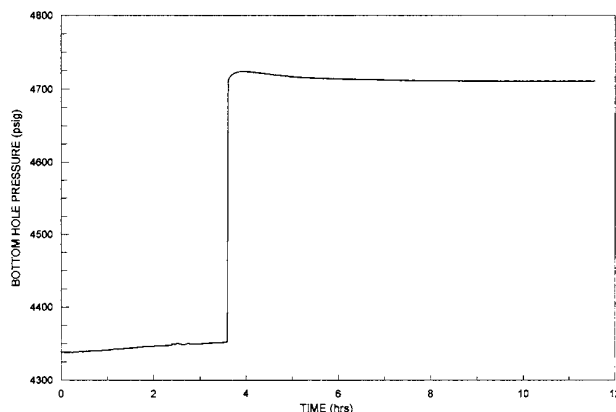


Fig. 6—BHP data for commingled Completions 35 and 36.

as a function of time for Completion 1. The sharp pressure increases at 35 minutes indicate the formation of a bridge in the screen/casing annulus. The rate was decreased from 3 to 2.25 bbl/min, and the job continued for another 10 minutes. Similar behavior, although not as pronounced, has been seen on other ALLPAK completions. Placement results appeared to become more consistent with the restricted-returns' approach, and the tell-tale screen was dropped.

An attempt was made to frac-pack Completion 29. However, because of a poor fracture design, high leakoff beyond the damaged zone, and high pump pressures, the fracture sanded off early and the blank pipe collapsed. Completion 29 was successfully washed over and fished. Completion 30 was a repeat of Completion 29, but stronger blank pipe and a better fracture design were used. When enough leakoff was developed by the fracture to handle a leakoff rate of 8 bbl/min, the annulus packed off instead of continuing fracturing. Use of a very large washpipe to restrict flow severely in the screen/washpipe annulus might have produced better fracturing results.

The fifth completion was a repeat of the fourth. A packer failure required pulling Completion 4 from the hole. The well was then re-completed with the same procedure, and the sand placement was almost identical. We learned two things from this experience. The first was that the apparatus was strong enough to be washed over and pulled without difficulty. The second was that all the shunt holes located in "dead" spaces in the screen assembly (collars and centralizer breaks) showed a slight key-slot erosion pattern associated with slurry flow through the shunt holes, indicating that considerable packing took place at these locations after formation of a bridge in the casing/screen annulus.

Well-test data on four recent completions can be used to illustrate the high well productivity being achieved with alternate-path gravel packing. These were chosen because the data were available.

Fig. 5 shows the rate out to be approximately 90% of the rate in until the return valve was pinched off at 24 minutes on Completion 36. The rate out was held to about 25% of the rate in for the remainder of the job. A distinct pressure increase is seen at 26 minutes. It is believed a bridge formed, and the remainder of the job was pumped through the shunt tubes until a sandout was obtained at 39 minutes, indicated by the increased separation of the pump and casing pressures. The average gravel placement over the perforated interval was 0.20 ft³/ft.

Bottomhole pressure (BHP) data for commingled Completions 35 and 36 are shown in Fig. 6. The well was initially opened on a 1/2-in. choke, and then choke size was increased to 7/64 in. for the stabilized flow period, with a final measured flow rate of 73.4 MMcf/D. The well continuously cleaned up over the final flow period, with an initial flowing BHP of 4,337 psi and a final flowing pressure of 4,353 psi. The well was still producing several hundred barrels per day of completion fluid at the end of the flow period. Reinjection of produced completion fluid and condensate obscured the entire buildup, and no quantitative analysis could be made. Permeability estimates from sidewall core data, log data, and injectivity tests before gravel packing indicate a value of about 60 md. This value agrees qualitatively with the BHP data. Using 60 md for the permeability and accounting for the partial completion effects, we estimate that approximately 50% of the 1,840, 0.818-in.-entrance-hole-diameter (EHD) perforations were contributing to flow.

Completion 39 is in a typical low-resistivity oil zone in a flexure trend reservoir. The total perforated interval was 160 ft, with an estimated net pay of approximately 50 ft. The zone was perforated with 12 shots/ft having a 0.6-in. EHD. To facilitate sand placement in the perforations, only 5% returns were taken at a pump rate of 6 bbl/min. Fracturing was initiated and then was halted by stepping the rate down until a high-pressure sandout occurred (Fig. 7). The well was

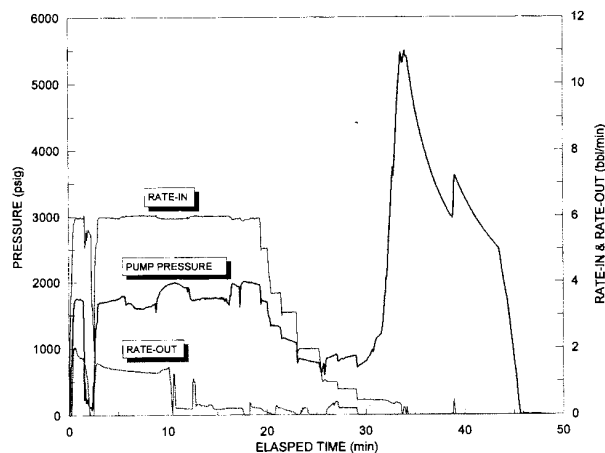


Fig. 7—Pump pressure, rate in, and rate out as functions of time for Completion 39.

tested at a rate of 1,600 BOPD for 202 hours. Fig. 8 shows both the semilog and derivative plots for the associated buildup. Calculated permeability-thickness product and skin effect were 3,014 md-ft and 1.1, respectively. The low skin effect reflects a relatively high number of packed perforations.

Completion 38 is a low-resistivity gas zone with multiple sealing boundaries. The zone was tested at 7.1 MMcf/D with associated condensate. Fig. 9 shows both the semilog and the derivative plots for the associated drawdown. Calculated permeability-thickness product and skin effect were 149 md-ft and 0.5, respectively. The zone was completed at 12 shots/ft with 0.6-in. EHD over a 72-ft interval with an estimated net pay of 32 ft. The low skin effect reflects a relatively high number of packed perforations.

Completion 37 is a replacement completion where a casing leak forced the abandonment of the initial completion. The initial completion was a non-ALLPAK completion perforated at 10 shots/ft with a 0.67-in. EHD and a 3 1/2-in. gravel-pack assembly. The replacement completion was an ALLPAK completion perforated at 6 shots/ft with a 0.53-in. EHD and a 2 1/16-in. ALLPAK gravel-pack assembly. Both completions covered the same net pay interval at the same measured depth with the same size production tubing. As

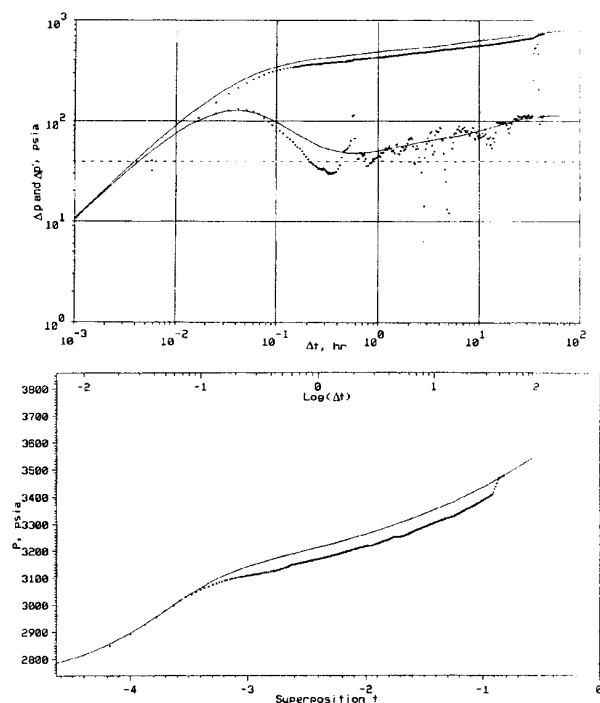


Fig. 8—Derivative and semilog plots of Completion 39 well test.

shown in Table 2, the ALLPAK completion indicates a 244% PI increase over the non-ALLPAK completion.

Conclusions

Alternate-path gravel packing provides a solution for most of the problems that have long plagued offshore operators. Well completion strategies and gravel-packing techniques previously considered infeasible can now be used to obtain greater reserves and higher well productivities. We observed the following:

1. Packing with ALLPAK and gel slurries appears to provide complete annulus packs and packing in all perforations that will take fluid at any hole deviation angle for completion lengths up to 480 ft or more, regardless of variations in permeability.
2. The average amount of gravel placed outside the casing increased from 0.10 to 0.15 ft³/ft to 0.42 ft³/ft.
3. Two or more pay zones of widely variable permeability separated by short or long shale zones can be completely packed without difficulty.
4. Higher well productivity and longevity than obtained from previous gravel-packing techniques are usually observed.
5. Failures to control sand production have been eliminated in more than 40 completions to date.
6. Alternate-path packing is adaptable to a wide variety of gravel-packing procedures, and packing operations can be simplified considerably.
7. The shunt screen assembly is fishable.
8. The need for gravel-pack logs and prepacked screens has been greatly reduced.

Nomenclature

- $m(p)$ = pseudopressure, m/Lt², psia²/cp
 $\Delta m(p)$ = pseudopressure change, m/Lt², psia²/cp
 Δp = pressure change, m/Lt², psia²/cp
 $\Delta p'$ = derivative of pressure change, m/Lt², psia²/cp
 t = time, t, hour
 Δt = elapsed time, t, hour

Acknowledgments

We express our appreciation to Mobil and Statoil for permission to publish this study.

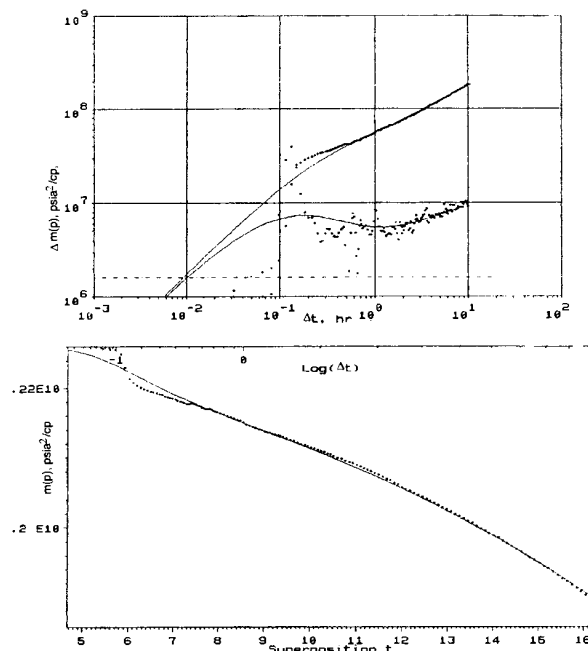


Fig. 9—Derivative and semilog plots of Completion 38 well test.

TABLE 2—COMPLETION COMPARISON

Completion Type	Shut-in tubing pressure (psi)	Production Data				Completion Area (ft ²)	Specific PI (BOPD/psi-ft ²)
		Flowing tubing head pressure (psi)	Oil (BOPD)	Gas (Mcf/D)	Gas/Oil Ratio (scf/bbl)		
Non-ALLPAK	4,200	3,100	3,700	2,491	673	5.4354	0.6188
ALLPAK	3,646	2,802	3,330	2,236	672	2.3252	1.6968

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SI Metric Conversion Factors

bbl × 1.589 873	E - 01 = m ³
ft × 3.048*	E - 01 = m
ft ³ × 2.831 685	E - 02 = m ³
in. × 2.54*	E + 00 = cm
md × 9.869 233	E - 04 = μm ²
psi × 6.894 757	E + 00 = kPa

*Conversion factor is exact.

SPEDC

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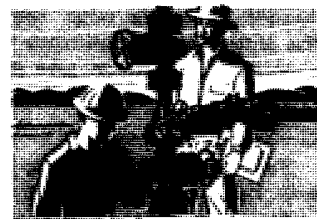


Bryant



Jones

EXHIBIT M



A New Development in Completion Methods— The Limited Entry Technique

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Abstract

Shell Oil Co., in Texas and New Mexico, has experienced excellent results from an improved well stimulation method called the limited entry technique. This method has proven much more effective than any other method in treating thick pay sections and in diverting treating fluids to multiple horizons. The limited entry treatment technique is accomplished by (1) limiting the number of perforations in a well and (2) providing sufficient injection rate to require the restricted flow capacity of the perforations to divert the treatment to a greater portion of the perforated interval.

From Dec. 3, 1960, to Jan. 1, 1963, Shell Oil Co. in Texas and New Mexico has treated 363 wells by this technique. The production performance of wells treated by limited entry completions is superior to that of conventionally treated wells. Gamma-ray tracer logs indicate most of the pay is being treated even though not covered by perforations. The limited entry technique has been used successfully in treating two separate reservoirs simultaneously in dually completed wells. Results of these simultaneous treatments have been gratifying in both well performance and reduced costs.

Introduction

The efficient simultaneous treatment of multiple porous intervals in a reservoir has been a long-standing problem in well stimulation. Various methods have been used to treat multiple zones with greater or lesser degrees of effectiveness. The bridge plug and packer method is effective, but is relatively expensive. Further, the injection rates are considerably reduced, and it is sometimes mechanically hazardous. Temporary plugging agents to divert the treatment have been used with apparent success. The main disadvantage of temporary plugging agents such as moth balls or gel blocks is the difficulty in determining the proper quantity of agent required to divert the treatment. Ball sealers are often ineffective because of (1) fluid communicating behind the casing between closely spaced perforations, (2) failure of the ball sealers to seat on the perforations and (3) abrasion of the ball sealers allowing fluid to by-pass. These stimulation techniques (for the

purposes of this paper) are considered to be conventional treatment methods.

The basic objective of all stimulation efforts is to make the best well, compatible with cost. To get an effective treatment, it is desirable to treat as much of the perforated interval as possible. Also, the treatment should be proportioned into the perforated intervals. Well performance has proven that both of these objectives can be better fulfilled by a properly designed limited entry treatment, than by conventional treatments.

Limited Entry Technique

Shell Oil Co., in Texas and New Mexico, has experienced excellent results from an improved well stimulation method called the limited entry technique. Based upon data obtained to date, this method is far superior to the other methods of obtaining simultaneous treatment of multiple zones or thick pay sections. The treatment is performed by (1) limiting the number of perforations in a well and (2) providing sufficient injection rate to require the restricted capacity of the perforations to divert the treatment to a greater portion of the perforated interval.

The first limited entry treatment in this region was performed in Shell TXL M-3, TXL Tubb field, Ector County, Tex., following a review of a paper by Murphy and Juch of Compañía Shell de Venezuela.^{1,2} From Dec. 3, 1960, to Jan. 1, 1963, 363 limited entry treatments have been performed in many different reservoirs (see Fig. 1). No mechanical difficulties have been encountered that can be attributed to this method of treatment. Treatment failures due to "sand-outs" have not been increased by this method. Treatments have been successfully performed in carbonate, sandstone, conglomerate and chert reservoirs. These reservoirs range in depths from 3,100 to 9,500 ft, with bottom-hole pressures varying from 1,000 to 3,600 psi.

Basic Theory of Fracturing Process

Conventional Treatment

The simultaneous treatment of multiple porous intervals by conventional methods is depicted in Fig. 2. Three zones with different bottom-hole fracture pressures are

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^{1,2}References given at end of paper.

opened up in the same wellbore. The zone which offers the least fracture resistance will take the treatment. This zone will continue to take the treatment until a diverting method is successfully utilized.

Limited Entry Treatment

To treat more than one porous interval, the bottom-hole treating pressure must be raised above the fracture initiation pressure of each successive zone to be treated. This can be accomplished by limiting the number and diameter of the perforations in the casing. As seen from Fig. 3, the perforation friction pressure varies directly with the rate pumped through the perforation. Therefore, by increasing the injection rate, the perforation friction will be increased. In other words, the perforations are acting as individual bottom-hole chokes. They create an increase in available bottom-hole casing pressure as the injection rate is increased. The accompanying increase in pressure in the casing will then break down or fracture the next zone as indicated in Fig. 4.

The process of breaking down each successive zone occurs rapidly, since maximum pressure and rates are established early in the treatment. Assuming adequate injection rate at the surface, this process is continued until either all of the perforated zones are being fracture treated

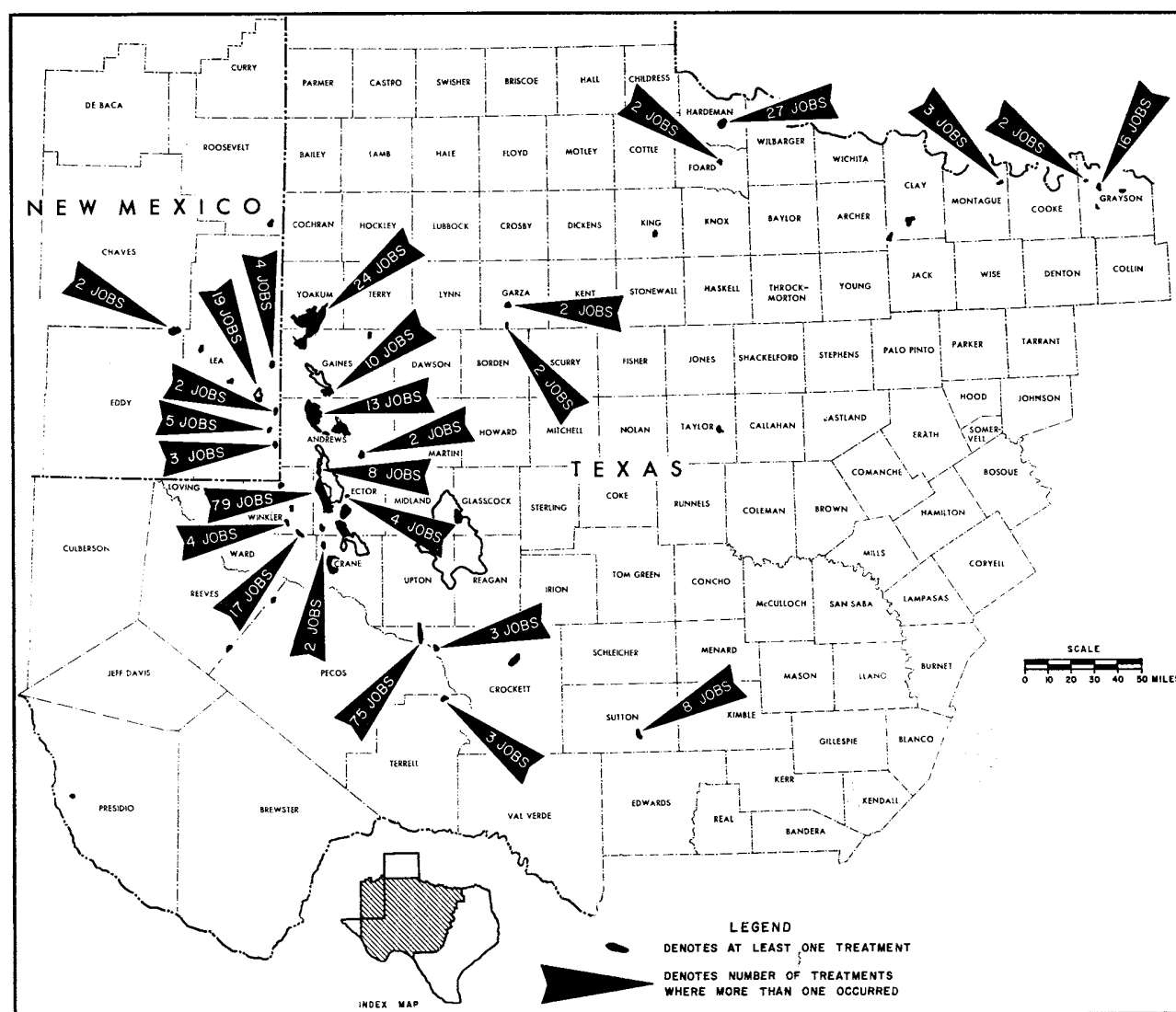
or the maximum permissible pressure on the casing is reached.

Specific Factors Affecting Design of Limited Entry Completions

Perforation Friction

Best results are obtained by maintaining perforation friction at a maximum during treatment. This insures treatment of all perforated intervals that will accept fluid within the permissible casing pressure limitations. It is recognized that all the perforations could be treated at a lesser injection rate. However, this would not be true if the bottom-hole fracture pressure of the individual porous members varies significantly. Therefore, to have the most assurance that all zones are being treated, an injection rate that will give a maximum permissible casing pressure is necessary.

Small-diameter perforations are preferred in limited entry treatments to (1) increase perforation friction and (2) lower hydraulic horsepower requirements. Fig. 3 shows that, for the same perforation friction, approximately twice as much fluid can be injected through a 1/2-in. hole as through a 3/8-in. hole. Therefore, by using the small perforations, less hydraulic horsepower is re-



quired to deliver an injection rate adequate to maintain a maximum perforation friction. Few difficulties have been encountered to date in fracture treating through $\frac{3}{8}$ -in. jet perforations. Therefore, $\frac{3}{8}$ -in. perforations are generally used for limited entry treatments.

Experiments have been performed by The Halliburton Co. and others where a variety of treating fluids with sand was pumped through $\frac{3}{8}$ - and $\frac{1}{2}$ -in. perforations. During the tests, small irregularities in the perforations were quickly smoothed out (with sand-oil mixtures) and the perforations altered from sharp-edged to round-edged orifices. The hole diameters, however, remained essentially unchanged within the normal pumping times of a fracture treatment.

Proportioning of Treatment

Limited entry treatments can be designed so that the desired amount of fluids will be injected into each porous zone. This is an important advantage where thick zones, which require more treatment, are treated in conjunction with thin zones. It is assumed that each perforation will accept approximately the same amount of fluid. Therefore, by proportioning the number of perforations according to the thickness of the zone, each zone will be given the desired amount of treatment.

A word of caution—the above method of proportioning fluids into zones through perforations depends on the

bottom-hole fracture pressures being similar. Where it is recognized that considerable variations exist in the bottom-hole fracture pressures of the zones, the treatment design should be altered. The zone with the lowest bottom-hole fracture pressure would normally receive the most treatment per perforation. Therefore, the number and/or size of the perforations should be reduced in this zone. In the zone with the highest bottom-hole fracture pressure, the converse would be true.

Design of a Limited Entry Treatment

As stated before, the main reason for limiting the number of perforations is to maintain control of the placement of the fracturing fluids. Therefore, it is important to know the number of perforations to use for a desired injection rate to obtain maximum perforation friction.

The equation for perforation friction is:

$$P_{pf} = P_s - ISIP - P_f \quad (1)$$

where P_s = surface injection pressure, psi,

$ISIP$ = instantaneous shut-in pressure, psi, and

P_f = casing or tubing friction loss, psi.

This equation was derived by substitution in the following equations:

$$BHFP = P_s + P_h - P_f - P_{pf}$$

$$BHFP = ISIP + P_h$$

where $BHFP$ = bottom-hole fracture pressure, psi, and

P_h = hydrostatic pressure, psi.

The design of a limited entry treatment is made by a trial-and-error method. First, a minimum number of perforations is chosen to treat all of the pay interval and properly proportion the treatment. Second, an injection rate is determined for those perforations that will maintain maximum perforation friction (within casing pressure limitations). If the calculated injection rate is considered unreasonable (either too high or too low), the number and placement of the perforations would be reviewed. For a sample design calculation, see the TXL K-18 field example.

Comparison of Conventional and Limited Entry Design

Fig. 5 shows a comparison between the design of a limited entry completion vs a conventional completion. This well has $5\frac{1}{2}$ -in. casing cemented through multiple porous zones. In the conventional completion as shown, with two perforations/ft of pay, any one zone could accept

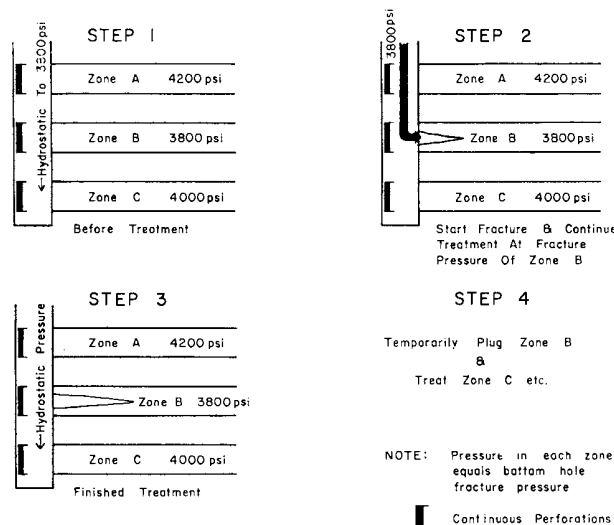


Fig. 2—Fracturing process—conventional treatment.

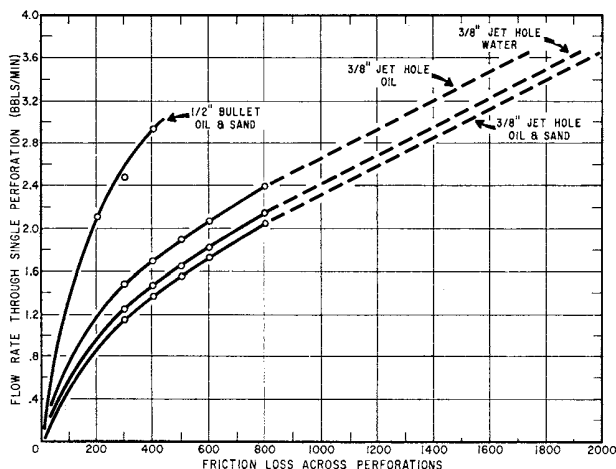


Fig. 3—Flow rate vs friction loss, laboratory measured (courtesy of The Halliburton Co.).

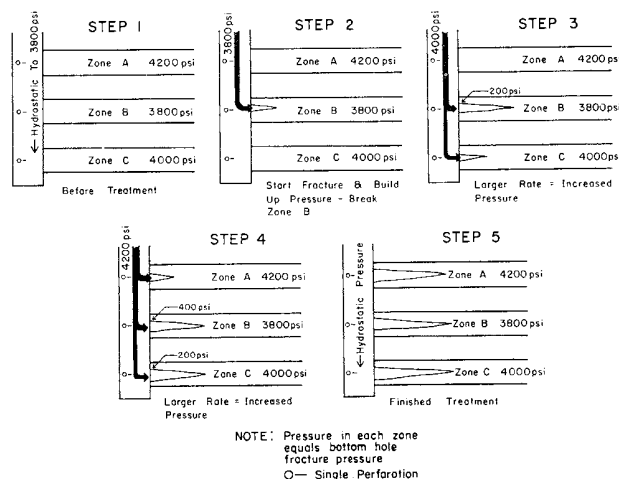


Fig. 4—Fracturing process—limited entry treatment.

all of the treatment unless diverting agents were successfully used. In the limited entry design, ten 3/8-in. holes were distributed into the various porous members to treat all of the pay and to properly proportion the treatment. The actual number of holes taking treatment can be determined from perforation friction calculations made from field data taken while treating. It would be difficult, if not impossible, to gain this kind of information while treating in the conventional manner.

Field Data Used in Treatment Analysis

The limited entry technique provides field data that can be used to determine the number of intervals that were treated. If this analysis indicates that all zones are not being treated, the completion design can be altered.

The three essentials necessary to determine the number of perforations accepting fluid are: (1) accurate injection rates, (2) accurate surface injection pressures and (3) an instantaneous shut-in pressure (*ISIP*) at the beginning of the job. Injection rates obtained by averaging over prolonged periods of the treatment are not generally adequate for this method. A continuous-rate recorder is considered most helpful.

If a perforation friction calculation is to be made while a sand-oil mixture is being injected into the formation, the instantaneous shut-in pressure as measured at the surface must be corrected for the change in hydrostatic pressure due to the addition of sand (see TXL K-18 sample calculation).

Based upon experience, the instantaneous shut-in pressure should be measured at the start of the treatment. This is necessary to calculate the actual number of perforations accepting fluid during treatment. A definition of *ISIP* is: that static pressure required to hold a fracture open. Fig. 6 is a treatment pressure chart. While pumping into the formation at fracture pressure, to get an *ISIP*, pumps are stopped instantaneously. The recorded surface pressure falls abruptly to a stabilized pressure and then bleeds-off slowly into the formation. The abrupt stabilized pressure point is a measurement of the *ISIP*. Note that the *ISIP* at the start of the treatment in Fig. 6 is 2,400 psi and has increased to 3,000 psi at the end of the treatment. This is not a freak occurrence. The *ISIP* increases during all treatments. Fig. 7 has been prepared to show the relationship between *ISIP* and treatment size.

The *ISIP* is plotted against the fluid volume displaced into the formation. There is a straight-line relationship between these two factors. Included in the volume displaced into the formation is the volume of fluid in front of the fracture treatment, the treatment volume itself and

any overdisplacement volume. In the example of the Hobbs K-6 (Fig. 7) the *ISIP* was 2,200 psi at the start of the treatment during breakdown with lease crude. The *ISIP* had increased to 3,500 psi at the end of the treatment after displacing 35,000 gal into the formation with lease crude. It is obvious that the calculation for perforation friction (P_{pf}) could vary considerably depending upon which *ISIP* is used. In the example of the Hobbs K-6, if the final *ISIP* were used, the calculation for P_{pf} would have had a negative value. This is an impossible figure. Using the final *ISIP* will not always give a negative value. As in the case of the Slator B-8, if the final *ISIP* were used, the P_{pf} would not be negative, but it would be some 400-psi lower than that if the initial *ISIP* had been used in the calculations. Therefore, the calculated injection rate per hole would be too low.

The only time that an instantaneous shut-in pressure is a direct surface measure of actual bottom-hole fracture pressure is at the start of a treatment. A theory is proposed to explain why this is true and why it is necessary to use the initial *ISIP* in the perforation friction (P_{pf}) calculations. Fig. 8 shows a wellbore with a perforation through which fluid is being pumped into a fracture. In this example, the bottom-hole treating pressure inside the casing is 5,700 psi and the perforation friction is 1,000 psi. The formation bottom-hole fracture pressure is 4,700 psi as measured at the start of the treatment.

Assume that the bottom-hole treating pressure and perforation friction remain constant during treatment. However, Fig. 7 shows that the *ISIP* does not remain constant. The *ISIP* is a direct surface measurement of the *BHFP*. Therefore, if the *ISIP* increases during treatment, so must the bottom-hole fracture pressure. It is proposed that the increase in *BHFP* is due to a pressure bank which is created around the fracture, due to fluid loss from the treating fluid. The fluids are forced from the fracture to

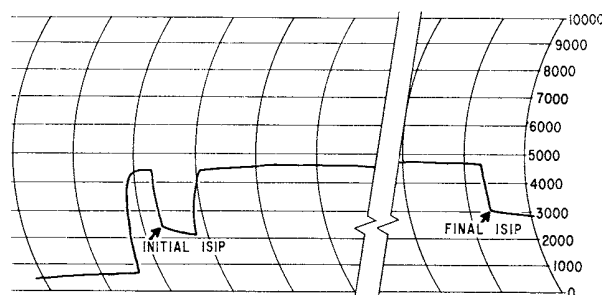


Fig. 6—Pressure chart.

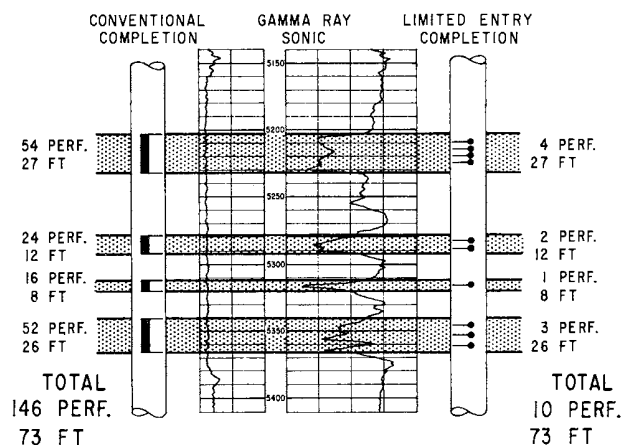


Fig. 5—Comparison of Completion design—limited entry vs conventional.

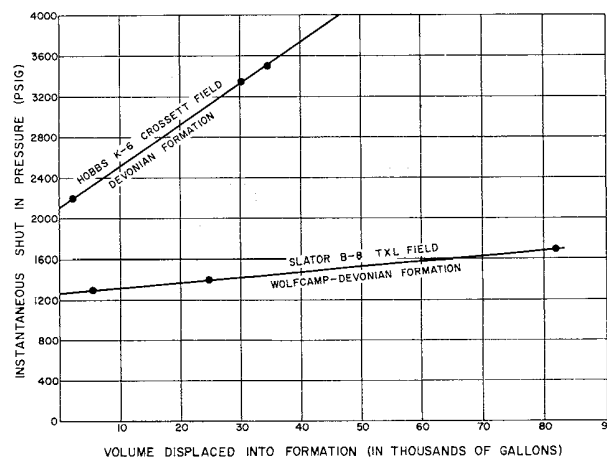


Fig. 7—Instantaneous shut-in pressure vs volume displaced into formation.

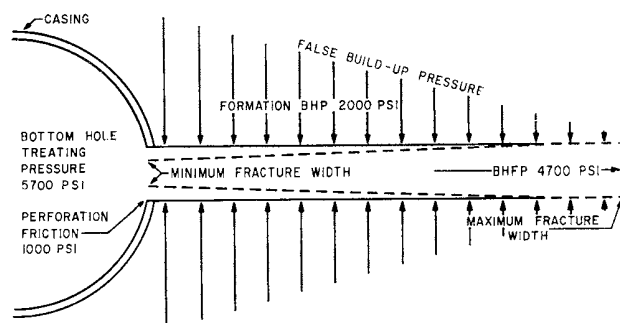


Fig. 8—Pressure bank build-up along fracture.

the matrix faster than they can escape through the matrix. This would create an increased pressure area around the fracture, or a pressure bank. As this pressure builds up, it becomes increasingly more difficult to hold the fracture open as evidenced by the increase in the *ISIP*. In other words, the pressure bank is attempting to close the fracture.

The highest pressure in the pressure bank occurs at the borehole at the mouth of the fracture. This region has had the longest time to be charged by the fluids that are forced from the fracture to the matrix. The pressure bank diminishes along the length of the fracture, and at the end of the fracture it would be essentially zero. Since there is no pressure bank build-up at the end of the fracture, the *BHFP* of 4,700 psi is still the same as measured initially when the treatment was started. Fluids can still escape along the fracture at the same *BHFP* as was initially measured at the start of the treatment. Therefore, the initial *ISIP* should be used in the P_{pf} calculations. Obviously, as the pressure in the pressure bank approaches the pressure inside the fracture, there will be a reduction in the fracture width which will eventually cause a reduction in the injection rate through each perforation. This, however, is not a normal occurrence.

Comparison of Limited Entry vs Conventional Completions

Multiple Porous Interval

The following data from wells in the TXL-Tubb field (Lower Clearfork formation) are offered as a comparison of initial performance of similar wells producing from multiple porous intervals in an area where the comparison is available (Table 1). The wells are comparable in the feet of pay developed, the size of fracture treatments and the expected ultimate recoveries. The pay is distributed over a gross interval of about 400 ft.

Table 1 includes all Shell TXL-Tubb wells in which pressure build-up tests have been taken. The data are considered to be of good quality because of the exceptionally good pressure build-up curves.

As indicated, the initial measurement of average *Kh* for conventional vs limited entry treated wells has been increased from 41 to 254 md-ft, or an increase of 520 per cent. The productivity index, as calculated from pressure build-up data, has been increased an average of 330 per cent over that of conventionally treated wells. Specific productivity index (PI per net feet of pay) has been increased an average of 340 per cent. The average official potential test has been 31-BOPD higher for the limited entry completions.

Single Porous Interval

Data from wells in the Crossett field (Devonian formation) are presented as a comparison of initial perform-

ance of similar wells producing from a single porous interval (Table 2). The average potential test was increased from 208 to 237 BOPD. This increase of 29 BOPD in favor of the limited entry completions is not too significant. However, a review of the productivity index data shows that much better wells have been made by the limited entry technique. The permeability feet total (*Kh*) was increased from 121 to 307, or 154 per cent higher in the limited entry completions. The limited entry completions also have a productivity index that is 116 per cent higher than the conventionally completed wells. Since the conventional completions were generally given a slightly smaller fracture treatment, an attempt was made to correlate PI with the size of the fracture treatment. No relationship could be established. The limited entry completions have an average of 63 ft of pay vs 48 ft of pay for the conventional completions. Therefore, to eliminate the effect of more pay on the productivity index, the specific productivity index was calculated. This is the productivity index per foot of net pay. The specific PI averaged 63 per cent higher for the limited entry completions.

Figs. 9, 10 and 11 are presented to show the relationship between PI and feet of pay. In the conventional completions shown in Fig. 9, the PI does not increase with an attendant increase in the net feet of pay. As indicated, the PI is the same for 20 ft of pay as it is for 120 ft of pay.

Figs. 10 and 11 show a definite relationship between the feet of pay and the PI for the limited entry completions. For example, from Fig. 10 the PI for 20 ft of pay is about 0.20 bbl/psi decrease; the PI for 120 ft has been increased to about 2.30. The PI is better in the thicker pay intervals because the limited number of perforations proportioned the treatment over the entire pay interval. Whereas, when the entire interval was perforated by two

TABLE 1—COMPARISON OF AVERAGE INITIAL WELL PERFORMANCE, MULTIPLE POROUS INTERVALS—LIMITED ENTRY TREATMENT VS CONVENTIONAL TREATMENT, TXL-TUBB FIELD, LOWER CLEARFORK FORMATION, ECTOR COUNTY, TEX.

	Treatment Method	
	Limited Entry	Conventional
No. of Wells	5	8
Net Pay, ft	54	50
No. of Perforations	24	233
Fracture Treatment		
Oil, gal	28,000	26,250
Sand, lb	42,000	46,000
Ball Sealers	7	138
Official Potential Test		
BOPD	244	213
Choke, in.	21/64	22/64
Bottom-Hole Pressure Build-up Data**		
<i>Kh</i> , md-ft	254	41
<i>K</i> , md	5.24	0.81
P^*PI	0.351	0.082
Specific $P^*PI \times 10^{-3}$	7.24	1.64

***Kh* = permeability (md) $\times$ feet of pay; P^* = extrapolation of pressure build-up curve to an infinite shut-in time; *PI* = productivity index = barrels (per day) per psi pressure drop; and specific P^*PI = productivity index per net feet pay.

TABLE 2—COMPARISON OF AVERAGE INITIAL WELL PERFORMANCE, SINGLE PRODUCTIVE INTERVAL—LIMITED ENTRY TREATMENT VS CONVENTIONAL TREATMENT, CROSSETT FIELD, DEVONIAN FORMATION, CROCKETT COUNTY, TEX.

	Treatment Method	
	Limited Entry	Conventional
No. of Wells	38	20
Net Pay, ft	63	48
No. of Perforations	9	150
Fracture Treatment		
Oil, gal	18,600	11,400
Sand, lb	16,700	14,900
Official Potential Test		
BOPD	237	208
Choke, in.	13/64	14/64
Bottom-Hole Pressure Build-up Data**		
<i>Kh</i> , md-ft	307	121
<i>K</i> , md	4.9	2.5
P^*PI	0.67	0.31
Specific $P^*PI \times 10^{-3}$	10.6	6.5

***Kh* = permeability (md) $\times$ feet of pay; P^* = extrapolation of pressure build-up curve to an infinite shut-in time; *PI* = productivity index = barrels (per day) per psi pressure drop; and specific P^*PI = productivity index per net feet pay.

or more perforations/ft, only the easier intervals to fracture took treatment.

Note the two separate relationships established between PI and feet of pay in Figs. 10 and 11, both of which are limited entry completions. The wells in Fig. 11 grouped themselves into two parts of the field in downthrown fault blocks. The wells in Fig. 10 are located in between, in the upthrown fault block. The porosity and permeability for the Crossett field are considered to be controlled by the degree of weathering that has taken place in the siliceous limestone. Therefore, it appears reasonable to assume that the upthrown block, underlying an erosional unconformity, received more weathering and should have better porosity and permeability characteristics than that of the downthrown blocks. This could account for the better PI vs feet of pay relationship in the upthrown block.

Operational Techniques

Opening Perforations Prior to Treatment

The major difficulty that has been encountered in limited entry treatments has been insuring that all holes are open prior to the fracture treatment. Seldom are all of the perforations able to accept fluids without first being acidized. It is believed that this problem exists with conventional completions, but usually remains unnoticed. Where the number of perforations is greatly limited, it becomes obvious if some are not open to the formation.

An acidizing technique has been adopted that is practical only for limited entry completions. The procedure involves staging the acid in small slugs (100 to 200 gal) separated by a maximum of two ball sealers in an oil spacer. The number of stages is determined by the number of ball sealers required to "ball out" the perforations. This allows a better estimate of the number of perforations that are open at the end of the acid treatment. After ball-out occurs, pressure is held on the remaining acid in the casing for a short time interval to provide every opportunity for additional perforations, if any, to be opened.

Fracture Treatment

Limited entry fracture treatments have been performed with injection pressures, rates, treating-fluid types and volumes similar to those of conventional treatments. Sometimes, it is undesirable or impossible to have injection

rates sufficient to insure treatment of all the perforations. In this case, ball sealers can be effectively used as a diverting agent. Experience indicates ball-sealer action to be near 100 per cent effective in limited entry treatments. This may be due to higher injection rate per hole and greater separation between perforations. Extra precaution should be taken to avoid excessive pressure surges due to the excellent ball-sealer action.

Individual perforations sometimes sand-out during treatment. A decrease in injection rate is indicative of the time and number of perforations affected when sand out occurs. A continuous-rate recorder is necessary for observing the loss of perforations taking treatment. It is also most helpful in determining the proper number of ball sealers to drop during a job.

Field Examples of Limited Entry Treatments

Fig. 12 shows the design and fracture treatment results

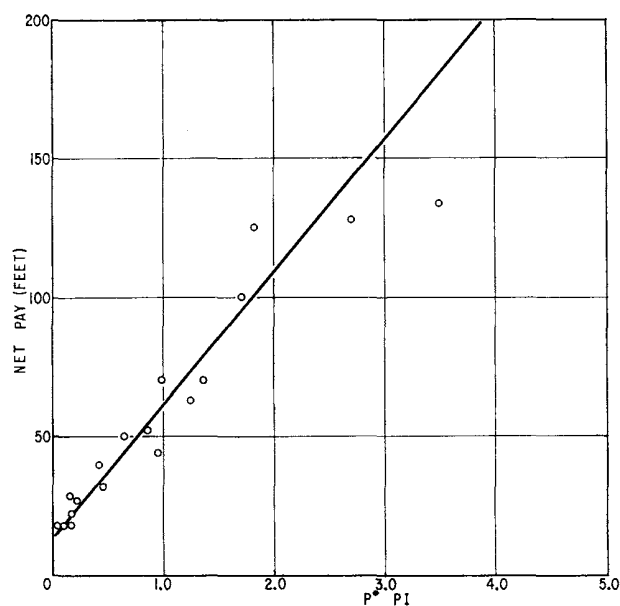


Fig. 10—Limited entry completions— $P \cdot PI$ vs net pay, Crossett field, Devonian formation, Crockett County, Tex.

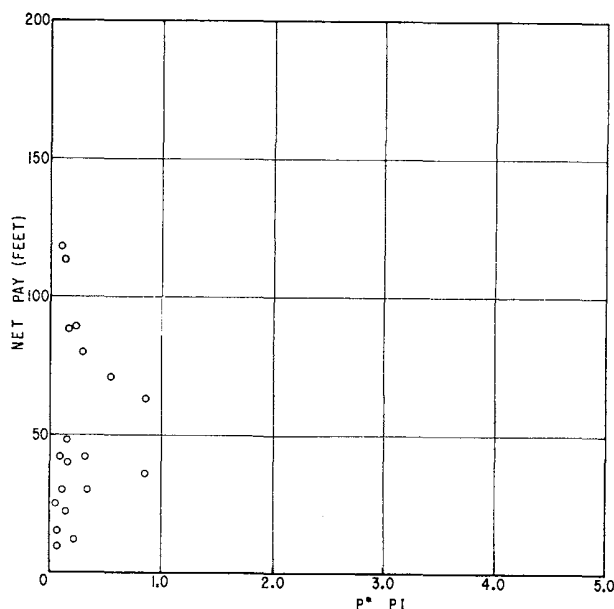


Fig. 9—Conventional completions— $P \cdot PI$ vs net pay, Crossett field, Devonian formation, Crockett County, Tex.

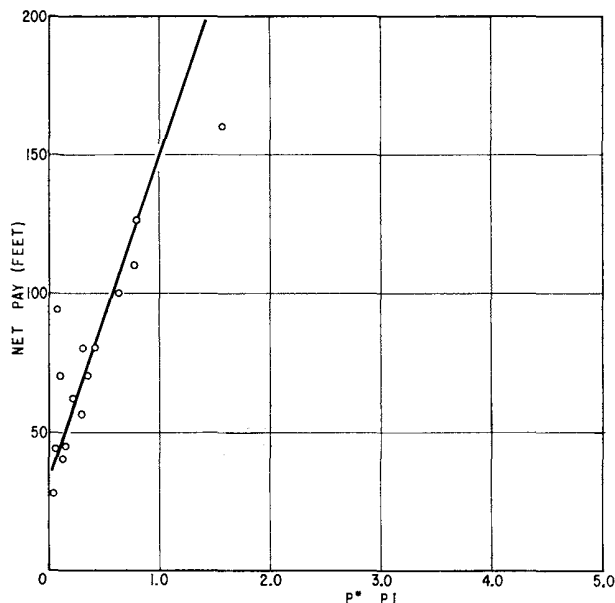


Fig. 11—Limited entry completions— $P \cdot PI$ vs net pay, Crossett field, Devonian formation, Crockett County, Tex.

of the Wolfcamp formation in Shell TXL K-18, Ector County, Tex. This well was fracture treated down the casing through nine $\frac{3}{8}$ -in. perforations at 31 bbl/min. The calculations indicated that all nine holes were accepting treatment. Shell TXL K-18 was fracture treated with a radioactive sand. Therefore, any radioactive increase above that of the base gamma-ray log is considered to be an indication of the fracture-treated interval.

Note that the perforations were placed so that all of the pay was fracture treated, as indicated by the radioactive increase opposite all of the pay, even though it was not perforated. The well was potentialed flowing 254 BOPD, through an 18/64-in. top choke, with a flowing tubing pressure of 300 psi.

Sample Calculation of Design and Analysis of a Limited Entry Treatment

Data

The following sample calculations pertain to a limited entry treatment conducted on Well No. TXL K-18 located in the TXL-Wolfcamp field, Ector County, Tex. This well was completed through 7-in., 23-lb casing with a gross pay interval ranging from 7,509 to 7,682 ft, and a net pay thickness of 63 ft.

Sample Calculation of Design

This well is to be fracture treated down 7-in. casing with a maximum permissible casing pressure of 3,600 psi. Based upon the pay distribution as shown by the porosity log (Fig. 12), a total of nine $\frac{3}{8}$ -in. holes was chosen to effectively proportion treatment over the pay interval.

From Eq. 1,

$$P_{pf} = P_s - ISIP - P_f,$$

where $P_s = 3,600$ psi (casing pressure limitation),

$ISIP = 1,700$ psi (determined from experience in formation and area), and

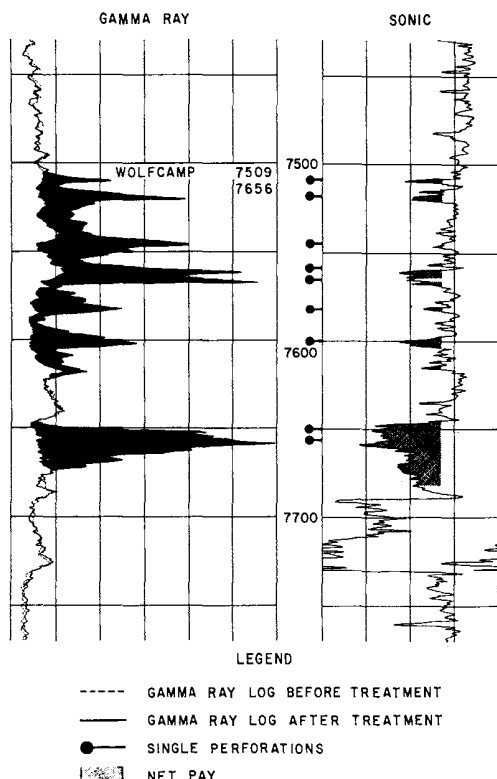


Fig. 12—More effective pay treatment by limited entry treatment, Shell-TXL K-18, TXL Wolfcamp field, Ector County, Tex.

$$P_f = 190 \text{ psi (from friction charts based upon trial rate of 25 bbl/min).}$$

Thus,

$$P_{pf} = 3,600 - 1,700 - 190,$$

$$P_{pf} = 1,710 \text{ psi.}$$

From Fig. 3, a perforation friction of 1,710 psi for an oil and sand mixture gives an injection rate of 3.3 bbl/min/hole. From these conditions, an injection rate through nine perforations would be expected to be $9 \times 3.3 = 30$ bbl/min. Since an injection rate of 25 bbl/min was assumed to determine the casing friction pressure, calculations should be repeated assuming an injection rate between 25 to 30 bbl/min until the calculated value of total injection rate through the nine perforations equals the assumed rate. In this case it would be 29 bbl/min, or 3.2 bbl/min/hole.

The calculated injection rate was acceptable. If this injection rate had been undesirable, either too high or too low, the number and placement of the perforations would have been reviewed.

Sample Calculation of Treatment Analysis

The following data were obtained: perforations—top 7,509 ft, bottom 7,656 ft, average depth 7,550 ft, nine holes; breakdown fluid—oil, 36° API gravity = 0.365 psi/ft; frac fluid—oil + $1\frac{1}{2}$ -lb/gal sand = 0.415 psi/ft; surface treating pressure (P_s) = 3,600 psi; injection rate = 31 bbl/min; instantaneous shut-in pressure surface ($ISIP$) = 1,700 psi; and casing friction (P_f) at 31 bbl/min at 7,550-ft depth = 315 psi.

This well was fracture treated down 7-in. casing through nine $\frac{3}{8}$ -in. perforations. Instantaneous shut-in pressure of 1,700 psi was measured during breakdown of formation with lease crude. The following calculation was made from data obtained while fracture treating with lease crude and sand. Therefore, it is necessary to correct $ISIP$ for increase in hydrostatic pressure due to addition of sand as follows:

$$ISIP \text{ Surface} - (\text{Frac Fluid, psi/ft} - \text{Breakdown Fluid, psi/ft}) \times \text{Average Depth.}$$

Thus,

$$ISIP \text{ (corrected)} = 1,700 \text{ psi} - (0.415 - 0.365) \times 7,550 = 1,320 \text{ psi.}$$

From Eq. 1

$$P_{pf} = P_s - ISIP - P_f,$$

Perforation Friction (P_{pf}) = 3,600 - 1,320 - 315,

$$P_{pf} = 1,965 \text{ psi.}$$

From Fig. 3, the injection rate per perforation in barrels per minute at a perforation friction of 1,965 psi is 3.6 bbl/min/perforation. Therefore, the theoretical rate through all perforations would be $9 \times 3.6 = 32$ bbl/min.

This compares favorably with the observed injection rate of 31 bbl/min, or 3.45 bbl/min/perforation.

From this comparison, it is concluded that all nine holes were treated. See Fig. 12 for confirmation of treatment analysis.

The simultaneous fracture treatment of two separate horizons, the El Cinco Detrital and El Cinco Devonian fields, is shown in Fig. 13. Both horizons were fracture treated with radioactive sand in a single operation. The radioactive tracer log indicates that the porosity was successfully fracture treated except for the bottom three Devonian perforations. This is an example of a problem in design, pointed out by a review of the treatment analysis and the tracer log. Based upon the porosity log, it appears that the design should have been straight-forward. There are three possibilities that account for the failure to treat the lower Devonian interval: (1) larger jet per-

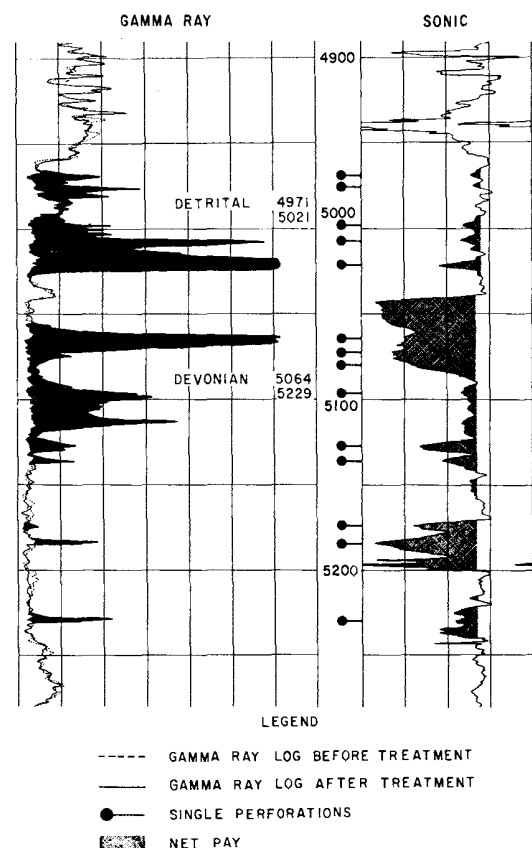


Fig. 13—Simultaneous treatment of separate horizons by limited entry treatment, Shell Wood-Cowden 1, El Cinco Detrital and El Cinco Devonian fields, Crockett County, Tex.

forations than anticipated, resulting in the upper perforations taking most of the treatment, (2) failure to provide adequate injection rate and (3) the bottom-hole fracture pressure of one zone being much larger than that of the other. All of these problems can be solved by recognizing that they exist and by varying the design of the treatment. The well was completed as a dual producer flowing 392 and 538 BOPD from the El Cinco Detrital and Devonian zones, respectively. Even though the performance of this well is good, the information obtained indicates that future remedial operations can be justified. With the combination of the limited-entry-designed completion and the radioactive tracer log, future remedial operations are greatly simplified.

With limited entry treatment, close proximity of two formations is not necessarily required for a successful simultaneous treatment. An example of this is shown in Fig. 14. The Tubb (LCF) and the Devonian horizons, separated by about 1,350 ft, were successfully fracture treated in one operation in the Shell TXL L-26, TXL field, Ector County, Tex. The Tubb (LCF) and Devonian zones were potentialized flowing 132 and 435 BOPD, respectively.

Conclusions

1. Limited entry treatments have proven more effective than other methods in treating multiple horizons and thick porous intervals.
2. No mechanical failures have occurred that can be attributed to this technique.
3. Performance to date of limited entry completions is superior to that of conventionally treated wells.
4. The number of perforations accepting fluid at any

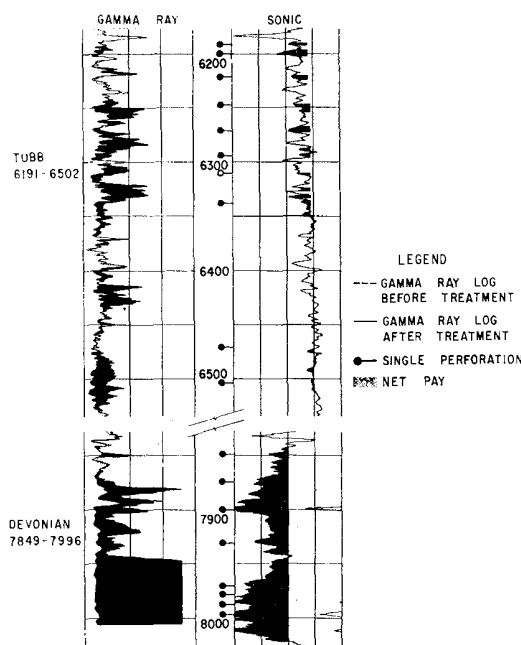


Fig. 14—Simultaneous treatment of separate horizons by limited entry treatment, Shell-TXL L-26, TXL-Tubb (LCF) and TXL Devonian fields, Ector County, Tex.

time during a treatment can be determined by calculations made from field observations. In order to estimate the proportion of the treatment received by the various perforations, a continuous injection-rate recorder is desirable.

5. Gamma-ray tracer surveys of radioactive sand used during fracture treatments have provided a graphical record of (1) the effectiveness of the limited entry technique in diverting the treatment and (2) the amount of the porous interval treated through one perforation.

6. The simultaneous treatment of dual horizons offers great savings in completion costs.

The limited entry technique is not devoid of problems. Sometimes portions of the pay remain untreated. However, by the use of the information gathered during the treatment, this problem can be recognized and improvements in the design can be made. In any method other than the limited entry technique, it would be difficult, if not impossible, to recognize that pay intervals are being left untreated.

Acknowledgment

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EDITOR'S NOTE: PICTURES AND BIOGRAPHICAL SKETCHES OF K. W. LAGRONE AND J. W. RASMUSSEN APPEAR ON PAGE 739.

EXHIBIT N



SPE 58743

Successful Application of Oil-based Drilling Fluids in Subsea Horizontal, Gravel-Packed Wells in West Africa

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Abstract

A new approach to drilling and completing long horizontal open-hole gravel packed intervals in a subsea West African Field development using oil-based drilling fluid throughout the well trajectory has resulted in significant cost savings and increased well productivity. Without this successful change and the use of horizontal wells, many of the subsea wells drilled in 50'- 2200' of water would have been uneconomical.

Previously, the upper, non-pay portions of the subsea wells were drilled with oil-based drilling fluids while the horizontal reservoir sections were drilled with a sized calcium carbonate-polymer drill-in fluid. To remove filter cake damage following gravel packing, acidization of the entire horizontal interval was required. Operations associated with changing the drill-in fluid and acidizing added significant cost and complexity to well completions. In addition to higher completion costs, the water-based drill-in fluid reduced drilling flexibility in the target channel sands resulting in more sidetracks and in some cases less than optimal completed intervals. It was recognized that continued use of oil-based fluids through the reservoir section would overcome these limitations, however, the damage potential of using oil-based drilling fluids prior to gravel packing was unknown.

This paper presents the development, application, and results of the new drilling and completion practice for horizontal,

gravel-packed, oil wells offshore West Africa. Large and small scale laboratory testing will be described, including formation damage core testing, development of displacement and cleanup procedures and fluid compatibility. Integration of technical advisors, laboratory personnel, and field operations led to rapid implementation of the new technologies. A pilot hole test was conducted in the field followed by successful application in three wells. The new procedures have resulted in improved drilling, considerable cost savings, and observed PI's 2-3 times higher than similar wells using water-based drill-in fluids.

Introduction

Initial wells developed in the field were vertical with cased-hole gravel packs. To improve well productivity, well completions were changed to open-hole highly deviated and/or horizontal well trajectories.¹ At the beginning of the open-hole completion program, the wells were drilled with oil-based fluid to the top of the pay interval. The horizontal section was then drilled with a water-based drill-in fluid and gravel packed with a water-based carrier fluid.

Previous laboratory tests showed that the drill-in fluid, weighted with acid soluble CaCO_3 , created a relatively thick filter cake and "fluff" on the formation wall. During simulated gravel pack operations, the thick cake remained attached to the formation and became embedded between the gravel pack sand and the formation. Laboratory testing showed that direct sustained contact with HCl was required; however, others have seen that acidizing was not required with this type of drill-in fluid.^{2,3} In field operations, acidizing with HCl was required to remove the filter cake and reduce damage.¹ Comparison of cased-hole vertical and horizontal open-hole well productivity indicated significant improvement, but in some cases, the residual damage was severe enough to offset the productivity gains of the longer horizontal pay intervals. One reason for the limited success was the difficulty in achieving uniform acid contact through long horizontal gravel pack completions.

In contrast to the water-based fluid, oil-based drilling fluids deposit a thinner, penetrable filter cake that can be easily lifted with little pressure differential. However, potential damage caused by barite weighting agent or emulsifiers was unknown. If stimulation was required, no proven cleanup fluids were available for barite-weighted oil-based muds. Even acid stimulation for carbonate-weighted oil-based muds can be difficult.^{4,5} Laboratory tests also confirmed that mixing of oil-based fluids and conventional water-based gravel carrier fluids could produce sludging and breakdown of the carrier fluid. Thus, improper displacement of the oil-based drill-in fluid prior to gravel packing could seriously jeopardize the gravel pack protection and well productivity.

Because of beneficial impact of oil-based fluid in horizontal drilling application the challenge was set to find means to use the oil-based barite weighted fluid as a drill-in fluid without negative impact to the gravel pack process and well productivity. The major areas of positive impact for the use of oil-based muds in this application included:

1. Reduce/eliminate sticking and subsequent sidetracks caused with water-based systems: Inter-bedded shales sensitive to water-based fluids were the primary cause of drilling problems in the horizontal section.
2. Provide drilling flexibility in order to pinpoint geologic targets: To maintain hole stability with the water-based fluid, casing was set as soon as it was thought the pay interval was encountered. Due to the meandering distribution of the sands and ellipse of uncertainty in the seismic interpretation it was not uncommon to find the sands thinning out rapidly causing a sidetrack or small completion interval.
3. Eliminate the need and cost of the acidizing operation to remove water-based mud filter cake: The high reservoir temperature (190+ °F) presented corrosion risks since the HCl had to be weighted with CaCl_2 to achieve proper density. Corrosion protection of the sand control screen from weighted acids can be difficult above about 150 °F.^{6,7}

Before changing operations over to using oil-based mud for the horizontal payzone, a thorough evaluation of the drilling, displacement and cleanup procedures was needed. Small and large-scale laboratory experiments were conducted along with a field test using the vertical pilot hole prior to application in the horizontal payzone. The rewards were apparent to all involved, but the risks at each stage of the operation needed to be quantified and minimized.

Aspects of the processes and areas of maximum perceived risk that would be addressed with testing included:

1. Formation damage caused by oil-based mud emulsifiers and barite weighting material
2. Ability to effectively displace oil-based mud to brine in an unsupported open hole horizontal prior to running screen
 - a. fluid compatibility of oil-based mud and displacement fluids
 - b. efficiency of removal of mud and “fluff” on formation face (very important since must gravel pack)
 - c. hole stability concerns due to interbedded shales throughout the pay as oil-based mud is replaced with brine
 - d. maintaining filter cake integrity to control fluid loss during displacement and gravel packing
3. Potential damage caused by gravel placement against the oil-based mud “filter cake”

Evaluations similar to those described above had already been conducted with the currently used water-based drill-in fluid to optimize its design and cleanup procedures. Even though the evaluations are not standardized within the industry,⁸ a significant amount of work has been done in the past ten years on the design and optimization of water-based drill-in fluids. Many efforts have been made to make these fluids as non-damaging as possible. However, for oil-based fluids, there is little history to compare or provide confidence of success, particularly when the well is to be gravel packed. Recently, BP-Amoco attempted open hole gravel packing following oil-based mud, but success was limited due to losses prior to and during gravel placement that prevented complete packing.⁹ However, the potential rewards, being so great, provided the impetus to carry on with the idea.

Laboratory testing was conducted, fluids and procedures were modified and relayed to field personnel, adjusted, re-evaluated, and agreed upon. For further confidence, a pilot hole field test was conducted prior to full-scale implementation.

Formation Damage Tests

Initial formation damage core work conducted for the offshore West Africa area incorporated the use of formation core to determine fluid sensitivities and damage potential. Once compatible brines were chosen, parallel and subsequent testing with high permeability (1-2 D) Berea core provided similar results. As a result, all work described here was conducted with high permeability Berea core. The use of Berea did provide reproducible core material for direct comparison of the various drilling fluids. The goal of the formation damage testing was to determine the degree of damage that could be expected from the oil-based mud.

Formation damage tests were conducted in a Hassler sleeve flow cell at 150 °F and 1000 psi system pressure. PD-23, a low viscosity mineral oil, was used as the baseline fluid for permeability measurements. A typical oil-based drilling fluid weighted to 10.5 ppg with barite was used in the testing prepared with the same formulation as used in the field. The oil-water ratio was 75-25 with 28% CaCl₂ brine as the internal phase.

All mud placement tests were conducted with 31 ppb of RevDust added to simulate drill solids. This represents a worst-case scenario since efforts were made to reduce drill solids prior to drilling the horizontal section. However, significant shale stringers throughout the horizontal were expected. Several industry reports show that drill solids contribute significantly to formation damage caused by drilling muds and must be included in laboratory testing.¹⁰⁻¹² Several tests were also conducted with 10 and 20 ppb of sized calcium carbonate. The role of the CaCO₃ (same CaCO₃ as used in water-based drill-in fluid for this reservoir) was to provide enhanced bridging of the pore throats to minimize barite invasion. It also provided an opportunity to acidize following completion, if necessary.

Mud placement tests were conducted by flowing mud across the face of the core at 500 psi overbalance followed by shut-in for at least two hours. Fluid loss was monitored throughout the test. Oil-based mud was then displaced with CaCl₂ brine at high rate. Production flow was conducted at low rate (0.5 ml/min) to observe “lift-off”. Rates were subsequently increased up to 30 ml/min to mimic well cleanup. Final returned permeabilities were those obtained at 5 ml/min following the high flow cleanup and compared to original values.

Results from the tests revealed several key data. Somewhat surprisingly, little or no difference in fluid loss was observed in the mud placement tests. The emulsion, fluid loss additives, and drill solids dominated fluid loss with little or no effective of the sized CaCO₃. No increase in fluid loss was observed during high-rate brine displacement of the mud. Liftoff pressures during production flow were very low (1-2 psi). Once the pressure on the filter cake was exceeded (became under-balanced), flow was initiated. This was in stark contrast to the much higher liftoff pressures observed with the water-based drill-in fluid (20-50 psi).¹

Following liftoff at 0.5 ml/min, the initial returned permeabilities were measured after stabilized production flow of PD-23 at 5 ml/min. (This rate is equivalent to field rates of 800 bpd per 100 ft of 8½” openhole, quite compared to expected production rates). Return permeability test results from representative tests 1-3 are shown in Table 1. After

producing at higher rates (up to 30 ml/min), lower pressures were noted at 5 ml/min in all three tests. Best results were obtained with 10 ppb of CaCO₃ after high rate production, but results for the three tests were quite similar. The return permeabilities of about 50% obtained in these tests were comparable to results obtained with water-based drill-in fluid *after* acidizing.

The results show that surging of the well can remove plugging particles at the face of the wellbore that reduce formation permeability. Note that the surges here were only for very short times, 5-10 minutes. Extended production at lower rates would give similar results. One point that this testing does not address is uniformity of cleanup. Since only a 1.5” diameter core was used, it does not represent cleanup over a long, horizontal openhole interval. However, the very low “lift-off” pressures required to initiate flow suggest uniform cleanup is possible. The particles removed during high rate production, likely barite and/or RevDust, should be small enough to migrate through a gravel pack and screen without plugging them. Testing with the horizontal wellbore simulator test incorporating a gravel pack would answer this question and provide a larger scale return permeability test for comparison.

Large Scale Laboratory Testing with Horizontal Wellbore Simulator

Key goals of the larger scale testing with the horizontal wellbore simulator were to:

1. observe displacement efficiency with viscous pill and high-rate brine flow
2. evaluate any changes in fluid loss that may occur during displacement
3. determine the degree of permeability impairment due to gravel pack plugging
4. obtain return permeability comparison to core testing

The cell for the simulator test consisted of a Plexiglas wellbore model 3” in diameter and 6.5’ in length. A porous metal tube was fitted inside the model. The configuration of the model and porous tube allowed flow into the tube (injection) or out of the tube (production). Pressure was monitored in the model and across the porous tube (ΔP).

The general procedure is as follows. Initial pressure drop across the tube was measured with PD-23. Oil-based drilling fluid (same as that used in core flow testing) was flowed along the annulus of the cell with an overbalance pressure of approximately 100 psi across the porous tube. A filter cake was formed on the outside of the tube and fluid loss through the tube was measured. The viscous pill was then pumped to displace the OBM followed by the high rate CaCl₂ brine displacement. The gravel pack carrier fluid was pumped prior to placing the gravel pack. The cell was gravel packed from the end to front with the perforations open, shutting them as

the gravel pack proceeded down the length of the cell. Finally, PD-23 was flowed back through the porous tube (simulated formation) and gravel pack to determine the degree of flow impairment caused by the OBM filter cake and gravel pack. Following the test, the gravel pack was removed and the flow through the porous tube alone was measured to separate damage of the tube (formation) from impairment in the gravel pack.

Mud Placement. Following initial permeability measurements with PD-23, oil-based mud without solids was flowed through the annulus of the simulator to displace PD-23, then the complete 10.3 ppg oil-based mud was pumped through the annulus. After discarding the initial wellbore volume, the mud was re-circulated back to the tank for continued use. Once re-circulation was established, the downstream valve was opened allowing flow through the porous tube. Fluid loss was monitored throughout the test. Oil-based mud was circulated at 1 gal/min and approximately 100 psi overbalance for 2 hours. As shown in Figure 1, the oil-based mud performed very well in limiting fluid loss through the porous tube. No change was observed during the period of attempted shut-in compared to the dynamic periods.

Viscous Pill and High Rate Displacements. Following mud placement, 11.0 ppg CaCl_2 brine gelled with xanthan (2.5 ppb) was pumped at 1 gal/min (100 psi overbalance) to displace the solids-laden mud. Immediately upon contact of the viscous pill with the filter cake, fluid loss increased significantly, but quickly returned to levels similar to those prior to contact (as shown in Figure 1 at 150 minutes). For a short period of time, overbalance pressure was reduced to near zero with no change in fluid loss noted. This was important since core flow tests showed that only a slight under-balance was required to lift-off the filter cake. The viscous pill effectively displaced 80-90% of the oil-based mud and solids from the simulator. Only a small portion of solids remained at the bottom of the wellbore.

Following the viscous pill, 10.3 ppg CaCl_2 brine was pumped at 2-5 gal/min through the annulus. Overbalance pressure was maintained between 50-100 psi. The rate was increased to 40 gal/min. At 30-35 gal/min, "turbulence" within the simulator was noted and the mud solids in the bottom of the wellbore were completely cleaned out of the simulator. No signs of filter cake "fluff" or residues were evident. After high rate displacement, the simulator was left static and 100 psi was maintained on the filter cake for about 15-20 minutes. As shown in Figure 1, the fluid loss actually decreased during the high rate displacement stage. By maintaining filter cake integrity during high rate displacement in the field, horizontal well gravel packing can be more successful.

Gravel Packing. At this point, the simulator contained CaCl_2 brine at 100 psi with little or no fluid loss through the porous tube. The simulator was subsequently gravel packed with

40/60 sand using 9.5 ppg CaCl_2 viscosified with 2.5 ppb of xanthan as carrier fluid. A slight increase in fluid loss was noted when gravel first entered the simulator, but as in previous operations, fluid loss quickly decreased to the levels observed during mud placement (at 200 minutes in Figure 1). System overbalance pressure was maintained at 50-100 psi. At 1 gal/min, carrying capability of the xanthan was excellent. A complete pack was obtained with no visible voids.

Production – Return Permeability. Following the gravel pack, PD-23 was flowed back through the porous tube and through the gravel pack. As in the core flow tests, no pressure peak or "lift-off" pressure was observed. Despite low fluid loss during the test, flow in the "production direction" was easily initiated. The presence of the gravel pack did not hinder filter cake lift-off and flow.

As rates were increased to 5000-6000 ml/min, then lowered to 2000 ml/min, an increase in permeability was observed. However, these increases were not sustained. During the higher rate "surges", lumps of gel were expelled from the system, resulting in lower pressure drop and increased apparent permeability. Obviously, the unbroken gravel pack gel was inhibiting production flow. Complete break of the xanthan fluid would be required for its use in the field.

After completion of the test, the simulator was disassembled and permeability through the porous tube only was determined. At 2000 ml/min, the same permeability was obtained as when the gravel pack was in place. A comparison of the pressure drops across the porous tube before and after the test is shown in Figure 2. The circles represent data points from flow through the tube after the gravel pack was removed. These pressure values fall in line with those observed with the gravel pack in place. In addition, when a high rate of PD-23 (5000 ml/min) was pumped through the porous tube only, a pressure decline was observed as in tests with the gravel pack in place. However, the pressure remained stable at the lower pressures further supporting that the pressure increases in the gravel pack were due to unbroken xanthan gel (these data are those that fall on the black line). Proper breaker schedules for gravel carrier fluids are required to avoid this potential damage mechanism. During the actual field treatments, viscoelastic surfactant (VES) gel was used as the gravel pack fluid – complete break of this fluid was easily obtained as it mixes with the produced oil.

In summary, displacement of oil-based drilling fluid was successfully achieved with CaCl_2 -based viscous pills and high rate brine stages. The viscous pill removed 80-90% of the mud, while high rate displacement cleaned out the remainder of the mud and solids. Fluid loss appeared to increase as a new fluid contacted the filter cake, but rate of fluid loss quickly returned to that observed during mud placement.

During the high rate displacement, fluid loss actually decreased to near zero.

Returned permeability in the wellbore simulator were very similar to those observed in core testing. As in the core testing, high rate production improved return permeability by dislodging particles. Presence of the gravel pack did not cause further damage, however, presence of unbroken gravel pack gel can potentially cause pressure increases and variation in production rates.

Concept Testing

Prior to committing to a subsea completion, a 6000' pilot hole penetrating the producing formation and a long section of overlying shales was chosen to verify the lab results of no shale swelling, no sand collapse and no massive losses after mud removal. After logging, the oil-based drill-in fluid was displaced out of the producing sand/shale interval with completion brine at rates and volumes that simulated comparable conditions achieved in the laboratory experiments. The drill string assembly was tripped out of the hole and a plug back assembly was run. During the trip back in, no shale swelling or hole stability problems were noted and fluid losses were minimal. This verified the lab test results to the extent that a field trial was justified.

Implementing the drill-in fluid change in the first well

With the confidence gained from the pilot hole, a completion was planned with oil-based barite weighted drill-in fluid. As had been done previously in all EG horizontal wells, the production casing was run and cemented just into the pay. However, instead of drilling out with a new mix of water-based fluids, the same oil-based fluid as had been used above the casing setting point was used.

Once TD was reached, the oil-based fluid was displaced with completion brine, the drilling assembly removed and the shrouded completion screens run to bottom with no problems. The well was gravel packed in the same manner as had been done historically with alternate path screen technology.¹³ The shunt tube system allows the bypassing of sand bridges that may form due to fluid losses during gravel packing. This was significant concern for oil-based filter cakes due to the low lift-off pressures observed in the laboratory testing.

In two of the three wells significant losses were observed, however complete sand placement was achieved in all cases. All wells exceeded expectations, producing in excess of 10,000 bopd with a lower draw down than any previous horizontal wells with water-based drill-in fluids.

Testing justifies changing the casing scheme

With the initial evidence that oil-based fluid could be used through the pay interval, a new approach to casing point

selection was planned. On the next well, instead of stopping and setting casing and swapping fluid at the indication of first pay, it was planned to take the 12-1/4" hole horizontally all the way to TD with the same oil-based drilling fluid. Once it appeared through MWD that an appropriate pay interval was exposed, then the casing point would be picked to optimize the gravel pack completion. A completion target of 600' of pay was established. It was fortunate in this case that the casing was not set at first pay indication, as the first two pay sands encountered were shaly and not within the planned target pay range. Without the casing set, the well trajectory was easily manipulated and 600' of clean sand was ultimately found. Using the historical drilling scheme, it is very likely that the original well path would have been abandoned and a cased-hole sidetrack attempted. Given this scenario, it is possible the third 600' sand could have also been missed entirely.

Field Success

In spite of the well variability, with the aide of continuous bottom hole pressure gauge readouts, a gross comparison of stabilized flow drawdown ratio over the length of pay was performed for four of the most recently completed wells. As illustrated in Figure 3, there is a significant difference in horizontal length of the four wells, but there is good agreement of the ratio comparison for like drill-in fluids. Given the simplifying assumptions that the completed sand quality is relatively the same for the wells, the bar graph indicates the wells drilled with oil-based barite weighted drill-in fluids are approximately three times more productive than those drilled with water-based fluids.

Cost Savings

Direct cost savings of 30% per well were achieved by the fourth well as a result of the reduced rig time, fluid cost and elimination of the acid job.

A potential bigger impact to the project development cost and reserve recovery has been the minimization of sidetracks and the improved ability to slide and turn the bit to follow the sand package to expose maximum quality sand in a complex geological depositional environment.

Additional savings have been forecasted with the elimination of pilot holes. Once a 12 1/4" hole has been successful in locating a producible interval, instead of re-drilling, the original hole could be extended to TD with the oil-based drilling fluid.

Conclusions

Oil-based drilling fluids allow improved drilling in offshore Africa channel sands that contain reactive shale stringers.

With oil-based fluids, casing point selection is more flexible allowing drilling and completion of the best producing sand channels.

Successful displacement of oil-based drilling mud prior to running screens with minimal fluid loss can be accomplished with use of a viscous pill followed by high-rate brine.

Very low pressures are required to lift-off an oil-based mud filter cake. As such, under-balanced situations must be avoided to minimize fluid losses.

Use of alternate path gravel packing systems can overcome problems associated with fluid losses during gravel pack operations.

Improved productivity and cost savings can be achieved with traditional oil-based drilling fluids in long horizontal openhole gravel packed wells.

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Table 1. Returned Permeabilities for Core Flow Tests with Oil-Based Mud

<i>Test</i>	<i>CaCO₃, ppb</i>	<i>Permeability (md)</i>	<i>Initial Returned Permeability, %</i>	<i>Final Returned Permeability, %</i>
1	0	1187	33	44
2	10	1612	27	54
3	20	1612	36	49*

*Increased from 44% to 49% after overnight shut-in.

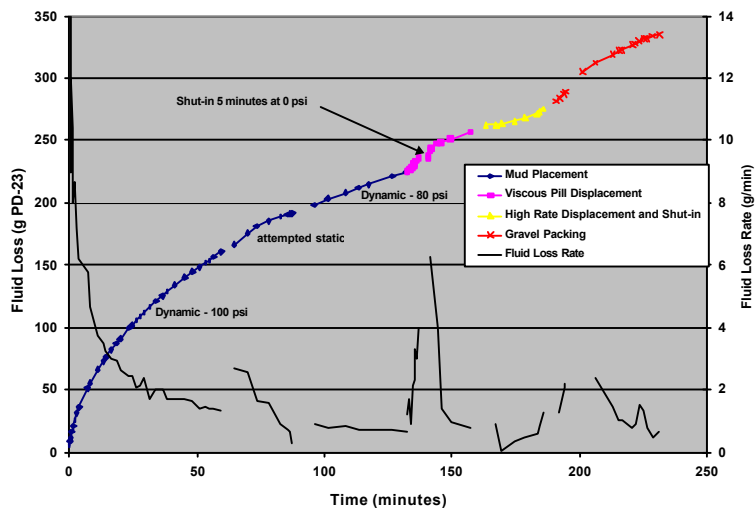


Figure 1. Cumulative fluid loss from porous tube during simulator test

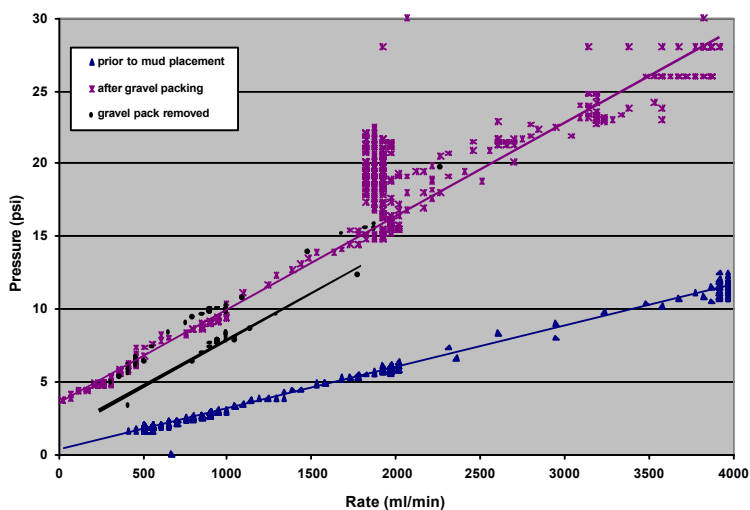


Figure 2. Pressure drop across porous tube before and after simulation run

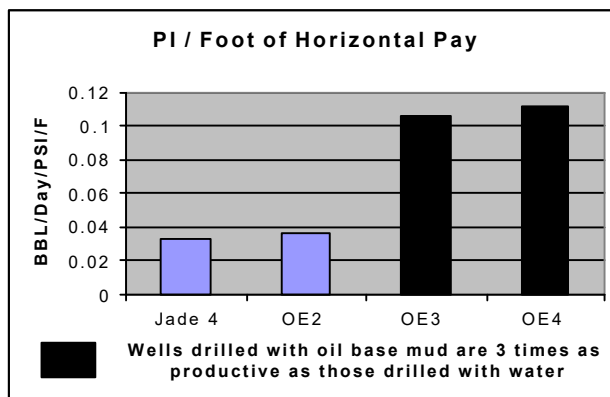


Figure 3. Productivity of wells drilled with water-based versus oil-based fluids