A Step Change in Cementing — Mitigating Sustained Casing Pressure

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Abstract / Wellbore construction practices are complex; and achieving dependable zonal isolation is a critical and challenging process for optimizing asset life and minimizing future well intervention. Sustained casing pressure challenges related to poor zonal isolation are well documented and can affect production, which may require significant remedial well intervention. The need to address these challenges called for revisiting cementing operational practices and led to the development of a basis of design (BoD) document as a tool to help manage well design practices and standards.

As a common industry practice to prevent fluid migration, slurry designs should be gas tight. To avoid fluid migrating to the surface, two things are required: less time to initiate migration, and the lack of a flow path. With analysis of the current cement slurries, designs were unable to perform successfully on inflow tests due to the low temperature of the zones to be cemented, increasing the transition time for a slurry to move from a liquid state into a solid phase. With extensive laboratory testing, it was concluded that current designs were not addressing the bulk shrinkage phenomenon of cement, which could lead to the creation of microannuli, creating conduits for fluid migration.

This article will discuss the detailed analysis and testing of the current and new designs and techniques validated by laboratory tests and field executions (cement bond logs) to prevent fluid migration and ensure that dependable long-term zonal isolation was delivered. Mud displacement mechanics needed to be optimized to reduce the risk of the mud on the wall phenomenon. This included the design of spacers to increase the annulus mud displacement efficiency, improved standoff, and optimum displacement rates to create sufficient annular velocity.

A comprehensive look at all the pertinent steps in the construction of the well, starting from the drilling phase, through the cement job design, preparation and execution, were required to ensure that the best practices were adopted to achieve the best results. Slurry selection, spacer formulation, centralization, hole cleaning, and excess volumes were all at the center of the improvements that were necessary to achieve optimum results. A BoD document was developed as a roadmap for cementing to further enhance wellbore integrity. It formalized the planning, design and job execution practices, and specified the slurry design, placement, and verification criteria for each casing section.

Several cement jobs have been executed utilizing the newly implemented practices with excellent zonal isolation results verified through cement integrity logs. Since implementation in all subsequent wells, no casing-casing annulus pressure issues have been reported.

Introduction

In a challenging field, common well construction challenges include well control, losses, and stuck pipe when total loss circulation is encountered or when drilling through reactive formations.

The focus of this article will be on the intermediate casing section. The purpose of this casing is to isolate potential flow zones and multiple loss circulation formations. In addition, it provides protection to drill high-pressure sections with heavy mud (+/- 125 pcf / 16.7 ppg) in the subsequent hole section.

The section is usually drilled as a vertical hole or S-shaped section to the casing point and can encounter high-pressure flows. Due to the high risk of losses, zonal isolation of this section is accomplished using a two-stage cement job technique.

The drilling is done in stages due to the different pressure gradients using salt polymer drilling fluids, starting with 73 pcf (9.8 ppg), and increasing the mud weight to 76 pcf (10.2 ppg) before drilling the shale section. Finally, the mud weight is gradually increased further to 84 pcf (11.2 ppg) at the casing point.

In addition to controlling the well dynamics such as potential flows and mitigating potential stuck pipe scenarios, attempting to cure losses is one of the most important steps in the drilling process. If partial losses are encountered in this section, attempts are made to cure any losses. If total losses are encountered, drilling continues with seawater, gel sweeps, and mud capping. If drilling ahead with total losses, an intermittent mud cap is pumped down the annulus while drilling.

Wellbore Isolation Strategy

The zonal isolation methodology consisted of the following.

Slurry Design

1. Two-stage cementing with conventional first stage lead, tail, and second stage single slurry system with densities ranging from 94 pcf to 118 pcf (12.6 ppg to 15.8 ppg).
2. No temperature analysis and common use of API temperatures for bottom-hole circulating temperatures.
3. Extended slurry thickening times due to excessive placement safety margins and unsuitable pump and displacement rates: This can have an effect on the cement setting properties and could lead to fluids migration and loss of zonal isolation.
4. Apply pressure in the annulus to sustain and then maintain the hydrostatic pressure above the pore pressure to avoid fluid flow. This was done for a short period and did not allow the cement to fully develop the required compressive strength. This also leads to fluids invasion causing casing-casing annulus pressure.
5. To mitigate cement shrinkage[1] an expanding additive is recommended to be added to the cement slurry to mitigate the creation of a path for the fluid to migrate. In current practices, a high temperature expanding additive was used across the open hole sections only.

Mud Removal

1. Pipe centralization: The centralization strategy calls for use of rigid centralizers with a uniform placement pattern across the open and cased hole sections.
2. Mud displacement spacer volume from 80 bbl to 150 bbl as a standard; this was not enough to mitigate for different wells, as not enough volume will bear the risk of leaving layers of mud in the wells, which will later allow fluids migration.
3. Mud displacement dynamics: Attempt to optimize the displacement rates for a good mud removal and control equivalent circulating density (ECD) during the cement job.

Lost Circulation

1. No details lost in the return fluid: Affects the top of the cement and cement quality to isolate the problematic zones.
2. Loses mitigation: No lost circulation material (LCM) added in the slurry, resulting in no mitigation for losses.

A comprehensive analysis at all the pertinent steps in the construction of the well, starting from the drilling phase, through the cement job design, and then the preparation and execution was required to ensure that the best practices are adopted to achieve the best results. Slurry selection, spacer formulation, centralization, hole cleaning and excess volumes were all at the center of the improvements that were necessary to achieve optimum results.

Consequences

It has been well documented that a significant number of oil and gas wells worldwide experience annulus integrity issues in one or more casing strings during their lifetime. While every effort should be made to ensure well integrity is met and maintained during all stages of the well's life cycle, gaps in zonal isolation practices, sometimes lead to well barrier defects that manifest themselves through the presence of sustained casing pressure. This is commonly the result of a well component leak that permits the flow of a fluid across a wellbore barrier element[2].

In the outer shallower casing strings, it is often caused by incomplete or poor cement bonding due to poor cement placement practices or because formation fluids channel through unset cement. Pressure and temperature changes from well production events can contribute to the development of microannuli or cracks in the cement. These defects, once created, are very difficult and costly to remediate with an extremely low success rate. Therefore, ensuring a proper primary cementing strategy is of prime importance.

Solution

Basis of Design (BoD)

A Basis of Design (BoD) document was developed as a roadmap for cementing to further enhance downhole well integrity. It formalized the planning, design, and job execution practices and specified the slurry design, placement, and verification criteria for each casing section. Each section was prepared on a uniform structure of job objectives, risks, assumptions and boundaries, solutions and mitigations, and finally, proposed cement job design. A detailed plan for slurry selection, spacer formulations, casing centralization, wellbore cleaning prior to cementing, and cement placement techniques are defined ensuring the success of the primary cement job.

Slurries and spacers pumped were designed to be robust enough to fulfill the criteria for gas tight slurry. The casing centralizer pattern was standardized regardless of the well inclination. Specific emphasis was placed on the need to ensure enough conditioning of the mud and lowering its rheologies to as low as reasonably possible.

Bottom plugs were recommended to be used and adequate excess volumes were planned to be pumped to account for the inevitable contamination of the fluids as they are being pumped down the large casing and placed within the annulus. Displacement rates were increased to have efficient mud removal and ultimately better placement of cement in the annulus. A systematic approach was taken to conclude the prevention and mitigation measures for the risks to well integrity in each section as summarized in Table 1.

Based on the identified risks, a step change in testing and design requirements were proposed to eliminate all the risks. Table 2 lists the minimum laboratory cement testing requirements.

From the technical perspective, a number of improvements were implemented in alignment with the newly developed BoD. Table 3 summarizes some differences between existing practices and new practices.

Table 1 A summary of the potential risks and mitigation measures to the well's integrity.

Potential	Consequence	Mitigation	Matrix								
Risk			Impact	Mgmt	30″	24″	$18\frac{5}{8}$″	$13\frac{3}{8}$″	$9\frac{5}{8}$″	7″	$4\frac{1}{2}$″
Poor mud removal	Channeling, lack of structural support, weak shoe, NPT	Reduce static time, conditioned mud, centralization > 75%, spacer volumes, hierarchies, placement modeling.	Mod	Low	N	Y	Y	Y	Y	Y	Y
Losses while cementing	ECDs exceeding FP and weak zones	Hydraulic simulations for ECD management, including restrictions, cementing fluids density management, rates, lost circulation spacers.	Mod	Mod	Y	Y	Y	Y	Y	Y	Y
Wet shoe	NPT, remedial cementing	Temperature simulations for BHCTs, low safety margins, OTF mixing, testing per API 65-2.	Hi	Low	N	Y	Y	Y	Y	Y	Y
Contamination of dry cement in rig silos	Insufficient slurry design, mixability issues, gelation	In between loading of blends, full blow down and sweep clean, prior to spud.	Mod	Low	Y	Y	Y	Y	Y	Y	Y
Floats not holding	NPT, shut-in while WOC	Function test floats prior to RIH casing, if floats fail apply and hold pressure.	Mod	Low	N	Y	Y	Y	Y	Y	Y
Channeling	Poor mud displacement efficiencies	Quality bow centralization for cement coverage, minimum, if possible with compromising drag and torque, of 75%.	Hi	Mod	N	Y	Y	Y	Y	Y	Y
Fluids contamination	Contamination of cementing fluids, potential gelation, acceleration, retardation	Conditioned mud, spacer(s) design to include volume, rheologies, and density hierarchy. Confirmed with wettability (where applicable) and compatibility testing. Wiper plugs.	Mod	Low	N	Y	Y	Y	Y	Y	Y
Inaccurate provided BHSTs	NPT, wet shoes, stuck pipe	Use "pumped up" LWD temperatures only after static state for over 36 hours for comparison, when applicable, wireline logging measurements.	Hi	Mod	N	N	Y	Y	Y	Y	Y
Large temperature difference across cement column	Over retarded cement, green cement	Numerical BHCT analysis across cement column, split single into two slurries, same designs, varying retarders for two annular temperatures.	Hi	Low	N	N	N	Y	Y	Y	Y
Fluid or gas migration	Compromise matrix, gas-cut fluids, unstable well environment, loss of well	Fluid migration control design with low CGSP, GFM, optimize spacer design and ECDs, placement optimization.	Hi	Low	N	Y	Y	Y	Y	Y	Y
Cement failure of long-term isolation	Sheath degradation due to well events, including production, perforating, stimulation	Detailed review of wells, estimated production temperatures, stimulation work, temperature and pressure cycling, how the cement is equipped to withstand life of well events.	Mod	Mod	N	Y	Y	Y	Y	Y	Y

Case History

A two-stage cementing operation was performed on Well-D. Once the casing landed on the bottom, the well was experiencing 120 barrels per hour (bph) of static losses and 200 bph of dynamic losses. The cement job volumes were pumped as per plan with 620 bbl of mud losses during the displacement. The first stage top plug was bumped. Due to mud losses, no spacer or cement returns were recovered after opening the stage tool and circulation was established. The theoretical top of the cement was 300 ft above the stage tool, accounting for 50% of the open hole excess.

The second stage was performed approximately 10 hours after the completion of the first stage. The plug was pumped at theoretical displacement volume and neat cement returns were recovered on the surface. Since a

Table 2 *Minimum laboratory cement testing requirements.*

Casing (in)	Slurry	FW (%) (45°)	FL (cc)	Rheologies (BHCT)	TT (hr)	UCA	SGS	GFM	BP Settling	Compatibility	Wettability	Temperature
36	Lead	<3	-	Tail Slurry 3-RPM > Lead Slurry 3-RPM > Spacer 3-RPM > 10	**Placement Time + 1-hr**	-	-	-		-	-	API
	Tail	0	-			-	-	-		-	-	API
30	Lead	<3	-			-	-	-		-	-	API
	Tail	0	-									API
24 1st Stg	Lead	0	-		**Placement Time + 2-hrs**	-	-	-		X	-	API, or otherwise verified by numerical simulator
	Tail	0	-			X	-	-				
24 2nd Stg	Lead	0	-			-	-	-		X	-	
	Tail	0	<50			X	X	X				
18-5/8 1st Stg or Liner	Lead	0	-			-	-	-		X	-	
	Tail	0	-			X	-	-		-		
18-5/8 2nd Stg or Tieback	Lead	0	-			-	-	-		X	-	
	Tail	0	<50			X	X	X		-	-	
13-3/8* 1st Stg or Liner	Lead	0	-			-	-	-		X	-	
	Tail	0	-			X	-	-		-	-	
13-3/8 2nd Stg or Tieback	Lead	0	-			-	-	-		X	-	
	Tail	0	-			X	X	X		-	-	
9-5/8 Liner	Slurry	0	<50			X	X	X	X	X	-	
9-5/8 Tieback	Slurry	0	<50			X	X	X	X	X	-	
7	Slurry	0	< 50			X	X	X	X	X	If required	
4-1/2 (Opt)	Slurry	0	< 50			X	**Per SME**		X	X	If required	

X=to be run, **FW**=free water, **FL**=fluid loss, **NC**=no control, **TT**=thickening time, **UCA**=ultrasonic cement analyzer, **SGS**=static gel strength (**<30/min transition**), **GFM**=gas flow model, **Sgl Stg**=single stage, **BP=**British Petroleum (Settling <5-pcf difference)

***NOTE: For 13-3/8", in case section is drilled without losses, then cement with tail slurry only**

Table 3 *Comparison between existing practices an new practices.*

Existing Practices	**New Practices**
Second stage, single system slurry to surface.	Two slurry system utilized with lead and tail, based on thickening time.
Conventional slurry designs.	Addition of contingency tight property systems with cement set enhancer. Better mixability, improved static gel strength development and transition time.
Extended slurry thickening times due to excessive placement safety margins and unsuitable pump and displacement rates.	Reduced thickening time for tail slurry covering the open hole, less than one-hour safety margin that results in a lower critical gel period for slurry and expedites the development of early compressive strength.
Apply pressure in the annulus to sustain and the maintain the hydrostatic pressure above the pore pressure to avoid the fluid flow.	Apply backpressure until slurry reaches minimum of 50 psi.
High temperature expansion additive in first stage cement slurries only.	Incorporation of low temperature post set cement expansion agents into the second stage cement design based to mitigate microannuli creation.
Centralization using rigid centralizers with poor or no standoff.	Improved the pipe stand off to more than 70%. Utilize single piece molded or hinged bow spring-type centralizer where applicable.
Conventional basic water-based spacer with volumes varying from 80 bbl to 150 bbl.	Increased spacer volumes with surfactant and a reactive bond enhancing additive to ensure good mud removal.
Attempt to optimize the displacement rates and control ECD during the cement job.	Optimized displacement rates to minimum 16 bpm.
No LCM added in the slurry resulting in no mitigation for losses.	Incorporate LCM material into spacers or use engineered loss circulation spacers.
No use of contingency mechanical isolation.	Use of high-pressure stage tools and introduction of expandable liner packers where possible.

30% cased hole excess was considered for the lead, and 20% for a tail, a total of 126 bbl of cement was recovered at the surface.

First Stage Job Execution

1. Once the casing landed, the cement head was installed, and pressure tested.
2. Circulate 120% of the casing volume.
3. Pump 250 bbl of thin mud.
4. Pump 200 bbl of an 85 pcf (11.4 ppg) spacer.
5. Drop a bottom plug (bypass plug).
6. Mix and pump cement slurry. (Slurry design as per Tables 4 and 5.)
7. Calculation assumed 50% excess open hole, 120 ft shoe track, top of lead at 300 ft above the stage tool, 1,000 ft of tail cement and 10 bbl of cement above the landing collar.
8. Drop shut-off plug with the 10 bbl cement behind.
9. Displace with 20 bbl of spacer, mud sandwiched with 50 bbl of spacer above and below the stage tool, bump the plug.
10. Pressure test casing to 1,000 psi over the bump pressure.
11. Drop bomb, inflate the stage tool packer, open the stage tool, and circulate.
12. No cement returns observed.
13. Wait on the cement and prepare the mix water for the second stage job.

The post-job execution when reviewed indicated that over 90% of the total slurry volume was continuously mixed within a density range variation of +/-2 pcf. This provided evidence that both the lead and tail cement were mixed and pumped as designed.

Figure 1 shows the lead and tail slurries' densities controlled using an online nonradioactive densitometer. The quality of the mixed slurries is more than 80%, increasing the confidence of a good cement.

Top of Cement Verification

The post-job pressure trend correlation was generated after the job, showing the designed surface pressure and the imported acquired pressure. Figure 2 is a graph showing the job execution showing: (a) spacer ahead, (b) lead slurry, (c) tail slurry, (d) top plug, and (e) displacement. Figure 3 shows the post-job pressure match showing the designed surface pressure and the imported acquired pressure. A very good trend correlation is noticed between

Table 4 *Lead slurry composition and fluid properties of the first stage job.*

Bottom-hole Static Temperature/Bottom-hole Circulating Temperature (BHST/BHCT)	235 °F/155 °F
Density	95 lbm/ft^3
Yield	2.70 ft^3/sk
Composition	
Class G Cement	—
Silica Flour	35% By Weight of Cement (BWOC)
Expansion Additive	1% BWOC
Antifoam	0.005 gps
Bentonite	4.5% BWOC
Dispersant	0.1% BWOC
Fluid Loss	0.5% BWOC
Retarder	0.5% BWOC

	Surface (80 °F)	**Downhole (155 °F)**
Plastic Viscosity (PV)	17.66 cP	16.73 cP
Yield Stress (TY)	19.64 lbf/100 ft^2	22.19 lbf/100 ft^2
10 Sec Gel	16.01 lbf/100 ft^2	13.88 lbf/100 ft^2
10 Min Gel	30.95 lbf/100 ft ft^2	25.62 lbf/100 ft^2
Thickening Time	8:14 hr:mn	
Free Fluid at 80 °F and 0° Inclination	0.0 ml/250 ml in 2 hours	

Table 5 *Tail slurry composition and fluid properties of the first stage job.*

BHST/BHCT	235 °F/155 °F
Density	118 lbm/ft^3
Yield	1.54 ft^3/sk
Composition	
Class G Cement	—
Silica Flour	35% BWOC
Expansion Additive	1% BWOC
Antifoam	0.005 gps
Dispersant	0.15% BWOC
Fluid Loss	0.25% BWOC
Retarder	0.32% BWOC

	Surface (80 °F)	**Downhole (155 °F)**
PV	108.08 cP	73.14 cP
TY	18.19 lbf/100 ft^2	26.53 lbf/100 ft^2
10 Sec Gel	14.94 lbf/100 ft^2	22.41 lbf/100 ft^2
10 Min Gel	127.01 lbf/100 ft^2	32.02 lbf/100 ft^2
Thickening Time	4:01 hr:mn	
Free Fluid at 80 °F and 0° Inclination	0.0 ml/250 ml in 2 hours	

Fig. 1 *The lead (left) and tail (right) slurries' densities controlled using an online nonradioactive densitometer.*

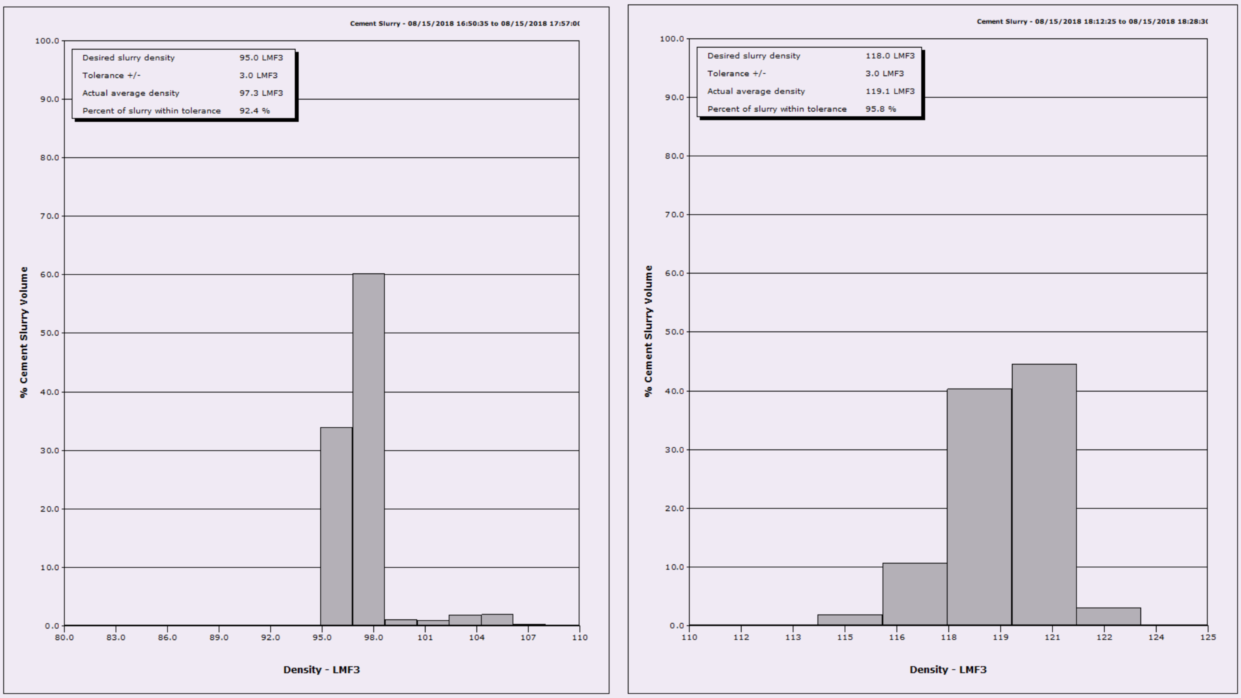


Fig. 2 *Job execution showing: (a) spacer ahead, (b) lead slurry, (c) tail slurry, (d) top plug, and (e) displacement.*

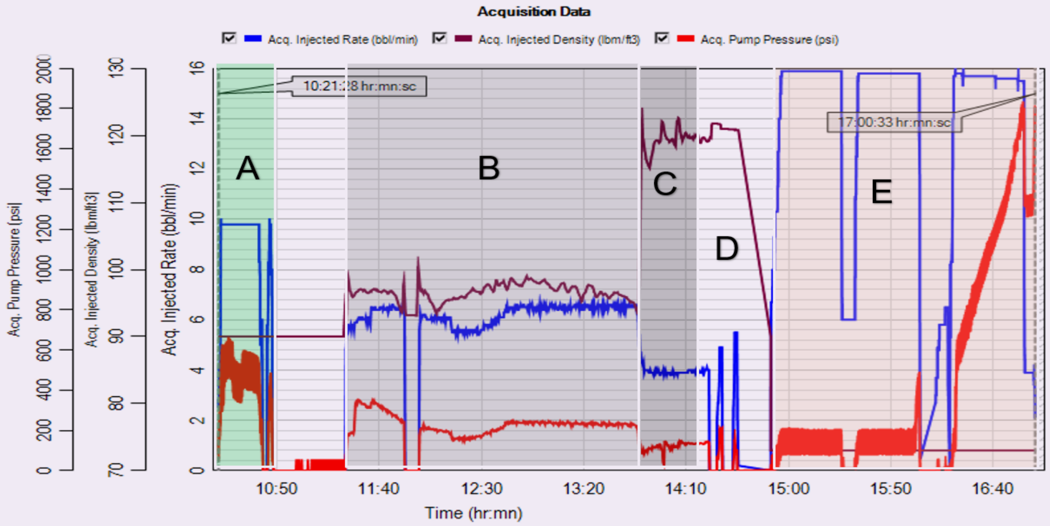
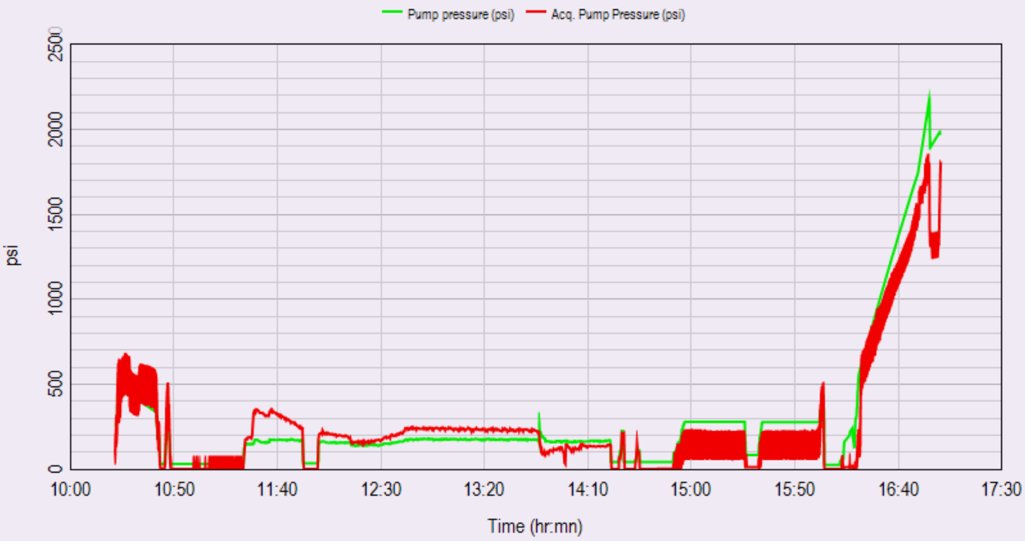


Fig. 3 *Post-job pressure match showing the designed surface pressure and the imported acquired pressure. Good trend correlation noticed between both pressures indicating no anomalies during the job.*



both pressures indicating no anomalies during the job.

- Less absolute pressure during lifting of heavier fluid in the annulus compared to the design, indicating a lower top of the cement.
- Overall, +/-600 bbl of losses reported during displacement, which will have a direct impact on the top of the cement.
- Extended time taken to drop the top plug causing the U-tubing effect.
- No spacer or cement was recovered after the stage tool was opened.
- The friction pressure increased while pumping the cement slurry, matching the pressure on that interval. The surface lines inside diameter were reduced to 1.175" simulating a higher friction pressure.
- Pressure match at the end of the displacement with 500% open hole excess, which lowered the top of the cement to 8,128 ft (620 bbl total volume reported lost during the cementing operation).

Second Stage Job Execution

1. The stage tool was located at a depth of approximately 4,000 ft.
2. Once the first stage was completed, the wait on cement time was approximately 10 hours.

3. Circulate the modified rheology mud pill ahead.
4. Pump spacer.
5. Mix and pump cement slurry. (Slurry design as per Tables 6 and 7.)
6. Top of lead at surface +20%, 1,000 ft tail slurry with gel transition time less than 40 minutes, Fig. 4.
7. Drop the stage tool closing plug and displace the plug with 10 bbl of cement followed by 20 bbl of spacer.
8. Displace with mud and bump the plug.
9. Pressure test the casing on the plug bump.
10. The stage tool was closed, and the pressure released, confirming that it is closed and holding the hydrostatic pressure of the cement in the annulus.
11. The tail slurry exhibited rapid compressive strength development at 100 °F providing casing support and enabling a casing pressure test post-cement placement, Fig. 5.
12. Pipe standoff > 70%. Utilize molded single piece and bow spring-type centralizer, Fig. 6.

Slurry Quality QA/QC

The reviewed second stage-post job execution indicated that over 90% of the total slurry volume was continuously mixed within a density range variation of +/-2 pcf. This provided evidence that both the lead and tail cement were mixed and pumped as designed.

Figure 7 shows the lead and tail slurries' densities controlled using an online nonradioactive densitometer.

Top of Cement Verification

A pressure match was also performed for the second stage cement job, a good agreement was reached between the designed pressure and the one acquired, Figs. 8 and 9. A subsequent cement bond log was performed to verify the isolation. After running in the hole with a drilling assembly, and cleaned out to 20 ft above the casing shoe, mud was displaced to 120 pcf. The test casing was tested to 1,100 psi by drilling 10 ft of new section and performing a formation integrity test to 135 pcf (18.0 ppg) with equivalent mud weight.

Cement Bond Logs

To verify the annulus cement's integrity and zonal isolation, circumferential sonic and ultrasonic logs were performed with and without a pressure pass, Fig. 10. The lower part — below the blue horizontal line representing the stage tool — of the log depicts the first stage and the upper part shows the second stage. The open hole zonal isolation in Wells A, B, and C are affected by the downhole conditions such as lost circulation and mud displacement using a legacy design and execution methodologies. When the new basis of design was implemented

Table 6 *Lead slurry composition and fluid properties of the second stage job.*

BHST/BHCT	144 °F/101 °F
Density	118 lbm/ft^3
Yield	1.54 ft^3/sk
Composition	
Class G Cement	—
Silica Flour	35% BWOC
Expansion Additive	1% BWOC
Antifoam	0.005 gps
Dispersant	0.3% BWOC
Fluid Loss	0.25% BWOC
Retarder	0.02 gps

	Surface (80°)	Downhole (101 °F)
PV	85.67 cP	75.76 cP
TY	22.21 lbf/100 ft^2	49.78 lbf/100 ft^2
10 Sec Gel	29.89 lbf/100 ft^2	30.95 lbf/100 ft^2
10 Min Gel	320.20 lbf/100 ft^2	34.15 lbf/100 ft^2
Thickening Time	4:47 hr:mn	
Free Fluid at 80 °F and 0° Inclination	0.0 ml/250 ml in 2 hours	

Table 7 Tail slurry composition and fluid properties of the second stage job.

BHST/BHCT	144 °F/101 °F
Density	118 lbm/ft^3
Yield	1.54 ft^3/sk
Composition	
Class G Cement	—
Silica Flour	35% BWOC
Expansion Additive	1% BWOC
Antifoam	0.005 gps
Dispersant	0.2% BWOC
GASBLOK LT	1.5 gps
Set Enhancer	0.010 gps

	Surface (80 °F)	**Downhole (101 °F)**
PV	121.09 cP	132.31 cP
TY	54.82 lbf/100 ft^2	58.69 lbf/100 ft^2
10 Sec Gel	58.70 lbf/100 ft^2	32.02 lbf/100 ft^2
10 Min Gel	320.20 lbf/100 ft^2	45.90 lbf/100 ft^2
Thickening Time	4:01 hr:mn	
API Fluid Loss	10 ml	
Free Fluid at 80 °F and 0° Inclination	0.0 ml/250 ml in 2 hours	

Fig. 4 Showing static gel strength and transit time below 40 minutes indicating that the slurry is gas tight.

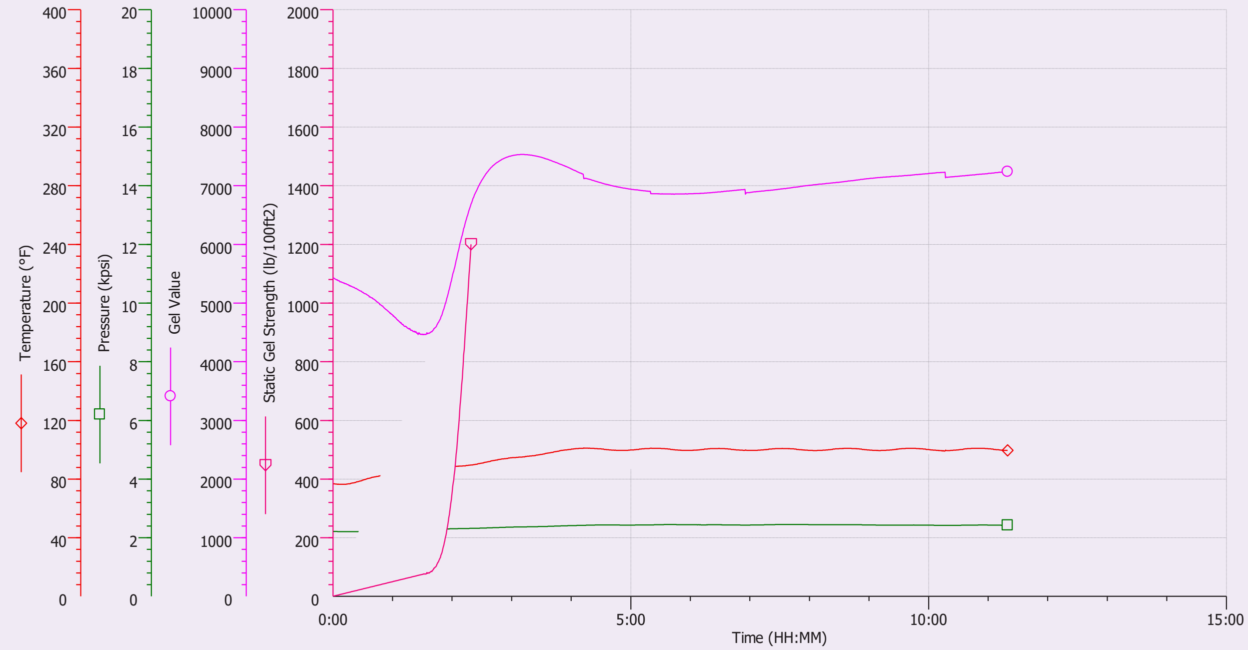


Fig. 5 *Early compressive strength development helps support the casing and perform pressure integrity test.*

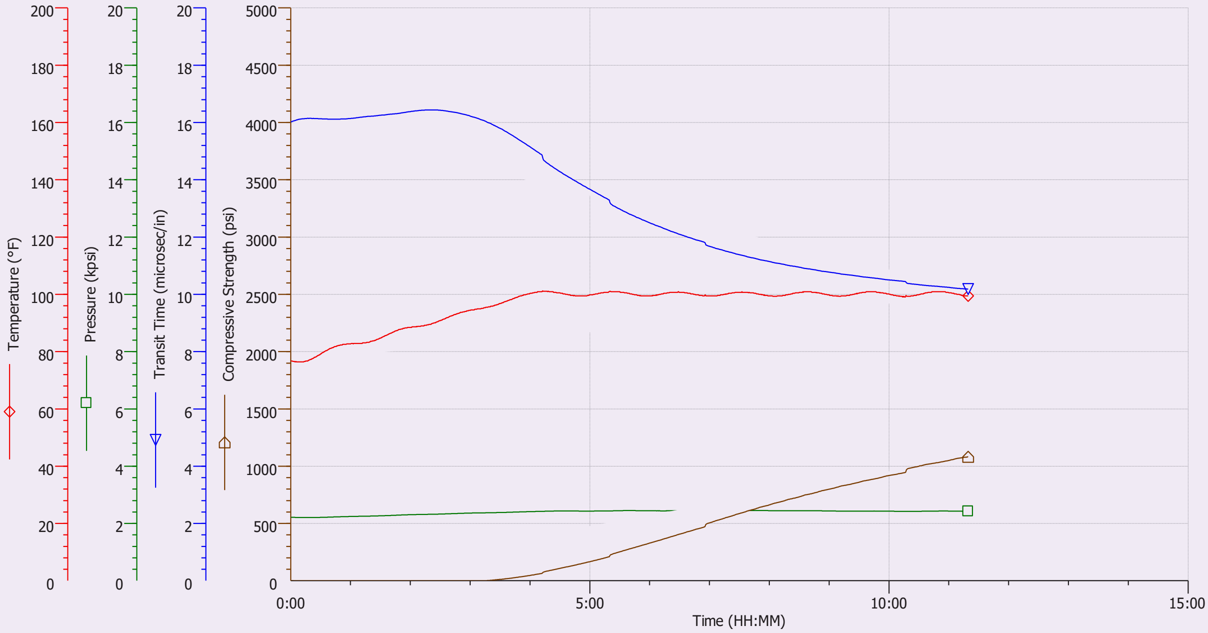


Fig. 6 *Engineering the standoff of the casing, looking at the stand at the centralizer (blue) and between the centralizers (red). Overall, improved good standoff.*

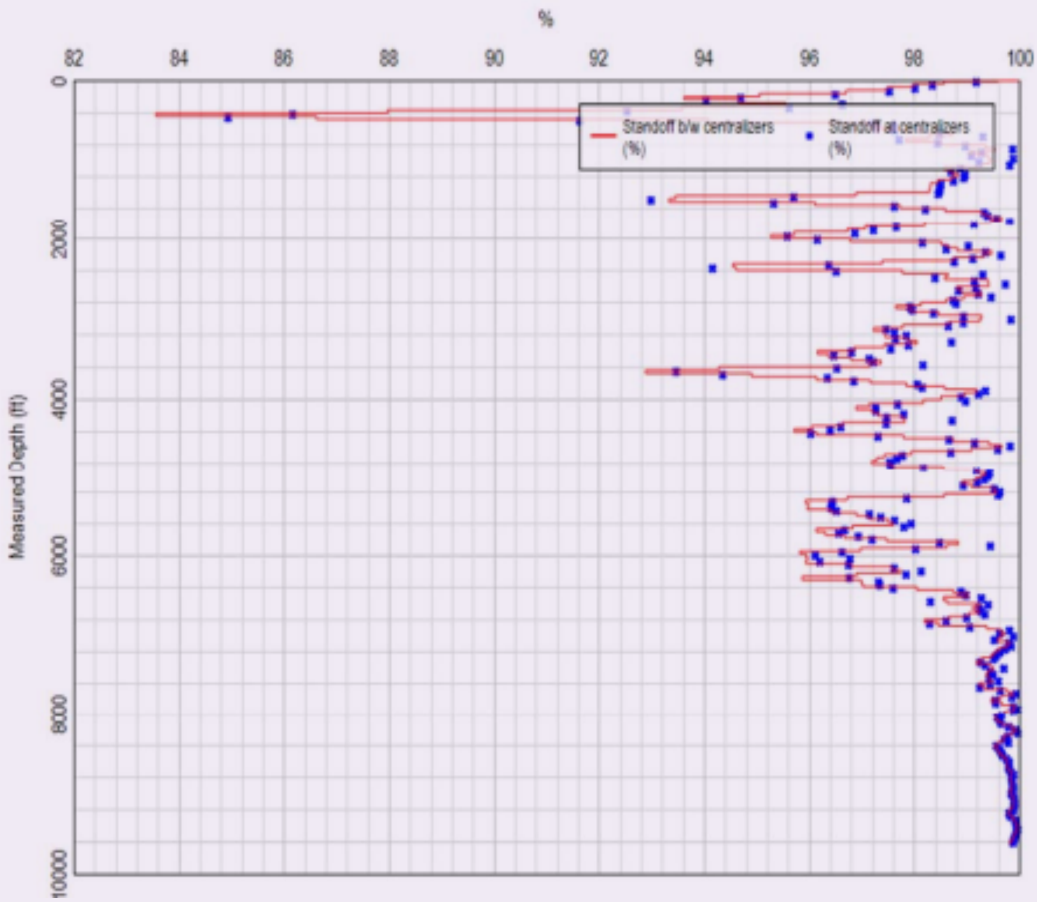


Fig. 7 *The lead (left) and tail (right) slurries' densities controlled using an online nonradioactive densitometer.*

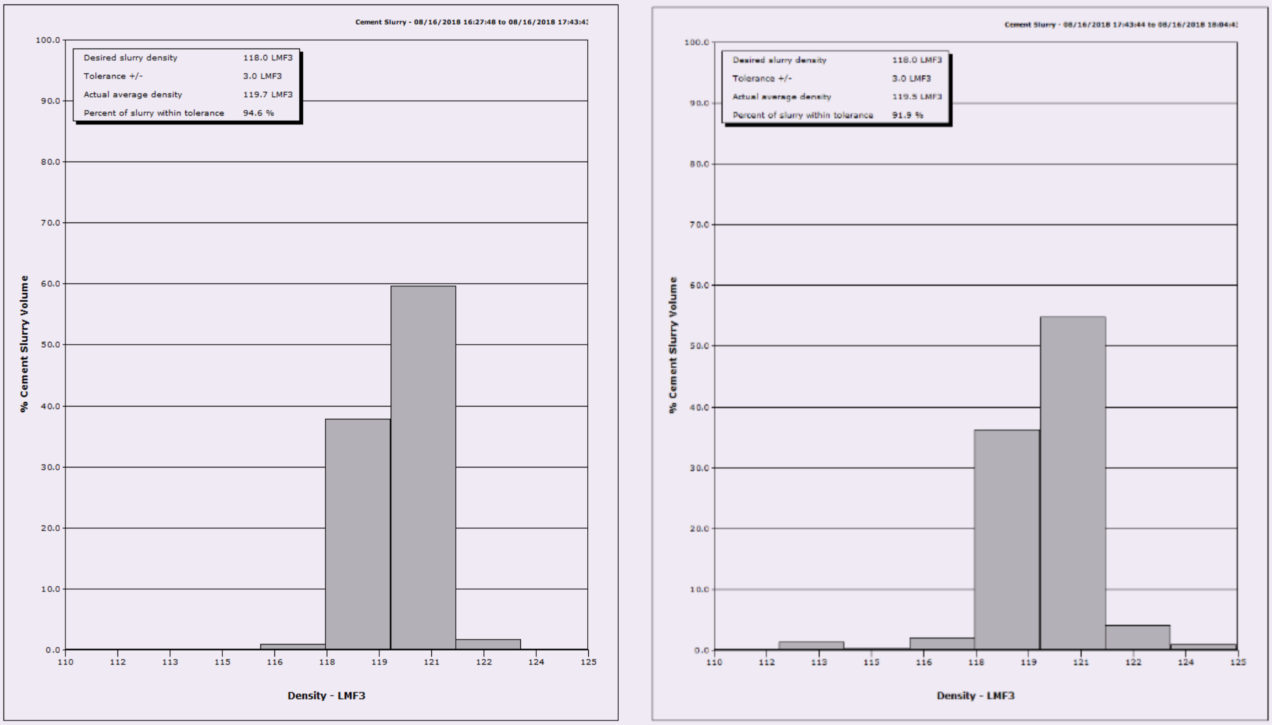


Fig. 8 *Job execution showing: (a) spacer ahead, (b) lead slurry, (c) tail slurry, (d) top plug, and (e) displacement.*

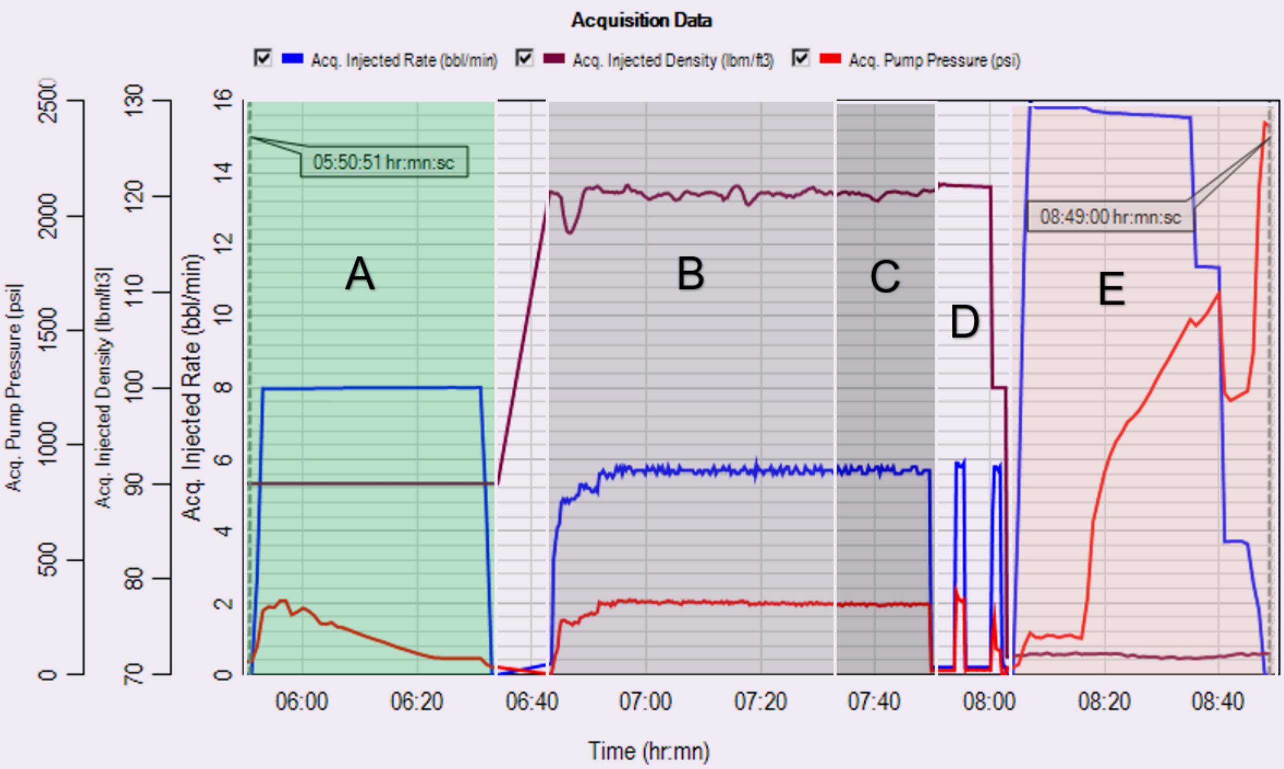


Fig. 9 *Post-job pressure match while pumping slurry by increasing the friction pressure of the surface lines of the cement lines. Displacement with rig pumps.*

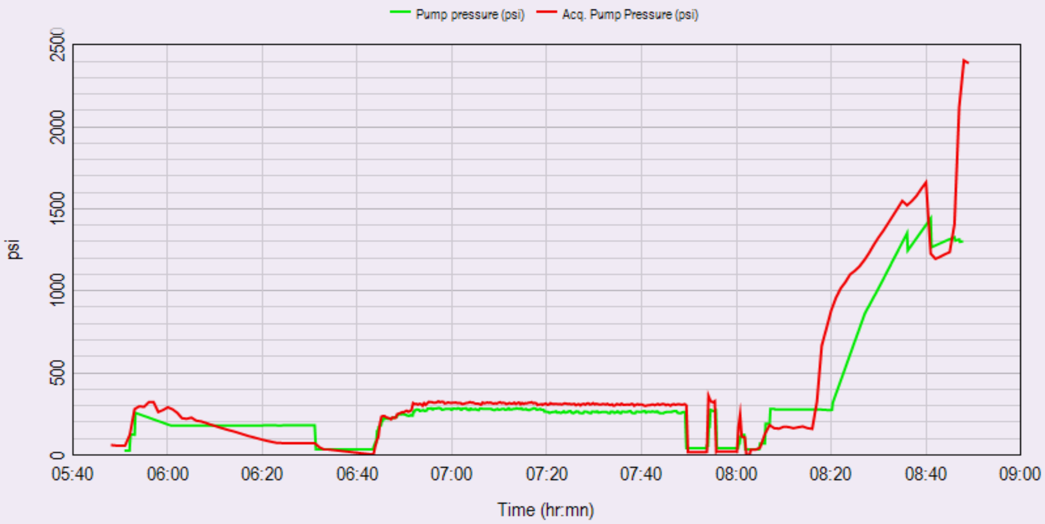
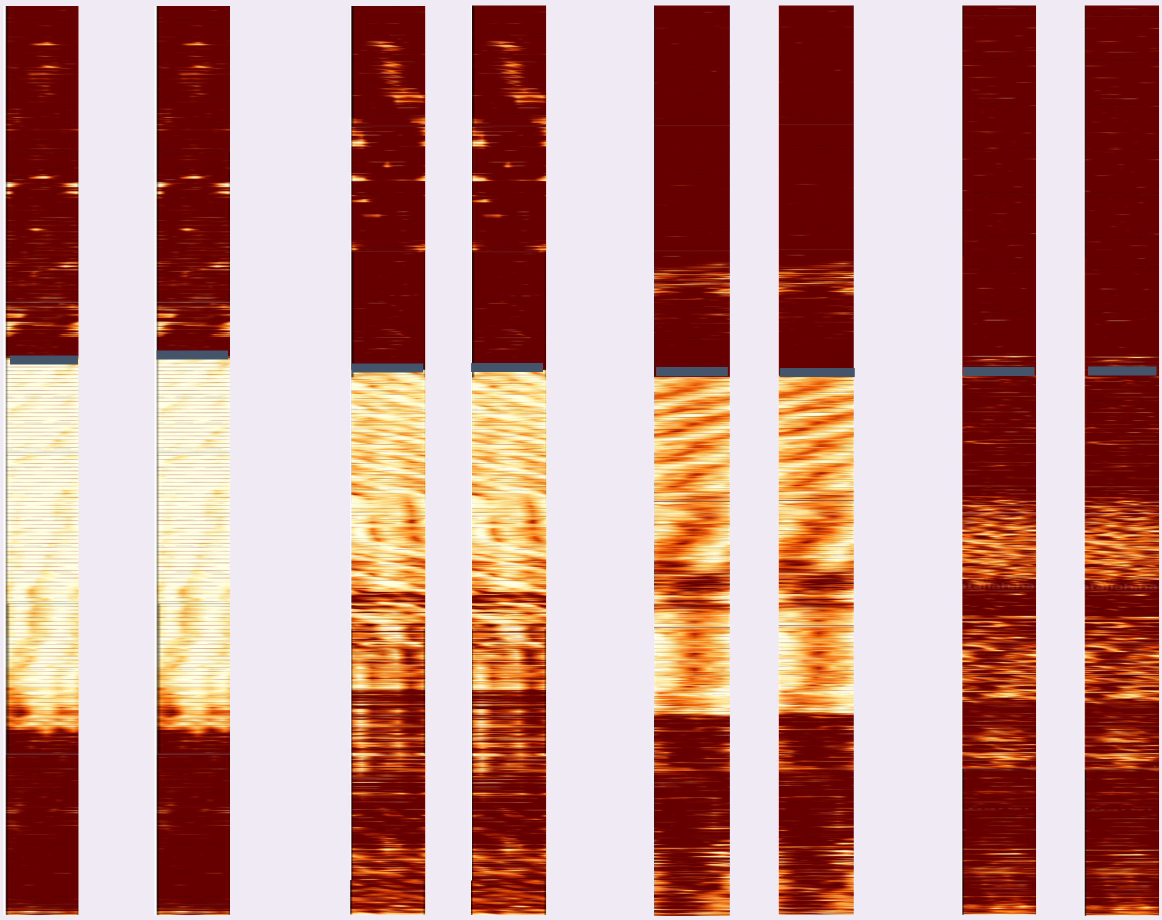


Fig. 10 *Ultrasonic logs showing isolation status of different wells and the improvement in the log response after the implementation of the BoD in Well-D.*



13⅜" Casing
Well-A

13⅜" Casing
Well-B

13⅜" Casing
Well-C

13⅜" Casing
Well-D

in Well-D, an immediate log response was noticed. The wellbore integrity logs show an improved isolation in both the challenging first stage and the second stage alike.

Conclusions

To ensure zonal isolation in this field with multiple downhole risks, a comprehensive study was performed, and new practices were successfully adopted to achieve better results. This was accomplished by developing a field specific cementing BoD methodology, which formalized planning, design and job execution practices, and specified the slurry design, placement, and verification criteria. The BoD was used as a roadmap to further standardize and enhance the wellbore integrity in this field and companywide.

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First Worldwide Implementation of a New Multilateral Intervention Tool Facilitates Logging in Complex Multilateral Wells

Sajid Mehmood, Rifat Said, Alaa S. Shawly, and Zouhir Zaouali

Abstract /

Reservoir monitoring, surveillance, and intervention present immense challenges in multilateral wells in terms of the availability of robust technology to access these wells. As more and more multilateral wells are drilled to improve the productivity or the injectivity of the formation, through a cost-effective and reduced footprint of well trees in the field, it is increasingly difficult to intervene in these wells and acquire the necessary data to map the flow profiles in producers or injectors. It has been a continuous endeavor of the oil industry to address these challenges by introducing new technologies in the field. To overcome these challenges, a new tool was developed to conduct production logging in multilateral wells, providing the access selectively to the desired lateral.

This tool can be deployed utilizing e-coil tubing (CT) or a wireline tractor. It consists of a rotation joint and a bend probe. The rotation joint is rotated so that the bend motion will point the nose toward the direction of the lateral relative to the top of the hole. The string is then pulled back and when the lateral is found, the spring-loaded nose will open in the lateral. The tool rotation and manipulations are controlled from the surface panel, and the angle and the tool directions can be monitored and controlled to enter any lateral utilizing well deviation surveys. The tool identifies the lateral based on angle and azimuth, and subsequently is confirmed by gamma ray signatures during logging.

The subject tool was successfully deployed in two wells, one oil well (trilateral producer) and the other one a power water injector (dual lateral). Each lateral was accessed multiple times during both flowing and shut-in conditions to acquire production logging tool (PLT) data. This article will describe the design, preparation and execution of first worldwide implementation of this tool in a field equipped with an artificial lift system. The article will also provide information on operational challenges and innovative solutions to obtain accurate flow profile in a challenging environment with optimum cost. It will also share lessons learned and possible future operational improvements.

Based on the experience gained from the first multilateral wells accessed and logged through this novel tool, robust logging procedures and strategies were built to be used for upcoming wells, and to acquire the best data, and significantly reduce the operational time during logging and interventions.

Introduction

Many multilateral wells are drilled in the Middle East every year, with the objective to improve reservoir production by accessing numerous production zones or by increasing the contact area between a wellbore and a formation. Well logging in multilateral wells is a challenge in terms of available technology to acquire data to map the flow profiles in producers or injectors.

As more and more multilateral wells are drilled to optimize the number of wells in a field, it is increasingly difficult to intervene in these wells for production logging or other intervention works. It has been a continuous endeavor of the oil industry to address these challenges by introducing new technologies in the field.

This article focuses on the novel tool and approach to accurately access different completion types of these multilaterals, and discuss the logging strategies and conduct production logging providing the access to selective laterals.

New Multilateral Tool (MLT) Description and Operations

The multilateral tool (MLT) can be deployed utilizing coil tubing (CT) or a wireline tractor to convey both open hole and cased hole logging tools. It consists of a rotation joint and a bend probe, Fig. 1. The rotation joint is rotated so that the bend motion will point the nose toward the direction of the lateral relative to the top of the hole. The string is then pulled back and when the lateral is found, the spring-loaded nose will open in the lateral.

The tool rotation and manipulations are controlled from the surface panel, Fig. 2, and the angle and the tool directions can be monitored and controlled to enter any lateral utilizing well deviation surveys. The tool identifies the lateral based on angle and azimuth, and is subsequently confirmed by gamma ray signatures during logging.

Fig. 1 Images of the MLT showing the rotation joint and bend probe.

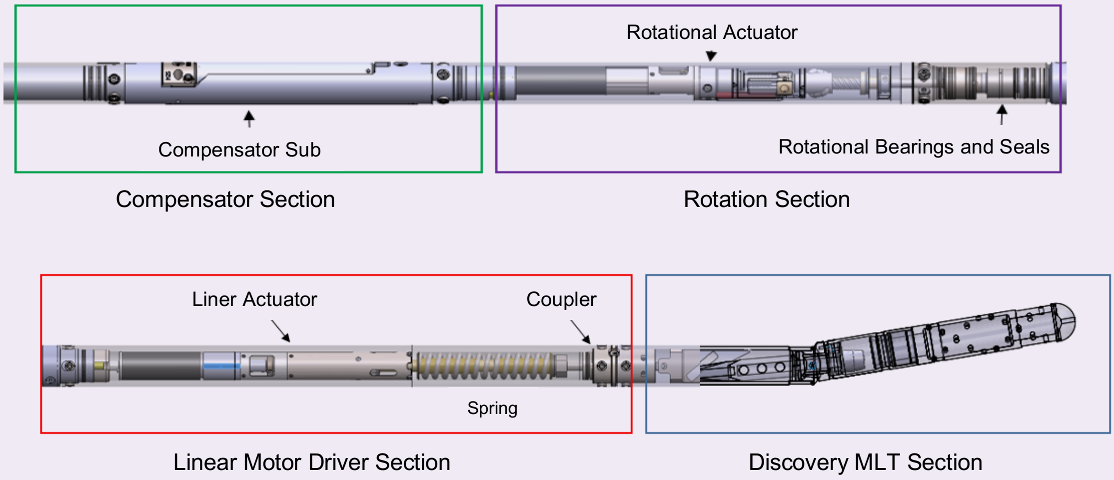
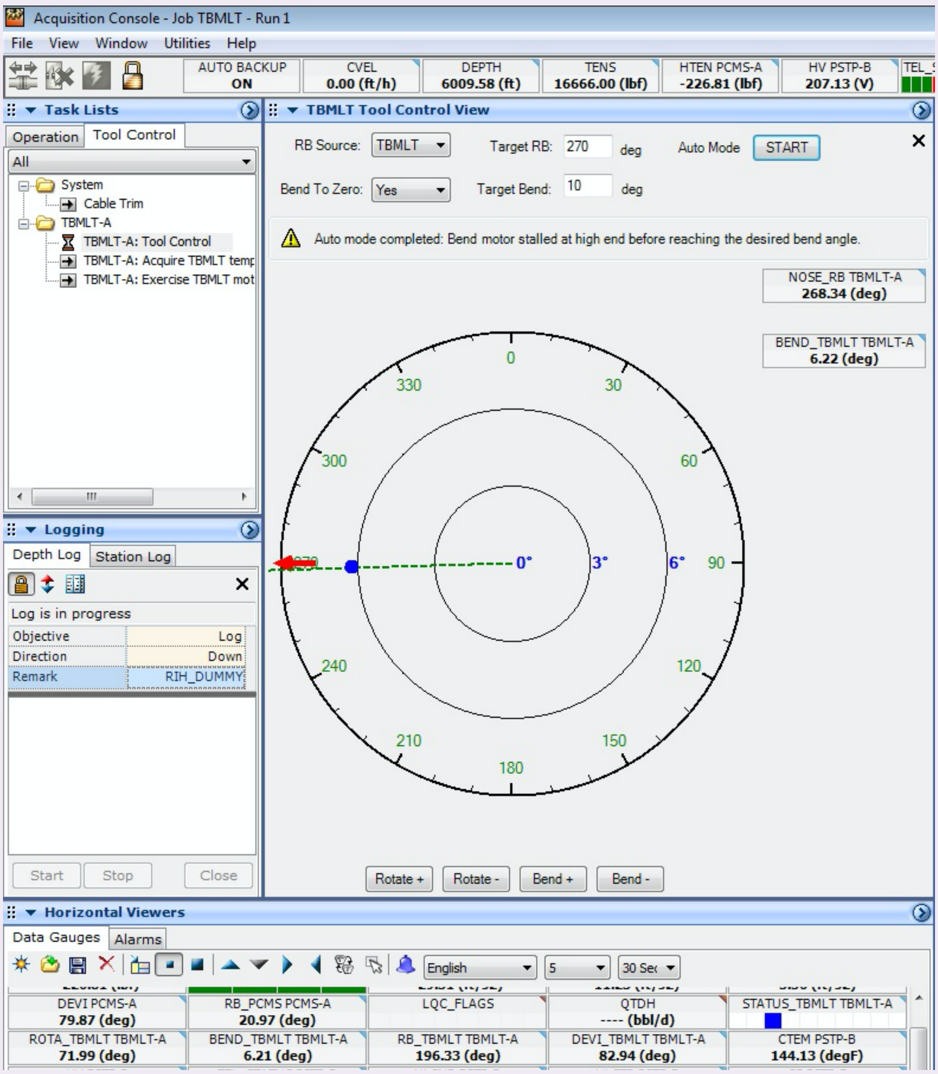


Fig. 2 A screen shot of the surface panel from which the tool rotation and manipulations are controlled from surface in real time.



Technical Details of the MLT

Details of the MLT include the following:

- Tool diameter: 2⅛”.
- Length: 11.9 ft (without probe extensions).
- Pressure rating: 15,000 psi.
- Temperature rating: 175 °C.
- Hydrogen sulfide rated: Yes.
- Well type: Open hole and cased hole, gas/oil/water wells.
- Probe rotation, range: -200° to +200°, +/- 5° accuracy.
- Logging while access the lateral capability.

MLT — Entering a Lateral

This example assumes that the direction of the multilateral is drilled relative to the top of the hole and is known by the well operators. Figure 3 is an illustration of the following steps.

Step 1: The MLT is pushed past the lateral window.

Step 2: The MLT rotation joint is rotated so that the bend motion will point the nose toward the direction of the lateral relative to the top of the hole. This is controlled using the rotation angle feedback and relative bearing measurement.

Step 3: The MLT bend probe is commanded to bend 9°. The probe tip will hit the opposite side of the bore and the bend probe feedback will indicate the nose did not open fully. This is desirable and needed to find the lateral. (This is why selecting the right extension length is important. Also, there is an option to not open the nose fully to 9°, but it is recommended that this is always commanded to open fully to 9° at this step.)

Step 4: The MLT is then pulled up-hole toward the window. The feedback from the bend probe is monitored.

Step 5: When the lateral is found, the spring-loaded nose will then spring open to 9°. This can be seen on the feedback from the bend probe.

Step 6: Then the tool is pushed downhole. The bend probe will enter the lateral and force the tool string to follow.

Integrated Production Logging Tool (PLT)

The spinner array production logging tool (PLT) provides continuous multiphase velocity distribution measurements and holdup data that are used to identify flow profiles, and analyze complex horizontal flow behavior.

The vertical axis orientation of the sensors enables the measurement of mixed and segregated flow regimes, including direct independent measurement of gas velocity in a multiphase horizontal well. All measurements are taken simultaneously at the same depth level[1]. Several jobs are run extensively, both in cased and open hole completions[2].

The PLT is capable of distinguishing three phases when compared to a conventional spinner that shows a single-phase fluid, Fig. 4. The flow scanner PLT consists

Fig. 4 *The conventional spinner PLT (left) in comparison with the flow scanner PLT (right).*

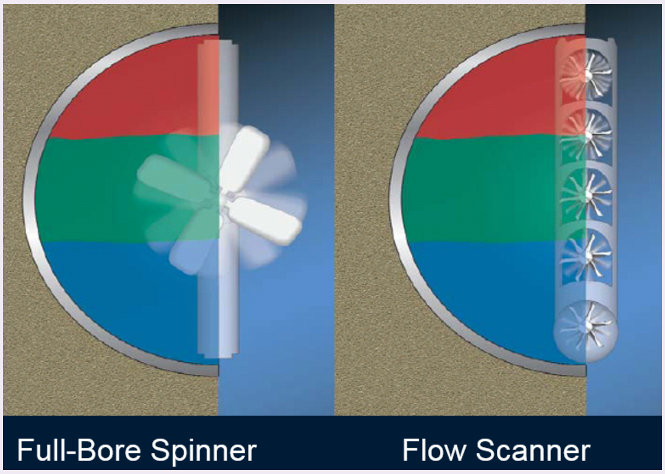
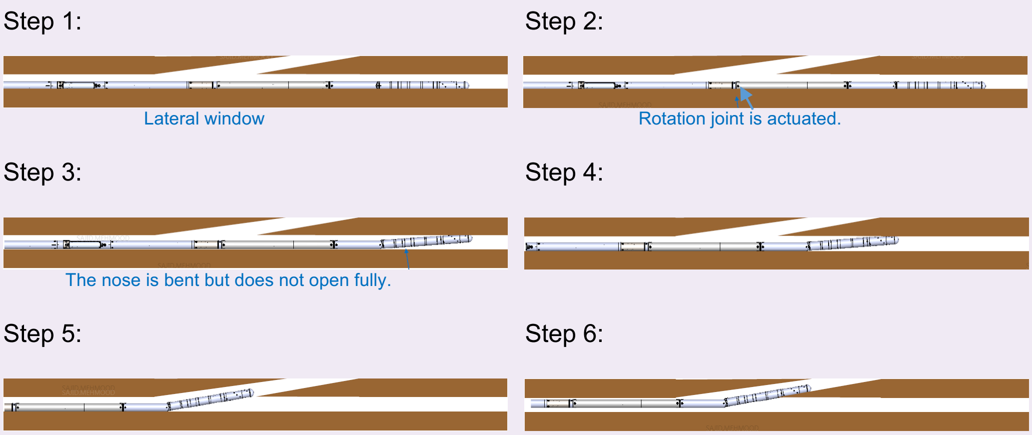


Fig. 3 *An illustration of the steps the MLT takes in drilling.*



of two retractable arms equipped with sensors for deployment along the vertical diameter of the wellbore providing real-time holdup and velocity profiles, Fig. 5. Five directional miniaturized spinners are mounted across the vertical axis of the pipe measuring the phase velocity profile. The second arm has two arrays of six electrical and six optical probes. The optical probes distinguish gas from liquid by a refractive index measurement. The electrical probes distinguish water from oil using an electrical impedance measurement.

The spinner array can be combined with the pulse neutron log that provides water flow log velocity and three-phase holdup measurements selectively across the lateral, as needed in the case of low amounts of water. The water velocity log is a stationary tool that activates oxygen molecules in the water by a burst of neutron particles. The time it takes the neutrons to move past the near and far field detectors determine the water velocity. In addition, the volume of activated water flowing by the detectors can be used to compute the three-phase holdup of the fluid and gas in the wellbore[3].

MLT Logging and Data Acquisition Workflow

Based on the experience gained from logging hundreds of horizontal wells in the Middle East, including several multilateral wells accessed and logged with this novel MLT and previous generations, a robust logging operation procedure and strategies were built. It consists of the following:

Job Planning

The job planning must consider:

- The wellbore trajectory and dogleg severity, which will aid in the decision to optimize the length of the tool string to be run, and the additional precautions to be taken during the logging. Job planner simulators can easily simulate this.
- The access angles of the lateral windows from the motherbore, to evaluate the success rate into these laterals, to aid the customer in making the right decision based on the economy.
- The caliper data for each lateral.
- The wellbore caliper to evaluate the potential washouts or restrictions. This will aid in deciding the lengths of the MLT probe nose.
- The well history, including workover. Most of the time the logging tools have a tendency to go to the last drilled or worked over lateral.

Dummy Run

A dummy run is required prior to logging to ensure the accessibility to all laterals and thereby reduce the risk of becoming stuck with the subsequent long logging strings, which may expose the well. The dummy run preferably includes the MLT, pressure, temperature, gamma ray, casing collar locator, deviation and the compression sub in case of the CT to act faster in case of a tag, and avoid damaging the tools and/or becoming stuck. This will also allow us to adopt a better strategy for the subsequent logging surveys with the main tools.

Main Logging Run

Depth correlation: In most logging jobs, gamma ray is the curve to be used for depth correlation; however, in several multilateral wells and/or in carbonate reservoirs, the gamma ray trend is quite similar between the laterals along the first few hundred feet from the windows. Therefore, it is important to use a deviation survey obtained by the tool and compare it to a well deviation survey from drilling or prior surveys to confirm in which lateral the tool is located.

Fig. 5 The location of the flow scanner PLT with multiple probes and spinners.

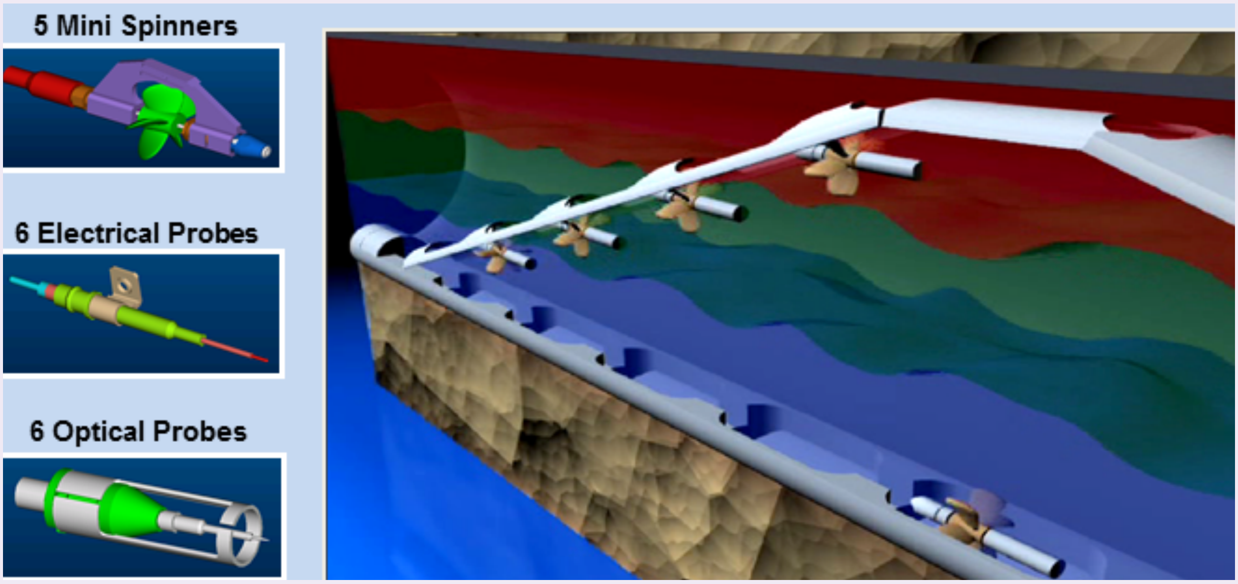


Figure 6 shows an example of depth correlation challenges in three lateral wells and how deviation is helping to confirm the accessed lateral.

Which lateral to start logging first? Depending on the logging objectives, it is usually best to start with the lateral producing the majority of the flow. In case all laterals are producing equally, we might consider logging the one producing the highest amount of water/gas. Therefore, it would be recommended to log first across all the lateral windows to estimate the total production from each lateral, and then to decide which lateral should be logged first. Nonproducing laterals should not be logged as they might contain many damaging fluids, which may cause stuck spinners and blinded probes.

Accessing the windows: After selecting the lateral to log, it is important to access the lateral at a low logging speed to avoid damaging the caliper of the multiphase logging tools.

If the direction of the multilateral drilled relative to the top of the hole is not known by the well operators, the sequence described earlier will be repeated multiple times. For each trial, the bent probe will be rotated to probe a different portion of the wellbore. How large the rotation steps are between trials is determined by the size of the multilateral vs. the main wellbore. For instance, if the multilateral and main well are the same size, it is sufficient to rotate 90° per trial since at minimum one of the trials will find the lateral. If the lateral diameter is smaller than the mainbore, the rotation angle between trials will be smaller.

Also, if the trial is unsuccessful, the bent probe should be straightened before being pushed downhole for the next trial.

Looking downhole, at least one trial spaced 90° apart — trial 2 in this example — will fall in the lateral if the lateral and main well are the same size.

Data Acquisition: It is recommended to first start the flowing surveys, then the shut-in survey. For both conditions, it is recommended to start logging across all windows, prior to logging the individual laterals to save time. Note that a shut-in survey is preferably run post-flow across the motherbore only. If there is cross-flow between the laterals, it would be recommended to log the individual laterals for accurate identification and quantification across the producing and thief zones.

Field Examples

The subject tool was successfully deployed in several wells in the target fields. In this article, we will discuss the results of two wells: oil producer and power water injector. Each lateral was accessed multiple times during both flowing and shut-in conditions to acquire production logging data. The details for each well is described next.

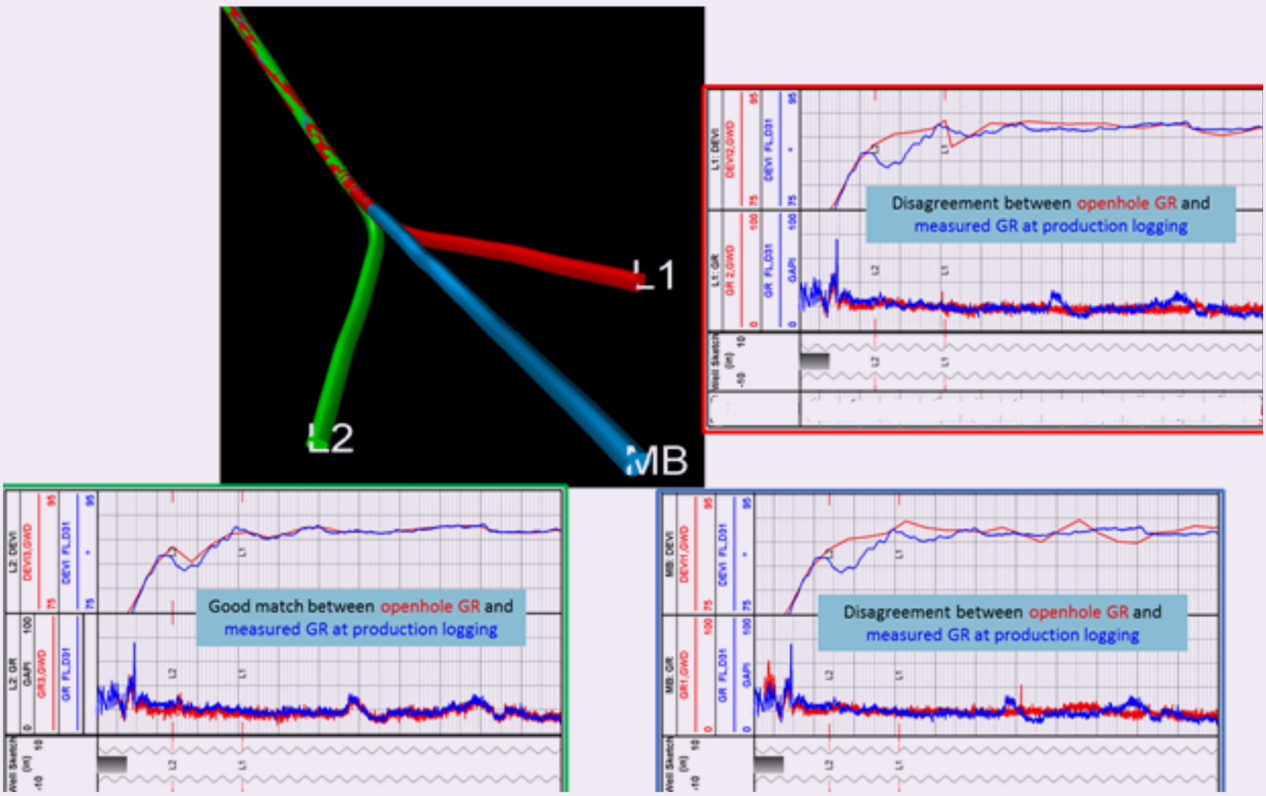


Fig. 6 *An example of the depth correlation in MLT wells, where the open hole gamma ray and deviation is in red vs. the recorded gamma ray and deviation during production logging, in blue.*

Well-1: Trilateral Oil Producer — First Worldwide MLT Logging Job

The logging objectives were to use CT and a MLT to convey the multiphase PLT to calculate zonal oil flow contributions across each lateral and identify crossflow if there is any.

The well was completed with 6⅛" open hole trilaterals, and lateral entry windows located in 7" casing liner in the mainbore.

Information from the 3D surveys included the WB-1 window located at 270° relative to the top of hole at x526 ft, and the WB-2 window located at 160° relative to the top of the hole at x205 ft.

Access of Laterals during a Dummy Run

A dummy run was run first with pressure, temperature, gamma ray, casing collar locator, and compression tools, then the main run was run with multiphase PLT sensors.

An extended nose was used with the MLT to negotiate the washout. A motor was also used to close the caliper arms of the multiphase tool to protect the tool while accessing the windows.

- The tool was run in hole (RIH) first with a dummy logging tool to access each lateral and prove the lateral as per the program before running in a live logging tool. WB-0 was accessed naturally without activating the MLT.
- WB-1 was tried at a 217° angle, and the tool entered the lateral on the first attempt. It was confirmed by the deviation survey of the hole.
- WB-2 was accessed after several attempts; probing with the MLT successfully found WB-2. The tool later entered lateral WB-1 at 130° deviation instead of 229°.

Access of Laterals during a Horizontal Logging Run

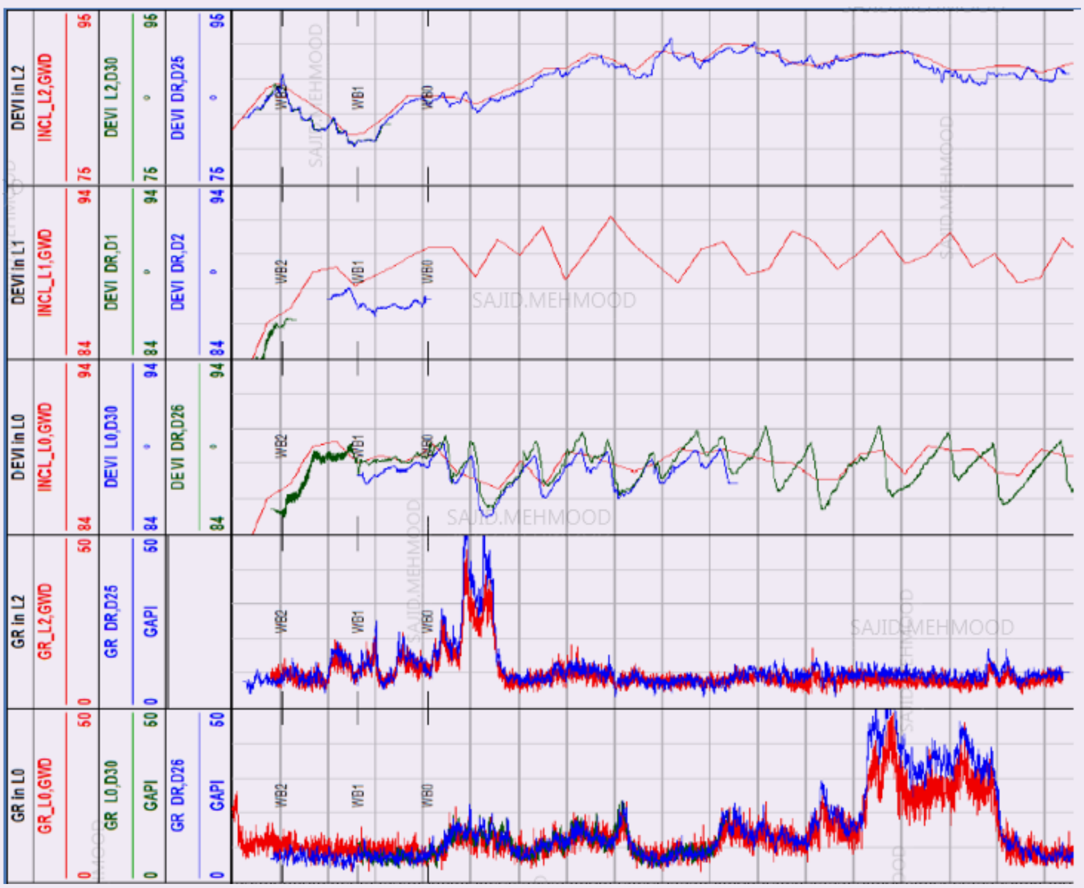
The MLT was used to access WB-2 with 130° angle to perform the horizontal logging across the lateral. WB-0 was accessed naturally. As for WB-1, it was not accessed as it was not needed.

Discussions on Well-1

Lateral WB-0 was accessed naturally without activating the MLT during the dummy run, and also during production logging. Gamma ray and deviation survey signatures of the laterals confirm entry into the lateral, Fig. 7.

Lateral WB-1 was accessed at a 217° angle as per the available deviation survey. The tool entered the lateral on the first attempt during the dummy run. The gamma ray and deviation survey signatures of the laterals confirm entry into the lateral. Production logging in lateral WB-1

Fig. 7 The gamma ray and deviation survey signatures of the laterals confirm entry into the lateral.



was dropped as logging was not required in this lateral.

Lateral WB-2 was attempted for entry with the dummy tool initially at an angle of 229° as per the available drilling deviation survey. The tool was not able to enter the lateral. It was decided to pull out of hole (POOH) to the top of WB-1 and to try again with a different angle other than the provided angle of the lateral.

In this attempt, the tool was activated to 130° angle and RIH. The tool entered the lateral properly. The gamma ray and deviation survey signatures, as previously seen n Fig. 7, confirm this. To confirm the entry angle, it was decided to POOH and try again with the same angle to access the lateral, which was successful again on the first attempt. The tool entered on the angle, which was set against the survey provided. The MLT was used to access lateral WB-2 with a 130° angle to perform the production logging across all laterals.

Figure 8 is a summary of the multiphase downhole flow profile across the laterals. Note that most of the oil production is coming from WB-0 and WB-1.

Well 2: Dual Lateral Power Water Injector

The logging objective was to evaluate the water injectivity across the two laterals using two lateral power water injector wells. The lateral's mainbore each have a 6⅛" open hole, and the lateral entry window is located in the 6⅛" open hole in the mainbore.

Access of Laterals during a Dummy Run

The dummy logging tool along with the MLT was run in as part of the program to access each lateral. Initially, the tool was not activated and WB-1 (L-0-1-1) was accessed naturally.

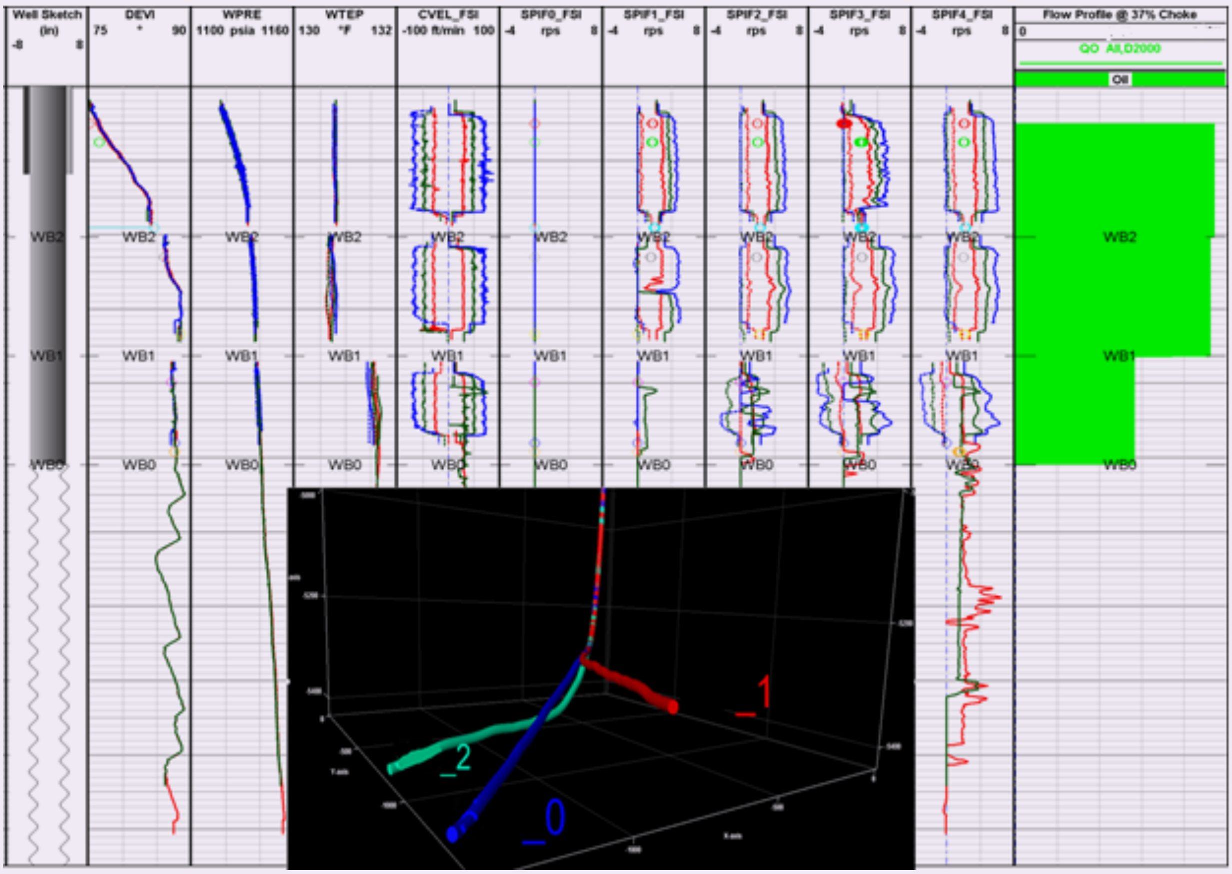
The mainbore (L-0-1) was attempted for access. After several attempts, it could not be accessed and the tool continued to land in WB-1 (L-0-1-1). It was suspected that there was a washout inside the open hole section as the nose will open fully until reaching ~6.9° if the inner diameter of the open hole section was 6⅛". It was decided to POOH and run with an extended MLT with PLT to check the caliper size.

Access of Laterals during a Horizontal Logging Run

This attempt entailed the same steps as the first run. It was decided to run the horizontal logging tool with the MLT, but with the extended nose as a washout was suspected in the wellbore. The tool was initially RIH in WB-1 without activating the MLT naturally — the same as the first run.

This run showed a washout in front of the lateral. This was confirmed through the PLT data that was reading

Fig. 8 *A summary of the multiphase downhole flow profile across the laterals.*



around 8.8". The lateral was accessed during the third attempt. After accessing the laterals, production logging was completed for both the laterals.

Figure 9 shows the downhole flow profile and zonal injectivity for the individual laterals. It was observed that most of the injected water was going to WB-1. Crossflow was also observed from WB-2 to WB-1.

Discussions on Well-2

The dummy tool was RIH initially to map WB-0. The tool naturally accessed the sidetracked lateral, L-0-1-1. Deviation survey signatures confirmed that the CT was inside WB-1 (and not WB-0).

After accessing WB-1, it was decided to map lateral WB-0. Multiple attempts were made to access the lateral, but the tools continued to land in lateral WB-1. On the top of the window, the MLT nose bend was activated and showed that the bend was fully opened to approximately 7.8°. This indicated the bottom nose was not touching the open hole section wall (6.18"). It was suspected that there was a washout inside the open hole section as the nose will open fully to ~6.9° if the inner diameter of the open hole section was 6.125".

After that, it was decided to POOH and run the PLT with the MLT, but with an extended nose as a washout was suspected in the wellbore. The tool went inside lateral WB-1 as naturally as with the first run. This run showed a washout in front of the lateral. This was confirmed through the PLT data that was reading around 8.8". The tool could not access the lateral during the dummy run due to a washout.

Once this was confirmed, it was subsequently decided to POOH to the liner and activate the tool with a different angle. In summary, the first two attempts to enter lateral WB-0 at 145° and 75° were not successful. The tool was then adjusted to a 340° angle and the tool successfully entered the lateral. This was confirmed by gamma ray and deviation surveys, Fig. 10.

Fig. 9 The downhole flow profile and zonal injectivity for the individual laterals.

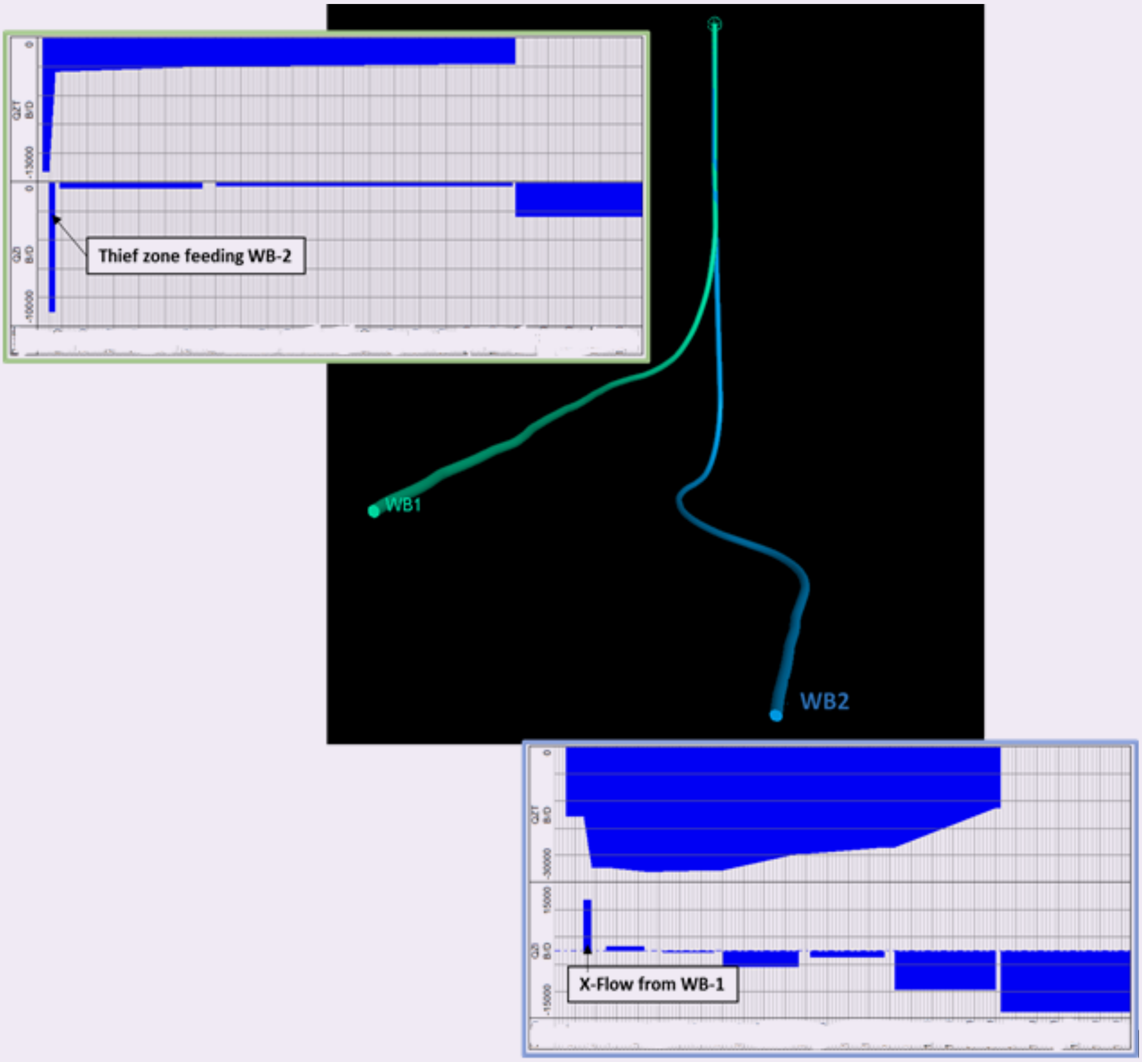


Fig. 10 *The gamma ray and deviation surveys for the MLT access confirmation.*

Conclusions

The novel MLT provides a controlled selective entry, on both the wireline tractor and CT, to all levels of multilateral wells and in all types of environments. It offers economical alternatives to traditional reentry techniques, and provides confirmation of correct access. The MLT enables production logs in all individual laterals and at different flowing conditions.

The utilization of this new MLT in the target fields provides a true understanding of well performance and reservoir heterogeneity, and allows for better assessment of the reservoir dynamics.

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Zouhir Zaouali is currently the Production and Perforation Domain Champion in Schlumberger, Saudi Arabia. He has spent his entire career with Schlumberger, working in various positions in the company's wireline and data processing centers in Algeria, France, Congo, the North Sea, Libya, and Saudi Arabia.

Zouhir has contributed to enhancing production logging and reservoir saturation interpretation, perforation optimization techniques, surveillance in brown fields, water control in gas wells and underbalanced perforations.

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Understanding Pitfalls of Nonreservoir Effects on Pressure Transient Test Data to Avoid Misleading Interpretation

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Abstract /

The determination of well and reservoir parameters is paramount during exploration, and the appraisal of new reservoirs are equally important during the development and production phases of a field. The interpretation of pressure transient test data is one of the tools to obtain such parameters under dynamic conditions. Often, this data is substantially influenced by nonreservoir factors such as gauge drift, adjacent noise due to natural or operational reasons, insufficient gauge resolution and dominant tidal effects. Any of these nonreservoir factors can significantly lead to a misleading interpretation of the formation. Rigorous vigilance against such occurrences is particularly important in designing deep transient well tests. The article quantifies these effects.

Obtaining strong, unequivocal reservoir responses in the pressure data are imperative in extracting the reservoir and well characteristics. Individual and convoluted effects of noise, drift, resolution, and periodic tides have been looked into quantitatively to demonstrate the situations when the reservoir signal is too weak to make any meaningful characterization. Reservoir models have been utilized to develop quantitative criteria to describe the dominance and subsidence of the effects of noise, resolution, drift, and periodic tides under different operating conditions. These criteria should guide the test design so that the subsequent test can produce meaningful data.

Depending on the amount of disruption caused in the measurements, there are situations when the test objective may not be achieved at all. Failure to create dominant reservoir responses results from an insufficient signal-to-noise ratio (SNR), due to the rate of production, and the pressure drawdown. It is a function of formation, fluid properties, or mechanical environment. A minimum rate of production for creating the required magnitude of SNR must be achieved to interpret correctly the reservoir response.

This article provides guidelines to determine the minimum rate and drawdown needed to obtain the presence of deep heterogeneities or boundaries with a reasonable level of certainty. If a test is run with a rate lower than the minimum value, e.g., the data will be biased by other hardware or natural factors, unrelated to the reservoir response. Examples are also presented with artifacts of nonreservoir effects to show how misleading characteristics of the reservoir and the well can be deduced with such distorted data.

This study establishes cause and effect relationships due to certain nonreservoir factors so that engineers can select their hardware, choose the methods and timings to mitigate the associated undesirable effects. Such a practical guide to select the most suitable transient test will rightfully fill in its place in the literature. The methodology applies equally to wireline testing operations, deep transient testing, drill stem testing, and production testing.

Introduction

Although pressures are measured in transient tests, the corresponding pressure derivative values are calculated to diagnose different flow regimes for identification of reservoir models. Pressure derivative values are supposed to magnify the reservoir responses and distinguish different flow regimes captured within the test duration.

Noise, when present in the measured pressure data, unintentionally becomes magnified with the reservoir responses while calculating pressure derivative values. In some cases, the pressure derivative of the measured data is not interpretable, or worse, misinterpreted because of the various artifacts of the measuring and differentiating process, collectively termed noise[1]. Nonideal performance of gauges can dramatically impact the calculation of basic reservoir and well properties such as permeability, reservoir pressure, and skin factor[2].

Ennaifer and Kuchuk (2018)[3] introduced the concepts of apparent accuracy and apparent resolution as observed in actual well test data. Their automated methodology can obtain and characterize the probability density function of the random noise in the data. According to Veneruso and Spath (2006)[1], the reservoir response is supposed to have a lower characteristic frequency than noise in the system because of electronic noise, bubbles, or turbulence in the pipe, or mechanical vibration of the gauge. Shumakov et al. (2019)[4] presented some practical solutions to operational issues that impact the quality of data during the well tests.

Pressure data captured during buildup and interference tests often contains low amplitude variations with a definite periodic behavior[5]. These semi-diurnal or ocean tide effects can provide reservoir characterization with sufficient data. Azzarone et al. (2014)[6] observed that pseudo-harmonic waves induced by tides with an amplitude of a fraction of a psia are capable of introducing significant noise, which becomes amplified at the late times.

Tidal effects have been correlated to the reservoir properties as pore volume compressibility and fluid bulk modulus with time-lapse measured downhole pressures[7-10]. Special algorithms have been developed to identify tidal signal in downhole pressure data and to remove the same[11-14].

Pinilla et al. (1997)[15] developed analytical type curves for an infinite acting reservoir subject to tidal effects by coupling geomechanic principles with equations for fluid flow through deformable porous media. Hsieh et al. (1987)[16] showed that aquifer transmissivity can be estimated if the phase shift is known for a rough estimate of the storage coefficient.

Hemala and Balnaves (1986)[17] reported to have observed ocean tide effects with an amplitude of 1 psia while testing wells in the Timor Sea. The presence of sinusoidal pressure oscillations in the reservoir caused by tidal effects particularly distorts the late-time buildup data and interference test data with small response magnitudes and long time lags[18]. Therefore, the tidal effects do not significantly impact the early-time buildup data and interference test data with strong response magnitudes and short time lags.

Marine (1975)[19] has shown from long, controlled pumping tests that anticipated permeability changes owing to tidal movement along fractures appear to be false. Later van Der Kamp and Gale (1983)[20] derived a generalized relationship between pore pressure and the stress changes due to Earth's tides and barometric loading effects. They also showed that the relationship presented by Bredehoeft (1967)[21] is a special case of their own. It was shown that different reservoirs may respond differently to Earth's tides based on their elastic properties.

Robinson and Bell (1971)[22] postulated that tidal water level fluctuations in wells can be reasonably explained by quantitative consideration of aquifer dilatation caused by solid Earth tides, barometric tides, and ocean tides.

The pressure oscillations on the sea floor as induced by changing water level are transmitted through overburden to the reservoir. The oscillating pressure signal at the reservoir depth, however, has a much smaller amplitude and may be shifted or delayed in time compared to the signal on the sea floor. The amplitude attenuation, the ratio of the amplitude in the reservoir to the amplitude on the sea floor, is a function of the total reservoir compressibility[7], and the time delay is a function of the formation permeability[17, 23, 24].

Identification of tidal signals in the downhole pressure data measured during a well test, therefore, offers a means for determining in situ formation compressibility and formation permeability. Despite a lot of interest in extracting reservoir characteristics from tidal effects as reported in the literature, this study concentrates on its negative impact on the data, which otherwise would have resulted in reservoir parameters handily.

Veneruso and Spath (2006)[1] argued that knowing characteristics of the gauge, such as drift, resolution and temperature effects, one can design well tests accurately with the anticipated reservoir responses.

This study establishes cause and effect relationships due to certain nonreservoir factors so that engineers can choose their hardware, methods, and timings to mitigate the associated blow back. The methodology applies equally to wireline testing operations, deep transient testing, drill stem testing, and production testing as explained later.

We have executed hundreds of simulation runs to understand the impacts of nonreservoir effects. These individual simulation runs illustrate the fact that the pressure derivative response deviates from the ideal response of an infinite acting radial flow behavior at different times, because the tidal effects become significant over the residual drawdown at the well for a given time. The simulation runs are intended to represent both formation tester response — usually with spherical flow regime at early time due to a limited entry well in an infinite acting reservoir combined with negligible wellbore storage effects — and regular well test response of a fully penetrating vertical well — with wellbore storage and no spherical flow — in an infinite acting reservoir.

We have considered a formation thickness of 40 ft and an anisotropy — vertical to horizontal permeability — ratio of 0.1 while varying transmissibility values. The comparative log-log plots for different transmissibility values presented in Fig. 1 show that both the spherical flow regime in a limited entry formation tester and the wellbore storage phenomenon with a wellbore storage constant of 0.001 bbl/psia in a fully penetrating wellbore response disappear about the same time, earlier than one hour into the buildup period. Therefore, the simulations with a fully penetrating wellbore model in this study apply to any regular well and formation tests.

Investigation of Relevant Cases

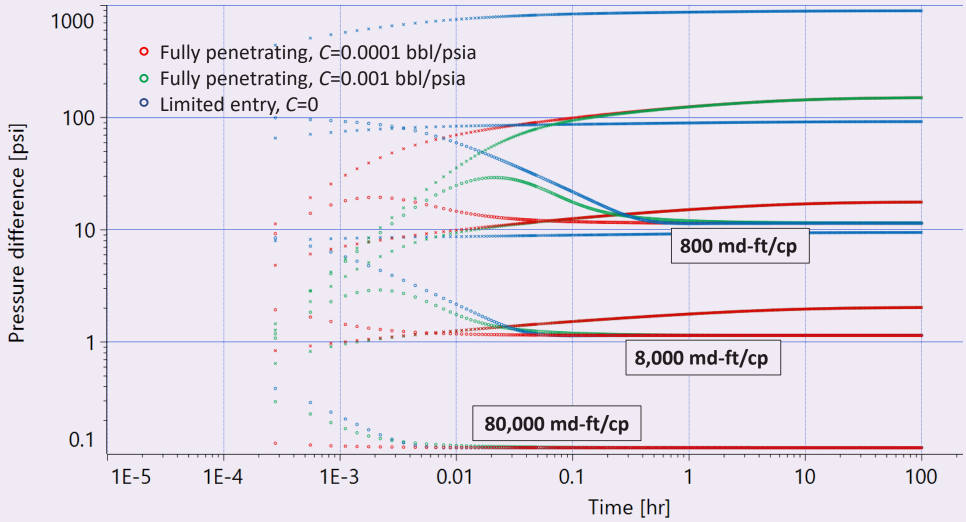
We investigate a number of cases to show impacts of nonreservoir issues on the quality of transient test data.

Tidal Effects

Tidal effects in reservoirs have also been reported geographically away from the sea in the study of Marechal et al. (2002)[25]. The observation well in their study is located about 270 km away from the nearest shoreline. Some large land reservoirs are also sensitive to the disruption of the gravity field from the moon, although not connected to the sea. The Earth tide phenomenon has been reported extensively with respect to its impact on underground reservoirs in the literature[7, 11, 20, 21].

Figure 2 shows typical pressure fluctuations due to

Fig. 1 *A comparison of a limited entry formation tester response to fully penetrating vertical well response.*

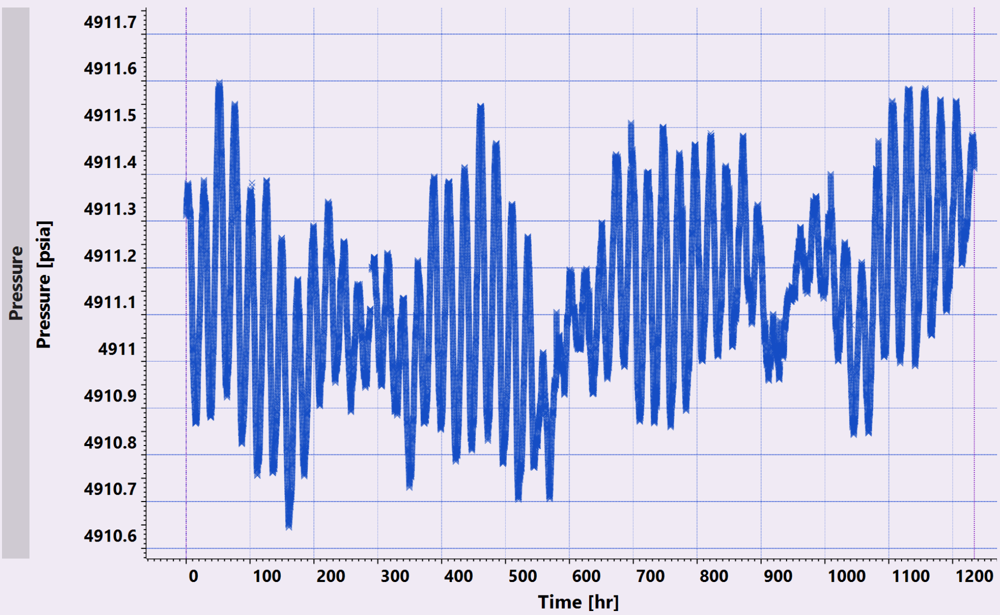


tidal effects in an observation well in an inactive field. These approximately semi-diurnal pressure cycles are repetitive with variations in amplitude over the lunar cycles. The peak-to-peak amplitude varies from 0.15 psia to 0.7 psia. Allegre et al. (2016)[26] observed an amplitude of 0.025 psia in the pressure fluctuations of an inland well. An offshore well has recorded 0.1 psia in amplitude in the study by Khurana (1976)[18].

Figure 3 shows the visible impact of the tidal effects on the pressure data in observation Well-B, which is in hydraulic communication with the active well subject to water injection almost at a constant rate. Here the superposition of a global trend to the tidal effects is clearly visible. Although the long-term data trend can be extracted after reaching a certain differential pressure due to the injection, short-term trends may be strongly affected by the tidal effects.

Figure 4 presents the log-log plot of the pressure data of Well-B, which shows that the reasonable pressure derivative can be followed after 100 hours. Within this first 100 hours, the signal-to-noise ratio (SNR) at Well-B has been too weak and is dominated by the tidal effects,

Fig. 2 *Typical pressure fluctuations due to the tidal effects in Well-A.*



due to the rock and fluid properties and the distance to the active well. As soon as the reservoir signal at observation Well-B has started prevailing on the tidal effects, the derivative values have become steady and meaningful after 100 hours.

Note that when the pressure derivative value becomes negative, the corresponding points are not plotted on the log scale, Fig. 4. Ignoring such negative values can lead to erroneous identification of flow regimes, due to a unilateral progression of the derivative profile as the pressure transient responds. In this campaign, there is another observation well, Well-C, whose response to the injection in the active well is presented in Fig. 5. The pressure responses in Fig. 5 appear to be much smoother than those in Fig. 3.

Figure 6 shows the log-log plot of the pressure data of Well-C. The pressure derivative values in Fig. 6 have started a trend at 50 hours onward. Here also, the SNR at Well-C has been too weak and is dominated by the tidal effects prior to 50 hours. As a result, the derivative values have not followed any trend. Once the reservoir signal at the observation well, Well-C, prevails on the tidal effects, there is a trend of the pressure derivative values after 50 hours.

The start time of a transient test — either drawdown or buildup data to be analyzed — with respect to the tidal cycle can cause distortions in the data in different ways. Here we examine the effects of the time shift on the test data. A time shift is a time lag between the beginning of a tidal cycle and the beginning of a testing sequence, typically the flow period, Fig. 7. Here we are considering a nine-hour flow period followed by a 100-hour shut-in period.

In this example, a zero-time shift illustrated in Fig. 7a can align the increasing pressure trend in the beginning of the shut-in period at odds with the trend of the falling tidal pressure at nine hours. This means that the shut-in period starts at the peak of the tidal effect. We have also considered a six-hour time shift, Fig. 7b, which allows the shut-in to start at the bottom of the tidal effect. Depending on the time shift difference between the tidal effect cycle and the beginning of the shut-in time, the resulting effects on the pressure derivative values can be different.

Figure 8 shows a comparison plot of log-log graphs for the cases of zero-, three-, six-, and nine-hour time shifts. Depending on the start of the buildup period with respect to the tidal cycle, the tidal effect can alter the pressure responses, and therefore, the derivative responses will distort in different ways and at different times during the buildup period. In some cases, at the early time, the pressure derivative profile goes up, and in others, the pressure derivative profile goes down, Fig. 8.

If these effects are not identified properly as tidal effects in an infinite acting radial flow regime, one may be tempted to misinterpret these as changing transmissibility (increasing or decreasing by observing the trend of pressure derivative), or just a boundary response. The test operator has an option of aligning the beginning of the buildup period with the time shift to minimize the

Fig. 3 *Impact of tidal effects on pressure data at Well-B due to a nearby active well.*

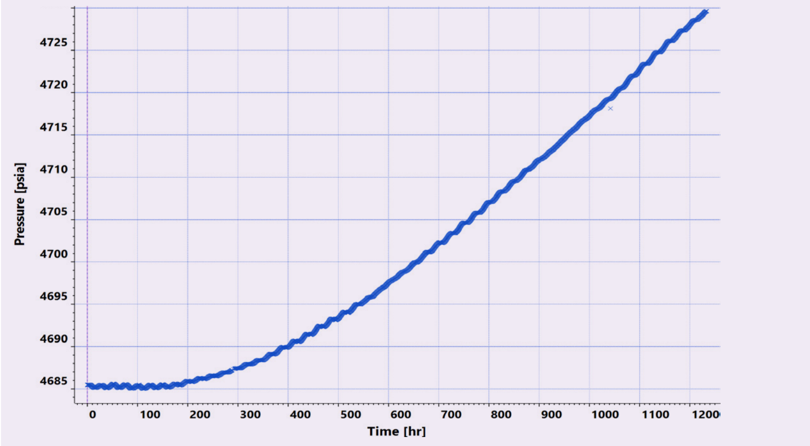


Fig. 4 *A log-log plot of the pressure data of Well-B. When the pressure derivative becomes negative, the corresponding points are not plotted on the log scale.*

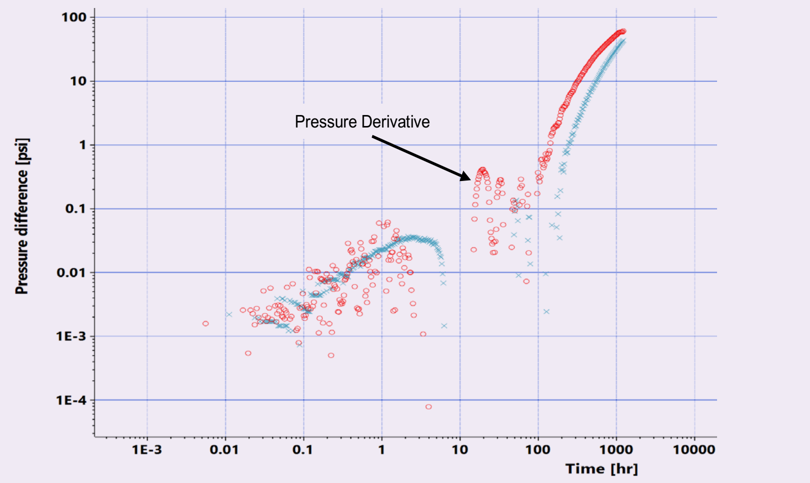
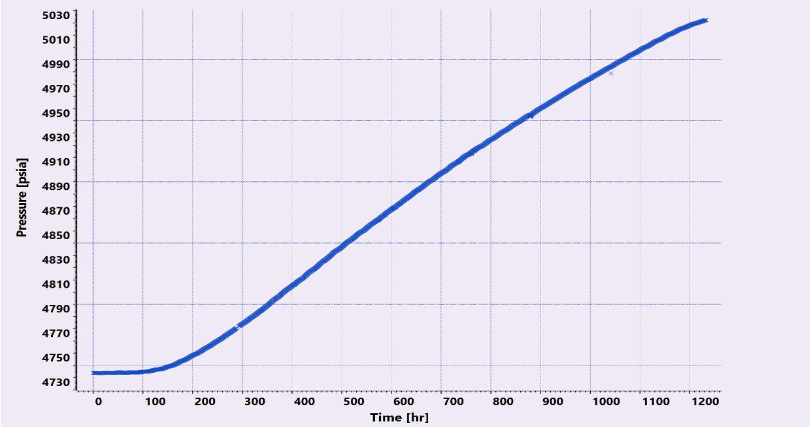


Fig. 5 *No apparent influence of tidal effects on pressure data at Well-C due to a nearby active well.*



impact of tidal effects on the data. Sometimes the time lag between the tidal effect at the surface and its transmission into the reservoir is not known.

Amplitudes of tidal cycles play an important role in distorting transient pressure data. The effects of amplitudes of 0.1 psia, 0.2 psia, and 0.3 psia on the reservoir systems of different transmissibility values, subject to a production rate of 100 stock tank barrels per day (stb/d), with a vertical well, are presented in Fig. 9. This shows that the highest amplitude has caused the most damage to the data of the prolific reservoir system with the transmissibility of 80,000 md-ft/cP. In this case, no apparent reservoir response is available after 0.3 hour. In contrast, the tightest reservoir system (800 md-ft/cP) has been hit the least, and the reservoir response prior to six hours remain intact.

A number of simulation runs have been performed to study the SNR under the following conditions:

- Infinite acting, homogeneous reservoir.
- Transmissibility from 200 md-ft/cP to 100,000 md-ft/cP.
- Production rates from 50 stb/d to 5,000 stb/d.
- Tidal effects with an amplitude of 0.3 psia and a time shift of six hours.

Two sets of sample simulation runs for well reservoir systems with transmissibility values of 2,000 md-ft/cP and 100,000 md-ft/cP are presented in Figs. 10 and 11, respectively. The presented graphs are not normalized deliberately so that the derivative profiles stay segregated for clear viewing of their behaviors. Note that any upper derivative profiles refers to higher production rates. This means that the bottommost profile — purple in Fig. 10, or

Fig. 6 A log-log plot of the pressure data of Well-C.

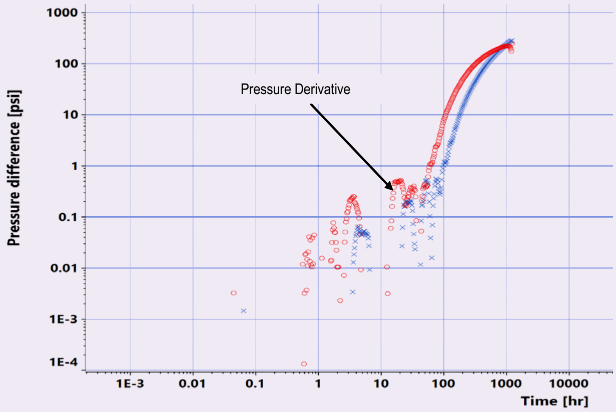


Fig. 7 Consideration of time shift in tidal effects: (a) no time shift, and (b) a six-hour time shift.

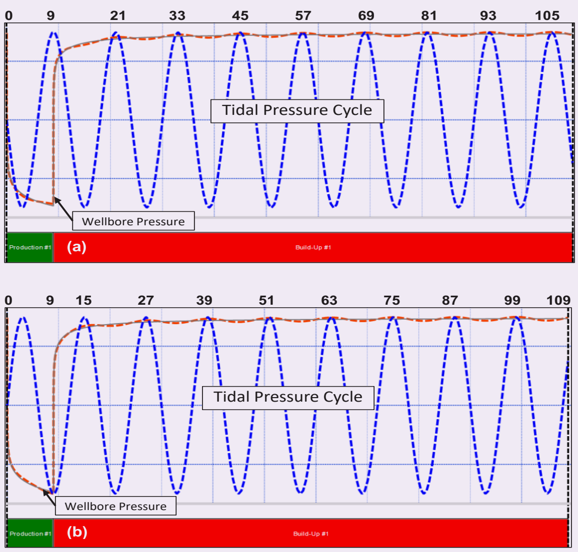


Fig. 8 A comparison plot of log-log graphs for the cases of zero-, three-, six-, and nine-hour time shifts.

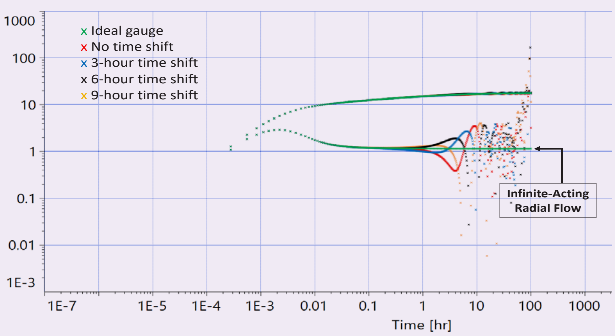
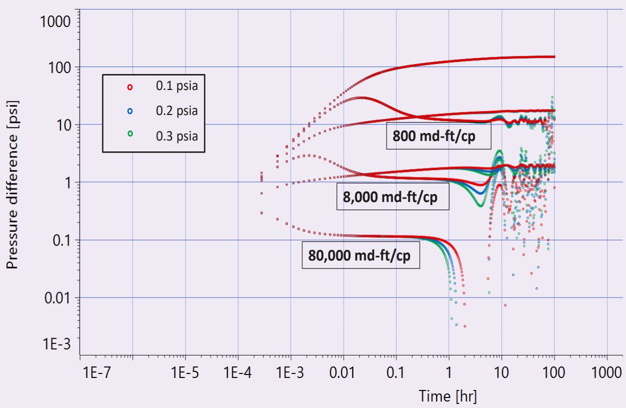


Fig. 9 The effects of amplitudes of 0.1 psia, 0.2 psia, and 0.3 psia tidal cycles on different reservoir systems.



blue in Fig. 11 — refers to the lowest production rate, 50 stb/d, while the upper profiles progressively refer to 100 stb/d, 200 stb/d, 500 stb/d, 1,000 stb/d, 2,000 stb/d, and 5,000 stb/d, respectively.

A comparison of the pressure derivative values for a particular production rate shows that a higher transmissibility case is more likely to be vulnerable to distortion due to a lower SNR. A higher rate causes a higher drawdown or a higher SNR for a given reservoir system with a fixed transmissibility value. In addition, a reservoir system with a higher transmissibility value is subject to a lower drawdown or a lower SNR as compared to another reservoir system with a lower transmissibility value subject to the same rate of production. In both Figs. 10 and 11, although the frequency of oscillation is constant in a linear scale, it appears to be accelerating in the log scale of time.

To summarize the results from all the cases of the simulation runs, the pressure derivative responses have been evaluated based on some acceptance criteria to see whether the acquired data can give confident interpretation results about the near wellbore transmissibility value, mid-field transmissibility value, and far-field transmissibility value or boundaries.

First, all the derivative data has been analyzed to see which cases with combinations of flow rates and transmissibility values would contain acceptable data to enable extraction of transmissibility values from the data with tolerable 10% deviations from the ideal transmissibility values at one hour and at 10 hours. The one-hour condition has been selected as a general criterion considering that the duration of the acquired data would be enough to obtain the near wellbore transmissibility, and the 10-hour condition has been selected to represent whether the acquired data can give information about the far-field formation properties or any potential boundaries.

The reason why a time criterion has been selected instead of a radius of investigation criterion is that the impact of tides depends on the drawdown created, which depends on the transmissibility of the reservoir system. Note that the commonly used formulas for the radius of investigation are based on permeability. Therefore, for different values of the pay thickness, the radii of investigation would be different due to different permeability values for the identical reservoir fluids.

Figure 12 shows the summary of this evaluation for all the cases considered with the acceptance criteria of one hour and 10 hours. The red points indicate that the pressure derivative data failed to provide the correct transmissibility values within a 10% accuracy when the buildup data at one hour is analyzed. This means that only the data within the first one hour or earlier into the buildup period can be used to obtain formation properties confidently, before the tidal effects considered in this article corrupts the data.

These cases cover high transmissibility formations tested with low flow rates. The gray points represent the cases where the buildup data at one hour gives accurate transmissibility information, but fails to provide the correct transmissibility value at 10 hours or before, indicating that

Fig. 10 *The effect of rates on SNR for transmissibility of 2,000 md-ft/cp. The direction of increasing rates from one set of plots to another set is upward. The frequency of oscillations appears to be accelerating in the log scale of time.*

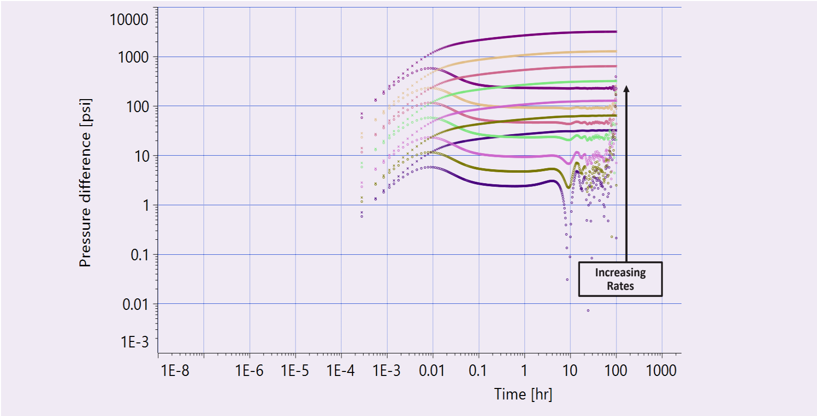


Fig. 11 *The effect of rates on SNR for transmissibility of 100,000 md-ft/cp. The direction of increasing rates from one set of plots to another set is upward. The frequency of oscillations appears to be accelerating in the log scale of time.*

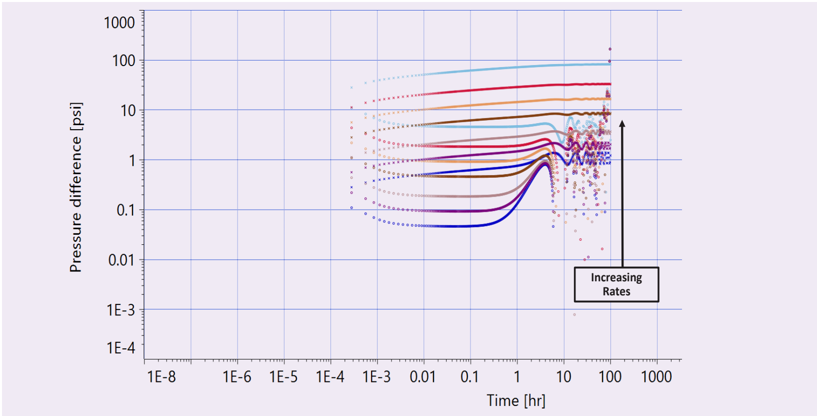
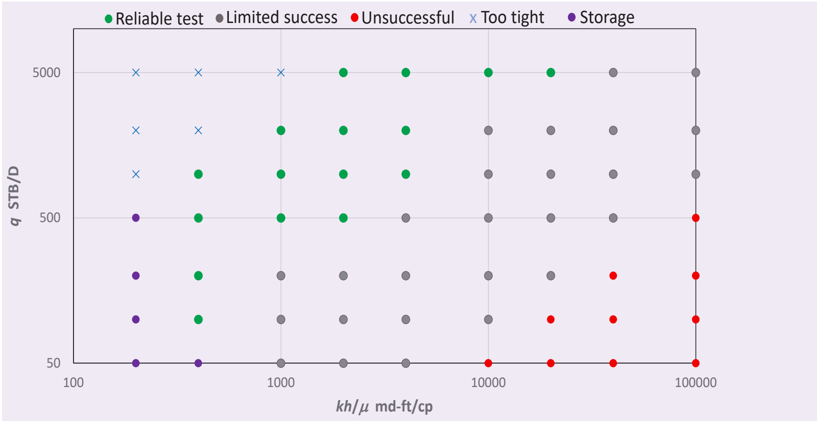


Fig. 12 *A summary of probable valid tests under tidal effects with test durations of one hour to 10 hours.*



the data can fail to provide far-field reservoir information.

The green points indicate that both the one-hour and 10-hour buildup data can be used to give accurate transmissibility calculations, providing accurate near wellbore and far-field formation properties. The blue crosses indicate the cases where the flow rates are too high for the given transmissibility conditions, and the required flow rates cannot be maintained for the simulation parameters used in this study. Finally, the purple points represent the cases where the wellbore storage used in these simulation runs or the spherical flow effects have not ended within one hour for the given parameters, including the pay thickness used in the simulation runs.

Second, another similar summary plot has been created using the acceptance criteria for one hour and four hours into the buildup period, Fig. 13. The four-hour criterion has been chosen to represent "mid-field" reservoir information, instead of the 10-hour criteria previously seen Fig. 12.

When compared with Fig. 12, it can be seen that the boundary between the grey points and the green points have shifted, indicating that some cases provide accurate transmissibility interpretation when using the four-hour buildup information, even though they fail to provide accurate information at 10 hours.

Noise

In its basic sense, noise is any unwanted interference that degrades or undermines the competing reservoir responses. Artifacts of tidal effects, gauge resolution or drift are not considered as noise in this study. Noise can originate from the electronics of the pressure gauge itself, fluid movement in the reservoir or production strings, pressure waves generated by downhole equipment as pumps, and fluid circulation in the wellbore or surface operations.

It is important to have dominant reservoir signals among inherent noise in the transient test data so that the SNR overcomes the threshold so that well and reservoir parameters can be extracted confidently. Noise can be smoothed out, but oversmoothing can distort reservoir signals unintentionally. The presence of noise can complicate the determination of the transmissibility and the distances to boundaries. Compounded with the other effects such as tidal effects, noise can lead to misinterpretation of data if not recognized a priori.

Identical noise has been introduced to the reservoir systems with different transmissibility values with a vertical well in an infinite acting reservoir to illustrate the effects of noise on data interpretation. Three different transient responses have been generated with a production rate of 100 stb/d for different transmissibility values by imposing the noise with a magnitude of 0.1 psia on the ideal pressure response.

Figure 14 shows a comparison of these cases. This figure shows that the system with 80,000 md-ft/cP has been the worst hit due to the impact on the SNR for the given production rate and the noise in the pressure data. All of these cases are duplicated with the addition of some tidal effects, and are presented in Fig. 15.

Although all the reservoir systems have suffered from data distortion at the late times, the system with 80,000 md-ft/cP may mislead to fictitious boundary conditions if the effects of noise and tides are discounted. Having

Fig. 13 *A summary of probable valid tests under tidal effects with test durations of one hour to four hours.*

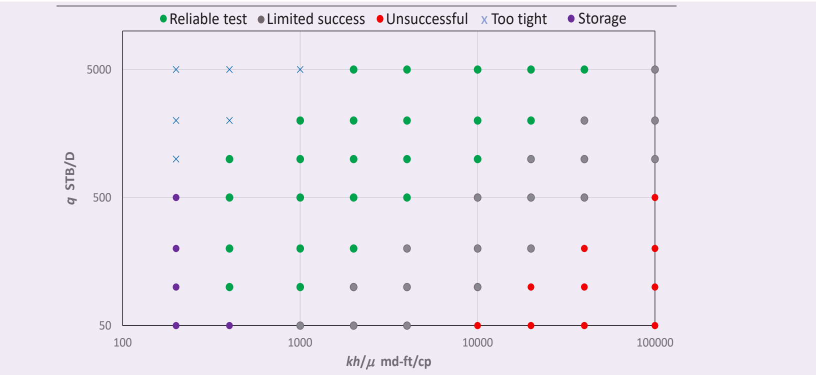


Fig. 14 *A comparison of log-log plots of different reservoir systems subject to random noise.*

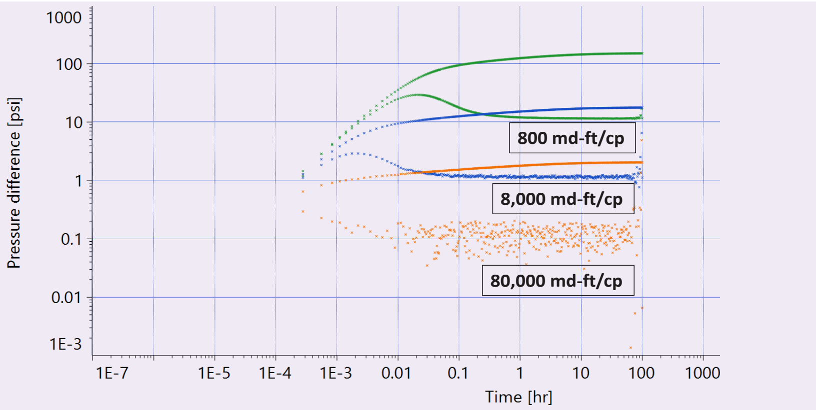
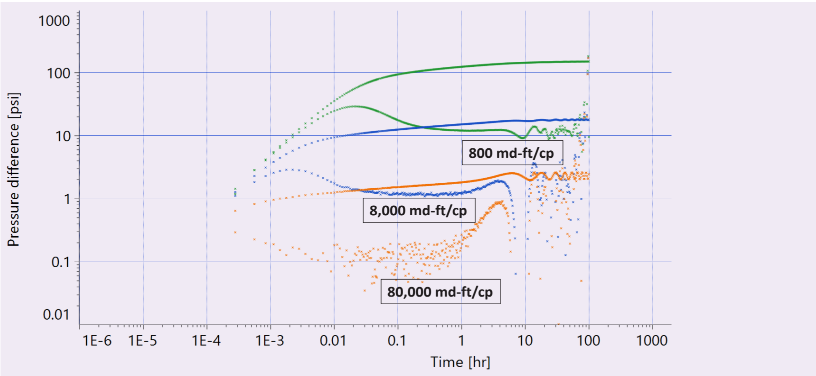


Fig. 15 *A comparison of log-log plots of different reservoir systems subject to random noise and tidal effects.*



artifacts of tidal effects in addition to the noise in the pressure data can complicate the interpretation and be misleading. In the derivative plot for the 80,000 md-ft/cP system in Fig. 15, the noise in the data can be seen clearly up to one hour. The interpretation results can be provided with the noise taken into consideration, such as giving a range of formation transmissibility values, using the minimum and the maximum levels of pressure derivative stabilization.

When the tidal effect response starts getting dominant (after one hour and until the derivative response is completely lost after four hours), the apparent noise in the pressure derivative data diminishes. This is truly an artifact of the tidal effects, masking the noise and giving the wrong impression that the noise has ceased to influence the reservoir response, which leads to an unrealistic confidence that this part of the data can be used for interpretation with certainty.

In reality, noise in the data has not diminished, and there are no boundaries in this simulation example. Rather this part of the data needs to be excluded from the interpretation. Unfortunately, this cannot be identified readily in a given set of actual data; therefore, for confident interpretations and to avoid any fictitious reservoir description, the test design needs to be carried out with due diligence, addressing such issues and by choosing the most suitable testing practices for the given formation characteristics.

Gauge Resolution

Gauge resolution is the minimum pressure change detectable above the noise level for the gauge. When referring to the resolution of a gauge, the associated electronics of the gauge must be taken into account, and one must also specify the resolution for a certain sampling time, e.g., 0.002 psia at a one second sampling rate[2]. Note that this definition of resolution is not simply the significant digit in the surface readout; rather, this definition provides a true measure of the operational limit of the complete gauge.

Specification of the gauge resolution deserves intense scrutiny, especially in high transmissibility reservoir systems, where pressure changes during transient testing are small. Veneruso et al. (1991)[2] observed parallel unit slope lines in the pressure derivative response of the log-log plot with measured pressure data with no smoothing and no filtering. They attributed these unexpected features in the pressure derivative response to the artifacts of aliasing in the data as made up for undersampling of the measured pressures.

Figure 16 presents an example of buildup pressure data impacted by low gauge resolution in Well-D. This zoomed in view captures a stair step increment of pressure with time during shut-in. Effects of the stair step increment are highlighted in the corresponding pressure derivative values in the log-log plot of Fig. 17. The pressure derivative values have failed to show a clear trend, making it difficult to identify flow regimes for selection of a reservoir model.

Gauge Drift

Gauge drift, also called "creep," can be another source of artifacts in the downhole pressure data. This is a measure of the stability of a gauge as a function of time. In other words, it is the ability of a gauge to retain its performance characteristics for a relatively long period of time.

The mean drift of a gauge is expressed as the rate of change of its measured value when subject to a constant input value. For example, a drift specification of commercial gauges in psia/yr typically considers the worst-case situation at the maximum rated temperature and pressure. Gauges can experience either a positive or a negative drift over a period of time.

A positive drift causes a gauge to report progressively growing higher pressures than the actual or ideal values with time, and a negative drift causes the gauge to report progressively slumping lower pressures than the actual or ideal values with time. Commonly, the gauge drift is believed to become important for long-term buildup data for extended well tests.

Depending on the drawdown or the SNR created to produce reservoir fluids from the reservoir and the

Fig. 16 A zoomed in view of raw pressure data during buildup in Well-D.

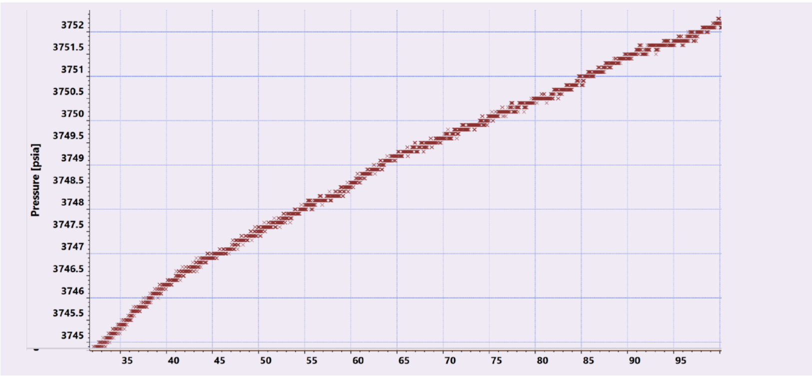
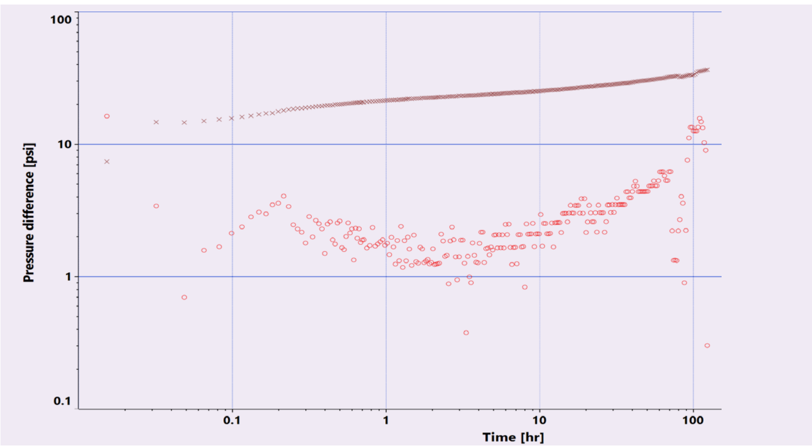


Fig. 17 A log-log plot of pressure data of Well-D.



gauge's drift specification, the impacts of the drift on the interpretation can be significant and can lead to misinterpretations, especially as nonexistent boundary effects. Veneruso et al. (1991)[2] observed artifacts of positive gauge drift in the form of the pressure derivative profile trending upward away from the homogeneous response of a vertical well in an infinite acting reservoir.

Figure 18 compares the log-log plots of responses from the gauges with positive drift (+1.5 psia/yr) and negative drift (-1.5 psia/yr) with the responses from an ideal gauge. This case belongs to a buildup test of a fully penetrating vertical well near a sealing fault, producing at 100 stb/d from a 100,000 md-ft/cP reservoir system.

The ideal response of pressure derivative truly captures the doubling of the stabilization value due to a nearby sealing fault, whereas the response for the positive drift curves upward, and the response for the negative drift falls abruptly toward the zero value. Note that the pressure derivative profile that is curving upward at the late time can be misunderstood as a channel reservoir behavior with a one-half slope, and the derivative profile that is falling abruptly at the late time can be misunderstood as the pseudosteady-state or steady-state behavior.

The effects of the production rate and gauge drift on pressure transient interpretation for different formation transmissibility values have also been evaluated by considering the production rates of 100 stb/d and 500 stb/d, reservoir systems with transmissibility values of 2,000 md-ft/cP and 100,000 md-ft/cP, and a gauge drift at 1.5 psia/yr on the pressure measurements. Due to a low SNR, impacts of low production rates are obvious in the high transmissibility case (100,000 md-ft/cP), Fig. 19, during the 100 hours of buildup period shown in the log-log plot, following the nine hours of flow period (total 109 hours), used for the simulations.

Subsequently, the effects in the low transmissibility case (2,000 md-ft/cP) are negligible as the derivative values with 100 stb/d and 500 stb/d overlay with that in the ideal case at the late times. These cases belong to a vertical well near a sealing fault. A weaker SNR with 100 stb/d causes more deviation from the ideal behavior because of the lower drawdown than the case with 500 stb/d.

Examples presented in Figs. 18 and 19 can easily mislead the analyst to suggest some other imaginary reservoir heterogeneity or boundary conditions if the effects of gauge drift at the late times are not suspected of influencing the data.

Discussion

The impact of drift, noise, and tidal effects can significantly affect the identification of reservoir models for pressure transient analysis, as we have shown. The effects vary in magnitude and can be misinterpreted for reservoir or near wellbore geological or features of reservoir fluids. It is therefore of utmost importance to ensure that a proper test design is performed prior to any pressure transient testing operations. The test design shall verify that the investigated reservoir parameters can be properly qualified and quantified, and that the range of uncertainty would not overwhelm the expectations. In general, such uncertainty is amplified by the lack of dominant "SNRs" in the pressure derivative features that we are looking to identify.

It is essential to perform these verifications before the operation — during its planning phase. These effects can be difficult to recognize and to quantify. Long build-up periods may permit us to determine the phase and amplitude of tidal effects where diurnal oscillations of pressure can be clearly seen on the data. All the gauges connected to the reservoir pressure should be experiencing the same level of disturbance.

As for the drift, or creep, it is very challenging to predict. Deployment of new types of gauges and their enhanced design and manufacturing control potentially leads to repeatable behaviors. Drift correction models have been around for a number of years, but they are difficult to prove and calibrate in laboratories, especially over long periods.

Noise from sensor, electronics, or the well can be

Fig. 18 Effects of positive and negative drifts on data for well near a sealing fault. The "ideal" trend represents a no-drift condition.

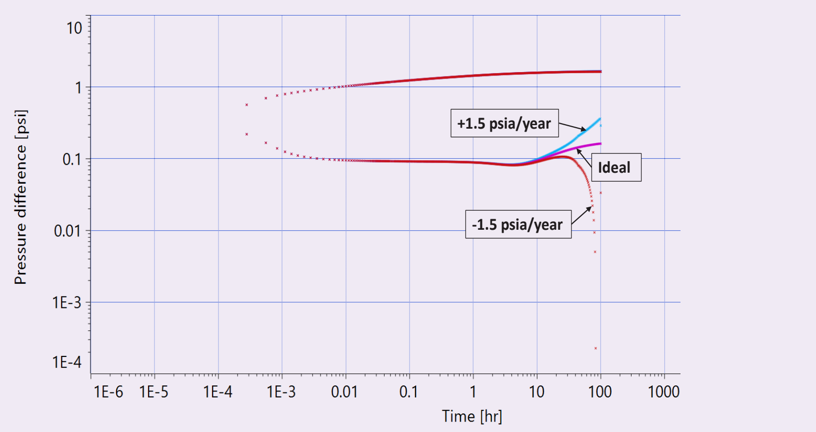
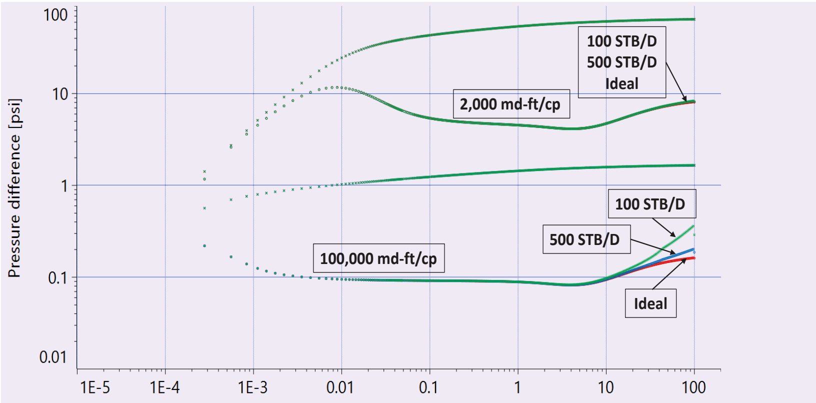


Fig. 19 Combined effects of low production rates and positive drifts on data from two reservoir systems. The "ideal" trend represents a no-drift condition.



estimated and quantified. Simple averaging can reduce the appearance of noise in data at a cost of leaving some characteristics out. Li and Ramakrishnan (2019)[27] showed that enhanced pressure derivative computation does abide by the behaviors of the mainstream pressure transient signals, and this can also lead to some losses of data at the end of the flow periods. Such losses are acceptable to avoid imposing any "end effects" on the data.

Special care should be taken in managing negative values of pressure derivatives corresponding to buildup periods. As these are not shown on log-log diagnostic plots, they can be easily and deceptively ignored, which can lead to the wrong identification of flow regimes. The verification of the match performance on a linear plot (or history plots) is mandatory to ensure high quality matches between the models and the actual data.

As a rule of thumb, tests with high SNR — larger flow rates and longer flow periods — do enhance the reliability of pressure transient analysis. Usually a trade-off or balance has to be struck among the flow rate, duration of the flow period and data quality, due to environmental, economical, space, time or regulatory constraints. A proper test design considering the effects of tides, noise and drift as discussed earlier can mitigate risks in such testing operations and gather meaningful data.

Conclusions

1. Identifying the effect of tidal movements and gauge drift on the well test derivative is not straightforward. Therefore, at the design phase, potential problems with the interpretation needs to be considered, and the suitable testing method and design need to be applied.
2. The tidal effects on the pressure data can be irregular over time, and are often unpredictable. The tidal effects cannot always be corrected.
3. A high transmissibility case is more likely to be vulnerable to distortion, due to a lower SNR. A higher rate causes a higher drawdown or a higher SNR for a given reservoir system with a fixed transmissibility value. In addition, a reservoir system with a higher transmissibility value is subject to less drawdown or a lower SNR as compared to another reservoir system with a lower transmissibility value.
4. Time shifts and amplitudes of tidal cycles dictate when and how much data might be distorted. In some cases of high transmissibility reservoir systems with large completed intervals, the impact of these effects can completely overwhelm the traditional pressure transient interpretation.

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