AADE-14-FTCE-11

Reduced Drilling Days and Low Friction Factors Hallmark Eagle Ford Water-Based Fluid Performance

Ian Everhard, Steven Willis, Mario Villalobos, Dennis Clapper, and Hatem Aly Salem, Baker Hughes

Abstract

A new water-based drilling system was introduced and used successfully to drill the Eagle Ford shale formation in South Texas. The mud system is based on three major components which primarily maintain rheological properties, provide filtration and seepage control, and reduce friction factors. Secondarily, these products provide lubricity, alkalinity and general wellbore stability. The mud system was built starting with recycled water-based mud from a previously drilled well to save on cost and avoid discharge of potentially useful fluid. The recycled mud had insufficient yield capacity, high amounts of dispersed clays and possible bacterial contamination. After minimal treatment with the new package, the resulting drilling fluid exhibited excellent rheological stability and filtration control. Dilution rates were limited to 0.1 bbl/ft and the use of solids control equipment for handling low gravity solids was heavily restricted. This created a challenging environment for the successful application of any standard water-based mud. Despite the challenges presented by the well, the operator was able to drill an 8 ¾-in deviated interval from 2,526 ft to a total depth of 13,944 ft in eleven days. The average ROP for the entire 8 ¾-in section was 268 ft/hr with a 0.105 average friction factor. Such performance from a low-cost, water- based mud challenges the notion that oil-based muds are the singular path towards speed, efficiency and reliability.

Introduction

The Eagle Ford shale formation is one of the most active areas for shale oil and gas drilling in the United States. The formation stretches from Webb County in the southwest to Walker County in East Texas. The Eagle Ford shale contains high concentrations of carbonate and quartz with low smectite content. In Dimmit County, close to the Texas-Mexico border, the Eagle Ford formation lies at a depth of about 6,000 to 10,000 ft. Vertical hole sections are drilled through the upper formations to a depth of about 7,000 to 10,000 ft. A deviated interval to horizontal is drilled to total depths of more than 10,000 ft.[1,2] Oil-based fluids are predominantly used, but some operators choose to drill with water-based fluids. Oil-based muds dominate the area because of higher ROP, fewer drilling days, and less non-productive time. Fluids related to non-productive time encompasses the usual litany of events – hole instability, stuck pipe and lost circulation. Operators choose to reduce the impact of these events by drilling with oil-based drilling fluids.

Although generally known to be second-place performers compared to oil-based muds, water-based muds comprise inherent advantages of reduced environmental impact, fewer regulatory issues and reduced disposal costs. In addition to these environmental and regulatory advantages, reuse of water-based muds can also reduce fluid cost and conserve water resources. A new water-based drilling fluid has been developed for shale oil and gas drilling with a three- additive package to improve performance for shale play lateral drilling. The three-component additive package specifically addresses areas of rheological property management, filtration/seepage control, lubricity and rate of penetration (ROP). The system proved flexible enough to establish initial make up properties with a relatively poor quality recycled mud. The combination of products addresses some operator concerns about water-based mud performance. Incorporating the new additive package into a water-based mud system improved drilling performance in the Eagle Ford formation.

Omne Trium Perfectum (OTP)

The water-based mud (WBM) system used in this field application is based on three major components. The key components include a single sack bentonite alternative, a differential sticking preventive and an ROP enhancer.

The bentonite alternative product was developed as a single-sack mixture containing products to quickly provide balanced rheological and filtration control fluid properties. This material provides a backbone of fluid properties and can be used early in the drilling sequence to either break over a simple 'spud mud' or revive a previously used WBM. The bentonite alternative is an ideal candidate for this application, because the fluid system was seeded with a recycled WBM that lacked sufficient rheological properties and filtration control. The single-sack mixture imparts fundamental rheological properties, filtration control and provides some lubricity when used in conjunction with bentonite.

The differential sticking preventative additive is the second major component in the system, which is primarily used to reduce stuck pipe occurrence and provide wellbore stability. The additive relies on anionic and nonionic, deformable, submicron particles that accumulate to develop an internal filter cake in low permeability formations, which inhibits unwanted filtrate invasion. By reducing spurt loss in tight formations, this additive limits instances of differentially stuck pipe and sloughing shale.

The third and final key component to the fluid system is the ROP enhancement additive, which reduces friction that contributes to torque and drag in WBM. This component enables drilling with reduced friction factors, in-line with oil-based mud performance. Use of this product displayed reduced lubricity coefficients in a lab setting as well as multiple case studies of enhanced ROP in the field (when compared with typical WBM systems).

Lubricity effects

Table 1 displays the effects of the WBM system components on friction coefficients using a laboratory lubricity tester. The test measures the frictional resistance to rotation or torque between two steel surfaces submerged in a test fluid compared to water, providing general insight into the effect of fluids on drillstring torque and drag. The friction coefficient is first tested on neat water (displayed as the 'base' value on the table) and consecutive tests are benchmarked against this value, resulting in the 'corrected lubricity coefficient'. Column A displays the results of a simple mud based on the bentonite alternative which, in conjunction with bentonite, imparts a lubricity coefficient reduction in excess of 30% compared to neat water. Columns B and C display the lubricity test data from a WBM system with the full additive package, and the effects of increasing the concentration of ROP enhancement additive. The ROP enhancement additive significantly reduces the friction coefficient in this system even in the presence of increased drill solids.

Table 1: Lubricity effects from bentonite alternative and ROP enhancement additive

Products	Water	A	B	C
Fresh Water (mL)	350	270	259	259
Wyoming Bentonite (lb/bbl)	-	5	-	-
Polyamine inhibitor (lb/bbl)	-	-	3.5	3.5
Bentonite Alternative (lb/bbl)	-	7	6.0	6.0
Dispersable Polymer (lb/bbl)	-	-	2.0	2.0
Differential sticking preventative (lb/bbl)	-	-	10.0	10.0
ROP Enhancer (lb/bbl)	-	-	4.7	9.4
Barite (lb/bbl)	-	190	186	186
Simulated Drill Solids (lb/bbl)	-	27	54	54
Lubricity Results				
Lubricity Coefficent	**0.340**	**0.228**	**0.214**	**0.123**

Contamination Stability

The effects of some common contaminants or unexpected situations that may be encountered while drilling are highlighted in **Table 2**. The formulations are 12.5 ppg (except for E, which is an example of elevated mud weight at 14 ppg), which rely on the three core products for filtration control, rheological characteristics and lubricity.

These contaminants pose a minimal impact to the overall rheology of the system; an increased PV and YP is expected in the scenario with the 14 ppg fluid. One significant effect is the rise in API fluid loss across all contaminants, most noticeably in the case of the cement addition which resulted in a doubling of the filtrate.

Table 2: Effects of common contaminants on 12.5 ppg formulations using bentonite alternative and other core products

Products	A	B	C	D	E
Fresh Water (mL)	268	268	268	268	247.65
Polyamine Inhibitor (lb/bbl)	3.54	3.54	3.54	3.54	3.54
Bentonite Alternative (lb/bbl)	4	4	4	4	4
Dispersible Polymer (lb/bbl)	0.50	0.50	0.50	0.50	0.50
Differential Sticking (lb/bbl)	4	4	4	4	4
ROP Enhancer (lb/bbl)	4.67	4.67	4.67	4.67	4.67
Barite (lb/bbl)	187	187	187	187	**269.64**
Simulated Drill Solids (lb/bbl)	54	54	54	54	54
Cement (lb/bbl)		5			
3.5% SeaWater (lb/bbl)			10		
Gypsum (lb/bbl)				2	
Initial Rheology					
6 (rpm reading)	4	4	4	6	11
3 (rpm reading)	3	3	3	5	10
PV (cP)	**20**	**22**	**18**	**19**	**27**
YP (lb/100ft^2)	**10**	**8**	**9**	**12**	**16**
10 sec gel (lb/100ft^2)	4	4	3	6	15
10 min gel (lb/100ft^2)	7	14	8	7	21
API (mL)	7.4	11.2	9.2	8.6	8.7
pH	7.25/9.49	10.44	8.45/9.01	7.55/9.55	7.59/9.59
Results After Hot Roll at 250°F					
6 (rpm reading)	5	7	4	5	8
3 (rpm reading)	4	6	4	5	8
PV (cP)	**12**	**7**	**11**	**13**	**19**
YP (lb/100ft^2)	**7**	**9**	**5**	**6**	**12**
10 sec gel (lb/100ft^2)	6	7	6	6	9
10 min gel (lb/100ft^2)	11	13	9	10	26
API fluid loss (mL)	5.3	11.7	7.4	8.0	6.8
pH	6.82/9.72	9.74	8.08/9.61	7.18/9.60	7.71/10.0

Filtration control across a range of permeable media

Table 3 shows the effect of using the differential sticking preventative material in a salt polymer WBM. With 10 ppb material added to the base fluid, there is a slight increase in system rheological properties, but within a manageable range. The material also reduces API, HPHT and dynamic fluid loss across a range of pore sizes. The blend of chemistries in this material encompasses a wide size range of anionic and nonionic particulates along with deformable submicron material that work together to build an effective internal filter cake.

Table 3: Effects of differential sticking preventative material on dynamic fluid loss and HPHT

Products	A	B
Fresh Water (mL)	236.9	236.9
Wyoming Bentonite (lb/bbl)	8	8
Lignite (lb/bbl)	5	5
Chrome Lignosulfonate (lb/bbl)	2	2
NaOH (lb/bbl)	1.82	1.82
NaCl (lb/bbl)	5.1	5.1
Polyanionic Cellulose (lb/bbl)	1	1
Barite (lb/bbl)	382.5	382.5
Simulated Drill Solids (lb/bbl)	27	27
Differential Sticking Preventative (lb/bbl)		**10**
Initial Properties		
PV (cP)	39	46
YP (lb/100ft^2)	18	22
10 sec gel (lb/100ft^2)	6	9
10 min gel (lb/100ft^2)	28	38
pH	11.2	10.6
API fluid loss (mL)	3.2	2.5
After HR at 150F for 16 hours		
PV (cP)	37	44
YP (lb/100ft^2)	11	17
10 sec gel (lb/100ft^2)	5	7
10 min gel (lb/100ft^2)	15	19
pH	10	9.6
HPHT at 250°F after HR at 250°F (mL)	15.2	11.4
Dynamic FL at 250°F on 3 µ Disk (mL)	35.6	22.8
Dynamic FL at 250°F on 20 µ Disk (mL)	40	26.4
Dynamic FL at 250°F on 60 µ Disk (mL)	34.2	27.4
Dynamic FL at 250°F on 90 µ Disk (mL)	29.2	19.2

Fluid Properties for Field Test

Table 4 highlights the flexibility of the additive package where baseline rheological properties are achieved without using bentonite clay. The last formulation in the chart shows a weighted fluid with 3% low- gravity solids and a very limited amount of product addition. Solids control was predicted to be inadequate because of the expected high rates of penetration. Therefore, the rheological properties of the fluid are likely to be sensitive to product over-treatment. The bentonite alternative product is formulated to provide baseline rheological characteristics while also maintaining low fluid loss and lubricity. This feature helps circumvent over-addition of products to an already crowded system by enabling the mud engineer to add only a single product.

Several formulations (Table 4) were given to the application engineers and the operations group to provide a product application guideline. The actual application of this system was established using a recycled water-based mud of which the exact composition was unknown. These formulations enabled the mud engineer onsite to determine how to properly build a fluid based around the bentonite alternative product.

The anticipated mud density at total depth (TD) was expected to be approximately 12 ppg. The formulations in Table 4 display fluids built for the minimum and maximum expected fluid densities. The highest bottomhole temperatures were not expected to exceed 215°F in this particular well location. Laboratory fluids were dynamically aged at 215°F for sixteen hours to simulate circulation and downhole conditions. Yield points dropped 56% on average after aging at this temperature. API fluid loss increased 11% on average after aging. Fluid pH fell slightly after aging and was readjusted after aging using small additions of NaOH solution.

Table 4: Prepared formulations for field trial reference

Products	10ppg	10ppg	12ppg	12ppg
Fresh Water (mL)	313	314	291	288
Wyoming Bentonite (lb/bbl)		3	3	
Bentonite Alternative (lb/bbl)	5.0	5.0	5.0	7.0
Fluid Loss polymer (lb/bbl)	3			
Barite (lb/bbl)	72	71	178	190
Simulated Drill Solids (%)	27	27	27	27
Initial Properties				
6 (rpm reading)	8	5	8	8
3 (rpm reading)	5	4	6	6
PV (cP)	24	15	22	27
YP (lb/100ft^2)	31	18	24	30
10 sec gel (lb/100ft^2)	6	4	7	7
10 min gel (lb/100ft^2)	7	9	16	9
API fluid loss (mL)	4.4	4.9	4.5	4.2
pH	8.34/ 9.04	8.66/ 9.04	8.4/9.4	8.3/9.3
Results After Hot Roll (215°F)				
6 (rpm reading)	3	3	2	3
3 (rpm reading)	3	2	2	2
PV (cP)	23	13	22	18
YP (lb/100ft^2)	13	8	9	16
10 sec gel (lb/100ft^2)	3	2	3	2
10 min gel (lb/100ft^2)	5	5	7	2
API fluid loss (mL)	3.9	4.6	4.2	3.4
pH	8.13/ 9.14	8.07/ 9.03	7.7/ 9.2	7.8/9.2

Environmental Considerations

In general, water-based drilling fluids offer environmental impact advantages over oil-based drilling fluids. Disposal of water-based drilling fluids is more convenient because these fluids are allowed lower disposal cost options. In the United States, each state establishes regulatory agencies and regulations governing the disposal of drilling fluids.[3,4] In Texas, oil and gas exploration, production and associated waste streams are regulated by the Texas Railroad Commission under a state regulation often referred to as "Rule 8."[5] If disposal occurs on the drilling lease, water-based drilling fluid and the generated drill cuttings may be land farmed on-site if chloride levels are below 3000mg/L. Additional requirements have been established for off-site land farming. These requirements include total petroleum hydrocarbons of the waste/soil mixture of less than 1% and pH between 6 and 10. Chloride levels at the end of well mud check were 600 mg/L, meeting the regulated chlorides limitation for land farming.

Field Trial Summary

The first commercial field trial of the proposed fluid took place in the Eagle Ford shale in Dimmit County, Texas. The goal was to drill an 8 ¾-in interval from 2,526 ft to a projected measured depth (MD) of 15,163 ft in 11 days.

The initial make-up drilling fluid comprised recycled mud from the previous well on the pad, resulting in the Application Engineering team deviating from the field trial plan. Baseline rheological properties were recorded and treatments with the proposed fluid components were revised to compensate for the recycled fluid properties.

System Treatment and Maintenance

Recycled WBM was used initially and the proposed fluid components were added to the system to maintain rheological properties as drilling progressed. Deviation from the field trial plan was necessary to maintain rheological properties of the fluid system.

Pilot testing was performed on location to show the effects of the 3 ppb addition of the bentonite alternative product on the recycled WBM. Results are shown in **Table 5**. The pilot testing indicated that the addition of this single product quickly provided an increased cuttings-carrying capacity along with a significant decrease in API fluid loss.

Table 5: Field pilot test showing Bentonite alternative additions for recycled WBM treatment

Products	A	B
Recycled WBM (mL)	350	350
Bentonite Alternative (lb/bbl)		3.0
Initial Rheology		
6 (rpm reading)	2	10
3 (rpm reading)	1	7
PV (cP)	8	27
YP (lb/100ft^2)	9	24
10 sec gel (lb/100ft^2)	1	7
10 min gel (lb/100ft^2)	6	14
API fluid loss (mL)	16.0	4.0
pH	8.7	9.1

The quantity of bentonite alternative used in the pilot test indicated that 3 ppb would be the maximum allowable concentration of the product in the system. Initially, a concentration of 2.5 ppb of bentonite alternative was added to the system. Application engineers adjusted the proposed fluid component concentrations to meet operator fluid specifications. Concentrations of the bentonite alternative were reduced as drilling progressed due to the high amount of low gravity solids (LGS) in the recycled drilling fluid which resulted in higher than expected rheological properties. Because of the reduced concentration of bentonite alternative, additional products were added to the fluid to meet API filtration control objectives.

The overall concentrations of the bentonite alternative and the differential sticking preventative were reduced by 30 to 50%. The ROP enhancer was maintained according to the plan. **Table** 6 displays the concentrations for the bentonite alternative, the differential sticking preventative and the ROP enhancer over the course of the section.

Table 6: Product Concentrations

Depth, (ft)	Bentonite alternative (lb/bbl)	Differential sticking preventative (lb/bbl)	ROP enhancer (lb/bbl)
5,813	2.64	1.10	5.05
7,255	2.19	0.91	3.79
7,501	1.99	0.86	5.09
7,779	1.59	1.36	4.08
9,525	1.13	1.39	4.52
11,960	1.07	1.98	4.23
13,994	1.48	2.54	5.97
13,994	1.38	2.48	8.46
Min	1.07	0.86	3.79
Max	2.64	2.54	8.46
Average	**1.68**	**1.58**	**5.15**
Planned	5-7	3-7	4.7-9.3

Friction Factor Measurement

Friction factors (FF), also known as friction coefficient, express the forces needed to overcome frictional force and the normal force of the element. In drilling, some notable areas of friction occur at the surface of the tool joint with the casing and with the open hole while sliding or rotating.

Friction factors are affected by drill string interaction with casing or open hole, type of drilling fluid, rheological properties and hole cleaning efficiency. Friction factors are not affected by the drilling mode (rotating or sliding) or the load applied. Typical ranges of friction factors found in the database are identified in **Table 7**.

Table 7: Typical friction factor ranges

Drilling Fluid	Cased Hole FF	Open Hole FF
WBM	0.17 – 0.28	0.23 – 0.44
OBM	0.10 – 0.16	0.13 – 0.26

Baker Hughes Advantage® modeling software calculates data based on the assumption that constant rotating and sliding are taking place. Friction factors will change depending on the drilling mode including RPM, ROP and side forces (normal force), but the friction factor will remain constant.

Baker Hughes engineers used a static friction factor calculation while determining friction factors on this project. This method uses off-bottom rotating torque data to remove variances that may be observed when calculating friction factors dynamically.

Lateral Section ROP and Friction Factors

The kick-off point was set at 7,251 ft (**Fig. 2**) and additions of the differential sticking preventative and the ROP enhancer were incorporated into the daily chemical treatments. **Table 8**, **Fig**. **1** and **Fig. 2** depict the rate of penetration (ROP), friction factors and inclination, providing an indication of the relative performance of the proposed fluid system.

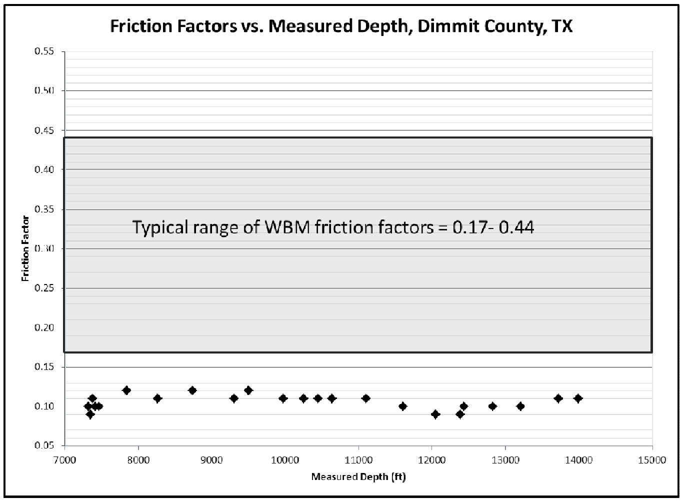

Fig. 1: Friction factors

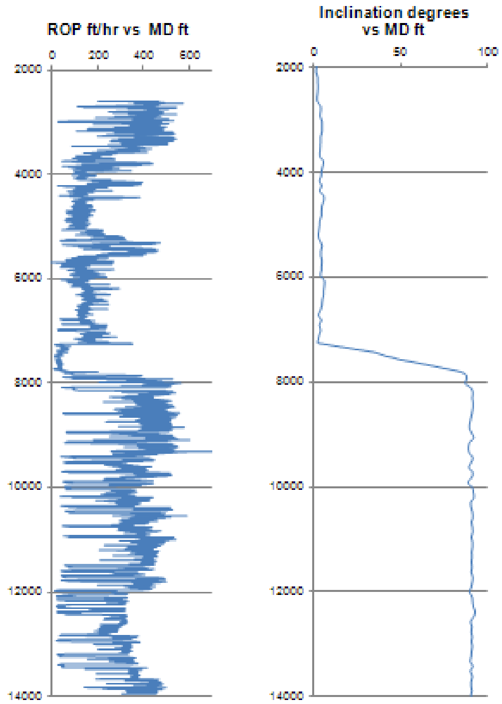

Fig. 2: ROP and Inclination

Table 8: ROP Information

	ROP ft/hr		
Section	**Avg**	**Max**	**Min**
Entire 8 3/4"	268.1	843.3	6.9
Vertical	216.2	569.9	123.5
Build	42.2	201.2	6.9
Horizontal	329.3	843.3	11.5

Days vs. Depth

OBM offset data was compiled using the Baker Hughes Advantage database. A data set was constructed using the average of several parallel wells with similar profiles drilled with OBM. The current well data set was superimposed over the oil-based reference data for comparison purposes (Error! Reference source not found.).

Approximately 1.5 days of NPT was associated with waiting on cement because of vehicle breakdowns and problems with the torque crew (insufficient equipment) while nippling up blowout preventers (BOP). Another 8 hours was associated with a measurement while drilling (MWD) tool failure. NPT not attributed to drilling fluid in this well is indicated by brackets A and B in **Fig. 3**.

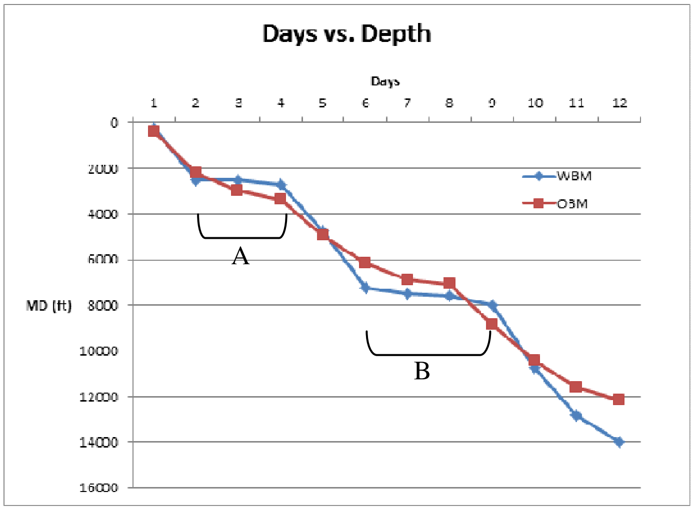

Fig. 3: Days versus depth

General Fluid Properties

The proposed fluid system met the objectives outlined and delivered exceptional performance while meeting budgetary goals. Rheological properties were easily maintained while drilling the curve and lateral sections of the well (**Table 9**). Wellbore stability was not a problem at any time and no non-productive time (NPT) was allocated to drilling fluids over the course of the well.

Table 9: Fluid Properties

MUD PROPERTIES			
Properties	**Average**	**Minimum**	**Maximun**
PV (cP)	16	12	22
YP (lb/100ft^2)	21	10	29
MW (ppg)	10.6	10.0	12.0
pH	8.6	8.0	9.1
API (mL)	5.6	4.0	10.0
Retort Solids (%)	12.6	11.0	16.0
Drill Solids (%)	7.9	3.4	11.4
ROP Enhancer (%)	2.70	0.00	4.00

Conclusions

The well was drilled to a measured depth of 13,994 ft (1,169 ft short of MD), and was determined by the operator as the final measured depth. Casing was set and cemented successfully. The final fluids cost was 8% below the planned cost. The well was completed within the 11-day timeframe stated in the initial fluids proposal.

- High ROPs were observed over the course of the well
- Friction factors were extremely low
- The new drilling fluid system was able to accommodate recycled mud with minimal treatment
- The new fluid is compatible with conventional drilling fluid products when necessary.
- No fluids related NPT was recorded
- The well was completed on time and under budget
- Wellbore stability was maintained throughout the drilling process

Acknowledgments

The authors gratefully acknowledge the valuable contributions of Alyssa Garcia and Melissa McCray during the laboratory development of the new fluid. Tim Beyers and Michael Foust contributed to the field test effort. Brian Daft is also acknowledged for his contribution to the media content in this paper. Finally, the authors thank Baker Hughes for the opportunity to publish and present this paper.

Nomenclature

BOP = *Blowout preventer*
LGS = *Low gravity solids*
MD = *Measured depth*
MWD = *Measurement while drilling*
ROP = *Rate of penetration*
TD = *Total depth*
NPT = *Non productive time*

References

1. Guo, Q., Ji, L., Rajabov, V., Friedheim, J., Portella, C. and Wu., R. : "Shale Gas Drilling Experience and Lessons Learned from Eagle Ford." SPE 155542, Americas Unconventional Resources Conference, Pittsburgh, June 5-7, 2012.
2. Mullen, J.: "Petrophysical Characterization of the Eagle Ford Shale in South Texas." CSUG/SPE 138145, Canadian Unconventional Resources and International Petroleum Conference, Calgary, October 19-21, 2010.
3. Clements, K. , Veil, J., and Leuterman, A.J.J.: " Global Practices and Regulations for Land Application and Disposal of Drill Cuttings and Fluids." SPE 126565, SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Rio de Janeiro, April 12-14, 2010.
4. Lyons, W.C. and Plisga, G. J., *Standard Handbook of Petroleum and Natural Gas Production Engineering*, second edition, pages 6-406 to 6-422.
5. Texas Railroad Commission "Guidelines for Processing Minor Permits Associated with Statewide Rule 8: Guidelines Developed by Technical Permitting in Coordination with Field Operations, 2009