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A Message from Eric Carre

Welcome to the third edition of Reservoir Innovations, a publication that was issued for the first time in 2012 by Halliburton’s Wireline and Perforating product service line. We are now extending it to other formation evaluation business units to give a broader view of our developments and to demonstrate the value gained by pulling together all sources of data in order to provide a seamless solution to your reservoir challenges.

In line with some of our current industry challenges, this edition is focused on unconventional plays. You will find eight recent, major Society of Petroleum Engineers (SPE) and Society of Petrophysicists and Well Log Analysts (SPWLA) industry papers, all written by Halliburton and operator experts. I hope that, by reading these articles, you will become more aware of the capabilities and experience Halliburton has in assisting our customers with their formation evaluation objectives.

For example, the paper “Petrophysical Evaluation for Enhancing Hydraulic Stimulation in Horizontal Gas Shale Wells” focuses on the economic recovery of gas from shale reservoirs. The paper presents enhanced reservoir evaluation of the Haynesville shale play located in east Texas. It details an application where we utilize data from wireline, logging-while-drilling, conventional core analysis, and a chemostratigraphy analysis of drill cuttings to determine parameters that are essential for comprehensive shale-gas evaluation and effective completion design. Also, the paper “Geosteering in Unconventional Shales: Current Practice and Developing Methodologies” reviews the current common practices used in geosteering in shales for both gas- and oil-producing reservoirs. Examples are examined to determine the viability of a particular strategy.

As always, I encourage you to collaborate with our technical sales and Formation and Reservoir Solutions (FRS) representatives to coauthor papers that raise awareness of your technology challenges, and to highlight solutions that have created value in your reservoir understanding.

We welcome your interest and feedback in Reservoir Innovations, and we sincerely hope you find it valuable and enjoyable.

Thank you,

Eric Carre
Senior Vice President, Drilling & Evaluation
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Well Placement Strategy in Unconventional Shales
Uncertainty Analysis for Determining Petrophysical Parameters with a Multi-Detector Pulsed Neutron Tool in Unconventional Reservoirs

Weijun Guo, Daniel Dorffer, Sushovon Roy, Larry Jacobson, and Dennis Durbin, Halliburton

Abstract

Uncertainty analysis for petrophysical parameters is important for well planning and stimulation decisions. This process is especially demanding for unconventional reservoirs. The complex factors include rock lithology variations and field production history.

Pulsed neutron tools (PNT) play an important role in the monitoring of production wells with cased completion. In saline formation water environments, the thermal neutron capture cross section (Sigma) measurement discriminates between water, gas, and oil. When the formation water salinity is low or varies as a result of flooding stimulation, the spectroscopy measurement of carbon and oxygen ratios (C/O) often leads to accurate residual oil saturation analysis, especially for reservoirs with medium to high porosity. With the recent development of the multi-detector PNT (MDPNT), case studies have been reported for gas saturation and depletion analysis in tight-gas reservoirs.

The accuracy of the reservoir saturation analysis with MDPNT depends on accurate rock lithology and porosity determination. When core data or openhole logs are not available, the MDPNT can be used to estimate these parameters and to obtain a standalone evaluation of porosity, lithology, and saturation. The results may be affected by errors resulting from statistical test responses and measurement dynamic ranges. This paper presents results from a comprehensive study and proposes a framework to quantify uncertainty from these error sources.

Background

Pulsed neutron tools (PNT) have been used for several decades to provide water saturation estimates during well lifecycle. Two classic interpretation techniques are Sigma saturation analysis and Carbon/Oxygen saturation analysis. The introduction of PNT logging more than four decades ago (Wahl et al., 1970; Youmans et al., 1984) provided the first through-casing measurement of formation water saturation. This was based on the observation that the inverse of the decay constant (Σ the capture cross section) for the gamma flux after a pulse of fast neutrons was related to formation parameters of interest:

\[ \Sigma_{\text{log}} = \Phi \cdot \Sigma_{fl} + (1 - \Phi) \cdot \Sigma_{ma} \]  

where \( \Sigma_{\text{log}} \) is the measured value, \( \Phi \) is the porosity, and \( \Sigma_{fl} \) and \( \Sigma_{ma} \) are the pore fluid and matrix neutron capture cross sections, respectively. Further, \( \Sigma_{fl} \) could be partitioned between water and oil:

\[ \Sigma_{fl} = Sw \cdot \Sigma_{w} + (1 - Sw) \cdot \Sigma_{o} \]

where \( Sw \) is the relative saturation of water, and \( \Sigma_{w} \) and \( \Sigma_{o} \) are the capture cross sections for water and oil, respectively. Combining these two equations and solving for \( Sw \) leads to:

\[ Sw = \frac{(\Sigma_{\text{log}} - \Sigma_{ma}) \cdot \Phi \cdot (\Sigma_{o} - \Sigma_{ma})}{\Phi \cdot (\Sigma_{w} - \Sigma_{o})} \]

From this equation, it is clear that the uncertainty for estimating \( Sw \) is smaller when \( \Phi \) is higher, and when the contrast between \( \Sigma_{w} \) and \( \Sigma_{o} \) is more significant. Although fresh water and oil have cross sections that are essentially the same (22 capture units), many reservoirs have high water salinity, i.e., large \( \Sigma_{w} - \Sigma_{o} \) contrast, and adequate porosity enabling the wide-spread application of this technology to well monitoring in casing.

A few years after introduction of PNT, the development of C/O logging using pulsed neutron technology solved the problem of saturation determination in freshwater reservoirs (Lock and Hoyser 1974; Schultz and Smith 1974), although somewhat less robustly. In this case, the C/O measurement in a sandstone reservoir was a direct measure of oil saturation (a similar equation exists for limestone):

\[ So = 1.24 \cdot \frac{(1 - .37 \cdot \Phi) \cdot \frac{Yc}{Yo}}{\Phi \cdot \left(\rho_{hc} - .78 \cdot \frac{Yc}{Yo}\right)} \]

where \( \rho_{hc} \) is the hydrocarbon density, and \( Yc/Yo \) is the measured ratio of the carbon and oxygen yield. The odd numerical coefficients in this equation arise from the relative atomic densities for carbon and oxygen in the materials in the reservoir. Service providers use several different methods for extracting \( Yc/Yo \) from the spectrometric measurements, which are not described further in this paper.

In recent decades, the need to determine gas saturation has become increasingly important (Badruzzaman et al., 2007) and several schemes have been explored to determine it. Eq. 2 can be expanded to include a gas term:

\[ \Sigma_{fl} = (1 - So) \cdot \Sigma_{g} + So \cdot \Sigma_{o} + Sg \cdot \Sigma_{g} \]

where \( Sg \) and \( \Sigma_{g} \) is the gas saturation and capture cross section, respectively. Plugging this into Eq. 1 and solving for \( Sg \):

\[ Sg = \frac{\Sigma_{\text{log}} - (1 - \Phi) \cdot \Sigma_{ma} - \Phi \cdot A}{\Phi \cdot (2g_{g} \cdot \Sigma_{w})} \]

The primary problem in using only PNC logging to obtain \( Sg \) is that the term in the numerator of Eq. 6 contains \( So \), which would have to be provided from some other source. For situations in which the formation water is fresh (\( \Sigma_{w} - \Sigma_{o} \),
there is little or no contrast between $\Sigma_{\text{g}}$ and $\Sigma_{\text{w}}$ (the fourth term goes to zero), and then:

$$S_{g} = \frac{\Sigma_{\text{log}} - (1 - \Phi) \cdot \Sigma_{\text{ma}} - \Phi \cdot \Sigma_{\text{w}}}{\Phi \cdot (2g - \Sigma_{\text{w}})} \tag{7}$$

However, even if the formation water is saline, in principle, $S_{t}$ could be determined by Eq. 4 [i.e., C/O logging] and used in Eq. 6. However, Badruzzaman et al. have raised issues with this; fundamentally, there are too many poorly known inputs.

Recently, techniques for quantifying gas saturation directly were proposed (Inanc et al., 2009) and demonstrated successes (Ansari et al., 2009; Zett et al., 2011). These gas saturation estimates are based on calibrated gamma count ratios that have traditionally been applied as qualitative indicators for gas zones. An algorithm using these ratios is constructed to match known gas saturation, based on a great deal of field data and lab and/or modeling measurements, with a strong emphasis on the latter because high-pressure gas cannot readily be used in lab formations. Accurate computer modeling and modern computer speed are essential in making these step changes from qualitative indicators to quantitative estimates. Unfortunately, these ratios involve two gamma detectors at different source-to-detector spacings. The measurements are sensitive to both hydrogen index and bulk density (thereby, rock lithology). Without fundamental improvements in tool physics, lithology effect has been reported to be strong on gas saturation interpretation (Inanc et al., 2009).

This paper reports a new technique for direct gas saturation determination, which is based solely on count rates from a single gamma detector. With the long-spacing detector of the MDPNT (Guo et al., 2010), the measurement sensitivity is optimized. This new technique has been tested in several North America tight-gas reservoirs (Wyoming, Rocky Mountain, and South Texas). One recent commercial application was monitoring gas cap expansion in mature oil reservoirs. In collaboration with operators, these logging data and interpretation workflow will be published in the near future. This paper focuses on explaining the details of tool physics, its application for gas saturation determination, and interpretation uncertainties. This paper presents simulated logs with model and laboratory data.

**SATG Physics**

With a PNT, 14MeV source neutrons interact with the surrounding medium to produce gamma rays. These gamma counts are tallied by detector(s) in both time and energy domains. The measurement of gamma rays provides useful information about rock properties, such as hydrogen index, bulk density, and lithology.

The neutrons emitted by a neutron generator go through a chain of stochastic scattering events until they are captured. Two statistically dominant scattering events are inelastic scattering and elastic scattering. When these high-energy neutrons are scattered by the nuclei of heavier earth elements, such as oxygen, silicon, and calcium, an inelastic reaction may occur, as shown in Fig. 1. The red circle in Fig. 1 indicates the spherical virtual source for inelastic gamma rays. Some of these inelastic gamma rays are tallied in detectors, with particular time and energy. A simplified gamma transmission efficiency model is characterized by exponential attenuation, as in Eq. 8, in which $N_{\text{in}}$ is the inelastic count rate, $\rho$ is formation density, $\mu$ is formation mass attenuation coefficient, and $L_{\text{in}}$ is the attenuation distance between the red circle and a single detector.

$$N_{\text{in}} = A_{\text{in}} e^{-\rho L_{\text{in}}} \tag{8}$$

Probabilistically, when high-energy neutrons scatter with a lighter earth element, such as hydrogen, the energy loss is large. Eventually, the neutron energy decreases to below one electron volt. These low energy neutrons have high likelihoods of being captured by formation nuclei. The blue circle in Fig. 1 indicates the source size for capture gamma rays. Similarly, Eq. 9 characterizes the exponential attenuation process for capture gammas.

$$N_{\text{cap}} = A_{\text{cap}} e^{-\rho L_{\text{cap}}} \tag{9}$$

The effects of hydrogen index on $N_{\text{in}}$ and $N_{\text{cap}}$ are complex. The greater the hydrogen index, the smaller the source sizes, and therefore, the longer the attenuation distances. This causes both $N_{\text{in}}$ and $N_{\text{cap}}$ values to decrease. However, the greater the hydrogen index, the smaller the formation density. This causes both $N_{\text{in}}$ and $N_{\text{cap}}$ values to increase. These two effects compete against one another as the hydrogen index varies from 0 (zero porosity rock) to 1 (water).

As shown in Fig. 1, the source-size difference between red circle and blue circle is a primary driving factor for the ratio between $N_{\text{in}}$ and $N_{\text{cap}}$ (RIC). As the detector-to-neutron-source distance increases with the long-spacing detector of MDPNT, the measurement sensitivity to hydrogen index is further enhanced, whereas rock lithology sensitivity is reduced. This statement is based on the observation that the average gamma transmission efficiency becomes similar, at a long SD spacing, between inelastic gamma and capture gamma during the transport from the edge of capture area to the detector. This theory is supported by laboratory measurements. These data are documented after the introduction of the new SATG concept.

Although RIC at a long-spacing detector optimizes the hydrogen index measurement with a much reduced lithology effect, this ratio is affected by other rock and fluid properties and logging environments. One of the most influential fluid properties is formation water salinity. Capture counts from a single gamma detector are sensitive to formation water salinity; however, inelastic counts are not as much affected. This leads to strong formation salinity dependence with RIC, regardless of detector spacing. Without additional technical improvements, the formation water salinity poses practical interpretation difficulties for reservoirs with unknown formation water salinity. Unknown formation water salinity is often the case with mature fields that have been water or steam flooded. Even with new
well developments, accurate formation water salinity is required to minimize uncertainty.

A customized processing algorithm was developed to overcome this potential limitation. As illustrated in Fig. 2, the capture gate is partitioned into fast and slow components. The inelastic gate overlaps with generator neutron pulses, and is most sensitive to rock density. The ratio between the inelastic gate and the slow capture gate is the saturation gate (SATG). As shown in Table 1, SATG laboratory measurements show no difference between 150 kppm of formation water salinity change, whereas the RIC value changes dramatically.

The new tool was tested in the rock laboratory, and lab data were carefully acquired to support the theory for SATG. As shown in Fig. 3, SATG measurements are reported for limestone rocks and sandstone rocks. In Fig. 3, the SATG measurement with long-spacing detector at 3 ft is indicated in red; the blue color is labeled SATG’, for which the SATG processing algorithm was applied with far-spacing detector at 2 ft. Squares indicate data points taken in limestone rocks, and circles indicate data points taken in sandstone rocks. The laboratory measurements cover porosity ranges of 18 to 45 pu. The SATG dynamic range is significantly improved by more than 40% from 2-ft to 3-ft spacing. The lithology effect is indicated by the separation of sandstone measurements (circles) from the limestone measurements (squares and lines). In terms of porosity units, SATG shows less than 3 pu separation, whereas the SATG’ at far-spacing detector shows more than 6 pu separation.

**SATG Saturation Analysis**

For reservoirs with gas in the pore space, the hydrogen index (HI) is a function of gas saturation. The larger the gas saturation, the smaller the HI value. For example, in a 10 vpu sandstone reservoir, the HI value reads 0.093 for water saturation of 90 su, whereas the HI value is 0.060 for a water saturation of 40 su. With this HI contrast, SATG is well suited for direct estimations of gas saturation.

To determine the gas saturation from a SATG log, a fan chart is used. Fig. 4 presents a SATG fan chart for a completion geometry with 6-in. borehole and 4.5-in. casing. Two lines in the fan chart are computed by MCNP (Briesmeister 2000). The x axis of the fan chart indicates the porosity input. The blue line indicates SATG responses for 100 su liquid HI, similar to water. The red line indicates the SATG response for 100 su gas. The logging measurements of SATG fall within the fan chart. The gas saturation is computed with an interpolation scheme.

Fig. 5 shows a simulated log example to illustrate SATG and its statistical uncertainty (STUN_SATG) in both tight sand and porous sand. Track 1 shows the volumetrics for model inputs. The strata of sand and clay were simulated. Two sandstone porosities were modeled, 30 pu for the top sand and 10 pu for the bottom sand. For each sand zone, gas/liquid contact was set to be in the middle of the 400-ft sand. Track 2 displays the far-spacing capture counts (red solid line) at 2 ft and near-spacing capture counts (blue dashed line) at 1 ft. This presentation has traditionally been used as qualitative gas indicators. With a proper log scale, the far-capture count rates exceed the near-capture counts in gas zones. When these two counts rates overlay in a porous liquid zone and hydrogen-rich clay zones, a tight liquid zone may show a small gas signature, as shown between depths 6,800 and 7,000 ft.

Track 3 presents SATG (red solid line) and STUN_SATG (blue dashed line) curves. The measurement dynamic range is excellent, as compared to statistical uncertainties. The SATG response swing from 100 su gas to 100 su liquid represents the measurement dynamic range. For both tight and porous sands, the dynamic

![Figure 2. SATG processing.](image)

![Figure 3. Laboratory data points with MDPNT in limestone and sandstone rock comparing 2-ft and 3-ft detectors.](image)

![Figure 4. An example fan chart for SATG saturation interpretation. This data was modeled for a well with 6-in./4.5-in. completion geometry. The scale is chosen to accommodate other fan charts with different completion geometries.](image)

![Figure 5. A simulated log example for SATG and statistical uncertainty STUN_SATG.](image)

<table>
<thead>
<tr>
<th>RIC</th>
<th>SATG</th>
</tr>
</thead>
<tbody>
<tr>
<td>33 pu sand w FW</td>
<td>1.7</td>
</tr>
<tr>
<td>33 pu sand w 150 kppm SW</td>
<td>3.1</td>
</tr>
</tbody>
</table>
range is more than 50%. For this porosity range, the statistical uncertainty STUN_SATG is approximately 1%. Combining the dynamic range and statistical uncertainty, the gas saturation interpretation error is less than 2 saturation units.

**Salinity Effects**

The formation water salinity effect is minimized for the SATG saturation analysis. This complements Sigma saturation analysis for reservoirs with low porosity and/or with low/unknown formation water salinity. Two simulated log examples are presented in this section to illustrate the dynamic range and interpretation uncertainty for SATG and Sigma saturation analysis.

**Fig. 6** shows a simulated log example for 30 pu sand located between two clay strata of 30 cu Sigma. Formation water salinity was chosen to be 40 kppm. Compared to 260 kppm for full salt saturation, this water salinity is low. Similar to Fig. 5, Track 1 presents the volumetrics with gas sand on top of wet sand. Track 2 presents the Sigma response. Track 3 displays the SATG and STUN_SATG curves.

First, the Sigma dynamic range is 8 cu. This is low in comparison to 50% of the SATG ratio swing. With 0.5 cu as a fair estimate for Sigma uncertainty, the Sw uncertainty from Sigma is 8 su, compared to 2 su for SATG saturation analysis.

Secondly, the clay effect is potentially larger for Sigma saturation analysis. The Sigma contrast between the clay response and wet sand is as significant as that for gas and water in clean sand. When the sand zone is shaly, the interpretation accuracy may be dominated by clay volume uncertainty.

For 30 pu sand, 20 kppm formation water salinity change leads to approximately 2.2 cu Sigma change. For Sw estimates, this causes a difference of approximately 25 su. For SATG saturation, 20 kppm formation water salinity variance does not affect the interpretation at all.

For 10 pu tight sand, **Fig. 7** presents a simulated log with the same presentation template as Fig. 6. It is clear that the SATG analysis significantly improves the measurement dynamic range. For 20 kppm of formation water salinity change, Sigma changes by 0.7 cu. This also leads to an approximate 25 su Sw uncertainty. The SATG interpretation, however, is not affected at all. **Table 2** summarizes these results.

**Borehole Washout Effects**

The borehole effect on SATG response is significant. A fan chart is presented in **Fig. 8** for 12-in. bit size and 9¾-in. casing completion. A comparison between Fig. 8 and Fig. 4 shows that the fan charts are significantly different. With accurate computer modeling, the SATG saturation analysis provides adequate results from small to large boreholes with either single-casing completion or dual-casing completion. To address the concern of SATG analysis uncertainty for washouts, a model was run by adding 1-in. washout to the log example presented in Fig. 5. **Fig. 9** compares the SATG response with and without the 1-in. washout. The green dashed line in Track 3 represents the SATG response with the washout. In comparison to the red solid line, the SATG dynamic range is slightly narrower.

**Table 2.** Sw interpretation results from 20 kppm formation water salinity uncertainty, comparing Sigma and SATG saturation analysis. Formation water salinity is 40 kppm.

<table>
<thead>
<tr>
<th></th>
<th>Sigma Sat (su)</th>
<th>SATG Sat (su)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 pu sand</td>
<td>50±25</td>
<td>50</td>
</tr>
<tr>
<td>30 pu sand</td>
<td>50±25</td>
<td>50</td>
</tr>
</tbody>
</table>

**Figure 6.** A simulated log example for SATG and Sigma saturation analysis for 30 pu sand with low formation water salinity (40 kppm).

**Figure 7.** A simulated log example for SATG and Sigma saturation analysis for 10 pu sand with low formation water salinity (40 kppm).

**Figure 8.** An example fan chart for SATG saturation interpretation. This data was modeled for a well with 12-in./10-in. completion geometry.

**Figure 9.** A simulated log to illustrate 1-in. washout effect for SATG saturation analysis.
The statistical code was run to estimate $S_w$ uncertainty attributable to a 1-in. washout. For 10 pu tight sand, the $S_w$ uncertainty was near 10 su; for 30 pu porous sand, the $S_w$ uncertainty was near 4 su.

**Porosity Error Propagation**

As previously described, rock porosity is an input parameter for the SATG saturation analysis. It is important to understand how the errors in porosity estimates are propagated in the SATG saturation analysis.

A statistical code was used to combine STUN_SATG and a 1% porosity error. Two scenarios were simulated. The first scenario is for a 10 pu sand with 50 su gas and 50 su liquid. The second scenario is for a 30 pu sand with 50 pu gas and 50 pu liquid. Table 3 shows the results. For the 10 pu sand, the $S_w$ estimates showed approximately 10 su uncertainty as a result of a 1% porosity error. For 30 pu sand, a 5 su $S_w$ uncertainty was observed. The smaller saturation uncertainty at higher porosity can be attributed to a wider dynamic range between the gas line and liquid line, as shown in Fig. 4. An additional contributing factor is that the liquid line is less steep at a higher porosity.

A similar code was applied to a Sigma saturation analysis with two scenarios, one with low formation water salinity and one with high formation water salinity. Tables 4 and 5 show the results.

**Conclusion**

The SATG log, implemented in the MDPNT, is developed with basis on new perspectives of fundamental nuclear physics. The advantage is optimizing the dynamic range for hydrogen index sensitivity, whereas the measurement sensitivity for lithology is reduced. STUN_SATG provides a measure of uncertainty for the SATG log. A SATG fan chart is enabled by accurate computer modeling and fast computer speed. Combining the SATG log with an accurate fan chart, the SATG saturation analysis provides gas saturation estimate for tight reservoirs with statistical uncertainty of 2 saturation units.

The SATG log is much less sensitive to formation water salinity as compared to Sigma. The saturation interpretation model using SATG holds significant potential for porous reservoirs with low or unknown water salinity.

A preliminary study was performed for porosity error propagation. Based on this study, the SATG saturation analysis is less subject to porosity errors than Sigma for low formation water salinity environment. For high formation water salinity environment, these two perform similarly.

The SATG log is sensitive to completion geometry. An MCNP computer model provides well-specific interpretation fan chart. The interpretation uncertainty from modest amount of washout is approximately 10 su.

| Table 3. SATG saturation interpretation results from 1% porosity error. |
|---------------------------|-----------|
| Porosity (pu) | $S_w$ (pu) | Range |
| 10 pu sand | 10±1 | 42 to 61 |
| 30 pu sand | 30±3 | 47 to 55 |

| Table 4. Sigma saturation interpretation results from 1% porosity error, for reservoirs with low formation water salinity. |
|---------------------------|-----------|
| Porosity (pu) | $S_w$ (pu) | Range |
| 10 pu sand | 10±1 | 31 to 73 |
| 30 pu sand | 30±3 | 41 to 61 |

| Table 5. Sigma saturation interpretation results from 1% porosity error, for reservoirs with high formation water salinity. |
|---------------------------|-----------|
| Porosity (pu) | $S_w$ (pu) | Range |
| 10 pu sand | 10±1 | 39 to 63 |
| 30 pu sand | 30±3 | 44 to 58 |
Authors

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Larry Jacobson joined Halliburton Energy Services in 1984 and is a member of the Physics Team. He holds a PhD (1969) in nuclear physics from the University of Wisconsin. Before joining Halliburton, he spent 15 years with Schlumberger, where he specialized in pulsed neutron logging and held several managerial positions. Larry holds 13 patents and is the author of numerous technical papers covering pulsed neutron capture and spectrometry logging, cased hole density modeling and log-filtering techniques. He is a member of the American Physical Society, SPWLA and SPE.

Dennis Durbin is a Principal Scientist with the Nuclear Physics team. He holds a BS degree in computer science and a minor in math (1982, University of Houston). Dennis worked briefly with the Dresser Titan Division, where he was involved with development of fracturing software. He joined Halliburton in December 1982 as a member of the Research department doing software development for the Nuclear and Electromagnetic teams.

References


Production Array Logs in Bakken Horizontal Shale Play Reveal Unique Performance Based on Completion Technique

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Abstract
ConocoPhillips drilled and completed three horizontal wells in the Bakken Shale, North Dakota in 2010; these wells contained between 33 and 40 stages. The lateral of each well consisted of a hybrid design using sliding sleeves in the toe-most half of the well and plugs/perforations for the heel-most half. Multiple completion techniques were pumped in an alternating pattern throughout the plug and perforation section of each well, and production array logs were deployed on coiled tubing in an attempt to determine fracture design best practices.

As one of the key parameters to horizontal well performance in the shale plays, fracture performance evaluation becomes the main objective. The flow contribution from each fracture stage was first determined from array production log interpretations in terms of the in-situ productivity index, which became the basis for fracture stage performance analysis. This paper also includes a discussion of the challenges associated with understanding the multiphase fluid flow behavior in horizontal wells. The subsequent analysis of fracture performance was performed to relate the in-situ productivity index with other well parameters, such as well trajectory, fracture method, fluid and reservoir information around the well and the mud log information during drilling. Oil, gas, and water rates were generated for each stage and correlated to completion technique.

The final analysis was aimed to answer some of the questions about how certain fracture stages performed better in comparison to others. This analysis includes identifying parameters in favor of increasing fracture performance and defining the steps needed to deal with the challenges related to the geological nature of the field. The information from this integrated evaluation result was then used to define a better strategy to improve the well performance in the future drilling campaign and to optimize the commercial value of the field.

Introduction
ConocoPhillips has actively implemented new technology in McKenzie County and Dunn County, North Dakota, to improve the recovery of hydrocarbons from the Middle Bakken formation. A project consisting of three horizontal wells was completed in this formation utilizing a hydraulic fracturing application. The project wells included the Aiden 31-13H, the Amanda 21-14H, and the Jorgenson Federal 44-9H, which are concentrated in the central part of the Bakken Field. All three wells were targeted toward the middle Bakken member.

As part of an effort to maintain continuous improvement in well deliverability and hydrocarbon recovery, several fracturing methods were implemented in such a way that will enable us to study and define the most appropriate method for each one of them. Three methods were implemented over different fracture stages for each well. The first two methods implement low and high proppant volumes over a single pumping schedule. The third method uses a two-stage pumping schedule with higher proppant volume. The results from the various fracture methods were measured using an array production logging tool, and through an interpretation process the flow contribution from each fracturing stage was defined.

The results from the production logging interpretation were used to generate the correlations among various well parameters and their contributions to the deliverability of the well. This review incorporates the data from fracturing, fluid rates from production logging, mud logs, and other geological data.

The summary of the evaluation is presented in terms of how each parameter influences the productivity index of the fracturing stages. Several different correlations between parameters are also presented for all the wells under evaluation.

Formation Evaluation
Lithology Summary. The lithology for the reservoir is predominantly defined using the three wells, Jorgenson Federal 44-9H, Amanda 21-14H, and Aiden 31-13H. All three wells are located in the northwest part of the Rockin AMI in Township 148N, Ranges 97 & 98. The wells basically lie along an east-west line as shown in Fig. 1.

The rock properties at the well locations are quite different from one another. The Aiden 31-13H well shows the best productivity of all. Based on the mud log data, the following properties can be summarized for the three wells:

- Coarser and cleaner reservoir for the Aiden 31-13H well, as compared to the other two wells
- Continuous gas reading (hydrocarbon content) throughout the section and higher reading in the Aiden 31-13H well
- The mud log data showed good intercrystalline porosity, which will help to improve the flow capacity of the well before and after (especially in the Aiden 31-13H well). This crystalline porosity is classified as secondary porosities, which might not be connected; however, the presence of hydraulic fractures will connect them and turn these non-connected pores into additional secondary permeability.

The drilling data indicates that the three wells have clear differences in ROP recordings during drilling. The Aiden 31-13H well seems to have high ROP values, which may indicate more porous rock, and the Amanda well having the hardest rock, as shown in Fig. 2.

Regional Stress Orientation. The well productivity in shale plays relies heavily on both hydraulic and natural fractures, which are influenced by
the major stress direction. As shown in Fig. 3, the major stress in this field is in the northeast-southwest direction.

The north-south well orientations are at an angle with the fracture direction (NE-SW), which will promote good fluid flows from the fracture system into the wellbore. In addition, the hydraulic fracture systems were also generated as a stimulation package during well completion.

Frac Method and Execution
Fracture Interval. The fracture interval was determined with an objective to establish above average economic production from the Middle Bakken formation through hydraulic fracture stimulation using 24-hour operations.

For the Aiden Federal 31-13H well, the job used a 33-stage fracture, consisting of 17 sliding sleeve stages and 16 perforated stages, to provide discrete exit points along the liner to facilitate improved coverage across the producing interval. The Amanda Federal 21-14H and Jorgenson

Federal 44-21H wells used a 40-stage fracture consisting of 20 sliding sleeve stages and 20 perforated stages. In all three wells, the sliding sleeve stages were located in the toe half of the lateral and the perforated stages were located in the heel half of the lateral. Only the perforated stages were considered for this evaluation due to coil tubing reach limitations.

Wellbore. The wellbores consist of 7-in. casing set and cemented with a 4\(\frac{1}{2}\)-in. uncemented liner run set in the Middle Bakken formation. Isolation between stages was achieved through the use of swellable packer. The horizontal sections of wellbore diagram (Fig. 4) show complete horizontal well configuration.

A sequence of three different fracture methods were implemented across the fracture stages in the Aiden 31-13H, Amanda 21-14H, and Jorgenson 44-9H wells. The different fracture methods consist of “hesitation” and “non-hesitation” methods and variations in the proppant volume (Fig. 5 a, b, c). The two-stage pumping schedule, also called the hesitation stage, has a time lag between the first and second halves of the proppant volume injection.

A variation is also applied in stage length (distance between packers) on the Aiden 31-13H, as shown in Fig. 5d. The data for stages 1 through 23 are not included because individual fracture production is not covered by the production log.

Production Log Evaluation
Production Contribution from Each Fracture Stage. The array production logging tool was used to quantify the fluid flow contribution from each fracture stage along the horizontal well. The approach uses the concept of layered fluid flow in a horizontal pipe in which the heavier fluid flows underneath the lighter fluid. This evaluation method is also called the cross-sectional segregated flow model.

As with any other interpretation of logging data, there are some challenges in interpreting array production logging in horizontal wells, including multiphase flow, multiple entry point, and low rate from each stages, as well as low well production rate.
The primary objective for production log interpretation for these three wells was to determine the fluid rate for each phase flowing from each fracture stage using array production tool sensors, including fullbore spinner, array spinner, radioactive density, gas holdup tool, capacitance water holdup tool, capacitance array tool, and array resistivity tool. In addition, pressure and temperature logging tools were also included in the package to complement the interpretation at different pressures and temperatures within the wellbore.

The tool string for production array logging illustrating the position of spinner, resistivity, and capacitance sensors is shown in Fig. 6.

The basic calculation performed for this interpretation is the in-situ fluid rate for each phase, calculated in Eq. 1.

\[ \sum_{i=1}^{180} Q_i = \sum_{j=1}^{5} V F_{ij} \times A_{ij} \times Y_{ij} \]  

(1) (Frisch et al. 2009a)

Where:
\[ Q_i = \text{Phase flow rate (water, oil and gas)} \]
\[ V F_{ij} = \text{Layer velocity} \]
\[ A_{ij} = \text{Layer area} \]
\[ Y_{ij} = \text{Layer fluid holdup} \]

The cross section flow is divided into 180 slices of multiphase segregated flow. The fluid flow phases generally are water, oil and gas. The velocity profile in the cross section is derived from the six-arm sensor circumferential Spinner Array Tool (SAT) by calibrating spinner revolutions to fluid flow velocity. The vertical interpolation is applied from six spinner measured data to whole layer velocity profile in the cross section and the same method is applied for the layer fluid holdup. The fluid holdup profile in the cross section is derived from two fluid holdup tools: the capacitance array tool and resistivity array tool, which both have 12 circumferential sensors.

The values of velocity and fluid holdup for each horizontal layer are used to calculate the fluid rate for each layer. Later, the sum of these 180 layers is generated to represent the value for the entire cross section for each fluid phase.

Layer Fluid Velocity Calculation (VF). The numbers 1 to 6 refer to the spinner sensor positioned around the perimeter of the tool. This design is intended to measure the fluid velocity around the pipe, rather than only at the center.
The cross-sectional fluid velocity was calculated from the array spinner measurement through spinner calibration by cross plotting spinner revolutions per second (RPS) vs. cable speed. The calibration slope is derived from the line regression of the cross plot. The data points were generated from the selected calibration zone by cross plotting between the spinner reading on the Y axis and the cable speed (logging speed) on the X axis. Fig. 8 shows the continuous fullbore spinner calibration from the PL survey on the Aiden well.

**Fluid Holdup Calculation (Y).** The fluid holdup profile in the cross section is derived from the combination of the capacitance array and resistivity array data.

The layer water holdup computed from resistivity array tool through Eq. 3:

\[
Y_w = \frac{(R_i - m)^2}{(R_i - m)^2 + S^2}
\]

Where:
- \(Y_w\) = Water holdup
- \(R_i\) = Apparent resistance of the insulating fluids (hydrocarbon)
- \(m\) = Mean value
- \(S\) = Standard deviation

The fluid holdups for oil and gas were derived from the capacitance array tool with predefined water holdup input from the resistivity array tool. The oil and gas water holdup was computed based on the three-point calibrations for the capacitance tool for water, oil and gas are 50 cps, 150 cps and 200 cps respectively.

The constraint for the total fluid holdup is defined in Eq. 4:

\[
Y_w + Y_o + Y_g = 1
\]

Where:
- \(Y_w\) = Water holdup
- \(Y_o\) = Oil holdup
- \(Y_g\) = Gas holdup

Table 1 lists the PL analyses results from the combined data of CAT-RAT-SAT for the three wells.

**Well Production Data and Productivity Review.** The correlation among the three wells in this evaluation focuses primarily on the well productivity and its parameters for each fracture stage using the fracture job data, production log,
**Table 1a.** Production rate contribution from each stage on the Aiden 31-13H

<table>
<thead>
<tr>
<th>Inflow Zone #</th>
<th>Stage #</th>
<th>From R</th>
<th>To R</th>
<th>Water STB/D</th>
<th>Oil STB/D</th>
<th>Gas MSCF/D</th>
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</thead>
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**Table 1b.** Production rate contribution from each stage on the Jorgenson Federal 44-9H

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<th>Inflow Zone #</th>
<th>Stage #</th>
<th>From R</th>
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<th>Water STB/D</th>
<th>Oil STB/D</th>
<th>Gas MSCF/D</th>
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**Table 1c.** Production rate contribution from each stage on the Amanda 21-14H

<table>
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<th>Inflow Zone #</th>
<th>Stage #</th>
<th>From R</th>
<th>To R</th>
<th>Water STB/D</th>
<th>Oil STB/D</th>
<th>Gas MSCF/D</th>
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<td>TOTAL</td>
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<td>169</td>
<td>1774</td>
<td></td>
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</tr>
</tbody>
</table>

The productivity index used the rates of each fracture stage calculated from the production log analysis with the following equation:

$$PI = \frac{Q_{sc}}{\text{Pres} - P_{wf}}$$

Where:

- $Q_{sc}$ = Fluid rate at surface condition calculated from production log analysis
- $P_{wf}$ = Downhole flowing pressure measured by the pressure sensor
- Pres = Reservoir pressure

### Well Correlation Case Studies

**Evaluation of Results.** The parameters evaluated for the productivity index optimization include the following:

- Lateral placement and mud log data for gas reading and lithology (qualitative view of the formation)
- Stage volume
- Flush volume
- Hesitation effectiveness (single vs. dual stage pumping)
- Stage length (distance between packers)

The fracture type from a certain fracture method was determined by the combination of various fracturing job parameters. The productivity trend demonstrated by the different fracture type is very clear in Aiden 31-13H; the other two wells have slightly distorted patterns as a result of inferior reservoir quality. This may be a result of inferior rock properties from the mud log data. The rock properties in the other two wells showed lower gas readings and ROP during drilling. They also contain less intercrystalline porosities, which can be connected by fractures.
Fig. 10 provides detailed information about the productivity index for each stage and classifies the wells in accordance to fracture type. The relationship between the fracture type and PI shows a specific pattern for the Aiden 31-13H well, but is not so clear for the other two wells as a result of inferior rock properties. Three fracture types were defined from slurry/proppant volume, pumping schedule for the proppant, and pumping rate variation.

The color codes of fracture methods shown in Fig. 10a through Fig. 10c include the following:
- Dark Green: fracture method 1, single-stage pumping and a high slurry volume.
- Blue: fracture method 2, single-stage pumping and low slurry volume.
- Red: fracture method 3, dual-stage pumping schedule “hesitation” and high slurry volume.
- Orange: fracture method 4, dual-stage pumping schedule, high slurry volume, long-stage length.

Lateral Placement and Mud Log Data/Gas Reading. Stage placement within the lateral shows a strong correlation with Productivity Index. As seen in the Aiden 31-13H (Fig. 11a), stages placed toward the top of the Middle Bakken target (shown in red) consistently show the strongest PI while stages placed lower in zone (shown in green and black) had lower PI results. This trend can also be observed on the Jorgenson Federal 44-9H and to a lesser extent on the Amanda 21-14H (Fig. 11b,c). The Aiden 31-13H shows more intervals with gas readings higher than background gas, compared to the Amanda and Jorgenson wells. This gas reading is in line with the evident of higher productivity index calculated for the Aiden 31-13H well.

Stage Volume. Alternating stage volumes along the lateral were designed to determine if larger stage volumes yield higher production rates. In Fig. 10 a-c, blue bars indicate stages with small (approximately 50,000 lb of proppant) volumes and all other colored bars indicate stages with large (approximately 100,000 lb of proppant) volumes. In general, smaller stages performed worse than larger stages, especially when compared in a stage-by-stage basis going along the length of the lateral. Exceptions arise when the stages lie toward the top of the Middle Bakken target and in those cases outperformed some of the larger volume stages placed lower in target.

Flush Volume. Flush volumes from the three wells indicate that over flushing reduces the productivity index to some degree. Stages 27 through 30 in the Jorgenson Federal 44-9H well shows over flush accompanied by a low productivity index for the stages. A similar situation existed in stages 23 through 28 in the Amanda 31-13H well, with relatively high flush volume and lower productivity index (Fig. 12a - Fig. 12c). The general trend correlation between flush volume and productivity index is inversely proportional.

Hesitation Effectiveness. A hesitation stage, or pumping two discreet proppant ramps in the same stage with a 30-minute shut down in between ramps, is a method for increasing...
hydrocarbon recovery that dates back to 1977 (Kiel). Every fourth stage on the Jorgenson Federal 44-9H and Amanda 21-14H was pumped as hesitation stages and every other stage on the Aiden 31-13H was a hesitation stage. Since all of the non-hesitation stages on the Aiden were of smaller volume, the results from that well cannot be used to evaluate hesitations. Focusing on the Jorgenson and the Amanda, the hesitation stages performed equally well with non-hesitation stages with approximately the same overall proppant volume.

Stage Length. The stage length was varied for Aiden 31-13H (Fig. 13). This was done to evaluate if hydrocarbon recovery would be reduced with closer stage spacing. The distance between packers on stages 26 and 30 was spaced to be 450’ (versus 225’ for all other stages) and all stages in the Aiden were alternated between small volume stages and large volume hesitation stages (Fig. 5c). As seen in Fig. 10a, the longer stages in the Aiden had PIs significantly lower than the stages with shorter spacing. The stage lengths for the Jorgenson Federal 44-9H and Amanda 21-14H were approximately the same.

Figure 11b. Mudlog showing lateral placement for Amanda 21-14H.

Figure 12a. Effect of over flush on productivity.

Figure 12b. Effect of over flush on productivity.

Figure 12c. Effect of over flush on productivity.

Figure 13. Cross plot of productivity and fracture length.
Conclusion
This integrated evaluation resulted in the following conclusions based on limited petrophysical evaluation:

- Lateral placement within Middle Bakken had the strongest correlation to productivity index. Stages placed in the upper portion of the Middle Bakken exhibited the best production.
- Larger proppant volumes injected in the stage generate higher productivity index than smaller volume stages.
- Hesitation stages yielded similar results as non-hesitation stages of the same overall volume.
- Increasing the stage length (distance between swell packers) decreased the productivity index when bounded by shorter stages.
- Over flush during fracture reduced the productivity index of the well.
- A correlation exists between gas reading and productivity index of the associated frac stages of the well.
- The array production logging tool was useful for evaluating the production performance of individual fracture stages. The fluid profile in a horizontal well is stratified, with heavier fluid flows on the low side and lighter fluid flows on the high side. The array tool measures the fluid speed across the area of the pipe using six spinner sensors, as opposed to the standard tool with one sensor in the middle, which will provide a more accurate measurement of fluid rate in the flow cross section.
- Production logs provide only a snapshot in time of the well performance. Consequently, for best results, multiple logging runs over a greater time span are recommended.

Acknowledgements
The authors thank the management of ConocoPhillips and Halliburton for their support and approval to publish this paper.

References


Advancing the Use of Rapid Time-Lapse Shear-Wave VSPs for Capturing Diffractions from Hydraulic Fractures to Estimate Fracture Dimensions

Mark Willis, Donghong Pei, and Arthur Cheng, Halliburton; Xinding Fang and Xuefeng Shang, MIT Earth Resources Laboratory

Presented at the 74th EAGE Conference & Exhibition Incorporating SPE EUROPEC 2012 Copenhagen, Denmark, 4–7 June 2012.

Abstract
Microseismic monitoring of hydraulic fracturing treatments is currently the primary method for accessing the lateral and vertical extent of each fracture stage. However, this only reveals the location where rocks are breaking and/or where existing faults have been reactivated. The previously published Lost Hills Field hydraulic fracture experiment demonstrated that scattered (diffracted) shear waves off fluid-filled hydraulic fractures can be almost as large in amplitude as the incident wave field, but diminish as the fluid pressure drops and the fracture stiffens. Based upon that study, as well as our modeling results, we propose a hydraulic fracture monitoring program consisting of quickly repeating a series of shear-wave VSPs at a small collection of shot points immediately after each fracture stage. The field data suggests the scattered energy from the fractures in previous stages will not interfere with the later stages as they will have stiffened up and not scatter energy. A series of migrated images is created after each fracture stage, where the output image plane is defined by a fit through the microseismic events. Thus the extent of the scattered shear-wave energy, i.e., the dimension of the fluid-filled fracture, can be visualized on these images.

Introduction
Unconventional resource plays typically require a cost-effective hydraulic fracturing program to create economical reservoir permeability. The primary method available for gauging the success of the treatment is to record and locate the microseismic events that are induced during the program. Microseismic events occur where the rock is breaking or slipping on existing faults. However, it may not necessarily reveal where the fracturing fluid and proppant are being injected. It is the goal of this paper to advance creating complementary information to the microseismic data to answer this question.

An intriguing data set was acquired by Chevron in the Lost Hills, California field (Meadows and Winterstein, 1994). As shown in Fig. 1, they placed a surface shear-wave source (near Well 11-10X), which was 287 m from the head of the 1-88 Well containing a single level, 3-component geophone near the bottom of the well. About midway between the source and receiver, and about 30 m off line, was Well 12-10 in which three stages of hydraulic fracturing were performed. Immediately after each fracture stage was completed and the pumps were shut off, they energized the shear-wave source at about every 15 minutes and captured the seismic energy with the monitor well geophone. They detected significant changes in the XX component — defined by the shear-wave source shaking orthogonal to the plane containing the source and receiver.

The right panel in Fig. 1 shows the time-lapse waveforms for Stages 2 and 3. They were created by subtracting the last waveform (labeled the Incident Wavelet) recorded about 3 and 2 hours, respectively, after pumping stopped, from each of the other traces in that stage. They found that immediately after the pumps shut off (for elapsed times less than about 45 minutes) large scattered signals are observed that decay with each subsequent measurement as the fluid pressure drops and the fractures close. Liu et al. (1997) performed Kirchhoff-based forward modeling to estimate the fracture dimensions from this data set.

Figure 1. Left – profile view of Lost Hills acquisition geometry. Right – time-lapse waveforms for Stages 2 and 3 of hydraulic fracturing from Lost Hills. (Modified from Meadows and Winterstein, 1994, used with permission.)
What seems important to take away from these studies is that the fluid-filled fracture forms a strong shear-wave scatterer, which diminished in effectiveness as the fluid pressure drops and the fracture stiffens. By collecting several time-lapse measurements and looking for systematic temporal trends, we remove the sensitivity to noise, and therefore the ambiguity, from a single time-lapse measurement. It also appears that after the fluid pressure has dropped, the scattering from the previous fracture stage is not detected in the subsequent stage. In this paper we explore how this type of time-lapse shear-wave VSP set of measurements could be used to identify the location and extent of the fluid-filled fractures. First we use a 3D elastic finite difference modeling code to simulate a reservoir. Then we use a prestack migration methodology to image the fracture plane.

Numerical Model-Based Study
The Chevron study used a single surface shear-wave source and a single-level geophone located below the reservoir. Here we propose to use a small number of shear-wave sources spaced strategically to illuminate the lateral extent of the hydraulic fracture, as shown in the left panel of Fig. 2. The blue star indicates the location of a monitor well, and the Xs denote the location of shear-wave sources. The magenta line shows a location of a horizontal treatment well with an induced fracture indicated by the black line.

We also propose to use multiple levels of 3-component geophones in the monitor well, as in a typical VSP or microseismic monitoring configuration. While desirable, in practice it is frequently difficult to place a geophone in and below the reservoir level because an existing producer may be used as the monitor well and thus the reservoir level may be isolated by a packer.

We created a 3D elastic model representing the general characteristics of the Marcellus shale in Bradford County, Pennsylvania with 64 horizontal layers. A portion of the P (blue) and S (red) wave velocity logs are shown on the right of Fig. 2. We omitted from the model the first 300 m of depth, so that the upper and lower Marcellus units in our model are between 1549 and 1645 m depth. We created two velocity models – one with a single fracture (shown in Fig. 2) and one without any fractures. The fracture is 200 m in total length in the north direction, and 44 m in height. In our numerical simulation, we use Schoenberg’s (1980) linear-slip fracture model where the thickness of a fracture is assumed to be infinitely small and its elastic property is described by the fracture compliance. In the finite difference model, the material in the single grid cell wide fracture is replaced by an equivalent medium, which represents a fluid-filled fracture (c.f. Coates and Schoenberg, 1995; Nihei et al., 2000; Willis et al., 2006).

We use a version of the MIT Earth Resources Lab 3D, elastic finite-difference modeling program to generate the synthetic wave field (Fang et al., 2010). The code is a standard staggered grid scheme with 4th order accuracy in space and 2nd order in time with the Convolution Perfectly Matched Layer absorbing boundary conditions. A directional shear-wave source was simulated by using a 40 Hz Ricker wavelet, point force oriented at an incline to vertical, first in the east direction, and then in the west direction. The difference of traces from these two simulations emulates a surface shear-wave source with polarized particle motion in the east/west (x) direction.

The right side of Fig. 2 shows a zoom in of the x component of velocity, Vx, of the model with the fracture for the monitor well receivers at depths between 600 m and 1800 m, spaced every 20 m. The green line shows the depths of the top and bottom of the fracture. The shot location is the red x and the monitor well is the blue star in the left side of Fig. 2. Next to the Vx record is the Difference record showing the subtraction of the corresponding traces from the model with and without the fracture. The Difference record has had gain applied to emphasize the scattered energy.
Fig. 3 shows a zoomed-in view of the snapshots of the difference plots showing the scattered seismic energy off of the fracture plane at a depth level above the fracture. Thus we see that there is scattered energy, which is propagating upward and away from the fracture on all three components, even though the source energy is excited in the X (east/west) direction. This may be from both back scattering (upward), and forward scattering (downward), which is then reflected off the deeper layer boundaries. The red dots on the Difference plot in Fig. 2, describe the minimum and maximum arrival times of shear energy back scattered upward off the fracture in a first arrival (minimum time) sense.

Using a migration method similar to Willis et al. (2009) for P waves, Fig. 4 shows the Kirchhoff prestack depth migrated image created using the shear-wave Vx difference traces from the five shots shown in Fig. 2. Only the depths of the geophones above the reservoir (shallower than 1550 m) were used in the migration. With even this limited number of shots, we were able to create an image, which brackets the fracture height and width. The result using an additional five infill shots did not significantly change this image.

**Discussion and Conclusions**

The Lost Hills hydraulic fracture experiment demonstrated that scattered shear-waves off fluid-filled hydraulic fractures can be almost as large in amplitude as the incident wave field, but diminish as the fluid pressure drops and the fracture stiffens. Based upon that study, as well as our modeling results, we propose a hydraulic fracture monitoring program consisting of quickly repeating a series of shear-wave source points immediately after each fracture stage into a monitor well with a VSP configuration of geophones. The field data suggests the scattered energy from the fractures in previous stages will not interfere with the later stages as they will have stiffened up. Only a limited number of surface shots locations for each stage would be practical due to the operational difficulties with shear-wave sources. The microseismic event locations can be used to define a migration imaging plane to capture the fracture dimensions, since attempting a full 3D migrated volume would likely be resolvable.

Of critical importance for the success of this proposed methodology is the determination of acquisition parameters required to generate significant amounts of shear-wave scattering from a fluid-filled fracture and an easily deployable shear-wave source. Scaled physical model studies (e.g., Stewart, et al., 2010; Blum et al., 2011) are demonstrating significant scattering from laser-induced features resembling fractures. Using tools like the numerical modeling we performed for the Marcellus field and the theoretical studies shown in Meadows and Winsten (1994) and by Liu et al. (1997), additional criteria upon which to design these surveys are becoming available. A field test of this methodology should be acquired utilizing the advancements in VSP technology that was unavailable for the original Lost Hills Field study.
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References


Petrophysical Evaluation for Enhancing Hydraulic Stimulation in Horizontal Shale Gas Wells

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Abstract
The economic recovery of gas from shale reservoirs requires optimal multistage hydraulic stimulation in horizontal wells. Important parameters to consider in shale-gas evaluation include gas-filled porosity and total organic content. Mechanical rock properties, including a calculated brittleness index, along with mineralogy, are also required to target and design individual horizontal fracture stages in the best zones. This type of formation evaluation in horizontal wells requires careful correlation and calibration to petrophysical measurements obtained in either vertical pilot holes or direct offset wells. This paper presents a comprehensive approach to the evaluation of an unconventional resource play drilled in the Haynesville Shale in east Texas.

Using openhole and logging-while-drilling (LWD) logs, conventional core analysis, and a chemostratigraphy analysis of drill cuttings, a shale analysis linking mineralogy, free gas, effective porosity, a shale brittleness index, and a clay linked transverse anisotropy is verified on separate vertical and horizontal control wells. Beyond that, pulsed neutron spectroscopy logs were run to develop a cased-hole evaluation solution from N-N (neural network) modeling that could replicate openhole wireline or LWD logs, and chemostratigraphy mineralogy results.

Subsequently, two horizontal wells were logged with LWD tools and afterward, through casing, using the pulsed neutron log and neural network calibration. Fracture stages for the logged horizontal wells were then evaluated vs. the log data. Generally, lower normalized treating pressures per fracture stage are noted where lower clay volumes exhibit less transverse anisotropy and a higher calculated shale brittleness index. Radioactive tracer and production log data also confirm lower amounts of gas production from zones that are apparently fractured, but are more ductile and clay-rich.

Introduction
The Haynesville Shale is a black, organic-rich, shale that covers Caddo, Bossier, De Soto, Red River, and Bienville parishes in north Louisiana and primarily Harrison, Panola, Shelby, and San Augustine counties in east Texas. The depth ranges from approximately 10,300 ft in the northwest part of the play to approximately 14,000 ft in the southeast. The Bossier Shale lies above the Haynesville Shale; the Haynesville Lime or Smackover Lime lie below it throughout the area. Both of these formations can be drilling targets, but the Haynesville Shale is of special interest because of generally thicker net pay and higher reservoir pressure with a gradient between 0.85 and 0.9 psi/ft. Varying depositional environments have left the shale with a thickness that varies between 80 and 350 ft, and facies that vary between a calcite-rich shale with little clay to a silica-rich shale with large amounts of bedded clay and lesser amounts of calcite (Parker et al., 2009).

Advanced evaluation suites can provide an abundance of reservoir information. The primary purpose is resource identification and a calculation of original gas in place. However, new formation analysis and presentation techniques are required for a comprehensive mechanical description of this shale to select an optimum horizontal target (Rickman et al., 2008; Mullen et al., 2007). Subsequently, the same type of information can be used to select and design optimum fracture stages along the horizontal well. Currently, a few operators are beginning to log their horizontal wells, but are not using any log data to strategically locate or plan the horizontal fractures. The current completion practice is still evolutionary because more fracture stages per lateral have achieved better results as more surface area is contacted. Perforation clusters and spacing per fracture stage have been increased or decreased, depending on whether at the location or on the operator. The one constant is that fracture treating pressures and rates, depending on job design, all indicate serious stratigraphic formation differences that must be accounted for. Post-fracture production data also supports the assertion that there are significant geologic differences to be recognized along the horizontal well, even when it has been successfully geosteered. A step change in horizontal estimated ultimate recovery (EUR) can be made only if we better understand the rock that is actually being stimulated per individual fracture stage.

Methodology
Several representative vertical Haynesville Shale wells were cored and logged in Rusk, Harrison, and Panola counties in east Texas by BP America in 2009 as part of an exploration program to determine best opportunities and practices for their initial horizontal program within the play. These wells are known to exist within the boundaries of a more clay-rich, but thicker Haynesville Shale package that is much less homogeneous than its north Louisiana counterpart (Parker et al., 2009). Challenges exist in east Texas to optimize and understand the mechanisms for increasing gas production in a more challenging facies that leaves little margin for error.

A complete reservoir characterization was attempted on the vertical wells, using full core analysis (including X-ray diffraction (XRD), inductively coupled plasma (ICP), and stress testing), laser-induced breakdown spectrometry (LIBS) chemostratigraphy elemental analysis of cuttings calibrated to core mineralogy, geochemical log analysis calibrated to core mineralogy, three-dimensional mechanical elastic properties analysis, and a PNS log for through-casing neural net evaluation calibration. One of the objectives was to obtain a brittleness index (Rickman et al., 2008), a function of Poisson’s ratio and Young’s modulus (Fig. 1), to determine if it could help quantify areas within which fracture conductivity is easier to achieve.
neural net calibration to openhole data. Hole logging consisted of PNS with subsequent geochemical, and cross dipole sonic logs. Cased-dipole sonic, wireline conveyed triple combo, included both vertical LWD triple combo and chemostratigraphy calibration. Openhole logging cored and sample cuttings were caught for data set for analyses. The well was full is provided as the most complete petrophysical described. The BP Glaspie #10 in Panola County data to the full blown analysis, as previously evaluation, ranging from standard triple combo exploited for various levels of formation Several vertical wells, old and new, were evaluated, conclusions drawn, and water rate had been established. Results 45 days of cleanout after a stable gas and Post-fracture production logs were run within 220,000 lb of 40/80 hydroprop per fracture stage. attempt to place 80,000 lb of 100 mesh sand and fairly generic water fracture design was used to per cluster. Whether or not the fracture is optimized for this shale can be debated, but a evenly generic water fracture design was used to attempt to place 80,000 lb of 100 mesh sand and 220,000 lb of 40/80 hydroprop per fracture stage. Post-fracture production logs were run within 45 days of cleanout after a stable gas and water rate had been established. Results were evaluated, conclusions drawn, and recommendations proposed. Vertical Well Calibration

Several vertical wells, old and new, were exploited for various levels of formation evaluation, ranging from standard triple combo data to the full blown analysis, as previously described. The BP Glaspie #10 in Panola County is provided as the most complete petrophysical data set for analyses. The well was full cored and sample cuttings were caught for chemostratigraphy calibration. Openhole logging included both vertical LWD triple combo and dipole sonic, wireline conveyed triple combo, geochemical, and cross dipole sonic logs. Cased-hole logging consisted of PNS with subsequent neural net calibration to openhole data.

Core XRD Lithology: A full core was acquired and an XRD analysis was performed. The matrix was dominated by calcite, quartz, illite, chlorite, and mixed layer illite-smectite clay. The volume of clay minerals as a percentage of the total matrix averages more than 30% for the whole core. This amount of clay will limit the effective gas-filled porosity of the shale and should make the shale softer and more ductile with a higher Poisson’s ratio.

Figure 1. Crossplot of Young’s modulus and Poisson’s ratio showing the brittleness index increasing to the southwest corner of the plot.

A pre-horizontal-drill study of the core and cuttings from the Glaspie #10 was conducted on ICP-optical emission spectroscopy/mass spectrometry (ICP-OES/MS) instruments to establish a chemostratigraphic zonation for the interval of interest. The resulting data was then used to calibrate the LIBS instrument for the wellsite application for future horizontal real-time cuttings analyses. In shales, and in particular shale gas plays, the chemostratigraphy helps to unravel the interplay of detrital, carbonate, and organic minerals with the paleoredox environmental proxy elements (nickel, vanadium, cobalt, molybdenum, and uranium) providing valuable clues as to the highest total organic carbon (TOC) values and the potential sweet spots to target. LIBS data acquired from the cuttings while drilling enables immediate correlation to the chemostratigraphic zonation, improves the knowledge of the stratigraphic location of the wellbore, and enables the adjustment of the wellbore (geosteering or Chemosteering®) as desired. The same elemental data can be used to accurately predict mineralogy through robust empirical modeling, which initially is ideally verified against mineralogy derived from the XRD analysis.

Geochemical Analysis – Neutron Activation Spectroscopy. Fourteen separate elements (hydrogen, carbon, oxygen, magnesium, aluminum, silicon, sulfur, chlorine, potassium, calcium, titanium, manganese, iron, and gadolinium) were measured using a state-of-the-art neutron activation spectroscopy tool (Galford et al., 2009) which was run in combination with a standard spectral gamma ray measuring elements potassium, uranium, and thorium. Using the same XRD and ICP data from the full core that was used to calibrate the LIBS chemostratigraphic analysis, oxides closure models were verified and 40 elements can be acquired for most shales and lith arenites (including rare earth elements and other low-abundance trace elements). Data for 15 to 30 elements can be obtained for less complex lithologies, such as quartzose arenites and clean carbonates. The identification of laser-pulse parameters to optimize the spectral response for a wide range of elements and the application of non-standard mathematical processing to extract the greatest number of elementals, at good accuracy and precision from a single spectrum, proved pivotal to the successful application of the LIBS technique.

BP Glaspie GU#10 Core XRD Results

Figure 2. Full core XRD results, BP Glaspie #10.

Geochemical Analysis – Sample Cuttings.

LIBS is a versatile analytical technique used for the real-time acquisition of elemental data on drilling rigs (Dix et al., 2006). The LIBS instrument is compact, portable, and well suited to the analysis of drilled cuttings, enabling results to be immediately applied to decision-making for drilling operations. A sample preparation is relatively simple and rapid, with data generated within 30 minutes. Robust data for more than 14 separate elements, at good accuracy and precision from a single spectrum, proved pivotal to the successful application of the LIBS technique.
calibrated for the neutron activation spectroscopy tool to convert the elemental data into actual dry weight minerals (Fig. 3).

A multimineral analysis was subsequently performed using the geochemical processed mineralogy. Wet rock volume fractions of quartz, calcite, dolomite, illite, chlorite, and sodium feldspar (plagioclase) were solved for. Separate uranium and rhob relationships were developed to match kerogen volumes to core that resulted in an accurate TOC (Total Organic Carbon) estimate. A bulk fluid analysis using n=1.6 and n=1.9 in the saturation equation best matches the core-derived gas volume (Fig. 4).

Core Stress Analysis and Integration. Single-stage triaxial compression tests were performed on multiple as-received shale samples on vertical, deviated, and horizontal samples at in-situ stress conditions. These triaxial compression tests were performed at room temperature with the pore pressure drained to atmospheric pressure. Dynamic mechanical properties were also simultaneously obtained using ultrasonic wave transmission tests. These tests enabled comparisons to be made between dynamic and static moduli (Fig. 5).

Laboratory testing, as shown in Table 1, indicates that the Young’s modulus value is greater when measured horizontally than vertically, whereas the Poisson’s ratio value averages slightly less measured horizontally than vertically. This significant transverse anisotropy (Fig. 6) observed in the Young’s modulus can be classified as shown in Eq. 1:

\[ \Delta \text{YME}_{\text{TIV}} = \frac{\text{YME}_{\text{HORIZ}} - \text{YME}_{\text{VERT}}}{\text{YME}_{\text{VERT}}} \times 100 \]  

This \( \Delta \text{YME}_{\text{TIV}} \) term quantifies the percentage increase in the horizontal Young’s modulus over the vertical. A crossplot of this anisotropy term with differing minerals reveals that this anisotropy can be modeled as a linear function of clay volume (Fig. 7).

This clay effect serves to increase the minimum horizontal stress required for hydraulic fracture initiation and for subsequent treating pressures by increasing the \( E_h/E_v \) term in the stress equation (Eq. 2).

\[ \sigma_x \propto \frac{E_h}{E_v} \left( \frac{V_x}{1 - V_h} \right) \sigma_v \]

Pulsed Neutron Spectroscopy Calibration of Triple Combo Neural Net Model and Subsequent Shale Analysis. The technique used to convert primary pulsed neutron data to openhole triple combo data through the application of neural net processing is well understood (Chen et al., 2004). This technique has been applied successfully in varied lithologies and mechanical configurations around the world since 2005. Of particular interest were a series of more than 300 vertical Mancos Shale wells logged in the Rocky

![Figure 3. Comparison of LIBS chemostratigraphy and neutron activation spectroscopy mineralogy results when compared to XRD mineralogy. Left to right: quartz (yellow), sodium plagioclase (dark blue), illite (grey), chlorite (green), calcite (light blue), dolomite (pink), and pyrite (red).](image)

![Figure 4. BP Glaspie #10 geochemical neutron activation spectroscopy data calibrated to core mineralogy and core gas porosity.](image)

![Figure 5. Static Young’s modulus vs. dynamic Young’s modulus for Haynesville Shale core in BP Glaspie #10.](image)

![Figure 6. Visualization of 3-dimensional stress tensors demonstrating transverse horizontal anisotropy as a result of layering.](image)
Mountains between 2006 and 2007, in which the cased-hole pulsed neutron N-N modeling process completely replaced conventional openhole logging. When it became apparent that operators in more recent geopressed shale plays, particularly the Haynesville and Eagle Ford Shales, were reluctant to obtain horizontal logs as a result of perceived high risk and expense, a proven, reliable cased-hole alternative was available for application.

The calibration process consists of training the pulsed neutron N-N model defined for a particular casing and hole size, to an already acquired openhole data set. A minimum data set is defined, such as deep resistivity, neutron porosity, and bulk density, but it also can include photoelectric absorption (PEF) and compressional sonic (DTC). Vertical openhole wells usually provide the broadest range of environmental training, but a horizontal LWD data set or drillpipe-conveyed conventional logs in the horizontal well are also acceptable. After the model has been developed for the hole size and casing size configuration, it can be applied to any PNS tool logged in a well with the same configuration. Generally speaking, the N-N model should be re-verified whenever moving to an area with a significant change in lithology. Practically speaking, this usually means another shale basin entirely. The applied N-N model typically must be checked for high-low endpoint calibration of both density and neutron output to the nearest vertical control well around a particular basin. This is accomplished by a crossplot analysis of the correlated vertical target interval data to the data from the horizontal N-N modeled triple combo. Sometimes the N-N model is very precise, but it usually benefits from a two-point normalization routine, at least for bulk density and neutron porosity.

The capture elemental spectrum lithology has recently become the logging standard because of its enhanced logging speed. A basic mineralogy interpretation, consisting of total clay, silica, and calcite, is readily achieved (Jacobson et al., 1998). In addition to the calcite and silica, a potassium yield is also available, but its resolution in the pulsed gamma spectrum is better suited for use as a quality check of areas showing higher total clay.

As described in the discussion about the Glaspie #10 core, a great deal of analyses focus on examining the differences in vertical vs. horizontal shear anisotropy when predicting an accurate stress model for fracture stimulation. Not surprisingly, those studies demonstrate that the total clay volume makes a large contribution to variations observed between vertical and horizontal shear measurements. Consequently, an accurate total clay estimate is indeed important to any evaluation, but we need to be careful because there may be other bedding in lower clay intervals that could also influence horizontal anisotropy.

A method of quantifying shale ductility is required to target those intervals containing the best free gas that have the opportunity for complex fracture generation for surface area drainage. A discreet function of Poisson’s ratio and Young’s modulus, a brittleness index, was developed and implemented (Rickman et al., 2008). The use of a best source dipole shear and a gas-corrected compressional velocity is required to calculate this index.

When a sufficiently large database of vertical dipole information is acquired in an area, such as the BP east Texas acreage, neural net modeling of synthetic DTC, DTS, Poisson’s ratio, and Young’s modulus can proceed from standard triple combo data and at least a three-component lithology model consisting of clay, calcite, and silica (Buller et al., 2010). Synthetic correlations of Young’s modulus are usually very robust and Poisson’s ratio is acceptable if the calculation is constrained by the analyst, using standard deviation analysis, to maintain the synthetic Poisson’s ratio within an accepted envelope for a particular shale type (Fig 8).
A pulsed neutron spectroscopy (PNS) log was run and calibrated to the openhole raw logs on the BP Glaspie #10 (Fig. 9). This Carthage field well suffered from severe washouts in the lower Bossier Shale and at the transition between the Bossier Shale and the Haynesville Shale. The effect on the neutron-density data quality was quite pronounced. The subsequent neural net modeled triple combo resulted in a much-improved log that was unaffected by the openhole washouts that had compromised stress calculations between the two shales.

A complete shale analysis was performed on this neural net and lithology processed PNS data (Fig. 9). The PNS clay, silica, and calcite percentages closely correlate with the core XRD (Fig. 2) and the geochemical processing from the openhole neutron activation analysis (Fig. 4). The upper 25 ft between 10,625 and 10,650 ft appears to be the best target interval for fracturing, but it is at the top of the gas shale column. An alternate target at +/- 10,690 ft could be proposed with some associated risk because of the varying amounts of more ductile clay both above and below that depth. Horizontal stratigraphic variations in clay deposition are noted in that part of the play. By this analysis, the Haynesville Shale averages one-third clay, one-third calcite, and one-third silica at this location. This finding is clearly supported by the full core analysis.

LIBS Chemostratigraphy Prediction of Relative Brittleness. Because the hardness or brittleness of a rock is, to a large degree, controlled by its mineralogy, it is possible to model a relative brittleness index (RBI), which can assist in assessing the fracturability of a rock. Brittleness is controlled by a combination of the relative abundance of carbonate and quartz compared to the clay content. The Haynesville Shale is typically more dominated by carbonate than by silica (quartz), but the BP Glaspie #10 demonstrates fairly equal volumes of all three (Fig. 10). The RBI, as calculated from the LIBS chemostratigraphy data, has been modified to take into account the relative effect of carbonate on brittleness in the Haynesville Shale. Each proxy element is multiplied by a brittleness coefficient (Eq. 3 & 4) which accounts for the mineral mechanical properties, mineral grain to grain relationships (texture), and overall mineral distribution in the rock (fabric). This data was collected by thin section analysis performed on the Glaspie #10 core.

Horizontal Well Application

The two horizontal wells drilled and evaluated for this paper are the BP T.W. George A9H located in the Blocker field, Harrison County, Texas and the BP CGU 13-17H located in Carthage field, Panola County, Texas. Both wells had vertical pilot wells (Fig. 11) immediately adjacent; consequently, the initial lateral control was perceived to be good. The George A8H (vertical pilot to horizontal George A9H) is deemed to be more homogeneous regarding a fairly constant 30% clay volume; the CGU 13-17H clearly indicates widely varying amounts of clay through the vertical section.

T.W. George A9H Horizontal Placement.
A horizontal trajectory traversing the lower Haynesville Shale A, all of the Haynesville Shale B, and the very upper Haynesville Shale C was selected for this well. A 4,300-ft lateral was drilled and correlated, as shown in Fig. 12. The entire horizontal well was deemed to be drilled on target. A complete horizontal evaluation was performed on this well, and all lessons and calibrations from the vertical wells were applied.

T.W. George A9H Horizontal Shale Evaluation. Real-time LIBS chemostratigraphy data was acquired using sample cuttings caught every 20 ft while drilling the well. At total measured depth, an LWD logging suite, consisting of resistivity, density, neutron, and dipole sonic, was run as a continuous wiper pass coming out of the 6½-in.
we will realize that the compressional waves in the horizontal scenario, shown in If we consider the acoustic wave propagation changing formation effects. The slower shear demonstrates two seems relatively featureless when compared to the slow shear. The slower shear demonstrates a lot of character that is obviously responding to the slow shear trying to travel through them.

Consequently, when searching for the best zone in which to fracture, we should look for both the fastest y-direction velocities, because they are the most brittle, as well as the fastest of the z-axis velocities because they will be most likely to enable the fractures to propagate and remain open (producing). A simple ratio of the semblance processed slow and fast shear velocities should provide a robust method for quantifying these horizontal TIV anisotropy effects. A low TIV ratio (DTS slow/DTS fast) should equate to a higher brittleness index. A higher TIV ratio should equate to a more ductile zone with a lower brittleness index.

Figure 12. BP T.W. George A9H correlated 4,300-ft lateral path within the Haynesville Shale. Green numbered fracture stages were considered successful with proppant placed. Stage 5 screened out with no placed proppant.

Figure 13. T.W. George A9H, acoustic slowness semblance plot from LWD dipole sonic. Because the synthetic Poisson’s ratio and Young’s modulus (from density, neutron, and lithology data) in the shale analysis are calibrated to vertical dipole sonic logs, it is safe to assume that they are, at best, an estimate of an averaged closure stress answer along the horizontal tunnel with no TIV anisotropy effect applied. If you know, or can directly measure with an LWD imager, the local formation dip along the horizontal well, you could calculate a corrected horizontal fast shear and vertical slow shear for computation of horizontal vs. vertical Poisson’s ratios and Young’s moduli. If you have this level of horizontal anisotropy data, the brittleness index should be calculated from the corrected slow shear data. This would guide the completion into areas that could achieve the best potential fracture height growth and stimulated reservoir volume from the point of fracture initiation.

Even if you do not have accurate formation dip data, a technique is proposed and used to combine the benefits of the calculated TIV ratio and the brittleness index because they are from separate log measurements. A relative fracture ratio (BRIT index/TIV ratio) is calculated that essentially increases or decreases the BRIT index based on the amount of TIV layering effects sensed by the horizontal dipole. This ratio is then rescaled as a FRAC Index between zero and one. The idea is that the intervals with the highest FRAC Index should be targeted for perforating and fracture initiation along the horizontal well. They will also be the intervals with the best probability of maintaining fracture conductivity over the life of the well because they should provide the best chance for width, complexity, and less fines embedment over time.

LIBS Chemostratigraphy Results. The LIBS relative brittleness calculation (Fig. 15) compares very favorably with the brittleness index calculated from the shale analysis using conventional logs (Fig. 16).
All logs indicate varying amounts of clay between 25 and 40% (Fig. 16). The lower porosity zone located halfway down the lateral is shown to be partially dolomitized by the LIBS data and is a suspected sequence boundary between the Haynesville A and the Haynesville B zones. Even with the clay volume, the effective porosity is still quite good at an average of 7%. The calculated brittleness index varies with the clay volume, and the fracture ease calculated from the brittleness index shows no obvious overly ductile interval that would warrant avoiding.

The TIV ratio is plotted next to the brittleness index, and a Frac Index is calculated using both as inputs. The bright green coded Frac Index highlights the best opportunity for creating fracture conductivity along the horizontal well. Crossplots of clay volume and TIV ratio (Fig. 17) clearly confirm in the results of the surface core mechanical anisotropy measurements made earlier by BP. There is no attempt to quantify the horizontal vs. vertical Young’s modulus and Poisson’s ratio without proper geometry information, but the relative magnitude of the TIV ratio is enough to begin a robust analysis. Clay volume is also directly linked to the brittleness index, and the brittleness index to TIV ratio determined anisotropy.

T.W. George A9H Fracture Stimulation

Without using any of the acquired horizontal well evaluation data, the well was subsequently completed using 10 separate fracture stages with perforations equally spaced every 110 ft along the horizontal well. Each stage had four sets of perforations with 12 shots per cluster. As described in our test methodology, each fracture stage was designed as a generic water fracture attempting to place 80,000 lb of 100-mesh sand and 220,000 lb of 40/80 hydroprop (Fig. 14). All stages pumped to completion, as designed on this well, except for stage #5 which screened out early. Stage #5 has a relatively low computed Fracture Index compared to the rest of the well and is demonstrating an elevated clay content.
(Fig. 16). Both may help to explain the proppant placement failure.

Horizontal production log profiling confirms a disturbing finding that has long been suspected. On average, only two sets of perforations per fracture stage are actually contributing any appreciable gas, which leads to a suspicion that there are sound mechanical reasons to perforate areas of highest brittleness and lower TIV anisotropy effects to achieve better post-fracture fracture conductivity.

Although all stage perforations are not contributing, or some potentially not fractured, almost all proppant was placed in every stage on this well (except stage 5). Good gas is associated throughout the Haynesville A, B, and C zones. The relatively constant and lower clay volume below ±10,600 ft suggests a zone of interpreted optimum fracturability in red. Note the drill time change and temporary mud log suppression at 10,630 ft at the base of the target window.

Figure 16. Baseline display of Section 13-17H, Panola County, Horizontal Placement. The vertical control well identified a target in the lower Haynesville A interval that had the potential, with fracture growth upward, to contact slightly better rock by brittleness index analysis. An LWD quad-combo (with dipole sonic) and horizontal PNS log were run on this well for fracture planning and diagnostic purposes. In the end, the well evaluation was more of a correlation tool that highlighted the difficulty of effectively fracturing a well that is drilled too near, and in and out of, a claystone facies.

Figure 18. Pipe and perf friction normalized rate and treating pressure plot for BP, George A9H.

CGU 13-17H, Panola County, Horizontal Placement. The vertical control well identified a target in the lower Haynesville A interval that had the potential, with fracture growth upward, to contact slightly better rock by brittleness index analysis. An LWD quad-combo (with dipole sonic) and horizontal PNS log were run on this well for fracture planning and diagnostic purposes. In the end, the well evaluation was more of a correlation tool that highlighted the difficulty of effectively fracturing a well that is drilled too near, and in and out of, a claystone facies.

After the LIBS, LWD suite, and PNS were logged, evaluated, and correlated to the steering data, it became apparent that the well path had become stuck in the base or below the intended target window (Fig. 20). Below the window is a very ductile clay. Above the target interval is also a more ductile layer at ±10,600 ft. The vertical drill rate change and temporary mud log gas suppression at ±10,630 ft suggests a zone of radically different mechanical properties. It is this difference that probably steered the horizontal well low, and kept it there, more so than the directional drillers.

Based on what we now know, a target window at ±10,590 ft would have been a better option for this well. Part of the problem for the exploration team was working with openhole logs affected by significant tool pulls in the upper part of the shale on the vertical pilot hole.

Figure 19. BP CGU 13-17H vertical pilot shale analysis showing an area of interpreted optimum fracturability in red. Note the drill time change and temporary mud log suppression at 10,630 ft at the base of the target window. Effect Pressure (Pw-Ppf-Pf)

Figure 20. BP CGU 13-17H correlated 4,400-ft lateral path within the Haynesville Shale. Green numbered fracture stages were considered successful with > 70% of proppant placed. Red numbered stages placed less than 30% of designed proppant. Yellow stages placed between 30 and 70% of the proppant.

equal amounts of mineralogy, the RBI may be overly sensitive to small changes in calcite, demonstrating the difficult nature of interpreting a general claystone.

CGU 13-17H, Horizontal Shale Evaluation. The shale evaluation and TIV ratio analysis were performed in the same manner as the T.W. George A9H. A striking characteristic of this well is that when it became trapped below the primary target, the total clay increased to 60% or greater. A very large TIV anisotropy (because of the clay volume) would be expected across large sections of this well, and that is what was shown by the LWD dipole and PNS used to perform the analysis (Fig. 22).

The well shows wide variations in the brittleness index and TIV ratio because of high clay, the calculated Frac Index indicates that stimulation can be accomplished, but would require entry points at optimum spots and an entirely different type of fracture design. High rate water fractures are probably less effective in this environment. The more ductile claystones will absorb all proppant conductivity and limit height growth unless a hybrid crosslink gel is used to place larger proppant across the more vertical section. This strategy would also help to maintain near-wellbore conductivity over time. The best option in this type of well is to select target intervals with the most net feet of rock with similar mechanical properties. Rock with the least amount of clay, highest brittleness index, and

Figure 21. LIBS chemostratigraphy analysis of RBI; consistently high clay mudstone, CGU 13-17H.
The shale analysis clearly shows distinct lithology changes along the horizontal well that should be used to cluster similar types rock into separate fracture stages.

**CGU 13-17H, Fracture Stimulation.** No attempt was made to use the horizontal data to plan the fracture stages. The same 10-stage, equal distance perforation scheme, linear gel water fracture design used on the George 9H was also used on the CGU 13-17H. Very poor proppant placement was achieved as a result. The placed conductivity in this well was poor because of high clay by volume, insufficient conductivity in the proppant pack itself, poor initiation site selection, and fracture stages that straddled lithological boundaries. The actual normalized treating pressures of the CGU 13-17H during pad placement were lower (except for stage 3) than the those of the T.W. George A9H, but this difference was not related to placed conductivity. The proppant just cannot be effectively placed by a low viscosity fluid in a ductile shale (Rickman et al., 2008).

Production log results indicate relatively poor performance even when a majority of the proppant was placed in a particular stage. In addition, even more perforation clusters showed little or no gas entry post-fracture stimulation than the T.W. George A9H. This would indicate that a higher differential anisotropy between perforation clusters will be encountered when a horizontal well is drilled in predominantly a claystone rather, than in a more calcareous or silicious shale. For the most part, the zones generating the most gas correlate well to the intervals showing the highest calculated Frac Index on the analysis, even though most fracture stimulation stages straddle large variations of clay-filled lithology.

The most significant issue with the under-performance of the CGU 13-17H, is that this horizontal well really got caught traversing into a zone of varying amounts of clay immediately below the primary zone of interest. Afterward, by design, no attempt was made to actually use the well evaluation tools that were run to plan or design the fracture stimulation stages. The logs were designed to be used as a post-fracture production evaluation tool only.

**Fracture Stimulation Considerations and Recommendations for High-Clay Shales**

Based on the results of the two horizontal well completions examined in this paper, a review of more recent shale stimulation methodologies is warranted. A high-pressure, clay-rich, ductile shale, such as the Haynesville in east Texas, is now recognized as the toughest stimulation completion challenge in the industry.

Core experiments show that complex, narrow width fractures are initiated when there is high TIV anisotropy, whereas planar, wider fractures are initiated where the rock is more homogeneous (Warpinski et al., 2008). These results can be correlated to near-well fracture behavior, and are critical to proppant placement and gas production because higher clay systems have less-effective fracture conductivity, they are also most subject to high-pressure drawdown effects that cause proppant embedment by fines intrusion that seals off production. These clay-rich zones, even if they are not vertically persistent, still act as a near-well choke and must have higher proppant conductivity through which to deliver gas. These clay zones are also the most susceptible to pressure cycling effects that can cause even...
more embedment over time. In addition, smaller effective fracture widths in higher clay intervals are also more prone to post-fracture diagenesis cementing of the proppant pack because there is much less surface area to actually fill (Weaver et al., 2008). This aluminum-silicate cementing occurs under higher temperature and pressure conditions when high-strength proppants are not chemically neutralized by surface coating or manufacture design.

Conclusions
As shown through the extensive petrophysical evaluations performed, shales are neither isotropic nor homogeneous, and extensive core analysis is necessary to build any comprehensive log models. In the case of the Haynesville Shale in east Texas, total clay volume and clastic dilution of a normally calcareous shale can cause large swings in relative brittleness and ductility that must be accounted for in the horizontal wells. This is because horizontal completion efficiency is governed by both intrinsic heterogeneity (near-wellbore) and extrinsic stresses (far field) acting on the formation.

Various solutions for obtaining best estimates of basic mechanical properties along the horizontal well have been demonstrated. Because of the horizontal anisotropy layering effects, a premium solution exists by combining basic triple combo data with a dipole sonic tool. This can be achieved by either LWD acquisition in openhole or wireline conveying a PNS triple combo N-N surrogate and a X-Y cross dipole in cased hole. A standalone PNS log is a very cost-effective solution, but it can only obtain estimates of TIV anisotropy through its lithology estimates of total clay volume. LIBS chemostratigraphy of sample cuttings provides a very viable solution for either geosteering or post-well analysis because the relative brittleness index can be calibrated to the log measurements, but it may be overly sensitive to brittleness variations when there is actually very little variation in total amounts of clay, calcite, and silica volumes when drilling a predominantly claystone matrix.

Whichever horizontal formation evaluation solution is selected, the data acquired must be integrated into the completion design. The post-fracture production analysis suggest that shooting less perforation clusters per fracture stage may be possible if horizontal logs are used to optimally place those perforations for the highest stimulated reservoir volume. In this manner, depending on the lithology, or stratigraphic section encountered, more fracture stages could possibly be placed along most long-reach laterals. One glaring need, and something to seriously consider for future evaluation, is the hypothetical existence of pressure compartmentalization within the shale. If internal differential pressure gradients do exist, that would seriously support the idea of grouping individual perforation clusters and fracture stages into intervals of similar petrophysical properties.

Lateral placement rules will dictate all well performance. It is not possible to fracture from bad rock into good and expect that it will produce at high rates. A near-wellbore choke is caused by narrow width and tortuous fractures in clay-rich rock. In other words, if a well is landed in the wrong place, a 300,000-lb fracture stage will deliver less than 200 mcf/d. Pre-drill vertical formation evaluation must be pursued with diligence and then optimum horizontal geosteering technology used. Even if the wells are geosteered, they still must be logged for selecting optimum stimulation intervals.

Authors

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Nomenclature

DTC  Sonic delta-T compressional travel time
DTS  Sonic delta-T shear travel time
ICP  Inductively coupled plasma
LIBS Laser-induced breakdown spectroscopy
LWD Logging-while-drilling
MS  Mass spectrometry
N-N  Neural network
OES  Optical emission spectroscopy
PEF  Photoelectric absorption
PNS  Pulsed neutron spectroscopy
PR  Poisson’s ratio
RBI  Relative brittleness index
TIV or TI-V Transverse isotropic, vertical axis symmetry
XRD  X-ray diffraction
YM  Young’s modulus

References


**Real-time Mineralogy, Lithology and Chemostratigraphy While Drilling Using Portable Energy-Dispersive X-ray Fluorescence**

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**Abstract**

Our objective is to obtain — while drilling, in real time — a complete petrophysical characterization from drill cuttings and the return mud-stream. Currently such rock and fluid direct characterization is achievable only, with significant time delay and at a considerable cost, from measurements on cores. The approach is to integrate the direct measurements on cuttings with the Logging While Drilling (LWD) practices and tools, to support drilling, geosteering and formation evaluation.

In this framework, it is key to accurately characterize drilling cuttings from a mineralogical and lithological point of view. This characterization can be achieved performing an elemental analysis, by means of Energy-Dispersive X-ray Fluorescence (ED-XRF), in real time, with a portable instrument capable for use at the rig-site, integrated inside the mud logging operations.

The portable X-ray Fluorescence (XRF), coupled with a methodology that enables to convert the elementary analysis into a mineralogical composition, produces a characterization comparable to what can be obtained by full scale X-ray Diffraction (XRD) laboratory equipment.

An experimental set up was deployed, to assess the ability to model the mineralogy from geochemically analyses of a set of rock samples.

After portable ED-XRF geochemical analyses, further lab-based analyses were carried out on the same samples: laboratory Wavelength-Dispersive XRF (WD-XRF) and ED-XRF in state of the art facilities. The geochemical data from the portable ED-XRF were compared to the lab-based XRF results (both WD-XRF and ED-XRF) and showed good agreement, particularly between the two ED-XRF instruments. As a final result, the modeled mineralogy from geochemical whole-rock data showed good agreement with the mineralogy determined from XRD analyses. Finally, a first field geochemical monitoring, by portable ED-XRF while drilling, was then successfully executed in Saudi Arabia.

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**Introduction**

Saudi Aramco seeks a method/technique to determine the mineralogical composition of cuttings, in real time, at the well-site. A phased study was initiated to determine the feasibility and capability of Halliburton’s LaserStrat® portable elemental analysis technology.

This collaborative R&D consisted of a feasibility study on mineralogy modeling from geochemical data determined from cuttings while drilling. Earlier, Laser Breakdown Spectrometry (LIBS) was utilized in Saudi Arabia for chemostratigraphic analysis of rock samples. Although already identified as a more suitable alternative for uncalibrated analyses, the Energy-Dispersive X-ray Fluorescence (ED-XRF) instrument for geochemical analysis was only recently introduced to operations. The ED-XRF instrument has the advantage that it can produce good results on a general calibration. Though the LIBS instrument can analyze a higher number of elements and some elements in lower quantities in the given time-frame, it needs to run on a rock-specific calibration, making it more difficult to utilize it on “unknown” sample material, i.e., uncalibrated at the rig-site. The portable well-site ED-XRF technology was therefore identified as more suitable for an uncalibrated test. Mineralogy modeling was performed using a straightforward mineralogy model from ED-XRF determination.

The objectives for the validation project were:

- Demonstrate the portable ED-XRF abilities to provide accurate geochemical data from whole-rock analyses.
- Perform the analyses under well-site conditions, i.e., restricted time frame, instrument settings and equipment used.
- Execute the analyses in a blind test on sample material with unknown lithology, composition and origin.
- Demonstrate that the geochemical data can be used for modeling the mineralogy of the rock samples.

**Advanced Mud Logging**

While traditional mud logging techniques provide largely qualitative data, the objective of Advanced Mud Logging (AML) is to provide quantitative real-time measurements and information in aid of drilling and a complete formation evaluation. Hence, during the past few years in Saudi Aramco, various techniques that were previously limited to laboratories for cores have been adapted for well-site usage on cuttings. A systematic comparison of results between laboratory instrument and field version instruments proved that the quality of results is not generally compromised when applying these techniques at the well-site. At present AML well-site techniques include a whole range of petrophysical direct measurements on cuttings, such as density, porosity, NMR and spectral gamma-ray.
Real-time mineralogy, lithology, and chemostratigraphy while drilling, using a portable ED-XRF is part of the AML objectives.

This analysis complements a wider AML petrophysical characterization on cuttings and has the potential to support geosteering, drilling optimization and formation evaluation while drilling.

Laboratory Techniques

X-ray Fluorescence. X-ray Fluorescence (XRF) spectrometry is an analytical technique to determine the elemental composition of various materials. XRF has the advantage of being nondestructive, multi-elemental, fast and cost-effective. The principle of XRF spectrometry is sketched in Fig. 1. A sample is irradiated with a beam of high-energy X-rays. As the excited electrons in the sample fall back to a ground state, they emit X-rays that are characteristic of those elements present in the sample.

Elemental concentrations in unknown samples are quantified by comparing the X-ray intensities against known calibration standards. XRF techniques can be categorized into two classes: wavelength dispersive systems (WD-XRF) and energy dispersive systems (ED-XRF). WD-XRF uses a crystalline structure mounted on a goniometer (an instrument used to measure angles) to diffract X-ray photons of a selected wavelength/energy (much like X-ray diffraction). ED-XRF instruments are based on the detector system’s capability to determine the energy of the photons.

The elements that can be analyzed and their detection levels mainly depend on the spectrometer system used. The elemental range for ED-XRF goes from Sodium (Na) to Uranium (U). For WD-XRF it is even wider, from Beryllium (Be) to Uranium. The concentration range goes from parts-per-million (ppm) levels to 100%. In this study, for lab comparison and LaserStrat® validation, SPECTRO X-LAB 2000 ED-XRF and PHILIPS PW2400 WD-XRF systems were both used for elemental composition determination respectively. We used pellet samples of 4.4g for the XRF analyses (4g of each powder was mixed well and homogenized with 0.4g of binder - Licowax C micropowder PM).

Both techniques, ED-XRF and WD-XRF, detect fluorescing photons, but one measures the energy while the other measures the wavelength of the photons. However, WD-XRF is an optical system and thus less suitable for transport into rough environments such as drilling rigs.

X-ray Diffraction. X-ray diffraction (XRD) is an analytical technique for phase identification and quantification that looks at the X-ray scattering from crystalline materials. Each material produces a unique X-ray “fingerprint” of X-ray intensity versus scattering angle that is characteristic of its crystalline atomic structure. In this study, to validate the mineralogical model form a LaserStrat® PANalytical XPERT PRO X-ray diffractometer with Co Kα radiation (\(\lambda = 1.719\)Å) was used. A monochromator and a proportional detector were used in conjunction with a fixed 10 divergent slit, a 0.3-mm receiving slit, and a fixed 10 scatter slit at instrument settings of 40 kV and 40 mA. All bulk pellet samples were briefly disaggregated and lightly crushed in a mortar and pestle, and then back loaded by hand into sample holders and analyzed from 4-70° 2θ, using a step size of 0.02° and a count time of 0.5 second per step. To identify the phases present in the sample, the XRD pattern of the sample was compared with every calculated pattern in a database, which is from the International Center for Diffraction data (ICDD) Powder Diffraction File (PDF) – or ICDD-PDF – database containing 291,440 inorganic and organic substances entries. Using the search-match capabilities of XRD software JADE 8.0+ and the ICDD-PDF database, all phases present in the samples were identified. Rietveld refinement method (whole profile fitting) was used for quantification and results were normalized to 100%.

LaserStrat® Analytical Methodology

The Portable Energy-Dispersive X-Ray Fluorescence. The LaserStrat® well-site portable ED-XRF instrument (Fig. 2) is based on a SPECTRO XEPOS ED-XRF instrument with a special calibration toward whole-rock analyses. It performs a spectral scan of the samples, so it takes no longer to acquire data for 60 elements than to obtain data for 30 elements. However, to
generate data for some of the rare earth elements (REEs) and very low abundance trace elements, analytical times must be increased substantially to achieve the desired accuracy and precision.

Consequently, a balance needs to be found between the time taken to obtain data and the element array, data accuracy and data precision generated at well-site. The instrument was set up to reflect this balance with the analytical time being set at 20 minutes, which optimizes the accuracy and precision of the data acquired for the key chem stratigraphic elements, e.g., the major elements Al, Si, Fe, Ti, Mg, Mn, Na, Ca, K and P, S, and the trace elements, such as Cl, Cr, Mo, Nb, Rb, Sr, Th, U, Y, Zn and Zr, while minimizing the time to obtain these data.

All spectrometry techniques (ICP-OES, ED-XRF and LIBS) suffer to varying degrees from the matrix effect, which may reduce the accuracy and precision of the data, especially if trying to use a general calibration to analyze samples with very different matrices, such as carbonates and siliciclastics. Well-site ED-XRF instrument is specifically calibrated for carbonate and siliciclastic rocks holding data from more than 160 international and in-house standards in its calibration.

Sample Preparation and Measurement. The work included the geochemical analysis of 19 selected rock samples, representing a selection of carbonate and siliciclastic rocks, mainly derived from core plugs. It was initiated as a blind test — where the mineralogical composition of samples was kept undisclosed — during the execution of the analysis and mineralogical modeling.

The samples were provided in the form of pieces of core plugs and thus did not require the usual cleaning process as applied at the well-site (Fig. 3). Part of each sample (about 4g) was homogenized into a very fine powder using an agate pestle and mortar. Grinding takes between five and ten minutes, depending on lithology.

An XRF binder was mixed with the powered sample and pressed to form a pellet using a manual pellet-press. The grinding equipment and pellet die were cleaned with deionised water following the grinding of each sample to prevent any contamination. The pellet was then introduced into the portable ED-XRF instrument for analysis.

The utilized portable ED-XRF instrument can analyze rock samples for up to 40 geochemical elements depending on lithology. Its calibration has been further developed and refined. Samples were prepared and analyzed in a well-site setting with a restriction in analytical time of about 20 minutes per sample.

Mineralogical Modeling. Developing a general mineralogy model from elemental data is a challenging task, especially when elemental data such as C and H are not available to model CO/CO₂ and H₂O. An additional obstacle is when information on oxidation states of elements such as Fe and S is not available.

An assumption has to be made on which minerals are likely to be present in the sample. In Fig. 4 is reported the list of minerals determined through a combination of XRD and petrography on the samples and obtainable from the portable ED-XRF through modeling of elemental analysis.

![Figure 4. Minerals obtained through modeling of well-site portable ED-XRF elemental analysis.](image)

The mineralogy model algorithm is based on calculations from elemental data converted into molecular proportions. The moles are then assigned to particular minerals in a proprietary method. The model works in two directions depending on the main lithology type of the sample, i.e., carbonates/sulphates and siliciclastics.

The order of assigning moles to particular minerals is a crucial process, as particular elements are sourced in different minerals, which otherwise can be present in the same mineral assemblage and sample; e.g., K can originate from feldspar, illite, mica and others.

XRF cannot determine H or H₂O. Therefore, the mineralogy model cannot distinguish between anhydrite and gypsum or illite and mica, which are chemically very similar. XRD analysis encounters similar difficulties, as for instance, the illite and mica peak in the spectrum appear at the same position. This problem was solved through petrographic study which identified mica. With this information the mineralogy model output was corrected toward mica instead of illite.

Blind Test Comparison

Subsequent to the portable ED-XRF geochemical analyses and the mineralogical modeling, lab-based analyses were carried out on the same samples: Wavelength-Dispersive XRF (WD-XRF) and Energy-Dispersive XRF (ED-XRF) in state of the art laboratory facilities. The geochemical data from the portable ED-XRF were compared to the lab-based XRF results. Moreover in the lab the mineralogical composition was determined through a combination of XRD and petrographic analysis and compared with the mineralogical modeling from the portable ED-XRF analysis.

Elemental Comparison. The elemental data determined on the portable
ED-XRF instrument were compared to those from laboratory state of the art ED-XRF and WD-XRF. The comparison showed that the two ED-XRF instruments (lab and portable) produce similar results for elemental concentrations, while the WD-XRF results show some discrepancies to both ED-XRF results (based on the technical principle, WD-XRF results are more accurate in analyzing the light elements whereas ED-XRF is preferable for heavy elements). The data presented in the Figures are normalized to 100%; the concentrations are given as weight percent oxide (%), as illustrated in Fig. 5 for a typical siliciclastic sample, in Fig. 6 for a kaolinite sample and in Fig. 7 for a typical carbonate sample.

Mineralogical Comparison. The LaserStrat® method applied a mineralogy model to the measured ED-XRF data, to obtain a mineralogical characterization of the samples. This mineralogy model was developed and successfully applied in North America. The model was initially successful for carbonates and anhydrite showing a good match with the results from XRD analyses.

On the contrary, results from modeling for siliciclastic samples were found not satisfactory, therefore a second model was developed, which was weighted more on rock-forming minerals such as feldspars than on clay minerals, as the first model. Then another key adjustment was a re-calculation from illite to mica followed by re-normalization to 100%.

This final adjustment led to good comparative results between the mineralogy modeled from ED-XRF data and those determined from XRD analyses, as illustrated in Fig. 8 for a typical siliciclastic sample, in Fig. 9 for a kaolinite sample and in Fig. 10 for a typical carbonate sample.
With a known/anticipated mineralogical composition, e.g., anticipated mineral assemblages, of the sample material, the mineralogy model can be further enhanced toward particular minerals. This development was not part of the current blind study, as it was aimed to determine the capabilities of mineral modeling on unknown rock samples.

Field Application
A geochemical monitoring by means of portable well-site ED-XRF was commissioned for the first out of three lateral sidetracks from mother-bore in a test well in Saudi Arabia. The well-site chemostratigraphy service was employed while drilling as a reconnaissance study, in addition to conventional biostratigraphy. The test well was drilled in under-balanced mode and with coiled-tubing techniques.

One hundred and one samples have been analyzed while drilling using the portable ED-XRF instrument. The instrument was specifically calibrated to analyze rock samples from a wide range of lithologies, e.g., siliciclastics, carbonates and evaporates. Both geochemical analyses (at the well-site) and interpretation (at a remote operation centre) were undertaken in near real-time.

The achieved objectives of this service while drilling were (Fig. 11):
• The well was monitored through geochemical data while penetrating the target sequences.
• Chemostratigraphic packages and units have been identified with confidence, despite diagenetic alterations of some sections, and correlated to reference sections.
• Mineralogy and lithotypes (18 possible lithotypes) have been determined from geochemical data.
• Additional geochemical features have been identified, which require further investigation.

The portable well-site ED-XRF instrument employed for the first time in Saudi Arabia produced reliable geochemical data enabling chemostratigraphic monitoring while drilling.

Conclusions
The main conclusions of the portable well-site ED-XRF technology deployment are as follows:
• The portable Energy-Dispersive X-Ray Fluorescence instrument produced good analytical measurements and data for different lithologies, i.e., siliciclastics, carbonates, and evaporites.
• The geochemical data were determined under well-site conditions: sample preparation and analytical settings on the portable ED-XRF instrument were as those at a well-site, e.g., 20 minutes analytical time and calibration, demonstrating the ability of this technology to be used at the well-site for near-real time mineralogy prediction/modeling.
• Mineralogy is derived through modeling from the elementary analysis, which is mainly developed for chemostratigraphic correlations and steering of wells in near-real time.

Portable well-site ED-XRF geochemical data were compared to state of the art lab-based analyses ED-XRF and WD-XRF instruments, and showed very good correlations. Similarly the modeled mineralogy from geochemical

![Figure 11. Chemostratigraphic correlation between nearby wells A & B, and LaserStrat® ED-XRF logged well (down and up sections).](image-url)
ED-XRF data showed good agreement with the mineralogy determined from petrography and laboratory XRD analyses. The portable ED-XRF instrument was then employed in real time for the first time in Saudi Arabia on a well drilled in underbalance with coiled tubing. It produced reliable geochemical data, enabling chemostratigraphic monitoring, as well as mineral and lithotype modeling while drilling.

The portable ED-XRF instrument is therefore identified as a key tool to support real-time petrophysical characterization from drill cuttings — while drilling — with clear potential for geosteering and chemostratigraphy.

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Nomenclature

<table>
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<tr>
<th>Acronym</th>
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<tbody>
<tr>
<td>XRD</td>
<td>X-ray Diffraction</td>
</tr>
<tr>
<td>XRF</td>
<td>X-ray Fluorescence</td>
</tr>
<tr>
<td>ED-XRF</td>
<td>Energy-Dispersive XRF</td>
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<td>WD-XRF</td>
<td>Wavelength-Dispersive XRF</td>
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<tr>
<td>ICP-OES</td>
<td>Inductively Coupled Plasma — Optical Emission Spectrometry</td>
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<td>LIBS</td>
<td>Laser Induced Breakdown Spectrometry</td>
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<td>AML</td>
<td>Advanced Mud Logging</td>
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References


Geosteering with Sonic in Conventional and Unconventional Reservoirs

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Abstract

Azimuthal variations in sonic logs have been observed for many years, both in wireline and LWD data. Rudimentary reactive geosteering methods have been used in the past, including drilling until real-time sonic log detected a change in formation velocity and subsequently altering the wellbore trajectory.

We propose taking sonic geosteering a step further by providing real-time azimuthal images showing the velocities as they vary around the wellbore. Images can also be transmitted at both shallow and deep depths of investigation to determine how close an approaching boundary may be.

While more traditional geosteering measurements, such as resistivity and gamma ray, are highly suitable in many cases, there are instances where the resistivity or gamma ray contrast between beds may be low or the depth of investigation very shallow, making geosteering problematic. However, in such environments, there may well be a porosity contrast, detectable as velocity differences by the sonic tool, which are more suitable to geosteering. In addition, sonic logs are an ideal way of determining gas contact points in a reservoir, as compressional velocity measurements are highly sensitive to gas.

For unconventional shale reservoirs, sonic anisotropy and its relationship to rock mechanical properties are a principle determinant of a well-placement strategy.

In this paper, we explore some key factors of sonic geosteering, such as depth of investigation, azimuthal resolution, and compressional vs. shear velocity responses. A workflow for integrating azimuthal sonic measurements into existing visualization and geosteering software is described. Field data examples are presented, showing the feasibility of sonic geosteering as well as its current limitations.

Introduction

LWD sonic tools have been used in simple geosteering scenarios since their introduction in the 1990s. The measurements used were typically limited to the compressional arrivals and (if available) refracted shear velocities. The methodology in using real-time information was limited to simple correlation or direct interpretation techniques. The practicality of using these measurements was limited by the complexity of the measurement in terms of environmental conditions (Market and Canady 2007). As a result, the tools have not enjoyed the same popularity in geosteering applications as other tools.

In recent work in shale reservoir systems, including the Haynesville (Buller et al. 2010), Eagleford, Woodford, and Marcellus, these tools have found new application and utility. In addition to using the compressional and shear data, these measurements are processed to provide dynamic Young’s modulus and Poisson’s ratio (Market et al. 2010). The tools are then used to produce a real-time brittleness index that can be used to land and geosteer within the optimal production zone.

This paper begins with a review of the measurement considerations to keep in mind when acquiring and analyzing azimuthal sonic data for geosteering. We then discuss the application of sonic geosteering in conventional reservoirs. A discussion of sonic geosteering in unconventional reservoirs follows, considering the additional complications that finely-layered strata contribute to the sonic response.

Finally, we detail an optimized workflow for acquiring and using azimuthal sonic data for real-time geosteering.

Measurement Considerations

Before we show logging application examples, we should briefly review some of the measurement principles concerned with azimuthal sonic logging. The primary factors include depth of investigation and azimuthal resolution. We also consider the differences in compressional and shear logging.

Depth of Investigation/Depth of Detection

The depth of investigation of sonic tools is dependent on the source frequency, formation resonant frequency, source-receiver spacing, and even the configuration (monopole, dipole, quadrupole) of the source (Market et al. 2009). A general “rule of thumb” is to estimate the depth of investigation to be approximately one wavelength. Thus, for a given formation, a high-frequency source at 10 kHz would give us half the depth of investigation of a low-frequency source at 5 kHz. Or, if we use the same 10-kHz source in a 100-µsec/ft formation and a 50-µsec/ft formation, the 50-µsec/ft formation would have a deeper depth of investigation. This is complicated by the fact that each formation has a natural resonant frequency range. In general, fast formations favor high frequencies, and slow formations favor low frequencies. Annulus size can also affect the resonant frequency: a small annulus shifts the resonant frequency range higher than a large annulus.

Though the rule of thumb is a reasonable starting estimate, a number of factors can both increase and decrease the depth of investigation. Fig. 1 illustrates the effect of frequency and slowness on depth of investigation.

The distance from transmitter to receiver is also a factor in the depth of investigation (Market et al., 2009) much like propagation resistivity tools, which are designed with multiple frequencies and multiple source-receiver spacings. Long source-receiver spacing yields a greater depth of investigation than short source-receiver spacings.

In general, higher-order sources can yield a greater depth of investigation than lower-order ones, thus dipole or quadrupole sources can read deeper than monopole sources. This is
a secondary effect compared to frequency or source-receiver spacing, however.

Depth of detection is not the same as depth of investigation (Bittar et al. 2008). Depth of detection is of particular interest in geosteering, as it refers to the depth at which we can first detect the presence of a deeper layer. In the case of resistivity tools, the measurement “seeks conductivity” such that, if the tool is in a high-resistivity bed approaching a low-resistivity (e.g., high conductivity) bed, the depth of detection is greater than if the tool is in a low-resistivity bed approaching a high-resistivity bed. Sonic tools “seek fast formations” such that if the tool is in a slow formation approaching a fast formation, the depth of detection is greater than if the tool is in a fast formation approaching a slow formation.

While the exact numbers will vary based on the tool design, frequencies, etc., an approximate depth of detection for a sonic tool located in a formation of DTC=100 µsec/ft approaching a formation of DTC=50 µsec/ft is approximately 3–4 ft. The inverse case would have a depth of detection of 1–2 ft.

Azimuthal Resolution. We can again look to azimuthal resistivity tools for comparison when considering the azimuthal resolution of sonic tools. Modern azimuthal-propagation resistivity tools generally have both short-spaced, high-frequency measurements and long-spaced, low-frequency measurements. The former have a short depth of investigation/depth of detection but high azimuthal resolution, while the latter have lower azimuthal resolution (often only quadrant resolution) but deep depth of investigation/detection. A similar situation exists for sonic, but the wavelength is the most predominant factor in determining the azimuthal resolution. Because acoustic wavelengths are relatively long (generally at least a foot), they limit the azimuthal resolution to something in the range of 10–20°. Sonic is not just simply the tool we should use to detect 1–2° wide features, as it is more the realm of ultrasonic or focused electrical imaging tools.

Earlier LWD sonic tools were not optimized for azimuthal imaging, as they were designed to get the compressional and shear slowness at each depth, though the effects of nearby layering and anisotropy were observed. The tools acquired waveform data at each depth without much regard for the orientation of the tool.

Recent developments of azimuthal LWD sonic capabilities, beginning in 2008 (Market and Deady 2008) have led to the development of tools that promise to bring an interesting dimension to sonic logging and geosteering with sonic measurements in horizontal wells. These tools fire multiple times at a range of azimuths at each depth to create a high-resolution azimuthal sonic image. Fully-capable tools have just become available (Market and Bilby 2011) and promise to deliver much greater flexibility in geosteering with sonic LWD.

An important consideration when comparing sonic log response to resistivity response is that, whereas resistivity tools integrate the resistivity of the nearby layers, yielding one resistivity value per transmitter-receiver/frequency combination, sonic tools actually detect a reflection from each layer that the wave encounters, like seismic tools. The various layer velocities are not averaged but rather appear as multiple distinct arrivals. Thus, the depth of detection with sonic tools might be considered the first point at which a nearby bed’s signal is strong enough to be detected, although there may also be an arrival visible from the bed wherein the tool itself resides. Fig. 2 shows an example of a tool residing in a formation with DTC = 100 µsec/ft formation with a nearby formation whose DTC is 130 µsec/ft.

**DTC vs. DTS.** Compressional or shear velocities can be used for steering, as well as flexural, Stoneley, and quadrupole modes. In general, refracted shear will have a slightly shallower DOI than compressional waves, as it is at similar frequencies as the DTC but slower. However, low-frequency dipole or quadrupole shear can have as much as twice the DOI as compressional waves. Of much greater interest is the propagation behavior of compressional versus shear waves.

Compressional waves travel parallel to the tool/wellbore. Compressional measurements are azimuthally sensitive in the sense that they can detect velocity differences around the wellbore, as in the case of Fig. 3a, where we have one bed above the tool and one bed below it. If we consider the case of fine layering, as in Fig. 3b, the compressional wave will effectively average over the velocities of the fine layers it passes through. Whereas, Fig. 3c would observe a different velocity than Fig. 3b; if we only look at the azimuthal response of Fig. 3b, as the tool rotates, we would see little azimuthal variation in the compressional velocity.

Shear waves, however, have decidedly different characteristics. They propagate perpendicular to the tool/wellbore, as shown in Fig. 3d. When
the waves reach the wellbore wall, they can polarize, with part of the energy propagating at the maximum stress (maximum velocity/minimum slowness) and part of the energy travelling at the minimum stress (minimum velocity/maximum slowness). In the case of Fig. 3d (fine layering), as we azimuthally rotate the tool, some of the energy will split into the fast direction, while some will split into the slow directions. If the transmitter/receiver array is oriented closely with the maximum stress direction, the maximum velocity wave will be detected with much higher signal amplitude than the minimum velocity.

Likewise, as the tool rotates toward the minimum velocity direction, that wave will have a higher signal. It is important to understand that we will not see a range of velocities between fast and slow shear but that we will have two distinct velocities whose amplitudes vary depending on the azimuthal orientation of the tool. Fig. 4 shows an example of data taken at the same depth while the tool is rotating. The left snapshot is taken as the tool is pointed within 25° in the minimum stress direction, while the right snapshot was taken very close to the maximum stress direction.

Therefore, while compressional waves and shear waves both can detect approaching bed boundaries, when we are considering finely-layered structures or stress anisotropy, it is the shear measurement that is most sensitive to azimuthal variations.

If the compressional wave behavior in fine layers and gross layers seems contradictory, it really is not. It all boils down to wavelength. If the layer thickness is on the order of the wavelength, the wave reflects off each layer similar to seismic. If the thickness of the layers is less than a wavelength, the compressional waves “average over” the fine layers within a wavelength of the wellbore wall.

**Conventional Reservoirs**

In the context of this paper, we will consider conventional reservoirs to be those cases where the target is a layer containing hydrocarbon that has a thickness of at least a few feet, as opposed to fine-layering structures containing hydrocarbons scattered throughout the fine layers (unconventional). When geosteering in conventional reservoirs, we are primarily concerned with reaching a target zone by the most direct route, then drilling a wellbore through the target zone as smoothly as possible and without exiting the hydrocarbon layer.

Most often, the primary tools for geosteering in such reservoirs are gamma ray and deep-reading azimuthal resistivity. As long as there is a contrast in the gamma ray or resistivity values between the target layer and the surrounding layers, we would still recommend these measurements as the primary geosteering methods. However, there are sometimes cases where there is little resistivity contrast between the layers, or the contrast is such that the depth of detection is very shallow. At such times, sonic geosteering provides an alternative.

For example, sonic logs are sensitive to porosity changes. In carbonates, it is not uncommon to have low-resistivity contrast between limestone and dolomite layers, particularly in water-flooded areas. The sonic velocity contrast can be much more significant, allowing us to steer toward the high-porosity layers. Fig. 5 shows a field example of such a case. This was a study in the relative geosteering abilities of sonic and resistivity, so a case was chosen that did have both resistivity and sonic contrasts (this portion of the field has not yet been flooded). The left
track shows the binned velocities from the top and bottom quadrants. In the middle of the section, we begin to approach a faster formation above us. The blue (up-looking) compressional curve begins to see this bed long before the red (down-looking) compressional curve responds. Then both curves read the same velocity as the tool crossed into the faster bed. The second track is a simple QC plot showing the semblance for the compressional data (to give confidence in the log). The third track shows the azimuthal image of the compressional wave. In the azimuthal image tracks, the edges are looking up, and the center is looking down.

The example in Fig. 5 is from a conventional carbonate reservoir. Given the ability to “see” the compressional variance around the borehole allows for zones of specific sonic properties to be targeted, and in the absence of any other petrophysical marker, it becomes clear when the particular range of compressional values has been exited, as well as to determine if the borehole either drilled out of the top or the bottom of the zone of interest.

Other environments that are well suited to sonic geosteering include gas reservoirs and tar mats. Compressional waves are very sensitive to even small amounts of gas in the pore space, and the log response is dramatic.

Unconventional Shale Reservoirs

“Unconventional shale reservoir” is a term applied to scenarios in which oil or gas is trapped within mud-rich sedimentary layers; the production method uses long, lateral wells drilled through target zones and stimulating the rocks by multi-zone fracturing.

In layered-rock systems, azimuthal sonic measurements can provide more insight into the formation being drilled. This information is from shear anisotropy measurements that take the form of a split- (fast and slow) shear response, as described earlier in this paper. The split-shear measurements are combined to give a transverse isotropic vertical (TIV) index that effectively describes the layering of the rocks in the near-wellbore environment (Buller et al. 2010). When combined with the brittleness index, it forms a powerful tool that describes the geomechanical environment in thinly-layered rock systems. These additional parameters were identified by using the tools for conventional petrophysical analysis in shale systems, but they are being examined to see if they are applicable in evaluating conventional and tight-gas reservoirs. The key element is to acquire the azimuthal shear data in real time for geosteering to the most appropriate geomechanical section of the reservoir for stimulation and then using the data to match to production logs for validation.

In unconventional reservoirs, standard sonic measurements are already contributing to characterizing shale systems. The brittleness of these systems is directly related to clay content, as evidenced by the core studies done in the Haynesville (Buller et al. 2010). Evidence is accumulating that near-wellbore brittleness measurements are closely correlatable to production (Fig. 6). The reasoning behind the idea that brittleness and layering impact production is that it is reasonable to expect higher stimulation-treatment pressures in clay-rich rocks. A second contention is that more brittle rocks will preferentially develop more complexity around induced fracture planes closer to the wellbore, allowing for greater surface area of the induced fracture to gain higher productivity from the rock. A third consideration is that proppant embedment occurs in areas of high clay content, which would reduce or eliminate connectivity from a fracture system into the wellbore, having an adverse effect on production.

A recent development from the non-azimuthal sonic tools is the ability to distinguish layering in shale systems (Buller et al. 2010). The layering effect is directly related to contrasting layers of fast and slow rock, detectable by an anisotropic shear response (Fig. 7). By extension, this effect may be present in conventional clastics and carbonates, possibly on a much reduced scale owing to the much less complex layering environment.
Given the sensitivity of this tool type to layering anisotropy, it may be possible to use this effect to map the presence or absence of layering in a conventional reservoir. Fine laminae should produce a similar effect, giving greater insight into the character of these reservoirs. While direct imaging of the layers is easily achievable by other means, using the acoustic tools will allow a fast, direct approach useful in decision making. A secondary advantage is that the acoustic tool is sensitive to layering in a volume of rock with a radius of approximately 1 m (3 ft). While high-resolution imaging tools can see the fine layering in the very near-borehole environment, this ability to sample a larger volume of the rock around the wellbore allows for a better understanding of the effects the layering may have on subsequent completions.

When used in geosteering, the conventional LWD sonic performs well, giving the seasoned practitioner a simple real-time good-rock/bad-rock indicator, from a stimulation perspective, of the current position of the BHA. What it is incapable of doing is showing the geosteering specialist which direction to steer to re-enter the best quality rock if the well exits the desired zone. The new azimuthal tool provides several ways to overcome this limitation.

An image of a particular measured property, such as compressional or shear velocities, can be presented, as in the left two tracks of Fig. 8. Combining the two properties into a brittleness index image, as in the right track of Fig. 8, in near real time provides a clear qualitative indication of the “fracability” of the zone. This would give the geosteering specialist the ability to map the brittleness index regardless of its relationship to stratigraphy, eliminating guess work on whether the zone of interest had pinched out, or did the well climb or drop out of the desired zone.

One very significant aspect of using the acoustic tool is that of optimized logging speed. The sonic tool has the distinct advantage of producing the split shear characteristic at any logging speed. High-resolution LWD imaging tools require high sample rates and low logging speeds to produce high-quality images of laminae. While the acoustic tool is not sensitive to individual laminae, the bulk-rock characteristics are readily identifiable, precluding a reduction in drill rate for logging, which would be an important economic consideration.

One consideration often raised in using sonic to determine real-time geomechanical properties for steering is the requirement of the Young’s Modulus equation for a density input. Current practice is to use the measured compressional and fast shear responses to compute Poisson’s ratio and Young’s modulus, then to convert the results into a brittleness index according to Rickman et al. (2008). An examination of Young’s Modulus demonstrates that the equation is insensitive to small variations in the density term and once the brittleness computation is performed; therefore, small changes in density have a low impact on the resulting brittleness index. This leads us to the current practice of forgoing a real-time density measurement in favor of using a static value derived from offset logs for the bulk interval, which could be refined by using extrapolated data from the same structural position, but unless very significant changes in density are present, the impact on the brittleness image logs is minor. Purists may prefer to run the density tool to gain a better answer, but practicality indicates that while desirable, this does not make a significant impact on the result and, in most cases, would not have altered the real-time geosteering decisions that were made.

Other potential areas of interest are in reservoirs with significant amounts of layering that are faster than the bulk rock matrix. The resulting semblance plot of such a system, which would describe sandstone with very tight cemented layers, should show a similar plot to that seen in clay-dominated systems shown above. The path that the shear waves took to reach the receivers would be inverted but with the same result.

**Processing Workflow**

Though it has long been recognized that there is some azimuthal sensitivity to LWD sonic measurements, geosteering with real-time sonic measurements has been a bit primitive. This was partially a result of limits in the real-time data.
quality transmitted while drilling and partially 
owing to the design of the tools themselves.

Simple LWD sonic tools transmit a single-
compressional value at each depth while 
drilling, without care for the orientation of the 
tool when the data were acquired. For example, 
observe the bottom track of Fig. 9 at 850 ft MD. 
If we consider a tool with a single transmitter/
receiver array and that array were pointed up, 
we would see the green formation only. If the 
array were pointed down, we would see only the 
yellow formation. If the array were pointed to 
the sides, we might see both green and yellow 
formations. So, if the tool is randomly rotating, 
we might see the effects of an approaching 
formation sporadically by looking at the real-time 
transmitted DTC curve. Unfortunately, if we were 
sliding (not rotating) because we were building 
angle or wiping the interval, we might not see 
an approaching bed at all if the tool was not 
oriented correctly.

One way this could be handled would be to 
forcibly orient the tool string such that the 
sonic receiver array was pointing in a particular 
direction, thus enhancing the chances of seeing 
an approaching bed. This is possible, but 
somewhat laborious, and could not be performed 
during the drilling process without impacting the 
drilling operation.

Another alternative is to have multi-array tools, 
which gives the chance that at least one array 
is pointed toward the approaching boundary. 
However, in the past, common practice was 
to sum the results (in the case of monopole) or 
difference of the front and back arrays (in the 
case of dipole) to enhance the signal-to-noise 
 ratio, which “blurs” the azimuthal sensitivity 
by effectively averaging the signal around 
the wellbore.

Instead, we suggest an approach by which we 
can use either a single-axis tool that is rotating 
or a multi-axis tool (rotating when possible, but 
with multiple arrays to give multiple azimuths 
even when not rotating). This tool would also 
have an azimuth sensor to determine the 
azimuthal orientation of each acoustic acquisition 
to azimuthally bin the acquisitions similar to an 
azimuthal density sensor. With this design, we 
can transmit an azimuthal image at each depth, 
such as is displayed in the top two tracks 
of Fig. 9.

The recent introduction of broad-frequency 
azimuthal sonic tools (Market et al. 2008; Market 
and Bilby 2011) provide for more advanced 
geosteering. High-resolution (quadrant or 
better) azimuthal images and multiple depths 
of investigation enable us to detect azimuthal 
velocity variations and enable true steering, as 
with azimuthal resistivity tools.

Fig. 9 is an example of a geosteering display 
using sonic compressional velocities. The sonic 
images displayed are a 4-quadrant DTC near 
image (top track) and a 4-quadrant DTC far image 
(second track), similar to the resolution that might 
be transmitted real-time (up to 16-bin images 
can be transmitted real-time, but quadrant 
information is generally good enough for steering 
purposes in conventional wells). The bottom 
track shows the geology model from the pre-well 
study. The middle three tracks are the expected 
DTC, resistivity, and gamma ray (these are the 
values from the geological model). The target in 
this case is the yellow formation shown in the 
geometry plot. In this example, there is not 
much resistivity contrast between the two 
beds (24 Ω·m and 30 Ω·m), which might make 
geosteering based on resistivity difficult; there is
considerable sonic contrast, however. The yellow formation is 60 µsec/ft, and the green formation is 85 µsec/ft; consequently, this is a case in which sonic geosteering could complement resistivity well placement.

In real time, sonic image tracks can be used as follows:

• To “land” the well. Because we are looking for the yellow zone, when the far image begins to detect the yellow formation in the bottom of the image (middle of the image track), we know that we are close to the top of the target zone and should flatten out our trajectory. Example at 80 ft MD in Fig. 9.
• After the near image shows that we are well within the yellow zone (we see yellow from above and below around the tool), we know that we are within the target reservoir. Example at 150 ft in Fig. 9.
• If we begin to see the green formation in the bottom of the far image (350 ft MD in Fig. 9), we know that we are getting near the bottom of the target zone and must steer up to get back in the middle of the zone.

**Conclusion**

Acoustic logs have not been widely accepted for geosteering purposes in the past owing to perceived complexity in processing and interpretation. New advances in tools and theory have combined to aid geosteering specialists, geologists, completion engineers, and reservoir engineers in better understanding their reservoirs. A workflow that incorporates the peculiarities of the acoustic environment can be used that allows the data acquired to be used for geosteering, geological interpretation, completion optimization, and stimulation optimization. The work described here allows for a simple workflow to acquire pertinent and valuable data into the hands of the geosteering geologist. Instead of complex and costly data processing to use the data, it is converted into curves and images that are readily interpreted, which enables the geosteering geologist to better impact the well placement and assist the well in achieving its potential economic value.
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References


Does the Presence of Natural Fractures Have an Impact on Production? A Case Study from the Middle Bakken Dolomite, North Dakota

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Abstract
During the last 10 years, more than 2,000 horizontal wells have been drilled and completed in the Middle Bakken formation, which is sandwiched between the two Bakken organic-rich shales. Although most of the debate about this reservoir has centered on the lateral length, stimulation treatment, and the number of treatments, little work has been performed to explore the variations of rock properties and the effect of natural fractures along the 6,000 to 10,000-ft lateral lengths.

Maintaining the horizontal well between the two Bakken shales is easily accomplished with only a gamma ray tool. There are, however, two important questions to be addressed. First, is this an optimal practice for well placement? Second, is there a “sweet spot” layer in which the horizontal well should be placed to increase production?

In a recent well, an azimuthally-focused resistivity (AFR) tool and an azimuthal deep-reading resistivity (ADR) tool were run as a final wiper trip to investigate the location of natural fracture swarms and the variations of rock properties along the 10,000-ft lateral. The goal of this exercise was to test the concept of improving production by using a “smart” horizontal completion technique, spacing the swellable packers, and locating fracture stages based on horizontal reservoir data. The AFR image log identified more than 839 individual fractures in four fracture swarms. The ADR mapping showed approximately 40% of the lateral in the sweet spot layer. The evaluation of a post-stimulation oil tracer indicates that these sweet spot layers provide 70% of the production after stimulation. If the well had been geosteered to remain within the sweet spot using a smart completion technology, the production modeling suggests that production could have been increased by 20%.

Introduction
The Bakken formation is part of a petroleum system that comprises five distinct stratigraphic units: the overlying Lodgepole Limestone formation, the upper, middle, and lower members of the Bakken formation; and the underlying upper Three Forks-Sanish formation (Meissner 1978). The upper and lower shale members of the Bakken provide the source rocks for the oil contained in all of these reservoirs. The Lodgepole and Three Forks formations serve as sealing formations, except where fracturing has enabled the Bakken-sourced hydrocarbons to bleed off into porous zones (e.g., the Middle Bakken and the Sanish sand) and charge these formations. The history of the Bakken completions began in the late 1950s with a few vertical completions. The first horizontal Bakken “boom” in the late 1980s targeted the Upper Bakken shale member for open hole horizontal completions. This program had a short life span because of the high costs of horizontal drilling, low permeability, and completion techniques. The second Bakken horizontal drilling boom began in Montana with the Lyco Energy Sleeping Giant project in the Elm Coulee field. Most of these wells were drilled in the maximum stress orientation to create longitudinal hydraulic fractures. This process simplified the completion and stimulation process. This development began in early 2000. The possibility of performing multiple fracture stages in one horizontal wellbore was technically challenging and risky. During the last 10 years, more than 2,000 wells have been drilled and completed with a variety of completion techniques, making the Middle Bakken play one of the more significant oil plays onshore North America of the past decade. The cumulative Bakken production is approximately 200 million bbl of oil, as shown in Fig. 1, its daily average production is 6 million bbl per month (North Dakota Oil and Gas Division 2010). The success of this program is largely attributed to a combination of technologies: cost-effective horizontal drilling and multi-stage stimulation.

Figure 1. Monthly Bakken production since 2000 (North Dakota Oil and Gas Division 2010).
The thickness of the Middle Bakken clastics ranges from 35 to 85 ft; the play is more carbonate to the west and quartz-rich carbonate to the east. The upper and lower shale serves as a pressure seal, making the reservoir section overpressured throughout much of the basin. LeFever et al. (1991) described the Middle Bakken with five distinct lithofacies, as shown in Fig. 2.

The open natural fractures represent the primary flow path of oil in the Bakken formation. These fractures are a result of structural tectonics, regional stress, and hydrocarbon expulsion and are lithologically dependent (Murray 1968). Sonnenberg and Pramudito (2009) suggested that Lithofacies 3 is the facies that is more susceptible to natural fracturing and has 5 to 10 times the fracture permeability. Ideally, this would make Lithofacies 3 an ideal target for the placement of a horizontal lateral well, which is the subject of this paper. Does it make any difference placing the lateral in the sweet spot zone and 10 ft below the sweet spot zone. Another purpose of this test was to observe the difference between the ball-actuated lateral in the sweet spot zone and 10 ft below the sweet spot zone. Another purpose of this test was to observe the difference between the ball-actuated stimulation sleeves and the plug and perf completion methods.

Scope of Trial. The intent of the trial was to gather data. Initially, the well was drilled to total depth (TD) using conventional geosteering techniques. A gamma ray sensor was the principal sensor used, and it was successfully deployed to maintain the well in the Middle Bakken unit for a total section length of 10,400 ft. The total stratigraphic thickness gamma profile is very correlatable along the line of section and provide adequate control to maintain the drilling assembly in the zone. Several tags of the upper and lower boundaries were made, but the well was placed successfully in the target zone for almost the complete section.

After the drilling phase was completed, two LWD tools were run to acquire geological data from the reservoir section. An ADR tool was run to provide accurate boundary mapping relative to the wellbore. This information would enable the wellbore to be evaluated within the context of structural position. The second tool was an AFR tool that was run to acquire very high-resolution image logs of the entire lateral. By combining the output from the two tools, the lithofacies and natural fracture patterns determined by the AFR could be placed into a structural context by the ADR to provide a more complete picture of the distribution dynamics of the lithofacies and fractures.

Geological Mapping
ADR. The ADR tool is based on the multi-frequency, multi-spacing tilted antenna concept (Bittar et al. 2007). The tool consists of a single 25-ft collar with six transmitters and three receivers; the transmitter-to-receiver distances range from 16 in. to 112 in. (see Fig. 3). This tool operates at three different frequencies: 2 MHz, 500 kHz, and 125 kHz. With multiple spacings and multiple frequencies, the ADR tool covers the entire range, from shallow- to very deep-reading, mapping the formation parameters from near the borehole to up to 18 ft radially. The compensated spacings are 16 in., 32 in., and 48 in. Transmitters T1, T2, T3, T4, T5, and T6 are non-tilted coaxial antennas, whereas receivers R1, R2, and R3 are tilted antennas. These receiver antennas are tilted 45 degrees with respect to the tool axis.

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**Figure 2. Lithofacies defined within the middle member of the Bakken formation (LeFever et al. 1991; Helms and LeFever 2005).**
As the tool rotates, phase shift and attenuation data are acquired in 32 azimuthally-oriented bins that are referenced to either the high side of the borehole or to magnetic north using magnetometers. The phase shift and attenuation measurements are transformed to resistivity values to obtain 32 azimuthally oriented phase shift and attenuation resistivities at multiple spacings and frequencies.

A feature of the tool is the production of geosignals (Bittar et al. 2010), which are used in a mathematical inversion process to determine the distance to a boundary around the tool. In this trial, the geosignals were processed by means of inversion to determine the distance to the nearest boundary, either above or below the tool. Fig. 4 shows the results of this inversion process.

Geosteering software was used to combine the inversion results with a geological model (Pitcher et al. 2010), and the subsequent geological model was exported to the reservoir modelers.

AFR. A 4.75-in. AFR sensor equipped for imaging in a 6.125-in. borehole was used to obtain resistivity images in the lateral after drilling. The AFR is configured with transmitter toroids at the top and bottom of the tool, and with three sets of current-sensitive electrode “buttons” between the transmitters (Prammer et al. 2007), as shown in Fig. 5. Each set or row of measurement buttons consists of three buttons spaced 120 degrees circumferentially around the tool. The AFR is equipped with high-resolution measurement buttons at the lower and upper button rows, and with standard-resolution measurement buttons at the middle button row. The tool was programmed to acquire 32 azimuthal sector measurements from the standard-resolution buttons, which were oriented relative to the high side of the borehole. The data from the high-resolution buttons were sampled in 64 azimuthal sectors, which were also oriented relative to the high side of the borehole.

In addition to providing full 360-degree images of the borehole while rotating, the sensor also provides omni-directional laterolog type resistivity measurements by summing the measurements of each button row for a virtual ring response.

By combining the uncompensated virtual ring responses from the upper and lower transmitters and the middle button row, a naturally compensated medium spaced laterolog type resistivity curve can be produced. By depth shifting the uncompensated virtual ring responses for the upper and lower button rows from the upper and lower transmitters, depth derived compensated shallow and deep laterolog type resistivity curves can also be produced. The compensation will provide symmetric responses as compared to uncompensated measurements using only the upper transmitter or lower transmitter. (Fig. 6.)

In addition to omni-directional resistivity measurements, azimuthal resistivity curves can be produced from the measurements, as shown in Fig. 7.

The AFR tool can also produce an at-bit measurement by transmitting with the upper transmitter and using the lower transmitter as a receiver to measure the total current return to the bottomhole assembly (BHA) below the receiver. Fig. 8 shows same interval in Fig. 6 with the at-bit measurement plotted with a bit to sensor offset of 0.0 ft. Shading has been added to Track 1 in Fig. 8 to illustrate the position of the wellbore (TVD curve) relative to the beds traversed by the wellbore. In the section from the top of the example log to XX625ft, the wellbore was drilling up section with
the wellbore traversing from a more conductive layer to a more resistive layer. The high-resolution resistivity image and compensated ring resistivity curves give a precise position of the bed boundaries being traversed in this example. Comparing these curves to the at-bit measurement, it is seen that the at-bit measurement does not respond immediately when the bit crosses from the more conductive bed to the more resistive bed but rather has a “lazy” response. From XX625ft to the end of the example log, the wellbore traverses back down and through the same beds. When the bit traversed back down-section from the more resistive layers back into the more conductive layer, the at-bit measurement reacts fairly sharply as soon as the bit has crossed into the more conductive layer, giving a truer at-bit response.

Well Completion. The completion of this well, shown in Fig. 9, consisted of 10 ball-actuated stimulation sleeve stages and nine plug and perf stages. Each fracture stage was tagged by using chemical tracers and oil-soluble tracers to monitor fluid flowback, as well as by adding radioactive (RA) tracers to the proppant. Gamma ray values of less than 40 API units and resistivity values of more than 40 ohms are the LWD characteristics that indicate being in the sweet spot zone. The sweet spot zone in this well was also heavily fractured; more than 839 individual natural fractures were identified (Fig. 10 and Fig. 11). The natural fracturing was limited to the sweet spot zone. Mud log shows were also present in the four of the five sweet spot zone penetrations.

To test the treatment plan for this well, water-soluble chemical tracers were added to each fracture stage to test the difference of the fracture flowback between the stimulation sleeve and the perf and plug stages. On the plug and perf stages, the same tracer was used for two fracture stages so that the total flowback percentage was evenly divided between the two stages. Unique oil-soluble tracers were added to each fracture stage to evaluate where the oil was being produced from this 10,400 ft lateral. RA tracers of iridium, scandium, and antimony were alternated between the stages,
which are shown in Fig. 11 as red, yellow, and blue bars in the Mud Log and Staging track. The stimulation treatment volumes and fluid systems, specified in Table 1, were approximately the same for the ball-actuated stimulation sleeves and for the plug and perf stages.

Discussion of Treatment Results. Table 2 shows the results from the stimulation treatments and flowback between the stimulation sleeve stages and the plug and perf stages and the sweet spot zone and non-sweet spot zone. These results suggest that there is very little difference in the completion practice between stimulation sleeve stages and plug and perf stages concerning the stimulation treatment instantaneous shut-in pressure (ISIP) or fracture fluid flowback. The oil flowback result is better in the stimulation sleeve stages, partially because the majority of these stages were in the fractured sweet spot zone. The RA tracer indicates a quite a bit more smearing of the tracer material in the plug and perf stages than the stimulation sleeve stages, which is possibly an effect of drilling out the plugs between stages and drilling out the baffles on the stimulation sleeve stages. This lateral had 2,059 ft (20%) within the sweet spot zone. It is interesting to note that four of the five sweet spot intervals had good mud log shows, whereas the other portions of the borehole did not have much mud log show. The oil flowback was slightly greater, 4% on average, in the sweet spot zone and the water flowback was slightly less. The five stages where the sweet spot zone was encountered accounted for 40% of the well production, based on the day 50 oil tracer analysis and 20% of the fracture fluid flowback. The non-sweet spot zone completions produced most of the fracture fluid flowback. On a %/1,000 ft basis, the stages in the sweet spot zone produced at an oil flowback rate of 20%/1,000 ft of lateral, whereas the non-sweet spot zone produced at an oil flowback rate of 15%/1,000 ft of lateral. In this well, 40% of the production comes from 20% of the fracture stages. This begs the question of what would have occurred if the entire lateral had been placed within the sweet spot zone. A reservoir simulation model was constructed to test this concept. Table 3 lists the layer properties.
Reservoir Simulation Modeling. The wellbore for the horizontal was placed in two locations. One simulation was performed with the wellbore in the middle of the sweet spot zone, and the other was performed with the wellbore 10 ft below the sweet spot zone. The horizontal layer profile is shown in Fig. 12.

The simulator was performed for a 10-year period. The results of this modeling show a difference of 20% increase in the 10-year oil production by placing the lateral in the sweet spot zone as compared to landing the lateral below the sweet spot zone (Fig. 13).

Table 3. Rock Properties by Layer for the Reservoir Stimulation

| Name          | Thickness (ft) | Depth to Top (ft) | Porosity ( ) | X Horizontal Permeability (mD) | Y Horizontal Permeability (mD) | Vertical Permeability (mD) | Initial Pressure (psia) | Dew/Bubblepoint Pressure (psia) | Initial SW ( ) |
|---------------|----------------|------------------|--------------|--------------------------------|-------------------------------|----------------------------|------------------------|-------------------------------|----------------|        |
| 1 UpperShale  | 15.0           | 10,000           | 0.0100       | 1.0000E-05                     | 1.0000E-05                    | 5.000                     | 3,250                  | 0.30                          |                |
| 2 Litho4      | 10.0           | 10,015           | 0.0004       | 0.004                          | 0.0004                        | 6,500                     | 3,250                  | 0.50                          |                |
| 3 Litho3      | 8.0            | 10,025           | 0.0010       | 0.0010                         | 0.0010                        | 6,500                     | 3,250                  | 0.30                          |                |
| 4 Litho3      | 8.0            | 10,033           | 0.0100       | 0.0100                         | 0.0100                        | 6,500                     | 3,250                  | 0.30                          |                |
| 5 Litho3      | 8.0            | 10,036           | 0.0010       | 0.0010                         | 0.0010                        | 6,500                     | 3,250                  | 0.30                          |                |
| 6 Litho2      | 45.0           | 10,044           | 0.0004       | 0.0004                         | 0.0004                        | 6,500                     | 3,250                  | 0.50                          |                |
| 7 Litho1      | 10.0           | 10,089           | 0.0004       | 0.0004                         | 0.0004                        | 6,500                     | 3,250                  | 0.50                          |                |
| 8 LowerShale  | 15.0           | 10,099           | 0.0100       | 1.0000E-05                     | 1.0000E-05                    | 6,500                     | 3,250                  | 0.30                          |                |
| 9 ThreeForks  | 50.0           | 10,114           | 0.0100       | 0.0100                         | 0.0100                        | 4,500                     | 3,250                  | 0.50                          |                |

Note: The following values are the same for all layers: Initial SG - 0.0000 • Initial Temp (°F) - 59.000 • Rock Type - Rock1.
The simulation grids for these two cases are shown in Fig. 14 and Fig. 15 (on the previous page). Fig. 14 shows the reservoir in which the lateral is landed in the sweet spot layer. Although the hydraulic fractures extend into the lower Middle Bakken, the first five year production is dominated by the better permeability in the sweet spot zone.

When the lateral is drilled below the sweet spot zone, the first five-year production is dominated by the lower permeability in the lower Middle Bakken. Although there is some drainage from the sweet spot layer, it does not drain this layer as effectively as when the lateral well is drilled in it.

Model Validation with Production. With any reservoir simulation, there are an endless number of knobs that can be turned to produce the results. A better test of the validity of a model is a comparison between the model and the actual well production. The two wells described here are four miles offset; consequently, some differences in their production characteristics are likely as a result of geologic differences, which are not taken into account. However, it demonstrates that remaining in the sweet spot zone makes a difference regarding the lower permeability Middle Bakken reservoirs (Fig. 16).

Conclusions
This study demonstrates that there are very little differences concerning well completion schemes between the ball-actuated stimulation sleeves and the plug and perf fracture initiation. Consequently, the decision to complete the lateral using all stimulation sleeves, plug and perf, or a combination of both would be primarily an operational and economic decision. The authors also investigated the placement of the lateral. The results of this study suggest that geosteering the lateral in the sweet spot zone in this particular area will result in a 20% increase in well productivity. The authors also suggest testing this concept and workflow in other portions of the Middle Bakken play. This paper began with the question of whether or not the presence of natural fractures has an effect on production. As shown in this study, placing your well in the most highly fractured interval, the sweet spot zone in this case, has a 20% increase in cumulative production.

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Geosteering in Unconventional Shales: Current Practice and Developing Methodologies

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Abstract
Current well placement in unconventional shale ranges from simple geometric well placement to a gamut of pattern-recognition systems and geosteering with geochemical and geomechanical analyses. The wide diversity of systems used leads to uncertainty in the effectiveness of any strategy, with confusion as to the true value or merit of a particular technique. Often, a well-placement strategy is based on what came before, with little regard as to the complexities or differences between reservoirs.

This paper reviews the current common practices used in geosteering in shales, for both gas- and oil-producing reservoirs. A brief history of strategy development is outlined, with comments about its perceived effectiveness and value. Examples of successes and failures are examined to attempt to determine the viability of a particular strategy.

Finally, alternative approaches and methodologies are reviewed and examined, with comments about the potential application, benefits, and value.

Introduction
Well placement in unconventional shales is primarily associated with drilling efficiency. Many operators are using simple geometric well placement techniques in which a well plan is followed, regardless of the rocks encountered along the wellbore. The assumption is that the hydraulic stimulation techniques pioneered in the Barnett shale will contact enough rock volume to make any attempt at proactive well placement futile. Recent published and public data (Buller et al. 2010; Pitcher and Buller 2011) indicate that well placement may have a major effect on stimulation efficiency and associated production. Where the well is placed in a thick shale sequence can have a dramatic effect on production, and many operators are following the path of geosteering in an attempt to remove some of the geological uncertainty. The primary goal of geosteering is typically concerned with placing a well in predefined stratigraphy.

The principal methodology used is gamma ray correlation, which is described in this paper, along with a review of some of the concerns and issues encountered when using this method. In addition to using gamma ray tools for geosteering, some operators are adding resistivity measurements to improve correlation, or imaging tools, such as density, to gain information about structure. These methods have some success, but it is often difficult to quantify how successful these systems are. Because tying results to the ultimate metric, production, is difficult, alternative methods of well placement are often discounted.

Alternative methods of geosteering include bio-steering, geochemical steering, and steering to geomechanics. Although biosteering has not found an application in the unconventional shale world, geochemical steering and geomechanics are rapidly gaining attention as solid, proven technologies that can deliver better results (Buller et al. 2010).

Geosteering with Gamma Ray
The predominant methodology for geosteering in shales is using basic natural gamma ray logging-while-drilling (LWD) tools. What is thought of by most as basic LWD technology may very well be one of the least understood and improperly used tools. Gamma ray technology measures the naturally occurring gamma radiation emitted by the formation. The statistical data is then transmitted to the surface for interpretation. The basic GR curve provides a qualitative view of the rock type, such as shale or shaley, sand or siltiness, and limestone or marl. The effectiveness of using GR to steer a horizontal well largely depends on the quality of the data collected, transmitted, and processed. Any significant error in one of those three processes can result in misinterpretation of the data and well placement.

Geosteering with GR uses basic pattern recognition to correlate data from the horizontal well back to a vertical pilot hole or offset total stratigraphic depth (TSD) log. Even in shales, we can sometimes see enough mineralogical variance in the GR measurements to correlate down to the tool resolution scale (approximately 1 ft/30 cm). Fig. 1 shows a correlation log from a Marcellus Shale well. A TSD representation, with the green curve the gamma ray from the offset well and the other curves are from real-time data, differing sections of the wells. The data has been deliberately offset on the log for clarity. The upper numbers on the depth scale are for the original well, and the lower numbers are for the drilled well.

The real-time data of this well is of appropriate quality, with high data density and low signal-to-noise ratio. This level of quality enables accurate correlation and interpretation. A common occurrence in shales is lateral facies changes, in which the same stratigraphic position yields a different gamma response. This result is illustrated in Fig. 1 at 8,029 ft TSD, where one pass of the tool reads lower than the previous passes through this zone.

The resulting interpretation cross section (Fig. 2) is relatively straightforward. Even in this area of structural complexity, the tool is capable, in the hands of skilled and proficient interpreters, of accurately identifying the structural and stratigraphic position of the well while it is being drilled.

In Fig. 2, the gamma ray log measured in real time along the well path is shown below the well path and the geological structure. This display is used in conjunction with the logs from Fig. 1 to
accurately determine the stratigraphic position of the well and the geological structure. Fig. 3 shows a more detailed view of the well section.

The detailed view shows how clean the gamma ray data is. This well had rates of penetration of approximately 150 ft/hr, with occasional instantaneous rates much faster. The data does not have gaps or excessive noise. This is an example of good data acquisition for gamma ray geosteering to stratigraphy.

Unfortunately, the quality of gamma ray logging does not always meet the standards necessary for accurate well placement. Gamma tools have some intrinsic limitations that are inherent in the tool design. If the tool in question has a small scintillation detector, it will have a high signal-to-noise ratio. Counting statistics play a very large part in how the data is acquired and processed downhole. Typically, a sample period is set, all gamma ray counts are collected, and an average count rate determined. If the sample period is set too short, which is often done because of high anticipated drilling rates, then the statistics will be skewed, resulting in a very noisy signal.

With ever-increasing drilling efficiency, higher drill rates in shales mean that detection rates of processed data through mud pulse telemetry must be very high. A telemetry rate of one data point every 20 seconds, for example, results in a data density of 1 data point per ft. Missing one data point results in a gap of 2 ft between data points, but if detection is lost for a minute, then the gap is 5 ft between the data points. A two-minute gap in detection results in a 10 ft gap in the log, which makes the log impossible to correlate in real time. Fig. 4 shows an example of poor data quality, with the initial part of the well from 900 to 2,700 ft, demonstrating almost the worst possible case.

In this case, the worst possible circumstances are encountered. The detection rate is the first issue, with large gaps in the log. The second issue is a very large signal-to-noise ratio. With some tools, a very small detector in a probe-based system has a very low efficiency which results in a high signal-to-noise ratio. A small detector, combined with a short sample frequency, poor detection, and fast drilling will result in unusable
logs for correlation. This section shows that each data point has substantial noise, with point-to-point swings of up to 30 API. When attempting to interpret this data, the gaps and noise make accurate correlation almost impossible. A comparison against an offset correlation well is shown in Fig. 5. In this comparison, the offset well correlation log is in blue, with the composite stratigraphic passes offset to the left, and the last pass through the stratigraphic sequence is offset to the right. This shows how difficult data of this quality is to correlate with any sense of conviction.

One of the most important considerations in geosteering in shales using LWD gamma is data quality. Experience has shown that not all vendors adequately understand the importance of getting the best quality from their sensors. A common refrain from sales personnel is that the sensor is API calibrated, and is therefore of a suitable quality. This claim is misleading because the API calibration does not take into account system efficiency or logging speeds. As long as a sensor has a 200 API difference between the two sections of the calibration pit, it passes the API calibration. This problem of data quality disparity is often the cause of concern between vendor’s tools reading differently in the same well, or a large disparity from wireline logs in the same well. The purchaser of LWD gamma services must understand the limitations of the various systems and the effect it may have on the ability to place wells within a specific stratigraphic section. A better metric for comparison could be the system sensitivity. For an API calibration, the system will have a detection efficiency for gamma rays expressed in counts per second per API value (C/S/API). A single small probe-based detector may have a detection efficiency of 0.11 C/S/API. A larger crystal or a multi-crystal array ganged together may have a detection efficiency of 0.35 C/S/API. As a result, the second system is three times more efficient and will exhibit a lower signal-to-noise ratio with all other variables equal. Because wells are drilled with a common ROP range, usually with the same mud system, then telemetry reliability and tool setup (sample period) become more significant variables.

Telemetry affects well placement in that without reliable telemetry, the data available for accurate correlation is just not available. Here, new systems, such as EM technology, are having a significant effect, delivering data with very high reliability to the surface. This aspect should not be ignored when screening potential vendors for services.

**Geosteering with Density Images**

Azimuthal density LWD logs have a long history in geosteering. The basic premise is that a source and two detectors are located on a stabilizer blade that sweeps the borehole while drilling. As the sensor package rotates, density measurements are made around the borehole and transmitted to surface. The density data is then reconstructed as an image of the borehole, enabling features, such as bedding planes and faults, to be seen (Fig. 6).

Density images are invaluable in providing experienced geosteering geologists with an insight into the localized structure through which the well is being drilled. Real-time dips, corrected for borehole size and depth of investigation, enable the determination of local apparent dip and the trajectory of the well relative to that dip. This answers the question of whether the well is going up structure, down structure, or paralleling dip (Al-Hajari et al. 2009).

Although not in common usage for shale development wells, these tools are often used in preliminary appraisal wells and step-out wells to validate structural models and confirm seismic interpretation.

**Geochemical Steering**

Geochemical steering was pioneered for use in the North Sea, drilling thick marine shales that
were very featureless on logs and in samples. The value of chemostratigraphy in shales is maximized through the careful construction of a regional net of correlations using drill cuttings and densely sampled cores from existing vertical wells. A chemostratigraphic zonation system is developed that is largely unrelated to lithological or petrophysical characteristics, and is on a vertical scale somewhat finer than that provided by cuttings descriptions (Fig. 7). Samples from drilling wells are analyzed in real time and are immediately tied into this framework, providing an independent interpretation of wellbore position (Schmidt et al. 2010).

This method is becoming increasingly common in shale plays. With samples approximately every 30 ft (10m), it can provide a crude mineralogy and lithology log along the well path (Marsala et al. 2011), as well as analogs to geomechanical parameters. These analogs are dependent on a satisfactory calibration to core and require a great deal of analysis. The major role of chemostratigraphy is the accurate determination of the structural position of the wellbore. When using a simple gamma ray tool, it is easy to become confused regarding the structural position, especially when encountering subseismic faults. Chemostratigraphic analysis can provide a definitive answer regarding stratigraphic position very quickly after a fault is encountered, usually within 100 ft (30 m) of a fault being crossed, which is much more rapidly than a correlation system based on LWD can manage.

Geosteering to Geomechanics
A new approach to well placement in shales is the concept of geosteering to geomechanical rock properties. This concept is based on the fact that in shale plays, the rock must be stimulated by hydraulic fracturing to enable production. The process of hydraulic fracturing is governed by geomechanics. This process has been discussed frequently in recent publications (Buller et al. 2010; Pitcher et al. 2011). The fundamental concept is that geomechanics in the near-wellbore environment have a controlling influence on the ability to effectively stimulate the rock, including the desired development of fracture complexity and the ability to maintain connectivity to an induced fracture system (Pitcher and Buller 2010) by mitigating proppant embedment.

There is a clear link between the ability to place fractures successfully in shales and the local clay content of the rock (Schmidt et al. 2010). Unfortunately, in shales, clay content is not directly related to natural gamma ray content because of the preferential fixing of uranium to kerogen in the marine environment (Passey et al. 2010.). This means that gamma ray measurements are not a reliable indicator of clay, or kerogen, in the system as the measurement is influenced by the two variables independent of each other.

An alternative method of clay measurement is by the effect on geomechanics. Sonic LWD measurements in horizontal shales in real time can provide a viable alternative as a steering indicator (Fig. 8). In this example, the type of sonic tool used (dipole) enables a single compressional measurement (DTC) and two shear measurements. The fast shear measurement (DTS_F) is representative of the shear measurement taken parallel to layering in the rock; the slow measurement (DTS_S) is representative of the measurement taken perpendicular to the layering. This is discussed in more detail in Buller et al. 2010 and Pitcher et al. 2011. The log shown in Fig. 8 has seven tracks, from left to right. Track 1 includes a gamma ray, a wellbore profile in TVD, a V-Shale estimate, and some estimates of porosity. Track 2 indicates depth. Track 3 includes various resistivity easements. Track 4 includes density, porosity, and stand-off correction measurements. Track 5 shows sonic measurements. Track 6 includes derived brittleness index, transverse isotropic ratio, and frac index. These last derived measurements are calculated according to the method outlined by Buller et al. (2010). The frac index, which is a modification of a brittleness index, is calculated and displayed in track 6 with a shading to indicate a frac index greater than 30%. This is an arbitrary cut-off used to highlight the most suitable rock for hydraulic stimulation.
Track 7 is an azimuthal gamma ray image to provide structural control, with dip sinusoids fitted.

What is apparent from the log is that sometimes the rock in which the highest gamma ray occurs (9,040 ft) correlates almost exactly with the best quality rock from a geomechanics standpoint. However, a second gamma peak at 9,250 ft does not show the same high-quality reservoir. This occurrence may be the result of this zone being clay-rich rather than kerogen-rich, leading to the notion that gamma measurements do not necessarily indicate the best rock to initiate stimulation. A gamma ray measurement of just under 300 API coincides with the best rock quality, but is nonunique. The nonuniqueness of the gamma measurement is one of the fundamental problems in using this tool as the sole source of geosteering information (Schmidt et al. 2010).

In the case of the Marcellus section shown in Fig. 8, it is clear that a good quality brittle zone, with lower clay content and good geomechanical properties, has been traversed as the well has dropped in TVD. However, the image log indicates that the well is climbing in section through this area. Without the image log, it is challenging to determine the correct structural position, but the addition of an image log simplifies the interpretation.

**Figure 8. LWD responses in a horizontal well in the Marcellus.**

**Conclusion**

At the time of writing, the majority of wells drilled in the unconventional shale wells are geosteered using the most basic of tools, usually LWD gamma ray, with ROP, cuttings descriptions, and gas analysis when available. The inherent limitations of this methodology, being subject to the vagaries of sensor physics, can lead even the most experienced geosteerer astray. Lateral heterogeneity, poor sensor measurements, high rates of penetration, poor counting statistics all lead to a difficult interpretation environment. Understanding of these limitations and the sources of error enable the geosteerer to take control of the process, enabling better wellbore placement within the stratigraphy.

Gaining a better understanding of the relative local structure by way of real-time image logs is a step change in enabling geosteering performance. This is not performed on a regular basis as yet, because of perceived complexity and lack of image interpretation tools available. Where it has been used, the increase in the ability to accurately interpret the structural geology and the higher level of confidence in the stratigraphic placement of the well has been a major benefit to geosteerers.

Finally, the case that steering to a different rock property has been raised. As yet, there is insufficient data for a definitive answer, but geosteering to geomechanical properties rather than pure stratigraphic placement has merit. The major cost in producing shale reservoirs is the stimulation of the shale by means of hydraulic fracturing. If geosteering to geomechanics using real-time acoustic logs enables better stage placement and ultimately, production, that can far outweigh the costs of upgrading the geosteering technology used to place the wells.
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