SPE 146658

The Effects of Fracturing Fluids on Shale Rock Mechanical Properties and Proppant Embedment

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This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA, 30 October–2 November 2011.

Abstract

The development of shale reservoirs has grown significantly in the past few decades, spurred by evolving technologies in horizontal drilling and hydraulic fracturing. The productivity of shale reservoirs is highly dependent on the design of the hydraulic fracturing treatment. In order to successfully design the treatment, a good understanding of the shale mechanical properties is necessary.

Some mechanical properties, such as Young's modulus, can change after the rock has been exposed to the hydraulic fracturing fluids, causing weakening of the rock frame. The weakening of the rock has the potential to increase proppant embedment into the fracture face, resulting in reduced conductivity. This reduction in conductivity can, in turn, determine whether or not production of the reservoir will be economically feasible, as shale rocks are characterized by their ultra-low permeability, and conductivity between the reservoir and wellbore is critical. Thus, shale reservoirs are associated with economic risk; careful engineering practices; and a better understanding of how the mechanical properties of these rocks can change are crucial to reduce this risk.

This paper discusses various laboratory tests conducted on shale samples from the Bakken, Barnett, Eagle Ford, and Haynesville formations in order to understand the changes in shale mechanical properties, as they are exposed to fracturing fluids, and how these changes can affect the proppant embedment process. Nanoindentation technology was used to determine changes of Young's modulus with the application of fracturing fluid over time and under high temperature (300 °F) as well as room temperature. Mineralogy, porosity, and total organic content were determined for the various samples to correlate them to any changes of mechanical properties. The last part of the experiments consisted of applying proppants to the shale samples under uniaxial stress and observing embedment using scanning acoustic microscope.

The results of this study show that maximum reduction of Young's modulus occurs under high temperature and in samples containing high carbonate contents. This reduction in Young's modulus occurs in "soft" minerals as well as the "hard" rock-forming minerals. This reduction of modulus can cause the effective fracture conductivity to decrease significantly.

Introduction

In geology, shale has traditionally been defined as a sedimentary rock containing high percentages (more than 50%) of clays and lower percentages of silica or carbonate minerals (Britt and Schoeffler, 2009). However, many of the shale prospects that are currently being developed in the petroleum industry are not shales, as defined in geology. They are, instead, "prospective shale" reservoirs, which are fine-grained clastics that are characterized by their ultra low permeability and usually composed of silica and carbonate with a small amount of clay minerals (Britt and Schoeffler, 2009).

Generally, shale rocks have been considered as source rocks for conventional oil and gas reservoirs. However, with technological evolution in the petroleum industry, such as hydraulic fracturing, the rising oil and gas prices, as well as the escalating demand for fossil fuels, these rocks are increasingly regarded as the source, the seal, and the reservoir. Subsequently, development of such reservoirs is becoming more and more technically and economically feasible.

The reasons behind the success of these shale systems are largely dependent on excellent hydraulic fracturing designs that require a good understanding of the mechanical properties of the subject and confining formations. In hydraulic fracturing design, Young's modulus is one criterion used to define the most appropriate fracturing fluid and other design considerations. Young's modulus provides an indication of how much fracture conductivity, $k_f w$, can be expected due to width and embedment considerations. Without adequate fracture conductivity, production from the hydraulic fracture will be minimized if not completely eliminated. This paper discusses conditions where Young's modulus is shown to decrease

significantly in the presence of certain fluids. Such decreases in Young's modulus lead directly to resulting decreases in fracture conductivity, and therefore, should be taken into account when designing for the required fracture conductivity in a given reservoir.

Methods and Testing Procedures

It has long been known that fracturing fluids can impact the formation face of the created factures and cause damage. This damage can manifest itself as filter cake, fluid imbibition, and other such damage mechanisms. However, in productive shale systems, the potential for an additional damage mechanism is possible. This additional mechanism is the potential weakening of the rock frame or modification of Young's modulus which could allow additional proppant embedment to take place. Such embedment, if occurring, could greatly affect the fracture conductivity of a given treatment.

This project was focused on evaluating such frame weakening and embedment by using a series of laboratory experiments including nanoindentation, quantitative evaluation of minerals by scanning electron microscopy (QEMSCAN), pyrolysis, and scanning acoustic microscope (SAM). Four different productive shale formations were tested including the Bakken (middle and lower), the Barnett, the Eagle Ford, and the Haynesville. The first step was to determine Young's modulus (E) before and after the application of fluids using a depth sensing indentation technology known as nanoindentation. Nanoindentation can be used to determine moduli on very small samples by recording force and displacement (Abousleiman et al., 2009) and is a non-destructive measurement technique (Oliver and Pharr, 1992). A series of 25 indentation measurements, in a 5 X 5 pattern, were taken on each shale sample prior to application of any fluid (Akrad, 2011). These measurements were converted to Young's modulus values and averaged to provide a singular value for that given shale sample as presented in Table 1. Fluids were then applied to the same samples, under different conditions including five days at room temperature (2% KCl slickwater), 15 days at room temperature (2% KCl slickwater), 30 days at room temperature (2% KCl slickwater), 48 hours at 300 °F (2% KCl slickwater), and 48 hours at 300 °F (fresh water). A second series of 25 indentation measurements, taken in the same 5 X 5 pattern but offset by at least 12.5 µm to avoid interference with the first sets of indents, were then taken and also averaged for comparisons purposes (Akrad, 2011).

After the nanoindentation measurements were performed, the samples were submitted to QEMSCAN testing to identify mineralogy and porosity. The QEMSCAN is an excellent tool for quantifying the porosity and mineralogy of fine-grained materials found in most shale systems (Appleby and Stammer, 2009). Figure 1 show the results of the QEMSCAN mineralogy for the different samples used including the Middle Bakken, Lower Bakken, Barnett, Eagle Ford and Haynesville, respectively, and Table 2 shows the mineral percentages and porosity measurements for all five samples. Once the QEMSCAN measurements were completed, the pyrolysis method was used in all samples to quantify the total organic content (TOC), classify the type of kerogen in the samples, the maturity level, and the rock's hydrocarbon potential (Jarvie, 1991). These results are presented in Table 2.

Finally, the shales were cut parallel to the bedding plane and proppants were placed between the cut faces of the shale samples. Lower pressure uniaxial stress was applied on the sample perpendicular to the cut faces with proppants between them and embedment was observed using a scanning acoustic microscope. SAM uses sound to investigate and image the surface and internal feature of an object. SAM is an excellent tool to investigate delaminations that are as narrow as a micrometer, as well as any inhomogeneity in the subsurface. The so-called C-scans were obtained of the samples that were focused in the fracture face. A C-scan is an x-y scan with a user defined time window. Thus, C-scans are images of the x-y plane that are made at various times corresponding to depths, z, in the sample. These scans allow the imaging of variations and cracks at or below the sample surface (Prasad et al., 2009).

Core Preparation

Cores, approximately one inch in height and 0.75 inches in diameter, were used from each formation for the nanoindentation, QEMSCAN, and SAM testing. The fracturing fluid mixture used in the experiments was a slickwater with KCl added. The reason for using the slickwater KCl in this experimental work is because of its wide use in fracturing shale systems. The mixture used consisted of a 2% KCl water with friction reducer at a concentration of 1.0 gallon per thousands (gpt). The addition of the KCl is intended to prevent swelling of clays, specifically smectite, present in the formation. The 1.0 gpt friction reducer concentration was used since it also falls within the range that is normally used in the industry for hydraulically fracturing shale systems.

As mentioned, time and temperature effects were studied on the different samples using nanoindentation methods. First, the effect of time was observed by exposing samples to the fluids at room temperature for 5, 15, and 30 days. Second, the effect of temperature was studied by heating certain samples to 300 °F for 48 hours and subsequently comparing them to the samples exposed to the same fluids at room temperature. In addition to the time and temperature comparisons, the effect of using KCl versus fresh water was studied on two samples with different mineralogical composition; a sample rich in calcite (Middle Bakken sample) and a sample rich in quartz and clay (Barnett sample). The various test parameters are listed in Table 1.

The mineralogy and porosity were determined using the QEMSCAN for each one of the different formations. Mineralogy scans were done on each sample where a 1 x 5 mm area was analyzed at a 2.5-µm resolution. Meanwhile, porosity was analyzed for a 10 x 10 mm area at a 2-µm resolution.

In order to prepare cores for the pyrolysis method, 100 mg of each sample was used. The samples were ground and pulverized down to 100-mesh. Once the total organic content (TOC) data was obtained, further analysis was done to classify the type of kerogen in the samples, the maturity level, and the rock's hydrocarbon potential.

The last laboratory part of this project consisted of applying stress on the core plugs while observing the embedment of proppants into the fractured face using a scanning acoustic microscope. C-scan images were obtained for every shale sample. Core samples were cut along the bedding plane and one layer of proppants (partial monolayer) was placed inside. Images were taken of the subsurface after each plug had been fractured and the 12/18 proppants were place before applying any stress. SAM images were then taken after applying uniaxial force in 5-lbs interval in order to observe the behavior of embedment.

Samples Used

Four formations that are major contributors to hydrocarbon production in the United States were tested for this research: The Bakken (North Dakota), the Barnett (Texas), the Eagle Ford (Texas), and the Haynesville (Texas and Louisiana). The tested formations differ from each other in their depositional environments and mechanical and reservoir properties, which made them good candidates for this experimental work. These differences make each reservoir unique, which can result in different reactions to the fracturing fluids. As seen in Figure 1, the QEMSCAN results show a variation in mineralogical composition. The different samples contain quartz, illite -smectite clays, and calcite with varying content percentages. Lower Bakken and Haynesville contain mostly water-sensitive illite-smectite clay, the Middle Bakken and the Eagle Ford are carbonate and are mostly composed of calcite, while the Barnett is quartz-rich.

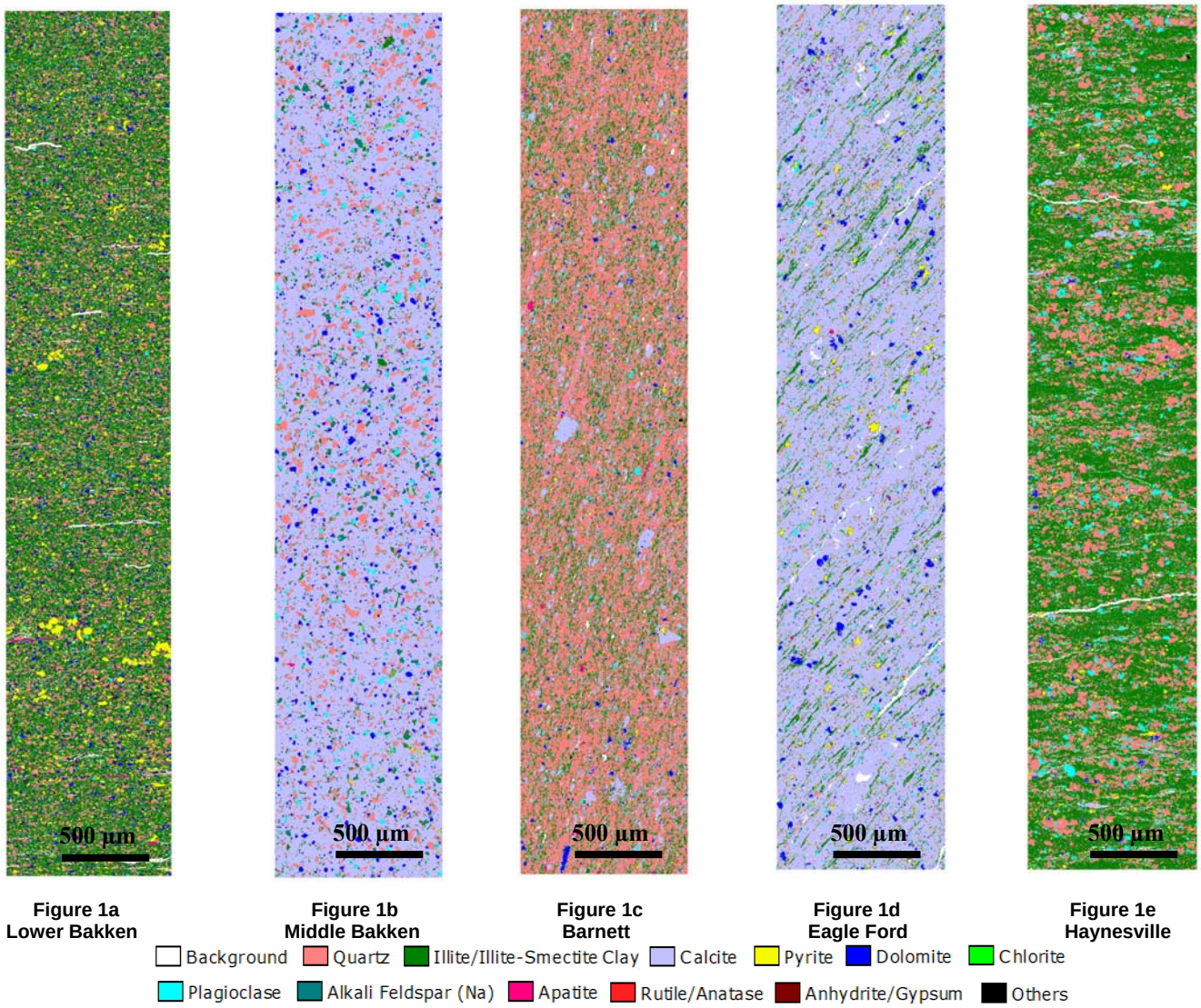

Figure 1. False-colored mineralogy images produced from QEMSCAN. The different samples come from the Lower Bakken, Middle Bakken, Barnett, Eagle Ford, and the Haynesville formations (order from left to right in the graph). The different images show that the Lower Bakken and the Hayneville are clay-rich samples, the Middle Bakken and Eagle Ford are calcite-rich samples, while the Barnett is mostly composed of quartz.

Results

Nanoindentation results are presented in Table 1 for each formation for the three different parameters studied: the effect of time, the effect of temperature, and the effect of KCl on the changes of Young's modulus.

Table 1. Nanoindentation Results for the Different Treatments.

Formation Tested	Treatment Done	E Before	E After	E Before	E After	E Reduction
		GPa	GPa	X 10^{+6} psi	X 10^{+6} psi	%
Lower Bakken	5 days @ room temp with 2% KCl slickwater	24.18	20.39	3.51	2.96	15.67
	30 days @ room temp with 2% KCl slickwater	47.39	33.85	6.87	4.91	28.56
	heated for 48 hrs @ 300 °F with 2% KCl slickwater	47.39	36.85	6.87	5.34	22.24
Middle Bakken	30 days @ room temp with 2% KCl slickwater	57.38	34.11	8.32	4.95	40.56
	heated for 48 hrs @ 300 °F with 2% KCl slickwater	70.84	33.73	10.27	4.89	52.39
	heated for 48 hrs @ 300 °F with fresh water	74.39	35.73	10.79	5.18	51.97
Barnett	5 days @ room temp with 2% KCl slickwater	45.97	41.35	6.67	6.00	10.06
	15 days @ room temp with 2% KCl slickwater	45.97	38.93	6.67	5.65	15.32
	30 days @ room temp with 2% KCl slickwater	47.22	40.98	6.85	5.94	13.22
	heated for 48 hrs @ 300 °F with 2% KCl slickwater	50.57	34.45	7.33	5.00	31.88
	heated for 48 hrs @ 300 °F with fresh water	74.17	44.05	10.76	6.39	40.61
Eagle Ford	5 days @ room temp with 2% KCl slickwater	35.09	25.18	5.09	3.65	28.25
	15 days @ room temp with 2% KCl slickwater	44.85	21.25	6.51	3.08	52.63
	30 days @ room temp with 2% KCl slickwater	35.09	19.35	5.09	2.81	44.85
	heated for 48 hrs @ 300 °F with 2% KCl slickwater	35.09	10.50	5.09	1.52	70.08
Haynesville	5 days @ room temp with 2% KCl slickwater	38.74	35.79	5.62	5.19	7.62
	30 days @ room temp with 2% KCl slickwater	38.74	36.32	5.62	5.27	6.26
	heated for 48 hrs @ 300 °F with 2% KCl slickwater	38.74	36.41	5.62	5.28	6.01

Effect of Time

Figures 2-5 show the effects of time on the modulus of the Lower Bakken, the Middle Bakken, the Barnett, and the Eagle Ford, respectively. It is evident from the results that the Young's modulus decreases with time for these four examples. This decrease is up to 51%, as demonstrated in Figure 5 for the Eagle Ford sample after only 15 days exposure to fluids. The decrease is significant in all samples except for the Haynesville, as seen in Figure 6, where the Young's modulus for that sample decreased by only 8%.

Effect of Temperature

Figures 3-5 for the Middle Bakken, Barnett and Eagle Ford, which were heated to 300 °F in the 2% KCl slickwater fracturing fluid mixture, show that the Young's modulus decreased substantially in comparison to the samples exposed to the fracturing fluids at room temperature. This shows that the temperature does have an effect on the Middle Bakken, Eagle Ford and Barnett. The higher the bottom hole temperature, the more decrease in modulus can be expected for these formations. However, for the Lower Bakken and the Haynesville, as seen in Figures 2 and 6, the Young's modulus did not decrease as significantly when the samples were heated.

Effect of KCl

Two samples with different mineralogical composition were used to study the effect of KCl on the change of Young's modulus. The two formations are the Middle Bakken, which is a calcite-rich formation, and the Barnett, a formation rich in quartz and clay. Figure 3 shows the results for the Middle Bakken sample. The results for the sample that was heated with fresh water had a Young's modulus decrease of 50%. Similarly, the Young's modulus decreased by 50% for the Middle Bakken sample that was heated with the fluid mixture containing KCl. The similar reduction in Young's modulus can be correlated to the mineralogy of the sample. The Middle Bakken has a low (4%) water sensitive illite-smectite clays while the dominate mineralogy is calcite with a 77% by volume. It can be concluded that KCl is not necessary in calcite-rich and clay-poor formations and that the use of KCl is ineffective when trying to prevent additional loss of Young's Modulus.

The second set of samples, used for the effect of KCl study, comes from the Barnett formation. For the Barnett sample that was heated in fresh water, the modulus decreased significantly by 30% of the original value as seen in Figure 4. When comparing the fresh water results to the slickwater-KCl fluids, the fresh water caused an additional 10% decrease in modulus value. Because the Barnett contains a fair amount of water-sensitive clays (21%), the presence of KCl may have contributed to preventing the rock frame from becoming less stiff once exposed to the fracturing fluids. Due to the fact that the decrease was insignificant and that only one sample was used, additional testing should be done to validate any final conclusions.

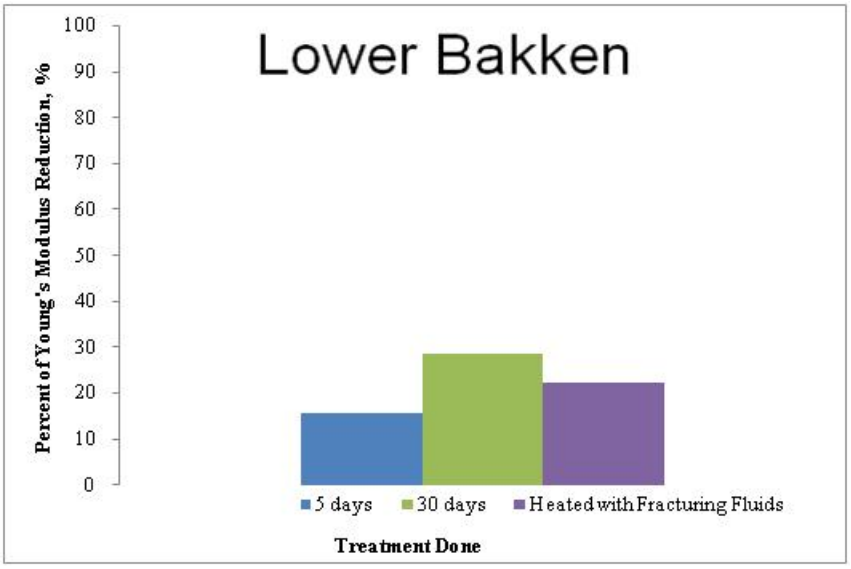

Figure 2. Nanoindentation average results of the clay-rich Lower Bakken show a decrease in Young's modulus after each treatment.

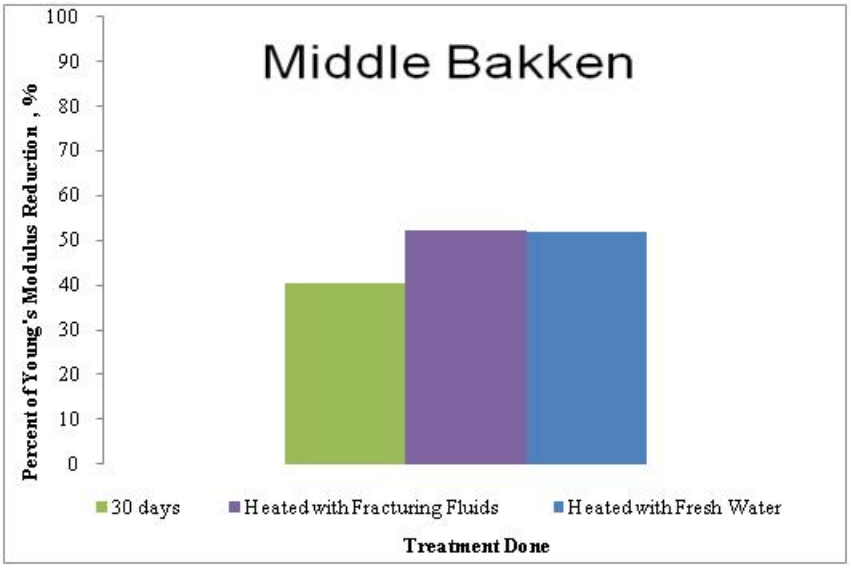

Figure 3. Nanoindentation results for the calcite-rich Middle Bakken sample show the decrease of Young's modulus after each treatment. The decrease for the 30-day with KCl treatment shows a high 48% loss of stiffness. For the heated samples, the modulus decreased by 50% of its original value with or without KCl in the water.

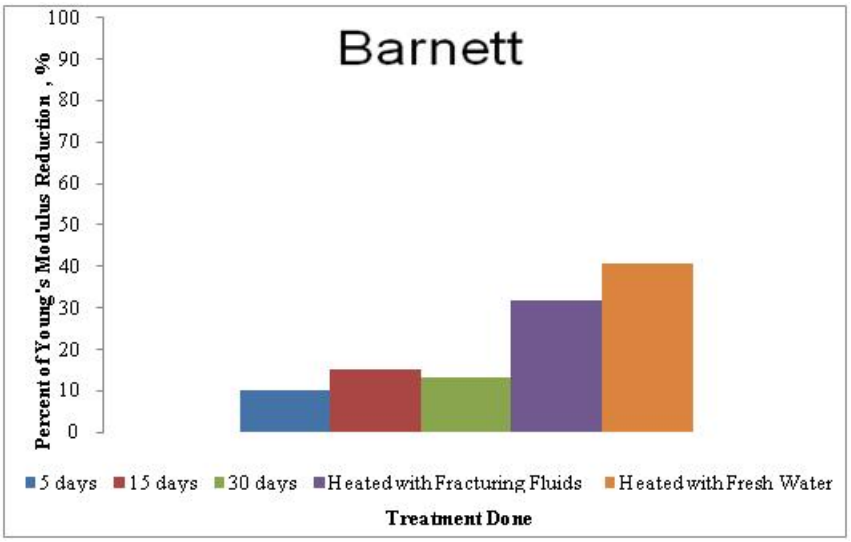

Figure 4. Nanoindentation results for the quartz-rich Barnett sample show a decrease of Young's modulus after each treatment. The modulus decreased significantly once it was heated.

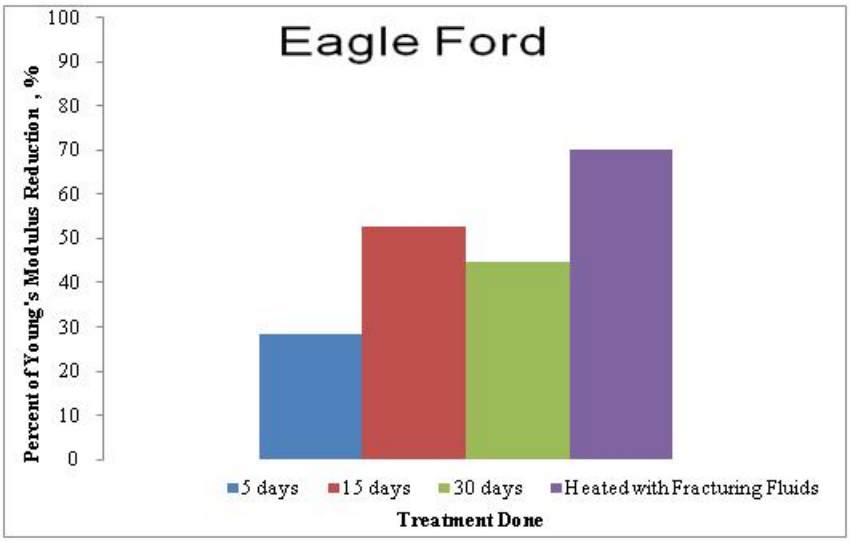

Figure 5. Nanoindentation average results for the calcite-rich Eagle Ford samples show a decrease of Young's modulus after each treatment. The modulus value decreased after being exposed to fluids for only five days at room temperature and continued decreasing with time. However, a higher decrease of the modulus was observed in the heated sample.

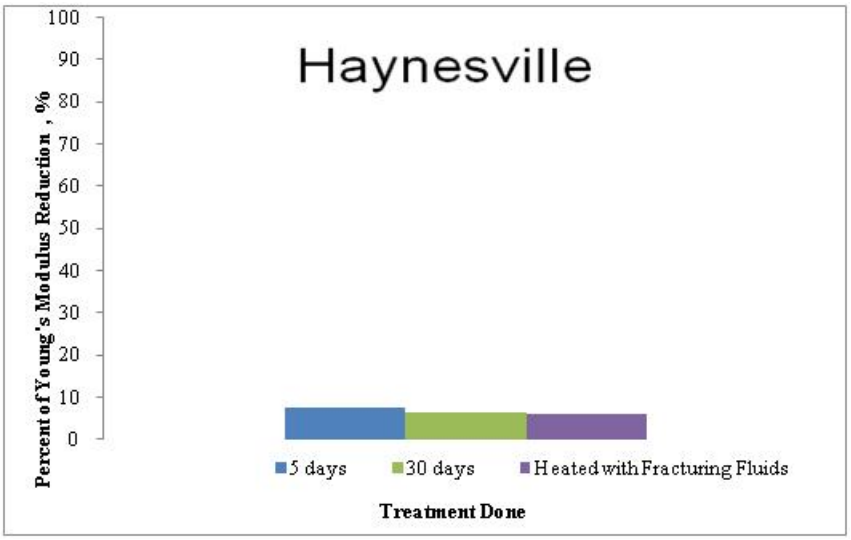

Figure 6. Nanoindentation average results for the clay-rich Haynesville samples after each treatment show a decrease of the modulus. The modulus value decreased by 8% after the sample was exposed to fluids for only five days at room temperature. No additional decrease in the modulus was seen with time or with heated fluids.

Comparison of "Soft" and "Hard" Minerals

"Soft" minerals can be defined as minerals with relatively low (below 30 GPa) Young's modulus. Clay minerals and organic matter would belong to this "soft" minerals category. On the other hand, "hard" minerals are the rest of the rock-forming minerals (Bathija, 2009; Mba et al., 2010).

Figure 7 is used to investigate whether the "soft" minerals or the "hard" rock-forming minerals are becoming less stiff after exposure to the 2% KCl slickwater fracturing fluids. The averages for samples heated to 300 °F for 48 hours were taken for each one of the samples. The nanoindentation data from each treatment were sorted by the Young's modulus values. Nanoindents that had a modulus value of less than 30 GPa were considered a "soft" clay mineral, while indents with a Young's modulus values above 30 GPa were considered "hard" minerals.

The averages for the "soft" minerals can be seen in the left-lower corner on Figure 7 while the averages for the "hard" minerals can be seen in the upper-right corner of the figure. The x-axis represents the original value of Young's modulus before treatments, while the y-axis shows the modulus averages after treatment, with the blue line representing the one-to-one ratio of values. As shown in Figure 7, the values of both the soft and the hard minerals decreased for almost all of the different formations. According to the general trend, not only do the "softer" minerals get less stiff, but so do the "harder" minerals. Since the Haynesville had little decrease in modulus, the increase in the modulus for the "hard" minerals value is likely due to measurement variability.

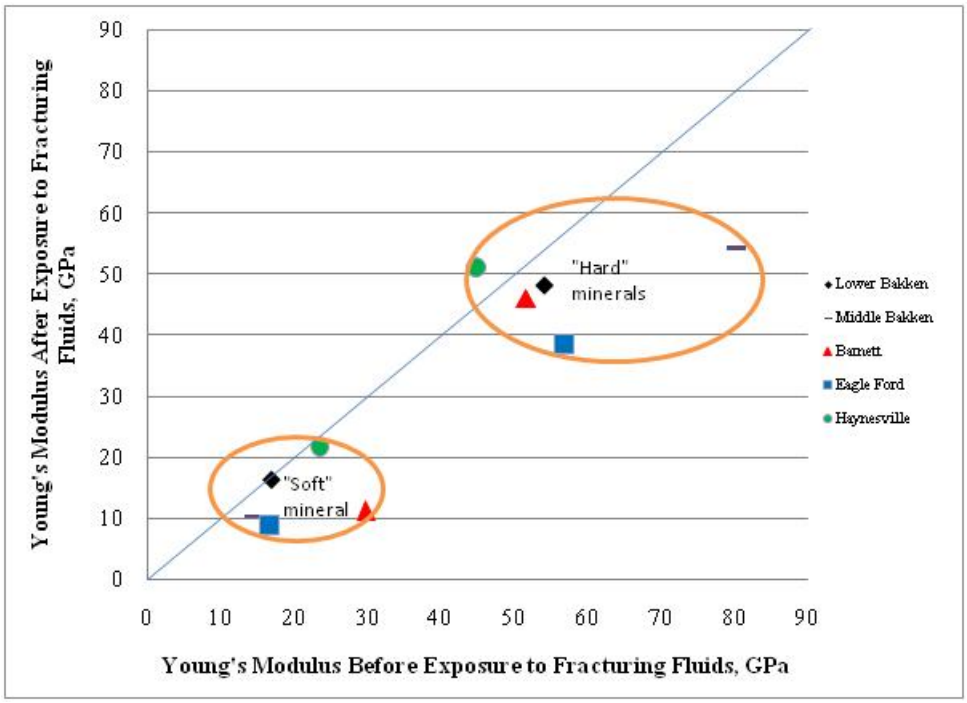

Figure 7. Average Young's modulus measurements for the different shale samples. The x-axis represents the initial Young's modulus value before any exposure to fracturing fluids while the y-axis shows the Young's modulus average values for the samples after heating with fracturing fluid mixture to 300 °F for 48 hours. The values for each sample were divided into "soft" minerals and "hard" minerals. The graph shows a decrease in modulus values for both, the soft and hard mineral in almost all samples.

Scanning Acoustic Microscopy Results

Two images for each sample were taken using the scanning acoustic microscope after cutting the samples in the middle and applying proppants: one image before applying stress to the sample, and another image after applying stress until the sample fractured. First, samples were cut in the middle of the core along the bedding planes. Proppants were then placed inside the sample and uniaxial stress was applied.

Figure 8 shows SAM images of an Eagle Ford sample. Figure 8a is a SAM image that was focused few millimeters into the sample to the point of where the rock was cut and proppants were placed. The variance in the brightness levels represents a difference in impedance which correlates to the difference in stiffness. Figure 8b is the same type of image as 8a but after applying some stress on the samples. Figure 8a displays a lighter-grey region (marked by arrows) representing the change in impedance. Figure 8b shows fractures initiated in the rock after applying a stress of 30-lbf to the sample. Looking at 8b, the rock samples tended to fracture along the impedance transition zone, or where the change in the brightness levels is observed after applying unconfined compressional stress.

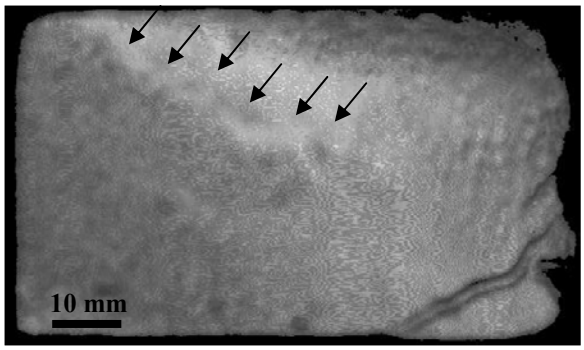

Figure 8a

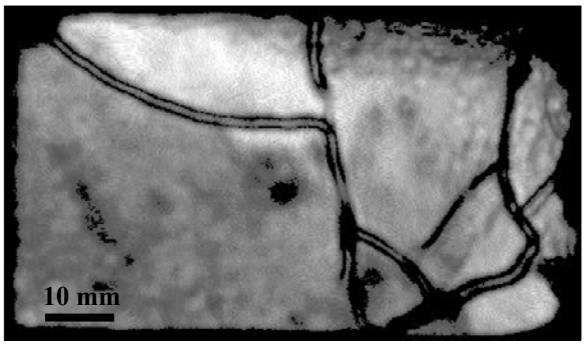

Figure 8b

Figure 8. Scanning acoustic microscope images that are focused into an Eagle Ford sample to where the sample was cut and proppants were placed. Figure 8a shows the initial state of the rock before applying any stress. The zones where the impedance changes from low to high can be observed by a change in the brightness levels. Figure 8b, displaying the rock's image after a 30 lbf was applied, shows that the rock failed and fractures initiated along the impedance transition zone.

A similar effect was seen in the Haynesville sample shown in Figure 9. Figure 9a is an acoustic scan that represents the proppant interface before applying and stress, while 9b represents an acoustic scan of the subsurface after applying 20 lbf. Looking at Figure 9a, some natural fractures can be noticed. After applying a 20 lbf to the sample, the rock failed along the natural fractures and along the high-low impedance transitional zone (marked by arrows), as seen in Figure 9b.

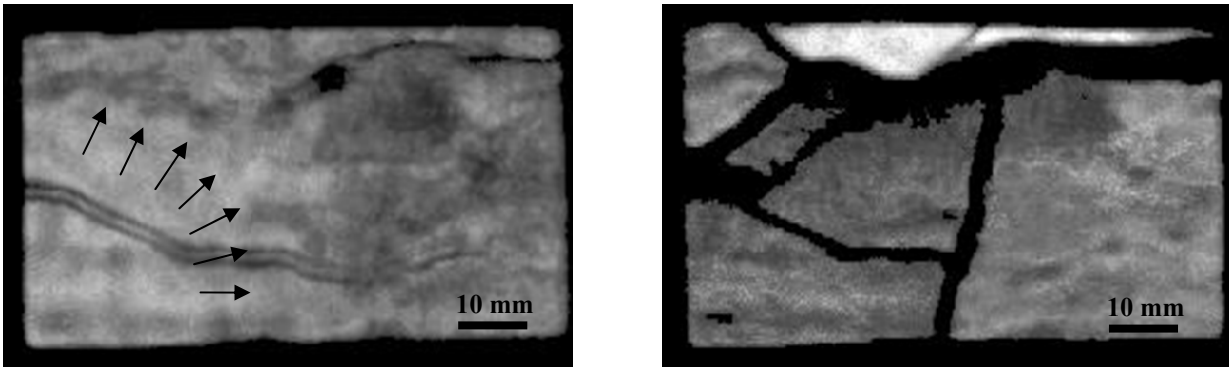

Figure 9a **Figure 9b**

Figure 9. Scanning acoustic microscope images that are focused into a Haynesville sample to where the sample was cut and proppants were placed. The region with a change in impedance is marked by a change in the brightness levels. Following the application of a 20 lbf to the sample, the initiation of fractures along this region, as well as along the natural fractures, is observed.

Another important observation was seen when the rock was taken apart. Most proppant embedment was detected in the region of high-low impedance change and in the region of where the rocks tend to break. Looking at Figures 10 and 11, it is evident that the embedment is mostly concentrated along the fractures.

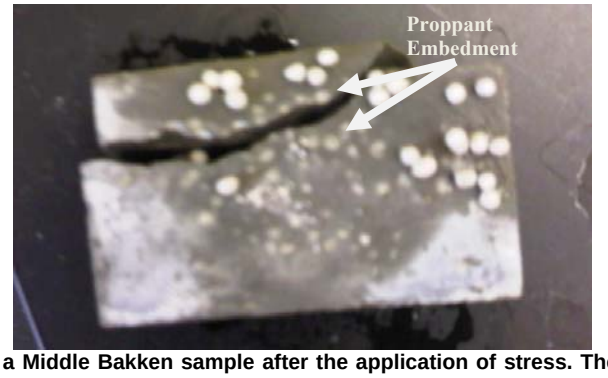

Figure 10. A photographic image of a Middle Bakken sample after the application of stress. The image shows embedment is most severe along fractures.

Figure 11 is a photo image of a Barnett sample showing the embedment being concentrated along the created fractures suggesting that embedment is most severe at the high-low impedance regions.

Figure 11. Barnett image showing the embedment is most severe along created fractures.

In the samples evaluated, the rock fractures in the high-low impedance transition regions. This can be explained by the stress buildup in the higher impedance region, while embedment cause stress relaxation at the less stiff region. Both Young's modulus and the impedance are calculated as a function of wave velocities of the rocks (V_p and V_s). Higher modulus value means higher impedance. Proppants usually have a very high Young's modulus and can undergo high stress that is up to 65

MPa (9,200 psi) closure stress for intermediate strength lightweight before they break or crush (Reinicke et al., 2010). When compared to the shale's modulus, proppants have a much higher modulus value of up to 380 GPa (55 X 10^6 psi).

Figure 12 shows an illustration of a rock cut in the middle with proppants placed inside. Figure 12a is a scenario where the rock has two regions with one region being stiffer than the other. The region on the left is the stiffest with (I_2) impedance and (E_2) modulus, while the region on the right is the softer region with (I_1) impedance and (E_1) modulus values. Unconfined uniaxial stress is being applied to the sample as seen in Figure 12a. After applying the stress, proppants get embedded into the fracture face in the softer region while stress builds up in the stiffer region. This causes the rock to break as seen with the scanning acoustic microscope images.

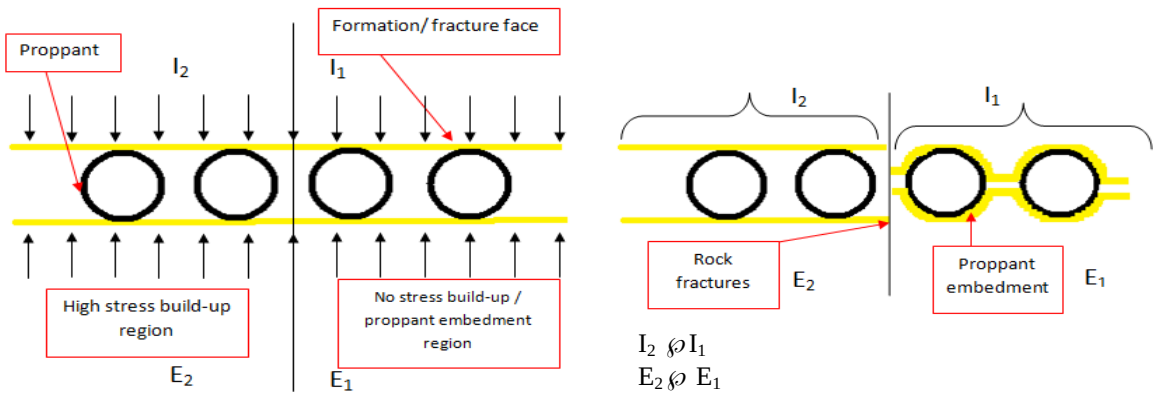

Figure 12a **Figure 12b**

Figure 12. A graphic illustration, explaining the fractures that occur in the high-low impedance difference in the rock. As uniform unconfined stress gets applied to a fracture containing proppants, the proppants tends to get embedded in the softer region while more stress builds up in the stiffer region. Thus, causing the rock to break at the region where there is an impedance difference.

Analysis and Discussion

In order to investigate the conductivity loss due to the additional embedment caused by the decrease of Young's modulus, a proppant embedment factor was calculated. The calculation of this factor was based on studies done by the Stim-lab Proppant Consortium (Stim-lab, 2006). Table 2 shows that the decrease of modulus can cause fractures to lose as much as 38% of their effective permeability, as observed in the Eagle Ford sample. The Haynesville sample shows a minimal loss of effective permeability and only a 1% loss of effective permeability due to the decrease of modulus. Table 2 shows the highest Young's modulus decrease (70%) and (52%) in the Eagle Ford and the Middle Bakken, respectively. Both samples had a similar mineralogical composition; a very high (77%) calcite for both samples and low (4%) and (8%) illite-smectite clays for the Eagle Ford and Middle Bakken, respectively. Similarly, the clay-rich samples like the Lower Bakken and the Haynesville, containing higher clay contents (47%) and (57%) respectively, had a lesser decrease in E values.

Correlations between Young's modulus decrease and the mineralogical composition can be made. The higher the calcite content in a shale sample, the more reaction the sample had to the fracturing fluids. Meanwhile, the higher the clay content, the less conductivity loss can be expected due to the change of E values. One of the factors, explaining the Young's modulus decrease in calcite-rich formations, is the tendency of carbonate to dissolve in water. Based on a paper by Brirkle et al., carbonates, such as calcite and dolomite, are sensitive to water and have temperature-dependent solubility (Brirkle et al., 2006). Therefore fracturing fluids, especially at higher formation temperatures, causes these minerals, particularly calcite, to precipitate.

Table 2. Summary of Results of all Shale Samples after Heating with Fracturing Fluids to 300 °F for 48 Hours

Test Conducted	Properties	Lower Bakken	Middle Bakken	Barnett	Eagle Ford	Haynesville
Nanoindentation	Young's Modulus Reduction (%)	22	52	32	70	6
	Conductivity Loss Due to E Reduction (%)	5	14	8	39	1
TOC	TOC (%)	17.18	0.45	4.40	4.99	3.53
	TOC Type	II Oil Prone	IV Inert	III Gas Prone	III Gas Prone	II Oil Prone
	TOC Maturity	Mature	Immature	Mature	Mature	Mature
QEMSCAN	Porosity (%)	16.0	0.8	5.4	4.8	9.7
	Illite-Smectite (%)	47	4	21	8	57
	Quartz (%)	21	11	59	3	28
	Calcite (%)	0	77	12	77	2
	Pyrite (%)	13	1	2	6	5
	Dolomite (%)	10	4	1	2	0

Conclusions

Conclusions from the performed experiments can be summarized as follows:

- For the formations and samples evaluated, the Young's modulus does decrease in shale rocks after being exposed to 2% KCl water with friction reducer added, thus decreasing the expected conductivity by as much as 40%. This decrease should be accounted for when designing for required conductivity;
- Decreases in modulus values tend to be higher for calcite-rich formations, while a lesser decrease can be expected for quartz and clay rich formations. The expected decrease is approximately 30-50% for calcite-rich formations, 3-30% for clay-rich formations, and 10-30% for quartz-rich formations;
- The decrease of Young's modulus in calcite can be related to the precipitation of the carbonate minerals; therefore, overdesigning for conductivity is advised especially in these types of formations;
- At higher temperatures, the modulus decreases more than it does at room temperature (10-25% more) in the Middle Bakken, the Barnett and the Eagle Ford. Clay-rich formations such as the Haynesville and Lower Bakken were not as temperature sensitive as the calcite and quartz-rich formations;
- The modulus decreases in “soft" minerals as well as “hard" minerals, which weakens the entire rock frame;
- The use of KCl has no effect in calcite-rich formations. However, the use of KCl may be helpful in preventing Young’s modulus decrease. However, further testing is required to validate any conclusions;
- Rocks do fracture in regions where there is a difference in impedance; this region is also where most embedment occurs; and,
- For the measured samples, no significant correlations can be made between organic content and decreases in Young’s modulus.

Nomenclature

E	=	Young’s modulus
I	=	Impedance
$k_f w$	=	Fracture conductivity
QEMSCAN	=	Quantitative Electron Microscope Scanner
SAM	=	Scanning acoustic microscope
TOC	=	Total organic content
V_p	=	Compressional wave velocity
V_s	=	Shear wave velocity

Acknowledgments

The authors gratefully acknowledge FAST Consortium at the Colorado School of Mines and its participants for funding this project. Prasad's work was supported by a grant from DOE (Award#: DE-NT0005672) and the Norwegian Research Council. Specific thanks are given to Encana, ConocoPhillips, and Calfrac for providing the required core samples, proppants, and fracturing fluids used. Other thanks to the Bakken Consortium at Colorado School of Mines for providing Bakken samples. The authors would also like to thank Eleanora Yurkevich for editing comments.

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