Overview of Rock Property Relationships and Characterization methods for Selected Oil and Gas Shales in North America

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Abstract

Oil and gas shale plays in North America have come to the forefront of hydrocarbon exploration and production, particularly in the United States, due to their extraordinarily large geographic extent and accompanying reserve capacity. Exploitation has occurred primarily through horizontal drilling and hydraulic fracturing to increase permeability to economic levels. Although the number of wells drilled is in the thousands, geophysical characterization rarely has been used to help identify engineering and reservoir properties of interest. Potential exists to identify productive zones within the shale plays from joint analysis of seismic and petrophysical data. This paper is an overview of five shale plays, including the Bakken, Marcellus, Barnett, Haynesville, and Woodford Shale. A brief geologic background for each is provided along with potential methods for multi-faceted geophysical characterization. Data examples are provided where available. These five shales exhibit some similarity amongst themselves in terms of composition and/or fracturing, but appropriately calibrated petrophysical and rock physics models and seismic-data analyses must be applied to each.

Introduction

This work presents basic relationships between reservoir and elastic properties observed for five producing shales in North America. The shales discussed here are the Bakken, Marcellus, Barnett, Haynesville, and Woodford Shales (Figure 1). These five are geographically widespread and have proven production histories over the previous 5-15 years.

Oil and gas production from shales has provided a large supply to the domestic market in the United States. This has occurred largely without geophysical, petrophysical, and/or rock physical characterization for many of the plays. In the instances where geophysics has been used, the specific applications differ substantially from shale to shale for many reasons. In some cases, the fluid produced is oil (the Bakken), which has a different effect on velocity than the other four shales, which all primarily produce gas. These shales may not always be naturally fractured, which is the case of the Haynesville. The other three may contain vertical fractures, horizontal fractures, or both. The shapes and sizes of pores also can influence shale characterization. In some cases, the pore sizes are on the nanometer scale, with shapes ranging from nearly spherical to flat and elongated, with corresponding larger or smaller stiffness and velocity. Finally, the amount and spatial distribution of organic content or kerogen can affect geophysical measurements and models. In principle, the more organic content that is present should correspond to a higher concentration of hydrocarbon. However, that hydrocarbon can be located in the pores of the kerogen itself (e.g., Curtis et al., 2010), within fractures, or in matrix porosity, all of which affect the elastic and transport properties of the shales. Ultimately, the transport properties are of most interest, and geophysical, petrophysical, and rock-physics tools can be used to determine locations with optimum rock properties and transport properties.

Regardless of the location of the hydrocarbon, permeability in each shale is extremely low, which requires hydraulic fracturing in order for production to be economic. Choosing the optimal location for fracturing is key for the drilling operations. However, ambiguity exists in relating geophysical data to engineering parameters useful for designing fracture operations. From an engineering standpoint, these fractures are easiest to keep open where the rock is the most brittle, where brittle is typically defined as a relatively high Young's modulus. This most brittle rock corresponds to the stiffest and most rigid composition. Thus, it would appear that the locations of interest to fracture correspond to the highest velocity and corresponding elastic moduli.

On the other hand, locations or subunits with significant concentrations of organics may include the highest hydrocarbon content. However, kerogen or organic content have extremely low elastic moduli. Thus, the low velocity intervals may be of economic interest. To complicate matters further, natural fractures, often aligned with the regional stress field tend to lower the effective moduli of the rock in a directionally dependent manner, but these fracture zones may or may not contain accumulations of hydrocarbon. From a geophysical view, there is a conflict regarding which zones in a given shale may be best suited for fracturing. Should the zones with slowest velocities be targeted, which should correspond to high TOC and fractures? These may produce high quantities initially but drop off very quickly. Or should the zones with high velocity be the focus where fractures should stay open for a longer

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
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Fig. 1: Map of North American gas shales. From The U.S. Energy Information Administration. The shales discussed in this paper are the Bakken (north center), Haynesville (south central), Barnett (central), Marcellus (northeast), and Woodford (central). Figure obtained from http://www.energyindustryphotos.com/shale_gas_map_shale_basins.htm.

duration, hopefully leading to extended economic production?

Geophysical characterization of any of the shale plays in Figure 1 currently stands as a potential way to obtain engineering information ahead of the drilling rig. Current research focuses on resolving ambiguities between geophysical observations and optimal engineering properties. The purpose of the overview here is to provide a general geologic background for each of the five shales as well as potential ways to characterize each from a geophysical standpoint. For the Bakken and Haynesville Shales, well-log examples and rock-physics modeling results are included. The data presented and the ideas put forth highlight the physical properties that significantly influence the measured elastic properties.

Bakken Shale

The Bakken Shale is located in the Williston Basin in the north central United States, extending into southern Canada (see Figure 1). This shale consists of three units: The Upper and Lower Bakken Shales, and the Middle Bakken Siltstone. This middle unit is the oil-producing unit, and both the encasing shales serve as the source rocks (Pitman et al., 1999; Lefever, 2006; Cramer, 1992). Cumulative thickness of these three units is 35-40 m. The upper shale is ~10 m thick, the lower ~15 m, and the middle unit also ~15 m thick. Depth to the top of the upper shale is about 3 km. Production from the Middle Bakken is oil, but low permeabilities require horizontal drilling and fracturing operations to make that production economic.

The Upper and Lower Bakken Shales are the only source rocks within 100s of meters from the Middle Bakken Siltstone. Charging of the Middle Bakken from above and below occurred as a result of kerogen reacting with water in the encasing shales. Mobile fluid hydrocarbons were the products of these reactions, with a volume expansion approaching 150%. This volume expansion forced the fluids out of the shales and into the middle siltstone. In order for the fluids to enter the siltstone, horizontally oriented macrocracks and micro-cracks were forced to open to accommodate the fluids (Pitman et al., 1999 and Sonnenberg et al., 2010). Impermeable carbonate units sit above the Upper Shale and below the Lower Shale. The presence of these carbonates forced the hydrocarbon into the Middle Bakken Siltstone. Vertical migration of the fluids through the Middle unit requires that a fracture network with some vertical or sub-vertical cracks are present (Pitman et al., 1999). In addition, the tectonic history of the Williston Basin strongly suggests vertical or sub-vertical fracturing occurred during uplift that gave rise to the Nesson anticline (Meissner, 1978).

Rock physics studies that relate the elastic properties (velocity) to the reservoir properties (composition, porosity) have been performed on all three units. (Vernik and Nur, 1990; Vernik and Nur, 1992; Vernik, 1994; Prasad et al., 2009; Spikes, 2011). For the purposes of this paper, analysis from a single well is included to demonstrate the effects of composition, fracture aperture, and fracture density on the elastic properties on the Middle Bakken Siltstone. Given the horizontal and vertical fracture network, this unit should demonstrate orthorhombic symmetry in terms of its elastic properties. Neither well-log measurements nor laboratory measurements, however, typically provide enough information to characterize this type of medium. If horizontal fractures dominate relative to the vertical, then the medium effectively will have vertically transverse isotropic (VTI) symmetry. Observing this behavior in the well-log data is difficult due to tool orientation and response. Accordingly, an isotropic approximation was adapted for the purposes of modeling.

Figure 2 shows crossplots of well log bulk modulus versus total porosity (a) and shear modulus versus total porosity (b). The lines on the plots come from the self-consistent approximation of Berryman (1980, 1995). This is an effective-medium model that combines user-defined shapes for solids and pores, moduli for these, and numerically computes the effective elastic moduli. Alternating colors for the lines correspond to different compositions, ranging from a dolomite-rich composition at the top to a clay-rich mixture at the bottom with constant amounts of quartz and feldspar. The histogram in c) displays the shape of fractures (the aspect ratio) used in the modeling. See Spikes (2011) for further details on this modeling. These modeling results indicate that the composition, the shapes of the fractures, and the number of fractures influence the elastic moduli. Specifically, fewer fractures should exist in the stiffest and most rigid locations (dolomite rich) relative to locations with the softest composition (clay). However, with more fractures, the effective elastic properties decrease. Accordingly, it can be difficult to determine the locations from seismic data best suited to induce fractures to enhance production.

Marcellus Shale

The Marcellus Shale, located in the eastern United States, is a Devonian age formation in the Appalachian Basin (de Witt et al., 1993). It is present in West Virginia, Ohio, Pennsylvania, and New York. Similar to other resource plays, economic production requires hydraulic fracturing to increase permeability around wells. The depositional system of the Marcellus is a wide spread deltaic system (Schweitering, 1979). The thickest parts of the Marcellus lie on the east side, and they progressively thin and eventually

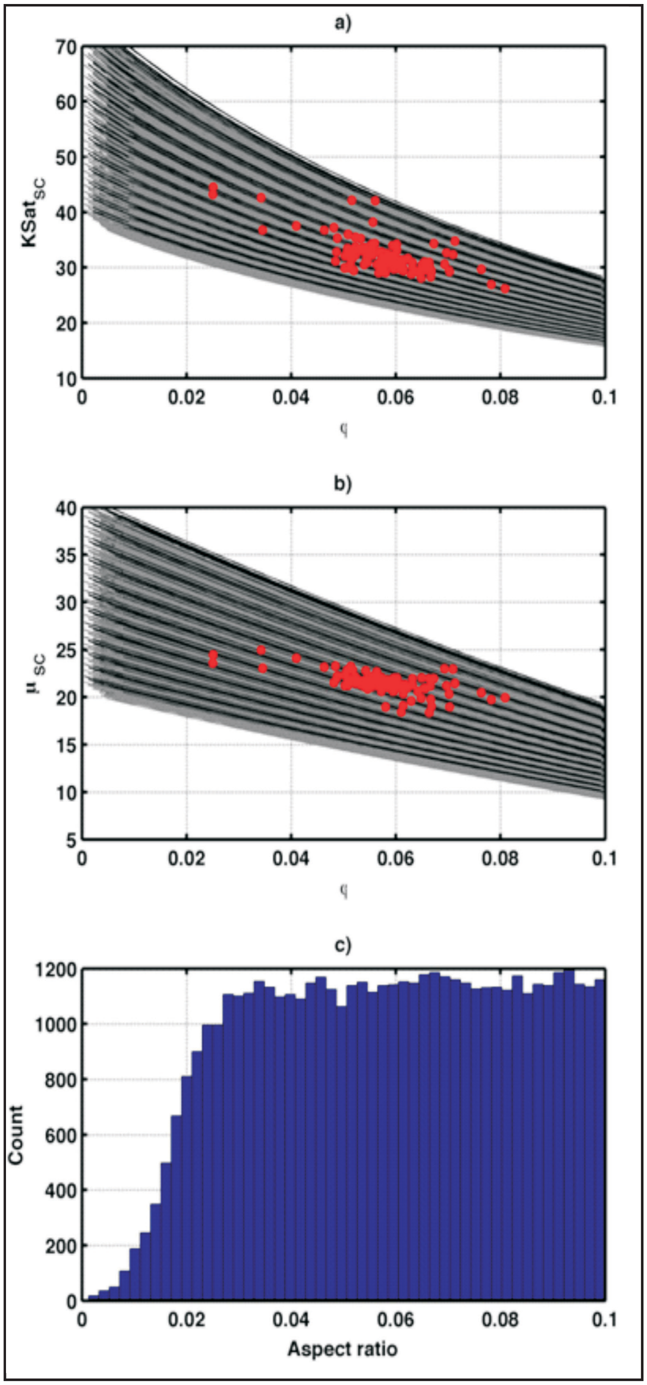

Fig. 2: a) Bulk moduli versus total porosity data (points) and self-consistent models (lines) for the Middle Bakken Siltstone. b) Shear modulus versus total porosity. These plots indicate that variations in composition and fracture size and shape explain the variations in the measured elastic properties as a function of porosity. c) The distribution of fracture shapes (aspect ratios) used in the modeling.

pinch out to the west. On the east side, sandstone, siltstone, and shale are present, but the on the west side, a fine-grained, organic-rich black shale is present (Potter et al., 1980). This black shale, which lies at the base of the formation, is the source of the natural gas that is present in small pores, in fractures, and within the organic material itself (Soeder, 1988).

Matrix composition of an organic-rich, high gamma-ray interval includes mineral assemblages of pyrite, calcite, quartz, and illite (Hoover and Lehman, 2008). In outcrop, the Marcellus exhibits multiple fracture sets that are approximately orthogonal, commonly referred to as the J1 and J2 fracture sets. These fractures provided pathways from the original organic-rich zone upwards through the rest of the section (Engelder et al., 2009). A unit named the Tully Limestone sits above the Marcellus Shale and confines the fracturing from above, whereas the Onondaga Formation confines it from below (Nyahay et al., 2007).

Seismic-based characterization of the Marcellus Shale requires assessing the velocity anisotropy present due to the in-situ fracturing (i.e., Vasconcelos and Grechka, 2007). For this type of analysis to be useful, sufficient azimuthal and offset coverage of the target zone must be present in the pre-stack seismic data. P-wave seismic data may be sufficient in some cases to identify fast and slow directions in the seismic data. However, multi-component seismic data (3D-3C) provides the most flexibility to unravel the directional velocity dependencies. More specifically, in an orthorhombic elastic system, the multi-component seismic data can help to characterize the two principal fracture densities and the fluids contained within those fractures (Gaiser et al., 2011).

From a rock-physics standpoint, forward-modeling a system with multiple fracture sets requires a model such as that of Hudson (1980, 1981) to account for the effective stiffness for the anisotropic medium. Directional velocities are the output from this model. Inputs to this model include isotropic background materials for the host material. For each set of fractures, the fracture density, average aspect ratio, the fluid properties, and the distribution type must be specified (Sava, 2004). Furthermore, stochastic processes are often required to provide a range of models that can explain the variations in measured seismic velocities that vary with azimuth and offset (AVAZ analysis).

Analysis of seismic data to determine the fast and slow velocity directions can be related to the rock properties of interest within the Marcellus using appropriate forward modeling and accounting for appropriate velocities (phase and group) in the real data. Optimal targets in the Marcellus are zones with high gas content that are naturally fractured. As a result, the combined effects of fractures and the fluid distribution within those fractures on the seismic response must both be taken into consideration.This analysis should also include examinations of principle regional or local stresses (e.g., Schmid et al., 2010).

Barnett Shale

Of the shale plays shown in Figure 1, the Barnett Shale was one of the first to be recognized and then exploited as a major gas and oil reservoir. Located in north central and west Texas, deposition occurred during the late Mississippian (~300Ma) during a marine transgressive regime (Henry, 1982). The top of the Barnett is at approximately 8000 ft, with an average thickness~1000 ft. Since 1998, thousands of wells have been drilled in the Barnett Shale. Most wells were initially vertical, but within a few years of that, horizontal drilling became the preferred operation accompanied by induced fracturing.

In general, permeabilities are very low (millidarcy to nanodarcy range) and porosities vary between 0 and 10% (Loucks et al., 2009). Natural fracture systems are present, and extensive core analysis has shown that a significant proportion of them are healed. Composition is variable, including organic material, clay, clastics, carbonates, and small amounts of dense siderite and pyrite. Given this mineral assemblage, porosity, and permeability, the Barnett Shale simultaneously provides its own source rock, reservoir, and seal, despite being fractured.

Sil and Sen (2008, 2009a,b) provided a quantitative seismic-based interpretation of anisotropic (fractured) media applicable to the Barnett Shale from a slightly different perspective than other works mentioned previously. They approached the problem from analysis of gathers transformed into the τ-p domain and introduced a delay time function to invert for elastic tensor components or Thomsen (1986) anisotropy constants. This method was shown to be efficient and an improvement over truncated time-distance estimates of the anisotropic parameters.

Forward modeling the elastic and seismic responses of the Barnett would require an approach similar to that of the Marcellus, in which at least one set of fractures would need to be included in an effective-medium model. These effective elastic moduli could then be combined with azimuthally dependent reflectivity calculations (Rüger, 1997) and full waveform synthetic seismic modeling to compare to pre-stack field data. This modeling approach could be validated with the anisotropic inversions obtained from the Sil and Sen (2008) technique for a quantitative assessment of the fracture distributions in Barnett Shale.

Haynesville Shale

The Haynesville Shale is an organic-rich, Jurassic aged formation located in east Texas and west Louisiana (Hammes, 2009). With an estimated capacity of 60 Tcf, it is one of the largest prospective gas shales in the United States. This shale originated in a shallow offshore depositional environment. At present, the formation lies between 10000-13000 ft (3-4 km) depth, with average thickness of ~200 ft. Most logs and cores indicated moderate porosity (5-20%) and extremely low permeability. Core samples indicate very few fractures in the Haynesville. This unit, however, is known for high temperatures and overpressure (Becker et al., 2010; Ewing, 2001; and Nunn, 2011).

Characterizing the Haynesville Shale in terms of its rock properties involves two primary approaches: composition and pore-shape effects (Jiang and Spikes, 2011). Mineralogic composition includes kerogen, calcite, quartz, clay, and pyrite (Lucier et al., 2011). Elastic moduli and density of these minerals ranges from small to very large (Ward, 2010). Both have the ability to skew the moduli and velocities down or up even with small relative percentages. The model used to describe these two effects was the differential-effective medium (DEM) model (Norris, 1985; Norris and Johnston, 1997). Similar to the self-consistent model, DEM incorporates multiple pore shapes into a background or host medium to numerically solve for the effective elastic moduli.

Figure 3a displays well-log P-wave velocity versus porosity, overlain by model lines. These five model lines, computed using DEM, vary in terms of composition. Kerogen and pyrite content were held constant at 7% and 1%, respectively. The other lines were computed by exchanging percentages of calcite, quartz, and clay content. Pore aspect ratios were normally distributed with a mean of 0.1 and standard deviation of 0.01. For this well data, the scatter of the velocity for any given porosity can primarily be described by the variation of composition. The lowest P-wave values correspond to the most organic-rich and clay-rich zone.

Figure 3b includes data from a different well in the Haynesville. P-wave velocity is plotted as a function of bulk density, and colored by the gamma-ray count. Although scatter is apparent, the highest gamma-ray values tend to be for the lowest velocity. Typically, an apparent trend of velocity and density exist, as in Figure 3a (for velocity-porosity). For the well data in 3b, the trend is very subtle or nonexistent. Explanations for this vary, but none provide a succinct reason. The model lines overlaying the data were computed using DEM. These lines were computed by using correlated composition and pore shapes to mimic the increasing clay content (inferred from the gamma-ray)with decreasing velocity.Compositions vary from pyrite at the top of each line to kerogen at the base. Furthermore, aspect ratios for pores are nearly spherical (very stiff) at the top and on the order of 10^{-4} at the base.

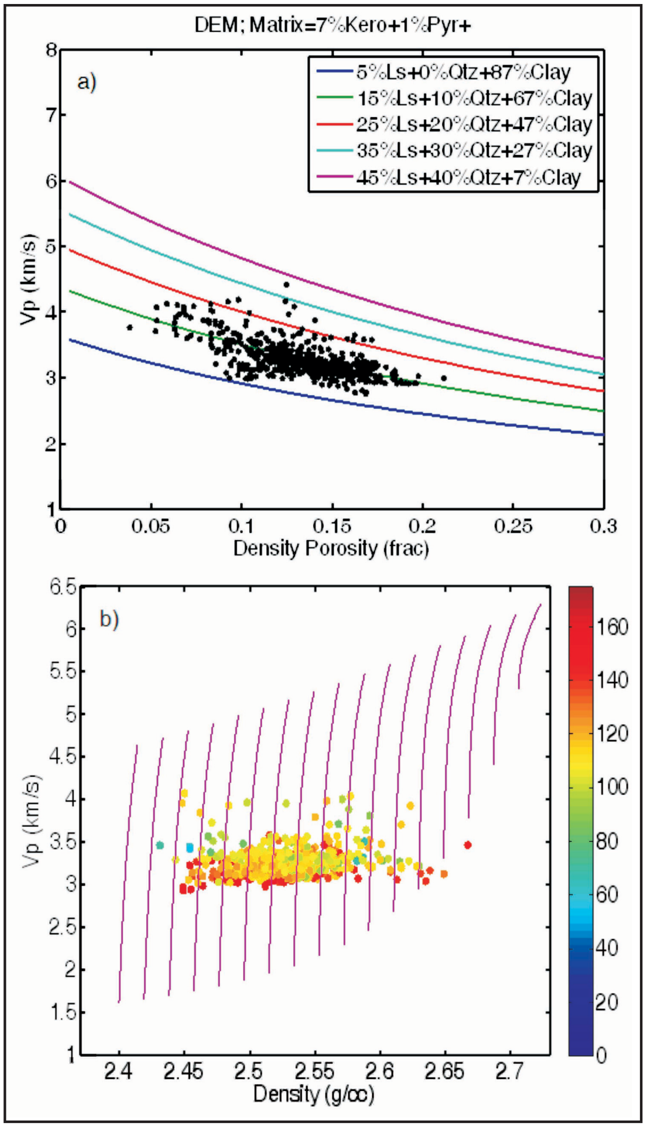

Fig. 3: a) P-wave velocity as a function of porosity for one well in the Haynesville Shale. The modeling lines from the differential effective medium model correspond to varying compositions for a single distribution of pore shapes. In b) data from a different well was modeled using velocity and density. To model this data, correlated grain and pore shapes were required, with the stiffest shapes and minerals at the top of each line and the most compliant at the bottom of each line. Each line corresponds to a single porosity value.

These two figures illustrate that the elastic properties in the Haynesville can be used to describe the composition (Figure 3a) or both the pore shape and composition (Figure 3b). The lowest velocities, while being associated with the highest organic content, may be associated with the softest (smallest aspect ratios) pore shapes. Flat pores, such as those shown in micro- and nano-scale images (e.g., Curtis et al., 2010), tend to close quickly after production, even after fracturing, particularly for soft matrix materials such as clay or organic material.

In terms of seismic characterization of the Haynesville, rock-property trends, such as those that include high TOC but low density, must be identified from and log core data. Mapping these to impedance inversion results, while accounting for uncertainty and upscaling, may prove useful. Løseth et al. (2011) show the seismic interpretation basis for this type of targeted inversion for TOC in the North Sea, essentially locating organic rich source rocks.

Woodford Shale

The Upper Devonian to lower Mississippian Woodford Shale is present in west Texas, Oklahoma, Arkansas, and New Mexico. Depending on the basin under consideration, various lithofacies within the Woodford are the major producing intervals dominated by chert, sandstone, dolostone, or siltstone (Comer, 1991, 2009). Total thickness averages several hundred feet but varies within the different basins that contain the Woodford. Organic content in a black shale unit (see Ali, 2009) at the base of the Woodford varies from 5 to 6% in the different basins, which serves as the source rock. Fractures within the above units serve as reservoir-charging pathways (Portas, 2010; Andrews, 2009).

With the lithologic variations present in the Woodford, porosity values vary over2-20%, excluding fracture porosity. The non-fracture permeability tends to be very low, allowing the Woodford acts as its own seal. An assumption often encountered when using effective-medium models (such as Hudson, 1980) to calculate effective properties of fractured rock is the complete separation of the pore space due to fractures from the pore space due to matrix porosity. This assumption may be safe for locations in a shale play where matrix porosity and permeability is exceedingly small. For situations where both the matrix and fracture porosities are both measurable, rock physics models must be able to account for both porosity types. Gurevich (2003) provided a model that allows for parameterizing both fracture and matrix porosity, allowing fluid to move from one to the other.

Seismic characterization of the Woodford requires fracture detection, coupled with delineation of dominant directions and densities. Similar to the Marcellus and Barnett Shales, full azimuthal coverage of seismic data is needed. Multi-component seismic data can significantly aid in interpretation when S-wave birefringence is analyzed from a modeling perspective and then used to map diagnostic patterns in real seismic data. Uncertainty in this type of analysis comes from many sources, but one significant source is identifying the fracture-filing material: fluid or mineral.

Conclusions

The five shales briefly discussed in this overview display some similarity to each other. Composition in the Haynesville, Barnett, and Marcellus Shales is similar, but far different from the Woodford and Bakken Shales. Fracture patterns in some of these can be seen in outcrop, which can help guide seismic-based analyses of fracture detection and delineation (the Woodford, Marcellus, and Barnett). Different still are the Bakken with primarily horizontal fractures and the Haynesville with very few if any fractures. To distill these gas plays into a uniform group is difficult and would require far-reaching and inaccurate generalizations.

Presently, geophysical characterization of gas shales comes after drilling operations. Drilling locations are often based on land positions as opposed to subsurface targets. To that end, P-wave seismic data typically is used only to identify faults and other potential drilling hazards. Few studies exist that relate the petrophysical properties to the elastic properties and the seismic data to provide information on optimal rock and transport properties that could be used to supplement drilling plans. The overview of rock-physics and seismic-based characterization schemes suggested here are based on analysis of core and well data, and the general geologic background of each of the five shales. A complete understanding of the interrelated reservoir and elastic properties will require integrated and advanced petrophysical analyses, rock physics modeling, and seismic data analysis, modeling, and inversion that go well beyond conventional reservoir characterization.

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