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Variability of Geologic Properties in Shale Gas and Tight Oil Plays

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ABSTRACT

Major productive shale gas and tight oil formations in the U.S. share common features including high total organic carbon (TOC) content (>2%), appreciable porosity (>5%), low clay volume (<40%), and optimal thermal maturities (0.6–3.0% vitrinite reflectance [R_o]). However, variability in the geologic properties of shales, created by their differing depositional environments and burial histories, has implications for the extent of resource development, the delineation of potentially productive areas, and the recovery efficiency of horizontal wells, among other factors. Furthermore, many studies on emerging unconventional oil and gas plays that lack robust data (e.g., in the U.K., Mexico, and China, as well as in the U.S.) use mature U.S. shale plays as analogs. Understanding the variability of geologic properties in mature U.S. plays allows for comparison between plays, development of appropriate proxies for new exploration wells, and understanding of the ranges of geologic factors that may limit or enhance productivity in each play.

Here we present a summary of the geologic characteristics of eight major U.S. shale gas and tight oil plays, including the Barnett, Haynesville, Fayetteville, Marcellus, Bakken, Eagle Ford, and the Wolfcamp of the Midland and Delaware basins. The Bureau of Economic Geology has been conducting resource evaluation studies on these plays since 2012, resulting in the assembly of a comprehensive dataset of properties from original Bureau studies and literature. Subsurface well log interpretations, when calibrated to core data, allow for mapping properties on a basin-wide scale. In each shale basin, 150–1200 wells have been studied.

The depth, thickness, and stratigraphic relationships of producing formations and subjacent/superjacent formations, and reservoir properties including porosity, TOC, lithofacies, and thermal maturity, are summarized and linked to the depositional and tectonic history of the plays. Properties are mapped on a square-mile block basis, providing a consistent characterization of the nature of the play without sampling bias, which is important for plays that are underdrilled relative to their size such as the Marcellus.

Play size ranges greatly, from ~2300 mi^2 to more than 46,000 mi^2 for the Fayetteville and Marcellus, respectively. Formation depths average from <4000 ft in the Fayetteville to >12,000 ft in the Haynesville, and formation thicknesses vary from <50 ft in the Middle Bakken to several thousands of feet in the Wolfcamp of the Permian Basin. Average shale play porosity ranges from 5.6–7.4%, and average present-day TOC concentration ranges from 2–3% for the Wolfcamp to >12% for the Upper and Lower Bakken source rocks.

INTRODUCTION

Production from shale gas and tight oil plays in the U.S. has increased from <5 billion cubic ft per day (bcfd) dry gas and <0.5 million barrels of oil per day (mmbd) in 2005 to 65 bcfd dry gas and >7.0 mmbd in 2018 (Fig. 1) (Energy Information Administration [EIA], 2019a, 2019b). Geologic characterization of these plays has improved in recent years with the increased availability of well data in productive plays and exploration of new plays. An understanding has been developed that the geologic properties of source rocks may vary both within and between shale gas and tight oil plays (e.g., Passey et al., 2010; Slatt and Rodriguez, 2012; Bruner and Smosna, 2011).

The Bureau of Economic Geology (BEG) at the University of Texas at Austin has studied the major U.S. shale plays for nearly a decade (e.g., Fu et al., 2015; Browning et al., 2013, 2014, 2015; Hammes et al., 2016; Ikonnikova et al., 2018), amassing a database of raw and interpreted geologic, engineering, and economic data for the major shale gas and tight oil formations. Together, the plays studied account for more than 70% of shale gas and 80% of tight oil production in the U.S. (Fig. 1). Combining and comparing data across plays allows for an understanding of the variability of geologic properties of shale formations both within and between plays. Comparison of shale

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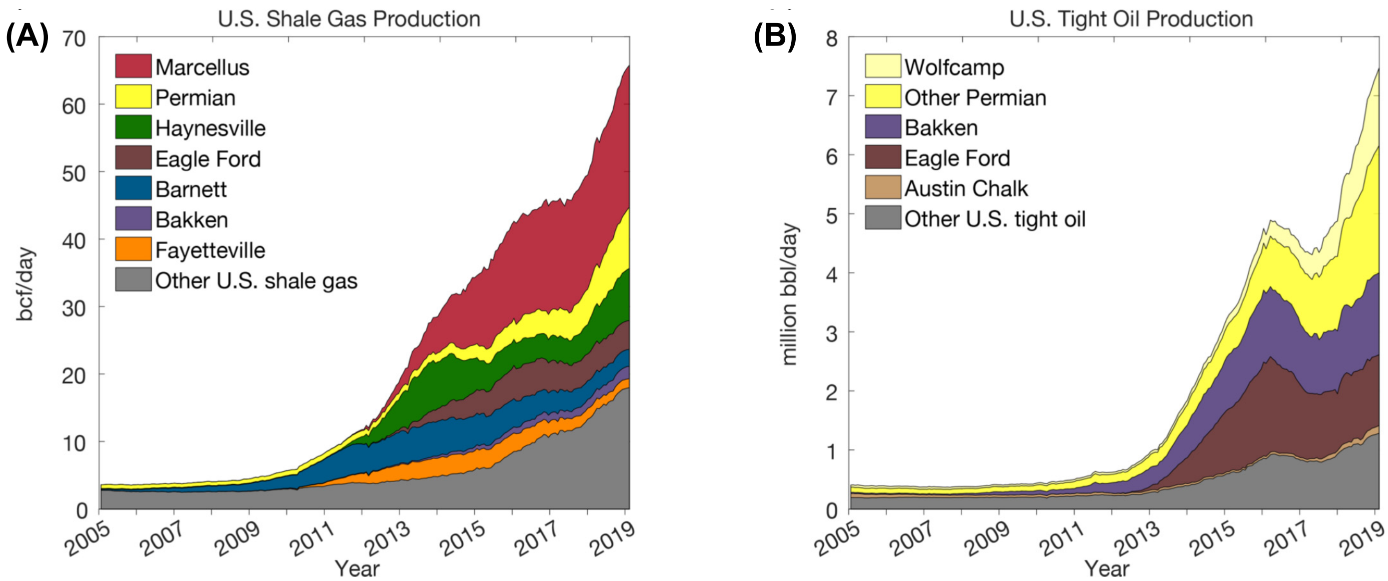


Figure 1. Production of U.S. (A) shale gas in billion cubic feet per day (bcf/day) and (B) tight oil in million barrels per day (bbl/day) for plays studied and other U.S. plays from 2005 through February 2019. Modified using data from EIA (2019a, 2019b).

properties is useful for understanding production trends, predicting the potential limits of production both in terms of spatial extent and reservoir quality, and developing analogs for emerging or data-poor plays.

Here we present and summarize properties that affect productivity of shale plays, including the thickness, porosity, total organic carbon (TOC), thermal maturity, and lithofacies. This includes both log and rock (core, outcrop) properties for the Barnett, Haynesville, Fayetteville, Marcellus, Bakken, Eagle Ford, and Wolfcamp of the Delaware and Midland basins (Fig. 2). Reservoir properties are derived from original subsurface geologic analysis and summarized from literature. The plays studied include both self-sourced formations, in which the source and reservoir are the same layer, and hybrid plays such as the Bakken, where the source and reservoir layers differ.

TECTONIC SETTING

The basins studied span a range of ages (Fig. 3), and depositional and tectonic histories (Table 1). More than 90% of the global recoverable oil and gas reserves were generated from source rocks making up just one-third of Phanerozoic time (Klemme and Ulmishek, 1991), and most of the shales in this study are of ages that were favorable for source rock deposition (Fig. 3).

Basins are classified based on the type of lithosphere they overlie, their position relative to the plate boundary, and the type of plate motion (Allen and Allen, 2013). Foreland basins such as the Appalachian (Marcellus) and Fort Worth (Barnett) form at convergent plate margins where lithospheric loading causes flexural deformation and subsidence. These basins are often asymmetric, as is the case in the Appalachian, Fort Worth, and Arkoma basins, with the structurally deepest part of the basin near thrust belts, and formations shallowing away from the structural front toward the cratonic interior. Sediments are usually derived from mountainous terrain associated with compression and thrusting; in the case of the Marcellus, terrigenous sediments were derived from the Acadian highlands to the east. In the Fort Worth Basin, equivalent highlands are absent, though an island arc chain may have been the source of some siliciclastics (Bruner and Smosna, 2011). Factors that influence reservoir properties, such as dilution of organic matter with clastic sediments, vary with basin length and distance from the thrust front. The life span of foreland basins usually ranges from 4–125 Ma (Allen and Allen, 2013). The Fort Worth and Appalachian basins both contain more than 10,000 ft of basin fill (Bruner and Smosna, 2011).

While the Fayetteville Shale is equivalent in age to the Barnett, its depositional setting differs. The Fayetteville was deposited on a southward-deepening, wide, shallow shelf with variable water depth, ranging from intertidal to up to 650 ft at the shelf/slope break (Handford, 1986). The foreland Arkoma Basin was not fully developed until after Fayetteville deposition (Handford, 1986; Ratchford et al., 2006). Terrigenous sediment appears to have been derived from the northeast, diluting organic carbon and influencing thickness and composition trends.

Cratonic basins, including the Williston with the Upper Devonian / Lower Mississippian Bakken and Three Forks formations, are formed by a sag in the continental craton, and generally exhibit slow subsidence and relatively thin, shallow (mostly near sea-level) deposition. Due to low strain rate and prolonged thermal subsidence, cratonic basins last from 60–440 Ma (Allen and Allen, 2013). The Williston Basin appears to have subsided continuously and steadily throughout most of the Phanerozoic (Fowler and Nisbet, 1985), and contains more than 16,000 ft of Phanerozoic fill. The basin is symmetric, and has undergone relatively little deformation apart from movement of Precambrian basement blocks (Gerhard et al., 1982).

The Permian Basin (Wolfcamp) of West Texas is a "composite" basin, having formed on an earlier cratonic sag—the Tobosa Basin—but fully developed in the foreland of the Marathon-Ouachita Thrust Front (Yang and Dorobek, 1995a, 1995b). The Delaware and Midland sub-basins are separated by intraforeland uplifts including the Central Basin Platform, an intervening basement high (Yang and Dorobek, 1995b). The complex tectonic history of this region has implications for basin stratigraphic development (Yang and Dorobek, 1995b).

The Eagle Ford and Haynesville reflect passive margin deposition over thick subsiding transitional crust. These environments are formed by rifting and opening of a full-scale ocean basin—in this case, the Gulf Of Mexico. Generally, sediments are deposited as a "wedge" that builds the continental shelf and slope, with a corresponding non-basinal geometry. Often the terrigenous siliciclastics and in-situ carbonates thicken seaward, then transition to deeper marine sediments. Both Eagle Ford and

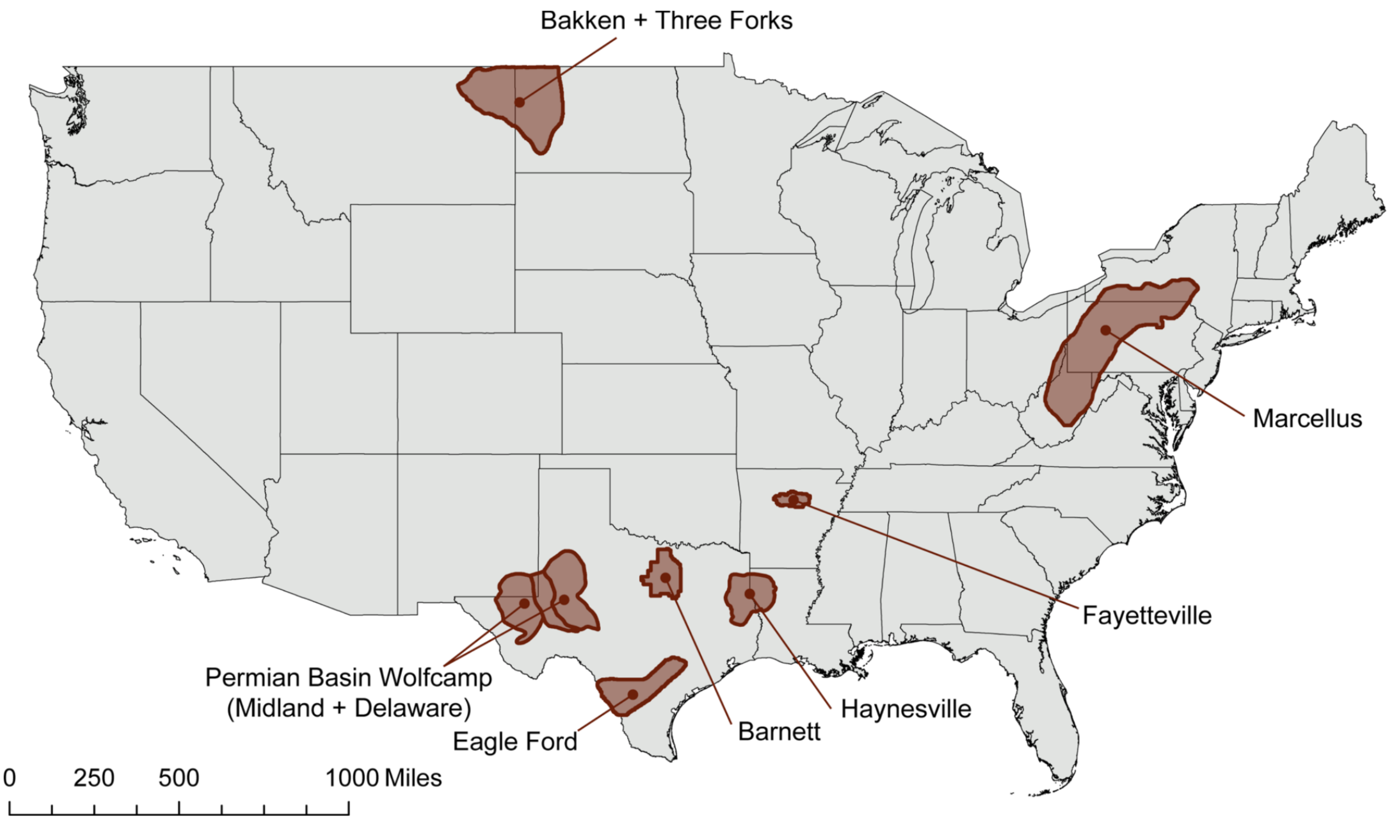


Figure 2. Shale gas and tight oil plays assessed for this study include the Barnett, Eagle Ford, and Wolfcamp (Midland and Delaware basins) in Texas, Haynesville of Texas and Louisiana, Fayetteville of Arkansas, Marcellus of Pennsylvania, New York, Ohio, West Virginia, and Maryland, and Bakken–Three Forks of North Dakota and Montana.

Haynesville lithological variation are influenced by fluvial input and pre-existing structures.

METHODS

Geologic characterization of each play utilizes subsurface data including petrophysical well logs and core analyses. The workflow consists of stratigraphic analysis, mapping of structure and thickness variations, and petrophysical characterization of important reservoir properties (following Browning et al. [2013, 2014, 2015], Fu et al. [2015], Hammes et al. [2016], and Ikonnikova et al. [2018]). In plays where core descriptions were available, facies analysis was conducted with log cutoffs to match core facies, and simplified facies models were applied.

Wireline logs were sourced with a focus on (1) core producing areas in each basin (2) well depth and intervals logged, and (3) log curve type and quality. Well logs utilized in the study included gamma ray (GR), bulk density (RHOB), and neutron porosity (NPHI). Resistivity (RES) and photoelectric (PE) curves were included where available, as was the caliper log, which provides an indication of borehole quality and a metric by which to assess log reliability. Where additional control was required, log and core data were sourced from operators.

The boundary for potentially productive acreage in each play was delineated based on factors such as structural complexity, thickness, depth, and thermal maturity windows. Each play was divided into square mile "blocks," and average properties for each block were determined. This methodology allows for direct comparison of properties across plays, as it includes interpolated values for acreage of marginal reservoir quality that is underrepresented in both drilling and data.

Stratigraphic analysis of producing and subjacent/superjacent formations was performed through correlation of formation tops (Table 1, Figs. 4 and 5). Using a high resolution Digital Elevation Model, ground elevation values were sampled to points along outcrop lines for Barnett and Marcellus formations and merged with formation top data sets for added structural control. Surface layers were interpolated using a Natural Neighbor (NN) algorithm in Arc Map 10.3. The NN algorithm only interpolates surfaces to the spatial extent of the data; in order to extrapolate to the full extent of the study area, a grid of points was created by sampling the NN raster values every 2000 ft. The grid values were extrapolated to the extent of the play boundary using an inverse distance weighted algorithm. Petrophysical characterization of producing formations varied between plays based on the complexity of the reservoir and availability of data.

Reservoirs

Barnett

Barnett Shale stratigraphic analysis utilized 1286 wells with digital logs across the Fort Worth Basin, building upon previous studies (Fu et al., 2015; Smye et al., in press). Formations studied include the Upper and Lower Barnett Shale, the intervening Forestburg Limestone, the Viola-Simpson (undifferentiated), and Ellenburger Group (Fig. 4A). All wells utilized log at least the top of the Barnett interval, while 1023 wells penetrate Ordovician Viola-Simpson formations and/or Ellenburger Group.

Barnett Shale porosity was computed from bulk density (ρ_b) logs (Eq. 1). A set of wells (n = 8) with core-calibrated petrophysical interpretation showed an average grain density (ρ_{matrix})

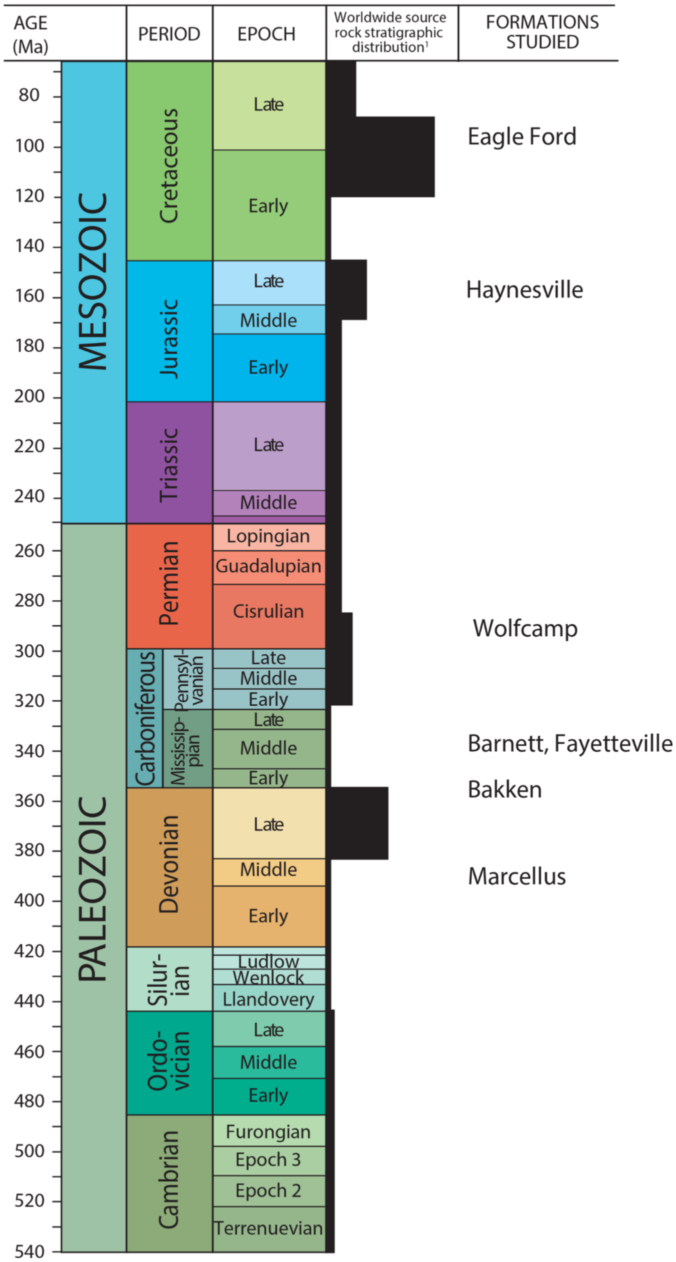


Figure 3. Geologic timescale (modified after Walker et al., 2018) showing ages of shale formations studied along with relative source rock contribution to worldwide reserves by stratigraphic interval (Klemme and Ulmishek, 1991).

of 2.63 g/cc, reflecting the mineralogical constituents present and their proportions, including low-density kerogen. This grain density was combined with an estimated fluid density (ρ_{fluid}) of 0.7 g/cc (Fu et al., 2015, and references therein), density porosity (ϕ_d or DPHI) was computed:

$$\phi_d = \frac{\rho_{matrix} - \rho_b}{\rho_{matrix} - \rho_{fluid}} \quad (1)$$

Fayetteville

In the Fayetteville Shale play, 159 wells were utilized to map structure and thickness; formation tops included the upper and lower Fayetteville, and the underlying Batesville and Hindsville (Fig. 4B). Fayetteville Shale TOC was computed from the bulk density log using the Schmoker method (Schmoker and Hester, 1983). Porosity was calculated from RHOB logs (Eq. 1) using assumed matrix density of 2.8 g/cc corrected for TOC, and fluid density of 0.6 g/cc. Computed log porosity values were calibrated core porosity for a subset of wells (n = 40) with an average gas-filled core porosity of 4.2%. Calibration factor from log to core porosity ranged from 0.66 to 1.13, reflecting the variation in TOC volume, affecting the density log reading.

Haynesville

Haynesville Shale geologic analysis included 198 wells. Identification of the Haynesville Shale relied on the NPHI and RHOB log curves, which exhibit a gas effect as they approach one another (Fig. 4C). The overlying Bossier Shale is productive in some areas, exhibiting a similar gas effect to that observed in the Haynesville. The Bossier pay zone was identified and mapped across much of the Haynesville Shale play trend.

DPHI was calculated for 135 wells with digital density logs (Eq. 1). A detailed petrophysical model for a subset of the wells (n = 25, 9 with core data) computed volumes of calcite, kerogen, porosity, quartz, and clay with a fixed quartz/clay ratio of 55:45 (Hammes et al., 2011, Eastwood and Hammes, 2011). DPHI values were calibrated to modeled porosities to account for the presence of low-density kerogen.

Marcellus

In the Marcellus, 838 wells were utilized in the stratigraphic analysis. The Upper and Lower Marcellus are separated by a limestone, here called the Cherry Valley but often combined with the Purcell Limestone (Lash and Engelder, 2011) (Fig. 4D). The Middle Devonian Marcellus Formation is the basal member of the Hamilton Group, which also includes the overlying gray shale Mahantango Formation. The Tully Limestone separates these Middle Devonian black and gray shales from Upper Devonian formations, which also contain high GR shales that are locally productive.

Marcellus petrophysical analysis included computation of porosity and TOC. TOC values computed are present-day, and are not restored to original TOC prior to maturation and expulsion. Subsets of wells for Marcellus (495 wells) and Mahantango (350 wells) porosity mapping were identified. To compute TOC, uranium (U) content was estimated using an exponential function relating U to the GR log response (Wang and Carr, 2012; Boyce, 2010). TOC was calibrated to U core data using a linear regression. Density porosity (ϕ_d) was computed from the bulk density log (ρ_B) using the TOC volume, density of TOC (ρ_{TOC}) derived from relation to thermal maturity values ($R_o \times 0.342 + 0.972$, where R_o is vitrinite reflectance) (Guidry et al., 1996; Ward, 2010), and matrix density (ρ_{matrix}) of 2.71 g/cc:

$$\phi_d = \frac{\rho_{matrix} - \rho_b\left(\dfrac{\rho_{matrix} \times TOC}{\rho_{TOC}} - TOC + 1\right)}{\rho_{matrix} - \rho_{fluid}} \quad (2)$$

Publicly available Marcellus core data are very limited, making porosity calibration challenging. However, calculations of TOC were calibrated to core data from state geological surveys.

Eagle Ford

Eagle Ford stratigraphic analysis included the Austin Chalk, Upper and Lower Eagle Ford, Buda, and Del Rio (Fig. 5A) for 340 wells (Hammes et al., 2016). Of those, approximately 150 wells with adequate log suites were used in petrophysical analysis to solve for volumes of calcite, clay (illite), quartz, TOC, and porosity. Log model lithology and porosity results were calibrated to limited core data.

Bakken

Bakken structure and stratigraphic thicknesses were mapped using 885 wireline well logs (Hamlin et al., 2017; Gherabati et al., 2019). Formations studied include the Lodgepole, Scallion, False Bakken, Upper Bakken, Middle Bakken, Lower Bakken, Three Forks, and Birdbear (Fig. 5B).

Lithologic heterogeneity of the Bakken–Three Forks source and reservoir rocks necessitated development of a detailed petrophysical log model to accurately characterize mineral proportions and reservoir properties such as porosity and water saturation. The log model was applied to 55 wells with log and core data, including porosity and permeability, water saturation, grain or matrix density, and mineralogy. The Upper and Lower Bakken log model solved for proportions of kerogen, quartz, clay, calcite, and dolomite. Anhydrite was included for analysis of the Three Forks.

Middle Bakken computed log porosity was compared to core porosity for 20 wells, and the data were discriminated for outliers (±3.5%), omitting 65 of 626 data points. The correlation coefficient (R) was 0.64 with a residual error of 0.12. Average total porosity was 5.9%, with a standard error of the estimate for discriminated data of ±1.8%.

Midland Wolfcamp

Wolfcamp stratigraphy in the Midland Basin was interpreted and mapped using wireline logs from 2260 wells. Wolfcamp lithofacies were described in 14 cores. Core description and mineralogical data were also used to calibrate 518 wireline logs for lithofacies mapping. Because the Wolfcamp is thicker than most productive shale formations, five Wolfcamp layers were correlated in the Midland Basin (Fig. 5C). Subsequent petrophysical analysis of 210 full wireline log suites was tied to lithofacies and layer.

Delaware Wolfcamp

Wolfcamp stratigraphy in the Delaware Basin was interpreted and mapped using wireline logs from 1952 wells. Wolfcamp lithofacies were described in 12 cores. Core description and mineralogical data were also used to calibrate 242 wireline logs for lithofacies mapping. Five layers within the Delaware Basin Wolfcamp were correlated and mapped (Fig. 5D). Subsequent petrophysical analysis of 119 full wireline log suites was tied to lithofacies and layer.

SHALE PLAY ATTRIBUTES

Log Responses

Log data utilized for stratigraphic interpretations included primarily GR, RHOB, NPHI, and RES (Figs. 4 and 5). Quantitative comparison of log responses of source rocks is useful to observe the variability between and within plays and to enable prediction of important reservoir properties. GR and RHOB log statistics were plotted for each formation and important adjacent formations.

GR logs (Fig. 6A) measure radioactivity from isotopes in the potassium, thorium, and uranium decay series. In shales, GR counts can be elevated due to adsorption of thorium and the presence of potassium in clays; in organic-rich black shales, very high GR readings are due to uranium associated with TOC. Uranium content, inferred from spectral or standard GR logs, is frequently used as an indicator of TOC in some organic-rich mudrocks (e.g., Luning and Kolonic, 2003; Boyce, 2010; Wang and Carr, 2012). The relationship between GR and core TOC is clear in mudrocks with high GR, TOC, and U, such as the Marcellus and Upper and Lower Bakken (Fig. 6A). However, in other mudrocks, the relationship is less clear (e.g., for the Utica, Wang et al., 2016). In particular, in mudrocks with relatively low TOC and high clay volume, such as the Haynesville Shale (Fig. 6A), the effect of uranium on the GR signal is diluted. Intervals with abundant carbonate, such as the upper Wolfcamp in the Midland Basin, the GR–TOC correlation is also less well developed (Hamlin and Baumgardner, 2012).

Decreasing source rock quality within basins is evident in decreasing GR values; formations that are secondary targets, such as the Mahantango overlying the Marcellus, or the Austin Chalk overlying the Eagle Ford, have GR values that are lower than the primary targets. For example, the Marcellus average GR is >200 American Petroleum Institute (API) units, while the Mahantango is closer to 120 API units. The exception is the Middle Bakken and Upper Three Forks, which host Upper and Lower Bakken migrated oil, and are not themselves source rocks; in these formations, GR is an indicator of clay volume.

While most productive shales studied have average GR of 100–225 API units, the average GR for the Eagle Ford, Austin Chalk, and Midland and Delaware Wolfcamp is <100 API units. The low Eagle Ford GR reflects its high carbonate content (see section on Composition). The Wolfcamp average GR values are also low due to numerous carbonate beds over its thick interval. However, when differentiated by facies, the average GR values for both the productive source rocks (siliceous/calcareous mudrocks) and the clay-rich mudrocks average >100 API units (Fig. 6B). These two facies cannot be differentiated using the GR log alone.

Organic-rich mudrocks also generally have low (~2.55 g/cc) RHOB values (Fig. 7). The density reading is a function of the densities of matrix and fluid and their respective fractions, and is affected greatly by the presence of low-density kerogen. Kerogen density varies with thermal maturity, and typical values are in the range of 0.95–1.26 g/cc, though values as high as 1.79 g/cc have been reported (Ward, 2010). RHOB is often used to compute TOC (e.g., Schmoker and Hester, 1983, Wang et al., 2016) and porosity.

The Upper and Lower Bakken, the most organic-rick source rocks studied, have extremely low RHOB readings, with a mean of ~2.26 g/cc. The Marcellus, Fayetteville, Haynesville, Upper and Lower Eagle Ford, and Wolfcamp all expectedly show average RHOB readings of ~2.55 g/cc. Secondary targets such as the Mahantango and Austin Chalk have higher RHOB readings in accordance with lower TOC and/or lower porosity.

The NPHI and DPHI log responses, and the separation between them, can also serve as indicators of source rock quality (e.g., Ver Hoeve et al., 2010). In gas shales, the NPHI and DPHI log curves can approach one another, or even cross over, particularly when gas saturation is high and clay volume is low. The presence of gas decreases the neutron response—with hydrogen more diffuse in gas than in liquid—and increases the density porosity response. A competing effect is caused by clay, which drives the curves apart. This effect is observed clearly in the Haynesville Shale (Fig. 3C), where low neutron-density separation is the most obvious log signature of pay. High neutron-density separation is correlated with low TOC, high clay, and low productivity (Ikonnikova et al., 2018).

Stratigraphic Relationships

While the properties of unconventional source rocks themselves are critical, their stratigraphic relationships are also important factors in understanding and predicting productivity. The properties of subjacent, superjacent, and interbedded formations may exert control on fracture propagation, and related formations

Table 1. Summarized geologic properties of shale formations studied, Part A. References indicated by numbers in parentheses and listed in Part C.

	Age		Basin Type	Depositional Environment	Area (mi^2)	Formations Studied	Thermal Maturity	Depth (Range in ft SSTVD)	Depth (Mean in ft SSTVD)	Surface Elevation (Mean ± SD in ft)	Drilling Depth (Mean in ft)
Barnett	Late Mississippian	354–322 Ma	foreland	deep-water, stratified column, anoxic bottom water depth 500–650 ft (1)	8151	Marble Falls Upper Barnett Forestburg Limestone Lower Barnett Viola/Simpson Ellenburger	0.83–2.37% R_o, avg. 1.55 (2) 0.5–2.0% R_o (3, 4)	2621–8148	5373	895 ± 204	6268
Fayetteville	Late Mississippian	354–322 Ma	foreland	open marine, starved outter ramp condensed section	2329	Upper Fayetteville Lower Fayetteville Hindsville / Batesville	2.0–3.5% R_o (9)	-264–7876	2907	634 ± 243	3541
Haynesville	Late Jurassic	157–151 Ma	extensional passive margin	transgressive carbonate-dominated, restricted basin surrounded by carbonate platforms and siliciclastic shelves, slope to basinal setting, stratified water column from euxinic to oxygenat-	5694	Bossier Haynesville Shale Smackover	1.8–>2.6% R_o	10,176–16,203	11774	256 ± 73	12,030
Marcellus	Middle Devonian	~390 Ma	foreland	deep-water, stratified column, anoxic bottom water depth 300–1000 ft (1)	46,648	Upper Devonian Tully Mahantango Upper Marcellus Cherry Valley / Purcell Lower Marcellus Onondaga	1.6–3.5% R_o CAI ≥ 3 or TAI ≥ 5 $T_{max} \geq 470^oC$ in core dry gas (1)	313–7347	4347	1612 ± 568	5959
Bakken	Late Devonian–Early Mississippian	416–360 Ma	cratonic	Upper and Lower Bakken shales—shallow marine restricted basin Middle Bakken and Three Forks—marine shoreface cycles	17,318	False Bakken / Scallion Upper Bakken Middle Bakken Lower Bakken Upper Three Forks Middle Three Forks Lower Three Forks Pronghorn	Tmax 425 - 450°C in oil window (22)	4514–8981	7500	2245 ± 210	9745
Eagle Ford	Late Cretaceous	94–89 Ma	extensional passive margin	marine carbonate anoxic conditions	13,739	Austin Chalk Upper Eagle Ford Lower Eagle Ford Buda Del Rio	R_o 0.45–1.4%	760–16,053	8473	471 ± 165	8944
Wolfcamp Midland	Early Permian	299–280 Ma	foreland-complex	basin floor having water depths 400–2000 ft in a periodically restricted silled basin (26)	15,308	Spraberry Dean Wolfcamp Upper Penn	R_o 0.6–1.6% (26, 28, B)	690–6999	4805	2780 ± 304	7585
Wolfcamp Delaware	Early Permian	299–280 Ma	foreland-complex	basin floor having water depths 1000–2000 ft in a periodically restricted silled basin (27)	12,689	Bone Spring Wolfcamp Upper Penn		559–9407	6373	3463 ± 688	9836

Table 1, continued. Summarized geologic properties of shale formations studied, Part B. References indicated by numbers in parentheses and listed in Part C.

	Thickness (Range in ft)	Thickness (Mean in ft)	Porosity (Mean ± SD in %)	TOC (wt. %)	Kerogen Type	Lithofacies	Composition
Barnett	60–939	284	5.6 ± 1.1	2–6 (1) 0.36–9.66, avg. 3.1 (2) 3.3–4.5; 1.8% Forest-burg (4) 3.16 (5) 2.4–5.1% (6)	type II with minor type III (1)	black siliceous shale, limestone, and minor dolomite (4, 7, 8)	35–50% quartz, 27% illite with minor smectite, 8–19% calcite and dolomite, 7% feldspars, 5% organic matter, 5% pyrite, 3% siderite, and traces of native copper and phosphate material (1)
Fayetteville	59–705	306	6.3 ± 0.6	0.1–10.8, avg. 4.07 (B) 2.4–6.4 (10) 0.3–9.6, avg. 3.48 (11)	type IV (12)	organic-rich calcareous-siliceous mudstones; organic-rich mud, starved-ripple-laminated “siltites,” laminated siltites and minor debrites; black laminated shale, gray shale, limestones and mudstones, with some beds of cherty limestones (11)	39–42% quartz, 29–32% illite/smectite, 9% dolomite, 2% calcite, 4% pyrite; higher carbonate content (up to 60%) in lower Fayetteville (13)
Haynesville	0–383	202	6.7 ± 1.6	0.7–6.2, avg. 2.8 (14)	type III (15)	bioturbated calcareous mudstone, laminated calcareous mudstone, silty peloidal siliceous mudstone, unlaminated siliceous organic-rich mudstone (14)	10–55% quartz, 10–50% clay (illite, mica, minor amounts of chlorite and kaolinite), 8–97% carbonate (mostly calcite, some dolomite, ankerite and siderite), minor pyrite (14)
Marcellus	11–583	128	7.4 ± 2.5	1–10 (1) 1.4–4.3 (16) 3.87–11.05 (17) 10–12 (18) 0.17–7.22, avg. 2.11 (19) 1–11, avg. 6.5 (20)	primarily type II with a mixture of type III (1)	calcitic coarse-grain mudstone, skeletal wackestone-packstone limestone, calcitic carbonaceous medium-grain mudstone, siliceous carbonacous fine-grain mudstone, and argillaceous coarse-grain mudstone (21)	27–31% quartz, 9–34% illite, 1–7% mixed layer clays, 0–4% chlorite, 3–48% calcite, 0–10% dolomite, 0–4% sodium feldspar, 5–13% pyrite, and 0–6% gypsum (1)
Bakken	0–80	35	5.9 ± 1.8	1.79–20.2, avg. 11.7 (N) up to 35 in deeper parts of basin (22)	primarily type II oil-prone with some type I, along shallow east flank of basin some type III (22)	Bakken shales—siliceous organic-rich mudrocks; Middle Bakken—wackestones, calcareous sandstones and siltstones; Three Forks—dolostones, siltstones, dolomitic mudrocks	30–45% biogenic, detrital and authigenic quartz silt, 20–30% clay, 5–10% feldspar, 2–11% detrital and authigenic dolomite, 3–9% pyrite (23)
Eagle Ford	25–255	120	6.6 ± 1.2	0.82–4.94, avg. 2.62 (B) 2–12 (24)	type II (25)	organic-rich marl and calcareous mudrock interbedded with limestones	40–90% carbonate, 14–20% clay, 15–20% quartz
Wolfcamp Midland	689–4271	1817	7.6 ± 3.0 (B)	0.5–6.4, avg. 2.4 (B)	type II–III oil-gas prone	siliceous mudrock, calcareous mudrock, muddy bioclast-lithoclast floatstone, skeletal wackestone/packstone	26% clay minerals, 31% carbonate, 39% quartz + feldspar, 4% other
Wolfcamp Delaware	124–9805	2839		0.5–7.3, avg. 2.3 (B)		argillaceous mudrock, siliceous mudrock, calcareous mudrock, carbonate mudstone/wackestone, muddy floatstone	21% clay minerals, 19% carbonate, 56% quartz + feldspar, 4% other

Table 1, continued. Summarized geologic properties of shale formations studied, Part C.

1	Bruner and Smosna (2011)	11	Ceron and Slatt (2011)	21	Bruner et al. (2015)
2	Klentzman (2009)	12	Bai et al. (2013)	22	Jin and Sonnenberg (2012)
3	Pollastro et al. (2007)	13	Roberts (2013)	23	Nandy et al. (2015)
4	Montgomery et al. (2005)	14	Hammes et al. (2011)	24	EIA (2014)
5	Jarvie (2004)	15	Nunn et al. (2012) and references therein	25	Romero and Philp (2018)
6	Jarvie et al. (2007)	16	Milici and Sweezey (2006)	26	Baumgardner et al. (2016)
7	Papazis (2005)	17	Hill et al. (2004)	27	Hills (1984)
8	Loucks and Ruppel (2007)	18	Engelder (2008)	28	Holmes and Dolan (2014)
9	Ratchford et al. (2006)	19	Enomoto et al. (2015)	B	Bureau core data
10	Alase (2012)	20	Nyahay et al. (2007)	N	NDGS core data

can also serve as additional targets for horizontal drilling and hydraulic fracturing. This is particularly true in formations where migration of oil and gas has occurred (e.g., in the Bakken–Three Forks system), and where organic-rich mudrock deposition occurred multiple times during basin evolution (e.g., in the Appalachian Basin).

In the Appalachian Basin, additional targets include the Mahantango Formation, a gray shale deposited after the Marcellus that has organic matter diluted by Catskill deltaic sediments. The Upper Devonian formations in the Appalachian Basin are also potential targets. The Austin Chalk overlying the Eagle Ford Group, the Bossier overlying the Haynesville, the Bone Spring/Spraberry overlying the Wolfcamp of the Delaware and Midland basins, respectively, and the Three Forks underlying the Bakken Formation are all either separate targets themselves or, in some cases, may contribute to productivity of a well landing in the primary target.

Formations that are not potential reservoirs may also exert control on productivity, as is the case for the carbonate formations that separate upper and lower members of the Barnett and Marcellus formations. In both basins, the intervening carbonate reaches a thickness at which it serves as a fracture barrier, creating an opportunity for stacked horizontal wells. Where the carbonate member is thin (e.g., in southwestern Pennsylvania for the Cherry Valley Limestone, separating the Upper and Lower Marcellus), wells landing in the lower formation may access gas or oil in the upper formation, or in even younger shales (e.g., the overlying Mahantango Formation).

In unconventional reservoirs where organic richness is highest at the base of the formation, making it an attractive landing zone (e.g., Marcellus, Barnett, and Eagle Ford), the lithology of the subjacent formation is particularly important, both for fracture mechanics and for production. Slatt and Rodriguez (2012) showed that many productive shales rest on unconformity surfaces, formed during a drop in relative sea level. Above the sequence boundary is a transgressive systems tract with high GR at the base of the formation, and the top of the high GR interval marks a maximum flooding surface. Above that, relatively cleaner (lower GR) highstand systems tract occurs. In the Fort Worth Basin, the lithology of the Ordovician carbonates underlying the Barnett Shale is critical. In the eastern and northeastern Fort Worth Basin, the tight (low-porosity) Viola Limestone underlies the Barnett; in other areas the underlying Ellenburger can be extensively karsted and dolomitized, with a corresponding increase in Barnett wells' water cut. In the Fayetteville Shale, the lithology of the underlying formation is either sandstone or limestone, and fracture mechanics may vary accordingly.

These stratigraphic relationships are important considerations not only for understanding resource-in-place, but also for calculating and interpreting well recovery factors. Assessment of whether a hydrofractured well is producing solely from the primary formation (e.g., the Marcellus), or whether it also produces from superjacent formations (e.g., the Mahantango) is critical in recovery factor evaluation. In the case of the more conventional Bakken Formation, it is important to consider whether the Middle Bakken or Three Forks reservoirs are the sole contributors to well productivity, or whether Upper or Lower Bakken shales might also contribute (e.g., Gherabati et al., 2019).

While the Wolfcamp does not have the same thick carbonate beds as the Barnett and Marcellus, in both the Midland and Delaware basins it is composed of a thick succession of thinly interbedded siliciclastic and calcareous lithofacies. Thin bedding is well displayed on the GR curve where numerous low GR spikes record carbonate wackestone, packstone, or floatstone beds, ranging from a few inches to 10 ft in thickness (Baumgardner et al., 2016) (Figs. 5C and 5D). High GR, organic-rich mudrocks are interbedded with the low GR carbonates. Thus, ductile, organic-rich mudrock beds alternate with brittle, organic-lean carbonates, forming a succession that is favorable for both oil in place and hydraulic fracture propagation.

Structure and Drilling Depths

The depth of an unconventional reservoir may reflect thermal maturity (if uplift has been minimal since hydrocarbon maturation) and formation pressure. Depth has implications for productivity, with greater depths—and related higher pressures—supporting productivity but increasing drilling costs.

Formation top depths for plays studied range from approximately sea level to more than 15,000 ft subsea true vertical depth (SSTVD) in parts of the Haynesville and Eagle Ford (Fig. 8). The Eagle Ford has the greatest variation in depth, and deepening of the formation across ancestral shelf margins makes it too deep for economically viable wells in the current environment. The Haynesville is the deepest play, on average, with most of the acreage falling in the range of 10,000–15,000 ft SSTVD.

The depth range of the Marcellus is comparable to that of the Fayetteville, although average elevation—and therefore drilling depth—is greater. Shallow depths control the extent of productive acreage in the Fayetteville Shale; with similar shallow depths as the Fayetteville, the Marcellus is expected to be depth-constrained in currently undrilled areas such as in southern New York State.

Thickness Trends

Mean thicknesses range from <100 ft in the Middle Bakken to >2500 ft in the Delaware Basin Wolfcamp (Fig. 9). In many

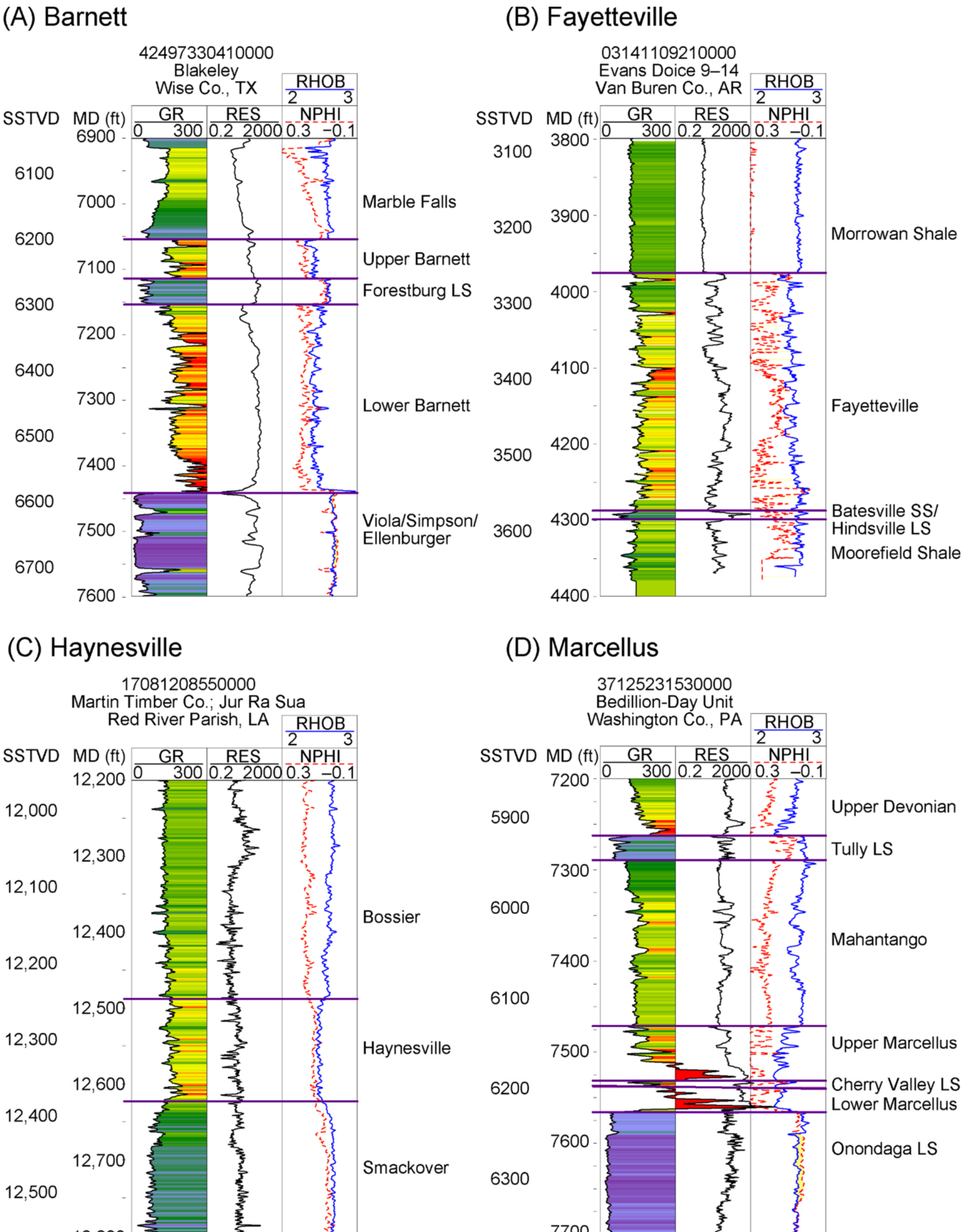


Figure 4. Type logs showing gamma ray (GR), deep resistivity (RES), density (RHOB), and neutron porosity (NPHI) for (A) Barnett, (B) Fayetteville, (C) Haynesville, and (D) Marcellus shales.

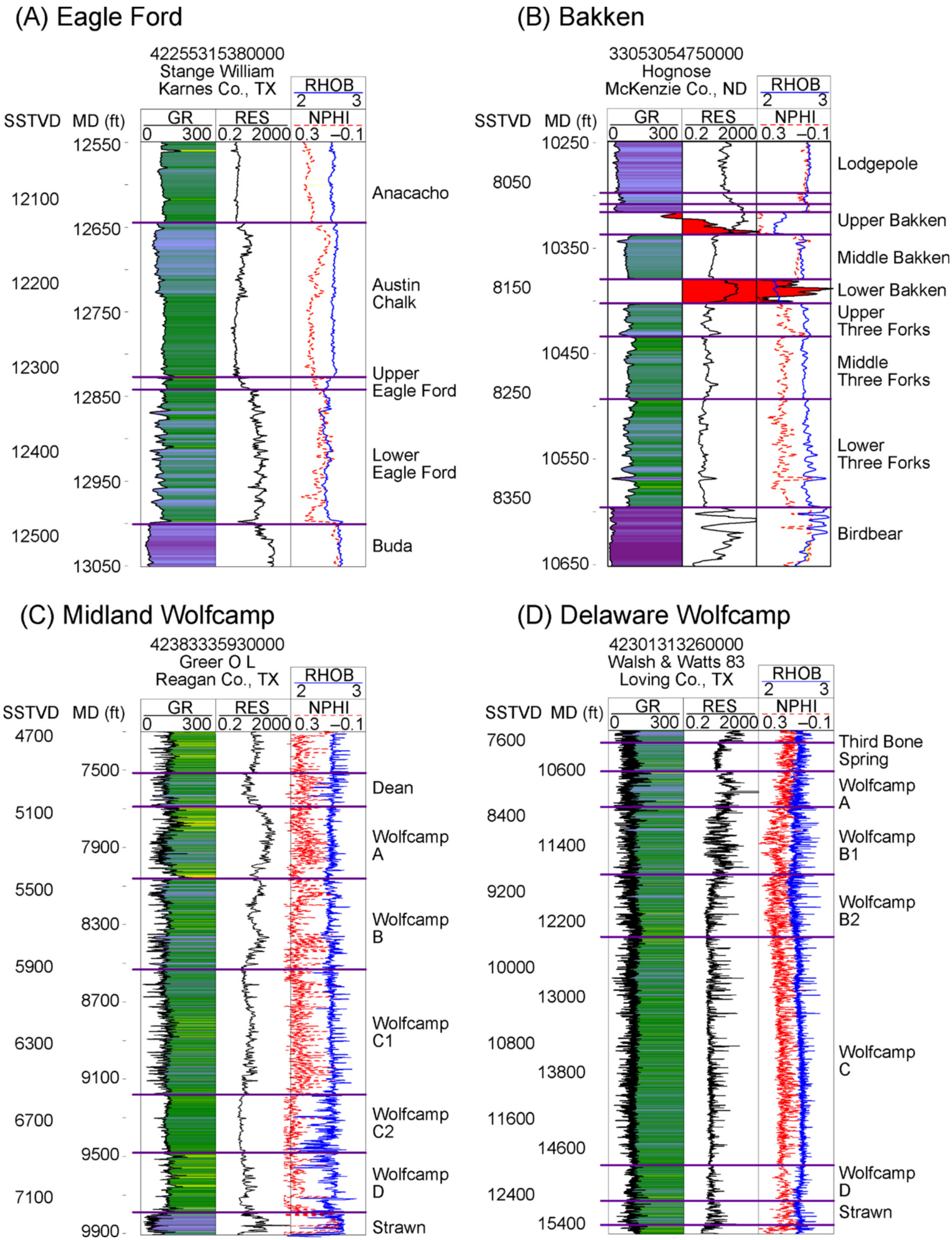


Figure 5. Type logs showing gamma ray (GR), deep resistivity (RES), density (RHOB), and neutron porosity (NPHI) for (A) Eagle Ford, (B) Bakken–Three Forks, (C) Midland Basin Wolfcamp, and (D) Delaware Basin Wolfcamp.

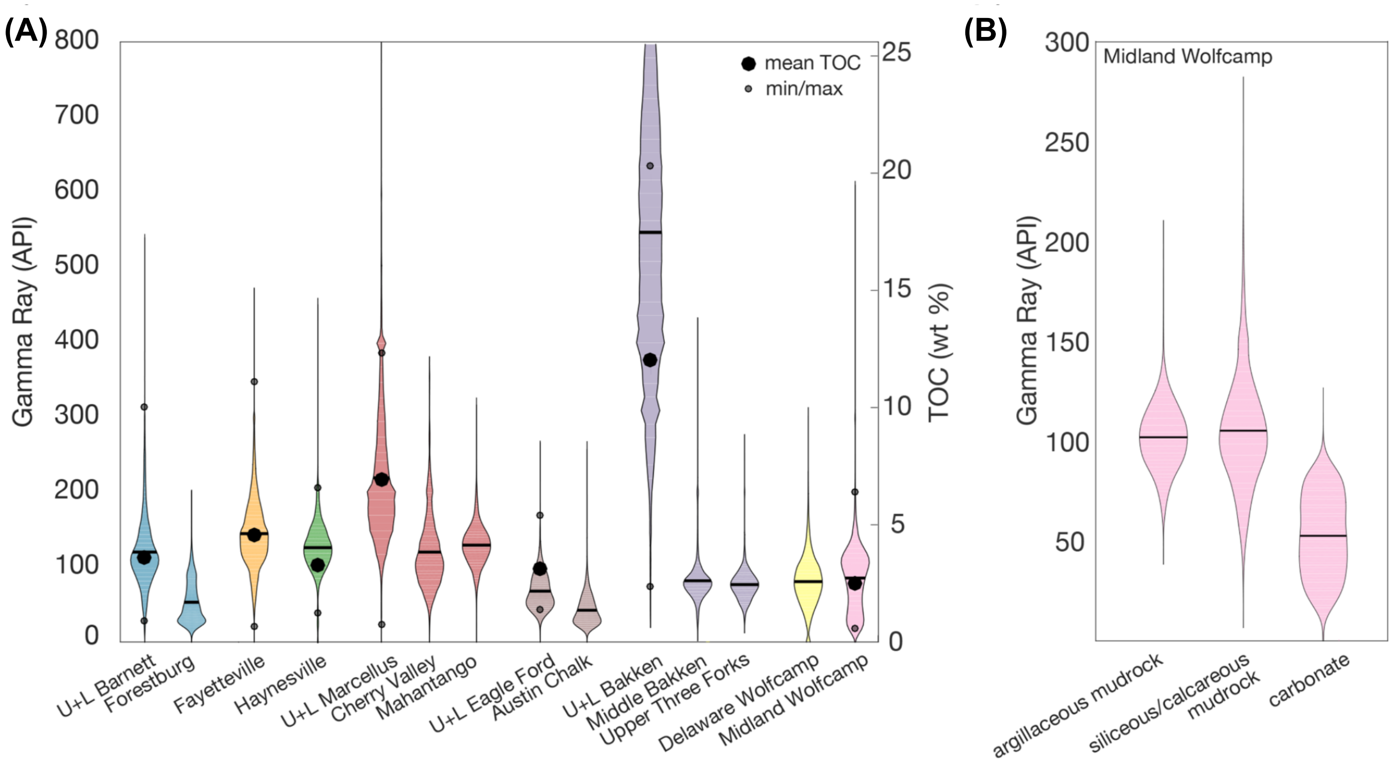


Figure 6. Kernel density estimations of raw GR log data for source rocks and adjacent formations; (A) Raw GR statistics calculated with bandwidth of 5 and black lines as mean values. Average, minimum, and maximum TOC from core data plotted as dots on secondary y-axis (references in Table 1); (B) Raw GR statistics for differentiated facies of the Midland Basin Wolfcamp. Note different GR scales between plots.

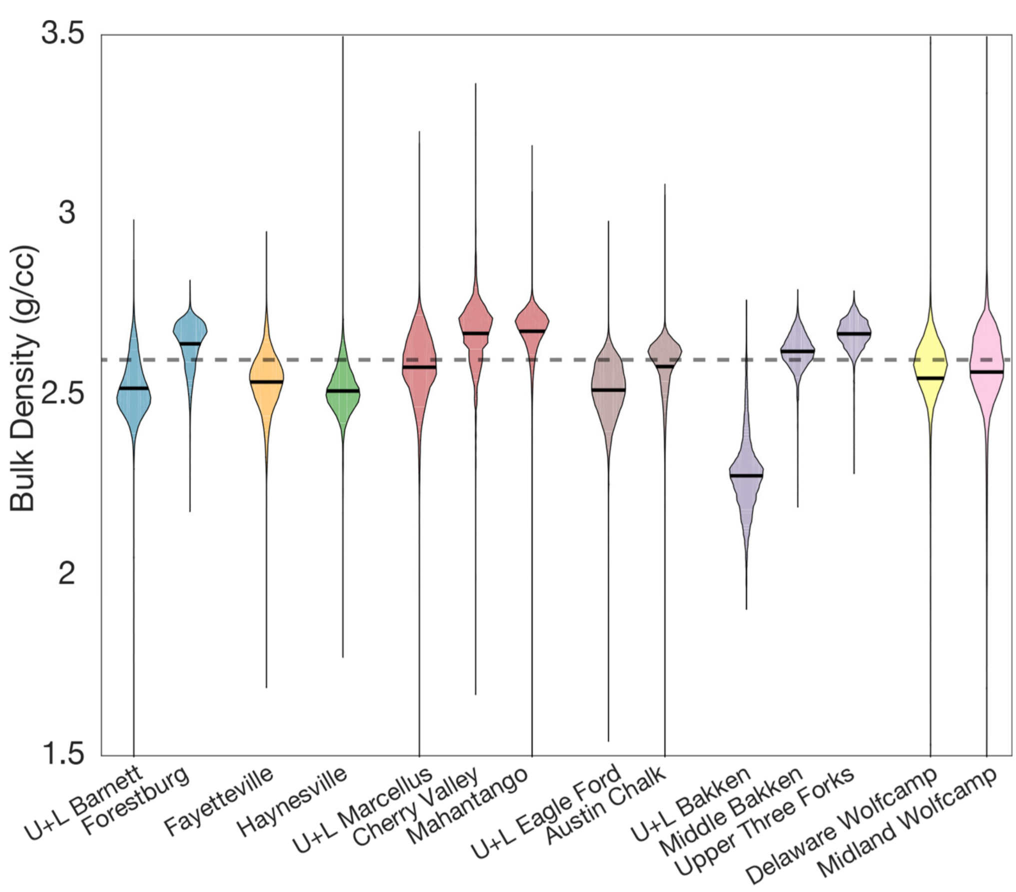
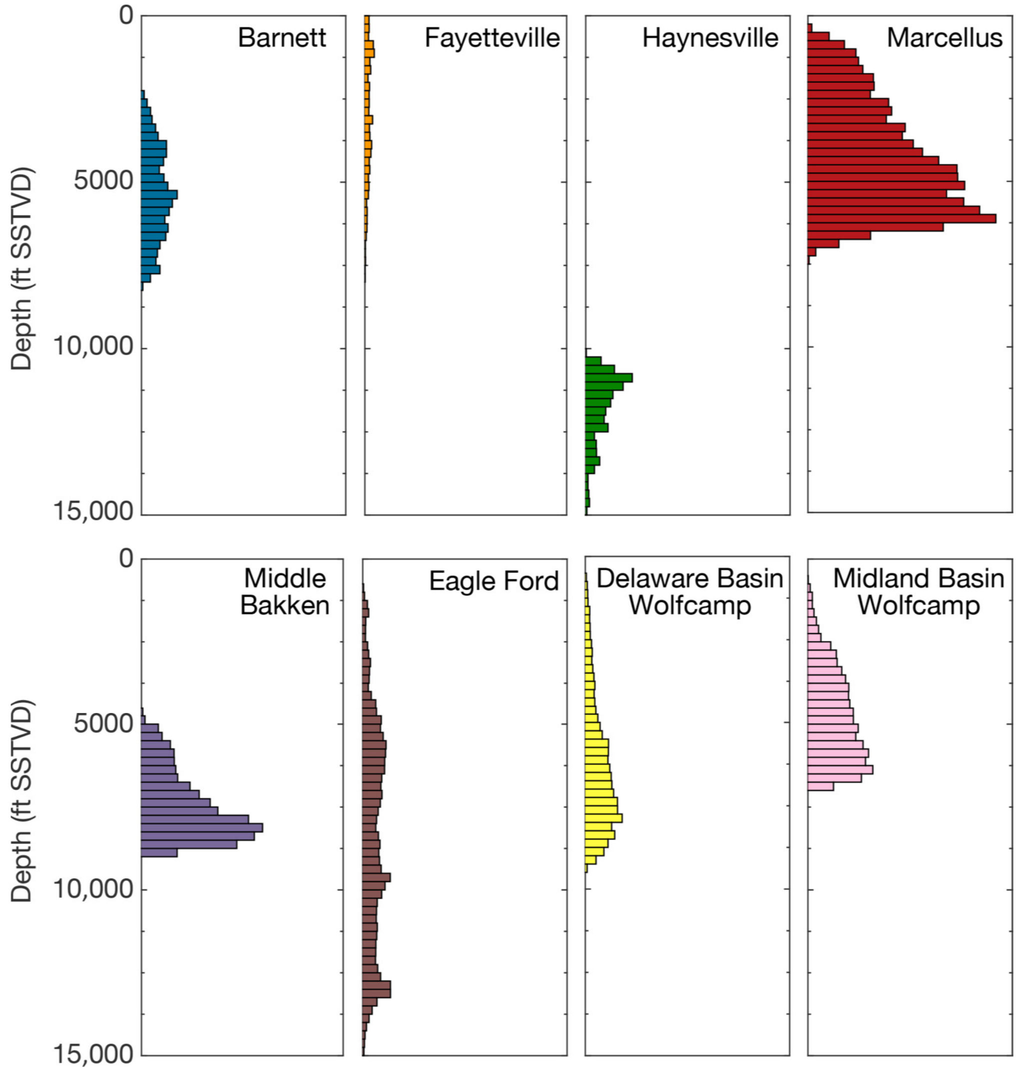


Figure 7. Kernel density estimations of raw density log data with bandwidth of 0.005 for density with black lines showing mean values. Dashed line is at 2.6 g/cc, below which most organic-rich mudrock bulk density values fall.

Figure 8. Depth histograms for each play. The vertical axis represents the frequency of each depth on a square-mile block basis, and the total area under the histograms is proportional to the number of square miles in each play.



plays (e.g., Marcellus, Barnett, Fayetteville, and Wolfcamp), formation thicknesses are great enough to allow for stacked horizontal wells. However, increased thickness is often related to increased clastic input, such as is the case in the Barnett, Fayetteville, northeast Marcellus, the northern portion of the Haynesville, and the lower part of the Wolfcamp. In these cases, the concentration of organic matter is diluted and reservoir quality is diminished, decreasing net-to-gross thickness.

The idea of using "net pay" cutoffs in resource plays was adopted from conventional oil and gas resource assessments. In some unconventional plays, the gross hydrocarbon pore volume and gas-in-place do not correlate strongly with productivity (e.g., Ikonnikova et al., 2018). This can be due to the fracture height being constrained to a limited portion of the reservoir in thicker sections. In these cases, a 200–300 ft thickness cutoff can be useful in understanding the recovery efficiency of wells. In other plays with vertical variability in resource density, such as the Bakken–Three Forks system, net pay cutoffs such as minimum porosity or TOC may better predict productivity. However, as completion strategies and technology evolve, a greater proportion of the resource-in-place might be accessed and recovered, making analysis of both the gross resource-in-place and the net resource given current recovery efficiency important.

Net pay cutoffs assessed in this study include a minimum GR, such as in the northeast portion of the Barnett, to exclude carbonate-dominated layers with low TOC, and a maximum GR cutoff in the Three Forks where GR reflects clay volume so thin clay-rich beds that may not contribute to production are excluded (Gherabati et al., 2019). In the Haynesville, separation between neutron and density logs was used as a proxy for clay volume and employed in net pay thickness and porosity mapping to exclude non-productive clay-rich, TOC–poor areas. Other options for net pay computation include minimum porosity or maximum water saturation (e.g., in Upper Eagle Ford, Hammes et al., 2016).

Rock Properties

Total Organic Carbon and Thermal Maturity

Although resource plays are commonly referred to as "gas" or "oil" plays, in reality their thermal maturities span a range of hydrocarbon generation and preservation limits (Fig. 10). The Fayetteville and Haynesville are almost exclusively dry gas plays, with most of the play in the maturity range of 2–3% R_o. In contrast, the Barnett and Marcellus produce primarily gas, but have areas that fall within the wet gas and oil generation windows. Maturity trends in the Barnett are influenced not only by post-depositional burial (Klentzman, 2009) but also by hydrothermal fluids related to Ouachita thrusting (Kupecz and Land, 1991; Pollastro et al., 2007; Bowker, 2007) and fault systems that act as conduits for those fluids (Montgomery et al., 2005). Marcellus maturity trends increase roughly toward east-northeast,

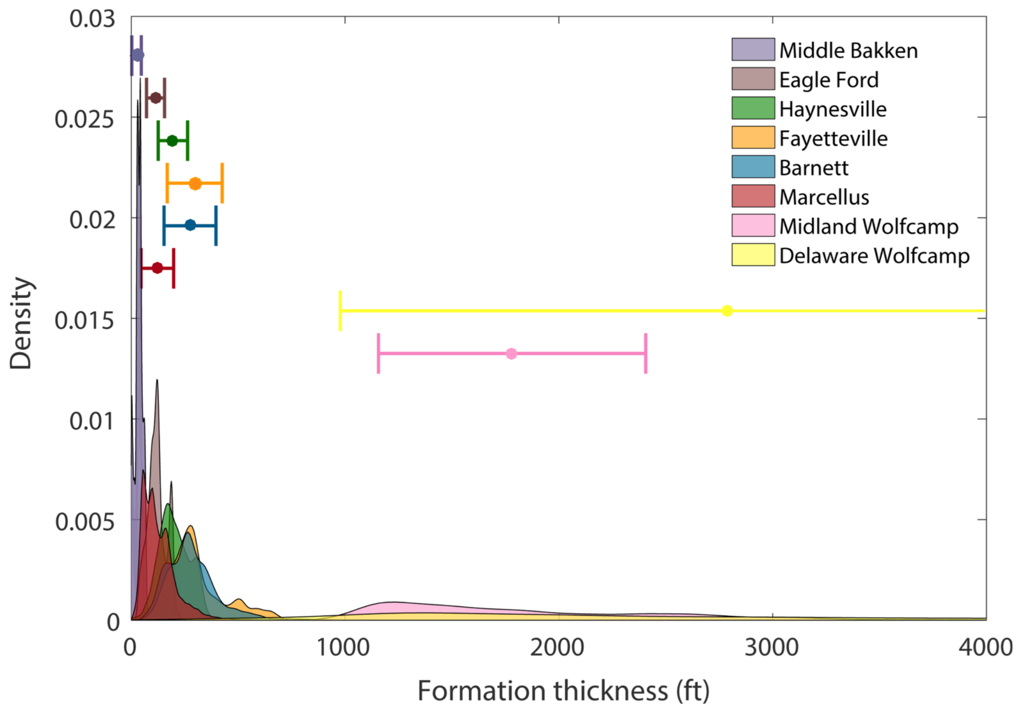


Figure 9. Kernel density estimation of formation thickness in each play. The central markers are mean thicknesses, and the bars represent standard deviation.

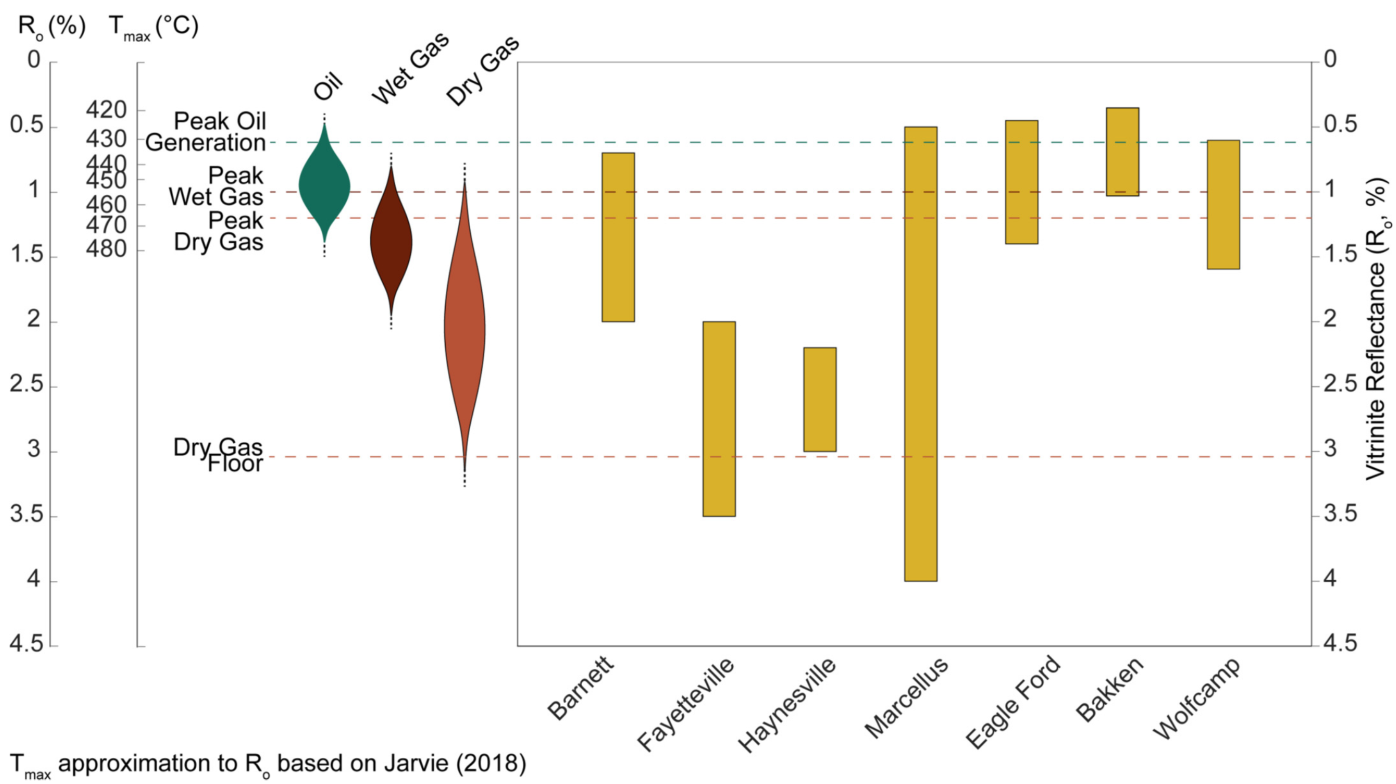


Figure 10. Comparison of the range of thermal maturity values in each play to oil, wet gas and dry gas generation and preservation limits. Approximation of R_o from T_{max} data based on Jarvie (2018). References in Table 1.

related to maximum burial depth and basement fault patterns (e.g., Repetski et al., 2008).

Thermal maturity of the Eagle Ford shale also ranges from oil to dry gas. Maturity increases with depth; in outcrop (northwest) the Eagle Ford is immature, and maturity increases with structural dip to the southeast. Some exceptions to the depth-maturity relationship occur, particularly along the Laramide-related Chittim Anticline of the Maverick Basin, where uplift and erosion have occurred (e.g., Cardneaux and Nunn, 2013).

The Bakken unconventional oil play is defined by thermal maturity. In the area of thermal maturity (oil window), the Bakken forms a continuous oil accumulation where generated oil remains in or adjacent to the source rock with minimal migration (Gaswirth and Marra, 2015). Outside the oil window the Bakken forms conventional reservoirs where significant migration has occurred (from the oil window). Thermal maturity in the Bakken unconventional play ranges from 0.4% R_o (T_{max} = 420°C) to 1.08% R_o (T_{max} = 460°C) (Jin and Sonnenberg, 2012; Theloy, 2014). Bakken thermal maturities do not coincide precisely with burial depth, suggesting spatial variation in paleo-geothermal gradients (Sonnenberg, 2012).

Thermal maturity in the Wolfcamp also ranges from oil to dry gas, and generally increases with depth, although there are exceptions in areas of post-depositional tectonic uplift and volcanism (Pawlewicz et al., 2005). In the Midland Basin Wolfcamp, thermal maturity increases with depth to the west but also increases to the south, an area that was deeply buried but subsequently uplifted. Thermal maturity in the Delaware Basin Wolfcamp increases to the west in response to uplift and volcanism. The Wolfcamp is marginally mature to immature in the northeastern parts of both basins, where burial depths are relatively shallow, and tectonic activity has been relatively subdued.

Average TOC concentrations range from 2–3% (Midland Wolfcamp) to >12% (Upper and Lower Bakken) (Fig. 6; Table 1). Present-day TOC concentration reflects deposition and preservation of organic matter, dilution, maturation and expulsion. The slightly lower average TOC for the Midland Wolfcamp is concentrated in thin siliceous/calcareous mudrock beds that alternate with other facies. In the Upper and Lower Bakken, Nandy et al. (2015) showed that optimal detrital sedimentation rate helped in quick burial and preservation of organic matter, as well as in nutrient supply influencing primary productivity. Marcellus average TOC is also high at close to 7%; high organic richness is concentrated in the West Virginia and southwestern Pennsylvania portion of the play, where the formation is thinner overall due to less clastic dilution compared to northeast Pennsylvania, and where thermal maturity is lower.

Composition

Understanding the lithology, mineralogy, and lithofacies of mudrocks, and their vertical and spatial distributions, is critical because many important reservoir properties (e.g., TOC and brittleness) vary along with them. Mineral composition can be visualized as a ternary diagram with carbonate (calcite + dolomite), quartz + feldspar, and clay at the apexes (Fig. 11). Significant vertical and lateral heterogeneity is present in unconventional source rock reservoirs (e.g., Passey et al., 2010; Slatt and Rodriguez, 2012). However, some generalizations can be made; in almost all productive shale plays, clay volume is less than ~50%. Carbonate volume frequently spans the entire range of the diagram, particularly for plays with interbedded carbonates such as the Barnett and Marcellus. Proportions of quartz and carbonate are important for reservoir geomechanics, with >50% quartz or carbonate a good indicator for brittle rock that is more amenable to fracturing.

Barnett, Haynesville, Fayetteville, and Marcellus compositions are remarkably consistent (Fig. 11A), though the Haynesville and Barnett tend toward being more siliceous. Composition of the Eagle Ford is distinct with its dominant carbonate component (Fig. 11B), trending on a line with roughly equal proportions of quartz and clay. The Bakken–Three Forks system consists of both source and reservoir rocks. The source rocks (Upper and Lower Bakken) are shales dominated by a clastic component with minor carbonate—mostly dolomite. The Three Forks is dominantly dolomite, with dolomite volume generally >50 vol. %, but with high variability. Bakken clay varies from 15–25 vol. %.

Lithofacies

For the two Wolfcamp plays, core description and core sample data were used to calibrate GR and RES logs for lithofacies mapping. GR and RES logs are common in most basins, providing widespread and consistent data types. GR curves are normalized to a common mean, X–ray fluorescence (XRF) and X–diffraction (XRD) mineralogy are the main core data used in the calibration process. GR and RES cutoffs are used to distinguish three lithofacies: argillaceous mudrock, siliceous/calcareous (low clay) mudrock, and carbonate. Once log-based lithofacies are identified and mapped, additional core data (for example, TOC and geomechanical data) are used to document facies control on reservoir and source-rock properties (Hamlin and Baumgardner, 2012; Baumgardner et al., 2016). Both siliceous and calcareous mudrocks cause high GR and high RES responses and so are difficult to distinguish separately using GR and RES cutoffs alone. Both siliceous and calcareous mudrocks, however, are relatively organic-rich and brittle and form the most prospective lithofacies for horizontal well landing zones. Siliceous/calcareous mudrocks are most abundant in Wolfcamp A and B layers in both basins.

For the Bakken play, core and petrophysical data were used to map lithofacies in the primary reservoir layers, Middle Bakken and Upper Three Forks. The lithofacies are based on dominant mineral composition: quartz, illite, calcite, and dolomite. In general quartz and dolomite lithofacies have the best reservoir properties (Theloy, 2014). Within the Bakken oil window, quartz increases to the north, and dolomite increases to the west in the Middle Bakken. In the Upper Three Forks quartz increases slightly to the northwest, whereas dolomite is abundant across most of the oil window.

Porosity

For the Barnett, Fayetteville, Haynesville, Marcellus, Eagle Ford, and Bakken, computed porosities were mapped and average values for each square-mile block were compared (Fig. 12). The majority of porosity falls in the range of 5–10% and distributions are roughly normal. Average porosity values for productive shale plays range from 5.6–7.4%.

SUMMARY AND CONCLUSIONS

Many geologic characteristics of shale plays, from stratigraphic and structural development to small-scale rock properties, have the potential to affect productivity. To determine the impact of geology on productivity, an understanding of the variability of properties within and between plays must be established. Here, the geologic properties of major U.S. shale gas and tight oil plays have been presented. Insights into the variation of geologic properties of shales include:

- Depths range widely, averaging from <4000 ft in the Fayetteville to >12,000 ft in the Haynesville. Depth is determined not only by basin type and lifespan, but also by post-depositional tectonic history. For plays with currently undrilled areas, such as the Marcellus in New York State, other plays, e.g., Fayetteville, may serve as analogs to determine the extent to which depth may constrain the drillable area.
- The thickness of productive shale plays range from <50 ft in the Middle Bakken to thousands of feet in the Wolfcamp of the Permian Basin. Thickness trends are driven by the duration and pace of deposition, as well as subsequent erosion. Greater thicknesses often correspond to lower net:gross thickness, decreased concentration of

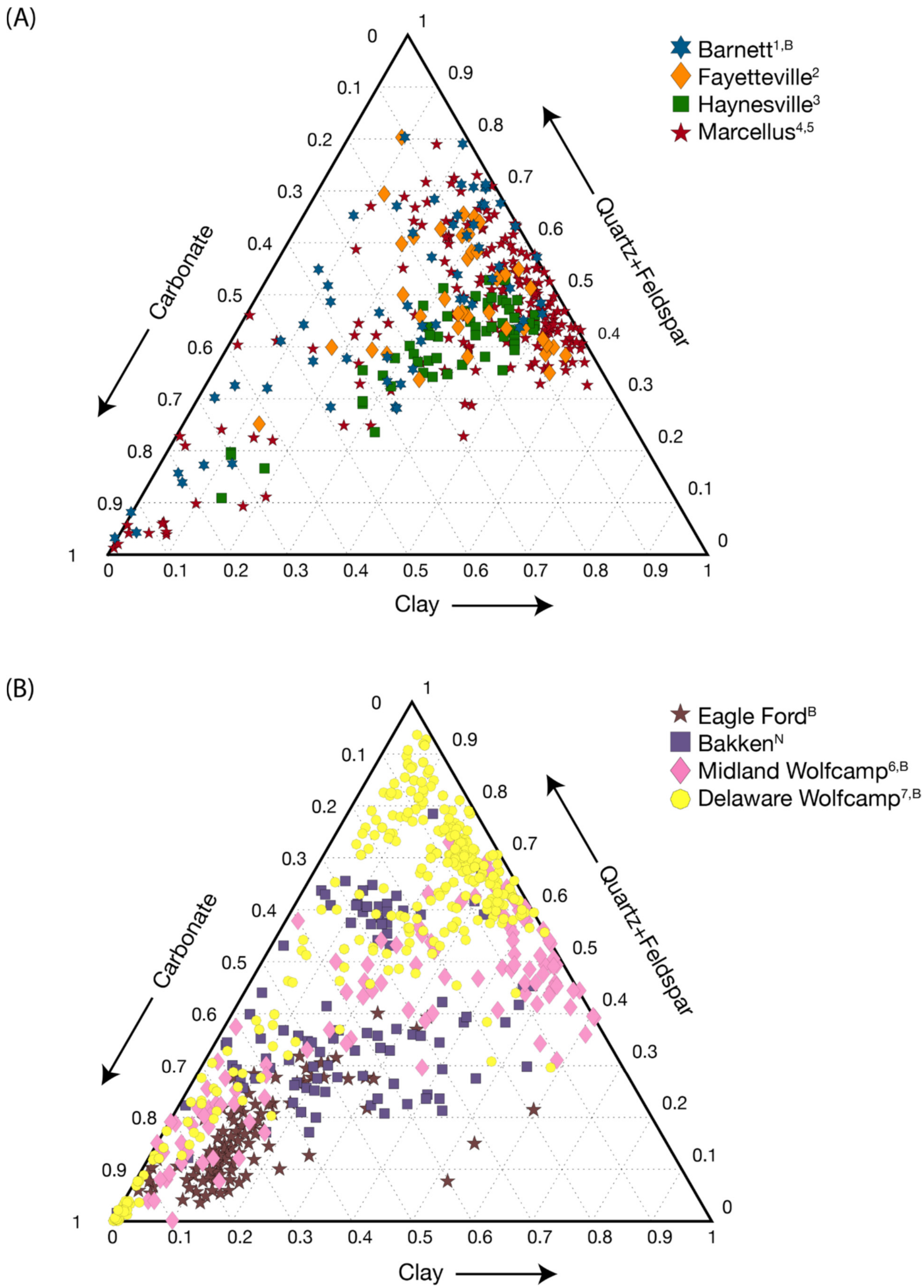


Figure 11. Ternary diagram showing composition of a) shale gas and b) tight oil formations in terms of carbonate (calcite + dolomite), clay, and quartz + feldspar. Data sources include legacy core data donated to BEG[B], NDGS[N] core data, and previous studies ([1]Loucks and Ruppel, 2007; [2]Roberts, 2013; [3]Hammes et al., 2011; [4]Enomoto et al., 2015; [5]Wang and Carr, 2013; [6]Baumgardner et al., 2016; and [7]Moede, 2018).

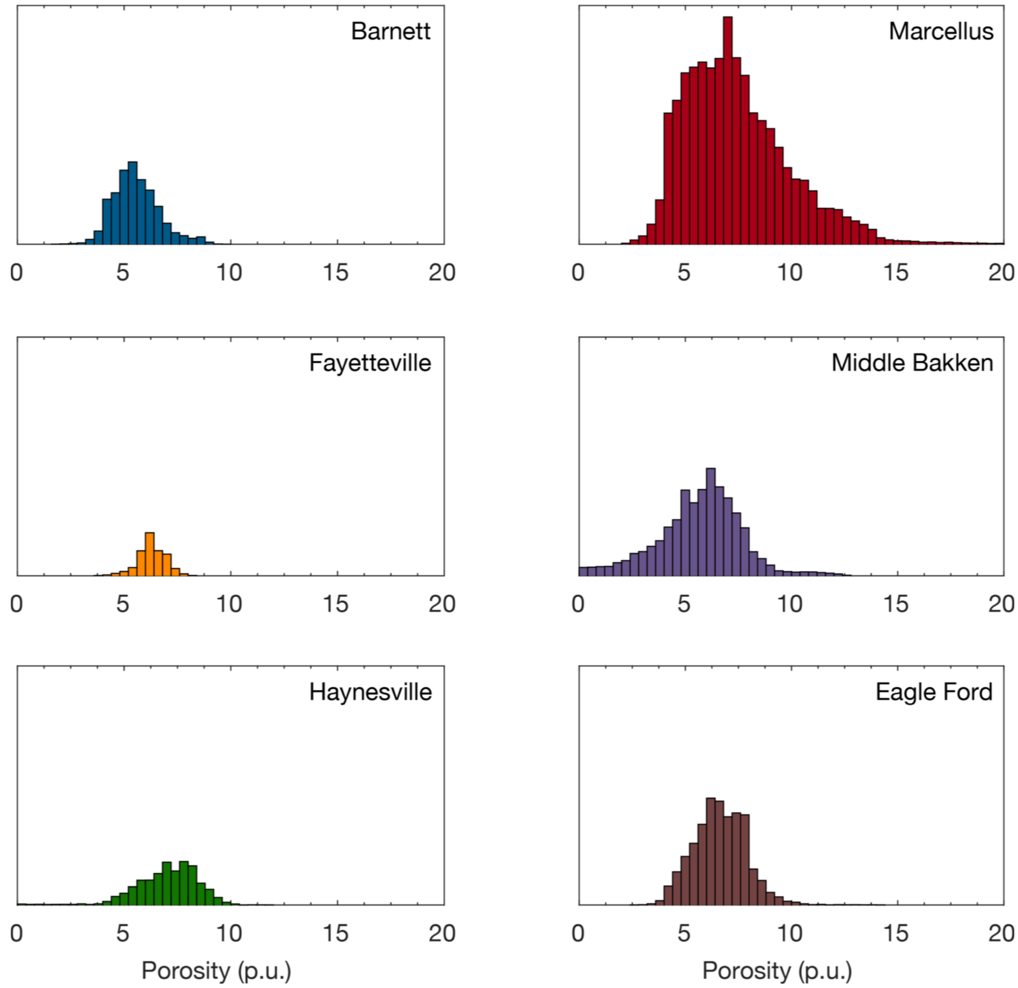


Figure 12. Porosity histograms for each play. The vertical axis represents the frequency of each porosity range on a square-mile block basis, and the total area under the histograms is proportional to the number of square miles in each play.

organic carbon, and decreased average reservoir quality. However, the potential for stacked wells in thicker formations, and for development of subjacent/superjacent formations, makes some basins more attractive.

- Porosity of productive shale formations is surprisingly invariant, with average porosity ranging from 5.6–7.4% for interpolated blocks, and up to 8.3% on average for core measurements.
- Average TOC concentration spans a wide range, with formation averages ranging from 2–3% in the Wolfcamp and Eagle Ford to >6% for the Marcellus and >12% for the Upper and Lower Bakken source rocks. Organic richness reflects basinal conditions including the deposition and preservation of organic matter, as well as dilution from clastic input.

This semi-quantitative comparison of geologic and petrophysical properties of shale gas and tight oil plays provides insight into the degree of heterogeneity between and within productive plays. Although the shale plays studied exhibit some similarities, distinct differences in their geologic characteristics lead to differences in productivity (Ikonnikova et al., 2015, 2018). Understanding this variability is a critical first step in the development of reasonable geologic models in analog basins lacking robust data coverage or for exploration wells drilled in frontier settings. Recoverability of shale gas and tight oil resources reflects a complex aggregate of reservoir properties that either enhance or limit productivity; combined, these properties determine the extent of play development. Further understanding of the impact of geologic variability on productivity will enable the development of shale basin archetype models that may lead to more efficient data collection and play development.

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