

# SHALE OIL & GAS RESERVOIRS

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CRITERIA AND CUTOFFS

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STEVEN W. HENNINGS, M.S., P.E.

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# Introduction

Many of the first engineers and geoscientists to evaluate modern shale plays had relatively few tools and little training for selecting well locations and completion intervals. Consequently, they turned to a mixture of simple analogies, statistical approximations, assumptions, and conventional analysis techniques. Many practitioners continue to rely on those methods, leading the 2020 president of the Society of Petroleum Engineers, Nancy Noonan, to list “improved shale reservoir training” as a critical requirement for meeting future oil and gas demands. This training objective is addressed in *Shale Oil & Gas Reservoirs: Criteria and Cutoffs*, with coverage of unique shale properties, lab tests, and practical evaluation concepts.

The intended audience is already familiar with conventional reservoir technologies, so the book is narrowly focused on shale concepts. However, some long-standing lessons from conventional evaluations still apply. For example, reliable techniques require an evolution from simply recognizing favorable rock properties to connecting them to specific storage and flow mechanisms. Also, effectively exchanging information and evolving development strategies requires a good understanding of the unique terminology and the basis of common rules of thumb. Therefore, this book addresses 180 shale characteristics and 150 cutoffs for screening prospects and completion intervals.

Guidance on improving reservoir characterization is also provided with a review of the rock properties having the greatest impact on shale well performance. This information is summarized in two tables (4.1 and 4.2) that specify the acceptable ranges for 20 critical shale gas attributes and 21 critical shale oil attributes.

The author has decades of experience in field operations where it is essential to maintain a focus on rapid and practical analysis techniques, plus he has an appreciation for complex and theoretical concepts from serving as the technology transfer coordinator at a major petroleum research center. He also found from years of computer simulation experience that advanced models can be highly reliable for conventional reservoirs, but they consistently fail to accurately predict shale well performance.

The challenges faced by the shale industry in relying on flow models and hydraulic fracturing simulators reflect the current inadequacies in shale data acquisition, physical measurements, and reservoir characterization processes. Until significant improvements are made in those three areas, empirical correlations derived from field observations and experiments will continue to be most effective for shale analysis. That same approach has been extremely valuable in conventional reservoir studies because it has distinct advantages in cost, availability, and timeliness when compared to computer simulation. Unfortunately, when considering shale plays, there is far less guidance on the limitations and

origins of the various empirical correlations being used to make huge investment decisions.

The need for more emphasis and documentation of practical evaluation methods was revealed to the author through direct involvement in the Bakken, Barnett, Eagle Ford, Haynesville, Marcellus, Montney, and Niobrara shale plays. Those experiences explain why the following chapters are primarily focused on practical aspects of shale analysis. Consequently, this book is unique in that it was prepared for professionals who are directly engaged in the exploration or development of shale.

One of the more common myths about shale is that increased organic content improves shale development potential. The original enthusiasm to locate intervals with high organic content, or total organic carbon (TOC), originated from the fact that all shale plays involve such intervals. Otherwise, the play does not qualify as shale. However, criteria for defining shale do not match the criteria for selecting the best development target, as will be illustrated multiple times in the following chapters.

Individuals gaining a firm understanding of shale evaluation concepts are indispensable to their company in identifying, ranking, and valuing shale prospects. They also become more effective in exchanging information with their interdisciplinary team members and in gleaning information from research papers and technical workshops. Unfortunately, such exchanges of technical information and concepts continue to be inhibited by inconsistent terminology. This reflects the many ongoing disagreements and misconceptions about key shale characteristics, which are addressed in this book.

An unspoken objective for many publications is to develop a three-letter abbreviation, or TLA, to replace a cumbersome phrase. This has led the modern shale industry to adopt dozens of new abbreviations that have not been totally accepted and/or apply to more than just one technical concept. For that reason, each section of this book begins with a list of the relatively unique shale terms and abbreviations to be discussed, recommended, or clarified in that section.

The author continues to teach various shale courses for engineers, geoscientists, technicians, and service providers who are transitioning from conventional reservoirs to shale or who have simply received too little training on that topic. These presentations on shale characterization and hydraulic fracturing for shale have been delivered every year since 2010, at various technical conferences and workshops, but they do not allow enough time to address all the key issues or to cover them in the detail provided in this book.

Many individuals and organizations can be credited with advancing shale analysis techniques decades before modern shale development swept across the United States and Canada. Although the earliest studies focused on how source rocks generated and expelled the petroleum found in conventional reservoirs, the study results eventually proved to be very valuable in guiding the direct development of shale reservoirs. In fact, many specialists who devoted their careers

to understanding shale storage and productivity characteristics were somewhat obscure until the shale booms elevated them to *rock star* status.

Contributions from shale pioneers gave modern operators and researchers a huge advantage in accelerating the modern shale development era. In addition, several long-standing processes from the coal and oil shale industries were incorporated into shale oil and shale gas analysis. The only drawback was that many of these cross-over techniques needed some refinements to fit the unique attributes of different types of plays. This resulted in slight changes in procedures, tests, and terminology that are not yet fully resolved, or even addressed, in most of the petroleum literature.

Feedback from shale training courses also indicates that many modern evaluators are not fully aware of how the assumptions applied in older techniques influence modern practices and strategies. Consequently, some major delays and costs can be blamed on assumptions that have not been validated from modern field results or that only apply to specific situations.

As mentioned earlier, the industry generally places too much emphasis on the organic content of shales. By comparison, too little attention is directed at the critical issues of:

- adsorption in shale gas *and* shale oil reservoirs impacting recovery factors.
- clay maturity, type, and concentration influencing productivity.
- shale pore network features prohibiting the flow of certain hydrocarbons.
- organic variability impacting hydrocarbon saturations and compositions.
- high organic concentrations restricting frac treatment effectiveness.

Methods and reasons for studying these five issues are outlined in the following four book chapters. The first outlines the essential criteria and characteristics of shale plays, while the second chapter focuses on specific changes in organic material and clays that dictate the development potential of specific intervals.

Chapter 3 provides an overview of tests and techniques used to identify variations in the shale reservoir properties that control flow rates and recoveries. The material introduced in the first three chapters is then summarized in the closing chapter, which also outlines the shale reservoir screening process and a simple method for anticipating frac efficiency.

The chapters are subdivided into 27 individual topic sections relating to the critical elements of shale analysis. Each section begins with an overview and a list of key terms, before delving into the main discussion. The overviews and lists, which mention 225 technical terms, are intended to help more advanced evaluators quickly locate the information needed to supplement their shale expertise. Otherwise, those who have received little to no formal training on modern shale evaluations will benefit from completing the entire book. Again, this conclusion and the book contents reflect feedback and observations culled from dozens of shale short courses over the past decade.

The subject matter also reflects contributions from apparently like-minded professionals in the industry who are often referred to as “we” or “us” in this book, but such references are not intended to hide the many disagreements inside and outside of that group. In fact, rather than representing a negative, the numerous opportunities for individuals to verify or advance shale evaluation techniques is an interesting and exciting feature of working these plays.

Current opinions regarding the required evaluation steps, critical rock properties, and optimum development procedures can also vary by operator and basin. This is primarily driven by differences in shale characteristics and financial considerations. Secondarily, experiences with specific wells always play a role in shaping the opinions of individual professionals and companies. Nonetheless, the *ideal* approach to any development project is straightforward and optimizes profitability. For that reason, *Shale Oil & Gas Reservoirs: Criteria and Cutoffs* is heavily influenced by the writings of Bob Barree, Randy Blood, Harry Dembicki, Julia Gale, Anne Grau, Rob Heller, Dan Jarvie, Steve Laubach, Katie Smye, Stephen Sonnenberg, Scott Thomson, Andrew Wiseman, and others providing clarity on what dictates shale well performance.

*Summary quote: “Competition makes us faster; collaboration makes us better.”*  
—Fyrefly

# 1

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## Characterizing Shale

**M**any are surprised to learn that the shale oil and gas industry does not target what most petroleum textbooks define as shale. Instead, shale reservoirs can simply be characterized as clay-rich source rocks that are not dominated by clay or organic material. This basic definition allows for a wide assortment of lithologic units to play a significant role in shale development. It also has an advantage over several other published definitions in that it is applicable to every shale play that has been a commercial success.

Ongoing disagreements about which shale play characteristics are critical to commercial success have led to different opinions on how to evaluate prospects, define play boundaries, and anticipate the hydrocarbon recovery potential. A common approach to investigating these issues involves spending millions of dollars on pilot production wells. However, significant cost savings are available to those who refine their exploration and development programs by first considering the rock property information described in this chapter.

*Summary quote: “Simplicity is the ultimate sophistication.”—Leonardo Da Vinci*

### 1.1 The Essential Shale Qualifiers: Clay and Organic Content

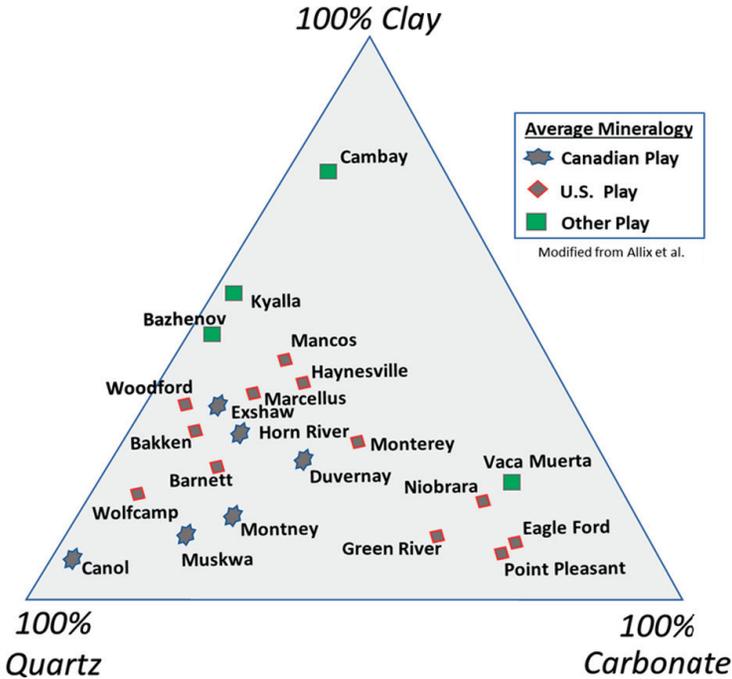
#### Topic Terminology

Rock brittleness, traditional shale, classic shale, soft shale, instantaneous shut-in pressure (ISIP), ISIP index, hydraulic fracturing efficiency, frac gradient, breakdown pressure, horizontal stress ratio, clay content, smectite, argillaceous, kerogen, total organic carbon (TOC), organic matter content (OMC), OMC cutoff, and non-recoverable organics (NRO).

#### Topic Overview

Every shale play contains varying amounts of clay and organic matter that are very impactful in dictating commercial viability. However, modern shale development

The focus on shales with less than 50% clay mineral content is evident from examining where the major shale plays are positioned on the mineralogical ternary plot shown in Figure 1.9.



**Figure 1.9.** Shale Mineralogy Ternary Diagram (data from Allix et al., 2010; Loucks et al., 2012; and Anderson, 2013)

The Kyalla (Australia) and Cambay (India) plays have both received considerable attention from potential developers, but their average clay content sits above the 50% line. This suggests the plays will not be successful without further technological advancements or unless sizable shale volumes are located where clay contents are much lower than the play averages.

In addition to mudrock mineralogy, particle size, and fissility, some evaluators focus on other physical characteristics to identify types of mudrock (O'Brien and Chenevert, 1973). Add this to the sampling bias from using a few wells to define massive rock volumes, and it is not surprising to find inconsistencies in how certain intervals are labeled. For example, there are major differences in how the Middle Bakken lithofacies are described in four technical papers that were published within two years of each other (Sondergeld et al., 2010).

What is needed is a new classification scheme that provides insights as to which mudrocks hold development potential and which ones basically serve as drilling hazards, fracture barriers, or cap rock.

The focus on developing intervals rich in type III kerogen diminishes during periods of low gas prices, but a significant concentration of this kerogen can usually be found in every source rock. Such a situation can be very useful because microscopic examination of type III kerogen, as discussed in section 2.1, can help estimate LOM for all other types of kerogen found in that same rock sample.

Another empirical method for quantifying source rock LOM involves dividing the thermally transformed kerogen volume by the estimated original transformable kerogen volume (Tissot and Welte, 1984). The resulting ratio is known as the transformation ratio, or TR.

Areas where maximum kerogen transformation has occurred are assigned a value of 1.0 TR, such as portions of the Utica Shale in Ohio. Conversely, kerogen that has not experienced any thermal transformation falls into the diagenesis category (Tissot and Welte, 1984) with a 0.0 TR value. This assignment does not equate to the source rock having no development potential, as it might hold microbial gas. In addition, 1.0 TR does not signify that a formation lacks kerogen. Instead, the transformation ratio only applies to *transformable* kerogen, without any consideration of the residual or inert kerogen fraction.

The kerogen residue remaining after transformation is primarily carbon that has lost the hydrogen needed to form hydrocarbons. For example, a hydrogen-rich kerogen has 7% to 10% hydrogen, but oil requires ~15% hydrogen and gas needs ~30%. Therefore, hydrogen will be consumed during the transformation process but there will always be a carbon remainder in spent source rock.

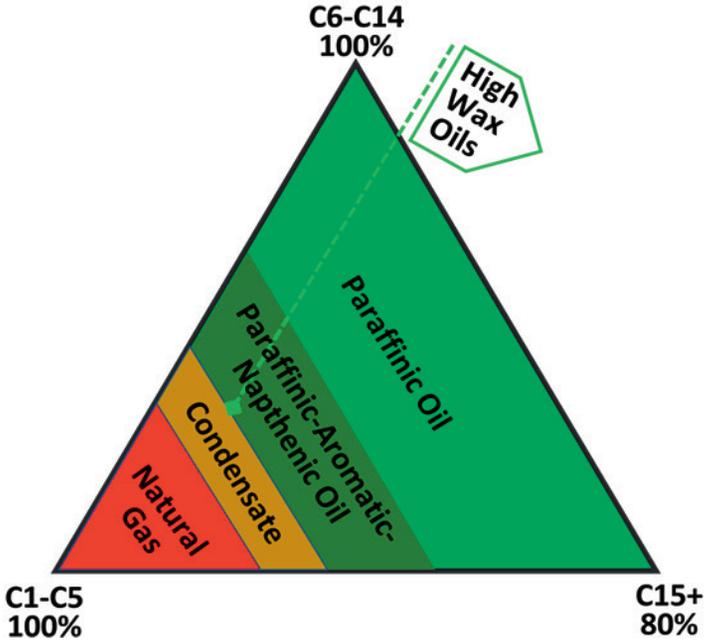
Since the first substance(s) generated during kerogen catagenesis are not hydrocarbons, a 0.05 TR (5% transformation) is generally needed before light hydrocarbons would be expected from type II kerogen. This milestone is delayed to 0.15 TR for type III kerogen.

Kerogen transformation accounts for about 90% of all the crude oil in the subsurface and most of the light oil. The remaining ~10% is directly derived through bacterial activity and low-temperature (<122° F) chemical reactions involving proteins, fats, and waxes that are derived from various organisms (Hunt, 1996). As with microbial gas, these liquids are generated during the diagenesis stage of organic maturity.

Unlike microbial gas, accumulations of diagenetic oil lack the mobility and saturation to be targeted for development. However, traces of diagenetic oil are sometimes used to help estimate the LOM and composition of thermogenic oil.

Diagenetic oil tends to be dominated by hydrocarbon compounds that have an odd number of carbon atoms and at least 15 total carbon atoms (C15) per compound. This *odd-carbon preference* is often quite noticeable in the ratios of C17 to C16, C29 to C30, and C31 to C30 (Anders and Robinson, 1973). These ratios also tend to increase throughout the diagenesis stage.

Thermogenic oil does not have an odd-carbon preference, so as more thermogenic oil mixes with the diagenetic oil, the odd-carbon preference declines.



**Figure 2.5.** Influence of Carbon Number Groups on Hydrocarbon Type (after Eglinton et al., 1990)

Hydrocarbon windows might also be identified using the commercial class of the petroleum produced from those intervals, which can also be related to carbon number ranges. For example, natural gas is dominated by methane (C1) and a small amount of ethane (C2). Propane (C3) and butanes (C4) from the wet gas window are primarily used as LPG (liquefied petroleum gas), while liquids from the condensate window are mainly used as gasoline (C5–C10).

Shale oil can be formulated into kerosene, diesel, and heating oil. Kerosene is the lightest of these liquids and is mostly composed of C11 through C13. Diesel includes C8 through C24, which is about the same carbon-number range for heating oil, except diesel is lighter with a greater concentration of C14 through C18.

The decrease in carbon number with increased maturity not only translates to lower molecular density, but it also involves a change in molecular structure. These structural changes decrease the adsorptive bond between kerogen and hydrocarbons while also altering the physical dimensions of the molecules. Both maturity-driven changes improve hydrocarbon mobility.

An extremely important point is that carbon numbers normally do not indicate the molecular structure of a hydrocarbon compound due to the many hydrocarbon isomers that share the same carbon number. As an example, there are two isomers for C4 and nine isomers for C9. Therefore, whenever hydrocarbon mobility is being evaluated, the structure of the molecules need to be considered.

Assuming sustained flow requires a circular opening four times the diameter of hydrocarbon molecules, and further assuming pores contain 25% immobile water, a large fraction of shale oil pores must fit the mesopore classification to be effective flow conduits. This is especially true when considering that pore throats are generally much smaller than the pores they connect.

It is also optimistic to assume flow rates are determined by the average liquid molecule and the average pore size. The largest molecules flowing through the smallest pore throats will lead to partial plugging, and this will certainly restrict flow to some degree.

Multiple Pennsylvanian shales in the Anadarko Basin were analyzed by Cranganu and Villa (2006), and the results indicated minimum pore size was 40% of the average. Also, King et al. (2015) found one-third of the porosity in Devonian shales is from pores with less than 3 nm diameter. This segment of the pore system is difficult to detect due to scanning electron microscopy (SEM) resolution being limited to 5 nm.

Alternative measurement methods have been developed that indicate SEM misses 75% (Mathia et al., 2016) to 80% (Klaver et al., 2015) of shale porosity. Still, many reservoir studies rely on just SEM and mercury injection for characterizing shale pores.

Consideration of molecules plugging pores reveals another challenge to establishing a porosity cutoff. Compositional analysis of produced fluids helps in understanding what molecules are being produced to surface, but the analysis will not reveal what is plugging the pores and being left behind in the reservoir. For example, flowing asphaltenes through a reservoir usually requires a large, connected pore system that would be found in sandstones with more than 15% porosity. These molecules will fit into larger primary pores and organopores found in shale, but those pore networks rarely have the connectivity to transport asphaltenes to a wellbore.

The kinetic diameter of asphaltenes and other molecules are listed in Table 3.2 along with the minimum pore throat size needed to transport each molecule. The minimum size assumes an opening must be four times the diameter of the molecules flowing through the opening. It also assumes the walls of the pore throat are coated with water, with a fixed 0.53 nm thickness, as expected in a water-wet system. The fixed thickness roughly translates to an assumed water saturation of 45% for shale gas reservoirs and 20% for shale oil.

Hydrocarbon	Kinetic Diameter	Pore Throat Min. Diameter	Reference
Methane	0.38 nm	2.6 nm	Breck, 1974
Propane	0.43 nm	2.8 nm	Breck, 1974
Toluene	0.58 nm	3.4 nm	Breck, 1974
Paraffinic Oil	0.7 nm	3.9 nm	Jimenez-Cruz & Laredo, 2004
Aromatic Oil	2 nm	9 nm	Tissot & Welte, 1978
Asphaltene	8 nm	33 nm	Tissot & Welte, 1978

**Table 3.2.** Hydrocarbon Pore Throat Requirements

methane is the smallest hydrocarbon molecule, this practice underestimates gas volumes for all wet gas plays and the many dry gas plays that contain ethane or larger hydrocarbon gas molecules.

The kinetic diameter of CO<sub>2</sub> is about 15% smaller than methane, but CO<sub>2</sub> possesses a greater affinity for adsorption that allows for two to three times more adsorption potential (Deng et al., 2006). This explains all the interest in injecting CO<sub>2</sub> into depleted coals for “clean coal technology” to remove that greenhouse gas from the atmosphere.

Kerogens’ affinity for CO<sub>2</sub> also leads to changes in gas composition for the wells producing from microbial resources in source rocks, such as the gas wells completed in the Antrim Shale and in many coal gas plays. The natural delay in the release of CO<sub>2</sub> from source rocks allowed for methane-rich production during the initial development of microbial gas, but continued pressure depletion eventually forced CO<sub>2</sub> to desorb and overwhelm the production stream.

All sales gas streams contain CO<sub>2</sub> so, despite being an inert gas, it boosts sales volumes and should not be ignored in the adsorption or resource volume analyses. Nitrogen is also found in produced gas, but it has only one-half to one-third the adsorption potential of methane (Arri et al., 1992). Consequently, unlike the case for CO<sub>2</sub>, using a methane isotherm to estimate nitrogen adsorption will cause the underground gas volume to be over-estimated.

Errors in estimating gas resource volumes are also introduced with the customary practice of testing adsorption on partially dehydrated samples. Water molecules can inhibit the access of gas to organic surfaces so the moisture content of a sample needs to be restored to allow lab measurements to replicate reservoir conditions. For some reason, this issue tends to receive far more attention with adsorption tests on coals than with those conducted on shale samples. In either case, using dehydrated source rock samples can lead to overestimating the adsorption capacity.

Another important consideration is that the isotherm curves, such as those displayed in Figure 3.11, are not actually lines connecting lab test results. Instead, the lines are developed from empirical equations that provide the best overall fit to the lab measurements. The most popular approach involves the Langmuir (1918) Isotherm equation, shown below:

$$\text{Gas Adsorption Volume} = V_L * \text{Pressure} / (\text{Pressure} + P_L) \quad (3.3)$$

The Langmuir equation has been dependable in predicting how the adsorption capacity of a source rock shifts with changes in reservoir pressure. However, accurate predictions require that the adsorption capacity of the sample be directly measured at two or more pressures. The two measurements allow for the unique solution of the two Langmuir variables,  $V_L$  and  $P_L$ . Conducting even more tests allows for further refinement of the variables, so it is common for the adsorption capacity of a sample to be measured at five or more different pressures.