CHAPTER

15

TIGHT GAS SANDSTONE RESERVOIRS, PART 2: PETROPHYSICAL ANALYSIS AND RESERVOIR MODELING

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15.1 INTRODUCTION

We discuss petrophysical analysis of wireline logs, methods for formation evaluation and issues in evaluating tight sandstone formations. The main concerns of log interpretation in tight gas sandstones include porosity interpretation, understanding the effect of clay on the log responses, accurate computation of water saturation, and permeability determination (Kukal et al., 1985). Moreover, validation of wireline-based petrophysics with routine and special core analysis, well tests, and petrography is often needed to develop a reliable interpretation model.

Petrophysical analysis can help evaluate the hydrocarbon potential, estimate gas in place and, to some extent, producibility of tight gas sands; completion technique and effort drive the economic viability for each play. Many tight gas sandstone formations are known as “tease” intervals—there is a gas show or gas kick but no or little production occurs on a conventional test. Improved technology in drilling and completion has made it possible to produce gas from many tight sandstone reservoirs. An appropriate stimulation program is critical to make wells economic in these types of reservoirs.

For optimal development of a field, a reservoir model that integrates all the data can be extremely valuable for planning the drilling, completion, and production design. The integrated data should include geological (including depositional and lithofacies such as discussed in the previous chapter), petrophysical, and engineering data. In this chapter, we first review some common issues in petrophysical analysis of wireline logs in tight gas sandstones. We then discuss the three main reservoir properties based on well logs and core data, including porosity, permeability, and water saturation. The three-dimensional (3D) modeling of these properties is presented to populate the reservoir model based on data from the wells. Issues in dynamic modeling of tight-gas sandstone reservoirs are also discussed.

Unconventional Oil and Gas Resources Handbook. http://dx.doi.org/10.1016/B978-0-12-802238-2.00015-8

15.2 COMMON ISSUES IN PETROPHYSICAL ANALYSIS OF TIGHT GAS SANDSTONES

Wireline logs in tight gas sandstones may include basic and high-tier logs. Basic logs are the triple or quad combination of neutron porosity, density porosity, resistivity, sonic velocity, and γ-ray logs. As in conventional reservoirs, the basic logs can be quite effective in determining some reservoir parameters. However, light hydrocarbon and clay effects may be exacerbated because of the abnormal pressure and low porosity. These problems need to be corrected for in characterizing tight gas sandstone reservoirs.

The spontaneous potential log (SP) is a basic measurement that may be available and useful, but often the deflection from baseline values is minimal or difficult to interpret. The SP deflection from a baseline can indicate permeability and be used to estimate connate water resistivity. In oil-based muds, typical of drilling, the spontaneous potential log is rendered useless by the mud system.

High tier logs may include spectral γ-ray, elemental spectroscopy, two-dimensional (2D) and 3D acoustic dipole velocity, nuclear magnetic resonance, and dielectric measurements. Spectral γ-ray measurements can identify the presence of uranium and help in clay typing and detection of reservoir zones. Elemental spectroscopy tools can be used to determine the percentage of minerals in the rock composition so that porosity and clay volume can be calculated more accurately. 2D and 3D acoustic dipole logs can show anisotropy and the shear-compressional data can be used as a direct hydrocarbon indicator. Nuclear magnetic resonance (NMR) data can be used as an independent porosity measurement, but can be affected by gas and light hydrocarbons. Density magnetic resonance processing is commonly used in tight gas to correct the NMR porosity and subsequent permeability estimate in the presence of gas (low hydrogen index). Dielectric logs can be used to determine water saturations using an external porosity. Work has shown that nuclear magnetic resonance and dielectric dispersion logging can be used to determine fluid types, permeability, and residual saturations (Al-Yaarubi et al., 2014).

In tight-gas sandstones, borehole washouts and rugosity can be a problem that affects all logs. In exploration areas, the log data may be old, the tight gas interval was not a zone of interest, and key data may be missing or difficult to interpret. Figure 15.1 is an example that shows washouts and a tension pull producing invalid readings in a well. Approximately 120 ft out of the 200 ft interval has been affected by the log pull or washouts. These need to be identified and corrected by using repeat runs that have useable data over the same interval.

The γ-ray measurement can be affected by kerogen and radioactivity not related to clay content (Ma et al., 2014a). Due to shallow invasion in many tight gas sands, neutron porosity deficit can be a very good indicator of formation gas. Excessive neutron porosity or neutron-density cross plots can be very useful as a shale/clay indicator. An overlay of the neutron porosity and γ-ray measurement can be used as a clay/pore fluid indicator. In the gas bearing part of the reservoir, the neutron porosity is usually lower than the γ-ray measurement. At the top of the reservoir, the presence of water can flip this relationship and can be used to pick the top of the pervasive or sustained gas. This technique can be very useful for thick intervals of stacked sandstones, but it is not really applicable for individual or limited sandstone deposits. While this technique may not always be precise, it can be a quick way to evaluate a thick stacked sandstone interval. Figure 15.2 illustrates the procedure.

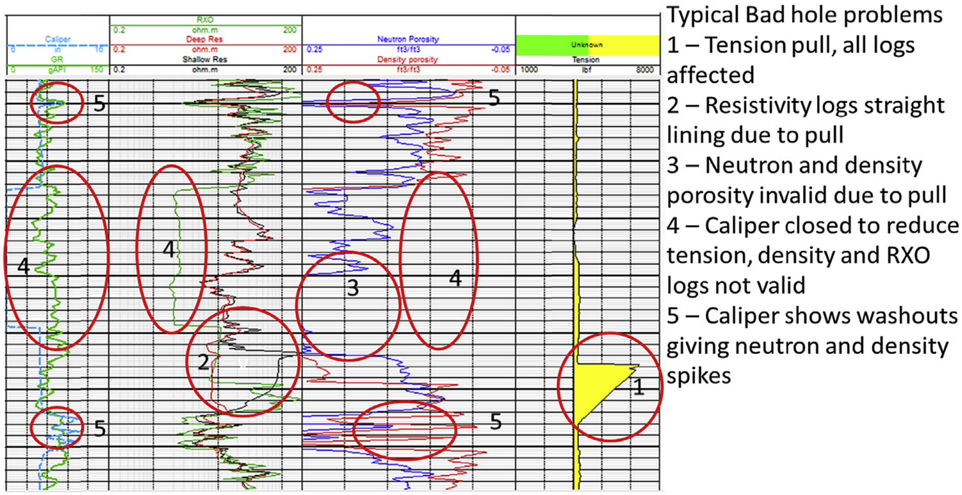

FIGURE 15.1

Typical bad hole problems.

Because there can be limited invasion in tight gas reservoirs due to low permeability and possibly higher pressure, the neutron and density porosities will need to be corrected for light hydrocarbon and gas effects. If there are differing data types from well to well, the data may need to be standardized to get a basis of comparison. Environment of deposition, rock type, and borehole size should all be considered in performing the standardization.

Figures 15.3–15.6 are plots of γ-ray, resistivity, and neutron and density porosity over stacked sandstone pay and blanket sandstone for some example intervals. They illustrate a variety of log signatures in tight gas sandstone intervals.

Figure 15.3 shows a 5000 ft interval of overpressured stacked sandstones in the Lance formation from Pinedale in the Greater Green River basin, Wyoming. The γ-ray, neutron porosity, resistivity, and density porosity all show fairly large deflections due to the moderate to high clay content.

Figure 15.4 is a 3000 ft interval of a normal to underpressured stacked sandstone in the Mesa Verde formation from the Piceance basins in Colorado. The γ-ray, resistivity, and neutron porosity deflections reflect less clay content.

Figure 15.5 illustrates a 1300 ft interval of a slightly over to under-pressured stacked sandstones in the Travis Peak formation from the East Texas Basin in Texas. The formation is fairly clean, and there is much less clay effect on the logs.

Figure 15.6 shows a 300 ft interval of blanket sandstones in the Frontier formation of the Powder River Basin in Wyoming. The formation is slightly overpressured and contains a moderate amount of clay.

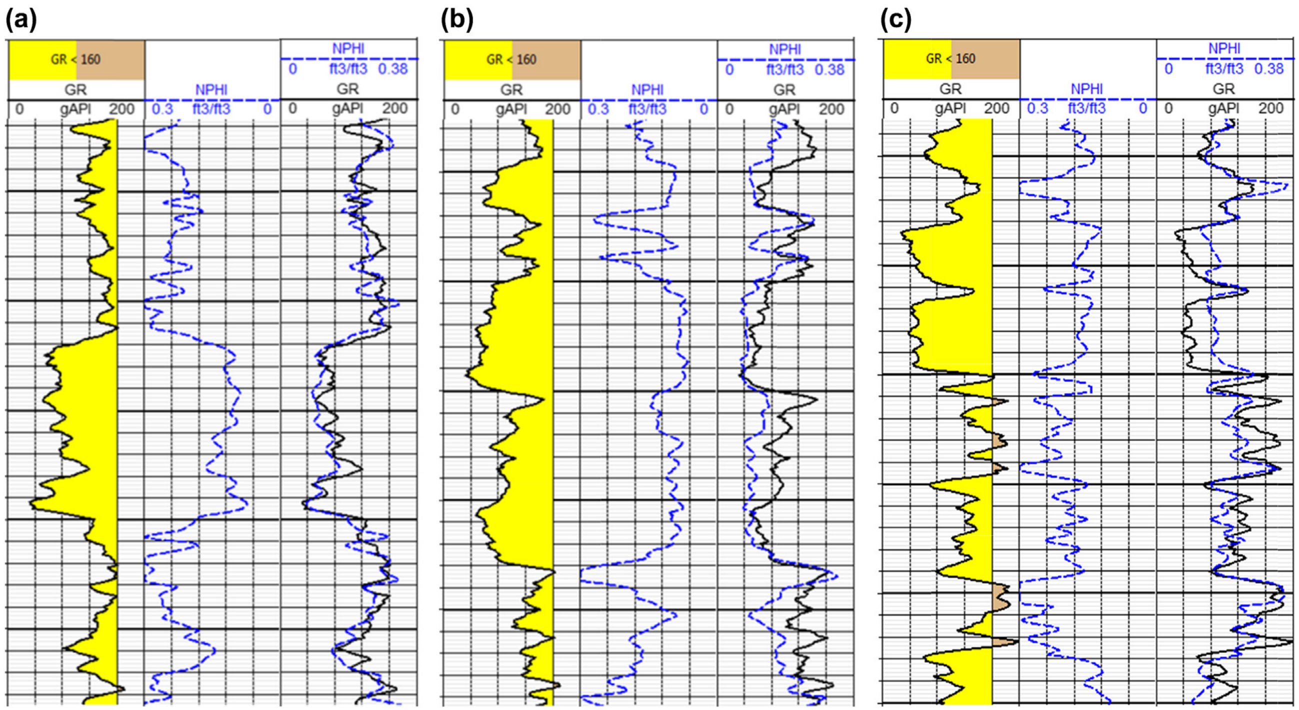

FIGURE 15.2

Example of using GR–NPHI to pick possible top gas. (a) Base of well, GR and NPHI set to overlie. (b) Middle of well—NPHI showing less shale effect than GR. (c) Top of interval—GR showing less shale effect than NPHI, probably above pervasive gas. Approximately 3000 ft between (a) and (c).

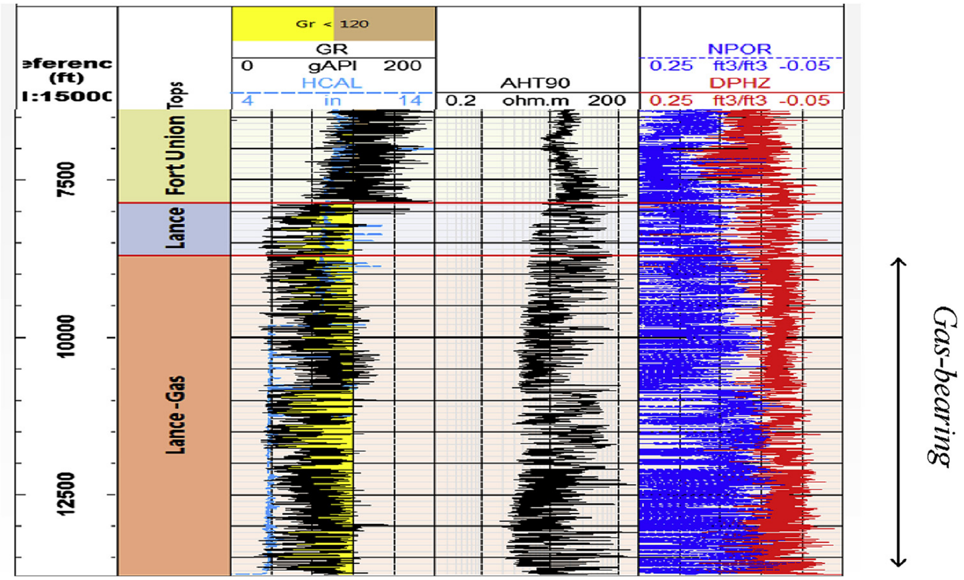

FIGURE 15.3

Log signatures of stacked sands in a productive interval at Pinedale Anticline, Wyoming (moderate clay content, overpressured zone).

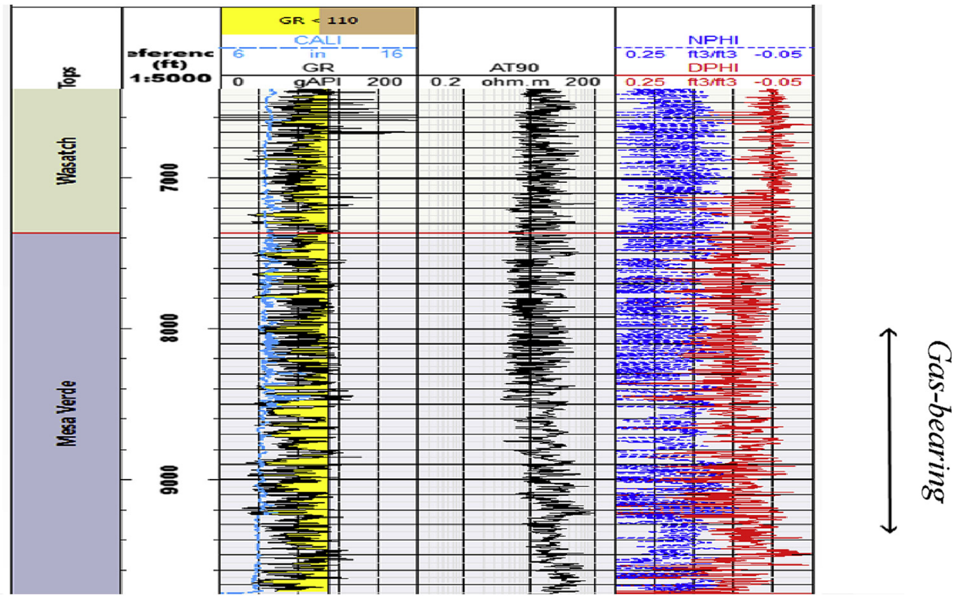

FIGURE 15.4

Log signatures of stacked sandstones in a productive interval, Piceance basin, Colorado (moderate clay content, normal to underpressured zone).

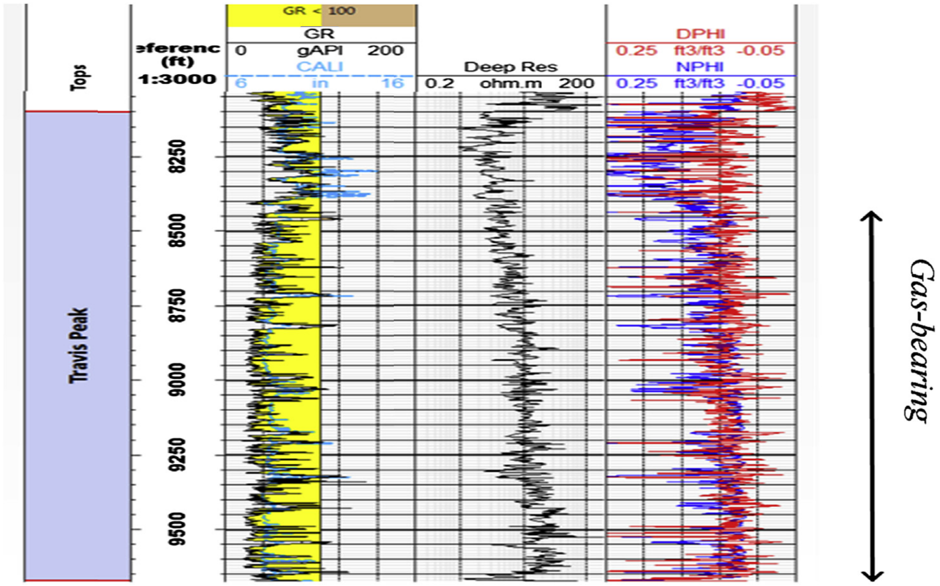

FIGURE 15.5

Log signatures of stacked sands in a productive interval of the Travis Peak formation in the East Texas Basin (minimal clay content, somewhat overpressured to underpressured zones).

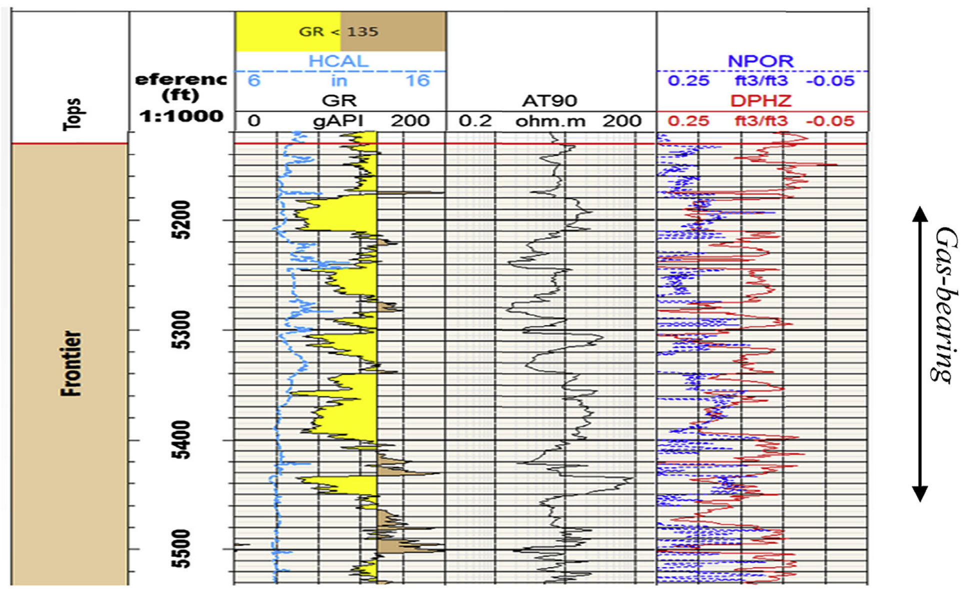

FIGURE 15.6

Log signatures of blanket sands in a productive interval of the Frontier formation of the Powder River basin, Wyoming (moderate clay, slightly overpressured zone).

15.3 PETROPHYSICAL ANALYSIS FOR RESERVOIR PROPERTIES

The main reservoir properties calculated from wireline logs typically include porosity, fluid saturation, and permeability. Interpretations of these properties using wireline logs and core are discussed here.

15.3.1 POROSITY

Total porosity is considered to be the combination of intergranular connected porosity, isolated (nonconnected) porosity, and apparent clay porosity. Effective porosity is considered to be the intergranular connected porosity. Porosity in tight gas sandstones usually ranges from 2% to 12%. Through diagenesis, the primary porosity may be reduced in the primary pore system by quartz overgrowths, and secondary porosity may be produced in feldspars or clays. The best reservoir may not equate to the cleanest because the cleanest formations often represent low porosity and producibility. (Byrnes, 1997).

The use of logs in tight gas sand analysis is in general similar to those of conventional reservoirs. Two major methods are used to derive porosity from wireline logs. The traditional method is to calculate effective porosity and water saturation through the environmentally corrected logs using a clay volume log, usually calculated from γ-ray, neutron porosity, or a combination of logs. The combinations of basic logs (density porosity–neutron porosity–sonic velocity–γ-ray measurements) can be quite effective in evaluating the porosity, but the interpretation can be enhanced by the use of core data and high tier logs. Many analysts use density porosity alone calculated from the bulk density with a variable grain matrix to correct for mineral composition (pyrites and clay minerals) and a fluid density lower than 1 to compensate for incomplete flushing in the measurement zone. This procedure can be used to generate acceptable values for effective formation porosity (Byrnes and Castle, 2000). However, only a limited number of minerals (pyrite, kerogen, quartz) can be confidently modeled using a basic log suite. In the multimineral method, the environmentally corrected logs are used in the model that defines the mineral and fluid types, and their log end points. Mineral types and volumes, porosity, and saturation are calculated to fit the input data in the model. The traditional method is simpler to implement but it does not explicitly account for mineral variations. The multimineral method is more complex as it requires more information to define mineral types and end points.

Total porosity from log interpretations in tight gas sandstones can appear to be high due to the effect of clay on the neutron porosity and sonic velocity measurements. In many areas, washouts and rugose boreholes resulting from over or under pressure can affect the log readings and make interpretation difficult, especially for density porosity. The typical response to borehole problems or increased mud gas is to raise mud weight, which can lead to even more washouts and borehole problems. Therefore, environmental corrections (borehole size, pressure, fluid type, salinity, and temperature) should be performed on all logs to get the most appropriate data set for analysis (Holditch, 2006; Moore et al., 2011). Figure 15.7 summarizes the general relationships between log measurements, core measurements, pore types, clay, rock framework, and fluid types based on an earlier study by Eslinger and Pevear (1988).

Core data can be used to validate the porosity interpretation from logs. In clean zones, the log and core should give similar readings, but these are often low porosity intervals. Sometimes, the better reservoirs could be the “shalier” zones. The γ-ray could be higher due to uranium from kerogen, or if porosity could be developed from the degradation of higher γ-ray rocks like feldspar. The core can guide building the interpretation model and the parameter selection used in these zones. Core porosity can be between the total and effective porosities depending on how the core was treated during the acquisition and analysis. Core analysis results are not absolute and can vary by laboratory (Luffel and Howard, 1987) or by the technique used (Morrow et al., 1991). Incidentally, how cores are treated prior to analysis can significantly affect the measured absolute and relative permeability (Morrow et al., 1991). If

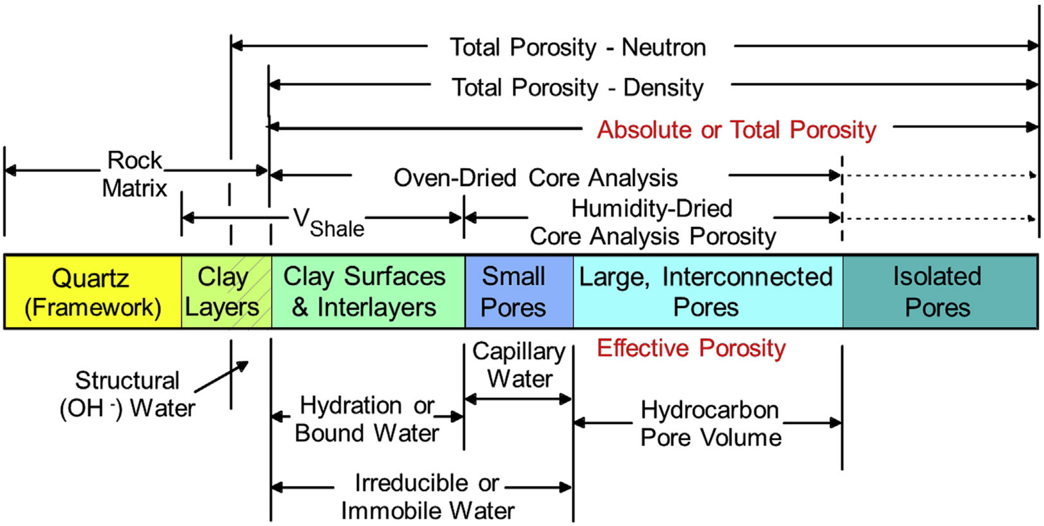

FIGURE 15.7

Porosity relationships among log measurements, core, pores, and fluids (modified from Eslinger and Pevear, 1988).

the available data is from older, publically available reports with unknown or undocumented methods, the error in core porosity may be unacceptable.

In tight gas sandstones, the total porosity calculated from logs is typically a little higher than the measured core porosity and the effective porosity calculated from logs is close to or a little lower than the measured core porosity. However, a number of variables may affect the core-log porosity relationships. When clay content is low, the total porosity calculated from logs is usually higher than measured core porosity and the effective porosity calculated from logs can be a little higher to somewhat lower than measured core porosity. When the clay content (feldspar decomposition—high illite, chlorite, and swelling clays) is high, the total porosity calculated from logs tends to be much higher than the measured core porosity and the effective porosity calculated from logs may be higher than the measured core porosity. The significant presence of heavy minerals (pyrite, siderite, dolomite and calcite) in the matrix or cement can affect the above stated core-log porosity relationships as well. A multimineral model can be used to correct the variable compositions, but often there is not enough special core analysis data (such as XRD–FTIR–XRF) or enough log data (such as spectroscopy) to differentiate the minerals.

In summary, common issues related to porosity interpretation in tight gas sandstones include:

1. Invasion can be shallow due to low permeability and generally high formation pressure, so the correction of logs for gas effect can be important.
2. Presence of heavy minerals, even at low volumes, can reduce the calculated porosity if not accounted for.
3. The cleanest intervals may be the tightest due to diagenetic factors, and may not be the best reservoir.

4. In stacked sandstone intervals, it is important to identify the top of overpressured gas when it is present, because the important parameters in the analysis (water salinity, Archie m and n, shale/clay points) may change at that point.
5. Washouts, rugose hole, and log-pull blind spots are common in tight gas intervals, and bad hole models need to be used over them where repeat passes fail to provide usable data.

15.3.2 FLUID SATURATIONS

Common issues in analyzing fluid saturations for tight gas sandstones include:

1. Irreducible water saturations can be high and may vary greatly depending on rock type.
2. Often, there is not much water production from tight gas sandstones even when estimated water saturations are high, and the water produced may be low salinity vapor from the gas phase. Using the parameters derived from traditional methods in a tight shaly sandstone, the Archie saturation equation may give abnormally high water saturation values. In this case, core capillary pressure versus water saturation curves correlated to actual production can be used to back out a salinity value that may be more representative.
3. While most tight gas sandstones do not produce a lot of water even for high water saturation zones, there can be higher porosity and permeability intervals that can.
4. Salinity may be variable over thick sections of tight gas sandstones.

Irreducible water saturation in tight gas sandstones can be quite high, and connate water resistivity can be variable. Because the Archie equation for computing water saturation was developed in the lab from empirical data in high porosity clean sandstones, using it to calculate water saturation in tight gas sandstone intervals can give inaccurate results. The exponents in the Archie equation are usually unknown, and the clay content used to correct the logs to use in the equation can be overestimated or underestimated. Clay corrected Archie equations (like Simandoux, Indonesian, and Dual Water) are often used but suffer from the uncertainties. Using log data alone for irreducible water saturation is less reliable; it is better to use core analysis (mercury injection capillary pressure measurements) to guide what the particular capillary characteristics of a producible zone are. Adjusting saturation parameters to align with capillary pressure measurements and production results can be very useful in interpreting the formation interval. The saturation and cementation exponents, m and n, from core data can be very helpful when available but should be used with caution due to core handling/analysis inconsistencies as discussed above. Figure 15.8 is an example of core measured Archie exponent m versus core porosity in a stacked sandstone interval. A linear or nonlinear fit can be used to calculate a variable, m, but confidence in the correlation, as indicated by the data scatter, will be low. More accurate relationships could be developed for different rock types, flow regimes, and lithofacies.

In stacked sandstone intervals, it is common to have a top sustained gas point at which abnormal pressure exists below it and normal or under pressure exists above it. Using different analysis parameters for the zone above the sustained gas point (salinity, Archie's m and n, clay points) can give more plausible results. Often, the formation water salinity will decrease, and Archie's m and n parameters will increase above the gas zone; thus keeping the parameters constant may result in false indications of hydrocarbons. Different methods can be used to pick this point—an increase in mud gas, an increase in connection gas, and divergence of normalized GR/NPHI (gamma ray and neutron porosity) overlay are commonly used. There are many parameters for the analysis of tight gas intervals

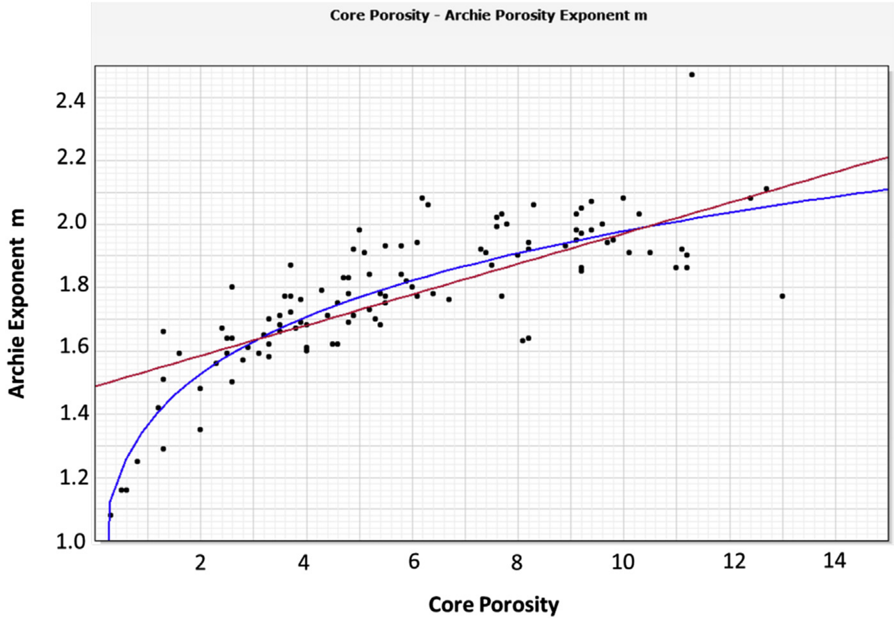

FIGURE 15.8

Cross plot of core porosity (horizontal axis) versus measured core Archie m (vertical axis) in a tight gas stacked sandstone interval. Red (gray in print versions) line shows a linear fit, and blue (dark gray in print versions) shows a nonlinear fit.

that depend on the fluid, pressure and rock type. Among them are neutron porosity corrections, density and sonic fluid corrections, and Archie m and n values.

Saturation history and not just current calculated saturation, can also affect production. The reservoir model may need to incorporate static (rock types) and dynamic (flow units) conditions to get a true picture of its viability (Kaye et al., 2013; Spain et al., 2013). If the area involved has a history of multiple burials or diagenetic events, saturation history should be investigated to understand production. Multiple instances of imbibition and drainage can affect the saturation and relative permeability of the reservoir, and may be important in reservoir development.

Capillary pressure curves can be important in defining reservoir types. Figure 15.9 illustrates capillary pressure—water saturation relationships that are typical in tight gas sandstones. There are three capillary pressure-water saturation relationships. The sweet spot sandstones are conventional reservoir sandstones within the thicker interval of tight gas sandstones, and show the lowest irreducible water saturation (15–20%) along with the lowest capillary pressure profile. The tight gas sandstones have higher irreducible water saturation (50%) and a higher capillary pressure. The shale and siltstones show the highest irreducible water saturation (more than 60%) and highest capillary pressure.

The tight gas sandstones could have relatively high water saturation but still be capable of water free gas production.

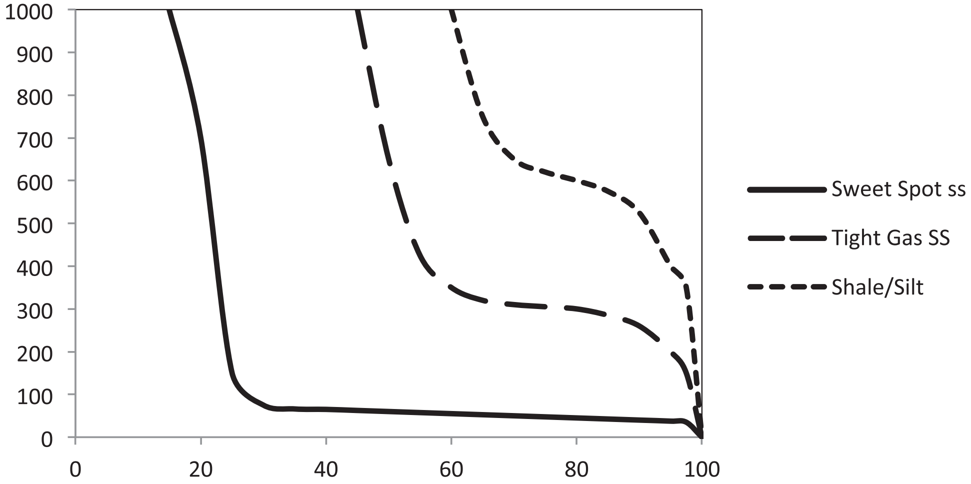

FIGURE 15.9

Conceptual models of capillary pressure versus water saturation (horizontal axis) for three different reservoir types.

Adapted from Burnie et al. (2008).

15.3.3 PERMEABILITY

Low permeability is a characteristic of tight gas sandstones, and it is generally less than 0.1 mD, often between 0.0001 and 0.01 mD. The permeability may correlate to porosity, rock type, mineralogy, stratigraphy, and other variables. Core permeability data can be used to derive a correlation between permeability and other petrophysical variables, but there is often a complex interplay among these variables in the low permeability of tight gas sandstones. Pressure, stress, rock type, diagenesis and natural fractures can all impact permeability. Sometimes, multiple porosity and permeability relationships may be necessary to correctly characterize the permeability (Kukal and Simons, 1985; Wells and Amaefule et al., 1985; Luffel et al., 1989; Davies et al., 1991; Deng et al., 2013).

Small scale tests (wireline or drill stem) can be useful in validating permeability and porosity–permeability relationships, but it may take a thorough fracture treatment, extended flow and buildup analysis to properly evaluate the permeability and porosity–permeability relationships of a tight gas sandstone interval. Higher permeability and porosity zones within a larger interval may also be water productive.

The measured gas permeability from core needs to be corrected for Klinkenberg effect for gas slippage. In a two phase gas–water reservoir fluid system, relative permeability as a function of fluid saturation drives the fluid production, which is especially pronounced when the absolute matrix permeability is in the microDarcy range, such as in tight sandstones. The accurate measurement or prediction of gas effective permeability as a function of water saturation can maximize gas production and control water cut.

Cluff and Cluff (2004) illustrated how to use core permeability measurements at reservoir net confining stress versus core measurements at some minimum confining stress for their permeability correlation. More typically, however, data sets contain only air permeability and Klinkenberg corrected

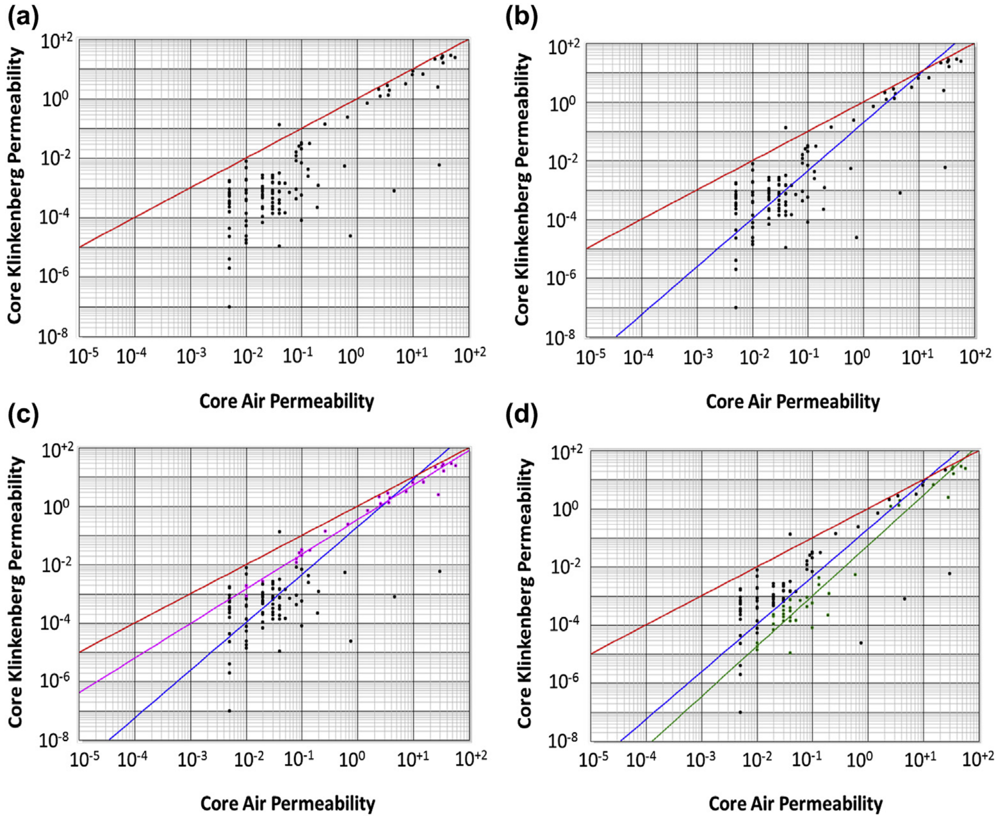

FIGURE 15.10

(a) A typical core air permeability to Klinkenberg permeability dataset. (b) Using all the data for a correlation. (c) Nonmagenta points are tight gas rocks, as a subset of the data for a correlation. (d) Green (light gray in print versions) points are tight-gas rocks, as a subset of the data for correlation. Note: red lines (dark gray in print versions) are one-to-one fits as a reference.

permeability values. Figure 15.10(a) is a multiwell core data set showing the spread that is present in many real datasets. The air permeability has not been reported with the same precision as the Klinkenberg permeability, and there is uncertainty in the correlation. Figure 15.10(b) uses a best fit line through all the data which tends to give an optimistic permeability. Figure 15.10(c) eliminates the lower permeability data, and is probably only representative of sweet spots within the tight gas interval. The selected low permeability data give a more realistic interpretation (Fig. 15.10(d)). The most appropriate solution is a combination of the models in Figs 15.10(c) and (d) using rock typing or another modeling technique for a more accurate correlation. Without enough knowledge, the correlations can be subjective, and care needs to be taken to select the appropriate data. If a permeability cutoff is used for pay determination, it should be recognized that the correlation may carry a large uncertainty in the model, leading to an uncertain estimate of the recovery, and possibly impacting the completion design.

15.3.4 DISCUSSION ON PETROPHYSICAL INTERPRETATIONS

There are a number of strategies for planning the evaluation of exploration or delineation wells. If washouts and rugose borehole are a problem, a geomechanical evaluation can be made to generate a safe mud weight window, which can help keep the borehole pressures balanced and the washouts to a minimum so that the traditional triple combo logs are not so adversely affected by the washouts. Repeat logs or down logs over these intervals may be necessary to get useable data. High tier logs can be acquired for better reservoir analysis. If core data is lacking or the existing core data measurements are of uncertain quality, more core data will be needed.

The interpretation of porosity from wireline logs can be reconciled with core data, which can then be used for model development. Along with routine core analysis, special core analysis should be performed to build a model: XRD–FTIR–XRF for mineralogy, mercury injection for rock typing, geomechanics testing to help calibrate the mechanical earth models and improve hydraulic stimulation design. For stacked sandstones over a thick interval, it may be important to analyze as many data points as possible, as the pressure regime may change over the interval.

Often there are just a few wells with core data, common and specialty logs, wherein either the traditional or multimineral method can be used to get the best analysis possible. The petrophysical model can then be simplified and applied to wells with less complete log suites and no core data. It is important that the core data distribution in both areal and vertical directions be as complete as possible to ensure adequate rock description. Rock typing can be very important to petrophysical parameter selection (Chapin et al., 2009; Liu et al., 2012). There can be sweet spots dispersed throughout the tight gas interval, and the tight gas zone parameters may not all be similar. Using the core data to constrain the calculated log porosity is generally a good practice, especially in cases where log data are limited. If there is not adequate core data for rock types, errors in porosity can be quite substantial. Where there is adequate delineation and validation, rock typing can enhance the reservoir characterization.

In summary, the analyst needs to tailor the log interpretation to fit the available data. Gross reservoir properties are fairly easy to determine, but it is the determination of what is net that requires the integration of the reservoir and petrophysical data to derive a relationship to production. High tier log data, if present, can be used to further refine the log interpretation model. While there is no absolute combination of basic and high tier logs that works all the time, each can be important and should be investigated for a given reservoir to determine its effectiveness. Using a comprehensive suite of log measurements can improve the interpretation and evaluation of the reservoir.

15.4 THREE-DIMENSIONAL MODELING OF RESERVOIR PROPERTIES

Some of the most important reservoir properties include porosity, fluid saturation, and permeability, of which porosity is the most basic variable that describes the pore space for fluid storage in the subsurface formation. Analysis and interpretation of core and well-log data describe reservoir characteristics at or near the wellbores, but hydrocarbon resource and production also depend on the distribution of reservoir properties in the field away from the wells. 3D modeling of main reservoir properties enables the calculations of field-wide pore volume and hydrocarbon pore volume, and evaluation of the heterogeneities of reservoir properties.

Because porosity is one of the most basic reservoir variables and its data are generally more available and reliable than fluid saturation and permeability data, porosity is typically modeled before modeling water saturation and permeability. When lithofacies or depositional facies models are available (discussed in the previous chapter), the porosity model should be constrained to the lithofacies or depositional facies model. This is because in the hierarchy of multiple scales of reservoir heterogeneities, characteristics of petrophysical properties are controlled by geologic facies or lithofacies (Ma et al., 2009). Geostatistical methods for modeling porosity include kriging and stochastic simulation, and they can be used with the lithofacies model as a constraint (Cao et al., 2014).

In tight gas sandstones, porosity, fluid saturation, and permeability are generally correlated with the lithofacies, and they are also correlated between themselves (Ma et al., 2011). Because of the correlation with porosity, fluid saturation, and permeability should be modeled in relation to porosity. Researchers often focus on using correlation for prediction; in fact, an accurate modeling of the correlation between fluid saturation and porosity is not just for prediction, but it has an impact on the estimation of the in-place volumetrics. Similarly, an accurate modeling of the porosity–permeability relationship is not just for better prediction of permeability, but has an impact on the hydrocarbon recovery rate.

15.4.1 CONSTRUCTING STATIC MODELS

15.4.1.1 Modeling Porosity

Geostatistical methods for modeling porosity include kriging and stochastic simulation. Kriging produces smoother results as the variance of the kriging model is smaller than the variance of the data. Commonly used stochastic simulation methods include sequential Gaussian simulation or SGS (Deutsch and Journel, 1992) and Gaussian random function simulation or GRFS (Gutjahr et al., 1997).

In early development of a field, few data are available and kriging may be a method of choice to generate the porosity model, and the moving average method can be a valid alternative technique. When more wells are drilled with a thorough formation evaluation program using well logs and geological analysis, stochastic methods may be a better choice to model porosity, especially for stacked sandstone reservoirs. Some academies have argued that stochastic simulation is preferable for modeling reservoir properties in early field developments because of limited data and high uncertainty. This can be true for the sake of a general analysis of uncertainty. In practice, however, when data is very limited, stochastic models generally have no operational value. On the other hand, when more densely sampled seismic data are available and can be calibrated with porosity, cosimulation of porosity with seismic data can be useful (Cao et al., 2014).

In addition, the lithofacies model can be used to constrain the spatial distribution of porosity using SGS or GRFS because depositional facies or lithofacies govern spatial and frequency characteristics of porosity to a large extent. Even though porosity can still be variable within each lithofacies, the porosity statistics by lithofacies generally exhibit less variation (Ma et al., 2008). Figure 15.11 compares two porosity models constructed with four different lithofacies models presented in the previous chapter.

Typically, a histogram of the effective porosity from the well logs exhibits a bimodal distribution (Fig. 15.11(a)), but a bimodal appearance often conceals some components from three or more lithofacies, as shown by the example (Fig. 15.11(b)). The hidden and nonhidden modalities can be modeled by mixture decomposition (Ma et al., 2014b). In this example, the lithofacies include

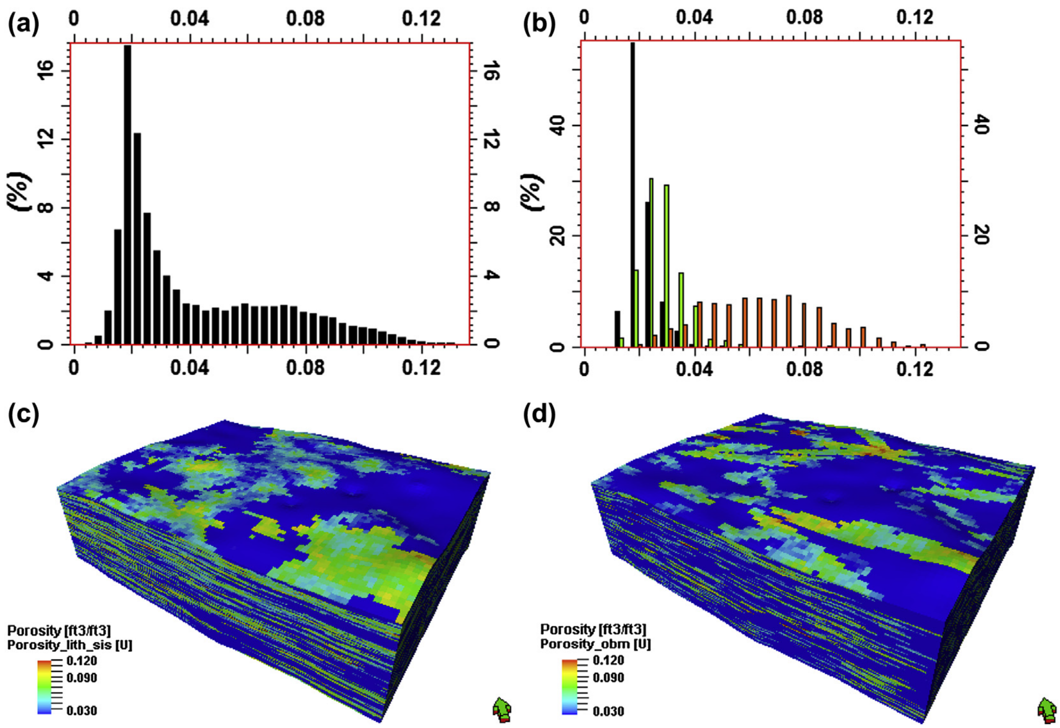

FIGURE 15.11

(a) Histogram of porosity from well logs. (b) Component histograms by lithofacies. Black is the porosity for shale, green is for siltstone, and red (dark gray in print versions) is for sandstone. (c) Porosity model constrained to the SIS lithofacies model (Fig. 14.8(b)) in the previous chapter). (d) Porosity model constrained to the defined object lithofacies model (Fig. 14.8(d)) in the previous chapter).

sandstone, siltstone and shale, and the lithofacies models constructed using SIS and defined object-based modeling techniques were used to constrain the porosity model. GRFS was used in modeling porosity by lithofacies, honoring its well log data, histogram and variogram. The models are shown in Figs 15.11(c) and (d), in which the shale was assigned zero effective porosity even though it has some total porosity.

15.4.1.2 Modeling Water Saturation and Permeability

Porosity, water saturation (Sw) and permeability in tight gas sandstone reservoirs are correlated, as shown in Fig. 15.12. As a result, Sw and permeability should be modeled in relation to porosity as porosity has more reliable data and its model is constructed first. Sometimes the correlation between porosity and Sw may only appear to be moderate; researchers may decide to model them independently because the statistical literature generally predicates the use of correlated variables for prediction. How to model the correlation between fluid saturation and porosity impacts the estimation of the in-place volumetrics. Unlike for predictions, when two physical variables are correlated, even

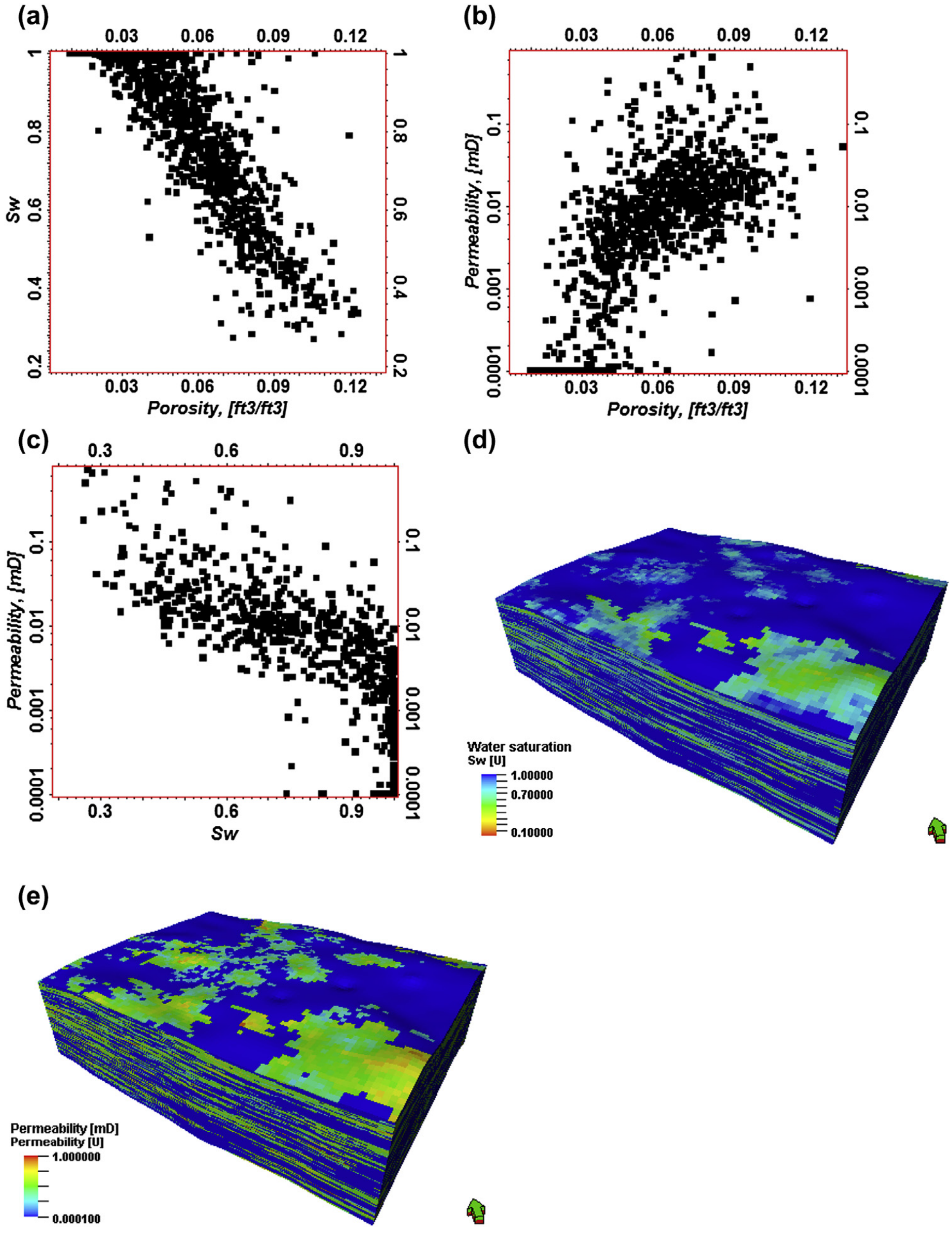

FIGURE 15.12

Reservoir property relationships based on the well-log data from a tight gas sandstone. (a) Porosity–Sw cross plot (correlation = −0.894), (b) porosity–permeability (logarithm) cross plot (correlation = 0.843). (c) Sw–Permeability (logarithm) cross plot (correlation = −0.855). (d) Sw model constructed using CocoSim that is constrained to the lithofacies model and honors the Sw data at the wells and correlation between porosity and Sw. (e) Permeability model constructed using CocoSim that is constrained to the lithofacies model and honors the permeability data at the wells and correlation between porosity and permeability.

moderately, their correlation may need to be modeled because the correlation impacts other physical properties. In the case of fluid saturation and porosity, how to model their correlation impacts the estimation of the in-place volumetrics, and thus should be modeled.

Sw and permeability can be modeled using collocated cokriging or collocated cosimulation (CocoSim) to honor the relationship between porosity and Sw or permeability (Ma et al., 2008; Cao et al., 2014). CocoSim can model Sw, honoring the well-log Sw data, its histogram, variogram, and its correlation with the porosity based on the well logs data. An example of a Sw model constructed using CocoSim is shown (Fig. 15.12(d)); the model is constrained to the SIS lithofacies model (Fig. 15.8(b) in the previous chapter) while honoring the Sw data at the wells, correlation between porosity and Sw, and the variogram synchronized between porosity and Sw.

Similarly, a 3D permeability model can be constructed using CocoSim that is constrained to a lithofacies model while honoring the well-log's permeability data, correlation between porosity and permeability, and the variogram synchronized between porosity and permeability (Fig. 15.12(e)). Other advantages of modeling the permeability using CocoSim have been discussed elsewhere (Ma et al., 2008; Cao et al., 2014). Notice that the porosity-permeability (logarithm) relationship in real data is a nonlinear correlation (Fig. 15.12). A linear transform, such as regression of the logarithm of permeability from porosity, reduces the permeability because the exponential of the mean is smaller than the mean of the exponential (Vargas-Guzman, 2009; Cao et al., 2014).

Because of the high correlations between porosity, Sw, and permeability, the Sw and permeability models generally are highly correlated as well. This correlation can be either implicitly modeled as a result of modeling the correlation between porosity and Sw and the correlation between porosity and permeability, or explicitly modeled using CocoSim.

15.4.2 DYNAMIC MODELING

Typically, static models are constructed at a high resolution to convey the geological heterogeneity, especially important in stacked sandstone reservoirs. These high-resolution models are upscaled into a coarser grid for dynamic simulation. In order to preserve the heterogeneities in the fine-grid model, the upscaling needs to select an appropriate method. Relatively robust upscaling techniques to preserve heterogeneity include the residual optimization method (Li and Beckner, 1999), and constrained optimization approach (King et al., 2006). For a relatively small sector model, upscaling may not be necessary (Apaydin et al., 2005).

One of the main tasks in dynamic simulation is the history match of the model to the production data, including pressure data from monitoring wells, historical flowing bottom hole pressures and historical productions of water and gas from producing wells (Iwere et al., 2009; Diomampo et al., 2010). Alternatively, completion, historical production and pressure data can be consolidated and directly input into a flow simulator. Boundary conditions derived from field operation can be used as production controls for the wells, and natural and hydraulic fracture properties can be assigned to the fracture cells for each well in the model (Apaydin et al., 2005). Streamline simulation can be also performed to analyze the reservoir connectivity, sweep efficiency, and other reservoir characteristics.

Forecasting performance of planned infill wells for tight gas sandstone reservoirs can be carried out by maintaining the existing well locations in the model while drilling down to the chosen well pattern and density or removing the existing well locations in the model while placing new wells with a chosen pattern and density (Diomampo et al., 2010).

Studies have shown a significant impact of the lithofacies modeling method on forecasting well performance (Apaydin et al., 2005). Typically, the SIS model has an overall higher connectivity than object-based models, and "produces" more gas and water. On the other hand, the lithofacies model using fluvial object-based modeling tends to have higher anisotropy: high connection in the fluvial direction and low connection in the perpendicular direction. The lithofacies model using object-based modeling with defined objects with ellipse-based geometry tends to have an overall spatial connectivity between the sequential indicator simulation and fluvial object-based models as this approach offers the flexibility to generate channel bodies spanning a spectrum of geometries from individual point bars to stacked and amalgamated sheets.

15.5 CONCLUSION

Petrophysical analysis based on well logs is the cornerstone for formation evaluation of tight gas sandstone reservoirs. A number of issues related to analyzing well logs in this type of formation are discussed in this chapter. Porosity is one of the most important reservoir variables in hydrocarbon resource evaluation as it describes the subsurface pore space for fluid storage. Deriving accurate porosity data based on the available well logs is thus highly important for estimation of the effective pore volume.

Volumetrics, including field-wide pore volume and hydrocarbon pore volume, depend on not only the data at wells, but more importantly the distributions of the porosity and fluid saturation of the formation in the field. The correlation between porosity and fluid saturation should be modeled not necessarily for the sake of the prediction, but for the sake of the physical nature and impact on the accuracy of in-place resource estimate. Similarly, the correlation between porosity and permeability and the correlation between fluid saturation and permeability impact the recovery of fluids in production. In a reservoir model, pathways characterized by high reservoir quality and connectivity are drained early, and more isolated and heterogeneous sandstone bodies may be drained later or remain undrained.

Because of the uncertainty and risk associated with development of tight gas sandstone reservoirs, all the development stages, including drilling, completion, stimulation, and production, should be optimized.

ACKNOWLEDGMENT

The authors thank Schlumberger Ltd for permission to publish this work and Dr Shujie Liu for reviewing and commenting on the manuscript.

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