

The petrophysics of shale gas reservoirs: Technical challenges and pragmatic solutions

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ABSTRACT: The host rocks of shale gas accumulations act as source, seal and reservoir. They are characterized by complex pore systems with ultra-low to low interparticle permeability and low to moderate porosity. The word ‘shale’ is used in the sense of a geological formation rather than a lithology, so shale gas reservoirs can show marked variations in rock type from claystones, marlstones and mudstones to sandstone and carbonate lithological ‘sweet spots’. The pore space includes both intergranular and intrakerogen porosity. The density of natural fractures varies markedly, and pore throat connectivity is relatively ineffective. Moreover, *in-situ* gas pore volume has to take account of both free and adsorbed gas, an evaluation exercise that is complicated by pronounced variations in water salinity. All these characteristics present major challenges to the process of petrophysical evaluation. The petrophysical responses to these issues are severalfold. First, a broader calibrating database of core measurements is required at key wells, especially as regards mineralogy, porosity and permeability data, shale/mudstone sample analyses, total organic carbon, gas desorption isotherms, and the analysis of extracted formation waters. Second, at least in the key wells, an extended suite of logs should include an elemental analysis log, magnetic resonance imager, electrical micro-imager, and a dipole sonic log. These databases lead to a rock-typing scheme that takes better account of dynamic properties and fracturability. They also allow reservoir partitioning based on exclusivity of empirical interpretative algorithms, e.g. quartz content vs. producibility. These responses comprise key elements of a functional petrophysical system that encompasses fit-for-purpose interpretation methods, such as a pseudo-Archie approach, i.e. the application of the Archie equations with non-intrinsic exponents. This system is presented as a workflow for application in shale gas reservoirs, for which bulk density retains a major influence on computed gas in place. The benefits of this approach are especially strong in reserves reporting of these unconventional gas reservoirs.

INTRODUCTION

In contemporary petrophysical parlance, there are two types of reservoir: those that conform to the implicit assumptions underpinning the work of Archie (1942) and those that do not. The second category includes most of the world’s reservoirs. It can be subdivided further into non-Archie conventional reservoirs and unconventional reservoirs (Worthington 2011a). Non-Archie conventional reservoirs include those with fresh formation waters, significant shale content, high capillarity, a bimodal pore system, or fractures. In other words, they infringe one or more of the Archie assumptions. Unconventional reservoirs include tight gas sands, coal seam gas reservoirs, gas hydrates, and shale gas reservoirs. Each of these infringes several of the Archie assumptions. At the limit, shale gas reservoirs infringe them all (Table 1), so a different *modus operandi* is required. Yet, the interpretative challenges presented by shale gas reservoirs go even further, because gas-bearing shale deposits co-function as

source, seal and reservoir. Therefore, their character contains elements of all three. Thus, for example, shale gas deposits contain kerogen porosity, have very low effective permeability to gas, and yet can show a markedly variable pore character. To be successful, a petrophysical methodology for the evaluation of shale gas deposits has to be founded on approaches that sit outside the conventional range of thinking. This paper presents a synthesis of the technical challenges that face shale gas petrophysics and collates practical solutions based on what is currently known. In so doing, the word ‘shale’ refers to a complex compositional and grain-size mixture of clay minerals, quartz, carbonates and heavy minerals. These matters cannot be considered in isolation from basin geochemistry and thermodynamics.

APPROACH

The approach recognizes three major influencing factors. First, shale gas petrophysics is on a steep learning curve and it will be

Table 1. Criteria for an 'Archie' reservoir with departures shown by shale gas reservoirs

No.	Archie criteria	Shale gas reservoir character	Selected references
1	Extensive single rock type	Multiple rock types: thin beds	Guidry & Walsh (1993); Jacobi <i>et al.</i> (2008)
2	Homogeneous	Heterogeneous, e.g. variable mineralogy/texture	Mullen (2010); Passey <i>et al.</i> (2010)
3	Isotropic at micro- and meso-scales	Anisotropic, e.g. ellipsoidal grain shape, laminations	Prasad <i>et al.</i> (2009); Suárez-Rivera <i>et al.</i> (2009)
4	Compositionally clean	Clay minerals	Campbell & Truman (1986); Passey <i>et al.</i> (2010)
5	Clay- and silt-free	Argillaceous and silty	Jarvie <i>et al.</i> (2007); Bruner & Smosna (2011)
6	No metallic minerals	Pyrite, etc.	Guidry <i>et al.</i> (1990); Sondergeld <i>et al.</i> (2010b)
7	Unimodal pore size distribution	Multimodal pore size distribution including microporosity	Bustin <i>et al.</i> (2008); Wang & Reed (2009)
8	Intergranular porosity	(Micro)fractures	Caramanica & Hill (1994); Shaw <i>et al.</i> (2006)
9	High-salinity brine	Variable water salinity	Luffel <i>et al.</i> (1992); Martini <i>et al.</i> (2008)
10	Water wet	Variable wettability	Andrade <i>et al.</i> (2011); Elgmami <i>et al.</i> (2011)
11	Archie exponents ≈ 2	Archie exponents $\neq 2$	Aguilera (1978); Quirein <i>et al.</i> (2010)
12	No organic solids	Kerogen	Passey <i>et al.</i> (1990); Curtis <i>et al.</i> (2010)

some time before a plateau is reached. Second, the lithological and hydraulic complexities of shale gas systems make it difficult to identify representative characteristics, especially in the absence of a unified rock-typing scheme. Third, the development of shale gas reservoirs should be founded on comprehensive reservoir characterization that draws upon the full ground-truthing potential of core analysis and utilizes correct cross-scale integration of core data and downhole measurements. These matters are implicit in the following treatment.

Technical challenges

These are grouped in terms of the technical tasks that would form part of a generic petrophysical workflow. They are data requirements, mineralogical characterization, total organic carbon, porosity evaluation, nature of gas storage, formation-water salinity, initial gas pore volume, pore connectivity, geomechanical properties, net pay, and producibility. The proper evaluation of shale gas reservoirs draws upon and extends the range of technologies that have been applied to clastics and carbonates as well as in source-rock evaluation. In so doing, we note that the word 'shale' is being used in the sense of a geological formation rather than a range of mineralogy, so that (self-sourcing) shale gas reservoirs can also include sandstone and limestone intervals as lithological 'sweet spots'. However, from a petrophysical perspective, we are dealing more with a quartzitic/calcareous shale rather than a shaly sand/limestone. The following comments intuitively adopt a combination of the scenario approach to petrophysical evaluation coupled with the key well concept for selecting and ground-truthing a petrophysical methodology (Worthington 2011b). The scenario approach organizes the problem into set work plans. The key-well concept is based on a complete study of representative wells so that a means of identifying the appropriate work plan(s) can be established (Worthington 2004). Here the word 'representative' relates to the variability of a shale gas system and the complete capturing of that variability within selected wells. An overarching petrophysical challenge is to manage this variability away from cored intervals.

Pragmatic solutions

The approach seeks to overcome the challenges identified above. A key-well concept is proposed with the aim of establishing an interpretation methodology that matches the complexity of the shale gas reservoir and optimizes future data acquisition programmes. The exercise draws upon existing methods in shale gas petrophysics as appropriate. The main deliverable from the key-well analysis is a set of parameters, concepts and empirical relationships in the form of a simplified and systematic workflow based on an optimized data acquisition programme (Fig. 1). The data required to do this at the key wells go beyond standard logging

suites and they will have to be ground-truthed to core. The next task is the pragmatic export of an interpretation methodology established at a key well to non-key wells that have a more limited petrophysical dataset. When doing this, a mineral-sensitive reduced logging suite may suffice in the non-key wells (Table 2), especially if a scenario approach based on rock types can be adopted.

DATA MATTERS

Data requirements

Shale gas reservoirs are highly variable and this calls for additional diagnosis, both in the laboratory and downhole. Lithology can vary markedly over scales that are well below log resolution. This heterogeneity increases the need for a calibrating core dataset within key wells. In particular, the sampling interval for the ground-truthing core plug data is an additional consideration.

Imaging of the pore system in the nanoporosity range has exposed some extremely complex pore networks within both 'inorganic' and 'organic' porosity. Some pore throats are too small to be penetrated by mercury injection (Sondergeld *et al.* 2010a). The industry standard of crushing shale gas core samples for analysis may cause some underestimation of permeability because it cannot take account of microfractures or any interconnectivity within the organic component of the rock (Wang & Reed 2009). Log analysis of unconventional reservoirs is evolving and this situation calls for core support in evaluating both organic and inorganic contents. A major task is the acquisition of a fit-for-purpose database that will allow a reservoir-specific rock-typing scheme to be extrapolated from key wells to uncored wells (Fig. 1).

Core calibration of log analysis

Core data play a most important role in shale gas evaluation. In shale gas petrophysics, the problem of core calibration is compounded relative to conventional reservoirs in that the measurement of basic core parameters, such as porosity and permeability, is not governed by any contemporary industry standards (Passey *et al.* 2010; Sondergeld *et al.* 2010b). The problem is exacerbated by the difficulty of making measurements at reservoir conditions. Until such standards are established, the petrophysical evaluation of shale gas will have to move forward without them, by making the most effective use of all data that are currently available. In other words, core data may not provide the ground-truthing to which the practitioner has become accustomed in conventional reservoirs. Of course, operators are free to send twin plugs to different core analysis laboratories and use the differences in measurement to reflect uncertainties in measured properties, after understanding the underlying protocols from the different laboratories.

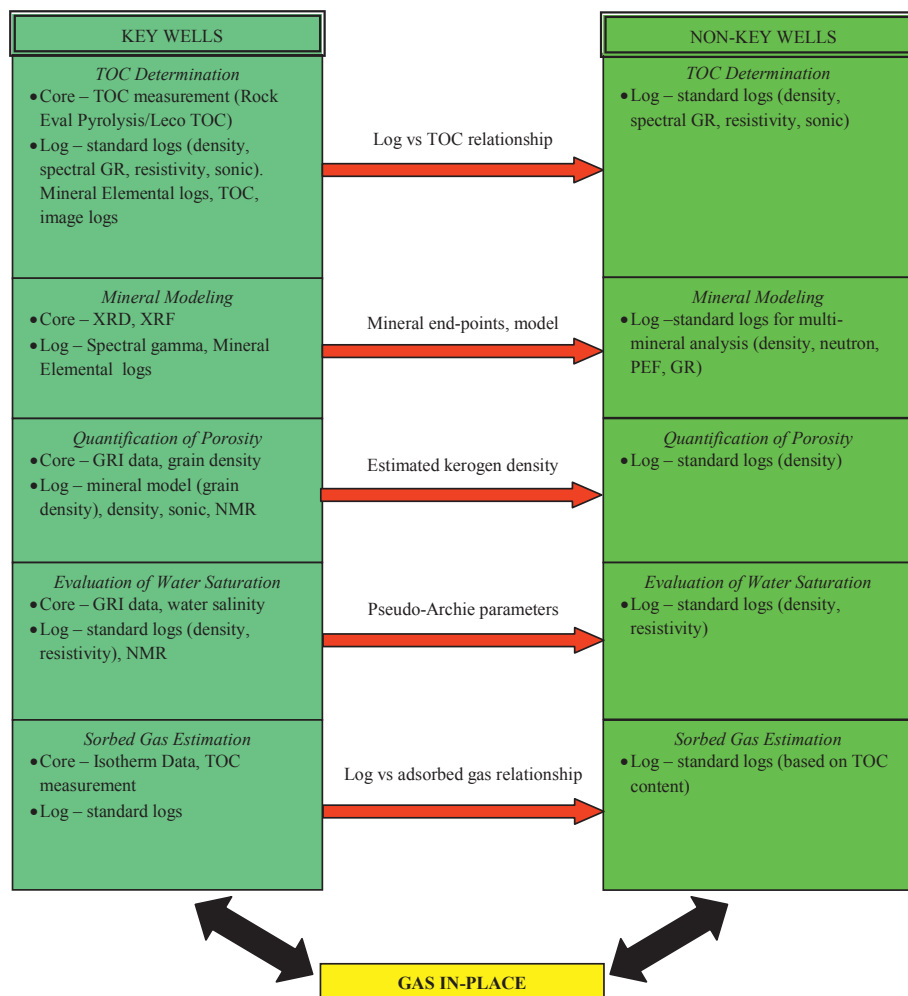


Fig. 1. Workflow for the petrophysical evaluation of key and non-key wells.

At present, core data for the estimation of hydrocarbon volumes in shale gas reservoirs are broadly of two types; data that assist in the understanding of the architecture associated with mineralogy and rock fabric (e.g. measurements based on the Gas Research Institute (GRI) protocols together with XRD/XRF data) and those that deal with the storage of the hydrocarbons (e.g. adsorption isotherm analysis and assessment of gas content). The coring programme for a key well should aim to capture fully the degree of heterogeneity of the shale gas reservoir. Core plugs will have to be sampled regularly to achieve this. Although this is already the preferred sampling methodology in conventional reservoirs, the programme must be followed even more strictly in shale gas reservoirs. A smaller sample spacing compared to the conventional 30cm should also be a consideration over target intervals.

If the science of shale gas reservoirs is to progress, a key-well database should include a standard logging suite plus an elemental analysis log for mineralogy, a magnetic resonance log for pore characterization, a micro-imaging log for identifying natural fractures, and a dipole sonic log for geomechanical applications, plus the requisite ground-truthing core data.

MINERALOGY

Nature

Shale gas reservoirs show a complex and highly variable mineralogy with theoretical end points of (i) a perfect shale in a petrophysical sense (100% clay minerals with only electrochemically-bound water in the pore space and thence a zero effective porosity) and (ii) a

Table 2. Data requirements for key and non-key wells

Petrophysical parameter	Key wells		Non-key wells
	Log	Core	Log
Organic content	Standard logs; Mineral elemental logs; NMR; Image logs	Leco TOC; RockEval Pyrolysis	} Standard logs
Mineral content	Standard logs; Mineral elemental logs	XRD, XRF	
Porosity	Standard logs; Mineral elemental logs; NMR	GRI analysis	
Permeability	Standard logs; NMR	Pressure pulse decay	
Fluid saturation	Standard logs; NMR	Fluid extractions; NMR	
Adsorbed gas	Standard logs	Langmuir isotherm	

porous, lithologically-clean sandstone/limestone. In reality, the mineralogy includes quartzitic or calcareous silts and clays; clay minerals such as chlorite, illite, smectite and kaolinite; and larger detritus that can include pyrite and siderite. Microscopic studies have suggested that the textural and mineralogical complexity of shales may not always be readily apparent (Aplin & Macquaker 2011). The inorganic minerals co-exist with solid organic matter in the form of kerogen.

Characterization

A major challenge for petrophysical evaluation is how to evaluate standard log responses (e.g. density, photo-electric factor, neutron porosity, sonic transit time) in the presence of both markedly heterogeneous inorganic solids and organic matter. In particular, a meaningful clay-mineral volume fraction is a prerequisite: many traditional log-derived clay-mineral indicators overestimate this fraction because they are calibrated in shale, which does not comprise clay minerals at the 100% level. These problems are compounded by disparities between core analyses from different laboratories and log deliverables from different logging companies (Ramirez *et al.* 2011).

Multi-mineral petrophysical models, often seen as a possible solution in shale gas petrophysics, provide non-unique results that require fine-tuning of the input parameters to achieve a better agreement with core data. Differences in interpretation are attributed to the mineral-model definition (e.g. mineral end-points) and technical assumptions about the physics of the reservoir (Ramirez *et al.* 2011). This problem highlights the importance of laboratory measurements such as X-ray diffraction (XRD) and X-ray fluorescence (XRF) in support of log analysis. These data are especially important given the presence of heavy minerals such as pyrite, which can distort the initialization of a multi-mineral model if proper account is not taken.

The classical porosity-evaluation concept of a matrix and clay-mineral system breaks down in shale gas formations, where grains have to be considered collectively and kerogen is present. This makes it difficult to identify rock types, which are needed for prioritizing candidate intervals for hydraulic fracturing. A pertinent aspect of mineralogical characterization is the recognition of geologically-driven mineralogical trends across a shale system (e.g. Mullen 2010): these can provide an overprint for the occurrence of different rock types.

Mineral modelling

Full characterization of shale gas reservoirs might be achieved through the integration of standard nuclear, electrical and acoustic logs with geochemical laboratory and/or log measurements to solve for all the significant minerals present in the shale gas formation. The fraction of organic matter present can be estimated either independently using simple correlations with other logging curves (these are then supplied as input to the mineral model) or determined as 'excess carbon' that cannot be attributed to the inorganic carbon matrix. Validation of the mineral model is achieved through the direct comparison of the resulting elemental composition with core XRD and XRF data (Skelt 2010), an important calibration exercise in a key well given the mineralogical complexity. Achieving a match to core may involve adjusting the mineral end-points and other input parameters, as well as refining the model specifications. The complexity of the model is a function not only of the mineralogy of the shale gas reservoir but also of the number of log curves available, taking due account of the projected optimization of the data acquisition programme during the drilling of non-key wells for which calibrating core data are not available.

The output from the analysis of key-well data will be the input parameters and assumptions for the mineralogical evaluation of non-key wells. This has to be fit for purpose in terms of data optimization and especially from the standpoint of rock-typing, which is a prerequisite for the scenario approach. For example, Kale *et al.* (2010) used a threefold core-derived rock-typing scheme for the Barnett Shale, with calcite content, porosity and total organic carbon as discriminators. Here, the (variable) rock fabric and capillary character of each rock type were also exclusive, suggesting that this partitioning might represent a petrofacies scheme in the strict sense of exclusive interpretative algorithms. Interestingly, Jacobi *et al.* (2008) developed a sevenfold core-calibrated rock-typing scheme for the Barnett Shale based on mineralogy derived from downhole measurements of elemental concentrations.

Where rock typing is not achievable, a possible way forward includes the construction of a variable grain-density curve from a geochemical log, ground-truthed to XRD for mineralogy and to XRF for elemental analysis (e.g. Quirein *et al.* 2010). Another option is partially to circumnavigate the problem by using an approach that has a reduced dependence on grain properties. A prime candidate is nuclear magnetic resonance (NMR) (Jacobi *et al.* 2008). However, NMR primarily benefits inorganic porosity, where the need for a mineralogical characterization remains paramount with other approaches. It is less clear how NMR responds to organic porosity, where pore diameter can be a few nanometres.

Once established, the underpinning process has to be rendered suitable for application using a more limited suite of downhole measurements.

TOTAL ORGANIC CARBON (TOC)

The TOC problem

For present purposes, TOC is the amount of carbon contained within kerogen, which is congenital with the sedimentary system. In short, if there is no kerogen, there is no source rock within the shale system. This simple statement renders TOC the most important parameter in shale gas evaluation. Its identification and quantification from logs draw upon methods developed for source-rock evaluation. Major challenges are to identify the concentration and distribution of total organic carbon as well as its effectiveness as a source. The former draws upon elemental-analysis logs (Pemper *et al.* 2009). The latter brings in thermal maturity, which is typically measured by the Vitrinite Reflectance (%Ro) method and also gives an assessment of thermogenic gas (e.g. Jarvie *et al.* 2007). Estimates of total organic carbon have ranged from 0–25% by weight within target layers of major North American shale gas plays (e.g. Faraj *et al.* 2004). These complexities underscore the interrelated nature of the shale gas evaluation process: interpretation challenges cannot be viewed in isolation. The situation is potentially compounded by any presence of bitumen, which is produced by kerogen during petroleum generation and can show nanoporosity.

Estimation of TOC

A number of core and log-based models have been developed for the estimation of TOC. The models are rooted in the variable response of the logs to organic matter, as seen in source-rock evaluation (Schmoker 1979, 1981; Fertl & Chilingar 1988). Empirical relationships between core-derived TOC and log curves (e.g. density, resistivity and uranium content) have been established and proved to be robust in creating a continuous estimate of TOC along the logged interval of a wellbore. For example, Schmoker (1979) computed organic content from the density log based on (i) a reported correlation between organic

content and pyrite content and (ii) the kerogen porosity being grouped with the kerogen. It was assumed that there was no free gas and that all the gas was in the kerogen. TOC was expressed as a function of the difference between a reference density log response in the absence of kerogen and the actual density log response. The problems lay in the assumed constancy of total porosity over the reference interval and in the sensitivity of the density tool to borehole rugosity. One major drawback of this kind of approach is the assumption that no large variations in other parameters exist to affect the readings of the logs. For example, the presence of pyrite in sufficient volumes may mask the effect of the organic matter on the density and resistivity logs (Passey *et al.* 2010). Again, the presence of apatite in marine source rocks, if not properly accounted for, may create an erroneous relationship between TOC and uranium content (Jacobi *et al.* 2008).

Recent advances in pulsed-neutron mineralogy can offer a possible solution to this problem. TOC is calculated from geochemical data in key wells, having first allocated part of the measured carbon content to the inorganic carbon components within the shale gas formation. The results of the geochemical log analysis can be verified through the use of acoustic and resistivity image logs and also through NMR-derived TOC (Jacobi *et al.* 2008).

The calibration of these techniques to laboratory-measured TOC is most important. Calibration factors have been used to take account of the different maturity levels of kerogen. Different baselines may also be required to zone the reservoirs because of variable mineralogy and water salinity. For example, Passey *et al.* (1990) used an overlay method involving the sonic and resistivity logs, the so-called $\Delta \log R$ method, with TOC empirically calibrated to sample data. The fact that discrete baselines can be established over extended intervals supports the concept of a scenario approach to shale gas evaluation.

Both the standard-log approaches and the pulsed-neutron methods should be investigated in key wells. The target deliverable is a methodology that can be used in conjunction with standard logs in other (non-key) wells. An important requirement is to identify the relationship between TOC and solid kerogen volume so that an appropriate porosity model can be developed (Guidry *et al.* 1990).

POROSITY

Nature of gas storage

Gas storage in shale gas reservoirs occurs in the adsorbed state within kerogen, in the released or free state within kerogen porosity, in the free state within intergranular pore space (including microfractures), and in natural macro-scale fractures. (We will not consider absorbed gas, i.e. gas dissolved in oil or water.) A significant fraction of the free gas can be stored within kerogen porosity. This statement is conditional upon the size of the intrakerogen pores, which in turn is a function of the nature of the kerogen and the degree of thermal maturity. Small intrakerogen pores may be occupied almost entirely by adsorbed gas, in which case the free gas will occur mostly in the inorganic pores. As more of the adsorbed gas is released into a potentially free state, kerogen porosity will increase. Larger kerogen pore sizes may be filled with free gas but they have a relatively small adsorbed gas content. A key challenge for petrophysics is to distinguish quantitatively between the porosities associated with free and adsorbed gas. Furthermore, adsorbed, released and inorganic free gas may have different properties (e.g. Ambrose *et al.* 2012). The amount of adsorbed gas expressed as a percentage of the total gas volume has been reported to vary from 20–85% within target beds of major North American shale gas plays (e.g. Faraj *et al.* 2004).

Types of porosity

There are three components of total porosity. First, there is the porosity within natural fractures, which provide flow conduits to a wellbore, perhaps via induced fractures. Second, there is intergranular porosity, which contains electrochemically-bound water, capillary-bound water, and free fluids that are mostly presumed to comprise gas. Intergranular porosity is non-zero in the (petrophysical) effective porosity system only if the shale is not electrochemically and compositionally 'perfect': it is always non-zero in the total porosity system. Third, there is porosity associated with the organic content. This 'organic porosity' sits well below the microporosity range and is visible to scanning electron microscopy (SEM) down to about five nanometres below which scanning transmission electron microscopy (STEM) is needed to see the very small pores. A useful petrophysical model has to accommodate the porosity created by gas desorption in the kerogen. This is an important issue because this created porosity can account for up to 50% of the kerogen volume (e.g. Elgmami *et al.* 2011). Kerogen porosity varies with thermal maturity, so any model that takes account of kerogen porosity will have to define kerogen properties in the light of the degree of maturity. Moreover, a model that discriminates between intrakerogen pore space and the kerogen itself will have to consider the organic porosity as potentially part of the total interconnected porosity. The problem is compounded by the observation that porosity occurs mostly within kerogen in some shales and mostly within the intergranular pore space in others (Sondergeld *et al.* 2010a). Note that formation-evaluation methods established for conventional reservoirs are likely to be stretched in shale gas reservoirs because of a high clay-mineral content that requires a large 'correction' to log responses. Once the distributions of organic and inorganic porosity have been established, they have to be related to any natural fracture network.

Quantification of porosity

The evaluation of porosity in shale gas systems has drawn heavily on the density log. The problems are severalfold. First, changes in mineralogy result in grain density variations that need to be taken into account. Second, there is no direct way of measuring the density of kerogen. Moreover, kerogen density changes as a function of its degree of maturation. There is also poor understanding of how the free and adsorbed gas contained within kerogen should be handled. One option is to treat this gas as part of the kerogen 'matrix', an approach that would effectively reduce kerogen 'density' significantly, given that intrakerogen porosity has been reported to be as high as 50% (Wang & Reed 2009; Passey *et al.* 2010). Another option is to separate the intrakerogen gas from the solid kerogen matrix. The latter would suggest a mineral model such as that shown in Figure 2. Yet again, Ambrose *et al.* (2012) proposed that adsorbed gas occupies part of the intra-kerogen porosity and that petrophysically-evaluated porosity must be corrected for the pore volume that is occupied by adsorbed gas, which is not available as a resource in real time. The impact of this correction, which is based on the Langmuir adsorption/desorption isotherm approach, is smaller for larger organic pores. The logical extension of this correction is to group the adsorbed gas with the kerogen.

The actual process for determining porosity is also impacted by the presence of gas. In conventional reservoirs, the gas effect is often handled through the introduction of a filtrate saturation (S_{xo}) term within porosity equations. However, the very low intergranular permeability of shale gas reservoirs precludes filtrate invasion, an outcome that renders the standard gas correction ineffectual. A possible solution is an iterative approach to

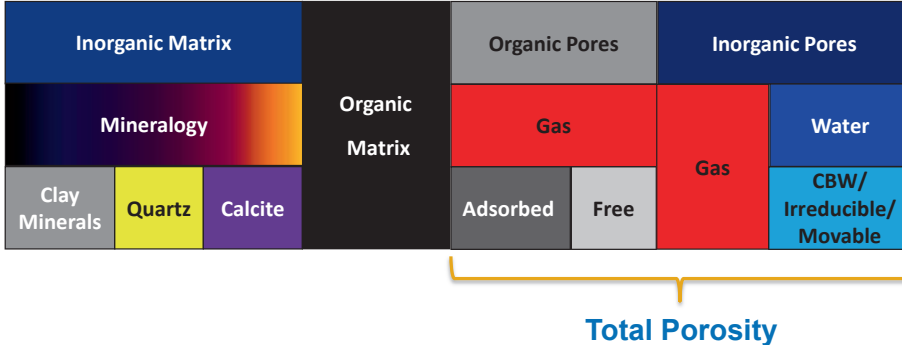


Fig. 2. Petrophysical model for shale gas reservoirs.

the determination of porosity and water saturation. This is the ethos of the following description.

The estimation of porosity from the density log can be achieved using a fundamental relationship between measured bulk density ρ_b and the densities of the various shale gas components that are depicted in Figure 2:

$$\rho_b = \rho_m V_m + \rho_k V_k + \rho_{gk} \phi_k + \rho_{gm} \phi_m \quad (1)$$

where ρ is density, V is fractional volume relative to the rock, ϕ is porosity, and the subscripts m, k, gk and gm stand for (inorganic) matrix, kerogen, intrakerogen gas and intermatrix gas, respectively. The gas within the intergranular pore space has been distinguished from that in the kerogen up to this point, although they are now grouped to obtain the following workable solution to equation (1).

Equation (1) can be re-arranged to generate a relationship for total porosity, $\phi_T = \phi_m + \phi_k$:

$$\phi_T = \frac{\rho_b - \rho_m - w_k \rho_b \left(1 - \frac{\rho_m}{\rho_k}\right)}{(\rho_g - \rho_m) + (\rho_w - \rho_g) S_{wT}} \quad (2)$$

where ρ_g is overall gas density within total porosity, ρ_w is formation-water density, w_k is weight fraction of kerogen, and S_{wT} is water saturation relative to total porosity. There are a number of key assumptions in deriving and using equation (2).

- (1) The free gas within the inorganic matrix has the same density as the free and adsorbed gas in the kerogen (ρ_g).
- (2) The kerogen is hydrocarbon wet such that water saturation in kerogen is zero.
- (3) The variable (inorganic) mineral density is calculated from a mineral model.
- (4) The adsorbed gas is considered part of the total porosity. A correction to the computed total porosity would be needed to remove the intrakerogen pore volume occupied by adsorbed gas, but this would introduce a departure from the total porosity system of petrophysical evaluation.

Subject to these assumptions, equation (2) is physically correct. An illustrative calculation has been made using equation (2) with input of parametric values identified by Sondergeld *et al.* (2010b) and subsequently re-listed as follows (J.T. Comisky, 2 May 2012, pers. comm.): $w_k = 0.05$, $\rho_k = 1.2 \text{ g cm}^{-3}$, $\rho_m = 2.71 \text{ g cm}^{-3}$, $\rho_w = 1.0 \text{ g cm}^{-3}$, $\rho_g = 0.3 \text{ g cm}^{-3}$, $S_{wT} = 0.2$ (see Table 3). If TOC is substituted into equation (2), there must be an identified

relationship between the weight fractions w_k and TOC to allow this to happen. In the absence of free oil, this relationship has been reported to be (Guidry *et al.* 1990):

$$w_k = TOC / c_k \quad (3)$$

where c_k is the weight fraction of carbon in kerogen. The value of c_k is reservoir-specific because it depends on the level of thermal maturity and the source of the kerogen itself (Luffel *et al.* 1992). Equation (3) allows one to work in kerogen 'space' by drawing upon measurements made in TOC 'space'.

Although a kerogen density of $1.1\text{--}1.2 \text{ g cm}^{-3}$ is common in the literature, this parameter remains a key uncertainty in porosity evaluation, especially with increased thermal maturity. Where available, established regional trends of kerogen density with thermal maturity constitute a useful reference source. A proposed solution is the use of a tool that has less dependence on the density of solids. A favoured approach is nuclear magnetic resonance (NMR), which should become an essential petrophysical tool in key wells. Comparisons of density porosity and a reference NMR-derived porosity might allow a requisite adjustment to be made either to the kerogen density in equation (2) or to an algorithm relating kerogen density to some parameter that can be measured using standard logs. Once closure of porosity has been achieved, density data can then be exported to non-key wells. Note that the NMR approach has reportedly delivered mixed results in shale-gas applications and, therefore, a key component of this exercise is to establish where it works best, not least because that information could be very diagnostic in itself.

The S_{wT} term in equation (2) requires both porosity and saturation to be solved iteratively. An initial estimate of S_{wT} is needed. The resulting initial porosity value is then used to re-estimate S_{wT} . This re-estimate may be based on a pseudo-Archie equation or an empirical relationship between porosity (or an associated parameter) and S_{wT} . The output is then looped back into equation (2) until satisfactory convergence is achieved. A similar iterative loop is required for any other parameter that may be a function of porosity.

There is a body of opinion that the density of adsorbed gas is somewhat greater than that of free gas and, as such, should be distinguished from free gas as it is in equation (1). If this distinction is retained, the porosity equation (2) has to be replaced with the following:

$$\begin{aligned} & \phi_m \rho_{gm} + \phi_k \rho_{gk} + (\phi_m + \phi_k) (S_{wT} (\rho_w - \rho_{gm}) - \rho_m) \\ & = \rho_b - \rho_m - w_k \rho_b \left(1 - \frac{\rho_m}{\rho_k}\right) \end{aligned} \quad (4)$$

Table 3. Sample calculations of porosity from the density log in a shale gas system

ρ_b (g cm ⁻³)	ϕ_T (Sondergeld 2010b) (dec)	$\phi_m + \phi_k$ (equation 2) (dec)
2.0	0.261	0.266
2.1	0.213	0.217
2.2	0.166	0.169
2.3	0.118	0.121
2.4	0.071	0.072
2.5	0.024	0.024

Equation (4) cannot be solved for total porosity ($\phi_m + \phi_k$) without a further relationship between ϕ_m and ϕ_k and a realistic assumption as to the value of ρ_{gk} . Because these additional inputs are speculative, and given that the kerogen density is measured with no adsorbed gas, equation (2) is retained for the present. The equation remains workable in shale gas systems. For example, if the ratio of adsorbed gas to total gas is around 50%, the effect on total porosity of varying ρ_{gk} from 0.3 to 0.7 g cm⁻³ is less than 0.5 porosity units for a total porosity of 5 porosity units. This effect is no greater than the precision of conventional measurements of core porosity. It is expected that these matters will progress with the introduction of additional diagnostic measurements.

As noted earlier, the interdependence of the free pore space and the adsorbed phase has prompted some researchers to apply corrections to the porosity derived from logs by subtracting the volume ‘consumed’ by the adsorbed gas (e.g. Ambrose *et al.* 2012). The correction factor (ϕ_a) takes account of the fractional volume occupied by the adsorbed phase (G_a), which is estimated from isotherm measurements. This correction has its roots in the difference between the total and effective porosity systems of petrophysical evaluation. In the total porosity system, all non-solid matter is grouped within the porosity. This includes electrochemically-bound water at (clay-)mineral surfaces in the case of water-wetting. In the case of hydrocarbon-wetting with gas, the adsorbed gas can be regarded as bound to the solid kerogen, by loose analogy with electrochemically-bound water, even though the processes of adhering are different. This means that a log-derived bulk volume of gas ($\phi \times (1 - S_w)$) is actually the total volume of gas sensed by a logging tool, both free and adsorbed. The adsorbed gas component ($\phi_a \times S_g$), where $S_g = 1$ in hydrocarbon-wet kerogen, can then be subtracted from this total gas volume to obtain an estimate of the free gas component (G_f), but this step leads towards an effective porosity (in a petrophysical sense), which then should strictly be honoured from the standpoint of water-wetting, too. Note that conventional laboratory measurements of TOC and/or kerogen content involve an initial desorption to remove the adsorbed gas from the solids (e.g. Peters 1986). This separation of the adsorbed gas from the kerogen is in accord with the requirement to quantify the constituent terms of equation (2). Free gas can be present in the inorganic pores where these are at sub-irreducible conditions. More generally, it is good petrophysical practice to regard the effective and total porosity interpretative systems as discrete and not to mix the underlying concepts. This is especially important given that the (unknown) density of adsorbed gas could turn out to be significantly higher than that of free gas.

None of the above discussion obviates the need to tie back to core porosity where this is reliable and represents the porosity that would be seen by a deployed porosity tool. For example, density-derived porosity can be tied to total porosity obtained from the analysis of crushed shale core samples (e.g. Zhao *et al.* 2007).

WATER SATURATION

Formation-water salinity

Water salinity leads to water conductivity and thence water resistivity, which is input to electrical methods of evaluating water saturation. Formation-water samples from shale gas reservoirs are scarce and, where available, they can be misleading due to the influence of produced flowback water and free water found in natural fractures, which may not be representative of the salinity in the shale. Moreover, water production from shale can be variable (Zuber *et al.* 2002). Water may not be produced from some shale gas pore systems because many of these have irreducible or even sub-irreducible water saturations (Wang & Reed 2009). Against this backdrop, formation-water salinity has been seen to be highly variable within shale gas systems. For example, Luffel *et al.* (1992) reported a salinity range of 12 000–222 000 ppm NaCl-equivalent based on Dean-Stark analysis of preserved, crushed whole-core from the Huron Formation in Devonian shale of the Appalachian region. Again, Martini *et al.* (2008) mapped the range of salinity of formation waters from the Antrim Shale in the Michigan Basin as about 3000–215 000 ppm and from the New Albany Shale in the Illinois Basin as about 10 000–90 000 ppm. It is uncertain whether every shale play is characterized by the salinity variations shown in the above examples or whether the variations may be attributed to local hydrostatic influences and/or fracture-based incursion of deep-basin waters. These degrees of variation are too pronounced to be accommodated through averaging and they call for either a log-based method of continuous salinity assessment or a salinity-independent method of evaluating water saturation. An ongoing challenge is to use these approaches conjunctively in key wells to define connate-water salinity as a basis for export to uncored wells.

As noted above, water salinity is a key unknown in resistivity-derived water saturation equations. Large variations in water resistivity over short vertical distances have been reported with no apparent relationship to organic content or any other petrophysical parameter (Sondergeld *et al.* 2010b). Where salinity analysis is based on extracted waters from crushed core, the data represent a combination of electrochemically-bound and capillary-bound waters. At higher clay-mineral contents, electrochemically-bound water will be more pronounced. At lower clay-mineral contents, capillary-bound water will predominate. Once again, the key-well concept can be highly beneficial, this time by providing a sampled reference set of laboratory-measured salinity of the interstitial water along targeted lengths of the wellbore. This dataset can be seen as potentially calibrating a log-derived method of predicting formation-water resistivity. In so doing, note that data quality can be a function of sample size.

Evaluation of water saturation

Water saturation has received less attention in the literature than porosity. This is possibly due to an incomplete understanding of the nature of gas storage and the still unresolved effort to establish a standard method for porosity determination, a situation that transmits practical problems to the definition of ‘saturation’ (Passey *et al.* 2010). Matters are complicated further where the total and effective porosity systems are mixed when calculating gas in place.

Even with the water-salinity issue resolved, the use of a resistivity-based water saturation equation is still questionable because of the problem related to the resistivity log reading itself. What is the resistivity tool measuring? In conventional reservoirs, Archie (1942) attributes the increase of true formation resistivity (relative to the resistivity of a water zone) to hydrocarbon occupying part of the pore space. The presence of ‘conductive’ solids in the form of clay minerals was later treated

as an 'excess conductivity' or a non-Archie component in the saturation equations, because it was seen to reduce formation resistivity. However, in shale gas petrophysics a third component exists in the form of solid kerogen, which has the opposite effect to clay minerals in that it increases formation resistivity. So, how are these three components to be handled?

The NMR tool offers a potential solution for the determination of water saturation independent of resistivity measurements. The problem of low signal amplitude associated with the presence of gas may be obviated by logging at very slow speeds. However, the measured data may not usefully represent the co-existence of free and adsorbed gas. The gas adsorbed to the surface of the kerogen is problematic and may not respond in the same way as free gas because there are solid-like constituents associated with its composition (Ramirez *et al.* 2011). Moreover, the high temperature of shale gas reservoirs, which is significantly greater than the supercritical temperature of natural gas, raises questions as to whether the adsorbate is in the form of a liquid or vapour (Ambrose *et al.* 2012). It is, therefore, unsurprising that current attempts to calibrate NMR-derived water saturations to core-derived values have been largely unsuccessful. It is worth recalling that equation (1) distinguished between adsorbed and free gas, whereas these were combined in the derivation of equation (2), which may turn out to be too simplistic.

Another possible solution to the water saturation problem lies in the adoption of a pseudo-Archie approach. Here the Archie equation is used but the characterizing porosity and saturation exponents are allowed to find their own data-driven levels, which could be very different from their respective defaults, $m = n = 2$. For example, cementation and saturation exponents of 1.7 were found to provide a good match to core-derived water saturation (Luffel *et al.* 1992). Departures from the default values have also been reported by Aguilera (1978) and by Quirein *et al.* (2010).

The pseudo-Archie approach does require a continuous water resistivity curve, because water salinity exerts a major influence on the pseudo-Archie exponents, m and n . This complicates matters but the requirement can be achieved in key wells by zoning the reservoirs based on changes in water salinity in much the same way that a reservoir can be zoned when determining TOC from logs. The pseudo-Archie parameters in each zone can then be varied to achieve a match to core-derived water saturation, perhaps measured using the Dean-Stark extraction method. In allowing the pseudo-Archie exponents to find their own data-driven levels, some of the problems associated with the resistivity measurements are circumnavigated. The approach is also consistent with the total porosity system, but the solution has to be looped back into equation (2) to solve for porosity and S_{wT} iteratively. The output from the analysis will be the pseudo-Archie parameters and formation-water salinities for the evaluation of water saturation in non-key wells.

Note that a Pickett-plot concept has been proposed for evaluating TOC and water saturation conjunctively (Yu & Aguilera 2011). The generic use of such a plot will require much calibration, not least with regard to pseudo-values of the governing porosity and saturation exponents.

INITIAL GAS PORE VOLUME

Free and adsorbed gas

Imported methods of evaluating gas in place can lead to sizeable errors in estimated gas volumes. The reasons are twofold. First, methods taken from conventional or other unconventional reservoir practices (such as for coal bed methane) are unlikely to be directly applicable to shale gas reservoirs because of the different

nature of the source/reservoir. Second, the degree of heterogeneity of a given shale gas reservoir can call for different approaches to formation evaluation within the same depositional system. To characterize a shale gas reservoir properly, it is necessary to evaluate the amount of free gas in the intergranular pore space and within the kerogen, as well as the adsorption properties of the kerogen itself. The key question remains, i.e. whether adsorbed gas should be included within the kerogen, thereby affecting properties such as kerogen density, or whether it should be seen as occupying intrakerogen porosity, in which case there is a need to distinguish between adsorbed gas and released gas within a total intrakerogen porosity.

Total gas in place

The approach described here seeks to gather all the parameters necessary for the calculation of total gas in place. The variability of shale gas reservoirs precludes the use of a single set of average reservoir parameters to estimate gas volumes. Each reservoir zone in each well would have its own set of average parameters. The fishbone diagram of Figure 3 identifies the required input parameters to estimate total in-place gas volumes and thereby adds to the workflow of Figure 1. These parameters can be based on well-specific core and log data, local shale-play data, or regional analogue information. The conventional equation for gas-in-place calculation can then be used, perhaps with the gross rock volume (GRV) constrained by the 'fractured volume', which includes the 'stimulated volume', the volume contacted by induced fractures (Economides & Wang 2010).

The total porosity system is adopted in the proposed workflow and this provides an estimate of the total gas in place, combining both free and adsorbed gas. The estimation of the fraction of volume occupied by free and adsorbed gas is important because ultimate recovery in reservoirs with significant adsorbed gas has been reported to be up to ten times higher than for other tight reservoirs of similar permeability and porosity (Economides & Wang 2010). To achieve this, the volume of free gas can be estimated using the same conventional equation for gas in place but applying an effective porosity methodology. This, however, introduces several complications, in particular the definition of 'effective' porosity and the differentiation between intergranular and intrakerogen porosities. At present, the nature of the GRI workflow for core porosity measurements does not allow calibration of effective porosity to core data. Moreover, the determination of the 'effective' free gas saturation is complicated by the fact that a resistivity tool cannot differentiate between free and adsorbed gas. Any free gas saturation estimated using resistivity measurements will, therefore, be overly optimistic where it encompasses adsorbed gas, especially given that the percentage of adsorbed gas in shale gas plays has been reported to be as high as 85% (e.g. Faraj *et al.* 2004).

A more pragmatic approach would be to estimate the adsorbed gas volume using a Langmuir isotherm experiment on cores. Corrections can be made to the isotherm measurement to take into account its dependence on TOC and temperature. A continuous estimate of adsorbed gas along a wellbore can be achieved by establishing a correlation between the adsorbed gas volume, often expressed in SCF/ton, and standard log curves. This relationship can then be exported to non-key wells.

GEOMECHANICAL PROPERTIES

Geomechanical challenges

There are three overarching needs. The first is to assess the degree of natural fracturing and how these fractures would be most effectively intersected by deviated or horizontal wellbores.

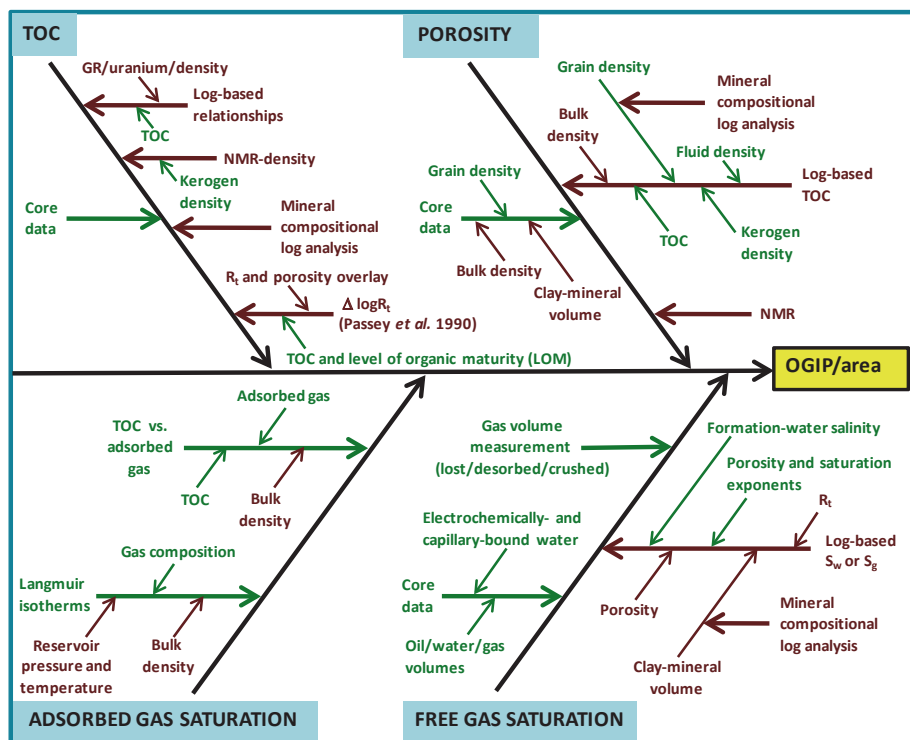


Fig. 3. Fishbone diagram of OGIP input parameters. Core data in green; field data in brown.

The second is to ascertain the degree of fracturability of intervals penetrated by intended production wells so that maximum benefits can be derived from a well stimulation exercise. The third is to manage the orientation and distribution of the induced hydraulic fractures. The productivity of a shale-gas resource strongly depends upon reservoir quality and the execution of an effective hydraulic fracture stimulation treatment (e.g. Cipolla *et al.* 2009; Wang & Reed 2009). Regardless of whether natural fractures are present, an ‘enhanced’ or ‘artificial’ reservoir is created within the shale gas resource by taking account of reservoir architecture and applying appropriate well completion methods. Petrophysics provides input to all three of these tasks, which are further complicated by the high degree of reservoir variability they can encounter.

Geomechanical characterization

In addressing the petrophysical challenges in geomechanical applications, the initial focus is on developing an understanding of the mechanical rock properties, overburden and pore pressure variations along the wellbore in order to calculate native state stress profiles (Mullen *et al.* 2007). Conventional wireline sonic, or preferably dipole sonic logs, may be used to calculate Poisson’s ratio, Young’s modulus, and shear or rigidity moduli from which to estimate pore pressure and net stress. In practice these dynamic log-based properties require calibration by using core data to estimate their static equivalents, especially Young’s modulus. To compensate partially for an absence of core, algorithms have been developed to convert log-based dynamic moduli to their static equivalents (Mullen *et al.* 2007; Jacobi *et al.* 2009). Brittle rock-type compositions are recognized by a low Poisson’s ratio and a high Young’s modulus (Rahmanian *et al.* 2010). Cross-plots of Poisson’s ratio and Young’s modulus can be used to identify brittle and ductile rock types within the shale play (Grieser & Bray 2007; Tyagi *et al.* 2011). Where core samples are available, Brinell hardness can be measured both before and after contact with stimulation fluids to assess fluid choices and Brinell Hardness

Number (BHN) can be used in evaluating potential proppant embedment and crushing. As each shale gas reservoir is unique, an understanding of mechanical rock properties, mineralogy and core-calibrated petrophysical attributes is pivotal to the selection of stimulation and completion methods on a case-specific basis (Rickman *et al.* 2008).

NET PAY

The adjustment from total gas in place to net gas in place calls for the application of net-pay criteria. There are no standard protocols for conventional reservoirs, let alone for unconventional reservoirs.

Net-pay issues

Net pay can only be measured at a wellbore. It is the aggregation of those intervals of penetrated rock that satisfy cut-offs relating to reservoir quality and hydrocarbon content. The adopted cut-offs should be data-driven. They have to be conditioned to the static, dynamic and geomechanical behaviour of the shale gas system. This is done so that the cut-offs represent effective limits of both reservoir storage and reservoir flow in a hydrocarbon-bearing interval (Worthington 2010). The association of these reservoir attributes is more complex in shale gas accumulations where storage can take the form of adsorbed gas within kerogen, released gas within kerogen porosity, free gas within intergranular pores, and free gas within natural fractures. The main challenges lie in bringing together all the major factors that influence net pay in shale gas systems, placing them within an ordered workflow for defining net pay, and thence demarcating net-pay intervals. This is likely to be not just a reservoir-specific process but rather specific to identified reservoir-rock types within a given shale gas system. A key component of net-pay analysis in shale gas reservoirs is handling a drainage system for which gas storage is within nano- and micropores and delivery to the wellbore is primarily through fractures.

Cut-off selection

The identification of net pay through data-driven cut-offs is in its infancy in shale gas reservoirs. The exercise draws upon reservoir storage and flow mechanisms, controlling factors for gas in place, and recovery potential over targeted intervals. Against this backdrop, a forward direction is emerging. Because these reservoirs will not flow in the absence of natural and induced fractures, the concept of net pay is meaningless unless it is somehow tied to fracturability. In conventional reservoirs, net-pay cut-off parameters are shale volume fraction, porosity, hydrocarbon saturation, and permeability. In shale gas reservoirs, where we are dealing with an arenaceous/calcareous shale rather than a shaly sand/carbonate, it makes sense to substitute the shale volume fraction cut-off with a quartz volume fraction cut-off based on an elemental analysis log. A mineralogically-based brittleness index (the ratio of quartz content to the sum of quartz, carbonate and clay-mineral contents) is in accord with this reasoning (Sondergeld *et al.* 2010b). Porosity should remain because this determines gas storage potential within both kerogen and intergranular pore space. Because a shale gas reservoir is also the source and seal, there can be no pay without significant TOC. Therefore, TOC partly takes the place of hydrocarbon saturation as a net-pay indicator: the other partial substitution is free gas saturation. Finally, the density of natural fractures as seen by a downhole imaging tool has to be considered alongside interparticle permeability. As with conventional reservoirs, there is no universal set of cut-offs. Indeed, it is even more important that each shale play be investigated separately and thoroughly. This means that each shale gas reservoir, or reservoir zone, will have its own set of net-pay cut-offs for the given reservoir situation. For example, TOC should be considered in the light of thermal maturity. Again, a mineralogically-based brittleness index would have to be assessed against a backdrop of geomechanics (Rickman *et al.* 2008), especially the fracturing opportunities indicated by high Young's modulus and low Poisson's ratio. The key requirement is to define critical values of the five cut-off parameters (sand volume fraction, brittleness, porosity, TOC and field permeability), above which a useful flow of hydrocarbons via an induced fracture network might be expected. Given the greater uncertainties in shale gas evaluation, this information can be expected to emerge at a later stage of appraisal relative to conventional situations. The process of net-pay identification is complicated by the observation that intervals with the most favourable geomechanical properties may not contain any organic matter. Therefore, some compromise in cut-off selection can be expected. Even so, there are preliminary indications that net pay may be useful as a design parameter in fracturing programmes (e.g. Kazakov & Miskimins 2011).

PRODUCIBILITY

In shale gas reservoir evaluation, reservoir quality typically has been characterized based on vertical key wells rather than on horizontal key wells. Thus, the lateral heterogeneity within reservoir zones from well to well and along horizontal well courses may be significantly different from that represented by vertical key-well characterization methods.

Pore connectivity

Pore connectivity ranges through the nanopores associated with kerogen, the intergranular nano- to micropores of the shale, meso- to macro-pores of lithologically-cleaner intervals, natural fractures and induced fractures (Slatt & O'Brien 2011). It is presumed that as adsorbed gas is released, it initially occupies kerogen pores until it migrates as free gas into the intergranular pores, which, in turn,

feed gas to the fractures. Moreover, where kerogen is present, it can be connected (Curtis *et al.* 2010). This is an important observation, because kerogen can have a porosity that is significantly higher than intergranular porosity and, given its hydrocarbon-wetness, it may give rise to an enhanced single-phase flow to the fracture network (Wang & Reed 2009). Therefore, a major challenge is to identify those concentrations of TOC that allow solely organic connectivity with the fracture network. Within the inorganic pore space, pore-throat-size distribution is an important controlling factor, and this can be very difficult to characterize. Beyond this, petrophysics can also contribute to the prediction of permeability reduction due to depletion.

Geochemical screening

The maximization of mud-logging information through examination of drill cuttings and mud-gas analysis deserves further emphasis. For example, real-time acquisition of elemental analysis from drill cuttings is enabled by using the Laser Induced Breakdown Spectrometry (LIBS) technique to estimate mineralogy and identify geochemical-stratigraphic zones. The geochemical-stratigraphic zonation for target intervals can improve knowledge of the stratigraphic location of the wellbore and facilitate geosteering of horizontal wells (Buller *et al.* 2010). The composition of mud-gas shows provides an indication of the gas composition at start of production, although it is recommended to ground-truth gas composition from canister gas analysis. In addition, monitoring gas composition/properties and reservoir pressure throughout the life of a well may aid in identifying changes from free gas to adsorbed gas as the main component of production. Adsorbed gas production occurs only after a significant pressure drop in the reservoir and it is often assumed that it will follow profiles based on the Langmuir isotherms inferred from canister laboratory tests. Determination of whether or not the adsorbed gas is the main component of gas production is essential to an understanding of the reservoir mechanism.

Reservoir mechanism

During shale gas production, the reservoir pressure is lowered by dewatering (of the fractures) and by free-gas production. This stimulates desorption and it allows the released gas to diffuse and/or flow to the fractures. This process is partially controlled by intergranular transmissibility as exposed at a fracture surface. If the latter is smaller than fracture transmissibility, the intergranular permeation properties will limit production. The converse can apply and the situation can change according to the stage of production. An assessment of prevailing hydraulic conditions brings together petrophysics, reservoir engineering and geomechanics. Faced with these potentially different situations, the key to enhanced production is high-volume fracture stimulation and an insight into fracture growth (e.g. Cipolla 2009). The main petrophysical challenge in selecting target zones for stimulation is to make a meaningful assessment of fracturability, for example by targeting intervals that are already naturally fractured (Du *et al.* 2009) or perhaps by using quartz content as an indicator of brittleness (e.g. Jarvie *et al.* 2007).

Sweet spots

Sweet spots are defined as the most prospective volumes of the shale play. They are primarily targeted to achieve early economic production. They are characterized by higher resource concentrations with potential for economically viable development (e.g. Hashmy *et al.* 2011). The identification of sweet spots has been synthesized into recognizing zones of good hydrocarbon reservoir quality (TOC and thermal maturity,

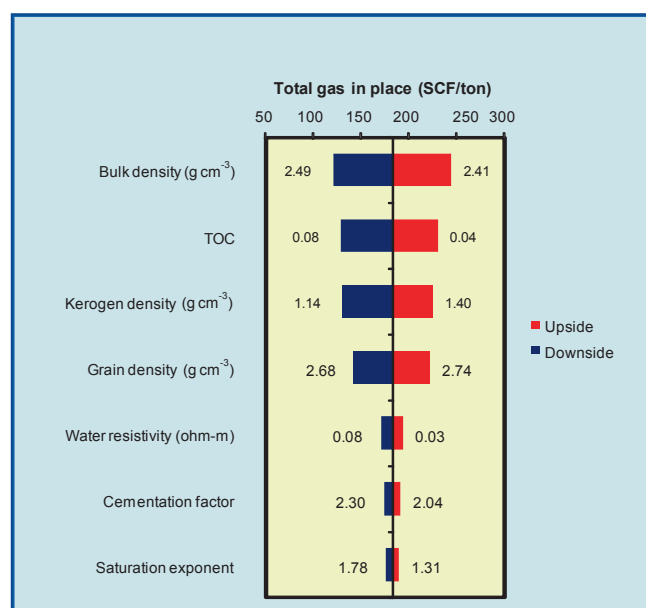
Table 4. Input parameters for sensitivity analysis

Input parameter variable	Input value		
	Low	Base	High
TOC, frac. wt	0.04	0.06	0.08
Bulk density, g cm ⁻³	2.41	2.45	2.49
Density of kerogen, g cm ⁻³	1.14	1.27	1.40
Grain density, g cm ⁻³	2.68	2.71	2.74
Water resistivity (R_w), ohm-m	0.03	0.05	0.08
Cementation factor (m)	2.04	2.17	2.30
Saturation exponent (n)	1.31	1.50	1.78

poro-perm character, fluid saturations, gas in place) and good completion quality (stress regime, mineralogy, natural fractures). Thus, a sweet spot can be described as a formation volume that has the following characteristics:

- low water saturation with high TOC content and thence high kerogen content;
- low clay content and thence high brittleness index for fracturability;
- higher porosity;
- higher (effective interparticle) permeability; and
- low fracture initiation pressure preferably evidenced by natural fractures.

These characteristics largely mirror net-pay criteria. For early delineation of sweet spots it is recommended to acquire cores and run specialized logging tools (micro-imager, an elemental analysis tool, a magnetic resonance device, and a sonic dipole tool) and conduct pilot tests. Even with this level of investigative practice, some of the completed intervals in horizontal wells may underperform, as evidenced by production logs. This is attributed to the heterogeneous nature of gas shale reservoirs (Miller *et al.* 2011), which may not be predictable from the results of pilot studies. The remedy lies in more comprehensive open-hole log data acquisition in horizontal (key) wells.

**Fig. 4.** Tornado chart summarizing the sensitivity analysis.

Geological bounds to completion intervals

An assessment of reservoir quality should include the identification of fracture barriers to enable improved targeting of shale-gas treatment intervals. Fracture barriers constrain the induced hydraulic fractures to stay within the shale-gas treatment interval and not penetrate into, or connect with, fluids in formations above or below the treatment interval. The identification of fracture-barrier rock types is based on rock strength and mechanical property information derived from well logs and core analyses. The fracture treatment interval (i.e. the targeted gas-productive interval between fracture-barrier rock types) offers a possible basis for the quantification of reservoir thickness and/or formation volume within a shale-gas resource. Monitoring the degree of hydraulic fracturing and mapping microseismic events are two of the methods used to assess the extent of the stimulated rock volume, the 'artificial' reservoir within a shale gas resource.

SENSITIVITY ANALYSIS

The evaluation of shale gas resources has to contend with major uncertainties in data acquisition, processing, interpretation and integration. Therefore, there is a need to identify the key parameters that have the greatest impact on the estimation of gas in place, productivity and hydraulic fracture design. Here, a sensitivity analysis has been made of the input parameters (variables) specifically for the calculation of gas in place in order to rank the relative influence of each variable. The input parameters and uncertainty ranges in Table 4 are based on a shale gas play investigated by the authors. In that analysis, the resistivity and gas expansion factor were fixed. The ranges of properties used in the analysis represent realistic values for the shale play, and the TOC and bulk density were inversely correlated. Calculations of gas in place were made using the total porosity system. Adsorbed gas was estimated using the relationship between adsorbed gas and TOC, as specified by Wang & Reed (2009).

The sensitivity analysis is displayed on a tornado chart to compare the relative impact of uncertainty for each variable on a top-down basis (Fig. 4). Thus, the uncertainty in the variable associated with the largest bar has the maximum impact on computed gas in place with each successive lower bar having a lesser impact.

The sensitivity analysis for gas in place shows that bulk density has the largest impact on gas-in-place calculations followed by TOC, kerogen density and grain density. Data acquisition in key wells should, therefore, be geared to minimize errors in these four parameters. Similar exercises can be carried out on other shale plays to identify the parameters with the most impact on the gas-in-place volumes. For example, Mullen *et al.* (2007) conducted sensitivity analyses on closure pressure and identified Poisson's ratio and pore pressure as the key parameters in the uniaxial strain equation.

CONCLUSIONS

The challenges facing shale gas petrophysics have been examined from the standpoints of gas in place and producibility. The practical solutions are based on what is currently known. A key-well concept has been adopted, and this draws upon the complete study of 'representative' wells with the aim of establishing a set of parameters, concepts and empirical relationships to be exported for the evaluation of non-key wells. The data acquisition programme for non-key wells can then be optimized based on a pragmatic workflow. The workflow organizes the petrophysical challenges into a set of work plans for different scenarios. The uncertainty associated with the estimation of reservoir parameters coupled with the high degree of heterogeneity in

shale gas reservoirs highlight the importance of establishing a broad database of core measurements. This has been incorporated in the workflow, and it may allow the partitioning of the reservoir using a data-driven rock-typing scheme to facilitate a scenario approach. A fit-for-purpose sensitivity analysis has been advocated to identify and rank critical parameters that most impact gas-in-place volume calculations. Data acquisition programmes in key wells should be designed to address the uncertainties related to the parameters that have the most impact on in-place gas volumes and thence producibility. An ordered petrophysical approach is beginning to emerge within the shale gas industry. However, it may be quite some time before favoured evaluation procedures become fully established.

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NOMENCLATURE

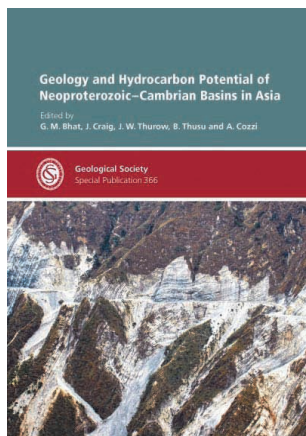
c_k	= weight fraction of carbon in kerogen (dec)
m	= pseudo-Archie porosity exponent
n	= pseudo-Archie saturation exponent
G_a	= adsorbed gas component of gas in place (SCF/ton)
G_f	= free gas component of gas in place (SCF/ton)
ρ_b	= log-measured subsurface bulk density (g cm^{-3})
ρ_g	= overall gas density (g cm^{-3})
ρ_m	= matrix density (g cm^{-3})
ρ_k	= kerogen density (g cm^{-3})
ρ_{gk}	= intrakerogen gas density (g cm^{-3})
ρ_{gm}	= intermatrix gas density (g cm^{-3})
ρ_w	= formation-water density (g cm^{-3})
ϕ_a	= fractional pore space occupied by adsorbed gas (dec)
ϕ_k	= kerogen porosity as a fraction of total volume (dec)
ϕ_m	= matrix porosity as a fraction of total volume (dec)
ϕ_T	= total porosity (dec)
R_w	= formation-water resistivity (ohm-m)
S_g	= gas saturation (dec)
S_{wT}	= total water saturation (dec)
S_{xo}	= invaded zone water saturation (dec)
V_m	= volume fraction of inorganic matrix (dec)
V_k	= volume fraction of solid kerogen (dec)
w_k	= weight fraction of kerogen in rock (dec)

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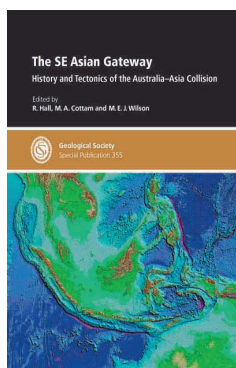
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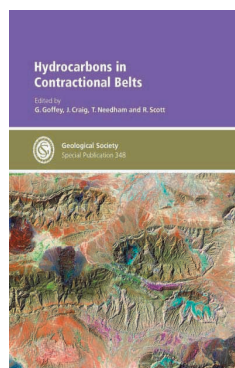
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