A PETROPHYSCIAL MODEL TO ESTIMATE FREE GAS IN ORGANIC SHALES

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ABSTRACT

A method is presented whereby conventional open hole logs – density, neutron, Pe (desirable but not essential), GR, and resistivity – can be used to quantify the volume of free gas in organic shale. The calculations involve determining silt and clay mineral volumes in the shale fraction of the rock. Porosity associated with the clay minerals is subtracted from total porosity, and the difference remaining is silt porosity. Silt porosity is added to any, usually very small, amounts of clean formation porosity which might exist when shale volume is less than 100%. This summed porosity is then combined with water saturation to determine free gas volumes. A summation of free gas-filled shale porosity can then be compared with cumulative adsorbed gas volume to yield a comprehensive petrophysical analysis.

INTRODUCTION

Petrophysical interpretation of shale gas reservoirs is not straight forward. Conventional reservoirs can be analyzed to define porosity accessible to hydrocarbons (often termed effective porosity), and its contained fluids – water, oil, and gas.

By contrast, petrophysical evaluation of shale gas reservoirs is in its infancy. Procedures applicable to conventional reservoirs cannot be applied, and new approaches need to be developed. Shale gas is comprised of two quite different types:

a. Gas adsorbed onto the rock surface, and concentrated in the TOC (total organic carbon) fraction of the shale. This gas is only released quite slowly as reservoir pressure is reduced.

b. Free gas located in the small to very small volumes of porosity dispersed within the shale reservoir. It is this type of gas – termed free gas – that assuming a successful stimulation, will flow toward the wellbore, and perform in an analogous manner to conventional reservoirs.

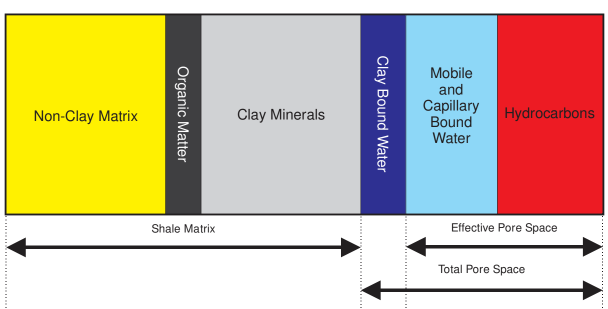
In this paper, we will examine methodologies to quantify both adsorbed and free gas volumes. For adsorbed gas, we used techniques that have already been published – notably Passey et al. For the free gas, the techniques are novel, developed over the past few years.

NOMENCLATURE

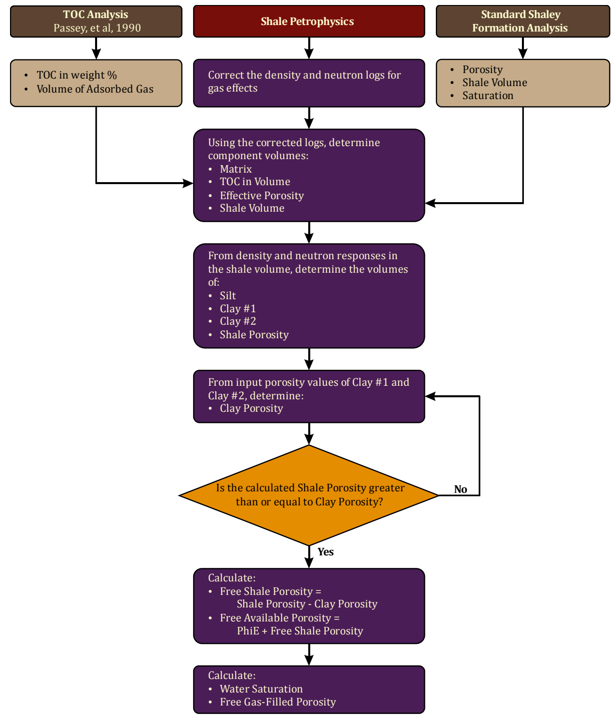
RhoB	Original raw density – gm/cc
NPhi	Original raw neutron – limestone, fractions
$RhoB_{Adjusted}$	RhoB corrected for gas effects – replace gas with water
$NPhi_{Adjusted}$	NPhi corrected for gas effects – replace gas with water
TOC_{Volume}	Convert from weight percent by multiplication – RhoB/1.25
Rho_{SH}	Adjust RhoB to reflect shale response only
$NPhi_{SH}$	Adjust NPhi to reflect shale response only
Silt Volume	Determined from cross plot of Rho_{SH} vs. $NPhi_{SH}$ – Silt Porosity chosen by interpreter
Clay 1 Volume	Determined from cross plot of Rho_{SH} vs. $NPhi_{SH}$ – Clay 1 point chosen by interpreter
Clay 2 Volume	Determined from cross plot of Rho_{SH} vs. $NPhi_{SH}$ – Clay 2 point chosen by interpreter

Clay 1 Porosity	Value of porosity to be assigned to Clay 1 – chosen by interpreter
Clay 2 Porosity	Value of porosity to be assigned to Clay 2 – chosen by interpreter
Shale Porosity	Cross plot porosity of Rho_{SH} vs. $NPhi_{SH}$
Clay Porosity	(Clay 1 Volume x Clay 1 Porosity) + (Clay 2 Volume x Clay 2 Porosity)
Free Shale Porosity	Shale Porosity – Clay Porosity
Phi_E	Effective Porosity (non-shale fraction)
Free Available Porosity	Phi_E + Free Shale Porosity
Water Saturation (S_W)	$\left(R_W/R_{Wa}\right)^{0.5}$ where: R_W = Water Resistivity R_{Wa} = Apparent Water Resistivity $(Phi_T{}^m \times R_t)$ Phi_T = Total Porosity m = Cementation Exponent R_t = Formation Resistivity
Free Gas Porosity	Free Available Porosity $\times (1 - S_W)$

TRADITIONAL SHALE PETROPHYSICAL MODEL



FLOW DIAGRAM OF ANALYSIS



PETROPHYSICAL CALCULATIONS – ADSORBED GAS

The starting point of the analysis is the identification of organic rich shale sequences, contrasted with organic lean shales. Using the ΔR technique of Passey et al, a value of resistivity in organic lean rocks is chosen, and then equivalent choices are made for porosity log responses.

The second step is to calculate TOC values. Calibration to the specific reservoir is required by an appropriate choice of level of organic metamorphosis (LOM), which is directly related to vitrinite reflectance (Ro). The calibration is best achieved if sample measurements of TOC are available.

TOC can then be converted to volumes of adsorbed gas. For the Barnett Shale, the transform is:

Gas content, SCF per ton = 16 x TOC (wt%)

The multiplier (16) is probably reservoir specific, but there is little published data. For metric systems the gas content is converted to SCM per ton by dividing the above calculation by 35.3147 ft^3/m^3.

Adsorbed gas-in-place can then be calculated using the following equation:

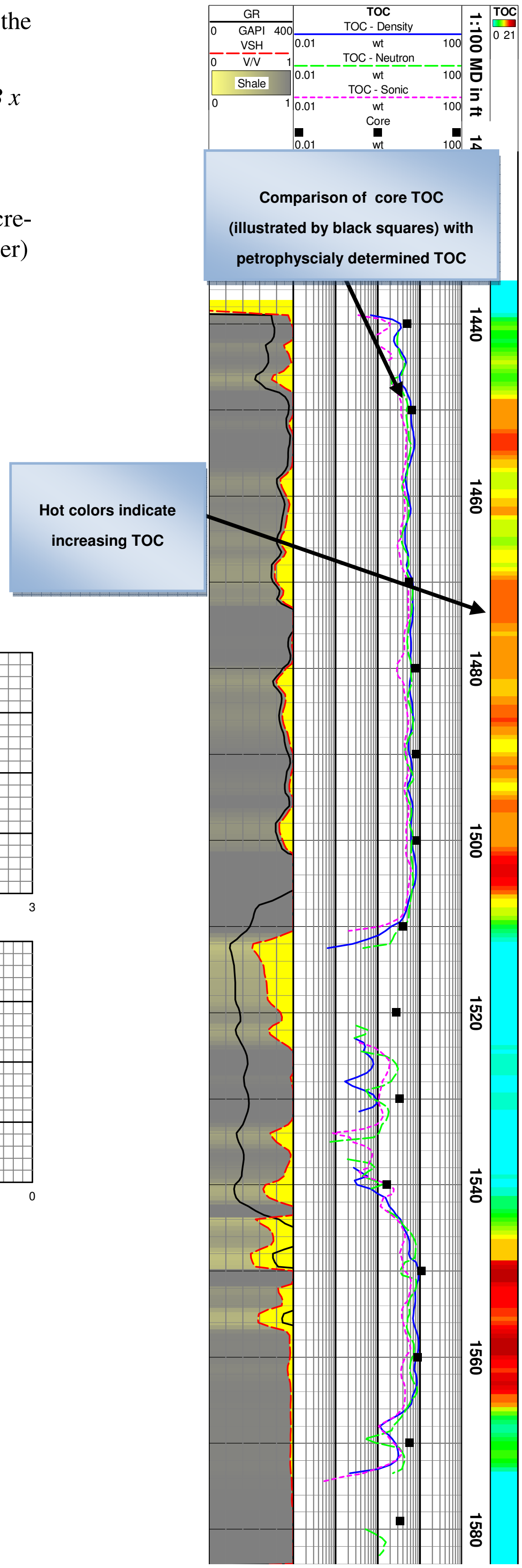
Adsorbed gas = Water Multiplier x Area x h x RhoB x Gas Content

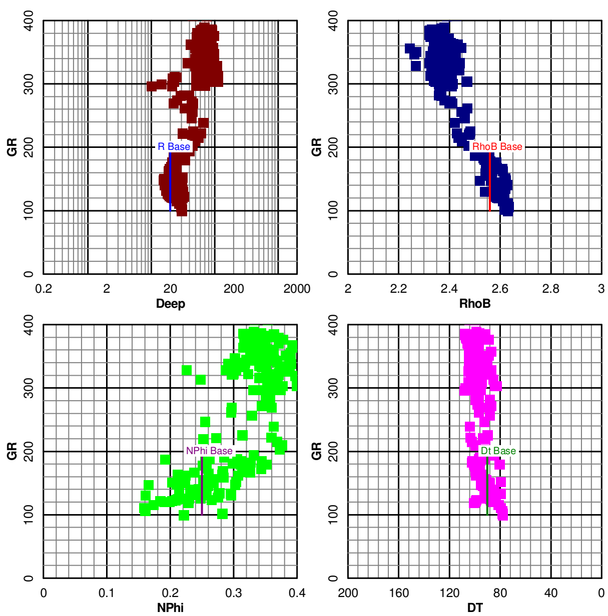
Units are MMCF (or MCM)

Water Multiplier = 1359.7 tons water per acre-foot (or 11,023.3 tons water per hectare-meter)

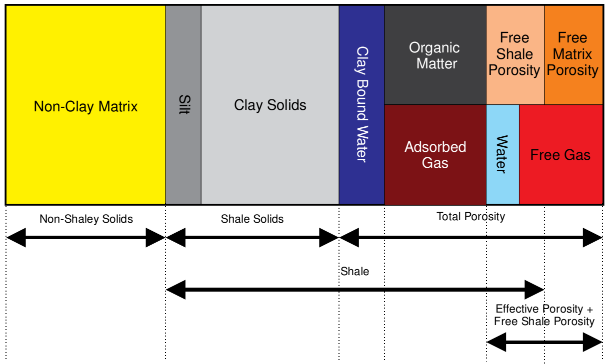
Area is measured in acres (or hectares)

h in feet (or meter) RhoB in gm/cc





MODIFID PETROPHYSICAL MODEL



PETROPHYSICAL CALCULATIONS – FREE GAS

Porosity that can be occupied by free gas in shales is of small to very small volumes. This can be supplemented by additional small volumes of effective porosity (Phi_E) in the non-shale fraction of the rock.

In the terminology used in this presentation:

Free Available Porosity = Phi_E + *Free Shale Porosity*

This Free Available Porosity has both gas and water as contained fluids

Free Gas Porosity = *Free Available Porosity x* $(1-S_W)$

The challenge is how to calculate the small volumes of free shale porosity. Phi_E is available using standard conventional reservoir analysis. Our approach is to segment the reservoir into a number of compartments, and then to determine petrophysical properties for each compartment. Our model currently uses only the density and neutron log combination, but we plan to add Pe responses in the near future. Compartments and their petrophysical characteristics are:

Component	Sub Set Components	Density Response	Neutron Response
Non-shale matrix	--	Matrix Density	~0
Shale	Solids: Silt	Silt Density	~0
	Solids: Clay Solids	?	?
	Fluids: Clay Water	1.0	1.0
	Fluids: Shale Porosity	?	?
Porosity	TOC	1.25	0
	Phi_E	1.0	0

At each level, volumes of the major components can be defined:

Component	Volume
Non Shale Matrix	$1 - V_{SH} - TOC - Phi_E$
Shale	V_{SH}
TOC	TOC
Phi_E	$Phi_T - V_{SH} \times Phi_{SH}$

Where:

Phi_T = Total Porosity (from a density/neutron cross plot)
Phi_{SH} = Density/neutron cross plot porosity reading in shale

Procedures are as follows:

1. Determine if there is gas in the porosity of the clean (non-shale) fraction, if the following criteria are met:

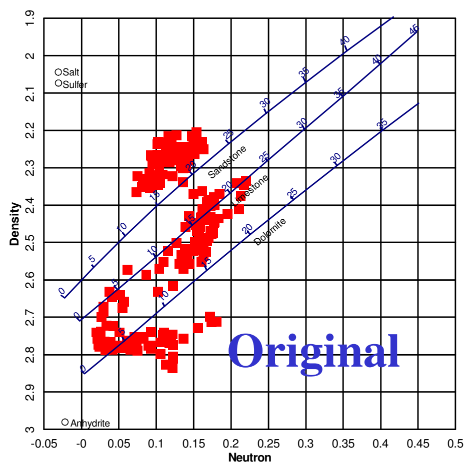
    a. Effective density porosity (Phi_{DE}) is greater than density/neutron cross plot (Phi_{DNE})

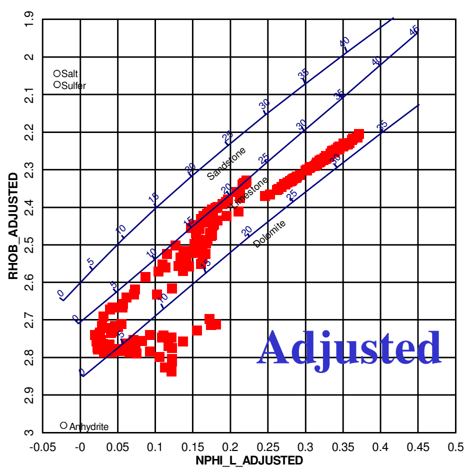
    b. Effective neutron porosity (Phi_{NE}) is less than density/neutron cross plot (Phi_{DNE})

    If differences do exist, adjust density and neutron porosities and recalculate RhoB and NPhi:

    $RhoB_{Adjusted}$ and $NPhi_{Adjusted}$

Example of the change for a gas reservoir:





For most shale gas plays, the adjustment is minimal.

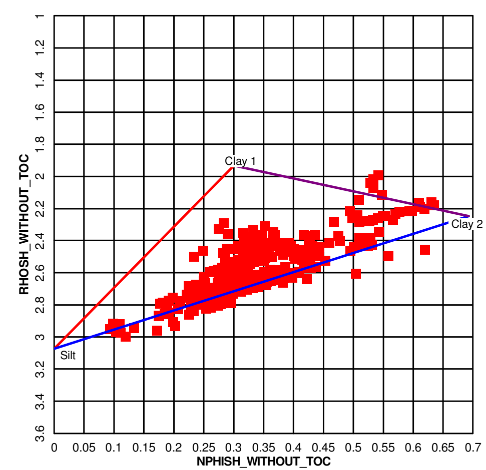
2. Run a standard shaley formation analysis to calculate effective porosity, Phi_E, and volume of shale, V_{SH}

3. From previously calculated values of TOC, convert from weight percent to volume percent:

    TOC, volume % = (RhoB/1.25 xTOC weight%

4. Solve for density and neutron responses in the shale fraction of the formation.

Example cross plot of Rho_{SH} vs. $NPhi_{SH}$ from the Antrim Shale of Michigan:



5. From the Rho_{SH} vs. $NPhi_{SH}$ cross plot shown above, choose the following three points to create an envelope encompassing the majority of the data, illustrated by the triangle:

    Silt, Clay 1, and Clay 2

    Then, choose Clay Porosity values appropriate to Clay 1 and Clay 2. These Clay Porosities refer to the amount of bound water associated with the clay minerals.

    For each of the three data points, determine:

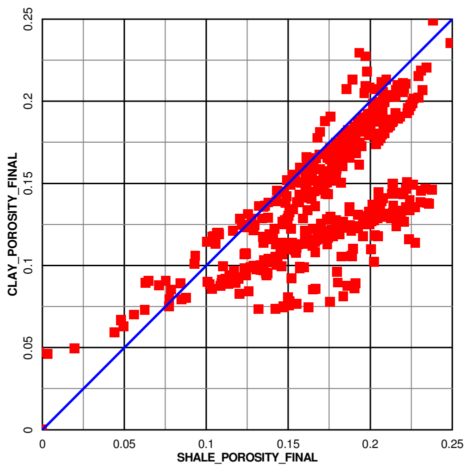
    - *% Silt, % Clay 1,* and *% Clay 2*
    - *Clay 1 Porosity contribution = % Clay 1 x Clay 1 Porosity*
    - *Clay 2 Porosity contribution = % Clay 2 x Clay 2 Porosity*
    - *Clay Porosity = Clay 1 Porosity contribution + Clay 2 Porosity contribution*

Calculate Shale Porosity from the Rho_{SH} vs. $NPhi_{SH}$ cross plot

Calculate Free Shale Porosity:

Free Shale Porosity = Shale Porosity – Clay Porosity

On a Shale Porosity vs. Clay Porosity cross plot, check that Shale Porosity is mostly equal to or greater than Clay Porosity:



If it is not, adjust choice of either Clay 1 Porosity or Clay 2 Porosity.

6. Add Free Shale Porosity to Phi_E, to yield Free Available Porosity. This is the porosity that is available for free gas. Compare with core porosity measurements if they exist. In the event of significant mismatch, edit and repeat item 5.

7. Calculate water saturation by empirical observation; the best calculation has been found by using a standard water resistivity approach:

$$S_W = (R_W/R_{Wa})^{0.5}$$

R_W = Water Resistivity

R_{Wa} = Apparent Water Resistivity (Phi_T^m x R_t)

Phi_T = standard calculation of total porosity

m = cementation exponent

R_t = formation resistivity

8. Calculate free gas porosity

Free Gas Porosity = Free Available Porosity x (1 – S_W*)*

9. Using appropriate gas formation volume factor, determine free gas-in-place

MECHANICAL PROPERTIES

If acoustic data are available, mechanical properties can be calculated using:

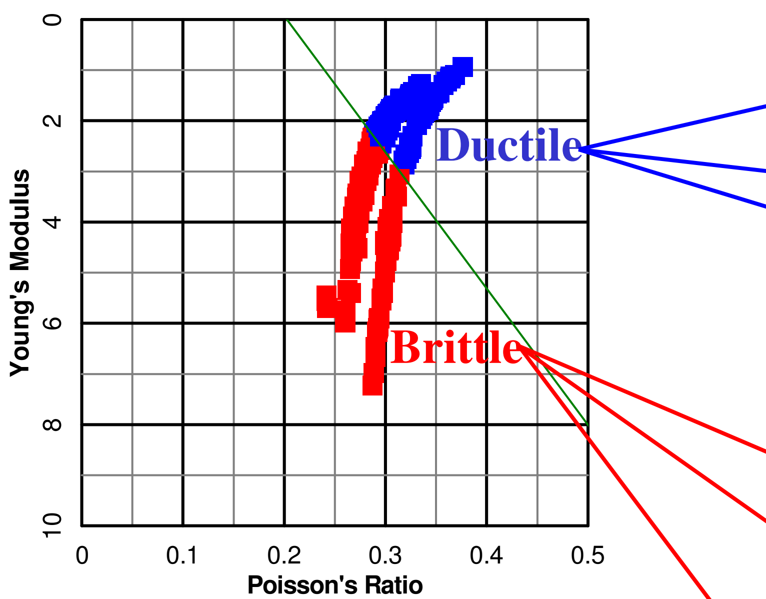
- Young's Modulus
- Bulk Modulus
- Shear Modulus
- Poisson's Ratio

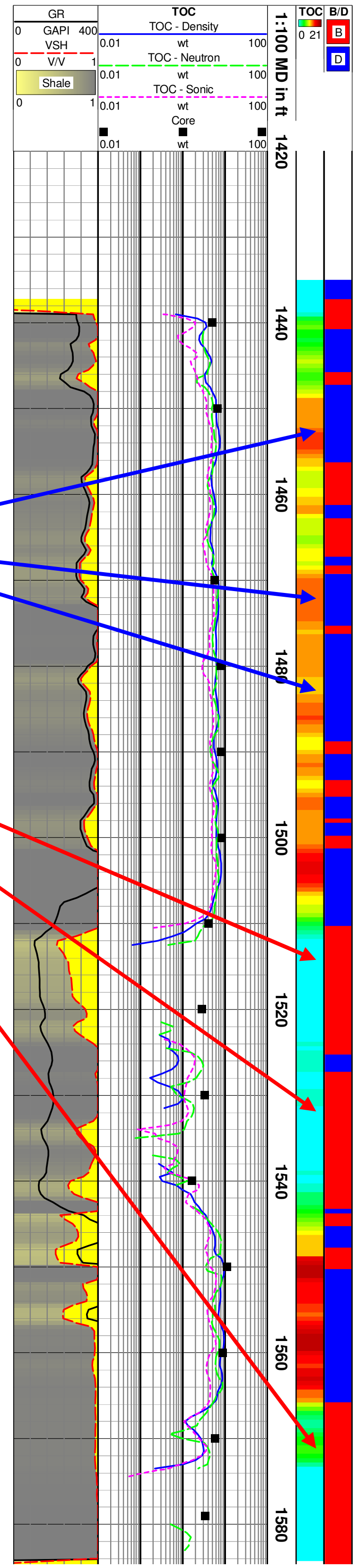
Curves required for these calculations are:

- Compressional Acoustic
- Shear Acoustic
- Density

If no shear data are available, reasonable estimates can be made through Rock Physics modeling. Using density and neutron as input, reconstruction of both pseudo compressional and pseudo shear data are possible. If there is convergence on measured compressional data, then it is reasonable to presume the shear pseudo curve is reliable.

Comparisons of Young's Modulus with Poisson's Ratio can be used to distinguish brittle from ductile rock. This distinction is valuable when completion intervals are chosen.

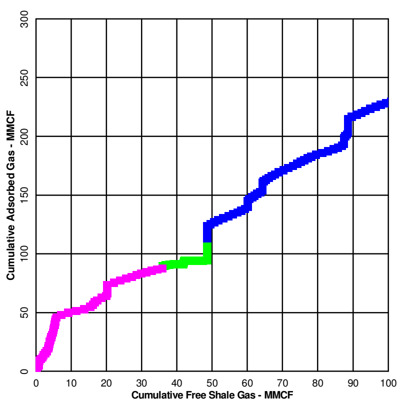


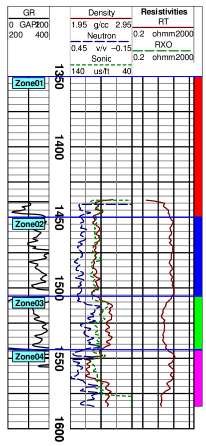


ADSORBED VS. FREE GAS

The distribution of Adsorbed vs. Free Gas can be shown by comparing cumulative values of the two entities. Since well productivity is influenced by both types of gas – free gas will tend to be produced more quickly than adsorbed gas – it is important to understand their relative abundance in the reservoir.

An example from the Antrim Shale, Michigan:





EXAMPLES

Data from two gas shale reservoirs are presented:

a. Antrim Shale, Michigan

b. Devonian Shale, Western Canada

Both wells have core pyrolysis measurements of TOC, and both core measurements include porosity, water saturation, grain density, and permeability.

Data interpretation includes

a. Standard analysis to calculate total and effective porosity, shale volume, and water saturation – the starting point for shale evaluation

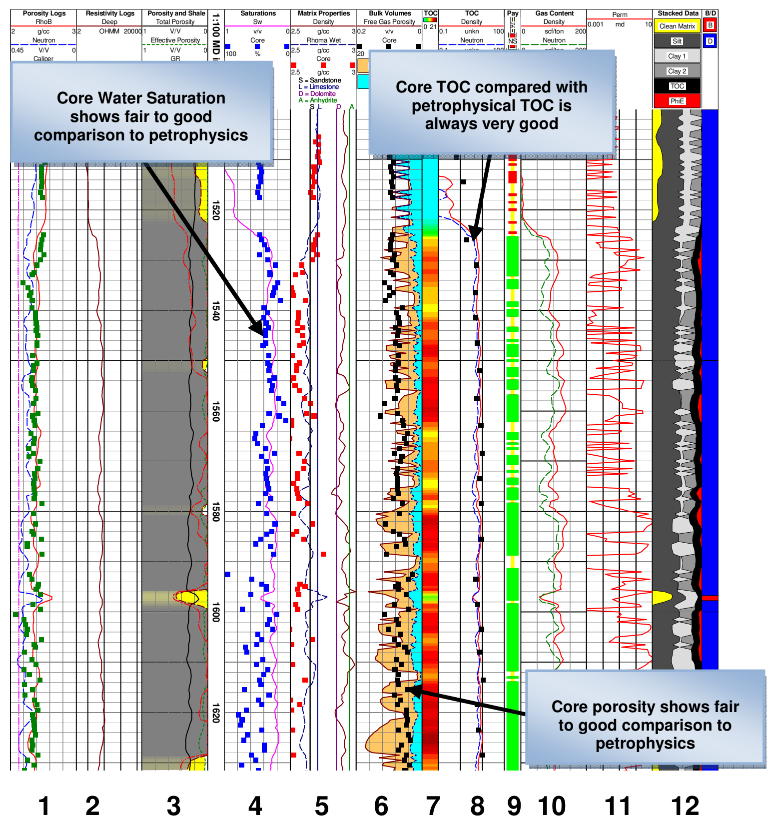
b. Petrophysical evaluation of TOC using the Passey et al technique

c. Shale analysis, to compute free shale porosity and associated water saturation

d. Component analysis, showing volumes of:

Non-Shale matrix
Silt
Dry clay
Clay bound water
Free water in shale porosity
Gas in shale porosity
TOC expressed as a volume

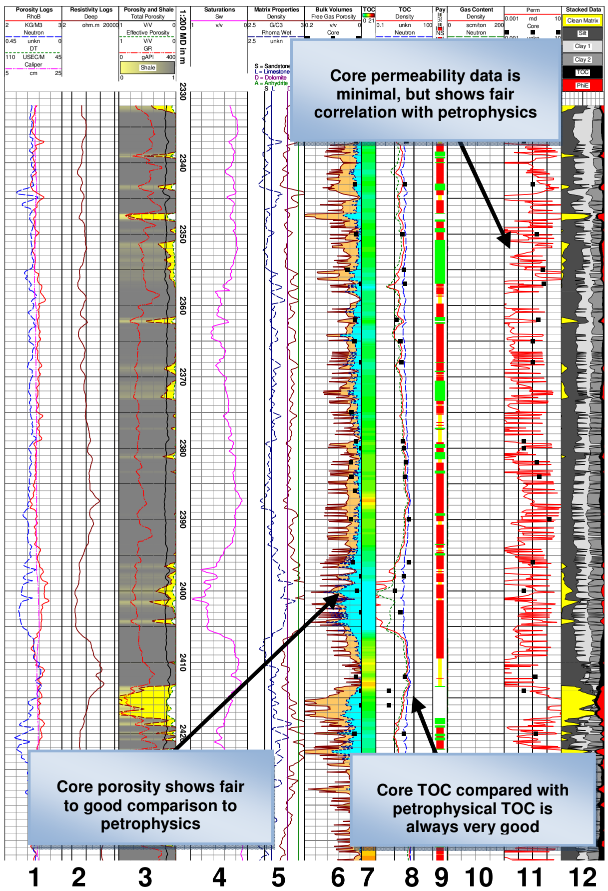
Example from the Antrim Shale, Michigan – note comparisons of core measurements (illustrated by symbols) with petrophysical calculations:



Track descriptions are as follows:

1: Raw Data – GR and Porosity logs
2: Raw Data – Resistivity
3: Bulk Volumes – shale, porosity, matrix
4: Water Saturation
5: Grain Density – wet and dry
6: Fluids in Free Available Porosity
7: Level of TOC – hot colors indicate high TOC
8: TOC from Passey et al
9: Net Pay
10: Adsorbed gas content
11: Permeability
12: Component Analysis

Example from Devonian Shale, Western Canada:



See previous example for track descriptions.

CONCLUSIONS

The methodology requires a standard suite of open hole logs:

Density
Neutron
GR
Resistivity
Acoustic – desirable but not essential
Pe – desirable but not essential

Adsorbed gas volumes are available from the straight forward technique of Passey et al.

Free shale gas porosity – i.e. porosity available to contain free (not adsorbed) gas – is determined by logical distinction of reservoir components built into the system and checks for impossible results due to unrealistic input.

If core data are available, additional fine-tuning of procedures is possible. However, the system does not require core data to run. Clearly, it is helpful to have knowledge of the reservoir sequence. Probably the most important piece of information is the likely range of TOC. Knowing the clay mineral species assemblage helps in the interpretation of the shale log responses.

Comparison of free gas volumes with adsorbed gas volumes will help in deciding which intervals to complete.

If acoustic data are available, or can be estimated from Rock Physics modeling, mechanical properties comparisons can be used to distinguish ductile from brittle rocks. This data is again helpful in deciding when to complete.

REFERENCES

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