A Petrophysical Model for Shale Reservoirs to Distinguish Macro Porosity, Free Shale Porosity, and TOC

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Abstract

A petrophysical model is presented whereby a number of shale reservoir components, both solids and porosity, can be identified. Input data are standard open-hole logs to include density, neutron, gamma ray, and resistivity.

The starting point is a standard shaley formation analysis to identify total and effective porosity, shale volume, and fluid saturations in the effective porosity fraction of the rock. A second task is to determine total organic carbon (TOC) content. The procedures used in this model are those of Passey et al, 1990, and include calibration to core measurements, if available.

Using the data from the initial analyses, detailed examination of the shale fraction of the rock can then be undertaken. First, density and neutron log responses are reduced to the shale only fraction, by subtracting contribution from matrix, effective porosity, and TOC. Then, by using a density/neutron cross plot of the shale only fraction, three points are chosen by the interpreter recognizing shale solids, clay species 1, and clay species 2. Once the three points have been chosen, it is possible to recognize the volumetric contribution of shale solids and the two clay components. The bulk density and neutron porosity properties of the two clay points are used to define porosity of the clays, which is assumed to be water filled. The cross plot porosity of the shale contains both clay porosity and free shale porosity, and the free shale porosity must always be greater than or equal to clay porosity. If this relationship is not honored (i.e. clay porosity greater than shale porosity), adjustments need to be made with respect to the log choices of shale solids, clay 1, and clay 2. Finally, free porosity in the shale is available by subtracting clay porosity from cross plot shale porosity.

A volumetric balance of the porosity components – effective porosity, clay porosity, free shale porosity, and TOC – is compared with total cross plot porosity, to ensure the model accounts for all porosity elements correctly. Comparisons are now possible among macro porosity (effective porosity), micro porosity (free shale porosity), and TOC.

Introduction

Conventional reservoirs are routinely 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 reservoirs is in its infancy. Procedures applicable to conventional reservoirs cannot be applied, and new approaches need to be developed. This paper describes the deterministic methodologies used in shale reservoirs to quantify four porosity components using standard triple combo open-hole logs:

1. Effective porosity - PHi_E
2. Clay porosity - Phi_{Clay}
3. Free shale porosity - Phi_{SH}
4. Total organic carbon - TOC

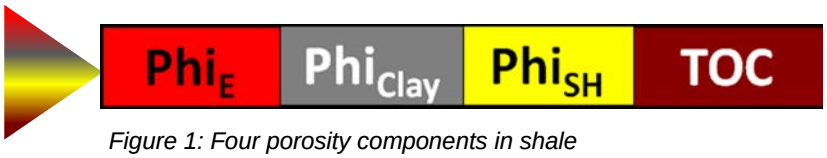


Figure 1: Four porosity components in shale

Figure 2 and Figure 3 compare the traditional petrophysical model for shale reservoirs with the proposed model.

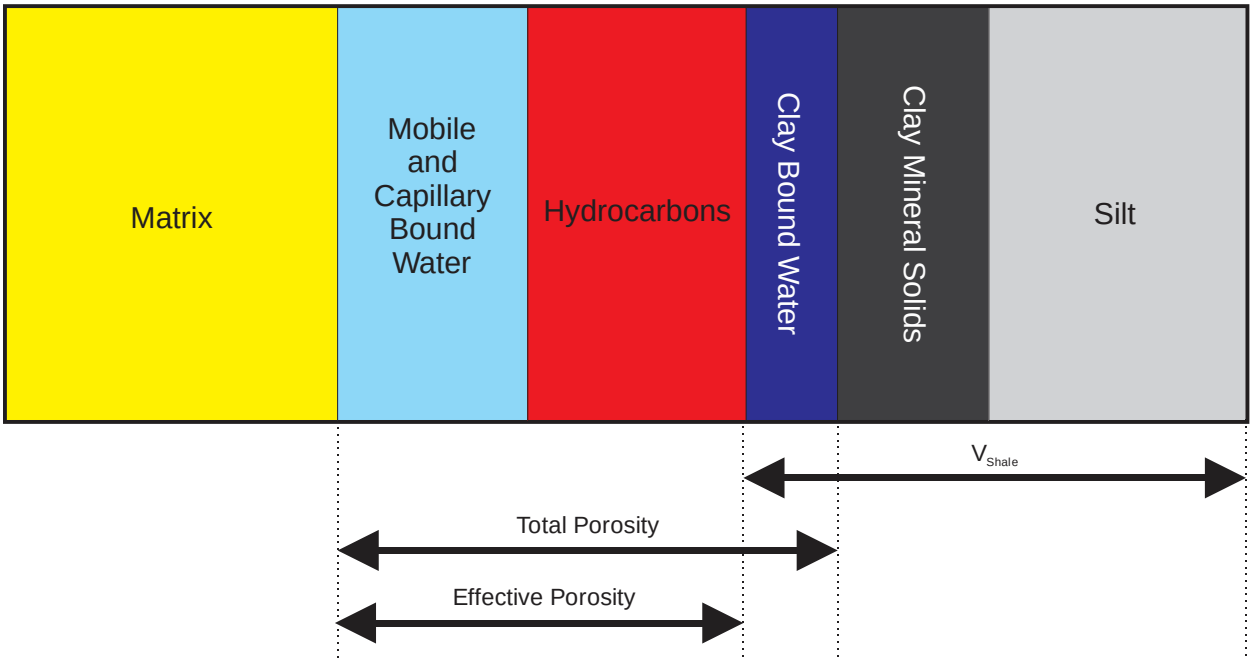


Figure 2: Traditional petrophysical model for shale reservoirs

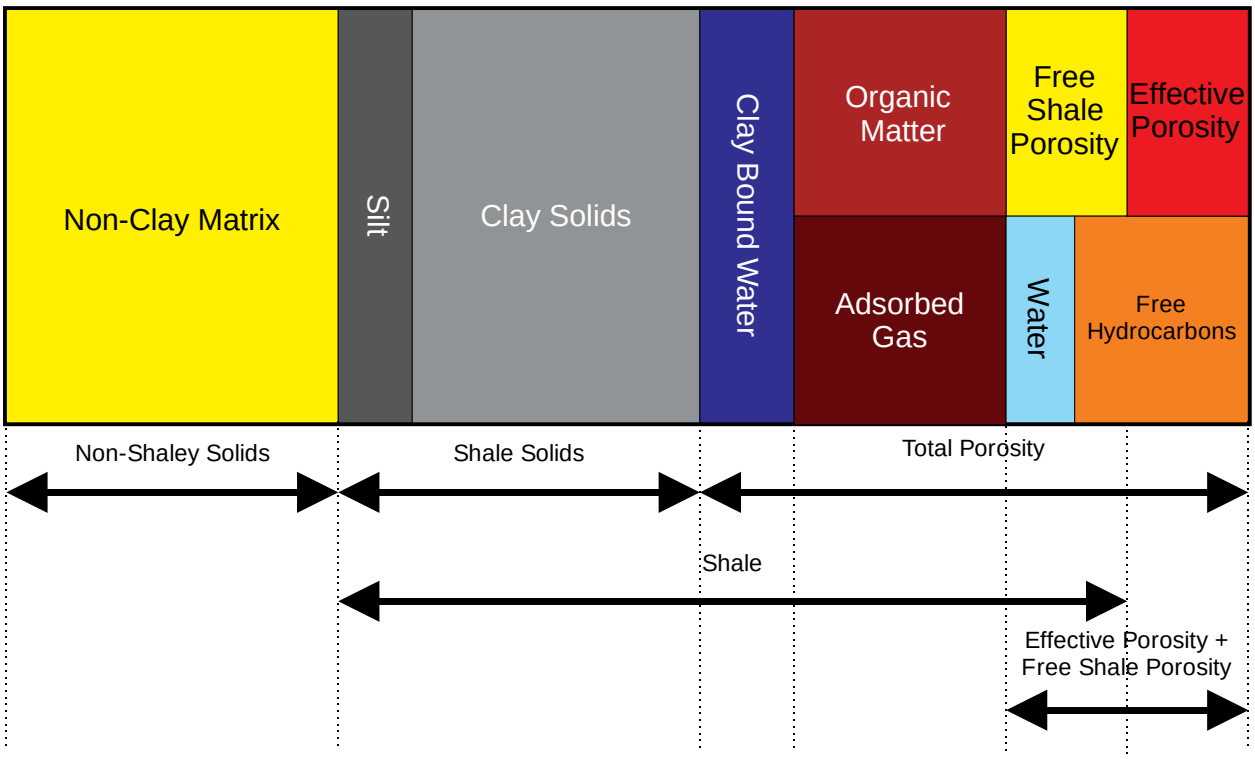


Figure 2: Proposed modified petrophysical model for shale reservoirs

Methodolology

To begin, perform a standard petrophysical analysis in order to define the input data required for the shale analysis – total and effective porosity (Phi_T and Phi_E), shale volume (V_{SH}), and matrix volume (V_{MA}). From these calculations, total organic carbon (TOC) volume can be determined using the Passey et al (1990) technique. In addition, calculate effective water saturation (S_{we}) from a shaley formation model.

Next, detailed analysis of density and neutron responses is carried out for each component of the shaley formation. Hydrocarbon effects (oil separate from gas) are accounted for since they influence the non-clay fraction of the rock. TOC is converted from weight percent to volume percent. Changing density and neutron responses of TOC can be accommodated.

Appropriate density and neutron responses for V_{MA}, Phi_E, and TOC are subtracted from the raw data, level-by-level. These values are then divided by V_{SH} to allow correct comparisons on a shale only density (Rho_{SH}) vs. neutron ($NPhi_{SH}$) cross plot. The Rho_{SH} and $NPhi_{SH}$ responses incorporate shale fractions of the rock (less TOC) scaled up to 100%.

From the Rho_{SH} vs. $NPhi_{SH}$ cross plot, three points are chosen – shale solids (at zero $NPhi_{SH}$) and two clay points. When the three points are connected, they should encompass the high V_{SH} data points (Figure 3). Frequently, points with low V_{SH} show large degrees of scatter, which is likely a consequence of slight inaccuracies in the absolute values of V_{SH}.

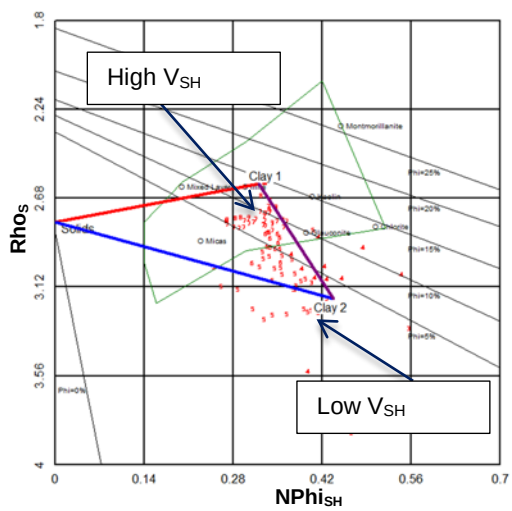


Figure 4: $NPhi_{SH}$ vs. Rho_{SH}

For each of the three data points chosen, determine percent shale solids, percent clay 1, percent clay 2. Using the cross plot porosity overlay, calculate:

- Clay 1 porosity contribution = % Clay 1 x Clay 1 Porosity
- Clay 2 porosity contribution = % Clay 2 x Clay 2 Porosity
- Total Clay porosity = Clay 1 porosity contribution + Clay 2 porosity contribution

Then, calculate shale porosity less TOC (Phi_{SH}) and final clay porosity (Phi_{Clay}):

- $Phi_{SH} = Phi_T – Phi_E$ – TOC volume
- Phi_{Clay} = total clay porosity x V_{SH}

At this point, the data can be validated or adjusted if needed. On a cross plot, compare Phi_{SH} vs. Phi_{Clay} (Figure 4), shale porosity must always be equal to or greater than final clay porosity. If it is not, the following adjustments should be made:

- Adjust the shale solids, clay 1, and clay 2 endpoints
- Verify the TOC values used
- Adjust density and neutron responses of TOC used to convert TOC in weight percent to volume percent

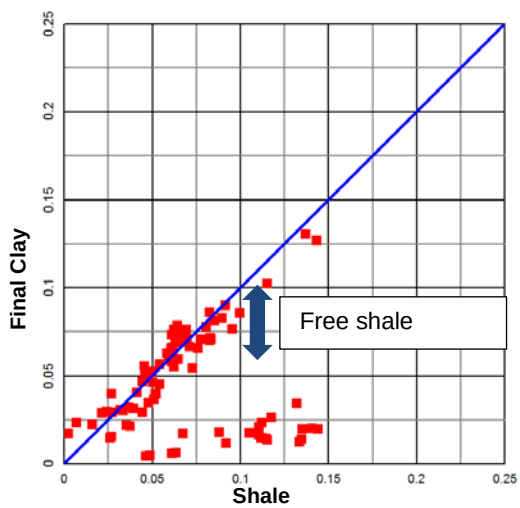


Figure 5: Phi_{SH} vs. Phi_{Clay}

Free shale porosity can then be calculated by subtracting the final clay porosity from shale porosity: Add free shale porosity to Phi_E to determine free available porosity. Bulk volume of water and hydrocarbon saturation in the free available porosity fraction of the rock can be calculated as follows:

- Bulk volume water = Free Available Porosity × S_{we}
- Bulk volume hydrocarbons = Free Available Porosity × $(1-S_{we})$

The final output recognizes the four porosity components:

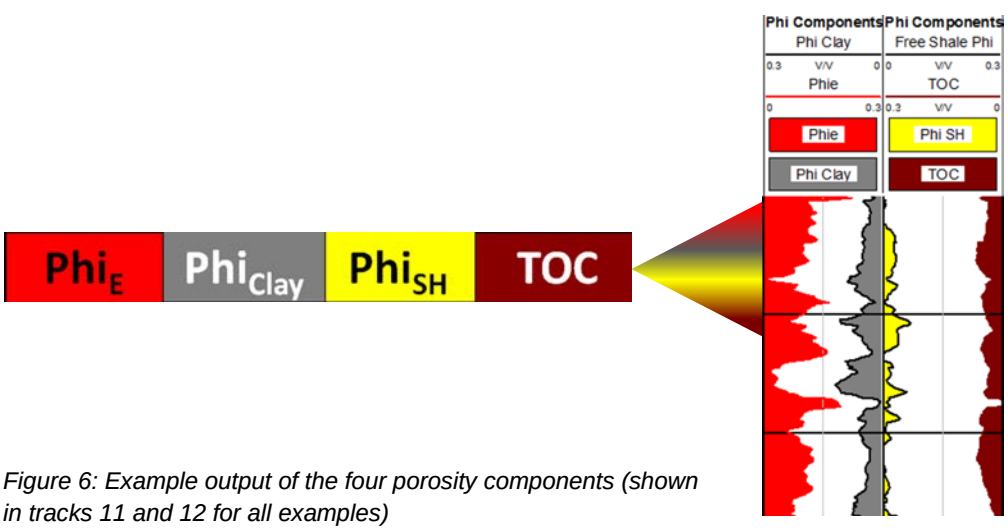


Figure 6: Example output of the four porosity components (shown in tracks 11 and 12 for all examples)

At this point, the porosity calculations can easily be verified and validated. To do this, calculate the sum of the porosity elements to create a total reconstructed porosity curve. The total reconstructed porosity curve can then be compared with the original Phi_T curve (Figure 7). Color fill between the curves indicate a mismatch. If there is a great deal of disagreement between the two curves, adjustments of the shale solids, clay 1, and clay 2 points should be made.

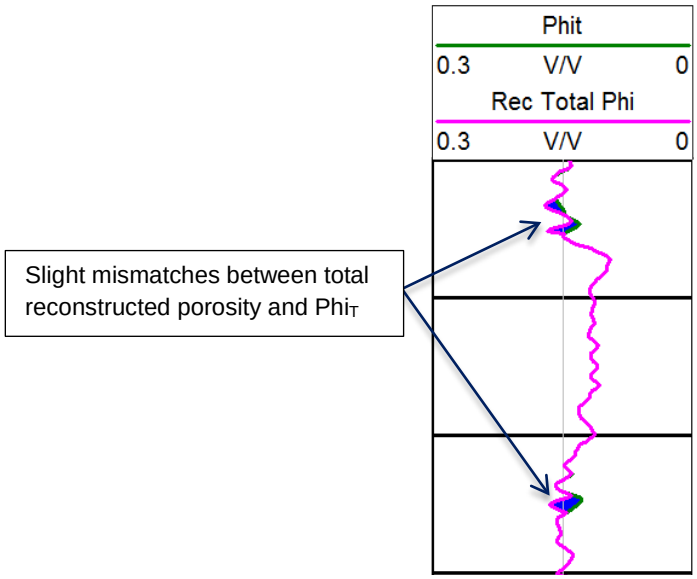
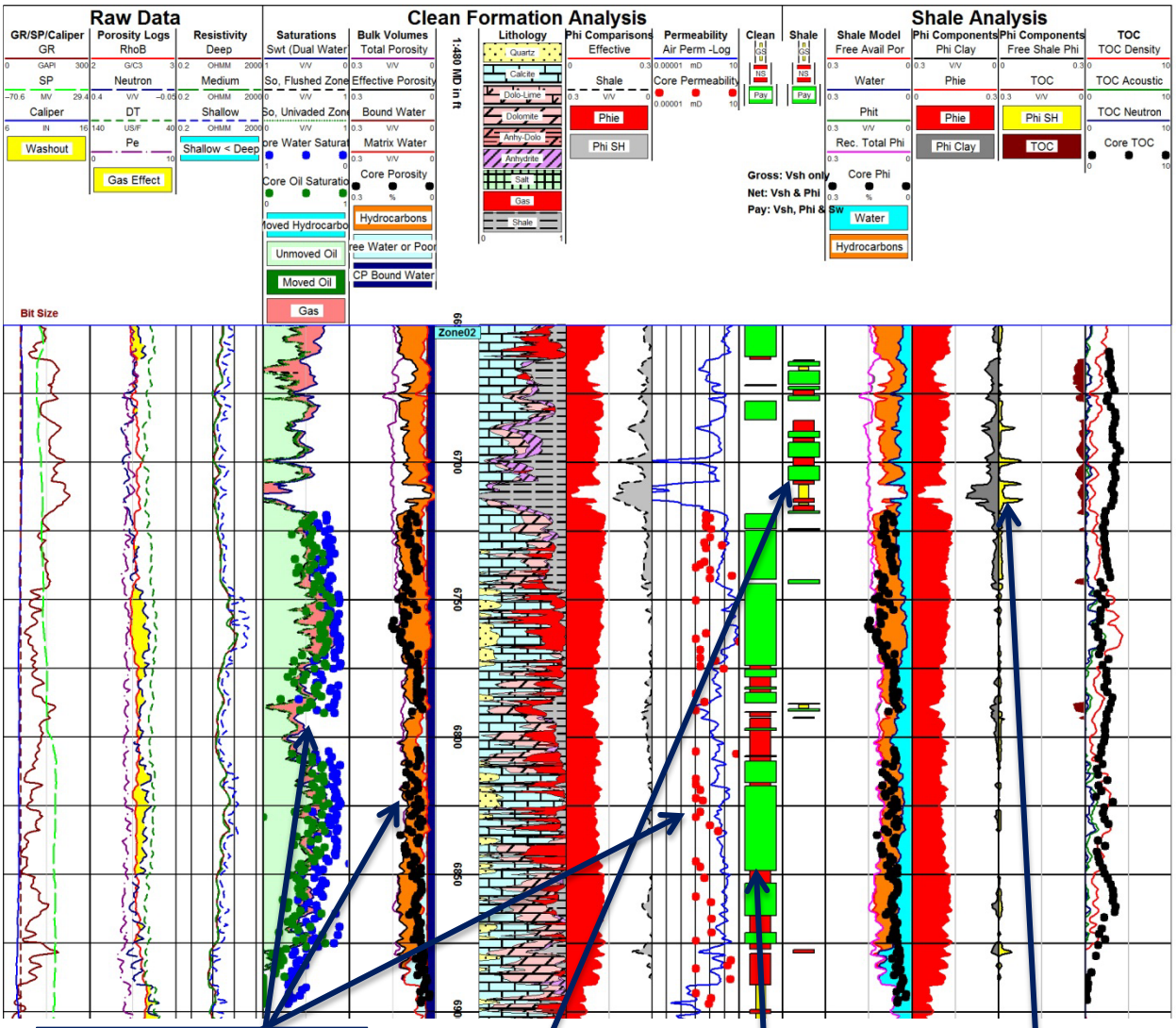


Figure 7: Total reconstructed porosity vs. Phi_T (shown in track 10 for all examples)

Examples

Both gas and oil bearing reservoirs are included. For all examples, a standard template is used to present the data, which displays both the clean and shale analysis. See Appendix 1 for a detailed description of the data displayed on the template.

Example 1 – Niobrara, Colorado Oil



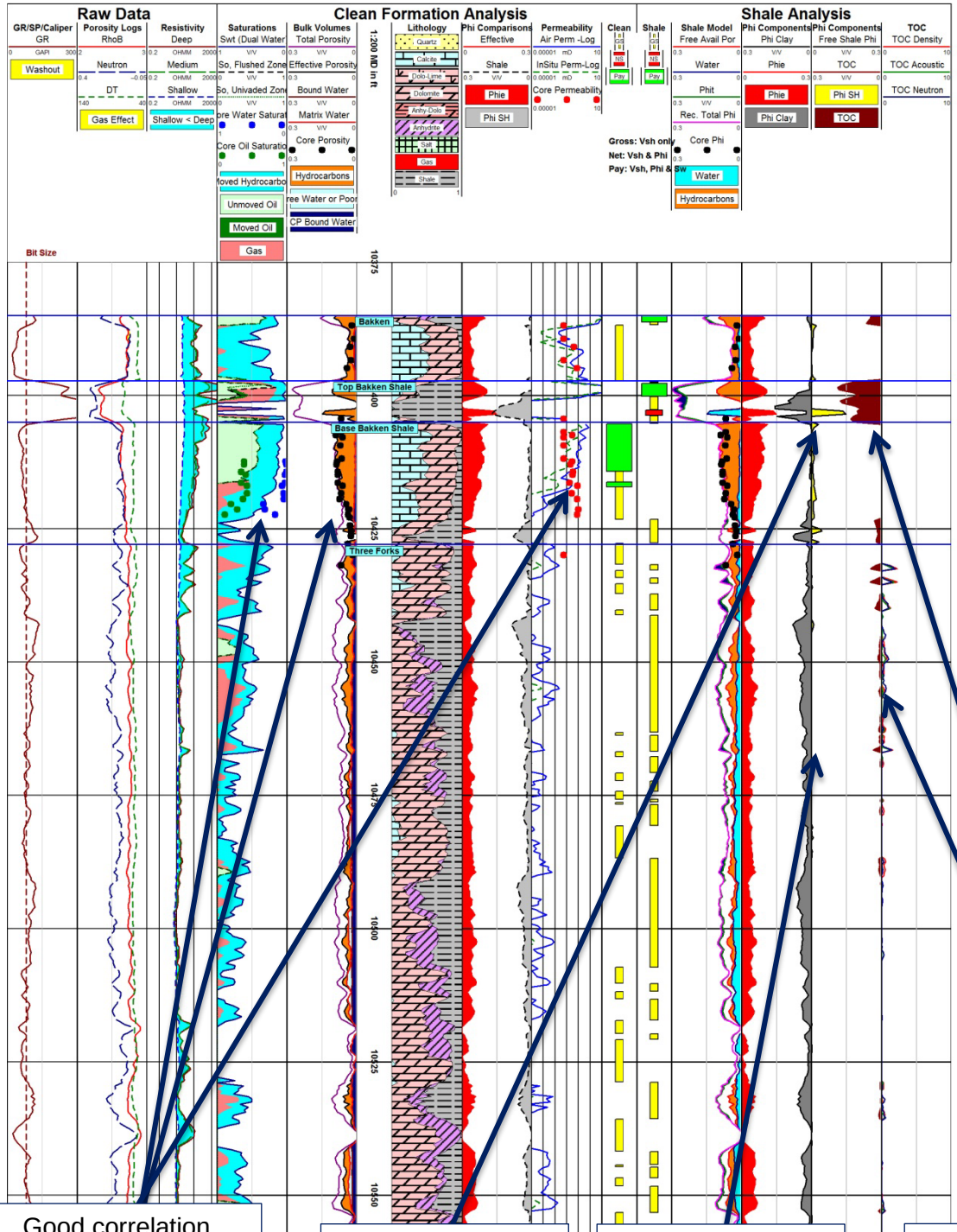
Good correlation between core and log calculated TOC, porosity, S_o, S_w, and permeability

Additional shale resources

Principal resource target

Small amounts of free shale porosity

Example 2 – Bakken, Montana Oil



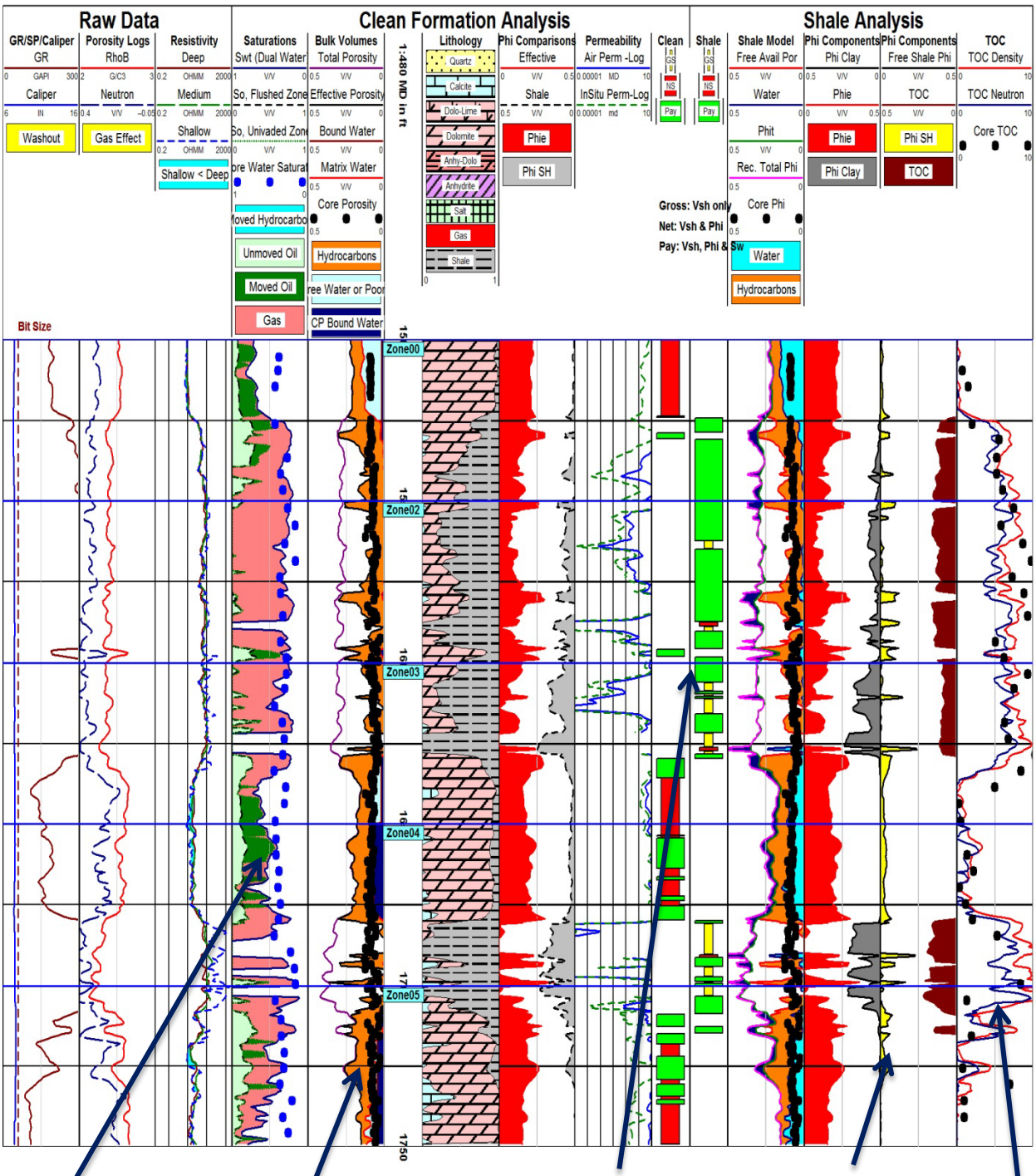
Good correlation between core and log calculated porosity, S_o, S_w, and permeability

Small amounts of free shale porosity in the Upper Bakken Shale

No free shale porosity in the Three Forks interval

Much lower TOC in the Three Forks as compared with the Bakken Shale

Example 3 – Antrim, Michigan Gas



Good correlation between core and log calculated S_w

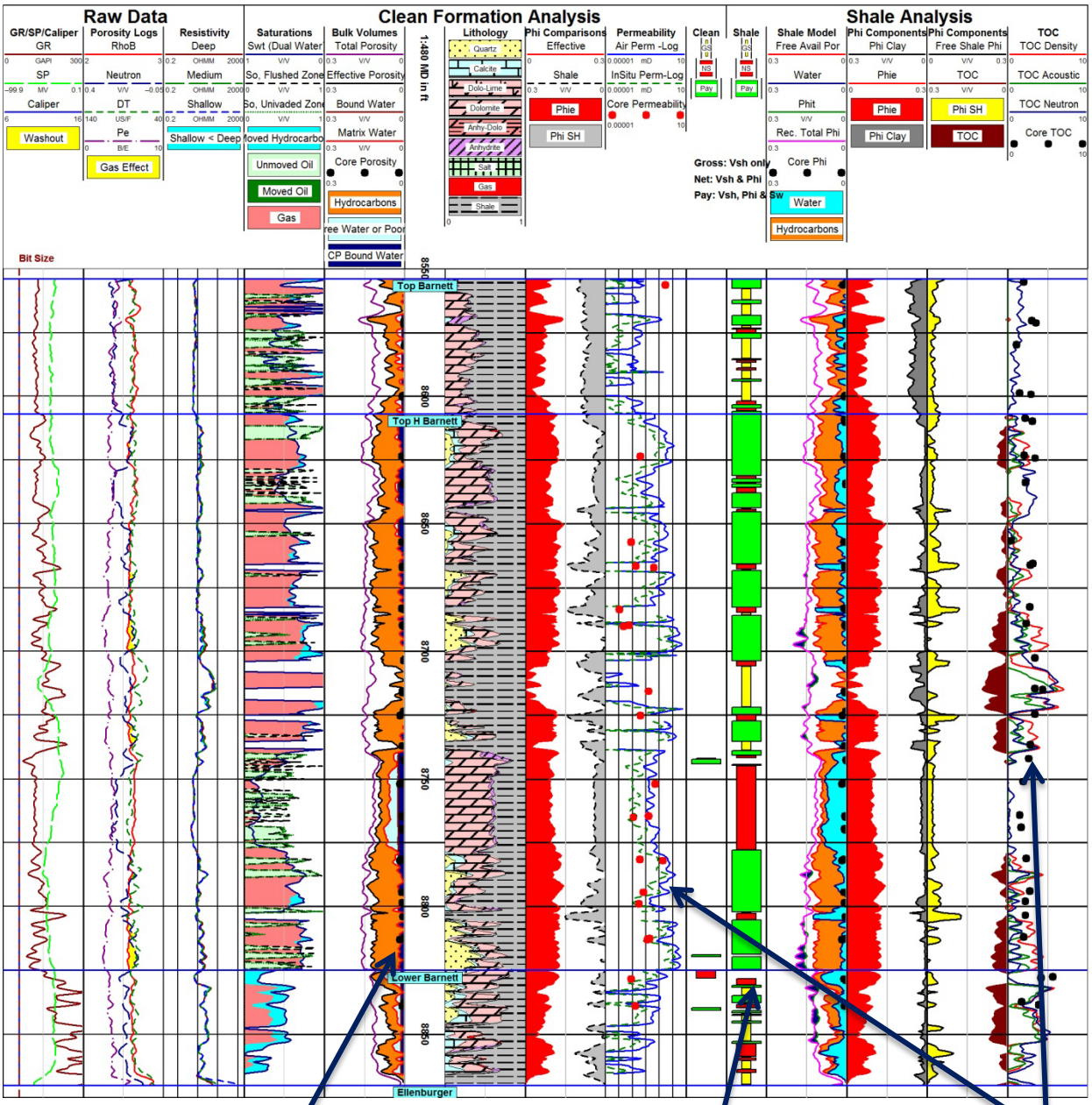
Core porosity much lower than log calculated porosity

Most of the gas resources reside in the shale fraction

Free shale porosity development is erratic

Excellent correlation between core and log calculated TOC

Example 4 – Barnett, Texas Gas

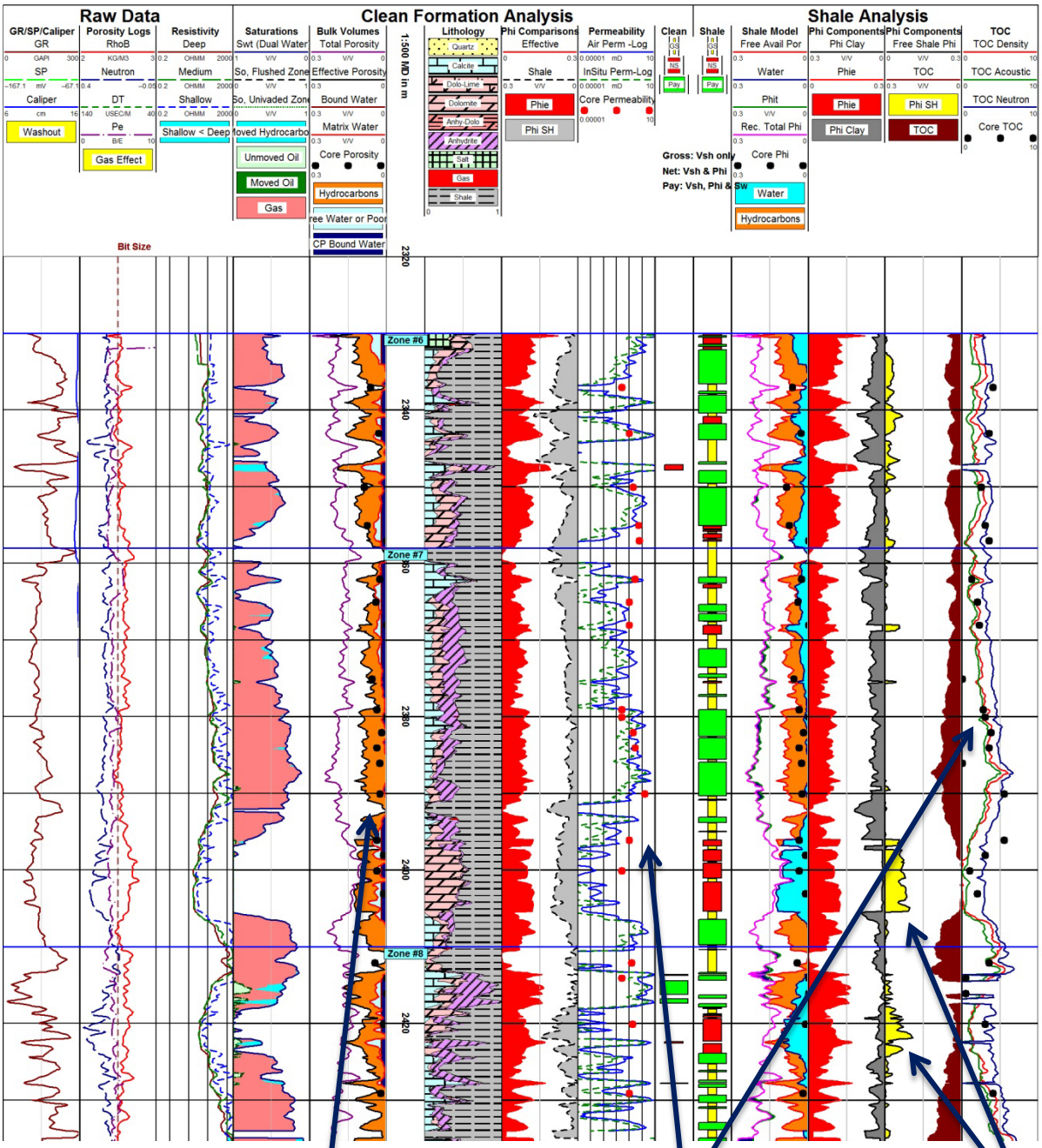


Core porosity much lower than log calculated porosity

Most resource in the shale fraction

Fair to good correlation between core and log calculated TOC and permeability

Example 5 – Devonian, Western Canada Gas



Core porosity frequently lower than log calculated porosity

Very good correlation between core and log calculated TOC and permeability

High values of free shale porosity seen throughout the interval

Summary and Conclusions

A deterministic technique to quantify porosity components in shaley formations, using standard triple-combo open-hole log data is presented:

The free shale porosity, which is usually only a small percentage of total porosity, will contribute to the overall resource base of free hydrocarbons and may be a measure of micro fractures.

Comparisons of petrophysical results with core measurements are useful to validate the methodology. However, it has been found that for many wells drilled prior to when unconventional core measurements were refined, core measured porosity is often less than log-derived porosity.

Addition of a quantitative definition of "free available porosity", the sum of effective and free shale porosity, is a measure of in-place hydrocarbons in the shaley fraction of the rock. Contribution to recoverable hydrocarbons is likely to be quite small, although in-place volumes are very high.
Both oil and gas adsorbed hydrocarbons which reside in the TOC fraction of the rock can also be quantified.

Nomenclature

$NPhi_{SH}$ – Neutron log response for the shale only fraction

Phi_{Clay} – Final clay porosity: total clay porosity x V_{SH}

Phi_E – Effective porosity

Phi_{SH} – Free shale porosity: Phi_T – Phi_E – TOC volume

Phi_T – Total porosity from clean formation analysis

Rho_{SH} – Density log response for the shale only fraction

S_{we} – Effective water saturation calculated from a shaley formation model

TOC – Total organic carbon

V_{MA} – Matrix volume

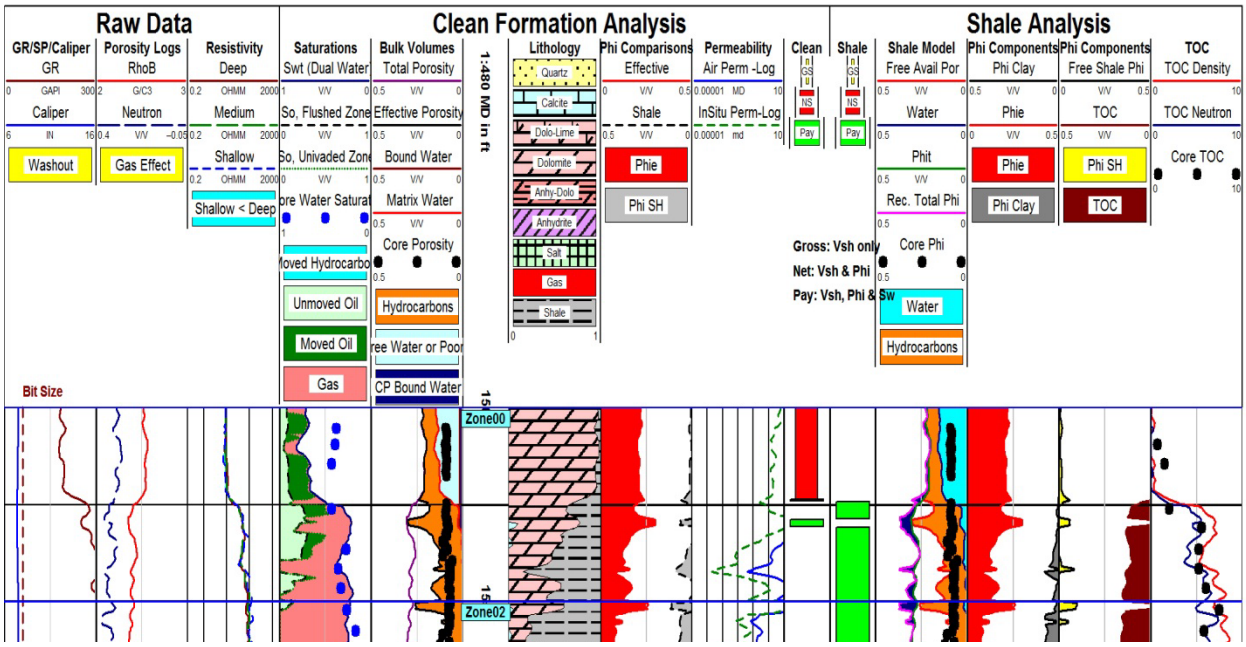
V_{SH} – Volume shale from clean formation analysis

References

1. Passey, Q.R., S. Creaney, J. B. Kulla, F. J. Moretti, and J. D. Stroud, 1990, A Practical Model for Organic Richness from Porosity and Resistivity Logs, AAPG Bulletin V. 74, No. 12, p. 1777-1794.
2. Denver Well Logging Society, 2008 Spring Workshop, Special Core Analyses
3. Denver Well Logging Society, 2010 Fall Workshop, Shale Petrophysics
4. Passey, Q.R., K.M. Bohacs, W.L. Esch, R. Klimentidis, and S. Sinha, ExxonMobil Upstream Research Co, 2010, From Oil-Prone Source Rock to Gas-Producing Shale Reservoir – Geologic and Petrophysical Characterization of Unconventional Shale-Gas Reservoirs, SPE 131350

Appendix 1

Description of data displayed in output template. All core data is illustrated by color filled dots.



Track #: 1 2 3 4 5 6 7 8 9 10 11 12 13

Data Type	Track #	Description of data displayed
Raw Data	1	Raw data: GR, SP, Caliper
	2	Raw data: Porosity logs – RhoB, neutron, DT, Pe
	3	Raw data: Resistivity – deep, medium, shallow
Clean Formation Analysis	4	Fluid analysis
	5	Bulk fluid volumes
	6	Log-calculated lithology
	7	Comparison of effective porosity (red) vs. shale porosity (grey)
	8	Permeability
Clean vs. Shale	9	Comparison of reservoir net pay (green) clean formation analysis vs. shale analysis
Shale Analysis	10	Bulk fluid volumes
	11	Phi_E and Phi_{Clay}
	12	Phi_{SH} and TOC volume
	13	TOC, weight %