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"A New Petrophysical Model to Define Porosity Components of Unconventional Reservoirs, Using Standard Open-hole Triple Combo Logs"

Michael Holmes, Dominic Holmes and Antony Holmes of Digital Formation

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Abstract

Unconventional reservoirs are composed of several types of porosity/hydrocarbon components – standard effective porosity, clay porosity, total organic carbon (TOC), and micro porosity associated with shales. Adsorbed hydrocarbons reside in the TOC component and "free" hydrocarbons in the effective porosity and shale micro porosity. An accurate definition of all these components is essential in defining the reservoir hydrocarbon resource volume.

TOC has a density response close to porosity and indeterminate neutron response. The log responses are probably related to the degree of thermal maturity.

Previous publications (Holmes, et al. 2011 and 2012) were earlier attempts to define these porosity components. This publication is a significant refinement, whereby TOC and clay log responses are determined using an iterative technique. An initial estimate of TOC properties (density vs. neutron) is subtracted from raw logs to derive a "TOC-free" log response. Then clay log responses are defined by subtracting matrix, effective porosity, and silt contributions. The resulting density/neutron cross plot is then compared with known clay mineral responses to determine if estimates of the various component log responses are reasonable. If not, these responses are adjusted and the procedure is repeated. A final check of the methodology is to calculate a reconstructed porosity, which is effective porosity + clay porosity + shale micro porosity, and see if it agrees with total porosity determined from the "TOC-free" reservoir model.

Examples of unconventional reservoirs – both gas and oil bearing – are presented.

Introduction

Before the advent of petrophysical evaluation of unconventional reservoirs the reservoir model was simplistic as shown in **Fig. 1.** When the importance of unconventional reservoirs became apparent, it was realized that a much more complex petrophysical model was required. Of prime importance is the dominant role of total organic carbon (TOC) in organic rich shale.

Also, recognition of the different hydrocarbons in shale is crucial to the understanding of their behavior when the reservoir is produced. Most of the hydrocarbons in the TOC fraction of the rock are adsorbed onto the rock surface. These hydrocarbons will only be produced – if at all - later in the life of the reservoir, when pressure has been significantly reduced. However, there are small volumes of free porosity within the shale – here termed "free shale porosity" - which contains conventionally mobile hydrocarbons. This is shown in **Fig. 2.**

The theme of this paper is to quantify the volumes of these two hydrocarbon components using standard triple-combo well log data.

Statement of Theory and Definition

A geometrical rock model is shown in **Fig. 3.** The components can be summarized as shown in **table 1.**
Free shale porosity is usually a small volume (often less than 5% of the total rock volume) and is probably associated with TOC. It is believed to contain free hydrocarbons and formation water.

From careful analysis of triple-combo data, combined with core analysis, if available, reasonable volumetric estimates of each of the components is possible. Core data, although extremely valuable for calibration, is not essential in the analytic process.

Emphasis is placed on quantifying the four porosity components Phi_e, Phi_{Clay}, Phi_{SH}, and TOC. This is demonstrated in **Fig. 4.**

Description and Application of Petrophysical Procedures

A rigorous sequence of calculations is required.

a) Calculate TOC weight percent from technique of Passey et al (1990) and Schmoker (1989)

Compare with core data if available. If no core TOC analysis are available for calibration, care must be exercised in application of a reasonable volume for level of organic metamorphism (Passey et al technique) which is a measure of thermal maturity, and is correlated with vitrinire reflectance (R_O).

Our approach is to identify organic-lean shales, which have low resistivities, and identify equivalent porosity log response. TOC from all 3 porosity logs (if all are available), is then automatically recognized. See **Fig. 5.**

b) Convert TOC weight percent to volume fraction conversion

TOC components have densities ranging from 1.25 to 1.8 gm/cc, depending on organic maturity. We have the capability of applying any value of grain density to make sure this conversion is consistent with the other components analyzed.

c) Make standard petrophysical calculations of total porosity (Phi_t), shale volume (V_{SH}) and effective porosity (Phi_e)

Our preferred approach is to calculate Phi_t from a density and neutron cross plot. This minimizes errors from changing grain density, and fluid components.

d) Subtract From the Density and Neutron Responses the Contribution of:

Matrix
TOC
Effective Porosity

To determine density and neutron responses of the shale only (less TOC) fraction of the rock. Cross plot porosity volumes of this shale only fraction are:

Clay Porosity
Free Shale Porosity

Examples of a shale-only cross plot is shown on Fig. 6.
The procedure has the added advantage of identifying the likely clay mineral make-up of the rock.

e) Calculate Free Shale Porosity As

Free shale porosity = $Phi_t - Phi_e - Phi_{Clay}$ ……………………………………………………….………….............(1)

Obviously negative images of free shale porosity cannot exist. If calculations indeed show negative values, the problem could be:
Incorrect $Phit$ and/or Phi_e, due to erratic log response or an inappropriate V_{SH} model
Incorrect calculations converting TOC from weight percent to volume percent.

f) Determine free available porosity

$Free\ Available\ Porosity = Phi_e + Free\ Shale\ Porosity$ ……………………………..………………….……….(2)

A comparison of Phi_e with free available porosity is helpful in verifying calculation integrity-clearly free available porosity must be greater or equal to Phi_e. See **Fig. 7.**

g) Calculations of Free vs. Adsorbed Hydrocarbon

Free hydrocarbon volumes are calculated using standard technique with the appropriate formation volume factors. Adsorbed hydrocarbons can be estimated using empirical relations:

For Gas:

$$Adsorbed\ G.I.P. = 1359.7 \times Area \times Thickness \times RhoB \times (16 \times TOC) \quad (3)$$

For Oil:

$$Adsorbed\ O.I.P. = S2 \times 0.001 \times RhoB \times h \times Area \times 7758 \quad (4)$$

S2 is the estimated volume of hydrocarbons generated by thermal cracking mg/g rock
An example is shown on a modified Lorenz plot (comparison of calculated values of each component) **Fig.7.**

Presentation of Data and Results

Example Unconventional Oil and Gas – Description of Output Data **Fig. 9.**

Examples are presented as follows

Niobrara Oil Reservoir – Colorado **Fig. 10a and 10b.**
Bakken Oil Reservoir – Montana **Fig. 11.**
Shale Gas Reservoir – Western Canada **Fig. 12.**
Barnett Shale Gas Reservoir – Texas **Fig. 13.**
Antrim Shale Gas Reservoir – Michigan **Fig. 14.**

Conclusion

A petrophysical methodology using standard triple-combo well logs has been developed to quantify both free and adsorbed hydrocarbons volumes in unconventional reservoirs. A key element of the model is the recognition of four porosity components:

Standard Effective Porosity
Clay Porosity
TOC Porosity
Free Shale Porosity

The last component is whatever the mismatch is between the sum of the prior 3 components and total porosity. The model should be calibrated to core whenever possible, but does not require core input. Output from the model quantifies the spatial distribution of free and adsorbed hydrocarbon in both clean and shale fractions of the reservoir sequence. An ancillary benefit of the model is an estimate of clay mineral species within the shale fraction.

Nomenclature

Phi_t = Total porosity
Phi_e = Effective porosity
V_{SH} = Shale volume
$RhoB$ = Density
$NPhi$ = Neutron porosity
$RhoB\_shale$ = Density contribution from shale formation
$NPhi\_Shale$ = Neutron contribution from shale formation
Phi_{Clay} = Clay porosity
Phi_{FS} = Free shale porosity
TOC = Total Organic Carbon
$S2$ = Estimated volumes of hydrocarbons generated by thermal cracking mg/g rock
Phi_{FA} = Free Available Porosity = $Phi_e + Phi_{FS}$
S_W = Water Saturation

References

Michael Holmes, Antony Holmes, and Dominic Holmes "A Petrophysicial Model to Estimate Free Gas in Organic Shales", Presented at the AAPG Annual Convention and Exhibition, Houston Texas, 10-13 April, 2011.

Michael Holmes, Antony Holmes, and Dominic Holmes "A Petrophysical Model for Shale Reservoirs to Distinguish Macro Porosity, Micro Porosity, and TOC", Presented at the 2012 AAPG ACE, Long Beach, California, April 22-25.

James W. Schmoker "Use of Formation-Density Logs to Determine Organic-Carbon Content in Devonian Shales of the Western Appalachian Basin and an Additional Example Based on the Bakken Formation of the Williston Basin".

Q.R. Passey, S. Creaney, J.B. Kulla, F.J. Moretti, and J.D. Stroud "A Practical Model for Organic Richness from Porosity and Resistivity Logs".

Tables

Component	Fluid Content
Non Shale Matrix (quartz, calcite, etc.)	None
Silt (quartz, calcite, etc.)	None
Clay Solids	Water
Total Organic Carbon (TOC)	Adsorbed Hydrocarbons + ?Water
Free Shale Porosity	Free Hydrocarbons + Water
Effective Porosity	Free Hydrocarbons + Water

Table 1, Summarized components of a geometrical rock model

Figures

Figure 1, Simplistic reservoir model

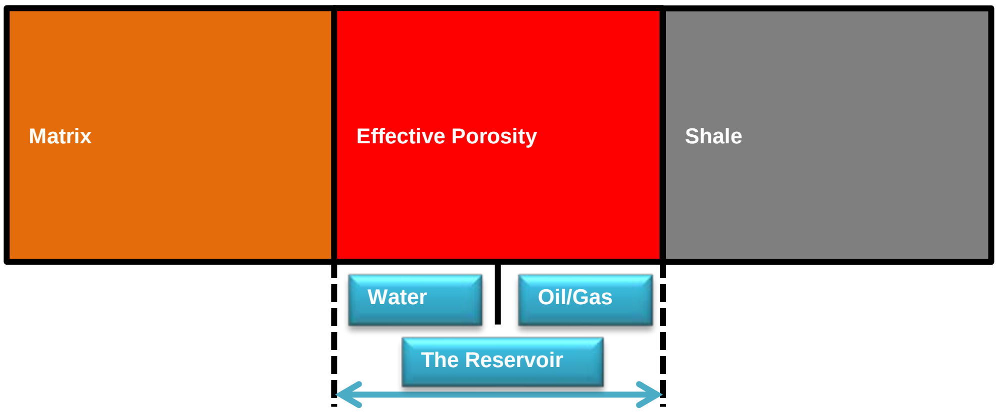


Figure 2, Shale hydrocarbons by types

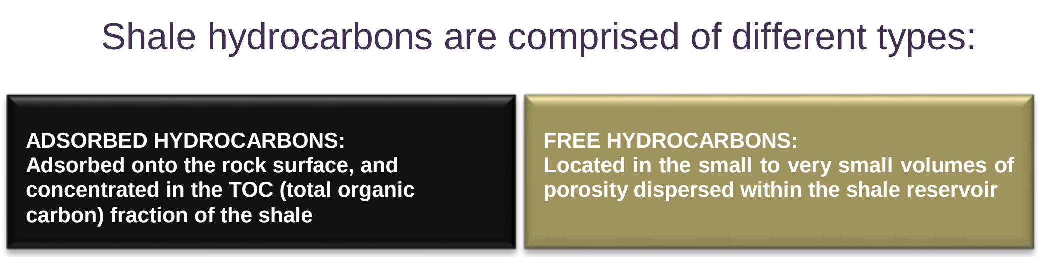


Figure 3, A geometrical rock model

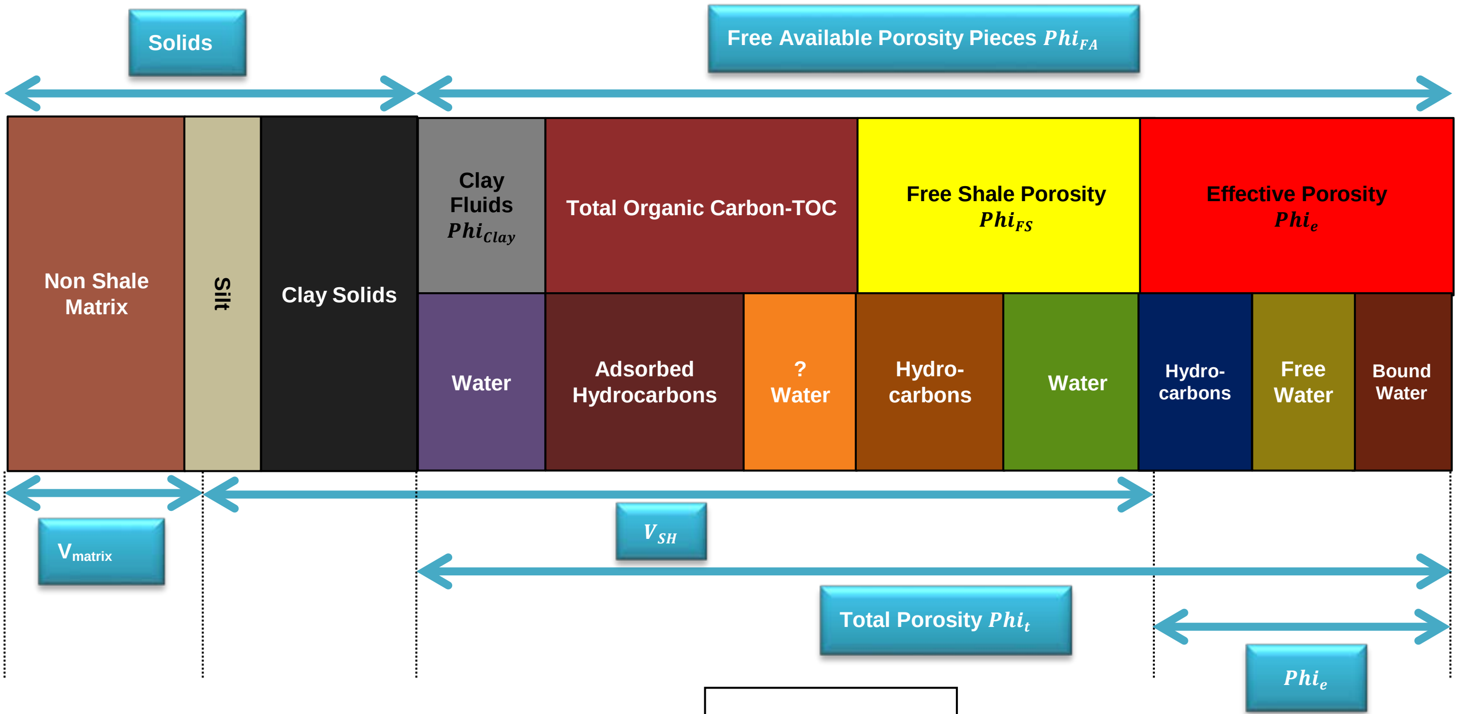
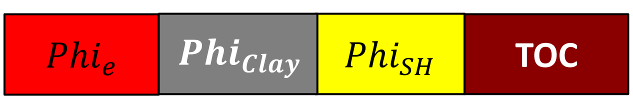


Figure 4, Four porosity components



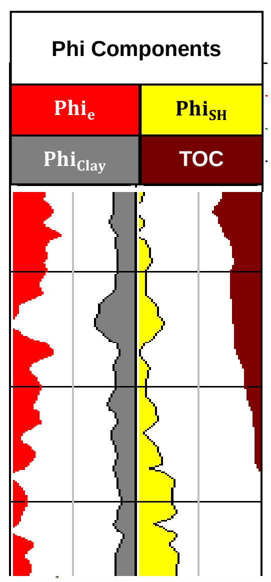


Figure 5, Comparison of core TOC

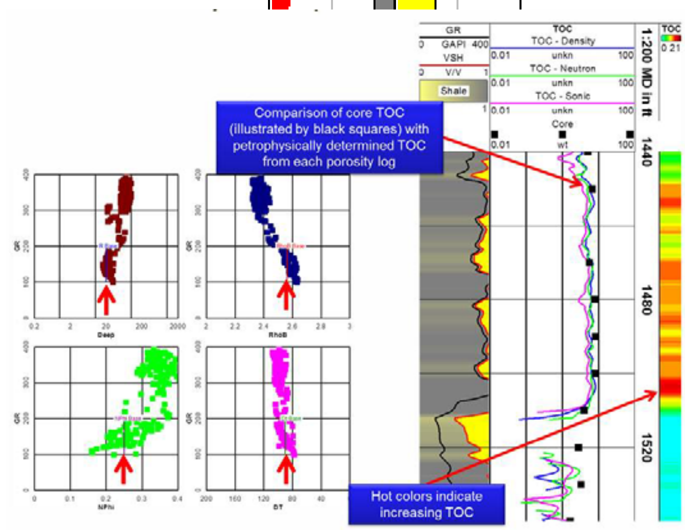


Figure 6, Shale-only cross plot

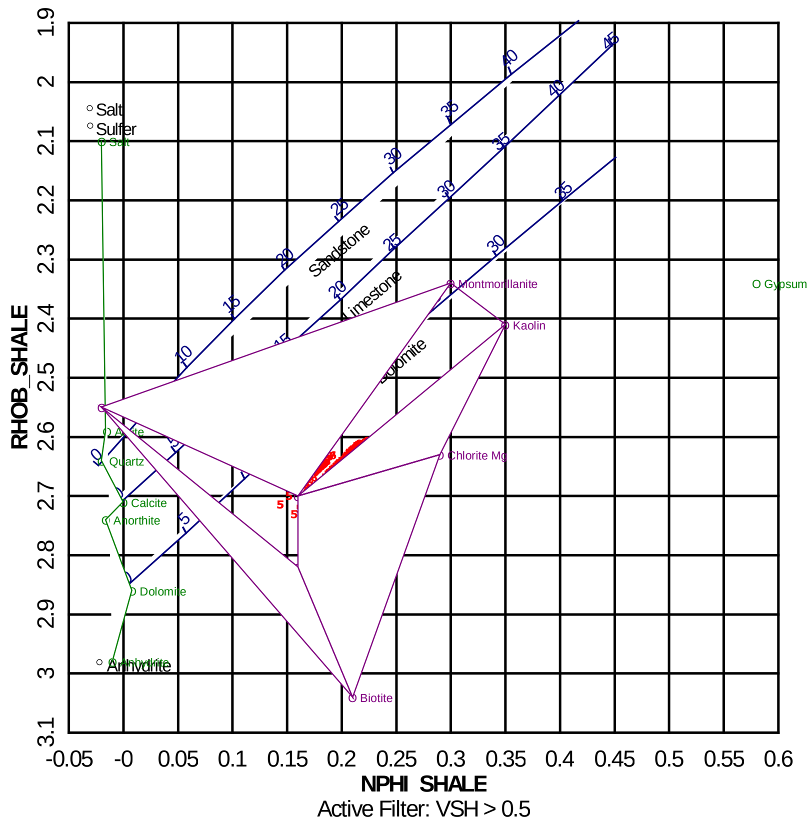


Figure 7, A comparison of Phi_e with free available porosity

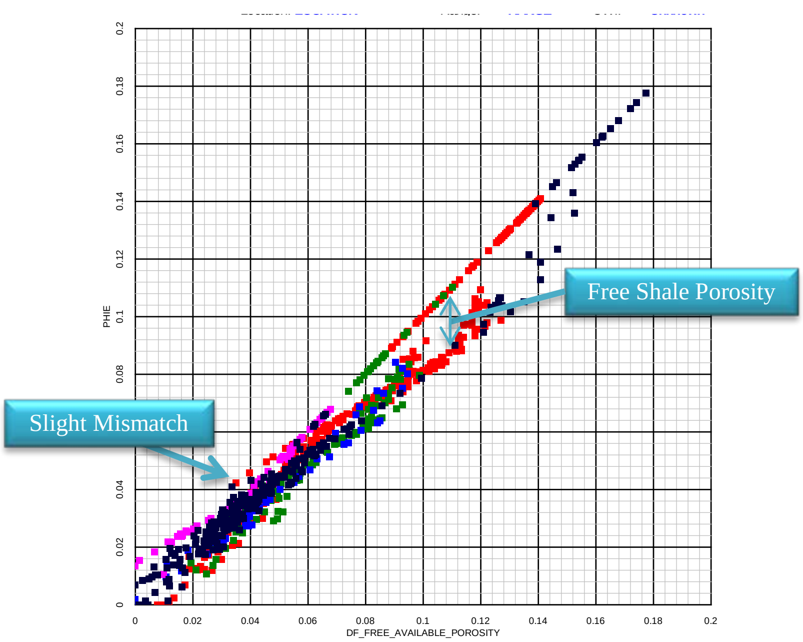


Figure 8, A modified Lorenz plot (comparison of calculated values of each component)

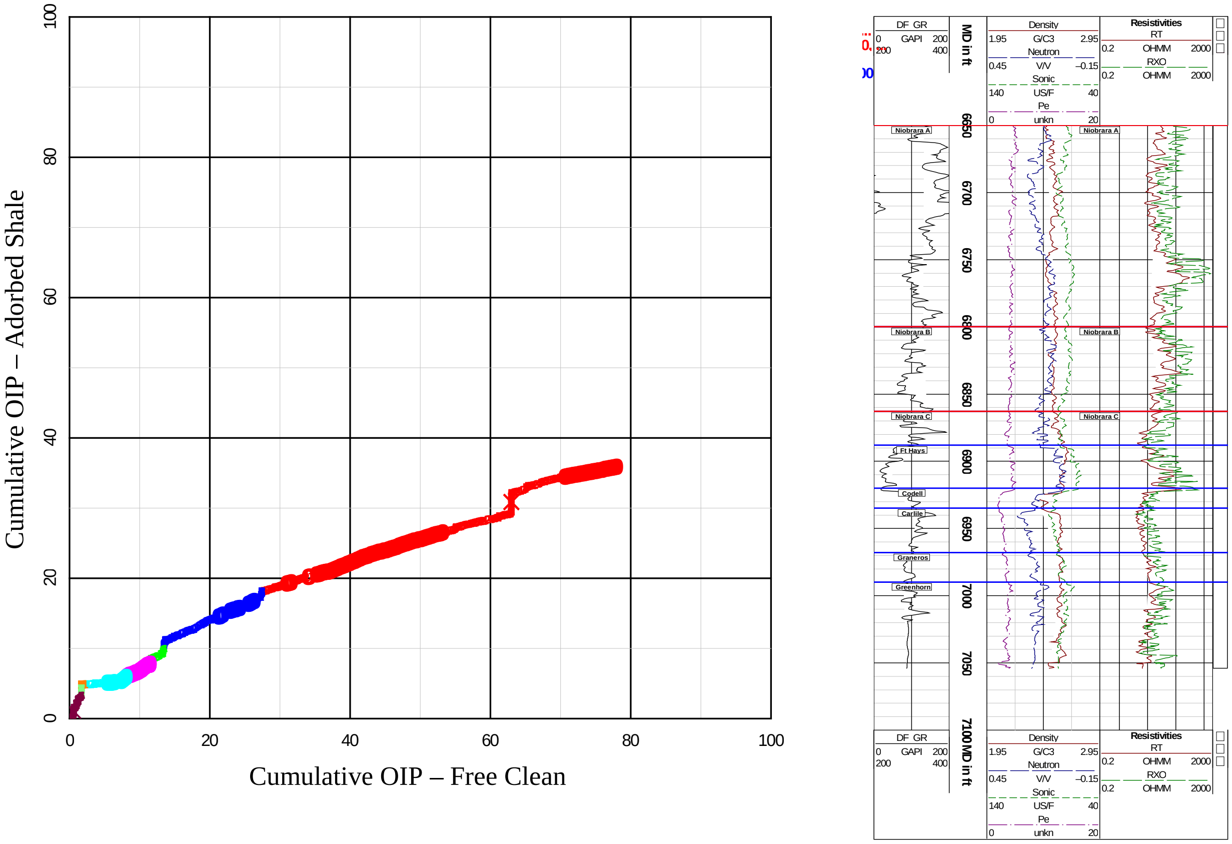


Figure 9, Unconventional Oil and Gas – Description of Output Data

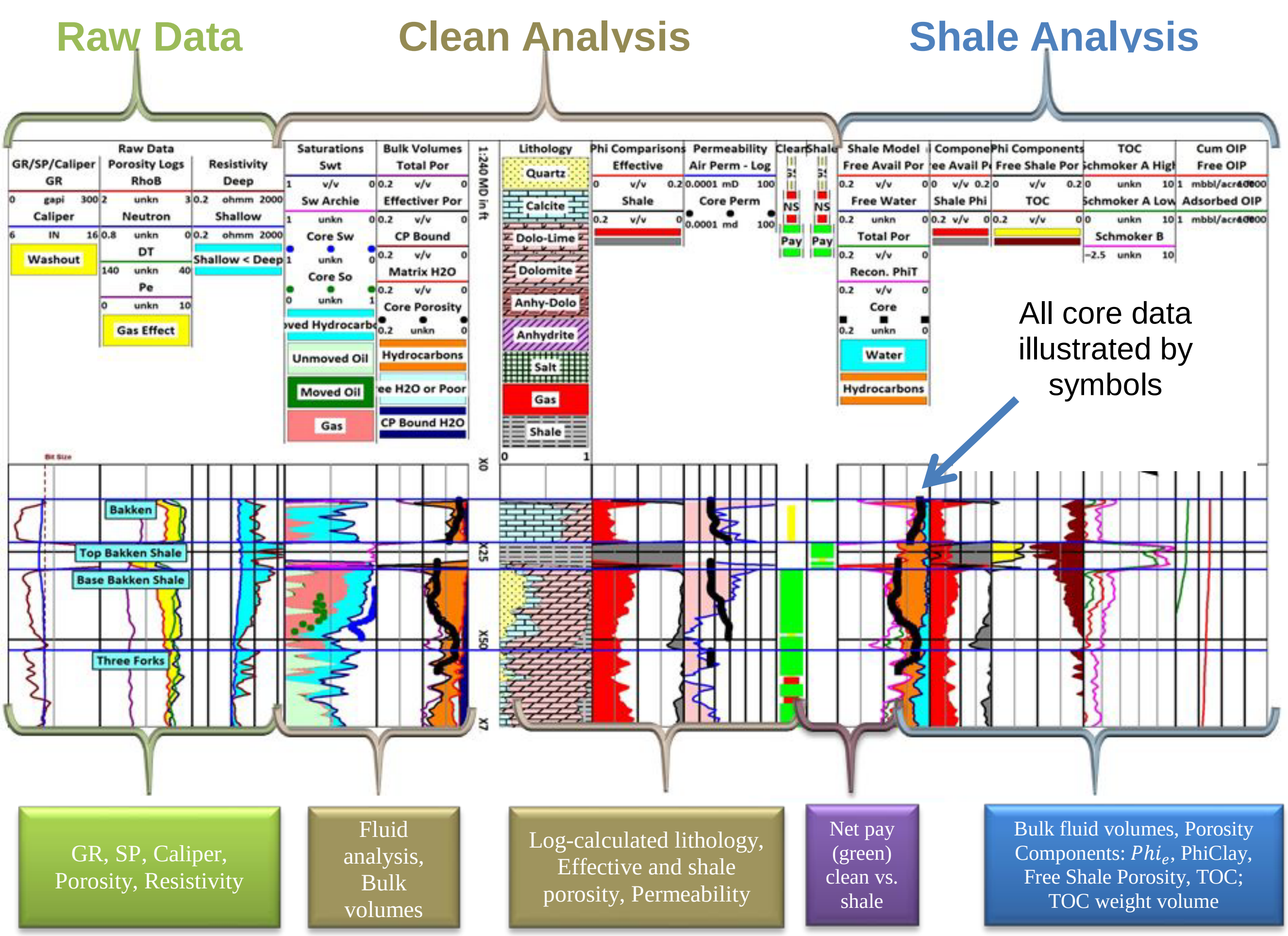


Figure 10a, Niobrara Oil Reservoir – Colorado

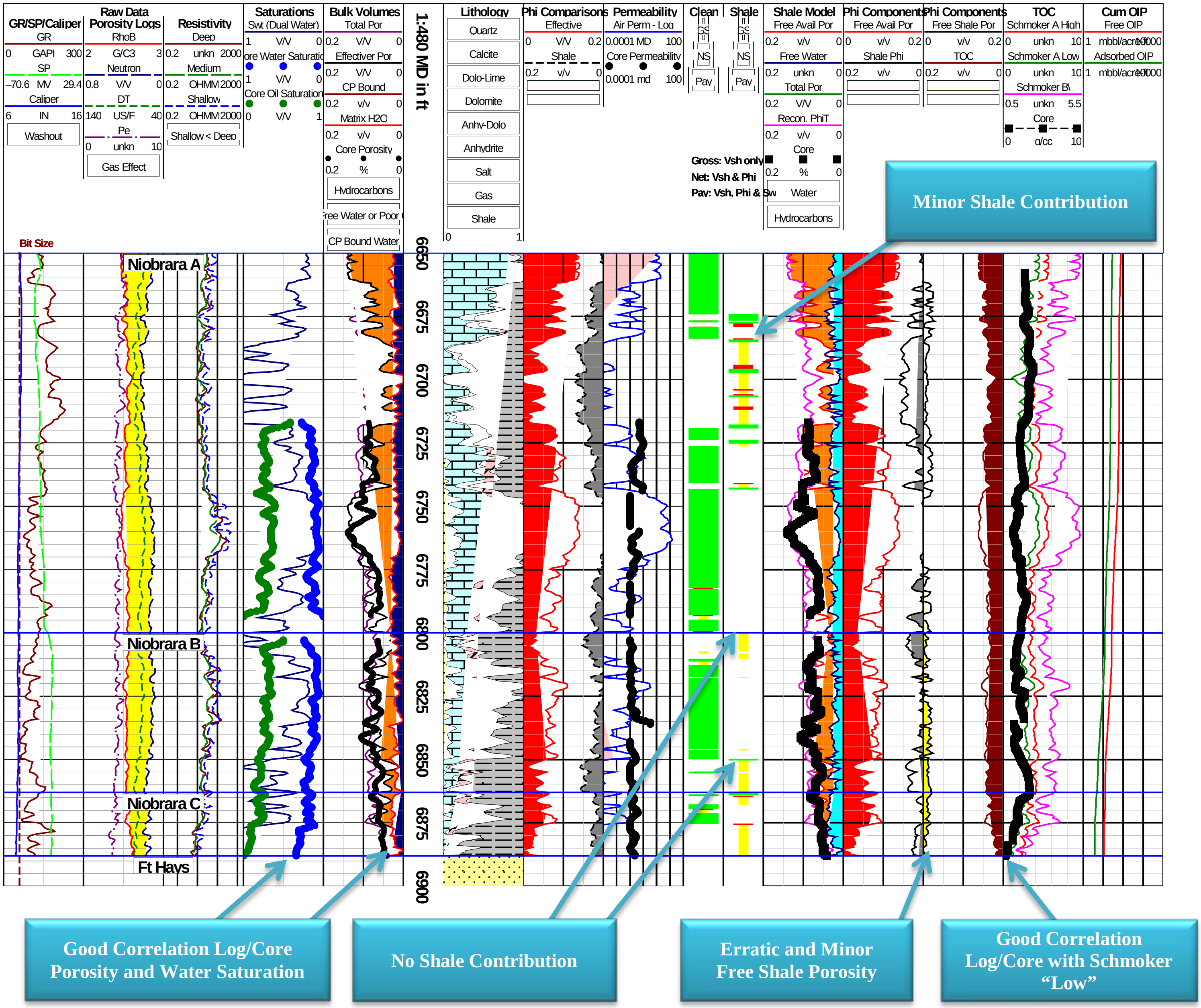
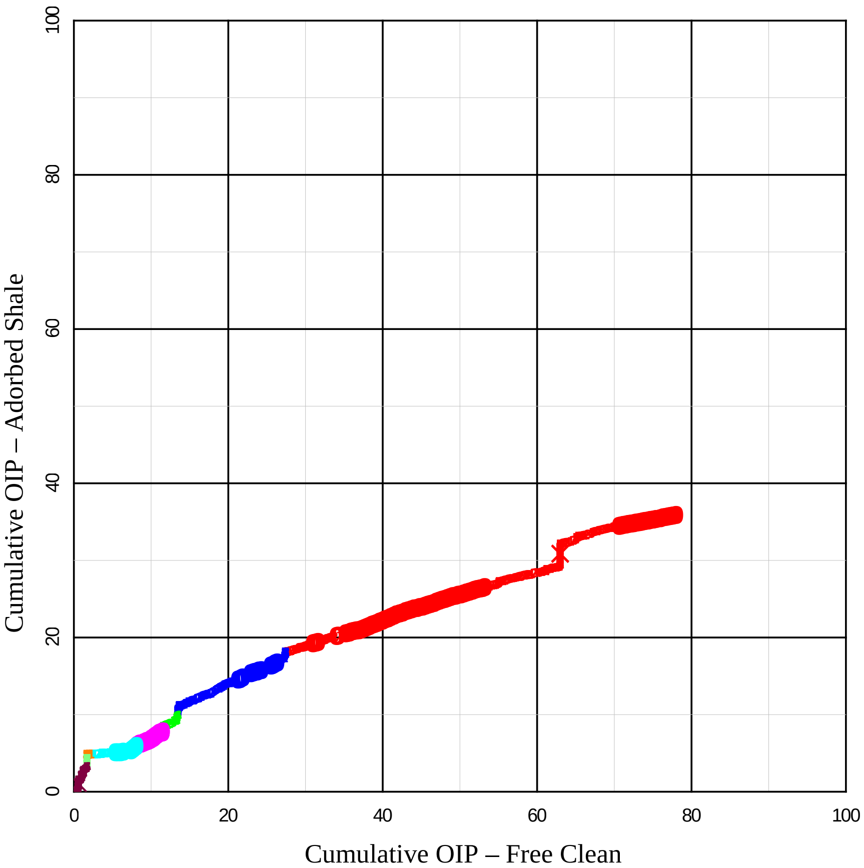


Figure 10b, Niobrara Oil Reservoir – Colorado



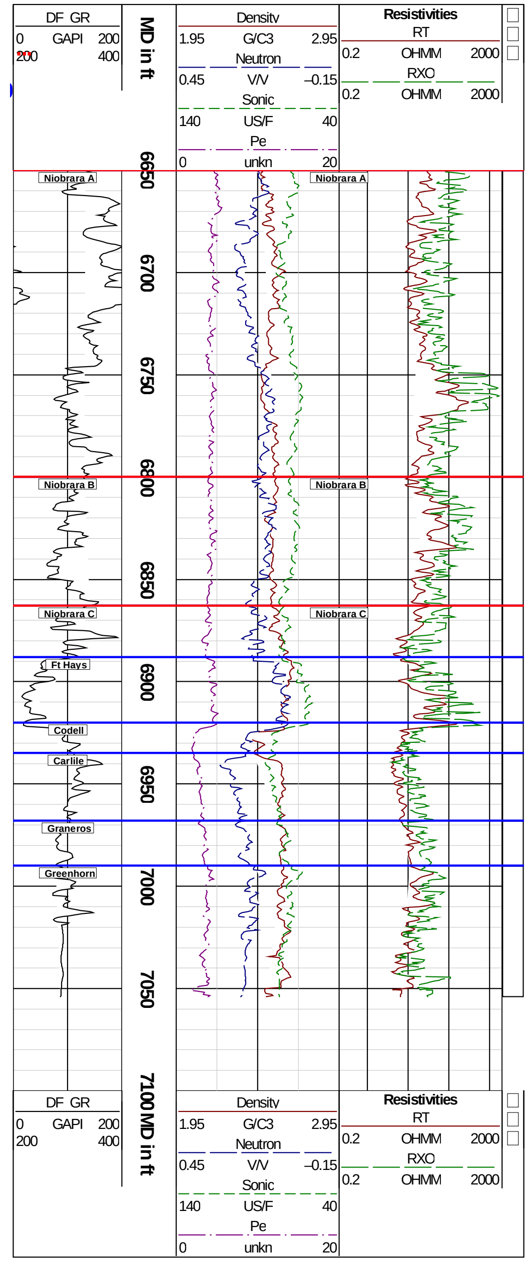


Figure 11, Bakken Oil Reservoir – Montana

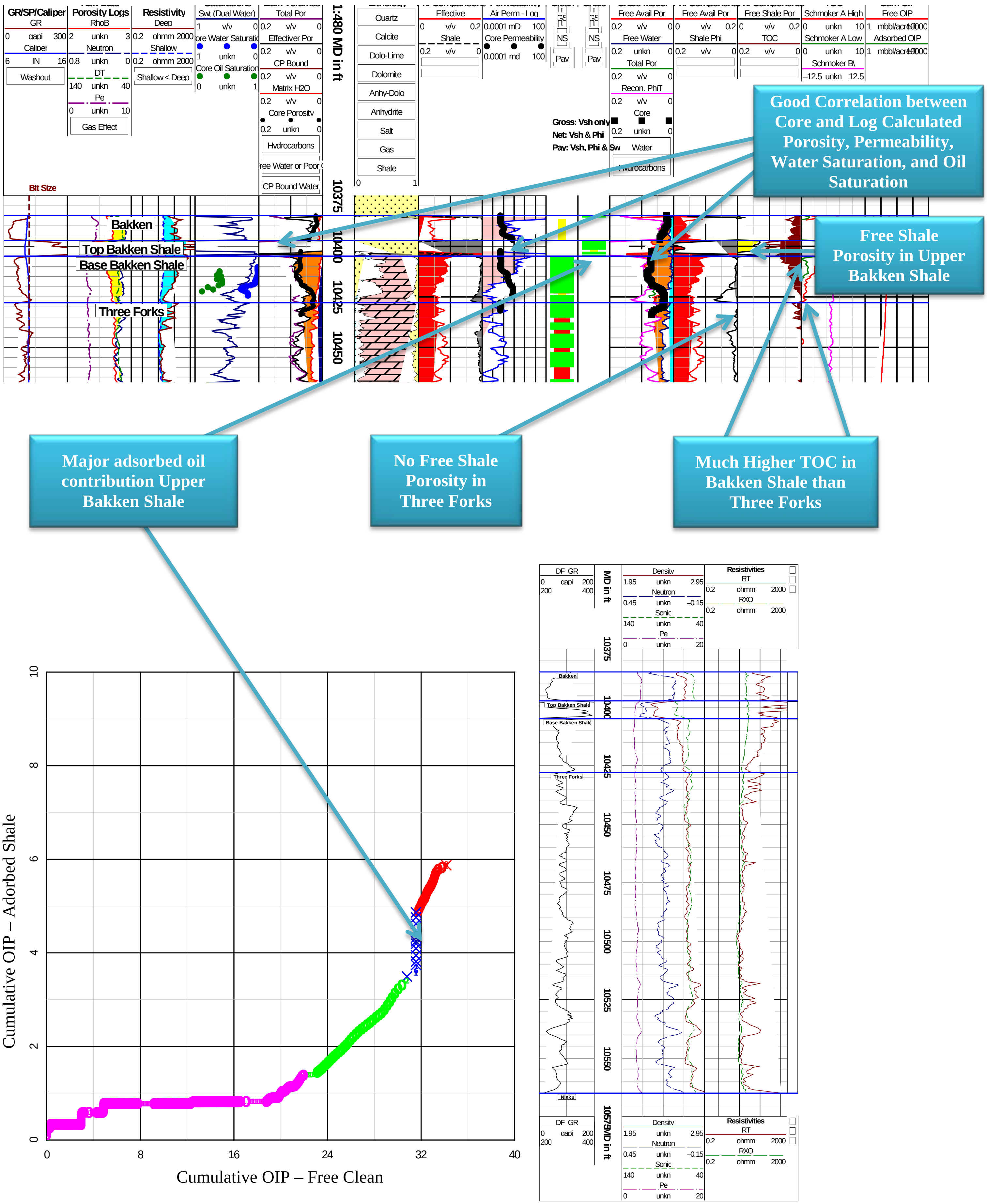


Figure 12, Shale Gas Reservoir – Western Canada

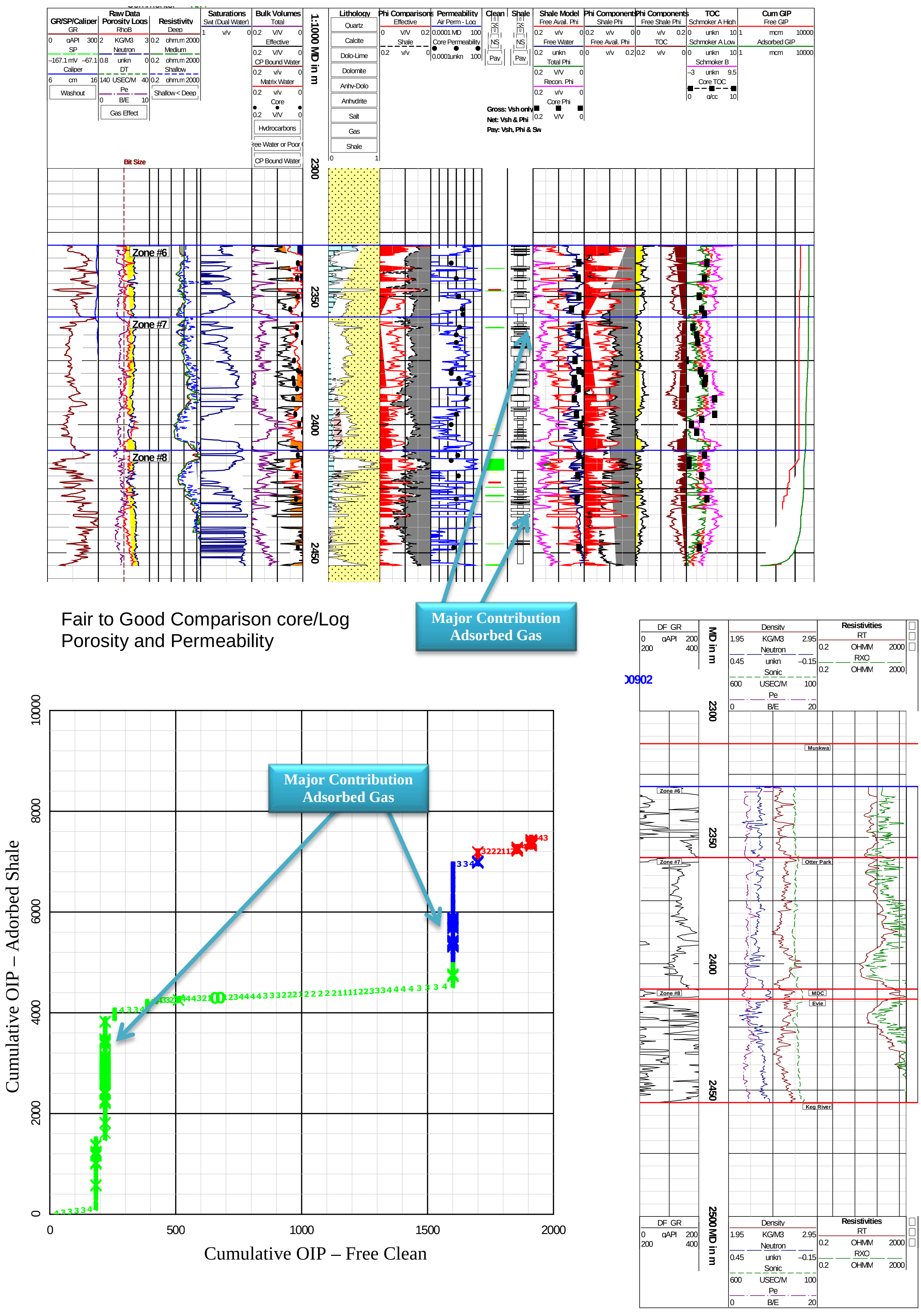


Figure 13, Barnett Shale Gas Reservoir – Texas

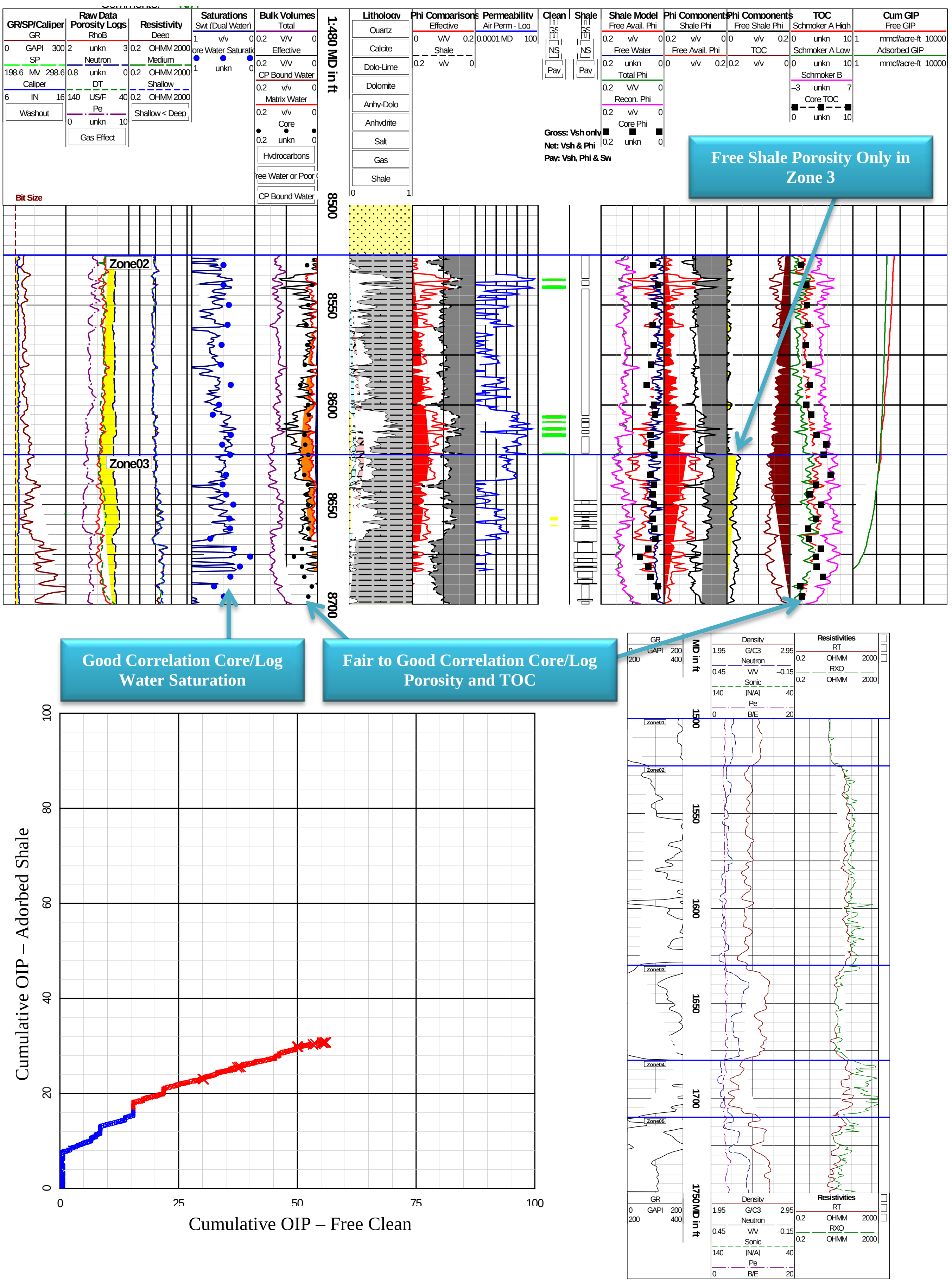
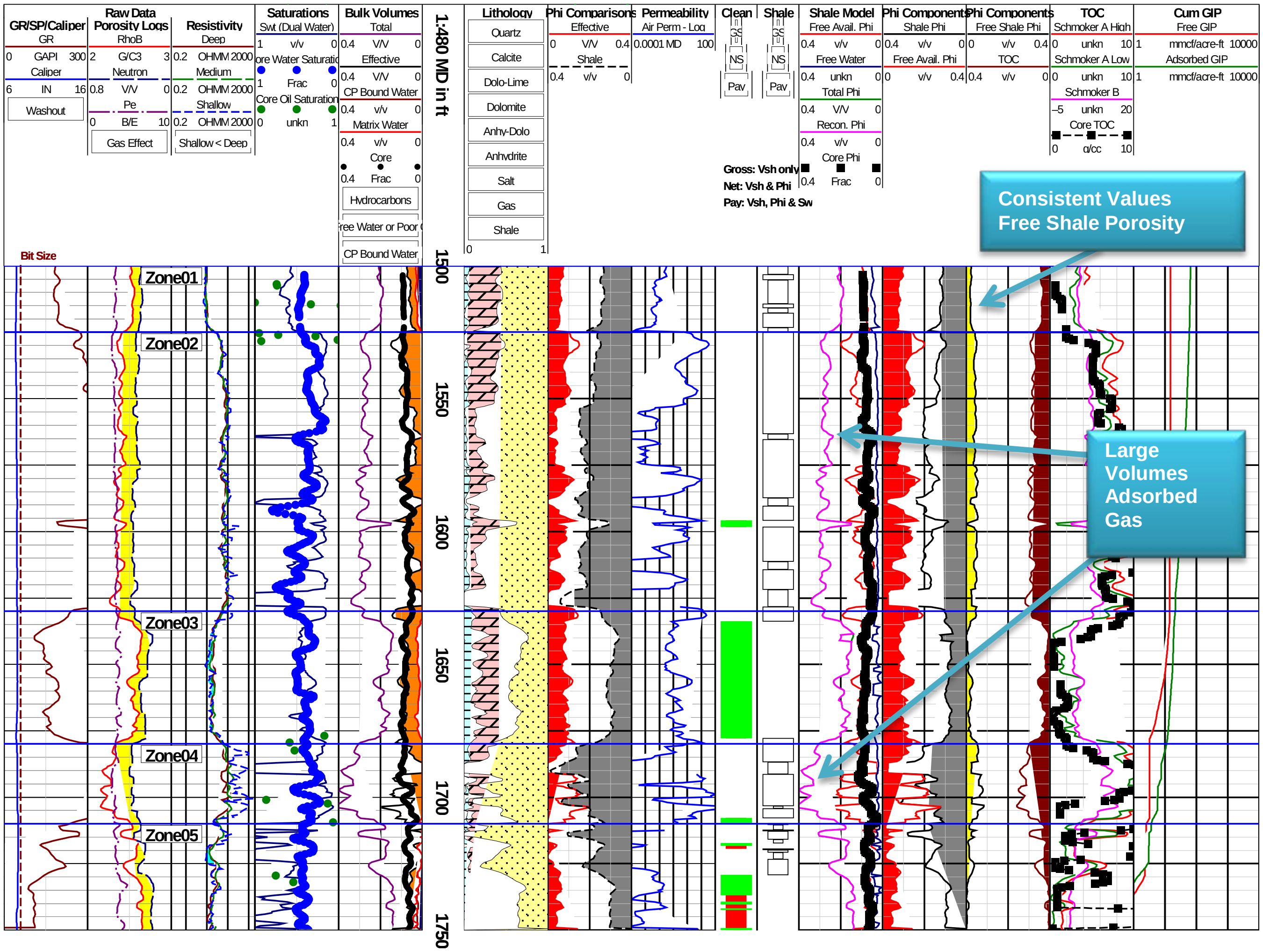


Figure 14, Antrim Shale Gas Reservoir – Michigan



Good to excellent correlations core/log water saturation, porosity, TOC