‘Shale Sweet Spots’ Based on Pe Versus RHOb Cross Plots and OGIPscf with and without Using Geochemical Logs, Jurassic Haynesville Shale

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EXTENDED ABSTRACT

Walls et al. (2012, 2014) developed a photoelectric effect (Pe) versus bulk density (RHOb) cross plot based on dual energy computed tomography (CT) whole core imaging that is designed to delineate ‘shale sweet spots.’ Pe and RHOb data from a 600 ft interval in the Jurassic Haynesville Shale was used to define a 185 ft shale sweet spot based on cutoffs of Pe < 4.0 and RHOb < 2.53 g/cc (after recommendation by Rick Lewis with Schlumberger).].

This 185 ft interval was then used to determine original gas in place in standard cubic ft (OGIPscf) using only triple combo log data (resistivity [Rt], neutron porosity in limestone matrix units [ΦNls], and RHOb], and also to determine OGIPscf using the triple combo log data plus geochemical (elemental capture spectroscopy [ECS]) log data. The results are listed below.

Triple Combo Data Only:

Method Used: Simultaneous equations using)Rt, ΦNls, and RHOb) to determine volume of clay (Vcl), total porosity (Φtotal), and volume of quartz (Vqtz), and total organic carbon (TOC) from the Schmoker equation (e.g., Schmoker, 1979; Schmoker et al., 1983).

OGIPscf: 48.4 billion cubic ft per section (BCF/sec.) (ka > 100nD)
ka = [(0.0108 * gas porosity [Φgas]) – 0.000256] * 10^6

Triple Combo plus Geochemical (ECS) Log:

Method Used: Φtotal from RHOb using variable matrix analysis (RHOma) and TOC from the Schmoker Equation.

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OGIPscf: 53.2 BCF/sec. (ka > 100nD)

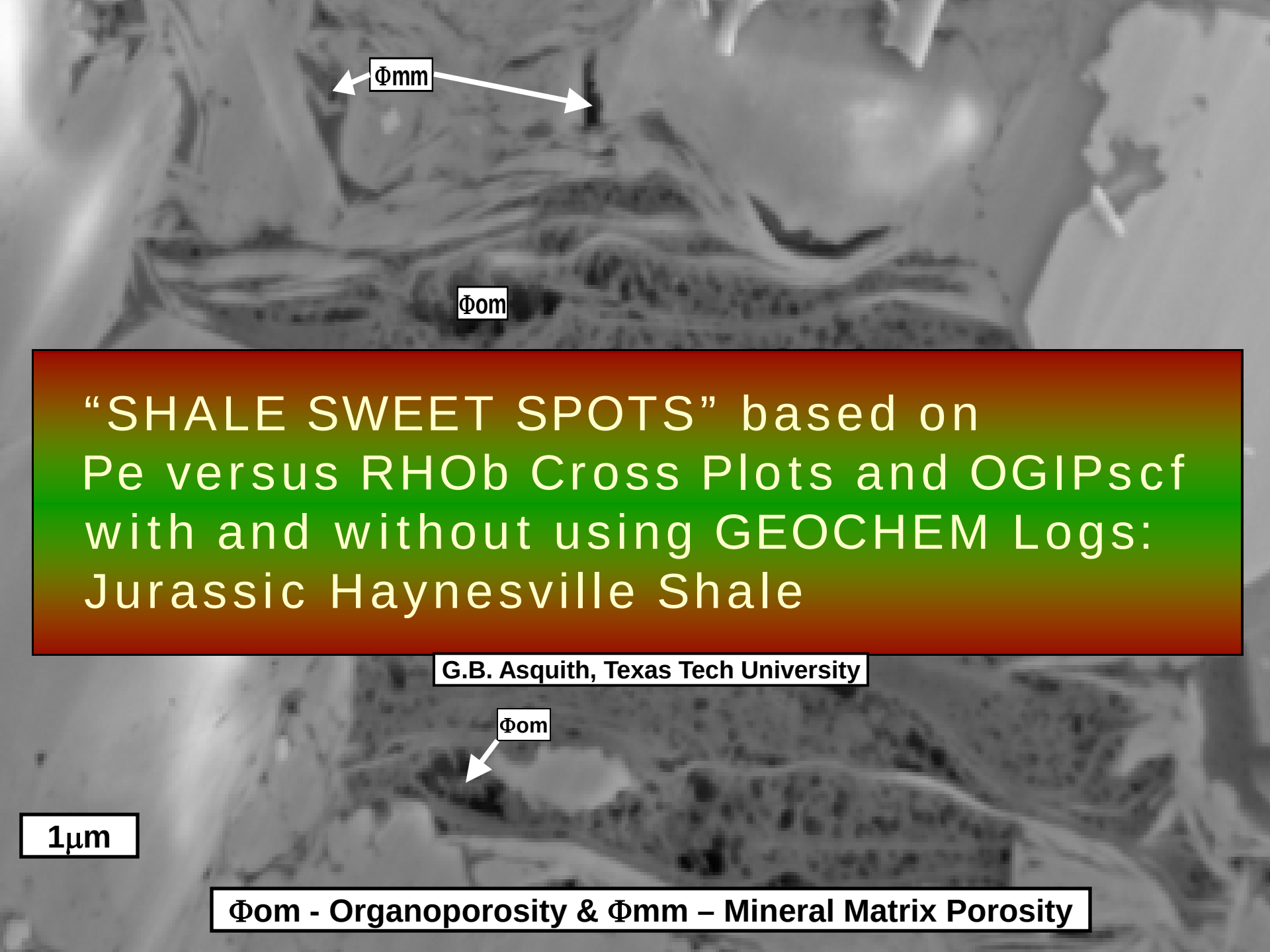
ka = [(0.0108 * Φgas) – 0.000256] * 10^6

The log data from this well also included compressional and shear wave data. Therefore Poisson's Ratio (μ) and Young's Modulus (E) were calculated so that the minimum closure stress (Shmin) and brittleness coefficient could be determined. In the 185 ft shale sweet spot determined from the Pe versus RHOb cross plot, calculated Shmin decreased from approximately 10,500 psi to 10,100 psi and calculated brittleness coefficient increased from approximately 45 to 60 (Fig. 3).

The author is very aware that the OGIPscf in this example only represent an analysis of one well. However, the OGIPscf analyses of this well does suggest that reliable OGIPscf values may be possible using "older" well logs with only Rt, ΦNls, and RHOb data. In addition, the Pe versus RHOb cross plot method can also be used to determine shale sweet spots that have superior geomechanical properties.

Recent work on the Haynesville Shale (Viswanathan et al., 2014; Ravinath et al., 2016) revealed that the hydrogen index (HI) from the nuclear magnetic resonance (NMR) log is 75% greater than bulk methane at the same pressure and temperature, which indicates a higher gas density than would expected from bulk methane at the same pressure and temperature (Fig. 4). This work (not verified by canister desorption core data) suggests the gas reserves may be 40% higher.

...



"SHALE SWEET SPOTS" based on Pe versus RHOb Cross Plots and OGIPscf with and without using GEOCHEM Logs: Jurassic Haynesville Shale

G.B. Asquith, Texas Tech University

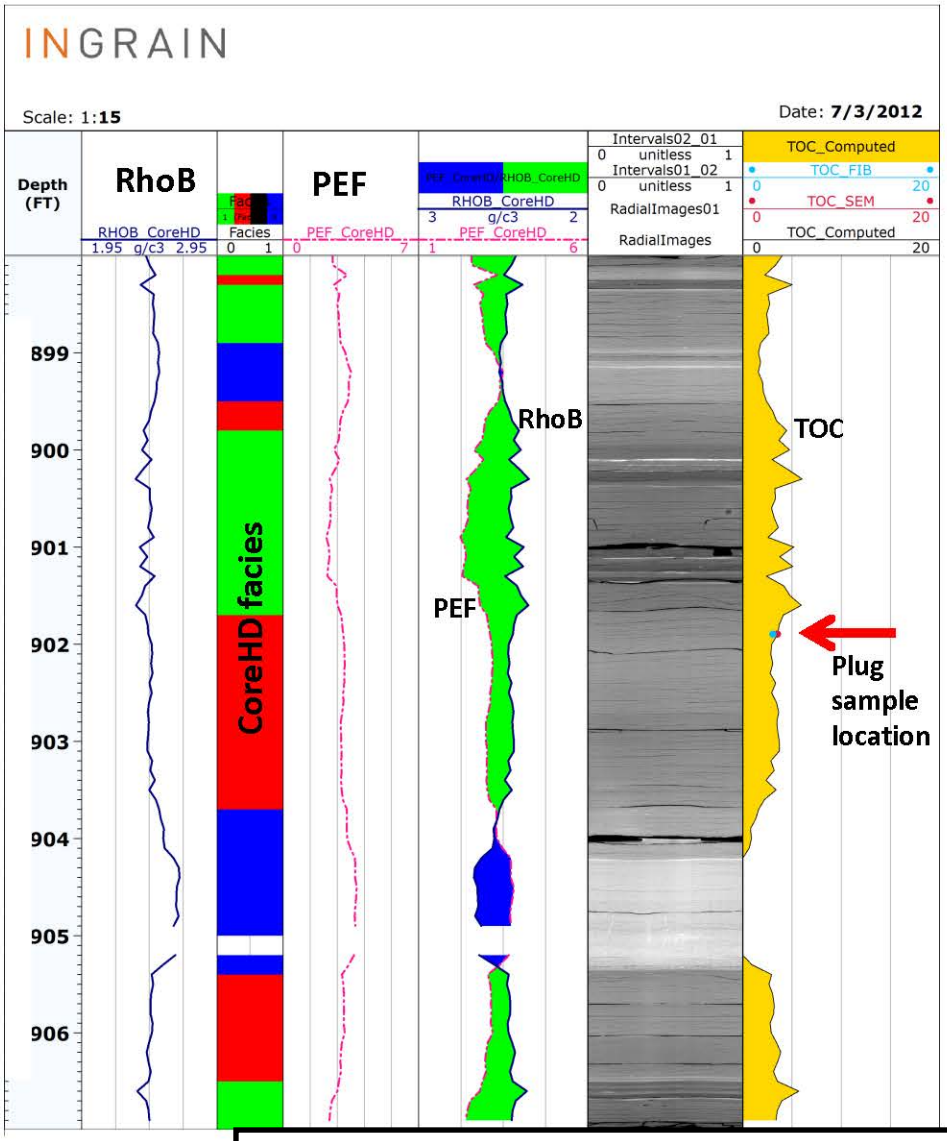
Φom - Organoporosity & Φmm – Mineral Matrix Porosity

Walls, J., B. Driskell, S.W. Sinclair, & J. Devito, (2012), Reservoir Characterization in the Eagle Ford Shale using Digital Rock Methods: WTGS 2012 Fall Symposium, Publ. No. 12-125.

- **Dual Energy (CT) whole core imaging for quick evaluation and sample selection for shale quality indication ("SHALE SWEET SPOTS").**

- **High resolution (0.5mm)** BULK DENSITY (RHOb) **and** PHOTOELECTRIC FACTOR (PEF)**.**

Whole bulk core density and photoelectric factor (PEF) for facies identification (Well SE) and sample selection

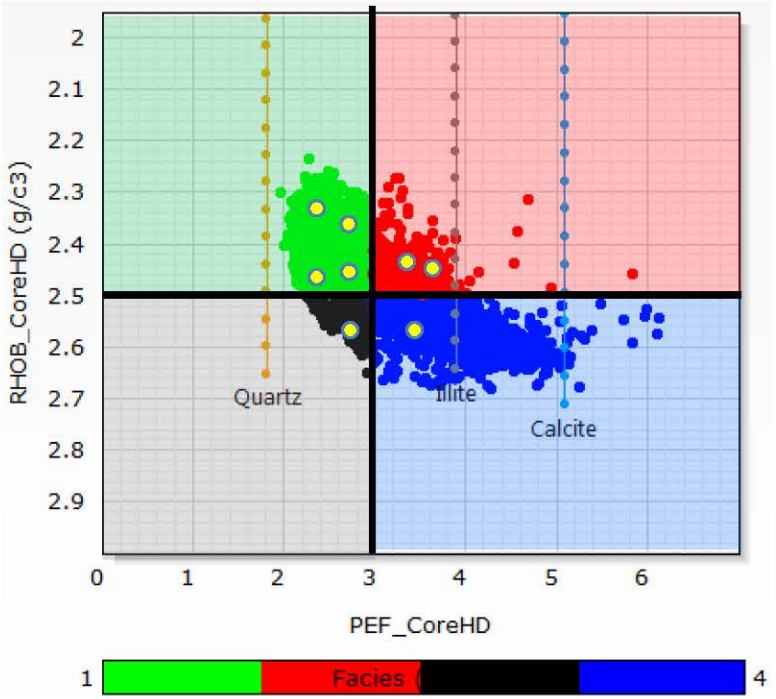


Green = Higher porosity and/or kerogen

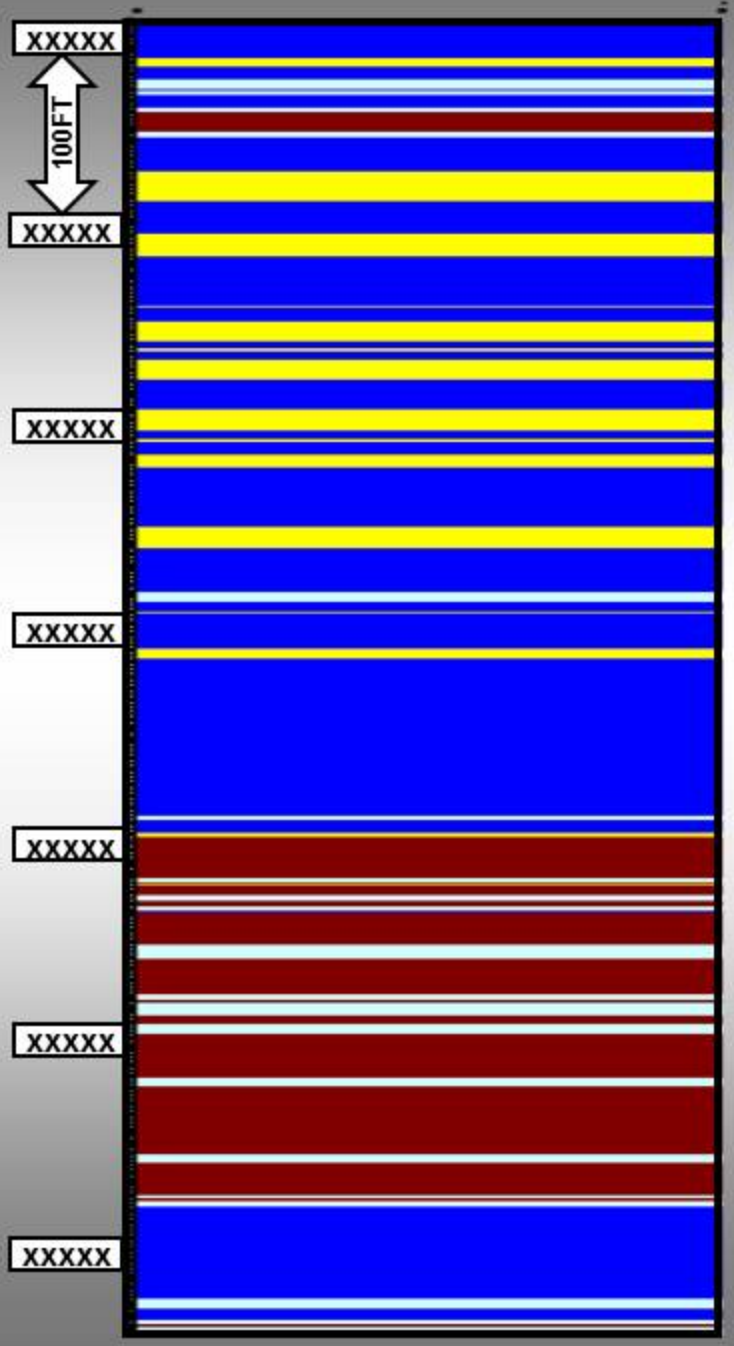
Red = Higher phi or kero; more calcite

Blue = Lower phi or kero, more calcite

Black = Lower phi or kero, less calcite



Modified After: Walls & others (2012) WTGS 2012 FALL SYMPOSIUM



Pe vs. RHOb Cross Plot
Jurassic
Haynesville Shale

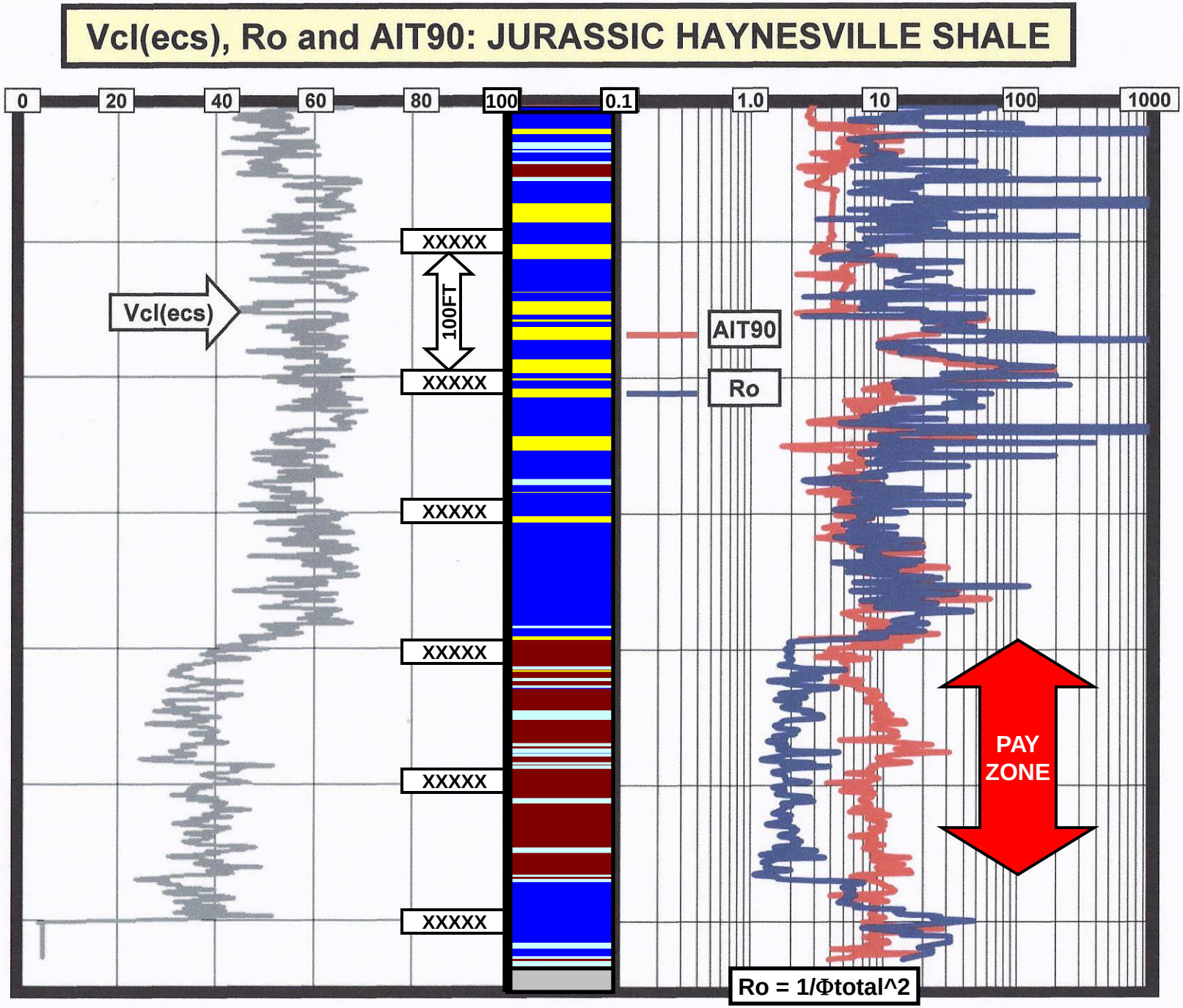
Pe<4.0 RHOb<2.53
More Φand/or Kerogen

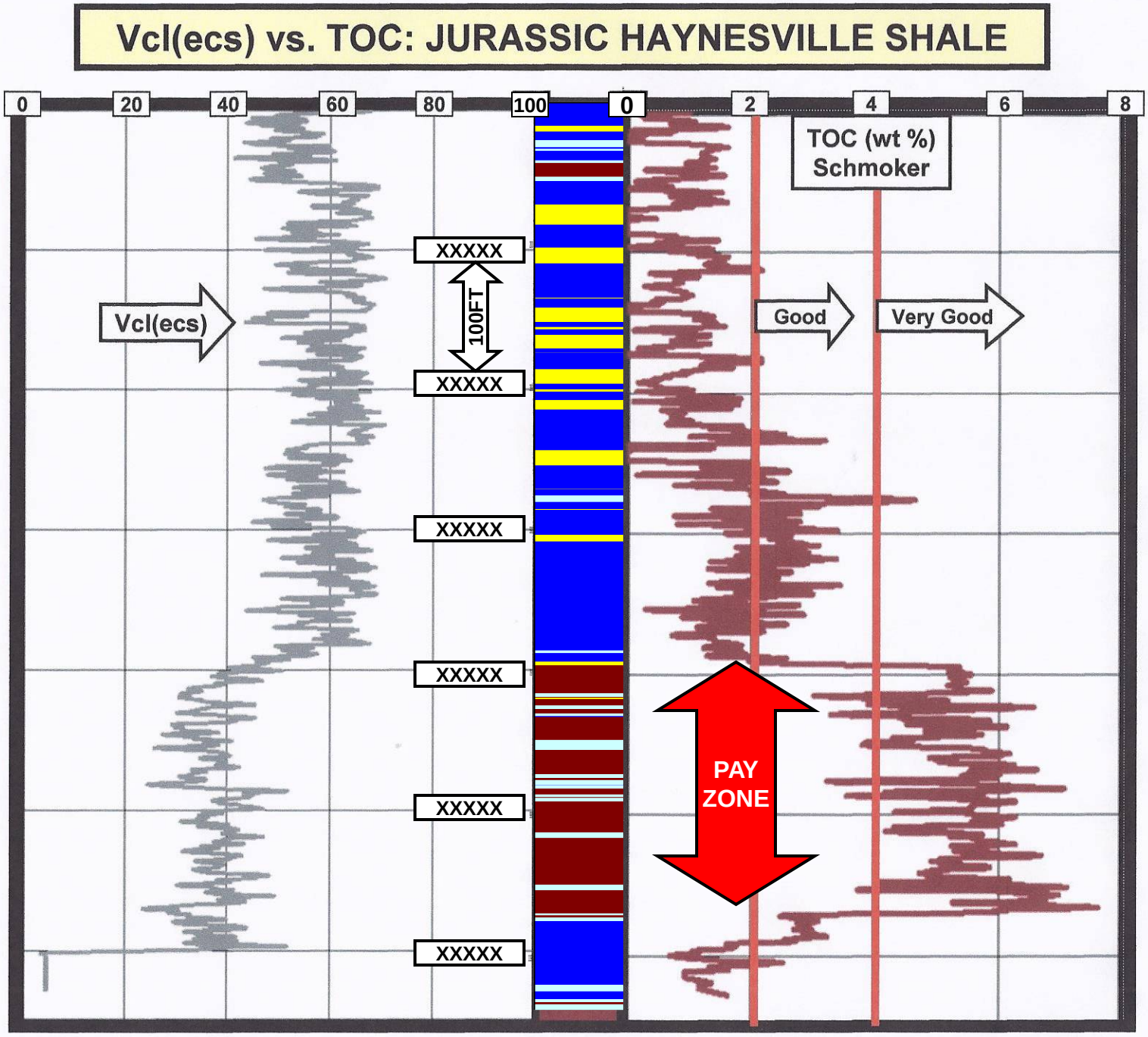
Pe>4.0 RHOb<2.53
More Φand/or Kerogen
More Calcite

Preferred Facies

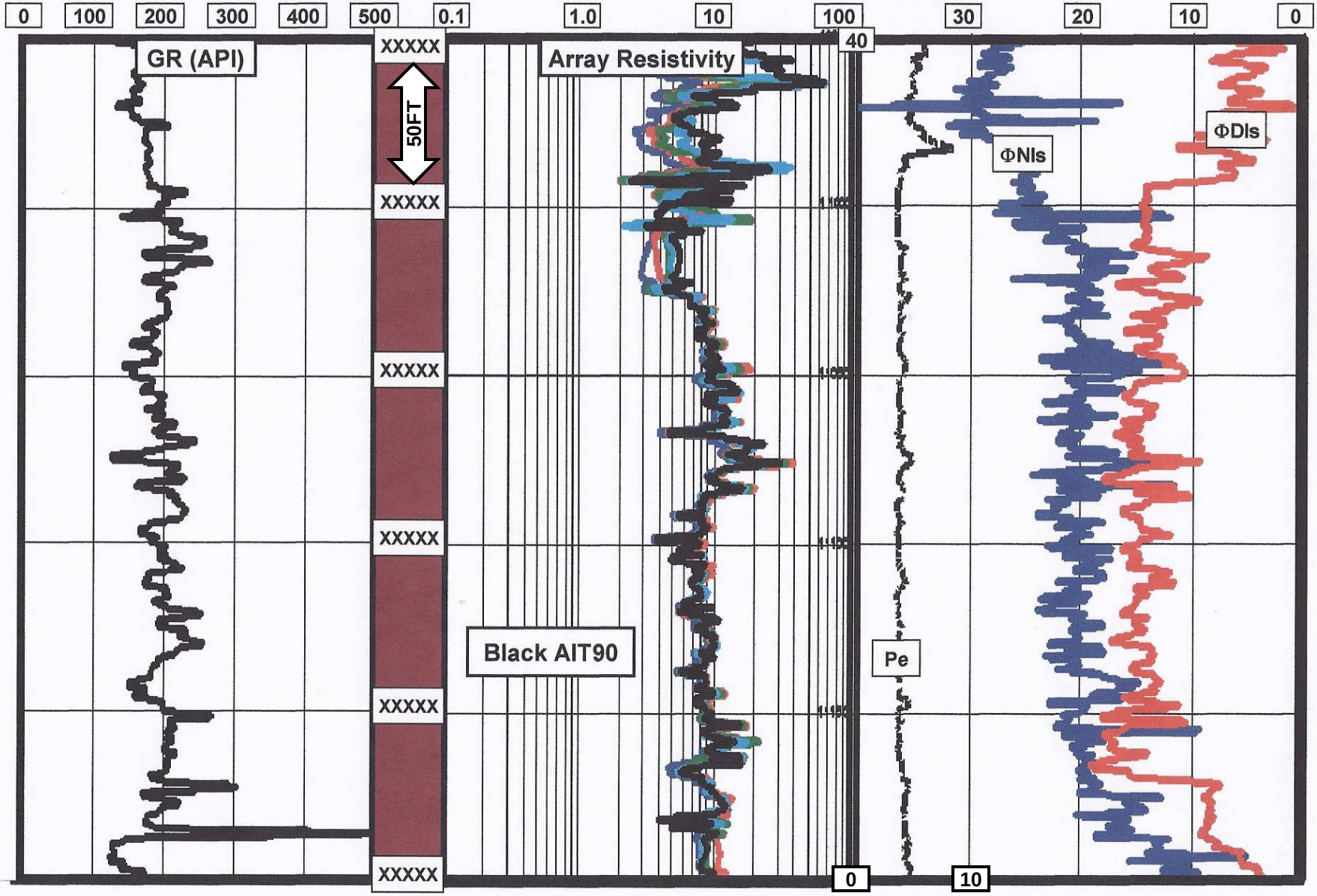
Pe<4.0 RHOb>2.53
Less Φand/or Kerogen
Less Calcite
More Clay

Pe>4.0 RHOb>2.53
Less Φand/or Kerogen
More Calcite


Vcl(ecs), Ro and AIT90: JURASSIC HAYNESVILLE SHALE
0
20
40
60
80
100
0.1
1.0
10
100
1000
Vcl(ecs)
XXXXX
100FT
XXXXX
XXXXX
XXXXX
XXXXX
XXXXX
AIT90
Ro
PAY ZONE
Ro = 1/Φtotal^2

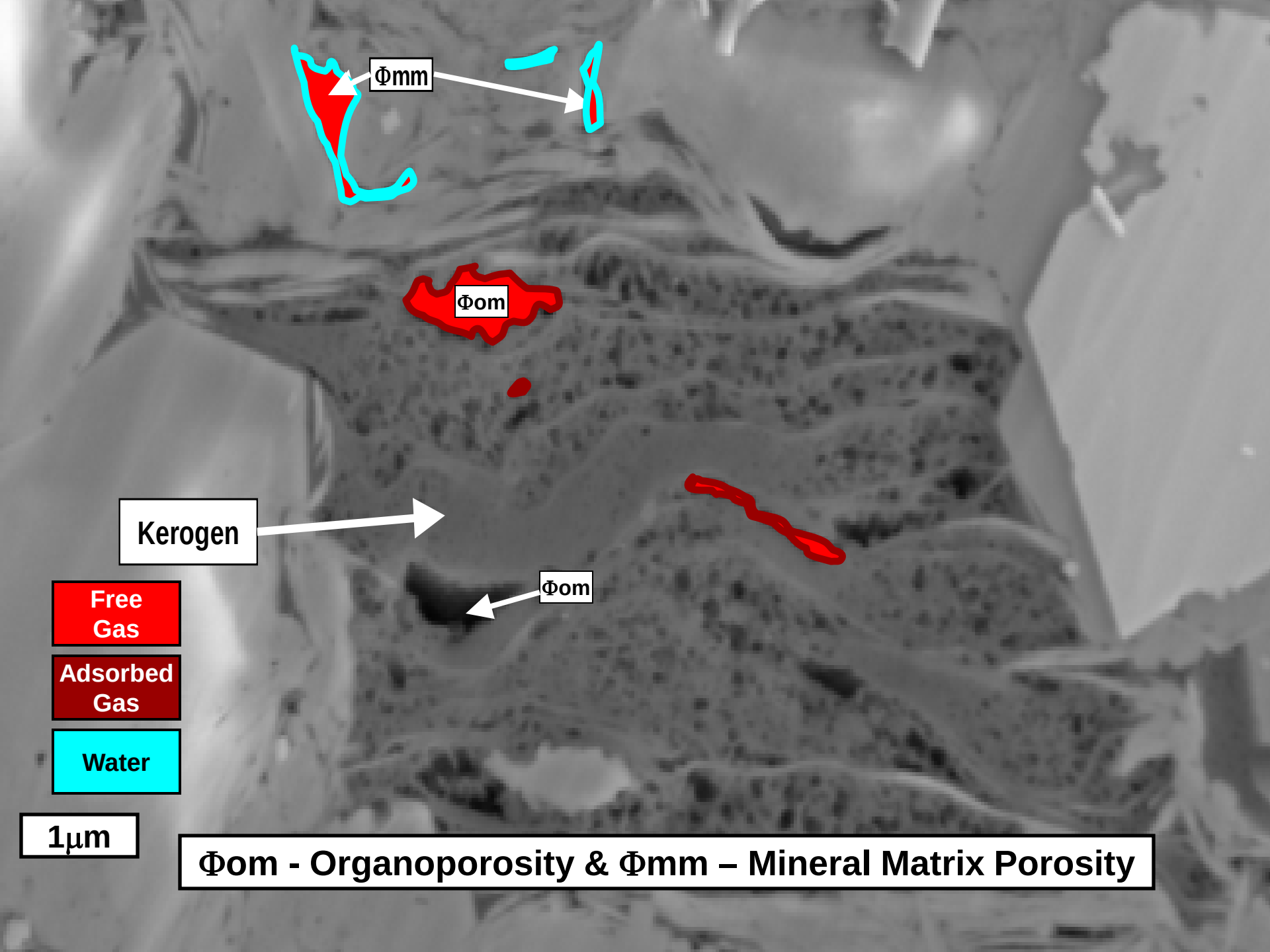

Vcl(ecs) vs. TOC: JURASSIC HAYNESVILLE SHALE
0
20
40
60
80
100
0
2
4
6
8
TOC (wt %)
Schmoker
Vcl(ecs)
XXXXX
100FT
XXXXX
XXXXX
XXXXX
XXXXX
XXXXX
Good
Very Good
PAY
ZONE

JURASSIC HAYNESVILLE SHALE [Pay Interval Only]



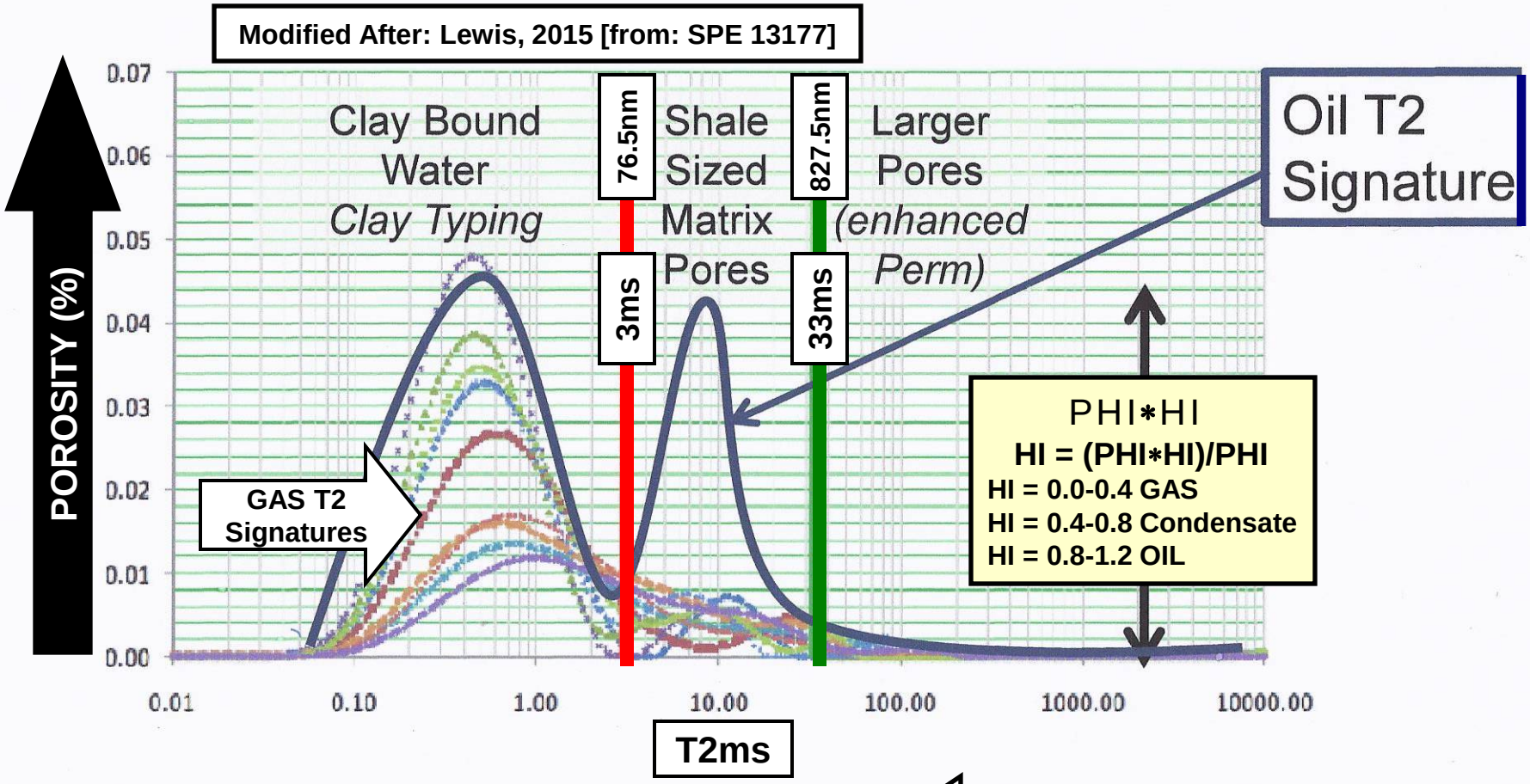
OGIPscf

Resistivity[AIT90], ΦNIs, & RHOb Logs



Φom - Organoporosity & Φmm – Mineral Matrix Porosity

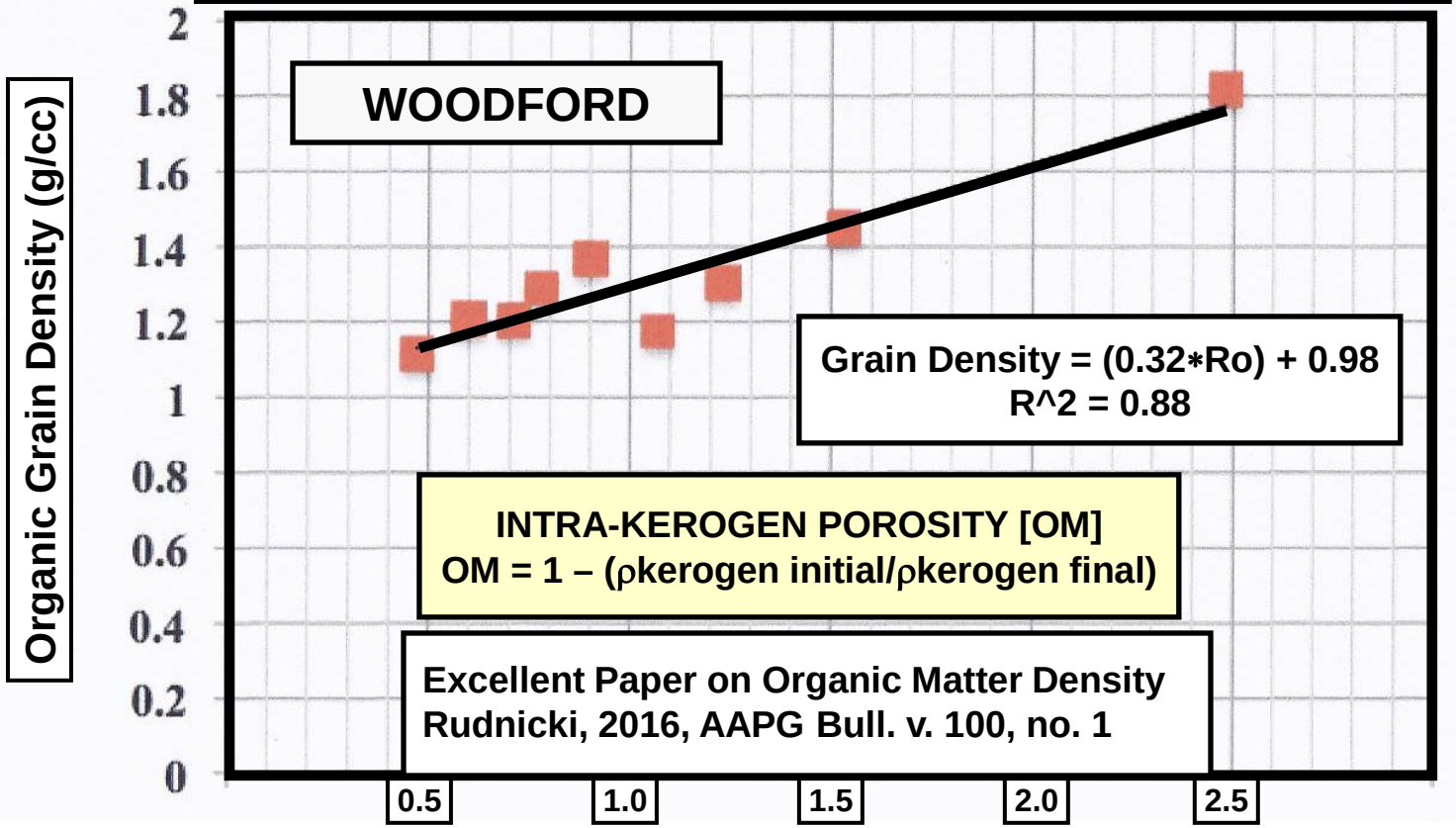
NMR RESPONSE to Φom and Φmm in ORGANIC SHALES



SEPARATION of GAS-WET [Φom] and WATER-WET [Φmm] POROSITIES

INTRA-KEROGEN POROSITY [OM] DETERMINATION

[Modified After: Lewis, 2015]



Therefore:
Φom = Vke∗OM
and
Φmm = Φe-Φom

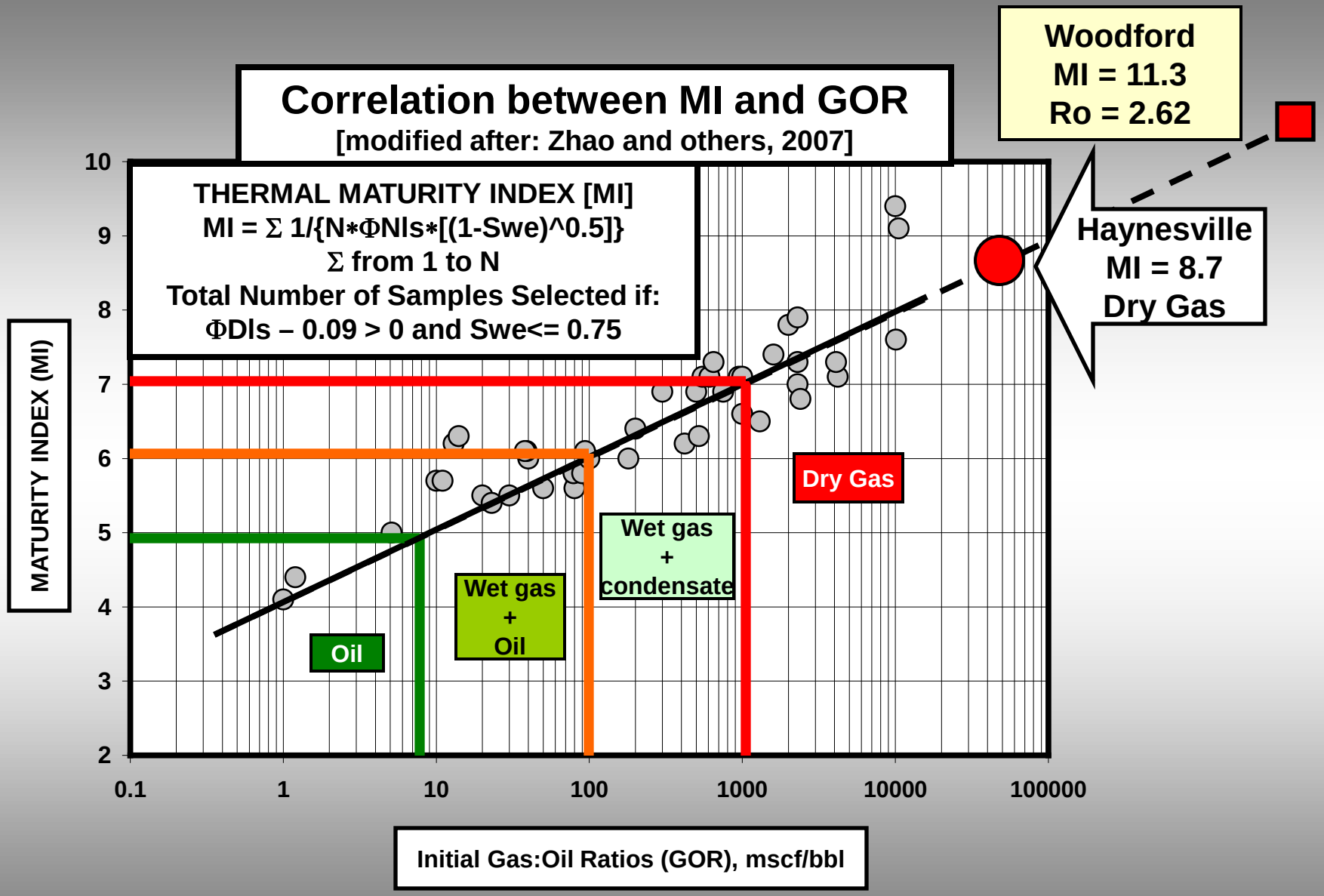
URTEC, 2015
Paper #1921752

PROBLEM:

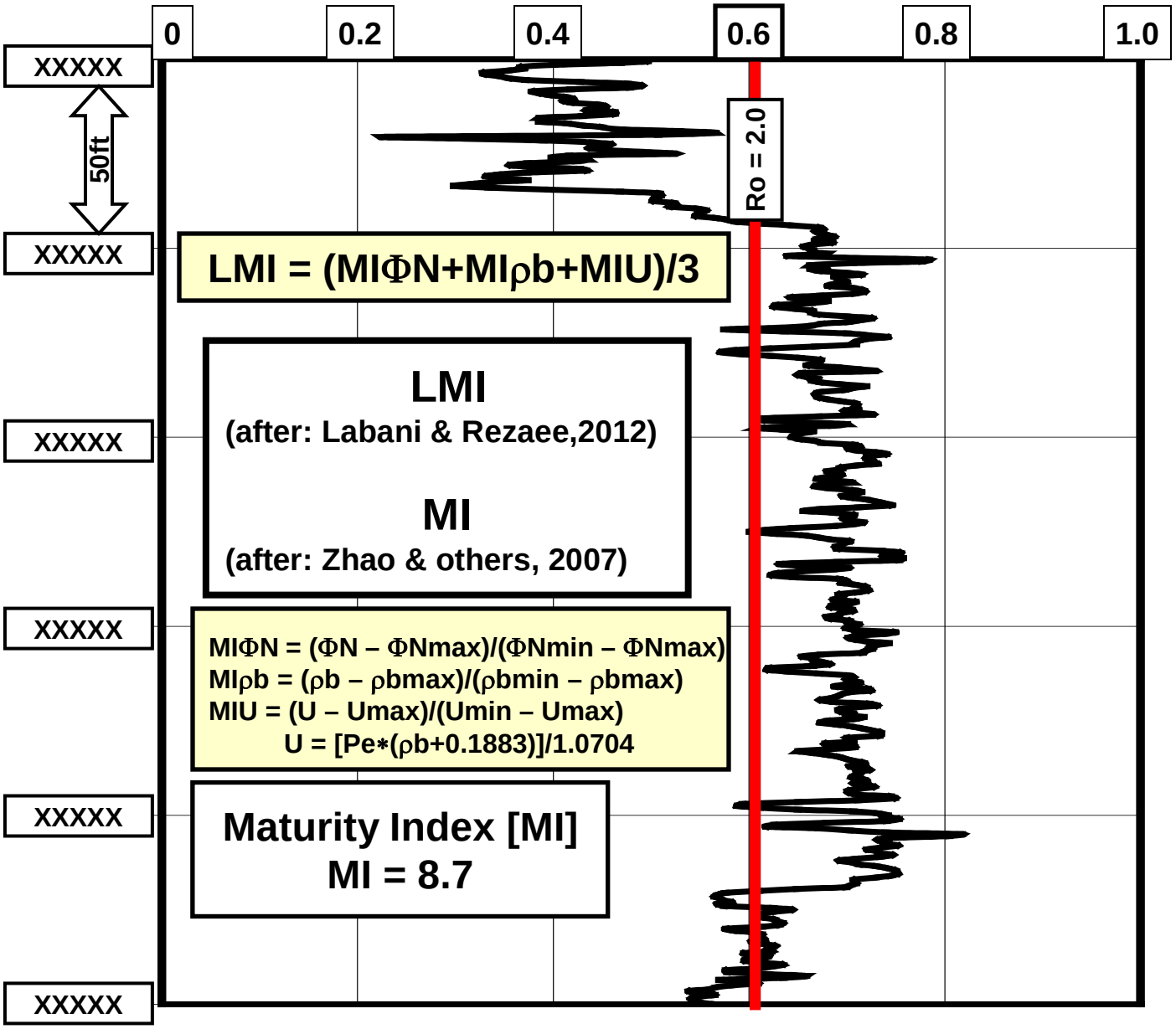
NO

VITRINITE REFLECTION [%Ro]

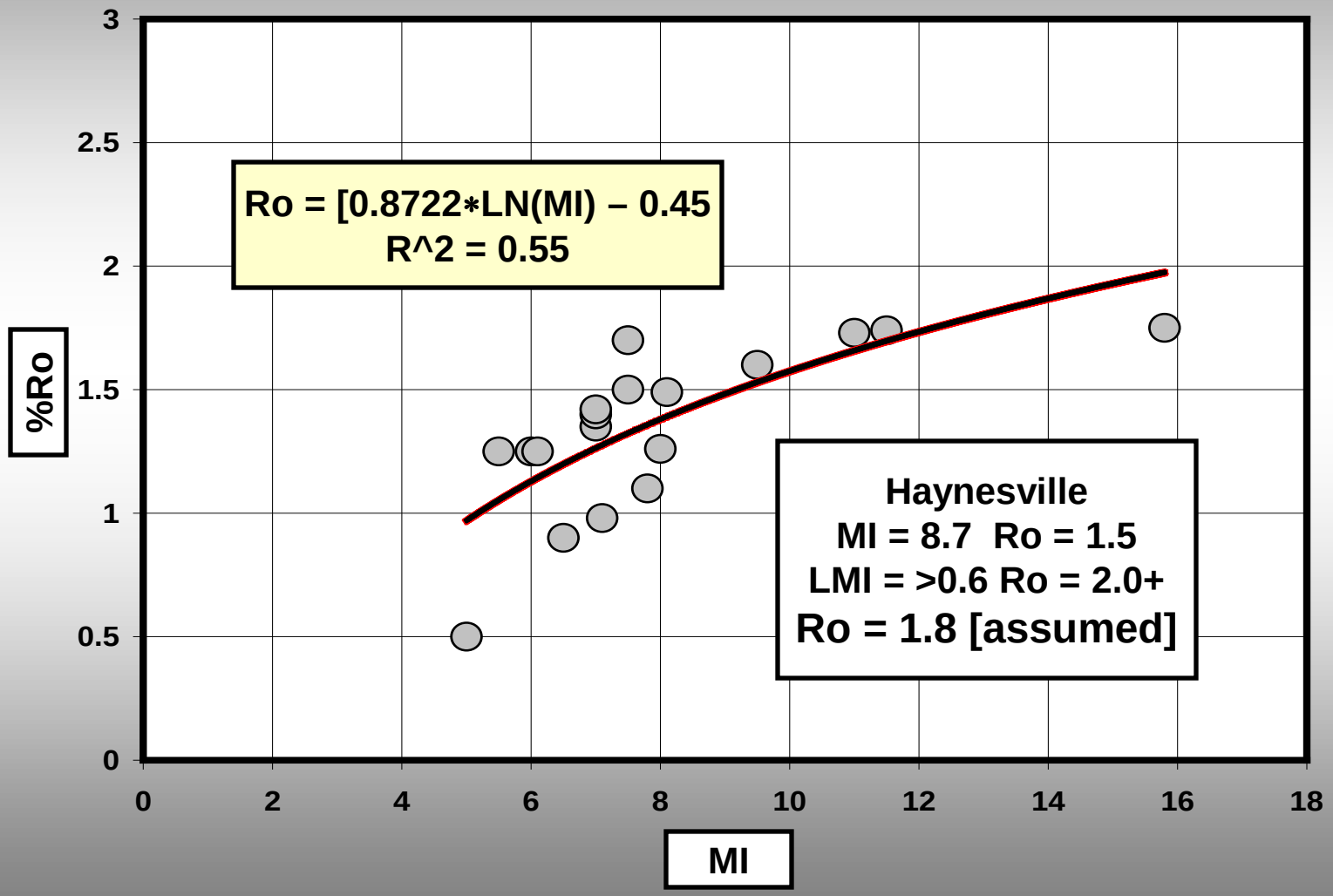
DATA


Correlation between MI and GOR
[modified after: Zhao and others, 2007]
THERMAL MATURITY INDEX [MI]
MI = Σ 1/{N∗ΦNls∗[(1-Swe)^0.5]}
Σ from 1 to N
Total Number of Samples Selected if:
ΦDls – 0.09 > 0 and Swe<= 0.75
Woodford
MI = 11.3
Ro = 2.62
Haynesville
MI = 8.7
Dry Gas
Dry Gas
Wet gas + condensate
Wet gas + Oil
Oil
MATURITY INDEX (MI)
10
9
8
7
6
5
4
3
2
0.1
1
10
100
1000
10000
100000
Initial Gas:Oil Ratios (GOR), mscf/bbl

LOG DERIVED MATURITY INDEX [LMI] JURASSIC HAYNESVILLE SHALE

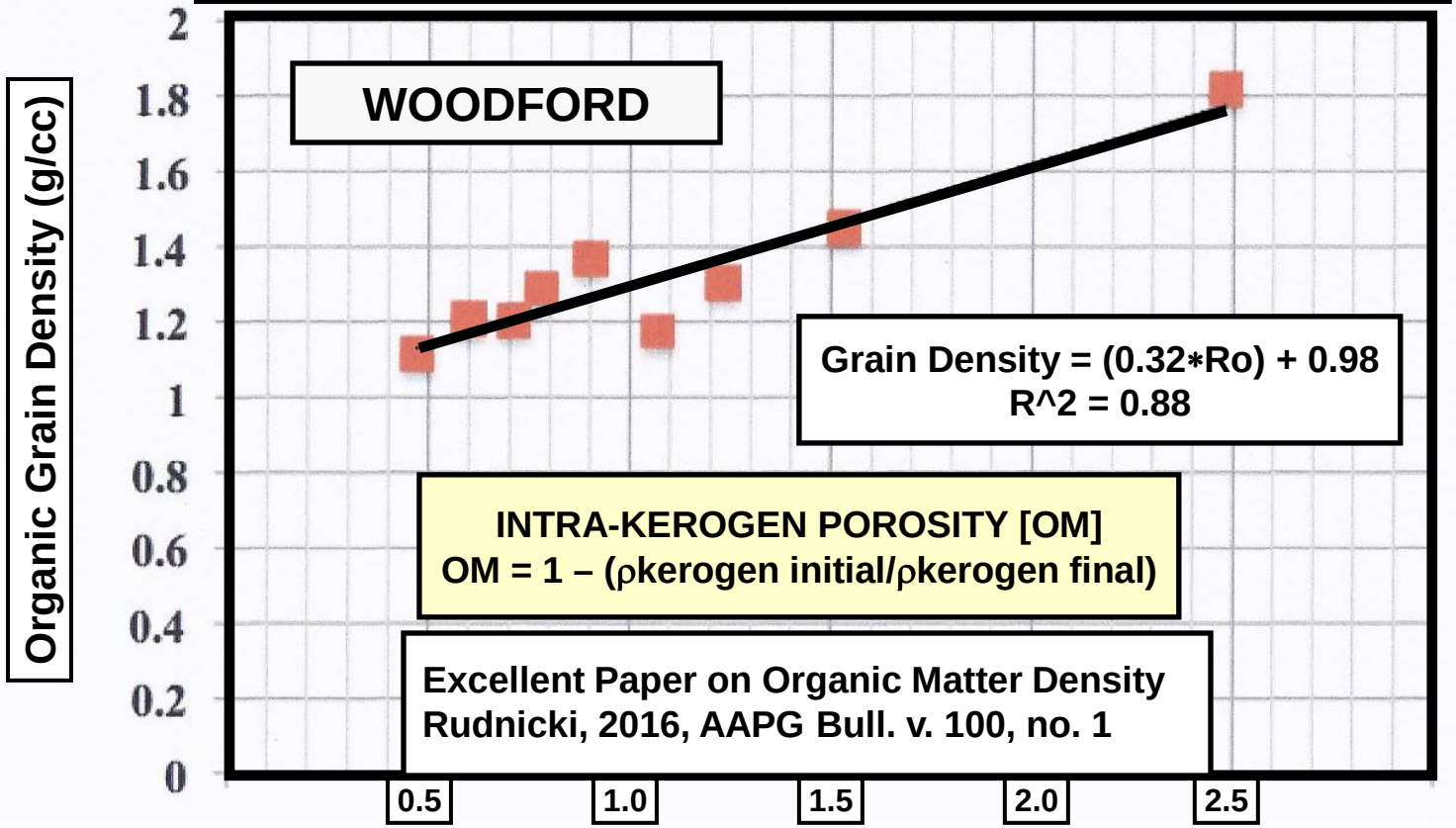


LOG DERIVED THERMAL MATURITY INDEX [MI] vs VITRINITE REFLECTION [%Ro]



INTRA-KEROGEN POROSITY [OM] DETERMINATION

[Modified After: Lewis, 2015]



HAYNESVILLE
ρkerogen-initial = 1.1g/cc
ρkerogen-final = 1.56
OM = 0.30

URTEC, 2015
Paper #1921752

Volume of Kerogen [Vke] from TOC(wt%)

- **TOC(wt%) = (156.956/RHOb) – 58.271**
- **SCHMOKER EQUATION**

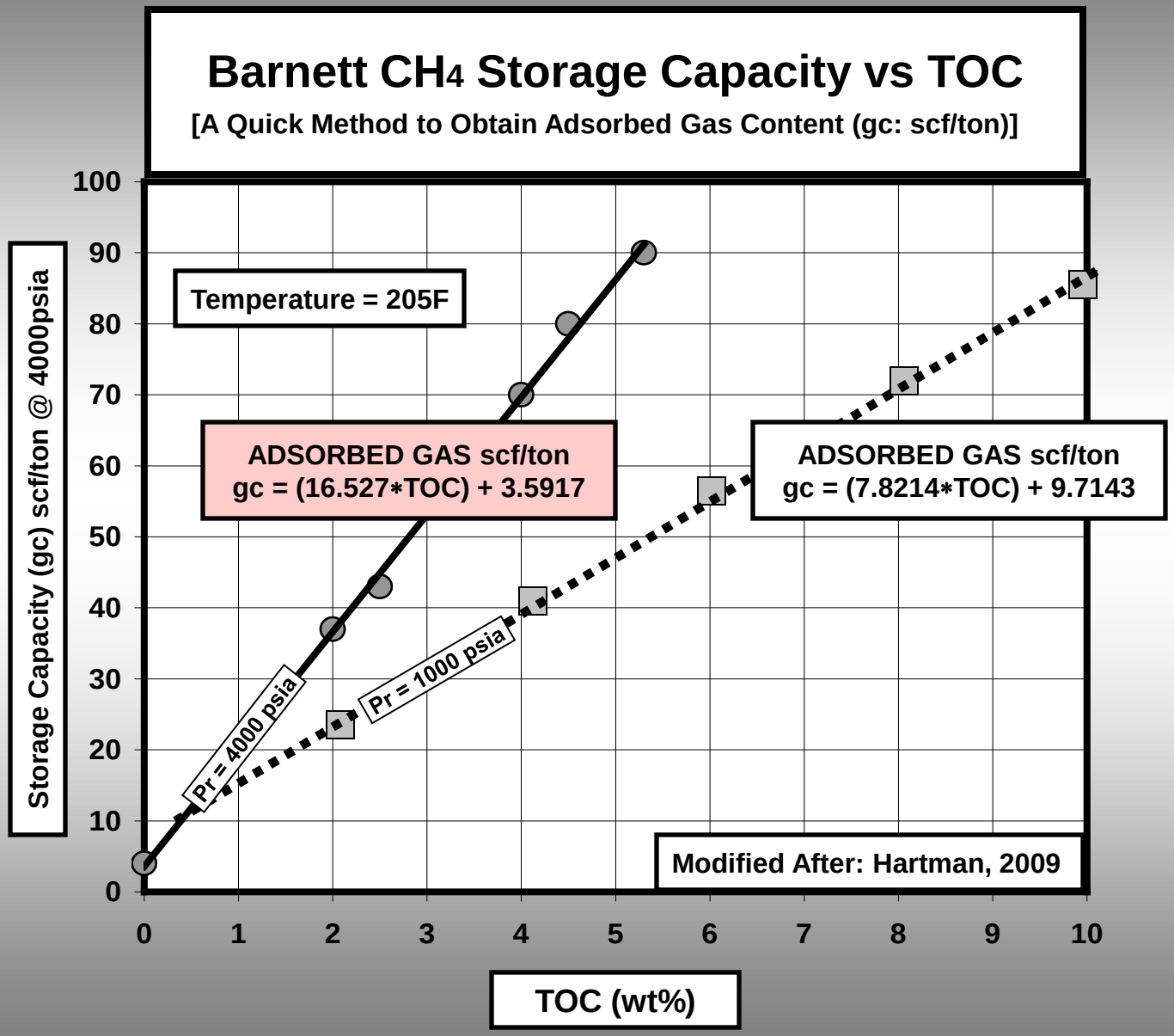
- **Vke = [(TOC∗Kvr∗RHOb)/RHOkerogen]/100**
- **Where:**
- **Vke = Volume of Kerogen [v/v]**
- **TOC = Total Organic Carbon (wt%)**
- **RHOb = Bulk Density (g/cc)**
- **Kvr = Kerogen Maturity Index [default = 1.2]**
- **RHOkerogen = Kerogen Density [1.56g/cc]**

POROSITIES in ORGANIC-RICH SHALES

- **Φtotal and Vcl**
  [Simultaneous Equations or ECS & Variable Matrix Analysis]
- **Φe = Φtotal – CBW CBW = Vcl∗Φclay**
- **Φclay = 0.10 [Illite]**
- **Φe = Φom + Φmm**
- **Φom = Vke∗OM OM = Intra-Kerogen Porosity**

Haynesville [%Ro = 1.8?]
Grain Density = (0.32∗Ro) + 0.98 = 1.56g/cc
OM = 1 – (1.1g/cc/1.56g/cc) = 0.30

- **Φmm = Φe – Φom**


Barnett CH4 Storage Capacity vs TOC
[A Quick Method to Obtain Adsorbed Gas Content (gc: scf/ton)]
Storage Capacity (gc) scf/ton @ 4000psia
100
90
80
70
60
50
40
30
20
10
0
Temperature = 205F
ADSORBED GAS scf/ton
gc = (16.527∗TOC) + 3.5917
ADSORBED GAS scf/ton
gc = (7.8214∗TOC) + 9.7143
Pr = 4000 psia
Pr = 1000 psia
Modified After: Hartman, 2009
0
1
2
3
4
5
6
7
8
9
10
TOC (wt%)

Gas Filled Porosity by Pore Type

- **Organoporosity [Φom]**
  - **Φom = (Vke∗0.30) – Pore Volume Adsorbed Gas [Ambrose Corrected]**
  - **Φgas = Φom ∗ (1 – Sw) Sw = 0.0**

    [Kerogen is Hydrophobic]

- **Mineral Matrix Porosity [Φmm]**
  - **Φmm = (Φe – Φom)**
  - **Φgas = Φmm ∗ (1 – Sw)**
- **Sw = (Ro/Rt)^0.5 Ro = (1/PHI^2)∗Rw**
- **PHI = Φtotal - Φom**

REMEMBER:

The resistivity logs are only responding to the clay-bound water [CBW] and pore water in the [Φmm] porosity.

The gas-wet organoporosity [Φom] is a non-conductive insulator distributed in a conductive matrix.

METHODS for CALCULATING OGIP(scf/area)

Adsorbed Gas-in-Place Volume

$$Gs = 1{,}359.7 * A * h * \rho * gc$$

Gs = adsorbed gas-in-place volume, scf/area
A = area (acres)
h = thickness
ρ = bulk density, g/cc
gc = adsorbed gas content, scf/ton [gc = (Vlc∗Pr)/(Plt+Pr) or gc = (16.527∗TOC)+3.517]
1,359.7 (units conversion) = 43,560 ft^3 per acre/32.0369 scf/ton per cc/g

Free Gas-in-Place Volume

$$Gf = 43{,}560 * A * h * \Phi gas * (1/Bg)$$

Gf = free gas-in-place volume, scf/area
A = area (acres)
h = thickness
Φgas = gas filled porosity
Bg = gas formation volume factor [reservoir volume/surface volume]

modified after: Hartman, 2009

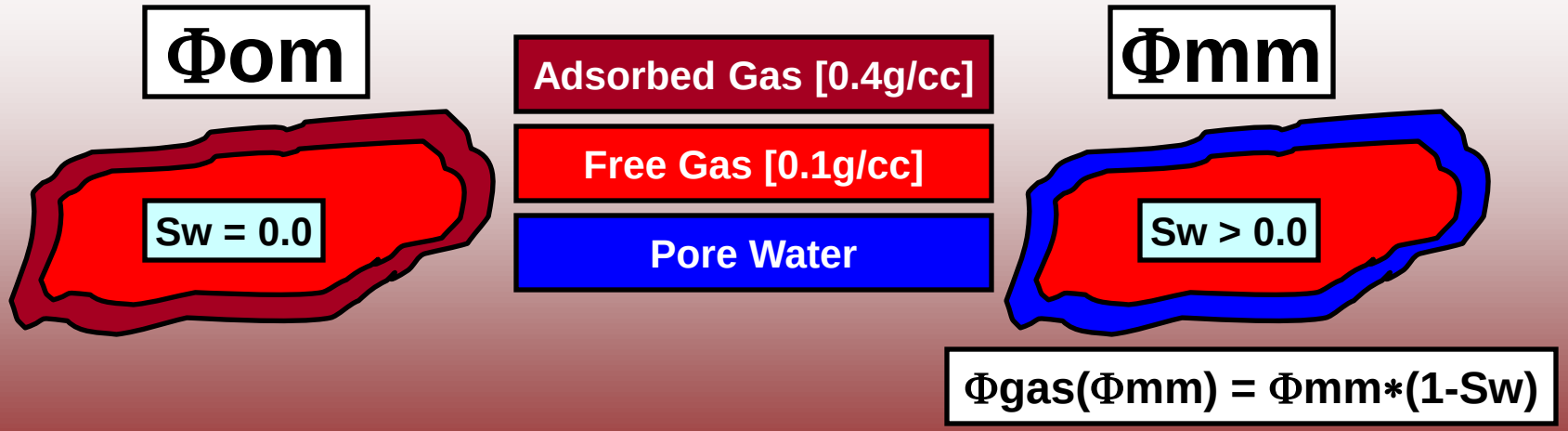
Ambrose & others (2010) Correction for Adsorbed Gas in Organoporosity

Adsorbed Gas Down Hole = {gc/[Depth/(62.4/ρb)]} ∗ Bg 62.4 [g/cc to lbs/ft^3]

Pore Volume Adsorbed Gas = Adsorbed Gas Down Hole ∗ (0.1/0.4)

Φgas(Φom) = Φom – Pore Volume Adsorbed Gas

NOTE: Permeability to Free Gas decreased due to the Adsorbed Gas and/or Pore Water.



Φgas(Φmm) = Φmm∗(1-Sw)

PERMEABILITY (nD)

GAS

- **ka = [(0.0108∗Φgas) – 0.000256] ∗ 10^6**

Where:

ka = permeability in nannodarcies (nD)

Φgas = gas-filled porosity

[Adsorbed Gas (Ambrose) & Sw Corrected]

Modified After: Lewis, 2009

ka [Cut-Off] > 100nD

MINERAL VOLUMES and TOTAL POROSITY

- **Vcl + Vqtz + Vke + Φtotal = 1.0** Vke = (TOC∗Kvr∗ρb)/ρkerogen
- **Vcl∗ρcl + Vqtz∗ρqtz + Vke∗ρke + Φtotal∗ρf = ρb**
- **Vcl∗Φncl + Vqtz∗Φnqtz + Vke∗Φnke + Φtotal∗Φnf = Φn**

TOCwt% = (156.956/ρb) – 58.271

Modified After: Lewis, 2009 w/ SCHLUMBERGER

Vcl = Volume of Clay

ρcl = density of clay Φncl = neutron porosity of clay

Vqtz = Volume of Quartz

ρqtz = density of quartz Φnqtz = neutron porosity of quartz

Vke = Volume of Kerogen

ρke = density of kerogen Φnke = neutron porosity of kerogen

Φtotal = Total Porosity

ρf = Sw∗ρwater + (1-Sw)∗ρgas

Φnf = Sw∗Φnwater + (1-Sw)∗Φngas

EFFECTIVE POROSITY

Φe = Φtotal – CBW

CBW = Vcl ∗ 0.10 Φclay = 0.10

CBW = Clay-Bound Water

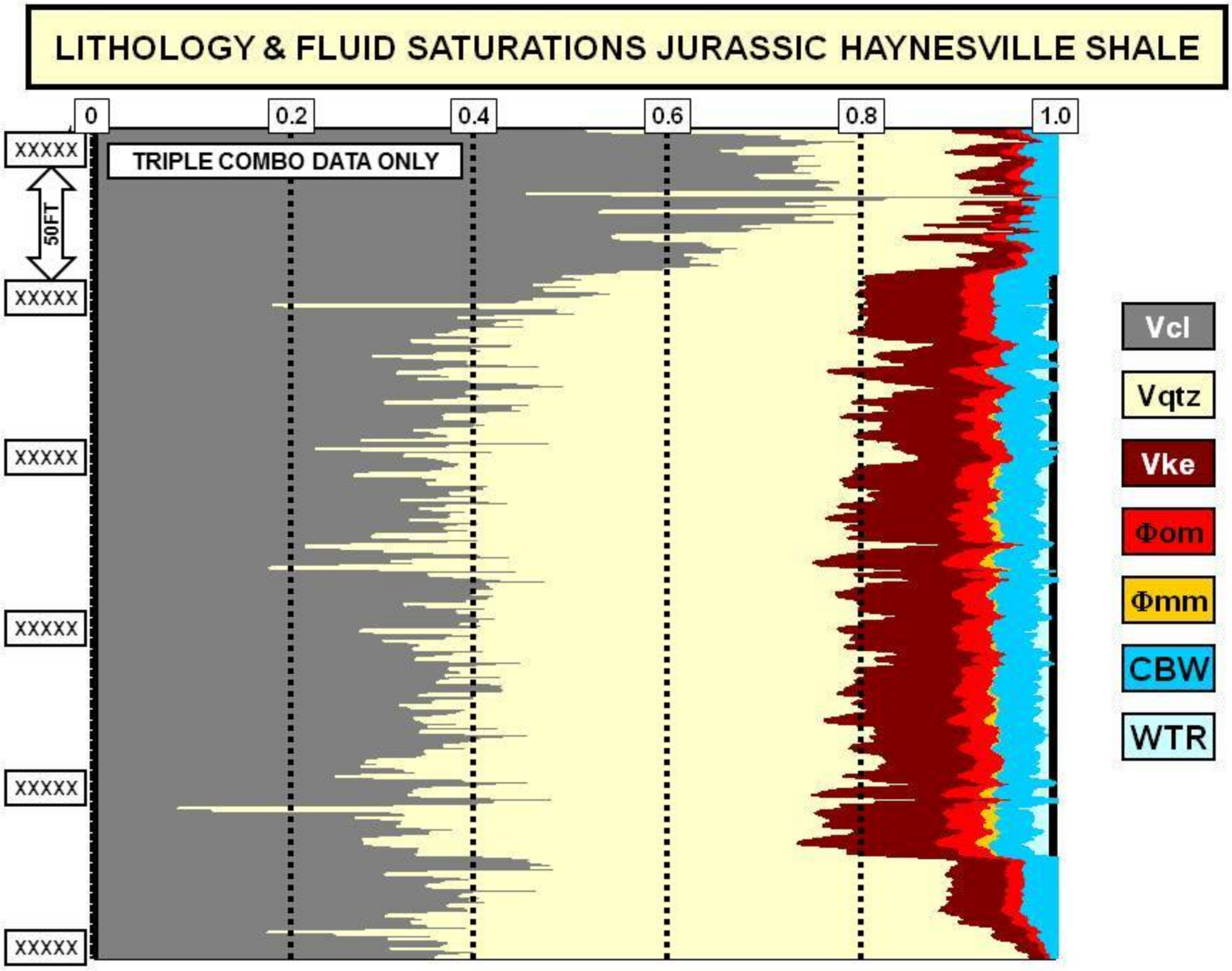
HYDROCARBON CORRECTION for Φnf and ρf

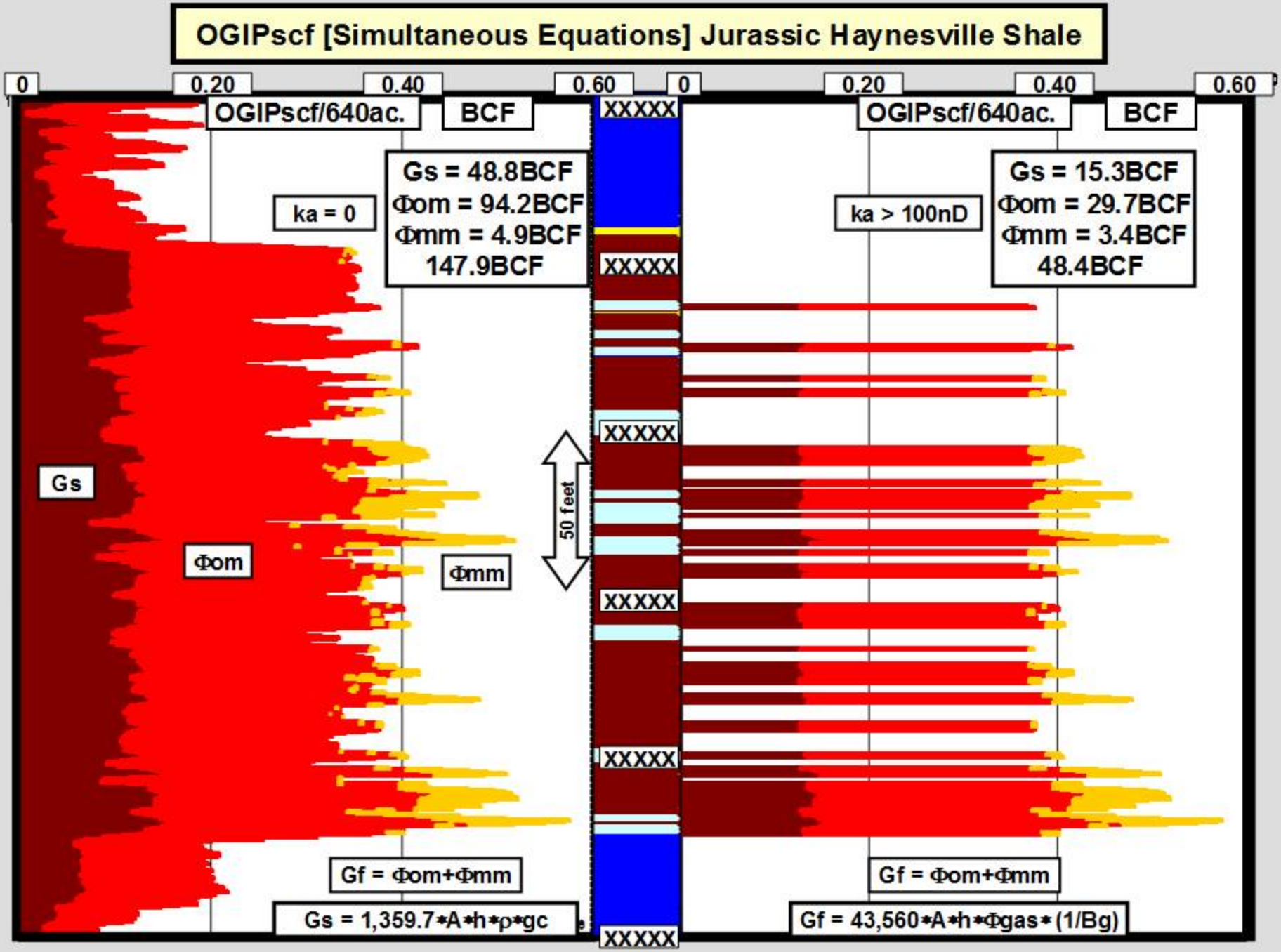
- GAS
  - **Φnf = (Sw∗Φnwater) + [(1.0-Sw)∗Φngas]**
  - **ρf = (Sw∗ρwater) + [(1.0-Sw)∗ρgas]**
- OIL
  - **Φnf = (Sw∗Φnwater) + [(1.0-Sw)∗Φnoil]**
  - **ρf = (Sw∗ρwater) + [(1.0-Sw)∗ρoil]**

Where:
Φngas = 0.4
Φnoil = 0.8
Φnwater = 1.0
ρgas = 0.1g/cc
ρoil = 0.85g/cc
ρwater = 1.1g/cc

LOGGING Co. CHART BOOKS

Sw = Water Saturation of the Uninvaded Zone [assume Sw = 0.20]


LITHOLOGY & FLUID SATURATIONS JURASSIC HAYNESVILLE SHALE
0
0.2
0.4
0.6
0.8
1.0
TRIPLE COMBO DATA ONLY
XXXXX
50FT
XXXXX
XXXXX
XXXXX
XXXXX
XXXXX
Vcl
Vqtz
Vke
Φom
Φmm
CBW
WTR


OGIPscf [Simultaneous Equations] Jurassic Haynesville Shale
0
0.20
0.40
0.60
OGIPscf/640ac.
BCF
Gs = 48.8BCF
Φom = 94.2BCF
Φmm = 4.9BCF
147.9BCF
ka = 0
Gs
Φom
Φmm
50 feet
XXXXX
Gf = Φom+Φmm
Gs = 1,359.7*A*h*ρ*gc
0
0.20
0.40
0.60
OGIPscf/640ac.
BCF
Gs = 15.3BCF
Φom = 29.7BCF
Φmm = 3.4BCF
48.4BCF
ka > 100nD
Gf = Φom+Φmm
Gf = 43,560*A*h*Φgas*(1/Bg)

OGIPscf

Resistivity[AIT90], ΦNls, RHOb Logs

plus

GEOCHEM [ECS] Logs

VARIABLE MATRIX ANALYSIS [GEOCHEM DATA]

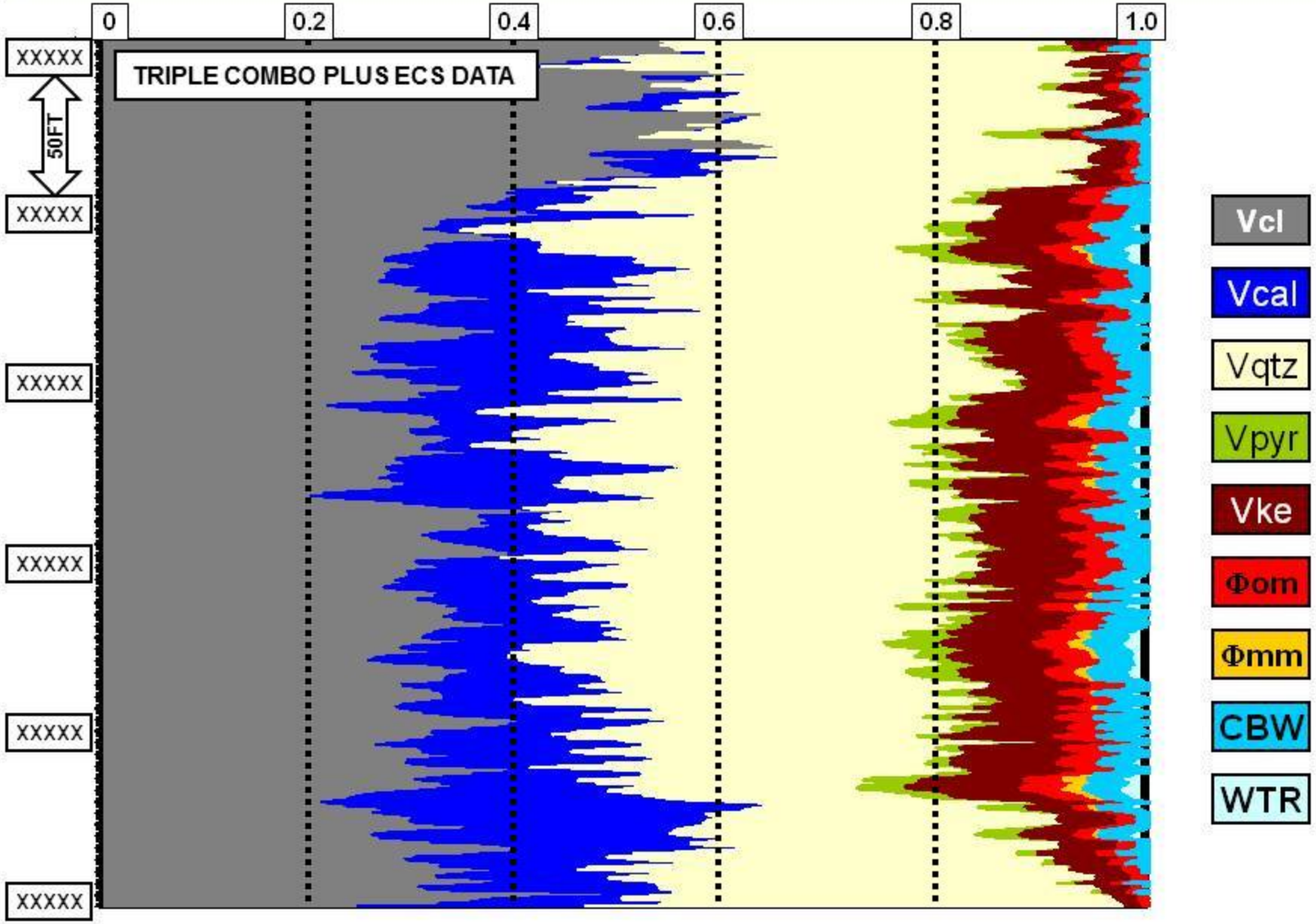
- **Φtotal = (ρma – ρb)/(ρma – ρf)**
- **ρf = (Sw∗1.1)+[(1-Sw)∗ρhc]**
- **ρhc = 0.1g/cc Gas ρhc = 0.85g/cc Oil**

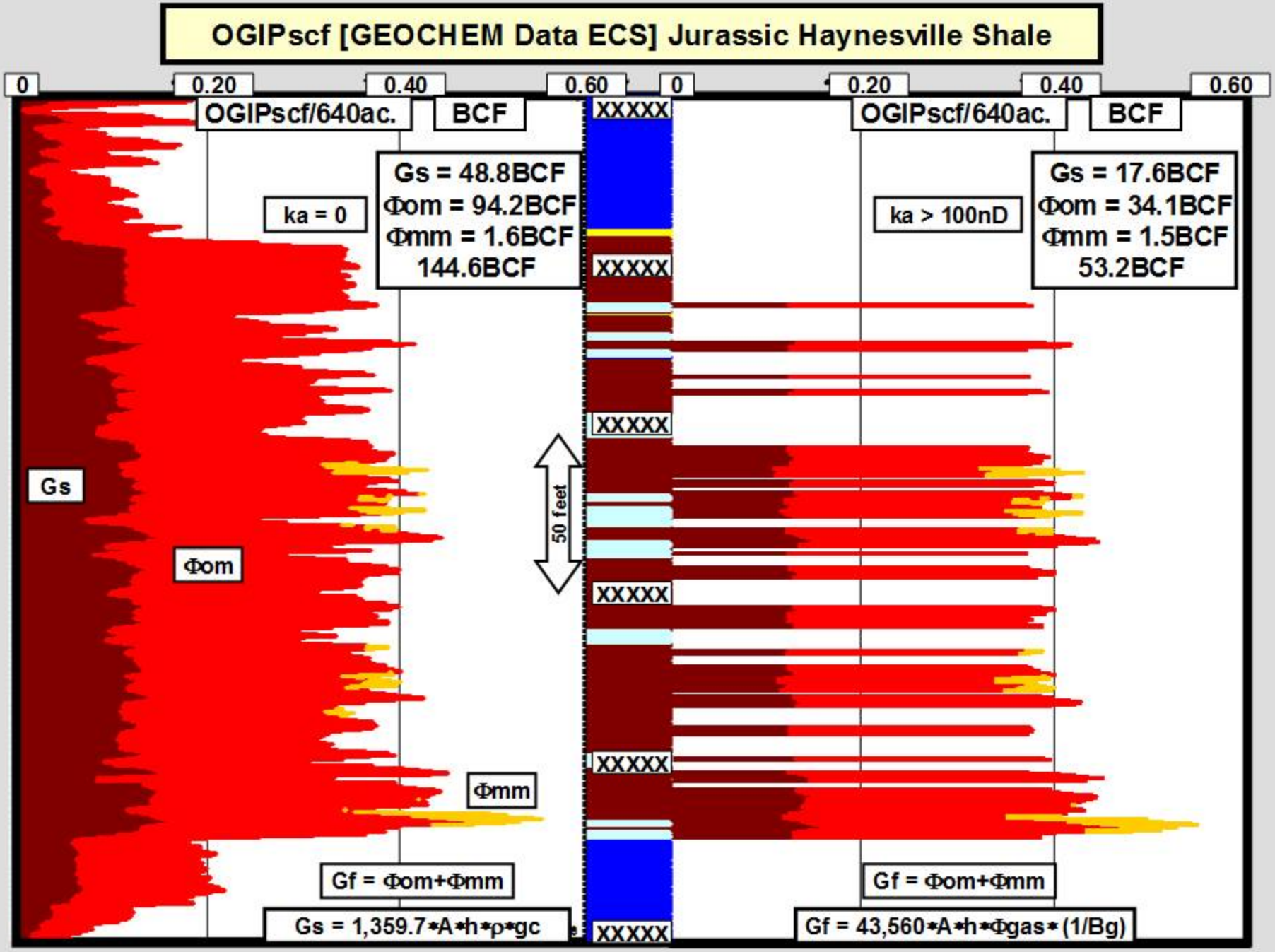
- **ρma = (Vcl∗ρcl)+(Vcal∗2.71)+(Vqtz∗2.65)+(Vpyr∗5)+(Vke∗ρke)**
- **ρke = 1.5 g/cc**
- **ρcl**
  - **Kaolinite = 2.61g/cc**
  - **Chorite = 2.92g/cc**
  - **Illite = 2.71g/cc**
  - **Illite/Smectite = 2.45g/cc**
  - **Smectite = 2.26g/cc**

Vke = (TOC∗Kvr∗ρb)/ρkerogen

EFFECTIVE POROSITY
Φe = Φtotal – CBW
CBW = Vcl ∗ 0.10 Φclay = 0.10
CBW = Clay-Bound Water

LITHOLOGY [ECS] & FLUID SATURATIONS JURASSIC HAYNESVILLE SHALE




OGIPscf [GEOCHEM Data ECS] Jurassic Haynesville Shale
0
0.20
0.40
0.60
OGIPscf/640ac.
BCF
Gs = 48.8BCF
Φom = 94.2BCF
Φmm = 1.6BCF
144.6BCF
ka = 0
Gs
Φom
Φmm
50 feet
XXXXX
Gf = Φom+Φmm
Gs = 1,359.7*A*h*ρ*gc
0
0.20
0.40
0.60
OGIPscf/640ac.
BCF
Gs = 17.6BCF
Φom = 34.1BCF
Φmm = 1.5BCF
53.2BCF
ka > 100nD
Gf = Φom+Φmm
Gf = 43,560*A*h*Φgas*(1/Bg)

GEOMECHANICS

ITTc & ITTs

Calculation of Minimum Horizontal Stress [σHmin] 2D

Isotropic Closure Stress Estimate (2D)

$$\sigma Hmin = [\mu/(1-\mu)]*[\sigma v-(X*Pp)]+X*Pp$$

μ = Poisson's Ratio
Pp = Pore Pressure [Depth∗0.9 psi/ft]
σv = Vertical Stress [Depth∗1.08psi/ft]
X = Poroelastic Constant [1.0]

Brittleness Coefficient

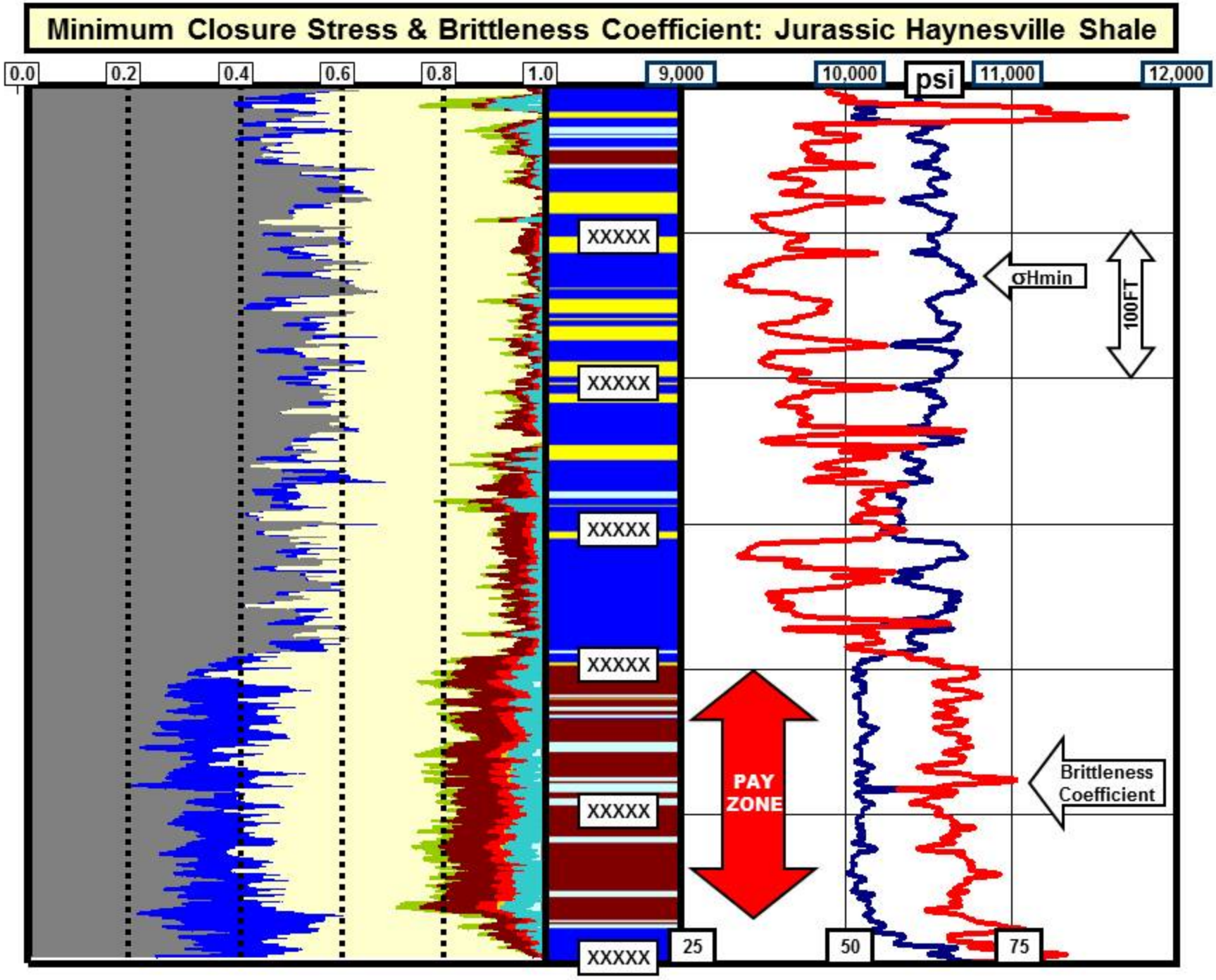
Brittleness Coefficient = 50∗{[(E-1)/7]+[(0.4-μ)/0.25]}

after: Rickman, and others, 2008 [from: Bateman, 2012]

Where:

E = Young's Modulus E = {2∗[(ρb/ITTs^2)∗1.34∗10^10]}∗(1+μ)

μ = Poisson's Ratio μ = [(0.5∗r^2)-1]/(r^2-1) r = ITTs/ITTc

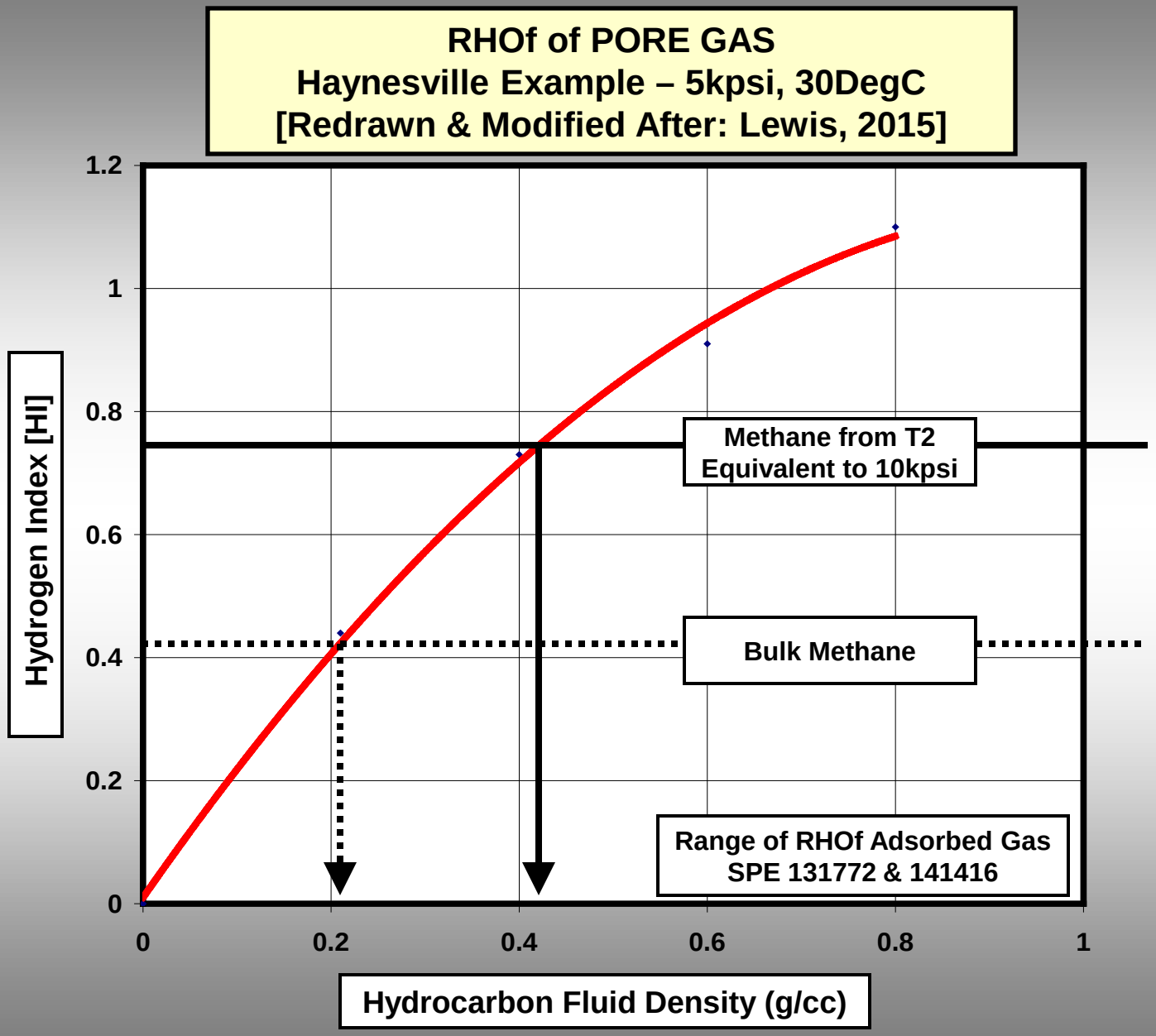

Minimum Closure Stress & Brittleness Coefficient: Jurassic Haynesville Shale
0.0
0.2
0.4
0.6
0.8
1.0
9,000
10,000
psi
11,000
12,000
XXXXX
XXXXX
XXXXX
XXXXX
XXXXX
XXXXX
σHmin
100FT
PAY ZONE
Brittleness Coefficient
25
50
75

CONCLUSIONS

- **OGIPscf calculated by the SIMULTANEOUS EQUATION Method using only Triple Combo log data [OGIPscf: 48.4BCF/sec] compares well with OGIPscf calculated using Triple Combo plus ECS data [OGIPscf: 53.2BCF/sec].**

- **Therefore reasonable values for OGIPscf can be calculated in the Haynesville Shale using the more commonly available Resistivity, ΦNls, and RHOb data.**

- **Pe versus RHOb Cross Plot is a Quick Look Method for defining the "SHALE SWEET SPOTS" with superior GEOMECHANICAL Properties.**


RHOf of PORE GAS
Haynesville Example – 5kpsi, 30DegC
[Redrawn & Modified After: Lewis, 2015]
Hydrogen Index [HI]
1.2
1
0.8
0.6
0.4
0.2
0
0
0.2
0.4
0.6
0.8
1
Hydrocarbon Fluid Density (g/cc)
Methane from T2
Equivalent to 10kpsi
Bulk Methane
Range of RHOf Adsorbed Gas
SPE 131772 & 141416

How Much More Methane in Pore Volume

[Haynesville Shale Data: (after: Lewis, 2015)]

- **Bulk Methane @ 5kpsi and 30 degC**
- **HI of 0.42 Equivalent to ρf of 0.2g/cc**

ALSO SEE:
Ravinath & others, 2016
SPWLA Trans. p. UUU

- **NMR Results of Core @ 5kpsi and 30degC**
- **HI of 0.73 Equivalent to ρf of 0.42g/cc**
- **Bulk Methane Equivalent Pressure of 9kpsi**
- **40% increase in Free Gas**
- **Results are NOT confirmed with canister desorption core data.**

HI (Hydrocarbon Hydrogen Index) = [NMR T2 Peak (3ms-33ms)]/Φnmr