Integration of Core and Log Data to Determine Producible Volume of Oil from the Eagle Ford Shale

(SPE 164554)

Erik Rylander, Tianmin Jiang, Philip Singer, Rick Lewis

Schlumberger

Steve Sinclair

Matador Resources

Key Factors for Economic Tight Rocks

- Hydrocarbon in Place
- Hydrocarbon Viscosity
- Matrix Permeability
- Pore Pressure
- Hydraulic Fracture Surface Area
- Hydraulic Fracture Conductivity
- Hydraulic Fracture Containment

Reservoir Quality

Completion Quality

Oil-Producing Shales

- Can oil flow through a shale matrix?
  - What is permeability to oil?
    - No commercial core analysis
  - Oil ~20 times more viscous than gas
  - Can we produce oil through nanopores?
  - Are pores and pore throats still nanoscale ?
  - Are we producing condensate or oil?
  - Is flow governed by something other than Darcy's law?

Darcy's Law

- Flow of fluid through porous medium

$$Q \propto \frac{k \bullet \Delta p}{\mu}$$

$$Q = \text{flowrate}$$

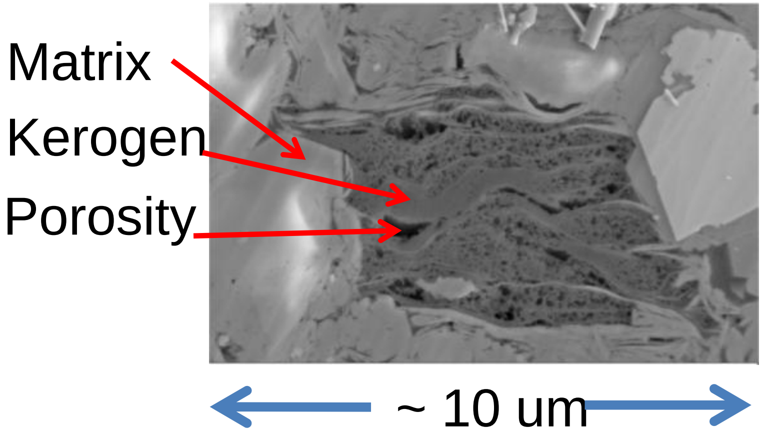
$$k = \text{permeability}$$

$$\Delta p = \text{pressure drop}$$

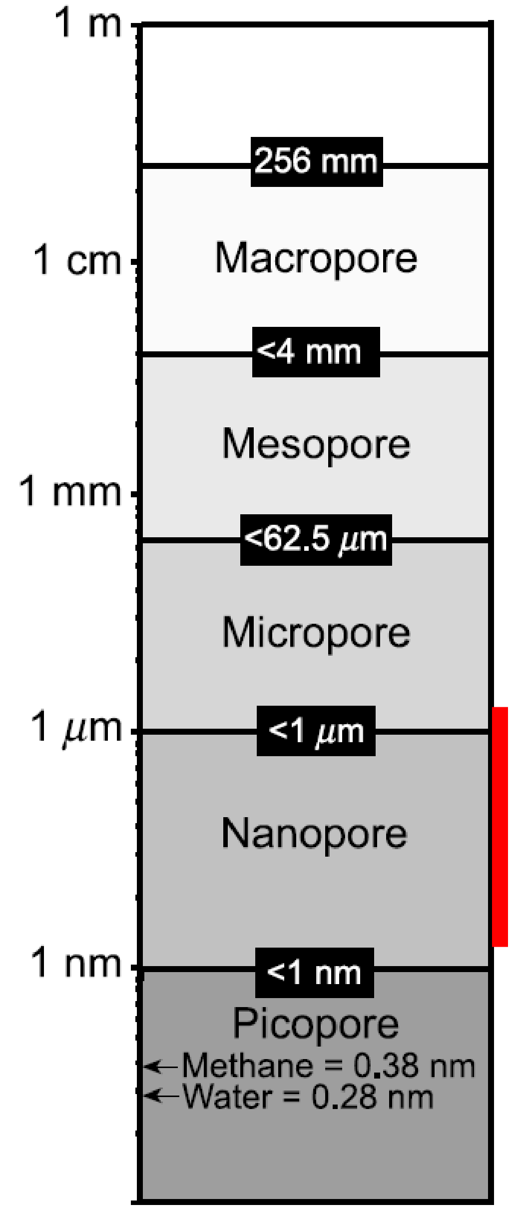
$$\mu = \text{viscosity}$$

- Viscosity
  - Gas 0.02 cP
  - Oil 0.4 cP

Organic Shale Pore System



Diameter (nm)	
0.38	Methane Molecule
0.38 to 10	Oil Molecule
4 to 70	Pore Throat
15 to 200	Virus
5 to 750	Organic Pore
10 to 2000	Inter/Intra Particle Pores
200 to 2000	Bacteria
35000-65000	Shale Size Particle (mean)



Loucks, et al, GCAGS, April 2010

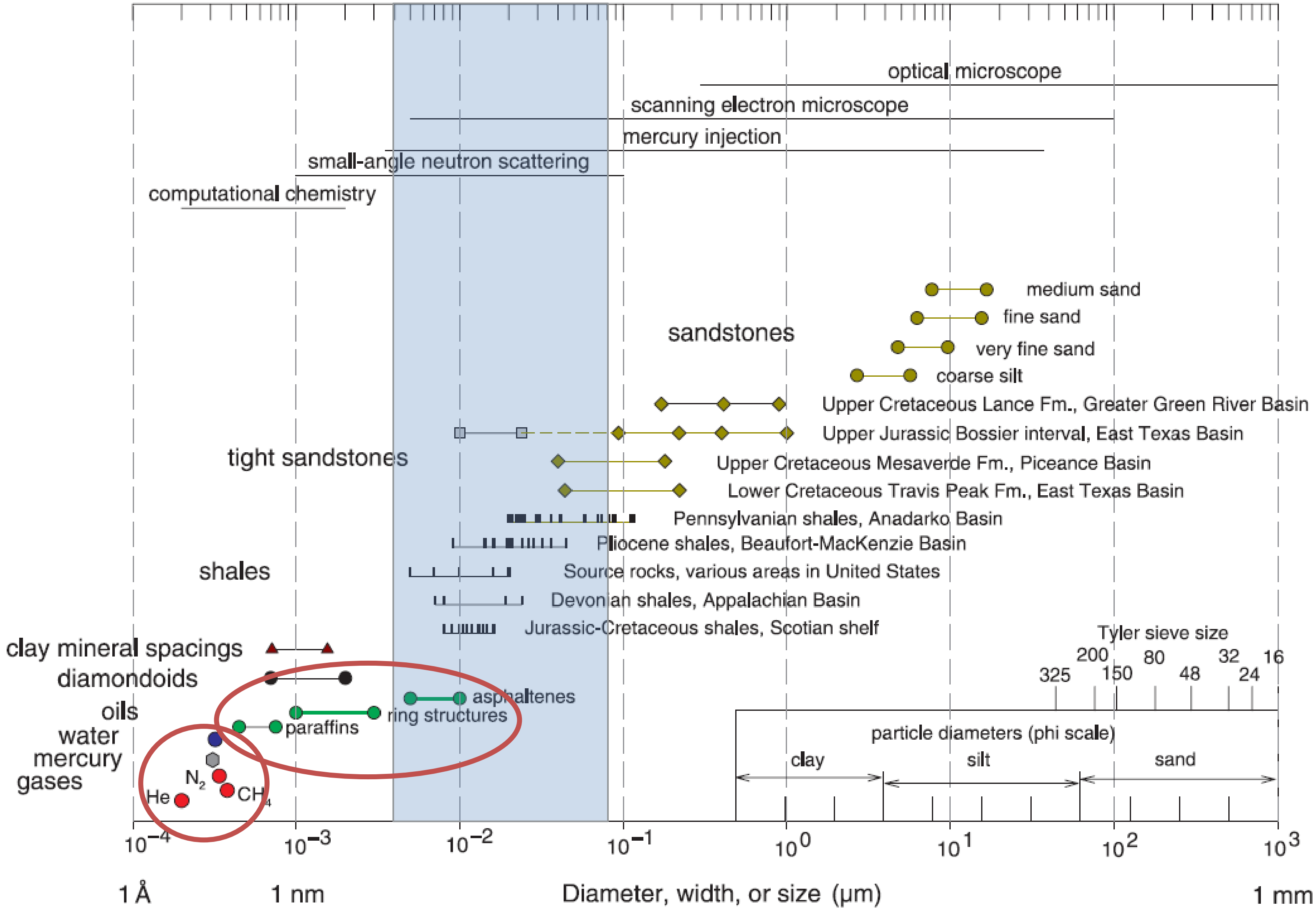


Figure 2. Sizes of molecules and pore throats in siliciclastic rocks on a logarithmic scale covering seven orders of magnitude. Measurement methods are shown at the top of the graph, and scales used for solid particles are shown at the lower right. The symbols show pore-throat sizes for four sandstones, four tight sandstones, and five shales. Ranges of clay mineral spacings, diamondoids, and three oils, and molecular diameters of water, mercury, and three gases are also shown. The sources of data and measurement methods for each sample set are discussed in the text.

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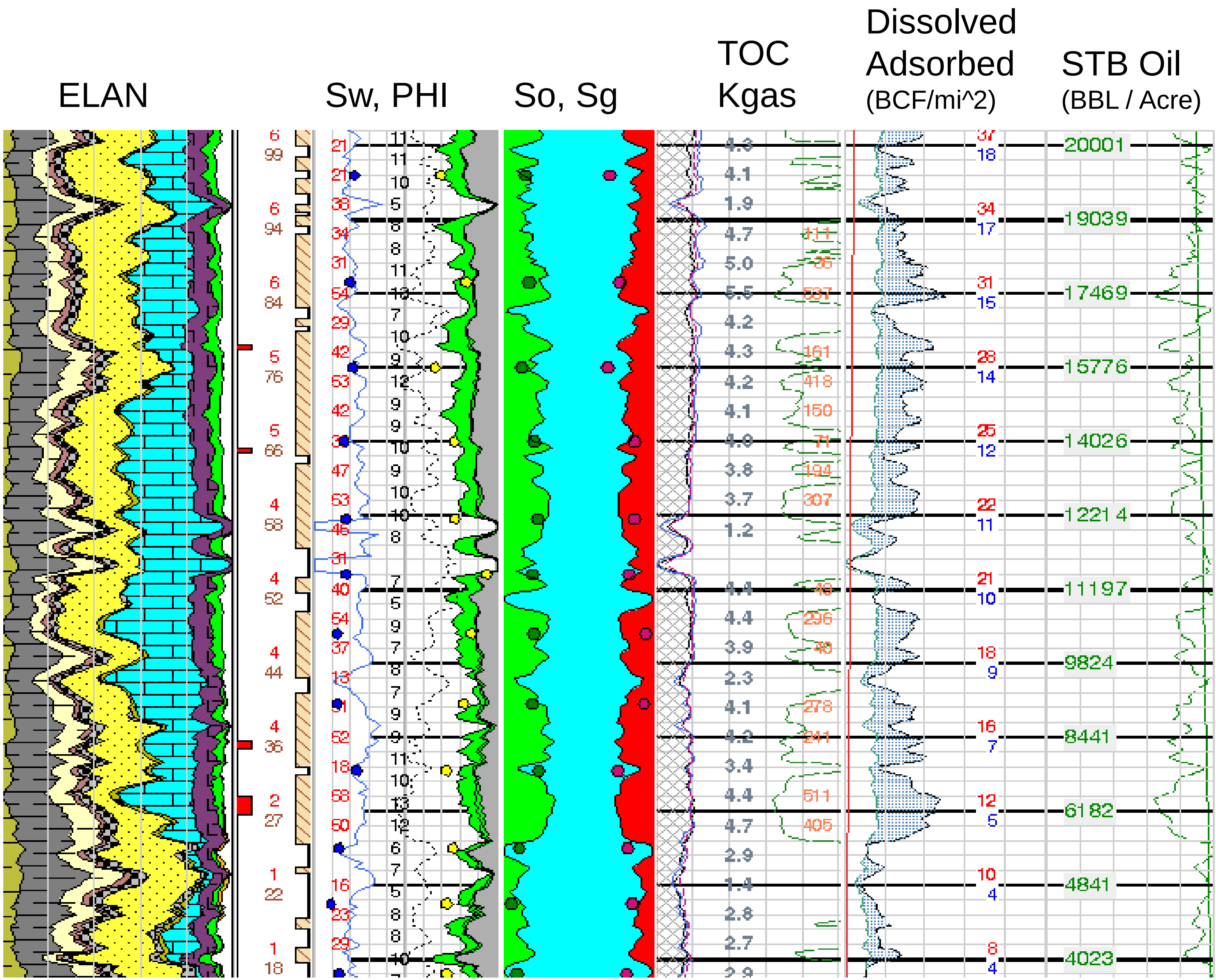
Oil Evaluation – Match to Core



What's Pay?

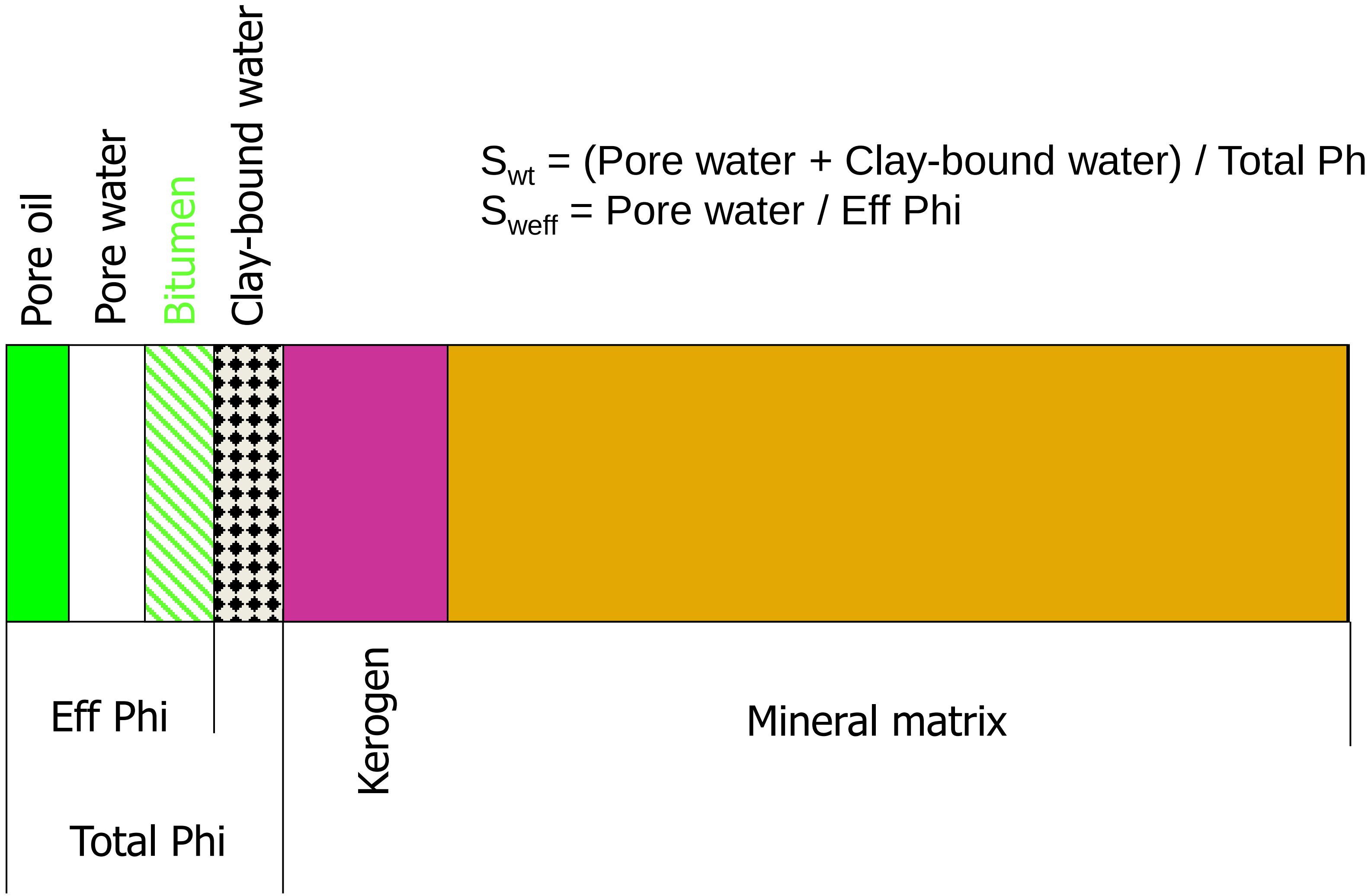
What is pay for shale liquid producer?

- Models for gas may be inadequate for viscous hydrocarbon.
- What is permeability to oil in nanopores?
- How much OIP is producible, not-producible?
- NMR core-log comparison provides indication of hydrocarbon expelled during core extraction.

Tight Oil Constituents by Volume

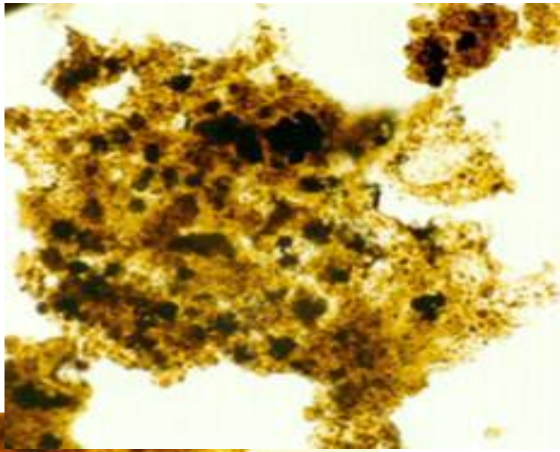
S_{wt} = (Pore water + Clay-bound water) / Total Phi

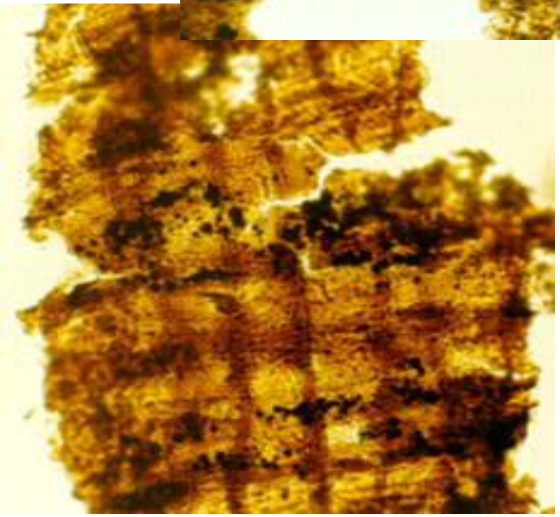
S_{weff} = Pore water / Eff Phi



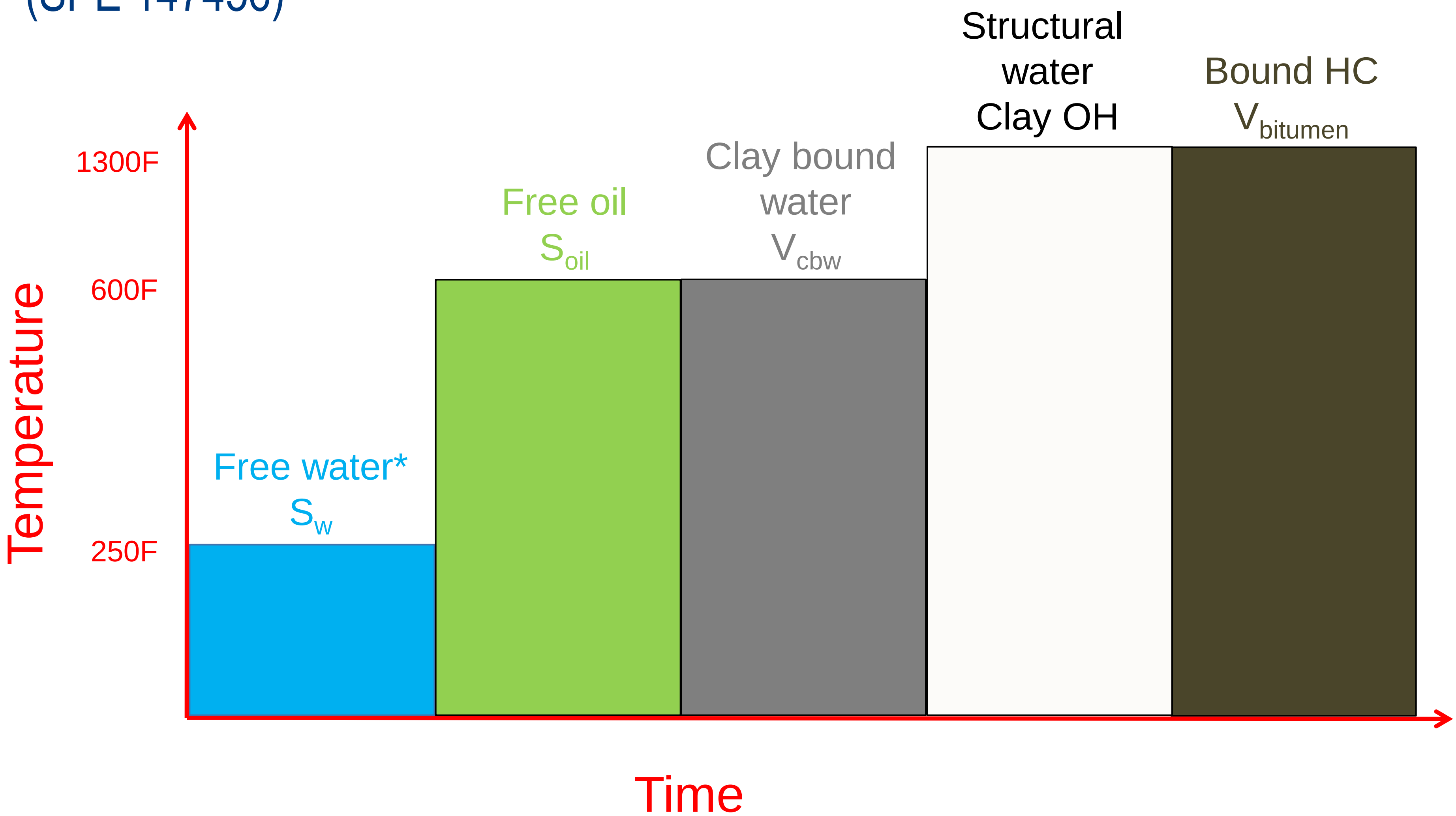
Definitions of Kerogen and TOC

- Kerogen
  - Insoluble organic matter
  - Primarily C and H
  - Lesser O, S, and N
  - H decreases with maturity
  - Rarely quantified by core analysis
  - Low grain density (1.1 to 1.4 g/cm^3) that increases with maturity
- Bitumen
  - Soluble organic matter
  - Low maturity product
  - Non-producible at typical reservoir temperatures
- Total Organic Carbon (TOC)
  - Weight percent carbon in organic matter
  - Does not include other elements in kerogen
  - Common core analysis, very consistent results





Retort Steps
(SPE 147456)



* May include CBW if smectitic clays present

Retort Core Data

Bound Hydrocarbon
Percent bulk volume

Mature Gas Shale

AR Bulk Density	AR Grain Density	Dry Grain Density	Porosity	H2O sat	Gas sat	Oil sat	GFP	BHC	BCW	TOC	Perm
2.59	2.69	2.73	6.15	34.22	61.90	3.89	3.81	0.24	5.26	3.85	0.000234
2.49	2.60	2.64	6.38	31.80	64.58	3.61	4.12	0.23	4.61	5.89	0.000159
2.54	2.66	2.68	5.48	18.02	77.68	4.29	4.26	0.24	3.15	4.64	0.000204
2.47	2.61	2.65	7.32	21.21	75.67	3.12	5.54	0.23	5.02	7.47	0.000255
2.77	2.82	2.83	2.27	13.58	82.34	4.08	1.87	0.09	1.44	1.54	0.000058
2.64	2.70	2.71	2.93	28.36	69.97	1.67	2.05	0.05	2.39	2.21	0.000068

Gas Shale

AR Bulk Density	AR Grain Density	Dry Grain Density	Porosity	H2O sat	Gas sat	Oil sat	GFP	BHC	BCW	TOC	Perm
2.52	2.56	2.60	4.19	42.67	41.77	15.56	1.75	1.05	5.64	1.67	0.000073
2.53	2.60	2.67	6.48	40.86	46.15	12.99	2.99	1.40	6.27	2.47	0.000103
2.58	2.66	2.77	9.25	63.16	34.27	2.58	3.17	0.00	9.06	1.16	0.000063
2.64	2.65	2.70	3.24	71.38	18.07	10.54	0.59	0.10	7.51	0.97	0.000033

Immature Shale

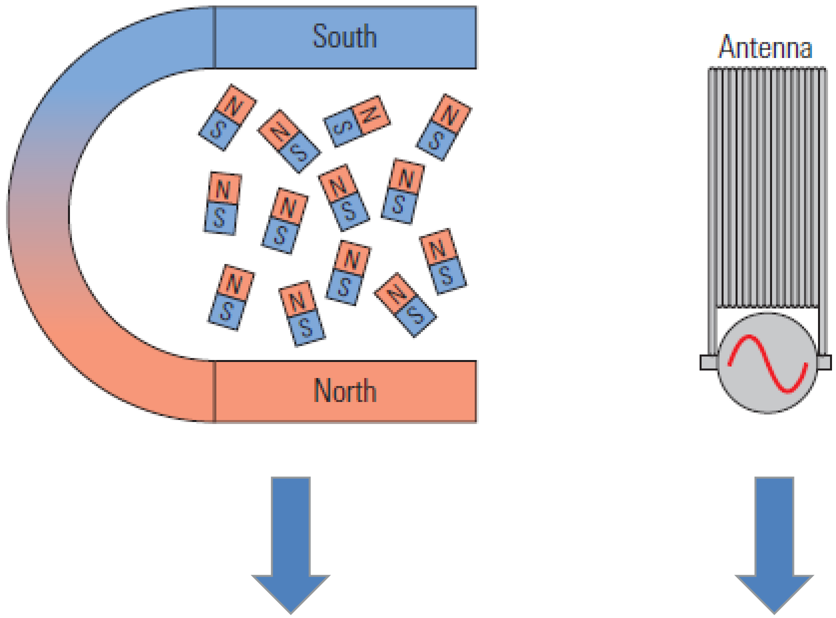
AR Bulk Density	AR Grain Density	Dry Grain Density	Porosity	H2O sat	Gas sat	Oil sat	GFP	BHC	BCW	TOC	Perm
2.47	2.54	2.66	9.70	59.29	26.67	14.04	2.59	2.73	6.50	3.21	0.000068
2.45	2.55	2.65	9.70	52.31	37.12	10.57	3.60	3.70	7.31	4.10	0.000084
2.34	2.41	2.48	7.22	26.65	44.93	28.42	3.25	7.61	4.11	6.93	0.000151
2.36	2.42	2.49	6.68	39.31	37.03	23.66	2.48	5.42	5.79	11.22	0.000147
2.41	2.47	2.51	4.87	35.51	54.22	10.27	2.64	3.10	0.97	6.95	0.000102
2.35	2.41	2.47	6.09	35.03	44.13	20.85	2.69	8.32	3.54	7.07	0.000075

NMR Theory

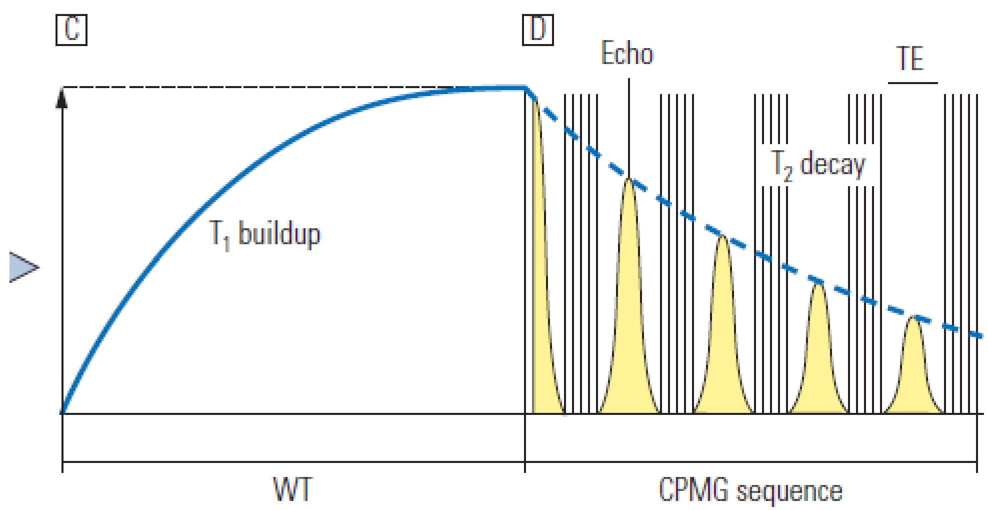
Hydrogen atoms behave like bar magnets and align with permanent magnets.

During set wait time, the nuclei polarize at exponential build up rate- T_1

Function of pore size distribution, fluid properties, and mineralogy.

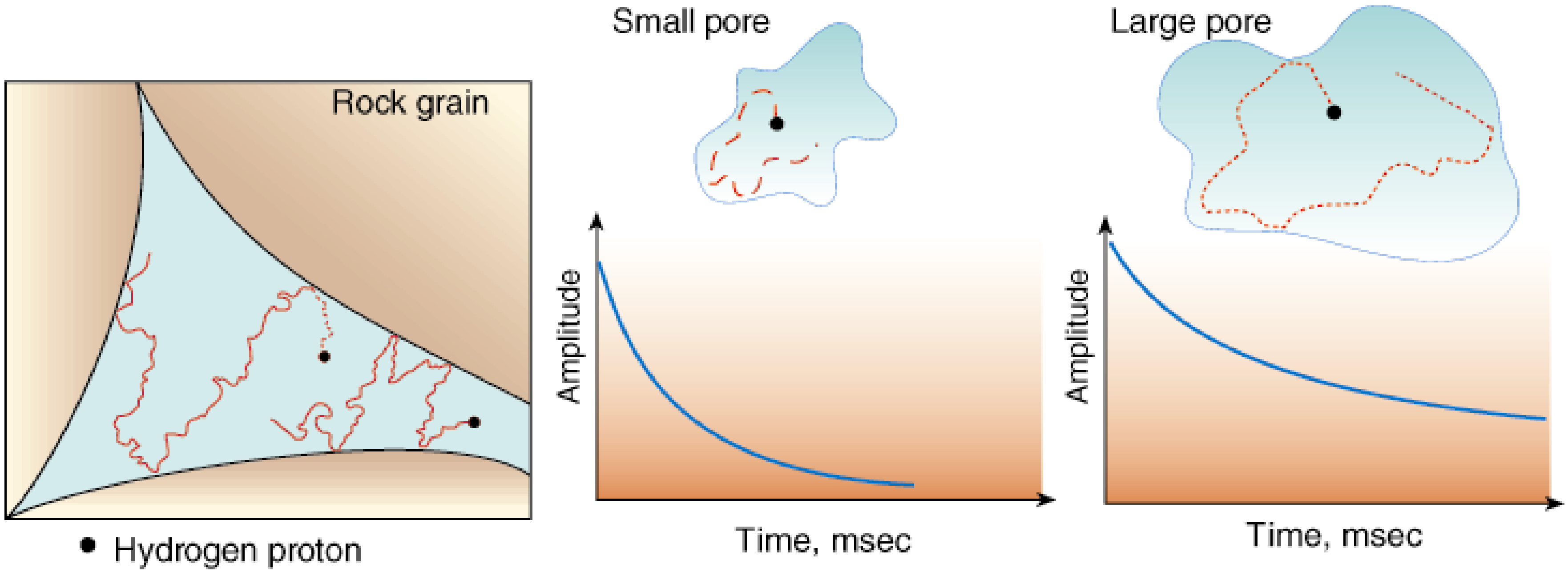


Train of RF pulses tip nuclei 90° and precess around permanent field. Fluids generate RF echoes between pulses which are received and measured by NMR tool.



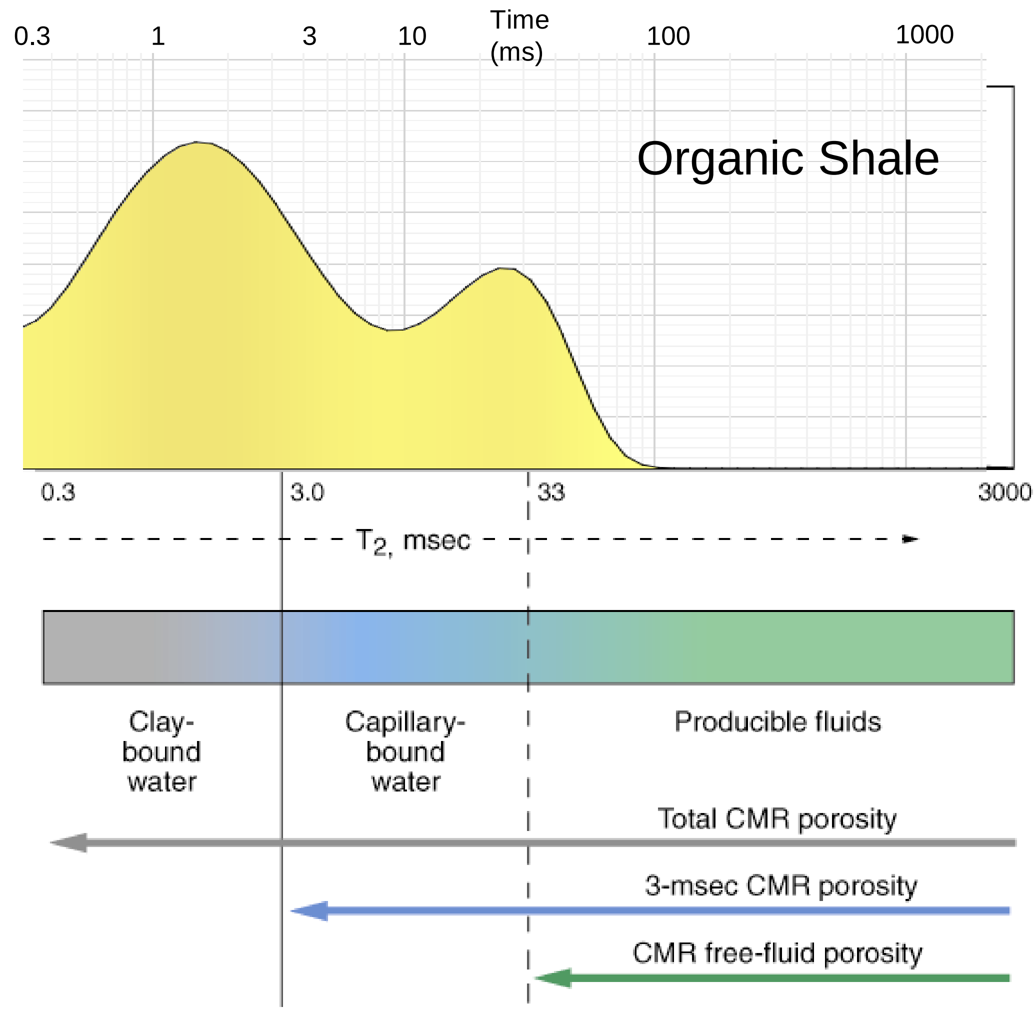
Grain Surface Relaxation

- T_2 relaxation time is a function of
  - Liquid viscosity
  - Pore size
  - Rock grain magnetic properties



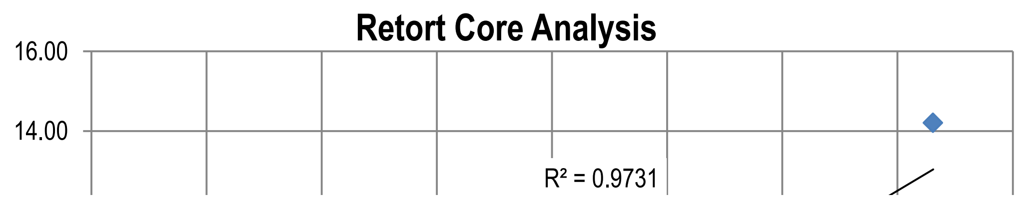
NMR T_2 Time Distribution

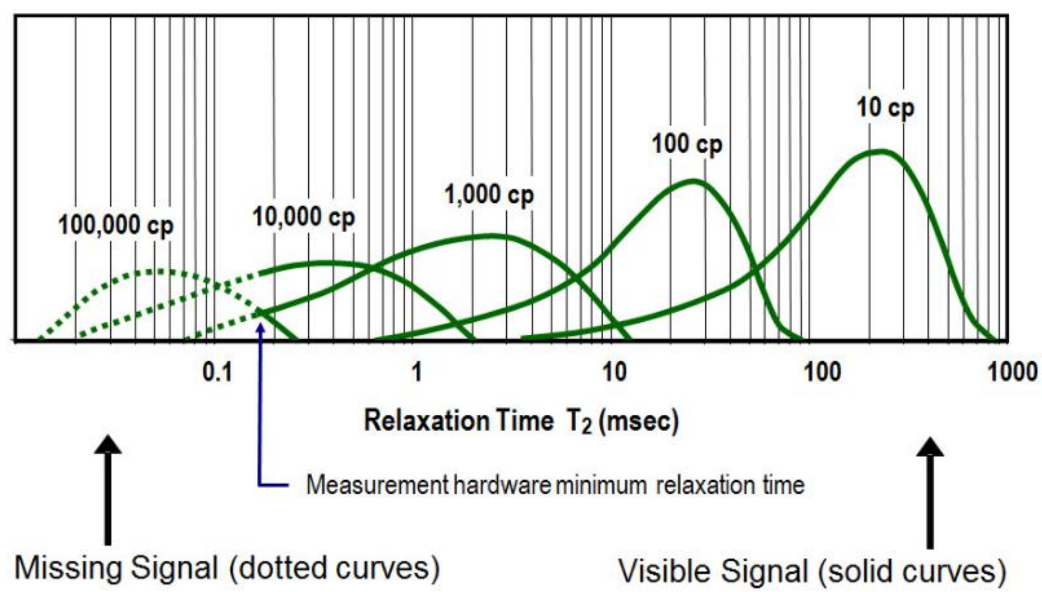
- T_2 time distribution is measured and binned for each 6" interval
- T_2 time distribution provides information on porosity and pore size distribution
- Total area is porosity
- Shorter time - smaller pore size
- Boundary between capillary bound and free water is empirical



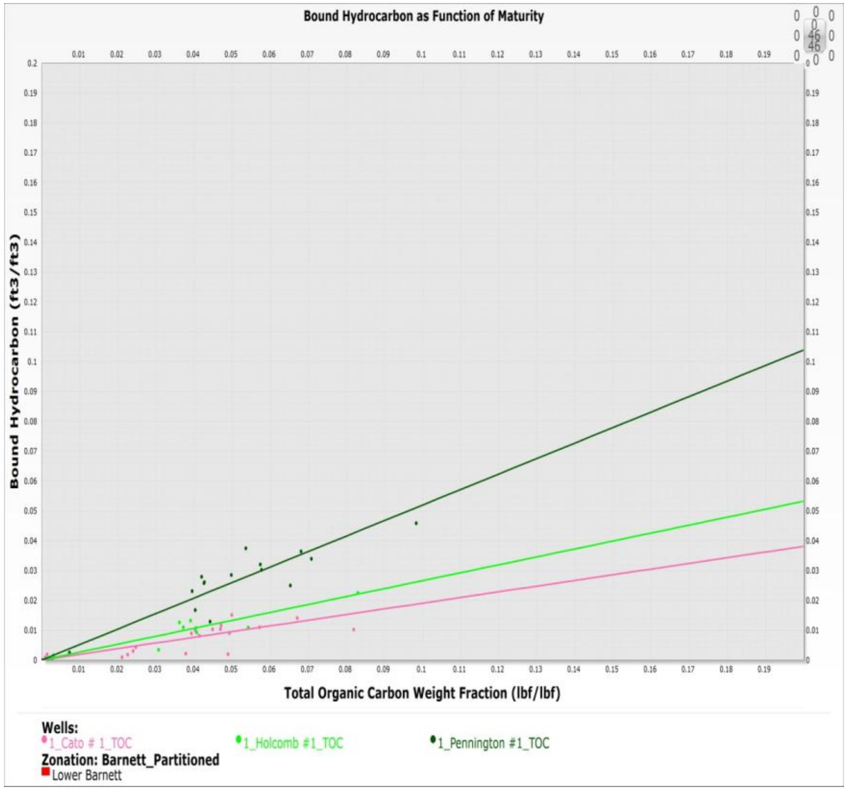
Types of Bitumen

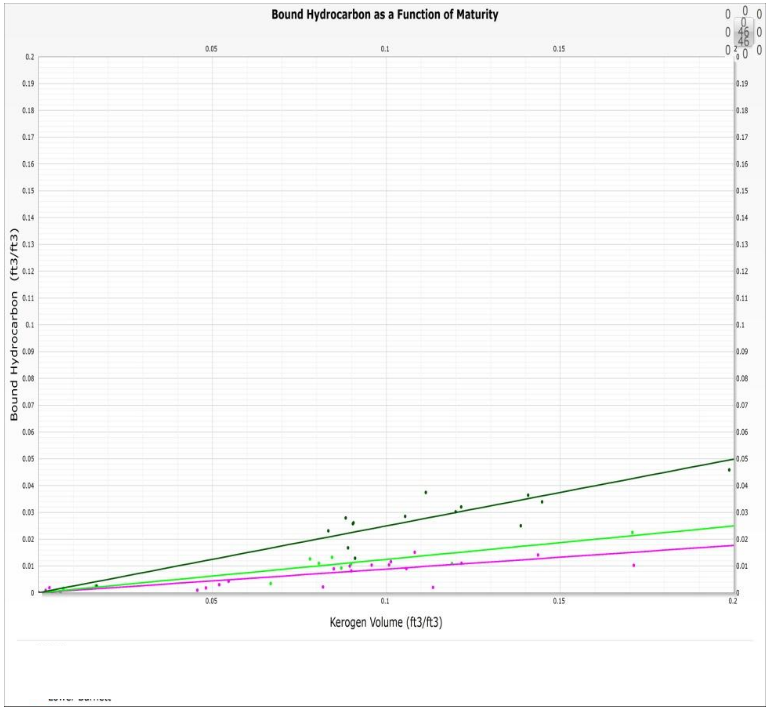
- Viscous hydrocarbon
- Source Rock Bitumen
  - Generated during early maturation of kerogen
    Converts to oil and gas
  - Soluble organic matter
- Crude Bitumen
  - Degraded remnants
  - Tar sands



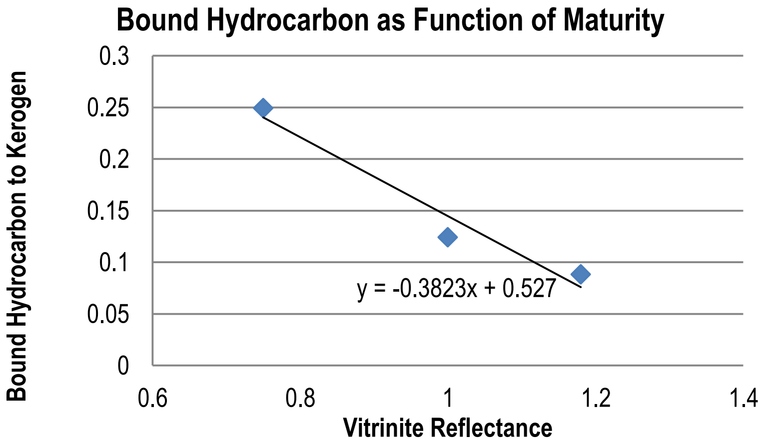


Bound Hydrocarbon as Function of Maturity





Well	VR	Bnd:TOC	Bnd:Kerogen
1	0.75	.51	.249
2	0.92		
3	1.00	.27	0.124
4	1.18	.19	0.088
5	1.28		

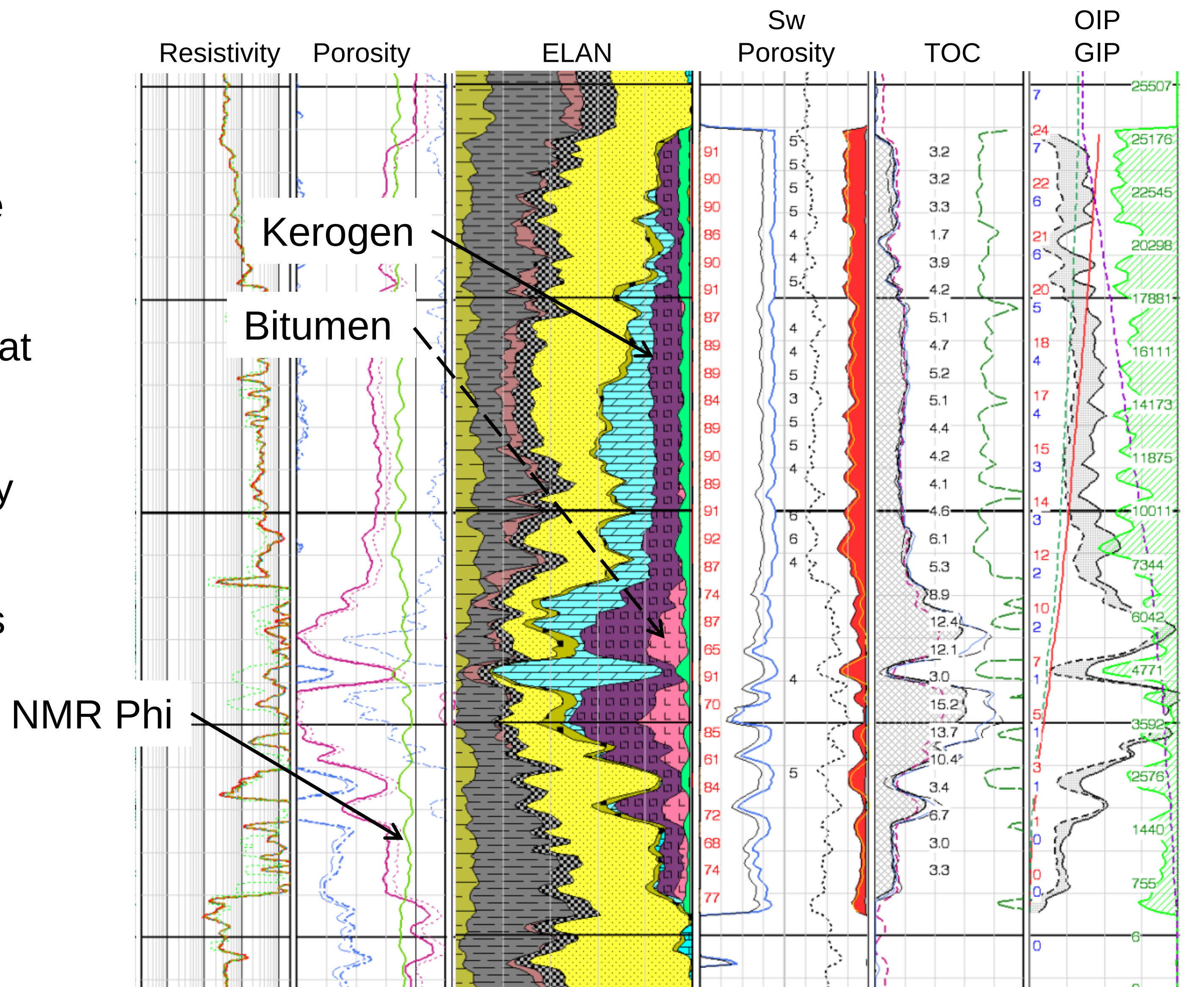


Bitumen Log Response

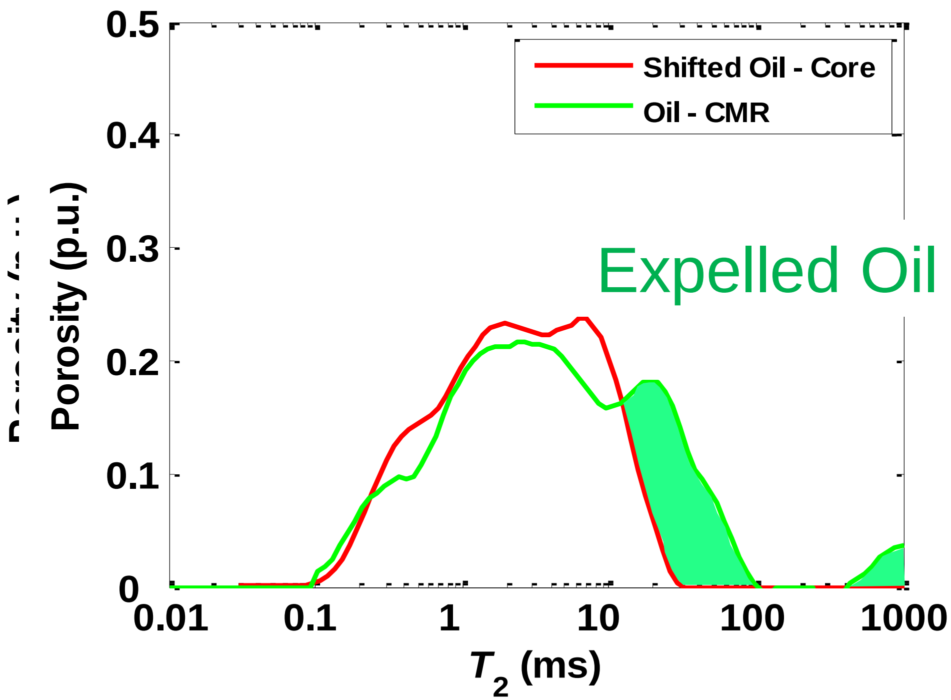
Nuclear log response similar to oil

Not imaged by NMR at typical viscosities

Typically exhibits very high resistivity
Absorbs water at reservoir conditions



Comparison of Core NMR to Log NMR: investigate expelled fluids



- Heated core to reservoir temperature to minimize shift in T2 distribution *(surface relaxivity function of viscosity)*

- Comparison of porosity taken at equivalent echo spacing (200 μs)

- Estimate position of water signal from T1/T2 data and magnitude from water saturation

- Remove water signal from both core and NMR data

- Shift to compare oil signal from core to log

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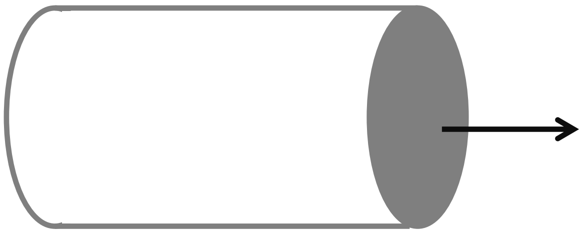
Centrifuge of core:
Free fluid already displaced

$$Q \propto \frac{k \bullet \Delta p}{\mu}$$



Length = 2.0 in
Area = 1.76 in
ΔP = 1000 psi
Maxflow = (0.1)/(3*24*60) = 2.315E-5 ml/min
(centrifuge resolution is 0.1cc, spun for 3 days)

$$mobility < \frac{Maxflow \bullet Length}{Area \bullet \Delta P} = 2.5nD / cP$$

No expelled fluid after spinning core to air at 1000 psi capillary pressure for 3 days; upper bound for core

Free Fluid in core was therefore displaced when the core was taken to ambient surface conditions

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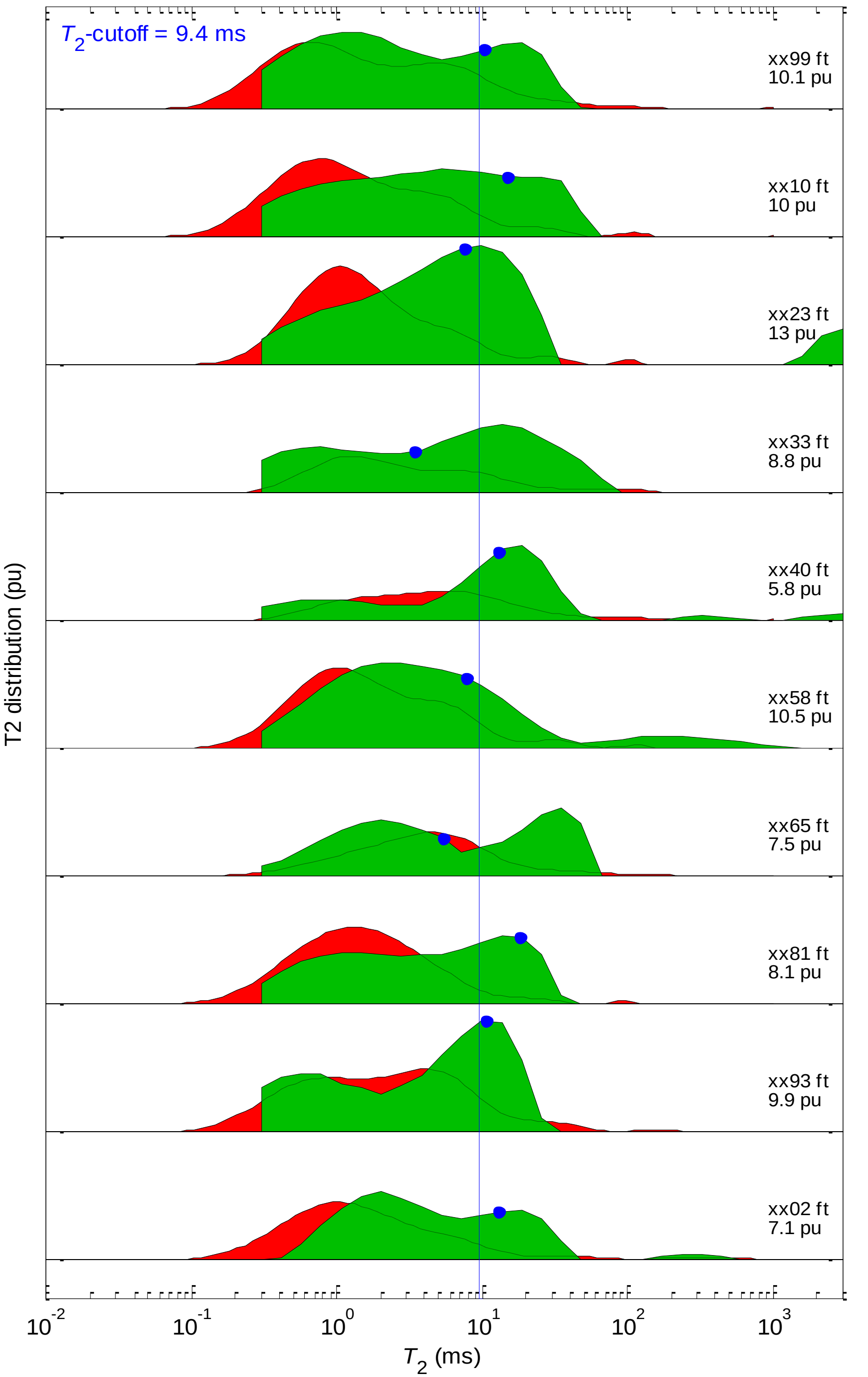
T2 Cutoff ~ 9.4 ms



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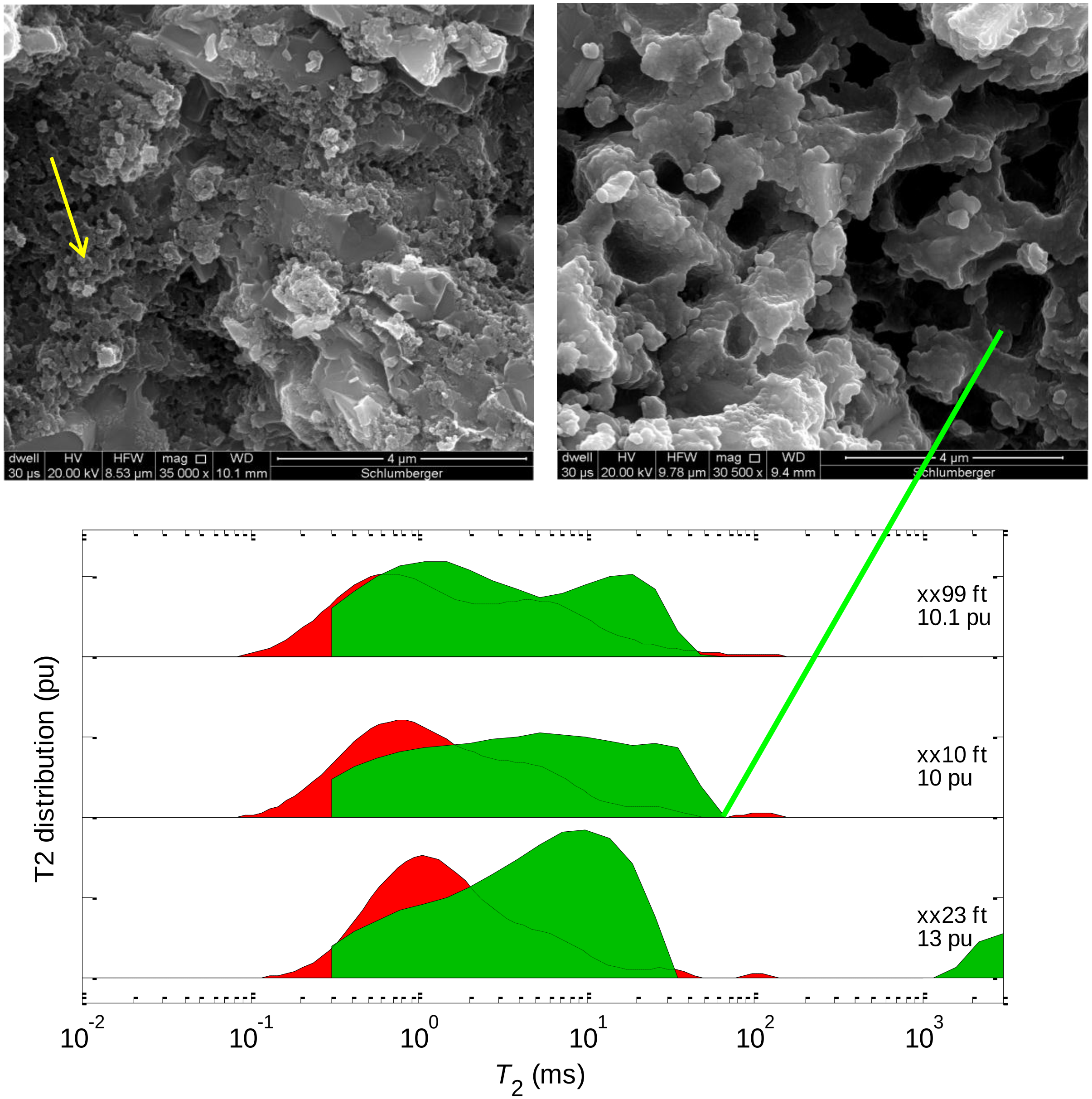
dwell
30 µs
HV
20.00 kV
HFW
8.53 µm
mag
35 000 x
WD
10.1 mm
4 µm
Schlumberger
dwell
30 µs
HV
20.00 kV
HFW
9.78 µm
mag
30 500 x
WD
9.4 mm
4 µm
Schlumberger
T2 distribution (pu)
xx99 ft
10.1 pu
xx10 ft
10 pu
xx23 ft
13 pu
10^{-2}
10^{-1}
10^{0}
10^{1}
10^{2}
10^{3}
T_2 (ms)

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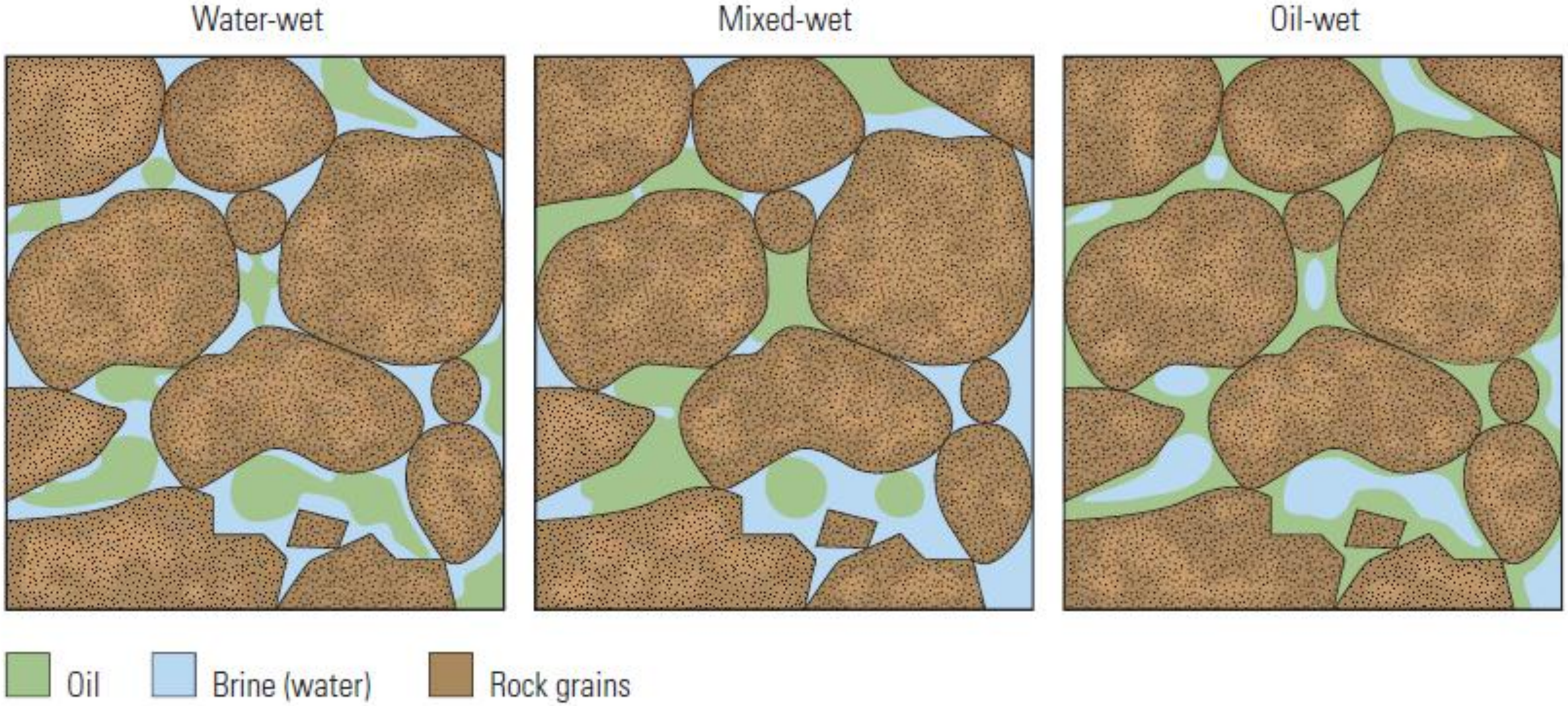
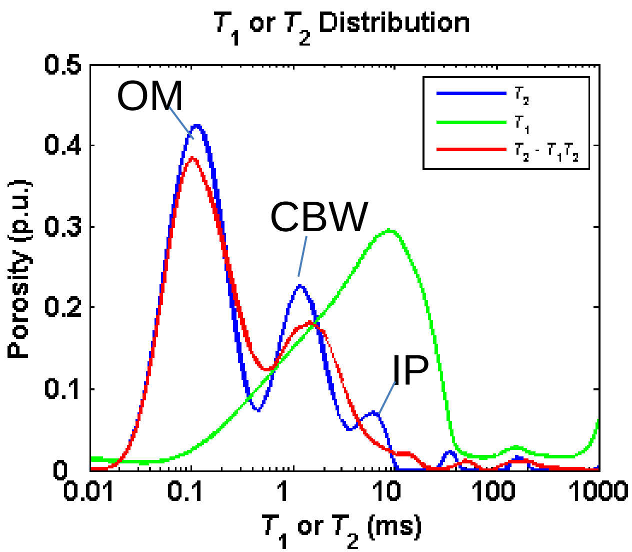
Wettability



T_1 vs. T_2 result from core: T_1 to T_2 ratio reflects wetting phase

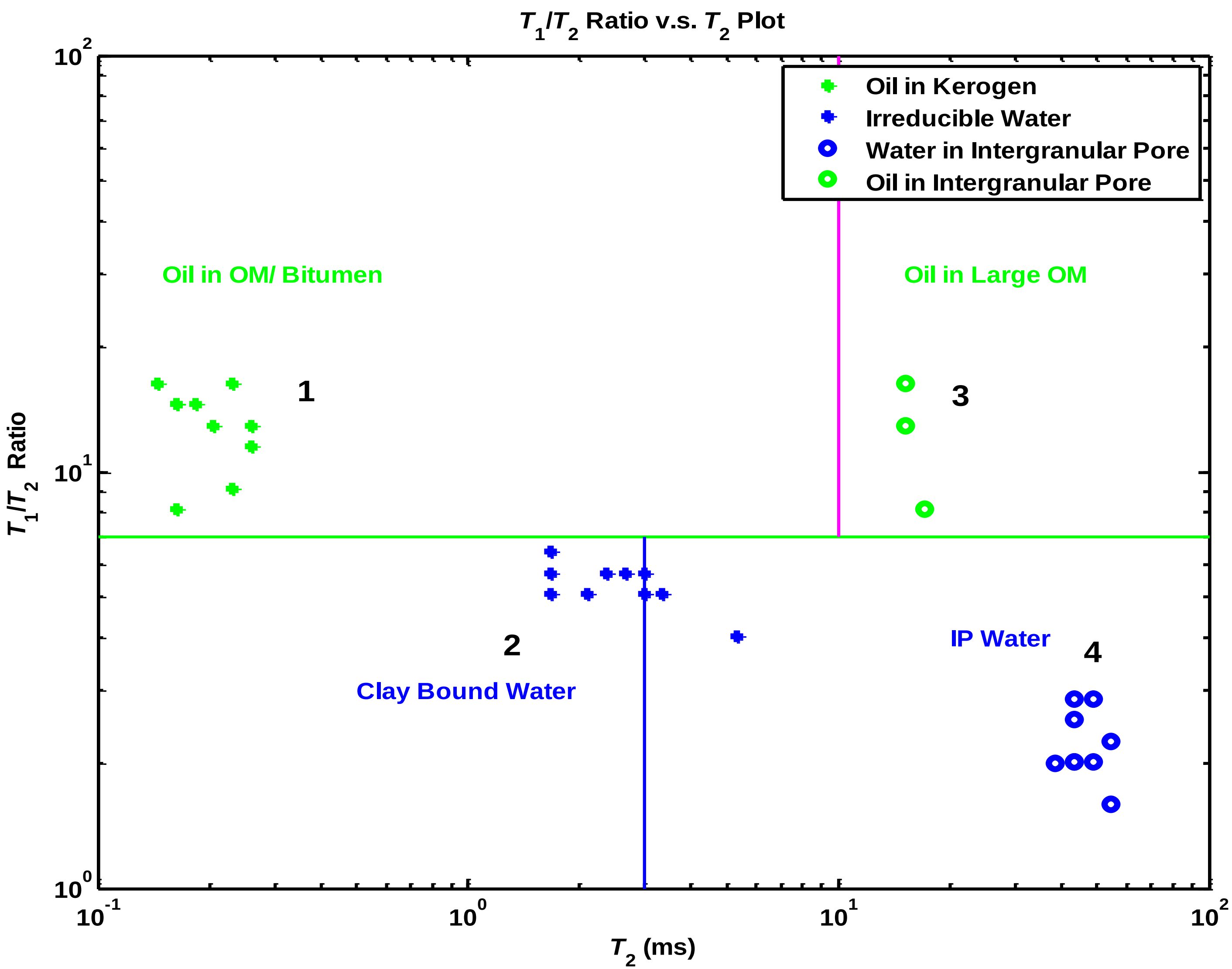


Interpretation

- Brine T_1/T_2 ratio is less than the hydrocarbon T_1/T_2 in shale*
    - OM pores are oil wet
    - IP pores are mixed wet
- Non-wetting fluid T_1/T_2 ratio close to 1
    - None observed! Implies
        - *Expelled fluids OR*
        - *Monophasic fluids*

* AYSE EZGI OZEN Norman, Oklahoma 2011

Four Pore Systems



Pore Distribution

Monophasic Pores

Clay-Bound Water Bitumen	Cap-Bound Water Cap-Bound Oil (OM Pores)	Cap-Bound Water Free Oil (Larger OM Pore > 250 nm)	Producible Fluids Oil and Water (Water wet pores)

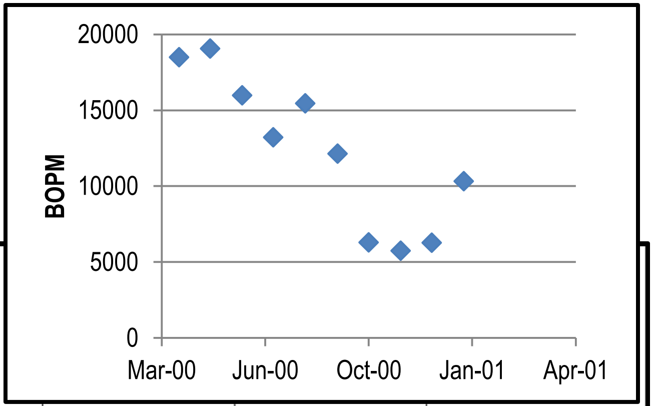
3 ms

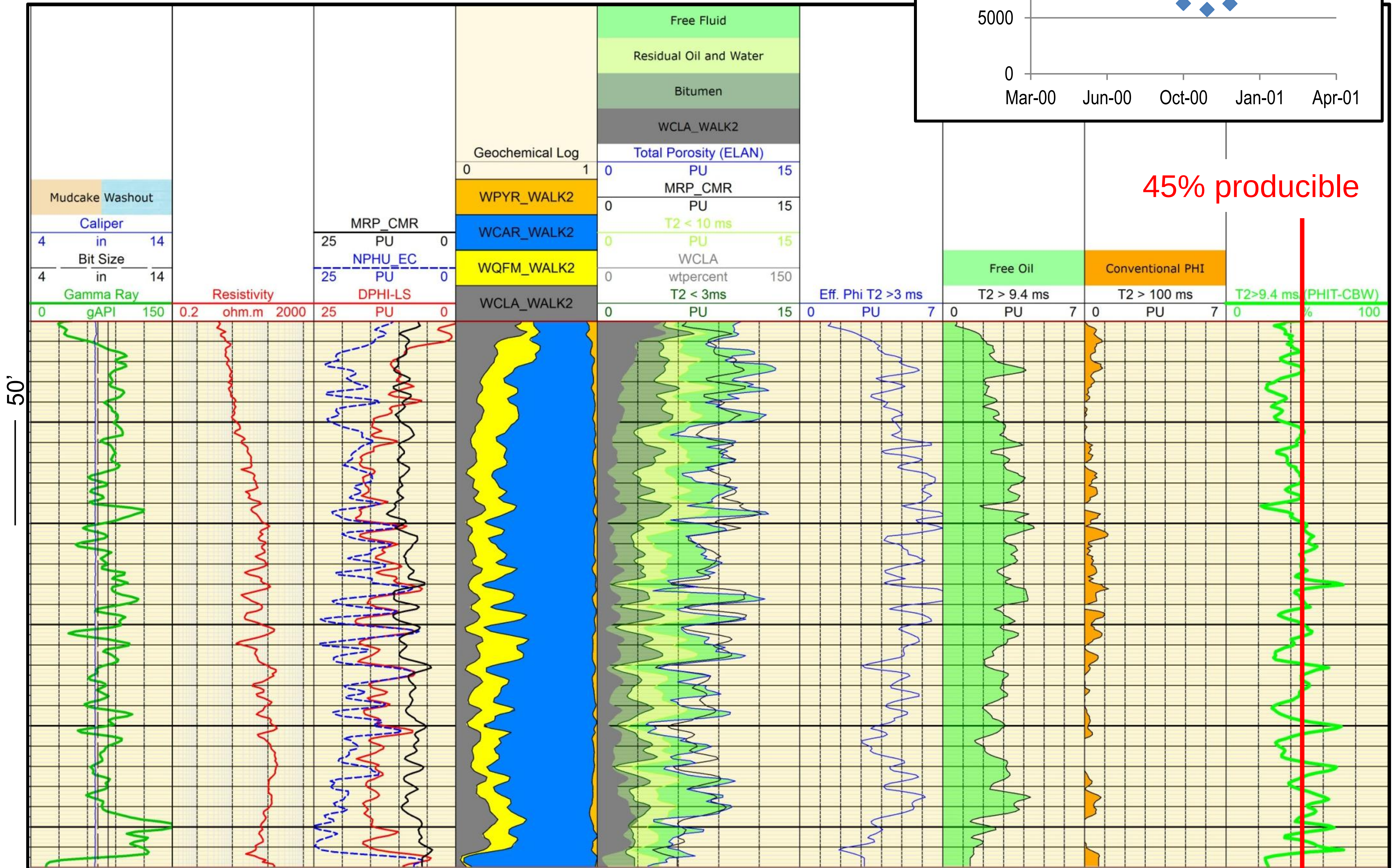
~10 ms

~33 to 100 ms

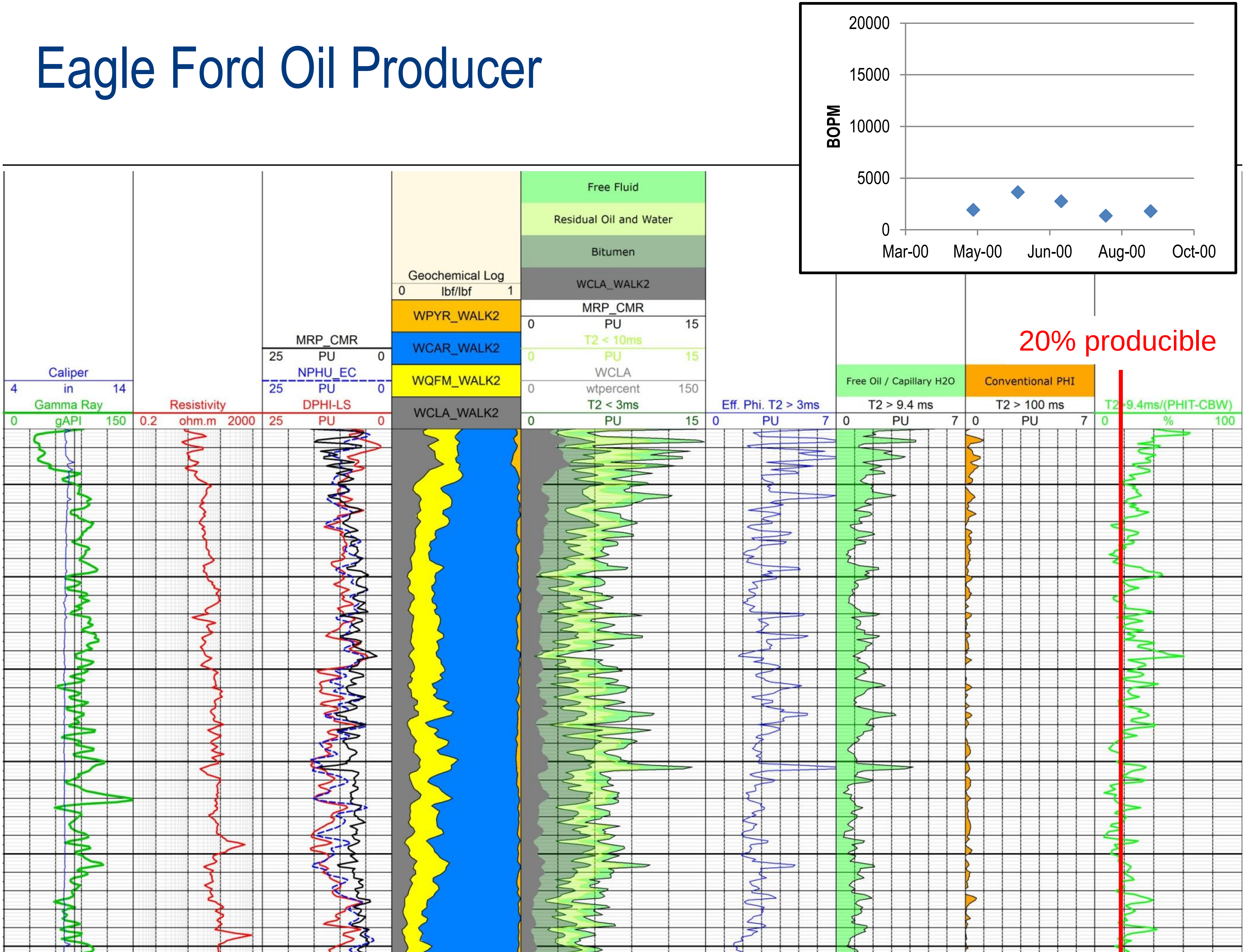
T_2 Cutoffs

Eagle Ford Oil Producer

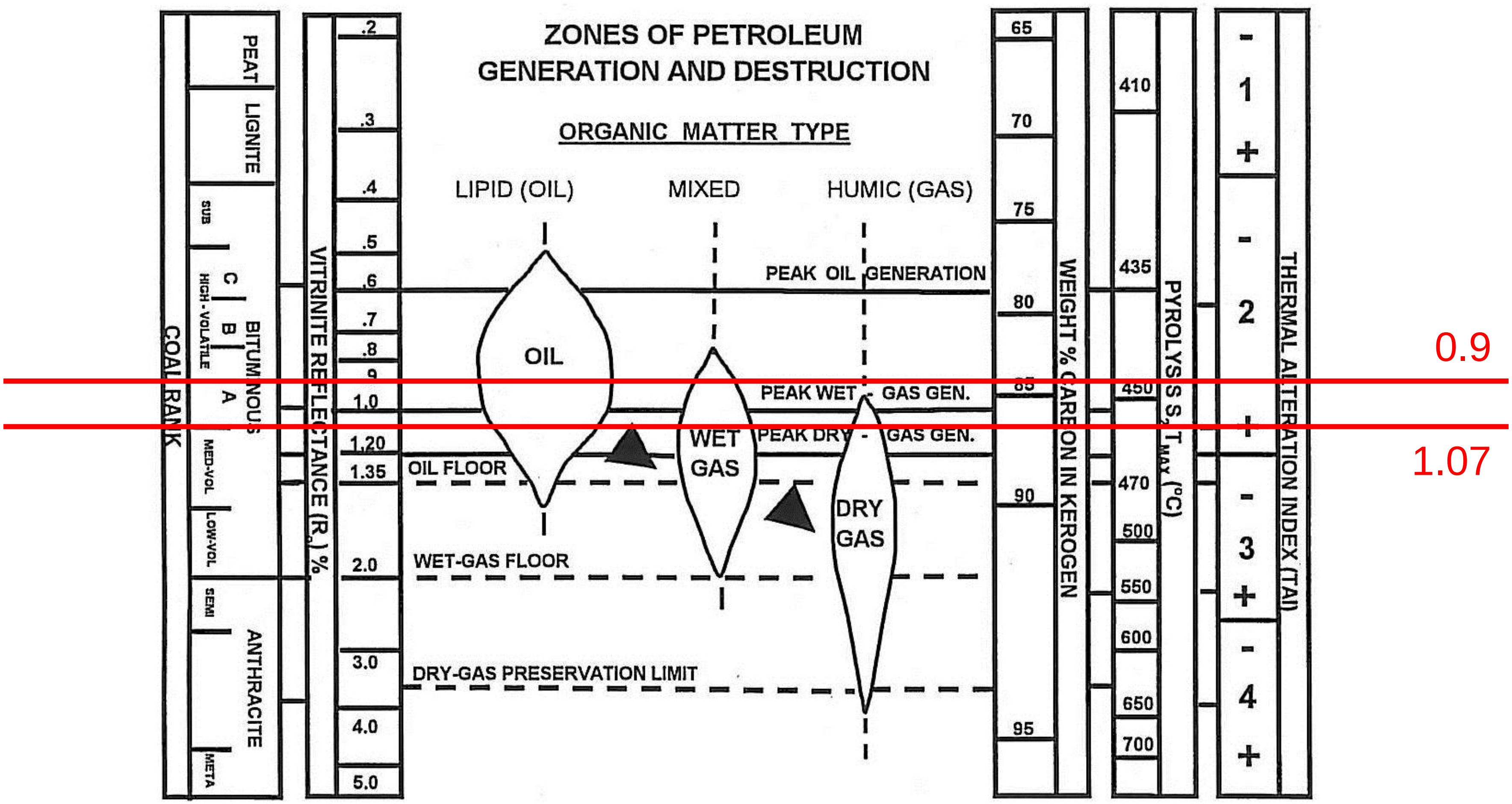




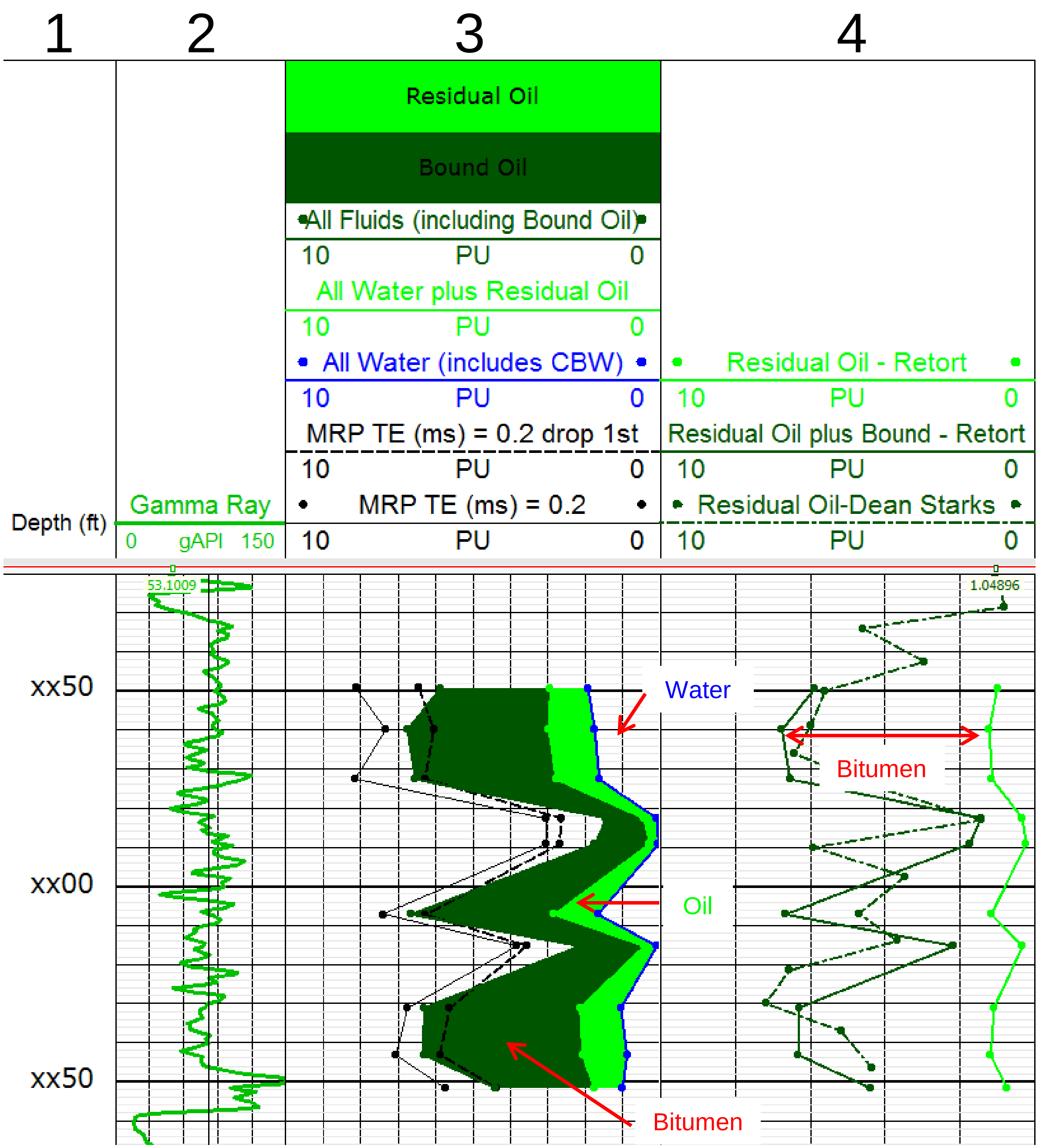
Eagle Ford Oil Producer



Tmax Data



CORRELATION OF VARIOUS MATURATION INDICES AND
ZONES OF PETROLEUM GENERATION AND DESTRUCTION



Core NMR porosity = all core fluids

Residual oil: oil volume from retort

Residual oil + bound hydrocarbon = Dean-Stark

Dean-Stark includes bitumen within pore volume

Expelled hydrocarbon not measured

Mercury Injection Capillary Pressure MICP Measurement

- Inject non-wetting Hg in pressure incre
  60,000 psi
- Estimate pore throat diameter
- Proxy for permeability

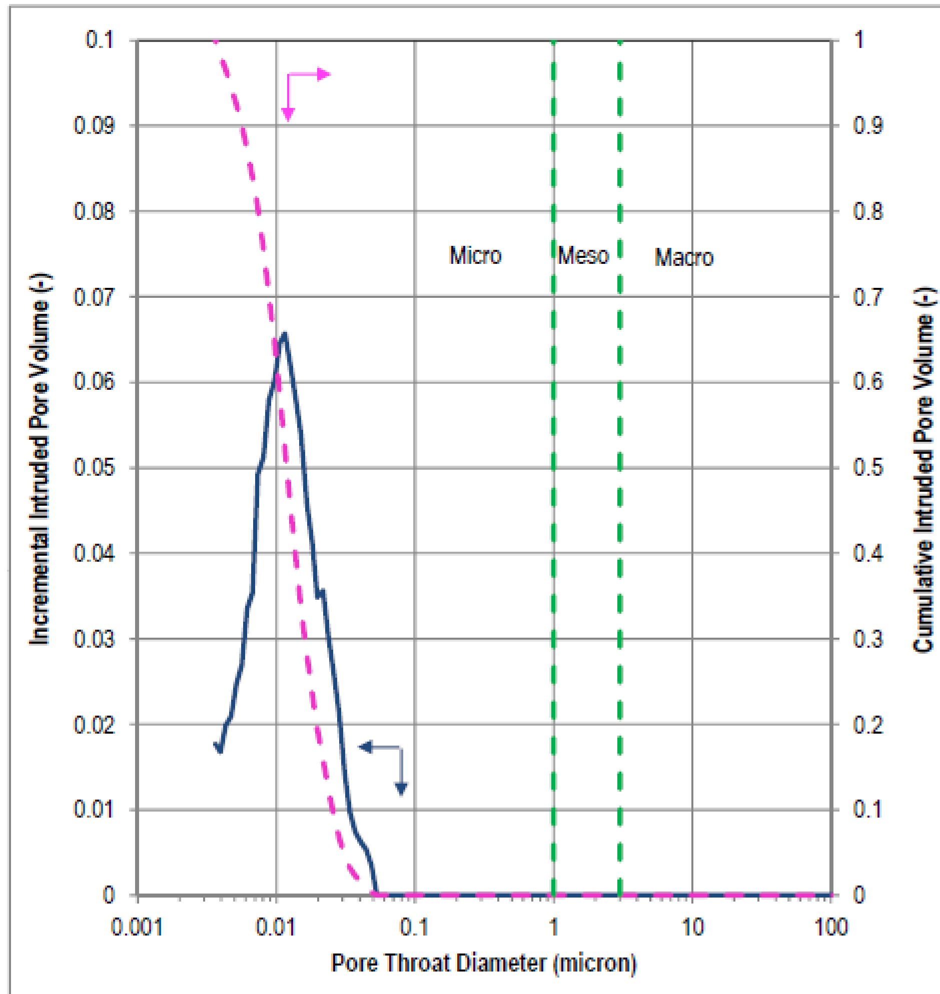
$$r_{pt} = 2\sigma * \cos\theta \big/ P_c$$

$$P_c = \text{capillary pressure}$$

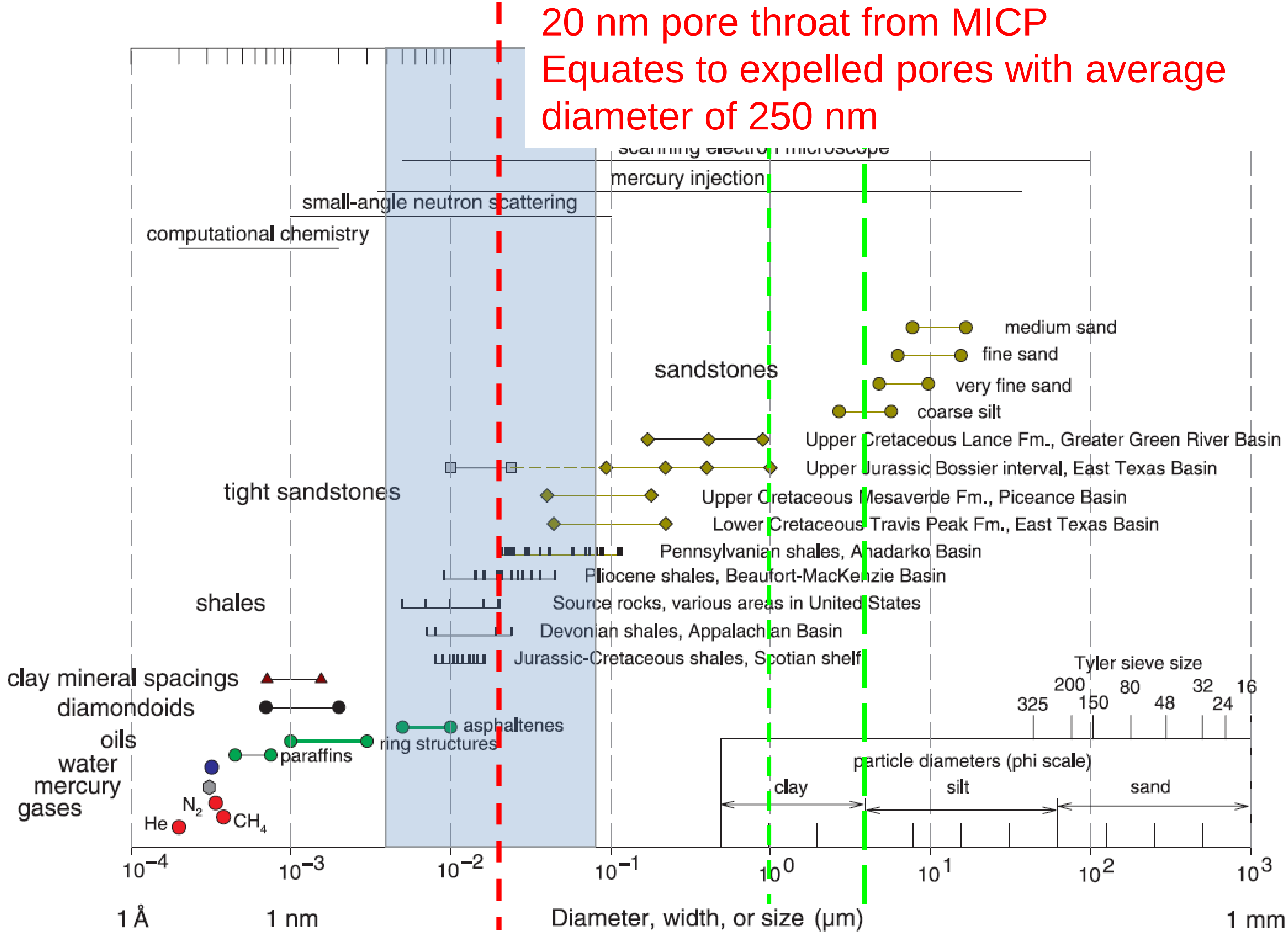
$$\sigma = \text{surface tension of Hg}$$

$$\theta = \text{contact angle of Hg in air}$$

$$r_{pt} = \text{radius of pore throat}$$



20 nm pore throat from MICP
Equates to expelled pores with average diameter of 250 nm



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Conclusions - Oil

- Developed core-log NMR methodology to determine expellable T_2 cutoff
- A portion of hydrocarbon pore volume is not expelled during core extraction (80 to 55%)
  - Bound hydrocarbon - Bitumen
  - Smaller kerogen-hosted pores
  - Capillary bound oil
- Larger kerogen-hosted pores ARE productive
- Oil in conventional pores is productive
- Productive zones show limited correlation with TOC content