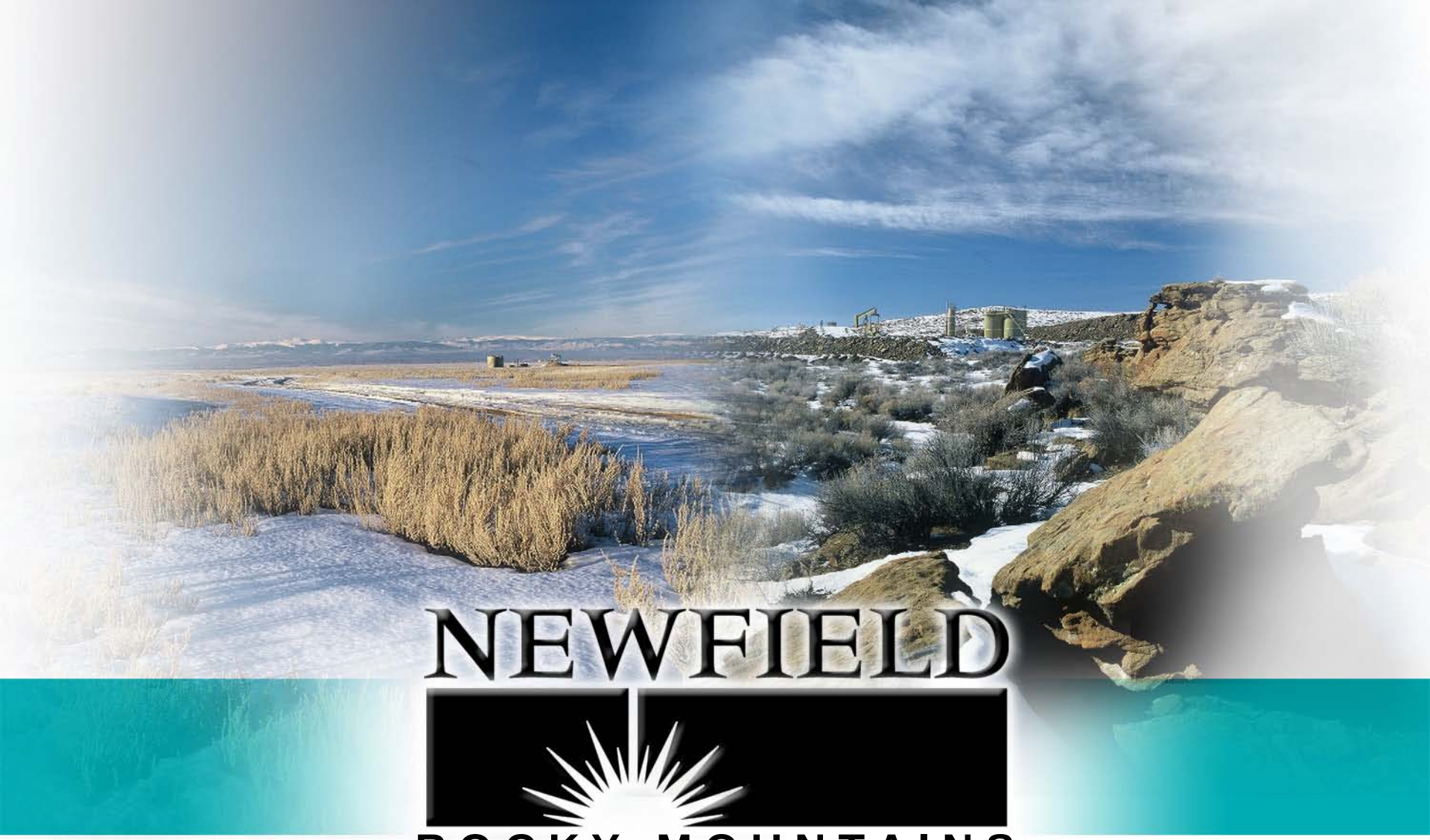


ROCKY MOUNTAINS

NMR APPLICATIONS IN TIGHT GAS SANDSTONE AND SHALE GAS RESERVOIRS

Dick Merkel

OUTLINE

- Clay bound water (VCBW)
- Tight Gas Sand Data
- Core-Log Modeling Comparison
- Shale Gas NMR Core/Log Data
- Shale Oil Source Rock NMR
- Discussion
- Conclusions

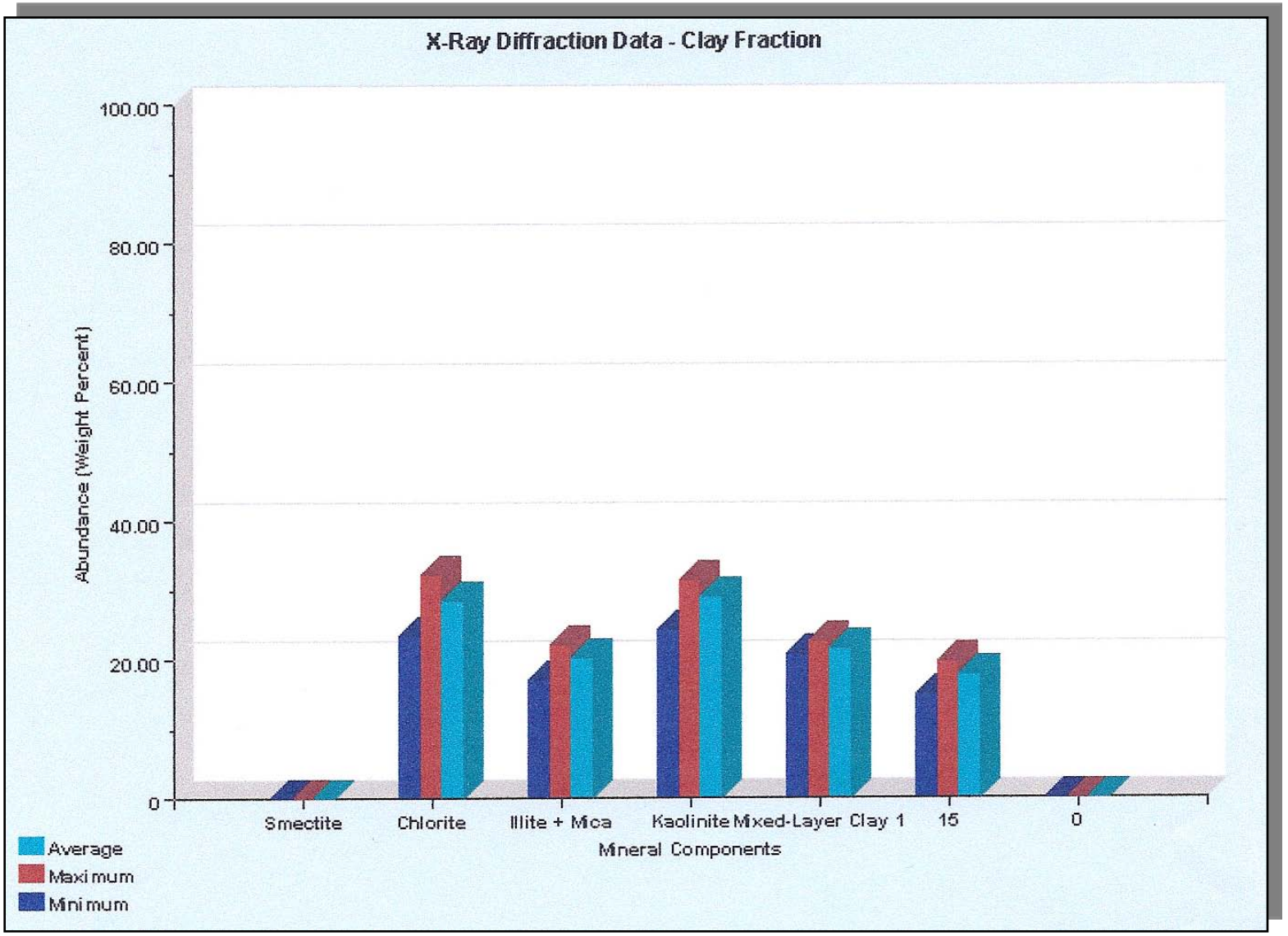
Why NMR?

It directly measures:

1. Irreducible Water (BVWI)
2. Free Water
3. Chemically Bound Water (VCBW)
4. Mud Filtrate (OBM,WBM)
5. Oil
6. Gas
7. Log Measurements @ Reservoir P/T
8. Core Measurements @ Native State

Tight Gas Sand Models

Uinta Basin Mesaverde



CLAY	ROMA_dry	ROMA_wet	VCBW	CEC
Illite	2.78	2.53	0.14	0.25
Kaolinite	2.68	2.62	0.036	0.10
Chlorite	2.94	2.78	0.08	0.15
Smectite	2.79	2.12	0.37	1.0

core

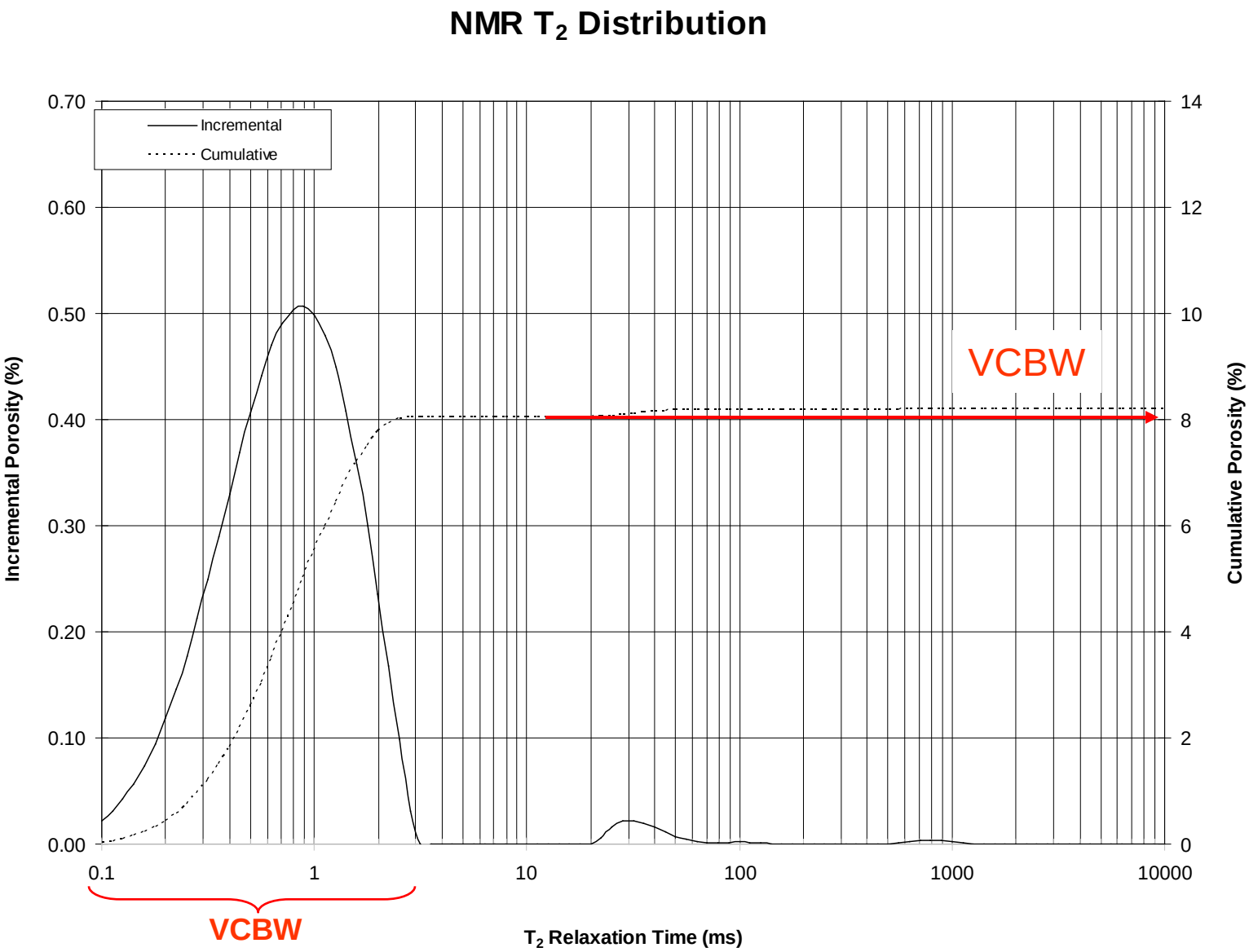
log

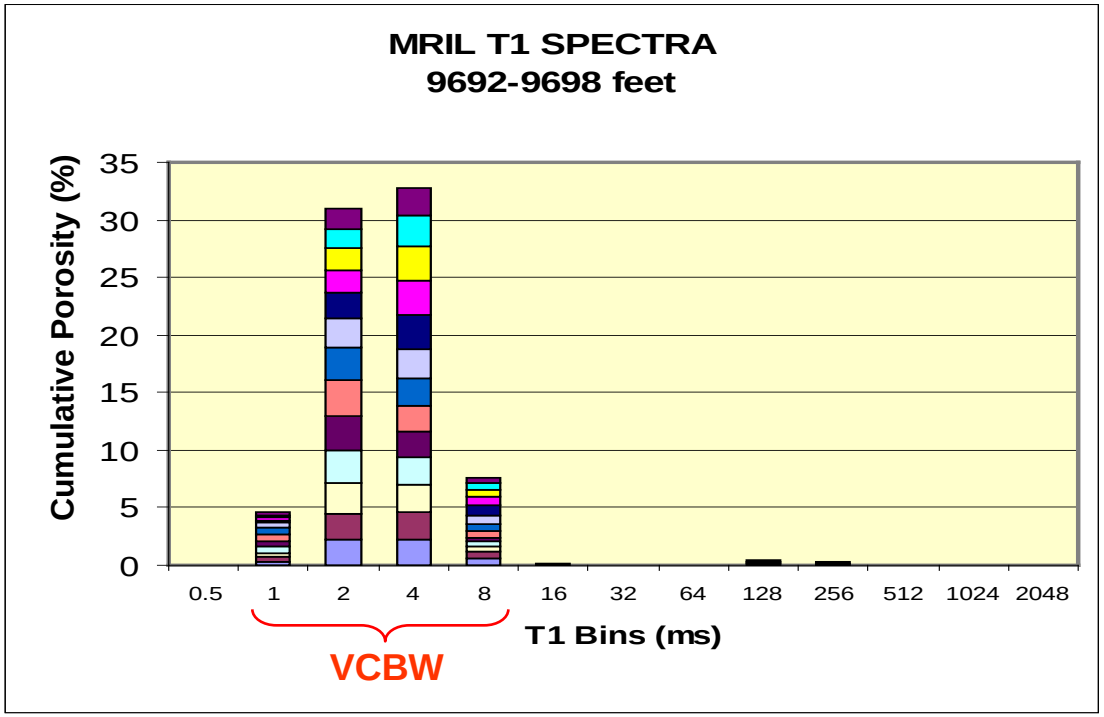
or

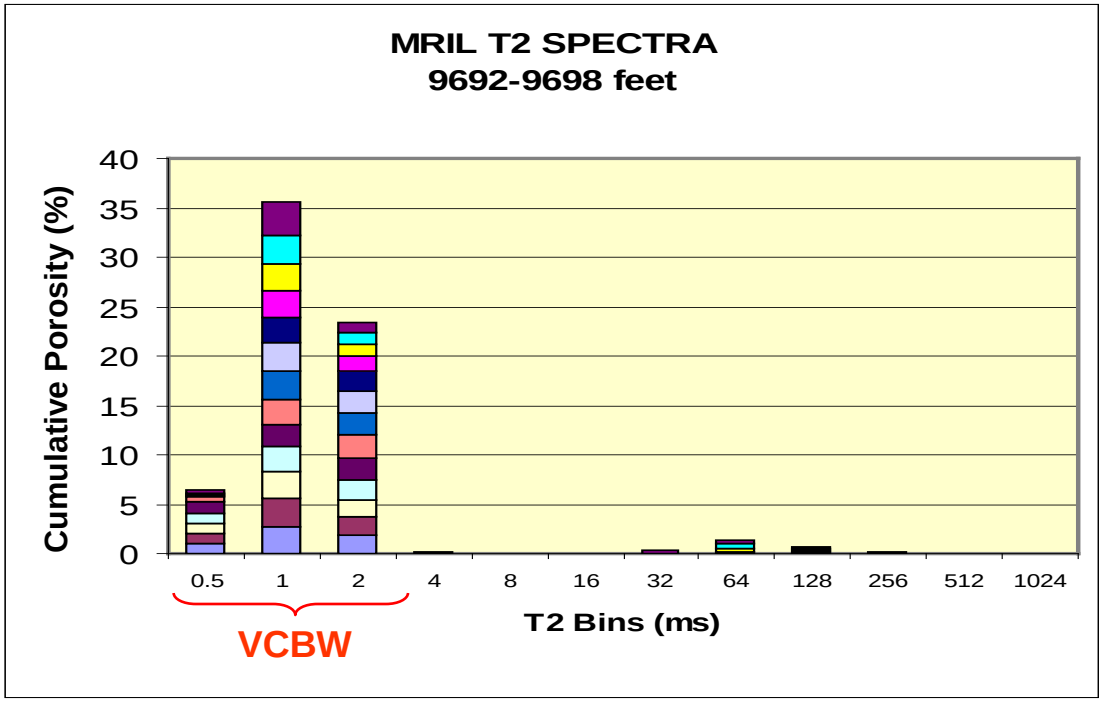
humidity

dried

Core Native State NMR T2 Distribution in Shaly Interval







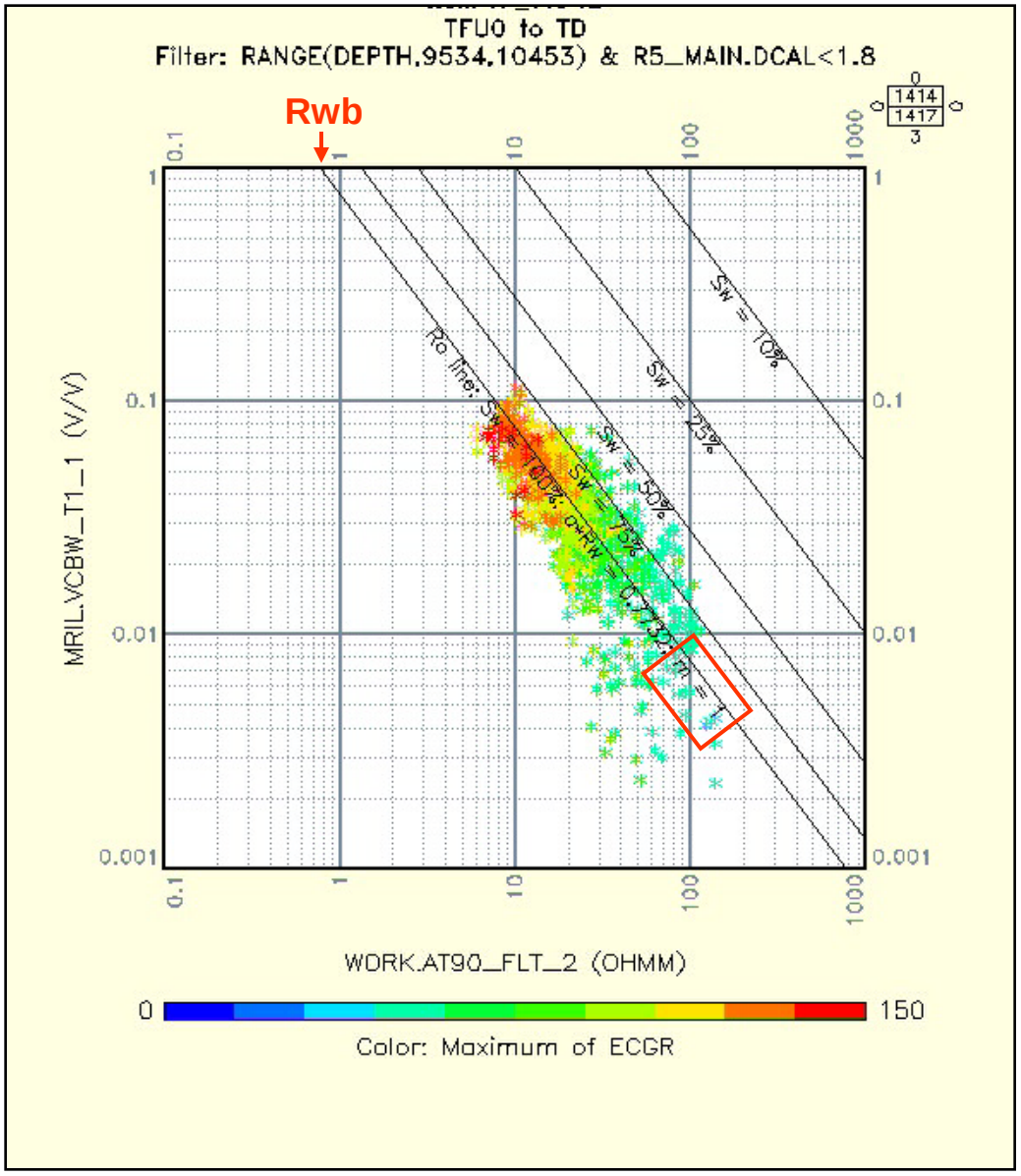
NMR Log Bin Distributions of T1 and T2 Summed over a Six Foot Shaly Interval

The Bin Distributions Give the Value of VCBW

VCBW (from NMR T1)
vs.
Deep Resistivity

The Intercept @ VCBW=1
Gives Rwb for this
Clay at this Temperature

For a Clay Change and/or
Different Depths, Rwb
Varies, but not the Slope



For a shale interval:

$$VCBW = \Phi$$

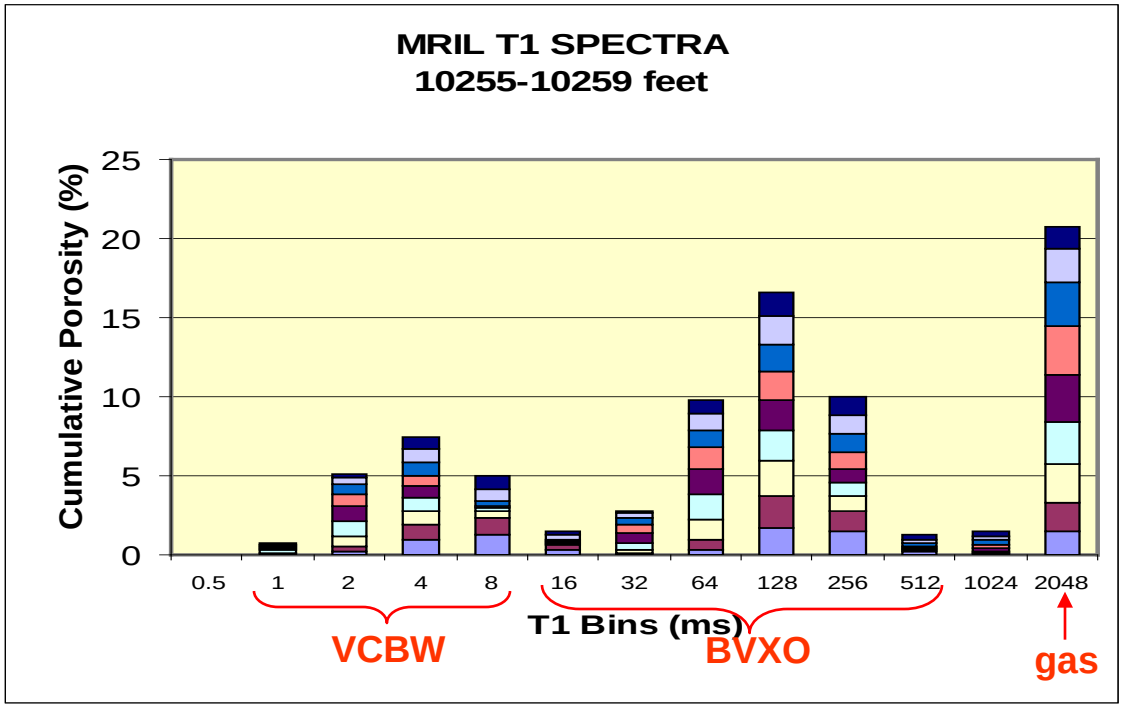
and since

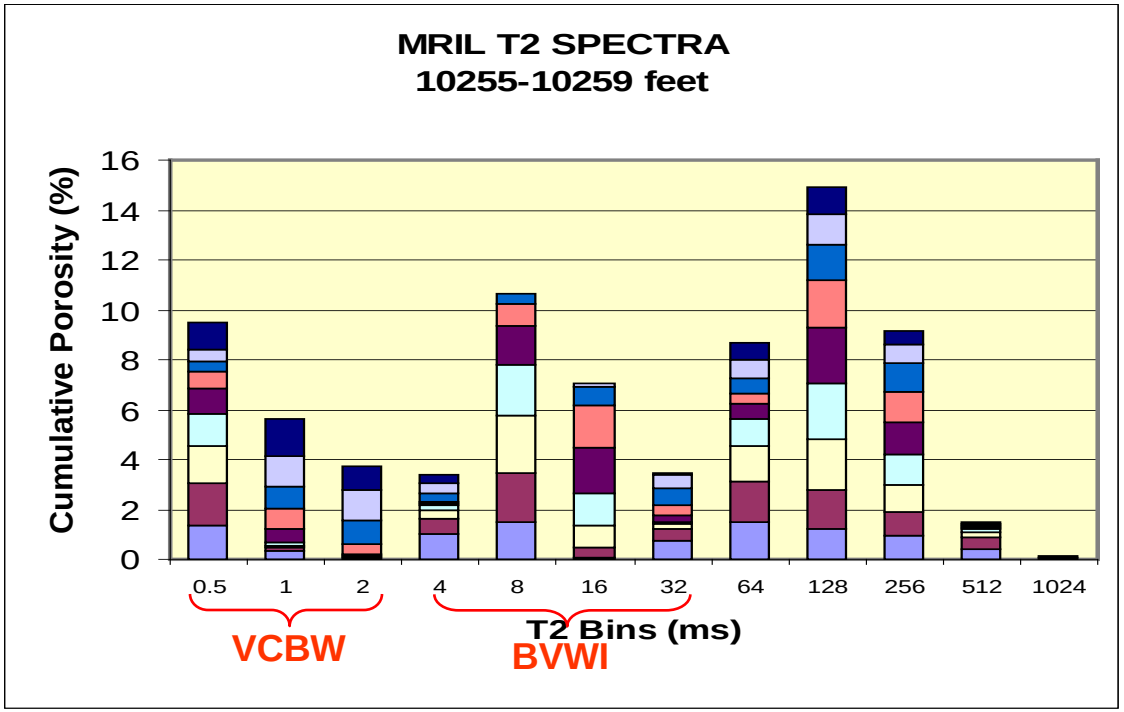
$$R_T = R_{wb} / \Phi^m$$

$$m = 1.0$$

$$R_T = R_{wb} / VCBW$$

$$C_t = C_{wb} * VCBW$$





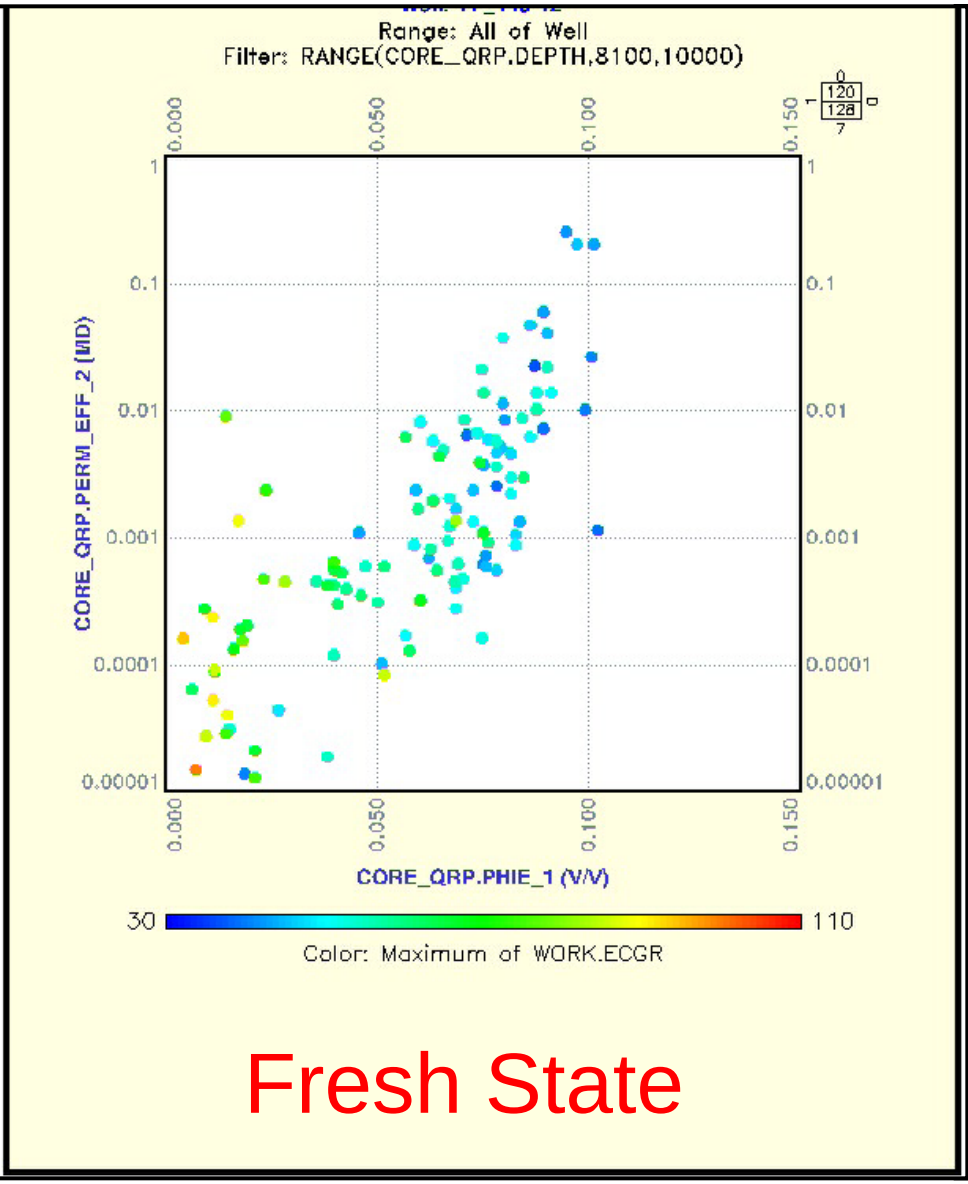
NMR Log Bin Distributions of T1 and T2 Summed over Six Feet in a Gas Sand

VCBW can be measured In both T1 and T2 space

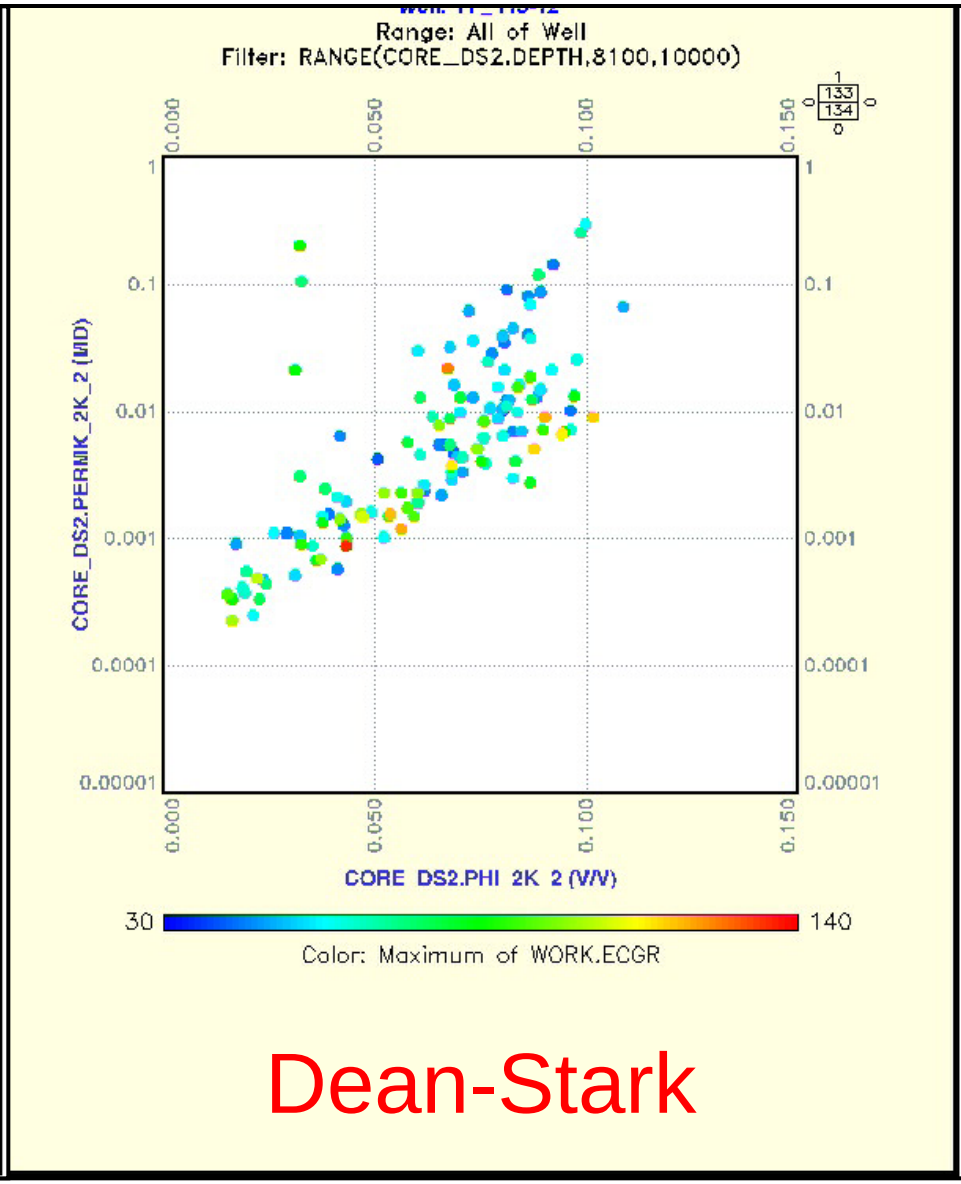
The Gas Signal is Identified at T1>1024ms, but Imbedded in the Liquid Signal in T2 Space

PVT – HI correction to the gas signal yields PHIT
VCBW correction gives PHIE

Native State vs. Cleaned/Dried

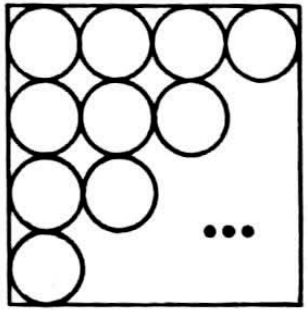


Fresh State

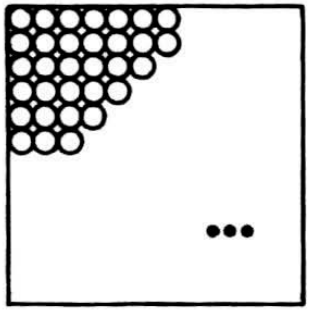


Dean-Stark

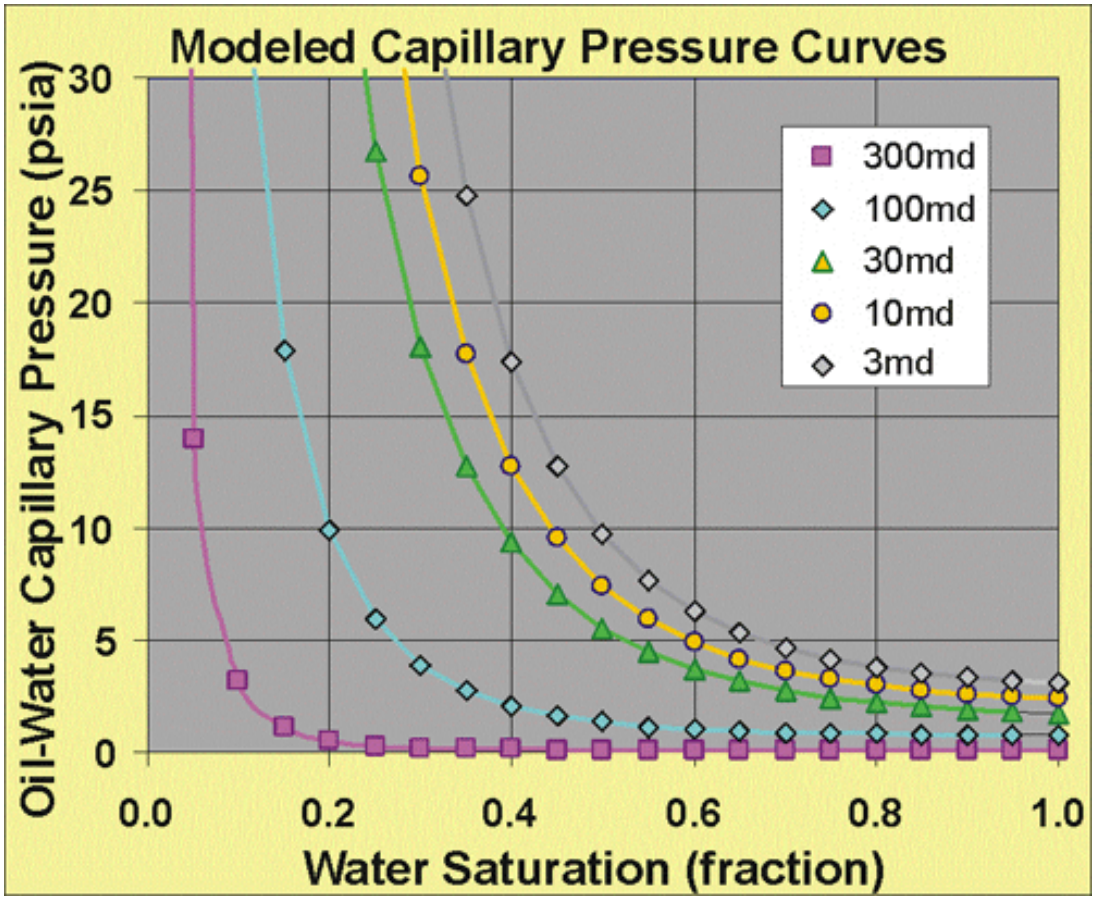
Basic Perm-Pc-Pore (throat) & Grain Size Relations for Constant PHI



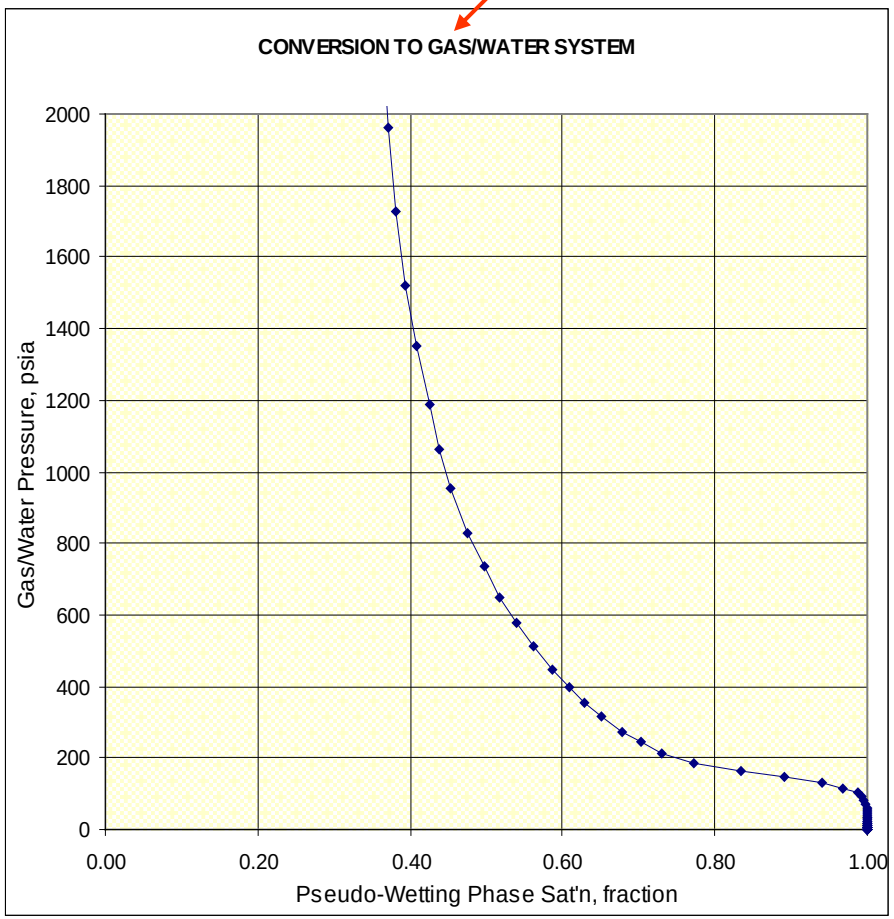
Rhombohedral packing, large spherical grains, large pore spaces



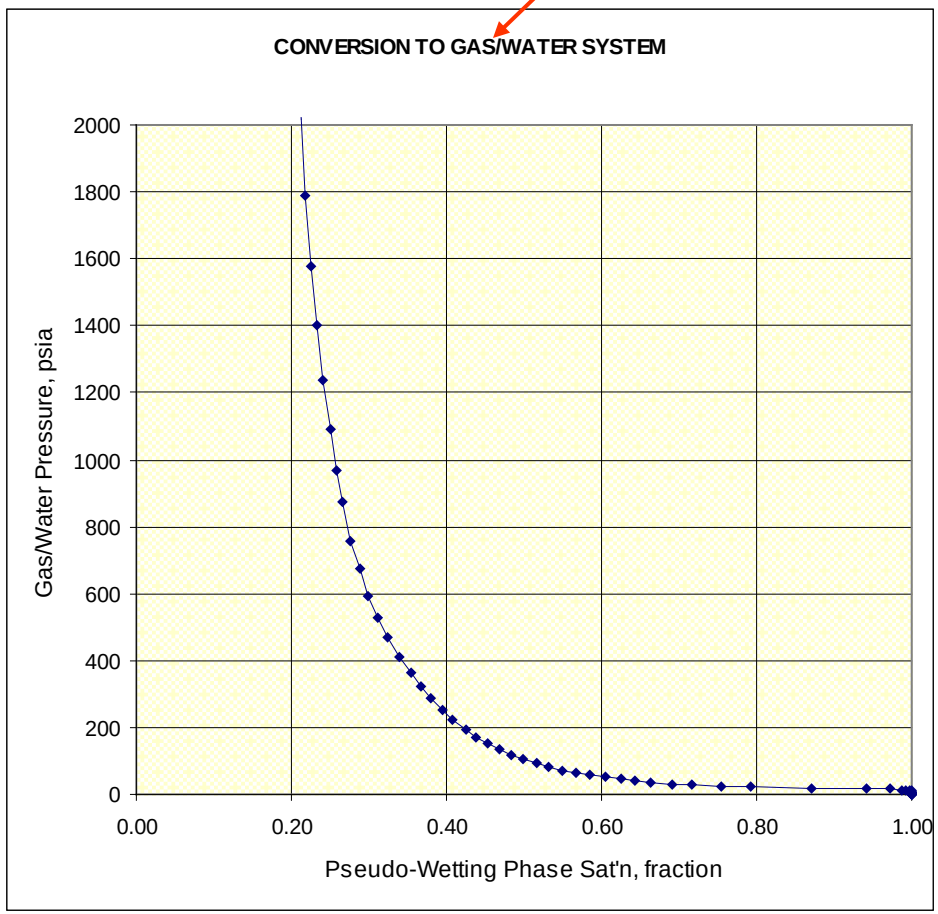
Rhombohedral packing, small spherical grains, small pore spaces



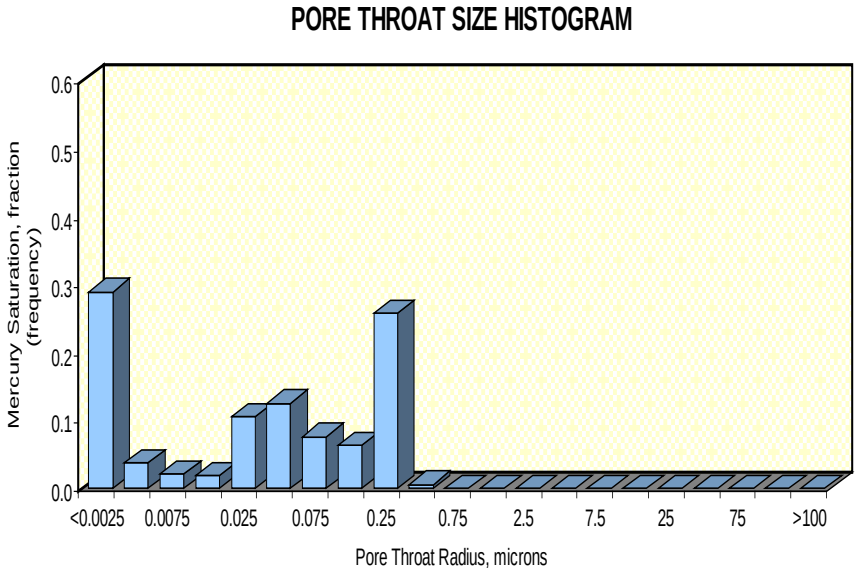
Sample:	172Sm		Host Plug	
Depth, feet:	9511.0	ambient	800psi	2000psi
Klinkenberg Permeability, md:		0.031	0.005	0.003
Permeability to Air, md:		0.075	0.011	0.008
Swanson Permeability, md:		0.012	-	-
Porosity, fraction:		0.076	0.079	0.077



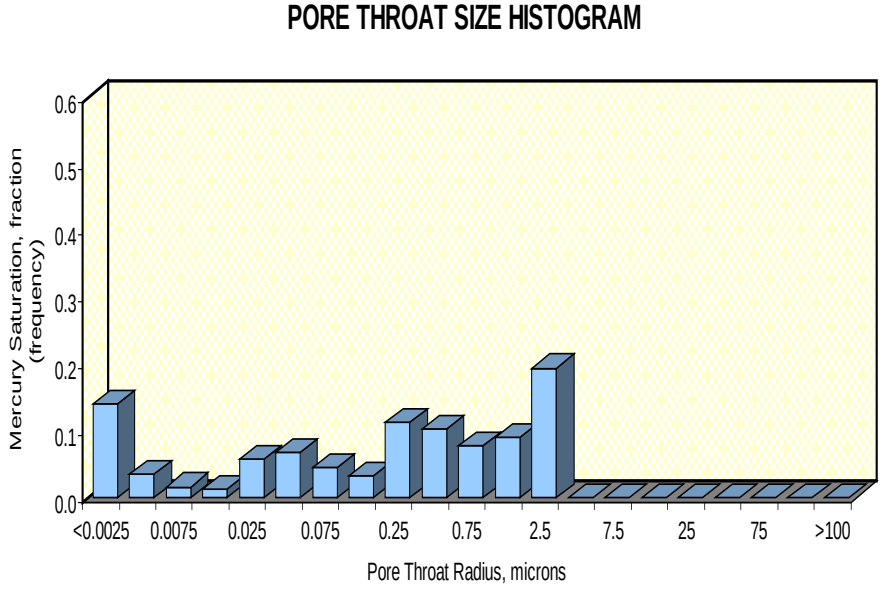
Sample:	132Sm		Host Plug	
Depth, feet:	9048.65	ambient	800psi	2000psi
Klinkenberg Permeability, md:		0.805	0.443	0.338
Permeability to Air, md:		1.15	0.512	0.394
Swanson Permeability, md:		0.636	-	-
Porosity, fraction:		0.103	0.107	0.104



Sample:	172Sm		Host Plug	
Depth, feet:	9511.0	ambient	800psi	2000psi
Klinkenberg Permeability, md:		0.031	0.005	0.003
Permeability to Air, md:		0.075	0.011	0.008
Swanson Permeability, md:		0.012	-	-
Porosity, fraction:		0.076	0.079	0.077
maximum Sb/Pc, fraction:		0.0022		
R35, microns:		0.0658		
R50 (median pore throat radius):		0.0289		

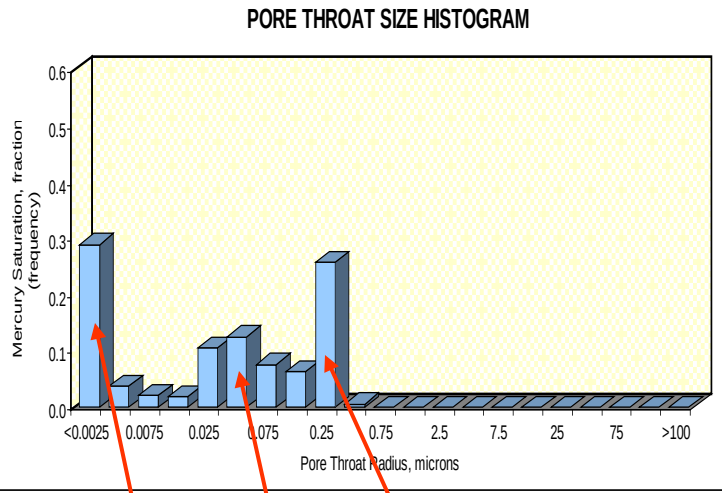


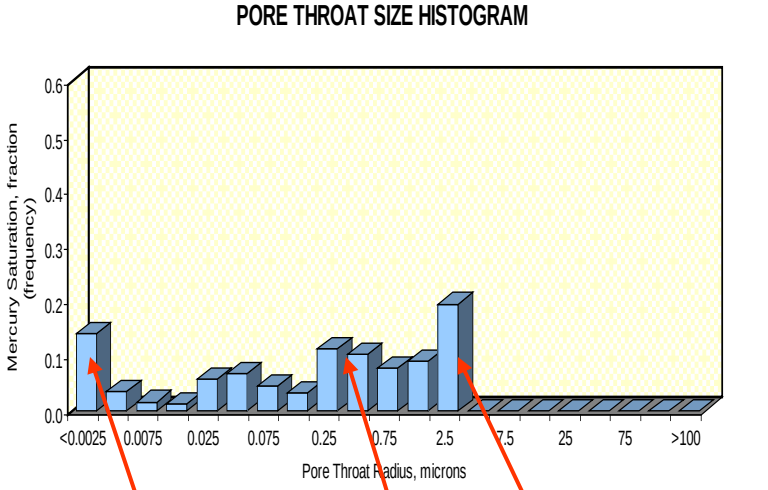
Sample:	132Sm		Host Plug	
Depth, feet:	9048.65	ambient	800psi	2000psi
Klinkenberg Permeability, md:		0.805	0.443	0.338
Permeability to Air, md:		1.15	0.512	0.394
Swanson Permeability, md:		0.636	-	-
Porosity, fraction:		0.103	0.107	0.104
maximum Sb/Pc, fraction:		0.022		
R35, microns:		0.548		
R50 (median pore throat radius):		0.198		

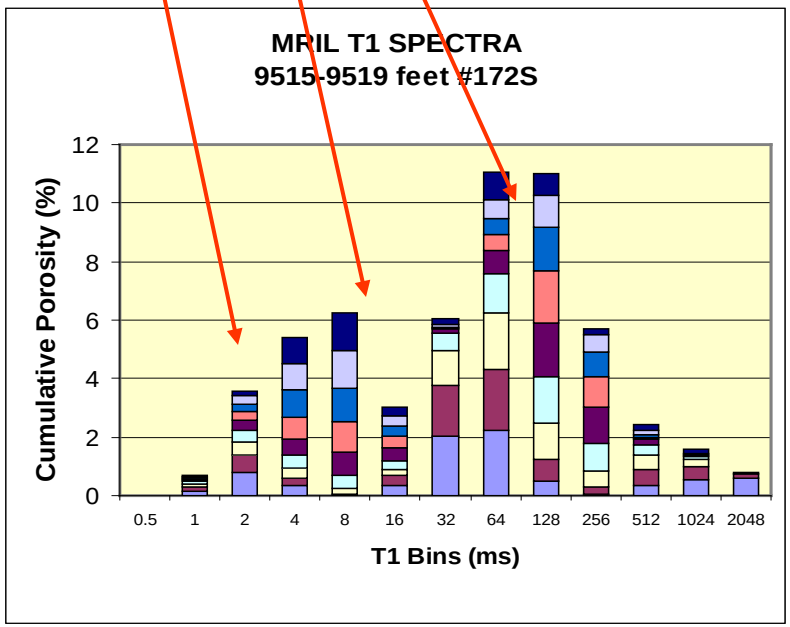


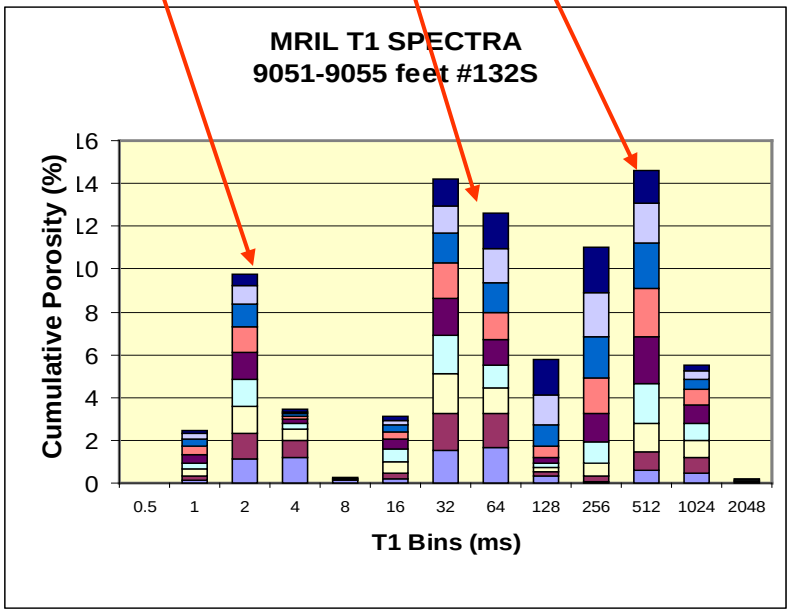
Sample:	172Sm		Host Plug	
Depth, feet:	9511.0	ambient	800psi	2000psi
Klinkenberg Permeability, md:		0.031	0.005	0.003
Permeability to Air, md:		0.075	0.011	0.008
Swanson Permeability, md:		0.012	-	-
Porosity, fraction:		0.076	0.079	0.077

Sample:	132Sm		Host Plug	
Depth, feet:	9048.65	ambient	800psi	2000psi
Klinkenberg Permeability, md:		0.805	0.443	0.338
Permeability to Air, md:		1.15	0.512	0.394
Swanson Permeability, md:		0.636	-	-
Porosity, fraction:		0.103	0.107	0.104





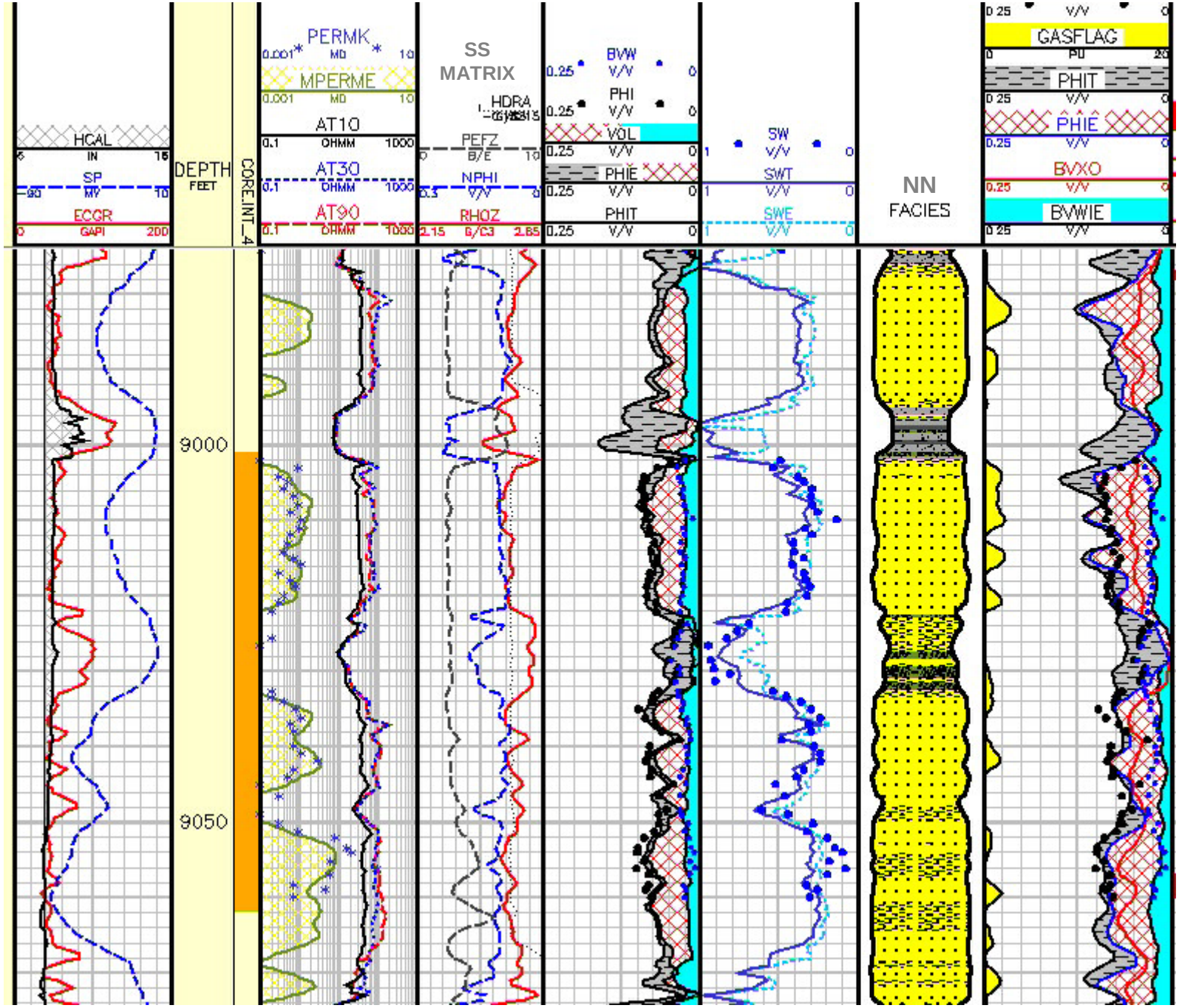




NMR Perm

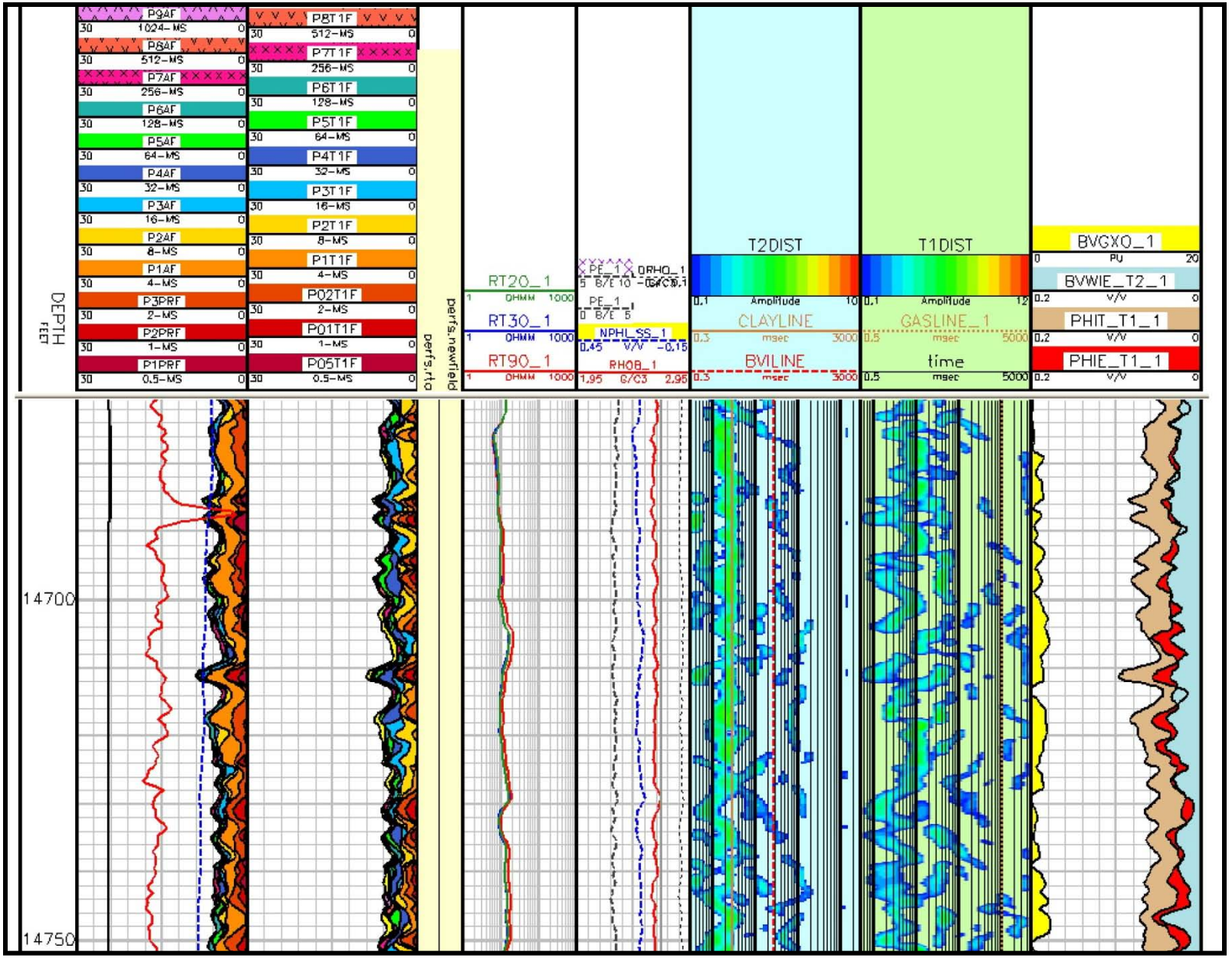
SS Resistivity Model

NMR Model



Shale Gas Models

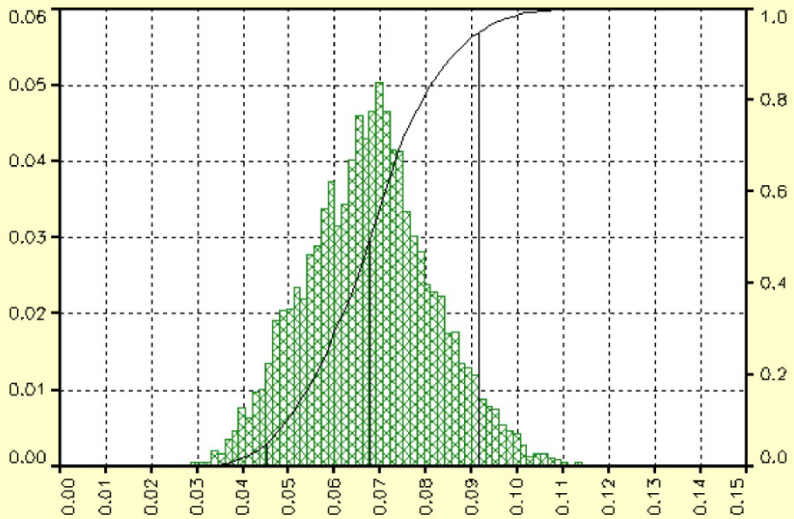
Mancos Formation



Mancos Log Porosity

PHIT

Histogram of MRIL.PHIT_T1
Well: FEDERAL_9-12-9-18
Intervals: KM, KMB, BKMB
Filter:



Statistics:

Possible values	8452
Missing values	0
Minimum value	0.02606
Maximum value	0.11717
Range	0.09111
Mean	0.06777
Geometric Mean	0.06630
Harmonic Mean	0.06476
Variance	0.00019
Standard Deviation	0.01391
Skewness	0.14513
Kurtosis	2.91320
Median	0.06784
Mode	0.06975

Wells:

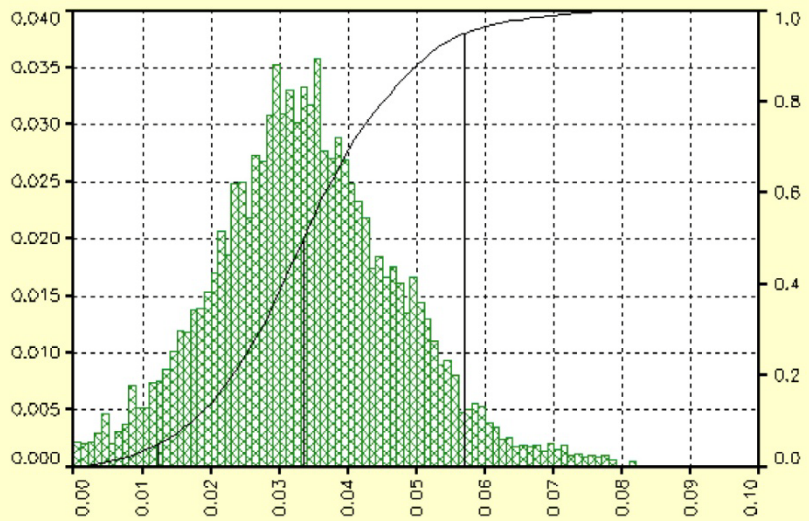
1. FEDERAL_9-12-9-18

Percentiles:

5%	0.04527
50%	0.06784
95%	0.09149

VCBW

Histogram of MRIL.VCBW_T1
Well: FEDERAL_9-12-9-18
Intervals: KM, KMB, BKMB
Filter:



Statistics:

Possible values	8452
Missing values	0
Minimum value	0.00005
Maximum value	0.08195
Range	0.08190
Mean	0.03406
Geometric Mean	0.03063
Harmonic Mean	0.02186
Variance	0.00018
Standard Deviation	0.01346
Skewness	0.26432
Kurtosis	3.21473
Median	0.03351
Mode	0.03550

Wells:

1. FEDERAL_9-12-9-18

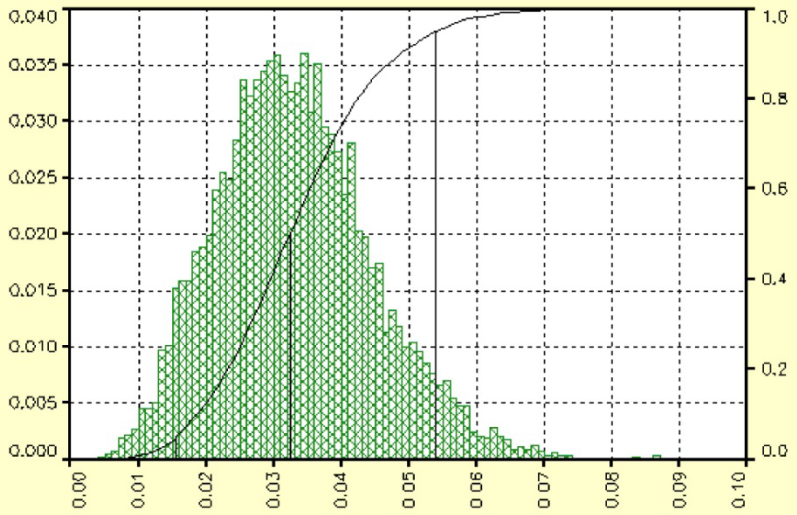
Percentiles:

5%	0.01231
50%	0.03351
95%	0.05894

Mancos Log Porosity

PHIE

Histogram of MRIL.PHIE_T1
Well: FEDERAL_9-12-9-18
Intervals: KM, KMB, BKMB
Filter:



Statistics:

Possible values	8452
Missing values	0
Minimum value	0.00441
Maximum value	0.08724
Range	0.08283
Mean	0.03316
Geometric Mean	0.03102
Harmonic Mean	0.02865
Variance	0.00013
Standard Deviation	0.01161
Skewness	0.46573
Kurtosis	3.30259
Median	0.03236
Mode	0.03450

Wells:

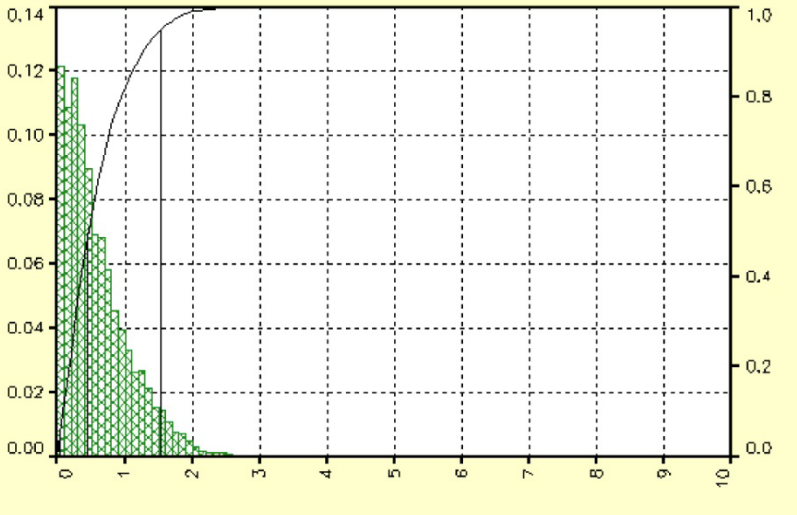
1. FEDERAL_9-12-9-18

Percentiles.

5%	0.01552
50%	0.03236
95%	0.05394

BVGXO

Histogram of MRIL.BVGXO
Well: FEDERAL_9-12-9-18
Intervals: KM, KMB, BKMB
Filter:



Statistics:

Possible values	8452
Missing values	0
Minimum value	0.00000
Maximum value	2.67393
Range	2.67393
Mean	0.57756
Geometric Mean	-
Harmonic Mean	-
Variance	0.22345
Standard Deviation	0.47271
Skewness	1.13375
Kurtosis	4.03290
Median	0.45397
Mode	0.05000

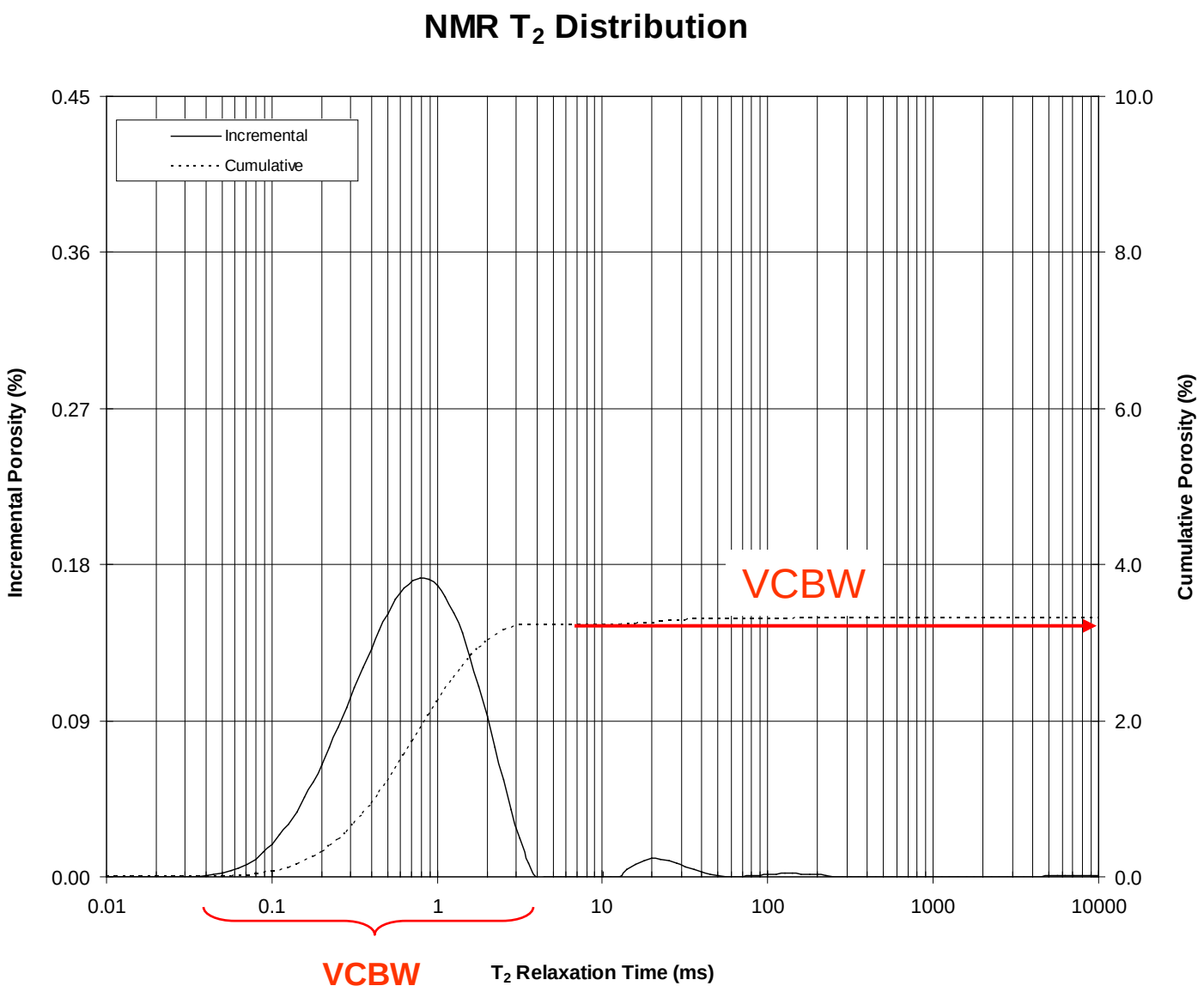
Wells:

1. FEDERAL_9-12-9-18

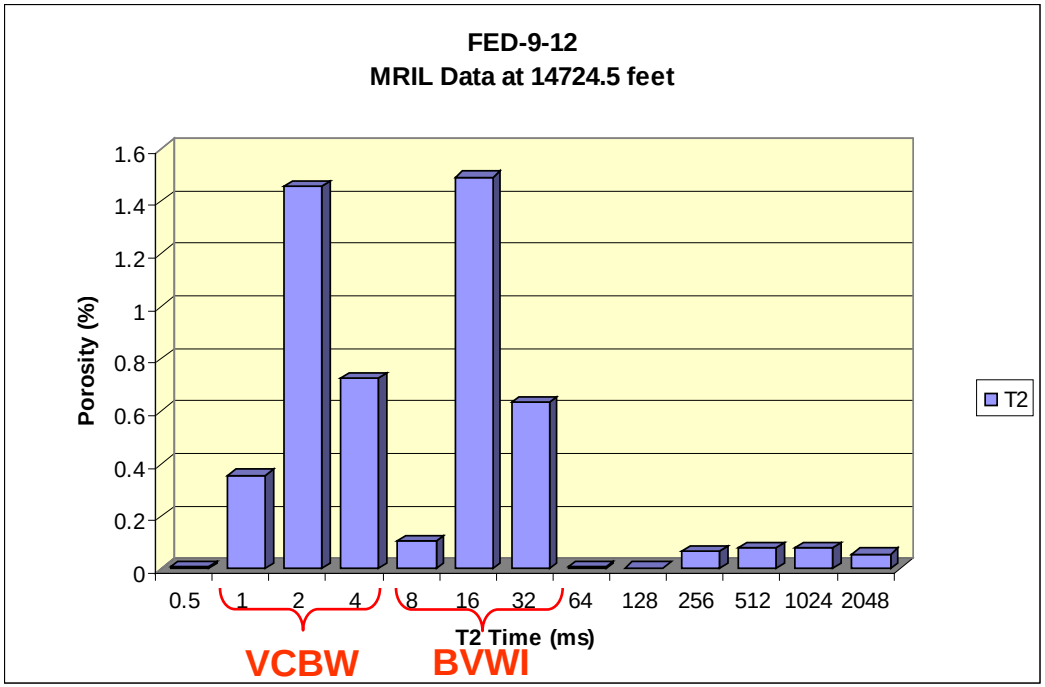
Percentiles.

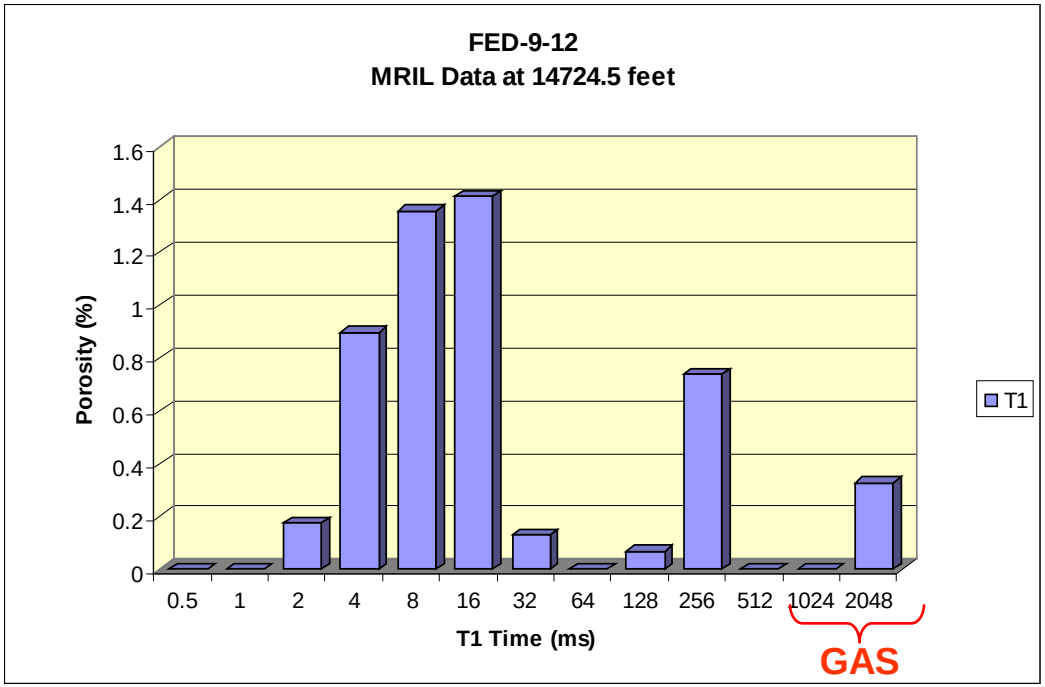
5%	0.04115
50%	0.45397
95%	1.53475

Mancos Core T2 Spectra



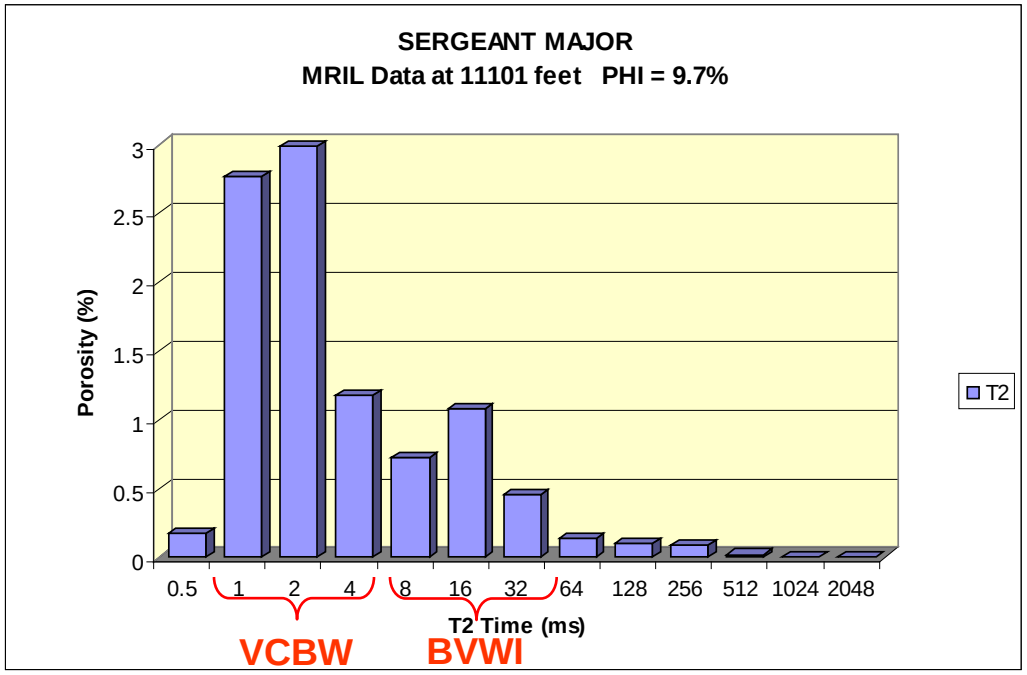
Mancos Log T2 & T1 Spectra

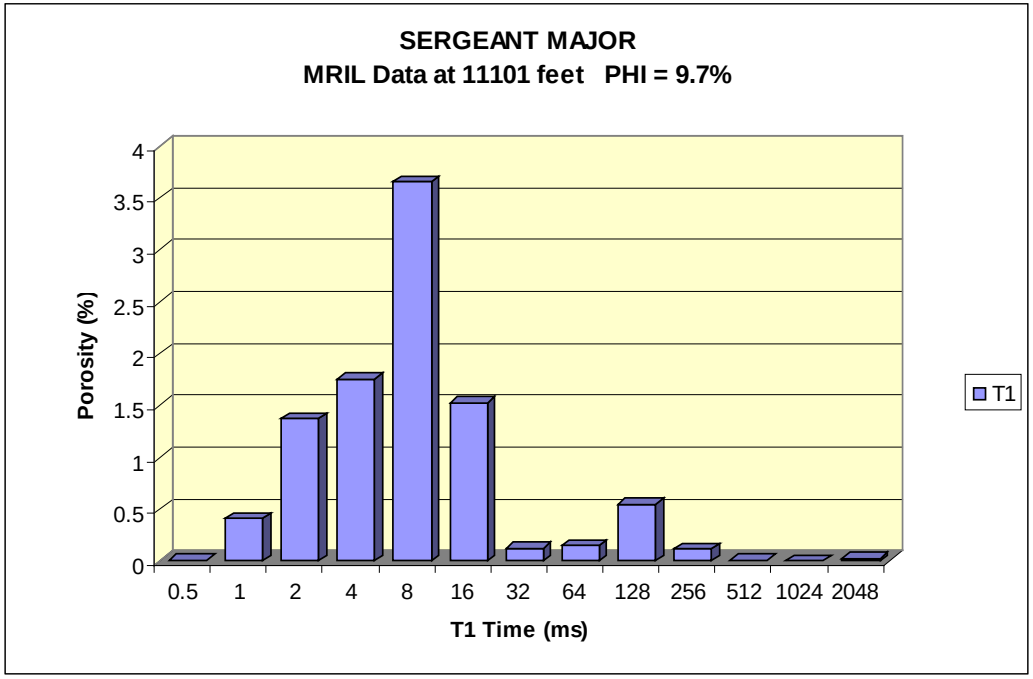




Shale Oil Source Rock NMR

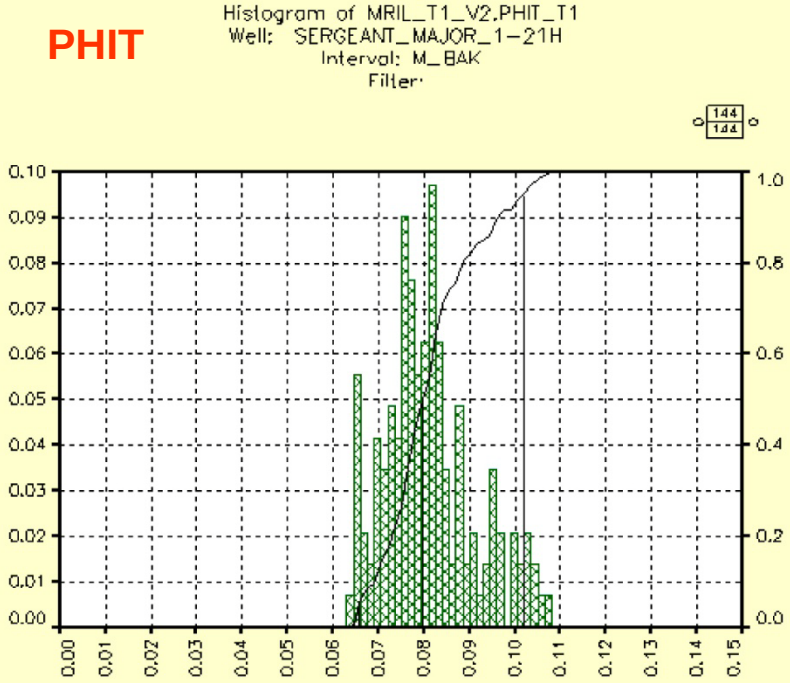
L-Bakken T2 & T1 Spectra





Lower Bakken Log Porosity

PHIT



Statistics:	
Possible values	144
Missing values	0
Minimum value	0.06311
Maximum value	0.10658
Range	0.04347
Mean	0.08104
Geometric Mean	0.08044
Harmonic Mean	0.07985
Variance	0.00010
Standard Deviation	0.01010
Skewness	0.62682
Kurtosis	2.90648
Median	0.07983
Mode	0.08175

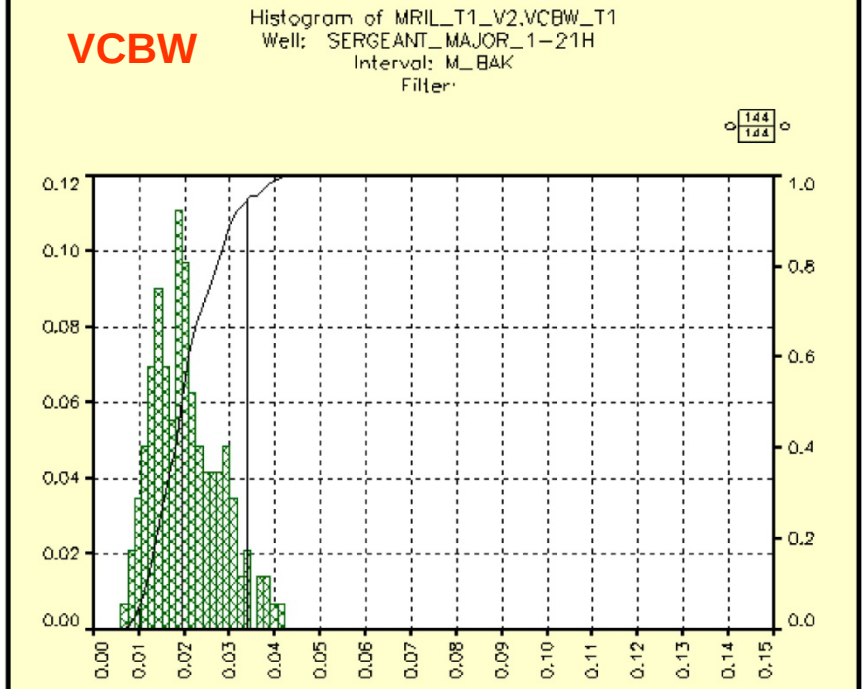
Wells:

1. SERGEANT_MAJOR_1-21H

Percentiles.

5%	0.06566
50%	0.07983
95%	0.10185

VCBW



Statistics:	
Possible values	144
Missing values	0
Minimum value	0.00702
Maximum value	0.04086
Range	0.03384
Mean	0.02045
Geometric Mean	0.01914
Harmonic Mean	0.01784
Variance	0.00005
Standard Deviation	0.00739
Skewness	0.58673
Kurtosis	2.84833
Median	0.01941
Mode	0.01875

Wells:

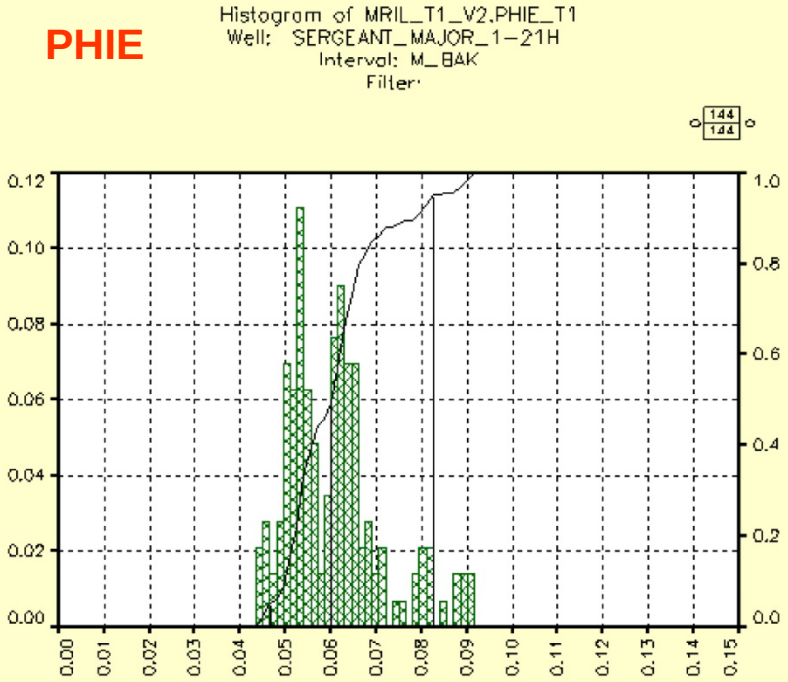
1. SERGEANT_MAJOR_1-21H

Percentiles.

5%	0.00996
50%	0.01941
95%	0.03390

Lower Bakken Log Porosity

PHIE



Statistics:

Possible values	144
Missing values	0
Minimum value	0.04402
Maximum value	0.09061
Range	0.04659
Mean	0.06059
Geometric Mean	0.05975
Harmonic Mean	0.05896
Variance	0.00011
Standard Deviation	0.01059
Skewness	0.99788
Kurtosis	3.69801
Median	0.06014
Mode	0.05325

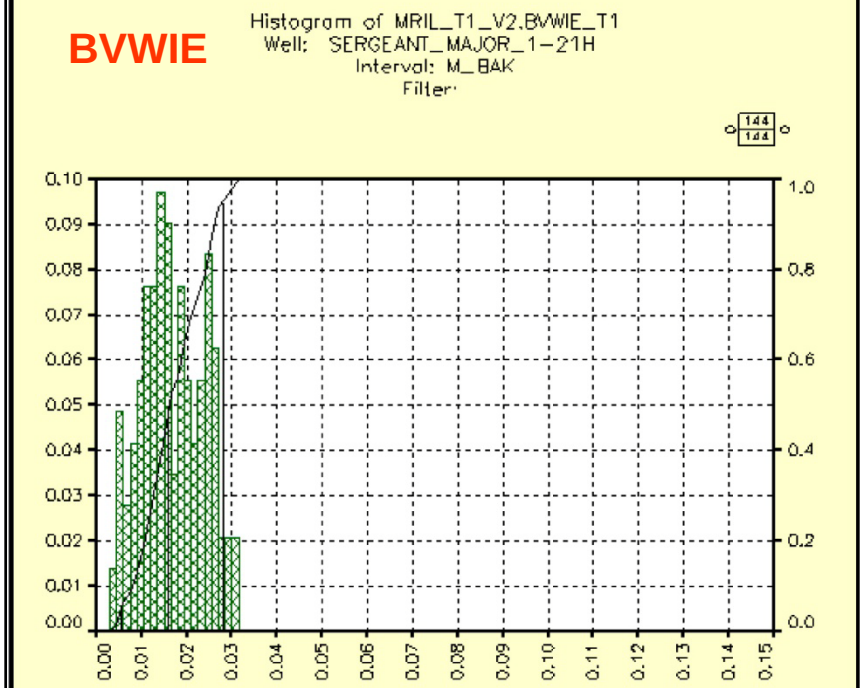
Wells:

1. SERGEANT_MAJOR_1-21H

Percentiles:

5%	0.04665
50%	0.06014
95%	0.08240

BVWIE



Statistics:

Possible values	144
Missing values	0
Minimum value	0.00335
Maximum value	0.03116
Range	0.02781
Mean	0.01686
Geometric Mean	0.01525
Harmonic Mean	0.01336
Variance	0.00005
Standard Deviation	0.00686
Skewness	0.08781
Kurtosis	2.12466
Median	0.01604
Mode	0.01425

Wells:

1. SERGEANT_MAJOR_1-21H

Percentiles:

5%	0.00561
50%	0.01604
95%	0.02790

CONCLUSIONS

NEWFIELD
ROCKY MOUNTAINS

1. For the Cretaceous sands evaluated in this study, clay conductivity is linearly related to VCBW
2. Analysis of Core and Log T1 and T2 data can yield values of PHIT, PHIE, VCBW, BVWI and Sgxo
3. VCBW relationships show why some shaly sand models are unstable in the Rocky Mountain area
4. Fresh State core analysis gives consistent porosity-permeability relationships that can be used in log transforms for TGS but not Shale Gas
5. NMR data give further insight into the physical properties of source rocks