Petrophysical Study of Barnett Shale

IC3 Team*

* Chandra. S. Rai, Carl. H. Sondergeld

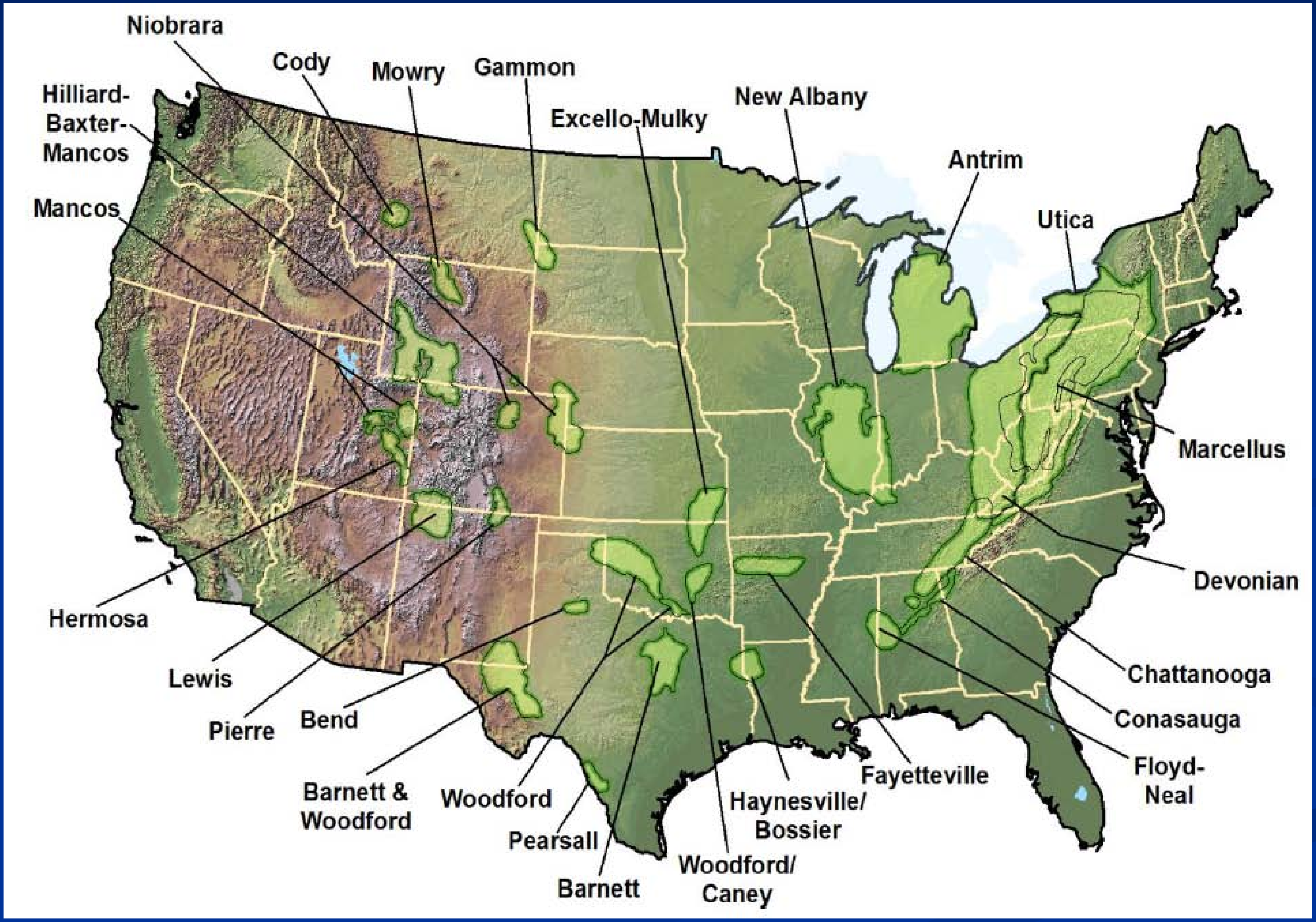
J. Moncrieff, S. Kale, A. Karastathis, N. Sondhi

Mewbourne School of Petroleum and Geological Engineering

University of Oklahoma

U - IC 3

United States Shale Gas Basins



(DOE Report, 2009)

Objective:

To identify, using petrophysical measurements, zones in Barnett that would be best for gas production.

Measurements:

- Porosity
- Permeability
- Mineralogy
- Nuclear Magnetic Resonance
- Compressional & Shear wave velocities
- Mercury injection capillary pressure
- Elastic Moduli
- Anisotropy
- Total organic carbon
- SEM studies

Measurements:

- Four wells from Fort Worth Basin
- Porosity, Mineralogy and TOC on ~800 plugs
- Mercury injection on ~ 150 plugs
- Velocity, permeability and other measurements on selected plugs

Porosity Measurements:

- Can not use standard gravimetric method to measure
- Low permeability and presence of organic matter
- Presence of reactive clays
- No ‘golden’ methodology exist

Work flow for Measuring Porosity

Obtain sample

Heat in oven at 100ºC for time t

Cool in dessicator

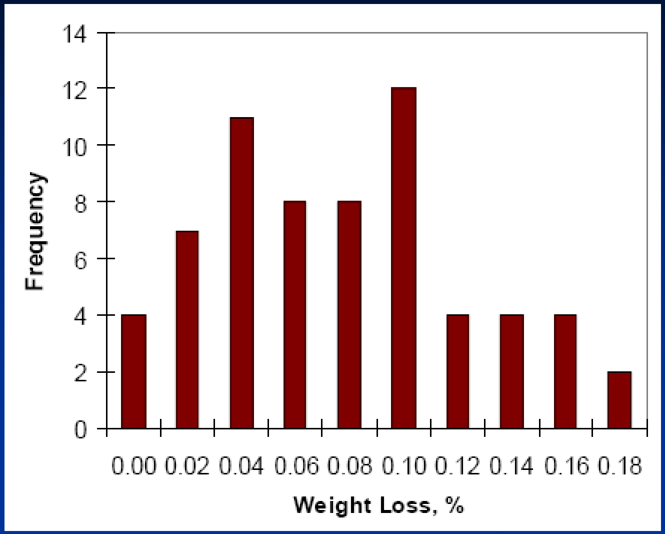
Obtain bulk volume and weight — V_b , W_n

Crush sample in crucible

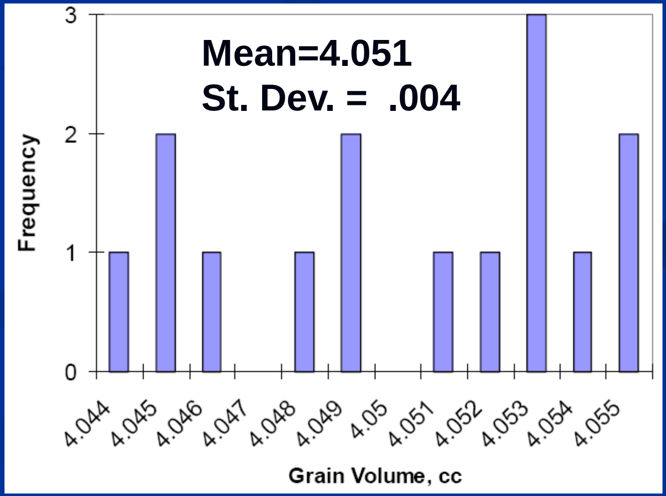
Dry powder in an oven

Cool in dessicator and obtain weight — W_n

Measure grain volume — V_g



$$\phi = \frac{V_b - V_g}{V_g}$$

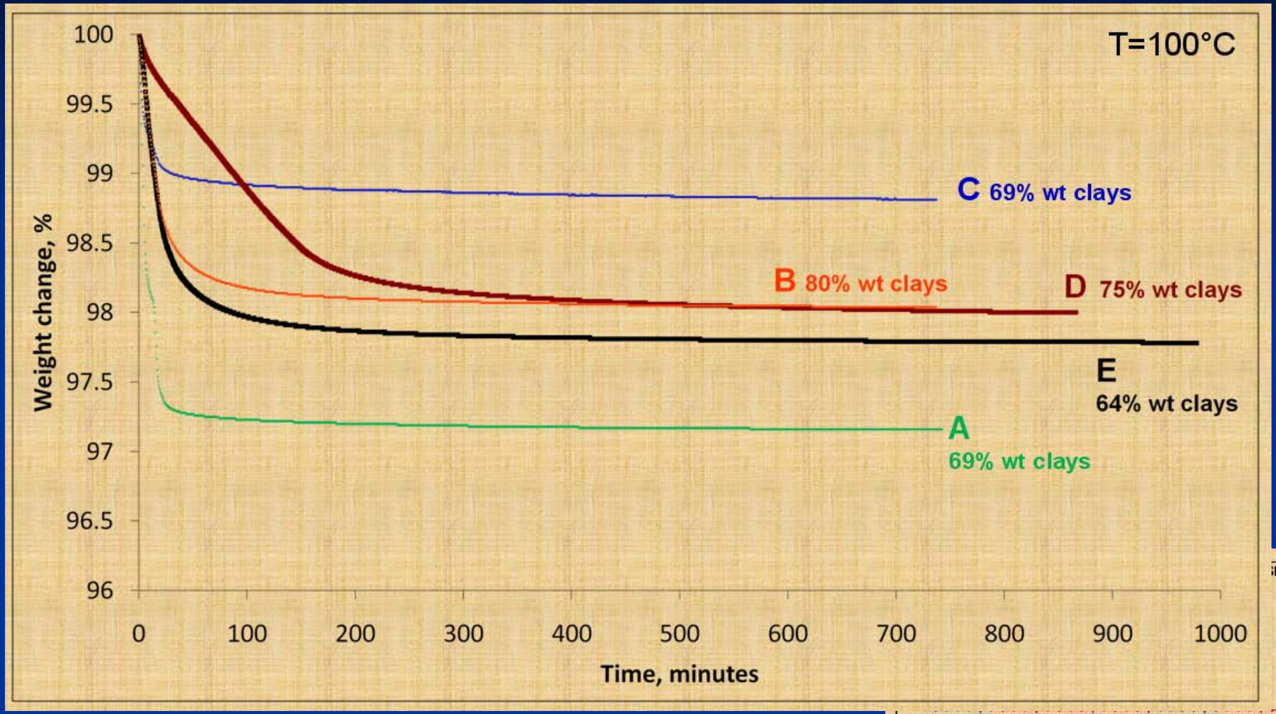


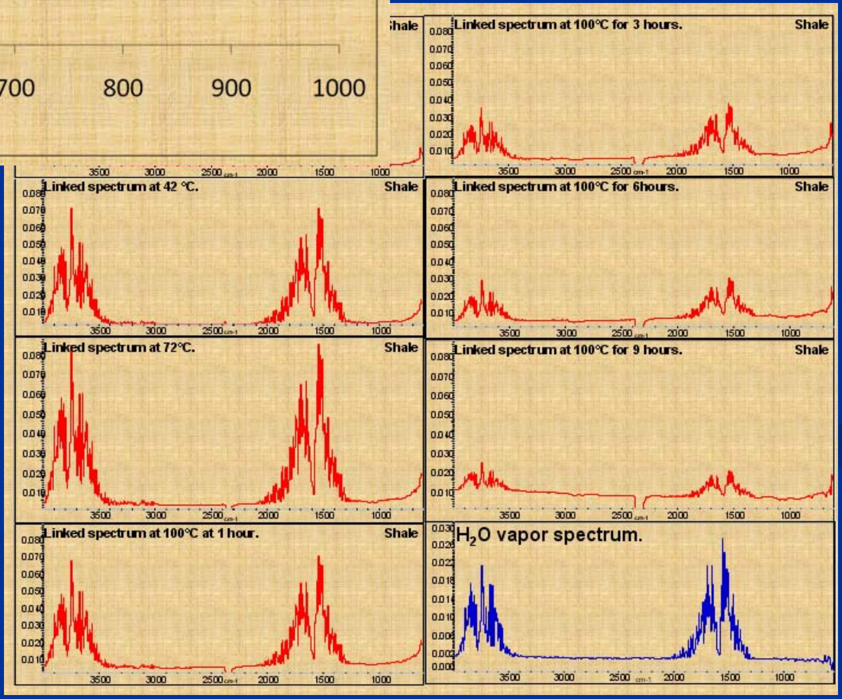
Crucible Assembly

Porosimeter

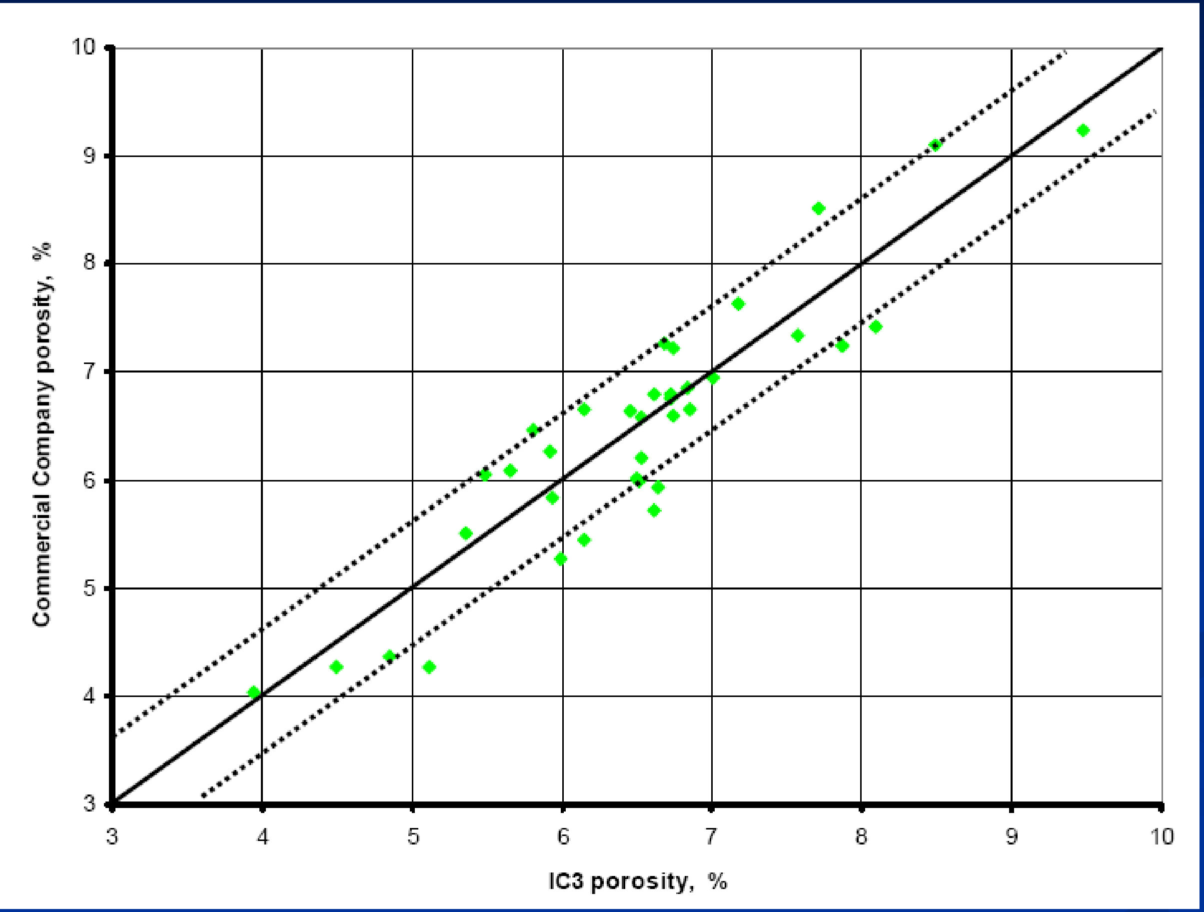
TGA- FTIR EXPERIMENTAL SET UP

TGA_FTIR Data for Shales

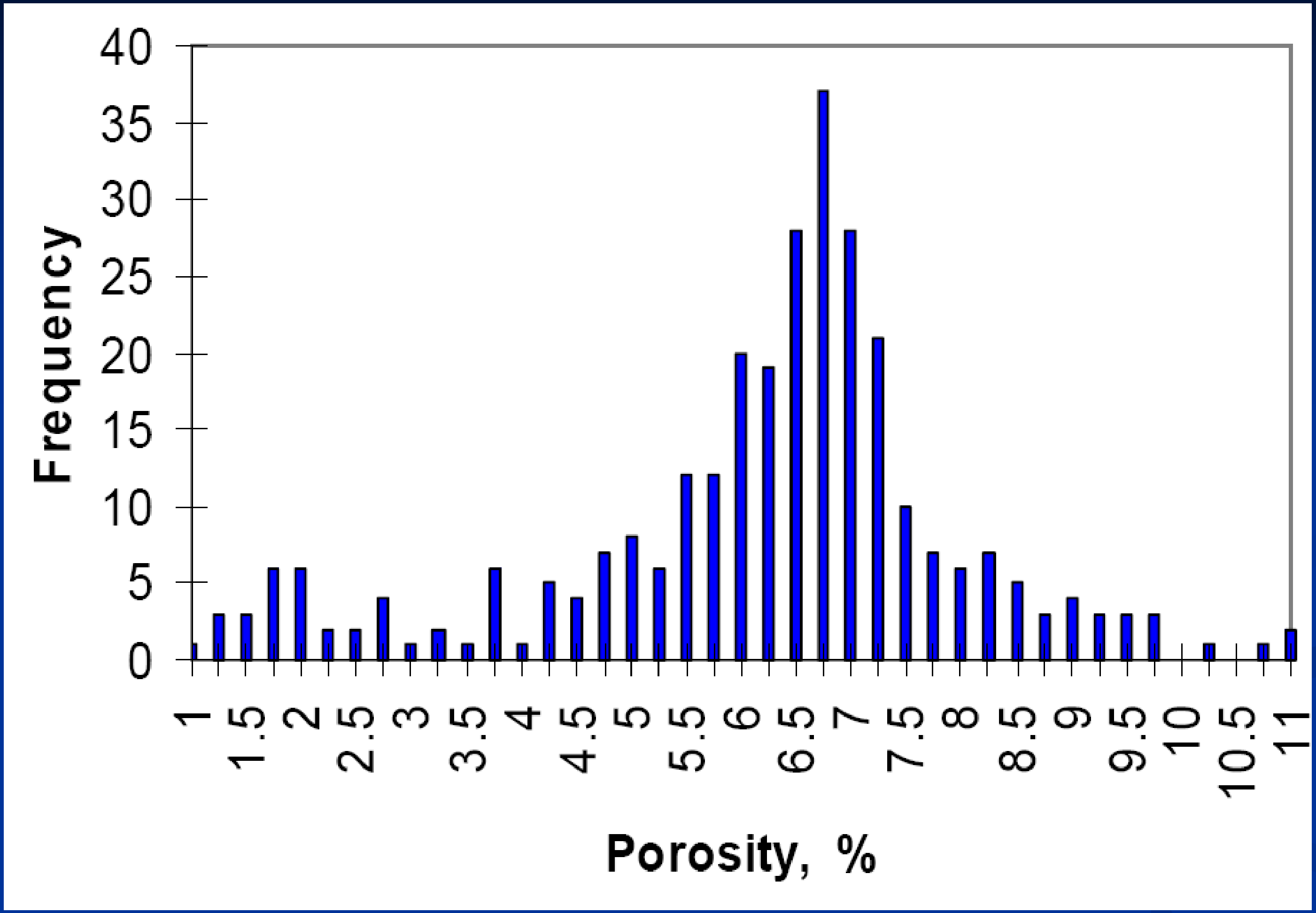




- Equilibration time is composition dependent
- No other vapor phase except water was detected

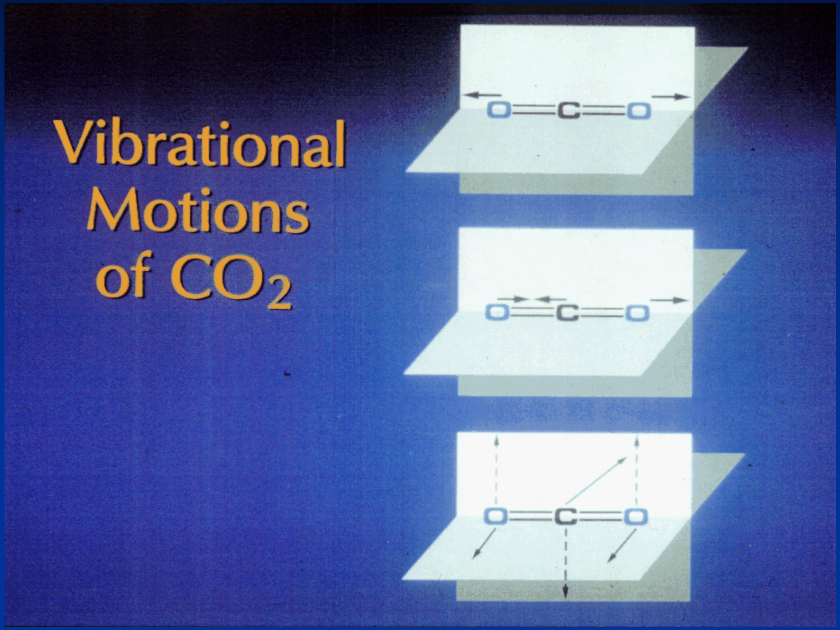


Comparison of porosity values measured in IC3 and a commercial lab. Sample depths are not exactly the same but within 0.2 ft. Note that the porosity values are within 0.5pu.



Porosity distribution in Well A, mean=6.1%

Fourier Transform Infrared Spectroscopy FTIR



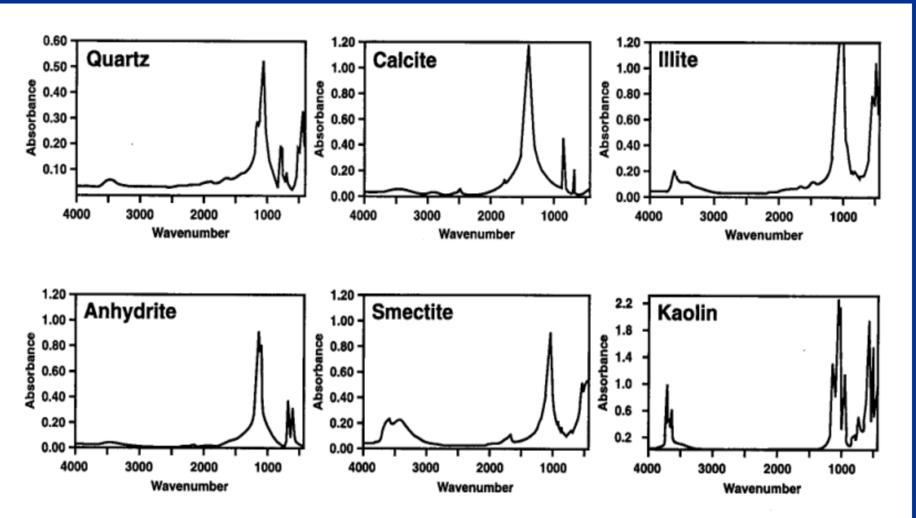
Beer's Law

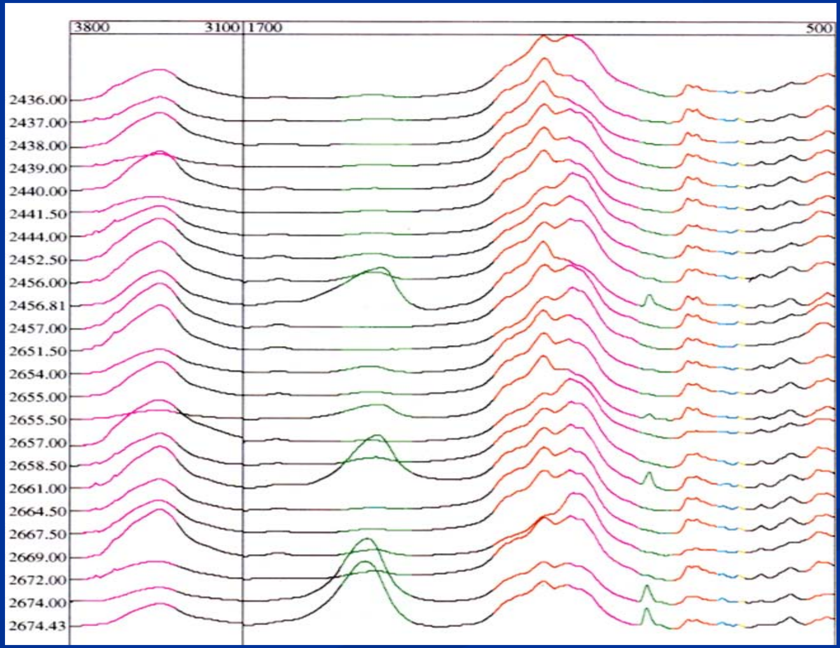
$A(\nu) = b\, k_i(\nu)\, C_i$

where: b = pathlength

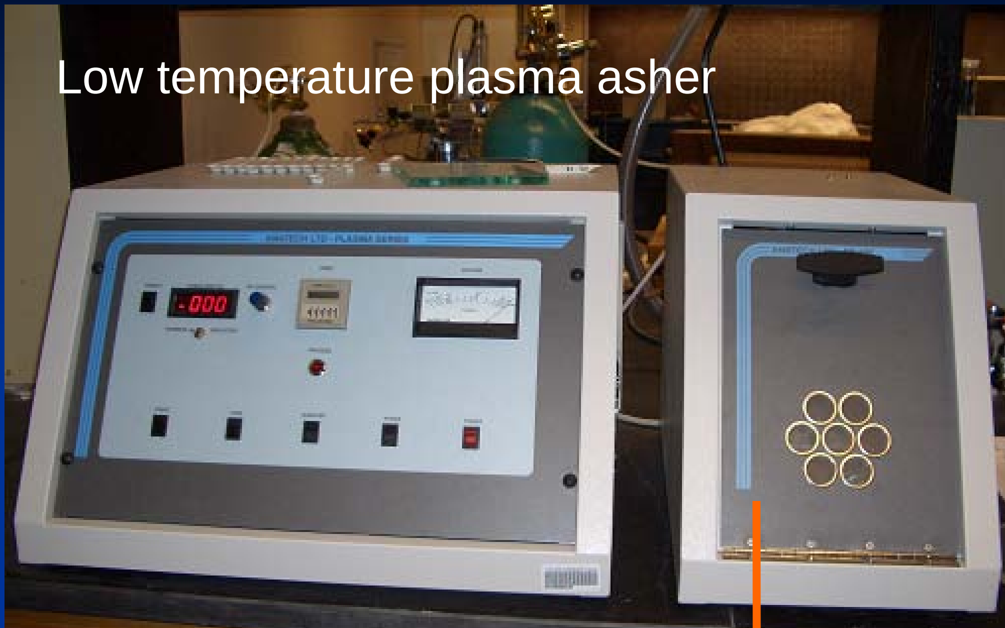
k_i = absorptivity of the i^{th} component

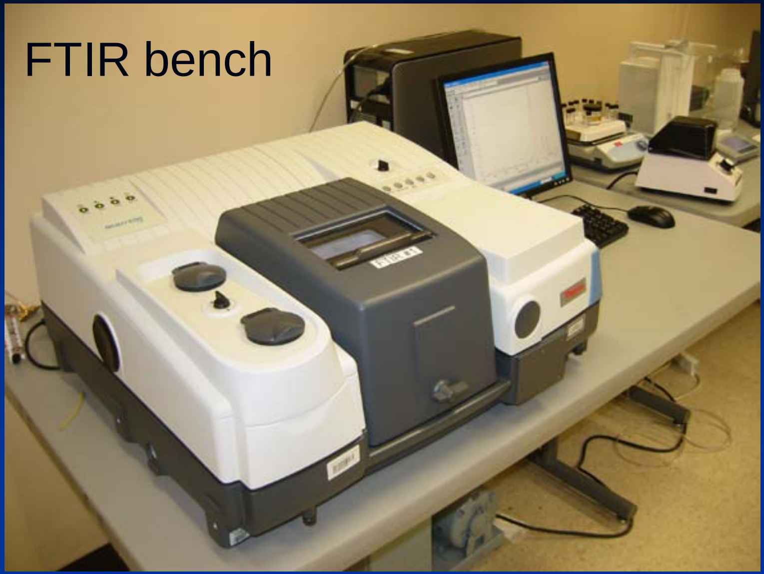
C_i =concentration of the i^{th} component

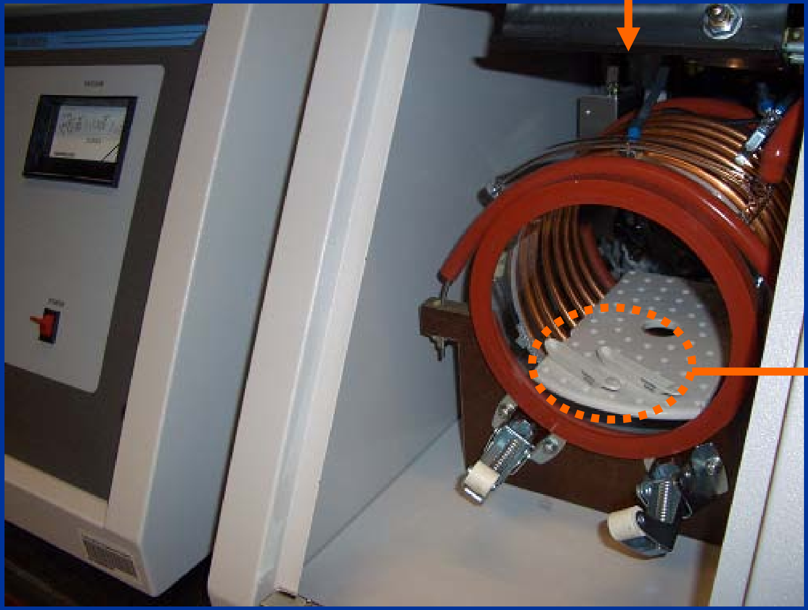


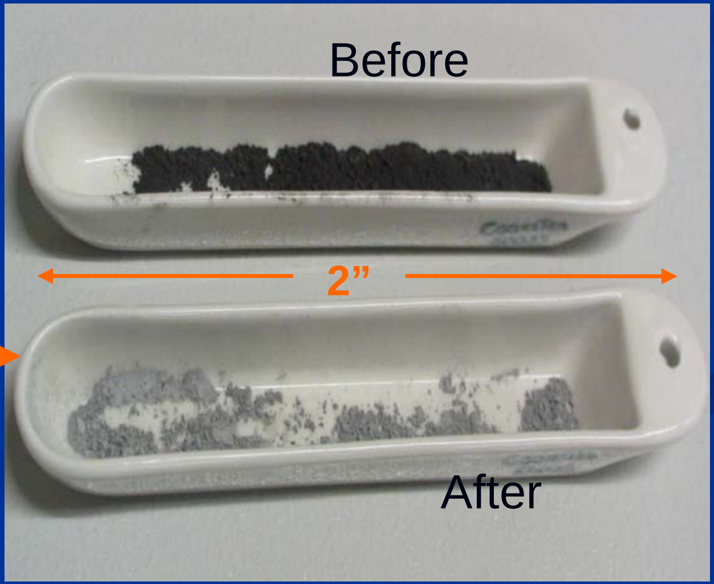


Invert spectra for 16 minerals.

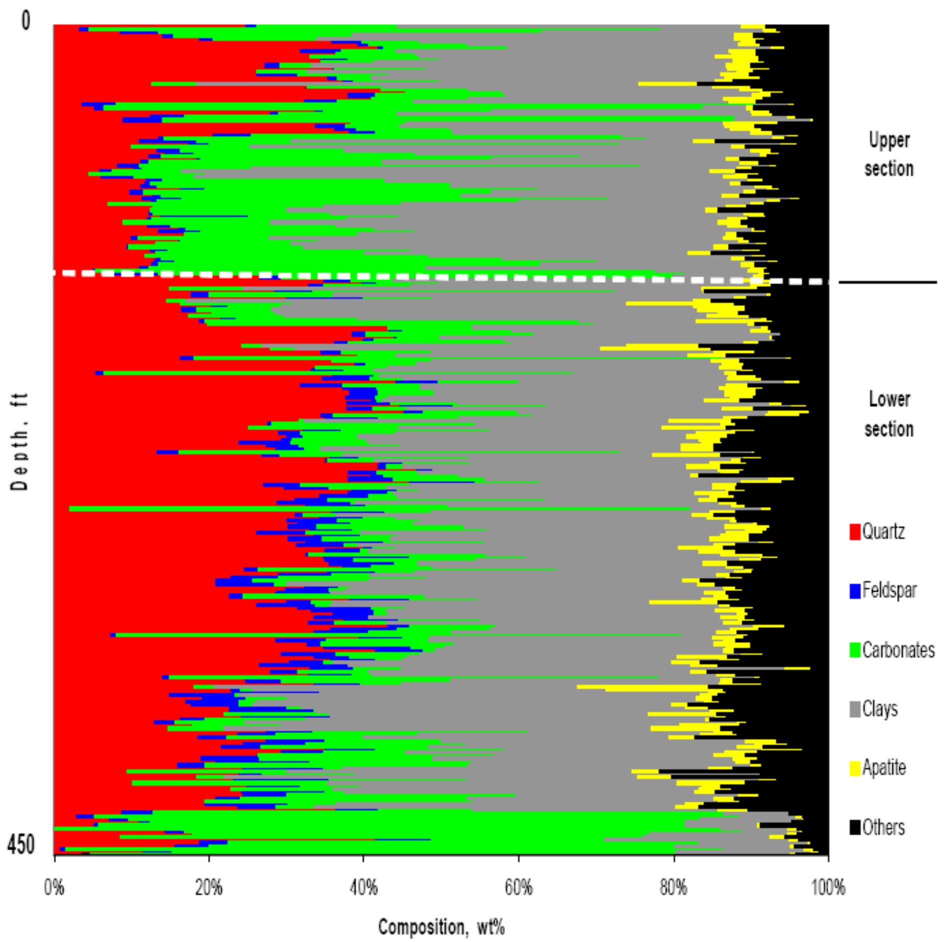

Low temperature plasma asher


FTIR bench



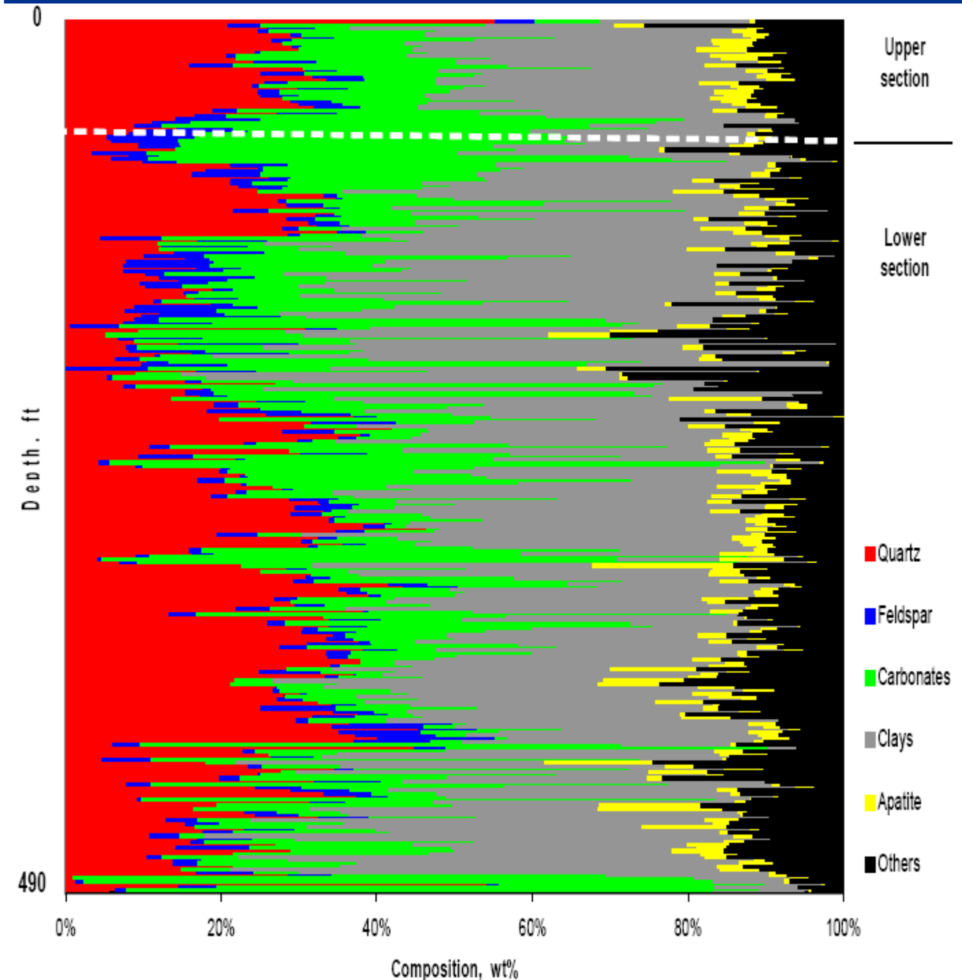

Before
2”
After

FTIR Mineralogy for Samples from Two Wells

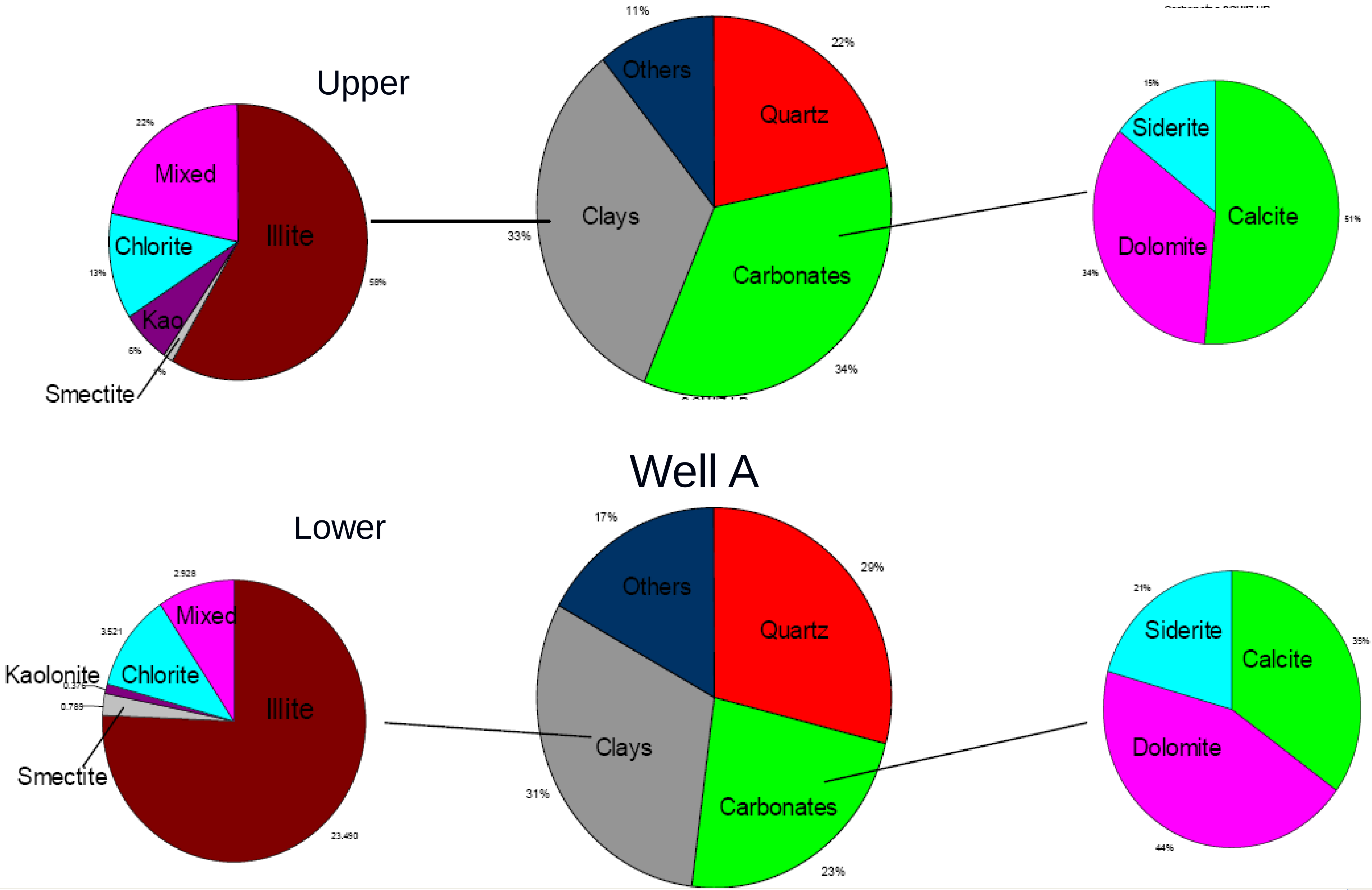


Well A

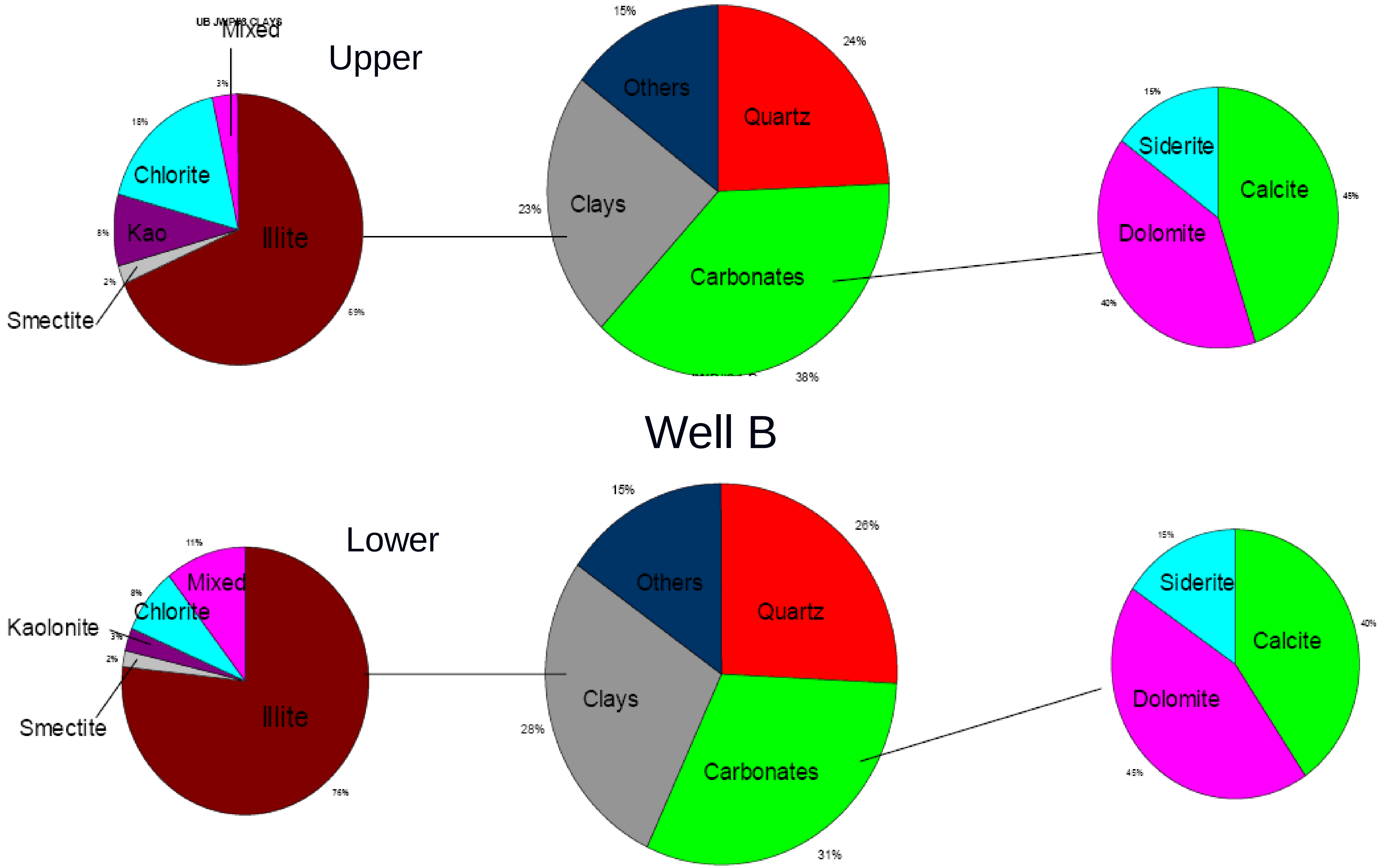
Well B



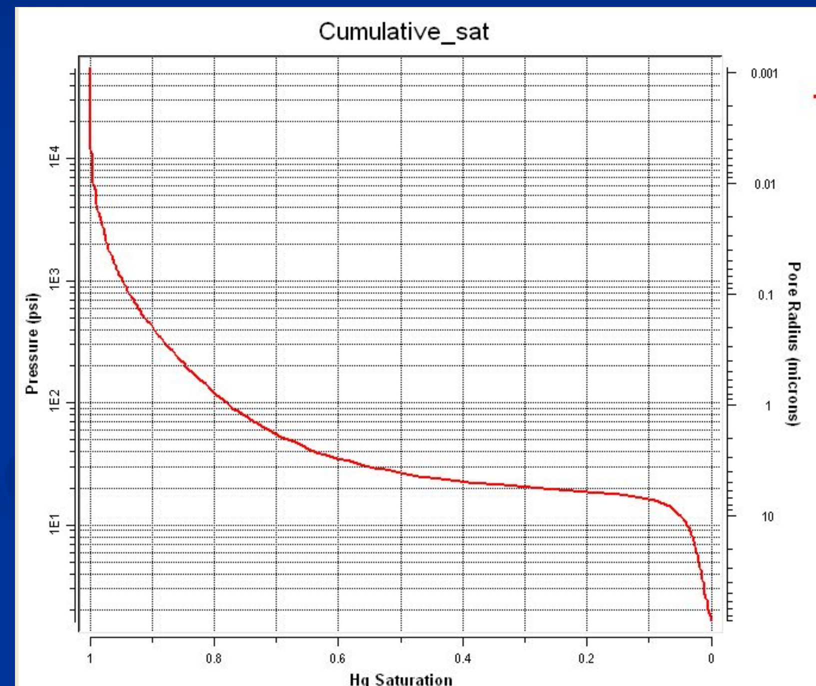
Comparison of Upper & Lower Barnett Mineralogy in Well A



Comparison of Upper and Lower Barnett Mineralogy in Well B



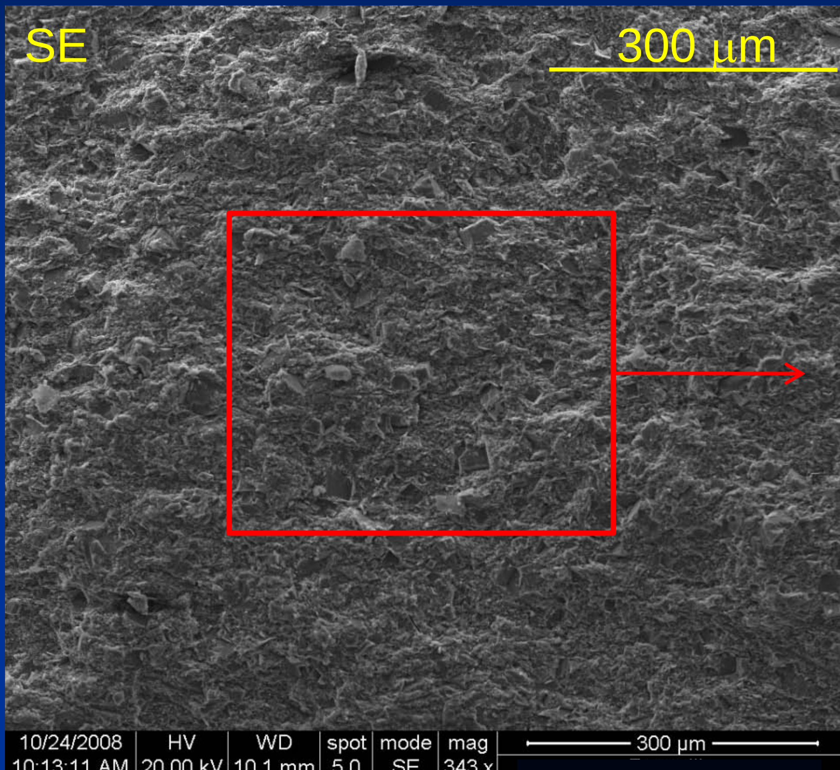
High Pressure Mercury Injection Capillary Pressure

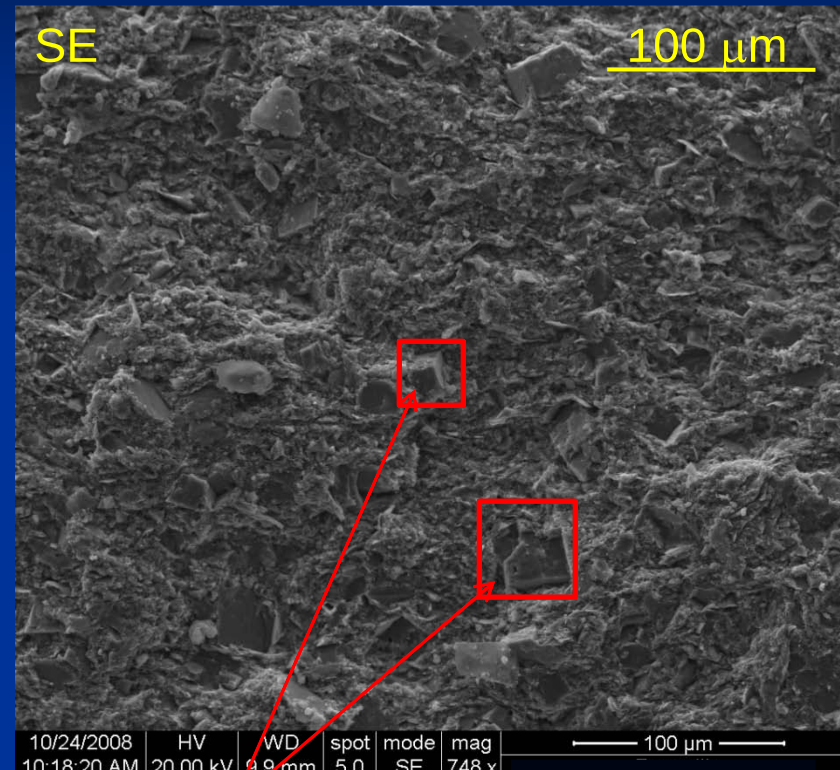


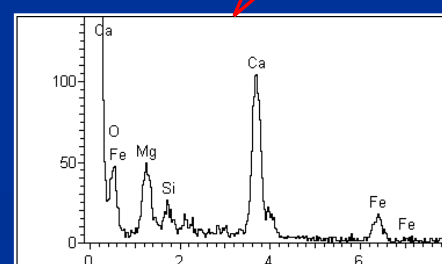
Microstructural Studies -SEM

- Fractured surfaces show us properties such as bedding planes and crystal habits
- However, fractured surfaces hide the nature of pores
- Polished surfaces can show us pore morphology
- Ion milling removes polishing artifacts and gives us a very low-relief surfaces
- Plasma-asher removes organic matter

Fractured

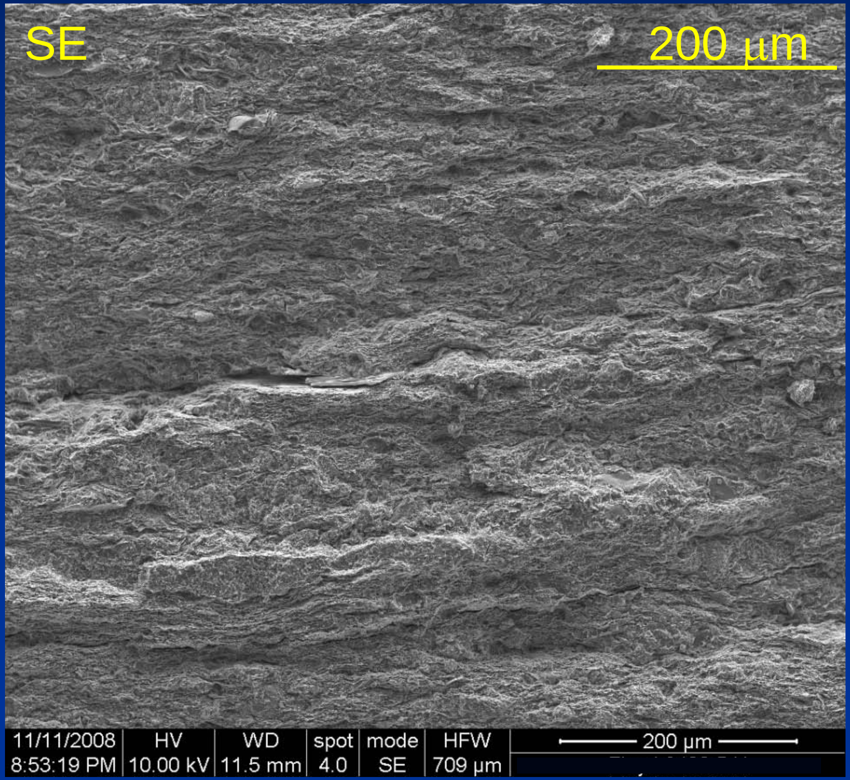


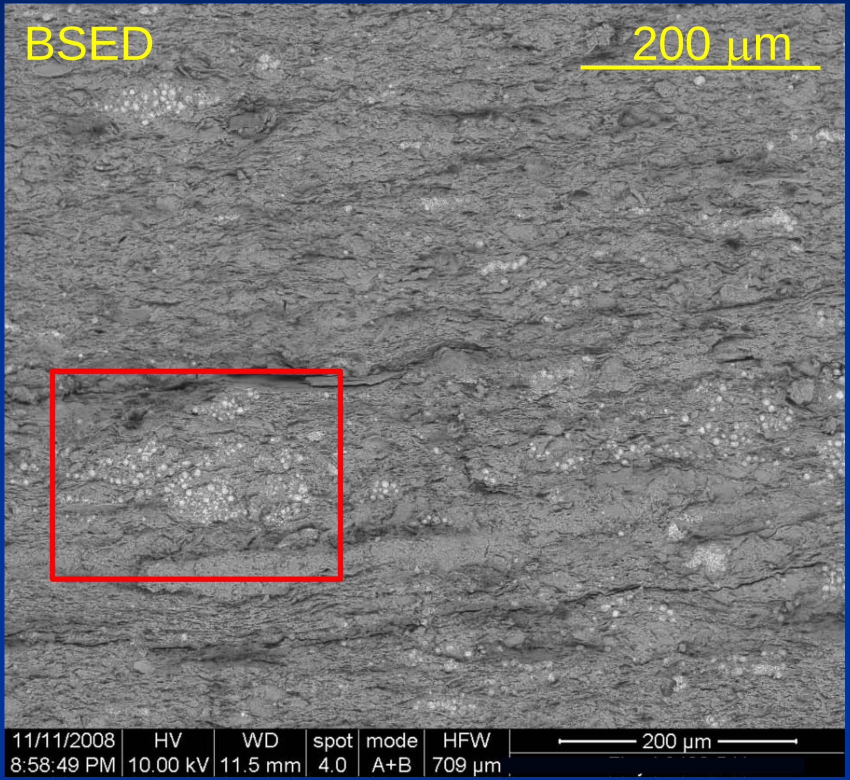




- Images of a fractured surface
- Looking parallel to bedding planes
- Note the abundance of dolomite

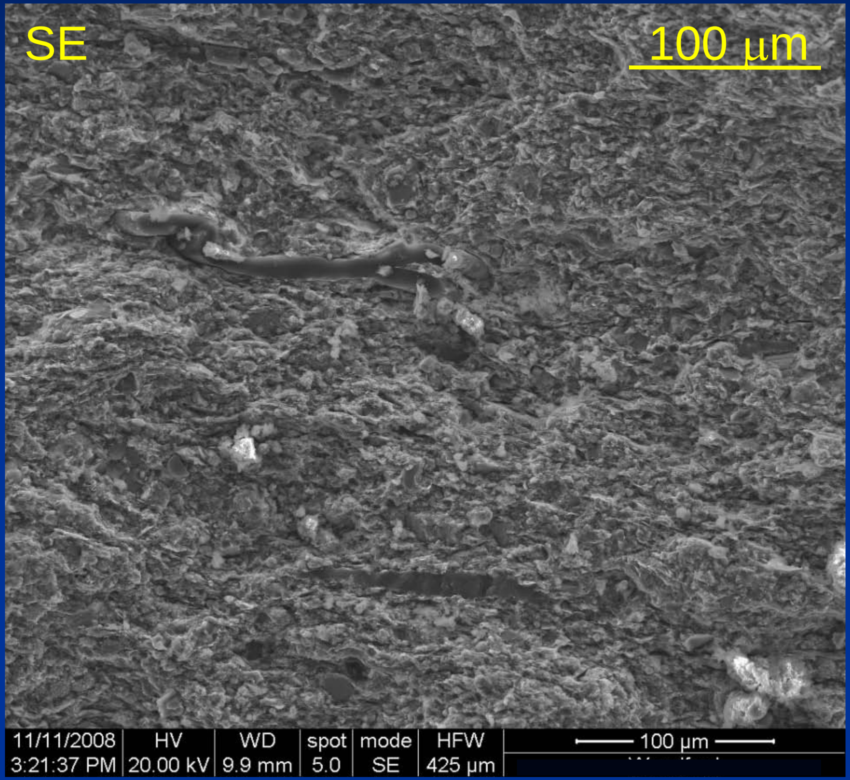
Fractured





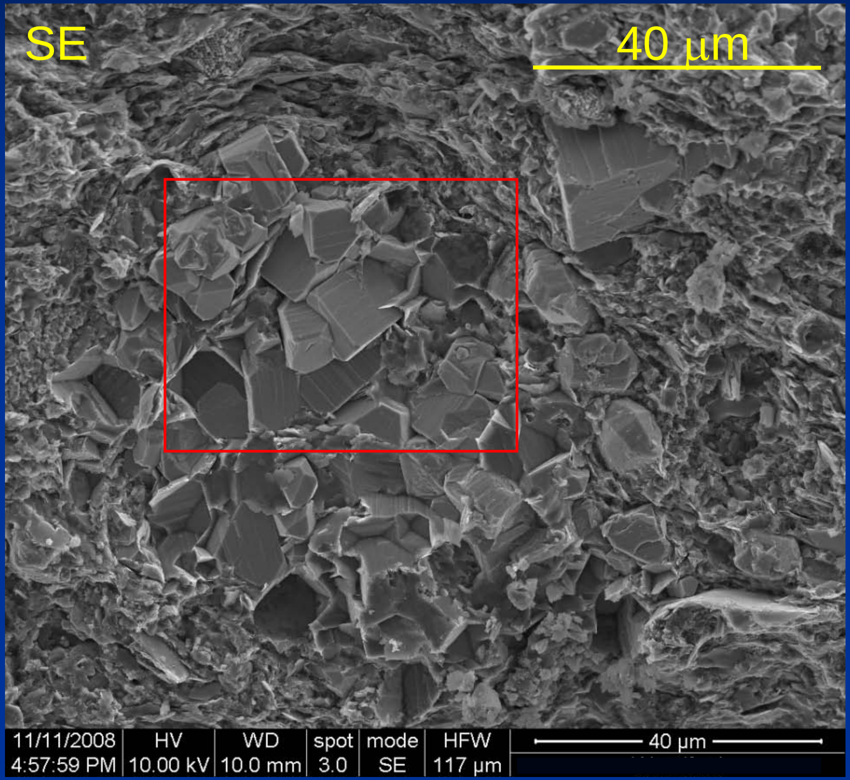
- Bedding planes easily visible
- Framboids easily seen using a backscatter electron detector and nearly invisible using secondary electrons
- Pyrite clusters appear linear and more concentrated in some beds

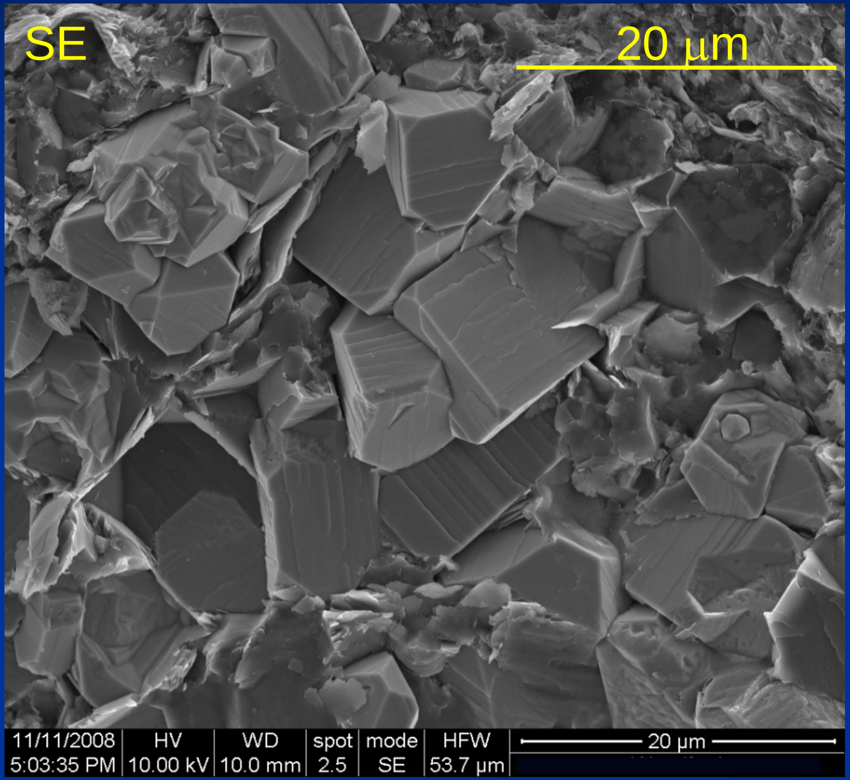
Fractured



- Sample contains pyrite, but in a more random distribution compared to last sample
- Backscatter image clearly shows distribution of pyrite and carbon features
- How does it look in 3D? How continuous are these carbon features?

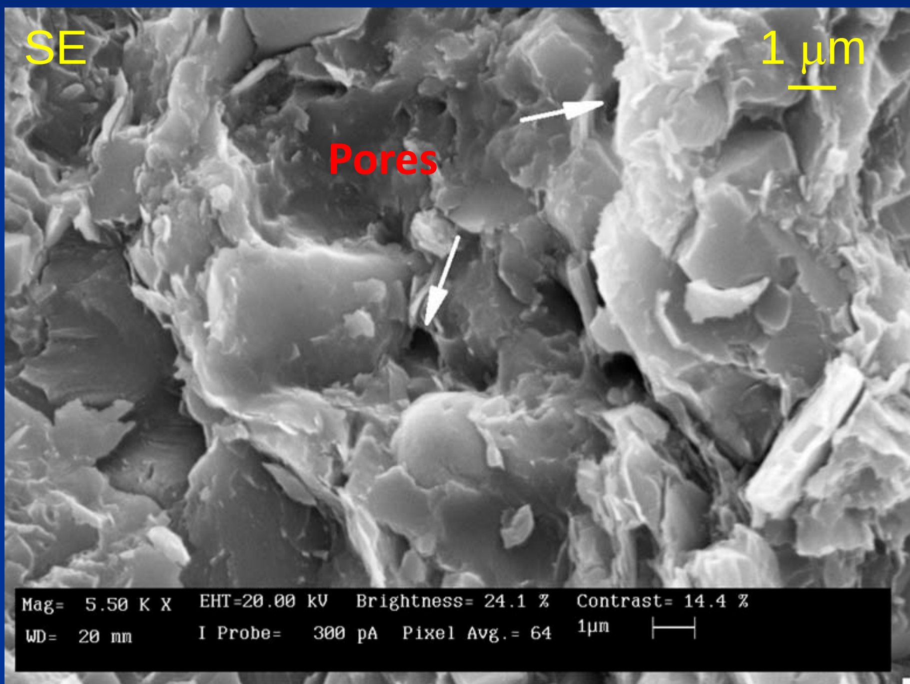
Fractured

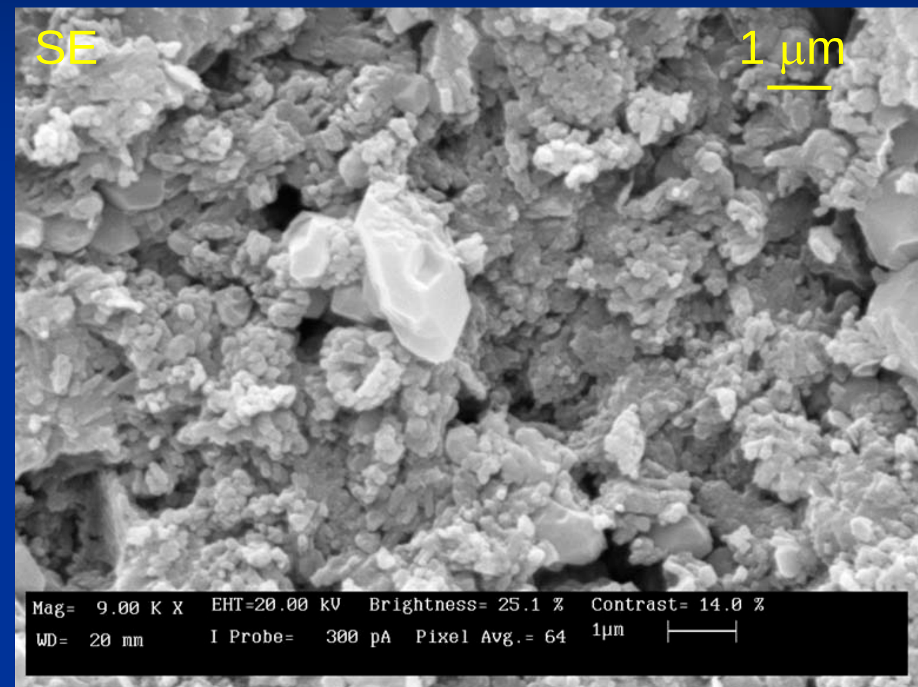




- Large cluster of pyrite
- Note the turning of clays around pyrite cluster

Fractured



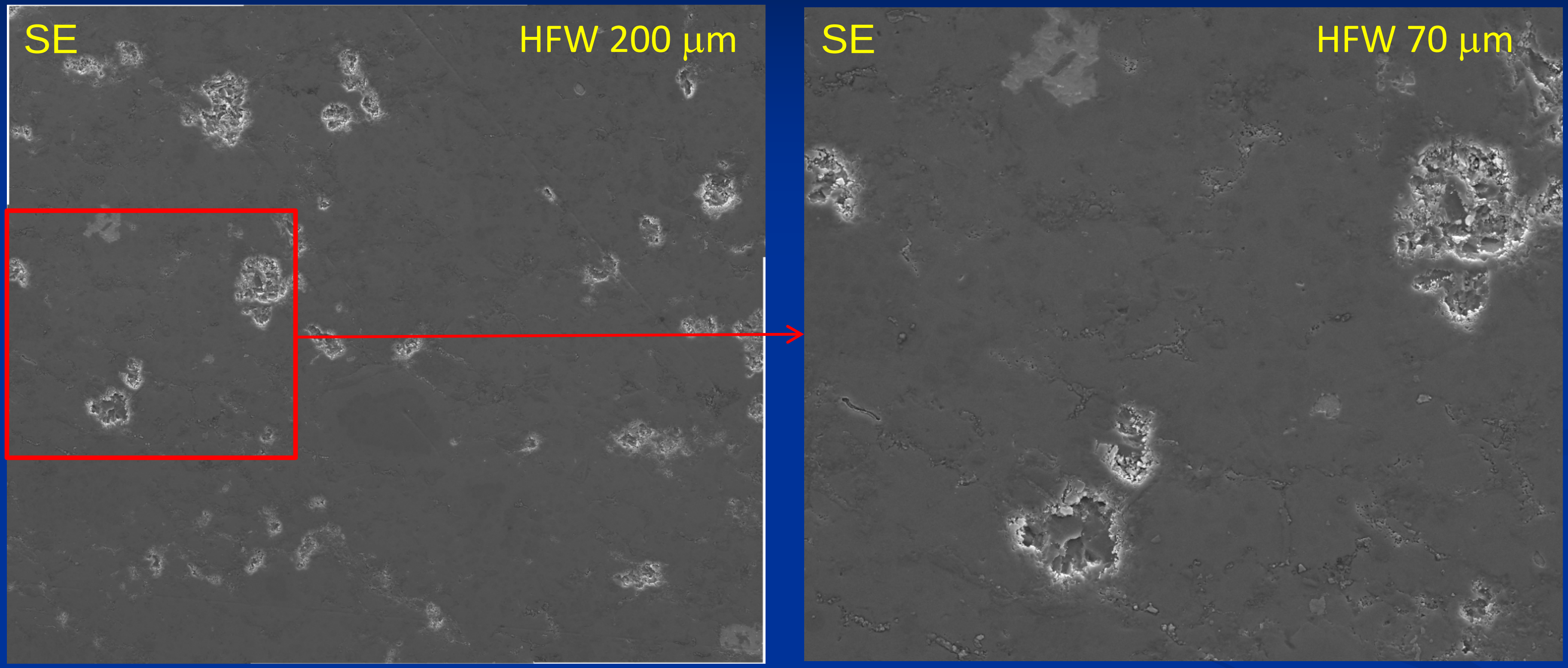


Pores: 300 nm – 800 nm

Pores: 200 nm – 1.1 µm

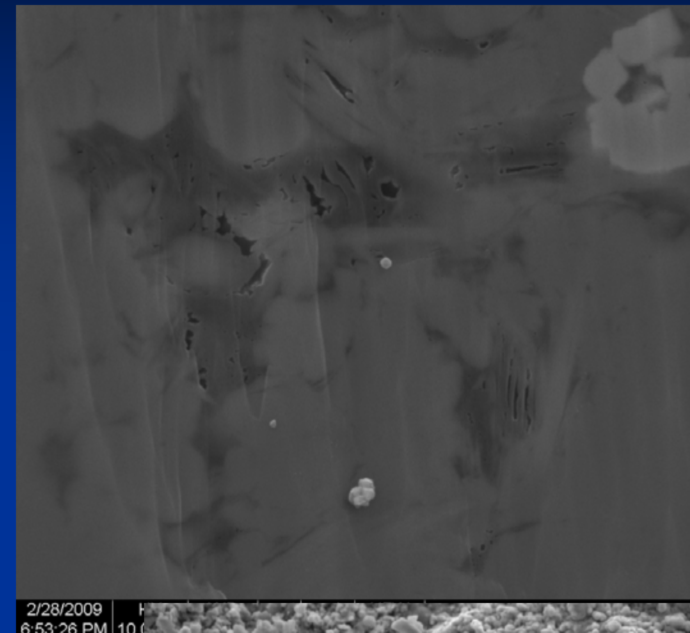
- Fractured surfaces are good at looking at microstructure, grains, and crystal habits

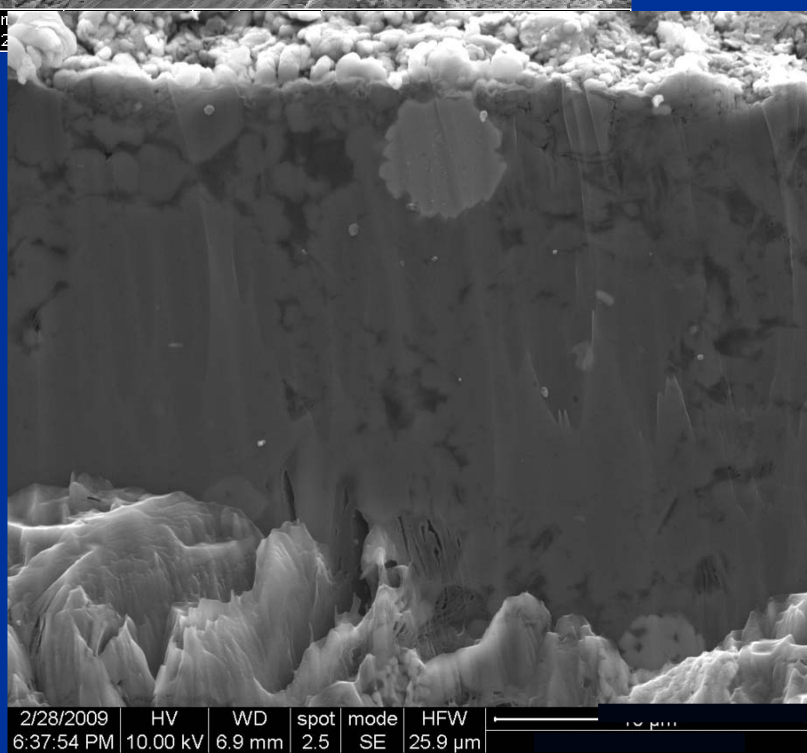
Polished

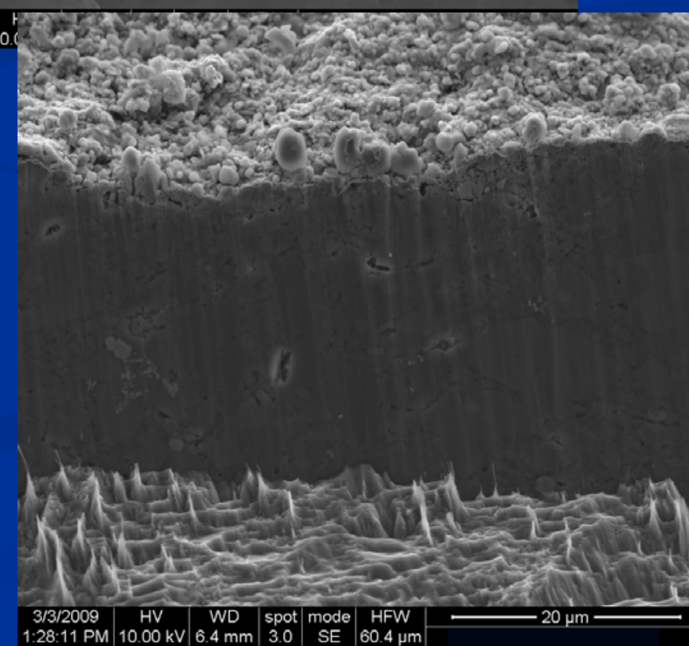


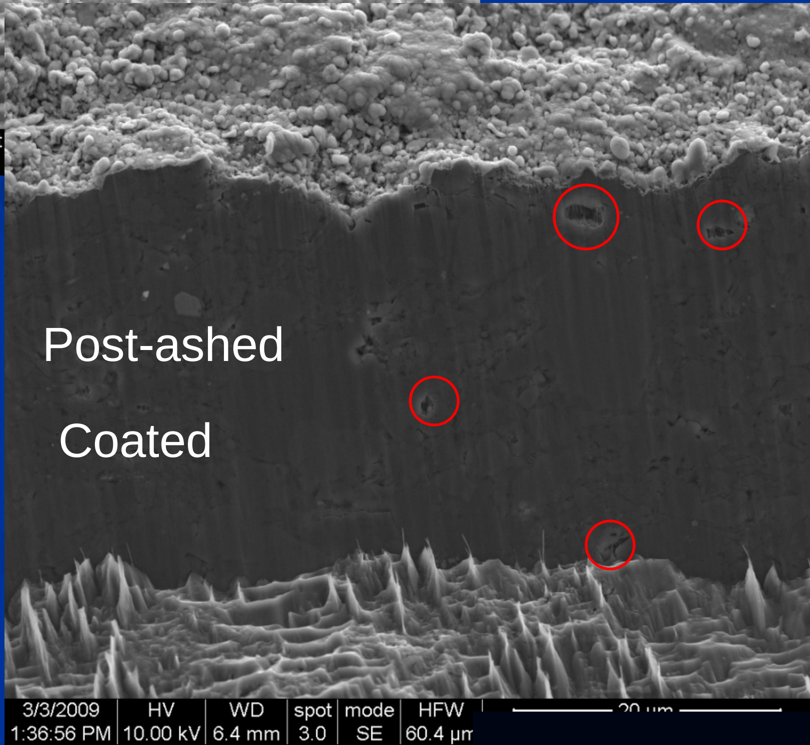
- Polished specimens loose a lot of texture and grain structure, but it enhances pore and crack/tube morphology

Ion-milled Surfaces



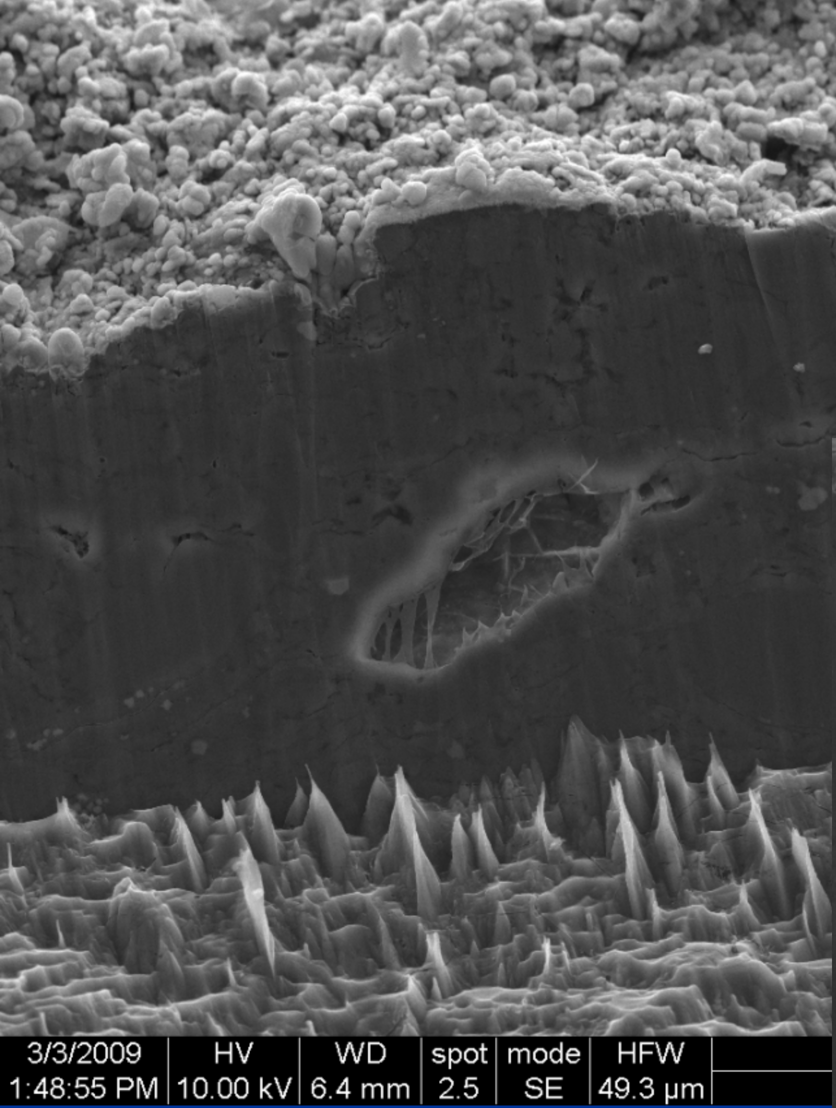


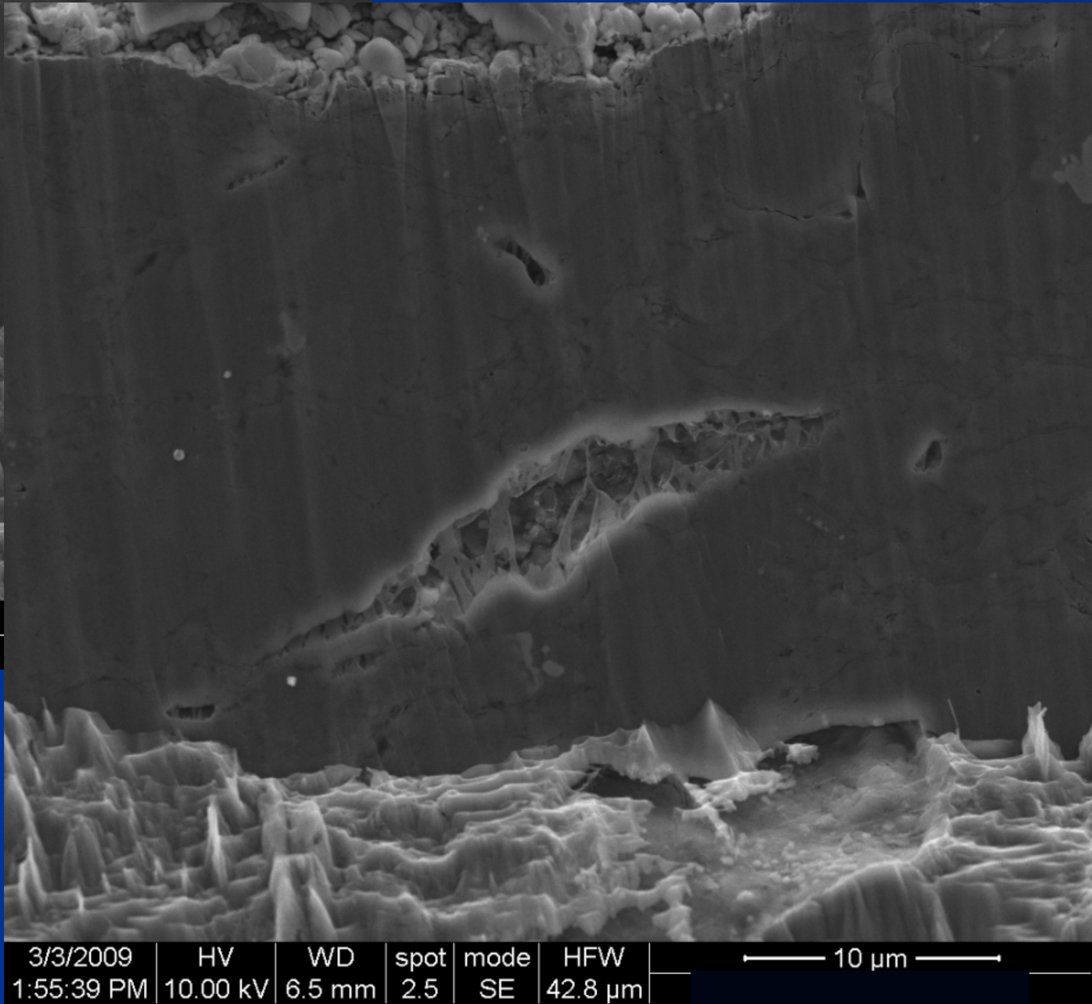




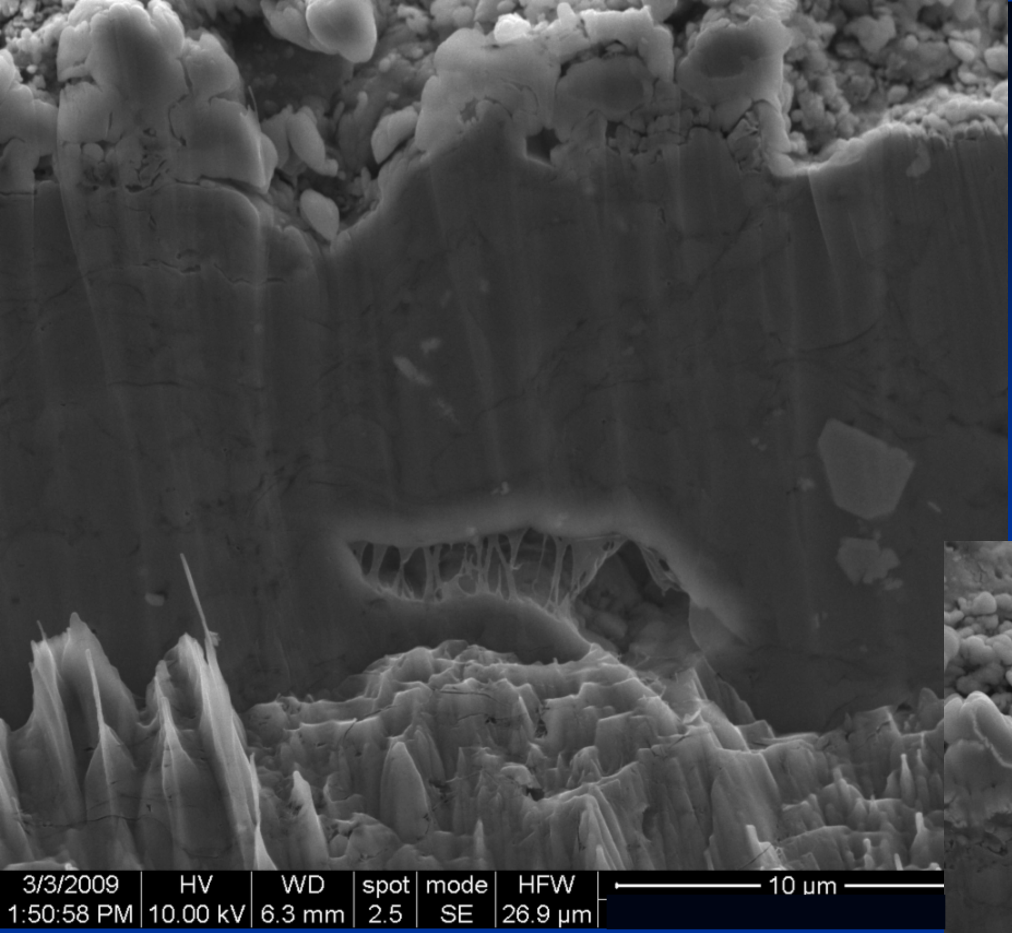
Removal of Organic Matter by Low Temperature Plasma Ashing

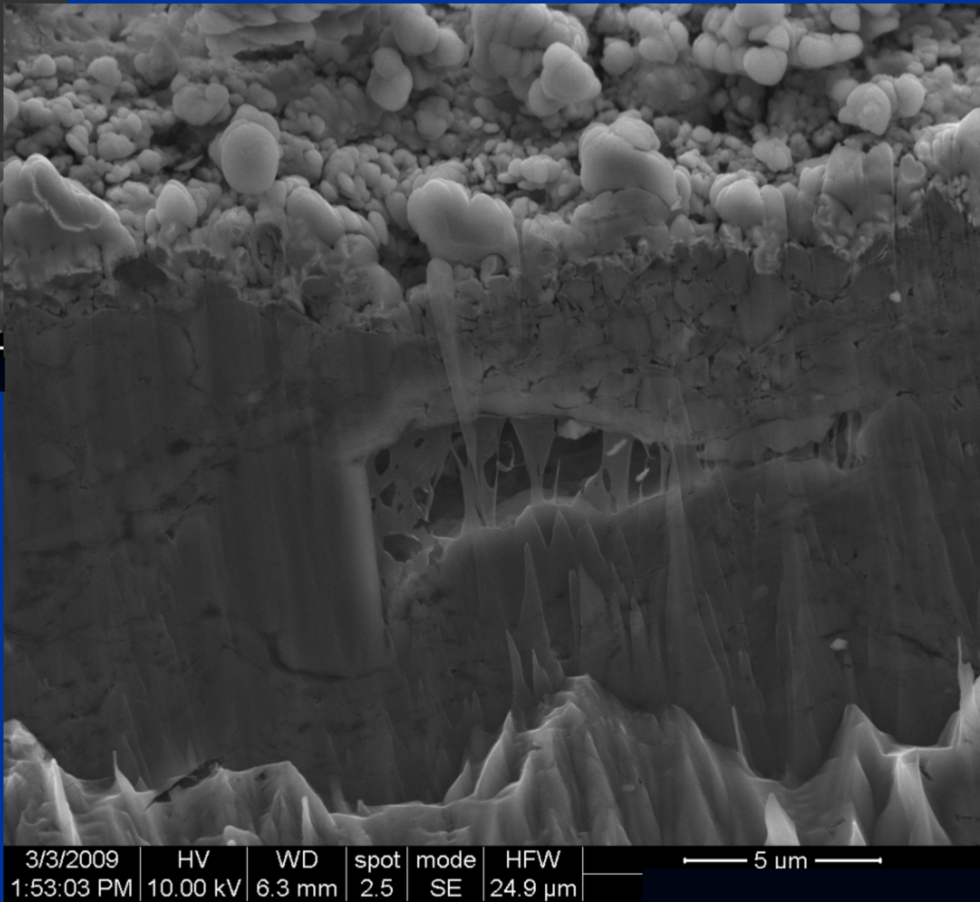
Ion-milled and Ashed



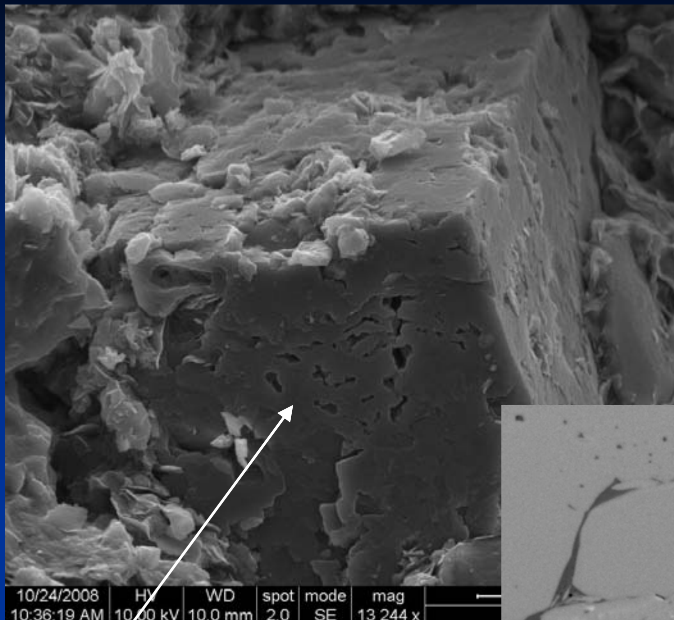


Ion-milled and Ashed

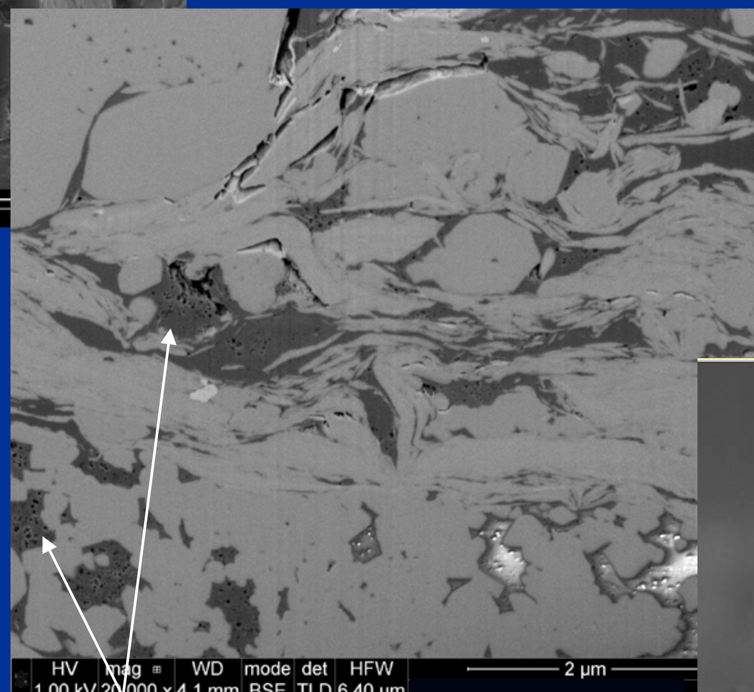




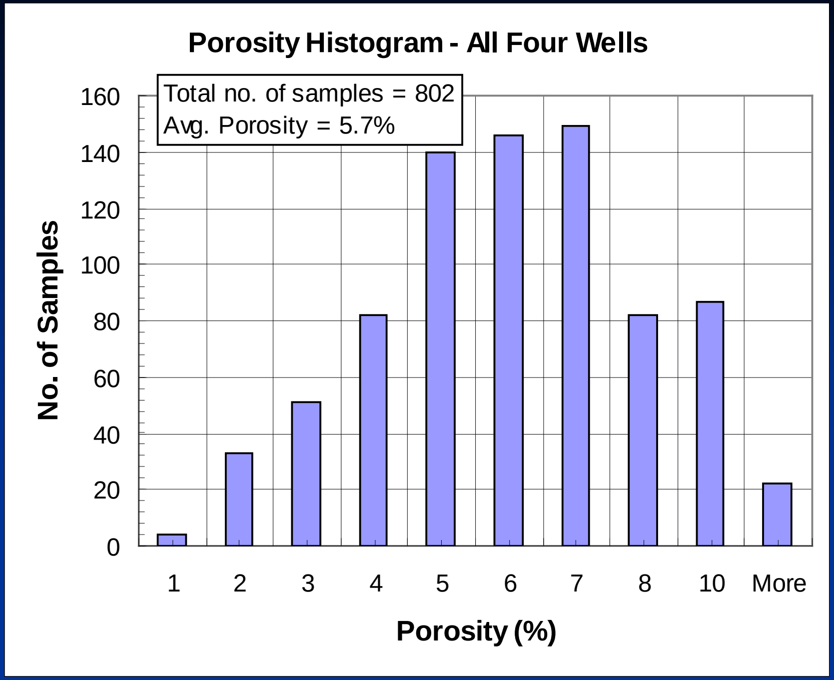
Where is the Porosity?

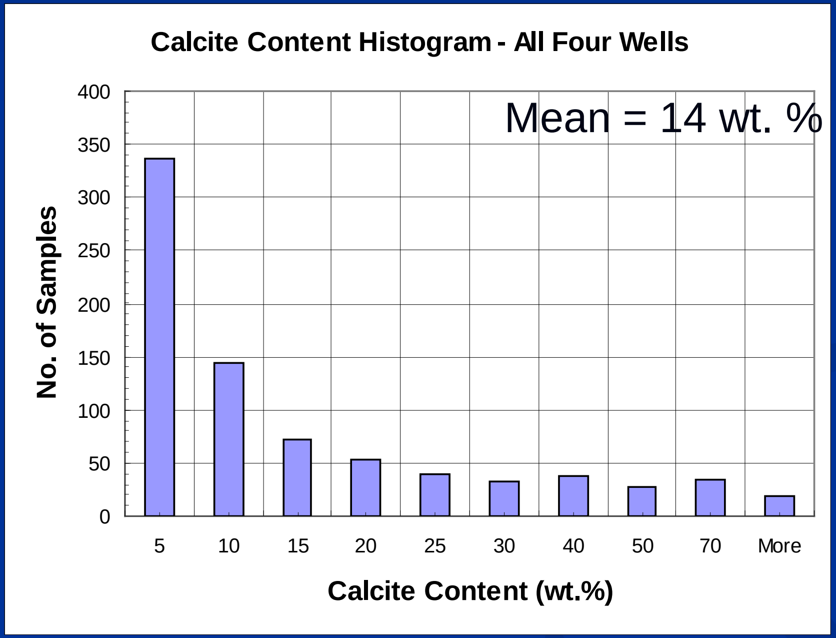


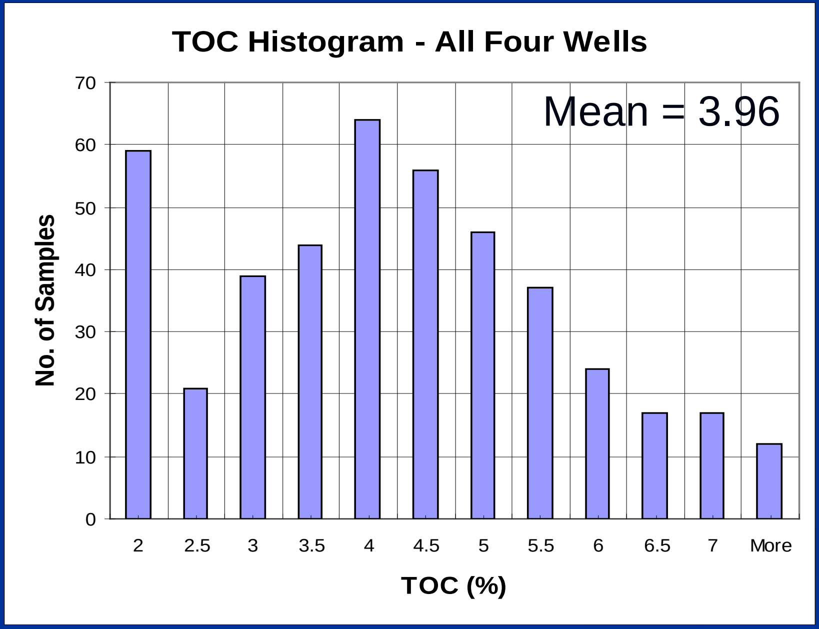
Mineral grains



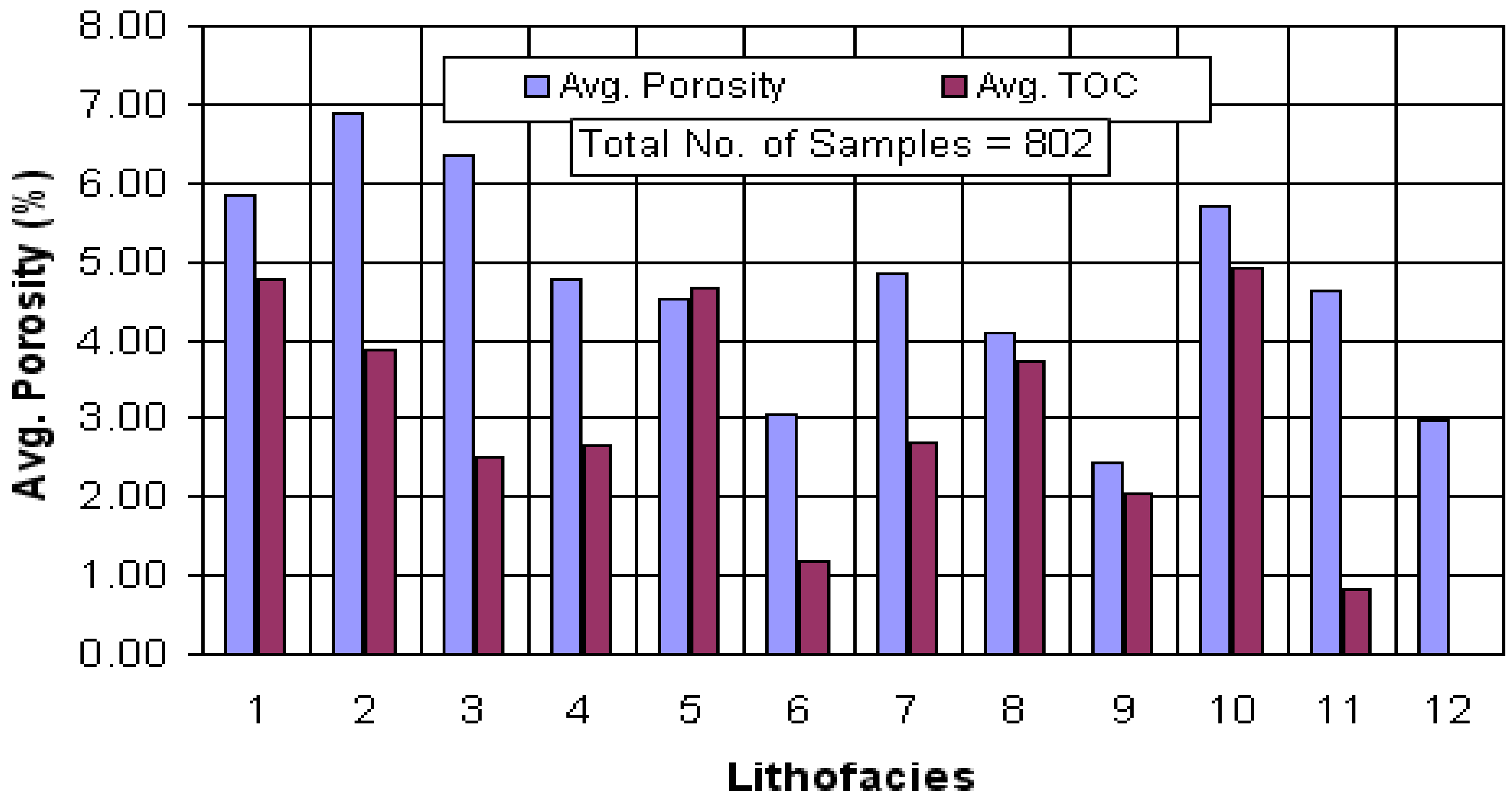
Organic matter


Porosity Histogram - All Four Wells
Total no. of samples = 802
Avg. Porosity = 5.7%
No. of Samples
0
20
40
60
80
100
120
140
160
1
2
3
4
5
6
7
8
10
More
Porosity (%)


Calcite Content Histogram - All Four Wells
Mean = 14 wt. %
No. of Samples
0
50
100
150
200
250
300
350
400
5
10
15
20
25
30
40
50
70
More
Calcite Content (wt.%)


TOC Histogram - All Four Wells
Mean = 3.96
No. of Samples
0
10
20
30
40
50
60
70
2
2.5
3
3.5
4
4.5
5
5.5
6
6.5
7
More
TOC (%)

Average Porosity & TOC of Lithofacies



1. Siliceous non-calcareous mudstone, 2. Siliceous calcareous mudstone, low calcite, 3. Siliceous calcareous mudstone, high calcite, 4. Silty-Shaly deposits, 5. Phosphatic deposits, 6. Limy mudstone 7. Dolomitic mudstone, 8. Calcareous laminae, 9. Concretions, 10. Fossiliferous deposits, 11. Spicule rich deposits, 12. Debris flow deposits **(Singh,2008)**

Petrotype 1:

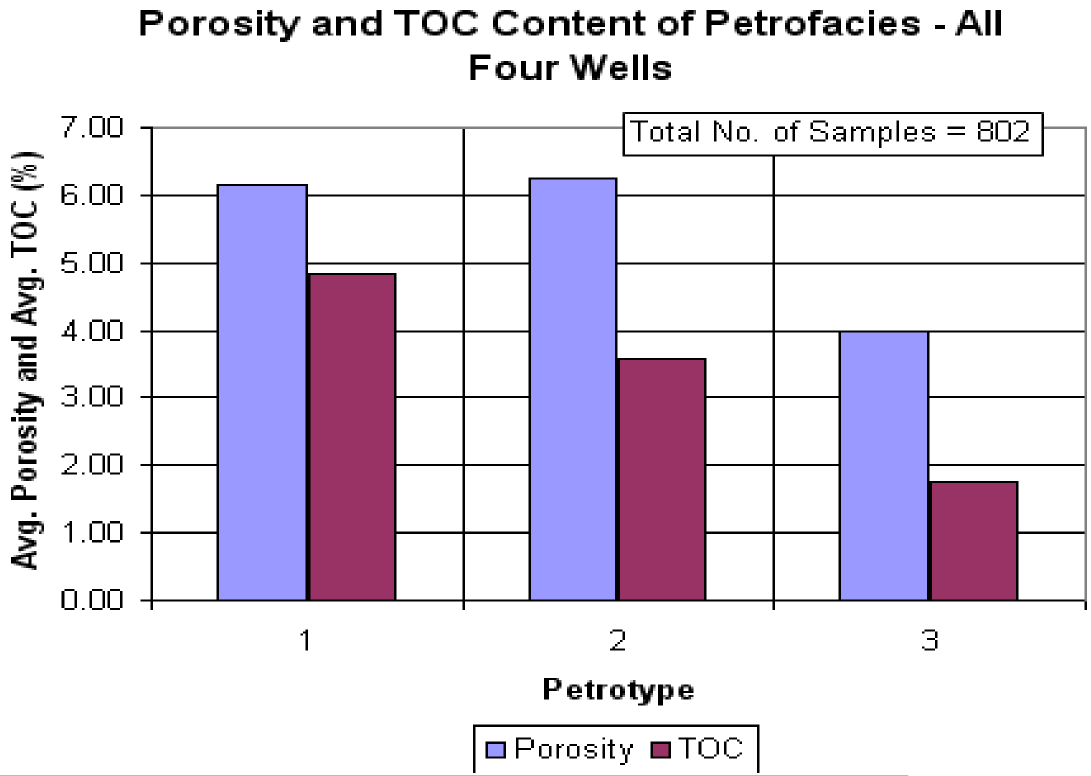
Lithofacies: 1, 5, 2 (Calcite < 10%)

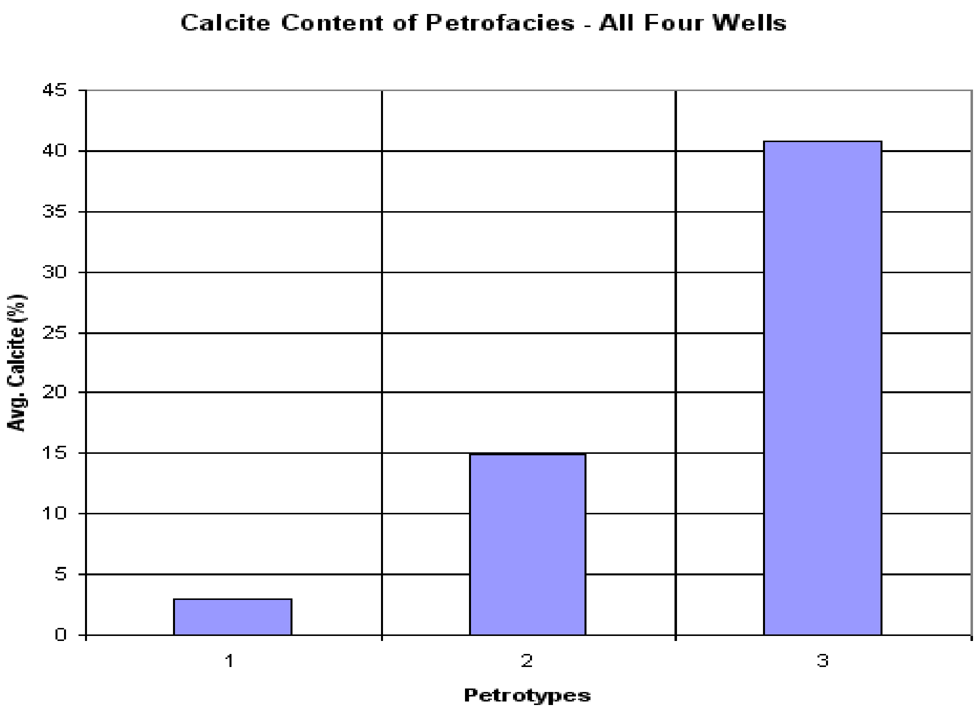
Petrotype 2:

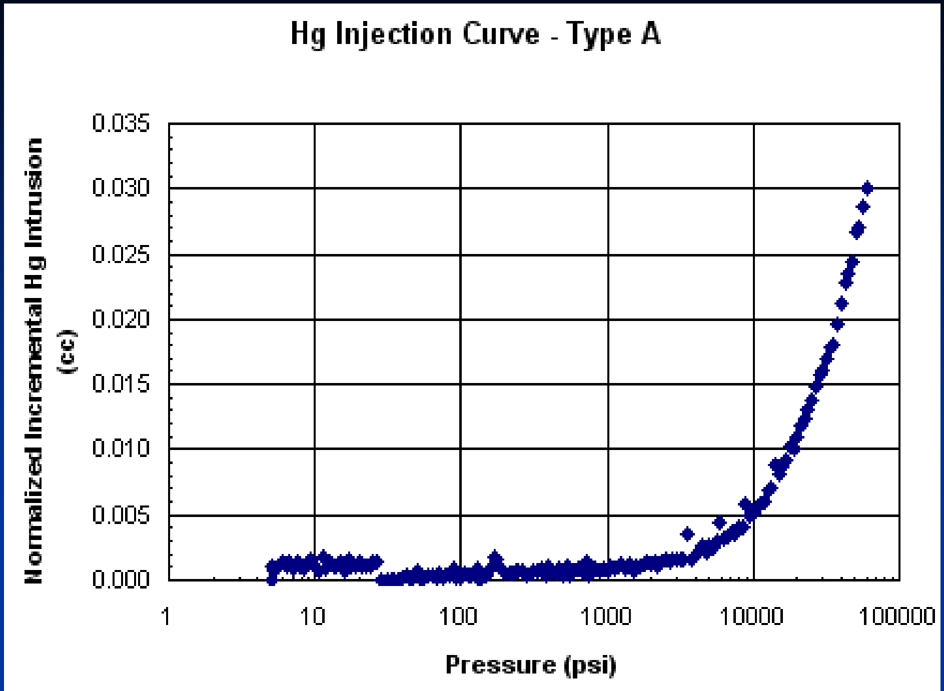
Lithofacies: 3,7,8, 10 and 2 (calcite > 10%)

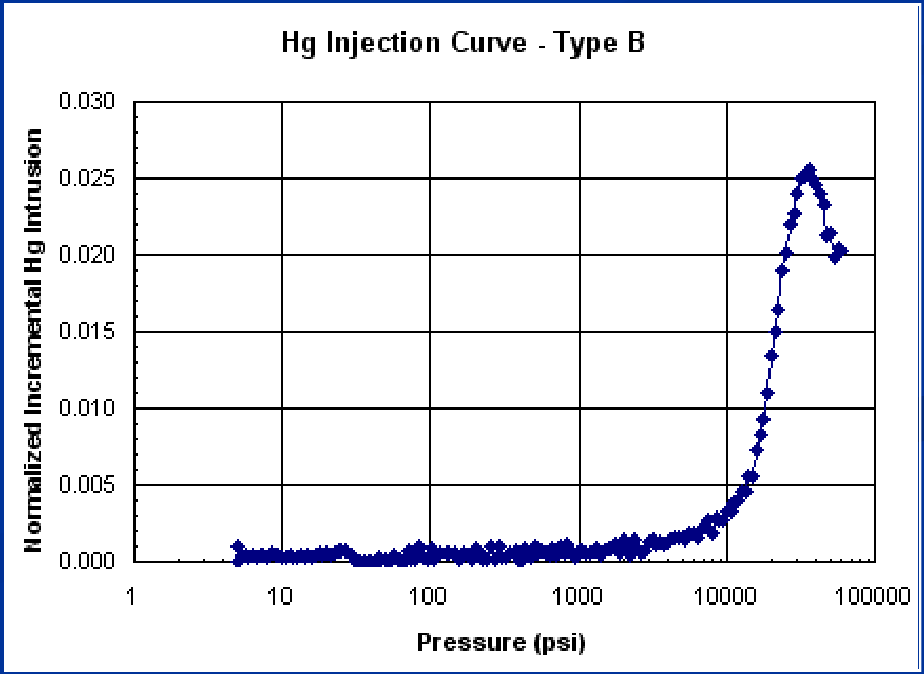
Petrotype 3:

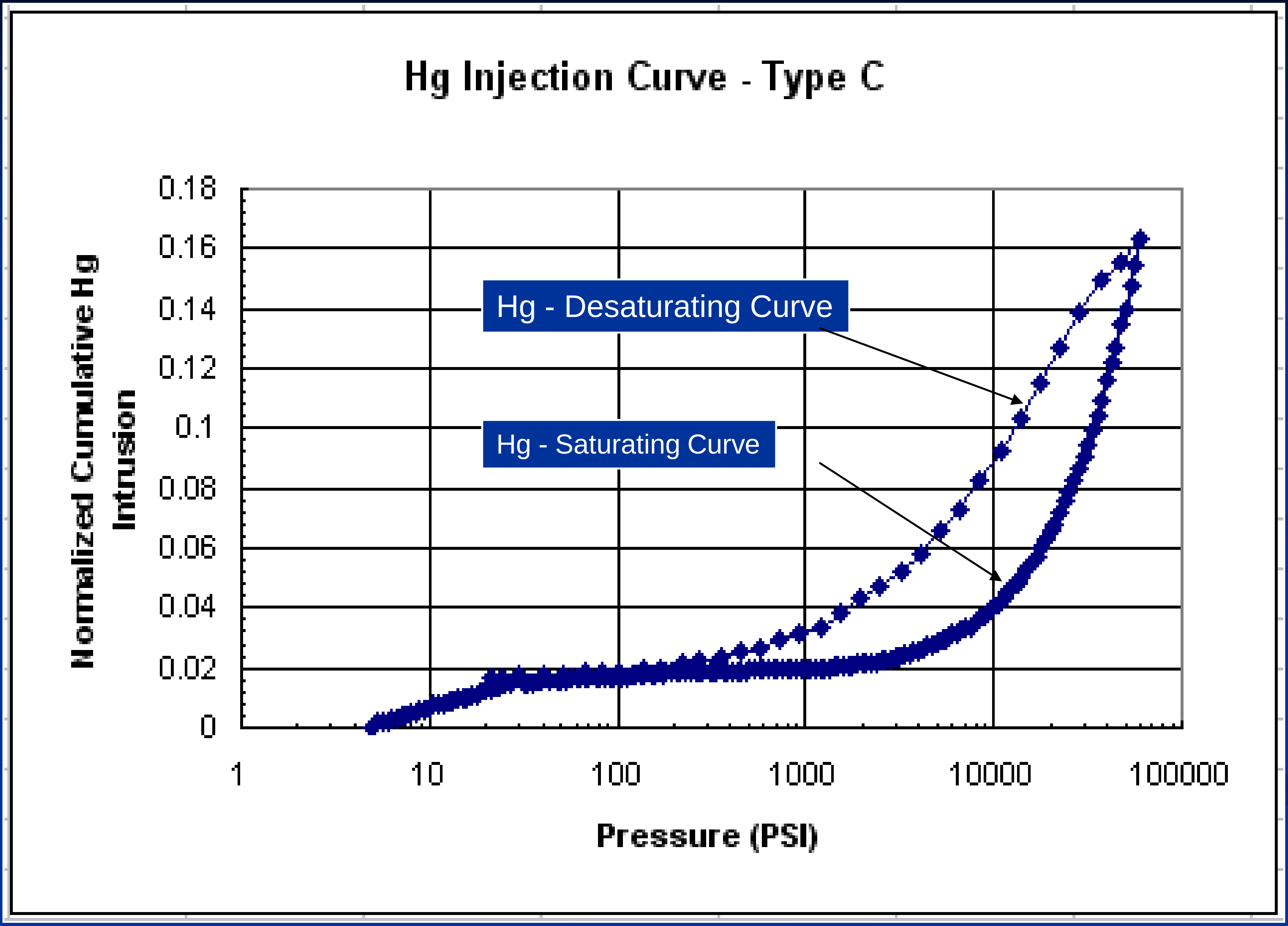
Lithofacies 6,9,4,11, and12


Porosity and TOC Content of Petrofacies - All Four Wells
Total No. of Samples = 802
Avg. Porosity and Avg. TOC (%)
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1
2
3
Petrotype
Porosity
TOC


Calcite Content of Petrofacies - All Four Wells
Avg. Calcite (%)
45
40
35
30
25
20
15
10
5
0
1
2
3
Petrotypes


Hg Injection Curve - Type A
Normalized Incremental Hg Intrusion (cc)
0.035
0.030
0.025
0.020
0.015
0.010
0.005
0.000
1
10
100
1000
10000
100000
Pressure (psi)


Hg Injection Curve - Type B
Normalized Incremental Hg Intrusion
0.030
0.025
0.020
0.015
0.010
0.005
0.000
1
10
100
1000
10000
100000
Pressure (psi)



Hg Injection Curve - Type C
Normalized Cumulative Hg Intrusion
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
1
10
100
1000
10000
100000
Pressure (PSI)
Hg - Desaturating Curve
Hg - Saturating Curve

Hg Injection Curve Type	Phi	TOC	Calcite	Quartz	No. of Samples
A	5.6	4.4	6	29	72
B	7.0	3.0	15	21	43
C	3.0	2.8	41	15	15

Petrofacies	Lithofacies	Porosity	TOC	Calcite	Quartz	Hg Rock Type
1	1, 2, 5	High (6.0 - 6.3%)	High (4.7 - 5.0%)	Low (0 - 10%)	High (28-32%)	A
2	2, 3, 7, 8, 10	High (6.0 - 6.6%)	Moderate (3.4 - 3.8%)	Moderate (10 - 25%)	Medium (18-22%)	B
3	4, 6, 9, 11, 12	Low (2.7 - 3.4%)	Low (1.5 - 2.2%)	High (>25%)	Low (12-16%)	C

Conclusions:

- Barnett shale can be classified into three ‘petro types”.
- Petrotype 1, which is clay rich with least amount of calcite and highest amount of TOC likely represents the best reservoir rock.
- Even though the dynamic range of porosity and TOC associated with different petro types is narrow, they differ considerably in terms of calcite content.
- Ion milling reveals the microstructure of shale.
- Porosity is seen mainly associated within organic matter, mineral grains and grain boundaries.