Innovative Methods for Flow Unit and Pore Structure Analysis in a Tight Gas Reservoir, Montney Formation, NE, BC, Canada*

Per K. Pedersen[1], Chris Clarkson[1], Jerry Jensen[2], Omar Derder[1] and Melissa Freeman[1]

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Abstract

Tight gas reservoirs are notoriously difficult to characterize using laboratory-based methods because of: the existence of heterogeneity at several scales; fine pore structure that may not correlate to depositional controls and environment due to the impact of diagenesis; stress sensitivity of porosity and permeability; sensitivity of permeability to fluid saturation; and non-Darcy flow effects under laboratory conditions, etc. Porosity, pore size distribution and permeability are correspondingly difficult to measure in the laboratory and upscale to reservoir scale. A promising technique to characterize flow heterogeneity in tight gas reservoirs is to relate permeability to dominant pore throat size; permeability is measured using steady- or non-steady-state techniques and dominant pore size is typically estimated using the mercury intrusion method. Permeability and porosity is measured on full-diameter core or core plugs which may contain heterogeneities that are at a much finer scale than the sample size, resulting in composite estimates of both properties.

We investigate the use of non-routine methods to characterize permeability heterogeneity and pore structure of a tight gas reservoir for use in flow unit identification. Profile permeability is used to characterize fine-scale (< 1 inch) vertical heterogeneity in a tight gas core; over 500 measurements were made. Profile permeability, while useful for characterizing heterogeneity, will not provide in-situ estimates of permeability; further, the scale of measurement is much smaller than log-scale. Pulse-decay permeability measurements collected on core plugs under confining pressure were used to correct the profile permeability measurements to in-situ and point averages of profile permeability were used to relate to log-derived porosity measurements. Finally, a new method (for tight gas) was used to estimate the pore size distribution of several tight gas samples: N2 adsorption. A uni- or bi-modal distribution was observed for the samples, with the larger peak corresponding to the dominant pore throat radius, as inferred from the rp35 calculations. Further, the adsorption-desorption hysteresis loop was

used to interpret the dominant pore shape as slot-shaped pores, which is typical of many tight gas reservoirs. The N2 adsorption method provides for rapid analysis and does not suffer from some of the same limitations of Hg-injection, however the method is limited to fine pore structures (< 1,000 nm).

Selected References

Edwards, D., D. Gibson, G. Kvill, and E. Halton, 1994, Triassic Strata of the Western Canadian Sedimentary Basin: Canadian Society of Petroleum Geologists and Alberta Research Council, p. 259–275

Moslow, T.F., 2000, Reservoir architecture of a fine-grained turbidite system: Lower Triassic Montney Formation, Western Canada Sedimentary Basin *in* P. Weimer, R.M. Slatt, J. Coleman, N.C. Rosen, H. Nelson, A.H. Bouma, M.J. Styzen, and D.T. Lawrence (eds.), Deep-water Reservoirs of the World: Gulf Coast SEPM Conference Proceedings, p. 686-713.

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Center for Unconventional Reservoir Evaluation

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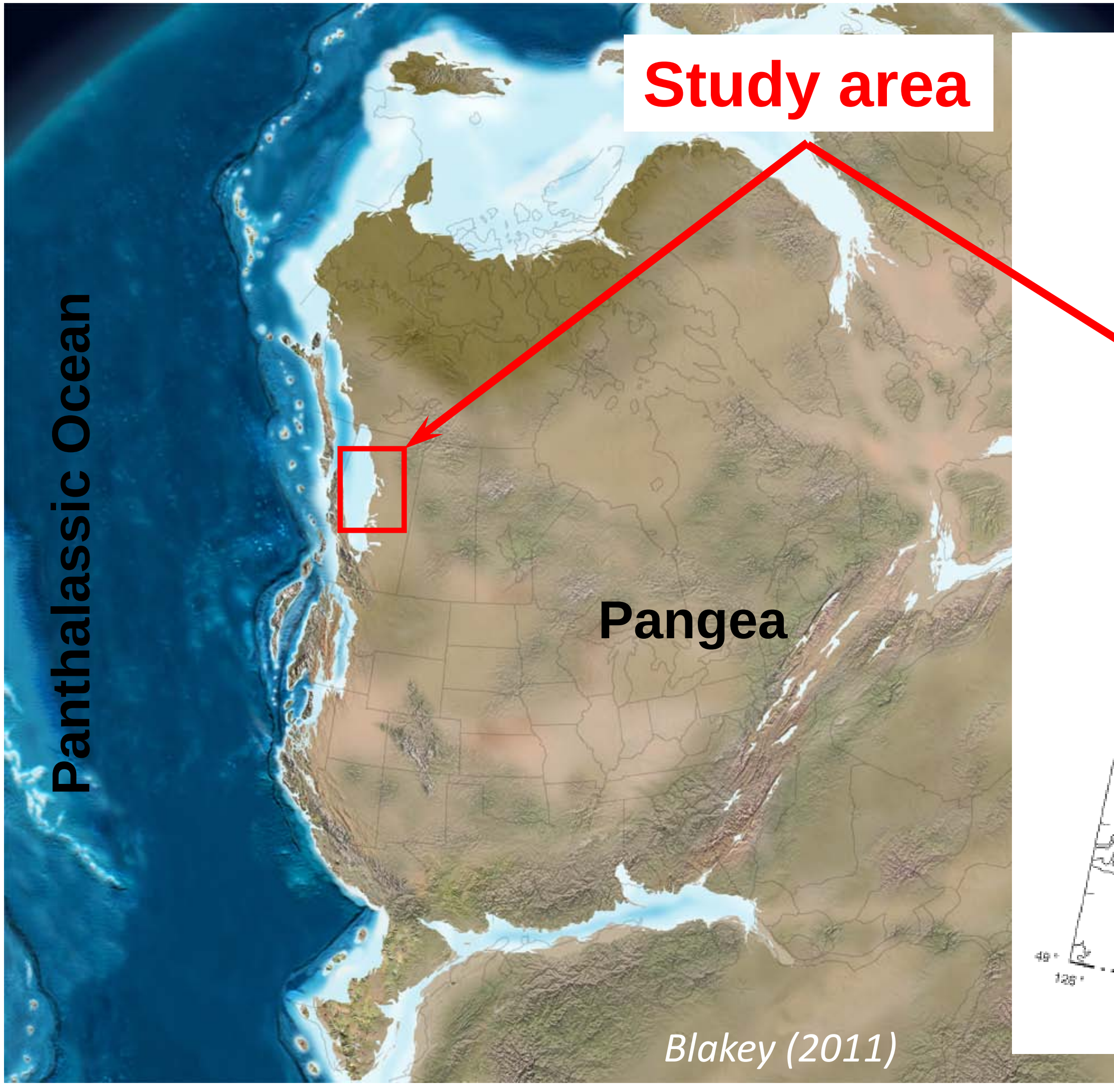
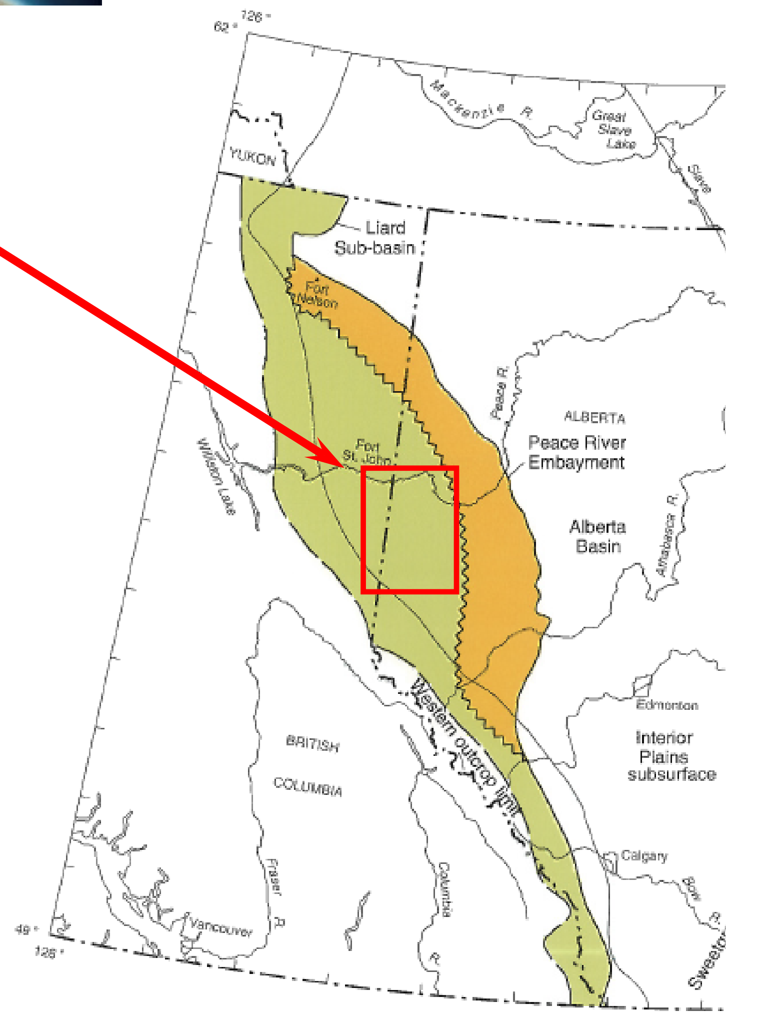
Early Triassic Back-Arc Setting

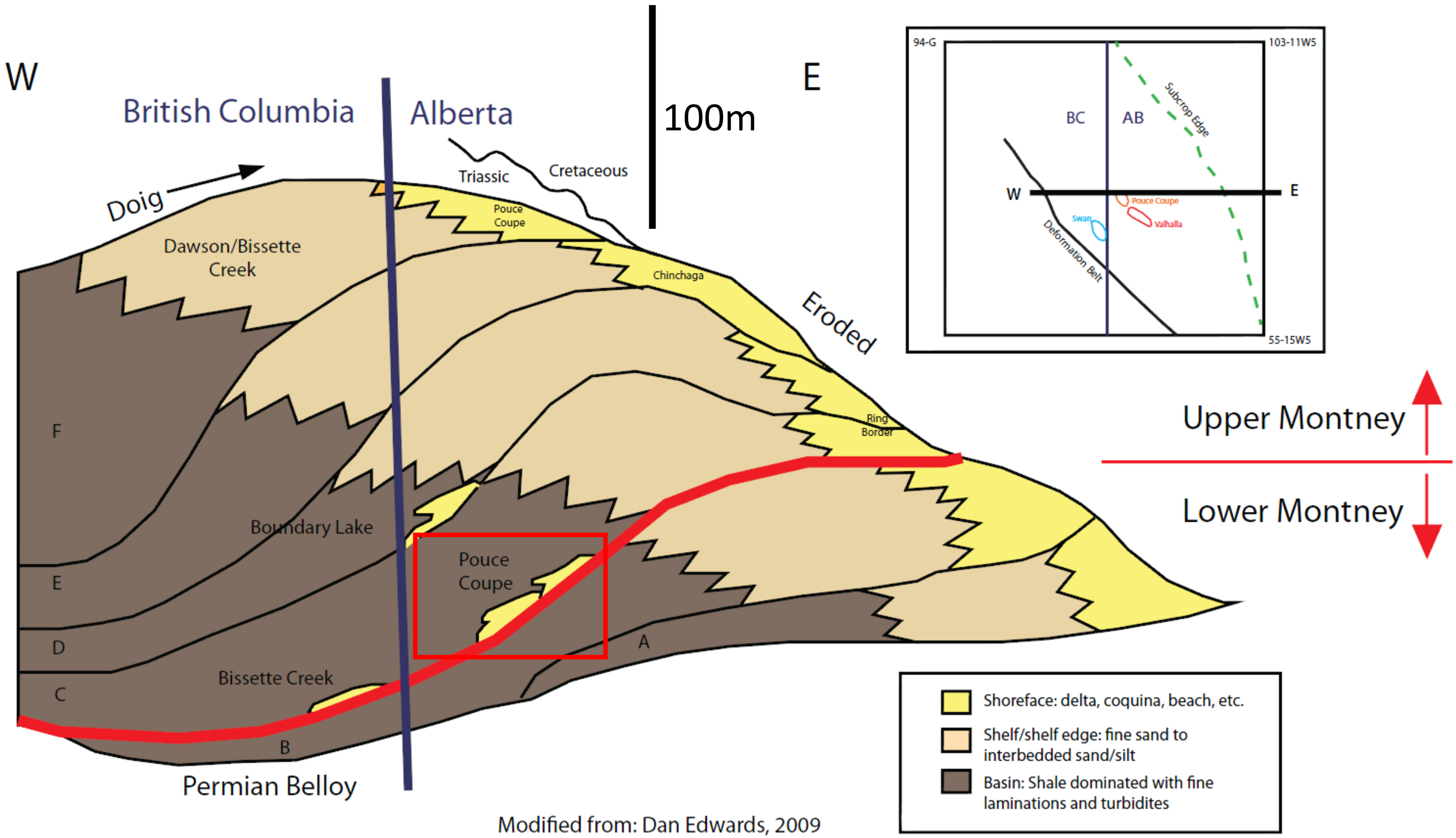


Blakey (2011)



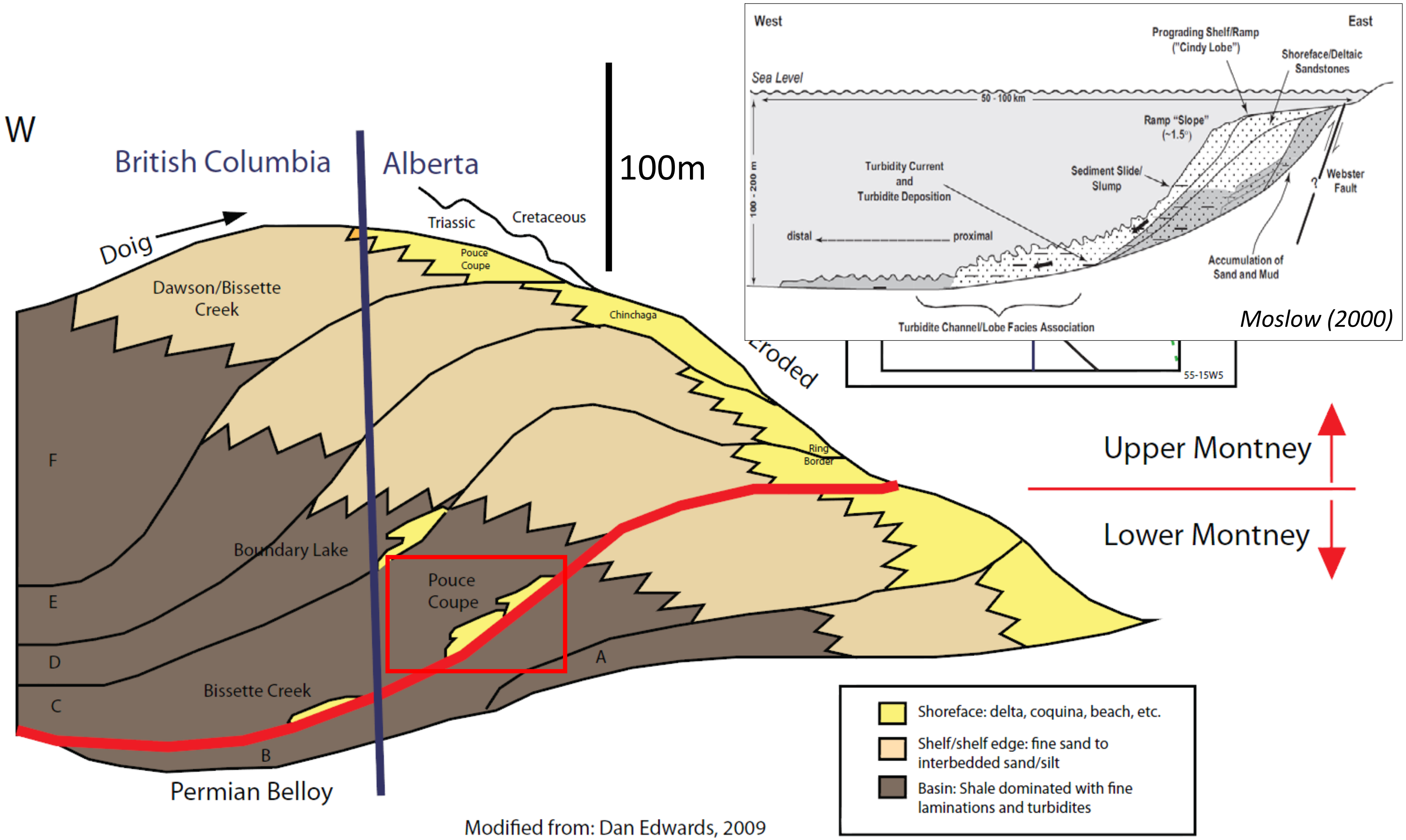
Edwards et al (1994)

Westward Prograding Clastic Wedge



Modified from: Dan Edwards, 2009

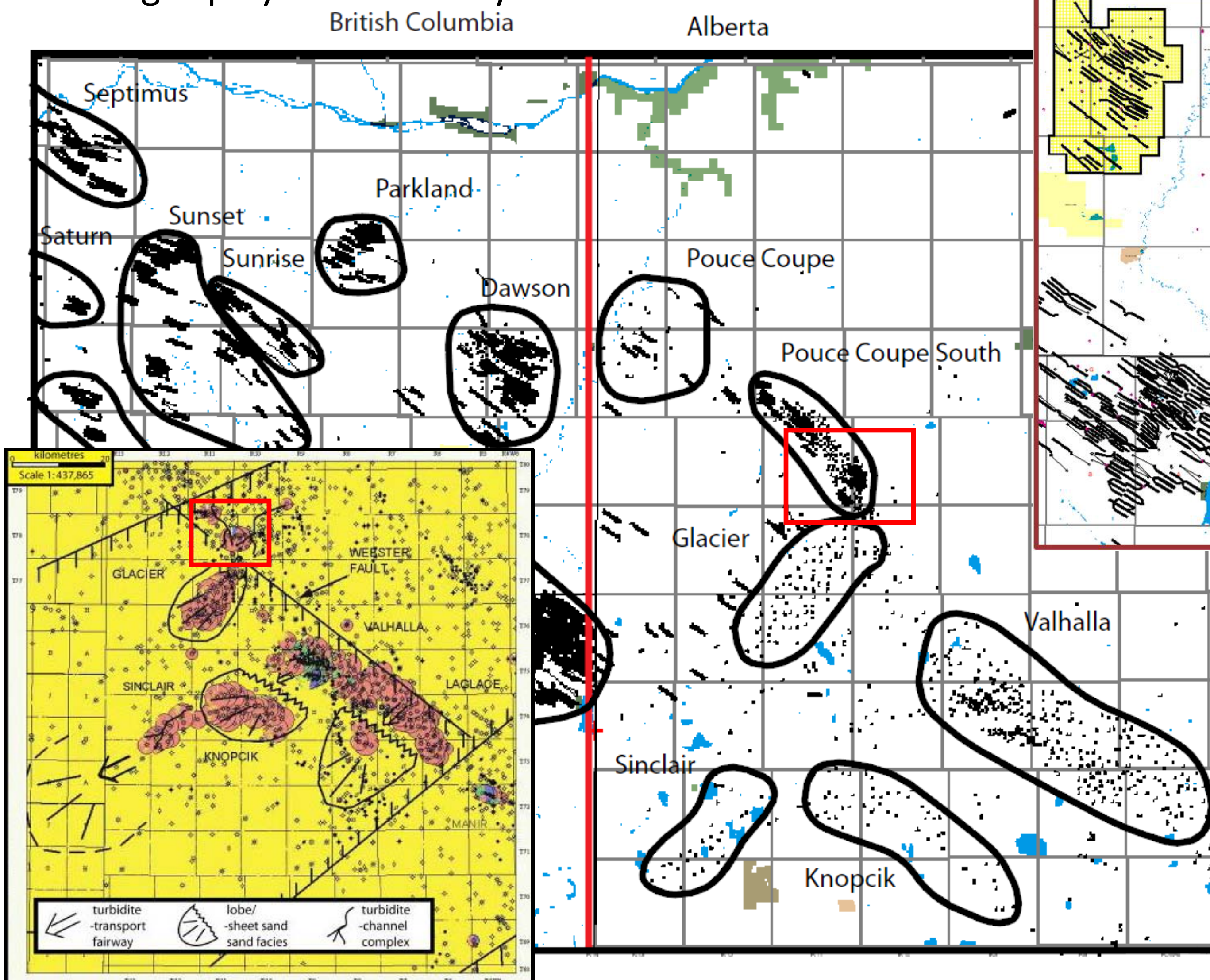
Westward Prograding Clastic Wedge

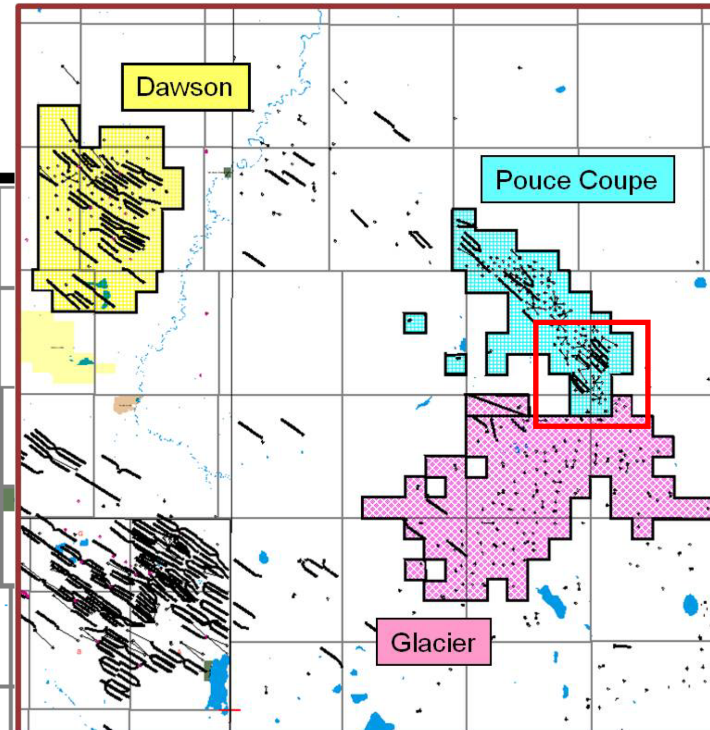


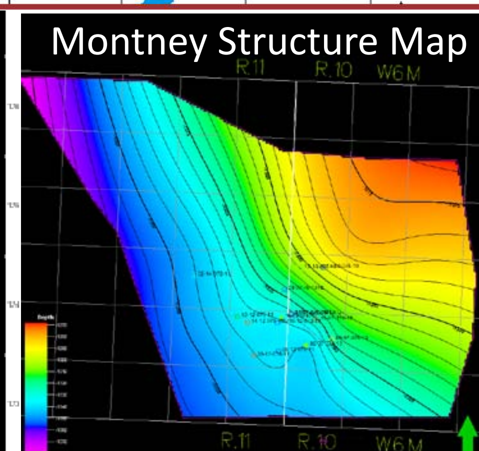
Modified from: Dan Edwards, 2009

Montney - Pouce Coupe South Pool

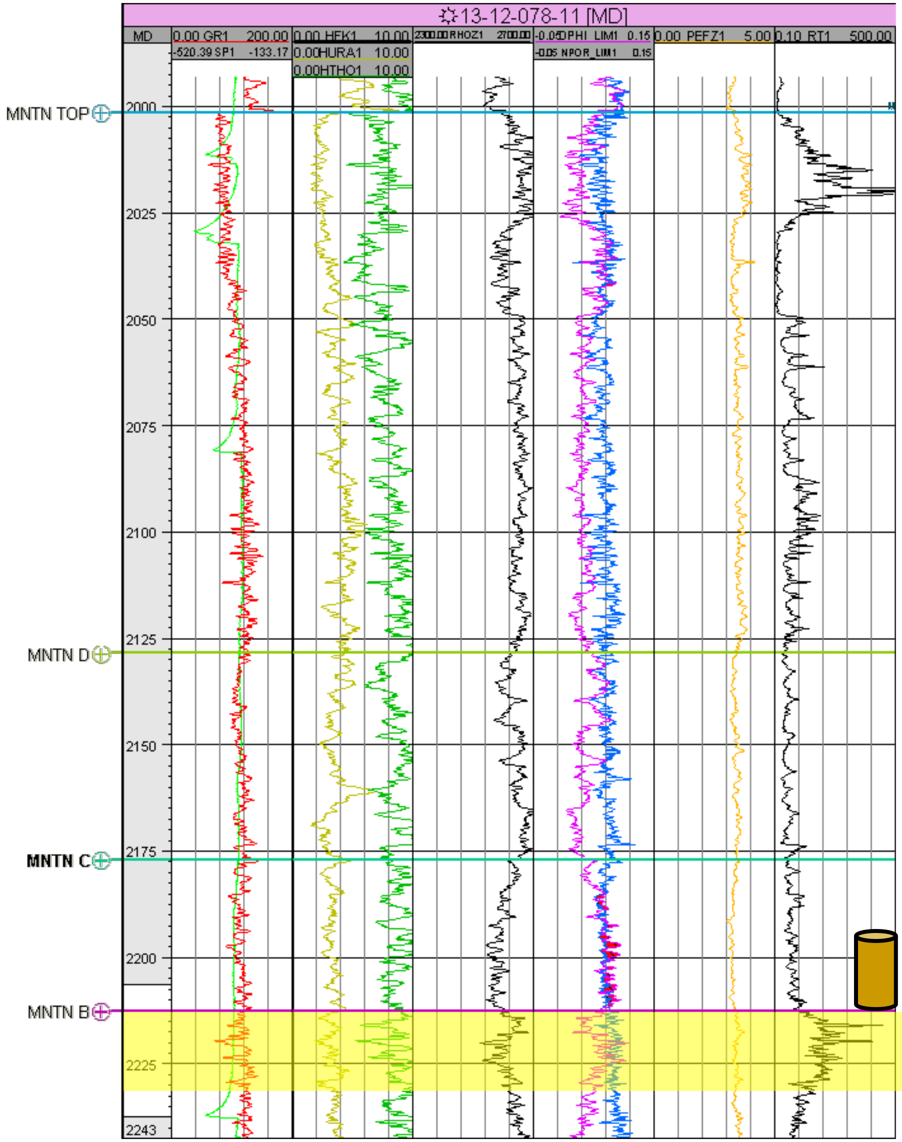
Conventional gas pools within turbidite lobe sandstones
New gas plays within shaly intervals

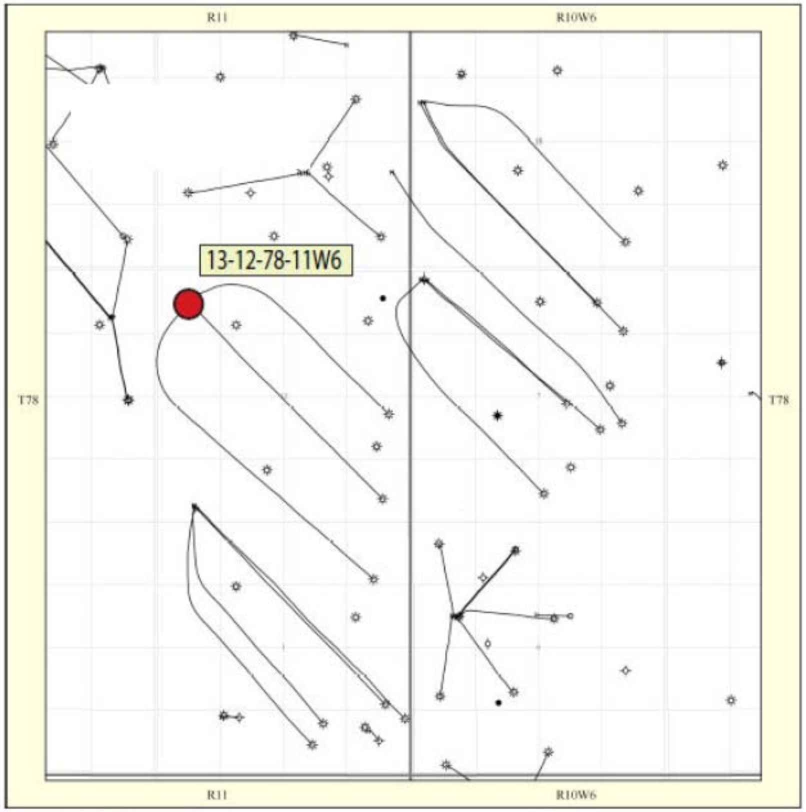






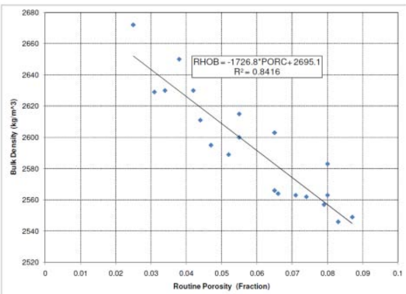
13-12-78-11W6 Cored Well

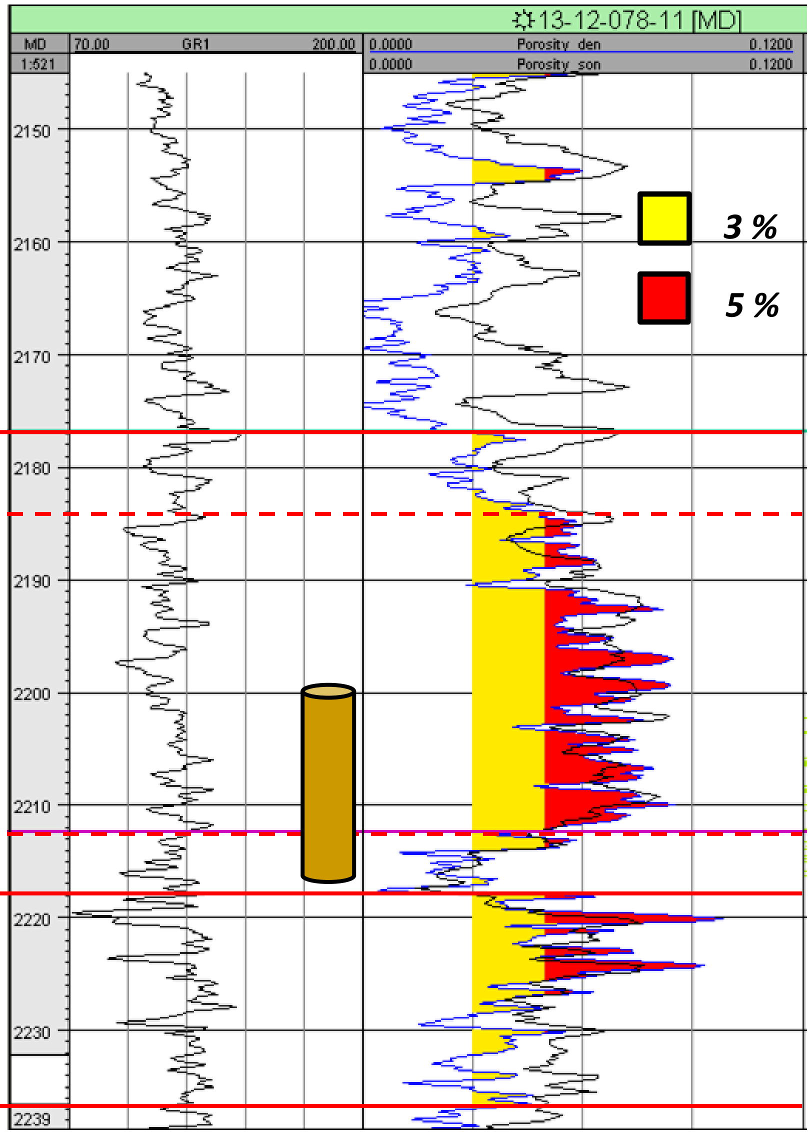




Distal Glacier turbidite fan sandstones

13-12-78-11W6 Cored Well





Montney C

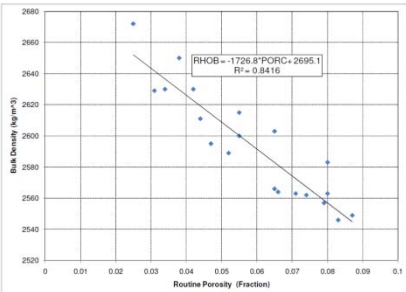
TOC 0.6 - 0.8 Wt %

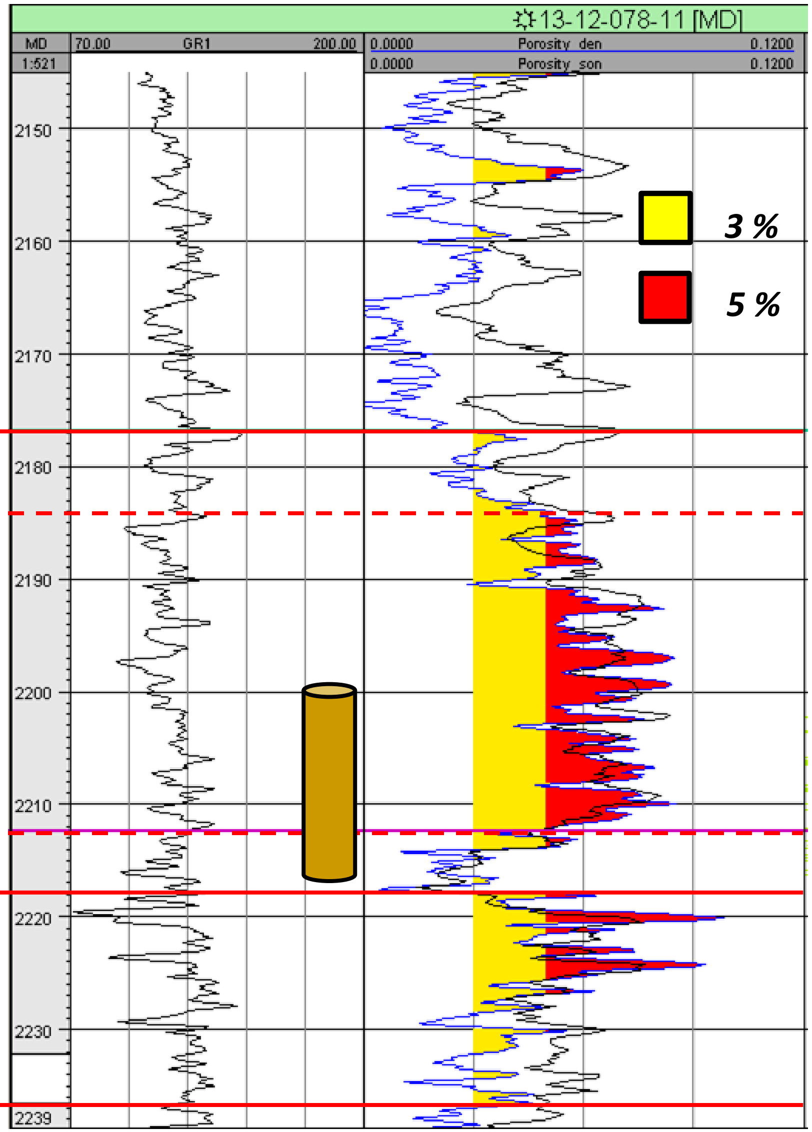
Montney B

TOC 1.1 - 1.8 Wt %

Leyva, Yazdi and Murdoch (2010)

13-12-78-11W6 Cored Well





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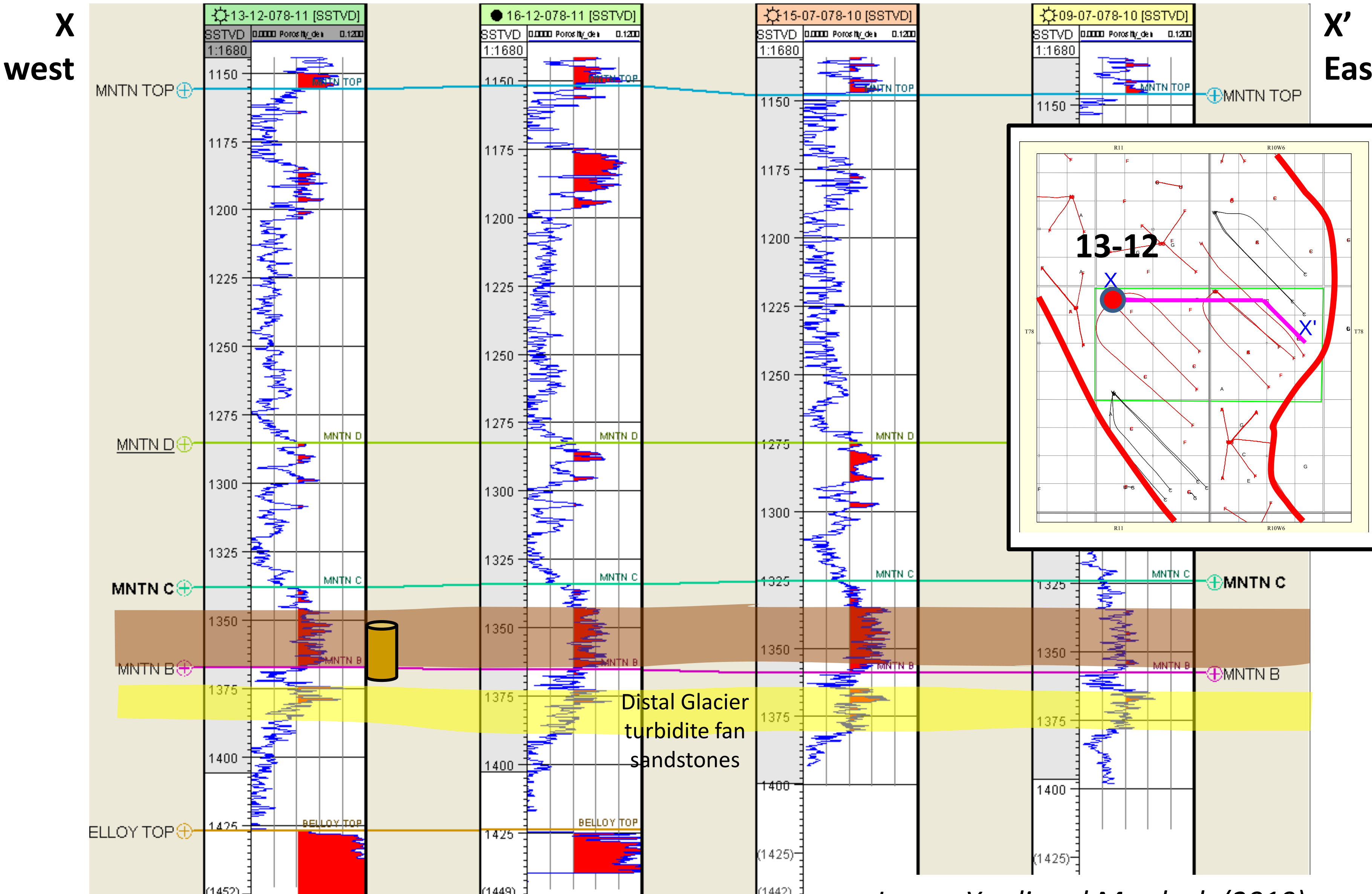
Leyva, Yazdi and Murdoch (2010)

Cross-Section – Computed Porosity



Leyva, Yazdi and Murdoch (2010)

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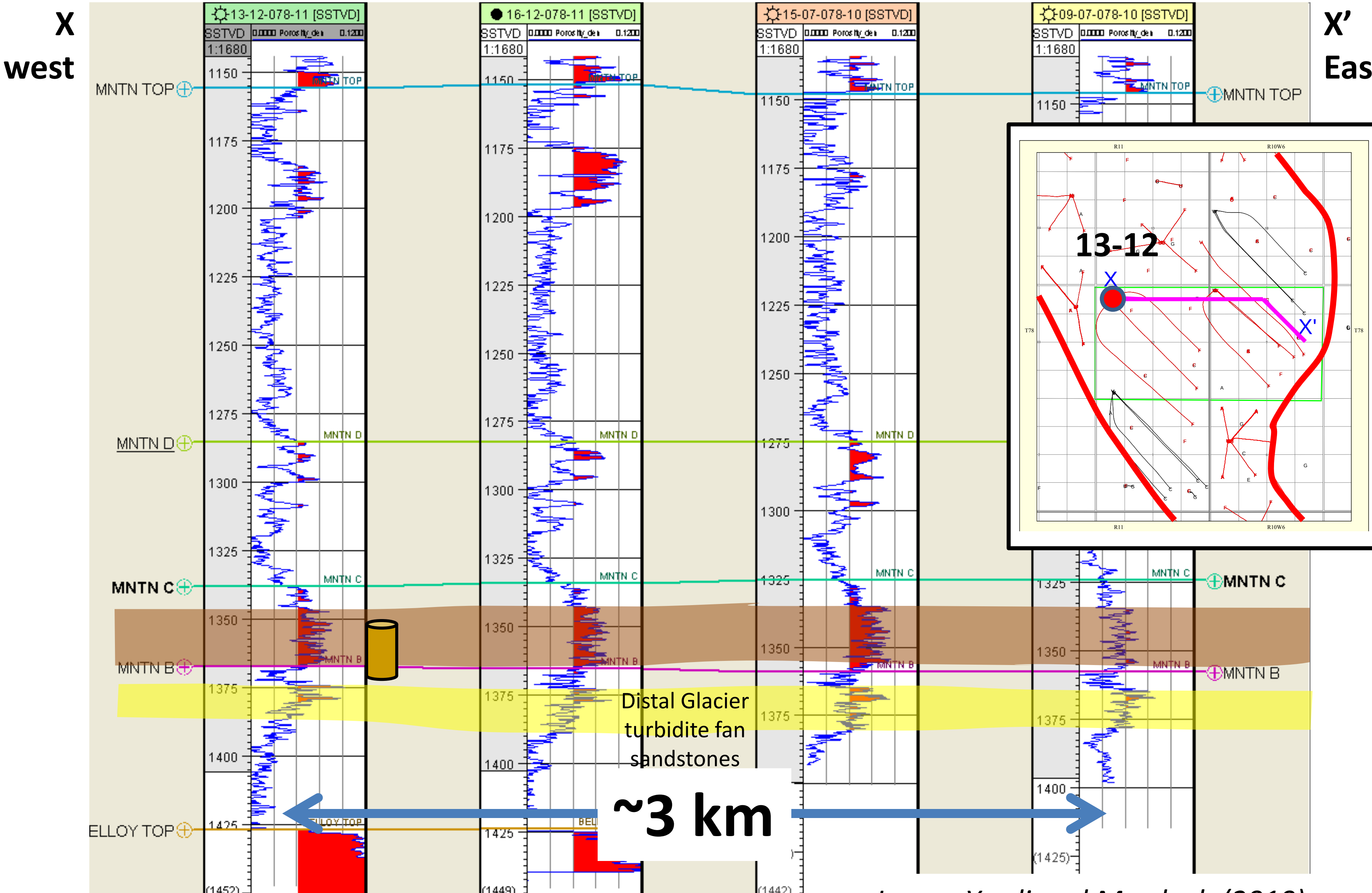
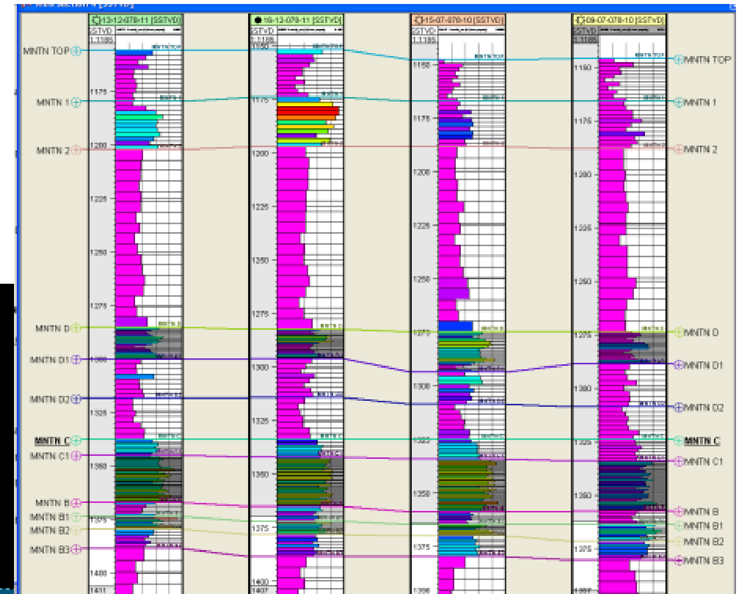
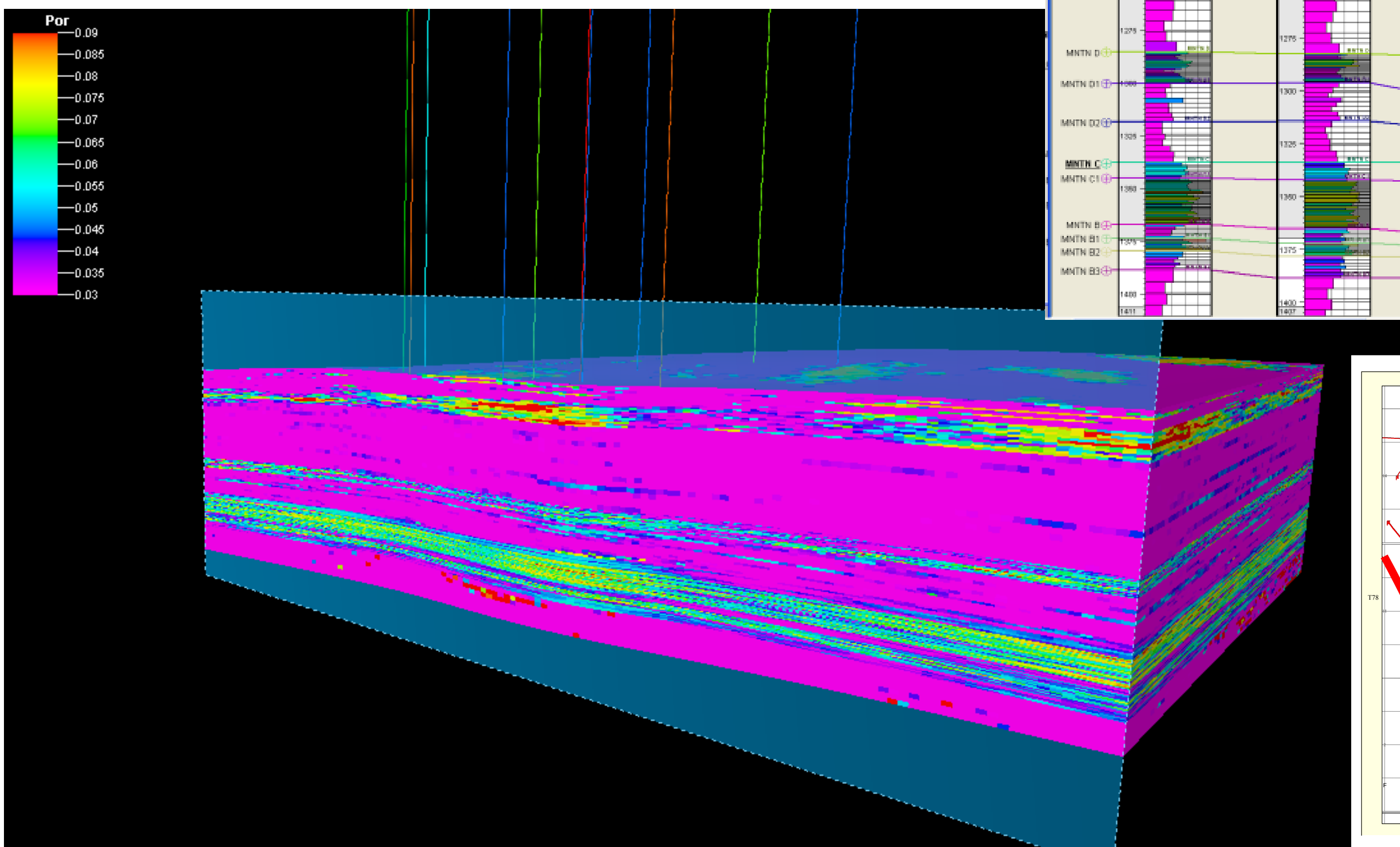


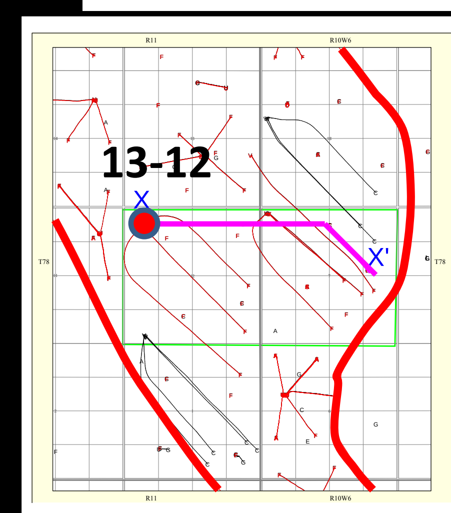
Leyva, Yazdi and Murdoch (2010)

STOCHASTIC 3D POROSITY MODEL





Leyva, Yazdi and Murdoch (2010)



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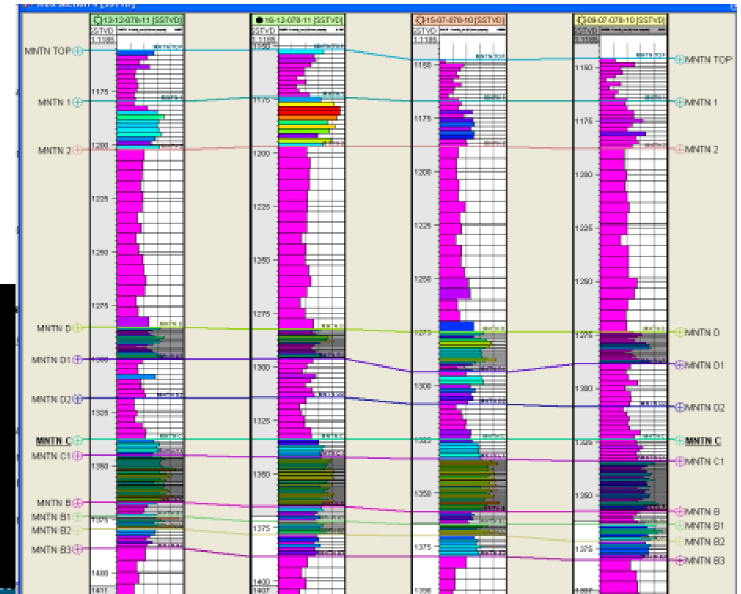

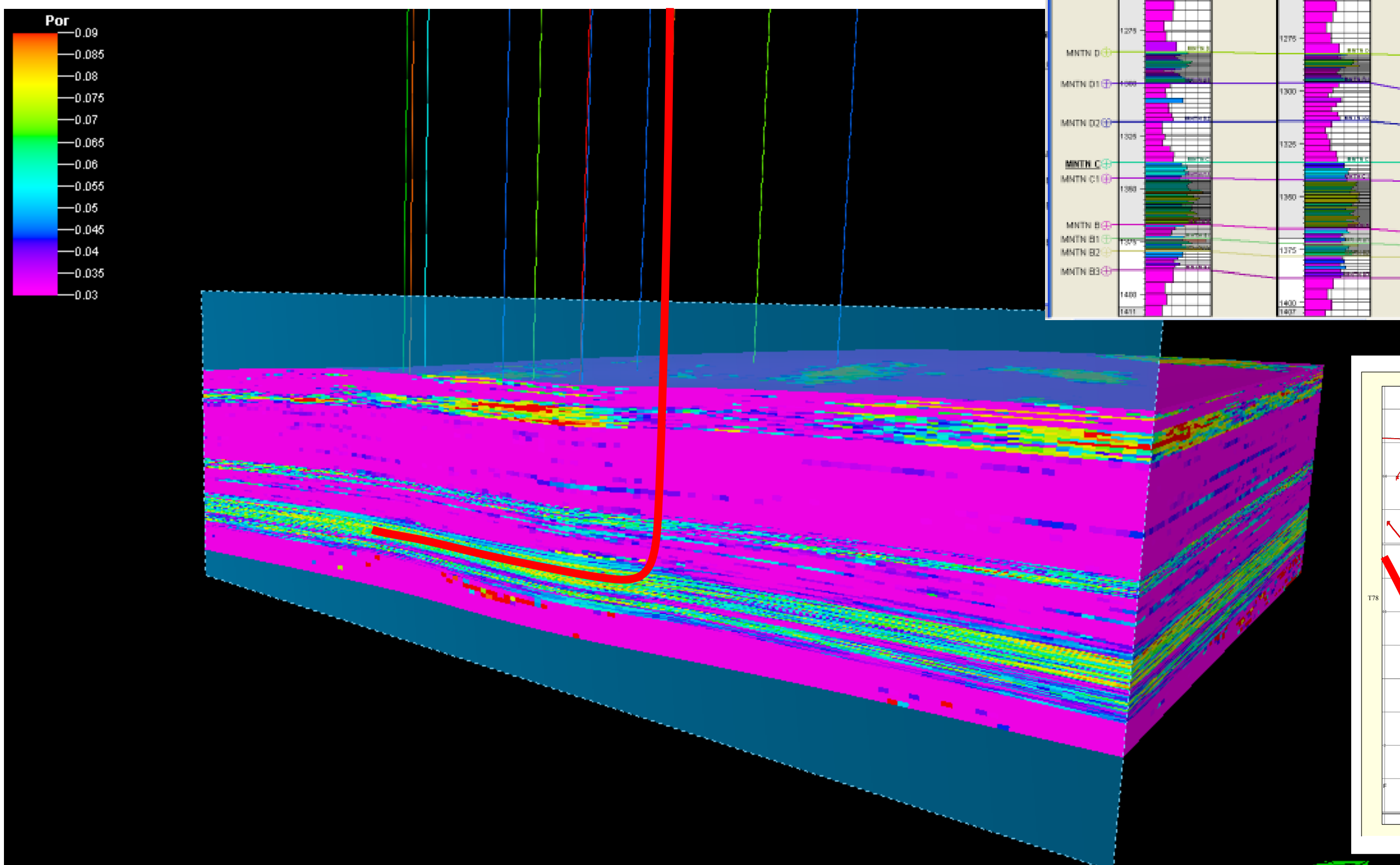

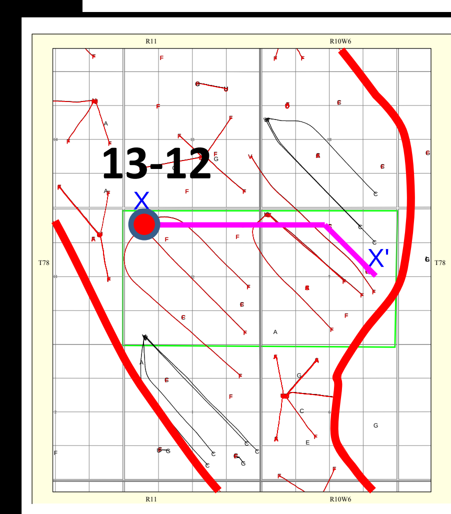

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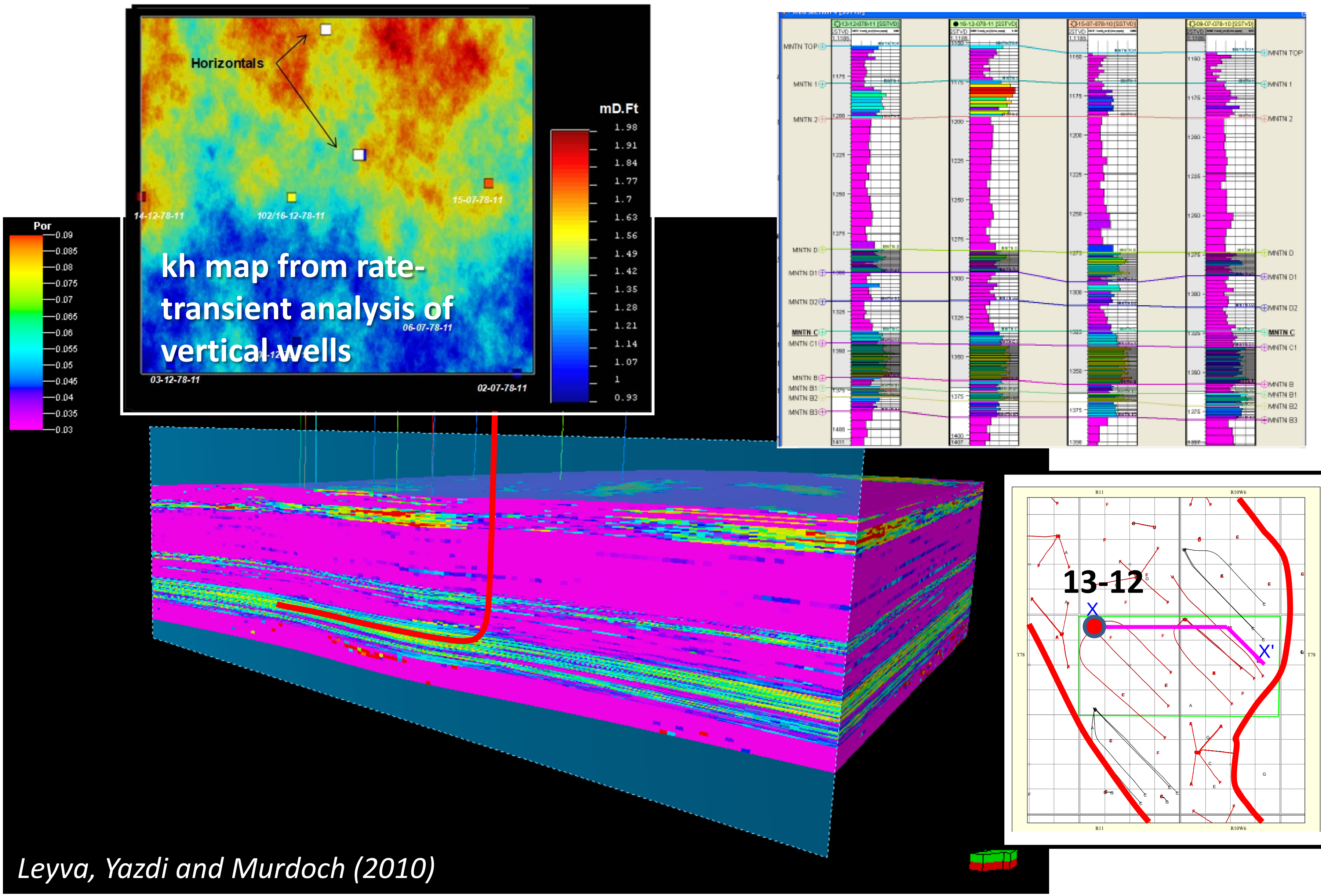
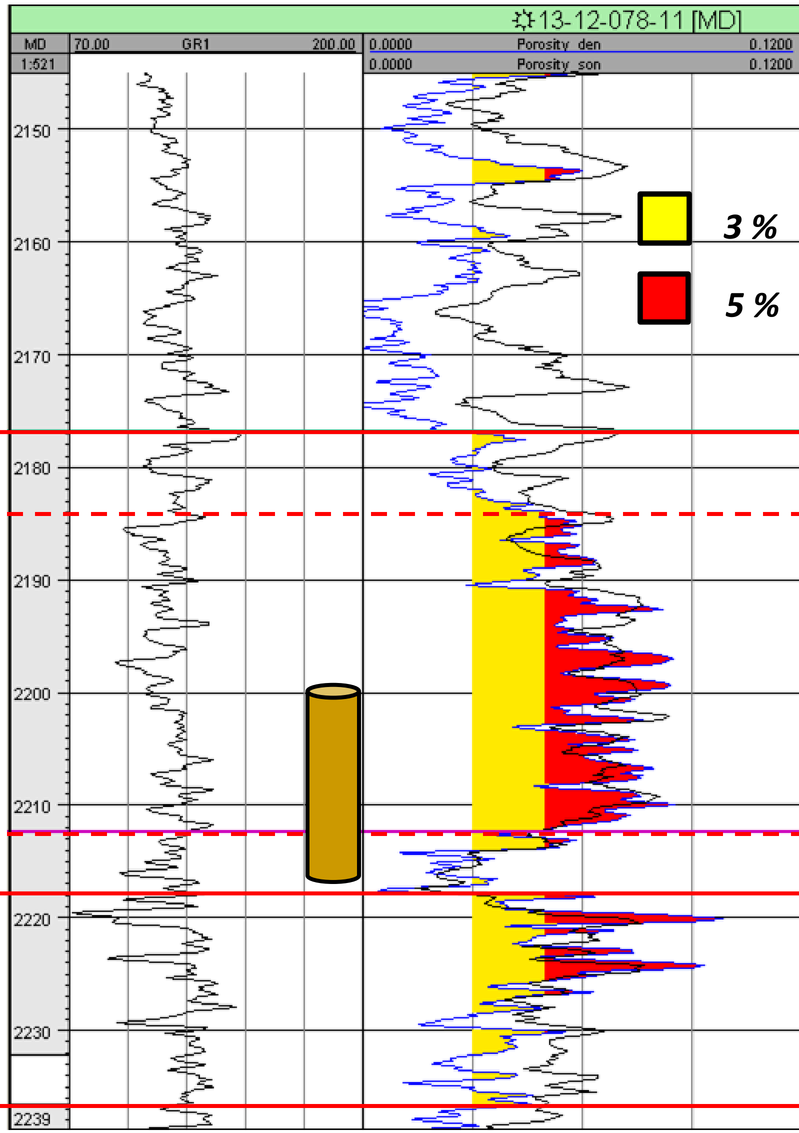


Sedimentary Facies – Flow Units

Montney D

Montney C

Montney B



Leyva, Yazdi and Murdoch (2010)

						COMPOSITION (PRIMARY+SECONDARY)					
Thin Section No.	Interval (mKB, log depth)	Avg. Grain Size (μm)	Textural Class	Sorting	Grain Shape	Qtz	Dol	Cal	Matrix + Organic Matter	Micas	Pyrite
TS1	2199.9	64	Very fine sand	Well	Subangular	40	15	10	28	5	2
TS2	2202.8	47.5	Coarse silt	Moderate -Poor	Subangular	44	20	7	28	1	-
TS3	2207.64	45.8	Coarse silt	Moderate -Poor	Subangular	40	35	5	14	5	1
TS4	2208.1	30	Medium silt	Moderate -Poor	Subround.	20	24	35	15	5	1
TS5	2213.37	55	Coarse silt	Poor	Subround.	40	20	15	19	5	1
TS6	2216	65	Very fine sand	Moderate	Subround.	35	20	25	15	5	-

UPPER FACIES

Finely laminated

Planar and rippled

60-70% siltstone

Middle fan facies

LOWER FACIES

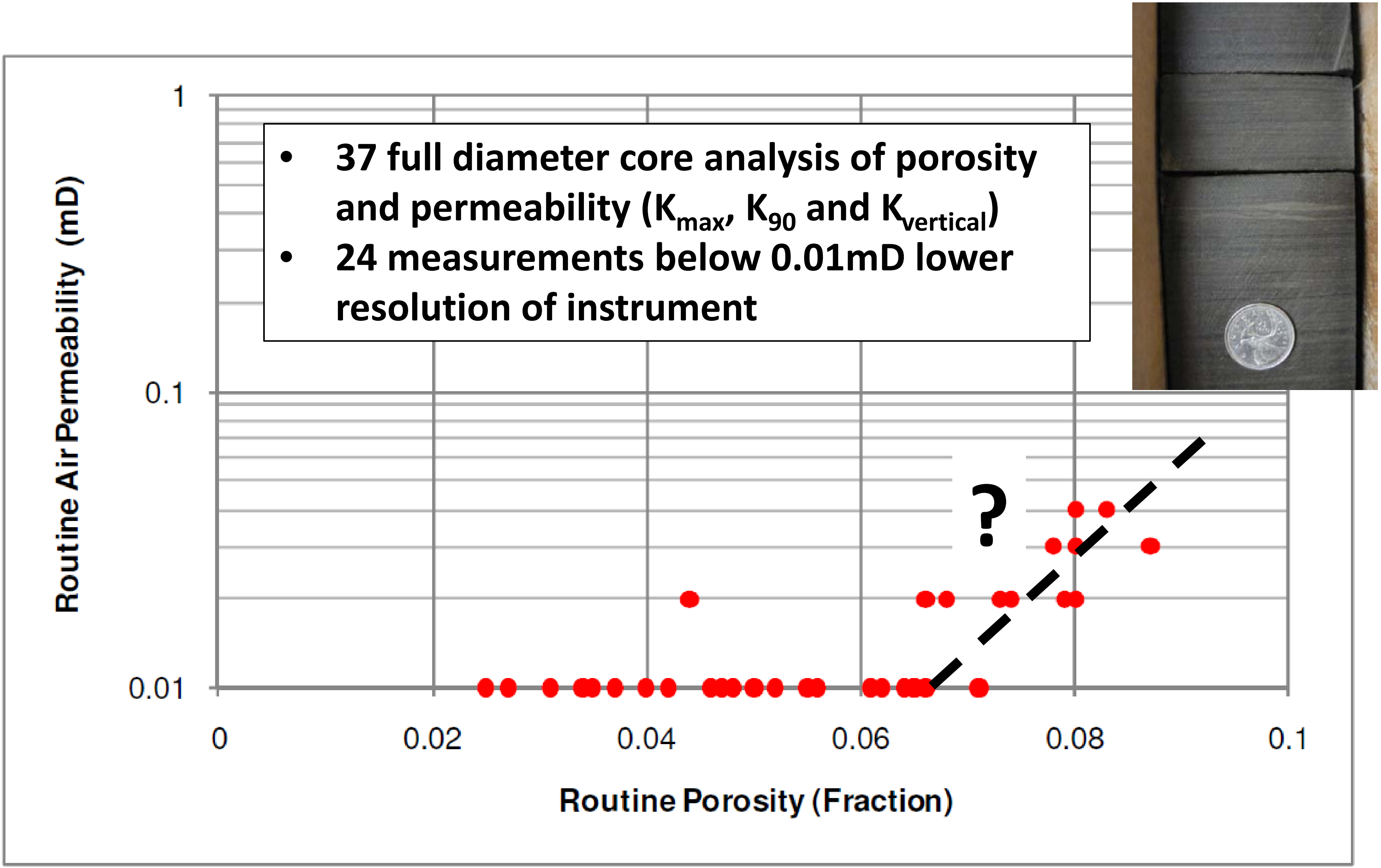
5-15 cm thick graded beds

silt and mudstones

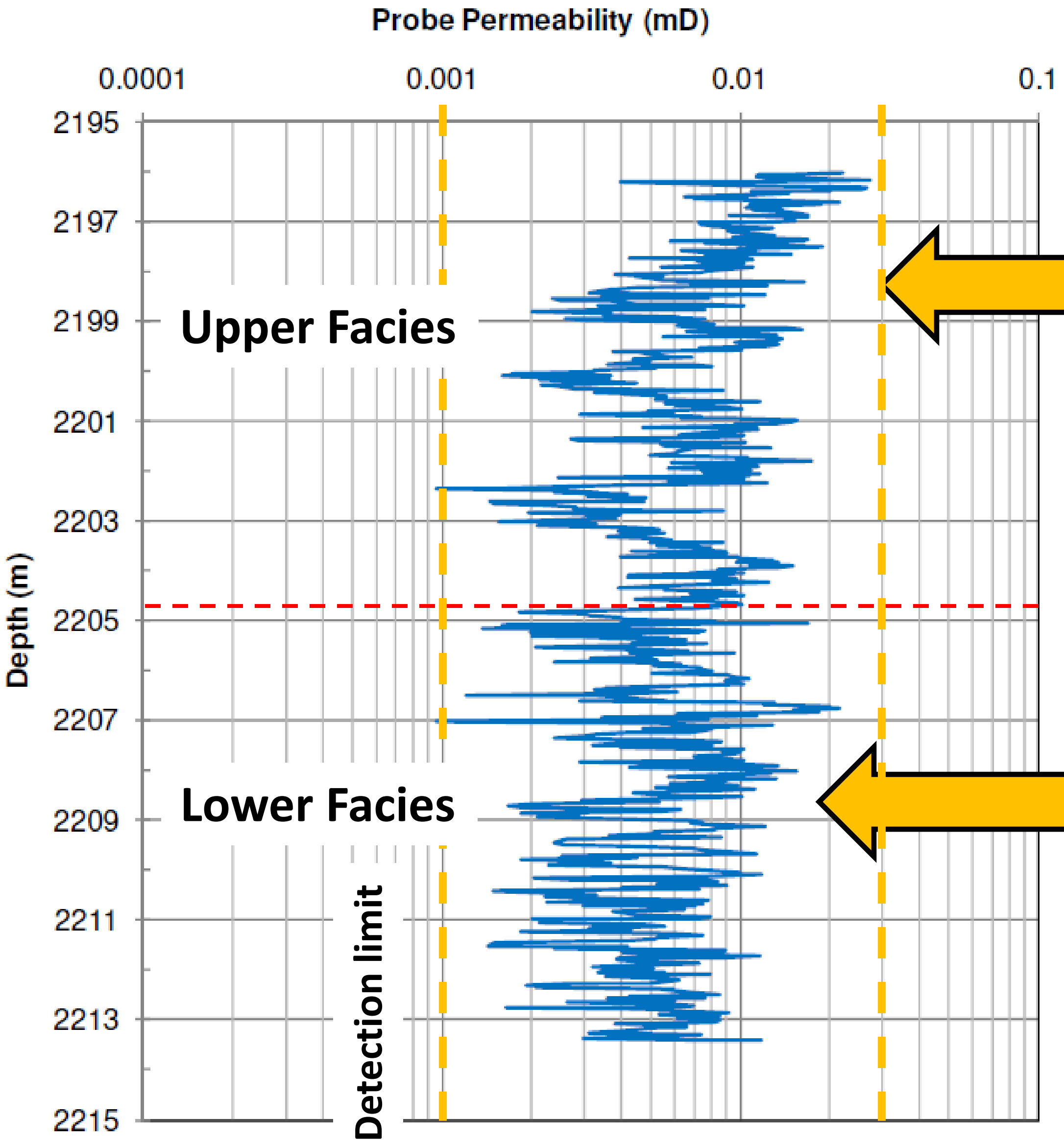
Distal fan facies

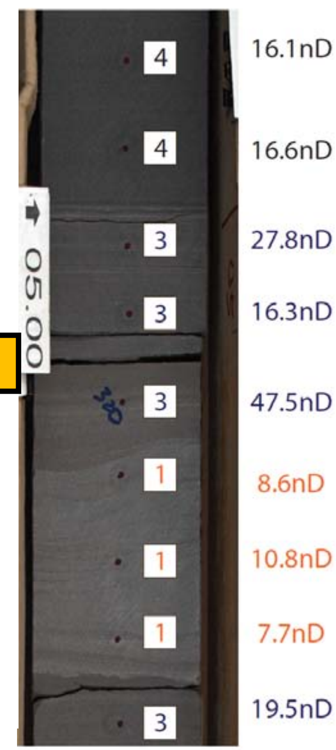
Routine Core Permeability and Porosity

- 37 full diameter core analysis of porosity and permeability (K_{max}, K_{90} and $K_{vertical}$)
- 24 measurements below 0.01mD lower resolution of instrument



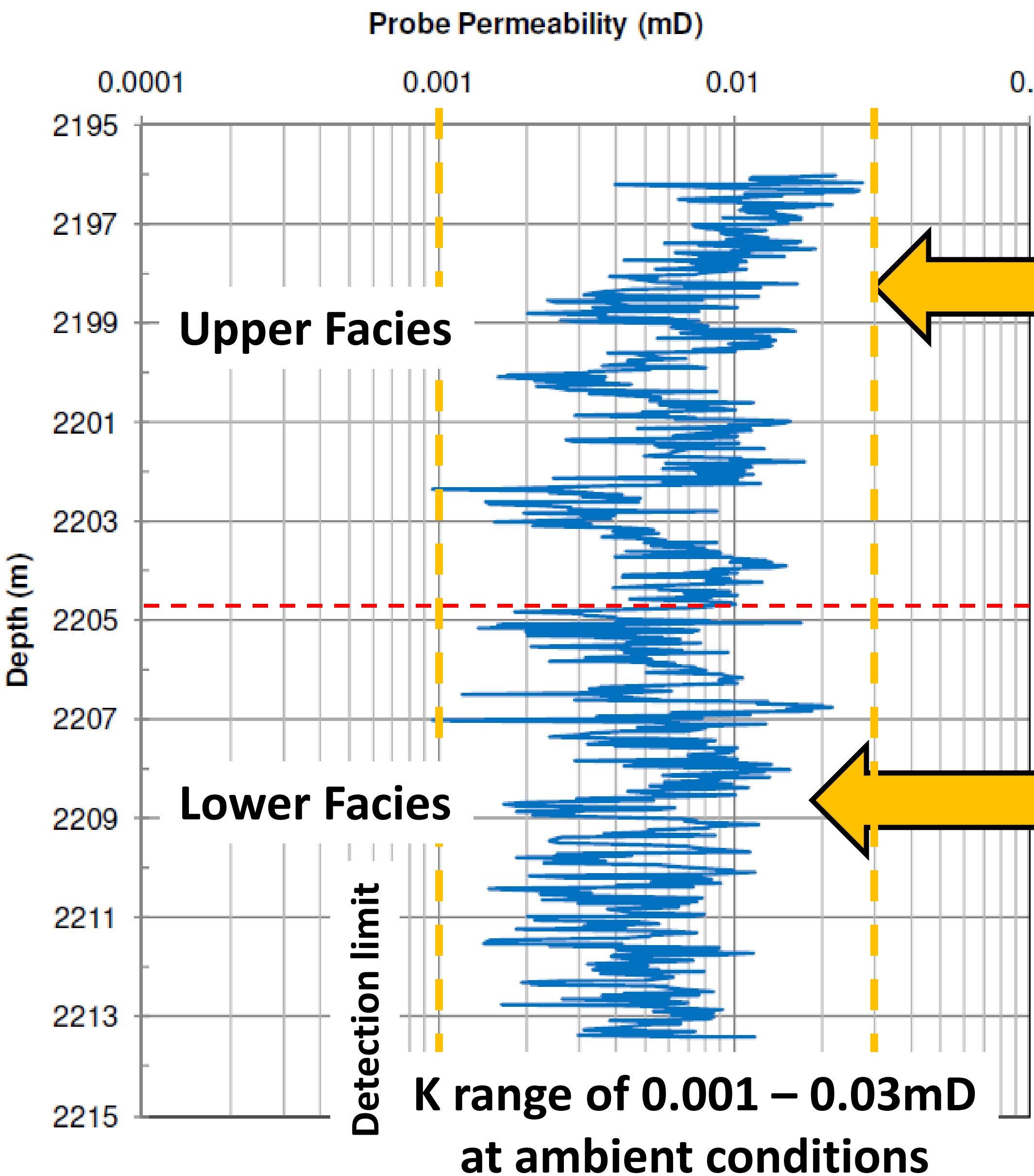
Slip-Corrected Probe Permeability

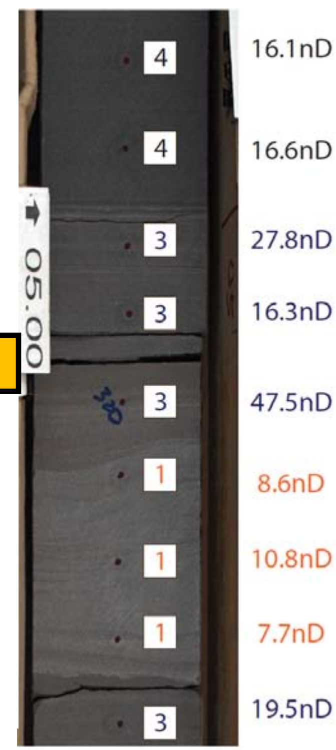




593 probe permeability measurement (2.5 cm spacing)

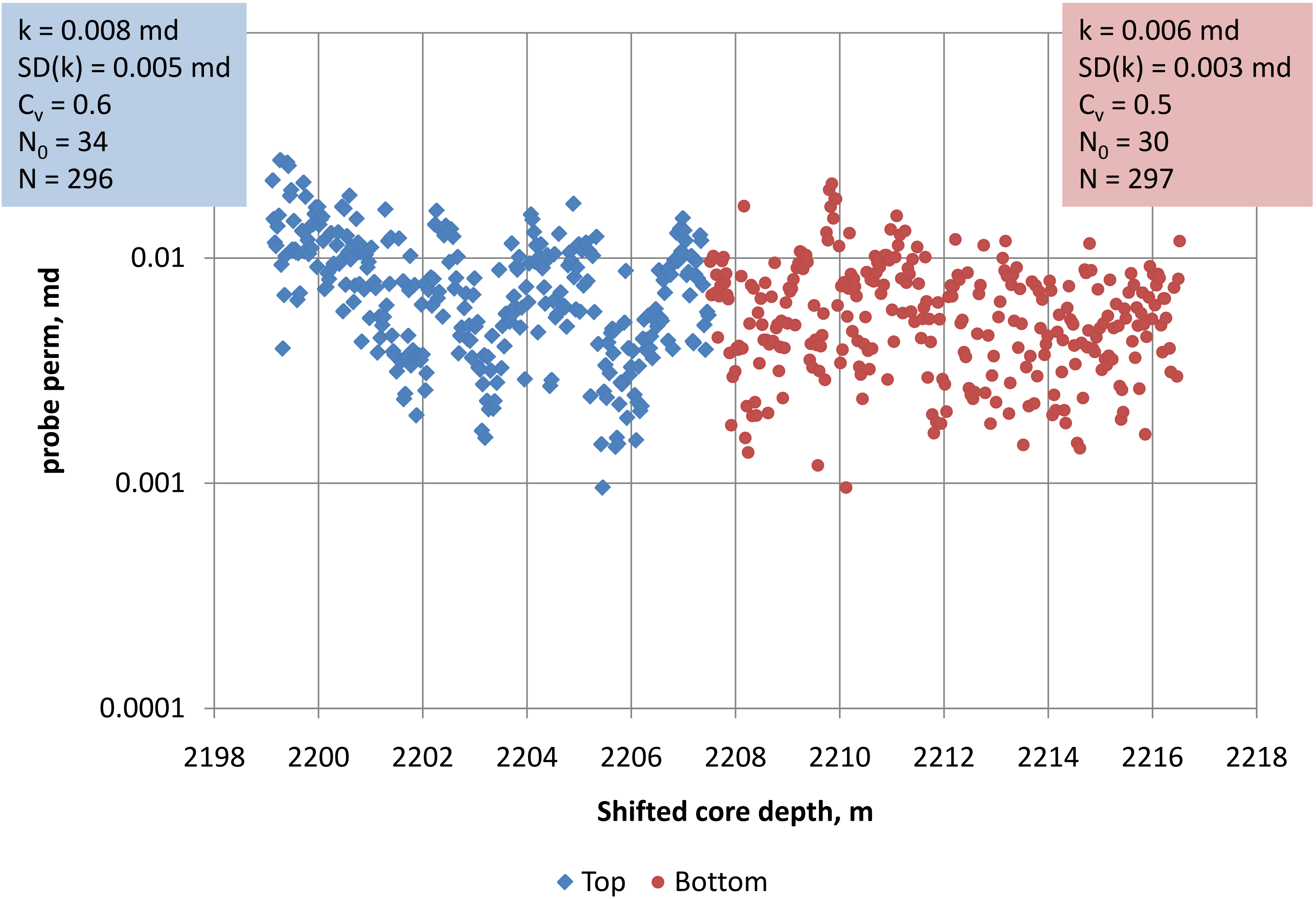
Slip-Corrected Probe Permeability



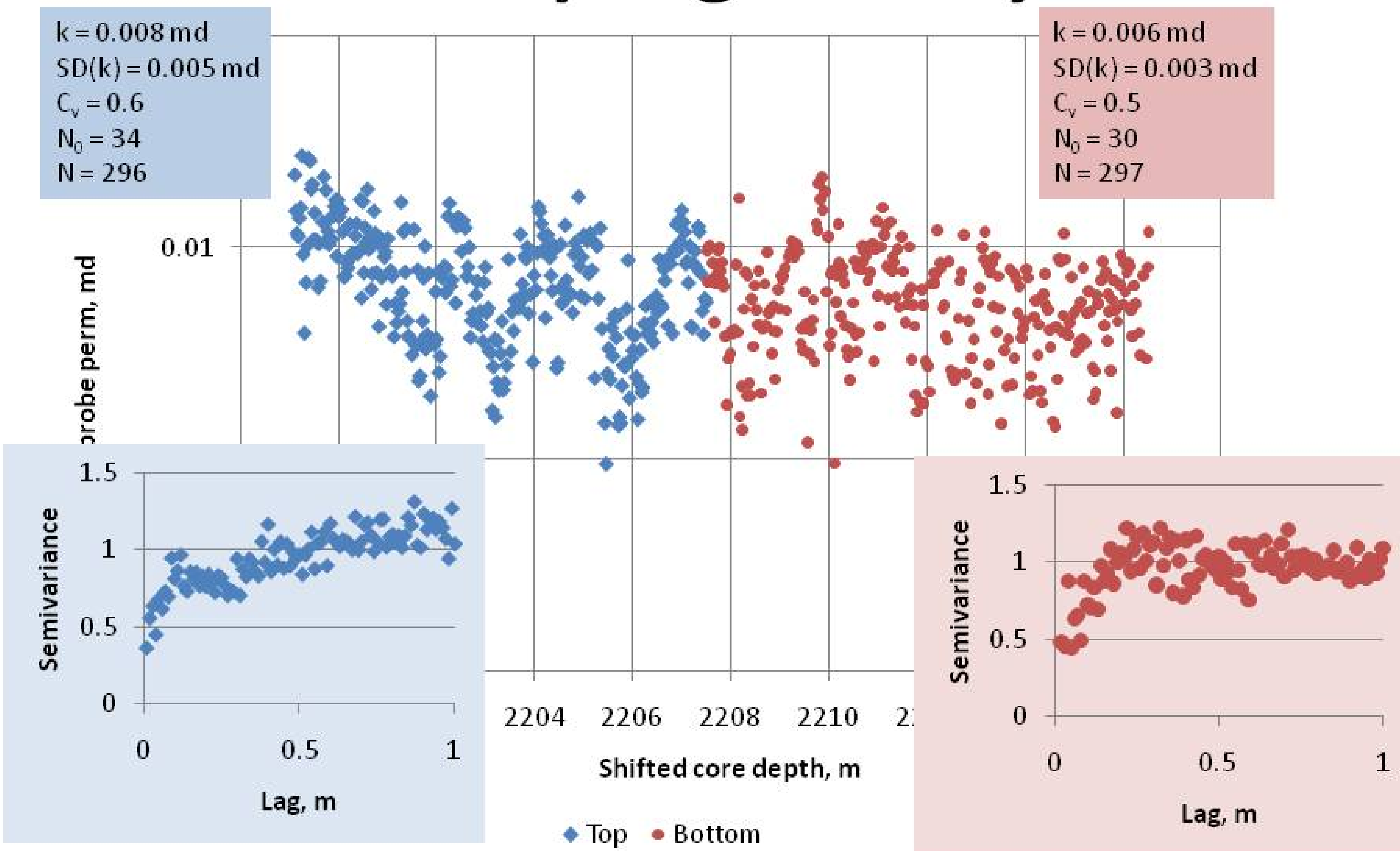


593 probe permeability measurement (2.5 cm spacing)

Reservoir Heterogeneity Sampling Density



Reservoir Heterogeneity
Sampling Density



Notes by Presenter: Here are a few statistics about these two intervals. Averages are statistically similar but the top is more variable than the bottom. The Cv = SD(k)/avg k suggests the top is a little more heterogeneous. No is a 'rule of thumb' number of measurements to estimate the average within 20% for 95% of the time. Actual number of measurements taken is about 10 times that needed for the average. Overall impression is that top and bottom perms and variabilities are similar and intervals are well sampled.

Profile Permeability

593 probe permeability measurement (2.5 cm spacing) allow establishment of relationship with microfacies

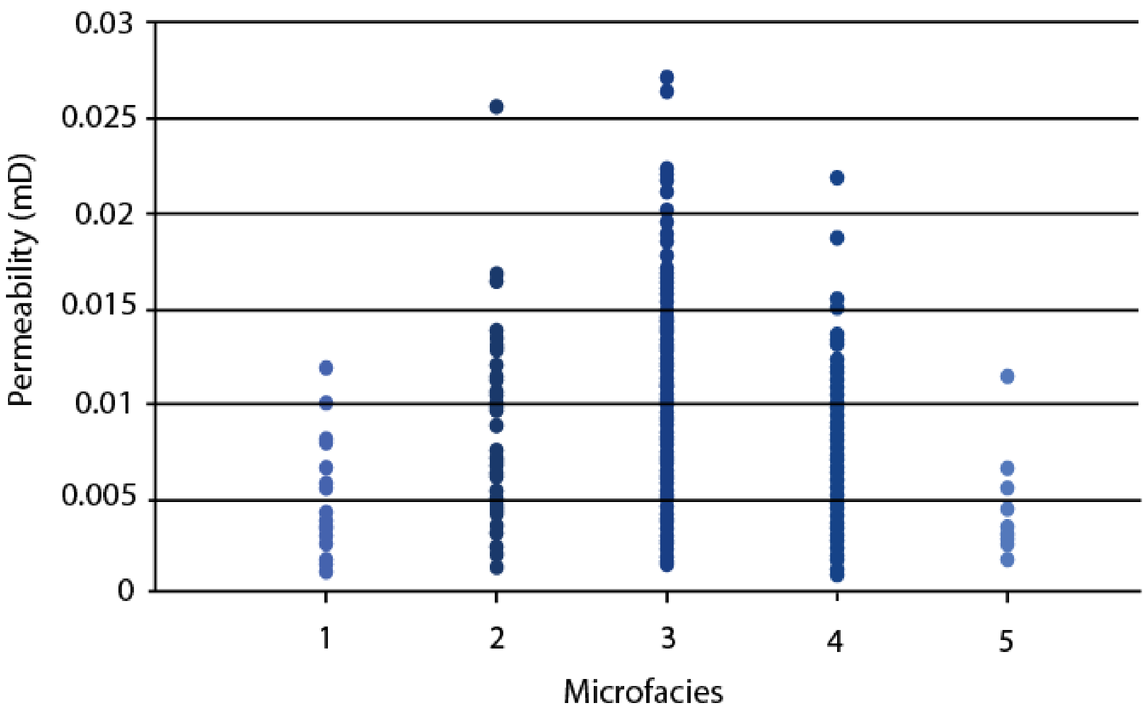
Upper Facies

Depth: 2200.7m

Lower Facies

Depth: 2205.9m

Microfacies Probe Permeability



2209.10m

Microfacies:

1: >5mm thick coarse siltstone beds/lamina

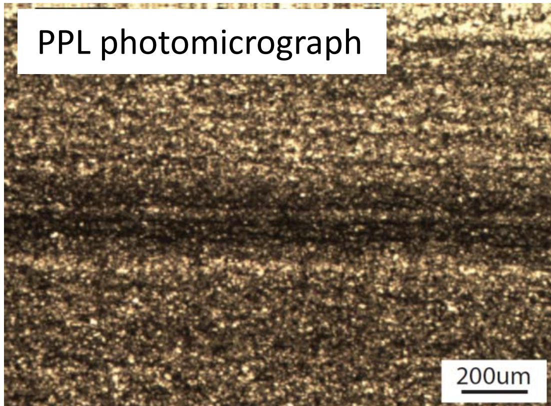
2: <5mm thick coarse siltstone lamina

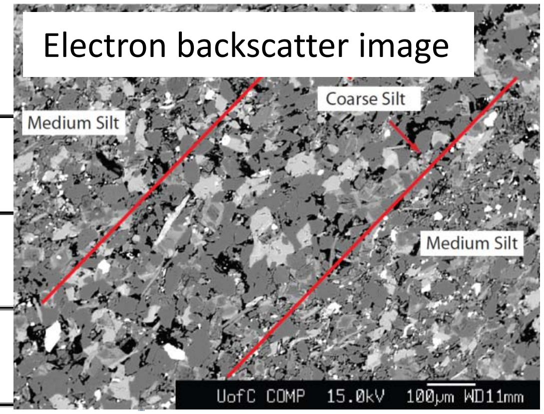
3: Finely laminated, fine to medium siltstone

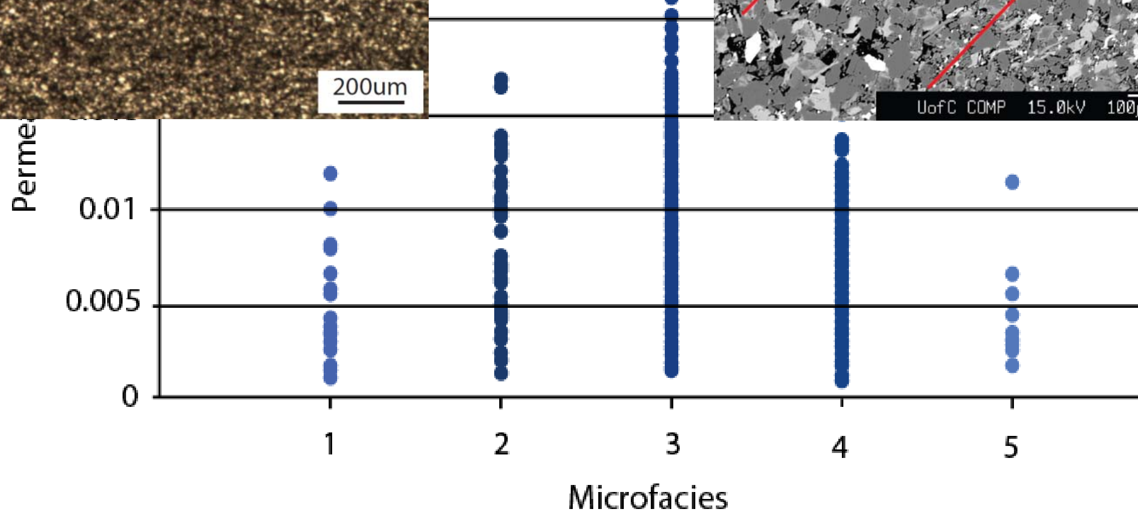
4: Thick bedded, fine to medium siltstone

5: Mudstone

Microfacies Probe Permeability







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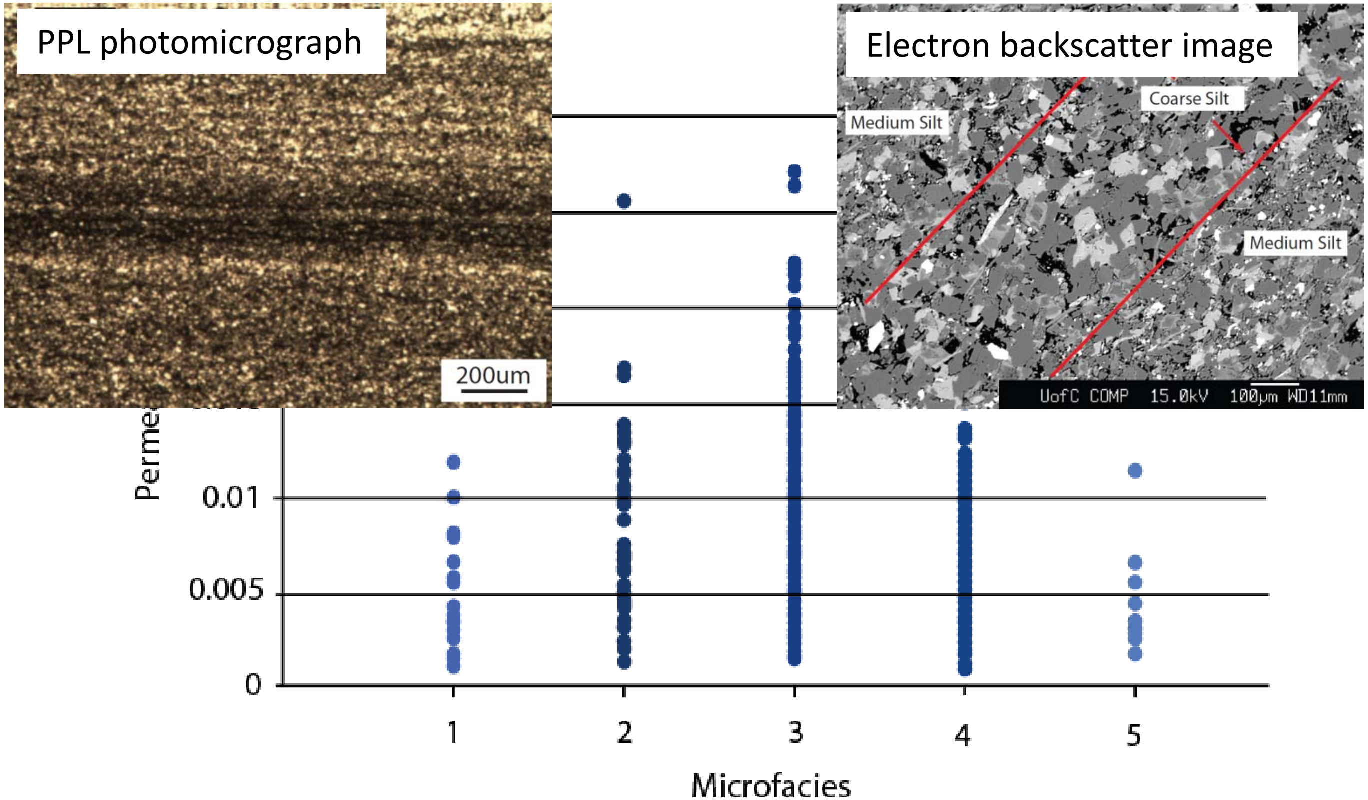

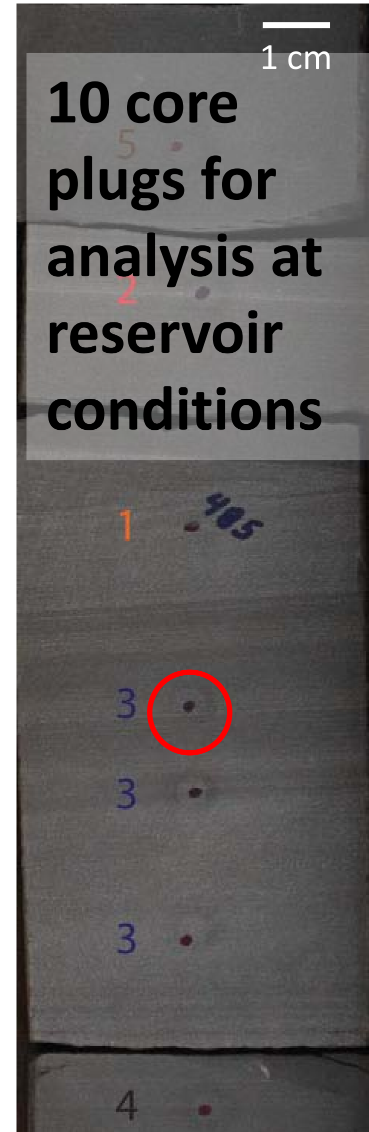

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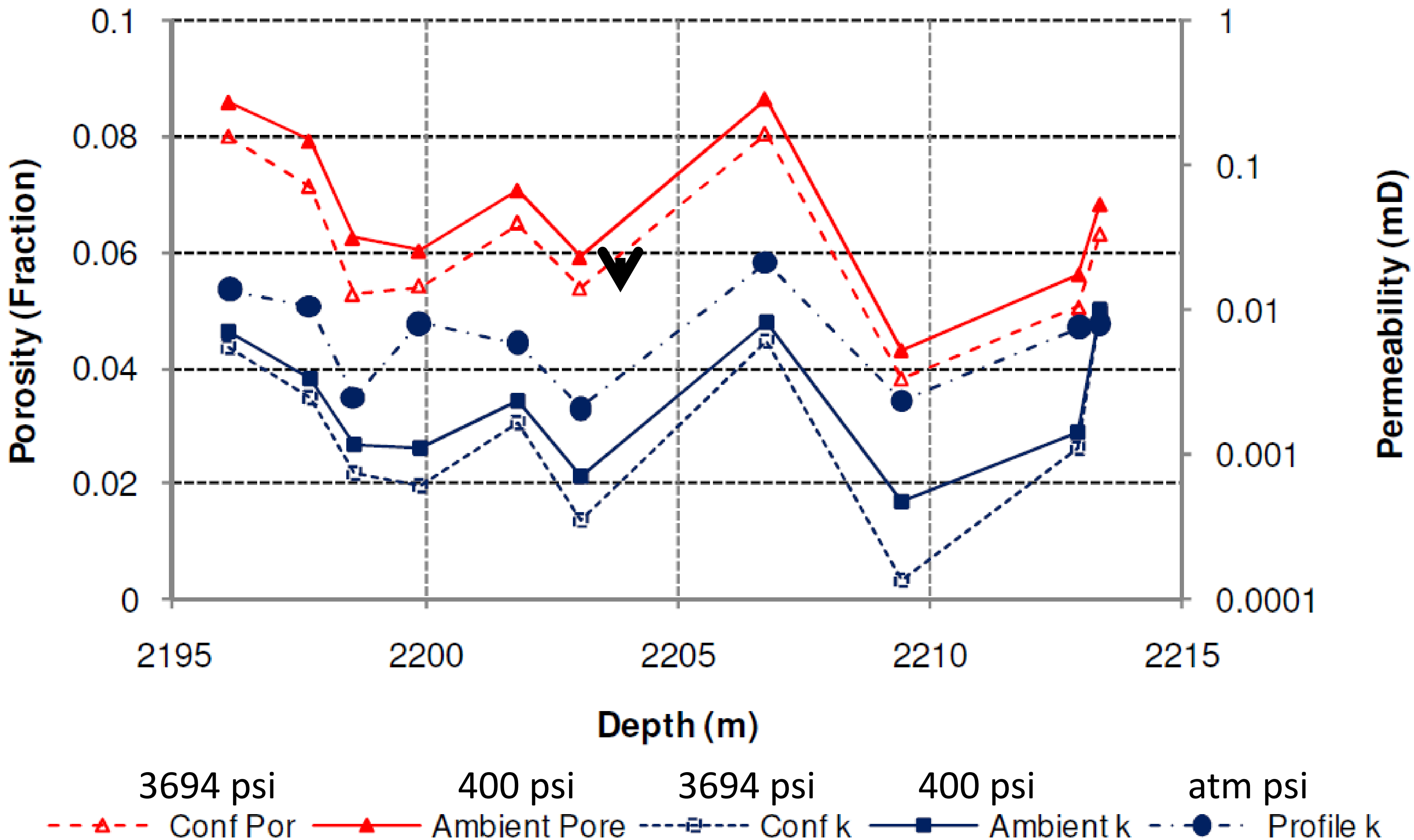
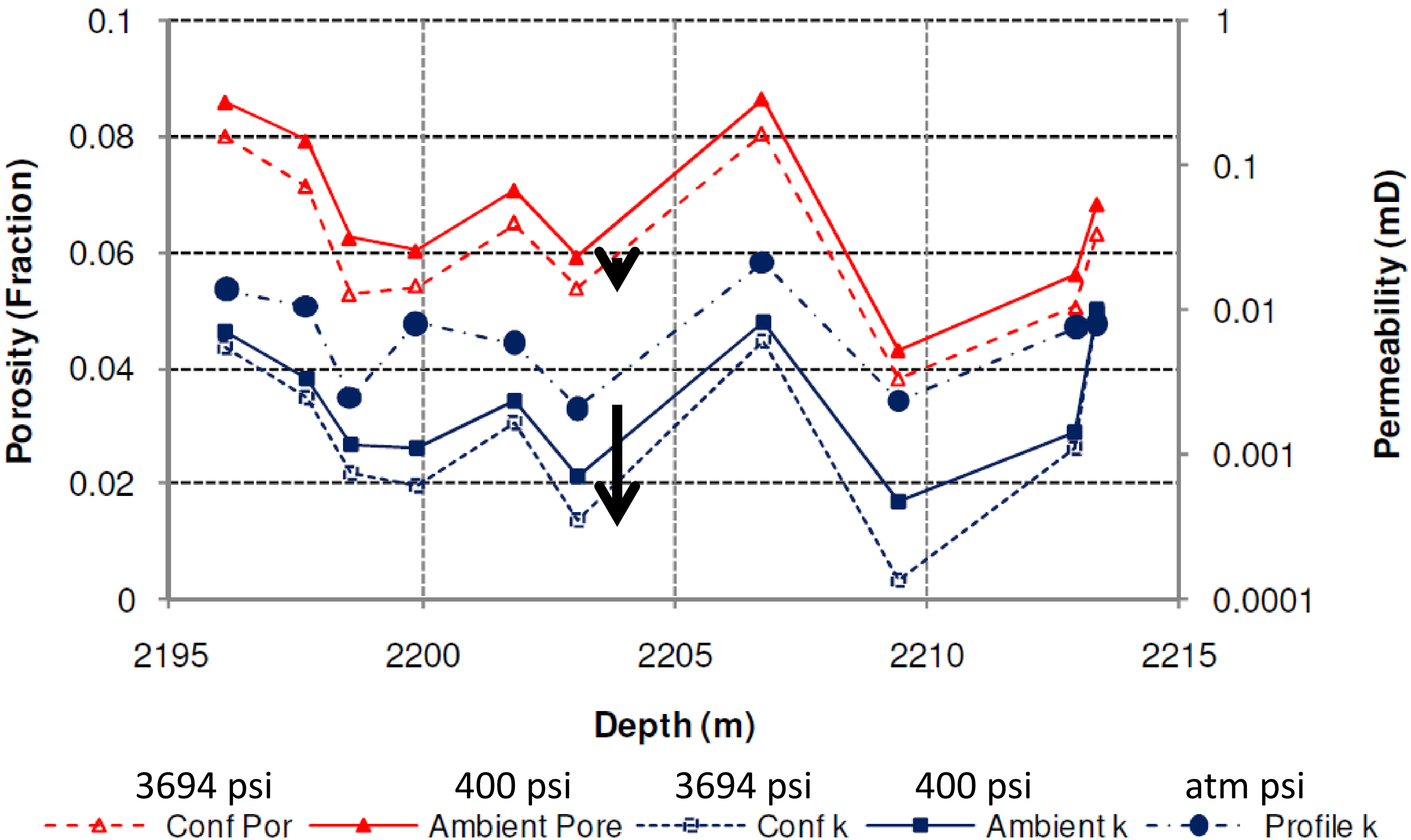
Ambient vs. Reservoir Net Overburden Pressure Porosity and Permeability



Porosity and Pulse-Decay permeability from core plugs

Ambient vs. Reservoir Net Overburden Pressure Porosity and Permeability



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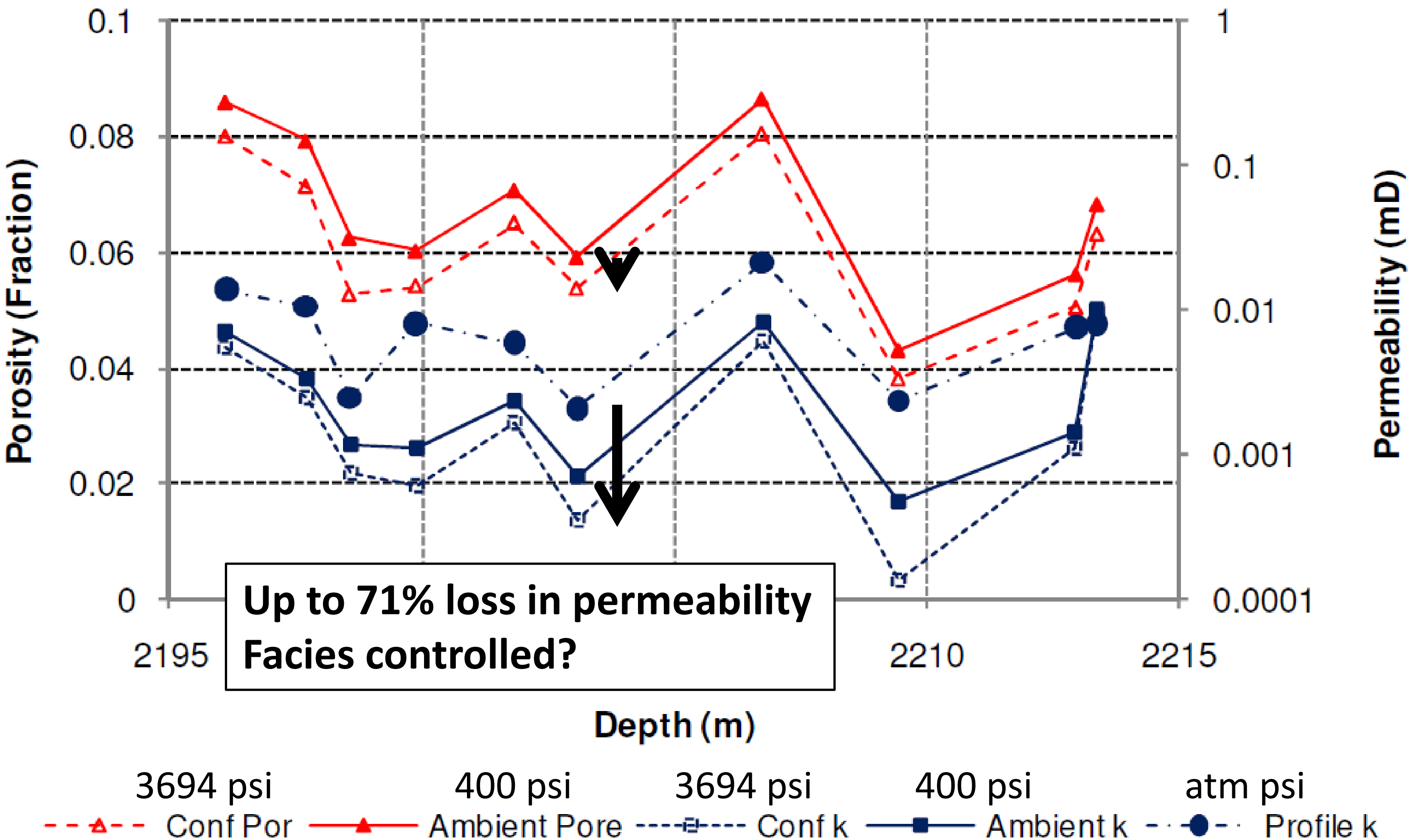

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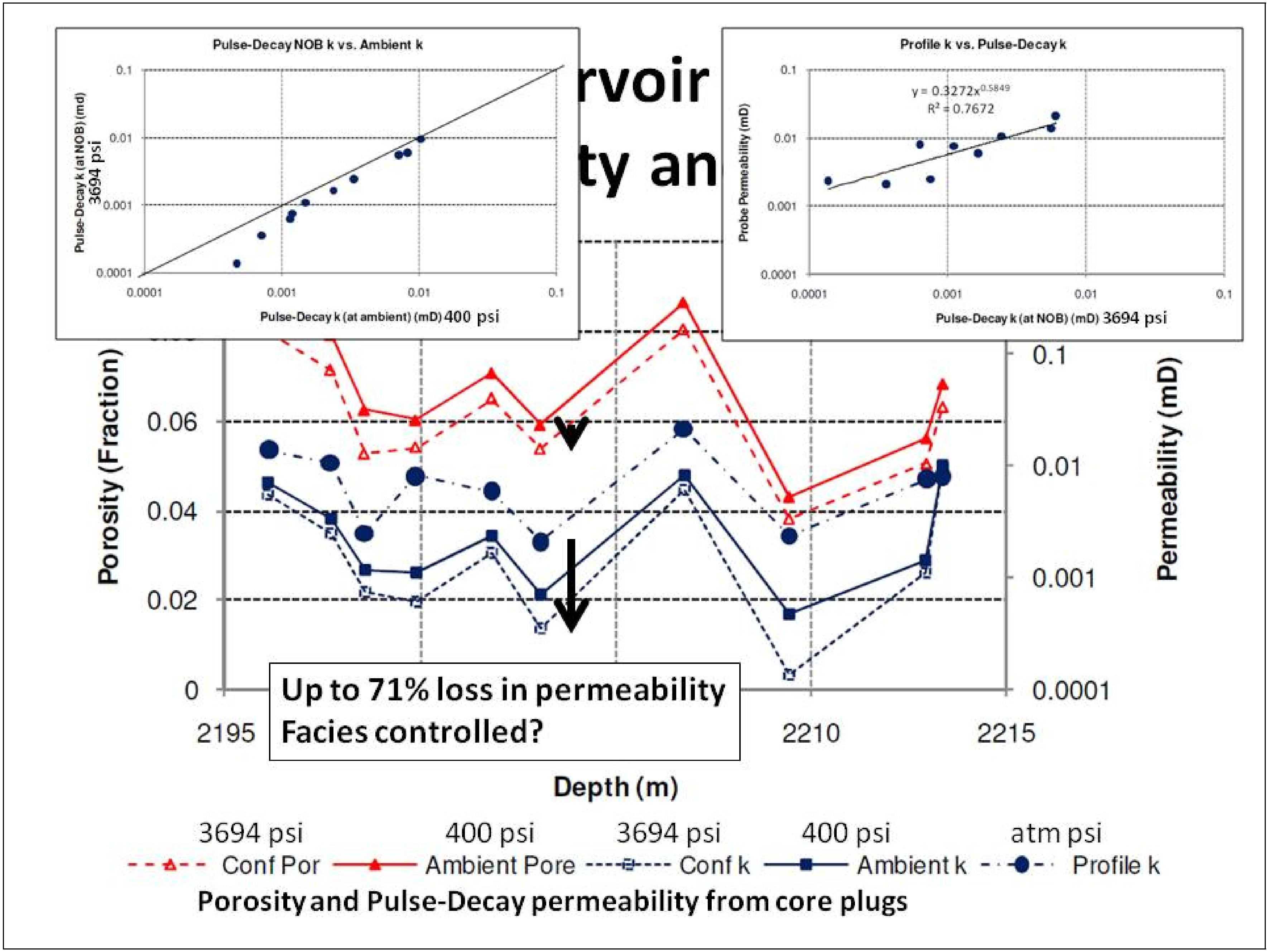
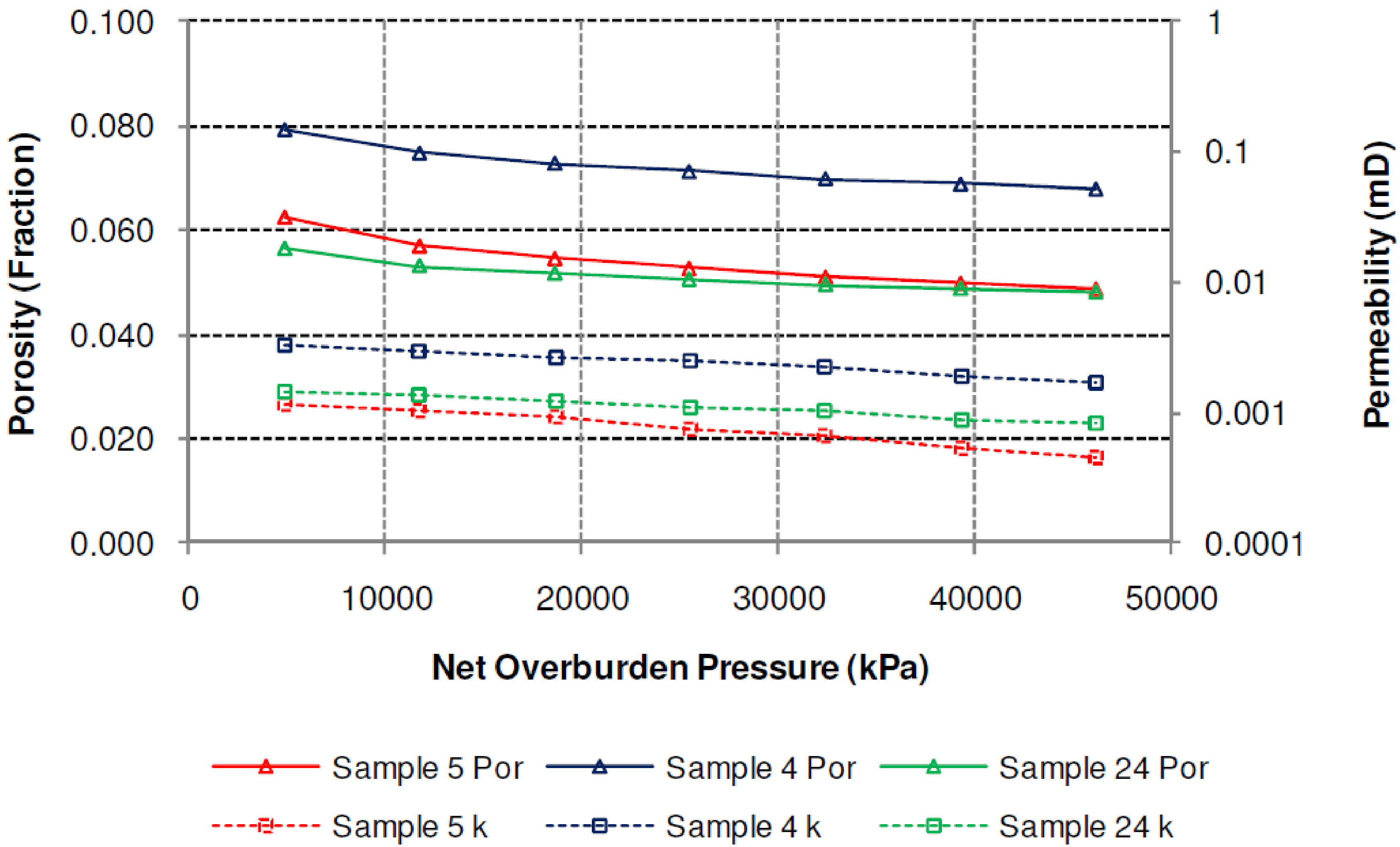


Notes by Presenter: The two different measurements of permeability are weakly correlated. They differ substantially in absolute value due to differences in measurement conditions and volumes of rock sampled.

Facies Control on Loss of Porosity and Permeability



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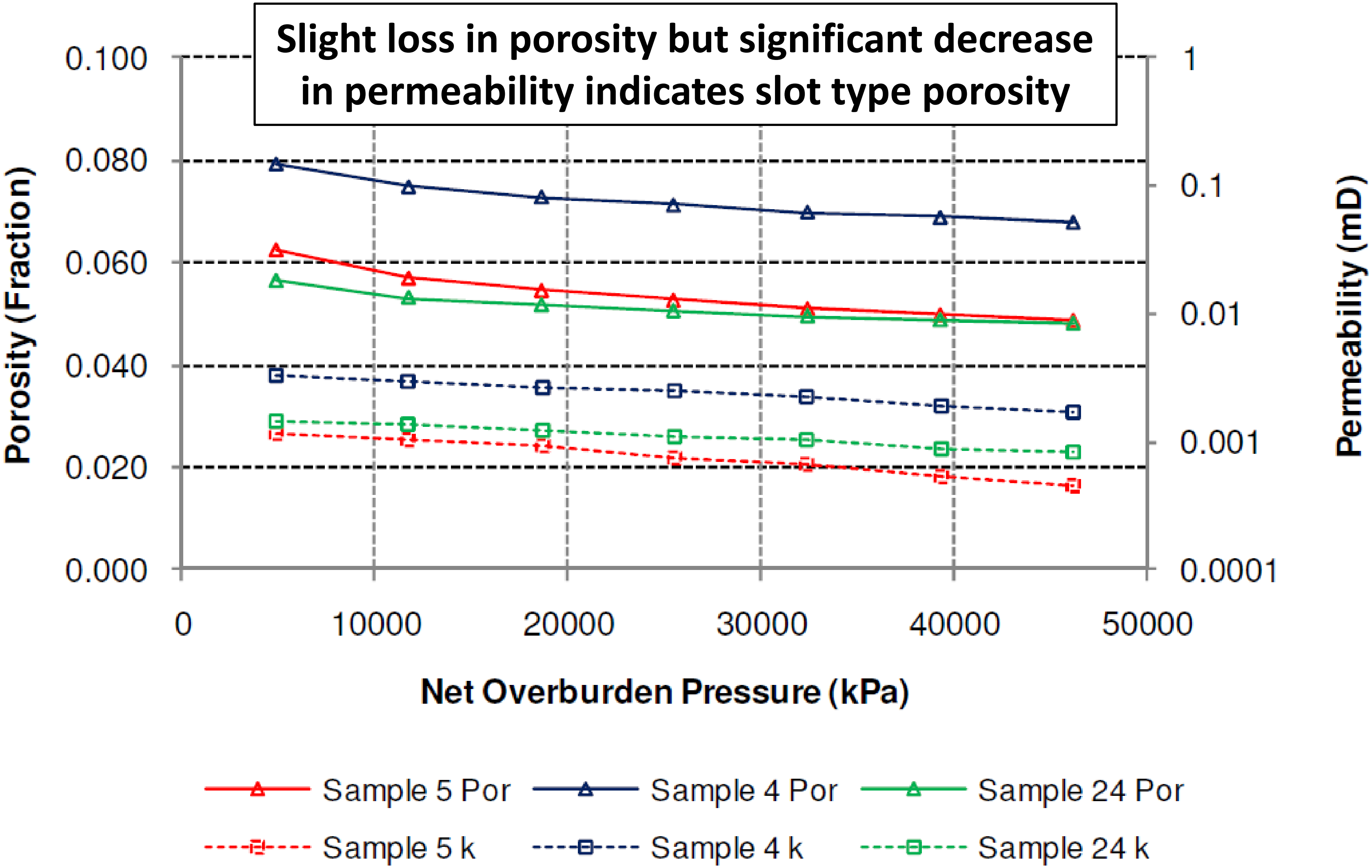
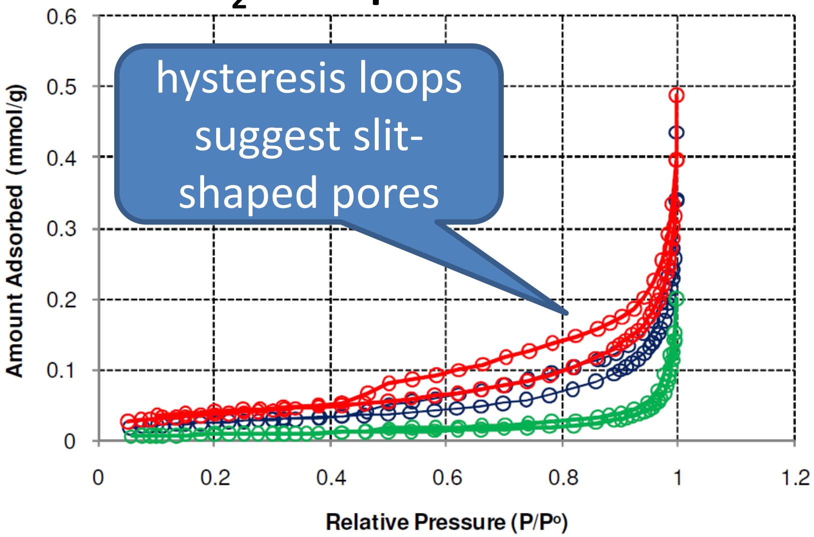
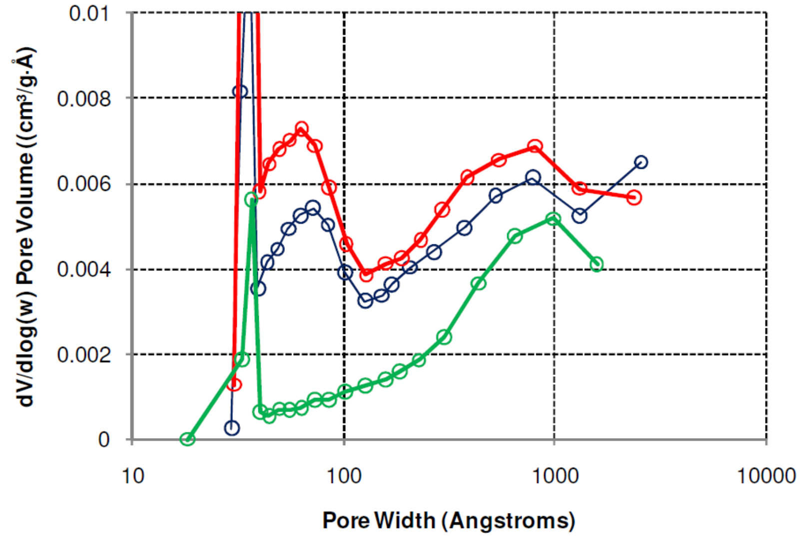


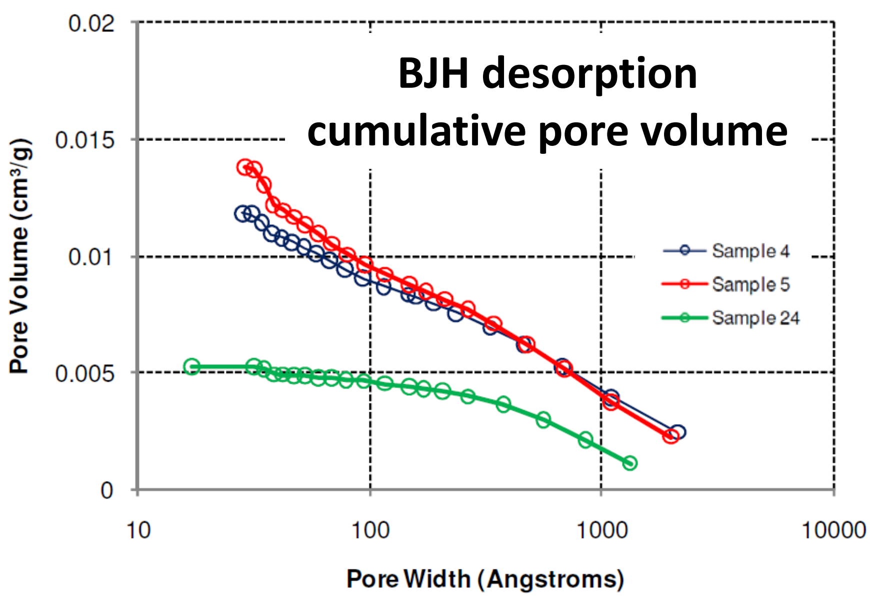
N_2 Adsorption Isotherm Analysis

N_2 adsorption isotherms

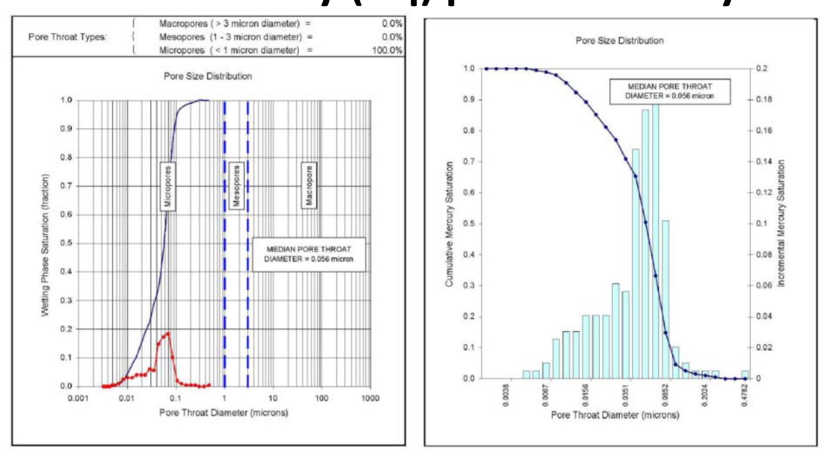


BJH pore size distributions





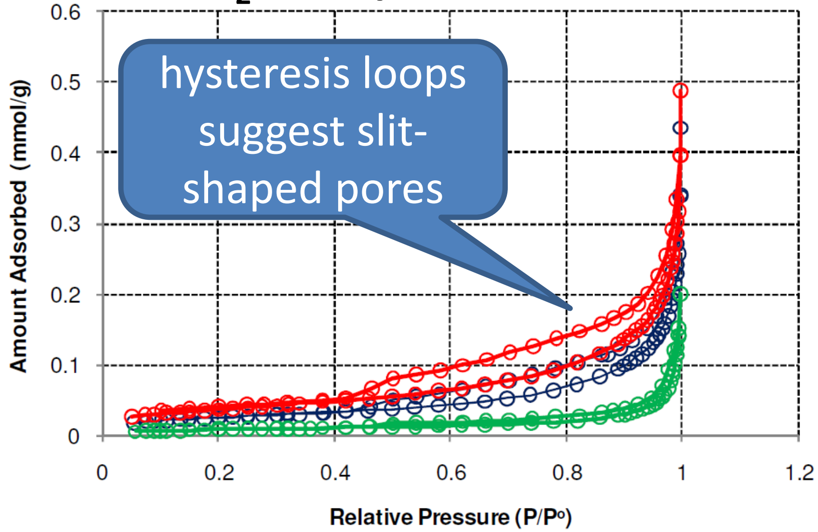
Mercury (Hq) pore size analysis



from nearby Montney core

N_2 Adsorption Isotherm Analysis

N_2 adsorption isotherms



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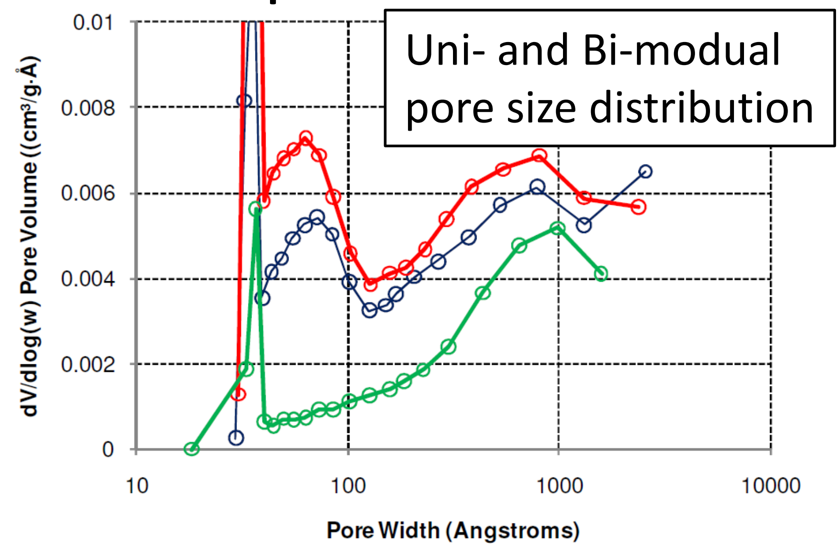

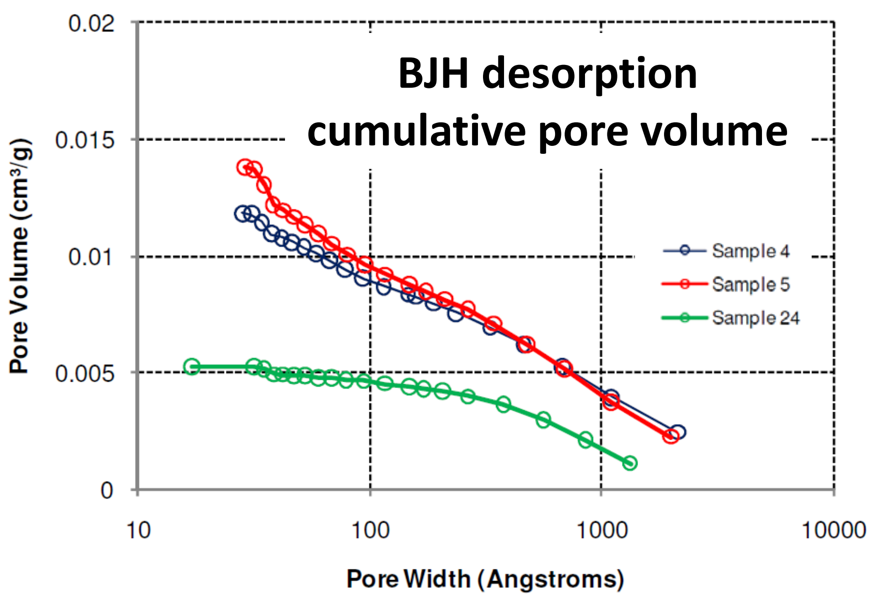

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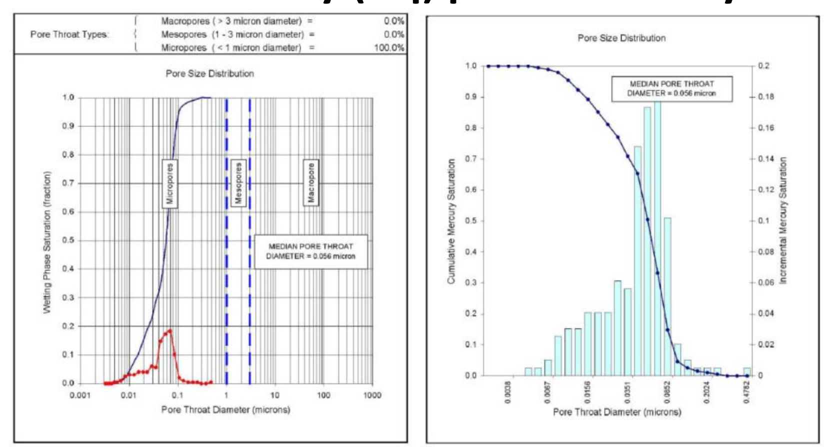

from nearby Montney core

N_2 Adsorption Isotherm Analysis

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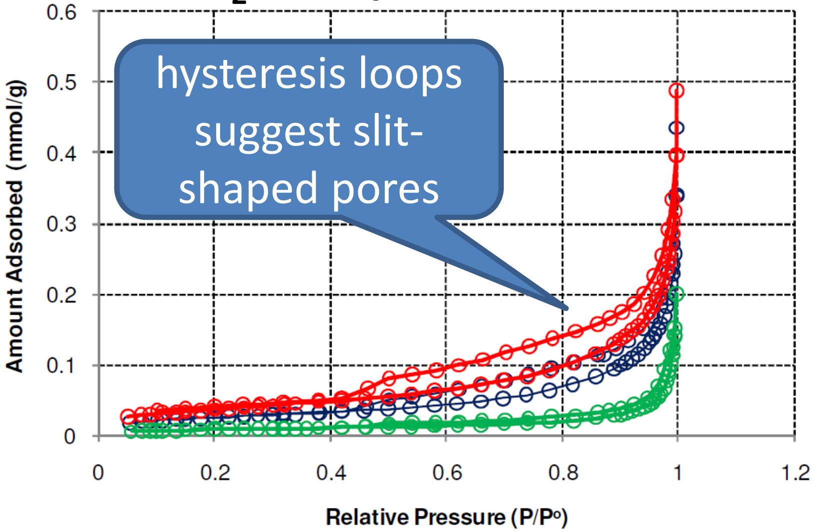

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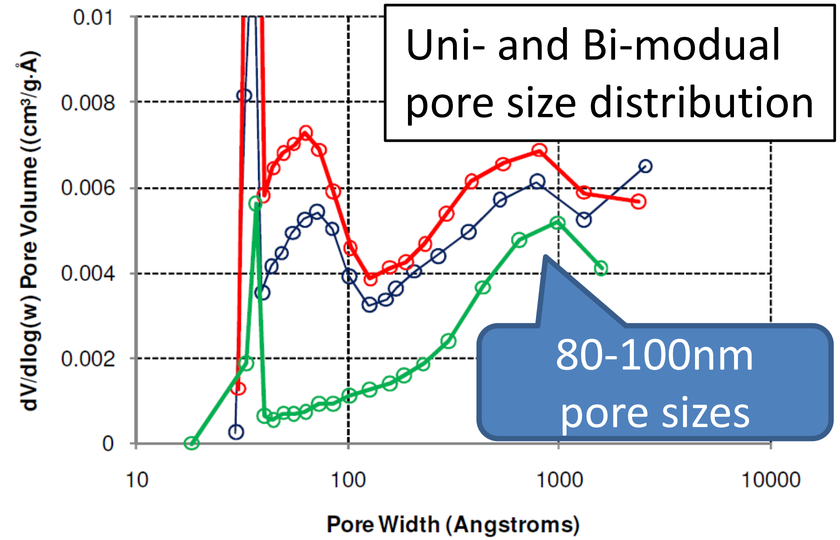
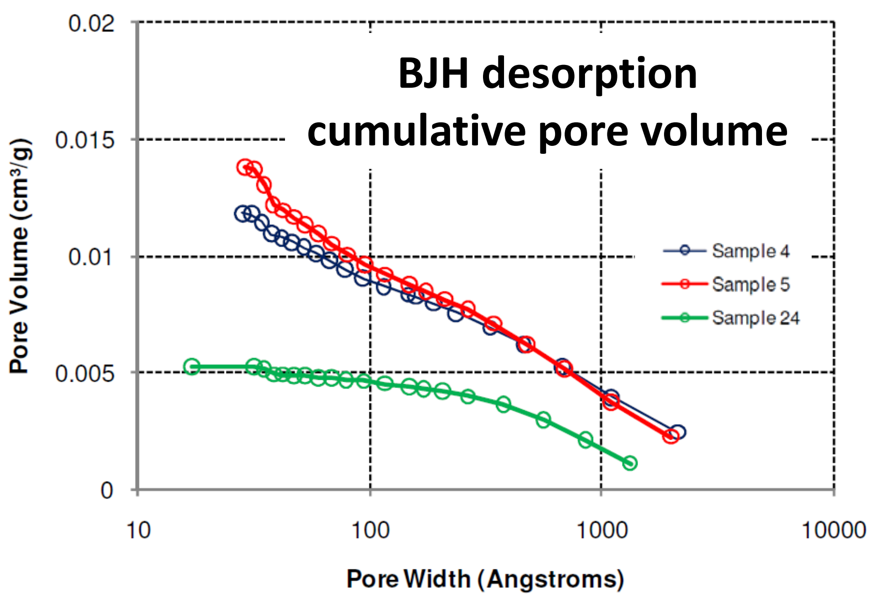
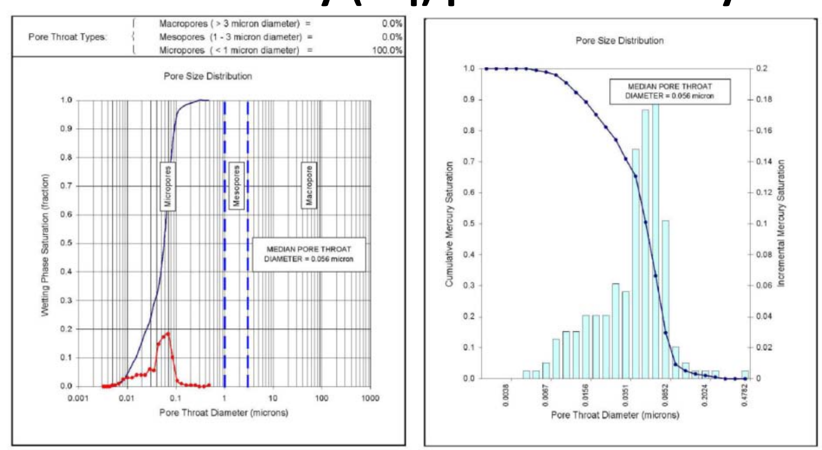




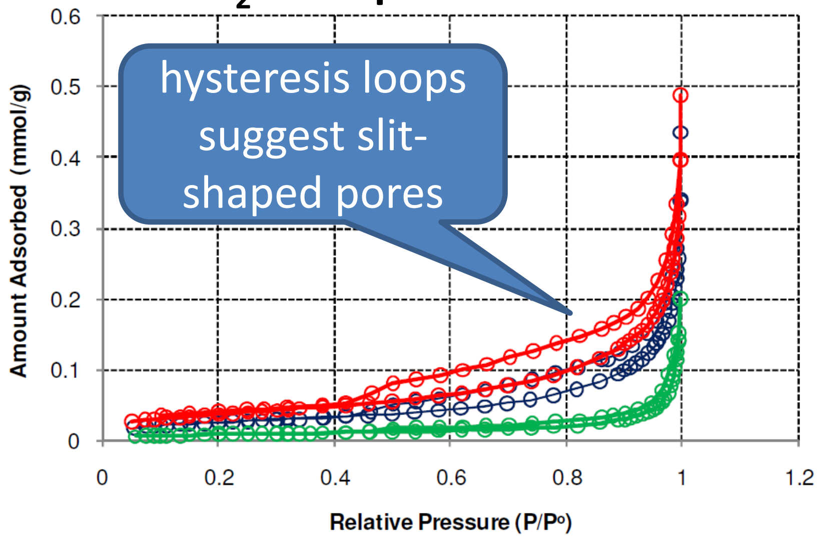
Mercury (Hq) pore size analysis



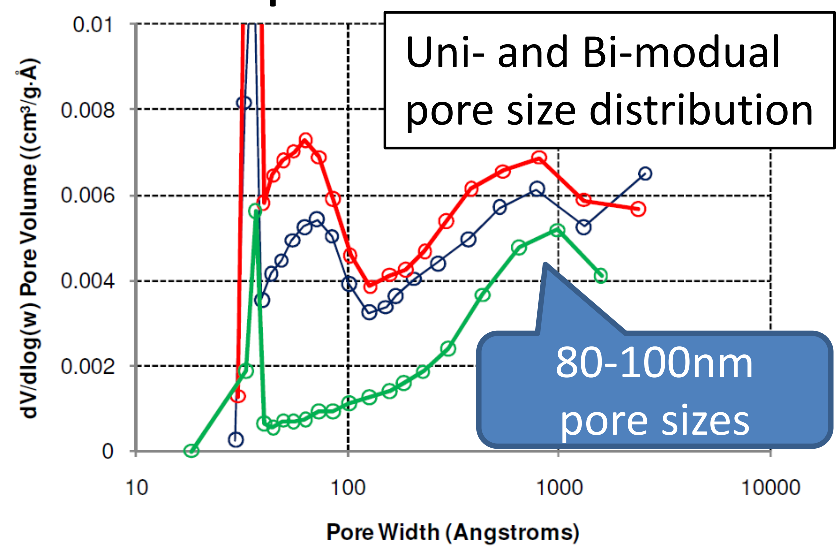
from nearby Montney core

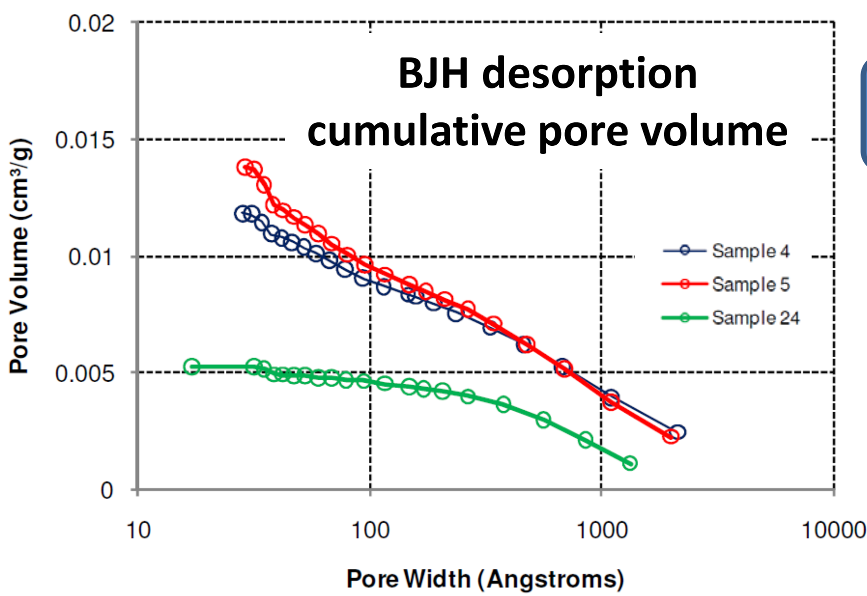
N_2 Adsorption Isotherm Analysis

N_2 adsorption isotherms

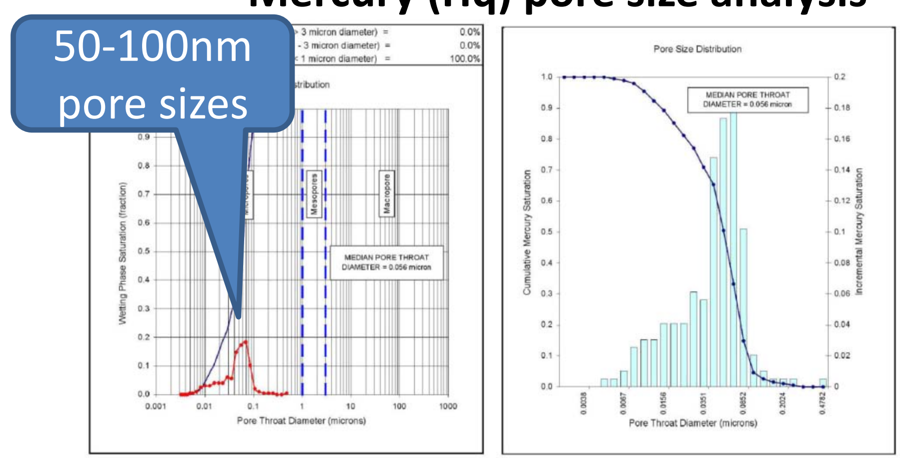


BJH pore size distributions





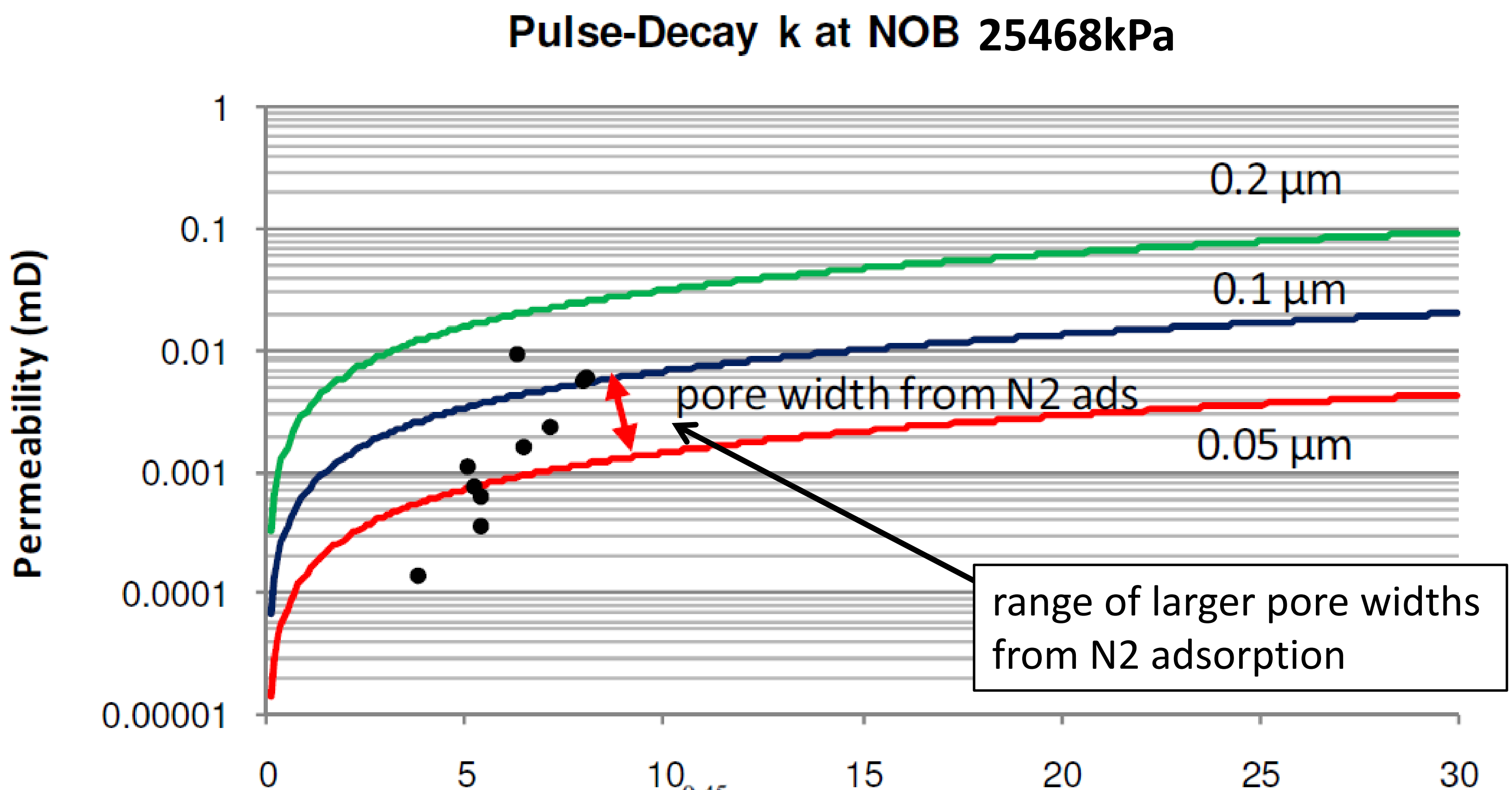
Mercury (Hq) pore size analysis



from nearby Montney core

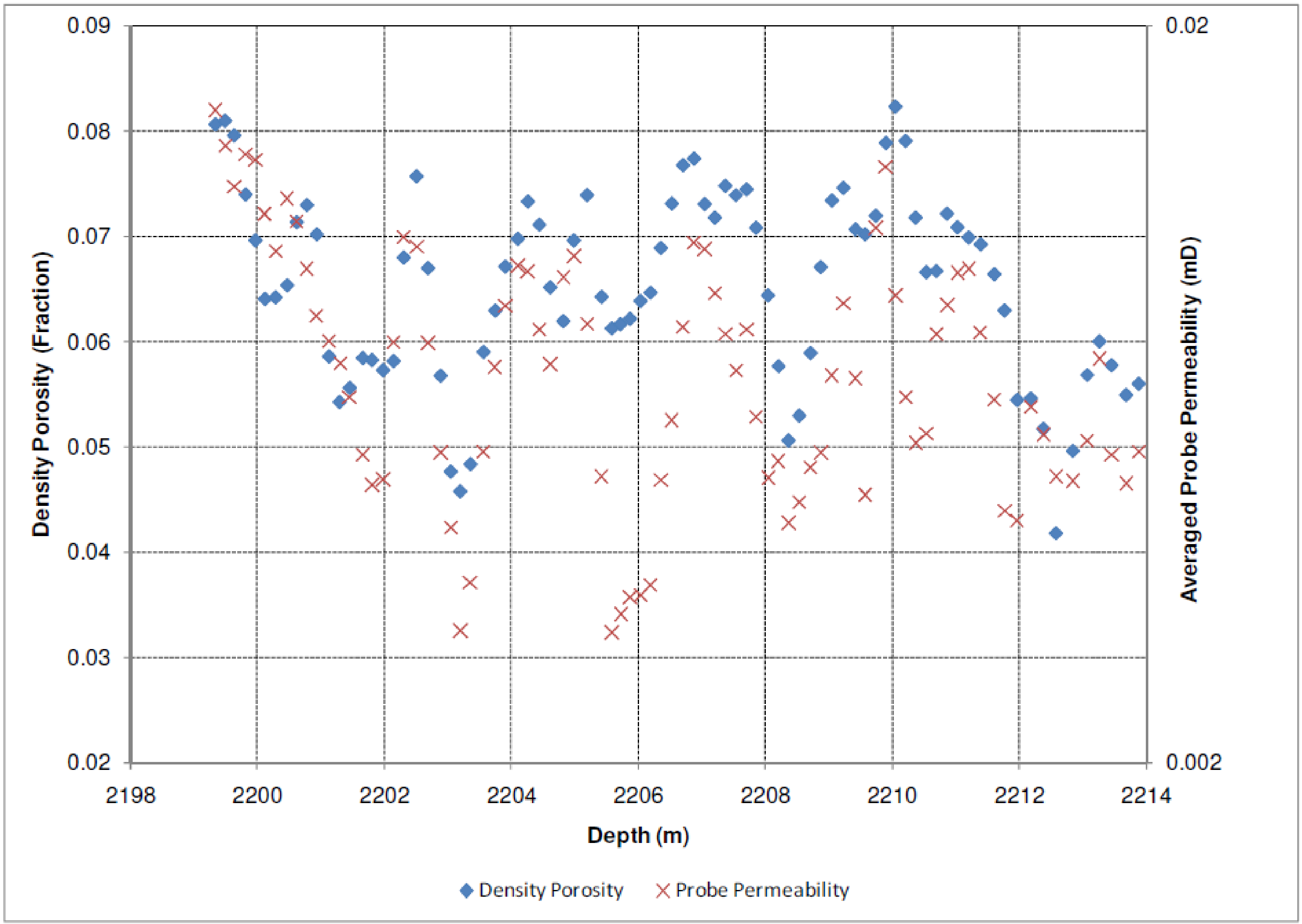
Flow Unit Identification

Core Plug Pulse-Decay Permeability vs. Porosity Data at Reservoir NOB

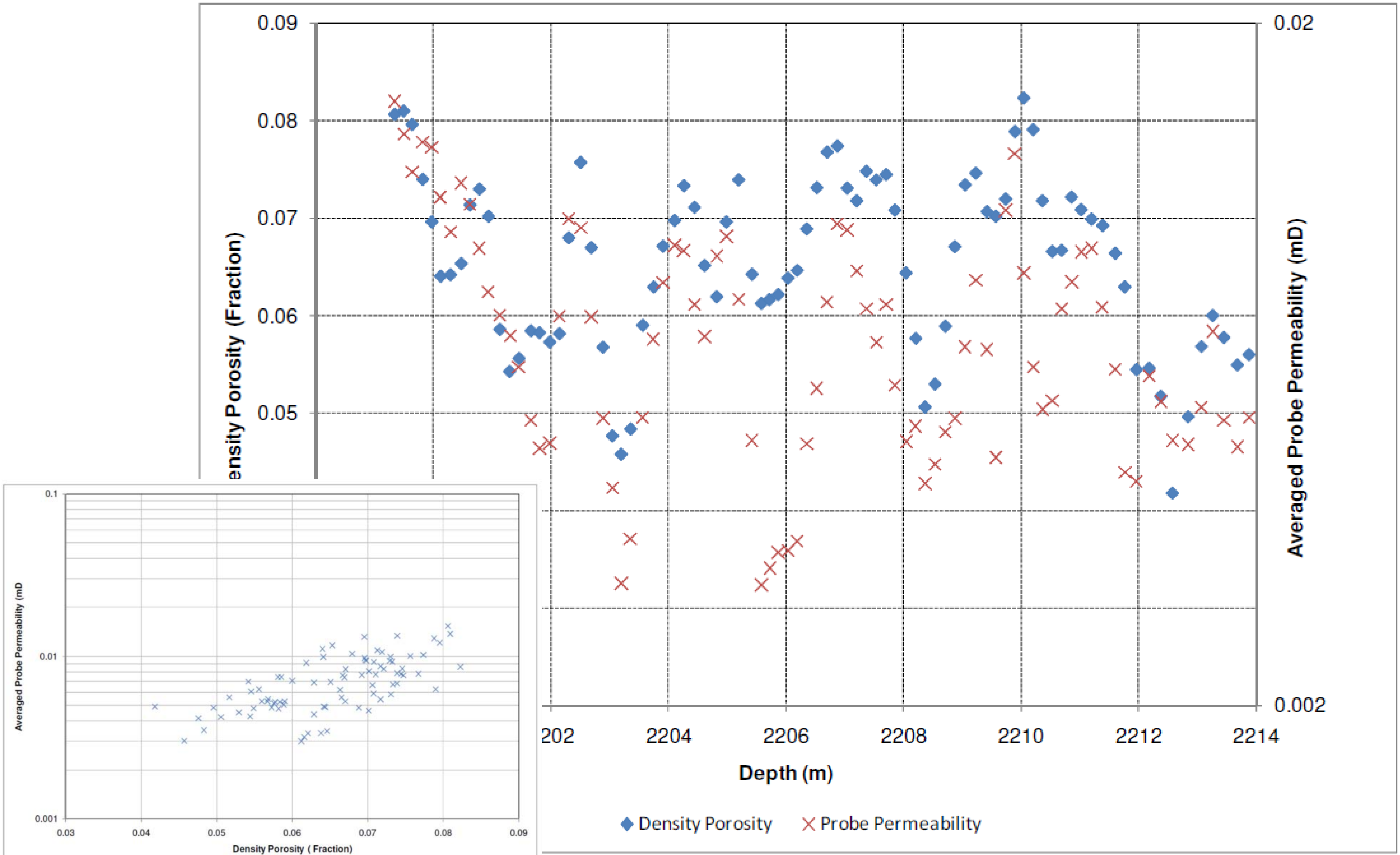


rp35 lines based on $r_{p35} = 2.665\left[\frac{k}{100\phi}\right]^{0.45}$ **Porosity (%)**

Averaged Probe Permeabilities (13-point) vs. Well Log Density Porosity

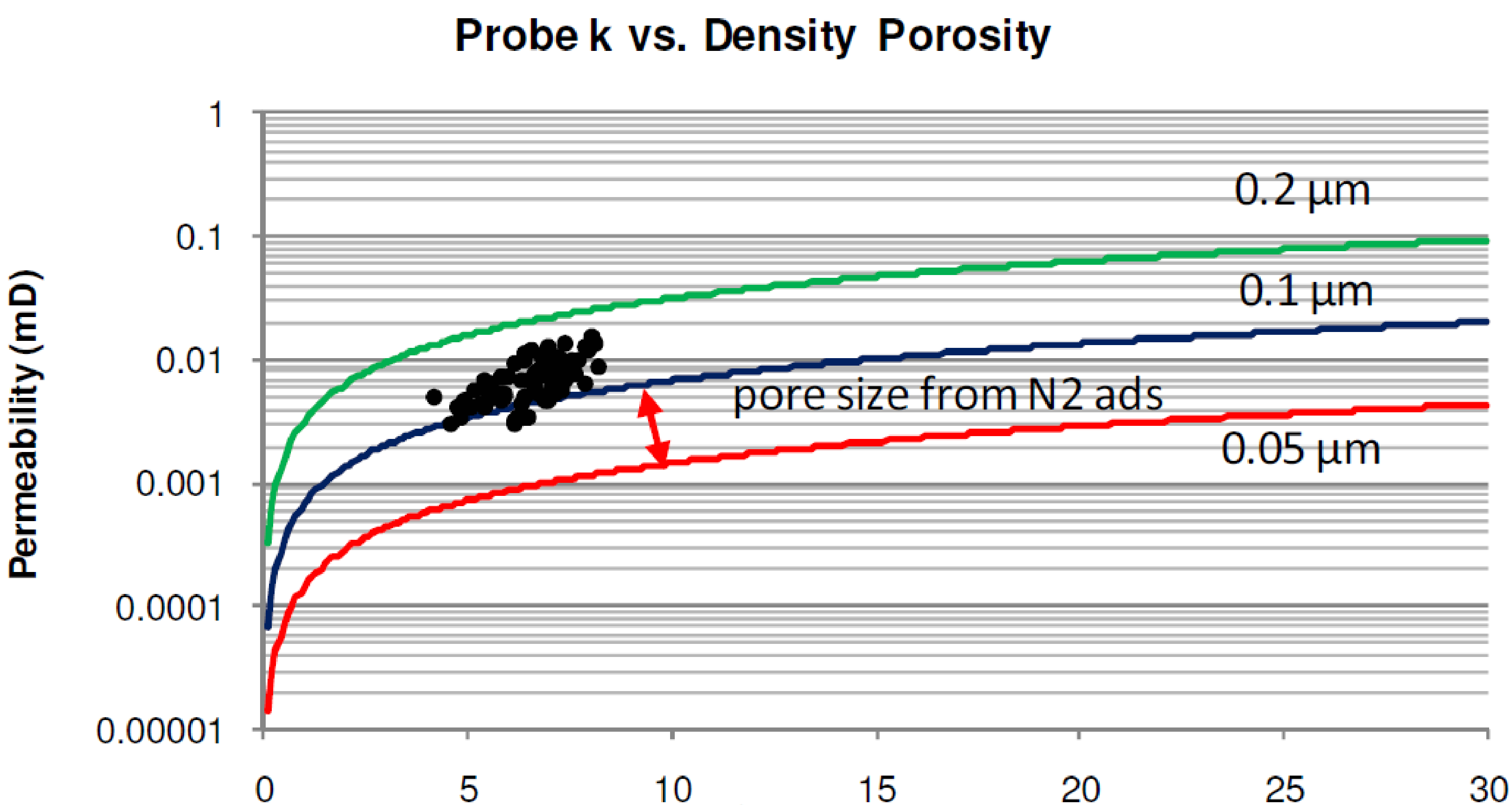


Averaged Probe Permeability (13-point) vs. Well Log Density Porosity



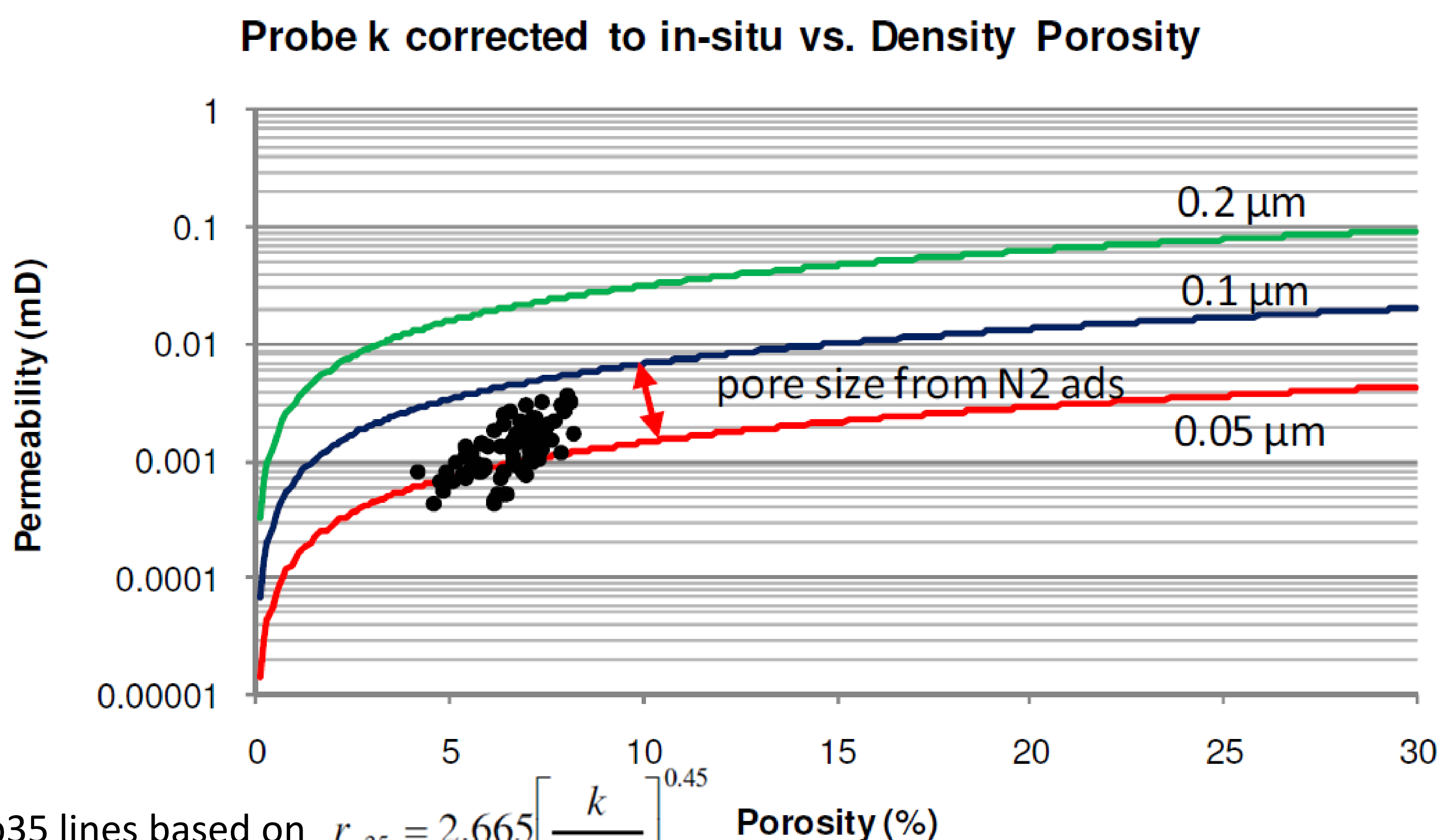
Flow Unit Identification

Uncorrected probe permeability data versus well log density porosity



rp35 lines based on $r_{p35} = 2.665\left[\dfrac{k}{100\phi}\right]^{0.45}$ **Porosity (%)**

Corrected to in-situ reservoir stress probe permeability data vs. density porosity



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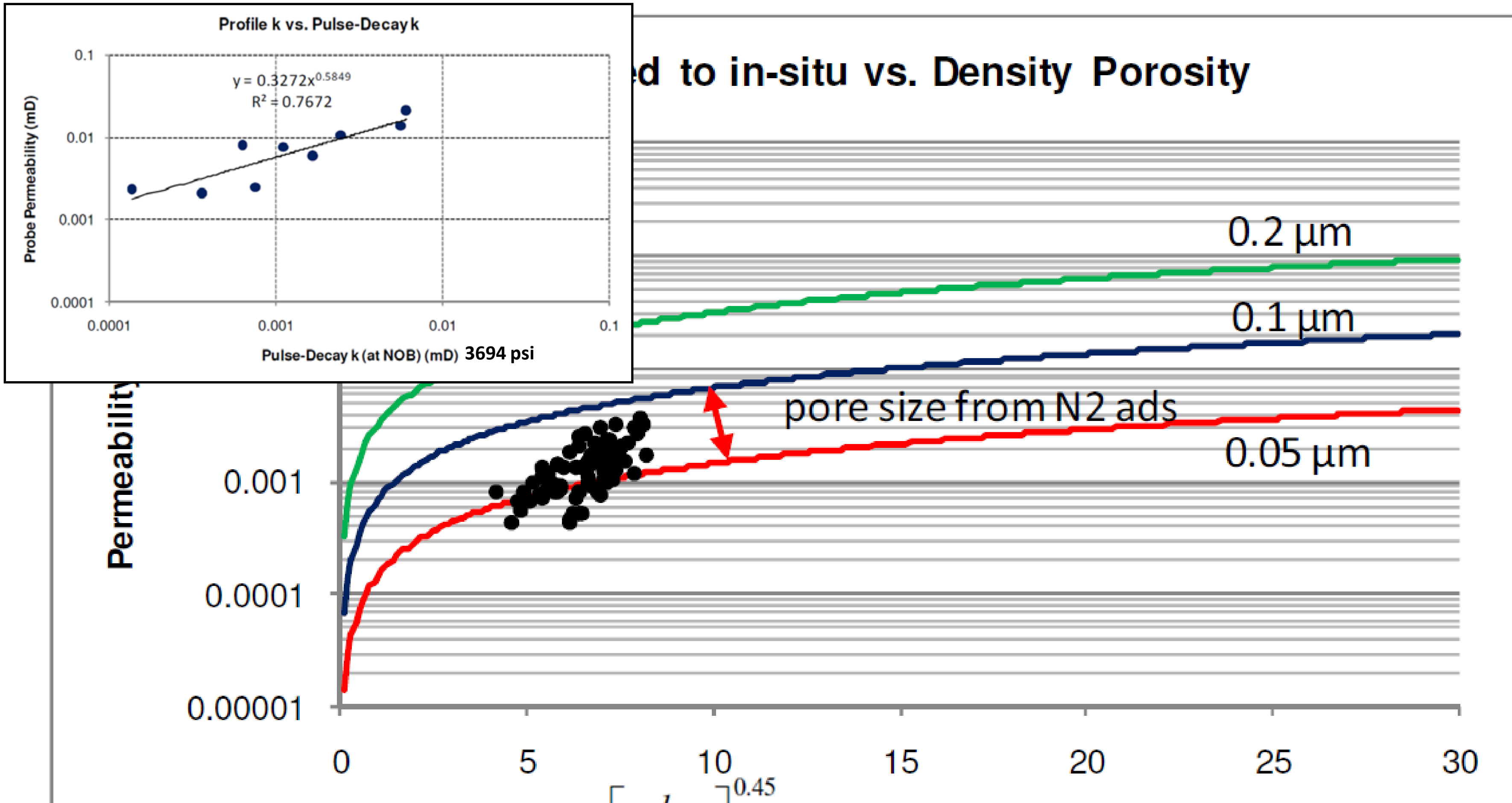

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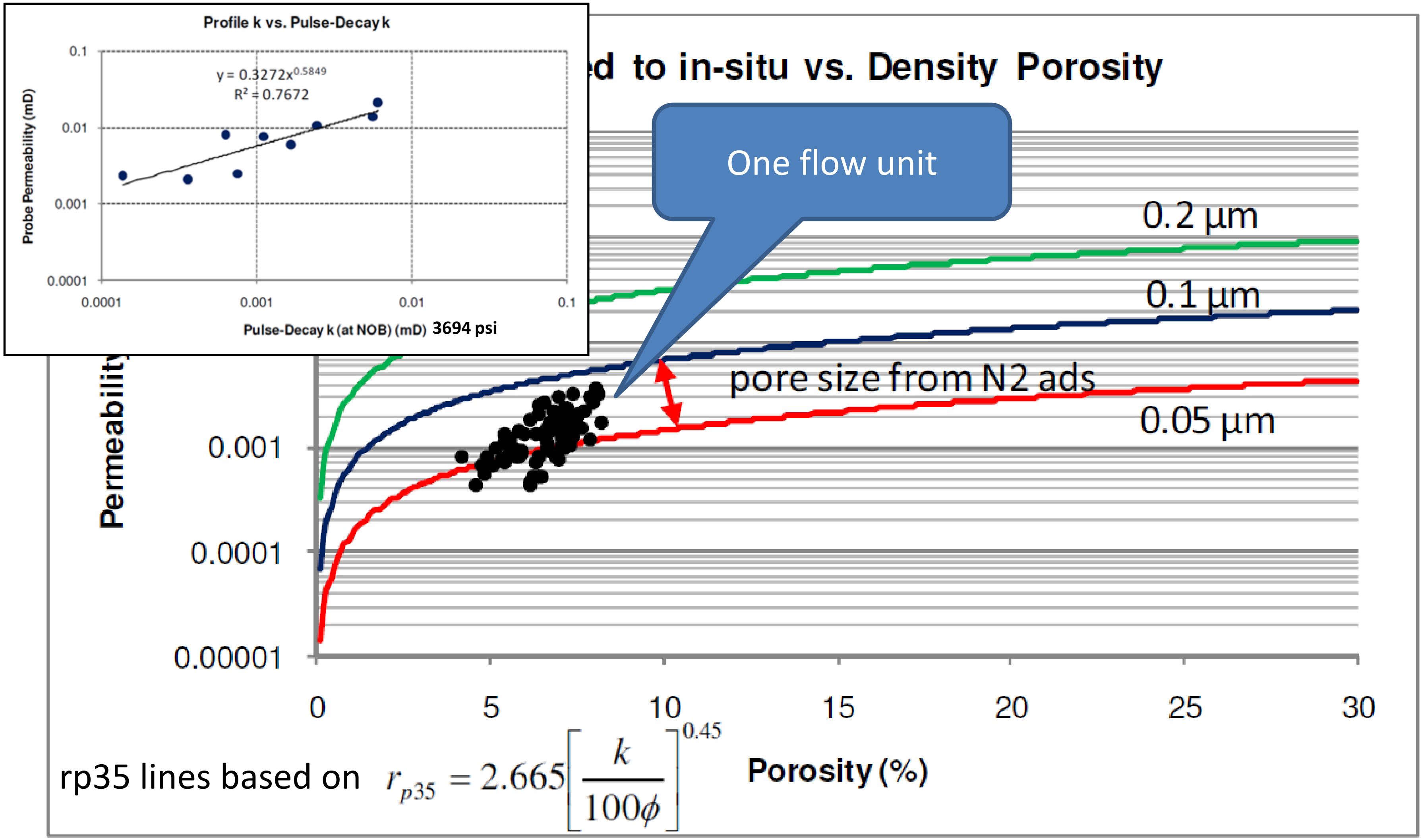
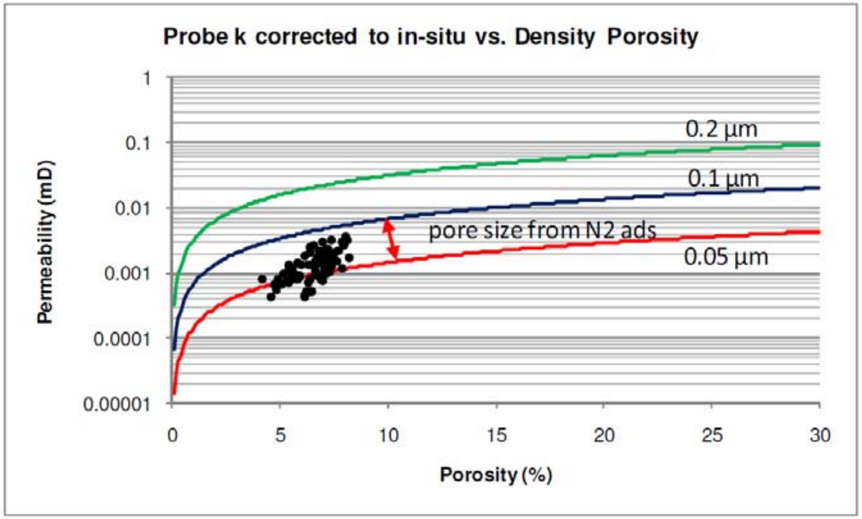
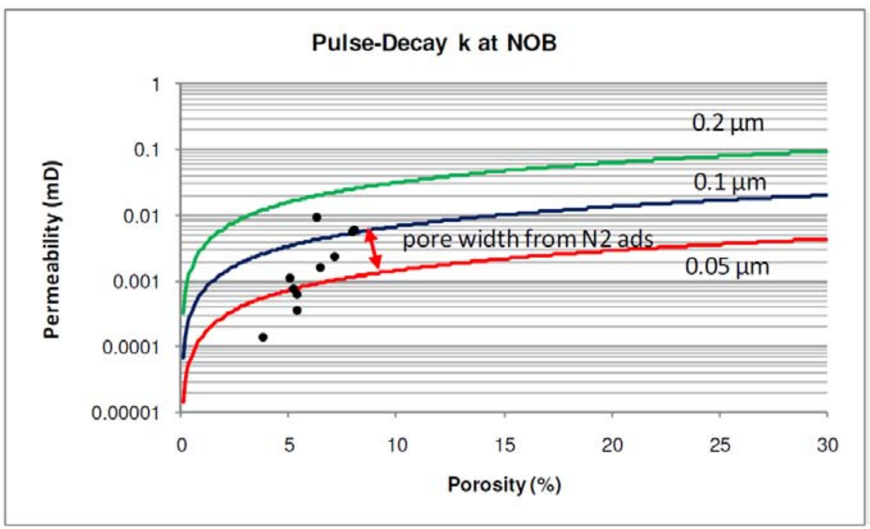
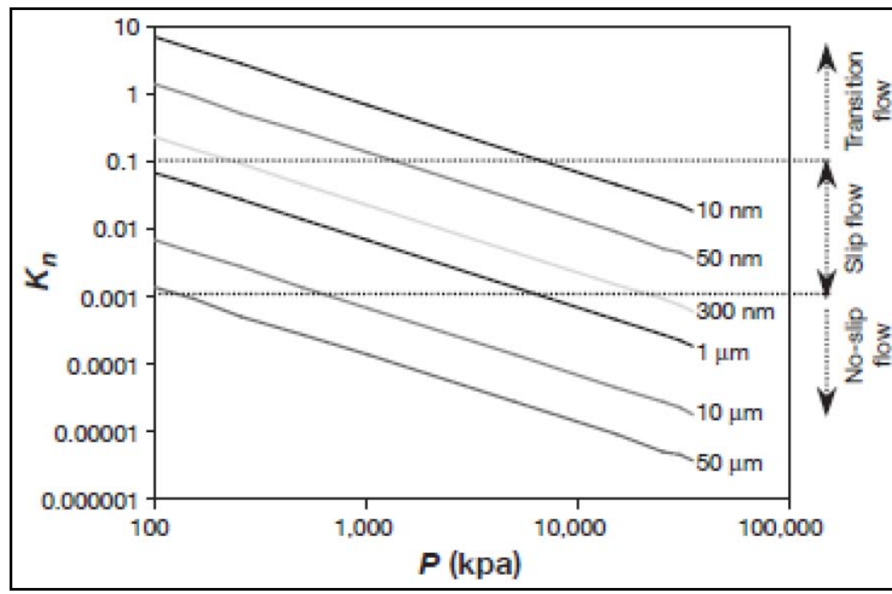


Core Plug Pulse-Decay k and Porosity



- Probe data can be used to identify dominant hydrological flow unit or units, given that lithology dependent compressibility has been taken into account
- Slip flow is likely dominant, i.e. modified Darcy model or diffusion-based model needed to characterize gas flow





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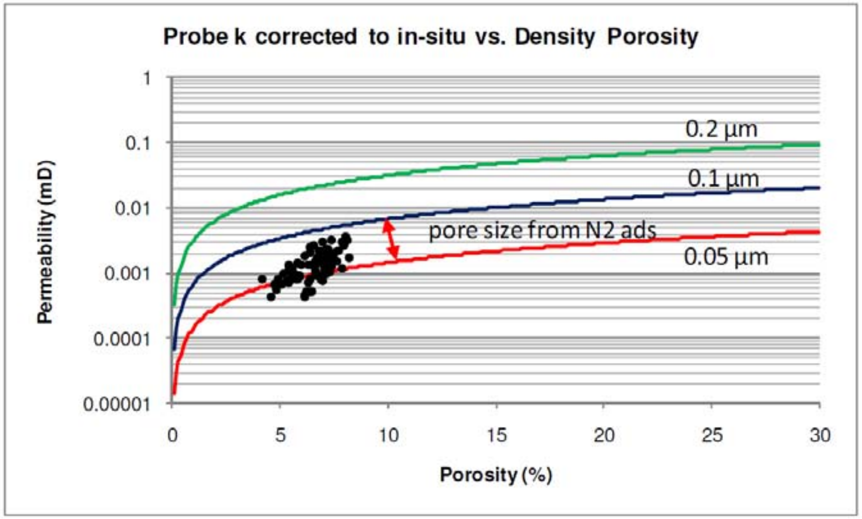
Core Plug Pulse-Decay k and Porosity



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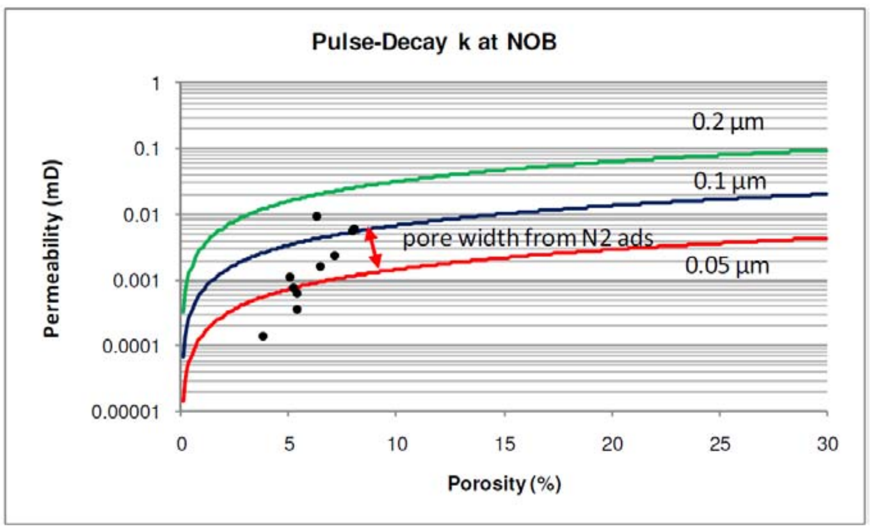

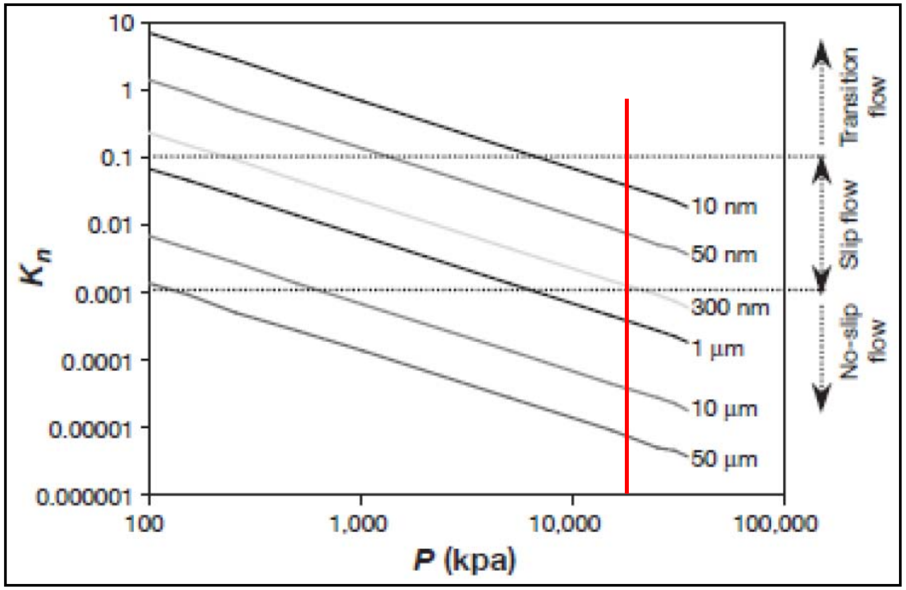

Javadpour et al.(2007)

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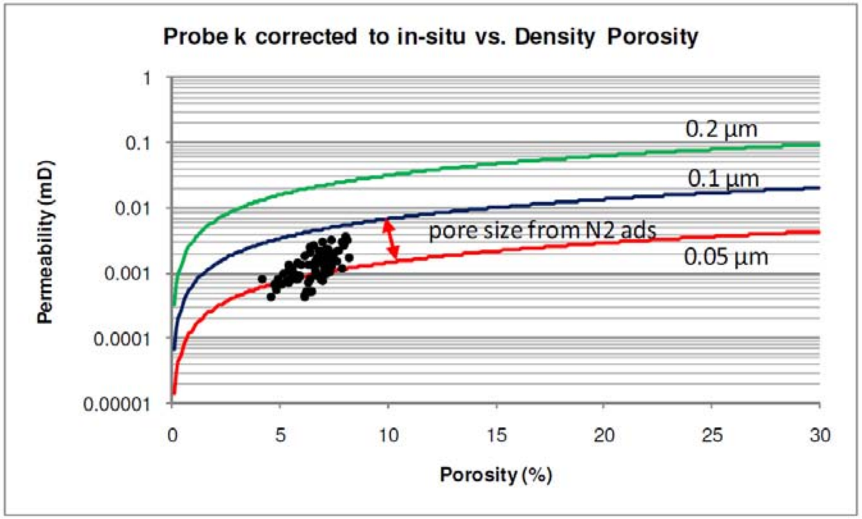

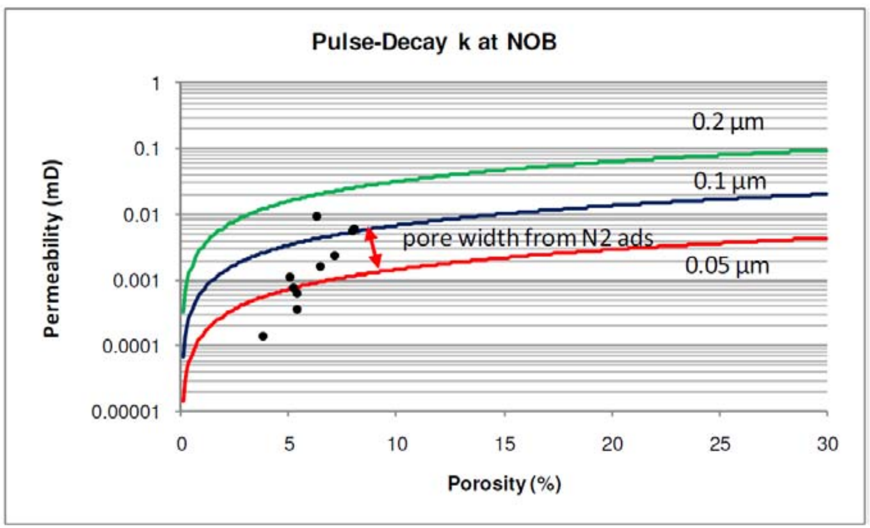

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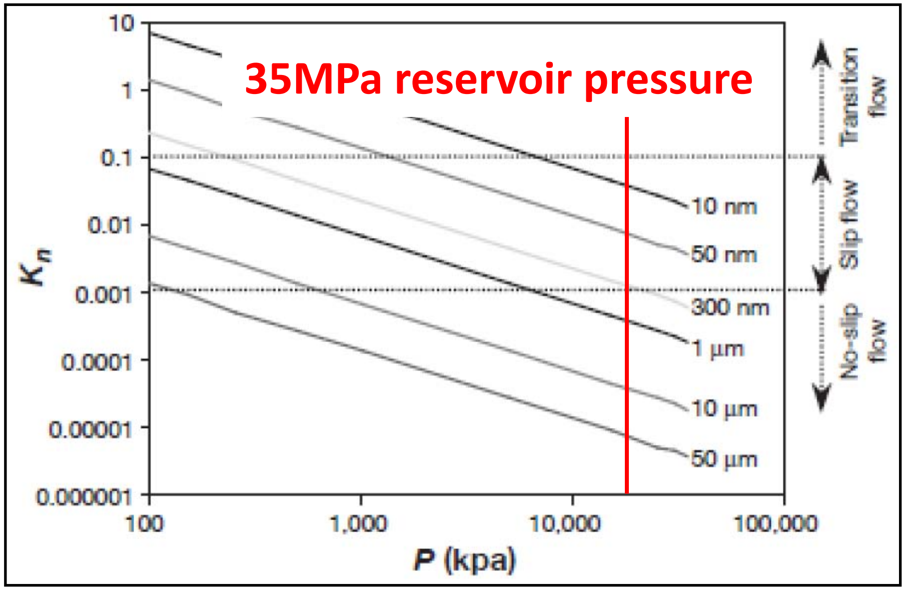

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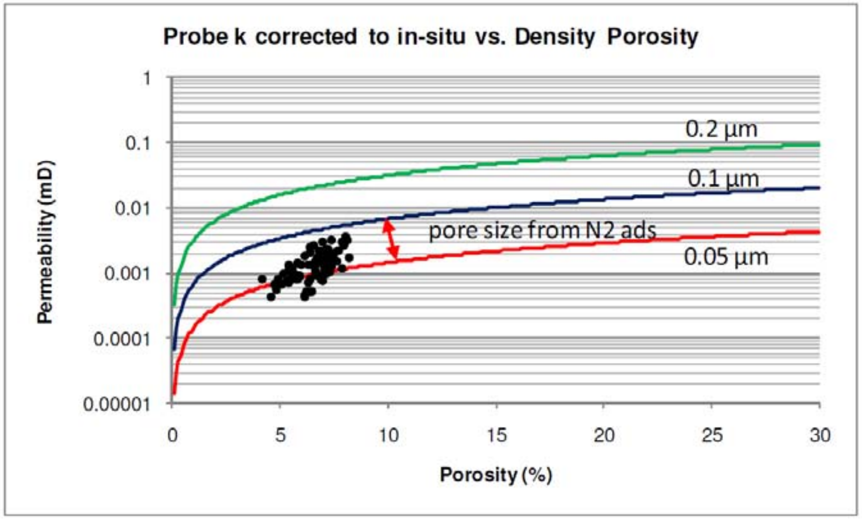
Core Plug Pulse-Decay k and Porosity



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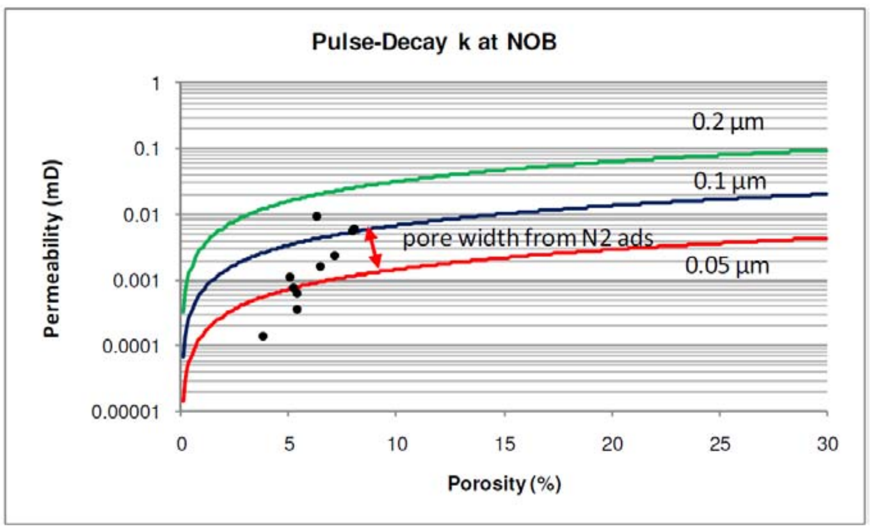

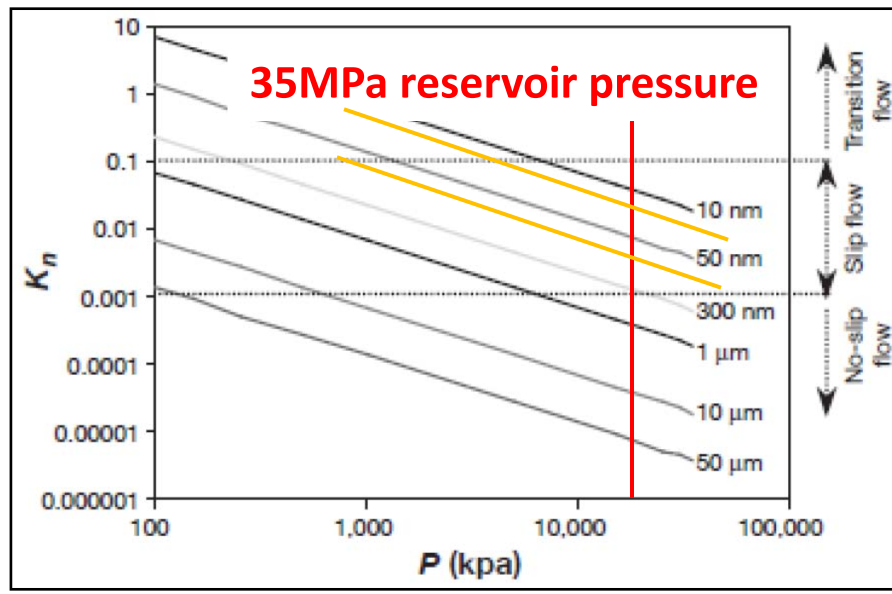

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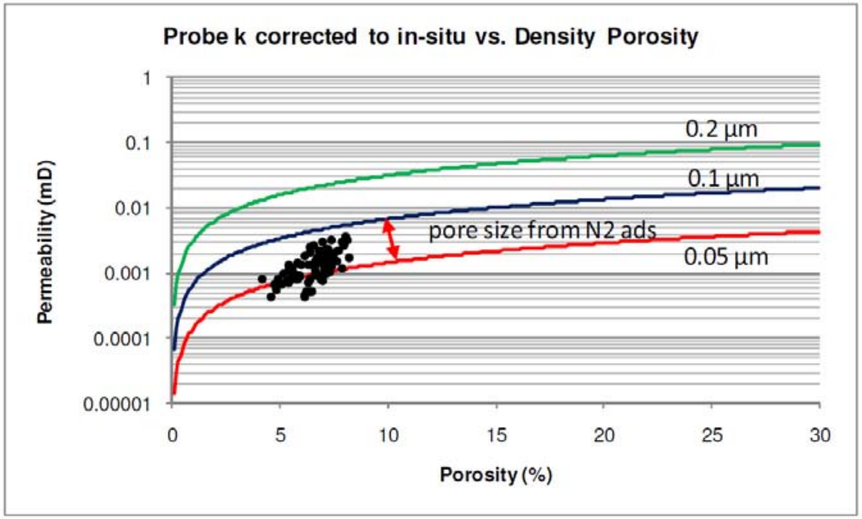

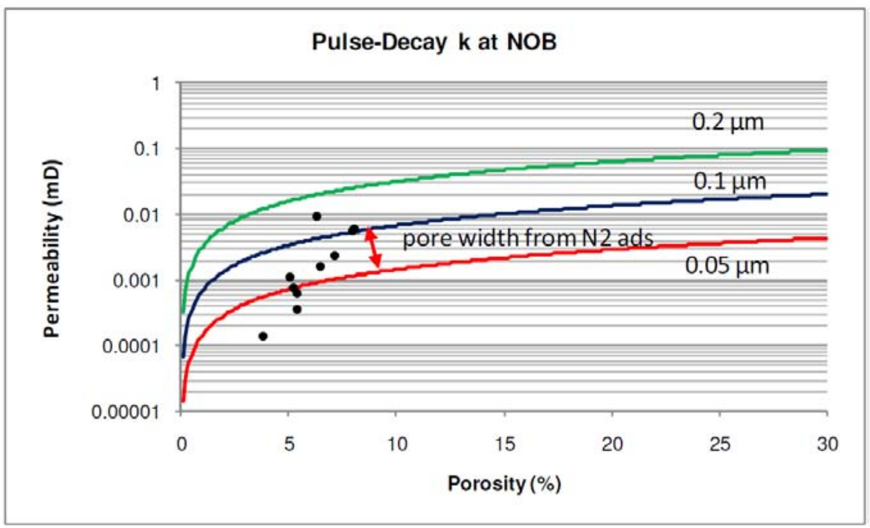

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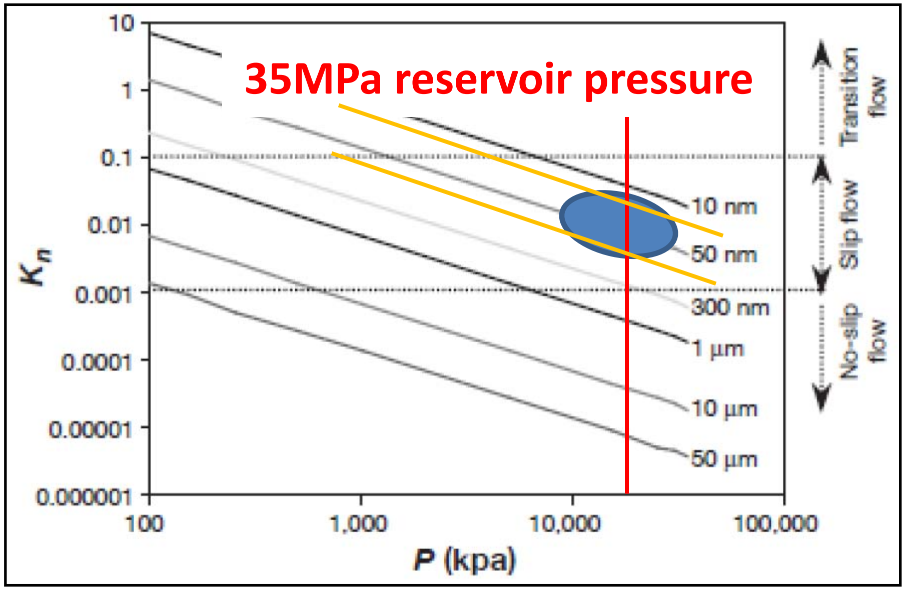

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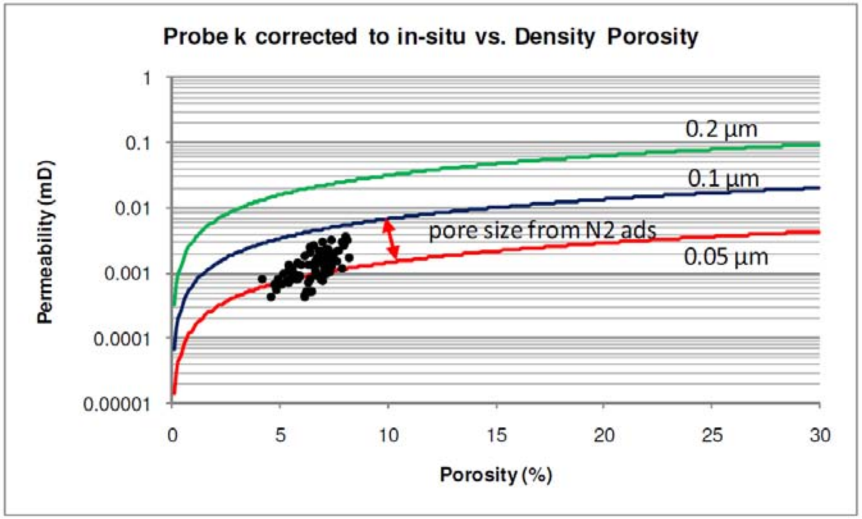
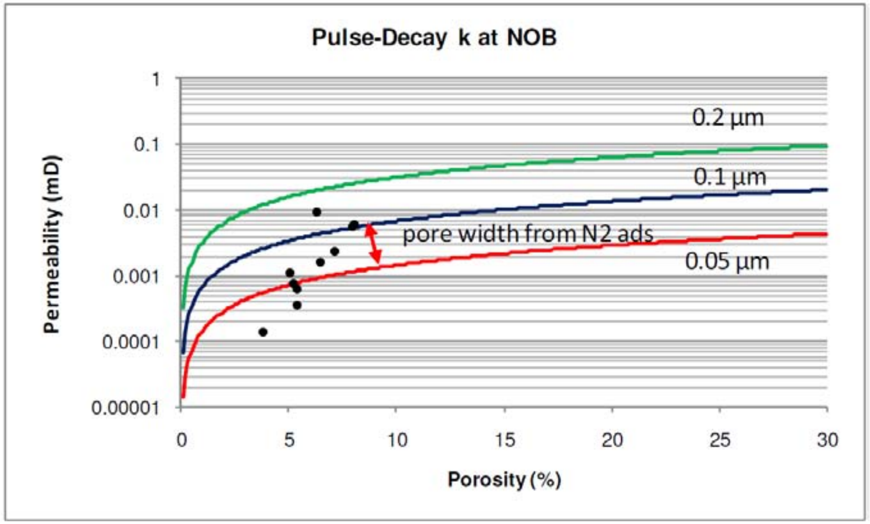
Core Plug Pulse-Decay k and Porosity





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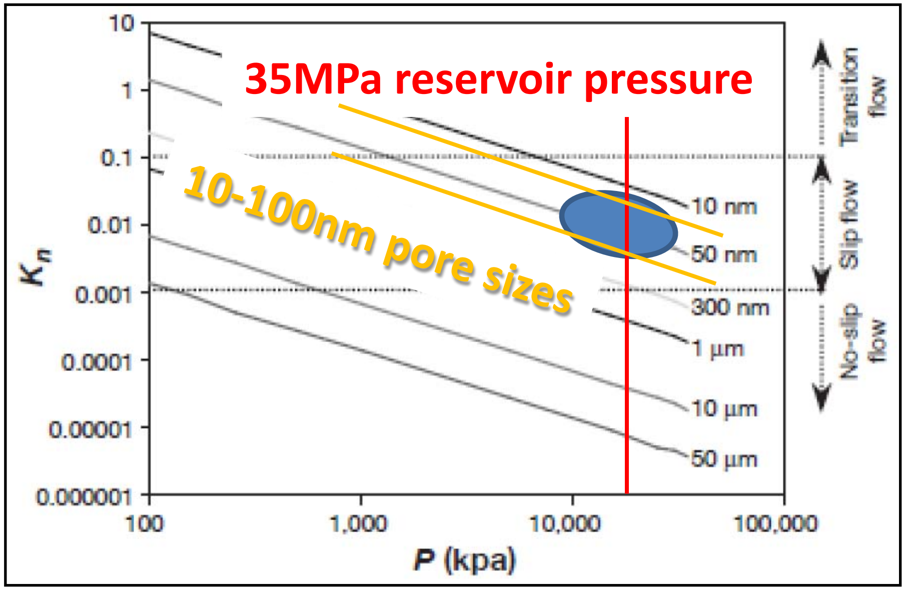

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Conclusions

- Routine core analysis performed on full diameter core is not useful for characterizing the subject tight gas siltstone reservoir due to:
  - the highly heterogeneous character of the reservoir
  - measurements are not performed under reservoir conditions
- Profile permeability data are very useful for quantifying fine scale heterogeneity (laminations)
  - Although more data still need to characterize it
- Profile permeability measurements require correction to in-situ stress conditions for use in flow unit identification.
  - Pulse-decay measurements on core plugs under reservoir conditions, appear to be useful for correcting the profile measurements
- N2 adsorption measurements can be applied to fine-grained tight gas reservoirs to identify dominant pore sizes
  - consistent with rp35 calculations and mercury intrusion measurements
- The dataset studied appears to correspond to a single flow unit, with a fairly narrow range of permeability for each porosity

Thanks

- **Acknowledgement**

  - Chris Clarkson would like to acknowledge Encana for support of his Chair position in Unconventional Gas at the University of Calgary.
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  - Jerry Jensen holds the Schulich Chair in Geostatistics at the University of Calgary.
  - Thanks to Dr. Azfar Hassan and Dr. Pedro Pereira for performing N2 adsorption experiments and Lou Monahan and Raymond Chan of CoreLab for assisting with permeability measurements.

- **References**

  - Clarkson, C.R., Jensen, J.L., Pedersen, P.K., Derder, O. and Freeman, M. (2011?) Innovative methods for flow unit and pore structure analyis mixed siltstone and shale gas reservoir.

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