Mercury Injection Capillary Pressure (MICP) A Useful Tool for Improved Understanding of Porosity and Matrix Permeability Distributions in Shale Reservoirs*

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Abstract

Those involved in the exploitation of shale gas reservoirs are acutely aware of the need for accurate porosity estimates. Most error associated with calculation of the free gas component of OGIP (original gas in place) is attributable to its over- or under-estimate. Throughout the shale gas industry, companies generally rely on porosity values derived from tight rock analysis of conventional and sidewall cores. Those values are then used to calibrate porosity logs through shale reservoirs. The purpose of this paper is to demonstrate the utility of another laboratory method - Mercury Injection Capillary Pressure analysis (MICP). This tool provides data that are equally suitable for the calibration of porosity logs and has the added advantage that the analysis can be done on fresh or archived cuttings samples as well as core. This allows for gathering of porosity data where none was previously available. MICP analysis is performed by placing a tarred sample in the instrument chamber which is then evacuated and flooded with mercury. Pressure on the mercury is incrementally increased forcing mercury through progressively smaller pore throats. By the end of the experiment (at 60,000 psia) pores accessible through throats as small as 36Å in diameter are intruded. The volume of mercury forced into the sample is equivalent to the volume of porosity accessed. Comparison of porosities derived by this method are in very good agreement with TRA porosities. A recent study on over 2400 samples representing twenty-five shales from thirteen basins shows that shale porosity averages 3.90% and ranges from less than 1.00% to in excess of 10%. Lower Tertiary and Upper Cretaceous shales from the Gulf Coast and several Cretaceous shales from western basins in the US and Canada consistently exhibit higher porosities then Paleozoic shales.

Mercury Injection Capillary Pressure (MICP)-

A useful tool for improved understanding of porosity and matrix permeability distributions in shale reservoirs

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Turning Resources Into Reserves ™

Talk Outline

- Overview of gas shale evaluation.
- The role of porosity.
- Laboratory methods for porosity.
- Results- 614 MICP analyses in 19 potential shale gas reservoirs.
- Compare laboratory measured porosity with logs.
- Calculated Swanson permeability from MICP.
- Conclusions.

Critical Factors for Shale Gas Evaluation

- Original Gas In Place (OGIP)
- Reservoir Rock Suitable for Hydraulic Fracture Stimulation
- Fracture Barriers

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Original Gas In Place (OGIP)

- Two components:
  - Free gas resides in the pore space and is controlled by T_r, P_r, Φ, S_o, S_w and maturity.
  - Adsorbed gas is held on the surfaces of the kerogen and is controlled by T_r, P_r, TOC and maturity.
  - Total OGIP is sum of these two components.

Free Gas

Free Gas = Φ_t (1-S_w) (Bg) k **Eq. 1**

where:	Free Gas	=	bcf / section foot
	Φ_t	=	Total porosity (fraction)
	S_w	=	Water saturation (fraction)
	Bg*	=	Gas formation volume factor (scf/cf)
	k	=	Converts scf/cf to bcf/section foot (0.27878)

(Assumes sample is in the dry gas window)

Source for most error is the estimate of porosity.

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Lab Methods for Porosity Determination

- Density Method
  - Measures grain and bulk density values then derives porosity (Eq. 2).
  - Requires core plug for bulk density
  - Crushed core or cuttings for grain density.
- Injection Method
  - Directly measures pore volume by forcing Hg into pore space.
  - Requires cuttings or crushed core.

$$\Phi = 1 - \left(\frac{\rho_{Bulk}}{\rho_{Grain}} \right) \qquad \text{Eq. 2}$$

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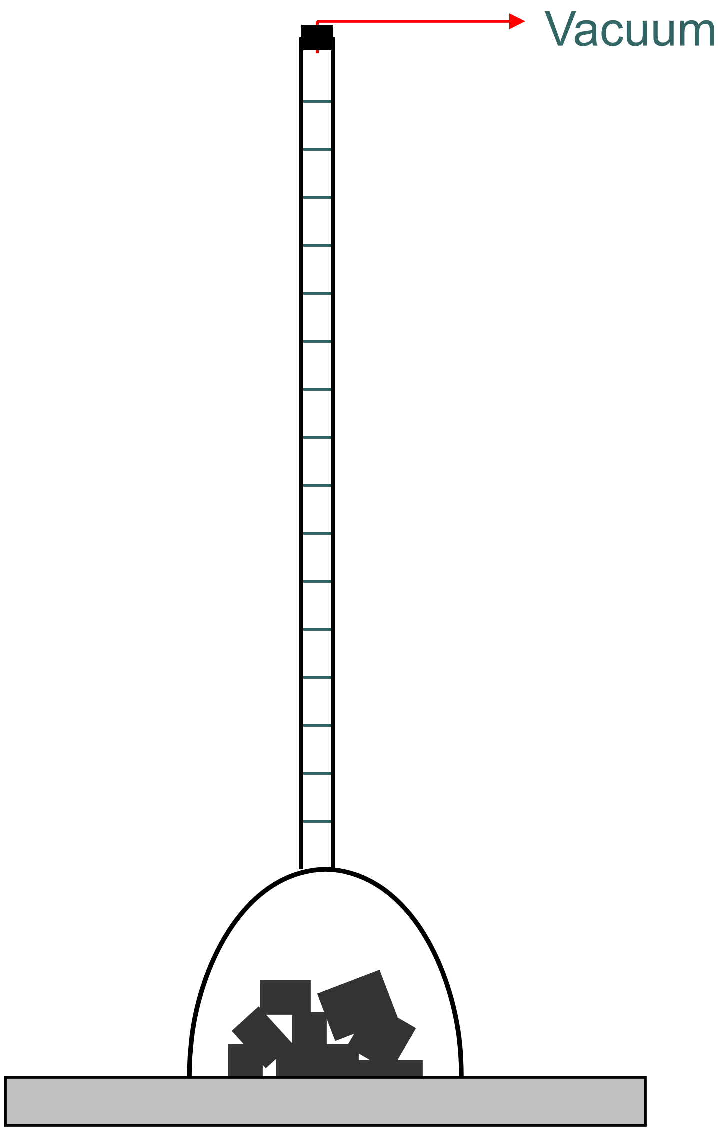
MICP Analysis



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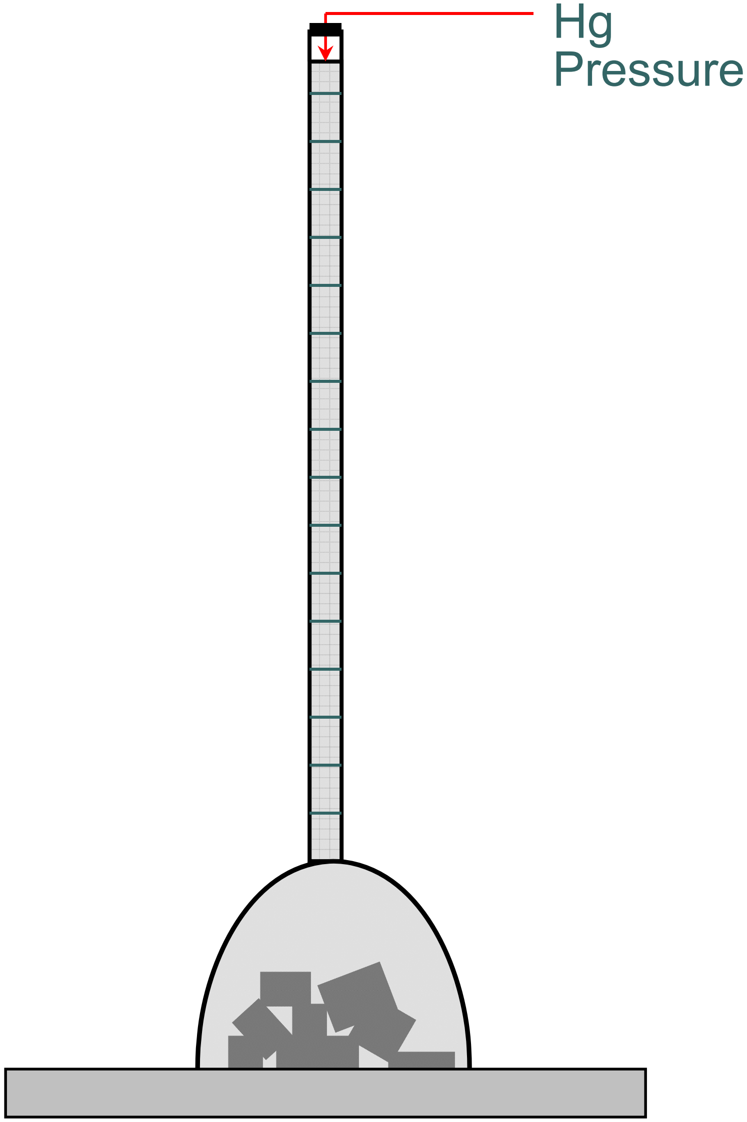
MICP Analysis



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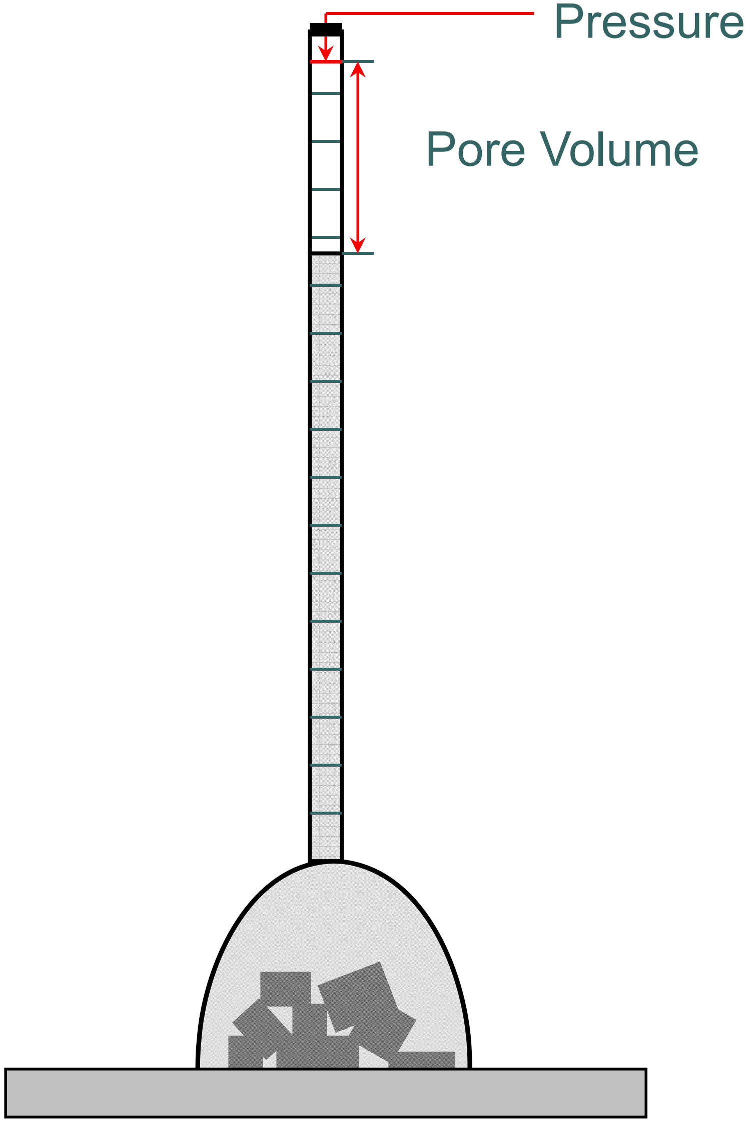
MICP Analysis



Mercury Porosimetry (MICP)

- Measures pore volume by forcing mercury into the pore space.
- Pressure controls the size of the intruded pore throat.
- At 60,000 psia mercury is forced through pore throat diameters as small as 36 Å.
- Methane molecular diameter is 2.16 Å.

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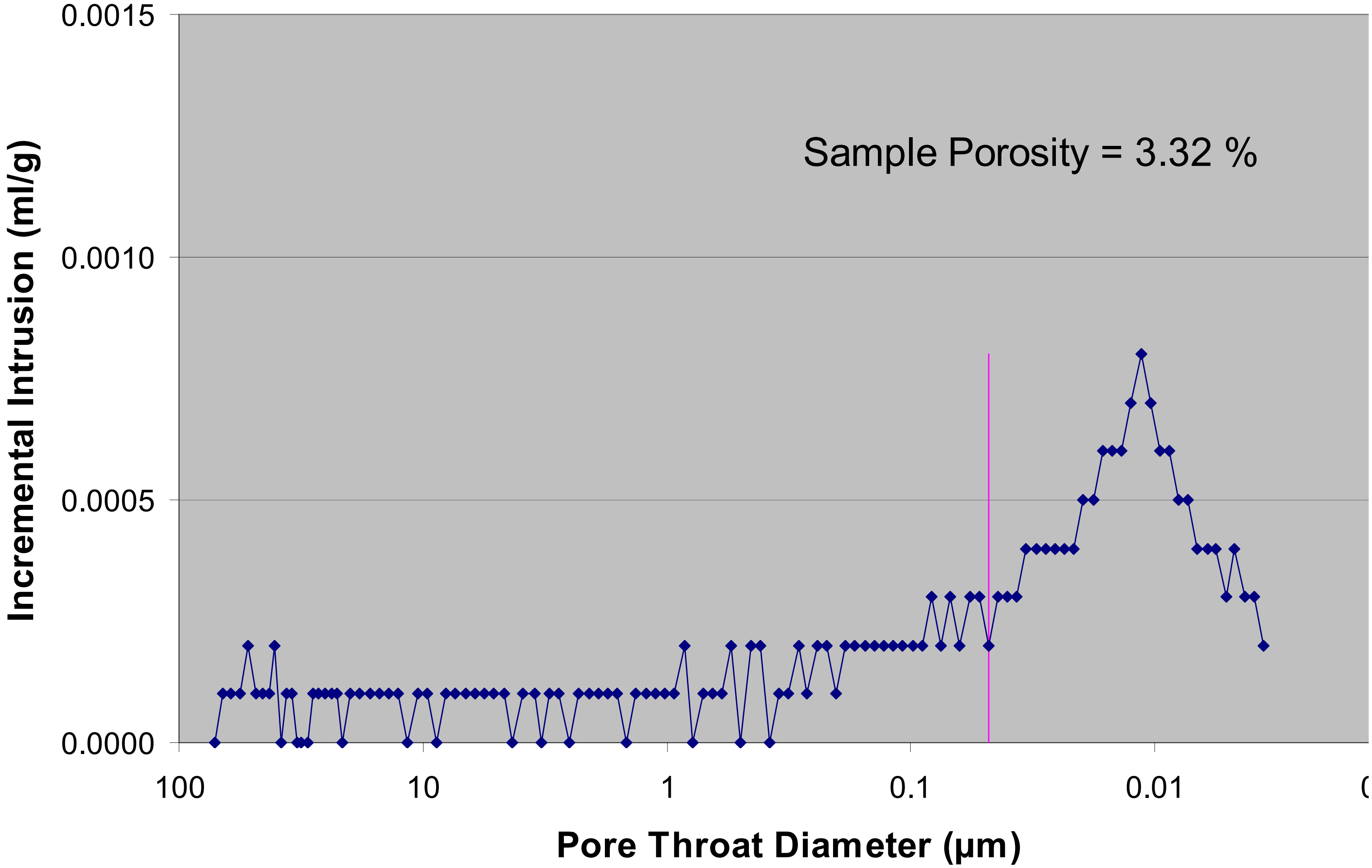
MICP Injection Curve



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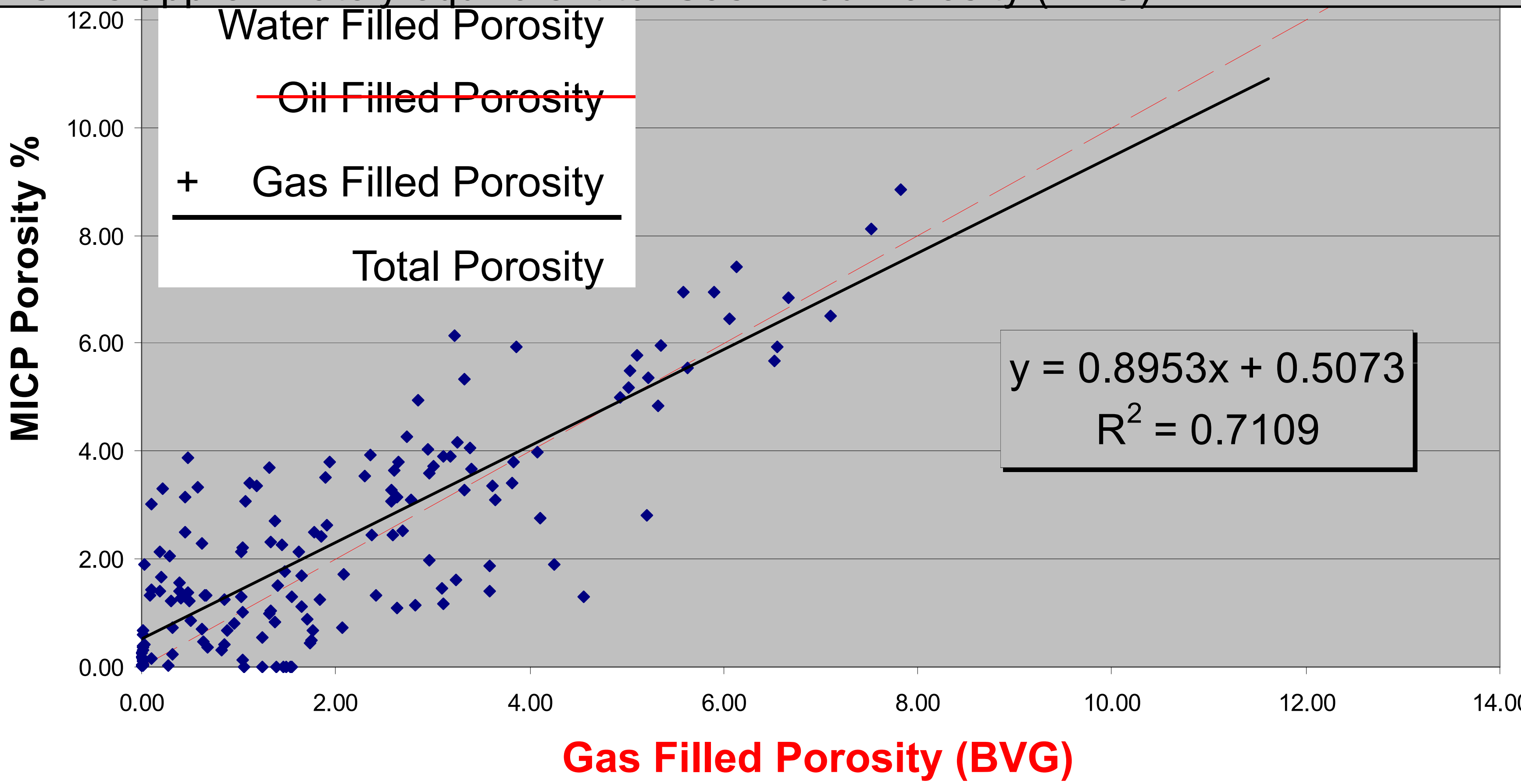
Density Versus MICP Porosity

‘As Received Porosity’ in high maturity shales measures ‘Gas Filled Porosity’ (BVG).

Reasonable agreement between ‘Gas Filled Porosity’ and ‘MICP Porosity’ suggesting MICP is approximately equivalent to ‘Gas Filled Porosity (BVG)’.



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Point Forward Assumption

MICP porosity measured on a sample from a thermally mature shale (dry gas window) is equivalent to gas filled porosity (BVG).

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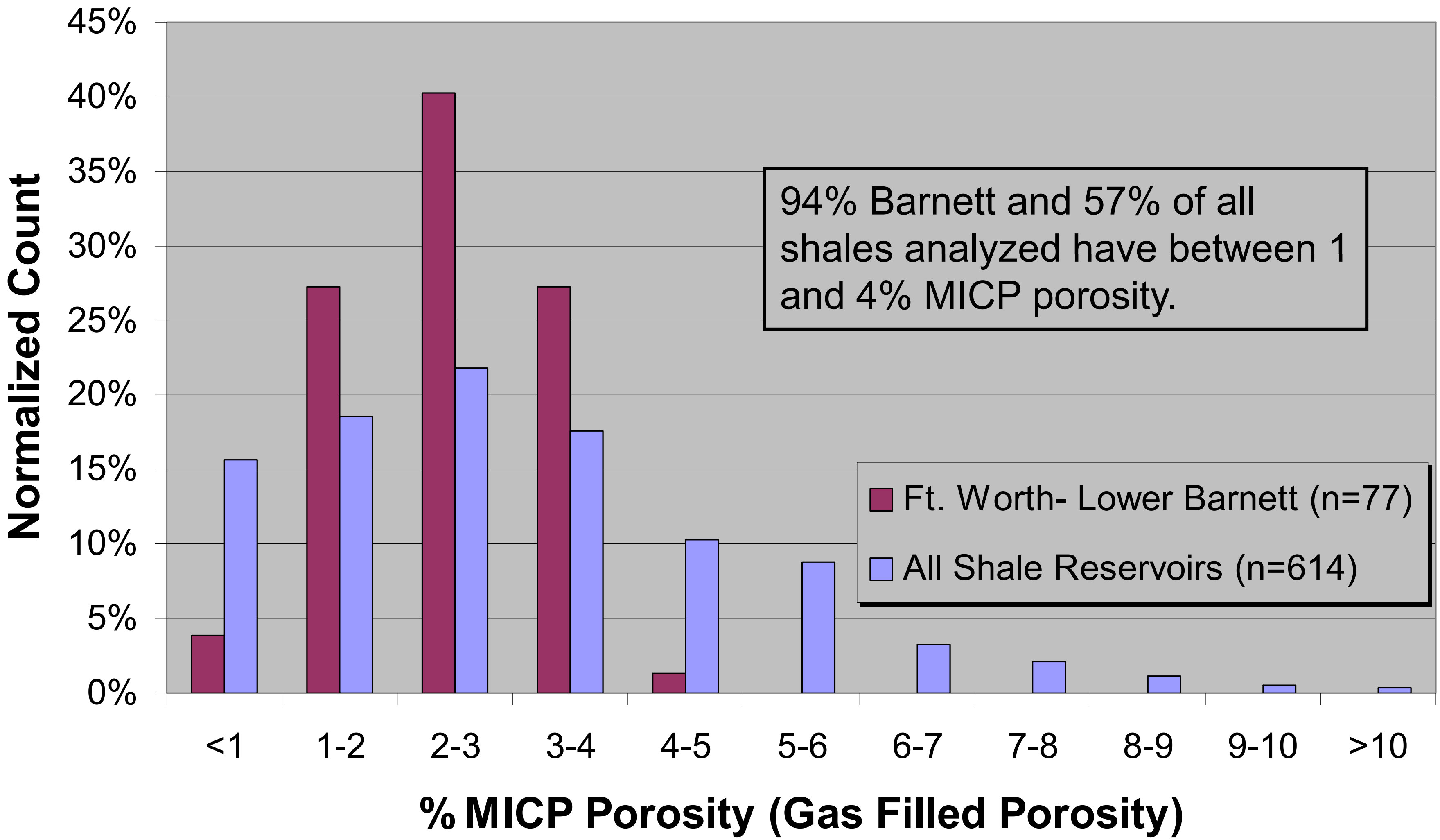
Shale Porosity Distribution



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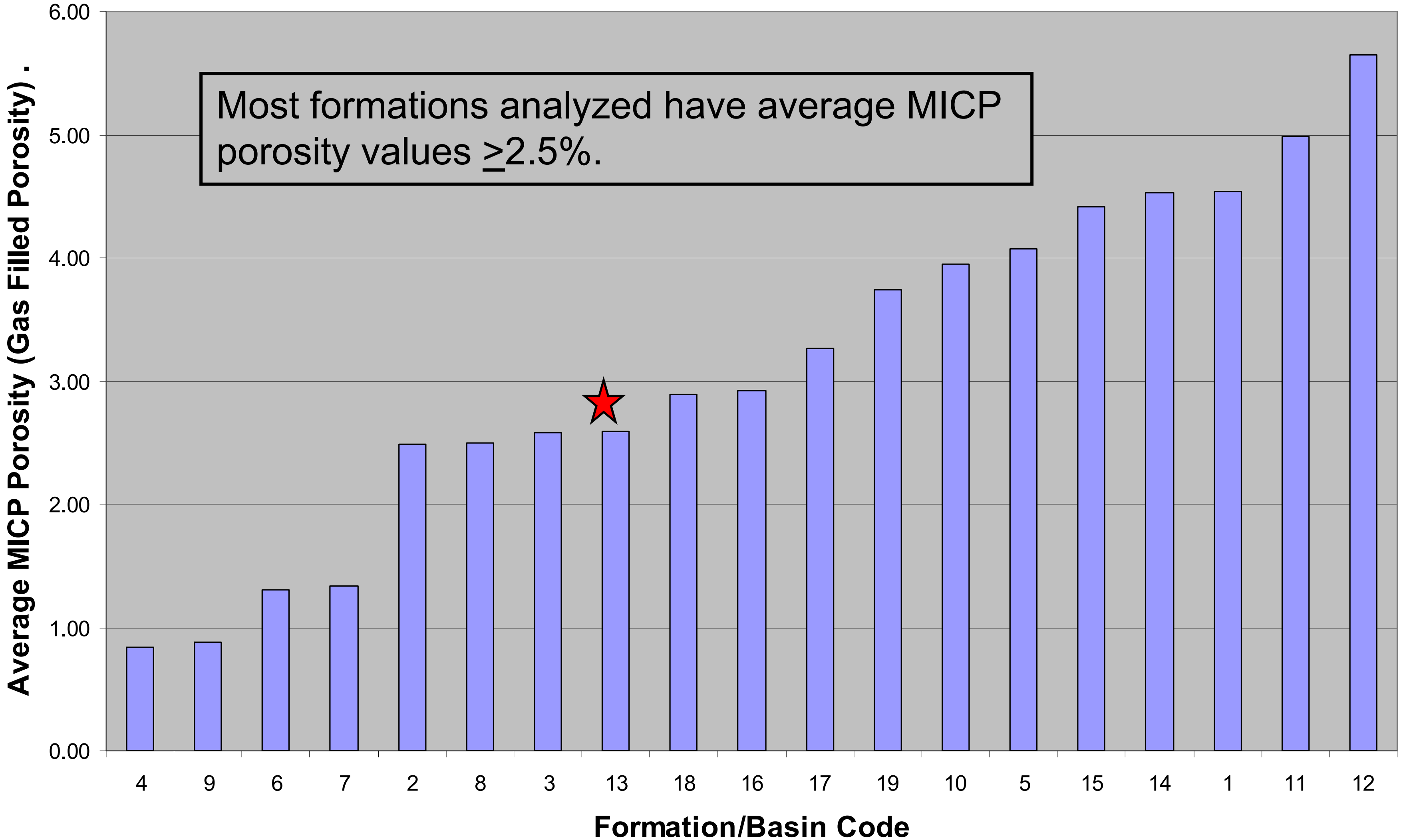
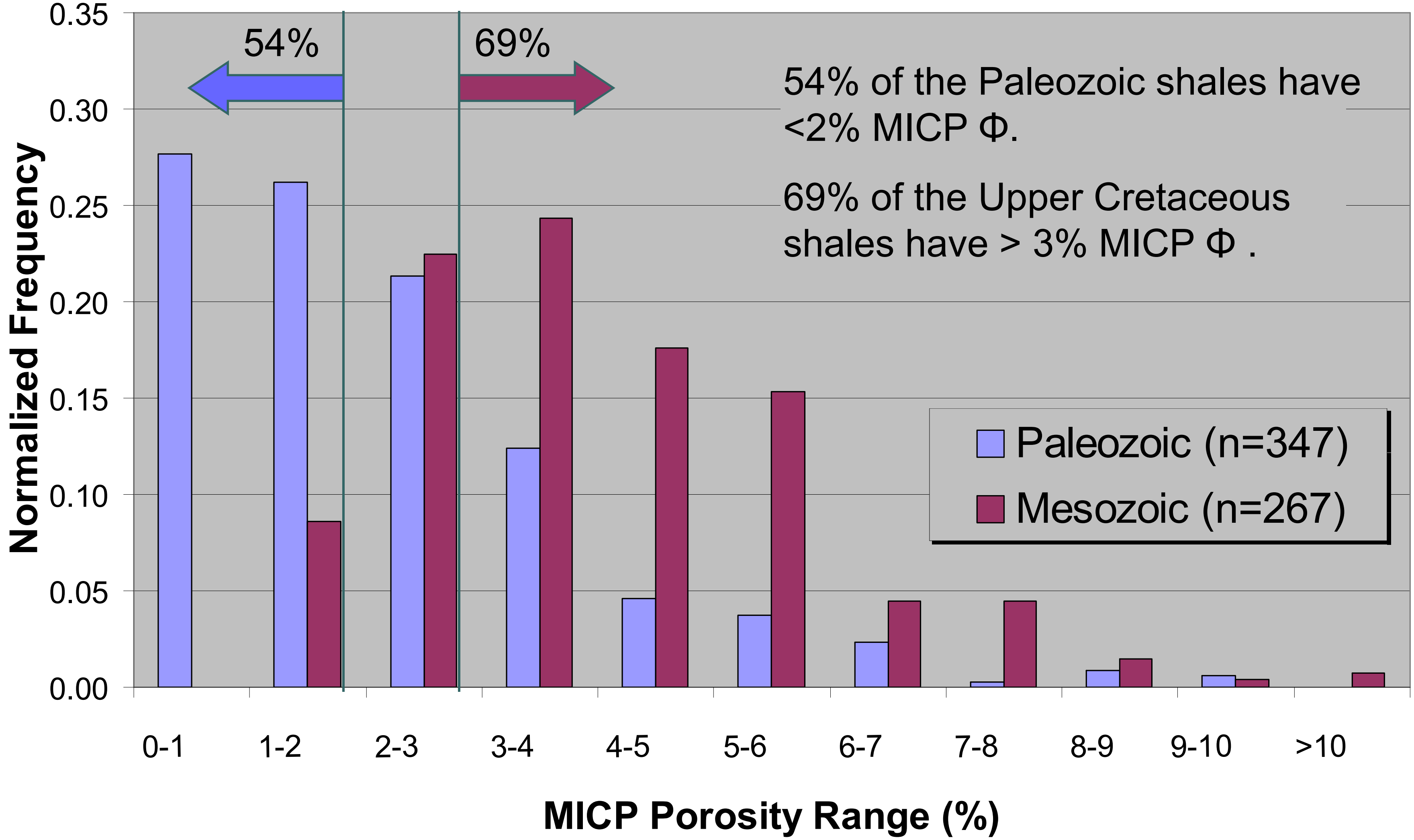
Average MICP Porosity



Average MICP Porosity

- Average MICP Φ for 19 shales 0.84% and 5.65%.
- Range demonstrates significant variation in gas storage capacity.
- The Lower Barnett shale averages 2.59% MICP Φ.
- Demonstrates that shales with 2.0 to 3.0% MICP Φ can be successful shale gas reservoirs.

Shale Porosity Distribution By Age



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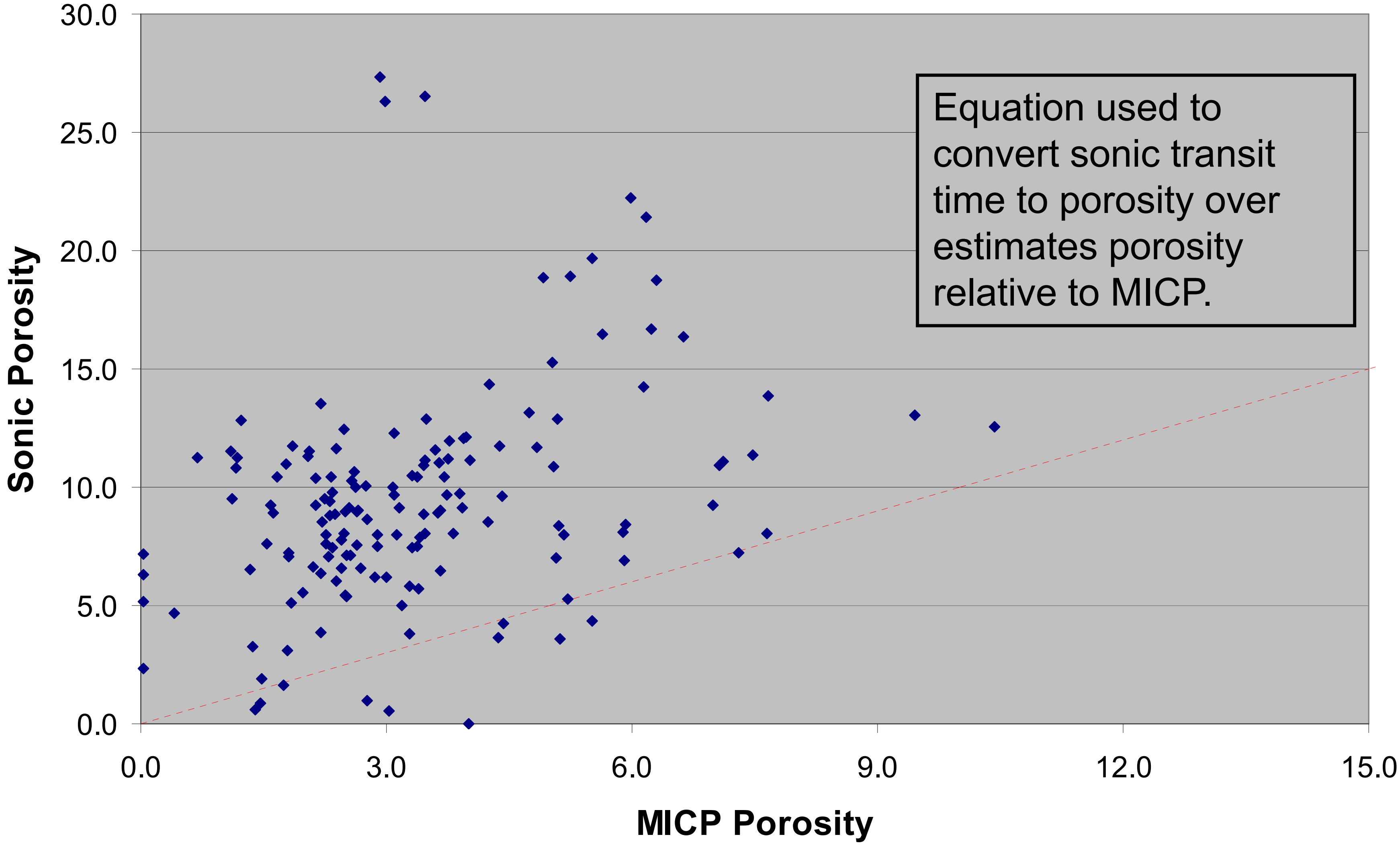
Common Wireline Porosity Tools

- Sonic
- Neutron
- Density

Sonic Porosity Contrasted With MICP



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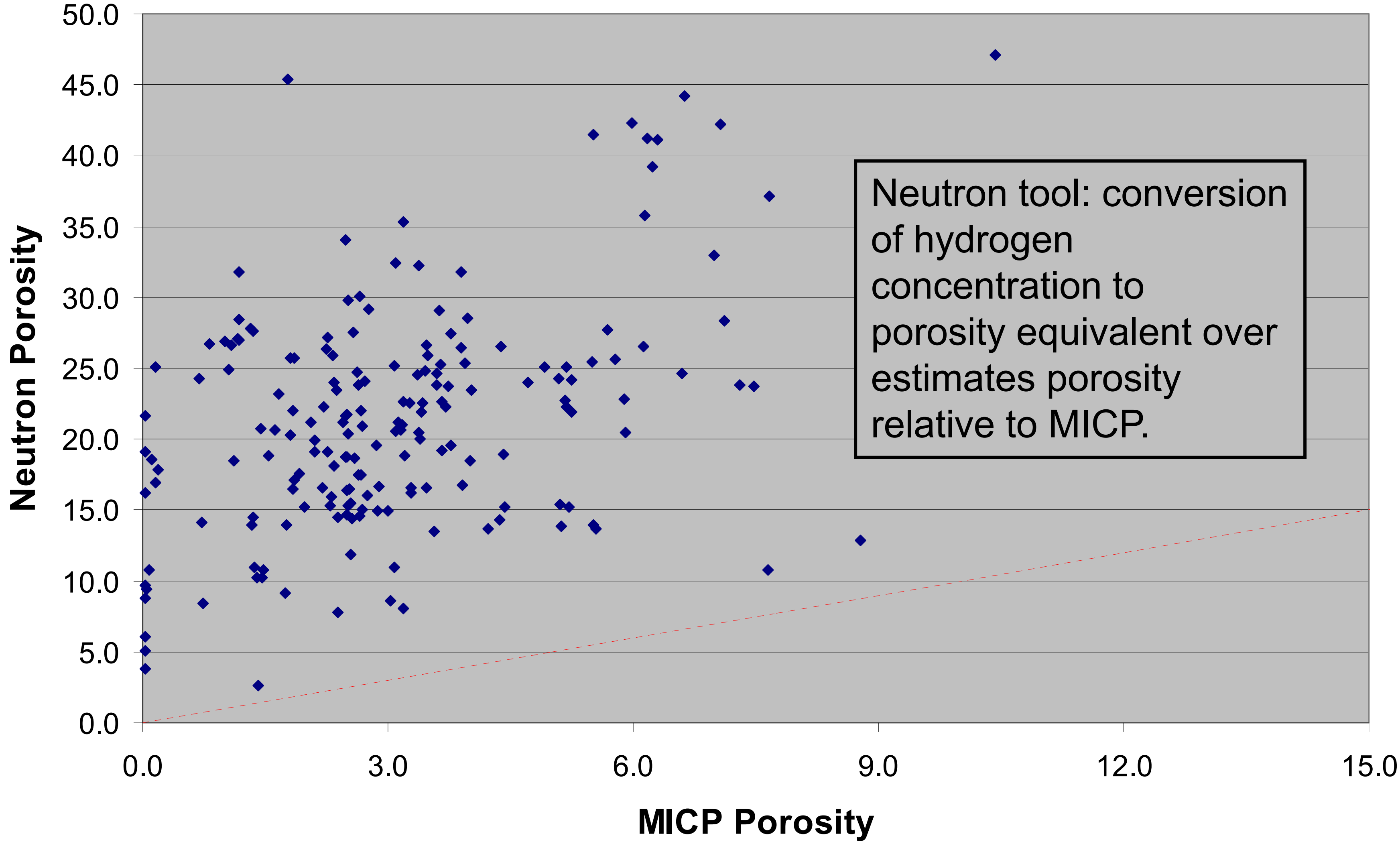
Neutron Porosity Contrasted With MICP



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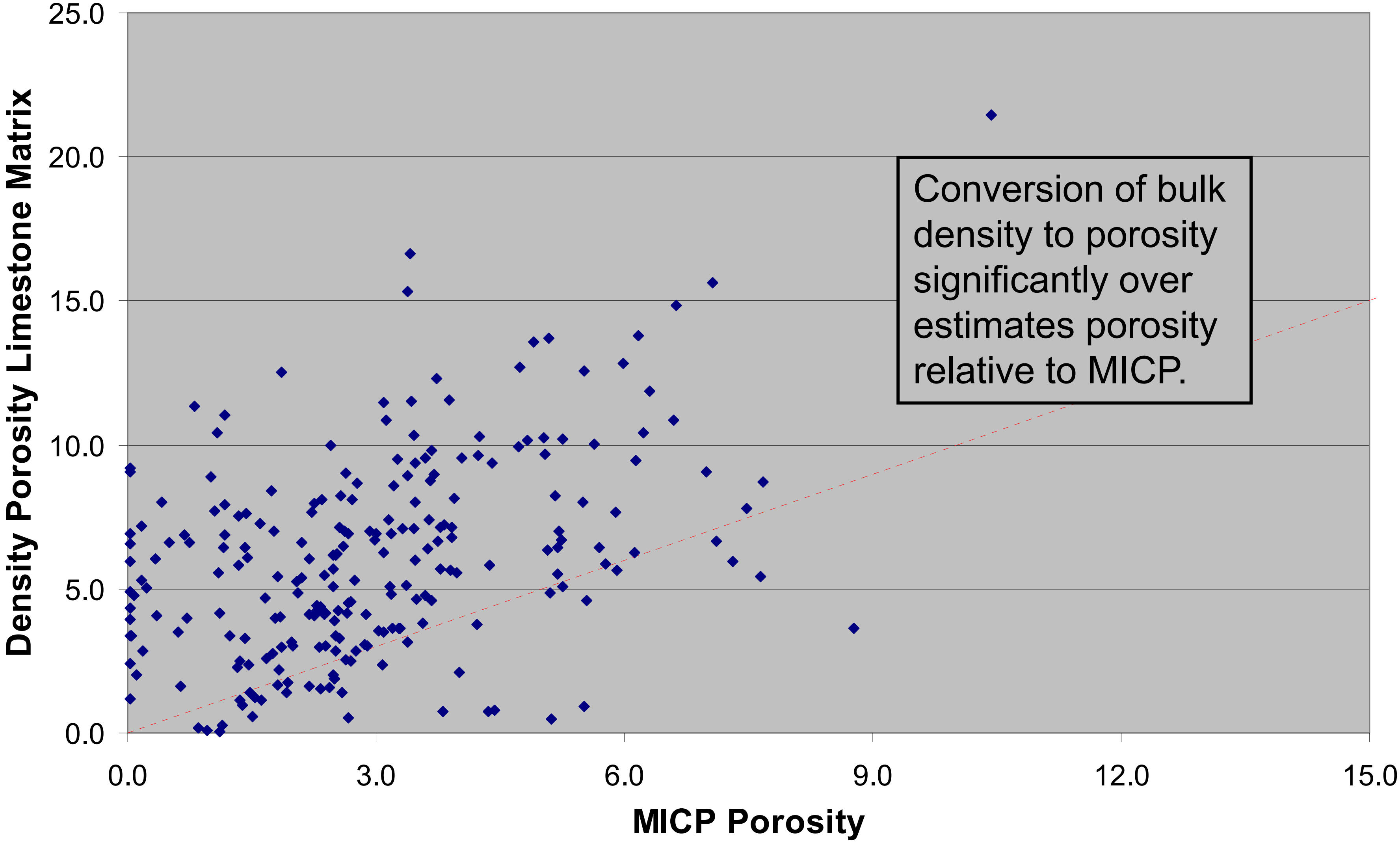
Density Porosity Contrasted With MICP



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Common Wireline Porosity Tools

- Sonic
- Neutron
- Density

Logs fail to accurately derive porosity because the general log equations do not account for the kerogen and heavy mineral content of organic rich shales.

Our challenge is to develop log equations that take these complex mixtures of silt and clay size materials and arrives at a more reasonable estimate of porosity.

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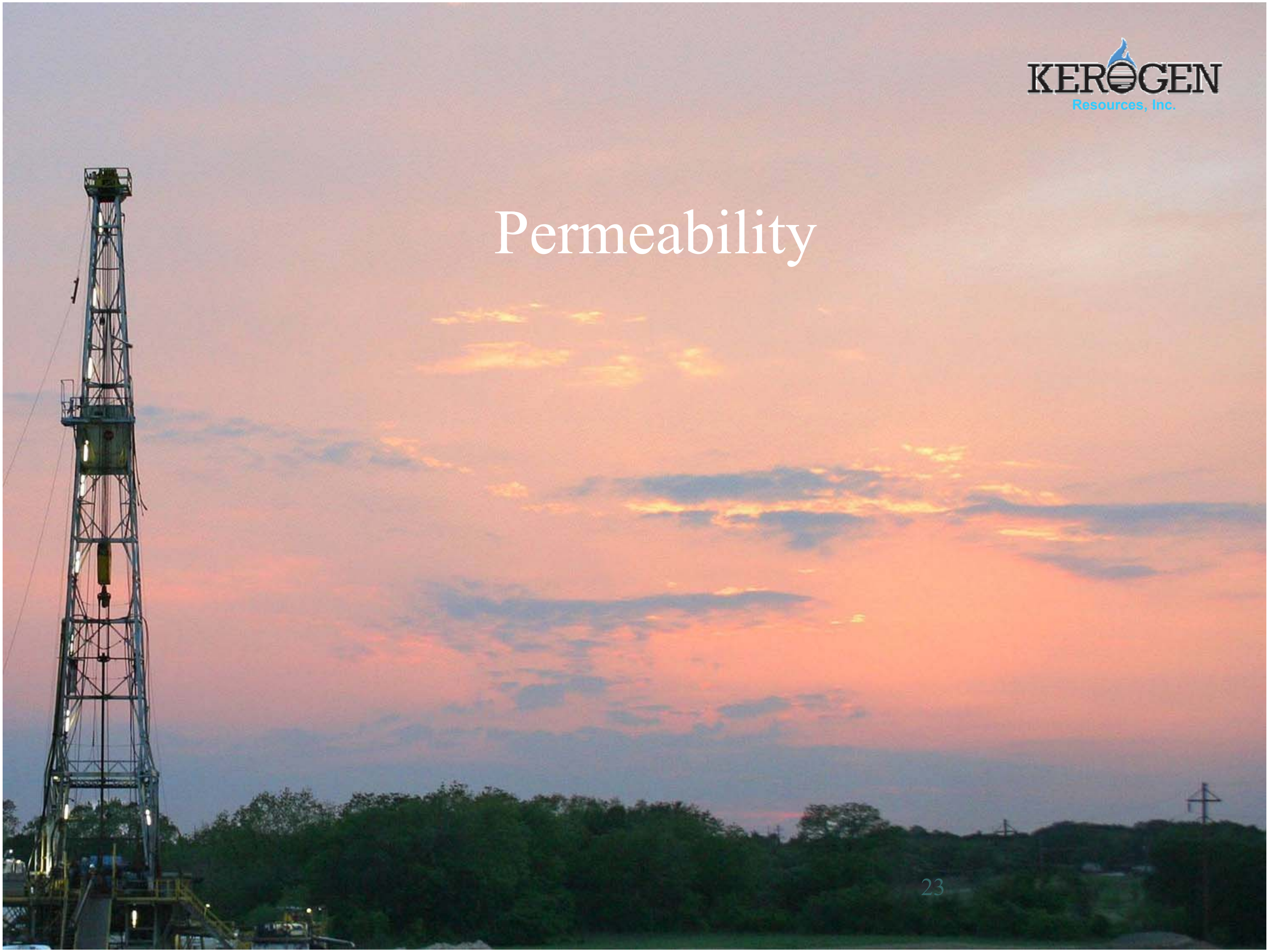
Permeability



Permeability

- Numerous models are in the literature that relate permeability to MICP measurements.

- Excellent review: Comisky, et al., 2007, SPE 110050.

- We chose Swanson (1981) model to derive permeability estimates.

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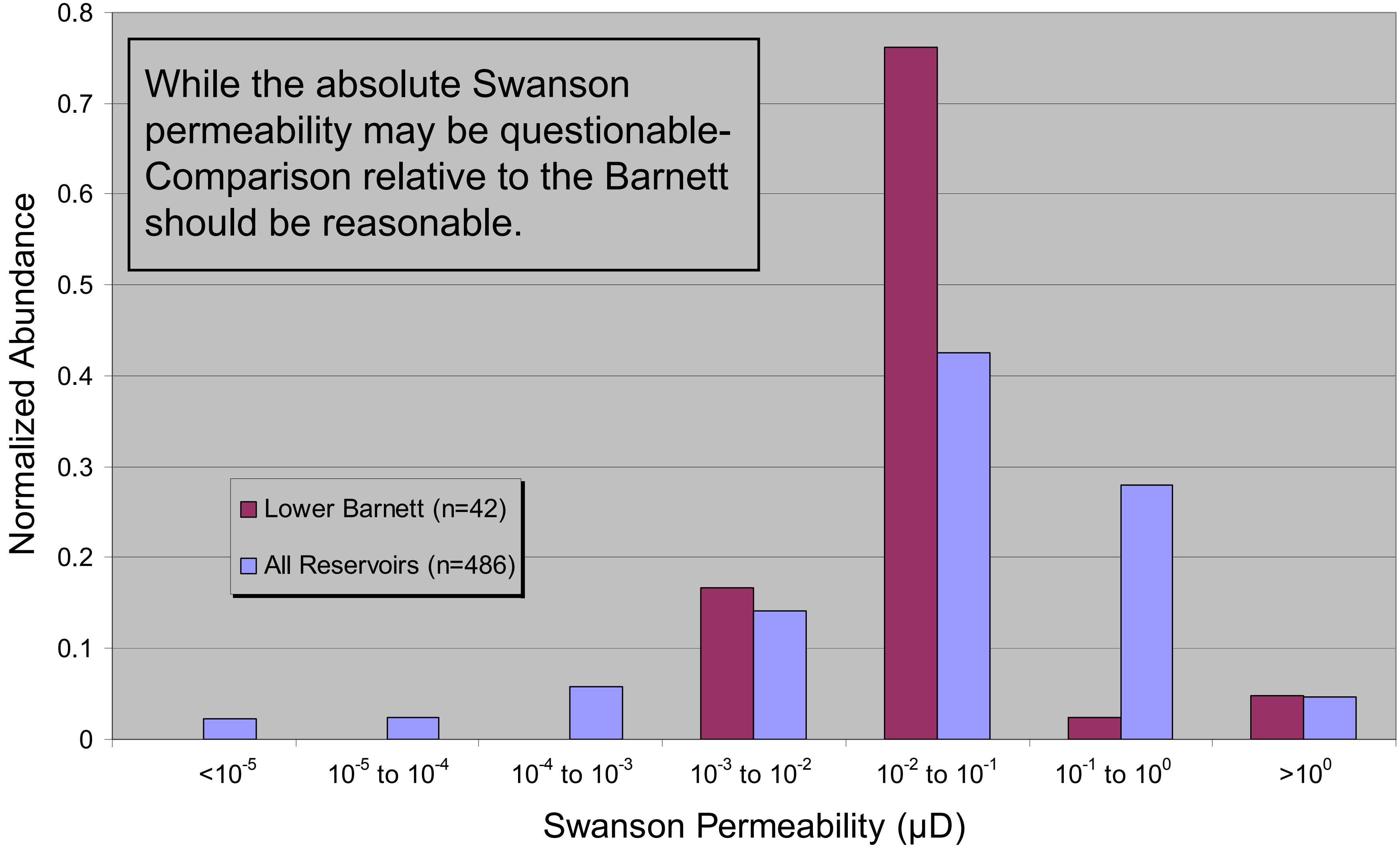
Swanson Permeability- All Reservoirs Relative to Barnett



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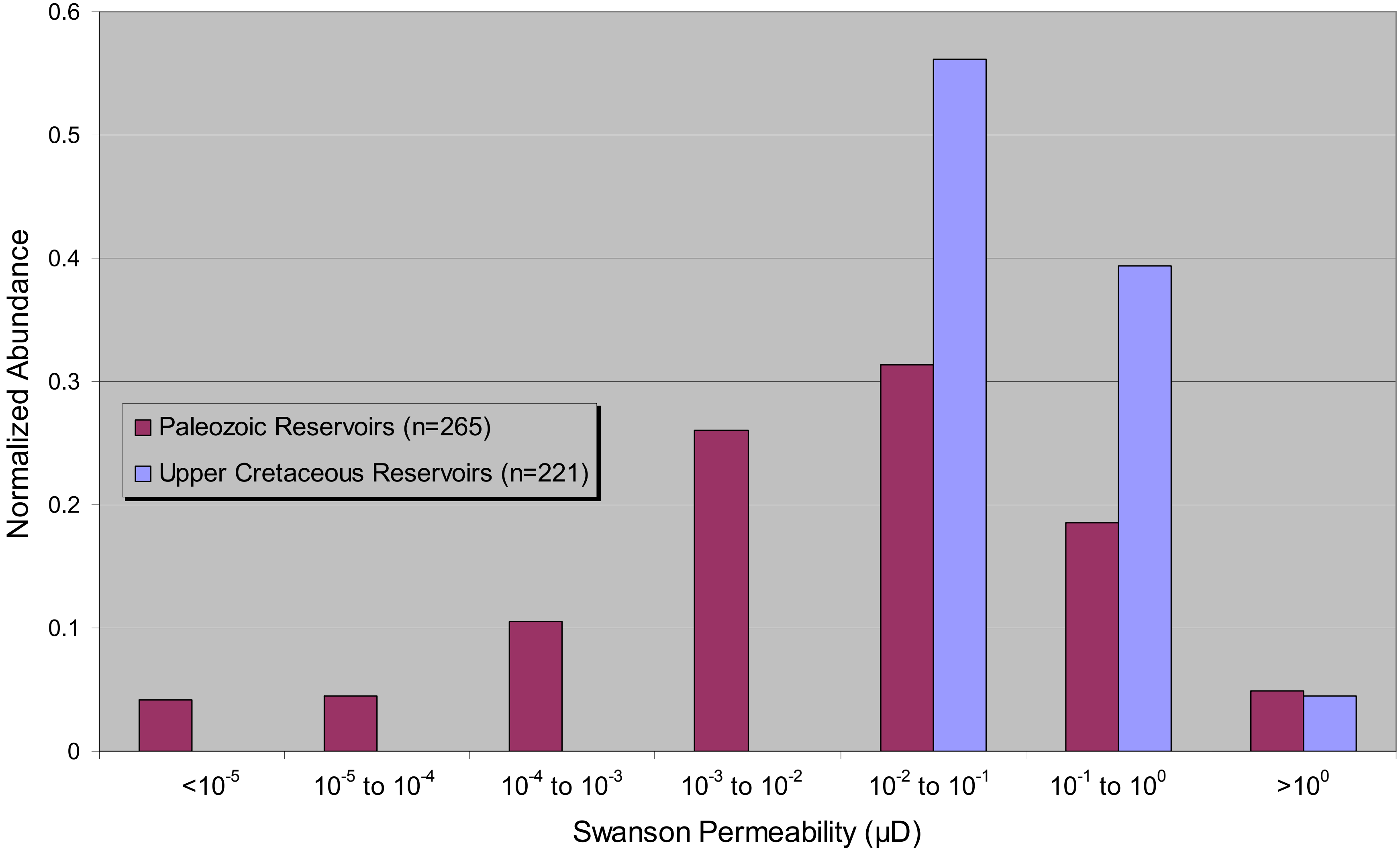
Swanson Permeability (By Reservoir Age)



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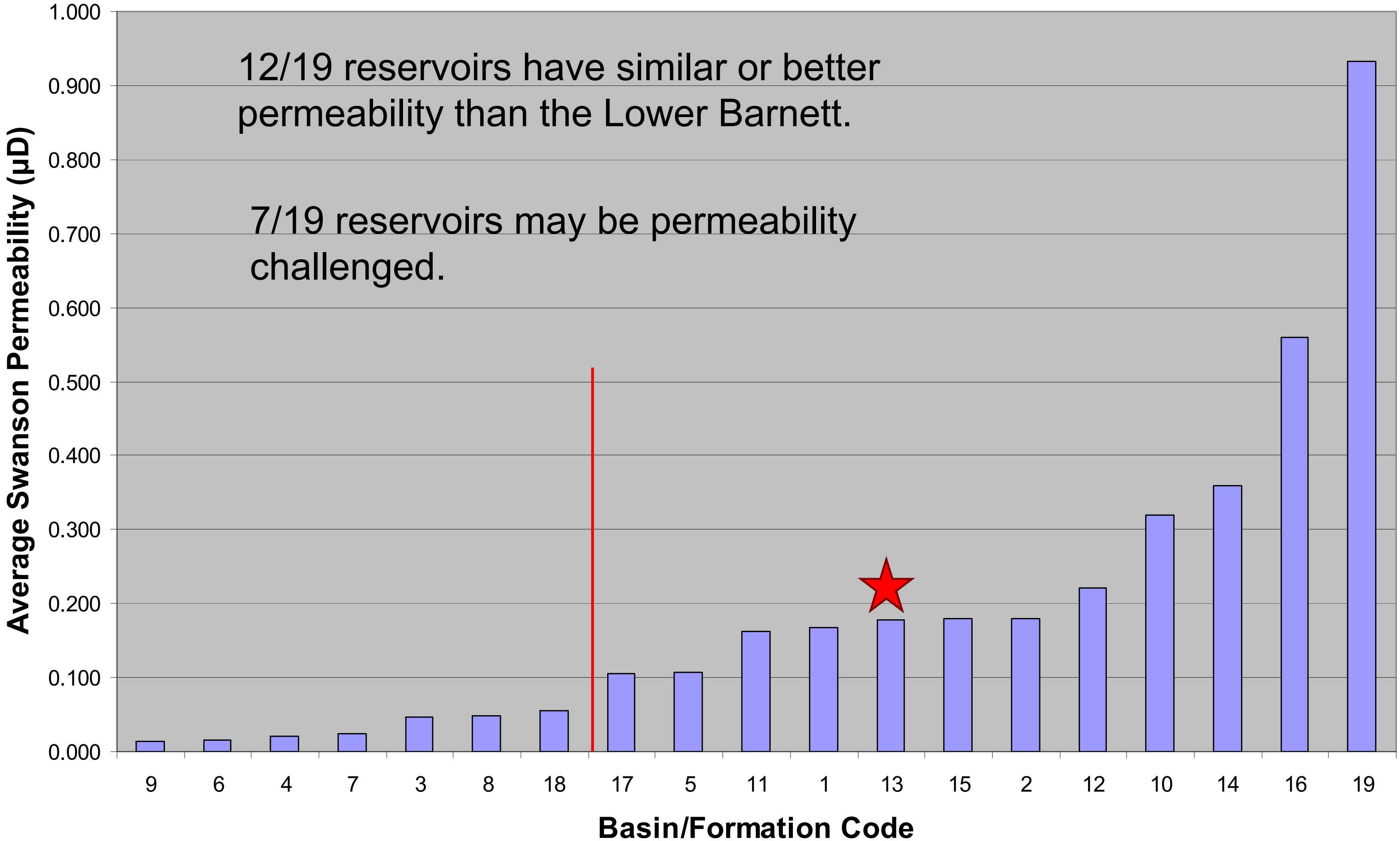
Average Permeability



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Conclusions

- MICP provides estimate of gas filled porosity.
- The average MICP Φ for 19 shales are between 0.84% and 5.65%.
- That wide range demonstrates significant variation in gas storage capacity.
- The Barnett shale averages 2.59% MICP Φ which shows that shales with 2.0 to 3.0% MICP Φ can be successful shale gas reservoirs.

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Conclusions (Cont.)

- MICP advantage- can be done on cuttings.
- Logs respond to kerogen and heavy minerals which must be accounted for in equations used to convert log measures to porosity.
- Swanson permeability estimates can be normalized to Barnett for comparison between prospective plays.

References

Comisky, J.T., K.E. Newsham, J.A. Rushing, and T.A. Blasingame, 2007, A comparative study of capillary-pressure-based empirical models for estimating absolute permeability in tight gas sands, *in* Innovate a Golden Opportunity for People and Technology: SPE Annual Technical Conference and Exhibition, 11-14 November, Anaheim, California: CD-ROM, SPE 110050.

Swanson, B.F., 1981, Simple correlation between permeabilities and mercury capillary pressures: Journal of Petroleum Technology, v. 33/12, p. 2498-2504.