Permeability Estimation in Tight Gas Sands and Shales using NMR – A New Interpretive Methodology*

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Abstract

One of the challenges of working with tight sands and shales is the measurement of permeability. One of the most difficult tasks can be acquiring a sample that has not been damaged by the coring and sampling process. Shales are fragile samples. The simple act of drilling a core plug can induce fracturing. Most of the methods used to measure permeability depend upon fluid flow through the sample and any sample damage, be it fracturing due to unloading or sample preparation, will invalidate the measurement even at high confining pressures. T_2 spectral characteristics are routinely used to infer petrophysical characteristics in both clastic and carbonate reservoir rocks. It would be advantageous to be able to apply those techniques to low-permeability samples. NMR spectral methodologies have distinct advantages in that they can be applied to damaged samples and they can be applied to well logs eliminating the need for a core sample. The major problem is that the methodologies available were deduced from sandstones and carbonates with permeabilities in the milliDarcy range, not those in the micro- and nano-Darcy range. The reason for this breakdown may be associated with the method of interpretation of the spectrum.

We present an alternative interpretation, relating the permeability to the modal T_2 time, not the geometric mean. The modal T_2 time represents the most common pore size. The utility of these methods arises from the relatively fixed aspect ratio between pore size and throat size in sandstones. Averaging approximately 2:1, the stability of this relationship means that pore size can proxy for throat size in any estimation equation. It is an interpretation which honors the petrologic characteristics of the pore network and, as a methodology, it relatively fast, inexpensive and it is one that can be applied to well logs.

As a demonstration of the efficacy of this technique, the results from an analysis of two data sets are presented. The first is a set of seven shale samples and the second is a set of 30 shale and sand samples from a tight gas unit. Subsamples were taken of each plug for MICP analysis from which permeability was derived using Swanson's air permeability method. Permeabilities were derived from the MICP data and compared with the log of the modal T_2 time. The resulting correlation was 0.93. The results were surprising, not only because of their strength, but because the technique worked well in both sands and shales.

Introduction

While the measurement of permeability in essentially impermeable rocks may seem to be an oxymoron, it is an integral step in formation evaluation in both tight gas and shale gas plays. The primary problem with direct assessment of low permeabilities is associated with the physical competence of the sample plug. It makes no difference if the measurements are derived from steady state or pulse decay methods. The magnitude of the resulting permeabilities ensure that any leakage in the seal confining the sample, any fracturing, even a desaturated shale parting in a sand, can and will cause leakage producing measurements that overestimate the true permeability. The only means to bypass this limitation is to employ laboratory methods that do not depend upon the rate of fluid movement through the sample.

NMR estimates of permeability are derived from the pore size distribution, and unlike those derived from Hg Capillary Pressure measurements and Micro-CT techniques, the technology can be applied to well logs. However, the commonly applied techniques for estimation of permeability from T_2 spectra are poorly adapted to low-permeability lithologies like tight gas sands and shales.

A brine-saturated reservoir-quality sandstone will typically produce a T_2 spectrum like the one shown in Figure 1. At long relaxation times there is usually a prominent mode associated with large, well-connected pores, the efficient fluid flow pathways of the pore network. At shorter relaxation times the peak falls off, encompassing progressively smaller pore features. If shale laminae are present or the sand is well cemented, there will be a minor peak at short relaxation times that is associated with microporosity, small pores found within the shale or intercrystalline porosity within the cement. Standard interpretation techniques dictate that one calculate the geometric mean as an indicator of average pore size. The area under the curve is associated with total porosity and this is subdivided into two components: BVM and BVI, denoting that portion of the pore network containing mobile and immobile fluids, respectively. Originally the cut off between the two was established at 33msec regardless of the petrology of the sample. This practice has been changed and the movable/immovable cut-off is now determined for each sample using plug-derived irreducible water saturation tests to determine BVI and setting the cut-off appropriately (Chen et al., 1998).

Permeability is commonly estimated using some variant of the Coates equation:

Equation 1
$$k_{Coates} = \left(\frac{\phi_{NMR}}{C} \right)^{m} \left(\frac{BVM}{BVI} \right)^{n}$$

The default equation sets the C, m and n coefficients to 10, 2, and 4 respectively, but different modifications have been published wherein one, two, or all of the coefficients are variable and are tailored for specific wells or formations using regression techniques (e.g. Shafer et al., 2005).

The T_2 spectra from low-permeability rocks are quantitatively and qualitatively different. As shown in Figure 2, the mode associated with efficient fluid flow pathways is absent, leaving a single prominent mode that may be accompanied by subsidiary modes at longer relaxation times. The subsidiary modes are commonly associated with fractures, molds, or in the case of tight gas sands, zones of the original high-efficiency pore network that remain after patchy cementation. Note that the prominent mode in the shale spectrum is incomplete. There is a significant amount of porosity that is below the level of detection.

The commonly applied techniques for estimating the permeability from NMR T_2 spectra are difficult to apply to samples such as these. As pore size decreases the ability to resolve it using NMR decreases and the error associated with that measurement increases. The variables used in the Coates equation ϕ_{NMR}, BVI and BVM are all derived from the entire distribution. When dealing with samples that have a well-preserved pore network and permeabilities in the milliDarcy range, the indistinct nature of the spectrum at low T_2 times does not have a significant effect. However, when the complete spectrum is found at low relaxation times, the distribution becomes increasingly under-determined and the error associated with ϕ_{NMR}, BVI and BVM increases, making them increasingly unstable.

The mode is non-parametric and does not rely on the assumption that the distribution is completely determined. As a measure of the most common pore size, it provides a much more robust indicator of permeability.

Sample Set

In an effort to test the viability of this technique, we assembled a test data set consisting of thirty tight gas sand plugs from an undisclosed formation and nine gas shale plugs from the Haynesville formation found in the south-central section of the United States. Determination of permeability from the plugs was problematic in that many of the plugs either fractured when received or developed imperfections during desaturation, prior to steady-state permeability tests. For this reason end trims were taken from each of the plugs for Hg capillary pressure testing. Permeabilities were then calculated using the method developed by Swanson (1981).

The remainder of each plug was then saturated with brine. The NMR measurements were made using a MARAN Ultra Magnetic Resonance Core Analyzer at a Larmor frequency of approximately 2 MHz. The brine-saturated samples were allowed to equilibrate at system temperature prior to loading into the MARAN Ultra. Relaxation times (T_2) were determined at 10,000 points using a CPMG pulse sequence and an inter-echo spacing of 0.30, 0.60 and 1.2 milliseconds. Of these the 0.30 spectra have the greatest resolution and were used for subsequent analysis. In each case CPMG pulse sequences were repeated a sufficient number of times to achieve a signal to noise ratio of 200 to 1. A delay time of 10 seconds was used between each pulse train to allow the sample to stabilize. All tests were conducted at net confining stress and room temperature.

The results, shown in Figure 3, were grouped by lithology and show a clear trend for each. The two outliers indicated represent mixed sand/shale plugs. In each case the end trim used for Hg capillary-pressure testing was predominantly sand, producing a higher apparent permeability than that indicated from the NMR spectrum. Sample repeatability is a function of sample size and is one of the limitations of capillary pressure tests.

The strong separation between the two trends suggests what may be a systematic variation associated with lithology. It may arise from systematic variations in surface relaxivity associated with mineralogy. It also may indicate a systematic decline in the aspect ratio between pore size and throat size associated with grain shape as the predominant clasts transform from ellipsoidal sand grains to discoidal shale particles. Regardless of the origin, the separation between the two lithologies demands that predictive relationships must be derived separately for each lithology. The log-linear nature of the relationship means that the parameters can be derived from simple regression using Equation 2 and solving for m and b.

Equation 2 $$log(K_{Hg}) = m \bullet log(\mathrm{Mode}) + b$$

Permeability estimates were calculated from the NMR data using both the Coates Equation and Equation 2 (Figure 4). The geometric mean, ϕ_{NMR}, BVI and BVM were determined for each plug and permeabilities were generated from the Coates equation using both default parameters and regression-defined parameters. The default parameters produced disappointing results with a tremendous amount of scatter and tended to overestimate the permeability in the sands (Figure 4A). The refined equation, with regression-derived parameters determined for each lithology, produced better results, but the relationship still breaks down below 1 microDarcy (Figure 4B). Within the microDarcy to milliDarcy range there was little error and it was symmetrically distributed. Below the microDarcy range the imprecision in ϕ_{NMR}, BVI and BVM result in a dramatic increase in scatter and a tendency toward overestimation. Equivalent estimates were generated for each lithology using the Modal T_2 time and Equation 2. The resulting estimates show very little scatter throughout the range of estimation and that scatter is symmetrical about the 1:1 line (Figure 4C).

Summary

Many of the difficulties associated with the reliable measurement of permeability from sub-milliDarcy samples arise from the fragility of the samples, but it may also be that we are at our limit when it comes to measuring permeabilities in impermeable rocks using direct fluid-flow methodologies. Other pore size-based methods such as Hg capillary pressure tests or micro-CT use very small samples that may not be representative of the plug and can be prohibitively expensive. NMR-based methods are relatively inexpensive and can be applied not only to plugs, but fragmentary samples and well logs. The problem with commonly accepted NMR-based methods is that they do not perform well in low-permeability samples.

Examination of a data set containing both tight gas sands and gas shales has shown some of the difficulty associated with using standard interpretation and estimation techniques. Using the Coates equation, permeability estimates were generated using both the default parameters and regression-derived parameters. The default results tended to overestimate permeability throughout the range of measurement. The regression-derived results clearly show that the relationship is unstable below one microDarcy and tends to overestimate permeability. It is our assertion that this breakdown arises from the increase in measurement error as pore size decreases. One way to minimize the error is to choose a non-parametric variable, the Modal T_2 time. The mode is robust and does not require the complete distribution to be quantified. When used to estimate permeability, the results exhibit very little scatter throughout the nanoDarcy to milliDarcy range and that scatter is symmetrically distributed.

Once again, the measurement of permeabilities in impermeable samples is oxymoronic, but it will remain an integral facet of the reservoir characterization process for tight sands and shales. With the Modal T_2 method it will be possible to obtain reliable estimates of permeability from all available samples, including those that have been compromised due to fracturing. Given the small pore size, it may also be possible to extend this technique to particulate samples such as drill cuttings, and extend it to the analysis of NMR logs.

References

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Acknowledgements

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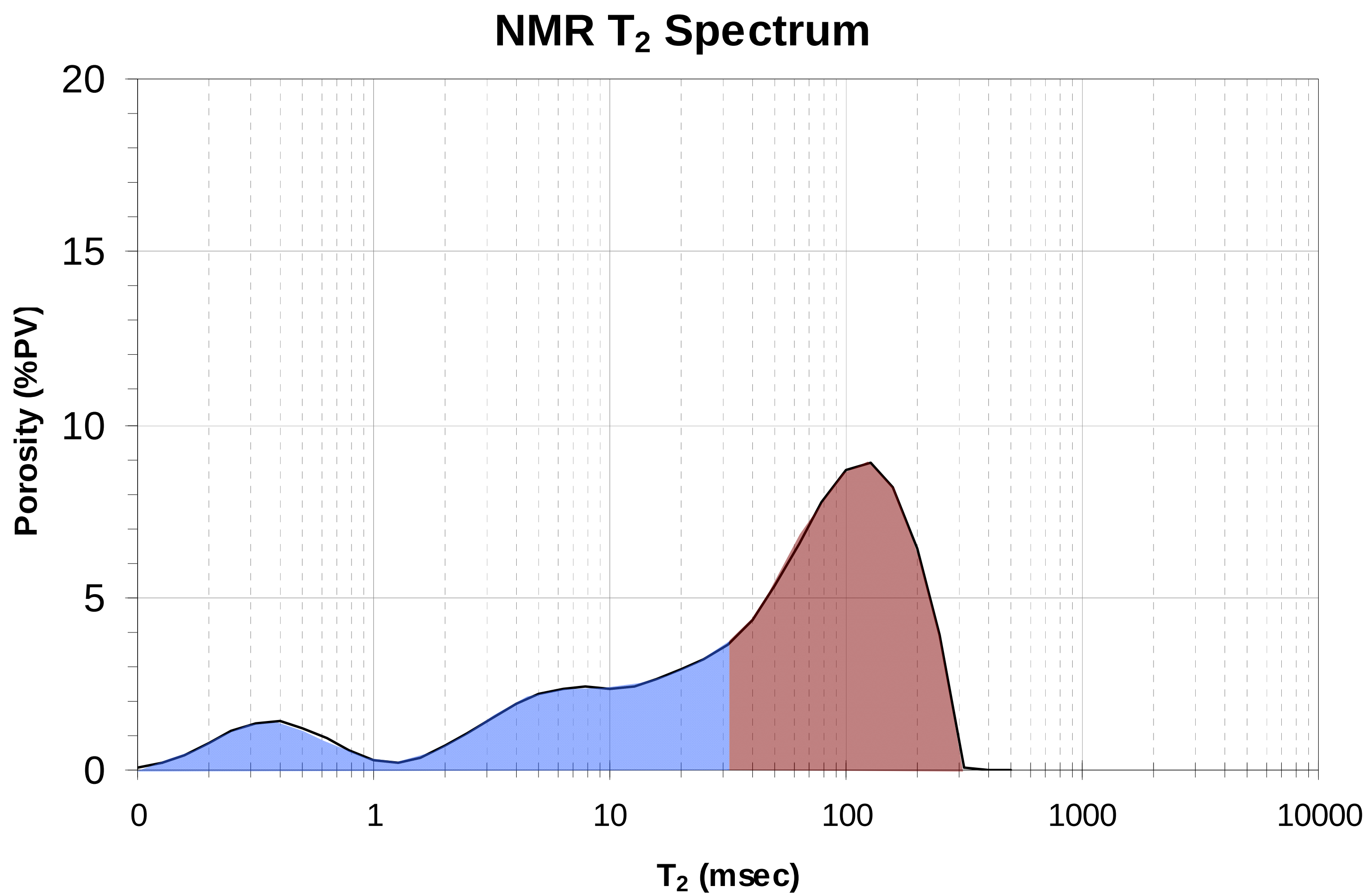

Figure 1. Standard interpretation of T_2 spectra derived from reservoir-quality sandstones.

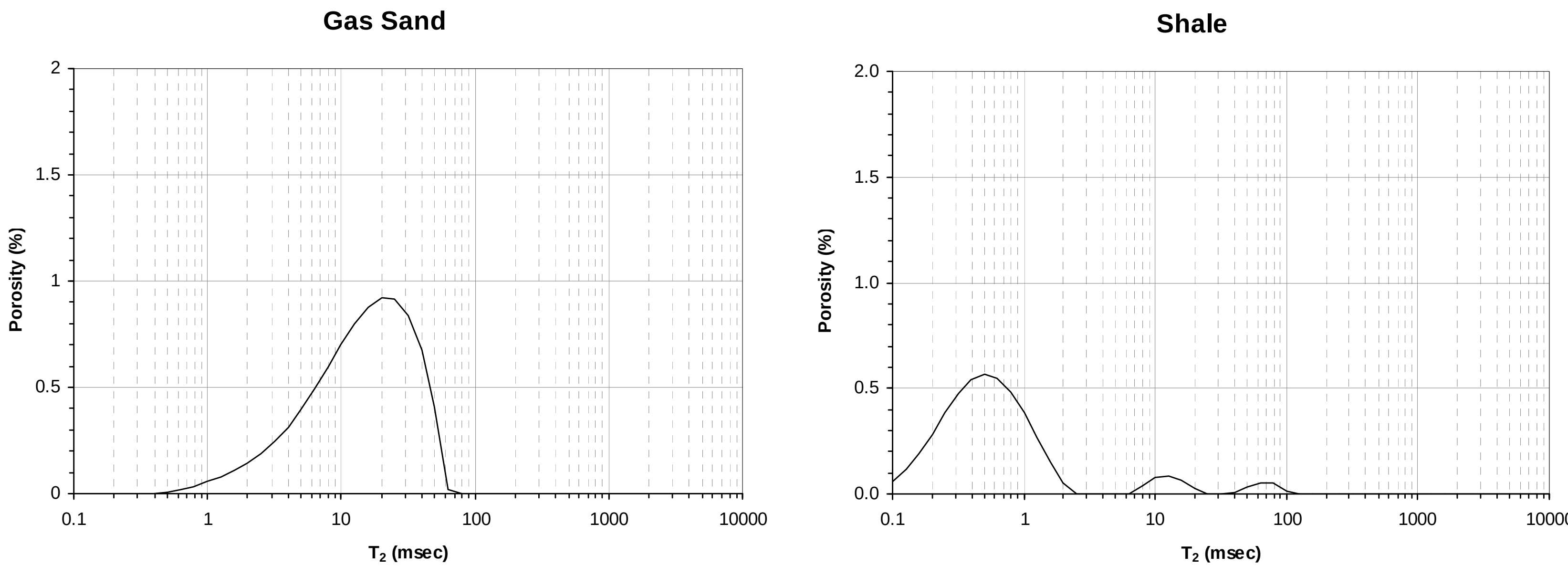

Figure 2. Representative T_2 spectra of Tight Sands and Shales. The shale spectrum on the right exhibits subsidiary peaks associated with fracture and/or moldic porosity.

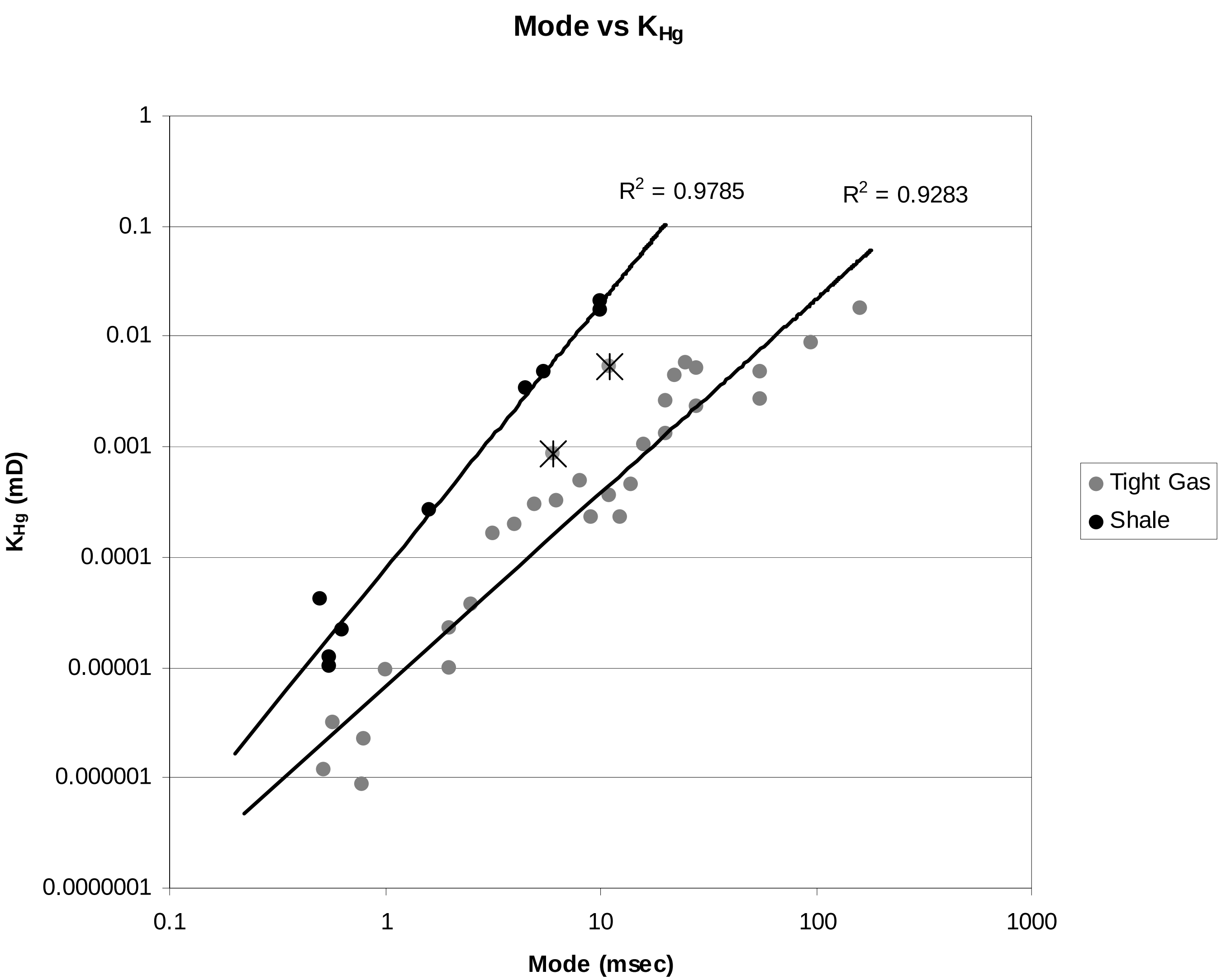

Figure 3. Modal T2 times plotted against Permeability. Most of the tight gas plugs were relatively homogeneous. The two outliers indicated on the graph represent heterogeneous plugs containing a significant amount of shale. In both cases the end trim used to determine permeability was from the sand-rich section of the plug.

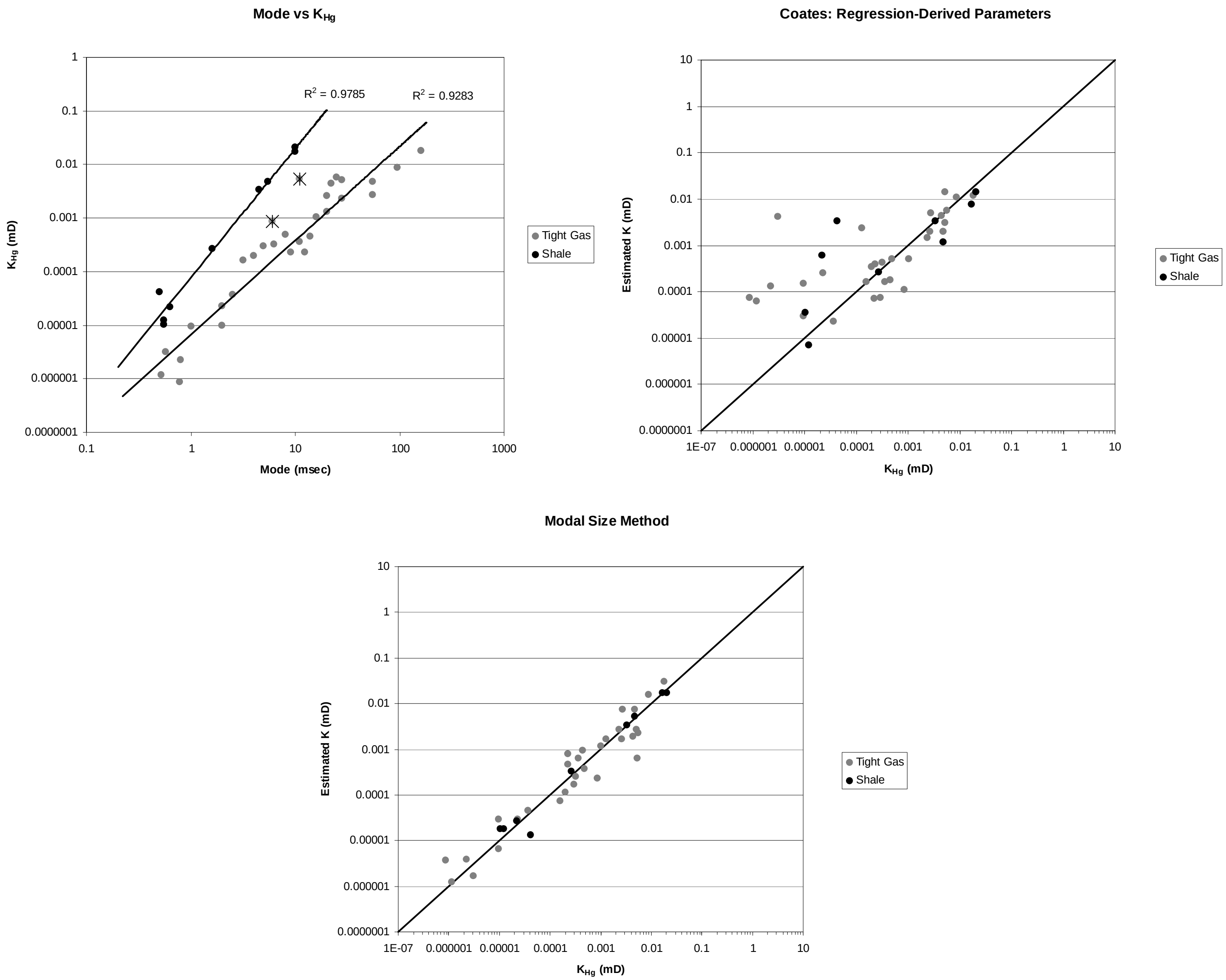

Figure 4. A comparison of different permeability estimation methodologies. **A)** Coates equation with default parameters. **B)** Coates with Regression-Defined parameters. **C)** Estimates derived using the Modal T_2 value.