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Quarterly Technical Progress Report

Analysis Of Critical Permeablity, Capillary Pressure And Electrical Properties For Mesaverde Tight Gas Sandstones From Western U.S. Basins

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National Energy Technology Laboratory

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Office of Fossil Energy

QUARTERLY TECHNICAL PROGRESS REPORT
FOR THE PERIOD ENDING MARCH 31, 2008

TITLE: ANALYSIS OF CRITICAL PERMEABLITY, CAPILLARY PRESSURE AND ELECTRICAL PROPERTIES FOR MESAVERDE TIGHT GAS SANDSTONES FROM WESTERN U.S. BASINS

DOE Contract No. DE-FC26-05NT42660

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DISCLAIMER:

ABSTRACT:

Basic analysis of all core plugs to be included in the project is complete. A total of 2209 core plugs have porosity, permeability, and grain density analyses. This represents nearly five times the total number of samples originally proposed for analysis. These core plugs were obtained from 44 wells and represent approximately 7,000 feet of described core. Grain density distribution averages 2.653±0.04 g/cc (error bar is 1 standard deviation). Geometric mean and median permeability for all samples is 0.0025 mD, and 0.0012 mD, respectively. Equations for predicting permeability are being developed. Preliminary multivariate linear equations using: 1) porosity, 2) rock class (1-3), and for each of three porosity classes separately (0-12%, 12-18%, >18%), performed separately for each basin, exhibit an average standard error of prediction of: 0-12%: 3.6±2.4X; 12-18%: 3.3±3.6X; >18%: 3.1X (for all basins undifferentiated for this high porosity class); where the range of error for each standard error of prediction indicates the range of standard error between basins.

The Project is moving into final wireline log algorithm development and refinement of all petrophysical prediction equations. Core descriptions and thin section analysis are being compiled for web presentation. A technical presentation is being given at the American Association of Petroleum Geologist Annual Meeting in San Antonio, TX, April 20-23, 2008.

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Acronyms

DOE = Department of Energy
k_{ik} = *in situ* Klinkenberg permeability, millidarcies
mD = millidarcy, 1 mD = 9.87×10^{-4} μm^2
n = number
psi = pound per square inch, 1 psi = 6.89 kPa
ϕ = porosity, percent or fraction depending on context

INTRODUCTION

Objectives - Industry assessment of the regional gas resource, projection of future gas supply, and exploration programs require an understanding of the reservoir properties and accurate tools for formation evaluation of drilled wells. The goal of this project is to provide petrophysical formation evaluation tools related to relative permeability, capillary pressure, electrical properties and algorithm tools for wireline log analysis. Major aspects of the proposed study involve a series of tasks to measure drainage critical gas saturation, capillary pressure, electrical properties and how these change with basic properties such as porosity, permeability, and lithofacies for tight gas sandstones of the Mesaverde Group from six major Tight Gas Sandstone basins (Washakie, Uinta, Piceance, Upper Greater Green River, Sand Wash and Wind River). Critical gas saturation (Sgc) and ambient and *in situ* capillary pressure (Pc) will be performed on 150 rocks selected to represent the range of lithofacies, porosity and permeability in the Mesaverde.

Project Task Overview -

Task 1. Research Management Plan
Task 2. Technology Status Assessment
Task 3. Acquire Data and Materials
- Subtask 3.1. Compile published advanced properties data
- Subtask 3.2. Compile representative lithofacies core and logs from major basins
- Subtask 3.3. Acquire logs from sample wells and digitize

Task 4. Measure Rock Properties
- Subtask 4.1. Measure basic properties (k, ϕ, grain density) and select advanced population
- Subtask 4.2. Measure critical gas saturation
- Subtask 4.3. Measure in situ and routine capillary pressure
- Subtask 4.4. Measure electrical properties
- Subtask 4.5. Measure geologic and petrologic properties
- Subtask 4.6. Perform standard logs analysis

Task 5. Build Database and Web-based Rock Catalog
- Subtask 5.1. Compile published and measured data into Oracle database
- Subtask 5.2. Modify existing web-based software to provide GUI data access

Task 6. Analyze Wireline-log Signature and Analysis Algorithms
- Subtask 6.1. Compare log and core properties
- Subtask 6.2. Evaluate results and determine log-analysis algorithm inputs

Task 7. Simulate Scale-dependence of Relative Permeability
- Subtask 7.1. Construct basic bedform architecture simulation models
- Subtask 7.2. Perform numerical simulation of flow for basic bedform architectures

Task 8. Technology Transfer, Reporting, and Project Management
- Subtask 8.1 Technology Transfer
- Subtask 8.2. Reporting Requirements
- Subtask 8.3. Project Management

EXECUTIVE SUMMARY:

Basic analysis of all core plugs to be included in the project is complete. A total of 2209 core plugs have porosity, permeability, and grain density analyses. This represents nearly five times the total number of samples originally proposed for analysis. These core plugs were obtained from 44 wells and represent approximately 7,000 feet of described core. Grain density distribution averages 2.653$\pm$0.04 g/cc (error bar is 1 standard deviation). Geometric mean and median permeability for all samples is 0.0025 mD, and 0.0012 mD, respectively. Equations for predicting permeability are being developed. Preliminary multivariate linear equations using: 1) porosity, 2) rock class (1-3), and for each of three porosity classes separately (0-12%, 12-18%, >18%), performed separately for each basin, exhibit an average standard error of prediction of: 0-12%: 3.6$\pm$2.4X; 12-18%: 3.3$\pm$3.6X; >18%: 3.1X (for all basins undifferentiated for this high porosity class); where the range of error for each standard error of prediction indicates the range of standard error between basins.

The Project is moving into final wireline log algorithm development and refinement of all petrophysical prediction equations. Core descriptions and thin section analysis are being compiled for web presentation.

RESULTS AND DISCUSSION:

TASK 3. ACQUIRE DATA AND MATERIALS

Subtask 3.2. Compile representative lithofacies core and logs from major basins

Basic analysis of all core plugs to be included in the project is complete. A total of 2209 core plugs have porosity, permeability, and grain density analyses. This represents nearly five times the total number of samples originally proposed for analysis. These core plugs were obtained from 44 wells and represent approximately 7,000 feet of described core. Analysis of the basic petrophysical properties of the Mesaverde cores indicates that the samples obtained for each basin exhibit approximately the entire porosity and permeability range exhibited by the Mesaverde for all samples analyzed. The 2209 core plugs represent 1165 unique depths with 760 duplicate samples and 284 cores for which a triplicate sample was obtained. Figure 1 illustrates the relationship between *in situ* Klinkenberg permeability and calculated *in situ* porosity for all samples by basin. *In situ* porosity was calculated using the routine-to-*in situ* correlation presented previously. Differences in permeability at a given porosity among basins can be primarily attributed to differences in grain size, mineralogy, and diagenesis as discussed below.

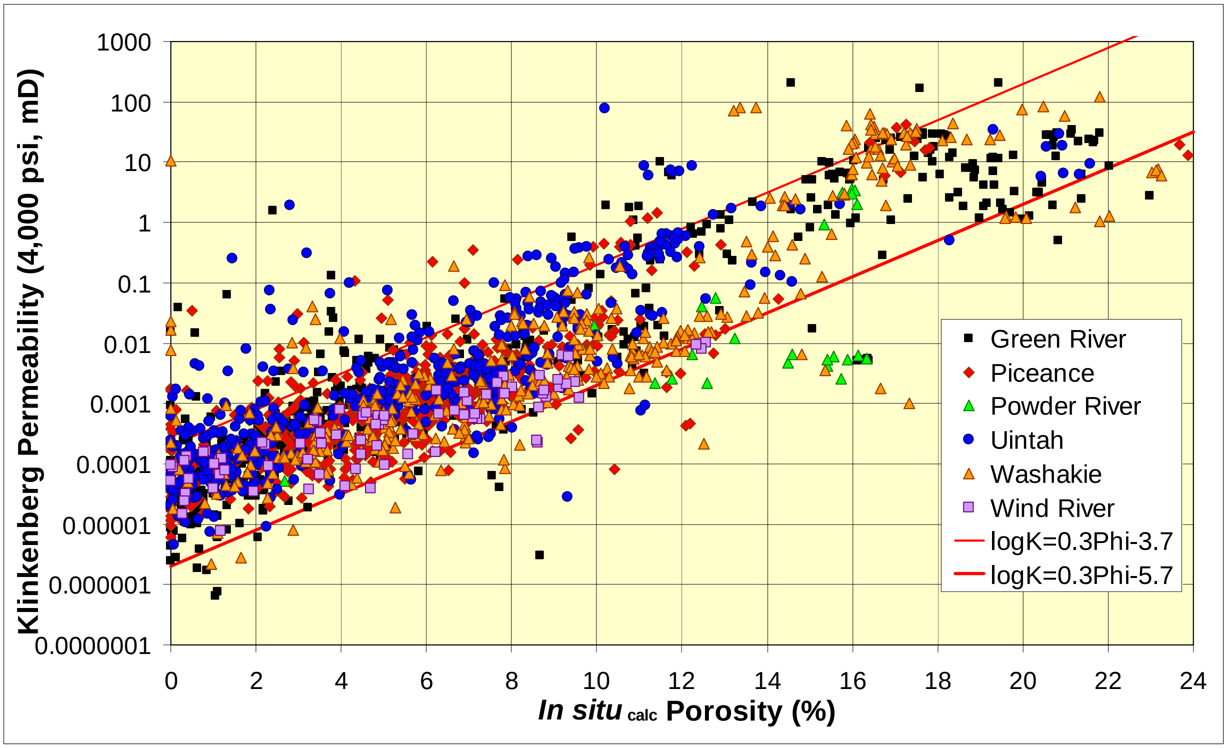

Figure 1. *In situ* Klinkenberg permeability versus calculated *in situ* porosity for all core samples by basin. Range of porosity and permeability of Mesaverde sandstones is generally exhibited by all basins.

TASK 4. MEASURE ROCK PROPERTIES

Subtask 4.1. Measure basic properties (k, ϕ, grain density) and select advanced population

Figure 1 illustrated the general permeability-porosity trend for 2200 Mesaverde sandstones samples. Nearly all samples that exhibit permeability greater than the "high" trendline exhibited either; 1) a microfracture, 2) a parting along a shale or carbonaceous lamina, 3) significant lithofacies heterogeneity for some fraction of the core plug parallel to flow (e.g. a high permeability sandstone within less porous lithofacies). Samples exhibiting permeability below the "low" trendline generally exhibited either; 1) churned/bioturbated lithology, 2) cross-bedding with laminae not parallel to flow, 3) extremely fine-grained, or 4) significant clay content.

Grain density distribution averages 2.653±0.04 g/cc (error bar is 1 standard deviation; Fig. 2). Grain density distribution is skewed slightly to high density reflecting variable concentration of calcite, dolomite, and rare pyrite cement. Grain densities for the wells sampled exhibit a slight difference in distribution between basins (Fig 3, Table 1). It is important to note the small sample population of the Powder and Wind River Basin samples and these may be biased for conditions in the few wells and intervals sampled.

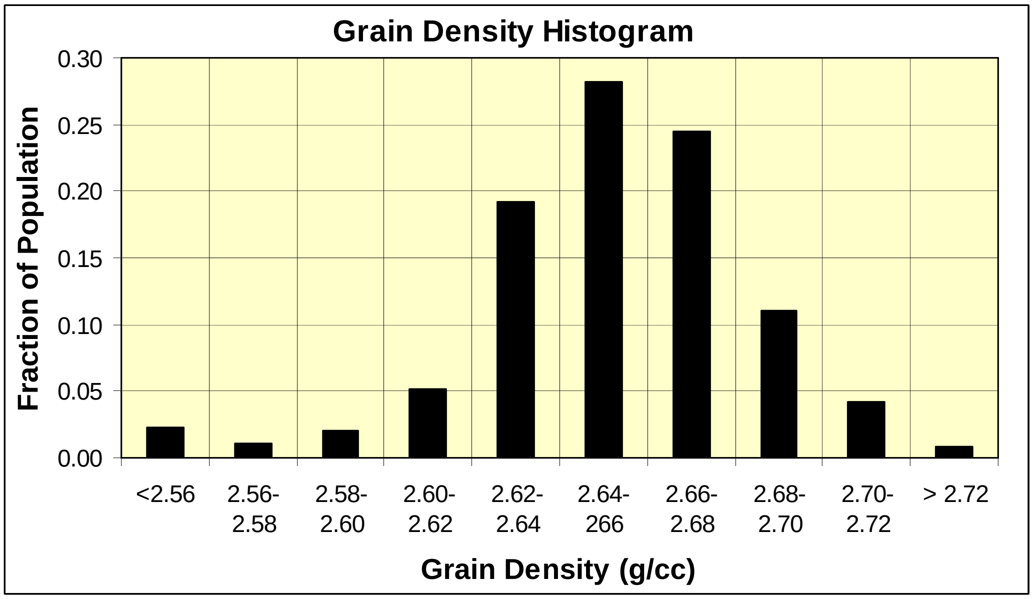

Figure 2. Grain density distribution for all basins and all samples (n=2200). Distribution is near normal with mean = 2.653+0.04 g/cc. Slight skewness to higher values primarily reflects variable concentration of carbonate cement.

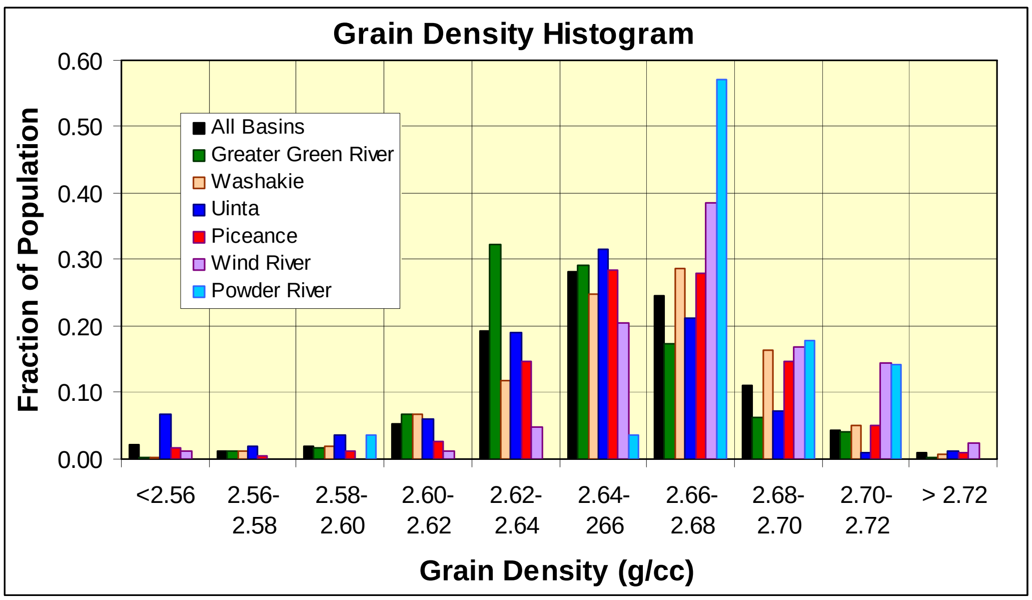

Figure 3. Grain density distribution by basin showing differences between basins as in Table 1.

	All Basins	Greater Green River	Washakie	Uinta	Piceance	Wind River	Powder River
Mean	2.653	2.648	2.660	2.639	2.660	2.673	2.679
Median	2.654	2.645	2.662	2.649	2.661	2.673	2.674
St Dev	0.040	0.029	0.034	0.052	0.038	0.029	0.026
Minimum	2.30	2.50	2.47	2.30	2.35	2.51	2.60
Maximum	2.84	2.77	2.79	2.80	2.84	2.73	2.75
Kurtosis	15.1	2.6	3.7	13.2	14.0	10.2	3.9
Skewness	-2.00	0.28	-0.18	-2.82	-1.19	-1.87	-0.28
Count	2184	566	393	532	583	82	28

Table 1. Summary statistics for grain density for all samples by basin.

The porosity distribution is skewed to lower porosity (Fig. 4) consistent with general porosity distribution in the Mesaverde sandstone. The large population of cores with porosity of ϕ=0-2% partially reflects a heavy sampling of low porosity intervals in two Green River Basin wells (Fig. 5).

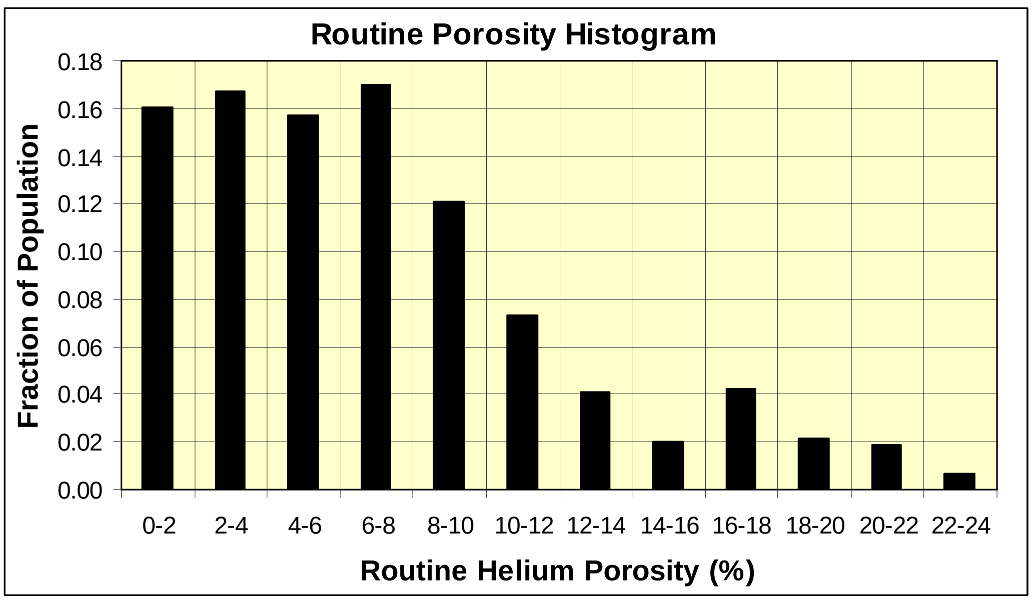

Figure 4. Porosity distribution for all samples (n = 2200).

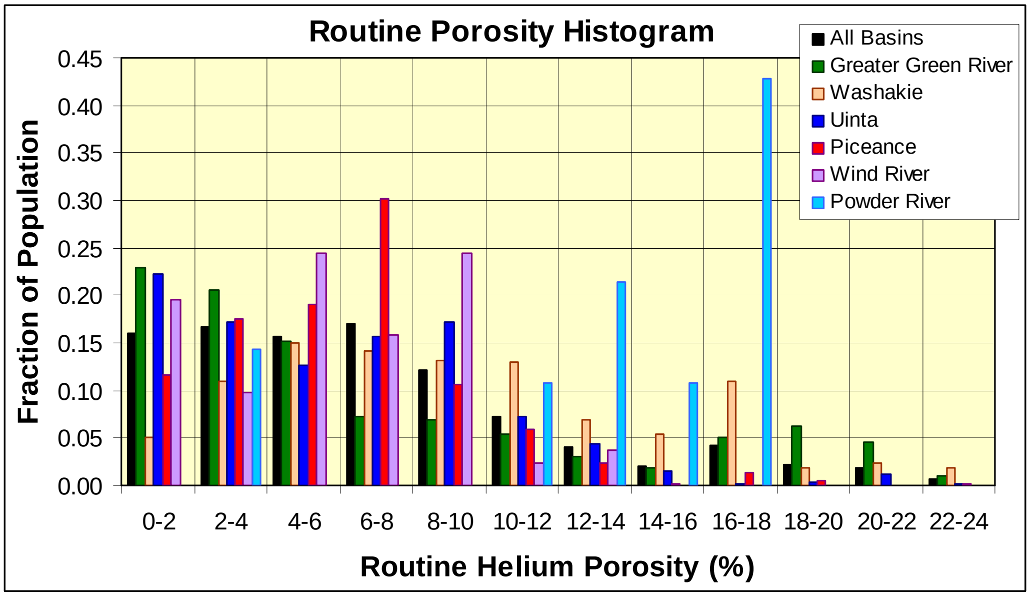

Figure 5. Porosity distribution by basin.

	All Basins	Greater Green River	Washakie	Uinta	Piceance	Wind River	Powder River
Mean	7.1	7.3	9.5	6.1	6.1	5.8	13.2
Median	6.2	4.6	8.7	5.9	6.1	5.5	15.1
St Dev	5.1	6.4	5.4	4.2	3.8	3.3	4.5
Minimum	0.0	0.0	0.0	0.0	0.0	0.0	2.6
Maximum	24.9	23.6	23.8	22.2	24.9	13.2	16.9
Kurtosis	0.7	-0.4	-0.4	1.1	4.5	-0.8	1.0
Skewness	1.0	1.0	0.5	0.9	1.4	0.1	-1.5
Count	2209	568	395	539	596	83	28

Table 2. Summary statistics for routine helium porosity for all samples by basin.

To provide a common reference stress reference frame i*n situ* Klinkenberg permeability has been measured at 4,000 psi net overburden stress. *In situ* Klinkenberg permeability was determined by measurement of permeability to nitrogen at two pore pressures and extrapolation of the k vs. 1/P trend to infinite pore pressure to obtain the Klinkenberg permeability at the intercept. The Klinkenberg gas permeability, which is equivalent to single-phase inert liquid or high pressure gas absolute permeability, increases with decreasing pore size.

Permeability for the samples is log-normally distributed (Fig. 6) with 52% of the sample exhibiting *in situ* Klinkenberg permeability in the range 0.0001-0.01 mD and 18% of the samples exhibiting k_{ik} < 0.0001 mD and 30% exhibiting k_{ik}>0.01 mD. The distribution of permeability for samples from different basins is generally similar (Fig. 8) though slight differences in the mean and standard deviation exist. It is important to note that these distributions are for the sample set and may not reflect actually distributions within the basins.

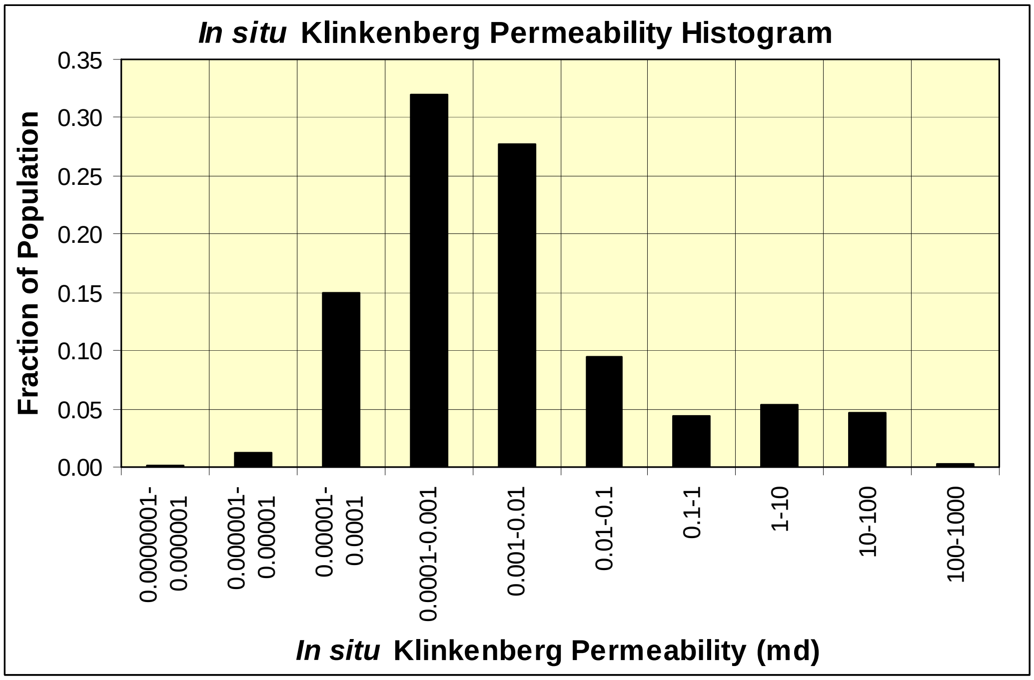

Figure 6. Distribution of *in situ* Klinkenberg permeability measured at 4,000 psi net effective stress for all samples.

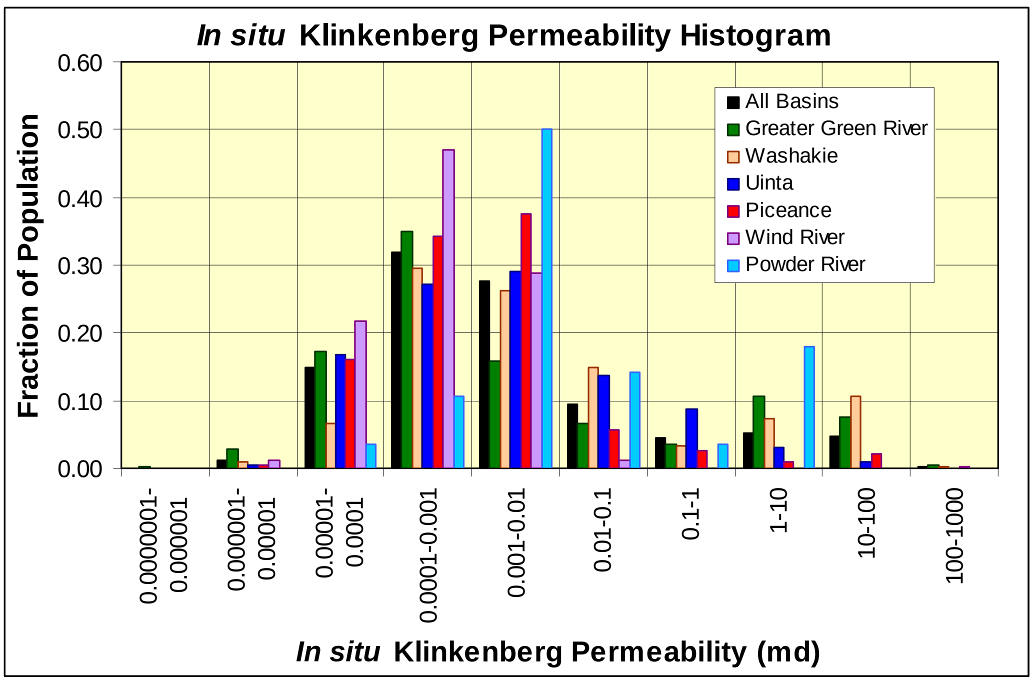

Figure 7. Distribution of *in situ* Klinkenberg permeability measured at 4,000 psi net effective stress by basin.

	All Basins	Greater Green River	Washakie	Uinta	Piceance	Wind River	Powder River
Mean logk	-2.60	-2.49	-2.03	-2.66	-2.95	-3.44	-1.88
Median logk	-2.93	-3.15	-2.46	-2.86	-3.03	-3.36	-2.21
St Dev log	1.58	1.94	1.78	1.36	1.13	0.69	1.39
Minimum logk	-6.19	-6.19	-5.66	-5.33	-5.23	-5.11	-4.29
Maximum logk	2.31	2.31	2.08	1.88	2.05	-1.98	0.55
Kurtosis	0.62	-0.54	-0.39	0.17	4.02	-0.49	-0.38
Skewness	1.05	0.79	0.76	0.74	1.48	-0.01	0.50
Count	2143	555	373	529	577	81	28
Mean	0.0025	0.0032	0.0094	0.0022	0.0011	0.0004	0.0133
Median	0.0012	0.0007	0.0035	0.0014	0.0009	0.0004	0.0062
St Dev	37.9	87.4	59.9	23.0	13.4	4.9	24.5
Minimum	0.000001	0.000001	0.000002	0.000005	0.000006	0.000008	0.000051
Maximum	206.0	206.0	121.0	76.2	112.2	0.010	3.53
Kurtosis	0.62	-0.54	-0.39	0.17	4.02	-0.49	-0.38
Skewness	1.05	0.79	0.76	0.74	1.48	-0.01	0.50
Count	2143	555	373	529	577	81	28

Table 3. Summary statistics for *in situ* Klinkenberg Permeability for all samples by basin.

Figure 8 illustrates the relationship between permeability and porosity parametric with the second rock classification digit which represents size-sorting (see March 2006 quarterly report). Characteristic of most sandstones, permeability at any given porosity increases with increasing grain size and increasing sorting though this relationship is further influenced by sedimentary structure (rock digit 4) and the nature of cementation (rock digit 5). Samples exhibiting permeability greater than the empirically defined high limit generally exhibit an anomalous lithologic property that influences core plug permeability such as microfracturing along fine shale lamination, microfracture, lithologic heterogeneity parallel to bedding with the presence of a high permeability lamina in a core plug dominantly composed of a lower permeability-porosity rock. Conversely, cores exhibiting permeability below the lower limit can exhibit such lithologic properties as churned-bioturbated texture, cross-bedding with fine-grained or shaly bed boundaries that are sub-parallel or perpendicular to flow and act as restrictions to flow, or high clay content. Permeability in low porosity samples and particularly below approximately 1% (vertical red line) is generally a complex function of final pore architecture after cementation and is only weakly correlated with original grain size.

Excluding samples exhibiting permeability outside the limits shown in Figure 8, the relationship between the porosity and lithologic variables and permeability was investigated. Although inclusion of a term for size/sorting significantly improves permeability prediction, a unique wireline log signature for predicting the size/sorting rock digit 2 was not identified. It was, however, found that three classes of size/sorting could be reliably identified from wireline log response. These three classes comprise: 1) shales/mudstones, silty shales, siltstones, and very shaly sandstones with digit X(0-2)XXX, 2) moderately shaly sandstones X3XXX, and 3) very fine – coarse grained sandstones X(4-9)XXX. The relationship between permeability and porosity for the three classes of rock is shown in Figure 9.

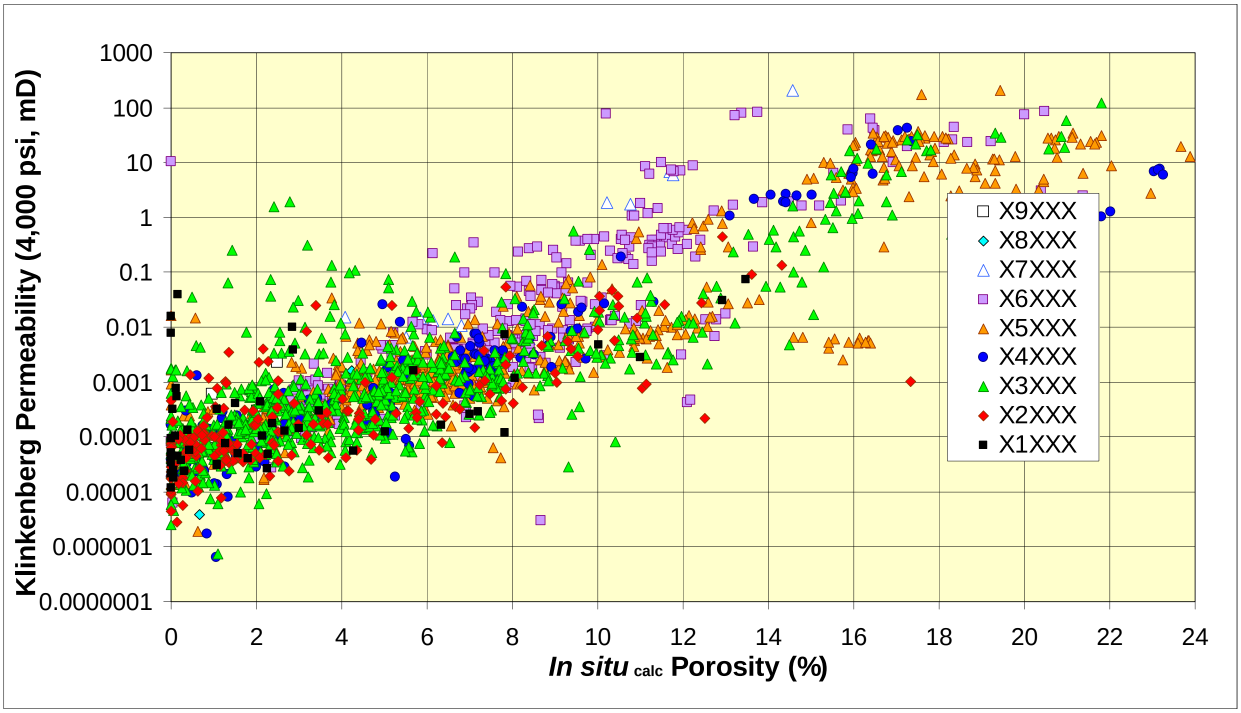

Figure 8. Crossplot of *in situ* Klinkenberg permeability (k_{ik}, mD, measured at 4,000 psi net effective stress) versus calculated *in situ* porosity ($f_{routine}$-0.8) by second rock type digit 2 representing size-sorting. The high limit generally defines the upper range for medium-coarse grained rocks. The lower limit generally represents the limit for siltstone rocks.

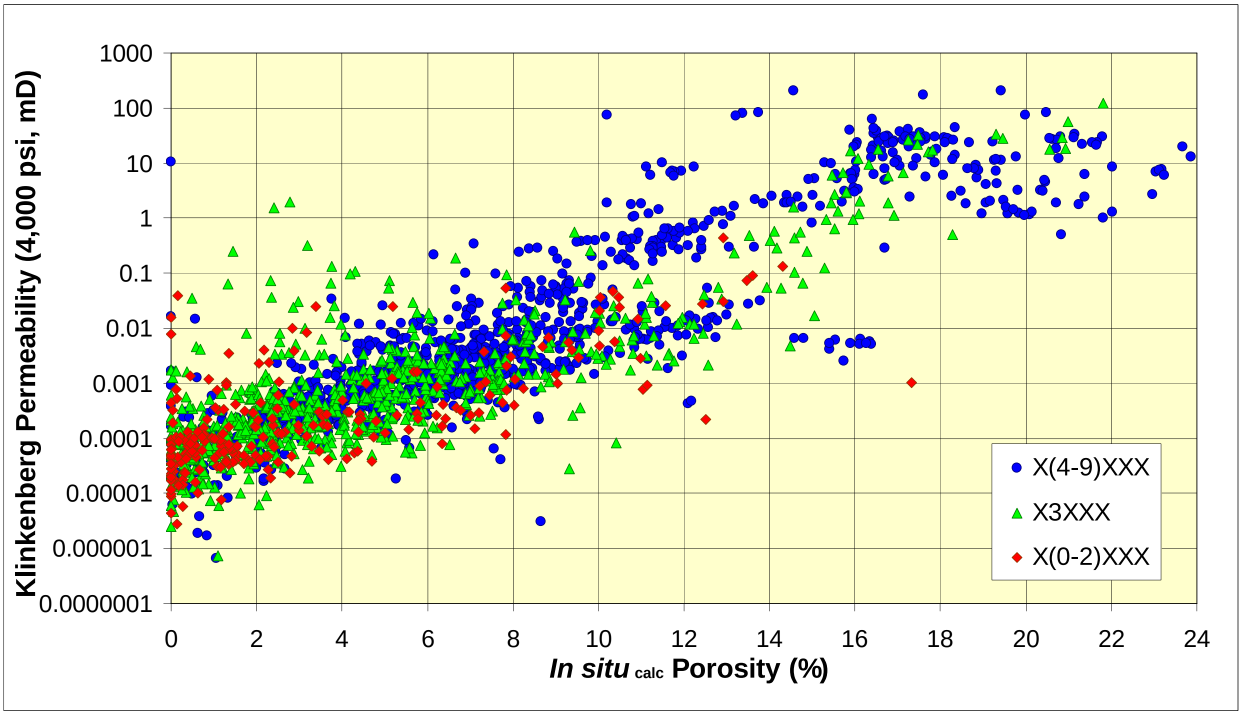

Figure 9. Crossplot of *in situ* Klinkenberg permeability (k_{ik}, mD, measured at 4,000 psi net effective stress) versus calculated *in situ* porosity ($f_{routine}$-0.8) by clustered second rock type digit representing size-sorting classes that are identifiable by wireline gamma ray log response.

Analysis was performed to identify accurate equations for permeability prediction. Although Artificial Neural Network (ANN) methods are capable of predicting permeability within a factor of 3.5X, the ease of sharing and applying an ANN model is not as great as simpler algebraic equations. Analysis is on-going for optimum equations. Permeability prediction for all samples from all basins and for the complete porosity range (~ 0-24%) using multivariate linear regression analysis using porosity and an integer of 1 to 3 for the three rock classes exhibits an average standard error of prediction of 5.7±5.6 (error bars represents 2 standard deviations).

Examination of Figure 9 shows that the permeability-porosity trend exhibits different relationships for the porosity ranges; 0-12%, 12-18%, and > 18%. Multivariate equations using: 1) porosity, 2) rock class (1-3), and for each of these three porosity classes separately (0-12%, 12-18%, >18%), and also performed separately for each basin provided equations that exhibit an average standard error of prediction of: 0-12%: 3.6±2.4X; 12-18%: 3.3±3.6X; >18%: 3.1X (for all basins undifferentiated). These errors are judged to be sufficiently low that this methodology will be adopted for final permeability equation development. Final equations are being developed.

TASK 8. TECHNOLOGY TRANSFER, REPORTING, PROJECT MANAGEMENT

Subtask 8.1 Technology Transfer

A technical talk is being presented at the American Association of Petroleum Geologists Annual Meeting in San Antonio, TX, April 20-23, 2008:

"Lithofacies and petrophysical properties of Mesaverde tight-gas sandstones in Western U.S. basins"

Alan P. Byrnes, John C. Webb, Robert M. Cluff, Daniel A. Krygowski, and Stefani D. Whittaker.

The relationship between core and log petrophysical properties and lithofacies sedimentary characteristics is examined in Mesaverde Group tight gas sandstones from forty cores in the Washakie, Uinta, Piceance, Upper Greater Green River, Wind River, Sand Wash, and Powder River basins. Fine-grained intervals of the Mesaverde Group are dominated by mudstones and silty shales; burrowed, lenticular and wavy-bedded very shaly sandstones; and wavy-bedded to ripple cross-laminated shaly sandstones. Sandstone intervals are dominated by ripple cross-laminated and cross-bedded, very fine to fine-grained sandstones, low-angle cross-laminated to planar laminated sandstones, and massive sandstones. For all lithofacies undifferentiated in the cores sampled, grain density averages 2.654±0.033 g/cc (error of 1 std dev) with grain density distributions differing slightly among basins. Core porosity ranges from 0-25%, averaging 7.2% (n=2200). *In situ* Klinkenberg permeability ranges from 0.0000001-200 millidarcies, averaging 0.002 millidarcies. Characteristic of most sandstones, permeability at any given porosity increases with increasing grain size and increasing sorting though this relationship is further influenced by sedimentary structure and the nature of cementation. Multivariate and neural network permeability prediction methods exhibit a standard error of 4.5X and 3.3X respectively. Capillary threshold entry pressure and pore characteristic length are well correlated with permeability. Archie cementation exponent, m, can be modeled with a dual porosity matrix-fracture model with m approaching one as porosity approaches zero. Critical gas saturation is generally less than 5% but increases with increasing bedform complexity. Integration of wireline log analysis and core petrophyscial relationships provides guidelines and equations for predicting reservoir properties. The Mesaverde Project website is (http://www.kgs.ku.edu/mesaverde).

CONCLUSIONS

Basic analysis of all core plugs to be included in the project is complete. A total of 2209 core plugs have porosity, permeability, and grain density analyses. This represents nearly five times the total number of samples originally proposed for analysis. These core plugs were obtained from 44 wells and represent approximately 7,000 feet of described core. Grain density distribution averages 2.653$\pm$0.04 g/cc (error bar is 1 standard deviation). Geometric mean and median permeability for all samples is 0.0025 mD, and 0.0012 mD, respectively. Equations for predicting permeability are being developed. Preliminary multivariate linear equations using: 1) porosity, 2) rock class (1-3), and for each of three porosity classes separately (0-12%, 12-18%, >18%), performed separately for each basin, exhibit an average standard error of prediction of: 0-12%: 3.6$\pm$2.4X; 12-18%: 3.3$\pm$3.6X; >18%: 3.1X (for all basins undifferentiated for this high porosity class); where the range of error for each standard error of prediction indicates the range of standard error between basins.

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