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PETROPHYSICAL ANALYSIS AND GEOGRAPHIC INFORMATION SYSTEM FOR SAN JUAN BASIN TIGHT GAS RESERVOIRS

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Submitted by:
Martha Cather
New Mexico Petroleum Recovery Research Center
801 Leroy Place
Socorro, NM 87801

Office of Fossil Energy

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(FINAL REPORT)

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MARTHA CATHER, PI
ROBERT LEE, PROJECT MANAGER
ROBERT BALCH , CO-PI
TOM ENGLER, CO-PI

CONTRIBUTORS:
ROGER RUAN
SHAOJIE MA

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NEW MEXICO PETROLEUM RECOVERY RESEARCH CENTER
NEW MEXICO INSTITUTE OF MINING AND TECHNOLOGY
801 LEROY PLACE
SOCORRO, NM 87801
(505) 835-5142

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ABSTRACT

The primary goal of this project is to increase the availability and ease of access to critical data on the Mesaverde and Dakota tight gas reservoirs of the San Juan Basin. Secondary goals include tuning well log interpretations through integration of core, water chemistry and production analysis data to help identify bypassed pay zones; increased knowledge of permeability ratios and how they affect well drainage and thus infill drilling plans; improved time-depth correlations through regional mapping of sonic logs; and improved understanding of the variability of formation waters within the basin through spatial analysis of water chemistry data. The project will collect, integrate, and analyze a variety of petrophysical and well data concerning the Mesaverde and Dakota reservoirs of the San Juan Basin, with particular emphasis on data available in the areas defined as tight gas areas for purpose of FERC. A relational, geo-referenced database (a geographic information system, or GIS) will be created to archive this data. The information will be analyzed using neural networks, kriging, and other statistical interpolation/extrapolation techniques to fine-tune regional well log interpretations, improve pay zone recognition from old logs or cased-hole logs, determine permeability ratios, and also to analyze water chemistries and compatibilities within the study area.

This single-phase project will be accomplished through four major tasks: Data Collection, Data Integration, Data Analysis, and User Interface Design. Data will be extracted from existing databases as well as paper records, then cleaned and integrated into a single GIS database. Once the data warehouse is built, several methods of data analysis will be used both to improve pay zone recognition in single wells, and to extrapolate a variety of petrophysical properties on a regional basis. A user interface will provide tools to make the data and results of the study accessible and useful. The final deliverable for this project will be a web-based GIS providing data, interpretations, and user tools that will be accessible to anyone with Internet access.

- During this project, the following work has been performed:
- Assimilation of most special core analysis data into a GIS database
- Inventorying of additional data, such as log images or LAS files that may exist for this area
- Analysis of geographic distribution of that data to pinpoint regional gaps in coverage
- Assessment of the data within both public and proprietary data sets to begin tuning of regional well logging analyses and improve payzone recognition.
- Development of an integrated web and GIS interface for all the information collected in this effort, including data from northwest New Mexico.
- Acquisition and digitization of logs to create LAS files for a subset of the wells in the special core analysis data set.
- Petrophysical analysis of the final set of well logs.

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INTRODUCTION

This project seeks to address two different but interrelated problems that have been identified by oil and natural gas producers working in the San Juan Basin the need for improved reservoir characterization, and the lack of access to important data. These problems are compounded by a general lack of time and expertise to develop methods of utilizing what data is available. Although this project seeks to answer San Juan Basin-specific needs, the methodologies and some interpretations may be used in other basins.

In a series of meetings in 2002 between researchers and producers/operators, improved reservoir characterization was given very high priority in many regions, including the San Juan Basin. Specifically, in New Mexico, with its long history of production, great emphasis was placed on using existing well-bores and data where possible; improving and applying cased hole techniques to better differentiate pay in thinly-laminated shale gas reservoirs; identifying bypassed pay zones in all reservoirs; identifying natural fractures and their orientation in tight gas sands and coalbeds; and in finding new ways of utilizing old log data to better understand petrophysical reservoir properties.

EXECUTIVE SUMMARY

The primary goal of this project was to increase the availability of and ease of access to critical data on the Mesaverde and Dakota tight gas reservoirs of the San Juan Basin. Secondary goals included tuning well log interpretations through integration of core, water chemistry and production analysis data to help identify bypassed pay zones; and improved understanding of the spatial variability of various petrophysical parameters such as porosity and permeability.

The project collected, cleaned, integrated, and analyzed a variety of petrophysical and well data concerning Dakota and Mesaverde reservoirs of the San Juan Basin, with particular emphasis on data available in the areas defined as tight gas areas under FERC regulations. Much of this data was collected and assembled prior to the time when electronic storage was available, thus was available to the public primarily in hard copy format, in fairly obscure or unpublished documents, and not in any standardized format that would be easy for researchers to use without substantial effort to digitize and clean the data.

Data was extracted from existing databases as well as paper records, then cleaned and integrated into a single GIS database for analysis and archive. The information was analyzed using neural networks, kriging, and other statistical interpolation/extrapolation techniques to fine-tune regional well log interpretations, improve pay zone recognition from old logs, determine permeability and porosity variation, and to help predict where additional drilling might recover more gas.

A user interface provides tools to make the data and results of the study accessible and useful. The final deliverable for this project is a web site that provides data and interpretations in both text-based format and an online GIS and user tools that are accessible to anyone with Internet access. The web site is http://octane.nmt.edu/SanjuanAjax/

During this project, the following work has been performed:

- Assimilation of most special core analysis data into a GIS database
- Verification of data accuracy
- Inventory and acquisition of additional data, such as log images or LAS files that exist for this area
- Analysis of geographic distribution of that data to pinpoint regional gaps in coverage
- Assessment of the data within both public and proprietary data sets to begin tuning of

regional well logging analyses and improve pay zone recognition

- Accumulation of some production data for core analysis wells
- Continued digitizing of logs to create LAS files for a subset of the wells in the special core analysis data set.
- Petrophysical analysis of the final set of well logs.
- Development of an integrated web and GIS interface for all the information collected in this effort, including data from northwest New Mexico.

EXPERIMENTAL METHODS

No experimental methods, materials, or equipment were used for this project. ArcGIS software was used for mapping of wells and petrophysical data. Microsoft SQL Server 2000 was used to store and access databases.

DISCUSSION OF RESULTS

DATABASE CONSTRUCTION

A key task for this project was the development of a dynamic web-accessible database for storing, managing, accessing, and analyzing data to be accessed by both web-based queries and GIS-initiated queries.

Data was collected from numerous sources. These included image files of well logs, core analysis reports, and various forms filed with the New Mexico Oil Conservation Division, also digital log data assembled for previous studies, and proprietary digital well and log data. However, the most important data source was books of information that were compiled by various oil companies for use as evidence in application hearings where companies were applying to have a particular area and formation given formal Tight Gas status as defined by the Federal Energy Regulatory Commission (FERC). Application books included copies of scout cards, well logs and well log headers, core analysis reports, and a wealth of miscellaneous information about the wells that were used for application purposes. Because much of the data had been collected for previous projects with different purposes, it required cleaning, standardization, and in many cases, verification with original sources for the current purpose. Such verification might include filling in gaps such as information about drilling or completion dates, adding useful information such as notes about core fractures, or correction of errors that occurred during digitization of image files to LAS files or text.

The final result of this work is a database(s) and files comprising:

- Core information data for some 140 wells, primarily completed in the Dakota, also general well information for these wells, production data for these wells, LAS files for certain logs, and digital images of important records for this set of wells;
- Dakota Formation top and perforation intervals for a larger set of wells used for geostatistical analysis, LAS files for this set of wells where available, production data, and any data generated from the geostatistical analysis of these wells;
- GIS layers of the above data and additional relevant information such as basin boundaries, well locations of all San Juan Basin wells, and relevant land grid;

This data is all available via our project-specific web site, located at http://octane.nmt.edu/SanjuanAjax/Default.aspx

Data Sets – Core Analysis Data

The original data set used for this project was derived from books that were used as exhibits in various company applications to designate a particular region and formation as a Tight Gas

Formation under regulations established by the Federal Energy Regulatory Commission (FERC). Typical information contained in these books included images of well header information, an image of a pertinent well log through the depth interval of interest, and any available core analysis data. Some books also contained information such as depth to the top of a particular unit, tops picked within the Dakota, and perforation intervals; however this data was not present in every area. The final data set of core analysis wells contained information on over 140 wells in the Dakota and Mesaverde formations.

In most cases, the core analyses were not done specifically for the application, but had been produced previously for some other reason. Most core analyses were performed in the late 1950s and early 1960s, although a few were older or younger, and different companies performed them, so they showed some variability in presentation format. Some records contained copies of the original analyses, while others only contained the tabular data that had been abstracted from the original analyses. Original analyses contained useful information that was often nonquantitative in nature (eg., lithologies, notable features, nonnumeric measurement designations such as TSTM for too small to measure). Where available, we made efforts to capture this information in the database in notes and remarks columns.

Initial digitization did capture the most important data; however it was necessary to go back and check the work, both to verify the information that had been captured, and to add other data that had not been considered necessary at the onset of the project. For each core analysis well records include basic well data, the core analysis data, image files of well records, and, in many cases image files of well logs. In addition, we digitized available well logs to create a reasonably complete suite of LAS files for the Dakota core analysis wells. For all wells with logs, stratigraphic units were picked, including the top of the Dakota, and the tops of several units within the formation. Some wells had pre-existing data on formation tops, either from scout cards, records from the NM OCD, or the application books. Examination of the various sets of tops revealed significant variations in both stratigraphic terminology and common usage of formation and unit names. We felt that it would provide a more consistent project if we created our own data set of tops, rather than trying to pull from a variety of other sources.

OTHER DATA SETS

One aspect of the original project was to not simply collect data, but to perform petrophysical and geostatistical analysis of the data with goals of improving log interpretation and also mapping petrophysical properties on a basin-wide scale. For this work, additional information was required. A significant amount of log data was already available from a proprietary set of LAS files for the San Juan Basin (>6000 LAS files), but there were several issues with using this data, thus it was necessary to digitize a number of well logs.

Production data for most wells was available in digital format in a limited basis. Most wells were lacking many years of data, generally from years prior to the mid-1980's. Significant efforts were made to gather at least annual production information for each of the wells for all years of production. This data was obtained from the Annual Reports of the New Mexico Oil & Gas Engineering Committee.

Additional information was acquired from IHS Energy. The data itself is proprietary, however some of the data was used in interpretations, which are presented publicly. This data is stored as a relational database in a propriety format, which can be exported to other formats (such as Microsoft Excel) by the software. For this study, only wells producing exclusively from the Dakota Formation were chosen from these datasets.

The quality and consistency of the dataset is the most important element to build any database, thus, the acquisition, cleaning, combination, and other data preprocessing tasks required a relatively large portion of the study. When possible we used human interpretation of data since it is more able to capture the intent of the data representation when data deviates from a standard form.

Spatial Data Analysis

Wire-line log data representing a vertical stream of data is commonly collected in all wells, whereas core data is expensive and only collected in a few places. An objective of the study was to extrapolate core data to non-cored wells. In order to perform spatial analysis of engineering and geologic factors we first required a subset of Dakota wells for which a common set of wire-line logs exists; Spontaneous Potential (SP), Gamma Ray (GR), and Deep Resistivity (LLD) were used as these were the most commonly-available curves in our database of proprietary LAS files. A number of these wells also had core analysis data providing interesting information such as directional permeabilities, core porosities, and water and gas saturation data. Integration of these two data sets allowed us to attempt to correlate wire-line and core analysis information, enabling extrapolation of data on a much greater scale, both horizontally and vertically, between wells using GIS spatial data analysis techniques.

Core Analysis Wells:

One of the first tasks was to find a common set of wells with both adequate log and core analysis data to perform meaningful spatial analysis. One set of well data included LAS files for some 916 Dakota wells which had a common set of wire-line logs (SP, GR, and LLD). The other primary data set was that of 98 Dakota wells with sufficient core analysis data. From these two data sets, only 18 wells having both log and core analysis data were found; in many cases the logs still required digitization. Since one objective of the study was to extrapolate core data to non-cored wells, these

18 wells allow comparison of predicted vs. actual reservoir values and provide a means for measuring success of any correlations. Figure 1 shows overall study area and the distribution of the wells with core analysis data.

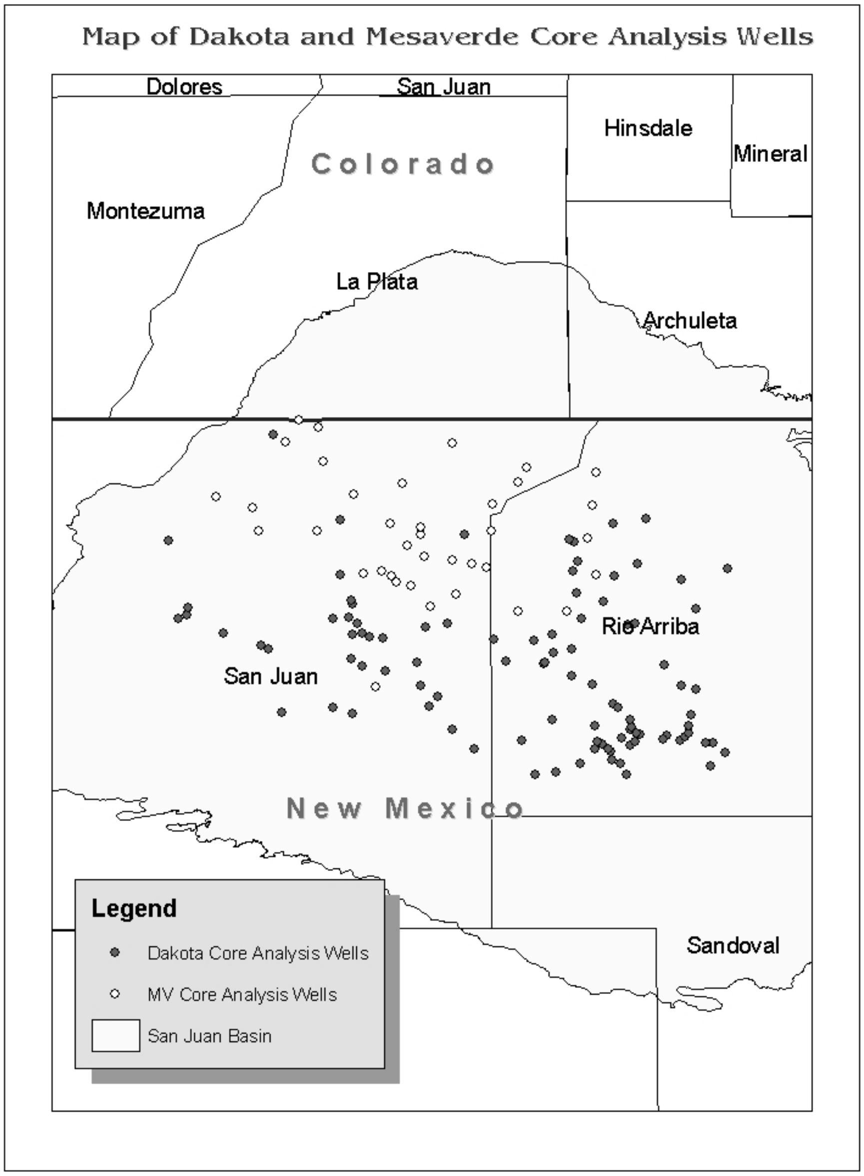

Fig. 1. Map showing study area and location of wells with core analysis data for either Dakota or Mesaverde samples.

Figure 2 shows the spatial distribution of the entire 916-well data set. In addition to the log and core data, it was also necessary to find the top of the productive Dakota interval, as well as perforated intervals.

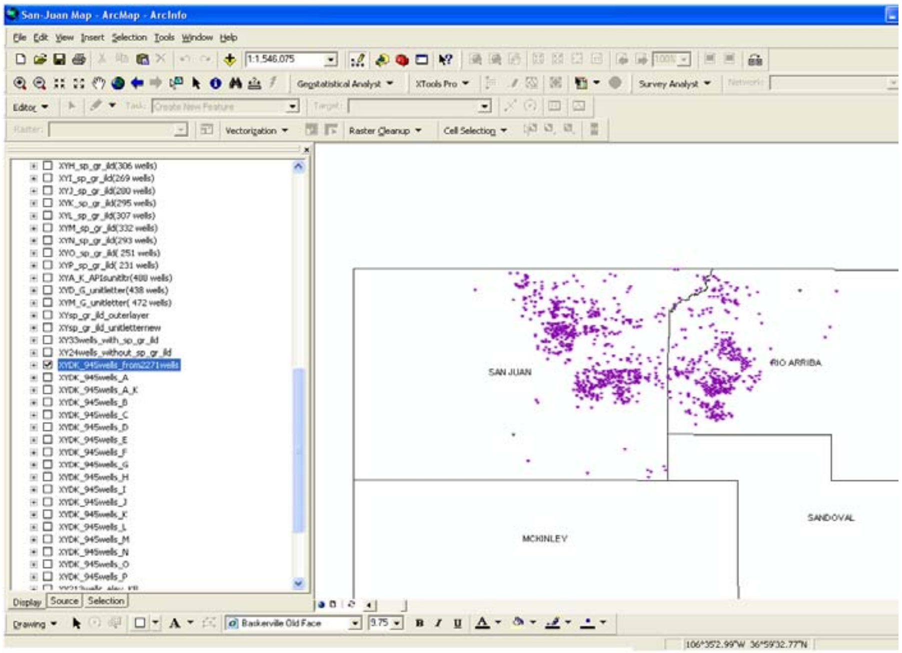

Fig. 2. Distribution of 945 wells with appropriate logs in the Dakota Formation.

To cut down on the amount of time-consuming work involved in picking log tops and perforation intervals, the large data set was decimated to create a smaller subset, which, once the top of the Dakota was picked, could be used for testing. Decimation was achieved by using only wells that were located in units A and K of any given section (a typical section of land is subdivided into 16 units of roughly 40 acres, lettered A-P). This subset of 177 wells had a geographical distribution that fairly closely matched that of the large data set (Fig. 3).

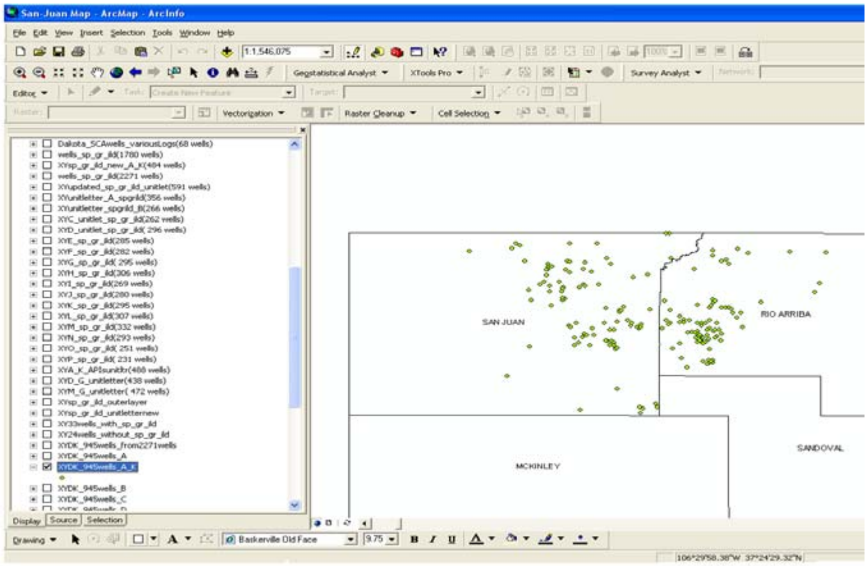

Fig. 3. Distribution of decimated set using wells only in Units A and K.

Spatial Analysis

Artificial Neural Network (ANN) theory has been widely applied in several aspects of well log interpretation in the petroleum industry including parameter prediction as well as other model recognition problems. Among several neural network models and algorithms applied in petroleum industry, the feed-forward neural network model and back-propagation algorithm are most widely used for their easy implementation and high robustness and are selected to predict logging parameters, such as porosity, permeability, oil saturation and water saturation (S_w), in the same oilfield.[1] In order to construct and apply the neural network to model the special core data, the software package PredictOnline[2] was used. PredictOnline is a supervised learning program that uses a scaled conjugate gradient algorithm and allows for multiple layer network architectures. It allows the user to quickly evaluate a number of different architectures by providing a correlation coefficient. In general, the closer the correlation coefficient is to 1.0 for both training and testing data, the better the neural network.

As an example of how a neural network can be used in this context, consider a well for which both log and core data are available for a number of points. Since core data is scarcer than log data, a neural network that could predict outputs of a core analysis from log data only would be a useful tool. To develop such a tool, a file is created with selected log data and the desired core output at each measurement interval. This file is used to train the neural network. Various architectures can be tried until a satisfactory network is developed, as measured by an R2 coefficient. Once this network has been developed, a file containing only the log data is uploaded, and the neural network predicts the desired output.

A systematic approach was used to develop the neural network. First, a training data file containing the three selected inputs and related outputs at the 18 wells was uploaded to PredictOnline. The data set consisted of 1831 sets of records. The three selected inputs were wireline log values of SP/GR/ILD and related outputs were porosity, permeability and water saturation. A constructive approach was chosen to find the best network by starting with simple networks and adding complexity until a desired and repeatable correlation coefficient was reached.

Porosity Correlation

The first correlation used the three selected inputs (SP/GR/ILD) and porosity measured from the core samples as the output and a solution was found using a 3-32-35-1 neural network with an average R2 value of 0.70 and a correlation coefficient of 0.84 for the training data. Ten percent of the total data was set aside for blind testing. On random testing the R2 value was 0.72 and the correlation coefficient was 0.84 (Fig. 4). The network was used to predict all data; the crossplot in Fig. 5 shows the relationship between actual and predicted data (a perfect correlation would show a line between 0 and 1). Neural networks are used to identify trends and result in generalized solutions that identify relationships in the overall distribution rather than focusing on precisely predicting fewer data. Analysis of the distribution shows that a robust solution was found. Predicted porosity values can be used in subsequent maps and analysis with a high degree of confidence.

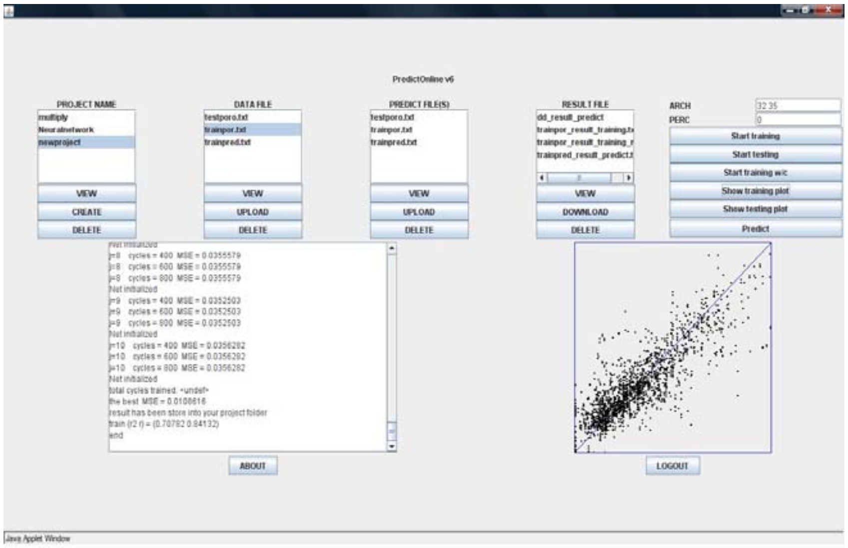

Fig. 4. Training plot of porosity.

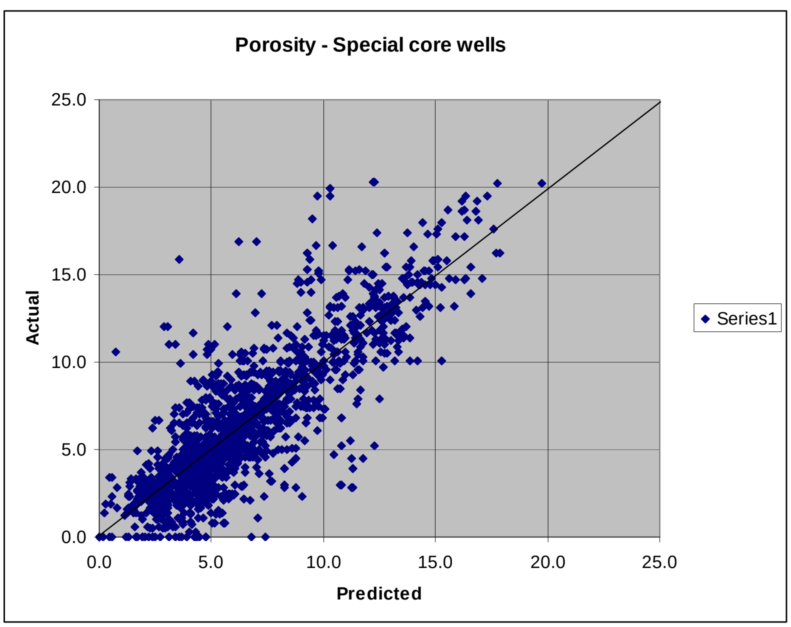

Fig. 5. Graph of actual vs. predicted porosity.

Permeability Correlation

Similar steps were taken to train the network for other data files using the same inputs but with different core-based outputs. The second training data file used core permeability as the output. A solution was found using a 3-15-15-1 neural network with an average R2 value of 0.78 and a correlation coefficient of 0.88. Again, 10% of the data was set aside for blind testing with an R2 value of 0.76 and correlation coefficient of 0.87 resulting (Fig. 6). The network was used to predict all data; the crossplot in Fig. 7 shows the relationship between actual and predicted data. While this solution appears numerically better than the porosity correlation, the fact that much of the data is dominated by very low values (millidarcies) indicates that the solution will be most useful in areas of high permeability and that lower permeability areas tend to be overgeneralized. It is possible that high permeability areas identified by this data could correspond to areas with above-average fracturing.

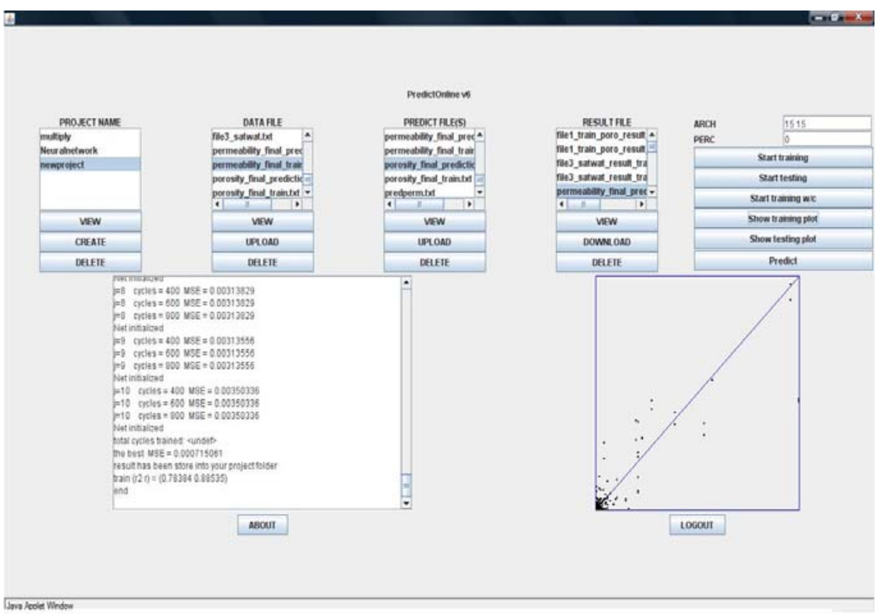

Fig. 6. Training plot of permeability.

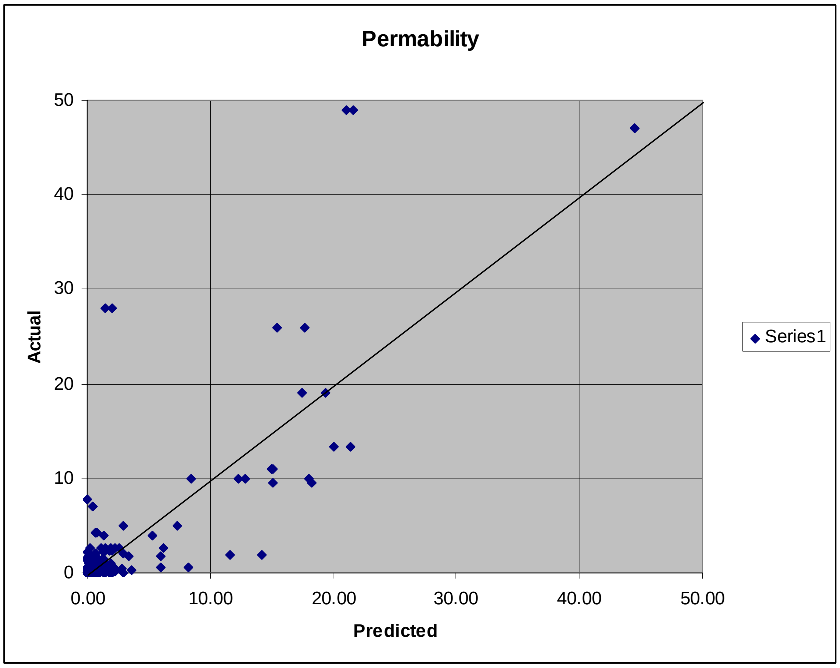

Fig. 7. Plot of actual vs predicted permeability. Note that predictions are much better in very low permeability rocks, and tend to overpredict permeabilities elsewhere.

Water Saturation Correlation

The third training data file used the same three inputs with Water Saturation as the output. A 3-40-40-1 neural network was trained with an average R2 value of 0.53 and a correlation coefficient of 0.73. Again, 10% of the data was set aside for testing; the predicted R2 value was 0.60 with a correlation coefficient of 0.77 (Fig. 8). The network was used to predict all data. The crossplot in Fig.9 shows the relationship between actual and predicted data. Numerically the S_w solution was the worst of the three; however, the solution did capture general trends and should be able to identify areas as high, medium, or low S_w effectively.

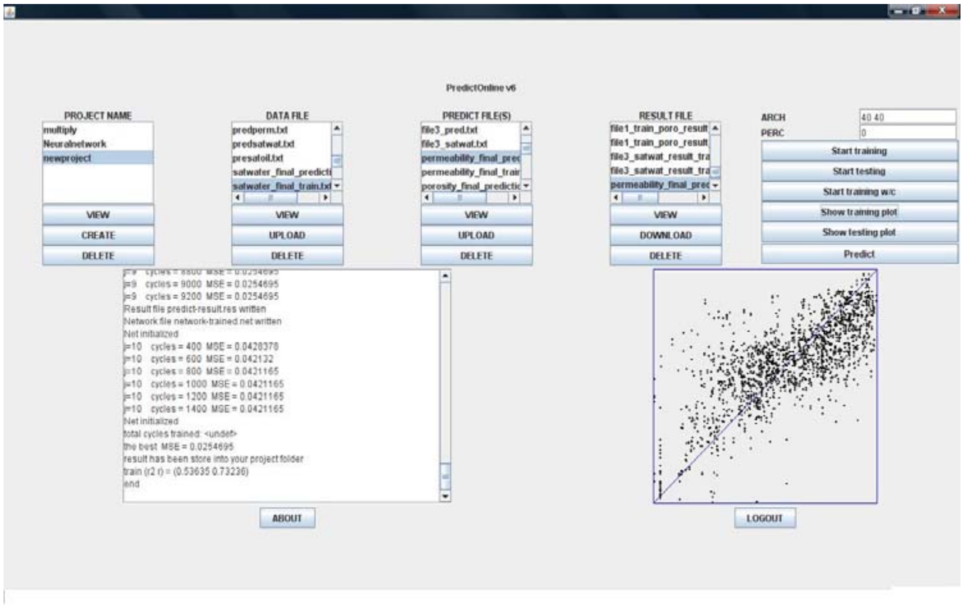

Fig. 8. Training plot of water saturation.

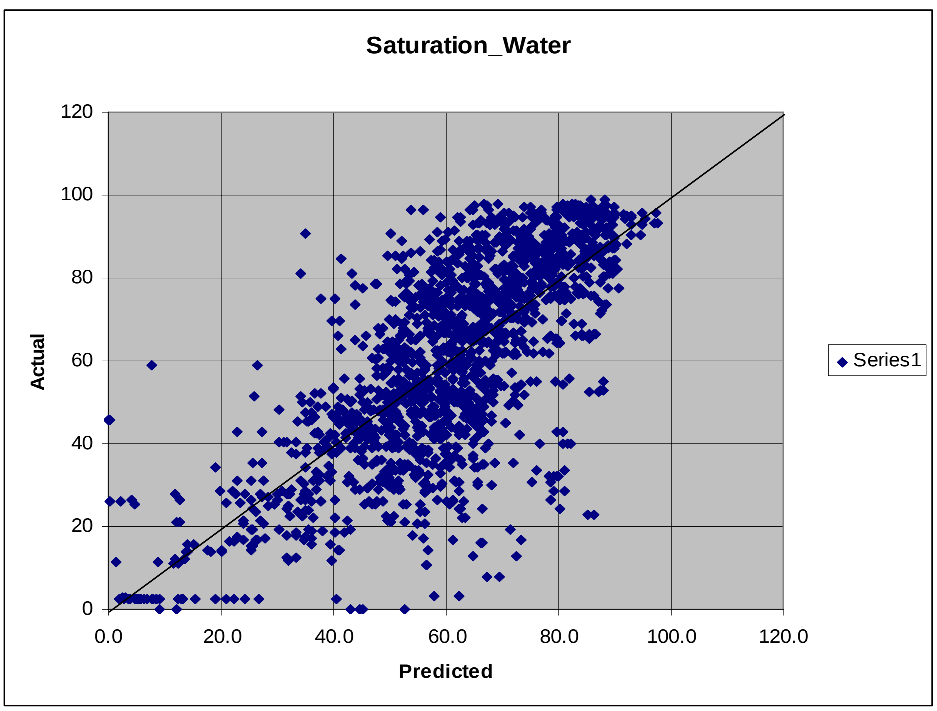

Fig. 9. Actual vs predicted water saturation.

Predictions at non-core wells

The data set containing 898 wells with the three key logs (SP/GR/ILD) but no core analysis data covers a much larger geographical area than the 18 core wells used in the neural network analysis. Using the equations for SP/ILD/GR generated using core data, we were able to predict porosity, permeability, and water saturation over a much larger area and typically in one-foot vertical intervals, effectively creating a large pseudo core data set. On the basis of this analysis, porosity had the best solution, water saturation had usable solutions, and permeability had less general value.

Using ANN correlations, values for porosity and water saturation became calculable across the entire area occupied by the Dakota formation. Several layers were required to complete the study. For predicted values at 898 wells in the study that had SP/GR/ILD well logs, layers of average values were generated, using kriging for extrapolation. This data was then evaluated using some rule-of-thumb parameters generally believed to be prerequisite for making a good Dakota well. These rules include having porosity greater than 5%, water saturation less than 50%, and finally, there must be a sufficient thickness of rocks meeting those two parameters to justify drilling and completing expensive wells. Layers depicting these various rules were generated and depicted using ArcGIS. In Figs. 10–15, results of this analysis can be seen. We see considerable artifacts of the analysis around the edges of the study area, as evidenced by the strong orthogonal patterns well away from data clusters. In the data-rich parts of the basin, the results appear to match what is seen in log values fairly well.

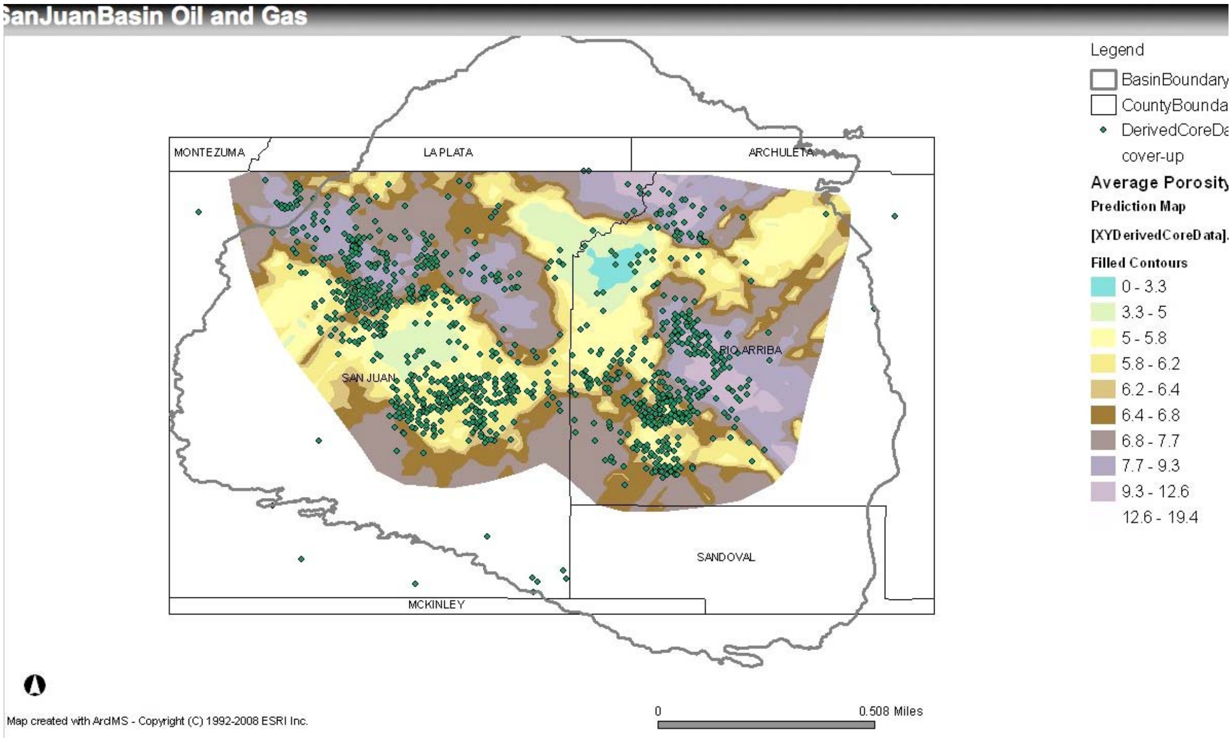

Fig. 10. Predicted pseudo- core porosity using a neural network.

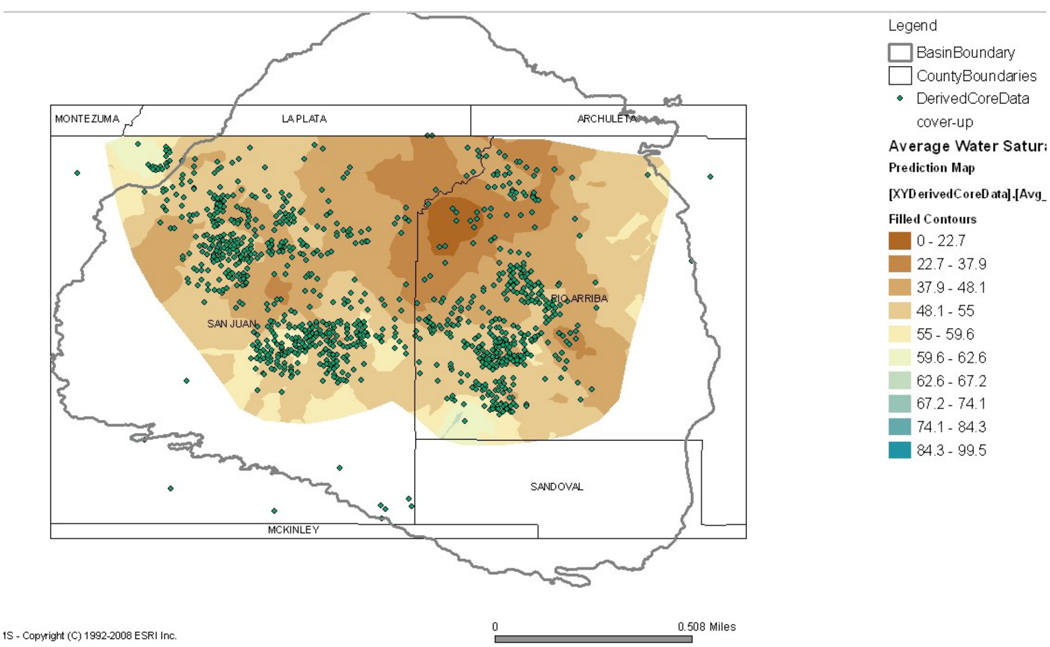

Fig. 11. Average predicted water saturation values determined from neural network.

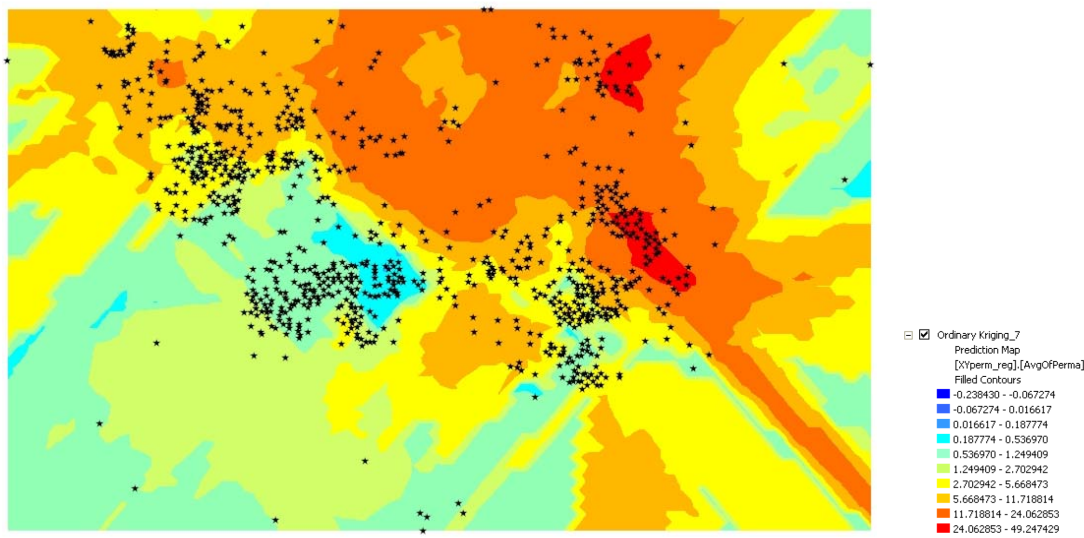

Fig. 12. Average predicted permeability. Colors represent predicted permeability in millidarcies. Warmer colors are higher predicted permeabilities. Strong orthogonal pattern is probably due to artifacts of the kriging process.

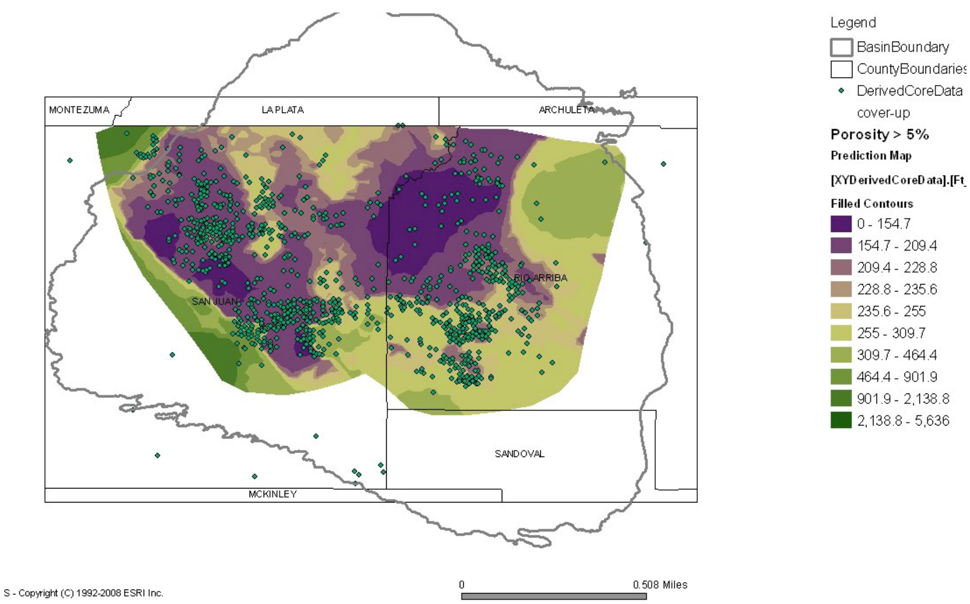

Fig. 13. Isopach of Dakota thickness in feet, where predicted porosity is greater than 5%. Purple colors represent thinner "quality" sands. Most variability at the edges of the map is an artifact of the lack of data in those areas.

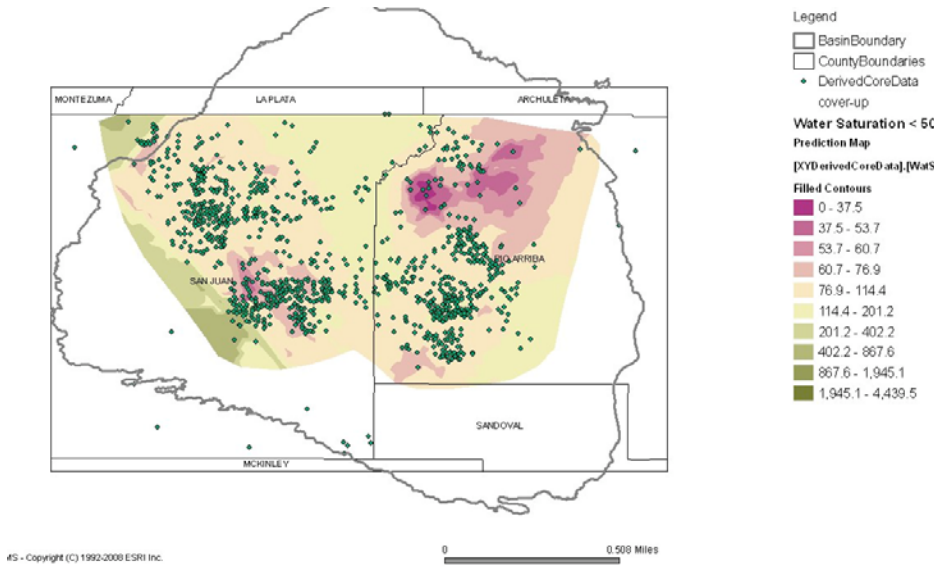

Fig. 14. Isopach map showing thickness of Dakota Formation in feet, where predicted water saturation is less than 50%. Purple colors represent thinner zones with low water saturation (better reservoir rock).

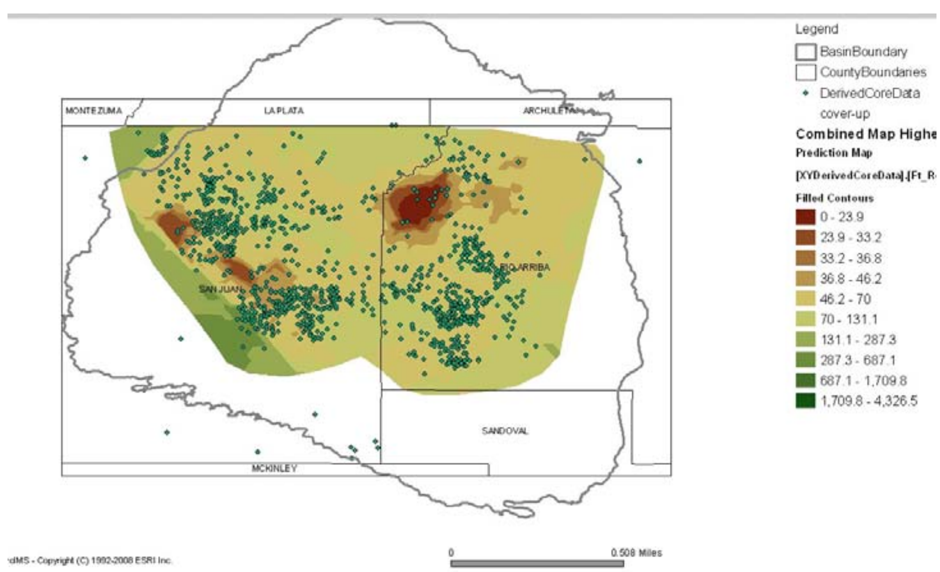

Fig. 15. Isopach map combining water saturation and feet of porosity. In general, areas of brightest colors show areas with higher predicted reservoir quality, as suggested by thicker zones of higher porosity and lower water saturation.

Summary of Spatial Analysis

The very complicated relationships between the three wire-line logs and core porosity were computed using neural network analysis. Using this technique, reasonable predictions of core porosity are possible, and when applied to more than 898 wells in the field, resulted in pseudo- core porosity data over a large area. The vertical detail in each of these predicted wells could be geostatistically interpolated to provide a core porosity volume for the region and could lead to more accurate estimates of gas in place. Water saturation was computed using a separate analysis and the same three inputs. A strong enough correlation was found to justify generating a data set of pseudo-water saturation data. A third neural network was used to calculate permeability; however the results were less satisfying since the Dakota is a very tight formation and the majority of the data is skewed to the low side of the distribution. A fourth network was attempted to determine oil saturation; however no reasonable solution was found.

Applications of Core Data Usage

The objective of this section was to demonstrate several practical applications using the collected, cleaned and assembled data for petrophysical analysis. The ultimate goal of the project is to expand the recoverability of natural gas from low-permeability formations. The approach is to improve reservoir characterization of the Dakota Formation in the San Juan Basin by integrating various sources of available information. For a given well, access to core data leads to the calibration of log data and refinement of the log interpretation. Furthermore, the resulting correlation can be extended to wells without core. In both cases, the potential benefit is the distinction of flow and storage capacity for various zones. This has implications for distinguishing pressure depleted zones, for identifying bypassed pay zones and for stimulation design. Furthermore, drainage shape can be inferred with multiple core permeability measurements and thus impact infill well potential. The following work provides methods and preliminary findings for applying the acquired data.

INFILL WELL POTENTIAL

In low-permeability reservoirs, the drainage area of a well is typically elliptical due to the permeability anisotropy. This anisotropy is enhanced by natural fractures. Figure 16 illustrates the fracturing that can occur in the Dakota Formation in the San Juan Basin.

Fig. 16. Surface outcrop photo of fracture network in the Dakota Formation, San Juan Basin[3]

To avoid depletion from existing wells, infill well locations need to be situated in areas of minimum drainage from the existing wells. As shown in Fig. 17, knowledge of permeability anisotropy plays an important role in optimizing well placement.

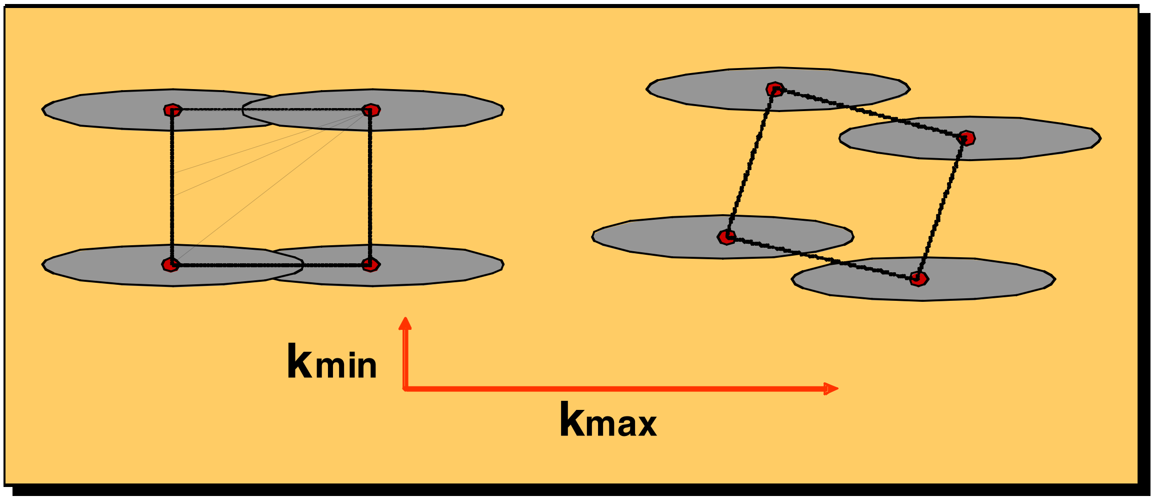

Fig. 17. Schematic of drainage area as a function of permeability anisotropy and well orientation.[4]

One problem is how to determine the permeability anisotropy. Analysis of multiwell pressure transient testing used in the Mesaverde was inconclusive. Particular problems occurred due to the low permeability, compressible fluid and multilayered system. Specialized logs can record oriented geologic information, but are expensive and frequently proprietary in nature. However, from this project, kmax/k90 core data was acquired and available for 10 wells in the Dakota. Figure 18 is a histogram of the kmax/k90 core data expressed as percent of samples residing in the given categories.

Notice in this figure how the distribution is skewed to the lower end; thus a majority of samples demonstrate isotropic or near isotropic behavior. The higher ratios are believed (not verified) to represent core samples with natural fractures. The highest ratio was 35:1 (2.13 md: 0.06 md), the average ratio of all of the data was 2.8.

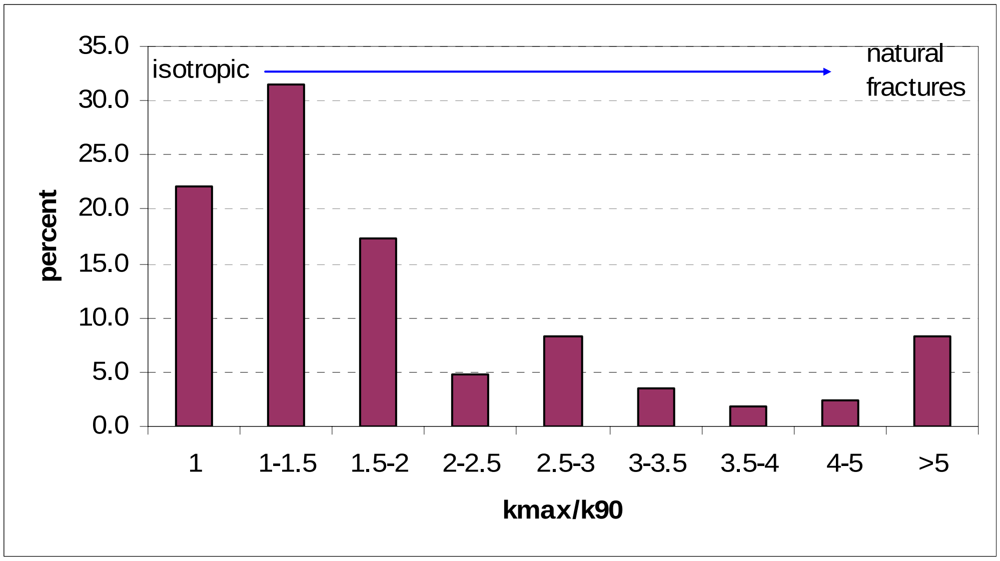

Fig. 18. Percent of kmax/k90 ratios for the given categories, N=168.

DISTINCTION OF FLOW/STORAGE CAPACITY FOR VARIOUS ZONES

To improve the correlation between a petrophysical model and actual production, log data was correlated with core information to build a petrophysical model for the Dakota Formation. The resulting calibrated model will have a robust correlation transferable to wells with log data only. The benefits will be to assist in identifying bypassed zones in existing wells and in quantifying net pay and reserves in producing zones. Furthermore, this work will aid in distinguishing a "relative" flow capacity of individual zones in the Dakota. This has implications on identifying pressure depleted zones and stimulation design.

From a database of over 100 cored wells, 18 wells were selected for analysis. The reduction was dependent on the log and production data available for the given set of cored wells.[5]

The fundamental equation for determining water saturation in a clean formation is Archie's Law.

$$S_w = \sqrt{\frac{FR_w}{R_t}} \qquad (1)$$

The formation water resistivity, R_w, was determined from two sources: SP logs from 33 cored wells and water samples from three wells. Water chemistry data is available at http://octane.nmt.edu/waterquality/data . Composite results are shown in Fig. 19.

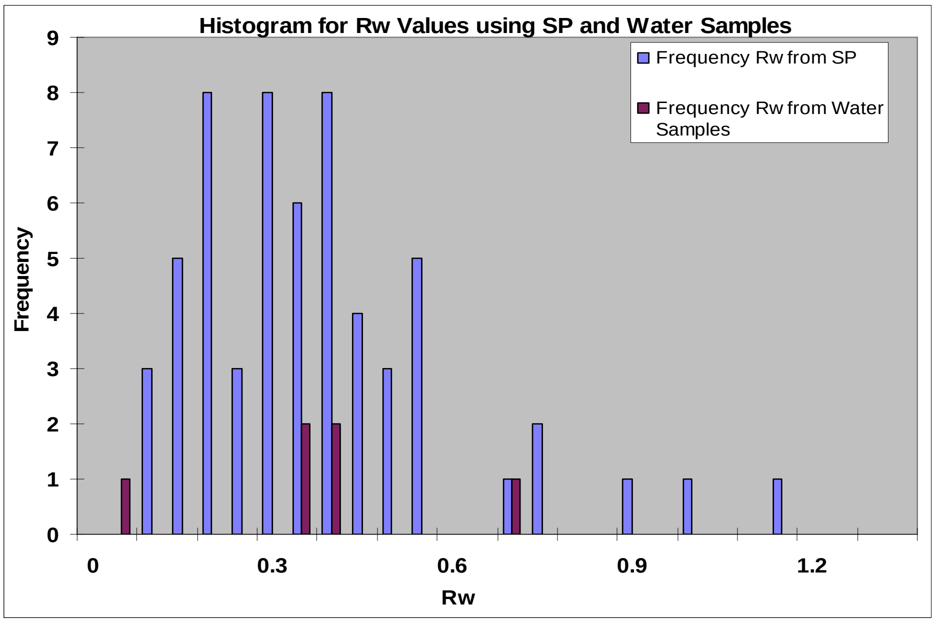

Fig.19. Histogram for Rw valuses using SP and water samples.

The wide range in R_w values is a result of the poor SP response due to shaliness, presence of gas, and limited invasion,[6] all of which occur in the Dakota. Therefore a subset of the cleanest, most prolific producing zones was removed and analyzed separately. The most frequent value of this subset, Rw = 0.30 ohmm, was selected for the remaining calculations.

The next step was to correlate core porosity with the log porosity. Of the 18 wells in the dataset, two-thirds had sonic logs and the remainder were density, neutron, or a density/neutron combination. Other possible applications of the core data are:

- comparison of core porosity to travel time from sonic logs,

- comparison of core porosity to bulk density measurements,
- application of core grain density measurements to density log calculations.

A comparison of core and log porosity is shown in Fig. 20 for a single well, Example A. Three log porosities are shown: neutron, density and the RMS of the density-neutron combination.

From this figure we can observe that the RMS log porosity provides the best fit to the core values. The artificially high neutron (and RMS) log porosity values at low core porosity is a response to the high level of bound water in shale zones. A perfect fit would result in a correlation matching a 45° line (dashed line). Notice the log porosity overpredicts for low core values and underpredicts for high core values.

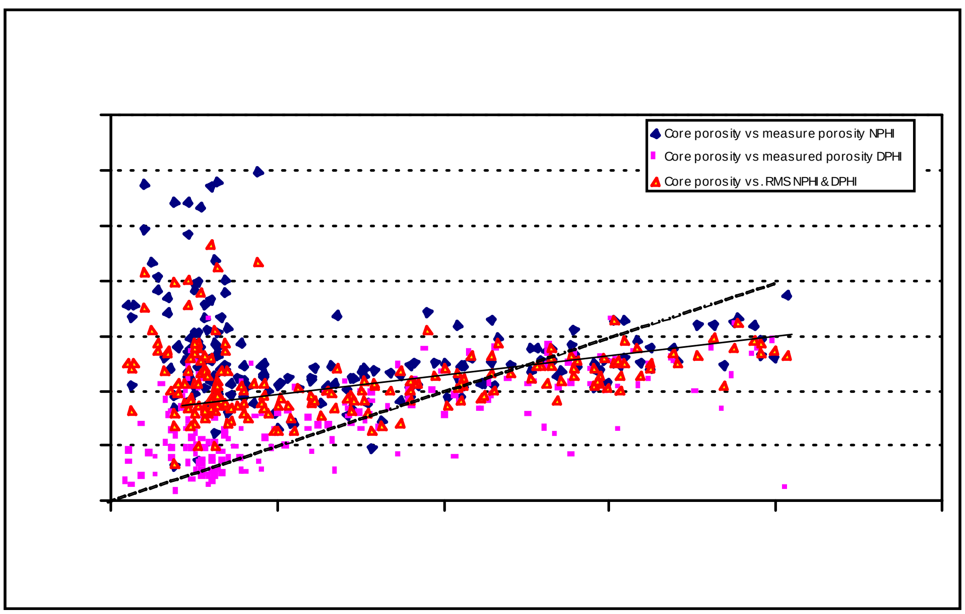

Fig. 20. Core vs log porosity for Example well A.

Estimating permeability from conventional well logs relies on some form of empirical equation. In this work, we used Morris and Biggs modification[7] for gas of Timur's original equation.

$$k_{\log} = B^2 \left(\frac{\phi_{\log}^6}{S_{wirr}^2} \right) \qquad (2)$$

where the constant B = 79 is for gas-bearing formations.

To estimate irreducible water saturation, bulk volume water (BVW) was used.[8] That is, BVW is a constant, given by:

$$BVW = S_{wirr} * \phi_{\log} = c \qquad (3)$$

Based on the work of Fertl and Vercellino[9] the BVW is considered constant for a given grain size. Substituting Eq. (3) into Eq (2), using core permeability values, and rearranging, results in an expression to solve for the constant, c.

$$c = \left(79^2 \left(\frac{\phi_{\log}^8}{k_{core}} \right) \right)^{1/2} \qquad (4)$$

The average values for given Dakota members are:

Table 1: Average Values for c by Geologic Member

Member	Constant, c	Grain size
Twowells	0.080	Silt
Paguate	0.047	Fine sand
Cubero	0.043	Fine sand
Oak Canyon	0.052	Very fine sand
Burro Canyon	0.040	Fine sand

Permeability from logs can now be determined by:

$$k_{\log} = 79^2 \left(\frac{\phi_{\log}^8}{c_i^2} \right) \tag{5}$$

where ci is the average member constant from Table 1. The results compared to core permeability are shown in Fig. 21 and for individual members in Fig. 22. Core data was adjusted to *in situ* conditions using published correlations.[10]

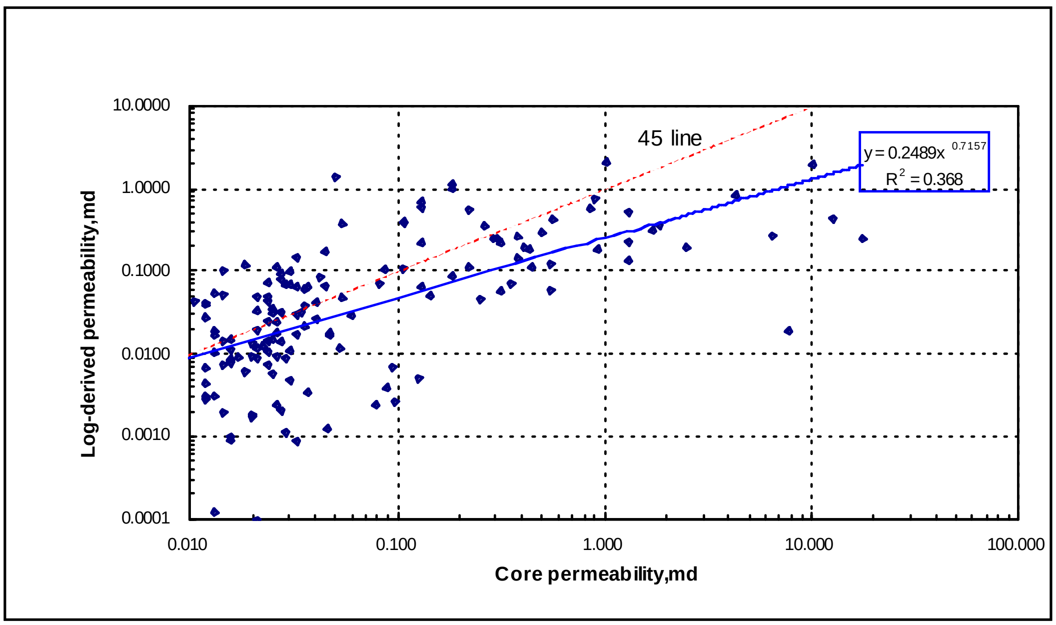

Fig. 21. Correlation between core and log permeability.

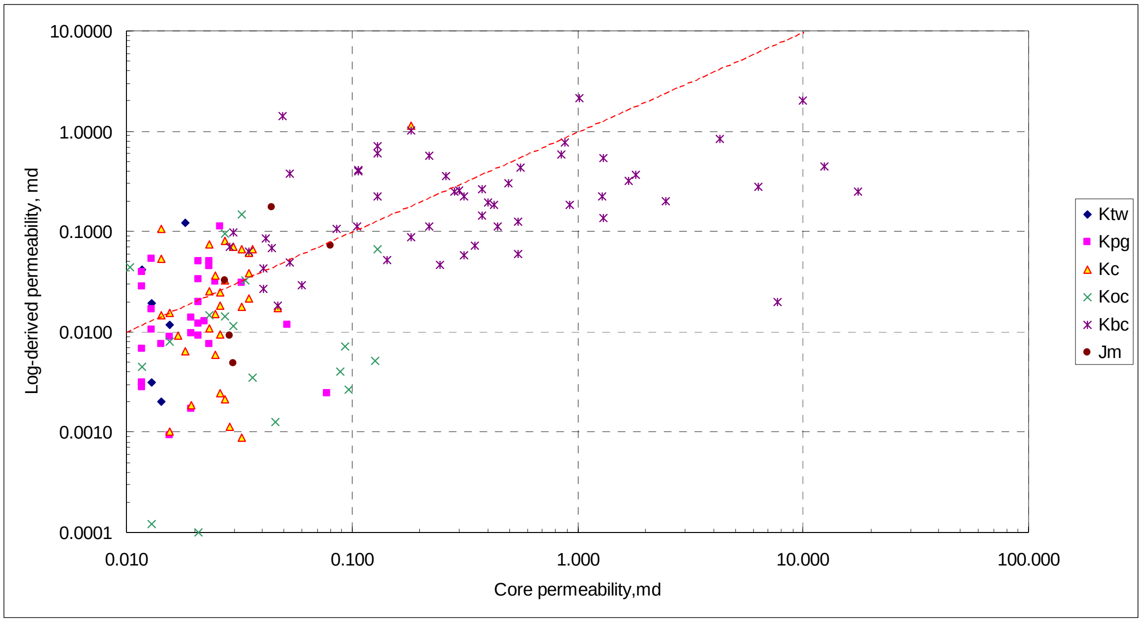

Fig. 22. Correlation between core and log permeability separated by geologic member.

The correlation is reasonable even though significant scatter does exist. The resulting log permeability correlation (Eq. 5) coupled with the c values from Table 1, were applied to other wells. Figure 23 illustrates the log interpretation results for Example well B. The perforation interval is indicated in the depth track of the log. Only the Cubero zone was perforated and produced. The calculated absolute open flow for this well was 5.27 mmscfd with cumulative production to date of 2.1 Bscf. The log evaluation confirms this as the best target in the well. Further, core data indicates the Oak Canyon zone contains high water saturation, and therefore was not completed. The log evaluation also confirms this high water saturation as well.

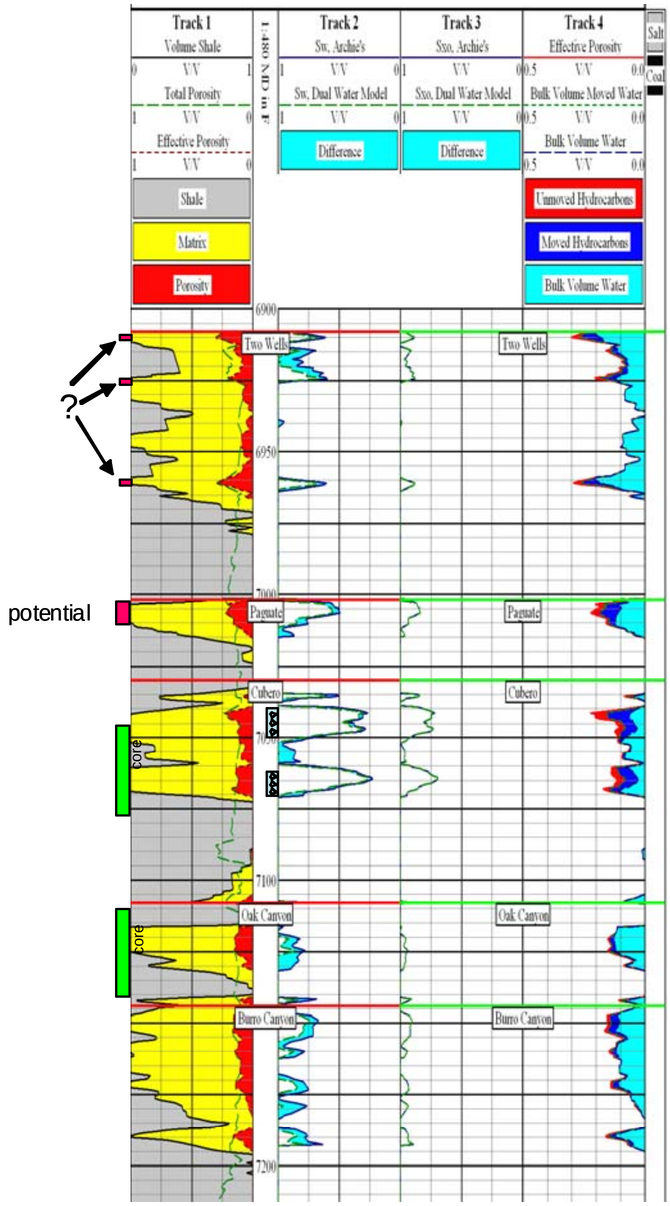

Fig. 23. Log interpretation for Example well B.

The log evaluation indicates several other zones that maybe productive, particularly in the Paguate interval. Table 2 shows the flow and storage capacity for the three zones for two different water saturation cutoff values. Notice the Cubero has the greatest storage capacity of all the cases.

Table 2. Storage capacity and flow for two different water saturation cutoff values.

	Sw cutoff = 50%		Sw cutoff = 60%	
Zone	kh (md-ft)	fhSg	kh (md-ft)	fhSg
Two wells	0.0	0.00	1.4	0.04
Paguate	8.6	0.06	34.7	0.43
Cubero	6.8	0.09	8.3	1.54

However, notice the Paguate displays very high flow capacity (especially at higher Sw cutoff). The response represents a thin productive layer with high permeability, likely naturally fractured. Subsequently, the storage capacity is small, but the flow capacity is great.

Future work in this area would include application of correlations to the entire 18 well set to develop kh vs potential and fhsg vs Gp relationships, to calculate c for more examples to determine if there is a variation or if it is fairly constant, and finally, to investigate different k_{log} correlations and the impact of using a different constant B.

Petrophysical Analysis

A significant number of wells were completed in the Dakota Formation in the 1950s and 1960s; many of which are still producing today. To assess the remaining potential, either in these existing wells or in stepout locations or infill locations, one option is to evaluate the core and log information gathered during that past time frame. The provided data could be relevant to an operator with the same vintage of data, or could be used to supplement recently gathered data in a specific area. The discussion below will cite several possible examples of using the old data for petrophysical interpretation.

A small subset of the core data available was selected for analysis. The vintage of the majority of core and log data used is from the 1950s through 1960s, with a few from the 1970s and early 1980s time period. Routine core analysis consisting of porosity, permeability and saturation measurements was available from core plugs. Also, some special core analysis was obtained and included vertical and/or maximum horizontal permeabilities, and grain density measurements. The logging suite varied, with gamma ray-spontaneous potential-induction-sonic the common assemblage.

Example 1

The first example well was drilled in 1960 with an oil emulsion mud. Approximately 80 feet of core was obtained from the Dakota Formation, with the majority analyzed for porosity, permeability and saturations. The logging suite consisted of gamma ray, spontaneous potential, induction and sonic logs. Fig. 24 illustrates the final results of the log analysis for this well, with the core water saturation and porosity measurements included for comparison. The reasonable match with water saturations was obtained by adjusting the formation water resistivity, R_w, for each zone. Accurate values for R_w are unknown and thus become a variable in the analysis process. In this example, R_w was determined to be $\sim$ 0.07 ohmm.

The perforated zones are indicated on the far left-hand side of the figure. Notice an excellent correspondence between these perforated zones to the clean, porous, gas-bearing zones on the logs; confirming the log analysis. This well tested at a CAOF of 2.2 mmscfd with a cumulative production of 1.7 Bscf. According to the logs and core data, the lower zones, below 6925 ft, are wet and thus have no potential.

Also noted in Fig. 24 are possible fracture intervals indicated by anomalously high porosity spikes. This is believed to be in response to cycle skipping on the sonic log. Core descriptions tend to confirm the existence of fractures. Subsequently, low water saturation values are incorrect in these zones and should be ignored.

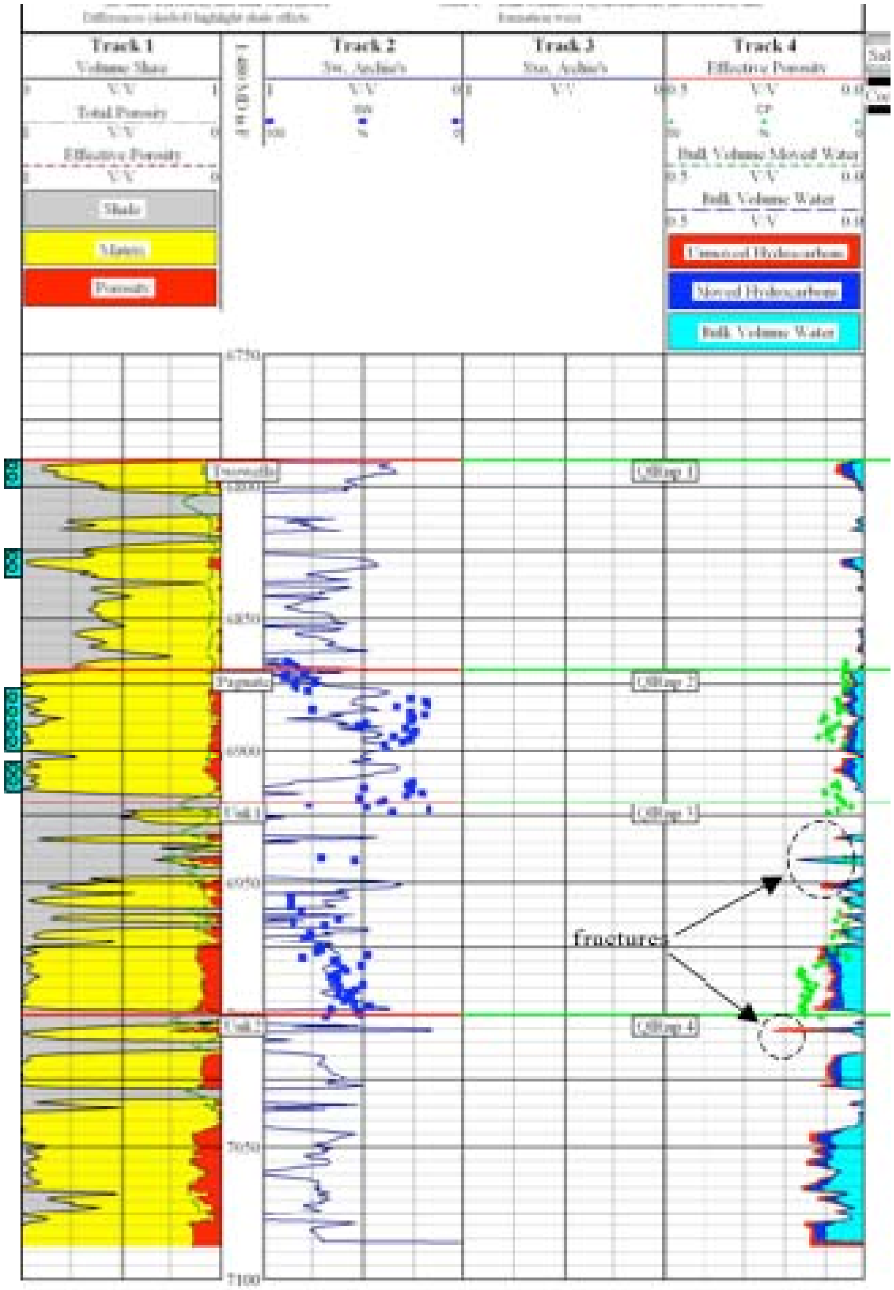

Fig. 24. Log analysis for example well 1 in the Dakota Formation. Core water saturation and porosity values are shown as discrete points. Perforated zones are indicated on the left-side of the log. (Digital Formation, Inc™)

Example 2

The second example well was drilled through the Dakota in 1980 with water-based mud. Core measurements consisted of the routine components; porosity, permeability and saturations. The logging suite includes gamma ray, spontaneous potential, induction and density-neutron porosity logs. Fig. 25 shows the final logging results with the core measurements shown for comparison.

The reasonable match with the core data was obtained by applying a matrix density of 2.65 gm/cc (average value obtained from core grain measurements) and adjusting R_w (in this case R_w = 0.10 ohmm). The perforated intervals correlate with the log-calculated productive intervals, confirming the log analysis. This well tested at a CAOF 0.5 mmscfd, with cumulative gas production of 1.26 Bscf.

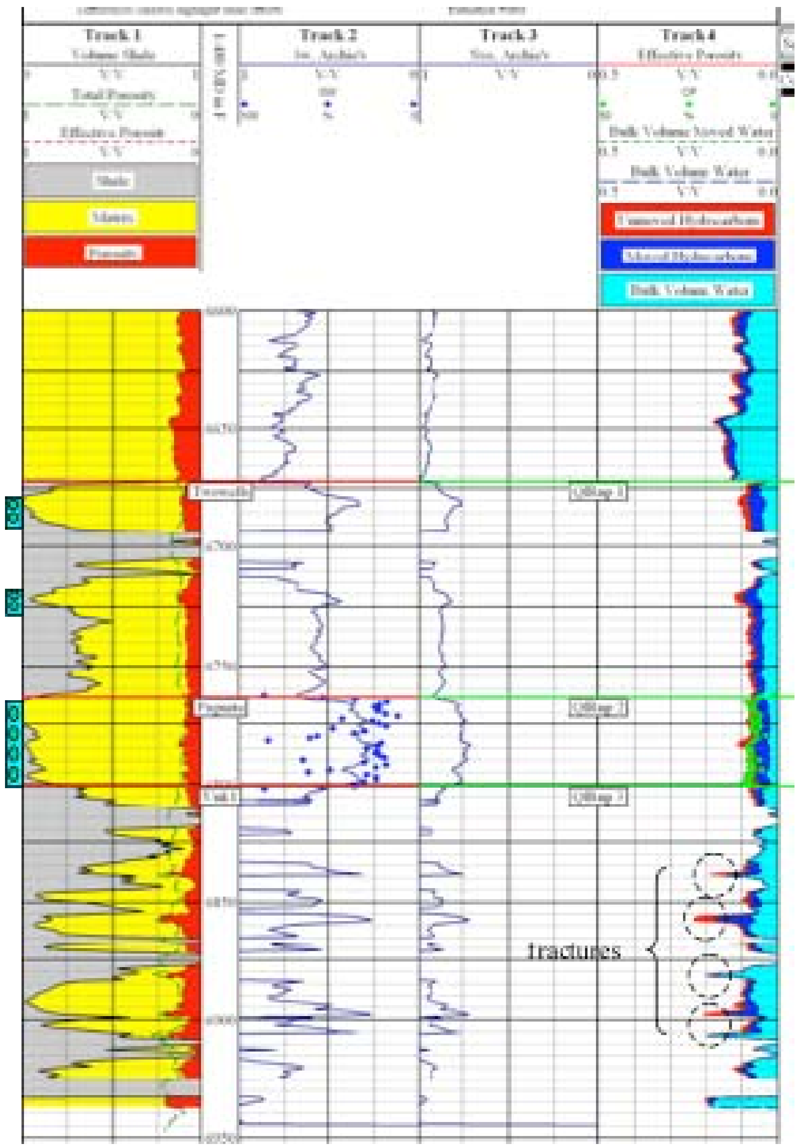

Fig. 25. Log analysis for example well 2 in the Dakota Formation. Core water saturation and porosity values are shown as discrete points. Perforated zones are indicated on the left-side of the log. (Digital Formation, Inc™)

Summary of Possible Applications

Several examples were given to demonstrate possible applications of using the available core data assembled in the first phase of this project. First, the use of multiple core permeability measurements provides a means to estimate horizontal permeability ratio and thus the anisotropy that might exist in the drainage area. This will impact location of infill wells. Second, a log-derived permeability was developed using core data and then applied to a well to identify producing zones. The producing interval and the high water saturated non-producing interval were correctly identified. Furthermore, a bypassed pay zone was identified as a potential target. These findings are preliminary and based only on a small set of wells. A robust correlation will require expansion by including additional wells on a more basinwide analysis.

San Juan Project Web Site

Access to all the data we have collected or created is an important aspect of this project. A website was created for the project (Fig. 26) on our GO-TECH web site (http://octane.nmt.edu). The direct link to the project home page is http://octane.nmt.edu/sanjuan/default.asp

The final data user interface allows users to both view and download data in a variety of ways. Searches may be text-based using an variety of input fields (Fig. 27). Data identified in this search tool can be viewed online, or downloaded (Figs. 28, 29). In addition, users can view and search for some of the data in a graphical map-based format (Figs. 30,31). We also provide shapefiles, a file format useful for those who want to import information into a GIS program. In addition to data files containing information from the database developed for this project, images of all available well files for each of the core analysis wells, obtained from the New Mexico Oil Conservation Division's archive have been provided. These image files are in TIF format and include general well files and reports, and in some cases, images of electric logs. Much of the non-proprietary data compiled for this study is also available by CD upon request, for users who don't wish to download data.

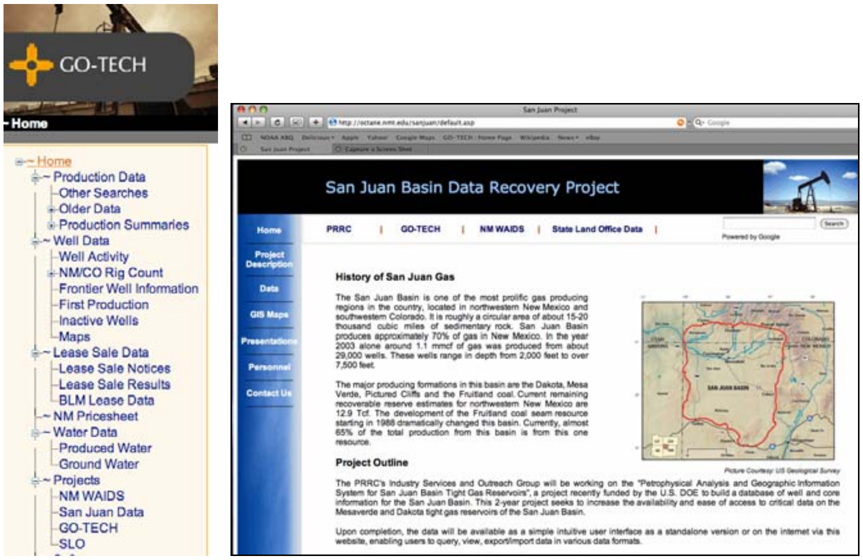

Fig. 26. Screen shot of Go-Tech web site menu with link to San Juan Data project and the San Juan Project home page.

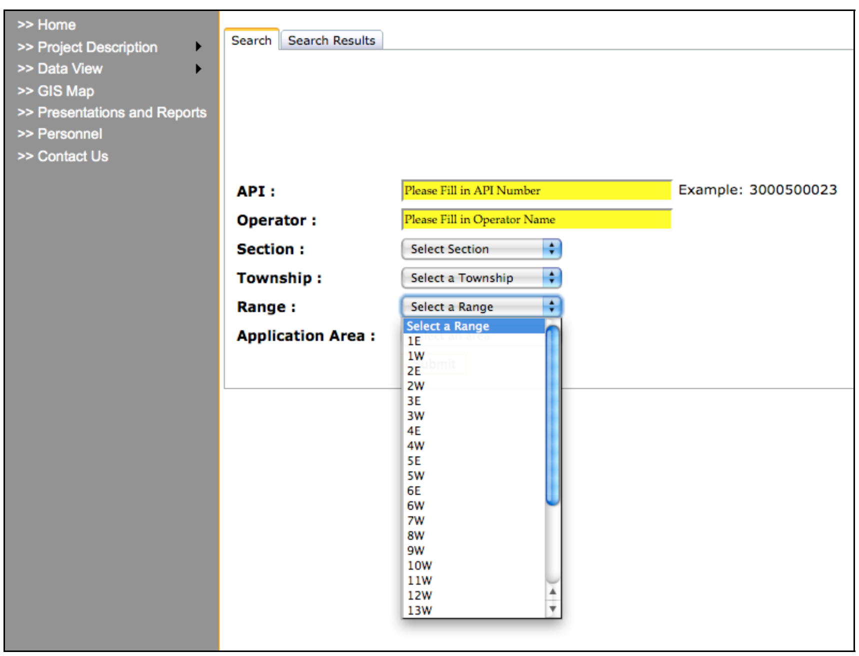

Fig. 27. Data search page. Users can search by a number of different criteria, including well, operator, or location.

CheckAll	API	Well Name	Operator	Section	Township	Range	SPECIAL CORE ANALYSIS	Production Data
	3004506096	HUERFANO UNIT, #080	BURLINGTON RESOURCES OIL & GAS CO	32	27N	10W	N	Production Data
	3004506104	MCADAMS, #002	R E JACKSON	34	27N	10W	N	Production Data
	3004506110	HUERFANO UNIT, #018	BURLINGTON RESOURCES OIL & GAS CO	32	27N	10W	N	Production Data
	3004506112	MCADAMS, #004	DUGAN PRODUCTION CORP	34	27N	10W	N	Production Data
	3004506114	HUERFANO UNIT, #022	BURLINGTON RESOURCES OIL & GAS CO	33	27N	10W	N	Production Data
	3004506116	MCADAMS, #002	DUGAN PRODUCTION CORP	34	27N	10W	N	Production Data
	3004506120	HUERFANO UNIT, #079	BURLINGTON RESOURCES OIL & GAS CO	31	27N	10W	N	Production Data
	3004506128	HUERFANO UNIT, #096	EL PASO NATURAL GAS	33	27N	10W	N	Production Data
	3004506131	HUERFANO UNIT, #106	BURLINGTON RESOURCES OIL & GAS CO	33	27N	10W	Y	Production Data
	3004506156	MCADAMS, #001	DUGAN PRODUCTION CORP	34	27N	10W	N	Production Data

Fig. 28. Search results are displayed in a text window. Users can view or download a variety of information including general well information, average core values, or detailed core analysis data.

General Well Info

API	Well Name	Section	Township	Range	Operator	Special Core Analysis	Production Data
3004506131	HUERFANO UNIT, #106	33	27N	10W	BURLINGTON RESOURCES OIL & GAS CO	Y	Production Data

General Core Info

API	Core Top	Core Bottom	Formation	Average Porosity
3004506131	6402	6503	GP	5.88

Detail Core Info

API	Core Top	Core Bottom	Formation	HPERM	HPERM 90	VPERM	Grain Density	Sat Oil	Sat Waters
3004506131	6402	6403	GP	0.02				0	82.2
3004506131	6403	6404	GP	0.01				0	85.8
3004506131	6404	6405	GP	0.04				0	64
3004506131	6405	6406	GP	0.02				12.2	56.2
3004506131	6406	6407	GP	0.01				5.6	64
3004506131	6407	6408	GP	0.02				4.3	71.9
3004506131	6413	6414	GP	0.02				3.8	75.6
3004506131	6414	6415	GP	0.29				11.8	20.9
3004506131	6415	6416	GP	0.16				5.9	21.9
3004506131	6416	6417	GP	0.16				8.6	21.9
3004506131	6417	6418	GP	0.05				9.6	40
3004506131	6418	6419	GP	0.06				13.3	60.3
3004506131	6455	6456	GP	0.04				11.9	59.6
3004506131	6456	6457	GP	0.04				0	39.2
3004506131	6457	6458	GP	0.08				5.9	44.7
3004506131	6458	6459	GP	0.13				2.7	42
3004506131	6459	6460	GP	0.14				3.8	42.1
3004506131	6460	6461	GP	0.02				10.4	37.5
3004506131	6461	6462	GP	0.02				4.8	47.7
3004506131	6462	6463	GP	0.03				4.1	28.5

1 2 3

Fig. 29. Average core analysis values for a selection of wells.

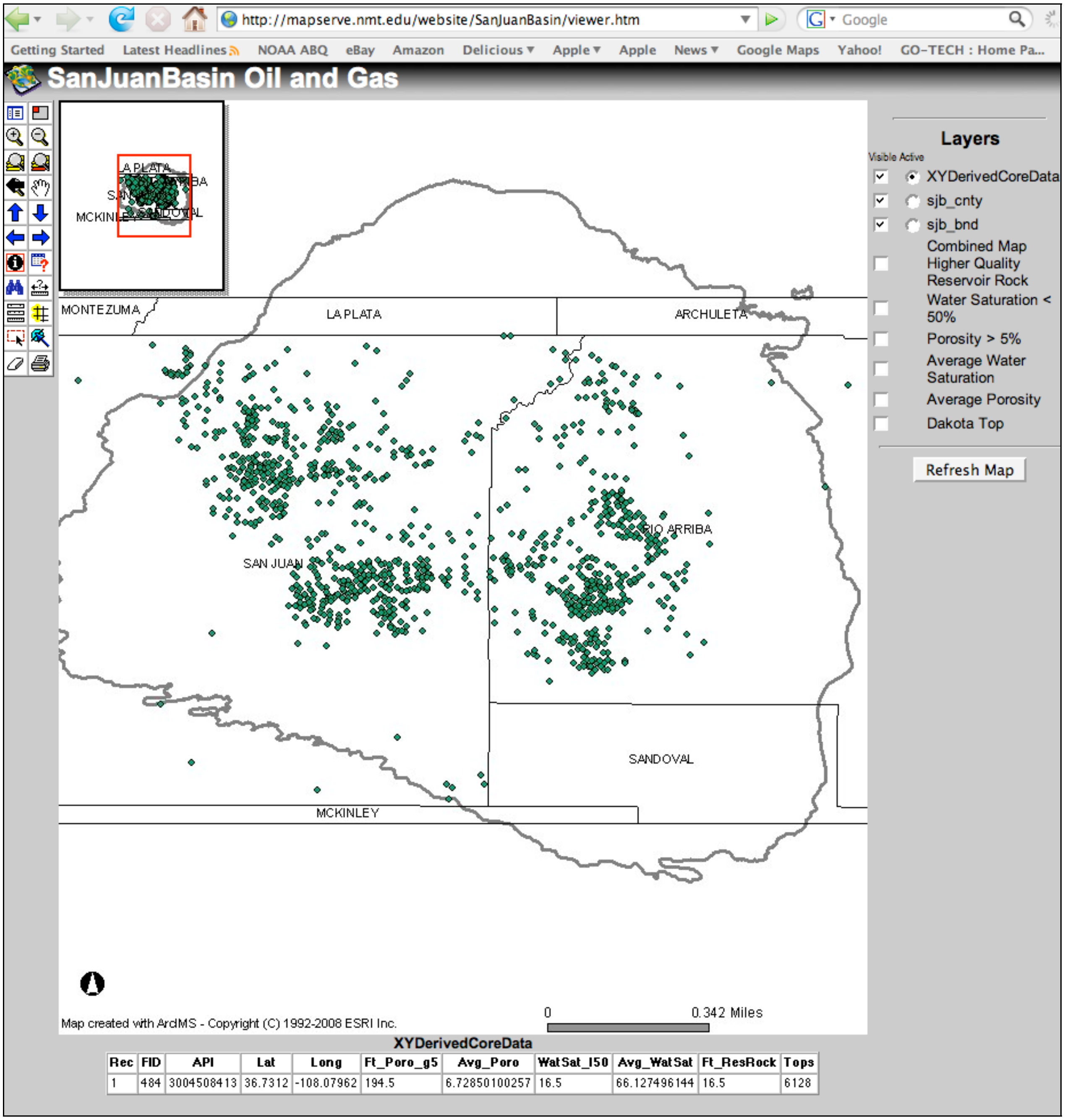

Fig. 30. Screen shot showing online GIS and locations of wells used in the geospatial analysis portion of this project.

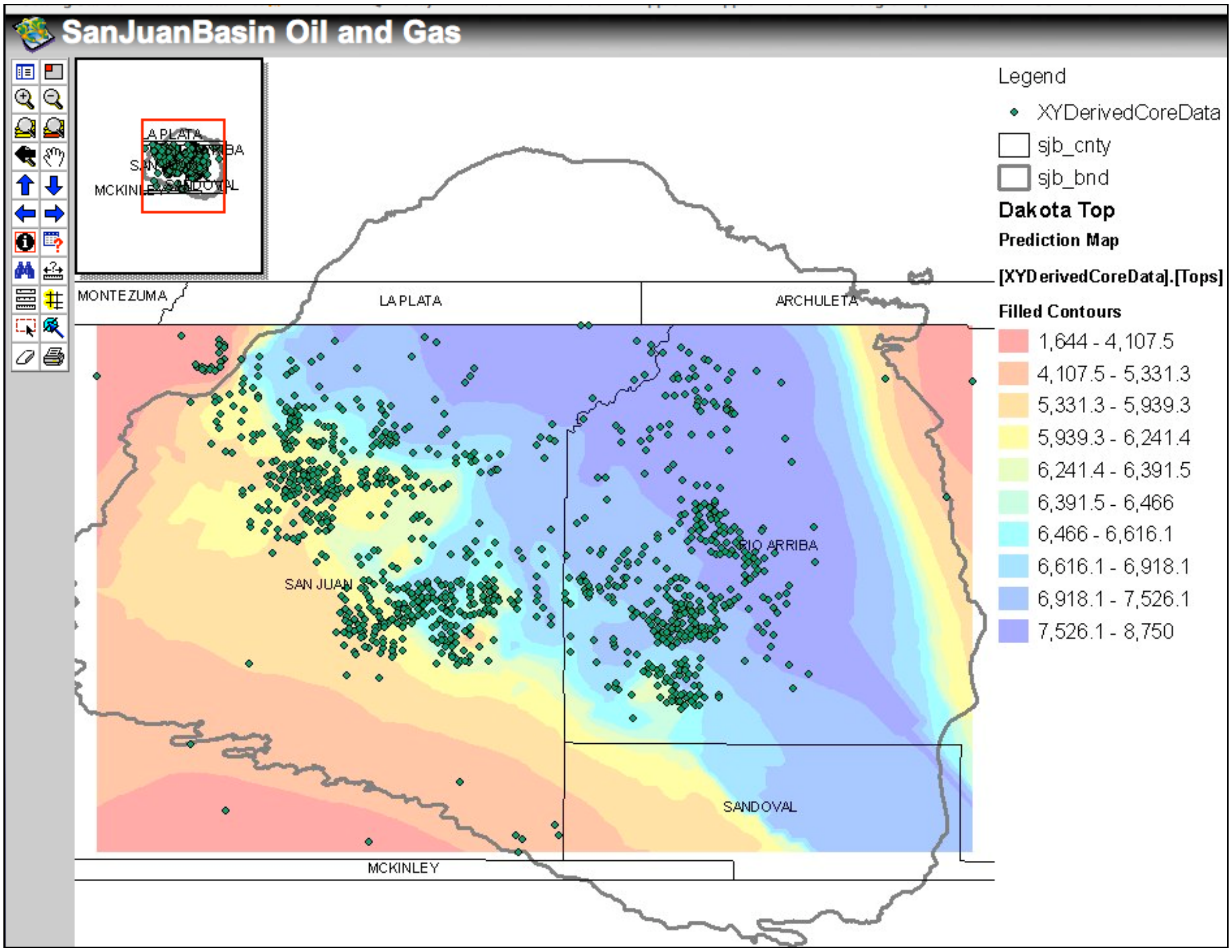

Fig. 31. Screen shot showing s depth to the top of the Dakota Formation, gridded across the study area.

TECHNOLOGY TRANSFER

Technology transfer for this project was conducted through several avenues. The primary means of tech transfer is through the web site itself. This site is a permanent archive and is always available through links from the GO-TECH web site (http://octane.nmt.edu), the primary site used by PRRC for dissemination of oil and gas data. The Go-Tech site gets several million hits each year, and the link to the San Juan Project is visible from each page of this web site. A second means of technology transfer was via talks given to local and regional groups of interest. These groups included the

Roswell Geological Society and SPE chapters, the Four Corners Geological Society, and the Independent Producers of New Mexico groups. The New Mexico Oil and Gas Association was also made aware of the project. In addition, we have visited with interested parties up in Colorado in personal visits. Formal presentations that included discussion of this project were also made at the 2008 meeting of Rocky Mountain Section of the AAPG, and also the 2008 Southwest Petroleum Short Course, as well as in kickoff meetings in Farmington NM at the onset of the project. Finally, there was an article covering this project in the semi-annual newsletter put out by the PRRC. This newsletter goes to several thousand readers in the New Mexico area.

CONCLUSIONS

During the course of this project, a great deal of data has been collected, cleaned, integrated, and analyzed for a variety of purposes. Core data became the basis for a study that successfully used neural networks to integrate core and wireline log data to interpret a variety of petrophysical parameters across the basin. Detailed core and log data was also used to make a number of other observations about the study area. First, the use of multiple core permeability measurements provides a means to estimate horizontal permeability ratio and thus the anisotropy that might exist in the drainage area. This will impact location of infill wells. Second, a log-derived permeability was developed using core data and then applied to a well to identify producing zones. The producing interval and the high water saturated non-producing interval were correctly identified. Furthermore, a bypassed pay zone was identified as a potential target.

The resulting collection of data has been integrated into a final online user interface that will allow anyone with internet access to download a tremendous amount of information regarding the Dakota Formation within the San Juan basin.

ACKNOWLEDGEMENTS

The authors would like to express their gratitude to Digitial FormationTM for use of their formation evaluation software, and to IHS EnergyTM for use of their production database. The New Mexico Oil Conservation Division and the New Mexico Bureau of Geology and Mineral Resources have also provided valuable resources for this project.

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National Energy Technology Laboratory

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

One West Third Street, Suite 1400
Tulsa, OK 74103-3519

1450 Queen Avenue SW
Albany, OR 97321-2198

2175 University Ave. South
Suite 201
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