

RESERVOIR CHARACTERIZATION OF UPPER DEVONIAN GORDON  
SANDSTONE, JACKSONBURG, STRINGTOWN OIL FIELD,  
NORTHWESTERN WEST VIRGINIA

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Jacksonburg, Stringtown Oil Field, Northwestern West Virginia

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## TABLE OF CONTENTS

<b>Table of Contents</b>	iii
<b>List of Figures</b>	v
<b>Abstract</b>	vii
<b>Executive Summary</b>	ix
<b>Introduction</b>	1
<b>Results and Discussion</b>	3
<b>Task 1: Subtask 1.3 - Log Digitization/Autocorrelation</b>	3
<b>Milestone 10</b>	3
<b>Task 1: Subtask 1.4 - Data Analysis</b>	3
<b>Milestone 13</b>	3
<b>Task 2: Subtask 2.2 – Structure</b>	3
<b>Milestone 21</b>	3
<b>Milestone 23</b>	5
<b>Milestone 24</b>	5
<b>Task 2: Subtask 2.5 – Petrophysics</b>	5
<b>Milestone 33</b>	5
<b>Milestone 34</b>	8
<b>Task 3: Outcrop Permeability Study</b>	10
<b>Milestone 41</b>	10
<b>Task 4: Subtask 4.2 - Modeling and Simulation</b>	13
<b>Milestone 50</b>	13
<b>Milestone 51</b>	13
<b>Task 6: Technology Transfer</b>	15
<b>Conclusions</b>	17
<b>References Cited</b>	19



## LIST OF FIGURES

Figure 1. Structure contour map of the Berea Sandstone.	4
Figure 2. Structure contour map of the Gordon.	6
Figure 3. Regular grid used for measuring permeability in cores.	7
Figure 4. Representative permeability maps.	9
Figure 5. Predicted and measured permeability.	11
Figure 6. Permeability distribution map.	12
Figure 7. Predicted cumulative oil production and production history.	14



## ABSTRACT

The Jacksonburg-Stringtown field was discovered in 1895. It is located on the western flank of the Burchfield syncline, in southeastern Wetzel, eastern Tyler, and northwestern Doddridge counties, West Virginia. Over 500 wells were drilled in the field between 1897 and 1901; most were plugged by 1910. Primary recovery has been estimated to lie between 1454 and 1590 barrels of oil per acre. Primary production was a result of solution gas drive and gravity drainage through the mid-1920's and resulted in production of an estimated 13 million barrels of oil.

Gas injection began prior to the 1940's. Recovery attributed to gas injection averaged 154 BOPA over a limited portion of the field. The pilot waterflood of the Gordon was installed in 1981 as an approximately 34 acre dual five-spot. Since 1990, more than 100 new wells have been drilled for water injection and 40 new wells drilled for production. Between January, 1991 and February, 1999, 1,864,782 barrels of oil have been produced as a result of the full-scale waterflood.

Study of small-variability in core permeability confirms the classification of Gordon strata within the Jacksonburg field into "pay sandstone" and "non-pay sandstone" based on gamma ray and density log signature. These two lithologies are found to have relatively high (10 - 200 mD) and low permeabilities, (0 - 5 mD), respectively.

Study of permeabilities in the Gordon strata classified as "conglomerate" based on log signature suggest that this material is more problematic. Conglomerates are found to have generally unpredictable permeability that can range from 0 to nearly 500 mD. Conglomerates may have permeability distribution and range similar to pay sandstone or to non-pay sandstone. Conglomerates are generally interbedded with either of these two lithologies but, do not necessarily take on the permeability characteristics of the interbedded sandstone, i.e., they may have no permeability when interbedded with pay sandstone or may exhibit permeabilities in the 50 to 200 mD range when interbedded with non-pay sandstone. Consequently, conglomerates may act as permeability barriers, as reservoir, or even as "thief zones." Many beds with contrasting permeability values cannot be distinguished by geophysical log signature because they are thinner than the resolution of the log.

Artificial neural networks trained using data from six wells were used to predict permeability in test wells. A three-layer back-propagation network with three slabs in the middle layer, each slab having a different activation function, yielded values for permeability that correlated highly with measured values. The network trained with the data from all seven wells was utilized to predict permeability for 125 wells having gamma ray and density logs. Using injection pressure-rate information and a reservoir model comprising an upper flow unit having good porosity but low permeability, and a lower unit having high permeability and porosity, a flow simulator replicated production history with a high degree of fit when permeabilities were predicted through a neural network. Permeabilities calculated by conventional regression gave relatively poor results.





## EXECUTIVE SUMMARY

The Jacksonburg-Stringtown oil field contained an estimated 88,500,000 barrels of oil in place, of which approximately 13,000,000 barrels were produced during primary recovery operations. A gas injection project, initiated in 1934, and a pilot waterflood, begun in 1981, yielded additional production from limited portions of the field. The pilot was successful enough to warrant development of a full-scale waterflood in 1990, involving approximately 8,900 acres in three units, with a target of 1,500 barrels of oil per acre recovery. However, PennzEnergy encountered technical barriers to production that must be overcome if they are to reach this enhanced production goal.

The West Virginia University Research Corporation is assisting PennzEnergy by developing a three-dimensional model of permeability for the Upper Devonian Gordon sandstone reservoir in the field. Two distinctly different approaches are being used: one involves a geostatistical analysis of geophysical and core data, whereas the other is based on direct measurement of permeability in core and in outcrops that are analogous to the subsurface reservoir. The goal is to establish relationships among permeability, geophysical and other data by integrating geologic, geophysical and engineering data into an interdisciplinary quantification of reservoir heterogeneity as it relates to production. To achieve this goal, six integrated tasks and their associated subtasks have been designed, along with a milestone plan and project deliverables.

This report documents achievements made during the third six-month period of the contract. During this interval of time, project focus was on completion of the database (Task 1), reservoir description (Task 2), outcrop permeability study (Task 3), and reservoir characterization (Task 4). Accomplishments include the following:

- Completion of all log digitization and correlation
- Subsurface structure contour maps drawn
- Preliminary examination of thin sections
- Small-scale permeability variation measured and studied
- Relationship between geophysical logs and core permeability established
- Outcrop permeability measurements started
- Preliminary modeling of porosity and permeability flow units

Study of small-variability in core permeability confirms the classification of Gordon strata into "pay sandstone" and "non-pay sandstone" based on gamma ray and density log signature. These two lithologies are found to have relatively high (10 - 200 mD) and low permeabilities, (0 - 5 mD), respectively. Gordon strata classified from logs as "conglomerate" range in permeability between 0 and nearly 500 mD, similar to the range in permeability between pay and non-pay sandstone. Conglomerates are generally interbedded with either of these two lithologies but in many places contrast in permeability with the surrounding sandstone, i.e., they may have no permeability when interbedded with pay sandstone or may exhibit permeabilities in the 50 to 200 mD range when interbedded with non-pay sandstone. Consequently, conglomerates may act as permeability barriers, as reservoir, or even as "thief zones." Many beds with contrasting

permeability values cannot be distinguished by geophysical log signature because they are thinner than the resolution of the log.

Artificial neural networks trained using data from six wells can be used to predict permeability in uncored wells. A three-layer back-propagation network with three slabs in the middle layer, each slab having a different activation function, yielded values for permeability that correlated highly with measured values. The network trained with the data from seven wells was utilized to predict permeability for 125 wells having gamma ray and density logs. Permeabilities calculated with a neural network were also used with injection pressure-rate information and a two-layer reservoir model in a flow simulator to predict production histories with high accuracy. Permeabilities calculated by conventional regression gave relatively poor results.

The project is on schedule, and we anticipate all milestones scheduled for the upcoming six-month interval to be accomplished as planned.

## INTRODUCTION

The Jacksonburg-Stringtown field was discovered in 1895. It is located on the western flank of the Burchfield syncline, in southeastern Wetzel, eastern Tyler, and northwestern Doddridge counties, West Virginia. Most of the 500 wells drilled in the field between 1897 and 1901 were plugged by 1910. Average well spacing was 13 acres per well. Average initial potential of these wells was 72 BOPD (barrels of oil per day), with a range of 0 to 300 BOPD (King, 1980). Wells were initially stimulated (“shot”) with nitroglycerine, many several times to increase production. Average production life of early wells was approximately 20 years. Based on an effective area of 4,388 acres, primary recovery has been estimated at between 1454 (King, 1980) and 1590 (Morrison, 1991) BOPA (barrels of oil per acre). Primary production was a result of solution gas drive and gravity drainage through the mid-1920's and resulted in production of an estimated 13 MMBO (million barrels of oil) (Morrison, 1991). Primary production ranged from 824 BOPA to 2,700 BOPA, using lease production records.

Gas injection began in 1934 (Boone and others, 1986) or mid 1920's (Putscher and King, 1983). Limited development and testing continued through the 1950's, with five injection wells spread out through the field. Recovery attributed to gas injection averaged 154 BOPA over a limited portion of the field (Boone and others, 1986). The pilot waterflood of the Gordon was installed in 1981 as an approximately 34 acre dual five-spot. An average of 1300 BOPA was recovered in 4 years. Lower than predicted (1500 BOPA) recovery is believed to be due to dump flooding of the eastern five-spot (Boone and others, 1986).

More than 100 new wells have been drilled for water injection and 40 new wells drilled for production since full-scale waterflooding began in 1990. Of these newly drilled wells, 24 of them have been drilled with low angle deviations to accommodate surface topographic and logistical constraints. PennzEnergy has divided the field into three areas or units for their waterflood development. Unit 1, consisting of 1,815 acres, was formed in 1981, and contains the pilot waterflood. Unit 2 (5,723 acres) was formed in 1986 and is located north of and adjacent to Unit 1. Unit 3, (1,360 acres) was formed in 1995 and is located south of Unit 1. From January, 1991 through February, 1999 1,864,782 barrels of oil have been produced as a result of the full-scale waterflood.

New well drilling and secondary recovery operations led to the following observations: 1) early breakthrough in water floods; 2) multiple sand bodies within the reservoir; 3) difficulties in converting old, shot wells to injection wells; 4) areas of unusually high production within the field; 5) growth faults in one part of the field; and 6) unexpected vertical communication between sand bodies.

This project comprises six scientific and engineering tasks: database development, reservoir description, a study of permeability in outcrop, and reservoir characterization. We report that task 1 is complete, and tasks 2 through 4 are in progress, with a number of subtasks complete.

Work reported previously showed that the Gordon section is approximately 50 feet thick and is bounded top and bottom by a series of interbedded sandstones and shales that have proved to be correlative throughout the field. In the pilot waterflood area, the Gordon is subdivided into three units, pre-Gordon, Gordon Pay and Conglomerate, and post-Gordon. The position of the pay zone can vary within the Gordon sandstone. Within the eastern part of the field, pre-Gordon includes a unit containing pay zones, and a unit largely devoid of reservoir sandstones.

We also found that minipermeameter readings are not affected by the presence of spray coatings and markings observed on cores, but that organic coatings on some outcrop exposures must be removed for accurate measurements.

In addition, previous reports detailed our efforts to predict permeability from geophysical logs. Because of the heterogeneous nature of the formation, more detailed formation characteristics such as grain size, lithology, and depositional environments might need to be incorporated in the development of the relationship between permeability and well log data. Application of a neural network, which has been found to be powerful tool for identifying the complex relationships, was to be investigated.

This report gives results on our use of a minipermeameter on cores to study very fine-scale trends in permeability, and use of neural networks to predict permeability in logged, uncored wells.

## RESULTS AND DISCUSSION

### Task 1: Database Development

#### Subtask 1.3 - Log digitization/Autocorrelation

#### Milestone 10 – Autocorrelation of all logs (STATUS: *Complete*)

Lack of significant structural complexity in the field has reduced the need for significant adjustments to log elevations to achieve good correlations between adjacent wells. Where visual correlation of logs has proven difficult or ambiguous, autocorrelation of the relevant wells has been used to provide the "statistically best correlation" to the project's stratigrapher. Areas indicated previously as showing generally better or poorer correlation trends (see Fig. 10, 2<sup>nd</sup> Semiannual Project Report) have been investigated extensively using log and available core data.

#### Subtask 1.4- Data Analysis

#### Milestone 13- Reservoir fluids analyzed (STATUS: *Complete*)

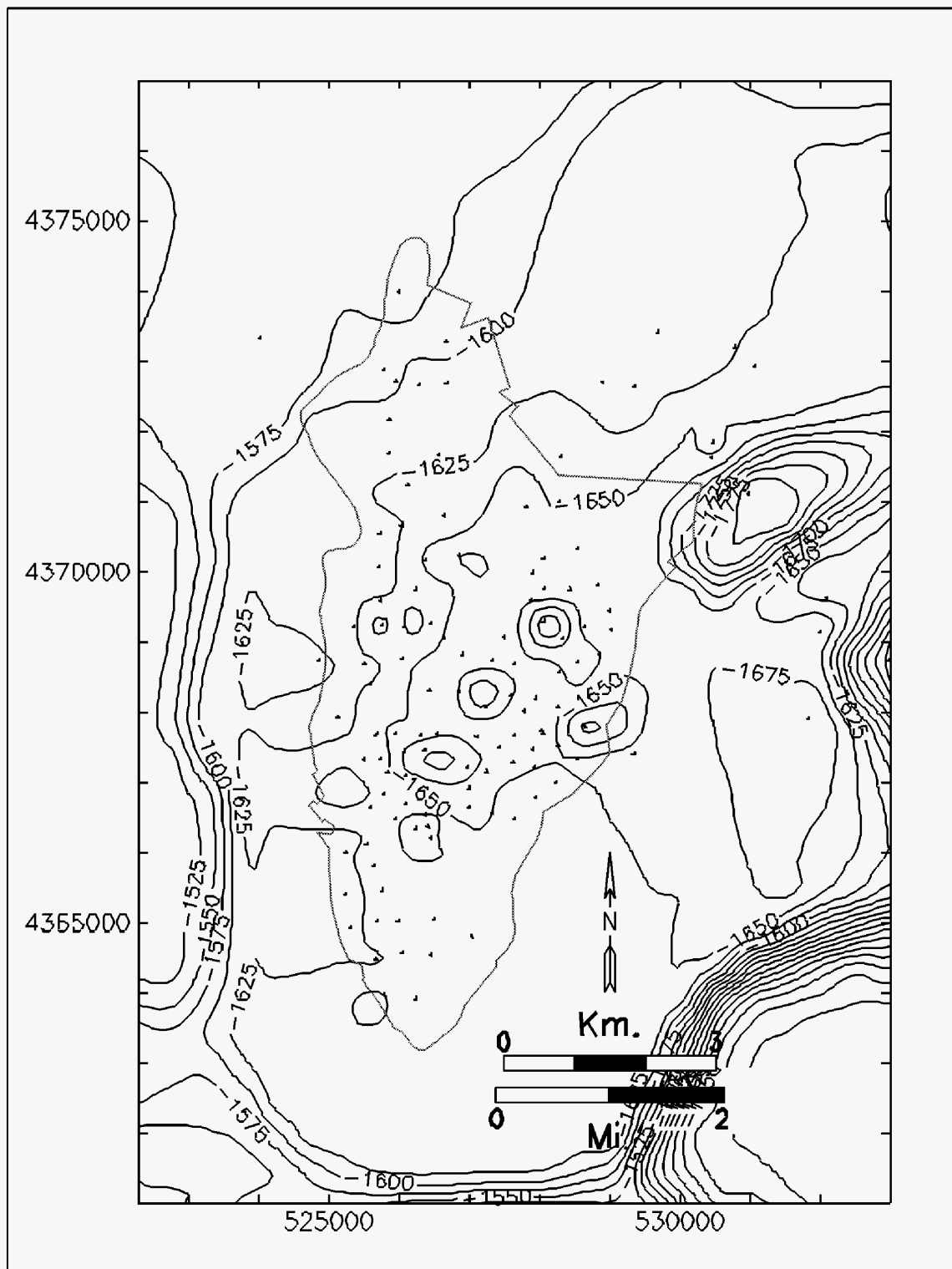
A sample of reservoir oil was obtained by PennzEnergy personnel and was made available for analysis. The analysis of the fluid sample did not generate any significant new information. It should be noted that the sample was taken at the surface and as result was not considered a representative reservoir sample. It should be pointed out that the likelihood of obtaining a representative reservoir fluid sample is practically nil considering the age of the reservoir and the gas and water injection history. The collected fluid property data, published records, and the results of the fluid sample analysis tend to indicate that the fluid properties are generally uniform through the field. Data collected on fluid properties will be utilized for modeling studies.

### Task 2: Reservoir Description

#### Subtask 2.2 - Structure

#### Milestone 21 - Completed computer-generated maps of subsurface structure for the field (STATUS: *Complete*)

As an aid to the understanding of the stratigraphy of the Gordon reservoir within the field, a number of field-scale structure maps were prepared. The first of these, based on the top of the Berea Sandstone overlying the Gordon, indicates that the field lies within a broad syncline (Fig. 1). Subsequently, a series of subsurface maps were prepared on horizons within the Gordon picked by the project's stratigrapher. In general, the Gordon conforms to the synclinal structure with the exception of a possible small



**Figure 1.** Structural contours on the top of the Mississippian Berea Sandstone showing post-Gordon development of a broad syncline in the area of the Jacksonville field. Contour interval is 25 feet.

fault across the southern end of the field that trends approximately N80°W and is down to the north (Fig. 2).

**Milestone 23** - Completed preliminary examination of thin sections (**STATUS: Complete**)

All thin sections prepared thus far for the project have been examined and observations for each recorded on a data sheet. Completed data sheets will be made available to all project members.

**Milestone 24** - Petrographic materials requiring additional analysis identified (**STATUS: Complete**)

Thin sections have been prepared using blue epoxy to highlight porosity. No staining of cements was requested as the suite of cements observed in preliminary examination of the initial thin sections produced showed that the carbonate cement suite was small, consisting primarily of calcite and siderite. All subsequent thin sections have been produced with permanent slide covers as it is expected that many project members will need to examine the sections.

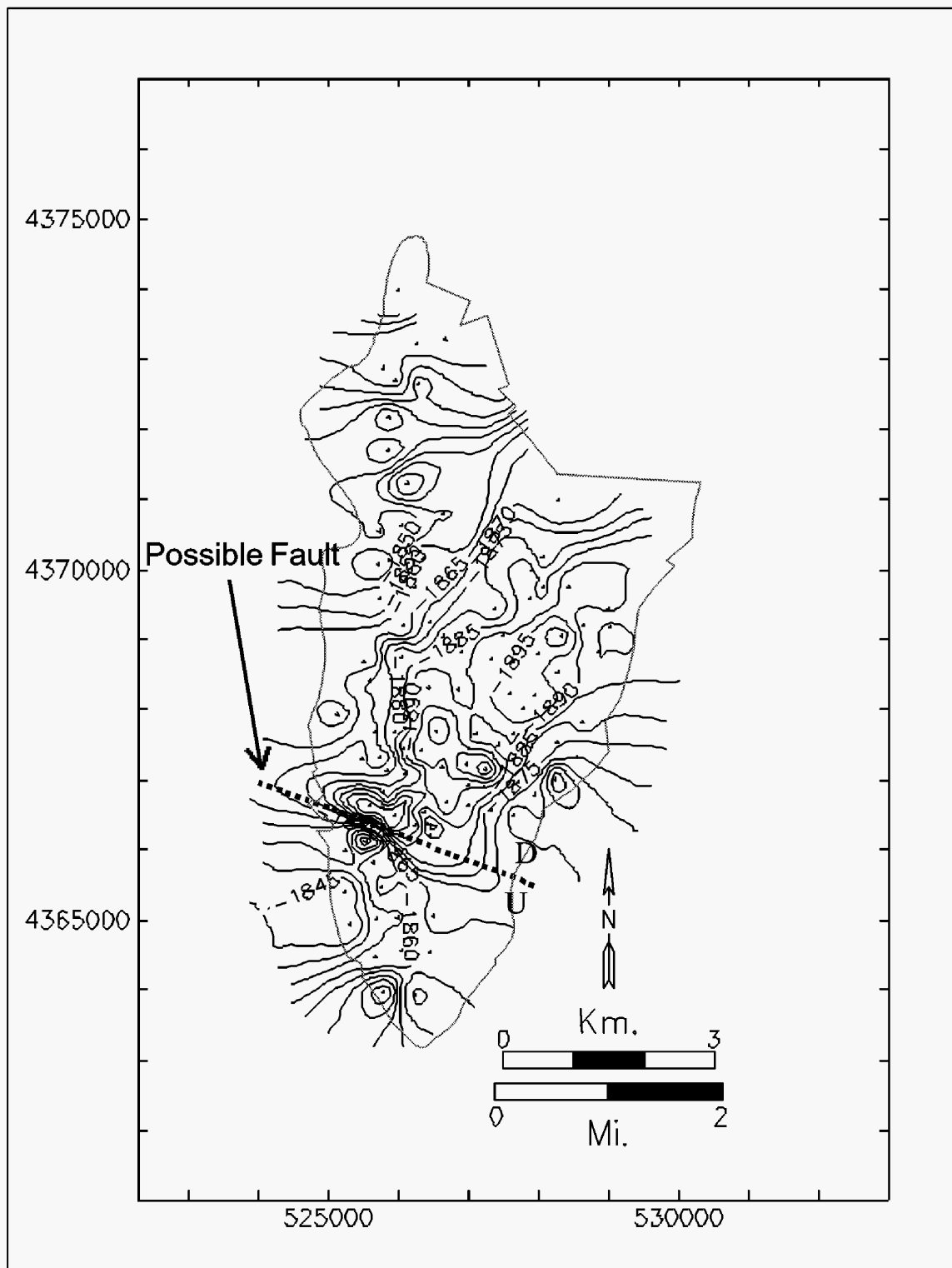
**Subtask 2.5** - Petrophysics

**Milestone 33** - Small-scale permeability variations in core quantified (**STATUS: Complete**)

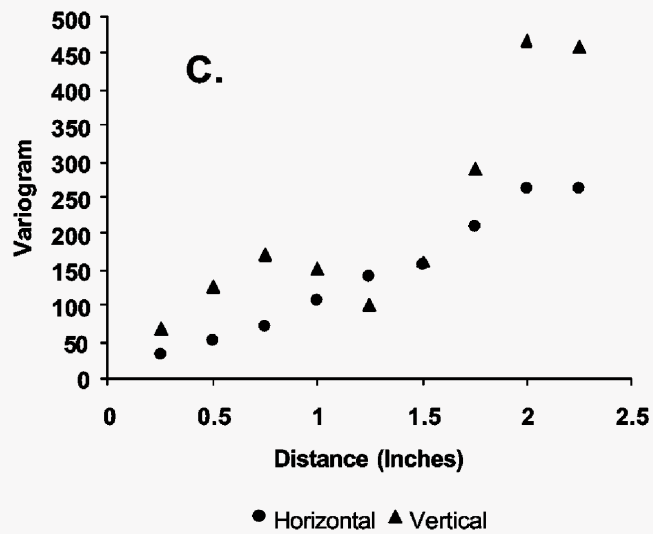
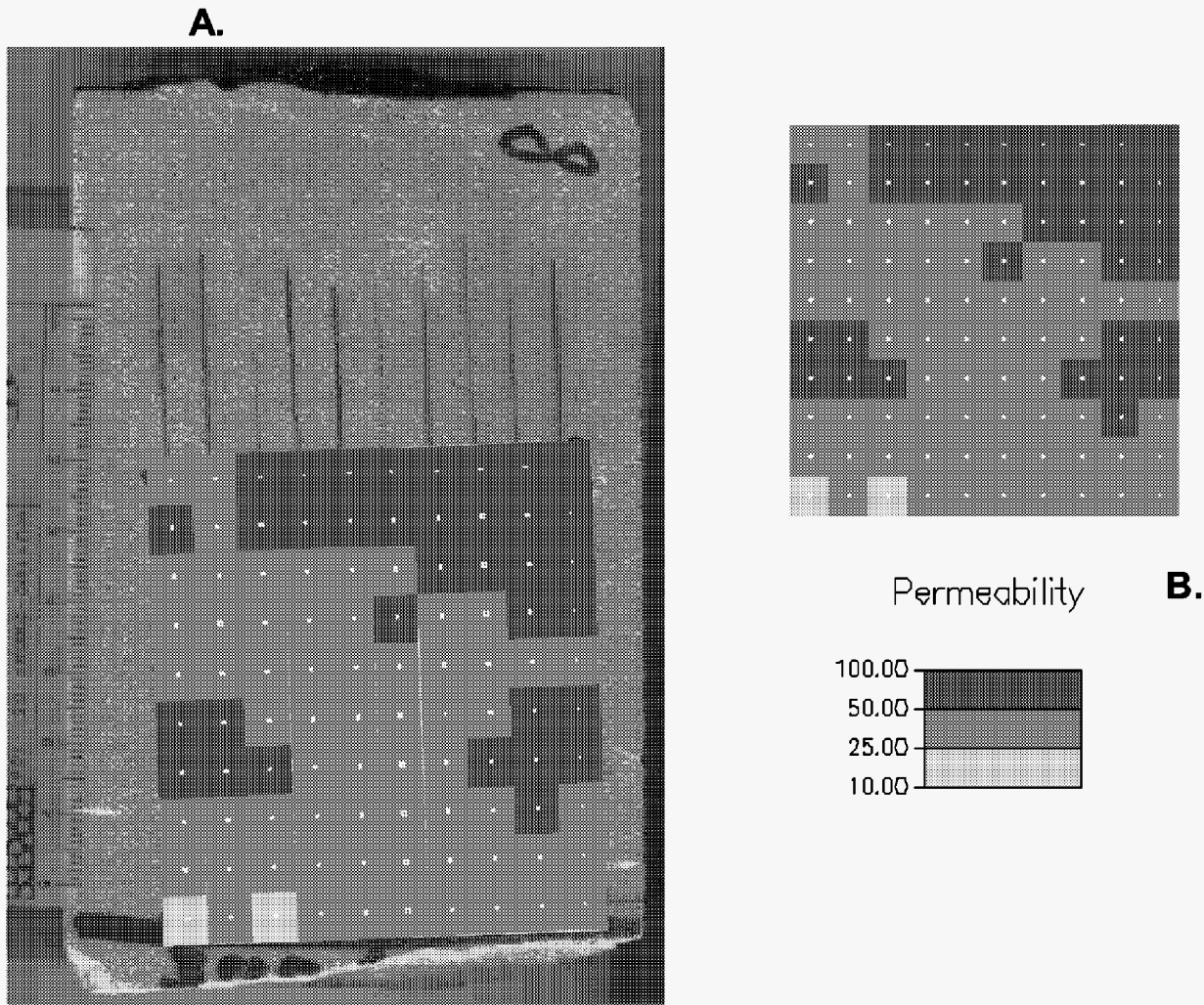
Using picked intervals based on gamma ray and density log signature, core material from six (E. B. Lemasters O13, Thompson Heirs #8, F. R. Ball #18, F. R. Ball #19, Peter Horner #9, and Irene Reilly #13) cored wells was classified as either "Pay Sandstone", "Non-pay Sandstone", or "Conglomerate." A square grid was drawn in pencil on the slabbed surface of nineteen core segments chosen as representative of each of these three log-based lithologic groups. Each grid consists of ten rows and ten columns of nodes equally spaced 0.25 inches apart. For those core segments with non-horizontal bedding, the grid was rotated so that the rows of the grid were parallel to bedding and, consequently, columns were at right angles to bedding. Permeability was measured and recorded using the TEMCO™ MP-401 minipermeameter at each grid node and a "map" of permeability was created for each grid. Finally, a variogram was created for each grid to help quantify the variability in permeability encountered within rows (along bedding surfaces) and within columns (at right angles to bedding). Figure 3 illustrates the results of the process.

Sixteen core segments were chosen for further analysis. Again, attempting to get representative samples of each of the three log-based lithologies, cores were cut at right angles to the slabbed core surfaces (or at the angle of observed bedding when not horizontal). A "quasi"-rectangular grid, with nodes spaced uniformly 0.25 inches apart was drawn on each core piece. Because of the hemispherical shape of the core surface,





**Figure 2.** Structural contours on the top of "Unit A" at the base of the Gordon interval within the field. The presence of a fault in the southern portion of the field is suggested by the 30 to 40 foot difference in elevation in this area. The possible fault trends N80°W and is down to the North. Contour interval is 5 feet.



**Figure 3.** Regular grid, taken at the 3101' interval from F. R. Ball #18 (095-1126). A - photograph of core segment with superimposed grid and permeability map. Note: grid has been rotated approximately 2° counter-clockwise to parallel bedding in the core. B - permeability map and legend. C - variogram quantifying variance in permeability within ("Horizontal") and across ("Vertical") bedding. All permeabilities in millidarcies.

grids were drawn to maximize the number of grid nodes and as a result, were never perfect rectangles (Fig. 4). Now operating within a single bedding surface, permeability measurements were taken at each grid node, stored, mapped, and subjected to variography (Fig. 4).

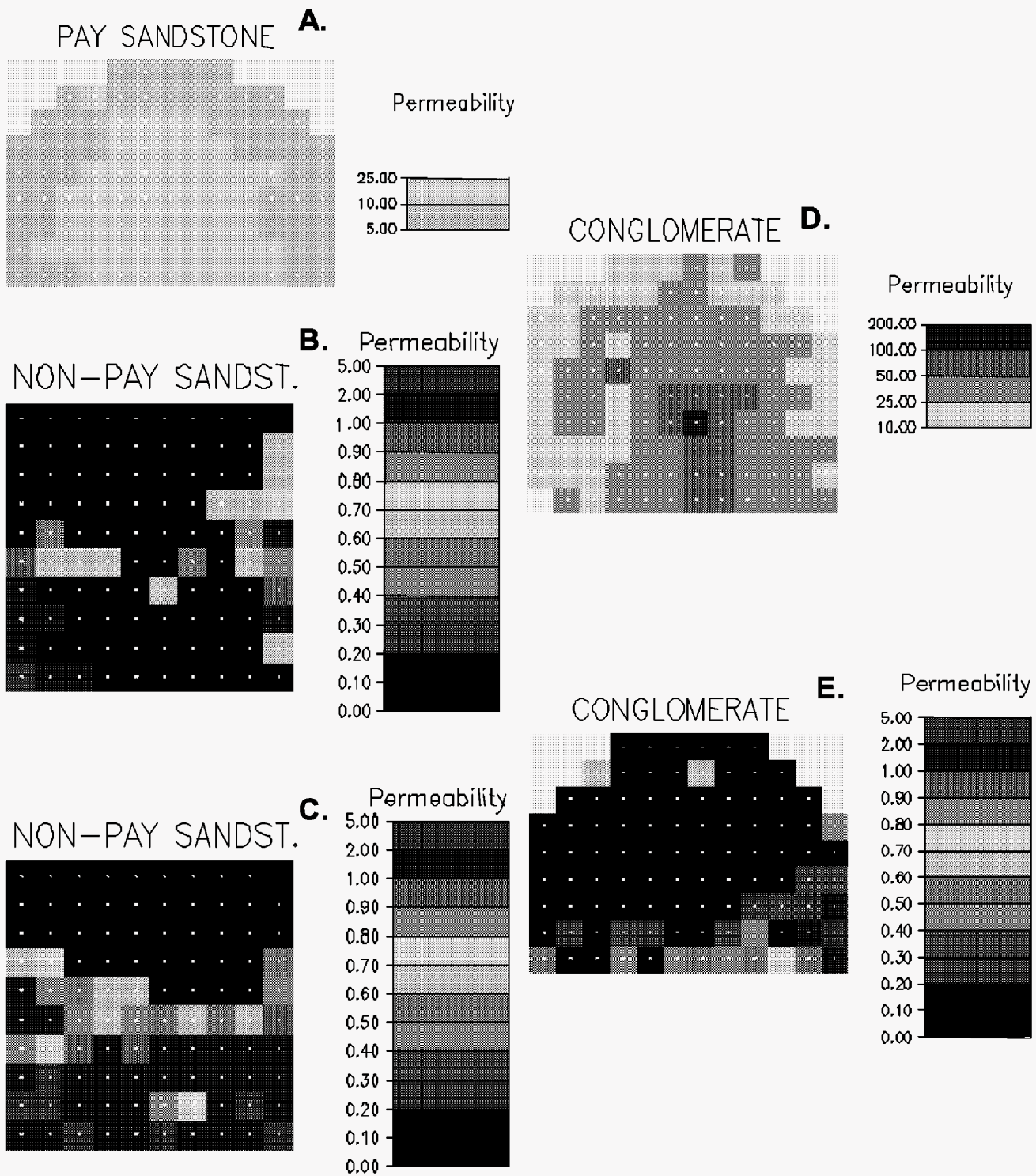
The following observations were made after the examination of permeability maps and variograms for thirty-five of these "miniature" grids: 1) Pay Sandstones as designated by log signature were, in large part, correctly classified based on measured permeabilities in the range 10 to 200 mD; 2) Non-pay Sandstones as designated by log signature were correctly classified based on measured permeabilities ranging from 0 (i.e., below the level of instrumental detection) to less than 5 mD; 3) Conglomerates were problematic in that some samples showed permeabilities similar to Pay Sandstones and others show permeabilities similar to Non-pay Sandstones; 4) the distribution of permeability within Pay Sandstones was fairly uniform except that a several samples exhibited an "edge effect" with lowered permeabilities in a zone around the edge of the core; 5) Non-pay Sandstones exhibited three types of permeability distributions - uniformly low, zoned-bedding parallel, and "patchy" (Fig. 4); and 6) Conglomerates showed the full spectrum of permeability distributions seen in both Pay and Non-pay Sandstones.

Consultations with the projects engineers suggest that the low permeability "rind" observed in some of the Pay Sandstone core segments may be the result of infiltration of fluids into the core during coring operations and subsequent precipitation of material plugging pore space. Thin sections have been taken from this material to try to determine the exact nature of the reduction in permeability.

More seriously, the variable nature of range and distribution of permeability within the Conglomerate lithology cannot be identified by log signature because, in general, the Conglomerates are thinner than the scale of resolution of the geophysical logs. This means that, since Conglomerates are interbedded with both Pay and Non-pay Sandstones, they may act like a barrier to permeability in some instances or as additional reservoir or even "thief zones" in others. In addition, Conglomerates do not always appear to take on the permeability characteristics of the lithology with which they are interbedded, e.g., Conglomerate interbedded with Pay Sandstone is not always equally permeable and Conglomerate interbedded with Non-pay Sandstone is not always impermeable.

**Milestone 34-** Statistical correlation between direct permeability and geophysical logs investigated. (STATUS: *Complete*)

Our previous investigations resulted in development of a preliminary correlation between core permeability with well log porosity (see Figure 13, 2<sup>nd</sup> Semiannual Project Report). However, the correlation was found to be unreliable (correlation coefficient of 70 percent) due to the heterogeneous nature of the formation. Our previous investigations have demonstrated that Artificial Neural Networks (ANN) may be successfully used to estimate formation permeability using geophysical well log data as input. Gamma ray and the bulk density logs are available from most wells within the Stringtown-Jacksonburg



**Figure 4.** Representative permeability maps. A - irregular grid on core surface cut parallel to bedding, Thompson Heirs #8 (095-1124), Pay Sandstone with low permeability rind from 2795'. B - regular grid, F. R. Ball #18 (095-1125), Non-pay Sandstone with "patchy" distribution of permeability, 3006.25'. C - regular grid, F. R. Ball #18 (095-1125), Non-pay Sandstone with zoned permeability parallel to bedding. D - irregular grid on core surface cut parallel to bedding, Peter Horner #9 (095-741), Conglomerate with permeability similar to Pay Sandstone in range and distribution, 2898.5'. E - irregular grid on core surface cut parallel to bedding, Irene Reilly #13 (103-1315), Conglomerate with permeability similar to Non-pay Sandstone in range and distribution, 2866.55'. All permeabilities in millidarcies.

field. ANN can identify the complex relationship between permeability and well log data without any assumption or predefined model. This relationship is completely different from well to well and even from point to point in the same well due to the inherent formation heterogeneity. ANN overcomes this heterogeneity drawback; it is a powerful, rapid, low cost alternative to measuring permeability. As a result, a study was conducted to accurately predict permeability using a neural network and core data from seven wells in the reservoir. The main assumption in this study was that geophysical log data can provide valuable information about formation permeability; in other words a relationship between permeability and log data exists which may not be direct and explicit.

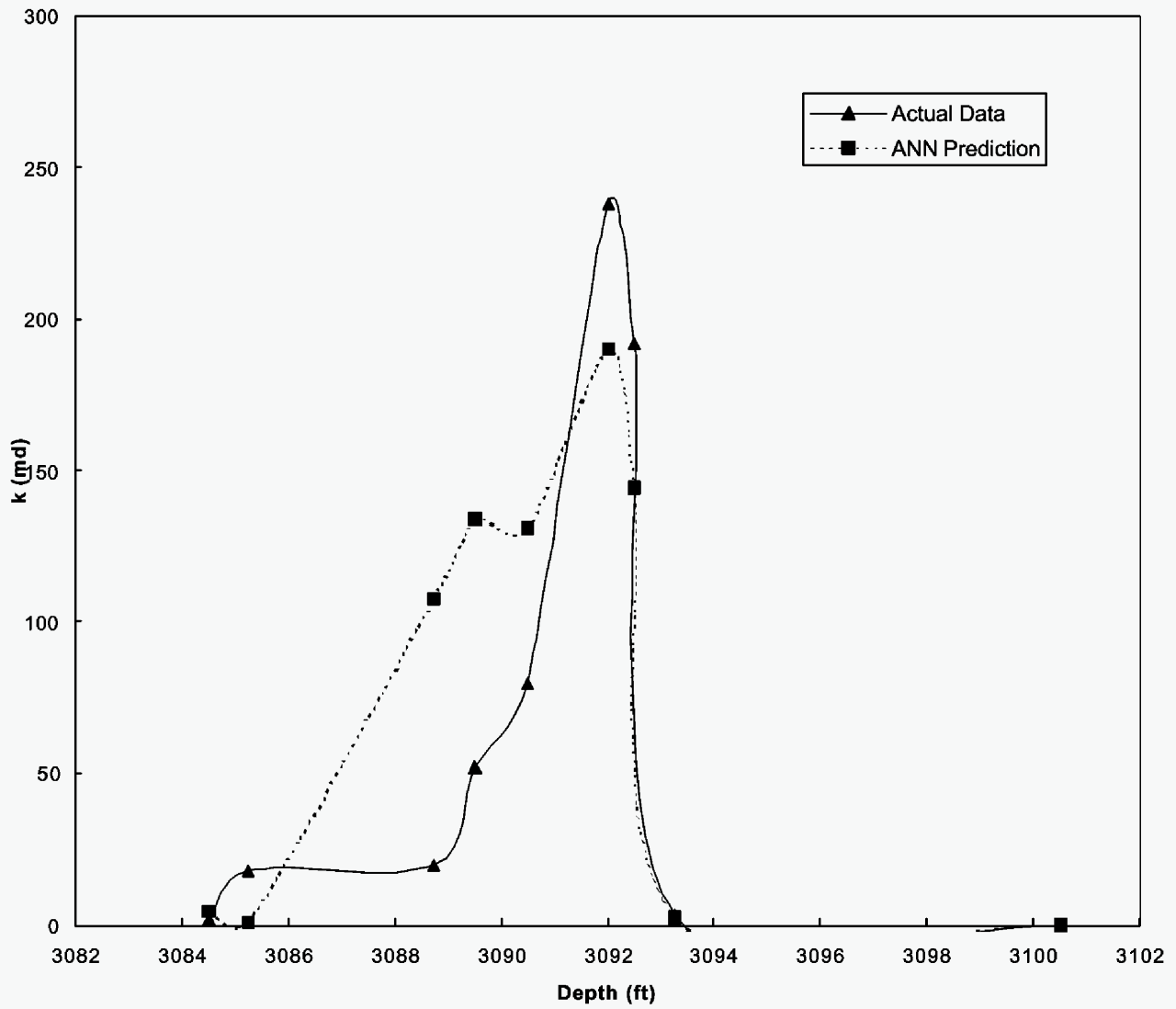
The data sets selected to train the ANN consisted of several input groups. The first input group included gamma ray and bulk density log data and corresponding depths. Although other logs, including neutron porosity and induction, are available from some of the wells, selection of these particular logs was primarily dictated by their availability in the majority of the wells in the Stringtown field. The second input group consisted of the first and the second derivatives of the log data with respect to depth. This group provided useful information relative to the shape of each log curve. The final group of input data consisted of well coordinates, log baselines, and core permeability measurements results as target outputs.

To obtain reliable permeability predictions, several artificial neural network architectures and paradigms were considered. It was concluded that a three-layer back-propagation network with three slabs in the middle layer, each slab having a different activation function is the most appropriate architecture. To verify the accuracy of permeability predictions by ANN, several similar networks were trained by using the data from six of the seven wells. Subsequently, the data from the seventh well were used as input for the trained network to predict the permeability values. The comparison of the ANN predicted permeability values and measured values provided significant correlation coefficients (95 percent or higher) for all the wells. Figure 5 illustrates the comparison of the predicted and measure permeability values for Peter Horner No. 11. With these promising results, the network trained with the data from all seven wells was utilized to predict the permeability profile for 125 strategically distributed wells in the field that have gamma ray and density logs available. Finally, the average permeability values for each well were calculated and the permeability distribution was mapped, as illustrated in Figure 6.

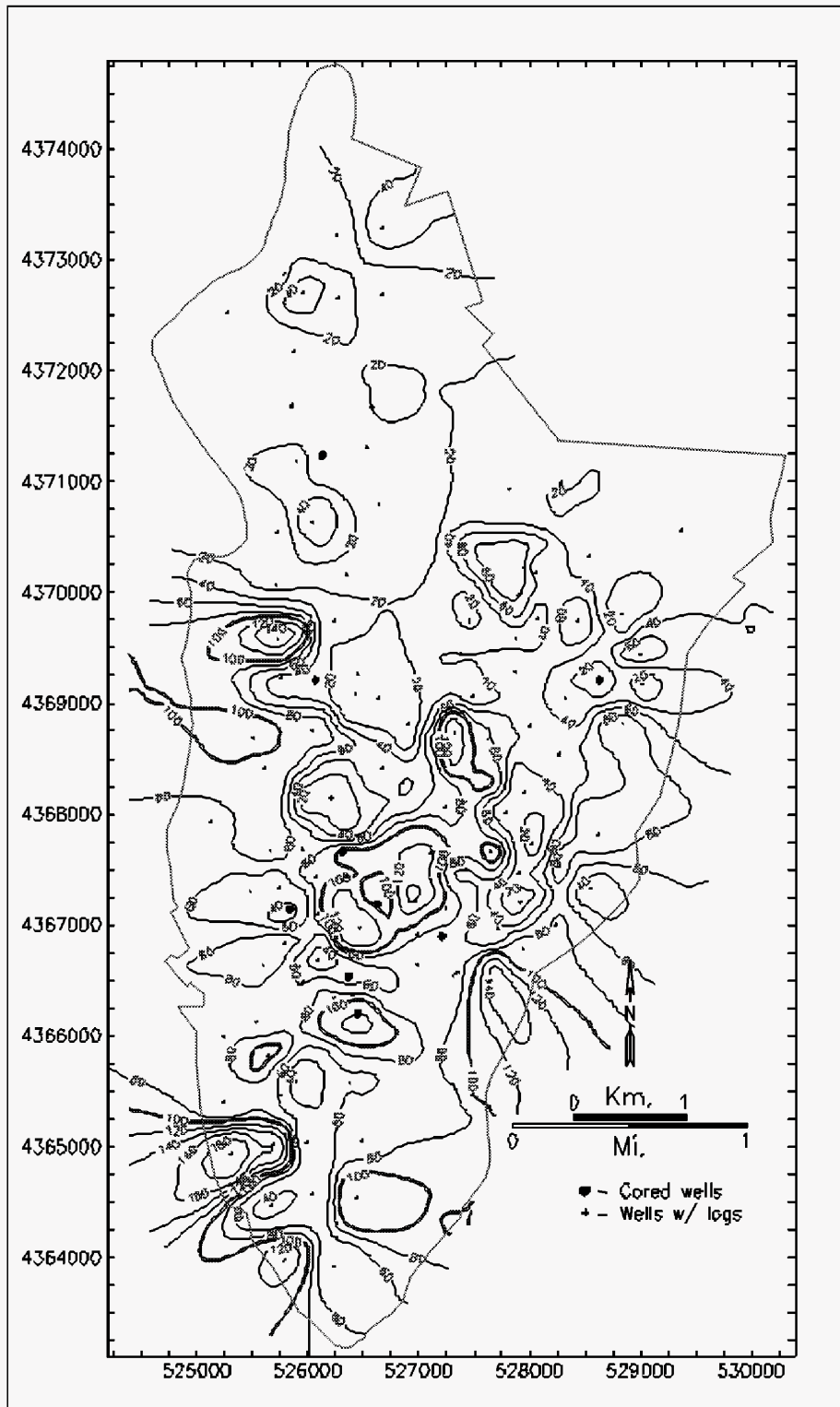
### **Task 3: Outcrop Permeability Study**

**Milestone 41** - Begin description of outcrop and creation of lithologic strip logs  
(STATUS: *Complete*)

A spacing of five feet between outcrop sections was chosen at the beginning of data acquisition at the Aurora outcrop (See Figure 18, 1<sup>st</sup> Semiannual Project Report). However, in practice, it has proven necessary to modify this spacing when irregularities (fractures, soil or vegetation cover, etc.) are encountered. It has proven most efficient to describe and log each outcrop section contemporaneously with the acquisition of



**Figure 5.** Comparison of the Predicted and Measured Permeability Values for Peter Horner No. 11.



**Figure 6.** Permeability Distribution Map. Contour interval is 20 mD.

permeability data. To date, thirteen sections have been described, logged, and subjected to permeability measurement at the Aurora locality. The remainder will be completed as permeability data are acquired during this summer's field season.

#### **Task 4: Reservoir Characterization**

##### **Subtask 4.2 - Modeling and Simulation**

**Milestone 50 - Three-dimensional modeling of porosity-permeability flow units (STATUS: *Ongoing*)**

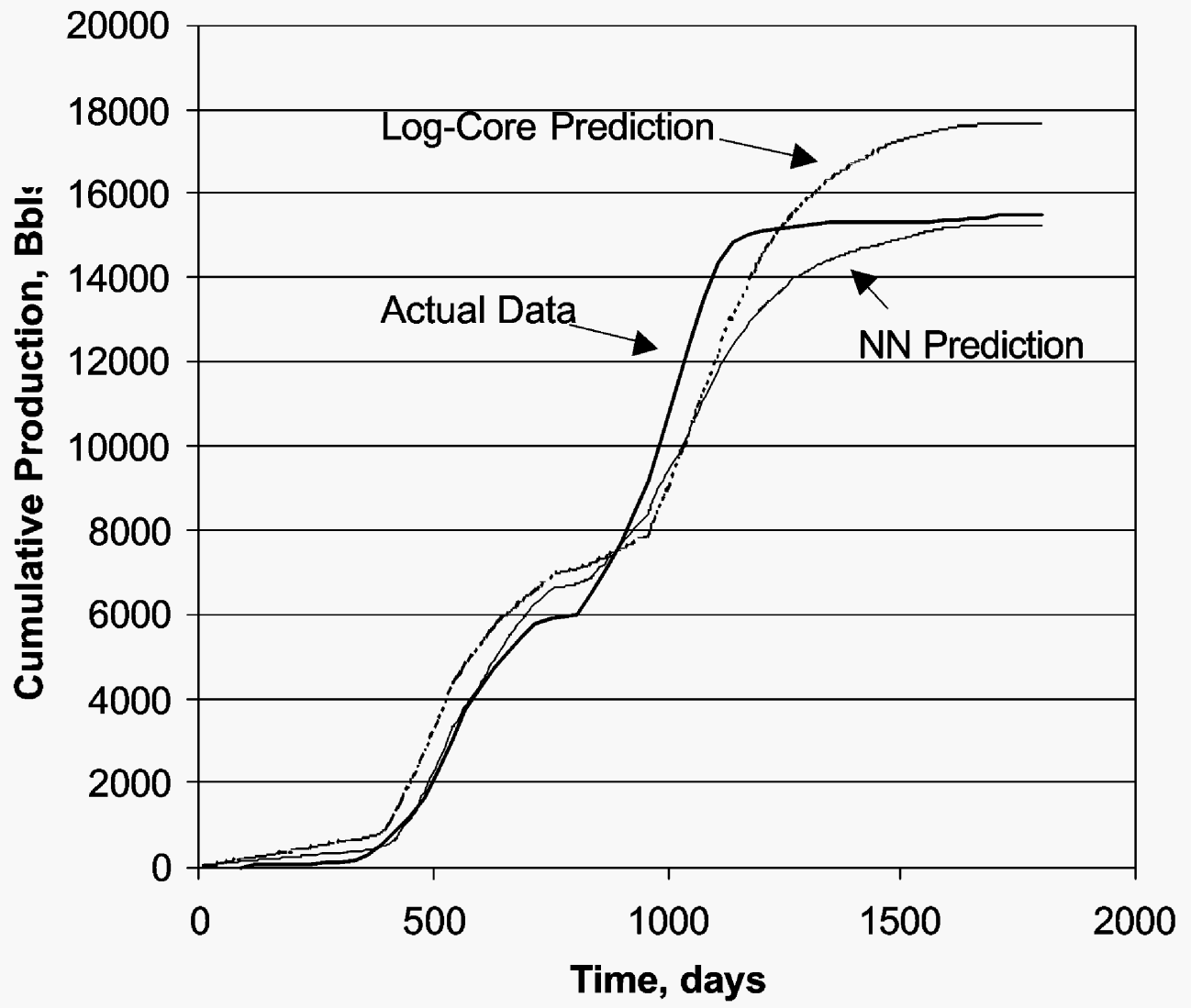
**Milestone 51 - Completed preliminary runs of BOAST simulator (STATUS: *Ongoing*)**

The simulation study was focused in waterflood pilot area where a significant amount of data were available. The pilot area is located in the southern part of the field. The pilot utilized a five-spot pattern. The collected well records, well logs, and core analysis data were utilized to determine the characteristics of the formation in the pilot area. The core analyses were available for two injection wells in the pilot. The core-log correlation and neural network were utilized to predict the permeability values in the wells without core analysis and to construct two separate 3-D models of the pilot area. The early simulation results indicated that a single layer model could not provide a reasonable match with production history. Therefore, the formation was divided into two layers. The vertical porosity and permeability variations in the wells indicated that two zones or flow units can be defined. The upper flow unit is characterized with good porosity but low permeability. The lower unit is characterized by high permeability and porosity. The thickness of each unit was evaluated based on the distribution of permeability and porosity in each well.

The two three-dimensional flow unit models and injection pressure-rate information were then used as inputs for a reservoir simulator to predict the oil production performance for the center producer in the pilot. BOAST III was used for the simulation studies. The predicted cumulative oil production performances for both models were then compared against the actual production history to evaluate the accuracy and reliability of each model.

Figure 7 compares the predicted cumulative oil production performances for the core-log correlation model and the neural network-based model with the actual production history. The predicted oil recovery based on the core-log correlation model showed 14.2 percent error. At the same time, predicted oil recovery based on the neural network-based model showed only 1.6 percent error. These results clearly indicate that the neural network-based reservoir model is superior to core-log reservoir model in predicting the production performance. Therefore, it can be concluded that the neural network predictions significantly improved the simulation of the secondary recovery performance.





**FIGURE 7.** Comparison of the Pilot Area Predicted Cumulative Oil Production and Production History.

**Task 6: Technology Transfer**

A poster entitled "Stratigraphic Heterogeneity within the Jacksonburg-Stringtown Oilfield, Northern West Virginia" (Matchen and others, 2000) was presented at the Southeastern Section - Geological Society of America Convention in Charleston, SC in late March. Two abstracts, one on the same topic and a second on small-scale variability in core permeability have been submitted to Eastern Section - American Association of Petroleum Geologists for the upcoming meeting in September of this year.



## CONCLUSIONS

Study of small-variability in core permeability confirms the classification of Gordon strata within the Jacksonburg field into "Pay Sandstone" and "Non-pay Sandstone" based on gamma ray and density log signature. These two lithologies are found to have relatively high (10 - 200 mD) and low permeabilities, (0 - 5 mD), respectively.

Study of permeabilities in the Gordon strata classified as "Conglomerate" based on log signature suggest that this material is more problematic. Conglomerates are found to have generally unpredictable permeability that can range from 0 to nearly 500 mD. Conglomerates may have permeability distribution and range similar to Pay Sandstone or to Non-pay Sandstone. Conglomerates are generally interbedded with either of these two lithologies but, do not necessarily take on the permeability characteristics of the interbedded sandstone, i.e., they may have no permeability when interbedded with Pay Sandstone or may exhibit permeabilities in the 50 to 200 mD range when interbedded with Non-pay Sandstone. Consequently, Conglomerates may act as permeability barriers, as reservoir, or even as "thief zones." Many beds with contrasting permeability values cannot be distinguished by geophysical log signature because they are thinner than the resolution of the log.

Artificial neural networks trained using data from six wells were used to predict permeability in test wells. A three-layer back-propagation network with three slabs in the middle layer, each slab having a different activation function, yielded values for permeability that correlated highly with measured values. The network trained with the data from all seven wells was utilized to predict permeability for 125 wells having gamma ray and density logs.

Using injection pressure-rate information and a reservoir model comprising an upper flow unit having good porosity but low permeability, and a lower unit having high permeability and porosity, a flow simulator replicated production history with a high degree of fit when permeabilities were predicted through a neural network. Permeabilities calculated by conventional regression gave relatively poor results.



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