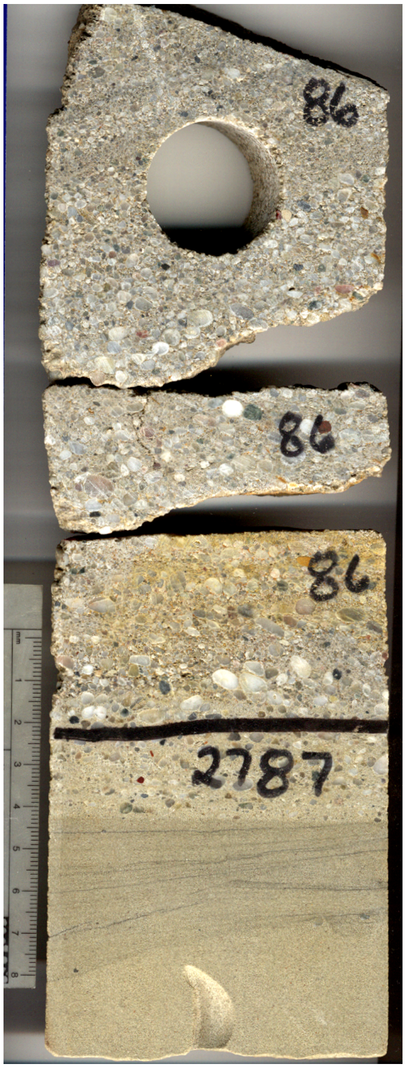

Petroleum Geology and Reservoir Characterization of the Upper Devonian Gordon Sandstone, Jacksonburg-Stringtown Oil Field, Northwestern West Virginia

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Introduction

This report contains five papers summarizing principal findings of a three-year study of the Jacksonburg-Stringtown field in northwestern West Virginia, funded by the U. S. Department of Energy. This field has produced oil since 1895 from the Upper Devonian Gordon sandstone interval. The purpose of the study was to spur development of economically attractive technologies for improved reservoir extraction. We set out to study the types and degree of reservoir heterogeneity at several scales, develop numerical techniques to define and predict geologic parameters, and present the results of our work to allow the results to be applied to other fields in the Gordon play as well as fields with similar geological characteristics.

In 1886, oil was discovered in a well on the Gordon farm in southwestern Pennsylvania; at the time, this was the world's deepest well at a total depth of 2,392 feet (Clapp, 1907). By 1890, oil and gas were being produced from Venango reservoirs in northern West Virginia. The Jacksonburg-Stringtown field was one of the earliest, discovered in 1895 (Whieldon and Eckard, 1963). By the time of the First World War, Gordon sandstones were producing oil from 18 fields in West Virginia. The overall trend of Gordon fields follows that of Gordon interval thickness. In many fields, production is limited to the Gordon Stray, an interval of sandstone and conglomerate westward of the thick Gordon trend and shallower stratigraphically.

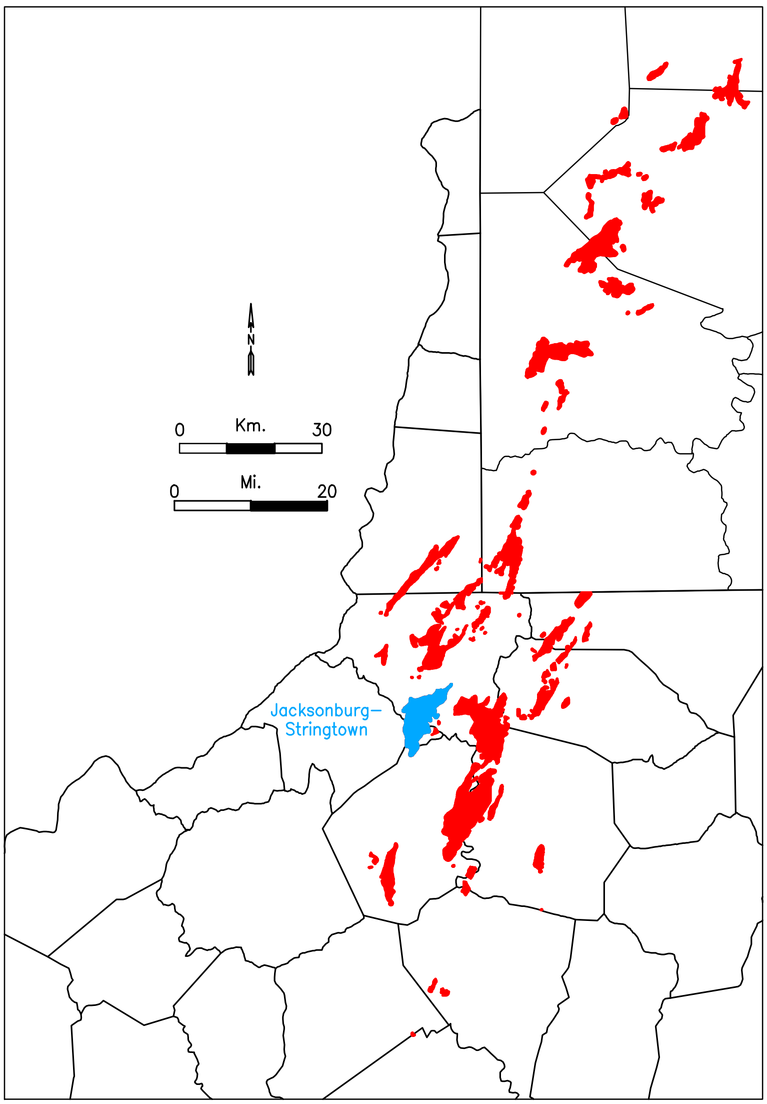

Figure 1. Location of the Jacksonburg-Stringtown field, as well as other fields with production form the Gordon interval.

Discovery and Development

Discovered in 1895, the Jacksonburg-Stringtown field is located in southeastern Wetzel, eastern Tyler, and northwestern Doddridge counties, West Virginia. Original oil in place is estimated to be over 80 million barrels of oil. More than 500 wells were drilled between 1897 and 1901, when annual oil production reached over one million barrels. Initial production averaged 72 barrels of oil per day. The typical well was completed open-hole at average depth of 3000 feet and was stimulated with nitroglycerine shot. By 1910, production declined significantly and most wells were abandoned.

The lease primary recovery ranges from 824 to 2700 barrels of oil and averages 1600 barrels of oil per acre. This equates to an average cumulative recovery of 23,000 barrels of oil per well. The primary recovery mechanism was solution gas drive.

From 1934 through the late 1960's, a limited gas injection project was operated but did not contribute significantly (less than 1 percent) to the primary recovery. The waterflood operation started with a pilot in 1981 and continued in several stages of development. The estimated ultimate waterflood recovery is 8 million barrels of oil of which approximately 2 million barrels has been recovered already.

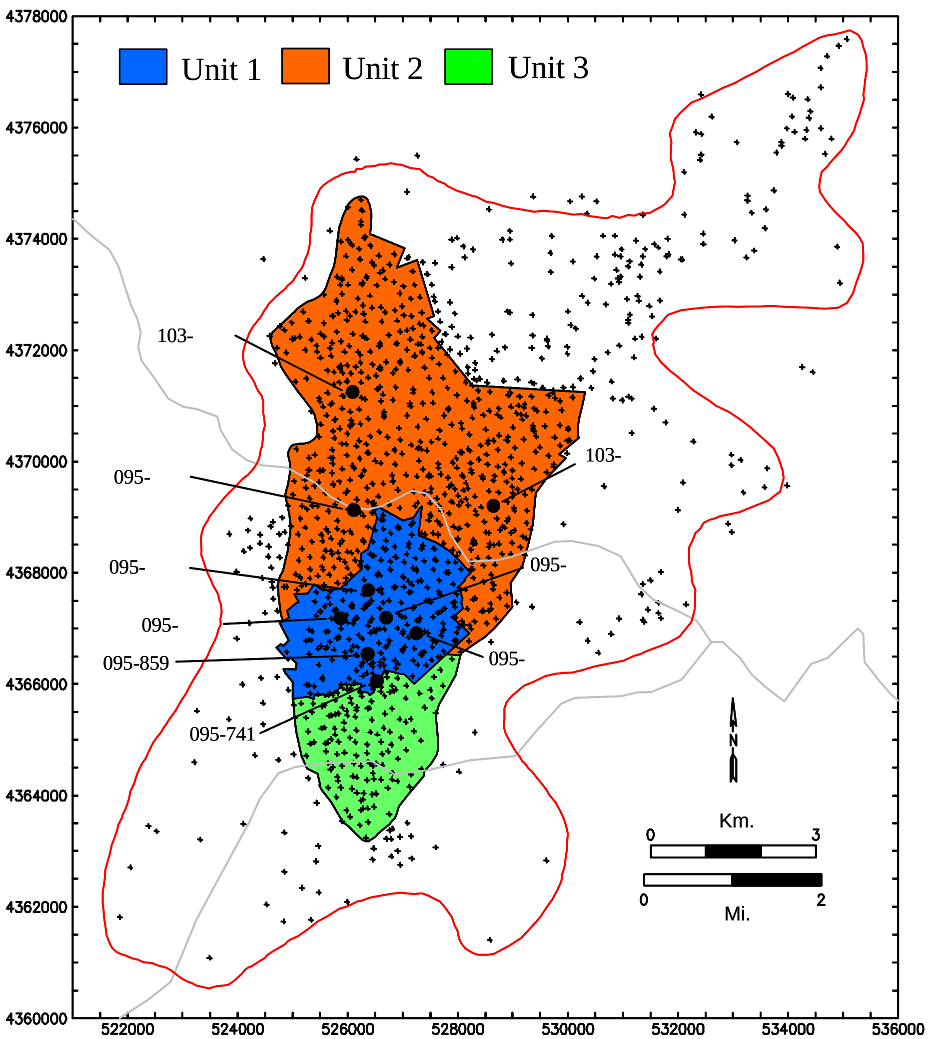

Figure 2 Map of Jacksonburg-Stringtown field, with well locations, outline of field (red line), production units as defined by PennzEnergy (color shading), and locations of cored wells (filled circles with permit numbers).

Throughout the development of the Jacksonburg-Stringtown field, isolated areas of new production have been discovered within the field. After initial discovery period for the field (1887-1903), each of the next five periods of development shows intrafield discoveries of new production. Within the first decade of drilling and production, two main trends in oil production were evident in the field: a north-south trend of relatively high production along the western margin of the field, and a north-northeast trend in the eastern half.

Regional and Local Geology

Gordon sandstones are part of the thick, Upper Devonian sedimentary section that correlates with non-marine red shales and fluvial sandstones of the Hampshire Formation in the eastern outcrop belt of West Virginia, Maryland and Pennsylvania, and the marine Ohio Shale in the western outcrop belt of Kentucky and Ohio. In the area of Jacksonburg-Stringtown field, Gordon rocks are interpreted to be shoreline/shoreface sandstones that occupied a broad, arcuate trend at the time of maximum regression

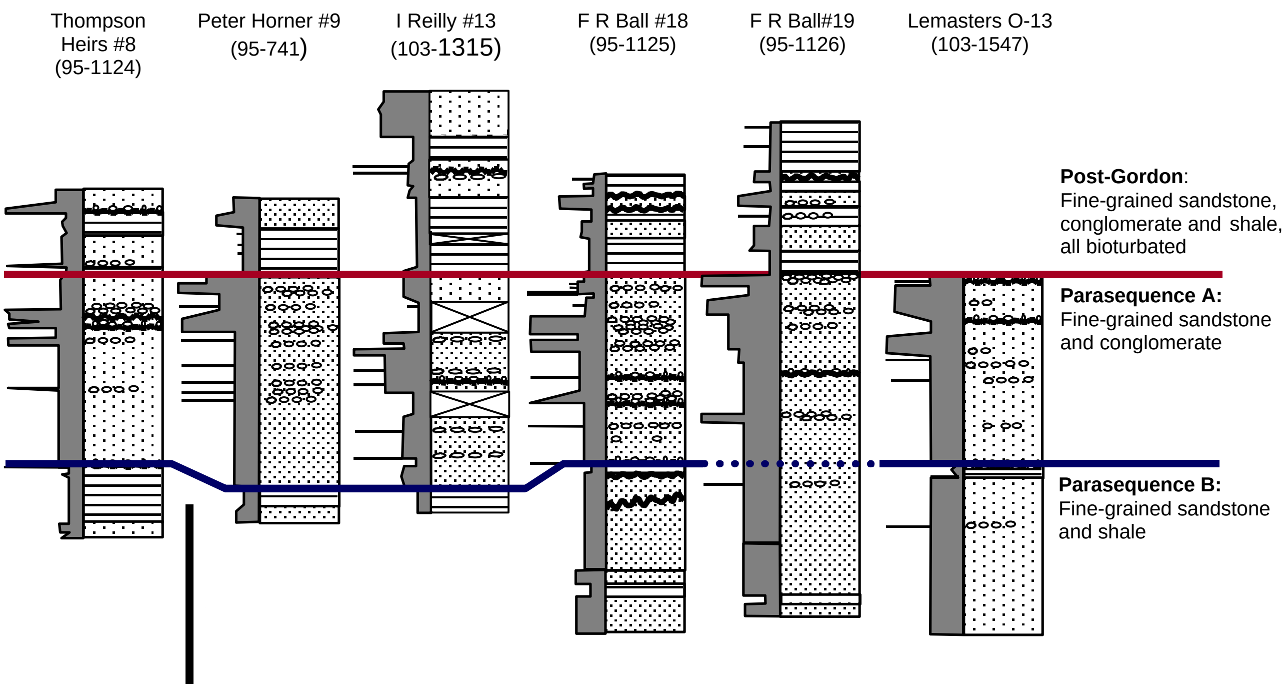

Figure 3. Correlation of all available cores, ordered roughly from east to west.

of the Acadian clastic wedge.

The Gordon interval is composed of three parasequences comprising five lithofacies: featureless sandstone, laminated sandstone, conglomeratic sandstone, shale, and heterolithic bioturbated lithofacies. Thin shales define the vertical limits of each parasequence; the heterolithic bioturbated lithofacies overlies the Gordon throughout the field.

Two types of compartmentalization are present in the field: structural and stratigraphic. A west-northwest to east-southeast fault in the southern part of the field appears to have sufficient throw to isolate reservoir rocks in the southern quarter of the field from reservoir sandstones to the north. Within each parasequence, permeable sandstone of the featureless lithofacies are

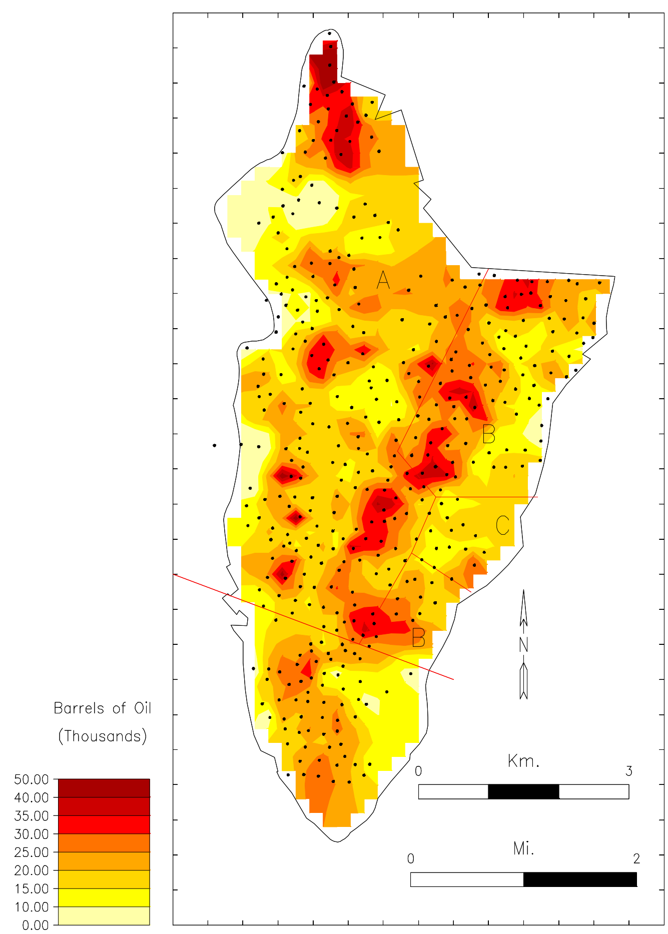

Figure 4. Reservoir sandstone related to estimated cumulative production and structure. Areas A, B, and C have significant thickness of featureless sandstone - the inferred reservoir - within corresponding parasequences psA, psB, and psC.

enclosed and interbedded with low permeability strata of the laminated sandstone, conglomeratic sandstone, and shale lithofacies. Northeast to southwest trends in estimated cumulative production coincide with trends in the thickness of the featureless sandstone lithofacies within the parasequences. Some wells produced oil from more than one parasequence. Although communication between reservoir compartments is generally hard to determine, it might exist in the eastern part of the field where compartments in two parasequences are in stratigraphic and geographic proximity.

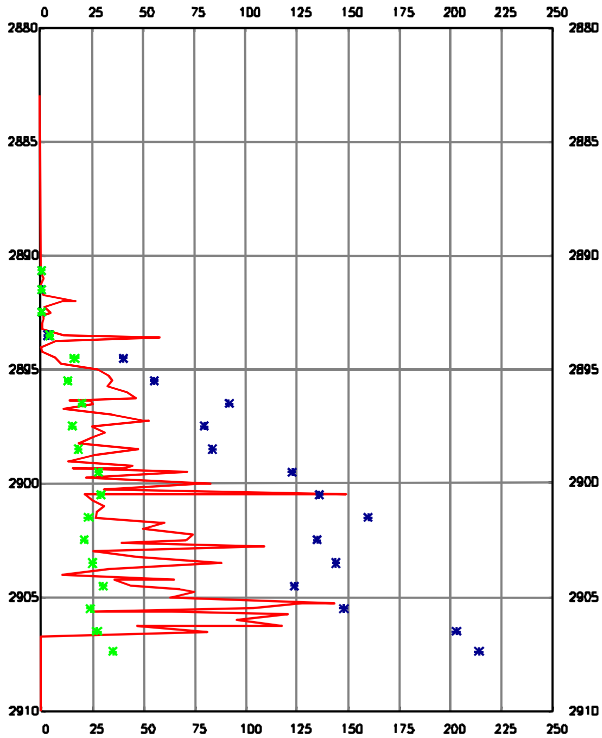

Figure 5. Graph of permeability with depth in Peter Horner #9 (095-741). Permeability from minipermeameter is shown in red; permeability from core plugs is shown in blue; permeability from whole core is shown in green.

Petrology and Petrophysics

Primary porosity observed in Gordon thin sections is intergranular; secondary porosity appears to occur in association with dissolved or partially dissolved potassium feldspars. Cements in Gordon samples consist of clay (primarily kaolinite associated with feldspars), calcite, silica, and siderite. In general, calcite and clay cements occur in an early, post-burial setting. Formation of clay cement continued with deeper burial and diagenesis as associated clays and feldspars were altered. Later, secondary quartz was precipitated in the form of euhedral overgrowths and pore-filling chert. Finally, siderite replaced earlier cements and filled remaining porosity in many Gordon samples. Presence of abundant siderite cement may have serious implications for secondary development in the Gordon because chemical reactions between the composition of injected water and iron of cement must be taken into account.

Minipermeameter readings show considerably more variability than permeabilities measured from either core plugs or whole core because of the greater frequency of sampling with the minipermeameter and the smaller volume measured. Minipermeameter values generally exceed whole core values and are less than core plug values. Because whole core analysis samples a significantly larger volume of

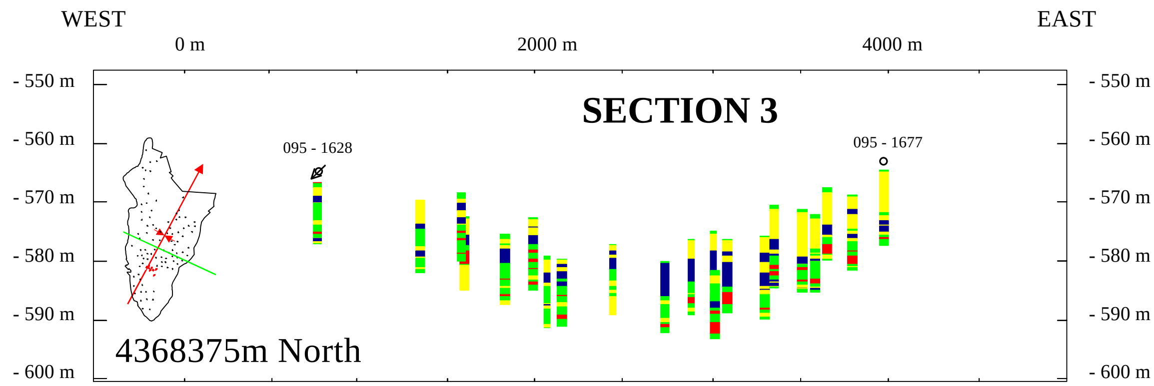

Figure 6. Electrofacies cross section oriented perpendicular to the axis of the Gordon syncline within the Jacksonburg-Stringtown field. Cross-section views the reservoir "looking" north-east. Vertical exaggeration is 50:1.

rock and may include sedimentary barriers to flow such as interbedded shales or stylolitic horizons, it is not surprising that whole core permeabilities may be lower than those measured with the minipermeameter.

Detailed observation of Gordon core material led to the following conclusions: 1) core materials classified as pay sandstone based on log signature were found to have permeabilities ranging from 10 to 200 mD; 2) permeability in non-pay sandstones identified by log signature range from less than the level of instrumental detection to 5 mD; 3) distribution of permeability within pay sandstones was fairly uniform; 4) distribution of small amounts of permeability within non-pay sandstones was usually either zoned parallel to bedding or "patchy"; 5) the conglomeratic material could take on the permeability characteristics of enclosing materials; 6) conglomeratic material was also found with permeabilities exactly the opposite of enclosing materials, e. g., extremely low permeability conglomerate in pay sandstone and high permeability conglomerate in non-pay or low permeability pay sandstone. The last two observations imply that conglomeratic materials, often difficult to pick on geophysical logs because of their thinness, can provide either an unexpected barrier to vertical flow or an unexpected path for horizontal flow.

Four electrofacies based on a linear combination of density and scaled gamma ray data best matched correlations made independently based on visual comparison of geophysical logs. Electrofacies 4 with relatively high permeability (mean value > 30 mD) appears to include the reservoir sandstone. This electrofacies is relatively continuous across the pilot water flood area, used in flow simulations. Electrofacies cross-sections taken perpendicular to the syncline axis demonstrated a distinct asymmetry in distribution of electrofacies across the field. In particular, electrofacies 3 thickens dramatically from the center towards the eastern margin of the field, reflecting a general increase in grain size to the east, the direction from which sediments were transported.

Permeability Distribution Prediction

Knowing the stratigraphic and well-to-well distribution of permeability is key to predicting reservoir performance. The major difficulty in predicting permeability in mature reservoirs is lack of sufficient data, particularly core analyses. Because geophysical well logs are the most abundant source of data in a reservoir, a methodology for estimating permeability based on well logs represents a technical as well as economic advantage.

Several artificial neural networks were designed and implemented utilizing geophysical log re-

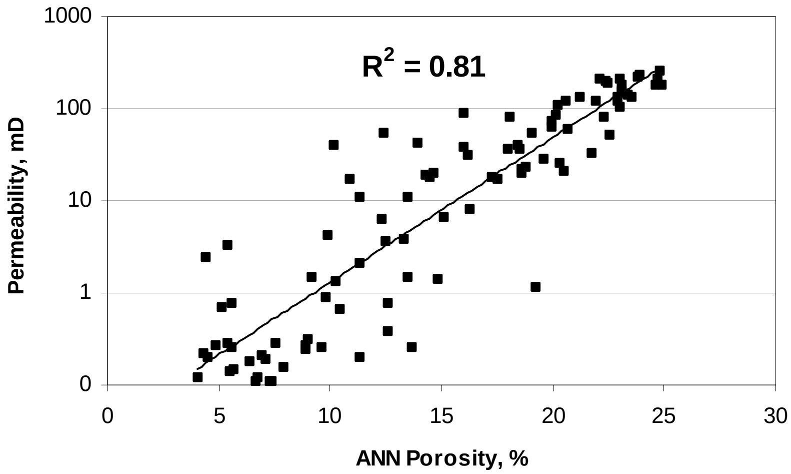

Figure 7. Correlation of measured permeability with ANN predicted porosity.

sponse, core analysis results, minipermeameter measurements, geological interpretations, and statistical methods. This approach led to development of reliable porosity and permeability distributions and identification of productive zones in the reservoir.

Well log data and geological information were used to divide the formation into two flow units, leading to further improvements in the prediction of permeability. Results were verified by successful simulation of production performance for the reservoir. The flow unit model was used to map permeability within the reservoir in 3 dimensions.

The methodology developed in this work can serve as a new tool for characterizing heterogeneous reservoirs.

Reservoir Characterization with Artificial Neural Networks

A simple reservoir model of the pilot water flood area based on well records, well logs, available core analyses, and permeability estimated from the cor-

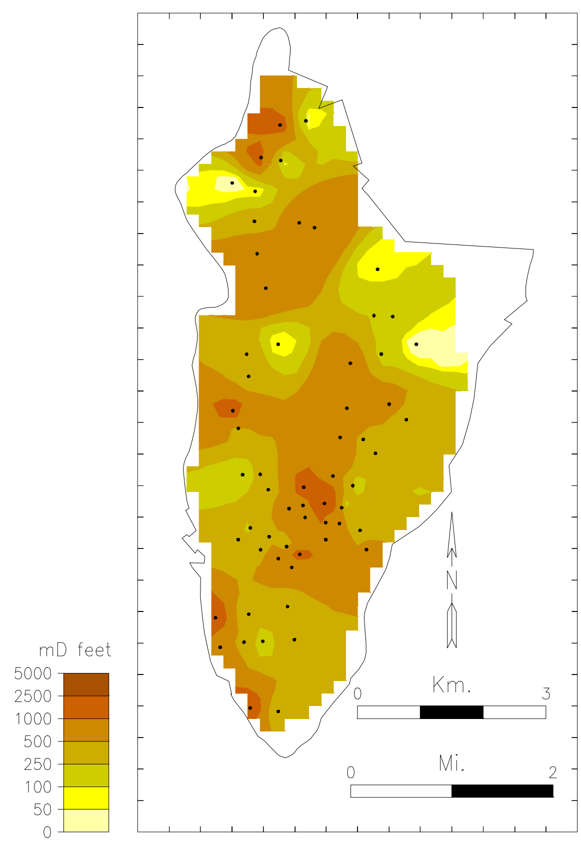

Figure 8. Permeability-Thickness of Flow Unit II.

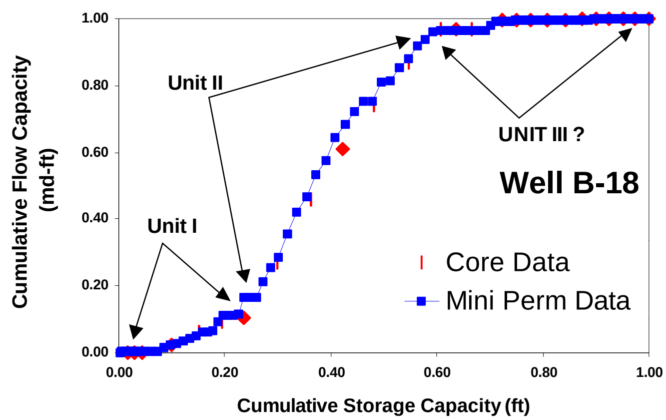

Figure 7.5 Definition of flow units in well B-18.

relation of porosity to permeability provided poor simulation of performance. The need for a more detailed, realistic reservoir model led to the application of the flow unit concept.

As in the prediction of permeability, determining flow units depends upon available core analyses, a rare commodity in mature Gordon fields. Therefore, an artificial neural network was used to identify flow units from logged wells, with geophysical log characteristics as input and the observed flow units in cored wells as the target. Models with two or three flow units were tested, and a model comprising two flow units was found to give good results as measured by the prediction of flow units in each cored wells from the other cored wells.

When this artificial neural network model was utilized with well log data in a waterflood area north of the pilot area, results of simulation were in very good agreement with the field history.
Artificial neural networks trained on all six cored wells were used to determine flow units throughout the field. Permeability profiles for all wells with available geophysical logs gave results similar to those reported in the previous chapter. Trends in permeability and flow unit distributions are similar to those observed in estimated ultimate oil production.

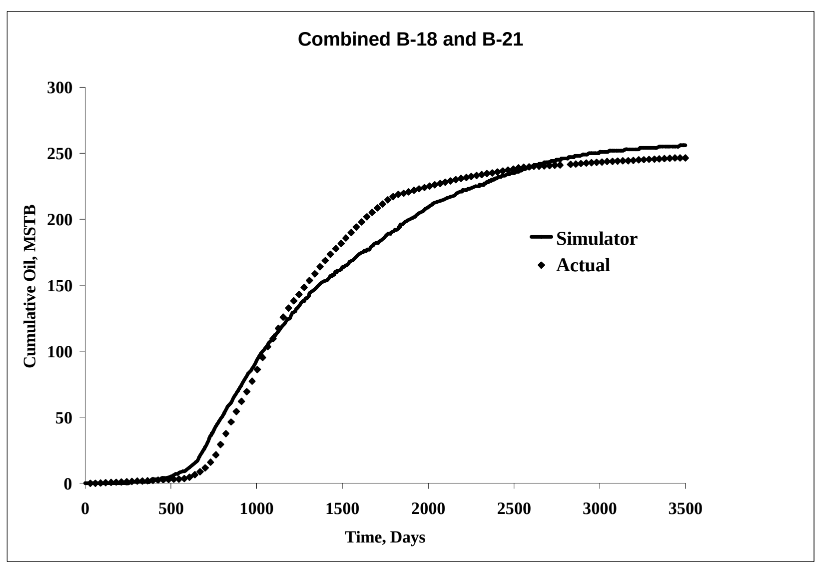

Figure 10. Comparison of the Field Production Performance and Simulator Predictions for Combined B-18 and B-21 Patterns