DOE/METC--90/4095-Vol.2

DE90 000448

Potential of Infill Drilling to Increase Devonian Shale Gas Reserves in the Appalachian Basin

Volume II: Ohio, Kentucky, and West Virginia

Technical Note

By
A.W. Layne

U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

January 1989

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

This report presents results of two studies to evaluate the potential of infill drilling as a production strategy in the Devonian shales. Volume I is a case study that analyzed the infill drilling potential in Kanawha County, West Virginia. Volume II is a study to evaluate the feasibility of infill drilling in the Devonian shale formations of Ohio, Kentucky, and West Virginia.

The U.S. Department of Energy analyzed the potential of infill drilling as a production strategy to increase the reserve base of the Devonian shale formations in Ohio, Kentucky, and West Virginia. Volume I is a case study in West Virginia that compares actual field data with simulations. Infill wells were placed in an existing field in an area of high flow capacity (determined by history matching). Results indicate that 50 percent more gas may be recovered over a 10-year period if infill wells are drilled in the more geologically favorable area of a field. Geologically favorable areas of a field are locations where high permeability and thickness have been calculated through history matching.

This study (Volume II) uses data evolved during the Eastern Gas Shales research program to compile gas-in-place estimates and to analyze key production mechanisms. Each of the three states was partitioned into areas based on key geological parameters and tectonophysics that established the natural stress and fracture regimes. Within these partitioned areas, a simulation study of infill drilling was conducted to determine the impact of reduced well spacing on 40-year cumulative gas production. In this approach, one, three, and five infill wells were randomly located in a field of five existing wells that had been producing for 20 years. After 20 years of well production, the well recovery for each simulated infill well was evaluated.

Volume I includes a simplified economic analysis to determine feasible infill scenarios. A Devonian-gas-shale economics model was used to evaluate the results of both studies. Required gas prices were calculated for a 20 percent rate-of-return on investment for each infill drilling scenario. Results determined that less than 80-acre well spacing was not economically feasible. A reduced number of wells spaced 80 acres or more apart was productive, in agreement with this study (Volume II). Accordingly, areas in West Virginia and Kentucky are candidates for infill drilling, but such areas of high flow capacity can only be found through a detailed geologic characterization with history matching.

1.0 INTRODUCTION

The efficiency of alternative well stimulation and production strategies were investigated. These results are limited to one of a few wells drilled in a given pattern. The Morgantown Energy Technology Center (METC) completed an infill drilling feasibility study of 10 wells: five were existing wells and five were infill wells. This provided a hypothetical simulation study that provided a more realistic scenario to evaluate the impact of reduced well spacing in each area. The SUGARMD reservoir model was used to predict the gas production for each area. Additional information on SUGARMD is found in Appendix A.

2.0 DATA COLLECTION

The primary data source for the infill drilling feasibility study was the reports published by Lewin and Associates on technically recoverable Devonian shale gas in Kentucky, West Virginia, and Ohio (Kruuskraa et al. 1985a, 1985b, 1985c). The reports provided the input modeling data for a full-field simulation. The areas for Ohio, West Virginia, and Kentucky are shown in Figure 1. The data derived from the reports included formation depth, rock pressure, gas content, net producing thickness, fracture permeability, permeability anisotropy, fracture intersection angle, fracture spacing, and the results of 40-year cumulative matched production for the area's representative well. The data listed correspond to the characteristics of the representative well.

These reports discussed in detail the procedure for determining a representative well for each area. In general, the well properties were such that the most frequent values in a given geologic area were used to characterize the well. These values for each area in Ohio, West Virginia, and Kentucky, are shown in Tables 1, 2, and 3. The reservoir properties held constant were matrix porosity and permeability, and fracture porosity. The matrix porosity was held constant at .1%, the matrix permeability was $.5 \times 10^{-5}$ mD, and the fracture porosity was held at .09%.

3.0 MODELING PROCEDURE

The impact of reduced well spacing for each of these areas was analyzed with full-field reservoir modeling. A random pattern of five existing wells in a 400-acre field was simulated for 40 years. The data for each well were taken from corresponding areas in each state. The pattern of wells is shown in Figure 2. After the five wells were produced for 40 years, their individual productions were compared to that of the representative wells in the Kruuskraa reports (Kruuskraa et al. 1985a, 1985b, 1985c) to ensure that the values matched. Then the simulations were repeated with one, three, and five infill wells installed after 20 years of production.

Half of this analysis was completed with the wellbores represented in 50 x 50 ft grid blocks. This was prior to the completion of the analysis that determined the PI (productivity index) to be functioning properly. The well position within the 50 x 50 ft grid blocks was such that boundary effects were decreasing the production of Well No. 4; this balanced out the overproduction of the other wells, and the full-field cumulative production matched. This full-field behavior was not accurate and warranted a more reliable methodology.

The modeling was then initiated to represent the existing wells accurately using the PI. A larger boundary was created for the full field so that boundary effects were not present.

The five representative wells for each area were then simulated using the PI option on the existing wellbores. After 40 years of production, the individual wells were checked to ensure that they matched the representative wells in the Kruuskraa reports (Kruuskraa et al. 1985a, 1985b, 1985c). Two areas in West Virginia did not match. Several attempts were made to resolve this problem; W. Sawyer of Lewin Associates was contacted to investigate the problem. A typographical error was found in the documentation. After these corrections were incorporated into the data, representative well production matches were obtained. One, three, and five shot wells were then simulated after 20 years of production to determine the impact of reduced spacing. The results of these simulations are shown in Figures 3, 4, and 5.

4.0 ECONOMIC ANALYSIS

To determine if the addition of infill wells was economical for each of these areas, an economic limit was calculated using the Devonian Shale Gas Economic Model (DGEM). Average well depths and producing intervals were calculated for each state. The remaining data remained constant and are shown in Table 4. Table 5 is a list of current tax values. The well production was varied until a 20-year cumulative production was determined that required a gas price of $2.00/Mcf to produce a realistic well placement scenario. Therefore, those areas where 60 or 40 acres are close to the feasible economic limit may be considered economically attractive if a decreased amount of interference were to take place with an existing or infill well.

5.0 CONCLUSION

Results of the Kanawha County case study (Volume I) indicate that variations in flow capacity exist throughout a shale reservoir, and a constant value of permeability or productive thickness is unlikely. Within a given field, extreme variation is unlikely. However, areas of relatively high flow capacity in relation to the other portions of a field exist; these areas are the desired candidate sites for infill well installation. In order to complete a comprehensive study of infill drilling feasibility for a large resource area (Kentucky, West Virginia, and Ohio), the possibility of accounting for the geologic variation in each partition is impossible. These areas can only be delineated through an in-depth analysis of each field, and knowledge of site-specific geology. Therefore, the existence of high flow capacity areas should be acknowledged when infill drilling is considered in what have been termed noncandidate locations.

The density of natural fractures or the flow capacity may vary within a field. A higher number of natural fractures (thus, higher flow capacity) means a potentially high productive area and potentially increased gas recovery. Therefore, the results of the feasibility study for West Virginia, Kentucky, and Ohio may not be applicable in all cases. For those partitions that are marginal or could be economically feasible for a slightly higher gas price, the governing geologic parameters may change because of variations in the natural fracture discontinuity or density, or in the producing formation. Therefore, some areas that are considered noncandidate from the results of the feasibility study may be candidates if discrete geologic data are available to characterize and identify these sites. It is concluded that dominant geologic features throughout the Appalachian Basin can delineate areas that are potential candidates for infill drilling. The geologic partitions of Kruuskraa et al. (1985a, 1985b, 1985c), then, could be used as a first step in determining an infill drilling site. However, sites of discontinuity exist that may hinder or improve the production potential of a promising partition.

6.0 REFERENCES

Kruuskraa, V.A., K.B. Sedurick, K.B. Thompson, and D.E. Wicks. May 1985a. Technically Recoverable Devonian Shale Gas in Kentucky. Lewin and Associates, Inc. DOE/MC/19239-1834, NTIS/DE85008608, 120 p.

Kruuskraa, V.A., K.B. Sedurick, K.B. Thompson, and D.E. Wicks. May 1985b. Technically Recoverable Devonian Shale Gas in Ohio. Lewin and Associates, Inc. DOE/MC/19239-1823, NTIS/DE85003209, 119 p.

Kruuskraa, V.A., K.B. Sedurick, K.B. Thompson, and D.E. Wicks. May 1985c. Technically Recoverable Devonian Shale Gas in West Virginia. Lewin and Associates, Inc. DOE/MC/19239-1750, NTIS/DE85003367, 117 p.

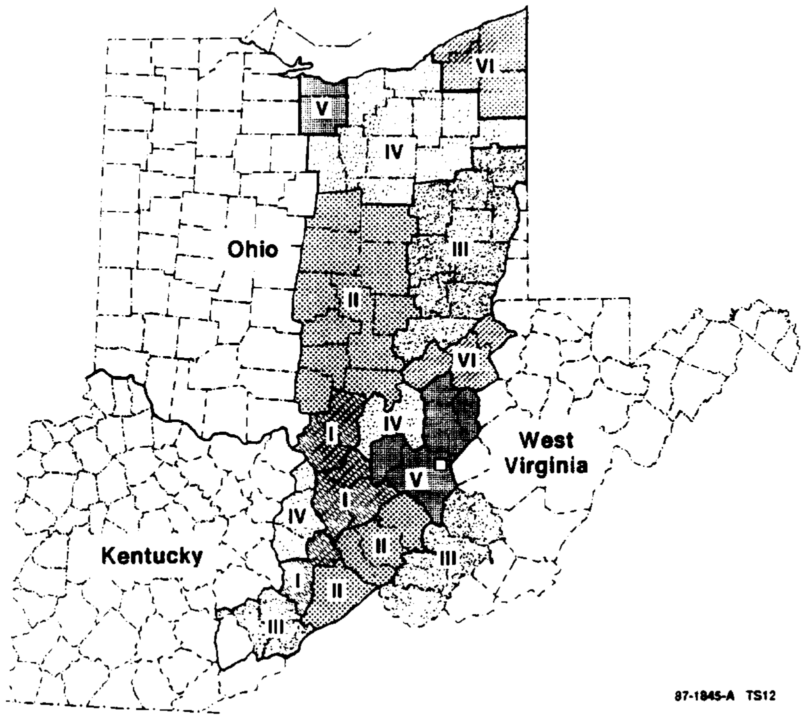

Figure 1. Geologic Partitions Used in the Feasibility Study

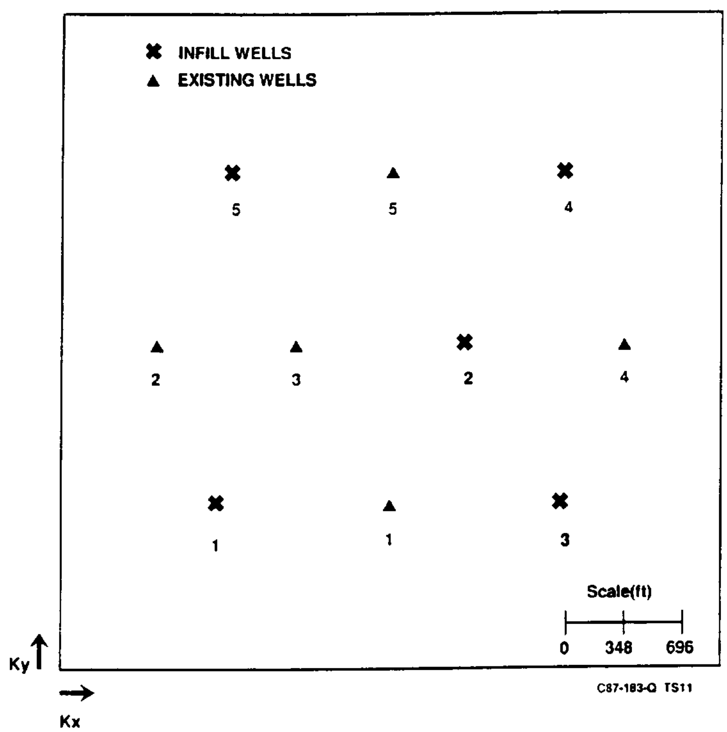

Figure 2. Feasibility Study Well Pattern

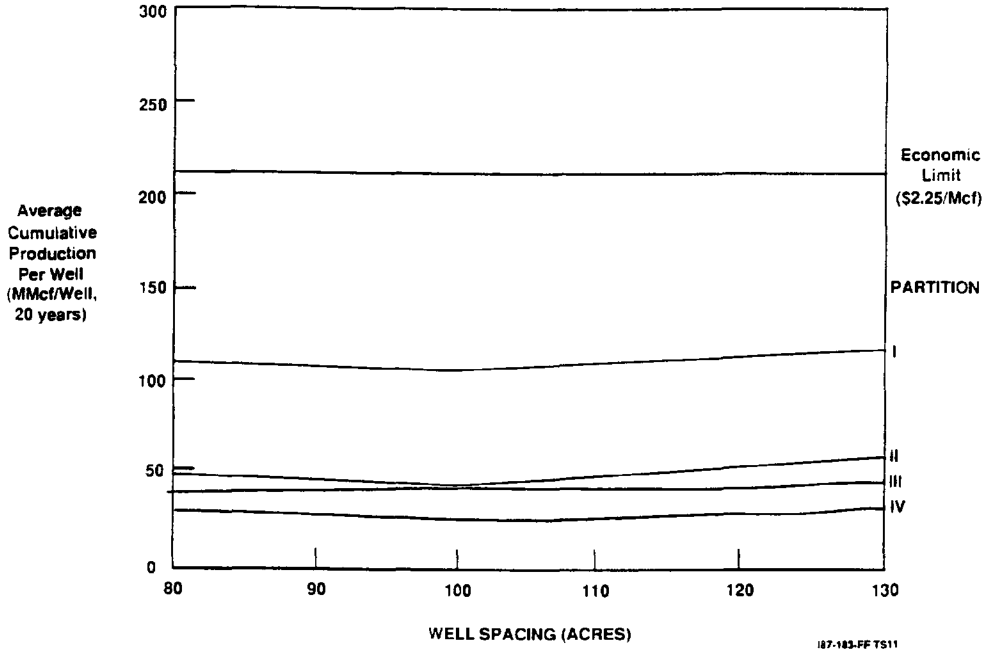

Figure 3. Ohio Infill Drilling Feasibility Study for Five Geologic Partitions

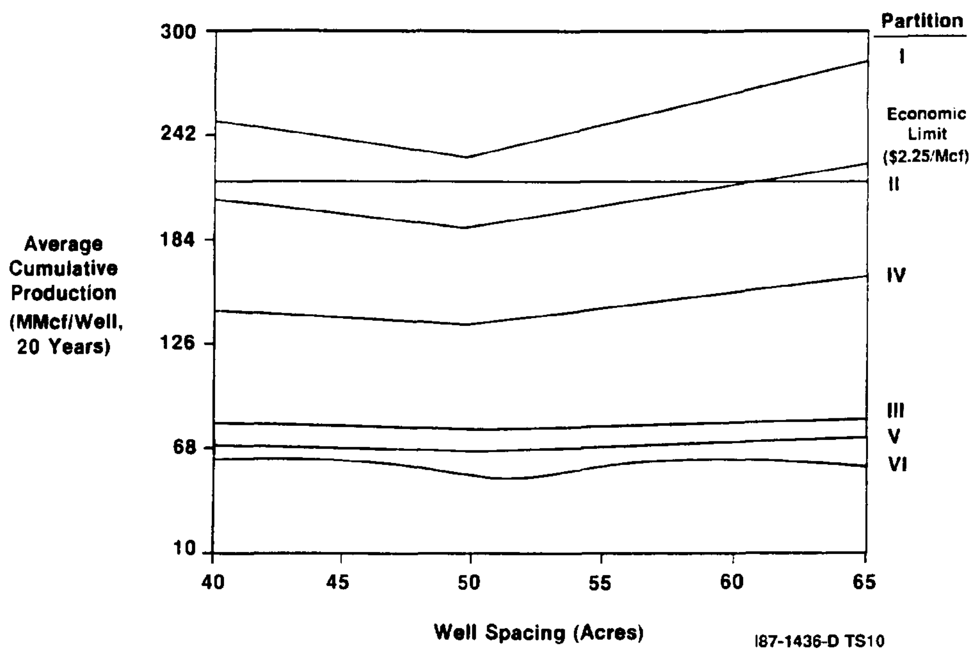

Figure 4. West Virginia Infill Drilling Feasibility Study for Six Geologic Partitions

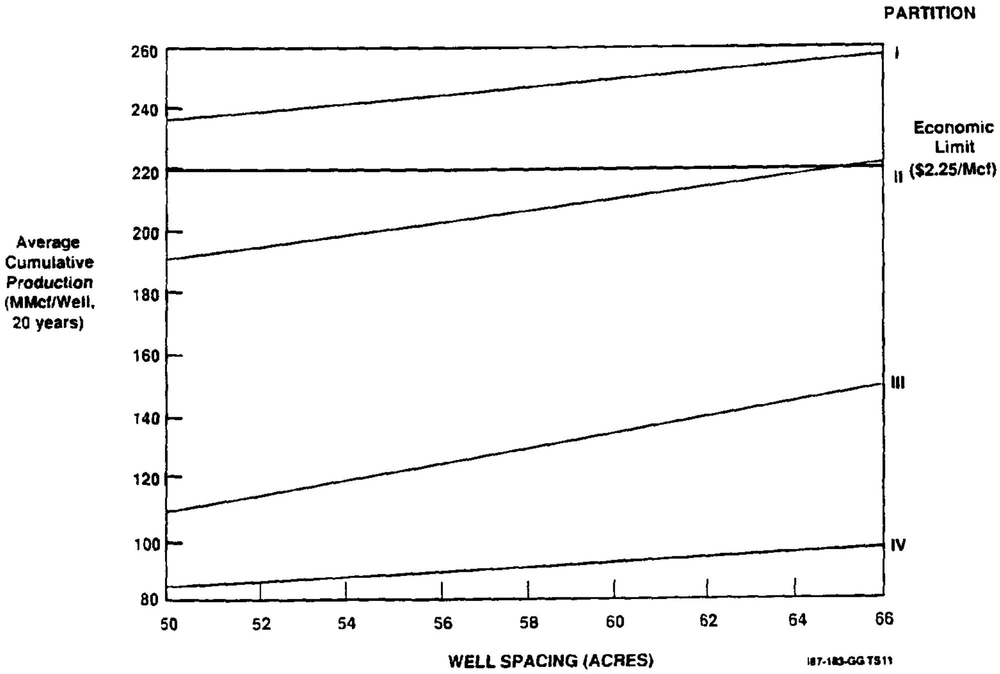

Figure 5. Kentucky Infill Drilling Feasibility for Geologic Partitions

Table 1. Ohio Partitioned Areas

Partitions (Counties)	Depth (ft)	Rock Pressure (psia)	Gas Content (Mcf/Acre ft)	Net Thickness (ft)	Fracture Permeability (mD)	Permeability Anisotropy (ratio)	Fracture Spacing (ft)	Cumulative Recovery (MMcf/well) 10-yr	40-yr
(Galia, Lawrence)	2,320	690	100	119	0.0278	1:1	10		
	1,500	240	90	60	.2993	6:1	20	64	206
	3,560	525	20	120	.02	4:1	20	42	127
	1,660	215	140	105	.0574	6:1	20	21	79
	365	90	200	10	4.429	8:1	20	11	39
	2,135	135	50	100	.02	8:1	20	3	10

Table 2. West Virginia Partitioned Areas

Partitions (Counties)	Depth (ft)	Rock Pressure (psia)	Gas Content (Mcf/Acre ft)	Net Thickness (ft)	Fracture Permeability (mD)	Permeability Anisotropy (ratio)	Fracture Spacing (ft)	Cumulative Recovery (MMcf/well) 10-yr	40-yr
Area I (Cabell, Wayne, Lincoln)	3,487	330	64	91	0.62	1:1	5	203	309
Area II (Mingo, Boone, Logan)	3,414	450	50	226	.074	1:1	5	184	446
Area III (Fayette, Raleigh, Wyoming, McDowell)	5,736	960	55	128	.024	8:1	30	86	235
Area IV (Mason, Jackson)	3,723	625	80	67	0.17	2:1	10	183	314
Area V (Wirt, Roane, Calhoun, Kanawha, Putnum)	4,383	340	50	160	.07	4:1	15	76	216
Area VI	4,051	450	60	100	.08	4:1	20	86	218

Table 3. Kentucky Partitioned Areas

Partitions (Counties)	Depth (ft)	Rock Pressure (psia)	Gas Content (Mcf/Acre ft)	Net Thickness (ft)	Fracture Permeability (mD)	Permeability Anisotropy (ratio)	Fracture Spacing (ft)	Cumulative Recovery (MMcf/well) 10-yr	40-yr
Area I (Martin, Floyd)	3,038	375	74	380	0.105	1:1	5	368	962
Area II (Pike)	3,878	590	81	114	0.100	1:1	5	213	452
Area III (Perry, Knott, Leslie, Letcher)	3,550	520	108	123	0.095	4:1	5	197	499
Area IV (Boyd, Lawrence, Johnson)	3,000	550	79	120	0.045	2:1	5	111	305

Table 4. Financial Analysis Parameters

Operating Cost Overhead (Fraction)	0.2000
G&A Rate on Investment (Fraction)	0.1000
Depreciation Life (Years)	20.0000
Royalty Rate (Fraction)	0.1250
Severance Tax Rate (Fraction)	0.0800
Windfall Profits Tax Rate (Fraction)	0.0000
Income Tax Credit Rate (Fraction)	0.1000
State Income Tax Rate (Fraction)	0.0200
Federal Income Tax Rate (Fraction)	0.4600
Discount Factor	1.2000
Year in Which Sales Begin (Year)	2.0000
Lease Bonus Capital Rate (Fraction)	0.0050
Year After Investment to Begin Depreciation	1.0000
Well Depth (Feet)	5000.
Net Pay Thickness (Feet)	29.0
Well Spacing (Acres/Well)	80.
Capital Costs Per Well	
Cost Category	Dollars
Geological and Geophysical Costs per Well	1,000
Drilling and Completion Costs per Well	112,500
Production and Lease Equipment Costs per Well for a Maximum Gas Production Rate of 90.4 Mcf/d/well	7,500
Stimulation Costs for Borehole Shooting	8,000
Allocated Dry Hole Costs for a 0.000 Dry Hole Rate at 188608.7 per Well for Drilling	0
and 8000.0 per Well for Stimulation	0
Total Investment	129,000
Average Annual Operating Costs Per Well	
Cost Category	Dollars
Primary Operating Costs (POC) per Well for an Average Gas Production Rate of 38.1 Mcf/d/well	3,000
Average Annual Operating Cost	3,000

Tangible capital costs include (a) 20% of all drilling and completion costs, and (b) all other capital costs excluding stimulation. Expense items/capital costs include (a) 80% of all drilling and completion costs, (b) all dry hole costs, (c) lease acquisition costs (expanded over project life), (d) stimulation costs, and (e) all geological and geophysical costs.

Table 5. Current Tax Values

Royalty Rate Fractures Percentage	12.5%
Severance Tax	6.5%
Ad Valorem Tax	62%
State Tax	8%
Federal Tax	40% -- 1987 34% -- Afterwards

APPENDIX A: SUGARMD MODEL DESCRIPTION

SUGARMD is a general purpose, two-dimensional reservoir simulator for gas reservoirs. The code can be used to study fractured reservoirs and will efficiently solve one- and two-dimensional problems in either cartesian or polar cylindrical coordinates. Boundary conditions are flexible in that any desired flowing pressures or gas flow rate, as a function of time, may be imposed at any interior or boundary block within the finite-difference grid. This permits simulation of fractured wells by one of several options.

In the radial mode, SUGARMD may be used as a single-well simulator. For example, it may be used for history matching of well test or production data, studying the effects of dual-porosity (primary or secondary) systems, or forecasting production performance of individual wells. In the rectangular mode, the reservoir may be made virtually any shape by use of "zero permeability blocks."

Complete heterogeneity of reservoir properties can be specified by assigning a unique porosity value and unique permeability value in each of the coordinate directions (permeability anisotropy) to each grid block in the system.

A naturally fractured reservoir may be simulated by choosing this option and specifying rock matrix porosity and permeability values and element size (fracture spacing). Also, deposition of gas from pore walls of the matrix can be considered by entering an appropriate desorption isotherm. The term matrix denotes the less permeable portion of the formation that delivers its gas content into an existing natural fracture system. The matrix acts as a uniformly distributed source within the fracture system.