OPTIMAL DEVELOPMENT OF UTICA SHALE WELLS

Final Report

Prepared for

THE NEW YORK STATE
ENERGY RESEARCH AND DEVELOPMENT AUTHORITY
Albany, NY

John Martin
Project Manager

Prepared by

ADVANCED RESOURCES INTERNATIONAL, INC.
Arlington, VA

Jonathan Kelafant
Project Manager

Project 8163

December 2008

NOTICE

ABSTRACT

In 1820, the first commercial shale well was drilled in the State of New York, which led to the eventual gas production from the Basin's Devonian Shale reservoirs. Today, thanks to successful and active development of the Barnett, Antrim, and Fayetteville shales, along with the Devonian (Huron/Ohio) of the Appalachian Basin, shale gas now accounts for 6% of U.S. gas production, totaling more than one trillion cubic feet (TCF) annually.

As a result, no two words are more attention grabbing than "shale gas" in today's oil and gas marketplace. While the Fort Worth Basin's Barnett Shale has garnered most of the news over the past decade, what was old is now new in the Appalachian Basin. Operators have improved technologies, which were developed and honed in the Fort Worth Basin, to thank for this resurgence as these technologies hold promise for developing the region's large Marcellus and Utica Shale gas deposits.

This report will discuss the role that these technologies, specifically horizontal well drilling and completion techniques, may have on Utica Shale gas development. For this, the report will conduct a parametric reservoir study for an example Utica Shale Gas development project. The subject wells were drilled and completed with modest stimulation treatments. This report will review past performance and assess optimum stimulation strategies (in terms of size and intensity) when using vertical and horizontal wells to produce the Utica gas shale.

This page is intentionally left blank.

TABLE OF CONTENTS

FIGURES

TABLES

SUMMARY

Since the first commercial shale well was drilled in the State of New York in 1820, operators have continuously developed new technologies to improve productivity. Thanks to this successful and active development shale gas now accounts for 6% of U.S. gas production. This report discusses the role these technologies, specifically horizontal well drilling and completion techniques, may play in the development of the Utica Shale. A parametric reservoir study for an example Utica Shale Gas development project was conducted, and the results are summarized in this report. This study reviews past performance and assesses optimum stimulation strategies (in terms of size and intensity) when using vertical and horizontal wells to produce the Utica gas shale.

Data from the Sheckells #1 well producing from the Utica Shale were used as a base to generate a sensitivity analysis on the optimal development of wells in that particular shale play. The well was stimulated via hydraulic fracture treatment which achieved a skin of -3. A draw-down build-up test was conducted on the Sheckells #1 well, and the test was history-matched manually in order to estimate parameters such as permeability and porosity, which are used as the base case for the sensitivity study.

Based on the results of the history-match, a parametric study was conducted on a vertical and horizontal well using Advanced Resources International's COMET3 model. The vertical well is assumed to be producing for 30 years at a flowing bottomhole pressure of 100 pounds per square inch (psi). Sensitivities were run on spacing, stimulation, permeability, fracture half-length, and matrix block size. As with the vertical well, the parameters from the build-up test history-match were used for the sensitivity study for the horizontal well. A 3,000 foot (ft) long horizontal on 160 acres spacing, producing at a bottomhole pressure of 100 psi, was assumed. Sensitivities were run on fracture half-length, and matrix block size.

Additionally, a case was run to optimize for field development using horizontal wells. It was assumed that a sweet spot was discovered with increased shale thickness and increased permeability. The fracture half-length of the horizontal well was fixed at 300 ft and the matrix block size was fixed at 10 ft.

The results of the parametric study show improvements in productivity for the Utica shale play are associated with improved reservoir quality, whether through the presence of a natural fracture system or good permeability (especially matrix permeability), and improved stimulation intensity. However, it is important to note that the study was based on data from only one well with a very limited production history. In addition, the well was only partially completed and lightly stimulated which may affect the results. Additional information is necessary to confirm these preliminary findings.

This page is intentionally left blank.

1. BUILD-UP TEST HISTORY-MATCH

Data from the Sheckells #1 well producing from the Utica Shale were used as a base to generate a sensitivity analysis on the optimal development of wells in that particular shale play. The well was stimulated via hydraulic fracture treatment which achieved a skin[1] of -3.

A draw-down build-up test was conducted on the Sheckells #1 well as illustrated in Figure 1. The plot shows an initial pressure of 960 pounds per square inch (psi) (section 1). The well flowed for 13 days (section 2) and was then allowed to build up for 35 days (section 3). The test was history-matched manually in order to estimate parameters such as permeability and porosity, which are used as the base case for the sensitivity study.

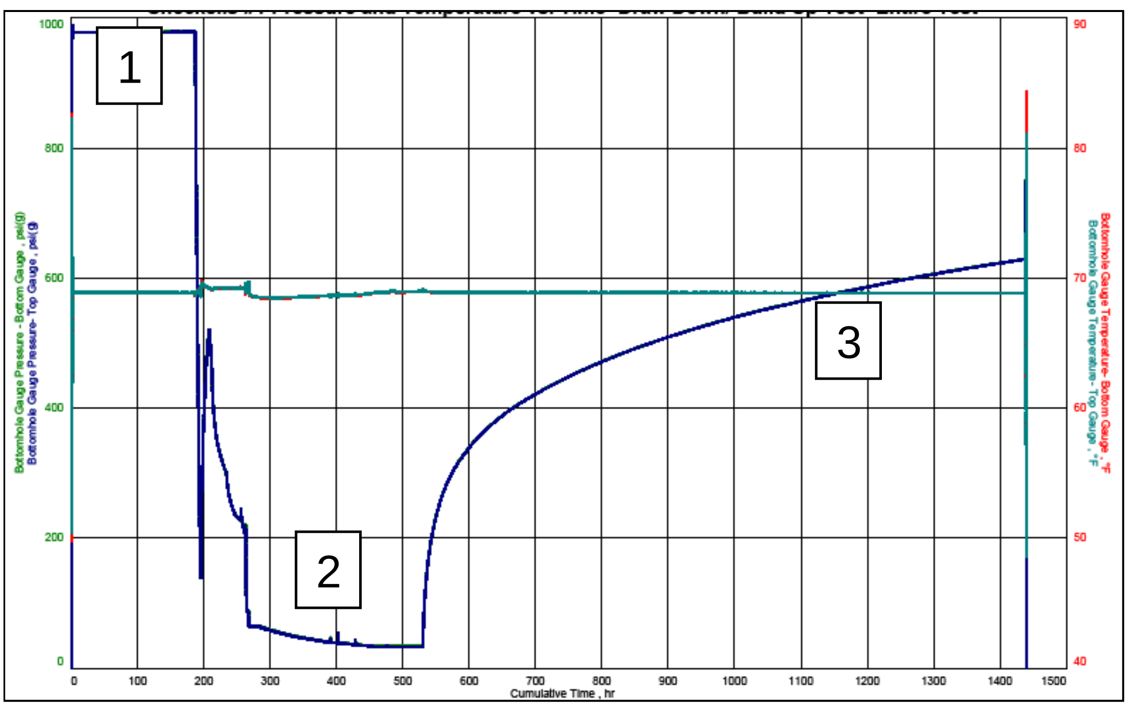

Figure 1. Draw-Down Build-Up Plot.

Table 1 shows the inputs used to match the data. The Langmuir volume and pressure terms were derived from the Utica isotherm curve in Figure 2.

[1] Mathematically, the degree of stimulation can be described by the dimensionless term called skin, or "S". A positive value of S indicates damage related to the natural condition of the reservoirs, and a negative value of S indicates stimulation. Values of S in the range of -3 have been documented in many coal seams throughout the United State.

Depth	**2388**	**ft**
Shale Thickness	**226**	**ft**
Initial Pressure	**960 psi @ 2388 ft**	
k fracture	**0.003**	**mD**
Phi fracture	**0.006**	
Sorption Time	**10**	**Days**
k matrix	**0.0005**	**mD**
Phi matrix	**0.05**	
Matrix Block Size	**10x10x10**	**ft**
Langmuir Volume (in-situ)	**4.2**	**scf/ft³**
Langmuir Pressure	**400**	**psi**
Pore Compressibility	**1.00E-04**	**1/psi**
Matrix Compressibility	**1.30E-05**	**1/psi**
Wellbore radius	**0.271**	**ft**
Skin	**-3**	

Table 1. History-Match Input Data.

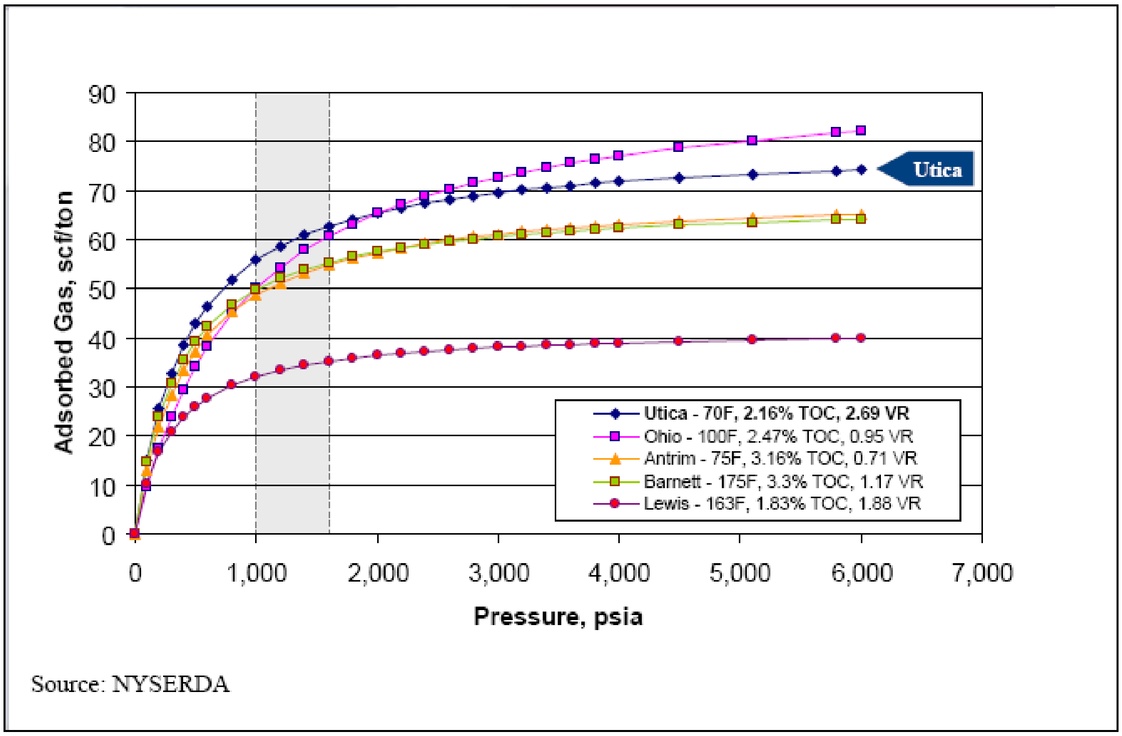

Figure 2. Isotherms from Various Shales.

The permeability (k) of the fracture was found to be 0.003 millidarcy (mD) and the permeability of the matrix 0.0005 mD. The respective porosities (phi) were 0.6% and 5%. Figure 3 illustrates the results of the history-match.

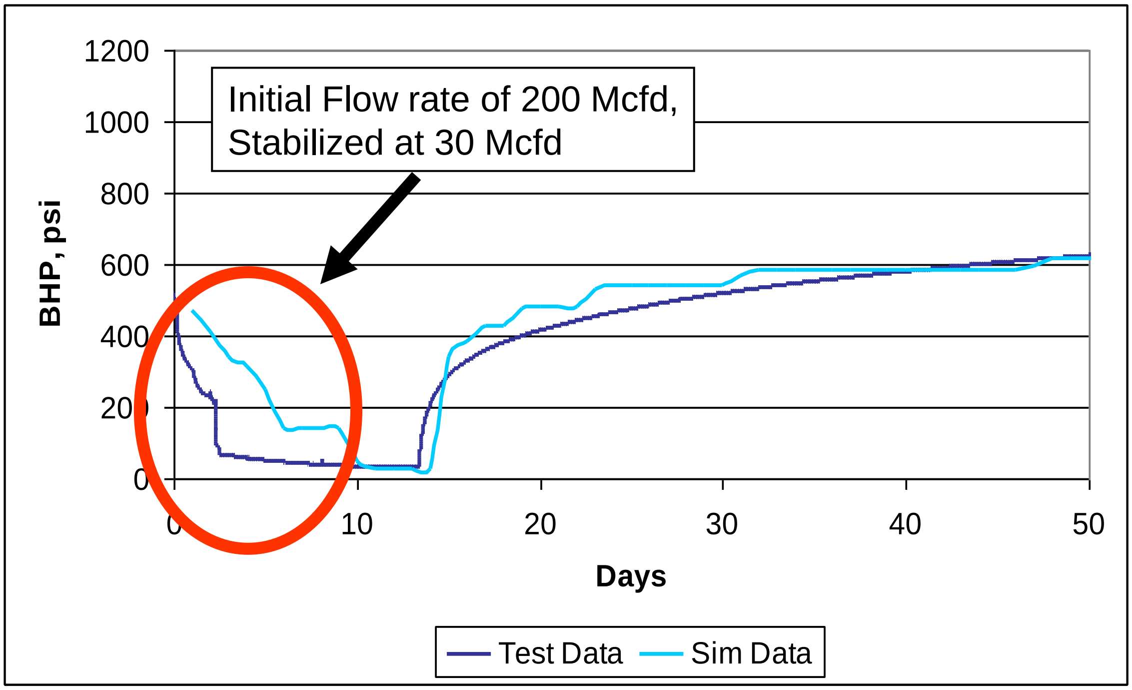

Figure 3. Build-Up Test History-Match.

This page is intentionally left blank.

2. VERTICAL WELL

Based on the results of the history-match, a parametric study was conducted on a vertical well using Advanced Resources International's *COMET3* model (triple porosity option). The well is assumed to be producing for 30 years at a flowing bottomhole pressure of 100 psi. Sensitivities were run on spacing, stimulation, permeability, fracture half-length, and matrix block size. All input parameters can be found in Table 1, and the results from the sensitivity analyses are discussed below.

SPACING SENSITIVITY

Well spacing of 20, 40, and 80 acres was investigated. Figure 4 shows the grid on 80-acre spacing as viewed in the reservoir simulator.

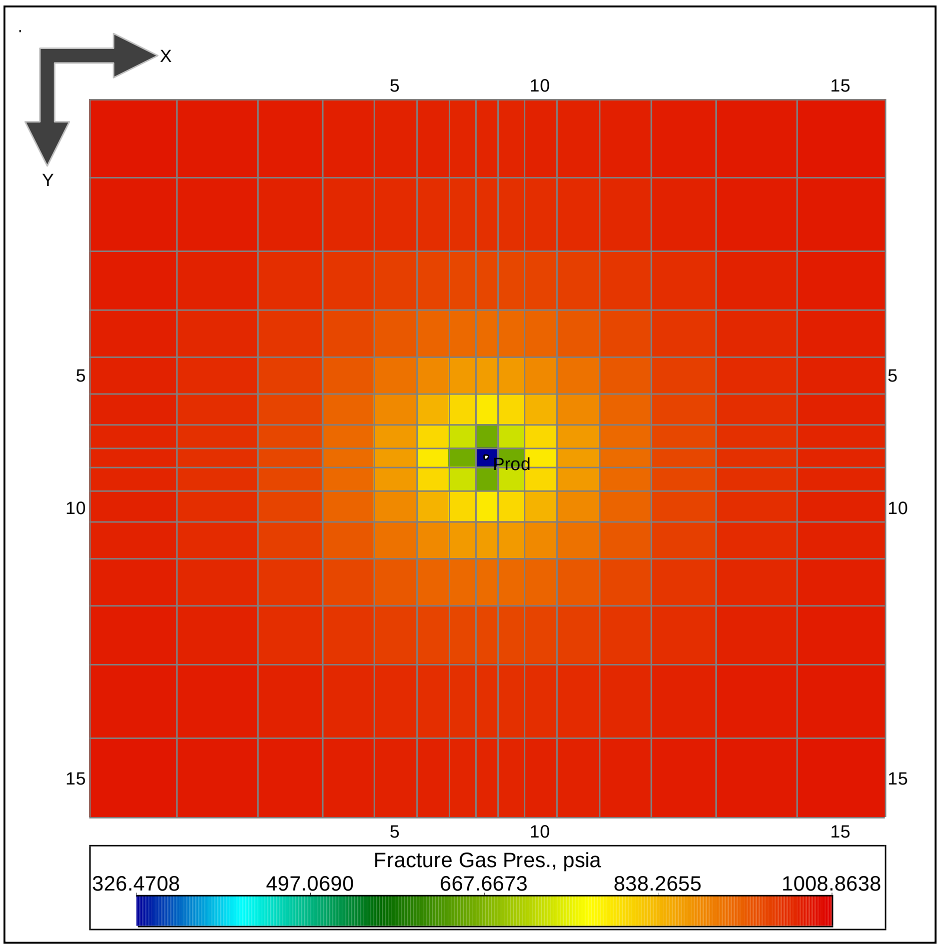

Figure 4. Model Grid View – Vertical Well on 80 Acres Spacing.

The gas rate for each case is shown on Figure 5 and the recoveries are summarized in Table 2.

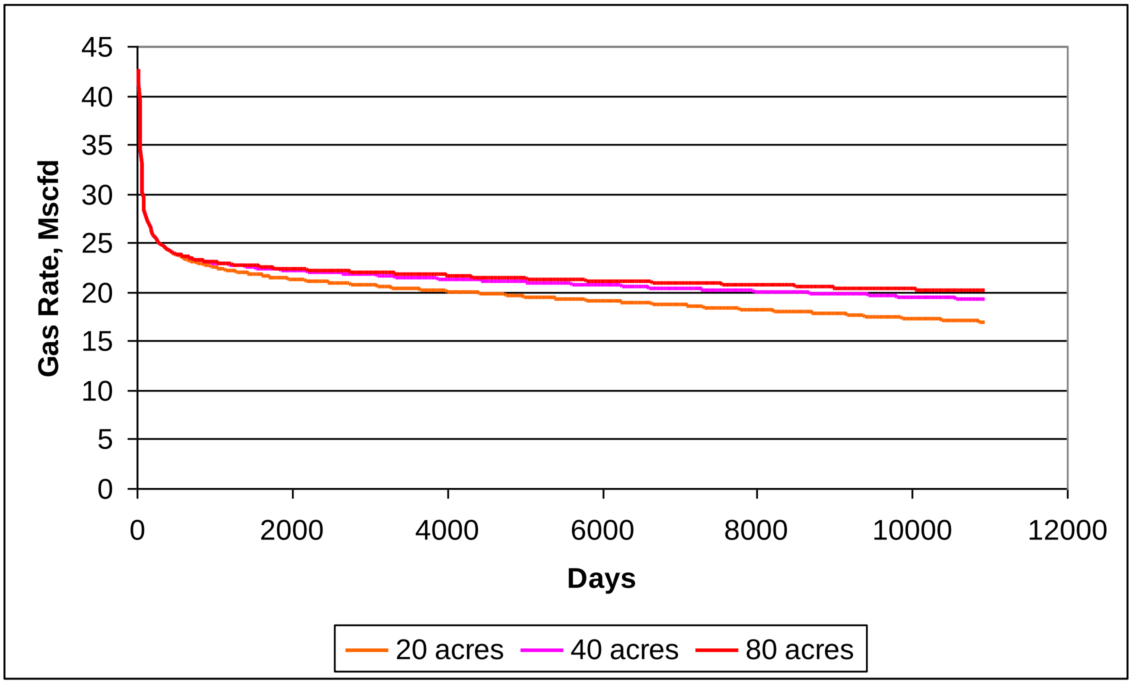

Figure 5. Vertical Well Production– Spacing Sensitivity.

	20 acres	40 acres	80 acres
OGIP (Bcf)	1.4	2.8	5.6
Cum Prod (Bcf)	0.2	0.23	0.24
Recovery (%)	15.6	8.3	4.2

Table 2. Recoveries – Spacing Sensitivity.

STIMULATION SENSITIVITY

For the stimulation sensitivity, a skin of -5 was used in order to account for a scenario where a greater degree of stimulation is achieved. The gas production rate for each well spacing is shown in Figure 6, and the recoveries are summarized in Table 3.

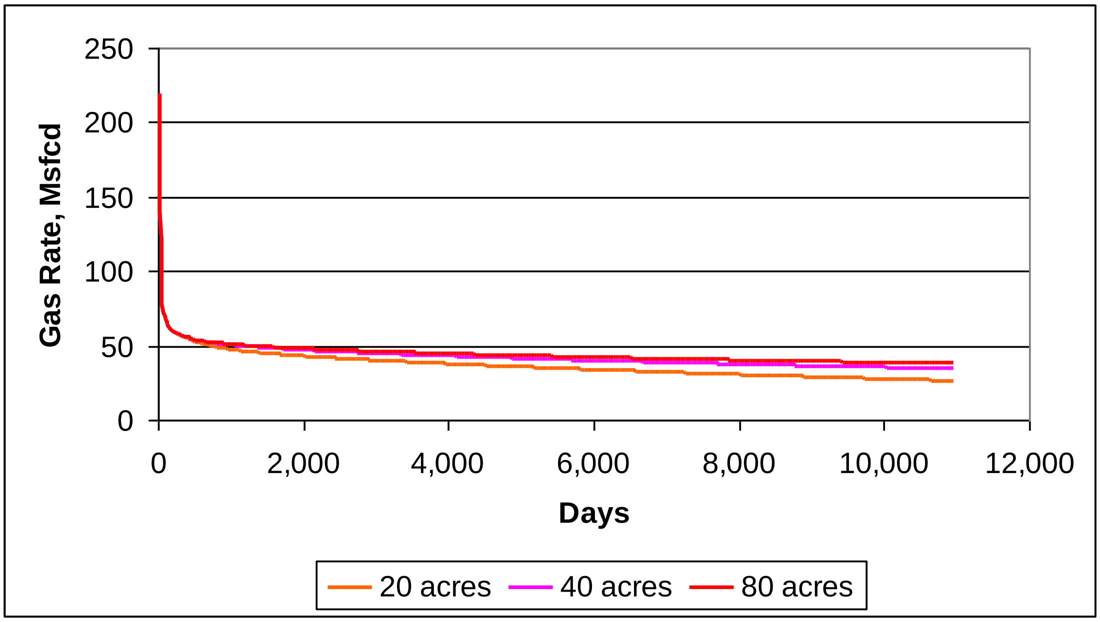

Figure 6. Vertical Well Production – Stimulation Sensitivity.

	20 acres	40 acres	80 acres
OGIP (Bcf)	1.4	2.8	5.6
Cum Prod (Bcf)	0.4	0.46	0.49
Recovery (%)	29	16.7	8.7

Table 3. Recoveries – Stimulated Vertical Well – Spacing Sensitivity.

From the above results, it can be noted that stimulation has a huge impact on well productivity as the recovery percentages roughly double when compared to the previous case.

PERMEABILITY SENSITIVITY

Next, cases were run assuming both fracture and matrix permeabilities were higher by an order of magnitude. The gas production rates are shown in Figure 7, and the recoveries are summarized in Table 4. These results show increased permeability greatly affects performance. For example, in the 80-acre case, recovery is multiplied by a factor of 6.

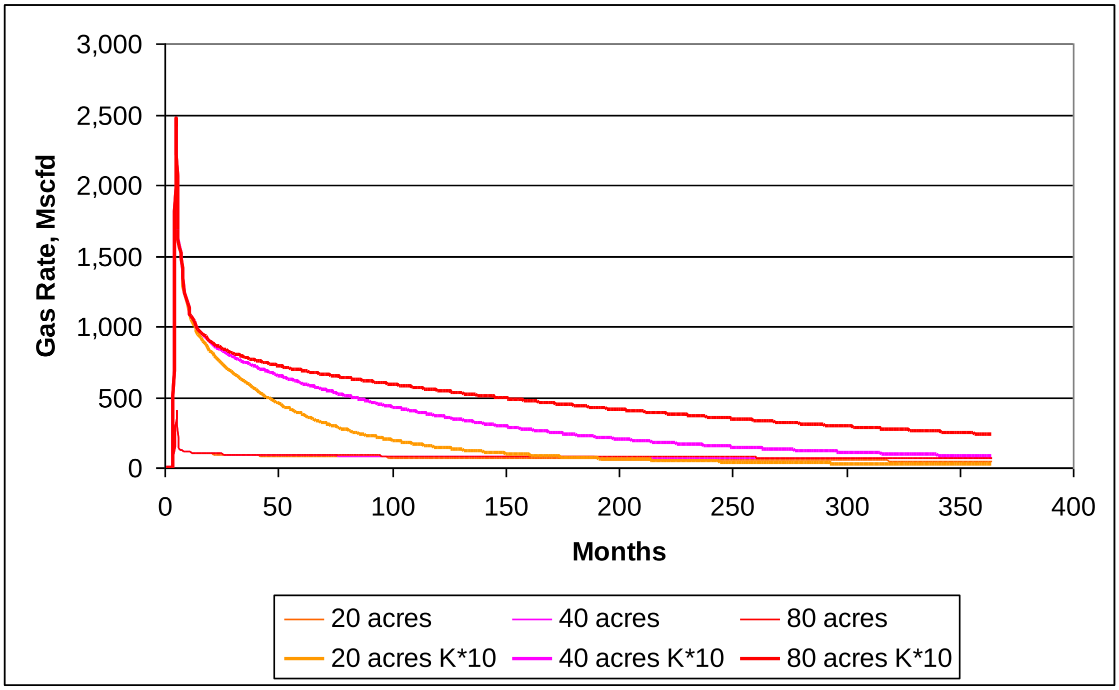

Figure 7. Vertical Well Production – Permeability Sensitivity.

	20 acres		40 acres		80 acres	
	K	K*10	K	K*10	K	K*10
OGIP (Bcf)	2.5	2.5	5.0	5.0	10.1	10.1
Cum Prod (Bcf)	0.76	2.1	0.88	3.6	0.92	5.3
Recovery (%)	30.1	82.1	17.4	71.5	9.1	52.9

Table 4. Recoveries – Permeability Sensitivity.

FRACTURE HALF-LENGTH SENSITIVITY

For the next sensitivity, the well spacing was fixed at 80 acres and fracture half-lengths of 150 feet, 300 feet, and 500 feet were considered. Figure 8 shows the model grid view with a 300 ft half-length fracture.

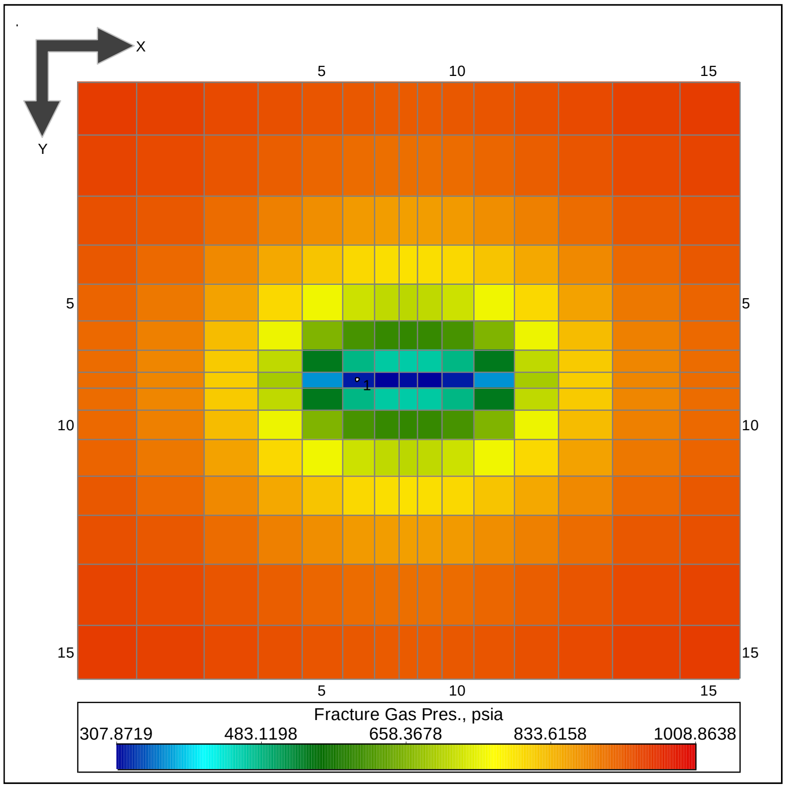

Figure 8. Model Grid View – Fractured Vertical Well.

The gas production rate for each case is shown in Figure 9, and the recoveries are summarized in Table 5.

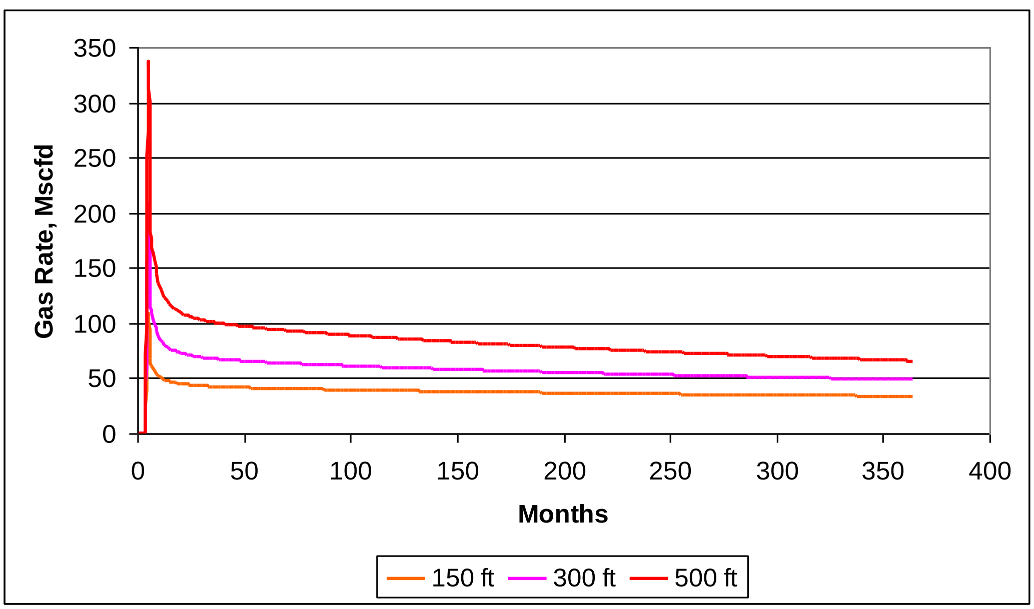

Figure 9. Vertical Well Production - Fracture Half-length Sensitivity.

	150 ft	300 ft	500 ft
OGIP (Bcf)	5.6	5.6	5.6
Cum Prod (Bcf)	0.42	0.64	0.91
Recovery (%)	7.5	11.5	16.4

Table 5. Recoveries – Fracture Half-Length Sensitivity

As expected, a longer fracture length facilitates flow, which increases production.

MATRIX BLOCK SIZE SENSITIVITY

The Warren and Root model used to model gas storage in shales is illustrated in Figure 10. A small quantity of gas is stored on the matrix external surface, the concentration being defined by the Langmuir isotherm. However, most of the gas is stored in the matrix porosity (micro porosity) in a free state and flows via Darcy's flow. Via Darcy's flow, gas flows from the matrix to the fractures, which also contain some free gas, then flows to the wellbore. The matrix block is illustrated in Figure 10.

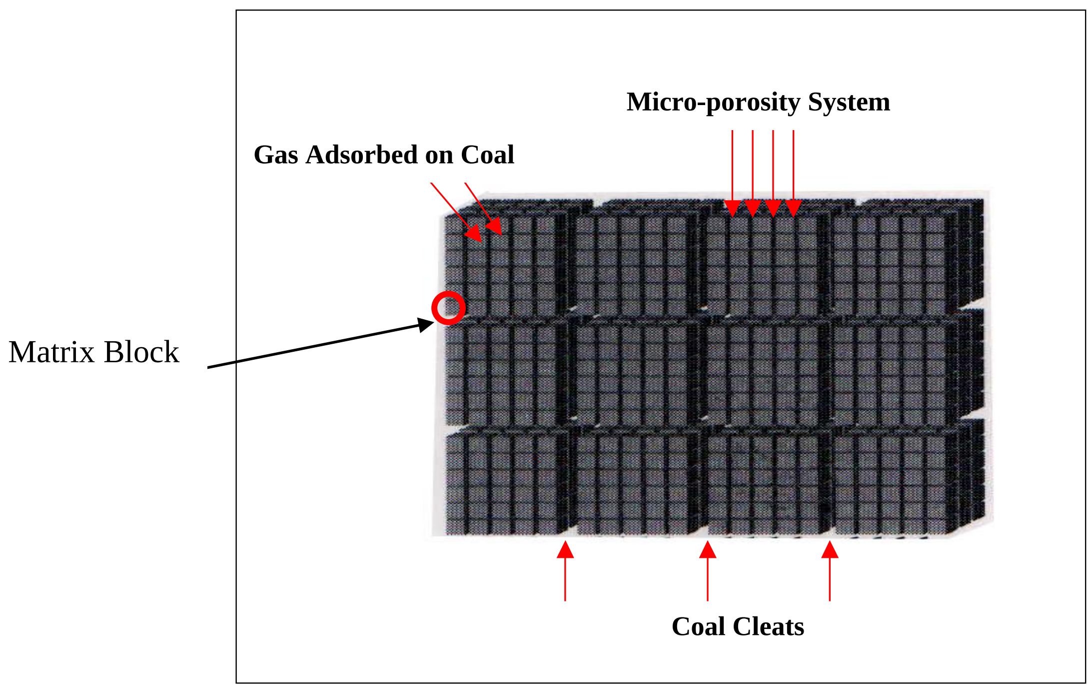

Figure 10. Illustration of the Warren and Root Model.

Simulations were run with fixed spacing of 80 acres and a fracture half-length of 500 ft. The gas production rate for each case is shown in Figure 11, and the recoveries are summarized in Table 6.

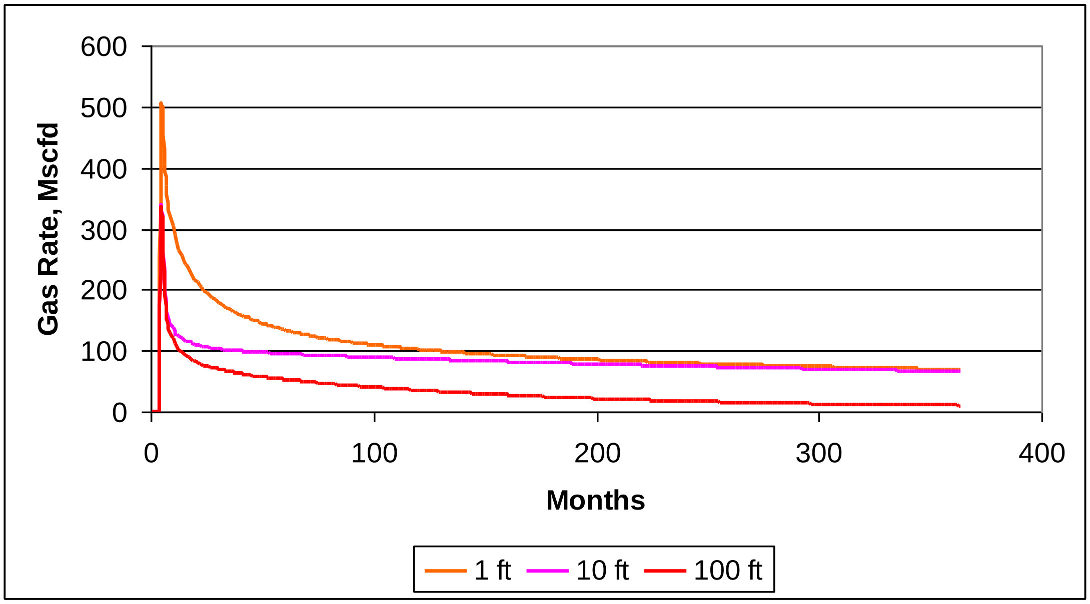

Figure 11. Fractured Vertical Well Production – Matrix Block Size Sensitivity.

	1 ft	10 ft	100 ft
OGIP (Bcf)	5.6	5.6	5.6
Cum Prod (Bcf)	1.15	0.91	0.36
Recovery (%)	20.8	16.4	6.4

Table 6. Recoveries – Matrix Bloc Size Sensitivity.

As expected, smaller matrix block sizes increase the recovery since they create a nested fracture network.

All sensitivity cases for the vertical well are summarized in Table 7.

<table>
<tr><th></th><th></th><th></th><th>IGIP (Bcf)</th><th>Cumulative Production (Bcf)</th><th>Recovery (%)</th></tr>
<tr><td rowspan="5">20 acres</td><td colspan="2">Base[1]</td><td>1.4</td><td>0.2</td><td>15.6</td></tr>
<tr><td>Skin</td><td>-5</td><td>1.4</td><td>0.4</td><td>29</td></tr>
<tr><td>Thickness (s=-5)</td><td>400 ft</td><td>2.5</td><td>0.76</td><td>30.1</td></tr>
<tr><td rowspan="2">Permeability (s=-5, H=400ft)</td><td>*10</td><td>2.5</td><td>2.1</td><td>82.1</td></tr>
<tr><td>*100</td><td>2.5</td><td>2.2</td><td>88.8</td></tr>
<tr><td rowspan="5">40 acres</td><td colspan="2">Base[1]</td><td>2.8</td><td>0.23</td><td>8.3</td></tr>
<tr><td>Skin</td><td>-5</td><td>2.8</td><td>0.46</td><td>16.7</td></tr>
<tr><td>Thickness (s=-5)</td><td>400 ft</td><td>5.0</td><td>0.88</td><td>17.4</td></tr>
<tr><td rowspan="2">Permeability (s=-5, H=400ft)</td><td>*10</td><td>5.0</td><td>3.6</td><td>71.5</td></tr>
<tr><td>*100</td><td>5.0</td><td>4.5</td><td>88.4</td></tr>
<tr><td rowspan="10">80 acres</td><td colspan="2">Base[1]</td><td>5.6</td><td>0.24</td><td>4.2</td></tr>
<tr><td>Skin</td><td>-5</td><td>5.6</td><td>0.49</td><td>8.7</td></tr>
<tr><td rowspan="3">Fracture Half Length</td><td>150 ft</td><td>5.6</td><td>0.42</td><td>7.5</td></tr>
<tr><td>300 ft</td><td>5.6</td><td>0.64</td><td>11.5</td></tr>
<tr><td>500 ft</td><td>5.6</td><td>0.91</td><td>16.4</td></tr>
<tr><td rowspan="2">Matrix Block Size (Xf = 500ft)</td><td>1 ft</td><td>5.6</td><td>1.15</td><td>20.8</td></tr>
<tr><td>100 ft</td><td>5.6</td><td>0.36</td><td>6.4</td></tr>
<tr><td>Thickness (s=-5)</td><td>400 ft</td><td>10.1</td><td>0.92</td><td>9.1</td></tr>
<tr><td rowspan="2">Permeability (s=5, H=400ft)</td><td>*10</td><td>10.1</td><td>5.3</td><td>52.9</td></tr>
<tr><td>*100</td><td>10.1</td><td>8.7</td><td>86.1</td></tr>
</table>

Table 7. Vertical Well Summary Results.

[1] Base case has the following parameters:

Matrix Block Size = 10 ft

Thickness = 226 ft

K fracture = 0.003 mD

K matrix = 0.0005 mD

3. HORIZONTAL WELL

As with the vertical well, the parameters from the build-up test history-match were used for the sensitivity study for the horizontal well. A 3,000 ft long horizontal on 160 acres spacing, producing at a bottomhole pressure of 100 psi, was assumed. An example of the model grid view, as well as a 3D view with a half-length fracture of 150 ft is shown in Figure 12.

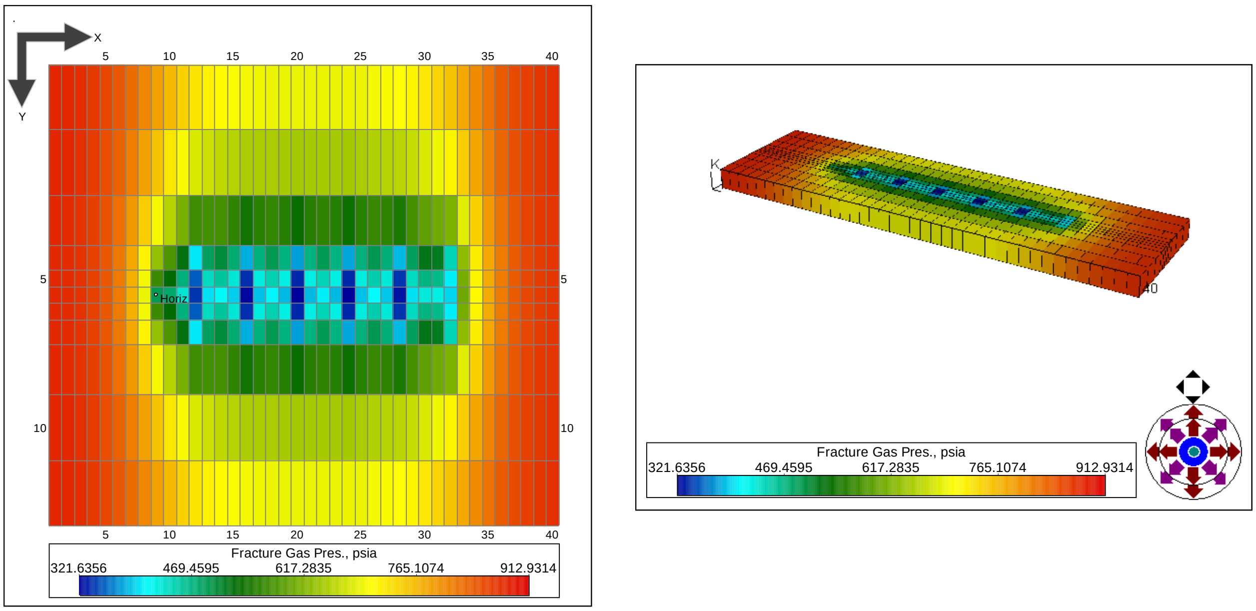

Figure 12. Horizontal Well Grid and 3D View.

Sensitivities were run on fracture half-length, and matrix block size. The results from the sensitivity analyses are discussed below.

FRACTURE HALF-LENGTH SENSITIVITY

Spaced every 500 ft, fracture half-lengths of 150 ft, 300 ft, and 500 ft were considered. The gas production rate for each case is shown in Figure 13, and the recoveries are summarized in Table 8.

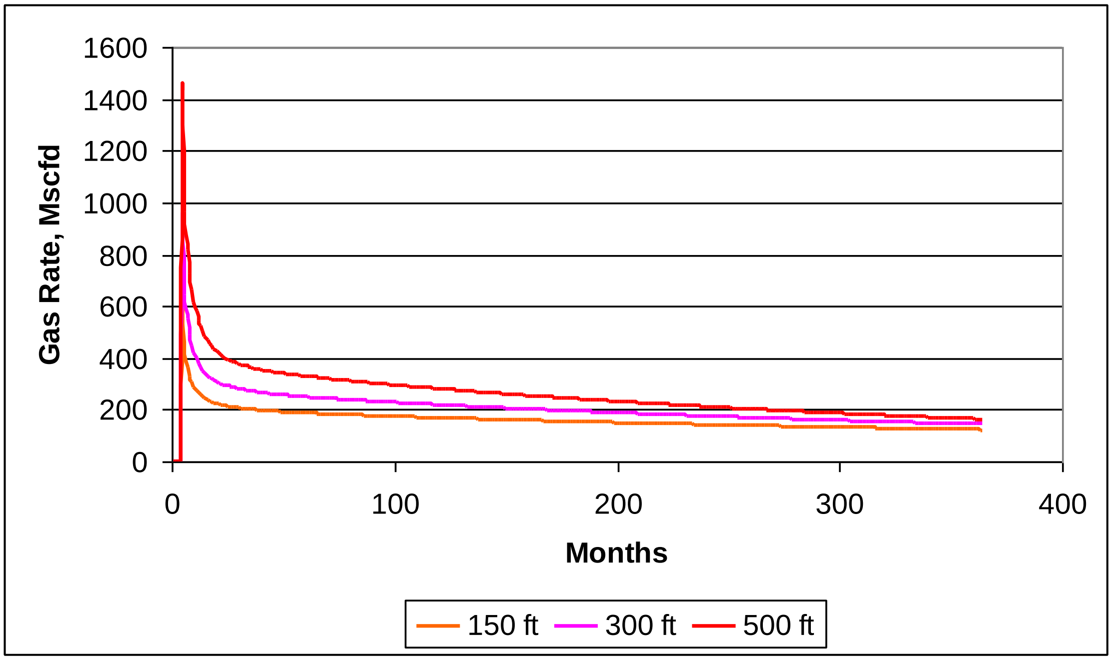

Figure 13. Horizontal Well Production – Fracture Half-Length Sensitivity.

	150 ft	300 ft	500 ft
OGIP (Bcf)	10.3	10.3	10.3
Cum Prod (Bcf)	1.77	2.27	2.88
Recovery (%)	17.2	22.1	28.1

Table 8. Recoveries – Fracture Half-Length Sensitivity.

MATRIX BLOCK SIZE SENSITIVITY

With the facture half-length fixed at 300ft, matrix block sizes of 1 ft, 10 ft, and 100 ft were considered. The gas production rate for each case is shown in Figure 14, and the recoveries are summarized in Table 9.

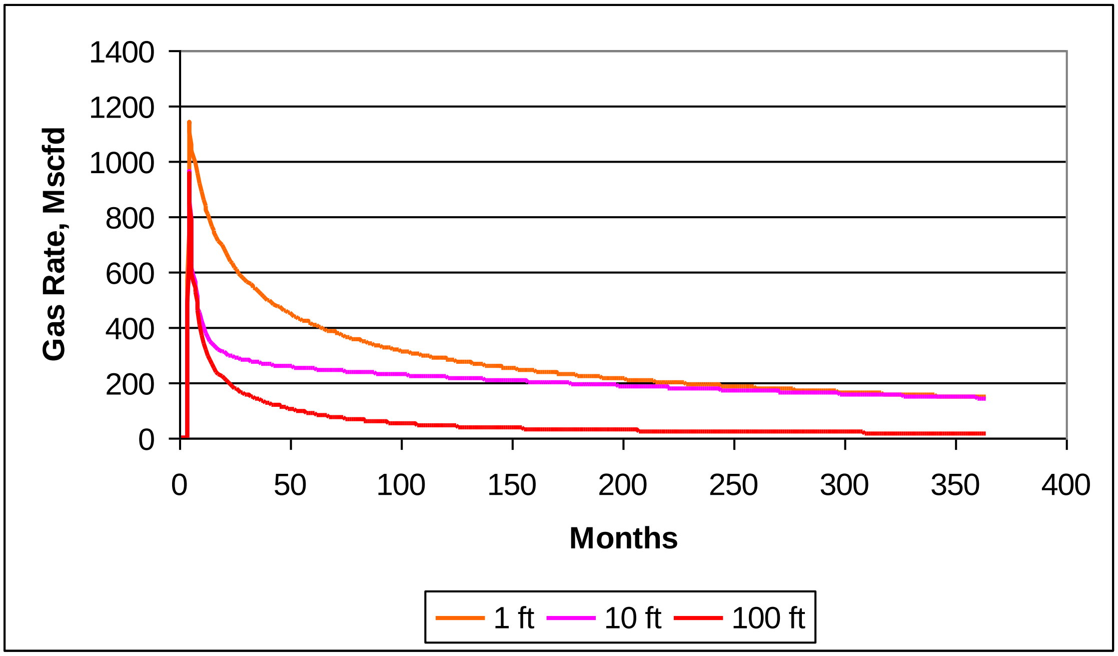

Figure 14. Horizontal Well Production –Matrix Block Size Sensitivity.

	1 ft	10 ft	100 ft
OGIP (Bcf)	10.3	10.3	10.3
Cum Prod (Bcf)	3.1	2.27	0.63
Recovery (%)	30.3	22.1	6.2

Table 9. Recoveries – Matrix Block Size Sensitivity.

The results are identical to the vertical well. As expected, smaller matrix block sizes increase recovery since they create a nested fracture network.

This page is intentionally left blank.

4. FIELD DEVELOPMENT

The next step was to upgrade the study for field development using horizontal wells. It was assumed that a sweet spot was discovered with increased shale thickness and increased permeability. The fracture half-length of the horizontal well was fixed at 300 ft and the matrix block size was fixed at 10 ft.

THICKNESS SENSITIVITY

The isopach map of the Utica shale (Figure 15) shows an average thickness of 400 ft, which was used for the sensitivity. The gas rate for each case is shown in Figure 16, and the recoveries are summarized in Table 10.

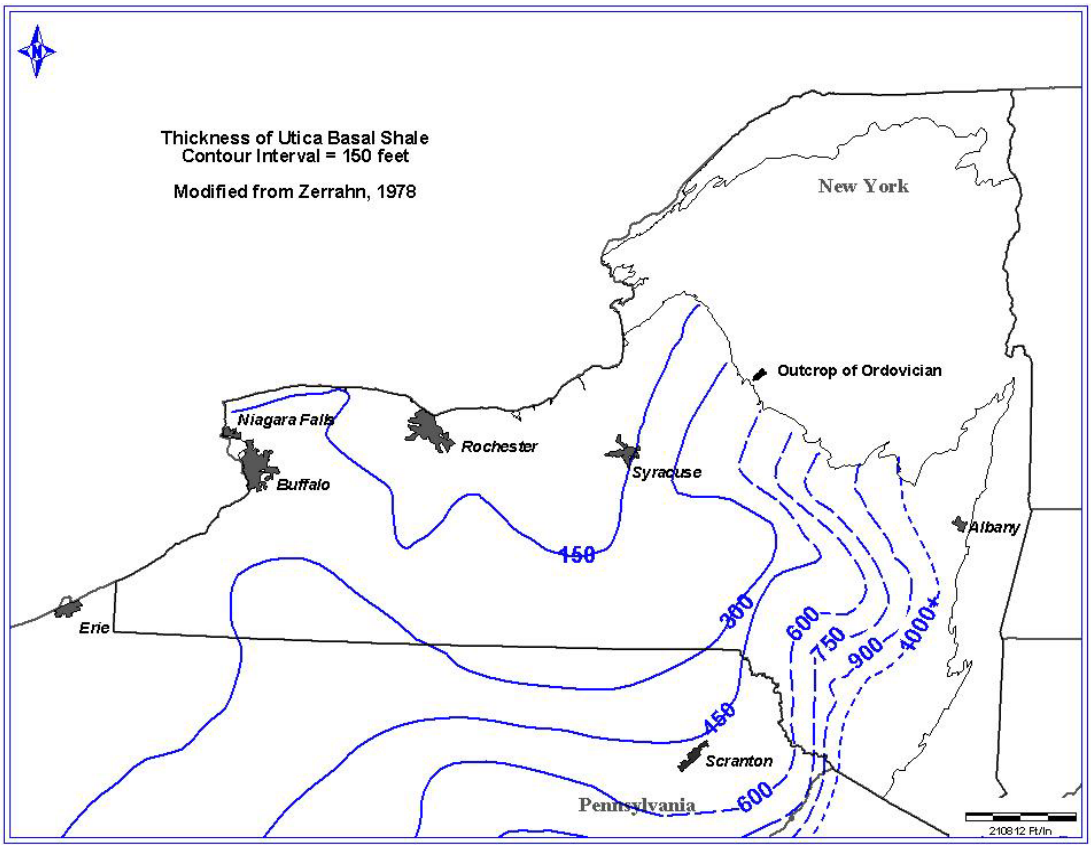

Figure 15. Utica Shale Isopach Map.

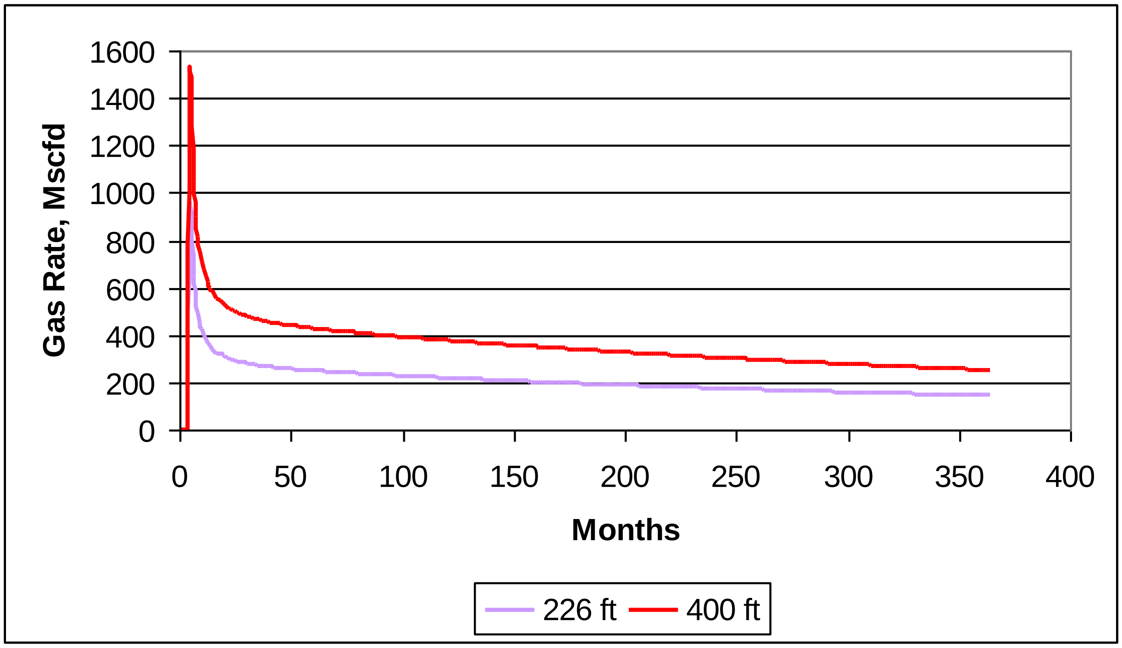

Figure 16. Field Development - Thickness Sensitivity.

	226 ft	400 ft
OGIP (Bcf)	10.3	18.2
Cum Prod (Bcf)	2.3	3.9
Recovery (%)	22.1	21.5

Table 10. Recoveries – Thickness Sensitivity.

PERMEABILITY SENSITIVITY

In addition to increased thickness, additional permeability of up to two orders of magnitude was considered for both the matrix and the fracture. The gas rate for each case is shown in Figure 17, and the recoveries are summarized in Table 11. The results show, with a permeability multiplied by a factor of 10, the recovery is more than tripled.

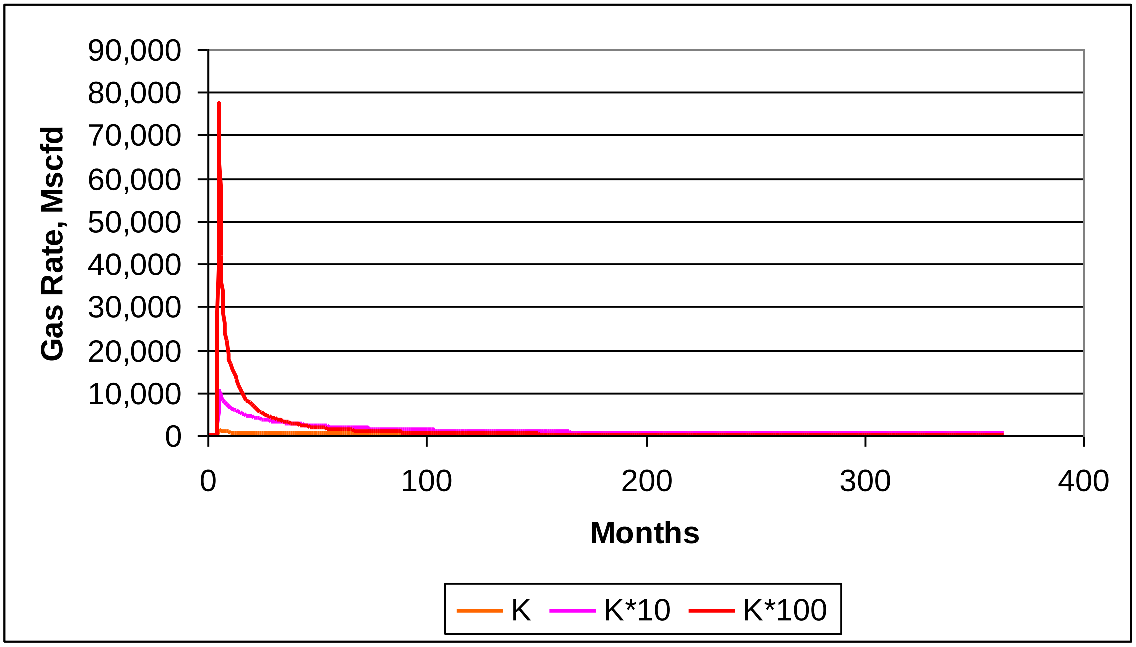

Figure 17. Field Development – Permeability Sensitivity.

	K	K*10	K*100
OGIP (Bcf)	18.2	18.2	18.2
Cum Prod (Bcf)	3.9	12.5	15.7
Recovery (%)	21.5	68.5	86.1

Table 11. Recoveries – Permeability Sensitivity.

All cases for the horizontal well sensitivities are summarized in Table 12.

	Base[1]	Matrix Block Size		Thickness	Permeability	
		1 ft	100 ft	400 ft	*10	*100
IGIP (Bcf)	10.3	10.3	10.3	18.2	18.2	18.2
Cum Production (Bcf)	2.3	3.1	0.6	3.9	12.5	15.7
Recovery (%)	22.1	30.3	6.2	21.5	68.5	86.1

Table 12. Horizontal Well Summary Table.

This page is intentionally left blank.

5. CONCLUSIONS

The sensitivities show that improvements in productivity for the Utica shale play are a result of:

- A natural fracture system being present;
- Good permeability (mainly matrix); and
- Stimulation to the well.

However, it is important to note that the study was based on data from only one well with a very limited production history. In addition, the well was only partially completed and lightly stimulated which may affect the results. Additional information is necessary to confirm these preliminary findings.