SPE-185628-MS

The Impact of the Hydraulic Fracture Properties on the Gas Recovery from Marcellus Shale

M. El Sgher, K. Aminian, and S. Ameri, West Virginia University

This paper was prepared for presentation at the 2017 SPE Western Regional Meeting held in Bakersfield, California, USA, 23 April 2017.

Abstract

Marcellus Shale, a Devonian black shale, spans the majority of the Appalachian Basin from New York through Pennsylvania, West Virginia and also extends into Ohio and Maryland (Bartuska, et al. 2012). The unconventional gas reservoir is a term commonly used to refer to ultra-low permeability formations that produces mainly dry natural gas and is not able to produce an economic flow rate without stimulation treatments. The natural gas in the Marcellus Shale is produced most efficiently through horizontal wells with multiple hydraulic fracturing stimulation treatments. Even though advances in technology have unlocked considerable reserves of hydrocarbon, the long-term production behavior of the horizontal wells with multiple hydraulic fractures is not well understood. This paper provides the results of parametric studies to investigate the impact of the hydraulic fracture properties and more specifically the impact of non-uniform fracture half-length, on the gas recovery from Marcellus Shale.

The purpose of this study is to evaluate the long-term production performance of horizontal wells with multiple hydraulic fractures completed in Marcellus Shale. A commercial reservoir simulator was used to develop the base model which incorporated the storage and production mechanisms inherent in shales. The core, log, completion, stimulation, and production data obtained from wells located at the Marcellus Shale Energy and Environment Laboratory (MSEEL) were utilized to generate the simulation model. MSEEL is a research collaboration between West Virginia University, Ohio State University, The Natural Energy Technology Laboratory, and Northeast Natural Energy. MSEEL aims to achieve a better understanding of the unconventional shale resources through application of advanced technology in drilling, completion, reservoir characterization, production and monitoring of horizontal wells. Furthermore, fracture properties (fracture half-length, fracture width and fracture conductivity) were obtained by using commercial software. Precision laboratory equipment was utilized to determine the shale properties from the core samples.

Field production data from two original horizontal Marcellus Shale gas wells at MSEEL site were utilized for history matching to establish the missing shale parameters. History matching was initially performed using production data for two years from one the horizontal wells. The matched model was then used to predict the production for the following two years to confirm the accuracy and reliability of the model. In addition, the base model was used to predict the second horizontal well production which provided reliable results. Finally, a number of parametric studies were performed with the model to investigate the impact of the hydraulic fracture properties and non-uniform fracture half-length, on the recovery.

Introduction

In recent years, the demand for energy from unconventional reservoirs has increased all over the world. The depletion of conventional resources has motivated technology advancement for economic recovery of oil and natural gas from unconventional resources. The unconventional shale reservoirs require the application of the massive stimulation treatments to achieve economic production. Typical unconventional reservoirs are tight-gas sands, coalbed methane, heavy oil, and shales. Marcellus Shale is the largest shale gas play in the U.S. Marcellus shale lies beneath much of Ohio, West Virginia, Pennsylvania and New York, as well as portions of Kentucky, Tennessee and Maryland. The Marcellus Shale covers an area of approximately 95,000 square miles at an average thickness of 50 ft to 200 feet. The depth of the Marcellus ranges from 4,000 ft to 8,500 ft. Marcellus Shale is a Middle Devonian-aged shale bounded above by shales of the Hamilton Group and below by limestones of the Tristates. It has been estimated that as much as 500 trillion cubic feet of gas in place may be present in the entire Marcellus play area (Englander and Lash, 2009). Shale gas reservoirs have become increasingly important energy sources in the recent years. Horizontal wells with multiple hydraulic fractures are the key technology to achieve economic production from shale gas reservoirs. However, the long-term production behavior of the horizontal wells with multiple hydraulic fractures in ultra-low permeability formations is not well established. More specifically, the impact of the non-uniform fracture half-length on the gas recovery has not been investigated.

Background

Shale is an organic-rich formation which could be both the source as well as the reservoir rock. The limited pore space of the shale can store gas in free state while the organic material gas store gas in adsorbed state (Cipolla 2009a). Shale is a complicated, naturally fracture reservoir with ultra-low permeability. Naturally fracture reservoir are often characterized by dual porosity model (Warren & Root, 1962). The dual porosity system consists of two interconnected media namely matrix and fissure. The matrix is primary porosity and contains most of the fluid in the system but has very low permeability. The fissures which are considered the secondary porosity and have greater permeability. However, it is believed that fissures in Marcellus Shale are mineralized and do not contribute to well productivity (Cipolla 2009b). The stimulation treatment is crucial to the production of natural gas from the shale because it is the key to creation of an interconnected fracture system to reach a large, highly fractured network. The economic gas production from Marcellus shale is mainly achieved by using of horizontal wells hydraulically fractured in multiple stages (Soeder, 2012). The first large slickwater stimulation treatment in Marcellus Shale was performed in southwestern Pennsylvania in 2004 (Fontaine, et al. 2008). Large water-fracs with light proppant are currently being used with success in many areas (Warpinski et al. 2008).

There have been attempts to evaluate the hydraulic fracture geometry from microseismic data. However, these approaches fail to present actual fracture geometry and conductivity precisely because microseismic data represent only a small portion of the complete hydraulic fracture deformation (Maxwell, et al., 2013; Cipolla and Wallace, 2014) and, therefore, cannot determine the location of proppant or distribution of fracture conductivity (Cipolla et al., 2011b and 2012). Furthermore, Diagnostic tools such as Fracture Mapping Tools, Radioactive Tracer, Fiber Optics, and Production Logging, etc. are qualitative and severely limited by non-uniqueness of the interpretation. Cipolla et al. (2010b) has displayed that about 40% of the perforation clusters were not producing gas. Several authors have performed study to determine hydraulic fracture properties, such as fracture half-length and fracture conductivity (Aboaba and Cheng, 2010; Yu and Sepehrnoori, 2014). However, all previous studies have considered shale gas reservoirs with a uniform configuration of hydraulic fractures.

OBJECTIVE AND METHODOLOGY

The objectives of this study were

- To evaluate the long-term production performance of horizontal wells with multiple hydraulic fractures.
- To investigate the impact of the hydraulic fracture half-length including non-uniform fracture halflength, on the gas recovery from Marcellus Shale.

The data collected and used in this study were obtained from the Marcellus Shale Energy and Environment Laboratory (MSEEL). MSEEL is field laboratory operated by Northeast Natural Energy (NNE). The production and stimulation data from two horizontal wells (MIP-4H and MIP-6H) that were drilled in 2011 at the site, were available through MSEEL project. Two additional horizontal wells (MIP-3H and MIP-5H) as well as a vertical science well (MIP-SW), located between the two new horizontal wells, were drilled in 2015. The vertical well was utilized to obtain core and log data as well for microseismic monitoring.

In order to accomplish the objective of this study, a methodology consisting of the following steps was employed:

- ➢ The results of logs and core data analysis were collected and used in the study. The petrophysical analysis performed through the Precision Petrophysical Analysis Laboratory (PPAL) (Elsaig et al., 2016) showed an average permeability of 120 nano-Darcy (nD) over a formation thickness of 90 ft. and an average porosity is about 2%. The geomechanical rock properties including the minimum horizontal stress, Young's modulus, and Poisson's ratio were estimated from the logs and core data.
- ➢ Completion data for two horizontal wells MIP-4H and MIP-6H were collected. MIP-6H was stimulated with eight fracture stages at over a lateral length of 2,380 ft. MIP-4H was stimulated with eleven fracture over a lateral of 3800 ft. The fracture treatment for both wells used a pump rate of 80 bpm. 339,172 gallons of a slick water; 1500 gallons of acid; 36,175 gallons linear 2000; and 400,000 lb of sand which included 100,000 lb of 100 mesh and 300,000 lb of 40/100 mesh were used in each stage. Young's Modulus, Poisson's Ratio and the minimum horizontal stress were assumed to be the same for all hydraulic fracturing stages. The hydraulic fracture properties were estimated from the completion data by employing a 3-D fracture modeling software (FRACPRO) which assumes isotropic rock properties for estimating the fracture properties.
- ➢ The results of data collection and analysis were used as input to develop the models for wells MIP-6H and MIP-4H. Table 1 summarizes the basic model parameter. The reservoir model for MIP-6H was set with dimensions of 4000 ft. in length, 1000 ft. in width, and 90 ft. in height. The lateral length is 2380 ft. with 8 fracture stages. Stage spacing is set as 340 ft. Since the exact distribution of the fissures (natural fractures) were not known, it was assumed that fissures are distributed uniformly with horizontal spacing 20-ft. A horizontal well is placed at the center of the model for efficient production.
- ➢ There are 1460 days of production data available for MIP-6H. Production history matching for MIP-6H was performed using production data for the first 730 days. The hydraulic fracture half-length was the main variable which was adjusted to achieve a match. The matched model was then used to predict the MIP-6H production for the next 730 days to confirm the accuracy and reliability of the model.
- ➢ Production history matching was also performed for MIP-4H and MIP-6H using the entire production data available. 6 different cases were modeled for each horizontal well to achieve history match. These cases are as follows:

1. All hydraulic fractures were assumed to have the same length and other properties.

2. The hydraulic fractures half-length were assumed to have different half-lengths (non-uniform) as listed in Table 5 for MIP-6H and Table 6 for MIP-4H. The production history was matched without changing any other input parameres.
3. One of the fracture stages was assumed to be non-contributing. Meyer et al. (2010) demonstrated that not all perforation stages necessarily contribute to production. The location of the noncontributing stage was alternated.
4. The fracture half-length was reduced but a region of increased fissure permeability around planar hydraulic fractures was assumed.
5. The fracture half-length was reduced but a stimulated reservoir volume with increased fissure permeability around the horizontal wellbore (2420 ft. in length, 400 ft. in width) was assumed for MIP-6H and (3840ft. in length, 800ft. in width) was assumed for MIP-4H
6. This case is similar to case 6 but the stimulated reservoir volume was assumed to have a higher fissure permeability in the region between the fracture stages and a lower permeability beyond the fracture tips.

➢ The matched model for MIP-6H with uniform fracture half-lengths and properties (case 1) was utilized for parametric studies to investigate the impact of the hydraulic fracture half-length and nonuniform fracture half-lengths, on the gas recovery (30-year simulated production) from Marcellus Shale. Eleven non-uniform fracture half-length configurations were investigated as illustrated in Figure 1. For cases 1, 2 and 3 small changes to the base model fracture half- length (200 ft.) were considered. For these cases, the two fracture half-length (260 and 140 ft.) in different orders were assumed. For cases 9, 10 and 11, the changes to fracture half-lengths were increased. For these cases, the fracture half-length of 300 and 100 ft. in different orders were assumed. Finally, for cases 6, 7 and 8 fracture half-length of 340 and 60 ft. in different orders were assumed. For case 4 several fracture half-lengths including 340 ft. at the beginning followed by fracture half-lengths of 300, 260, 220, 180, 140,100 and 60 ft. For case 5, the same fracture half-lengths as case 4 were assumed but in the reverse order.

Table 1—Basic Model for MIP-6H and for MIP-4H

Basic Model Parameters		
Reservoir Parameters		
Initial Reservoir pressure	4700	Psia
Depth	7470	ft
Thickness	90	ft
Fracture porosity	0.001	fracture
Matrix Porosity	0.02	fracture
Fracture Permeability	0.0013,0.0013,0.00013	I,j,k md
Matrix permeability	0.00012,0.00012,0.000012	I,j,k md
Denisty	120	lb/ft^3
Natural Fracture Spacing I and J	20	ft
Natural Fracture Spacing K	0	ft
Gas saturation	0.85	fracture
Water saturation	0.15	fracture
Hydraulic Fracture Properties		
Number of Transver Fractures		
Fracture Half-Length, x_f		(ft)
Conductivity, k_f w_f		(mD-ft)
Top of Fracture	7470	ft
Bottom of Fracture	7560	ft
Well Production Controls		
Pwf		psi
Adsorption		
Langmuir Pressure	0.002	psia^-1
Langmuir Volume	0.12	(gmol/lb)

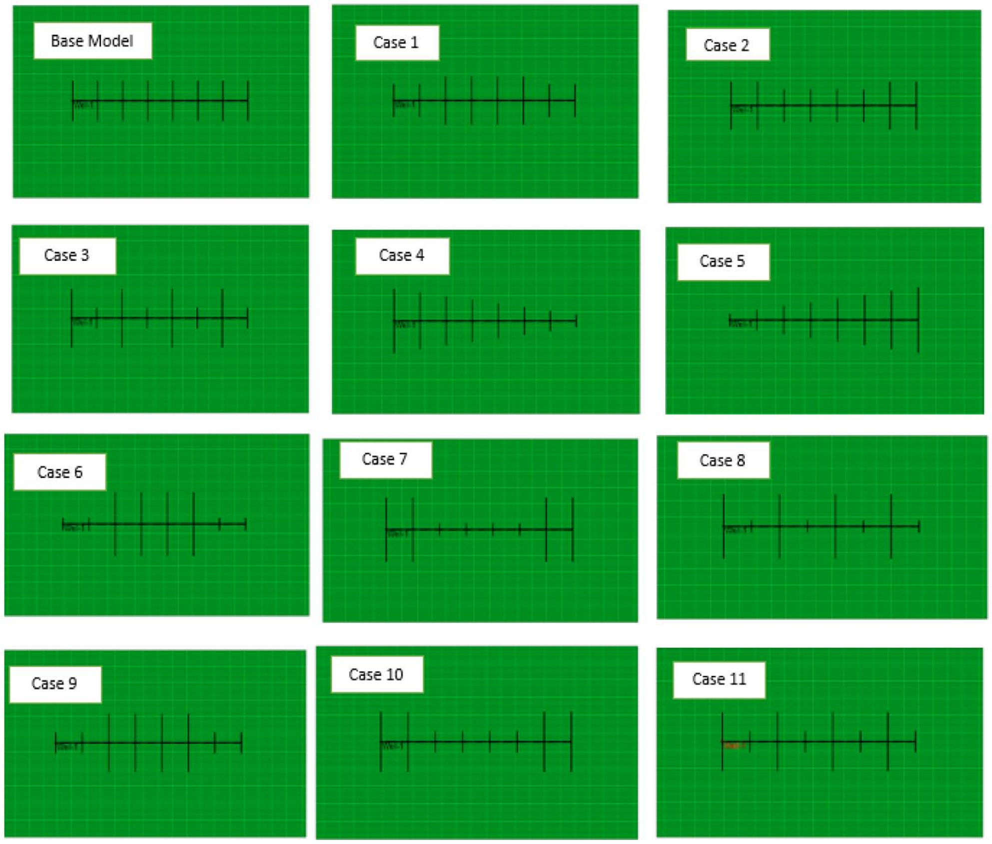

Figure 1—illustrates eleven non-uniform fracture half-length configurations

Result and Discussion

The results fracture-modeling software are provided in Table 2 and 3 for MIP-4H and MIP-6H. The large fracture height growth was suspected because no significant barriers exist which would limit the fracture height growth. It should be noted that even with good quality input data, the fracture properties in shale cannot be accurately estimated because of complex interactions of rock, stress, and natural fracture characteristics. The fracture model used in this study assumes isotropic rock properties. The models that account for anisotropy are computationally expensive, especially when numerous simulations must be performed by varying the input parameters for parametric studies.

Table 2—Hydraulic Fracture Properties for MIP-4H

Treat #	Top Depth MD	Bottom Depth MD	Fracture Half-Length	Propped Half-Length	Fracture Height	Total Propped Height	Avg. Fracture Width	Avg. Fracture Width	Avg. Conductivity	Dimensionless Conductivity	Fracture Permeability	Total Slurry Pumped	Total Proppant Pumped	Closure Stress Gradient (psi/ft)
	(ft)	(ft)	(ft)	(ft)	(ft)	(ft)	(in)	ft	(mD·ft)		md	(bbls)	(klbs)	
1	11093	11333	693	559	517	417	0.588	0.049	152.9	2736.65	3,120	9739.8	419.8	0.917
2	10743	11023	703	566	515	414	0.582	0.049	156.8	2772.43	3,233	9731.8	419.8	0.916
3	10393	10708	706	568	514	414	0.579	0.048	157.7	2775.26	3,268	9723.8	419.8	0.916
4	10043	10323	714	574	513	412	0.572	0.048	159.4	2777.37	3,344	9715.8	419.8	0.915
5	9693	9973	870	695	458	366	0.504	0.042	153.2	2202.96	3,648	9711.8	419.8	0.878
6	9343	9623	881	708	456	366	0.5	0.042	152.4	2152.8	3,658	9703.8	419.8	0.875
7	8993	9273	871	700	457	367	0.518	0.043	147.7	2109.61	3,422	9695.8	419.8	0.873
8	8643	8923	862	692	455	365	0.539	0.045	143.7	2075.6	3,199	9687.8	419.8	0.869
9	8293	8573	857	688	455	371	0.544	0.045	142.4	2069.84	3,141	9679.8	419.8	0.869
10	7943	8223	860	691	455	365	0.54	0.045	146.3	2118.63	3,251	9671.8	419.8	0.869
11	7593	7873	879	710	456	368	0.506	0.042	144.7	2038.76	3,432	9723.8	419.8	0.874

Table 3—Hydraulic Fracture Properties for MIP-6H

Treat #	Top Depth MD	Bottom Depth MD	Fracture Half-Length	Propped Half-Length	Fracture Height	Total Propped Height	Avg. Fracture Width	Avg. Fracture Width	Avg. Conductivity	Fracture Permeability	Total Slurry Pumped	Total Proppant Pumped	Closure Stress Gradient (psi/ft)
	(ft)	(ft)	(ft)	(ft)	(ft)	(ft)	(in)	ft	(mD·ft)	md	(bbls)	(klbs)	
1	9935	10175	806	500	608	377	0.835	0.07	179.4	2578	9715.8	419.8	0.875
2	9635	9875	790	491	610	379	0.848	0.07	175.4	2482	9707.8	419.8	0.873
3	9335	9575	779	483	608	377	0.862	0.07	171.5	2387	9699.8	419.8	0.869
4	9035	9300	755	468	613	380	0.882	0.07	161.7	2200	9695.8	419.8	0.868
5	8735	8975	734	455	619	384	0.898	0.07	148.3	1982	9687.8	419.8	0.866
6	8435	8675	726	450	622	386	0.903	0.08	148.4	1972	9679.8	419.8	0.866
7	8135	8375	723	448	623	386	0.905	0.08	146.9	1948	9675.8	419.8	0.866
8	7835	8075	754	468	612	380	0.883	0.07	157.3	2138	9667.8	419.8	0.867

The results of history matching for MIP-6H using production data for the first 730 days are provided in Table 4. As can be seen from Table 4, all hydraulic fractures were uniform. The history matching was performed by varying hydraulic fracture properties such as fracture half-length and fracture conductivity, while the reservoir properties were held constant. Figure 2 illustrates the match between the numerical simulation results and the actual field production data. Subsequently, the matched model was used to predict the production for the next 730 days to verify accuracy and reliability of the matched model. The predicted production rates appear to be very close to the actual data as it can be seen in Figure 4. These results confirmed the reliability of the matched model.

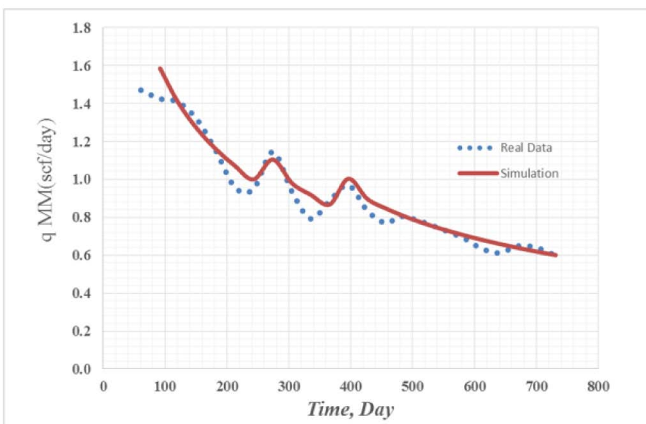

Figure 2—History Matching for MIP-6H well for first two years

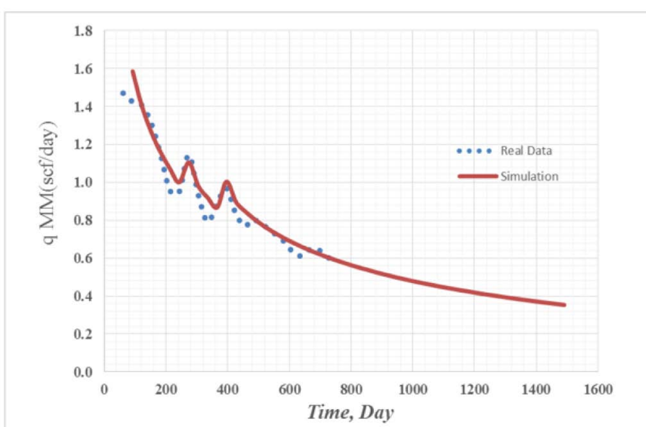

Figure 3—Forecasting of gas rate for MIP-6H well for the second 2 years

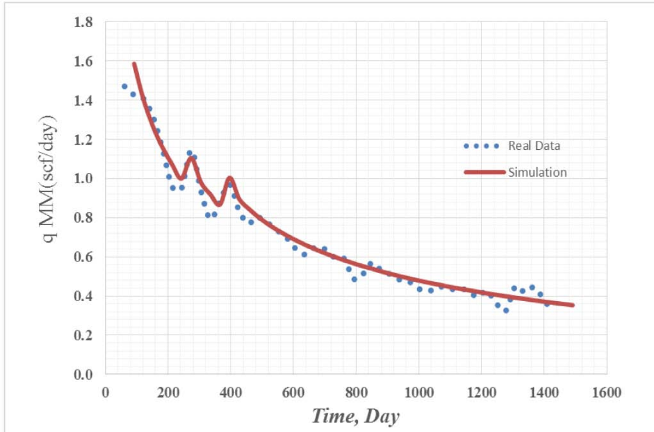

Figure 4—History Matching for MIP-4H well for four years

Table 4—History Matching parameters for MIP-6H well for first two years

Fissure permeability I,j,k (md)	0.001.3,0.0013,0.00013
Number of hydraulic fractures	S
Fracture Half-Length, x, (ft)	200
Conductivity, ky wy-. (mD-ft)	10

The results of history matching for all the 6 cases, as described earlier, are summarized in Tables 5 and 6.

Table 5—History matching parameters for MIP-6H

	case 1	Case 2	case 3
Fissure permeability I,j,k (md)	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013
Number of hydraulic fractures	8	8	7
Fracture Half-Length, x_f (ft)	200	4 stage 140, 4 stage 260	230
Conductivity, k_f w_f, (mD-ft)	10	10	10

	Case 4	
Fissure permeability I,j,k (md)	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013
Fissure permeability aroudd hydraulic fracture I,j,k (md)	0.0043,0.0043,0.00043	0.009,0.009,0.0009
Number of hydraulic fractures	8	8
Fracture Half-Length, x_f (ft)	140	100
Conductivity, k_f w_f, (mD-ft)	10	10

	Case 5	
Fissure permeability I,j,k (md)	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013
Fissure permeability aroudd hydraulic fracture and between stages I,j,k (md)	0.0025,0.0025,0.00025	0.0036,0.0036,0.00036
Number of hydraulic fractures	8	8
Fracture Half-Length, x_f (ft)	140	100
Conductivity, k_f w_f, (mD-ft)	10	10

	Case 6	
Fissure permeability I,j,k (md)	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013
Fissure permeability inner region I,j,k (md)	0.0028,0.0028,0.00028	0.004,0.004,0.0004
Fissure permeability outer region I,j,k (md)	0.0018,0.0018,0.00018	0.0028,0.0028,0.00028
Number of hydraulic fractures	8	8
Fracture Half-Length, x_f (ft)	140	100
Conductivity, k_f w_f, (mD-ft)	10	10

Table 6—History matching parameters for MIP-4H

	case 1	Case 2	case 3
Fissure permeability I,j,k (md)	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013
Number of hydraulic fractures	11	11	10
Fracture Half-Length, x_f (ft)	400	5 stage 460, 6 stage 350	460
Conductivity, k_f w_f, (mD-ft)	3.5	3.5	3.5

	Case 4	
Fissure permeability I,j,k (md)	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013
Fissure permeability aroudd hydraulic fracture I,j,k (md)	0.0024,0.0024,0.00024	0.005,0.005,0.0005
Number of hydraulic fractures	11	11
Fracture Half-Length, x_f (ft)	360	300
Conductivity, k_f w_f, (mD-ft)	3.5	3.5

	Case 5	
Fissure permeability I,j,k (md)	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013
Fissure permeability aroudd hydraulic fracture and between stages I,j,k (md)	0.0018,0.0018,0.00018	0.0025,0.0025,0.00025
Number of hydraulic fractures	11	11
Fracture Half-Length, x_f (ft)	360	300
Conductivity, k_f w_f, (mD-ft)	3.5	3.5

	Case 6	
Fissure permeability I,j,k (md)	0.0013,0.0013,0.00013	0.0013,0.0013,0.00013
Fissure permeability inner region I,j,k (md)	0.0019,0.0019,0.00019	0.0028,0.0028,0.00028
Fissure permeability outer region I,j,k (md)	0.0015,0.0015,0.00015	0.002,0.002,0.0002
Number of hydraulic fractures	11	11
Fracture Half-Length, x_f (ft)	360	300
Conductivity, k_f w_f, (mD-ft)	3.5	3.5

For case 1, the base model which was used in MIP-6H was used to predict MIP-4H except for the hydraulic fracture properties. The reservoir model dimensions were set as 5000 ft. in length, 1200 ft. in width, and 90 ft. in height. The lateral length is 3800 ft. with 11 fracture stages or stage spacing of 380 ft. The history match was obtained by adjusting the hydraulic fracture half-length. The final simulation results and the production rates for four years are shown in Figure 5

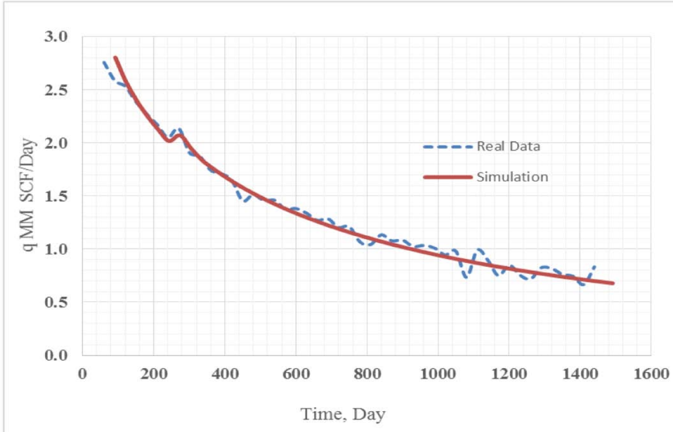

Figure 5—History Matching for MIP-4H well for four years

For the second case, the hydraulic fractures half-length were assumed to be different (non-uniform) as listed in Table 5 and 6. As it can be seen from the Table 5, the half-lengths for MIP-6H were reduced for four stages but in order to obtain a history match it is necessary to increase the half-lengths for the other four stages. The same results were also obtained for MIP-4H as can be seen in Table 6.

The third case was simulated to investigate the possibility that one the stages is not contributing to the production. The production history was matched but required higher fracture half-lengths for other rest of the stages. The results are summarized in Table 5 and 6.

The fourth case was simulated to investigate the impact of hydraulic fractures on the fissure permeability. For this case, the fissure permeability enhancement was assumed to be around planar hydraulic fracture, which could be caused by shear or dilation during the injection. To model this, a region of increased fissure permeability around planar hydraulic fractures was assumed. Two matches were obtained. The first was based on the fracture half-length of 140 ft. and the fissure permeability around the hydraulic fracture was increased to 0.0043 mD to obtain the match. The second one was based on a fracture half-length of 100 ft. and fissure permeability was needed to be increased to 0.009 mD to achieve a match.

The fifth case was simulated to investigate the impact of hydraulic fractures on the formation around the horizontal wellbore by assuming a stimulated reservoir volume around the horizontal wellbore (2420 ft. in length, 400 ft. in width). Two matches were obtained. The first was based on the fracture half-length of 140 ft. and the fissure permeability of 0.0025 (mD). The second one was based on a fracture half-length of 100 ft. and fissure permeability was needed to be increased to 0.0036 mD.

The sixth case was similar to the fifth case however the stimulated reservoir volume around the horizontal wellbore was assumed to have a higher permeability in the region between the fracture stages and a lower permeability beyond the fracture tips. Two matches were obtained. The first was based on the fracture half-length of 140 ft. and the fissure permeability of 0.0028 mD in the inner region and 0.0018 mD in the outer region. The second one was based on a fracture half-length of 100 ft. and fissure permeability was needed to be increased to 0.004 mD in the inner region and 0.0028 mD in the outer region.

Impact of Fracture Half-length

The history-matched model for MIP-6H, as described in case 1 above, was used to investigate the impact of the hydraulic fracture half-length, on the gas recovery from Marcellus Shale. The gas recovery was estimated as the 30-year cumulative production based on the model predictions. Figures 6 illustrates that the impact of fracture-half-length on cumulative production which increases as the fracture half-length increases. Therefore, fracture half length is a major contributor to the gas recovery. The fracture halflength impact is much more significant during the early production.

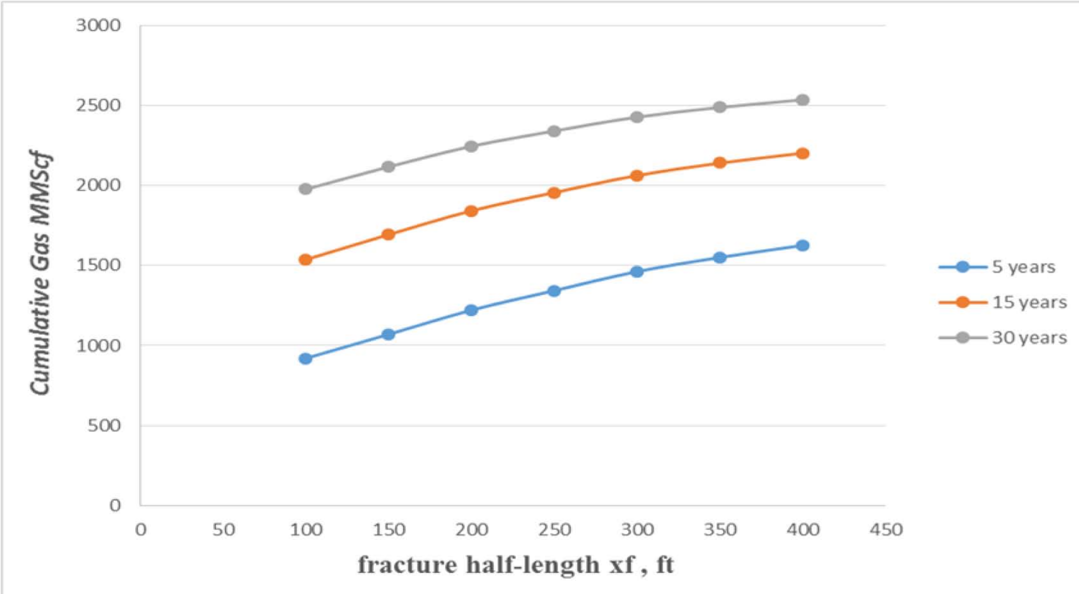

Figure 6—shows fracture half-length xf vs Cumulative Gas

Effect of Non-uniform Fracture Half-Length

Table 7 summarizes the model predictions for all eleven cases and compares them against the base model predictions. As can be observed case 10 provides the highest and case 6 results in the lowest cumulative recovery. However, the impact of non-uniform fracture half-length is not very significant.

Table 7—Hydraulic Fracture Geometry

	Fracture Half-Leneth. ft								Cumulative Gas MMScf	*Deviation*, %
	stase 1	stage 2	stage 3	stage 4	stage 5	stage 6	stage 7	stage 8		
Base Model	200	200	200	200	200	200	200	200	2245	-
Case 1	140	140	260	260	260	260	140	140	2201	-1.962
Case 2	260	260	140	140	140	140	260	260	2269	1.073
Case 3	260	140	260	140	260	140	260	140	2245	0.022
Case 4	340	300	260	220	180	140	100	60	2194	-2.285
Case 5	60	100	140	180	220	260	300	340	2199	-2.059
Case 6	60	60	340	340	340	340	60	60	2106	-6.183
Case 7	340	340	60	60	60	60	340	340	2266	0.951
Case 8	340	60	340	60	340	60	340	60	2245	0.019
Case 9	100	100	300	300	300	300	100	100	2159	-3.805
Case 10	300	300	100	100	100	100	300	300	2274	1.300
Case 11	300	100	300	100	300	100	300	100	2248	0.158

Conclusion

1. The fracture half-length and fracture conductivity predicted for both of the wells (MIP-4H and MIP-6H) by 3D fracture model resulted in significantly higher production than observed from the field data. This can be attributed to the fracture model assumption of isotropic rock properties.

2. There is no unique explanation for the differences between the model predictions and the observed production history. A number of possibilities were investigated and the production history can be matched in each case by adjusting the fracture half-length.
3. If two of the hydraulic fracture stages were assumed to be non-contributing, the hydraulic fracture half-length obtained from reservoir simulation nearly matches the 3-D fracture model results for both wells. Obviously, the fracture half-lengths that were obtained from either models are not the true fracture half-length. However, it can be concluded that various fracture stages do not contribute uniformly to the production.
4. Fracture half-length has a significant impact on the gas recovery.
5. The impact of non-uniform fracture half-length is not very significant.

Reference

Anderson, D.M. Nobakht, M. Moghadam, S.and L. Mattar (2010): "Analysis of Production Data from Fractured Shale Gas Wells," SPE 131787, 23-25 February 2010, Pittsburgh, Pennsylvania.

Aboaba, A., and Cheng, Y. 2010. Estimation of fracture properties for a horizontal well with multiple hydraulic fractures in gas shale. SPE Paper 138524. SPE Eastern Regional Meeting, Morgantown, WV, October 12–14.

Cipolla, C.L., Lolon, E.P., Erdle, J.C., & Tathed, V. (2009a): "Modeling Well Performance in Shale-Gas Reservoirs," SPE 125532, October 2009, Abu Dhabi, UAE.

Cipolla, C.L., Lolon, E.P., and Dzubin, B. (2009b): "Evaluating Stimulation Effectiveness in Unconventional Gas Reservoirs," SPE-124843, October 2009, New Orleans, Louisiana

Cipolla, C., and Wallace, J., 2014. Stimulated Reservoir Volume: A Misapplied Concept? Paper SPE 168596, SPE Hydraulic Fracturing Technology Conference, The Woodlands, TX, February 4–6.

Elsaig, M., Aminian, K., Ameri, S., and Zamirian, M., (2016). Accurate Evaluation of Marcellus Shale Petrophysicl Properties. SPE Eastern Regional Meeting. Canton, Ohio, USA: SPE 184042-MS.

Fontaine, J., Johnson, N., & Schoen, D. (2008): "Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History," SPE 117772, October 2008, Pittsburgh, Pennsylvania.

Marcellus shale -appalachian basin natural gas play. (2012). Retrieved from http://geology.com/articles/marcellus-shale.shtml

Maxwell, S.C., Weng, X., Kresse, O., and Rutledge, J., 2013. Modeling Microseismic Hydraulic Fracture Deformation. Paper SPE 166312, SPE Annual Technical Conference and Exhibition, New Orleans, LA, September 30-October 2.

Meyer, B.R., Bazan, L.W., Jacot, R.H., and Lattibeaudiere, M.G.: "Optimization of Multiple Transverse Hydraulic Fractures in Horizontal Wellbores," SPE 131732, February 2010.

Soeder, D. J. (2012): "Shale Gas Development in the United States." In H. Al-Megren (Ed.), *Advances in Natural Gas Technology* (pp. 1-28). Rijeka, Croatia: InTech.

Warpinski, N.R., Mayerhofer, M.J., Vincent, M.C., Cipolla, C.L., and E.P. Lolon (2008): "Stimulating Unconventional Reservoirs: Maximizing Network Growth While Optimizing Fracture Conductivity," SPE 114173, February 2008, Keystone, Colorado.

Yu, W., & Sepehrnoori, K. (2014). Sensitivity Study and History Matching and Economic Optimization for Marcellus Shale. Paper URTeC 1923491, Unconventional Technology Conference, Denver, CO, August 25-27 August 2014