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Sensitivity Analysis of Hydraulic Fractures for Well Stimulation in Shale Gas Reservoirs

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Abstract. Unconventional reservoirs are formations incapable of producing significantly and economically without the use of massive stimulations, due to low porosity and permeability values. Despite these restrictions, the unconventional resources were responsible for the increase in the volume of gas production in the US, mainly with Shale Gas. Among the forms of stimulation of oil wells, hydraulic fracturing is the most used. This technique consists of injecting a pressurized fluid into the formation until the rock breaks. In this context, the proposed article aims to evaluate a Shale Gas reservoir with a horizontal well and multiple transverse fractures, where the main geometric parameters – length, fracture height and spacing between fractures - were combined with different values to obtain the productivity of these configurations. Furthermore, with the same reservoir properties and fracture geometric parameters, the permeability was studied for 3 different values, to compare the influence of permeability on production. The purpose of this study is to, in the future, develop a computational tool capable of predicting the ideal dimension and spacing of fractures that maximize the recovery factor of Shale Gas reservoirs. For now, the simulations aim to evaluate the fracture parameters that most influence productivity, through a correlation matrix.

Keywords: Shale gas, Hydraulic Fracturing, Unconventional Reservoirs, Well Stimulation.

1 Introduction

The American geologist Masters [1], an important figure in the history of oil exploration in North America, theorized in one of his publications that natural resources are distributed throughout the Earth according to a log-normal function. According to his study, the accumulations of highest quality, which would be the most valuable and easy to produce, are small and difficult to locate, while low quality accumulations, which require a high degree of technology and favorable economic conditions to be viable, represent most of the resource's reserves. This analysis was called the resource triangle.

Since the original publication by Masters until the present time, the technologies for the production of unconventional hydrocarbons, located in unconventional reservoirs, which have low porosity and permeability values, have advanced in such a way that accumulations of this type are already responsible for expressive portions of world production volumes, mainly in the US, where natural gas production from shale or low permeability reservoirs corresponds to approximately 85% of all natural gas produced in the country, according to the EIA [2].

The development of production in unconventional reservoirs was only possible thanks to horizontal wells with multiple transverse fractures. These fractures are made using well stimulation techniques, where hydraulic fracturing is the most used. This technique consists of injecting a fluid into the formation under a pressure high enough to cause the rock to rupture.

In this context, the present paper aims to evaluate a Shale Gas reservoir with multiple hydraulic fractures in horizontal wells through flow simulators in porous media, in which the main geometric parameters – length, fracture height and spacing between fractures (Fig. 1) – and reservoir permeability were combined with different values to obtain the productivity of these configurations. This analysis seeks to determine which parameters most influence well productivity, through a correlation matrix with the study parameters.

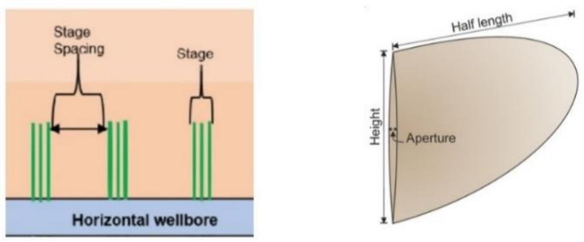


Figure 1: Geometric parameters of the hydraulic fracture [3, 4]

2 Methodology

2.1 Hydraulic Fracturing

Having its first experiment carried out in 1947 in the Klepper No.1 well of Hugoton Field, in Grant County Kansas, USA, hydraulic fracturing is one of the main well stimulation methods currently used. This technique consists of injecting a pressurized fluid into the formation, with low permeability in general, to increase the pressure inside it until the rock breaks and, consequently, fractures.

According to Alarifi and Miskimins [5], the creation of fractures in subsurface rock formations is a phenomenon of mechanical failure by tension, which can occur either by naturally present forces or by the application of high pressures, as is the case of hydraulic fracturing. Fractures begin when the injection pressure reaches the strength limit of the formation and then propagate at a rate dependent on the pressure continuously applied by the injection of fracturing fluid.

After the formation rupture, solid particles known as proppants are injected to keep the fracture open, since the in-situ stresses existing in the rocks tend to close them with the cessation of the fluid pumping. The main objective of this technique is the creation of new paths with greater permeability in order to facilitate the flow of fluid through these spaces [6].

The pioneering projects of the 1940s began a long trajectory of technological progress, leading to the latest in hydraulic fracturing technology today. These technological advances, according to Du [7], were fundamental for the technical feasibility and economics of operations such as the exploration of shale gas reservoirs in the USA. By opening high permeability preferential paths for gas flow within fractures treatment-induced, it is possible to obtain commercial production rates on these plays that were previously considered unprofitable.

Therefore, this technique is essential to obtain feasibility in the exploration of gas or oil reservoirs in low permeability rocks (shale, tight sands, or tight carbonates), basin-centered gas accumulations (basin-centered gas) and methane in coal (coal -bed-methane – CBM).

2.2 Reservoir Simulation

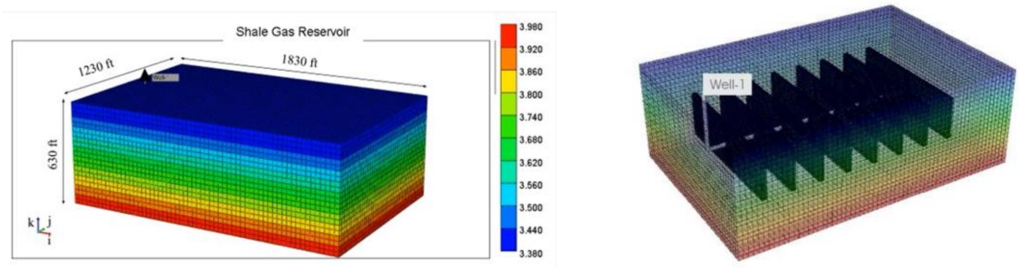
In a simulation study, a tool called a simulator is needed. According to Vitor [8], the simulator is created from the subdivision of a reservoir into finite volume elements, in a process called discretization. The reservoir is then divided into a series of interconnected blocks and the flow between them is numerically resolved. Each volume contains petrophysical properties that represent the modeled and analyzed reservoir, and the set of all elements is denoted by a grid. The equations used to describe the reservoir models derive from fundamental principles such as thermodynamic equilibrium, mass conservation, heat transfer, as well as fluxes in porous media, which are governed by Darcy's Law.

To carry out the simulations and sensitivity analysis studies, the reservoir simulation software CMG (Computer Modeling Group) was used. The simplified model of the shale gas reservoir was built using Builder ®, a pre-processing software for creating reservoir models. In this case study, the GEM ® module (Compositional & Unconventional Simulator) was used, as it is a compositional simulator developed specifically for the study of unconventional reservoirs, with features such as mesh discretization in adequate proportions to study the flow of hydrocarbons through of hydraulic fractures and the possibility of using the concept of double permeability, where the fracture has permeabilities greater than the matrix by some orders of magnitude [9].

3 Case Study

3.1 Simplified Model

In order to verify and evaluate a Shale Gas reservoir with a horizontal well and multiple transverse fractures, a simplified three-dimensional model was developed, created using the finite element method. The reservoir model was constructed with dimensions of 1830ft (558m) in length, 1230ft (375m) in width and 630ft (192m) in height, with impermeable (back feed) boundaries, for analysis over a period of 10 years from a 3-inch, horizontal, hydraulically fractured, 930-foot (283m) long well. The finite volume model is composed of a mesh 61 blocks in length, 41 blocks width, and 21 blocks in height, in which blocks are cubic with 30ft (9m) edges. The well is positioned centrally in the model, specifically in block 11 in the height direction, in block 21 in the width direction and from blocks 5 to 55 in the length direction, as shown in Fig. 2.



(a) (b)

Figure 2: (a) Mesh Model; (b) Reservoir model with fractured well inserted centrally

3.2 Reservoir and Hydraulic Fracturing Properties

The properties of the modeled reservoir to perform the simulations are presented in Table 1 with their respective values.

Table 1. Reservoir properties

Property	Value
Grid Top (ft)	3380
Gas-Water contact (ft)	4500
Porosity (%)	3
Permeability (mD)	0,0001/0,001/0,01
Formation compressibility (1/psi)	$1 * 10^{-6}$
Initial Gas Saturation (%)	80
Langmuir constant (1/psi)	0,002
Initial Reservoir Pressure (psi)	1500
Reservoir Temperature (°F)	100

Regarding hydraulic fracturing, the simple fracture model was chosen to be simulated in the software used, because it is easier to simulate in relation to the fracture network model and because it presents a good response to the productivity of the simulations performed. Therefore, to perform the sensitivity analyses, the following values were used for the hydraulic fracturing parameters, as shown in Tab.2.

Table 2. Fracturing parameters studied

Parameters	Range	Variance/Steps
Half Length (ft)	100 - 500	50
Fracture Height (ft)	30 - 240	30
Spacing between Fractures (ft)	60 - 150	30
Fracture Permeability (mD)	10000	-
Fracture Opening (in)	0,25	-

From the combination of the values of the two tables presented above, with the permeability variation for 3 different values, a total of 864 simulations were performed.

4 Results

After performing the simulations in the GEM module, the results of each study were obtained with their respective combinations of the geometric parameters of the fractures. In this way, it is possible to perform the analysis of the sensitivity that each parameter has on the influence of the productivity of the shale gas well. First, each parameter will be evaluated independently, where the other values of the fracture geometry will be kept fixed for the same permeability and porosity value. After analyzing all parameters, the correlation matrix will allow the visualization of the results of all simulations, showing which factors have the greatest influence on the productivity index.

4.1 Half-Length (ft)

The first parameter studied was the fracture half-length and its influence on productivity with the variation of its size. In this analysis, permeability values (0.001mD), fracture spacing (120ft), and fracture height (120ft) were fixed, while the half-length ranged between 100 and 500, in a step of 100. It is possible to verify through the analysis of the graph in Fig. 3 that, with the increase of the half-length of the fracture, greater will be the accumulated production of gas over time since the gas has greater paths to be conducted.

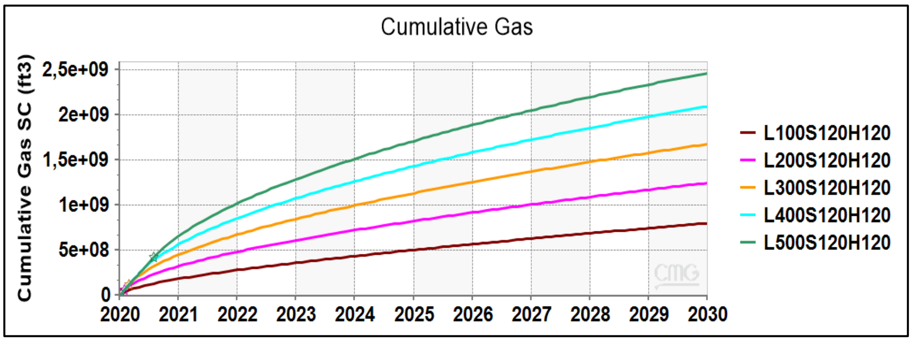


Figure 3: Cumulative gas curves with the variation of half length

4.2 Spacing between Fractures (ft)

Similar to the previous case study, to analyze the influence of spacing on well productivity, all other values were fixed. For the same well length, a smaller spacing between fractures allows more fractures to be made. Thus, for the spacings of 60ft, 90ft, 120ft and 150ft, 21, 15, 11 and 9 fracture stages were obtained respectively. Intuitively and as shown in Fig. 4, it can be said that as the spacing between fractures decreases, productivity increases, since the increase in the number of fractures allows gas to flow into the well in greater quantity. In this example, the following fixed values were used: Half length (100ft), fracture height (120ft) and permeability 0.001mD.

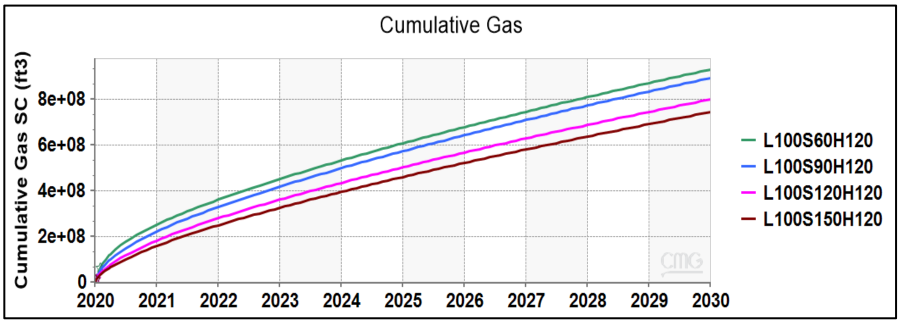


Figure 4: Cumulative gas curves with the variation of spacing

4.3 Fractures Height (ft)

Finally, the last geometric parameter evaluated was the fracture height and its influence on productivity. This analysis was made from 8 different height values with the other fixed parameters. As expected, the combinations of parameters that present higher values of height also have higher cumulative productions, as the gas has greater paths to flow into the well, as in the other cases. The Fig. 5 shows the cumulative gas curves with different height values, with fixed values of 300ft for half length, 120ft for spacing and 0.001mD for permeability

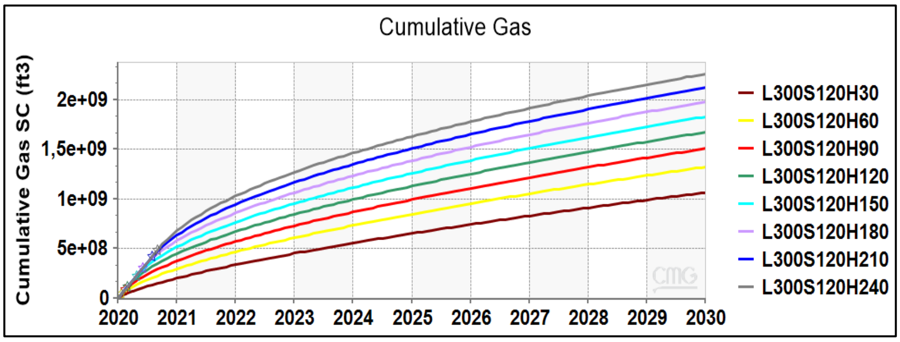


Figure 5: Cumulative gas curves with the variation of height

4.4 Permeability

In addition to the sensitivity analysis of productivity with the variation of the geometric parameters of hydraulic fracturing, a study of the influence of a parameter of the fractured reservoir was also carried out, in order to meet several possible combinations. In this case, the permeability of 3 different types of reservoirs was studied. The following permeability values were used: 0.0001mD, 0.001mD and 0.01mD. Since permeability represents the ability, or measure of the ability of a rock, to transmit fluids, it is expected that the accumulated productivity of the more permeable reservoir will be greater, as it presents greater paths for the gas to flow at a greater flow. As shown in Fig. 6, the reservoirs with the lowest permeability show a sharp drop in flow in the first year, while the reservoir with the highest permeability has a less sharp drop curve.

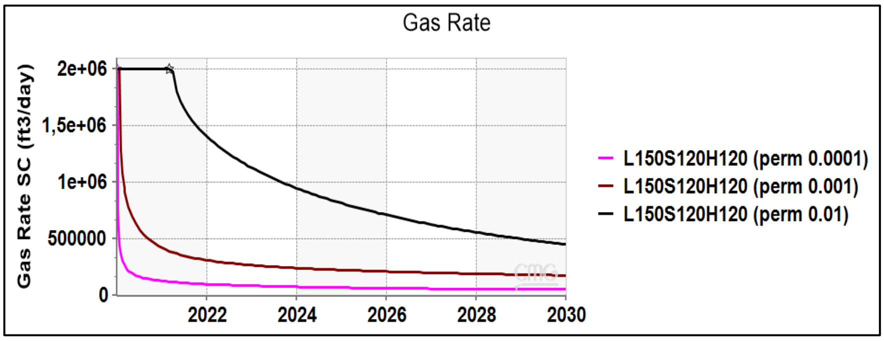


Figure 6: Gas rate curves with the variation of permeability

This drop in gas flow shown in the image above directly influences the production accumulated over 10 years. As shown in Fig. 7, as the permeability value of the reservoir increases, the production curves become larger, so that the reservoir produces much more.

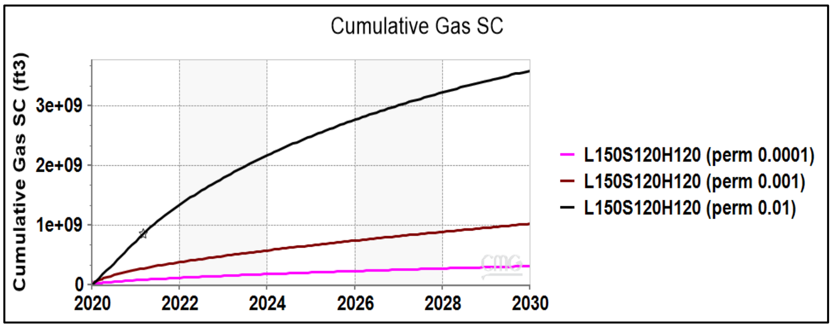
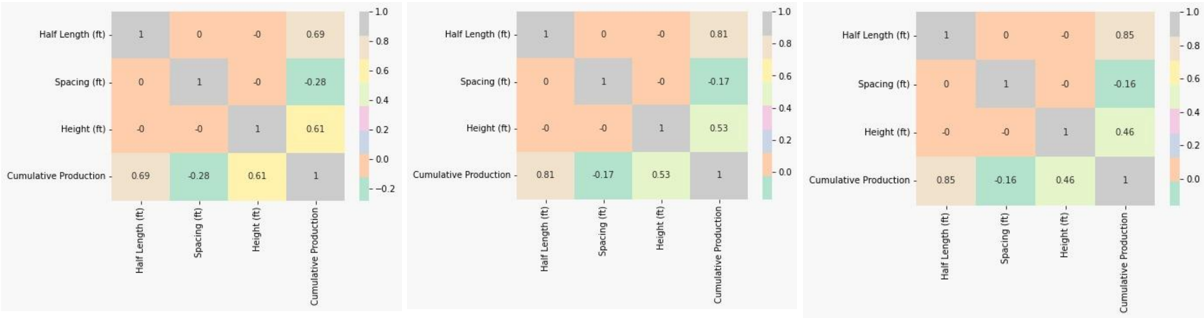


Figure 7: Cumulative gas production curves with the variation of permeability

4.5 Correlation Matrices

After simulating the 864 case studies, a correlation matrix was generated for the 3 analyzed reservoir models. Through this graph, it is possible to determine how strong the correlation between the variables is, and whether it is a positive or negative correlation. As expected in the 3 cases, the fracture geometry parameters are independent variables since they have zero correlation with each other. The correlation values found between the accumulated production and the geometric parameters also met what was expected, since the greater the length and height of the hydraulic fractures, the greater the productivity of the well. Likewise, a smaller value of spacing between fractures, which results in a greater number of fractures for the same length of well, results in higher production volumes, which explains correlations with negative values.

Comparing the correlation matrices shown in Fig.8, it can be seen that the variation in the permeability of the reservoir influences the relationship between the variables. As reservoir permeability increases, the influence of half-length and spacing on cumulative production becomes stronger. On the other hand, fracture height has an opposite relationship, since its influence on productivity decreases with increasing permeability. These analyzes are evidenced when comparing the correlation matrix of the reservoir with the highest permeability (0.01 mD) shown in Fig.8c, in which the half-length and spacing present correlations with higher values while the height decreases.



(a) (b) (c)

Figure 8: (a) Correlation matrix for permeability 0.0001mD; (b) Correlation matrix for permeability 0.001mD; (c) Correlation matrix for permeability 0.01mD

5 Conclusion

According to the adopted methodology, it is possible to analyze that the geometric parameters of the fracture have directly proportional relationships with the productivity, because as seen in the results, as the half-length and height of the fracture increases, the production of shale gas will also increase. Likewise, less spacing between fractures will also increase productivity, as the number of fractures created for the same fracture length will be greater.

When compared to reservoirs with different properties, the influence of some fracture parameters on productivity changes. In the case of reservoirs with different permeabilities, the fracture half-length and spacing will be increasingly influential in the productivity analysis with the increase in permeability, while the fracture height presents an inversely proportional relationship.

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