Middle East Research Journal of Engineering and Technology
ISSN: 2789-7737 (Print) ISSN: 2958-2059 (Online)
Frequency: Bi-Monthly
DOI: https://doi.org/10.36348/merjet.2024.v04i03.002

Website: http://www.kspublisher.com/
Email: office@kspublisher.com

Simulation of Shale Gas Flow in the New Albany and Antrim Wells

Guilherme Baião Guerreiro[1], João Alexandre Gomes Neto[1], Roberta Flávia Romero[1], Licianne Pimentel Santa Rosa[2*], e Laio Damasceno da Silva[3]
[1]Jorge Amado University Center, Av. Luís Viana Filho, 6775, 41.745-130, Paralela, Salvador BA
[2]Federal University of Sergipe, Department of Chemical Engineering, Av. Marcelo Déda Chagas, s/n, Rosa Elze, São Cristóvão - SE, 49107-230
[3]Chemical Engineering Pos Graduate Program / Federal University of Bahia, Federal University of Bahia, Av. Aristides Novis, nº 02, Federação, Salvador, 40.210-630 BA, Brazil

Abstract: "Unconventional" resources are defined as hydrocarbons found in reservoir rocks that are not very permeable, which makes it difficult for the fluid to move through them. A highlight in unconventional production is shale gas, due to the low permeability of this type of formation. In this context, this work aims to compare gas production velocity profiles from shale formations and analyze the flow using software: ANSYS and MATLAB. In addition, the influences of this flow on the New Albany and Antrim wells will be analyzed. The results show that the Antrim well performs better. This may be associated with the hydrogen injection process.

Keywords: Shale Gas, Ansys; Velocity Profile, MATLAB.

Research Paper

***Corresponding Author:**
Licianne Pimentel Santa Rosa
Federal University of Sergipe, Department of Chemical Engineering, Av. Marcelo Déda Chagas, s/n, Rosa Elze, São Cristóvão - SE, 49107-230

How to cite this paper:
Guilherme Baião Guerreiro *et al* (2024). Simulation of Shale Gas Flow in the New Albany and Antrim Wells. *Middle East Res J. Eng. Technol*, *4*(3): 91-97.

Article History:
| Submit: 17.08.2024 |
| Accepted: 16.09.2024 |
| Published: 18.09.2024 |

1. INTRODUTION

Natural gas is composed by a mixture of hydrocarbons which, when they are at the surface, are in gaseous form and in the reservoir these mixtures can be in both gaseous form and dissolved in oil (ROSA, 2006). Exploiting unconventional shale gas still requires a great deal of time and technology, as this natural gas is difficult to remove due to the low porosity of its formation. Among the new ways of exploiting natural gas, it is possible to highlight the use of gas from fine-grained sedimentary rock formations, coming from the compaction of silt, which is a mineral similar to fine sand that can be transported and deposited as sediment, as well as other minerals, known as shale. The pioneering production of shale gas came from the United States around the year 2000 with the discovery of the production potential of the basin known as the Barnett Shale, which is why fields were chosen in the US region by the Mitchell Energy and Development Corporation (EIA - U. S. Energy Information Administration, Natural Gas Explained, 2015).

The term unconventional gas was first used in the US to classify resources that were not economically viable to exploit or even those with marginal economic returns (COLOMER, 2015). Over time, this concept ceased to be guided by economic aspects and began to be directed by the geological differences of the reservoirs. There are several classifications of unconventional gas: gas allocated to deep reservoirs (deep gas), gas allocated to deep water reservoirs (deep water), gas allocated to low permeability formations (tight gas), coalbed methane, geopressurized gas and methane hydrates (CESÁRIO, 2010). In order to remove the gas from the formation, which has low permeability, it is necessary to carry out a billing operation, which involves blasting a fluid at high speed to open a fracture in the formation and thus stimulate the flow of the gas.

The aim of this work is to study the efficiency of wells producing shale gas through the velocity profiles developed for this type of production. To do this, we used software that can carry out various flow calculations, ANSYS and MATLAB, so that we can check the different flows of this gas in the different wells simulated and thus observe some factors such as which one manages to remove the greatest amount of gas from the wells.

2. METHODOLOGY

2.1 Well Data

The fields were chosen because of their proximity to each other. The New Albany field is formed by a blackshale in the southern part of Illinois and extends into Indiana and Kentucky. The vertical wells drilled in this field have an average production of 25 to

75 Mscfd (million cubic feet per day under standard conditions) initially while the horizontal wells can reach up to 2000 Mscfd (BRYAN, 2008). The Antrim field is in a shallowshale formation and is located in Michigan. Its development was accelerated by financial incentives from the state, and its production ranges from 50 to 60 Mscfd per well (BRYAN, 2008). Table 1 shows production data for the Antrim and New Albany wells located in the USA. Where it was possible to observe the base of information such as maximum and minimum temperatures, reservoir pressure, porosity and pressure gradient for each well.

The composition measured in four different wells in these New Albany and Antrim are, shown in Tables 2 and 3.

Table 1: Production data, adapted from YAO TIAN (2010)

Data	Antrin	New Albany
Depth (ft)	600-2200	500-2000
Temperature at the bottom of the well (F)	75	80-105
Total porosity (%)	9	10-14
Reservoir pressure (psi)	400	300-600
Gas production (Mcf/day)	40-500	10-50
Pressure gradient (psi/ft)	0.35	0.43

Table 2: Gas composition in the New Albany adapted from BRYAN (2008)

1. Composição de New Albany					
Poço	C1	C2	C3	CO2	Total
1	87,7	1,7	2,5	8,1	100
2	88	0,8	0,8	10,4	100
3	91	1	0,6	7,4	100
4	92,8	1	0,6	5,6	100
MÉDIA	**89,875**	**1,125**	**1,125**	**7,875**	**100**

Table 3: Gas composition in the Antrim adapted from BRYAN (2008)

2. Composição de Antrin						
Poço	C1	C2	C3	CO2	N2	Total
1	27,5	3,5	1	3	65	100
2	57,3	4,9	1,9	0	35,9	100
3	77,5	4	0,9	3,3	14,3	100
4	85,6	4,3	0,4	9	0,7	100
MÉDIA	**61,975**	**4,175**	**1,05**	**3,825**	**28,975**	**100**

Tables 2 and 3 show that the Antrin well has a nitrogen composition that averages almost 29% of the total, which is an indication that this gas was injected into the well to stimulate production, maintain the internal pressure of the wells and facilitate the faster sale of the gas.

2.2 Calculation of Density, Molar Mass, Compressibility Factor and Viscosity Density and Molar Mass:

From the data presented in Tables 2 and 3, it was possible to find the density and molar mass of each well using the Unitrove calculator software (http://unitrove.com/engineering/tools/gas/natural-gas-density).

Compressibility Factor:

The compressibility factor Z is a variable that corrects the behavior of a real gas when compared to the behavior predicted for ideal gases. The compressibility factor (Z) is dimensionless and is defined as the ratio of the real volume of n moles of gas at T and P and the volume of the same number of moles of an ideal gas at the same T and P (MACEDO, 2009). To calculate Z (compressibility factor) with the data generated, the following Equations 1 to 4 must be applied:

$$P_{Pr} = \frac{P}{P_{Pc}} \quad (1)$$

$$T_{Pr} = \frac{T}{T_{Pc}} \quad (2)$$

$$P_{Pc} = 708.75 - 57.5d_{\$} \quad (3)$$

$$T_{Pc} = 169 + 314d_{\$} \quad (4)$$

Where $P_{\%\&}$ pseudo reduced pressure, $T_{\%\&}$ pseudo-reduced temperature, $P_{\%c}$ pseudo-critical pressure, $T_{\%c}$ pseudo-critical pressure, *T* the temperature at the bottom, *P* the pressure at the bottom. Equations 1 to 4 were used to find the compressibility factor Z, using the graph shown in Figure 2:

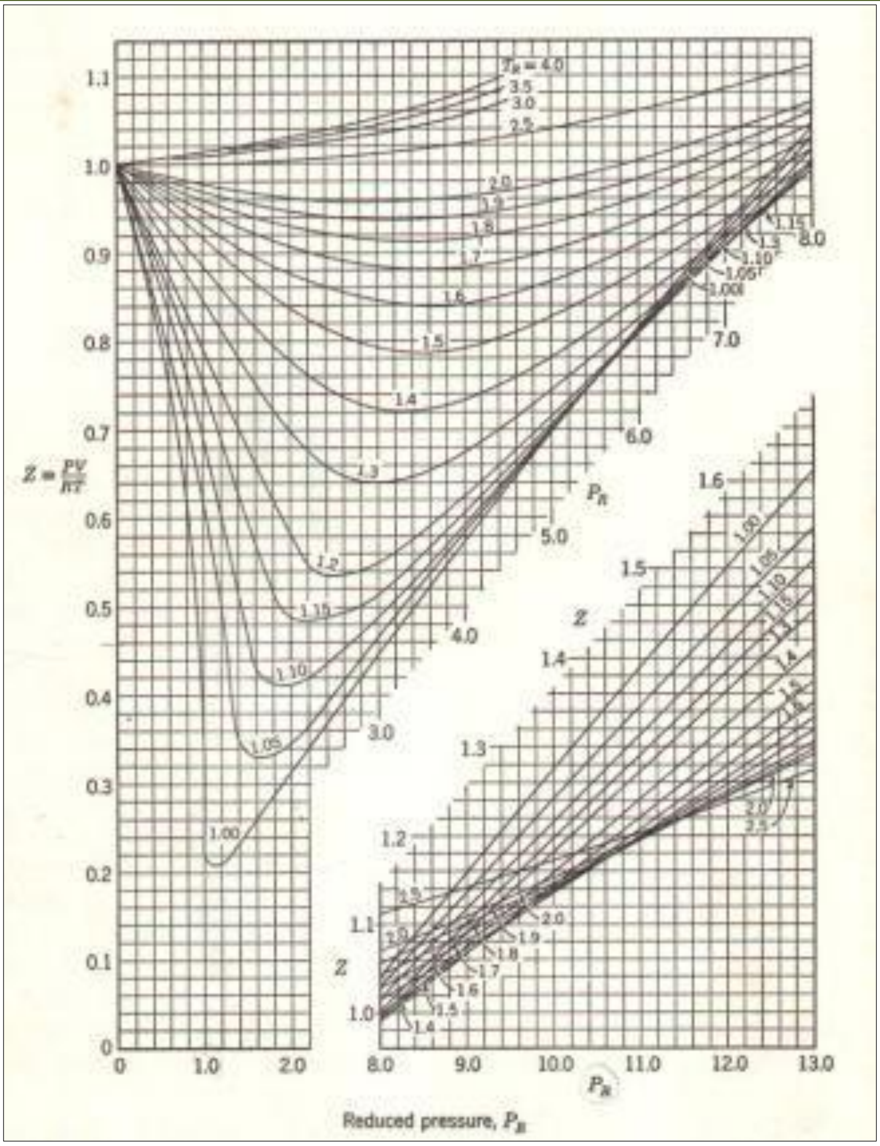

Figure 2: Compressibility factor x Pressure (ROSA, 2006).

Viscosity:

From the average composition of each well, it is possible to calculate the viscosity of the fluid inside each simulated well, using the tabulated value of the viscosity multiplied by the composition of each type of gas present by the values obtained from the average of each well (Antrin and New Albany) from Tables 2 and 3, shown in Table 4.

Table 4: Standard Viscosity adapted from BRYAN (2008)

Gas type	Standard Viscosity
C1	0,0103
C2	0,0093
C3	0,0076
CO2	0,0148
N2	0,0174

2.3 Gas Flowrate

Darcy's law is an equation that describes the flow of a fluid through a porous medium. This law was founded by Henry Darcy based on the results of experiments published in the 19th century on the flow of water through sand beds (TOMAS, 2011).

$$Q = -\frac{kA}{\mu}\frac{dP}{dx} \qquad (5)$$

where Q is the volumetric flow rate, A is the cross-sectional area of the rock, dP/dx is the pressure gradient and k is the permeability of the rock.

In order to observe the gas flow rate along the pipe from the flow rate obtained during production, it is necessary to use Equation 6. It is capable of correcting the flow rate value as a function of the temperature and pressure variation in the wells:

$$Q_{\$} = \frac{Q_{\$_{std}} P_{std} T Z}{T_{std} P} \qquad (6)$$

where $Q_\$$ is the gas flow rate, $Q_\$std$ is the gas flow rate under standard conditions, P_{std} is the pressure under standard conditions, T is the temperature, Z is the compressibility factor (considered constant for the analysis term), T_{std} is the temperature under standard conditions and P is the pressure.

3. RESULTS AND DISCUSSIONS

This section aims to show results of the simulations of the shale gas from the wells: New Albany and Antrim. First results of the properties are presented fowling by the simulations of velocity profile for the both wells.

3.1 Density, Molar Mass, Compressibility Factor and Viscosity

Table 5 shows the density results at the bottom pressure of the Antrin and New Albany wells as well as the molar mass of them.

Table 5: Density at bottomhole pressure

	Antrin	New Albany
Density (Kg/mt)	24,962	24,098
Molar Mass (Kg/Kmol)	21,4614	18,7188

In order to visualize the variation of the density as a function of pressure, simulations were carried out to calculate it at pressures from 0 to 10 MPa, as can be seen in Figure 2.

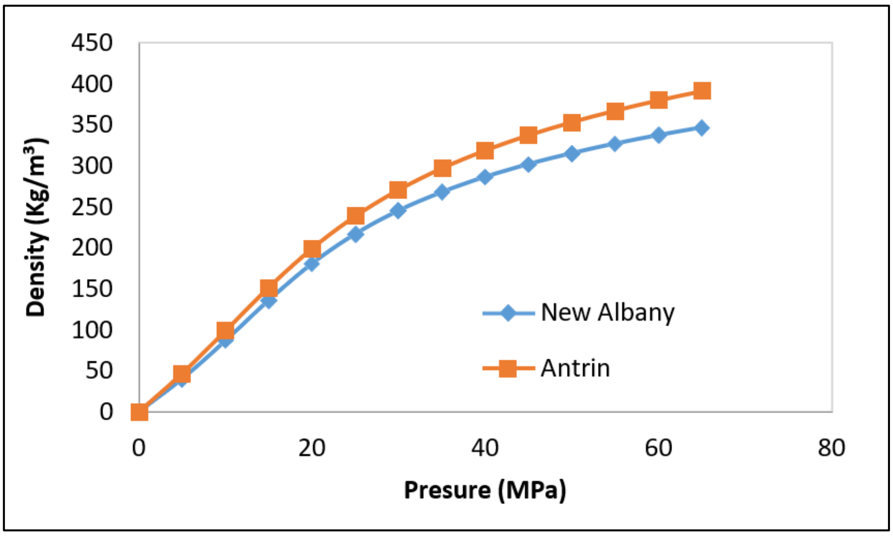

Figure 2: Density and pressure curves in the wells.

From the average composition of each well, it is possible to calculate the viscosity of the fluid inside each simulated well, using the tabulated value of the viscosity multiplied by the composition of each type of gas present by the values obtained from the average of each well (Antrin and New Albany) from Tables 2 and 3, shown in Table 6.

Table 6: Viscosidade calculada para poço simulado

Gas Type	Standard viscosity	New Albany	Antrin
C1	0,0103	0,925	0,638
C2	0,0093	0,010	0,038
C3	0,0076	0,008	0,008
CO2	0,0148	0,116	0,056
N2	0,0174	0	0,504
Mixture	-	0,0105	0,0124

After using the Equations 1-4 and the graph from Figure 1, the Z values for New Albany and Antrim are 0.76 and 0.95 respectively.

3.2 Velocity Profile Simulations

In order to observe the behavior of the flow based only on the composition (Figure 3 and 4), a velocity behavior profile was drawn up using ANSYS software on a section of pipe with an area of 0.28 m², because as the specified flow rate was dimensioned in Mcf/day, the simplification adopted was to use 1 ft as the radius and the formula for the area of the circumference resulting in the above value, as it is simpler to feed the software with SI units, where the red region represents the highest velocity and the blue the lowest velocity, and the colors in between represent a subtle variation.

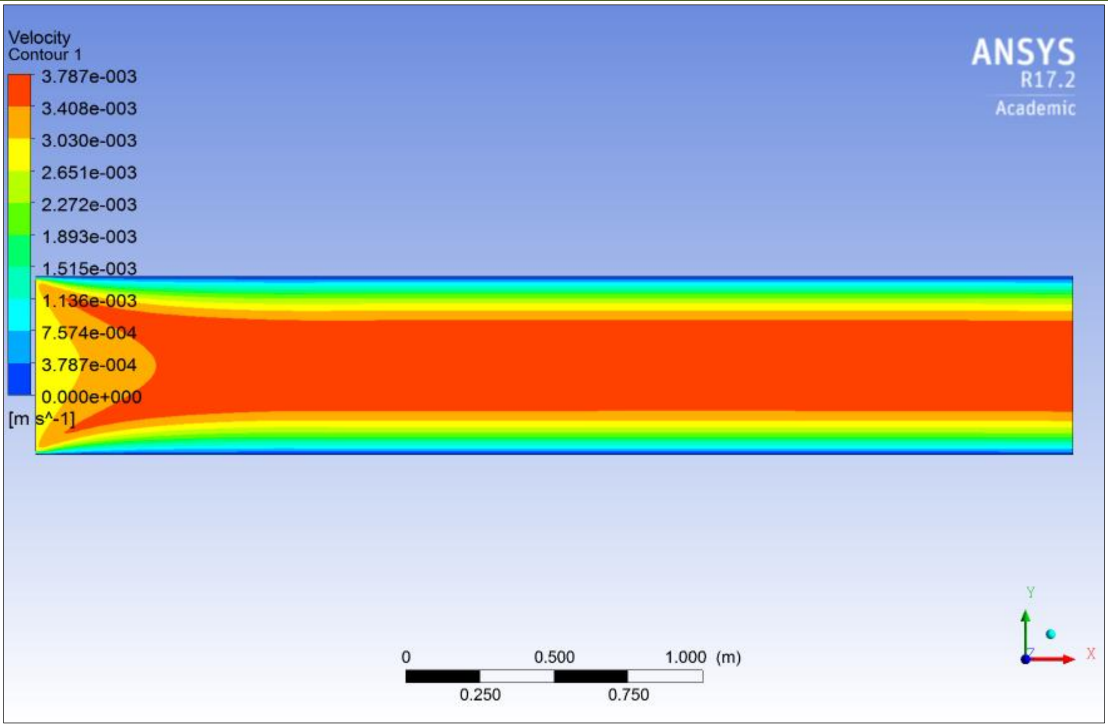

Figure 3: Velocity Profile for the Antrim

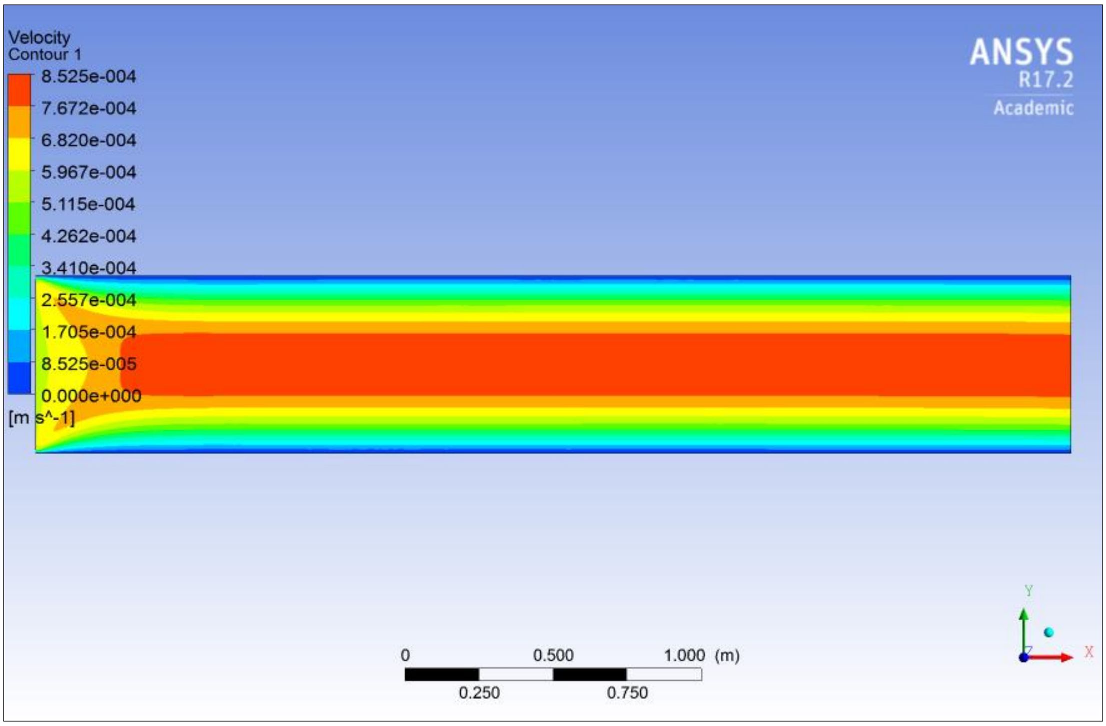

Figure 4: Velocity profile for the New Albany.

The profiles show in Figures 3 and 4 reveals that the velocity distribution is concentrated in the center and loses intensity as it approaches the pipe walls, but this loss is more pronounced in the New Albany pipe section, possibly because it has a heavier gas composition. Based on the lowest flow rates, lowest depths and production values, and the average temperature of the New Albany and Antrim fields according to Table 1, it was possible to simulate in MATLAB a velocity behavior profile along a pipe with a constant area equal to 0.28 m^2 and for this calculation the equations for the variation of the production flow rate (Equation 6) and Darcy's Law for flow in porous media (Equation 5) were used to observe the behavior of the shale and then generate the velocity curves found in Figure 5.

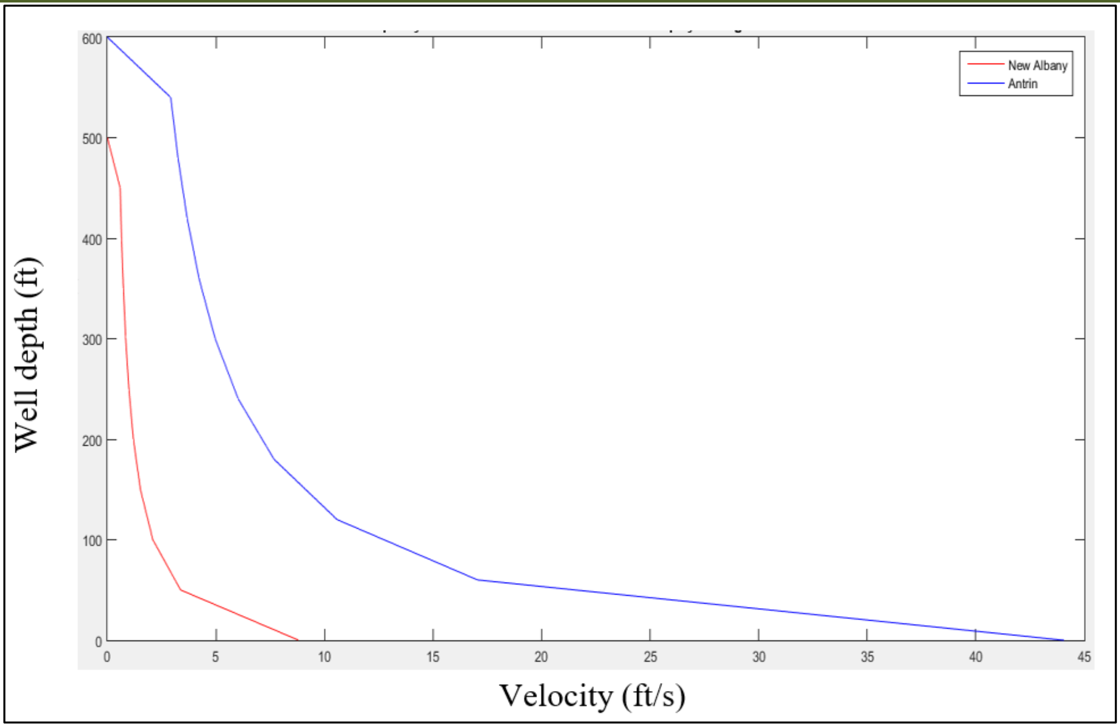

Figure 5: Flow velocity profiles at the New Albany and Antrim wells at different flowrates

The graph in Figure 5 shows the velocity profiles of the New Albany and Antrin wells. The influence of the initial flow rate and the compressibility factor on the curves can be seen. It can be seen that the velocity varies with decreasing depth and that this variation is accentuated closer to the surface.

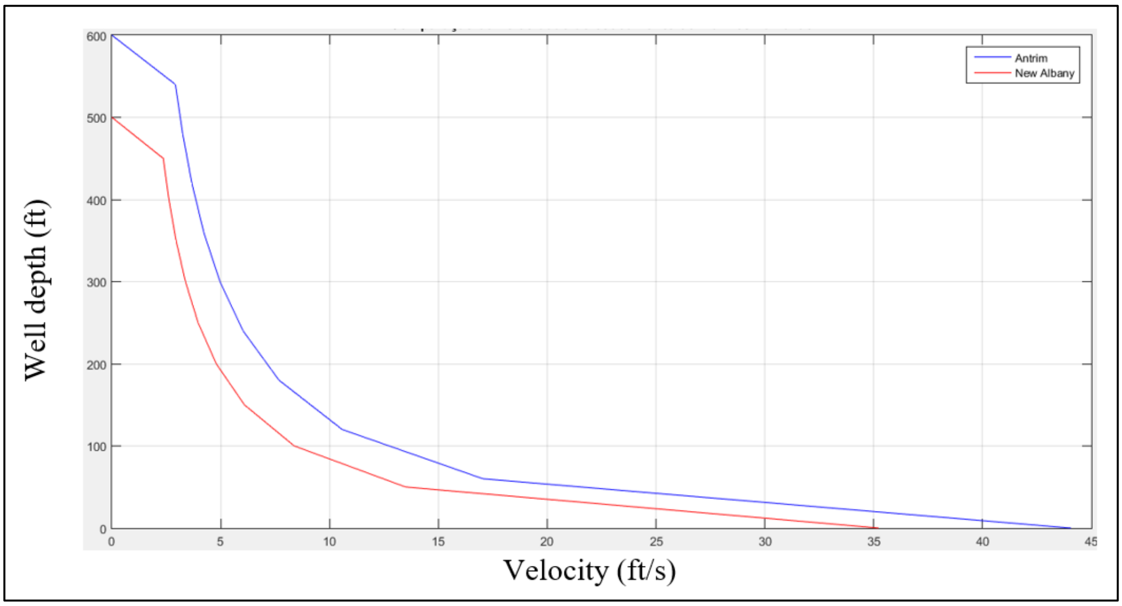

Figure 6: Flow velocity profiles at the New Albany and Antrim wells at the same flowrates

There is also a large variation at the very beginning of the profile, as there was no calculation for the behavior of the shale altered by the hydraulic billing, which also has a variation in effectiveness in the flow rates, being approximately 2.36 m/s in New Albany and 2.92 m/s in Antrin without any fracturing, and for the same flow rate, but the gain in New Albany in the observed flow rate is only 0.6 m/s. Another factor that can be observed in relation to the flow rate is that at more than 100 feet the Antrim well already produces at a rate equivalent to the New Albany well under standard conditions, as can be seen in Figure 6.

The Antrim well has a higher flow rate, which could already be seen from the production data, although New Albany had a higher temperature and lower pressure, which should provide a higher flow rate, but this can be explained by the composition where a high nitrogen content was found in the reservoir. This type of analysis can also provide an idea of the gain in flow generated by hydraulic billing, which can be observed by the misalignment of the velocity curve and by means of the difference between the velocities, enabling the flow gain to be estimated. In addition, the work also aims to integrate reality with academic knowledge by applying real data, data estimated from it and also empirical data together.

At first glance, it may be known that the Antrim well has a higher production than the New Albany well, but the latter ends up being more expensive, since 28% of the volume obtained in its production is actually nitrogen, a gas that was probably used for the hydraulic billing operation itself, when it was injected at high pressure into the reservoir, to result in a higher productivity rate and make the well commercially valid, while the New Albany well did not need such an artifice, making it a well with a lower production cost.

The application of nitrogen can be seen as a worthwhile investment, as this gas helps to maintain reservoir pressure, which will guarantee a longer production time so that the well can overcome the costs generated during its production and if the non-hydrocarbon gas portions were removed, the situation would be one of a hydrocarbon supply rate of 29, 605 m/s for Antrin and 32.46 m/s for New Albany, which represents a little more flow, but it is known from Tables 2 and 3 that the Antrin well has a composition that generates more expensive by- products.

4. CONCLUSION

This work aims to compare gas production velocity profiles from shale formations and analyze the flow using software: ANSYS and MATLAB. The velocity analysis for both wells proved that although the hydrogen injection method was expensive, it gave the well an advantage both in terms of flow and productivity time. Using the Ansys software, it was possible to see that the composition of the gas containing hydrogen facilitates the distribution of the velocity in a stretch of pipe, while the Matlab simulation showed that the compressibility factor obtained in the well with nitrogen was higher and this factor helped the velocities, not to mention that the hydrofracturing process proved to be more effective in the well that used this hydrogen when you look at the contrast with the initial velocity of the curve made in Matlab.

REFERENCES

- (AGA) Transmission Measurement Committee Report No. 8, American Petroleum Institute (API) MPMS, Chapter 14.2, Segunda Edição, Novembro 1992.
- Air Products. Disponível em <http://www.airproducts.com.br/industries/Energy/Enhanced-Oil- and-Gas-Recovery-Technology.aspx> Acessado em 10 de Maio de 2017.
- Bullin, K. (2010). Composition Variety Complicates Processing Plans for US Shale Gas. 9.f
- Cesário, J. (2010). Superintendente de Comercialização e Movimentação de Petróleo, *seus Derivados e Gás Natural*, 19.
- Gupta, R. *Hydrology and Hydraulic Systems*. 3a ed. 896 páginas, Editora Waveland press.
- ISO 12213-2 Natural gas - Calculation of compression factor - Part 2: Calculation using molar- composition analysis, 2006.
- Macedo, E. Avaliação de Correlações e Equações de Estado para Determinação de Fatores de Compressibilidade de Gás Natural. 2009.221.f. . Tese (Mestrado em Química) – Universidade do Estado de Rio de Janeiro.
- Natural Gas Density Calculator. Disponívelem <http://unitrove.com/engineering/tools/gas/natural-gas-density> Acessado em 28 de Maio de 2017 .
- Osperigos potenciais do fraturamento hidráulico. Disponívelem<http://www.ecycle.com.br/component/content/article/35/1206-os-perigos-potenciais-do- fraturamento-hidraulico.html> Acessado em 17 de Maio de 2017.
- Recovery Methods. Disponível em < http://www.bnkpetroleum.com/operations/recovery - methods> Acessado em 23 de Maio de 2017.
- Rosa, A. (2006). Engenharia de reservatórios de petróleo. 1ª edição. Local: *Interciência*, 808.
- SOARES, LUIS FILIPE M. RIBEIRINHO. Desenvolvimento em matlab de um programa de elementos finitos para percolação. 2010. 174 f. Dissertação (Mestre em Engenharia Civil)-Departamento De Engenharia Civil, Faculdade de Engenharia da Universidade do Porto, Porto, Portugal, 2009.
- Starling, K. E., & Savidge, J. L. (1992). Compressibility Factors for Natural Gas and Other Related Hydrocarbon Gases, *American Gas Association*.
- The Process of Shale Gas Development. Disponível em < http://shalegas-europe.eu/shale-gas-explained/the-process-of-shale-gas-development/> Acessado em 23 de Maio de 2017.
- Tian, Y. (2010). An Investigation of Regional Variations of Barnett Shale Reservoir Properties, And Resulting Variability of Hydrocarbon Composition and Well Performance. 2010.114 f. Tese (Mestrado em Ciência) - Office of Graduate Studies, Texas A&M University, Texas.