Romanian Journal of Petroleum & Gas Technology
VOL. IV (LXXV) • No. 2/2023

ARTIFICIAL INTELLIGENCE SIMULATION OF MULTIPHASE FLUID FLOW THROUGH EXTRACTION PIPES

Alexandra Damascan [1]

Mihai Albulescu [2]

Doru Stoianovici [2]

Doru Bârsan [2]

[1] Serinus Energy, Bucuresti, Romania
[2] Petroleum-Gas University of Ploiesti, Romania
email (corresponding author): doru_stoianovici@yahoo.com

DOI: 10.51865/JPGT.2023.02.20

ABSTRACT

The flow of petroleum fluids through extraction pipes is a phenomenon difficult to describe in mathematical terms. Complex numerical relationships are usually used, most of which are derived from observation of wells in operation and analysis of collected production data, and others are determined from laboratory experiments. But a model that uses artificial intelligence in this field has not been created to date, even if this concept is widely used in the oil industry. This is precisely why this article proposes a numerical model based on artificial intelligence that determines the flow equations and their limits according to the type of flow, determines the relative velocities of gas and oil liquids during the ascent through the extraction pipes and also statistically analyzes the data obtained as a result of applying the described model with real data collected from a group of wells in production.

Keywords: oil and gas, fluid modelling, artificial intelligence, well production.

INTRODUCTION

In the vast majority of cases, in the pipelines installed for the extraction of gases and associated fluids and their transport to the treatment and conditioning facilities, a heterogeneous flow occurs [1].

This type of flow consists of a gas phase and one or more liquid phases (immiscible or partially miscible), the gas phase, present in the deposit, being formed by the extracted natural gases [2].

In some cases (in oil fields associated with natural gas or in natural gas fields associated with condensate), the extracted gases also contain some liquid fractions (compounds that vaporize before or even during the flow through the extraction pipes).

Since the physical properties of the extracted fractions change during their rise and differ from each other, both in the extraction stage and in the storage phase, the laws of homogeneous flow cannot be applied (equations that do not associate momentum transfer phenomena with phase transformations of fluids during flow through extraction pipes) [2].

Also, in real conditions of the ascent of petroleum fluids through pipelines, the flow velocities of the components (of the phases) are not equal, gases and vapors, having a specific weight lower than that of liquids, have a tendency to dissolve (a creep) more easily in petroleum liquids and therefore an increased ascent velocity relative to the liquid phase.

In conclusion, the gas phase has relative motion, both with respect to the walls of the wellbore and with respect to the component petroleum liquids, with this (gas) phase currently sliding or creeping among the component particles of the liquid phase.

Among the most important factors that characterize the flow of a mixture of gases, vapors and liquids in vertical pipes in this paper was analyzed [3]:

a. The relative movement speed between the two phases (liquid and gas),
b. Energy losses resulting from friction,
c. The structure of the mixture of phases (gaseous or liquid).

To facilitate the phenomenological understanding of the flow of fluids through pipelines, it was considered that the vapors of extracted oil fractions and natural gas are contained in a gaseous phase, without distinguishing between them except in terms of physico-chemical properties.

In the laboratory, studies were carried out on the determination of the flow structure (the structure of the petroleum mixture consisting of gases and liquids), depending on the flow rate ratio between the two phases (gas + liquids), the difference between their densities, as well as the viscosity and surface tension of the fluids components.

The nature of the mixture of petroleum fluids favors their structure, the following flow structures being determined in the laboratory (figure 1 and figure 2) [3, 4]:

a. Dispersed bubble structure (Bubble). The flow is characterized by very small gas-liquid ratios and in this case the gas bubbles rise to the upper part of the fluid.
b. Elongated bubble structure (Slug). This type of flow appears with the increase of gas-liquid rations and then the gas bubbles increase forming plugs.
c. Stratified flow structure (Stratified), where gases and liquids form separate layers, and gas plugs join at the top of the pipe.
d. Wave type structure (Wave), characterized by high gas rations, which in the ascending movement produce wave-like structures in the liquid.
e. Plug structure (Plug). At even higher gas rates, it is found that the waves reach the upper part of the pipeline, fixing the large gas plugs (tens of meters) between them;
f. Annular fog type structure (Mist). It is characterized by extreme gas-liquid ratios. In this case, the flow of the liquid is realized as a form of mist dispersed in the gas flow.

Laboratory research, carried out by visual observation of the phenomena of the flow of biphasic mixtures through vertical pipes, concluded that as the mixture of gases and liquids rises through the extraction pipes (of constant diameter), the pressure along them decreases and in this case increases the volumetric gas flow rate (gas-liquid ratio).

So there is a point, where the condition for the existence of the bubble structure can no longer exist, but also the gas flow is not high enough for the resulting velocity of the gases to entrain the liquid in the form of rings or droplets.

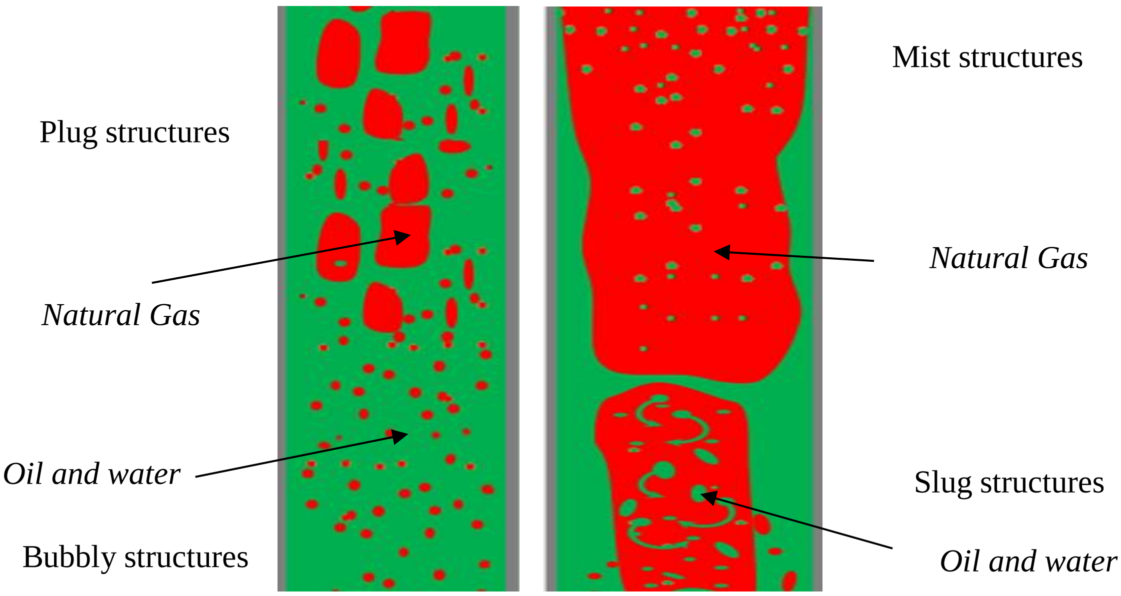

***Figure 1**. The structure of the mixture of gases and liquids when flowing through extraction pipes* [1]

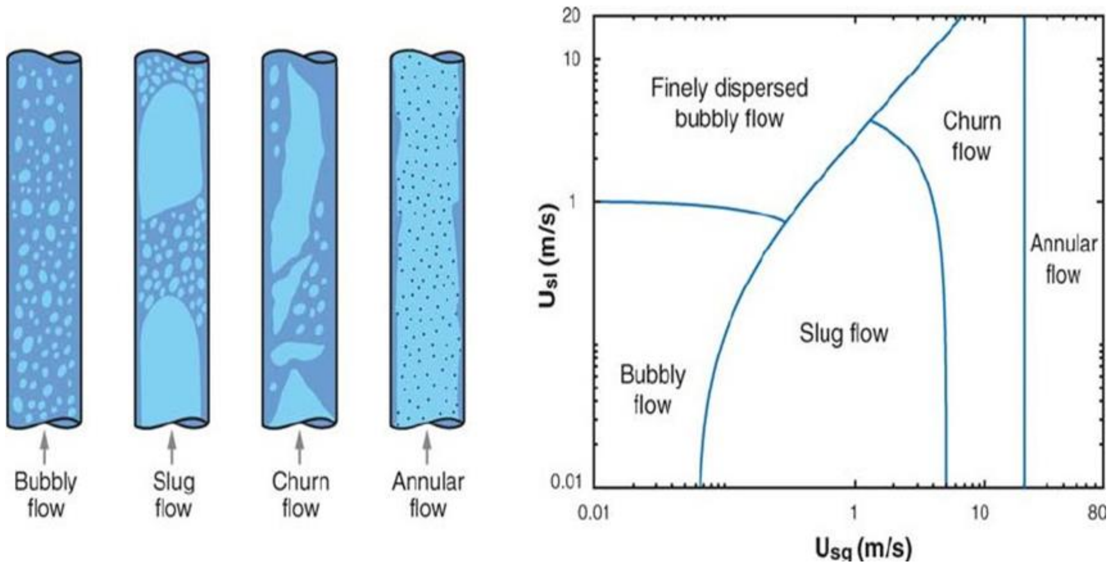

***Figure 2**. The type of flow through vertical pipes of the two-phase mixture* [3, 4]

In this case, the probe will produce a smaller amount of liquid than the one that entered the extraction pipes from the layer, later being removed in the form of plugs.

By increasing the ratio between the gas and liquid volumetric flow rates, the instability of the flow decreases and the regime approaches a continuous flow, the structure of the mixture being formed by chains of liquid rings through which the associated gas flows.

By increasing the gas-liquid ration, the phenomenon of fog appears, the liquid moving in the form of particles (droplets) in the gas mass.

The flow of fluids through vertical pipes occurs as a result of the transformation of potential energy into pressure energy (for liquids) and into kinetic energy of motion (for gases).

The potential, available energy of the mass of liquid and free or dissolved gases (after their passage through the filter slits) is consumed during the process of ascent of the liquid-gas mixture to the surface for [2]:

a. Carrying out the mechanical work of lifting the liquid and gas mass from the filter openings to the surface,
b. Overcoming friction (losses of energy through friction) resulting during the flow of petroleum fluids from the bottom of the well to the surface (friction also resulting from the flow through the surface nozzles, through contact with the pipe walls and the losses incurred during the passage through the filter slots),
c. Ensuring an optimal transport speed of petroleum fluids from the bottom of the well to the surface.

ENERGY BALANCE IN FLOWING FLUIDS EXTRACTED FROM GAS DEPOSITS ASSOCIATED WITH CONDENSATE

The energy balance, of an extraction process of petroleum fluids, can be written as a summation of the initial energy along with the sum of all the energies exchanged with the ambient environment, for two points of the analyzed system.

In the assumption that we do not have a mechanical exchange of work with the outside, the equation for the mass unit has the form [3]:

$$\int V\,dp + \Delta\left(\frac{v^2}{2g}\right) + \Delta h + F = 0 \tag{1}$$

But equation (1) can also be written in differential form:

$$\frac{dp}{\rho g} + \frac{v\,dv}{g} + dh + dF = 0 \tag{2}$$

Taking into account that $dh = dl\ sin\theta$, equation (2) can be rewritten in the form:

$$\frac{dp}{dl} = \rho g\ sin\theta + \frac{\rho g\ dF}{dl} + \frac{\rho v\ dv}{dl} \tag{3}$$

Assuming that the pressure gradient can be determined by the sum of three factors:

$$\left(\frac{dp}{dl}\right)_t = \left(\frac{dp}{dl}\right)_{st} + \left(\frac{dp}{dl}\right)_{acc} + \left(\frac{dp}{dl}\right)_{fr} \tag{5}$$

We get:

$$\frac{dp}{dl} = \rho g\ sin\theta + \frac{4f\,\rho\,v^2}{2d} + \frac{\rho v\ dv}{dl} \tag{6}$$

In the relations above we noted with:

- p is the system pressure,
- V represents the specific volume analyzed,
- $\frac{m\,v^2}{2}$ represents the kinetic energy,
- mgh is the potential energy,
- F is the energy loss due to friction,
- m is the mass of the system,
- v is the velocity of the system,
- g is the gravitational acceleration,
- ρ is the density of the analyzed fluids,
- $(\frac{dp}{dl})_{st} = \rho g\ sin\theta$ is the potential energy component,
- $(\frac{dp}{dl})_{fr} = \rho g\ s\frac{dF}{dl}$ represents the friction loss component,
- $(\frac{dp}{dl})_{acc} = \rho v\frac{dv}{dl}$ is the kinetic energy component,
- θ is the angle formed between the flow pipe and the horizontal position of the treatment facilities.

The energy loss due to friction can be written in the forms proposed by Fanning and Weisbach [4, 5]:

$$F = 4f\frac{\Delta h v^2}{2dg} \tag{7}$$

$$F = \lambda\frac{\Delta h v^2}{2dg} \tag{8}$$

In relations 7 and 8 the terms f and λ are defined as dimensionless friction factors and can be determined with the relation $\lambda=4f$.

Considering that the extraction pipes are vertical $\theta=90^o$, so $dl=dh$, the equation of the pressure gradient when flowing through the wells can also be written in the form:

$$\frac{dp}{dh} = \rho g + \frac{4f\ \rho\ v^2}{2d} + \frac{\rho v\ dv}{dl} \tag{9}$$

THE RISE OF THE LIQUID PHASE

In some cases, the pressure at all points in the extraction pipes is higher than the gas saturation pressure of the liquid phase and in this case only one phase flows through the pipes, the rise being due to the potential energy [5, 6].

The equation of the liquid influx entering from the porous medium into the well has the form:

$$Q = K(p_c - p_f)^n \tag{10}$$

In this case we can write the pressure equation as:

$$p_f = \gamma H + p_{fr} + p_2 \tag{11}$$

Where:

$$p_{fr} = \lambda \frac{H}{d} \frac{v^2}{2g} \gamma \tag{12}$$

$$v = \frac{4Q}{\pi d^2} \tag{13}$$

Relation 11 can also be written in the form:

$$p_2 = p_c - \sqrt[n]{\frac{Q}{K}} - \gamma H - \gamma \frac{81 \cdot 10^{-2} Q^2 H \gamma}{d^5} \tag{14}$$

Where p_2 is the value of the dynamic pressure before the nozzle (pressure required to obtain a programmed flow rate Q).

In the case of stopping the probe (Q=0), until the pressure in front of the p_2', nozzle stabilizes, we obtain:

$$p_c = p_2' + \gamma H \tag{15}$$

And so the pressure in the p_c layer is also obtained.

In the relations above we have:

- p_c, p_f și p_2 and p_2 are the pressure in the layer, the pressure at the level of the perforations respectively the pressure in front of the nozzle, N/m^2,
- H is the depth to the level of the perforations,
- γ represents the specific gravity of the liquid N/m^3,
- Q is the liquid flow rate, m^3/s,
- v represents the displacement speed of the liquid, m/s.

MATERIALS AND METHODS

Artificial intelligence is increasingly used in the oil industry, and that is why we also analyzed how to apply it in the study of the flow of petroleum fluids through pipelines.

In principle, the role of the algorithm used in this paper consists of:

a. Creation of equations to determine flow time limits,
b. Determination of flow parameters *x* and *y*,
c. Determination of the flow type according to figure 2,
d. Determination of the relative error and the absolute deviation of the data obtained from the actual data.

The type of flow, according to the model created in this thesis, is determined using the sliding speeds of gases U_{sg} (x) and that of liquids U_{sl} (y).

a. The first flow structure is of the bubble flow type and starts from the minimum values: y=0,01, x= 0,01, Also, the maximum value of this type of flow is given by the points:

y=1, x= 0,01,

y=0,9, x=0,8.

This type of flow is also delimited by the following equations:

- compared to the slug flow type, the equation is:

$y = -2,8931x^2 + 3,7507x - 0,2322$, where $R^2 = 0,9996$,

- compared to the structure of the annular fog type (Finely dispersed bubbly flow), the equation is:

$y = -2040,5x^5 + 1943,3x^4 - 542,87x^3 + 45,015x^2 - 2,6151x + 1,021$, where $R^2=0,9977$.

b. The type of elongated bubble flow (slug flow) is comprised between:

Minimum values:

x=0,065 and y= 0,01.

And the maximum values:

x=5 and y=0,01,

x=1,5 and y=2,2.

Also this type of flow is delimited by the equation:

$y = 5E+10x^6 - 2E+10x^5 + 5E+09x^4 - 5E+08x^3 + 3E+07x^2 - 790981x + 9949,6$ where $R^2=1$, compared to the structure of dispersed bubbles (bubbly flow),

by the equation:

$y = 23,432x^4 - 20,285x^3 - 24,968x^2 + 24,831x - 1,9094$ where $R^2=1$, compared to the annular fog type structure (Finely dispersed bubbly flow),

and by the equation:

$y = -2,4831x^5 + 43,926x^4 - 301,28x^3 + 996,02x^2 - 1579,8x + 964,44$ where $R^2=1$ against the type of flow in waves (Churn flow).

c. The fine dispersed bubbly flow type is delimited by the numerical values of the sliding speed of gases x and liquids y (the sliding speeds of gases Usg (x) and that of liquids Usl (y)):

Minimum values:

x=0,01, y=1.

Maximum values:

x=0,01, y=20,

x=8, y=20,

x=0,89 y=0,9.

The domain is also delimited by the equations:

$y = -2040,5x^5 + 1943,3x^4 - 542,87x^3 + 45,015x^2 - 2,6151x + 1,021$, where $R^2=0.9977$, against the type of flow, dispersed bubbles (Bubble flow),

$y = -1,4545x^2 + 5,7636x – 3,2091$ where $R^2=1$, compared to the type of flow, elongated bubbles (Slug flow),

$y = -0,4583x^3 + 6,5x^2 – 25,542x + 37,5$ where $R^2=1$, against the type of flow in waves (Churn flow).

d. Churn flow is defined by:

x= 5, y=0,01,

x=2, y=0,5,

x=9, y=20,

x=20, y=20,

x=20, y=0,01.

And the equations:

$y = -2,4831x^5 + 43,926x^4 - 301,28x^3 + 996,02x^2 - 1579,8x + 964,44$ where $R^2=1$, compared to Slug flow type,

$y = -0,4583x^3 + 6,5x^2 - 25,542x + 37,5$ where $R^2=1$, against the type of flow, ring fog (Finely dispersed bubbly flow),

and by the line given by the values:

x=20, y=0,01,

x=20, y=1,

x=20, y=20,

compared to the plug flow type (Annular flow).

e. The plug-type flow (Annular flow) is delimited by the line constructed with the values:

x=20, y=0,01,

x=20, y=1,

x=20, y=20,

f. Against the type of flow type in waves (Churn flow) and the maximum values:

x=80, y=0,01,

x=80, y=20.

Starting from the diagram made by Baker (figure 3) for determining the type of flow through horizontal pipes (extraction pipes), a software was created that provides based on the fluid flow (liquid and gas) flowing through the pipe, the density of the two phases, of the dynamic viscosity of the liquid phase, of the internal diameter and of the surface tension of the liquid phase, the possibility to define the terms X and Y.

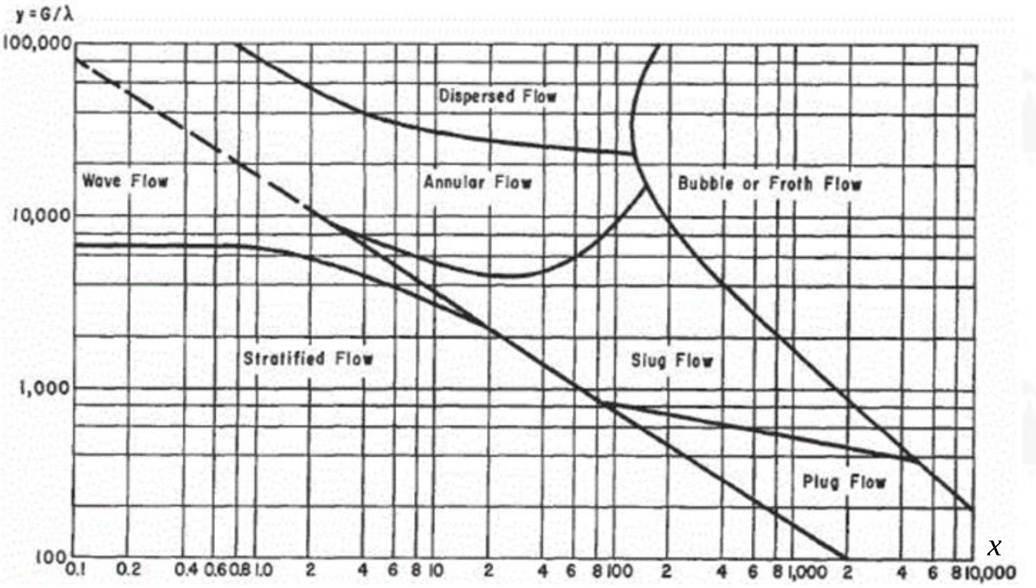

Figure 3*. Baker's diagram for determining the type of two-phase flow in extraction pipes* [6]

Where:

$$X = W_m * \psi * \lambda / G \tag{16}$$

$$Y = G/\lambda \tag{17}$$

$$\lambda = \left(\frac{\rho_g}{0{,}075} \cdot \frac{\rho_l}{62{,}3}\right)^{0{,}5} \tag{18}$$

$$\psi = \frac{73}{\gamma}\left(\mu_l\left(\frac{62{,}3}{\rho_l}\right)^2\right)^{1/3} \tag{19}$$

- W_m is the wellbore liquid flow rate (lb/hr ft^2),
- G is the wellbore gas flow rate (lb/hr ft2),
- ρ_l is the density of the liquid phase in the well (lb/ft^3),
- ρ_g is the density of the gas phase in the well (lb/ft^3),
- μ_l represents the viscosity of the liquid phase, cP,
- μ_g represents the viscosity of the gas phase, cP,
- γ is the surface tension of the liquid in the well, dynes/cm.

CONCLUSIONS

The results of running our chosen model and the AI-created model to determine the flow type concluded that they have a maximum error of 1% (on a set of over 1000 data collected over 3 months from 5 extraction wells gases with condensates).

Also in the article, the types of crude oil flow through vertical pipelines were discussed, the energy balance necessary to ensure a constant flow of natural gas was analyzed, and it was compared with models prescribed by us. It is noted that the errors are at most 2% (on a set of over 1000 data collected over 3 months from 5 gas condensate extraction wells).

REFERENCES

[1] Brown, E.K., Lea F.J., Nodal Systems Analysis of Oil and Gas Wells, Journal of Petroleum Technology, October. 1985

[2] Damascan A., Albulescu M., Chis T., The Mathematical Modeling of the Flow Variation of Natural Gas Extraction Wells Depending on the Diameter of the Mixing Pipe, Engineering and Technology Journal. Vol. 7, Iss. 9, pp. 1477-1482, 2022

[3] Damascan, A.C., Albulescu, M., Stoianovici, D., The Influence of the Perforation Density and Damaged Zone Permeability on a Gas Well Production, Romanian Journal of Petroleum & Gas Technology, vol. 3, iss.2, 65-76, 2022.

[4] Multiphase Flow Pressure Gradient, http://multifasico.usuarios.rdc.puc-rio.br/MF-Brill_Multiphase-Flow-Wells.pdf

[5] Brandstaetter, W., Ragab A., Shalaby S., Modeling of Two-Phase Flow, and Slug Flow Characteristics in Horizontal/Inclined Pipelines using CFD, 150 Years of Petroleum Industry: Tradition & Challenges, 14-17 October, Bucharest, Romania SPE Romanian Section Conference, 2007

[6] Baker, O., Multiphase Flow in Pipe Lines, Oil and Gas Journal, Nov.10, 1958, 59, 156

Received: December 2023; Accepted: December 2023; Published: December 2023