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ADVANCES IN UNDERSTANDING AND CONTROLLING LIQUID LOADING IN GAS-CONDENSATE PRODUCTION WELL

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ABSTRACT

Gas-condensate production wells frequently encounter retrograde condensation as a result of significant pressure and temperature changes during production, which disrupts mass conservation, alters fluid composition, and changes flow regimes along the wellbore and production tubing with depth. This phenomenon can lead to liquid accumulation, resulting in reduced gas flow rates at the bottomhole zone and unstable well operation. The transition from annular to slug flow regimes typically marks the onset of liquid loading, which poses risks to well integrity and may ultimately lead to production failure. This paper reviews the conventional understanding of well liquid loading and explores various deliquification techniques used to mitigate its impact. Based on detailed analysis, introduces a novel pipe element and an automated control system designed to maintain stable production in gas-condensate wells. The pipe element helps sustain constant mass flow through the production tubing and effectively prevents liquid loading. Laboratory testing of this element demonstrated a 20–40 % improvement in production stability. The automated control system enables real-time synchronization between the choke valve and the pressure differential between the wellhead and bottomhole, ensuring optimal gas flow rates. It functions by continuously monitoring changes in wellhead and downhole pressures, comparing them to predefined optimal values, and adjusting flow conditions accordingly. Overall, this integrated control approach has shown promising results in simulation scenarios and offers a practical solution for improving production efficiency and operational reliability in gas-condensate wells. The presented research advances scientific and theoretical understanding of the fluid loading process in gas-condensate production wells and introduces practical, more easily applicable technologies aimed at ensuring smooth well operation within normal operating limits.

Keywords: gas-condensate reservoir; retrograde condensation; liquid loading; vertical flow regimes; automatic control system.

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1. Introduction

In gas-condensate wells, retrograde condensation can occur even when reservoir pressure remains above the retrograde condensation threshold. This phenomenon leads to a violation of the mass conservation condition, where $M(h) \neq \text{constant}$ with M representing the mass of the flowing fluid at a given cross-section of the production tubing, and h denoting the well depth [1-5]. When retrograde condensation occurs, the composition of the fluid and flow regime change with depth (h) as fluid moves upward within the well. During the initial phase of gas extraction, especially when gas flow rate is high, gas travels at the pipe's centre, carrying the liquid phase as well. Since, the most of the liquid forms a thin film along the inner wall of the pipe, this is transported through pipe wall representing annular flow, while some of the condensate present as a discontinuous phase in gas [6-8]. As the condensate ratio increases in the production tubing, the gas phase becomes inadequate in lifting liquid out of the well, leading to liquid accumulation at the bottomhole. Consequently, this accumulation raises backpressure on the formation and reduces the effective gas permeability due to increased liquid saturation in the reservoir section [7, 8]. At this stage, a transition from annular to slug flow is observed as accumulated condensate is intermittently pushed to the surface by increased reservoir pressure, forming a sequence of liquid slugs and gas pockets. This shift in flow regime leads to unstable well operation, characterized by sudden surges in liquid production followed by sharp spikes in gas output. Such behavior is widely recognized as the onset of liquid loading. Following a decline in gas and liquid production or increasing condensate/gas ratio (CGR), the cycle continues until insufficient reservoir pressure can't reach the liquid to the surface, potentially leading to the production of the well stops [1, 9-11]. It is worth noting that, under ideal conditions, maintaining stable well operation with minimal fluctuations in gas flow rate over time helps prevent unplanned outages, reduces equipment wear, and minimizes operational risks.

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There are two main approaches to determine the onset of liquid loading: 1) predictive methods and 2) observation of field symptoms. Transition to the slug flow regime, erratic production below the target decline curve, and an increase in the difference between surface-measured tubing/casing pressures are key field symptoms indicating the onset of liquid loading [12]. While actual field symptoms are generally preferable due to their direct reflection of real conditions, they don't always indicate the happening of the liquid loading because variations in production drop and pulsations in gas condensate wells can occur due to diverse causes. Therefore, it can't be said that wellhead pressure and the CGR are the sole determining parameters. Factors such as salt and wax deposition, as well as sand or water influx into the wellbore, can lead to similar operational issues [13-15]. In other words, liquid loading and flow instability can arise from a variety of causes, all of which must be carefully considered before implementing appropriate corrective measures. To this end, in addition to monitoring wellhead symptoms, a thorough analysis of fluid composition and flow parameters is essential [16].

This research offers practical solutions to a critical challenge in gas-condensate well management while also advancing the broader understanding of gas-condensate production dynamics. A key contribution of the study is the development of a novel automated control system designed to maintain stable well production by synchronizing choke valve operation with real-time wellhead and bottomhole pressure data. This system optimizes gas flow rates, regulates well performance, and prevents condensate accumulation within the wellbore. The proposed control methodology demonstrates strong potential for enhancing both production efficiency and operational stability in gas-condensate wells.

2. Physical and thermodynamic aspects of liquid loading in gas-condensate wells: implications and consequences

2.1. Practical observations and insights into the liquid loading phenomenon in gas-condensate wells

Data from two wells – No. 20 and No. 25 – located in the Bulla-Deniz field, one of Azerbaijan's high-pressure gas-condensate reservoirs, have been analyzed. These wells were brought into operation during the early stages of field development. Figures 1 and 2 present a comparative analysis of the relationship between wellhead pressure and the daily gas-condensate ratio over time (in months) for both wells.

Well number 20 was put into production during the initial period of reservoir exploitation in 1976. At that time, since the reservoir pressure was higher than the retrograde condensation pressure, the single-phase fluid system could be accepted despite laboratory results indicating otherwise [17]. However, the decrease in pressure (from 71 to 27 MPa) and temperature (from 102 to 20 °C) along the production tubing confirmed the occurrence of condensation in the well. As shown in figure 1, the condensate gas ratio varies between 200 and 400 g/m^3, depending on time. However, the initial condensate gas ratio of the reservoir was determined to be 320 g/m^3. This tendency was observed to follow a similar cyclic pattern in the wellhead pressure dynamics during the subsequent period of production. It should be noted that during these years, the well was operated with dual flow lines with the 15 mm and 10 mm choke sizes.

Well No.25 was put into operation relatively later in June 1977, and at that time, the two-phase flow was observed in the wellbore. Therefore, sharper variations in both parameters depicted in fgure 2 were expected to be observed in the well. However, subsequent investigations have shown that this was regulated by the choke valves. Initially, the well was operated with the chokes, sizes 17 mm and 13 mm on the flow lines, and then the diameters of chokes were gradually increased to 18 mm and 14 mm, respectively. Despite these changes, certain synchronous variations were observed in both the condensate gas ratio and wellhead pressures (fig. 2).

In general, studies conducted on several other wells (Nos. 29, 31, 32, and 34) in the Bulla-Deniz field have demonstrated that sufficiently high reservoir and bottomhole pressures contribute to stable and efficient well operation. It was also observed that increasing flow velocity through the choke valves promotes single-phase flow within the wellbore. However, over time, these methods have proven to be less effective, particularly as reservoir depletion progresses. This decline in effectiveness has led to significant operational challenges, including well integrity issues and damage to the downhole zone, production tubing, manifolds, separators, and control and measurement systems [18, 19].

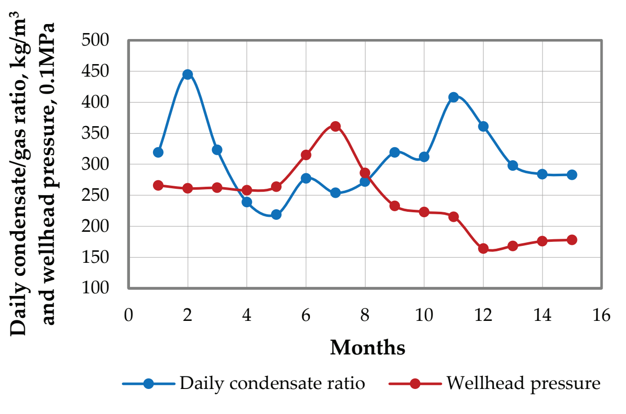


Fig. 1. Change of parameters in the production of Well No. 20 of the «Bulla Deniz» field during the first 15 months

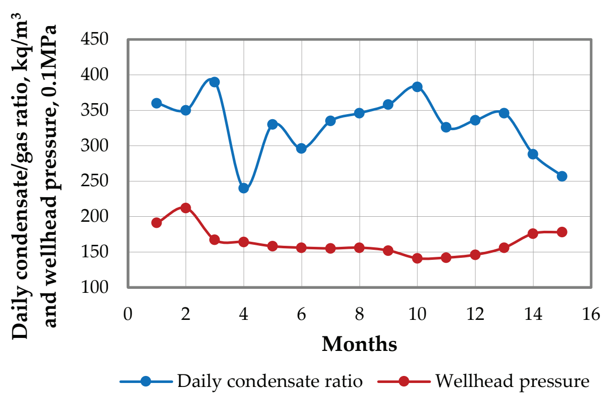


Fig. 2. Change of parameters in the production of Well No. 25 of the «Bulla-Deniz» field during the first 15 months

2.2. The forming mechanism of the liquid loading regime in a gas-condensate well

During production (including additional water content along with hydrocarbon components), an increase in the density of the fluid column can be observed within the well because some amount of liquid remains in the well-production tubing (fig. 3a). That happens due to change in the pressure and temperature of fluid flowing from bottom up to surface that results in liquid drop-out process takes place and well flows in its out of normal condition moves from normal (N) to loaded (L) (fig. 3b). The process is consequently leading to an increase in hydrostatic pressure at the bottom of the well. This pressure change reduces the difference between the reservoir pressure and the bottom hole pressure, resulting in a decrease in the amount of fluid flowing from the reservoir into the well according to Darcy's law [18, 20, 21].

If, during the increase in bottom-hole pressure, the reservoir pressure or any value of pressure above optimal (normal), it leads to the fluid column being expelled from the well, then the volume of the fluid is produced. The well liquid rate increases quite fast and it moves from loaded (L) to normal (N) and then unloaded (U) condition (fig. 3b). Thus, the increase (decrease) in bottom-hole (wellhead) pressure initiates a cyclic pattern [2, 8, 20].

In some cases, when the energy in the reservoir is insufficient, the gas-condensate well loaded with liquid may cease its activity. In such situations, the gas-condensate well can switch to a periodic blow-out regime, which can increase the occurrence of anticipated problems [22, 23].

The phenomenon of liquid loading not only significantly reduces the productivity of the well but also disrupts its safe operating regime due to slug flow. This flow pattern leads to rapid variations in mass distribution and pressure along the wellbore and production tubing, leading to significant vibrations. These vibrations induce transient stresses that can lead to fatigue failure, localized buckling, and even bending or rupture of the tubing. Such fluctuating stresses significantly compromise the safe operation of the well, accelerating tubing corrosion and causing severe damage to the wellbore [20]. Therefore, accurately identifying the onset of liquid loading and implementing targeted mitigation measures are essential not only for maintaining uninterrupted production but also for ensuring the overall safety and efficiency of well operations.

2.3. Flow regimes in a gas condensate well

Based on the above observations, the flow patterns occurring during upward flow in the gas-condensate annulus can be explained as follows. In general terms, figure 3a illustrates the distribution of density, condensate ratio, and flow directions as typically observed in multiphase flow within the well. However, further insights, largely drawn from our previous investigations, are provided below to offer a more detailed understanding of the flow behavior.

During the vertical flow of gas-liquid mixture in the well, the mixture can exhibit various structural forms depending on the composition of the fluid, hydrodynamic parameters of the flow, and the rheological characteristics of the phases. Based on a series of experiments and observations on real systems [21, 24], the following classification of flow patterns in gas-condensate wells can be made in the direction of decreasing pressure and temperature towards the wellhead (fig. 4).

The liquid as a highly dispersed state in a gas phase. In this case, the bottomhole pressure is higher than the retrograde condensation pressure (RCP), and the flow remains in a single-phase state depending on the temperature. This is typically observed in high-pressure gas-condensate reservoirs, and if the pressure at the wellhead is also higher than the RCP at that temperature, the uninterrupted flow of the condensate is ensured.

Small droplets or mist-like state. This state occurs at pressures very close to the RCP value and even encompasses the RCP-1.3×RCP interval [17, 25]. Under such conditions, a single-phase state is maintained for static equilibrium. However, during vertical flow and due to factors arising from the system's rheological properties, the dispersed phase is compressed towards the pipe wall, resulting in an increase in density as the flow approaches the pipe wall. The number of liquid droplets in the unit volume of gas increases on the internal wall of the pipe, leading to an increase in CGR accordingly. As a result, at distances close to the pipe wall and at pressures higher than the RCP, but probable below about 1.3×RCP at temperature of given depth a condensate film is formed (about the condition 2 or transition between 2 and 3 (fig. 4).

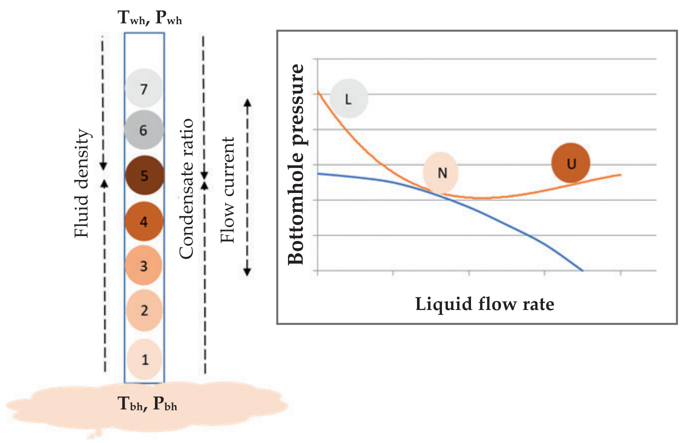
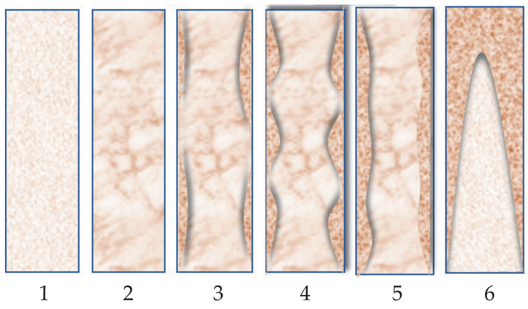


Fig. 3. Liquid loading and unloading cycle in the gas-condensate producer well



1–highly dispersed state (P>RCP),
2–mist-like state (P≥RCP),
3–mist and droplets (P≤RCP),
4–mist and annular-like (P<RCP),
5–annular flow,
6–slug flow

Fig. 4. Flow pattern of gas condensate fluid in the production tubing

Foamy and dispersed or mist-like state. This is a transition from the second state with the reduction of pressure and temperature to an annular or dispersed annular state. The initiation of retrograde condensation in the centre of the flow results in a mist state. Near the pipe wall, a flow of liquid saturated with gas is formed. During such flow, there is a gradual migration of the mist phase towards the centre of the flow.

Annular and annular-dispersed state. In this state, there is a sharp difference in density between the mixture of flowing liquid/gas at the center and the mixture at the periphery of the flow. This leads to annular flow, and as it rises, the velocity difference between the mixtures continues to increase. The higher velocity at the center causes the entrainment of lighter components from the mixture near the walls. Such flow increases the density of the liquid mixture near the pipe wall, gradually transforming the flow into a piston-like or slug flow.

Piston-shaped or slug flow. When such a profiled flow reaches the surface, it causes successive liquid and gas flows to fluctuate with wide amplitude in the wellhead pressure and causes significant instability and formation of hydraulic shocks on the downhole reservoir section, production tubing, wellhead and flow line of the well (fig. 3).

2.4. Liquid loading prediction

Droplet reversal and film reversal are two main mechanisms used to explain ad predict initiation of liquid loading. The droplet reversal mechanism means that liquid loading occurs when the gas velocity is insufficient to lift the largest droplet [1]. Two mathematical models by [26], were proposed to explain the process. The first model considered condensate flow as tape-like liquid particles in a gas medium but proved flawed. The second droplet reversal model considers condensate droplet precipitation in the gas environment, where droplet density and diameter play critical roles. It's assumed condensate accumulates in the well when droplet velocity is slower than gas velocity. Researchers proposed a formula to determine the critical gas velocity when the largest droplet starts to flow downward [3]. However, field practise shows that gas wells are not loaded with liquid though actual flow rate is lower than the prediction of Turner's model even with 20 percent adjustment [27, 28]. This inaccuracy is explained by two factors: the use of a solid spherical model rather than an oscillating droplet model, and the testing of the Weber number in air instead of within the gas well [3, 28]. [7] suggested that Turner's model can effectively predict the critical flow rate for low-pressure gas wells with wellhead pressures below 3.448 MPa (500 psi), and this prediction holds true without the need for the 20% upward adjustment. [29] argued that Turner and Coleman's models overlooked the deformation of liquid droplets in a gas medium, highlighting how high-velocity gas streams cause pressure imbalances, leading to droplet shape alteration from spherical to flat, which affects their efficiency in being lifted to the surface. Despite the widespread use of Turner's and Coleman's models in American gas fields, Li's models are commonly employed in gas fields across China [27]. [18] proposed a new approach based on the Turner model and accepted the kinetic energy of the gas environment as the main parameter. They developed a model that allows determining the minimum value of the kinetic energy to ensure the flow of gas, oil, water, and solid particles in the form of smoke or dust. During experimental tests, the Guo method was found to be more conservative and accurate, leading to its expanded application even considering the bottom-hole condition of the gas wells [3, 30]. For example, during the drilling process, the minimum kinetic energy equation of the gas environment has been successfully utilized to remove solid particles to the surface. However, this method didn't consider time, accumulation and kinetic terms [8].

However, in recent years, many investigators have questioned the droplet reversal mechanism's validity suggesting that liquid loading occurs under film reversal conditions due to the downflow of the liquid film instead of droplet reversal. A new film reversal model was introduced by [5] using stability analysis to predict the change of the flow regime from annular to intermittent flow. [19] derived the critical velocity for the transition from slug to annular flow by constructing momentum and continuity equations for slug flow, considering the entire liquid-film region as the control volume and incorporating closure relationships such as interfacial-friction factor and liquid entrainment in the gas core. Later, Barnea's model was modified multiple times by many authors to improve its capability in vertical and inclined pipes. [31] presented a figure comparing transition boundaries from different models, showing Turner's model with the lowest critical velocity, Barnea's model with the most conservative results, and Zhang's model falling in between, revealing significant differences in critical velocities between droplet and film models, with Barnea's velocity potentially twice that of Turner et al. It's important to emphasize that film reversal is a transient process that occurs as gas velocity decreases. This reversal process involves complex flow behavior, including changes in the direction of the liquid phase and chaotic interfacial structures on the liquid film. Thus, understanding the physical phenomena during this reversal process and investigating its evolutionary characteristics are crucial.

Despite ongoing efforts, many models are based on assumptions that do not fully reflect actual field conditions, thereby limiting their practical applicability. Additionally, the complicated nature of multiphase flow in gas-condensate wells, compounded by pressure and temperature variations along the well, poses challenges in developing a universally validated prediction model for liquid loading. In general, as indicated by previous research [3], accurately determining liquid loading is not always straightforward, and thus a thorough analysis of well data is essential. While developing the new Automated Controlling Method, we relied on this established approach [3], but also ensured the reliability of liquid loading prediction by carefully collecting and analysing relevant data.

3. Advantages and disadvantages of conventional techniques for managing the liquid loading process

Each of the mentioned models relies on a certain scientific basis and proposes minimum requirements for the transportation of fluid during gas-liquid flow. It is known that to prevent liquid loading in the well, the fundamental condition can be expressed simply as follows [16].

$$\nu_{gas}=\nu_{l.d}+\nu_{l.s} \tag{1}$$

where: ν_{gas} – velocity of the gas environment; $\nu_{l.d}$ – velocity of the liquid droplet (upward); $v_{l.s}$ – settling velocity of the liquid droplet relative to the gas environment.

As seen from statement (1), although increasing the velocity of gas can be one of the ways to solve the problem, but it is not always possible. Factors such as the reservoir energy, the fluid and gas lifting capacity of the well, the required pressure for surface processes, and the maximum allowable bottom-hole pressure limit the possibilities. However, additional measures can be taken to reduce the settling velocity of the droplets or to bring the droplet lifting velocity to match the velocity of the flowing fluid.

Parameters that can be controlled to prevent the accumulation of condensate in the reservoir have been proposed under the influence of Archimedes, weight, and Stokes forces for the settling velocity of the condensate droplets, with the condition of $v_{l.s}=0$. A similar approach, considering statement (1), can also be applied during the upward flow in the tubing. Therefore, measures such as increasing the viscosity of the gas phase and reducing both the density and diameter of liquid droplets, through enhanced dispersion techniques, can contribute to achieving a continuous and stable fluid flow. Overall, it is important to emphasize that any method applied to enhance oil and gas production or to optimize well performance should be straightforward, energy-efficient, and cost-effective to ensure its practical value.

3.1. Application of the gas lift method

Gas lift enhances gas well production by injecting gas into the tubing, reducing fluid density, lowering the condensate-gas ratio (CGR), and increasing flow velocity above the critical threshold [31-33]. The lift gas is typically sourced from the reservoir's produced gas, with CO_2 additions improving condensate dissolution [4, 34]. Gas lift can be continuous or intermittent, with intermittent lift being more economical for wells with liquid loading and low gas production. It is especially suitable for wells with high gas-to-liquid ratios deviated or horizontal wells, and those with sand production issues [12, 35]. Gas lift can be combined with other methods, such as plunger lift or surfactant injection, to improve efficiency [36]. However, it can be costlier and less efficient than rod pumping, depending on compressor size, and requires complex surface infrastructure, making its implementation viable only when gas supply and economic feasibility are ensured [34, 36].

3.2. Application of chemical reagents

Foaming uses surfactants to create bubbles, reducing surface tension, liquid density, and critical velocity, thereby aiding liquid removal in gas-condensate wells [35]. This method is cost-effective, easy to apply, requires minimal downhole modifications, and has shown positive results in many gas wells. Foam composition includes surfactants, stabilizers, and additives tailored to specific well conditions [23]. It is particularly effective in wells with high water cut and moderate gas-liquid ratio (GLR) making it ideal for offshore applications and low-loading horizontal wells [36]. However, foaming techniques are generally unsuitable in conditions with high condensate concentrations, elevated condensate-to-water ratios, high gas-to-liquid flow rates, or under slug flow regimes, where their efficiency significantly declines due to increased frictional pressure losses [37]. Furthermore, the application of gas-condensate foaming introduces operational challenges in separation facilities. Currently many on-going researches aim to optimize its implementation and mitigate these limitations [3, 38].

3.3. Application of plunger lift

The plunger lift system addresses liquid loading in gas-condensate wells by employing a traveling metal plunger to lift accumulated liquids while minimizing liquid fallback. The process involves intermittent well shut-ins to allow pressure buildup, followed by the release of high-pressure gas that drives the plunger upward [31, 34]. [22] reported increased production in 19 wells after installing plunger lift systems in abandoned gas-condensate wells. This method is cost-effective, requiring no external power, and is ideal for wells with large tubing diameters, high liquid accumulation, and a need for automation [36, 37]. Despite its advantages, plunger lift can experience downtime, leading to revenue loss, and becomes ineffective when reservoir pressure drops too low. It also faces challenges in deviated or horizontal wells [36].

3.4. Application of production pumps

Sucker rod pumps (SRPs) and electric submersible pumps (ESPs) are effective for deliquifying gas-condensate wells, each with unique advantages and limitations. SRPs lift accumulated condensate through the production tubing while gas flows through the annulus [35]. As SRPs are independent of gas velocity, they are well-suited for low-pressure wells where other methods fail [36]. However, SRPs (sucker rod pumps) entail high initial and maintenance costs, depend on external energy sources, and are susceptible to gas locking, necessitating careful design and operational optimization [12]. ESPs, designed primarily for liquid applications, must be carefully configured to prevent gas interference, which reduces pump efficiency and may cause damage. [39] found electric submersible centrifugal pumps (ESCPs) most effective in mitigating liquid loading in low-pressure gas-condensate wells. ESP performance depends on factors such as liquid level, gas-oil ratio (GOR) transitions, surface equipment availability, and robust design to ensure economic viability [37].

4. Recommended technologies for managing liquid loading in producing wells

As mentioned in the introduction, this paper recommends two new technologies developed based on conventional methods discussed earlier. Both technologies offer advantages by minimizing the need for external energy sources, optimizing production rates, and ensuring smooth well operations, including reservoir management.

4.1. Application of specialized pipe design

During the research conducted in collaboration with the authors [17, 19], the colloidal properties of the gas-condensate system have been investigated and it has been determined that at pressures higher than the retrograde condensation pressure, work done against the molecular forces of the fluid leads to the dispersion of small fluid droplets by the dissolution of gas components in the condensate. The maximum volume of the fluid droplets remaining in suspension is achieved through Brownian motion. The subsequent increase in pressure, under isothermal conditions, causes further agitation and fragmentation of the fluid droplets, resulting in a stronger sustainable, dispersed system. Therefore, these studies have established the gas-condensate system as a highly dispersed system at pressures higher than the retrograde condensation pressure. It can be concluded from this that it is possible to control the monophasic state of the gas condensate system by utilizing the mechanism of obtaining dispersed systems. This can be achieved by dispersing the fluid or solid particles in the dispersed medium, bringing them to Brownian motion, or by condensing the substance in the dispersed environment that is in a vapour state, thus transitioning it to a dispersed phase.

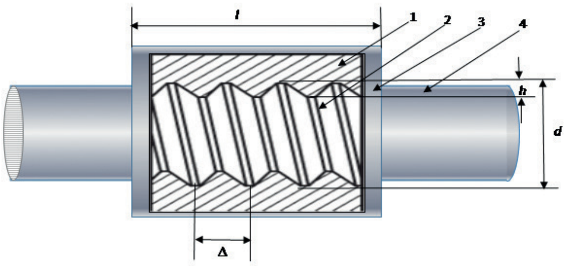
According to the general principles of colloid physics, it is also possible to create dispersed systems by mechanically agitating and dividing into tiny particles the dispersed phase (fluid or solid particles). By utilizing this principle and the dispersibility properties of gas-condensate systems, during the transportation of gas-condensate systems in pipeline networks, [40] successfully employed a specially designed pipe construction in the inclined sections of the pipeline (especially in conditions with seabed relief) to disperse the accumulated fluid mass through turbulent flow, enabling its entrainment in the gas flow. Based on this principle, a specialized pipe design that can be integrated into the production tubing has been proposed. This pipe element is illustrated in figure 5. The design incorporates a screw-like structure defined by the parameters l (length), Δ, d, and h, which allow for optimization of the element's shape and functionality.

The working principle of the proposed pipe element lies in its inwardly directed, spiral-shaped channel, which induces rotational motion in the fluid. This motion transforms the annular flow regime into a dispersed flow, promoting a more uniform flow profile and enhancing mass transfer efficiency (fig. 5). Therefore, the main objective of the proposed construction is to fulfil the conditions (2).

$$\frac{dM}{dh}=0,\quad \frac{dn_i}{dh}=0,\quad \frac{de}{dh}=0,\quad e=\frac{d_e}{d}=1 \qquad (2)$$

where: n_i – the molar quantity of the desired, i component of the mixture at any cross-section of the flow; e – a parameter indicating the ratio of the live cross-sectional diameter (d_e) of the flow to the actual internal diameter (d) of the pipe, characterizing the efficiency of the flow.

As mentioned above, the same laboratory setup and construction described in our previous work [40] was used in this study. However, in this case, the flow pipe, with an internal diameter of d_{pl}=0.032 m and a length of L=3m, was positioned vertically to simulate a section of production tubing. Initially, slugging or liquid loading conditions were created within the vertical pipe using hydrocarbon condensate (density: 776.71 kg/m³) and dry natural gas. Flow rate and pressure readings were measured, along with parameters characterizing fluctuations such as frequency, amplitude, and wave period, all under isothermal conditions. Once liquid loading cycles were stabilized or confirmed through consistent parameter behavior, the flow was redirected to a second vertical pipe containing the proposed flow centrifuge element. Measurements were again collected for detailed analysis. This process was repeated to determine the optimal dimensions for the proposed pipe element. The following optimal values were identified for the structural parameters: $d\approx(1.5–2.0)\ d_{pl}$; $l\approx(3–5)\times10^{-3}\ L$; and $\Delta\approx d$.



1 – flow centrifuge
2 – screw-like cutting with parameters Δ, d, h
3 – coupling for connection
4 – pipeline

Fig. 5. Flow centrifuge, pipe construction

As a result of the conducted experimental research in the proposed experimental setup, during the vertical flow of gas and liquid mixture in the form of a liquid slug, simultaneous reduction of pressure differentials between the lower and upper points of the well by 20-40 % depending on time and homogenization of the flow have been achieved.

4.2. Description of a new automated controlling method

By adjusting the production parameters of a gas-condensate well, the gas flow rate – which is influenced by the velocity and kinetic energy of the gas phase can be effectively controlled. In such cases, regulating the wellhead pressure or bottomhole pressure using a choke valve installed at the wellhead or along the flowline is considered a more practical and efficient approach. Reducing the diameter of the production tubing or using a special restriction adapter [24] in the lift system is also included into these technologies. With this approach, it is possible to control gas flow rate and its kinetic energy by utilizing wellhead choke valve. It should be noted that changing the working parameters is more beneficial in wells with relatively high reservoir pressure in preventing liquid loading (during the initial exploitation stage of the reservoir). However, in wells with low reservoir pressure, this method leads to loss in productivity.

In this research, we developed a specialized program in collaboration with fellow researchers to enhance the proposed method by enabling automatic synchronization between the choke valve and the wellhead (or bottomhole) pressure. In other words, an automatic control system was implemented to regulate well operation, with the primary objective of preventing condensate accumulation in the wellbore and production tubing.

In this case, the difference in pressure between the wellhead pressure (P_{wh}) and the bottomhole pressure (P_{bh}) is considered as the leading parameter (ΔP). This pressure differential provides a more accurate basis for estimating the remaining volume of condensate within the well. As mentioned above when the volume of condensate increases in the production tubing, it increases the hydrostatic pressure exerted by the fluid and makes it more difficult to lift the mixture to the wellhead. To facilitate the operation of the well, it is necessary to reduce the pressure at the wellhead and increase the flow rate. This can be achieved through the installation of an automatic regulator, controlling choke position in the wellhead.

However, when the well is unloaded, the bottom hole pressure (P_{bh}) decreases again, and this decrease, if it exceeds the allowable limit, can lead to damaging wellbore and well string equipment in the well. Therefore, as the value of hydrostatic pressure (ΔP) decreases (i.e., as more fluid is released from the well), the well should automatically return to its previous operating regime and should not exceed the nominal value of the bottom hole pressure.

The methodology for implementing the aforementioned principles, along with the operating mechanism of the control system developed for this purpose, is illustrated in figure 6. The control unit continuously monitors changes in both bottomhole pressure and wellhead pressure to regulate system performance accordingly. The difference in pressure between the optimal bottomhole pressure and wellhead pressure, $\Delta P\ Un$ – nominal, is predetermined and provided to the system. Accordingly, a potentiometer is installed and connected to the «ADC» channel of the microcontroller's analogue-to-digital converter. In the next step, as the specific gravity of the fluid in the well varies (increases or decreases from the nominal value), this difference changes, and the value of Ur is obtained.

$$M = Ur - Un \quad \text{or} \quad G = 100\frac{M}{Un} \tag{3}$$

where, M – variation from the nominal value, G – Percentage of increase or decrease.

Once these parameters are determined, an electrical device corresponding to the opening (closing) percentage of the K-controller is energized. The «Holl» sensor installed in the electrical device records the number of cycles and sends a «STOP» command to the electrical device when necessary, cutting off the power. In this case, the minimum allowable limit for the bottomhole pressure and samples taken from the wellbore, which are affected by various factors such as sand, water flow, sediments, etc., are controlled to prevent excessive weight in the production tubing. The selection of the M factor for controlling the wellbore operation should not have a negative impact on the operation of technological blocks such as separators, gas treatment system etc. After implementing these necessary measures, the operation of the control block should be adjusted accordingly.

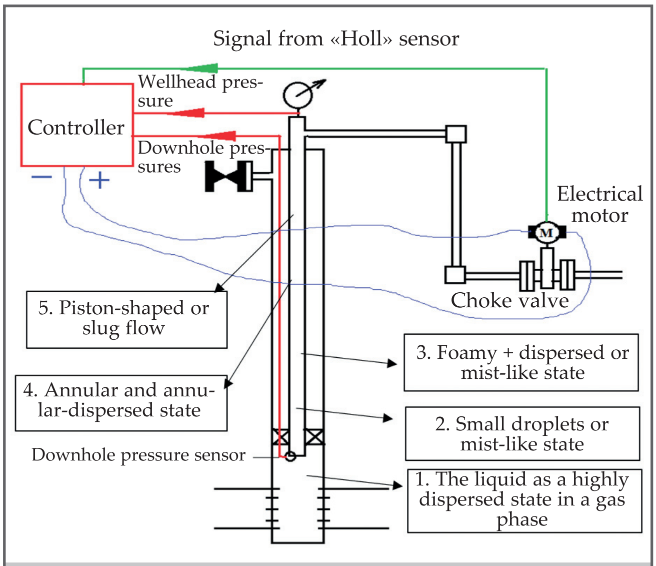


Fig. 6. Schematic representation of wellhead controller and possible flow regimes in a gas condensate well

«C++» programming language was used to write the algorithm for the system on an AVR type microcontroller (specifically Atmega128) and simulated using the PROTEUS program (fig. 7). Figure 7 illustrates the impulses transmitted by the «Holl» sensor, the «STOP» mode, and simulation parameters displayed on the screen. Here, as a control condition, the regulation in the wellbore and production tubing is adjusted in accordance with the rising percentage of the hydrostatic pressure (K=G, q=K-1).

Successful results were confirmed through tests conduct-

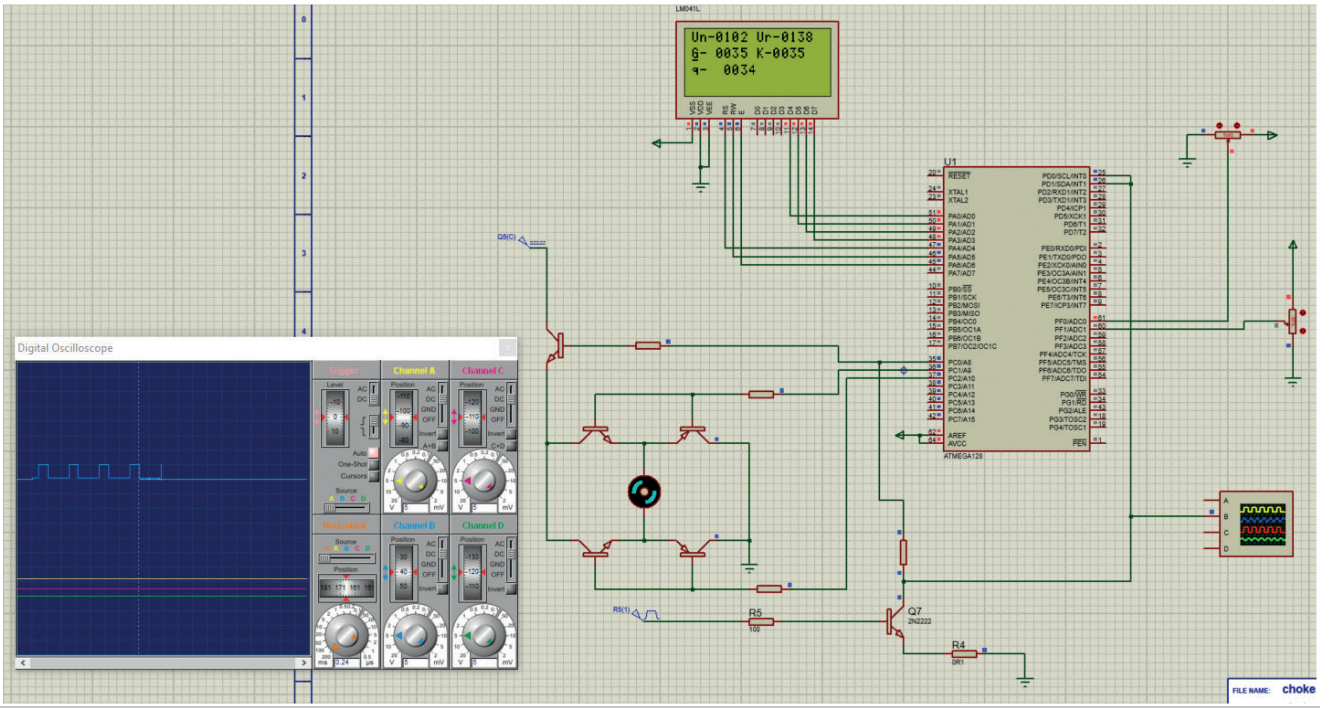


Fig. 7. Schematic representation of the simulation of automatic control of gas condensate well operation

ed under various simulation scenarios. One key challenge is the high cost and impracticality of installing gauges to directly measure bottomhole pressure. To address this, it has been proposed to use regression equations developed by Z. Y. Abbasov [24] to estimate bottomhole pressure in gas-condensate producing well.

Conclusions

1. This study explains the nature of liquid loading issues in gas-condensate well operations based on both theoretical principles and practical experience. The mechanism of liquid loading is described in a structured manner, taking into account phase behavior changes within the wellbore and production string due to pressure and temperature variations. Particular emphasis is placed on the aerosol-dispersion characteristics of multiphase flow in the well production tubing.
2. Various methods for controlling or preventing liquid loading are reviewed, with a detailed discussion of their respective advantages and limitations. Building on the principles of mass conservation and gas-condensate dispersion mechanisms, a novel pipe element design has been proposed. This specialized pipe promotes phase spinning and mixing within the production tubing, thereby creating mechanical dispersion conditions that enhance mass flow stability. Laboratory tests demonstrated that the implementation of this pipe design resulted in a 30–40 % improvement in efficiency.
3. Both theoretical analysis and practical observations confirmed that the pressure differential between the bottomhole and wellhead is a critical parameter, as it allows for more accurate estimation of the remaining condensate volume in the well. Building on this insight, an Automated Control System was developed to continuously monitor this differential and dynamically adjust operating conditions – specifically by regulating the choke valve position in real time. This approach ensures the well remains free of liquid loading and operates within optimal performance limits. The system's effectiveness was validated through a range of simulation scenarios.

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