Hydrodynamics of three phase flow in upstream pipes

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Abstract: In this article, work done by several researchers with respect to predictive models, three phase flow regimes and methods of identifying flow regimes were reviewed. Additionally, effects of water cut and fluid velocities on pressure drop, liquid holdup and flow regimes were also discussed. The three phases under investigation by the researchers were gas, oil and water flowing through horizontal, vertical or inclined pipes. The models reviewed were developed to anticipate liquid phase heights and pressure drop. The multi-fluid and drift-flux methods that can be applied to model the flow, were reviewed. The two main categories for the flow regimes identified were the oil-based and water-based flow patterns, where the water-based flow patterns would occur upon phase inversion. Conductance, algorithm and network mapping methods of identifying flow patterns were also reviewed. Additionally, it was seen that pressure gradients increased with superficial gas and liquid velocities and water cut had varying impacts on flow pattern transitions. Work done on the effects of temperature and pipe diameter were briefly explored. Furthermore, measurement of fluid flows, ways to measure flows and methods to detect the type of flow and simulate them were briefly investigated.

Keywords: three phase flow; predictive models; flow regimes; oil-dominated; water-dominated; pressure drop

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Dhurjati Prasad Chakrabarti is specialized in hydrodynamics of flow phenomena. He is presently working as a Senior Lecturer in the Department of Chemical Engineering at The University of the West Indies, St Augustine, Trinidad and Tobago. Past few years he is in this area of research to define different kind of flow phenomena theoretically as well as experimentally. His work on pipe flow, T-junctions are widely known and cited. Simultaneously his contribution to instrumentation for the detection of flow phenomena is well appreciated. Presently his research tries to combine different titles as multiphase flow, reaction engineering, thermodynamics etc. together.

PUBLIC INTEREST STATEMENT
Simultaneous flow of several phases or multiphase flow is commonly experienced in many engineering processes. Simultaneous flow of as many as four phases namely, water, crude oil, gas and sand is not uncommon during oil exploration. Two-phase flow is the simplest case of multiphase flow. There are many common examples of two-phase flows. Fog, smog, rain, clouds, snow, icebergs, quick sands, dust storms and mud occur in nature are some of the examples of simultaneous flow. In industries different variations of multiphase flow or three-phase flow are commonly observed. Among them, the flow of oil, water and air raises a lot of questions about their flow pattern or “how the flow looks” and their effect on flow rate, friction in the path, etc. The current study is aimed to explore these facts in terms of the work done by different researchers in different time frames.
1. Introduction to three phase flow

Taitel, Barnea, and Brill (1995) noted that three phase flow stability research is rare, which is astonishing since it is so vital in the oil and gas industry. To research three phase flow, which is a comparatively untapped area of Transport Phenomena, will definitely be advantageous since this research can lead to plant optimization in the Oil and Gas industry. For example, predicting whether flow will be stable or unstable will be beneficial in the oil industry. This is because unstable flow involves high fluid velocities and, therefore, high pressures. High pressures can result in failure of pipelines. Shi, Cai, and Jepson (1999) explained that oil, if it is the continuous fluid, will lead to the pressure drop inside the pipe being high since the effective viscosity of the combined liquid phase becomes higher. These high pressures can lead to bursting of pipes.

Ghorai, Suri, and Nigam (2005) devised a model to predict hold-up as well as differences in pressure for gas-oil-water stratified flow through a horizontal pipe, which is an important initial step when examining flow stability for the stratified regime, as well as building transition characteristics. They computed the wall shear stress. Additionally, the impact of gas/liquid ratio (GLR) and pipe diameter in relation to pressure gradient and hold-up were studied. Furthermore, oil, specifically its viscosity and non-Newtonian characteristics, were investigated to observe how the hold-up and pressure gradient would be affected. A structural stability analysis was performed to investigate the developed model’s sensitivity. Roscoe (1996) studied liquid holdup by the employment of a pulsed-neutron source.

Multiphase flow is of great significance in the petroleum industry as it happens in many pipe networks in the production and transportation stages of oil and gas recovery. In this paper, various flow regimes such as stratified (smooth and wavy), slug, bubble (dispersed and elongated), as well as annular, that were investigated by other researchers will be reviewed. Crivelaro, Seleghim, and Hervieu (2002) commented that detection of flow regimes automatically, such as via the use of neural networks, is vital in the oil industry. Detection of flow regimes is another method by which unstable flow can be predicted since the transition from one type of flow to another can often be a very good indicator of whether the flow might be heading towards instability. Lin and Hanratty (1987) identified the slug pattern using pressure values.

Water cut and flow regimes are important factors in pipeline failure. Al-Hadhrami, Shaahid, Tunde, and Al-Sarkhi (2014) commented on this. They pointed out that significant corrosion of carbon steel pipelines does not occur at low water cut since the corrosive water would be greatly distributed in the oil. However, at high water cuts and for flow patterns such as stratified flow, water droplets come together and the oil and water phases become divided. The water phase, in horizontal pipes, would flow at the bottom. This corrosive water leads to corrosion of the pipe. Al-Dhahli, Geiger, and van Dijke, (2014) obtained a method of obtaining precise accounts of oil layers in three phase flow. Kee et al. (2015) employed two ways of obtaining images of the flow regimes. One method was to use a video camera and the other was the employ conductivity pins. Liu, Zhong, Li, Liu, and Wang (2014), however, used windows to view the flow patterns.

Hence, researching the pressure gradient and water cut impacts on flow, as well as flow regimes, in horizontal, inclined and vertical pipes is beneficial to the engineering community and process industry. In this paper, a large number of research papers have been reviewed so that the progress in three phase flow in pipes thus far can be seen.

2. Temperature effects

Researchers Gadelha, Neto, Swarnakar, and Barbosa de Lima (2013) studied the effect that temperature has on the thermo-hydrodynamics for the core-annular three phase passing of air, heavy-oil, as well as water, flow through a pipe that was horizontally positioned. They found that when the temperature of the fluids was increased upon entering the pipe, the superficial velocity of the oil was altered because its viscosity changed. Also, due to the reduction of the oil viscosity, the oil at the core increased in height because it was able to flow with less resistance and, thus, less oil accumulated.
at the core. Additionally, they also found that due to the oil and water viscosities both being decreased due to temperature increase, the resistance to flow of these liquids decreased and the pressure drop, therefore, decreased.

3. Diameter of pipe
 Scientists Poesio, Strazza, and Sotgia (2012) investigated gas, oil and water flow through a 50 mm inner diameter pipe in order to shed light on flow through larger diameter pipes. They found their research to be significant since it would aid designing pipelines in Petrochemical industry as they investigated larger sized pipes.

Spedding, Murphy, Donnelly, Benard, and Doherty (2008) investigated oil, water and gas simultaneously sent through horizontally positioned pipes of 0.0259 m, as well as 0.0501 m, in inner diameter. They found that reduction in the pipe diameter led to increased pressure drop once the other flow conditions were unchanged. This can be expected since there would be more resistance to flow through a smaller diameter pipe and, hence, increased pressure drop.

Wegmann, Melke, and Rudolf von Rohr (2007) studied three phase flow regime maps by passing deionised water, air and low viscosity (4.5 × 10\(^{-3}\) Pa s) paraffin oil at a density of 818.5 kg/m\(^3\) and temperature of 20°C concurrently through Schott Duran® glass pipes of 5.6 and 7 mm inner diameters. It was found that a decrease in pipe diameter led to alterations in both flow maps and transition boundaries. The flow patterns were captured via high speed photographs and light was shed on the pipe using laser induced fluorescence with the laser passing through the pipe, more specifically, the axial vertical plane. The water contained uranine which is a luminous dye. The laser stimulated the dye so that each fluid type was able to be identified. They compared their flow maps to those of previous researchers.

4. Use of neural networks
 Wu, Zhou, and Wu (2001) measured sudden differential pressure signals of gas-oil-water flow through a horizontally placed pipe. These signals were denoised using wavelet theory. The vectors for specific flow patterns were obtained from these denoised signals using fractal theory. These vectors were then sent to a neural network so that the network can learn these vectors. Once the network learns these vectors with their known corresponding flow regimes, when unknown vectors were sent to the network, the network will be able to identify the flow pattern (Chakrabarti, Pilgrim, Sastry, & Das, 2010; Shirley, Chakrabarti, & Das, 2012) since the network has been trained to do so. This method of identifying flow regimes has been concluded to be a fast, automatic and highly accurate method of identifying flow patterns.

Roshani, Feghhi, Mahmoudi-Aznaveh, Nazemi, and Adineh-Vand (2014) developed an artificial neural network that would be able to anticipate air, oil and water percentages. MCNP-4C code was used to simulate the values. The results predicted by the artificial neural network agreed well with that produced by the simulation.

Roshani, Nazemi, and Roshani (2016) proposed a new way to categorize flow patterns as well as anticipating volume fractions for the flow of gas, oil and water. They utilized dual energy fan-beam gamma-ray attenuation technique, in addition to artificial neural networks.

5. Approach to measurement of flows
 An electrical capacitance tomography (ECT) sensor using internal electrodes, acting like an ECT and ERT (electrical resistance tomography) dual-modality sensor, was studied by Sun and Yang (2015) in order to quantify gas-oil-water flow for the stratified regime. In this experiment, measuring of current, in collaboration with voltage excitation method, was applied to the ECT and ERT measurements. The proposed strategy was found to have benefits such as easier sensor design. Thorn, Johansen, and Hammer (1999) also investigated tomographic techniques. They found that these techniques would be most advantageous for flow pattern recognition purposes and for purposes of
the computation of phase velocities. If accurate measurements of these are obtained, the error of measurement of three-phase instruments over various operating conditions in the industry could be diminished.

Zhuang et al. (2016) developed a rotating electric field conductance sensor and, using eight electrodes, measured gas, oil, and water flow. Their results show that their method effectively classified flow patterns. They also concluded that MS-WCECP can successfully show flow pattern transitions, as well as serve as a helpful aid for determining nonlinear dynamics of the flows.

Roach and Watt (1997) investigated the effectiveness of the CSIRO multiphase flow meter (MFM) to quantify gas, oil, and water rates in oil well pipelines and found the meter to be successful in finding these rates. The MFM consisted of two gamma-ray transmission gauges, along with pressure and temperature sensors, mounted on a pipeline carrying the three-phase flow of the production stream and is shown in Figure 1. The first gauge was a density gauge that measured the intensity of 662 keV gamma-rays transmitted through the fluids in the pipeline. The second, the dual energy gamma-ray transmission (DUET) gauge, measured transmitted intensities of 59.5 and 662 keV gamma-rays. All flow rates were found from water cut and fluid flow rates. Water cut, the mass or volume ratio of water to liquids, was determined by DUET techniques. The flow rates of each phase were found by integrating measurements of oil-water and gas rates, as well as ratio of water and liquids. When calculating flow rates from these measurements, a correction was applied so that there was consideration for slip in velocity between the liquid and gas.

Li, Kong, and Gao (2011) investigated Independent Component Analysis and employed it to measure the velocity of oil-gas-water flow. Fast Independent Component Analysis was employed to examine conductance signals obtained from the vertical seven-electrode conductance sensor-centred signal acquisition system. They concluded that Independent Component Analysis effectively yielded the gas/liquid phase flow characteristics of three-phase flow. Additionally, they found that combining Independent Component Analysis and Time Delay Estimation provided another way for quantifying flow.

Dang, Zhao, Li, and Yin (2012) concluded that using a conductance sensor to measure gas-oil-water flow was another practical method. However, Li, Gao, Liu, and Xie (2014) found that the energy demodulation algorithm was, also, a practical method to measure the individual fluid velocity of the system.
The usefulness of a capacitance wire mesh sensor to study flow of gas-liquid-liquid was investigated by Da Silva and Hampel (2013) in a laboratory. They passed air, silicone oil and water at static as well as dynamic flow conditions. They found that the sensing device effectively produced illustrations showing how relative permittivity values at the cross section were distributed. The permittivity values characterize the phases present in the mixture, showing the reliability of the sensor for investigating three phase flows.

Luther, Schuster, Leipertz, and Braeuer (2013) studied mass transfer using a quantitative approach. They investigated the compressible multi-phase system of carbon dioxide, ethyl acetate and water at a high pressure of 8.5 MPa and 298 and 310.5 K temperatures. The multi-phase system was produced within a micro capillary. Each mass transfer path was able to be quantified, despite occurring simultaneously between the three phases. This quantification was based experimentally on applying an optical long distance microscopy technique that would supply data about the carbon dioxide volume shrinkage and the oil phase refractive index. These two pieces of data will allow the mass transfer model to be solved while allowing mutual interaction of the involved transfer paths.

Forte, Galindo, and Martin Trusler (2013) noted that by learning about the behaviour of crude oil, carbon dioxide and water, oil recovery can be increased and geological storing of carbon dioxide can be enhanced. They studied a system of carbon dioxide, propane and water at conditions that would allow equilibria of the three phase system and recorded phase equilibrium measurements by utilizing quasi-static-analytical high-pressure apparatus. Phase compositions were attained along four isotherms between a 311 and 353 K temperature range and for maximum pressures of upper critical end points (UCEP) where phases that were high in propane and carbon dioxide became critical. These results were compared with the anticipated results that were predicted by applying statistical associating fluid theory for potentials of variable range (SAFT-VR).

Forte, Galindo, and Martin Trusler (2011) noted that knowing the behaviour of each phase in three phase mixtures of oil-water, as well as carbon dioxide, is necessary in reservoir engineering, particularly for obtaining improved oil yield in addition to geological carbon dioxide storage. As a result, they investigated a mixture of n-decane with water in the presence of carbon dioxide as a sample mixture. New analytical apparatus was produced for the measurement of phase equilibria for high pressure. The highest operating pressure and temperature was 45 MPa and 423 K, respectively. The apparatus is based on the recirculation of two coexisting phases with the use of a two-channel micropump which functioned magnetically. Also, the apparatus relied on the application of gas chromatography. The equipment was verified by comparing it with published data for isothermal vapour-liquid equilibrium (VLE) for the two phase n-decane, along with carbon dioxide, system. New experimental results were attained for the three phase mixture under three phase equilibria conditions. For temperatures between 323 and 413 K, results for the three simultaneous phases were attained on five isotherms for maximum pressures where two of the phases convert to critical. Experimentally derived work was used in addition to theoretical models that were developed for these molecules. The theory was within the SAFT-VR structure and had been used for computation of phase behaviour for three binary subsystems. Modifications were made to the Hudson and McCoubrey combining rules when applying them, where applicable. Experimentally-derived results and theoretical predictions for the three phase mixture were compared. Additionally, an in-depth examination of the three phase system was performed using, as the basis, a contrast with accessible results for each two-phase subsystem. Therefore, the effects on solubility on addition of the third phase were observed.

Al Ghafri, Forte, Maitland, Rodriguez-Henriquez, and Martin Trusler (2014) also investigated the effects of the addition of a third phase. They offered phase equilibrium measurements for the three phase mixture of methane, water and carbon dioxide. The experiments were conducted using a high-pressure quasi-static analytical equipment and quantities were recorded for two phase VLE conditions, three-phase vapour-liquid-liquid equilibrium (VLLE) and four phase vapour-liquid-liquid-hydrate equilibrium.
Then Al Ghafri, Forte, Galindo, Maitland, and Martin Trusler (2015) investigated three phase equilibria of a heptane, water and carbon dioxide system by using a quasi-static analytical equipment with compositional analysis via gas chromatography. The equipment was calibrated by applying an absolute area method. The entire measurement system was verified by comparing it with published data of the heptane and carbon dioxide system. The compositions of the three phases when they were together in equilibrium were measured along five isotherms with temperatures ranging between 323.15 and 413.15 K, as well as pressures ranging from about 2 MPa to the UCEP pressure at which the two non-aqueous phases become critical. The test results were matched up against predicted results derived from SAFT-VR. It was concluded that the theoretical results were similar to the experimentally derived ones.

Da Silva, Schleicher, and Hampel (2007), as well as Al-Hajeri, Wylie, Shaw, and Al-Shamma’a (2009), produced sensors to examine multiphase flow. Da Silva et al. (2007) used a wire mesh sensor that relied on measurements for capacitance. It was possible to employ this type of sensor in measuring transient composition distributions in a flow cross-section. It has the capability to distinguish between fluids of various relative permittivity values in multiphase flow. Da Silva et al. (2007) designed and produced the trial sensor. This trial sensor was made up of 16 wires each that were evenly spaced across the test cross section. The measurements were taken where the wire crossings were located. The trial sensor's time resolution was 625 frames per second. It was found that the sensor and the measurements taken were accurate. For silicone oil-water bubbly flow pattern type of scenario, trials were done to test the wire-mesh sensor. Al-Hajeri et al. (2009) noted that examining flow in a dynamic pipe was a major issue within the oil industry. They also added that to successfully manage the oil field wells, precise line sensors to screen oil, gas and water flow in pipelines would be required. Al-Hajeri et al. (2009) offered a non-intrusive sensor design. It relied on an electromagnetic (EM) waves cavity resonator as well as resonant frequencies shifts.

6. Quantifying gas-oil ratios
Liqiang, Feng, Jianhai, Guoqing, and Hong (2015) investigated a method to calculate gas-oil ratios in the Yingdong oil/gas field in the Qaidam Basin. They found that conventional logging data differentiates between oil and gas layers fairly well because of the impacts of hydrogen index, formation pressure, borehole conditions, shale content and invasion of drilling mud. NMR was found to be very successful at distinguishing oil and gas layers, but it was an expensive method. The star chart of gas components was found to be the most successful way to distinguish between the oil and gas layers.

7. Quantifying fluid hold-up
Kong, Du, Li, and Kong (2013) investigated a method of measuring gas holdup for gas, oil and water flowing through an oil well. The method was based on new type multi-optical fibre sensors data fusion estimation. Using multi-sensor data fusion tools, pre-processing of the original data that was obtained by sensor was done at first. Then, local estimation was performed for each sensor based on time fusion adaptive weight. Global estimation was performed for the sensor using time-space fusion of the weighted average and recursive estimation as the basis.

Figure 2 shows the three phase flow loop set up by Karami, Torres, Pereyra, and Sarica (2015). The flow loop was made up of two parallel 56.4 m long sections containing 6 inch inner diameter pipes. At the end of each section were acrylic visualisation sections which were about 8 m in length. An iris lens system, small-sized camera was placed concentrically inside the pipe so that the flow patterns would be captured. They found that three-phase water hold up predictions of the Tulsa University Fluid Flow Project (TUFFP) unified representation agreed more with experimentally-derived results than transient-multiphase-simulation software predictions. Tulsa University Fluid Flow Projects (2008) report also indicated that the TUFFP gave close results to the experimental data concerning anticipating gas-oil-water flow features.
8. Simulation of three phase flow
Wang, Ma, Sun, Li, and Du (2013) studied gas-oil-water going through a horizontal pipeline for high water cut values by numerical simulation and obtained the resulting phase distribution diagram. They found that when the volume air fraction was increased, the flow regimes went from bubble to laminar flow. Additionally, when the mixture velocity increased, the flow regimes transitioned from laminar to slug. They also noted that volume oil rate and crude oil viscosity do not impact flow regimes significantly.

Pavlidis et al. (2014) noted interface-capturing, as well as compositional procedure, of simulation of multiphase flow. Fully-unstructured meshes were employed. A control volume–finite element combined formulation was applied in order to spatially discretize the equations. Interface-capturing was done by applying high-order exact compressive advection technique. To allow effective and timely time-integration, two-level time stepping was employed. A Petrov–Galerkin method was applied like an implicit large-eddy replication. Juanes and Patzek (2003) devised, also, a stabilized finite element method to model three-phase systems in porous media. The control volume finite element method was, as well, used by Fu, Yang, and Deo (2005). Moortgat, Sun, and Firoozabadi (2011) employed the higher order finite element method in order to simulate three phase flow according to composition.

Ahamadi, Rakotondramiara, and Rakotonindrainy (2014) discussed the models of other authors and compared their models with other literature. They stated that Krogstad et al. (2009) employed the finite element method for flow modelling, while Geiger-Boschung, Matthäi, Niessner, and Helmig (2009) considered the finite element/finite volume approach. Lee, Wolfsteiner, and Tchelepi (2008) implemented the finite volume approach to their modelling. Abreu (2014) devised a gas-oil-water model, but it does not incorporate flow compressibility and solubility of elements in phases. These four approaches were different compared to the method used by Ahamadi et al. (2014) since those three methods do not consider gravity nor solubility of a less dense element in oil whilst implementing the finite volume scheme. Hajibeygi and Jenny (2009) and Lunati and Jenny (2006) both employed the multiscale finite volume methods to simulate their multiphase flow.

Cazarez, Montoya, Vital, and Bannwart (2010) devised a transient, two-fluid, thermal, one-dimensional representation that can be applied to bubbly gas–bubbly oil regimes for gas, heavy oil along with water flowing in a vertical pipe with water as the continuous fluid. This model was made up of energy, mass and momentum conservation equations and was able to successfully anticipate volumetric fraction, pressure, velocity profiles and temperature. To have an accurate representation,
sufficient closure relationships had to be specified and, therefore, virtual mass forces, as well as drag, were considered for gas and oil phases, with particular consideration given to drag force between gas and oil. When this drag has been added to the proposed representation, they concluded that this drag was of equal size to the drag for the oil. They also noted that both drag sizes were smaller compared to the drag for the gas. Additionally, pressure, in addition to gas and oil velocities, had been impacted. Their volume fraction profiles had, also, been impacted. They, as well, found that the numerical stability improved. The predictions made by the devised model predictions agreed with experimental data provided in other literature. Lewis and Pao (2002) used a three-dimensional method to simulate three phase flow.

Zhu, Jin, Gao, Du, and Wang (2012) used conductance signals that were quantified from vertical upward flow of gas, oil and water experiments and applied time frequency modelling, in addition to surrogate data techniques for studying dynamical features for oil in a continuous phase of water when the flow patterns were bubble and slug. They that found the oil-in-water bubble regime formed deterministic motion when superficial gas velocity and oil phase fraction both rose under specific fixed two phase flow rates. Dynamics of the slug regime studied was impacted due to oil phase fraction variations. Dynamics of the slug flow increased in complexity as the superficial gas velocity rose at specific oil-water flow rates. They concluded that the surrogate data technique was a reliable method to characterize dynamic features of these regimes.

Bonizzi and Issa (2003), like Soprano, Da Silva, and Maliska (2012), produced a mathematical model for stratified and slug three-phase horizontal flow of gas-oil-water. Their method, too, relied on transient one-dimensional, two-fluid representation. Gas was one phase, while the two liquids were considered to be another phase. Drift-flux representation was utilised for simulating movement of the two liquids relative to each other. Closure models were used, such as those that relate to phase inversion, slip between the liquids, as well as mixture viscosity. Mixture viscosity was said to change suddenly upon phase inversion. Equations were numerically worked out by applying finite volume method. This developed mathematical model was shown to successfully anticipate if the two liquids created a dispersion of water in continuous oil phase, oil in continuous water phase or stratified regime. Slugging was also successfully anticipated. Their research also indicated the importance of slip between liquid phases when finding slug characteristics for three phase flow.

Oddie et al. (2003) performed experiments where they observed flow regimes for gas, oil and water flows, such as bubble, elongated bubble, churn, slug and stratified, as well as stratified wavy. They compared their results with those predicted by the Petalas and Aziz (2000) model and found that their results agreed well with the predicted ones for the case of flow regimes and holdup.

Wang, Chen, Xu, Wang, and Luo (2015) created gas within water, which was, in turn, within oil, phase multi-cores double emulsions using microfluidic apparatus. They were able to obtain one original stable regime in which these unique emulsion types can be produced with ease. Another investigation objective that was explored was how flow rates affected structure, as well as size, of double emulsions. Additionally, they developed arithmetical representations that would be able to anticipate structure, as well as size, of the double emulsions.

Argüelles-Vivas and Babadagli (2014) found that at low capillary numbers, which is common for oil reservoirs, the viscosity, as well as temperature, does not greatly affect residual oil saturation of processed crude oils.

Corlett (1999) experimentally investigated the appropriateness of applying an ECT system for crude oil, water and gas three phase visualization. The system was tested over various flow conditions and flow patterns. The results proved that, at low water fractions, the ECT system was suitable. At high water fractions, the slug and stratified flow patterns were able to be observed. It was noted that the image reconstruction scheme that was applied played a crucial part in the quality and consistency of the resulting images.
9. Artificial lift
Descamps, Oliemans, Ooms, and Mudde (2007) have performed laboratory experiments to investigate the gas-lift method. Vertical three phase flow was observed carefully when phase inversion occurred. The effect that injected air bubble size has on effectiveness of the gas-lift method, especially when phase inversion occurs, was observed by using various kinds of gas injectors. Additionally, the velocities of the gas and liquid had been altered. Air bubbles had been identified via optical fibre probes. The time-averaged gas volume fraction, pressure and the bubble velocity, as well as size, had been quantified. They found that the phase inversion was related to a sudden rise in the pressure gradient. As the air was injected, the pressure variation for air, oil and water flow was much less compared to the oil-water flow, apart from when phase inversion occurred. Additionally, they stated their finding that air injection would not greatly affect critical concentration of water and oil when there was the occurrence of phase inversion. They attributed their results to result from presence of dispersed liquid greatly impacting the bubble size. Additionally, they concluded that gas rate affecting how individual liquid phases were distributed in the pipe was an immense contributor to the results.

Bannwart, Rodriguez, Trevisan, Vieira, and de Carvalho (2009) noted that core-annular regime was an important two phase flow type since core-annular flow is useful for heavy oil transport as well as artificial lifting technique in Brazilian offshore situations.

10. Predictive models

10.1. Neogi, Lee, and Jepson (1994)
Neogi et al. (1994) derived the following two Equations (1) and (2) below to find predicted oil and water thickness values and compare them to the experimentally obtained ones. They stated that the equations must be solved simultaneously using the Newton-Raphson method to obtain the predicted oil and water film heights. The results for the oil and water heights showed good agreement between the experimental and predicted ones. Figure 3 aids in visualising the equation variables in relation to the pipe. The diagram on the left shows the fluid as it flows through the length of the pipe. The diagram on the right depicts the circular pipe cross sectional area.

\[
\begin{align*}
C_G \frac{\left( \frac{DU_G}{\gamma_G} \right)^m \rho_G U_G^5 \left( \frac{D_G}{U_G} - \frac{U_G}{A_G} \right)}{2} & = C_l \frac{\left( \frac{DU_L}{\gamma_L} \right)^n \rho_L U_L^5 \left( \frac{D_L}{U_L} - \frac{U_L}{A_L} \right)}{2} \\
- \frac{C_l}{D} \frac{\left( DU_L \right)^n \rho_L \left( U_L - U_W \right) U_W^5}{\gamma_L} & = \frac{C_l}{D} \frac{\left( DU_G \right)^m \rho_G U_G^5 \left( \frac{D_G}{U_G} - \frac{U_G}{A_G} \right)}{2} \\
+ \left[ 1 + 15 h^{0.5} \left( \frac{U_G^5}{5.0} - 1 \right) \right] C_l \frac{\left( \frac{DU_G}{\gamma_G} \right)^m \rho_G U_G^5 \left( \frac{D_G}{U_G} - \frac{U_G}{A_G} \right)}{2} & = 0
\end{align*}
\]
Figure 4. Liquid height, $h_L$, and water height, $h_W$, for the gas-oil-water (G-O-W) system Taitel et al. (1995).

\[
\begin{align*}
C_G \left( \frac{DU_O^S}{\gamma O} \right) \frac{-n \rho_O U_O^S}{2 \left( \frac{D}{U_O} \right) A_O} & - C_L \left( \frac{DU_W^S}{\gamma W} \right) \frac{-n \rho_W U_W^S}{2 \left( \frac{D}{U_W} \right) A_W} \\
+ \left[1 + 15h^{0.5} \left( \frac{U_G^S}{5.0} - 1 \right) \right] & C_G \left( \frac{DU_G^S}{\gamma G} \right) \frac{-n \rho_G U_G^S}{2 \left( \frac{D}{U_G} \right) A_G} \\
& - C_L \left( \frac{DU_L^S}{\gamma L} \right) \frac{-n \rho_L U_L^S}{2 \left( \frac{D}{U_L} \right) A_L}
\end{align*}
\]

\[
\left( \frac{S_{i1}}{A_O} + \frac{S_{i1}}{A_W} \right) + \left( \rho_O - \rho_W \right) g \sin \alpha = 0
\]

where $C_G$, $C_L = \text{empirical coefficients}$, $D = \text{hydraulic diameters}$, $\rho_O$, $\rho_W = \text{densities of gas, oil and water phases, respectively}$, $\gamma = \text{kinematic viscosities}$, $S = \text{wetted perimeters}$, $A = \text{areas of flow}$, $\alpha = \text{inclination angle of the pipe with the horizontal}$, $D = \text{diameter of pipe}$, $g = \text{acceleration because of gravitational force}$, $U^S = \text{superficial velocities}$, $m, n = \text{exponents}$, $S_{i1}, S_{i2} = \text{perimeters at the oil-water and oil-gas interfaces, respectively}$, $\tau = \text{shear stress that acts on wall wetted by fluid}$, $\tau_S, \tau_j = \text{shear stress that acts on oil-gas as well as oil-water interfaces, respectively}$, $A_t = \text{total area of flow for liquid (that is, } A_t = A_O + A_W)$, $U = \text{velocities}$, $H_t = \text{liquid height}$, Subscripts G, O and W symbolise gas, oil and water, respectively. The symbols with the bar are dimensionless.

10.2. Taitel et al. (1995)

Taitel et al. (1995), like Neogi et al. (1994), researched the gas, oil and water holdups for gas-oil-water systems. To find the water and liquid levels, $h_W$ and $h_L$, respectively, Equations (3) and (4) below can be worked out concurrently, resulting in possible multiple solutions. Figure 4 shows the equation variables and symbols in relation to the pipe cross section.

\[
-\tau_L \frac{S_L}{A_L} + \tau_G \frac{S_G}{A_G} + \tau_j \frac{S_j}{A_G} \left( \frac{1}{A_L} + \frac{1}{A_G} \right) - \left( \rho_L - \rho_G \right) g \sin \alpha = 0
\]

\[
-\tau_W \frac{S_W}{A_W} + \tau_G \frac{S_G}{A_O} - \tau_j \frac{S_j}{A_W} \left( \frac{1}{A_W} + \frac{1}{A_O} \right) - \left( \rho_W - \rho_G \right) g \sin \alpha = 0
\]

To deal with the complexity of multiple solutions, Taitel et al. (1995) suggested an iterative method of solving the equations, just as required by Neogi et al. (1994).
Additionally, Taitel et al. (1995) noted the difference in the number of solutions for horizontal and vertical pipe situations where the pipe diameters were both 5 cm. They concluded that for a horizontal pipe, only one solution for water and oil heights was possible at given liquid and gas flow rates, liquid properties and pipe diameters. However, for upward inclined pipes, there were multiple solutions. It was found that there were three possible solutions for three phase flow at low liquid flow rates. When more than one steady state solution existed, they concluded that the realistic solution would be the only practical and valid solution. For both two and three phase flow, the solution with the thinnest liquid layer was the realistic, valid one and the remaining two solutions were the unstable, unacceptable ones.

10.3. Aswad, Hamad-Allah, and Alzubaidi (2006)

Aswad et al. (2006) experimentally investigated liquid and water thickness as well as pressure drop for air-kerosene-water flowing in a 0.051 m inner diameter pipe that was 4 m in length. They developed models to predict these thicknesses and pressure drop. They developed the following three Equations (5)–(7) that can be used to anticipate liquid and water height and pressure drop for the three phase stratified flow. They found that their models were accurate since the model predictions gave good agreement with their experimental results.

\[
\frac{h_L}{D} = a_1 + a_2 \ast (WLR \ast Q_L)^{a_3} + a_4 \ast (1 - WLR) \ast Q_L^{a_5} + a_6 \ast Q_G^{a_7}
\] (5)

where \(h_L\) is the liquid height, WLR is the water liquid ratio, \(D\) is the pipe diameter, \(Q\) is the volumetric flow rate in m³/h and subscripts \(L\) and \(G\) denote liquid and gas respectively, and,

\[
\begin{align*}
a_1 &= -0.116227 \\
a_2 &= 0.451614 \\
a_3 &= 0.850409 \\
a_4 &= 0.48286 \\
a_5 &= 0.981403 \\
a_6 &= 0.364976 \\
a_7 &= -0.19315
\end{align*}
\]

\[
\frac{h_w}{D} = b_1 + b_2 \ast (WLR \ast Q_L)^{b_3} + b_4 \ast (1 - WLR) \ast Q_L^{b_5} + b_6 \ast Q_G^{b_7}
\] (6)

where \(h_w\) is the water height and,

\[
\begin{align*}
b_1 &= -0.117454 \\
b_2 &= 0.620129 \\
b_3 &= 0.590837 \\
b_4 &= 0.047055 \\
b_5 &= 0.805945 \\
b_6 &= 0.173923 \\
b_7 &= -0.375791
\end{align*}
\]

\[
\Delta P = c_1 \ast ((WLR \ast Q_L + (1 - WLR) \ast Q_L) \ast Q_G)^{c_2}
\] (7)

where \(\Delta P\) is the pressure drop and,

\[
\begin{align*}
c_1 &= -0.000863 \\
c_2 &= 0.409815
\end{align*}
\]

10.4. Soprano et al. (2012)

Soprano et al. (2012) used the drift-flux approach to solve gas-oil-water systems in oil wells. The aim of their research was to make a contribution to the petroleum industry by providing a method to estimate and optimize oil production. They stated that the multiphase flow was ruled by Navier-Stokes rules, as well as mass conservation laws and, because of the spatial scale between wellbore and petroleum reservoir domains, it was possible to consider flow in the wellbore as being one-dimensional. Additionally, the pressure loss as a result of lateral mass influx of the three phases must be considered via friction models. They adopted a homogeneous flow model and the slip between phases was obtained from literature. Equations (8)–(11) below are the resulting system of equations developed. These equations had been discretized by applying Final Volume Methodology. Pressure-velocity coupling had been solved via a staggered grid shown in Figure 5. In this grid, pressure, as well as volume fractions, had been accumulated in one grid and the phase and mixture velocities were on another grid. The Newton-Method was applied and, therefore, a Jacobian matrix like that shown in Figure 6 was constructed so that solutions can be found to the equations. Each block of this
matrix has the form showed in Table 1. To apply their numerical model to the gas-oil-water system, Soprano et al. (2012) firstly considered a gas-liquid system and then applied this same procedure for the oil and water phases.

\[ \frac{\partial (\rho_g u_g)}{\partial t} + \frac{\partial (\rho_g u_g u)}{\partial x} = q_g \]  \hspace{1cm} (8)
where subscripts \( g \) denotes gas, \( o \) denotes oil, \( p \) denotes a phase and \( m \) denotes mixture. Additionally, \( x \) is the direction of flow, \( g \) is the gravitational constant, \( q \) denotes mass flux per unit volume, \( \alpha \) denotes volumetric fraction, \( V \) denotes volume, \( P \) denotes pressure, \( \rho \) is denotes density, \( u \) is the velocity, \( f \) denotes friction factor, \( D \) represents pipe diameter.

10.5. Spesivtsev, Sinkov, and Osipstov (2013)

Spesivtsev et al. (2013) compared multi-fluid and drift-flux methods of modelling multiphase flow. They looked at different ways to model multiphase flow in a wellbore by devising the mathematical model, then substituting values into the models and simulating them.

They expressed mass conservation for both multi-fluid and drift-flux methods as Equations (12) and (13) below:

\[
\frac{\partial (\alpha_g \rho_o g)}{\partial t} + \frac{\partial (\alpha_g \rho_o g u_g)}{\partial x} = q_o \tag{9}
\]

\[
\frac{\partial \sum (\alpha_p \rho_p p)}{\partial t} + \frac{\partial (\alpha_p \rho_p p u_p)}{\partial x} = \sum q_p \tag{10}
\]

\[
\frac{\partial \sum (\alpha_p \rho_p p u_p)}{\partial t} + \frac{\partial (\alpha_p \rho_p p u_p)}{\partial x} = -\frac{\partial P}{\partial x} - \frac{\rho_m g x}{2D} - \frac{f}{2D} \rho_m |u_m| \tag{11}
\]

where subscripts \( g \) denotes gas, \( o \) denotes oil, \( p \) denotes a phase and \( m \) denotes mixture. Additionally, \( x \) is the direction of flow, \( g \) is the gravitational constant, \( q \) denotes mass flux per unit volume, \( \alpha \) denotes volumetric fraction, \( V \) denotes volume, \( P \) denotes pressure, \( \rho \) is denotes density, \( u \) is the velocity, \( f \) denotes friction factor, \( D \) represents pipe diameter.

11. Previous research on three phase flow regimes

11.1. Horizontal pipes

Using a 10 cm Plexiglass pipeline, Lee, Sun, and Jepson (1993) devised flow regime maps for carbon dioxide-oil-water flowing for varying compositions of oil and water. They found that the composition of the liquid has a significant effect on these maps. Figure 7 shows the flow system that was set up. Observed patterns observed are shown in Figure 8. The three main types of patterns were stratified, intermittent and annular flows.
11.1.1. Stratified flow

The stratified flow types are shown in Figure 8 and they are the smooth, wavy and rolling wave flow types with the flow occurring in a pipe. The stratified flow occurred where the gas which was at the top flowed above the oil, which, in turn, passed above the bottom layer of water. The two interfaces which were present were the oil-water and gas-oil interfaces. For low water velocity and gas velocity, the interfaces were both smooth. As the oil velocity was increased, it was observed that, close to the oil-water boundary, oil droplets were seen in the water and water droplets were seen in oil. With higher gas velocity, there were waves being seen at gas-oil interface. Increasing this velocity more caused the observed waves to have a rolling wave shape where gas-oil interface was located.

When gas velocity was very high, the oil-water interface began to become fragmented and the two liquid layers became well-mixed forming a homogeneous liquid phase. Additionally, at the gas-oil interface, there was wavy or rolling wave type of flow. For Arcopak90 oil, the oil and water layers became properly mixed at lower flow rates than for the LVT 200 oil.
11.1.2. Intermittent flow
Figure 8 shows the three intermittent flow types, namely plug, slug and pseudo slug flow. For plug pattern, oil flowed above the water phase while oil bridged the pipe.

For slug flow, when the gas and liquid flow rates were low, oil flowed over the water. There was a similarity between the observations made for pseudo slug regime and for gas-liquid two phase flow.

11.1.3. Annular flow
Figure 8 shows the annular flow type. The observations made were found to be similar to two phase gas and liquid flow. The liquid phases were very well mixed and formed an annular film. Gas was flowing in the middle.

11.1.4. Three phase flow regime maps
Figure 9 presents the regime map for 50% LVT200 oil- 50% water and carbon dioxide. Also, Figures 10 and 11 show the effect of various liquid compositions on the flow regime maps.

For LVT200 oil, as seen in Figure 10, when the water cut decreased, transition to slug occurred for lower liquid velocity. It was observed that for 75% oil fraction, transition to slug pattern happened at 0.18 m/s liquid velocity. When the oil fraction further decreased to 50% and then to 25%, the transition to slug happened at 0.2 m/s, as well as 0.22 m/s liquid velocities, respectively. The gas velocity to achieve the annular pattern increased with a decrease in oil composition. It was also observed that transitioning from slug to pseudo slug was not greatly impacted by liquid fractions. Similar conclusions were drawn for the Arcopak90 oil by observing the three phase flow regime maps in Figure 11.

11.1.5. Oil-based flow regimes
Açıkgöz, França, and Lahey (1992) concluded that there were oil-based and water-based flow regimes, as identified by Regions 1-10 in Table 2. They discussed the oil-based flow patterns observed. For comparatively low air and water velocities, oil-based dispersed plug flow pattern had been achieved, which is depicted in Figure 12. This occurred since for these low flow rates, water combined with the oil leading to a foamy liquid mixture. Açıklöz et al. (1992) distinguished between slug and plug flow by stating that once the air was being driven by the liquid phase, this flow type would be classified as the plug regime. When the air velocity was increased, it was observed that the liquid phase was, then, being driven by the air, which was classified as the oil-based dispersed slug flow, shown in Figure 13. The liquid phase was still foamy, but the edges of the large air bubbles were not defined sharply, as with the oil-based plug pattern.

The oil-based dispersed stratified/wavy flow pattern (depicted in Figure 14) displayed phase layers and separation of the phases due to gravity. The water was at the pipe bottom and, on top of this water, an oil-based mixture with water entrained. Observed at the gas-liquid interface were small
amplitude waves. When liquid phases became segregated fully, this was identified as the oil-based separated stratified/wavy flow, and is shown in Figure 15. The oil floated on top of the water due to it having a lower density than the water. The oil also had a complex wave structure best observed from the top view of the pipeline. Additionally, ripple waves had been seen at the oil-water interface.
Figure 12. Oil-based dispersed plug flow (region 1 according to Table 2) by Açıklık et al. (1992).

Figure 13. Oil-based dispersed slug flow (region 2 according to Table 2) by Açıklık et al. (1992).

Figure 14. Oil-based dispersed stratified/wavy flow (region 3 according to Table 2) by Açıklık et al. (1992).
Figure 15. Oil-based separated stratified/wavy flow (region 4 according to Table 2) by Açığöz et al. (1992).

Figure 16. Oil-based separated wavy stratifying annular-flow (region 5 according to Table 2) by Açığöz et al. (1992).

Figure 17. Oil-based separated/dispersed stratifying-annular flow (region 6 according to Table 2) by Açığöz et al. (1992).
For oil-based separated wavy stratifying annular regime (shown in Figure 16), the upper oil structures were seen to be denser than that of the oil-based dispersed stratified/wavy pattern. These upper oil structures were seen to be linked to a thinner oil layer. The regime was also stratified.

When the air velocity increased, the separated/dispersed stratifying-annular flow regime (shown in Figure 17) occurred where variations in oil layer thicknesses near the top of the pipe no longer existed. For this flow pattern, tiny air bubbles were entrained in this oil layer. Additionally, the pattern was stratified.

11.1.6. Water-based flow regimes
Açıkgoz et al. (1992) noted that at low air velocities and high water velocities, bubbles of air with tails were observed and this pattern had been categorized as water-based dispersed slug pattern, shown in Figure 18. The driving fluid was the air phase and a fairly high concentration of droplets of oil was seen in areas around the tail of the air bubbles. When the air velocity increased, froth developed replacing the clear space which was in the area behind the air bubble tails.

Açıkgoz et al. (1992) noted that for the water-based dispersed stratified/wavy flow, shown in Figure 19, air flowed through the top and water flowed at the bottom. Oil droplets were dispersed in the water phase. The gas-liquid interface was wavy, with the waves being of small amplitude. Increasing the air velocity led to the water-based separated dispersed incipient stratifying-annular flow, shown in Figure 20. In this flow regime, the small waves at the gas-liquid interface became rolling waves.

The water-based dispersed stratifying-annular flow regime is shown in Figure 21. It was observed that the wall of the pipe had been fully wetted by a water-based film that had droplets of oil scattered within it.

Like Açıkgoz et al. (1992), Spedding, Donnelly, and Cole (2005) found that three phase flow had oil- or water-based flow patterns.
In another work (Karami, Pereyra, Torres, & Sarica, 2017a), three-phase flow is modeled in near-horizontal pipes with stratified flow pattern where researchers predicted liquid holdup, pressure gradient and interfacial wave characteristics. The oil-water mixing level in the liquid phase is estimated by an energy balance.

Commonly used multiphase flow models (Karami, Pereyra, Torres, & Sarica, 2017b) neglected the number of entrained droplets in stratified wavy flow. Nevertheless, the experiment showed high entrainment values (above 50% in some cases) makes it possible for large errors to be caused in modelling predictions.

Study accomplished by Ersoy, Sarica, Al-Safran, and Zhang (2017), described a significant oil-water mixing process during the slug initiation process at lower pipe dip for flow in undulating pipe line. For moderate to high flow conditions, significant change in slug frequency as well as length had been noted at water cut values of 20% and 80%. OLGA predicted holdup, slug frequency and length in the upstream and downstream horizontal sections.

11.2. Vertical and inclined pipes
Wilkens and Jepson (1996) investigated the occurrence of flow regimes of carbon dioxide gas, oil and water using a non-visual method for pipes with 0° and 5° inclination angles and various system pressures. In the experiments conducted, the oil used was light oil petroleum distillate of viscosity of 2.0 cP as well as density of 800 kg/m³. ASTM seawater was used. The flow system is shown in Figure 22. They concluded that, upon increase in liquid flow rate, slug frequency increased in spite of the pressure, pipe inclination and liquid composition. It was, also, found that the slug frequency, the
plug-to-slug transition and the stratified/intermittent boundary all did not depend on pressure. Additionally, when the pressure was increased, it led to pseudo-slug pattern. This was anticipated since the pseudo-slug flow pattern was the gas-dominated end of the flow regime map and, thus, density and, therefore, pressure plays a large role and their impacts are more noticeable.

Cai, Gopal, and Jepson (1999) investigated flow pattern transitions of gas, oil and water flowing through an inclined pipe. The 18 m long, 10 cm inner diameter pipe were inclined at ±2° under system pressures ranging from 0 to 79 MPa. The effects of pipe inclination, system pressure and oil/water liquid composition ratio were studied. The flow system was composed of 316 stainless steel. It was able to handle a maximum pressure of 12 MPa. Carbon dioxide gas was used, in addition to a 2 cP viscosity oil at a temperature of 40°C.

Cai et al. (1999) found that the pipe inclination had no significant impact on slug-annular transition in pipes of large diameter.

They also found that, at constant superficial gas velocity, at higher system pressure, the stratified to slug flow transition had been reached when the liquid superficial velocities was higher. This occurred because the gas wall friction factor was increased when the pressure increased. This meant that more momentum was lost to the wall and thus a higher liquid velocity is reached. Additionally, increasing the system pressure at constant gas velocity led to the slug into annular flow transition to be reached when the liquid velocities were lower. This was attributed to the increased liquid shear stress due to a greater gas density.

For downward flow experiments at 0.13 MPa, it was observed that as the water fraction in the liquid phase was increased, stratified to slug transition happened greater superficial liquid velocities at constant gas superficial velocity. This was caused by resultant fall in overall liquid viscosity as water fraction increased. In the slug to annular transition, water fraction has little impact.
However, for the upward flow experiments at 0.13 MPa, slug flow was the dominating pattern and stratified flow did not happen under the conditions that were investigated. There was plug flow at low superficial velocities. Rise in gas velocity led to slug flow pattern. Gas velocity increased, leading to pseudo-slug flow. Annular flow happened for the highest gas velocities with the heavier fluid flowing as an annular film around the pipe wall. It was also concluded that water fraction of the liquid had no significant impact on the transition.

Hanafizadeh, Shahani, Ghanavati, and Akhavan-Behabadi (2017) investigated three-phase flow pattern in a 20 mm diameter inclined pipe with a length of 6 m with a high speed digital camera. The superficial velocities were in the range of 0.25–3, 0.25–2.3, and 0.08–13 m/s for water, low viscosity oil and air, respectively. Two parameters as Interaction of gas and liquids mixture and interaction of water and oil phases were considered. Flow pattern observed were stratified-oil/water (or water/oil), wavy stratified-o/w, bubbly-o/w, plug-o/w, plug-stratified and annular-o/w. Major flow patterns for upward and downward pipe were slug-o/w and wavy-stratified-o/w, respectively, within the inclination of −45° to +45° at different oil cuts. At increasing oil cut, the bubbly region extends and plug region becomes smaller.

Woods, Spedding, Watterson, and Raghunathan (1998) identified oil-dominated Regimes 1–4 and water-dominated Regimes 5–8 for vertical flow of air, oil as well as water.

11.2.1. Oil-dominated flow regimes
Regimes 1–4 are shown in Figure 23 and are the oil-dominated regimes, according to Woods et al. (1998). Regime 1 is the Oil Annulus/Dispersed Annular, Regime 2 is the Broken Annulus, Regime 3 is the Dispersed Churn and Regime 4 is the Dispersed Slug. Regime 1 is the Oil Annulus/Dispersed Annular, Regime 2 is the Broken Annulus, Regime 3 is the Dispersed Churn and Regime 4 is the Dispersed Slug. In Regime 1, the oil formed an annulus film at the pipe wall and this film was overlaid by an annular-type scattering of droplets of water in an oil layer. At the pipe centre was the gas core. The oil annulus lost thickness when the gas and/or water velocities increased. The oil annulus became thin until there was complete scattering of the water in oil phase. At this point, the flow was
white and opaque and was called the oil dispersed annular regime. This regime, Woods et al. (1998) found, could be semi-annular in nature. Regime 2, the broken annulus regime, occurred upon increase in the water velocity close to the point of inversion, that is, when the system transitions into water-dominated after being oil-dominated. The oil-dominated annulus at the pipe wall broke down and was, slowly, replaced by a water-dominated one. Similar to that found by Spedding et al. (2005) for horizontal flow, short strips of the oil-dominated annulus delaminated from the wall and these strips were replaced by a water-dominated phase and later pasted over by the oil-dominated dispersed film. The pipe wall has a marbled appearance with a lot of liquid entrained in the gas phase. Piela, Delfos, Ooms, Westerweel, and Oliemans (2009) investigated three fluid dispersed flow through horizontal pipeline. They concluded that gas bubbles do not greatly impact inverting of the phases. However, inverting of phases was found to have a significant impact on the gas bubbles.

According to Woods et al. (1998), Regime 3, the dispersed churn regime, resembled that to its equivalent two-phase churn flow where water droplets were dispersed in oil and the oil had a vertical oscillating movement. Regime 4 resembled two-phase slug flow where the oil had water droplets dispersed in it. However, no liquid counter-current flow was seen at the pipe wall in the annulus which surrounded the rising gas bubble.

11.2.2. Water-dominated flow regimes
According to Woods et al. (1998), Regimes 5–8 are shown in Figure 24 and are the water-dominated regimes. Regime 5 is the Water Annulus/Oil Annular, Regime 6 is the Dispersed Annulus/Oil Annular, Regime 7 is the Dispersed Churn and Regime 8 is the Dispersed Slug. Regime 5 occurred when the water velocity increased above the inversion point. This regime was transparent and the annular oil film could flow as an annular or semi-annular film with rolling waves or ripple waves on the oil surface, depending on the gas flow. Regime 6 had a more mixing of the liquid phases, leading to a partial dispersion of oil droplets in the annulus of water. The annular film that interacted with the gas could flow as an annular film or with rolling or rippling waves on the surface, depending on the gas rate. Regimes 7 and 8 both resembled their respective equivalent two-phase regimes.
Regime 9 was water dominated oil slug regime. The oil quickly moved in slugs within an annulus of water. The water and oil separated into layers in the film region surrounding the gas slug at low slug frequencies, but this separation was not seen at high slug frequencies.

12. Methods of identifying flow regimes

Zhao, Jin, Ren, Zhu, and Yang (2016) also developed an approach to categorize flow regimes (slug, churn and bubble flow). They allowed gas, oil and water to flow upwards through a 20 mm inner diameter vertical pipe. They examined conductance fluctuating signals using long-range relationships via deconstruction of signals into series of both magnitude and sign. The magnitude series were linked to non-linear characteristics and sign series was linked to linear properties. The flow patterns were able to be identified via a mixture of sign and magnitude series scaling exponents.

Li, Xie, and Yu (2013) used hybrid particle swarm optimization using natural selection (NPSO) for the optimization of parameters for Least Square Support Vector Machine (LSSVM). It was able to predict flow patterns like slug, bubbly and bubbly-slug flows successfully.

Two network mapping methods Flow Pattern Complex Network (FPCN) in addition to Fluid Dynamic Complex Network (FDCN) were proposed by Gao and Jin (2011a). They found that these networks were able to effectively classify gas-oil-water regimes via detection of community structure of FPCN on a K-means clustering basis.

Gao and Jin (2011b) also put forward a technique to identify three common flow regimes. They found that detrended fluctuation analysis scaling exponent was responsive regime transition. Therefore, the exponent has potential for categorization of nonlinear dynamics for the flow of three phases. Upon investigating three phase flow with respect to phase categorization and scaling analysis, they found that their technique has potential to give novel perspectives about studying complicated mechanisms in regime transitions. Their method was concluded to be effective and applicable to broader situations.

Arvoh, Hoffmann, and Halstensen (2012) investigated the flow of gas, crude oil as well as water obtained in various North Sea gas fields within Norway. They conducted trials at 80°C with pressures of 100 bar that were similar to temperature and pressure in the field. Stratified-wavy, dispersed, annular as well as slug regimes were studied and various volume fractions of each phases had been studied. Gamma measurements, in collaboration with multivariate calibration, were utilized to calculate approximately the phase volume fractions and categorise the flow types.
13. Pressure-drop and water cut effects in three phase flow

Al-Hadhrami et al. (2014) also studied gas as well as liquid velocity impacts on pressure drops for horizontal pipes. They investigated water cuts in the range 10–90% and fluid rates between 0.3 and 3 m/s for the liquid and between 0.29 and 52.5 m/s for the gas. Pressure gradients increased with superficial gas and liquid velocity. Aswad et al. (2006) supported this conclusion as well. Additionally, Al-Hadhrami et al. (2014) noted that when the gas velocity was constant, the pressure gradient increased with increasing liquid velocity.

Al-Hadhrami et al. (2014) found pressure drop to rise with gas and liquid rates and, for constant gas rate, pressure drop rose with rising liquid rate. Annular flow was observed when the gas velocity was high and stratified and dispersed bubble flow types were observed at low gas rates. Therefore, it was found that the pressure gradient was at a maximum when the regime was annular and a minimum when the regime was stratified and dispersed bubble. At high gas rates above 1.0 m/s, the pressure drop values increased greatly with increased gas rate. When these gas velocities were high, the increase in both superficial gas and liquid velocities led to a more prominent increase in pressure drop.

Shi et al. (1999) found that pressure drop increased then decreased with increasing water fraction and their results are shown in Figure 25. They found that the pressure drop increased up to when the water fraction was about 0.4 then it began to decrease. They went on to discuss that, at approximately 0.4 water fraction, the flow was well mixed relative to the flow at other water fractions. As a result, the apparent viscosity would be highest at this point and, thus, the pressure drop would be highest.

14. Conclusions

In this review paper, work performed by various researchers pertaining to multiphase flow through various pipeline inclinations had been reviewed. The predictive models reviewed were devised by researchers to predict liquid phase heights and pressure drop.

Additionally, the multi-fluid and drift-flux procedures to model the flow were reviewed. The two principal categories for three phase regimes had been distinguished for horizontal, vertical as well as inclined pipes, namely the oil-based and water-based flow patterns.

The flow patterns went from oil-dominated to water dominated upon phase inversion. Conductance, algorithm and network mapping methods of were seen to be ways of identifying these flow patterns. Pressure gradients had been concluded to increased as superficial gas and liquid velocities became higher. Additionally, it was seen that water cut had varying impacts on flow pattern transitions. Work done by researchers to explore effects of the temperature and the diameter of pipe on flow were briefly reviewed. Furthermore, the measurement of fluid flows, ways to measure flow, detect the type of flow and simulate them were also briefly investigated.
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