Liquid Accumulation in Gas-Condensate Pipelines – An Experimental study

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Abstract
In slightly upwardly inclined pipes with low liquid flow rates there exists a region were the holdup increases almost like a discontinuity with decreasing gas flow. To predict this transition region accurately is of great importance for design and operation of gas-condensate pipelines. The multiphase flow models have to little extent been tested in this respect. In this paper we present recent experimental data from a series of three-phase flow experiments focusing on how the pipe inclination, the gas density and the water cut affect the onset of transition to high holdup. The data have been compared to OLGAS 2000 predictions.

NOMENCLATURE

\[ A \quad \text{cross sectional area of pipe} \quad [m^2] \quad H \quad \text{liquid holdup} \quad [%] \]

\[ \frac{\partial p}{\partial x} \quad \text{frictional pressure gradient} \quad [Pa/m] \quad R_w \quad \text{Water fraction in H} \quad [-] \]

\[ g \quad \text{acceleration due to gravity} \quad [m/s^2] \quad S \quad \text{perimeter} \quad [m] \]

\[ U \quad \text{velocity} \quad [m/s] \]

Greek symbols

\[ \alpha \quad \text{gas void fraction} \quad [-] \quad i \quad \text{interface} \]

\[ \beta \quad \text{liquid holdup} \quad [-] \quad l \quad \text{liquid phase} \]

\[ \theta \quad \text{pipe inclination} \quad [\text{deg.}] \quad g \quad \text{gas phase} \]

\[ \rho \quad \text{phase density} \quad [kg/m^3] \quad s \quad \text{superficial} \]

\[ \tau \quad \text{shear stress} \quad [Pa] \quad w \quad \text{water/wall} \]

1 INTRODUCTION

1.1 Motivation
An important design parameter for long distance gas-condensate pipelines is the liquid inventory under different operating conditions. Liquid accumulated during periods of low production can cause serious operational problems in case of shut-in and production increases. It is well known that below a certain production rate the holdup rises steeply,
almost like a discontinuity, with decreasing gas flow rate. This occurs typically for flow conditions represented by very low liquid loading in moderate upwardly inclined pipes. To predict this transition region accurately is therefore a challenge of particular relevance for gas-condensate pipelines. Present multiphase flow models have to little extent been tested for accuracy in this respect. Some data exists on two-phase liquid-gas flow, but for three-phase oil-water-gas flow there is at present limited experimental data available. This nearly discontinuous change in the holdup is also closely related to the issue of multiple solutions to the holdup equation, which will also briefly be discussed.

1.2 Theory and related work
Considering the momentum balances for equilibrium stratified 2-phase flow, see Figure 1-1, we arrive at the following two momentum equations:

For the liquid phase:

\[ \beta \frac{\partial \rho_l}{\partial x} = -\tau_{wl} \frac{S_l}{A} + \tau_i \frac{S_i}{A} - \beta \rho_l g \sin \theta, \text{ where } \beta = \frac{A_i}{A_g + A_i} \]  

(1)

For the gas phase:

\[ \alpha \frac{\partial \rho_g}{\partial x} = -\tau_{wg} \frac{S_g}{A} - \tau_i \frac{S_i}{A} - \alpha \rho_g g \sin \theta, \text{ where } \alpha = \frac{A_g}{A_g + A_i} \]  

(2)

Eqs. (1) and (2) are simplified in the sense that they do not account for the effects of liquid droplets in the gas or gas bubbles in the film. The equation for the holdup is found by eliminating the pressure gradient between the two momentum equations, yielding:

\[ F(\beta) = \beta \tau_{wg} S_g - \alpha \tau_{wl} S_l + \tau_i S_i - \alpha \beta A (\rho_l - \rho_g) g \sin \theta = 0 \]  

(3)

![Figure 1-1. Stratified flow configuration in an inclined pipe](image)

Equation (3) is an implicit equation where the number of solutions may vary from one to three. The aforementioned abrupt, nearly discontinuous change in holdup is closely related to this issue of multiple solutions, which typically appears for low liquid flow rates in slightly upwardly inclined pipe, and thus makes this issue particularly relevant for flow in gas-condensate pipelines. From a modelling point of view it is of course important to know which solution to choose and if more than one solution can possibly be physically feasible. This has been treated theoretically in the literature, e.g. by Landman 1991 (4, 5), and by Barnea and Taitel 1992 (3). They conclude that the low holdup solution is always stable. This
has been the accepted view and the equation solvers in most steady state multiphase flow codes are designed to always choose the low holdup solution. Landman argues that the high holdup solution may also be stable for some conditions. Barnea and Taitel state that the intermediate solution is always unstable and the high holdup solution is also structurally unstable for large disturbances. Following the works of Landman and Barnea and Taitel, Espedal et al. 1998 (2) searched experimentally for the co-existence of two solutions in stratified gas-liquid flow, but concluded that, except for possible minor hysteresis effects, the holdup was unique, given the flow rates, pipe inclination, etc. Quite recently multi-holdups in stratified liquid-liquid flow have, however, been demonstrated experimentally, Ullmann et al. 2003 (1).

1.3 Main objectives
The main objective with the present work has been to search experimentally for these regions of steep holdup gradients, in both two-phase and three-phase flow, and quantify the holdup behaviour by systematically changing:

- The pipe inclination
- The water cut
- The gas density

Particular emphasis has been made in obtaining data for how the presence of water influences the holdup, both with respect to water accumulation (oil-water slip) and to the onset of the transition.

The above objectives may seem to have a rather theoretical approach, but the work also has important practical implications. During concept and design studies for long gas-condensate pipelines one of the key parameters is the liquid content in the pipeline. In this respect accurate prediction of the onset of liquid accumulation is essential in order to give confidence to the simulation results. To capture this phenomenon correctly is not straightforward and it represents a major challenge for the multiphase flow models. It has therefore been an important task to validate the ability of the OLGA flow models to predict the transition region.

2 THE EXPERIMENTS

2.1 The test facility
The experiments have been conducted in IFE’s Well Flow Loop. This is a closed multiphase oil-water-gas flow loop with a 25 m long test section with internal diameter 100 mm. An outline of the test rig is shown in Figure 2-1. The flow rig consists of the test section (17), return sections (15 and 16), a gas-liquid separator (2), an oil-water separator (1), pumps (4 and 5), a gas compressor (3), and a flow rate control system. The gas is cooled after compression and an automatic control system maintains a constant gas temperature at the inlet of the test section. The oil and water are circulated through the loop by centrifugal pumps or, for very low flow rates, as was the case in the present study, by dosage pumps.

The test facility utilises a dense gas (SF₆) at a maximum pressure of 10 bars in order to better simulate the gas-to-liquid density ratios found in oil and gas pipelines. For the present work the loop pressure was either 3.5 bars or 7.1 bars. The test section (17) can be positioned at any pipe inclination between vertical and horizontal. For this study the test section inclination with the horizontal was between 0.5° and 5° upwardly inclined.
2.2 Instrumentation

The gas flow rate
The gas flow rate was measured with a turbine meter with an accuracy of ± 0.3% of reading. Combined with the positive displacement twin-screw pump used to circulate the gas, we were able to control and adjust the gas velocity to within ± 1 cm/s.

The liquid flow rates
The oil and water were circulated by dosage pumps with adjustable stroke length and speed. The pumps were calibrated in situ and the accuracy in the liquid superficial velocities is estimated to ± 0.1 mm/s.

The holdup
The holdup was measured with 3 broad beam gamma densitometers distributed along the test section. The estimated uncertainty (absolute) in the holdup is ± 2%.

The pressure gradients
The pressure gradients were measured with several differential pressure transducers connected to pressure tappings distributed between the inlet and outlet of the test section. The estimated uncertainty in the pressure gradients is ± 5% of reading.

Figure 2-1. Schematic of the process components and the piping of the Well Flow Loop

1: Oil-water separator    2: Gas-liquid separator    3: Gas compressor
4: Water pump            5: Oil pump              6: Heat exchanger, gas
7: Heat exch., water    8: Heat exch., oil       9: Main switch board
10: Turbine meter, gas   11: Flow rate, water    12: Coriolis meter, oil
2.3 Fluid properties

The water used in the experiments was ordinary tap water without any additives. The oil phase was ExxsolD80. The oil and water viscosity, surface tension and oil-water interfacial were measured for samples of oil and water from the loop. A White Surface and Interfacial Tension Balance Meter, Type 0/74124, and a viscometer of type Viscolab LC100 from Physica Instr. were used for these measurements, all carried out at atmospheric pressure and room temperature. The oil density was determined from the Coriolis flow rate meters.

The gas density was measured using a sample bottle of accurately known volume. The viscosity of the gas is taken from physical properties for SF₆. The surface tension between SF₆ and ExxsolD80 (under pressure) has previously been measured at an external fluid lab and the data are taken from this analysis. The fluid properties are summarised in Table 2-1.

### Table 2-1. Physical properties for the fluids used in the experiments

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Density [kg/m³]</th>
<th>Viscosity [mPas]</th>
<th>Surface tension to air [mN/m]</th>
<th>Surface tension to SF₆ [mN/m]</th>
<th>Oil-water interf. tension [mN/m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>998</td>
<td>1.0±0.05</td>
<td>62 ±3</td>
<td>-</td>
<td>27±3</td>
</tr>
<tr>
<td>ExxsolD80</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3.5 bara</td>
<td>812±2.5</td>
<td>1.8±0.05</td>
<td>29.5±3</td>
<td>23</td>
<td>27±3</td>
</tr>
<tr>
<td>7.1 bara</td>
<td>821±2.5</td>
<td></td>
<td></td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>SF6 – 3.5 bara</td>
<td>22.6±0.5</td>
<td>0.015±0.002</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>SF6 – 7.1 bara</td>
<td>46.9±0.5</td>
<td></td>
<td></td>
<td>-</td>
<td></td>
</tr>
</tbody>
</table>

2.4 The test matrix

The tests were carried out for a fixed liquid superficial velocity of 0.001 m/s, in combination with several water cuts (WC) covering the entire range from 0-100% WC. 4 pipe inclinations between 0.5° and 5° were examined. Most of the experiments were conducted with a gas density of 22.6 kg/m³, corresponding to a pressure of 3.5 bars. However, in order to investigate the sensitive in the liquid accumulation phenomenon upon changes in the gas density, a series of tests were also made for an elevated pressure of 7.1 bar (gas density of 46.9 kg/m³). An overview of the test matrix is given in Table 2-2.

### Table 2-2. The test matrix

<table>
<thead>
<tr>
<th>Loop pressure/gas density</th>
<th>3.5 bara/ 22.6 kg/m³</th>
<th>7.1 bara/ 46.9 kg/m³</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water Cut</td>
<td>0%, 15%, 40%, 60%, 85% and 100%</td>
<td>0%</td>
</tr>
<tr>
<td>Pipe inclinations</td>
<td>0.5°, 1.0°, 2.4° and 5° upwardly inclined</td>
<td></td>
</tr>
<tr>
<td>Superficial liquid velocity</td>
<td>0.001 m/s (28 litres/hour)</td>
<td></td>
</tr>
</tbody>
</table>
Superficial gas velocities \(~ 4 -1.5 \text{ m/s}; \text{ to be varied in small steps } (\Delta U_{sg} \sim 0.02 \text{ m/s})\) around the region of steep holdup gradients

2.5 The test procedure
The experiments were carried out by doing so-called $U_{sg}$-traverses; one for each combination of loop pressure, pipe inclination and WC. The test procedure for each $U_{sg}$-traverse was as follows:

1. Adjust the pipe inclination to one of the four pipe inclinations
2. Start the liquid dosage pumps, set to give a total superficial liquid velocity of 0.001 m/s
3. Start the gas compressor and adjust the gas flow rate to a relatively high value (~ 4 m/s) in order to ensure a low holdup
4. When the flow reached an averaged steady state condition, the holdup and pressure gradient were measured
5. The gas velocity was then reduced by typically
   - 0.1-0.3 m/s when we were far off from the transition region
   - 0.02-0.04 m/s when we were in, or close to, the transition region
6. Steps 4 and 5 were repeated until we reached the high holdup region where large waves or aerated slugs dominated the flow

It can be added that accomplishment of a $U_{sg}$-traverse, as described above, could take considerable time. In the most demanding cases, which were for three-phase flow with low WC, we are talking about typically 48 hours required to conduct such a step-wise accumulation of liquid.

3 THE EXPERIMENTAL RESULTS
In the presentation that follows we will have the main focus on the holdup results. Since the flow was mainly in the gravity dominated region, the pressure gradient data and the holdup data are closely linked. We will frequently refer to a parameter called the critical gas velocity, $U_{SG,CRIT}$, in the meaning of the minimum gas velocity that maintains a low holdup value.

3.1 Flow regimes
3.1.1 The gas-liquid flow regimes
For the highest gas velocities, giving a holdup of less than 2%, there were small amplitude 3D waves, commonly denoted as ripple waves, at the interface. As we gradually reduced the gas velocity and approached the transition region, the surface waves became more distinct and they grew in amplitude. Within the transition region the liquid layer was close to stagnant and the 3D surface waves became ‘wobbly’ in nature, see Figure 3-1 (right). In addition we frequently observed short 2D waves, particularly when we had an oil-water dispersion layer present. In general, however, the interface appeared smoother in three-phase than in two-phase flow.

After the transition, when the high holdup solution had been reached, long wavelength waves appeared on the interface; see Figure 3-1 (left). These were low frequency waves, appearing every 5-10 second or so, depending on the pipe inclination. Eventually, for the lowest gas velocities, the waves turned into breaking waves and short aerated pseudo-slugs.
3.1.2 The oil-water flow pattern

In the low holdup situation, with the liquid layer being only a few mm thick, the oil and water were flowing partly segregated with intermittent patches, or pools, of water and oil. When liquid started to accumulate, this was mainly in the form of water accumulation, with the oil being effectively transported in a thin film on top of the (nearly stagnant) liquid layer. There were also some oil drops floating in the upper part of the water layer, thus forming a dispersion layer. This dispersion layer could temporarily during transients be dominating in the liquid layer.

3.2 Results two-phase gas-liquid flow

Based on the two-phase data we will describe the effects upon the transition phenomenon when changing:

- The pipe inclination
- The liquid phase (oil versus water)
- The gas density

3.2.1 Pipe inclination effects

The effect of increasing the pipe inclination was a significant increase in $U_{SG,CRIT}$, from ~1.8 m/s at 0.5° to ~3.2 m/s at 5°, as can also be seen in Figure 3-2 (left) for the two-phase oil-gas experiments. This can be argued for by the following simplified force balance considerations. When liquid starts to accumulate the liquid layer is close to stagnant and the wall friction is minor. Due to the low holdup also the pressure gradient term in eq. (3) is small. This means that at the onset of transition the interface force and the gravity force roughly balance each other. Increasing the pipe inclination, and hence the gravity force, means that the onset of transition occurs for a higher interface force, i.e. a higher gas velocity.
It is also a trend in the results that the transition is less discontinuous for the lower pipe inclinations. Further, we can see that the change in holdup across the transition, ΔH, increases with decreasing pipe inclination. While ΔH is ~12% for the 5° pipe inclination, it is in excess of 20% for the lowest inclinations.

For pipe inclinations 0.5° and 1° the flow regime was still stratified or stratified with long 2D waves after the transition, while for 2.4° and 5° pipe inclinations the flow regime was roll waves or short aerated slugs. The local dip in the holdup that is seen for the 1° data, just after the high holdup has been reached, is caused by the onset of waves that effectively transport the liquid, thus lowering the time averaged steady state holdup.

The right plot in Figure 3-2 shows the pressure gradients for the two-phase oil-gas experiments. We can clearly see the close relation between the holdup values and the pressure gradients, which is a typical feature for gravity dominated flows.

![Figure 3-2](image.png)

**Figure 3-2.** Effect of pipe inclination on the transition from low to high holdup for ExxsolD80-gas, $p_{\text{gas}} = 22.6$ kg/m³; Holdup (left) and pressure gradients (right)

### 3.2.2 Water versus ExxsolD80 as the liquid phase

The changes in the onset of transition between water and ExxsolD80 have been plotted for all 4 pipe inclinations in Figure 3-3; open symbols for water-gas, filled symbols for ExxsolD80-gas. We can see that water gives systematically higher $U_{SG,CRIT}$ than the oil. Since the water density is ~23% higher than the oil density this is as expected from a simple force balance consideration. The fact that $\Delta U_{SG,CRIT}$ (water vs. oil) tends to decrease rather than increase with increasing pipe inclination indicates that there are other mechanisms than gravity alone that are important for the onset of transition. Visual observations of the gas-liquid interface structure indicated a smoother interface with oil compared to the water as the liquid. A smoother interface will give a lower interface friction force and therefore increase $U_{SG,CRIT}$ compared to the rougher water-gas interface. The differences in density and surface tension between the oil and the water phases thus act in opposite direction with respect to the impact upon $U_{SG,CRIT}$. 
3.2.3 Gas density effects

In order to investigate the sensitivity in the critical gas velocity caused by a change in the gas density, the two-phase oil-gas tests were conducted for both 3.5 and 7.1 bars loop pressure, corresponding to gas densities of 22.6 and 46.9 kg/m$^3$, respectively. The results are summarised in Figure 3-4. We can see a significant change (~0.5 m/s) in the critical gas velocity towards a lower value when increasing the pressure (or the gas density). This is because the gas-liquid interface force increases proportionally to the gas density, which implies that a certain interface force will be obtained at a lower gas velocity if the gas density is increased.
3.3 Results three-phase water-oil-gas flow

The three-phase experiments were carried out for water cuts 15%, 40%, 60% and 85%, according to Table 2-2. Although there were some pipe inclination specific effects seen in the data, the overall results show some very clear trends related to the presence of two liquid phases. First of all the slip between the oil and water was significant when liquid started to accumulate, i.e. for $U_{SG} < U_{SG,CRIT}$. As already stated the oil was mainly transported in a thin layer on top of a more significant water layer. Typically, the water fraction in the holdup was around 0.9 in most cases. In addition we could observe a dispersion layer (oil drops in a water continuous layer), the thickness of which varied with the pipe inclination.

3.3.1 Pipe inclinations 0.5° and 1°

For the details we start by looking at the results for pipe inclination 0.5°, which also proved to be representative for the 1° inclination. For these near horizontal inclinations there were hardly any waves appearing on the gas-liquid interface until we were well into the high holdup region. As a consequence there was little mixing between the oil and water, resulting in a high degree of segregation between the two liquids and nearly absence of oil drops in the water. In the high holdup region the maximum oil holdup that was measured was $H_{oil} \sim 2\%$ (oil fraction in the holdup of $\sim 0.08$), which means that the values are within the uncertainty band of the holdup measurements.

The holdup and pressure gradients for the various WC-values for pipe inclination 1° are shown in Figure 3-5. We can see that there is a significant WC-effect in the critical gas velocity for onset of transition from low to high holdup. Typically $U_{SG,CRIT}$ increases with increasing WC, but seems to reach a maximum for WC $\sim 60\%$. This WC-effect is assumed to be an “oil on troubled water”-effect. A thin oil-film is known to dampen possible interface waves, giving less interfacial drag and therefore also transition to high holdup at a higher gas velocity. It is also a trend in the results that the transition becomes more gradual with increasing WC. Again, high consistency is seen between the holdup (left) and the pressure gradients (right).

![Figure 3-5. Effect of WC on the transition from low to high holdup for pipe inclination 1° and $\rho_{gas} = 22.6$ kg/m³. Holdup (left) and pressure gradients (right)](image)

- 0% WC
- 15% WC
- 40% WC
- 60% WC
- 85% WC
- 100% WC
- $U_{SG}$ [m/s]
- Holdup [%]
- $\rho_{gas} = 22.6$ kg/m³
- Pressure gradients [Pa/m]
3.3.2 Pipe inclinations 2.4° and 5°

We then look at the details for the two steeper inclinations, illustrated with the 2.4° results shown in Figure 3-6. What distinguishes these results from the ones from the less inclined pipe is that relatively large 2D waves appeared on the interface once we started to accumulate liquid. This resulted in a more significant dispersion layer, particularly during the transients bringing the flow across the ΔH-jump. For the lowest WC of 15% this dispersion led to a markedly less discontinuous jump in the holdup. This can be clearly seen in Figure 3-6. The same phenomenon was seen in the 5°-data. For the other WCs the critical gas velocity was again shifted towards values higher than for the water-gas situation (100% WC). The earliest onset of transition was found for 60% WC.

It was only within the transition region for the 15% WC cases that we measured oil fractions in the holdup above 0.1. This was connected to the relatively dense dispersion that was found for these particular cases.

![Figure 3-6. Effect of WC on the transition from low to high holdup; Pipe incl. 2.4°, and ρgas =22.6 kg/m³](image-url)
4 COMPARISON WITH OLGA PREDICTIONS

The experimental data has been compared with model predictions using the point model of OLGAS 2000.

Some typical results from comparison between predictions and measurements for the two-phase data are shown in Figure 4-1. Each of the two plots contains measurements (Meas.) and predictions (OLGA) for both system pressures examined. We see that for the lowest pipe inclination of 0.5° (left plot) there is good agreement between measurements and model predictions, although the code underestimates slightly the critical gas velocity for transition between low and high holdup. For the steeper pipe inclinations the model overestimates the critical velocity, exemplified by the results from pipe inclination 2.4° (right plot). In all cases it proves to be better agreement between measurements and model predictions for the highest loop pressure (=gas density 46.9 kg/m³).

![Figure 4-1](image)

**Figure 4-1. Comparison between measurements and model predictions for two-phase flow at two different pressures – Left: Pipe inclination 0.5°; Right: Pipe inclination 2.4°**

In the three-phase situation the model predictions of the WC-effect show very much the same typical trends as we found in the measurements. This can be seen by comparison of the two plots in Figure 4-2; measurements to the left and model predictions to the right. For both data sets we can see that the critical gas velocity for all the three-phase cases are higher than for the 100% WC case and also that the maximum in \( U_{SG, \text{CRIT}} \) is found for the highest water cut values.
Figure 4-2. Measurements (left) and OLGA-predictions (right) of the effects of the three-phase effects upon the transition from low to high holdup; Pipe inclination 0.5°

Another unambiguous result we see in the simulations is that once the holdup starts to increase, it is mainly the water that accumulates, giving water fraction values in the holdup, $R_w$, close to unity. This result is in good agreement with the measured phase fractions, see Figure 4-3. It should be added that in the measurement plot (left) we have assumed that there is no-slip between oil and water for $U_{SG} > U_{SG,CRIT}$. (The holdup is so low in this region that the gamma densitometer can not distinguish between oil and water in the holdup.) Also in three-phase flow the critical gas velocity is overestimated quite significantly for the steepest pipe inclinations.

Figure 4-3. Comparison between measured (left) and predicted (right) water fraction in the holdup for pipe inclination 2.4°
5 SUMMARY

Two-phase oil-gas and three-phase water-oil-gas pipe flow experiments in upwardly inclined pipes with low liquid flow rates have been conducted. For this kind of flow the holdup is known to increase dramatically when the gas velocity goes below a certain critical value, \( U_{SG,CRIT} \). We have found regions where the holdup changes from 1-2% to over 20% by a reduction in the gas velocity of 2-3 cm/s. The occurrence of this transition region is strongly influenced by the pipe inclination, the gas density, the water cut and the liquid flow rate. The latter has been held fixed at 0.001 m/s in this study.

The results show that the critical gas velocity increases with increasing pipe inclination and with decreasing gas density, as could be expected from simple force balance analysis. The transition from low to high holdup is found to be relatively gradual for the lowest pipe inclination of 0.5°, compared to the steeper inclinations 1°, 2.4° and 5°. There is also a distinct difference in \( U_{SG,CRIT} \) between water-gas and oil-gas, with the former fluid combination giving the highest critical gas velocity.

The effect of having two liquid phases present is a shift in the critical gas velocity to values higher than for two-phase water-gas flow. Highest \( U_{SG,CRIT} \) is found for the highest WC-values of 60-85%. When liquid starts to accumulate this is mainly the water phase, independent of the WC, while the oil is effectively transported in a thin film on top of the more significant water layer.

The data has been used to validate the flow model in OLGAS 2000. For the lowest pipe inclination the onset from low to high holdup is well predicted, but for the steeper inclinations the critical gas velocity is overestimated. The three-phase effects are reasonably well reproduced in the predictions, both the water accumulation and the shift in \( U_{SG,CRIT} \) with WC.

6 CONCLUDING REMARKS

The present tests have been carried out in a pipe with diameter 100 mm, which is an order of magnitude smaller than a typical gas-condensate pipe. Since the transition from low to high holdup involves phenomena that one can expect are pipe diameter sensitive, an important question is how well the models extrapolate to larger diameters. While the multiphase flow models used in today’s commercially available tools are heavily based on tuning against experimental data, new generations of more mechanistically based models are likely to avail possible problems related to diameter scaling and extrapolation beyond the empirical data.

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7 REFERENCES


