FLOW ASSURANCE IN KUMUJE WET-GAS PIPELINE: ANALYSIS OF PIGGING SOLUTION TO LIQUID ACCUMULATION

ACCUMULATION

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ABSTRACT

Liquid condensation in gas-condensate pipelines in a pronounced phenomenon in long transporting lines because of the composition of the gas which is highly sensitive to variations in temperature and pressure along the length of the pipeline. Hence, there is a resultant liquid accumulation in onshore wet-gas pipelines because of the pipeline profile. This accumulation which is a flow assurance problem can result to pressure loss, slugging and accelerated pipeline corrosion if not properly handled.

Kumuje wet-gas pipeline is an onshore 19" carbon steel line which is approximately 70 km long in a hilly terrain with an elevation of 700 m above sea level. With the pipeline's maximum design gas capacity and field operational capacity pegged at 165 and 135 MMSCFD respectively, this study was tasked with proposing an efficient pigging scheme for the removal of liquid inventory from the pipeline using the capacity of the slugcatcher as the basis for the scheme, also, factors which affected liquid accumulation and pigging efficiency was investigated using a dynamic multiphase simulator – OLGA. Using OLGA 2016.2, both steady and dynamic runs were carried out in other to investigate into some critical factors such as pipe profile and inclination, pig velocity, gas velocity, bypass pig leakage etc. that influence liquid condensation and holdup in a wet-gas pipeline.

Of the three (3) pigging schemes considered, scheme 2 proved to be the ideal operational scheme because the surge volume (395 m^3) generated by the pig is within the handling capacity of the slugcatcher (600 m^3). Also, liquid holdup was seen to be strongly influenced by the pipe profile and a high flow-rate was observed to significantly reduce the volume of liquid held-up in the pipeline.

Conclusively, OLGA simulator proved to be an excellent tool in simulating dynamic multiphase flow and predicting liquid holdup in wet-gas pipelines in a hilly terrain.

KEY WORDS: Wet-gas, slugging, pigging, slugcatcher, pipeline profile, pigs, holdup

INTRODUCTION

Natural-gas condensate is a low-density mixture of hydrocarbon liquids that are present as gaseous components in the raw natural gas produced from many natural gas fields. Some gas species within the raw natural gas will condense to a liquid state if the temperature is reduced to below the hydrocarbon dew point temperature at a set pressure.

Wet Gases

Natural gas that contains significant heavy hydrocarbons such as propane, butane and other liquid hydrocarbons are known as wet gas or rich gas. Wet gas exists solely as a gas in the reservoir throughout the reduction in reservoir pressure. Unlike retrograde condensate, no liquid is formed inside the reservoir.

Liquid drop-out in wet gas pipelines is becoming increasingly common because of high changes in the composition and low quality of the natural gas supply. Predictions of possible locations where liquid drop-out occurs are, on occasion, very difficult to obtain. Moreover, estimating the amount of liquid condensation in the gas pipeline is even more challenging. From an operating gas company prospective, it is fundamental to identify those issues and take the appropriate actions to solve them before they significantly affect the operation of the entire pipeline system (Mark et al., 2016).

Flow assurance is a multidisciplinary process designed to prevent pipe blockage and help ensure uninterrupted, optimum productivity in oil and gas streams. The fluid journey from reservoir pore to process facility involves many disciplines using advanced technologies. Even long-producing fields develop flow assurance problems as time goes by and ever-deeper fields bring new challenges that extend the envelope in which the oil and gas industry can safely and economically produce (OTC, 2006).

The main issues considered when designing gas condensate systems are usually pressure drop, liquid handling and hydrate prevention. Pipeline pressure drop is mainly related to selection of correct pipeline size, while liquid handling relates to slug catcher size and plant liquid processing capacity. A large diameter pipeline will usually give a low pressure drop, but a high liquid content, causing liquid handling problems, while a smaller pipeline diameter will give higher pressure drop, but less liquid content. In addition liquid handling and hydrate prevention are closely tied to the operational procedures of the pipeline, for operations such as rate changes, shut-in and start-up, blowdown and pigging (OTC, 2006).

Hold Up/Accumulation

Liquid holdup H_L, is defined as the fraction of an element of pipe which is occupied by liquid at same instant. It is a common phenomenon in two-phase flow through a vertical pipe; when gas flows at a greater linear velocity than the liquid, slippage takes place and liquid holdup occurs. Hold up is the cross sectional area occupied by the liquid in the pipe carrying the wet gas flow. In multiphase flow, each fluid moves at a different speed due to different gravitational forces and other factors, with the heavier phase moving slower, or being more held up, than the lighter phase. The holdup of a particular fluid is not the same as the proportion of the total flow rate due to that fluid, also known as its cut. To determine in-situ flow rates, it is necessary to measure the holdup and velocity of each fluid. The sum of the holdups of the fluids present is unity.

In wet gas transportation, liquid condensation can occur in systems where the inlet feed conditions to the pipeline is nominally all in the vapor phase. As the pressure drop occurs in the pipeline, the gas will cool due to *Joule Thompson effect* and liquids can condense from the gas. Besides pressure and temperature, the other factor impacting condensation is the components of the gas composition. The phase behavior of wet gas is quite sensitive to pressure, temperature and gas composition. Change in pressure and temperature can condense some of the heavier molecules in the gas. Thus, the amount of liquid formed in the pipeline is dependent upon these three (3) parameters and multiphase flow results in higher friction pressure losses as compared to single phase flow (Leksono et. al., 2008).

For undulating pipelines with various inclinations and elevations, the gravitational force due to liquids must be considered. In wet gas pipelines, liquid holdup is strongly dependent on pipe inclination, especially at low gas velocities. Undulating pipeline profiles reduce the ability of gas to carry or sweep liquid in pipeline. It usually occurs in steep segments of pipe that requires more rates to transport all the liquids up the incline. Due to low velocity, liquid will accumulate at a low spot. Table 1.2 (as presented by Rydahi and Shea (2003)) shows the qualitative behavior of undulating pipelines transporting gas and liquid at different ranges of gas superficial velocity.

METHODOLOGY

Pigging Operation

Using OLGA 2016.2 dynamic multiphase simulator, three (3) different pigging scenarios were considered in order to determine an efficient pigging scheme for the removal of loaded liquid in the pipeline. Given the complexity of the pipeline profile as indicated in Figure 1, factors which affect pigging efficiency and liquid holdup were investigated using the parametric tool available in the software. The pipeline profile and properties of the pig used for the simulation are highlighted in Figure 1 and Table 1 respectively below.

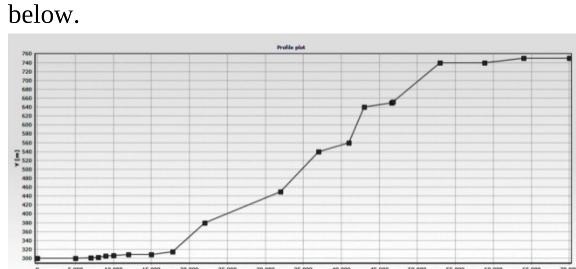

Figure 1: Kumuje pipeline profile

Table 1: Pig data for simulation model

PIG DATA	
Type	Short Bypass
Static Force	19,000 N
Wall Friction	9,500
Linear Friction	0
Quadratic Friction	4,750
Mass	600 kg
Diameter	19 inches
Leakage Factor	1%

To determine the efficient pigging scheme for the Kumuje pipeline, the *maximum liquid inventory method* of Yufei et al. (2017) was adopted.

Several factors influence pigging operation, including topography, diameter, length, OHTC (Overall Heat Transfer Coefficient), fluid components, environmental conditions, GOR, gas velocity and so forth. It is generally agreed that, surge volume is affected primarily by the velocity of pig and total liquid inventory, which are influenced directly by gas velocity in pipeline (Yufei et. al, 2017).

It is found that increasing flow rate or decreasing operating pressure can raise gas velocity and diminish total liquid inventory before pigging, while boosting the operating pressure or reducing the throughput can lower the gas velocity and slow down the pig during pigging operation. Based on the analysis above, considering operability in real field operations and range of operating pressure, three (3) different pigging schemes were designed by varying production rate and operating pressure to determine a most efficient pigging process which is economically feasible and will also produce slugs within the handling capacity (600 m^3) of the slug catcher.

Pigging Scheme 1

The throughput of the pipe line was raised from 80 MMSCFD to 90 MMSCFD after 5 hours before it will be increased to 100 MSm^3/h. After 15 hours, the throughput was increased to 120 MMSCFD, and the flow rate reduced to 90 MMSCFD before the pig was launched at the 27th hour. After the pig was received at the trap, the throughput was increased back to 120 MMSCFD.

Pigging Scheme 2

The pipeline throughput was kept constant at 120 MMSCFD and the outlet pressure decreased from 50 bara to 45 bara for 3 hours. When total liquid inventory reached stable state, the outlet pressure was raised back to 50 bara and pigging operation conducted.

Pigging Scheme 3

With the output held at 50 bara, the throughput of the pipeline was raised from 90 MMSCFD to 100 MMSCFD for 16 hours and then the outlet pressure was decreased to 45 bara before the pig was launched into the pipeline.

RESULTS

Pigging Scheme 1

Profile analysis of Kumuje Pipeline prior to pigging and at a maintained flow rate shows the holdup of liquid in relation to the piping angle. The effect of liquid holdup is more pronounced in the uphill sections of the pipeline where significant hydrostatic pressure gradients can be induced. Fig. 2 illustrates how, for a given low flow rate, liquid holdup varies with gradient In this example, liquid holdup, expressed as percentage of cross-sectional area, varies by a factor of 4 for a one percentage point change in pipeline gradient.

Once holdup has occurred, slugging can be induced by changes in flow rates or at low points in the pipeline. When the flow rate in a multiphase pipeline is increased, steady-state liquid holdup is reduced.

Fig. 2 below shows a direct relationship between the amount of liquid holdup and pipeline profile (angle of inclination). Although pipe section 41,175 m to 42,973 m has an angle of about 1.61, the liquid holdup in that section doesn’t show any corresponding increase as compared to other pipe sections, this is because the angle is too steep to hold a large volume of liquid, hence the relative low volume of liquid holdup.

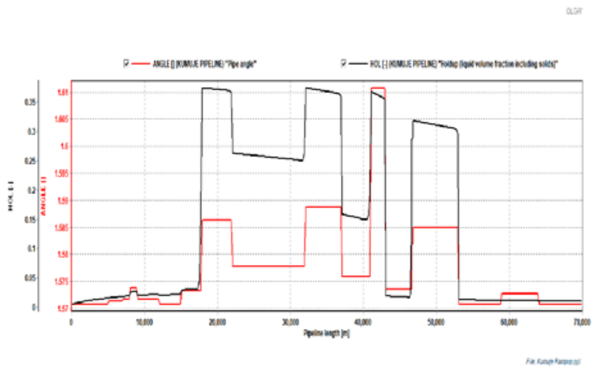

Figure 2: Liquid Holdup vs. Pipeline Angle at a maintained flow of 80 MMSCFD

In a wet-gas pipeline, the liquid present at a given location varies with gas flow rate as confirmed in Fig. 2. At low flow rates, the gas has difficulty sweeping the entrained liquid along the pipeline and liquid accumulation (or holdup) occurs. At high flow rates, however, the liquid is more easily swept along, and liquid holdup is low and of limited impact on the pressure drop.

As the gas flow rate is increased, Fig. 3 shows that the increased flow resulted in a decrease in the volume of liquid held-up in the pipeline from a maximum of 0.37 at 80 MMSCFD to a maximum of 0.32 at 90 MMSCFD, and 0.3 at 100 MMSCFD. This is because as the flow-rate was increased, some of the liquid became entrapped in the gas and then carried on to the slug catcher. The flow rate was further increased to 120 MMSCFD and it translated into the removal of more held-up liquid until steady state was reached. Increasing the throughput beyond 120 MMSCFD is not operationally advisable based on the design parameters of the pipeline; hence, the line will have to be pigged to remove the remaining loaded liquid in the pipeline.

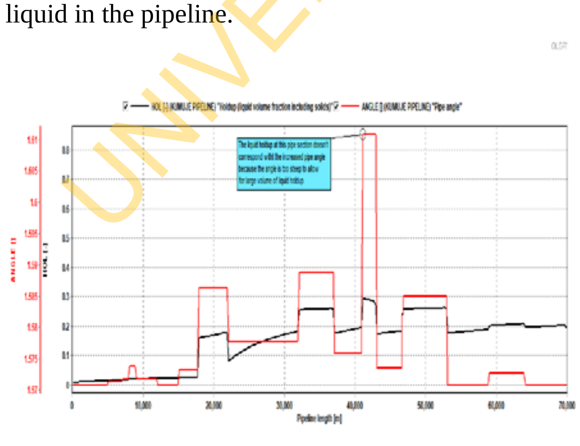

Figure 3: Liquid Holdup vs. Pipeline angle after 16 hours of simulation (Q_{16h} = 120 MMSCFD)

Prior to commencement of pigging, the flow rate was decreased to 90 MMSCFD to ensure that the speed of the bypass pig will be within the allowable limit of 1 – 5 m/s as indicated by Quarini and Shire (2007). At the 27th hour of the simulation, the pig was launched and then received at the trap after 11.3 hours. Fig. 4 shows the holdup of liquid in the pipeline after the pig was removed.

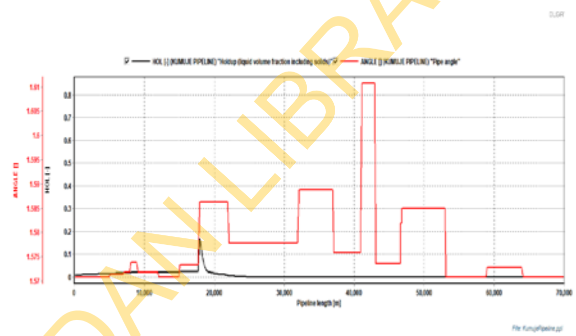

Figure 4: Liquid Holdup vs. Pipeline Angle after 40 hours of simulation (Q_{40h} = 120 MMSCFD)

Pigging Scheme 1 Efficiency

Vol. of Liquid in Pipe Prior to Pigging ($LiqVol_{bp}$) = 902 m^3

Vol. of Liquid in Pipe after removal of pig at trap position ($LiqVol_{ap}$) = 80 m^3

Pigging operation efficiency,

$$Pig_{eff} = \frac{LiqVol_{bp} - LiqVol_{ap}}{LiqVol_{bp}} * 100$$

Therefore, $Pig_{eff} = 91.1\%$

Although scheme 1 proved to be quite efficient in removing loaded liquids in pipe, maintaining an operational flow rate of 125 MMSCFD may present operational challenges since it is close to the maximum operational rate of 135 MMSCFD.

To determine if the Pigging Scheme 1 is adoptable as a pigging schedule for the subsequent removal of loaded liquid in Kumuje pipeline, the amount of removed liquid was compared with the capacity of the slugcatcher which is 600 m^3. Figure 5 below indicates the surge volume and the flow rate of liquid at the exit (Pipe-19 [section 31]) of Kumuje pipeline.

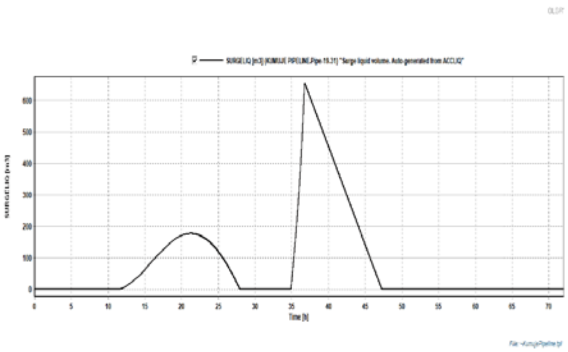

Figure 5: Slug catcher surge volume for pigging scheme 1

From the figure above, it is observed that the maximum surge volume is about 654 m^3 just as the pig was about to be trapped. This volume exceeds the slug catcher capacity of 600 m^3 situated at the pipe end; hence, this pigging scheme can't be adopted without causing an over-flooding of the slug catcher.

Pigging Scheme 2

Figure 6 below shows the liquid hold with respect to pipeline profile. The maximum surge volume expected at the slug catcher is also indicated in Figure 7.

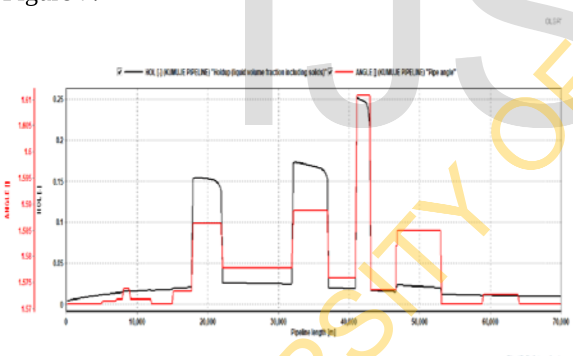

Figure 6: Variation of liquid hold up with pipeline profile for pigging scheme 2

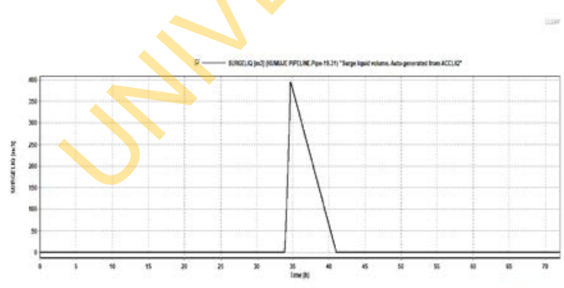

Figure 7: Slug catcher surge volume for pigging scheme 2

From Fig. 6, the liquid hold up in the section is seen to increase correspondingly with the pipe angle of inclination as compared with pigging scheme 1 (Fig. 2) which had some exception. This is because the high gas flow rate and the reduced outlet pressure allows for liquid to remain in the accumulated pipe section. Also, the maximum liquid holdup value is seen to be 0.25 as compared to the 0.37 recorded in pigging scheme 1.
The estimation of the surge volume for scheme 2 shows that maximum surge of 395 m^3 is expected at the slugcatcher after the bypass pig reaches the trap. This value is within the slug catcher's design capacity; hence, this pigging scheme is adoptable for the removal of loaded liquid from Kumuje gas-condensate pipeline.

Pigging Scheme 2 Efficiency

Vol. of Liquid in Pipe Prior to Pigging ($LiqVol_{bp}$) = 534.32 m^3

Vol. of Liquid in Pipe after removal of pig at trap position ($LiqVol_{ap}$) = 69 m^3

$$Pig_{eff} = 87.1\%$$

Pigging Scheme 3

For pigging scheme 3, the maximum liquid holdup in the pipeline was found to be 0.32. Although this value is lower than that recorded for scheme 1, the surge volume is significantly larger than that of scheme 1. This could be attributed to the higher gas flow rate in scheme 1 which was sufficient to carry out a good portion of the liquid before the commencement of pigging operation.

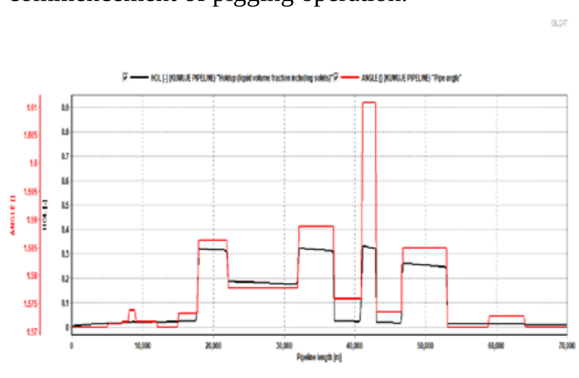

Figure 8: Variation of liquid hold up with pipeline profile for pigging scheme 3

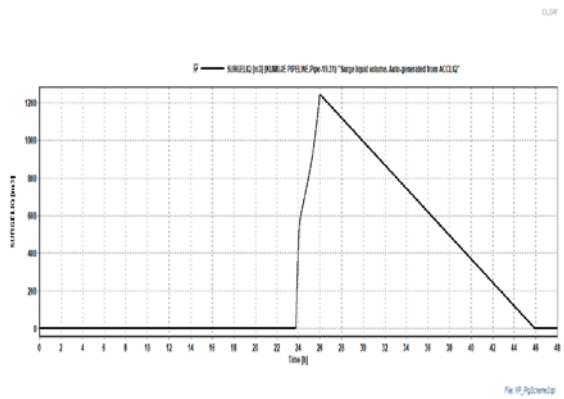

Figure 9: Slug catcher surge volume for pigging scheme 3

Pigging Scheme 3 Efficiency

Vol. of Liquid in Pipe Prior to Pigging ($LiqVol_{bp}$) = 1511 m^3

Vol. of Liquid in Pipe after removal of pig at trap position ($LiqVol_{ap}$) = 75 m^3

$$Pig_{eff} = 95.0\%$$

Pig Speed vs. Pig Efficiency

From the simulation result for pigging scheme 1 – 3, the effect of the velocity on the efficiency of the pig was determined. Figure 10 below shows that at a constant leak opening of 1%, the accumulated liquid removal efficiency of the pig increases with a decrease in pig speed and this relationship is found to be valid within a pig velocity of 1 – 5 m/s.

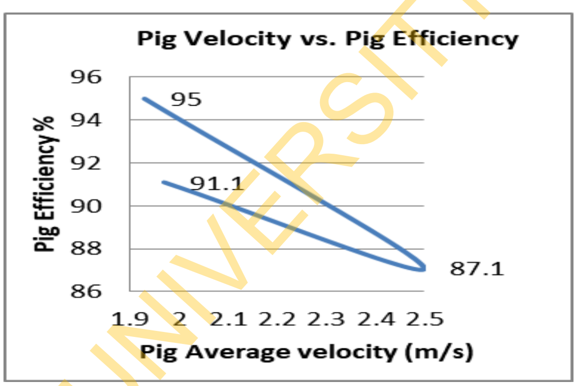

Figure 10: Effect of pig velocity on pig efficiency in removing loaded liquid

Gas velocity vs. Holdup

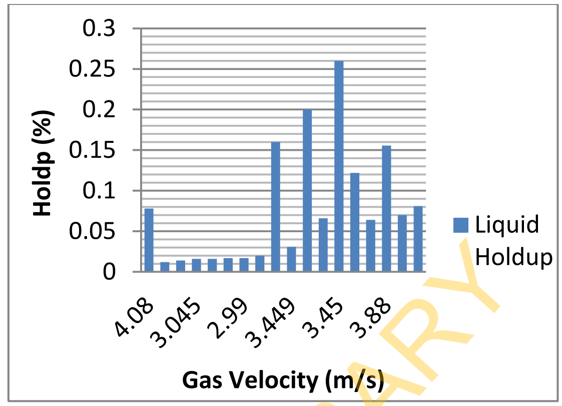

Figure 11: Holdup vs. Gas velocity

Hence, the optimum gas velocity was calculated as 3.46 m/s

Flow Regime

Three (3) different flow regimes were recorded in Kumuje pipeline during the dynamic flow simulation using pigging scheme 1. The dominant flow in the pipeline was stratified flow except at pipe bends in which slug flow is briefly observed. After the pig was lunched in the 27th hour of simulation, bubble flow was briefly observed as indicated in Figure 12.

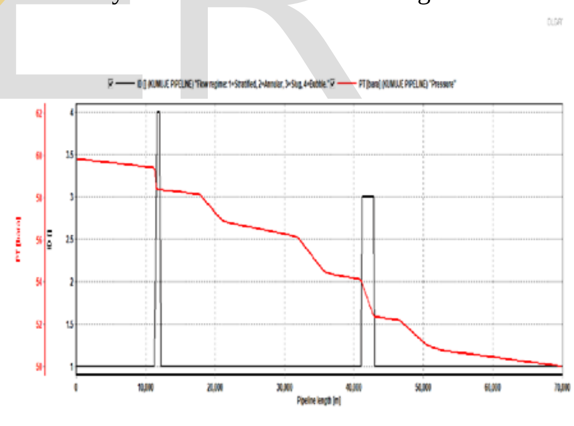

Figure 12: Flow regime in Kumuje pipeline

P&T vs. Liquid Holdup

Pipe section 9 was studied under pigging scheme 2 so as to determine how variations in pressure and temperature affect the condensation of liquid in the pipeline. Fig. 13 shows the trend profile from OLGA dynamic multiphase simulator.

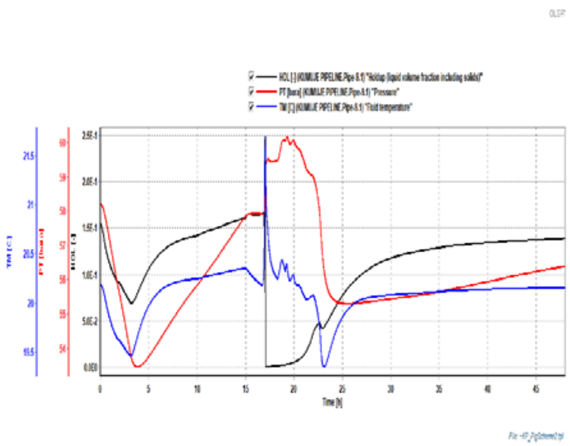

Figure 13: PT vs. Holdup

Table 2 below presents the summary of the dynamic simulation of Kumuje gas-condensate pipeline. It can be seen that Pigging Scheme 2 is the most effective way of removing loaded liquid from the pipeline without imposing any additional financial or technical constraint on the operation of the pipeline.

Table 2: Summary of transient simulation of Kumuje Pipeline using OLGA

Pigging Scheme	Acc. Liq. (m^3)	Holdup (%)	Pig speed (m/s)	Gas velocity (m/s)	Pigging efficiency (%)	Surge volume (m^3)	Slug catcher capacity (m^3)	Is scheme viable?
1	1996	0.37	1.97	2.16	91.1	654	600	No
2	624	0.25	2.5	3.32	87.1	395	600	Yes
3	1504	0.32	1.93	3.24	95	1312	600	No

CONCLUSION

Having investigated into flow assurance challenges in onshore wet-gas pipelines, specifically liquid holdup/accumulation in pipelines; the following conclusions can be drawn after a complete review and analysis of the results obtained from the dynamic simulator:

1. Kumuje gas-condensate pipeline model was successful built using OLGA dynamic multiphase simulator and several simulation cases were run to study the phenomenon of liquid loading in onshore gas pipes.
2. Liquid condensation in wet-gas pipelines is a function of the sensitivity of the gas composition to changes in pressure and temperature over the entire length of the pipeline.
3. The liquid holdup in the pipeline is strongly dependent on the pipeline profile and angle of inclination.
4. There is a direct relationship between pig velocity and pig efficiency for velocity values between 1 – 5 m/s.
5. The slugcatcher can be used as a basis for the design of a pigging scheme
6. Pigging scheme 2 was adopted as the ideal scheme for the pigging of the pipeline after it yielded a surge volume less than the slug catcher's design capacity.

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