Abstract

A number of multiphase flowmeters were recently deployed in the Yamal peninsula in Northern Siberia to perform multiphase measurements of the rates of gas and condensate wells. The utilization of multiphase flowmeters in wet gas and condensate wells is relatively new, and significant progress have been made in the understanding and the quantification of multiphase flowmeter uncertainties in flow loop. Little field experience is documented to date and this paper presents field data in this very challenging domain.

The paper describes the metrological evaluation of the full operations – not limiting itself to the dual energy gamma Venturi multiphase flowmeter that is being used, but also to the fluid property estimation. A discussion of the specific regulatory reporting in Russia for gas wells also presents some of the particularities of these operations. The paper presents the results of testing over 50 wells since 2006 – comparison to traditional and other multiphase flow metering devices are presented. Some unexpected behavior of these condensate wells are presented – confirmed by other instruments, resulting in a series of recommendations that provide a significant modification to the traditional guidelines used for the measurements of rates of gas, condensate and water in similar wells.

A brief discussion on the applicability of the multiphase measurements to condensate allocation workflows concludes the paper.

Introduction

Recent focus on gas condensate testing in the Yamal peninsula has pushed a number of operators to consider alternative way to perform such measurements. The operating are is quite challenging and located slightly north of the arctic circle in Northern Siberia as shown in Figure 1.
Fig 1: Operating area of the Yamal Peninsula - Siberia

The drivers for this change were:
1. Reduced logistical needs
2. More efficient operation
3. Safety
4. Environmental footprint
5. Condensate rate accuracy and resolution
6. Independent verification of prior data

The utilization of multiphase flowmeters is becoming more and more common in the world to estimate the performance of oil and gas wells. They are used in what is called “well tests” and provide information about flow rates of oil, gas and water. These measurements are essential to the determination of the productivity of wells, diagnostics of problems associated with the oil or gas reservoir, detection of mechanical problems related to the production system located in the well (so called “completion”) and the determination of the efficiency of artificial lift system (pumps allowing the flow of oil and water from reservoir which pressure is too low to push the fluids to surface). Figure 2 illustrates the various types of application of gas condensate testing in production wells.
The traditional approach consists in using a separator to segregate the flow of commingled oil, gas and water into three distinct single phase flow streams that are then metered using traditional metering technologies. These separators have been in use for the last 150 years in the upstream oil and gas industry. They tend to be bulky, associated with many moving parts to control the separation process and their large body must be protected by safety pressure relief valves to avoid the risk of over-pressurization if a valve comes to close downstream or if the flow becomes too large for the system to handle. Typical separator skid mounted system to meter up to 15,000 blpd and 35 MMSCFD is shown in figure 3.
These separator are quite bulky with a typical weight of 16 Tons. The overall uncertainty of the rate measurement depends entirely on the quality of separation. They do however provide a continuous split of the phases (either gas and liquid, or full three phase split – oil gas and water) which may be essential to the performance of some operations where the disposal of the fluid is mandatory – such as in exploration and clean-up testing. Latest developments introduced by the service industry consist of detection of the carry-over and carry-under respectively in the gas and liquid line, the utilization of variable wear to control actively and efficiently the level of the interfaces and thus optimize the retention times to enhance quality of separation.

In the Yamal peninsula, other types of well testing devices are also used. A common device involves a centrifugal separation in a small vessel. It enables the separation of the condensate which is accumulated over short period of times – typically 15 minutes – and meters in batch mode. Such a device is show in Fig 4. These device are not equipped per-se with measurement devices. A “DIKT” device is used to meter the gas rate and consists of a differential pressure measurement device located at the tip of the flare across a fixed orifice plate located between two flanges. The volumetric measurement by batch is performed in the centrifugal separator by timing the duration to fill the bottom of the device between two ports located about 50 cm apart.
Well testing is in essence an activity that is performed either at the well head, in production manifold or in production plant. Today every well is tested on average about every 3 months – some legal requirements for production reporting request much more frequent testing – once a month or even once every two weeks.

Well testing performed at the well head or in production manifold is usually performed by services companies using specially designed mobile equipment. A traditional separator well test set would fit on a large trailer and require a crew of 4 people to operate. The transport of such equipment can be quite challenging.

The separator challenges in Gas Condensate Testing:

In the early 90s many attempts were developed to design and deploy in-line multiphase flowmeters which would alleviate the problems associated with separator mentioned earlier. These attempts resulted in a number of concepts that were deployed in the field with a varying degree of success. Many concepts using various combinations of measurements were used for the purpose of estimating the flow rates of oil gas and water, and many failed to prove to be sufficiently robust – the whole key of the well test. Some other approached the problem from a different angle with the idea of tuning a concept of measurements against a reference – leading to virtual flow meters methodology. Such implementation rely heavily on a reliable measurement with tradition separation capability and a proper field architecture – such implementation are still few and located mostly on tight offshore platform where permanent test facilities are available in the production system.

One of the drivers for in-line measurement was also the elimination of the dependency of the data quality on the quality of separation. With increasingly high rates at the well head resulting from horizontal well with large drain being drained, High-Pressure-High-Temperature completions and longer hydraulic fractures, the need for even larger separator set-up appeared to improve retention times in the vessel and sure adequate separation – leading in some cases to design of skids weighing over 60 tons. Such deployment are challenging to say the least – making even more the case for in-line flow multiphase flowmeters that can deliver similar capability in 3.5 ton-skids.
The quality of separation is an issue that has been recognized for many years in the industry and is still hunting the well test community in particular in the gas condensate testing environment. The utilization of centrifugal systems has also been used – either in stand-alone devices or as internal add-ons within the separator bodies. Fig. 4 showed an example of such device deployed in the well test in the Yamal area. Tests performed against the multiphase flowmeter have shown that one can observe little carry-over during the measurement period. However the batch nature of the measurement does not allow for the proper capture of the transient nature of the flow in some wells or choke conditions and the shortness of the liquid rate measurement does not provide for full coverage of the slugging effects.

It is important to evaluate the consequence of carry-over and carry-under on the metering performance of the whole system. The presence of a small amount of liquid in the gas line does create – especially at low pressure – large error on single phase gas measurements acquired with orifice plate devices for example. Newer technologies such as Coriolis meters are also affected – the measurement of density provides an indicator as to the presence of liquid in the gas line – but the basic assumption of that the two phases are moving in synch in the vibrating tube is usually difficult to prove – thus leading to uncertainty as to the quantification of the liquid phase present in the gas line and the proper correction to the computation of the gas rate in that very same line. Similar considerations are true for presence of gas in the liquid line – carry-under.

New types of dedicated devices using Sonar techniques for example have been recently developed to provide better quantification and correction for the presence of carry-over and carry-under. It is interesting to note that these devices are in essence multiphase flowmeters with a particularly dedicated operating rate of Gas Volume Fraction (GVF) , pressure and temperature. Ref (1). They start to be deployed in well testing systems in challenging applications.

The evaluation of the metrological performance of multiphase flowmeters in oil wells has been the topic of many Joint Industry Projects and individual initiatives (ref 2). The multiphase flowmeters presented various degrees of accuracy and repeatability – depending on the type of measurement methodology that is being used. But all multiphase flowmeters demonstrated more or less a similar degradation of the accuracy of the measurement of liquid flow rate with increasing GVF – not a surprise in itself, as the problem becomes more and more difficult with the relative rarefaction of the liquid in the full stream.

Challenges of Multiphase flow metering in gas condensate wells:

Multiphase flowmeters were developed to tackle initially the oil wells with GVF below 85%. However, it was soon realized that some oil wells experienced higher GVF in specific production applications such as gas-lift systems where gas is injected in the completion and allows a effective reduction of the average density of the mixture in the production tubing that allows for the induction of flowing conditions. However, once at surface the mixture of free gas from the hydrocarbon stream from the oil reservoir and injected gas from the lift gas generates a large volume of gas that leads to GVF that can reach an average of 96%. Furthermore, it is not uncommon to see such wells operating in non-optimal unsteady modes, leading to periods when almost only gas is produced. The measurement of such wells presents a number of specific challenges which are not only linked to the high GVF, but also to the transient nature of the measurements. The Vx technology proved to be extremely effective at managing this type of measurement environment as documented in Ref. 3.

The Dual-Energy Gamma Venturi multiphase flowmeter:

The Vx technology was developed as a combination of a dual-energy gamma Venturi combination of measurements to perform rapid acquisition of the characteristics of the flow 45 times per seconds and provide an accurate estimate of the rates of oil gas and water in the stream. This research and engineering effort was led with Framo Engineering as a partner. It was initially commercialized in the upstream part of the oil fields in 2000 for the oil wells. The meter is connected on top of a blind T. Its overall schematics is illustrated in the following Fig. 5. It consists of a venturi with a beta ratio of 0.5 combined with a dual energy gamma system using a small Ba 133 source which beams gamma ray through the throat of the venturi. A proprietary nuclear detector was designed as a
further development of the Schlumberger density logging program. This high speed system allows for a full spectral analysis of the nuclear signature of the flow to be performed every 22 ms. A very high sensitivity and extremely high stability are the key elements for a high accuracy measurement even at high GVF.

In 2005, further hardware combined with significant improvements to the rate computation model (Atkinson et al., 2004) allowed an extension of the application of the Vx technology in the gas field – yielding impressive results even at very high GVF (98%). Originally targeted in ensuring a very robust gas rate measurements in all conditions (+/-2%), the liquid rate computed is also quite robust and provides significant improvement over traditional means of measurements – especially at high rate when separation based device become too large to handle.

![Diagram of Dual-Energy Gamma ray – Venturi multiphase flowmeter.]

**Fig 5: Dual-Energy Gamma ray – Venturi multiphase flowmeter.**

**Sensitivities to set-up parameters of the Dual-energy Gamma Venturi multiphase flowmeter applied to the gas condensate testing environment:**

The computation of flowrates cannot be performed without knowledge of some of the properties of single phase fluids flowing inside a meter – for several reasons:

- the allocation between the phases must be performed in relation to the properties of each of the phases present at measurement conditions
- the reporting of standard volumetric rates requires some knowledge of PVT relationship describing the evolution of the fluid undergoing a flash (or series of flashes) from measurement conditions to standard conditions

It is important to note that the second point is also affecting the performance of single phase flowmeters located on the outlet of a separator system. The mass reporting system used in Russia by the authorities presents the benefit of being conservative – The C5+ mass fraction is independent of the transfer of mass of the hydrocarbon in the liquid phase to the gas phase or reciprocally when one takes the fluids from the measurement conditions to standard conditions. Unfortunately there is no direct way to perform such chromatographic measurements on the so called “Unstable” condensate which would require a chromatographic column to run under pressure and temperature of the process. The local lab performs a flash to standard conditions in a single stage and the individual stream of liquid and gas evolved from this flash are metered individually and analyzed individually to obtain the proper recombined unstable condensate composition originally present at measurement conditions. Some of the Russian well testing PVT analysis report standard also suggests the utilization of a debutinization process to obtain the proper fraction of C5+ in the stream.
It is possible to predict the propagation of the uncertainty related to the input parameters on the final computed standard conditions rates. Such dependencies allow the determination of the need for accuracy in the fluid properties that are used to compute the rates of condensate, gas and water. In the case of the in-line multiphase meters, it is surprising to note that regardless of the technology used that the uncertainty associated on the gas properties under measurement conditions impacts very largely the liquid rate (condensate + water). This is an essential non-intuitive difference from the traditional separator based system. On the other side, the prediction of the overall metrological performance of the Vx technology is not affected by the quality/efficiency of separation.

The following figure presents an example of such sensitivity. We have developed a specially designed software which enables such prediction – non intuitive in the gas condensate domain – to facilitate the selection of the proper methodology of determining the fluid properties in the field. A relative variation of 0.5% of the value of the density of each of the gas generates for example only a change of 0.73% of the computed gas rate, but generates a 15.7% change on the condensate rate in this particular case.

Fig 6: Dependency of the condensate, gas and water rate on the fluid properties uncertainty

It is therefore utmost important to ensure that the dry gas properties are quite accurately characterized at line conditions in order to perform a proper measurement of the liquid rate. A specific proprietary software has been developed to help field operator and production engineers to design properly the well testing operations and allow for a better understanding of the performance of the multiphase flowmeter in such environment. It is important to note that the sensitivity of the gas properties on the liquid computation is a particular behavior observed in all existing in-line multiphase flowmeters.

A word of caution needs to be stated here: it may seem straight forward to build a sensitivity model from the published equations extracted from multiphase flowmeter manufacturer publications. One shall beware that there are a number of simplification in the expression of the models that does not provide for the full understanding of the linkage between all of the parameters inside the flowrate computational model actually used, and direct conclusion from the general equations may not show the full complexity of the problem. We recommend to obtain specific simulation of sensitivities on the actual behavior of the multiphase flowmeter directly from the manufacturer to obtain reliable information.

A key element of success: the Multiphase Sampling Device:

Consequently, a special effort was developed to obtain representative and quality samples of each of the phases in the multiphase stream.

In order to capture and characterize condensate, gas and water, a specific sampling device has been developed. It connects downstream of the measurement section of the dual-energy Venturi multiphase flowmeter.

The multiphase sampling device hardware consists of:

- A multi-probe sampling device that retrofits to the liquid sampling port on the multiphase flowmeter (MPFM);
- Optical phase detector (OPD) used to sense the type of fluid entering or leaving the sample chamber, based on the differences in their refractive index;
- A well site fluid property measurement kit which allows the direct measurement of the key fluid property inputs at line and standard conditions for any type of multiphase flow meter;
- A dedicated data acquisition software to receive the directly measured fluid property inputs as alternative to the standard correlation available with the MPFM multiphase meters.
The multiphase sampling device hardware addresses the sampling and thermodynamic equilibrium issues with the following features:

- The multi-probe sampling device is inserted through the liquid sampling trap and into the multiphase flowmeter stream. This configuration benefits from the mixing in the Venturi located upstream the sampling probes. Additionally the samples are taken at the same point, which ensures that the pressure and temperature is constant and refer to the same thermodynamic equilibrium.

A detailed description of the operating procedure of the multiphase sampling system has been presented earlier by Afanasyiev et al. The suggested system provides the following benefits:

- Multi-probe assembly: The multi-probe sampling device has several probes in the flow stream arranged axially and facing both upstream and downstream. This allows the optimum selection of a given sampling probe to collect predominantly condensate, gas or water.

- The ability to enrich any desired phase during the sampling process: If a specific phase exists in a very small fraction inside the flow the multiphase sampling device enables active enrichment of this particular phase so that a large enough volume is captured by displacement of the “unwanted” phases.

- The pressure and temperature is maintained by heating and insulation during the sampling, segregation and enrichment process to ensure there is no mass transfer between the phases.

- The ability to verify that the correct phase has been captured or transferred utilizing an optical phase detection technique.
Fig 9: Multiphase sampling system rigged up on the multiphase flowmeter.

Integration of the fluid properties into the computation graph of the flow rate:

As discussed earlier, the importance of setting properly the meter is essential to the proper estimation of the multiphase flowmeter. In well testing services, as opposed to the permanently installed metering system, it is rare that all of the fluid information be available before the operation itself. In our modus operandi, we collect the samples concurrently with the measurements of the raw data to compute rates, and perform the fluid analysis later – with a delay that can range form hours to months – depending on the complexity of the analysis required and the logistical environment.

Once the fluid information is obtained after sampling and analysis, it is necessary to integrate these data properly into each of the steps of the work flow leading to the computation of the flow rates of condensate, gas and water. Once again, it is necessary to never forget that all in-line multiphase flowmeter tie-in deeply into their computations the rates of each of the phases – and that the changes of the properties of one of the phases in the calculations will affect (to an extent that will be a function of the GVF and WLR) the rates of the other two phases.

Such implementation is illustrated in the following over all processing flowcharts:

Fig 10: Overall Flowchart illustrating the processing of the data to obtain flowrates – the post processing is presented in the following figure.
The post processing chain is described in figure 11:

![Flowchart Illustrating the Processing of the Data to Obtain Flowrates](image)

**Fig 11: Overall Flowchart illustrating the processing of the data to obtain flowrates**

It shall be noted that in order not to perform the well test “blind” a set of parameters are entered in real time in the meter (or prior the beginning of the operation) and allows an early estimate of the flowrate that will be available immediately. This estimate can be significantly off the final computation in gas condensate testing, for example if the gas properties have been poorly guessed initially.

**Multiphase flowmeter metrological performance in wet gas environments:**

The metrological performance of the flowmeter can be estimated in flow loops. A number of tests were performed in various installations in the world to ensure that the meter performs truly independently of flow patterns and flow regimes – signatures are seen to be somewhat intrinsic to each flow loop. The metrological performance of the meter obtained during very short flow periods of 10 minutes can be summarized as a function of the gas volume fraction. For the gas rate and provided that the pressure is high enough (above 35 bars) we obtain an uncertainty (90% level confidence of +/- 2%. For the liquid rate the metrological performance deteriorates as the GVF reaches 100% - there is not enough liquid to be detected in the in-line (ie no separation) meter. The flow short flow loop test period have demonstrated that an absolute performance of the liquid rate determination in order of +/- 10% from 95 to 97% GVF and +/- 15% from 97 to 99 % GVF. We obtain reasonable liquid rate in the field even at higher GVF, but on much longer flow periods where the integration of the liquid rate becomes more reliable than its instantaneous measurement.

It is true that the shortness of the duration of the flow loop tests does not provide for the full understanding of the actual capability of the meter in the actual field performance. It is very challenging to obtain very stable flow conditions and consistent GVF over long period of time in flow loops – and rather costly. Field production conditions tend to provide more stable overall flows – although the instantaneous flow regimes may change continuously.
The field operations have demonstrated an amazing capability of resolution in the order of $1g/m^3$ of liquid over a period of 50 hours of measurements. An example of the distribution of the condensate to gas (CGR) ratio over a 4-day flow period is shown in Fig 12:

![Distribution of 1-min instantaneous CGR collected over a “stable” flow of four days – comparison between 5 flow periods under different choke conditions from the same well showing the resolution capability of the dual energy-gamma multiphase flowmeter.](image)

All flow measurement periods right after a build-up, even short, are showing large amount of transient behavior – gas rate stabilizes in minutes – liquid rate may stabilize in days…

**Recommendations for operations of in-line multiphase flowmeter during well testing operations in gas condensate well:**

**Test design:**

Test design is referred as the process to establish the optimum test program and various contingency to be applied to mitigate potential problems that may be encountered during the operations – either because of “unconformities” during the execution of the program or because of deviation against the expected well / reservoir behavior – by the way – that is the whole reason for such tests.

The test design shall consider that the change of chokes setting will affect the stability of the condensate bank and the well. The change of the reservoir response come essentially from changes in the saturation of condensate around the well bore due to changes of pressure mostly – but could also be the effect of rate or in case of build-up the effect of liquid back at the bottom of the well due to well bore redistribution effects and cooling in the upper region of the tubing.
The duration of the flow period shall be long enough to allow for full stabilization of the tubing column and good statistical description of the flow pattern – we have found that in some wells in the Yamal peninsula, this could take up to 4 days per flow period. Finally a sensitivity of the variation of the fluid input parameter in the computational model of the flow rates must be performed prior to the test to ensure that the expected uncertainty will be mitigated with proper fluid identification processes.

**Rig-up / Layout:**
The preferred rig-up consist is installing the multiphase flowmeter upstream of the choke – or choke manifold and direct the effluent to the production line. This provides a safer system and avoids burning of effluent at the well site. It also ensures that the meter will be operated at a higher pressure – normally leading to enhanced metrological performance in the retrograde condensate behavior of the multiphase well fluids. It also provides a chance to operate away from the hydrate forming conditions - which deteriorates significantly the quality of a well test as discussed above.

It is also better to ensure a proper stabilization of the pressure in the multiphase flowmeter. Small variation of back pressure may change significantly the split of the phases in the meter simply by changing the position of the mixture in the phase envelope. The integration of these instantaneous changes is not linear and is best avoided by making sure that the pressure (and hopefully temperature) will be reasonably stable over the test flow period.

**Duration of operation:**
The main issues during the operation are the lack of capability to act rapidly when hydrates starts to appear in the system. One has to start injecting in a controlled manner methanol or glycol. The injection process shall as smooth as possible (otherwise the meter will pick up the transients created by the slug of injected chemicals). Furthermore accurate metering and timing of the injected rate is to be collected in order to correct the reading for the presence of the chemicals. A nuclear attenuation of the injected chemical with an in-situ is also recommended.

The determination of the proper empty-pipe and gas in-situ reference point are essential. The test procedure shall provide ample amount of time for the determination of these points and ensure post test verification. The duration of such empty-pipe reference could be as long as 12 to 24 hours, the longer the better for the metrological performance of the system. The procedure for the gas point characterization in the Yamal area involves the performance of a gas in-situ reference which requires also quite a significant amount of time. Alternative option consists in the determination of a “theoretical” gas attenuation from its composition.

**Sampling recommendations:**
Collect samples on all flow periods and compare the gas properties and liquid shrinkage – during a multirate test, there could be significant difference of the contribution of various zones and changes in composition of the near well bore area in the condensate bank that may affect significantly the commingled gas properties measured at the surface. If not considered in the computations of the liquid rates, such changes may generate significant error.

**Hydrate:**
Management of hydrate is a primary concern – in particular when the multiphase flowmeter cannot be installed upstream the choke. Hydrate formation can occur in seconds and lead to a partial plugging of the lines downstream of the choke. Smooth injection of methanol or glycol is a must in order to mitigate the problem and maintain the flow. It is very important to achieve a smooth injection in order to be able to back calculate the rate of chemical injection from the meter readings. Change of back pressure may also affect the rate computations and shall be considered when defining the reliable period of flow that may be considered during testing.

**Data management**
Data shall be gathered in such a way that post processing of the rate information is possible to include the latest knowledge of fluid properties that will impact the computations. The linkage between gas properties and the computation of the liquid rate is very strong and shall be managed properly in the data management chain – as such fluid related information may be available only weeks after the operation. It is therefore important to ensure that a strong process enables a proper identification of the fluid properties used to provide flowrate. The case of permanent installation is quite different, as no sudden change of fluid composition would normally be expected under stable flowing conditions.
Verification / post job analysis
The procedure to verify the flow rate consists in a detailed audit procedure of the following factors:

- Empty pipe
- Gas in-situ reference point
- Fluid sampling periods
- Operating triangle analysis
- Stability of flow periods
- Hydrate identification in meter
- Chemical injection rate subtractions
- Fluid parameters input
- CGR consistency check

The analysis of gas condensate wells based on the dual-energy gamma multiphase flowmeter provides a good insight as to the real instantaneous performance of gas and liquid productions – in particular in transient modes in the presence of a condensate bank in the near wellbore zone. The analysis of such information is quite unconventional and requires expert analysis – a number of phenomenon ranging from temperature stabilization, liquid loading, and retrograde condensate behavior shall be taken in consideration in the data analysis.

Applicability to allocation processes:

The dual-energy gamma Venturi multiphase flowmeter can be used to allocate production in gas well allocations. The gas allocation will be quite robust (noting the +/- 2% uncertainty). The liquid allocation will need to be evaluated carefully on an ad-hoc basis. The uncertainty of the liquid production is quite large (+/- 10 to 15 % typical depending on the GVF), but more importantly the issue of mass transfer between the various stream needs to be careful evaluated if there is significant variability in the produced stream. The shrinkage factor in particular can be dramatically affected by the blending of products (either upstream or downstream of the meter) and the processing chain well defined to ensure that all standard conditions reporting is performed according to the actual process and agreed upon.

Regular sampling of the streams also needs to be performed to ensure that no significant variation of the gas properties has occurred. Systematic processes of control of the gas properties need to be in place to ensure consistent reliable allocation over time with the multiphase flowmeter.

Changes in processing conditions may impact the measurement is there is no control of pressure in the meter – another factor that needs to be mitigated – thus the recommendation to perform the multiphase metering at a controlled and agreed pressure throughout the process. In sub-sea application this may not be possible and requires the validation of the mass transfer model. A verification of the samples at the receiving arm will also provide a check as to the consistency of the input parameters set inside the meter.

A final word of caution: liquid production may be quite more sporadic than would be expected from gas wells, when a condensate bank is present. A particular care should be taken to ensure that the measurement duration are long enough to ensure a proper accounting of the “rogue” slugs that may appear – not often – but could carry a significant contribution to the liquid content of the stream.

Conclusions

The challenge of multiphase metering in gas wells can be met for well testing upstream application with dual energy gamma – Venturi multiphase flowmeters.

The operability of such devices in challenging environment of the Arctic Operating area of Gazprom, Achimgaz and Rospan International in the Yamal Peninsula has been confirmed. A number of benefits ranging from logistics to the ability to monitor continuous the flow of gas, condensate and water during a sequence of change of chokes provides unmatched capabilities.

The technical challenge of metering wet gas is complicated with the unsteady nature of the flow with instantaneous GVF ranging from 80% to 100%. Overcoming such challenge requires a very fast acquisition of the fraction and proper flow model to cover large variations of flow regimes inside the metering section.
The determination of the empty-pipe reference point is essential in the proper set-up of the multiphase flowmeter – not only for the longer term type of operations but also for shorter jobs. These empty pipe could be as long as 12 to 24 hours to optimize the performance of the meter.

Operational issues still to be worked on involve the management of hydrates on smaller chokes when testing downstream of the choke manifold. Non continuous injection of methanol complicates the matter significantly in defining acceptable and representative data.

The linkage between fluid property and rates is very strong – and non-intuitive for the in-line multiphase flowmeters such as the dual energy gamma – Venturi multiphase flowmeters. The sensitivity of the liquid rate measurement is essentially a function of the gas properties – unlike traditional separation based system.

The determination of the exact fluid properties for the gas and the condensate – including shrinkages and proper densities is essential and can only be performed by collecting representative samples of the fluids during the tests. A special multiphase-fluid-sampling device has been devised and has performed very well – collecting representative samples of gas and condensate that are of PVT analysis quality – in the absence of a separator. This approach differs notably from more traditional isokinetics sampling methodologies because it does not rely on the assumption that one can collect a multiphase sample with the representative relative volumes of the three phases present in the flow.

No such assumption is performed here and each of the single phase fluid is analyzed separately and recomputed (either mathematically or physically) using the recombination rations from the multiphase flowmeter – but with rates recomputed using the actually measured properties from the analysis of the samples collected. The quality of these surface samples collected from the multiphase fluids sampling device was verified against downhole samples.

The interpretation of the data acquired in terms of condensate to gas ratio during a multirate well test must consider the transient phenomena created by the growth and change of conditions of the condensate bank around the well bore. These phenomena can occur rather rapidly after shut-in periods or change of choke and present significant hysteresis. The multiphase flowmeter provides insights as the stabilization time for these wells – thus leading the operator to extend the flow periods significantly until full stabilization is reached again – in cases days. Some research work needs to be performed to provide a robust methodology of interpretation of these transients.

A number of recommendations are provided in the paper to ensure optimum deployment of dual energy gamma multiphase flowmeters - ranging from rig-up and deployment to operational issues.

Condensate monitoring with in-line dual energy gamma ray venturi multiphase flowmeters is possible and provides new insight on gas well performance in the presence of a developing condensate bank. Analysis of the full meaning of transient of CGR observed in the field is still on-going but it is hoped that these could provide additional information as to the well performance and near well bore behavior in the condensate bank.

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References:


**Nomenclature**

<table>
<thead>
<tr>
<th>CGR</th>
<th>= Condensate to Gas Ratio (at standard conditions)</th>
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<tr>
<td>GVF</td>
<td>= Gas Volume Fraction (at line conditions)</td>
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<tr>
<td>WLR</td>
<td>= Water Liquid Ratio (at line conditions)</td>
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