Advanced Formation Testing and PVT Sampling in Deep Gas Condensate Reservoir: Case Study from Malaysia

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Abstract

Downhole sampling in gas condensate reservoir is well known to be challenging due to the nature of near critical fluids. Reservoir fluid properties can change dramatically with slight changes in reservoir pressure and temperature. As a result, accurate and representative PVT data are essential for reservoir fluid modeling and field development planning but difficult to obtain using conventional sampling techniques.

This paper presents the first successful downhole gas condensate sampling in a high pressure gas condensate field, offshore East Malaysia. Samples collected from the previous surface tests showed large variation in Condensate Gas Ratio (CGR) from 50 to 200 stb/mmscf. This resulted in large uncertainty in the dew point pressure, condensate yield, well productivity, and reservoir fluid type. There was strong need to acquire high quality downhole samples to reduce these uncertainties, which can potentially affect the entire field development plan. Through the use of new technology and an integrated team approach, it was possible to take representative single phase fluid sample using controlled drawdown and real time fluid analysis of downhole sample.

There were several key challenges in this operation. The team had to take single phase gas sample, with minimum contamination in a High pressure High temperature (HPHT) well drilled with Oil Based Mud (OBM), station time had to be as short as possible to avoid tool getting stuck, and have an initial estimate of dew point pressure and Gas Oil ratio (GOR) from downhole measurements. This was achieved using real time data monitoring and control of the entire wells site operation from PETRONAS Carigali office. The latest downhole fluid identification tool was used along with focused sampling to minimize OBM contamination. This paper will highlight the effective use of various elements of new technology and team work.

Fluid density measurement was found useful in answering some of the questions. It allowed comparison with optical fluid analyzer to provide an improved fluid identification. It also allowed to optimize the number of pretests and hence reduce the rig time and cost. By measuring the change in fluid density during clean up, the in-situ density tool also complemented other spectrometer based optical analyzers in determining the contamination level during sampling process.

In this complex gas reservoir, there were potential reservoir compartments of different gas composition. Fluid samples from different zones confirmed the presence of such compartmentalization. The deeper zones showed much leaner gas composition compared to the shallower intervals. The knowledge of in-situ dew point pressure from downhole fluid analyzer was used to ensure a single phase gas sample during wireline sampling. This information was later used to design a well test to keep flowing bottom hole pressure above dew point pressure and thus obtain representative surface fluid samples.

This paper demonstrates how a proper job planning, real time monitoring and sample handing can contribute towards an efficient sampling operation. This field example presents the key parameters that can help in getting successful gas condensate sample, both downhole and surface, through prudent use of new technology. To complete the cycle of this case study, the PVT lab analysis results were also used to verify the in-situ downhole fluid analyzer including contamination level.
Field Background and Deep Gas Condensate Reservoir Challenges

The subject well is located in Offshore Sabah, Northwest Borneo, Malaysia. This field was discovered in late 1980’s and it consists of three distinct accumulations, Main, West, and East, that are fault dependant closures with Late Miocene shelf sandstones reservoirs. The largest uncertainty in fluid characteristic was in the west area where the subject well was located. An accurate fluid characterization was needed for field development. Any error in fluid characteristic in particular expected condensate yield during field life could potentially result in under or over design of facilities.

PVT behavior in gas condensate reservoirs is much more complex and challenging and therefore needs a focused approach for the entire sampling process from downhole to laboratory. Gas condensate reservoirs are becoming more common as drilling progresses to HPHT. The CGR from such reservoirs could easily vary from 500 bbl/MMscf (rich gas condensate)\(^1\) to less than 10 bbl/MMScf (lean gas condensate). There is no clear boundary between rich and lean gas condensate reservoirs. However, the following guidelines are often used to distinguish rich condensate fluids: an initial GOR of 3300 to 5000 scf/stb\(^2\), heptane plus concentrations close to 12.5%\(^3\), maximum liquid drop-outs of up to 35% and an initial liquid yield of over 100 stb/MMscf.

Figure 1 Constant composition phase diagram of a gas-condensate system\(^4\).

In some gas condensate reservoirs, the initial conditions are close to critical point resulting in low producing GOR and light surface oil. In some cases it is quite difficult to identify gas and liquid phases in the reservoir condition. Formation testing is the most appropriate way to collect samples of such gas as we can restrict drawdown during sampling, while the real time measurement of fluid properties (such as Downhole Fluid Analyzer or DFA) ensures that the flowing fluid is in single phase. During the pump-out period, the mud filtrate is pumped out while monitoring the fluid flowing through the flowline using DFA.

Different type of gas condensate reservoirs would require different considerations for field development. For example, lean gas condensate reservoirs usually have less gas condensate blockage since they have velocity stripping zone due to high capillary number at the near wellbore region\(^5\). This velocity-stripping effect helps to improve productivity in the long term\(^6\). On the contrary, the rich gas condensate reservoir would face more challenges in terms of condensate blockage; velocity stripping zone does not have much positive effect\(^7\). In other types of gas condensate such as rich gas and near critical reservoirs, the fluid composition can change during the life of reservoirs. For example in rich gas condensate reservoirs, during the shut-in after the high production rate, reservoir fluid can behave as the volatile oil system\(^8\). A detailed fluid characterization is essential to estimate future well productivity and condensate yield during field life. In this example deeper zones with a relatively lean but high pressure gas will need a slightly different development strategies compared to rich gas in upper zones where condensate dropout is a major concern.

As a result of this complex reservoir behavior, a single-phase and representative fluid sampling is an essential requirement for proper field development. Small OBM contamination could overestimate liquid fraction since most OBM composition is ranges from C\(_{11}\)-C\(_{19}\). Fig-2 shows composition of the base oil used for this well. The operator had observed significant errors in reported OBM contamination from PVT labs. Therefore minimizing OBM contamination was a key objective of this sampling operation.
Selecting the Best Sampling Techniques in Difficult Environments

There are basically three methods to acquire hydrocarbon samples:

1. Bottomhole Sampling (BHS) : using drillstem test (DST) or wireline formation tester (WFT)
2. Wellhead Sampling (WHS) : collected at wellhead of full well stream.
3. Recombined Surface Sampling (RSS): gas and liquid samples are collected separately at surface and then recombined in the lab for further analysis.

Bottom hole sampling using wireline formation testers has certain advantages over other sampling techniques, namely:

Samples from individual zones

In heterogeneous reservoirs, different zones may have slightly different fluid composition. A traditional samples from a well would provide a mixture of fluids produced from various zones. On the other hand WFT can be used to extract fluid sample from individual zones with precise depth control. Samples collected from different zones can provide additional information such a compositional gradient and reservoir compartments. In this particular job, fluid sample from three different zones were collected; each of different condensate to gas ratio.

Fluid Scanning using DFA

When combined with downhole fluid analyzers (DFA), the WFT can identify variations in fluids from different zones before the fluid is taken to the surface. Some of the new measurements such as in-situ GOR, pH \[9\], density \[10\], fluid composition\[6\] including CO2\[11\] may help in differentiating small differences in fluid composition. This technique can complement the routine PVT sampling and analysis and help identification of compositional gradient\[12\] and compartmentalization \[13\]. The GOR measured in these samples closely matched with GOR that was later measured during DST.

Real Time Monitoring and Oil Based Mud Contamination (OCM) Monitoring

The OBM contamination was continuously monitored in real time using DFA that helped in collecting representative fluid samples with negligible OBM contamination\[14\]. The real time monitoring was very useful in optimizing job time and making fast decisions throughout the sampling job.

Cost and Operational Efficiency

Since WFT is routinely used for pressure and permeability measurements, the cost of additional modules for sampling and fluid identification was rather small compared to its benefits. The fluid identification tool, DFA, helped in reducing the rig time through optimization of pump-out time. It also helped in reducing the risk of tool stuck by minimizing the station time. Overall it resulted in making the operation more efficient and cost effective. Real time data availability and quick decision making by the project team was a key factor in exploiting this technology.
Challenges with Bottomhole Sampling

Although the incorporation of downhole pump modules and fluid analyzers had allowed new generations of wireline formation testers to collect high quality downhole samples, there are still a number of challenges faced by the industry. The extensive stationary time required to remove the mud filtrate in the invasion zone increases the risk of tool sticking and rig cost. The exposure of the formation tester tool in high pressure and high temperature environment for long period also increases the risk of tool malfunction. Contamination due to OBM filtrate in gas condensate sampling, even in small quantity, can render the sample unrepresentative.

Recently, with the introduction of focused sample probe (as shown in right hand side figure below), time spending at sample stations to obtain acceptable contamination level was reduced significantly. Clean sample flowing though the sample flowline allows better fluid properties with DFA. However, real time monitoring with quick decision making with the project team is crucial for this type of operation to make sure that the sample objectives can be met.

The presence of these challenges had prompted the operator to plan for the downhole sampling operations months before the actual operations. Some of the practices, which later became the standard procedures in the operator, are listed below

Pre-job Simulations

Single well numerical simulator model were built prior to the job to predict the performance of the formation tester in this environment. The inputs to the model include drilling fluid data, petrophysical data from the offset wells and also experiences of the drawn locally and worldwide. The past fluid samples in the same field, though having lot of uncertainty in CGR, were used to select a range of dew point pressure. Following were the key objectives

1. Obtain single phase gas sample (staying above dew point pressure throughout).
2. Minimum OBM contamination in the sample
3. Minimize station time to avoid tool getting stuck and reduce total job time.

Single well simulator was used to best achieve above objectives. The key results from the model include total tool stationary time to achieve acceptable contamination level. Formation testers with conventional probe, focused probe and dual packer were compared to select the most practical and efficient way to collect high quality samples in this environment. The simulation studies allowed the selection of optimum tool parameters to be used during the sampling operations. This is often critical as one of the pitfall of downhole sampling is for the sample to go into two phase un-intentionally during the high pressure drawdown.

Extensive Use of Downhole Fluid Analyzers

Early in the planning stages, the downhole fluid analyzers were identified as the main component to overcome the issues with OBM contaminations and ensuring sample integrity. Fluorescence detector in the fluid analyzer was used to ensure the gas condensate remains in single phase before capturing it in the PVT bottles. High resolution fluid compositional analyzers, which is capable of measuring the C1, C2, C2-C5 and C6+ compositions in the reservoir fluid are being used to estimate the
Condensate Gas Ratio (CGR) and OBM contamination level. The fluid density sensor allows measurement of the hydrocarbon density directly.

**Tool configuration and Preparations**

Although the ratings of the downhole formation testers (20,000 psia and 350 degF) are above the well environment, extensive equipment preparations were performed. Two main logging section are in 8-3/8" and 6-1/8" inch hole sections. All downhole tools were heat qualified and tested in the shore base prior to mobilization to the wellsite. As the downhole pumps are sometimes plugged due to solids in the drilling fluid, correctly sized filters are installed at the inlets of the tools that are exposed to drilling fluids. Operational checks were conducted using the actual mud provided by the drilling fluid company. As a final precaution, a 2.75 gallon chamber was filled with appropriate fluids to clean any plugging during the job that might be caused by excessive solids in the pumping module or the flowline.

The WFT logging tool string consists of single probe for pre-test, focused sampling probes for collecting fluid samples, two pumped-out modules with 3 DFA tools, i.e. LFA (OCM contamination in guard and sample flowline), and IFA for fluid properties was planned in advanced. The location and type of each module was planned specifically for each job depending on the type of mud system, reservoir fluids, reservoir properties, and test objectives.

**WFT Sampling Results**

After extensive openhole logging, the wireline formation tester were used in final section of this exploration well. At 15000 ft and 300 degF, the well is the deepest exploration well drilled by the operator offshore Borneo Island in East Malaysia.

Six pressure tests were performed prior to the sampling operations to acquire formation pressure and estimate the formation mobility. All pre-test show low mobility of less than 10 mD/cp., except one station with mobility of 80 mD/cp. This high mobility zones are generally favoured for sampling purposes as the pumps can operate at higher rate to remove the invasion fluid more efficiently while keeping the pressure drawdown low. Although a number of pressure points were acquired in the main sand body, the pressure points were too scattered to conclusively derive fluid density from the pressure gradient plot.
Three sampling stations with similar reservoir properties within 30 ft apart were selected by the operator. The lower station was tested with a focused probe whereas the upper point was tested using both focused probe and conventional large diameter probe.

**First Station with Focused Sampling Probe**

Sampling station #1 was at 1x090 ft MD. The porosity was approximately 23 % with measured drawdown mobility of 80 md/cp. Initially, only the guard pump was activated to remove the OBM filtrate from the invaded zone. Once hydrocarbon was detected by the fluid analyzers, the synchronized focused sampling mode were activated to guard the OBM filtrate away and allow only clean hydrocarbon fluid to enter the sampling flowline. Two independent fluid analyzers, namely compositional fluid analyzer (CFA\(^1\)) and In-situ Fluid Analyzer (IFA\(^2\)) were used to measure the hydrocarbon compositions, GOR and presence of fluorescence in the hydrocarbon. As seen from Figure 7, during early stage of the clean up, the fluid measured by the fluid analyzers mainly constituted of C6+ components, i.e. mostly the OBM filtrate. At 2000s, the C6+ components reduced significantly as the focused probe began guarding the filtrate away. The GOR and lighter components (C1, C2, C3-C5) in turn, increased and stabilized almost immediately after 4000s. During the clean-up process, the drawdown pressure was controlled precisely to ensure the reservoir fluid remained monophasic. By placing the fluorescence sensor at the up-stream side of the pump, the presence of condensate dropout can be detected easily due to fluid segregating occurring in the pump module.

![Figure 7 The pump-out fluid viscosity measured from InSitu Density tool](image)

**Table 1 Fluid Compositions measured from Downhole Fluid Analyzer and Lab Measurement**

<table>
<thead>
<tr>
<th>Component</th>
<th>%wt InSitu Fluid Analyzer</th>
<th>Lab Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>58.8</td>
<td>57.6</td>
</tr>
<tr>
<td>C2-C5</td>
<td>18.3</td>
<td>19.4</td>
</tr>
<tr>
<td>C6+</td>
<td>22.9</td>
<td>19.1</td>
</tr>
</tbody>
</table>

As the measured formation pressures (as shown in Figure 6) were too scattered to derive the hydrocarbon pressure gradient, the mechanical density sensor, located in the focused probe module, was used to measure the in-situ fluid density. As seen in Figure 8, the fluid density in the flowline quickly stabilized to 0.28 g/cc when focused sampling mode was engaged. Two PVT samples were eventually collected at 7000s and 8000s respectively when the composition, GOR, fluorescence, and density had been stabilized. These samples were later sent to laboratory for PVT analysis.

The results from the PVT analysis showed that the samples were of very good quality, with level of OBM contamination less than 3% weight. The GOR and fluid density measured by the fluid analyzer and In-situ density were also within 5% and 3% of the laboratory results respectively. The GOR measured during sampling was confirmed during DST. Comparison of the laboratory results and downhole fluid analyzers are tabulated in Table 1.

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\(^1\) Mark of Schlumberger
Second Station with Focused Sampling Probe

Sampling station #2 was at 1x064 ft MD. The porosity was approximately 20% and measured drawdown mobility was 10 md/cp. As shown in Figure 9, compared to the first sampling station, the GOR, fluid density and hydrocarbon compositions did not stabilize as quickly as the first station but in a more gradual manner. Similarly, the pressure drawdown (500 psia) was also higher than the first station due to lower quality sand (mobility 10 mD/cp). At 8000s, when the fluid analyzers indicated the level of contamination was below the required limit, 2 PVT bottles were collected for lab analysis. The lab results show that the level of OBM contamination was slightly higher than the first station, at approximately 5% weight.

![Figure 9 The InSitu Density measured during the pump-out period. This density measured at the Focused sample probe and it has been stabilized for sometimes before we open the sampling bottles](image)

![Figure 10 Fluid composition and GOR versus time measured during the focused sample operation. The clean-up takes longer since mobility is much less than from the first section](image)

Third station with Conventional Sampling Probe

Sampling station #3 was at approximately 1 ft away from the second station. The porosity and drawdown mobility were almost identical to the second station. The objectives of this station were to estimate the gas condensate dew point pressure and compared the performance of conventional probe versus the focused probe. Two pumps were run synchronized at maximum rates to create pressure drawdown below the dew point pressure. However, even at the maximum production rates, the flowline pressure did not go below 1000 psia from the formation pressure and no condensate dropout was observed. The test shown that the reservoir fluid is likely to be under saturated and away from the saturation points. The effectiveness of the focused probe vs the conventional probe was also compared by withdrawing equal amount of filtrate from the invaded zone and monitoring the fluid compositions using the fluid analyzers. It is reasoned that since the main compositions of the OBM filtrate are C6+ components, comparing the C6+ fraction between the partially cleaned up fluid will indicate the level of contaminations in the captured sample. As shown in Figure 12, the C6+ fraction in the reservoir fluid using conventional probe was at least 50% more than the sample with focused probe. With faster cleanup time using the focused probe, the operator can minimize the risk of tool sticking by reducing the total sampling period.
DFA Fluid scanning stations were used to compare reservoir fluid from each pumping stations. Figure 12 shows composition data, i.e. C1, C2-C5, and C6+, from two sampling stations within 30 ft apart. The DFA results, such as composition, GOR, and density, show similar reservoir fluids.

After downhole sampling, the DST was performed to evaluate reservoir parameters, well productivity, and collected surface samples. The GOR measured from DFA was used to cross check gas and oil rate during the DST test. The result showed good comparison. Also, the WFT mobility, pressure drop, and the knowledge of formation pressure and dew point pressure were used to design well test program. The DST test was design in such a way that the bottom hole flowing pressure was kept above dew point pressure in one case, and below dew point pressure in the second test. The objective was to create a situation of condensate drop out around wellbore and thus study its impact on well productivity. This became a key input for later single well studies and reliable prediction of production profiles that was a key input for field development planning.

Conclusions and Recommendations

1. Gas condensate reservoirs are more complex than other fluid systems. The proper field development program requires single and representative downhole fluid samples with minimum OBM contamination.
2. This field example shows that it is possible to collect clean sample, i.e. samples with negligible filtrate contamination using the new focused WFT probe while minimizing station time.
3. The focused sample probe allows clean sample to flow though the sampling flowline, and as a result, it enablers the downhole fluid analyzers to measure in-situ fluid properties. The field example shows that the in-situ fluid parameters are comparable to the results from the lab analysis and surface testing data.
4. The DFA data can be used as fluid comparison between zones, and help in identifying reservoir gradient and compartmentalization.
5. A fair understanding of PVT properties from early on helped the project team to design a DST test to study condensate drop out phenomenon in detail. This became a key input for predicting future well productivity and production profiles for field development planning.
6. Real-time monitoring by the project team, pre-job planning, an integrated operation between service company and the operator and new technology were the key components behind the success of this job.

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References