Abstract

Accurate PVT information contribute significantly to improve metering uncertainty for either topside or subsea business and for multiphase and/or wet gas meters. This is because flow rates need to be provided at standard conditions. Usually, the subsea meters have been set-up using PVT information collected from samples taken during drilling. Rarely this data have been updated after meter installation due to lack of access to quality representative samples. The same issue is raised from a flow assurance point of view by numerous tiebacks to a main subsea production line and with little challenge on the compatibility and effects due to poor access to representative samples.

This paper will address the issues regarding access to well stream fluids, ability to capture representative samples, sample handling and storage, and the data needed to recombine the samples and possibilities to implement solutions to these challenges.

If subsea multiphase meters serve as the operator’s eyes and provide volumetric flow rates of oil, water and gas phases.

The data provided by the meters is used also for flow assurance, allocation, and production management and to gain understanding of the reservoir structure, hence the importance of maintaining the measurement over time. As any meters, the measurements are reported at line conditions, where the measurements are taken, usually near the subsea tree, but the operator usually requires the meter to provide flow rates in standard conditions as well. These line conditions measurements are then converted to standard conditions using a dedicated or not PVT model. Depending on the fluids, the method used can have an impact of up to +/- 30% uncertainty at standard conditions (Joshua Oldham, Exxon Mobil, at Subsea Tieback 2008).

In order to reduce this source of uncertainty, the EOS must be updated as needed. If wells are commingled subsea the only way to gather, the information needed is to sample the fluids at meter conditions in a representative state and recombine them in the lab. The remainder of the paper will describe the innovative tools and methods needed to achieve this.
Introduction

Oil and gas field operators are increasingly moving into deep and ultra-deep waters to develop new fields. This has encountered considerable success in Brazil, West Africa, and Gulf of Mexico despite the increasing need for more reliant subsea production infrastructures. This trend is also very strong in Asia Pacific with Australia and Indonesia, and lately Malaysia. The vast area full of water in Asia Pacific is only at the beginning of this new endeavor. Increased water depths, longer tiebacks, complex reservoirs and the continuous effort to reduce the cost of the subsea infrastructure, while still ensuring the highest possible recovery rates, raise new challenges in terms of reservoir and production management, flow assurance, and enhanced oil recovery. This is becoming very important with the development cost of such field going way above estimation and in the way slowing down the expansion or the growth of this subsea business for the good of everybody.

Pressure and temperature met in these reservoirs are also higher and higher versus time and the fact that production needs to be reported in standard conditions (usually around 14.7 psia and 60 DegF) create an additional challenge. In this scenario, subsea sampling is rapidly becoming a simple and effective way to gather samples of the produced fluids through the field life, enabling accurate measurements of their properties and the changes that occur through the years.

Subsea sampling, combined with the expanding use of subsea multiphase and wet gas meters, provides new levels of understanding of subsea reservoirs and of their behavior, improving the decision making process thanks to increased accuracy, and leading to extended recovery rates, while also enabling simpler and more cost effective architectures of the subsea infrastructures.

The Need for Subsea Sampling

Subsea sampling is a commonly used expression for the functionality where equipment permanently installed on the seabed allows a deployed unit to capture/extract samples of liquid or gas from subsea oil and gas installations. Common terminologies do not distinguish between the different methods that have been used for this need but in this paper, a thorough explanation of the terminology and technology used by the authors will be given.

Production management processes and workflows can be grouped into three main sets of activities. These are:

- Production Monitoring and Reporting
- Production Surveillance and Analysis
- Diagnosis and Production Optimization

All of these activities require accurate measurement of the quantities of each phase (oil, water, and gas) being produced by each well, and on the properties of the produced fluid. Meanwhile, most of the oil and gas engineers have tendency to forget that it is not only the produced volume but also the quality of the oil and gas that make the final price of the barrel. Usually heavy oil are derated by 20% to 30% and condensate can be appreciated up to 300% versus price of the standard barrel of oil (WTI or Brent)

In such challenging conditions, subsea sampling, particularly in deep and ultra-deep waters, is gaining increasing acceptance as the preferred method for achieving high-quality representative measurements of produced fluid properties that enable effective production management.

The need for subsea flow measurements is already addressed by the use of subsea multiphase meters, which are already widely accepted in the industry but the overall uncertainty is associated at standard conditions by metering performances and fluid properties uncertainty. Figure 1 presents the performance of a multiphase meter at line conditions and how this uncertainty/performance is becoming wider (i.e. poorer, the poorer uncertainty being related to the larger width under the curve for a given probability)
which means bad with the used of PVT weak PVT information. This is even becoming worst if the expertise or training has not been made or resident with multiphase/wet gas meter user.

Furthermore, monitoring and reporting well, reservoir, and field performance is usually more complicated in deep-water subsea developments due to commingling of fluids from multiple wells and increasingly long tiebacks to other fields before reaching surface. Reservoirs and individual wells that are commingled at the seabed are often operated by different company partnership groups, and accurate allocation is key to production and royalties’ allocation. Gaining representative seabed samples prior to commingling enables geochemical fingerprinting and reduced uncertainty of flow measurements for calculating allocations.
Reservoir surveillance and analysis activities are at the core of any production management workflow, and focus on the surveillance of the reservoir, to understand and predict its behavior, while ensuring uninterrupted production through the subsea infrastructure. The main activities in this group are:

- Reservoir Modeling and Management
- Water/Gas/Chemical Injection Management
- Flow Assurance

In addition to flow rates, knowledge of the physical properties of the produced fluids is essential. Changes in these properties during the field life, if not detected and not properly accounted for, can lead to significant inaccuracies in the models used for the decision making process, with significant financial impact for the operator.

Geochemical fingerprinting is another important activity enabled by subsea sampling, which, combined with flow measurements, allows the operator to allocate the production to each zone of a well. This is important because it enables multi zone wells in countries that would otherwise require separate wells for each zone. Drilling one well per zone to meet allocation requirements could result in a decision that the discovery is not commercially viable.

Diagnosis of production problems and corresponding production optimization activities requires accurate reservoir models. Accurate knowledge of fluid properties at line conditions reduces uncertainty and inaccuracies in these models and subsequent fluid dynamics simulations. Combined with multiphase flow measurements, subsea sampling provides essential information to support:

- EOR / IOR
- Production Optimization
- Production Troubleshooting
- Intervention Planning

Knowledge of the exact composition of the fluids produced from each well at line conditions enables accurate evaluation of pressure, volume, temperature (PVT) relationships and determination of a tuned equation of state (EOS). These are essential in the management of potential challenges such as scale, waxing, and hydrate deposition.

**Subsea Sampling Adding Value**

Based on the explanation said before, PVT (and subsea sampling) plays an important role in the whole production management process for subsea field developments. An increasing number of operators are realizing the additional value provided by subsea sampling and are including the requirements of such system in their subsea architecture designs usually for a minor increase if the right technology is used. Figure 3 summarizes the most significant trends in the subsea production world and how these trends represent important technical drivers for the subsea sampling market, particularly in deep and ultra-deep waters.

In addition to addressing technical challenges in deep-water developments, subsea sampling also supports more accurate production allocation through more accurate inputs to flow measurement systems. This is important for not only individual operating and partner companies, but also to meet increasingly stringent industry standards and national regulations.

API published its Manual of Petroleum Measurement Standards (MPMS) Chapter 20.3 in January 2013, superseding API Recommended Practice 86-2005, which is withdrawn. Others documents have been published such as Norwegian Regulations: Måleforskriften (Regulations relating to measurement of petroleum for fiscal purposes) and British Regulations by DECC Guidance Notes for Petroleum Measurement Issue 8. The new standards address multiphase flow measurement in the production environment, upstream of the custody transfer (single-phase) measurement point, where allocation is applied. The
documents address operational requirements or constraints in multiphase measurement systems, including expectations for flow meter acceptance, calibration criteria, and flow-loop and in-situ verifications. It specifically describes representative sampling as the ultimate way of setting up any Multiphase flow meter (MPFM). Furthermore, API MPMS Chapter 20.3 points to the importance of representative sampling as essential to reduce uncertainty in the overall measurement.

For example, the API also points to the challenges of capturing representative subsea samples, as described below:

- The sampling point should be in a vertical leg of the flow line; the best setup is immediately downstream of a flow line component providing a mixing effect.
- Multiple subsequent samples should be taken, allowing each sample to completely separate before the WLR is measured. For some crude oils, this will require the use of a de-emulsifier.
- The sampling point should be close to the MPFM. An acceptable sample should contain all of the mixture constituents and the timeframe for the samples shall be selected such that the samples are representative of the fluids passing through the MPFM during the same timeframe.

The API Chapter 20.3 has an additional note in this section “NOTE 1 Verification techniques are used by some meters to determine fluid property changes, hence reducing or potentially eliminating the need for physical sampling”. It is the understanding of this paper’s authors that this is the industry’s ultimate goal for the future, but that the vendors are not there yet. Automatic update of an assumed salinity and non-representative in-situ measurements do not provide accurate and reliable information to claim elimination of need for physical sampling.

It is also important to note that API 20.3 is aware of the challenge of obtaining phase representative samples. Phase representative samples are measuring Water Liquid Ratio (WLR) and Gas Volume Fraction (GVF) from the content of sampling bottles. It is our understanding that these parameters can be challenging to obtain from subsea samples with the complex nature of multiphase flow facing difficulties such as slug flow, emulsions etc. The following precautions mentioned by API 20.3 are listed:

- The sampling point should be in a vertical leg of the flow line; the best position is immediately downstream of a flow line component providing a mixing effect.
- Multiple subsequent samples should be taken, allowing each sample to completely separate before the WLR is measured. For some crude oils, this will require use of de-emulsifier.
The sampling point should be close to the MPFM. An acceptable sample should contain all of the fluid constituents and the timeframe for the samples shall be selected such that the samples are representative for the liquid constituents passing through the MPFM during the same timeframe.

It is important to note that due to the issues with multiphase sampling, samples may not fully represent the volume fractions. The Norwegian Petroleum Directorate (NPD) recently issued new requirements in its “Måleforskriften”, which address metering for production allocation for fiscal regulations. This also states that:

“Subsea inline multiphase flow meters are typically set-up using samples obtained during drilling. The composition of produced hydrocarbons changes over time and these changes are likely to be significant over the life of a deep-sea development. Obtaining representative samples from the production system at line conditions enables maintenance of the inputs of multiphase and wet gas flow meters, leading to more accurate allocation.”

Of all the main drivers for subsea sampling mentioned in the previous chapter, the need for more accurate conversion of flow rate data from line to standard condition can be listed higher on the most valuable drivers. In allocation regimes where actual flow is being allocated according to ownership structures, a small failure in the conversion can lead to a significant value loss for one or some of the partners. The term PVT is well described in literature. The methods of PVT correction are described in this paper; The PVT (Pressure, Volume, and Temperature) is the knowledge about the volumetric changes caused by the shrinkage-expansion (density variations) and phase change of all three phases present in a multiphase stream of oil water and gas. This knowledge can be summarized as the fluid behavior path. It is important to note that the density of a single fluid at line conditions does not supply enough data to generate the PVT relationship between the produced fluids.

Hence assuming that a multiphase meter can, with its densitometer, compensate for changing PVT relationships is a gross misstatement and can only be characterized as ‘misleading marketing’. Another fact that is important to highlight, is that the hydrocarbon mass remains the same through the journey from line to standard conditions, so this can be used for production allocation for meters that are true 3-phase meters measuring oil, water, and gas without the input of GOR. Obviously, the volumetric proportion of oil and gas will change with the different stages in the fluid behavior path; as pressure and temperature drop. The mathematical recombination based on the compositional analysis and assumed GOR gives a new phase envelope of the fluid (see figure 4) as described earlier and then leads to a new definition of the following 6 parameters:

- bo Oil shrinkage factor
- bw Water shrinkage factor
- bg Gas expansion factor
- Rst gas dissolved in oil ratio
- Rwst gas dissolved in water ratio
- rgmp Gas condensate drop out ratio

Based on the above definition, the following set of equations can be used to convert flow rate from line to standard conditions. It should be understood that we are showing the simple way assuming a direct flash and then no steam, in a short way this represent a typical black oil at low temperature.

\[
q_{oil,SC} = bo \cdot q_{oil,LC} + rgmp \cdot bg \cdot q_{gas,LC}
\]

\[
q_{wat,SC} = bw \cdot q_{wat,LC}
\]

\[
q_{gas,SC} = bg \cdot q_{gas,LC} + Rst \cdot bo \cdot q_{oil,LC} + Rwst \cdot bw \cdot q_{wat,LC}
\]

The “q” in the equations above represents the volumetric flow rate for a given phase.
Based on this set of equations above, few things can be mentioned immediately. There is no way to provide high quality flow rates at standard conditions without a proper Fluid Behavior Model or PVT information, it will be totally underestimating the right amount of work to say the opposite. The various guidelines/directives mentioned earlier do not skip this main point. It is also impossible to find today a multiphase flow meter or wet gas meter capable to measure all of these properties, if from a technical point of view this is possible, this is not inline with the market need going right now for cost effective solution. One of the authors has been involved in a solution that was linking PVT and Metering but the size of the entire equipment was reaching more than 2,000 kg and lot of automation were use but still expertise was required. At the end, this device was not proposed to the multiphase community albeit the tests on flowloops were outstanding. It was, for sure, not possible to bring this to subsea yet, and it was requiring still lot of work beyond what the market could handle today from an economical point of view. It is dreamt that in 20 years, this could be something to look at when oil/gas will be much higher in price and then the EOR could be in the third or fourth stage of a given subsea field.

Coming back to the fluid behavior and its importance, figure 5 shows the phase envelope for the gas and oil sample, separately analyzed as taken for example of a separator or a relevant spot in a multiphase line. Combining both and having a given GOR defines the entire fluid phase envelope of the mixture. It should be noted that the interception point of the gas and liquid envelope defines the operating pressure and temperature conditions. This point should give the exact conditions (P and T) where both samples of oil and gas have been taken. This is an important point for quality control, because if they do not cross at this location it can indicate that the sample has been contaminated or suffered from others damages, such as failure to maintain the thermo-equilibrium conditions during the sampling process or during the transport to a laboratory. Probably this may highlight for some of our readers the work done when a sample of gas and oil is given to a lab and then a report comes back with a fluid recombination and sometime a note explaining that they have “tuned” the recombination sample to be in line with the given data.

This new Equation of State (EOS) can then be used to post-process the raw data of the multiphase flow meter collected at the time of the sampling. Obviously, this is a big assumption made that the data recorded can be replayed in the same manner than during the acquisition, this means the data recorded need to be as “raw” as possible and clean of any tuning factor or calibration for some of the meters on the market. Meters, having this capability, will generate an updated and improved GOR and associated
recalculated flow rates. This GOR can now be used to recombine (still mathematically) the initial sample of gas and liquid to obtain a new EOS. It can be seen clearly that this is an iteration process (see figure 6). Amazingly, the convergence is very quick - less than 3 iterations are necessary.

Defining the new equation of state provides a clear benefit for the reservoir, allocation and flow assurance, which is the possibility to identify potential pitfalls, and if necessary correct the expected
development of the field to improve the recovery factor, which is the ultimate need from an operator’s point of view.

It is always the optimum situation to have good downhole sample from the reservoir during the exploration phase. Good sample here means uncontaminated sample obtained as a single-phase fluid at the reservoir conditions or near reservoir condition that is known, and with sufficient quantity to allow comprehensive fluids and flow assurance analyses. Integration of reservoir properties and robust understanding of the fluid characteristics and behaviors allows a thorough assessment of the field development concept, plan and operating philosophy that are most viable economically and technically.

Nevertheless, sufficiently good downwhole sample is often a challenge during field development, especially when sampling is done without proper planning for analysis requirements. It is also common field development plan kicks off years after its exploration long after the time when samples were taken (down hole or at the well test separator). Handling, treatment and condition experienced by the sample over this period may not have been recorded precisely; fluid compositions, properties and characteristics may have changed. As a result, assumptions are often made on limited knowledge of the history of the fluid sample, limited fluid data (e.g. single fluid data as opposed to commingled fluid). Operation experience and reference to the nearby reservoirs are used but with large safety margins in the design of production system and operating philosophy. Uncertainties in reservoir properties, geological system as well as simulation tools often tend to increase the safety margins. These uncertainties will result in operational challenges, which have to be resolved reactively or proactively but at a price.

Apart from the uncertainty in the fluid data available from the early phase of a field development, there is a potential change of reservoir fluids compositions over field life due to numerous parameters: injection gas breakthrough, injection water breakthrough, unexpected communication with other reservoirs having different fluid compositions, commingling of productions from different wells/zones/reservoirs/tie-ins, microbiological induced souring etc.

Often the reservoir/production optimization and maintenance team, who faces fire-fighting and production management issues, tries to figure out the causes/current status of the system in order to manage the response appropriately and effectively. Over the field life, there are three main varying groups in the system: reservoir condition; fluid composition, condition, properties and characteristics; and operating condition. For a well-planned and maintained production system, continuous data of down hole and subsea pressure/temperature/flow rate at points along the flow line is used in conjunction with PVT models of surface sample (recombined from gas and liquid phases obtained at the test separator) to identify potential causes of production issues and current status of the system. Unfortunately, production fluid arrives at the surface has often left behind some of its components along its flow journey. The re-combined surface sample is not able to represent the reservoir fluid and can lead to misinterpretation or fault analysis.

The availability of the well stream compositions from each well (subsea sampling at the wellheads) and in the main flow line (subsea sampling at the manifolds), will reduce uncertainties and increase the efficiency and confidence to achieve an effective operational responses.

Nevertheless, the subsea sample can still suffer loss of some elements (e.g. wax/scale/asphaltene precipitation/deposition in the wellbore) or change of properties (increased viscosity due to cooling or emulsion, where the data may not be available during design) when travelling up the well or from the wellhead to the manifold. Compared investigating the full fluid journey (from reservoir to the top side separator), subsea sampling at wellheads and manifolds when integrated with the pressure/temperature/flow rate measurements helps to find out where this event takes place along the fluid journey, which makes trouble-shooting faster and efficiently. It is helpful to have the well stream composition at the manifold; this data helps to understand characteristics and behaviors of commingled well streams, which are usually assumed or have limited information during design phase; production monitoring system/
models can be updated to better predict the system behaviors that allow good production optimization and planning.

Production allocation is a tedious but important production activity. The importance of production allocation in deep-water fields with complex commingled streams and royalty allocations can be challenging; inefficient measurement can lead to costly resolution. Production meters are often set-up based on fluid obtained from the exploration samples, which can change over the field life. To have reliable metering, it is important to periodically update these meters with fluid properties from each well and commingled fluid, if applicable, over the field life. This fluid composition also enables fluid fingerprint identification when checking the change in fluid composition or tracing specific streams or fluid components.

Subsea sampling, in addition to the top side sampling, extends the ability to understand a subsea production system with increased confidence. This continuous information over the field life, when integrated with the reservoir information and flow conditions (pressure, temperature and flow rates) form a powerful surveillance database to allow proactive operational actions and production optimization/maintenance:

- Early identification of discrepancy in the crude compositions from the down hole sample obtained during exploration phase (subject to correction for contamination and changes over time between sampling and testing) and periodic subsea sampling, allows early alert and sufficient time to investigate the possible causes, revise/adjust operating philosophy/strategy/requirements and early actions, if required.
- Subsea sampling at the wellhead and manifold helps identifying the insitu fluid composition hence crosscheck the status of the fluid characteristics and behaviors in reservoir and along the production systems.
  - This information allows fine-tune of the reservoir, well and production models over the production life, and consequently enables good prediction of system response for planned/unplanned activities with increased confidence.
  - up to date fluid composition and PVT increase the confidence and reduce the time in trouble shooting production issues. Earlier and effective responses can be taken to assure optimum production uptime with minimum risks.
  - Confident fluid data that is available continuously without interruption to the production helps to optimize operation and run life of each equipment in the production system improves the system integrity and minimizes risk of production down time and supply interruption.
  - This data will be used to update and fine-tune the reservoir, well, production and facilities models, which can be a powerful tool for production surveillance, monitoring, planning and system modifications/upgrading.
- Efficient and reliable production allocation by periodically providing updated information for an Equation of State

Subsea Sampling Technology

OneSubsea offers a subsea sampling system that is unique in the industry in its ability to provide high-quality multiphase fluid samples for full recombination and EOS modeling. The sampling module is manipulated by a remotely operated underwater vehicle (ROV) and connects hydraulically with the subsea infrastructure at a “blind-tee”. Subsea architectures of the PhaseWatcher Vx flow meter include a sampling interface as a standard option. Interface systems are also available for integration into the design of other subsea metering systems. It should be noted that the incremental CAPEX cost of including the
interface in subsea architecture design is negligible, especially considering the long-term potential benefits.

The sampling module, which is the mobile unit that connects with the permanent sampling interface, is initially configured as a loop to flush and pre-heat the sampling lines. When the flushing is complete, the sample is captured in the pressure compensated bottles. The ROV-enabled operation is usually performed in a campaign that sequentially samples multiple wells in a field.

The subsea sampling system comprises several key components in order to capturing truly representative subsea samples, these key components are briefly described in the following section. A Schlumberger custom-designed displacement pump displaces the sample fluid with a minimal differential pressure. The design of this pump is an adaptation of a technology used in Wireline sampling tools to the subsea environment. This pump is able to move fluids at a controlled rate from a high pressure point to another high pressure point. Incidentally, it also generates low mixing and pre-separation of the phases. All pumped volumes are measured by volumetric meters.

The main components of the sampling system are:

- **OPD**: optical phase detectors. In order to control correctly, which phases are being collected, optical probes are used in the flow lines. Using those probes allows the sampling engineer to select which phase will be collected in the sample bottles. This is also an adaptation of an existing Schlumberger technology (used in production logging and surface sampling tools) to the subsea environment.
- **Separator**: the system makes use of a small separator to be able to sample the phase of interest. This is particularly required to collect the “minority” phase. For instance if there is only 1% water in the production flow and the requirement is to collect a water sample, the separator enables the enrichment of the water content in the sample.
- **Heated bath**: the full system is maintained at line temperature until the sample is captured (isothermal sampling). This prevents composition change in the sample and particularly the precipitation of asphaltene and other heavy components (asphaltene deposition is more pressure dependent than temperature).
- **DOT bottles with internal piston**: the sample bottles are DOT approved and can be shipped directly from the sampling module. The internal piston ensures a controlled filling of the sample bottle during operations and nitrogen precharge in the bottle ensures the sample is maintained above line pressure during recover to surface and transportation to the lab.

The sampling lines are short and maintained at temperature. On the permanently installed subsea sampling Interface, the sampling ports are located in a Blind Tee ensuring a partial separation of the liquid and gas phases. The Blind Tee sampling Interface can be deployed as a standalone device or together with Multiphase Flow meters.

When at the lab it is only necessary to heat the fluid back to the line conditions. The capability to monitor and control the pressure and temperature during the subsea sampling operation is also essential to prevent hydrates, waxes, scale, or asphaltene deposition.

**Subsea Sampling Technology**

One of the main advantages of capturing a representative subsea sample is the ability to take subsea samples in close conjunction with the Multiphase flow meter – for example, an OneSubsea PhaseWatcher Vx. Since the subsea sampling Interface is based on a Blind Tee, that is also a required inlet conditioner for the Multiphase flow meter, it forms a powerful combination.

First, the two together allow for recombination of the gas and oil samples, as described earlier. This enables analysis to generate a tuned EOS for the sampled well. This is not possible with only one of the devices by itself. This will reduce the uncertainty of PVT effects in an allocation regime, if volumes are
utilized. Second, the combination of flow rates of oil, water and gas with their accurate compositions enables more in-depth flow assurance analysis. This can, for example, identify risks of commingling production subsea from different reservoirs. The third and last benefit by combining subsea sampling with Multiphase meter – PhaseWatcher Vx is the combination of two unique measurements.

The PhaseWatcher Vx provides a unique measurement by use of a gamma system. This is based on a Barium 133 source that emits gamma rays at various energy levels. The traditional set up for the

![Simplified Subsea Sampling System Diagram](image)

![Various System Parts - Top Left: ROV and Sampling Device; Bottom Left: the sampling device alone; Top Right: The separator and DOT Bottles; Bottom Right: The interface permanently installed subsea](image)
PhaseWatcher Vx is by use of two energy levels, also known as dual energy gamma ray detection. These measurements provide accurate and reliable WLR and GVF from the PhaseWatcher Vx.

These measurements are based on the 100% accurate hold up of gamma rays i.e. theoretical known properties. In order to explain this all thoroughly we have added a sketch in figure 8.

Please refer to figure where the green encircle, gamma system measurement provides rate of oil, water and gas @ actual conditions; the orange encircle, the Venturi measurement provides total mass flow rate; and the Blind Tee at the inlet as the area from where the samples will be withdrawn.

These measurements are possible to log as raw data files that can be post processed with dedicated post processor software and the analyzed composition from a truly representative sample. Operators can establish a correct EoS state in the Multiphase flow meter computer and hence generate a more correct conversion from line to standard.

The focus in this case is set on the conversion from line to standard because this is the biggest uncertainty contributor. It is a fact that the Multiphase flow meter

PhaseWatcher Vx needs input data as a reference: attenuation for the energy levels in use for oil, water and gas as well as the densities. However, this information is not as critical in the overall uncertainty budget as the conversion from line to standard.

It is important to highlight the main points of the combination of subsea sampling and Multiphase metering and hence this summary of chapter 6.

- Subsea sampling and multiphase metering are not dependent on each other
- Subsea sampling and Multiphase metering can form a powerful combination in the following cases:
  - EOS determination for allocation
  - Fluid Compositional Analysis combined with flow rate for Flow Assurance workflows/modeling.

- All multiphase meters can gain from having a full compositional analysis from a truly representative subsea sample like: Mass attenuation coefficients, densities, permittivity of oil, water and gas to update input parameters.

**Conclusion**

Oil and gas field operators are increasingly moving into deep and ultra-deep waters to develop new fields. Pressure and Temperature met in these reservoirs are higher and higher versus depth and the fact that oil and gas production need to be reported in standard conditions (usually around 14.7 psia and 60 DegF) creates a challenge. The use of the fluid behavior or PVT to go from line conditions to standard conditions is essential in the success of the use of metering device and even more important with multiphase or wet gas meter where there is a mix of the 3 phases at any time. Additionally, the live fluids will be at any pressure and temperature exchanging material between them. It is then impossible to overlook this step
and if some metering companies can be providing good metering devices it is the expertise cross domain that it is essential in such domain.

The regulatory bodies around the world and the first ones who have already published guidelines are well aware of this component and including the way of “auditing” the quality of the produced fluid versus time and then they are recommending or not requesting a sampling mechanism at the seabed level.

Furthermore, flow assurance is a major driver for subsea, and then recent projects were starting utilizing this technology specifically for that purpose. Subsea Sampling is a requirement for some applications throughout the world and is being recognized by government regulations as such. Nevertheless, representative subsea sampling is the right sampling that government regulations are talking about to be able to look at the sensitivity of any measurement versus the pressure and temperature. This representative sampling is a basis of knowledge about the produced fluid and its behavior that can be used in many flow assurances and measurement related situations and based on this forms an important source of securing investment in subsea fields.

Unfortunately, some players in the subsea market misunderstand the value of this sampling technology and suggest inaccurate solutions to overcome their challenges, such as use of densitometers to gather fluid properties in a producing well.

Assuming that the pipe is clean and that the fluids are pure are rather large suppositions to make in the upstream oil and gas production and it will never give anyway access to the phase transfer phenomena.

Subsea sampling technology discussed in this paper went through an extensive qualification program albeit it is by a large extent, based on existing technologies from topside and downhole. This innovative solution comes from the synergy of proper topside understanding of sampling and handling and from expertise in subsea business. This unique combination of expertise lead to overcome, first, safety issues by opening a pipeline subsea, and second being able to take representative samples and by proper handling and analysis, provide oil and gas operators with the valuable knowledge as discussed.

It should be highlighted that this paper has been avoiding talking about the conditioning of samples taken subsea up to surface and then up to the laboratory for analysis, this is on its own a project and it is essential for proper recombination and getting access to the right composition of the field inside the reservoir and its behavior versus pressure and temperature.

From an economical point of view, the value involved in the subsea business development is in the unit of billion $. The subsea sampling cost is probably reaching the one million $ taking the entire process into account, but overall failing to address it could bring an entire field to a situation with no flow and then loss of millions $ per day. Remedial action to put in place to fix it could be even higher in cost for deep or ultra-deep solution. Pinguet and alt in a different paper (Ref [4]) addressed specifically this subject.

It is important to know what is the possible shortcut or key investment to do during the development phase even if sampling may happen only once each 2 to 5 years after production following conditions and reservoir size and associated complexity and not discussed in detail inside this paper. Failing to address this need from the day#1 gives barely no option later during the production phase to modify the subsea layout. If the flow assurance subject could be handled by large amount of chemical injection, this will be at the cost of space, weight at surface and OPEX or onshore for collecting, reconditioning and reinjecting such chemical. Worst this will not solve or improve the uncertainty on the production and metering side and sometime leads some wetgas or multiphase meters to be off due to the use of chemical product being sensitive to some techniques of measurement such as electromagnetism. Beyond this cut cost or short cut taken will lead on short or long term to increase the poor recovery factor due to lack of proper understanding of the reservoir behavior and additional OPEX for a small gain from a CAPEX point of view at the FEED stage.
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