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Allocation & Fiscal Allocation Applications: A Comparison of Current North Sea Practice with Recently Issued Guidelines and Regulations

Bruno Pinguet, Michael Smith and Eivind Vethe, OneSubsea

1. ABSTRACT

Multiphase and wet gas flowmeter measurement devices have been deployed in the North Sea and elsewhere for around 20 years. From the early days it has been known that, to work properly, these devices need information about the produced fluids. To enable conversion from line conditions to standard conditions, all multiphase and wet gas flow meters require inputs such as permittivity, conductivity, and density of each of the phases, plus PVT models.

Several guidelines and regulations relating to North Sea operations have recently been published concerning the measurement of multiphase production streams for the purposes of fiscal allocations. These include the API Committee on Petroleum Measurement and Allocation Measurement of Multiphase (MPMS) Flow Chapter 20.3 which states requirements regarding measured inputs and PVT requirements along with guidance on how they should be managed.

This paper reviews the methods listed under API MPMS 20.3, specifically those outlined in section 3.4.7 “Changing fluid properties over field life for maintaining inputs”, with a focus on reducing uncertainty of the final input values. This section is critical, because each method of evaluating fluid properties has its own uncertainty associated with it and choosing one over another will have an impact on final statement uncertainty.

API MPMS 20.3 states that vendors have proposed specific technology solutions involving a variety of methods from in-line measurement of some fluid properties to extracting samples to measure the properties in lab conditions. This paper reviews what can be applied today and the practicality of these methods versus the trend of the industry over the last 15 years.

At the same time as API worked on its guideline document, national governments have developed their own requirements for technologies to be used for allocation within their borders. The North Sea is a leading area where governments have shown a willingness to define standards that take advantage of the technologies available for improving the accuracy of measurements used for fiscal allocation. The paper considers regulations defined by Norwegian and UK legislative authorities and how they compare to the API MPMS Chapter 20.3 document. Other countries developing their own standards include Mexico and Brazil, and subsea measurement technologies are increasingly being used to resolve complex cross-border fiscal allocation issues, as have previously been presented in this conference.

2. INTRODUCTION

In the petroleum industry, allocation refers to practices of breaking down measures of quantities of extracted hydrocarbons across various contributing sources (API 2013). Allocation aids the attribution of ownerships of hydrocarbons as each contributing element to a commingled flow, i.e. where produced fluids from multiple wells and/or producing zones are combined before flowing to a surface facility, which in deep water is typically a floating production, storage and offloading **(**FPSO**)** unit. Commingled flow is becoming increasingly common in the growing number of deepwater developments, where subsea production facilities combine flow before joining riser systems that transport hydrocarbons to the surface. Such systems often include tiebacks to other oil or gas fields operated by different company partnerships.

Allocation of produced hydrocarbons has major fiscal consequences for a variety of involved parties. It directly impacts the revenue and tax liabilities of oil and gas operators and is the subject of increasingly stringent guidelines and regulations from industry bodies and government authorities. Manufacturers of equipment and suppliers of services to the oil and gas industry are challenged to meet the requirements of these guidelines and regulations, and have developed new technologies and processes to enable more accurate measurement of hydrocarbon production on a well-by-well basis.

Multiphase flowmeters (MPFMs) installed at the subsea wellhead are used to measure the flow rates of oil, water and gas, and hence compute allocation. The meters require knowledge of physical parameters of the fluids - such as density - to provide accurate measurements. Fluid characteristics are usually tested during drilling of with wireline deployed instruments shortly after drilling in the exploration phase. However, it is known that produced fluids change over time, and computation of measurements based on samples obtained during exploration may not be representative of reservoir fluids flowing after several years of production.

There is a tendency in the subsea measurement market for solutions the authors believe is to be inaccurate to overcome some challenges, such as use of densitometers to gather fluid properties in a producing well. Associated required assumptions such as that the pipe is clean and that the fluids are pure are likely to be inaccurate in upstream oil and gas production. The authors of this paper believe that automatic updates based on an assumed salinity and non-representative in-situ measurements do not provide accurate and reliable information that can eliminate the need for physical sampling of produced fluids.

3. API MPMS 20.3

API published its Manual of Petroleum Measurement Standards (MPMS) Chapter 20.3 in January 2013, superseding API Recommended Practice 86-2005, which is withdrawn. The new standard addresses multiphase flow measurement in the production environment, upstream of the custody transfer (single-phase) measurement point, where allocation is applied. The document addresses operational requirements or constraints in multiphase measurement systems, including expectations for flow meter acceptance, calibration criteria, flow-loop and in-situ verifications. It specifically describes representative sampling as the ultimate way of setting up any MPFM. Furthermore, API MPMS Chapter 20.3 points to the importance of representative sampling as essential to reduce uncertainty in the overall measurement.

The API MMPS 20.3 also points to the challenges of capturing representative subsea samples, and suggests that 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. It also proposes that the sampling point should be close to the MPFM. An acceptable sample should contain all of the fluid constituents and the time frame for the samples shall be selected such that the samples are representative for the liquid constituents passing through the MPFM during the same time frame.

4. NORWEGIAN REGULATIONS

The Norwegian Petroleum Directorate (NPD) recently issued new requirements in its "Måleforskriften", which addresses metering for production allocation for fiscal regulations. This also states that subsea inline MPFMs are typically set-up using samples obtained during drilling. It acknowledges that 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.

5. UK REGULATIONS

The UK Department of Energy and Climate Change (DECC) Licensing, Exploration and Development Guidance Notes for Petroleum Measurement Issue 8 for systems operating under the Petroleum (Production) Regulations was published in July 2012 (DECC 2012). It states that fiscal multiphase measurement may be appropriate in production allocation applications where hydrocarbons from more than one field are commingled in a shared production facility, and where cost benefit considerations indicate that single-phase measurement of each field cannot be not economically justified.

The guidance notes state that the operator should provide the MPFM vendor with details of the anticipated initial values of flow rates, pressures, temperatures and composition as well as their expected profiles throughout life of the field. It notes that all MPFMs depend on knowledge of fluid characteristics for their correct operation.
When the fluid properties change, systematic bias in the output of the MPFM may be expected unless the relevant parameters in the meter software are updated to reflect these changes.

The DECC guidelines note that obtaining a representative sample from a multiphase stream is challenging, particularly in subsea MPFM applications, and there are currently no standards which provide guidance in this area. However, subsea sampling is actually already a proven technology and delivered technology. With proper planning of subsea completion systems is cost-effective to implement. We believe, with increasing industry acceptance of the technology, authorities such as DECC are likely to include sampling as a requirement in future revisions of their guidelines.

6. THE NEED FOR SUBSEA SAMPLING

By definition the fluid coming from the reservoir is always in an equilibrium state between the liquid and the gas phase and with changes is pressure and temperature there is a migration in or out of each phase. Although the overall composition may not change, the composition of each individual phase may vary considerably. For example, H_2S could be migrating from the gas phase to the oil and water phases, or the gas composition might be richer in light components dependent on pressure. In addition, the overall composition of produced fluids is likely to change considerably over the life of a field. It is unlikely that, without representative sampling, MPFM settings will accurately represent the particular conditions of the wellhead.

Guidelines and regulations increasingly require subsea sampling in recognition of the impact of changing fluid composition on MPFM accuracy and hence allocation accuracy prior to comingling. It is necessary to sample production from each well at line conditions of pressure, volume and temperature (PVT) in order to properly convert the measurements to the point-of-sale conditions at the surface for fiscal allocation. Representative sampling enables accurate calibration of instruments and reduced uncertainty in the measurements. Remote monitoring of measurements from the subsea instruments can then better identify and take action if issues arise as early as possible to eliminate large scale allocation imbalances.

Fluid parameters required for accurate meter measurements include viscosity, densities, water properties, and attenuation (electromagnetic or gamma ray). There is no multiphase flow meter on the market capable of accurately measuring fluid properties that is independent of knowledge of these parameters. For example, no system is capable of measuring the volume of gas dissolved inside the oil, which can be extremely critical in wet gas conditions.

Current MPFM systems to measure fractions of oil, water and gas are based on microwave and/or nuclear technologies, both of which are affected by changes in the full composition. While some systems estimate the salt content, this is not the only factor impacting compositional variations that impact the accuracy of measurements.

Sampling is a key technology for reliable measurements and there is a clear trend for the sampling use in the subsea business and specifically in wet gas conditions, as highlighted by Pinguet et al (2012). The need for sampling should be considered during the field subsea pipeline architecture design. Benefits include not only more accurate allocation, but also verification of the compatibility of multiple fluids and, most importantly, for flow assurance purposes.

7. CONCLUSIONS

Industry organizations such as the API and North Sea regulators such as the NPD and DECC agree that, for accurate allocation, MPFM measurements require representative samples of the produced fluids. As oil and gas developments move into ever deeper waters, subsea productions systems will become increasingly common, and will involve comingling of fluids from multiple wells, reservoir zones and/or fields. Subsea sampling at the wellhead is a proven technology, and regulations are moving towards making this a requirement for fiscal allocation purposes. The authors question whether oil and gas industry are moving in an appropriate direction, or even conforming to the latest regulatory requirements for mentioned type of measurements.

REFERENCES

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