Index

Paper 1.2

Production Measurement Management

Lex Scheers, Shell GS International
Chris Wolff, Shell GS International

Production Measurement Management

by

Lex (A.M.) Scheers, Shell GS International

and

Chris (C.J.M.) Wolff, Shell International E & P

Summary

The production measurement process is more than just measurement hardware in the field but is the entire chain from data collection in the field up to the final production reporting. It includes all intermediate steps such as measurement and sampling guidelines, operational procedures, data processing (pVT), data transmission and reconciliation/allocation procedures. The "customers" of this measurement process are generally spread over several disciplines in the oil and gas companies and their partners or government bodies. Each of these customers has their own requirements regarding the measurement process.

Production measurements have a vital economic impact on the business; it not only costs money, but also delivers data that is used in decision-making processes such as production optimisation or reservoir modelling and in measuring the economic returns. Economics then not only set the uncertainty requirements for the production measurement process but often also indicate the most critical measurements. This could be oil flow rate, gas flow rate, watercut, GOR, gas volume fraction or even water flow rate in water-constrained facilities.

As every field development has its own specific requirements for the production measurement process it will be demonstrated that a "design phase" and "operations phase" should be established. In the design phase the requirements from the customers are investigated and then compiled into a measurement philosophy and subsequently this results in detailed design and description of the system. Once production has started the measurement process should be managed through proper custodianship. The latter should be transparent and auditable and some organisational issues will be further discussed.

In addition, with the more advanced measurement technology being installed in the field, such as multi-phase flow meters or modelling techniques, it becomes clear that proper management of this technology is essential in order to meet the customer's expectations.

1 Introduction

A significant amount of publications have been issued over the last decade on the new metering concepts, like Coriolis meters for mass flow rate and net-oil measurement, Ultrasonic gas flow meters, Multiphase Flow Meters and Wet Gas Meters. However, most of these publications, if not all, are discussing the pure technical measurement issues, e.g. meter performance, test loop evaluations, accuracies and the various operational applications. With the introduction of all this more advanced measurement equipment in the upstream area of the oil and gas business one should ask the question whether we can still manage the production measurement chain with the resources we were using in the old days of orifice plates and turbine meters. The introduction of more advanced electronics, sophisticated fluid flow models, wet gas over-reading correlations, the number of additional fluid parameters required to properly run the modern measurement equipment also makes it necessary to adapt the skills of the staff in the field. Moreover the organisation should be tuned such that proper management (custodianship) of this "production measurement chain" can be done with the appropriate tools.

In addition to the more advanced technology, the industry has changed over the last decade in how they develop their infrastructure. Productions facilities of different oil companies have been linked together, hydrocarbon production is crossing concession boundaries, oil and gas is treated in facilities owned by other oil companies and pipelines are used to transport commingled production. One thing remains unchanged, as soon as money is involved we all want to have our fair share of the money pot and measurements are the basis for this.

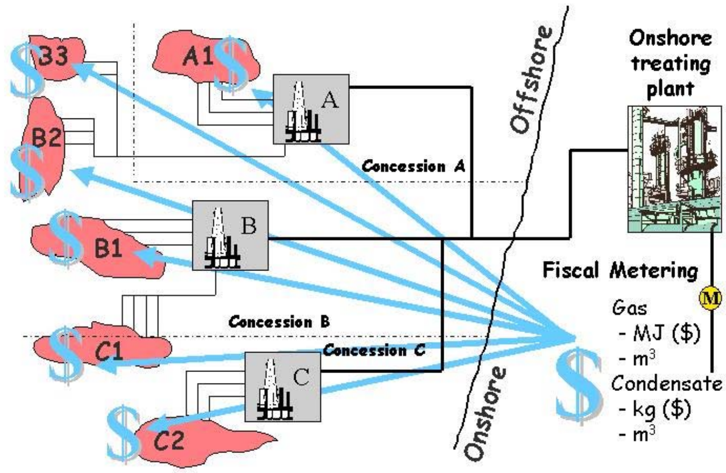

Figure 1, Split of "sales money pot" based on various measurements in the upstream area.

2 Costs vs. Accuracy

The value of any well flow rate production measurement, whether it is a regular well test with a fully equipped three-phase test separator or a relatively simple differential pressure measurement over the choke of a wellhead, should be evaluated in order to justify the measurement. It should not only be evaluated at design stage but also during the operation phase. Who will use the data and for what purpose? What should be the accuracy? What are the costs (both capital investments and operational expenses)? In general there are three main purposes why we need production measurements in the upstream area of the oil and gas industry.

1. **Surface control**
   Information allows the operators to monitor and optimise well production and manage facility throughput, e.g. well performance-monitoring, optimisation of production with artificial lift, planning, programming and forecasting.
2. **Sub-surface control**
   Information used by reservoir engineering, petroleum engineering to optimise the sub-surface part of the production process, e.g. work over wells, open/close zones, adjust artificial lift, manage reservoirs, etc.
3. **Fiscal or allocation measurement**
   This is a sales or allocation measurement that directly influences the cash flow of the company. With proper single phase fluids the uncertainties attached to these measurements are generally random and it may be a loss or a gain with an average of zero. However, with allocation measurements moving further upstream and dealing with non-ideal single-phase fluids and more complex metering equipment, systematic errors might be introduced with the consequence of a permanent gain or loss.

For measurements that fall into the first two categories, in the past often an uncertainty of 10% for each individual oil, water and gas stream was quoted. However, a sound justification for the origin of the 10% figure was never given. It can be argued that for some developments this uncertainty figure is too stringent and for some developments this uncertainty is too relaxed. Hence, the obvious question now is; what should be the optimum measurement uncertainty for a particular flow rate or composition in a certain project.

The uncertainty and cost issue is graphically presented in figure 2. Too low uncertainty (high certainty) in the measurements will result in high capital and operational expenditures (blue line in figure 2) but results in relatively low risks in future field developments (green line), this because of the availability of good production data. Note that the exact shape of this green line may be different from project to project but obviously will increase with increasing uncertainty. Too high uncertainty (low certainty) will save on the capital and operational expenditures for metering but results in poor quality production data and consequently the future development is exposed to higher risks and thus high uncertainty in future investments. Combining the blue and the red line results in a line with a minimum cost and an optimum uncertainty. The challenge now is to determine this optimum uncertainty figure and most likely each oil and gas development should have it's own optimal value. In other words, accuracy of a production measurement should be determined and should be negotiated with the various disciplines parties involved. Often also the repeatability of a measurement needs to be considered, in particular in the first two categories of surface and sub-surface monitoring and control, this is often more important that the absolute uncertainty. In other words if measurements are having systematic errors, e.g. due to a wrong density or wrong flow model in the flow computer, the accuracy of the measured production data might be significantly out but if trends are still detectable the information is useful. Moreover, systematic errors in upstream production measurements can often be reduced out in a reconciliation process where upstream measurements are reconciled with more accurate measurements further downstream.

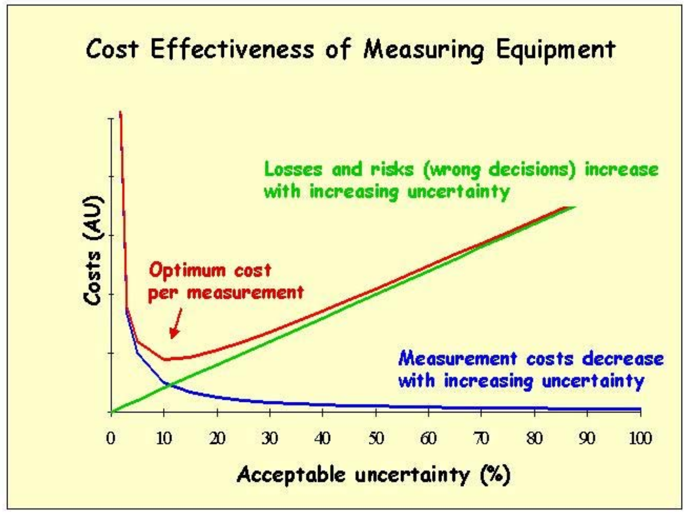

Figure 2, Uncertainty vs. costs.

The last category, fiscal or allocation measurements, traditionally shows the lowest degree of uncertainty, i.e. the best that is technically achievable. However, in the light of the above also here it can be argued that the uncertainty in fiscal measurements can be negotiated. The uncertainty in a fiscal type of measurements can be directly related to an uncertainty in money flow and this should be compared with the investments to install and operate fiscal metering stations.

Note that the traditional use of the words fiscal measurement or custody transfer are applied to those meters at the end of process were hydrocarbon product streams (i.e. money flow) to the government or partners/buyers are measured. However, with the sharing of production facilities, with production streams crossing concession

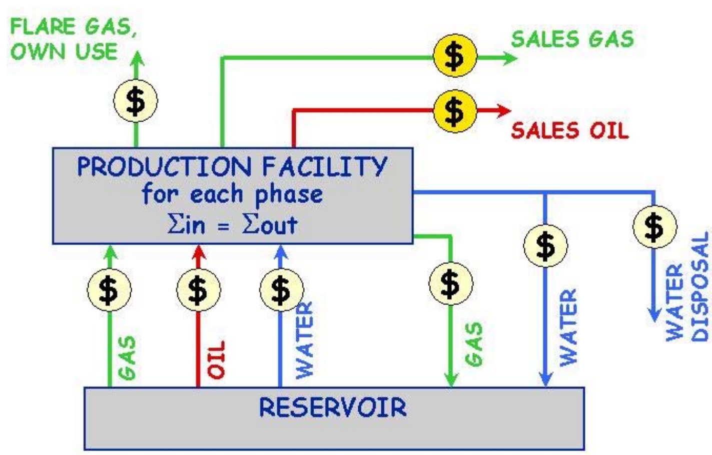

Figure 3, Not only the sales measurements have an impact on the money flow but also further upstream measurements do.

boundaries and with jointly operated pipelines, the infra structure in the upstream area becomes increasingly complex. Often upstream measurements like ex-field, ex-platform or even (test) separator measurements and flare measurements are directly influencing the company or government money flow (see figure 3). If those measurements influence the company money flow they also should be classified as fiscal or custody transfer measurements. It should also be mentioned that in today's oil and gas business the term fiscal measurement should not be used anymore to indicate a certain quality of the measurement, e.g. a 1% or 2% type of measurement, since it only indicates the type of service of the meter, i.e. "payment meter" rather than a "control meter".

Production measurements, whether single-phase or multi-phase, have an economic impact on the business. The implementation and use of production measurements not only costs money, but also delivers data that is used in measuring the economic returns and that is used in decision-making processes in a number of disciplines in the industry. Generally, the following three issues need proper consideration:

2.1 Value of information

The information retrieved from production measurement is used in decision-making processes; this is either in production optimisation processes or in the reservoir modelling processes (see figure 4). As an example one can relate the uncertainty in a measurement to the uncertainty band of the Ultimate Recovery (i.e. total production over field life). With poor accuracy in the measurements, it is likely that the uncertainty band will stay relatively large. With better and more accurate measurements the uncertainty band will reduce. In economic considerations related to further field development, the Ultimate Recovery is a critical parameter and the smaller the uncertainty band in the Ultimate Recovery the lower the economic risk. Take, as an example, a field of 100 million bbl, which has only produced 98 million bbl (2% less), because of non-optimum reservoir management. The decrease of revenues could be as high as tens of millions US$ (depends on oil price, production lifetime and discount rate, etc.). Similarly, if in the same field the production could be increased with only 2%, because of improved measurement, this could increase the revenue by the same order of magnitude. It is fair to state that assessing the value of information is the most difficult part and it is probably for that reason that it is rarely done properly, if done at all.

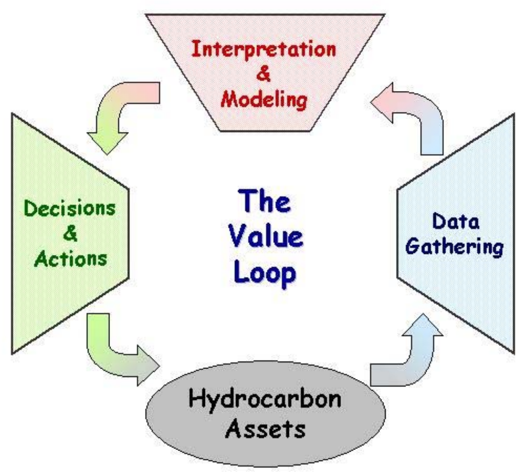

Figure 4, Production measurement data is a key component in the value loop.

For well flow rate measurements (like regular well testing with separators or multiphase flow meters) in the far upstream area of the business, e.g. the well testing, often the repeatability is more important than absolute accuracy, this to allow proper trending of some parameters and the fact that reconciliation processes may be used to reduce the systematic errors.

2.2 Hardware costs

This is the easiest part in the total cost estimate. Capital expenditures for production facilities, test separators, test lines, multi-phase flow meters, data acquisition systems, hydrocarbon oil and gas accounting, etc. can all be assessed relatively easily. It should also be noted that the higher the accuracy requirement for a particular product stream, the more expensive the meter hardware and the higher the operational cost will be.

2.3 Operating costs

It seems that often the expenditures, which are planned for operating costs, are heavily under-estimated. This is particularly true for the more advanced measurement equipment, like multi-phase and wet gas flow meters, and a considerable amount of operator attendance and specialist support is required. In general the commissioning phase is rather long. For multiphase flow meters and wet gas flow meters, we haven't reached the stage where we can apply the "fit and forget" concepts and it is foreseen that it will take another 3-4 years to reach this stage. However, this should not stop us from applying the technology to reap the cost benefits as long as we don't forget to provide adequate support in the project implementation and operations phase. In some cases the operating costs during the commissioning phase or special attendance during the initial operation period can be as high as 25% of the hardware costs. We should also realise that for higher accuracy, higher operating costs are required, due to more involvement from the various disciplines concerned.

3 Production Measurement Management System

3.1 Organisation

With all the disciplines that have an interest in the production measurement process (see figure 5) and the fact that all these disciplines have different requirements, it becomes clear that it is very desirable to have a coordination function in place. This function can be fulfilled by a dedicated group of staff, e.g. a Production Measurement Team. Preferably this team should be positioned in a corporate part of the organisation. This team should have sufficient skills in house to give guidance to the entire metering process (from sensor to final report) and they should be considered as the focal point for the companies metering philosophy and strategy. They also should provide in-depth technical support to the rest of the organisation, i.e. support on existing and future hardware, knowledge on the applications, awareness of standards and best practice guidelines, etc. They not only should have sufficient metering background but at the same time they should have a feel for what is required by the so-called customers of the metering process, e.g. the reservoir, petroleum and operation engineers, as well as partner companies and government bodies. They are responsible for all the company fiscal metering, the product reallocation procedures and, if applicable, the sales allocation procedures. However, all the above doesn't mean that this team should carry the responsibility for each individual meter or that they are responsible for each individual calibration activity. They should be responsible for the processes, tools and procedures that people in the field use to manage the data measurement equipment and execute the data processing and their validation. The ultimate responsibility whether the metering concepts or data processing comply with the company standards is then in the hands of the various Business Units

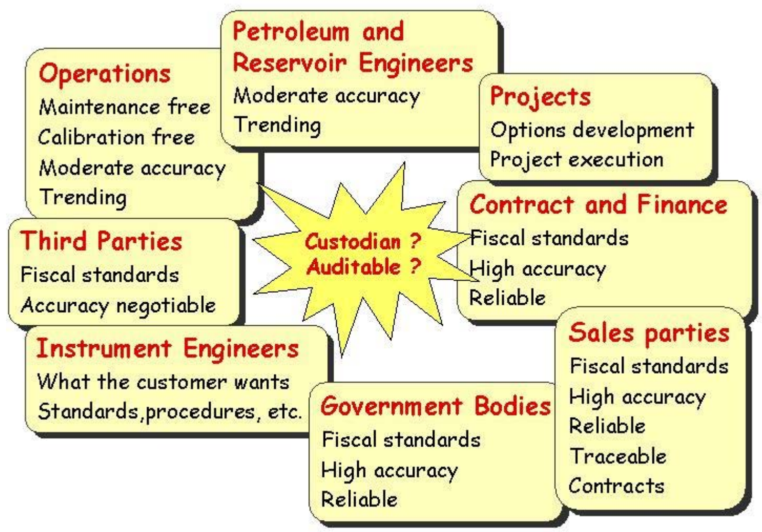

Figure 5, Various disciplines that are involved in the production measurement issue.

or Assets Teams. An example is the various stand-alone spreadsheets that are floating around in operations to correct, validate and/or smooth data. Often no formal approval exists, no documentation is in place and when the spreadsheet's author departs a gap is created.

In addition, the Production Measurement Team is the technical spokesman to third parties and government authorities, for all company production measurement and allocation activities. It has been demonstrated that when third parties and governments authorities speak to individual Business Units or Asset Teams they might hear different stories and this might cause unnecessary confusion and debate. Having one spokesman will at least ensure a consistent communication to the outside world. A further task of this Production Measurement Team is to execute audits on the systems as operated by the Business Units or Asset Teams.

The above seems in contradiction with the present trend in the oil companies to decentralise the various responsibilities deeper into the organisation (e.g. creating Business Units and Assets Teams) and let each unit carry its own responsibility in terms of project development, thus also for measurement concepts, measurement guidelines and measurement specifications. However, this approach might also lead to conflicts, as the Asset Team objectives might not be aligned with the company corporate objectives. An example is setting the meter requirements for an "Asset Team oil export meter" into the company's corporate pipeline (see figure 6). Here a measurement error in that export meter will affect all other Assets Teams in the company once a reconciliation process is carried out. Although clearly belonging to a particular asset the corporate Production Measurement Team should be the one that specifies the requirements for that particular measurement set-up. In fact this Production Measurement Team should have a mandate to force Business Units and Asset Teams to fulfil measurement requirements that are of a corporate nature.

Where exactly the boundary between corporate and Business Unit or Asset Team production measurement aspects is located is open for debate but a general rule would be that any production measurements that have a corporate character and is positioned such that metering uncertainty influences the production figures of other Business Units, Asset Teams or third parties, should fall under the responsibility of this corporate Production Measurement Team.

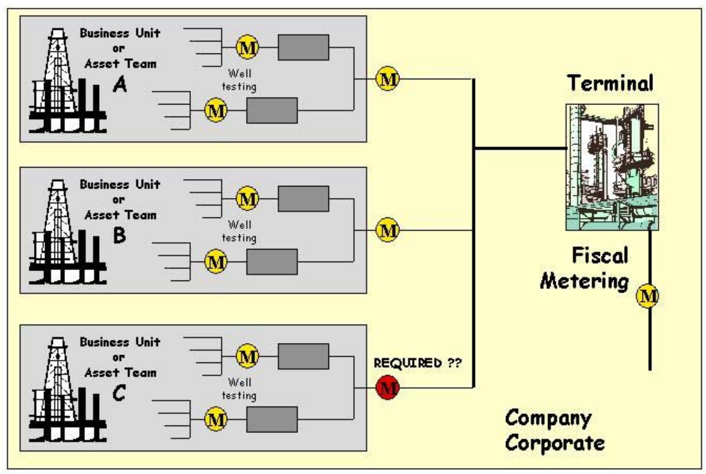

Figure 6, Who should be the custodian of a Business Unit export meter?

3.2 Production Measurement Development Phases

Various stages can be considered in the design and operation of a production measurement system. Note that a production measurement system should be considered as the entire chain of equipment, procedures and actions, which is involved to get from the raw meter data to the final production reports. This includes data processing, (sometimes called validation or smoothing) like intermediate reconciliation, pVT corrections or final allocation. It also includes uncertainty considerations and investigates how uncertainties work their way through in the various algorithms used for reconciliation and allocation. The phased approach, considered to be very useful, is similar to the phases the oil and gas industry uses to develop their projects and are further explained below.

3.2.1 Conceptual Design Phase

In this phase the boundary conditions with respect to metering are set. It is important to distinguish between the firm boundary conditions and boundary conditions that are still open for further discussion and negotiation. Often government requirements are fixed, corporate company requirements are already set and sometimes there is already a sales contract and/or allocation procedure in place. For new areas the sales contracts and allocation contracts are often under discussion and then it is important to get measurement expertise in the loop, e.g. the above-mentioned Production Measurement Team. Next to the external requirements there are also internal requirements from reservoir and petroleum engineers. It should be highlighted which production data is critical in maximising the oil and gas production. This does not necessarily mean that the oil, water and gas flow rates are important but it could well be that watercut or GOR (Gas Oil Ratio) measurements are more important. Furthermore it is relevant to consider what is required at later field life when watercut and GVF (Gas Volume Fraction) tend to get into the 80-100% range. Input from reservoir and petroleum engineering is key in this stage and they also should be able to indicate the criticality of the measurement, in other words what are the uncertainty requirements for the measurement. Although some of the above is being considered and reviewed it is rarely properly documented and consequently it is often lost after a few years. Hence, it is recommended to compile a high level document called the "Production Measurement and Monitoring Philosophy" which could be part of the "Operating Philosophy". In summary that document should contain the following information:

1. Requirements related to **fiscal measurements**; e.g. contractual commitments, government or legislative requirements, corporate and/or sales allocation procedure requirements. Disposal streams, flare metering requirements, etc. should also be included. With the above info, a conceptual design for the production measurement system should be prepared.
2. **Reservoir monitoring and production optimisation requirements**; e.g. what are the important decision that are foreseen in future field life, both sub-surface and surface and what are the economics of those decisions. What will be the supportive data that is required in that decision process and how does the accuracy in the data influence that decision. Is continuous metering required or will a spot measurement be sufficient (note that a very accurate spot measurement, e.g. a 1% well test for 1 day in a month can result in a much higher uncertainty in the monthly cumulative oil-flow than a continuous measurement with a 10-20% uncertainty in the oil-flow rate). What will be the requirements in latter field life (note that often the importance of a watercut measurement increases with field life and is very critical in abandonment decisions)? Issues like test separator, multi-phase or wet gas metering, testing by difference, etc. need proper considerations and the impact on the conceptual design of the facilities should be highlighted. It appears that for oil fields more emphasis should be given to net-oil flow rate (thus watercut measurement is important) and gas/oil ratio. For gas fields the gas flow rate and condensate/gas ratio and water/gas ratio seem to be more relevant.

3.2.2 Detailed Design Phase

In the detailed design phase the high level "Production Measurement and Monitoring Philosophy" should be used as a start and subsequently the details of the production measurement system should be further filled in. This finally should lead to a second, and more detailed, document called the "Production Measurement Manual". This will be the day-to-day working document of which the Production Measurement Team should be the custodian and this document can be used by anyone in the organisation that needs certain specific knowledge on the production measurement system. Tools and communication processes should be in place to ensure proper information flow is guaranteed from field staff into that document. In principle, it should contain a detailed description on the following aspects (note that these cover both hardware and procedures and the novelty is that these aspects are now dealt with in one and the same document):

1. Overview of the production process, process drawings should be included with meter locations highlighted.
2. Production forecast, e.g. operating envelopes of field or wells over the field life. Are metering concepts able to cope with the changes in production (decreasing flow rates, higher watercuts and higher Gas Volume Fractions)
3. Specifications of meters, instruments and computing hardware. Relevant information like performance envelopes and accuracies should be mentioned. Impact of rough operational conditions like sand production, wax and/or scale deposition, viscosity, etc. need to be addressed.
4. PVT models or shrinkage factors used to handle the conversion from actual to standard conditions should be mentioned.
5. Procedures to convert field data into data used in the reports. This should include validation processes
6. Allocation and reconciliation algorithms,
7. Management of fluid parameters (e.g. z-factor, density), how often is parameter determination required and how is data validation done. How do variations in fluid parameters influence the measurement result? When is it required to update flow computers with the new data. Note that also for the more advanced multi-phase and wet gas metering technology fluid properties are key and this needs proper management.
8. Sensitivity analyses, often Monte Carlo simulations are easy to use and can quickly reveal the uncertainty of more complex systems.
9. Operating, maintenance and calibration procedures and calibration frequencies.

3.2.3 Operation Phase

One of the prime tasks is to keep the documentation up-to-date, in particularly the earlier mentioned Production Measurement Manual. The system description (both the drawings and the reconciliation/allocation algorithms), the fluid properties used, the references to company guidelines, local or international standards.

Responsibility for maintenance, calibrations and the technical integrity of production measurement systems in the first place is in hands of the operational staff in the field (Business Units and Asset Teams). They should carry out the activities to ensure that the measured data are reliable and are according to the specifications. The corporate Production Measurement Team should provide the operations staff with the procedures and tools to execute their job. Next to the more common guidelines to maintain and calibrate meters there are still a few gaps. One of the major ones is related to the management of the fluid parameters used in the measurement process. Often use is made of fluid parameters like base density, z-factor, gross heating value, viscosity, etc. These parameters are used in flow computers to calculate flow or energy rates. A more practical example is the management of the base densities of oil and water for a Coriolis meter that is used as a net-oil computer or management of the various fluid parameters used in multiphase flow meters (mass absorption coefficients, dielectric constants, etc.). Proper systems to keep track of these parameters (e.g. database plus a custodian) and tools to decide when to change the actually used values need to be in place. Should we change a base density each time we find a new density reading or should we use more advanced statistics to manage these parameters in the longer run.

Most of the composition measurements, e.g. a Coriolis meter that is used for net-oil measurement or a more complicated multiphase flow meter, are influence by changes in fluid parameters, e.g. changes in salinity, in base density, in base dielectric constants, in gamma ray absorption coefficients, etc. If the application is for a development with different reservoir/well characteristics or the development will be a seawater-injected reservoir it is important to have a database in place where all these fluid parameters are properly stored. Moreover it is important to have sufficient knowledge on how variations in all these parameters will influence the metering accuracy.

4 Conclusions

The changes that have taken place in the last decade, like the introduction of more complex metering systems (multiphase and wet gas flow meters), more complex (shared) production systems, various production optimisation efforts, abandonment policies, flaring constraints, etc., etc. have a significant effect on the way we design, operate and manage our production measurement facilities. More emphasis should be given to the entire chain in the measurement process, i.e. from sensor to the final report. This includes the intermediate validation process, conversion algorithms, how the uncertainties work their way through in the reconciliation and/or allocation processes.The introduction of a corporate Production Measurement Team that is responsible for the production metering philosophy and strategy in the company ensures a common approach and this team should fulfill the role of spokesman to the outside world. This team should be the focal point for all metering, data processing and allocation issues as soon as there is any corporate involvement. This team also should play a key role in setting the companies or new project metering strategies (Production Measurement Philosophy document) and should be the custodian of the Production Measurement Manual i.e. the manual that describes the measurement process in terms of configurations and algorithms used to get from raw sensor data to final reported data. In addition this team should be given the responsibility to execute audits in the Business Units or asset Teams.

Various stages should be considered in the lifecycle of a production measurement system. To start with, a conceptual design phase should be included. Here the Production Measurement Philosophy is set. This then is followed by a detailed design phase that should result in a Production Measurement Manual describing all metering configurations and algorithms used (reconciliation, PVT corrections, etc). In the operation phase the field staff is responsible to execute the metering process according to the company procedures and guidelines.

Last but not least, in the conceptual and detailed design phase the value that is attached to the measurements information should be one of the main drivers in the metering selection process. The accuracy requirements should be defined and justified in the Production Measurement Philosophy.