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Design of a subsea fiscal oil export metering system

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1 Introduction

1.1 Why a subsea fiscal oil export metering station?

Tankers used as floating storage and offloading units has an expected life time of 20-30 years. This life time is often shorter than the expected lifetime of an oil field. During the life time, these tankers use a substantial amount of fuel, emit large amounts of CO2 and have significant operational costs. At the end of the life time extensive repairs and recertification or replacement is required.

A subsea storage will have a longer life time than a floating tanker and also have lower operational costs. Hence there are substantial business drivers to develop a subsea storage concept which can replace tankers used as floating storage units. To export oil from a subsea storage, a fiscal oil export metering system will be required under the Norwegian statutory regime. This is thus a strong driver to start developing a subsea fiscal oil export metering system.

A subsea fiscal oil export metering system must:

1. Measure flow, pressure, temperature, density and water fraction
2. Provide a way of collecting representative liquid samples
3. Provide traceable measurements within the statutory uncertainty requirements
4. Be retractable / exchangeable via module replacement
5. Provide redundancy and have condition monitoring capabilities
6. Be robust to the expected variation of fluid parameters

Statoil is currently developing a subsea fiscal oil export metering concept. The paper will present this concept.

1.2 Requirements to design - Authority requirements

In Norway, the authority requirements to fiscal measurement can be found in “The Measurement Regulations: “ REGULATIONS RELATING TO MEASUREMENT OF PETROLEUM FOR FISCAL PURPOSES AND FOR CALCULATION OF CO2-TAX

Requirements that are significant for station design are included in this section.

Section 13 – Parallel metering runs
“On sales metering stations the number of parallel meter runs shall be such that the maximum flow of hydrocarbons can be measured with one meter run out of service,”

Section 13 – Shut of valves
“Shutoff valves shall be of the block and bleed type. All valves of significance to the integrity of the metering station shall be accessible for inspection to secure against leakage.”

Section 13 – Design in accordance with recognized standards
“The measuring system shall be planned according to the requirements in this regulation and according to recognised standards for such measuring systems.”

Recognized standards are identified in the document: “Standards relating to measurement of petroleum for fiscal purposes and for calculation of CO2-tax” available at the Norwegian Petroleum Directorate” net site.

Section 14 – Permanent equipment for calibration shall be available
“If other types of flow meters [than turbine meters] are used for liquid metering, permanent equipment for calibration of the metering device shall be available.”

1.3 Recognized standards

API MPMS 5.1
API MPMS 5.1:2008 “General Considerations for Measurement by Meters” is regarded by the measurement regulations to be a recognized and significant standard for design of fiscal oil export metering systems.

A few essential sections are included here.
API MPMS 5.1 – Meter proving
“5.1.9.4.1 Each meter run should be connected to a permanent prover or connections should be provided for a portable prover or master meter to obtain and demonstrate the use of meter factors that represent current operations. The proving methods shall be acceptable to all parties involved.”

API MPMS 4.5 – Master meter provers
“3.3 Indirect master meter proving method.
This proving method requires that the line meter and a master meter be in series. The line meter is proved by comparison to the master meter whose meter factor was determined by a previous direct proving on a different flow stream and/or conditions. This method has a significant higher uncertainty than the other methods because a displacement prover is not in series with the master meter and the line meter.”

“Master meter proving is used when proving by the direct method cannot be accomplished because of meter characteristics, logistics, time, space, safety, and cost considerations.”

ISO 17089 – Reference meter method for ultrasonic meters in series
This standard is valid for gas metering applications. For gas metering applications it has become common to put two ultrasonic meters in series. This standard describes a method for monitoring of the quality of the flow meters:
“Annex C (Informative) The flow reference meter method for ultrasonic meters is series
C1. General
With two ultrasonic meters in series, a systematic approach, the flow reference meter method, may be employed to monitor the quality of the meters (with the exception of common-mode errors).”

2 Basic design of the metering system

2.1 Introduction to basic design

First step in the development is to put up a feasible basic design. The intention with the basic design is to arrive at a design that meets statutory requirements and industrial standards. The basic design will then form the basis for a Failure Mode and Effect Analysis and an analysis of the total risk for loss of profit. The following sections summarize these assessments. Also it is important to identify components that are already existing and qualified, and which components will have to be developed.

2.2 Components that already exists for subsea application

A number of subsea components already exist and can be regarded as qualified. The following components are here regarded as sufficiently qualified:

- Horizontal and vertical pipe connectors
- Tubing connectors
- Relevant signal and power connectors
- Block valves
- Double block valves
- Temperature and Pressure transmitters

2.3 Component to be developed and qualified - Subsea ultrasonic flow meters

Due to long term stability, large turn down range, low pressure loss, linearity and low uncertainty - ultrasonic flow meter has become the most used flow meter in new topside metering station designs.

Several manufacturers provide ultrasonic flow meters for topside application. Without putting more consideration into it, it is taken as granted that a subsea version can be designed for any of the topside ultrasonic flow meters. On a preliminary basis it is also taken for granted that the uncertainty requirements can be met by using an ultrasonic flow meter. The uncertainty is further addressed in a later section.

2.4 Selection of proving method for a subsea design

Without further consideration it is here taken for granted that due to the need for frequent maintenance it will not be feasible to develop a conventional large volume prover or a conventional small volume piston prover for subsea application. In such proving systems there are too many moving parts that are susceptible for wear and tear and hence will need some kind of maintenance.

The only remaining proving system will then be an indirect master meter proving system. The master meter, and the line meter, will have to be adjusted and calibrated on a similar fluid at a topside calibration facility before installation in the subsea facility.

Note: It is explicitly stated in API MPMS that the master meter must be in series with the line meter. It is not explicitly stated that the master meter need to be in a by-pass to the line meter. However, in a typical drawing in the standard, it is indicated that the master is in a bypass to the line meter.

Conventional master meter solution contains a master meter in a by-pass. However, the development of ultrasonic flow meters has opened up for the possibility to install the master meter in line with the line meter. In gas metering systems an inline master meter in series with the line meter has become quite common. Also in oil metering systems this is now becoming more common.

2.5 Sampling system

It is considered that for a subsea fiscal metering system, a sampling system in accordance with the Norwegian statutory requirements for fiscal measurement will be required. It is further considered that a subsea sampling system, with transport of the sample in the umbilical to a nearby topside facility and sub-sampling by a conventional topside sampling will be feasible. This will be elaborated in the following section.

The following extracts are intended to give an overview over the most fundamental statutory requirements.

- “Sampling shall be carried out in a manner which ensures that representative amounts are sampled.”
- “Sampling shall be automatic and flow proportional. In addition it shall be possible to carry out manual sampling.”
- “The sampling probe shall be placed at a location where a representative sample will be obtained. A mixing device may be required.”
- “Manual spot sampling shall be available also with automatic sampling/fast loop out of service.”

The following high level considerations are made regarding the design.

- The sample can be extracted from the main pipe by using a conventional sample probe
- The sample probe should be placed in a vertical section upstream the flow meters
- The sample stream can be transported to the top side facility via tubing in the umbilical
- To overcome the pressure loss in the sampling line, and to elevate the sample above sea level up to the platform, a sampling pump will be required in the subsea system
- To be able to perform maintenance on sample probe, pump and valves - the sampling system should be included in a retrievable module or system.
- At the top side facility, a conventional system for fiscal sampling will have to be installed for sub-sampling of the sample stream from the umbilical.
- For redundancy, the system should contain two independent sampling systems
- A conventional flow metering control system should be located at the topside facility to control both the metering system and the sampling system.
- The time delay for transport of the sample from the subsea must be accounted for by the metering control system to obtain representative flow proportional sampling

The system should be designed with redundancy within the sampling system. However – If one of the sampling systems fails, retraction and replacement of the sampling module will have to be scheduled. Detail design will decide if the sampling system is part of the metering module or in a separate module.

2.5.1 Detailed design of the sampling system

2.5.1.1 Design considerations – location of the sampling probe

If the sampling probe is placed in a horizontal pipe, a static or dynamic mixing device will be required to ensure proper mixing. In a horizontal pipe, velocities above 6 – 7 m/s will be required to ensure proper mixing and equal distribution of water in oil over the pipe cross section. The system may be driven by difference in density between water and oil – and not by pumps. In this case static mixing is not desired, as a static mixer will introduce a pressure loss, and consequently also lower flow rates. A dynamic, pumped mixing system is not desirable because of the complexity it would add to a subsea system.

However, it is evident from ISO 3171 sub - clause 5.2 that installation of a sample probe in a vertical pipe section is preferable to get a homogeneous mixture of water in oil at the sampling point. It is also indicated in Figure 10.5 til 10.8 in NFOGM Handbook of Water Fraction Metering, that in a vertical pipe, equal distribution of water over the cross section can be expected for velocities above 1 m/s even for water fractions up to 5 %.

As the velocities will be well above 1 m/second in normal operation, sufficient mixing of water in oil can be expected in the vertical pipe sections. To avoid removal of liquid from the pipe after it has been measured, the sampling probe should be placed at the vertical pipe section at the entry of the metering system. Exact location in the vertical section will have to be optimized based on evaluation of effects of the upstream pipe configuration. Due consideration will have to be paid to the centrifuge effect of Pipe bend.

2.5.1.2 Design considerations - Flow velocity in the sampling tube

To maintain a representative mix of water and oil, and to avoid settlement of free water, the flow velocity in the umbilical need to be kept in the turbulent flow range. It is assumed that a flow velocity higher than 1 m/s will be required to avoid accumulation of free water, or solids, in the sampling line inside the umbilical.

A theoretical upper limit for flow velocity is assumed to be in order of magnitude 5 m/s. However, due to the pressure loss it is assumed that a velocity of approximately 1 m/s will be achievable. Velocity down to 0,5 m/s may be evaluated.

Tubing in the umbilical is typically 12 mm super duplex tubing. The maximum operational pressure in the tubing is typically 690 Bar. It is regarded fully feasible to pump the sampling stream at a sufficient flow rate through tubing in the umbilical.

The system should be design for a sample flow rate of minimum 1 m/s through the tubing in the umbilical.

2.5.1.3 Design considerations - Sample transport time

Another design consideration to be made is how to handle the time delay from the subsea metering station to the top side facility.

An offshore loading operation will take about 15 – 20 hours. Further it is assumed that the subsea facility will be placed about 1000 m from a top – side facility. Assuming a flow velocity of 1 m/s, the sample will use 1000 seconds to be transported from the subsea facility to the top-side facility. 1000 seconds is equal to about 17 minutes. Hence the automatic sampling system at the topside system will have to be able to handle a time delay of 17 minutes.

The following design will handle a time delay of 17 minutes:
First, topside sub - sampling of the content coming from the sampling line will have to be delayed 17 minutes to be sure that the fluid sample is representative for the batch. A flowmeter should be placed topside to allow more exact online calculation of the delay, based on flow rate and volume of the sampling line.

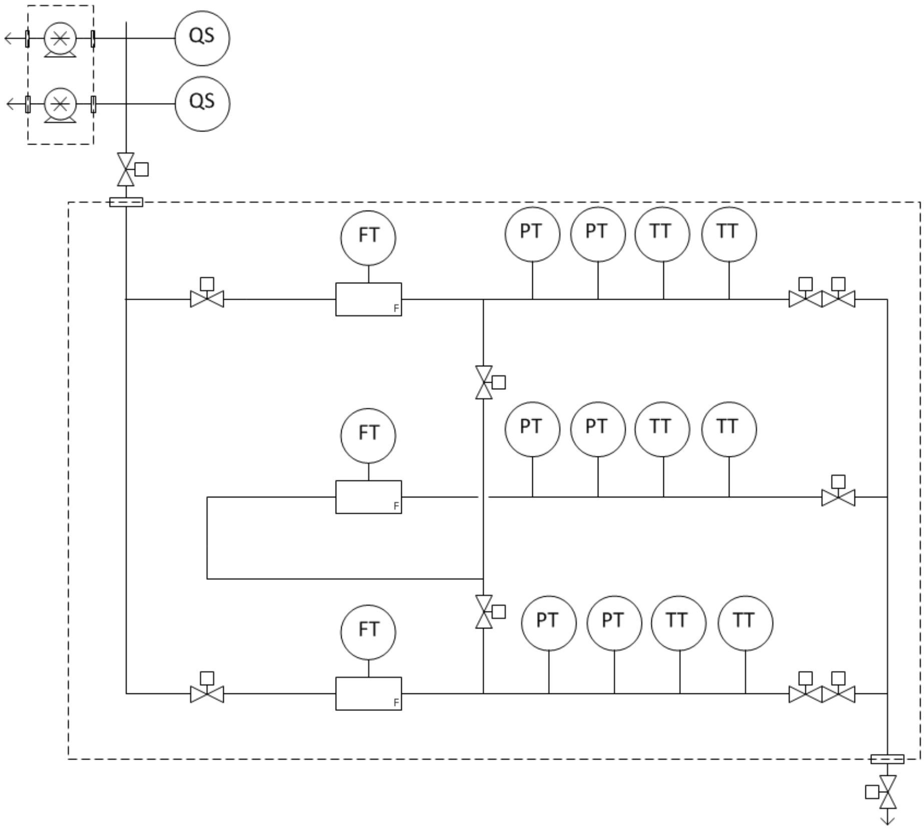
Second – Fluid sampling shall be flow proportional. Consequently the sampling rate should be proportional to the flow rate measured 17 minutes ago, and not to the flow rate at the moment.

Third – sub - sampling of the flow from the sampling line will have to continue for 17 minutes after the flow through the subsea fiscal oil metering station has been stopped. Hence the pumps will have to be running, and the fluid reservoir for the main flow in the main pipe should be open for 17 minutes after the offloading has stopped.

It should thus be evident that the sampling can be both representative and flow proportional by just taking into account the transport time for the sample from the subsea facility to the top – side facility. The sampling system can be controlled by a conventional metering control system placed at the top – side facility.

2.6 Basic design: 2 metering runs – 1 line meter in each –1master meter in a bypass

The following design is regarded to meet significant statutory design requirements:



QS = Sampling System, FT = Ultrasonic Flow Meter, PT = Pressure Transmitter, TT = Temperature Transmitter.
In this figure, the fluid is flowing in from top left side, passing the sampling systems and then passing through 1 of the 2 metering runs in parallel. The second metering run is a spare metering run. The flow from each of the two metering runs can be routed via the master meter run in the middle for calibration and adjustment of the line (duty) meter.

Rather than having many pipe connectors within the metering system and thereby increasing the complexity, the system design shown here has only 2 pipe connectors. These are shown as a little rectangle where the line is passing the stippled box. The systems within the stippled box are retractable.

As the metering system is placed at the seabed, calibration will require retraction of the system, and replacement with a calibrated spare system. Also valve leakage, or failure to prove valve tightness, will require the system to be retracted and replaced. The complete system will have to be replaced if any of the components in the system need maintenance.

2.7 Uncertainty analysis for the basic design

2.7.1 Introduction to the uncertainty analysis

An uncertainty analysis is required both by the measurement regulations and by authority guidelines for Plan for Installation and Operation of facilities for transport and utilisation of Petroleum.

Norwegian Society for Oil and Gas measurement is currently developing a tool for performing uncertainty analysis of fiscal oil metering stations. This tool is utilised for the uncertainty analysis in this document.

As the actual metering systems has not been built and test, the uncertainty analysis is an a priori estimate of uncertainty. This a priori estimate is based on a number of assumptions which are identified below. The accuracy of the assumptions below is not of critical importance for the result.

Operational pressure	30	bara
Operational temperature	45	degC
Viscosity	1	cP
Velocity	7	m/s
Pipe diameter	0,5	m
Density	800	kg/m3
Reynolds number	2,8 E6	

Further – it is assumed that all uncertainties for the individual instruments in the metering system are equal to the uncertainty requirements in “The measurement regulations”. It is also assumed that internal corrosion of the pipe and wax deposits is avoided by design.

The fluid will be sampled through the umbilical and analysed at a topside facility in accordance with conventional methods. Hence density and water cut will also be determined within the uncertainty requirements in The measurement regulations. The uncertainty in determination of water cut (0,05%) is excluded from this evaluation. It will be showed that this uncertainty contribution will not have a significant effect on the result.

2.7.2 Flow profile and fluid effects on ultrasonic meters

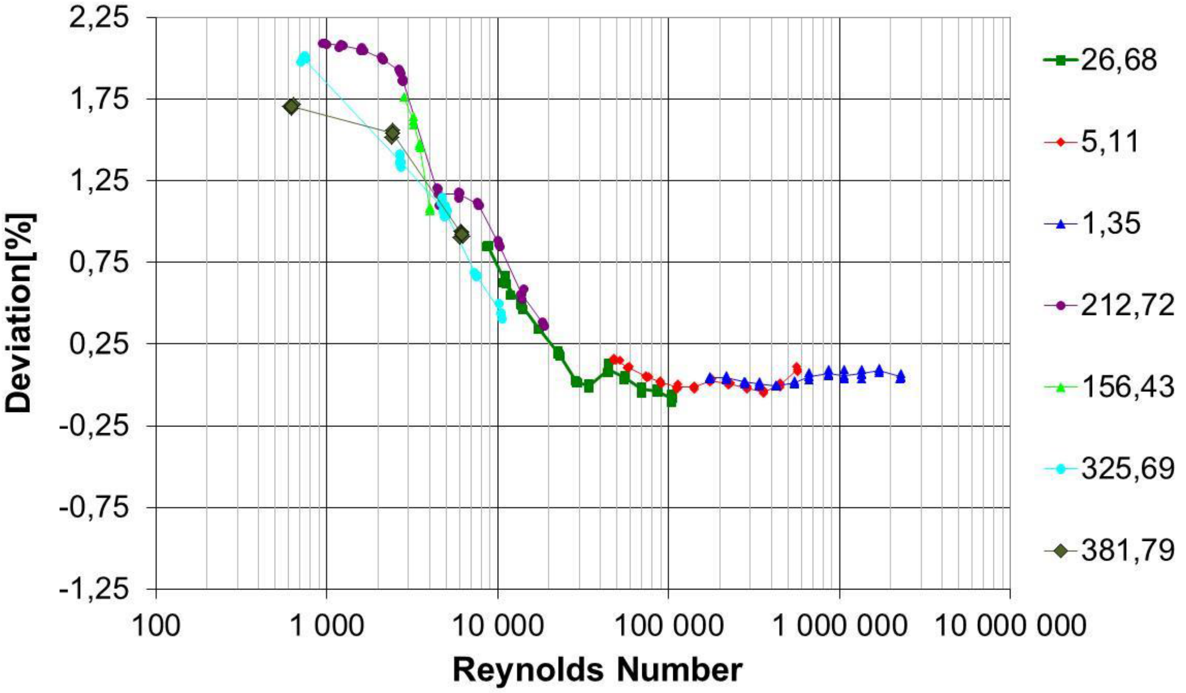
The ultrasonic meter will have an uncertainty component which may be termed “Flow profile and fluid effects on the master meter” this uncertainty component is meant to cover:

- The effect of the difference in pipe configuration between the laboratory and field installation.
  This effect is regarded to be neglible as the meter will be calibrated using the same upstream pipe configuration.
- The effect of difference in pipe roughness between the laboratory and field installation.
  This effect is regarded to be neglible as the pipe will be made by a non-corrosive material

- The reproducibility of the master meter between laboratory conditions and operational conditions where viscosity, density, Reynolds number and flow profile will vary

Note that uncertainty contribution arising from the linearity of the meters is covered by a separate uncertainty contribution.

For the last bullet point it is recognized that the meters will be operated at Reynolds numbers far into the turbulent range. It is also recognized that the flow profile is quite flat at such Reynolds numbers. The following calibration curve is obtained by using original weighting factors and no velocity profile correction for an ultrasonic meter. The curve demonstrates that the calibration curve becomes flat at high Reynolds numbers. The curve also demonstrates that the Reynolds number has to be taken into consideration when evaluating uncertainty for ultrasonic meters.

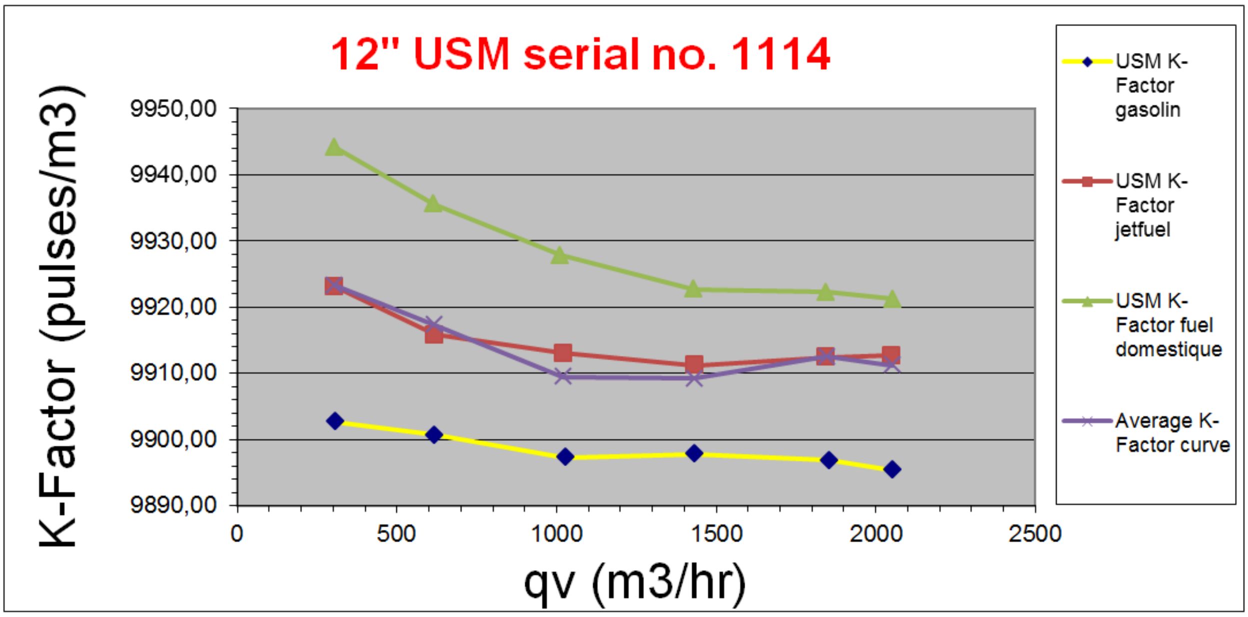


The figure is taken from the following paper: “Qualification of Fiscal Liquid Ultrasonic Meter for Operation on Extended Viscosity Range” By Øyvind Nesse and Tore Bratten - presented at the North Sea Flow Measurement Workshop in 2013.

2.7.2.1 *Uncertainty estimate for “Flow profile and fluid effects” based on experience from a recent project*

Experience from a recent project provides some insight into the possible influence from fluid variation on the measurement result. 12” ultrasonic meters were used in this project. The three meters were calibrated on gasoline 0,5 cP, jet fuel 1,5 cP and domestic fuel 4 cP. The calibration results demonstrates that the meter factor varied approximately 0,15 % from the average meter factor for these three fluids. Investigations are currently being conducted to understand and reduce the fluid effect for these particular meters. However, these tests give an indication about the level of uncertainty that may arise from flow profile and fluid effects.

The calibration results are presented in the following figure. The meters were neither calibrated nor adjusted for the calibration fluids before the calibration documented in these figures.



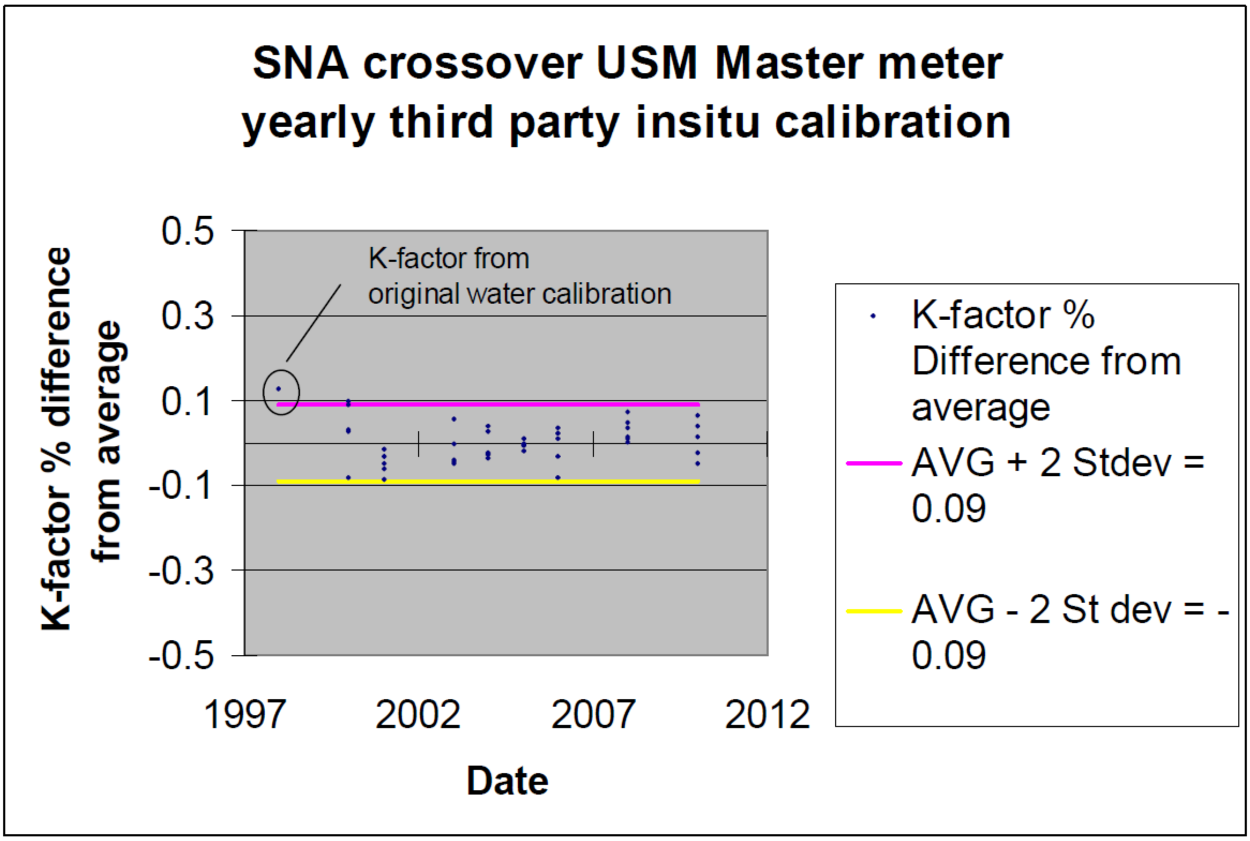
It should be noted that the calibration curve clearly and consistently is influenced by the viscosity of the product. When a systematic effect has been determined during calibration, it is reasonable to assume that operational routines will ensure some monitoring of the viscosity of the product. The calibration curve for the viscosity which is closest to the viscosity of the measured product can then be selected in operation.

As demonstrated by this calibration curves, the change in meter factor due to viscosity was up to 0,15 % in this particular case. If we assume that the calibration curve for the viscosity closest to the operational viscosity is selected, it is reasonable to assume that the maximum uncertainty due to variation in viscosity is approximately half this change (0,075 %).

2.7.2.2 Uncertainty estimate for "Flow profile and fluid effects" based on experience from the Snorre platform

The following figure contains operational experience for a meter at Snorre A, which were operated on a similar fluid as studied in this analysis. The fluid had a viscosity of approximately 2,5 cP. The experience is documented in the paper: "Operational experience with liquid ultrasonic meters" A paper for Presentation at the 29'th North Sea Flow Measurement Workshop in Tønsberg 2011 By Dag Flølo et al.

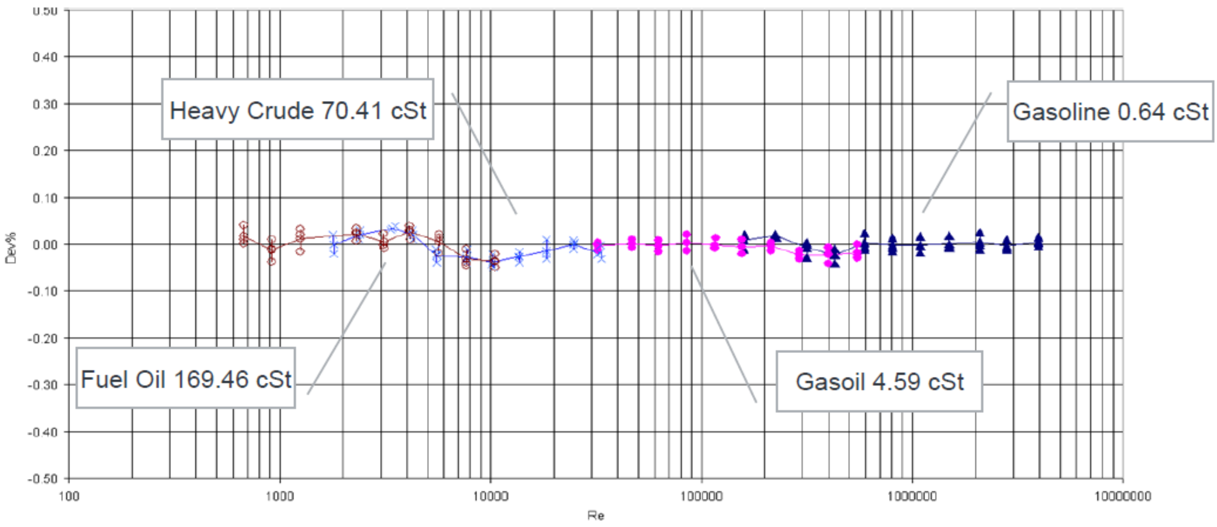
The charts below shows all K-factors achieved at the yearly on-site calibration performed by using real product.



Operational experience with this meter demonstrates that the variation in meter factor due to both linearity, flow profile and fluid effects is approximately 0,1 % @ 95 % confidence level in this particular case. Similar results were obtained for a similar meter at Snorre B. The operational experience also demonstrates that there is no sign of significant aging effects. Hence it is reasonable to regard the influence from aging to be insignificant.

2.7.2.3 Uncertainty estimate for "Flow profile and fluid effects" based on manufacturers data for a newly developed meter.

The presentation by Pico Brand from Krohne at NFOGM annual technical workshop 2015 "Are liquid ultrasonic flowmeters independent of fluid properties?" contains data for a newly developed 7 beam meter that were tested on a variety of products. As can be seen in the figure below, the meter demonstrated an exceptional linearity over a large range of Reynolds number.



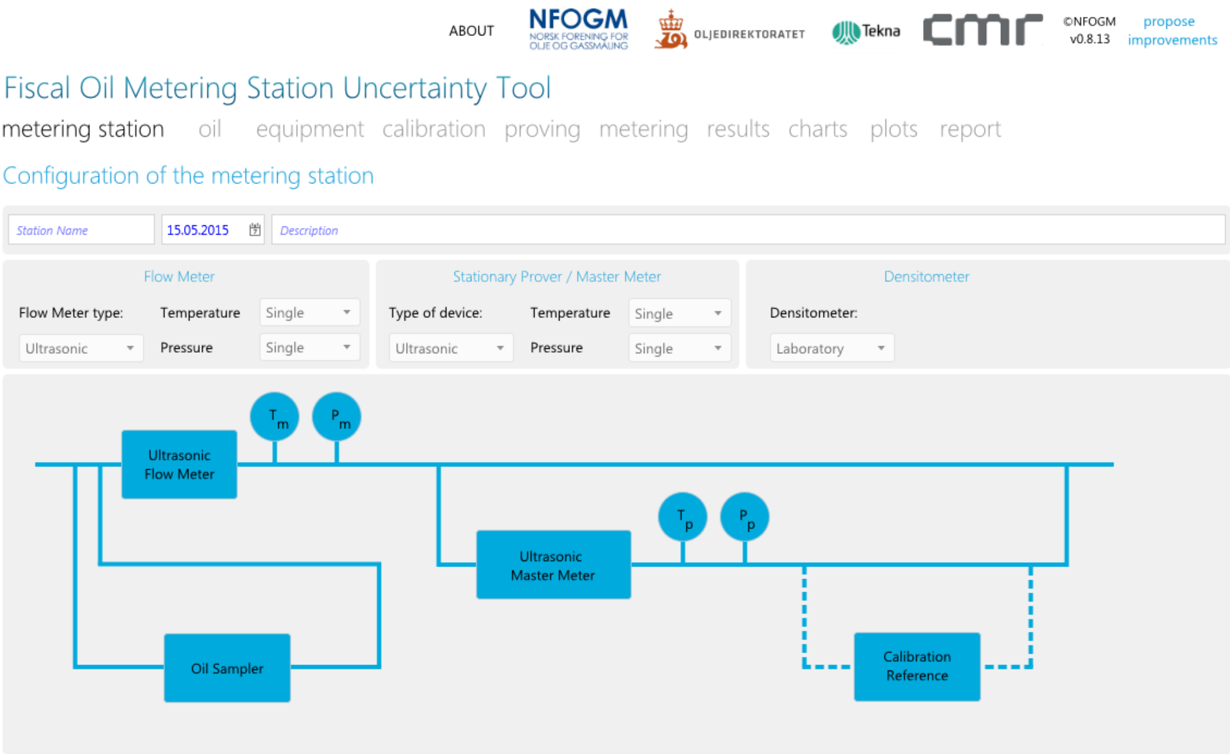
Judging from these data it will be reasonable to assume that the influence of flow profile and fluid effects on meter factor will be well within 0,1 % for this meter. The capabilities will have to be confirmed by testing.

2.7.3 Conclusion about the uncertainty component "Flow profile and fluid effects"

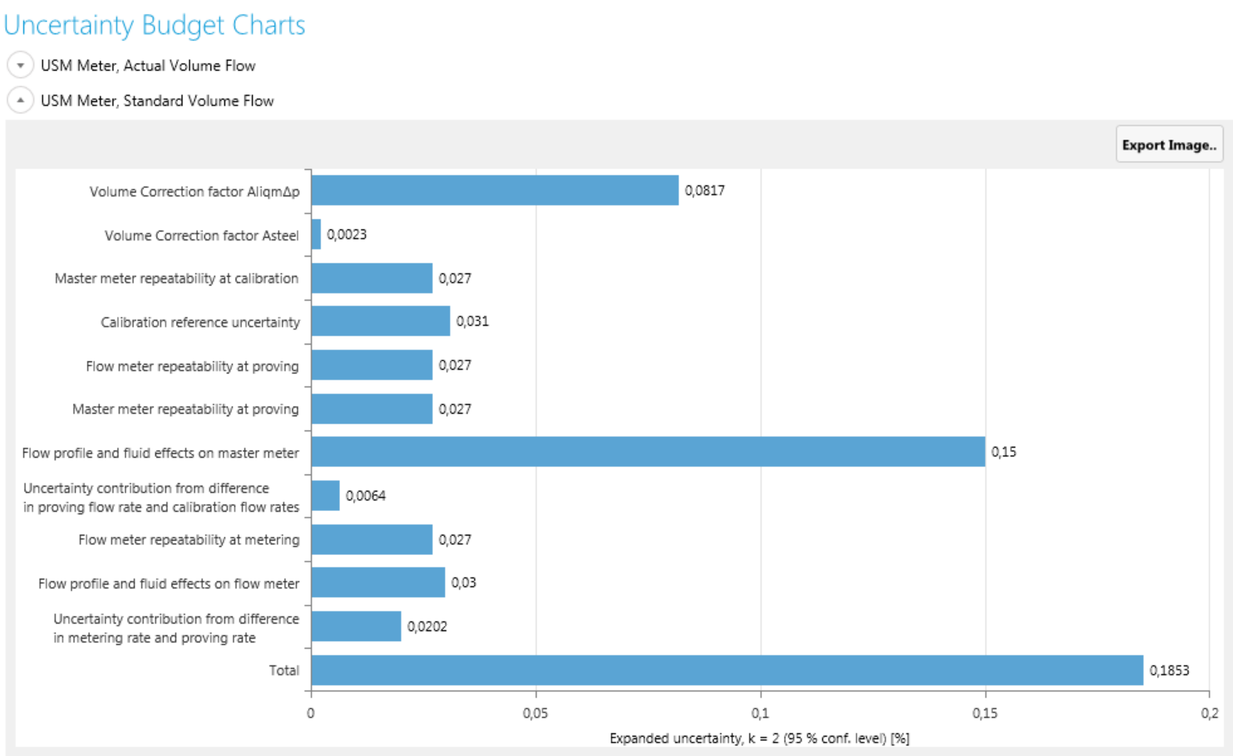
Based on the experience presented in this document and taking into account the additional premises that significant systematic errors will be revealed and rectified under governance of the operational procedures it seems reasonable to assume that the uncertainty component "Flow profile and fluid effects" will be in the order of magnitude 0,15 % @ 95 % confidence level.

2.7.4 Uncertainty budget for the basic design

The assumptions above were then used as input variables in the uncertainty tool currently being developed by the Norwegian Society for Oil and Gas measurement. As can be seen from the configuration picture below, the tool matches perfectly the basic design:



Based on the assumptions in previous sections in this document, the following chart shows the uncertainty contributions and relative expanded uncertainty at 95 % confidence level for the measured standard volume of oil.



The total uncertainty in Standard Volume is estimated to be approximately 0,19 % @ 95% confidence level. If we take into account an additional uncertainty of 0,05 % @ 95% confidence level from determination of water in oil the resulting uncertainty will be 0,2 % @ 95% confidence level for the basic design.

Hence, the design will meet the uncertainty requirement of 0,3 % of standard volume as required by The Norwegian measurement regulations.

3 Design considerations

3.1 Failure Mode and Effects Analysis

3.1.1 Failure mode – Need for calibration and adjustment

For the purpose of this evaluation it is assumed that calibration will only be performed if the condition monitoring indicates that calibration and adjustment of one or several components will be required. It is further assumed that the stability of the components is such that replacement for the sole purpose of calibration will not be required during the lifetime of the system. However it is assumed that the system will be retrieved during the lifetime. And that the system will then be replaced by a calibrated spare system.

3.1.2 Failure mode – Corrosion of the internal surface of the pipe

It is recognised that change of the internal pipe surface may affect the performance of a flow meter. A master meter will be exposed to much of the same conditions as the line meter. Hence the master meter will also be exposed to the same failure mode as the line meter. Consequently corrosion will have to be avoided by constructing the metering systems with materials than cannot corrode under the operating conditions.

Without putting more consideration into the selection of pipe material or coating strategy, it is here concluded that the metering system must be constructed in a way that prevents corrosion of the internal surfaces.

3.1.3 Failure mode – Wax deposits on the internal surfaces

It is recognised that deposits on the internal surface will affect the performance of a flow meter. A master meter will be exposed to much the same conditions as the line meter. Hence the master meter will also be exposed to the same failure mode as the line meter. Consequently wax deposits will have to be avoided by heating and/or chemicals.

Wax can be avoided by keeping fluid temperature above the wax appearance temperature. Wax can be removed by heating the fluid to above the wax dissolution temperature. Without putting more consideration in the wax strategy here, it is here concluded that if there is a wax potential, the metering system must be constructed in a way that prevents wax deposits on the internal surface of the pipe.

3.1.4 *Failure mode – Flow meter - Failure or deterioration*

A remaining failure mode to be evaluated is failure or deterioration of the meter electronics or transducer. It is reasonable to consider that such failure can happen. It is also reasonable to assume that it is equally likely that such failure can happen to the master meter, as it is that the failure can happen to the line meter.

By putting the master meter in a by-pass, it is regarded implicit that the master meter will only be used for calibration of the line meter, and that the duration of periods where the meters are run in series will be limited to the time needed for calibration within the repeatability requirements.

It is also considered that the best way to reveal such failure would have been long term comparison of the flow meter with the master meter. One operational method that has been developed for monitoring of flow meters is described in ISO 17089 “Measurement of fluid flow in closed conduits – Ultrasonic meters for gas.

ISO 17089 contain a reference meter method for ultrasonic meters in series. The method is based on the establishment and maintenance on the difference between hourly volume totals for the two meters at metering conditions.

By putting two flow meters in series a large historic database over the difference between the two flow meters can be established and maintained. By putting the master meter in line with the line meter, the reference meter method can be fully employed. By having the master meter in a temporarily used bypass, the reference meter method cannot be fully employed.

3.1.5 *Failure mode – Valve leakage or failure to confirm that a valve is not leaking*

If a master meter is placed in a bypass to the flow line, it is clear that the outlet valve from line meter run will have to be tight. A leakage through the metering run outlet valve will cause a systematic mismeasurement. As a consequence, a system which can be used to demonstrate that the valve is tight will be required. Leakage through one of the two seals within the valve will remove the possibility to confirm that the valve is tight. Consequently if one of the seals is leaking, or if the leakage detection system fails, the system will have to be retracted, replaced and overhauled.

From experience, the frequency for this failure is quite high. The consequence is also quite dire, as it is required to keep the valves tight and hard to quantify a leakage. This failure mode will be quite significant for systems having this kind of valves in the system.

3.2 Consideration of measurement uncertainty

When the master meter is placed in a by-pass it is implicit that it will be used for calibration and adjustment of the line meter, and that it will not be used for continuous measurement. Consequently the measurement uncertainty of the master meter will be transferred to the line meter at proving, with the additional uncertainty contributions from repeatability and the difference between flow rate at calibration and flow rate at measurement. The resulting measurement uncertainty will be higher than the measurement uncertainty for the master meter alone.

If the master meter is placed in line with the line meter, the master meter can be used for measurement, in addition to its use as a master meter. In addition it can also be used use in the reference meter method. From

Guide to the expression of Uncertainty in Measurement, it is known that the measurement uncertainty will be reduced if the measurand is the average of 2 or more measurements. For uncorrelated uncertainty contributions, the resulting measurement uncertainty will be equal to the measurement uncertainty for each meter divided by the square root of the number of meters.

If we first assume that the uncertainty of one meter is 0,15 % at 95% confidence level, the resulting uncertainty for measurements based on the average of meters in series will then be:
For measurement based on 1 meter: 0,15 % * 1 / (Square root of 1) = 0,15 * 1,00 = 0,15 %
For measurement based on 2 meters: 0,15 % * 1 / (Square root of 2) = 0,15 * 0,71 = 0,11 %
For measurement based on 3 meters: 0,15 % * 1 / (Square root of 3) = 0,15 * 0,58 = 0,09 %

Consequently a metering station where the master meter is put in line with the line meter, and where the measurement result is the average of the flow meters in series, will have a significantly lower uncertainty than a conventional solution with the master meter in a by-pass to the flow line.

4 An alternative metering system

4.1 Arguments for a metering system with 3 meters in series

One main reason for putting a master meter in a bypass is to avoid that the master meter is exposed to the same deteriorating conditions as the line meter. It is here recognised that an ultrasonic flow meter does not contain any moving parts; hence this failure mode is completely removed by the flow meter design.

It is also considered that corrosion can be avoided by using non-corrosive materials and that wax deposits can be avoided by heating the fluid or by applying heating to the metering section at no flow conditions. It is also worth noting that the basic design, with a master meter in a bypass, will not be more robust to these two failure modes than other designs. If you have a problem with the internal pipe surface in the metering run, you will be exposed to the same failure mode in the master meter run. So if you get a problem with the flow metering run, you are likely to get the same problem with the master meter run. Or you may be unable to tell if you have the same problem with the master meter run, or if it is the master meter run that have the problems and not the flow metering run.

A remaining failure mode is failure or deterioration of the meter hardware. It is assumed that such failure is best revealed by long term comparison of the line meter with the master meter. By having the master meter in a by-pass the possibility for close long term monitoring is greatly reduced. By putting the master meter in series with the line meter a large historic database over the difference between the two flow meters can be established and maintained. Hence the best possible database for monitoring quality is established.

Furthermore, it is recognized that a design with master meter in a bypass will have two failure modes related to valve leakage. If one of the two seals in each valve is passing, or if the valve leakage detection system has failed, the metering system will have to be retracted, replaced and overhauled. In a design with the master meter in series with the line meter, this failure mode is completely removed.

Hence, a design with the master meter in line with the line meter is recommend over a design with the master meter in a by-pass. Mainly because a design with the master meter in series with the line meter will:
- Have lower uncertainty
- Avoid the failure modes related to valve leakage

- Have better quality monitoring capabilities

In addition, cost, size, complexity and weigh will be much lower than a system with the master meter in a by-pass to the main line.

In addition to the arguments for putting the master meter in-line with the line meter, there are three arguments for adding a third flow meter into the single flow metering run.

The first reason is that the measurement uncertainty will be somewhat reduced (20 %) as the measurement uncertainty will be equal to the measurement uncertainty for each meter divided by the square root of the number of meters. 1 / (Square root of 2) = 0,71 and 1 / (Square root of 3) = 0,58.

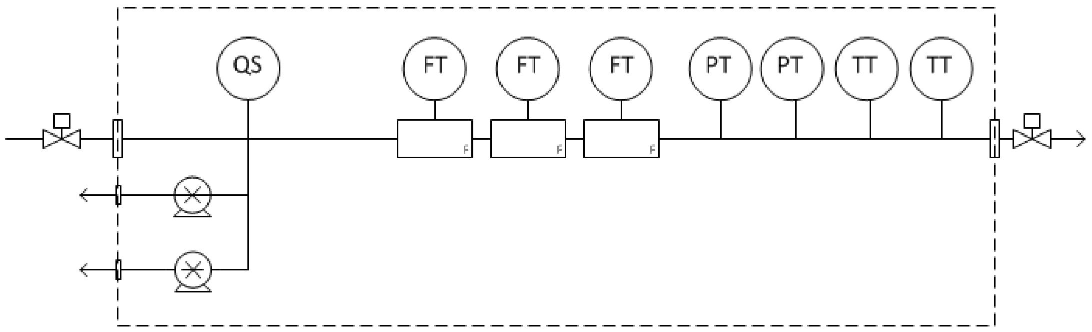
The second reason to add a third meter into the design is that it will make it more ease to find out which meter has failed or deteriorated, if so happens.

The third reason is that even if one of the three meters fail the metering station will be fully operational. Replacement of the defective meter can be postponed and maybe entirely avoided during the lifetime of the metering station.

4.2 Metering system with 3 meters in series - Design

The basic system is in compliance with the significant requirements the measurement regulation. Mainly as it has parallel metering runs and permanent equipment for calibration of the flow meter. However, the Failure Mode and Effect Analysis and the uncertainty evaluations have revealed that this is not be the best design.

Based on the Failure Mode and Effect Analysis and the uncertainty consideration above the following design have been identified as a better design of the metering system.



QS = Sampling System, FT = Ultrasonic Flow Meter, PT = Pressure Transmitter, TT = Temperature Transmitter.
In this figure, the fluid is flowing in from the left side, passing the sampling system and then passing through 1 metering run containing a duty meter, a master meter and a spare meter installed in series.

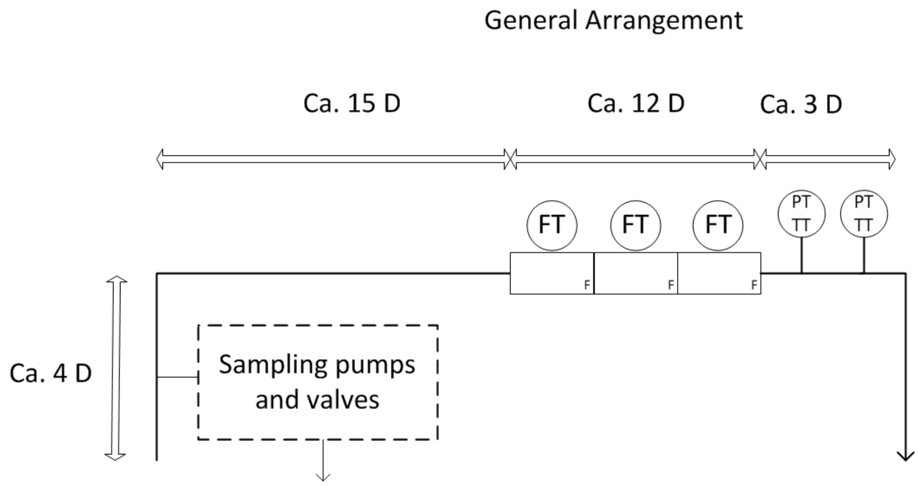
This system has the following main features when compared with basic design:

1. The measurement uncertainty is reduced
2. The failure mode related to leakage through high integrity valves is completely removed
3. Size, weight, complexity and costs are much lower

4. The facilities for monitoring of the flow meters are improved
5. The fault finding capabilities for the flow meters are improved

4.3 Metering system with 3 meters in series - General arrangement

Based on the considerations about station design, and design of the sampling system, the following figure indicates one possible arrangement that will meet significant design considerations for the fiscal metering system. The system will be retrievable.

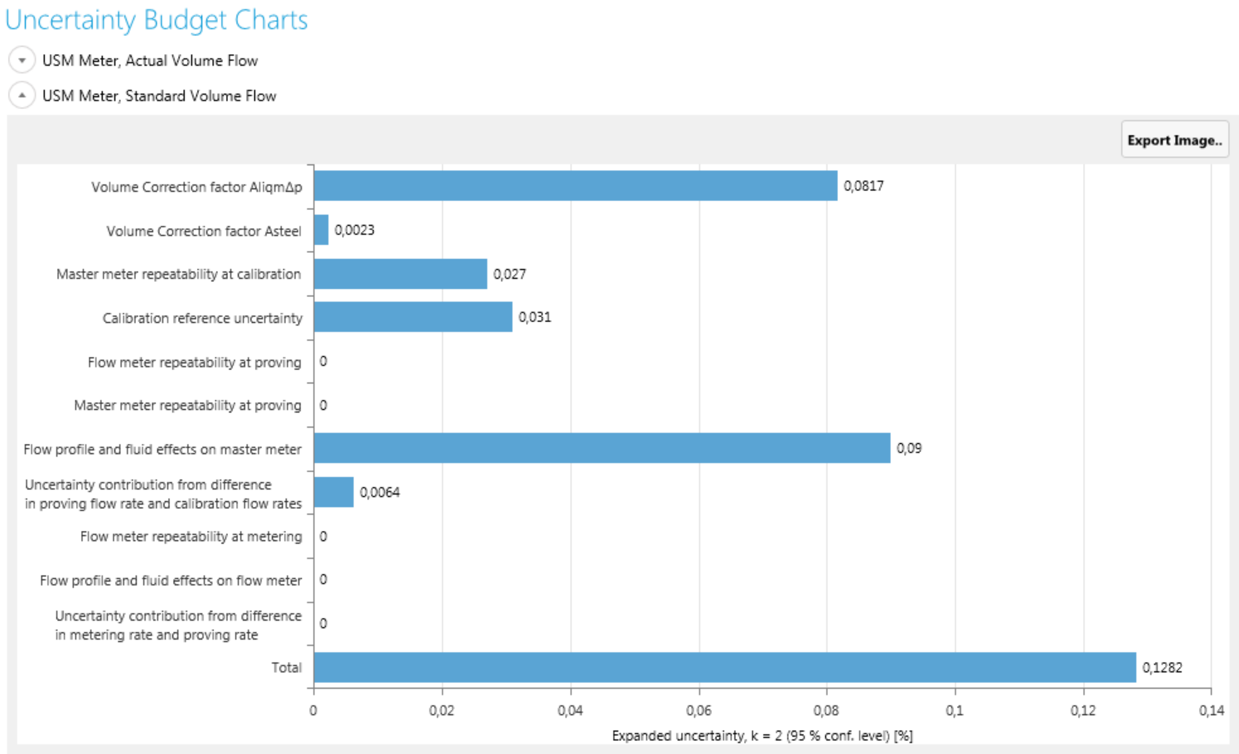


4.4 Metering system with 3 meters in series - Uncertainty analysis

From Guide to the expression of Uncertainty in Measurement it is known that the measurement uncertainty will be reduced if the measurand is the average of 3 measurements. For uncorrelated uncertainty contributions the resulting measurement uncertainty will be equal to the measurement uncertainty for each meter divided by the square root of the number of meters.

If we accept the uncertainty analysis in a previous section, the uncertainty of one meter will be approximately 0,15 % @ 95% confidence level. The resulting uncertainty for a measurement based on the average of 3 meters in series will then be approximately: 0,15 % * 1 / (Square root of 3) = 0,15 * 0,58 = 0,09 % - if the uncertainty contributions are uncorrelated.

The following uncertainty budget chart illustrates the uncertainty that may be expected for a metering system consisting of 1 metering run with 1 line meter, 1 master meter, 1 spare meter which are all used for measurement and monitoring. The tool cannot be configured for this particular uncertainty analysis. However, by combining the uncertainty contributions for the 3 flow meters into the master meter we can simulate this configuration. In the uncertainty budget below the uncertainty for the three meters are combined into the uncertainty component for the Master meter and sat equal to 0,09 %.



The total uncertainty in Standard Volume, for a metering system with 3 meters in series is now estimated to be approximately 0,13 % @ 95% confidence level.

If we take into account the additional uncertainty of 0,05 % @ 95% confidence level from determination of water in oil the estimated uncertainty will be 0,14 % @ 95% confidence level. It seems clear that this design will meet the uncertainty requirement of 0,3 % of standard volume as required in the measurement regulations.

If the uncertainty contributions from the three ultrasonic meters are fully uncorrelated, the uncertainty of the average from the three meters will be reduced by 1/ (square root of 3) to 0,09 % @ 95% confidence level. The resulting uncertainty will then be 0,14 % @ 95% confidence level.

If the uncertainty contributions from the three ultrasonic meters are fully correlated, the uncertainty of the average from the three meters will remain equal to the uncertainty of one ultrasonic meter, estimated to 0,15% @ 95% confidence level. The resulting uncertainty will then be 0,19 % @ 95% confidence level.

5 Selection of the preferred system

5.1 Methodology for selection of preferred system

A principle for performance of cost benefit analysis is described in NORSOK I-106 Fiscal metering systems for hydrocarbon liquid and gas (Edition 1, November 2014) ANNEX C System selection criteria (informative).

Measurement uncertainty represents a risk for loss of income. A risk for loss of income represents an equal risk for loss of profit. The risk for loss by measurement uncertainty (NOK) can be calculated as 0,2 * Measurement uncertainty @ 2 standard deviations. In this calculation the measurement uncertainty (m3) has to be converted to a monetary unit (NOK) by taking into account the product value (NOK/m3).

Risk is regarded to be Probability times consequence. A cost is a consequence having probability 1. Consequently all direct and indirect costs related to the measurement system will also represent risks for loss of profit. Probability and costs can also be estimated for all the failure modes.

The methodology for comparing alternative systems will then be to add all risks for each metering system design and compare the total measurement risk for these systems. The purpose should be to arrive at the system design that minimizes the total measurement risk. The total Risk for loss of profit by the metering system.

A total measurement risk evaluation has to take into account:

- Risk for loss of income, and profit, by measurement uncertainty
- Risk for maintenance costs as revealed by the Failure Modes and Effects Analysis
- Costs for spare components and systems
- Direct and indirect costs over the whole lifetime of the metering system

5.2 Assumptions put into the evaluation

A few key assumptions are included here to facilitate an overall understanding of the summary:

1. Net present value of the total oil export 2,00E+11 NOK
2. Indirect project costs = 2 * purchase order costs for the metering system
3. The retractable / replaceable unit is shown within the stippled box
4. A spare unit is available for the systems within the stippled boxes
5. A fixed development cost is included for the sampling system and subsea ultrasonic meter
6. Failure mode related to corrosion is avoided by ensuring that the internal surface is non – corrosive
7. Failure mode related to wax deposits is avoided by design or by the wax strategy
8. Failure frequency for valve tightness is set to 1 / (valve * lifetime (25 years))
9. Failure frequency for sampling system is set to 1 / (system * lifetime (25 years))
10. Flow meters can be calibrated at full flow rate at an accredited laboratory
11. Due du complexity and extent of the basic system with master meter in a bypass, the total costs for replacing this system is sat to 2,5*10E7 NOK.
12. As the preferred system with 3 meters in series is a much simpler system, the total costs for replacing this system is sat to 1*10E7 NOK.

For the basic design, with a master meter in a bypass, the failure frequency for each flow meter is set to 0,5 / (meter * lifetime (25 years)). As there are 3 flow meters – and each failure will cause a replacement to take place the total failure frequency will be 3*0,5=1,5.

For the preferred design, with 3 meters in series, failure frequency for each flow meter is set to 0,5 / (meter * lifetime (25 years)). However, with 3 meters in place there is redundancy in place for the 2 meters that are required for the station to be fully functional. The resulting failure frequency for the station is therefore sat equal to the combined failure frequency for 2 meters: 0,5 * 0,5 = 0,25.

5.3 Evaluation of alternative metering design

In the original evaluation several systems were considered. Only the results for the highlighted systems are presented here:

2 metering runs, 1 line meter in each + 1 master meter in a bypass

1 metering run , 1 line meter in line with 1 spare meter + 1 master meter in a bypass

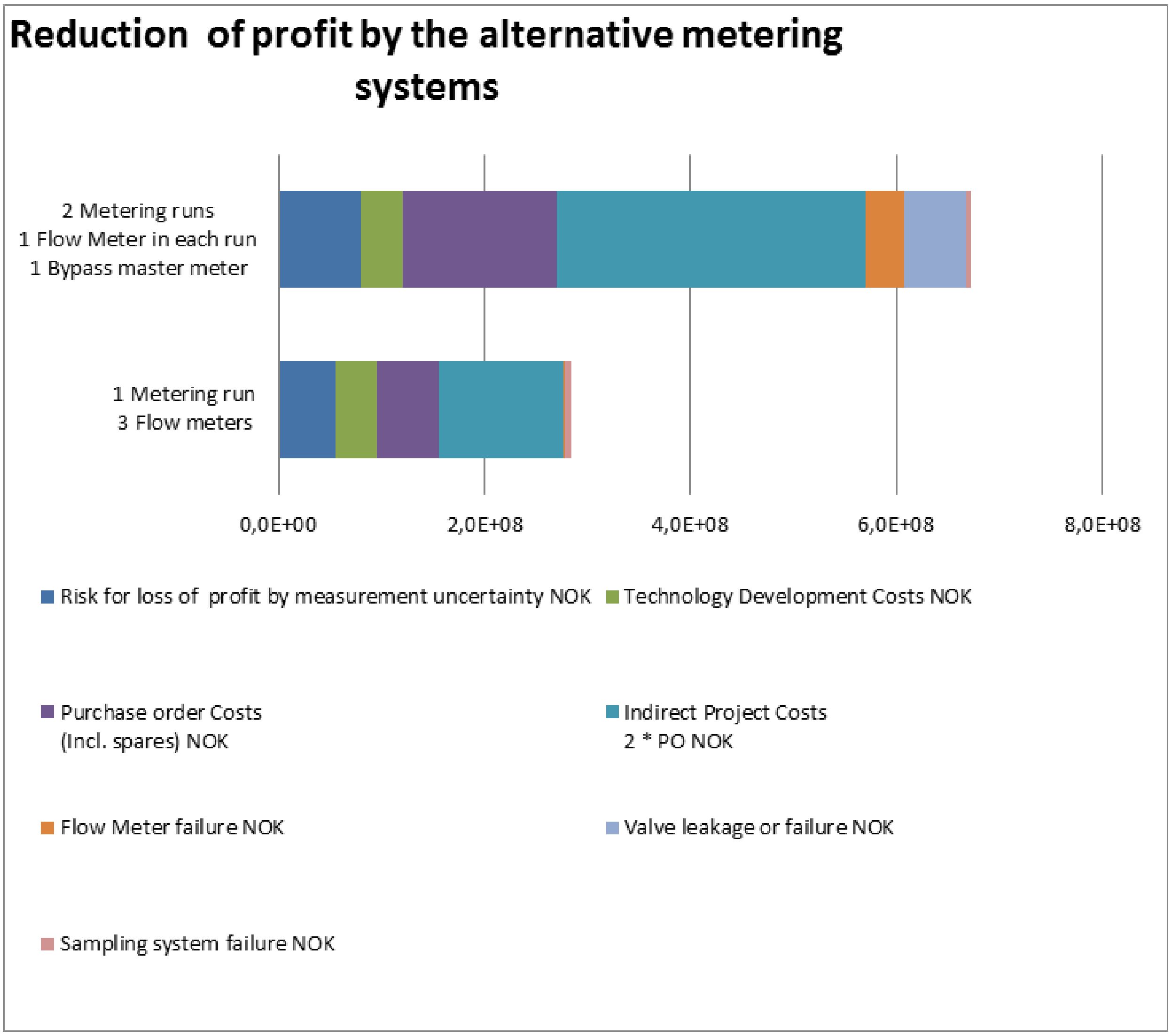
2 metering runs, 1 line meter in line with 1 master meter in each run

1 metering run – 1 line meter in line with 1 master meter

1 metering run – 1 line meter in line with 1 master meter and 1 spare meter

Ship survey

The figure below shows the result of the analysis.



5.4 Preferred design for a subsea fiscal oil export metering system

It is very clear from the analysis that the complexity of a conventional system, with parallel metering runs and a master meter, has huge direct and indirect cost consequences. It is also clear that a conventional system does not have the benefits of redundancy, lowest possible measurement uncertainty and best possible monitoring capabilities as a system with three meters in series will have.

Hence, a conventional system can be improved by simplifications. The measurement uncertainty will be reduced by putting the master meter in line with the line meter and by letting the measurement result be the average of the master meter and the line meter. By putting the master meter in line with the line meter, high integrity metering valves are not needed. As high integrity metering valves are removed from the design the failure mode related to valve tightness also vanish. This will significantly reduce the direct and indirect costs.

It is also worth noting that a master meter run will be exposed to the same failure modes as the flow metering run. So if you get a problem with the flow metering run, you are likely to get the same problem with the master meter run. Or - you may be unable to tell if you have the same problem with the master meter run, or if it is the master meter run that have the problems and not the flow metering run.

By putting the master meter in line with the line meter some redundancy is built into one metering run. However there will then be only one master meter and one line meter. There will not be any redundancy if one of the two meters fails. Such redundancy can be achieved by adding a third flow meter into 1 single metering run.

This third flow meter will contribute to reduction of the measurement uncertainty because the measurement will be the average of three meters. The third flow meter will also improve the fault finding capabilities. The fault finding capabilities are improved as it will be easy to see if one of three meters has drifted relative the two other meters. This third flow meter can also serve as redundancy both for the line meter and for the master meter. If one meter fails, the metering system will still be fully operational. Replacement can be planned to a suitable time. At the end of the lifetime it may even be acceptable to operate the metering system with one meter out of operation.

The solution consisting of 1 metering run consisting of 1 line meter, 1 master meter and 1 spare meter is therefore preferred because it has:

1. Installed spare functionality
2. The best quality monitoring capabilities
3. The best fault identification capabilities
4. The lowest measurement uncertainty of all the evaluated systems
5. Much lower costs than conventional systems
6. Much lower total risk for loss of profit than conventional systems

The design rests on the assumption that it will be possible to calibrate the system at full flow rates, If not, parallel metering runs will most likely be required. The cost will be significantly impacted by parallel runs.
The preferred system will deviate from the measurement regulation by not having a parallel metering run and by not having a conventional solution with a master meter in a by-pass to the flow line. These deviations will have to be formalized with the authorities. The design also has to be accepted by the partners.

Under the Norwegian tax system the company will have to pay 78 % of the profit in tax to the Norwegian state. Consequently, in relative terms, the company and the state will be equally exposed to the total measurement risk for the alternative metering systems. The evaluation of total measurement risk can then form the basis for an application for deviation from statutory requirements. What is good for company profit will also be good for the tax income to the state.

6 Summary

Based on the work presented in this paper it can be concluded that it will be feasible to design a subsea fiscal oil export metering station within the uncertainty requirements in the measurement regulations.

A basic design consisting of 2 metering runs, with 1 ultrasonic flow meter in each run, and an ultrasonic master meter in a bypass will meet the most significant requirements in "The measurement regulations".

It is also regarded feasible to route a sample stream via the umbilical to a nearby topside facility for sampling with a conventional sampling system.

However it has been demonstrated that a metering system consisting of 1 metering run with 1 line meter, 1 master meter and 1 spare meter in series is preferable because it has:

1. Installed spare functionality
2. Better quality monitoring capabilities
3. Better fault identification capabilities
4. Lower measurement uncertainty
5. Much lower costs than the basic system
6. Much lower total risk for loss of profit than the basic system

The uncertainty requirement in The Norwegian measurement regulations is 0,3 % of standard volume.
The uncertainty for the preferred system is estimated to be less than 0,2 volume % @ 95 % confidence level.

References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL

Note that this reference was not part of the original paper, but has been added subsequently to make the paper searchable in Google Scholar.