PROBLEMS UNIQUE TO OFFSHORE MEASUREMENT

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INTRODUCTION

As the worldwide demand for oil and gas forces offshore exploration into waters off the continental shelves into depths of over a mile deep, capital expense spending (CapEx) and production operation expense (OpEx) budgets are slashed and the Environmental Health and Safety (EH&S) requirements as well as some companies' goals for a 'greener image' raises the standards of operations even higher, the demands placed on accurate hydrocarbon measurement with minimal maintenance, space and weight requirements becomes increasingly greater. These financial, governmental and technical challenges coupled with normally high flow rates and therefore wide flow range requirements have enhanced the development and application of new technology such as ultrasonic gas and liquid meters, multiphase flow meters, microwave and near infared (NIR) water cut analyzers, coriolis flow meters for oil and gas and compact orifice meter tubes utilizing isolating flow conditioners and liquid meter provers. This paper will attempt to provide guidelines in selecting, installing and operating this equipment to insure cost effective designs and reliable operation with a high degree of accuracy. Since the author's background is primarily in project design, emphasis will be placed on the decision process of selecting, installing and commissioning metering equipment.

DESIGN DILEMMAS

Nearly every E&P project group responsible for the design, engineering and fabrication of an offshore production platform goes through a decision process whereby conventional measurement equipment (orifice meters for gas sales and pipe provers for liquid turbine/displacement meter calibration) are compared to alternative equipment based on space and weight requirements. The project groups' responsibility to reduce CapEx by installing compact metering must be balanced by operational factors such as reliability or mean time between Failure (MTBF) which translates to OpEx, safety, governmental and contractual requirements and approval of interested parties (partners, purchasers and pipeline operators).

Recently, regardless of country location, depth of water or fluid application (oil or gas field), there is nearly always a very strong consideration for the use of Multiphase Flow Meter (MPFM) for well testing and/or allocation mainly due to the estimated reduction of topsides weight and space when compared to conventional separators and associated metering equipment. The vendors have what appears to be an infinite supply of information to support the installation of MPFM in various applications.

Engineering studies have shown that 'alternative metering concepts (multipath ultrasonic meters for gas and compact provers for liquids) with the same accuracy of today's conventional concepts, might reduce space and weight by more than 50% compared to present layouts. The total cost savings might be twice the actual procurement cost of the metering skid.'[1] Although this does not address reliability, it is inferred that these alternative devices are as reliable as their conventional counterparts. Another engineering study conducted on behalf of North Sea operators estimated (based primarily on vendor's input) the MTBF for multi-path ultrasonic meters to be 2 hours of downtime over a period of 78 years or an estimated 'uptime' of 99.9997%! However, this may not be the case as an offshore platform in the North Sea that recently installed 13 ultrasonic meters have reported 11 failures within the first two years of operation. The lack of reliability in emerging technology is not always the case, as with compact provers that have proven to be a real workhorse in offshore applications, some with well over 100,000 cycles or 'piston strokes' between failures in offshore crude oil applications.

Lately, a very common equipment selection discussion revolves around the application of conventional orifice versus multi-path ultrasonic measurement equipment for the custody transfer of natural gas. Arguments supporting the use of the ultrasonic meter over orifice include space and weight saving, increased flow rangeability, reduced pressure drop, inherent diagnostics, reduced maintenance (calibration), tolerance to entrained liquids (wet gas) and improved accuracy to name a few.

DEEP WATER EXPLORATION CHALLENGES

The incremental cost ($/lbm) to support topsides facilities on a deep water *floater* such as a Tension Leg Platform (TLP) is estimated to be 5.5 $/lbm (excluding deck, drilling facilities and hull) which translates into $180,000 for 100′ of 20″ Sch 120 pipe with two pair of 600# RF flanges. This estimated incremental cost does not reflect any associated cost savings for possibly decreasing the deck size and weight by reducing the size of facility equipment such as orifice meters or liquid provers. Another deep water challenge is the potential for hydrate formation in flow lines as the seabed temperature at 3000+′ of water is 34°F which is accentuated by the unbelievable approximate cost to work over a subsea completed well at this depth of $12,000,000. These significant cost factors force every deep water project team to investigate new ways to reduce weight and space or 'footprint' of topside measurement equipment and to work with vendors to develop new equipment to measure relatively small amounts of free water and/or water vapor for hydrate control.

ENVIRONMENTAL CONCERNS

There are various international, regional and national conventions, agreements and laws that define operational standards for oil-contaminated effluents and discharge water from offshore platforms and facilities. Typically, the average discharge limits of oil in water is 29-40 mg/l (36-50 ppmv for 0.8 SG oil) over a period of 30 days with maximum discharge levels 42-100 mg/l. Some major oil companies have endorsed self imposed 'greener' guidelines to further reduce emissions; BPAmoco plans to maintain total current emissions levels (that meet or exceed regional guidelines) regardless of new field development or production rates. These conservative discharge limits place increased demands on separation facilities and associated measurement equipment in mature oil fields where water cuts are greater than 60-80%.

FLUID PROPERTY AND OPERATIONAL ISSUES

Today's typical offshore platform location of sales or allocation measurement equipment is downstream of final phase separation facilities (no dehydration of gas, if not compressed) and immediately before the fluid leaves the platform in a subsea pipeline. The measured fluids at this point, although separated as well as economically possible, are typically at hydrocarbon and water dewpoint for gas and at bubble point for liquids. Neither of these above described fluids conditions are considered ideal for custody transfer measurement and sampling. In the event of any upset in the production separators, liquids may *carry over the top* thus allowing liquids in the gas line or gas may *carry under* allowing free vapors in the liquid line. Even without an occasional operational upset, any normal cooling of gas due to ambient temperatures or inevitable pressure drop due to frictional piping losses will cause liquids to condense and likewise any pressure drop in the liquid line will allow free gas to evolve. These potential separator and resulting multiphase fluid problems will cause numerous metering problems such as liquid accumulation near the orifice plate, cavitation in liquid meters, problems in obtaining a representative sampling from gas streams, repeatability in proving of liquid meters and if liquids are introduced to an on-line gas chromatograph, catastrophic failure of the analyzer.

EQUIPMENT SELECTION FOR OPTIMAL DESIGN SOLUTIONS

For offshore fiscal gas metering applications where economic space constraints require a compact design with a high degree of reliability, *life of field* design criteria requires extreme rangeablity in flow rate and of course accuracy is considered to be essential, the author's preference is to use two or more conventional, concentric orifice meters installed in parallel as follows:

- low loss, isolating flow conditioner with a minimum of thirteen (13) pipe diameters upstream meter tube
- maximum thickness allowed orifice plates
- single, 0-400 IWC differential pressure range *smart type* transmitter
- orifice flange taps oriented above the pipe centerline (12 o'clock preferred) with transmitters installed on direct mount, full bore manifolds

The above design when using 0.2-0.6 orifice to pipe ratio (ß) and 30-150 inches of water column (IWC) differential pressure for normal operations and a maximum ß of 0.66 and 300 IWC differential pressure for emergency capacity operations will provide a flow range of 80 to 1 with an estimated random uncertainty in volume of less than ±0.75%. This uncertainty may be validated from the following sources:

- offshore, wet gas pipeline accumulated system energy and volume balance of <0.2%
- flow conditioner tests results from Southwest Research Institute (SWRi)[2]
- orifice discharge coefficient data from API 14.3 Part 1
- mass error due to plate bending by Jepson and Chipchase[3]
- differential pressure transmitter field calibrations

With all the vendor 'information' available and the emphasis to reduce deck space to save CapEx and reduce maintenance in order to save OpEx, it would be very easy to conclude that the multi-path ultrasonic is a better choice over the orifice meter for offshore, wet gas applications. After all, the ultrasonic meter is reported to be more accurate than the orifice (when wet calibrated), more tolerant of the effects of wet gas, require significantly less deck space and maintenance and have greater flow range capability.

However, let's take an objective look at each of these comparison claims starting with the accuracy claim. Regardless of the vendors' statements on meter accuracy, keep in mind that the reliability or mean time between failure (MTBF) is also extremely important when depending on the meter's output for the monthly accounting statement so that a loss of data for any reason will always produce negatively biased errors (losses to the seller) such that a downtime of one (1) hour in a contract month will cause a –0.14% error and an eight (8) hour downtime will cause a –1.1% error.

The implementation of an isolating flow conditioner installed at a proper distance upstream (13-17 pipe diameters overall from last piping disturbance to the plate) will not only reduce the upstream length requirements historically required for an orifice meter but lab tests have shown a near perfect correlation and excellent precision with the API 14.3 Reader-Harris/ Gallagher (RG) empirical coefficient of discharge equation (data base using 45-80 diameters of straight pipe upstream) over a wide range of ß ratios. This improvement in measurement is due to the isolating flow conditioner's capability to eliminate any effects from upstream piping and create an ideal flow pattern or axisymmetric velocity profile, free of swirl for virtually all worst case disturbances.

There is an inherent overall uncertainty advantage of the orifice over the ultrasonic in that the orifice is an *inferential head* type device with flow computed as a function of the square root of differential pressure and fluid density as opposed to the ultrasonic meter, a *linear* device so that any error in density will have roughly twice the additive effect on the ultrasonic.

As stated above, the use of dual orifice meter runs with isolating flow conditioners upstream, taps rotated above centerline, smart transmitters mounted directly on fittings by means of full bore manifolds, higher differential pressure ranges and thicker plates with (ratios up to 0.66, allows for a flow range of 80 to 1, prevent dishing of orifice plates from inadvertent blow downs and provide for an accurate, reliable wet gas system balance (<±0.2%) with minimal maintenance requirements.

Although, the issue of improved wet gas tolerance have not been fully evaluated at this date (data is currently being compiled as part of the GRI sponsored Wet Gas Metering JIP conducted at CEESI), the use of self draining, full bore direct mount manifolds and tap rotation above pipe centerline minimizes any detrimental effects in the impulse lines. Regarding reduced maintenance, the smart type transmitters appear to be very stable requiring less frequent calibrations, making this a moot point as most companies prefer to have qualified technicians carefully check all metering components on a monthly basis, especially if the gas volume is significant.

Offshore gas volume measurement facilities may be complimented with reliable, accurate on-line gas chromatographs (GC) to providing real time energy measurement provided the GC is installed properly as follows:

- sample probe installed with the tip in the center third of the pipe
- use heat traced, 1/8″ SS tubing to insure no liquid drop out and minimal lag time
- heated regulator (located near the probe) to insure no condensation due to J-T cooling
- 1/8″ SS heat traced tubing from the regulator to the GC sample inlet
- emergency shut off solenoid valve in the sample line — fail upon high-high level alarm from the production separator
- inlet sample filter types and sizes to minimize possibility of liquid contamination without removing any *heavy end* hydrocarbons
- protect sample exhaust manifold from wind velocity effects
- appropriately blended, tested and heated calibration gas

For offshore fiscal liquid metering applications (custody transfer and allocation), where deck space, cost effectiveness, pressure drop, fluid stability (bubble point) and accuracy are critical issues, meters may be installed as follows:

- dual (parallel) metering is preferred
- locate meter/prover at least one deck below separator
- use oversized, low loss piping to minimize pressure drop
- operate separators at highest liquid level, especially during proving
- install small volume prover upstream of meter(s)
- install separator control valve(s) downstream of metering
- locate sample probe downstream of meter(s) in a vertical pipe section

The above design does not require a pump to increase pressure above the bubble point, but simply uses the fluid hydraulic head pressure and meter component location to maintain sufficient pressure for metering and proving. This design has been validated to provide repeatable[3] results (repeatability <0.05% for five consecutive runs) where repeatability is defined as follows:

Repeatability (%) = $(V_{high} - V_{low}) * 100/V_{avg}$

The type of meter selected should be based on the particular application depending on gravity, flow rate, viscosity, sand production and water cut (if operating separator in two phase mode). Regardless of meter principal of operation or type, low pressure drop sizes and models are required.

CORROSION SOLUTIONS AND PREVENTION

The issue of external corrosion due to high humidity, sea spray, salt water washdowns and deluge systems is common to all offshore facilities. Solutions to corrosion problems include the use 316 SS over 304 due to increased resistance from chloride pitting due to 3-4% molybdenum content. Care should be given to insure all components are resistant to corrosion as if two stainless steel components are fastened with a mild steel, even if cadium plated, the result will be evident in a matter of weeks or even days. The use of Denso 'Petrolatum tape systems' in highly corrosive environment such as offshore facilities can significantly reduce the effects of a salt laden atmosphere. All electrical conduit should be PVC coated using SS fasteners and bulkhead connectors with SS or fiberglass enclosures.

PREVENTING UNNECESSARY PROBLEMS DURING COMMISSIONING

Several common, some preventable and some inevitable problems are encountered during the commissioning phase of the construction project. These problems are caused from the use of sea water for hydrostatic pipeline testing, careless deposits of foreign materials and debris from drill bit cuttings, welding slag and sand blast particles, acids and produced sand during the well completion process and the application of extreme physical force to overcome unexpected resistance. Many of these problems are preventable and with a little planning and control may be completely avoided by following a few simple guidelines:

- allow measurement technicians to commission new equipment — this will allow technicians to become familiar with equipment before actual operation begins as well as protecting equipment from destruction by the construction gorillas
- remove turbine and displacement meters and orifice plates from the line and bypass the prover until final commissioning is complete
- clean taps and orifice fitting slot of rust and debris
- provide for the supply of air free water for prover waterdraw
- **do not** operate the GC during the first week to month of production operations — use a fixed composition in the flow computer and edit the data as required

NET OIL MEASUREMENT ON HIGH WATER CUT PLATFORMS, EARLY WATER DETECTION FOR HYDRATE CONTROL IN DEEPWATER SUBSEA FLOW LINES AND THE APPLICATION OF MULTI-PHASE FLOW METERS (MPFM)

Due to the gradual watering of wells in mature oil fields and the eventual use of water flood techniques to enhance production, a well's water cut (fraction of water of produced in total liquids) may increase to 90% and above. This increase in water cut will significantly increase the total produced fluid resulting in problems in adequate phase separation and water handling capabilities of an offshore platform. When trying to accurately measure net oil for allocation and reservoir management purposes with *real time* reporting, meet desired production expectations at minimal OpEx budget of management and adhere to increasingly stringent effluent requirements, the implementation of emerging technology measurement devices is essential. This equipment ranges from the use multiphase flow meters, coriolis meters for volume and water cut, microwave and near infrared or NIR principle devices for water cut and for some applications, the combination of these devices to complement and work in concert. Extreme diligence is required when selecting the types of equipment to be employed to insure the user's objectives are met. Coriolis and microwave techniques may be used successfully, if installed and applied appropriately. However, both of these methods are subject to increased errors in net oil at very high water cuts (*i.e.,* ±10% error in net oil at 90% water cut). NIR devices, relatively new on the market, may be a better fit for very high water cut applications or monitoring interstage rejection water processing.

The investigation into measurement equipment for early water detection for hydrate control in deepwater, subsea flow lines has caused project groups to consider a wide range of equipment and methods. These include *downhole* devices using a combination of venturis in series and annular capacitance techniques, sand monitoring (acoustical) devices to *listen* for the sound of ice crystals bouncing along the pipe, system pressure drop to predict pipeline clogging due to reduced hydraulic area from ice and the use of modified MPFM. Some of these methods *might* work but none have been proven in the field.

Multiphase flow meters for well test and allocation are being considered for several reasons both onshore and offshore. The potential for economic benefits from using MPFM for well testing offshore range from increased production by use of test lines as flow lines, reduced size and weight as compared to a test separator, reduced well test time and possibly, improved measurement. Each application must be carefully evaluated considering range of types of wells to be tested, gas void fractions, effects of salinity, viscosity, accuracy of data and usually government or royalty owner approval.

When considering the MPFM for allocation keep in mind that although this is not sales, it is *fiscal* measurement and a 10% error could be very costly to your company's bottom line. However, MPFM may be the best *fit for service* method when marginal fields are introduced into existing facilities and the only other alternative is additional processing facilities or isolated phase separation for measurement purposes only.

SUMMARY AND CONCLUSIONS

In summary, the fiscal measurement of hydrocarbons on offshore facilities, although sometimes more expensive than onshore counter parts, can be very accurate, reliable and cost effective if common sense is employed:

- work around the problems you cannot control
- apply the KISS principle (Keep it Simple Stupid) and apply emerging technology carefully
- respect Mother Nature and protect the equipment
- use the pipeline balance to monitor results

Working around the problems you cannot control requires that you first recognize the problem such as wet gas, bubble point crude or liquid carry over from separators and then finding tools, equipment, orientation and location to prevent failure thus insuring reliable, accurate measurement.

The application of the *KISS principle* could not be more important than when selecting high volume metering equipment for the fiscal measurement of natural gas offshore in today's project management economy. *Emerging technology* equipment should be carefully, realistically and objectively evaluated before being installed offshore.

Respecting *Mother Nature* means protecting the equipment by using corrosive resistant materials and adequately protecting equipment from the forces of nature.

A *Gas Pipeline Energy Balance* is defined as the % difference between the total re-delivered energy from the pipeline and the total delivered energy into the pipeline as follows:

$$\text{Energy Balance} = \frac{\sum \text{Re-Delivered} - \sum \text{Delivered}}{\sum \text{Re-Delivered}} \text{ (MMBTU)}$$

A well designed and operated system with a tight balance may be used to monitor the performance of measurement equipment and identify problems early.

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