November 1, 2007

Karlene Fine, Executive Director
North Dakota Oil and Gas Research Council
North Dakota Industrial Commission
State Capitol-14th Floor
600 East Blvd. Ave. Dept 405
Bismarck, ND 5505-0840

Dear Ms. Fine,

Please find attached a funding request from Ward Williston Oil Company to the North Dakota Oil and Gas Research Council requesting $98,000 (total project $196,000) of matching funds to conduct a production measurement study using a portable measurement system on oil wells. The purpose of this study is create and use a purpose-built portable production measurement system to measure flow rates from pumping wells involved in conventional and enhanced recovery operations. Data is critical for developing existing fields as enhanced recovery candidates; fluid and gas measurement can be expensive especially if individual flow lines, and production manifolds have to be installed in order to test individual wells. There is also the question of the environment as the installation of flow lines, treaters, etc may disturb existing ecosystems. It is hoped that the success of the project will allow small to medium size operators to measure individual well performance accurately using a fit for purpose system, at an affordable cost, negating the need to install individual flow lines, manifolds, etc, thereby reducing the overall costs of implementing the project while decreasing the impact on the environment.

Please accept this letter as a binding commitment on behalf of Ward Williston Oil Company to complete the project as described in the application if the Commission approves the grant requested.

Sincerely,

James Cron
Ward Williston Oil Company

A Request for Funding:

Purpose-Fit Portable Multi-Phase Production Measurement System

A Grant Application for the Amount of $98,000

As Submitted To:

North Dakota Oil and Gas Research Council

Respectfully Submitted by

Ward Williston Oil Company

November 1, 2007

Principal Investigator:

James W. Cron, Chief Engineer, Ward Williston Oil Company

Table of Contents

Executive Summary

Ward Williston proposes to procure, modify and test a multiphase flow metering system that is purpose fit for use in North Dakota, procuring most items and services within North Dakota. The total estimated project costs are $196,000, for which we petition the North Dakota Oil and Gas Research Council for $98,000.

Secondary Recovery methods, primarily water flooding, provide an ever increasing amount of oil production in the State of North Dakota. The impact on North Dakota from oil production is significant, producing $168.3 million in taxable sales and purchases in 2006, up 50% from 2005 (source: ND Petroleum Council). Clearly extending the life of existing fields is beneficial to the State of North Dakota.

Secondary recovery efforts can produce significant volumes of water, smaller volumes of oil and varying degrees of natural gas. The measurement of oil, water and gas production in secondary operations is important to determine reserves, the economics of continued operations and to evaluate optimization efforts such as recompletion, introduction of permeability-alteration products, horizontal well development, acidizing, etc to improve oil and gas production and/or reduce water production. Accurate, consistent data is critical to making the aforementioned capital intensive decisions, timely and correct.

Traditionally, conventional production well testing is currently fulfilled by the use of centralized separation and metering stations or to a lesser amount by portable testers. Central testing systems require extra flow lines to be installed and maintained over their entire lives. However, for new secondary recovery candidates, most wells produce through disparate production facilities. For small operators, a typical strategy prior to implementing a secondary operation is to minimize the number of production batteries to reduce ongoing field costs and eliminate any negative environmental exposure. However this strategy contradicts the use of conventional testing methods as they require creating of individual flow lines for each well and larger test manifolds. To implement a conventional testing strategy results in increased capital investments, higher operational costs and additional risk. Portable testing systems allow metering at an individual well (or wells) and thereby do not require additional manifolds and lines to be installed and maintained. Based on our experience, low-cost portable testers are not accurate enough, due to sampling frequency and gas interference, as well as the extreme weather conditions of North Dakota.

Portable testing units that have a high degree accuracy cost greater than $225,000, which is out of the economic reach of most independent operators. To this end we have employed a design that while having a higher initial cost, we would be able to optimize via our learnings', thereby lowering future procurement, modification and installation costs on future units by 50%. Ward Williston feels that by employing an accurate testing system, we will be able to negate the need to install conventional testing systems, thereby saving several hundred thousand dollars per secondary recovery project.

An available power source is critical to this project: to lower carbon missions, increase reliability and reduce production costs; many operators such as Ward Williston have electricity available on each production site, allowing us to test a multiphase flow metering system.

This unit after procurement and modification, will be field tested in the Mouse River Park Madison Unit which has lower gravity oil, with a higher H_2S concentration, on both low-rate, mid-rate and higher rate wells, and the North Westhope Unit, which has higher gravity oil, with lower H_2S concentrations. Data will be accumulated, analyzed, summarized and published. Expected project completion time will be November 2008, with final report submission in December of 2008 or the 1st quarter of 2009.

In order to make this project a success, Ward Williston will work with Dr. K.T. Liu, of Accuflow™, who has prior metering experience in North Dakota, and is an expert in multiphase measurement.

Project Description

The objective of this study is to determine whether a fit-for-purpose multiphase flow meter can function successfully in oil fields in North Central, North Dakota.

Our effort is based on the work done by Texaco, et al, in developing portable well testing in the Bakersfield, CA region. The major differences between that region and the Williston basin is the difference in the mean surface temperature, oil viscosity, the difference in H_2S content, and the recovery method for secondary recovery (steam vs. water flood), and the presence of free gas.

Phase 1

The first phase of the project will be concerned with the procurement and construction of the measurement system from Accuflow. The planned configuration consists of the following:

ANSI rating ANSI 150#

Design/Welding code Per ASME B31.3 design code, w/ 10% X-ray radiography of welds

Coating: Vessel and Piping will be internally plastic coated.

Separating System

Accuflow Jr. multiphase metering system, consisting of:

- 10” diameter pipe separator
- 2” diameter gas flow line
- 1” diameter liquid flow line

For low production wells (e.g., 50 BBL/day or lower), a snap acting control mechanism is provided. This includes mechanical liquid level switch on the separator pipe to actuate an on-off control valve in the liquid flow line. Compressed air (80 psig) is required to operate this mechanism.

Liquid flow/net oil meter: A Coriolis flow meter (Micro Motion, Model CMF100M, 1” size) is used for liquid flow measurement. The meter will be equipped with a “Net Oil Computer” to provide water cut and net oil measurement. Water cut is determined utilizing density differential principle. Please see the appendix for the measurement system’s schematic drawing, as well as discussion on the Coriolis meter.

Gas flow: ½” vortex meter is used to measure gas flow rate. The vortex meter has built-in temperature and pressure sensors, and its flow transmitter is capable of performing temperature and pressure compensation calculation to display gas volume at standard condition.

Piping: Inlet and outlet pipe to be re-designed and re-oriented for flexible hose connections.

Hoses: Flexible H_2S resistant hoses will be procured from Jasper Engineering of Bismarck, ND. These hoses will connect the well head and the measurement system, and back from the measurement system to the flow line, so production is not deferred during the time of testing.

Phase 2

The second phase of the project will feature the modification of the measurement system from a skid to a trailer mounted, fully-enclosed unit. This will require the skid to be mounted on a low profile “bare” trailer, due to the meter’s unusual dimensions: 4’Wx8’Lx11’ wide. Using local resources, we will build a custom enclosure around the measuring system that is suitable for our climate extremes (insulation), features explosion proof wiring, both floor and ceiling venting (for H_2S), and multiple point of ingress/egress. The self-contained skid enclosure will be environmentally friendly and designed to minimize the chance of spills during the use of the meter. As part of the design, the enclosure will be large enough to include an additional gas separator if needed during the test. During this point of the project, a suitable vehicle will be procured to move the trailer from point to point. The vehicle will be a diesel ¾ ton, 4x4, extended-cab truck purchased locally. To lower carbon emissions, we plan to select a vehicle that can use biodiesel, if available. During this period the enclosure will be modified to allow for the use of exterior quick connect piping. In addition, four initial wells from each of the test fields will be identified and the wellheads modified to accept the flexible hoses and valves install to divert the production to the measurement system. From available wells in each field, samples of fluid will be taken at the formation via well bore sampling using WISCO in Williston, ND, and the samples will be brought to Astro-Chem in Williston, North Dakota for analysis.

Phase 3

During Phase 3, the lease operators and engineer will undergo familiarization with the measurement system, and undergo two days of training in its use. In addition the unit will be under preliminary test at a sight using conventional testing to determine accuracy and eliminate any issues. Over the remaining five-six months, the unit will be used for testing wells bases on the following:

1. High Rate Wells >100 bfpd:
    a. 2 hour test
    b. 6 hour test
    c. 24 hour test

2. Medium Rate Wells >50bfpd<100 bfpd
    a. 6 hour test
    b. 24 hour test

3. Low Rate Wells 50 bfpd<
    a. 6 hour test
    b. 24 hour test
    c. 48 hour test

The test data will be recorded, compiled and analyzed. In addition, any changes to the measurement system or trailer will be made as needed.

Three major parameters during testing will be evaluated:

1. Accuracy as compared to conventional testing, and pump off controllers.
2. The effect on the accuracy of the measurement system due to the presence of free gas.

3. Changes in fluid properties, salinity, temperature, API gravity, as the secondary recovery process matures.

Phase 4

Phase 4 will coincide with Phase 5, and will be used for potentially retesting wells where the results are in doubt or new opportunities become apparent with the application of the measurement system.

Phase 5

During Phase 5, the results of the tests will be analyzed for accuracy, and the economics of the project will be also assessed. As Phase 5 coincides with Phase 4, any results that are in doubt will lead to re-test or any new opportunities captured.

Phase 6

Phase 6 will consist of results being compiled and put into a final report for internal submission and subsequent submission to Oil and Gas Research Council.

Standards of Success

The following items will result in a successful project:

1. Procurement of the measurement system, and its modification for use in North Dakota.
2. Deployment of the measurement system across several fields.
3. Acquisition of data and analysis.
4. The system displays reliability and repeatability.
5. Development of best practices.
6. Prepare results for publication.

Background/Qualifications of Participants

Multiphase flow measurement is an ongoing challenge in mature oil producing regions such as the Williston Basin, especially when secondary recovery methods are being contemplated or already implemented.

Ward Williston Oil Company (WWOC) is an operator of oil wells primarily in Bottineau, Burke and Renville Counties. WWOC's staff brings years of experience to operating North Dakota oil fields in both primary and secondary recovery phases.

One of our constant challenges is to allocate production, through common flow-lines, back to the source well during both primary and secondary recovery operations. Secondly, when developing properties we, like other smaller operators, are faced with higher installation costs, delays and higher operating costs due to installation and maintenance of expensive flow lines to common production and tests manifolds. Third, we wanted a reliable method to measure fluid flow so we could adjust our POC (pump off controller) technology to correctly model production as well as down hole and surface producing conditions. Our past attempts to measure multiphase flow using low-tech and "medium" tech methods have been a failure as either the method has been too labor intensive (and expensive) or the technology was not suited for our rather extreme winter conditions (NATCO Porta-Test[tm]), neither system did a good job of measuring gas rates. What we want is a system that we would own, is simple to use, requires low labor inputs, is reliable, transportable, and can be modified to work in extreme weather conditions. During our research we found either vendors with reliable products but did not have experience in creating systems that are portable or they wanted to sell the system as a service. Accuflow, the measurement system provider for this project, is the provider of measurement systems for Process Instruments and Controls, LLC (http://process-instruments.com/field_services.htm), which offers trailer mounted well testing services in California. By the use of Accuflow's system, we feel we can modify their technology for use for our needs.

The measurement project effort will be performed by the principal investigator, managers, and field personnel. James Cron, Ward Williston's Chief Engineer, will be the primary investigator, with Rodney Conway, VP of Operations at Ward Williston will also participate in the investigation process. Both aforementioned individuals have extensive field and operations experience. The work on this project will be performed by or under the supervision of James Cron, Rodney Conway, field supervisors and field personnel.

Value Statement

This is valuable project for the State of North Dakota. It will allow technology and processes to be developed that will allow marginal properties near the end of their ultimate producing life to become secondary recovery projects. In addition the project will allow optimization of current secondary recovery projects, in case, adding additional tax revenue to the State's general coffers, and ensuring while expanding job opportunities for the citizens of North Dakota. In addition, this project will extend technology, processes and technical knowledge transfer to our State to benefit our producers and service providers. Through our "Buy North Dakota" strategy, we will procure the majority of the goods and services for this project from local North Dakota businesses.

Project Management

The measurement project effort will be performed by the principal investigator, managers, and field personnel. James Cron, Ward Williston's Chief Engineer, will be the primary investigator, with Rodney Conway, VP of Operations at Ward Williston will also participate in the investigation process. Project administration will be performed by Ward Williston Oil Company. The work on this project will be performed by or under the supervision of James Cron, Rodney Conway, field supervisors and field personnel. Microsoft Project^{tm} will be used as the primary project management software for this project.

Project Time Table

Phase	Event	Conclusion
1	**Measurement Skid Procurement and Construction**	**Q1, 2008**
2	**Skid, Trailer Modified Truck Procured**	**Q2, 2008**
3	**Training/Testing Begins**	**Q3, 2008**
4	**Testing Concludes**	**Q4, 2008**
5	**Final Results**	**Q4, 2008**
6	**Results Published**	**Q4, 2008 or Q1, 2009.**

Project Budget

The funding requested is necessary to achieve the project's objectives within the proposed timetable. If no funding or less funding is available than what is requested, the project's objectives cannot be attained.

Measurement Project Estimated Costs

			S&H	
Measurement Skid		$55,500.00	$4,200.00	$59,700.00
Hoses		$12,000.00	$300.00	$12,300.00
Trailer		$10,000.00	$500.00	$10,500.00
Trailer Modifications		$35,000.00	$0.00	$35,000.00
3/4 Ton Pickup		$40,000.00	$500.00	$40,500.00
Wellhead Modifications		$8,000.00		$8,000.00
Total Tangible				$166,000.00
Fluid				
Fluid Sample Acquisition		$7,000.00		
Lab Work		$4,000.00		
Engineering				
	Management	$2,000.00		
	Testing	$2,000.00		
	Analysis	$2,000.00		
	Final Report	$2,000.00		
Field Production Staff		$3,000.00		
Travel/Training		$5,000.00		
G&A		$3,000.00		
Total Intangible				$30,000.00
Total Estimated Project Cost				$196,000.00
Total Grant Support Requested				$98,000.00

Project Matching Funds

The total requested matching funds by Ward Williston Oil Company is $98,000.

Confidential Information

All of the information in this application is of a confidential nature. We request all reports and associated data remain confidential for one year from the date of report submission.

Patents and Rights to Technical Data

Ward Williston would like to reserve the right to all items or processes that do not already carry a valid patent or have a patent pending.

Tax Liability Affidavit

Please see attached the tax affidavit as part of the Appendix of this document.

Bibliography

Liu, K.T., KTL & Assoc, Kouba, G.E., Chevron Petroleum Technology Company, “Coriolis-based net oil computers gain acceptance at the wellhead”, Oil and Gas Journal, June 27, 1994.

Means, Steve R. Portable Well Testing System Using New Oil/Water Monitoring Technology, Texaco Exploration and Production, Bakersfield Region, Web: http://www.agarcorp.com/media/papers/agar_texaco_ow_report.pdf, accessed October 10, 2007.

Appendix

The documents as noted in the earlier text will be attached in the Appendix.

Tax Liability Affidavit

I, James W. Cron, do hereby confirm that to the best of my knowledge, Ward Williston does not have an outstanding tax liability owed to the State of North Dakota or any of its political subdivisions.

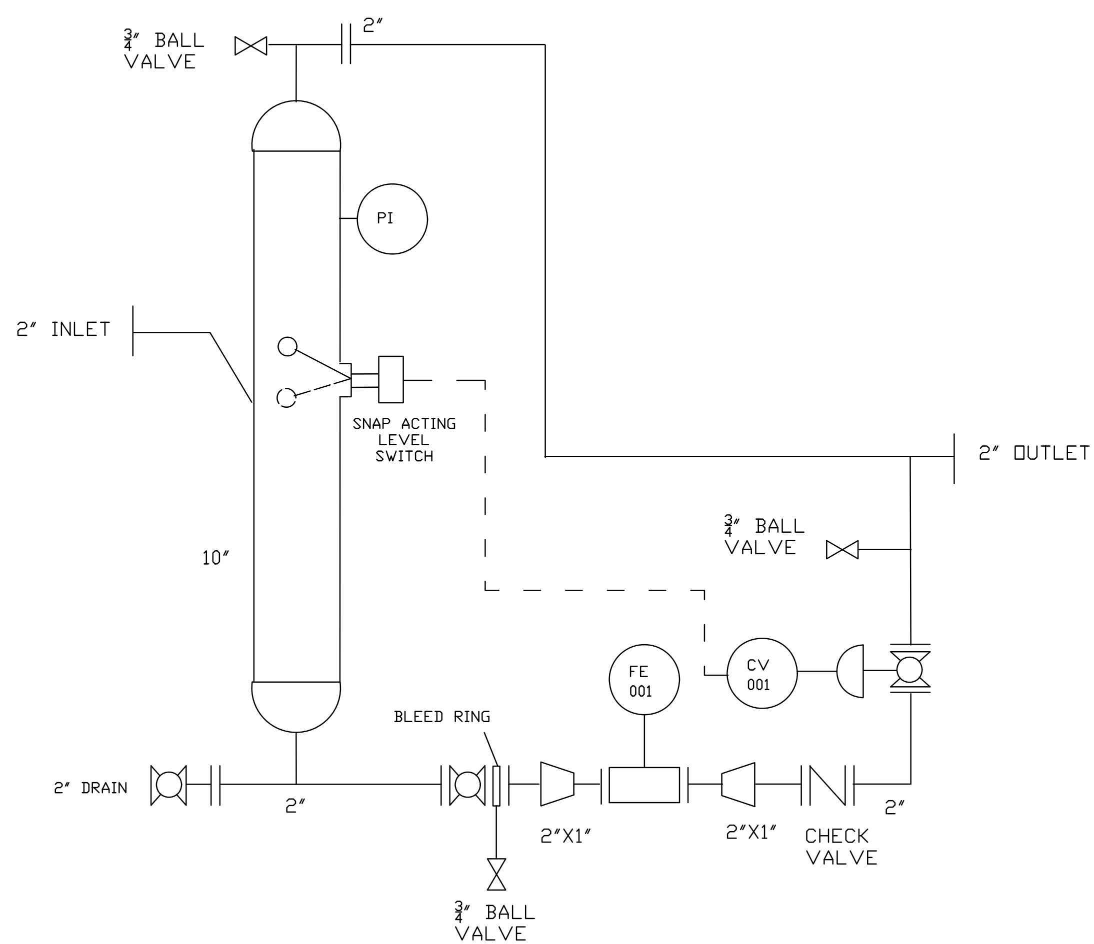
____
(Affiant's Signature)

STATE OF ND)
)ss
COUNTY OF Bottineau)

On November 1, 2007,
known to me to be the person described in and who executed the foregoing instrument, personally appeared before me and acknowledged that (s)he executed the same as a free act and deed.

Shirley Conway
____
Notary Notary Public
Seal State of N.D, County of Bottineau
My Commission expires ________________

SHIRLEY CONWAY
Notary Public
State of North Dakota
My Commission Expires April 12, 2008



LEGEND

FE001 – 1″ CORIOLIS METER W/ NET NET OIL COMPUTER
CV001 – ON/OFF CONTROL VALVE, 2″
PI – PRESSURE GAUGE

REV	DESCRIPTION	D.B.	DATE	CHKD
1	DELETE GAS METER	HJL	9/6/07	
0	FOR CUSTOMER REVIEW	HJL	7/10/07	

Accuflow, Inc.

Description
ACCUFLOW MULTIPHASE METERING SYSTEM

Accuflow Serial#
.

Customer App. Sign.

Customer P.O.#
.

Drawing#

Revision#
1

A Reprint From
OIL&GAS JOURNAL

Coriolis-based net oil computers gain acceptance at the wellhead

K.T. Liu *KTL & Associates Cerritos, Calif.*
G E. Kouba *Chevron Petroleum Technology Co. La Habra Calif.*

Full-range, water-cut capability and a nonintrusive nature enable the Coriolis-based net oil computer (NOC) to meter produced fluids directly from the wellhead.

Several hundred NOCs are currently installed at individual wellheads on low-GOR wells. A majority of the wells have wellhead pressures greater than the bubble point pressure of the crude oil. Because no entrained gas is present in the liquid stream, a test separator is unnecessary.

System benefits

The Coriolis-based NOCs are cost effective, especially in high water-cut applications. Field experience shows the units are rugged, reliable, and accurate when properly installed and operated.

The NOC system continues to evolve with improvements in implementation procedures and techniques to enhance operation and expand application opportunities.

Increasing numbers of Coriolis-based NOCs are used simultaneously to measure crude and water production from individual wells or leases. In this NOC system, the Coriolis force flowmeter (CFF) serves as both water-cut analyzer and flowmeter.

Compared to other conventional measurement systems, this technology offers the following advantages:

- Measures full-range water cut
- Reduces repair frequency and test cycle time. This lessens operating and maintenance costs
- Lowers overall capital costs.

Since introduction in 1988, more than 1,200 Coriolis-based NOCs have been installed for commercial operation worldwide. About 700 NOCs are in tandem with test separators. The remaining NOCs are at the wellhead and monitor well production on a real time, continuous basis.

The Coriolis-based NOC system feasibility has been demonstrated and described elsewhere.[1] The inherent simplicity of NOC systems, however, has in some instances led to overlooking fundamental principles required for successful applications.

Applications

Measurement of crude oil produced from individual wells or leases is important, often essential in oil field operations. Accurate and timely information ensures prompt operating decisions, equitable royalty distribution to interest owners, and efficient reservoir management. But measurement accuracy is often in doubt.

Problems may stem from several possible shortcomings of conventional well testing systems, such as inefficient separation, poor sampling, rangeability of flowmeters, failure to maintain instrument calibration, and lack of appropriate measurement technology.

Conventional oil and water flow measurement from a producing well or a group of wells involves a two-phase or three-phase separator to remove produced gas. Free water and the emulsion

Fig. 1

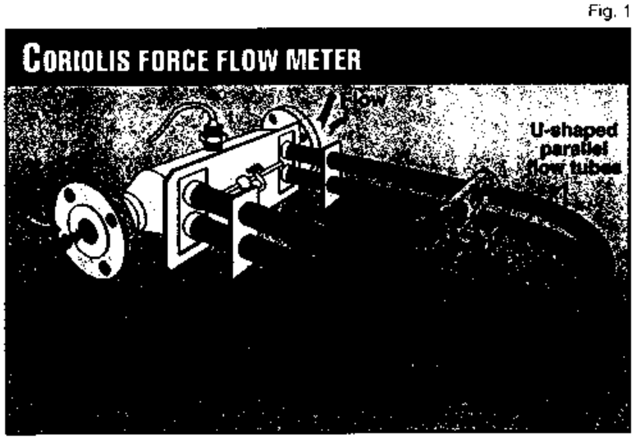
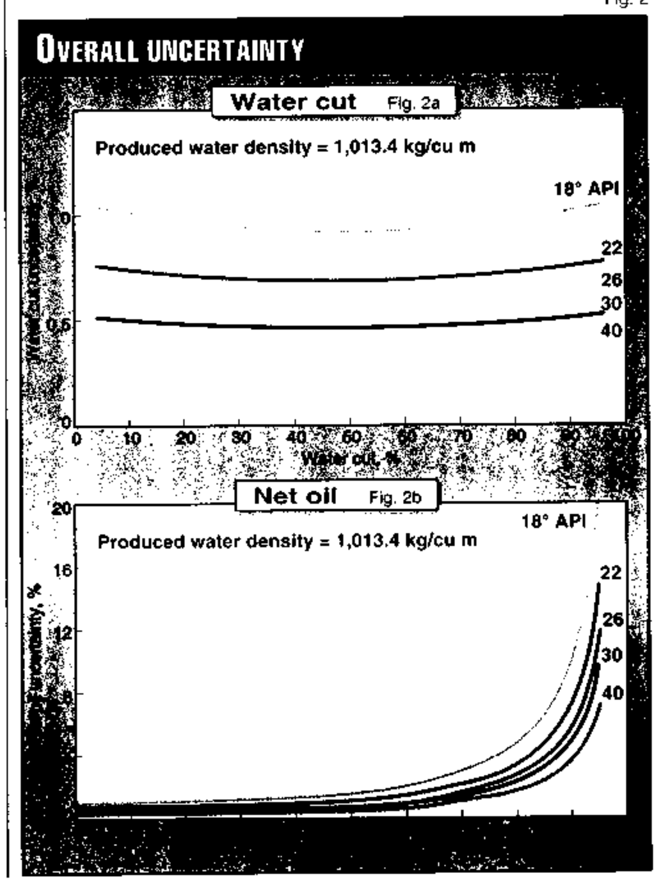


Fig. 2



flow rates are measured with respective flowmeters.

Emulsion stream water cut is determined by an on-line sampler, a grab sample from the emulsion flow line, or an on-line capacitance-type water cut analyzer. Combined signals from the flowmeters and water cut analyzer then determine oil and water production.

One major measurement error is attributed to water cut determination, especially when water cut is relatively high. High water cut can occur in the following situations:

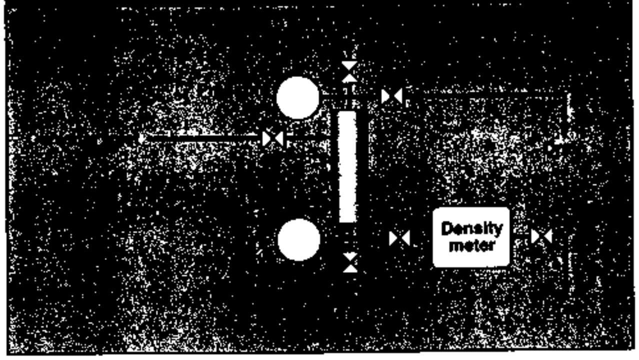
- Maturing reservoir
- Small test separator for high production wells
- Two-phase separator
- Tight emulsion that prevents separation of free water.

On-line and grab samples may not represent total flow because crude and water usually are not uniformly distributed in the pipe, and water cut will generally fluctuate with time. Consequently, systems that rely on sampling techniques for water-cut determination can suffer significant measurement errors.

Analyzers based on capacitance measurement principles are reasonably accurate only when water cut is relatively low and the oil/water emulsion is oil-continuous (i.e., water droplets in oil-continuous phase). Because these analyzers depend on dielectric properties of the emulsion, erroneous measurements occur at high water cuts when the emulsion becomes water-continuous (i.e., oil droplets in the water-continuous phase).

Fig. 3

Density measurement assembly



No distinctive transition region exists in which an oil-continuous emulsion changes completely to a water-continuous emulsion. In most cases, the highest water cut of the oil-continuous emulsion occurs at about 35-60%.

Recently, several new water cut analyzers have been developed to measure full water-cut streams. These include those based on microwave and radio frequency techniques. In the authors' opinion, however, none of these analyzers has yet fully demonstrated its claimed capabilities.

Another difficulty pertains to flowmeter reliability. Conventional well-testing systems typically employ a positive displacement meter or a turbine meter to measure various liquid streams.

Because these flowmeters have rotating parts, they are susceptible to wear and clogging caused by sand or paraffins in the production stream. Consequently, these flowmeters frequently need repair and recalibration, and the measurement becomes unreliable in the interim.

The Coriolis NOC technology was developed to alleviate problems with high water-cut measurement and flowmeter wear.

Coriolis-based NOC

For net-oil measurement applications, the Coriolis force flowmeter (CFF) simultaneously serves as a flowmeter and a density meter.

In brief, a typical CFF shown in Fig. 1 has two identical tubes that are vibrated in opposition at their natural frequency by an electromagnetic drive mechanism. Because of the Coriolis effect, the fluid flowing through the vibrating tubes creates an asymmetric distortion between the inlet and outlet legs.

The distortion magnitude, measured by two position detectors placed on opposite tube legs, is directly proportional to the mass flow rate.

Besides mass flow rate, the fluid density can also be measured by the change in vibrating frequency of the meter tubes. A resistance-type temperature sensor continuously monitors the meter tube temperature for various signal processing purposes.

Many CFFs provide mass flow and density measurement accuracies of 0.15% and 0.0005 g/cc, respectively. Details of the operating principle of CFF are described elsewhere.[2,3]

From the basic outputs of a CFF, water cut, net oil volume, and net water volume are calculated with the following equations:

$$X_e = (D_e - D_o)/(D_w - D_o) \quad (1)$$

$$\text{Net oil volume} = (M_e/D_e) \times (1 - X_w) \times \text{Ctl,o} \quad (2)$$

$$\text{Net water volume} = (M_e/D_e) \times X_w \times \text{Ctl,w} \quad (3)$$

where:

X_e = Water cut in emulsion, volume fraction

D_e = Emulsion density measured by the Coriolis meter

D_o = Known, predetermined density of dry crude oil

D_w = Known, predetermined density of produced water

M_e = Total emulsion mass measured by the Coriolis meter

Ctl,o = Crude-oil volume correction factor that adjusts measured crude volume to standard temperature.

Ctl,w = Produced-water

Table 1

Sensitivity analysis

This site near a wellhead has an NOC without a test separator. The wellhead is not shown (Fig. 4).

volume correction factor that adjusts measured water volume to standard temperature.

Because water cut is based on density difference between oil and water, accurate measurements can be obtained over the full range of 0-100% water cut, regardless of whether the emulsion is oil-continuous or water-continuous.

Also, because the Coriolis meter is a nonintrusive instrument and has no moving parts within the flow path, it requires significantly less maintenance than conventional positive displacement and turbine meters.

High rangeability of the Coriolis flowmeter (up to 80 to 1 turn-down ratio) allows the NOC to accommodate a wide range of flow rates from different wells. Also, its internal temperature sensor corrects net oil volume to standard temperature.

Performance characteristics

Under normal operations, NOC accuracy is primarily governed by the accuracy of input dry oil and produced water densities, and the accuracy of the emulsion density measured by the Coriolis meter. Typical performance characteristics in terms of water cut and net oil determinations are illustrated in Fig. 2.

Note that these performance curves are generated on the basis that the uncertainties of dry oil density (D_o), produced water density (D_w), and measured emulsion density (D_e) are all on the order of 0.5 kg/cu m. Field data show that these uncertainty levels are achievable with proper calibration.

Fig. 2 shows that the measurement uncertainties for both water cut and net oil decrease as the API gravity of the crude oil increases. It is intuitive that the lighter the crude oil, the larger the density difference between the oil and water, and therefore the better the measurement accuracy.

Fig. 2a also shows that, for a given API gravity of crude oil, the uncertainty of the water cut measurement is relatively insensitive to the water cut level. With a 26° API oil, the water cut uncertainty ranges from 0.5% to 0.6% over the entire water cut range.

The corresponding uncertainty in net oil volume, however, depends on both the crude's API gravity and also on the instantaneous water cut of the emulsion. As shown in Fig. 2b, the uncertainty is relatively small in the low water cut range and is only slightly higher in the mid water cut range, up to 80%.

As the water cut increases further, however, the uncertainty increases sharply. Mathematics explain this behavior.

In Table 1, the net oil volume uncertainties resulting from inaccurate water density and mixture density are proportional to the inverse of $(1 - X_w)$. This implies that the overall net oil uncertainty will increase exponentially at very high water cuts.

Again with 26° API crude, Fig. 2b shows that the net oil uncertainty increases from 0.6% to about 3% between 0 and 80% water cut. It then increases to about 6% at 90% water cut and escalates to about 12% at 95% water cut.

It should be noted that water-cut analyzers will also exhibit the same behavior with high water-cut streams.

To obtain the best performance from the Coriolis-based NOC, it is imperative that:

- Dry oil and produced-water densities at operating pressure must be predetermined accurately.
- Dry oil and produced-water densities must be consistent over time.
- Emulsion streams must contain no free gas.
- Direct measurement of extremely high water-cut streams should be avoided or minimized.

Accurate densities

At metering conditions, crude and produced-water densities from individual wells or leases must be predetermined and programmed into the NOC. The "live oil" density rather than the "dead oil" density must be used as the input parameter.

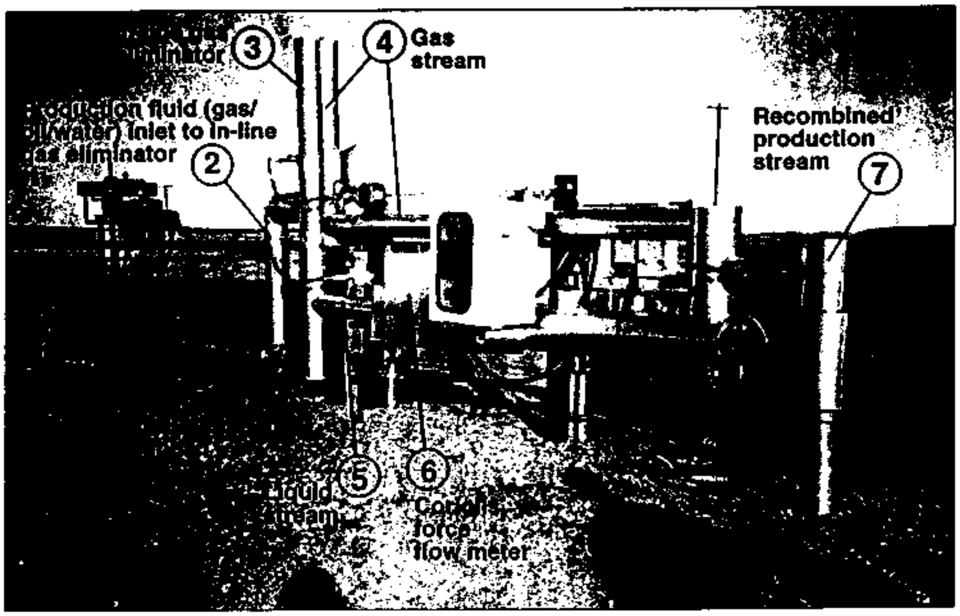
Live oil in this context refers to the crude that is saturated with solution gas at the separator pressure and temperature. Reduction of liquid pressure to stock-tank pressure will cause the live oil to lose its solution gas or light-end components and become a dead oil.

Depending on GOR and separator pressure, the live and dead oil densities can be very different. Water cuts will read too low and net oil volume too high if the dead-oil density is used.

For example, for a well producing a 26° API oil at 50% water cut, if the dead-oil density is 10 kg/cu m higher than the live-oil density, water cut would read about 4% too low and net oil volume would read about 8% too high as a result of wrong crude-oil-density input. Table 1 lists ways to estimate the sensitivity of various parameters on water cut and net oil measurements.

Three methods are commonly being used to determine the live-oil density accurately.

The first involves sampling liquid, with a pressurized bottle, near or at the separator. The sample is processed in the laboratory



This wellhead NOC installation has an in-line gas eliminator. The net oil computer enclosure is not shown (Fig. 5).

to remove free water while maintaining the sample slightly above the separator pressure to prevent the solution gas from flashing off. The dry crude oil is then measured with a high-precision laboratory density meter, capable of measurement at elevated pressures.

The second method uses a Coriolis meter as a density measurement device. It involves blocking off the liquid inlet and outlet of the test separator for an extended time to allow free water and the emulsion to separate in the separator. The emulsion, which may still contain water, is then flowed through the Coriolis meter, and density and temperature readings are recorded.

Meanwhile, an emulsion sample is withdrawn from the flow line and its water content determined. The dry crude-oil density can then be computed from the density, temperature, and water content of the emulsion.

The third method uses a sampling and measuring assembly (Fig. 3).

Typical operating procedure involves withdrawing a liquid sample into the small cylindrical sample container and allowing the sample to stand an extended period while the sample container is connected to the separator gas line.

Similar to the second method, the produced water and crude densities can be determined by flowing water and dry emulsion through the density meter. The main advantages of this approach are relative cost, portability, and local processing of the samples so that oil and water densities can be quickly updated with relative ease.

Gas effect

Many Coriolis meters tolerate an amount of entrained gas. A small amount of gas may not affect mass measurement accuracy. Depending on meter design and size, the gas tolerance limits can range from several percent to 10-20% by volume, especially when gas bubbles are well dispersed in the liquid stream.

The entrained gas, however, will certainly affect the water-cut determination of the NOC. Entrained gas will cause a decrease in density reading, which is misinterpreted as a decrease in water cut.

For example, a 0.5% by volume of entrained gas will underestimate water cut by as much as 4.3% for a 26° API crude.

There are two ways in which entrained gas may be present at the Coriolis NOC:

1. Gas carry-under with the liquid stream
2. Gas evolving out of solution in the crude oil.

Gas carry-under may be caused by high liquid viscosity, improper separator operation, or poor separator design. Problems with separator operation and design are beyond the scope of this discussion but must be corrected for proper operation of the NOC.

A pressure reduction may cause gas to flash out of solution as crude flows from the separator to the NOC. The amount of evolved gas depends on crude properties, operating temperature and pressure, and pressure drop.

Most test separators are designed to remove practically all entrained gas from the liquid. In some production situations, however, extremely tight emulsions can occur in the production line and test separator. Tight emulsions are characterized by unusually high viscosities, sometimes many times more than the crude oil viscosity.

Separating the entrained gas from this emulsion is not efficient even with a large test separator. Demulsifier chemicals that break the tight emulsion and facilitate free gas removal, however, have been found to be effective and practical.

One way to minimize or prevent the solution gas from flashing off is to install the Coriolis meter below the separator. In a properly designed system, the static head gain effectively offsets the dynamic pressure losses in the flow line. This results in a higher pressure at the meter than at the separator, thus preventing solution gas from flashing. The design criterion is expressed as:

$$\Delta P_s > \Delta P_p + \Delta P_m$$

where:

P_s = Liquid static head measured from the liquid level in the separator to the flowmeter

P_p = Dynamic pressure loss in flow line and fittings from the test separator to the flowmeter inlet

P_m = Pressure drop across the flowmeter

The frictional pressure loss (P_p) can be minimized by installing the Coriolis sensor as close to the test separator as practical and using larger-diameter connecting pipes. Piping elements, such as tees, elbows, and reducing unions, should also be minimized between separator and meter. Sampling ports, static mixer, meter proving connections, dump valve, back pressure regulator, or other flow-restricting devices should be installed downstream of the flowmeter.

If a cut-off valve must be installed between the separator and the flowmeter, a full-port valve should be considered.

To minimize the pressure drop across the flowmeter, (P_m), it may be necessary to use a larger flowmeter than normally needed. Because of the high rangeability of the Coriolis flowmeter, flow measurement accuracy can still be achieved even at very low flow rates.

The minimum vertical height between the Coriolis meter and the liquid level in the test separator can now be estimated from:

$$H_{min} = 2.3 \times (P_p + P_m)/D_o$$

where:

H_{min} is in ft

P_p and P_m are in psi

D_o is in g/cc

To illustrate this design, consider an application in which a 3-in. Coriolis flowmeter is installed at the separator outlet. Assuming a maximum fluid flow rate of 6,000 b/d and fluid viscosity of 1 cp, the pressure drop across the Coriolis flowmeter (P_m) is calculated to be 1.1 psi.

It is further assumed that the total equivalent length of the pressure drops through the 3-in. diameter connecting pipe and other piping elements (elbows, valve, etc.) is 20 ft.

The piping pressure (P_p) drop is calculated to be 0.7 psi. Therefore, the required static pressure head (P_s) must not be less than 1.8 psi. For a 26° API oil (D_o = 0.8975 g/cc), the Coriolis flowmeter must be installed at least 4.6 ft below the liquid level in the separator to prevent the solution gas from flashing off in the meter.

Another method to prevent gas flashing raises the liquid pressure above the separator pressure by installing a charge pump upstream of the flowmeter. Although a limited approach, it effectively boosts pressure and has been successful in several installations.

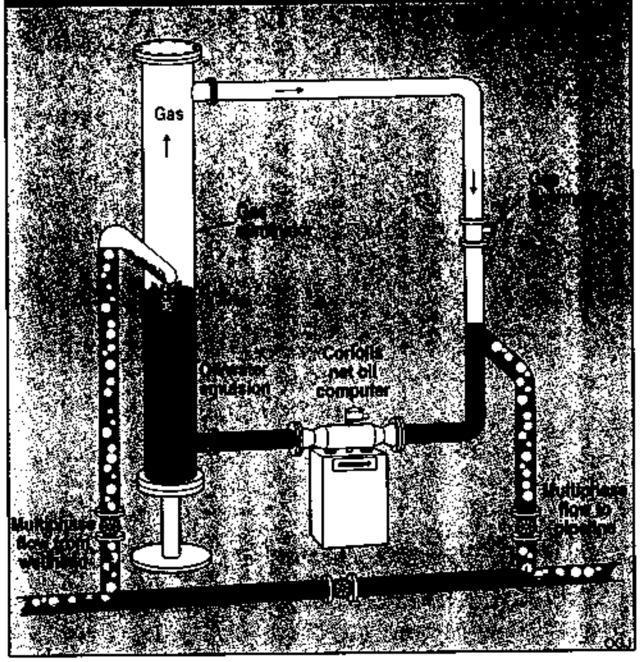
Fluid densities

The NOC requires that oil and water densities in the product stream not vary significantly with time. For an individual well, this is generally the case.

The possibility of varying oil and water densities exists for wells with multizone completion and for wells undergoing initial stages of enhanced oil recovery (EOR). Again, the potential effect

Fig. 6

MULTIPHASE METERING LOOP



needs to be evaluated prior to installing the NOC.

In theory, the NOC may be unsuitable for measuring commingled production. Changing production rates from individual wells may cause the oil and water densities in the commingled stream to vary.

In practice, however, no appreciable density variations have been reported, to date, in all applications of this type. Nevertheless, it is advisable that the potential effect of density variations be evaluated against the expected performance.

When the NOC is used in commingled applications, more frequent update and adjustment of oil and water densities may be required.

High water cut

To reduce measurement uncertainty with very high water cut (e.g., 90% or higher), it is imperative to keep instantaneous water cut as low as practical when the emulsion passes through the meter. One effective method uses a three-phase separator to remove a portion of the free water from the bulk production stream, thereby keeping the water cut in the emulsion stream at a lower level.

If a two-phase separator is used, a snap-acting control mechanism has been found to be very effective. This control mechanism allows some free water to settle at the bottom of the separator during the standing cycle.

At the beginning of the dumping cycle, clean produced water (i.e., 100% water cut) flows through the meter. Then an oil/water emulsion stream follows that has a significantly lower water cut than the overall value.

This operating scheme also is ideal for determining or updating the produced water density. Because only clean produced water flows through the meter at the beginning of the dumping cycle, the density reading from the Coriolis meter can be used as the produced water density.

Wellhead application

For wellhead applications, the typical crude oil GORs are less than about 100 scf/bbl (17.8 cu m/cu m), and the bubble point pressure ranges from about 100 to 250 psig (791 to 1,825 kPa). The gravity of the crude oil varies from 22 to 40° API with water cut ranging from 0%

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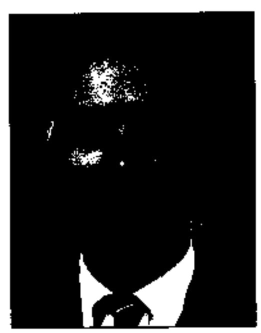

Kouba

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to as high as 95%.

These NOCs are installed on flowing wells, and wells equipped with electrical submersible pumps and beam pumps. Well production rates range from about 2,000 to 20,000 b/d (318-3,180 cu m/day) of gross fluid.

The applications generally require 3-in. or larger meters. Fig. 4 shows a typical installation. Because production wells are normally located in remote areas, these NOCs are typically linked to a central computer by means of radio telemetry.

To prevent solution gas from breaking out from the crude oil, it is critically important to ensure that the fluid pressure at the flowmeter is at least several psi above the bubble point pressure of the crude oil. Bubble point pressures can vary from well to well.

In addition to laboratory PVT analysis and flash calculations, using the installed NOC to determine the bubble point pressure has been found to be easy and practical. The method involves varying the well head pressure and observing the density indicated on the NOC. The bubble point corresponds to the pressure where the density (or the indicated water cut) reading on the NOC decreases abruptly.

Major users of this type of application include PDO (Petroleum Development Oman), OXY Colombia, CPI (Caltex Pacific Indonesia), and Saudi Aramco.

A wellhead NOC enables wells to be monitored on a continuous basis. Significant savings on capital investment and operating expenses have been demonstrated because individual flow lines and conventional well test facilities are eliminated.[3]

When wellhead pressures are maintained below the bubble point pressure, a certain amount of gas will be present in the production stream. The use of a Coriolis-based NOC in this situation requires some form of gas separation. Several users have successfully taken the approach of attaching the NOC downstream of a simple and low cost in-line gas eliminator.

Fig. 5 shows a gas eliminator assembly that handles a production stream containing a small amount of free gas (up to about 3-5% by volume). The gas and liquid are separated in a vertical gas elimination pipe, and the liquid stream is measured with the NOC and recombined with the gas.

Currently, Chevron Corp. is developing a similar system aimed at handling a full range of multiphase flow streams. Fig. 6 shows the Chevron Multiphase Metering Loop (CMML) concept.

Separation in the gas eliminator is performed by a cylindrical cyclone. The performance of the gas/liquid cyclone is further enhanced by initial separation in the downward-sloping tangential inlet pipe. After separation, the gas flow rate is measured by any appropriate conventional gas meter, and the oil and water rates are measured by the Coriolis NOC.

Initial laboratory and field prototypes have demonstrated that this system is capable of handling much higher GORs than a simple vertical separator.

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