A Review of the Current State and Direction of Methods for Sampling Wet Gas Flows

FINAL REPORT

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1.0 Introduction

This report presents the results of research designed to evaluate, document, and upgrade natural gas sampling technology in selected areas of need, as directed and supervised by the American Petroleum Institute (API) Manual of Petroleum Measurement Standards (MPMS) Chapter 14.1 Gas Sampling Project Working Group. The project was funded jointly by the Gas Research Institute* (GRI) and the Minerals Management Service (MMS), U.S. Department of the Interior. Southwest Research Institute was contracted to perform this research, as part of a multi-year program in support of the revision of API MPMS Chapter 14.1, *Collecting and Handling of Natural Gas Samples for Custody Transfer* (Reference 1).

Five individual tasks were included in the 2002 study:

1. Comparative evaluation of equation-of-state models and characterization methods for determining the hydrocarbon dew point of a natural gas stream.
2. An evaluation of the fill-and-empty sampling method as a self-heating method when equipment temperature is below the hydrocarbon dew point.
3. Development of a performance verification test protocol for new gas sampling methods.
4. A review of the current state and direction of gas sampling research under saturated and wet gas conditions.
5. A review of methods for preparing natural gas blends used as calibration standards for chromatography equipment.

The last two research tasks were co-funded by the Minerals Management Service. This report to MMS presents the findings of the fourth task, a review of common methods of sampling "wet gas" streams.

In this report, a "wet gas" stream is defined as a hydrocarbon stream that is either saturated gas or a mixture of hydrocarbon gases and liquids in equilibrium, but does not contain water vapor or liquid water. This review discusses existing sampling equipment and techniques for such applications. The review also briefly describes metering technologies used to measure liquid and gas flow rates in wet gas streams. As part of the review, several facilities that routinely create gas-liquid flows were surveyed about their capabilities. The goals of the survey were to identify facilities that can create saturated or low-liquid-content hydrocarbon flows, document their capabilities, and determine if any of the facilities would be useful as future test sites for sampling separators and sampling methods. The survey results are also reported here.

A separate report to MMS (Reference 2) covers the fifth task of the 2002 project, a study of methods for preparing calibration gas blends and the accuracy of blend compositions. This report and Reference 2 serve as final deliverables for the research tasks co-funded by MMS during 2002. A separate GRI report (Reference 3) to be published at the end of 2003 will discuss the findings of research tasks 1, 2 and 3, along with related research to be performed in 2003.

* In April 2000, Gas Research Institute (GRI) and the Institute of Gas Technology (IGT) combined to form Gas Technology Institute (GTI).

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2.0 Industry Practices and Current Issues in Wet Gas Sampling

The research into current wet gas sampling methods began with a review of sampling standards and with interviews of several members of the natural gas industry. Individuals working for transmission companies, consulting firms, and equipment distributors were asked for information on industry practices. A literature review also provided information on current research interests, particularly in the United Kingdom. This chapter reviews current wet gas sampling practices and research interests in the United States and Europe, while later chapters discuss equipment and techniques for sampling and metering wet gas flows.

2.1 Wet Gas Sampling Practices in the United States

Recall that for the purposes of this report, "wet gas" denotes gas that contains condensed hydrocarbon liquids, as opposed to water vapor and other condensate. In the United Kingdom, wet gas sampling is considered an essential research topic for the oil and gas industry (Reference 4). This research need is primarily driven by the North Sea gas industry, where natural gas production and transmission often involve wet gas flows. Plans for future research by the United Kingdom's NEL (formerly the National Engineering Laboratory) are discussed later in this chapter.

In the United States, the stance generally adopted by the natural gas industry is that sampling of wet gas should be avoided, and that if it must be done, it should be performed carefully. As stated in the API Manual of Petroleum Measurement Standards, Chapter 14, Section 1, Appendix B (Reference 1),

> "Sampling of multiphase (gas and liquid) mixtures is not recommended and should be avoided if at all possible. In the [sic] multiphase flow, the ideal system would mix the gas and liquid flows uniformly and collect a sample of the true mixture flowing in the line by using a properly designed sample probe and an isokinetic sampling system. Current technology of natural gas sampling is not sufficiently advanced to accomplish this with reasonable accuracy. When sampling a multiphase liquid-gas flow, the recommended procedure is to eliminate the liquid from the sample. The liquid product that flows through the line should be determined by another method."

Appendix C of the same document discusses lessons learned during tests of spot sampling methods in wet gas conditions, and supports the recommendation of API MPMS Chapter 14.1 against sampling gas/liquid mixtures without separating the phases.

> "The data indicated that some [spot-sampling] methods might be capable of allowing sampling below the hydrocarbon dew point, but with higher uncertainties. The data also clearly demonstrated that under some severe operating conditions, when free liquids are present, none of the current methods are capable of obtaining a representative sample."

Other industry standards for natural gas sampling also state that representative samples cannot be obtained from two-phase streams using current methods for single-phase sampling (References 5 and 6).

When the possibility of a wet gas stream is encountered, the recommended procedure before drawing any samples is to perform an analytical or experimental dew point analysis, using previous composition data, to determine if condensed hydrocarbons may be present. If gas-liquid flow is believed to exist, the preferred sampling method in the U.S. natural gas industry is to draw separate samples of the liquid and gas phases through various separating sampling devices, such as those described in Chapter 3. These devices must be used properly to avoid distortion of the samples after phase separation. For instance, recent research has demonstrated that misuse of the Gas Processors Association (GPA) Separator can lead to sample distortion, and the recent revision to GPA 2166 seeks to avoid this

(Reference 5). Some separator users work to reduce or prevent condensation of the gas stream after it leaves the separator by heating the gas transfer line between the separator and the recipient sample cylinder (References 5 and 7).

Mayeaux (References 8 and 9) states that it is very difficult, if not impossible, to sample both the liquid and gas streams at the same time, with a single probe, without contaminating the sample. This is because the properties of the two streams are inherently different, and sample temperatures and pressures will affect the two phases in different ways. The primary difficulty encountered by many sampling methods is keeping the samples in their original form, once they have been withdrawn from the stream. If the phases are allowed to commingle in the same container at the same operating temperature and pressure, for example, the higher molecular weight compounds in the gas phase will absorb into the liquid and the two-phase sample will become distorted. Changes in either the temperature or pressure within the sample container will also result in composition changes between the phases, as shown in Figure 1, leading to possible errors in the analyzed heating value (*i.e.*, BTU content) of the gas phase and the computed monetary value of the gas. If a two-phase sample is drawn, it must be kept at the temperature and pressure at which it was obtained, or sample distortion will occur.

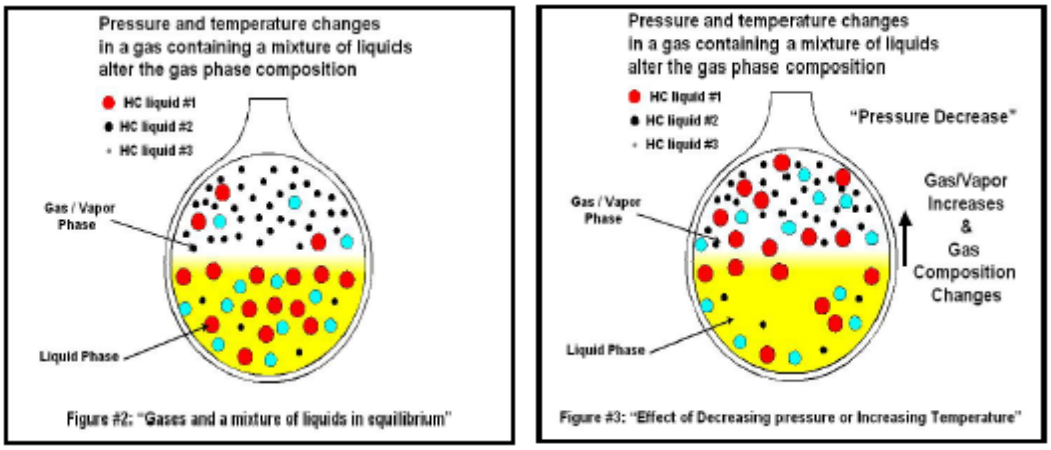

Figure 1. Sample distortion caused by a change in pressure of a two-phase hydrocarbon sample (Reference 9). Reproduced with permission.

The most common sampling devices now available in the U.S. are intended to selectively sample only the gas phase. Some designs physically separate the liquid and gas phases before or after a sample is drawn from the pipeline, while others are designed to keep the gas phase in its original form through proper sample conditioning. Once the phases are properly separated, single-phase sampling methods may be applied to the gas stream, and to the liquid stream if desired. The next chapter describes various sampling separators available commercially. Reference 10 describes equipment and procedures for obtaining samples of natural gas liquids for analysis, and References 1 and 5 describe several accepted methods for sampling the gas phase. Methods of collecting natural gas samples from single-phase gas flows, and their advantages and limitations, are well documented in those standards, and the reader is referred to References 1 and 5 for details.

Other issues presented by sampling in wet gas streams are:

- How is equipment calibrated?
- What is the cost of maintenance?

- How is maintenance performed on in-situ devices?
- Are wet gas samples truly representative of the flowing gas stream when only "spot samples" are pulled?

These questions should be considered by sampling personnel when choosing a sampling method for their own application, since the answers can be specific to the sampling method and the situation.

It should be noted that more methods of sampling and metering water vapor content have been developed than methods for sampling or metering hydrocarbon condensate. This is due to the fact that the hydrocarbon streams are more difficult to resolve, sample in-situ, and maintain in their original "pipeline" state than streams containing water vapor. Since water vapor is outside the scope of this study, no discussion of water vapor sampling methods appears here.

Metering wet gas (*i.e.*, measuring the mass or volumetric flow rate of the phases) is also a challenge to the natural gas industry, but more methods appear to have been developed for wet gas metering than for wet gas sampling. Wet gas meters offer various methods of determining if liquids are present, as well as the volumetric flow rate of any liquids passing through the meter. Because these devices can be useful in identifying the need for wet gas sampling, a review of wet gas metering methods has been included in Chapter 4.

2.2 Wet Gas Research Needs in the United Kingdom

A recent report by NEL (Reference 4) outlines a three-year plan of potential future research projects for the National Measurement System Directorate (NMSD). The NMSD manages programs that support measurement standards for the United Kingdom, including flow measurement standards. As part of the program development, NEL identified research needs in the UK by conducting a survey of industry, academia, regulatory bodies, and government agencies. They received a total of 57 completed questionnaires from a variety of industrial sectors – pharmaceutical, chemical, petrochemical, aerospace, power, transport, water, and oil and gas. The oil and gas industry respondents completed about 35 surveys, more than half of the survey population.

The survey found that respondents' use of new metering technologies had significantly increased since the last survey in 1998. The major changes identified by the survey were in the areas of ultrasonic metering, multiphase metering and wet gas metering systems. This was evident in the dramatic increase in Venturi meters among respondents (26 of the 57 survey respondents had used Venturi meters). Wet gas meters and multiphase meters were also listed as general meter types that had increased in number since the 1998 survey.

The survey also asked the respondents to comment on the national primary standard flow facilities for the United Kingdom (located at NEL). Survey respondents commented mainly about the lack of a natural gas calibration facility. In addition, pertaining to wet gas, the respondents were concerned about the lack of a two-component liquid test facility that could be used to develop wet gas technologies. Of the research topics desired by survey respondents, wet gas and multiphase metering was listed as the highest priority for future research. (21 of the 57 participants surveyed wanted multiphase or wet gas research to be included in future research at NEL.) These comments were included in a project proposal for the 2002-2005 program work scope. This proposal included several projects related to multiphase metering:

- Maintenance of an existing NEL multiphase flow facility, and assurance that calibrations at the facility are traceable to national standards;
- A feasibility study to upgrade existing multiphase or wet gas facilities to allow high-pressure, three-phase operation in wet gas conditions;
- Evaluation of ultrasonic technology for multiphase flow measurement;

- A study of dual-measurement sensors in multiphase flows, and potential measurement diagnostics for such sensors;
- Research into the effects of varying flow properties and installation effects on the performance of wet gas meters.

The second project, in particular, could directly benefit research into wet gas sampling by providing a testbed for evaluating new methods.

In comparing the "state of the art" of gas sampling in the United States with that of the United Kingdom, it is clear that most of the current research and development in wet gas metering and sampling is occurring in the U.K. This research has apparently been stimulated by the North Sea gas industry, where production and transmission companies must handle rich gas and wet gas on a regular basis. The need for wet gas technologies is not unique to companies in that area of the world. New production sites worldwide, particularly offshore production sites, may produce wet gas streams that could benefit from wet gas sampling technology. The economic and regulatory pressures experienced by North Sea production, however, appear to have encouraged aggressive research by companies in that region. Other regions of the world may take an interest in this research, if economic benefits or pipeline integrity benefits are identified.

Another observation from participants in the NEL survey is that wet gas metering systems are inexpensive when compared to the costs of separating wet gas into two phases for measurement. The European industry, consequently, has concentrated on making advances in metering wet gas and multiphase flows *in situ*, rather than separating them. These metering technologies will be discussed further in Chapter 4.

3.0 Equipment and Techniques for Sampling Wet Gas Streams

This chapter describes several sampling devices intended to produce accurate samples of wet gas streams. One device works to separate the gas and liquid phases so that both phases can be sampled accurately. Others are designed to preserve the composition of a gas sample as it is withdrawn from the flowing stream, ignoring the liquid phase. These devices are sold commercially, but where possible, the information appearing here is taken from conference proceedings and published papers, rather than sales literature. One method of avoiding sample distortion is also described that does not rely on specific sampling devices.

Except where otherwise stated, the authors are not aware of any independent evaluations of the effectiveness of the various methods described in this chapter, or of the accuracy of compositions determined using them. This will be discussed further in Chapter 5.

3.1 Petrotech® IsoSplit® Wellhead Sampling Method

Petrotech is a company based in Norway that provides reservoir and process engineering services for natural gas production companies. As part of their business services, Petrotech advertises (on their company web site) several techniques for sampling and testing gas/condensate wells, as well as multiphase metering technology. One wet gas sampling system is based on a device known as the Thorton Mini-Lab Wellhead sampler. This device was originally developed by Shell Research and transferred to Petrotech, which worked to develop an improved version of the device. The device is now offered commercially, but is sold primarily outside the United States (Reference 11). The device is used in flows where both the liquid and gas phases are to be sampled.

The sampling system operates within the pipeline through use of an insertion sampling probe that obtains samples of both the gas and liquid streams. If the liquid stream volume is fairly small, the gas is processed and contained over the time period required until a sufficient liquid sample is collected. As described on the Petrotech website (www.petronett.com),

> "During the test a mixing/sampling manifold is installed upstream of the choke manifold. The manifold contains a static mixing device to collect liquid from the wall and to distribute it homogeneously into the body of the flowing gas stream. A dynamic representative sample of the two-phase stream is withdrawn isokinetically through a probe inserted radially and located downstream of the mixing device. The isokinetic sampling rate (same linear velocity as the wellhead fluid stream) is calculated from the probe size and the gas flow rate measured at the test separator. The isokinetic sample stream is processed in a separation unit (Mini-lab) which enables a wide range of process conditions to be used."

The gas stream output of the separation unit is sampled to confirm the efficiency of the separator. Note that the sample stream is said to be withdrawn isokinetically in order to preserve the hydrocarbon distribution between the phases. API MPMS Chapter 14.1 (Reference 1) states that the single-phase gas sampling methods described in that document cannot draw isokinetic samples from a two-phase stream with reasonable accuracy, based on recent test results and previous experience. The Petrotech technology was specifically designed for wet gas applications, and employs a mixer to attempt to create a homogeneous phase distribution, which is required for representative, isokinetic sampling of both phases.

3.2 Probe Pressure Regulators

These devices are used to sample gas-only streams that are susceptible to condensation problems caused by a high hydrocarbon dew point. Examples of a probe regulator and its installation are shown in Figure 2. In this approach, the probe withdraws a gas sample from the stream at the same pressure and temperature as the stream itself. The sample then immediately passes through a regulator, where the sample pressure is reduced. A pressure reduction normally lowers the temperature of the sample through Joule-Thomson cooling. However, the probe's design uses the flowing gas stream as a heat sink to stabilize the sample temperature at the regulator and offset the cooling effect of the pressure reduction (References 8, 9, and 12).

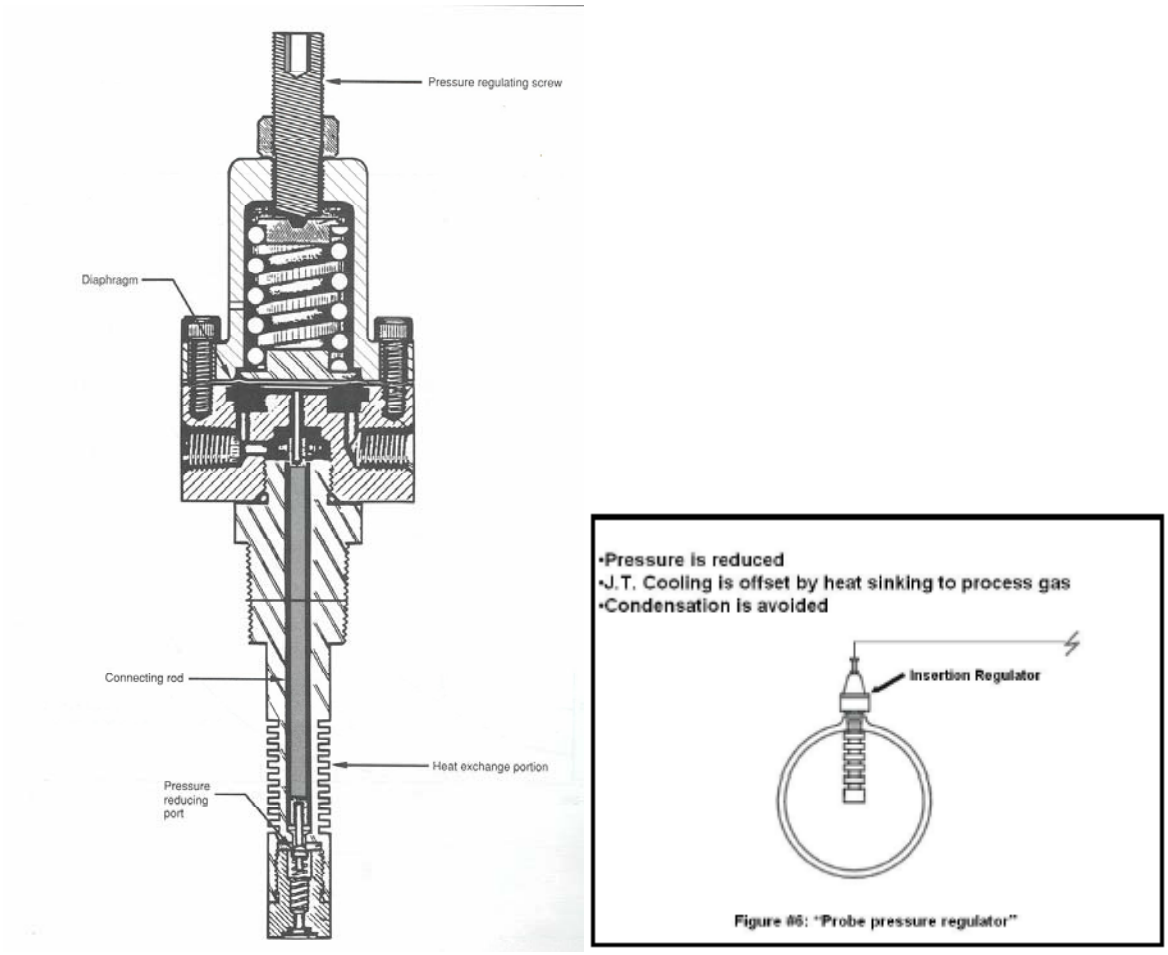

Figure 2. Details of a typical probe pressure regulator. Left, cutaway diagram of a probe regulator (Reference 1); bottom right, installation of a probe regulator in a pipeline (Reference 9).

Several sampling equipment companies in the United States sell probe regulators. They are useful in instances where lowering the sample pressure at constant temperature will move the gas stream away from the hydrocarbon dew line and reduce the chances of sample condensation. Probe regulators are also used to improve the accuracy of water vapor determination. However, if liquids are initially present in the gas stream, these devices will not work properly, and samples could be contaminated or

distorted by liquid droplets that flash into the gas phase as the pressure drops. The next section describes a method of avoiding such distortion by separating the liquid phase from the gas sample.

3.3 Phase-separation Membranes

If liquids are initially present in the stream to be sampled, and only the gas stream is of interest, the liquid and the gas should be separated so that the gas can be sampled and analyzed correctly. Phase-separation membranes, shown in Figure 3, can be attached to sampling probes as one means to attempt to separate the liquid and gas phases inside the pipeline. Some designs place the filter downstream of the regulator, while others separate the phases near the probe entrance, at the same pressure and temperature conditions as the pipeline flow. In the latter case, the gas sample can then be regulated to help avoid condensation after it has been withdrawn from the flow stream (References 8, 9 and 12).

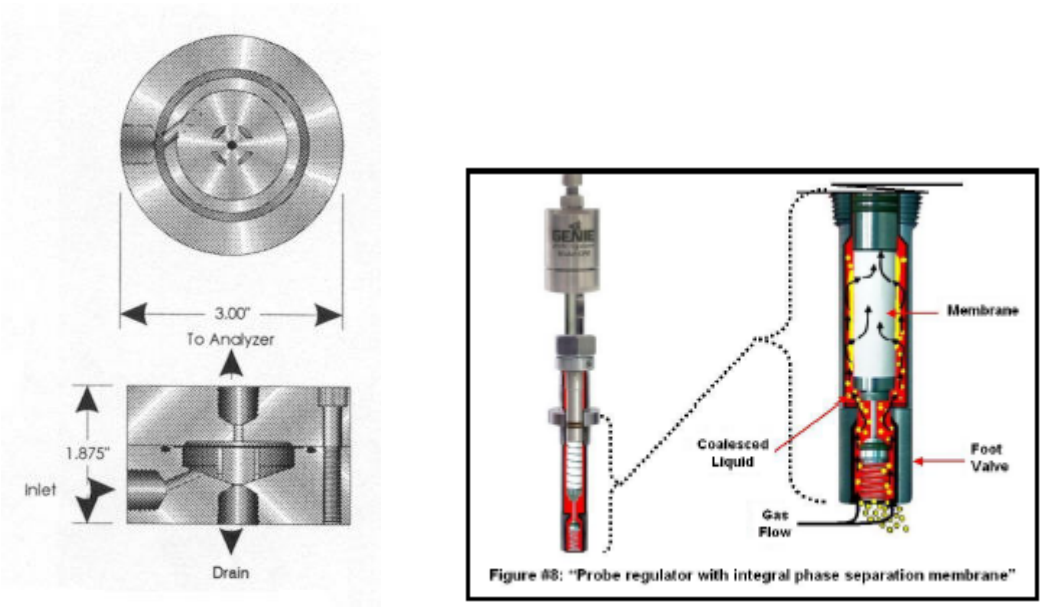

Figure 3. Examples of phase separation membranes. Left: a Welker® Liquid Eliminator membrane filter, for mounting external to the probe (Reference 13). Right: an A+ Genie filter, with membranes both at the probe tip and external to the pipeline (Reference 9). Figures reproduced with permission.

The concept of a sample phase separator was first introduced to the industry in 1982 (Reference 14), and today, several membrane designs are available commercially. Examples include the Genie series separators available from A+ Corporation, and the Liquid Eliminator sold by Welker®. As stated, the location of the membrane varies between designs. Some membranes are mounted on the probe tip before the regulator; others are placed within the probe downstream of the regulator; still other designs mount the separator externally. In Figure 3, the Welker design is an example of an externally mounted separator, while the Genie filter is an example of a separator placed before the regulator and internal to the pipeline. Note that if a filter is used outside the probe, the device must be able to maintain the sample at the temperature and pressure of the source stream to avoid sample distortion.

3.4 Constant Pressure Sample Cylinders

A constant pressure sample cylinder, also known as a floating piston cylinder, is shown on the next page in Figure 4. The cylinder is a tube with removable end caps that houses a moving piston. The end caps are removable to allow access to the piston, and also hold taps for valves, gauges or connections.

The inside surface of the cylinder is honed to allow o-rings on the edge of the piston to create a seal between samples or gases on opposite sides of the piston, while still allowing the piston to move freely. In some applications, an inert gas is charged to one side of the cylinder to create backpressure as a sample enters the other side (Reference 1). This approach is useful because it provides a controlled environment for the sample.

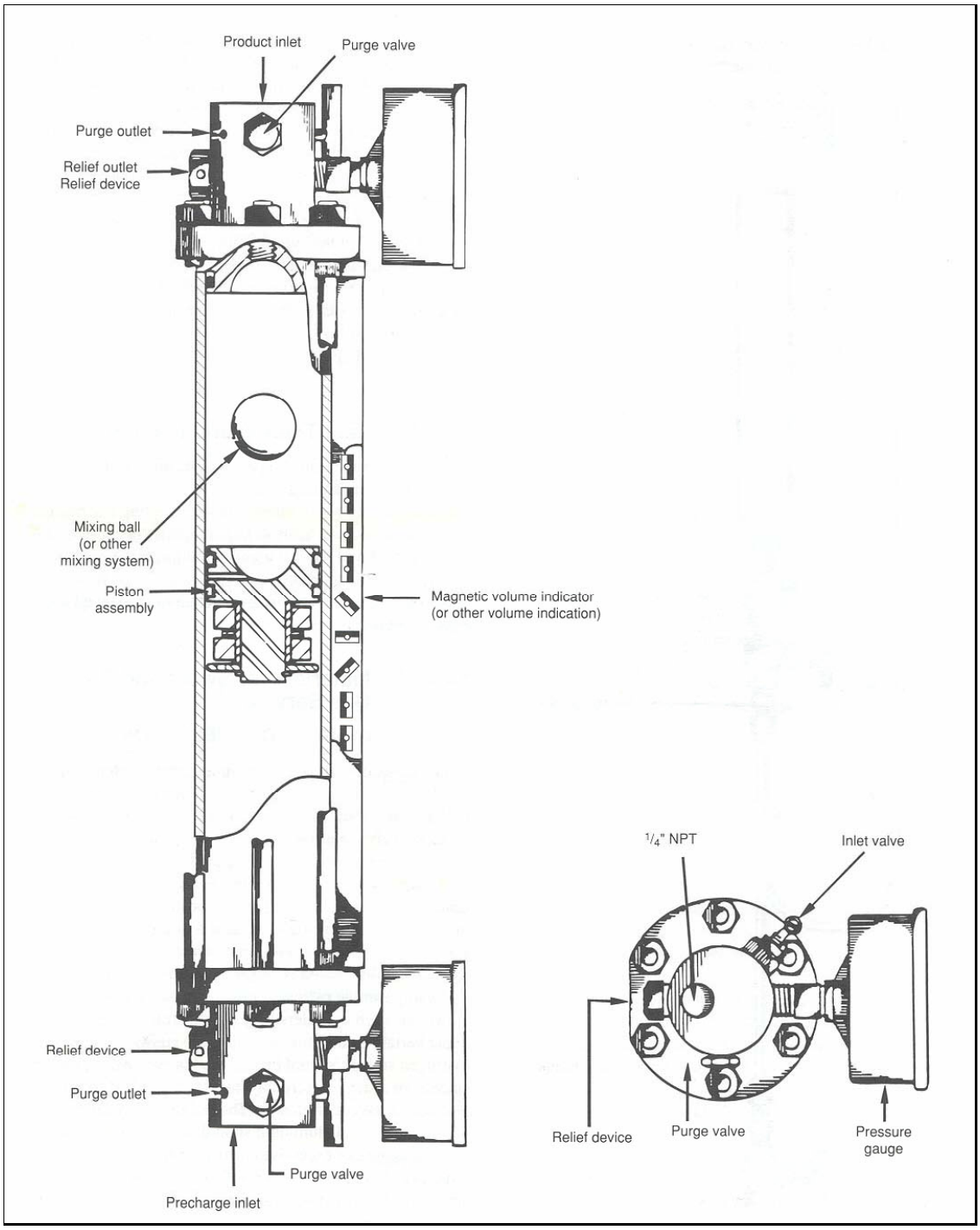

Figure 4. Typical constant-pressure sample cylinder (Reference 1).

Some manufacturers advocate the use of constant-pressure sample cylinders to sample both phases of a wet gas stream without a separator. If the cylinder can be prepared correctly, the pressure and temperature of the wet gas stream could be maintained as the sample enters the cylinder, and a phase change could potentially be avoided in the sampling process. In one proposed sampling method, the cylinder would be stored vertically for 24 hours, with the sample kept at the pressure and temperature of the wet gas stream. The long storage time would allow liquids to settle to the bottom of the chamber. After 24 hours, a sample of the gas phase would then be drawn through the inlet at the top of the cylinder, with pressure and temperature held constant. Next, the cylinder would be rotated 180 degrees and stored for another 24 hours. The settled liquids would then be drawn from the bottom of the cylinder. This method involves two key assumptions: (1) that the mixture can be sampled uniformly by the cylinder and the probe, and (2) that the sample would be representative of both phases of the wet gas stream. While studies have been performed to attempt to quantify the measurement uncertainty associated with samples drawn from dry gas streams using constant-pressure cylinders (Reference 15), the authors are not aware of any similar performance assessments for wet gas streams.

3.5 Sight Glasses

Sight glasses are windows or transparent columns, built to withstand high pressures and temperatures, that allow operators to see liquids accumulate within a sampling device. Devices with sight glasses are made by several manufacturers. An example of a sight glass, made by Welker Engineering to be incorporated into a sample line, is shown in Figure 5. Sight glasses can be extremely useful in helping to control the flow into a sampling container, or to manipulate the pressure and temperature within the sampling container to avoid liquid condensation. Some users depend on devices with sight glasses to identify whether liquids are present in the pipeline. However, if liquids are seen in a sample, the key question that inevitably must be answered is whether the liquids were present before the hydrocarbon mixture passed into the sampling device, or whether the act of sampling created condensate inside the device. Clearly, sampling devices with sight glasses are most useful when the original stream in the pipeline can be confirmed as a single gaseous phase, and the sight glass is used to avoid condensation (Reference 13).

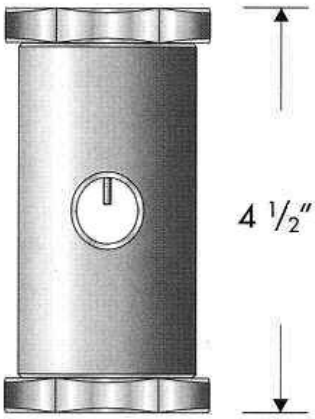

Figure 5. In-line sight glass for visual identification of liquids in sample streams. Reproduced with permission of Welker Engineering.

3.6 Heating of Regulators, Valves and Sampling Equipment

In this method, heat tracing is used to keep surfaces in contact with the gas stream above the hydrocarbon dew point temperature. This technique is commonly used to prevent condensation of the gas phase after it has been extracted from the flowing stream. This technique may be more costly than other methods to avoid gas phase condensation, particularly if the sampling location is far downstream of a separator. The method must also be used carefully to avoid sample distortion. For example, if liquid droplets are ingested into a sample of the gas phase, and the sampling equipment is heated, the liquid may vaporize and distort the composition of the gas phase sample. However, if heat is applied to a gas immediately upon exiting a separator that is effectively separating the gas and liquid phases, the gas composition will remain unchanged. Some experts in the natural gas industry advocate the technique of combining heating with a sample separator, while others cite the potential for large errors from sample distortion (References 7, 8 and 9). Clearly, the technique must be used carefully, but may provide representative samples of the gas phase of a wet gas flow.

4.0 Metering Technologies for Wet Gas Streams

The previous chapter reviewed several methods of sampling wet gas streams to determine the composition of the gas phase, or both the gas and liquid phases. Often, it is necessary to determine if wet gas is present before using the appropriate sampling method. The meters and technologies described in this chapter could potentially be used to make such a determination.

4.1 Existing Technology

As discussed by Ting (Reference 16), current wet gas metering technology falls into three general categories:

- Commercial gas meters – these must be used with a separate *a priori* determination of the liquid flow rate to correct the gas flow rate measurement, and are subject to large measurement uncertainties if the liquid flow rates vary significantly.
- Wet gas meters – these measure gas and liquid flow rates simultaneously, and have not yet been extensively evaluated by third parties.
- Separation meters – these use a gas/liquid separation device to produce a gas stream and a low-gas multiphase stream. The gas stream can be measured with a conventional gas meter, while a commercial multiphase meter can be used to measure the liquid stream.

Since the intent is to identify meters that can determine the presence of liquids in wet gas streams, all but one of the meter designs discussed in this section fall into the category of wet gas meters. The last device is a rotary separator that may also be useful in measuring gas flow rates in wet gas flows.

4.1.1 Coriolis Meters

Coriolis flow meters infer the mass flow rate of a fluid by measuring a phase shift in the frequency of a vibrating tube containing the flowing stream. The shift in oscillation from the natural frequency of the tube is proportional to the Coriolis force acting on the tube. The Coriolis force, in turn, is proportional to the mass flow rate of the flowing fluid, as shown in Figure 6. The basic formulas for mass flow rate through a Coriolis meter include only properties of the meter itself, though actual meters must be calibrated for the fluid being measured. Coriolis meters have traditionally been used in liquid applications, but recently the natural gas industry has taken interest in their application to gas flows. Manufacturers of Coriolis meters for natural gas applications include Micro Motion, Endress & Hauser and FMC Measurement Solutions. Because of the mechanics involved, these meters are typically limited to pipeline diameters of 6 inches or less (Reference 17).

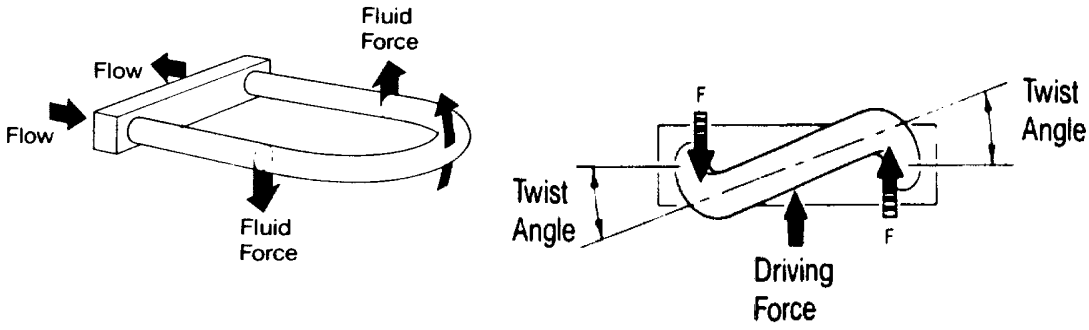

Figure 6. Principles of operation of a Coriolis meter (Reference 18). The driving force causes the U-tube to oscillate at its natural frequency. The Coriolis force is proportional to the fluid mass flow rate through the U-tube.

Early experiments in the 1980s (References 19 and 20) found that Coriolis meters held some promise for measuring total mass flow rates of gas-liquid flows and liquid flows containing solid particles. These may have generated initial interest in using the device for oil field applications. Tests of single-tube and dual-tube Coriolis meters in liquid flows by Grumski and Bajura (Reference 19) found that the meters could measure single-phase mass flow rates to within ±0.4% of reading. Air was then injected into a water flow to test the tolerance of the Coriolis meters to gas in the liquid. The single tube meter gave mass flow rate readings accurate to within ±2% for flows up to 1.5% gas by volume, then its accuracy dropped until complete failure occurred between gas volume fractions of 2.5% and 3.4%. The dual tube meter fared better; errors of less than ±2% were observed for gas volume fractions below 7.5%, and failure occurred between gas volume fractions of 16% to 20%. By comparison, commercial meters of other designs used in the United States for natural gas custody transfer are routinely capable of measurement accuracy of ±1% of reading or less.

More recent research (Reference 21) has continued to investigate whether Coriolis meters are able to measure the total mass flow rate of both gas and liquid phases. Experimental research at NOVA initially showed good results could be obtained for the total mass flow rate of both water and gas phases, if the volume of the liquid phase was determined independently. Research to determine if meters can be adapted for use in wet gas (hydrocarbon liquid and gas) streams may be ongoing, but results have not yet been made public. If Coriolis meters are found to be useful in this area, an analysis of measured changes in flow rate could signal users to the presence of liquids and the need for appropriate sampling methods.

4.1.2 The McCrometer V-Cone® Flow Meter

The V-Cone flow meter, manufactured by McCrometer, is a meter that uses differential pressure measurements to determine flow rates. Conventional orifice meters have a central opening for the flow, and pressure taps at the wall on either side of the orifice plate to measure the pressure drop of the flow through the orifice. The V-Cone also produces a differential pressure to measure flow rate, but the differential pressure is created by a cone whose axis coincides with the pipe axis (Figure 7). The fluid flows around the cone, and differential pressure is measured between a tap on the pipe wall and a second tap on the downstream end of the cone. According to the manufacturer, the design provides some "conditioning" of the flow field as it passes through the meter and, unlike conventional orifice meters, allows liquids to pass by the cone unobstructed. Flow conditioning reduces or eliminates the sensitivity of a meter to measurement error as a result of flow field distortion, such as velocity profile asymmetry or swirl.

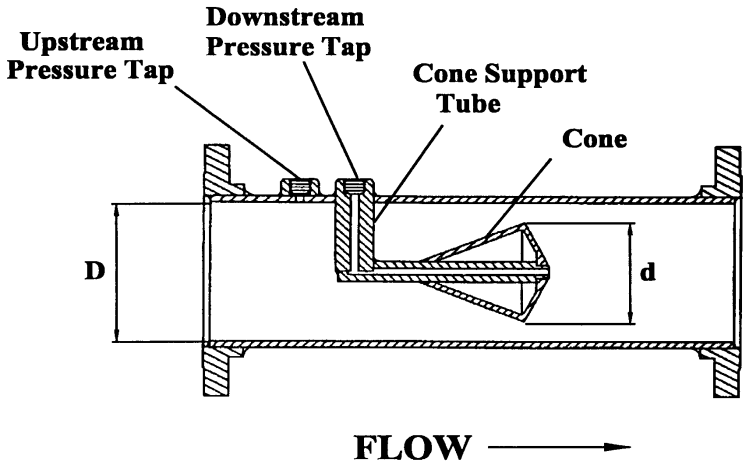

Figure 7. Interior geometry of a V-Cone Flow Meter (from McCrometer Publication 5M/GD/2-97/24509-10.)

McCrometer recently tested the usefulness of the V-Cone flow meter for measuring gas flow rates in wet gas flows. The tests were conduced in the NEL Wet Gas Loop in Scotland. Two V-Cone meters with different area ratios were tested in wet gas at three test pressures and over a range of gas and liquid flow rates. The different test conditions allowed the effects of gas density, gas velocity and liquid content on measurement error to be determined. The entrained liquids had a clear and repeatable effect on the V-Cone meters, causing them to over-register the gas mass flow rate in wet gas flows. However, this over-registration was found to depend on the amount of liquid present, the pressure of the flow and the gas flow rate itself. This suggests that the V-Cone could be used with another device, sensitive only to the gas flow rate, to indicate the presence of liquids in the flowing stream.

Correlations were created for the V-Cone meters that corrected the mass flow rate for the liquid-induced error. For the most part, the measurement uncertainty of these correlations was ±2% of reading (Reference 22). It is expected that the uncertainty in the corrected volumetric flow rate of the gas stream would be slightly larger.

4.1.3 The Agar Wet Gas Meter

A meter design from the Agar Corporation determines both gas and liquid flow rates through a combination of dissimilar flow sensors. The wet gas meter design is actually a portion of a patented, multiphase flow meter (the 400 Series MPFM, also sold by Agar) that is advertised for use in three-phase flows involving oil, water and gas. The wet gas meter design uses a vortex shedding meter in combination with a patented, dual Venturi meter. The dual Venturi determines the gas volume fraction in a two-phase stream, while the vortex shedding meter determines the total volumetric flow rate. By combining these quantities with data on liquid and gas densities, the mass flow rates of the liquid and gas phases can be determined. A non-zero liquid flow rate in a pipeline would signal to the user that wet gas sampling methods should be applied.

According to company literature, the mass flow rate of each phase can be determined by the Agar Wet Gas Meter to within ±5% of reading plus ±0.1% of full scale value. The device is designed primarily for streams with gas volume fractions of 90 to 100%, such as the wet gas streams of interest here. Tests of the complete multiphase flow meter, including the Wet Gas Meter, have been published in the literature (References 23 and 24). These tests found that the total flow rate determined by the MPFM for the combined oil, water, and gas phases were in agreement with the reference loop to about ±2% of reading. However, the flow rates for the individual phases were accurate to ±2% of full scale, or ±10% of reading. (As mentioned earlier, custody transfer meters for natural gas are routinely capable of ±1% of reading accuracy.) It was concluded that the MPFM can handle flow conditions with gas volume fractions up to 99.4% to accuracy within the vendor's specifications. No information on separate tests of the Agar Wet Gas Meter have been found in the open literature.

4.1.4 The Solartron ISA Dualstream II Wet Gas Flow Meter

The Dualstream II, marketed by Solartron ISA of the United Kingdom, is another wet gas meter that uses multiple devices to determine both gas and liquid flow rates. Like the Agar Wet Gas Meter, the Dualstream II works best when minimal amounts of liquid are present, as in wet gas flows. The meter technology was originally developed by Advantica (formerly the R&D division of British Gas PLC) and licensed to Solartron ISA. According to information from the Solartron website (www.solartronisa.com), the unit consists of a classical Venturi located between two specially-designed differential pressure (DP) flow meters. The first DP device simply serves as a flow conditioner, while measurements from the Venturi and second DP device are used to infer the gas and liquid flow rates. While no third-party evaluations or published literature on the performance of the Dualstream II have been located, Solartron literature states that the meter determines the gas and liquid flow rates with measurement uncertainties of ±5% of reading for gas and better than ±10% of reading for liquid.

4.1.5 Use of a Rotary Separator as a Wet Gas Meter

Ting (Reference 16) recently reported on tests of an inline rotary separator that also showed promise as a meter to measure the flow rate of the gas phase in a wet gas stream. The device under test was an IRIS™ separator manufactured by Multiphase Power and Processing Technologies, LLC. Unlike conventional static separators, the IRIS device includes a rotor assembly that collects liquids on its outer wall. An inlet swirl generator directs the flow to the "separation zone" at the rotor, where the rotating flow acts as a centrifuge to force the liquid to the outer wall of the rotor. Dry gas exits through the center of the separator, while the separated liquid on the drum wall spins off and moves along the outer wall toward a drain.

During tests, it was discovered that the gas flow rate in wet gas conditions could be inferred by measuring the rotor speed. At liquid-to-gas ratios of 3% or less, the rotor speed demonstrated low sensitivity to the liquid flow rate, and the gas flow rate could be estimated to within ±5% of reading accuracy using only the rotor speed for dry gas conditions. At higher liquid loadings, the rotor speed dropped off due to increased fluid drag, and at a constant gas flow rate, the reduction in rotor speed was found to be proportional to the liquid flow rate. Calibration of the rotor at flowing conditions, with several liquid/gas ratios, was suggested to develop a speed curve for interpolating gas flow rates. For this device, a drop in rotor speed could act as a simple indicator of a wet gas flow, requiring appropriate sampling methods.

4.2 Technology Under Development

The previous section reviewed meters and equipment that are commercially available, and are now sold or have been proposed for use as meters in wet gas flows. This section presents technologies that are still in the development stage, but may be of interest to those involved in wet gas sampling research. These technologies may someday be incorporated into sensors that could be used to detect two-phase flow, and would alert personnel of the need for an appropriate wet gas sampling method before sampling begins.

4.2.1 Pattern Recognition Techniques

These techniques were first developed by engineers dealing with flow abnormalities and the resulting behavior of meter outputs. The proposed concept, described in technical briefs by NEL (References 25 and 26), uses an analysis of multiple sensor outputs and variations in sensor response to determine properties of the wet gas stream. Current metering technologies are made to filter out the interference of noise, which is often associated with liquids in the wet gas stream. Such noise is essential to analyzing multiphase flows, however, as the unfiltered signal contains potentially useful information about the liquid phase behavior. A typical "intelligent system" would combine techniques for measuring phase volume fractions, such as gamma densitometry or electrical impedance tomography, with more conventional meters for measuring phase velocities or flow rates such as ultrasonic meters or Venturis. The system would then apply statistical analyses, neural networks, knowledge-based systems, or other pattern recognition (PR) techniques to objectively estimate phase flow rates from patterns in the unfiltered signals.

Pattern recognition techniques are also advocated as tools for identifying multiphase flow regimes and changes in the physical behavior of the flow. Combined with appropriate sensors, a PR technique could potentially be used to notify a high-vapor sensor or high-water sensor of the presence of liquids or certain components in the flow. Combinations of sensors could be turned "on" and "off" to gather appropriate data for the wet gas flow, depending on the PR analysis. At present, PR techniques can be used to enhance the performance of certain gas or liquid sensors. No standard exists for the application of such techniques to multiphase flows, however, and the area of wet gas flow measurement has not yet adopted PR measurement techniques. This may be due to the fact that pattern recognition tools must be

customized to the sensors and the application, and cannot be treated as a "black box" that universally solves all measurement needs. The technical briefs by NEL (References 25 and 26) list research reports on the techniques, as well as needs that must be met for the implementation of pattern recognition in the oil and gas industry. Once applied, however, PR techniques could readily be used as wet gas indicators for sampling technicians.

4.2.2 Gamma-Ray Absorption

Several methods used to measure phase volume fractions in multiphase flows involve radiation, such as neutrons, gamma rays, or x-rays, that is partially attenuated by the flow. Information about local density or phase distributions can be obtained by measuring the attenuation of radiation through the flow, or by triangulating the locations of radiation sources within the flow (Reference 27). Generally, because times on the order of minutes are required to collect statistically significant samples, radiation absorption techniques yield time-averaged results. As a result, they are better suited for flows where the amounts of each phase are stable over long periods. Gamma-ray methods also require that the gas and liquid phases have significantly different attenuation properties for useful quantitative results. The methods have the advantage of being nonintrusive, however, which is helpful if the gas and liquid phases are to remain separated and unmixed.

Simple applications of this technique are used in several commercially available meters for wet gas and multiphase flows. A simple gamma densitometer, shown in Figure 8, consists of a single gamma ray source and one or more detectors on opposite sides of the pipe. The detectors measure the intensity of gamma radiation reaching them through the fluid. The amount of gamma radiation absorbed by the fluid is a function of the fluid density and the attenuation properties of the fluid. A comparison of the number of gamma rays reaching the detector to the number emitted by the source reveals the fluid density. In the case of multiphase flows, the resulting density is a weighted average over the length of the beam (References 28 and 29). Standard applications use a broad beam of gamma rays from a single source to cover a large region of the flow, but if the phases are separated, as in a stratified flow, the measurement of gamma absorption may not easily yield information on the phase volume fractions, due to the weighted averaging process (Reference 30). The method could, however, signal the presence of liquids through a simple change in the beam-averaged density in the pipe.

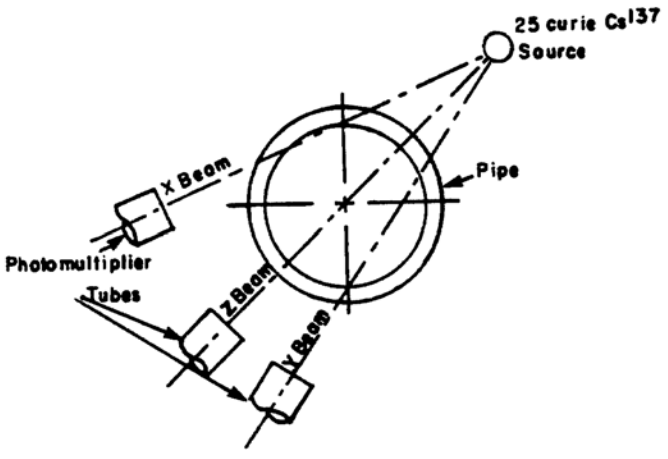

Figure 8. Conceptual design of a three-beam gamma densitometer (Reference 29).

Research is ongoing to improve the usefulness of gamma radiation techniques. NEL (Reference 30) recently reported on tests of a triple-beam gamma densitometer that enabled local measurements of the mixture density in an air/water flow along three different beam paths. A post-processing program was used to calculate the gas volume fraction along each beam, and the shape of the interface between the gas and liquid in stratified flows. The method performed "successfully" for flows with medium to high gas fractions, such as wet gas flows, and was found to be an improvement over systems using a single gamma-ray beam.

The triple-beam device tested by NEL represents an intermediate step between single-beam commercial devices and an experimental technique known as gamma-densitometry tomography, or GDT. This technique measures the attenuation along many different paths through the flow, and combines the information using linear tomographic reconstruction methods to produce an image of the phase distribution in the flow. This would be useful information in selecting sampling locations within a pipeline. GDT has been investigated for some time as a tool for multiphase flows, and References 31 and 32 provide comprehensive reviews of the technique. However, because wet gas flows typically involve small amounts of liquid, the data collection times needed for GDT to resolve liquid amounts in wet gas flows may be prohibitive. The multiple-beam technique described by NEL may be a more practical approach to wet gas identification at the present time.

4.2.3 Electrical-Impedance Tomography

Another class of non-intrusive techniques for measuring gas and liquid volume fractions in a multiphase flow relies on measurements of the variation in electrical properties of the flow to provide an image of the pipeline contents. A general name for the method is electrical-impedance tomography, or EIT. Depending on the properties of the flow, the instrumentation may actually determine the resistance, capacitance or complex impedance of the flow to locate the gas and liquid phases.

In EIT, a number of electrodes are mounted to the surface of a pipe wall or other structure housing the flow. As a controlled current is injected into the flow at one electrode and withdrawn at another electrode, voltages are measured at the remaining electrodes (Figure 9). These voltage measurements at the flow boundary are used to reconstruct the impedance distribution within the domain. Finally, the phase distribution is inferred from the computed impedance distribution. The equations that relate the impedance and voltage distributions in the flow must be solved iteratively to obtain the impedance distribution that corresponds to the measured boundary voltages. In some applications, a controlled voltage is applied to the electrodes and the current is measured, but the same iterative process is followed to arrive at the phase distribution of the flow.

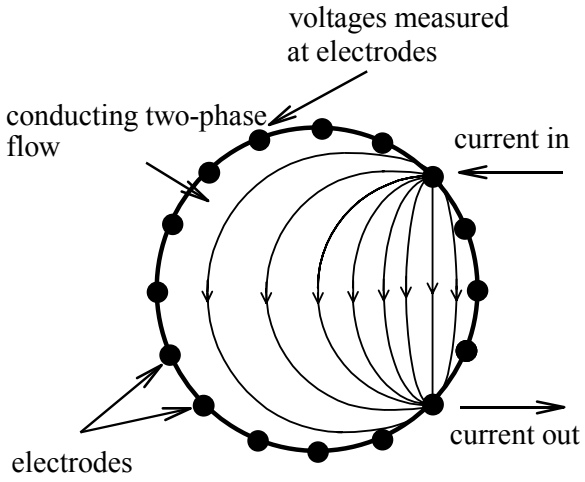

Figure 9. Conceptual diagram of an EIT system applied to a wet-gas pipe flow (adapted from Reference 33).

The resolution of the image of the phases is strongly related to the number and size of electrodes on the wall. As the number of electrodes and the resolution increase, the sensitivity to noise increases as well. At present, few systems are capable of real-time imaging of the phase distribution, but this is an eventual goal of much EIT research. More information on EIT theory and the development of EIT systems for the study of multiphase flows may be found in articles by Dickin *et al.* (Reference 33) and Ceccio and George (Reference 34).

Several studies of the accuracy of EIT in gas-liquid flows have been conducted at Sandia National Laboratories (References 35 and 36). The Sandia system was initially used to measure air-water distributions in a vertical column resembling a chemical reactor. Rather than concentrate on imaging the phase distribution, this work sought to improve the accuracy of measured gas and liquid volume fractions at different locations in the column. For flows with gas volume fractions from 0 to 15%, the average values and radial gas distributions determined by EIT agreed with measurements from a gamma densitometry system to within 1% of volume fraction. Though these bubble column flows differ from wet gas pipeline flows, the tests suggest that EIT may be capable of accurately measuring volumes of gas and liquid in such flows. Work has also begun on an EIT system capable of operating in an electrically conducting column (Reference 37), which would enable the concept to be applied in pipeline environments.

More relevant tests of EIT technology were conducted at NEL with a mixture of crude oil, water and nitrogen (Reference 37). In the NEL tests, an electrical capacitance tomography (ECT) system was installed around a Perspex spool piece through which the horizontal three-phase flow could be videotaped. While the system successfully visualized the various flow regimes, quantitative measurements of the gas volume fraction showed significant errors (on the order of 20% of reading) when the water cut of the three-phase flow exceeded 5% by volume. Volume fractions of two-phase oil and water flows could be more accurately measured with ECT, particularly at low flow rates. Improvements in the reconstruction algorithm, or the use of ECT with other measurement techniques, may be needed to improve the accuracy of volume fractions determined by this method. Improved accuracy will be needed for EIT to eventually be acceptable for oil and gas allocation, and eventually for the identification of wet gas flows.

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5.0 Capabilities of Potential Test Sites for Wet Gas Sampling Methods

Previous chapters have reviewed techniques for sampling and metering wet gas flows. The ability to accurately sample saturated and low-liquid-content gas streams is considered critical for gas quality management in the United Kingdom, and is expected to become critical for future gas quality management in the United States. As new wet gas sources are explored and new sampling methods are developed in response, determining the accuracy of these new methods is crucial. Even if the liquid phase need not be measured, equipment and practices that ignore the liquid phase in order to sample or measure the gas phase correctly need to be developed and proven. Recognizing this, the API MPMS Chapter 14.1 Working Group asked SwRI personnel to identify facilities that can create saturated or low-liquid-content hydrocarbon flows, document their capabilities, and decide if any existing facilities would be useful as test sites for sampling separators and other wet gas sampling equipment.

Five existing facilities in the United States and Europe were identified as having the ability to create saturated or low-liquid hydrocarbon flows. The facility operators were asked to participate in a survey characterizing their facilities' ability to establish the conditions required to conduct rich gas and wet-gas sampling tests. Four of the five facility operators completed and returned surveys about their pressure and temperature conditions, gas, water and hydrocarbon liquid compositions, flow rates, measurement accuracies and equipment traceability. The responses of the four participants are reproduced in Table 1 at the end of this chapter. As specified by an agreement with the participants, the facilities have not been identified by name in this report. Specifications have been converted to British units, where necessary, to allow direct comparisons.

An ideal facility for testing wet gas sampling methods would recreate the range of flow pressures, temperatures, gas and liquid compositions and flow regimes found in natural gas production and transmission systems. While no one facility has all the ideal characteristics, three of the four sites have a wide range of flow conditions. Facility D uses an existing pipeline as its source of natural gas, and injects liquids into the test section to create wet gas flows. The reported gas and liquid flow rates suggest that Facility D could create wet gas flows with small amounts of hydrocarbon liquid, which are of interest to the API MPMS Chapter 14.1 Working Group. Because flow conditions at Facility D are tied to pipeline conditions, wet gas sampling methods could be tested only over relatively small ranges of pressure and temperature. The other three facilities can operate over wider ranges of pressures representative of production and transmission conditions. Facilities A and C can create flows from 40 to 120ºF, a temperature range where pipeline flows can reasonably be expected to occur. Facility B cannot simulate winter temperatures below 68ºF, but can create flows simulating summer temperatures.

All facilities can create wet gas flows with a wide range of liquid hydrocarbon compositions. Facilities A and C can also operate with gas streams of varying compositions. Accounting for the range of line pressures, all four facilities can potentially operate at gas volumetric flow rates of interest to the U.S. natural gas industry. However, none of the facilities use line sizes larger than 8 inches in diameter, which may be of concern if geometric scaling becomes a significant technical issue. The liquid mass flow rates are sufficient for creating wet gas flows of interest, as well as other flow regimes involving higher amounts of liquid.

The methods used to determine the gas compositions of the flows vary among the facilities, but methods of determining the liquid compositions are similar. Facility B uses a separation technique to sample the gas phase from the flow, which may be expected to give a representative analysis of the gas phase. Facility B samples the liquid phase before it is injected into the flow, although there is no mention as to whether or not the liquid phase is sampled after it reaches equilibrium with the gas in the flow. Facility D uses a regulated, temperature-compensated probe connected to an on-line gas chromatograph to determine the gas phase composition of the flowing stream. This method might also be expected to obtain a representative analysis of the gas phase. The liquid phase is manually sampled and sent by

Facility D to a lab for analysis. Facility A also uses an on-line gas chromatograph to sample the gas phase, but does not discuss any details of the probe used. This facility routinely draws spot samples of the liquid phase and sends them to a lab for extended analysis, but can use other liquid sampling methods as required. Finally, Facility C currently uses spot sampling methods to determine the compositions of both the gas and liquid phases.

A key task in future sampling work will be defining the "reference" phase compositions used to judge the accuracy of any sampling method being evaluated. Currently, the API MPMS Chapter 14.1 Working Group is preparing a verification test protocol for new methods of sampling gas-only streams. The draft protocol includes specific steps for independently determining the gas composition, so that a benchmark exists for the performance of the sampling method being tested. A similar procedure, including steps to identify the "reference" gas and liquid phase compositions, will be necessary if wet gas sampling methods are to be evaluated.

In summary, of the four facilities surveyed, all have the ability to create wet gas flows suitable for testing sampling methods. Three of the four can produce a wide range of flow pressures and temperatures of interest, and two of the four have the capacity for testing sampling methods under a range of gas and liquid compositions. An issue that must still be addressed before sampling methods are evaluated is the means of determining the "reference" gas and liquid compositions that the sampling methods must accurately reproduce. This will require research by the facilities or a consensus by an appropriate standards group, such as the API MPMS Chapter 14.1 Working Group.

Table 1. Specifications of potential test sites for wet gas sampling methods.

		Facility A	Facility B	Facility C	Facility D
1	Minimum line pressure rating:	100 psig	435 psig	50 psig	800 psi (625 psi downstream of nozzles)
2	Maximum line pressure rating:	1440 psig	2260 psig	3600 psig	870 psi (700 psi downstream of nozzles)
3	Pressure control tolerance:	±1 psig		Approximately 2 psig	None (pipeline pressure)
4	Minimum temperature rating:	40 °F	68 °F	40°F (can be lower with chiller modification)	41°F (winter)
5	Maximum temperature rating:	120 °F	140 °F	120°F	60°F (summer)
6	Temperature control tolerance:	±2 °F		Approximately 2°F	None (pipeline gas temperature)
7	Gas composition range:	1,000 to 1,500 BTU/ft^3.	Dry Gas: 83% C_1, rest C_2. Rich Gas: 78% C_1, 10% C_2, 6% C_3, 0.8% IC_4, 1.7% NC_4, rest C_{5+}.	As requested by customer.	
8	Liquid hydrocarbon (HC) composition range:	Various mixtures containing C_3 through C_{12}, with C_9 through C_{11} as the predominant components.	All kind of liquid hydrocarbons. Stabilized condensate and naphtha is readily available on site. Stabilized condensate mainly $C_5 - C_{10}$.	As requested by customer.	Various compositions can be injected.
9	Water content range:	Depending upon the test, the water content can range from dry gas to a free liquid flow of 135 GPM.	0-100%	0% to 100%	< 4 lbs/MMSCF
10	Minimum gas mass flow rate:	0.3 MMSCFD	0.034 MMACFD (~1 MMSCFD of gas at 435 psig)	0 (liquid-only flows)	3 MMSCFD

Table 1 (continued).

		Facility A	Facility B	Facility C	Facility D
11	Maximum gas mass flow rate:	50 MMSCFD	1.7 MMACFD (~260 MMSCFD of gas at 2260 psig)	0.1 MMACFD (~24.6 MMSCFD of gas at 3600 psig); 0.21 MMACFD (~52 MMSCFD at 3600 psig) with motor change.	87.4 MMSCFD
12	Minimum liquid HC mass flow rate:	70 lb/hr	0.35 ACFH (~14.5 lb/hr assuming n-C_6)	0	N.A.
13	Maximum liquid HC mass flow rate:	25,000 lb/hr	7,060 ACFH (~292,000 lb/hr n-C_6)	4680 ACFH (~194,000 lb/hr n-C_6); 9000 ACFH (~373,000 lb/hr n-C_6) with motor change	N.A.
14	Minimum water mass flow rate:	70 lb/hr	0.35 ACFH (~22 lb/hr)	0	N.A.
15	Maximum water mass flow rate:	5,000 lb/hr	7,060 ACFH (~441,000 lb/hr)	4680 ACFH (~292,000 lb/hr); 9000 ACFH (~562,000 lb/hr) with motor change	N.A.
16	Drying/cleaning limits and practices:	Separators to catch free liquids, and a dehydrator unit to remove water vapor.	Flushing with liquids (water, methanol, etc.).	Filter coalescer on liquids side to remove water. Cyclone separators currently used to remove liquids from gas stream. Separators will be augmented with a gas scrubber in the near future.	N.A.
17	Liquid injection methods and specifications:	Positive displacement pumps (tri-plex) to inject liquids through spray nozzles.	Liquids are recycled and injected via high-pressure pump. Possible to install injection nozzles of different types.	Flow from high to low pressure or positive displacement pump.	Injection nozzles and pump with capacity up to 8 gal/min.

Table 1 (continued).

		Facility A	Facility B	Facility C	Facility D
18	Gas sampling methods and specifications:	On-line gas chromatograph measuring components to C_{9+}.	Gas is sampled after separation and after compressor, i.e., sampling is performed on one phase flow. Standard refinery lab procedures and equipment are used.	Spot sampling.	Welker probe (temperature compensated pressure regulator) to GC (±1Btu).
19	Liquid sampling methods and specifications:	Spot samples drawn periodically and sent to labs for extended analysis. A particular sampling method can be initiated for any specific test.	Liquid is sampled before injection into the one-phase gas stream to create the wet-gas flow.	Spot sampling.	Manual sampling and lab analysis.
20	Gas analysis procedures (sampling/GC):	See 19 above. In addition sample cylinders can be sent to labs for extended analysis.	Gas analysis by GC.	Send sample to commercial lab.	On-line GC (±1Btu) using a continuous average.
21	Reference devices for gas flow rate:	Turbine meter and venturi meter	V-Cone meters, 8” and 3”	6” orifice meter	Choked nozzles (bank of 25) and gravimetric weigh tank
22	Reference devices for liquid HC flow rate:	Coriolis meters	Coriolis meters, 3”, 1” and ¼”	3/8”, 1” and 3” Coriolis	N.A.
23	Reference devices for water flow rate:	Turbine meter	Coriolis meters, 3”, 1” and ¼”	3/8”, 1” and 3” Coriolis	N.A.
24	Traceability of reference devices (NIST, NMi, etc.):	NIST traceable calibrations on all reference meters.	Coriolis and V-cone meters are calibrated at CEESI. Coriolis meters are factory calibrated.	6” orifice meter traceable to NIST, Coriolis meters calibrated at MicroMotion (traceable to NIST).	Pressure: NIST Temperature: NIST Weights: Measurement Canada

Table 1 (continued).

		Facility A	Facility B	Facility C	Facility D
25	Line diameters:	3" through 8"	Main line is 8", but may be able to test in smaller line diameters branching from the main line.	1" to 6"	3", 4", 6" and 8"
26	Two-phase flow regime(s):	Stratified through mist, depending upon gas superficial velocity.	From 0% liquid to 100% liquid.	All flow regimes in 2" and smaller diameters; annular flow possible in 3" and smaller diameters. Horizontal and vertical flow regimes possible.	Up to 5% by mass.
27	Capability to install test items:	The facility is located outdoors. Forklifts and cranes are available for large and heavy devices.	Good capabilities. The rig is designed to take in test items.	Yes.	33 to 49 feet length of test item.
28	Repeatability, reproducibility, and stability of flow conditions:	These parameters are very much flow related; however, an estimate of 1% can be used for most conditions.	Good. (See item 29.)	Have not yet been quantified.	±0.15%

29 Accuracy of measurements (including statistical confidence intervals):

(Note that respondents did not identify percent uncertainties as relative or percent of full scale.)

Facility A	A complete uncertainty analysis is now being prepared. The gas mass flow uncertainty will be approximately 0.9%, the liquid mass flow will be approximately 0.5%, and the liquid density will be about 1% at a 95% confidence interval.
Facility B	Not yet developed. This will be done in February 2003.
Facility C	Approximately 1% or less, varies with flow rate (U_{95}).
Facility D	±0.25%.

Table 1 (continued).

30 Type of research projects conducted at this facility in the past:	
Facility A	Wet-gas metering effects through an industry JIP. Hydrate research through DOE and gas storage consortium. Gas sampling studies through GRI and SwRI.
Facility B	We have and can in the future test all kinds of equipment; pumps, compressors, valves, meters, analyzing equipment and so forth. Two projects have recently been performed on development of multiphase meters.
Facility C	Wet gas metering, multiphase metering, wet gas sampling and hydrate research.
Facility D	Metering, compression, pipeline.
31 Facility specialization or unique features:	
Facility A	Gas flow calibrations and specialized research studies.
Facility B	High pressure, high gas- and liquid flow. Able in some cases to do tests simultaneously. Very good infrastructure. Location is on site of a large gas treatment plant. Therefore we have steam, nitrogen, and compressed air at hand. We are also connected to the gas treatment plant with rich and dry gas.
Facility C	High-pressure rating; 1,300 ft 1" test section.
Facility D	Instrumentation for pulsation effects, instrumentation for liquid contaminant effects, swirl generation and flow profile measurement.

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6.0 Conclusions and Future Research Needs

The measurement of wet gas is an essential research topic for the oil and gas industries of the United States and Europe. Wet gas will be encountered more often as the world's exploration moves into untapped fields of oil and natural gas, and as existing fields are depleted. Production and transmission companies will have to deal regularly with gases containing higher amounts of heavy hydrocarbons. To address this issue, this report has reviewed standards, equipment and test facilities of interest to companies that deal with wet gas streams. The main focus of this review has been methods for sampling wet gas streams to determine the composition of the gas phase and, if desired, the liquid phase. The API MPMS Chapter 14.1 Working Group and the U.S. Minerals Management Service requested this information, because the heating value and other properties of a natural gas stream, determined from samples of the stream, are required for equitable custody transfer.

The key conclusions of this review are listed below.

- Most of the current research and development in wet gas sampling is occurring in the United Kingdom. This research appears to have been stimulated by the North Sea gas industry, where production and transmission companies regularly handle wet gas, and economic and regulatory pressures have encouraged such research. New production sites worldwide, particularly offshore production sites, also produce wet gas streams. Other regions of the world could potentially benefit from wet gas sampling technology, if economic benefits or pipeline integrity benefits are identified.
- The present technology for metering and sampling wet gas flows is not as advanced or as robust as analogous technology for single-phase flows. For example, the most accurate wet gas flow rate measurements are not as accurate as single-phase flow rate measurements. Because the accuracy requirements of allocation are not as tight as the requirements for custody transfer, this does not appear to be a concern as yet.
- Overseas, technology for sampling wet gas streams has concentrated on obtaining samples of the liquid and gas phases simultaneously. Likewise, measurement technology seeks to determine the flow rates of both phases in the same stream. It is generally accepted in the United Kingdom that handling both phases is more cost-effective than separating the phases and measuring or sampling the separate streams. In contrast, sampling practices and standards in the United States are based on the premise that accurately sampling the composition of the phases, particularly the gas phase, requires the phases to be separated and handled without distortion. This has led to the development of regulated probes, filters, and other devices to obtain only a gas sample, and to prevent liquids from either entering the gas sample or forming from condensation of the gas.
- Facilities are available in the United States and elsewhere that can simulate a range of wet gas flows, and may serve as testbeds for evaluating wet gas sampling and metering techniques. However, work is still required to establish methods of judging the accuracy of new and existing wet gas sampling methods. This may involve the creation of a test protocol that includes a method of independently determining the gas and liquid phase compositions, and may also require work on the part of research organizations or the proposed test facilities to develop the methods.

This review identified several topics that are recommended for further research. As wet gas is encountered more often and companies must deal more often with wet gas streams, these issues must be addressed.

- The accuracy of existing wet gas sampling methods must be assessed for the benefit of production and transmission companies that will use them. In the United States, the more

common sampling approach is to obtain a representative sample of only the gas phase. The accuracy of methods that use this approach will depend on their effectiveness in obtaining a representative gas phase sample, and on their ability to deliver the gas sample to the analysis point without phase change. Independent testing can determine whether existing methods can accomplish these steps effectively. After testing, production and transmission companies in the United States can apply these methods to wet gas flows with less potential financial impact. Sampling methods used in Europe have been evaluated, but no independent results are yet available in the open literature.

- A testing protocol must be developed to assess existing and future wet gas sampling methods. Such a protocol might describe the requirements of test sites, the equipment needed for analyzing sample streams, testing preparations, test procedures, data collection requirements, and acceptance criteria. A test protocol would allow many sampling methods to be evaluated on an equal basis, by users or by independent investigators, under the same conditions. The API MPMS Chapter 14.1 Working Group has recently developed a testing protocol for single-phase gas sampling methods that could serve as a model for this.
- Methods of determining reference phase compositions and flow rates in potential wet gas test facilities must be verified. This is crucial to determining whether samples are representative of the phases in the flowing stream. The traceability of single-phase flow quantities is common. For example, facilities that calibrate meters for natural gas custody transfer must establish the traceability of their flow rate references to an accepted national or international standard. Similarly, the single-phase sampling test protocol developed by the API MPMS Chapter 14.1 Working Group includes specific steps for determining the gas composition, so that a benchmark exists for the performance of the sampling method under test. The review of potential wet gas test sites in Chapter 5 found that methods used to determine the gas composition in the flows vary widely among facilities. Some facilities analyze the phases after they are separated from the wet gas flow, while others analyze the compositions of the phases before they are introduced into the test section. In either case, procedures to confirm the "reference" gas and liquid phase compositions will be necessary to confirm the effectiveness of wet gas sampling methods.
- Research into European wet gas sampling methods should be expanded. As mentioned above, the common European approach to analyzing wet gas streams is to measure the flow rates of both phases *in situ*, rather than to separate the phases and measure or sample the separate streams. European research on wet gas sampling methods has been conducted, but is not yet available. Discussions with Europeans experienced in wet gas sampling may identify other sampling methods used in Europe that are more effective than methods now used in the United States. Information on the cost effectiveness, advantages and disadvantages of sampling and measuring wet gas flows *in situ* would also be instructive.
- New methods for wet gas sampling must be developed. This report has described several methods for sampling the gas and liquid phases of a wet gas stream. None of the methods described here have been independently evaluated for their ability to produce a representative sample of the gas phase (or the liquid phase, if applicable). As production and transmission companies begin to deal on a regular basis with gases rich in heavy hydrocarbons, they will require accurate sampling and analyses of the gas phase to address custody transfer requirements. A research program to develop new methods for sampling in wet gas flows, or to improve the accuracy of existing methods, can address these anticipated needs.

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