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API WET GAS SAMPLING TECHNICAL REPORT

API TECHNICAL REPORT

First EDITION, TRxxxx, 2023

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Contents

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Abstract

The API Wet Gas Sampling Committee under API Committee on Production Measurement & Allocation (CPMA) conducted a study to identify potential sources of errors in the wet gas sampling of natural gas flow streams containing free liquids. The objectives of the study were to quantify measurement uncertainty associated with using dry gas methods to sample natural gas flow streams containing free hydrocarbon liquid, a.k.a. wet gas, and to provide recommendations for future wet gas sample testing.

A two-phase, two-component, binary gas mixture of methane and n-heptane was used as a testing media. The testing was conducted in a closed loop test facility at an elevated pressure of 700 psig in a three-inch pipe. The dry gas sampling method per API 14.1¹ (Collecting and Handling of Natural Gas Samples for Custody Transfer) section 12.8 purge-fill-and-empty (PFE) was used to gather the wet gas samples. Wet gas samples were analyzed using gas chromatograph methods and compared to measured reference gas flowrate and liquid flowrate streams. This report summarizes the wet gas testing methodology, test setup, test results, conclusions, lessons learned, and recommendations.

Disclaimer:

The dry gas sampling method per API 14.1 (Collecting and Handling of Natural Gas Samples for Custody Transfer) section 12.8 purge-fill-and-empty (PFE) was used to gather the wet gas samples in this study. *API 14.1 scope is limited to gas sampling at or above the natural gas hydrocarbon dew point. Furthermore, API 14.1 states: The sampling of multi-phase flow streams (free liquid and gas) should be explicitly avoided.*

1. Introduction

Current API/GPA standards only address dry gas sampling. Dry gas can be defined as gas at or above the saturation temperature at the operating pressure in the pipe with no free liquids present. Dry gas sampling techniques can produce large bias errors when free liquids are brought into the sampling vessel. Captured wet gas samples may not represent the true ratio of the gas and the liquid components in the flow stream. In two-phase flow, the gas and the liquid components are not homogenous; they flow at different velocities, and in different quadrants of the pipe. They are a function of the fluid's two-phase flow regime which depends on complicated wet gas parameters including the gas-liquid density ratio, superficial gas and liquid velocities, pipe diameter, interfacial tension, and other two-phase flow parameters. Upstream and downstream fittings and pipe elevation changes can create liquid "hold-up", areas where liquid velocities slow and occupy a larger percentage of the pipe. The objective is to determine if it is possible to characterize the uncertainty of wet gas sampling using dry gas sampling techniques.

¹ Note: API 14.1 scope is limited to gas sampling at or above the natural gas hydrocarbon dew point. Furthermore, API 14.1 states the sampling of multi-phase flow streams (free liquid and gas) should be explicitly avoided.

2. Wet Gas Physical and Technical Challenges

Extracting the correct liquid to gas ratio is crucial to obtaining a sample that represents a two-phase source. In a two-phase natural gas stream, the liquid phase contains high concentrations of the heaviest hydrocarbon components, the heaviest components have the highest heating value per unit volume, and a small volume of liquid expands to a large volume of gas. Uncertainty in the quantity of liquid included in a two-phase sample magnifies uncertainty in the composite fluid composition, which is the basis for determining heating value. Too much liquid in the sample and the heating value will be too high, too little liquid in the sample and the heating value will be too low.

The ratio of the gas mass flow rate to the liquid mass flow rate directly impacts the fluid's overall composition which in turn affects the BTU content traveling down the pipe. Extracting a wet gas sample from a single, discreet location in the pipe may not represent the true ratio between the gas and the liquid bulk mass flow rates. Liquids may not flow uniformly from the sampling probe's tip through the connecting tubing leading to the sampling vessel. Depending on the sampling fluid velocity in the connecting tubing, liquids can cling to the connecting tubing walls or collect in the connecting fittings. Depending on heat losses between the connecting tubing and the ambient air, the saturated gas flowing through the connecting tubing can further condense depositing additional liquids in the connecting tubing walls and fittings. Depending on the pressure drop from the sampling probe's tip to the sampling vessel, liquids clinging to the connecting tubing walls may flash or further condense and change the sample vessel's composition.

Existing analytical methods of a captured wet gas sample require the entire sample be raised to an elevated temperature that vaporizes all the sample's components. Since the components in the captured sample are not known a priori, one must guess the required elevated temperature to vaporize all the components. Additionally, sampling bottle seals are often not rated to the temperature required for complete vaporization.

Given the daunting challenges associated with wet gas sampling and the many variables that influence the results, the API Wet Gas Sampling Committee decided to conduct a limited-scope wet gas sampling study using a two-phase, binary mixture of methane and heptane. The goal of the study was to develop a testing methodology and analysis that could be used as a template for future testing on more complex mixtures that better represent wet gas components that exist in the field. Furthermore, the study aimed to quantitatively characterize the uncertainty of the wet-gas sampling used on the tested binary mixture.

3. Executive Summary

Wet gas samples of a two-phase, binary mixture of methane and n-heptane were taken in a controlled, closed loop test facility. The dry gas sampling method API 14.1 section 12.8 purge-fill-and-empty (PFE) was used and the resulting sampling errors were determined. Wet gas samples were analyzed using gas chromatograph methods and the resulting compositions were

compared to measured reference gas and liquid mass flowrate streams. The testing was limited in scope to 700 psig, temperature, constant gas rate, a three-inch pipe, and using only the API 14.1 Purge-Fill-Empty (PFE) method. The sampling probe tip was placed at a single elevation in the center of the pipe. The closed loop test facility used a gas-liquid separator, a multiphase pump to circulate the gas-liquid mixture, and a heat exchanger to control temperature. A calibrated orifice plate was used to measure the methane gas mass flow rate. A calibrated Coriolis meter was used to measure the n-heptane liquid mass flow rate prior to being comingled upstream of the sampling point. Methane gas mass flow rates and n-heptane liquid mass flow rates were measured in their respective single-phase measurement locations. Pressures and temperatures were monitored at various points in the system to maintain operating target conditions. A total of 28 wet gas samples were taken downstream of the gas-liquid mixing tee at four different Lockhart-Martinelli Numbers (XLM). Seven samples (six repeats) were taken at each Lockhart-Martinelli Number to determine repeatability. An expanded uncertainty analysis was performed and included both random and systematic errors in the flow loop reference standards, relevant flow loop instrumentation, the gas chromatograph wet gas sample analysis, and the mixing equations-of-state (EOS) model used in the analysis. The results are as follows:

- For all Lockhart-Martinelli Numbers tested (XLM=0.01, 0.015, 0.02, 0.025), more than 50% of the free liquids were missed using the dry gas sampling method.
- For all GVF's tested (GVF=99.8, 99.6, 99.5, 99.4), more than 50% of the free liquids were missed using the dry gas sampling method.
- At Lockhart-Martinelli Numbers of XLM=0.01, 0.015, 0.02, 0.025, the molecular weight bias error negatively increased from -1.8%, -2.9%, -3.1% to -4.2% respectively.²
- At Lockhart-Martinelli Numbers of XLM=0.01, 0.015, 0.02, 0.025, the resulting measured binary mixture's molecular weight expanded uncertainty at a 95% confidence level was 2.35%, 2.20%, 4.69% and 3.51% respectively.²
- Data suggest that as liquid loading increases, the dry gas sampling method misses over half of the liquid present in the flow stream.³
- The random error in the wet gas sampling (variability in the wet gas measured molecular weight) was (on average) 10 times larger than the saturated gas random error. This suggests sample extraction issues; specifically, the liquid in the pipe is not consistently making it from the tip of the sampling probe, through the connecting tubing and associated needle valves and into the sampling vessel. Alternately the large random error could be caused by

² The wet gas sampling work group did an independent uncertainty analysis to validate SWRI values. The values in the main body of this report here are from SWRI, while the workgroup values are listed in a separate spreadsheet available with this document.

³ **Warning: The reader of this report should not apply the results of this study unless all the conditions below are met:**

1. Results only apply to a methane/n-heptane binary mixture at 700 psig.
2. Results only apply to a 3" Schedule 160 pipe.
3. Results only apply to the API 14.1 "Purge-Fill-Empty (PFE)" sampling technique where the sampling probe is inserted into the center of a 3" pipe.
4. Results only apply to Lockhart Martinelli (XLM) numbers between 0.01 and 0.025. API Type I wet gas flow is defined as $XLM < 0.02$. API Type II wet gas flow is defined as $0.02 < XLM < 0.025$.

flow regime dependencies and the chaotic nature by which liquid flows with the gas in a 2-phase environment.

The testing scope and methodology developed by the API Wet Gas Sampling Committee along with lessons learned, and recommendations are presented herein.

4. Wet Gas Sampling and Testing Methodology Considerations

A description of the history and the importance of wet gas sampling can be found in Appendix A of this report. As mentioned in the introduction, wet gas sampling is an extremely difficult measurement with many influencing variables.

Various single-phase gas sampling methods were initially considered for the wet gas sampling testing program. The full descriptions of these methods, their potential use in wet gas applications, and probe orientations, are described further in a literature survey report which focuses on identifying potential wet gas sampling methods. This literature survey report is located in Appendix C.

Based on the literature survey findings, three different techniques that are traditionally used for single-phase gas sampling were recommended for evaluation under the wet gas sampling testing program. These sampling methods include:

1. purging - fill and empty
2. helium pop
3. constant pressure cylinder methods

In addition to the single-phase gas sampling techniques considerations, the API Wet Gas Sampling Committee considered two different testing approaches for evaluating the wet gas sampling methods. This includes the liquid dropout testing approach and the liquid injection testing approach. Each of these testing approaches offer different benefits and complexities when being used to evaluate the sampling methods. A description of these testing approaches is described in each respective subsection below.

4.1 Liquid Dropout Testing Approach

In the liquid dropout testing approach, the flow loop utilizes a closed-loop system in which a high hydrocarbon dew point gas is used as the test fluid. This gas would transition between a single-phase gas stream to a wet gas stream, by using heating and cooling systems (i.e., heaters and chillers).

It was anticipated that the dry gas section of the flow loop, upstream of the wet gas stream, would have dry gas metering and a sampling port. An online gas chromatograph would measure and analyze the composition of the dry gas to establish quasi steady-state conditions of the flow. The wet gas section of the loop would need to facilitate the wet gas sample probe configurations and

additionally have a wet gas meter and use a liquid measurement system to verify the amount of liquid present in the flow line. A two-phase separator vessel is used to separate the liquid and vapor phases, and adequately measure the amount of liquid in the flow line.

The liquid dropout test approach is a test method that best represents the gas phase change process that would occur for generating a wet gas stream in the field. Therefore, the methods that are used for sampling a single-phase gas could (in theory) effectively be evaluated for sampling a wet gas under similar field conditions. Although this test approach best represents the physical wet gas generation process, this approach has less controllability in the formation of wet gas as it is strongly dependent on thermal processes. Previous liquid-dropout tests proved difficult to control. A closed loop mass and energy balance confirmed that it is impractical to achieve the Lockhart-Martinelli Numbers of interest. Additionally, producing this type of flow in a recirculating flow loop would require substantial thermal insulation and significantly large heating and cooling systems to convert the gas into a liquid phase, and vice versa. This approach is therefore limited on the heating and cooling resources available to generate a wet gas stream.

4.2 Liquid Injection Test Approach

In the liquid injection testing approach, the flow loop utilizes a closed-loop system, where a single-phase saturated liquid hydrocarbon is measured using a reference meter, and injected into a single-phase, saturated gas stream creating a two-phase “wet gas” stream. The two-phase stream flows through the test section with the sampling probe installed and discharges into a vessel to separate the mixed stream into their respective bulk fluid phases downstream of the test section.

Like the liquid dropout testing approach, the liquid injection testing approach has saturated gas metering and a sampling port on the saturated gas section of the flow loop, where a gas chromatograph measures and analyzes the composition of the saturated gas to establish quasi steady-state conditions of the flow.

The liquid injection test approach replicates a wet gas stream without the use of thermal or phase change processes by injecting a saturated liquid, at a defined flow rate, into a single-phase saturated gas stream. While this test approach does not fully represent the physical wet gas generation process, it provides a controlled method for producing a wet gas stream with known and repeatable conditions and eliminates the need of large heating and cooling resources for transitioning the single-phase gas stream to a wet gas stream.

5. Test Objectives and Approach

The objective of the testing program was to evaluate and quantify the performance of a single-phase dry gas sampling method to obtain representative samples of a wet gas stream. Specifically, this effort evaluated the sampling method performance with Lockhart-Martinelli (XLM) parameters less than or equal to 0.020, which cover the range of API Type I flows. While the original scope was to evaluate sampling performance with XLM parameters less than or equal to

0.020, after the initial test results were evaluated by the committee, it was decided to increase the XLM parameter limit to 0.025. This is discussed further in the Test Matrix section of this report.

To make the best use of both the testing program's cost and schedule constraints, the API Wet Gas Committee decided to conduct a limited-scope feasibility testing campaign using a 2-phase, binary mixture of methane and n-heptane. This feasibility study focused on controlling a few key variables for the initial wet gas sampling performance assessment. The following scope-limiting decisions were made to reduce the cost of the testing:

- One single pipe size, 3-inch Schedule 160.
- One gas sampling technique assessed, API 14.1 Purge-Fill-Empty (PFE)
- Utilizing a 2-component mixture, methane, and n-heptane. Note, EOS mixing equations are well established for binary mixtures.
- Four Lockhart-Martinelli Numbers, API Type I and Type II wet gas zones were studied, $X_{LM} = 0.01, 0.015, 0.02$ and 0.025 .
- One single sampling probe tip geometry, square-cut tip.
- One single sampling probe location, center of the pipe.
- One single pressure, 700 psig. This limits the gas-liquid density ratio to one.

Additionally, the wet gas sampling testing effort was completed using a liquid injection approach, in which a known single-phase saturated liquid stream was injected into a known single-phase stream of saturated gas to create a reference two-phase stream of wet gas upstream of a wet gas sampling location. A schematic drawing of the testing configuration is shown in Figure 1. Once the samples were collected from the flow loop, a compositional analysis of the wet gas sample was compared to the reference wet gas stream to assess the performance of the purging – fill and empty dry gas sampling method.

The test program was conducted over a two-day period, in which fluid samples were collected from the wet gas stream in accordance with recommendations from API MPMS Chapter 14.1. After collection, the sample bottles were provided to FESCO for sample analysis per GPA 2261.

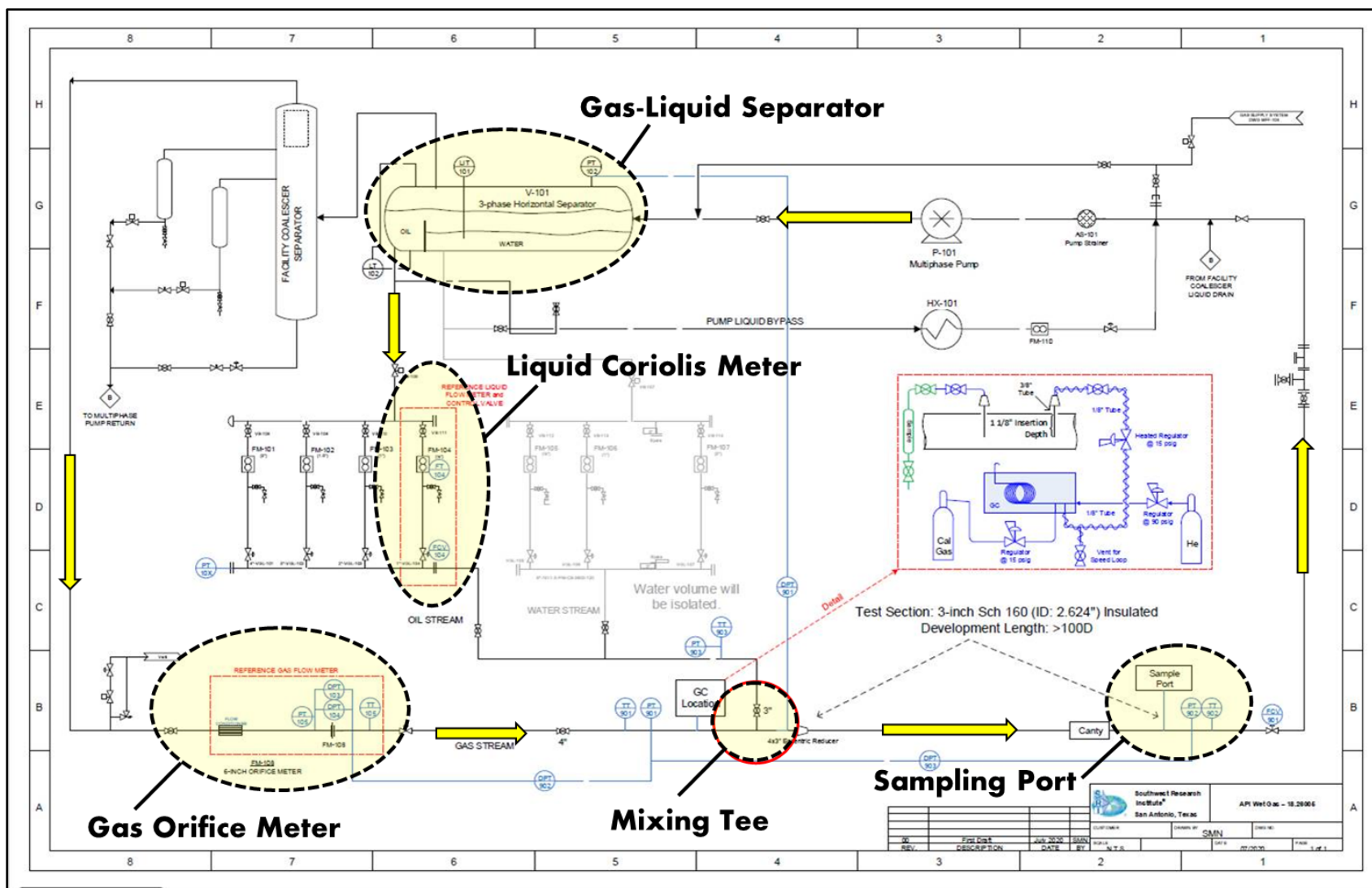


Figure 1. Closed Loop Liquid-Injection Testing Configuration P&ID Drawing¹

¹ Schematic drawing taken from SwRI Report Project No. 18.26005

6. Test Facility and Testing Configuration

Testing was conducted in the high-pressure flow loop at Southwest Research Institute's Multiphase Flow Facility (MFF), which is rated for pressures up to 3,600 psig and can operate within a temperature range of approximately 60°F to 100°F.

The main components of the flow loop are a twin-screw multiphase pump with variable speed drive, a gas/liquid separator, a gas filtration/drying vessel (containing cyclones, vane pack, and coalescing elements), various meters, control valves, and a test section. Although the flow loop can be configured in a variety of ways to accommodate different types of testing, the general operation of the loop consists of the multiphase flow stream from the pump discharging into the separator, where the flow is then divided into gas and liquid streams that can be separately metered and routed to the test section. The liquid stream can be separated into a water and oil stream by using separator internals and a weir plate. The flow loop also has a liquid bypass line around the pump that is used for capacity control and to maintain the minimum 5% liquid flow volume required by the pump. A heat exchanger on the liquid bypass is used to control the loop temperature. Figures 2 through 5 show photographs of the facility, a model of the test layout, and the test section used during this program.



Figure 2. SwRI Multiphase Flow Facility²

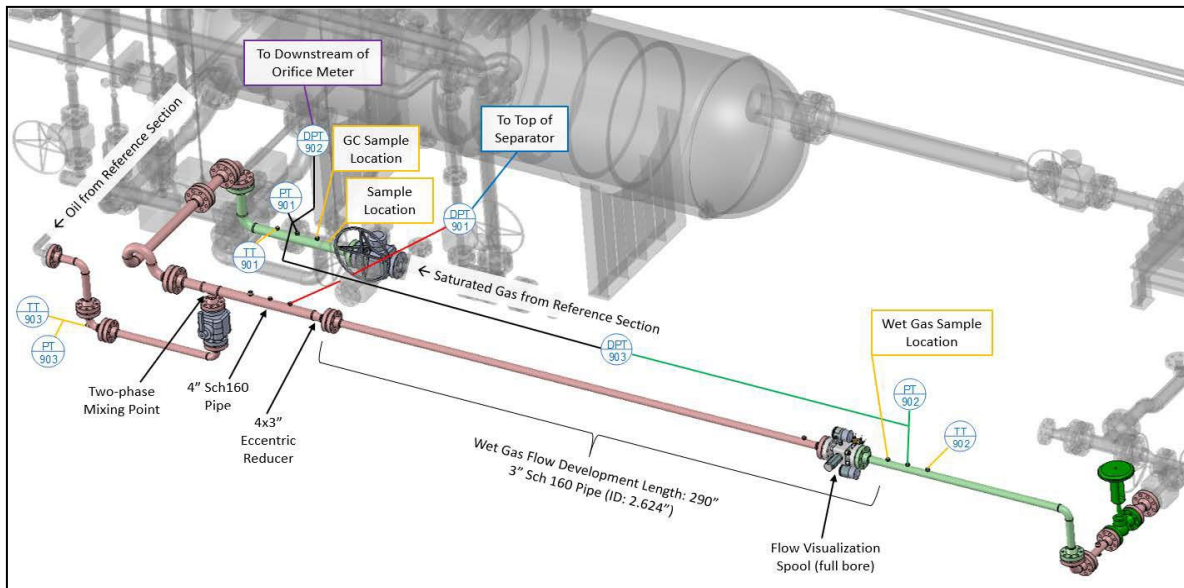


Figure 3. Model of Test Section Layout²

² Photograph and Model Courtesy of SwRI.

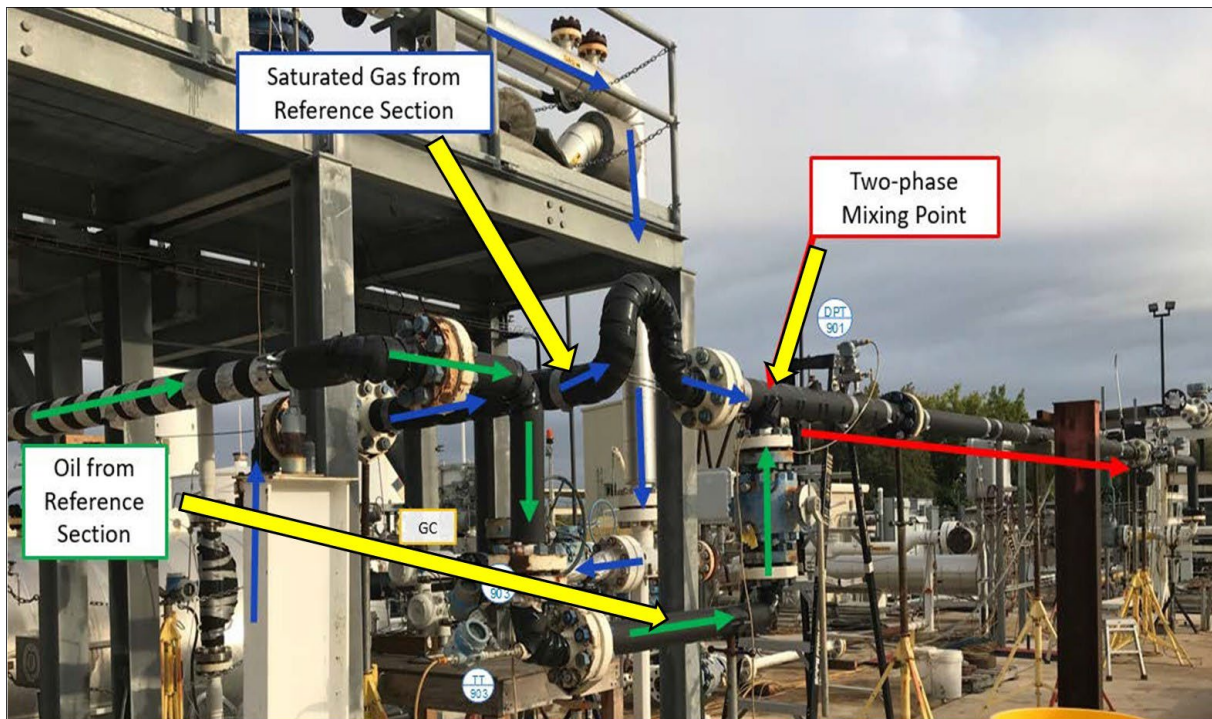


Figure 4. Test Section Photograph – View from Upstream of Wet Gas Sample Location³. The liquid and saturated gas streams were independently metered (not visible in image) before being combined at a vertically oriented tee.

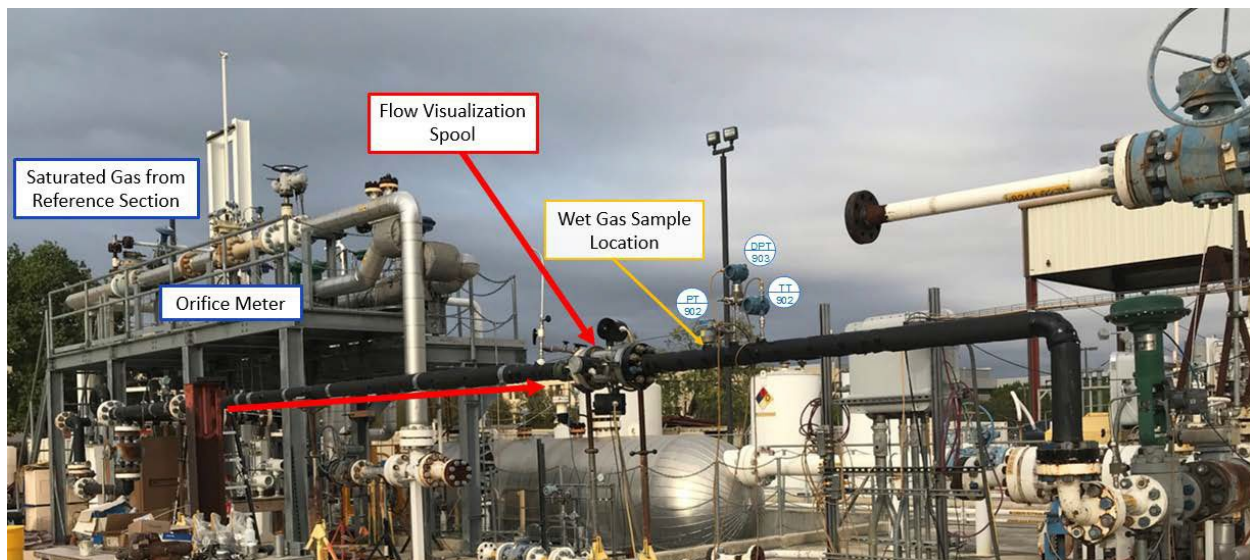


Figure 5. Test Section Photograph – View from Upstream of Wet Gas Sample Location². Downstream of the liquid injection tee, the test section contained 110 diameters of 3-inch horizontal pipe to provide fully developed flow upstream for the wet gas sampling location.

6.1 Test Setup

A model of the test setup integrated into the flow facility is provided in Figure 3. The MFF was configured to complete the wet gas sampling testing program using a liquid injection approach in which a single-phase liquid stream was injected into a single-phase stream of saturated gas at a mixing point to create a two-phase stream of wet gas upstream of the wet gas sampling location. For this testing effort, high-purity liquid heptane (n-heptane, 99%+ pure) was used for the liquid phase and methane was used for the gas phase. A stock tank compositional analysis of the n-heptane per GPA 2186 was used to verify its purity.

The MFF operates as a closed-loop, recirculating system in which the facility separator is used to provide separate reference gas and liquid streams. The reference gas stream was measured by an orifice flow meter and analyzed by an online gas chromatograph (GC) located upstream of the liquid injection location. Although the gas stream at this location is a single-phase fluid, the gas is saturated with heptane according to the natural equilibrium of the closed-loop system at a given pressure and temperature. The online GC measurements at this location allowed for the stability monitoring of the mass fractions of the various constituents of the reference gas phase during testing. The GC was calibrated at the beginning of each test day using a natural gas calibration blend.

The test setup also included a sample probe just upstream of the online GC to allow samples of the saturated gas stream to be collected and analyzed by the same GC used to analyze the wet gas samples. The sample probes, provided by Welker, were installed in the saturated gas and wet gas sample locations in accordance with the recommendations of API MPMS Chapter 14.1. The sample probes included 3/8" OD x 0.065" wall thickness 316 stainless steel tubing installed in a single, fixed, vertical orientation at both sample locations with a square-cut tip located at the centerline of the pipe.

The reference liquid stream was measured by a Coriolis flow meter upstream of the liquid injection point. To combine the two reference streams, the liquid stream flowed vertically upward through a 3-inch diameter branch tee connection into the horizontally flowing 4-inch diameter gas flow path. This location is notated as the two-phase mixing tee in Figure 1. The horizontal two-phase mixture then flowed in a short section of 4-inch diameter piping before being reduced to 3-inch diameter piping and continued uninterrupted for approximately 110 diameters until reaching the wet gas sampling location. This uninterrupted flow development length was comprised of 3-inch Sch. 160 piping.

The static pressures and temperatures of the process flows were monitored at various locations including the GC sampling location (PT-901 and TT-901), the reference liquid stream (PT-903 and TT-903), and near the wet gas sampling location (PT-902 and TT-902). The flowing differential pressure distributions were also monitored between the gas orifice meter and the GC location (DPT-902), between the GC location and the wet gas sample location (DPT-903), and between the facility separator and the two-phase mixing point (DPT-901). A list of all reference instrumentation used during this testing program is provided in Appendix B.

Included in the test section was a full-bore flow visualization spool near the wet gas sampling location. The purpose of this spool was to visually record samples of the steady-state flowing condition for each of the main test conditions. Two or three videos were recorded during each stable test condition (usually 15-20 seconds in length). However, given the annular/mist flow regimes of the target test conditions, it was difficult to visually discern any major differences between conditions when viewing the two-phase flow through the high velocity liquid film. A description of the visualization spool can be found in Appendix B.

During the test program, the gas rate was kept constant for all conditions to ensure that the wet gas conditions were comparable. An elevated test pressure of 700 psig was chosen to increase the overall gas density and allow for a more stable flow loop control, a more stable phase equilibrium, and a better thermal mass transfer as the fluids were circulated throughout the system. To ensure minimal liquid dropout from the saturated gas during the test, it was decided that the process temperature would be controlled at a value approximately 5°F below the current ambient temperature. During testing, the ambient conditions varied slightly throughout the day, but were constant during any one condition. With ambient temperatures ranging from 70°F to 74°F during testing, the process conditions were kept at temperatures ranging from 65° to 68°F and were held steady for the duration of any one steady-state test condition.

Both a pre-test and post-test liquid sample was taken from the single-phase heptane liquid stream and was analyzed for its water content using a Karl Fisher analysis as per ASTM D4928. The analysis results indicated very low levels of water detected in the heptane liquid, less than 41.1 ppm wt. Because there was so little liquid injected during this study, the sensitivity to the liquid composition was low. When substituting typical analytical uncertainties for the conservative estimates used, the impact from the liquid composition was small.

6.2 Test Procedure

Prior to test execution, the MFF facility was brought up to the target test temperature and flow rate conditions. The flowing conditions were then stopped, and a zero check of the flow meter was assessed. Additionally, all differential pressure transmitters relevant to the testing were checked to ensure that the

zero-flow conditions resulted in a differential pressure reading within a normal bounds of instrument stability.

Once a zero and stability check of the flow meter and reference instrumentation had occurred, the flow facility was turned on, and only gas was allowed to flow through the test section. Once the target gas flow rate through the test section was achieved, the system continued to circulate for a period of time in order to sweep as much remaining free liquid from the test section as possible. This gas-only flowing state was also confirmed using the visualization spool as no discernable liquid film or movement could be seen in the video after some length of time. Once the system was stable and all measurements confirmed, the sampling process for the first test condition was conducted.

After the first gas-only condition was completed, the oil reference flow line was opened, and the operator adjusted the necessary control valves to bring the test section XLM value to the first wet gas target. After flowing at the target flow rates and before the sampling process began for the first wet gas condition, a liquid sample was taken from the oil reference flow line directly downstream of the reference flow meter. After the liquid sample was completed, the first wet gas test condition and sampling process was conducted. After completing the sampling process, the oil reference rate was adjusted to reflect the new target XLM value. This process was repeated until all samples were collected for the desired wet gas conditions as provided in the test matrix shown in Table 2.

6.3 Sampling Procedure

Fluid samples were collected from the saturated gas sample location and the wet gas sample location using the purge-fill-empty (PFE) method in accordance with the recommendations of API MPMS Chapter 14.1. The sampling bottle locations were configured in a close-coupled setup with an extension tube isolation device (pigtail) and a drilled orifice vent as shown in Figure 6. The valves numbered one through five correspond to the sampling procedure outlined in Table 1.

The samples were collected in 300-cc fixed-volume sample bottles provided by and prepared by FESCO. The sample bottles were initially steam cleaned, evacuated, and charged with approximately 5 psig of helium. The sample bottles were warmed and kept in a heated oven at $>100^{\circ}\text{F}$ just prior to sample collection, and the bottles were covered in foam pipe insulation during the sampling process. The sample bottle serial number was recorded to link the sample collected, test condition, and sample analysis results.

Table 1 details the sequence of steps completed for each sample collected. After venting the initial sample helium volume, each sample process underwent three fill and empty cycles before collecting the actual gas sample on the fourth cycle.

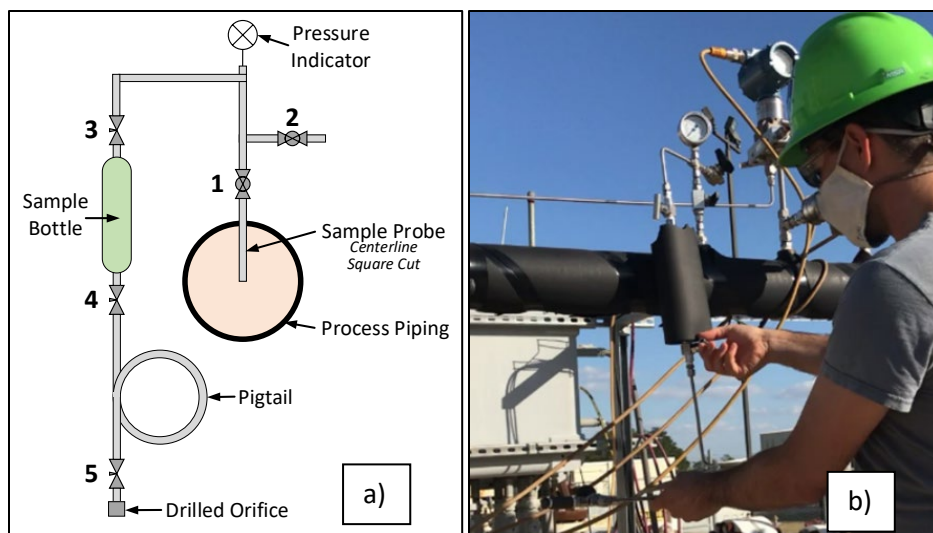


Figure 6. A close-coupled sampling setup included an extension tube isolation device (pigtail) and a drilled orifice vent, where the valves numbered one through five correspond to the sampling procedure outlined in Table 1.

Table 1. Gas sampling procedure, where after venting the initial sample helium volume, each sample process underwent three fill and empty cycles before collecting the gas sample on the fourth cycle.

Procedure Step		Valve Position					Sample Bottle Pressure (after completing step)
		1	2	3	4	5	
	Start	Close	Close	Close	Close	Close	~5 psig (He)
	Remove Caps, Attach Bottle						~5 psig (He)
	Release He	Close	Close	Close	Open	Cracked	~0 psig
	Reset	Close	Close	Close	Open	Close	~0 psig
Cycle 1	Fill	Open	Close	Open	Open	Close	~700 psig
	Empty	Close	Close	Open	Open	Cracked	~0 psig
	Reset	Close	Close	Open	Open	Close	~0 psig
Cycle 2	Fill	Open	Close	Open	Open	Close	~700 psig
	Empty	Close	Close	Open	Open	Cracked	~0 psig
	Reset	Close	Close	Open	Open	Close	~0 psig
Cycle 3	Fill	Open	Close	Open	Open	Close	~700 psig
	Empty	Close	Close	Open	Open	Cracked	~0 psig
	Reset	Close	Close	Open	Open	Close	~0 psig
	Fill	Open	Close	Open	Open	Close	~700 psig
	Sample	Close	Close	Close	Close	Close	~700 psig
	Vent	Close	Open	Close	Close	Open	~700 psig
	Detach Bottle; Install Caps						~700 psig

	Stop	Close	Close	Close	Close	Close	~700 psig
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6.4 Test Matrix

An initial test matrix was developed with a range of target Lockhart-Martinelli (XLM) numbers that contained one gas-only flowing condition and four wet-gas flowing conditions with XLM numbers of 0.05, 0.01, 0.015, and 0.02.

Each test condition had nine fluid samples that were collected from the flow loop: one sample of the saturated gas stream at the start of a steady-state condition, seven samples collected consecutively from the wet gas sample location, and a second saturated gas stream sample taken at the end of the steady-state condition. To make the best use of the schedule and available resources, it was decided that the testing would be split into two days to allow for the analysis of the fluid samples from the first test day to be completed before moving on to the second day.

On the first test day, two wet-gas conditions corresponding to XLM values of 0.01 and 0.02 were completed. These two wet-gas conditions were conducted first so a decision regarding modifications to the initial test matrix could be made after the sample analysis results had been completed. After the initial sample analysis results were reviewed, it was decided that the test condition with a XLM value of 0.005 would not be conducted and it would be replaced by a XLM value of 0.025. Thus, the second test day saw the completion of the final two wet-gas conditions (XLM = 0.015 and XLM = 0.025).

Table 2 highlights the relevant values for the test conditions, as well as the order and selection of conditions that were completed. Figure 7 shows the wet gas operating conditions superimposed on a flow pattern map demonstrating that each test condition was within the annular/mist flow regime. The flow regime map was generated using the FLOPATN software package described by Pereyra and Torres (2005).

Table 2. Wet Gas Sampling Test Matrix

Actual Test Order	Sample Set Name	Wet Gas Number of Samples	Sat. Gas Number of Samples	XLM	Mass Gas Rate	Superficial Gas Velocity	Mass Liquid Rate	Superficial Liquid Velocity
				--	kg/hr	m/s	kg/hr	m/s
1	Sat. Dry Gas	7	2	0	7115.5	16.23	0.0	0.000
Excluded from Test		7	2	0.005	7115.5	16.23	154.0	0.019
3	Wet Gas 2	7	2	0.01	7115.5	16.23	308.0	0.037
5	Wet Gas 4	7	2	0.015	7115.5	16.23	462.0	0.056
2	Wet Gas 1	7	2	0.02	7115.5	16.23	616.0	0.075
4	Wet Gas 3	7	2	0.025	7115.5	16.23	770.1	0.094

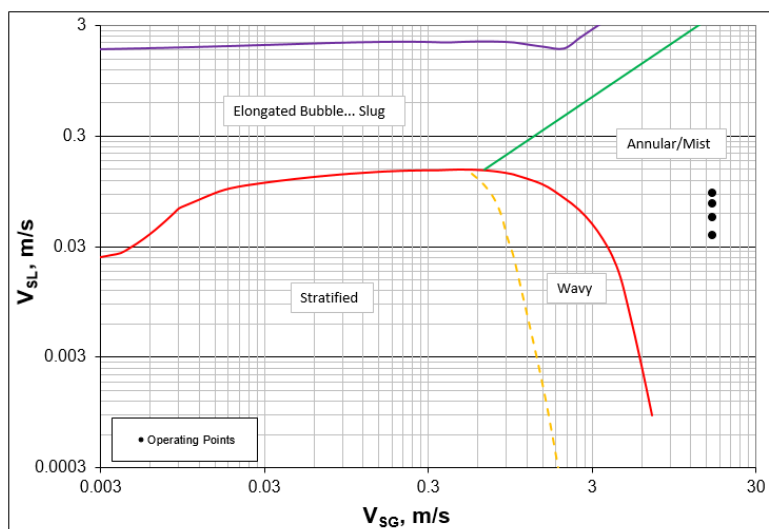


Figure 7. The flow pattern map indicates that each wet gas test operating condition was in the annular/mist flow regime.

The samples that were collected during the testing program were analyzed by FESCO using a single gas chromatograph (GC) for all the analyses. A standard gas compositional analysis was conducted on all the samples with the hydrocarbons resolved out to heptane (C7). As a result, hydrocarbons with a carbon number of 7 or greater were combined and reported as heptane+. The standard analysis was determined to be sufficient since the liquid phase for the testing was high purity heptane and did not contain hydrocarbon constituents beyond C7. A total of nine samples were collected and analyzed for each of the five test conditions completed.

Table 3 through Table 6 shows the testing sequence for each set of samples, as well as the sample analysis results for each respective sample taken during this test program.

Table 3. Test Matrix for Saturated Gas

Test Condition SG1 (XLM = 0.00)									
Sample Name	Sample Time	Sample Location	Bottle Serial No.	mol%					Dry Heating Value (BTU/CF)
				Nitrogen	CO ₂	Methane	Ethane	Heptane +	
SG1-A	12:27:50	GC	T-5976	0.120	0.012	99.380	0.058	0.430	1,029
SG1-1	12:32:30	Test Section	T-2374	0.127	0.025	99.296	0.054	0.498	1,032
SG1-2	12:35:50	Test Section	T-4723	0.107	0.019	99.440	0.063	0.371	1,026
SG1-3	12:39:10	Test Section	T-3589	0.120	0.033	99.369	0.061	0.417	1,028
SG1-4	12:43:00	Test Section	T-3537	0.155	0.026	99.233	0.058	0.528	1,033
SG1-5	12:50:20	Test Section	T-5795	0.140	0.024	99.314	0.055	0.467	1,030
SG1-6	12:55:20	Test Section	T-5847	0.112	0.012	99.416	0.060	0.400	1,028
SG1-7	12:59:35	Test Section	T-2514	0.112	0.014	99.437	0.057	0.380	1,027
SG1-B	13:04:40	GC	T-2723	0.222	0.021	99.255	0.059	0.443	1,028
Online GC	Continuous	GC	--	0.097	0.000	99.534	0.041	0.327	1,024
Average Sat Gas Composition				0.171	0.017	99.318	0.059	0.437	1,028

Table 4. Test Matrix for Wet Gas XLM=0.010. The analysis of WG2-1 (1) was conducted along with the other WG2 samples, and WG2-1 (2) and WG2-1 (3) were conducted in succession on a separate day.

Test Condition WG2 (XLM = 0.01)									
Sample Name	Sample Time	Sample Location	Bottle Serial No.	mol%					Dry Heating Value (BTU/CF)
				Nitrogen	CO ₂	Methane	Ethane	Heptane +	
WG2-A	16:39:25	GC	T-4730	0.106	0.018	99.472	0.048	0.356	1,025
WG2-1 (1)	16:45:30	Test Section	T-5633	0.114	0.010	99.302	0.058	0.516	1,033
WG2-1 (2)	16:45:30	Test Section	T-5633	0.120	0.000	98.979	0.063	0.838	1,049
WG2-1 (3)	16:45:30	Test Section	T-5633	0.117	0.000	98.983	0.061	0.839	1,049
WG2-2	16:50:30	Test Section	T-1885	0.128	0.035	99.082	0.055	0.700	1,042
WG2-3	16:54:10	Test Section	T-0746	0.127	0.014	98.960	0.050	0.849	1,049
WG2-4	16:58:10	Test Section	T-2988	0.114	0.014	99.255	0.050	0.567	1,036
WG2-5	17:02:10	Test Section	T-3401	0.112	0.017	99.213	0.062	0.596	1,037
WG2-6	17:05:50	Test Section	T-5370	0.112	0.014	99.249	0.061	0.564	1,036
WG2-7	17:10:40	Test Section	A-0939	0.128	0.022	98.958	0.056	0.836	1,049
WG2-B	17:15:30	GC	T-1561	0.107	0.035	99.428	0.056	0.374	1,026
Online GC	Continuous	GC	--	0.098	0.000	99.547	0.041	0.314	1,023
Average Sat Gas Composition				0.107	0.027	99.450	0.052	0.365	1,026
Average Wet Gas Composition				0.119	0.014	99.109	0.057	0.701	1,042
Reference Wet Gas Composition				0.106	0.026	98.791	0.052	1.025	1,055

Table 5. Test Matrix for Wet Gas XLM=0.015. The analysis of WG4-4 (1) was conducted along with the other WG4 samples, and WG4-4 (2) and WG4-4 (3) were conducted in succession on a separate day.

Test Condition WG4 (XLM = 0.015)									
Sample Name	Sample Time	Sample Location	Bottle Serial No.	mol%					Dry Heating Value (BTU/CF)
				Nitrogen	CO ₂	Methane	Ethane	Heptane +	
WG4-A	14:12:30	GC	G-0073	0.253	0.024	99.269	0.063	0.391	1,026
WG4-1	14:14:30	Test Section	T-4501	0.282	0.037	98.675	0.059	0.947	1,052
WG4-2	14:28:30	Test Section	G-0237	0.243	0.033	98.975	0.057	0.692	1,040
WG4-3	14:34:00	Test Section	T-5730	0.246	0.017	98.908	0.059	0.770	1,044
WG4-4 (1)	14:37:00	Test Section	T-4747	0.243	0.039	98.966	0.062	0.690	1,040
WG4-4 (2)	14:37:00	Test Section	T-4747	0.225	0.000	99.097	0.060	0.618	1,037
WG4-4 (3)	14:37:00	Test Section	T-4747	0.242	0.000	99.085	0.059	0.614	1,037
WG4-5	14:41:00	Test Section	T-2848	0.268	0.037	98.798	0.064	0.833	1,047
WG4-6	14:45:00	Test Section	T-3576	0.254	0.041	98.936	0.061	0.708	1,041
WG4-7	14:48:20	Test Section	T-2836	0.314	0.033	98.644	0.063	0.946	1,052
WG4-B	14:52:30	GC	A-0921	0.267	0.015	99.189	0.061	0.468	1,029
Online GC	Continuous	GC	--	0.241	0.001	99.399	0.041	0.318	1,022
Average Sat Gas Composition				0.260	0.020	99.229	0.062	0.430	1,028
Average Wet Gas Composition				0.257	0.026	98.898	0.060	0.758	1,043
Reference Wet Gas Composition				0.257	0.019	98.264	0.062	1.398	1,070

Test Condition WG1 (XLM = 0.02)									
Sample Name	Sample Time	Sample Location	Bottle Serial No.	mol%					Dry Heating Value (BTU/CF)
				Nitrogen	CO ₂	Methane	Ethane	Heptane +	
WG1-A	14:40:40	GC	T-5247	0.115	0.022	99.438	0.052	0.373	1,026
WG1-1	14:46:40	Test Section	T-4285	0.109	0.034	99.004	0.046	0.807	1,047
WG1-2	14:51:45	Test Section	T-4581	0.102	0.023	99.035	0.061	0.779	1,046
WG1-3	14:56:40	Test Section	T-5425	0.104	0.018	99.027	0.057	0.794	1,047

WG1-4	15:02:00	Test Section	T-4209	0.138	0.024	98.708	0.054	1.076	1,060
WG1-5 (2)	15:07:20	Test Section	T-2090	0.143	0.043	98.739	0.058	1.017	1,057
WG1-6	15:19:00	Test Section	T-2187	0.172	0.019	98.809	0.060	0.940	1,053
WG1-7	15:24:00	Test Section	T-2168	0.106	0.032	99.044	0.055	0.763	1,045
WG1-B	15:30:20	GC	T-5340	0.107	0.018	99.463	0.059	0.353	1,025
Online GC	Continuous	GC	--	0.098	0.000	99.544	0.041	0.317	1,023
Average Sat Gas Composition				0.111	0.020	99.451	0.056	0.363	1,026
Average Wet Gas Composition				0.125	0.028	98.909	0.056	0.882	1,051
Reference Wet Gas Composition				0.109	0.020	98.170	0.056	1.645	1,083

Table 7. Test Matrix for Wet Gas XLM=0.025. The analysis of WG3-2 (1) was conducted along with the other WG3 samples, and WG3-2 (2) and WG3-2 (3) were conducted in succession on a separate day.

Test Condition WG3 (XLM = 0.025)									
Sample Name	Sample Time	Sample Location	Bottle Serial No.	mol%					Dry Heating Value (BTU/CF)
				Nitrogen	CO ₂	Methane	Ethane	Heptane +	
WG3-A	12:51:50	GC	A-0308	0.244	0.061	99.255	0.069	0.371	1,024
WG3-1	12:57:50	Test Section	T-1555	0.240	0.029	98.816	0.060	0.855	1,048
WG3-2 (1)	13:02:20	Test Section	T-0839	0.250	0.030	98.832	0.055	0.833	1,047
WG3-2 (2)	13:02:20	Test Section	T-0839	0.237	0.000	98.783	0.060	0.920	1,052
WG3-2 (3)	13:02:20	Test Section	T-0839	0.225	0.000	98.775	0.073	0.927	1,053
WG3-3	13:06:30	Test Section	T-3663	0.278	0.020	98.118	0.055	1.529	1,081
WG3-4	13:11:00	Test Section	T-1704	0.276	0.018	98.268	0.065	1.373	1,074
WG3-5	13:15:30	Test Section	T-4194	0.283	0.034	98.433	0.062	1.188	1,064
WG3-6	13:19:50	Test Section	T-5893	0.262	0.024	98.646	0.061	1.007	1,056
WG3-7	13:31:40	Test Section	T-0610	0.244	0.025	98.603	0.062	1.066	1,059
WG3-B	13:36:30	GC	T-3547	0.262	0.028	99.216	0.061	0.433	1,028
Online GC	Continuous	GC	--	0.243	0.001	99.395	0.042	0.320	1,022
Average Sat Gas Composition				0.253	0.045	99.236	0.065	0.402	1,026
Average Wet Gas Composition				0.257	0.019	98.557	0.062	1.105	1,061
Reference Wet Gas Composition				0.248	0.044	97.655	0.065	1.988	1,097

The following conditions were maintained for all the tests conducted under this program:

- Gas flow rates were kept constant to ensure the wet gas conditions were comparable.
- All tests were run at a pressure of 700 psig.
- Ambient conditions varied slightly throughout the day, ranging from 70°F to 74°F.
- Process conditions were kept at temperatures ranging from 65° to 68°F and were held steady for the duration of any one steady-state test condition.

7. Results

By comparing the wet gas samples' average molecular weights to the molecular weights determined by the reference gas and liquid meters, a large percentage of the free liquids can be observed as missing from the wet gas samples. For all Lockhart-Martinelli Numbers the wet gas sampling method missed more than 50% of the liquids present. Figures 8. and 9. show the percentage of liquids missed when using the wet gas sample method versus Lockhart-Martinelli Number and percent GVF respectively. Despite an increase in the Lockhart-Martinelli number, the liquid missed in the sample remained constant at 50%. This may be explained by the flow regime in the pipe, which is annular but slightly misty (as shown in Figure 7).

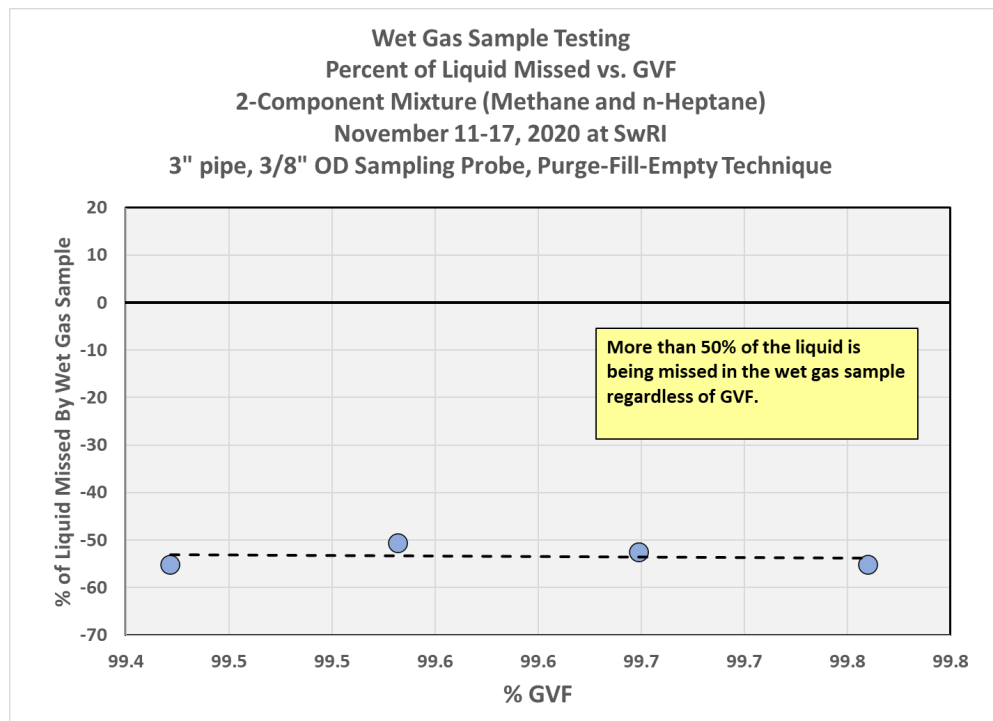


Figure 8. Free Liquids Missed by the Wet Gas Sampling Method vs. Lockhart-Martinelli No.

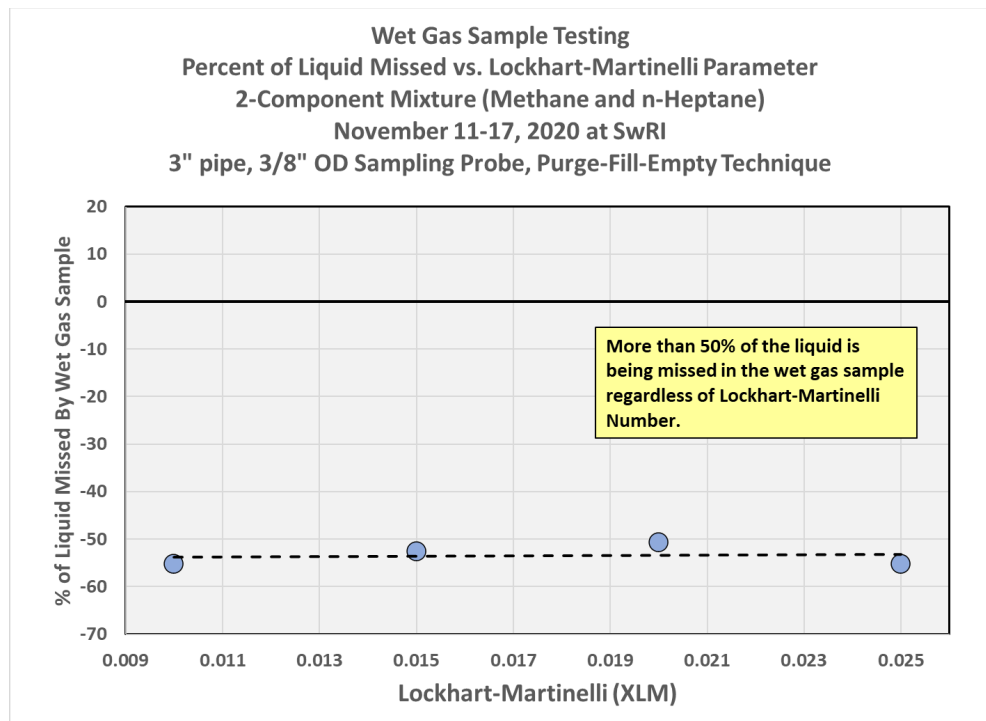


Figure 9. Free Liquids Missed by the Wet Gas Sampling Method vs. % GVF

The graph in Figure 10 shows Wet Gas Sampling Molecular Weight Percent Error versus the Lockhart-Martinelli Number. This graph illustrates that as the liquid percentage in the pipe increases, the error in the molecular weight increases. The “yellow” area in the graph in Figure 8 represents the averaged expanded uncertainty at a 95% confidence level of the reference meters and their respective input variables including random and systematic error. The error bars at each point represents the expanded uncertainty at a 95% confidence level of the seven wet gas samples analyzed at each Lockhart-Martinelli Number and include both random and systematic error.

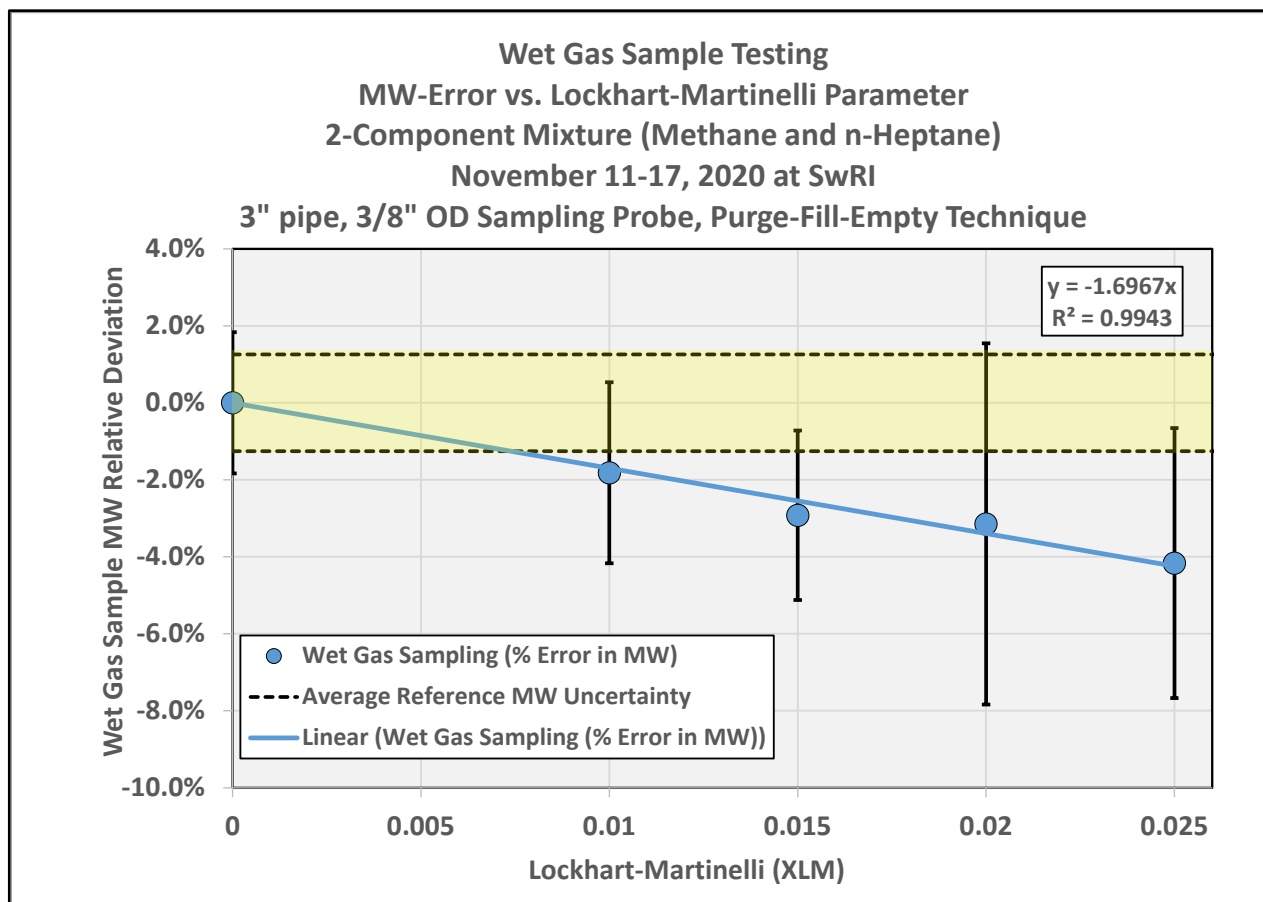


Figure 10. Wet Gas Sampling Molecular Weight Percent Error vs. Lockhart-Martinelli No.

The graph in Figure 11 shows the Molecular Weight Random Error Percentage vs. Lockhart-Martinelli Number for both the saturated gas samples and the wet gas samples. In a sample size of seven for each Lockhart-Martinelli Number, the average random error component for the wet gas samples was approximately half of the total error (50%). The wet gas random error was approximately 10 times larger than the saturated gas random error that only had a sample size of two.

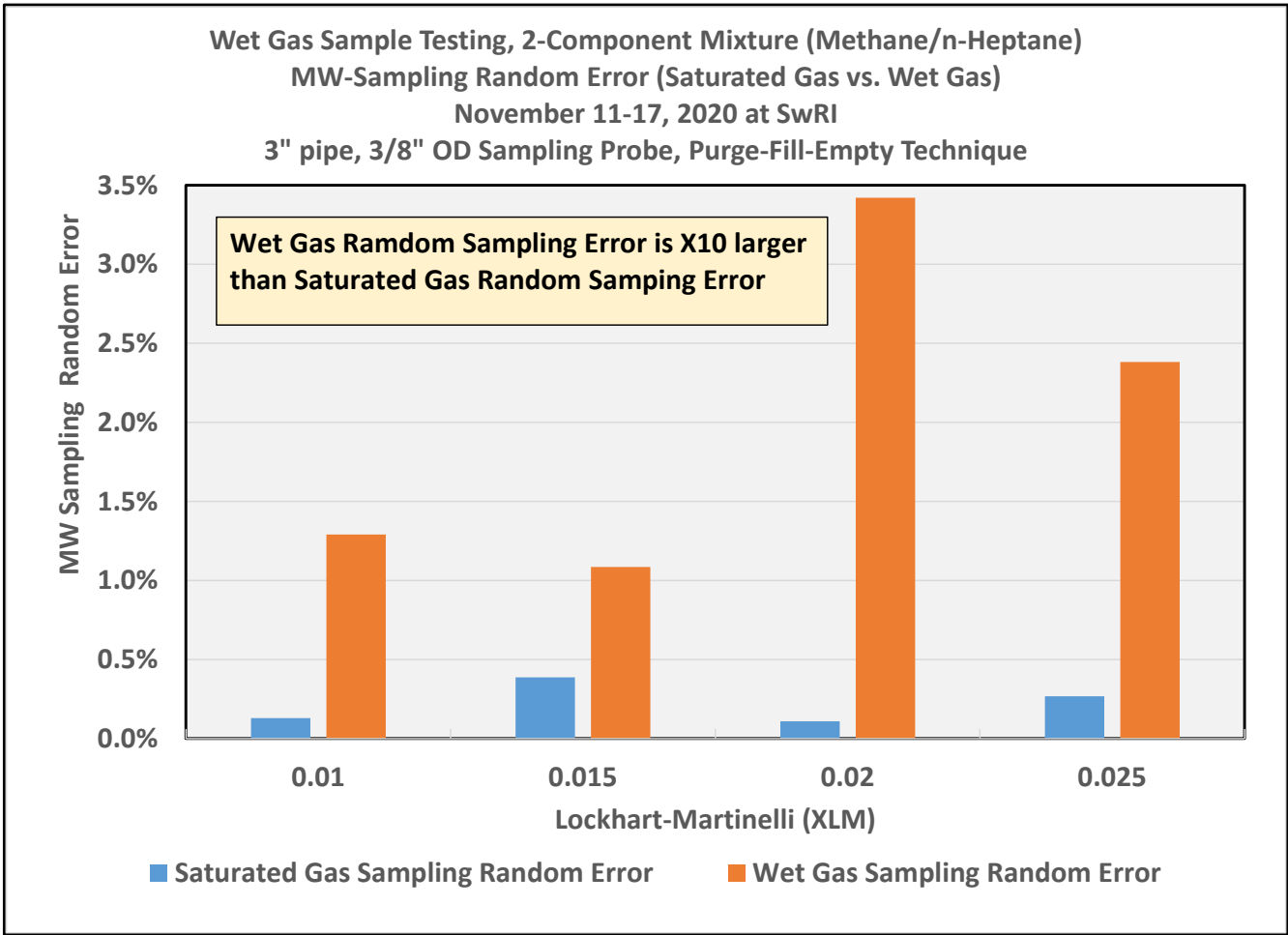


Figure 11. Molecular Weight Random Error Percentage vs. Lockhart-Martinelli No.

8. Uncertainty Analysis

An exhaustive uncertainty analysis was performed by API Wet Gas Committee members on the reference flow meters (Orifice plate for gas, Coriolis meter for liquid) used to determine the reference molecular weight at each flow rate.

- The Orifice plate the uncertainty analysis included the discharge coefficient, measured pipe and throat diameters, gas expansion, gas composition, gas compressibility, static pressure, line pressure, differential pressure, and random error. The appropriate sensitivity coefficients were applied per the GUM, JCGM 100:2008.
- The Coriolis meter uncertainty analysis included SwRI reported systematic 0.1% base uncertainty plus Coriolis zero stability from Micro Motion. Initial zero flow offset was considered zero because the Coriolis meter was zeroed at operating pressure and temperature before flowing liquids. Uncertainties were not added in quadrature because they are not random and independent. Zero stability and zero flow offset errors are cumulative, bias errors. Pressure and temperature errors were not included and could be assumed to be captured by the zero flow offset error at the operating pressure and temperature. Random error was determined by the number of samples taken for each point.

The resultant API Wet Gas Committee Orifice Plate and Coriolis uncertainties were compared to the reported SwRI uncertainties and were in good agreement. Table 8 shows the Orifice plate uncertainties for the API Wet Gas Committee and SwRI. Table 9 shows the API Wet Gas Committee and SwRI uncertainties for the Coriolis meter. Uncertainty budgets for the Orifice Plate and the Coriolis meter are shown in Table 10 and 11 respectively.

Gas Mass Flowrate Uncertainty

Test	LM	Gas Flow Rate (MRg)	SwRI Stated Gas Mass Flow Uncertainty	**Expanded Gas Mass Flow Uncert. @ 95%
SG1	0	273.35	0.49%	0.54%
WG1	0.02	274.23	0.49%	0.50%
WG2	0.01	274.95	0.49%	0.50%
WG3	0.025	273.44	0.49%	0.51%
WG4	0.015	273.70	0.49%	0.53%

Table 8. Comparison of SwRI Stated Uncertainties to API Wet Gas Committee Calculated Uncertainties for Orifice Plate Gas Flow Rates

Liquid Mass Flowrate Uncertainty

Test Condition	LM	Mass rate liq. MRI (lbs/min)	SwRI Stated Liq. Mass Flow Uncertainty	**Expanded Liq. Mass Flow Uncert. @ 95%
SG1	0	0.01	0.10%	n/a
WG1	0.02	23.02	0.10%	0.11%
WG2	0.01	11.77	0.10%	0.12%
WG3	0.025	28.43	0.10%	0.11%
WG4	0.015	17.22	0.10%	0.12%

Table 9. Comparison of SwRI Stated Uncertainties to API Wet Gas Committee Calculated Uncertainties for Coriolis Liquid Flow Rates

Percentage of Total Gas Mass flow Rate Error

Test	Orifice Cd+ VOA+d	Gas Expansion	Gas Composition	Gas Compressibility	Static Pressure	Line Temperature	Differential Pressure	Random Error	Total
SG1	34.3%	0.01%	34.0%	0.9%	11.1%	3.0%	0.1%	16.6%	100.0%
WG1	40.6%	0.01%	40.3%	1.0%	13.2%	3.5%	0.2%	1.2%	100.0%
WG2	40.4%	0.01%	40.1%	1.0%	13.1%	3.5%	0.2%	1.7%	100.0%
WG3	38.2%	0.01%	38.1%	1.0%	12.4%	3.3%	0.2%	6.8%	100.0%
WG4	35.5%	0.01%	35.5%	0.9%	11.5%	3.1%	0.1%	13.3%	100.0%
Ave. of all Tests	37.8%	0.01%	37.6%	0.9%	12.2%	3.3%	0.2%	7.9%	100.0%

Table 10. Orifice Plate Uncertainty Budget

Percentage of Total Liquid Mass flow Rate Error

Test	Coriois Base Calibration	Coriolis Zero Stability+Offset	Random Error	Total
SG1	n/a	n/a	n/a	n/a
WG1	98.0%	1.6%	0.4%	100.0%
WG2	94.1%	5.7%	0.2%	100.0%
WG3	97.3%	1.2%	1.5%	100.0%
WG4	95.7%	2.9%	1.4%	100.0%
Ave. of all Tests	96.3%	2.9%	0.9%	100.0%

Table 11. Coriolis Meter Uncertainty Budget**8.1 Mass Flow Rate Uncertainty Methodology:**

Orifice plate uncertainty analysis was rigorously performed using API 14.3.1, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids-Concentric, Square-edged Orifice Meters ©2012, JCGM 100:2008, Evaluation of Measurement Data-Guide to the Expression of Uncertainty in Measurement (GUM), in conjunction with data presented in SWRI report 18.26005 dated January 22, 2021 and raw data supplied in excel format by SwRI. The GUM was used to combine systematic and random error in quadrature using SwRI reported standard deviations for measured values.

Saturated gas compositional analysis was not considered a correlated variable because saturated gas sampling was done independently and separate from the 2-phase compositional analysis.

8.2 Compositional Uncertainty

The gas mass flow rate uncertainties and the liquid mass flow rate uncertainties were used in the calculation of the wet gas compositional uncertainties per the equations and methodologies shown in Figures 12-15.

Reference saturated gas compositional uncertainties were determined from saturated gas samples analyzed by FESCO. GPA 2261-13 Table IV was used with certified reference blend compositions to calculate expected Repeatability and Reproducibility.

Unfortunately, the saturated liquid flow stream was not sampled or analyzed. Saturated liquid composition was estimated using available published data for similar mixtures and a PVTsim CALSEP model. Large uncertainties were applied to the saturated liquid composition, but this had little effect on the overall compositional uncertainty because there was so little liquid present relative to the gas on a molar basis. A summary of the saturated gas, the saturated liquid, and the reference wet gas compositions and their respective uncertainties are given in Tables 12-18.

Reference wet gas stream composition

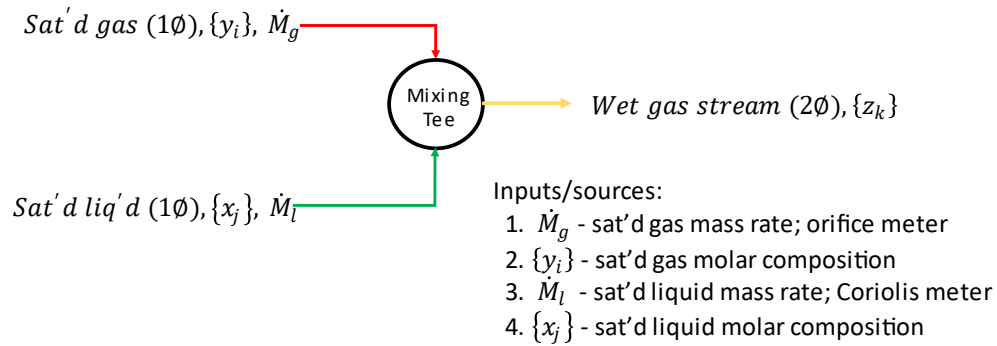


Figure 12. Equations/methodology to Determine Wet Gas Composition

Reference wet gas properties

Calculations:

A. Sat'd gas molecular weight

$$MW_g = \sum_i MW_i y_i$$

B. Sat'd gas molar rate

$$\dot{m}_g = \frac{\dot{M}_g}{MW_g}$$

C. Sat'd liquid molecular weight

$$MW_l = \sum_j MW_j x_j$$

D. Sat'd liquid molar rate

$$\dot{m}_l = \frac{\dot{M}_l}{MW_l}$$

E. Reference wet gas molar composition

$$z_k = \frac{\dot{m}_g y_k + \dot{m}_l x_k}{\dot{m}_g + \dot{m}_l}$$

F. Reference wet gas molecular weight

$$MW_{wgr} = \sum_k MW_k z_k$$

Figure 13. Equations/methodology to Determine Wet Gas Composition

Propagation of uncertainty– ref wet gas MW

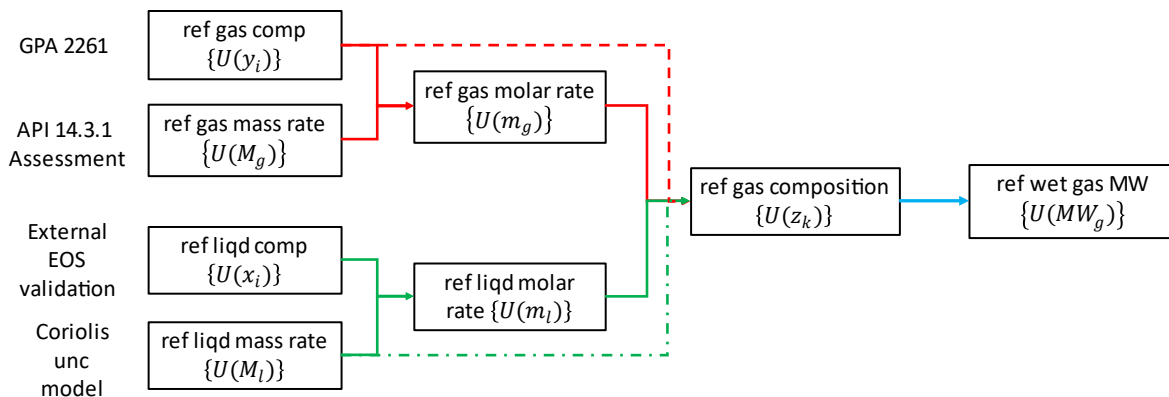


Figure 14. Equations/methodology to Determine Wet Gas Composition
Propagation of uncertainty

Sat'd gas molecular weight

$$MW_g = \sum_i MW_i y_i$$

Sat'd gas molar rate

$$\dot{m}_g = \frac{\dot{M}_g}{MW_g}$$

$$U(MW_g) = \sqrt{\sum_i \{u(MW_{Ci})^2 + u(y_{Ci})^2\} \times (MW_{Ci} y_{Ci})^2}$$

$$U(\dot{m}_g) = \sqrt{u(\dot{M}_g)^2 + u(MW_g)^2} \times \dot{m}_g$$

Figure 15. Equations/methodology to Determine Wet Gas Composition

		Gas Mass Rate Uncertainty Analysis			Liquid Mass Rate Uncertainty Analysis		
Test Condition	LM		WG Calculated per API 14.3.1			WG Calculated per API 14.3.1	
		Gas Mass Rate (lb/min)	Gas Mass Rate Relative Unc. @95% Conf. % rdg	Gas Mass Rate Abs. Unc. (lb/min)	Liquid Mass Rate (lb/min)	Liquid Mass Rate Relative Unc. @95% Conf. % rdg	Liquid Mass Rate Abs. Unc. (lb/min)
		(MRg)	u(MRg)	U(MRg)	(MRI)	u(MRI)	U(MRI)
SG1	0	272.45	0.54%	1.47			
WG1	0.02	273.84	0.50%	1.36	23.02	0.11%	0.026
WG2	0.01	274.51	0.50%	1.37	11.77	0.12%	0.015
WG3	0.025	272.72	0.51%	1.40	28.43	0.11%	0.032
WG4	0.015	272.83	0.53%	1.45	17.22	0.12%	0.020

Table 12. Reference Metering Uncertainty Estimation

	WG1 (LM = 0.02)		WG1 (LM = 0.01)		WG1 (LM = 0.025)		WG1 (LM = 0.015)	
	Y (mol%)	U _y (mol%) API	Y (mol%)	U _y (mol%) API	Y (mol%)	U _y (mol%) API	Y (mol%)	U _y (mol%) API
Nitrogen	0.111	0.053	0.107	0.052	0.253	0.079	0.26	0.081
CO2	0.02	0.033	0.027	0.036	0.045	0.043	0.02	0.032
Methane	99.451	0.599	99.45	0.599	99.236	0.598	99.229	0.598
Ethane	0.056	0.012	0.052	0.012	0.065	0.013	0.062	0.012
Heptane +	0.363	0.031	0.365	0.031	0.402	0.032	0.43	0.033

Table 13. Saturated Gas Composition (from gas analysis) and Uncertainty

	WG1 (LM = 0.02)		WG1 (LM = 0.01)		WG1 (LM = 0.025)		WG1 (LM = 0.015)	
	X (mol%)	U _x (mol%) API	X (mol%)	U _x (mol%) API	X (mol%)	U _x (mol%) API	X (mol%)	U _x (mol%) API
Nitrogen	0.008	0.0008	0.008	0.0008	0.019	0.0008	0.019	0.0008
CO2	0.012	0.0016	0.015	0.0016	0.027	0.0016	0.012	0.0016
Methane	22.534	0.7496	22.329	0.7482	22.682	0.7474	22.679	0.7479
Ethane	0.063	0.0041	0.055	0.0041	0.073	0.0041	0.07	0.0041
Heptane +	77.383	3.1217	77.593	3.1233	77.199	3.1243	77.22	3.1237

Table 14. Saturated Liquid Composition (from PVT package) and Uncertainty

	WG1 (LM = 0.02)		WG1 (LM = 0.01)		WG1 (LM = 0.025)		WG1 (LM = 0.015)	
	Z (mol%)	U _z (mol%) API	Z (mol%)	U _z (mol%) API	Z (mol%)	U _z (mol%) API	Z (mol%)	U _z (mol%) API
Nitrogen	0.109	0.052	0.106	0.051	0.248	0.078	0.257	0.080
CO2	0.02	0.032	0.027	0.035	0.045	0.042	0.02	0.014
Methane	98.166	1.251	98.791	1.265	97.655	1.266	98.264	1.290
Ethane	0.056	0.012	0.052	0.012	0.065	0.012	0.062	0.012
Heptane +	1.649	0.079	1.025	0.049	1.988	0.096	1.398	0.065

Table 15. Reference Wet Gas Composition and Uncertainty

	WG1 (LM = 0.02)		WG1 (LM = 0.01)		WG1 (LM = 0.025)		WG1 (LM = 0.015)	
	S (mol%)	U _s (mol%) API	S (mol%)	U _s (mol%) API	S (mol%)	U _s (mol%) API	S (mol%)	U _s (mol%) API
Nitrogen	0.125	0.050	0.119	0.015	0.257	0.034	0.257	0.052
CO2	0.028	0.012	0.014	0.010	0.019	0.011	0.026	0.016
Methane	98.909	0.738	99.109	0.283	98.557	0.531	98.898	0.272
Ethane	0.056	0.010	0.057	0.009	0.062	0.007	0.06	0.005
Heptane +	0.882	0.726	0.701	0.267	1.105	0.509	0.758	0.222

Table 16. Wet Gas Composition and Uncertainty

	XLM = 0.01		XLM = 0.015		XLM = 0.02		XLM = 0.025	
	API		API		API		API	
	Avg from Samples	Reference	Avg from Samples	Reference	Avg from Samples	Reference	Avg from Samples	Reference
Uncertainty + (mol%)	0.267	0.049	0.222	0.065	0.726	0.079	0.509	0.096
Uncertainty - (mol%)	-0.267	-0.049	-0.222	-0.065	-0.726	-0.079	-0.509	-0.096
Heptane + (mol%)	0.701	1.025	0.758	1.398	0.882	1.649	1.105	1.988

Table 17. Average Wet Gas Uncertainty

XLM	WG Sample MW Rel Unc	WG Sample MW Abs Unc	WG Reference MW Rel Unc	WG Reference MW Abs Unc	WG Combined MW Rel Unc	WG Combined MW Abs Unc	Sample % Random Error Sat. Gas	Sample % Random Error Wet Gas
0	1.83%	0.302	1.30%	0.214	1.83%	0.30	0.16%	0.61%
0.01	2.35%	0.391	1.24%	0.210	2.4%	0.39	0.13%	1.3%
0.015	2.20%	0.369	1.26%	0.218	2.2%	0.37	0.39%	1.1%
0.02	4.69%	0.793	1.24%	0.217	4.7%	0.79	0.11%	3.4%
0.025	3.51%	0.597	1.27%	0.226	3.5%	0.60	0.27%	2.4%
WG Ave:	3.19%	0.54	1.25%	0.22	3.19%	0.54	0.21%	1.76%

Table 18. Average Wet Gas Uncertainty

8.3 Discussion

SwRI used a Monte Carlo Simulation to estimate the analytical uncertainties for the reference and wet gas compositional uncertainty. The API workgroup used the reference method, GPA 2261 precision statement to calculate the reference and wet gas uncertainty. The value listed on the blend certificate used by the contract laboratory was stated as 1% overall uncertainty. The blend used by SwRI for their online GC was stated per component. The uncertainty values listed per component on the SwRI blend were substituted in for the Fesco calibration gas uncertainties and the results were similar to the SwRI estimates used in their report.

Subsequently, the GPA statistician who did the work for GPA 2261 suggested an approach for instances when the analytical uncertainty per component is not provided by the manufacturer. This approach was not used since it is not part of the reference analytical method. Annex Z, "Evaluation of laboratory Performance for GPA Methods" describes that process to calculate the analytical uncertainty. This approach yields similar results to the SwRI approach."

The difference between these two methodologies is approximately 0.1% and is considered negligible. For this reason, the API committee used the SWRI calibration blend uncertainty for the analytical uncertainty.

9. Conclusions

This study utilizing a two-phase, two-component, binary gas mixture provided a roadmap for the methodology to quantitatively determine the wet gas sampling error and its associated uncertainty. This study revealed that it is very difficult to accurately sample a simple two-phase mixture with relatively low liquid loadings using the API 14.1 section 12.8 purge-fill-and-empty (PFE) gas sampling method.

1. For all Lockhart-Martinelli Numbers tested ($XLM=0.01, 0.015, 0.02, 0.025$), more than 50% of the free liquids were missed using the API 14.1 section 12.8 purge-fill-and-empty (PFE) gas sampling method.
2. For all GVF's tested ($GVF=99.8, 99.6, 99.5, 99.4$), more than 50% of the free liquids were missed using the API 14.1 (Collecting and Handling of Natural Gas Samples for Custody Transfer) section 12.8 purge-fill-and-empty (PFE) gas sampling method.
3. At Lockhart-Martinelli Numbers of $XLM=0.01, 0.015, 0.02, 0.025$, the molecular weight bias error negatively increased from -1.8%, -2.9%, -3.1% to -4.2% respectively.
4. At Lockhart-Martinelli Numbers of $XLM=0.01, 0.015, 0.02, 0.025$, the resulting measured binary mixture's molecular weight expanded uncertainty at a 95% confidence level was 2.35%, 2.20%, 4.69% and 3.51% respectively.⁴
5. Data suggest that as liquid loading increases, dry gas sampling methods miss over half of the liquid present in the flow stream.
6. The random error in the wet gas sampling (variability in the wet gas measured molecular weight) was (on average) 10 times larger than the saturated gas random error. This suggests sample extraction issues; specifically, the liquid in the pipe is not consistently making it from the tip of the sampling probe, through the connecting tubing and associated needle valves and into the

^{4 4} The wet gas sampling work group did an independent uncertainty analysis to validate SWRI values. The values in the main body of this report here are from SWRI, while the workgroup values are listed in a separate spreadsheet available with this document.

sampling vessel. Alternately the large random error could be caused by flow regime dependencies and the chaotic nature by which liquid flows with the gas in a 2-phase environment.

10. Lessons Learned

The following list is comprised of lessons learned from this testing effort:

- A detailed written plan for sample collection, handling, sample conditioning, GC analysis and data analysis should be written and approved before execution.
- Consider utilizing constant pressure cylinder for better sample conditioning.
- Size reference meters so that all test rates are at least 10% of the meter's full scale range.
- A detailed facility reference metering uncertainty analysis should be developed, reviewed and approved before testing is initiated.
- Liquid composition was not measured during the test program since the test was designed with a binary gas-liquid mixture. The uncertainty analysis also revealed that liquid composition did not have a significant impact on uncertainty given the XLM range covered during the test program. Consider liquid composition analysis specially for higher XLM numbers.

11. Recommendations

- Results documented in this technical report represent one data point. Additional research and testing are required to acquire the knowledge necessary to produce and publish additional API documents that provide recommendations for equipment, methodologies and best practices for wet gas sampling and analysis to produce compositional data and subsequent physical property calculations with reduced uncertainties for use in production measurement and allocation.
- Future testing should consider:
 - Higher Lockhart-Martinelli Numbers.
 - Probe geometry, immersion depth, and location effects
 - Pipe diameter effects
 - Upstream flow disturbance effects
 - Higher heating value (current study ~1000 Btu/scf)
 - A robust test matrix with a larger testing budget
 - Spot, composite, continuous sampling.
 - Adequate sample handling and analysis techniques.
 - Binary mixtures with different molecular weight ratios and different gas-liquid density ratios to explore density ratio dependencies (i.e. methane-water, ethane-heptane).
 - Different connecting tubing diameters, lengths, and elevations above the process piping to explore sample extraction physical dependencies.
 - Impact of flow regime on the wet gas sampling.
 - Relationship between process conditions (pressure, temperature, gas/liquid composition, flow rates), flow regime, and probe characteristics.

Appendix A

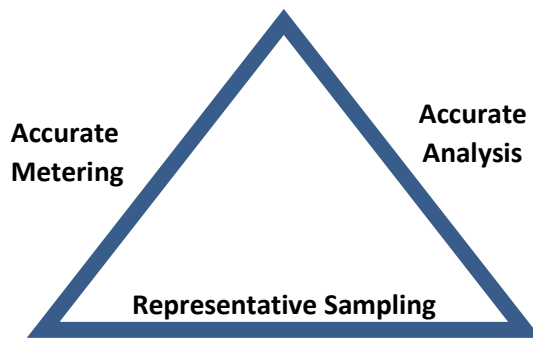
Background Paper for CPMA Wet Gas Technical Report

Background Paper for CPMA Wet Gas Technical Report

Several papers have been written regarding the scope, work, and the need for research and those papers and the suggestions addressed in them are available and in the public domain. An example of that body of work is Matthew Zimmerman's White Paper addressing the challenges of wet gas sampling.¹ The total content of those papers does not need to be repeated in this paper. Clearly those earlier discussions have led us to where we are today and this technical report.

INTRODUCTION AND HISTORICAL BACKGROUND

The need to be able to take a representative sample of a hydrocarbon product such as natural gas, is necessary to ensure accurate measurement, accounting for transactions and efficient product processing. The "Measurement Triangle" shown below is a graphical presentation of the components required to attain accurate results in measurement. –



The amount of hydrocarbon product that is transported between producer, processor, distributor, and user is significant. To be able to verify and identify the composition of the product is important from an economic and product processing standpoint. Obtaining an accurate and representative sample is important to the success of these two transactions. The natural gas industry is focused on two primary measurement issues – Quantity and Quality. Our concern with this paper is the matter of the most accurate determination of the quality of hydrocarbon wet gas streams. If the best sampling procedures are followed, the potential for disputes between supplier and customer will be greatly reduced. The importance of properly determining the hydrocarbon composition benefits all parties involved and will achieve greater significance of the proper handling of this valuable commodity.

Natural Gas sampling has been performed for years with techniques handed down from generation to generation. Most of the earlier methods are not sufficient to meet today's requirements of accuracy and repeatability; however, standards have been developed and continue to be updated to meet those demands. The most widely known standards for sampling of natural gas are API 14.1 (2016), GPA-2166-05 and ISO-10715 (currently under revision and final approval). In 2018, API and GPA joined together to combine API 14.1 and GPA 2166 into one document. This combined standard should be available in 2022 or 2023.

From the Gas Processors Association publication GPA 2166-05, "The objective of the listed sampling procedures is to obtain a representative sample of the gas phase portion of the flowing stream under investigation. Any subsequent analysis of the sample regardless of the test, is inaccurate unless a representative sample is obtained." And, from ISO-10715, a representative sample is, "A sample having the same composition as the material sampled, when the latter is considered as a homogeneous whole." API 14.1 offers a similar definition in the latest revision, "a representative sample is compositionally identical or as near to identical as possible, to the sample source stream", These standards are the most commonly referenced on gas sampling procedures.

Proper sampling is fundamental to the correct determination of the product composition. In most cases, the sample is also the source for the determination of the specific gravity of the gas. This figure is a critical component of the flow formula, from which we derive the product quantity. An error in sampling affects both quality and quantity, and operational integrity by increased uncertainty.

Most current Gas Chromatographs attain a high degree of accuracy. A faulty sampling method or improperly installed and maintained equipment may alter the BTU content of the flowing stream by 25 BTU or greater. While the accuracy of the GC may be considered as a given, the properly executed technique for taking the sample is certainly not a given.

In the last 20-30 years, the measurement of natural gas has encountered some new challenges that are different from the traditional operational parameters of the past several decades as they have transitioned from the supplier of clean, dry gas to the mover of billable gas energy. We have typically dealt with what the industry called "clean, dry natural gas" and our contracts addressed the occasional "water wet" aspect of gas flow and the seldom seen "hydrocarbon wet" carryover in a midstream or downstream gas stream. Gas processing plants have a reasonable assurance of "dry" gas. The water, condensate, or heavy hydrocarbons that create unwanted liquids have been basically removed by processing, separation, or filtration of some type. Today, new production from shale formations, deep sea completions, multiphase operations, changes in operational procedures and a broader range of gathering systems has introduced a greater presence of "hydrocarbon wet" natural gas streams. This presents us with new challenges in both the measurement of volume quantity, as well as the sampling and quality of the gas stream. It is not only important that we sample the natural gas at flowing conditions, but that we also sample ALL components present in the pipeline, regardless of phase, since they are all part of the total stream. To isolate portions of the stream from our sample for whatever reason is to leave us with a non-representative sample of the flowing stream. The importance of properly determining the hydrocarbon composition benefits all parties involved for an accurate accounting of the production and effective and efficient product treatment. Today's measurement issues are different from the past, and they are here to stay. Our challenge is two-fold: a sampling method for hydrocarbon wet gas systems and then an analytical or conditioning technique for proper analysis of the sample.

Liquids are present for several reasons. Producers are trying to meet the demand. Liquids are being passed along in the interest of providing energy. We pull from our storage domes harder and faster than ever before. Deeper wells, shale plays and colder pipelines in deep-water production are yet other sources of liquids. Separator outflows used to be gas and liquid. Today, they are mostly gas and mostly liquid. Two-phase streams see changes in liquid content due to changes in temperature and pressure. Those liquids must be measured and analyzed in a fashion that is representative of the manner in which they were measured as volume. MMBTU is the total of volume and energy. Hydrocarbon liquids that

are present in a natural gas pipeline have monetary value and must be accounted for. Sampling is the energy determination delivery system for this equation, and the results have a dramatic influence on the volume measurement totals. The basis for the current work is the result of the fact that we now see gas pipelines with more liquid content than before. Many are in fact nearing multiphase pipelines. At times, we are led to believe that our leaders of the past never faced or thought of this issue. Here is an interesting paragraph from a paper presented at the University of Oklahoma, to the International School of Hydrocarbon Measurement by Charles Drake in 1981 --- 40 years ago.

“The ability to “tame” liquids when they appear in the gas sample streams or cylinders is now at hand with the availability of high-quality new equipment. The capability of determining the heating value of the gas at any pressure and temperature condition can be determined with reasonable accuracy by conditioning the sample as it is directed to the measuring instrument. However, there is a need to define a “liquid” more precisely in our contracts and state how to account for the heating value of the fluid when liquid is present as an aerosol or otherwise. Should the BTU be determined on the gas at flowing conditions, or should it be determined at a greatly reduced pressure and elevated temperature? Should a pressure and temperature be selected for determining the BTU that would correspond with the average annual ground temperature and average annual pipeline pressure? These and other points must be resolved before any determined effort can be instituted to standardize BTU determination procedure on aerosol gasses.”²

And we are still working on that question today.

The Wet Gas Sampling matter clearly came to the forefront during the API 14.1 work. The Scope of API 14.1 was not inclusive of Hydrocarbon Wet Gas as we know and understand it to be today. At the October 2012 API COPM meeting in New Orleans, the interest of Wet Gas Sampling was brought up in the API 14.1 Working Group of COGFM. It was suggested to move this interest to CPMA. In that meeting, there was clear interest in the matter and an Ad Hoc committee was established to present a white paper for this subject. In 2017 API opened a Working Group to investigate techniques for sampling hydrocarbon wet gas and that group is now currently the active Working Group within API Committee on Production Measurement Allocation (CPMA) that began its work in 2018.

One thing has been very clear in recent discussions on this subject -- there appears to be at least two different concerns about hydrocarbon wet gas. The upstream community needs a sample that will give them the components for meter factors and basic operational information, while the midstream and downstream community needs an accurate analysis for billing and custody transfer that dictates much finer resolution than that needed upstream. We are also addressing those matters in the Working Group.

Current sampling standards clearly state that they are for single phase gas streams. Today’s equipment and technology is not currently designed for multiphase systems at whatever content level is present. In 2008, PRCI along with SwRI conducted research in Wyoming to see the effects of temperature and phase changes with sampling equipment and procedures. That work led to the understanding that further work was needed to address hydrocarbon wet gas systems and to reinforce the needs for hydrocarbon wet gas sampling guidance. An additional discovery was how quickly a single sampling location can change, due to operational changes in a gathering system. Most gas being consumed today is a combined gas

from several origins or is switched from source to source by contractual updates, in some cases by daily or even hourly arrangements.

This issue has promoted the focus for research, and potentially the need for new technologies and/or procedures to minimize the impact of the uncertainty of current wet gas sampling. The concerns of the hydrocarbon measurement industry are real and legitimate concerns. In the race to find answers, we should not fail to keep in mind the lessons that we have learned and have documented to be true in the past. They will allow us to appreciate the current advancements and accept how we arrived at them. We must incorporate that knowledge into the pursuit of future advancements. Technology can provide solutions to these new challenges but as we provide advancements in measurement, we must be cautious to not retreat from lessons that we have learned in the past.

This issue has been driven by several concerns. Value determination has been moving closer and closer to the well head due to allocation, royalty (landowners, State and Federal Government), joint ventures (more partners with commercial interests), streamlining of operations, etc. Sampling used to be done after the gas processing plant, as clean, dry pipeline quality gas – and often by the same company or no more than two parties involved. Liquids were stripped and sampled as liquids. Now, people are concerned with custody transfer earlier in the process. Offshore production, deeper wells, colder temperatures, richer gas streams, shale gas formations and other considerations, all lead to higher BTU gas production and Hydrocarbon Wet Gas streams. Our current gas sampling standards do not address gas streams that are considered as wet gas streams or below hydrocarbon dew point (inside the phase envelope).

The scope of API 14.1 and the resulting data produced from the revision of that standard, was limited to natural gases that “are at or above their hydrocarbon dew point.” The current initial intent, while understandably not the final scope of potential research, is to pursue the next step beyond the scope of 14.1.

Therefore, we seek to determine and quantify (in the field and laboratory) the variability of compositional and BTU content analysis associated with gas sampling in upstream production conditions and similar pipeline conditions, using existing sampling methods (from API 14.1 and GPA 2166) with the target flow regime for this initial testing program to be a Type I (Lockhart-Martinelli) wet gas flow stream.

In closing, for many years the industry has talked about the 4 main ingredients to a successful measurement program:

- The reliability of the equipment and instrumentation used
- The specified policies and practices followed while performing the task
- The quality of the training and performance of the technician
- The proper recording and documentation of the transactions based on a quantifiable standard.

We can now add a fifth major consideration to a superior measurement program:

- Awareness of the total changing environment in which you work, including the evolving system, the changing technology and the revision and introduction of new standards.

¹ “Addressing the Challenges of Wet Gas Sampling and Analysis in the Context of Upstream Production Measurement and Allocation – A White Paper”, Matthew Zimmerman, Presented to API Committee on Production Measurement & Allocation, 2017

² “Techniques of Natural Gas Sampling”, Charles F. Drake, International School of Hydrocarbon Measurement, Norman, Oklahoma, May 1981

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Appendix B

Flow Visualization Spool

To ensure no free liquids were present in the saturated gas stream, SwRI used a full-bore visualization spool shown in the figure below. The two light sources for the spool, which are located directly on the top and bottom of the spool, can be seen. Since the camera is looking through the side of a clear cylinder, the very top and very bottom of the circular image are just distortions from the curved glass. The inner diameter of the cylindrical sight glass was designed to match the inner diameter of the 3-inch, Sch. 160 pipe (2.624-inch diameter) to cause minimal disturbances to the flow.

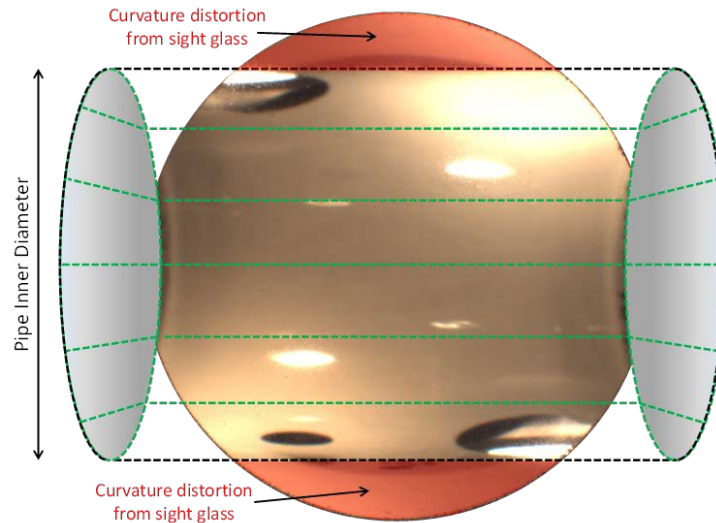


Figure B1. Lateral Flow Image - although the full image is a circle, the very top and bottom portions of the image are just distortions from looking through the side of a clear cylinder. The central core of the image represents the inner diameter of the pipe, which matches the inner diameter of 3-inch Sch. 160 pipe (2.624 inches).

Southwest Research Institute (SwRI) Reference Instrumentation

A summary of the reference instrumentation used during this test program is included in Table 1. This includes the Coriolis meter used for measuring the liquid rates, orifice meter instrumentation, and the pressure, differential pressure, and temperature transmitters installed in the test section. All reference instruments were connected to the facility data acquisition and control system (Emerson Process Management DeltaV) via a FOUNDATION fieldbus digital interface. The data from each sensor were sampled at two-second intervals. The data acquisition system allowed for a real-time display of all measurements during the testing.

Gas flow rate calculations were completed using AGA standards, with equations used from Report No. 3 (AGA3) to calculate mass flow rates. Gas density was determined from the AGA8 equation of state.

Table B1. Reference Instrumentation, where the corresponding ranges of operation and uncertainty for each instrument are shown in the table below.

TAG ID	MEASURED PARAMETER	MANUFACTURER	MODEL	RANGE	UNCERTAINTY
FM-104	Liquid Flow Rates	Micro Motion®	F050P	150 lb/min	< ±0.18% of rate
PT-105	Gas Flow Rates - Orifice Static Pressure	Rosemount™	3051S	0-4,000 psi	±0.065% of span
DPT-104	Gas Flow Rates - Orifice Differential Pressure	Rosemount	3051S	0-250 inH ₂ O	±0.04% of reading
TT-105	Gas Flow Rates - Orifice Temperature	Rosemount	3144P	0-120°F	DIN-IEC-751 Class B Tolerance
PT-901	Saturated Gas Stream Static Pressure	Rosemount	3051S	0-4,000 psi	±0.065% of span
TT-901	Saturated Gas Stream Temperature	Rosemount	3144P	0-120°F	DIN-IEC-751 Class B Tolerance
PT-902	Wet Gas Sample Static Pressure	Rosemount	3051S	0-4,000 psi	±0.065% of span
TT-902	Wet Gas Sample Temperature	Rosemount	3144P	0-120°F	DIN-IEC-751 Class B Tolerance
PT-903	Liquid Stream Static Pressure	Rosemount	3051S	0-4,000 psi	±0.065% of span
TT-903	Liquid Stream Temperature	Rosemount	3144P	0-120°F	DIN-IEC-751 Class B Tolerance
DPT-901	DP - MFF Separator to Gas/Oil Mixing Location	Rosemount	3051C	0-1,000 inH ₂ O	±0.065% of span
DPT-902	DP - Downstream of Orifice to GC Location	Rosemount	3051S	0-250 inH ₂ O	±0.065% of span
DPT-903	DP - GC Location to Wet Gas Sample Location	Rosemount	3051S	0-250 inH ₂ O	±0.065% of span

Appendix C

Addressing the Challenges of Wet Gas Sampling and Analysis in the Context of Upstream Production Measurement and Allocation – A White Paper

Problem Statement

Fluid sampling is an intrinsic part of the oil & gas industry. Fluids samples are used for various purposes throughout the entire production value chain, from upstream to downstream segments. A sample of fluid that is representative of the reservoir hydrocarbon composition is required to obtain fluid properties and other information that are used as input for production measurement and allocation purposes.

When the objective is to obtain surface samples to recreate the original reservoir fluid composition, or the composite composition of several hydrocarbon sources, the task becomes extremely challenging when the flowing stream is in a two-phase state. For gas dominated flow regime, this gives rise to what is called *wet gas sampling*.

There is no industry standard for this type of sampling. Wet gas sampling methodologies and equipment used today either rely on industry standards that were not intended for the application, or on bespoke methods and equipment. The misapplication of current standards or use of bespoke techniques potentially lead to increased variability and uncertainty in derived information, such as composition and heating value, which are used as input in production measurement and allocation activities.

What is the impact of the misapplication of standards? What uncertainty range exists with the current approach? There is plenty of anecdotal evidence for the existence of the problem, but there is no real consensus on the magnitude of the problem.

The white paper seeks to address wet gas sampling challenges by looking at the broad picture, inclusive of the information required from the sample and the associated analytical procedures. The term representative will be used in the context of a composite mixture that recreates the reservoir fluid composition, regardless of the state of the fluid samples used to create such mixture.

The **goal** is to produce and publish an official API document that provides recommendations for equipment, methodologies and best practices for wet gas sampling and analysis to achieve a representative recombined mixture and thereby minimizing the uncertainty of fluid properties and other information used in production measurement and allocation.

The **objectives** to achieve the goal are outlined in the Proposed Course of Action section below.

Introduction

In upstream production, information regarding the fluids of interest is required as input parameters throughout the entire measurement and allocation process. The information typically includes the components in the mixture and their relative amounts, physical and thermodynamic properties, fluid phase behavior and water fraction. Knowledge of the fluid composition and properties allows the determination of other properties that are used as input for operational, commercial and regulatory purposes. In the natural gas industry, several applications including custody transfer, process and quality

control, facilities integrity management and regulatory compliance rely on information from the gas stream. The information, in turn, is obtained from a sample of the flowing fluid stream.

Natural gas changes ownership at numerous points over the entire value chain. This change or transfer of ownership occurs at custody transfer points. Gas properties such as energy content (Btu/scf) and density are critical for monetary valuation in custody transfer. Accurate measurement of water and hydrogen sulfide contents can identify potential pipeline integrity issues, which then drives appropriate mitigation measures.

If the flowing gas stream is in the single-phase state, either sufficiently away from or close to the saturation or dew-point curve, and the intent is to capture sample of the single-phase gas, API 14.1 and GPA 2166-05 provide recommendations for equipment, methodologies and best practices to increase the probability and reliability of obtaining a single-phase sample.

When the conditions in the pipe causes the flowing stream to enter the two-phase region, then simultaneous gas and liquid flow occurs. If the intent is to capture aliquot samples of the gas and liquid phases such that when recombined recreates a *representative* reservoir fluid, this gives rise to a wet gas sampling condition. Wet gas sampling is outside the technical scope of above cited industry standards.

Nevertheless, wet gas sampling today largely relies on the same industry standards that were intended for single-phase sampling applications. Practitioners have developed bespoke practices and in-house equipment for wet gas sampling. Since sampling systems and practices are rarely, if ever proved or audited to assess their efficacy, the industry is silent regarding the potential uncertainties that may arise from current practices.

Gas production has historically been sourced from naturally occurring gas reservoirs. This reservoir fluid type is called lean or dry gas and is characterized by very high methane concentration. These types of fluids produce very little, or no liquid when brought to surface conditions.

With the development of deep-water basins like the Gulf of Mexico, production from conventional crude oil reservoirs brought with it tremendous volume of what is called associated gas. These gases are often “rich” with lower methane and increased light to intermediate hydrocarbon components concentration. These rich gases are characterized by gross heating values in excess of 1,700 Btu/scf in contrast to lean gases’ 1,150 Btu/scf or less.

The natural gas market has experienced tremendous growth in the last decade. This is due to discoveries of new gas fields and the development of new methods of extraction. Gas production, particularly in North America, has been experiencing a transformation due to new production technologies that have been brought to bear on technically challenging resources such as tight gas plays. These new technologies have created a step change in terms of the volume of natural gas that has come into the market but has also resulted in the increased complexity of its management.

The drive to improve production measurement and allocation of products, use of complex shared pipeline networks and demands to improve the measurement of properties of difficult production fluids have made the industry shine a light on the concerns involved in potentially large uncertainties introduced by wet gas sampling inaccuracies.

Background

Fluid samples are required to obtain information about the hydrocarbon mixture. Samples of a wet gas stream may be needed for several reasons. These include:

- Determination of liquid loading for correction of single-phase meters used in wet gas flow measurement
- Provision of configuration parameters for single-phase or wet gas/multiphase meters
- Determination of the overall fluid composition for the calculation of physical and thermodynamic properties for input in allocation and custody transfer
- PVT analyses on the fluids
- Determination if water is present and the amount for operational and facility integrity management purposes
- Well testing and performance monitoring
- Solids determination for flow assurance

It is common knowledge in the industry that the wet gas sampling is very challenging to perform if the objective is to capture gas and liquid portions with the relative volumetric proportion such that when recombined, produces the overall composition of the combined gas and liquid flowing in the pipe.

Gas sampling equipment has been inadequate to provide accurate, consistent, and reliable samples when applied to wet gases. Operators and service companies have developed bespoke practices and in-house equipment for wet gas sampling. Sampling systems and practices are rarely, if ever proved or audited to assess their efficacy. The measurement impact of a distorted wet gas sample is acknowledged but the business impact has largely been un-quantified. George and Kelner [4] estimated that biased analysis due to liquid condensation, if left un-captured, can produced errors in heating value or other gas properties more than 10 percent.

Proposed Course of Action to Develop an API Document on Wet Gas Sampling

The following steps are proposed in order to address the wet gas sampling challenges articulated in this white paper.

Phase I is to conduct a thorough investigation on the state of the art of wet gas sampling, per API 14.1/GPA 2166-05 or otherwise. This would include the following:

- Equipment currently available in the market
- Equipment used by operators and service companies
- Methods, practices and procedures used in wet gas sampling
- On-going product development or research
- Performance evaluation of wet gas samplers

Phase II is to quantify the uncertainty range on information derived from fluid samples utilizing the equipment and methodologies from step one. Included in this step is the framing of a business case based on the uncertainties.

Phase III explores new methodologies, equipment, and analytical procedures in wet gas sampling with the intent of recreating a mixture that is representative of the reservoir fluid.

At the very least, the outcome of Phases I and II will be incorporated into an API Technical Report. Depending on the outcome of Phase III, the development of an API Standard or Recommended Practice may be warranted.

Task Group I Report on the Literature Survey to Identify Potential Wet Sampling Methods to Test in Phase II of API CPMA Wet Gas Sampling Research Prepared for the Wet Gas Sampling Working

Background

A Wet Gas Ad-Hoc group was formed at the October 2016 CPMA Meeting chaired by David Courtney, COP. Joe Landes, SPL, agreed to lead the group. In April of 2018, an SR3 was submitted via letter ballot to CPMA which was approved by COPM in May 2018. A Wet Gas Working group was subsequently established, chaired by Dave Curtis, Anadarko. The SR3 Wet Gas Sampling study was conceived to evaluate various wet gas sampling methods currently used in the industry. The goal is to establish baseline technical performance capability that would enable the quantitative assessment of the business impact of wet gas sampling in upstream measurement and allocation. The SR3 proposed a research plan to test various wet gas sampling methods. The proposed plan is broken down into 3 phases as follows:

- Phase I – identify dry gas sampling methods to be tested in wet gas sampling conditions in Phase II; identify “prototype” wet gas sampling methods to be tested in wet gas sampling conditions in Phase III Phase II – test dry gas sampling methods identified in Phase I on Type I wet gas flow and evaluate performance
- Phase III – test “prototype” wet gas methods identified in Phase I on Type I wet gas flow and evaluate performance

Phase I is a non-funded, volunteer-based part of the study, tasked with identifying and recommending existing and prototype gas sampling methods to be tested in Phases II and III. Existing gas sampling methods refer to dry gas methods and equipment covered under MPMS Chapter 14 – Natural Gas Fluids Measurement, Section 1 – Collecting and Handling of Natural Gas Samples for Custody Transfer (API 14.1) and GPA Standard 2166-05 – Obtaining Natural Gas Samples for Analysis by Gas Chromatography (GPA 2166). Prototype wet gas sampling methods are those that are either currently in development, offered in the market or used internally by operators or service companies. The label prototype stems from the lack of industry standards that cover such techniques.

A literature and industry survey is the planned approach to accomplish Phase I objectives. Phase II is the funded portion of the study that will test API 14.1/GPA 2166 dry gas methods that have been identified and recommended by Phase I survey. The plan is to test sampling methods under wet gas conditions of the API Type I class, with Lockhart-Martinelli number of 0.02 or less. Phase III is intended to test prototype wet gas sampling methods also with Type I wet gas flow regimes. This part of the study is currently unfunded.

In August 2018, two Task Groups were formed to advance the Phase I and Phase II objectives. This report details the finding of TG I per the deliverables listed in Section 2.2 – (a) and (b). The wet gas sampling check list per Section 2.2 (c) is presented in a separate document.

Task Group I Objectives

TG I is tasked with the following objectives: 1. Identify API 14.1/GPA 2166 dry gas sampling methods that showed promising but unquantified results in previous bodies of work. 2. Identify prototype wet gas sampling methods that are in development, currently offered in the market or used by service companies. 3. Develop guidelines for the design of wet gas sampling testing

Deliverables

TG I is tasked with the delivery of a report that includes the following:

- a. Recommended dry gas sampling methods per API 14.1/GPA 2166 to be tested in Phase II of the API CPMA Wet Gas Sampling Study
- b. Recommended prototype wet gas sampling methods be tested in future Phase III of the API CPMA Wet Gas Sampling Study
- c. Wet Gas Sampling Checklist is a document that contains guidelines on how to conduct wet gas sampling tests.

The checklist include: (a) types of data to gather, (b) test procedures and analytical equipment quality control, (c) general information on experience and lessons learned from previous body of testing on gas sampling

Dry Gas Sampling Methods Literature Survey Results

A literature survey narrowed the down relevant documents to the Topical Reports produced from a body of work on natural gas sampling funded by the Gas Research Institute (GRI), the American Petroleum Institute (API) and the former US Minerals Management Services (now BSEE). The documents are listed below:

1. Behring II, K. A., Kelner, E.: Natural Gas Sample Collection and Handling – Phase I, GRI Topical Report No. GRI-99/0194, Aug. 1999.
2. Kelner, E., Behring II, K. A., and Sparks, C. R.: Natural Gas Sample Collection and Handling – Phase II: Experimental Testing Under Simulated Field Conditions, GRI Topical Report No. GRI-01/0069, Jan. 2003.
3. Kelner, E., Behring II, K. A., and Sparks, C. R.: Natural Gas Sample Collection and Handling – Phase III: Experimental Investigation of Gas Sampling Techniques and Equipment, GRI Topical Report No. GRI-01/0070, Aug. 2002.
4. George, D. L., Barajas, A. M., Kelner, E., and Nored, M.: Natural Gas Sample Collection and Handling – Phase IV, GRI Topical Report No. GRI-03/0049, Jan. 2005.
5. George, D. L., Burkey, R. C., and Morrow, T. B.: Natural Gas Sample Collection and Handling – Phase V, GRI Topical Report No. GRI-05/0134, Mar. 2005.
6. Nored, M. and George, D. L.: A Review of the Current State and Direction of Methods for Sampling Wet Gas Flows, prepared for the U.S. Minerals Management Service, May 2003.

7. George, D. L.: Testing of Environmentally-Friendly Gas Sampling Methods at Hydrocarbon Dew Point Conditions, prepared for the Measurement Technical Committee, Pipeline Research Council International, Inc., April 2009.

Prototype wet gas sampling methods industry survey

An industry survey was conducted to publicize prototype wet gas sampling techniques that are not common knowledge in the industry. It is recognized that some of these techniques may be only used “in-house” by service companies, while a few may be offered in the market and some may yet be in development. The various systems are not listed here due to a lack of commonly accepted functional specifications for these prototype devices. This could be the subject of the future Phase III work scope.

Summary of Findings – Dry Gas Sampling Methods with Potential for Wet Gas Application

There are eight (8) dry natural gas spot sample methods listed in GPA 2166-05 and API 14.1-2006. These are:

1. Purging – Fill and Empty Method
2. Purging – Controlled Rate Method
3. Evacuated Container Method
4. Reduce Pressure Method
5. Helium Pop Method
6. Glycol Displacement Method
7. Water Displacement Method
8. Floating Piston Cylinder Method

The following are key takeaways from the review of the documents previously listed:

- a. When the flowing gas stream is well above dew-point conditions (Ref #1):
 - i. Any API 14.1/GPA 2166 method is capable of reproducing the source gas composition
 - ii. Sample integrity appear to be insensitive to probe design and location
- b. In-transit gas, i.e., gas stream flowing from the pipe exit point to a container, if exposed to ambient or equipment conditions below dewpoint, could retain sample integrity provided:
 - i. Liquid drop-out are swept into a closed-end container
 - ii. Close-coupled methods that employ dead-end filling are employed (Ref #1)
- c. API 14.1/GPA 2166 spot sampling methods tested under two-phase flowing conditions did not produce quantitative results (Ref #2)
- d. Trends in Phase I laboratory tests were generally reflected in Phase II simulated field tests, but with higher (unquantified) uncertainties (Ref #2)
- e. Probe location should be away from flow disturbance when flowing conditions are near or at dew-point conditions (Ref #2)
- f. Certain API 14.1/GPA 2166 spot sampling methods showed promising (but unquantified) results when two-phase hydrocarbon gas-liquid conditions exist either in the pipe or any point along the sampling system between the pipe exit and in container inlet points
- g. The three methods per item (f) are:
 - i. Fill and Empty Purging Method (Ref #2 and Ref #7)
 - ii. Helium Pop Method (Ref #2)

- iii. Constant Pressure Cylinder Method (Ref #2 and Ref #7)

Phase II Testing Recommendations

Based on the review of the documents cited in Section 3.1, the following API 14.1/GPA 2166 spot sampling methods are identified to have the potential to be utilized for sampling of wet natural gas streams, and are hereby recommended for testing in Phase II of this study:

1. Fill and Empty Purging Method
2. Helium Pop Method
3. Constant Pressure Cylinder Method.