

FUNDAMENTALS OF NATURAL GAS LIQUID MEASUREMENT

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Introduction

The measurement of natural gas liquids (NGL) is similar in many respects to that of other hydrocarbon liquids but is markedly different in other aspects. The main difference in NGL measurement is the need to properly address the effects of solution mixing. Measuring NGL by mass measurement techniques will properly address solution mixing effects because the mass measurement process is not sensitive to the effect that pressure, temperature and solution mixing have on the fluid measured.

Another difference is the effect of higher vapor pressures on the measurement of natural gas liquids. In static measurement methods, the liquid equivalent of the vapor space must be determined. In dynamic measurement methods, the equilibrium vapor pressure, or that pressure at which a liquid and its vapor phase is in equilibrium at a given operating temperature, must be deducted from the operating pressure when determining the compressibility effects on measured volumes.

This paper will describe the basic concepts used to measure and report the quantities of NGL streams.

Natural Gas Liquids

Natural gas liquids are a mixture of light hydrocarbons, with small amounts of inerts, in liquid form. NGLs are typically produced by natural gas processing activities such as those found in cryogenic gas plants, lean oil absorption plants and Joule-Thompson (J-T) plants. The liquid condensing in piping and vessels as part of the process of gathering raw natural gas from the wellhead may also be NGL. An NGL stream is often called Y-Grade, raw product or raw make.

NGL composition can vary widely but is expected to include a mixture of hydrocarbons from ethane through hexanes plus. Table 5 provides an example of an NGL composition. Some NGLs have more ethane and others have significantly less than in this example. Liquefied petroleum gas, LPG or LP-Gas, is a subset of the NGL composition. LPG is propane and/or butanes, as well as their olefin equivalents, with small amounts of other hydrocarbons. LPG results from further processing the NGL stream in a fractionation plant. A fractionation plant distills the NGL feed stream into individual component streams like ethane, propane, isobutane, normal butane and natural gasoline.

Propane and butanes are also obtained as by-products of crude oil refining processes. Whether propane are derived from natural gas streams (approximately 60%) or derived from crude oil refining processes (approximately 40%), they are chemically the same. Historically, the term LPG came from the crude oil refining industry while the term NGL came from the natural gas production industry.

Measurement Methods

Static measurement can be described as that measurement of a natural gas liquid while the liquid is at rest. Static measurements can be performed on either a direct or inferred mass basis.

Dynamic measurement can be described as that measurement of a natural gas liquid while the liquid is flowing in a pipe. Dynamic measurements can be performed on either a direct or inferred mass basis.

Static Volumetric Measurement

Types of tanks (pressurized and non-pressurized) used for static measurement of hydrocarbon volumes:

- Upright cylindrical
- Spheres and Bullets
- Trucks and Rail Cars
- Ships and Barges

Natural gas liquids can take the form of lower vapor pressure hydrocarbon liquids (e.g., low vapor pressure condensates) in which the liquid volumes can be measured in low pressure upright cylindrical tanks or in low pressure horizontal tanks. The horizontal tanks can be in the form of stationary bullet tanks, truck mounted trailer tanks or railroad tank cars.

Natural gas liquids can take the form of higher vapor pressure hydrocarbon liquids (e.g., condensates, ethane, propane, butane mixes) in which the liquid volumes can be measured in spherical tanks, or in horizontal cylindrical tanks with high pressure end caps. The horizontal tanks can be in the form of truck mounted trailer tanks or railroad tank cars.

In either case the tank is calibrated so that its liquid volumetric capacity is correlated to the liquid level in the tank. Manual gauging of liquid levels in lease tanks on low vapor pressure liquids is accomplished by using a calibrated tape and bob. Other forms of gauging include the use of float and tape gauges, servo gauges and radar gauges. The equipment and methodologies are described in various sections of the American Petroleum Institute (API) Manual of Petroleum Measurement Standards (MPMS), Chapter 3.

For this discussion, assume the absence of any sediment and water as well as any free water that would normally be present with produced crude oil.

For this discussion, assume the liquid to be condensate for which volume and density corrections can be made using physical properties data in API MPMS Chapter 11 (Tables 5A/6A or 23A/24A).

To determine a liquid volume at standard conditions of 60 degrees F and equilibrium vapor pressure at operating conditions the following are required:

- Tank capacity table for the measuring tank
- Tank liquid level (API MPMS Chapter 3)
- Tank liquid temperature (API MPMS Chapter 7)
- Composite sample (API MPMS Chapter 8)
- Density of liquid at test temperature (API MPMS Chapter 9)
- Equilibrium vapor pressure at tank liquid temperature

Determine the gross standard volume of the liquid:

- Using the tank capacity table and the tank liquid level, determine the total observed volume (TOV).
- Make any necessary corrections to the tank volume itself (e.g., steel temperature of the tank shell vs. reference shell temperature) at operating temperature to determine the gross observed volume (GOV).
- Using the physical property data in API MPMS Chapter 11, determine the density of the liquid at 60 degrees F.
- Using the physical property data in API MPMS Chapter 11, determine the correction for temperature of the liquid (CTL) to correct the volume to what it would be at 60 degrees F.
- Using calculation procedures in API MPMS Chapter 12, calculate the gross standard volume (GSV) of the liquid in the tank:

$$GOV \times CTL = GSV \quad \text{Equation (1)}$$

- From the tank capacity table determine the space of the vapor volume.
- Using methods described in GPA 8173 determine the equivalent liquid volume by:

$$GSV_v = (Vapor\ Volume) \times \left(\frac{P_o}{P_a}\right) \times \left(\frac{T_a}{T_o}\right) \times (FACTOR\ for\ liquid\ volume) \quad \text{Equation (2)}$$

- Total Liquid Volume at 60 degrees F = (Liquid Volume at 60 degrees F) + (Equivalent Liquid Volume from Vapor at 60 degrees F).

Failing to calculate the equivalent liquid volumes of the vapor space can produce errors great than 4%.

Static Mass Measurement:

Weighing is the only truly direct method of static mass measurement, but the following illustrate four different approaches including weighing of truck and railcar tanks.

Inferred Static Mass - by static volumetric measurement:

- Use the “Mass = Density x Volume” relationship from the static volumetric measurements above
- Mass = (Density of Total Liquid Volume at 60 degrees F) x (Total Liquid Volume at 60 degrees F)

Inferred Static Mass - by hydrostatic tank gauging (HTG) methodology on upright cylindrical tanks:

- Install precise pressure gauges at top in vapor space, middle and bottom (i.e., PT, PM, PB)
- Depends upon known tank area
- Depends upon known vertical height (HBM) from PB to PM
- Depends upon uniform density
- Calculate Mass: $(PB - PT) \times \text{Area}$
- Calculate Density: $(PB - PM) / (\text{HBM})$
- Calculate Volume: $(\text{Mass}) / (\text{Density})$
- Calculate Level: $(PB - PT) \times (\text{Density}) + \text{HBM}$

Direct Static Mass – by Weigh Scale Measurement

- Weighing tank trucks
- Weighing tank railcars

Whether measuring gross standard volumes, inferred mass or direct mass, all measurement equipment must be in calibration and traceable to the National Institute of Standards and Technology.

Dynamic Mass Measurement

There are two basic forms of dynamic mass measurement:

- Inferred mass measurement by a turbine meter and a density meter (densitometer)
- Direct mass measurement by Coriolis force flow meter

Inferred Mass Measurement

When operating a turbine meter on a volumetric basis, and assuming an NGL which is basically free of any entrained sediment and water as well as free water, it is normally assumed that physical property data along with proving the meter will enable the user to calculate a net standard volume, which is the volume at 60 degrees F and equilibrium vapor pressure at operating temperature, by the following:

$$NSV = IV \times MF \times CTL = IV \times CCF \quad \text{Equation (3)}$$

Where: IV = Indicated volume
MF = Meter Factor
CTL = Correction for Liquid Temperature
CPL = Correction for Liquid Pressure

This approach is suitable for single grade NGL streams because physical property data exists with which to predict changes in density and volumes with changes in temperature and pressure. This approach does not work so well when two or more grades of NGL are mixed together in a flowing stream because the volume of the mixed stream is not as great as the total of the two or three components. Furthermore, the physical property data is not as reliable in predicting changes in densities and volumes with changes in temperature and pressure as it is in single grade products. The answer in this case is to go on a mass basis by using a density meter in conjunction with the flow meter. By knowing the density of each segment of volume at operating temperature and pressure, one can calculate the mass of each of those volumetric segments. Later, when a gas

chromatograph is used to determine the weight percent of each component, known physical property data can be used to determine the volume of each component at standard conditions.

The mass for each metered segment is calculated by:

$$Mass = IV \times MF \times Density \times DCF \quad \text{Equation (4)}$$

Where: IV = Indicated volume of the turbine meter
MF = Meter Factor
Density = Density from the density meter
DCF = Density meter correction factor

To make this really work well, the system must be designed so that there is no significant temperature differential from the flow meter to the densitometer, and even through the meter prover and pycnometer during proving operations. For this reason, many inferred mass metering systems are insulated at least in part, and care is given to minimizing pressure drop in the piping.

The turbine meter itself is an inferential device in that it does not directly sense volume but rather senses flowing stream velocity. By design, it senses the average velocity. A volume throughput is inferred by a combination of average velocity and the area of the flow meter housing. As the flow velocity increases, so does the rotational velocity of the rotor in a linear fashion. At lower flow rates especially, when Reynolds numbers are less than 4,000 the flow regime is either laminar or in a transition phase. This compromises the linearity of the meter response. A Reynolds greater than 4,000 is required to develop turbulent flow and even then, depending upon the upstream piping configuration, it can be skewed or swirling without the use of appropriate flow conditioners. Generally, for liquid turbines the upstream piping, free of any protrusions, must be at least ten pipe diameters in length including the flow conditioner. There are situations where even ten pipe diameters is not enough and some flow conditioners are more effective than others. Tube bundles themselves correct swirling but are not complete flow conditioners unto themselves. Turbine meters typically work best from 40% to 100% of their maximum design rating for the liquid being measured.

Debris in tube bundles or partially plugged strainers can cause distortions in the flow profile as well. It is now well documented that even shifting a strainer basket from one cleaning to another can cause changes in the flow profile so strainer baskets should be locked in place in a consistent manner following each cleaning. For the reasons of both flow profile variations and meter performance itself, it is important to prove the meter at the same conditions (e.g., flow rates) as are present during normal operations.

The downstream side of the meter must have a minimum of five pipe diameters. There must be a sufficient back pressure at the outlet side of the meter to ensure that no cavitation takes place. The minimum back pressure must be at least 125% of the equilibrium vapor pressure of the liquid at flowing conditions plus at least two times the pressure drop through the meter itself.

Displacement provers, of several different types and designs (e.g., bi-directional, unidirectional, and unidirectional with external detectors and a captive displacer) are used to prove flow meters. When proving a flow meter, regardless of type, care must be taken to ensure that only the liquid flowing through the meter being proved passes through the prover, and that no liquid from an adjacent meter in a parallel manifold passes through the prover. These issues are addressed through the use of double block and bleed valves. Double block and bleed valves are used for the prover bypass valve for the meter being proved, and the prover inlet valves from each of the adjacent meters in a parallel meter manifold. The double block and bleed valves need to be verified for bubble tight seal each time they are closed because that is precisely the most likely time for them to fail. All vents, drains and thermal relief valves must also be monitored for leaks which would compromise the accuracy of the proving of the meter. If for any reason a bypass line is installed in a metering system, it must have a double block and bleed valve as well to ensure that the entire flowing stream intended for a meter run is actually going through the meter.

In a single proving pass, from the first detector to the second detector in a given direction, a snapshot reading is taken from the meter being proved during the exact same time that a displacer moves from one detector to the next in a single pass. Since the prover, calibrated by field standards traceable to the National Institute of Standards and Technology (NIST) has a known volume, either on a round trip or unidirectional basis, it can be used to prove the meter (i.e., judge its performance) and determine its meter factor. The meter factor is subsequently used to correct the volumes indicated by the meter.

Temperature and pressure transmitters must be calibrated and verified on a regular basis or errors will be introduced into the measuring process. A test well should be placed adjacent to each thermometer location for the purpose of verification. Even the flow computers must be verified for both the integrity of their receipt of online data (e.g., meter pulses, temperature, and pressure). All measurement devices must be traceable to NIST.

Just as the flow meter needs to be proved on a regular basis, so does the density meter. A pycnometer, used to prove the density meter, is a pressurized vessel with a known volume and weight. Mounted in parallel or in series with the density meter, enough flow must be induced through the pycnometer to assure that it is measuring the same fluid as the density meter, and that the temperature is also the same. The system is also designed to minimize pressure drop through the pycnometer. Any damage to the pycnometer can compromise either its volume or its weight in which case it would need to be re-calibrated.

The procedure for each proving run, starting with a calibrated, clean, empty and fully evacuated pycnometer, and insulated pycnometer, would include the following steps: (a) weigh the evacuated pycnometer; (b) confirm that the tare weight is within 0.02% of the reference evacuated weight stated on the calibration report; (c) hook up the pycnometer (inlet and outlet) in proximity to the density meter; (d) slowly fill the pycnometer through its inlet valve; (e) slowly open the outlet valve of the pycnometer; (f) allow the flow through to continue until the temperature has reached the temperature of the density meter and the density reading has become stable, slowly close the outlet valve on the pycnometer; (g) slowly close the inlet valve on the pycnometer; (h) disconnect the pycnometer which is still 100% full; (i) weigh the fluid filled pycnometer; (j) purge the pycnometer and clean as necessary; (k) re-evacuate the pycnometer; (l) re-weigh the pycnometer to again confirm its reference evacuated weight; (m) repeat steps “c” through “m” and confirm that the DCF of the three runs are within 0.05%.

Coriolis Force Meters

The Coriolis force flow meter is basically made up of one or two flow tubes in parallel. For this discussion a two-tube configuration is assumed. A coil and magnet type driver is placed at the mid-point of the two tubes. The driver induces a vibration in the tubes at or near the resonant frequency of tubes (e.g., 80 Hz). Pick-up coil assemblies are usually mounted equidistantly from the driver location. One is mounted upstream of the driver location at a point of flow direction change, and the other is mounted downstream of the driver location at a symmetrical point of flow direction change. Each pick-up coil assembly generates a sinusoidal voltage wave. In a no-flow condition, with the meter properly zeroed, these two sinusoidal waves are in-phase. When there is flow, the sensor tubes twist in such a way that the sine waves for upstream and downstream get out of phase. Viewed on an oscilloscope, the inlet sine wave would be slightly ahead of the outlet sine wave in time. This time lag would vary with the rate of mass flow through the meter tube sensors.

Because the Coriolis force meter depends upon the use of resonant frequency in its principle of operation, it is susceptible to error cause by improper installation. The meter must be isolated from outside induced harmonics and there should be no stress induced by improper alignment of connecting flanges. Two Coriolis meters in parallel can actually corrupt their respective signals if not properly installed. The housing of the meter should never be used to support any other structure, and all stresses to the meter should be relieved.

The Coriolis force meter naturally reads out in mass units. Because it uses electronically manufactured pulses rather than directly generated pulses as is done with a turbine meter, meter proving might require using more runs for a proving while allowing a wider range. API MPMS Chapter 4.8 provides guidance on varying the number of runs for proving. For example, while five consecutive runs within a range of 0.05% might be all that is required to prove a turbine meter, there are cases where using the same prover at the same flow rate might require the use of ten consecutive runs with a range of 0.10%. In this example though, the statistical uncertainty, considering repeatability alone, would be a confidence level of 95% that the meter factor determined is within 0.026 percent of the true value.

Although a density meter is not needed for the purpose of determining the mass throughput of the meter, it would be necessary in conjunction with the operation of the displacement prover. That is because the displacement prover is a volumetric device and a proving density is needed to infer the known mass as compared to the Coriolis force meter output. In this situation, though the Coriolis meter can be configured to give a density readout the density used in proving should be determined by a separate density meter that has been calibrated by means of a pycnometer.

Automatic Sampling

Once mass has been determined, either by a combination of a turbine meter and density meter, or by a Coriolis force meter, it is necessary to test the composite sample using a gas chromatograph to be able to discern the component barrels of the various components of the natural gas liquids stream.

The sampling is performed by taking discrete bites (grabs) either from the center half of the pipe in the metering manifold, or by using a so-called smaller diameter “fast loop” which is essentially a slip stream. In this case the slip stream flow should equal the maximum flowing velocity in the main line. Stream conditioning, either by static mixing elements or by power mixing is used to ensure that the sampling bites are representative of the flowing stream. The bite size must consistently be within 5% of its stated size (e.g., 0.95 to 1.00 ml or 1.00 to 1.05 ml). The sampler is best paced using the custody transfer meters so that sampling frequency increases at higher flow rates and decreases and lower flow in a linear fashion. If alternate meters are used they must be able to meter a volume within 10% of the true value. The sample bites themselves are usually caught in a pressurized balanced pressure cylinder which is taken to lab at the end of the measurement period for analysis.

Terminology

Mass is an absolute measure of the quantity of matter, a fundamental property. It is one of the seven base quantities together with length, time, temperature, amount of substance, electric current and luminous intensity. It is a numerical measure of the inertia of an object. Mass is constant, providing the speed of the object is not approaching the speed of light, such that mass is the same in Houston, in Denver at its higher elevation, on the moon and on the International Space Station (ISS). On the other hand, weight is the force that gravitational acceleration has on an object with mass. Weight varies with location and is essentially zero on the ISS. Confusion can result from both mass and weight using the same units of measure.

Density is a property that is mass per unit volume and is often represented by the lowercase Greek letter rho, ρ . Its units of measure for NGL measurement include grams per cubic centimeter, g/cc, pounds per gallon, lb/gal, pounds per barrel, lb/bbl and kilograms per meter cubed, kg/m³.

The components found in an NGL stream are often abbreviated on analysis reports, meter tickets, calculations and in casual conversation. Table 1 lists the abbreviation associated with typical NGL components.

Component	Abbreviation
Nitrogen	N ₂
Carbon Dioxide	CO ₂
Methane	C ₁
Ethane	C ₂
Propane	C ₃
Isobutane	iC ₄
Normal Butane	nC ₄
Isopentane	iC ₅
Normal Pentane	nC ₅
Normal Hexane	nC ₆
Hexanes plus	C ₆₊
Normal Heptane	nC ₇
Heptanes plus	C ₇₊
Normal Octane	nC ₈

Table 1. Typical Abbreviations

Chemistry & Physical Properties

The hydrocarbon molecules found in an NGL stream vary in size from a relatively small ethane molecule through a relatively large normal hexane molecule to even larger, higher carbon-content molecules. It is this difference in size at the molecular level that leads to solution mixing. Solution mixing is the phenomenon of smaller molecules fitting between the spaces left between larger molecules in the mixture. Although not to scale, Table 2 gives a feel for the size difference between some typical hydrocarbon molecules.

Mixing sand and gravel in equal volumes provides a reasonable illustration of solution mixing. Since the sand will fit between the larger gravel pieces, the volume of the mixture is less than the sum of the two original volumes. Of course, a screening operation would be able to separate the sand from the gravel and return each to their original volume. The apparent difference between the volume of the mixture and the sum of the volume of each component is the shrinkage.

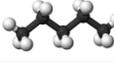
Component	Molecular Representation
C ₁	
C ₂	
C ₃	
iC ₄	
nC ₄	
iC ₅	
nC ₅	
nC ₆	

Table 2. Molecular Representation (Wikipedia)

Solution mixing causes an indicated NGL volume to be less than the sum of the volumes of the individual, pure components. In many cases, this difference is around 4%.

Temperature and pressure affect the volume of the liquid because they affect the density of the fluid. As temperature increases, a given mass of liquid will occupy more volume. Since density is the property of mass per unit volume, a larger number in the denominator results in a lower density. An increase in temperature causes a decrease in density. For light hydrocarbons, the change in density with respect to temperature is not linear and is not represented by a simple equation.

Figure 1 shows the density for typical ethane, propane, normal butane and gasoline compositions for temperatures between 0 and 150 degrees F. The ethane graph more clearly indicates the non-linear relationship between density and temperature for hydrocarbons typically found in NGL. Note that its density curve ends around 93 degrees F when the ethane reaches its critical temperature. Slight changes in temperature near the critical point cause large changes in density. A graph of the density of water from 32 to 150 degrees F is shown for comparison purposes.

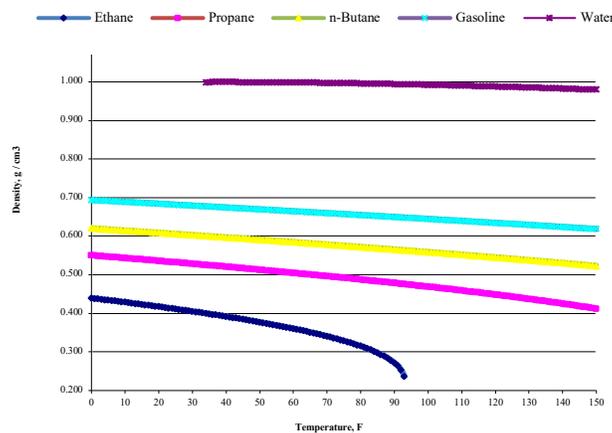


Figure 1. Density vs. Temperature

Density increases as pressure increases, however the change is smaller than seen for temperature. Water also exhibits this density increase with higher pressure, but the change in density for light hydrocarbons is roughly seven times more sensitive to pressure than water. It is important to know that the increase in density occurs for pressure above the equilibrium vapor pressure of the fluid.

Equilibrium vapor pressure is the pressure of vapor when it is in equilibrium with its liquid phase at a given temperature.

Relative density is the ratio of the density of a liquid to water at the same temperature, typically 60 degrees F in the U.S. Vapor relative density is the density of the vapor relative to air at the same temperature and pressure. Relative density has been and continues to be called specific gravity although relative density is the preferred term.

Calculations

The quantity of NGL is determined in units of mass such as pounds, kilograms or metric tonnes. When the measurement method is inferred mass, the total mass quantity is determined through multiplying the measured volume by the measured density where the volume and the density are at the same process conditions and using consistent units. Inferred mass measurement by a meter (dynamic measurement) multiplies the indicated volume at flowing conditions by the meter factor developed from a volumetric proving and then multiplies that quantity by the flowing density as corrected by its density meter factor. The result is in mass units. A flow computer is commonly used to make these calculations in real time.

Directly measuring mass, such as happens across a truck scale, results in a mass quantity. A Coriolis meter, configured to output in units of mass, is similar except that its indicated mass is multiplied by the meter factor for that meter when it is proved by mass. Like the inferred method, the resulting quantity is in mass units.

Intermediate calculations are required in the proving process and will use the familiar temperature correction (CTL) and pressure correction (CPL) terms. Refer to GPA 8182 / API Ch. 14.7 for details.

Component Volume

An NGL stream is further processed at a fractionation plant to produce individual products such as ethane, propane, isobutane, normal butane and natural gasoline. Buyers and sellers use prices for each of these products to determine the value of the NGL stream. Unlike a single product, an NGL stream transaction value computation is more complicated than applying a single price to the apparent volume of NGL in the transaction.

GPA Standard 8173 describes the method used to calculate liquid volumes at equilibrium vapor pressure and base temperature from the measured mass of an NGL. In addition to the measured mass, the method relies on the composition of the NGL and the values of absolute density for each component. This method is often called component distribution.

The method determines the mass of each component that comprises the NGL in the transaction. Each component's mass is equal to the total mass in the transaction multiplied by the component mass (weight) fraction in the analysis. See the example in Table 3. The mass (weight) fraction is the mass percent (or weight percent) value divided by 100. Individual component mass is then translated into a liquid volume through dividing by the absolute density of that component at base temperature and equilibrium vapor pressure. See the example calculation in Table 4.

Ticket Mass	2,810,261	pounds mass
Component	Weight %	Component Mass in pounds
CO ₂	1.286	36,140
C ₁	0.259	7,279
C ₂	32.777	921,119
C ₃	26.748	751,689
iC ₄	11.722	329,419
nC ₄	12.865	361,540
iC ₅	4.796	134,780
nC ₅	2.798	78,631
C ₆	6.749	189,665
Total	100.000	2,810,261

Table 3. Mass Distribution

The absolute density values for pure components are found in GPA 2145. Contracts usually specify using the latest edition of GPA 2145 for calculation purposes.

Chromatographic analysis of an NGL stream typically groups the heavy ends into one pseudo component. This may be hexanes and heavier (C₆+), heptanes and heavier (C₇+), or some other grouping. GPA 2145 provides physical property values for the pure, straight-chain hydrocarbon compounds, for some of the related hydrocarbons and inerts, and for the heavier NGL components normal hexane (nC₆) through normal decane (nC₁₀). The heavy-end grouping is typically analyzed in an extended chromatographic analysis to identify its constituents and to determine its physical properties. GPA TP-17 is the source for the pure component properties beyond those published in GPA 2145.

Component	Component Mass in pounds	Absolute Density in lb/gal	Component Volume in gallons
CO ₂	36,140	6.8129	5,305
C ₁	7,279	2.5000	2,911
C ₂	921,119	2.9704	310,099
C ₃	751,689	4.2285	177,767
iC ₄	329,419	4.6925	70,201
nC ₄	361,540	4.8706	74,229
iC ₅	134,780	5.2120	25,860
nC ₅	78,631	5.2584	14,953
C ₆	189,665	6.0320	31,443
Total	2,810,261		712,769

Table 4. Component Volume Calculation

Most liquid analysis reports include component percentage values for the three measures in Table 5: mole percent; liquid volume percent and weight percent. Think of mole percent as a ratio of the number of molecules of a component to the total number of molecules in the sample, liquid volume percent as a ratio of the gallons of a component to the total number of gallons in the sample and weight percent as the pounds of a component to the total number of pounds in the sample. Note that it is more precise to think of weight percent as mass percent.

Many laboratories calibrate their chromatographs to the mole percent values of their reference standard blend. In this case, the liquid volume percent and the weight percent figures in the analysis report are calculated from mole percent using published properties for the pure components. Other laboratories calibrate to liquid volume percent and calculate mole percent and weight percent. Know that the values for one set of units can be calculated from the other.

Component	Mole %	Weight %	Liquid Volume %
CO ₂	1.246	1.286	0.744
C ₁	0.689	0.259	0.408
C ₂	46.496	32.777	43.508
C ₃	25.872	26.748	24.940
iC ₄	8.602	11.722	9.849
nC ₄	9.441	12.865	10.414
iC ₅	2.835	4.796	3.628
nC ₅	1.654	2.798	2.098
C ₆	3.165	6.749	4.411
Totals	100.000	100.000	100.000

Table 5. Example NGL Analysis

Once the component volumes are known (see Table 4), there is a straightforward application of individual component pricing to their respective volumes for ethane, propane, isobutane and normal butane. However, the rest of the volumes take additional work. The carbon dioxide volume is usually excluded because it is an inert compound that has no value. Methane, below the contract limit, typically is grouped with and priced the same as the ethane. The allowable volume of methane is often limited to 1.5% of the ethane volume and any methane quantity above that amount is excluded. The sum of the volumes from isopentane through the heaviest hydrocarbon grouping is termed and priced as natural gasoline.

Now that the quantity reaches the pricing stage and the measurement task is complete, there are some important items to keep in mind. First, it is critical that the NGL sample represents the measured liquid so that the composition reflects the stream. For dynamically measured liquids, the sample will be flow-weighted, i.e., taken proportional to flow. Statically measured quantities also require a sample that appropriately represents their composition. Second, the component distribution method also works for NGL vapors. This may be useful in movements involving large pressurized tanks like ships, barges and batteries of bullet tanks.

Lastly, it is important to measure the composition of the heavy ends grouping, such as the C₆+ fraction in these examples, on a regular frequency. The composition of the heavy ends grouping is determined by an extended chromatographic analysis. This extended analysis takes significantly longer to run and costs more than the typical C₆+ run. It is common practice in the industry to run the extended analysis on a less frequent basis than the C₆+ analysis and to apply the molecular weight, absolute density and other physical properties from the extended analysis to each of the sample analyses until the next extended analysis is available. If the sample is caught and analyzed monthly, it might be appropriate to run the extended analysis on a quarterly or semi-annual basis. If the sample is caught weekly, the extended analysis basis could be monthly, quarterly or perhaps semi-annually. An evaluation of the physical properties for the heavy ends grouping will lead to the selection of the appropriate analysis frequency.

Summary

Accurate quantities of NGL can be determined using mass measurement techniques and commonly available metering technologies by following industry standards, best practices and manufacturer directions. Mass measurement techniques are different from volumetric techniques because of the importance of flowing density to the inferred mass stream or to the prover quantity when using a Coriolis meter and because of the use of composition to determine the component volumes.

References

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GPA Standard 8182 / API Manual of Petroleum Measurement Standards, Chapter 14.7 – Mass Measurement of Natural Gas Liquids