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Flow Measurement Using Electronic Metering Systems—Electronic Gas Measurement

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Flow Measurement Using Electronic Metering Systems— Electronic Gas Measurement

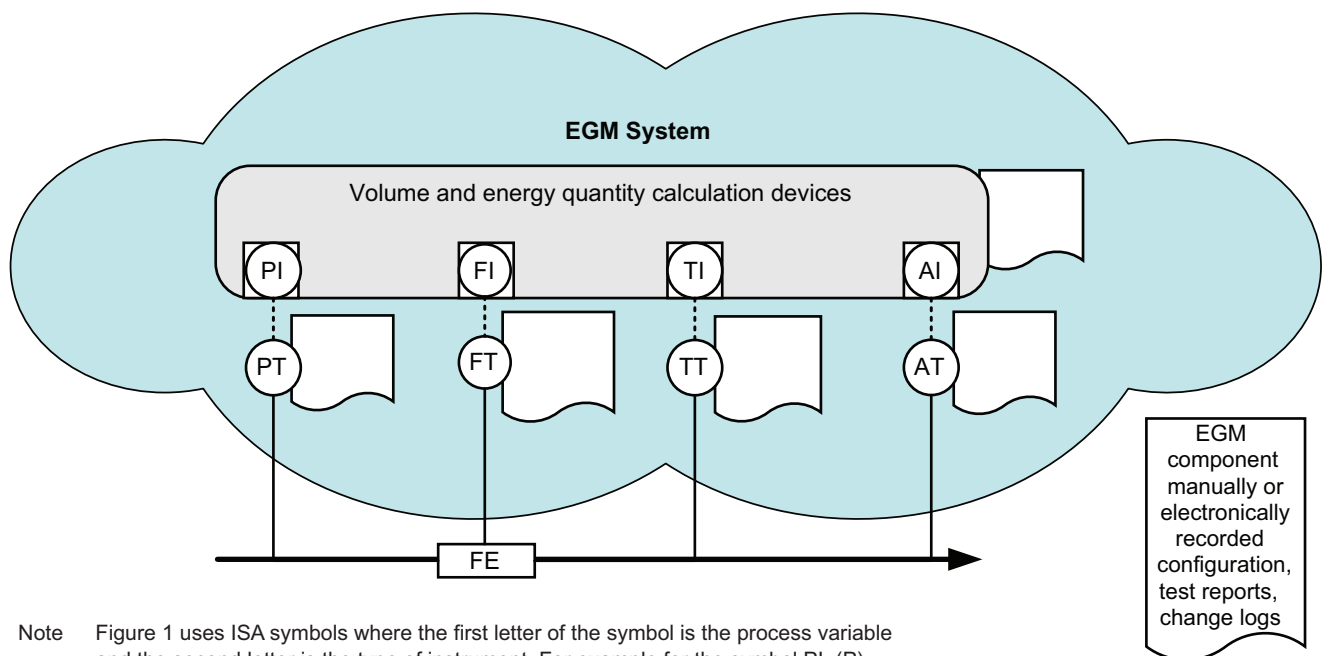
1 Scope

This standard describes the minimum specifications for electronic gas measurement systems used in the measurement and recording of flow parameters of gaseous phase hydrocarbon and other related fluids for custody transfer applications utilizing industry recognized primary measurement devices.

Electronic gas measurement (EGM) systems may be comprised of a number of components which work together to measure and record gas flow as shown in Figure 1. The components contained in the cloud are considered part of the EGM system. The components may be considered individually or be integral parts of the EGM system and the calculations may be performed onsite and/or off-site.

This standard provides the minimum reporting and change management requirements of the various intelligent components required for accurate and auditable measurement. The requirements can be met by a combination of electronically and/or manually recorded configuration, test reports, change record reporting of the electronic gas measurement system components and flow parameters. It is recognized that diagnostic capabilities of the newer meter and transmitter technologies are important but due to the device specific complexity, intelligent device diagnostics are out of scope for this standard.

For all existing installations, the decision to upgrade the system to satisfy the current standard is at the discretion of the parties involved.



Note Figure 1 uses ISA symbols where the first letter of the symbol is the process variable and the second letter is the type of instrument. For example for the symbol PI, (P) stands for pressure instrument and (I) stands for indicator. The process variables in the figure are pressure (P), flow rate (F), temperature (T), and analytical (A) and the types of instruments are indicator (I), transmitter (T), element (E).

Figure 1—Graphical Representation of an Electronic Gas Measurement (EGM) System and Its Relationship to Other Devices

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API *Manual of Petroleum Measurement Standards (MPMS)*, Chapter 14.1, *Collecting and Handling of Natural Gas Samples for Custody Transfer*

API *Manual of Petroleum Measurement Standards (MPMS)*, Chapter 14.3, *Concentric, Square-Edged Orifice Meters* (ANSI ¹/API 2530, A.G.A. Report No. 3, GPA 8185) [All sections]

AGA Report No. 7 ², *Measurement of Gas by Turbine Meters*

AGA Report No. 8, *Compressibility Factors of Natural Gas and Other Hydrocarbon Gases*

AGA Report No. 9, *Measurement of Gas by Multipath Ultrasonic Meters*

AGA Report No. 11, *Measurement of Natural Gas by Coriolis Meter*

National Oceanic and Atmospheric Administration ³, *U.S. Standard Atmosphere*, U.S. Department of Commerce, National Technical Information Service, October 1976

3 Descriptions, Definitions, and Symbols

3.1 Description of an Electronic Gas Measurement System

For the purpose of this standard, the measurement system consists of primary, secondary, and tertiary devices.

The primary device defines the basic type of meter used for gas measurement, including, but not limited to, an orifice, turbine, ultrasonic, Coriolis, rotary, or diaphragm meter.

The secondary device produces data such as, but not limited to, static pressure, temperature, differential pressure, relative density, and other variables that are appropriate for inputs into the tertiary device discussed in this standard.

The tertiary device is one or more calculation devices that need to be programmed correctly to perform flow rate calculations within specified limits using information received from primary and/or secondary devices. Each primary device requires one or more specific or properly configured tertiary devices appropriate to the type of meter used.

Secondary devices are typically located with the primary device, but the tertiary device may be located remotely. The primary, secondary, and tertiary devices may be contained in one or more enclosures, or packaged separately.

3.2 Elements of a Gas Measurement System

3.2.1 Transducers/Transmitters

In electronic measurement systems, the secondary device is an electromechanical transducer that responds to an input of static pressure, temperature, differential pressure, frequency, relative density (specific gravity), or other

¹ American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, New York 10036, www.ansi.org.

² American Gas Association, 400 N. Capitol St., NW, Suite 450, Washington, DC 20001, www.aga.org.

³ National Oceanic and Atmospheric Administration, 1401 Constitution Avenue, NW, Washington, DC 20230.

variable. Transducers respond to changes in the measured parameters with a corresponding change in electrical output. These devices are referred to as transmitters when they have been specifically designed to enhance the transmission of information from one location to another by the addition of an electronic circuit that converts the transducer output to a standard signal. The signal may be, but is not limited to, analog, digital, or frequency form.

3.2.2 Signal Processing

The electronic signals from the secondary devices transmit information to the tertiary device(s). The tertiary device(s) receive the information, combine it with programmed instructions, and calculates the quantity of gas flowing through the primary device.

3.2.3 System Uncertainties

While electronic flow measurement can provide a high degree of accuracy, it is important to realize that each primary, secondary, or tertiary device is subject to separate measurement uncertainties. Consider each device when viewing the overall uncertainty of the system.

3.2.4 Data Management

EGM systems must comply with audit trail/audit package requirements for reported volume, mass and/or energy quantities. All data editing of data in the EGM or other systems shall be identified. Quantity Transaction Records (QTRs) that are modified or corrected by systems, either manual or automatic, must be recorded and maintained as part of the audit trail (see Section 5, *Audit and Record Requirements*).

3.3 Definitions

The purpose of these definitions is to clarify the terminology used in the discussion of this standard only. The definitions are not intended to be an all-inclusive directory of terms used within the measurement industry, nor are they intended to conflict with any standards currently in use.

3.3.1

absolute static pressure

The flowing pressure referenced to an absolute vacuum.

NOTE Absolute static pressure can be measured directly or can be calculated by adding atmospheric pressure to gauge pressure.

3.3.2

accounting period

A defined time interval over which business transactions will be based.

3.3.3

accuracy

The ability to indicate values closely approximating the true value of the measured variable.

3.3.4

analog to digital converter

A/D converter

A signal processor that converts an electrical analog signal to a corresponding digital number.

3.3.5

atmospheric pressure

The pressure exerted by the weight of the atmosphere at a specific location.

3.3.6**audit trail****audit package**

The record for an EGM system shall contain verification or calibration measurements for all tertiary and secondary devices, actual specifications for the primary device, constant values, times and dates of any changes affecting reported volumes, and should include identification of individuals making the changes (see Section 5, *Audit and Record Requirements* and Section 6, *Data Availability Data Availability*).

3.3.7**average flowing differential pressure**

The flow time linear average of instantaneous differential pressures taken over a specified period of time.

3.3.8**average flowing pressure**

The flow time linear average of instantaneous flowing static pressures taken over a specified period of time.

3.3.9**average flowing temperature**

The flow time linear average of instantaneous flowing temperatures taken over a specified period of time.

3.3.10**calibration range****calibration span**

See span, limit, and range definitions.

3.3.11**certified thermometer**

An instrument that measures temperature with performance traceable to primary standards maintained by an internationally recognized standards organization such as the National Institute of Standards and Technology (NIST).

3.3.12**commissioning**

The process of the initial verification and documentation that the EGM system is installed and functioning according to its specification, design, and regulatory/contract requirements.

3.3.13**Configuration Log**

A record that contains and identifies all selected flow parameters used in the generation of a QTR.

3.3.14**constant flow parameter**

Any value that affects the quantity calculation, is not associated with a property or state of the flowing gas, and does not frequently change. Orifice plate bore diameter, meter tube internal diameter, linear meter pulse per unit volume factors, and base pressure are examples of constant flow parameters.

3.3.15**contract day**

A time period of 24 consecutive hours beginning at the time specified in the contract except for the days which have been adjusted for Daylight Savings Time.

3.3.16**differential meter**

A device that generates a differential pressure when placed in a flow stream.

3.3.17
differential pressure

The pressure difference between the differential meter upstream and downstream pressure taps used to calculate flow rate.

3.3.18
differential pressure transmitter

A sensing device that converts a differential pressure into an electrical signal.

3.3.19
electronic gas measurement
EGM

The process whereby gas flow rates are calculated by means of an electronic computer. Computations can be made directly at the site of the primary element or after transfer of the data to another computer at any off-site location. This transfer can be manual, using a data storage device, or automatic, using a communication system.

3.3.20
Event Log

A record that notes and records all exceptions and changes to the flow parameters contained within the Configuration Log that occur and have an impact on a QTR.

3.3.21
factory calibration

A maintenance process which uses a transmitter that is calibrated at a factory or calibration facility that is traceable to primary standards maintained by an internationally recognized standards organization such as the NIST.

3.3.22
flow computer

An arithmetic processing unit and associated memory that accepts electrically-converted signals representing input variables from a measurement system and performs calculations for the purpose of providing flow rate and total quantity data.

3.3.23
flow time

The period of time during the QTR when gas is flowing.

3.3.24
flow time linear average

The average value of a measured or calculated variable using only values taken when gas is flowing.

3.3.25
gauge line

The tubing that connects a tap on a meter run to a sensing device.

3.3.26
gauge pressure

The absolute static pressure minus the local atmospheric pressure at the time of measurement.

3.3.27
intelligent device

Any device which contains a microprocessor that is used for digital signal processing or calculation purposes.

3.3.28**input variable**

A data value associated with the flow or state of a gas that is input into the computer for the purpose of being part of a calculation. This input may be a measured variable from a transducer/transmitter or a manually entered fixed value. Static pressure, temperature, and relative density are examples of input variables.

3.3.29**integral value****IV**

The value resulting from the integration of the factored portion of the flow rate equations that best defines the conditions of continually changing flow over a specified time period.

3.3.30**linear meter**

A flow device that generates a signal, typically pulses, which is directly proportional to flow rate.

3.3.31**live input variable**

The output of any primary or secondary device which provides updates during a Quantity Calculation Period (QCP).

3.3.32**lower calibrated limit****lower range limit****lower user defined operating limit**

See span, limit, and range definitions.

3.3.33**manufacturer span**

See span, limit, and range definitions.

3.3.34**no flow cutoff**

The minimum value of the flow dependent variable, below which the signal is considered to be meter or flow noise. No flow rate or quantity shall be calculated below this value.

3.3.35**off-site**

A location not at the primary measurement device.

3.3.36**onsite**

The location of the primary measurement device.

3.3.37**pre-commissioning**

The process of reviewing and checking of commissioning documentation prior to performing onsite commissioning. (It can also be done as part of the onsite commissioning process.)

3.3.38**quantity**

The volume, mass, or energy accumulated during the QCP and/or reported in the QTR.

3.3.39
quantity calculation period
QCP

The period of time over which the calculated total quantity is to be integrated.

3.3.40
Quantity Transaction Record
QTR

A set of unedited historical data, calculated values, and information in a preset format that supports the determination of a quantity over a given period.

3.3.41
Quantity Transaction Record corrected
QTR_{corr}

The result of a change to a QTR.

3.3.42
Quantity Transaction Record time
QTR_{time}

The specific time in hours, minutes, and seconds logged at the beginning or completion of the QTR.

3.3.43
Rans methodology

A statistical evaluation method to determine the amount of measurement uncertainty that exists for any given flow pattern across an orifice plate or linear type meter for a specified flow parameter sampling frequency.

3.3.44
sampling frequency

The number of data values taken per unit of time (for example, 1/second) that a live input variable is retrieved.

3.3.45
sampling period

The time between the retrieval of live input variables.

3.3.46
Span, Limit, and Range Definitions

3.3.46.1
calibration range

The set of values as bounded by the upper and lower calibrated limits.

3.3.46.2
calibration span

The mathematical difference between the upper and lower calibrated limits.

3.3.46.3
lower calibrated limit

The minimum engineering value the unit was calibrated for by certified equipment (either factory or field) and, in all applications, cannot be less than the lower range limit.

3.3.46.4
lower range limit
LRL

The minimum engineering value that can be measured as specified by the manufacturer.

3.3.46.5**lower user defined operating limit**

The engineering value that is set by the operator which defines the minimum operating point for the unit and, in all applications, cannot be less than the lower calibrated limit.

3.3.46.6**manufacturer span**

The mathematical difference between the upper and lower range limits.

3.3.46.7**span**

The mathematical difference between upper and lower limits.

3.3.46.8**upper calibrated limit**

The maximum engineering value the unit was calibrated for by certified equipment (either factory or field) and, in all applications, cannot be greater than the upper range limit.

3.3.46.9**upper range limit****URL**

The maximum engineering value that can be measured as specified by the manufacturer.

3.3.46.10**upper user defined operating limit**

The maximum engineering value that is set by the operator which defines the highest operating point for the unit and, in all applications, cannot be greater than the upper calibrated limit.

3.3.46.11**user defined operating range**

The set of values as bounded by the upper and lower operating limits defined by the user.

3.3.46.12**user defined span**

The mathematical difference between the upper and lower operating limits defined by the user.

3.3.47**static pressure**

The force per unit area exerted by a gas at a selected point in the system and can be represented as gauge or absolute pressure.

3.3.48**static pressure transmitter**

A sensing device that converts the static pressure to an electrical signal.

3.3.49**temperature**

The value of thermal energy of the flowing gas.

3.3.50**temperature transmitter**

A sensing device that converts the fluid temperature into an electrical signal.

3.3.51**transducer**

A device that provides a usable output signal in response to a measurement.

3.3.52**type testing**

The verification and approval of EGM system algorithms and components that cannot be changed from their factory state. Type approval of the testing and calculations apply to the installed device.

3.3.53**uncertainty**

The amount by which an observed or calculated value may depart from the true value.

3.3.54**uncorrected quantity**

The quantity accumulated over the flow period at flowing conditions not corrected to standard conditions.

3.3.55**upper calibrated limit****upper range limit****upper user defined operating limit**

See span, limit and range definitions.

3.3.56**user configurable**

Refers to flow computers or EGM systems where the flow calculation algorithms cannot be altered by the user, but the components and ranges of the EGM system and other measurement characteristics can be configured using the manufacturer supplied user interface. These types of devices can be type approved.

3.3.57**user defined operating range****user defined span**

See span, limit and range definitions.

3.3.58**user programmable**

Refers to flow computers or EGM systems where the user can change the portion of the program which contains the flow calculation algorithm, and then compiles and downloads this program to the EGM device. These types of devices cannot be type approved and require individual device verification of the algorithms.

3.4 Symbols

This standard reflects electronic gas measurement symbols in general technical use.

Symbol	Represented Quantity
$C_d(FT)$	is the coefficient of discharge for a flange-tap orifice meter;
$Counts$	is the accumulation of meter pulses;
d	is the orifice plate bore diameter calculated at flow temperature (T_f);
DP_i	is the differential pressure at sample i ;
DP_{IV}	is the average differential pressure calculated from the IV (see Annex B);
DP_{Linear}	is the flow time linear average of differential pressure (see Annex B);

DP_Y	is the average differential pressure to be used in the expansion factor calculation. (DP_Y is the volume weighted average of differential pressure or calculated from DP_{Linear} and DP_{IV} using the equation in 4.4.4.4.);
DV_i	is the dynamic variables, representing the live input variables, taken at sample i ;
E_v	is the velocity of approach factor;
FT	is flange taps
ft	is the flow time
G_r	is the real gas relative density (specific gravity);
h_w	is the orifice differential pressure in inches of water column at 60°F;
h_{w_i}	is the differential pressure at sample i ;
i	is the sample number;
IMV	is the integral multiplier value, representing the relatively static measured and calculated values;
IV	is the integral value;
$\overline{IV}$	is the average extension;
$k\text{-factor}$	is the single linear meter constant in counts per unit volume;
$k\text{-factor}_i$	is the multipoint linear meter constant in counts per unit volume calculated at interval i ;
mf_i	is the meter factor for period i (when multi-point meter factors are used);
n	is the number of samples taken over the QCP (i.e. QCP / Δt);
P_{atm}	is the atmospheric pressure;
P_b	is the pressure at base conditions;
P_f	is the pressure at flowing conditions;
P_{f_i}	is the pressure at sample i ;
P_{f_1}	is the flowing pressure (upstream tap), absolute;
P_s	is the standard pressure;
Q	is the flow rate;
Q_i	is the flow rate based on data taken at sample i ;
Q_f	is the flow rate at actual conditions;
Q_{fi}	is the flow rate at actual conditions based on data taken at sample i ;
t	is the time;
Δt_i	is the sampling interval;
T_b	is the temperature at base conditions;
T_f	is the flowing temperature, absolute;
T_s	is the standard temperature;
V	is the quantity accumulated between time t_0 and time t or quantity accumulated over the QCP;
Y_1	is the expansion factor (upstream tap);
Z_b	is the compressibility at base conditions;
Z_f	is the compressibility at flowing conditions;
Z_s	is the compressibility at standard conditions (P_s , T_s);
Z_{f1}	is the compressibility at flowing conditions (P_{f1} , T_f);

4 Electronic Gas Measurement System Algorithms

4.1 General

This section defines sufficient component and composite algorithms for both differential and linear meter measurement. The component algorithms define sampling and calculation methodologies and averaging techniques. As each component algorithm is applied to the appropriate flow equation, a composite algorithm is defined that will ensure an acceptable gas measurement system.

When applying these methods to differential pressure measurement, the appropriate flow equations are found in the latest revision of API *MPMS* Ch. 14.3, Parts 1 through 4 for orifice meters or other approved differential pressure metering standards for other differential meters.

The flow equations appropriate for application of these methods to linear meter measurement are found in the latest revision of AGA Report No. 7 for turbine meters or other approved linear metering standards for other linear meters.

All supporting equations referenced, such as the equations of state for compressibility calculated using the AGA Report No. 8, shall be consistently applied with the latest revision of the standard.

4.2 Overview

4.2.1 Intent

The intent of this section is to provide calculations for orifice (API *MPMS* Ch. 14.3) and linear (AGA Report No. 7) meters. For other approved metering standards, these methodologies shall be applied to their equations.

The effect of sampling and calculation frequencies during fluctuating flow and the application of the various algorithms have been addressed by computer modeling to assure a difference within $\pm 0.05\%$ when compared to one second sampling. A statistical model known as the Rans Methodology provides, in part, the basis for the recommended sampling and calculation frequencies to support limits for statistical uncertainty. This methodology is included in Annex A.

4.2.2 Total Quantity

In metering applications, a total quantity is determined by the integration of a flow rate equation over a defined time interval. In equation form, the calculation of total quantity is expressed as the following:

$$V = \int_{t_0}^t Q dt \quad (1)$$

where

V is the quantity accumulated between time t_0 and time t ;

Q is the flow rate;

t is the time and dt is the differential of time.

Some of the variables used in the determination of flow rate are typically not static. A true total quantity is the flow rate integrated during continuously changing conditions over a specified QCP. In reality, the variables used for flow

determination are not read continuously; they are taken at discrete sampling intervals. The integral form of the equation is approximated by the following:

$$V = \sum_{i=1}^{i=n} (Q_i \Delta t_i) \quad (2)$$

where

V is the quantity accumulated over the QCP;

i is the sample number;

Q_i is the flow rate based on data taken at sample i ;

Δt_i is the time between samples;

n is the number of samples taken over the QCP.

NOTE Time units for Q_i and Δt has to be consistent.

4.3 Quantity Calculation Period (QCP)

The maximum QCP shall be 5 minutes unless it can be shown that the error introduced by a longer QCP causes less than 0.05 % difference in the quantity calculation. In all cases the QCP shall not exceed one hour. The Rans methodology in Annex A can be used as a guide in estimating the variability errors.

A QCP should be designed so that an integer (whole) number of QCPs occur during one hour.

To aid in recalculation of incorrect constant flow parameter changes, a QCP should end and a new QCP should begin any time one or more constant flow parameters are changed.

4.4 Differential Meter Measurement

4.4.1 General

The flow rate (Q_i) can take several forms, depending on whether the ultimate quantity being measured is volume at flowing conditions, volume at base conditions, mass, or energy. For example the calculation of flow rate through a flange tapped orifice at standard conditions taken from API MPMS Ch. 14.3, Part 3 (Third Edition, August 1992) equation 3-6b is:

$$Q_v = 7709.61 C_d(FT) E_v Y_1 d^2 \sqrt{\frac{P_{f_1} Z_s h_w}{G_r Z_{f_1} T_f}} \quad (3)$$

where

7709.61 is the unit conversion factor;

$C_d(FT)$ is the coefficient of discharge for flange-tap orifice meter;

E_v is the velocity of approach factor;

Y_1 is the expansion factor (upstream tap);

d	is the orifice plate bore diameter calculated at flow temperature (T_f), in inches;
P_{f_1}	is the flowing pressure (upstream tap), in pounds force per square inch absolute;
Z_s	is the compressibility at standard conditions (P_s , T_s);
h_w	is the orifice differential pressure, in inches of water at 60 °F;
G_r	is the real gas relative density (specific gravity);
Z_{f_1}	is the compressibility at flowing conditions (P_{f_1} , T_f);
T_f	is the flowing temperature, in degrees Rankin.

Other forms of the equation or equations for other types of differential meters are acceptable.

The determination of a quantity from the flow rate equation shall be done in one of two ways;

- 1) the flow rate shall be calculated at the sampling frequency using the entire flow rate equation and summed (see 4.4.3), or
- 2) the flow rate equation shall be factored into static and live components which are then combined at the end of each QCP to obtain a quantity (see 4.4.4).

4.4.2 Sampling Flow Variables

Differential pressure, static pressure, and temperature shall be sampled at least once per second⁴ and shall be averaged using a flow time linear average as described in Annex B, *Averaging Techniques*. Other live input variables may be sampled at their update frequency.

A slower sampling frequency may be used if the Rans Methodology or another methodology can demonstrate that the difference in calculated quantity associated with a less frequent sampling time is no more than ± 0.05 % different than the quantity associated with a one second sampling frequency for a given application, and the slower sampling frequency is agreeable to the parties involved.

4.4.3 Quantity Determination from the Full Flow Rate Calculation

It is recognized that the most accurate method of determining a quantity from a series of instantaneous flow rate calculations is to calculate flow rate at the sampling frequency (minimum once per second). This will generally result in a calculation difference of less than 0.005 % (50 ppm per API *MPMS* Ch. 14.3, Part 4) when all the variables and calculations required by the applicable measurement standard (e.g. API *MPMS* Ch. 14.3, Part 3) and gas compressibility determined per the applicable standards (e.g. AGA Report No. 8) are included.

If the full flow rate calculation is used, a separate QTR Integral Value or Average Extension shall be calculated, stored, and reported for verification purposes. The calculation of the integral value is expressed as follows:

$$IV = \sum_{i=1}^{i=n} (\sqrt{h_{w_i} P_{f_i}} \Delta t_i) \quad (4)$$

⁴ Exactly consistent sample intervals may not be possible due to computer architecture and the complexity of the algorithms in question. However the effect of minor variations in the sample period will not be statistically significant if the average sample period is small compared to the observed variation in flow dynamics.

where

- h_{w_i} is the differential pressure at sample i ;
- P_{f_i} is the absolute static pressure at sample i ;
- Δt_i is the sampling interval;
- i is the sample number.

Some EGM systems report the average extension instead of integral value:

$$\overline{IV} = \frac{IV}{ft} \quad \text{or} \quad IV = \overline{IV} \times ft \quad (5)$$

where

- $\overline{IV}$ is the average extension;
- IV is the integral value;
- ft is the flow time:

$$= \sum (\Delta t_i) \text{ for intervals when } \sqrt{h_{w_i} P_{f_i}} \text{ is greater than 0.}$$

It is acceptable to include the additional live input variables in the IV , such as flowing temperature (T_f) and relative density (G_r), if their average is reported in the QTR. Because the sampling frequency of relative density is generally much slower than once per second, IV 's containing relative density has to use the most recent value of relative density.

At a minimum, hourly quantities as defined in Section 6, *Data Availability* shall be calculated and maintained.

4.4.4 Quantity Determination from the Factored Flow Rate Calculation

4.4.4.1 General

If quantity is not calculated using the full flow rate calculation described in 4.4.3 then the method described in this section has to be used to determine volume.

Instead of calculating the entire flow rate equation at the sampling frequency, the flow equation is factored into two parts; one containing the live input variables that can change significantly with time, and one containing the static variables that remain relatively constant with respect to time.

$$Q_i = IMV \times DV_i \quad (6)$$

where

- Q_i is the flow rate based on data taken at sample i ;
- IMV is the Integral Multiplier Value, representing the static variables;
- DV_i is the Dynamic Variables, representing the live input variables, taken at sample i .

For calculations not done at the sampling frequency:

$$V = IMV \sum_{i=1}^{i=n} (DV_i \Delta t_i) \quad (7)$$

The term $\sum_{i=1}^{i=n} (DV_i \Delta t_i)$ is called the Integral Value (IV), such that $V = IMV \times IV$.

NOTE Using factored flow rate calculations in situations with high differential pressure/static pressure ratios and highly fluctuating flow will generally result in calculation differences greater than 0.05 % compared to the full flow rate calculation method if the DPY requirements of 4.4.4.4 are not followed.

4.4.4.2 Integral Value (IV) Calculation

An Integral Value (IV) is the value resulting from the integration of the factored portion of the flow rate equations that best defines the conditions of continually changing flow over a specified time period. The minimum requirements for the IV shall be the square root of the product of differential pressure and absolute static pressure calculated at the sampling interval. In equation form, the calculation of the IV is expressed as follows.

$$IV = \sum_{i=1}^{i=n} (\sqrt{h_{w_i} P_{f_i}} \Delta t_i) \quad (8)$$

where

h_{w_i} is the differential pressure at sample i ;

P_{f_i} is the absolute static pressure at sample i ;

Δt_i is the sampling interval;

i is the sample number.

Some EGM systems report the $\overline{IV}$ instead of integral value:

$$\overline{IV} = \frac{IV}{ft} \quad \text{or} \quad IV = \overline{IV} \times ft \quad (9)$$

where

$\overline{IV}$ is the average extension;

IV is the integral value;

ft is the flow time:

$$= \sum (\Delta t_i) \text{ for intervals when } \sqrt{h_{w_i} P_{f_i}} \text{ is greater than 0.}$$

It is acceptable to include the additional live input variables in IV, such as flowing temperature (T_f) and relative density (G_r), if their average is reported in the QTR. The sampling frequency of relative density (G_r) is generally much slower than once per second, IV's containing relative density has to use the most recent value of relative density.

The IV shall not contain any constants or configurable/calculated variables. A list of live variables and the calculations of IV or $\overline{IV}$ shall be stated in the Configuration Log (see 5.4).

For IV calculation whenever the sampled differential pressure is less than or equal to the no flow cutoff value (refer to 4.4.5), the value of h_{w_i} is zero.

Where multiple samples within one second have been taken and averaged over the one-second time period, the value of Δt will be $\frac{1}{3600}$ hours (one second), regardless of the sampling frequency.

4.4.4.3 Integral Multiplier Value (IMV) Calculation

IMV is the value resulting from the calculation of all factors of the flow rate equation that are not included in the IV . IMV shall be calculated at the end of each QCP using flow time linear average values of the live inputs with the exception of the gas expansion factor (Y).

4.4.4.4 Differential Pressure for Expansion Factor Calculations

Analysis of the expansion factor calculation has shown significant errors may be introduced in highly variable flow at high differential pressure/static pressure ratios which frequently occur at low operating pressure. Unless the full flow rate calculation described in 4.4.3 is used the expansion factor variability becomes significant and the expansion factor needs to be factored into its dynamic and static parts. Differential pressure is the dynamic portion of expansion factor and a flow-weighted differential pressure is required to calculate the QCP expansion factor.

$$\text{Flow Weighted Differential Pressure} \approx \frac{\sum_{i=1}^n (h_{w_i} IV_i)}{\sum_{i=1}^n IV_i} \quad (10)$$

because the expansion factor correction is small, the error introduced by using $\sqrt{h_{w_i}}$ as the IV is insignificant and DP_Y becomes:

$$\text{Flow Weighted Differential Pressure} \approx \left(\frac{\sum_{i=1}^n (h_{w_i} \sqrt{h_{w_i}})}{n} \right)^{2/3} \quad \text{or} \quad (11)$$

$$\text{Flow Weighted Differential Pressure} \approx \left(\frac{\sum_{i=1}^n (h_{w_i})^{3/2}}{n} \right)^{2/3}$$

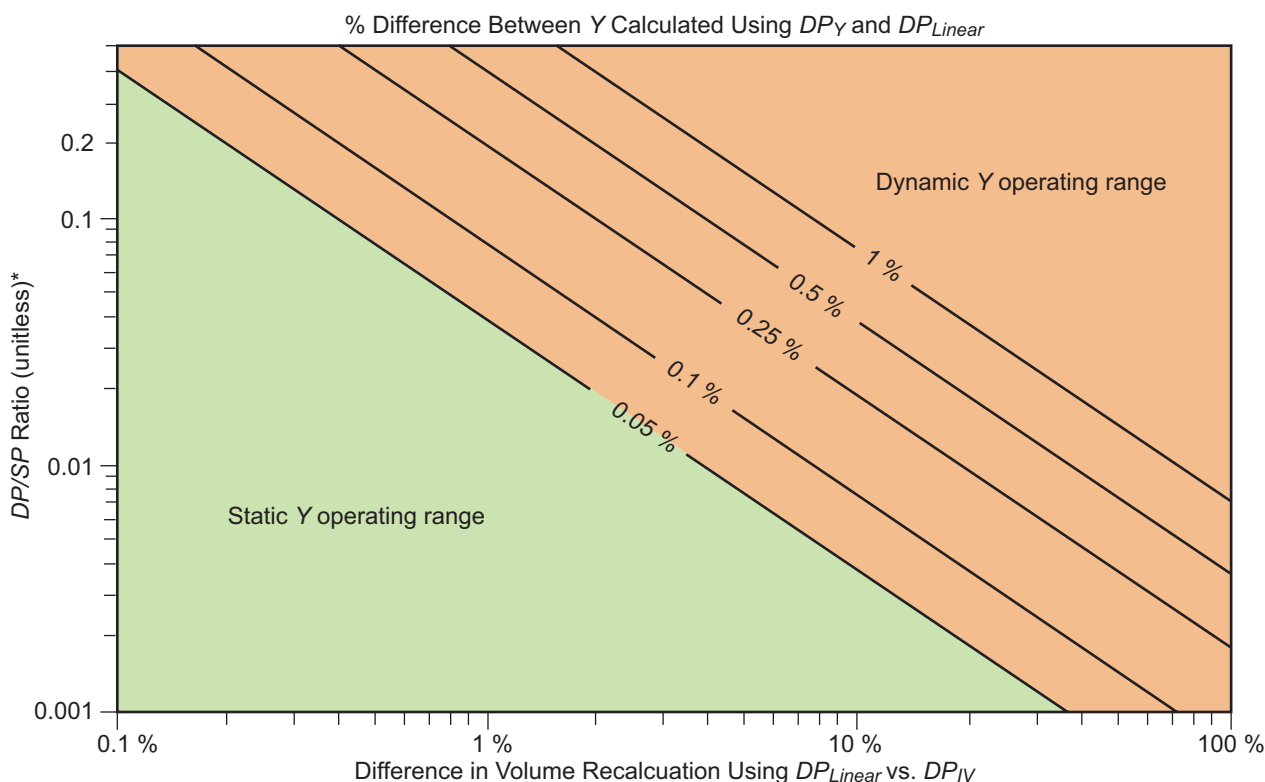
where

DP_Y is the differential pressure used to calculate the QCP expansion factor;

h_{w_i} is the differential pressure at sample i ;

IV_i is the integral value at sample i ;

i equals the sample number.



*Based on linear flow time averages of DP and SP and IV reported in the hour quantity transaction record.

Notes:

1. See Annex A.4.2 for additional details and examples of how this figure can be used.
2. If volume is calculated using the full flow rate calculation described in 4.4.3 there is no averaging error and the methods and requirements of this section do not apply.
3. DP_Y can be calculated from the differential pressure (DP_{Linear}) and integral value (IV or $\overline{IV}$) contained in the QTR.
4. Because DP_Y approaches DP_{Linear} as the flow fluctuation reduces, it is recommended that DP_Y be used in calculation of expansion factor in all QCP calculations.
5. To detect DP_Y and IV errors caused by gauge line amplification of flow noise, the differential pressure flow pattern shall be confirmed as real flow whenever the DP_{Linear} vs. DP_{IV} volume recalculation exceeds 10 % or the DP_Y vs. DP_{Linear} Y calculation exceeds 0.5 % as shown in Figure 2.

Figure 2—Estimated Expansion Factor Errors Based Hourly QTRs and DP/SP Ratios

Under highly variable flow at high differential pressure/static pressure ratios, either a new differential pressure average (DP_Y) needs to be added or an approximation of DP_Y needs to be calculated from the existing averages. DP_Y shall only be used as the value of differential pressure in the meter expansion factor calculation.

Using the two averages of differential pressure that can be obtained from the existing QCP, an approximation of DP_Y has been empirically derived ⁵.

$$DP_Y \approx \left[1 + 3.345 \times \left(\frac{\sqrt{DP_{Linear}}}{\sqrt{DP_{IV}}} - 1 \right) \right] \times DP_{Linear} \quad (12)$$

⁵ Gas Volume Calculation Errors in Highly Erratic Flow White Paper.

where

DP_{Linear} is the flow time linear average of differential pressure (see Annex B);

DP_{IV} is the average differential pressure calculated from the integral value (see Annex B).

Two remaining issues need to be addressed.

- 1) When should the expansion factor be considered dynamic?
- 2) Should DP_Y be calculated in addition to other averages of the differential pressure if calculations are being performed using the factored flow rate calculation method?

Figure 2 has been developed to answer the first question. It uses the DP_Y equation above to calculate the expansion factor error as a function of the differential pressure/static pressure ratio and flow variability estimated by the percent difference caused by recalculation using the DP_{Linear} and DP_{IV} averages. This recalculation difference can be estimated by:

$$\% \text{ Volume Difference} \approx \left(\sqrt{\frac{DP_{Linear}}{DP_{IV}}} - 1 \right) \times 100 \quad (13)$$

The expansion factor shall be characterized as static or dynamic based on Figure 2. The expansion factor can be considered static if the meter consistently operates at or below an error threshold of 0.05 % and dynamic for operating conditions that exceed this threshold. For static conditions the flow time linear average of differential pressure should be used to determine gas expansion factor if DP_Y is not used. For dynamic conditions DP_Y shall be used.

The frequency for demonstrating compliance shall be mutually agreed upon by the parties involved, and/or as required by law, statute, or regulation.

4.4.4.5 Volume Calculation

At the end of each QCP, the IMV is multiplied by the IV to obtain a total quantity for the QCP. At a minimum, hourly quantities as defined in Section 5 shall be calculated and maintained. If the QCP is less than one hour, the quantities for each QCP can be maintained and reported, or, the quantities determined for each QCP can be summed for each hour.

4.4.5 No Flow Cutoff

The no flow cutoff is used to address the differential pressure transmitter zero stability and site induced false flow. The recommended no flow cutoff value is determined by calculating 0.25 % of the user defined span of the differential pressure transmitter, not to exceed 0.5 in. H₂O of differential pressure. Additional consideration of documented site conditions may result in a no flow cutoff value that is above or below the recommended limit.

4.5 Linear Meter Measurement

The flow rate (Q_i) can take several forms, depending on whether the ultimate quantity being measured is volume at flowing conditions, volume at base conditions, mass, or energy. One example of the calculation of flow rate in general terms is:

$$Q_i = Q_f \left(\frac{P_f}{P_b} \right) \left(\frac{T_b}{T_f} \right) \left(\frac{Z_b}{Z_f} \right) \quad (14)$$

where

Q_i is the flow rate based on data taken at sample i ;

Q_f is the flow rate at flowing conditions;

P_f is the pressure at flowing conditions;

P_b is the base pressure;

T_f is the temperature at flowing conditions;

T_b is the base temperature;

Z_f is the compressibility at flowing conditions;

Z_b is the compressibility at base conditions.

Other forms of the equation or equations for other types of linear meters are acceptable.

The flow equation may be factored into two parts: one representing the actual volume and one containing the measured variable that remain relatively constant with respect to time.

$$Q_i = IMV \times Q_f \quad (15)$$

where

Q_i is the flow rate;

IMV is the Integral Multiplier Value, representing the relatively static measured and calculated values;

Q_f is the flow rate at flowing conditions.

Combining the factored form of the equation with the quantity calculation above, yields:

$$V = IMV \sum_{i=1}^{i=n} Q_{fi} \Delta t_i \quad (16)$$

The term $\sum_{i=1}^{i=n} Q_{fi} \Delta t_i$ is called the Integral Value (IV), such that $V = IMV \times IV$.

4.5.1 Sampling Flow Variables

The frequency or rate from a linear meter shall be sampled once every second or be continuously accumulated. If the flow rate is calculated for operational use from a low frequency meter, take care to use a calculation interval appropriate to the meter output.

Static pressure and temperature shall be sampled at least once per second⁶ and averaged using flow time linear averages. Other live input variables may be sampled at their update frequency.

⁶ Exactly consistent sample intervals may not be possible due to computer architecture and the complexity of the algorithms in question. However the effect of minor variations in the sample period will not be statistically significant if the average sample period is small compared to the observed variation in flow dynamics.

A slower sampling frequency may be used if the Rans Methodology can demonstrate that a difference in uncertainty associated with a less frequent sampling time is no more than $\pm 0.05\%$ greater than the uncertainty associated with the one second sampling frequency for a given application, and the slower sampling frequency is agreeable to the parties involved.

4.5.2 Integral Value (IV) Calculation

The Integral Value (IV) for linear meters is defined as:

$$IV = \sum_{i=1}^{i=z} Q_{fi} \Delta t_i \quad (17)$$

where

IV is the integral value;

Q_{fi} is the flow rate at flowing conditions;

Δt_i is the time between samples;

z is the number of samples taken over the QCP.

and:

$$z = \frac{QCP}{\Delta t}$$

NOTE See 4.3 for maximum QCP.

4.5.3 Integral Multiplier Value (IMV) Calculation

The Integral Multiplier Value (IMV) for linear meters is defined as:

$$IMV = \left(\frac{P_f}{P_b} \right) \left(\frac{T_b}{T_f} \right) \left(\frac{Z_b}{Z_f} \right) \quad (18)$$

where

IMV is the integral multiplier value;

P_f is the pressure at flowing conditions;

P_b is the base pressure;

T_f is the temperature at flowing conditions;

T_b is the base temperature;

Z_f is the compressibility at flowing conditions;

Z_b is the compressibility at base conditions.

and the values are based on flow time linear averages of the variables for the QCP.

4.5.4 Q_f —Flow Rate at Flowing Conditions

For synchronous linear meters such as turbine and rotary meters, Q_f is calculated by totalizing the pulse output. With the introduction of intelligent linear meters, the types of output have changed to include manufactured pulses, serial or analog rate and serial accumulator outputs. This has resulted in the need to redefine the calculation of Q_f .

Traditional synchronous meters have also been subjected to external linearization, utilizing multiple k -factors or meter factors, to reduce measurement uncertainty. Intelligent linear meters may have this linearization done within the meter or externally applied. This requires an understanding of how these factors are applied in the calculation of IV .

NOTE 1 In the following subsections: Counts/Flow Rate/Accumulator Difference is intended to be the non-linearized volumetric output of the meter at actual conditions and IV is intended to be the linearized volumetric output of the meter at actual conditions. The QTR ratio of IV divided by the non-linearized volumetric output is the QTR average meter linearization (See Annex J for examples of how these equations can be applied).

NOTE 2 The equations presented below may be adapted to different linear metering technologies and to support additional mathematical equations that give equivalent results.

NOTE 3 Some linear meter standards define k -factor as the inverse of the definitions in this section. Take care to use the correct mathematical definition when applying this standard to those metering technologies.

4.5.4.1 Linear Meters with Synchronous Pulse Outputs

$$IV = \sum_{i=1}^{i=n} Q_{fi} \Delta t_i \text{ is expressed as } \sum_{i=1}^{i=n} \frac{mf_i}{k\text{-factor}_i} \sum_{j=1}^{j=z} \text{Counts} \text{ or } \sum_{i=1}^{i=n} mf_i \sum_{j=1}^{j=z} \frac{\text{Counts}}{k\text{-factor}} \text{ or } \frac{1}{k\text{-factor}} \sum_{i=1}^{i=n} mf_i \sum_{j=1}^{j=z} \text{Counts} \quad (19)$$

where

Counts is the accumulation of meter pulses;

$k\text{-factor}$ is the single linear meter constant in counts per unit volume;

$k\text{-factor}_i$ is the multi-point linear meter constant in counts per unit volume calculated at interval i ;

mf_i equals 1 or mf_i equals the meter factor for period i (when multi-point meter factors are used);

j is the sampling period;

z is the number of samples per calculation period;

i is the calculation period;

n is the number of calculation per QTR period.

NOTE 1 Due to the mechanical design of these devices, the pulse is synchronized to the flow.

NOTE 2 j and z should be chosen such that $n = \text{QTR period} / (j \times z)$ is an integer.

NOTE 3 $\text{Counts}/k\text{-factor}$ is considered a variable input and this summation shall be reported in the QTR. (This value may be reported as $\text{frequency} = \text{Counts}/\text{flow time}$.)

4.5.4.2 Linear Meters with Manufactured Pulse Outputs

$$IV = \sum_{i=1}^{i=n} Q_{fi} \Delta t_i \text{ is expressed as } \sum_{i=1}^{i=n} \frac{mf_i}{k\text{-factor}_i} \sum_{j=1}^{j=z} \text{Counts} \text{ or } \sum_{i=1}^{i=n} mf_i \sum_{j=1}^{j=z} \frac{\text{Counts}}{k\text{-factor}} \text{ or } \frac{1}{k\text{-factor}} \sum_{i=1}^{i=n} mf_i \sum_{j=1}^{j=z} \text{Counts} \quad (20)$$

where

- Counts* is the accumulation of meter pulses;
- k-factor* is the single linear meter constant in counts per unit volume;
- k-factor_i* is the multi-point linear meter constant in counts per unit volume calculated at interval *i*;
- mf_i* equals 1 or *mf_i* equals the meter factor for period *i* (when multi-point meter factors are used);
- j* is the sampling period;
- z* is the number of samples per calculation period;
- i* is the calculation period;
- n* is the number of calculation per QTR period.

NOTE 1 Due to the manufactured nature of the meter pulse output, the meter manufacturer needs to ensure the manufactured pulses are synchronized to the flow.

NOTE 2 *j* and *z* should be chosen such that $n = \text{QTR period} / (j \times z)$ is an integer.

NOTE 3 *Counts/k-factor* is considered a variable input and this summation shall be reported in the QTR. (This value may be reported as *frequency = Counts/flow time*.)

4.5.4.3 Linear Meters with Rate Output

$$IV = \sum_{i=1}^{i=n} Q_{fi} \Delta t_i \text{ is expressed as } \sum_{i=1}^{i=n} mf_i Q_{mi} \Delta t_i \text{ or } \frac{1}{k\text{-factor}} \sum_{i=1}^{i=n} mf_i Q_{mi} \Delta t_i \quad (21)$$

where

- Q_{mi}* is the meter flow rate at actual flowing conditions for period *i*;
(units are volume/unit time if the *k-factor* is included in the meter flow rate or counts/unit time if the *k-factor* not included in the meter flow rate);
- mf_i* equals 1 or *mf_i* equals the meter factor for period *i* (when multi-point meter factors are used);
- i* is the calculation period;
- n* is the number of calculations per QTR period;
- k-factor* is the single linear meter constant in counts per unit volume.

NOTE 1 The meter output needs to be read at a frequency that is sufficient to correctly capture the fluctuation in the flow.

NOTE 2 The meter output may already be corrected for *k-factor*.

NOTE 3 $mf_i Q_{mi}$ is considered a variable input if a multi-point meter factor is used and its average shall be reported in the QTR.

4.5.4.4 Linear Meters with Accumulator Output

$$IV = \sum_{i=1}^{i=n} Q_{fi} \Delta t_i \text{ is expressed as (Accumulator Difference for the QTR) or } \sum_{i=1}^{i=n} mf_i \times \text{Accumulator Difference}_i \quad (22)$$

where

mf_i equals 1 or mf_i equals the meter factor for period i (when multi-point meter factors are used);

i is the calculation period;

n is the number of calculation per QTR period.

NOTE 1 The accumulator handles rate fluctuation and therefore does not need to be read more frequently than the QCP unless external meter factor corrections are being applied.

NOTE 2 The meter manufacturer needs to ensure that manufactured accumulations are synchronized to the flow.

NOTE 3 The meter output has to already be corrected for *k-factor* and meter factor.

NOTE 4 *Accumulator Difference* is considered a variable input if a multi-point meter factor is used and its accumulation shall be reported in the QTR.

4.5.5 No Flow Detection/No Flow Cutoff

No flow shall be defined as an absence of counts over a period of time.

The no flow cutoff is used to address the site induced false flow.

For pulse output meters, the recommended no flow cutoff value is 0 pulses/period of time. The time period is based on the expected frequency of the meter.

For rate output meters, the recommended no flow cutoff value is 0 for serial rate meters (or as recommended by the meter manufacturer) and 0.25 % of span for analog output rate meters.

In some cases the no flow cutoff is integral to the meter based on its operating characteristics. The meter manufacturer shall provide a description of this process and the no flow cutoff value.

Consideration of documented site conditions may result in an increased no flow cutoff value.

4.5.6 Volume Calculation

At the end of each QCP, the *IMV* is multiplied by the *IV* to obtain a total quantity for the QCP. At a minimum, hourly quantities as defined in Section 5 shall be calculated and maintained. If the QCP is less than one hour, the quantities for each QCP can be maintained and reported, or, the quantities determined for each QCP can be summed for each hour.

4.6 Value Determination For Live Inputs

At a minimum, the IV and hourly averages of all live inputs shall be maintained and reported (see Section 5). Flow time linear averages shall be used and must only include values taken when there is flow (above the no flow cutoff) unless there is no flow for the whole QTR. If the QCP is less than one hour, the averages for each QCP can be maintained and reported, or, the averages determined for each QCP can be combined to obtain an hourly average (see Annex B.4, *Calculation of QTR Averages*).

4.7 Compressibility, Density, Heating Value, and Composition

Compressibility, density, heating value and composition may be required in the calculation of mass, energy, and/or volume. They may be introduced into the calculation as a constant value, sampled input, or calculated value using a combination of constant values and sampled inputs. Increasing the frequency of updating/calculation of these variables can minimize mass, energy and/or volume calculation uncertainty. All sampled inputs should be determined using the techniques given in 4.4 and 4.5 and be consistent with the time interval of the calculations.

5 Audit and Record Requirements

5.1 Introduction

This section defines the minimum requirements of a QTR and QTR_{corr} documentation associated with the operation of an EGM, and the minimum data retention periods to report and verify the integrity of the measurement.

An EGM system shall be capable of establishing an audit trail by compiling and retaining sufficient data and information for the purpose of verifying daily and hourly quantities. This documentation shall include units of measure for all reported values.

The audit trail shall include, but is not limited to, QTRs, Configuration Logs, Event Logs, field test reports, QTR_{corr}, and reason for correction (edit). The records and reports in this section may be created onsite or off-site, or a combination of both and shall include units of measure where applicable.

The primary reason for retaining historical data is to provide support for the current and prior quantities reported on the measurement and quantity statements. The data will provide sufficient information to apply reasonable adjustments when the EGM equipment:

- requires correction for measurement errors or metering standards changes (see 5.7.1);
- has stopped functioning;
- is determined to be out of tolerance;
- has incorrectly recorded measurement parameters.

The data will also allow parties with a direct interest in the measurement results to independently verify the correctness of the reported gas quantities.

5.2 Quantity Transaction Record (QTR)

The QTR is the set of unedited historical data and information supporting the accounted quantity or quantities of volume, mass, or energy. The QTR will be identified by a unique identifier denoting a specific electronic metering device and primary device.