The Financial and Regulatory Impact of the New CO_2 Mass Measurement Standards

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Although the oil and gas industry has been measuring CO_2 for more than 40 years, serious technical challenges remain. This is a proposal from the API (American Petroleum Institute) MPMS (Manual of Petroleum Measurement Standards) COLM (Committee for Liquid Measurement) for addressing cost and regulatory challenges by developing new standards for carbon dioxide (CO_2) measurement.

This paper covers the following

- Identifying challenges of CO_2 measurement due to its tendency to exist in multiple phases
- Development of two new API standards for dense and supercritical CO_2 measurement
- How these standards support accurate financial reporting and regulatory compliance
- Benefits for producers, pipelines and storage operators across the CO_2 industry. Other stakeholders include capture facilities, Direct Air Capture (DAC) and emitters.

BACKGROUND

In the oil and gas industry, particularly in the Permian Basin, CO_2 has been used for tertiary recovery since the 1970s. Also called “enhanced oil recovery” (EOR), this process involves injecting carbon dioxide into mature oil reservoirs to mobilize and extract additional crude oil that primary and secondary methods cannot access.

Studies show that secondary recovery with CO_2 which involves water or gas injection, increases recovery by 20-40% as it forces additional oil toward the well. Additionally, by injecting CO_2, injecting chemicals, or heating to change the oil fluid properties (EOR), additional recovery increases can be as high as 30-60%. [1]

For example; pipelines such as; Kinder Morgan’s Cortez and Canyon Reef Carriers Pipelines, Arco’s Sheep Mountain Pipeline, and OXY’s Bravo Pipeline transport this valuable commodity.

With over 5,300 miles of CO_2 pipelines and counting, the United States of America leads the international race to operate and capture CO_2. According to *World Pipeline*, Capacity

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[1] US Department of Energy “Enhanced Oil Recovery” Website

needed for 2050 of nearly 360,000 km of pipelines may be needed to transport the CO_2 for industrial, oil and gas processes. [2]

THE IMPACT OF CO_2 MEASUREMENT UNCERTAINTY

The efficiency of modern transportation pipelines can produce volumetric flow rates which make seemingly minute measurement error costs profound. For example: for 2,671 PCO_2e (metric tons of carbon dioxide equivalent) transmission capacity:

Impact of a 1% CO_2 metering error is:

cost (USD/TCO_2e)*	**Annual impact (USD)**
10	$26,710
30	$80,130
60	$160,260
100	$267,100
158.8	$424,155

*Source: Average carbon credit costs projected around $60/t (metric tons of carbon dioxide) by 2030; compliance carbon prices in some jurisdictions reach $158.8/metric tons of carbon dioxide (t) Carbon Pricing Dashboard.

Impact of a 2% CO_2 metering error

We already calculated that a 1% metering bias in setup corresponds to about 2,671 TCO_2e per year. Doubling that to 2% error gives:

Annual error $\approx 2 \times 2{,}671 = 5{,}342$ tCO_2e/year

cost (USD/tCO_2e)	**Annual impact (USD)**
10	$53,420
30	$160,260
60	$320,520
100	$534,200
158.8	$847,930

Note: Prices vary widely. Voluntary market averages are often in the $30–$60/t range, while compliance markets (like EU ETS) can exceed $100–$150/t. [3]

As the data shows, accurate, consistent measurement practices are critical to success of any CO_2 operation.

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[2] Dimitrios Bardakos, Global Carbon Leader, American Bureau of Shipping (ABS)

[3] Apex Measurement provided the parameters for the calculation

CARBON DIOXIDE MEASUREMENT ACROSS A VALUE CHAIN

Measurement of the quantity and quality of the transported CO_2 are required at different stages across the value chain.

The purpose of these measurements include:

- Regulatory
- Contractual/custody transfer
- Operations, i.e., leak detection
- Allocation

For the purposes of this analysis and with respect to the applicable measurement standards discussed, the primary focus is "custody transfer" where measurement error limits are typically more stringent. The proposed standards discussed however can also be applied in design and implementation in other commodity transportation applications.

Figure 1 Schematic showing a CO2 value chain and possible measurement locations illustrates potential metering locations along the transport chain.

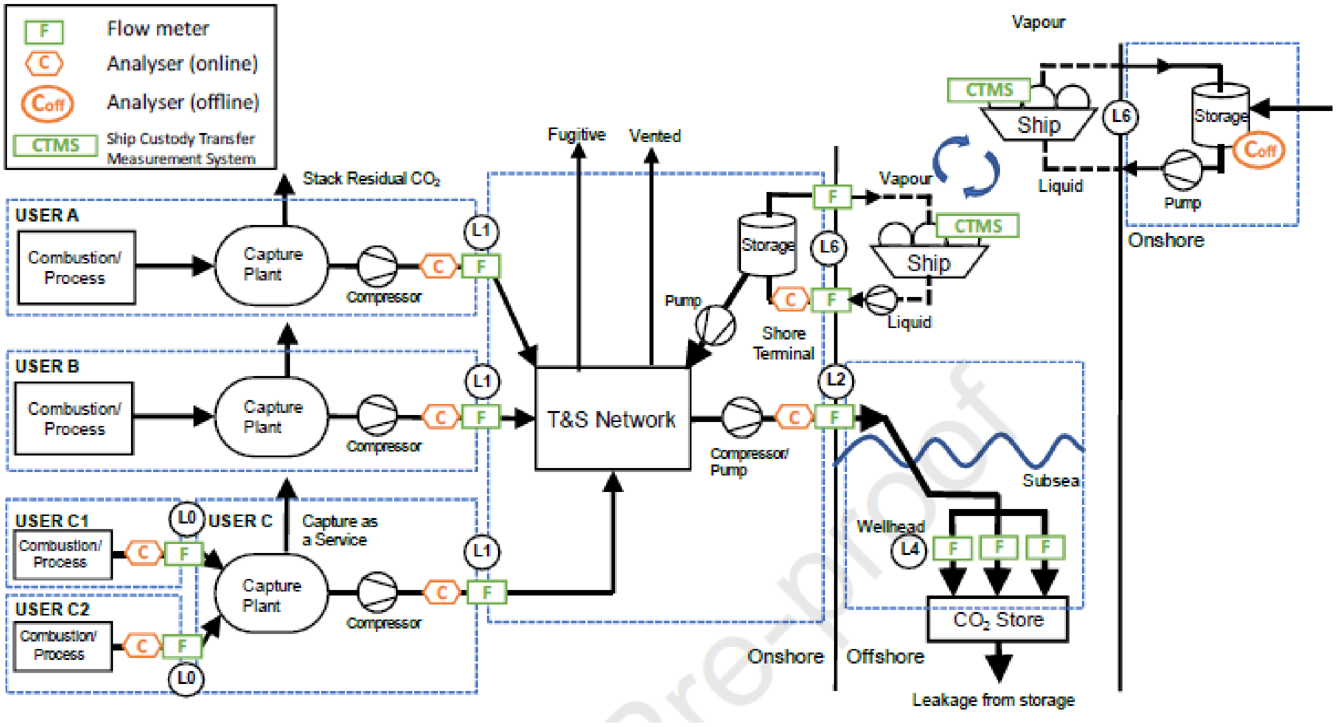
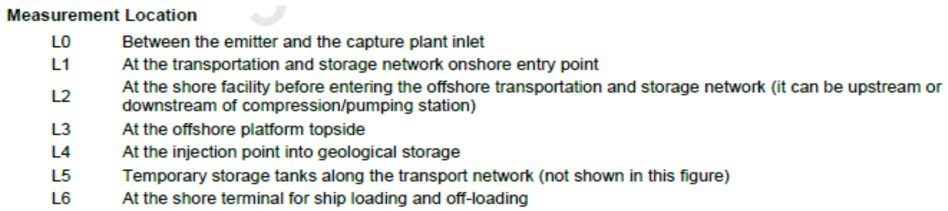


Figure 1 – Schematic showing a CO2 value chain and possible measurement locations*



Measurement Location

L0	Between the emitter and the capture plant inlet
L1	At the transportation and storage network onshore entry point
L2	At the shore facility before entering the offshore transportation and storage network (it can be upstream or downstream of compression/pumping station)
L3	At the offshore platform topside
L4	At the injection point into geological storage
L5	Temporary storage tanks along the transport network (not shown in this figure)
L6	At the shore terminal for ship loading and off-loading

**System boundaries represented as dash lines. Note: This figure is general in nature and not intended to encompass all possibilities that could exist.* [4]

In general, there are three main quantities to be determined:

A. CO_2-rich mass quantity, i.e., total stream mass, pure CO_2 and impurities
B. CO_2 mass quantity, i.e., the mass of pure CO_2 fraction only
C. Impurities concentration in the CO_2 stream

For contractual purposes (A) is usually reported and sometimes (B). Regulatory reporting focuses on (B). (C) is chiefly mandated for asset integrity, health, and safety purposes, and usually specified in a contractual agreement.

CO_2 MEASUREMENT CHALLENGES

Within a value chain, and as depicted in Figure 2 – Pure CO2 Phase Diagram, CO_2 can be a liquid, gas or supercritical phase, or all three; gas, liquid and solid all at one time – triple point. Additionally, the steep almost singularity type density changes can be problematic to deal with at times.

All the various phases present different measurement challenges. Furthermore, as the phase boundaries lie close together, maintaining the desired fluid phase can be challenging. This is particularly the case for transportation across large pipeline networks that span hundreds of miles where regulation of the fluid temperature and pressure is difficult due to varying climates and elevations.

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[4] Proposed Value Chain Schematic from API MPMS 6.XX in Development

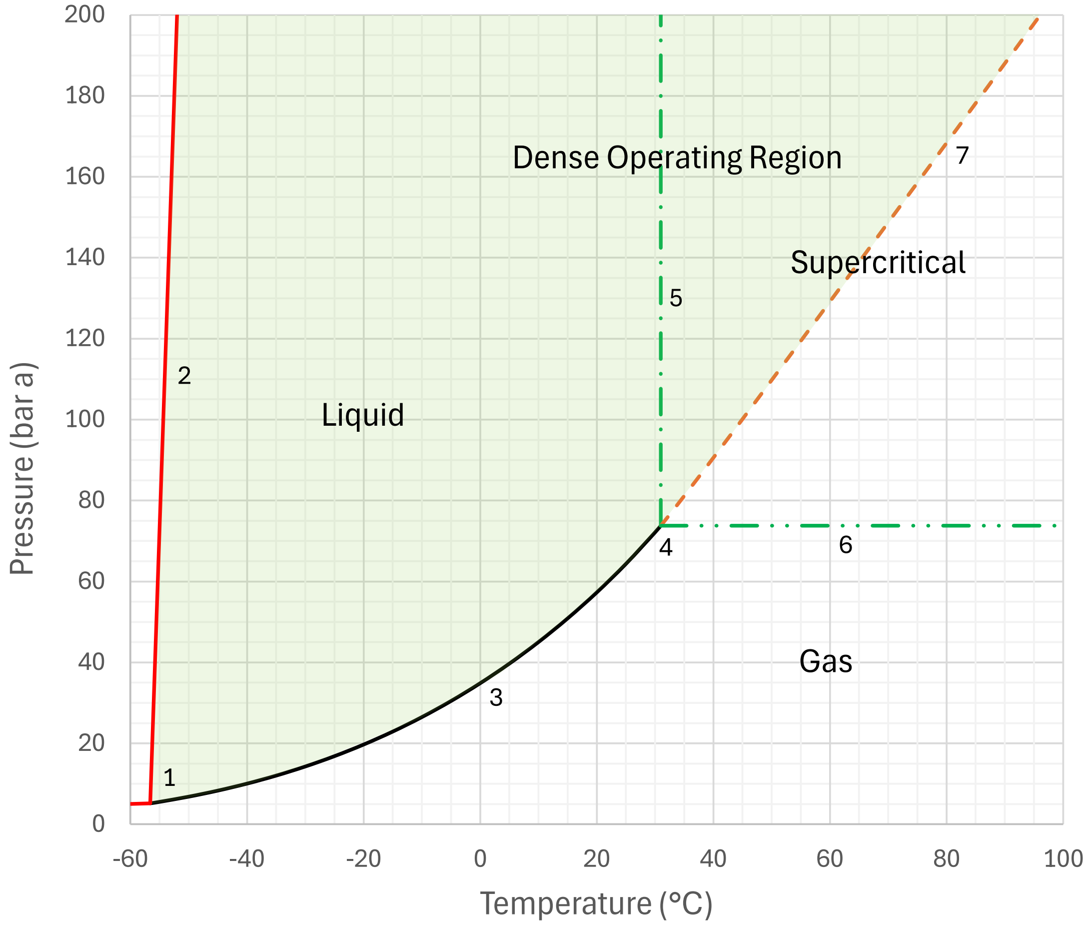

Figure 2 – Pure CO2 Phase Diagram [5]

1 Triple Point
2 Solid/Liquid phase boundary
3 Liquid/gas phase boundary
4 Critical/point
5 Liquid/supercritical phase boundary
6 Gas/Supercritical phase boundary
7 500 kg/m3 line
8 🟩 Dense Operating region

Important Notes Related to Pure CO_2 *Phase Diagram (Figure 2)*

1. Phase: Pure CO_2 can exist in one of four states or phases: solid phase, liquid phase, gas phase or supercritical phase. [6]

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[5] Proposed Pure CO_2 Phase Diagram from API MPMS 6.XX in Development

2. Supercritical Phase: The supercritical phase is the fluid state at a temperature and pressure above the critical point where distinct liquid and gas phases do not exist. For CO_2 the critical temperature is 304.128K [30.9780 °C, 87.7604 °F] and critical pressure is 7.3773 MPa [73.773 bar, 1,070.0 psi]
3. Dense Phase: The term "dense phase" does not have a universal interpretation, and care should be taken to confirm actual conditions when reference is made to "dense phase" conditions. *Dense phase is not interchangeable with supercritical phase.* For purposes of both standards, dense phase is not used in the standard(s), instead the terminology "dense operating region" is used. The term "dense phase" does not have a corresponding thermodynamic definition and hence may be subject to misinterpretation.
4. Dense Operating Region: Transportation and measurement of high-density CO_2 is commonly achieved using pumps and metering technologies used in liquid applications. In the API 6.xx standard, the dense operating region defines operation in the liquid and/or supercritical phase with density equal to or greater than 500 kg/m^3. As the supercritical phase of CO_2 covers a wide range of densities, the *dense operating region* spans only part of the supercritical region.
5. Phase Diagram: A phase diagram is a plot showing the material state as a function of variables such as temperature and pressure. A pressure/temperature phase diagram for pure CO_2, showing the phase boundaries and the dense operating region as defined in this standard, is presented in Pure CO_2 Phase Diagram, Figure 2.
6. Phase Transition: A change from one state of matter to another. When changes in temperature and pressure cause a transition across the liquid/gas phase boundary (line 3 in Figure2), non-equilibrium conditions can result in two-phase flow owing to both liquid and gas being present simultaneously. When crossing the liquid/supercritical (line 5 in Figure 2) or gas/supercritical (line 6 in Figure 2) boundaries, the fluid remains essentially homogeneous and two-phase flow is avoided.

TRANSPORTATION / OPERATIONS

Many pipelines transport operations can easily reach CO_2's critical temperature (30.97 °C, 87.76 °F) because of its proximity to ambient temperature. Operating near the critical point can present significant technical challenges for process control and measurement as small changes in temperature and pressure can cause large changes in fluid properties, i.e., density, speed of sound, etc.

IMPURITIES

Impurities can cause significant shifts in fluid phase boundaries, the critical point, and two-phase region. Most important, they can create two-phase flow at process conditions that would be single-phase gas or single-phase liquid for pure CO_2. Figure 3 below illustrates this shift in the gas-liquid transition region for a mixture of CO_2 and hydrogen (H2) with varying hydrogen concentrations.

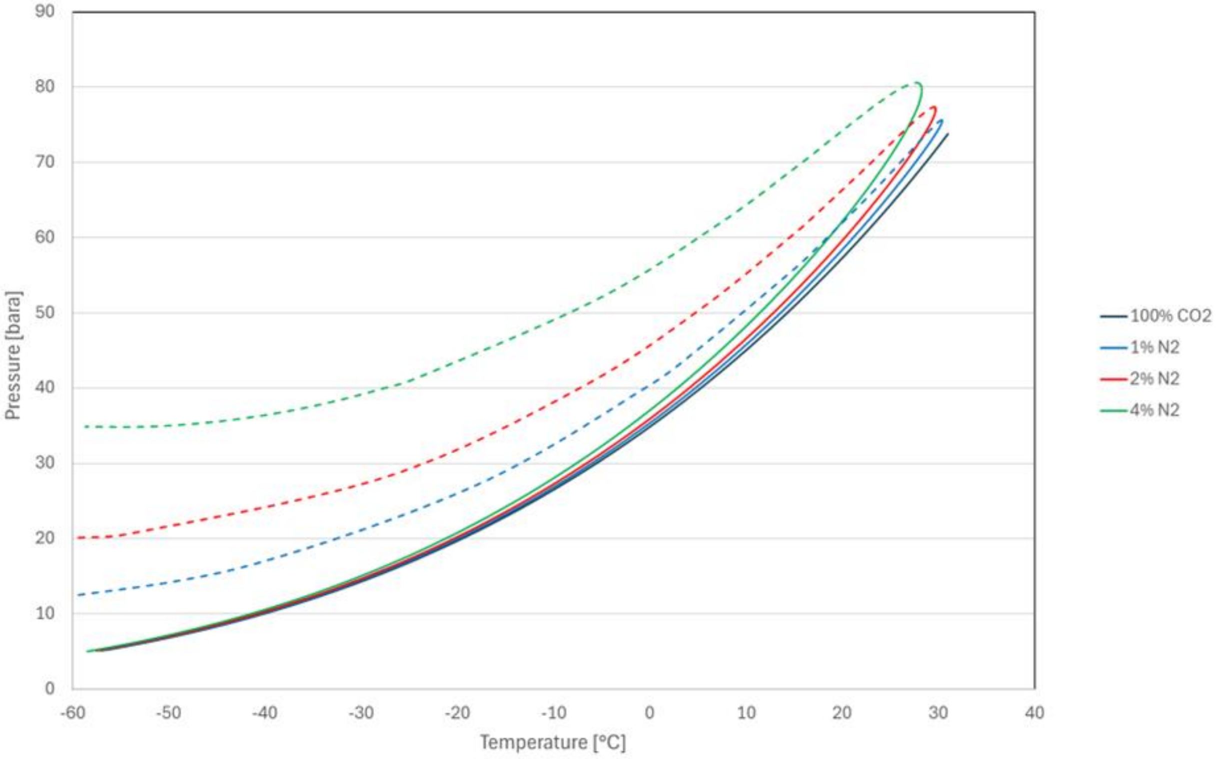

Figure 3 – CO_2 Phase Envelope Impact Due to Impurities (i.e. Nitrogen)[7]

METER CHALLENGES

Meters with high accuracy requirements, e.g., Custody Transfer, should be operated at single phase of fluid conditions. Exceptions to this single-phase condition requirement are permissible in custody transfer applications only when the duration and additional uncertainty owing to these transitions has a small impact on the overall uncertainty of corresponding batch total.

This may necessitate the use of gas meters at certain locations and liquid meters at other locations along the same piping network. The fluid's phase envelope must be predictable and controllable to avoid the presence of two-phase flow. Two-phase flow can severely degrade meter accuracy, and, in some cases, potentially cause irreversible damage including meters with moving internal parts.

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[7] Proposed CO_2 Phase Envelope Impact Due to Impurities (i.e. Nitrogen) from API MPMS 6.XX in Development

CORROSION

Corrosion can have a negative impact on the measurement integrity and technologies being used within the metering system. Of specific concern, the potential for free water should be carefully considered for each application and minimized since it can result in the formation of highly corrosive carbonic acid and hydrates. It should be noted that this corrosion effect may depend on the fluid phase (gas vs liquid).

TWO PHASE MEASUREMENT ISSUES

In the past, AGA, API and ISO considered two-phase measurement a “no-no” because it undermines accuracy, reliability, and trust in gas metering. The industry solved this by separating phases before measurement or by using specialized wet-gas meters only when unavoidable. Two-phase measurement (gas mixed with liquid or solid particles) is avoided in the hydrocarbon measurement business because it introduces large errors, instability, and uncertainty. Hydrocarbon meters are designed for single-phase flow, and the presence of a second phase disrupts their calibration, causes over- or under-reading, and makes custody transfer unreliable

For purposes of this paper, “custody transfer measurement” is defined as “Provides quantity and quality information for the physical and fiscal documentation of a change in ownership and/or a change in responsibility for commodities.” API and AGA have in the past provided standards for single phase gas, NGLs or crude.

The ability of CO_2 to phase from gas, dense or supercritical is the major challenge for measuring for exchange of monetary value, especially now in the regulatory environment.

It is important to note that the implementation of these standards will provide an auditable document to meet regulatory requirements and credits.

CO_2 MEASUREMENT ESSENTIALS

Three main areas are essential to monitor CO_2 across the Carbon Capture and Storage Chain (CCS) chain:

- Sampling of the CO_2 mixture
- Determining the physical properties
- Flow measurement

Sampling of the CO_2

Sampling of the CO2 stream is necessary to determine the CO_2 concentration and for the regulatory reporting of other non-CO_2 components in the CO_2 stream. As the composition of the CO_2 stream will vary continuously both at the capture plant and throughout the transportation network, continuous sampling should be undertaken.

Determining Physical Properties

New equations of state and phase diagrams for determining the physical properties of the many different CO_2 mixtures that are likely to arise in pipelines. The API MPMS 6.x Standards examine how best to establish validated industry standards and tools, both hardware/software, to minimize inconsistencies across a wide variation of results between different CO_2 mixtures. Physical properties software modelling packages and algorithms will need to be validated to demonstrate the level of accuracy, as even small errors can result in serious problems during the processing and transport of CO_2.

Flow Measurement

Flow measurement, in conjunction with CO_2 concentration derived from sampling of the CO_2 stream is required to calculate the transformation of CO_2 on a mass basis across the pipeline. The API MPMS 6.x has not determined the flow measurement uncertainty levels, but recommendations target 1.5%.

To achieve such levels, the API MPMS 6.X standard will outline the design and installation of the correct type of flow meter, ensuring the flow conditions are stable along the network, operating at the single-phase condition it was designed for, assuming all conditions are stable. Use of gas meters may be needed at certain locations, and liquid meters at other locations along the network. Special consideration should be given to any flow meter selected to measure supercritical phase, to ensure the flow meter is suitable, of sound design and proven accuracy within this specific phase.

DEVELOPMENT OF CO_2 MEASUREMENT STANDARDS

In 2022, API Committee for Liquid Measurement (COLM) recognized that industry guidance was needed regarding custody transfer. The decision was to develop two complementary standards.

API 6.XA Metering Assemblies for Supercritical and Dense Phase Fluids

API development of a custody transfer measurement standard for fluids provides more accurate measure of CO_2 which are compressible when transported in supercritical state.

Guidance includes overall design and operation of the measurement system.

For purposes of this standard, “supercritical fluid” is defined as *a fluid that is maintained above its critical temperature and critical pressure, such that the fluid has characteristics of both liquid and gas phases. These fluids behave as compressible fluids and are known to have rapid density change with changing process conditions.*

Fluid examples provided for this standard are Ethylene (Ethane/Ethene) and Anhydrous Ammonia.

API 6.XB Metering Assemblies for the Measurement of Liquid, Dense or Supercritical Phase Carbon Dioxide

For Carbon Capture and Storage (CCS) this standard is essential for all captured CO_2 to be accurately measured across each stage of the value chain. This standard is necessary for process control to detect CO_2 leaks, and for verification of the CO_2 quantity accounted under the emissions trading/credit scheme. Figure 4 CO_2 Operating Ranges illustrates the unusual relationship and closeness of its triple point and critical point to the temperatures and pressures commonly found in industrial processes. In addition, most CO_2 CCS applications require multiple title (custody) transfers to transport captured CO_2 from emitter to injection sites:

- Dense
- Supercritical
- Liquid
- Gas

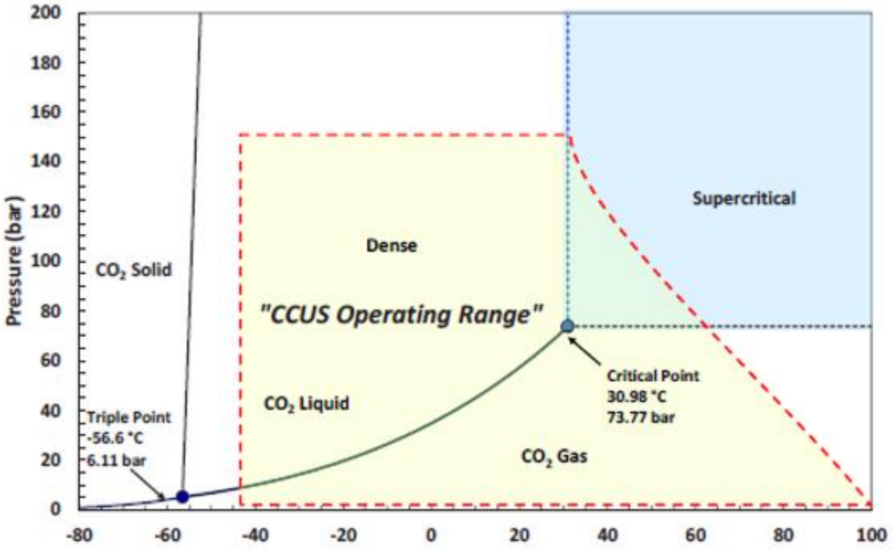

Figure 4 – CO_2 Operating Ranges[8]

METERING SYSTEM

A Metering System is defined in both standards as a combination of primary, secondary and tertiary measurement components, along with piping and other equipment instrumentation necessary to determine custody transfer quantity and data documented on the measurement ticket. A metering system has the general characteristics or functionality:

- Flow meters to measure flow quantity
- Means to determine fluid properties, including composition

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[8] Modified drawing from cyrogenicsociety.org for proposed API 6.XX standard

- Means to inspect, verify and calibrate devices and equipment that can affect custody transfer quantity and the quality determination that can affect it.
- Accessibility for equipment maintenance
- Flow computation device(s)

CO_2 can be transported by onshore or offshore subsea pipelines and in liquid, gaseous, dense, or supercritical phase. Pipeline metering systems used for CO_2 custody transfer are typically required at the pipeline's entry and/or exit points across a pipeline network.CO_2 is normally transported by pipeline to:

- An injection site (onshore or offshore) for geological storage
- A shore facility for continued transport to an offshore subsea injection site for geological storage
- A shore facility for temporary storage and ship loading

Marine metering systems can be used for CO_2 custody transfer measurement between a marine vessel and shore facility during loading/unloading operations. For marine transport, CO_2 is in liquid phase at low temperatures and low to medium pressures. Metering for marine transport applications offers several benefits, including minimum vessel turnaround time, increased reliability and accuracy, traceable field standards (provers), automated reporting and safety.

System Design and Installation Considerations

Metering systems for CO_2 measurement can have various configurations, which are dependent upon

- Contractual uncertainty requirements,
- Fluid properties, density, phase, vapor pressure,
  operating parameters (flow range, pressure, temperature),
- Mode of operation (intermittent or continuous),
  redundancy requirements,
  verification/calibration (proving) requirements
- Other miscellaneous requirements such as available utilities, or varying flow directions including bidirectional flow

Both API 6.XA and 6.XB provide a high-level description of the process or steps for designing mass custody transfer metering systems for carbon dioxide (pure CO_2 and CO_2-rich mixtures) measurement:

1. Define operating envelope
    a. Marine Vessel Loading/Unloading Operating Envelope (Liquid Phase Only)
    b. Pipeline Operating Envelope (Gas Phase Only)
    c. Pipeline Metering Operating Envelope (Liquid and Supercritical Phases)
    d. Pipeline Metering Operating Envelope (Liquid and Supercritical Phases with Crossing of 500 kg/m^3 line)
2. Define meter technology and mass measurement methods
3. Select meter technology and mass measurement methods. There are a number of flow meters that may be suitable for CO_2 and some of these have been already in

use for production and pipelines. The API MPMS 6.X standard provides some guidance for design, installation, calibration and maintenance. Considerations in the standard include referencing existing AGA, API, ISO standards as well as ensuring traceable to labs in CO_2 under the conditions which they will be required to operate.

   a. Differential Pressure (DP) Flow Meters
      1. Orifice Plate Meters (API MPMS 14.3 (AGA Report 3) and API 21.1): Long track record in measuring CO_2 and used widely in stable single phase conditions with uncertainty levels of ±1%.
      2. Venturi and V Cone meters – not normally recognized as custody transfer, and not as commonly used with CO_2 applications.
   b. Volumetric Flow Meters
      1. Turbine Meter (AGA Report 7 and API MPMS 5.2)
      2. Vortex Meters – Not enough experience with CO_2
      3. Ultrasonic Meter (AGA Report 9)
   c. Mass Flow Meter
      1. Coriolis Meter

4. Selection meter calibration and field verification method (see above 3. Meter Technology)
5. Determine meter run configuration
6. Determine meter system configuration

QUALITY DETERMINATION

Determining custody transfer quantities requires

- Product quality information (density, product composition, etc.)
- Ensuring product quality specifications are met
- Protection of pipeline integrity, including corrosion
- Avoidance of two-phase flow conditions

Both API 6.XA and 6.XB consider that the quality of supercritical fluids can be challenging due to their unique properties. Some of these challenges include:

- Highly varying density: Supercritical fluids can have large changes in density with small changes in pressure and/or temperature, especially when operating near to the fluid’s critical point.
- Unusual properties behavior: Supercritical fluids can exhibit unusual behavior for properties such as changes in viscosity and compressibility
- Potential for fluid phase transition: Supercritical fluids require operational awareness of the phase envelope to avoid two-phase flow conditions.

It is a requirement in the measurement of supercritical fluids streams to obtain a compositional analysis online or offline that represents the homogenous mixture of components being metered. In Table 1. Compositional Methods for Analysis and Impurities[9] .Compositional analysis and impurity analysis of the supercritical fluids within the scope of this standard may be performed using any of the methods listed below or methods agreed upon by the contracting parties.

Table 1. Compositional Methods for Analysis and Impurities[9]

CO2 and/or Ethane	
Liquid	
GPA 2177-20	Analysis of Natural Gas Liquids by Gas Chromatography
GPA 2165	Analysis of Natural Gas Liquid Mixtures by Gas Chromatography
GPA 2186-22	Method for extended analysis of hydrocarbon liquid mixtures containing nitrogen and carbon dioxide by temp programmed GC
Gas	
GPA 2261-20	Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography
GPA 2286-14	Method for the Extended Analysis of Natural Gas and Similar Gaseous Mixtures by Temperature Program Gas Chromatography
ASTM D8098-23	Standard Test Method for Permanent Gases in C2 and C3 Hydrocarbon Product by Gas Chromatography and Pulse Discharge Helium ionization Detector
ASTM D2504-88 (2015)	Standard Test Method for Noncondensable Gases in C2 and Lighter Hydrocarbon Products by Gas Chromatography

Ethylene	
D5234-92 (2017)	Standard Guide for Analysis of Ethylene Product
ASTM D6159-17	Standard Test Method for Determination of Hydrocarbon Impurities in Ethylene by Gas Chromatography
ASTM D2505-88 (2015)	Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography

DENSITY

Density is required for applications where inferred mass measurement techniques are utilized including orifice meters, ultrasonic meters, turbine meters, etc. Considerations for Density addressed in the standard include:

- Density Design
- Density Determination by On-line Density Meter
- Density Determination by Equation of State
- Density Determination Using a Fixed Value

CASE HISTORY: SUPPORTING ACCURATE FINANCIAL REPORTING AND REGULATORY COMPLIANCE

So, let's take an example of a project already in place:

Occidental Petroleum (Oxy) – Permian Basin, TX

- *Project Type:* Direct Air Capture (DAC) facility in Ector County, Texas.
- *How It Works:* Giant fans pull CO_2 directly from the atmosphere, then the gas is compressed and either stored underground in saline formations or used in enhanced oil recovery.
- *Tax Credit Impact:*
    - For secure geological storage, Oxy earns about $85 per ton of CO_2 captured.
    - For utilization in oil recovery, the credit is about $60 per ton.
- *Scale:* The facility is designed to capture up to 500,000 tons of CO_2 annually, which translates into tens of millions of dollars in tax credits each year.
- *Why It Matters: This project is one of the first large-scale DAC plants in the world, and the 45Q credit makes it financially viable.*

Credit revenue scenarios for 500,000 tCO_2/year

Pathway	**Credit per ton (USD)**	**Annual Volume (tCO_2)**	**Annual Credits (USD)**
Secure geological storage	85	500,000	42,500,000
Utilization for EOR	60	500,000	30,000,000

Impact of metering uncertainty at 1% and 2%:

A total measurement uncertainty of ±x% means the true captured CO_2 could be ±x% from reported. For our purposes:

- **Baseline:**
    - **Captured:** 500,000 tCO_2/year
    - **1% uncertainty:** ±5,000 tCO_2
    - **2% uncertainty:** ±10,000 tCO_2
- **Dollar swing by pathway:**
    - **Storage at $85/t:**
        - **±1%:** $\pm 5{,}000 \times 85 = \pm \$425{,}000$
        - **±2%:** $\pm 10{,}000 \times 85 = \pm \$850{,}000$
    - **EOR at $60/t:**
        - **±1%:** $\pm 5{,}000 \times 60 = \pm \$300{,}000$
        - **±2%:** $\pm 10{,}000 \times 60 = \pm \$600{,}000$

CONCLUSION

CO_2 measurement, as hydrocarbon measurement, is a risk management issue. Establishing a uniform measurement standard for CO_2 across producers, pipelines, and storage operators creates consistency, trust, and efficiency throughout the carbon management value chain.

Specific stakeholder benefits include:

Revenue certainty: Accurate metering ensures captured CO_2 volumes translate into the correct number of credits or tax incentives (e.g., 45Q).

Regulatory compliance: Standardized measurement aligns with IRS, EPA, and ISO requirements, reducing audit risks.

Market credibility: Transparent, verified data builds confidence with buyers of carbon credit and investors.

Operational optimization: Reliable flow and purity data help optimize capture efficiency and compression systems.

Risk reduction: Minimizes disputes over reported volumes and prevents under- or over-crediting.

Note: Volunteering for API 6.XX Committee(s) is still open. API can make the API 6.xxx ballot open for comment at request. The API 6.xx standards presently are not published and should be completed and released in 2026. Please reach out to myself, Nick Monchak (MonchakN@api.org) or Chair Joseph Ullman (joseph.w.ullman1@exxonmobil.com) for additional information or to join the committee.