API Manual of Petroleum Measurement Standards

COLM TR 25XX

MEASUREMENT OF PRODUCED WATER FOR CUSTODY TRANSFER

(MONTH) (YEAR)

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Measurement of Produced Water for Custody Transfer

Introduction

This Technical Report (TR) provides users with guidance for applying metering technology to achieve produced water measurement uncertainties of better than or equal to +/- 5.0% of reading unless otherwise agreed to by contractual parties or regulatory agency.

Produced water quantity (mass or volume) does not necessarily require temperature or pressure correction to standard conditions. However, temperature and pressure can be measured for alternate purposes (e.g., safety, ancillary information). Note that generally accepted correction tables do not exist for temperature and pressure correction in produced water.

This Technical Report is not intended to cover produced water quality, emulsions, or separator/allocation measurement.

1. Scope

This technical report provides guidance for dynamic quantity measurement of produced water. This technical report provides additional direction for the design, selection, and maintenance of a produced water measurement system for custody transfer applications.

2. Normative References

There are no documents referred to in the text in such a way that some or all of their content constitutes requirements of this document.

3. Terms and Definitions

3.1. produced water

a fluid from oil and natural gas wells that primarily consists of formation water and may include injection water and other naturally occurring and added compounds, solids, and constituents.

3.2. flow assurance

the act of ensuring successful flow of the fluid stream from reservoir to the point of sale.

3.3. calibration

a set of operations which establish, under specified conditions, the relationship between the values indicated by a measuring device and the corresponding known values indicated when using a suitable measuring standard.

3.4. verification

the process or procedure of comparing an instrument to a reference standard to ensure its indication or registration is in satisfactorily close agreement, without making an adjustment.

3.5. flow meter diagnostics

hardware, software, or firmware internal or external to a flow meter for the purpose of monitoring, analyzing, and/or identifying functionality, status, or performance of the flow meter.

3.6. gross volume

the actual volume of fluids at flowing temperature and pressure

4. Selection of Methods for Dynamic Measurement Quantity Determination Using Available Equipment

4.1. Measurement Considerations

Selecting the best measurement technology to be used for custody transfer of produced water requires the user to consider the technology best suited for the application and the manufacturer's recommendation for use. Table 1 includes some considerations.

Table 1. Measurement Considerations

Technology	Preplanning	Operational	Maintenance and Repair
Select the technology best suited for the application. Consider: ☐ Capacity ☐ Accuracy (uncertainty) ☐ Available pressure ☐ Power availability ☐ Installation space.	☐ Area classification ☐ Power availability ☐ Flow capacity ☐ Line pressure ☐ Max / Min Temp ☐ Flow conditioning and straight pipe runs ☐ Remote / Local access ☐ Mounting to maintain full pipe	☐ Power consumption ☐ Non resettable totals ☐ Uncertainty limits ☐ Remote connectivity ☐ Proving frequency ☐ Multivariable measurement ☐ Operating temperature and pressure ranges ☐ Oil in water content ☐ Gas breakout or leaking into produced water	☐ Mechanical wear ☐ Replacement parts ☐ Diagnostics available ☐ Ancillary equipment needed ☐ Software and hardware tools required ☐ Brine / corrosion ☐ Calcium buildup or coating

4.2. Produced Water Contract Conditions

Contracts can specify produced water measurement methods, including any references to measurement standards. The contract can also clarify who will bear the expense and responsibility of procurement, installation, operation, and maintenance of the produced water meter systems. Contracts can also specify:

• Point of Delivery

- Operating Ranges and Requirements
- Fluid Properties and Requirements
- Measurement Equipment Requirements
- Sharing of Data

Contracts can also specify or reference documents that specify requirements for operation and maintenance of metering equipment, including any applicable requirements and frequencies associated with equipment inspection, verification, and calibration. They can also specify that equipment verifications/calibration/proving be scheduled in advance and that non-operating parties be allowed to witness all these activities. For process monitoring and analysis, contracts can also request the provision of additional data, such as data from individual devices, (e.g., flow meters, instruments, etc.).

5. General Metering System Design

While produced water properties and conditions may vary depending on specific applications, common produced water processes typically have:

- greater than 50 % water,
- high salinity,
- trace amounts of hydrocarbons entrained,
- varying amounts of fluids and particulates associated with the drilling, production, and fracturing,
- varying amounts and sizes of solids.

In addition to the above properties and conditions, there are many factors to consider when designing a produced water metering system, including process conditions, fluid properties, and a flow meter technology selection. Some considerations related to process conditions and fluid properties are listed below. Some meter technology types are discussed in Section 7.2, and API *MPMS* Chapter 5.1 also provides considerations for some flow meter types.

5.1. Process Conditions, Fluid Properties & Flow Assurance Considerations

- Expected volumes
- Instantaneous flow rate range
- Pressure range
- Temperature range
- Process and fluid stability
- Propensity for plugging
- Propensity for pulsation or vibration
- Fluid properties, including but not limited to:
  - Propensity to cause corrosion or erosion, scaling, coating or build-up, abrasiveness
  - density
  - viscosity
  - Pour point
  - Freeze point
  - solids content
  - presence of gas/liquid entrainment
  - vapor pressure
  - cleanliness
  - lubricating qualities.

5.2. Metering System – General Design Considerations

- Pipe diameter, material, and connection type
- Materials of construction
- Permanent pressure loss through the metering system
- Potential for damage or error due to foreign materials or pulsation
- Secondary containment requirements
- Ambient conditions and exposure
- Physical dimensions and weight
- Orientation
- Power supply availability or limitations
- Measurement units, i.e., mass or volume
- Accuracy or meter linearity requirements across flow rate range
- Single or multiple meter solution
- Ability to be serviced, tested, or repaired under operating conditions
- Uni- or bi-directional measurement
- Requirements for proving or calibration, including repeatability requirements
- Maintenance requirements
- Accessories, peripheral, or tertiary equipment needed
- Whether metering will be used for other products

5.3. Metering System - Controls, Diagnostics, and Operator Interface Considerations

- Control system requirements
  Diagnostic requirements
- Communications protocol requirements
- Input/Output type and channel count requirements
- Alarming requirements
- Recorded data access, output, and security requirements
- Operator interface requirements

5.4. Capability and Uncertainty

It is up to the user to understand the differences between the two types of uncertainty; uncertainty of the individual components of the system, versus the uncertainty of all components combined as a functioning system.

The methods to be used for determining and combining uncertainties are found in the latest edition of the American Petroleum Institute (API) Manual of Petroleum Measurement Standards (*MPMS*), Chapter 13, or the latest edition of the International Standard Organization (ISO) Standard 5168: Measurement of Fluid Flow – Estimation of Uncertainty of a Flow-rate measurement. API *MPMS* Chapter 14.13 may also be referenced for additional performance-based methodologies. The Norwegian Society for Oil & Gas Measurement and API TR 2579 also provide uncertainty calculations, for reference.

6. Design and Selection of Metering System Components

6.1. Flow Meter Technologies

Produced water has a multitude of characteristics that can vary by location, region, fluid properties, chemistry, infrastructure, well traits, etc. No single quality standard has been created or agreed to that defines what produced water's composition should be. As such, this technical report does not prevent the use of any flow meter technology for custody transfer quantity measurement of produced water. Some technologies are more commonplace within the produced water industry, and it may be beneficial to consult with others within your organization or industry.

Meters should be installed in accordance with manufacturer's specifications and best practices, including any straight run and/or flow conditioning requirements for some meter types. Meter considerations can include multiple variable and diagnostic capabilities.

Typical flow measurement technologies in use include, but are not limited to, the technologies listed alphabetically in Table 2. In addition to the flow meter types listed in Table 2, there are other metering technologies suitable for the measurement of produced water. Cost (capital & operational), maintenance, operation, performance, process conditions, and flow assurance should all be considered when evaluating different metering technologies.

Table 2. Typical Meter Types for Produced Water Measurement

Meter Type	Principle of Operation	Comment
Coriolis	Also referred to as Coriolis mass meter or Coriolis force flow meter. A Coriolis meter is a device which by means of the interaction between a flowing fluid and the oscillation of a tube(s), measures mass flow rate and density. The Coriolis meter consists of a sensor and a transmitter.	These meters utilize the Coriolis effect, which measures the mass flow rate of fluids by analyzing the deflection of a vibrating tube, making them highly suitable for precise monitoring of water transfers in petroleum operations. These meters also directly measure density and volumetric flow rate at base conditions.
Differential Pressure	A device that induces and uses pressure loss across an obstruction to determine the rate of flow.	
Displacement	A flow measurement device in which the measuring element measures a volume of liquid by mechanically separating the liquid into discrete quantities of fixed volume and counting the quantities in volume units.	These meters utilize the principle of fluid displacement to provide precise volumetric measurement, making them well-suited for monitoring water transfer in various petroleum operations.
Magnetic	A device that uses magnetic principles of induction and conductivity to determine the rate of flow.	Magnetic flow meters, leveraging Faraday's law of electromagnetic induction, offer accurate and precise measurement of water flow. Proper grounding is critical.
Turbine	A flow measuring device in which the action of the fluid stream passing through the devices turns a bladed turbine and produces an electrical output signal having a frequency proportional to the turbine speed.	These flow meters offer precise volumetric measurement by utilizing the rotational speed of a turbine within a flowing liquid, making them suitable for monitoring water transfer in various petroleum operations.

Ultrasonic	A device that uses the transit time of ultrasonic signals through a fluid to determine flow rate.	These meters utilize ultrasonic waves to determine the velocity of water flow, providing precise volumetric measurements and ensuring transparent and accountable transactions in petroleum operations. They are non-intrusive, meaning they do not require direct contact with the fluid, eliminating the risk of flow obstruction or contamination. Ultrasonic flow meters are also versatile, capable of measuring bidirectional flow and accommodating various pipe sizes and materials.
Vortex	A device that induces and uses the vortex shedding effect to create electrical pulses, which are proportional to rate of flow.	

Annex A includes additional details for the meter types listed in Table 2, including some advantages and disadvantages.

API *MPMS* provides detailed guidance on the selection of various flow meter technologies in the following sections:

- **Chapter 5.2:** Measurement of Liquid Hydrocarbons by Displacement Meters
- **Chapter 5.3:** Measurement of Liquid Hydrocarbons by Turbine Meters
- **Chapter 5.6:** Measurement of Liquid Hydrocarbons by Coriolis Meters
- **Chapter 5.8:** Measurement of Liquid Hydrocarbons by Ultrasonic Flowmeters
- **Chapter 14.3:** Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids-Concentric, Square edged Orifice Meters
- **Vortex:** TR 2577 – Performance of Full Bore Vortex Meters for Measurement of Liquid Flows

From the British Standards Institute:

- **Clamp-On Ultrasonic:** BS 8452 Use of Clamp-On (externally mounted) ultrasonic flow-metering techniques for fluid applications – Guide

6.2. Flow Meter Sizing

Sizing of the flow meter is a critical step. Flow meters should be selected and sized based on design operating ranges and fluid properties. Meter sizing should be based on manufacturer's recommendations and the specified instantaneous flow rate range and meter linearity for the application. Different technologies and manufacturers require varying amounts of data to perform this task, but at a minimum the user should supply the following parameters:

- Min/Norm/Max Flow Rate
- Min/Norm/Max Process Pressure
- Min/Norm/Max Process Temperature
- Process Water Fluid Properties

6.3. Piping & Valves for Metering Maintenance and Integrity

Upstream and downstream isolation valves are recommended for all custody transfer meters to facilitate repair, maintenance, and testing.

Bypass piping is not permitted in custody transfer applications.

6.4. Flow Meter Compatibility with Electrical System

Mechanical meters generally require preamplifiers and pulse generators to output volumetric flow rates to facilitate totalization and proving. Consult with the manufacturer to ensure compatibility with the metering system.

6.5. Strainers and Filters

Suspended solids in the fluid being measured can cause inaccuracy and even damage metering equipment. Solid particulates should be prevented from reaching the meter by using an appropriate strainer or filter per meter manufacturer recommendations.

The strainer or filter should be installed such that it can be monitored and/or checked periodically to avoid restricting flow, which could lead to:

- Vaporization that could cause equipment damage, or
- Decreased flow rate, from the flow conditions when the metering system was proved, affecting metering accuracy by causing the system to deviate.

6.6. Air Eliminators

Air eliminators are required in systems where air or vapor can be introduced into the system. If not eliminated, air will adversely affect measurement and can cause damage.

If air eliminators are installed, they should be installed upstream of the meter, and their purpose is to dispose of any air or vapor in the delivery line before it passes through the meter. If a system is designed so that significant amounts of air, vapor, or both cannot be introduced, an air eliminator is not required.

A sight glass can be located between the air eliminator and the flow meter to monitor the functionality of the air eliminator and to ensure the piping between the unloading arm coupler and meter is always full of product during metering operations.

6.7. Insulation or Heat Tracing

See API *MPMS* Chapter 6.1A for information related to insulation and heat tracing.

6.8. Thermal Relief Systems

See API *MPMS* Chapter 6.1A for information related to thermal relief systems.

6.9. Vents

See API *MPMS* Chapter 6.1A for information related to vents.

6.10. Drains

See API *MPMS* Chapter 6.1A for information related to drains.

6.11. Pumps

System hydraulics can affect meter performance. System pumps and controls should be designed to meet the desired operation of the facility such that adequate pressure and flow are provided. The ability to prime the pump and the effect of fluid properties, such as density and viscosity, should be considered when selecting pumps.

7. Start-up and Commissioning

Care should be taken to prevent damage to the custody transfer meter at initial start-up. The meter should be placed in service only after the process line has been flushed and hydrostatically tested. If strainers are used, they should be cleaned after flushing and periodically during operation.

8. Record Keeping

8.1. General

The recommendations of this section are intended to ensure that the minimum necessary data is documented and retained in order to reflect that accepted standards were adhered to and reflect the necessary documents to ensure the level of uncertainty was accomplished. Electronic flow measurement “EFM” or manual record keeping methodologies may be applied. Additional data points (e.g., temperature and pressure) can be used to improve the overall accuracy and to potentially reduce the uncertainty of volumes.

GV calculations do not require temperature or pressure measurement inputs; however temperature and pressure inputs and/or averages in this section can be used for corrections to standard conditions where applicable.

8.2. Data Availability

The recommendations of this section are intended to ensure data is collected and retained in order to allow proper determination of the quantities measured through the primary device and allow a thorough audit of the system operation and quantity determinations.

8.2.1. Data Collection

For metering systems where custody transfer measurement (calculations) are performed on-site, the information in sections 8.2.1.1 through 8.2.1.4 may be made available on-site, or be collectable on-site with a portable data collection device.

8.2.1.1. Data Parameters

Data collected or utilized since the last completed data may include, but are not limited to the following:

a. Dates and times for all averages and totals.
b. Total quantity accumulated during each contractually specified measurement period.

8.2.1.2. Input Variables

Input variable values affecting measurement may include, but are not limited to the following:

a. Meter run reference diameter, orifice bore reference inside diameter, and the calibrated span of the pressure, differential-pressure, and temperature transducers as applicable.
b. Meter and/or K factors and the calibrated span of any span adjustable values for pressure and temperature as applicable.

8.2.1.3. Data Records

An electronic or hard copy record should include, but is not limited to, the following:

a. "As found" and "as left" equipment calibration values for differential-pressure~~,~~ pressure, temperature, and meter and/or k factors as applicable.
b. Old and new values for changes to any input value that will affect calculated quantities.
c. A complete summary of all alarm or error conditions affecting measurement, including a description of each alarm condition as applicable.
d. Time or percent of time for flow or no flow as applicable.
e. Time stamped event log
f. The unique identification number of the metering system

8.2.1.4. Quantity Statement

A quantity statement should include, but is not limited to, custody transfer quantity totals. If applicable, quantity statements can also include average temperature and pressure values.

8.3. Audit and Reporting Recommendations

Refer to API *MPMS* Ch. 21.2 Audit and Reporting section for requirements.

8.3.1. Algorithm Identification

An algorithm identification should be provided to identify the calculations performed in the electronic liquid measurement system, such as software or manufacturer's version.

8.3.2. Configuration Log

The configuration log should be part of the audit package for the accounting period.

8.3.3. Event Log

The event log should be a part of the audit package for the accounting period. The event log is used to note and to record exceptions and changes to the flow parameters, contained in the configuration log, that occur and that have an impact on a measurement volume (API *MPMS* Ch. 21.1 states quantity transaction records).

Each time a constant flow parameter that can affect the quantity transaction record is change in the system, the old and new value, along with the date and time of the change, should be logged.

The date and time of all events in the log should be identified chronologically.

8.3.4. Test Record

A test should be part of the audit package and consists of any documentation or record (electronic or hard copy) produced in the testing or operation of metering equipment that would affect the calculation of measured quantities. The documentation may include, but not limited to, calibration/verification reports, orifice plate and equipment change tickets; and peripheral equipment evaluation reports.

8.3.5. Data Retention

The off-site retention period for the audit trail data should be defined by regulation, statute, tariff, or contract.

8.4. Performance Records

Results based performance monitoring records should also be maintained and kept. System balances within a contractually or company defined tolerance may indicate the flow meters measuring the produced water of a system are all performing as desired. Additionally, control charts which track the results of meter maintenance activities (e.g., proving, calibration, verification, etc.) may support less frequent maintenance activities.

8.5. Security

Transmitters should be secured against tampering or unauthorized or un-documented changes to any variable or parameter that can alter the quantity measurement. This can be achieved by several methods such as including passwords, or tamper evident seals, internal write protection switches, or other lock out methods. See API *MPMS* Ch. 21.2.

9. Confirmation of Performance

Methods for confirming the performance of produced water measurement systems vary by user, region, contract, compliance requirements, and quantities. Initial calibration of the flow meter to be used should be performed.

Periodic re-calibration, verification, and/or use of self-monitoring and diagnostics is recommended. Users should define their performance goals/requirements and decide the frequency and methods best suited for their application.

Typical accepted methods suggested by API and/or manufacturers:

a. Calibration at factory when new, transferred to field
b. In-situ secondary and/or tertiary device verification or calibration;
c. Primary element inspection;
d. Off-site meter proving;
e. In-situ meter proving (master meter, displacement, or tank);
f. Verification of self-monitoring and diagnostic results;
g. Comparison of values to another calibrated device

Annex A
(Informative)
Table A.1 - Flow Meter Technology Advantages and Limitations

FLOW METER TECHNOLOGY	SIZE RANGES	ADVANTAGES IN PRODUCED WATER APPLICATIONS	LIMITATIONS IN PRODUCED WATER APPLICATIONS
Coriolis	Up to 16"	– High accuracy, turndown, and repeatability – Ability to measure in mass or volume – No moving parts = low maintenance – Bi-directional – No flow conditioning or straight runs required	– Can create pressure loss – Typically limited to 16" and below
Differential Pressure	Up to 24"	– Variety of primary elements to fit needs – Low power requirements – Multi-Variable options available	– Creates pressure loss – Lower turndown – Lower accuracy than some technologies – Requires most straight runs of upstream and downstream piping
Displacement Meter	Up to 16"	– Cooperative with typical proving methods – Low pressure drop – Some models have very high accuracy	– Typically requires more maintenance or repairs due to wear – Requires upstream protection (i.e., strainer, filter, etc.)
Magnetic	Up to 72"	– Low or no pressure loss – Bi-directional – Wide variety of materials for chemical and temperature compatibility – No moving parts = low/no maintenance – Minimal flow conditioning required	– Can require straight runs of upstream and downstream piping per manufacturer's recommendation – Liner and electrode chemical compatibility is critical – Coating/Scaling of electrodes can cause error/uncertainty – Larger line sizes can be heavy – Conductivity dependent
Turbine	up to 18"	– Low pressure drop – Some models have very high accuracy	– Typically requires more maintenance or repairs due to wear – Requires upstream protection (i.e. strainer, filter, etc.) – Requires straight runs of upstream and downstream piping

FLOW METER TECHNOLOGY	SIZE RANGES	ADVANTAGES IN PRODUCED WATER APPLICATIONS	LIMITATIONS IN PRODUCED WATER APPLICATIONS
			– Typically requires flow conditioning – Flow profile sensitive
Ultrasonic	Up to 72"	– Available for in-line and external installations – Low or no pressure loss – Bi-directional – No moving parts	– Requires straight runs of upstream and downstream piping – Typically requires flow conditioning – External sensitive to improper or un-maintained pipe coupling – External, non-intrusive installations can often lower accuracy – Flow profile sensitive
Vortex	Up to 14"	– Low maintenance – Low power requirements (typically loop-powered, AKA 2-wire) – Multi-Variable options available – Low pressure drop	– Requires upstream protection (i.e. strainer, filter, etc.) – Requires straight runs of upstream and downstream piping – Susceptible to vibration and pulsation

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