Manual of Petroleum Measurement Standards Chapter 8.2

Standard Practice for Automatic Sampling of Petroleum and Petroleum Products

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Designation: D4177 – 15a

Manual of Petroleum Measurement Standards (MPMS), Chapter 8.2

Standard Practice for Automatic Sampling of Petroleum and Petroleum Products[1]

This standard is issued under the fixed designation D4177; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ε) indicates an editorial change since the last revision or reapproval.

This standard has been approved for use by agencies of the U.S. Department of Defense.

INTRODUCTION

The previous version of the automatic sampling practice described the design, installation, testing, and operation of automated equipment for the extraction of representative samples from the flowing stream and storing mainly for crude oil.

This practice is a performance-based standard. It still includes the design, installation, testing, and operation of automated equipment for extraction of representative samples. It also includes the testing and proving of a sampling system in the field under actual operating conditions to ensure that the equipment, installation, and operating procedures produce representative samples. The acceptance criteria for custody transfer are covered in this practice. This practice does not address how to sample crude at temperatures below the freezing point of water. Extensive revisions have been made to the prior version of D4177 (API *MPMS* Chapter 8.2).

This practice also provides guidance for periodic verification of the sampling system.

This practice is separated into three parts:

General—Sections 5 – 17 (Part I) are currently applicable to crude oil and refined products. Review this section before designing or installing any automatic sampling system.

Crude Oil Sampling—Section 18 (Part II) contains additional information required to complete the design, testing, and monitoring of a crude oil sampling system.

Refined Product Sampling—Section 19 (Part III) contains additional information required to complete the design of a refined product sampling system.

A representative sample is "A portion extracted from the total volume that contains the constituents in the same proportions that are present in that total volume." Representative samples are required for the determination of chemical and physical properties that are used to establish standard volumes, prices, and compliance with commercial and regulatory specifications.

The process of obtaining a representative sample consists of the following: the physical equipment, the correct matching of that equipment to the application, the adherence to procedures by the operator(s) of that equipment, and the proper handling and analysis.

1. Scope*

1.1 This practice describes general procedures and equipment for automatically obtaining samples of liquid petroleum and petroleum products, crude oils, and intermediate products from the sample point into the primary container. This practice also provides additional specific information about sample container selection, preparation, and sample handling. If sampling is for the precise determination of volatility, use Practice D5842 (API *MPMS* Chapter 8.4) in conjunction with this practice. For sample mixing and handling, refer to Practice D5854 (API *MPMS* Chapter 8.3). This practice does not cover sampling of electrical insulating oils and hydraulic fluids.

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[1] This practice is under the jurisdiction of ASTM Committee D02 on Petroleum Products, Liquid Fuels, and Lubricants and the API Committee on Petroleum Measurement, and is the direct responsibility of Subcommittee D02.02 /COMQ the joint ASTM-API Committee on Hydrocarbon Measurement for Custody Transfer (Joint ASTM-API). This practice has been approved by the sponsoring committees and accepted by the Cooperating Societies in accordance with established procedures. This practice was issued as a joint ASTM-API standard in 1982.

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***A Summary of Changes section appears at the end of this standard**

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1.3 *Units*—The values stated in either SI units or US Customary (USC) units are to be regarded separately as standard. The values stated in each system may not be exact equivalents; therefore, each system shall be used independently of the other. Combining values from the two systems may result in non-conformance with the standard. Except where there is no direct SI equivalent, such as for National Pipe Threads/diameters, or tubing.

1.4 *This standard does not purport to address all of the safety concerns, if any, associated with its use. It is the responsibility of the user of this standard to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to use.*

2. Referenced Documents

2.1 *ASTM Standards:*[2]

D4007 Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure)
D4840 Guide for Sample Chain-of-Custody Procedures
D4928 Test Method for Water in Crude Oils by Coulometric Karl Fischer Titration
D5842 Practice for Sampling and Handling of Fuels for Volatility Measurement
D5854 Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products

2.2 *API Standards:*[3]

MPMS Chapter 3 Tank Gauging
MPMS Chapter 4 Proving Systems
MPMS Chapter 5 Metering
MPMS Chapter 8.3 Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products (ASTM Practice D5854)
MPMS Chapter 8.4 Practice for Manual Sampling and Handling of Fuels for Volatility Measurement (ASTM Practice D5842)
MPMS Chapter 10 Sediment and Water
MPMS Chapter 13 Statistical Aspects of Measuring and Sampling
MPMS Chapter 20 Production Allocation Measurement for High Water Content Crude Oil Sampling
MPMS Chapter 21 Flow Measurement Using Electronic Metering Systems

2.3 *ISO Standards:*[4]

ISO 1998 Petroleum Industry – Terminology – Part 6: Measurement

NOTE 1—See the Bibliography at the end of this standard for important historical references.

3. Terminology

3.1 *Definitions of Terms Specific to This Standard:*

3.1.1 *automatic sampling system, n*—fluid sampling system that consists of: *(a)* flowing fluid stream conditioning, if required; *(b)* a means of automatically extracting a representative sample; *(c)* pacing of the sample extraction in a flow or time proportional manner; and *(d)* delivering of each extracted sample to a sample container or an analyzer.

3.1.1.1 *Discussion*—The system consists of a sample extractor with an associated controller and flow-measuring or timing device, collectively referred to as an automatic sampler or auto-sampler. In addition, the system may include a flow conditioner, slipstream, sample probe, and sample conditioning.

3.1.1.2 *Discussion*—Systems may deliver the sample directly to an analytical device or may accumulate a composite sample for offline analysis, in which case, the system includes sample mixing and handling and a primary sample container.

3.1.1.3 *Discussion*—Automatic sampling systems may be used for liquids.

3.1.2 *batch, n*—discrete shipment of commodity defined by a specified quantity, a time interval, or quality.

3.1.3 *component testing, n*—process of individually testing the components of a system.

3.1.4 *dead volume, n—in sampling*, the volume trapped between the extraction point and the primary sample container.

3.1.4.1 *Discussion*—This represents potential for contamination between batches.

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[2] For referenced ASTM standards, visit the ASTM website, www.astm.org, or contact ASTM Customer Service at service@astm.org. For *Annual Book of ASTM Standards* volume information, refer to the standard's Document Summary page on the ASTM website.

[3] Available from American Petroleum Institute (API), 1220 L. St., NW, Washington, DC 20005-4070, http://www.api.org.

[4] Available from American National Standards Institute (ANSI), 25 W. 43rd St., 4th Floor, New York, NY 10036, http://www.ansi.org.

3.1.5 *droplet dispersion, adj*—degree to which a fluid in an immiscible fluid mixture is composed of small droplets distributed evenly throughout the volume of the pipe.

3.1.6 *flow-proportional sample, n*—sample taken from a pipe such that the rate of sampling is proportional throughout the sampling period to the flow rate of the fluid in the pipe.

3.1.7 *free water, n*—water that exists as a separate phase.

3.1.8 *grab, n*—volume of sample extracted from a flowing stream by a single actuation of the sample extractor.

3.1.9 *homogeneous, adj*—quality of being uniform with respect to composition, a specified property or a constituent throughout a defined area or space.

3.1.10 *linefill, n*—volume of fluid contained between two specified points in piping or tubing.

3.1.11 *sample controller, n*—device used in automatic sampling that governs the operation of a sample extractor.

3.1.12 *sample extractor, n—in sampling*, a mechanical device that provides for the physical measured segregation and extraction of a grabbed sample from the total volume in a pipeline, slip stream, or tank and ejects the sample towards the primary sample container.

3.1.13 *slip stream sample loop, n*—low-volume stream diverted from the main pipeline, intended to be representative of the total flowing stream.

3.1.14 *slip stream take-off probe, n*—device, inserted into the flowing stream, which directs a representative portion of the stream to a slip stream sample loop.

3.1.15 *volume regulator sampler, n*—device that allows pipeline pressure to push a set volume into a chamber that is then trapped and redirected to the sample receiver.

3.2 *Definitions Related to Sample Containers:*

3.2.1 *constant volume sample container, n*—vessel with a fixed volume.

3.2.2 *floating piston container, FPC, n*—high-pressure sample container, with a free floating internal piston that effectively divides the container into two separate compartments.

3.2.3 *portable sample container, n*—vessel that can be manually transported.

3.2.4 *primary sample container, n*—container in which a sample is initially collected, such as a glass or plastic bottle, a can, a core-type thief, a high-pressure cylinder, a floating piston cylinder, or a sample container in an automatic sampling system.

3.2.5 *profile average, n—in sampling*, the average of all point averages.

3.2.6 *profile testing, n*—procedure for simultaneously sampling at several points across the diameter of a pipe to identify the extent of cross-sectional stratification.

3.2.7 *representative sample, n*—portion extracted from a total volume that contains the constituents in the same proportions that are present in that total volume.

3.2.8 *sample, n*—portion extracted from a total volume that may or may not contain the constituents in the same proportions as are present in that total volume.

3.2.9 *sample probe, n*—device extending through the meter tube or piping into the stream to be sampled.

3.2.10 *sampling, n*—all the steps required to obtain a sample that is representative of the contents of any pipe, tank, or other vessel, based on established error and to place that sample into a container from which a representative test specimen can be taken for analysis.

3.2.11 *sampling system, n*—system capable of extracting a representative sample from the fluid flowing in a pipe.

3.2.11.1 *Discussion*—system capable of extracting a representative sample from the fluid flowing in a pipe. **(ISO 1998-6)**

3.2.12 *sampling system verification test, n*—procedure to establish that a sampling system is acceptable for custody transfer.

3.2.13 *secondary sample container, n*—vessel that receives an aliquot of the primary sample container for the purpose of analysis, transport, or retention.

3.2.14 *stationary sample container, n*—vessel that is physically fixed in place.

3.2.15 *stream conditions, n*—state of a fluid stream in terms of distribution and dispersion of the components flowing within the pipeline.

3.2.16 *stream conditioning, n*—mixing of a flowing stream so that a representative sample may be extracted.

3.2.17 *time-proportional sample, n*—sample composed of equal volume grabs taken from a pipeline at uniform time intervals during the entire transfer.

4. Significance and Use

4.1 Representative samples of petroleum and petroleum products are required for the determination of chemical and physical properties, which are used to establish standard volumes, prices, and compliance with commercial terms and regulatory requirements. This practice does not cover sampling of electrical insulating oils and hydraulic fluids. This practice does not address how to sample crude at temperatures below the freezing point of water.

PART I—General

This part is applicable to all petroleum liquid sampling whether it be crude oil or refined products. Review this section before designing or installing any automatic sampling system.

5. Representative Sampling Components

5.1 The potential for error exists in each step of the sampling process. The following describes how sampling system components or design will impact whether the sample is representative. Properly address the following considerations to ensure a representative sample is obtained from a flowing stream.

5.1.1 *Location*—Locate the sampling system close to or at a position where the custody transfer is deemed to have taken place. The quality and quantity of the linefill between the extractor and the sample container may be significant enough to impact the quality of the sample.

5.1.2 *Conditioning of the Flowing Stream*—Disperse and distribute (homogenize) the sample stream at the sample point so that the stream components (for example oil, water, and sediment) are representative at the point of the slip stream sample loop inlet (if used) or where the sample is to be extracted.

5.1.3 *Sample Extraction*—Take grabs in proportion to flow. However, if the flow rate during the total batch delivery (hours, days, week, month, and so forth) varies less than ±10 % from an average flow rate, and if the sampling stops when the flow stops, a representative sample may be obtained by the time proportional control of the sampling process.

5.1.4 *Sample Containers*—The sample container shall be capable of maintaining the sample's integrity, which includes not altering the sample composition. Minimize the venting of hydrocarbon vapors during filling and storage and protect the sample container from adverse ambient elements. The sample container should also be compatible with the fluid type to avoid degradation of the sample container and possible leakage of the sample.

5.1.5 *Sample Handling and Mixing*—Provide a means to allow the sample to be made homogenous before extraction of aliquots for analysis, retention, or transportation. For more information regarding the handling and mixing of samples, refer to Practice D5854 (API *MPMS* Chapter 8.3).

5.1.6 *System Performance Verification*—Perform test(s) to verify the system is performing in accordance with the criteria set forth within this practice or as otherwise agreed.

5.1.7 *Performance Monitoring*—Provide performance measurement and recording of the sampling system to validate that the system is operating within the original design criteria and compatible with the current operating condition.

6. Design Criteria

6.1 The following items shall be addressed when designing a sampling system:

6.1.1 Volume of sample required for analysis and retention;

6.1.2 Conditions (temperature, pressure, viscosity, density, minimum and maximum flow rates, sediment, water, and contaminants);

6.1.3 Type of fluid (crude oil, gasoline, diesel, kerosine, or aviation fuel);

6.1.4 *Grabs per Batch*—Ensure the sample extractor(s) samples at a high enough frequency to obtain the required number of grabs without exceeding the limits of the equipment or other sampling system constraints. Increasing the number of grabs taken per batch reduces sampling uncertainty as described in Annex A1. For large custody transfer batch quantities, to ensure representativeness of the total volume of extracted sample in the sample receiver, some operators have set an expectation that is equivalent to a margin of error of 0.01 with 95% confidence. Eq A1.6 calculates this to be 9604 grabs per batch. In practice, a rounded up recommended value of 10 000 grabs per batch is often used in industry. Small batch sizes, small capacity of the primary sample container and other sampling system constraints may result in designs with a different design criterion than 9604 grabs per batch;

6.1.5 *Batch Size(s)/Duration*—Ensure the sample extractor(s) samples at a high enough frequency to obtain the required sample volume without exceeding the limits of the equipment;

6.1.6 *Homogeneity of the Fluid/Stream Conditioning*—Ensure the pipeline content is homogeneous at the point of extraction (sample point) over the entire flow range of all anticipated product types. Give special consideration to viscosity, density, and vapor pressure;

6.1.7 Consider the interface between batches;

6.1.8 Consider incorporating additional analyzers in the sampling system design that would provide for valuable feedback with regards to the stream being sampled;

6.1.9 Consider the failure and maintenance of any devices inserted directly into the process pipeline and their ability to withstand pressure surges. Additionally, consider bending moment and vibrations caused by flow-induced vortices that the devices may encounter;

6.1.10 Consider the interconnection between the sample extractor and the primary sample container to ensure the sample remains representative of the batch;

6.1.11 Provide a flow measurement device or a method to provide a flow signal for flow proportioning the sampling system;

6.1.12 Ensure the tubing from the sample probe or extractor to the sample container slopes continuously downward towards the sample container point of entry;

6.1.13 Provide a control system (which may include an overall supervisory reporting system (Human-machine Interface (HMI)/Supervisory Control and Data Acquisition (SCADA))) to operate the sample system in proportion to flow;

6.1.14 Use performance monitoring equipment to verify that samples are being taken in accordance with the sampling system design and this practice;

6.1.15 Provide environmental protection that may consist of a building, enclosure, or shelter and heating or cooling systems. Heating may impact the electrical certification. It may be necessary to install parts or all of the sampling system in heated (or cooled) or enclosed environments to maintain the integrity of the samples taken, sample handling, or reduce the incidence of mechanical failure, for example, caused by increased viscosity or wax content. Safety protections in regard to static electricity and flammable vapors when sampling shall also be considered;

6.1.16 Consider sample system integrity and security;

6.1.17 Ensure all applicable regulatory requirements are met;

6.1.18 Consider the properties of interest to be analyzed;

6.1.19 Extracting samples in proportion to flow or time;

6.1.20 Locating the opening of the sample probe in the part of the flowing stream where the fluid is representative;

6.1.21 Locating the opening of the sample probe in the direction of the flow;

6.1.22 Ensuring the fluid entering the sample probe tip follows a path that creates no bias;

6.1.23 Ensuring that the fluid from the extractor flows into the primary sample container;

6.1.24 Ensuring all of the samples taken during the batch go into the primary sample container, the sample container contents are properly mixed, and any portion extracted for analysis is representative; and

6.1.25 Ensuring that good sampling and handling procedures are followed to maintain representativeness at each stage of the mixing, distribution, and handling of the sample from point of first receipt into the primary sample container to its analysis.

6.2 *Other Considerations:*

6.2.1 *High Reid Vapor Pressure (RVP) Fluids (Examples are Crude and Condensate)*—Where the crude oil or crude condensate has a RVP greater than 96.53 kPa, the process and practicalities of handling and transporting large pressurized (constant pressure) containers precludes the possibility of taking 9604 grab samples. A practical expectation for handling is normally 1 L to 4 L. Systems and processes that yield samples based on less than 9604 grabs should be established and agreed between all interested parties.

6.2.2 *Representative Sample—Sample Extractor to Container*—Sample grabs are extracted from the flowing pipe by the sample extractor. At the beginning of each batch, the volume retained in the internal mechanism of the sampling device or tubing between the sample extractor and sample container may contaminate the properties of the subsequent batch if not properly displaced. This may be minimal where the sampling process is measuring identical products in sequential batches belonging to a common owner. However, where sequential batches may possess significantly different properties, be different types of refined products or be of differing ownership, the volume between the point of sample extraction and the sample container has the potential to produce non-representative samples. These non-representative samples can impact the integrity of the custody transfer and volumetric reconciliations of each batch transferred and may also result in unwarranted product quality concerns. Consider the evaluation of this interface and minimize the dead volume. Purging with alternate fluids, air, or inert gas has the potential to displace this linefill into the proper sample container, but exercise caution to ensure that other quality properties of the sample are not impacted. A sampling system capable of purging through the sampling container and using multiple containers may also be an alternative.

7. Automatic Sampling Systems

7.1 Automatic sampling systems may be fixed or portable and are divided into two types: in-line or slip stream sample loop. Each system design has a sample extraction mechanism that isolates a sample from the stream. The sample extractor can be within the flowing stream or mounted offset as in the case of a volume regulator (Fig. 3). When a fixed system is not practical, the use of portable designs may be considered, see Figs. 1 and 2.

7.2 *In-line Sampling Systems*—An in-line sampling system places the sampling extraction mechanism or the take-off probe of a volume regulator sampler directly within the flowing stream. See Fig. 1 and Fig. 3.

7.3 *Slip Stream Sample Loop System*—A slip stream sample loop system has a take-off probe located in the main pipeline that directs a portion of the fluid flow into the slip stream sample loop (see Fig. 2) and past a sample extractor or the take-off probe of a volume regulator sampler (see Fig. 3).

7.3.1 Give consideration to the following aspects involving the take-off probe placement and design to prevent stratification or separation of the hydrocarbon stream components or significant lag time:

7.3.1.1 The opening size;

7.3.1.2 Forward facing; and

7.3.1.3 Sufficient velocity through interconnecting piping, sample extractor or analyzers, and slip stream sample loop system.

7.3.2 Avoid blockage in the slip stream sample loop or pressure pulses created by sample extractors. See Fig. 2. For more information on crude oil design characteristics, refer to 18.4.

7.4 *Portable Sampling Systems*—Portable samplers are those that may be moved from one location to another. The requirements for obtaining a representative sample with a portable sampler are the same as those of a fixed sampling system.

7.4.1 In crude oil, fuel oil, or product sampling applications, a typical application of a portable sampling system is on board at the manifold of a marine vessel or barge. There are also occasional applications on shore.

7.4.2 The same design criteria for representative sampling apply to both portable and stationary sampling systems. An example of portable samplers is shown in Fig. 4.

8. Sampling Location

8.1 *System Location*—The optimal location for installation of the sampling system is to be as close as possible to the custody transfer point. Consideration should be given to onshore, offshore, shipboard, tanker, rail car, loading arm installations, and linefill issues that may impact the location, geography, or environmental restrictions, and other possible locations. It may not be practical to place the system close to this optimal position; therefore, minimize the distance from the system to the custody transfer point. See Fig. 5.

8.2 *Sample Take-Off Probe Location*—For sample extractor probes or sample take-off probes, to prevent the sample from being misrepresentative of the flowing line, insert the sample probe in the center half of the flowing stream. Verify that the probe is installed correctly, the probe opening is facing in the desired appropriate direction for the application, and the external body of the probe is marked with the direction of flow. See Fig. 6 (probe design).

8.2.1 The sample probe shall be located in a zone in which sufficient mixing results in adequate stream conditioning (see 19.2).

8.2.2 The recommended sampling area is approximately the center half of the flowing stream as shown in Fig. 7.

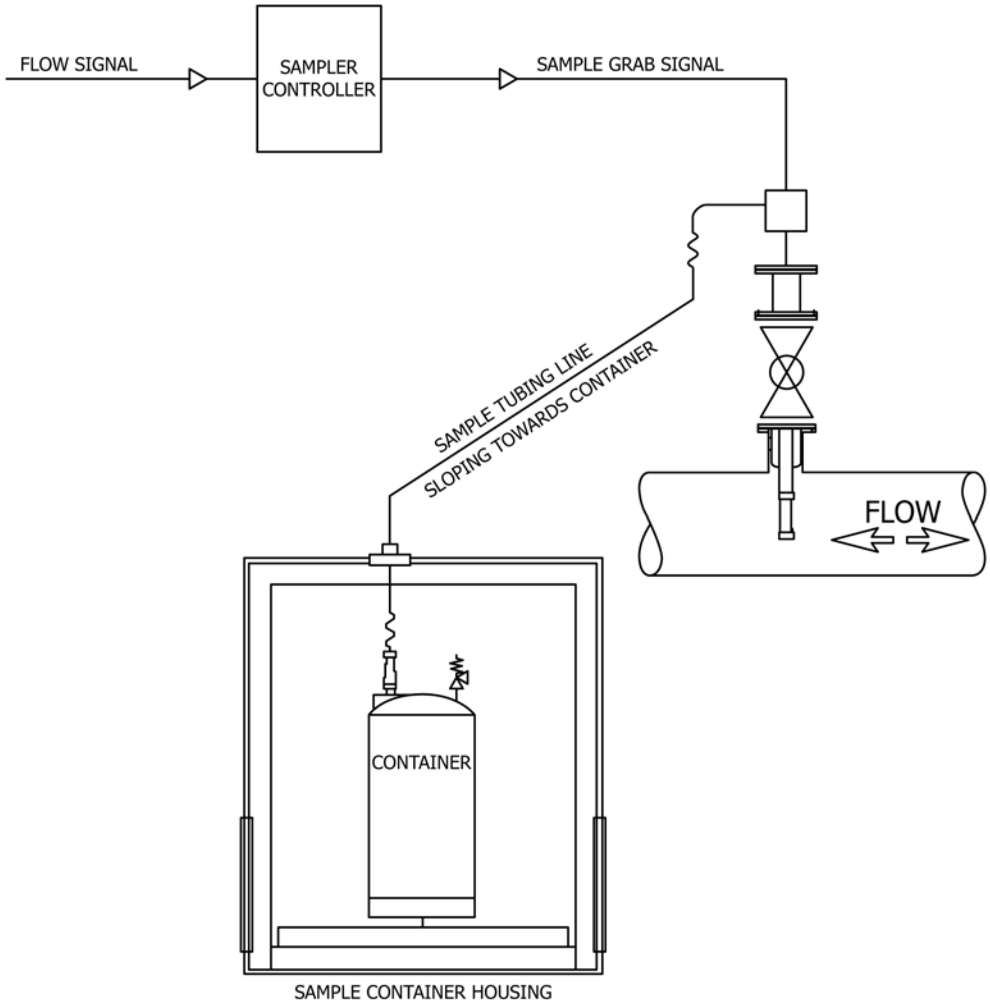


FIG. 1 In-Line Sampling System

8.2.3 When a main line mixing device is used, the manufacturer shall be consulted for the sample probe's optimum location with regard to downstream distance and piping.

8.2.4 When possible, the preferred orientation of the extractor probe is horizontal.

8.2.5 Use a sample take-off probe of sufficient strength to resist the bending moments and vortices that may be created across the full process range.

8.3 *Sample Extractor Location*—The position and design of the extractor within the piping cross section may be influenced by the basic properties of the product being sampled. Design and install the extractor in the pipeline in a position so that it minimizes any change to the properties of the sample as it is withdrawn.

8.3.1 Install the probe in a position on the cross section considered as representative. Insertion of the probe within the center half of the flowing stream see Fig. 7 meets the criteria.

8.3.2 If stream conditioning has been used to improve the homogeneity at the sample position, install the sample extractor in the optimal position downstream. The recommended distance downstream will be supplied by the stream conditioner manufacturer.

8.3.3 Use an extractor probe of sufficient strength to resist the bending moments and vortices that may be created across the full process range.

8.4 *Linefill Considerations*—When the transfer happens, when the receipt point and sample point are a substantial distance apart such as in excess of a mile away from the meters and sampling system, the linefill between the receipt point and the sampling system will not be sampled until the next movement occurs. Account for the linefill at a later date when the volume is displaced. See Fig. 5 (linefill).

8.4.1 *Linefill*—The linefill portion of a parcel may be handled in a variety of ways. Some line fills are pushed the final distance using water or inert gas. This clears the pipeline of the batch and samples the last few cubic metres (bbl) of the parcel into the same sample container.

8.4.2 Linefill is a known or estimated volume and requires special consideration as part of cargo transfer calculations and procedures. The simplest example is one ship or tank and one pipeline. Consider the volume of the batch to be sampled between the take-off point and the transfer position, which is known as linefill. The influence of the properties of interest in

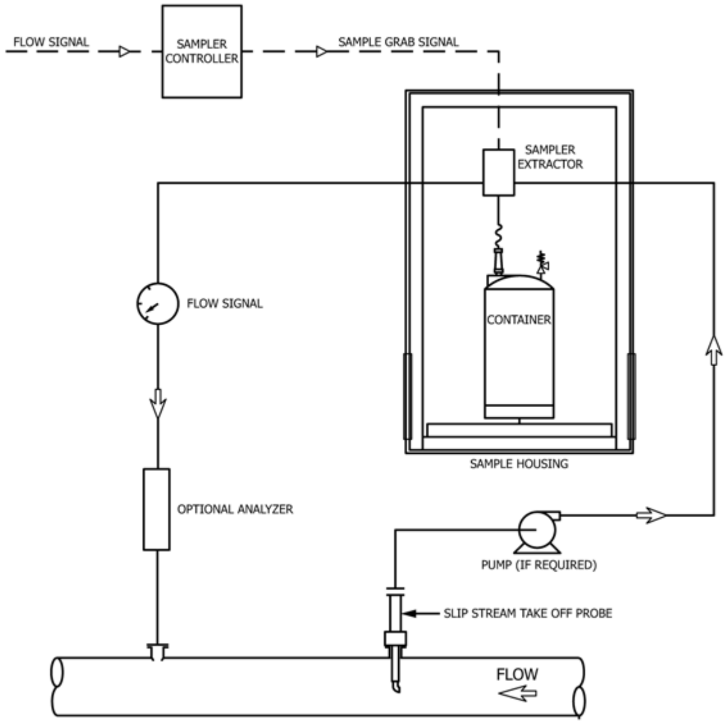


FIG. 2 Slip Stream Sample Loop Sampling System

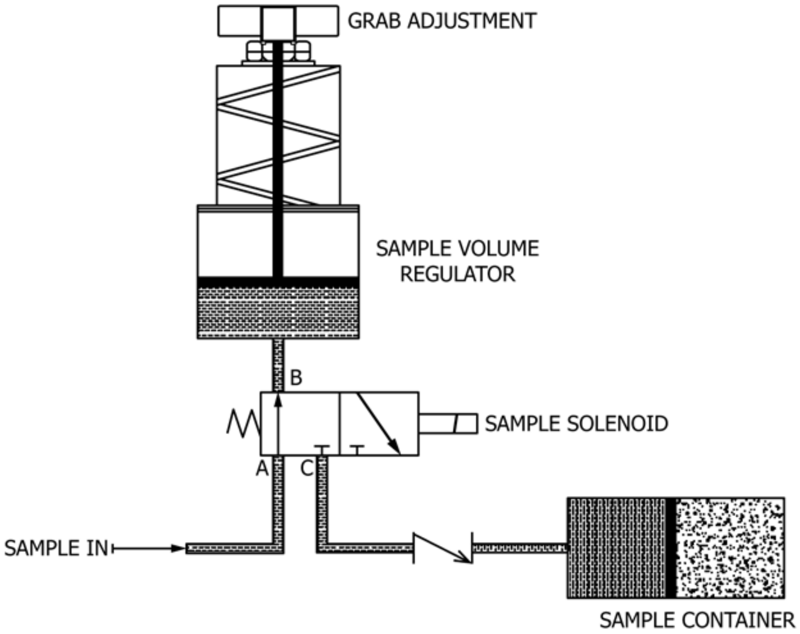


FIG. 3 Sample Volume Regulator

relation to the overall batch volume may be significant enough to alter the composite sample.

9. Mixing of the Flowing Stream

9.1 *Stream Conditioning:*

9.1.1 Stream conditioning increases the level of turbulence by using additional energy. Ensure that, at the point of sampling the fluid is homogenous so that, when the fluid is tested, the test result is representative of the entire stream. When there is not adequate turbulence, additional efforts are required to condition the stream so that it will be representative at the point of sampling.

9.1.2 Hydrocarbon fluids containing a denser phase product (that is, water, sediment, or both) will require energy to disperse the contaminants within the flowing stream. Refined petroleum products and non-crude feed stocks, such as naphtha, are generally homogeneous and usually require no special stream conditioning. Exceptions include when free

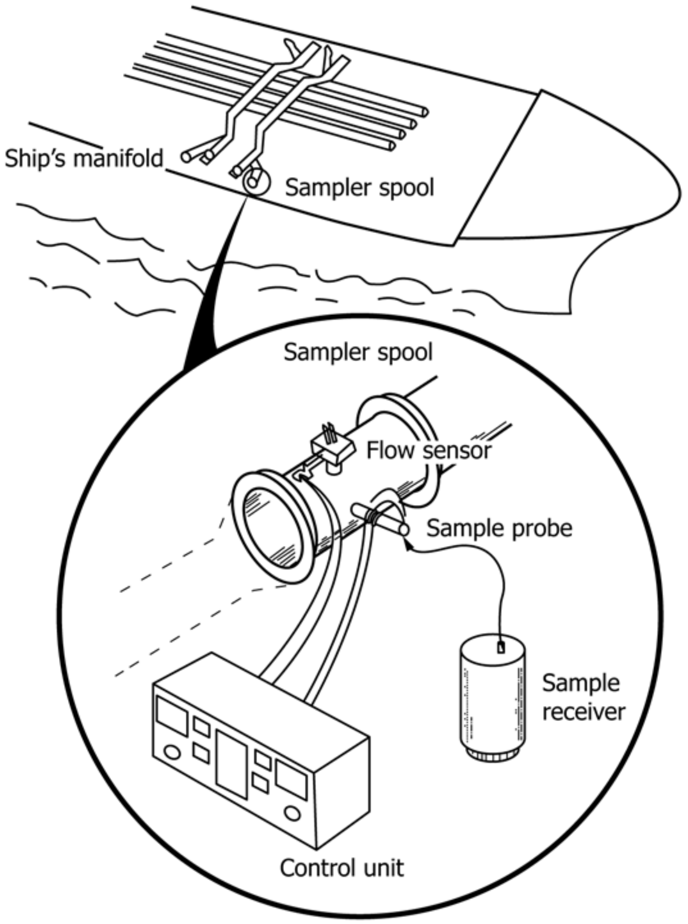


FIG. 4 Typical Portable Installation

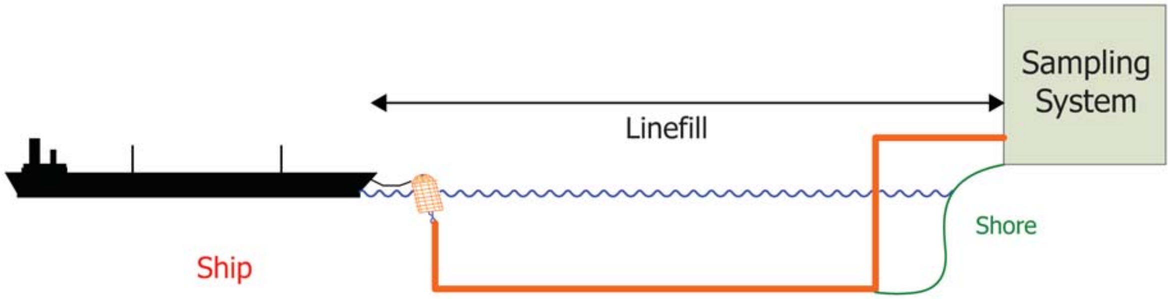


FIG. 5 Linefill

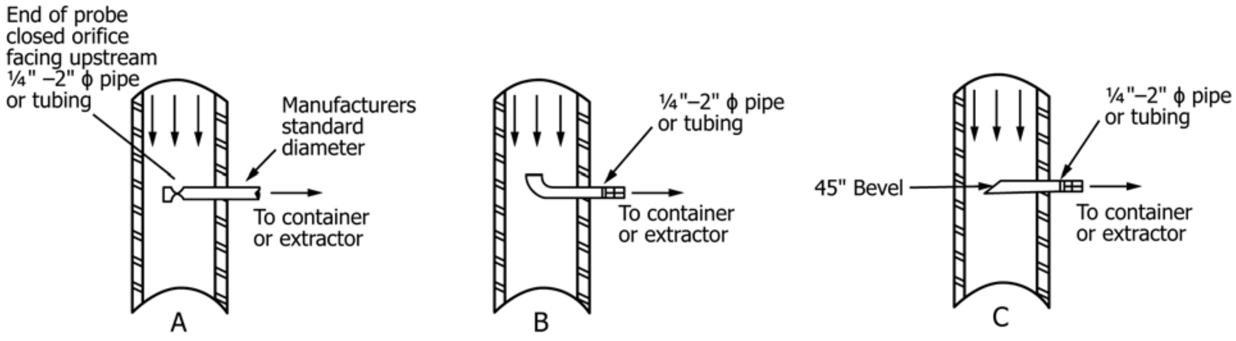


FIG. 6 Probe Design

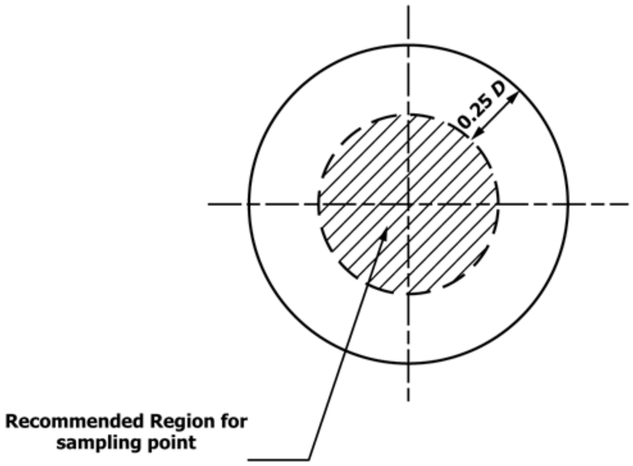


FIG. 7 Sample Probe and Slip Stream Take-Off Probe Location for Vertical or Horizontal Pipe

water, sediment, or unique contaminants are present or if a nonhomogeneous product is being sampled.

9.1.3 Stream conditioning is impacted by upstream piping elements such as elbows and valves. These elements can promote mixing but may also skew the flow profile. Piping elements can be installed that are specifically designed to develop a homogenous stream. Other elements can be installed to add energy to the stream, increasing turbulence.

9.2 *Stream Conditions:*

9.2.1 When assessing whether stream conditions require that additional measures be taken to ensure adequate mixing, consider the following, in each case considering the worst-case conditions:

9.2.1.1 *Velocity of the Flowing Stream*—It is most difficult to ensure representative sampling at low-stream velocities. If an in-line mixing element is installed, pressure drops will increase as the stream velocity increases potentially resulting in unacceptable pressure drops across the mixing element. For streams at or near their bubble point, pressure drops across the mixing element may lead to phase separation.

9.2.1.2 *Water Content*—It is more difficult to sample streams with higher water contents because water droplets in the emulsion tend to be larger and slugging of the water can occur.

9.3 *Methods of Stream Conditioning:*

9.3.1 *Base Case Stream Properties*—Some streams are sufficiently homogenized because of the fluid properties and velocity so that additional stream conditioning is not required.

9.3.2 *Upstream Piping Elements*—Thoughtful selection of the location of the sampling point can improve the chances of a well-mixed stream. Harnessing the impact of upstream elements such as valves, tees, elbows, flow meters, reducers, air eliminators, or pumps can enhance mixing of the flowing stream. To be effective, the sample point needs to be located in close proximity to selected upstream elements. The effectiveness of this approach in generating a homogenous stream is not assured in any case and may not be adequate for all stream conditions.

9.3.3 *Static Mixer*—A device that uses the kinetic energy of the moving fluid to achieve stream conditioning by placing a series of internal obstructions in the pipe designed to mix and evenly distribute all stream components throughout the pipe cross section.

9.3.4 *Power Mixer*—Power mixing systems use an external energy source; typically, an electric motor or pump to increase fluid velocity and turbulence.

9.4 *Location of Automatic Sampling System:*

9.4.1 *General*—An automatic sampling system should be located in a position that best guarantees access to a homogeneous stream. Consideration should be given to using any mixing benefits of upstream elements and avoiding partially filled pipes, dead legs, or headers.

9.4.2 *Multiple Run Metering Systems and Headers*—When a sampling system is used in conjunction with a multiple-run metering system, the sample point should not be located on an individual meter run, inlet, or outlet header. For example, a horizontal pipeline carrying crude oil and water will, at low flow rate, have the potential for stratification resulting in free water, which is likely to be divided unevenly between the metering streams. Additionally, flow patterns within headers are unpredictable and impacted by the number and order of streams in service. The sampling system may be located upstream or downstream of the metering system. If the velocity of the product in the pipe at the sample point does not provide adequate homogeneity for sampling (under worst-case flow and product conditions), the system requires additional stream conditioning. (For water-in-oil sampling, see *C1/C2* calculations in Annex A2 for further guidance around mixing.)

9.4.3 *Stream Blending*—Ensure automatic sampling systems are sufficiently downstream of points where different streams are blended to enable thorough mixing to occur.

10. Proportionality

10.1 An automatic sampling system controller paces a sampling device to extract representative samples throughout a batch or period. The proportionality of the samples being extracted can be defined by the following categories:

10.1.1 *Flow-Proportional Sampling:*

10.1.1.1 *Custody Transfer Meters*—Use custody transfer meters to pace the sampler where available. When using a single sampling point and measuring flow by multiple meters, pace the sampler by the combined total flow signal. In some circumstances, install a separate sampling system in each meter run. In this case, pace the sampler by the meter it is supporting (API *MPMS* Chapter 5).

10.1.1.2 *Special Flow Rate Indicators*—Automatic tank-gauging system for custody transfer may pace the sampling system in proportion to flow API *MPMS* Chapter 3.

10.1.1.3 An add-on flow metering device such as a clamp-on meter may be able to pace the sampling in proportion to flow.

10.1.2 *Time-Proportional Sampling*—Sampling in a time-proportional mode is acceptable if the flow rate variation is less than ±10 % of the average rate over the entire batch and if the sampling stops when the flow stops.

10.2 Care shall be taken not to sample faster than either the sample extractor or the sample control system is capable of operating. Operating a sampling system in this manner will result in a non-representative sample.

11. Sample Extractor Grab Volume

11.1 Sample extractors extract a wide variety of volumes per sample grab. When designing the sample system, consider the extractor grab volume. The extraction of larger volumes per grab may require a larger container to provide the necessary resolution of the desired 9604 grabs per batch. (See Annex A1 on how to calculate the error when the grabs per batch are reduced.)

11.2 Larger grab volumes may also be required to fill a container to an acceptable level per Practice D5854 (API *MPMS* Chapter 8.3) during small-volume batches delivered at high flow rates. For the same overall volume collected, larger sample grab volumes will reduce the sample frequency and also the resolution of the sample.

11.3 Sample grab volumes should be repeatable within ±5.0 %. The nominal grab volume (as determined by the sample probe manufacturer) is not necessarily the same as the actual grab volume. For purposes of establishing the sampling frequency for a batch, only the actual volume should be used.

11.4 The actual grab volume may be determined as an average by measuring 100 grabs into a suitably sized graduated cylinder. The volume contained in the cylinder at the end of test shall be divided by 100 (or the number of grabs taken) to establish the actual grab volume.

11.4.1 For example, if a sampler grabs 100 samples with the nominal grab size of 1.0 mL and an actual grab size of 1.2 mL, the end result would be 120 mL. In that situation, the person taking the sample could expect to observe anywhere from a low of 114 mL to a high of 126 mL during future verifications of the grab size.

12. Containers

12.1 *Sample Containers:*

12.1.1 A sample container is required to hold and maintain the composition of the sample in liquid form. This includes both stationary and portable containers, either of which may be of variable or fixed volume design. If the loss of vapors will significantly affect the analysis of the sample, a variable volume type container should be considered. Materials of construction should be compatible with the petroleum or petroleum product sampled. In general, one sample container should be used for each batch. Sampling a single batch into two receivers should be avoided since this will increase the potential for error.

12.1.2 Fixed primary sample containers require local mixing. Perform flushing, cleaning, and inspection of the internal mixing system after each batch. Clean, flush, and inspect transportable primary containers either on location or at the laboratory.

12.1.3 The containers types will generally be either variable volume (constant pressure) or fixed volume (constant volume). Sample containers may be stationary or portable and shall allow for cleaning and inspection. When designed for off-site analysis, both in-line and slip stream sample loop-type sampling systems will have primary sample containers. Use a sample container designed to hold and maintain the composition of the sample in liquid form. Stationary systems typically require local product mixing for any potentially nonhomogeneous product. Stationary sample containers remain permanently attached to the sampling system and are not intended to be removed while portable sample containers are removed from the sampling system and transported to the laboratory for mixing and analysis.

12.1.4 Both the design and materials of a sample container shall be tailored for the application. Container components including gaskets and O-rings, couplings, closures, seals, and relief valves should be assessed when reviewing the compatibility of container materials. The materials used in the construction of the sample container shall be compatible with the fluids to be collected and retained, as well as not compromising the properties of interest to be tested. Some contaminants may be adsorbed or absorbed by typical container materials. Special coatings or surface preparations may be required to avoid such effects.

12.1.5 The design of the sample container shall facilitate mixing of the sample to obtain a representative sample. The sample container may require special construction details to obtain an aliquot or test specimen for the purpose of performing an analysis and sample retention. Some analyses require that the sample not be exposed to air which will impact the method of sealing the container as well as other design considerations.

NOTE 2—If an aliquot or test specimen is to be drawn directly into the testing device, the primary sample container may need to have the capability of being homogenized.

12.1.6 Sample containers that are exposed to ambient environmental conditions (that is, sunlight, rain, heat, cold, ice, and other weather conditions) may impact the ability to mix and remove aliquots (for example, viscous or waxy products at low-temperature extremes) or sample integrity (for example, high-temperature loss of light ends of high RVP products).

12.1.7 A sampling system will typically be comprised of one or more sample containers (see Fig. 8). Multiple containers may be required on systems moving multiple batches, to take samples of linefill, or even to provide a safety backup.

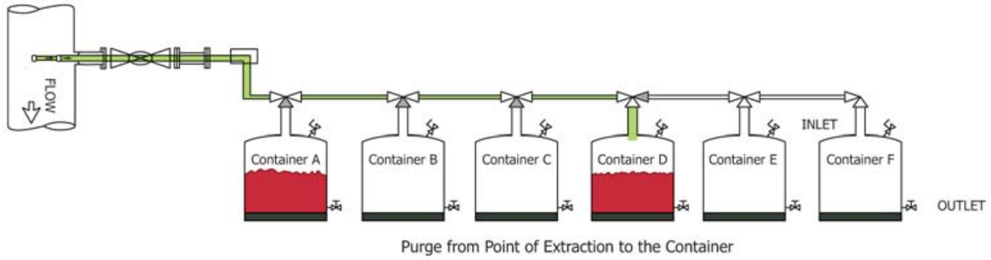


FIG. 8 Sample Probe with Multiple Containers

Consider the number of containers to be used, how these will be monitored, and whether the sample trapped in the interconnecting tubing will influence the representivity of the sample. Use methods to provide purging from the extraction point to the container. Failure to purge into another empty container or drain system will compromise the integrity of the next sample. The purge volumes are variable and in a multi-product system, purge volumes required are often a multiplier of the actual volume to sweep clingage away. Consult with manufacturer for guidance with system purging requirements.

12.1.8 Any containers used for the collection and handling of samples shall:

12.1.8.1 Meet the local health, safety, and environmental requirements, including spill and overflow containment;

12.1.8.2 Provide for relief valves that can be set and maintain a pressure that does not exceed the design pressure of the container;

12.1.8.3 Be designed so as to allow adequate mixing of the sample;

12.1.8.4 Use a design and materials that prevent retention of any of the components within the sample (such as water, metals, and long-term buildup/encrustation) and that do not react with the sample over the period in which it is likely to be in contact with the container material;

12.1.8.5 Facilitate complete withdrawal of the sample. When using mixing systems, they shall be capable of being fully drained;

12.1.8.6 Ensure internal pockets or dead spots are cleaned or mixed during a normal cycle. This includes any attachments such as glass level gauges;

12.1.8.7 Include a vacuum breaker if required for the removal of the sample or draining of the sample;

12.1.8.8 Be equipped with a pressure gauge;

12.1.8.9 Provide facilities for security sealing to prevent tampering with the sample;

12.1.8.10 Require closures on containers of sufficient size to facilitate easy inspection and cleaning;

12.1.8.11 Unless included in an auxiliary monitoring system, provide a means to monitor filling of the container; and

12.1.8.12 Unless included in an auxiliary monitoring system, provide a high-level alarm.

13. Sample Handling and Mixing

13.1 Maintain the properties and composition of the product in the container to ensure its contents are not compromised. Transfer of samples from the primary sample container to another container or the analytical glassware in which they will be analyzed requires special care to maintain their representative nature. Adequately mix the sample in the container to ensure a homogenous sample. For more information on the handling of the sample, refer to Practice D5854 (API *MPMS* 8.3) for detailed procedures.

14. Control Systems

14.1 The control system for automatic samplers is now generally microprocessor-based. The control system shall have adequate speed to ensure that the required number of samples is taken proportionally across the entire batch. However, the sampler control may at times be integrated as part of an overall process and, therefore, it is a requirement that the timing of the sample extractor signal (output) is within an acceptable tolerance for the system. While sample pacing is important, other aspects of the control system may include, but are not limited to:

14.1.1 Power failure signal,
14.1.2 Flushing of lines between batches,
14.1.3 Filling progress,
14.1.4 Sample verification,
14.1.5 Low-flow or no-flow alarm,
14.1.6 Over-fill warning,
14.1.7 Sample counter,
14.1.8 Sample container switching,
14.1.9 Batch calculations, and
14.1.10 Manual test fire button.

14.2 Do not change the sampling frequency (that is, units in volume per grab) during the sampling of a batch as it will render the resulting composite sample not representative.

14.3 Considering all the provisions of the sample control system shown in 14.1, the sampling frequency can also be manually calculated using the following guidelines shown as an example below. Variables used in the calculations are shown in Table 1.

14.3.1 Calculate the volume of sample to fill the container to expected percent of fill – SV_e (mL):

$$SV_e = SV_{cap} \times SV_{\max\%} \tag{1}$$

TABLE 1 Sample Frequency Variables

SV_{cap}	Sample container volume (total capacity	expressed in mL
$SV_{\max\%}$	Sample container volume (maximum fill %/API *MPMS* 8.3)	expressed in % fill
PV_e	Parcel (batch) volume expected	expressed in m^3 (bbl)
b	Expected extractor grab size as determined by prior testing	expressed in mL

where:

SV_{cap} = 22 712 mL,
$SV_{max\%}$ = 75 %, and
SV_e = 22 712 mL · (75/100) = 17 034 mL.

14.3.2 Calculate total grabs necessary (N_e) to achieve the SV_{cap} for the batch.

Where:

$$N_e = SV_e/b$$
$$N_e = 17\ 034\ \text{mL}/1.2\ \text{mL} = 14\ 195\ \text{grabs} \tag{2}$$

14.3.3 Calculate the frequency of sampling (B) based on the parcel volume expected PV_e.

Where:

$$B = PV_e/n$$
$$PV_e = 125\ 000\ \text{bbl}$$
$$N_e = 14\ 195\ \text{grabs} \tag{3}$$
$$B = 125\ 000/14\ 195\ \text{grabs} = 8.805\ \text{bbl/grab}$$

14.3.3.1 If B is rounded to 8.8 bbl/grab, then N_e is recalculated to N_e = 125 000 /8.8 =14 204 grabs and SV_e is recalculated to 14.204 · 1.2 mL = 17 004 mL.

14.3.3.2 If B is rounded to 9.0 bbl/grab, then N_e recalculated to N_e = 125 000 /9.0 = 13 888 grabs and SV_e is recalculated to 13 888 · 1.2 mL = 16 665 mL.

14.4 As shown in the example below, consider that the frequency of sampling is achievable based on the equipment being used and the flow rate at which the batch is being delivered. The calculated frequency of samples shall be within the performance capabilities of the sampling equipment.

14.4.1 Assume the cycle time design limitation of the sample probe is 4s/grab and the flow rate is 5 000 bbl/h, which is equivalent to 1.4 bbl/s.

14.4.2 For example 4 s/grab · 1.4 bbl/s = 5.6 bbl/grab is the highest frequency of sampling that can be achieved. Therefore, the required sampling frequency of 8.8 bbl/grab can be achieved because the frequency at 8.8 bbls/grab is less frequent than the sampling frequency at the 5.6 bbl/grab.

14.4.3 If the flow rate is at 10 000 bbl/h or 2.8 bbl/s, the frequency of the sample will not be achievable within the design limitations of the equipment.

14.4.4 For example 4 s/grab · 2.8 bbl/s = 11.2 bbl/grab is the highest frequency of sampling that can be achieved. Therefore, the required sampling frequency of 8.8 bbl/grab cannot be achieved because the sampling frequency of 8.8 bbl/grab is more frequent than the sampling frequency of 11.1 bbl/grab.

15. Sample System Security

15.1 To ensure that the collected sample is representative of the batch, do not alter the collected portion or corresponding electronic records and maintain the chain of custody.

15.2 Several measures can be implemented to maintain and demonstrate the physical integrity of the sample by restricting access to the sample location and sampling devices. This may comprise a locked and secured perimeter, such as fencing, or by housing the sampling apparatus inside a locked building. Numbered wire seals that provide an indication if the physical security of the sample may have been compromised, serve to demonstrate the integrity of a physical sample. If for any reason sample security is not maintained, treat the sample as questionable.

15.3 Consider electronic data regarding sample collection and testing as another aspect of sample security. House electronic records such that they may not be easily altered; track any changes by means of an audit trail. Reference API *MPMS* Chapter 21 regarding appropriate security measures involving electronic flow measurement devices.

15.4 Another significant aspect to maintaining the integrity of a sample is the sample's chain of custody documentation. This documents the sample's location and facilitates identification of personnel who may have had access to the sample.

15.5 Used together, these measures ensure that all samples can be clearly traced to the original batch.

15.6 For custody transfer purposes, document the process describing how the sample was homogenized and split in each instance, including the operators involved and witnesses. Also, refer to Guide D4840 for detailed guidance regarding sample security and sample traceability.

16. System Proving (Performance Acceptance Tests)

16.1 The performance of any installed system may be proved by testing to the agreed acceptance criteria.

16.2 System proving is the method by which the performance of the sampling system is compared to the criteria defined in 18.6 for crude oil. Perform testing of the system after it has been installed for service.

16.3 The intent of proving is not to establish the mechanical reliability of the system, but that the properties of interest, such as water, density, and RVP are capable of being detected and are representative of the flowing stream, as described in this practice. To enable proving to be undertaken, control and record the property of interest or use a tracer method to ensure that the sample taken is representative.

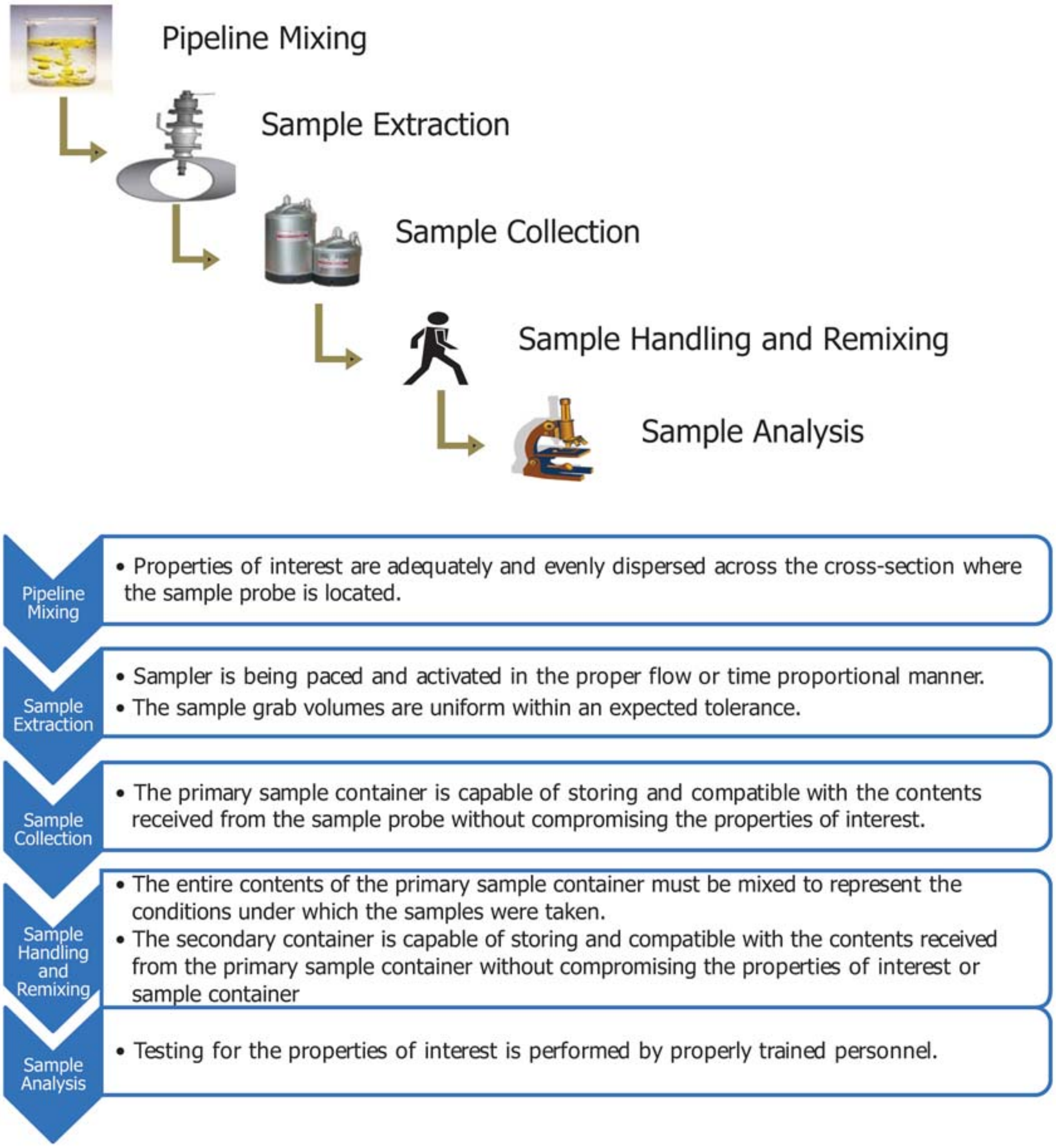
16.4 Evaluate individually the steps that comprise the sampling process by component testing as shown in Fig. 9. The uncertainty will be a result of the impact that each step contributes to the overall result.

16.5 This practice outlines the methods for testing samplers. The test methods fall in two general categories: total system testing and component testing. Component testing, for immiscible fluids, is discussed in profile testing.

16.6 While component testing is a useful tool in the overall evaluation and, in some circumstances, the only practical method, ideally a system should be proved by an evaluation of the entire process chain including the proposed analysis equipment and methods. Component testing is a less preferred option if a full system proving can be performed.

16.7 Once a system has been tested and proven, replacement of equipment other than like for like requires that the process be repeated. Any change to the provisions of this practice shall have the approval of all interested parties.

16.8 If required by contract or regulation, test the sampling system upon initial operation. Where there is significant value



Pipeline Mixing
- Properties of interest are adequately and evenly dispersed across the cross-section where the sample probe is located.

Sample Extraction
- Sampler is being paced and activated in the proper flow or time proportional manner.
- The sample grab volumes are uniform within an expected tolerance.

Sample Collection
- The primary sample container is capable of storing and compatible with the contents received from the sample probe without compromising the properties of interest.

Sample Handling and Remixing
- The entire contents of the primary sample container must be mixed to represent the conditions under which the samples were taken.
- The secondary container is capable of storing and compatible with the contents received from the primary sample container without compromising the properties of interest or sample container

Sample Analysis
- Testing for the properties of interest is performed by properly trained personnel.

FIG. 9 Sampling Components and Related Tests

or commercial risk involved in the transactions, the sampling system should be proven after the initial installation and thereafter, every five years but not to exceed seven, or when significant changes either in the product quality or flow profile are experienced. Some users will opt for this to be performed at an agreed frequency or this could also be mitigated by a program of ongoing evaluation of the mechanical attributes/performance of the components within the system or comparing results on a regular or frequent basis with other reliable analytical data upstream or downstream of the sample point.

16.9 Extreme caution shall be taken when a sampling system has been tested and proven in one application then rebuilt and installed in a slightly different application under dissimilar conditions. Just because the system passed at its original location does not mean the duplicated design can pass certification at a different site. The only way to know if a sampling system is performing properly is to validate it through testing and performance monitoring. More information regarding the revalidation of sample systems for crude oil is provided in 18.7.

16.10 Additional steps are provided to allow for testing a pipeline for the distribution of water within crude oils. This is titled profiling and appears in the crude oil section.

17. Performance Monitoring

17.1 Performance monitoring is comparing an initial set of expected performance parameters during a batch with the actual results. It is a means of verifying that the sample extractor and the equipment downstream of the extractor are performing as it was originally tested and as designed. The results from an active, robust performance monitoring program can also be used to identify potential problems before they become major issues. Some of the issues are:

17.1.1 The sample control system not controlling the sample extractor in a consistent manner and not delivering the expected number of grabs.

17.1.2 The seals within the sample extractor are worn and beginning to fail.

17.1.3 The sampler pacing device (not the custody transfer device) fails to agree with the actual custody transfer volume.

17.1.4 The sampling system was inactive during part of the batch.

17.1.5 The volume in the sample container does not reflect the expected result.

17.2 The criteria for performance monitoring are discussed in more detail in 18.7.

PART II—Crude Oil Sampling

This part contains additional information required to complete the design, testing, and monitoring of a crude oil sampling system. See Fig. 10.

18. Crude Oil

18.1 There are additional considerations when sampling crude oil and specifically as it relates to sampling for water, within the crude oil stream. Refer to the API *MPMS* Chapter 20 for high-water content crude oil sampling.

18.2 *Conditioning of Flowing Stream:*

18.2.1 It is essential that the contents of a flowing crude oil pipeline are mixed before a sample can be extracted. When considering the type or adequacy of pipeline mixing, the designer should not only study all the process parameters but should also include important peripheral issues such as:

18.2.1.1 The dispersion required by the sample extraction device;

18.2.1.2 The location of the sample extractor relative to the mixing device;

18.2.1.3 The pressure drop caused by the mixing device or the running costs or both;

18.2.1.4 The utilities required for the mixing device;

18.2.1.5 The maintainability of the mixing device;

18.2.1.6 The range of the mixing device;

18.2.1.7 The available space and accessibility for the mixing device;

18.2.1.8 The installation constraints of the mixing device;

18.2.1.9 The location of the water injection point ensures that all injected water reaches the sampling point; no dead legs, traps, and so forth; and

18.2.1.10 The location of the water injection sufficiently located upstream to simulate free water and its path through elements that may produce mixing.

18.2.2 Confirming that the pipeline contents are adequately mixed will come from testing. Designing for the test requires

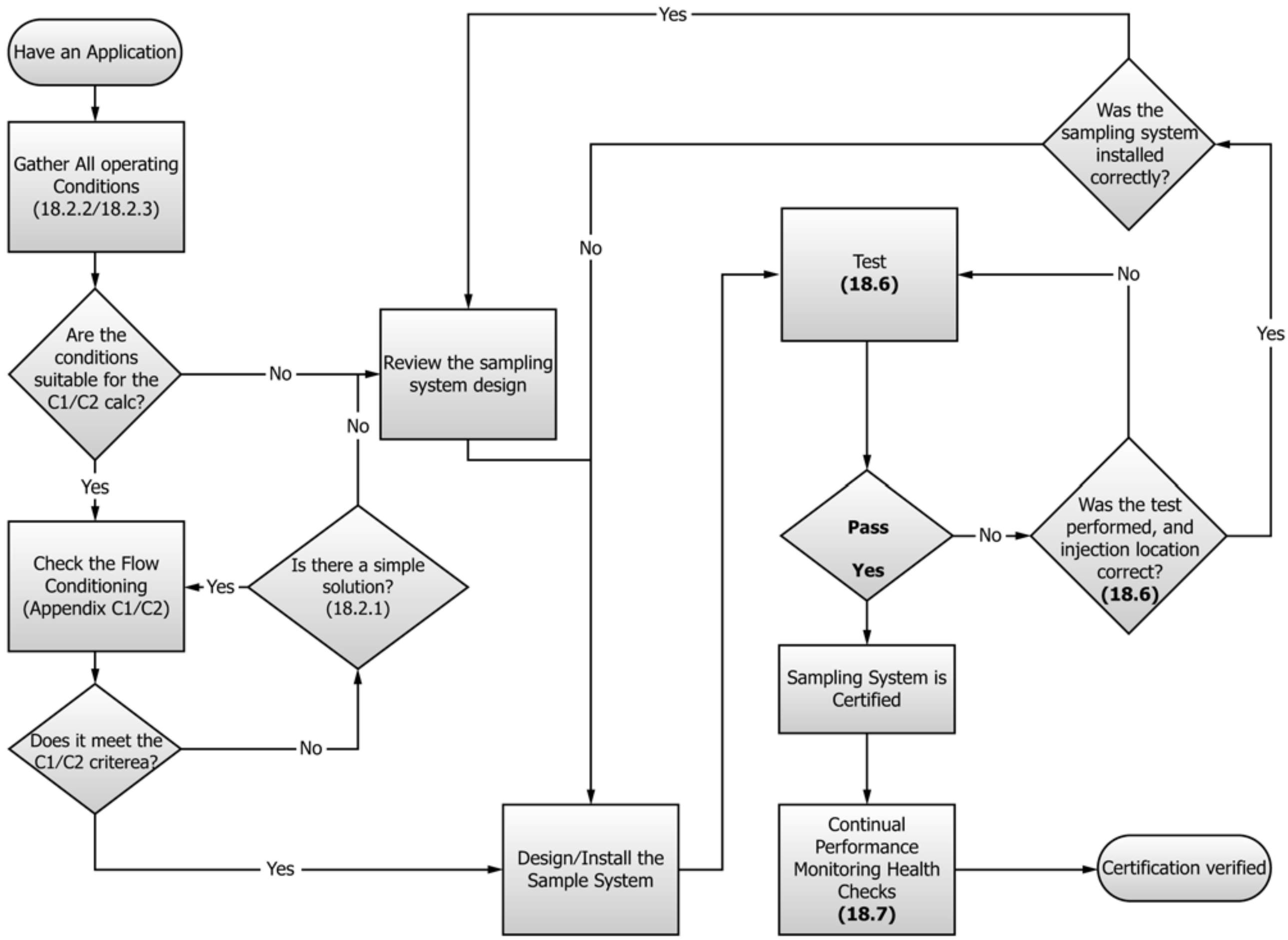


FIG. 10 Flowchart

that the worst-case conditions of a flowing stream be considered. Worst-case conditions could occur at the:

18.2.2.1 Minimum flow rate (worst case is a one in ten operation—10.0 %);

18.2.2.2 *Density*—High-density fluids are more likely to stratify;

18.2.2.3 *Viscosity*—High-viscosity fluids are more likely to stratify, while stratification of contaminants such as water occurs more readily in low-viscosity fluid streams; and

18.2.2.4 Highest water content.

18.2.3 The important process parameters to consider when determining the amount of mixing in a crude oil pipeline are flow rate (energy dissipation), viscosity, density, and water content (amount, dispersion, droplet size, and dropout rate). Velocity in the line shall be sufficient so that water droplets in the oil, typically studied in a vertical rising pipe, cannot fall faster than the velocity driving them upwards. Viscosity of the crude oil is an important parameter because water dropout rate increases as product viscosity decreases. Methods exist to estimate the homogeneity of the stream using computational fluid dynamics (CFD). Water droplet diameter is an important parameter because larger water droplets tend to drop out faster than smaller droplets. Surface tension is an important parameter because it is a factor in the formation and diameter of water droplets. See Annex A2 for *C1/C2* calculation.

18.2.4 Water droplet size should be sufficiently smaller than the sample probe opening. Also, see Annex A2 for *C1/C2* calculation.

18.2.5 Where stream conditioning is required, in all cases, additional energy is needed to increase the level of turbulence. Consideration shall be given to assure adequate homogeneity by one of the following methods:

18.2.5.1 Select an alternative location to be evaluated in which elements such as partly closed valves, T's, elbows, flow meters, reducers, pumps, and so forth create additional turbulence, which may or may not be adequate to ensure homogeneity under "worst flow/product" conditions;

18.2.5.2 Static mixers are devices that provide stream conditioning by means of using the kinetic energy of the flowing fluid;

18.2.5.3 Power mixing are devices that uses an external source of power to achieve stream pipeline conditioning; and

18.2.5.4 When evaluating the mixing system, due consideration should be given to the range of operation (velocity, viscosity, density, water, and sediment) of any proposed device and the impact on the pipeline flow. Design the stream conditioning for the worst conditions—normally, the minimum flow rate experienced at any point during the transfer (in the case of tankers during startup and stripping) for products with the minimum viscosity and density.

18.3 *Sample Extraction*—Challenges can occur during crude oil extraction for various reasons. Physical characteristics that affect crude oil sampling are many and varied, including density, viscosity, wax content, chemical additives, temperature affect, particulate matter, and naturally occurring chemical composition. The effect each of these can have on the transfer of the sample from the flowing stream to the sample container shall be considered.

18.3.1 Sample grab volumes typically range from 0.5 mL to 3 mL. There are instances in which the grab sizes may be greater than 3 mL. It is advisable to establish a performance-monitoring program, as specified in 18.7, to ensure the sample being analyzed in test laboratories is representative of the batch of from which the crude oil the sample was taken.

18.3.2 Tubing extending from the downstream side of the extractor has a potential to have a residual inventory equal to the volume of the tubing. The potential inventory is the sum total of liquid trapped in the tubing run at the time the primary sample container is changed. Sags or low areas in the tubing run will remain filled with sample. Whenever the flow of liquid in the tube stops, there is a potential for water to drop out and settle in the tube.

18.3.3 There is a possibility that a wax accumulation can plug tubing thereby causing the entire contents of the tube to remain in the tubing as residual inventory. Adequate heat tracing and insulation can often mitigate this problem.

18.3.4 The residual inventory should be purged into the primary container or, at least, the tubing should be sloped to facilitate natural draining towards the container. A 0.6 cm outside diameter tube 183 cm long and a wall thickness of 0.12 cm can hold residual inventory of 18.6 mL. Purging should be done with a fluid that does not change other physical properties of interest to the transaction.

18.3.5 Tubing orientation presents another potential source of measurement error. Because of low-fluid velocities, sample probes and extractor tubing that flow uphill have potential to experience oil and water separation. Free water being heavier and less viscous than most crude oils has the potential to lag behind the flow of crude oil. Under the right conditions, water may actually escape from probes before entering the extractor. Likewise, free water that forms in tubing runs has the potential to remain in the tubing instead of draining into the primary sample container. Low temperatures increase the effect viscosity has on the flow ability of waxy and heavy crude oils but has little effect on condensates. Water behaves much like condensate at temperatures above freezing; in freezing conditions, however, flow through probes and tubing is likely to stop altogether as water droplets change into crystals of ice and free water becomes solid ice.

18.3.6 The count of sample grabs used to represent a batch is a component of the total error that will exist in any subsequent quality determinations, such as percent water. It is recommended for all installations that the number of sample grabs obtained minimize the margin of error. It is recognized that some installations cannot achieve 9604 sample grabs within a batch, perhaps as a result of small batch size or limitations of the equipment. For additional information on how the number of grab samples has an effect on the representativeness of the accumulated sample, see Annex A1.

18.3.7 Therefore, if it is known that the volume of a batch is too small to extract 9604 grabs to achieve the minimal amount of error, the sample rate for that batch shall be set to run at its maximum (fastest) speed to extract the most representative sample possible. (See Annex A1 on how to calculate the error when the grabs per batch are reduced.)

18.4 *Slip Stream Sample Loop Probe Design Considerations:*

18.4.1 The probe diameter should be as large as the slip stream sample loop pipe diameter (minimum) to allow unrestricted flow through the loop.

18.4.2 The velocity and the design of the slip stream shall be sufficient to maintain homogeneity and avoid water drop-out.

18.4.3 Avoid "dead legs," uneven divided flow streams, and water traps in the slip stream sample loop design. If on-line analyzers, for example density, viscosity, on-line water determination, are to be fitted in the slip stream, these shall be fitted in series.

18.4.4 Flow is returned to the pipeline either at the same point as diverted from the pipeline or at a suitable point either downstream or upstream.

18.4.5 Be aware that crude oils with high wax content can coagulate and clog the slip stream sample loop probe, which can be easily addressed with heat trace and insulation and in some cases the provision of flushing.

18.4.6 The design for the leading edge of a slip stream sample loop probe should be facing upstream and chamfered so as to "cut" a coupon or consistent core from the flowing stream, the leading edge can have an chamfer so as to direct the flow to the inside diameter of the probe, or the probe can have a 45° beveled cut. These designs can provide a good inlet to the slip stream system. Specific applications or installation may prefer one design over the other. See Figs. 11 and 12.

18.4.7 *Between-Batch Purging*—When starting a new batch, the volume contained in the sample loop between the leading edge of the slip stream sample probe and the sample extractor or volume regulator probe should be considered. The flow velocity within the loop may well ensure that this volume has been purged several times before any sample is taken.

18.4.8 *Between-Batch Purging-Crude Oil*—Other considerations applicable to crude oil that will influence the purging are:

18.4.8.1 High-viscosity crudes (greater than 100 mm^2/s (100 cSt)) may require a longer cycle or purge time than low-viscosity crudes,

18.4.8.2 Crudes with high wax content paraffin can coagulate and clog the sample tubing,

18.4.8.3 Crudes containing high water content, and

18.4.8.4 Change in crude type (high vapor pressure crude or condensate to heavy crude).

18.5 *Containers*—It is not possible to cover all sample container requirements; therefore, when questions arise as to a container's suitability for a given application, rely upon API *MPMS* 8.1, API *MPMS* 8.3, and performance-based testing.

18.5.1 *Container Design*—The following information is given to assist in the design of the container and may be taken into account to obtain representative samples from the automatic sampling storage container or containers. It is important to consider the range of crude oil characteristics as well as the potential effects of atmospheric conditions on the sample integrity. This includes rain, direct intense heat, freezing temperature, and relative humidity of the air in the empty container.

18.5.2 Containers used for the collection and handling of samples may incorporate many of the following general design features as applicable to a given container style, site, operating conditions, crude characteristics, and application.

18.5.2.1 The bottom of the container shall be continuously sloped downwards towards the drain to help facilitate complete liquid sample withdrawal. There should not be any internal pockets or dead spots. Internal surfaces of the container should

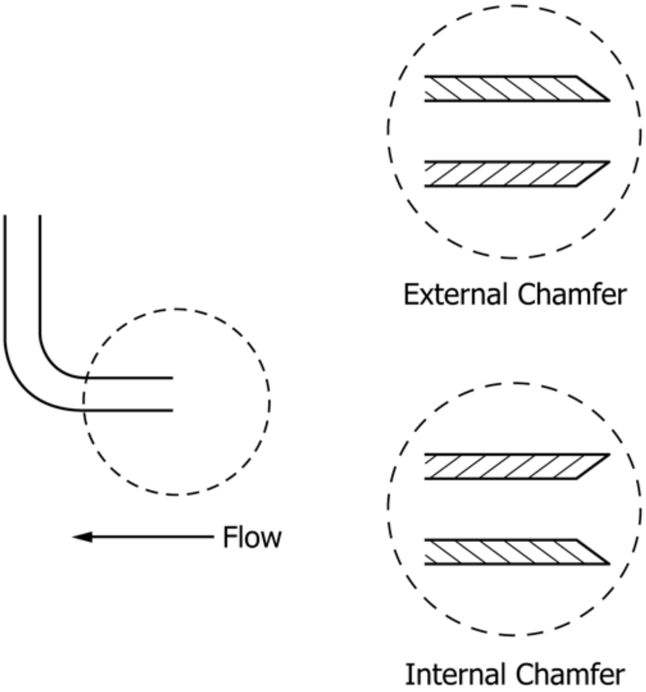


FIG. 11 Probe Chamfer Design

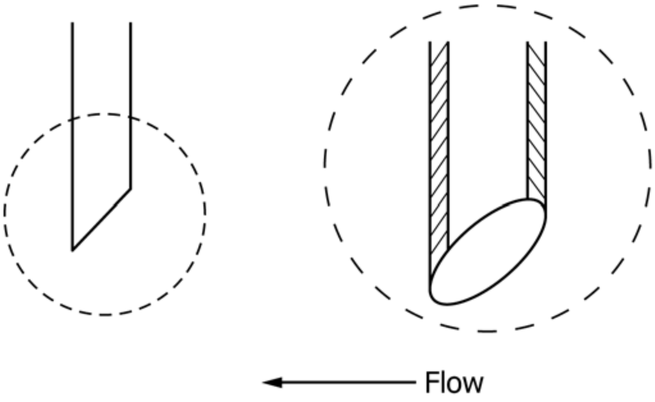


FIG. 12 Beveled Probe

be designed to minimize corrosion, encrustation, and clinging. This may require grinding of welds or specialized coating or both as necessary.

18.5.2.2 The "container mixing system" design will allow for a homogeneous mixture of the sample that can be validated and will be able to provide a representative secondary sample. See API *MPMS* 8.3 for more information.

18.5.2.3 Internal spray bar configurations will perform differently for varying products or grades of crude. It is important to understand what the limitations are of the internal spray bar to ensure the sample is properly mixed and is representative of the flowing batch.

18.5.2.4 The circulating system shall not contain any dead legs, as these tend to be locations for water retention within the system. Dead legs also prevent the water from being properly mixed and represented at the correct content levels of the collected sample.

18.5.2.5 If deemed necessary in performance-based testing, the circulation system should provide for complete washing/spraying of the interior of the container to rinse any condensation or clinging back into the sample. (**Warning—**If the moisture in the container is a product of the atmospheric condensation, then the interior wash may skew sample test results. Therefore, the container's design and cleaning protocol shall make precautions to minimize the effects of atmospheric condensation on the container design. Other considerations may require use of inert gas purge or variable volume containers.)

18.5.2.6 The circulation system should be sized to homogenize properly the sample for analysis. However, caution shall be taken to avoid over mixing that can result in the emulsification of the sample. Performance-based testing for various crudes will add clarity to the proper mixing time and the avoidance of driving the sample into an emulsion.

18.5.2.7 A means to break a vacuum may need to be provided to permit the sample aliquot withdrawal from the container during circulation of the contents.

18.5.2.8 A pressure gauge should be provided.

18.5.2.9 A means should be incorporated to monitor the filling of the container. Monitoring may be done visually onsite or remotely via electronic means. For high-value/risk transfers, performance monitoring may be critical.

(1) Onsite Monitoring—If a sight glass is used, it shall be easy to clean and it shall not trap water. It shall be protected. It will have a provision to monitor the filling of the container locally.

(2) Remote Monitoring—Weigh scales and liquid level indicators shall comply with hazardous location requirements.

18.5.2.10 Consider the use of a high-level indication device.

18.5.2.11 A sample draw-off port should be provided and located on the circulation piping at a point that ensures the aliquot will be representative of the contents of the container.

18.5.2.12 Containers may need to be heat traced, insulated, or both when high-pour-point, high-viscosity petroleum, or petroleum products with high wax contents are sampled. Alternatively, they may be kept in a heated, insulated housing, or both. Exercise caution to ensure added heating does not affect the sample integrity or composition.

18.5.2.13 Containers should have an opening of sufficient size to facilitate easy inspection and cleaning. Take into consideration prohibiting ingress of water from rain, washing, and so forth.

18.5.2.14 A pressure safety valve (PSV) or rupture disk may need to be provided to meet design or regulatory requirements.

18.5.2.15 Designs shall meet the local health, safety, and environmental requirements.

18.5.2.16 Ensure the container is compatible with the components of interest within the sample (such as water, metals, and long-term buildup/encrustation) and they do not react with the sample over the period in which it is likely to be in contact with the container material.

18.5.2.17 Facilities for security sealing should be provided where tampering may occur with the sample collected.

18.5.2.18 A standard operating procedure should be developed to ensure the container is clean before use.

18.5.2.19 Performance-based testing will verify the effectiveness of the procedure. Individual, group, or specific testing methods should be considered in the design of the container (Practice D5854 or API *MPMS* 8.3).

18.5.2.20 In addition to the requirements listed above, any sample container that contains hazardous materials or the residue of hazardous materials offered for shipment or transportation (that is, air, public roadway, rail, water, or any combination thereof) shall meet the requirements set forth in applicable national or regional regulations. There are many governmental agencies and jurisdictions that have regulations governing the storage and disposal of petroleum samples that can be classified as hazardous materials or hazardous wastes. Those who handle petroleum samples shall be familiar with these regulations in addition to their own company policies and procedures.

18.5.3 *Stationary/Fixed Containers*—Stationary (fixed) containers can be fixed volume or constant pressure/variable volume (normally piston or bladder) containers. Fixed containers are popular when the fluids sampled are broadly compatible with little variation in quality between batches. Analysis is most likely to be performed in proximity to the sampling location. The use of stationary containers will often add a step to the overall sampling process when a secondary container is used. This can increase the potential uncertainty of the overall result.

18.5.4 *Portable Sample Containers*—Portable containers can either be fixed volume or constant pressure/variable volume (normally piston or bladder) containers. Consideration should be given to the dry and filled weight as they are crucial to meeting practical as well as health and safety constraints. Provisions for transporting the container shall be available to assist in safe handling. Adequate precautions and secondary protection may be required to maintain the safety of the sample container and the integrity of its content to allow for changes in internal pressure (as a result of changes in temperature). These containers may be primary or intermediate containers. In addition to considerations outlined in 18.5.2, portable containers may include the following additional features:

18.5.4.1 Light weight,

18.5.4.2 Quick-release connections for easy connection/disconnect to the probe/extractor and the laboratory mixer.

18.5.5 *Variable Volume Containers:*

18.5.5.1 These containers will always take into account the vapor space considerations for sampling, transportation, or both.

18.5.5.2 The container will typically be designed to maintain full pipeline pressure on the sampled product or at least maintain pressure above the vapor pressure of the product. The container will maintain a liquid full volume only by the use of a sliding piston or a bladder assembly inside the container. Typically, the higher-pressure vessels will be the piston-style container.

18.5.5.3 The piston or bladder will allow a backpressure or constant pressure to be maintained on the sample at all times to prevent vaporization of the sample.

18.5.5.4 The circulation system should provide for complete agitation of the interior contents of the container.

18.5.6 *Container Sizing Guidance:*

18.5.6.1 Table 2 shows common container sizes for different crude applications. It is not meant to be an all-inclusive table but is a recommendation that can be considered.

TABLE 2 Container Size when Used In Different Applications

Lease automatic custody transfer	10 L to 60 L
Pipelines (crude petroleum)	20 L to 60 L
Pipelines (products)	4 L to 20 L
Portable	1 L to 20 L
Tanker Marine	20 L to 60 L
Linefill (marine applications)	Volume required for tests

18.5.6.2 Size the containers to ensure that the container will be filled to 60% to 80 % of capacity. Size the container to match its intended use and operating conditions. Factors that need to be considered for the sizing of the primary container include flow rate, batch size, practical sampling frequency, total weight when full; bite size, and total sample volume contractually required.

18.5.7 *Cavitation Avoidance*—In fixed-volume containers, take caution to be sure that the container is filled to at least 60 % capacity to avoid cavitation of the mixing pump.

18.5.8 *Guidance in Mixing*—For crude oil sampling, consult API *MPMS* Chapter 8.3 or Practice D5854 for guidance in mixing. Proper mixing is critical in crude oil because of the properties of the product and the presence of water and sediment.

18.5.9 *Cleaning*—Clean containers between batches to assure that there is no contamination from the previous sample.

18.5.9.1 An improperly designed sample container and sample container mixing system can result in significant measurement error. For example, a sample container and the container mixing system components is found to contain 50 mL of residual inventory from a previous batch. Fifty millilitres of residual inventory has the potential to impact analysis results significantly.

(1) For a 20 L container filled with 15 L of sample, 50 mL of residual inventory will skew the analysis results:

(a) By 0.0033 % if the residual contains 1.0 % water,

(b) By 0.0165 % if the residual contains 5.0 % water, and

(c) By 0.165 % if the residual contains 50 % water.

(2) For a 114 L container filled with 95 L of sample, 50 mL of residual inventory will skew the analysis results:

(a) By 0.000 005 3 % if the residual contains 1.0 % water,

(b) By 0.002 64 % if the residual contains 5.0 % water, and

(c) By 0.0264 % if the residual contains 50.0 % water.

18.6 *System Verification:*

18.6.1 The automatic sampling system is an integral component of the total system used for custody transfer of crude oil. Once installed in the field, all of these components of the measurement system are tested (proven) and verified on a periodic basis to ensure the results they produce are accurate and repeatable to an accepted industry standard.

18.6.2 If required by contract or regulation, test the sampling system upon initial operation. The recommended period for retesting of the automatic sampling system is every five years not to exceed seven years. The need for retests is determined by the parties involved with the custody transfer of the crude oil.

18.6.3 The tests described in the following are methods to prove and verify the automatic sampling system is producing representative samples of batches and the results from those samples are acceptable for custody transfer. The tests use the injection of water into a flowing stream, since water is the only component of the sediment and water that can be introduced and measured into a flowing stream.

18.6.4 The test is accomplished by dividing the total volume of injected water by the total volume of water and oil that pass the automatic sampling system during the test period. The actual results are then compared to the expected (calculated) results and the two shall be within the acceptance criteria (see Table 3).

18.6.5 During the agreed upon intervals between testing, it is recommended that a sampling system be monitored for changes in the original sampling system design criteria such as piping, crude oil properties, system gain/losses, flow rates, and sample system components. It may become necessary to retest when changes occur either in the system or when comparing results on a regular basis through performance monitoring.

18.6.6 The sampling system proving test is intended to ensure that the entire sampling system is within acceptable tolerances per Table 3 and repeatable over two sequential tests. Test results (average of two or more tests) should not show a significant bias. Testing the entire sampling system ensures that the chain of uncertainty (see Fig. 9) is accounted for. When performing an overall system test, then the equipment and processes normally used should be used for this test, substitution of alternate equipment for example different containers, different collection positions or different analysis methods should be avoided unless it can be proven that the uncertainties so created will be equal to or less than the system to be proven. Where for example a smaller volume of sample is collected, ensure that the uncertainty of this process matches that of the original. For example the use of Karl Fischer, where Centrifuge is the normal procedure is likely to provide a more accurate result that will not be reproduced in normal daily use.

TABLE 3 Allowable Deviations for the Single and Dual Sampler Water Injection Acceptance Tests (Volume by Percent)

Volume Percent	Using Tank Gages	Using Meters
0.5	0.13	0.09
1.0	0.15	0.11
1.5	0.16	0.12
2.0	0.17	0.13
2.5	0.18	0.14
3.0	0.19	0.15
3.5	0.20	0.16
4.0	0.21	0.17
4.5	0.22	0.18
5.0	0.23	0.19

NOTE 1—The reference to tanks or meters refers to the method used to determine the volume of crude oil or petroleum in the test.

NOTE 2—Deviations shown reflect use of the Karl Fischer test method described in Test Method D4928 (API *MPMS* Chapter 10.9) for water.

NOTE 3—Interpolation is acceptable for water concentrations between values shown in the table. For example, if the total water is 2.25 %, the allowable deviation using tank gages would be 0.175% and 0.135 % if using meters.

NOTE 4—This table is based, in part, on statistical analysis of a database consisting of 36 test runs from 19 installations. Because of the number of data, it was not possible to create separate databases for analysis by the volume determination method, that is, by tank or meter. Therefore, it was necessary to treat the data as a whole for analysis. The database is valid for the water range 0.5% to 2.0 %.

NOTE 5—The reproducibility standard deviation calculated for the data, at a 95 % confidence level, has been used for the meter values shown in the table in the water range 0.5 to 2.0 %. Assigning these values to the meter is based on a model that was developed to predict standard deviations for volume determinations by tanks and meters. Values shown in the table for the tank, in the range 0.5% to 2.0 %, were obtained by adding 0.04 % to the meter values in this water range. The value of 0.04 % was derived from the aforementioned model as the average bias between tank and meter volume determinations.

NOTE 6—As there is insufficient test data for water levels over 2.0 %, values shown in the table above 2.0 % have been extrapolated on a straight-line basis using the data in the 0.5% to 2.0 % range.

NOTE 7—To develop a broader database, owners of systems are encouraged to forward a copy of test data using test data sheets as shown in Annex A3 to the American Petroleum Institute, Industry Services Department, 1220 L St., N.W., Washington, DC 20005.

18.6.7 *Water Injection Volume-Balanced Tests:*

18.6.7.1 Two test methods have been shown to be acceptable in proving the performance of pipeline and marine automatic pipeline sampling systems and they are single sampler and dual sampler.

18.6.7.2 The following procedures are presented for the testing of systems to ensure the water in the crude oil is being sufficiently mixed and accurately represented at the sample point. The same approach may be modified to apply to crude oil blending systems.

18.6.7.3 The single- and dual-sampler tests are designed to test the entire sampling system starting with the stream condition in the pipeline through collection and analysis of the sample. These are volume balance tests in which a known amount of water is injected into a known volume of oil of known baseline water content. As these volumes pass the sampler under test, a sample is collected and the results analyzed for comparison against the known baseline water plus injected water.

18.6.7.4 The single-sampler test requires a consistent baseline of oil and water throughout the test period. If a consistent baseline cannot be achieved, questionable results may be obtained. (Refer to 18.6.9.)

18.6.7.5 A multiple sampler test using one sampler per meter on parallel meter runs is also an acceptable method for testing samplers. In this test, the baseline is established simultaneously for each sampler and the weighted average of each sampler's test results are used to determine the passing or failing of the test.

18.6.7.6 The dual sampler test is a two-part test that incorporates two samplers on the same line. In the first part, the two samplers are compared to one another at the baseline water content. In the second part of the test, water is injected between the two samplers to determine if the baseline water plus injected water is detected by the primary sampler.

18.6.8 *Preparations before Acceptance Test:*

18.6.8.1 The sample volume collected during the sampler acceptance test is usually less than the volume expected under normal conditions. Specific testing for the expected sampler test volume may be required in accordance with Practice D5854 (API *MPMS* Chapter 8.3).

18.6.8.2 Determine the method and accuracy by which the water and oil volumes will be measured. Water injection meters should be installed and proven in accordance with API *MPMS* Chapter 4 and 5. Oil volumes should be measured by custody transfer tank gauge or meter in accordance with applicable API *MPMS* Chapters 3, 4 and 5 guidelines.

18.6.8.3 The meter used to measure the water into the system during the test shall:

(1) Be proven every twelve months;
(2) Use fresh water as the meter proving fluid;
(3) Be accurate to within 1 % at the injection flow rate; and
(4) Be rated for the operating pressure of the system.

18.6.8.4 If the Karl Fischer titration method is used for water determination of the samples during the test, then its operation shall be verified per Test Method D4928 (API *MPMS* 10.9). It may be necessary to change the reagents used in the Karl Fischer titration during the test as they become saturated with crude. After the changing of the reagents, it shall also be necessary to verify the device's operation per Test Method D4928 (API *MPMS* 10.9).

18.6.8.5 If water determination is to be performed using a centrifuge, then the operation of the centrifuge shall comply with the method currently in use either Test Method D4007 (API *MPMS* 10.3) or API *MPMS* 10.4. At a minimum, verified centrifuge tubes shall be used during the water determination.

18.6.8.6 Consideration should be given to the linefill between the sample extractor and the sample container to ensure the entire sample reaches its designated container. It is important to be able to ensure all of the samples taken from the line during the test make it into the container for analysis.

18.6.8.7 Exercise care to ensure that the location and manner in which water is injected does not contribute additional mixing energy at the point of sampling, which may distort the test results. The velocity of the injected water shall not exceed the line velocity within 15 pipe diameters upstream of the mixing point. Equipment or facilities used to inject water should be in accordance with local safety practices.

18.6.8.8 Review the normal operating conditions of the pipeline in terms of flow rates and crude types. Select the most common, worst-case conditions to test the sampling system. The worst case will likely consist of the lowest normal flow rate, the lowest density crude oil (highest API gravity crude oil) or the highest viscosity normally received or delivered (worst case is referred to as a one-in-ten operation—10.0 %).

18.6.8.9 Select a place to inject the water. The water injection point should be upstream of all elements that are expected to produce mixing: piping elements such as bends, elbows, tees, valves, meter runs, and so forth.

18.6.8.10 Concentrations of water in crude oil being delivered from a vessel, storage tank, or pipeline usually does not come in 100 % slugs. Therefore, whenever possible, locate the injection point far enough upstream of the sample probe so that the water has a chance to spread out in the pipeline.

18.6.8.11 Ensure that all of the injected water will reach the sampling system during the test period.

18.6.8.12 Avoid traps where the water can fall out and not make it past the sample point.

18.6.8.13 Avoid dead legs where the water can go another direction other than past the sampling system.

18.6.8.14 The volume of water injected will vary depending upon the percent of water in the baseline of oil delivered through the pipeline. When a system's baseline contains less than 1.0 % water, it is recommended the injected water be equal to the baseline plus 0.50 %. For example, if the system's baseline is 0.30 % an additional 0.50 % of water is added to the stream, the expected water content of the sample container should be approximately 0.80 %.

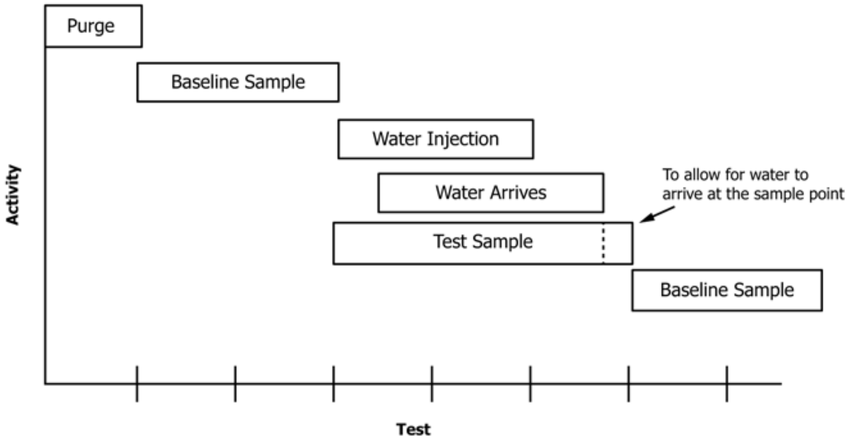
18.6.8.15 When system's baseline contains more than 1.0 % water, it is recommended the injected water be equal to the baseline plus 50 % of the baseline. For example, if the system's baseline is 1.20 % and an additional 0.60 % of water is added to the stream, the expected water content of the sample container should be approximately 1.80 %.

18.6.8.16 The pump used to inject the water shall be capable of overcoming the line pressure at the injection point.

18.6.8.17 The flow rate of the water being injected by the pump should be smooth and not surging, which can damage the water flow meter.

18.6.8.18 Injecting water into the top, side, or bottom of the pipe will typically have no effect on the results of the tests.

18.6.9 *Single Sampler—Acceptance Test:*



NOTE—Times are calculated based on minimum oil flow rate and the distance between the injection and the sample point.

NOTE 1—Times are calculated based on minimum oil flow rate and the distance between the injection and the sample point.

FIG. 13 Sequence of Acceptance Test Activities

18.6.9.1 Purge the system at a sufficiently high flow rate to displace free water that may be laying in the pipeline system upstream of the automatic sampling system. Refer to Fig. 13 as a reference to the sequence of test activities.

18.6.9.2 Establish the flow rate for the test. The flow rate used for the test should be lowest expected flow seen 10.0 % of the time.

18.6.9.3 Collect the first baseline sample(s). A baseline sample may be a composite sample collected in a separate sample container or several spot samples collected at intervals directly from the sample extractor. The range of results from the testing of three consecutive spot samples shall be within ±0.10 % of the average of the three readings or better. The following example illustrates this calculation:

(1) Three readings that pass:
  (a) 0.6 %
  (b) 0.55 %
  (c) 0.45 %
  (d) Average = 0.53 %
  (e) 0.6% to 0.53 % = 0.07 % (pass)
  (f) 0.53% to 0.45 % = 0.08 % (pass)
(2) Three readings that fail:
  (a) 0.3 %
  (b) 0.1%
  (c) 0.05 %
  (d) Average = 0.15 %
  (e) 0.3% to 0.15 % = 0.15 % (fail)
  (f) 0.15% to 0.05 % = 0.1 % (pass)

18.6.9.4 Begin the test.

18.6.9.5 Record the start time of the test. Also record the time of each of the different steps as the test is performed.

18.6.9.6 Record the initial oil volume by tank gauge or meter reading and simultaneously begin collecting grabs in the sample container.

18.6.9.7 Record the initial water meter reading. Then turn the water on and adjust injection rate.

18.6.9.8 It is recommended that the water be injected for a minimum of 1 h, as the situation warrants. However, there will be times when being able to inject water for 1 h will not be a reasonable way to carry out the test. In this case, the 1 h injection time shall be waived to allow for a more realistic approach to accomplishing the test.

18.6.9.9 After sufficient collection time, turn the water off and record the water meter reading and the time the meter is read.

18.6.9.10 Continue sampling into the container until the injected water has cleared through the sample extractor and all other connected appurtenances. When dealing with low-viscosity crudes, the length of time needed to purge water through the system may take longer than when dealing with high-viscosity crudes. Special consideration shall be given to the purge time.

18.6.9.11 End the test. If the tests are occurring simultaneously, then the ending baseline from the first test can be used as the beginning baseline for the second test. If the ending baseline of the first test is not the beginning baseline of the second test, then there is no need for the baselines to be compared with the baselines of the second test.

18.6.9.12 Stop the collection of test sample and simultaneously record the oil volume by tank gauge or meter reading and the time the stop time of the test.

18.6.9.13 Collect the second baseline sample(s) and analyze. The results from the testing of three consecutive spot samples shall repeat within ±0.10 % of the mean.

18.6.9.14 Mix and analyze the test sample. When production water is used, make correction for dissolved solids as applicable.

18.6.9.15 Using Eq 4 to calculate the deviation between the water in the test sample minus the water in the baseline, corrected to test conditions, compared to the amount of water injected.

$$DEV = (W_{test} - W_{bl}) - W_{inj} \tag{4}$$

where:

DEV = deviation (vol percent),
W_{test} = water in test sample (vol percent), and
W_{bl} = baseline water adjusted to test conditions (vol percent).

$$= W_{avg} \times (TOV - V)/TOV \tag{5}$$

where:

W_{avg} = average measured baseline water (vol percent),
TOV = total observed volume (test oil plus injected water) that passes the sample point or sampler,
V = volume of injected water, and
W_{inj} = water injected during test (vol percent).

$$= (V / TOV) \times 100 \tag{6}$$

18.6.9.16 Repeat above steps until two consecutive tests that meet the criteria in Table 3 have been obtained. If two consecutive tests fail to meet the repeatability criteria in Table 3, do not continue testing until something within the equipment being tested has been changed, modified, or repaired to ensure proper operation of the sample system.

18.6.10 *Dual Sampler—Proving Test:*

18.6.10.1 The dual sampler test is a two-part test. In the first part, the two samplers are compared to one another at the baseline water content. In the second part of the test, water is injected between the two samplers to determine if the baseline water plus injected water is detected by the samplers.

18.6.10.2 Collect the first baseline sample(s). A baseline sample may be a composite sample collected in a separate sample container or several spot samples collected at intervals directly from the sample extractor. The results from the testing of three consecutive spot samples from each sampler shall repeat within ±0.10 % of the average.

18.6.10.3 *Baseline Test Procedure:*

(1) Purge system to remove free water.

(2) Establish steady flow in line.

(3) Start baseline sampler. Record the tank gauge or meter reading.

(4) Start primary sampler after pipeline volume between samplers has been displaced.

(5) Stop baseline sampler after collecting targeted sample volume; a minimum of 1 h, as the situation warrants. However, there will be times when being able to capture the baseline sample for 1 h will not be a reasonable way to carry out the

test. In this case, the 1 h collection time shall be waived to allow for a more realistic approach to accomplishing the test. Record the tank gauge or meter reading.

(6) Stop primary sampler after pipeline volume between baseline and primary samplers has been displaced.

(7) Analyze test samples and compare results and make ensure they are within acceptable tolerance per Table 3.

(8) Water Injection Test:

(a) Record water meter reading.

(b) Start baseline sampler, injection of water, and record tank gauge or meter reading all simultaneously.

(c) Collect required sample volume with baseline sampler.

(d) Stop baseline sampler, record tank gauge or meter reading, and shut off water injection all in rapid succession. Record the water meter reading.

(e) Stop primary sampler after displacement of pipeline volume between baseline and primary samplers.

(f) Analyze test samples.

(g) Repeat steps in 18.6.10.3*(8)* until two consecutive tests that meet the criteria in have been obtained for both parts of the test.

18.6.11 *Acceptance Criteria for Custody Transfer:*

18.6.11.1 The acceptance test is valid and the automatic sampling system is acceptable for custody transfer if two consecutive test runs meet the following criteria:

(1) Single-Sampler Test:

(a) The difference in the results of the beginning and ending baselines shall be within ±0.10 % of the average, and

(b) The deviation between the test sample and the known baseline plus injected water is within the limits shown in Table 3.

(2) Dual-Sampler Test:

(a) This method is only used when the baseline at the primary sampler is not stable. The baseline for the dual sampler test shall be collected upstream of where the water is injected. The water found in this sample shall be used as the baseline value in the calculations.

(b) The difference between the second sampler (test sampler) and the baseline sampler plus injected water shall be within the limits shown in Table 3.

(3) Procedures to Follow if the Acceptance Test Fails:

(a) Ensure volume of oil was calculated and recorded correctly.

(b) Ensure volume of water was calculated and recorded correctly. Ensure scaling factor is correct or the meter factor has been applied to obtain correct volume or both.

(c) If inadequate stream conditioning in the pipeline is suspected, validate the sample point by one of the following:

Annex A2 to estimate the water-in-oil dispersion or a multiple-point profile test as described in A3.1.

Performance monitoring (health checks).

18.7 *Sampling System Monitoring:*

18.7.1 Once the sampling system is tested and meets the acceptance criteria detailed in this practice, then the sampling system performance shall be monitored and maintained on an ongoing basis. Monitoring and maintenance data should be recorded and evaluated to determine if the system performance is comparable to the original acceptance test data.

18.7.2 The sophistication of performance measurement and reporting for sampling systems will depend on the system type and transaction values. Performance monitoring can vary from simple hand-recorded measurements to fully automated electronically recorded measurements. More sophisticated online real-time performance measurement will allow dynamic performance measurement throughout the sampling operation in addition to total batch measures.

18.7.3 For the collected sample to be representative, one shall account for variations in flow. While flow-proportional sampling is preferred to meet this objective time-proportional sampling is also acceptable if the flow rate does not vary by more than ±10 % of the average value throughout the batch and the sampling stops when the flow stops.

18.7.3.1 It is important that continuous performance measurements (such as accumulating the weights of successive grabs into a sample container) take into account the initial voids in the line from sample probe to container or other non-uniform events (such as brief power failures).

18.7.3.2 This section outlines the report requirements, methodologies, and acceptance criteria for the physical performance of samplers. Variables used in this section are as follows:

b = Expected extractor grab size as determined by prior testing (see 11.3)
SV_{min} = Sample container minimum fill
N_{min} = Minimum acceptable number of actual grabs, normally 10 000
B = Frequency of sampling in unit volume/grab put into controller (see 14.3.3)
N = Total number of grabs recorded by the controller
SV = Sample volume collected in the primary container
PV_s = Batch parcel volume as measured by sampler flow-sensing device
N_e = Total number of grabs expected from the sampling batch setup (see 14.3.3)
PV_{co} = Custody transfer volume
GF = Grab factor
CF = Controller factor
SA = Flow sensor accuracy
GCF = Grab count factor
MV = Minimum volume
PF = Performance Factor (overall)
GCF' = Grab count factor modified by a change from setup size to actual batch parcel size
PV = Batch parcel gross volume as measured by the custody transfer system
PV_e = Batch parcel volume expected from the sampling system batch setup
SV_e = Sample volume expected to be collected from the sampling system setup (see 14.3.2)
SV_{min} = Minimum acceptable sample volume collected in the primary container (see API *MPMS* 8.3)
F = Sampling time factor
TS = Total time of sampling
TP = Total time of batch parcel

18.7.4 *Performance-Monitoring Criteria—Grab Count Factor (GCF):*

18.7.4.1 It is required that the number of grabs taken during the sampling period exceed the minimum required sample grabs. The *GCF* provides the acceptance criteria.

$$GCF = n/n_{\min} \tag{7}$$

(1) Actions Related to GCF:

(a) If $GCF \geq 1$, then no further action related to *GCF* is required.

(b) If *GCF* is < 1, then further evaluate by:

$$GCF' = n/n_{\min} \times PV/PV_e \tag{8}$$

(2) Actions Related to GCF':

(a) If $GCF' < 1$ then the indication is a failure in the sampling system.

(b) If $GCF' \geq 1$ then the indication is a failure in the operations.

- Operational failure might be the basis for negotiating the acceptance of secondary measurements.
- Operational failure could be due to an unavoidable batch size change.
- Operational failure could be due to faulty sampling system setup guideline.

18.7.4.2 Alternatively, if the total number of grabs recorded by the controller (*n*) is not available, then the *GCF* may be calculated as:

$$GCF = SV/b \times n_{\min} \tag{9}$$

(1) Actions Related to GCF:

(a) If $GCF \geq 1$, then no further action related to *GCF* is required.

(b) If $GCF < 1$, then further evaluate by:

$$GCF' = SV/b \times n_{\min} \times PV/PV_e \tag{10}$$

(2) Actions Related to GCF':

(a) If $GCF' < 1$, then the indication is a failure in the sampling system.

(b) If $GCF' \geq 1$, then the indication is a failure in operations.

- Operational failure might be the basis for negotiating the acceptance of secondary measurements.
- Operational failure could be due to an unavoidable batch size change.
- Operational failure could be due to a faulty sampling system setup guideline.

18.7.4.3 Determination of the minimum sample grabs is discussed in 18.4.7.

18.7.5 *Performance-Monitoring Criteria—Flow Sensor Accuracy (SA):*

18.7.5.1 It is required that the flow sensor that is used to pace the sampler is accurate in comparison with the custody transfer measurements. The *SA* provides the acceptance criteria.

$$SA = PV_{co}/PV_s \tag{11}$$

(1) Acceptable if *SA* is between 0.9 and 1.1.

18.7.5.2 If the same measurement device is used for both, then this criterion calculates to one.

18.7.5.3 While the criteria are intended to be used with batch-closing values, it is recommended to monitor dynamically *SA* throughout the transfer as an additional confirmation of linearity. For dynamically monitored systems, flow sensor performance of intermediate values can be of a far wider range (0.5 to 1.5).

18.7.5.4 For flow proportional sampling, it can be assumed that any metering device capable of generating a flow signal with linearity better than ±10 % of measurement point over the full range of flows expected is acceptable. In general, (non-fiscal) metering technology is significantly better than this and a target value of better than ±5 % should be attainable.

18.7.6 *Performance-Monitoring Criteria—Minimum Sample Volume (SV_{min}):*

18.7.6.1 It is required that the volume collected in the primary sample container be greater than the primary sample container minimum fill. The SV_{min} provides the acceptance criteria.

$$SV_{\min} = SV/SV_{\min} \tag{12}$$

(1) Acceptable if $SV_{min} > 1$.

18.7.6.2 Refer to API *MPMS* 8.3 for primary sample container minimum fill requirements.

18.7.7 *Performance-Monitoring Criteria—Controller Factor (CF):*

18.7.7.1 It is required that the controller initiate the number of grabs expected. The *CF* performance-monitoring criteria provide the criteria.

$$CF = N/N_e \tag{13}$$

where:

$N_e = PV_s/B$.

(1) Acceptable if *CF* is between 0.99 and 1.01.

18.7.7.2 It is important that continuous performance measurements (such as accumulating the weights of successive grabs into a sample container) take into account the initial voids in the line from the sample probe to the container or other non-uniform events (such as brief power failures).

18.7.8 *Performance-Monitoring Criteria—Grab Factor (GF):*

18.7.8.1 It is required that the sample grabs are of similar size as they were designed or were determined from testing. Differences indicate an extractor failure. The *GF* performance-monitoring criteria provide this check.

$$GF = SV/(N \cdot b) \tag{14}$$

(1) Acceptable if *GF* is between 0.95 and 1.05.

18.7.8.2 Alternatively, if the total number of grabs recorded by the controller (*N*) is not available, then the *GF* may be calculated as follows:

$$GF = SV/(N_e \cdot b) \tag{15}$$

where:

$N_e = PV_s/B$.

18.7.8.3 While the criteria are intended to be used with batch-closing values, it is recommended for automated systems to monitor *GF* throughout the transfer as an additional confirmation of linearity. For dynamically monitored systems, it is important that continuous performance measurements are compared when the system is operationally stable. As examples, at the start of a batch with pre-purged sample-line connection between the extractor and the container, the sample line will be empty; therefore, there will be an offset in time/volume between the start of the sampling process and the appearance of sample in the collection containers and, where sample container weighing systems are used, the density may change.

18.7.9 *Performance-Monitoring Criteria—Sampling Time Factor:*

$$SF = \text{Total Sampling Time / Total Batch Parcel Time} = TS/TP \tag{16}$$

(1) Acceptable if *SF* is between 0.95 and 1.05.

18.7.10 *Performance-Monitoring Criteria—Performance Factor*—The controller, grab size, pacing sensor, and continuous sampling during the transfer operation are all factors in the performance of the sampling system. The overall performance of the sampling system for a given batch parcel can be determined by the following:

$$PF = (SV \times B)/(PV \times b) \tag{17}$$

18.7.10.1 Acceptable if *PF* lies between 0.90 and 1.10.

18.7.11 The performance of the sampling system shall demonstrate an acceptable level during each of the independent checks including *GF*, *GCF*, *SA*, *SF* and *PF*. Each check is judged independently by its respective criteria. If the overall *PF* falls, the other checks can be used to help sort out the reasons for the failure. When the overall *PF* passes, then the performance of the sampling system remains in doubt whenever any other independent checks fail to meet its criteria because it is possible to have offsetting errors.

18.7.12 *Performance-Monitoring Criteria—Operating Conditions:*

18.7.12.1 A review of the process conditions is required to ensure the sampling system is operating within the conditions it was last tested. The evaluation of conditions shall include:

(1) Flow rate,
(2) Density,
(3) Viscosity,
(4) Crude characteristics, and
(5) Water content.

18.7.12.2 If any of the above conditions have changed and it is considered that the sampling system performance will be impacted by this, then the sampling system should be retested to the acceptance criteria as outlined in this practice.

18.7.13 *Performance-Monitoring Criteria—Equipment Confirmations:*

18.7.13.1 Depending upon the design of the sampling system it is required to confirm:

(1) For slip stream sample loop designs, the slip stream sample loop continuously maintained flow through the entire sampling period and

(2) For slip stream sample loop designs, the slip stream sample loop flow rate was greater or equal to the flow rate used for the sampler proving test.

18.7.14 *Performance-Monitoring Criteria—Audit and Reporting:*

18.7.14.1 Maintain reports of the sampling system performance and any identifiable operating issue.

18.7.14.2 Record the sampling system performance metrics electronically or manually for future reference.

18.7.14.3 Record any preventative maintenance.

18.8 *Uncertainty:*

18.8.1 Calculating the overall uncertainty of an automatic sampling system is complex because it contains the following aspects, the uncertainties of which shall be combined in accordance with principles outlined in API *MPMS* Chapter 13:

18.8.2 Acceptance test uncertainty derived from:

18.8.2.1 Statistical uncertainty based upon repeatability;

18.8.2.2 Tank gauging, flow meter, or temperature uncertainty; and

18.8.2.3 Use of nonstandard temporary sample container.

18.8.3 Effects of uncertainty in the performance of:

18.8.3.1 Mixing elements or other stream conditioning elements or power mixers,

18.8.3.2 Effective ratio of *C1/C2* (see Annex A2) being as close to 1.00 as possible,

18.8.3.3 Insertion depth of the sampling probe,

18.8.3.4 Controller functionality,

18.8.3.5 Flow-proportionally sample grab (bite) pacing,

18.8.3.6 Uniform size of sample grabs (bites),

18.8.3.7 Agreement of actual sample volume to calculated (programmed) sample volume,

18.8.3.8 Distribution and dispersion of water droplets,

18.8.3.9 Isokinetic sampling probes (extractors),

18.8.3.10 Primary and intermediate sample containers (containers),

18.8.3.11 Portable samplers,

18.8.3.12 Slip stream sample loop configuration,

18.8.3.13 Velocity of slip stream on slip stream sample loop systems,

18.8.3.14 Fluid properties,

18.8.3.15 Type of water determination analysis being performed,

18.8.3.16 Sample handling and mixing at each stage of transfer and testing, and

18.8.3.17 Diligence in monitoring of sampling performance for each transfer.

PART III—Refined Product Sampling

19. Refined Products

19.1 *Design:*

19.1.1 All design considerations including material compatibility, handling of low-level constituents, heating or cooling or both requirements, and flushing as examples are shown in Part I General, Section 5 to 17 apply.

19.1.2 A representative sample does not necessarily require 9604 grabs per parcel because the product is usually homogeneous.

19.2 *Performance Testing:*

19.2.1 Performance testing of the refined products sample system should be performed as required by contract after it has been installed for use.

19.2.2 Refined product auto-samplers are often used to capture a representative proportion of a multi-component blend or delivered batch of material involved in a custody transfer exchange. There is no expectation of proving or certifying refined product auto-samplers in a fashion similar to crude auto-samplers, but routine comparison of auto-sample analysis results is considered a normal quality control validation activity.

19.2.3 Injected tracer testing (dyes, isotopes, other) can be used for systems in which inadequate mixing or non-representative sampling is suspected.

19.2.4 The testing requirement of any installed refined product sampling system shall have an acceptance criteria agreed to by all parties involved with the system.

19.3 *Performance Monitoring:*

19.3.1 System monitoring and quality control validation procedures should be documented.

19.4 *Operations:*

19.4.1 All operating considerations shown in Part I General, Section 5 to 17 apply.

20. Keywords

20.1 acceptance tests; automatic petroleum sampling; controllers; extractor; intermediate sampling container; isokinetic sampling; mixing elements; portable samplers; primary sample container; probe; representative sampling; representative sampling criteria; slip stream sample loop; sample mixing; sampling handling; stream conditioning

ANNEXES

(Mandatory Information)

A1. CALCULATION OF THE MARGIN OF ERROR BASED ON NUMBER OF SAMPLE GRABS

A1.1 This annex explains one aspect relating to the uncertainty of the representativeness of a composite sample collected by an automatic sampler. How to determine the total number of grabs is demonstrated, in relation to the batch size, that is necessary to achieve a 95 % confidence level, which will validate the contents of the sample container are representative of the batch. It is understood that there will be times when the confidence level may fall below 95 % because of shortened batch sizes or catastrophic failure of the sampling device. In cases in which there was not a catastrophic failure of the sampling system, but simply a result of a shorter batch than planned, or the result of limitations because of the batch size/grab size/sample container size/sampling probe maximum rate combination, the potential random error can also be determined using the calculations in the following.

A1.2 The symbols used in the calculations (see Table A1.1) are to be used for the illustration of this exercise only. They are not to be confused with the symbols used in earlier calculations.

A1.3 The first equation is used to represent the minimum number of samples necessary to sample adequately (and, therefore, represent) the entire population (batch) to within some error level (for example, 0.01) at a confidence level of 95 % (where the outcome is either pass or fail).

A1.4 From statistics theory, the sample size (S) needed to represent a population of size (N) to a degree of accuracy (d) at a confidence level of (w), is given by:

$$S = \frac{X^2NP(1 - P)}{d^2(N - 1) + X^2P(1 - P)} \qquad \text{(A1.1)}$$

where:

$X^2(w)$ = chi-square value at a confidence level (w),

N = batch size divided by the actual size of the sample grab with both volumes being in the same units, and

P = population proportion (for a one-variable pass or fail test, this is 0.5).

A1.5 If we now let the population size (N) approach infinity:

$$\lim_{N\to\infty}(S) = \lim_{N\to\infty}\left(\frac{X^2NP(1 - P)}{d^2(N - 1) + X^2P(1 - P)}\right) \qquad \text{(A1.2)}$$

A1.5.1 Let

$$\begin{gathered}\beta = X^2P(1 - P)/d^2 \\ \alpha = 1 - \beta\end{gathered} \qquad \text{(A1.3)}$$

TABLE A1.1 Symbols

Symbol	Represents	Value
N	Batch size divided by the actual size of the sample grab with both volumes being in the same units (for example, batch size in barrels divided by sample grab size in decimal barrels or batch size in millilitres divided by sample grab size in millilitres).	To be determined by user
P	Population portion	0.5
d	Degree of accuracy or potential error	0.01
χ^2	Chi squared for 95 % confidence level and 1 degree of freedom	$(1.96^2) = 3.8416$
(w)	Confidence level used to acquire χ^2 (Chi squared)	0.05
N_s	Actual number of samples taken if less than the output from Eq A1.1	To be determined by user

A1.5.2 Then

$$\lim_{N\to\infty}(S) = \beta \lim_{N\to\infty}\left(\frac{N}{N-\alpha}\right) \tag{A1.4}$$

A1.5.3 Since

$$\lim_{N\to\infty}\left(\frac{N}{N-\alpha}\right) = 1 \text{ for } \alpha << N$$
$$\lim_{N\to\infty}(S) = \beta \qquad \text{or} \tag{A1.5}$$
$$\lim_{N\to\infty}(S) = \frac{X^2P(1-P)}{d^2}$$

A1.6 Therefore, the maximum number of samples given any population can be determined from Eq A1.1, but is guaranteed to be less than or equal to S^{max}:

$$S^{\max} = \frac{X^2P(1-P)}{d^2}$$
$$S^{\max} = \frac{(3.8416)\times 0.5\times(1-0.5)}{(0.01)^2} = 9604 \text{ samples} \tag{A1.6}$$

A1.7 *Example 1*—Assume a batch size of 1000 barrels and a sample grab size of 3 mL. Converting the barrels to millilitres and dividing by the sample grab size of 3 mL would give a total population of 52 995 765 mL. For a population of (N) = 52 995 765 mL, a confidence level of (w) = 95 %, and an error no greater than (d) = 0.010, Eq A1.7 can be used to calculate the number of grabs necessary for the batch.

$$S = \frac{X^2NP(1-P)}{d^2(N-1)+X^2P(1-P)}$$
$$S = \frac{(3.8416)(52\ 995\ 765)(0.5)(1-0.5)}{(0.01)(0.01)(52\ 995\ 764)+(3.8416)(0.5)(1-0.5)}$$
$$S = 9602 \tag{A1.7}$$

A1.8 To determine the margin of error to be expected when the number of samples collected from the population (N) is less that the number specified to reach the desired confidence level of 95 % use Eq A1.9.

A1.8.1 If the sampling equipment is only capable of sampling at a specific rate, such that the optimum samples as determined by Eq A1.8 cannot be attained, the resulting error can be calculated from Eq A1.9 as follows:

$$S = \frac{X^2NP(1-P)}{d^2(N-1)+X^2P(1-P)} \tag{A1.8}$$

A1.8.1.1 Rearranging

$$d = \sqrt{\frac{X^2P(1-P)(N-S)}{NS}} \tag{A1.9}$$

A1.8.2 *Example 2*—For the population described in Example 1, the sampler is only capable of taking 4000 samples over the course of the batch instead of the 9602 maximum that is calculated from Eq A1.8. The expected error can be calculated from Eq A1.9:

$$d = \sqrt{\frac{3.8416\times 0.5\times(1-0.5)(52\ 995\ 765-4\ 000}{52\ 995\ 765\times 4\ 000}}$$
$$d = 0.015 \tag{A1.10}$$

A1.9 Table A1.2 and Fig. A1.1 show how the margin of error increases as the number of grabs decreases. This is calculated using the formulas in Eq A1.8 and Eq A1.9.

TABLE A1.2 Samples versus Margin of Error

N	*P*	chi-square	Degrees of Freedom	Confidence Level %	*d*	*S*
300 000 000	0.5	3.8416	1	95	0.010	9604
300 000 000	0.5	3.8416	1	95	0.015	4268
300 000 000	0.5	3.8416	1	95	0.020	2401
300 000 000	0.5	3.8416	1	95	0.025	1537
300 000 000	0.5	3.8416	1	95	0.030	1067
300 000 000	0.5	3.8416	1	95	0.035	784
300 000 000	0.5	3.8416	1	95	0.040	600
300 000 000	0.5	3.8416	1	95	0.045	474
300 000 000	0.5	3.8416	1	95	0.050	384
300 000 000	0.5	3.8416	1	95	0.060	267
300 000 000	0.5	3.8416	1	95	0.070	196
300 000 000	0.5	3.8416	1	95	0.080	150
300 000 000	0.5	3.8416	1	95	0.090	119
300 000 000	0.5	3.8416	1	95	0.100	96

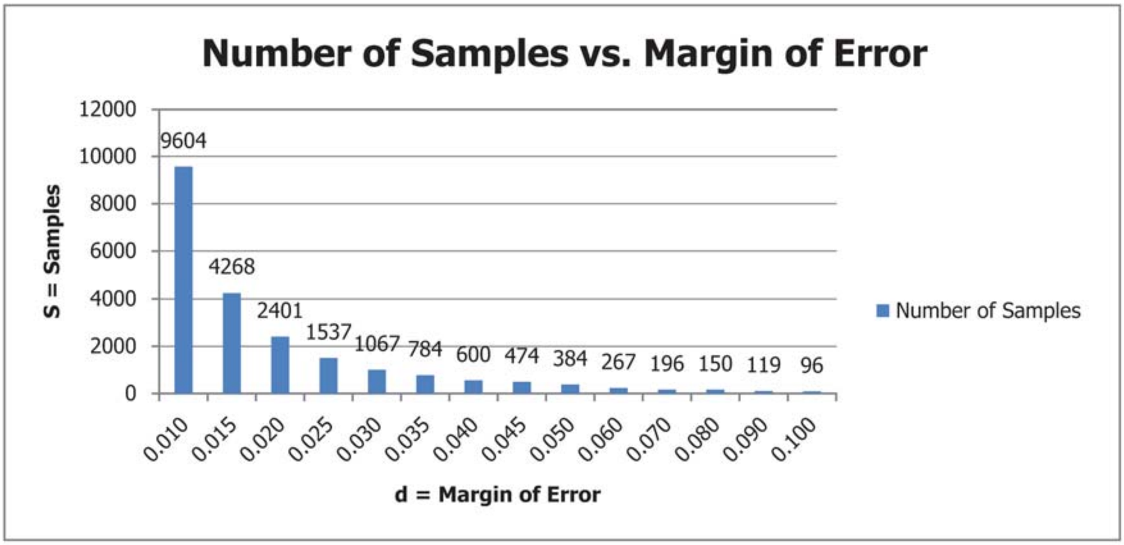


FIG. A1.1 Number of Samples versus Margin of Error

A2. THEORETICAL CALCULATIONS FOR SELECTING THE SAMPLER PROBE LOCATION

A2.1 Introduction

A2.1.1 This annex describes calculation procedures for estimating the dispersion of water-in-oil at a sampling location. These procedures have a very simple theoretical base with many of the equations not being strictly applicable; therefore, they should be used with extreme caution in any practical application. A conservative approach is strongly recommended when estimating the acceptable limits for adequate dispersion (steam conditioning).

NOTE A2.1—From IP Petroleum Measurement Manual, Part IV Sampling.

A2.1.2 The equations contained in this annex have been shown to be valid for a large number of field data. The range of the field data covered the following correlating parameters:

Relative density	0.8927 to 0.8550 (27 to 34° API)
Pipe diameter	40 cm to 130 cm
Viscosity	6 mm^2/s to 25 mm^2/s (6 cSt to 25 cSt) at 40 °C
Flowing velocity	>0 m/s to 3.7 m/s
Water concentration	<5 %

NOTE A2.2—Use caution when extrapolating outside of these ranges.

A2.1.3 When evaluating if dispersion is adequate or not in a given system, using the worst-case conditions is recommended.

A2.1.4 When calculating the dispersion rate *E* in A2.4, note that dispersion energies of different piping elements are not additive in regard to dispersion, that is, when a series of elements is present, the element that should be considered is the one that dissipates energy the most.

A2.1.5 As an aid in determining the element most likely to provide adequate dispersion, Fig. A2.1 has been developed. When using Fig. A2.1, it is important to consider it as a guide only and that particular attention should be paid to the notes. Fig. A2.1 does not preclude the need for a more detailed analysis of these elements, within a given system, shown by the table to be the most effective.

A2.2 Symbols

A2.2.1 The symbols used in Annex A2 are presented in Table A2.1.

A2.3 Dispersion Factors

A2.3.1 As a measure of dispersion, the ratio of water concentration at the top of a horizontal pipe C_1 to that at the bottom C_2 is used. A C_1/C_2 ratio of 0.9 to 1.0 indicates very good dispersion while a ratio of 0.4 or smaller indicates poor dispersion with a high potential for water stratification. Calculations giving less than 0.7 should not be considered reliable as coalescence of water droplets invalidates the prediction technique.

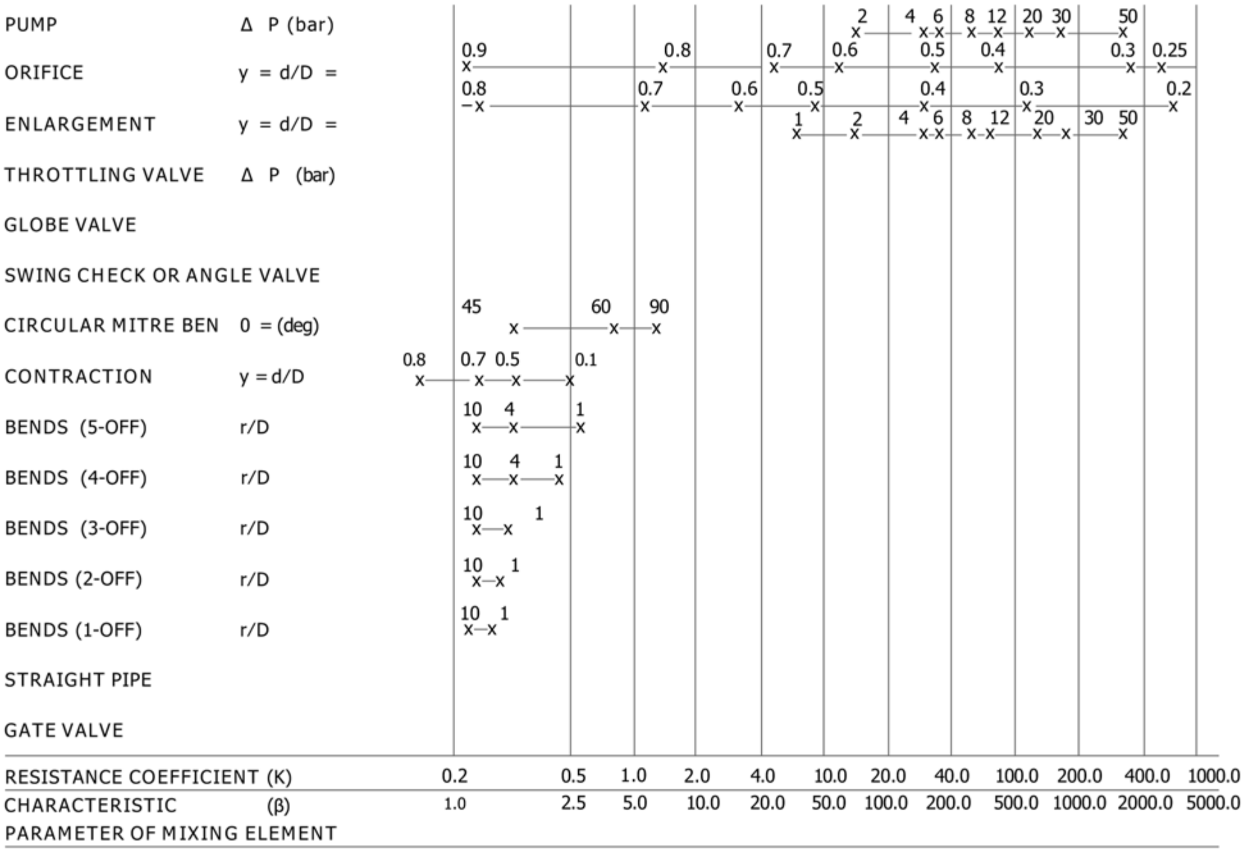
A2.3.2 The degree of dispersion in horizontal pipes can be estimated by:

$$\frac{C_1}{C_2} = \exp\left(\frac{-W}{\varepsilon/D}\right) \qquad \text{(A2.1)}$$

where:

C_1/C_2 = ratio of water concentration at the top (C_1) to that at the bottom (C_2);
W = settling rate of the water droplets; and
ε/D = turbulence characteristic, where ε is the eddy diffusivity and D the pipe diameter.

A2.3.3 An alternative measure of dispersion, *G*, can be defined in Eq A2.2. Table A2.2 presents the relationship of C_1/C_2 with *G*.



NOTE 1—The table has been compiled assuming the same pipeline diameter downstream of any device. If the downstream diameter of any two devices is not identical, comparisons using FIG A2.1 cannot be performed.

NOTE 2—It is not intended that FIGA 2.1 be used to ascertain β or K values but only to provide a comparison of the likely mixing effects of devices.

NOTE 3—For centrifugal pumps and throttling valves, the dissipation energies, which are defined without the use of β values (see Table A2.4), the comparison has been done using an assumed β equal to *E/E*$_o$ and the following typical values—*D* = 0.4 m, ν = 16 mm^2/s, ρ = 900 kg/m^3, and *V* = 5.6 m/s.

NOTE 1—The table has been compiled assuming the same pipeline diameter downstream of any device. If the downstream diameter of any two devices is not identical, comparisons using Fig. A2.1 cannot be performed.

NOTE 2—It is not intended that Fig. A2.1 be used to ascertain β or *K* values but only to provide a comparison of the likely mixing effects of devices.

NOTE 3—For centrifugal pumps and throttling valves, the dissipation energies, which are defined without the use of β values (see Table A2.4), the comparison has been done using an assumed β equal to E/E_o and the following typical values—D = 0.4 m, ν = 16 mm^2/s, ρ = 900 kg/m^3, and V = 5.6 m/s.

FIG. A2.1 Comparison of Mixing Devices

$$G = \frac{\varepsilon/D}{W} \tag{A2.2}$$

A2.3.4 Note that the uncertainty of the calculations is such that errors in *G* of more than 20 % may result at low values of *G*. For this reason, it is recommended that no reliance be placed upon calculated *G* values of less than three and that additional energy dissipation calculated *G* value.

A2.4 Determination of Energy Dissipation

A2.4.1 Two different techniques are given for determining the rate of energy dissipation.

A2.4.2 Method A uses the relationship in Eq A2.3.

$$E = \frac{\Delta P V}{\Delta X \rho} \tag{A2.3}$$

where:

ΔP = pressure drop across the piping element,
V = flow rate at the pipe section in which energy is dissipated, and
ΔX = characteristic length that represents the distance in which energy has been dissipated.

A2.4.2.1 In most cases, Δ*X* is not known with any confidence. Wherever possible, the value to be used should be supported by experimental data.

NOTE A2.3—If Δ*X* is not known, a substitute value of Δ*X* = 10*D* may be used as a very rough approximation for devices of low mixing efficiency such as those in Table A2.3. For specially designed high-efficiency static mixers, the value Δ*X* will be small and should be obtained from the designer.

NOTE A2.4—If Δ*P* is not known, calculates it from Eq A2.4.

TABLE A2.1 Symbols Used in Annex A2

NOTE 1—1 Pa = 10^{-5} bar.

NOTE 2—1 $m^2/s = 10^6$ cSt = 10^6 mm^2/s.

NOTE 3—1 N/m = 10^3 dyn/cm.

Symbol	Term	Units
C	water concentration (water/oil ratio)	dimensionless
D	pipe diameter	m
d	droplet diameter	m
E	rate of energy dissipation	W/kg
E_o	energy dissipation in straight pipe	W/kg
E_r	required energy dissipation	W/kg
G	parameter, defined in A2.3.3	dimensionless
K	resistance coefficient	dimensionless
n	number of bends	dimensionless
ΔP	pressure drop	Pa (Note 1)
Q	volumetric flow rate	m^3/s
r	bend radius	m
V	flow velocity	m/s
V_j	flow nozzle exit velocity	m/s
W	settling rate of water droplets	m/s
ΔX	dissipation distance	m
β	parameter, defined in A2.4.3	dimensionless
γ	ratio between small and large diameters	dimensionless
ε	eddy diffusivity	m^2/s
θ	turn angle	degrees
ν	kinematic viscosity	m^2/s (Note 2)
σ	surface tension	N/m (Note 3)
ρ	crude oil density	kg/m^3
ρ_d	water density at line temperature	kg/m^3
φ	flow nozzle diameter	m

TABLE A2.2 Dispersion Factors

G	C_1/C_2	C_2/C_1
10	0.90	1.11
8	0.88	1.14
6	0.85	1.18
4	0.78	1.28
3	0.71	1.41
2	0.61	1.64
1.5	0.51	1.96
1	0.37	2.70

$$\Delta P = \frac{K \rho V^2}{2} \tag{A2.4}$$

where:

K = resistance coefficient of the piping element under consideration.

A2.4.2.2 Suggested values of K for different piping elements are given in Table A2.3.

A2.4.3 Method B uses the relationship $E = \beta E_0$, where β is a characteristic parameter of a mixing element and E_0 is the rate of energy dissipation in a straight pipe. E_0 is calculated from Eq A2.5.

TABLE A2.3 Suggested Resistance Coefficients, *K*

NOTE 1—γ is the small diameter/large diameter and K is based on the velocity in the smaller pipe.

Contraction	$K = 0.5(1 - \gamma^2)$	$(0 \leq K \leq 0.5)$
Enlargement	$K = \frac{(1 - \gamma^2)^2}{\gamma^4}$	$(0 \leq K \leq 0.5)$
Orifice	$K = 2.8(1 - \gamma^2)\left[\left(\frac{1}{\gamma}\right)^4 - 1\right]$	
Circular miter bends	$K = 1.2\ (1 - \cos\theta)$ where θ = turn angle	$(0 \leq K \leq 1.2)$
Swing check valve	$K = 2$	
Angle valve	$K = 2$	
Globe valve	$K = 6$	
Gate valve	$K = 0.15$	

$$E_0 = 0.005 \nu^{0.25} D^{-1.25} V^{2.75} \tag{A2.5}$$

Where ν is given in mm^2/s (cSt).

A2.4.4 Suggested values of β and tentative relationships for E (other than $E = \beta E_0$) are given in Table A2.4 and Table A2.5, respectively.

A2.5 Contraction

A2.5.1 Contraction effects can be calculated with Eq A2.6.

$$\beta = 2.5(1 - \gamma^2) \tag{A2.6}$$

A2.6 Enlargement

A2.6.1 Enlargement effects can be calculated with Eq A2.7.

$$\beta = \frac{5(1 - \gamma^2)}{\gamma^4} \tag{A2.7}$$

A2.7 Mean Water Droplet Diameter

A2.7.1 The mean water droplet diameter d may be estimated using Eq A2.8.

$$d = 0.3625 \left(\frac{\sigma}{\rho}\right)^{0.6} E^{-0.4} \tag{A2.8}$$

where:

σ = droplet surface tension between water and oil measured in N/m. All formulas and examples in this Annex A2 assume σ = 0.025 N/m.

TABLE A2.4 Dissipation Energy Factors (β)

NOTE 1—The value n is the number of bends of radius r in a pipe of diameter D.

NOTE 2—The spacing between the bends may affect the degree of dispersion. For this relationship to hold, the distance between each bend should not exceed 30 pipe diameters.

r/d	1	1.5	2	3	4	5	10
$n = 1$	1.27	1.25	1.23	1.22	1.18	1.15	1.07
$n = 2$	1.55	1.50	1.48	1.45	1.38	1.30	1.13
$n = 3$	1.90	1.80	1.75	1.70	1.56	1.44	1.18
$n = 4$	2.20	2.10	2.00	1.93	1.72	1.56	1.23
$n = 5$	2.60	2.40	2.30	2.20	1.90	1.70	1.28

TABLE A2.5 Dissipation Energy Relationships

Centrifugal pump	$E = 0.125\,\dfrac{\Delta PQ}{\rho D^3}$
Throttling valve	$E = \dfrac{\Delta PV}{20\rho D}$
Flow nozzle	$E = 0.022\,\dfrac{Vj^3}{\phi}$

A2.7.2 Interfacial tension values may be significantly affected by additives and contaminants. If it is known that the value is other than 0.025 N/m, the water droplet settling velocity, W, given in section A2.8, should be modified by multiplying by Eq A2.9.

$$\left(\frac{\sigma}{0.025}\right)^{0.5} \tag{A2.9}$$

A2.8 Water Droplet Settling Velocity

A2.8.1 The determination of either of the dispersion factors requires knowledge of the water droplet settling rate, W. This can be calculated using the relationship in Eq A2.10.

$$W = \frac{855(\rho_d - \rho)E^{-0.8}}{\nu\rho^{2.2}} \tag{A2.10}$$

where:

ρ_d = water density. For salt water (from wells or tankers), a suggested value is 1025 kg/m^3 if the actual one is not available.

A2.8.2 If the mean water concentration is higher than 5 %, multiply W by 1.2.

A2.9 Turbulence Characteristic

A2.9.1 Determination of either of the dispersion factors requires the turbulence characteristics ε/D to be evaluated using Eq A2.11.

$$\frac{\varepsilon}{D} = 6.313 \times 10^{-3} V^{0.875} D^{-0.125} \nu^{0.125} \tag{A2.11}$$

A2.10 Verification of an Existing Sampler Location

A2.10.1 It is important to select the worst-case conditions in the following sequence.

A2.10.1.1 Determine the desired profile concentration ratio C_1/C_2 and, using Table A2.2, the corresponding value of G.

A2.10.1.2 Determine, using Fig. A2.1, which pipeline fittings within 30D upstream of the sampler are most likely to provide adequate dispersion.

A2.10.1.3 Estimate the energy available from each of the most likely fittings using either of the methods described in Section A2.4.

A2.10.1.4 Calculate the value of G from the highest value of available energy obtained in step (c) using the formulas presented in sections A2.3, A2.8, and A2.9.

A2.10.1.5 Obtain the C_1/C_2 ratio from Table A2.2.

A2.10.1.6 Check that the calculated C_1/C_2 (or G) value is higher than the desired value obtained in section A2.10.1.1. If it is, the sampler location should prove suitable for the application. If not, remedial action should be taken.

A2.11 Selection of a Suitable Sampler Location

A2.11.1 It is again very important to select the worst case and continue the above sequence (sections A2.10.1.1 – A2.10.1.6).

A2.11.1.1 Determine if the desired profile concentration ratio C_1/C_2 and, using Table A2.2, the corresponding value of G.

A2.11.1.2 Determine the turbulence characteristic ε/D as described in section A2.9.

A2.11.1.3 Calculate the water droplet settling rate using Eq A2.12.

$$W = \frac{\varepsilon/D}{G} \tag{A2.12}$$

A2.11.1.4 Determine the energy required to produce the desired profile concentration ratio using the formula presented in section A2.8 rewritten in the form of Eq A2.13.

$$E_r = \frac{4630}{\rho^{2.75}}\left[\frac{\rho_d - \rho}{\nu W}\right]^{1.25} \tag{A2.13}$$

A2.11.1.5 Select from Fig. A2.1 the available piping elements most likely to provide adequate energy dissipation.

A2.11.1.6 Calculate the dissipation energy E for the selected piping elements using either of the methods described in section A2.4.

A2.11.1.7 Compare E_r with E to determine if an acceptable profile can be achieved. If for any piping element $E > E_r$, then a satisfactory profile can be achieved using that element. If $E < E_r$ for all piping elements, then additional dissipation energy shall be provided. This can be done by reducing the pipe diameter (a length > 10D is recommended) by introducing an additional piping element or by incorporating a static or dynamic mixer.

A2.11.1.8 If the flow rate has been increased by reducing the pipe diameter, repeat sections A2.11.1.2 – A2.11.1.7.

A2.11.1.9 If a new piping element has been introduced into the system without changing the flow rate, check, using section A2.11.1.6, that its dissipation energy is larger than the best so far achieved and, if so, proceed to section A2.11.1.7.

A2.11.1.10 If a static or dynamic mixer is considered, then the manufacturer should be consulted as to its design and application.

A2.12 Examples of Verification of an Existing Sampler Location

A2.12.1 Using the procedure of section A2.10, for an installation in a 500 mm pipe where the most severe operating conditions are represented by:

$$\begin{gathered} V = 2\ \text{m/s} \\ \rho = 850\ \text{kg/m}^3 \\ V = 8\ \text{mm}^2\text{/s} \\ \rho_d = 1025\ \text{kg/m}^3 \end{gathered} \tag{A2.14}$$

A2.12.1.1 The desired C_1/C_2 ratio is 0.9, from Table A2.2, $G = 10$.

A2.12.1.2 The pipeline fittings within 30D upstream of the sampler are a globe valve, an enlargement with diameter ratio, $\gamma = 0.5$ and two 90° bends. Then, from Fig. A2.1, the globe valve or the enlargement is clearly most likely to provide adequate dispersion.

A2.12.1.3 The energy available may be calculated using either Method A or B of section A2.4. However, only K values are given for the globe valve; therefore, these shall be used to compare the likely mixing effects of the globe valve and the enlargement.

$$\begin{gathered} \text{Globe Valve } K = 6 \quad (\text{Table} \quad \text{A2.4}) \\ \text{Enlargement } K = \frac{(1 - \gamma^2)^2}{\gamma^4} = 9 \end{gathered} \tag{A2.15}$$

A2.12.1.4 The enlargement has the higher K value and should be used in the following calculations. Section A2.4 may be used for the rest of the calculation.

(a) Using Method A, section A2.4:

$$E = \frac{\Delta PV}{\Delta Xp}\ W/\text{kg} \tag{A2.16}$$

or as:

$$\Delta P = \frac{K\rho V^2}{2}\ W/\text{kg} \tag{A2.17}$$

then:

$$E = \frac{KV^3}{2\Delta X}\ W/\text{kg} \tag{A2.18}$$

and using $\Delta X = 10D$

$$E = \frac{9 \times 2^3}{2 \times 10 \times 0.5} = 7.2\ W/\text{kg} \tag{A2.19}$$

A2.12.1.5

$$G = \frac{\varepsilon/D}{W} \tag{A2.20}$$

$$\frac{\varepsilon}{D} = 6.313 \times 10^{-3} V^{0.375} D^{-0.125} \nu^{0.125}\ \text{m/s} \tag{A2.21}$$

$$W = \frac{855(\rho_d - \rho)}{\nu\rho^{2.2}} E^{-0.8}\ \text{m/s} \tag{A2.22}$$

$$\therefore \frac{\varepsilon}{D} = 6.313 \times 10^{-3} \times 2^{0.875} \times \frac{1}{0.5^{0.125}} \times 8^{0.12} = 16.37 \times 10^{-3}\ \text{m/s} \tag{A2.23}$$

and

$$W = \frac{855(1025 - 850)}{8 \times 850^{2.2}} \times \frac{1}{7.2^{0.8}} = 1.38 \times 10^{-3}\ \text{m/s} \tag{A2.24}$$

$$\therefore G = \frac{16.37 \times 10^{-3}}{1.38 \times 10^{-3}} = 11.83 \tag{A2.25}$$

A2.12.1.6 From Table A2.2 the C_1/C_2 ratio is greater than 0.9.

A2.12.1.7 The calculated value of C_1/C_2 is greater than the required value, and therefore, adequate conditions for sampling exist.

A2.12.1.8 Using Method B, section A2.4:

$$E = \beta E_0\ W/\text{kg} \tag{A2.26}$$

$$\beta = \frac{5(1 - \gamma^2)^2}{\gamma^4} = 45 \quad (\text{Table} \quad \text{A2.4}) \tag{A2.27}$$

$$E_0 = 0.005\nu^{0.25} D^{-1.25} V^{2.75} \tag{A2.28}$$

$$\therefore E = 45 \times 0.005 \times 8^{0.25} \times \frac{1}{0.5^{1.25}} \times 2^{2.75} = 6.0545\ W/\text{kg} \tag{A2.29}$$

A2.12.1.9

$$G = \frac{\varepsilon/D}{W} \quad (\text{Table} \quad \text{A2.2}) \tag{A2.30}$$

$$\varepsilon/D = 16.37 \times 10^{-3}\ \text{m/s} \tag{A2.31}$$

as calcualted for Method A:

$$W = \frac{855(\rho_d - \rho)}{\nu\rho^{2.2}} E^{-0.8}\ \text{m/s} \tag{A2.32}$$

$$= \frac{855(1025 - 850)}{8 \times 850^{2.2}} \times \frac{1}{6.0545^{0.8}} = 1.59 \times 10^{-3}\ \text{m/s} \tag{A2.33}$$

$$\therefore G = \frac{16.37 \times 10^{-3}}{1.59 \times 10^{-3}} = 10.29 \tag{A2.34}$$

A2.12.1.10 Follow sections A2.12.1.5 and A2.12.1.6 for Method A.

A2.12.2 *Example of Selection of a Suitable Sampler Location Using the Procedure of Section A2.11:*

A2.12.2.1 The proposed pipeline configuration consists of a 600-mm line enlarging to 800 mm followed by a line of three 90° bends each with an r to D ratio of 1 and finally a throttling valve with the differential pressure of one bar. The most severe operating conditions are represented by the following conditions:

$$\begin{gathered} V = 1.5\ \text{m/s} \\ \rho = 820\ \text{kg/m}^3 \\ \nu = 7\ \text{cSt} \\ \rho_d = 1025\ \text{kg/m}^3 \end{gathered} \tag{A2.35}$$

A2.12.2.2 The desired C_1/C_2 ratio is 0.9; then, from Table A2.2, $G = 10$.

A2.12.2.3 The turbulence characteristic from section A2.9 is:

$$\varepsilon/D = 6.313 \times 10^{-3} V^{0.875} D^{-0.125} \nu^{0.125} \text{ m/s} \tag{A2.36}$$

$$= 6.313 \times 10^{-3} \times 0.5^{0.875} \times \frac{1}{0.8^{0.125}} \times 7^{0.125} = 11.81 \times 10^{-3} \text{ m/s} \tag{A2.37}$$

A2.12.2.4 The water droplet settling velocity is:

$$W = \frac{\varepsilon/D}{G} = \frac{11.81 \times 10^{-3}}{10} = 1.18 \times 10^{-3} \text{ m/s} \tag{A2.38}$$

A2.12.2.5 The energy dissipation rate required per Eq A2.39 is:

$$E_r = \frac{4630}{\rho^{2.75}} \left[\frac{\rho_d - \rho}{\nu W} \right]^{1.25} \tag{A2.39}$$

$$= \frac{4630}{820^{2.75}} \left(\frac{1025 - 820}{7 \times 1.18 \times 10^{-3}} \right)^{1.25} = 13.99 \ W/\text{kg} \tag{A2.40}$$

A2.12.2.6 From Fig. A2.1, the throttling valve is clearly the element most likely to provide sufficient energy dissipation.

A2.12.2.7 Method B is the only one to provide an energy dissipation formula for a throttling valve; see Table A2.5.

$$\therefore E = \frac{\Delta P V}{20 \rho D} \ W/\text{kg}$$

$$= \frac{1 \times 10^5 \times 1.5}{20 \times 820 \times 0.8} [1 \quad \text{bar} \quad = \quad 10^5 \quad \text{Pascal}] \tag{A2.41}$$

$$= 11.43 \ W/\text{kg}$$

A2.12.2.8 The energy dissipation rate E provided by the throttling valve is less than required E_r. Therefore, a G value of 10 has not been achieved and sampling from this location is unlikely to prove adequate. If the enlargement from 600 to 800 mm is moved downstream of the throttling valve and sampling location, then the following recalculation applies with $D = 0.6$ m and $V = 2.67$ m/s:

A2.12.2.9

$$\frac{\varepsilon}{D} = 6.313 \times 10^{-3} \times 2.67^{0.875} \times \frac{1}{0.6^{0.125}} \times 7^{0.125} \text{ m/s} = 20.25 \times 10^{-3} \text{ m/s} \tag{A2.42}$$

A2.12.2.10

$$W = \frac{\varepsilon/D}{G} = \frac{20.25 \times 10^{-5}}{10} = 2.02 \times 10^{-3} \text{ m/s} \tag{A2.43}$$

A2.12.2.11

$$E_r = \frac{4630}{820^{2.75}} \left[\frac{1025 - 820}{7 \times 2.02 \times 10^{-3}} \right]^{1.25} W/\text{kg} = 7.13 \ W/\text{kg} \tag{A2.44}$$

A2.12.2.12 Unchanged from previous calculation.

A2.12.2.13

$$E = \frac{\Delta P V}{20 \rho D} \ W/\text{kg} \tag{A2.45}$$

$$= \frac{10^5 \times 2.67}{20 \times 820 \times 0.6} \tag{A2.46}$$

$$= 27.10 \ W/\text{kg}$$

A2.12.2.14 The energy dissipation rate provided by the throttling valve located in the smaller diameter pipe is more than sufficient to give a G value of 10. Adequate sampling should therefore be possible.

A3. PERFORMANCE CRITERIA FOR PORTABLE SAMPLING UNITS

A3.1 Representative sampling is more difficult to document and verify when a portable sampler is used. The flow sensing device is usually limited in accuracy and turndown. Stream conditioning is usually limited to piping elements and flow velocity. The sampler controller data logging is usually limited. Special precautions and operating procedures with additional record keeping by the operator can overcome these limitations. For more information regarding Performance Monitoring, refer to section 18.7.

A3.2 Calculations before Operation

PV_e = batch parcel volume expected from the sampling system batch setup,

B = expected extractor grab size as determined by prior testing (see 11.1),

SV_e = sample volume expected to be collected from the sampling system setup (see 14.3.1), and

N_e = total number of grabs expected from the sampling batch setup (see 14.3.2).

$$N_e = \frac{SV_e}{b} \tag{A3.1}$$

B = frequency of sampling in grab/unit volume put into controller (see 14.3.3).

$$B = \frac{PV_e}{N_e} \tag{A3.2}$$

A3.3 Data from the Sampling Operation

N = total number of grabs recorded by the controller,

SV = sample volume collected in the primary container,

PV_s = batch parcel volume as measured by sampler flow-sensing device, and

PV_{co} = custody transfer volume.

A3.4 Calculation of Performance Report

A3.4.1 The following calculations can be helpful in evaluating if a sample is representative:

A3.4.2 *Grab Factor (GF):*

$$GF = \frac{SV}{N \times b} = 1 \ \pm 0.05 \qquad (A3.3)$$

A3.4.3 *Modified Performance Factor (PF_m):*

$$PF_m = \frac{SV}{\frac{PV_s}{B} \times b} = 1 \pm 0.10 \qquad (A3.4)$$

A3.4.3.1 PV_s is normally not available. When this is the case, use PV_{co} that excludes the effect of flow sensor malfunction or inaccuracy on PF_m. If PV_s is available from the controller, calculate PF as in 18.7.

A3.4.4 *Flow Sensor Accuracy (SA)*—The volume as measured by the sampler(s) flow sensor(s) is normally not available. The volume measured by the flow sensor(s) is calculated from the number of grabs ordered by the controller(s).

$$SA = \frac{N \times B}{PV_{co}} = 1 \pm 0.10 \qquad (A3.5)$$

A3.4.5 *Sampling Factor (SF):*

$$\text{Sampling Factor} = \frac{\text{Total sampling time}}{\text{Total parcel time}} = 1 \text{ at } \pm \ 0.05 \qquad (A3.6)$$

A3.4.6 *Stream Conditioning:*

A3.4.6.1 For 95 % of the parcel volume, the flow rate in piping ahead of the sampler(s) was a minimum of 2 m/s.

Yes _____ No _____

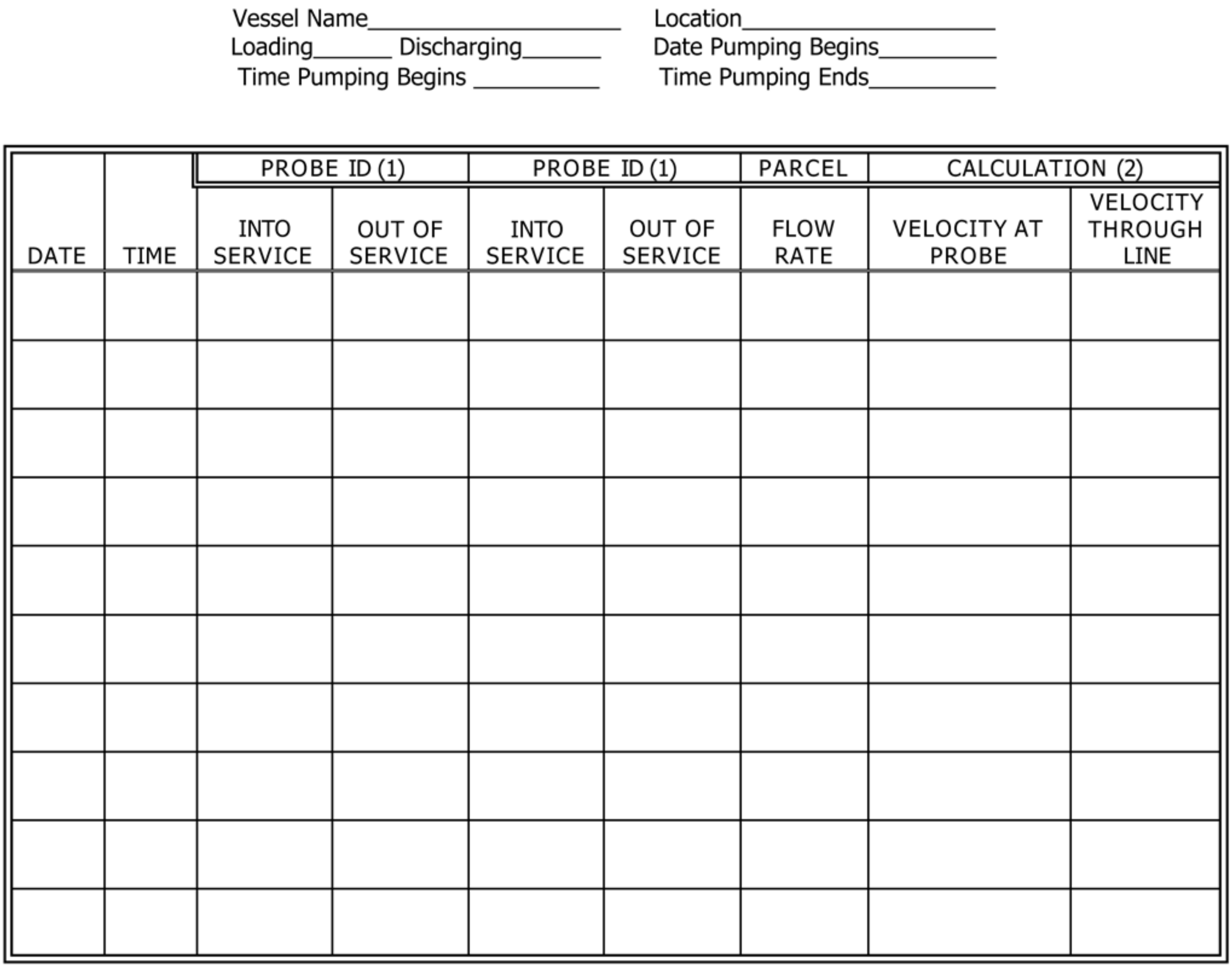
A3.4.6.2 No more than 10 % of the total free water in the tanks/compartments was pumped at flow rates of less than 2 m/s.

Yes _____ No _____

A3.4.6.3 The criteria for stream conditioning are met if both answers are "Yes."

A3.5 Line and Manifold Data

A3.5.1 Complete forms as outlined in Figs. A3.1-A3.4 for each sample.



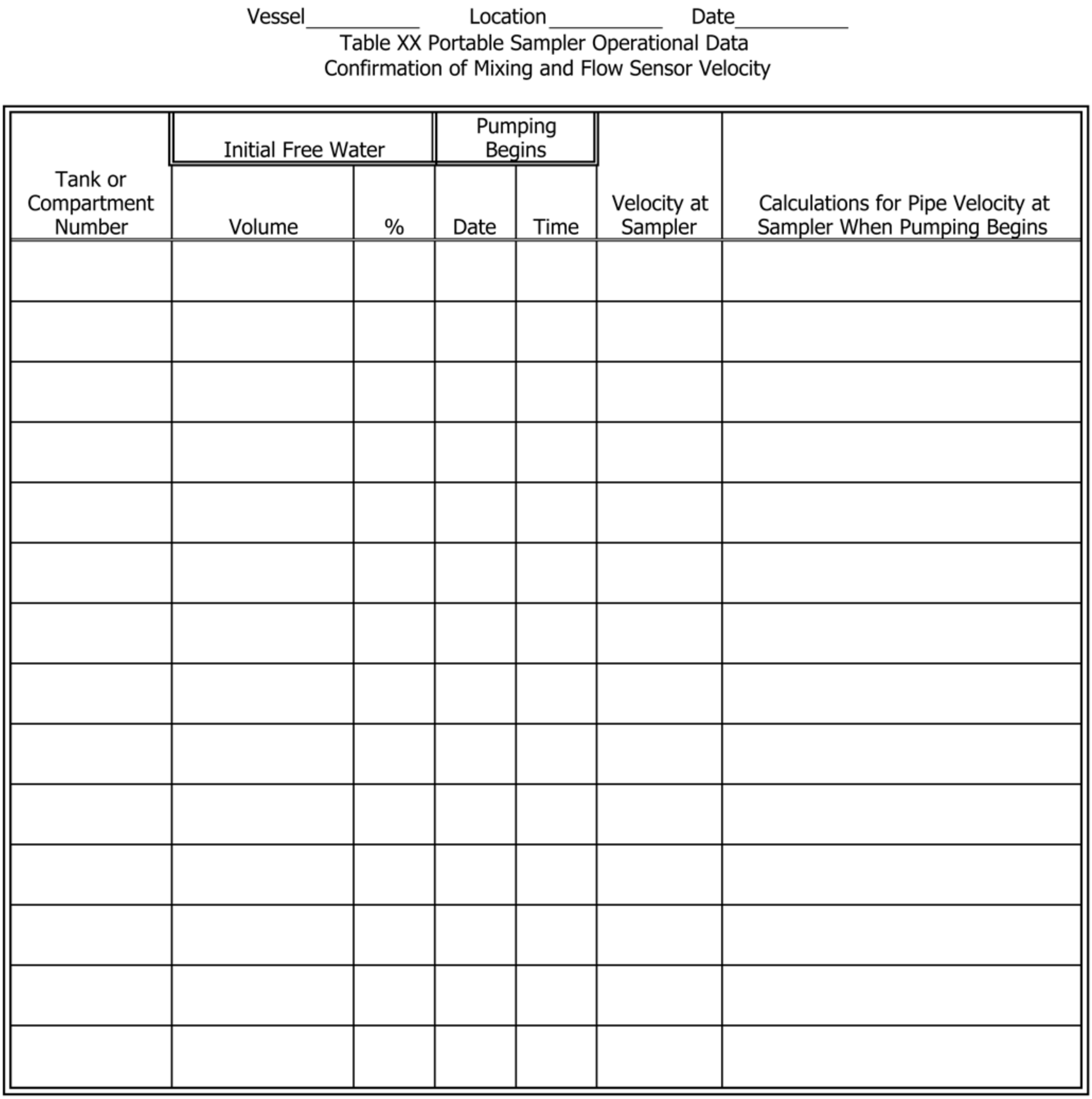
Vessel Name____________________ Location____________________
Loading______ Discharging______ Date Pumping Begins_________
Time Pumping Begins __________ Time Pumping Ends__________

		PROBE ID (1)		PROBE ID (1)		PARCEL	CALCULATION (2)	
DATE	TIME	INTO SERVICE	OUT OF SERVICE	INTO SERVICE	OUT OF SERVICE	FLOW RATE	VELOCITY AT PROBE	VELOCITY THROUGH LINE

NOTE 1—Line No. = Identification letter or number from FIGS A32.3 or A3.4.

NOTE 2—Velocities should be calculated for lines A to D in FIG A3.4 as major rate changes occur and arms/hoses are added or removed from service. The same applies to spools I to IV on the vessel. The same applies for lines and spools designated I to IV in FIG A3.3.

FIG. A3.1 Portable Sampler Operational Data Confirmation of Mixing and Flow Sensor Velocity

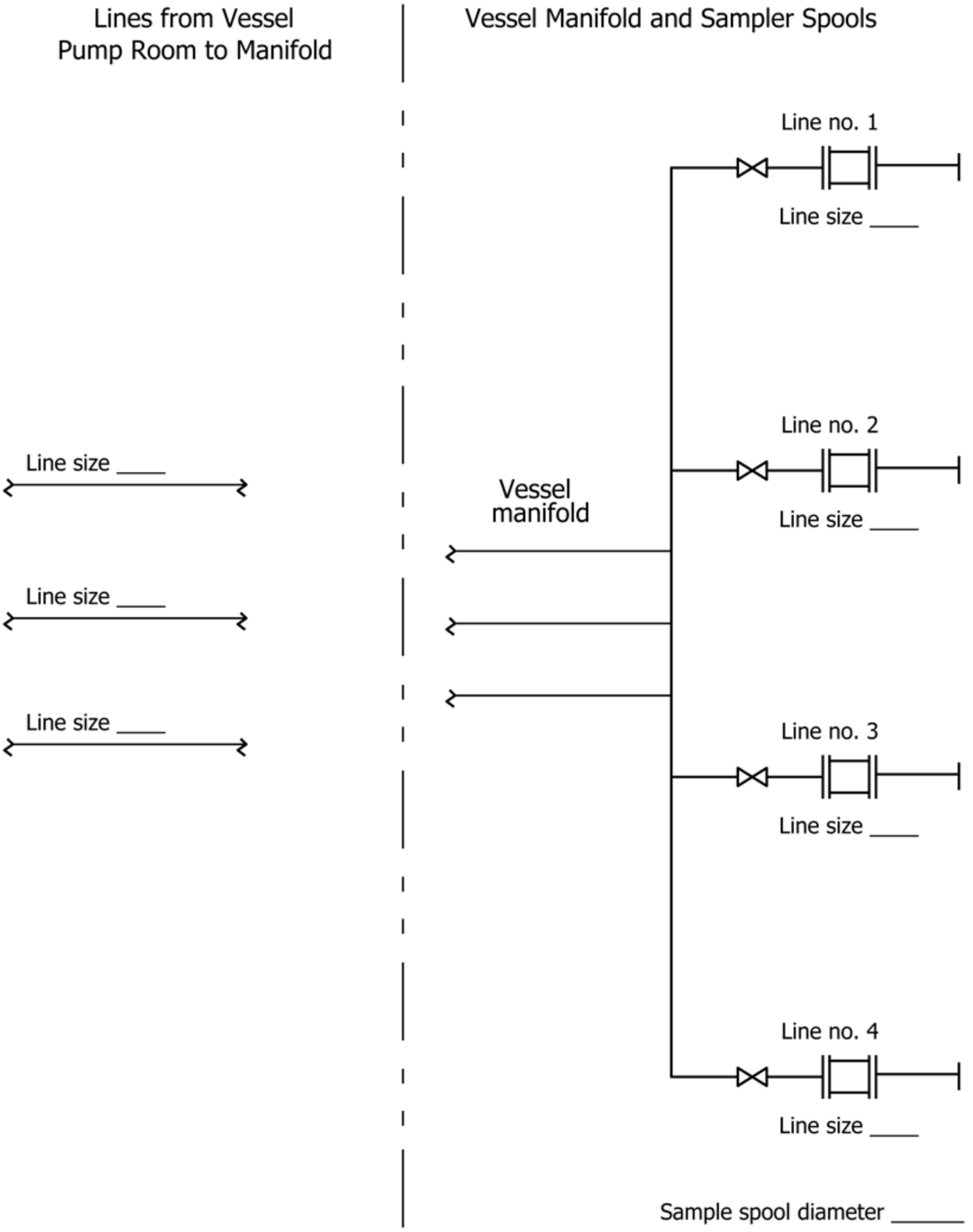


Vessel__________ Location__________ Date__________

Table XX Portable Sampler Operational Data
Confirmation of Mixing and Flow Sensor Velocity

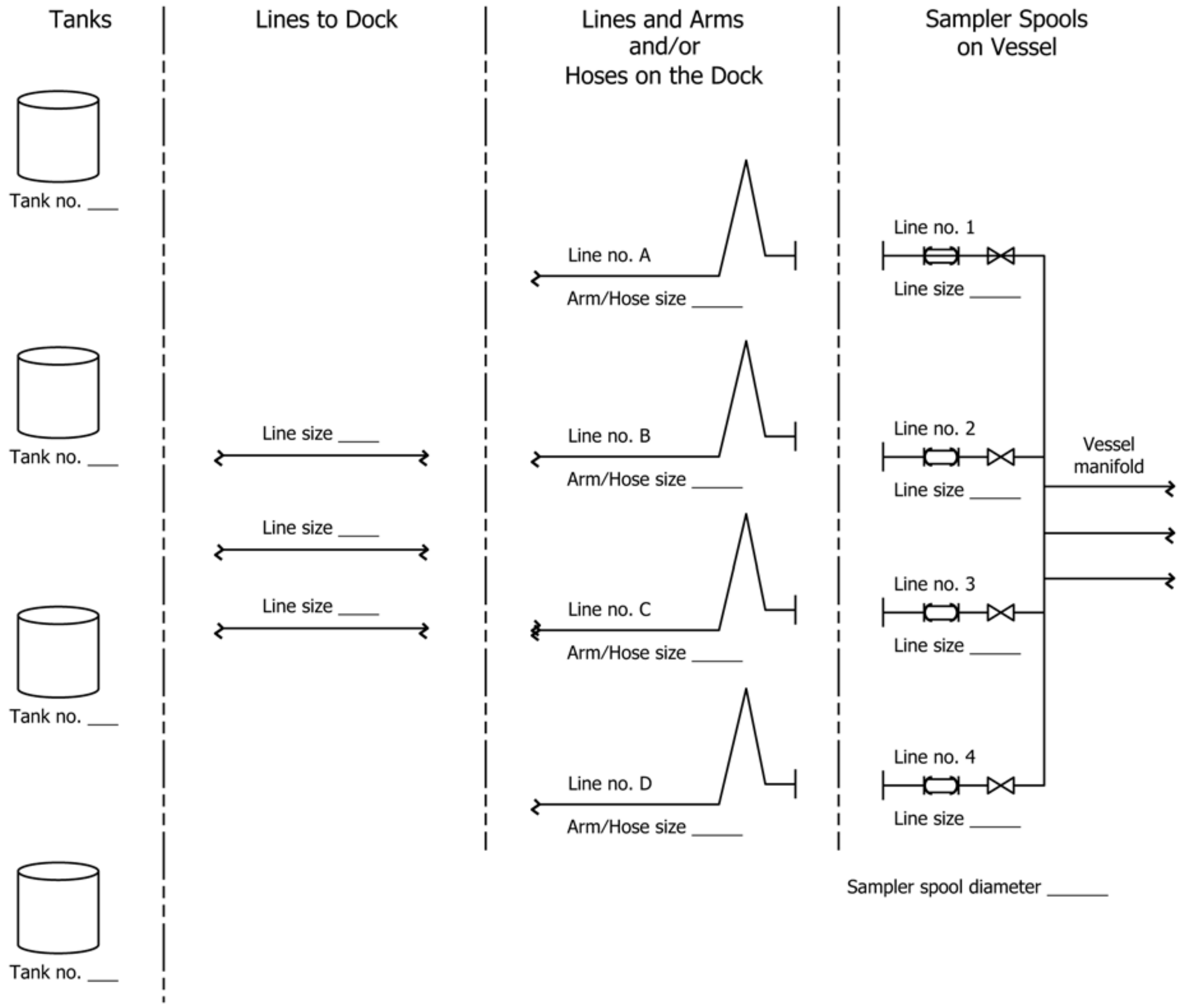
Tank or Compartment Number	Initial Free Water		Pumping Begins		Velocity at Sampler	Calculations for Pipe Velocity at Sampler When Pumping Begins
	Volume	%	Date	Time		

FIG. A3.2 Portable Sampler Operational Data Confirmation of Free Water Sampled



Note—In the spaces provided, enter the tank numbers and line sizes used during discharges.

FIG. A3.3 Typical Piping Schematic to be Recorded for Discharges



NOTE—In the spaces provided, enter the line sizes used during loading.

FIG. A3.4 Typical Piping Schematic to be Recorded for Loading

A4. PROFILE PERFORMANCE TEST

A4.1 Profile Test to Determine Stream Condition

A4.1.1 The extent of stratification or non-uniformity of concentration can be determined by taking and analyzing samples simultaneously at several points across the diameter of the pipe. The multipoint probe shown in Fig. A4.1 is an example of a profile probe design. This test should be conducted in the same cross section of pipe where the sample probe will be installed.

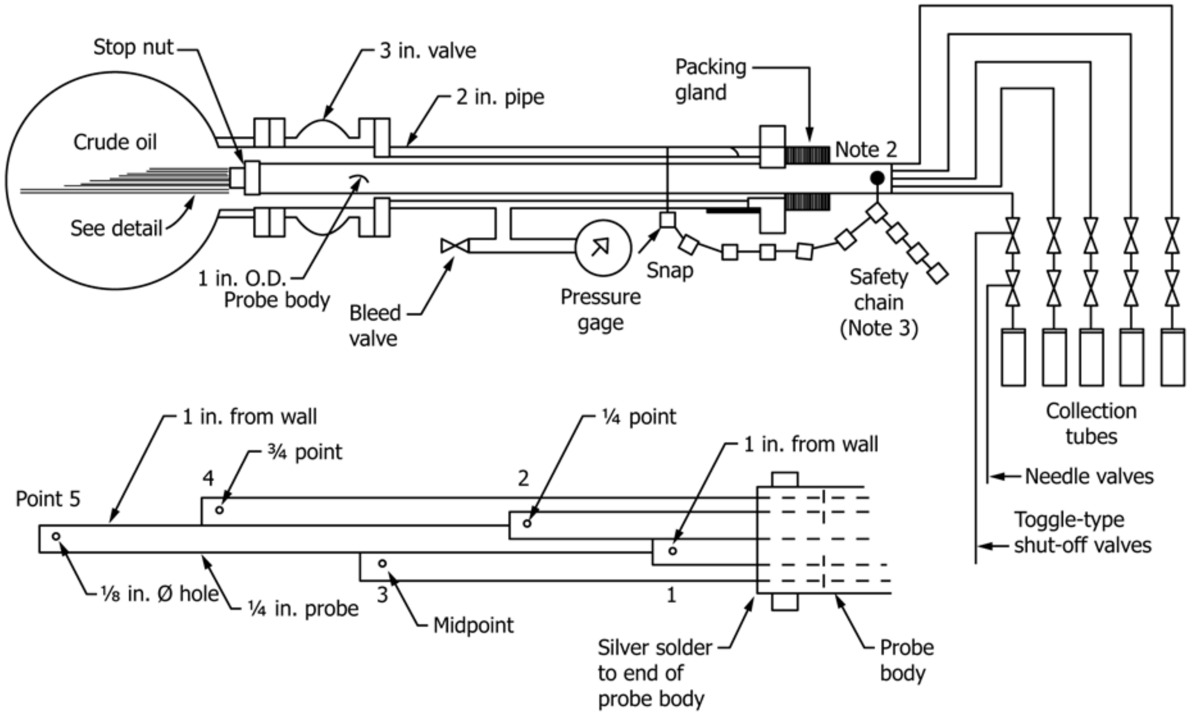
A4.1.2 *Criteria for Uniform Dispersion and Distribution*—A minimum of five profile tests meeting criteria in A4.3.2. If three of those profiles indicate stratification, the mixing in the line is not adequate.

A4.1.3 *Profile Probe*—A probe with a minimum of five sample points is recommended for 30 cm pipe or larger. Below 30 cm pipe size, three sample points are adequate.

A4.1.4 *Sampling Frequency*—Profile samples should not be taken more frequently than at 2 min intervals.

A4.1.5 *Probe Orientation*—Profiles in horizontal lines shall be taken vertically, whereas profiles in vertical lines should be taken horizontally.

A4.1.6 *Test Conditions*—The test should be set up to measure the worst-case conditions including the minimum flow rate and lowest flow viscosity and density or other conditions as agreed upon.



NOTE 1—For pipes less than 30 cm, delete the ¼ and ¾ points.

NOTE 2—The punch mark on probe sleeve identifies the direction of probe openings.

NOTE 3—When the probe is fully inserted, take up the slack in the safety chains and secure the chains tightly.

NOTE 4—The probe is retractable and is shown in the inserted position.

FIG. A4.1 Multi Probe for Profile Testing

A4.1.7 *Water Injection*—The water injection method described in testing automatic sampling systems (see A4.3.2 and A4.4.1.3) is recommended.

A4.1.8 *Sampling*—Sampling should begin 2 min before the calculated water arrival time and continue until at least ten profiles have been taken.

NOTE A4.1—Probe installation and operation are covered in A4.4. As a safety precaution, the probe should be installed and removed during low-pressure conditions. However, the probe should be equipped with safety chains and stops to prevent blowout should it be necessary to remove it during operation conditions.

A4.2 Definitions of Terms Specific to This Standard

A4.2.1 The following definitions are included as an aid in using Tables A4.1 and A4.2 for profile test data and point averages and deviation.

A4.2.1.1 *minimum flow rate, n*—lowest operating flow rate, excluding those rates which occur infrequently (that is, one of ten cargoes) or for short time periods (less than 5 min).

A4.2.1.2 *overall profile average, n*—average of all point averages.

A4.2.1.3 *point, n*—single sample in a profile.

TABLE A4.1 Typical Profile Test Data, in Percent by Volume of Water

NOTE 1—For invalid sample or missed data point, the point should be shown as missing data and the remaining data averaged.

Profile	Point (Percent by Volume – Water)				
	A Bottom	B ¼ Point	C Midpoint	D ¾ Point	E Top
1	0.185	0.096	0.094	0.096	0.096
2	0.094	0.182	0.135	0.135	0.135
3	13.46	13.72	13.21	12.50	12.26
4	8.49	7.84	8.65	8.65	8.33
5	6.60	7.69	7.69	6.60	8.00
6	6.73	7.02	6.48	6.73	5.38
7	7.88	6.73	6.73	7.27	5.96
8	2.78	3.40	3.27	3.08	2.88
9	1.15	1.36	1.54	1.48	1.32
10	0.58	0.40	0.48	0.55	0.47

TABLE A4.2 Calculation of Point Averages and Deviation

NOTE 1—The system is rated with respect to the worst point average in the test: point average E has the largest deviation (–0.28).

NOTE 2—For representative sampling, the allowable deviation is 0.05 % water for each 1 % water in the overall profile average. In this example, the allowable deviation is given by the (5.69 × 0.05) % *W* = ±0.28 % *W*.

	Point (Percent Volume – Water)					Average E Percent
	A	B	C	D	E	
Average of profiles 4 through 9	5.61	5.67	5.73	5.64	5.31	5.59
Deviation from overall profile average (Note 1) (percent water)	+ 0.02	+ 0.08	+ 0.14	+ 0.05	0.28	
Allowable deviation (Note 2)	(5.59 × 0.05) percent water = ±0.28 percent water					

A4.2.1.4 *point average, n*—average of the same point from all profiles (excluding profiles with less than 1.0 % water).

A4.2.1.5 *profile, n*—multi-point samples taken simultaneously across a diameter of the pipe.

A4.3 Application of Dispersion Criteria

A4.3.1 Table A4.2 lists data accumulated during a typical profile test. Units are percent volume of water detected. Approximately 1000 barrels of seawater were added to a center compartment of a 76 000 dead weight ton crude oil tanker. The quantity of water was verified by water cut measurements shortly before the loading operation.

A4.3.2 To apply the dispersion criteria, it is best to eliminate all profiles with less than 0.5 % water and the profile taken in the leading edge of the water (which occurs in Profile 3 of Table A4.2). Typically, a profile of the leading edge is erratic with respect to water dispersion. While it is a useful means of verifying arrival time, it hinders evaluation of profile data and can cause an unnecessarily reduced profile test rating. Calculate the point average and deviation for all other profiles with 1 % or more water.

A4.4 Water Profile Test Procedures

A4.4.1 Refer to Fig. A4.1 while following the steps of this procedure.

A4.4.1.1 Install profile probe in line. Check that the probe is properly positioned and safely secured.

A4.4.1.2 Position a slop can under the needle valves. Open the shut-off and needle valves and purge the probes for 1 min (or sufficient time to purge ten times the volume in the probe line).

A4.4.1.3 Adjust needle valves so that all sample containers fill at equal rates.

A4.4.1.4 Close shut-off valves.

A4.4.1.5 Open the shut-off valves, purge the probe lines, and quickly position the five sample containers under the needle valves. Close shut-off valves.

A4.4.1.6 Repeat A4.4.1.5 at intervals of not less than 2 min until a minimum of ten profiles have been obtained.

A4.5 Sample Probe/Extractor Test

A4.5.1 The grab size should be repeatable within ±5 % over the range of operating conditions. Operating parameters that may affect grab size are sample viscosity, line pressure, grab frequency, and back pressure on the extractor.

A4.5.2 Test the sample probe/extractor by collecting 100 grabs in a graduated cylinder and calculate the average grab size. Perform the test at the highest and the lowest oil viscosity, pressure, and grab frequency.

A4.5.3 The average grab size will determine if the target number of grabs will exceed filling the sample receiver above the proper level. The average grab size is also used in determining the sampler performance (see Annex A3 and Annex A5).

A5. SAMPLER ACCEPTANCE TEST DATA

A5.1 Fig. A5.1 is an example of the sampler acceptance test data sheet.

SAMPLER ACCEPTANCE TEST DATA SHEET

COMPANY: _________________ LOCATION: ___________________ SAMPLER ID: _________________ TEST# ______ OF ______

DATE: ______________ COMPANY WITNESS: _________________ OTHER WITNESS: ____

SYSTEM DATA CRUDE GRADE: __________ __________	VISCOSITY: ________ cSt / cP VISC TEMP: ________ °F/°C	API: ________ API TEMP: ________ °F/°C	FLOW TEMP: ______ °F/°C INTERFACIAL TENSION ______________ ____	FLOW RATE: _______ (bbl/h)/(m^3/h) VELOCITY: _______ (f/s)/(m/s)	LINE SIZE: _____ in

CRUDE VOLUME DETERMINATION BY: _____ METER _____ TANK TANK INCREMENTS VOL. __________ bbl/m^3 SAMPLER RECEIVER VOLUME: _________ gal/L TEST SAMPLER VOLUME: ______________ gal/L	PROBE DESIGN: _____ ISOKINETIC _____ ELL _____ BEVELED _____ PLAIN _____ OTHER _____ GRAB SIZE (mL)	PROBE ORIENTATION: _____ TOP _____ SIDE _____ BOTTOM _____ SAMPLE _____ LOOP	STREAM CONDITION: _____ POWER MIXING _____ STATIC MIXER-VERTICAL _____ STATIC MIXER-HORIZONTAL _____ PIPING ELEMENT-VERTICAL _____ PIPING ELEMENT-HORIZONTAL _____ NONE	LABORATORY ANALYSIS: _____ CENTRIFUGE _____ DISTILLATION _____ KARL FISCHER _____ MASS _____ VOLUME TEST WATER: _____ FRESH _____ BRACKISH SEA _____ PRODUCTION

TEST DATA

BASELINE TEST DATA

1. SINGLE SAMPLER METHOD BASELINE TEST

(W_{avg}) = (1ST BASELINE ____________ % + 2ND BASELINE __________ %) /2 = _________ %

2. DUAL SAMPLER METHOD BASELINE TEST:

A. BEFORE WATER INJECTION COMPARISON TEST

FIG. A5.1 Sampler Acceptance Test Data Sheet

(BASELINE SAMPLER ________________ % – PRIMARY SAMPLER __________%)
= ___________ %
MAXIMUM DEVIATION FROM TABLE A-1
= ___________ %

B. DURING WATER INJECTION TEST: (W_{avg}) = ___________ %

WATER INJECTION AND CRUDE VOLUMES:

3. WATER INJECTED (V)

STOP METER TOTALIZER ___________ gal/L
START METER TOTALIZER ___________ gal/L
V= DIFFERENCE ___________ gal/L × ___________ × ______________________ = ___________ bbl/m^3
(METER FACTOR) (0.0238 gal/bbl OR 0.001 L/m)

---

4. CRUDE VOLUME

STOP TANK OR METER TOTALIZER ___________ bbl/m^3
START TANK OR METER TOTALIZER ___________
DIFFERENCE ___________ bbl/m^3 × ____
= ___________ bbl/m^3

---

5. TOV (LINE 3+ LINE 4) = ___________ bbl/m^3

CALCULATIONS:

D_{ev} = (W_{test} + W_{bl}) – W_{ing}
WHERE:
W_{test} = PERCENT WATER IN TEST SAMPLE

6. W_{BL} = W_{avg} × [(TOV – V) / TOV]
= ______________________ × [(____________ – ___________) / __________ = ___________ %
(LINE 1 OR 2 B) (LINE 5) (LINE 3) (LINE 5)

7. W_{inj} = (V/TOV) × 100
= (_______________________ / ___________) × 100 = ___________ %
(LINE 3) (LINE 5)

D_{ev} = (_______________________ – _____________) – _________________________ = ___________ %
(W_{test}) (LINE 6) (LINE 7)
MAXIMUM DEVIATION FROM TABLE A-1 = ___________ %

Comments:

____

Notes:

1. All percent figures are percent volume
2. Correct the volume of water injected for solids content, as applicable, if production water is used.
3. Deviation must be within limits outline in MPMS Chapter 8.2, Table A-1
4. Notes below any physical or procedural changes made between consecutive test runs.
   Attach copy of sampler receiver-mixer proving test reports. See MPMS Chapter 8.3.

FIG. A5.1 Sampler Acceptance Test Data Sheet *(continued)*

APPENDIXES

(Nonmandatory Information)

X1. DESIGN DATA SHEET FOR AUTOMATIC SAMPLING SYSTEM

X1.1 Fig. X1.1 is a sample of the design data sheet for an automatic sampling system.

DESIGN SHEET FOR AUTOMATIC SAMPLING SYSTEMS

Process Data

Type of Product
Density or API Gravity
- Maximum ________________
- Minimum _________________
- Normal ___________________

Viscosity (cSt)
- Maximum _______________
- Minimum ________________
- Normal __________________

Vapor Pressure
- Maximum ______________
- Minimum _______________
- Normal ________________

Sediment and Water Content (Volume %)
- Maximum ______________
- Minimum _______________
- Normal ________________

Other Physical Properties

Design Data

Pipeline I.D.
Design Pressure
Operating Pressure
- Maximum ________________
- Minimum _________________
- Normal ___________________

Flow Rate
- Maximum ________________
- Minimum _________________
- Normal ___________________

Operating Temperature
- Maximum ________________
- Minimum _________________
- Normal ___________________

Parcel or Batch Size
Maximum ______________ Minimum _____________

Ambient Temperature
- Maximum ________________
- Minimum _________________
- Normal ___________________

Other Information

Sampler Data

Grab Size (mL/grab)
Collection Period: Hours ____ Days ___ Weeks _____
Probe Insertion Length Required _________
Air Pressure ____psi
Electricity Voltage ___volts
Proportional to Time ______ Flow________
Meter Manufacturer
Type __________________________
Signal _________________________

Sample Container

Total Volume _______________________
Design Pressure ___________________
Material of Construction ______________
Internal Coating_____________________
Portable_________ Fixed ________
Accessories:
Pressure Relief Valve ______ (setting)
Vacuum Relief _____(setting)
Pressure Gauge ______

Sampler Controller Alarms

High Level Alarm ______
Level Indication ______
Weight of container (scales) ________
Other

System Specifications

Installation:
Permanent_____________ Portable___________
Electrical Classification at Proposed Site __________

Available Utilities
Electrical: Voltage _____ Hz_____ Phase______
Air: Pressure _______ Instrument_________
Steam: Pressure __________ Temperature_______

Notes:

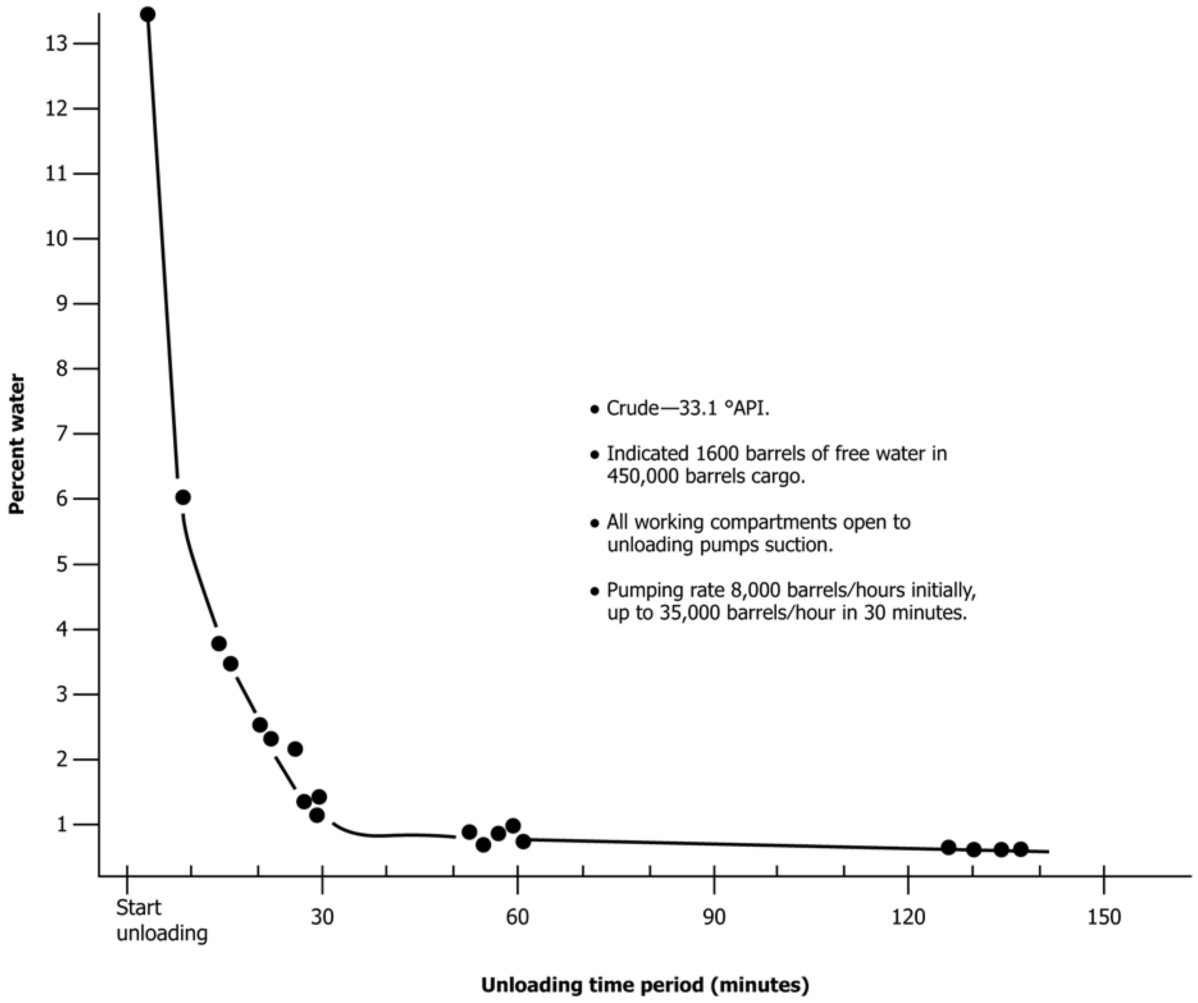
Company _______________________
Address _______________________
Date Prepared ___________________

Proiect Name _________________________
Date Required ________________________

FIG. X1.1 Design Data Sheet for Automatic Sampling System

X2. COMPARISON OF PERCENT SEDIMENT AND WATER VERSUS UNLOADING TIME PERIOD

X2.1 Fig. X2.1 presents a comparison of percent sediment and water versus unloading time period (API *MPMS* Chapter 10).



- Crude—33.1 °API.
- Indicated 1600 barrels of free water in 450,000 barrels cargo.
- All working compartments open to unloading pumps suction.
- Pumping rate 8,000 barrels/hours initially, up to 35,000 barrels/hour in 30 minutes.

FIG. X2.1 Comparison of Percent Sediment and Water versus Unloading Time Period

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SUMMARY OF CHANGES

Subcommittee D02.02 has identified the location of selected changes to this standard since the last issue (D4177 – 15) that may impact the use of this standard. (Approved Oct. 1, 2015.)

(1) Revised subsections 18.4.7, 18.6.8.7, 18.6.8.14, and 18.6.8.15.
(2) Added new subsection 18.6.6.
(3) Revised Fig. 2.

Subcommittee D02.02 has identified the location of selected changes to this standard since the last issue (D4177 – 95 (2010)) that may impact the use of this standard. (Approved May 15, 2015.)

(1) Complete rewrite of practice to make it more performance based.

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