KLM Technology Group
#03-12 Block Aronia,
Jalan Sri Perkasa 2
Taman Tampoi Utama
81200 Johor Bahru
Malaysia

GUIDELINES FOR FLOW MEASUREMENT

(PROJECT STANDARDS AND SPECIFICATIONS)

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SCOPE

This Project Standard and Specification defines minimum requirements for design, selection, materials, construction, and installation of flow and differential pressure measurement devices.

REFERENCES

Throughout this Standard the following dated and undated standards/codes are referred to. These referenced documents shall, to the extent specified herein, form a part of this standard. For dated references, the edition cited applies. The applicability of changes in dated references that occur after the cited date shall be mutually agreed upon by the Company and the Vendor. For undated references, the latest edition of the referenced documents (including any supplements and amendments) applies.

1. American Gas Association (AGA)

   “Measurement of Gas by Turbine Meters, Report No. 7”

2. American Petroleum Institute (API)

RP 551	“Process Measurement Instrumentation”
	“Manual of Petroleum Measurement Standards”

3. American Society of Mechanical Engineers (ASME)

B16.36	“Orifice Flanges”
B109.3	“Rotary Type Gas Displacement Meters”
MFC-1M	“Glossary of Terms Used in the Measurement of Fluid Flow in Pipes”
MFC-14M	“Measurement of Fluid Flow Using Small Bore Precision Orifice Meters”
PTC-6	“Performance Test Codes”

4. Gas Processors Association (GPA)

   “Standards and Recommended Practices”

PHILOSOPHY

General

Design, application, and installation of flow instruments for process control application shall comply with API RP 551. More stringent requirements for custody transfer applications are described later.
Flow shall be measured with a primary flow element.
This Project Standard and Specification includes devices used to measure liquids, vapors, and gases. Unless specified otherwise, dense phase fluids (fluids above the critical point) shall be treated as gases.
Industry standards for flow measurement include API Manual of Petroleum Measurement Standards (MPMS), GPA Standards and Recommended Practices, Institute of Petroleum (UK) documents, AGA, ASME, and International Standards Organization documents.

Selection of Flow Elements

Table 1 provides general information to aid in selection of primary flow elements. Specific instructions are included in applicable sections of this specification.
If more than one type of flow element will meet application requirements, the following shall be considered to ensure proper selection:

- A flow system, not individual flow element, shall be evaluated. System typically includes primary element and transducer transmitter, and/or relay.
- Installation costs.

Use of flow elements other than concentric orifices shall be subject to Purchaser approval.

Basis for Sizing Flow Elements

1. Calculations for sizing of concentric square edged orifice plates shall comply with API MPMS, Chapter 14.3. Flow calculations shall be based on 1990 API equation.
2. Elements shall be sized to give even scale or chart factors.
3. Unless approved otherwise, beta ratios shall preferably be between 0.2 and 0.65. Beta shall never exceed 0.7.
4. Flow instruments shall be sized such that normal flow for:
   - Head types is 80% to 90% of expected maximum.
   - Other types is 90% of expected maximum.

5. For liquid applications, lowest pressure generated by flow element shall be above vapor pressure.
6. The following units of measurement shall be used for flow instruments:
   a. Oil - barrels (42 gallons) per hour (bbl/hr) at 60°F.
   b. Steam - pounds per hour (lb/hr) or 1000 (M) lb/hr.
   c. Water - gallons per minute (gpm) at 60°F.
   d. Air-Gas - standard cubic foot per hour (SCFH) or thousand cubic foot per hour (MSCFH) at 60°F and 14.65 psia.
   e. Liquid Products - bbl/hr at 60°F.

Straight Run Requirements

1. Straight runs before and after a head type primary flow element shall be maximized to provide for lower measurement uncertainty.
2. Minimum straight run length requirements before and after a head type primary flow element shall comply with the more stringent of the following:
   - Beta = 0.8 orifice meter
   - Manufacturer’s recommendations.
3. Flow conditioners may be used to reduce minimum straight run length requirements. Use of flow conditioners shall require Owner approval.
4. Straight run lengths for turbine meters shall comply with API MPMS, Chapter 5.3.
5. Straight runs shall have smooth concentric pipe 5 pipe diameters immediately upstream of flow element. Smooth concentric pipe shall comply with out of roundness and smoothness requirements of API MPMS for each type of flow element.
6. Temperature wells or pressure connections shall not be located in straight run before flow elements. Temperature wells and pressure connections may be located 5 diameters downstream of any meter.
7. Upstream and downstream straight run sections in dirty services shall be flanged to facilitate removal for cleaning.
8. Variable area flow meters and positive displacement meters that do not have upstream straight run length requirements shall be exempted.

Requirements for Removal of Insertion Type Flow Elements

Critical service is defined as that part of process in which flow interruption or stoppage would have significant impact on facility operations and/or profitability.
Flow elements in critical services shall be capable of being taken out of service during unit operation.

Removal capability may be provided by:

- Flow assemblies that are fully retractable under line pressure and process temperature. Such assemblies shall have proper mechanism(s) to ensure safe operation.
- Isolation block and bypass valves, such that flow assembly can be removed from service without interrupting process flow.

Local Flow Indicator

Flow control loops that include a control valve shall have local flow indication. Local flow indicator shall be located such that it can be easily read from control valve bypass valve.
Local electronic flow indicators shall meet electrical area classification.
Local pneumatic flow indicator shall be a 3-1/2 inch receiver gage.

Custody Transfer

1. Meters used for custody transfer shall comply with API MPMS and GPA Standards and Practices.
2. Except for positive displacement meters and variable area meters, use of flow conditioners is recommended for custody transfer of clean fluids. Location of flow conditioners shall comply with MPMS and/or AGA standards.
3. Liquid turbine meters shall have flow conditioners in accordance with the API MPMS.
4. Use of flow conditioners shall be subject to Purchaser approval.
5. Beta ratios for orifice elements shall be 0.35 <= beta <= 0.6 and shall be sized for flange taps only. This may require a line size change.
6. Upstream and downstream meter runs for orifice flow runs shall be certified meter tubes.
7. Exact API specifications for orifice plate thickness and beveling shall be followed.
8. Single or dual flow element chambered orifice holders shall be used for orifices. Exceptions shall require Owner approval.
9. Five valve full bore manifolds for orifice installations shall be preferred over fabricated manifolds. Manifold bore size shall match tap size (which is dependent on line size).
10. Liquid turbine meters shall preferably be used in moderate to low viscosity custody transfer services.
11. For high viscosity applications, specifically designed liquid turbine meters are commercially available. Usage shall require Owner approval.

12. A prover shall be used to calibrate liquid turbine meters. Use of a master meter shall require Owner approval.
13. Gas turbine meters shall not be installed in pulsating flow conditions.
14. Gas turbine meters shall be calibrated directly to a bell prover (see note below)or by transfer proving with a master meter. Use of critical nozzles or positive displacement meters to calibrate gas turbine meters shall require Owner approval.

    Note: A bell prover is a volumetric gaging device used for gases consisting of a stationary tank containing a sealing liquid into which is inserted a coaxial movable tank (the bell), the position of which may be determined. Volume of gastight cavity produced between movable tank and sealing liquid may be deduced from position of movable tank. (From ASME MFC-1M.)
15. If other meters capable of operating in service conditions do not meet accuracy requirements, liquid positive displacement meters shall be used not meet accuracy requirements.

TRANSMITTERS

Design

1. Differential Pressure Transmitters
    a. Differential pressure transmitters shall be transducers with digital communications capability.
    b. Ranges
        i) Preferred range of differential pressure shall be 100 inches of water. If lower ranges are necessary, meter range shall be 10 inches, 20 inches, or 50 inches dry calibration. If higher ranges are necessary, meter range shall be 150 inches, 200 inches, or 250 inches.
        ii) Maximum differential in inches of water shall be of the order of the line pressure in psia to minimize permanent pressure loss.
        iii) If approved by Owner, maximum differential pressure, in inches of water, may be as high as 4 times line pressure in psia, and ratio of downstream pressure to upstream pressure shall be greater than 0.8. Estimated pressure loss is of the order of $(1- \beta^2)\Delta P$.
        iv) Deviation from these ranges shall be subject to Purchaser approval.
    c. Two transmitters may be used with an orifice element to provide rangeability greater than 4:1 and/or precise flow measurement.

2. Static Pressure and Temperature Transmitters

Static pressure and temperature transmitters (transducers) shall be provided for compensation of flow measurement as required to meet process requirements or applicable flow metering standards.

Materials and Construction

1. Differential Pressure Transmitters

   a. Normally, differential pressure transmitters shall as a minimum be rated 1500 psig. If service conditions allow, low range meters (e.g., 10 inch, 2 inch, or lower) may have a minimum rating of 500 psig.

   b. In normal services, parts of transmitter bodies that contact process fluid (wetted parts) shall be 316 SS. Nonwetted parts of transmitter bodies shall be carbon steel. In corrosive services, wetted parts shall be special alloy (e.g., Hastelloy or Monel). If suitable alloy metals are not available, seal pots or diaphragm seals shall be considered for corrosive services.

   c. Unless specified otherwise, in hydrogen services, wetted parts shall be 316 SS. If process conditions warrant or if specified by Purchaser, wetted parts shall be gold plated to prevent hydrogen permeation.

   d. Hardware used with transmitters shall be 316 SS or other corrosion resistant alloy. Plated bolts shall not be used.

   e. Seal and drip pots shall:

      - In normal services, be made of carbon steel.
      - In corrosive services, be made of stainless steel, Monel, or other suitable alloy.
      - Comply with pressure, temperature, and corrosion allowance specifications of process line to which they connect.

2. Non Differential Pressure Transmitters

   a. Electronic transmitters (transducers) shall preferably have digital communications capability or have an output of 4 to 20 mA.

   b. Transmitters shall have a span adjustment for calibration.

   c. Hardware used with transmitters shall be 316 SS or other corrosion resistant alloy. Plated bolts shall not be used.

Installation

Differential Pressure Transmitters

1. Unless severe economic penalties result and Purchaser approval is obtained to deviate, transmitters shall be line mounted (nominally within 2 feet).

2. If transmitter manifolds are mounted adjacent to primary flow element, centerline of the body shall be as follows:
   a. Liquid services - not more than 2 inches below pressure taps.
   b. Gas and vapor services - above elevation of pressure taps.
   c. Steam service - below taps with a minimum of 24 inch impulse lines. Blowdown legs shall be provided.
3. If transmitters which are not practical to line mount are used, the following shall apply:
   a. Transmitters shall be mounted at grade or be accessible from a platform.
   b. Impulse lines shall be sloped at not less than ½ inch per foot toward instrument. Slope shall be up for gases and down for liquids.
4. Transmitter heating shall comply with the following:
   a. Transmitter heating shall be provided if required for freeze protection.
   b. Maximum temperature limits for transmitter shall not be exceeded.
5. Piping from first block valve to instrument shall comply with the following:
   a. Unless service conditions require a different alloy, piping material shall be 3/8 inch O.D., 0.035 (minimum) wall, and 316 SS tubing.
   b. Swagelok, Parker, or Owner specified tubing union shall be used to join two or more pieces of stainless steel or other alloy tubing. Use of tubing unions shall be minimized.
   c. Unless specified otherwise, 316 SS five valve manifolds shall be used.
   d. Pressure bleed valves, either in body or piping, shall be provided.
6. If desirable to isolate measured fluid from differential pressure instrument, seal pots shall be provided near pressure connections. Suitable sealing liquid, such as oil, water (for steam), or 100% glycol shall be used to seal instruments and pots.
7. Services that require seal pots include:
   a. Acid flow meters (oil seal).
   b. Differential pressure instruments on acid contactors (oil seal).
   c. Caustic flow meters (oil seal).
   d. Some steam services (water seal).
8. Transmitters in gas or vapor service mounted below pressure taps shall have drip pots. Connections to transmitter shall be from top of drip pot.
9. Services that require drip pots (if transmitter is mounted below pressure taps) include:
   a. Fuel gas.
   b. Wet, unprocessed natural gas.
   c. Plant air.
10. Purging of differential pressure leads shall comply with the following: