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Modern Methods and Devices for Associated Petroleum Gas Metering

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Abstract—Main terms and definitions relevant to associated petroleum gas metering were presented along with the classifications, components, and metrological assurance requirements for metering systems. Particular attention was given to the operation conditions and requirements, as well as to special selection criteria for associated petroleum gas flow meters intended for low-pressure flare lines. Flow measurement methods were reviewed, and the results of a comparative study of flow meters were presented.

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INTRODUCTION

Out of 55–60 billion m^3 of associated petroleum gas (APG) that is produced in Russia annually, ca. 26% (15–16 billion m^3) is flared (according to the Russian Federation Ministry of Natural Resources and Environment, 2006). By no means all the oil production facilities are equipped with gas metering systems. The volume of petroleum gas at the well level is most commonly determined by calculation, specifically as the product of the volume of crude oil extracted by the oil to gas ratio. This procedure is fairly inaccurate and does not give the exact amount of the associated gas flared. Another source of information (the Annual Message of the President of the Russian Federation to the Federal Assembly of April 26, 2007) provides an estimate of 20–25 billion m^3 for the amount of associated petroleum gas being flared in Russia annually.

In the United States, flaring of >3% APG is prohibited legislatively, and in Norway APG flaring is totally banned. In Kazakhstan, commercial production of oil and gas fields without APG utilization is prohibited. Decree of the Government of the Russian Federation no. 7 of January 8, 2009, "On Measures to Stimulate the Reduction of Air Pollution Products from Burning Associated Gas in Flares" requires that no less than 95% associated gas be processed by January 1, 2012 [The Scientific and Practical Commentary to the Federal Law on Environmental Protection, edited by A.P. Anisimov, Dr. Sci. (Jur.)]. This means that, starting from 2012, flaring of no greater than 5% of the volume of APG produced will be allowed.

Since January 1, 2012, the payments for emissions of harmful (polluting) substances generated by gas burning will be calculated by a modified procedure. Specifically, the payments for emissions due to gas burning in excess of the permissible level will be interpreted as those for extra-limit pollution. An incentive for oil and gas companies to reduce the associated petroleum gas flaring will consist in an additional factor of 4.5 to be applied to the standard payment rates. For companies lacking in facilities for measuring and recording the actual amount of the APG produced, used, and burned, this coefficient will be set to 6.

Major oil companies in Russia have already taken appropriate measures and adopted long-term investment program on petroleum gas flaring reduction by 2012. Those programs are aimed at metering, as specified by regulations, all the petroleum gas at the production facilities and flares under operation.

The basic documents regulating the associated (free) petroleum gas metering is GOST (State Standard) R 8.615-2005 "State System for Ensuring Uniform Measurements. Measuring the Amount of

Typical level and content of components of natural gas and associated petroleum gas

Component	Content, vol %	
	natural gas	associated petroleum gas
Methane	60–100	42.5
Ethane	0–12	15.66
Propane	0–6	16
Butanes	0–4	2.1 (*i*-butane) 6.1 (*n*-butane)
Pentanes	0–4	2.3 (*i*-pentane) 2.5 (*n*-pentane)
Hexane		1.44
Nitrogen	0–16	11.43
Carbon dioxide	0–16	0.05
Hydrogen sulfide	0–1	1.28
Water, g m^{-3}		5–30

Petroleum and Petroleum Gas Extracted from the Bowels: General Metrological and Technical Requirements (as modified by Amendment nos. 1 and 2)" and GOST R 8.647-2008 "State System for Ensuring Uniform Measurements. Metrological Assurance of Determining the Amount of Petroleum and Petroleum Gas Extracted from a Bowels Site: Basic Provisions." Those documents contain the main relevant terms and definitions. In particular, "free petroleum gas" is defined as the mixture of hydrocarbon gases released from crude oil during its production, transportation, and treatment. Before proceeding with discussion of petroleum gas metering aspects, let us consider in more detail the measured medium, i.e., the subject of measurement.

Subject of Measurement

What is the difference between associated petroleum gas (APG) and natural gas?

Physicochemical properties. According to GOST 30319-96 "Natural Gas: Methods for Calculation of Physical Properties," natural gas is a gas mixture whose major components are saturated hydrocarbons, nitrogen, carbon dioxide, and hydrogen sulfide. The table lists the typical level and content of the components of natural gas against those of associated petroleum gas.

Though similar in physicochemical composition, associated petroleum gas and natural gas differ in the proportions, the ratios of components. Associated gas may include minor amounts of other components, e.g., water vapor, hydrogen, oxygen, argon, carbon monoxide.

Natural gas is extracted, treated, and transported to processing facilities or to the Gazprom Open Joint-Stock Company gas transport system under high pressures of an order of tens of atmospheres, while petroleum gas is released from oil at close to atmospheric pressures.

Gas treatment. Production and treatment of natural gas as a mineral resource includes removal of solid and liquid gas impurities, heavy hydrocarbon condensate, and hydrogen sulfide, as well as gas drying.

Associated petroleum gas is a byproduct in oil production and is not interpreted as mineral resource even by the Russian Federation legislation. The extraction and treatment of associated petroleum gas do not include removal of solids, drying, etc. Because of imperfect processes, the APG lines may contain condensed water, hydrocarbon condensate, oil droplets, and even instantaneously discharged crude oil.

Therefore, associated petroleum gas may be regarded as natural gas in terms of its physicochemical composition and the level and content of its components, but the operation conditions for APG and the degree of its treatment are different from those of natural gas, which fact is to be taken into account when choosing the appropriate metering devices for APG. Also, the choice of a metering device need to address the following cost considerations: Being more expensive than APG, natural gas is subject to by an order of magnitude stricter metering accuracy requirements.

As already mentioned, nearly one-third of APG undergoes processing, which suggests the existence of APG treatment stages: cleaning, drying, desulfurization, etc. This issue, untypical and irrelevant to the specific features of APG, was not addressed in this section when comparing the APG and natural gas.

Assiciated Gas Volume and Parameters Metering System

The definition provided by GOST R 8.615-2005 is as follows: "The system for associated gas volume and parameters metering (SGVM): a set of functionally integrated measuring devices, data processing systems, and process equipment designed to measure the

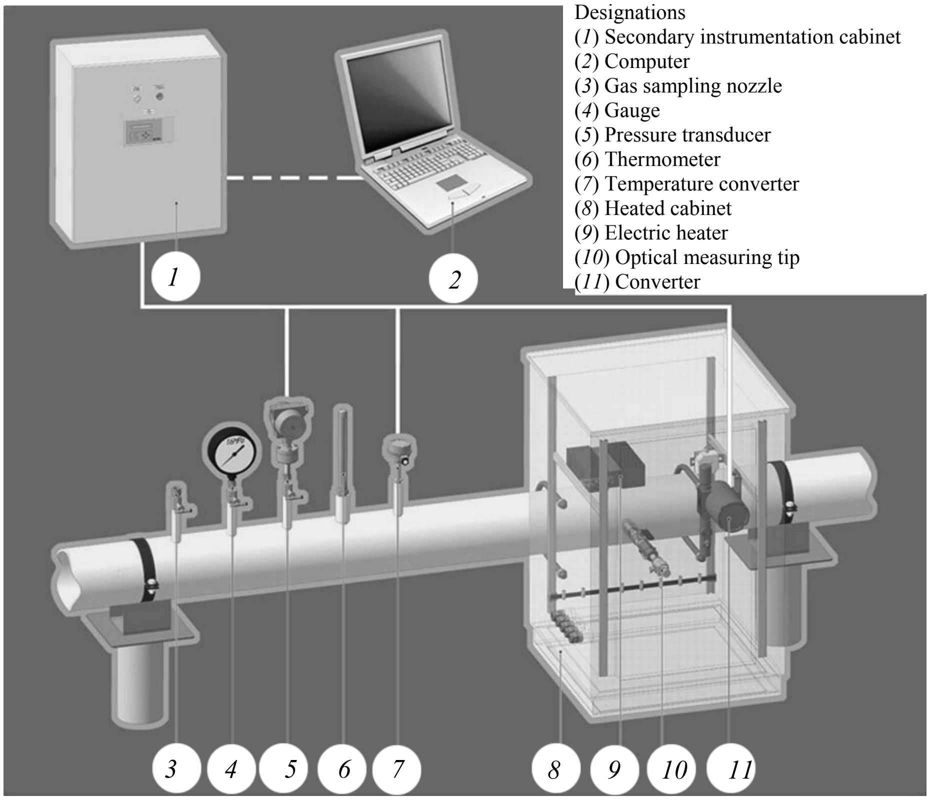

Fig. 1. Typical scheme of an SGVM based on optical flow meters.

volume and parameters of associated gas, to calculate the associated gas volume converted to standard conditions, and to display (indicate) and record the results."

The SGVM components are chosen in the technical design specification stage with due regard to the SGVM functions.

Each SGVM is comprised of four components (Fig. 1).

(1) *A measurements complex (MC):* a flow meter, a manometer, a thermometer, a densitometer (if the APG density is to be determined in SGVM directly), a differential pressure transducer (when a differential pressure device is used), a chromatograph (if the APG components content and level are to be determined in SGVM directly), and water and hydrocarbon dew point analyzers.

(2) *A data acquisition and processing system (API):* a calculator, a computer, or a production server with a data acquisition and processing bus and interface converters; an alarm and report printer; an automated operator workstation; a system for data transfer to an upper level; and a source of uninterruptible power supply.

(3) *A technological component*: instrumentation lines with rectilinear sections located immediately upstream and downstream the flow transducer; stop valves; a sampler; a filter, a demister, and condensate tanks; and bleed lines.

(4) *An industrial safety system*: fire alarm, as well as gas pollution control, power supply, and grounding segments.

Metrological Assurance of SGVM

According to GOST R 8.615-2005, the associated gas volume should be measured with a critical relative accuracy of ±5%. The petroleum gas volume is to be determined using measuring devices supplied with type approval certificates and entered into the State Register of Measuring Devices, as prescribed by the appropriate metrology rules.

Some oil companies in their internal corporate documents established more stringent requirements on the SGVM accuracy depending on the volumetric gas flow rate and purpose of SGVM. The permissible relative accuracy for SGVM having a productivity of >100000 $m^3\,h^{-1}$ under standard conditions and intended for mutual settlements between sellers and buyers is set at ±1.5%.

The limiting permissible accuracy for SGVM is typically established in the concept design stage. The calculation of metrological characteristics tailored to specific process features, the level and content of gas components, the measured medium and ambient parameters, and the configuration and type of measuring devices is to be performed by the measurement procedure, which is developed in the SGVM design stage primarily with the aim to determine the method for calculating the APG flow rate and volume for specific SGVM. In accordance with GOST R 8.615-2005, the petroleum gas volume is converted to standard conditions: temperature 20°C and absolute pressure P_s = 101325 Pa (760 mm Hg).

Given below are the formulas for calculating the APG flow rate and volume converted to standard conditions.

(1) The volumetric flow rate of APG, converted to standard conditions:

$$q_s = q\rho/\rho_s,$$

where q_s is the volumetric flow rate of APG, converted to standard conditions, $m^3\ h^{-1}$; q, volumetric flow rate of APG under operating conditions, $m^3\ h^{-1}$; ρ, density of gas under operating conditions, kg m^{-3}; and ρ_s, density of gas under standard conditions, kg m^{-3}.

(2) The volume of APG under standard conditions V_s, m^3, is calculated as the sum of the volumetric flow rates over a certain time interval:

$$V_s = \Delta\tau \sum_{i=1}^{n} q_{s\,i},$$

where $\Delta\tau$ is a constant time interval, h; and $q_{s\,i}$, volumetric flow rate converted to standard conditions over ith interval, $m^3\ h^{-1}$.

The main metrological characteristic of SGVM is the relative error in measuring the volumetric flow rate.

Example of Calculation of the Relative Error in Measuring the Volumetric Flow Rate of APG

The relative accuracy of measurement of the volumetric flow rate of APG, converted to standard conditions δq_s, %, is determined by the formula

$$\delta q_s = \sqrt{\delta q^2 + \delta f_{calc}^2 + \delta q_{s\,calc}^2 + \delta\rho^2 + \delta\rho_{st}^2}\,.$$

Here δq is the relative error of measurement of the gas flow rate under operating conditions of the volumeter, %; δf_{calc}, relative error of the calculator in the frequency to digital conversion of the signal generated by the flow meter under operating conditions, %; $\delta q_{s.calc}$, relative error of calculation of the volumetric flow rate of APG, converted to standard conditions; $\delta\rho$, relative error of determining the density of APG under operating conditions,%; and $\delta\rho_{st}$, relative error of determining the density of the APG under standard conditions, %.

The measurement procedure needs to be approved by the State Metrological Center and certified by the RF Committee for Standardization, Metrology, and Certification. Each SGVM project is subject to metrological evaluation.

Experience suggests that, for most of SGVM, the relative error in measuring the volumetric flow rate is largely contributed by the relative error of determining the density of APG under standard conditions. This is due to a more extensive use of the indirect method for measuring the gas flow rate (via calculating the density as a function of the pressure and temperature for the gas characterized by specific level and content of components). The level and content of the APG components is determined via laboratory analyses to be performed 6–12 (often only 1–2) times a year, whose results are to be entered into the calculator as quasipermanent parameters. In reality, the level and content of the APG components exhibit greater temporal variability, which necessarily increases the inaccuracy of conversion of the gas volume to standard conditions.

This difficulty can be easily eliminated via direct measurement of the gas density by a flow densitometer or of the level and content of the APG components by a flow chromatograph, which inevitably increases several times the cost of SGVM.

The next place, in order of importance for the metrological characteristics of SGVMs, belongs to gas flow meters.

Classification of SGVMs

Based on the purpose and location, SGVMs can be conditionally subdivided into the following categories:

– systems intended for mutual settlements between sellers and buyers [in the case of transportation to gas-processing plants (GPP)];

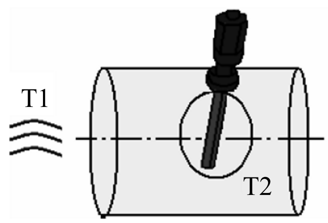

Fig. 2. Pipeline cross-section.

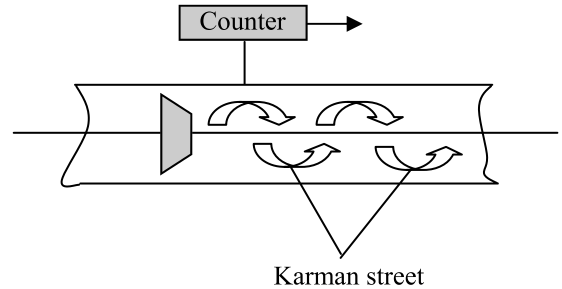

Fig. 3. Scheme of the vortex method.

– metering systems for gas to be used for satisfying the internal needs of extractive companies: gas lift systems, gas turbine power plants, gas reciprocating power plants, boilers, oil heaters, etc.;

– control systems for the air emissions generated by process equipment, including flare systems, discharge of the gas against a candle flame, etc.

In view of the fact that, in selection of SGVM constituents, the greatest difficulty is associated with choosing appropriate flow meters, we will discuss below the above-mentioned SGVM categories in terms of how their operation parameters affect the accuracy of flow meter readings.

Today, the State Register of Measuring Devices contains over 50 flow meters (volume meters) for gases of various types, available from various manufacturers, which are suitable in principle for SGVM applications with associated petroleum gas. Virtually all of them meet the requirements posed on systems to be used in the first of the above-mentioned SGVM categories: narrow ranges of flow rate, high excess pressures, invariant level and content of the APG components, and lacking wet component. These are the operation conditions characteristic for systems used for measuring the volume and parameters of petroleum gas to be transported to GPPs. Flow meters of any type, including imported ones, are suitable for these purposes.

Systems for measuring the volume and parameters of associated petroleum gas, intended for satisfying the needs of extractive enterprises, are also operative under invariant excess pressures and over narrow flow rate ranges though with a more poorly treated gas. The gas can be characterized by variable level and content of the components, including in particular solids, moisture, hydrogen sulfide, etc. This leads to a narrow range of types of flow meters suitable for application in the second-category SGVMs.

Presumably, in an attempt to achieve 95% petroleum gas utilization, oil companies would apply various procedures for petroleum gas treatment, aimed at delivery of the entire petroleum gas amount to GPPs, gas-transmission pipelines or at on-site separation into commercial products (propane-butane fraction, stable diesel gas, or commercial dry lean gas). This would automatically eliminate the gas metering problems, and any type of flow meters used with natural gas will be suitable for 95% of APG produced. Therefore, further discussion of APG metering aspects will focus on the most specific and more abundant third-category systems. According to the analytical report on APG, prepared by Globotek APG System Closed Joint-Stock Company (Tolyatti) and submitted by the RF Accounting Chamber, 1035 flare systems were not supplied with gas flow meters as of early 2010.

Flow Meters for Flare Systems

Based on the operating parameters that significantly affect the choice of flow meter, flare systems can be subdivided into two main groups: high-pressure (0.5–10.0 kg cm^{-2} at flow velocity 0.5–15.0 m s^{-1}) and low-pressure (0.05–3.0 kg cm^{-2} at flow velocity 0.05–15.0 m s^{-1}) flare systems.

The former group is characterized by relatively high minimal limits of measurement of excess pressure and flow velocity of a gas, under which conditions the choice of flow meter does not pose difficulties.

The main problems are associated with specifically the latter (more abundant) group due to the difficult operating conditions.

The specific features of operation of gas flow meters on low-pressure flare lines are as follows:

(1) A wide, >100-fold dynamic range of flow velocity measurement. The upper limit is determined by the emergency mode of operation of the flare line,

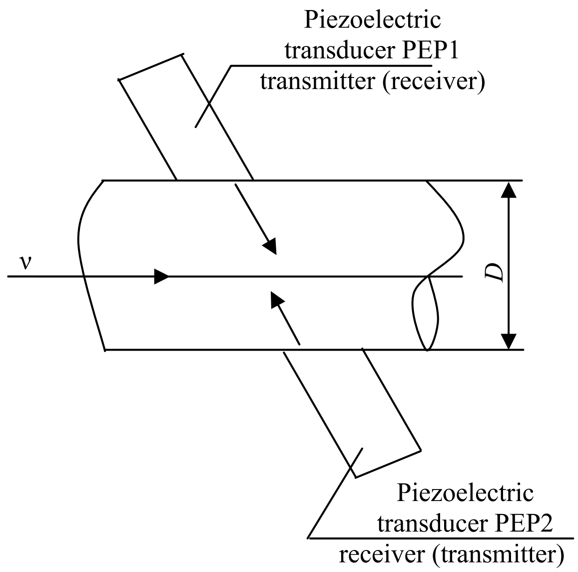

Fig. 4. Scheme of the ultrasonic method.

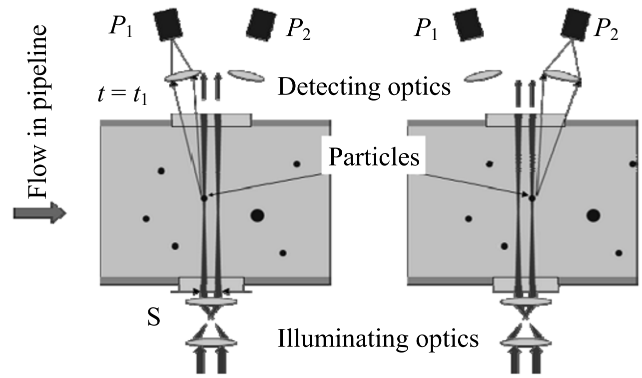

Fig. 5. Scheme of the optical method.

and the lower limit, by the need to measure even minor flows rates of associated gas to be flared. The flow transducer should measure the flow rates throughout the range with the desired accuracy.

(2) A low limit of the flow velocity measurement range starting from 0.05 m s^{-1}. The flow transducer should provide stable measurements with the desired accuracy at close to zero flow rates of the measured medium.

(3) A low minimum limit of measurement of excess pressure. The flow transducer should provide stable measurements with the desired accuracy at close to zero excess pressures of the medium.

(4) Absence of the possibility to artificially increase the lower limit of the range of flow rates via changing to a smaller-diameter instrumentation line and to employ in SGVM those flow transducers that provide resistance to flow, since, according to the "Rules of Design and Safe Operation of Flare Systems (PB 03-591-03)," "a pressure loss in a flare system in the case of emergency discharge should not exceed 0.02 MPa for process plant and 0.08 MPa for the segment extending from the process plant to the flare tip."

(5) Up to 100% moisture content (in the form of water vapor and condensate) in the gas mixture.

(6) A liquid hydrocarbon fraction mixture in the form of droplets or instantaneous discharges contained in the gas.

The above-listed operation features underlie the selection criteria for methods and means to be used in SGVM for measuring the flow rate of associated gas in low-pressure flare lines.

Selection of Methods for Measuring the Flow Rate of APG in Low-Pressure Flare Lines

There exist several methods for measuring the flow rate of APG in low-pressure flare lines.

Thermoanemometric method. Thermoanemometeric measurements are carried out with flow meters whose operation is underlain by measuring the flow velocity at one point of the pipeline cross-section (Fig. 2). The flow velocity depends on the degree of cooling of the sensing element (a resistance thermometer) being heated. The heating current for the sensor is adjusted in such a way that its temperature remains constant, and the mass flow rate is estimated from the thermal power dissipation by anemometer. The denser the medium, the larger the amount of heat removed from the thermal anemometer and the higher the measured flow rate.

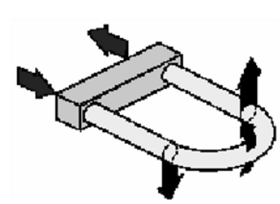

Fig. 6. Scheme of Coriolis method .

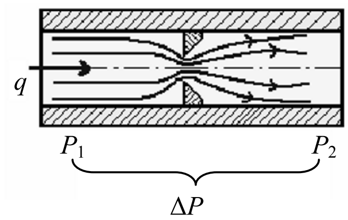

Fig. 7. Scheme of differential pressure measurement method.

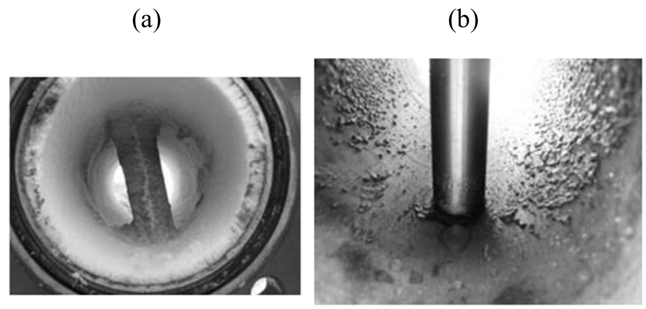

Fig. 8. The interior of the pipeline and vortex meter (a) before and (b) after application of thermal insulation.

Benefits. Thermal anemometers can be available from Russian and foreign producers at a price of ca. 200000 rubles. The advantages of thermoanemometeric method include low operating costs and possible disassembly without pressure loss in the instrumentation line. Most of oil companies have experience of exploitation of thermoanemometers. The requirements contained in item nos. 1–4 are met.

Disadvantages. The reliability of data is strongly affected by the moisture content in petroleum gas and contamination of electrodes with liquid hydrocarbon fraction.

The thermoanemometric method can be recommended for application with dry petroleum gas freed from the liquid hydrocarbon fraction.

Vortex method. The operation of vortex flow meters is underlain by the effect that consists in trailing behind a bluff body of a chain of vortices (Karman vortex street) whose frequency over a broad velocity range is proportional to the volumetric flow rate of the medium. The vortex shedding frequency is measured by a sensitive detector element of the vortex detector located in the flow channel of the bluff and susceptible to velocity or pressure oscillations (Fig. 3). The dimensionless Strouhal number (Sh) describing oscillating flow mechanisms depends on the ratio of inertial to viscous forces in the body overflow (Reynolds number Re) solely. The relationship between these two hydrodynamic similarity numbers is universal for various media and their parameters. Using the calibration plot obtained for the volumeter via comparison with a reference volumeter it is possible to estimate the volumetric flow rate of medium from the output signal frequency.

Benefits. Vortex flow meters can be available from a number of Russian and foreign producers at a price of ca. 200000 rubles. The advantage of the vortex-based method includes low operating costs. Most of oil companies have experience of their exploitation. Requirements contained in item 4–5 are met.

Disadvantages. The vortex-based method does not ensure reliable data at low limits of velocities and pressures (item nos. 1–3). The reliability of the data is strongly affected by the contamination of electrodes with the liquid hydrocarbon fraction.

The vortex-based method can be recommended for measuring the flow of petroleum gas freed from the liquid hydrocarbon fraction at minimal flow velocities of >1.0 m s^{-1}.

Ultrasonic method. The ultrasonic flow meters measure the difference of the transit time of ultrasonic pulses propagating in and against flow direction. The pulses are generated by ultrasonic transducers installed in the measuring section of pipe (Fig. 4). The transducers are alternately switched into the receiving and transmitting mode and provide transmission into and reception from the measured medium of ultrasonic pulses at a pipeline inclination angle. The movement of the measured medium causes a change in the upstream and downstream ultrasound propagation times.

The volumetric flow rate can be calculated by multiplying the cross-sectional area of the pipe by the measured mean flow velocity. If the ratio of the flow velocity of the measured medium to the volumetric flow rate is a function of the velocity profile, the instruments determine the actual flow rate with the use of the preliminarily plotted calibration curve to be entered into the software of the instrument.

Benefits. Ultrasonic flow meters satisfy requirements contained in item nos. 1–4; they can be disassembled without pressure loss in the instrumentation line.

Disadvantages. Ultrasonic flow meters can be available from foreign manufacturers at a price of 30 thousand euros. The operability of the liquid phase is significantly affected by condensed water and/or hydrocarbon fraction.

Ultrasonic flow meters are recommended for application at large and medium-capacity (10000 $m^3 h^{-1}$) facilities for petroleum gas freed from the liquid fraction.

Optical method. The operation of optical flow meters is based on measuring the velocity of the aerosol particles in the gas flow in the vicinity of the head of the probe (Fig. 5). In the probe there is a channel for passage of the stream, translucent by two laser beams. Laser beams are concentrated into two bands, and the time of passage of particles between these beams is recorded. Based on the exact distance separating the two beams of particles and the time of travel of particles between them, the flow meter calculates the velocity of passage of particles in the probe tip aperture. The velocity is measured on the axis of a pipeline with the diameter of 100–150 mm and on 0.25R for large diameters.

Benefits. Optical flow meters meet the requirements contained in item nos. 1–5. They can be disassembled without pressure loss in the instrumentation line.

Disadvantages. Optical flow meters are available from a single foreign producer at a price of ca. 15 thousand dollars. The operation is significantly affected by the liquid phase represented by the hydrocarbon fraction.

This optical method can be recommended for petroleum gas with the liquid hydrocarbon fraction removed.

Coriolis method. The Coriolis mass flow meters use the Coriolis effect to measure the amount of mass moving through the element, a U-shaped pipe loop that is caused to vibrate at a constant frequency (Fig. 6). The fluid to be measured passes through the vibrating tube and causes it to twist. The amount of twisting is directly proportional to mass flow.

Coriolis mass flow meters have no moving parts, and the measurement results for them are independent of density, viscosity, presence of solids, and the flow regime of the measured medium.

The Coriolis method is unsuitable for measuring the flow rate of associated petroleum oil gas at low-pressure flare lines because of a significant flow resistance.

Differential pressure measurement method. This method employs standard and nonstandard orifices (diaphragms, nozzles, or averaging tubes) which constrict flow in a measurement pipe (Fig. 7). The resulting pressure drop is proportional to the measured flow velocity.

Differential pressure flow meters are unsuitable for measuring the flow rate of associated petroleum gas at low-pressure flare lines because of significant flow resistance.

Testing Different Types of Flow Meters at Samaraneftegas Open Joint-Stock Company

In February–March 2010, the “Metrology and Automation” Limited Liability Company participated in organization of comparative tests of gas flow meter of different types, operating by different principles, at a preliminary water discharge facility. Those tests were aimed to confirm the serviceability and determine the actual measurement inaccuracy under operation conditions for gas flow meters offered by Russian and foreign manufacturers.

The following flow meters, gas meters, were submitted to the tests.

(1) TFG Series Turbo Flow gas flow meters available from Turbulentnost’-Don Scientific and Production Association Ltd., Rostov-on-Don, Russia.

(2) Dymetic-9423 gas meters available from Dymet Closed Joint-Stock Company, Tyumen, Russia.

(3) Focus optical flow meter available from Photon Control Inc., Canada.

(4) Irvis-RS4 vortex counting flow meter available from Irvis Scientific and Production Enterprise Ltd., Kazan, Russia.

(5) FLOWSIC 100 ultrasonic flow meter available from by SICK MAIHAK GmbH, Germany.

(6) SURG 1.000-Ex gas mass flow meter available from Shibbolet Ltd, Ryazan, Russia.

(7) TRZ turbine flow meter available from Elster Gazelektronika Ltd., Arzamas, Russia.

The results of measurements during the tests showed that it is reasonable that all the flow meters be assessed, without differentiation between reference and working ones, by methods of statistical analysis of measurements results.

The tests were carried out under severe conditions: ambient temperature –30°C in February and +5°C in March. The lower limit of temperature measuring range was –15°C. The flow transducers were installed sequentially on one process line of an operative setup, and the secondary devices and calculators were arranged on a separate board in the control room of the PWDF. Owing to the archiving function available in all the instruments tested, the data could be easily received and synchronized for further analysis.

The instruments were tested in different modes, with flow, pressure, and temperature as varied parameters. During the tests, the level and content of the components of the medium were varied as well. Also, the measurement accuracy and serviceability of each of the instruments were examined in relation to the presence of moisture, hydrates, and other factors. Some results of the tests may be helpful in SGVM designing, installing, and handling.

In particular, without thermal insulation applied to the operating pipelines, up to 1.5-cm-thick hydrate deposits were detected on the inner walls of the pipe (Fig. 8), which significantly reduced the internal cross-sectional area of the pipeline. This fact suggests high humidity of associated petroleum gas. Under such conditions, the results of measurements by all the meters without exception cannot be considered reliable.

After thermal insulation was applied, there was no hydrate deposition, but liquid droplets were detected on the inner surfaces of pipelines and flow meters. The measurement results that were presented for the statistical analysis after thermal insulation was applied in strict compliance with the separator operating regime (level) were recognized as reliable data.

Also, the tests demonstrated that liquid droplets can be efficiently removed from the medium with the use of a compact cyclone separator upstream of SGVM.

Thus, the flow meters were exposed to severe testing conditions (low ambient temperature and variable level and content of the gas components and parameters), but the tests confirmed the serviceability of all the instruments involved after the appropriate engineering measures were taken and the thermal insulation of the instrumentation line was applied. The inaccuracy in measuring the volume of associated petroleum gas by Turbo Flow TFG, Dymetic, Irvis-RS4, FOCUS Probe, and FLOWSIC 100 flow meters was estimated at ±5% of the calculated average value.

Based on the results of the tests, a number of recommendations were formulated concerning the designing, installing, and handling of SGVM that comprise various types of flow meters.

SGVM Operation Problems

Of much importance is not only the correct choice of SGVM for a specific object in the design phase but also the observance of its operation modes and requirements. Let us consider the most problematic aspects.

(1) Instantaneous discharges of crude oil into the instrumentation line cause failures of sensors in flow meters (regardless of the type) designed for operation with a gaseous medium solely. The sensors can be restored to operable status by removal from the instrumentation line and cleaning.

Virtually all types of modern flow meters intended for APG measurements offer the possibility for removal of the sensor from the flow without stopping the process and dropping the pressure. This can be done by a service organization in response to an emergency call or as part of the routine maintenance work. High-quality service eliminates the consequences only temporarily, while in reality the core of the problem lies in the technology. In accordance with the requirements contained in item no. 3.8 of the "Rules of Arrangement and Safe Exploitation of Flare Systems (PB 03-591-03)," gas and vapor discharged into common and separate flare systems should be free from liquid droplets and solids. The satisfying of these requirements by flare lines necessitates improving the petroleum gas treatment procedure and arranging additional separators.

(2) Paraffin, tar, and hydrate deposition, as well as water and hydrocarbon condensation inside the pipelines and flow meters lead to distorted readings or even total failure of the instruments. The narrowing of the cross-sectional area of the test section leads to overestimated readings available from volumeters on the basis of gas flow rate measurements. The consequences can be eliminated by the maintenance organization, but the actual solution to the problem lies in APG treatment.

(3) Currently, SGVMs are unable to control the metrological characteristics of flow meters during the calibration interval at the exploitation site. The reasons are the technical complexity of this task and the lack of appropriate control instruments operable under the

conditions of interest. Typically, instruments are verified on stationary equipment calibration rigs which are separated from the exploited facilities by tens or hundreds of kilometers. The calibration medium at such facilities is atmospheric air, and special conversion coefficients are used for recalculation of the data for the specific operating parameters and the level and content of the gas components. When volumeters are removed to be verified at verification setups it is difficult to meet the requirements concerning the internal diameter difference, misalignment, and length of straight sections. All of these factors may lead to additional, extra-limit errors, and distortion of measurement results. The need to meet the requirements, as well as the verification and installation conditions, correct input of the verification results into the calculator, etc. pose increased criteria to be satisfied by the staff of the organizations engaged in SGVM maintenance.

(4) Conversion of the measured gas volume to standard conditions implies the input into the calculator of quasi-permanent parameters, e.g., the level and content of the gas mixture components, gas mixture density under the operation and standard conditions, and the compressibility factor for associated petroleum gas. If gas sampling and determination of quasi-permanent parameters with input of new data into the calculator are rare events, this inevitably leads to an unaccounted error in conversion of the gas volume to standard conditions. Prerequisites to successful solving of this problem include a briefer inter-sampling period, which concerns the operating organization, and appropriate qualifications of the staff of the service organization, engaged in updating of the calculator parameters.

CONCLUSIONS

(1) Associated petroleum gas is a medium that is hard to measure because of both the dynamically varying level and content of its components and the occurrence of solid and liquid phase elements. Mining companies need to improve the quality of the petroleum gas treatment procedure, above all remove solids and the liquid phase upstream of the instrumentation line of SGVM.

(2) Considering the features distinguishing the measurements of APG from those of natural and other "pure" gases (single-phase gas media), SGVMs should comprise only those flow meters and flow calculators that are recommended for application in APG measurements.

(3) The specific aspects of APG metering require high skills and experience of organizations engaged in designing, maintenance, and metrological servicing of SGVMs.