

GAS CONTRACTS: THEN AND NOW

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Our industry has seen tremendous progress in the accuracy of natural gas measurement since the implementation of electronic gas measurement (EGM) in the 1980s. With respect to orifice measurement, the transition from mechanical chart recorders to EGM had an unprecedented impact on our ability to measure natural gas and adjust to market demands throughout the country. In order to realize the benefits of EGM, gas contracts should include measurement provisions specific to this technology and its downstream data management requirements. Furthermore, they should represent both buyer and seller in the most equitable manner possible. This writing discusses some of the challenges in our industry, both then and now, while recommending measurement provisions for gas contracts.

In the era dominated by circular orifice charts, the gas measurement industry was often described as *part art—part science*. Interpreting recorded variables during chart integration is subjective, at best. The subjective nature of this phase of the measurement process has been a major point of contention between buyers and sellers. Few contracts addressed this matter or offered any practical dispute resolution provisions. Consequently, whoever took responsibility for determining the gas volume at the sales point had discretionary control over this important data. Needless to say, buyers and sellers were typically at odds over this measurement issue.

The most immediate benefit of electronic gas measurement has been the elimination of subjective

interpretation from chart integration. Despite widespread awareness of this problem, even current contracts fail to provide suitable guidelines for processing orifice charts. Since the methods for resolving these issues are fairly expensive and imprecise, we highly recommend utilizing EGM wherever custody transfer measurement is performed. EGM equipment records the flow variables with greater resolution and accuracy than mechanical chart recorders. Accordingly, approximately one-third of all measurement disputes could be averted using electronic gas measurement.

Currently, one of the most neglected issues within the industry is auditing. In our opinion, the party responsible for managing measurement data should furnish audit data to each participant in the transaction. That information should be in a mutually acceptable format that allows for detailed verification of the volume. Because auditing yields an average four-to-one return on the investment, the right to audit should be explicit in every gas contract written.

The measurement provision of your gas contract should comprise a fundamental agreement between buyer and seller to employ acceptable standards and procedures for measurement, sampling, auditing, and dispute resolution. Even today, most contracts do not contain the necessary language to meet these objectives. We believe the following provision will serve to improve the quality of gas measurement and the relationship of trust between buyer and seller.

2002 ASGMT SAMPLE EGM CONTRACT

- 1.00 For purposes of this contract, volumes will be calculated and reported on a calendar month basis, from 9:00 a.m. on the 1st of each month through 9:00 a.m. on the 1st of the following month.
- 1.01 The unit of volume for measurement of gas delivered hereunder shall be one thousand (1,000) cubic feet of gas at a base temperature of sixty (60°F) degrees Fahrenheit and at an absolute pressure of fourteen and sixty-five hundredths pounds per square inch, absolute [14.65 psia (Texas state requirement)]. All volumes shall be measured and calculated according to the current standards prescribed in the American Gas Association Report No. 3, Orifice Metering of Natural Gas and Other Hydrocarbon Fluids, Parts 1-4, as amended from time to time or as mutually agreed upon between the parties hereto. Any volume recalculation shall utilize a mutually agreeable technique to compensate for the inherent inaccuracy associated with calculating volumes from averages of the flowing parameters as opposed to the actual instantaneous values used by the original flow computing device.
- 1.02 The Electronic Gas Measurement (EGM) system shall be capable of establishing an audit trail by compiling and retaining sufficient electronic data and information for the purpose of verifying daily and hourly quantities, and shall comply with the American Petroleum Institute — Manual of Petroleum Measurement Standards, Chapter 21, Section 1 — Electronic Gas Measurement (API Chapter 21), or other mutually agreeable standards. Pipeline shall preserve audit trail information for a minimum of 4 years or the time required by any governmental agency, whichever is greater.

1.03 Upon request, the measurement data described in paragraph 1.02 of this article and calculated by the meter shall be preserved and provided for auditing purposes in a mutually agreeable standard format. Standard format shall mean the API Chapter 21 compliant electronic format provided by the manufacturer of the meter or another format for which commercially available EGM Review and Recalculation software exists and is mutually agreed upon by the parties hereto. Printed paper data is not acceptable for audit purposes. In addition, the final custody transfer volumes and MMBtus and a log of the changes made between the amounts calculated by the meter and the settlement amounts shall be provided. Unless a currently unresolved exception exists, all volumes shall be considered final after 3 years.

1.04 Pipeline, or its designee, shall be responsible for measurement at the point of delivery. Measurement station shall operate within a .25 to .60 Beta Ratio range with an Electronic Gas Measurement (EGM) recording device. This device shall utilize close-mount transmitters installed on an orifice meter run whose orifice taps are in the vertical plane, along with all related equipment necessary to accurately measure the gas delivered hereunder. Close-mount shall mean that the distance between the orifice tap and the transmitter will not exceed 24 inches. The differential pressure measuring range shall not exceed 300 inches of water. Alarm limits shall be set in the meter and all alarm conditions shall be logged so as to identify flow conditions which are outside the proper operating conditions of the meter. The alarm report shall be made a part of the standard audit trail including all alarm conditions.

The calibration and programming of and data collection from the recorder and related equipment shall be the responsibility of Pipeline or its designee. All calibration and adjustment of this equipment shall be in accordance with Paragraph 1.08 of this article.

1.05 Producer may, at its option and expense, install check meter equipment upstream of Pipeline's measurement station for checking the Pipeline's metering equipment. Such measurement equipment shall be installed so as not to interfere with the operation of Pipeline's facilities and shall comply with the standards set forth in this contract. In addition, producer may install a check recorder on pipeline's meter run utilizing a dual-mount manifold system on the same orifice taps which provides independent isolation between each parties respective recording devices. This system shall be installed so as not to interfere with the operation of pipeline's facility.

1.06 The temperature of the gas flowing through each of the meters at these stations shall be measured with a temperature element so installed as to provide an accurate measurement of the flowing temperature at the primary device.

1.07 The specific gravity, gross heating value, and composition of the gas will be determined by Pipeline by taking a representative sample once Monthly at Pipeline's meter tube. Sampling or collection shall be performed during the Pipeline's scheduled meter inspection and calibration test and all samples shall be obtained and analyzed using current Gas Processors Association (GPA) standards. These analytical results shall be applied at the beginning of the month the sample was taken and until a subsequent representative sample is applied.

Producer shall have the right to obtain a duplicate sample of the pipeline's gas. If a difference between the pipeline and producer's duplicate sample exceeds one-half percent (.5%) in MMBtu, then the Producer shall have the right to call for a retest and the analysis from the preceding period shall be used until the results can be verified or a representative sample is obtained and applied. Upon written request, pipeline or producer shall furnish the requesting party with their natural gas sample, chromatographic gas analysis report, or any other information which may be required to verify the other party's analytical procedures or results.

1.08 Producer shall have the right to have a representative present at the time of any installing, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with the equipment used in measuring gas deliveries hereunder. The records from such measurement equipment shall remain the property of Pipeline, or its designee, but Pipeline will make information available in accordance with Paragraph 1.03.

1.09 At least Monthly Pipeline shall calibrate or cause to be calibrated the meters and instruments used for measurement hereunder. Pipeline shall give Producer sufficient advance notice so the Producer may, at its election, have a representative present at such tests. For purposes of measurement hereunder, the atmospheric pressure shall be assumed to be fourteen and forty hundredths per square inch (14.40 psia) irrespective of variations in the actual atmospheric pressure from time to time. If the transmitter measures actual atmospheric pressure, then actual atmospheric pressure shall be used.

Where unacceptable measurement differences exist and all other tests have been conducted to remedy the error, the orifice meter run shall be inspected and tests shall be performed to verify compliance with current AGA Committee Report No. 3, Part 2, Specification and Installation Requirements, as amended from time to

time. The expense shall be shared equally between pipeline and producer if the error is not discovered in this process, but if the problem is found in the tube or its accessories, costs for the inspection, repair, and/or replacement of the tube shall be born by the pipeline unless it can be determined that the malfunction was caused by the producer's gas. At least once every 3 years, this inspection and test procedure shall be conducted at the pipeline's expense regardless of any apparent discrepancies, unless such right is waived by both parties hereto.

- 1.10 If, upon any test, the metering equipment in aggregate is found to be recording inaccurately by one-half percent (0.5%) or more of the correct rate in MMBtu under actual flowing conditions, registration thereof and payment based upon such registration shall be corrected at the rate of such inaccuracy for any period of inaccuracy that is definitely known and/or agreed upon. In the event such period of inaccuracy is not definitely known and/or agreed upon, the adjustment will be made halfway back to the preceding test. Following any test, any metering equipment found to be inaccurate to any degree shall be adjusted immediately to record accurately. The maximum zero-cutoff value which may be programmed for the differential transmitter reading is .25 inches.

If for any reason the meter is out of service or repair so that the quantity of gas deliveries through such meter cannot be ascertained or computed from the readings thereof, the quantity of gas so delivered during the period when the meter is out of service or repair shall be determined on the basis of the first of the following methods which is feasible, as agreed between the parties hereto.

- a.) By using the registration of the Producer's check measuring equipment, if such equipment is recording accurately. The Producer agrees to allow the same provisions for the Pipeline to witness and audit such measurement that the Pipeline allows on the custody transfer measurement equipment;
 - b.) By using the cumulative volumes from any field measurement source adjusting for historical differences and/or fuel consumption between the field meters and sales. The Producer agrees to allow the same provisions for the Pipeline to witness and audit such measurement that the Pipeline allows on the custody transfer measurement equipment;
 - c.) By correcting the error mathematically if the amount of such error is ascertainable by calibration, test, or calculation;
 - d.) By estimating the quantity from the amount of deliveries during, preceding, and/or following periods where the delivery conditions were similar and the meters were recording accurately or;
 - e.) By any other method which is mutually agreeable.
- 1.11 Any error resulting from a source other than meter calibration shall be corrected retroactive to the date from which the error began, regardless of percent error, unless other arrangements are made by mutual consent between Pipeline and Producer.
- 1.12 Any volume or energy revision made by the measurement party following initial close-out, shall not be made without a detailed written explanation of the revision and such changes must be mutually agreed upon between the parties. Also, measurement party shall respond in writing within 30 days following receipt of any adjustment request, either by making the requested volume adjustment or by stating its reasons for not doing so.
- 1.13 The heating value of the gas delivered hereunder shall be determined from the analysis by calculating the gross heating value of the gas in Btu per real cubic foot at a pressure base of fourteen and sixty-five hundredths pounds per square inch absolute (14.65 psia (Texas state requirement)) and a temperature base of sixty (60°F) degrees Fahrenheit with the gas assumed to be As Delivered. Such Btu shall be multiplied by each hourly volume in Mcf and divided by one-thousand (1,000) to yield the MMBtu for that hour.

Commercial software is available to create similar documentation customized to your needs and conditions. Our company recommends that you have your legal department approve the language used in any commercial software purchased; however, no change should be made without consulting with your measurement department.



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