Directive 046: Production Audit Handbook

January 2003

Effective June 17, 2013, the Energy Resources Conservation Board (ERCB) has been succeeded by the Alberta Energy Regulator (AER).

As part of this succession, the title pages of all existing ERCB directives now carry the new AER logo. However, no other changes have been made to the directives, and they continue to have references to the ERCB. As new editions of the directives are issued, these references will be changed.

Some phone numbers in the directives may no longer be valid. Contact AER Inquiries at 1-855-297-8311 or inquiries@aer.ca.

ERCB

Production Audit Handbook

January 2003 (with updates June 2011)

June 2011
This directive has been updated to reflect changes that have been made in Directive 017 (April 2011 edition). Sections no longer required have been grayed out. This directive has also been updated to reflect the name change of EUB to ERCB and renaming guides to directives.

Energy Resources Conservation Board
Directive 046: Production Audit Handbook

2nd edition, January 2003

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(continued)

1 Overview

This *Production Audit Handbook*, *Directive 46*, defines the production audit protocols for the Energy Resources Conservation Board (ERCB) and is designed to ensure that ERCB auditors conduct production audits of oil and gas production facilities, gas plants, and injection systems in a consistent manner throughout Alberta. The Directive is available to industry to enhance understanding and communication between production accounting and operating personnel in industry and ERCB staff.

1.1 What's New in This Edition

This revised edition of *Directive 46* includes an overall enhancement of selection criteria, audit procedures, and protocols. In addition, the former appendices have been updated, as follows:

- Appendix A-2 – Revised Tank Gauging Procedure
- Appendix A-3 – Changed tank sizing coefficient from 0.69 to 0.39
- Appendix A-4 – Added New Split Loads Policy
- Appendix A-5 – Added Cascade Testing
- Appendix B-1 – Removed appendix on Confirming Integrator Values and renamed former Appendix B-2: Gas Volume Calculations as B-1; added AGA3 (1990) calculation formula
- Appendix B-3 – Removed this appendix on Determination of Supercompressibility (hand calculations)
- Appendix B-4 – Renumbered Acid Gas Measurement as Appendix B-2
- Appendix B-5 – Combined with Gas Volume Calculation in Appendix B-1
- Appendix C-3 – Recommended water-cut procedure has been modified to include various BS&W ranges
- Appendix D-1 – Added that new sales/gas delivery point orifice meters must conform to the latest AGA3 specifications
- Appendix D-4 – Removed "Conversion of Planimeter Readings to Values of h_w and P_f" (hand calculation); added new integration technology submission rule for audits
- Appendix D-5 – Transferred Guidelines for Inspecting Automated Measurement Systems from *Directive 64*, Appendix 5, with modification to accuracy, calibration, audit submission, and reporting requirements; added upstream pressure tap factors and parameters to test cases
- Appendix D-6 – Removed LPG Storage Vessel Code (transferred to *Directive 64*)
- Appendix E-2 – Added Gas-in-Solution determination requirements
- Appendix E-3 – Modified Gas Equivalent Factor formulas and liquid to gas conversion according to 2003 Gas Processors Association (GPA) factors

- Appendix F-2 – Updated Data Request Letter and Sheet
- Appendix F-3 – Added the updated Facility Check sheet (combined previous Appendices F-5 and F-6)
- Appendix F-4 – Added Production Audit Enforcement Ladder Definitions
- Removed previous Appendices F-3, F-4, and F-7
- Appendices G and H—Updated list of API and AGA standards and ERCB Directives, interim directives (IDs), and informational letters (ILs)

1.2 Production Audits

The ERCB conducts detailed production audits of oil and gas facilities in Alberta to ensure that

- facilities are constructed and operated in accordance with the Oil and Gas Conservation Act and Regulations, Oil Sands Conservation Act and Regulations, other ERCB requirements, and the facility licence or approval;
- ERCB standards for measurement accuracy are being met;
- monthly production reports are completed in a satisfactory manner;
- environmental concerns are dealt with; and
- companies are aware of the ERCB enforcement ladder of escalating consequences for noncompliance.

A production audit selectively monitors production operations licensed by the ERCB, with an emphasis on production measurement and reporting. It involves evaluations of

- process equipment, measurement, and SCADA devices,
- operation and measurement procedures,
- accuracy and completeness of recorded data,
- accounting procedures,
- data processing (production accounting programs), and
- completion of production reports.

In the course of completing an audit, the ERCB auditor applies the requirements outlined in this Directive, as well as those in

- Oil and Gas Conservation Act and Regulations (OGCA and OGCR)
- Oil Sands Conservation Act and Regulations (OSCA and OSCR)
- *Directive 7: Production Accounting Handbook*
- *Directive 55: Storage Requirements for the Upstream Petroleum Industry*
- *Directive 56: Energy Development Application*

- *Directive 60: Upstream Petroleum Industry Flaring*
- *Directive 64: Facility Inspection Manual*
- *Internal Guide 8: Safety Manual*
- industry standards (see Appendices G-2 and H)

1.3 What This Directive Contains

This Directive provides instructions on how auditors should conduct production audits and includes

- Selecting a Facility for Audit
- Preinspection Procedures
- Facility Inspection Procedures
- Records Review Procedures
- Appendices with detailed procedures and guidelines, calculations, forms, and conversion factors. Appendices G and H list all API and AGA standards and ERCB documents (Directives, IDs, and ILs) cited in this Directive.

2 Selecting a Facility for Audit

Any upstream facility is subject to audit at any time. However, most audit candidates are selected by the Production Audit section based on one or more of the following criteria:

- previous unsatisfactory audits or inspections of any of the licensee's facilities
- significant trucked-in production, by volume or percentage of total facility throughput
- questionable custody transfer measurement
- facilities with mixed measurement and/or well types
- consistently poor proration factors or high metering differences
- facilities with excessive flaring and venting
- facilities subject to allowables or GOR penalties
- external and internal requests
- unapproved facilities
- random selection
- other criteria that may arise

3 Preinspection Procedures

The ERCB auditor must notify the appropriate Field Centre that an audit is to be conducted in the coming months. The Field Centre may elect to conduct a joint audit. The auditor must then review documentation on the facility and notify the licensee of the upcoming audit.

3.1 Facility/Corporate Familiarization

Check the corporate information on the computer system to determine licensee status.

Review all available internal files regarding the facility and the licensee history.

Note that beginning with the October 2002 reporting month and the implementation of the Petroleum Registry, the previous “S” statements are now called monthly volumetric submissions.

Gather information on previous audits, field inspections, special approvals, and requirements. This may be obtained from the battery or plant file available from the Microfilm Section in Calgary.

Obtain a copy of a recent schematic from the licensee’s operation contact to take to the facility.

Obtain a copy of the well listing for the facility. Note the status of each well.

Review the facility approval licence and schematics. Become familiar with the facility design, equipment, metering points, sample points, header system, injection system, satellites, and fluid disposition. Identify meter bypass routes, unmetered fluid streams, transfer points, common flow lines, and field headers.

Review several months of production reports. Note potential problem areas, such as
- proration test frequency required based on oil production volume of each oil well
- gas well tied into oil batteries and vice versa
- poor proration factors
- excessive metering differences or none reported where expected
- excessive flaring
- no flared, vented, or fuel gas reported
- reporting measured production at flow-lined wells
- well status incorrect
- large receipt volumes of trucked-in oil

Review other approvals for terms and conditions that may affect measurement and operations, such as
- allowables
- disposal, pressure maintenance, enhanced oil recovery (EOR) approvals
- injection wells
- maximum rates and pressures
- source and measurement of injection fluids
- approvals for charts greater than 8-day cycle
- miscellaneous orders and approvals
- gas measurement exemptions
- microfilm records
- production surveillance history

Prepare a tentative inspection procedure to ensure that all items of interest are checked (see Appendices F-1 and F-3).

3.2 Notifications

Notify the appropriate ERCB Field Centre at least one week prior to the site inspection.

In the case of First Nations sites, notify Indian Oil and Gas Canada (IOGC) and the Band office, and for Metis settlements, notify Metis Counselor and Settlement offices.

Notify the licensee of your intention to audit the facility. Explain the purpose of the audit and how it will be conducted, including setting a time and place to meet, putting a well on test for proration batteries, and demonstrating sampling and basic sediment and water (BS&W) procedures on site. Do not arrive at the facility unannounced.

Contact someone at the facility at the production superintendent/production operations manager level to advise of the impending audit. This person or a delegate will be responsible for procuring the requested information (e.g., site schematic drawings, production records), ensuring that remedial measures are completed, and meeting with you at the completion of the audit (records review).

3.3 Preparations

Contact the field foreman and/or battery operation personnel to arrange the field inspection and advise that it will take at least one day to inspect a gas battery and usually two days for oil batteries. Ensure that the facility will be operating normally. Attempt to schedule your inspection to conform to the normal schedule of the operation personnel. Try to evaluate the operating procedure under normal, routine conditions.

Ensure that the operation personnel and field foreman understand their role in the audit process. They are to show the auditor the requested facilities, put wells on test if applicable, perform their normal duties, and answer any questions regarding field operational issues. (Ask them to wait until you arrive before proceeding with the testing.)

Request that any stabilization or purge procedure be completed prior to your arrival so that the well is ready to go on test. If you wish to witness the testing of specific wells because of allowables, royalty relief, common flow lines, etc., advise the operation personnel in advance.

Find out if you require special safety equipment or a work permit to enter the lease. Conform to the requirement. Find out if the facility is locked when unattended; if so, arrange access.

If wells at the battery qualify for gas measurement exemption, try to schedule the inspection during the annual retest or request a gas test if possible.

4 The Facility Inspection

Carry out the facility inspection in accordance with *Directive 64*. The major portion of the inspection involves

- evaluation of the battery equipment and ERCB accounting meters,
- observation of the measurement procedures, and
- gathering information on production characteristics of the well(s), the operating procedures, field records, and production data capture.

Careful and detailed documentation of the field inspection data is very important. You may summarize the data gathered on the Production Data Sheet for oil batteries as shown in Appendix F-1. Note that new technology and methodology used in measurement are allowed, provided that the licensee can demonstrate that it can operate within the uncertainty guidelines in the OGCR Schedule 9.

4.1 Oil Batteries Equipment Inspection

Confirm the accuracy of the flow diagram on file and note any changes. Sketch your own flow diagram if necessary.

Conduct a battery inspection as outlined in *Directive 64*. Pay particular attention to its Appendix 1, Sections 1 to 4, on measurement.

Record the following accounting meter data:

- Liquid meters – manufacturer, serial and model number, calibration date, meter factor, and method of temperature compensation. Does the metering conform to OGCR, Section 14.180? If not, is there a special reason? See Appendix A-1 for recommended flow rates.

- Water meters must comply with OGCR, Sections 14.140, 14.160, 14.170, and 14.180.

- Orifice meters – static, differential and temperature ranges, chart drive speed, upstream run size, manufacturer, serial and model number, manufacture and calibration dates; have the operation personnel pull plate in meter if possible; check spare plates for damage and proper storage. Orifice meters must comply with OGCR, Section 14.070, which requires compliance with the latest American Gas Association Report No. 3 (AGA3) for orifice meter installation requirements, including minimum upstream and downstream pipe lengths. (See “Meter run inspection” in Appendix D-1.)

- Other meters – meter factors, manufacture and calibration dates, manufacturer, serial and model number, flow rate through meter. Are the meters temperature or pressure compensated?

- Automated measurement systems – any measurement performed using electronic or SCADA equipment must conform to the requirements of Appendix D-5.

- Check to ensure that the meter bypass is closed for all accounting meters. If it is not, ask why.

Record the capacity and dimensions of each storage tank.

- Are tanks on automatic level control?
- At what levels do the control switches engage?
- Do gauge boards have the proper increments (see Appendix A-2)?
- Record daily gauges and time of gauge.
- Is secondary containment in place (see *Directive 55*)?
- Record approximate density of oil in tanks from past records.
- Are tanks equalized?

Record the pressure and temperature of each process vessel.

Record header pressures (test and group lines).

Initial each chart for verification during records review.

Are any wells using casing head gas for fuel? Is it measured? Estimated?

4.2 Oil Batteries Operational Procedures

Operation personnel are a valuable source of information. Ask questions, observe, and listen carefully. Accompany the operation personnel on his rounds to satellites and well sites. You should check as many wells as possible within the time frame of the inspection. Discretion is required as to what type and which well(s) you should choose to go to. The well(s) on test should be inspected. Inspect equipment and observe procedures at each installation. Note any adjustments made to wellhead or process equipment.

4.2.1 Tank Gauging (see Appendix A-2 for tank gauging procedure)

Check the tank gauging method for accuracy, and record the gauge readings taken by the operation personnel.

Observe how the operation personnel gauges each tank, including equalized tanks. If tank gauging is not performed, ask the operation personnel to do so on site. This is only considered a deficiency if it is not done under one of these conditions:

1) at month end
2) as the only means of trucked-in measurement
3) tank used as a test tank

Verify frequency of gauging.

See Appendix A-3 for test tank sizing.

4.2.2 Gas Charts

See Appendix D for recommended gas chart operating procedures, integration standards, documentation, etc.

4.2.3 Proration Testing Procedure

The testing of conventional oil wells is to be done in accordance with the criteria set in *ID 94-1* and Schedule 16 of OGCR, as well as *ID 91-3* for heavy oil. The following information, to be obtained from the operation personnel, will help you to assess the integrity of the testing operation:

- criteria for accepting or rejecting well tests
- well purging and/or stabilization procedure
- testing procedure following shut-in periods or when production conditions have changed
- general production characteristics of the wells – fluid rates, water-cut ranges, production stability, and problem wells
- procedure, equipment, and frequency for GOR testing of gas measurement exempt wells

In addition, the following questions must be answered:

- Are wells on timers?
- Do wells flow when not pumping?
- Does production time include the nonpumping hours?
- Are there any common flow lines in the system?
- How often are flow lines pigged, and does this affect flow rates? Do they retest after pigging?

In your inspection field notes, record the test liquid readings (meter or tank) to two (2) decimal places for the well test being witnessed. Record the time the test went on. Take note if the operation personnel resets the meter before every test (if applicable), and record the readings to two decimal places.

Determine how and when the meter correction factor is applied, if applicable.

4.2.4 Header Switching

Confirm that the well put on the test is the same as indicated on the test chart from header or field valving. Also check if the well is on stream by checking valve positions on the wellhead.

Are the wells adequately identified at the header?

Do wells have adequate time to stabilize at test conditions prior to testing?

4.2.5 Basic Sediment and Water (BS&W) or Water-Cut Procedure for Test Production

Review of the BS&W procedure is normally done on the second day of the field audit, when the proration test is completed and the sample collected. A wellhead sample is not recommended for conventional oil but is allowed below 10 per cent BS&W; however, it is acceptable for heavy oil (>920 kg/m^3). Observe the operation personnel's normal water-cut procedure. Document the procedure and results.

Ensure that the operation personnel collects a large enough sample, according to Appendix C-3.

Allow the operation personnel to complete the procedure before commenting on the accuracy of the methods used.

See Appendix C-3 for recommended water-cut procedure.

4.2.6 Trucked Fluid Receipts and Deliveries

Try to witness truck loading or off-loading to observe the procedure for measurement, sampling, and water-cut.

See *IL 90-6* and *IL 92-8* for guidelines and Appendix C-3 for recommended water-cut procedure.

4.3 Other Oil Battery Information

Day One of Inspection

Through your observations or by questioning the operation personnel, gather the following information:

- Record any other meter readings, such as fuel gas, flare, condensate or LPG, group oil or water, water injection or disposal—anything that affects the accounting at the battery.
- Determine how products are transported or sold from the battery (through pipeline, truck, etc.).
- Determine the type of field data capture system used, such as the accounting procedure or software used to calculate the volumes.
- Record the type of measurement used to determine the sales volume (LACT, tank gauging, etc.). Record the meter reading or gauge reading taken by the operation personnel.
- Fill out Facility Check Sheet (Appendix F-3) and send to the appropriate Field Centre.
- Check what data are recorded and where they are recorded. Review all log(s), load oil injection/recovery records, gauge sheets, test records, trucking records, water injection records, etc., and have the operation personnel explain each entry and calculation. Determine what records are sent to the operating company’s head office.
- Record the method of measurement or estimate of blowdown gas and the blowdown frequency.

It is important to take detailed notes before you leave the lease, when your observations are fresh in your mind. Go over your notes and elaborate if necessary. Write down any points you may have missed or points requiring further clarification.

Day Two of Inspection

On the second day of your inspection, confirm all procedures and operating conditions, note any changes, and gather any information you missed the previous day.

Record all meter readings taken by the operation personnel, as done on the previous day. Record the time off for the well test(s) witnessed.

4.4 Gas Batteries Equipment Inspection

Confirm the accuracy of the flow diagram on file. Note any changes or additions. Sketch your own flow diagram if necessary, noting all measurement points.

Record the following meter data:

- Liquid meters – manufacturer, serial and model number, calibration date, meter factor, flow rate through meter. Does the metering conform to OGCR, Section 14.180? If not, is there a special reason? See Appendix A-1 for recommended flow rates.

- Condensate meters must comply with OGCR, Sections 14.090 and 14.180, and water meters must comply with OGCR, Sections 14.140 and 14.160 to 14.180.

- Orifice meters – static, differential and temperature ranges, chart drive speed, upstream run size, manufacturer, serial and model number, manufacture and calibration dates; have operation personnel pull the plate in use, if possible, and check spare plates for damage and proper storage. Orifice meters must comply with OGCR, Section 14.070, and conform with AGA3 for orifice meter installation requirements, including minimum upstream and downstream pipe lengths. (See "Meter run inspection" in Appendix D-1.)

- Other gas meters – calibration date, manufacturer, serial and model number, flow rate through meter. Are these meters temperature or pressure compensated? (See Appendix B-1 for calculations.)

- Automated measurement systems – any measurement performed using electronic or SCADA equipment must conform to the requirements of Appendix D-5.

- Check to ensure that the meter bypass is closed for all accounting meters.

Try to witness the meter calibration procedure if possible.

Note any unmetered gas, condensate, LPG, or water streams (fuel, recycle, etc.).

Record the capacity and dimensions of each storage tank, including LPG bullets.

Record the pressure and temperature of each process vessel and liquid sampling point.

Initial each chart for verification during records review.

Check approval for any chart greater than 8 days.

Complete a Facility Check Sheet (Appendix F-3).

Vessel drain line must be directed to a suitable container or bull plugged and not directed to a pit.

Check if condensate tank vapours are vented, gathered, or flared. Record the volume of vented gas measured or estimated.

Check the location of test taps for effluent measurement wells or for southeast Alberta proration wells. (See Section 4.5.4: Test and Sampling Procedures, below.)

4.5 Gas Batteries Operational Procedures

Operation personnel are a valuable source of information. Ask questions, observe, and listen carefully. Accompany the operation personnel on rounds to the well sites. Check as many wells as possible within the time frame of the inspection. Discretion is required as to what type and which well(s) you should choose to go to and if you should visit all well(s) on test (proration or effluent measurement systems). Inspect and observe procedures at each installation. Note any adjustments made to wellhead or process equipment.

4.5.1 Tank Gauging (see Appendix A-2 for operating procedures)

4.5.2 Gas Charts (see Appendix D-1 for operating procedures)

4.5.3 Trucked Fluid Receipts and Deliveries (see *IL 90-6* and *IL 92-8* for operating procedures)

4.5.4 Test and Sampling Procedures

For gas wells in southeast Alberta proration systems and any other systems approved for proration, ensure that well tests are conducted and volumes determined in accordance with *IL 93-10* and *Directive 7*, Appendices 10 and 11.

For gas wells that require semi-annual water rate testing, ensure that procedures outlined in *Directive 4* for determining water production are followed. Ensure that water/gas ratios (WGR) records are updated and reported accordingly.

For effluent wellhead measurement, ensure that the test taps are located downstream of the effluent meter and the effluent correction factors (ECF) are updated accordingly.

Record the operating temperature and pressure at the gas meter run or at the effluent meter run.

Check for up-to-date meter calibrations (see *ID 90-2*). This is to be done once every 12 months for gas meters and once every 6 months for condensate meters. Shop calibration of condensate meters is permissible when the condensate rate is less than 2 cubic metres per day (m^3/d) or less than 3 m^3/d and the gas equivalent volume of the condensate is less than 3% of the measured gas volume. (Also see *Directive 64*, Section 2.1(d).)

Check flow rate through liquid meter (see Appendix A-1).

Check BS&W determination procedures (see Appendix C-3).

Record any other meter readings or tank gauges, such as fuel, flare, condensate, water disposal, blowdown, and anything that affects the accounting at the battery.

4.6 Other Gas Battery Information

Through your observations or by questioning the operation personnel, gather the following information:

- Field records – What data are recorded and where are they recorded? Review all log books, gauge sheets, test records, trucking records, water injection records, etc., and have operation personnel explain each entry and calculation. Determine what records are sent to head office.

- Measurement or estimate of blowdown gas; blowdown frequency.
- Location of group measurement point and any field compressors and line heaters.
- Tie-in location of other gas systems.
- Status of nonproducing wells.
- Dates of last well tests, if applicable.

Check flaring and venting records.

Check where fuel gas comes from and where sales gas is delivered.

Check how water is disposed of.

Note if any liquids are recovered at compressor stations and how they are handled—recombined or trucked out.

Record all test meter readings taken by the operation personnel if applicable. Record the time off for the well test(s) witnessed.

It is important to take detailed notes before you leave the lease when your observations are fresh in your mind. Go over your notes and elaborate if necessary. Write down any points you may have missed or points requiring further clarification.

Check to ensure that the battery type code matches with what is going on in the field.

Check for wet and dry gas metering producing to the same battery. Wet metering requires proration from a group measurement point. If dry metering is mixed with wet metering, all the dry volumes have to be subtracted from the group meter before proration. OGCR, Section 14.040, does not permit metering by difference unless special approval is given by the ERCB.

Check for oil wells tied into a gas battery. *Directive 60* requires that oil well (associated) gas tying into a gas battery be reported separately under a different battery code and vice versa.

5 Records Review

All of the following reviews are to be completed in the office after the field trip.

Records Request

Attach a cover letter to the Data Request Sheet (see samples in Appendix F-2):

- Address it, by name if possible, to the Production Superintendent/Operations Manager level.

- Identify the battery name, legal land description, operator code, facility code, and licence or approval numbers, if applicable.

- Allow the licensee a reasonable time to assemble the information requested. Consider the size and complexity of the facility. Choose a due date at least 30 days from the time of the request.

- Follow up your request letter verbally to check if it was received and to ensure the information will be filed within a reasonable time.

Data Request Sheet

Request all field and accounting records relevant to the facility being audited, as listed on the Data Request Sheet in Appendix F-2. You may also wish to request additional information not covered on the request sheet.

Receipts of Records

Review the contents and request any information not submitted.

Ask for an explanation for any requested item that the licensee is unable to provide.

5.1 Oil Batteries

5.1.1 Oil Battery Production Reports

Monthly volumetric submission amendments must be completed, as outlined in *Directive 7*, through the Petroleum Registry. Request amendments if significant and correctable reporting errors are noted. You may use the following criteria to determine amendment requirements for most cases:

- Any error that results in a change in the total battery production must be corrected, regardless of the magnitude of the change, since the error will affect the production for all the wells in the battery.

- Any error that results in a change in the estimated and/or actual oil production at a well in excess of a predetermined criteria may warrant an amendment. The graph of amendment criteria (see Figure 1) can be used as baseline data when production volume amendments are being considered.

5.1.2 Oil Battery Equipment

Measurement equipment is unsatisfactory if it does not meet the ERCB measurement requirements or if additional equipment is required. See

- *Directive 64: Facility Inspection Manual*

- Oil and Gas Conservation Act and Regulations

- Oil Sands Conservation Act and Regulations

- Appendices D-1 and F-3.

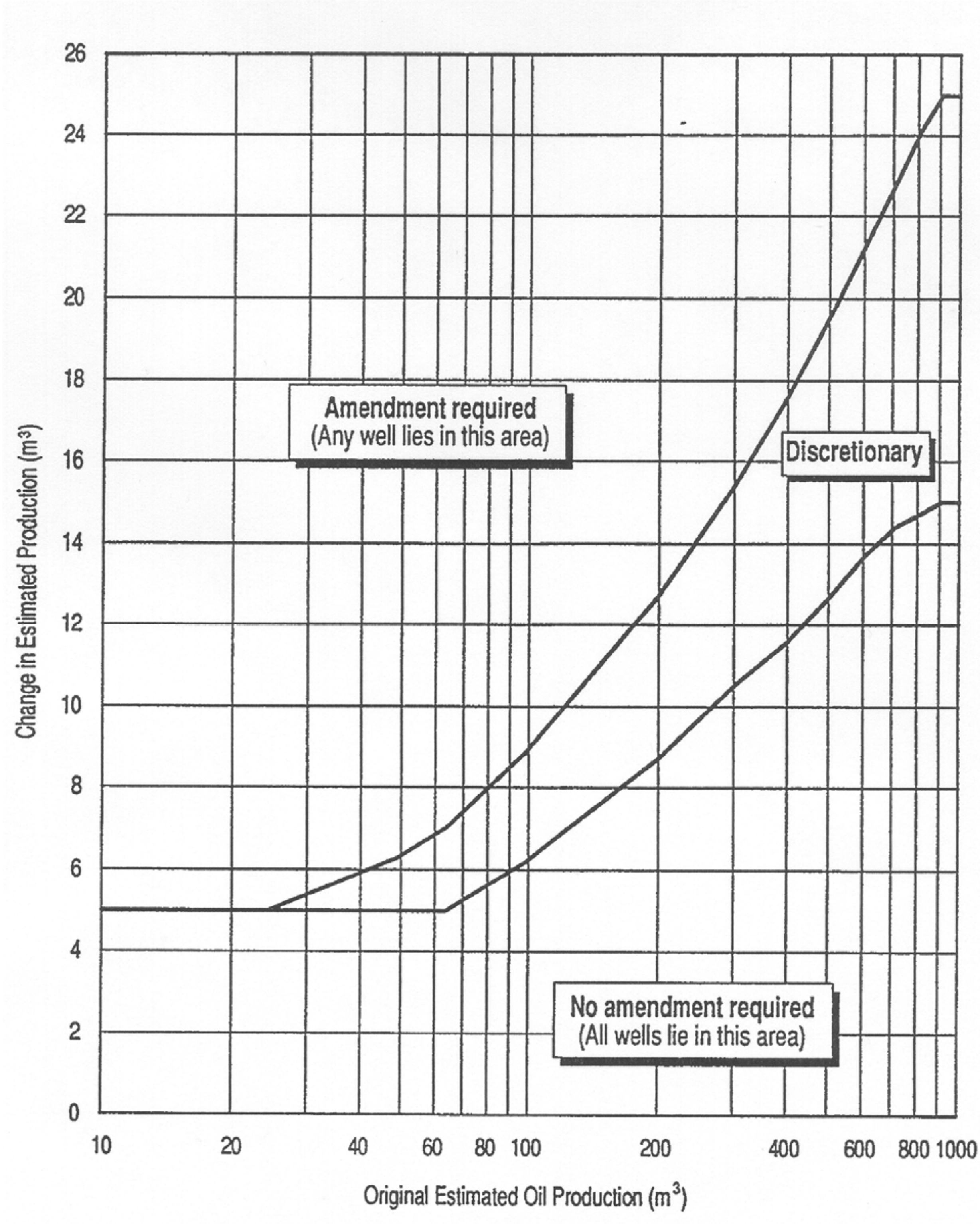


Figure 1. Criteria for requesting amendments; permissible change before amending on a per well basis

Central Facility/Satellites

Do the group vessels and tankage provide adequate separation of oil, gas, and water?

Are enough test vessels installed to comfortably meet the minimum test frequency (see *ID 94-1* and Schedule 16 of OGCR; *ID 91-3* for heavy oil)?

Are test vessels and test tanks correctly sized for the flow conditions encountered? Test tank diameter sizing calculation is summarized in Appendix A-3.

Are gas wells associated with oil battery? *Directive 60* requires gas wells flowing to oil batteries to have separate battery codes and special approval from ERCB.

Field Header/Common Flow Lines

Can the required purge duration and test frequencies be met with existing equipment?

- Use the total fluid flow rate of the producing well and the test line capacity to calculate the minimum purge time required.

- Example: Calculate the minimum purge time required for the following common test line:

  - Line dimensions = 1500 m length, 88.9 mm OD pipe, 3.2 mm wall thickness

  - Two wells tied in

    Well #1 flow rate = 5.5 m^3 oil/d, 12.0 m^3 water/d
    Well #2 flow rate = 7.2 m^3 oil/d, 18.9 m^3 water/d

    Step 1

    $d = (88.9 – 3.2 \times 2)/1000 = 0.0825$ m

    $$\text{Test line capacity} = 3.1415926 \times d^2 \times \text{length} / 4$$
    $$= 3.1415926 \times (0.0825)^2 \times 1500 /4$$
    $$= 8.02\ m^3$$

    Step 2

    Purge time required = Test line capacity (m^3)/ Well flow rate (m^3/h)

    $$\text{Well \#1 total fluid flow rate} = (5.5\ m^3 + 12.0\ m^3) /24\ h$$
    $$= 0.729\ m^3/h$$

    $$\text{Purge time required} = 8.02\ m^3/ 0.729\ m^3/h$$
    $$= 11.00\ h$$

    $$\text{Well \#2 Total fluid flow rate} = (7.2\ m^3+ 18.9\ m^3) /24\ h$$
    $$= 1.088\ m^3/h$$

    $$\text{Purge time required} = 8.02\ m^3/ 1.088\ m^3/h)$$
    $$= 7.37\ h$$

    Therefore the minimum purge time required for Well #1 is 11 hours and for Well #2 is 7.5 hours.

Fluid Samplers – All Meters

Are sampling devices operating as per manufacturer's specification? (See Appendix C-1.)

Oil Meters

Determine if additional meters are required. (See Central Facility Satellites on previous page.)

Is downstream valve snap acting or throttling? (See OGCR, Section 14.080.)

Ensure that the meters used are appropriate for the flow conditions encountered. (See Appendix A-1.)

5.1.3 Oil Battery Procedures and Records

Refer to your field notes, operation personnel's field records, and gas charts to complete this section. Determine if the procedures the operation personnel demonstrated and described are consistent with the recorded data.

Proration Tests

Check all proration tests.

Are the minimum proration test duration and frequency requirements met?

Is the test frequency and duration adequate to ensure a representative test? Some wells may require longer test duration for a representative test, such as 48 or 72 hours.

Does the duration match the on/off times, accounting worksheets, field records, etc.?

Are common test lines and test vessels adequately purged?

Where there is more than one well on a common flow line, does the operation personnel cascade test or shut one well in at a time to test? Check for approval to conduct cascade testing (see Appendix A-5).

Do the test and group lines operate within an acceptable pressure difference (200 kPa maximum)?

Are wells retested within a reasonable time when production conditions are changed (e.g., the initial production from a well after shut-in or workover)? Wells should be retested as soon as practical after conditions change.

Are all valid well tests recorded, submitted, and used? Some reasons why well tests might be rejected are

- insufficient data due to equipment failure during a test
- insufficient purge time allowed
- well flow conditions changed during a test (e.g., choke setting, pump stroke, etc.)
- battery upset or emergency shutdown
- production/BS&W fluctuation

Sort test data reports (usually gas charts) by test vessel and arrange in chronological order. A continuous test in excess of 24 hours is to be counted as one test. The test date is the day when the test starts.

Check meter readings and on/off times to ensure that they correspond from test to test. Look for purge time and misrun tests. Volumes are to be measured to the nearest 0.01 m^3 and rounded to the nearest 0.1 m^3.

Compare the test meter readings witnessed during the field inspection to what are submitted for review.

Are well tests spaced evenly throughout the month?

What is the status of nonproducing wells?

For heavy oil well testing, see *ID 91-3*, Section 4.2.

Fluid Sampling and BS&W Determination

Samples should be sufficiently large to get a representative sample (see Appendix C-3). Larger samples are required for higher water cut and large volume producers.

Is sampling conducted as outlined in OGCR, Section 14.150?

If water content is greater than 10%, use proportional sampler and analyze the sample accurately or use product analyzer. If less than 10%, you may determine water content by centrifuging two well-spaced samples taken during each test and averaging the results or by the above methods.

The samples should be taken in close proximity to the measurement point. The centrifuge method is acceptable for samples containing less than 10% water. The graduated cylinder method should be used for all other samples. (See Appendix C-3.)

Mason jars with tape attached are not acceptable for determining BS&W.

Trucked Production

Is volume of each outside load measured and reported to the nearest 0.1 m^3?

Is the method of sampling emulsion satisfactory? (See Appendix C-1 and *IL 90-6*.)

If loads are split by transferring free water to the water tanks and the emulsion to another tank, each part must be accurately measured.

Meter Calibrations

Calibrations must be done in accordance with the following:

Oil meters	Test:	OGCR, Section 14.110
	Group:	OGCR, Section14.120
Gas meters	*ID 90-2*	
Condensate meters	OGCR, Section 14.090 (2) (3)	
Water meters	OGCR, Section 14.140 (3) (4)	

Check for up-to-date calibration tags and records.

Shop calibration of liquid meters (density less than 920 kg/m^3) is permissible when the average liquid rate (i.e., total fluid for a two-phase separator and liquid in oil leg for three-phase) of all wells being tested through the meter is less than 2.0 m^3/d and no well exceeds 4.0 m^3/d. For densities at 920 kg/m^3 or greater, shop calibration is permissible under *ID 91-3*, Section 4.4.

Field Records

Look for completeness and accuracy.

All field measurement and pertinent operational data must be recorded and retained on file for 12 months, in accordance with OGCR, Section 12.170, except for heavy oil, which requires 18 months of records to be on file, in accordance with the OSCR, Section 17.

Check field estimates, calculations, and summary reports for blowdown, flared and vented volumes, stock tank vapour estimates, lease fuel estimates, etc.

Errors in calculations or data not affecting the production report volumes should not be recorded as a deficiency (daily prorations, etc.).

Tank Gauging

Is linear metre to cubic metre conversion satisfactory? Are gauging tables used?

Is each tank, including test or equalized tanks, gauged to the requirement of Appendix A-2?

Gas Chart Documentation

See Appendix D.

Load Fluid

See *Directive 7*, appendix on Load Fluid.

5.1.4 Oil Battery Accounting

Production Summary

Review the general accounting formula for the facility (i.e., how the measurement, estimates, receipts, deliveries, and inventories are added and subtracted to determine the numbers entered on the production reports).

Review the flow diagram to ensure that the accounting formula matches the physical facility. Are measurement and estimate points included?

Is well status correct?

Are all estimates included?

Are receipts and deliveries determined satisfactorily?

Are inventories determined satisfactorily?

Is shrinkage accounted for?

Are all applicable temperature and density corrections applied?

Are associated gas wells reported on their own production reports?

How is gas-lift gas metered and reported?

Production hours for wells with intermittent timers, pump-off controls, plunger lifts, etc., that are "operating normally and as designed" are to be considered on production even when the wells are not pumping. Physical well shut-ins and emergency shutdowns (ESDs) are considered down time. The operation personnel has to make a judgement call based on the operating environment in other situations where the wells are not shut in but may or may not have production.

Pipeline Tickets

These include LACT meter, gauge sheet, and truck terminal tickets. Are meter factors, BS&W, and temperature and density correction factors applied?

Compare the meter readings or gauge readings with the field inspection results.

Gas Chart Reading

The integrator traces must closely follow the chart pen traces. Verify the accuracy of the average static, differential, and temperature readings on the chart reading summary. Send the chart out for rereading if necessary.

Confirm the accuracy of the chart information (temperature, orifice size, run size, chart drive speed, on/off times, and gas density) entered on the chart-reading summary.

The integrator operator must not estimate missing pen traces unless there are instructions from the operation personnel to do so.

Integrators record flowing time and test duration. Do not prorate gas summary volumes to 24 hours.

See Appendix D-1 to D-4 for more information on gas charts.

Gas Volume Calculation

- For orifice meters, gas volume must be calculated as outlined in AGA3 and *IL 87-1*. (See Appendix G-1 for metric conversion factors.)

- PD Meter Measuring Gas—Meter readings must be corrected to base temperature and pressure conditions, including the compressibility factor. (See Appendix B-1.)

Unmetered Gas Estimates

There could be routine flaring and/or venting of treater gas or other unmetered gas streams. Estimate these using the same methods as outlined in the GOR below. Or if there is emergency flaring or venting where meters are bypassed or flare meters are overranged, estimate the volume from the facility gas flow balance or refer to the Canadian Association of Petroleum Producers (CAPP) *Directive for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*. Ensure that *Directive 60* requirements are met for reporting of flaring and venting. Pilot or dilution gas for flare is to be reported as fuel.

- Lease Fuel Estimates

  Consider all gas source points and fuel users, including satellite gas taps, casing head gas, pump motors, instrument gas, building heaters, heated tanks, treaters, line heaters, FWKOs, flare pilots, etc. Fuel usage greater than 500 m^3/d must be measured in accordance with *Directive 64,* Section 1.4 (b).

  Estimates for less than 500 m^3/d usage must be based on quantifiable data, such as manufacturer's specifications or previous measurement of fuel rates. Estimating fuel consumption at treaters and FWKOs is discussed in Appendix E-1.

Gas-Oil Ratio (GOR)

Licensees are no longer required to formally apply for Gas Measurement Exemption. The requirement to annually test the gas rates and update the GOR remains in effect.

Review the most recent GOR test results. See requirements in Section 15.140(3) of OGCR.

Ensure that the gas-in-solution correction (below) and upstream lease fuel (e.g., casinghead gas) are applied to the test gas volume used to determine the GOR.

Check calculations.

GOR applies only to wells and facilities producing gas less than 500 m^3 (0.5 10^3 m^3) per day for conventional oil and up to 2.0 10^3 m^3/d for heavy oil (see *IL 91-9*).

See *Directive 7,* appendix on Crude Oil/Bitumen Battery, Exemptions from Gas Measurement.

Estimated Production

Estimated production must be calculated using the test-to-test method outlined in *Directive 7,* appendix on Crude Oil/Bitumen Battery, Prorated Production.

Ensure that the test(s) you witnessed is used and that it is consistent with the licensee's valid test criteria.

A computer program can be used to perform this calculation. Spot check the arithmetic for several wells and verify all entry data.

If the calculation is done by hand, complete the Monthly Proration Test Worksheet (see example in *Directive 7*) to verify the estimates.

All valid well tests must be used.

Consecutive-day tests should be entered as one extended test unless the first day(s) are measurements of flush production, stabilization period, etc.

No well can be recorded as “measured” if the production is flow-lined to a proration battery unless this is the only well producing to the battery for the month. However, there can be prorated and measured production in the same month, such as a single-well battery trucked in to the main battery for part of the month and then flow-lined.

The actual test duration, to the nearest 15 minutes, must be used to determine estimated production rates.

Test gas volume must include an estimate of gas-in-solution with oil (see Gas-in-Solution section below).

Truck Tickets and Summary

Are all volumes on the tickets accounted for in the production records?

Are BS&W splits and other corrections correctly calculated?

Is the trucked-in emulsion (oil) from the same pool as the flow-lined wells? Did the density change from load to load? Shrinkage correction is required if there is blending of emulsion (oil) before measurement and the densities differ by more than 40 kg/m^3.

Are there open and close gauge or meter readings?

Is the decimal format correct?

Check for split loads. (See split loads policy in Appendix A-4.)

Are the requirements outlined in *IL 90-6* and *IL 92-8* adhered to?

Gas Density

Gas density must be updated in accordance with *Directive 49: Gas Density Measurement Frequency*.

Density will vary with process temperature and pressure. Therefore, density must be measured at each orifice metering point in accordance with *Directive 49*.

Gas-in-Solution Estimates

Gas-in-solution is the volume of gas liberated from the oil as the pressure is reduced. It is sometimes referred to as “test-to-group correction.”

The gas-in-solution correction factor will be reported to standard conditions in cubic metres of gas per cubic metre of oil per kilopascal of pressure drop.

The number of stages of separation and the conditions at each stage will affect the volume of gas liberated.

A correction factor is required for each test vessel and for each unique test temperature/pressure situation. This correction is imperative for low GOR pools and multipool batteries and when testing at high pressure.

Gas-in-solution volumes must be added to the group measurement volume, unless a metered vapour recovery unit(s) (VRU) is in use. Gas-in-solution volumes for the well on test must be added to the well test gas volumes based on pressure drop and oil volume.

See Appendix E-2 for details.

Injection Summary

Check the accounting formula used to determine the receipt, delivery, and injection volumes reported on the monthly volumetric submissions for Injection/Disposal.

Ensure that measured volumes are used and metering differences are reported, if any.

5.2 Gas Batteries

5.2.1 Gas Battery Production Reports

Monthly volumetric submissions must be completed, as outlined in *Directive 7*, through the Petroleum Registry. Request amendments if significant and correctable reporting errors are noted:

- Any error that results in a change in the total battery production should be corrected, regardless of the magnitude of the change, since the error will affect the production for all the wells in the battery.

5.2.2 Gas Battery Equipment

Measurement equipment is unsatisfactory if it does not meet the ERCB measurement requirements or if additional equipment is required. See

- *Directive 64: Facility Inspection Manual*
- Oil and Gas Conservation Act and Regulations
- Oil Sands Conservation Act and Regulations
- Appendix D-1: Orifice Meter Inspection Guidelines
- Appendix F-3: Facility Check Sheet
- *ID 90-2: Gas Meter Calibration*

5.2.3 Gas Battery Procedures and Records

Refer to your field notes, operation personnel's field records, and the gas charts to complete this section. Determine if the procedures the operation personnel demonstrated and described are consistent with the recorded data.

Production Tests

Production tests can be used in place of continuous measurement for southeast Alberta gas proration batteries and other ERCB-approved gas proration batteries. Testing is also required for effluent meter correction (ECF) and the WGR, if applicable, and is performed in accordance with *Directive 4*, unless special approval has been obtained from the ERCB Compliance and Operations Branch for relaxing of the testing frequency.

For effluent measurement, ensure that proper procedures are followed.

See *IL 93-10*; *Directive 7,* Appendices 10 and 11; and *Directive 4.*

BS&W Determination

See Appendix C-3.

Trucked Production

Volume of each receipt load must be measured and reported to the nearest 0.1 m^3.

If condensate and water are trucked from the wells, where are they delivered?

If loads are split by transferring free water to the water tanks and the condensate to another tank, each part must be accurately measured.

Meter Calibrations

Oil meters	Test: OGCR, Section 14.110 Group: OGCR, Section 14.120
Gas meters	*ID 90-2*
Condensate meters	OGCR, Section 14.090 (2) (3)
Water meters	OGCR, Section 14.140 (3) (4)

Check for up-to-date calibration tags and records.

Shop calibration of condensate meters is permissible when the condensate rate is less than 2.0 m^3 per day **or** less than 3.0 m^3 per day and the gas equivalent volume of the condensate is less than 3% of the measured gas volume.

Field Records

Look for completeness and accuracy.

All field measurement and pertinent operational data must be recorded and retained on file for one year, in accordance with OGCR, Section 12.170.

Check field estimates, calculations, and summary reports for blowdown, flared and vented volumes, stock tank vapour estimates, lease fuel estimates, etc.

Errors in calculations or data not affecting the production report volumes should not be recorded as a deficiency.

Tank Gauging

Is the procedure satisfactory?

Is linear metre to cubic metre conversion (strapping tables) satisfactory? Is the correct gauge table being used?

Each tank, including equalized tanks, must be gauged to the requirements in Appendix A-2.

Gas Chart Documentation

See Appendix D-1 to D-4.

Is blowdown recorded on chart?

Fuel, flaring and venting gas—Are pressure and temperature recorded? Are they measured?

Load Fluid

See *Directive 7*, appendix on Load Fluid.

5.2.4 Gas Battery Accounting

Production Summary

Review the general accounting formula for the facility (i.e., how the measurement, estimates, receipts, deliveries, and inventories are added and subtracted to determine the numbers entered on the production reports).

Review the flow diagram to ensure that the accounting formula is correct. Are measurement and estimate points included?

Is well status correct? Is gas well producing oil, as opposed to condensate?

Are all estimates included?

Are receipts and deliveries determined satisfactorily?

Are inventories determined satisfactorily?

Is shrinkage accounted for?

How is liquid handled? If it is trucked out from tanks, where is it delivered? Or is it metered and recombined or ECF used?

Wells with intermittent flow controls, plunger lifts, etc., that are "operating normally as designed" are considered on production even when the wells are not flowing. Physical well shut-in and ESDs are considered down time. The operation personnel has to make a judgement call based on the operating environment in other situations where the wells are not shut in but may or may not have production.

Pipeline Tickets

Are meter factors, BS&W, and temperature and density correction factors applied?

Gas Chart Reading

The integrator traces must closely follow the chart pen traces. Verify the accuracy of the average static, differential, and temperature readings on the chart-reading summary. Send the chart out for reread if necessary.

Confirm the accuracy of the chart information (temperature, orifice size, run size, chart drive speed, on/off times, and gas density) entered on the chart-reading summary.

The integrator operator must not estimate missing pen traces unless there are instructions from the operation personnel to do so.

Integrators record flowing time and test duration. Do not prorate gas summary volumes to 24 hours.

See Appendix D-1 to D-4 for more information on gas charts.

Gas Volume Calculation

For orifice meters, gas volume must be calculated as outlined in AGA3 and *IL 87-1*.

See Appendix G-1 for metric conversion factors.

Positive displacement (PD) meter measuring gas—Meter readings must be corrected to base temperature and pressure conditions, including the compressibility factor. (See Appendix B-1.)

Acid gas volume—see Appendix B-2.

Unmetered Gas Estimates

Consider all gas source points and fuel users, including pump motors, instrument gas, building heaters, heated tanks, line heaters, FWKOs, and flare pilots.

Estimates must be based on quantifiable data, such as manufacturer's specifications or previous measurement of fuel rates.

See Appendix E-1.

Unmetered flare and vent gas estimate—Where there is flaring or venting when meters are not present or when bypassed or if flare meters are overranged, estimate the volume from the facility gas flow balance or refer to the CAPP *Guide for Estimation of Flaring* *and Venting Volumes from Upstream Oil and Gas Facilities*. Ensure that *Directive 60* requirements are met for reporting of flaring and venting. Report pilot or dilution gas for flare as fuel.

Estimated Production

Are estimated volumes calculated correctly?

Is meter factor applied to liquid meter volumes?

Is water volume determination satisfactory?

No well can be reported as "measured" if the production is prorated unless approved by the ERCB. This is not required to be reported to the Petroleum Registry. However, look out for "mixed" measurement: measured gas in proration battery or measured gas mixed with effluent measurement. This requires special approval from the ERCB Compliance and Operations Branch because of measurement by difference.

See *IL 93-10* and *Directive 7*, Appendix 10.

Truck Tickets and Summary

Are all tickets accounted for?

Are there open and close gauge or meter readings? The gauge readings should be there if they are taken.

Is the decimal format correct?

Identify delivery type (disposal, sale, etc.).

Gas Density

Gas density must be updated in accordance with *Directive 49: Gas Density Measurement Frequency*.

Density varies with process temperature and pressure. Therefore, density must be measured at each orifice metering point, in accordance with *Directive 49*.

Gas Equivalent Calculation

NGL and condensate are normally stored and measured in a liquid state; however, they must be reported on the production reports (except gas processing plant products monthly volumetric submissions or production monthly volumetric submissions, as well as disposition monthly volumetric submissions if trucked out) as a gas equivalent volume (10^3 m^3).

A conversion factor can be calculated from a compositional fluid analysis. The three methods of calculating gas equivalent factors are outlined in Appendix E-3.

The fluid analysis used to derive the factor must be updated annually, unless gas production is 16.9 10^3 m^3/d or less, when it must be updated once every two years. (See OGCR, Section 11.080, and *Directive 49*.)

Injection Summary

Check the accounting formula used to determine the receipt, delivery, and injection volumes reported on the injection/disposal monthly volumetric submission.

Ensure that measured volumes are used and metering differences are reported, if any.

5.3 Audit Results

Record the inspection result for each category inspected and total the overall result. The original stays in the audit file. Give a copy to the Production Audit technician for statistical use.

Appendix A Liquid Measurement

A-1 Recommended Rates and Pressure Drops for Liquid Meters

When evaluating fluid measurement systems, it is important to first determine if the control or dump valve is a snap-acting type valve. By having snap-acting control, as well as having a properly designed separator system, the meter will immediately get up into the recommended operating range of approximately 30% to 70% of the meter capacity.

Each meter manufacturer guarantees a specific accuracy range for a given meter provided that the recommended flow rates and pressure drops are adhered to. The following two tables and chart list several meters currently in service for oilfield production measurement. The manufacturer's recommended flow rates and pressure drops are indicated. If the meter is not on the list, record the meter type, size, model, and serial number and call the manufacturer or local representative for that information.

The following procedure can be used to check if a meter has been sized to operate within the manufacturer's specifications:

- Record the meter's opening and closing readings.
- Watch the dump valve when it is actuated to determine if it is snap-acting. (The valve should open fully in 3 to 4 seconds.)
- Record the time required for the dump valve to open and close completely (referred to as duty-cycle).
- From the duty-cycle and the meter readings, a 10-second flow rate can be determined.
- **Volume (L) = [Closing meter reading (m^3) – Opening meter reading (m^3)] x 1000 L/m^3**
- **Flow rate (L/10s) = [Volume (L) / Time (s)] x 10**
- **Flow rate (LPM) = [Volume (L) / Time (s)] x 60**
- Compare your result to the manufacturer's recommended 10-second flow rates.
- Watch the dump valve close to determine if the valve leaks. (The meter will continue to spin after the leaking valve is closed.)

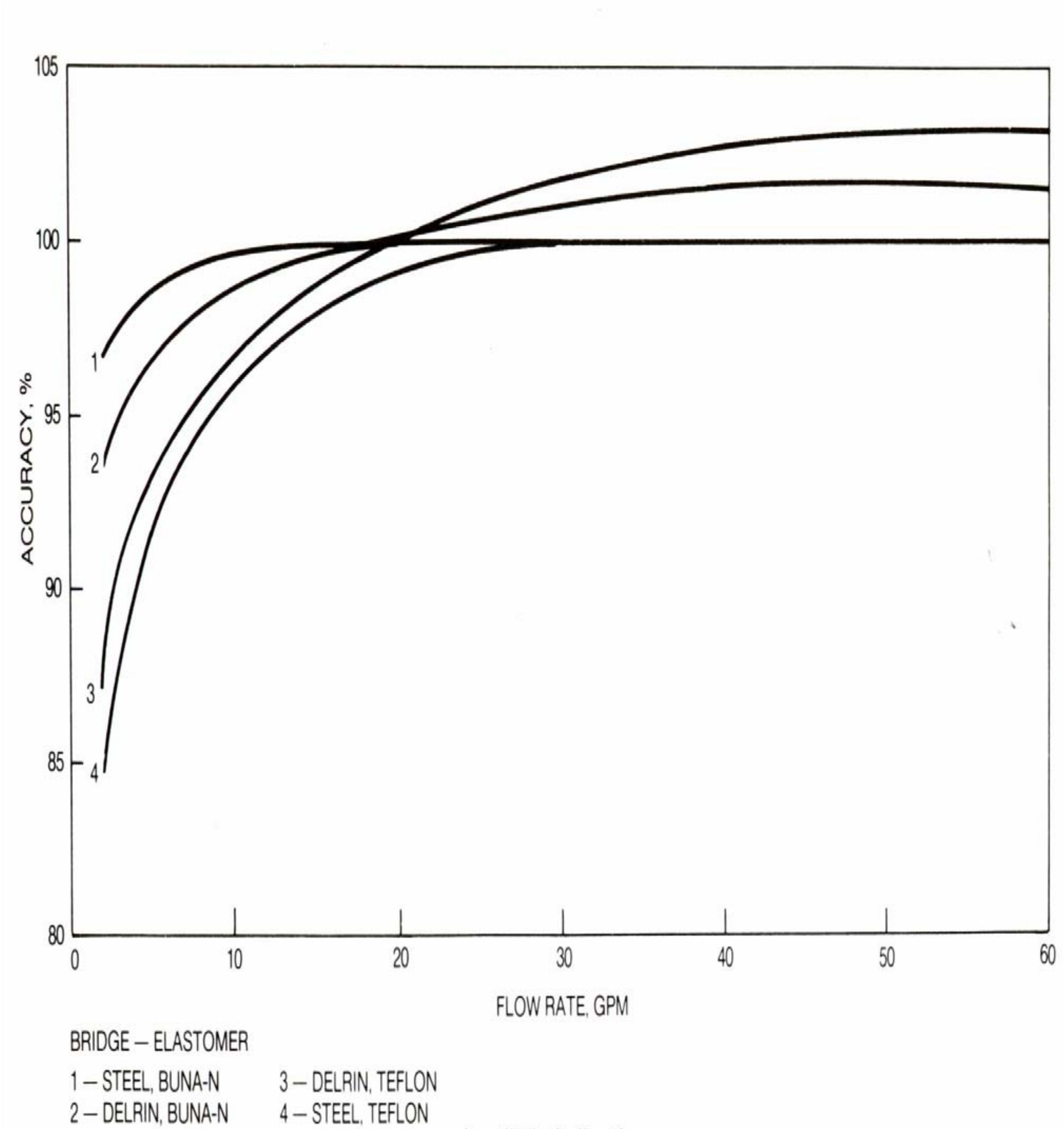
Table 1. Positive Displacement Meters

Type	Size (inches)	Flow rate (m³/day)	Oil and water pressure drop (psi) Min - Max	Condensate pressure drop Min – Max	Flow rate (L/10 sec) Min - Max
AO Smith	1 ½ – 2	133.5 – 686	.02 – 2.5	Not recommended	15 – 79.5
	2 ½ – 3	305 - 1525	.02 – 4.5		35.5 – 176.5
Mock & Floco					
500#	1 – 2	32 – 326	1.0– 15.0	3 – 15	3.7 – 38.0
500 – 2500#	3	49 – 490	.5 – 6.0	3 – 15	5.6 – 56.0
2500 – 5000#	1	32 – 326	1.5 – 15.0	3 – 15	3.7 – 38.0
2500#	2	32 - 326	1.0 – 15.0	3 - 15	3.7 – 38.0
Flotrac	1 – 306	23 – 476	2.5 – 50.0	2.5 – 50.0	2.6 – 55.0
	1 - 380	8 - 81	1.5 – 45.0	1.5 – 45.0	1.0 – 9.0
Brooks (Red)	1 – 793	26 – 286	1.0 – 20.0	3 – 15	3.0 - 33
(Black)	1 – 792	7.9 - 108	1.0 – 5.0	1 – 15	.1 – 13
Neptune	5/8	11 – 109	Not available	Not recommended	1 – 12
	¾	16 – 164			2 – 18
	1	27 – 271			3 – 31
	1 ½	55 – 545			6 – 63
	2	87 - 872			10 – 100

Table 2. Turbines

METER TYPE	METER SIZE	AVERAGE K-FACTOR (pulses/gal)	AVERAGE K-FACTOR (pulses/m^3)	FLOW RATE (GPM)		FLOW RATE (BPD)		FLOW RATE (LPM)		FLOW RATE (m^3 PD)	
				Min	Max	Min	Max	Min	Max	Min	Max
Blancett	3/8"	15364	4059169	0.3	3.00	10.3	102.9	1.14	11.36	1.5	16.4
	1/2"	11145	2944509	0.75	7.50	25.7	257.1	2.84	28.39	4.1	40.9
	3/4"	3033	801309	2.0	15.0	68.6	514.3	7.57	56.73	10.9	81.8
	7/8"	3047	805007	3.0	30.	102.9	1328.6	11.36	113.55	16.4	163.5
	1"	847.04	223788	5.0	50.0	171	1714	18.93	189.25	27.3	272.5
	1-1/2" & 2"	318.42	84027	15	180	514	5171	57	681	81.8	981.1
	2"	46.23	12214	40	400	1371	13714	151	1514	218.0	2180.2
	3"	51.46	13596	60	600	2057	20581	227	2271	327.0	3270.2
	4"	30.13	7960	100	1200	3429	41143	379	4542	545.0	6540.5
	6"	7371	1947	200	2500	6857	85714	757	9463	1090.1	13626.0
	8"	3014	796	250	3500	8571	120000	946	13248	1362.6	19076.5
	10"	1643	434	500	5000	17143	171429	1893	18925	2725.2	27252.1
Cliff Mock	1"	860.02	227218	5.0	50.0	171	1714	18.93	189.25	27.3	272.5
	1-1/2"	325.01	85867	15	180	514	6171	57	681	81.8	981.1
	2"	53.00	14003	40	400	1371	13714	151	1514	218.0	2180.2
	3"	56.00	14796	50	600	2057	20571	227	2271	327.0	3270.2
	4"	29.00	7662	600	1200	3429	41143	379	4542	545.0	5540.5
Daniels	3/4"	940.42	248458	3.9	28.8	132.1	987.6	14.58	109.03	21.0	157.0
	1"	570.25	150660	6.0	60.0	206	2057	22.71	227.08	32.7	327.0
	1-1/2"	140.05	37000	14.9	129.9	510	4454	56	492	81.0	708.0
	2"	115.05	30396	25.0	224.8	656	7706	94	851	136.0	1225.0
Halliburton	3/8"	20001	5234137	0.30	3.00	10.3	102.9	1.14	11.36	1.6	16.4
	1/2"	13000	3434689	0.75	7.50	25.7	257.1	2.84	28.39	4.1	40.9
	3/4"	3000	792621	2.0	15.0	68.6	514.3	7.57	56.78	10.9	81.8
	7/8"	1601	423000	3.0	30.0	102.9	1028.6	11.36	113.55	16.4	153.5
	1"	920.02	243070	5.0	50.0	171	1714	18.93	169.25	27.3	272.5
	1-1/2"	330.01	87177	15	180	514	6171	57	681	81.8	981.1
	2"	55.00	14531	40	400	1371	13714	151	1514	218.0	2180.2
	3"	57.00	15060	60	600	2057	20571	227	2271	327.0	3270.2
	4"	29.00	7662	100	1200	3429	41143	379	4542	545.0	6540.5
	6"	7.37	1947	200	2500	6857	85714	757	9463	1090.1	13526.0
	8"	3.01	796	350	3500	12000	120000	1325	13248	1907.6	19076.5
Hydril	1/2"	12000	3170482	0.72	7.28	25	250	2.71	27.57	3.9	39.7
	3/4"	3200	845462	2.0	15.0	66	515	7.50	56.81	10.8	81.8
	1"	860.03	253639	5.0	49.5	170	1698	18.75	187.50	27.0	270.0
	1-1/2"	320.01	84546	15.0	174.8	515	5995	58.81	661.80	81.8	953
	2"	213.01	56276	37.8	378.9	1296	12990	143.06	1434.02	206	2065
ITT Barton	3/4"	2885	762255	2.5	30.0	36	1030	9.51	113.68	13.7	163.7
	1"	1048	276948	6.0	75.1	205	2575	22.64	284.3	32.6	409.4
	1-1/2"	419	110779	15.0	180.3	515	6182	56.87	682.50	81.9	982.8
	2"	138	36399	25.0	300.5	659	10302	94.79	1137.29	135.5	1637.7
	3"	41	10814	55.1	561.1	1868	22666	208.47	2502.21	300.2	3603.2
Natco	3/4" LF	4548	1201512	1.32	13.12	45	450	5.00	49.65	7.2	71.5
	3/4"	1875	495388	3.21	23.04	110	790	12.15	87.22	17.5	125.6
	1"	938	247826	6.4	63.9	220	2190	24.31	241.74	35	348.1
	1-1/2"	345	91088	17.5	175.0	600	6001	56.25	662.50	95.4	954
	2"	180	47557	33.0	289.9	1131	9939	127.86	1097.22	179.8	1580
Tejas/ Camco	3/4"	2101	555066	2.92	29.17	100	1000	11.04	11.42	15.9	159
	1"	700	185022	8.8	87.5	300	2999	35.12	331.04	47.7	476.7
	1-1/2"	350	92511	17.4	174.8	598	5995	55.97	661.80	95	953
	2"	220	58149	29.2	291.5	1000	9996	110.35	1103.47	58.9	1589

Chart 1. Flow Curves for 1" and 2" Floco Meters



A-2 Tank Gauging Procedure

There are two basic methods for obtaining manual tank gauge readings:

1) Innage gauge – the depth of liquid in a tank is measured from the surface of the liquid to the tank bottom or to a fixed datum plate. (The bob and tape must be lowered so that the bob just touches the tank bottom. Lowering the bob too far will cause incorrect gauge readings.)

2) Outage gauge – the distance from a reference point at the top of the tank to the surface of the liquid is measured. This gauge is then subtracted from the full height gauge (from the same reference point) of the tank to determine the liquid content.

Either of the above manual tank gauging methods is acceptable for gauging crude oil storage tanks. Ensure that the correct gauge table is used to calculate the liquid volume, because two tanks of the same volume could have different tank diameters.

See Directive 017, section 14.7 for requirements (April 18, 2011)

For manual custody transfer gauging:

- For tanks greater than 160 m^3 (1000 bbl), two consecutive readings to be within a range of 3 mm (1/8 in.) of each other are required; use the average of the two readings.

- For tanks 160 m^3 (1000 bbl) or less, one reading is acceptable. All readings must be determined to the nearest 3 mm (1/8 in.).

For noncustody transfer gauging, such as inventory control, one reading on the gauge tape is acceptable for all tanks and must be determined to the nearest 3 mm (1/8 in.).

Note that the gauge tape should stay in contact with the tank hatch while lowering and raising the bob in the tank. This will ensure that static charge is not allowed to build up while the tape is being used. For custody transfer or truck receipts, the operation personnel should ensure that the tank level is not changing when the readings are taken (this may require shutting in the tank before gauging). For production tanks, no shut-in is required when gauging the tank.

For all nonmanual or automatic tank gauging systems, one reading on the instrument is acceptable and must be determined to the nearest 3 mm (1/8 in.). Ensure that the gauging system is operating freely, without obstruction, before the reading is taken. Eye-level readings are required for reading gauge boards. Gauge board markings should be to the nearest 3 mm (1/8 inch).

The automatic gauging system should be calibrated in accordance with API MPMS Chapter 3.1B.4 calibration procedures, except for the frequency of calibration. The gauging system must be calibrated before being put into service and on a yearly basis thereafter.

A-3 Well Test Tank Diameter Sizing Guidelines

Tank gauging is subject to errors or uncertainty in the reading of the tape (in and out), as well as in the accuracy of the tape itself (in and out). The error in total volume measurement can be minimized by maximizing the height of the fluid column being gauged. Given a specified tank diameter, uncertainty at 1%, and gauge reading to the nearest 1/8 inch or 3 mm according to Appendix A-2, the required test volume can be estimated. Conversely, knowing the rates of the wells (i.e., test volume), the required tank diameter can be calculated.

See Directive 017, section 12.3.4 and 14.7.3 for requirements (April 18, 2011)

To meet accuracy requirements for total test fluid measurement, the minimum test fluid volume or maximum tank diameter should be determined as follows:

$V >= a \times d^2$ OR $d = < (V/a)^{1/2}$

Where:

V = test volume in m^3

d = test tank diameter in metres

a = accuracy coefficient

= 0.39 for 1.0% uncertainty

There is some flexibility when applying this rule of thumb. Practicality suggests that requirements for low-productivity wells might be less than the guidelines suggest.

Note that test tank volumes must also be temperature corrected.

A-4 Split Loads Guideline - Replaced by Directive f017, section 10.3.5 (April 18, 2011)

A split load is defined as existing when a truck takes on partial loads from more than one well or battery in a single trip or when load oil is delivered to more than one receipt point or wells.

Allowed:

- Single-well oil battery
- Gas wells with condensate tanks—less than 2.0 m^3 liquids per day production
- Blending of heavy oil and condensate
- Load oil—for well servicing only; load up from a single source only

Not allowed:

- Multiwell batteries
- Gas wells with greater than 2.0 m^3 liquids per day production

Requirements: Densities must be "similar" (within 40 kg/m^3); if they are not, blending tables are required to calculate shrinkage. The shrinkage volume is to be prorated back to each battery on a volumetric basis.

Measurement: Volume from each well or source must be measured at the time of loading onto the truck (or off loading from the truck for load oil) by one of the methods below:

i) gauging the battery lease tank;
ii) gauging the truck tank (not allowed for density difference over 40 kg/m^3 for any oils or emulsions); or
iii) truck-mounted meter—calibrated minimum once every 6 months.

Calibrated gauge tables are required for methods (i) and (ii) above.

Sampling: Fluid from each single-well oil battery must be sampled to determine the BS&W and the oil/water volumes. The truck driver is to collect the samples by taking at least 3 well-spaced grab samples during the loading period. The operation personnel of the unloading location is to determine the BS&W from the samples taken.

For load oil, the BS&W should be determined at the loading source.

Records: The truck tickets must show the individual load volumes, as well as the total volume at delivery (receipt) point, supported by opening and closing gauge or meter readings.

Accounting: For battery emulsions, the total load is to be measured and sampled at the unloading location and prorated to each of the wells based on the measured loading volumes and BS&W from each of the wells.

For load oil, the initial volume must be measured at the loading source and prorated to each delivery point based on the measured volume delivered to each well.

A-5 Cascade Testing

When a prorated oil well has low gas production such that it cannot properly operate test equipment, a licensee may test two oil wells simultaneously—cascade test—through the same test separator. See Directive 017, section 6.7 for requirements. (April 18, 2011) In such cases, the following procedure must be followed:

1) Establish accurate oil, gas, and water production volumes for a high gas producing oil well by testing it individually through the test separator for a period of 24 hours or longer for a representative test.

2) Conduct a representative test for both the high gas producing oil well and low gas producing oil well together through the same test separator for a period of 24 hours or longer immediately after testing the high gas producing well, allowing time for stabilization. (The testing sequence may be reversed, with testing the combined wells first.)

3) The operating condition of both wells must not be changed. If it is, a new set of tests is required.

4) Total test oil, gas, and water volumes determined for the cascade test minus the test oil, gas, and water volumes for the high gas producing oil well will be the test volumes for the low gas producing well.

5) It is recommended that both wells have similar BS&W percentages. If any of the calculated oil, gas, or water volumes for the low gas producing oil well is negative, the tests are not representative and both tests must be repeated.

The use of cascade testing does not require special approval from the ERCB.

Common Flow Line: Cascade testing is allowed for common flow-lined wells, provided that they meet the above conditions for cascade testing. However, the combined (cascade) test must be conducted first, and then the low gas producing well must be shut in to test the high gas producing well, allowing sufficient purging and stabilization time. Note that the use of common flow lines requires special approval from the ERCB, except for heavy oil if exempted in *ID 91-3*.

Example

Well A = High gas producing
Well B = Low gas producing

Test Results

Well	Test date	Oil (m^3)	Gas (10^3 m^3)	Water (m^3)
Well A+B	July 4	80.0	20.0	20.0
Well A	July 5	50.0	19.0	12.0
Well B = (Well A+B - Well A)	July 4	30.0	1.0	8.0

Appendix B Gas Measurement

B-1 Gas Volume Calculation

Orifice Meters: Gas volumes are calculated from gas chart readings using either one of the following formulas.

AGA 3 (1985)	AGA3 (1990)
$Q\ (Mcf/h) = C' \times (h_w \times P_f)^{1/2} / 1000$	$Q\ (Mcf/h) = N_1 \times C_d \times E_v \times Y_1 \times d^2 \times (h_w \times P_{f1} \times Z_s / G_r / T_f / Z_{f1})^{1/2} \times F_{pb} \times F_{tb} \times (Z_b / Z_s)$
Where: $C' = F_b \times F_r \times Y \times F_{pb} \times F_{tb} \times F_{tf} \times F_g \times F_{pv} \times F_a$ Q = Volumetric flow at base conditions F_b = Basic orifice factor F_r = Reynolds number factor Y = Expansion factor F_{pb} = Pressure base factor F_{tb} = Temperature base factor F_{tf} = Flowing temperature factor F_g = Specific gravity factor F_{pv} = Supercompressibility factor F_a = Orifice thermal expansion factor H_w = Inches of water differential from the chart P_f = Absolute static pressure	Where: N_1 = Unit conversion factor (7.70961 for imperial units) C_d = Coefficient of discharge E_v = Velocity of approach factor Y_1 = Upstream expansion factor d = Orifice plate bore diameter at flowing temperature P_{f1} = Absolute upstream static pressure Z_s = Compressibility of gas at standard conditions Z_b = Compressibility of gas at base conditions Z_{f1} = Compressibility of gas at upstream flowing conditions G_r = Real gas specific gravity T_f = Absolute temperature at flowing conditions

Multiply Q by the number of flowing hours to obtain the total volume for the period.

Metric Conversion for Volume

From (MCF)	To (10^3 m^3)	F_{pb}, F_{tb} values	Conversion factor
@ 101.325 kPa, 15°C	@ 101.325 kPa, 15°C	F_{pb} = 1.0023	
		F_{tb} = 0.9981	0.02831685
@ 14.65 psia, 60°F	@ 101.325 kPa, 15°C	F_{pb} = 1.0055	
		F_{tb} = 1.0000	0.02817399

Other Meters: Gas volume for positive displacement meters, turbine meters, and vortex meters can be calculated by using the following formula:

$Q = CR \times P_f / P_b \times T_b / T_f \times 1/Z$

Where:

CR = Meter counter reading difference
P_f = Flowing pressure (absolute)
P_b = Base pressure (absolute)
T_f = Flowing temperature (absolute)
T_b = Base temperature (absolute)
1/Z = Compressibility factor at P_f (from AGA8, Redlich-Kwong, etc., based on sample analysis; see *IL 87-1*)

Note that there might be a meter factor to be applied to the CR. In some cases, meters have built-in temperature and/or pressure correction. If so, the temperature and/or pressure correction portion of the formula can be ignored. Use the same absolute units for P_f and P_b, T_b, and T_f.

Gas density is not required to perform the above corrections. However, a gas sample analysis is required to calculate the compressibility factor for varying pressures and temperatures. The sampling frequency should match those listed in Schedule 1 of *Directive 49*.

Computer programs should be used to verify the flow calculations. All hand calculation procedures have been removed from this Directive.

B-2 Acid Gas Measurement

The quantity of acid gas going to sulphur plants is generally a low-pressure gas measurement at an average of 100 to 110 kPag; therefore, the orifice meter must be in excellent condition if accurate measurement is to be achieved. This measured volume is reported as “Acid Gas” on the gas plant monthly volumetric submission.

Acid gas is saturated with water vapour, which represents a significant portion of the total gas measured. The amount of water vapour varies significantly with temperature. Therefore, it is necessary that there be a temperature record on a continuous basis. The gas gravity factor must also include the water content, and the orifice coefficient must include a factor to exclude the water vapour content of the gas in the final volume computation for reporting purposes. The accuracy of the gas gravity factor and water content determination must be checked. These calculations may have to be done by the operation personnel on a daily basis.

If a meter or recording device other than an orifice meter is being used, it should be evaluated by the auditor in association with the ERCB Production Operation Section, Compliance and Operations Branch.

See Directive 017, section 11.2 for requirements (April 18, 2011)

Determining Acid Gas on a Dry Basis

For ideal gases, the total vapour pressure of a system containing several components is the sum of the vapour pressure of the individual components at the temperature of the system.

The component’s vapour pressure percentage of the total pressure of a system is equal to the volume percentage of that component in the system.

1) Determine the acid gas gravity on a wet basis.

2) Determine the acid gas and water vapour flow rate corrected from actual flowing pressure and temperature to 101.325 kPaa and 15°C.

3) The volume calculated in Step 2 contains water vapour and the pressure and temperature related to this volume are 101.325 kPaa and 15°C.

Therefore, the factor used to correct the acid gas from a wet to dry basis is

Correction Factor (CF)
= (101.325 kPaa – vapour pressure of water at flowing temperature) / 101.325 kPaa

Sample Acid Gas Calculation from Wet to Dry Basis

A. Gas Data

Hours produced = 24 h
Flowing temperature = 33°C

Flowing pressure = 17.9 kPag
Atmospheric pressure = 99.3 kPaa

B. Component on a dry basis from acid gas analysis:

(i) **H_2S** = 90.1% **CO_2** = 9.1% **C_1** = 0.8%

C. Calculate percentage of components, including water vapour, on a wet basis:

Maximum percentage of water vapour =

(100 x Vapour pressure of water at 33°C) / (Flowing pressure + Atmospheric pressure)

Vapour pressure of water at 33°C = 5.075 (from the Saturated Steam table in the Thermodynamics section of the GPSA *SI Engineering Data Book*)

Percentage of water vapour = (100 x 5.075) / (17.9 +99.3) = **4.33%**

Calculate new component percentages on a wet basis = 100% - 4.33% = **95.67%**

H_2S = 90.1% x 95.67 / 100 = 86.199%

CO_2 = 9.1% x 95.67 / 100 = 8.706%

C_1 = 0.8% x 95.67 / 100 = 0.765%

Revised analysis (wet basis):

(ii) **H_2S** = 86.199% **CO_2** = 8.706% **C_1** = 0.765% **H_2O** = 4.330%

D. Calculate specific gravity (SG) on a wet basis for volume computations of acid gas to sulphur plant:

SG from the Physical Properties section of the GPSA *SI Engineering Data Book*

(iii) **H_2S** = 1.1765 **CO_2** = 1.5195 **C_1** = 0.5539 **H_2O** = 0.6220

(iv) Revised SG

H_2S	= 86.199 x 1.1765 /100	= 1.0141
CO_2	= 8.706 x 1.5195 / 100	= 0.1323
C_1	= 0.765% x 0.5539 / 100	= 0.0042
H_2O	= 4.33 x 0.6220 / 100	= <u>0.0269</u>
New SG		**= 1.1775**

Therefore, use an SG of 1.1775 for calculating the acid gas volume.

Summary

	(i)	(ii)	(iii)	(iv)
H_2S	90.1%	86.199%	1.1765	1.0141
CO_2	9.1%	8.706%	1.5195	0.1323
C_1	0.8%	0.765%	0.5539	0.0042
H_2O		4.330%	0.6220	0.0269
Total	100.0%	100.0%		1.7775

Use the above corrected SG of 1.1775 to calculate the flow rate from the gas chart reading, at 101.325 kPa and 15°C (including water vapour).

Flow rate from chart reading = 52.6 10^3 m^3/d

Correct from a wet to a dry gas basis:

Vapour pressure of water at 15°C = 1.7051 (from the Saturated Steam table in the Thermodynamics section of the GPSA *SI Engineering Data Book*)

CF = (101.325 - 1.7051) / 101.325

= 0.9832

Corrected Gas Volume = 52.6 x 0.9832

= **51.7** 10^3 m^3/d

This volume is to be reported as “Acid Gas” on the monthly volumetric submission.

Appendix C Fluid Sampling and BS&W

C-1 Fluid Samplers

Automatic fluid sampling devices collect samples of fluid flowing though a line or meter for BS&W determination. The two basic classifications of automatic samplers are discussed below.

See Directive 017, section 14.8 for the conditions for sampling requirements (April 18, 2011)

OGCR, Sections 14.140(5) and (6), stipulate the conditions of use for proportional samplers or product analyzers to determine water production; Sections 14.150(1) and (2) stipulate the conditions for use in test water measurement.

Continuous Sampler, Flow-Responsive (Proportional) Type

A flow-responsive (proportional) sampler is designed and operated to automatically adjust the quantity of the sample in proportion to the rate of flow. The volume of the sample taken may be varied by varying the frequency of fluid transfer to the sample container or by varying the volume of the fluid collected to the sample container while maintaining the frequency of fluid transferred to the container.

This type of sampler is recommended for fluids with free water or fluids with suspended water and/or solids and for flow rates that vary throughout the flow period in order to obtain a representative sample.

Continuous Sampler, Time-Cycle (Nonproportional) Type

A time-cycle (nonproportional) sampler is designed and operated to transfer equal quantities of the fluid from the sample point to a sample container at a uniform rate or predetermined interval.

This type of sampler is recommended for fluids without free water or suspended solids and can provide a representative sample under these conditions. However, if fluid characteristics fluctuate or the flow rate varies, the collected fluid may not provide a representative sample of the total fluid passing through the line or meter.

C-2 Water-Cut Analyzers

Water-cut analyzers are devices that provide on-line, continuous measurement of water content in a hydrocarbon/water mixture under flowing conditions. With a water-cut analyzer, the hydrocarbon and water do not need to be fully separated prior to measurement.

Inspection of Water-Cut Analyzers

Check how the analyzers are calibrated, the frequency of calibration, and documentation of the calibrations.

Types of Water-Cut Analyzers (for informational purposes only)

This section describes items to be considered for selecting a water-cut analyzer and accessory equipment and is for information only. The section also discusses more specific guidelines and requirements pertaining to three types of commonly used water-cut analyzers: a capacitance-type analyzer, a density-type analyzer, and an energy absorption-type analyzer. It is recognized that water-cut analyzers other than those described herein exist. This document is not intended to preclude the use of such devices.

The use of a certain type of water-cut analyzer depends on the following:

1) anticipated range of water cut and expected performance in this water-cut range

2) anticipated range of liquid flow rates (or flow velocity) and expected performance in this operating range

3) range of operating pressure, pressure losses through the water-cut analyzer, and consideration of whether or not the pressure in the analyzer is adequate to prevent the liquid from flashing

4) effect of varying liquid properties (e.g., viscosity, oil gravity, water density) on performance

5) operating temperature range and the applicability of automatic temperature compensation

6) material of construction of the analyzer and effect of corrosive contamination on its operating life

7) quantity and size of foreign solid particles that may be carried in the liquid stream, for determining potential of erosion

8) space and location for the water-cut analyzer installation and the in-line calibration facility required

9) types of secondary elements (e.g., electronic processor unit and readout device) and acceptable maximum distance between these secondary elements and the water-cut analyzer itself

10) compatibility of the output electronic signal, if applicable, to other associated devices and the method of adjusting this output signal

11) class and type of pipe connections

12) power supply requirements for the analyzers and the secondary elements

13) electrical code requirements

14) type, method, and frequency of calibration

15) presence of paraffin, tar, and other impurities that may coat the sensing element

Test Separator

The performance of a water-cut analyzer is affected by the presence of free gas in the liquid stream. The test separator should be properly designed and sized to provide adequate retention time for complete gas-liquid separation.

The test separator can also incorporate an additional mechanism, if required, to further separate the liquid phase into a free-water phase and an oil/water emulsion phase. With the free water separated, the water cut in the emulsion stream is reduced, even though the overall water cut from the incoming stream may be relatively high.

The test separator should include liquid level sensing and flow control devices, as well as back-pressure regulators in all outgoing streams.

Installation Requirements

Installation requirements vary with different types of water-cut analyzers. Some general requirements are described below.

To minimize pressure loss and thus prevent flashing of the hydrocarbon liquid, the water-cut analyzer should be installed upstream of the dump valve and as close to the separator as possible. A minimum amount of upstream piping components should be used so that the pressure drop between the test separator and the analyzer does not exceed 2 psi at the maximum flow rate.

Installing the analyzer at a certain vertical distance below the test separator may also be considered as an alternative. This installation scheme effectively increases the liquid pressure as a result of a static head gain of the liquid column.

The mounting position of the analyzer is critical. Installation guidelines specified by the manufacturer should be strictly followed for optimum results.

Whenever possible, install the analyzer in such a way that it measures the full liquid stream. However, if installation of the analyzer in the slip stream is necessary or unavoidable, care must be taken to ensure homogeneous mixing in the main liquid stream.

To promote mixing of the liquid stream, a static mixer may be installed immediately upstream of the analyzer. However, when selecting a static mixer, the added pressure loss should be considered.

To facilitate periodic calibration, the water-cut analyzer should be installed so that it can be conveniently isolated from the normal flow path.

Net Oil Computer

A typical net oil computer receives electronic signals from the flow meter(s) and the water-cut analyzer. It computes, totals, and displays the individual amounts of hydrocarbon and water. Temperature compensation, pressure compensation, and other capabilities may also be included in the net oil computer.

Depending on the required electrical codes, the net oil computer may be located in the general vicinity of the water-cut analyzer, or it may be designed for installation at a certain distance away from the water-cut analyzer.

Capacitance-Type Water-Cut Analyzer

The capacitance-type water-cut analyzer uses the property that there is a significant difference in dielectric constant between water and hydrocarbon emulsion. The water-cut level in the emulsion can then be determined.

Calibration

Factory calibration – The relationship between dielectric constant and water cut varies with different types of hydrocarbon and water. The analyzer should be calibrated in the factory using the hydrocarbon liquid and water identical or similar to those in the actual application. A calibration curve between the actual water cut and the probe output should be developed and incorporated into an associated electronic processor device.

Recalibration – At installation and periodically after use, the analyzer must be properly zeroed and spanned, in accordance with the procedure specified by the manufacturer.

Special Guidelines

The capacitance-type water-cut analyzer is affected by the following factors:
- water-cut level and nature of emulsion
- mixing
- operating temperature
- variations of hydrocarbon and water properties
- presence of free gas
- paraffin deposition

Therefore, the following should also be seriously considered:

- Water-cut level and nature of emulsion – The capacitance-type analyzer is applicable as long as the liquid mixture is an oil-continuous emulsion that occurs at a water cut below a certain level. Erroneous measurement would result at higher water cuts wherein the emulsion physical properties of the hydrocarbon should be exercised to ensure that the liquid mixture is in the oil-continuous emulsion range when a capacitance-type analyzer is used.

- Mixing – The capacitance-type analyzer should be mounted in a vertical pipe run with the axis of the sensing probe parallel to the direction of the flow. It can be installed in either an up-flow or a down-flow position, but tests indicate the down-flow position is preferable. The vertical mounting position is desirable to obtain more uniform mixing of the hydrocarbon/water mixture stream.

- Operating temperature – Significant variations in the temperature of the liquid can also affect the performance of the analyzer, because dielectric constants of both hydrocarbon and water are functions of temperature. For greatest accuracy, the analyzer should be calibrated in the range of normal operating conditions.

- Hydrocarbon and water properties – Dielectric constants differ with different types of hydrocarbon and water. Significant variation in the properties of these liquid components would also affect the performance of the analyzer. Therefore, the analyzer should be calibrated with the most representative hydrocarbon liquids and its application should be limited to those liquids with similar properties.

- Free gas – The presence of free gas in the liquid stream tends to under-measure water cut. Prudent separator design and installation guidelines described in previous sections should be followed to minimize or eliminate the free gas.

- Paraffin deposition – Paraffin buildup on the analyzer decreases its sensitivity and results in erroneous measurement. Remedial practices include chemical treatment of the liquid stream, heat tracing, and frequent cleaning of the analyzer.

Density-Type Water-Cut Analyzer

The density-type water-cut analyzer is based on the property that the densities of the hydrocarbon liquid and water are different. By measuring the density of the hydrocarbon/water mixture, the water cut in the mixture is then determined.

Several types of density meters can be adopted for this application. These include, but are not limited to, vibrating element density meter, Coriolis mass flow meter, differential pressure density meter, and nuclear-type density meter.

Calibration

Unless requested otherwise, most manufacturers will calibrate the density meter on two or more fluids of known density, such as water, varsol, diesel, or air.

Upon installation and periodically thereafter, the equipment must be verified or recalibrated as per the manufacturer's suggested intervals. Verification can be done by fluid sample, master density meter, or tank gauging method. Recalibration is accomplished by filling the sensor with fluids of known density and calibrating the output appropriately. Verification and recalibration are important for the optimum performance of density measuring equipment and must be provided for in the design of facilities using this equipment.

Special Guidelines

The performance of a density-type water-cut analyzer is affected by the following factors:

- density measurement accuracy
- fluid temperature
- presence of free gas
- hydrocarbon and water density determination
- variation of hydrocarbon and water densities
- variation of operating conditions
- external vibration
- paraffin deposition

In addition, the following should also be seriously considered and emphasized:

- Accuracy of density meter – The accuracy of measured emulsion density determines the accuracy of water-cut measurement. When selecting a density-type water-cut analyzer, the accuracy of the density meter should be examined to determine the corresponding accuracy on water-cut measurement.

- Fluid temperature – An accurate temperature measuring device must be incorporated to measure the fluid temperature. Temperature measurement is needed for computing water cut and performing temperature compensation of the density meter.

- Free gas – Free gas in the liquid stream lowers the apparent density and may significantly underestimate water-cut measurement. Extreme care must be taken to minimize or eliminate the free gas.

- Hydrocarbon and water density determination – The density-type water-cut analyzer requires that the individual hydrocarbon and water densities be predetermined prior to measurement. Special care must be taken to ensure that these densities are determined under metering pressure.

- Variation of hydrocarbon and water densities – The density-type water-cut analyzer requires that the hydrocarbon and water densities remain fairly constant during measurement. Reverification of these densities should be performed periodically.

- Variation of operating conditions – Since the liquid stream being measured is normally under its bubble point condition, significant variations in pressure and temperature from their normal conditions may affect the performance of the analyzer.

- External vibration – Excessive external vibration may detrimentally affect the performance of the vibrating element density meter and Coriolis mass flow meter. If this type of water-cut analyzer is used, it should be installed at a certain distance away from the vibration sources, such as pumps and compressors. Vibration isolation devices may also be used if necessary.

- Paraffin deposition – Paraffin buildup on the analyzer decreases its sensitivity and results in erroneous measurement. Remedial practices include chemical treatment of the liquid stream, heat tracing, and frequent cleaning of the analyzer.

Energy Absorption-Type Water-Cut Analyzer

The energy absorption-type water-cut analyzer is based on the principle of electromagnetic energy absorption. The difference in energy absorption rates between water and hydrocarbons is utilized by this analyzer to measure water content. The principle of operation is not affected by changes in the individual oil and water densities of the stream to be monitored. The deposition of paraffin and other impurities on the sensor has less effect on accuracy than with other analyzers.

Calibration

The analyzer may be partially or fully calibrated at the factory. However, final calibration and verification of factory settings should be conducted in the field at the installation site, using the actual fluid to be monitored. For optimum performance, recalibration and reverification should be conducted periodically as per the manufacturer’s calibration, procedures, and suggested intervals.

Special Guidelines

The performance of an energy absorption-type water-cut analyzer is affected by the following factors:

- installation orientation
- water-cut level and nature of emulsion
- fluid temperature
- presence of free gas
- paraffin deposition

Therefore, the following should also be seriously considered:

- Installation orientation – The sensor should be installed in a vertical position with the fluid flowing downward.

- Water-cut level and nature of emulsion – The energy absorption-type analyzer is accurate as long as the liquid mixture is an oil-continuous emulsion that occurs at a water cut below a certain level. The performance of this type of analyzer in the water-continuous region may be affected by the variation of flowing velocity and the properties of the fluid. Erroneous measurement could result at higher water cuts wherein the emulsion becomes water-continuous.

- Fluid temperature – Even with temperature compensation, large variations in process temperature may affect accuracy, requiring recalibration.

- Free gas – Free gas in the liquid stream will significantly affect the accuracy of the water-cut measurement. Any free gas in the stream must be eliminated.

- Paraffin deposition – Significant paraffin buildup on the sensor may slightly affect the analyzer’s accuracy. Paraffin deposition may be reduced or eliminated by maintaining sufficient velocity through the sensor housing, maintaining relatively constant process temperature, heat tracing, and/or frequent cleaning.

C-3 Water-Cut (BS&W) Procedure

Obtaining accurate water-cut (BS&W) percentage during well proration testing is an important aspect of oil well measurement and accounting because it directly affects the oil volume determination. However, it is one that is frequently overlooked. In some cases, well test liquids are easily separated using standard procedures, such as adding a small amount of demulsifier and spinning the sample in a centrifuge, as discussed later in this section. Other situations (such as very high water cuts or tight emulsions) require additional effort to achieve accurate results.

Due to varying BS&W ranges, water-cut procedures have been divided into three categories, which are described on the following pages. Note that these procedures are not considered enforceable ERCB regulations but are recommended for well test applications.

For further reference, BS&W determination is discussed in more detail in the API MPMS, Chapter 10, Section 4: Determination of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure).
See Directive 017, section 6.4.3 for requirements and Appendix 4. (April 18, 2011)

For 0% to 10% BS&W

Obtain a representative sample of liquid (minimum 500 ml). If a manual grab sample procedure is used, the sample should be taken as close to the test meter as possible.

Shake the sample inside the container vigorously to ensure a good mix prior to pouring into centrifuge tubes.

Fill each of two centrifuge tubes with the sample to the 50 ml mark in 100 ml tubes or to the 100 ml mark in 200 ml tubes (read the top of the meniscus).

Add solvent (toluene, varsol, etc.) to bring the level in the tubes to 100 ml or 200 ml respectively (solvent should be water saturated at 60^{o}C).

Add demulsifier as required. Stopper the tubes and shake vigorously to ensure a good mix. Heat the samples to 60^{o}C or treater operating temperature before spinning.

Place the sample tubes in the centrifuge on opposite sides to create a balanced condition. Spin for at least 5 minutes. Compare the results from each tube. If the two results are not the same, return the tubes to the centrifuge and spin again for at least 5 minutes (do not shake the tubes at this stage). Repeat this operation, and if the samples still do not match after two more spins, discard this sample and take another one.

Read and record the volume of water and sediment in the bottom of each tube.

- For 100 ml tubes, read to the nearest 0.05 ml from the 0 to 1 ml graduations and to the nearest 0.1 ml above the 1 ml graduation mark.

- For 200 ml tubes, read to the nearest 0.05 ml from the 0 to 3 ml graduations, to the nearest 0.25 ml between the 3 and 5 ml graduations, and to the nearest 0.5 ml above the 5 ml graduation mark.

For 100 ml tubes, water cut is determined by adding the results of both tubes together. When using 200 ml tubes, water cut is determined by reading the results directly from one tube.

See Example 1:

Example 1

100 ml centrifuge tube	200 ml centrifuge tube
Reading from each tubes = 0.50 ml	Reading from each tube = 1.00 ml
Water cut = (0.50 + 0.50) / 100 = 1.0 %	Water cut = 1.00 / 100 = 1.0 %

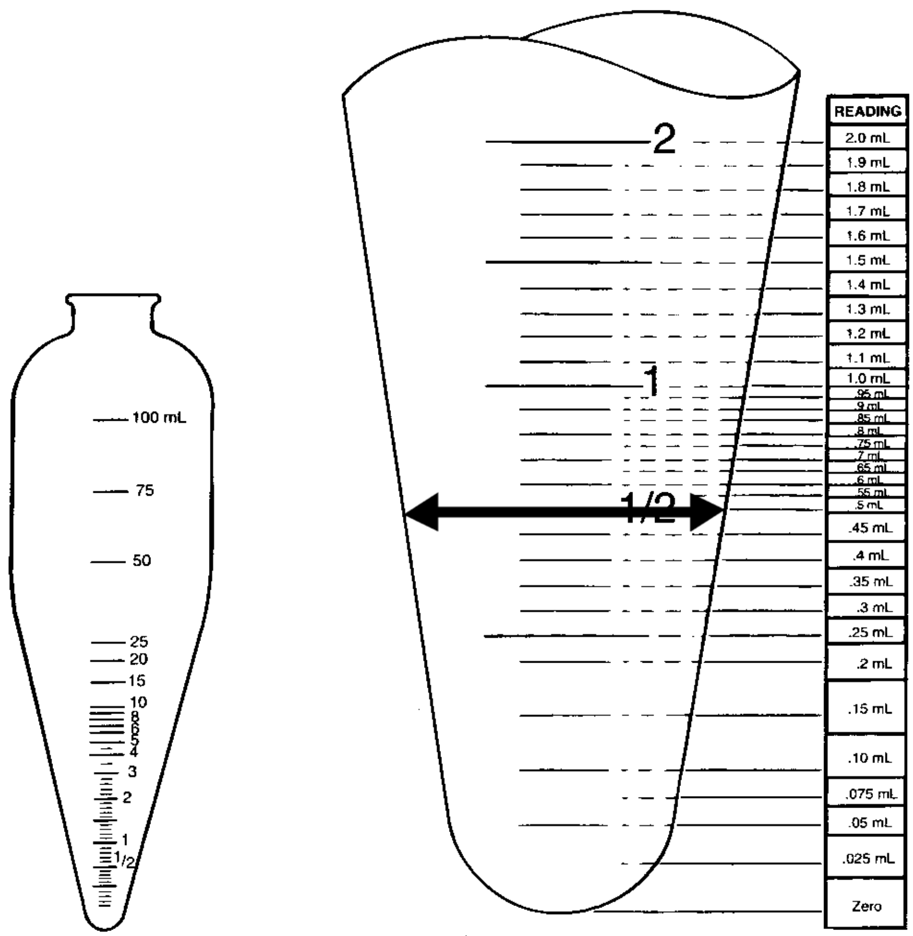


Figure 1. Reading a 100 ml centrifuge tube

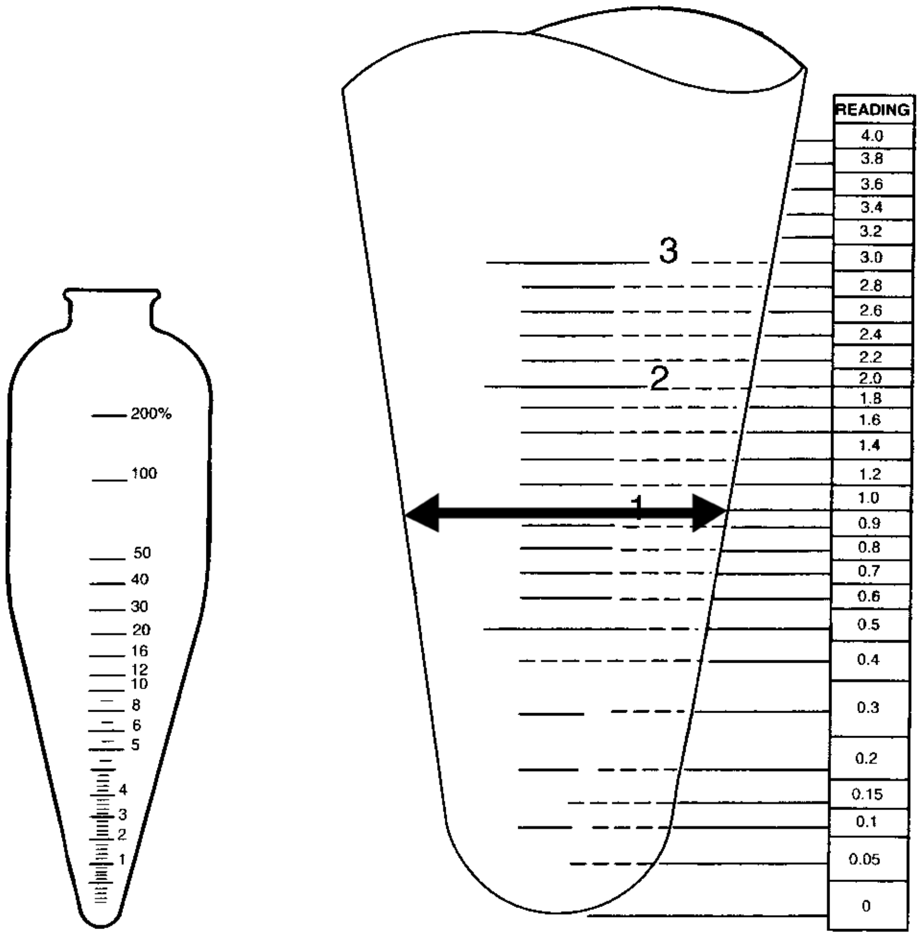


Figure 2. Reading a 200-part centrifuge tube

For 10% to 80% BS&W

Obtain the maximum representative sample of liquid feasible (between 800 and 1000 ml).

Transfer the entire sample into an adequately sized graduated cylinder. (Mason jars will not provide adequate results.)

Place the graduated cylinder into a heat bath at approximately 60^{o}C (or as close to treater temperature as possible) until the sample temperature and free water fallout have stabilized. A clear oil/water interface should be visible.

Read and record the total volume, volume of free water, and volume of oil in the graduated cylinder. Calculate the free water percentage as follows:

Percentage of free water = Volume of free water / Total volume x 100%

Using a burette filler, draw 100 ml from the oil portion in the graduated cylinder and fill each of two centrifuge tubes exactly to the 50 ml mark. Add heated solvent to bring the level in the tubes to exactly the 100 ml mark. Add demulsifier as required. Follow the procedure outlined for spinning samples of 0% to 10% water cut.

Once the centrifuge has stopped, read and record the volume of water and sediment in the bottom of each tube. The combined results will be the water cut of the emulsion. Calculate the percentage of water remaining as follows:

Percentage of water remaining =
Total oil volume in cylinder x Water cut of oil / Total volume

Calculate the total water-cut percentage as follows:

Total water-cut percentage = Percentage of free water + Percentage of water remaining

See Example 2:

Example 2
1000 ml graduated cylinder

Percentage of free water = 600 ml / 900 ml x 100% = 66.7%

Percentage of water remaining = 300 ml / 900 ml x 10%* = 0.33%

* Water cut of oil portion determined by spinning samples

Water-cut percentage = 66.7% + 0.33%= 67.03%

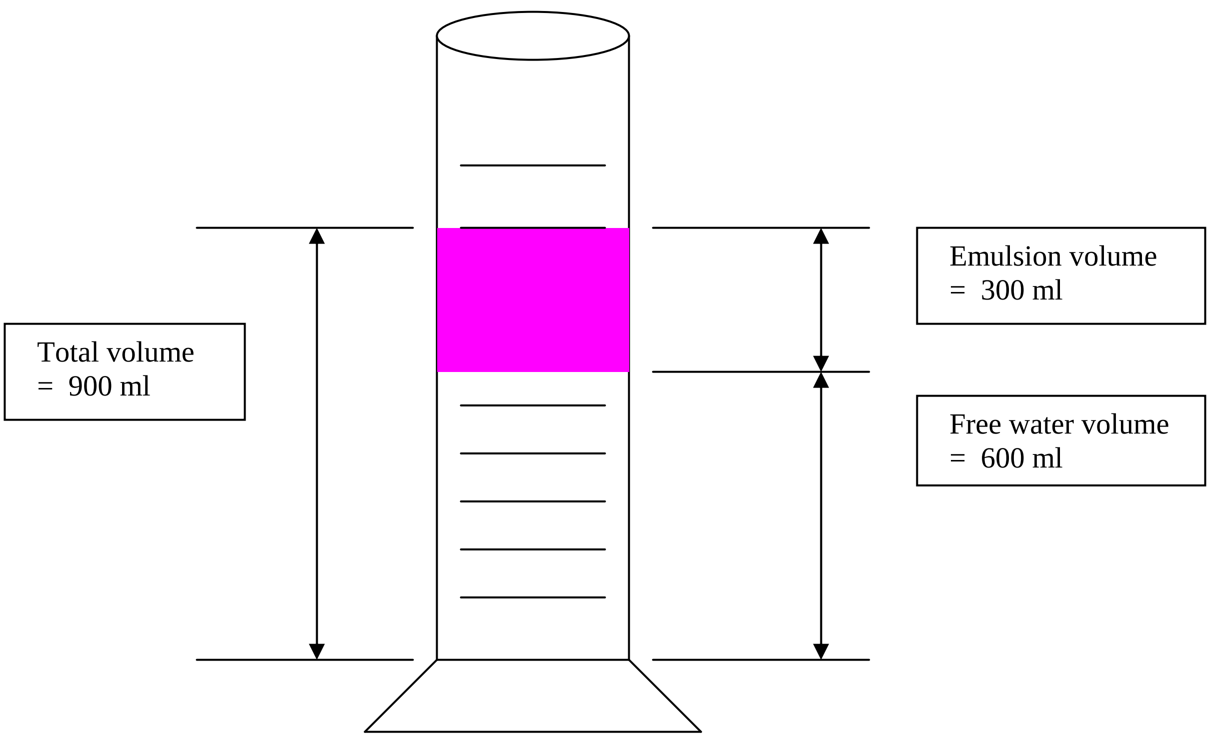


Figure 3. Water cut = 10% to 80%

For 80% to 100% BS&W

Obtain the maximum representative sample of liquid feasible (between 800 and 1000 ml).

Transfer the entire sample into an adequately sized graduated cylinder. (Mason jars will not provide adequate results.) For very high water-cut wells, it may be necessary to wash out the inside of the sample container with a measured volume of solvent to ensure that all of the oil is removed. If this is done, it is necessary to account for the additional amount of solvent added when calculating water cut.

Place the graduated cylinder into a heat bath at approximately 60^{o}C (or as close to treater temperature as possible) until the sample temperature and free water fallout have stabilized. A clear oil/water interface should be visible.

Read and record the total volume and volume of free water in the graduated cylinder. Calculate the water-cut percentage as follows:

Water-cut percentage = Volume of free water / Total volume x 100%

If solvent is added to the sample at any stage of this procedure, it must be accounted for in the calculation as follows:

Water-cut percentage = Volume of free water / (Total volume - Volume of solvent) x 100%

The oil portion of the samples does not have to be spinned due to the limited amount of the oil portion of the sample available.

See Example 3:

Example 3
1000 ml graduated cylinder
Water-cut percentage = 750 ml / 900 ml x 100% = 83.3%

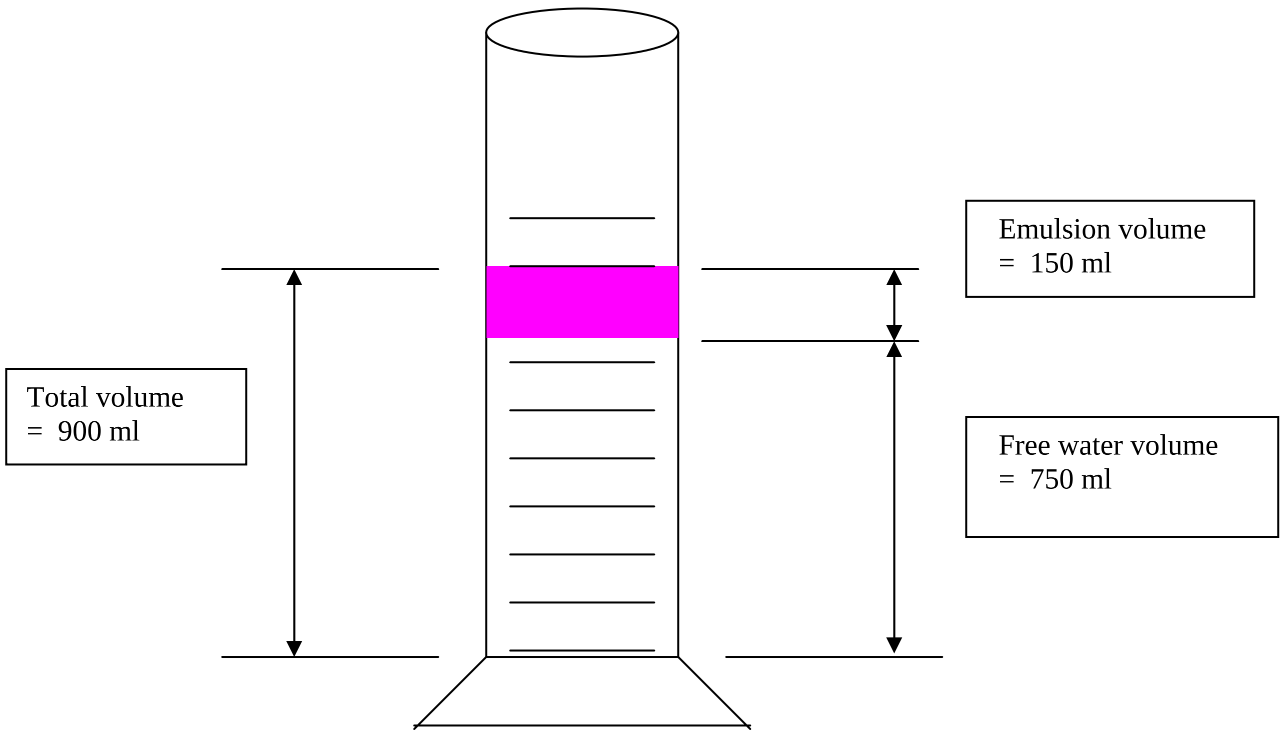


Figure 4. Water cut over 80%

Appendix D Inspection Guidelines

D-1 Orifice Meter Inspection Guidelines

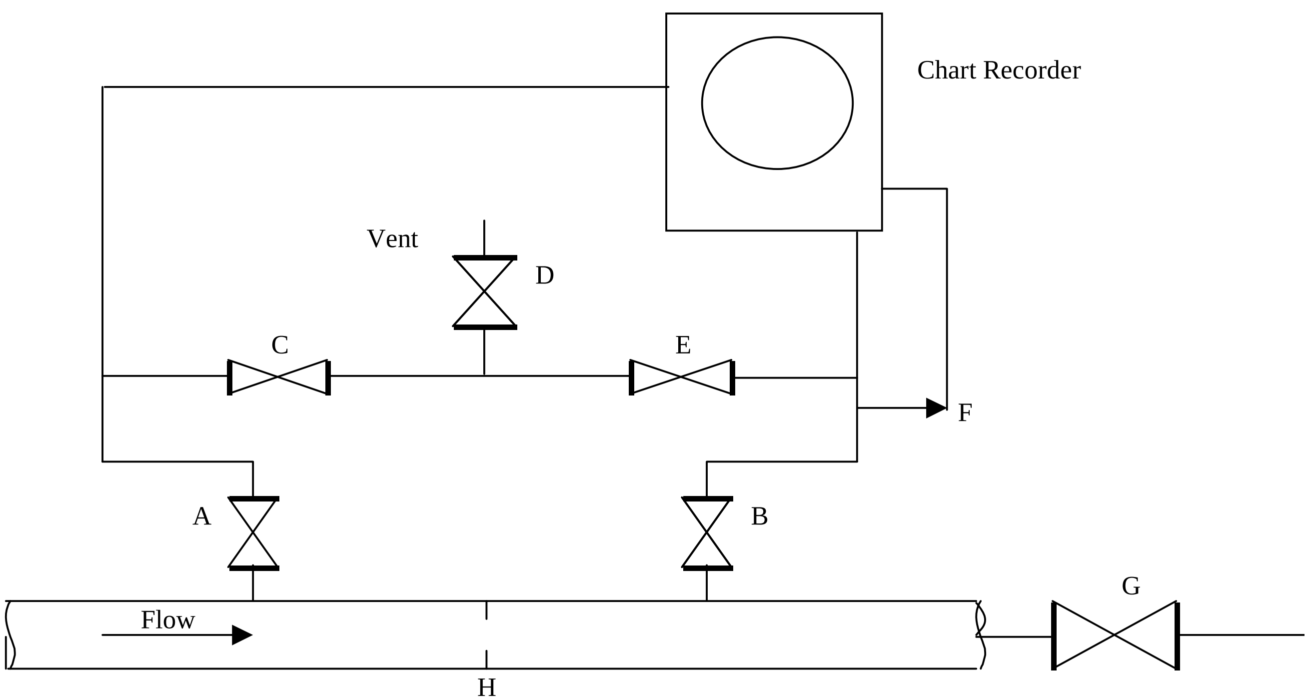
When inspecting orifice meters at oil or gas facilities, the following items should be noted and recorded:

- Is the well sweet or sour?
- Is the manifold vent line directed outside the building?
- Are there any leaks?
- Are there any controllers utilized with the meter?
- Are there any potential ignition sources?

Note that all “hands-on” operations of the chart recorders and orifice meters should be conducted by qualified company personnel. ERCB audit personnel should not operate any of the inspected facilities.

The following items shown on the figure below can be verified by on-site inspection and requesting the operation personnel to pull the orifice plate:

- A and B - taps or inlet valves
- C and E - pressure equalization valves
- D - bleed-off valve
- F - static element
- G - backpressure valve
- H - orifice plate



Also note and record the following information:

Make and serial number of chart recorder: These may be found on the inside of the meter door.

Meter in operation? Determine this by checking the chart and noting valve positions.

Group or test meter? Check the chart, or trace the sensing lines to the meter location.

Clock speed: Note whether a 24-hour, 7-day, or other chart is on the meter. Sometimes the clock speed and chart do not agree, so note the position of the pens on the chart relative to the time.

Orifice fittings make: Most fittings have a nameplate. A quick-change fitting is one that will allow the removal of an orifice plate without causing flow stoppage. A slow-change fitting is one that requires a shutoff of gas flow or rechannelling of gas flow through a bypass in order to remove the orifice plate.

Meter run size: Many meter runs have a small metal plate welded to the meter run giving the micrometer sizes (upstream and downstream) of the inside diameter (ID) of the meter run. If there is no plate, the meter run size is called nominal (2.067", 3.068", etc.). However, the upstream ID should be determined and used.

Size of orifice: All orifice plates are stamped with the size, which must also appear on the chart face.

Pressure tap: To determine whether the pressure tap is upstream or downstream, look on the back of the chart recorder. If a small pipe is seen connecting the static element in the recorder to the downstream inlet line, then the pressure tap is downstream, or vice versa. Ensure the same tap position is used during flow calculation.

Type of taps—flange or pipe: The centre of the upstream and downstream flange tap holes are located 1" from the nearest orifice plate face. The center of the pipe tap holes are located two and a half times (2.5) the inside diameter of the upstream pipe from the nearest orifice plate face and eight (8) times the inside diameter of the downstream pipe from the nearest orifice plate face.

Differential range: The chart will provide an indication, but this is not always reliable. The range may be determined by a manometer check. If the range is in question and a calibration sheet is not available, instruct the operation personnel to recalibrate.

Static element range: Most pressure elements are stamped. You will find the static element in the upper back right-hand corner of the chart recorder case. Ensure that it matches what is on the chart and the calibration sheet.

Gas temperature: A thermowell should be installed in the meter run usually downstream of the orifice plate, in accordance with AGA3 specifications. Gas temperature must be recorded at least once per chart cycle on the chart face.

Flow differential record: Record the general appearance of the trace (smooth, painting, spiking, etc.) and the approximate range of the differential trace on the chart, so as to be able to identify if this is the same chart later submitted as part of the records. You may also initial the chart, preferably within the hub or on the edge of the chart area.

Flow static record: Record the general appearance of the trace (smooth, painting, spiking, etc.) and the approximate range of the static trace on the chart for future identification.

Manifold valving operation: Check the manifold valve positions under normal operation when

- inlet valves are open,
- equalization valves are closed, and
- bleed valve is open.

Zeroing differential: It is a good operating practice to zero the differential pen at least once per chart cycle. However, this is not a requirement under the OGCR or other rulings. This can be done by having the company operation personnel carry out procedures (a) to (i), as follows:

a) Close one of the inlet valves.

b) Close the bleed valve.

c) Open both equalization valves.

The differential (red) pen should now fall to the zero on the chart. The operation personnel should adjust the differential pen to zero, if it is not on zero. There will still be pressure on the meter. Reverse the procedure to bring the chart back to normal operation or continue to check for static zero.

Check static zero: Following the differential zero check, have the operation personnel check the static zero by the following procedure:

d) Close both inlet valves.

Observe for a moment if the static (blue) pen has any change, which would indicate a leaking valve somewhere in the manifold. Pressure decrease indicates that the bleed valve is leaking.

e) Open the bleed valve.

The static pen should fall to zero. **Do not** adjust the static pressure pen, even though it does not fall on zero; do call for a recalibration. The operation personnel should follow the procedure below to return to normal operation:

f) Close the bleed valve.

g) Open both inlet valves.

h) Close both equalization valves.

i) Open the bleed valve.

Meter dampening: A dampening plug restricts the flow of fluids between the two differential chambers in the chart recorder. The amount of dampening set on the recorder can be judged by the speed of response of the differential pen, especially when it is being zeroed. Too little dampening would be indicated by immediate response of the differential pen. Wide sweeping on the chart by the differential pen could also indicate too little dampening. If the pen moves very slowly, it indicates over-dampening.

Meter chamber free from oil or liquids: Check for oil or liquids when bleeding the recorder. Oil or liquids could come from the meter run. If the chamber is full of liquids, have the operation personnel call for service to clean it out and recalibrate the chart recorder. There should not be any dips in the inlet piping (tubing). They should be self-draining towards the meter run. Otherwise, drip-pots might have to be installed to catch the liquids. Drip-pots could amplify the metering errors under pulsating conditions.

Chart ranges: The differential, static, and temperature pen ranges should be the same as what is printed on the chart. If the chart range is different, the actual range must be noted on the chart so that the chart can be correctly read.

Pens (inking continuously, pen arcs, clock stoppage): The pens should be kept clean, free of sediment, etc., and should ink continuously. An unsatisfactory "pen arc" is noted when any pen fails to follow the curvature of the time arc on the chart. A static or temperature pen misalignment up to 15 minutes of the differential pen is permissible. Clock stoppages should be noted. Pen pressure should be light enough to allow continuous recording and also prevent any lag in the movement of the pen. A normal check is to press inward on the chart; the pen should not follow the indent but should be free from contact with the chart. If the clock stopped or traces are missing because of a dry pen, the operation personnel may hand draw the lines on the chart, with an explanation for the chart reader about what has happened, or write a request on the chart for the chart reader to read as average flow for the missing period.

Meter run inspection: The number of pipe diameters upstream and downstream of the orifice is the measured distance from the orifice plate to the first bend, valve, or take-off fitting before or after the orifice fitting, divided by the inside diameter of the pipe. Calculate and record the number of the upstream and downstream pipe diameters. Compare the number of pipe diameters to the AGA3, 3rd edition, Part 2, Section 2.6, to see if they meet the specifications. All sales/gas delivery point meter runs manufactured after January 2003 must conform to the latest AGA3 (4th edition, Part 2, Section 2.6) specifications, as required by OGCR, Section 14.030.

Orifice plate: Have the operation personnel remove the orifice plate, check for stamped size, and measure the orifice size to ensure correct stamped size. It is normally stamped near the outer edge of the plate on the downstream side. The bevelled side must always be pointing downstream. It is very important that the edge of the orifice is sharp and free of nicks and defects. The orifice plate must conform to the specifications in AGA3, 4th edition, Part 2, Section 2.4. Sludge, oil, or wax on the plate near the orifice edge will cause measurement error and is not acceptable. The orifice plate must be checked and cleaned regularly for optimum performance. On quick-change fittings, confirm that the orifice plate has been inserted into the holder correctly and that there are no cracks on the rubber ring. Record any unsatisfactory items in your notes.

Orifice fitting leaks: Sometimes the orifice fitting may leak, or there may be an ice or wax plug preventing the changer from bleeding down, making it unsafe to remove the orifice plate. The operation personnel must not open the orifice fitting under pressure.

Information Required on Chart Face:

- Facility name and identification of the stream being metered
- Date and time when the chart was placed on and removed from the recorder
- Meter run and orifice plate sizes; if the orifice plate is changed during the chart period, this must be recorded on the chart and the time noted
- Temperature of the flowing gas

D-2 Orifice Meter Measurement Error Percentage

The following shows the percentage of error when an orifice plate is subjected to the conditions below.

Conditions	%*
Leaks around orifice plate	
1. With one clean cut through sealing unit	
a. Cut on top side of fitting	(3.3)
b. Next to tap holes	(6.1)
2. With "V" notch cut through sealing unit 1/4" wide at top of "V"	
a. "V" notch up at top	1.5
b. "V" notch down at bottom	(0.4)
c. "V" notch on tap side	(0.9)
d. "V" notch on opposite side from taps	(1.2)
3. Orifice plate carrier up approximately 3/8" from bottom (plate not centred)	(8.2)
Valve lubricant on upstream side of orifice plate	
1. Coated bottom half of plate 1/16" thick	(9.7)
2. Three deposits	0.0
3. Nine deposits	(0.6)
4. Orifice plate uniformly coated over full face 1/16"	(15.8)
Valve lubricant on downstream side of orifice plate	
1. Coated bottom half of plate 1/16" thick	(0.8)
2. Three deposits	(3.3)
3. Nine deposits	(2.6)
4. Orifice plate uniformly coated over full face 1/16"	1.7
Valve lubricant on both sides of orifice plate	
1. Plate coated bottom half of plate 1/8" thick	(10.1)
2. Plate coated over full face 1/8"	(17.9)
3. Plate coated over full face 1/4"	(27.4)
Obstruction in 1/2" tap hole	
1. Put 3/8" solid rod in upstream tap hole	(1.1)
2. Put 3/8" solid rod in downstream tap hole	0.6
Plate warp tests	
1. Plate warped toward gas flow 1/8" from flat	(2.8)
2. Plate warped away from gas flow 1/8" from flat	(0.6)
3. Plate warped toward gas flow 1/4" from flat	(9.1)
4. Plate warped away from gas flow 1/4" from flat	(6.1)

(continued)

Conditions	%*
Orifice upstream edge bevelled 45° full circumference (machined)	
1. 0.01 bevel width	(2.2)
2. 0.02 bevel width	(4.5)
3. 0.05 bevel width	(13.1)
4. Bevelled side upstream**	(24.4)
Nicked (notched) edge - sharp edge other than machined notch	
1. A 0.02" notch @ 45° on top in run	(0.2)
2. A 0.02" notch @ 45° on bottom in run	0.7
3. A 0.02" notch @ 45° placed opposite taps	5.7
4. A 0.02" notch @ 45° placed on tap side	2.3
5. Two 0.02" notches @ 45° and 90° apart with one on top and one next to tap	0.8
6. Two 0.02" notches @ 45° and 90° apart with one on bottom and one opposite taps	(0.3)
7. Four 0.02" notches, two horizontal and two vertical in run	(0.4)
8. A 0.05" notch 45° placed on top in run	0.1
9. A 0.05" notch 45° placed on bottom in run	0.8
10. A 0.05" notch 45° placed on tap hole side	0.7
11. A 0.05" notch 45° placed opposite tap hole side	(1.4)
12. Two 0.05" notches placed one on top and one next to tap holes	2.1
13. Two 0.05" notches placed one on bottom and one opposite tap holes	(1.0)
14. Four 0.05" notches being 90° apart and placed vertically and horizontally in run	5.4
15. Dull edge for one-quarter of the circumference	(1.5)
16. Dull edge for one-half of the circumference	(6.1)
17. Dull edge for three-quarters of the circumference	(9.4)
18. Dull edge for entire plate	(12.7)
Turbulent gas stream	
1. Upstream valve partially closed - straightening vanes in	(0.7)
2. Upstream valve partially closed - straightening vanes out	(6.7)
3. Liquid in meter tube 1" deep in bottom of tube	(11.3)
4. Grease and dirt deposits in meter tube	(11.1)

* Numbers in parentheses are negative.

** Not a part of the above test, but the actual difference in custody transfer measurement where an inspection found the bevelled side of the orifice upstream. When the orifice was installed properly without a change in flow rate, the differential pressure changed from 21 inches to 32.5 inches.

Note that these tests were made on a town border-type meter station using a 4-inch orifice meter tube and measuring at 100 psig. The average load through the station during the test period was approximately 1500 Mcf per day. The load pattern was that of a typical distribution system.

The results of the various conditions were based on the volumes delivered during a 24-hour period; therefore, it seems that the percentage error would be a function of or directly related to the flow rate.

D-3 Common Errors in Orifice Meter Chart Interpretation

1) Incorrect reading of planimeter or integrator counter

2) Incorrect calculation of static pressure caused by
   - not including atmospheric pressure on standard charts
   - including atmospheric pressure on standard charts where the pen is set to record absolute pressure (operation personnel using standard charts instead of square root charts)
   - not including atmospheric pressure on square root charts where the pen has been zeroed at atmospheric pressure (operation personnel using square root charts instead of standard charts)
   - not using the correct integrator setback
   - using incorrect atmospheric pressures for the meter in question (atmospheric pressure decreases with increase in altitudes)

3) Using incorrect or incomplete orifice coefficients

4) No estimates of gas production when
   - pens fail to ink properly
   - orifice plate is out of the meter run during long periods of dewaxing
   - chart stops moving (clock stopped, chart hub loose)
   - meter is temporarily out of service for inspection or repairs
   - differential pen exceeds chart range
   - operation personnel neglects to lower the orifice plate back into the meter run

5) Failure to follow pen traces closely when integrating chart

6) Not correcting for ranges of h_w and P_f when reading charts with a square root planimeter or by eye

7) Incorrect machine constant being used by the integrator operation personnel

8) Reading a chart with a radial planimeter when a square root or integrating planimeter should be used

9) Reading a chart with a square root planimeter when it should be integrated

10) Reading a fluctuating differential trace by eye or with a square root planimeter when the gas flow is intermittent, resulting in periodic zero differential recordings

11) Failure to use separate coefficients in calculations when orifice plate changes are recorded on the chart

12) No compensation for errors caused by an incorrect static setup or differential zero

13) Reporting of incorrect flowing temperatures, producing wells, orifice size, date and time of producing period, meter run size, etc.

14) Faulty pen arcing—cannot follow with the integrator

D-4 Directive to Good Gas Charts and Gas Chart Reading

Below are the generally accepted practices for chart operation and chart reading.

Field Operation

Field (chart) operation personnel should ensure the following:

- The meter station is properly identified.
- The charts are correctly dated.
- The correct orifice plate and line size are recorded.
- The exact time of any orifice plate change is indicated on the chart.
- The chart differential, static, and temperature scale correspond to the respective ranges on the recorder.
- Pressure ranges of the meter are noted on square root charts.
- A notation is made on the chart whether or not the meter is set up for atmospheric pressure.
- The accuracy of the meter clock speed is checked and the chart reader is instructed accordingly.
- The flowing gas temperature is recorded once per chart cycle.
- The differential pen is zeroed once per chart cycle and if any adjustments to the reading are warranted.
- The on and off chart times are noted.
- Proper chart reading instructions are provided when the pen fails to record because of sensing line freezing or other reasons (draw in the estimated traces, request to read as average flow for the missing period, or provide estimate).
- Differential pen recordings read in the upper two-thirds of the chart whenever possible.
- When there is a painted differential band, instructions are provided as to where it should be read.

Chart Reading

The chart integrator operator should ensure the following:

- No visible gap is evident between the integrating traces and chart traces.
- The counter is read correctly.
- The integrator is calibrated periodically and after each change of pens.
- The correct integrator or square root planimeter constants are noted.
- The correct integrator setback is recorded on charts.
- The correct coefficient, using all of the required factors, is recorded.
- The correct atmospheric pressure is recorded.
- When reading square root charts, the operation personnel traces through the centre of a painted differential band, unless directed by the field personnel to do otherwise.

If the chart is integrated using new technologies, such as scanning, there may not be visible integrating traces. In this case, the ERCB requires the producer to provide proof that the chart was read correctly either by giving the ERCB a copy of the original and electronic integrating image of the chart or arranging for a manual reading of the selected charts involved.

D-5 Guidelines for Inspecting Automated Measurement Systems

1 General Inspection Guidelines

The following items should be checked during a production audit of these facilities:

1) Verify flow calculation accuracy by any one of the three methods below at the discretion of the operation personnel based on system location, availability of audit trail, manual input capability, and output capability of the system. However, the auditor may ask for more information or witness the documentation generation when deemed necessary.

    a) Conduct a performance evaluation test on the system by inputting known values of flow parameters into the operation personnel's flow computer on site to verify the volume calculation and coefficient factors. Six test cases for orifice meters, each with different flow conditions, are included in this section. Note that the flow computer being verified should calculate flow volumes within 0.25% of the samples.

    b) Evaluate the flow calculation with other acceptable flow calculation programs. The operation personnel can provide the auditor with instantaneous flow parameters and factors, the instantaneous flow rate, and configuration information for this purpose.

    c) Have the operation personnel provide adequate documentation and flow calculation verification as proof of the system accuracy.

2) Witness or review the calibration procedures on end devices and ensure that end devices are properly installed. Included in this section are Tables 1 and 2, giving differential and static pressure ranges and the corresponding milliamp reading. These tables can be used as a guideline for reviewing analog end device calibrations.

3) Review the licensee's database for selected metering points to verify meter data, such as run sizes, orifice plate size, and gas analysis. What are the licensee's procedures for making changes to the database? Who can make changes?

4) Review the licensee's system for the handling and storage of required reports and data. Is information stored as hard copy, on disk, or on tape? Are the reports being generated in compliance with the guidelines below?

5) Review the system reliability with respect to downtime. Any major problems should be discussed with the ERCB Production Operations Section, Compliance and Operations Branch, prior to taking any action.

Table 1. Differential pressure and the corresponding 1-5 volts and 4-20 milliamp readings

Volts	Milliamp	50 " 12.5 kPa	100 " 24.9 kPa	150" 37.4 kPa	200 " 49.8 kPa	300 " 74.7 kPa	400 " 99.6 kPa	500 " 124.5 kPa
1.000	4.0	0.00	0.0	0.0	0.0	0.0	0.0	0.0
1.125	4.5	0.39	0.78	1.17	1.56	2.33	3.11	3.89
1.250	5.0	0.78	1.56	2.34	3.11	4.67	6.23	7.78
1.375	5.5	1.17	2.33	3.51	4.67	7.00	9.34	11.67
1.500	6.0	1.56	3.11	4.68	6.23	9.34	12.45	15.56
1.625	6.5	1.95	3.89	5.84	7.78	11.67	15.56	19.45
1.750	7.0	2.34	4.67	7.01	9.34	14.01	18.68	23.34
1.875	7.5	2.73	5.45	8.18	10.89	16.34	21.79	27.23
2.000	8.0	3.13	6.23	9.35	12.45	18.68	24.90	31.13
2.125	8.5	3.52	7.00	10.52	14.01	21.01	28.01	35.02
2.250	9.0	3.91	7.78	11.69	14.56	23.34	31.13	38.91
2.375	9.5	4.30	8.56	12.86	17.12	25.68	34.24	42.80
2.500	10.0	4.69	9.34	14.03	18.68	28.01	37.35	46.69
2.625	10.5	5.08	10.12	15.19	20.23	30.35	40.46	50.58
2.750	11.0	5.47	10.89	16.36	21.79	32.68	43.58	54.47
2.875	11.5	5.86	11.67	17.53	23.34	35.02	46.69	58.36
3.000	12.0	6.25	12.45	18.70	24.90	37.35	49.80	62.25
3.125	12.5	6.64	13.23	19.87	26.46	39.68	52.91	66.14
3.250	13.0	7.03	14.01	21.04	28.01	42.02	56.03	70.03
3.375	13.5	7.42	14.78	22.21	29.57	44.35	59.14	73.92
3.500	14.0	7.81	15.56	23.38	31.13	46.69	62.25	77.81
3.625	14.5	8.20	16.34	24.54	32.68	49.02	65.36	81.70
3.750	15.0	8.59	17.12	25.71	34.24	51.36	68.48	85.59
3.875	15.5	8.99	17.90	26.88	35.79	53.69	71.59	89.48
4.000	16.0	9.38	18.68	28.05	37.35	56.03	74.70	93.38
4.125	16.5	9.77	19.45	29.22	38.91	58.36	77.81	97.27
4.250	17.0	10.16	20.23	30.39	40.46	60.69	80.93	101.16
4.375	17.5	10.55	21.01	31.56	42.02	63.03	84.04	105.05
4.500	18.0	10.94	21.79	32.73	43.58	65.36	87.15	108.94
4.625	18.5	11.33	22.57	33.89	45.13	67.70	90.26	112.83
4.750	19.0	11.72	23.34	35.06	46.69	70.03	93.38	116.72
4.875	19.5	12.11	24.12	36.23	48.24	72.37	96.49	120.61
5.000	20.0	12.50	24.90	37.40	49.80	74.70	99.60	124.50

Table 2. Static pressure and the corresponding 1-5 volts and 4-20 milliamp readings

Volts	Milliamp	100 psi 689.5 kPa	500 psi 3447.5 kPa	1000 psi 6895 kPa	1500 psi 10342.5 kPa	2000 psi 13790 kPa	3000 psi 20685 kPa	5000 psi 34475 kPa
1.000	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.125	4.5	21.5	107.7	215.5	323.2	430.9	646.4	1077.3
1.250	5.0	43.1	215.5	430.9	646.4	861.9	1292.8	2154.7
1.375	5.5	64.6	323.2	646.4	969.6	1292.8	1939.2	3232.0
1.500	6.0	86.2	430.9	861.9	1292.8	1723.8	2585.6	4309.4
1.625	6.5	107.7	538.7	1077.3	1616.0	2154.7	3232.0	5386.7
1.750	7.0	129.3	646.4	1292.8	1939.2	2585.6	3878.4	6464.1
1.875	7.5	150.8	754.1	1508.3	2262.4	3016.6	4524.8	7541.4
2.000	8.0	172.4	861.9	1723.8	2585.6	3447.5	5171.3	8618.8
2.125	8.5	193.9	969.6	1939.2	2908.8	3878.4	5817.7	9696.1
2.250	9.0	215.5	1077.3	2154.7	3232.0	4309.4	6464.1	10773.4
2.375	9.5	237.0	1185.1	2370.2	3555.2	4740.3	7110.5	11850.8
2.500	10.0	258.6	1292.8	2585.6	3878.4	5171.3	7756.9	12928.1
2.625	10.5	280.1	1400.5	2801.1	4201.6	5602.2	8403.3	14005.5
2.750	11.0	301.7	1508.3	3016.6	4524.8	6033.1	9049.7	15082.8
2.875	11.5	323.2	1616.0	3232.0	4848.0	6464.1	9696.1	16160.2
3.000	12.0	344.8	1723.8	3447.5	5171.3	6895.0	10342.5	17237.5
3.125	12.5	366.3	1831.5	3663.0	5494.5	7325.9	10988.9	18314.8
3.250	13.0	387.8	1939.2	3878.4	5817.7	7756.9	11635.3	19392.2
3.375	13.5	409.4	2047.0	4093.9	6140.9	8187.8	12281.7	20469.5
3.500	14.0	430.9	2154.7	4309.4	6464.1	8618.8	12928.1	21546.9
3.625	14.5	452.5	2262.4	4524.8	6787.3	9049.7	13574.5	22624.2
3.750	15.0	474.0	2370.2	4740.3	7110.5	9480.6	14220.9	23701.6
3.875	15.5	495.6	2477.9	4955.8	7433.7	9911.6	14867.3	24778.9
4.000	16.0	517.1	2585.6	5171.3	7756.9	10342.5	15513.8	25856.3
4.125	16.5	538.7	2693.4	5386.7	8080.1	10773.4	16160.2	26933.6
4.250	17.0	560.2	2801.1	5602.2	8403.3	11204.4	16806.6	28010.9
4.375	17.5	581.8	2908.8	5817.7	8726.5	11635.3	17453.0	29088.3
4.500	18.0	603.3	3016.6	6033.1	9049.7	12066.3	18099.4	30165.6
4.625	18.5	624.9	3124.3	6248.6	9372.9	12497.2	18745.8	31243.0
4.750	19.0	646.4	3232.0	6464.1	9696.1	12928.1	19392.2	32320.3
4.875	19.5	668.0	3339.8	6679.5	10019.3	13359.1	20038.6	33397.7
5.000	20.0	689.5	3447.5	6895.0	10342.5	13790.0	20685.0	34475.0

2 Automated Measurement Systems: General Description and Requirements

An automated measurement system is any system that replaces chart and manual records with a system that directly calculates or accumulates flow volumes. These systems are generally manifested as flow computers or electronic flow measurement (EFM) and SCADA (Supervisory Control and Data Acquisition) systems. The system may be as simple as one meter run and a flow computer, or it may involve a number of metering locations at remote sites that communicate back and forth to a central computer system. Automated systems may also perform varying degrees of control over well and/or facility operation.

The ERCB involvement with these systems arises out of concern for accurate measurement. Any system must be able to perform calculations within the ERCB accuracy limits defined in Section 3.2. Not only must the system be capable of this accuracy, but provisions must also be made within the system to verify and prove that the system is functioning correctly.

Most commercially available systems are more than capable of meeting the ERCB accuracy limits. The auditor needs to concentrate on the area of system reliability and the provision of an adequate “audit trail” for confirming volumes. **However, older systems approved under *Directive 34* might not be able to meet some of the newer requirements of this directive, such as data storage duration, and they are to be inspected in accordance with their approval criteria under *Directive 34*.**

Some of the following definitions are not used in this directive but are provided for informational and educational purpose only.

Definitions

RAM	Random access memory
ROM	Read only memory – memory cannot be overwritten
EPROM	Electronically programmable ROM – memory can be “burned on” to chip
UPS	Uninterruptible power supply – consists of power filtering and battery backup
AD CONVERTER	Converts an analog electrical signal (voltage or amperage that is proportional to the parameter being measured) to a digital number that can be read by a computer
CMOS	Type of transistor/chip that is of low power consumption
MTU	Master terminal unit
RTU	Remote terminal unit
RTD	Resistance temperature detector
PLC	Programmable logic controller

WATCH DOG TIMER	Internal time clock in the computer that checks for software or computer problems
END DEVICES/ TRANSMITTERS	Pressure and temperature sensing devices that convert pressures/temperatures into a 4-20 mA electrical signal (or digital signal)

Automated measurement systems can be divided into two main categories, with subdivisions within each category:

1) SCADA systems — Remote sites that communicate with a central computer
   - Smart RTU — Remote units that are capable of performing flow calculations on their own
   - Dumb RTU — Remote units that only perform a data acquisition function but not any calculations
2) Flow computers — Stand-alone single or multiple meter computers
   - Programmable — User can install calculation and control programs into the flow computer
   - Nonprogrammable — Software is permanently installed on ROM chips from the factory and is not changeable by the user

2.1 SCADA Systems

The following provides a general description of SCADA systems and outlines some of the system requirements.

2.1.1 Hardware

MTU for some plants may consist of two host computers, one active, with the second as a warm backup ready to take over at any time should the main computer fail. If only one host computer is used, it should be capable of greater than 99% reliability.

The master radio station should have a good supply of replacement parts or an extra radio in the event of a failure. For those systems using cable communications, the communications hardware should have enough spare parts to enable a quick repair.

It is generally best if the computers are placed in a separate climate-controlled room. This is not as critical with newer computers, but even some of these have experienced problems when located in plant control rooms due to the corrosive atmosphere around sour gas plants.

The RTU should auto start after a power failure or after a reboot initiated by the watch dog timer. The memory on-board must allow for at least 32 days’ worth of flow data to be stored before being erased. The RTU should be equipped with its own on-board battery to protect the memory in the event of a power failure.

Communications between the MTU and RTU may be by cable, radio, microwave, or satellite. The polling interval for RTUs should be a minimum of once every 60 seconds for dumb RTUs and up to once an hour for smart RTUs.

End devices, such as transmitters, are normally rated by the manufacturer as having an accuracy of 0.25% over the calibrated range for a temperature of -40°C to +50°C.

The calibration of end devices should follow the standard calibration procedures and frequency, as stipulated in *Directive 017, section 2.5 (April 18, 2011)*. The end devices calibration should be completed with a check through the system to the value that the host computer is reading. Values should be recorded as they are found before any adjustments are made to the device. If end devices are found to continually drift by more than 2%, they should be replaced. (See Section 2.5 for details.)

The MTU is normally powered through a UPS system with enough battery backup to last through a power failure. The RTU may be powered by a thermal electric generator, solar power, or normal AC power. In any case, the RTU should be equipped with 24 hours of backup battery power. It may be acceptable to have less backup if the plant or well shuts in when a power failure occurs.

2.1.2 Software

Review what functions the system will perform, whether it be strictly flow calculations or some control functions. If control functions are performed, think about the safety aspects of those functions, particularly any emergency shutdown (ESD) device functions that may be present. The ESD system should have a pneumatic backup control in the event of a power failure.

The system should have various levels of system security, with the highest level of access to the program restricted to authorized people.

The communications system must use a data integrity error-checking routine to ensure that the data transmitted are correct. Typical routines use a cyclical calculation number that is attached to each transmission of data. Simple parity checks of the data are generally not sufficient to ensure the integrity of the data transmitted.

Data that have been transmitted to the host computer should be transferred to tape or disk at frequent intervals. If dumb RTUs are used, these data should be written to disk more frequently (perhaps every four hours) than for other systems. At smart RTUs, the data should be protected on a battery backed-up memory board and should be retrievable by going to the RTU directly in the event of a communications failure.

Review the flow calculation routine to ensure that calculations are completed in accordance with AGA3 and that the correct super-compressibility calculation is used in accordance with *Directive 017, section 4.3.2 (April 18, 2011)*. Pay particular attention to the base temperature, pressure, and metric conversion factor used to ensure that they are correct. Most factors should be calculated at each interval, except for those that do not change with changes in flow. The super-compressibility should be calculated and updated every five minutes or every flow calculation point, whichever occurs first. Some systems accumulate readings and calculate a pseudo-integrator reading, which is later calculated into a flow. Another alternative is to perform parts of the calculation in the host and then download those values to the RTU.

The system should be able to identify when bad data (i.e., outside program parameters) are received. Protection should be installed to eliminate extended use of bad data, such as an alarm signal, if three consecutive polls of bad data are received.

In the event of a computer failure or communication failure for excessive lengths of time in a system equipped with dumb RTUs, the well should be shut down. For smart RTUs, if the RTU fails, then the well should be shut down. Communication link or host computer failures do not require ESD.

The system should be set to alarm on high and low differential pressure, over-range of any end devices, low power, and communication failures. These alarms are to be recorded on the alarm report.

Any changes made to the data or any manually entered values that affect the flow calculation must be flagged so it is clear that these are estimated and not actual readings. This flagging should carry through to values calculated from the data.

2.1.3 Reports See Directive 017, Section 4.3.6 and 14.10 for EFM requirements. (April 18, 2011)

A complete review of the reports generated from the system is one of the most important inspection items. These reports, logs, and records are required for audit purposes and must be generated on demand by the auditor.

All data for generating the reports must be kept for a minimum period of 12 consecutive months. Companies may want to retain data for longer periods to meet internal and external audit requirements. These data may be stored as hard copy or on magnetic media, such as computer disk or tape.

When differential pressure alarms occur, orifice plates change, or other parameters change, such as meter factors, fluid analysis, and transmitter range, that affect the flow calculation, a signoff procedure is required to ensure that the change is made in the flow computer and must be produced on demand. In the absence of the event or alarm logging capability for some older flow computers, the signoff documents may be supplied as a replacement of those logs.

The Daily Report

The daily report should include the following as applicable:

- meter identification
- daily accumulated flow, with indicating flag for estimated flows made by the system or by the operation personnel and alarms that have occurred for over-ranging of end devices
- hours on production or hours of flow (specify)
- meter correction factors for liquid measurement
- daily averages of differential pressure, static pressure, and temperature

Any estimated flows or manually entered values must be flagged on both the daily and month-end reports. Often, companies will have the required information on different reports. The important thing is that the information is saved or printed at the required frequency.

The Meter Report

The meter report details the configuration of each meter and must be saved or printed any time a change is made to any of the meter information. These values are used as the "audit trail" to confirm that the flow calculation is functioning correctly. Without them there is no way of verifying the accuracy of the system. The meter report must include the following as applicable:

1) instantaneous flow rate
2) instantaneous static pressure
3) instantaneous differential pressure
4) instantaneous flowing temperature
5) configuration information as indicated in Table 1 of API MPMS, Chapter 21, for differential meters or for other types of meters, whichever is applicable:
    - 5.1) meter identification
    - 5.2) date and time
    - 5.3) contract hour
    - 5.4) atmospheric pressure (if appropriate)
    - 5.5) pressure base
    - 5.6) temperature base
    - 5.7) upstream meter tube inside diameter
    - 5.8) orifice plate reference bore size
    - 5.9) static pressure tap location
    - 5.10) orifice plate material
    - 5.11) meter tube material
    - 5.12) calibrated static pressure range
    - 5.13) calibrated differential pressure range
    - 5.14) calibrated temperature range
    - 5.15) high/low differential cutoff
    - 5.16) relative density (if not live)
    - 5.17) compressibility (if not live)
    - 5.18) gas components (if not live)
6) optional: instantaneous (AGA3) factors or parameters used in the flow calculation (see Performance Evaluation, Section 3.2, for more detail, including the orifice meter test cases for input and output information)

The Event Log

This log is used to note and record exceptions and changes to the flow parameter, configuration, programming, and database affecting flow calculations, such as, but not limited to,

- orifice change
- gas/liquid analysis update (sample date)

The Alarm Log

The alarm log includes any alarms that may have an effect on the measurement accuracy of the system. The time of each alarm condition and the time of clearing of each alarm must be recorded. Alarms to be reported must include, but are not limited to,

- master terminal unit failures
- remote terminal unit failures
- communication failures
- low-power warning
- high differential pressure (for differential measurement devices)

The Monthly Production Report

This report is for the entire system, giving each metering point. It is to contain the following at each measurement point as applicable:

- monthly cumulative flow
- monthly averages of differential pressure, static pressure, and temperatures
- flags indicating any changes made to flow parameters
- atmospheric pressure used for calculation
- total hours on production or hours of flow (specify)
- test date for water/gas ratio
- gas/oil ratio if used to estimate gas production

Test Records

Test records consist of all documents produced in the testing or operation of metering equipment that affect the measured volumes. The documentation must include, but is not limited to,

- equipment calibration reports
- equipment change tickets
- peripheral equipment evaluation reports

2.2 Flow Computers

The programmable flow computer is treated much the same as the SCADA system. In some cases, data are collected from the flow computer through an RTU or by radio, hand-held device, or telephone.

Any system installation has to be reliable in terms of mechanical and electrical installation, and the operation personnel must be able to demonstrate that the flow computer database will be kept up to date. Also, each system must incorporate an acceptable method of taking and recording readings from the flow computer if it is not tied into a printer system. A sample log report that the operation personnel uses to record readings from the flow computer should be requested.

Measurement Uncertainty

Gas and liquid volumes must be measured within the maximum uncertainties specified in OGCR, Schedule 9, as well as uncertainties for processing plants, compressor stations, and injection wells that have been added and some others that have been revised. **These monthly flow and measurement uncertainty limits will be replaced by the chapter on uncertainty in the Measurement Directive in progress when it is approved.**

2.3 Gas Measurement

Electronic gas measurement systems must be designed and installed in accordance with the American Petroleum Institute *Manual of Petroleum Measurement Standards (API-MPMS)*, First Edition, Chapter 21.1: Electronic Gas Measurement, with the following exceptions and clarifications:

- Where an orifice meter is used to measure gas, volumes may be calculated according to the provisions of either the 1985 edition or the latest edition of the AGA3, *Orifice Metering of Natural Gas.*

- Correction for deviation from the Ideal Gas Laws may be based on equations published in the latest edition of the AGA Report No. 8, *Compressibility and Super-Compressibility for Natural Gas and Other Hydrocarbon Gases* or the equations specified in *IL 87-1*.

- Slower sampling or integration frequencies than stated in *API-MPMS*, Chapter 21, Clauses 1.4.2.1, 1.4.2.2, and 1.4.3.1, may be used if it can be demonstrated using the Rans Methodology that uncertainties are still being met.

- Hourly quantity transaction records as specified in *API-MPMS*, Chapter 21, Clauses 1.6.2.2 and 1.6.2.4, are not required.

2.4 Liquid Measurement Systems

Where a turbine or PD meter is used to measure liquid, volumes must be calculated according to the provisions of the latest edition of *API-MPMS*, Chapter 12.2: Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters, and the meter must be designed and installed according to the manufacturer's specifications.

Where an orifice meter is used to measure liquids, the meter must be designed and installed according to the provisions of either the 1985 edition or the latest edition of the AGA3, *Orifice Metering of Natural Gas*, and the volumes must be calculated using the equations published in the *Flow Measurement Engineering Handbook.*

The reporting requirements outlined in this directive must be met.

2.5 End Device Calibrations

Contact the licensee well in advance so that you can witness, if possible, the regularly scheduled calibrations during your inspection. This is particularly important if calibrations are performed by outside instrument companies.

ERCB staff are to only *witness* calibrations on end devices. In no event should an auditor attempt a calibration check on the end devices or attempt to check an orifice plate or other meter. Since most of these systems are on automatic flow control, a seemingly simple operation (such as rolling out the orifice plate) can have serious consequences.

The first step in a calibration is checking the "as found" values of the end device. This normally involves a five-point check, including 0% and 100% for the analog output differential pressure end device (a three-point check [0%, 50%, 100%] is sufficient for digital output end devices), and a three-point check, including 0%, 50%, and 100%, for the static pressure end device. The static and differential pressures should be checked against a dead weight tester or equivalent device with the same or better accuracy and using an accurate ammeter to get the corresponding 4-20 mA signal (for analog output systems).

The device is then calibrated, if necessary, and the points checked and recorded again. If the system has dumb RTUs, each of the points should be checked against what the host computer reads and those values recorded. If different, the analog-to-digital converter will require calibration or replacement. Calibration of the analog-to-digital converter for smart RTUs is not required, since most of them cannot be calibrated in the field.

RTDs used for detecting temperatures may be calibrated by checking them against a mercury thermometer. They may also be calibrated in a thermal bath or done on the bench. The electronics can be checked against a resistance box, and if the RTD is reading the right temperature when compared to a thermometer reading, the RTD can be considered calibrated.

Liquid meters are to be proved as required by the OGCR, Sections 14.090, 14.110, 14.120, and 14.140, and the electronic outputs should be checked for accuracy by comparing them to the mechanical readings on the meter. If no mechanical reading is available, the electronic reading should be used to calculate the meter factor.

The end devices should be located close to the meter. If they are more than 3 m away, request that they be relocated closer. During the orifice meter calibration, watch for liquids in the end devices and ask how often they are blown clear. The orifice plate should also be checked, if possible, during each calibration and its size recorded. End devices should be installed above the flow line for gas measurement and below the flow line for liquid measurement.

It is recommended that when witnessing a calibration, you obtain a copy of the calibration report. This can then be used later for review and evaluation.

3 Review and Evaluation

3.1 Database Review

The database in use contains data such as meter run size, end device ranges, and gas analysis. These data should be checked for completeness and accuracy. Use the completed calibration sheet after witnessing the calibrations to check the data for that meter. If problems are found, other meters will have to be checked; otherwise, a spot check of the database is sufficient.

3.1.1 Database Changes

Request the operation personnel to explain how a change, such as an orifice plate change, is handled on the system. Ensure that only knowledgeable personnel have access to the system and that any change is documented. This normally involves printing the event log and putting it on file or saving it on computer disk or tapes.

3.1.2 Handling Reports

Request the operation personnel to show how the reports in Section 2.1.3 are generated. The required reports can be printed daily and a system used to file the reports or keep the data on tape or disk for long-term storage.

3.1.3 Printed Reports

Review each report, especially the daily and meter report, to ensure completeness. The reports must contain the information indicated in this directive. This is one of the most important checks to be completed.

3.1.4 System Reliability

Review with the operation personnel any downtime experienced. Discuss problems with calculation, software, communications, or RTU failures. If there are any of the above problems, consult with the ERCB Production Operations Section, Compliance and Operations Branch, before taking any action.

3.2 Performance Evaluation

A performance evaluation test for orifice meters must be completed, inputting known values of flow data to verify the accuracy of flow factor calculations. Several sample test cases are attached for this purpose. The volumetric gas flow rate obtained from the performance evaluation test should agree to within ± 0.25% of those recorded on the sample test cases or other acceptable flow calculation programs. Exceeding this limit does not automatically make the system unsatisfactory, but a more detailed review of the calculation algorithm is required. If no AGA3 factor outputs are available for either the test cases in this section or the other approaches, the acceptable volumetric gas flow rate limit is lowered to ± 0.15%.

3.2.1 Test Cases for Verification of Orifice Meter Gas Flow Calculation Programs

The ERCB maintains the test cases that follow to verify that computer programs correctly calculate gas flow rates from orifice meters. The test cases were calculated on the following basis:

- The final component was assumed to be normal heptane.
- The ideal gas relative density was converted to the real gas relative density.
- The same static pressure value is used either for upstream (U/S) or downstream (D/S) pressure calculations.
- The AGA3 (1985) results were calculated in imperial units with a soft conversion to metric (i.e., C' is in scf/hr/[inches H_2O x psia]$^{1/2}$ and the conversion factor is 0.02831685) based on upstream conditions. The compressibility factors were calculated using the Redlich Kwong equation, with the Wichert Aziz correction for sour gas.
- The AGA3 (1990) results were calculated in metric units, with the compressibility factors calculated using AGA8 (1992).
- The AGA3 (1990) results were calculated using the upstream expansion factor Y_1, as recommended by the AGA3 (1990), Part 1, Section 1.8, even though the pressure tap may be downstream of the orifice plate (the Y_2 factor is also provided for reference when applicable).
- The orifice plate was assumed to be made of 316 SS.

The ERCB will consider a computer program that uses the AGA3 (1985) equation to be correct if for each of the test cases,

- each of the factors Y, F_a, F_r, and F_{tf} it calculates is within 0.01% of the ERCB-determined values,
- the F_b factor it calculates is within 0.1% of the ERCB-determined value,
- the F_g factor it calculates is within 0.2% of the ERCB-determined value,
- the F_{pv} factor it calculates is within 0.2% of the ERCB-determined value,
- the correct conversion factor is used in association with accurately calculated F_{tb} and F_{pb} factors, and
- the gas rate it calculates is within 0.25% of the ERCB-determined value.

The ERCB will consider a computer program that uses the AGA3 (1990) equations to be correct if for each of the test cases,

- both the gas expansion coefficient (Y_1) and the velocity of approach factor (E_v) it calculates are within 0.01% of the ERCB-determined values,
- both the discharge coefficient (C_d) and base compressibility factor (Z_b) it calculates are within 0.1% of the ERCB-determined values,
- the compressibility factor at flowing conditions (Z_f) it calculates is within 0.2% of the ERCB-determined value, and
- the gas rate it calculates is within 0.25% of the ERCB-determined value.

TEST CASE NUMBER 1

Gas Analysis

N_2	-	0.0184	iC_4	-	0.0081
CO_2	-	0.0000	nC_4	-	0.0190
H_2S	-	0.0260	iC_5	-	0.0038
C_1	-	0.7068	nC_5	-	0.0043
C_2	-	0.1414	C_6	-	0.0026
C_3	-	0.0674	C_7	-	0.0022

Ideal gas relative density - 0.7792

Meter Data (flange taps)

Meter run	I.D.	-	52.370 mm (2.0618 inches)
Orifice	I.D.	-	9.525 mm (0.375 inches)

Flow Data (24 hr)

Static pressure	-	2818.09 kPa(a) (408.73 psia)
Differential pressure	-	10.2000 kPa (40.9897" H_2O)
Flowing temperature	-	57.0°C (134.600°F)

Gas Volume Result

AGA3 (1985)

	U/S Tap	D/S Tap	
F_b	28.429	28.429	
Y	0.9989	1.0007	
F_{tb}	0.9981	0.9981	
F_g	1.1308	1.1308	
F_a	1.0012	1.0012	
F_r	1.0006	1.0006	
F_{pb}	1.0023	1.0023	
F_{tf}	0.9351	0.9351	
F_{pv}	1.0360	1.0361	
C'	31.174	31.233	
Q	2.7422	2.7474	10^3 m^3/24 h

AGA3 (1990)

	U/S Tap	D/S Tap	
C_d	0.5990	0.5990	
Y_1	0.9989	0.9989	
Y_2	N/A	1.0007	
E_v	1.0005	1.0005	
Z_b	0.9959	0.9959	
Z_f	0.9280	0.9277	
Q	2.7478	2.7532	10^3 m^3/24 h

TEST CASE NUMBER 2

Gas Analysis

N_2	-	0.0156	iC_4	-	0.0044
CO_2	-	0.0216	nC_4	-	0.0075
H_2S	-	0.1166	iC_5	-	0.0028
C_1	-	0.7334	nC_5	-	0.0024
C_2	-	0.0697	C_6	-	0.0017
C_3	-	0.0228	C_7	-	0.0015

Ideal gas relative density - 0.7456

Meter Data (flange taps)

Meter run	I.D.	-	102.26 mm (4.026 inches)
Orifice	I.D.	-	47.625 mm (1.875 inches)

Flow Data (24 hr)

Static pressure	-	9100.94kPa(a) (1319.98 psia)
Differential pressure	-	11.0000 kPa (44.2046" H_2O)
Flowing temperature	-	50.0°C (122.0°F)

Gas Volume Result

AGA3 (1985)			AGA3 (1990)		
	U/S Tap	**D/S Tap**		**U/S Tap**	**D/S Tap**
F_b	733.697	733.697	C_d	0.6019	0.6019
Y	0.9996	1.0002	Y_1	0.9996	0.9996
F_{tb}	0.9981	0.9981	Y_2	N/A	1.0003
F_g	1.1564	1.1564	E_v	1.0244	1.0244
F_a	1.0010	1.0010	Z_b	0.9967	0.9967
F_r	1.0002	1.0002	Z_f	0.8098	0.8097
F_{pb}	1.0023	1.0023	Q	146.08	146.18 10^3 m^3/24 h
F_{tf}	0.9452	0.9452			
F_{pv}	1.1072	1.1073			
C'	888.93	889.52			
Q	145.93	146.06 10^3 m^3/24 h			

TEST CASE NUMBER 3

Gas Analysis

N_2	-	0.0500	iC_4	-	0.0000
CO_2	-	0.1000	nC_4	-	0.0000
H_2S	-	0.2000	iC_5	-	0.0000
C_1	-	0.6000	nC_5	-	0.0000
C_2	-	0.0500	C_6	-	0.0000
C_3	-	0.0000	C_7	-	0.0000

Ideal gas relative density - 0.8199

Meter Data (flange taps)

Meter run	I.D.	-	590.55 mm (23.250 inches)
Orifice	I.D.	-	304.80 mm (12.000 inches)

Flow Data (24 hr)

Static pressure	-	10342.14 kPa(a) (1500.00 psia)
Differential pressure	-	22.1600 kPa (89.0522" H_2O)
Flowing temperature	-	60.0°C (140.0°F)

Gas Volume Result

AGA3 (1985)

	U/S Tap	D/S Tap
F_b	30429.66	30429.66
Y	0.9993	1.0004
F_{tb}	0.9981	0.9981
F_g	1.1027	1.1027
F_a	1.0013	1.0013
F_r	1.0001	1.0001
F_{pb}	1.0023	1.0023
F_{tf}	0.9309	0.9309
F_{pv}	1.1076	1.1078
C'	34638.2	34663.15
Q	8603.6	8612.97 10^3 m^3/24 h

AGA3 (1990)

	U/S Tap	D/S Tap
C_d	0.6029	0.6029
Y_1	0.9993	0.9993
Y_2	N/A	1.0004
E_v	1.0375	1.0375
Z_b	0.9968	0.9968
Z_f	0.8216	0.8213
Q	8564.9	8575.6 10^3 m^3/24 h

TEST CASE NUMBER 4

Gas Analysis

N_2	-	0.0029	iC_4	-	0.0000
CO_2	-	0.0258	nC_4	-	0.0000
H_2S	-	0.0000	iC_5	-	0.0000
C_1	-	0.9709	nC_5	-	0.0000
C_2	-	0.0003	C_6	-	0.0000
C_3	-	0.0001	C_7	-	0.0000

Ideal gas relative density - 0.5803

Meter Data (flange taps)

Meter run	I.D.	-	146.36 mm (5.762 inches)
Orifice	I.D.	-	88.900 mm (3.500 inches)

Flow Data (24 hr)

Static pressure	-	9839.99 kPa(a) (1427.17 psia)
Differential pressure	-	6.6130 kPa (26.575" H_2O)
Flowing temperature	-	22.35°C (72.23°F)

Gas Volume Result

AGA3 (1985)

	U/S Tap	D/S Tap
F_b	2694.99	2694.99
Y	0.9998	1.0001
F_{tb}	0.9981	0.9981
F_g	1.3116	1.3116
F_a	1.0001	1.0001
F_r	1.0002	1.0002
F_{pb}	1.0023	1.0023
F_{tf}	0.9884	0.9884
F_{pv}	1.0842	1.0842
C'	3790.56	3791.44
Q	501.70	501.87 10^3 m^3/24 h

AGA3 (1990)

	U/S Tap	D/S Tap
C_d	0.6047	0.6047
Y_1	0.9998	0.9998
Y_2	N/A	1.0001
E_v	1.0759	1.0759
Z_b	0.9980	0.9980
Z_f	0.8425	0.8425
Q	503.45	503.65 10^3 m^3/24 h

TEST CASE NUMBER 5

Gas Analysis

N_2	-	0.0235	iC_4	-	0.0088
CO_2	-	0.0082	nC_4	-	0.0169
H_2S	-	0.0021	iC_5	-	0.0035
C_1	-	0.7358	nC_5	-	0.0031
C_2	-	0.1296	C_6	-	0.0014
C_3	-	0.0664	C_7	-	0.0007

Ideal gas relative density - 0.7555

Meter Data (flange taps)

Meter run	I.D.	-	154.05 mm (6.0650 inches)
Orifice	I.D.	-	95.250 mm (3.750 inches)

Flow Data (24 hr)

Static pressure	-	2499.9 kPa(a) (362.58 psia)
Differential pressure	-	75.000 kPa (301.395" H_2O)
Flowing temperature	-	34.0°C (93.2°F)

Gas Volume Result

AGA3 (1985)

	U/S Tap	D/S Tap
F_b	3111.24	3111.24
Y	0.9894	1.0044
F_{tb}	0.9981	0.9981
F_g	1.1486	1.1486
F_a	1.0005	1.0005
F_r	1.0001	1.0001
F_{pb}	1.0023	1.0023
F_{tf}	0.9695	0.9695
F_{pv}	1.0381	1.0386
C'	3564.23	3599.72
Q	800.25	812.70 $10^3\ m^3/24\ h$

AGA3 (1990)

	U/S Tap	D/S Tap
C_d	0.6042	0.6042
Y_1	0.9894	0.9897
Y_2	N/A	1.0057
E_v	1.0822	1.0822
Z_b	0.9962	0.9962
Z_f	0.9240	0.9217
Q	799.84	813.00 $10^3\ m^3/24\ h$

TEST CASE NUMBER 6

Gas Analysis

N_2	-	0.0268	iC_4	-	0.0123
CO_2	-	0.0030	nC_4	-	0.0274
H_2S	-	0.0000	iC_5	-	0.0000
C_1	-	0.6668	nC_5	-	0.0000
C_2	-	0.1434	C_6	-	0.0180
C_3	-	0.1023	C_7	-	0.0000

Ideal gas relative density - 0.8377

Meter Data (flange taps)

Meter run	I.D.	-	52.500 mm (2.0669 inches)
Orifice	I.D.	-	19.050 mm (0.750 inches)

Flow Data (24 hr)

Static pressure	-	2506.33 kPa(a) (363.50 psia)
Differential pressure	-	17.0500 kPa (68.5171" H_2O)
Flowing temperature	-	7.2°C (44.96°F)

Gas Volume Result

AGA3 (1985)

	U/S Tap	**D/S Tap**
F_b	115.14	115.14
Y	0.9979	1.0012
F_{tb}	0.9981	0.9981
F_g	1.0902	1.0902
F_a	0.9996	0.9996
F_r	1.0003	1.0003
F_{pb}	1.0023	1.0023
F_{tf}	1.0148	1.0148
F_{pv}	1.0708	1.0714
C'	136.15	136.62
Q	14.599	14.654 10^3 m^3/24 h

AGA3 (1990)

	U/S Tap	**D/S Tap**
C_d	0.6005	0.6005
Y_1	0.9978	0.9978
Y_2	N/A	1.0018
E_v	1.0088	1.0088
Z_b	0.9951	0.9951
Z_f	0.8588	0.8578
Q	14.687	14.746 10^3 m^3/24 h

Appendix E Determining Gas Estimates

E-1 Method to Estimate Fuel Gas

For Treaters

The two methods below can be used to estimate fuel gas use for treaters and lease fuel reporting. They are only estimates and are to be treated as such.

Method 1 – This method uses the specific heats of oil and water to calculate the amount of fuel required to heat up one unit of oil-water mixture.

Specific Heat of Oil = 150 Btu/bbl/^oF = 1698.3 Btu/m^3/^oC

Specific Heat of Water = 350 Btu/bbl/^oF = 3962.8 Btu/m^3/^oC

Temperature difference [dT (^{o}C)] = Oil (Water) Outlet Temperature - Emulsion Inlet Temperature

Assuming Btu content of gas = 1000 Btu/ft^3 = 35 494 Btu/ m^3

Fuel consumption (m^3/month) =

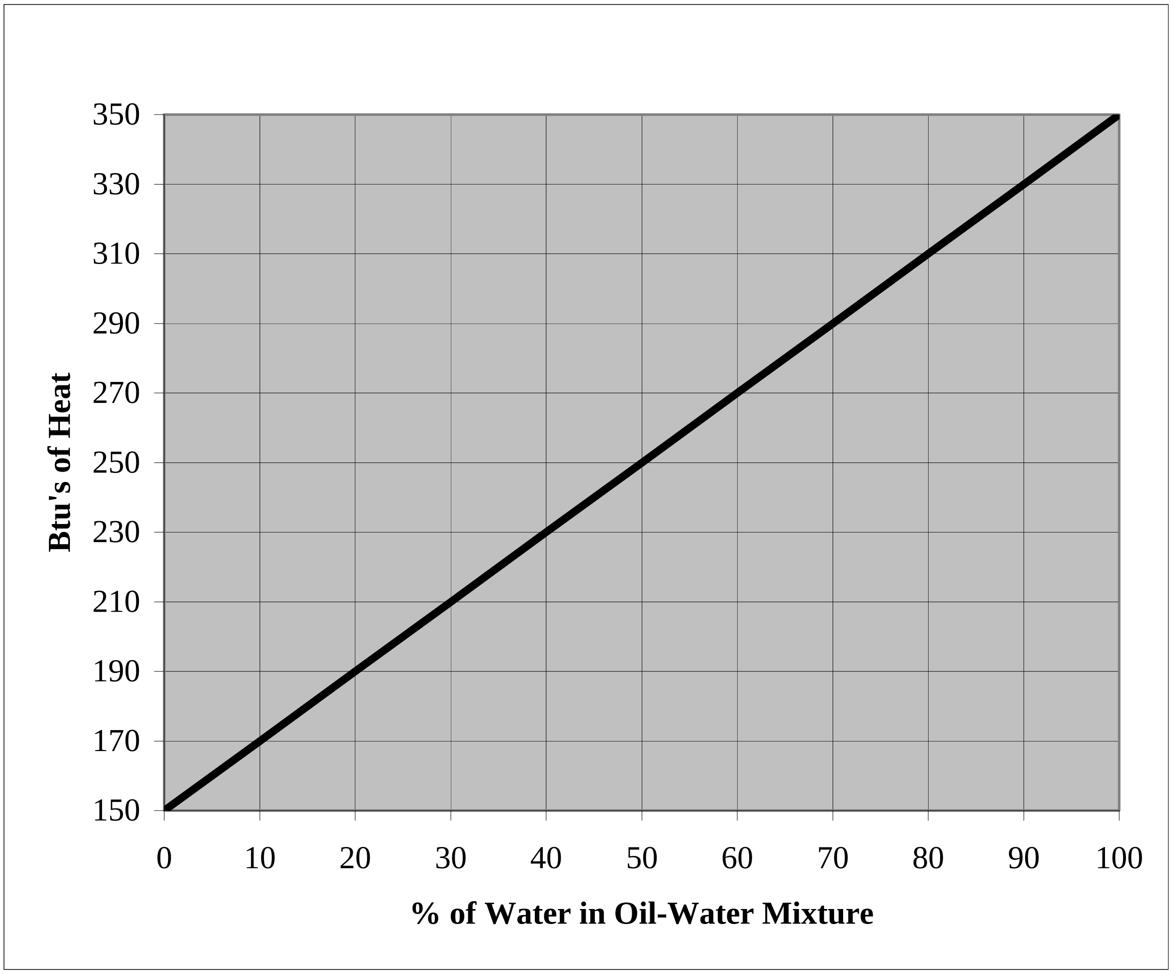
(Oil Volume per month / (35494 / 1698.3) + Water Volume per month / (35494 / 3962.8)) x (dT / Firetube efficiency)

The treater firetube efficiency can be obtained from the manufacturer's specification.

Method 2 (using graph)—This method uses the percentage of water in the oil-water mixture to look up on a graph the heat required to increase the temperature of the oil-water mixture and then calculate the amount of fuel required.

Heat required (Btu) = Emulsion per month (bbl) x dT(°F) x Btu of Heat (from graph)/bbl/°F

Fuel consumption (m^3/month) =
Heat required (Btu) / [Firetube efficiency x 1000 (Btu/ft^3)] x 0.02831685 (m^3/ ft^3)



Btu's of heat required to raise 1 barrel of oil-water mixture by 1°F

Fuel gas measurement is required if fuel gas usage is greater than 500 m^3/day, according to *Directive 64*.

For Compressors
If a compressor is found to have no meter for the measurement of fuel gas, the operation personnel has to supply the fuel gas usage estimate based on the make, model, and operating conditions (rpm and HP) of the engine. (The fuel gas usage may be obtained from the manufacturer's specifications or from Figure 4-13 of the GPSA *Engineering Data Book.*)

For Reboilers and Other Equipment
The reboiler fuel gas requirements, as well as those for glycol pumps and others, should be obtained from the operation personnel, who can cite manufacturer specifications or provide a reasonable estimate. Ensure that all fuel information is obtained during the inspection.

E-2 Gas-in-Solution

Correcting Produced Gas Volumes to Include Unmetered Solution Gas

Definition: Solution Gas/Oil Ratio (dissolved gas, *Rs*): The amount of gas that will evolve from the oil as the pressure is reduced.

The OGCR, Part 14.060(3), requires "a reasonable estimate of all unmetered gas production in the gas volume computation for the period covered by a chart, meter, index counter or data printer." See Directive 017, Section 4.3.5 for requirements (April 18, 2011)

Oil wells generally produce under some pressure. Wellhead pressure ranges from very high to minimal. The volume of gas produced in conjunction with the oil will also show considerable variation not only because of the producing pressure and temperature, but also due to the properties of the oil itself. It is not always economically feasible to measure wells at each stage of separation.

See Directive 017, Section 4.3.5 for requirements (April 18, 2011)

To determine total gas produced for single wells or wells producing to a proration battery, an adjustment for unmetered gas liberated from the oil after it leaves the initial separation vessel is required. The adjustment for test gas volumes from the test vessel pressure to group pressure then stock tank pressure or zero kPa gauge is sometimes incorrectly referred to as the "test to group correction." It is actually a gas-in-solution adjustment. The gas volume adjustment to include gas-in-solution produced will affect well gas production, battery proration factors, and total battery gas produced.

Note that an estimate of gas-in-solution is necessary for individual wells producing to a proration battery, the total oil produced at the proration battery, and single-well batteries.

Common Methods of Determining Gas-in-Solution Correction Factors: The gas-in-solution correction factor will be reported to standard conditions (101.325 kPa and 15°C) in m^3 of gas / m^3 of oil/kPa of pressure drop (see OGCR 14.030).

1) Pressure-Volume-Temperature (PVT) Analysis (PVT data may be on file at the ERCB):

This method requires that a sample of the produced fluids be taken at operating conditions and then sent to a laboratory, where tests are done simulating the various steps of separation the fluid will go through as it is processed. From these tests, analysts are able to determine the volume of gas that will break out of the oil at each stage of separation. These volumes will be reported in m^3 of gas / m^3 of oil.

The formula used to determine the volume of dissolved gas remaining in the oil at the various separation stages is explained in the *Petroleum Engineering Handbook*, Chapter 22: Oil System Correlation (Paul Butold, author; published by Society of Petroleum Engineers).

2) Computer Simulation Program (Alpha Sim, Aspen Plus, Chemcad III, Design II, Hysim, Prosim, etc.):

With a computer simulation model, the analysis of the reservoir fluid is entered into the program. The one-time flash volumes are then calculated at each stage of separation through the process. The end product is a theoretical volume of gas liberated at each stage of separation reported in m^3 of gas / m^3 of oil. This method requires various parameters, such as separator operating pressures, densities, and temperature, to be entered into the HYSIM computer program. As with PVT analysis, samples are required to determine composition.

3) Estimation of Solution Gas/Oil Ratio of Black Oils (Rollins, McCain, Creeger, *Society of Petroleum Engineers Journal*, July 1988):

This method takes into consideration all producing parameters and develops an equation and a nomogram for stock tank gas/oil ratios.

4) Other methods, including Standing Correlation and Vasquez & Beggs Correlation (see CAPP *Directive for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*)

5) Rule of thumb (stock tank vapours)

A *rule of thumb* estimate of 0.0257 m^3 of gas released/m^3 of oil/kPa of pressure drop is a metric conversion of 1.0 scf/bbl/psi pressure drop. The *rule of thumb* is a discretionary application that may be used at some facilities with low oil volumes, established pools, mature pools with declining GORs, or some heavy oil production facilities. This method may be acceptable where the stock tank vapours are flared or vented.

Note that gas-in-solution correction factors may require review throughout the year, as seasonal adjustments to vessel operating temperatures and pressures may have an effect on solution gas volumes.

Determination of Total Produced Gas for a Single-Well Oil Battery

To determine gas, oil, and water produced at a single well, the production from the well flows from the wellhead to a separator operating at less than wellhead pressure (see Figure 2). Here, most of the gas and liquid separate. Oil and water are measured after leaving the separator and go to tanks for storage; the gas leaves the separator through the top and passes through a meter. The oil flowing from the separator into the storage tank will have the same initial pressure and temperature of the separator, but the storage tank will usually be at atmospheric pressure or zero kPa gauge. Thus, additional light end hydrocarbons remaining in the liquid (gas-in-solution), not having been released from the oil during the initial pressure drop at the separator, will be released at the tank. This volume of gas-in-solution released from the oil after the last metered point must be added to the metered gas volume when reporting the well’s total produced gas. It appears on the production reports as vented if the gas is not conserved or collected. If the gas is directed to a flare stack, it must be reported as flared.

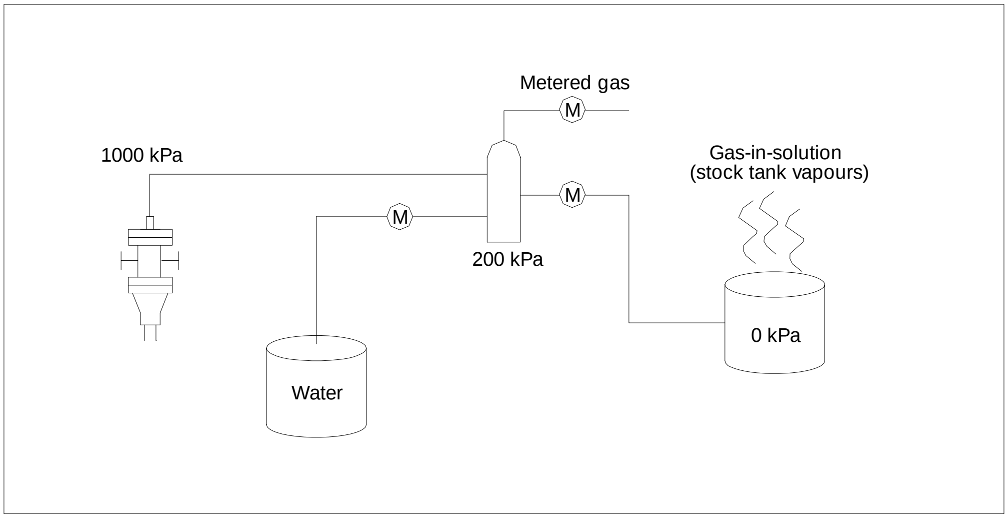


Figure 2. Typical single-well oil battery

Sample Calculation: Actual Gas Volume Single-Well Battery (Figure 2)

Monthly totals (hypothetical):
Gas meter volume: **96.3** 10^3 m^3 (from chart readings)
Oil meter volume**: 643.3** m^3 (from meter or tank gauging)
Water meter volume: 42.7 m^3
Pressure drop = 200 kPa

Gas-in-solution correction factor is **6.37** m^3/m^3 oil at separator conditions (determined from any approved methods).

Gas-in-solution volume is **6.37** x **643.3** = 4097.8 / 1000 = 4.10 10^3 m^3.

The gas-in-solution correction can also be expressed as **0.03185** m^3/m^3/kPa.

The total battery gas production for the reporting month would be

96.3 10^3 m^3 + (**0.03185 m^3/m^3/kPa** x **643.3 m^3 oil** x **200 kPa**)

= (**96.3** 10^3 m^3 + **4.1** 10^3 m^3) = **100.4** 10^3 m^3

Determination of Total Produced Gas for an Oil Proration Battery

For a proration battery, the gas-in-solution correction factors are based on the conditions the test separator is operating at and would be applied to each well's estimated oil volume. A proration battery with several satellites and wells producing from various pools would have several gas-in-solution correction factors. The gas-in-solution correction factor may contribute a significant additional volume to the metered gas volume of satellite wells when the satellite is operating at a pressure much higher than the test and/or group vessels at the main battery.

Note that the gas-in-solution correction must be done for each well, as producing conditions may vary between wells.

Wells on test at the satellite in Figure 3 will require a gas-in-solution correction based on a 600 kPa pressure drop. Wells tested at the main battery will require a gas-in-solution correction based on a 200 kPa pressure drop. These adjustments, calculated using a correction factor arrived at through an approved method, must be added to the test gas volume for each well. The gas-in-solution correction plus the test gas volume must be used in the test-to-test gas estimate calculation.

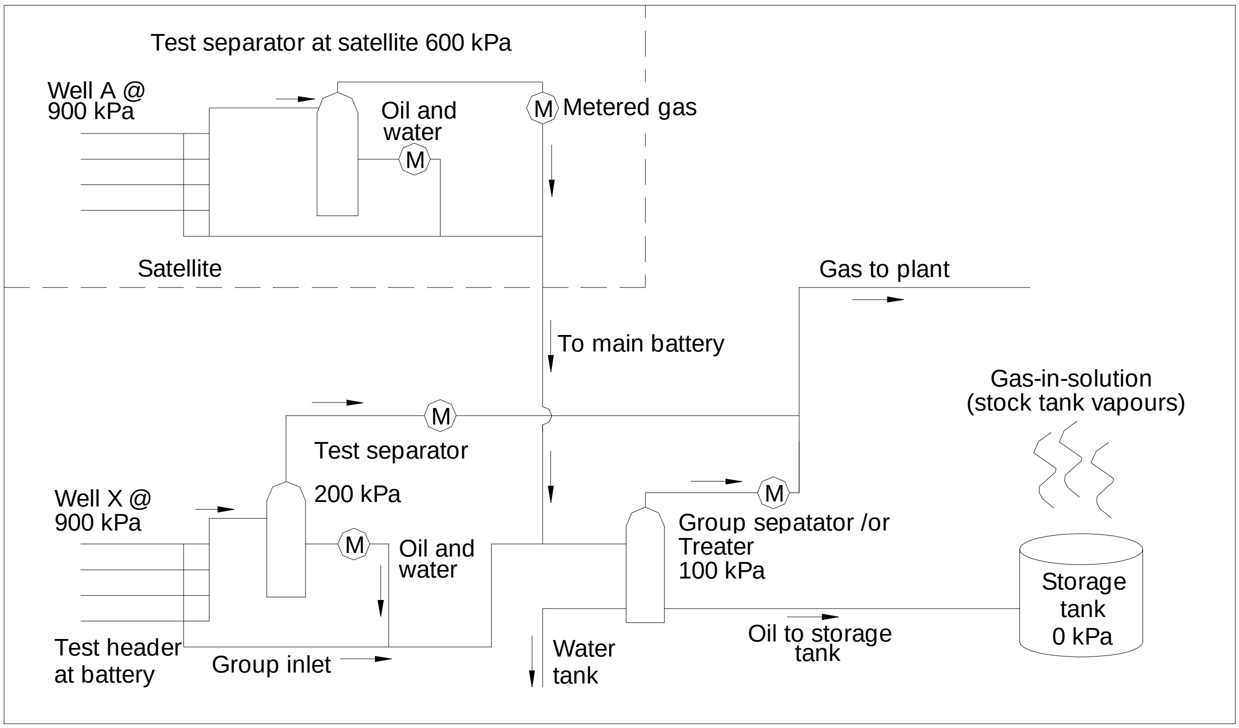


Figure 3. Typical multiwell oil battery

Sample Calculation: Theoretical Test Gas Volumes for Wells in the Satellite – Figure 3

Test volumes at the satellite (hypothetical):

Well “A” test oil is 7.22 m^3, test water is 1.01 m^3, measured test gas is 1.27 10^3 m^3.

Satellite separator @ 600 kPa to group pressure @ 100 kPa, then to storage tank pressure at atmospheric or zero kPa gauge.

Gas-in-solution correction factor is 0.0427 m^3 gas/m^3 oil/kPa (determined from any approved methods).

Gas-in-solution volume is = 0.0427 m^3/m^3/kPa x 7.22 m^3 oil x 600 kPa / 1000 m^3/10^3 m^3 = 0.19 10^3 m^3.

Therefore, total test gas produced for well “A” for this test period is

1.27 10^3 m^3 + 0.19 10^3 m^3 = 1.46 10^3 m^3.

Sample Calculation: Theoretical Test Gas Volumes for Wells in the Battery

Well “X” test oil is 3.85 m^3, test water is 4 m^3, measured test gas is 2.33 10^3 m^3.

Satellite separator @ 200 kPa to group pressure @ 100 kPa, then to storage tank pressure at atmospheric or zero kPa.

Gas-in-solution correction factor is 0.0395 m^3/m^3/kPa.

Gas-in-solution volume is = 0.0395 m^3/m^3/kPa x 3.85 m^3 oil x 200 kPa / 1000 $m^3/10^3\,m^3$ = 0.03 $10^3\,m^3$.

Therefore the total test gas volume for well "X" for this test period is 2.33 $10^3\,m^3$ + 0.03 $10^3\,m^3$ = 2.36 $10^3\,m^3$.

Sample Calculation: Actual Gas Production for the Battery—Figure 3

Oil production for the Figure 3 proration battery is 745 m^3 for the month; measured gas production is 97.4 $10^3\,m^3$.

Pressure drop from the group vessel to stock tanks = 100 kPa.

Gas-in-solution correction factor determined from any approved methods = 0.0399 m^3/m^3/kPa.

Gas-in-solution volume is = 0.0399 m^3/m^3/kPa x 745 m^3 oil x 100 kPa / 1000 $m^3/10^3\,m^3$. = 2.97 $10^3\,m^3$.

The total produced gas volume for the battery = 97.4 $10^3\,m^3$ + 2.97 $10^3\,m^3$ = 100.4 $10^3\,m^3$.

Receipts considered dead oil, such as trucked oil and most pipeline connected oil, may be recycled through the treater. This receipt volume must **not** be included with the actual battery production when determining the gas-in-solution correction.

Note that at some facilities, a vapour recovery unit (VRU) may be in place downstream of the last gas meter equipped process vessel to collect any gas-in-solution that may be released. If the VRU is equipped with a meter, a gas-in-solution calculation would not be required because the measured VRU gas will be added to the rest of the measured gas volumes.

Temperature changes between vessels will have a significant effect on gas volumes liberated. Seasonal changes should be taken into consideration when determining gas-in-solution correction factors. Correction factors for summer and winter operating conditions may be required.

The above examples illustrate the basics for gas volume calculations. There are other parameters that must be taken into consideration when determining total well and/or facility gas volumes. These include fuel gas, both metered and estimated, gas lift gas, blanket gas, and other receipts gas.

E-3 Gas Equivalent Factor Determination

Definition: Gas equivalent is the volume of gas (10^3 m^3) that would result from converting 1 m^3 of liquid into a gas.

This is generally used for condensate and other hydrocarbon liquids.

Method of Calculation

The gas equivalent of a liquid may be calculated by one of three methods, depending upon the type of analysis of the liquid (by volume, mole, or mass fractions) and the known properties of the liquid. The volume analysis method is the most commonly used in industry.

Engineering Data

Certain constants are used in the various methods of calculating the gas equivalent factor:

Density of water = 999.10 kg/m^3 @ 15^{o}C

1 mole = 22.414 L @ 101.325 kPa and 0^{o}C

1 kmol = 22.414 x (273.15 + 15) / 273.15

= 23.645 m^3 @ 101.325 kPa and 15^{o}C

See Directive 017, Section 8.3 for requirements (April 18, 2011)

Liquid Analysis Example

Component	Liquid Volume %	Mol. %	Mass %
N_2	0.06	0.19	0.08
CO_2	0.81	1.58	1.09
H_2S	0	0	0
C_1	8.28	16.17	4.05
C_2	11.17	14.62	6.87
C_3	12.75	15.33	10.56
IC_4	3.94	3.98	3.62
NC_4	8.91	9.35	8.49
IC_5	4.83	4.36	4.92
NC_5	5.4	4.93	5.56
C_6	7.65	6.14	8.35
C_7	8.8	6.78	10.54
C_8	8.27	5.89	10.32
C_9	5.7	3.68	7.26
C_{10}	3.63	2.22	4.8
C_{11}	2.25	1.31	3.05
C_{12}	7.55	3.47	10.44
TOTAL	100.00	100.00	100.00

Properties of Total Sample and C_{12}+ Residue at 15ºC

	Specific Gravity	API Gravity	Molecular Weight (gm/mol)
Total Sample	0.613	99.3	64.0
C12+	0.848	35.4	192.4

Properties of C_5+ & C_7+ Portion of Sample

	Mol. %	Wt. %	Liq. Vol. %	Mol. Wt.	Sp. Gr.	API
C5+	38.78	65.24	54.08	107.7	0.740	59.7
C7+	23.35	46.41	36.20	127.2	0.786	48.5

Gas Equivalent Factor by Volume Fraction Calculation

Gas Equivalent Factor = Total (10^3 m^3 Gas / m^3 Liquid)

Well or Plant Name: ______________________________

Component	Vol. Fraction Liquid Analysis		GPA 2003 10^3 m^3 Gas / m^3 Liquid @ 101.325 kPa & 15ºC		Pseudo 10^3 m^3 Gas / m^3 Liquid
N_2		x	0.68040	=	
CO_2		x	0.44120	=	
H_2S		x	0.55460	=	
C_1		x	0.44217	=	
C_2		x	0.28151	=	
C_3		x	0.27222	=	
IC_4		x	0.22906	=	
NC_4		x	0.23763	=	
IC_5		x	0.20468	=	
NC_5		x	0.20681	=	
C_6		x	0.18216	=	
C_7		x	0.16234	=	
C_8		x	0.14629	=	
C_9		x	0.13303	=	
C_{10}		x	0.12194	=	
				Total =	

Gas Equivalent Factor = Total (10^3 m^3 Gas / m^3 Liquid)

= ______ (10^3 m^3 Gas / m^3 Liquid)

Note:

For C_5+ or C_7+ Volume Fraction (if used):

Properties of C_5+ or C_7+ sample @ 15ºC

Rel. Density (RD) = ______

Mol. Wt. = ______

10^3 m^3 Gas / m^3 Liquid = 23.645 x RD / Mol. Wt. x 999.10 / 1,000

10^3 m^3 Gas / m^3 Liquid = ______ Input this factor to the table above

Example 1

Gas Equivalent Factor by Volume Fraction Calculation

Gas Equivalent Factor = Total (10^3 m^3 Gas / m^3 Liquid)

Well or Plant Name: ______________________

Component	Vol. Fraction Liquid Analysis		10^3 m^3 Gas / m^3 Liquid @ 101.325 kPa & 15ºC		Pseudo 10^3 m^3 Gas / m^3 Liquid
N_2	0.0006	x	0.68040	=	0.0004
CO_2	0.0081	x	0.44120	=	0.0036
H_2S		x	0.55460	=	
C_1	0.0828	x	0.44217	=	0.0366
C_2	0.1117	x	0.28151	=	0.0314
C_3	0.1275	x	0.27222	=	0.0347
IC_4	0.0394	x	0.22906	=	0.0090
NC_4	0.0891	x	0.23763	=	0.0212
IC_5	0.0483	x	0.20468	=	0.0099
NC_5	0.0540	x	0.20681	=	0.0112
C_6	0.0765	x	0.18216	=	0.0139
C_7+	0.3620	x	0.14598	=	0.0528
		x		=	
		x		=	
		x		=	
	1.0000			Total =	0.2248

Gas Equivalent Factor = Total (10^3 m^3 Gas / m^3 Liquid)

= 0.22478 (10^3 m^3 Gas / m^3 Liquid)

Note:

For C_7+ Volume Fraction:

Properties of C_7+ sample @ 15ºC

Rel. Density (RD) = 0.786

Mol. Wt. = 127.2

10^3 m^3 Gas / m^3 Liquid = 23.645 x RD / Mol. Wt. x 999.10 / 1,000

10^3 m^3 Gas / m^3 Liquid = 0.14598 Input this factor to the table above for C_7+

Gas Equivalent Factor by Mol. Fraction Calculation

Gas Equivalent Factor = 23.645 (m^3 / kmol) x Total (1/m^3/kmol) / 1,000

Well or Plant Name: ______________________________

			GPA 2003		
Component	Mol. Fraction Liquid Analysis		m^3 / kmol @ 101.325 kPa & 15ºC		Pseudo m^3/kmol
N_2		x	0.034752	=	
CO_2		x	0.053590	=	
H_2S		x	0.042630	=	
C_1		x	0.053475	=	
C_2		x	0.083992	=	
C_3		x	0.086859	=	
IC_4		x	0.103220	=	
NC_4		x	0.099501	=	
IC_5		x	0.115520	=	
NC_5		x	0.114330	=	
C_6		x	0.129800	=	
C_7		x	0.145650	=	
C_8		x	0.161630	=	
C_9		x	0.177740	=	
C_{10}		x	0.193910	=	
				Total =	

Gas Equivalent Factor = 23.645 (m^3 / kmol) x Total (1/m^3/kmol) / 1,000

= [ ] (10^3 m^3 Gas / m^3 Liquid)

Note:

For C_5+ or C_7+ Mol. Fraction (if used):

Properties of C_5+ or C_7+ sample @ 15ºC:

Rel. Density (RD) = [ ]

Mol. Wt.= [ ]

m^3 / kmol = Mol. Wt. / 999.1 / RD

m^3 / kmol = [ ] Input this factor to the table above

Example 2

Gas Equivalent Factor by Mol. Fraction Calculation

Gas Equivalent Factor = 23.645 (m^3 / kmol) x Total ($1/m^3$/kmol) / 1,000

Well or Plant Name: ______________________________

Component	Mol. Fraction Liquid Analysis		m^3 / kmol @ 101.325 kPa & 15ºC		Pseudo m^3/kmol
N_2	0.0019	x	0.03475	=	0.0001
CO_2	0.0158	x	0.05359	=	0.0008
H_2S		x		=	
C_1	0.1617	x	0.05348	=	0.0086
C_2	0.1462	x	0.08399	=	0.0123
C_3	0.1533	x	0.08686	=	0.0133
IC_4	0.0398	x	0.10322	=	0.0041
NC_4	0.0935	x	0.09950	=	0.0093
IC_5	0.0436	x	0.11552	=	0.0050
NC_5	0.0493	x	0.11433	=	0.0056
C_6	0.0614	x	0.12980	=	0.0080
C_7+	0.2335	x	0.16198	=	0.0378
		x		=	
		x		=	
		x		=	
	1.0000			Total =	0.1050

Gas Equivalent Factor = 23.645 (m^3 / kmol) x Total ($1/m^3$/kmol) / 1,000

= 0.00248 (10^3 m^3 Gas / m^3 Liquid)

Note:

For C_7+ Mol. Fraction:

Properties of C_7+ sample @ 15ºC:

Rel. Density (RD) =	0.786
Mol. Wt. =	127.2

m^3 / kmol = Mol. Wt. / 999.1 / RD

m^3 / kmol = 0.16198 Input this factor to the table above for C_7+

Gas Equivalent Factor by Mass Fraction Calculation

Gas Equivalent Factor = 23.645 (m^3 / kmol) x 999.10 (kg/m^3) x RD / Total / 1,000

Well or Plant Name: ____________________

Component	Mass Fraction Liquid Analysis		GPA 2003 Mol. Wt.		Pseudo Mol. Wt.
N_2		x	28.013	=	
CO_2		x	44.010	=	
H_2S		x	34.082	=	
C_1		x	16.042	=	
C_2		x	30.069	=	
C_3		x	44.096	=	
IC_4		x	58.122	=	
NC_4		x	58.122	=	
IC_5		x	72.149	=	
NC_5		x	72.149	=	
C_6		x	86.175	=	
C_7		x	100.202	=	
C_8		x	114.229	=	
C_9		x	128.255	=	
C_{10}		x	142.282	=	
				Total =	

Rel. Density (RD) = [ ] (for entire sample from Sample Analysis)

Gas Equivalent Factor = 23.645 (m^3 / kmol) x 999.10 (kg/m^3) x RD / Total / 1,000

= [ ] (10^3 m^3 Gas / m^3 Liquid)

Note:

For C_5+ or C_7+ Fraction (if used):

Mol. Wt. Is obtained from Sample Analysis

Mol. Wt. = [ ] Input Mol. Wt. to the above table

Example 3

Gas Equivalent Factor by Mass Fraction Calculation

Gas Equivalent Factor = 23.645 (m^3 / kmol) x 999.10 (kg/m^3) x RD / Total / 1,000

Well or Plant Name: ______________________________

Component	Mass Fraction Liquid Analysis		Mol. Wt.		Pseudo Mol. Wt.
N_2	0.0008	X	28.013	=	0.0224
CO_2	0.0109	X	44.010	=	0.4797
H_2S		X		=	
C_1	0.0405	X	16.042	=	0.6497
C_2	0.0687	X	30.069	=	2.0657
C_3	0.1056	X	44.096	=	4.6565
IC_4	0.0362	X	58.122	=	2.1040
NC_4	0.0849	X	58.122	=	4.9346
IC_5	0.0492	X	72.149	=	3.5497
NC_5	0.0556	X	72.149	=	4.0115
C_6	0.0835	X	86.175	=	7.1956
C_7+	0.4641	X	127.200	=	59.0335
		X		=	
		X		=	
		X		=	
	1.0000			Total =	88.7030

Rel. Density (RD) = 0.613 (for entire sample from Sample Analysis)

Gas Equivalent Factor = 23.645 (m^3 / kmol) x 999.10 (kg/m^3) x RD / Total / 1,000

= 0.16326 (10^3 m^3 Gas / m^3 Liquid)

Note:

For C_7+ Mass Fraction:

Mol. Wt. is obtained from Sample Analysis

Mol. Wt. = 127.2 Input this factor to the table above for C_7+

F-1 Production Data Sheet see Directive 017, section 6.4.4 (April 18, 2011)

EUB Alberta Energy and Utilities Board

PRODUCTION DATA SHEET

BATTERY	INSPECTOR	DATE
WELL(S) BEING TESTED		

SEPARATORS (LOCATION OR NO.)		SERIAL NO.	RANGES: TEMP. DIFF, STAT, RATE	OPERATING TEMP./PRESS.	METER: GAS-TYPE FLUID-FACTOR	CALIB. DATE	READING OPEN/TIME	READING CLOSE/TIME	H_2O %
TEST	G								
	O								
	W								
TEST	G								
	O								
	W								
GROUP	G								
	O								
	W								
TREATER	G								
	O								
	W								
FUEL	G								

COMMENTS

DAP 17(a) 89-05

TANKS

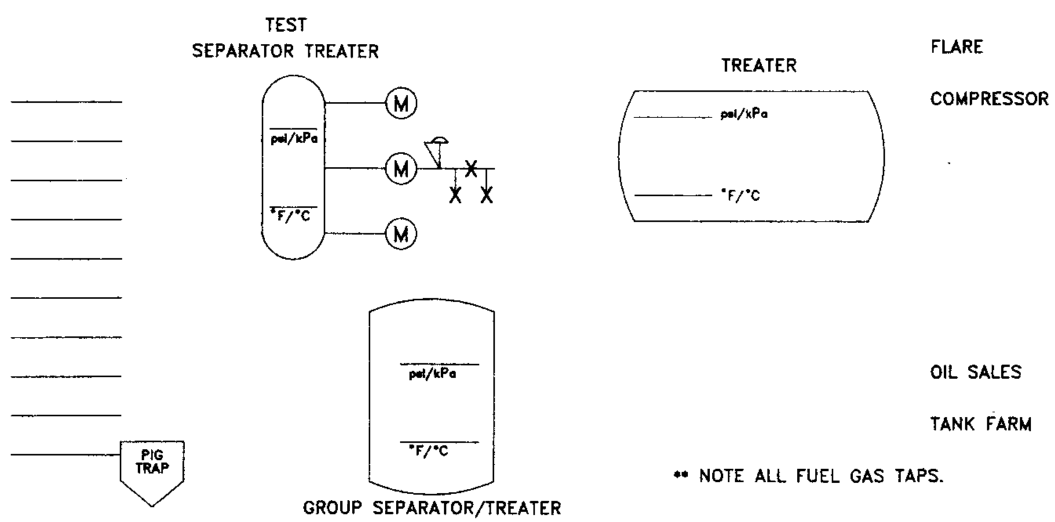
O/W	NUMBER LOCATION	SIZE bbl/m	HEIGHT DIAMETER	GAUGE		GENERAL REMARKS/OBSERVATIONS
				OPENING/TIME	CLOSING/TIME	

PUMPING WELLS (List only if operating)

LOCATION					
STROKE LENGTH					
STROKES/ MINUTE					
TUBING SIZE					

FLOWING WELLS (List only if operating)

CHOKE SIZE					
TUBING PRESSURE					
CASING PRESSURE					



** NOTE ALL FUEL GAS TAPS.

COMMENTS: ____________________

DAP 17(b) 89-05

F-2 Data Request Letter and Sheet

Date

Contact Name
Company Name
Address
Calgary, Alberta T2P ___

PRODUCTION AUDIT

FACILITY NAME:
FACILITY UID:
FACILITY CODE:
FACILITY TYPE:

In accordance with the Oil and Gas Conservation Act, Parts 5, 7, and 13, the Energy Resources Conservation Board (ERCB) is responsible for ensuring accurate measurement and reporting of oil and gas production in Alberta. Part of this responsibility includes conducting detailed production audits of selected facilities.

The subject facility has been selected for production audit in 200_. Attached to this letter is an **Audit Data Request Sheet** listing the information required to evaluate this facility. This information is for the ________, 200_, Production Month <u>only</u> and will be retained on our files. Gas charts, truck tickets and/or other original records will be returned at the completion of our audit.

The required information must be submitted to this office by **_______ __, 200_.** If any of the requested audit data are unavailable, a written explanation must be submitted upon receipt of this letter. Should you require further information, please contact the undersigned at (403) 297-____.

____
Production Audit
Compliance and Operations Branch

Attachment

pc: ERCB, ______ Field Centre

AUDIT DATA REQUEST SHEET

In order to conduct this audit, we require the following information for the production month of **____________, 200_.**

I PROCESS AND MEASUREMENT

The most recent process and accounting meter diagram for the subject facility—the diagram must show the following information:

1) A list of all wells and a statement on how each ties into the facility, including
   - producing, suspended and injection/disposal wells,
   - satellites,
   - headers, and
   - common flow lines.
2) All process equipment, flow lines, fuel lines, flare lines, and blowdown/drain lines. Provide the operating temperature and pressure of each process vessel.
3) All oil, emulsion, gas, condensate, and water tanks/vessels. Provide the dimensions and capacity of each storage tank.
4) All meters, measurement points, sampling points, and custody transfer points. Provide type of meter(s) and sampling device(s).

II FIELD RECORDS AND PROCEDURES

1) **Field Records:** The facility operation personnel's daily facility, well test, and injection well records. Include the applicable original recordings of measurements used to determine the particulars for the record.
2) **Field Data Capture:** The product name and version number of your field data capture software.
3) **Orifice Meter Charts:** If orifice meters configured with chart recorders are used, all charts for accounting meters.
4) **Gas-Oil Ratios (GOR):** If GORs are used, forward the most recent GOR test results and indicate where they are applied.
5) **Water-Gas Ratios (WGR):** If WGRs are used, forward the most recent WGR test results and indicate where they are applied.
6) **Effluent Measurement:** If gas, hydrocarbon liquids, and water are not separated before measurement, forward the most recent well test results upon which the effluent correction factors are based.
7) **Oil Pipeline Tickets:** All original oil pipeline tickets and a summary report.
8) **Truck Tickets:** All original truck tickets and a summary report. Include tickets for movements of product from individual wells.
9) **Trucked-in Production:** Outline the method used to measure the gross volume and water cut of fluids trucked into the subject facility.
10) **Meter Calibration Reports:** Copies of the most recent gas meter calibration and liquid meter prover reports for all accounting meters, including
    - all test gas, emulsion, and water meters,
    - all injection/disposal meters,
    - all fuel, flare, and vented gas meters,
    - group gas meter, and
    - oil pipeline (LACT) meter.

11) **Automated Measurement Systems:** Audit Trail
    - Quantity Transaction Record (QTR) – The data supporting the reported volumes for the stated period.
    - Configuration Log – Identifying all constant flow parameters used in the generation of the QTR. This log must contain all information listed in API Chapter 21, Section 1.6.4, Table 1.
    - Event Log – The record noting all exceptions and changes to the flow parameters (contained in the configuration log) that have occurred and have an impact on the QTR.
    - Corrected QTR – Constant values, times, and dates of any changes affecting the original QTR and/or reported volumes.
    - Test Records – Any documentation produced in the testing or operation of metering equipment that affects measured volumes. This includes the record containing volume verification and calibration measurements for all secondary and tertiary devices.
12) **Automated Measurement Systems:** Verification
    - Provide volume calculation accuracy verification using the six test cases given in Appendix D-5 or provide instantaneous flow calculations (including all factors, parameters, and meter details) for the electronic flow measurement devices used for accounting purposes. Include with your calculations all gas or liquid analysis data used.
13) **Tank Gauging Equipment:** Outline the method and frequency of calibrating gauge boards and/or tank volume sensors, and provide copies of strapping tables for each tank from which inventories/test data are derived.
14) **Meter Factors:** State when in your reporting procedures the meter factors are applied.
15) **Load Fluid Recovery:** Outline the method used to determine well flow rates during load fluid recovery.
16) **Common Flow Lines:** Outline the test procedure and purge time for wells on common flow lines.
17) **Field Headers:** Outline the test procedure and purge time for wells producing to a field header. Test line capacity. Test and group operating line pressures.
18) **BS&W Procedures:** Give the frequency and method of determining the water cut of test production.
19) **Valid Test Criteria:** Provide your criteria for accepting or rejecting well production tests.
20) **Casing Head Gas:** List wells in the subject facility using casing head gas and/or produced gas for lease fuel.
21) **Oil Density:** Give the density of the oil from all pools producing into and/or delivered to this facility (kg/m^3). Where density of the oil is greater than 920 kg/m^3, provide the royalty and ownership structure for each well.
22) **Facility Flaring and Turnaround**
    - Provide the facility flare log for all routine and nonroutine flaring occurrences.
    - State when the facility was last shutdown for routine maintenance or turnaround.

III ACCOUNTING RECORDS AND CALCULATIONS

1) **Production Summary:** Summary of monthly production, injection, and disposition of all fluids.
2) **Estimated Production Worksheet:** The worksheet for determining the estimated production for each well (well test summary). Include previous month’s data.

3) **Gas Chart Reading Summary:** For all orifice meter charts. Include all orifice meter coefficients and factors used in the volume calculation. If gas charts are scanned, provide a copy of all digital chart images and the applicable viewer software.
4) **Gas and Hydrocarbon Liquid Analysis:** Provide the latest gas and hydrocarbon liquid analyses for all accounting meters.
5) **Engineering Estimates**
   - Outline the method used to estimate unmetered flare, fuel, or vented gas streams. Include sample calculation showing all particulars.
   - Outline the method used to estimate gas-in-solution with oil dumped to stock tanks and with oil at test conditions. Include fluid analysis data and sample calculation.
6) **Gas Equivalent Calculations:** The latest test data used to calculate gas equivalent of well condensate and the gas equivalent of all gas liquid streams (condensate, propane, butane, etc.). Include sample calculation and analysis frequency.
7) **Production Accounting Software:** The product name and version number of your production accounting software.
8) **List of Licensees:** For facilities with mixed licenseeship,
   - provide a list all other licensees in the subject facility,
   - indicate which wells, satellites, pipelines, or other equipment are licensed to which licensee, and
   - include a contact name and full mailing address for each licensee.
9) **Other:** Any other estimate, correction, or adjustment used to calculate volumes.

F-3 Facility Check Sheet (from *Manual 001*)

The ERCB auditor must complete a Facility Check Sheet when conducting a physical inspection of a production facility. Not all items on the check sheet must be checked for every inspection. Do not check a box for any item not inspected. Ensure that the inspection is entered on the Production Surveillance System (PSS) database. The check sheet is to be used as a written record of every inspection item examined.

With the exception of follow-up inspections, do not complete the Facility Check Sheet unless an actual physical inspection of a production facility is conducted.

Note that the check sheet is in abbreviated form: each item on the form may require several items to be inspected. Each unsatisfactory item should be noted in the most appropriate place, rather than in two or more places.

Leave a copy of the inspection form with the licensee or fax a copy to a company representative after completion of each inspection. A copy of the completed form should also be sent to the appropriate Field Centre.

The check sheet cannot possibly cover all items of concern, and therefore additional items must be expanded upon in the "Remarks and Comments" section.

The production audit involves more detailed review for some items on the form than at the field level. During the audit, some items checked as "satisfactory" may be found "unsatisfactory" once further relevant information has been reviewed.

Refer to *Manual 001*, Section 2, for details on how to complete the Facility Check Sheet.

F-4 Production Audit Enforcement Ladder Definitions see Directive 019: ERCB Compliance Assurance-Enforcement (April 18, 2011)

The ERCB routinely conducts production audits on upstream oil and gas production facilities. If an ERCB Production Audit identifies a minor, major, or serious noncompliance event, the actions and expectations of the ERCB and the affected licensee are handled in accordance with the Generic Enforcement Ladder as described in ERCB *Informational Letter (IL) 99-4: ERCB Enforcement Process, Generic Enforcement Ladder, and Field Surveillance Enforcement Ladder*.

1) MINOR Noncompliance Events

- Error in measurement, production accounting, and/or submission/reporting up to $50,000.
- Measurement devices do not meet ERCB requirements or are outside ERCB uncertainty limits, not installed, calibrated, maintained, or operated in accordance with ERCB requirements.
- Original production records do not meet the ERCB requirements in Section 12 of the Oil and Gas Conservation Regulations.
- Required audit data not provided and no acceptable explanation given.

2) MAJOR Noncompliance Events

- Error in measurement, production accounting, and/or submission/reporting greater than $50,000.
- SCADA data not available as required by the ERCB.
- No measurement data or audit trail on production information to support reported volumes.

3) SERIOUS Noncompliance Event

- Conducting an activity without an approval/licence where required (e.g., operating without a facility licence where required).
- Falsification or misrepresentation of production measurement, reporting, and/or production accounting records.

THE ERCB RESERVES THE RIGHT TO ENFORCE AND/OR ESCALATE NONCOMPLIANCE ISSUE(S) TO ANY LEVEL SHOULD CONDITIONS WARRANT.

Appendix G Metric Conversions and API and AGA Standards

G-1 Metric Conversions

There has been some confusion in converting imperial volume measurements to metric. The problem generally centres on the change in standard temperature and pressure at which volumes are to be reported. The new standard of 101.325 kPa is equal to 14.696 psia, not 14.65 psia, and 15°C is equal to 59°F, not 60°F. These differences affect the volumes to be reported.

The simplest method to convert gas volumes from ft^3 to m^3 is to calculate the gas volume according to AGA Report No. 3 using the old pressure base of 14.65 psia and temperature base of 60°F. This volume is then converted from ft^3 to m^3 by applying the conversion factor of 0.02817399. This factor also corrects the flow to the standard conditions in metric of 101.325 kPa and 15°C.

Metric Conversion for Volume

From (MCF)	To (10^3m^3)	F_{pb}, F_{tb} Values	Conversion Factor
@ 101.325 kPa, 15°C	@ 101.325 kPa, 15°C	F_{pb} = 1.0023	
		F_{tb} = 0.9981	0.02831685
@ 14.65 psia, 60°F	@ 101.325 kPa, 15°C	F_{pb} = 1.0055	
		F_{tb} = 1.0000	0.02817399

A similar problem occurs when measuring liquids; however, the effect is not as significant, since liquids are not as compressible as gas. The different standard conditions for liquid affect the volume in relation to the gravity of the fluid. The effect of gravity is only significant for large volumes (e.g., 10 000 m^3) and therefore can generally be ignored for our purposes.

The following conversion factors take the effect of liquid gravity into account:

1 bbl of water (60°F) = 0.158 98 m^3 (15°C)

1 bbl of crude oil/pentanes plus (60°F) = 0.158 91 m^3 (15°C)

1 bbl of butane (60°F) = 0.158 81 m^3 (15°C)

1 bbl of propane (60°F) = 0.158 73 m^3 (15°C)

1 bbl of ethane (60°F) = 0.157 97 m^3 (15°C)

Note that all measurements must first be corrected to 60°F and 14.65 psia before converting to metric.

If the measurements are first corrected to 59°F (15°C) and 14.696 psia (101.325 kPa), then the conversion factor of 0.158987 is to be used for changing barrels (bbl) to cubic metres (m^3).

The following table lists other conversion factors that may be required.

Cubic Foot Reference Conditions

Pressure (psia)	Temperature (°F)	Conversion Factor (ft^3 x factor = m^3)*
14.4	60	0.02769320
14.65	60	0.02817399
14.696	60	0.02826245
14.7	60	0.02827015
14.73**	60	0.02832784
14.9	60	0.02865478
15.025	60	0.02889517

* Standard reference conditions for the cubic metre are specified at a temperature of 15°C and an absolute pressure of 101.325 kPa.

** Industry Canada, Standards Branch, stipulates that for the purposes of the Gas Inspection Act, 30 inches of mercury at 32°F is equivalent to 14.73 psia. This is in line with the position taken by the American Gas Association in its *Gas Measurement Manual*.

Note that butane, propane, and ethane volumes are reported at equilibrium pressure of the fluid, not at atmospheric pressure, as in the case of oil.

Conversion Factors

In the conversion factor tables that follow, factors for conversion, including conversions to the International System of Units (SI), are based on ASTM Standard for Metric Practice E 380-76.

Btu (IT) = 1055.055 852 62 joule (exactly)
Calorie (IT) = 4.186 800 joule

For information only: the following are other definitions that may be used elsewhere:

Btu (mean) = 1055.87 joule
Btu (39°F) = 1059.67 joule
Btu (60°F) = 1054.68 joule
Btu (thermochemical) = 1054.350 joule
Calorie (mean) = 4.190 02 joule
Calorie (15C) = 4.185 80 joule
Calorie (20C) = 4.181 90 joule
Calorie (thermochemical) = 4.184 000 joule

The fundamental relationship between the Btu and calorie:

$$\frac{\text{gram-pound relationship}}{\text{Fahrenheit – Celsius scale relationship}}$$

or $$\frac{\text{Btu x } 453.592\ 37}{1.8} = \text{calorie (IT, mean, or other)}$$

Other useful relationships:

Thermochemical unit x 0.999 331 2 = IT unit (Btu or calorie)

Thermochemical cal/g x 1.8 x 0.999 331 2 = IT Btu/lb

Entropy, 1 Btu/(lb°R) = 4.186 8 kJ/(kg·°K)
Enthalpy, 1 Btu/lb = 2.326 kJ/kg
Grain = 64.798 91 mg
Grains/100 SCF = 22.883 52 mg/m^3
Grains/US gallon = 17.118 06 g/m^3
°C =5/9 (°F - 32)
°F= (9/5 x °C) + 32
°K = °C + 273.15 = 5/9°R
°R = °F + 459.67 = 1.8 °K
1 newton of force = 1 kg·m/s^2 = 1 N
1 pascal pressure = 1 N/m^2 = 1 Pa

Conversion Factor Tables

Velocity (Length/unit of time)

ft/s	ft/min	miles/h(U.S. statute)	m/s	m/min	km/h
1	60	0.6818182	0.3048	18.288	1.09728
0.01666667	1	0.01136364	5.08×10^{-3}	0.3048	0.018288
1.466667	88	1	0.44704	26.8224	1.609344
3.280840	196.8504	2.236936	1	60	3.6
0.05468066	3.280840	0.03728227	0.016667	1	0.06
0.9113444	54.68066	0.6213712	0.2777778	16.66667	1

Energy

Ft · lbf	kg · m	Btu (IT)	Kilocalorie (IT)	hp · h	kW · h	Joule (J)
1	0.1382550	1.285068×10^{-3}	3.238316×10^{-4}	5.050505×10^{-7}	3.766161×10^{-7}	1.355818
7.233014	1	9.294911×10^{-3}	2.342278×10^{-3}	3.653037×10^{-6}	2.724070×10^{-6}	9.806650
778.1692	107.5858	1	0.2519958	3.930148×10^{-4}	2.930711×10^{-4}	1055.056
3088.025	426.9348	3.968321	1	1.559609×10^{-3}	1.163×10^{-3}	4186.8
1980000.	273744.8	2544.434	641.1865	1	0.7456999	2684520.
2655224.	367097.8	3412.142	859.8452	1.341022	1	3600000.
0.7375621	0.1019716	9.478171×10^{-4}	2.388459×10^{-4}	3.7525061×10^{-7}	2.777778×10^{-7}	1

Length

Inches	Feet	Yards	Miles (U.S. Statute)	mm	m
1	0.08333333	0.02777778	1.578283×10^{-5}	25.4	0.0254
12	1	0.3333333	1.893939×10^{-4}	304.8	0.3048
36	3	1	5.681818×10^{-4}	914.4	0.9144
63360.	5280	1760	1	1609344.	1609.344
0.03937008	3.280840×10^{-3}	1.093613×10^{-3}	6.213712×10^{-7}	1	0.001
39.37008	3.280840	1.093613	6.213712×10^{-4}	1000	1

Area

$Inches^2$	$Feet^2$	$Yards^2$	Acres	$Miles^2$ (US statute)	m^2
1	6.944444×10^{-3}	7.716049×10^{-4}	1.594225×10^{-7}	2.490977×10^{-10}	6.4516×10^{-4}
144	1	0.1111111	2.295684×10^{-5}	3.587006×10^{-8}	9.290304×10^{-2}
1296	9	1	2.066116×10^{-4}	3.228306×10^{-7}	0.8361274
6272640.	43560.	4840.	1	0.0015625	4046.856
401448600	27878400.	3097600.	640	1	2589988.
1550.0031	10.76391	1.195990	2.471054×10^{-4}	3.861022×10^{-7}	1

Capacity-volume

Inches^3	Feet^3	Yards^3	Litres	m^3	US gallons	Imperial Gallons	Barrels (42 US g)
1	5.787037×10^{-4}	2.143347×10^{-5}	0.01638706	1.638706×10^{-5}	4.329004×10^{-3}	3.604649×10^{-3}	1.030715×10^{-4}
1728	1	0.03703704	28.31685	0.02831685	7.480520	6.228833	0.1781076
46656	27	1	764.5549	0.7645549	201.9740	168.1784	4.808905
61.02374	0.03531467	1.307951×10^{-3}	1	0.001	0.2641720	0.2199692	6.289810×10^{-3}
61023.74	35.31467	1.307951	1000	1	264.1720	219.9692	6.289810
231.0000	0.1336806	4.951132×10^{-3}	3.785412	0.003785412	1	0.8326739	2.380952×10^{-2}
277.4196	0.1605437	5.946064×10^{-3}	4.546092	0.004546092	1.200950	1	0.02859406
9702.001	5.614584	0.2079475	158.9873	0.1589873	42	34.97230	1

Mass

Ounces	Pounds	Short tons	Long tons	kg	Metric Tons
1	0.0625	3.125×10^{-5}	2.790179×10^{-5}	0.02834952	2.834950×10^{-5}
16	1	5×10^{-4}	4.464286×10^{-4}	0.4535924	4.535924×10^{-4}
32000	2000	1	0.8928571	907.1847	0.9071847
35840	2240	1.12	1	1016.047	1.016047
35.27396	2.204623	1.102311×10^{-3}	9.842065×10^{-4}	1	0.001
35273.96	2204.623	1.102311	0.9842065	1000	1

Weights per unit of area

lb/ft^2	lb/in^2	kg/cm^2	kg/cm^2	S. tons/ft^2	L. tons/ft^2	kg/mm^2
1	0.006944444	4.882428×10^{-4}	4.882428	0.0005	4.464286×10^{-4}	4.882428×10^{-6}
144	1	0.07030695	703.0695	0.072	0.06428571	7.030695×10^{-4}
2048.161	14.22334	1	10000	1.024081	0.9143578	0.01
0.2048161	0.001422334	0.0001	1	1.024081×10^{-4}	9.143578×10^{-5}	0.000001
2000	13.88889	0.9764855	9764.855	1	0.8928571	0.009764855
2240	15.55556	1.093664	10936.64	1.12	1	0.01093664
204816.1	1422.334	100	1 000 000	102.4081	91.43578	1

Weights per unit of area, pressure

kgf/cm^2	kPa	lbf/in^2	mm mercury (0°C)	in. mercury (32°F)	in. water (39.2°F)	atmospheres (standard)	millibars
1	98.06650	14.22334	735.561	28.9591	393.712	0.9678411	980.6650
0.01019716	1	0.1450377	7.50064	0.295301	4.01474	0.009869233	10
0.07030695	6.894757	1	51.7151	2.03603	27.6807	0.06804596	68.94757
0.00135951	0.133322	0.0193367	1	0.0393701	0.535253	0.00131579	1.33322
0.0345315	3.38638	0.491153	25.4	1	13.5954	0.0334210	33.8638
0.00253993	0.249082	0.0361263	1.86827	0.0735541	1	0.00245825	2.49082
1.033227	101.3250	14.69595	760.002	29.9213	406.794	1	1013.250
0.001019716	0.1	0.01450377	0.750064	0.0295301	0.401474	9.869233×10^{-4}	1

G-2 API and AGA Standards for References

From the API *Manual of Petroleum Measurement Standards:*

API Chapter 1: Petroleum Measurement Vocabulary

API Chapter 2: Tank Calibration

API Chapter 3: Tank Gauging (see also Standard 2545)

API Chapter 4: Proving Systems
- 4.1 Introduction
- 4.2 Conventional Pipe Provers
- 4.3 Small Volume Provers
- 4.4 Tank Provers
- 4.5 Master Meter Provers
- 4.6 Pulse Interpolation
- 4.7 Field-Standard Test Measures

API Chapter 5: Metering
- 5.1 General Considerations for Measurement by Meters
- 5.2 Displacement Meters
- 5.3 Turbine Meters
- 5.4 Accessory Equipment
- 5.5 Fidelity and Security of Pulsed Data

API Chapter 6: Metering Assemblies
- 6.1 Lease Automatic Custody Transfer
- 6.2 Loading Rack and Tank Truck Meters
- 6.3 Retail and Service Station Meters
- 6.4 Aviation Hydrant Fuelling
- 6.5 Meter Systems for Marine Bulk Carriers
- 6.6 Pipeline Metering System
- 6.7 Metering Viscous Hydrocarbons

API Chapter 7: Temperature Determination
- 7.1 Dynamic
- 7.2 Static

API Chapter 8: Sampling
- 8.1 Manual
- 8.2 Automatic Pipeline

API Chapter 9: Density Determination
- 9.1 Hydrometer Test Method for Density and Gravity
- 9.2 Pressure Hydrometer Test Method for Density

API Chapter 10: Sediment And Water
- 10.1 Sediment in Crude Oils and Fuel Oils by the Extraction Method
- 10.2 Water in Crude Oil by Distillation
- 10.3 Water and Sediment in Crude Oil by the Centrifuge Method (Lab)
- 10.4 Water and Sediment in Crude Oil by the Centrifuge Method (Field)
- 10.5 Determination of Water in Products and Bituminous Material
- 10.6 Determination of W&S in Fuel Oils by Centrifuge (Lab)

API Chapter 11: Physical Properties Data
- 11.1 Volume Correction Factors
- 11.2.1 Compressibility Factors for Hydrocarbons 0-90° API Gravity Range
- 11.2.2 Compressibility Factors for Light Hydrocarbons 0.350 to 0.637 Relative Density Range
- 11.2.3 Water Calibration of Volumetric Provers
- 11.3.2.1 Ethylene Density
- 11.3.3.1 Propane Compressibility Table
- 11.3.3.2 Propylene Compressibility Table

API Chapter 12: Calibration of Petroleum Quantities
- 12.2 Calculations for Turbine or Displacement Meters

API Chapter 13: Statistical Aspects of Measuring and Sampling
- 13.1 Statistical Concepts and Procedures in Measurement

API Chapter 14: Measuring, Sampling, Testing for Natural Gas Fluids
- 14.3 Orifice Metering of Natural Gas (AGA Report No. 3)
- 14.4 Gross Heating Values, Specific Gravity, and Compressibility of Natural Gas Mixtures
- 14.8 Liquefied Petroleum Gas Measurement

API Chapter 15: Guidelines for Use of the International System of Units (SI)

API Chapter 16: Measurement of Hydrocarbon Fluids
- 16.1 Measurement of Hydrocarbon by Weight or Mass
- 16.2 Mass Measurement of Liquid of Hydrocarbon in Vertical Cylindrical Storage Tanks by Hydrostatic Tank Gauging

API Chapter 17: Marine Measurement
- 17.1 Guidelines for Marine Measurement
- 17.2 Manual for Measurement of Cargoes on Board Tankships and Barges

API Chapter 18: Custody Transfer
- 18.1 Measurement for Crude Oil Gathered from Small Tanks by Truck

API Chapter 19: Evaporative Loss Measurement
- 19.1 Evaporative Loss from Fixed-Roof Tanks
- 19.2 Evaporative Loss from Floating-Roof Tanks
- 19.3 Evaporative Loss Measurement
- 19.4 Recommended Practice for Speciation of Evaporative Losses

API Chapter 20: Allocation Measurement

API Chapter 21: Flow Measurement Using Electronic Metering Systems
- Sec. 1 Electronic Gas Measurement
- Sec. 2 Electronic Liquid Volume Measurement Using P.D. Displacement and Turbine Meter

From the American Gas Association (AGA) standards:

- AGA Report 3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids (1985, 1990, 2000 versions)
- AGA Report 7: Measurement of Gas by Turbine Meters (1985)
- AGA Report 8: Compressibility and Super-Compressibility for Natural Gas and Other Hydrocarbon Gasses (1992)

Appendix H Applicable ERCB Documents

Guides

Internal Directive 8: Safety Manual
Directive 4: Determining Water Production at Gas Wells [rescinded]
Directive 7: Production Accounting Handbook
Directive 34: Guidelines for Automated Measurement System Applications
Directive 38: Noise Control Directive User Directive
Directive 46: Production Audit Handbook
Directive 48: Monthly Custom Treating Plant Statement
Directive 49: Gas Density Measurement Frequency
Directive 55: Storage Requirements for the Upstream Petroleum Industry
Directive 56: Energy Development Application Directive
Directive 58: Oilfield Waste Management Requirements for the Upstream Petroleum Industry
Directive 59: Well Drilling and Completion Data Filing Requirements
Directive 60: Upstream Petroleum Industry Flaring Directive
Manual 001: Facility Inspection Manual

Interim Directives (IDs)

ID 81-3: Minimum Distance Requirements Separating New Sour Gas Facilities from Residential and Other Developments
ID 90-2: Gas Meter Calibration [rescinded]
ID 91-2: Corporate-Level Emergency Response Plans
ID 91-3: Heavy Oil/Oil Sands Operations [all section 4 rescinded by Directive 017 – April 18, 2011]
ID 91-3 – Clarification (May 2001): Heavy Oil/Oil Sands Operations [rescinded]
ID 94-1: Measurement of Oil, Gas & Water Production [rescinded]
ID 99-8: Noise Control Directive

Informational Letters (ILs)

IL 85-10: Maximum Daily Rate of Production for Gas Wells
IL 87-1: Compressibility Factors Used in Gas Volume Calculations and Physical Property Data for Natural Gases [rescinded]
IL 88-15: Production Injection Disposition Reporting Requirements [rescinded]
IL 90-3: Application for Special MRLS, GPP, and GOR Penalty Relief
IL 90-6: Measurement Guidelines – Trucked Oil Production [rescinded]
IL 90-15: Need for Prompt and Accurate Filing of S-Forms [rescinded]
IL 90-17: Emergency Procedure Plans for Sour Gas Facilities [rescinded]
IL 91-3: Well Production Records and S-4 Submissions [rescinded]
IL 91-9: Exemption from Gas Measurement Crude Oil/Bitumen Wells [rescinded]
IL 92-8: Crude Oil Pipeline Truck Terminal Measurement Guidelines [rescinded]
IL 92-9: Revised Reporting Procedures – Load Fluids [rescinded]
IL 93-1: Gas Density Measurement Frequency – Orifice Meters [rescinded]
IL 93-10: Revised Measurement and Accounting Procedures for Southeastern Alberta Shallow Gas Wells [rescinded]
IL 94-7: Coriolis Force Flowmeters [rescinded]
IL 94-20: Meter Proving Monitoring Program [rescinded]
IL 96-4: ERCB Policy Update and Clarification on the Use of Earthen Pits
IL 99-4: ERCB Enforcement Process, Generic Enforcement Ladder, and Field Surveillance Enforcement Ladder [rescinded]
IL 99-5: The Elimination of the Surface Release of Produced Water [rescinded]