COLORADO
Oil & Gas Conservation Commission
Department of Natural Resources

COGCC OPERATOR GUIDANCE
RULES 1101 AND 1102: FLOWLINE GUIDANCE

Document Control:

Created Date:	May 15, 2015
Last Updated Date:	May 15, 2015
Last Updated By:	Stuart Ellsworth
Review Cycle:	Yearly Review
Systems Used:	None
Document Owner:	Stuart Ellsworth
Work Units:	Engineering, Field Inspection, Environmental

Background

Purpose:

The purpose of this Flowline guidance is to provide operators with guidelines on how to comply with Rules 1101 and 1102 of the Colorado Oil and Gas Conservation Commission (COGCC), which regulates installation, reclamation, operations, maintenance, repair, and abandonment of Flowlines.

COGCC created this guidance in response to findings and recommendations made by the COGCC's "Risk-Based Inspections: Strategies to Address Environmental Risk Associated with Oil and Gas Operations" ("Study"), where Flowline failures were identified as a frequent cause of reportable spills and releases. The Study recommended that operators and the COGCC take actions to reduce the risk of spills and releases resulting from Flowline failures by improving the integrity of Flowlines through appropriate construction standards, periodic testing and maintenance, and COGCC audits of required pressure testing.

Applicability:

COGCC rules related to Flowlines apply to those lines located upstream of sales meters or custody transfers. Flowlines are defined in COGCC's 100-Series Rules as "those segments of pipe from the wellhead downstream through the production facilities ending at: in the case of gas lines, the gas metering equipment; or in the case of oil lines the oil loading point or LACT unit; or in the case of water lines, the water loading point, the point of discharge to a pit, the injection wellhead, or the permitted surface water discharge point."

Fluids in Flowlines may include methane, natural gas, condensate, crude oil, produced water, or any combination of these produced fluids. Production facilities may include but are not limited to: separators, heater treaters, dehydrators, and production storage tanks. NOTE: These testing requirements do not apply to the actual production facilities themselves but rather only to the Flowlines identified below.

This equipment is generally located on the same pad as the wellhead, at a nearby location, or otherwise upstream of the gathering line connection. Separate Flowlines may be used for crude oil, natural gas and/or produced water.

These lines sometimes go by different names. Therefore, the COGCC has determined that Flowlines include all of the following:

1. Well Site Flowline – the line between the wellhead and the separator.

2. Sales Line – the gas line from the separator to the gas meter.

3. Dump Lines – the low pressure water, condensate and oil lines which go to storage tank(s).

4. Process Piping – in multi-well pad situations, individual dump lines manifold together prior to going to a set of tanks connected by piping.

5. Non-Well Site Flowline – the line between the Well Site and the point of transfer when the water treatment facility, production facility or transfer point is not located at the Well Site.

All such lines must comply with Rules 1101, 1102, and 1103.

The definition of "gathering line" is based on the function performed by that type of pipeline. Gathering lines refer to those pipelines that collect produced fluids from multiple well locations downstream from sale meters or custody transfer points. In

Colorado, gas gathering lines are regulated by the Public Utilities Commission. Gathering lines are beyond the scope of this policy.

New Flowline Installation Guidance

The following are recommended best practices for all new Flowline installations. These best practices are intended to provide additional guidance to ensure greater compliance with Rules 1101 and 1102.

The American Society of Mechanical Engineers (ASME) guidelines are recommended design standards that operators can consult for additional information related to design. See appendix A for a detailed list of potential resources. Some of these resources are not applicable to Flowlines but can still provide ideas to operators.

The following bullets provide more detailed examples either taken from the above references or from COGCC experiences and are presented as guidance for operators to consider on a case by case analysis:

1. Welded Flowlines be installed with welded or flanged connections. The welders of pipe and components should have welding qualification in accordance with Section 6 of API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code or equivalent qualification.

2. All threaded metallic pipe should be joined with recommended lubricant/sealant.

3. All non-metallic pipes that require welded joints should be installed with appropriate equipment to meet manufacturer recommendations and welded with qualified welders.

4. All buried non-metal Flowline installation should contain a continuous metallic tracer line attached to the pipeline with surface access or other means of surface location.

5. Consider the following for welded connections:
    a. As appropriate, X-rayed around the entire circumference of the weld on at least a 10% random selection basis per welder, and
    b. Meet the specifications in ASME B31.3, which is equivalent to API 1104 Sec 9. Welding should be performed by a qualified welder in accordance with welding procedures specified in Section 5 of API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code or equivalent.

6. All buried metallic pipes should be coated with Fusion Bond Epoxy (FBE) or coated with appropriate primer and non-shielding coating tape or in accordance with manufacturer recommendations.

7. Buried metallic connections and welds should be coated with a rolled sealing compound to;
   a. 10 mil thickness for open trench,
   b. 70 mil thickness for bored placement or
   c. In accordance with manufacturer recommendations.

8. All Flowlines should be tested per manufacturer specifications and industry standards.

In addition, Rule 1101.e.(1) requires all Flowlines to be pressure tested to maximum anticipated operating pressure prior to placing the Flowline in service. It is recommended that in order to have a successful test, operators begin the test after fluid pressure has stabilized and test for an appropriate time. COGCC recommends a minimum of 15 minutes and potentially up to 60 minutes. Pressure loss exceeding 10% and has not stabilized in the last 5 minutes is considered a failed test.

Pressure deviations identified during the test should be internally documented and retained. Any pressure deviations not readily explained by test fluid type, weather fluctuation or other reasons should be treated as potential leaks in the system, investigated accordingly, and repaired if required.

Existing Flowline Installation Guidance

COGCC Interpretation of Rule 1101.e:

Rule 1101.e requires all existing Flowlines, as highlighted above, to be pressure tested to “maximum anticipated operating pressures” once per calendar year. The COGCC’s interpretation of this rule allows for two methods of compliance with this requirement:

1. Perform an actual pressure test each calendar year to maximum anticipated operating pressures isolating the Flowlines as required.

2. Install a continuous monitoring program that monitors the actual operating pressure 24 hours a day, 7 days a week and file for a Rule 502.b variance for such program.

COGCC's interpretation regarding the use of a continuous monitoring program, with an associated Rule 502.b variance request, as a substitute for annual testing rests on the premise that continuous monitoring provides actual pressure data in real time. Staff believes continuous monitoring programs, if implemented as specified below, provide equal protections to public health, safety and welfare than the annual testing requirements of Rule 1101.e. However, after internal consultation, Staff believes the rule as written, would still require operators to file a Rule 502.b variance.

Option 1: Performing Annual Pressure Tests:

All Flowlines, except for low-pressure (less than 15 psig), as identified above, must be pressure tested each calendar year per Rule 1101.e and the results maintained for at least three years.

Flowlines should be tested per manufacturer specifications and industry standards.

Operators should consider pressure testing higher risk Flowlines at a greater frequency. The following are risk factors that might cause Flowlines to be considered higher risk:

1. Years the Flowlines have been in service.
2. Flowlines in a Sensitive Area as defined in the 100-Series Rules.
3. Flowlines in a Surface Water Supply Area as defined in the 100-Series Rules and Rule 317B.
4. Pipeline material and design considerations (e.g. steel lines vs. poly lines).

The following are recommended practices for pressure testing existing or repaired Flowlines:

1. Flowlines may be pressure tested with wellhead fluids or hydro-tested. By rule, flowlines are to be tested to maximum anticipated operating pressure, based on the previous year's operating pressures. It is recommended that the test begin after fluid pressure has stabilized and test for an appropriate time. The COGCC recommends a minimum of 15 minutes and potentially up to 60 minutes if in higher risk areas such as Sensitive Areas or Surface Water Supply Area as defined in the 100-Series Rules.

2. Pressure deviations greater than 10% during the test or has not stabilized in the last 5 minutes does not satisfy the pressure testing requirement of Rule 1101.e unless an exception is granted.

3. It is recommended that pressure deviations identified during the test be internally documented and retained. Any pressure deviations not readily explained by test fluid type, weather fluctuation or other reasons should be treated as potential leaks in the system, investigated accordingly, and repaired if required.

4. Systems operated at less than an average of 15 psig are exempt from pressure testing requirements per Rule 1101.e.(2). Operators will be required, upon request, to provide sufficient data to demonstrate the applicability of this exemption. The may be accomplished through any number of energy equation computations that use 3-phase fluids. This does not exempt operators from correcting known Flowline leaks on these exempt Flowlines.

Shut in wells where the Flowlines have been blown down do not need to be tested annually but would need to be tested prior to the Flowlines being put back in service. Documentation to prove the Flowlines were blown down may be required during a COGCC audit.

Option 2: Installing a Continuous Monitoring Program with a Rule 502.b Variance:

Operators may use a continuous monitoring program in-lieu of the pressure testing requirements stated above to comply with the ongoing pressure testing requirements documented in Rule 1101.e.

For this option to occur, the following elements are required:

1. Pressure data is monitored continuously, 24 hours a day 7 days a week, and the monitoring would identify integrity or pressure anomalies.

2. Systems are capable of being shut-in for repairs immediately upon discovery of anomalous conditions, either through automation or through a documented manual process.

3. The continuous monitoring program is fully documented and documentation demonstrates how an operator will maintain and repair Flowlines lacking integrity.

4. Details of the continuous monitoring program are made available to the COGCC upon request or when integrity failures are observed.

5. A map of the Flowline system is available. (See example in Appendix B). The map should illustrate the Flowline alignments, location of isolation valves and pressure-monitoring points.

6. Operator performs periodic look-listen "walk-the-line" inspections of Flowlines to check for obvious leaks and stressed vegetation.

7. Operator submits a Rule 502.b variance request via a Form 4 Sundry with the details of their continuous monitoring program, including the above information, to the COGCC Engineering department for review and approval. COGCC Engineering staff will review to ensure the program suffices for compliance with Rule 1101.e.

8. All variance requests granted for continuous monitoring programs will expire after five years and would need to be renewed.

A single variance may be granted for an entire oil and gas field or basin.

The following elements are presented as additional potential components of a continuous monitoring program:

1. Supervisory Control and Data Acquisition (SCADA), or an equivalent industrial control system, with detection devices set to trigger alarms when anomalous pressure conditions occur but prior to conditions which could result in Flowline rupture.

2. Spot checks of Flowline integrity using ultrasonic thickness (UT) or other equivalent technology.

3. Automated shut-in systems for Flowlines.

4. Corrosion protection program for metallic Flowlines that may include:
    a. Corrosion coupon monitoring.
    b. Impressed current cathodic protection (ICCP).
    c. Sacrificial thickness within the design life.

5. Above ground Flowlines at Oil and Gas Facilities, which can be readily observed during routine site visits and inspections, could be addressed through an operator's documented integrity program, which may include such

programs as EPA SPCC requirements or CDPHE Regulation 7 OVA inspections/LDAR monitoring.

Operators need to document all issues identified by the continuous monitoring program and maintain such documentation for at least three years. Documentation needs to include the location of all repairs such that the location can be identified with GPS or the operator's process flow diagrams.

COGCC Auditing of Operator Pressure Testing

As part of the Study, it was recommended that COGCC staff perform audits on operator's pressure testing of Flowlines to ensure compliance with rules. COGCC will begin conducting these audits in January 2016 related to operator's pressure testing in calendar year 2015.

Beginning in January 2016, Operators will be randomly selected for Flowline pressure testing audits. If an operator is selected for a COGCC audit, COGCC staff will require proof of compliance for one-third of the operator's Flowlines for any given calendar year. If an operator is selected two years in a row, COGCC staff would expect proof of compliance for a different one-third of the operator's Flowlines, and so on, year by year. Operators can demonstrate compliance through either the performance of flowline pressure tests or through approved continuous monitoring programs as described above.

Failure to demonstrate that one-third of an operator's Flowlines have been pressure tested per one of the above options will likely result in either a Warning Letter or an NOAV.

Operator Flowline Inventory and Testing Schedule:

Operators are encouraged to develop an inventory of all their Flowlines and be able to provide the inventory to the COGCC within five business days upon request. The inventory should include the following information for each Flowline segment:

1. Date of last pressure test.

2. Results of last pressure test.

3. Whether the Flowline is exempt per Rule 1001.e.(2) or a general statement that Flowlines in the inventory are covered by an approved continuous monitoring program.

Integrity Program and Documentation

Flowline Integrity Programs:

Rule 1102 requires that operators take reasonable precautions to prevent failures, leakage, and corrosion of Flowlines and to repair those conditions within a reasonable timeframe such that safe and proper operations of the Flowline is not adversely affected. To accomplish this, operators are encouraged to have a documented Flowline integrity program for all Flowlines, which includes a Flowline inventory and the procedures undertaken to ensure integrity during installation, maintenance, inspection, testing and/or monitoring. The program should include repair procedures when integrity failures are identified.

Flowline Failure Documentation:

Documentation of any Flowline integrity failure should include the date and time the failure was identified, the exact location of the failure, the cause of the failure, the amount of commodity and/or Exploration & Production Waste lost, and the means of repair. Such documentation should be retained within the operator's well files. Per Rule 1100, records are to be kept for at least three years.

Guidance Disclaimer

This is a guidance document, not a formal rule. The purpose of this guidance document is to inform all interested stakeholders of the Commission's interpretation of, and expectations concerning, the formal Commission Rules discussed herein. Interpretative rules or general statements of policy, such as this guidance document, are not meant to be binding as rules under the Administrative Procedures Act. § 24-4-103(1), C.R.S.

Appendix A – Reference Specifications

COGCC referred to the bulleted list of industry specifications shown below during creation of this guidance. Some of the information, concepts, specifications and practices identified can be applied to natural gas Flowlines or to crude oil, condensate and produced water Flowlines. The following list of references is provided to assist operators in the creation of their integrity programs.

American Petroleum Institute (API)

- API-5L-07 Specification for Line Pipe: American National Standards Institute (ANSI)/API Specification 5L, 44th edition, October 1, 2007 American Petroleum Institute.
- API RP 80 Guidelines for the Definition of Onshore Gas Gathering Lines: April 1, 2000 American Petroleum Institute.
- API RP 1110 Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide.
- API RP 1173 Pipeline Safety Management System Requirements.

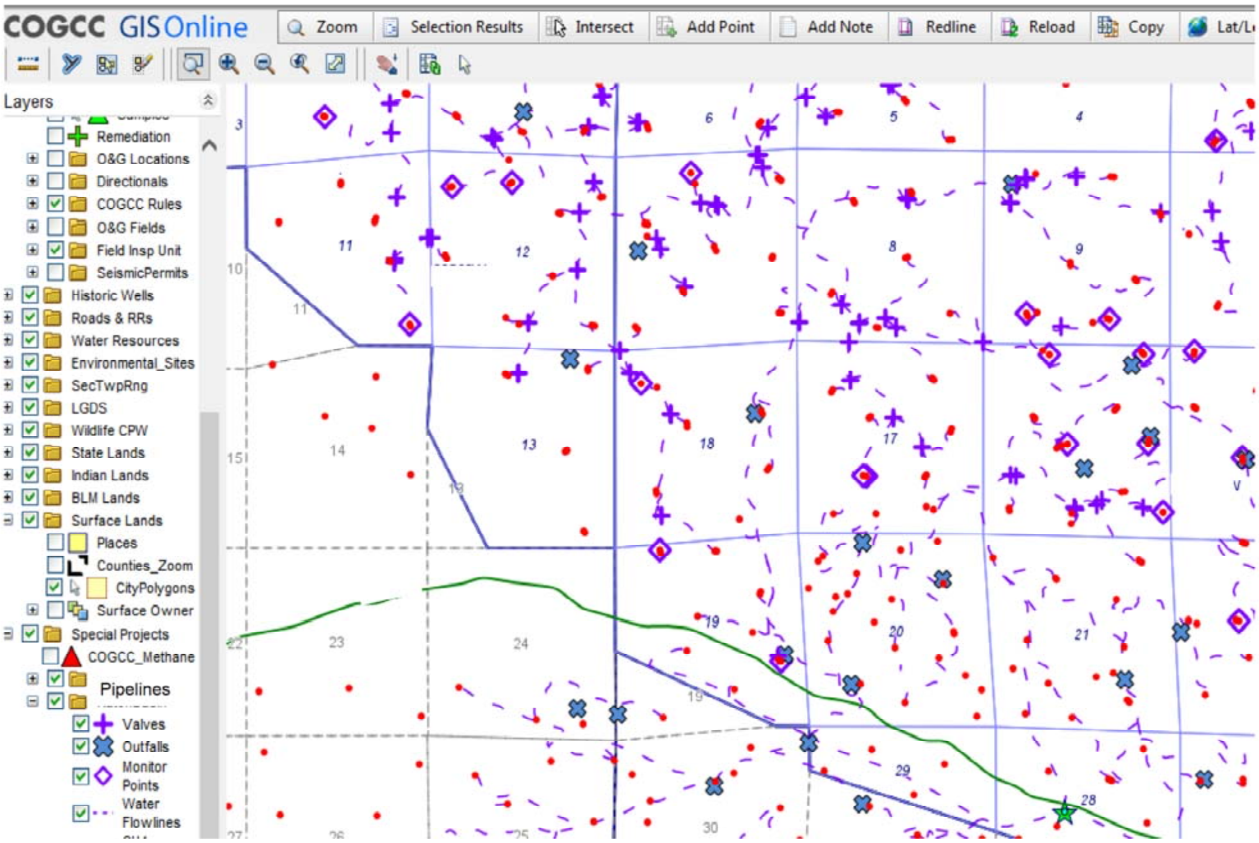
American Society for Testing and Materials (ASTM):

- ASTM A106/A106M Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service.
- ASTM A 333 / A 333 M Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service and Other Applications with Required Notch Toughness.
- ASTM/API Specification 6D, “Specification for Pipeline Valves”.
- ASTM D2513 Standard Specification for Thermoplastic Gas Pressure Piping.

American Society or Mechanical Engineers (ASME)

- ASME B31.8S – Managing System Integrity of Gas Pipelines.
- ASME B31.4 - Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids.
- ASME B31.8 - Gas Transmission and Distribution Piping Systems.
- National Association of Corrosion Engineers (NACE) International Standard Practice (SP) 0502 “Pipeline External Corrosion Direct Assessment Methodology”.
- Multi-layered reinforced thermoplastic composite pipe (RTCP)-R&D potential (application for non-regulated piping).
- CFR 49 Part 192 – Transportation of Natural Gas and Other Gas by Pipelines.
- CFR 49 Part 195 – Transportation of Hazardous Liquids by Pipelines.

Appendix B -- Example GIS map of Flowlines



Appendix C – Example Annual Flowline Spill Summary

Annual Flowline Spill Summary

Date	Location	Root Cause	Action Taken

Document Change Log

Change Date	Description of Changes
May 15, 2015	Document Created and Finalized