SAFETY REGULATIONS

601. INTRODUCTION

The rules and regulations in this section are promulgated to protect the health, safety and welfare of the general public during the drilling, completion and operation of oil and gas wells and producing facilities. They do not apply to parties or requirements regulated under the Federal Occupational Safety and Health Act of 1970 (See Rule 212).

602. GENERAL

The training and actions of an operator's employees, as well as the proper location and operation of equipment, are essential to any safety program.

a. Operators must familiarize their employees with these Rules as they relate to their job functions. Each new employee should have his or her job outlined, explained and demonstrated.

b. Employees must immediately report unsafe and potentially dangerous conditions to their supervisor and any such conditions shall be remedied as soon as practicable.

c. An operator must notify the Director and the local governmental designee of the applicable jurisdiction of reportable safety events at an oil and gas facility. Reportable safety events include:

   (1) Any accidental fire, explosion, or detonation, or uncontrolled release of pressure;

   (2) Any accident or natural event that results in a reportable injury as defined by the U.S. Department of Labor, Occupational Safety and Health Administration, at 29 C.F.R. § 1904.39 in existence as of the date of this regulation and no later amendments. 29 C.F.R. § 1904.39 is available for public inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. Additionally, 29 C.F.R. § 1904.39 may be found at https://www.osha.gov. ; or

   (3) Any accident or natural event that results in an injury to a member of the general public that requires medical treatment.

d. Initial notification from the operator of a reportable safety event described in c.(1) -(3) above, must occur as soon as practicable, but no more than 6 hours after the safety event. An Accident Report, Form 22, must be submitted to the Director within 3-days of the accident or natural event.

   (1) At the Director's request, the operator must submit a supplemental report that details the root cause, information about any repairs, or other information related to the accident.

   (2) At the Director's request, the operator must present its root cause about the accident to the Commission or to an oil and gas safety review organization approved by the Director.

e. Where unsafe or potentially dangerous conditions exist and first responders are on-site, the owner or operator must respond as directed by first responders (such as sheriff, fire district director, etc.)

f. Vehicles of persons not involved in drilling, production, servicing, or seismic operations must be located a minimum distance of one hundred (100) feet from the wellbore, or a distance equal to the height of the derrick or mast, whichever is greater. Equivalent safety measures must be taken where terrain, location or other conditions do not permit this minimum distance requirement.

g. Existing producing facilities are exempt from the provisions of these regulations with respect to minimum distance requirements and setbacks unless they are found by the Director to be unsafe.

h. Self-contained sanitary facilities shall be provided during drilling operations and at any other similarly staffed oil and gas operations facility

603. STATEWIDE LOCATION REQUIREMENTS FOR OIL AND GAS FACILITIES, DRILLING, AND WELL SERVICING OPERATIONS

a. Statewide location requirements.

(1) At the time of initial drilling, a Well shall be located not less than two hundred (200) feet from buildings, public roads, major above ground utility lines, or railroads. Rule 604 setback requirements apply with respect to Building Units and Designated Outside Activity Areas.

(2) A well shall be located not less than one hundred fifty (150) feet from a surface property line. The Director may grant an exception if it is not feasible for the Operator to meet this minimum distance requirement and a waiver is obtained from the offset Surface Owner(s). An exception request letter stating the reasons for the exception shall be submitted to the Director and accompanied by a signed waiver(s) from the offset Surface Owner(s). Such waiver shall be written and filed in the county clerk and recorder's office and with the Director.

603.b. **Statewide rig floor safety valve requirements.** When drilling or well servicing operations are in progress on a well where there is any indication the well will flow hydrocarbons, either through prior records or present conditions, there shall be on the rig floor a safety valve with connections suitable for use with each size and type of tool joint or coupling being used on the job.

603.c. **Statewide static charge requirements.** Rig substructure, derrick, or mast shall be designed and operated to prevent accumulation of static charge.

603.d. **Statewide well servicing pressure check requirements.** Prior to initiating well servicing operations, the well shall be checked for pressure and steps taken to remove pressure or operate safely under pressure before commencing operations.

603.e. **Statewide well control equipment and other safety requirements.** Well control equipment and other safety requirements are:

(1) When there is any indication that a well will flow, either through prior records, present well conditions, the planned well work, or special orders of the Commission, blowout prevention equipment shall be installed.

(2) When required, blowout prevention equipment shall be in accordance with API Standard 53: “Blowout Prevention Equipment Systems for Drilling Wells,” 4th Edition (November 2012). Only the 4th Edition of the API bulletin applies to this rule; later amendments do not apply. All material incorporated by reference in this rule is available for public inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. In addition, these materials may be examined at any state publications depository library and are available from API at 1220 L Street, NW Washington, DC 20005-4070.

(3) Drilling after setting the surface casing shall not proceed until blowout prevention equipment is tested and found to be serviceable. Low pressure and high pressure tests shall be performed. Test pressure, test duration, and test frequency shall be in accordance with API Standard 53: “Blowout Prevention Equipment Systems for Drilling Wells,” 4th Edition

(November 2012), except that the minimum low pressure for a low pressure test shall be 250 psi. Test pressure loss shall be less than or equal to 10% of the initial stabilized surface pressure at the end of the test when testing with rig pumps against casing. When a test plug is used to isolate the casing from the blowout prevention equipment being tested, then there shall be no unexplainable pressure loss at the end of the test.

(4) While in service, blowout prevention equipment shall be inspected daily and a preventer operating test shall be performed on each round trip, but not more than once every twenty-four (24) hour period. Notation of operating tests shall be made on the daily report.

(5) All pipe fittings, valves and unions placed on or connected with blowout prevention equipment, well casing, casinghead, drill pipe, or tubing shall have a working pressure rating suitable for the maximum anticipated surface pressure and shall be in good working condition as per generally accepted industry standards.

(6) Blowout prevention equipment shall contain pipe rams that enable closure on the pipe being used. The choke line(s) and kill line(s) shall be anchored, tied or otherwise secured to prevent whipping resulting from pressure surges.

(7) Pressure testing of the casing string shall be conducted prior to drilling out any string of casing except conductor pipe. The minimum test pressure shall be 500 psi. Test pressure loss must be less than or equal to 10% of the initial stabilized surface pressure over a test period of 15 minutes, in order for the casing string to be considered serviceable. Upon request, the Operator shall provide to the Director evidence of performing the pressure test pursuant to Rule 205.f.

(8) If the blind rams are closed for any purpose except operational testing, the valves on the choke lines or relief lines below the blind rams should be opened prior to opening the rams to bleed off any pressure.

(9) All rig employees shall have adequate understanding of and be able to operate the blowout prevention equipment system. New employees shall be trained in the operation of blowout prevention systems as soon as practicable to do so.

(10) Drilling contractors shall place a sign or marker at the point of intersection of the public road and rig access road.

(11) The number of the public road to be used in accessing the rig along with all necessary emergency numbers shall be posted in a conspicuous place on the drilling rig.

603.f. **Statewide equipment, weeds, waste, and trash requirements.** All locations, including wells and surface production facilities, shall be kept free of the following: equipment, vehicles, and supplies not necessary for use on that lease; weeds; rubbish, and other waste material. The burning or burial of such material on the premises shall be performed in accordance with applicable local, state, or federal solid waste disposal regulations and in accordance with the 900-Series Rules. In addition, material may be burned or buried on the premises only with the prior written consent of the Surface Owner.

603.g. **Statewide equipment anchoring requirements.** All equipment at drilling and production sites in geological hazard areas shall be anchored. Anchors must be engineered to support the equipment and to resist flotation, collapse, lateral movement, or subsidence. Anchoring requirements in Floodplains are governed by Rule 603.h.

603.h. **Statewide Floodplain Requirements.** When operating within a defined Floodplain:

(1) The following requirements apply to new Oil and Gas Locations and Wells:

A. Effective August 1, 2015, Operators must notify the Director when a new proposed Oil and Gas Location is within a defined Floodplain, via the Form 2A.

B. Effective June 1, 2015, new Wells must be equipped with remote shut-in capabilities prior to commencing production. Remote shut-in capabilities include, at a minimum, the ability to shut-in the well from outside the relevant Floodplain.

C. Effective June 1, 2015, new Oil and Gas Locations must have secondary containment areas around Tanks constructed with a synthetic or geosynthetic liner that is mechanically connected to the steel ring or another engineered technology that provides equivalent protection from floodwaters and debris.

(2) The following requirements apply to both new and existing Wells, Tanks, separation equipment, containment berms, Production Pits, Special Purpose Pits, and flowback pits:

A. Effective April 1, 2016, Operators must maintain a current inventory of all existing Wells, Tanks, and separation equipment in a defined Floodplain. Operators shall ensure that a list of all such Wells, Tanks, and separation equipment is filed with the Director. As part of this inventory, Operators must maintain a current and documented plan describing how Wells within a defined Floodplain will be timely shut-in. This plan must include what triggers will activate the plan and must be made available for inspection by the Director upon request.

B. Effective June 1, 2015 for new and April 1, 2016 for existing, tanks, including partially buried tanks, and separation equipment must be anchored to the ground. Anchors must be engineered to support the Tank and separation equipment and to resist flotation, collapse, lateral movement, or subsidence.

C. Effective June 1, 2015 for new and April 1, 2016 for existing, containment berms around all Tanks must be constructed of steel rings or another engineered technology that provides equivalent protection from floodwaters and debris.

D. Effective June 1, 2015 for new and April 1, 2016 for existing, Production Pits, Special Purpose Pits (other than Emergency Pits), and flowback pits containing E&P waste shall not be allowed within a defined Floodplain without prior Director approval, pursuant to Rule 502.b.

E. An Operator may seek a variance from the effective date for the requirements for existing facilities referenced in subparts 603.h(2)B, C or D by filing a request for an alternative compliance plan with the Director on or before February 1, 2016.

604. SETBACK AND MITIGATION MEASURES FOR OIL AND GAS FACILITIES, DRILLING, AND WELL SERVICING OPERATIONS

a. **Setbacks.** Effective August 1, 2013:

(1) **Exception Zone Setback.** No Well or Production Facility shall be located five hundred (500) feet or less from a Building Unit except as provided in Rules 604.a.(1) A and B, and 604.b.

A. Urban Mitigation Areas. The Director shall not approve a Form 2A or associated Form 2 proposing to locate a Well or a Production Facility within an Exception Zone Setback in an Urban Mitigation Area unless:

i. the Operator submits a waiver from each Building Unit Owner within five hundred (500) feet of the proposed Oil and Gas Location with the Form 2A or associated Form 2, or obtains a variance pursuant to Rule 502; and

ii. the Operator certifies it has complied with Rules 305.a, 305.c., and 306.e.; and

iii. the Form 2A or Form 2 contains conditions of approval related to site specific mitigation measures sufficient to eliminate, minimize or mitigate potential adverse impacts to public health, safety, welfare, the environment, and wildlife to the maximum extent technically feasible and economically practicable; or

iv. the Oil and Gas Location is approved as part of a Comprehensive Drilling Plan pursuant to Rule 216.

B. Non-Urban Mitigation Area Locations. Except as provided in subsection 604.b., below, the Director shall not approve a Form 2 or Form 2A proposing to locate a Well or a Production Facility within an Exception Zone Setback not in an Urban Mitigation Area unless the Operator certifies it has complied with Rules 305.a., 305.c., and 306.e., and the Form 2A or Form 2 contains conditions of approval related to site specific mitigation measures sufficient to eliminate, minimize or mitigate potential adverse impacts to public health, safety, welfare, the environment, and wildlife to the maximum extent technically feasible and economically practicable.

(2) **Buffer Zone Setback.** No Well or Production Facility shall be located one thousand (1,000) feet or less from a Building Unit until the Operator certifies it has complied with Rule 305.a., 305.c., and 306.e. and the Form 2A or Form 2 contains conditions of approval related to site specific mitigation measures as necessary to eliminate, minimize or mitigate potential adverse impacts to public health, safety, welfare, the environment, and wildlife.

(3) **High Occupancy Buildings**. No Well or Production Facility shall be located one thousand (1,000) feet or less from a High Occupancy Building Unit without Commission approval following Application and Hearing. Designated Setback Location and Exception Zone Setback mitigation measures pursuant to Rule 604.c. shall be required for Oil and Gas Locations within one thousand (1,000) feet of a High Occupancy Building, unless the Commission determines otherwise. Provided that this paragraph does not apply to a school facility or child care center, because the school facility and child care center setback is governed by Rule 604.a.(6).

(4) **Designated Outside Activity Areas.** No Well or Production Facility shall be located three hundred fifty (350) feet or less from the boundary of a Designated Outside Activity Area. The Commission, in its discretion, may establish a setback of greater than three hundred fifty (350) feet based on the totality of circumstances. Designated Setback Location mitigation measures pursuant to Rule 604.c. shall be required for Oil and Gas Locations within one thousand (1,000) feet of a Designated Outside Activity Area, unless the Commission determines otherwise.

(5) **Maximum Achievable Setback**. If the applicable setback would extend beyond the area on which the Operator has a legal right to locate the Well or Production Facilities, the Operator may seek a variance under Rule 502.b. to reduce the setback to the maximum achievable distance.

(6) School Facility and Child Care Center Setback.

A. No well or production facility will be located one-thousand (1,000) feet or less from a school facility or child care center, unless:

i. The relevant school governing body agrees in writing to the location of the proposed well or production facility, in which circumstance the Director may approve the Form 2, Application for Permit to Drill, or Form 2A, Oil and Gas Location Assessment; or

ii. The Commission authorizes the Director to approve a Form 2, Application for Permit to Drill, or Form 2A, Oil and Gas Location Assessment, following application and a hearing held at a location reasonably proximate to the lands affected by the application. The Commission may allow a well or production facility within one-thousand (1,000) feet or less from a school facility or child care center if the Commission determines that potential locations outside the applicable setback are technically infeasible or economically impracticable and sufficient mitigation measures are in place to protect public health, safety, and welfare. The operator will file an application with the Commission requesting the hearing and demonstrate, to the Commission's satisfaction, that potential locations outside the applicable setback are technically infeasible or economically impracticable.

B. Mitigation measures pursuant to Rule 604.c.(1-4) will be required for all oil and gas locations subject to the school facility or child care center setback.

C. If the operator and school governing body disagree as to whether a proposed well or production facility is one-thousand (1,000) feet or less from a school facility or child care center, the operator or school governing body may file an application with the Commission requesting a hearing to determine the matter. At the hearing, the operator must demonstrate that the well or production facility is more than one-thousand (1,000) feet from any school facility or child care center.

604.b. Exceptions.

(1) **Existing Oil and Gas Locations.** The Director may grant an exception to setback distance requirements set forth in Rule 604 within a Designated Setback Location when a Well or Production Facility is proposed to be added to an existing or approved Oil and Gas Location if the Director determines alternative locations outside the applicable setback are technically or economically impracticable; mitigation measures imposed in the Form 2 or Form 2A will eliminate, minimize or mitigate noise, odors, light, dust, and similar nuisance conditions to the extent reasonably achievable; the operator has complied with the notice and consultation requirements of Rule 305A, if applicable; the proposed location complies with all other safety requirements of these Commission Rules; and:

A. An existing or approved Oil and Gas Location is within a Designated Setback Location solely as a result of the adoption of Rule 604.a., above, which established the Designated Setback Locations; or

B. The Oil and Gas Location is located within a Designated Setback Location solely as a result of Building Units constructed after the Oil and Gas Location was approved by the Director.

(2) **Existing Surface Use Agreement or Site Specific Development Plan**. The Director shall grant an exception to setback requirements set forth in Rule 604.a. for a Surface Use Agreement or site specific development plan (as defined in § 24-68-102(4)(a), C.R.S. that establishes vested property rights as defined in § 24-68-103, C.R.S.), that was executed on or before August 1, 2013, and which expressly governs the location of Wells or Production Facilities on the surface estate, provided mitigation measures imposed in the Form 2 or Form 2A will eliminate, minimize or mitigate noise, odors, light, dust, and similar nuisance conditions to the extent reasonably achievable and the location complies with all other safety requirements of these Commission Rules.

(3) **Surface Development after August 1, 2013 Pursuant to a Surface Use Agreement or Site Specific Development Plan.** A Surface Owner or Building Unit owner and mineral owner or mineral lessee may agree to locate future Building Units closer to existing or proposed Oil and Gas Locations than otherwise allowed under Rule 604.a. pursuant to a valid Surface Use Agreement or site specific development plan (as defined in § 24-68-102(4)(a), C.R.S., that establishes vested property rights as defined in § 24-68-103, C.R.S.) that expressly governs the location of Wells or Production Facilities on the surface estate. All setback, notice, consultation and meeting requirements contained in Rules 305, 306, and 604.a shall apply with respect to all Building Units that are not governed by the applicable SUA or site specific development plan. Copies of any applicable SUA or site specific development plan shall be submitted by the Operator with a Form 2A Application or associated Form 2 for a proposed Oil and Gas Location on the relevant surface estate.

(4) In the event the Director refuses to grant an exception or variance requested pursuant to Rule 604.a.(5) or 604.b., a hearing before the Commission shall be held at the next regularly scheduled meeting of the Commission, subject to the notice requirements of Rule 507.

604.c. **Mitigation Measures.** The following requirements apply to an Oil and Gas Location within a Designated Setback Location and such requirements shall be incorporated into the Form 2A or associated Form 2 as Conditions of Approval.

(1) **Provisions for future encroaching development.** If a location comes within a Designated Setback Location solely as a result of surface development after well pad construction begins or production equipment has been placed, certain mitigation measures may not apply as determined by the Director.

(2) **Location Specific Requirements – Designated Setback Locations.** Subject to Rule 502.b., the following mitigation measures shall apply to any Well or Production Facility proposed to be located within a Designated Setback Location for which a Form 2, Application for Permit—to-Drill or Form 2A, Oil and Gas Location Assessment, is submitted on or after August 1, 2013:

A. **Noise.** Operations involving pipeline or gas facility installation or maintenance, or the use of a drilling rig, are subject to the maximum permissible noise levels for Light Industrial Zones, as measured at the nearest Building Unit. Short-term increases shall be allowable as described in 802.c. Stimulation or re-stimulation operations and Production Facilities are governed by Rule 802.

B. Closed Loop Drilling Systems – Pit Restrictions.

i. Closed loop drilling systems are required within the Buffer Zone Setback.

ii. Pits are not allowed on Oil and Gas Locations within the Buffer Zone Setback, except fresh water storage pits, reserve pits to drill surface casing, and emergency pits as defined in the 100-Series Rules.

iii. Fresh water pits within the Exception Zone shall require prior approval of a Form 15, Earthen Pit Report/Permit. In the Buffer Zone, fresh water pits shall be reported within 30-days of pit construction.

iv. Fresh water storage pits within the Buffer Zone Setback shall be conspicuously posted with signage identifying the pit name, the operator's name and contact information, and stating that no fluids other than fresh water are permitted in the pit. Produced water, recycled E&P waste, or flowback fluids are not allowed in fresh water storage pits.

v. Fresh water storage pits within the Buffer Zone Setback shall include emergency escape provisions for inadvertent human access.

C. Green Completions – Emission Control Systems.

i. Flow lines, separators, and sand traps capable of supporting green completions as described in Rule 805 shall be installed at any Oil and Gas Location at which commercial quantities of gas are reasonably expected to be produced based on existing adjacent wells within 1 mile.

ii. Uncontrolled venting shall be prohibited in an Urban Mitigation Area.

iii. Temporary flowback flaring and oxidizing equipment shall include the following:

aa. Adequately sized equipment to handle 1.5 times the largest flowback volume of gas experienced in a ten (10) mile radius;

bb. Valves and porting available to divert gas to temporary equipment or to permanent flaring and oxidizing equipment; and

cc. Auxiliary fuel with sufficient supply and heat to sustain combustion or oxidation of the gas mixture when the mixture includes non-combustible gases.

D. **Traffic Plan.** If required by the local government, a traffic plan shall be coordinated with the local jurisdiction prior to commencement of move in and rig up. Any subsequent modification to the traffic plan must be coordinated with the local jurisdiction.

E. Multi-well Pads.

i. Where technologically feasible and economically practicable, operators shall consolidate wells to create multi-well pads, including shared locations with other operators. Multi-well production facilities shall be located as far as possible from Building Units.

ii. The pad shall be constructed in such a manner that noise mitigation may be installed and removed without disturbing the site or landscaping.

iii. Pads shall have all weather access roads to allow for operator and emergency response.

F. **Leak Detection Plan.** The Operator shall develop a plan to monitor Production Facilities on a regular schedule to identify fluid leaks.

G. **Berm construction.** Berms or other secondary containment devices in Designated Setback Locations shall be constructed around crude oil, condensate, and produced water storage tanks and shall enclose an area sufficient to contain and provide secondary containment for one-hundred fifty percent (150%) of the largest single tank. Berms or other secondary containment devices shall be sufficiently impervious to contain any spilled or released material. All berms and containment devices shall be inspected at regular intervals and maintained in good condition. No potential ignition sources shall be installed inside the secondary containment area unless the containment area encloses a fired vessel. Refer to API Bulletin D16: Suggested Procedure for "Development of a Spill Prevention Control and Countermeasure Plan," 5th Edition (April 2011). Only the 5th Edition of the API bulletin applies to this rule; later amendments do not apply. All material incorporated by reference in this rule is available for public inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. In addition, these materials may be examined at any state publications depository library and are available from API at 1220 L Street, NW Washington, DC 20005-4070.

H. **Blowout preventer equipment ("BOPE").** Blowout prevention equipment for drilling operations in a Designated Setback Location shall consist of (at a minimum):

i. **Rig with Kelly.** Double ram with blind ram and pipe ram; annular preventer or a rotating head.

ii. **Rig without Kelly.** Double ram with blind ram and pipe ram.

Mineral Management certification or Director approved training for blowout prevention shall be required for at least one (1) person at the well site during drilling operations.

I. **BOPE testing for drilling operations.** Upon initial rig-up and at least once every thirty (30) days during drilling operations thereafter, pressure testing of the casing string and each component of the blowout prevention equipment including flange connections shall be performed to seventy percent (70%) of working pressure or seventy percent (70%) of the internal yield of casing, whichever is less. Pressure testing shall be conducted and the documented results shall be retained by the operator for inspection by the Director for a period of one (1) year. Activation of the pipe rams for function testing shall be conducted on a daily basis when practicable.

J. BOPE for well servicing operations.

i. Adequate blowout prevention equipment shall be used on all well servicing operations.

ii. Backup stabbing valves shall be required on well servicing operations during reverse circulation. Valves shall be pressure tested before each well servicing operation using both low-pressure air and high-pressure fluid.

K. **Pit level indicators.** Pit level indicators shall be used.

L. **Drill stem tests.** Closed chamber drill stem tests shall be allowed. All other drill stem tests shall require approval by the Director.

M. **Fencing requirements.** Unless otherwise requested by the Surface Owner, well sites constructed within Designated Setback Locations, shall be adequately fenced to restrict access by unauthorized persons.

N. **Control of fire hazards.** Any material not in use that might constitute a fire hazard shall be removed a minimum of twenty-five (25) feet from the wellhead, tanks and separator. Any electrical equipment installations inside the bermed area shall comply with API RP 500 classifications and comply with the current national electrical code as adopted by the State of Colorado.

O. **Loadlines.** All loadlines shall be bullplugged or capped.

P. **Removal of surface trash.** All surface trash, debris, scrap or discarded material connected with the operations of the property shall be removed from the premises or disposed of in a legal manner.

Q. **Guy line anchors.** All guy line anchors left buried for future use shall be identified by a marker of bright color not less than four (4) feet in height and not greater than one (1) foot east of the guy line anchor.

R. **Tank specifications.** All newly installed or replaced crude oil and condensate storage tanks shall be designed, constructed, and maintained in accordance with National Fire Protection Association (NFPA) Code 30 (2008 version). The operator shall maintain written records verifying proper design, construction, and maintenance, and shall make these records available for inspection by the Director. Only the 2008 version of NFPA Code 30 applies to this rule. This rule does not include later amendments to, or editions of, the NFPA Code 30. NFPA Code 30 may be examined at any state publication depository library. Upon request, the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203, will provide information about the publisher and the citation to the material.

S. **Access roads.** At the time of construction, all leasehold roads shall be constructed to accommodate local emergency vehicle access requirements, and shall be maintained in a reasonable condition.

T. **Well site cleared.** Within ninety (90) days after a well is plugged and abandoned, the well site shall be cleared of all non-essential equipment, trash, and debris. For good cause shown, an extension of time may be granted by the Director.

U. **Identification of plugged and abandoned wells.** The operator shall identify the location of the wellbore with a permanent monument as specified in Rule 319.a.(5). The operator shall also inscribe or imbed the well number and date of plugging upon the permanent monument.

V. **Development from existing well pads.** Where possible, operators shall provide for the development of multiple reservoirs by drilling on existing pads or by multiple completions or commingling in existing wellbores (see Rule 322). If any operator asserts it is not possible to comply with, or requests relief from, this requirement, the matter shall be set for hearing by the Commission and relief granted as appropriate.

W. **Site-specific measures.** During Rule 306 consultation, the operator may develop a mitigation plan to address location specific considerations not otherwise addressed by specific mitigation measures identified in this subsection 604.c.

(3) **Location Specific Requirements – Exception Zone Setback.** Within the Exception Zone Setback, the following mitigation measures will be mandatory:

A. All mitigation measures required pursuant to subsection 604.c.(2), above, and:

B. Berm Construction:

i. Containment berms shall be constructed of steel rings, designed and installed to prevent leakage and resist degradation from erosion or routine operation.

ii. Secondary containment areas for tanks shall be constructed with a synthetic or engineered liner that contains all primary containment vessels and flowlines and is mechanically connected to the steel ring to prevent leakage.

iii. For locations within five hundred (500) feet and upgradient of a surface water body, tertiary containment, such as an earthen berm, is required around Production Facilities.

iv. In an Urban Mitigation Area Exception Zone Setback, no more than two (2) crude oil or condensate storage tanks shall be located within a single berm.

(4) **Large UMA Facilities**. Large UMA Facilities should be built as far as possible from existing building units and operated using the best available technology to avoid or minimize adverse impacts to adjoining land uses. To achieve this objective, the Director will require a combination of best management practices and required mitigation measures, and may also impose site specific conditions of approval related to operational and technical aspects of a proposed Large UMA Facility.

A. All Rule 604.c.(3) Exception Zone Setback mitigation measures are required for all Large UMA Facilities, regardless of whether the Large UMA Facility is located in the Buffer Zone or the Exception Zone.

B. Required Best Management Practices. A Form 2A for a Large UMA Facility will not be approved until best management practices addressing all of the following have been incorporated into the Oil and Gas Location Assessment permit.

i. Fire, explosion, chemical, and toxic emission hazards, including lightning strike hazards.

ii. Fluid leak detection, repair, reporting, and record keeping for all above and below ground on-site fluid handling, storage, and transportation equipment.

iii. Automated well shut in control measures to prevent gas venting during emission control system failures or other upset conditions.

iv. Zero flaring or venting of gas upon completion of flowback, excepting upset or emergency conditions, or with prior written approval from the Director for necessary maintenance operations.

v. Storage tank pressure and fluid management.

vi. Proppant dust control.

C. Site Specific Mitigation Measures. In addition to the requirements of subsections A. and B. of this Rule 604.c.(4), the Director may impose site-specific conditions of approval to ensure that anticipated impacts are mitigated to the maximum extent achievable. The following non-exclusive list illustrates types of potential impacts the Director may evaluate, and for which site-specific conditions of approval may be required:

i. Noise;

ii. Ground and surface water protection;

iii. Visual impacts associated with placement of wells or production equipment; and

iv. Remote stimulation operations.

D. In considering the need for site-specific mitigation measures, the Director will consider and give substantial deference to mitigation measures or best management practices agreed to by the operator and local government with land use authority.

605. OIL AND GAS FACILITIES.

a. Crude Oil and Condensate Tanks.

(1) Atmospheric tanks used for crude oil storage shall be built in accordance with the following standards as applicable. Only those editions of standards incorporated by reference within this rule shall apply to this rule; later amendments do not apply. The material incorporated by reference in this rule is available for public inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. In addition, these materials may be examined at any state publications depository library and are available from API at 1220 L Street, NW Washington, DC 20005-4070 and from Underwriters Laboratories, Inc. at 100 Technology Drive, Broomfield, CO 80021.

A. Underwriters Laboratories, Inc., No. UL-142, "Standard for Steel above ground Tanks for Flammable and Combustible Liquids," 9th Edition (December 28, 2006);

B. API Standard No. 650, "Welded Steel Tanks for Oil Storage," 12th Edition (March 2013);

C. API Standard No. 12B, "Bolted Tanks for Storage of Production Liquids," 15th Edition (October 2008);

D. API Standard No. 12D, "Field Welded Tanks for Storage of Production Liquids," 11th Edition (October 2008); or

E. API No. 12F, "Shop Welded Tanks for Storage of Production Liquids," 12th Edition (October 2008).

(2) Tanks shall be located at least two (2) diameters or three hundred fifty (350) feet, whichever is smaller, from the boundary of the property on which it is built. Where the property line is a public way the tanks shall be two thirds (2/3) of the diameter from the nearest side of the public way or easement.

A. Tanks less than three thousand (3,000) barrels capacity shall be located at least three (3) feet apart.

B. Tanks three thousand (3,000) or more barrels capacity shall be located at least one-sixth (1/6) the sum of the diameters apart. When the diameter of one tank is less than one-half (1/2) the diameter of the adjacent tank, the tanks shall be located at least one-half (1/2) the diameter of the smaller tank apart.

(3) At the time of installation, tanks shall be a minimum of two hundred (200) feet from any building.

(4) Berms or other secondary containment devices shall be constructed around crude oil, condensate, and produced water tanks to provide secondary containment for the largest single tank and sufficient freeboard to contain precipitation. A synthetic or engineered liner shall be placed directly beneath each above-ground tank. Berms and secondary containment devices and all containment areas shall be sufficiently impervious to contain any spilled or released material. Berms and secondary containment devices shall be inspected at regular intervals and maintained in good condition. No potential ignition sources shall be installed inside the secondary containment area unless the containment area encloses a fired vessel. Any electrical equipment installations inside the bermed area shall comply with API RP 500: Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities classified as Class I, Division I and Division 2, 3rd Edition (January 2014) and the current national electrical code as adopted by the State of Colorado. Only the 3rd edition incorporated by reference within this rule shall apply to this rule; later amendments do not apply. The material incorporated by reference in this rule is available for public inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. In addition, these materials may be examined at any state publications depository library and are available from API at 1220 L Street NW, Washington, DC 20005-4070 and from the Department of Regulatory Agencies, Colorado Electrical Board at 1560 Broadway, Suite 110, Denver, CO 80202.

(5) Tanks shall be a minimum of seventy-five (75) feet from a fired vessel or heater-treater.

(6) Tanks shall be a minimum of fifty (50) feet from a separator, well test unit, or other non-fired equipment.

(7) Tanks shall be a minimum of seventy-five (75) feet from a compressor with a rating of 200 horsepower, or more.

(8) Tanks shall be a minimum of seventy-five (75) feet from a wellhead.

(9) Gauge hatches on atmospheric tanks used for crude oil storage shall be closed at all times when not in use.

(10) Vent lines from individual tanks shall be joined and ultimate discharge shall be directed away from the loading racks and fired vessels in accord with API RP 12R-1, 5th Edition (August 1997, reaffirmed April 2, 2008). Only the 5th Edition of the API standard applies to this rule; later amendments do not apply. The API standard is available for public inspection during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, Colorado 80203. In addition, these materials may be examined at any state publication depository library.

(11) During hot oil treatments on tanks containing thirty-five (35) degree or higher API gravity oil, hot oil units shall be located a minimum of one hundred (100) feet from any tank being serviced.

(12) **Labeling of tanks.** All tanks and containers shall be labeled in accordance with Rule 210.d.

605.b. Fired Vessel, Heater-Treater.

(1) Fired vessels (FV) including heater-treaters (HT) shall be minimum of fifty (50) feet from separators or well test units.

(2) FV-HT shall be a minimum of fifty (50) feet from a lease automatic custody transfer unit (LACT).

(3) FV-HT shall be a minimum of forty (40) feet from a pump.

(4) FV-HT shall be a minimum of seventy-five (75) feet from a well.

(5) At the time of installation, fired vessels and heater treaters shall be a minimum of two hundred (200) feet from buildings or well defined normally occupied outside areas.

(6) Vents on pressure safety devices shall terminate in a manner so as not to endanger the public or adjoining facilities. They shall be designed so as to be clear and free of debris and water at all times.

(7) All stacks, vents, or other openings shall be equipped with screens or other appropriate equipment to prevent entry by wildlife, including migratory birds.

605.c. **Special Equipment.** Under unusual circumstances special equipment may be required to protect public safety. The Director shall determine if such equipment should be employed to protect public safety and if so, require the operator to employ same. If the operator or the affected party does not concur with the action taken, the Director shall bring the matter before the Commission at public hearing.

(1) All wells located within five hundred (500) feet of a Residential Building Unit or well defined normally occupied outside area(s), shall be equipped with an automatic control valve that will shut the well in when a sudden change of pressure, either a rise or drop, occurs. Automatic control valves shall be designed so they fail safe.

(2) Pressure control valves required in (1) shall be activated by a secondary gas source supply, and shall be inspected at least every three (3) months to assure they are in good working order and the secondary gas supply has volume and pressure sufficient to activate the control valve.

(3) All pumps, pits, and producing facilities shall be adequately fenced to prevent access by unauthorized persons when the producing site or equipment is easily accessible to the public and poses a physical or health hazard.

(4) Sign(s) shall be posted at the boundary of the producing site where access exists, identifying the operator, lease name, location, and listing a phone number, including area code, where the operator may be reached at all times unless emergency numbers have been furnished to the county commission or its designee.

605.d. **Mechanical Conditions.** All valves, pipes and fittings must be securely fastened, inspected at regular intervals, and maintained in good mechanical condition.

605.e. **Buried or partially buried tanks, vessels, or structures.** Buried or partially buried tanks, vessels, or structures used for storage of E&P waste shall be properly designed, constructed, installed, and operated in a manner to contain materials safely. A synthetic or engineered liner shall be placed directly beneath. Such vessels shall be tested for leaks after installation and maintained, repaired, or replaced to prevent spills or releases of E&P waste.

605.f. **Produced water pits, special use and buried or partially buried vessels, or structures.** At the time of initial construction, pits shall be located not less than five hundred (500) feet from any Building Unit.

606A. FIRE PREVENTION AND PROTECTION

a. Gasoline-fueled engines shall be shut down during fueling operations if the fuel tank is an integral part of the engine.

b. Handling, connecting and transfer operations involving liquefied petroleum gas (LPG) shall conform to the requirements of the State Oil Inspector.

c. Flammable liquids storage areas within any building or shed shall:

(1) be adequately vented to the outside air;

(2) have two (2) unobstructed exits leading from the building in different directions if the building is in excess of five hundred (500) square feet.

(3) be maintained with due regard to fire potential with respect to housekeeping and materials storage;

(4) be identified as a hazard and appropriate warning signs posted;

d. Flammable liquids shall not be stored within fifty (50) feet of the wellbore, except for the fuel in the tanks of operating equipment or supply for injection pumps. Where terrain and location configuration do not permit maintaining this distance, equivalent safety measures should be taken.

e. Liquefied petroleum gas (LPG) tanks larger than two hundred fifty (250) gallons and used for heating purposes, shall be placed as far as practical from and parallel to the adjacent side of the rig or wellbore as terrain and location configuration permit. Installation shall be consistent with provisions of NFPA 58, “Standards for the Storage and Handling of Liquid Petroleum Gases”.

f. Smoking shall be prohibited at or in the vicinity of operations which constitute a fire hazard and such locations shall be conspicuously posted with a sign, “No Smoking or Open Flame”. Matches and all smoking equipment may not be carried into “No Smoking” areas.

g. No source of ignition shall be permitted in an area where smoking has been prohibited unless it is first determined to be safe to do so by the supervisor in charge or his designated representative.

h. Open fires, transformers, or other sources of ignition shall be permitted only in designated areas located at a safe distance from the wellhead or flammable liquid storage areas.

i. Only approved heaters for Class I Division 2 areas, as designated by API RB 500B, shall be permitted on or near the rig floor. The safety features of these heaters shall not be altered.

j. Combustible materials such as oily rags and waste shall be stored in covered metal containers.

k. Material used for cleaning shall have a flash point of not less than one hundred degrees Fahrenheit (100° F). For limited special purposes, a lower flash point cleaner may be used when it is specifically required and should be handled with extreme care.

l. Firefighting equipment shall not be tampered with and shall not be removed for other than fire protection and firefighting purposes and services. A firefighting water system may be used for wash down and other utility purposes so long as its firefighting capability is not compromised. After use, water systems must be properly drained or properly protected from freezing.

m. An adequate amount of fire extinguishers and other firefighting equipment shall be suitably located, readily accessible, and plainly labeled as to their type and method of operation.

n. Fire protection equipment shall be periodically inspected and maintained in good operating condition at all times.

o. Firefighting equipment shall be readily available near all welding operations. When welding, cutting or other hot work is performed in locations where other than a minor fire might develop, a person shall be designated as a fire watch. The area surrounding the work shall be inspected at least one (1) hour after the hot work is completed.

p. Portable fire extinguishers shall be tagged showing the date of last inspection, maintenance or recharge. Inspection and maintenance procedures shall comply with the latest edition of the National Fire Protection Association's publication NFPA 10.

q. Personnel shall be familiarized with the location of fire control equipment such as drilling fluid guns, water hoses and fire extinguishers and trained in the use of such equipment. They shall also be familiar with the procedure for requesting emergency assistance as terrain and location configuration permit. Installation shall be consistent with provisions of NFPA 58, “Standards for the Storage and Handling of Liquefied Petroleum Gases”.

606B. AIR AND GAS DRILLING

a. Drilling compressors (air or gas) shall be located at least 125 feet from the wellbore and in a direction away from the air or gas discharge line.

b. The air or gas discharge line shall be laid in as nearly a straight line as possible from the wellbore and be a minimum of 150 feet in length. The line shall be securely anchored.

c. A pilot flame shall be maintained at the end of the air or gas discharge line at all times when air, gas, mist drilling, or well testing is in progress.

d. All combustible material shall be kept at least 100 feet away from the air and gas discharge line and flare pit.

e. The air line from the compressors to the standpipe shall be of adequate strength to withstand at least the maximum discharge pressure of the compressors used, and shall be checked daily for any evidence of damage or weakness.

f. Smoking shall not be allowed within 75 feet of the air and gas discharge line and flare pit.

g. All operations associated with the drilling, completion or production of a well shall be subject to the Colorado Air Quality Control Act, 25-7-101, C.R.S.

607. HYDROGEN SULFIDE GAS

a. When well servicing operations take place in zones known to contain at or above one hundred (100) ppm hydrogen sulfide gas, as measured in the gas stream, the operator shall file a hydrogen sulfide drilling operations plan (United States Department of the Interior, Bureau of Land Management, Onshore Order No. 6, November 23, 1990).

b. When proposing to drill a well in areas where hydrogen sulfide gas in excess of one hundred (100) ppm can reasonably be expected to be encountered, the operator shall submit as part of the Form 2, Application-for-Permit-to-Drill, a hydrogen sulfide drilling operations plan (United States Department of the Interior, Bureau of Land Management, Onshore Order No. 6, November 23, 1990).

c. Any gas analysis indicating the presence of hydrogen sulfide gas shall be reported to the Commission and the local governmental designee.

608. COALBED METHANE WELLS

a. Assessment and monitoring of plugged and abandoned wells within one-quarter (1/4) mile of proposed coalbed methane (CBM) well.

(1) Based upon examination of the Commission and other publicly available records, operators shall identify all plugged and abandoned (P&A) wells located within one-quarter (1/4) mile of a proposed coalbed methane (CBM) well. The operator shall assess the risk of leaking gas or water to the ground surface or into subsurface water resources, taking into account plugging and cementing procedures described in any recompletion or P&A report filed with the Commission. The operator shall notify the Director of the results of the assessment of the plugging and cementing procedures. The Director shall review the assessment and take appropriate action to pursue further investigation and remediation if warranted and in accordance with Colorado Revised Statute 34-60-124(4)(A).

(2) Operators shall use reasonable good faith efforts to obtain access to all P&A wells identified under Rule 608.a.(1) above to conduct a soil gas survey at all P&A wells located within one-quarter (1/4) mile of a proposed CBM well prior to production from the proposed CBM well and again one (1) year and thereafter every three (3) years after production has commenced. Operators shall submit the results of the soil gas survey to the Director within three (3) months of conducting the survey or advise the Director that access to the P&A wells could not be obtained.

b. Water well sampling.

(1) If a conventional gas well or P&A well exists within one-quarter (1/4) mile of a proposed CBM well, then the two (2) closest water wells within a one-half (1/2) mile radius of the conventional gas well or the P&A well shall be sampled ("Water Quality Testing Wells"). If possible, the water wells selected should be on opposite sides of the conventional gas well or the P&A well not exceeding a one-half (1/2) mile radius. If water wells on opposite sides of the conventional gas well or the P&A well cannot be identified, then the two (2) closest wells within a one-half (1/2) mile radius of the conventional gas well or the P&A well shall be sampled. If two (2) or more conventional wells or P&A wells are located within one-quarter (1/4) mile of the proposed CBM well, then the conventional well or the P&A well closest to a proposed CBM well shall be used for selecting water wells for sampling.

If there are no conventional gas wells or P&A wells located within a one-quarter (1/4) mile radius of the proposed CBM well, then the selected water wells shall be within one-quarter (1/4) mile of the proposed CBM well. In areas where twoor more water wells exist within one-quarter (1/4) mile of the proposed CBM well, then the two (2) closest water wells shall be sampled. If possible, the water wells selected should be on opposite sides of the proposed CBM well. If water wells on opposite sides of the proposed CBM well cannot be identified, then the two (2) closest wells within one-quarter (1/4) mile radius shall be sampled. If two (2) water wells do not exist within a one-quarter (1/4) mile radius, then the closest single water well within either a one-quarter (1/4) mile radius or within a one-half (1/2) mile radius shall be selected.

If no water well is located within a one-quarter (1/4) mile radius area as described above or if access is denied, then a water well within one-half (1/2) mile of the proposed CBM well shall be selected. If no water wells meet the foregoing criteria, then sampling shall not be required. If the Commission has already acquired data on a water well within one- quarter (1/4) mile of the conventional well or the P&A well, but it is not the closest water well, then it shall be given preference in selecting a water well to be tested.

(2) The “initial baseline testing” described in this section shall include all major cations and anions, total dissolved solids (TDS), iron, manganese, selenium, nitrates and nitrites, dissolved methane, field pH, sodium adsorption ration (SAR), presence of bacteria (iron related, sulfate reducing, slime, and coliform), and specific conductance. Hydrogen sulfide shall also be measured using a field test method. Field observations such as odor, water color, sediment, bubbles, and effervescence shall also be included. The location of the water well shall be surveyed in accordance with Rule 215.

(3) If free gas or a dissolved methane concentration level greater than two (2) milligrams per liter (mg/l) is detected in a water well, gas compositional analysis and stable isotope analysis of the methane (carbon and deuterium) shall be performed to determine gas type. If the test results indicate biogenic gas, no further isotopic testing shall be done. If the test results indicate thermogenic or a mixture of thermogenic and biogenic gas, then the operator shall submit to the Director an action plan to determine the source of the gas. If the methane concentration increases by more than five (5) mg/l between sampling periods, or increases to more than ten (10) mg/l, the operator shall notify the Director and the owner of the water well immediately.

(4) Operators shall make a good faith effort to conduct initial baseline testing of the selected water wells prior to the drilling of the proposed CBM well; however, not conducting baseline testing because access to water wells cannot be obtained shall not be grounds for denial of an Application for Permit-to-Drill, Form 2. Within one (1) year after completion of the proposed CBM well, a “post-completion” test shall be performed for the same analytical parameters listed above and repeated three (3) and six (6) years thereafter or in accordance with the requirements of field rules developed pursuant to Rule 608.f. If the methane concentration increases by more than five (5) mg/l between sampling periods or increases to more than ten (10) mg/l, the operator shall prepare an action plan to determine the source of the gas and notify the Director and the water well owner immediately. If no significant changes from the baseline have been identified after the third test (i.e. the six-year test), no further testing shall be required. Additional “post-completion” test(s) may be required if changes in water quality are identified during follow-up testing. The Director may require further water well sampling at any time in response to complaints from water well owners.

(5) Copies of all test results described above shall be provided to the Commission and the water well owner within three (3) months of collecting the samples. The analytical data and surveyed well locations shall also be submitted to the Director in an electronic data deliverable format.

c. Coal outcrop and coal mine monitoring.

(1) If the CBM well is within two (2) miles of the outcrop of the stratigraphic contact between the coal-bearing formation and the underlying formation, or within twomiles of an active, inactive, or abandoned coal mine, the operator shall make a good faith effort to obtain the access necessary to survey the outcrop or mine prior to drilling the CBM well to determine whether there are gas seeps and springs or water seeps that discharge from the coal-bearing formation in the area.

(2) If a gas seep is identified during the survey, then its location and areal extent shall be surveyed in accordance with Rule 215 and the concentration of the soil gas shall be determined. If possible, a sample of gas shall be collected from the seep for compositional analysis and stable isotope analysis of the methane (carbon and deuterium). Thereafter, the operator will inspect the gas seep, survey its areal extent, and measure soil gas concentrations annually, if access can be obtained. The operator shall submit the results of the outcrop or mine monitoring to the Commission and the landowner within three (3) months of its completion of the field work. The analytical data shall also be submitted to the Director in an electronic data deliverable format.

(3) If a gas seep is identified during the survey, the Director shall advise the landowners, local government, Colorado Geological Survey (CGS), and the Colorado Division of Reclamation, Mining, and Safety (DRMS), as appropriate, of the findings. In collaboration with state, local, and private interests, the CGS, DRMS, and the Commission may elect to develop a geologic hazard survey and determine whether the area should be recommended to be designated as a geologic hazard in accordance with Colorado Revised Statute 34-1-103 and 24-65.1-103.

(4) If the CBM well is within two (2) miles of the outcrop of the stratigraphic contact between the coal-bearing formation and the underlying formation, the operator shall survey the outcrop, review publicly available geologic and hydrogeologic data, and interview landowners to identify springs or water seeps that discharge from the coal-bearing formation.

If such a water feature is identified, then the operator shall survey its location and areal extent in accordance with Rule 215, measure the flow rate, photograph the feature, and collect and analyze a water sample in accordance with Rule 608.b.(2). Thereafter, the operator will inspect, survey the areal extent of, and measure the flow rate of the spring or water seep annually, if access can be obtained. The operator shall submit the results of the spring or water seep monitoring to the Commission and the landowner within three (3) months of its completion of the field work. The analytical data shall also be submitted to the Director in an electronic data deliverable format.

d. **Prior to producing - static bottom-hole pressure survey.** Prior to producing the well, the operator shall obtain a static bottom-hole pressure test on at least the first well drilled on a government quarter (1/4) section. The survey shall be conducted by either a direct static bottom-hole pressure measurement or by a static fluid level measurement. The data acquired by the operator and a description of the procedures used to gather the data shall be reported on a Bottom Hole Pressure, Form 13, and submitted with the Completed Interval Report, Form 5A, filed with the Director. After reviewing the quality of the static bottom-hole pressure data and the adequacy of the geographic distribution of the data, or at the request of the operator, the Director may vary the number of wells subject to the static bottom-hole pressure survey requirement. If an application for increased well density or down spacing is filed with the Commission, then additional testing may be required.

e. **Bradenhead testing.** Upon completion of any well, and on wells presently completed, the operator shall equip the bradenhead access to the annulus between the production and surface casing, as well as any intermediate casing, with approved fittings to allow safe and convenient determination of pressure and fluid flow. All valves used for annular pressure monitoring shall remain exposed and not buried to allow for COGCC visual inspection at all times. A rigid housing may be used to protect the valves, provided that the housing can be easily opened or removed by the operator upon request of COGCC staff. This rule shall apply to all wells, regardless of function, completed for CBM production or below the coal-bearing formation. All wells capable of production, injection, or observation shall be tested by the operator for pressure and flow, with results submitted to the Director on a Bradenhead Test Report, Form 17, and to other applicable regulatory agencies. Bradenhead tests shall be performed on all wells on a biennial basis. Remedial requirements shall be determined by the appropriate regulatory agency. The bradenhead testing requirement shall not apply if the operator demonstrates to the satisfaction of the Director annular cement coverage greater than fifty (50) feet above the base of surface casing and zonal isolation is confirmed by reliable evidence such as a cement bond log or cementing ticket indicating that the height of cement coverage is fifty (50) feet above the base of the surface casing, and zonal isolation is confirmed by two consecutive bradenhead tests preceded by a minimum shut-in period of seven (7) days each.

f. **Locally specific field orders.** The provisions of this Rule 608 may, with the Director's approval, be modified or superseded on a basin, region, or county specific basis by field orders developed by the Commission in consultation with affected parties, including operators, county governments, and other state or local agencies, taking into account the goals of the 600-Series Rules and particular local geologic and operational conditions. In addition, the operator or other affected party shall have the right to file an application with the Commission to develop field orders for the basin, region, or county that modify the Rule 608 requirements as provided herein, which application shall set forth an explanation of good cause for the development of such orders.

609. STATEWIDE GROUNDWATER BASELINE SAMPLING AND MONITORING:

a. Applicability and effective date.

(1) This Rule 609 applies to Oil Wells, Gas Wells (hereinafter, Oil and Gas Wells), Multi-Well Sites, and Dedicated Injection Wells as defined in the 100-Series Rules, for which a Form 2, Application for Permit-to-Drill, is submitted on or after May 1, 2013.

(2) This Rule 609 does not apply to an existing Oil or Gas Well that is re-permitted for use as a Dedicated Injection Well.

(3) This rule does not apply to Oil and Gas Wells, Multi-Well Sites, or Dedicated Injection Wells that are regulated under Rule 608.b., Rule 318A.e.(4), or Orders of the Commission with respect to the Northern San Juan Basin promulgated prior to the effective date of this Rule that provide for groundwater testing.

(4) Nothing in this Rule is intended, and shall not be construed, to preclude or limit the Director from requiring groundwater sampling or monitoring at other Production Facilities consistent with other applicable Rules, including but not limited to the Oil and Gas Location Assessment process, and other processes in place under 900-series E&P Waste Management Rules (Form 15, Form 27, Form 28).

(5) An operator may elect to install one or more groundwater monitoring wells to satisfy, in full or in part, the requirements of Rule 609.b., but installation of monitoring wells is not required under this Rule.

b. **Sampling locations.** Initial baseline samples and subsequent monitoring samples shall be collected from all Available Water Sources, up to a maximum of four (4), within a one-half (1/2) mile radius of a proposed Oil and Gas Well, Multi-Well Site, or Dedicated Injection Well. If more than four (4) Available Water Sources are present within a one-half (1/2) mile radius of a proposed Oil and Gas Well, Multi-Well Site, or Dedicated Injection Well, the operator shall select the four sampling locations based on the following criteria:

(1) Proximity. Available Water Sources closest to the proposed Oil or Gas Well, a Multi-Well Site, or Dedicated Injection Well are preferred.

(2) Type of Water Source. Well maintained domestic water wells are preferred over other Available Water Sources.

(3) Orientation of sampling locations. To extent groundwater flow direction is known or reasonably can be inferred, sample locations from both downgradient and up-gradient are

preferred over cross-gradient locations. Where groundwater flow direction is uncertain, sample locations should be chosen in a radial pattern from a proposed Oil and Gas Well, Multi-Well Site, or Dedicated Injection Well.

(4) Multiple identified aquifers available. Where multiple defined aquifers are present, sampling the deepest and shallowest identified aquifers is preferred.

(5) Condition of Water Source. An operator is not required to sample Water Sources that are determined to be improperly maintained, nonoperational, or have other physical impediments to sampling that would not allow for a representative sample to be safely collected or would require specialized sampling equipment (e.g. shut-in wells, wells with confined space issues, wells with no tap or pump, non-functioning wells, intermittent springs).

c. **Inability to locate an Available Water Source.** Prior to spudding, an operator may request an exception from the requirements of this Rule 609 by filing a Form 4, Sundry Notice, for the Director's review and approval if:

(1) No Available Water Sources are located within one-half (1/2) mile of a proposed Oil and Gas Well, Multi-Well Site, or Dedicated Injection Well;

(2) The only Available Water Sources are determined to be unsuitable pursuant to subpart b.5, above. An operator seeking an exception on this ground shall document the condition of the Available Water Sources it has deemed unsuitable; or

(3) The owners of all Water Sources suitable for testing under this Rule refuse to grant access despite an operator's reasonable good faith efforts to obtain consent to conduct sampling. An operator seeking an exception on this ground shall document the efforts used to obtain access from the owners of suitable Water Sources.

(4) If the Director takes no action on the Sundry Notice within ten (10) business days of receipt, the requested exception from the requirements of this Rule 609 shall be deemed approved.

d. Timing of sampling.

(1) Initial sampling shall be conducted within 12 months prior to setting conductor pipe in a Well or the first Well on a Multi-Well Site, or commencement of drilling a Dedicated Injection Well; and

(2) Subsequent monitoring: One subsequent sampling event shall be conducted at the initial sample locations between six (6) and twelve (12) months, and a second subsequent sampling event shall be conducted between sixty (60) and seventy-two (72) months following completion of the Well or Dedicated Injection Well, or the last Well on a Multi-Well Site. Wells that are drilled and abandoned without ever producing hydrocarbons are exempt from subsequent monitoring sampling under this subpart d.

(3) Previously sampled Water Sources. In lieu of conducting the initial sampling required pursuant to subjection d.(1) or the second subsequent sampling event required pursuant to subsection d.(2), an Operator may rely on water sampling analytical results obtained from an Available Water Source within the sampling area provided:

A. The previous water sample was obtained within the 18 months preceding the initial sampling event required pursuant to subsection d.(1) or the second subsequent sampling event required pursuant to subsection d.(2); and

B. the sampling procedures, including the constituents sampled for, and the analytical procedures used for the previous water sample were substantially similar to those required pursuant to subparts e.(1) and (2), below. An operator may not rely solely on previous water sampling analytical results obtained pursuant to the subsequent sampling requirements of subsection d.(2), above, to satisfy the initial sampling requirement of subsection d.(1); and

C. the Director timely received the analytical data from the previous sampling event.

(4) The Director may require additional sampling if changes in water quality are identified during subsequent monitoring.

e. Sampling procedures and analysis.

(1) Sampling and analysis shall be conducted in conformance with an accepted industry standard as described in Rule 910.b.(2). A model Sampling and Analysis Plan ("COGCC Model SAP") shall be posted on the COGCC website, and shall be updated periodically to remain current with evolving industry standards. Sampling and analysis conducted in conformance with the COGCC Model SAP shall be deemed to satisfy the requirements of this subsection f.(1). Upon request, an operator shall provide its sampling protocol to the Director.

(2) The initial baseline testing described in this section shall include pH, specific conductance, total dissolved solids (TDS), dissolved gases (methane, ethane, propane), alkalinity (total bicarbonate and carbonate as CaCO3), major anions (bromide, chloride, fluoride, sulfate, nitrate and nitrite as N, phosphorus), major cations (calcium, iron, magnesium, manganese, potassium, sodium), other elements (barium, boron, selenium and strontium), presence of bacteria (iron related, sulfate reducing, slime forming), total petroleum hydrocarbons (TPH) and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Field observations such as odor, water color, sediment, bubbles, and effervescence shall also be documented. The location of the sampled Water Sources shall be surveyed in accordance with Rule 215.

(3) Subsequent sampling to meet the requirements of subpart d.(2) shall include total dissolved solids (TDS), dissolved gases (methane, ethane, propane), major anions (bromide, chloride, sulfate, and fluoride), major cations (potassium, sodium, magnesium, and calcium), alkalinity (total bicarbonate and carbonate as CaCO3), BTEX compounds (benzene, toluene, ethylbenzene and xylenes), and TPH.

(4) If free gas or a dissolved methane concentration greater than 1.0 milligram per liter (mg/l) is detected in a water sample, gas compositional analysis and stable isotope analysis of the methane (carbon and hydrogen – 12C, 13C, 1H and 2H) shall be performed to determine gas type. The operator shall notify the Director and the owner of the water well immediately if:

A. the test results indicated thermogenic or a mixture of thermogenic and biogenic gas;

B. the methane concentration increases by more than 5.0 mg/l between sampling periods; or

C. the methane concentration is detected at or above 10 mg/l.

(5) The operator shall notify the Director immediately if BTEX compounds or TPH are detected in a water sample.

f. **Sampling Results.** Copies of all final laboratory analytical results shall be provided to the Director and the water well owner or landowner within three (3) months of collecting the samples. The analytical results, the surveyed sample Water Source locations, and the field observations shall be submitted to the Director in an electronic data deliverable format.

(1) The Director shall make such analytical results available publicly by posting on the Commission's web site or through another means announced to the public.

(2) Upon request, the Director shall also make the analytical results and surveyed Water Source locations available to the Local Governmental Designee from the jurisdiction in which the groundwater samples were collected, in the same electronic data deliverable format in which the data was provided to the Director.

g. **Liability.** The sampling results obtained to satisfy the requirements of this Rule 609, including any changes in the constituents or concentrations of constituents present in the samples, shall not create a presumption of liability, fault, or causation against the owner or operator of a Well, Multi-Well Site, or Dedicated Injection Well who conducted the sampling, or on whose behalf sampling was conducted by a third-party. The admissibility and probity of any such sampling results in an administrative or judicial proceeding shall be determined by the presiding body according to applicable administrative, civil, or evidentiary rules.

610. GRADE 1 GAS LEAK REPORTING.

An operator must initially report a Grade 1 Gas Leak from a flowline to the Director in accordance with Rule 906 and must submit the COGCC Spill/Release Report, Form 19, document number on a Flowline Report, Form 44 for the Grade 1 Gas Leak.