

RULES AND REGULATIONS

DEFINITIONS (100 Series)

ACT shall mean the Oil and Gas Conservation Act of the State of Colorado.

ANNULAR OVER-PRESSURIZATION means a wellbore condition that occurs when fluids in the annulus between the surface casing and the intermediate or production casings are pressurized to a degree that may cause migration of confined fluids or gases out of the annular space.

ANNULUS means the space between the borehole and a casing string or between two casing strings in a well.

APPLICANT shall mean the person who institutes a proceeding before the Commission which it has standing to institute under these rules.

AQUIFER shall mean a geologic formation, group of formations or part of a formation that can both store and transmit ground water. It includes both the saturated and unsaturated zone but does not include the confining layer which separates two (2) adjacent aquifers.

AUTHORIZED DEPUTY shall mean a representative of the Director as authorized by the Commission.

AVAILABLE WATER SOURCE shall mean a water source for which the water well owner, owner of a spring, or a land owner, as applicable, has given consent for sampling and testing and has consented to having the sample data obtained made available to the public, including without limitation, being posted on the COGCC website.

BARREL shall mean 42 (U.S.) gallons at 60° F. at atmospheric pressure.

BATTERY shall mean the point of collection (tanks) and disbursement (tank, meter, LACT unit) of oil or gas from producing well(s).

BASE FLUID shall mean the continuous phase fluid type, such as water, used in a hydraulic fracturing treatment.

BEST MANAGEMENT PRACTICES (BMPs) are practices that are designed to prevent or reduce impacts caused by oil and gas operations to air, water, soil, or biological resources, and to minimize adverse impacts to public health, safety and welfare, including the environment and wildlife resources.

BRADENHEAD shall mean the annular space between the surface casing and the next smaller diameter casing string that extends up to the wellhead.

BRADENHEAD TEST AREA shall mean any area designated as a bradenhead test area by the Commission under Rule 207.b.

BREAKOUT TANK means a tank used to either relieve surges in a liquid hydrocarbon pipeline system or receive and store liquid hydrocarbons transported by a pipeline for reinjection or continued transportation by pipeline.

BUILDING UNIT shall mean a Residential Building Unit; and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

CEASE AND DESIST ORDER shall mean an order issued by the Commission or the Director pursuant to C.R.S. §34-60-121(5).

CEMENT shall be measured in 94-pound sacks.

CENTRALIZED E&P WASTE MANAGEMENT FACILITY shall mean a facility, other than a commercial disposal facility regulated by the Colorado Department of Public Health and Environment, that (1) is either used exclusively by one owner or operator or used by more than one operator under an operating agreement; and (2) is operated for a period greater than three (3) years; and (3) receives for collection, treatment, temporary storage, and/or disposal produced water, drilling fluids, completion fluids, and any other exempt E&P wastes that are generated from two or more production units or areas or from a set of commonly owned or operated leases. This definition includes oil-field naturally occurring radioactive materials (NORM) related storage, decontamination, treatment, or disposal. This definition excludes a facility that is permitted in accordance with Rule 903 pursuant to Rule 902.e.

CHEMICAL ABSTRACTS SERVICE shall mean the division of the American Chemical Society that is the globally recognized authority for information on chemical substances.

CHEMICAL ABSTRACTS SERVICE NUMBER OR CAS NUMBER shall mean the unique identification number assigned to a chemical by the chemical abstracts service.

CHEMICAL(S) shall mean any element, chemical compound, or mixture of elements or compounds that has its own specific name or identity such as a chemical abstract service number, whether or not such chemical is subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2) (2011).

CHEMICAL DISCLOSURE REGISTRY shall mean the chemical registry website known as fracfocus.org developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. If such website becomes permanently inoperable, then chemical disclosure registry shall mean another publicly accessible information website that is designated by the Commission.

CHEMICAL FAMILY shall mean a group of chemicals that share similar chemical properties and have a common general name.

CHEMICAL INVENTORY shall mean a list of the Chemical Products (including Material Safety Data Sheets) brought to a well site for use downhole during drilling, completion, and workover operations, including fracture stimulations, and the maximum capacity of fuel stored on the oil and gas location during those operations. The Chemical Inventory shall include how much of the Chemical Product was used, how it was used, and when it was used.

CHEMICAL PRODUCT shall mean any substance consisting of one or more constituent chemicals that is marketed or sold as a commodity. Chemical Products shall not include substances that are known to be entirely benign, innocuous, or otherwise harmless, such as sand, walnut shells, and similar natural substances.

CHILD CARE CENTER means a child care center as defined in § 26-6-102(5), C.R.S., that is in operation at the time of the pre-application notice pursuant to Rule 305.a.(4). A child care center will include any associated outdoor play areas adjacent to or directly accessible from the center and is fenced or has natural barriers, such as hedges or stationary walls, at least four (4) feet high demarcating its boundary.

CLASSIFIED WATER SUPPLY SEGMENT shall mean perennial or intermittent streams, which are surface waters classified as being suitable or intended to become suitable for potable water supplies by the Colorado Water Quality Control Commission, pursuant to the Basic Standards and Methodologies for Surface Water Regulations (5 C.C.R. 1002-31).

COMMERCIAL DISPOSAL WELL FACILITY shall mean a facility whose primary objective is disposal of Class II waste from a third party for financial profit.

COMMISSION mean the Oil and Gas Conservation Commission of the State of Colorado.

COMPLETION. An oil well shall be considered completed when the first new oil is produced through wellhead equipment into lease tanks from the ultimate producing interval after the production string has been run. A gas well shall be considered completed when the well is capable of producing gas through wellhead equipment from the ultimate producing zone after the production string has been run. A dry hole shall be considered completed when all provisions of plugging are complied with as set out in these rules. Any well not previously defined as an oil or gas well, shall be considered completed ninety (90) days after reaching total depth. If approved by the Director, a well that requires extensive testing shall be considered completed when the drilling rig is released or six months after reaching total depth, whichever is later.

COMPREHENSIVE DRILLING PLAN shall mean a plan created by one or more operator(s) covering future oil and gas operations in a defined geographic area within a geologic basin. The Plan may (a) identify natural features of the geographic area, including vegetation, wildlife resources, and other attributes of the physical environment; (b) describe the operator's future oil and gas operations in the area; (c) identify potential impacts from such operations; (d) develop agreed-upon measures to avoid, minimize, and mitigate the identified potential impacts; and (e) include other relevant information.

CONTAINER shall mean any portable device in which a hazardous material is stored, transported, treated, disposed of, or otherwise handled. Examples include, but are not limited to, drums, barrels, totes, carboys, and bottles.

CORNERING AND CONTIGUOUS UNITS when used in reference to an exception location shall mean those lands which make up the unit(s) immediately adjacent to and toward which a well is encroaching upon established setbacks.

CROP LAND shall mean lands which are cultivated, mechanically or manually harvested, or irrigated for vegetative agricultural production.

CRUDE OIL TRANSFER LINE means a piping system that is not regulated or subject to regulation by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to 49 C.F.R. § 195 Subpart A, and that transfers crude oil, crude oil emulsion or condensate from more than one well site or production facility to a production facility with permanent storage capacity greater than 25,000 barrels of crude oil or condensate or a PHMSA gathering system. 49 C.F.R. § 195 Subpart A, in existence as of the date of this regulation and not including later amendments, 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, 49 C.F.R. § 195 Subpart A may be found at <https://www.phmsa.dot.gov>.

CUBIC FOOT of gas shall mean the volume of gas contained in one cubic foot of space at a standard pressure base and a standard temperature base. The standard pressure base shall be 14.73 psia, and the standard temperature base shall be 60° Fahrenheit.

D–J BASIN FOX HILLS PROTECTION AREA shall mean that area of the State consisting of Townships 5 South through Townships 5 North, Ranges 58 West through 70 West, and Township 6 South, Ranges 65 West through 70 West.

DAY shall mean calendar days.

DEDICATED INJECTION WELL shall mean any Class II wells used for the exclusive purpose of injecting fluids or gas from the surface for enhanced oil recovery or the disposal of E&P wastes. A gas storage well is not a dedicated injection well.

DESIGNATED AGENT, when used herein shall mean the designated representative of any producer, operator, transporter, refiner, gasoline or other extraction plant operator, or initial purchaser.

DESIGNATED SETBACK LOCATION shall mean any Oil and Gas Location upon which any Well or Production Facility is or will be situated within, a Buffer Zone Setback (1,000 feet), or an Exception Zone Setback (500 feet), or within one thousand (1,000) feet of a High Occupancy Building Unit or a Designated Outside Activity Area, as referenced in Rule 604. The measurement for determining any Designated Setback Location shall be the shortest distance between any existing or proposed Well or Production Facility on the Oil and Gas Location and the nearest edge or corner of any Building Unit, nearest edge or corner of any High Occupancy Building Unit, or nearest boundary of any Designated Outside Activity Area.

DESIGNATED OUTSIDE ACTIVITY AREA: Upon Application and Hearing, the Commission, in its discretion, may establish a Designated Outside Activity Area (DOAA) for:

- (i) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government seeks to have established as a Designated Outside Activity Area; or
- (ii) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly where ingress to, or egress from the venue could be impeded in the event of an emergency condition at an Oil and Gas Location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

The Commission shall determine whether to establish a Designated Outside Activity Area and, if so, the appropriate boundaries for the DOAA based on the totality of circumstances and consistent with the purposes of the Oil and Gas Conservation Act.

DIRECTOR shall mean the Director of the Oil and Gas Conservation Commission of the State of Colorado or any member of the Director's staff authorized to represent the Director.

DOMESTIC GAS WELL shall mean a gas well that produces solely for the use of the surface owner. The gas produced cannot be sold, traded or bartered.

DOMESTIC TAP means an individual gas service line directly connected to a flowline.

DRILLING PITS shall mean those pits used during drilling operations and initial completion of a well, and include:

ANCILLARY PITS used to contain fluids during drilling operations and initial completion procedures, such as circulation pits and water storage pits.

COMPLETION PITS used to contain fluids and solids produced during initial completion procedures, and not originally constructed for use in drilling operations.

FLOWBACK PITS used to contain fluids and solids produced during initial completion procedures.

RESERVE PITS used to store drilling fluids for use in drilling operations or to contain E&P waste generated during drilling operations and initial completion procedures.

EMERGENCY ORDER shall mean an order issued by the Commission pursuant to C.R.S. §34-60-108(3).

EMERGENCY SITUATION for purposes of C.R.S. §34-60-121(5) and the rules promulgated thereunder shall mean a fact situation which presents an immediate danger to public health, safety or welfare.

EXPLORATION AND PRODUCTION WASTE (E&P WASTE) shall mean those wastes associated with operations to locate or remove oil or gas from the ground or to remove impurities from such substances and which are uniquely associated with and intrinsic to oil and gas exploration, development, or production operations that are exempt from regulation under Subtitle C of the Resource Conservation and Recovery Act (RCRA), 42 USC Sections 6921, et seq. For natural gas, primary field operations include those production-related activities at or near the wellhead and at the gas plant (regardless of whether or not the gas plant is at or near the wellhead), but prior to transport of the natural gas from the gas plant to market. In addition, uniquely associated wastes derived from the production stream along the gas plant feeder pipelines are considered E&P wastes, even if a change of custody in the natural gas has occurred between the wellhead and the gas plant. In addition, wastes uniquely associated with the operations to recover natural gas from underground storage fields are considered to be E&P waste.

FIELD shall mean the general area which is underlaid or appears to be underlaid by at least one pool; and “field” shall include the underground reservoir or reservoirs containing oil or gas or both. The words “field” and “pool” mean the same thing when only one underground reservoir is involved; however, “field”, unlike “pool”, may relate to two or more pools.

FINANCIAL ASSURANCE shall mean a surety bond, cash collateral, certificate of deposit, letter of credit, sinking fund, escrow account, lien on property, security interest, guarantee, or other instrument or method in favor of and acceptable to the Commission. With regard to third party liability concerns related to public health, safety and welfare, the term encompasses general liability insurance.

FIRST AID TREATMENT shall mean using a non-prescription medication at non-prescription strength; administering tetanus immunizations; cleaning, flushing, or soaking wounds on the surface of the skin; using wound coverings such as bandages, gauze pads, or butterfly bandages; using hot or cold therapy; using any non-rigid means of support such as elastic bandages; using temporary immobilization devices when transporting an accident victim; drilling of a fingernail or toenail to relieve pressure or draining fluid from a blister; using eye patches; removing foreign bodies from the eye using only irrigation or a cotton swab; removing splinters or foreign material from areas other than the eye by irrigation, tweezers, cotton swabs, or other simple means; using finger guards; using massages; or drinking fluids for the relief of heat stress.

FLOODPLAIN shall mean any area of land officially declared to be in a 100 year floodplain by any Colorado Municipality, Colorado County, State Agency, or Federal Agency.

FLOWLINE means a segment of pipe transferring oil, gas, or condensate between a wellhead and processing equipment to the load point or point of delivery to a U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration or Colorado Public Utilities Commission regulated gathering line or a segment of pipe transferring produced water between a wellhead and the point of disposal, discharge, or loading. This definition of flowline does not include a gathering line. The different types of flowlines are:

Wellhead Line means a flowline that transfers well production fluids from an oil or gas well to process equipment (e.g., separator, production separator, tank, heater treater), not including pre-conditioning equipment such as sand traps and line heaters, which do not materially reduce line pressure.

Production Piping means a segment of pipe that transfers well production fluids from a wellhead line or production equipment to a gathering line or storage vessel and includes the following:

Production Line means a flowline connecting a separator to a meter, LACT, or gathering line;

Dump Line means a flowline that transfers produced water, crude oil, or condensate to a storage tank, pit, or process vessel and operates at or near atmospheric pressure at the flowline’s outlet;

Manifold Piping means a flowline that transfers fluids into a piece of production facility equipment from lines that have been joined together to comingle fluids; and

Process Piping means all other piping that is integral to oil and gas exploration and production related to an individual piece or a set of production facility equipment pieces.

Off-Location Flowline means a flowline transferring produced fluids (crude oil, natural gas, condensate, or produced water) from an oil and gas location to a production facility, injection facility, pit, or discharge point that is not on the same oil and gas location. This definition also includes flowlines connecting to gas compressors or gas plants.

Peripheral Piping means a flowline that transfers fluids such as fuel gas, lift gas, instrument gas, or power fluids between oil and gas facilities for lease use.

Produced Water Flowline means a flowline on the oil and gas location used to transfer produced water for treatment, storage, discharge, injection or reuse for oil and gas operations. A segment of pipe transferring only freshwater is not a flowline.

Flowline Exclusion. A line that would otherwise meet any of the foregoing descriptions will not be considered a flowline if all of the following are satisfied:

- the operator prospectively marks and tags the line as a support line;
- the line is not integral to production;
- the line is used infrequently to service or maintain production equipment;
- the line does not hold a constant pressure; and
- the line is isolated from a pressure source when not in use.

FLOWLINE SYSTEM means a network of off-location flowlines.

FUTURE SCHOOL FACILITY means a school facility that is not yet built, but that the school or school governing body plans to build and use for students and staff within three years of the date the school or school governing body receives a pre-application notice pursuant to Rule 305.a.(4). In order to be considered a future school facility, the following requirements must be satisfied:

- For public, non-charter schools, the school governing body must affirm the nature, timing, and location of the future school facility in writing; or
- For charter schools, the school must have been approved by the appropriate school district or the State Charter School Institute, § 22-30.5-505, C.R.S., at the time it receives a pre-application notice pursuant to Rule 305.a.(4), and the school governing body must affirm the nature, timing, and location of the future school facility in writing; or
- For private schools, the school governing body must be registered with the Office of the Colorado Secretary of State at the time it receives a pre-application notice pursuant to Rule 305.a.(4), and must provide documentation proving its registration with the Office of the Colorado Secretary of State, its tax exempt status, and its submitted plans to the relevant local government building and planning office.

GAS FACILITY shall mean those facilities that process or compress natural gas after production-related activities which are conducted at or near the wellhead and prior to a point where the gas is transferred to a carrier for transport.

GAS STORAGE WELL means any well drilled for the injection, withdrawal, production, observation, or monitoring of natural gas stored in underground formations. The fact that any such well is used incidentally for the production of native gas or the enhanced recovery of native hydrocarbons shall not affect its status as a gas storage well.

GAS WELL shall mean a well, the principal production of which at the mouth of the well is gas, as defined by the Act.

GATHERING LINE means a gathering pipeline or system as defined by the Colorado Public Utilities Commission, Regulation No. 4, 4 C.C.R. 723-4901, Part 4, (4 C.C.R. 723-4901) or a pipeline regulated by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration pursuant to 49 C.F.R. §§ 195.2 or 192.8. 49 C.F.R. §§ 195.2 or 192.8 and 4 C.C.R. 723-4901 in existence as of the date of this regulation and does not include later amendments. 49 C.F.R. §§ 195.2 or 192.8 and 4 C.C.R. 723-4901 are 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, 49 C.F.R. §§ 195.2 or 192.8 may be found at <https://www.phmsa.dot.gov>, and 4 C.C.R. 723-4901 may be found at <https://www.sos.state.co.us>.

GRADE 1 GAS LEAK means a gas leak that ignites or represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

GREEN COMPLETION PRACTICES shall mean those practices intended to reduce emissions of salable gas and condensate vapors during cleanout and flowback operations prior to the well being placed on production.

GROUNDWATER means subsurface waters in a zone of saturation which are or can be brought to the surface of the ground or to surface waters through wells, springs, seeps or other discharge areas.

HEALTH PROFESSIONAL shall mean a physician, physician assistant, nurse practitioner, registered nurse, or emergency medical technician licensed by the State of Colorado.

HIGH OCCUPANCY BUILDING UNIT means:

- any School, Nursing Facility as defined in § 25.5-4-103(14), C.R.S., Hospital, Life Care Institutions as defined in § 12-13-101, C.R.S., or Correctional Facility as defined in § 17-1-102(1.7), C.R.S., provided the facility or institution regularly serves 50 or more persons; or
- an operating Child Care Center as defined in § 26-6-102(1.5), C.R.S.

HORIZONTAL WELL shall mean a well which is drilled in such a way that the wellbore deviates laterally to an approximate horizontal orientation within the target formation with the length of the horizontal component of the wellbore extending at least one hundred feet (100') in the target formation, measured from the initial point of penetration into the target formation through the terminus of the horizontal component of the wellbore in the same common source of hydrocarbon supply.

HYDRAULIC FRACTURING ADDITIVE shall mean any chemical substance or combination of substances, including any chemicals and proppants, that is intentionally added to a base fluid for purposes of preparing a hydraulic fracturing fluid for treatment of a well.

HYDRAULIC FRACTURING FLUID shall mean the fluid, including the applicable base fluid and all hydraulic fracturing additives, used to perform a hydraulic fracturing treatment.

HYDRAULIC FRACTURING TREATMENT shall mean all stages of the treatment of a well by the application of hydraulic fracturing fluid under pressure that is expressly designed to initiate or propagate fractures in a target geologic formation to enhance production of oil and natural gas.

INACTIVE WELL shall mean any shut-in well from which no production has been sold for a period of twelve (12) consecutive months; any well which has been temporarily abandoned for a period of six (6) consecutive months; or, any injection well which has not been utilized for a period of twelve (12) consecutive months.

INDIAN LANDS shall mean those lands located within the exterior boundaries of a defined Indian reservation, including allotted Indian lands, in which the legal, beneficial, or restricted ownership of the

underlying oil, gas, or coal bed methane or of the right to explore for and develop the oil, gas, or coal bed methane belongs to or is leased from an Indian tribe.

INTERVENOR shall mean a local government, or the Colorado Department of Public Health and Environment intervening solely to raise environmental or public health, safety and welfare concerns, or the Colorado Parks and Wildlife intervening solely to raise wildlife resource concerns, in which case the intervention shall be granted of right, or a person who has timely filed an intervention in a relevant proceeding and has demonstrated to the satisfaction of the Commission that the intervention will serve the public interest, in which case the person may be recognized as a permissive intervenor at the Commission's discretion.

ISOLATION VALVE means a valve closed to the atmosphere that stops fluid flow and isolates a segment in a flowline or crude oil transfer line.

LACT ("Lease Automated Custody Transfer") shall mean the transfer of produced crude oil or condensate, after processing or treating in the producing operations, from storage vessels or automated transfer facilities to pipelines or any other form of transportation.

LAND APPLICATION shall mean the disposal method by which E&P waste is spread upon or sometimes mixed into soils.

LAND TREATMENT shall mean the treatment method by which E&P waste is applied to soils and treated to result in a reduction of hydrocarbon concentration by biodegradation and other natural attenuation processes. Land treatment may be enhanced by tilling, disking, aerating, composting and the addition of nutrients or microbes.

LARGE UMA FACILITY shall mean any Oil and Gas Location proposed to be located in an Urban Mitigation Area and on which: (1) the operator proposes to drill 8 or more new wells; or (2) the cumulative new and existing on-site storage capacity for produced hydrocarbons exceeds 4,000 barrels.

LOCAL GOVERNMENT means a county, home rule or statutory city, town, territorial charter city or city and county, or any special district established pursuant to the Special District Act, C.R.S. §32-1-101 to 32-1-1807 (2013).

LOCAL GOVERNMENTAL DESIGNEE means the office designated to receive, on behalf of the local government, copies of all documents required to be filed with the local governmental designee pursuant to these rules.

LOCKOUT means installing a device, such as a blind plug, blank flange, or bolted slip blind that prevents operation of an energy-isolating device, such as a valve, and ensures the equipment cannot be operated until the lockout device is removed.

LOG or WELL LOG shall mean a systematic detailed record of formations encountered in the drilling of a well.

MATERIAL SAFETY DATA SHEET (MSDS) shall mean the most current version of written or printed material concerning a hazardous chemical.

MAXIMUM ANTICIPATED OPERATING PRESSURE means the highest operational pressure the operator expects to apply to a flowline when in service.

MEDICAL TREATMENT shall mean the management and care of a patient to combat a disease or disorder. An injury or illness is an abnormal condition or disorder. Injuries include cases such as, but not limited to, a cut, fracture, sprain, or amputation. Illnesses include both acute and chronic illnesses, such as, but not limited to, a skin disease, respiratory disorder, or poisoning. "Medical treatment" includes situations where

a physician or other licensed health care professional recommends medical treatment but the employee does not follow the recommendation. "Medical treatment" does not include first aid treatment, as defined herein, visits to a physician or other licensed health care professional solely for observation or counseling, or the conduct of diagnostic procedures such as x-rays and blood tests, including the administration of prescription medications used solely for diagnostic purposes.

MINIMIZE ADVERSE IMPACTS shall mean, wherever reasonably practicable, to avoid adverse impacts to wildlife resources or significant adverse impacts to the environment from oil and gas operations, minimize the extent and severity of those impacts that cannot be avoided, mitigate the effects of unavoidable remaining impacts, and take into consideration cost-effectiveness and technical feasibility with regard to actions and decisions taken to minimize adverse impacts.

MINIMIZE EROSION shall mean implementing best management practices that are selected based on site-specific conditions and maintained to reduce erosion. Representative erosion control practices include, but are not limited to, revegetation of disturbed areas, mulching, berms, diversion dikes, surface roughening, slope drains, check dams, and other comparable measures.

MITIGATION with respect to wildlife resources shall mean measures that compensate for adverse impacts to such resources, including, as appropriate, habitat enhancement, on-site habitat mitigation, off-site habitat mitigation, or mitigation banking.

MULTI-WELL PITS shall mean pits used for treatment, storage, recycling, reuse, or disposal of E&P wastes generated from more than one (1) well that do not constitute a centralized E&P waste management facility and that will be in use for no more than three (3) years.

MULTI-WELL SITE shall mean a common well pad from which multiple wells may be drilled to various bottomhole locations.

NON-CROP LAND shall mean all lands which are not defined as crop land, including range land.

OIL AND GAS FACILITY means equipment or improvements used or installed at an oil and gas location for the exploration, production, withdrawal, treatment, or processing of crude oil, condensate, E&P waste, or gas.

OIL AND GAS LOCATION shall mean a definable area where an operator has disturbed or intends to disturb the land surface in order to locate an oil and gas facility.

OIL AND GAS OPERATIONS means exploring for oil and gas, including conducting seismic operations and the drilling of test bores; siting, drilling, deepening, recompleting, reworking, or abandoning a well; producing operations related to any well, including installing flowlines; the generating, transporting, storing, treating, or disposing exploration and production wastes; and any constructing, site preparing, or reclaiming activities associated with such operations.

OIL WELL shall mean a well, the principal production of which at the mouth of the well is oil, as defined by the Act.

OPERATOR shall mean any person who exercises the right to control the conduct of oil and gas operations.

ORDINARY HIGH-WATER LINE shall mean the line that water impresses on the land by covering it for sufficient periods to cause physical characteristics that distinguish the area below the line from the area above it. Characteristics of the area below the line include, when appropriate, but are not limited to, deprivation of the soil of substantially all terrestrial vegetation and destruction of its agricultural vegetative value. A flood plain adjacent to surface waters is not considered to lie within the surface waters' ordinary high-water line.

ORPHAN WELL shall mean a well for which no owner or operator can be found, or where such owner or operator is unwilling or unable to plug and abandon such well.

ORPHANED SITE shall mean a site, where a significant adverse environmental impact may be or has been caused by oil and gas operations for which no responsible party can be found, or where such responsible party is unwilling or unable to mitigate such impact.

OUT OF SERVICE LOCKS AND TAGS (OOSLAT) means locks and tags that an operator applies when equipment is in pre-commissioned status, is placed in an out of service status, or is in the process of abandonment. Out of service locks and tags must be visibly different from lock out and tag out devices used during repair or maintenance of the equipment.

OWNER shall mean the person who has the right to drill into and produce from a pool and to appropriate the oil or gas produced therefrom either for such owner or others or for such owner and others, including owners of a well capable of producing oil or gas, or both.

PETITION FOR REVIEW shall mean the written request filed by a Complainant for Commission review of the Director's resolution of a complaint filed on a Form 18, Complaint Report.

PIPELINE means a flowline, crude oil transfer line or gathering line as defined in these Rules.

PIT shall mean any natural or man-made depression in the ground used for oil or gas exploration or production purposes. Pit does not include steel, fiberglass, concrete or other similar vessels which do not release their contents to surrounding soils.

PLUGGING AND ABANDONMENT means the cementing of a well, the removal of its associated production facilities, the abandonment of its flowline(s), and the remediation and reclamation of the wellsite.

POINT OF COMPLIANCE means one or more points or locations at which compliance with applicable groundwater standards established under Water Quality Control Commission Basic Standards for Groundwater, Section 3.11.4, must be achieved.

POLLUTION means man-made or man-induced contamination or other degradation of the physical, chemical, biological, or radiological integrity of air, water, soil, or biological resource.

The words **POOL, PERSON, OWNER, PRODUCER, OIL, GAS, WASTE, CORRELATIVE RIGHTS and COMMON SOURCE OF SUPPLY** are defined by the Act, and said definitions are hereby adopted in these Rules and Regulations. The word "operator" is used in these rules and regulations and accompanying forms interchangeably with the same meaning as the term "owner" except in Rules 301, 323, 401 and 530 where the word "operator" is used to identify the persons designated by the owner or owners to perform the functions covered by those rules.

POTENTIAL FLOW ZONES means formations or zones which have the potential to flow against or are unable to support the hydrostatic pressure exerted by fluid in the well.

PRODUCED AND MARKETED. These words, as used in the Act, shall mean, when oil shall have left the lease tank battery or when natural gas shall have passed the metering point and entered into the stream of commerce as its first step toward the ultimate consumer.

PRODUCED WATER TRANSFER SYSTEM means a system of off-location flowlines that transports produced water generated at more than one well site.

PRODUCTION FACILITY means any storage, separation, treating, dehydration, artificial lift, power supply, compression, pumping, metering, monitoring, flowline, and other equipment directly associated with a well.

PRODUCTION PITS means pits used after drilling operations and initial completion of a well, including pits related to produced water flowlines or associated with E&P waste from gas gathering, processing and storage facilities, which constitute:

SKIMMING/SETTLING PITS used to provide retention time for settling of solids and separation of residual oil for the purposes of recovering the oil or fluid.

PRODUCED WATER PITS used to temporarily store produced water prior to injection for enhanced recovery or disposal, off-site transport, or surface-water discharge.

PERCOLATION PITS used to dispose of produced water by percolation and evaporation through the bottom or sides of the pits into surrounding soils.

EVAPORATION PITS used to contain produced waters which evaporate into the atmosphere by natural thermal forces.

PROPPANT shall mean sand or any natural or man-made material that is used in a hydraulic fracturing treatment to prop open the artificially created or enhanced fractures once the treatment is completed.

PROTESTANT shall mean a person who has timely filed a protest in a relevant proceeding and has demonstrated to the Commission's satisfaction that the person filing the protest would be directly and adversely affected or aggrieved by the Commission's ruling in the proceeding, and that any injury or threat of injury sustained would be entitled to legal protection under the act.

PUBLIC WATER SYSTEM shall mean those systems listed in Appendix VI to these Rules. These systems provide to the public water for human consumption through pipes or other constructed conveyances, if such systems have at least fifteen (15) service connections or regularly serve an average of at least twenty-five (25) individuals daily at least sixty (60) days out of the year. Such definition includes:

- (i) Any collection, treatment, storage, and distribution facilities under control of the operator of such system and used primarily in connection with such system.
- (ii) Any collection or pretreatment storage facilities not under such control, which are used primarily in connection with such system.

The definition of "Public Water System" for purposes of Rule 317B does not include any "special irrigation district," as defined in Colorado Primary Drinking Water Regulations (5 C.C.R. 1003.1).

RECLAMATION shall mean the process of returning or restoring the surface of disturbed land as nearly as practicable to its condition prior to the commencement of oil and gas operations or to landowner specifications with an approved variance under Rule 502.b.

REFERENCE AREA shall mean an area either (1) on a portion of the site that will not be disturbed by oil and gas operations, if that is the desired final reclamation; or (2) another location that is undisturbed by oil and gas operations and proximate and similar to a proposed oil and gas location in terms of vegetative potential and management, owned by a person who agrees to allow periodic access to it by the Director and the operator for the purpose of providing baseline information for reclamation standards, and intended to reflect the desired final reclamation.

REGULATORY COMPLIANCE PROGRAM shall mean a documented program that evaluates an operator's operations on a scheduled basis to determine compliance with regulatory requirements, especially those required by the Act, or Commission rules, orders, or permits. Such a program should include written procedures, a recognized authority within the organization, and designated personnel whose purpose is monitoring and maintaining compliance with applicable regulatory requirements, and documentation of results of evaluations conducted.

RELEASE shall mean any unauthorized discharge of E&P waste to the environment over time.

RELEVANT LOCAL GOVERNMENT means a local government with land use authority over the application lands.

REMEDIATION shall mean the process of reducing the concentration of a contaminant or contaminants in water or soil to the extent necessary to ensure compliance with the concentration levels in Table 910-1 and other applicable ground water standards and classifications.

RESERVE PITS shall mean those pits used to store drilling fluids for use in drilling operations or to contain E&P waste generated during drilling operations and initial completion procedures.

RESIDENTIAL BUILDING UNIT means a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes.

RESPONDENT shall mean a party against whom a proceeding is instituted, or a protestant who protests the granting of the relief sought in the application as provided in Rule 509.

RESPONSIBLE PARTY shall mean an owner or operator who conducts an oil and gas operation in a manner which is in contravention of any then-applicable provision of the Act, or of any rule, regulation, or order of the Commission, or of any permit, that threatens to cause, or actually causes, a significant adverse environmental impact to any air, water, soil, or biological resource. RESPONSIBLE PARTY includes any person who disposes of any other waste by mixing it with exploration and production waste so as to threaten to cause, or actually cause, a significant adverse environmental impact to any air, water, soil, or biological resource.

RESTRICTED SURFACE OCCUPANCY AREA shall mean the following:

- rocky mountain bighorn sheep production areas;
- desert bighorn sheep production areas;
- areas within 0.6 miles of any greater sage-grouse, Gunnison sage-grouse, and lesser prairie chicken leks (strutting and booming grounds);
- areas within 0.4 miles of any Columbian sharp-tailed grouse or plains sharp-tailed grouse leks (strutting grounds);
- areas within 1/4 mile of active Bald Eagle nest sites, Golden Eagle nest sites, or Osprey nest sites;
- areas within 1/2 mile of active Ferruginous Hawk nest sites, Northern Goshawk nest sites, Peregrine Falcon nest sites, or Prairie Falcon nest sites;
- areas located within 300 feet of the ordinary high-water mark of any stream segment located within designated Cutthroat Trout habitat; and
- areas within 300 feet of the ordinary high-water mark of a stream or lake designated by the Colorado Parks and Wildlife as “Gold Medal.”

Maps showing and spatial data identifying the individual and combined extents of the above habitat areas shall be maintained by the Commission and made available on the Commission website, and copies of the

maps shall be attached as Appendix VII. The extent of restricted surface occupancy areas is subject to update on a periodic but no more frequent than annual basis and may be modified only through the Commission's rulemaking process, as provided in Rule 529. Any changes to restricted surface occupancy areas shall not affect Form 2As or Comprehensive Drilling Plans approved prior to the effective date of such changes.

RISER means the component of a flowline transitioning from below grade to above grade.

SCHOOL means any operating Public School as defined in § 22-7-703(4), C.R.S., including any Charter School as defined in § 22-30.5-103(2), C.R.S., or § 22-30.5-502(6), C.R.S., or Private School as defined in § 22-30.5-103(6.5), C.R.S.

SCHOOL FACILITY means any discrete facility or area, whether indoor or outdoor, associated with a school, that students use commonly as part of their curriculum or extracurricular activities. A school facility is either adjacent to or owned by the school or school governing body, and the school or school governing body has the legal right to use the school facility at its discretion. The definition includes Future School Facility.

SCHOOL GOVERNING BODY means the school district board or board of directors for public schools or the board of trustees, board of directors, or any other body or person charged with administering a private school or group of private schools, or any body or person responsible for administering or operating a child care center. A school governing body may delegate its rights under these rules, in writing, to a superintendent or other staff member, or to a principal or senior administrator of a school that is in proximity to the proposed oil and gas location.

SEISMIC OPERATIONS shall mean all activities associated with acquisition of seismic data including but not limited to surveying, shothole drilling, recording, shothole plugging and reclamation.

SENSITIVE AREA is an area vulnerable to potential significant adverse groundwater impacts, due to factors such as the presence of shallow groundwater or pathways for communication with deeper groundwater; proximity to surface water, including lakes, rivers, perennial or intermittent streams, creeks, irrigation canals, and wetlands. Additionally, areas classified for domestic use by the Water Quality Control Commission, local (water supply) wellhead protection areas, areas within 1/8 mile of a domestic water well, areas within 1/4 mile of a public water supply well, ground water basins designated by the Colorado Ground Water Commission, and surface water supply areas are sensitive areas.

SENSITIVE WILDLIFE HABITAT shall mean:

- mule deer critical winter range (being both mule deer winter concentration areas (that part of the winter range where densities are at least 200% of the surrounding winter range density during the same period used to define winter range in 5 out of 10 winters), and mule deer severe winter range (that part of the winter range where 90% of the individuals are located during the average 5 winters out of 10 from the first heavy snowfall to spring green-up)) (west of Interstate 25 and excluding Las Animas County);
- elk winter concentration areas (west of Interstate 25 and excluding Las Animas County);
- pronghorn antelope winter concentration areas (west of Interstate 25);
- bighorn sheep winter range;
- elk production areas (being that part of the overall range occupied by the females for calving) (west of Interstate 25 and excluding Las Animas County);

- Columbian sharp-tailed grouse and plains sharp-tailed grouse production areas (being an area that contains 80% of nesting and brood rearing habitat for any identified population);
- greater sage-grouse and Gunnison sage-grouse production areas (being an area that contains 80% of nesting and brood rearing habitat for any population identified in the Colorado Greater Sage-Grouse Conservation Plan (CPW, 2008) or the Gunnison Sage-Grouse Range-Wide Conservation Plan (May 2005), respectively);
- lesser prairie chicken production areas (being an area that includes 80% of nesting and brood rearing habitat);
- black-footed ferret release areas;
- Bald Eagle nest sites and winter night roost sites; and
- Golden Eagle nest sites.

Maps showing and spatial data identifying the individual and combined extents of the above habitat areas shall be maintained by the Commission and made available on the Commission website, and copies of the maps shall be attached as Appendix VIII. The extent of sensitive wildlife habitat is subject to update on a periodic but no more frequent than biennial basis and may be modified only through the Commission's rulemaking procedures, as provided in Rule 529. Any modifications to sensitive wildlife habitat shall not affect Form 2As or Comprehensive Drilling Plans approved prior to the effective date of such changes.

SHUT-IN WELL shall mean a well which is capable of production or injection by opening valves, activating existing equipment or supplying a power source.

SIMULTANEOUS INJECTION WELL shall mean any well in which water produced from oil and gas producing zones is injected into a lower injection zone and such water production is not brought to the surface.

SOLID WASTE shall mean any garbage, refuse, sludge from a waste treatment plant, water supply plant, air pollution control facility, or other discarded material; including solid, liquid, semisolid, or contained gaseous material resulting from industrial operations, commercial operations, or community activities. Solid waste does not include any solid or dissolved materials in domestic sewage, or agricultural wastes, or solid or dissolved materials in irrigation return flows, or industrial discharges which are point sources subject to permits under the provisions of the Colorado Water Quality Control Act, Title 25, Article 8, C.R.S. or materials handled at facilities licensed pursuant to the provisions on radiation control in Title 25, Article 11, C.R.S. Solid waste does not include: (a) materials handled at facilities licensed pursuant to the provisions on radiation control in Title 25, Article 11, C.R.S.; (b) excluded scrap metal that is being recycled; or (c) shredded circuit boards that are being recycled.

SOLID WASTE DISPOSAL shall mean the storage, treatment, utilization, processing, or final disposal of solid wastes.

SPECIAL FIELD RULES shall mean those rules promulgated for and which are limited in their application to individual pools or fields within the State of Colorado.

SPECIAL PURPOSE PITS means pits used in oil and gas operations, including pits related to produced water flowlines or associated with E&P waste from gas gathering, processing and storage facilities, which constitute:

BLOWDOWN PITS used to collect material resulting from, including but not limited to, the emptying or depressurizing of wells, vessels, or flowlines, or E&P waste from gathering systems.

FLARE PITS used exclusively for flaring gas.

EMERGENCY PITS used to contain liquids during an initial phase of emergency response operations related to a spill/release or process upset conditions.

BASIC SEDIMENT/TANK BOTTOM PITS used to temporarily store or treat the extraneous materials in crude oil which may settle to the bottoms of tanks or production vessels and which may contain residual oil.

WORKOVER PITS used to contain liquids during the performance of remedial operations on a producing well in an effort to increase production.

PLUGGING PITS used for containment of fluids encountered during the plugging process.

SPILL shall mean any unauthorized sudden discharge of E&P waste to the environment.

STIMULATION means a treatment performed to restore or enhance the productivity of the formation and falls into two main types of treatment: hydraulic fracturing treatments performed above the reservoir fracture pressure, and matrix treatments performed below the reservoir fracture pressure.

STORMWATER RUNOFF shall mean rain or snowmelt that flows over land and does not percolate into soil and includes stormwater that flows onto and off of an oil and gas location or facility.

STRATIGRAPHIC WELL means a well drilled for stratigraphic information only. Wells drilled in a delineated field to known productive horizons shall not be classified as "stratigraphic." Neither the term "well" nor "stratigraphic well" shall include seismic holes drilled for the purpose of obtaining geophysical information only.

SURFACE OWNER shall mean any person owning all or part of the surface of land upon which oil and gas operations are conducted, as shown by the tax records of the county in which the tract of land is situated, or any person with such rights under a recorded contract to purchase.

SURFACE USE AGREEMENT shall mean any agreement in the nature of a contract or other form of document binding on the Operator, including any lease, damage agreement, waiver, local government approval or permit, or other form of agreement, which governs the operator's activities on the surface in relation to locating a Well, Multi-Well Site, Production Facility, pipeline or any other Oil and Gas Facility that supports oil and gas development located on the Surface Owner's property.

SURFACE WATER INTAKE shall mean the works or structures at the head of a conduit through which water is diverted from a classified water supply segment and/or source (e.g., river or lake) into the treatment plant.

SURFACE WATER SUPPLY AREA shall mean the classified water supply segments within five (5) stream miles upstream of a surface water intake on a classified water supply segment. Surface Water Supply Areas shall be identified on the Public Water System Surface Water Supply Area Map or through use of the Public Water System Surface Water Supply Area Applicability Determination Tool described in Rule 317B.b.

SUSPENDED OPERATIONS WELL shall mean a well in which drilling operations have been suspended prior to reaching total depth and at least one casing string (the surface casing) has been set and cemented in the wellbore. This definition does not include wells in which only conductor pipe has been set, and the surface hole has not been spud.

TAGOUT means securely fastening a tagout device to an energy-isolating device, such as a valve, to indicate that the energy-isolating device and the equipment being controlled may not be operated until the tagout device is removed.

TAGOUT DEVICE means a prominent warning device, such as a tag, that will not deteriorate or become illegible with exposure to weather conditions or wet and damp locations. The tagout device must include: an instruction to not operate the equipment; the date the tag was applied; the date of the last successful integrity test; and the reason for tagging out the equipment.

TANK shall mean a stationary vessel constructed of non-earthen materials (e.g concrete, steel, plastic) that provides structural support and is designed and operated to store produced fluids or E&P waste. Examples include, but are not limited to, condensate tanks, crude oil tanks, produced water tanks, and gun barrels. Exclusions include Containers and process vessels such as separators, heater treaters, free water knockouts, and slug catchers.

TEMPORARILY ABANDONED WELL shall mean a well that has all downhole completed intervals isolated with a plug set above the highest perforation such that the well cannot produce without removing a plug or a well which is incapable of production or injection without the addition of one or more pieces of wellhead or other equipment, including valves, tubing, rods, pumps, heater-treaters, separators, dehydrators, compressors, piping or tanks.

TIER 1 OIL AND GAS LOCATION shall mean an oil and gas location where the slope is less than five percent (5%), the soil has low erosion potential, vegetative cover or permanent erosion resistance cover is greater than seventy-five percent (75%), the distance from a perennial stream or Classified Water Supply Segment is greater than five hundred (500) feet, and the oil and gas location size is less than one (1) acre, measured by the amount of surface disturbance at the time of the termination of a construction stormwater permit issued by the Colorado Department of Public Health and Environment.

TOTAL WATER VOLUME shall mean the total quantity of water from all sources used in the hydraulic fracturing treatment, including surface water, ground water, produced water or recycled water.

TRADE SECRET shall have the meaning set forth in § 7-74-102(4) (2011) of the Colorado Uniform Trade Secrets Act.

TRADE SECRET CHEMICAL PRODUCT shall mean a Chemical Product the composition of which is a Trade Secret.

URBAN MITIGATION AREA shall mean an area where: (A) At least twenty-two (22) Building Units or one (1) High Occupancy Building Unit (existing or under construction) are located within a 1,000' radius of the proposed Oil and Gas Location; or (B) At least eleven (11) Building Units or one (1) High Occupancy Building Unit (existing or under construction) are located within any semi-circle of the 1,000 radius mentioned in section (A) above.

WAITING ON COMPLETION WELL shall mean a well which has been drilled, cased, and cemented but the objective hydrocarbon formation has not yet been completed or stimulated using an open-hole, a liner, or a perforated casing completion.

WATER SOURCE shall mean water wells that are registered with Colorado Division of Water Resources, including household, domestic, livestock, irrigation, municipal/public, and commercial wells, permitted or adjudicated springs, or monitoring wells installed for the purpose of complying with groundwater baseline sampling and monitoring requirements under Rules 318A.e.(4), 608, or 609.

WATERS OF THE STATE mean any and all surface and subsurface waters which are contained in or flow in or through this state, but does not include waters in sewage systems, waters in treatment works of disposal systems, water in potable water distribution systems, and all water withdrawn for use until use and treatment have been completed. Waters of the state include, but are not limited to, all streams, lakes, ponds, impounding reservoirs, wetlands, watercourses, waterways, wells, springs, irrigation ditches or canals,

drainage systems, and all other bodies or accumulations of water, surface and underground, natural or artificial, public or private, situated wholly or partly within or bordering upon the State.

WELL when used alone in these Rules and Regulations, shall mean an oil or gas well, a hole drilled for the purpose of producing oil or gas, a well into which fluids are injected, a stratigraphic well, a gas storage well, or a well used for the purpose of monitoring or observing a reservoir.

WELL SITE shall mean the areas that are directly disturbed during the drilling and subsequent operation of, or affected by production facilities directly associated with, any oil well, gas well, or injection well and its associated well pad.

WILDCAT (EXPLORATORY) WELL means any well drilled beyond the known producing limits of a pool.

WILDLIFE RESOURCES shall mean fish, wildlife, and their aquatic and terrestrial habitats.

ZONE OF INCORPORATION shall mean the soil layer from the soil surface to a depth of twelve (12) inches below the surface.

ALL OTHER WORDS used herein shall be given their usual customary and accepted meaning, and all words of a technical nature, or peculiar to the oil and gas industry, shall be given that meaning which is generally accepted in said oil and gas industry.

GENERAL RULES

201. EFFECTIVE SCOPE OF RULES AND REGULATIONS

All rules and regulations of a general nature herein promulgated to prevent waste and to conserve oil and gas in the State of Colorado while protecting public health, safety, and welfare, including the environment and wildlife resources, shall be effective throughout the State of Colorado and be in force in all pools and fields except as may be amended, modified, altered or enlarged generally or in specific individual pools or fields by orders heretofore or hereafter issued by the Commission, and except where special field rules apply, in which case the special field rules shall govern to the extent of any conflict. Operators will ensure compliance with all applicable rules and regulations.

Nothing in these rules shall establish, alter, impair, or negate the authority of local and county governments to regulate land use related to oil and gas operations, so long as such local regulation is not in operational conflict with the Act or regulations promulgated thereunder.

These rules shall not apply to: (i) Indian trust lands and minerals; or (ii) the Southern Ute Indian Tribe within the exterior boundaries of the Southern Ute Indian Reservation. These rules shall apply to non-Indians conducting oil and gas operations on lands within the exterior boundaries of the Southern Ute Indian Reservation where both the surface and oil and gas estates are owned in fee by persons or entities other than the Southern Ute Indian Tribe, regardless of whether such lands are communitized or pooled. Additionally, the State of Colorado shall exercise criminal and civil jurisdiction within the Town of Ignacio, Colorado or within any other municipality within the Southern Ute Indian Reservation incorporated under the laws of Colorado, as provided by Sec. 5, Public Law No. 98-290 (1984).

If any portion of these Rules is found to be invalid, the remaining portion of the Rules shall remain in force and effect.

202. OFFICE AND DUTIES OF DIRECTOR

The office of Director of the Commission is hereby created. It shall be the duty of the Director to aid the Commission in the administration of the Act, as may be required of the Director from time to time and to act as hearing officer when so directed by the Commission.

203. OFFICE AND DUTIES OF SECRETARY

The office of Secretary to the Commission is hereby created. The duties of the Secretary shall be as determined from time to time by the Commission.

204. GENERAL FUNCTIONS OF DIRECTOR

The Director and the authorized deputies shall also have the right at all reasonable times to go upon and inspect any oil or gas properties, disposal facilities, or transporters facilities and wells for the purpose of making any investigation or tests to ascertain whether the provisions of the Act or these rules or any special field rules are being complied with, and shall report any violation thereof to the Commission.

205. ACCESS TO RECORDS

- a. All producers, operators, transporters, refiners, gasoline or other extraction plant operators and initial purchasers of oil and gas within this State, shall make and keep appropriate books and records covering their operations in the State, including natural gas meter calibration

reports, from which they may be able to make and substantiate the reports required by the Commission or the Director or otherwise demonstrate compliance with these Rules.

- b. Beginning May 1, 2009 on federal land and April 1, 2009 on all other land, operators shall maintain MSDS sheets for any Chemical Products brought to a well site for use downhole during drilling, completion, and workover operations, excluding hydraulic fracturing treatments. With the exception of fuel as provided for in Rule 205.c., the reporting and disclosure of hydraulic fracturing additives and chemicals brought to a well site for use in connection with hydraulic fracturing treatments is governed by Rule 205A.
- c. Beginning June 1, 2009, operators shall maintain a Chemical Inventory by well site for each Chemical Product used downhole during drilling, completion, and workover operations, excluding hydraulic fracturing treatments, in an amount exceeding five hundred (500) pounds during any quarterly reporting period. Operators shall also maintain a chemical inventory by well site for non-vehicular fuel stored at the well site during drilling, completion, and workover operations, including hydraulic fracturing treatments, in an amount exceeding five hundred (500) pounds during any quarterly reporting period.

The five hundred (500) pound reporting threshold shall be based on the cumulative maximum amount of a Chemical Product present at the well site during the quarterly reporting period. Entities maintaining Chemical Inventories under this section shall update these inventories quarterly throughout the life of the well site. These records must be maintained in a readily retrievable format at the operator's local field office. The Colorado Department of Public Health and Environment may obtain information provided to the Commission or Director in a Chemical Inventory upon written request to the Commission or the Director.

- d. Where the composition of a Chemical Product is considered a Trade Secret by the vendor or service provider, Operators shall only be required to maintain the identity of the Trade Secret Chemical Product and shall not be required to maintain information concerning the identity of chemical constituents in a Trade Secret Chemical Product or the amounts of such constituents. The vendor or service provider shall provide to the Commission a list of the chemical constituents contained in a Trade Secret Chemical Product upon receipt of a letter from the Director stating that such information is necessary to respond to a spill or release of a Trade Secret Chemical Product or a complaint from a potentially adversely affected landowner regarding impacts to public health, safety, welfare, or the environment. Upon receipt of a written statement of necessity, information regarding the chemical constituents contained in a Trade Secret Chemical Product shall be disclosed by the vendor or service provider directly to the Director or his or her designee.

The Director or designee may disclose information regarding those chemical constituents to additional Commission staff members to the extent that such disclosure is necessary to allow the Commission staff member receiving the information to assist in responding to the spill, release, or complaint, provided that such individuals shall not disseminate the information further. In addition, the Director may disclose information regarding those chemical constituents to any Commissioner, the relevant County Public Health Director or Emergency Manager, or to the Colorado Department of Public Health and Environment's Director of Environmental Programs upon request by that individual. Any information so disclosed to the Director, a Commission staff member, a Commissioner, a County Public Health Director or Emergency Manager, or to the Colorado Department of Public Health and Environment's Director of Environmental Programs shall at all times be considered confidential and shall not become part of the Chemical Inventory, nor shall it be construed as publicly available. The Colorado Department of Public Health and Environment's Director of Environmental Programs, or his or her designee, may disclose information regarding the chemical constituents contained in a Trade Secret Chemical Product to Colorado Department of Public Health and Environment staff members under the same terms and conditions as apply to the Director.

- e. The vendor or service provider shall also provide the chemical constituents of a Trade Secret Chemical Product to any health professional who requests such information in writing if the health professional provides a written statement of need for the information and executes a Confidentiality Agreement, Form 35. The written statement of need shall be a statement that the health professional has a reasonable basis to believe that (1) the information is needed for purposes of diagnosis or treatment of an individual, (2) the individual being diagnosed or treated may have been exposed to the chemical concerned, and (3) knowledge of the chemical constituents of such Trade Secret Chemical Product will assist in such diagnosis or treatment. The Confidentiality Agreement, Form 35, shall state that the health professional shall not use the information for purposes other than the health needs asserted in the statement of need, and that the health professional shall otherwise maintain the information as confidential. Where a health professional determines that a medical emergency exists and the chemical constituents of a Trade Secret Chemical Product are necessary for emergency treatment, the vendor or service provider shall immediately disclose the chemical constituents of a Trade Secret Chemical Product to that health professional upon a verbal acknowledgement by the health professional that such information shall not be used for purposes other than the health needs asserted and that the health professional shall otherwise maintain the information as confidential. The vendor or service provider may request a written statement of need, and a Confidentiality Agreement, Form 35, from all health professionals to whom information regarding the chemical constituents was disclosed, as soon as circumstances permit. Information so disclosed to a health professional shall not become part of the Chemical Inventory and shall in no way be construed as publicly available.
- f. Such books, records, inventories, and copies of said reports required by the Commission or the Director shall be kept on file and available for inspection by the Commission for a period of at least five years except for the Chemical Inventory, which shall be kept on file and available for inspection by the Commission for the life of the applicable oil and gas well or oil and gas location and for five (5) years after plugging and abandonment. Upon the written request of the Commission or the Director for information required to be maintained or provided under this section, the record-keeping entity or third-party vendor shall supply the Commission or the Director with the requested information within three (3) business days in a format readily-reviewable by the Commission or the Director, except in the instance where such information is necessary to administer emergency medical treatment in which case such information shall be provided as soon as possible. Information provided to the Commission or the Director under this section that is entitled to protection under state or federal law, including C.R.S. § 24-72-204, as a trade secret, privileged information, or confidential commercial, financial, geological, or geophysical data shall be kept confidential and protected against public disclosure unless otherwise required, permitted, or authorized by other state or federal law. Any disclosure of information entitled to protection under any state or federal law made pursuant to this section shall be made only to the persons required, permitted, or authorized to receive such information under state or federal law in order to assist in the response to a spill, release, or complaint and shall be subject to a requirement that the person receiving such information maintain the confidentiality of said information. The Commission or the Director shall notify the owner, holder, or beneficiary of any such protected information at least one (1) business day prior to any required, permitted, or authorized disclosure. This notification shall include the name and contact information of the intended recipient of such protected information, the reason for the disclosure, and the state or federal law authorizing the disclosure. Information so disclosed shall not become part of the Chemical Inventory and shall in no way be construed as publicly available. 200-4 As of May 30, 2009
- g. The Director and the authorized deputies shall have access to all well records wherever located. All operators, drilling contractors, drillers, service companies, or other persons engaged in drilling or servicing wells, shall permit the Director, or authorized deputy, at the Director's or their risk, in the absence of negligence on the part of the owner, to come upon any lease,

property, or well operated or controlled by them, and to inspect the record and operation of such wells and to have access at all times to any and all records of wells; provided, that information so obtained shall be kept confidential and shall be reported only to the Commission or its authorized agents.

- h. In the event that the vendor or service provider does not provide the information required by Rules 205.d, 205.e, or 205.f directly to the Commission or a health professional, the operator is responsible for providing the required information.
- i. In the event the operator establishes to the satisfaction of the Director that it lacks the right to obtain the information required by Rules 205.d, 205.e, or 205.f and to provide it directly to the Commission or a health professional, the operator shall receive a variance from these rule provisions from the Director.

205A. HYDRAULIC FRACTURING CHEMICAL DISCLOSURE.

a. **Applicability.** This Commission Rule 205a applies to hydraulic fracturing treatments performed on or after April 1, 2012.

b. **Required disclosures.**

(1) Vendor and service provider disclosures. A service provider who performs any part of a hydraulic fracturing treatment and a vendor who provides hydraulic fracturing additives directly to the operator for a hydraulic fracturing treatment shall, with the exception of information claimed to be a trade secret, furnish the operator with the information required by subsection 205A.b.(2)(A)(viii) – (xii) and subsection 205A.b.(2)(B), as applicable, and with any other information needed for the operator to comply with subsection 205A.b.(2). Such information shall be provided as soon as possible within 30 days following the conclusion of the hydraulic fracturing treatment and in no case later than 90 days after the commencement of such hydraulic fracturing treatment.

(2) Operator disclosures.

A. Within 60 days following the conclusion of a hydraulic fracturing treatment, and in no case later than 120 days after the commencement of such hydraulic fracturing treatment, the operator of the well must complete the chemical disclosure registry form and post the form on the chemical disclosure registry, including:

- i. the operator name;
- ii. the date of the hydraulic fracturing treatment;
- iii. the county in which the well is located;
- iv. the API number for the well;
- v. the well name and number;
- vi. the longitude and latitude of the wellhead;
- vii. the true vertical depth of the well;

- viii. the total volume of water used in the hydraulic fracturing treatment of the well or the type and total volume of the base fluid used in the hydraulic fracturing treatment, if something other than water;
 - ix. each hydraulic fracturing additive used in the hydraulic fracturing fluid and the trade name, vendor, and a brief descriptor of the intended use or function of each hydraulic fracturing additive in the hydraulic fracturing fluid;
 - x. each chemical intentionally added to the base fluid;
 - xi. the maximum concentration, in percent by mass, of each chemical intentionally added to the base fluid; and
 - xii. the chemical abstract service number for each chemical intentionally added to the base fluid, if applicable.
- B. If the vendor, service provider, or operator claim that the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical is/are claimed to be a trade secret, the operator of the well must so indicate on the chemical disclosure registry form and, as applicable, the vendor, service provider, or operator shall submit to the Director a Form 41 claim of entitlement to have the specific identity of a chemical, the concentration of a chemical, or both withheld as a trade secret. The operator must nonetheless disclose all information required under subsection 205A.b.(2)(A) that is not claimed to be a trade secret. If a chemical is claimed to be a trade secret, the operator must also include in the chemical registry form the chemical family or other similar descriptor associated with such chemical.
- C. At the time of claiming that a hydraulic fracturing chemical, concentration, or both is entitled to trade secret protection, a vendor, service provider or operator shall file with the commission claim of entitlement, Form 41, containing contact information. Such contact information shall include the claimant's name, authorized representative, mailing address, and phone number with respect to trade secret claims. If such contact information changes, the claimant shall immediately submit a new Form 41 to the Commission with updated information.
- D. Unless the information is entitled to protection as a trade secret, information submitted to the Commission or posted to the chemical disclosure registry is public information.
- (3) Ability to search for information. The chemical disclosure registry shall allow the Commission staff and the public to search and sort the registry for Colorado information by geographic area, ingredient, chemical abstract service number, time period, and operator.
- (4) Inaccuracies in information. A vendor is not responsible for any inaccuracy in information that is provided to the vendor by a third party manufacturer of the hydraulic fracturing additives. A service provider is not responsible for any inaccuracy in information that is provided to the service provider by the vendor. An operator is not responsible for any inaccuracy in information provided to the operator by the vendor or service provider.

- (5) Disclosure to health professionals. Vendors, service companies, and operators shall identify the specific identity and amount of any chemicals claimed to be a trade secret to any health professional who requests such information in writing if the health professional provides a written statement of need for the information and executes a confidentiality agreement, Form 35. The written statement of need shall be a statement that the health professional has a reasonable basis to believe that (1) the information is needed for purposes of diagnosis or treatment of an individual, (2) the individual being diagnosed or treated may have been exposed to the chemical concerned, and (3) knowledge of the information will assist in such diagnosis or treatment. The confidentiality agreement, Form 35, shall state that the health professional shall not use the information for purposes other than the health needs asserted in the statement of need, and that the health professional shall otherwise maintain the information as confidential. Where a health professional determines that a medical emergency exists and the specific identity and amount of any chemicals claimed to be a trade secret are necessary for emergency treatment, the vendor, service provider, or operator, as applicable, shall immediately disclose the information to that health professional upon a verbal acknowledgement by the health professional that such information shall not be used for purposes other than the health needs asserted and that the health professional shall otherwise maintain the information as confidential. The vendor, service provider, or operator, as applicable, may request a written statement of need, and a confidentiality agreement, Form 35, from all health professionals to whom information regarding the specific identity and amount of any chemicals claimed to be a trade secret was disclosed, as soon as circumstances permit. Information so disclosed to a health professional shall in no way be construed as publicly available.

c. Disclosures not required. A vendor, service provider, or operator is not required to:

- (1) disclose chemicals that are not disclosed to it by the manufacturer, vendor, or service provider;
- (2) disclose chemicals that were not intentionally added to the hydraulic fracturing fluid; or
- (3) disclose chemicals that occur incidentally or are otherwise unintentionally present in trace amounts, may be the incidental result of a chemical reaction or chemical process, or may be constituents of naturally occurring materials that become part of a hydraulic fracturing fluid.

d. Trade secret protection.

- (1) Vendors, service companies, and operators are not required to disclose trade secrets to the chemical disclosure registry.
- (2) If the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical are claimed to be entitled to protection as a trade secret, the vendor, service provider or operator may withhold the specific identity, the concentration, or both the specific identity and concentration, of the chemical, as the case may be, from the information provided to the chemical disclosure registry. Provided, however, operators must provide the information required by Rule 205A.b.(2)(B) & (C).

The vendor, service provider, or operator, as applicable, shall provide the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical claimed to be a trade secret to the Commission

upon receipt of a letter from the Director stating that such information is necessary to respond to a spill or release or a complaint from a person who may have been directly and adversely affected or aggrieved by such spill or release. Upon receipt of a written statement of necessity, such information shall be disclosed by the vendor, service provider, or operator, as applicable, directly to the Director or his or her designee and shall in no way be construed as publicly available.

The Director or designee may disclose information regarding the specific identity of a chemical, the concentration of a chemical, or both the specific identity and concentration of a chemical claimed to be a trade secret to additional Commission staff members to the extent that such disclosure is necessary to allow the Commission staff member receiving the information to assist in responding to the spill, release, or complaint, provided that such individuals shall not disseminate the information further. In addition, the Director may disclose such information to any Commissioner, the relevant county public health director or emergency manager, or to the Colorado Department of Public Health and Environment's director of environmental programs upon request by that individual. Any information so disclosed to the Director, a Commission staff member, a Commissioner, a county public health director or emergency manager, or to the Colorado Department of Public Health and Environment's director of environmental programs shall at all times be considered confidential and shall not be construed as publicly available. The Colorado Department of Public Health and Environment's director of environmental programs, or his or her designee, may disclose such information to Colorado Department of Public Health and Environment staff members under the same terms and conditions as apply to the director.

e. Incorporated materials. Where referenced herein, these regulations incorporate by reference material originally published elsewhere. Such incorporation does not include later amendments to or editions of the referenced material. Pursuant to section 24-4-103 (12.5) C.R.S., the Commission maintains copies of the complete text of the incorporated materials for public inspection during regular business hours. Information regarding how the incorporated material may be obtained or examined is available at the Commission's office located at 1120 Lincoln Street, Suite 801, Denver, Colorado 80203.

206. REPORTS

All producers, operators, transporters, refiners, gasoline and other extraction plant operators, and initial purchasers of oil and gas within the State shall from time to time file accurate and complete reports containing such information and covering such geographic areas or periods as the Commission or Director shall require.

207. TESTS AND SURVEYS

a. **Tests and surveys.** When deemed necessary or advisable, the Commission is authorized to require that tests or surveys be made to determine the presence of waste or occurrence of pollution. The Commission, in calling for reports under Rule 206 and tests or surveys to be made as provided in this rule, shall designate the time allowed to the operator for compliance, which provisions as to time shall prevail over any other time provisions in these rules..

b. Bradenhead monitoring.

- (1) The Commission may approve specific fields or portions of fields as bradenhead test areas.

- A. The Director may propose specific fields or portions of fields as bradenhead test areas by notice to all operators on record within the area and by publication.
 - B. The proposed designation, if no protests are timely filed, will be placed upon the Commission consent agenda for the next regular meeting of the Commission following the month in which such notice was given. The Commission will hear the proposed designation in accordance with Rule 531.
 - C. If a protest is timely filed, the Commission will hear the proposed designation in accordance with the 500 Series Rules.
- (2) The Commission order will describe the bradenhead testing or monitoring required and become effective upon approval by the Commission unless the Commission orders otherwise.

208. CORRECTIVE ACTION

The Commission shall require correction, in a manner to be prescribed or approved by it, of any condition which is causing or is likely to cause waste or pollution; and require the proper plugging and abandonment of any well or wells no longer used or useful in accordance with such reasonable plan as may be prescribed by it.

209. PROTECTION OF COAL SEAMS AND WATER-BEARING FORMATIONS

In the conduct of oil and gas operations each owner will exercise due care in the isolation of coal seams and groundwater.

Special precautions will be taken in drilling and abandoning wells to guard against any loss of artesian water from the stratum in which it occurs and the contamination of groundwater by produced water, liquid hydrocarbons, or natural gas. Before any oil or gas well is completed, all oil, gas, and groundwater bearing formations above and below the producing formation(s) will be isolated to prevent the intermingling of formation fluids and gases between formations.

210. SIGNS AND MARKERS

The operator shall mark each and every well in a conspicuous place, from the time of initial drilling until final abandonment, as follows:

- a. **Drilling and Recompletion Operations.** Directional signs, no less than three (3) and no more than six (6) square feet in size, shall be provided during any drilling or recompletion operation, by the operator or drilling contractor. Such signs shall be at locations sufficient to advise emergency crews where drilling is taking place; at a minimum, such locations shall include (i) the first point of intersection of a public road and the rig access road and (ii) thereafter at each intersection of the rig access route, except where the route to the rig is clearly obvious to uninformed third parties. Signs not necessary to meet other obligations under these rules shall be removed as soon as practicable after the operation is complete.

- b. **Permanent Designations.**

- (1) **Wells.** Within sixty (60) days after the completion of a well, a permanent sign shall be located at the wellhead which shall identify the well and provide its legal location, including the quarter quarter section. When no associated battery is present, the additional information required under Rule 210.b.(2) shall be required on the sign.

- (2) **Batteries.** Within sixty (60) days after the installation of a battery, a permanent sign shall be located at the battery. At the option of the operator, or at the request of local emergency response authorities, the sign may be placed at the intersection of the lease access road with a public, farm or ranch road if the referenced battery is readily apparent from such location. Such sign, which shall be no less than three (3) square feet and no more than six (6) square feet, shall provide: the name of the operator; a phone number at which the operator can be reached at all times; a phone number for local emergency services (911 where available); the lease name or well name(s) associated with the battery; the public road used to access the site; and the legal location, including the quarter quarter section. In lieu of providing the legal location on the permanent sign, it may be stenciled on a tank in characters visible from one-hundred (100) feet.
- c. **Centralized E&P Waste Management Facilities.** The main point of access to a centralized E&P waste management facility shall be marked by a sign captioned "(operator name) E&P Waste Management Facility." Such sign, which shall be no less than three (3) square feet and no more than six (6) square feet shall provide: a phone number at which the operator can be reached at all times; a phone number for local emergency services (911 where available); the public road used to access the facility; and the legal location, including quarter quarter section, of the facility.
- d. **Tanks and Containers.**
- (1) All tanks with a capacity of ten (10) barrels or greater shall by September 1, 2009 be labeled or posted with the following information:
- A. Name of operator;
 - B. Operator's emergency contact telephone number;
 - C. Tank capacity;
 - D. Tank contents; and
 - E. National Fire Protection Association (NFPA) Label.
- (2) Containers that are used to store, treat, or otherwise handle a hazardous material and which are required to be marked, placarded, or labeled in accordance with the U.S. Department of Transportation's Hazardous Materials Regulations, shall retain the markings, placards, and labels on the container. Such markings, placards, and labels must be retained on the container until it is sufficiently cleaned of residue and purged of vapors to remove any potential hazards.
- e. **General sign requirements.** No sign required under this Rule 210. shall be installed at a height exceeding six (6) feet. Operators shall maintain signs in a legible condition, and shall replace damaged or vandalized signs within sixty (60) days. New operators shall update signs within sixty (60) days after change of operator approval is received from the Commission.

211. NAMING OF FIELDS

All oil and gas fields discovered in the State subsequent to the adoption of these rules and regulations shall be named by the Director or at the Director's direction.

212. SAFETY

For safety regulations regarding industry personnel, contact the U.S. Department of Labor, Occupational Safety and Health Administration, Regional Administrator, Colorado Region VIII, 1244 Speer Blvd Suite 551 Denver, CO, 80204, (720)-264-6550. For State Safety regulations regarding public safety see Rules 601-608.

213. FORMS UPON REQUEST

Forms required by the Commission will be furnished upon request. (Please see Procedures and Forms Guidelines)

214. LOCAL GOVERNMENTAL DESIGNEE

Each local government which designates an office for the purposes set forth in the 100 Series shall provide the Commission written notice of such designation, including the name, address and telephone number, facsimile number, electronic mail address, local emergency dispatch and other emergency numbers of the local governmental designee. It shall be the responsibility of such local governmental designee to ensure that all documents provided to the local governmental designee by oil and gas operators and the Commission or the Director are distributed to the appropriate persons and offices.

215. GLOBAL POSITIONING SYSTEMS

Global Positioning Systems (GPS) may be used to locate facilities used in oil and gas operations provided they meet the following minimum standards of the Commission:

- a. GPS instruments are differential grade.
- b. GPS instruments are capable of one-meter horizontal positional accuracy after differential correction.
- c. The operator must report an accuracy value in meters when submitting location data. If unavailable and except as otherwise provided in the Rules, a position dilution of precision (PDOP) value less than six (6) is acceptable.
- d. Elevation mask (lowest acceptable height above the horizon) shall be no less than fifteen degrees (15°)
- e. Latitude and longitude coordinates shall be provided in decimal degrees with an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of 1983 (e.g.; latitude 37.12345 N, longitude 104.45632 W).
- f. Raw and corrected data files shall be held for a period of three (3) years.
- g. Measurements shall be made by a trained GPS operator familiar with the theory of GPS, the use of GPS instrumentation, and typical constraints encountered during field activities.

216. COMPREHENSIVE DRILLING PLANS

- a. **Purpose.** Comprehensive Drilling Plans are intended to identify foreseeable oil and gas activities in a defined geographic area, facilitate discussions about potential impacts, and identify measures to minimize adverse impacts to public health, safety, welfare, and the environment, including wildlife resources, from such activities. An operator's decisions to initiate and enter into a Comprehensive Drilling Plan are voluntary.

- b. **Scope.** A Comprehensive Drilling Plan shall cover more than one (1) proposed oil and gas location within a geologic basin, but its scope may otherwise be customized by the operator to address specific issues in particular areas. Although operators are encouraged to develop joint Comprehensive Drilling Plans covering the proposed activities of multiple operators where appropriate, Comprehensive Drilling Plans will typically cover the activities of one operator.
- c. **Information requirements.** Operators are encouraged to submit the most detailed information practicable about the future activities in the geographic area covered by the Comprehensive Drilling Plan. Detailed information is more likely to lead to identification of specific impacts and agreement regarding measures to minimize adverse impacts. The information included in the Comprehensive Drilling Plan shall be decided upon by the operator, in consultation with other participants. Information provided by operators to federal agencies to obtain approvals for surface disturbing activities on federal land may be submitted in support of a Comprehensive Drilling Plan. The following information may be included as part of a Comprehensive Drilling Plan, depending on the circumstances:
- (1) A U.S. Geological Survey 1:24,000 topographic map showing the proposed oil and gas locations, including proposed access roads and gathering systems reasonably known to the operator(s);
 - (2) A current aerial photo showing the proposed oil and gas locations displayed at the same scale as the topographic map to facilitate use as an overlay;
 - (3) Overlay maps showing the proposed oil and gas locations, including all proposed access roads and gathering systems, drainages and stream crossings, and existing and proposed buildings, roads, utility lines, pipelines, known mines, oil or gas wells, water wells known to the operator(s) and those registered with the State Engineer's Office, and riparian areas;
 - (4) A list of all proposed oil and gas facilities to be installed within the area covered by the Comprehensive Drilling Plan over the time of the Plan and the anticipated timing of the installation;
 - (5) A plan for the management of exploration and production waste;
 - (6) A description of the wildlife resources at each oil and gas location;
 - (7) Wildlife information that is determined necessary after consultation with the Colorado Parks and Wildlife;
 - (8) Locations of all proposed reference areas to be used as guides for interim and final reclamation;
 - (9) Past economic uses to which the land has been put in the previous ten (10) years reasonably known to the operator(s);
 - (10) Any planned variance requests that are reasonably known to the operator;
 - (11) Proposed best management practices or mitigation to minimize adverse impacts to resources such as air, water, or wildlife resources; and
 - (12) A list of all parties that participated in creating the Comprehensive Drilling Plan pursuant to Rule 216.d.(2).

d. Procedure.

- (1) One or more operator(s) may submit a proposed Comprehensive Drilling Plan to the Commission, describing the operator's reasonably foreseeable oil and gas development activities in a specified geographic area within a geologic basin. The Director may request an operator to initiate a Comprehensive Drilling Plan, but the decision to do so rests solely with the operator.
- (2) The operator(s) shall invite the Colorado Department of Public Health and Environment, the Colorado Parks and Wildlife, local governmental designee(s), and all surface owners to participate in the development of the Comprehensive Drilling Plan. In many cases, participation by these agencies and individuals will facilitate identification of potential impacts and development of conditions of approval to minimize adverse impacts.
- (3) The operator(s), the Director, and participants involved in the Comprehensive Drilling Plan process shall review the proposal, identify information needs, discuss operations and potential impacts, and establish measures to minimize adverse impacts resulting from oil and gas development activities covered by the Plan.
- (4) The Director shall place on the Commission's hearing agenda in a timely manner a Comprehensive Drilling Plan that has been agreed to in writing by the operator(s) and that the Director considers suitable after consultation with the Colorado Department of Public Health and Environment and the Colorado Parks and Wildlife, as applicable, and consideration of any other comments.
- (5) The Director shall identify and document the agreed-upon conditions of approval for activities within the geographic area covered by the accepted Comprehensive Drilling Plan.
- (6) Comprehensive Drilling Plans that have been accepted by the Commission shall be posted on the COGCC website, subject to any confidential or proprietary information belonging to the operator or other parties being withheld. Written information obtained or compiled from landowners and operators in conjunction with development of a Comprehensive Drilling Plan is exempt from disclosure to the public, provided that any page containing information subject to withholding under the Colorado Open Records Act is clearly labeled with the words "Confidential Information." The Commission, the Colorado Department of Public Health and Environment, and the Colorado Parks and Wildlife will keep all such data and information confidential to the extent allowed by the Colorado Open Records Act.
- (7) Before initiating a Comprehensive Drilling Plan, operators are encouraged to discuss with the Director and, as appropriate, the Colorado Department of Public Health and Environment and the Colorado Parks and Wildlife, the scope of the Plan, the schedule for its preparation, the information to be included, any public participation opportunities, and whether the Plan is intended to satisfy Form 2A requirements.

e. Variances and site-specific approvals.

- (1) A Comprehensive Drilling Plan may incorporate variances to any of these rules, provided that all of the requirements for granting variances are met.
- (2) Practices and conditions agreed to in an accepted Comprehensive Drilling Plan shall be:

- A. Included as conditions of approval in any Form 2 or other permit for individual wells or other ground-disturbing activity covered by the Plan, where no Form 2A is required under Rule 303.d.(2).B.
- B. Included as conditions of approval in any Form 2, Form 2A, or other permit for individual wells or other ground-disturbing activity covered by the Plan, where a Form 2A is required under Rule 303.d.(1).

Any permit-specific condition of approval for wildlife habitat protection will be included only with the consent of the surface owner.

f. **Incentives.** The following incentives shall apply as a means to facilitate and encourage the development of Comprehensive Drilling Plans by operators:

- (1) Where the Comprehensive Drilling Plan contains information substantially equivalent to that which would be required in a Form 2A for the proposed oil and gas location and the Comprehensive Drilling Plan has been subject to procedures substantially equivalent to those required for a Form 2A, then a Form 2A shall not be required for a proposed oil and gas location that was included in the Comprehensive Drilling Plan and does not involve a variance from the Plan or a variance from these rules not addressed in the Comprehensive Drilling Plan.
- (2) Where the Comprehensive Drilling Plan does not contain information substantially equivalent to that which would be required in a Form 2A for the proposed oil and gas location or the Comprehensive Drilling Plan has not been subject to procedures substantially equivalent to those required for a Form 2A or the operator seeks a variance from the Comprehensive Drilling Plans or a provision of these rules that is not addressed in the Plan, then a Form 2A shall be required for a proposed oil and gas location included in the Comprehensive Drilling Plan. However, the Director shall modify the informational and procedural requirements for such Form 2A to reflect the information included in and procedures used to approve the Comprehensive Drilling Plan and with input, where appropriate, from the Colorado Department of Public Health and Environment and the Colorado Parks and Wildlife.
- (3) Where a proposed oil and gas location is covered by an approved Comprehensive Drilling Plan and no variance is sought from such Plan or these rules not addressed in the Comprehensive Drilling Plan, then the Director shall give priority to and approve or deny an Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, within thirty (30) days of a determination that such application is complete pursuant to Rule 303.h unless significant new information is brought to the attention of the Director.
- (4) Where the Director does not issue a decision on an Application for Permit-to-Drill, Form 2, or an Oil and Gas Location Assessment, Form 2A, for an oil and gas location as described in Rule 216.f.(3) above within thirty (30) days, then within five (5) days the Director shall provide the operator with a written explanation for the delay and the anticipated decision date, and the operator may request a hearing before the Commission. Such a hearing shall be expedited but will be held only after both the 20 days' notice and the newspaper notice are given as required by Section 34-60-108, C.R.S. However, the hearing may be held after the newspaper notice if all of the entities listed under Rule 503.b waive the 20-day notice requirement.
- (5) Any party requesting a hearing pursuant to Rule 503.b.(7) on the Director's approval of an Application for Permit-to-Drill, Form 2, or an Oil and Gas Location Assessment, Form 2A, for an oil and gas location that includes conditions of

approval arrived at as part of an accepted Comprehensive Drilling Plan shall bear the burden of establishing that the conditions of approval are insufficient to protect public health, safety, welfare, the environment, and wildlife resources due to new information or changed circumstances occurring since the Comprehensive Drilling Plan was accepted by the Commission.

- g. **Duration.** Once accepted by the Commission, a Comprehensive Drilling Plan shall be valid for a period of six (6) years.
- h. **Modification.** An accepted Comprehensive Drilling Plan may be modified using the same process as that leading to acceptance of the original Plan either upon the initiative of the operator or upon the initiative of the Director and upon a showing that there has been a change in an applicable provision in these rules or a significant change to the basis upon which the Plan was developed. The review and approval of the modification shall focus only on the proposed modification(s).

DRILLING, DEVELOPMENT, PRODUCTION AND ABANDONMENT

301. RECORDS, REPORTS, NOTICES-GENERAL

Any written notice of intention to do work or to change plans previously approved must be filed with the Director, and must reach the Director and receive approval before the work is begun, or such approval may be given orally and, if so given, shall thereafter be confirmed to the Director in writing.

In case of emergency, or any situation where operations might be unduly delayed, any notice or information required by these rules and regulations to be given to the Director may be given orally or by wire, and if approval is obtained the transaction shall be promptly confirmed in writing to the Director, as a matter of record.

Immediate notice shall be given to the Director when public health or safety is in jeopardy. Notice shall also be given to the Director of any other significant downhole problem or mechanical failure in any well within ten (10) days.

The owner shall keep on the leased premises, or at the owner's headquarters in the field, or otherwise conveniently available to the Director, accurate and complete records of the drilling, redrilling, deepening, repairing, plugging or abandoning of all wells, and of all other well operations, and of all alterations to casing. These records shall show all the formations penetrated, the content and quality of oil, gas or water in each formation tested, and the grade, weight and size, and landed depth of casing used in drilling each well on the leased premises, and any other information obtained in the course of well operation. Such records on each well shall be transferred to and maintained by any subsequent owner.

Whenever a person has been designated as an operator by an owner or owners of the lease or well, such an operator may submit the reports as herein required by the Commission.

302. COGCC Form 1. REGISTRATION FOR OIL AND GAS OPERATIONS

- a. Prior to the commencement of its operations, all producers, operators, transporters, refiners, gasoline or other extraction plant operators, and initial purchasers who are conducting operations subject to this Act in the State of Colorado, shall, for purposes of the Act, file a Registration For Oil and Gas Operations, Form 1, with the Director in the manner and form approved by the Commission. Any producer, operator, transporter, refiner, gasoline or other extraction plant operator, and initial purchaser conducting operations subject to the Act who has not previously filed a Registration For Oil and Gas Operations, Form 1, shall do so. Any person providing financial assurance for oil and gas operators in Colorado shall file a Form 1 with the Director. All changes of address of the parties required to file a Form 1 shall be immediately reported by submitting a new Form 1.
- b. **Designation of Agent, Form 1A.** Operator employees approved to submit documents shall be listed on a completed Designation of Agent, Form 1A. A company/individual other than the operator may be designated as an agent, and its representatives shall be listed on a completed Designation of Agent, Form 1A. This agency shall remain in effect until it is terminated in writing by submitting a new Designation of Agent, Form 1A. All changes to reported agent information shall be immediately reported by submitting a new Designation of Agent, Form 1A.
- c. **Operator Registration with Local Governments for Advance Planning.**

(1) When used in this subpart, "municipal local jurisdiction" means a home rule or statutory city, town, territorial charter city, or combined city and county.

- (2) Beginning on May 1, 2016, all operators that have filed a Form 1 with the Commission shall register with each municipal local jurisdiction and county in which it has an approved drilling unit or a pending or approved Form 2 or Form 2A. An operator registers by complying with the local registration process established by the municipal local jurisdiction or county. If a local registration process does not exist, an operator may comply by delivering current copies of its Form 1 and Form 1A to the Local Governmental Designee ("LGD") in jurisdictions that have designated an LGD, and to the planning department in jurisdictions that do not have an LGD.
- (3) A municipal local jurisdiction may request any operator registered within its jurisdiction provide the following information to the municipal local jurisdiction and the Commission's Local Government Liaison ("LGL"):
- A. Based on an operator's current business plan as of the date of the request, a good faith estimate of the number of wells the operator intends to drill in the next five years in the local jurisdiction. A publicly traded company's well estimates may be based on reserves classified as "proved undeveloped" for SEC reporting purposes.
 - B. A map showing the location within the local jurisdiction of an operator's existing well sites and related production facilities; sites for which the operator has approved, or has submitted applications for, drilling and spacing orders, Form 2s or Form 2As; and, sites the operator has identified for development on its current drilling schedule for which it has not yet submitted applications for Commission permits.
 - C. An operator will provide the well estimates requested pursuant to this subsection 3 using reasonable business judgment based on information known to the operator as of the date the estimates are requested. Well estimates are subject to change at any time at the operator's sole discretion.

303. REQUIREMENTS FOR FORM 2, APPLICATION FOR PERMIT-TO-DRILL, DEEPEN, RE-ENTER, OR RECOMPLETE, AND OPERATE; FORM 2A, OIL AND GAS LOCATION ASSESSMENT.

a. FORM 2. APPLICATION FOR PERMIT-TO-DRILL, DEEPEN, RE-ENTER, OR RECOMPLETE, AND OPERATE.

- (1) **Approval by Director.** A complete Form 2, Application for Permit-to-Drill, Deepen, Re-enter or Recomplete and Operate (Application for Permit-to-Drill) must be approved by the Director before commencement of operations with heavy equipment for the following operations:
- A. Drilling any well;
 - B. Deepening any existing well;
 - C. Re-entering any plugged well (except for re-entry to re-plug shall require a Well Abandonment Report, Form 6, per Rule 311);
 - D. Recompleting and operating any existing well; or
 - E. Drilling a sidetrack from any well.

- (2) **Approved Location.** An approved Form 2A, Oil and Gas Location Assessment, is required for the well location per Rule 303.b.
- (3) **Operational Conflicts.** The Permit to Drill shall be binding with respect to any provision of a local governmental permit or land use approval that is in operational conflict with the Permit to Drill.
- (4) **Filing Fees.** A Form 2, Application for Permit-to-Drill, shall be submitted with a filing and service fee established by the Commission (see Appendix III). Wells drilled for stratigraphic information only shall be exempt from paying the filing and service fee.
- (5) **Information Requirements.**

The Form 2 requires the following information:

- A. Every Form 2, Application for Permit-to-Drill, will specify the distance between the Well and wall or corner of the nearest building, Building Unit, High Occupancy Building Unit, Designated Outside Activity Area, public road, above ground utility, railroad, and property line.
- B. **Wellbore Diagram.** A Form 2 to deepen, to re-enter, to recomplete to a different reservoir, or to drill a sidetrack of an existing Well will have a wellbore diagram attached.
- C. A Form 2 to deepen, to re-enter, to recomplete to a different reservoir, or to drill a sidetrack of an existing Well will include the details of the proposed work.
- D. **Well Location Plat.** A Form 2 to drill a new Well or a new wellbore will have a well location plat attached. The plat will be a current scaled drawing(s) of the entire section(s) penetrated by the proposed well with the following minimum information:
 - i. Dimensions on adjacent exterior section lines sufficient to completely describe the quarter section(s) containing the proposed Well surface location, top of productive zone, wellbore, and bottom hole location will be indicated. If dimensions are not field measured, the plat will state how the dimensions were determined.
 - ii. For irregular, partial or truncated sections, dimensions will be furnished to completely describe the entire section(s) containing the proposed Well.
 - iii. The field-measured distances from the nearer north/south and nearer east/west section lines will be measured at 90 degrees from said section lines to the Well surface location and referenced on the plat. For unsurveyed land grants and other areas where an official public land survey system does not exist, the Well locations will be spotted as footages on a protracted section plat using Global Positioning System (GPS) technology and reported as latitude and longitude in accordance with Rule 215.
 - iv. The latitude and longitude of the proposed surface location will be provided on the drawing with a minimum of 5 decimal places of accuracy and precision using the North American Datum (NAD) of 1983 (e.g. latitude 37.12345 N, longitude 104.45632 W). If GPS technology is utilized to determine the latitude and longitude, all GPS data shall meet the requirements set forth in Rule 215.

- v. The well location plat will include the proposed top of the productive zone and the bottom hole location. If the wellbore penetrates multiple sections, the well location plat will depict every section penetrated by the wellbore.
 - vi. A map legend.
 - vii. A north arrow.
 - viii. A scale expressed as an equivalent (e.g. 1 inch = 1000 feet).
 - ix. A bar scale.
 - x. The ground elevation.
 - xi. The basis of the elevation (how it was calculated or its source).
 - xii. The basis of bearing or interior angles used.
 - xiii. Complete description of monuments and/or collateral evidence found; all aliquot corners used will be described.
 - xiv. The legal land description by section, township, range, principal meridian, baseline, and county.
 - xv. Operator name.
 - xvi. Well name and well number.
 - xvii. Date of completion of scaled drawing.
- E. **Deviated Drilling Plan.** A Form 2 to drill a deviated (directional, highly deviated, or horizontal) wellbore utilizing controlled directional drilling methods will have the deviated drilling plan attached. The deviated drilling plan will meet the requirements set forth in Rule 321.
- F. **Casing and Cementing Plan.** A Form 2 to drill a Well will include a casing and cementing plan that addresses anticipated groundwater by demonstrating how it will be isolated, potential flow and hydrocarbon bearing zones, and subsurface hazards. The casing and cementing plan will describe the top and bottom depths and the concentration of total dissolved solids (TDS) in milligrams per liter of all groundwater from the surface to the depth of the bottom hole, and demonstrate compliance with the casing and cementing requirements of Rule 317.e. To identify top and bottom depths and TDS concentrations of groundwater, the Operator will use all available sources of pertinent information, including but not limited to reports from the Water Quality Control Commission, the Division of Water Resources, the Colorado Geological Survey, the United States Geological Survey, the Colorado Groundwater Atlas; peer-reviewed publications; the Commission's Field Scout Cards; electric logs (e.g. resistivity logs); produced water samples; groundwater samples collected to support aquifer exemptions and samples collected from domestic, municipal, agricultural, and industrial water wells. If the top or bottom depth, or TDS concentration cannot be determined using these sources the Operator will comply with Rule 317.e.(5) to ensure isolation of all such groundwater.
- G. **Statewide Offset Well Evaluation.**

- i. The Form 2 will include an offset well evaluation. The Operator will evaluate the construction and integrity of all offset wells within 1,500 feet of the proposed wellbore. The Operator will provide a plan to address all offset wells within 1,500 feet that do not meet isolation and integrity requirements.
 - ii. The Operator will attach any consents obtained pursuant to Rule 317.v. to the Form 2.
 - iii. The Operator will provide notice as required by Rule 317.w.
- H. **Hydraulic Fracturing Treatment at Depths 2,000 Feet or Less.** If an Operator proposes to drill a Well at a depth less than 2,000 feet true vertical depth (TVD) below the surface that will be subject to hydraulic fracturing treatment, the following requirements apply:
- i. **Geology and Hydrogeology Assessment.** The Operator will characterize and assess the local geology and groundwater resources within 2 miles of the proposed oil and gas Well.
 - ii. **Engineering Assessment.** The Operator will describe the proposed drilling process, well design, completion process, hydraulic fracturing treatment process, production methods, and facilities. The assessment will identify any risks to geology and hydrogeology and explain how the operator will prevent, minimize, or mitigate any identified risk.

303.b. **FORM 2A, OIL AND GAS LOCATION ASSESSMENT.**

- (1) Unless exempted under subsection 2, below, a completed Form 2A, Oil and Gas Location Assessment, approved by the Director or the Commission is required for:
- A. Any new Oil and Gas Location. For purposes of this section, “new Oil and Gas Location” shall mean surface disturbance at a previously undisturbed site;
 - B. Surface disturbance for purposes of modifying or expanding an existing Oil and Gas Location; or
 - C. The addition of a well or a pit, except an Emergency Pit or a Flare Pit where there is no risk of condensate accumulation, to any existing Oil and Gas Location.
- (2) **Exemptions.** A new Form 2A shall not be required for the following:
- A. Surface disturbance, other than for purposes described in subsections 303.b.(1) B and C. above, at an existing Oil and Gas Location within the originally disturbed area, even if interim reclamation has been performed;
 - B. For an Oil and Gas Location covered by an approved Comprehensive Drilling Plan and where such Comprehensive Drilling Plan contains information substantially equivalent to that which would be required for a Form 2A for the proposed Oil and Gas Location and the Comprehensive Drilling Plan has been subject to procedures substantially equivalent to those required for a Form 2A, including but not limited to consultation with Surface Owners, local governments, the Colorado Department of Public Health and Environment or Colorado Parks and Wildlife, where applicable, and public notice and opportunity to comment, and where the operator

does not seek a variance from the Comprehensive Drilling Plan or a provision of these rules that is not addressed in the Plan;

- C. Seismic operations;
- D. Pipelines for oil, gas, or water; or
- E. Roads.

(3) **Information Requirements.**

The Form 2A requires the following information:

- A. A Form 2A shall specify the shortest distance between any Well or Production Facility proposed or existing on the Oil and Gas Location and the edge or corner of the nearest building, Building Unit, High Occupancy Building Unit, the nearest boundary of a Designated Outside Activity Area, and the nearest public road, above ground utility, railroad, and property line.
- B. **Location Pictures.** A minimum of four (4) color photographs, one (1) of the staked location from each cardinal direction shall be attached. Each photograph shall be identified by: date taken, well or location name, and direction of view.
- C. A list of major equipment components to be used in conjunction with drilling and operating the well(s), including all tanks, pits, flares, combustion equipment, separators, and other ancillary equipment and a description of any pipelines for oil, gas, or water.
- D. **Location Drawing.** A scaled drawing, or scaled aerial photograph showing the approximate outline of the Oil and Gas Location and all wells and/or Production Facilities used for measuring distances shall be attached. The drawing shall include all visible improvements within five hundred (500) feet of the proposed Oil and Gas Location (as measured from the proposed edge of disturbance), with a horizontal distance and approximate bearing from the oil and gas facilities. Visible improvements shall include, but not be limited to, all buildings and Building Units, publicly maintained roads and trails, fences, above-ground utility lines, railroads, pipelines or pipeline markers, mines, oil wells, gas wells, injection wells, water wells known to the operator and those registered with the Colorado State Engineer, known springs, plugged wells, known sewers with manholes, standing bodies of water, and natural channels including permanent canals and ditches through which water may flow. If there are no visible improvements within five hundred (500) feet of a proposed Oil and Gas Location, it shall be so noted on the Form 2A.
- E. **Hydrology Map.** A topographic map showing all surface waters and riparian areas within one thousand (1,000) feet of the proposed Oil and Gas Location, with a horizontal distance and approximate bearing from the Oil and Gas Location shall be attached.
- F. **Access Road Map.** An 8 1/2" by 11" vicinity map, U.S. Geological Survey topographic map, or scaled aerial photograph showing the access route from the highway or county road to the proposed Oil and Gas Location shall be attached.

G. Designation of the current land use(s) and landowner's designated final land use(s) and basis for setting reclamation standards.

i. If the final land use includes residential, industrial/commercial, or cropland and does not include any other uses, the land use should be indicated and no further information is needed.

ii. If the final land use includes rangeland, forestry, recreation, or wildlife habitat, then a reference area shall be selected and the following information shall be attached:

aa. **Reference Area Map.** A topographic map showing the location of the site, and the location of the reference area; and

bb. **Reference Area Pictures.** Four (4) color photographs of the reference area, taken during the growing season of vegetation and facing each cardinal direction. Each photograph shall be identified by date taken, well or Oil and Gas Location name, and direction of view. Provided that these photographs may be submitted at any time up to twelve (12) months after the Form 2A.

H. **NRCS Map Unit Description.** Natural Resources Conservation Service (NRCS) soil map unit description shall be attached.

I. **Construction Layout Drawing.** If the Oil and Gas Location disturbance is to occur on lands with a slope ten percent (10%) or greater, or one (1) foot of elevation gain or more in ten (10) foot distance, then the following information shall be attached:

i. Construction layout drawing (construction and operation); and

ii. Location cross-section plot (construction and operation).

J. If the proposed Oil and Gas Location is within one thousand (1,000) feet of a Building Unit, the following information shall be attached:

i. **Facility Layout Drawing.** A scaled facility layout drawing depicting the location of all existing and proposed new Oil and Gas Facilities listed on the Form 2A;

ii. **Waste Management Plan.** A Waste Management Plan describing how the Operator intends to satisfy the general requirements of Rule 907.a.; and

iii. **Rule 305.a.(2) Certification.** Evidence that Building Unit owners within the Buffer Zone received the pre-application notice required by Rule 305.a.(2).

K. **Certification of Local Government Notification in Urban Mitigation Areas.**

i. If a proposed Oil and Gas Location is within an Urban Mitigation Area, but is not a Large UMA Facility, the operator shall submit evidence

that the local government with land use authority received the pre-application notice required by Rule 305.a.(1).

- ii. For a proposed Large UMA Facility, the operator shall certify on the Form 2A that the operator complied with Rule 305A and submit documentation supporting its certification demonstrating one of the following:
 - aa. The operator and local government with land use authority reached agreement regarding the site for the proposed Large UMA Facility;
 - bb. The proposed Large UMA Facility was subject to an exception under Rule 305A.e.;
 - cc. The local government with land use authority waived the notification and consultation procedures in Rule 305A.a.(1) and 305A.c. in writing;
 - dd. The local government with land use authority did not timely respond to the Notice of Intent to Construct Large UMA Facility; or
 - ee. The operator and local government with land use authority engaged in consultation and at least 90 days passed after the local government received the Notice of Intent to Construct Large UMA Facility but no agreement was reached regarding the siting of the proposed Large UMA Facility.
- iii. For a proposed Large UMA Facility, the operator shall submit evidence that Proximate Local Governments received the pre-application notice required by Rule 305.a.(3).
- L. **Multi-Well Plan.** Where the proposed Oil and Gas Location is for multiple wells on a single pad, a drawing showing proposed wellbore trajectory with bottom-hole locations shall be attached.
- M. A description of any applicant-proposed Best Management Practices or, where a variance from a provision of these rules is sought, any applicant-proposed measures to meet the standards for such a variance. With the consent of the Surface Owner, this may include mitigation measures contained in a relevant Surface Use Agreement.
- N. If the proposed Oil and Gas Location is covered by an approved Comprehensive Drilling Plan pursuant to Rule 216, a list of any conditions of approval.
- O. Contact information for the Surface Owner(s) and an indication as to whether there is a Surface Use Agreement(s) or any other agreement(s) between the applicant and the Surface Owner(s) for the proposed Oil and Gas Location.
- P. Designation of whether the proposed Oil and Gas Location is within sensitive wildlife habitat or a restricted surface occupancy area.

- Q. If the proposed Oil and Gas Location is within a zone defined in Rule 317B, Table 1, documentation that the applicant has provided notification of the application submittal to potentially impacted public water systems within fifteen (15) stream miles downstream.
 - R. Any additional data as reasonably required by the Commission as a result of consultation with the Colorado Department of Public Health and Environment or Colorado Parks and Wildlife.
 - S. Oil and Gas Locations in wetlands. The Form 2A shall also indicate if an Army Corps of Engineers permit pursuant to 33 U.S.C.A. §1342 and 1344 of the Water Pollution and Control Act (Section 404 of the federal “Clean Water Act”) is required for the construction of an Oil and Gas Location.
 - T. The Operator shall indicate on the Form 2A whether it intends to seek a location exception under Rules 604.b(2) or b(3), and, if so, the relevant Surface Use Agreement(s) shall be attached.
 - U. **Schools and Child Care Centers.** If the proposed oil and gas location is subject to the notice requirements of Rule 305.a.(4), then the following information will be attached or included:
 - i. **Facilities Map.** A map or scaled aerial image depicting the oil and gas location boundary and proposed and existing wells and production facilities in proximity to any surrounding school facility or child care center; and
 - ii. A statement indicating whether the school governing body requested consultation and whether, after consultation, the school governing body and operator reached agreement regarding identification of a school facility or child care center.
- (4) Where the information required under subsection (3) has been included in a federal Surface Use Plan of Operations meeting the requirements of Onshore Oil and Gas Order Number 1 (72 Fed. Reg. 10308 (March 7, 2007)), or for a federal Right of Way, Form 299, then the operator may attach the completed pertinent information and identify on the Form 2A where the information required under this section may be found therein.

303.c. **PROCESSING TIME FOR APPROVALS UNDER THIS SECTION.**

- (1) In accordance with Rule 216.f.(3), where a proposed Oil and Gas Location is covered by an approved Comprehensive Drilling Plan and no variance is sought from such Plan or these rules not addressed in the Comprehensive Drilling Plan, the Director shall give priority to and approve or deny an Application for Permit-to Drill, Form 2, or, where applicable, Oil and Gas Location Assessment, Form 2A, that is not a Large UMA Facility within 30 days of a determination that such application is complete pursuant to Rule 303.h., unless significant new information is brought to the attention of the Director. The Director shall give priority to a Form 2A proposing a Large UMA Facility that is consistent with a Comprehensive Drilling Plan, or a local government comprehensive plan that specifies locations for oil and gas facilities, and shall approve or deny such an application within 90 days.
- (2) **Request for Hearing.**

- A. An operator may request a hearing before the Commission on an Application for Permit-to-Drill, Form 2, and on an Oil and Gas Location Assessment, Form 2A, that is not a Large UMA Facility if the Director has not issued a decision within 75 days following a determination that the application is complete;
- B. An operator may request a hearing before the Commission on an Oil and Gas Location Assessment, Form 2A, for a Large UMA Facility if the Director has not issued a decision within:
 - i. 90 days following a determination that the application is complete, if:
 - aa. At the time the Form 2A is submitted, the operator and the local government with land use authority reached agreement regarding the site for the proposed Large UMA Facility;
 - bb. The Form 2A was excepted from the Rule 305A consultation process; or
 - cc. The local government with land use authority waived the 305A procedures in writing or did not timely respond in writing to the Notice of Intent to Construct.
 - ii. 120 days following a determination that the application is complete, if, at the time the Form 2A is submitted, the operator and the local government with land use authority had not reached agreement regarding the site for the proposed Large UMA Facility.
- C. A hearing pursuant to either subpart A. or B. shall be expedited but will be held only after both the 20 days' notice and the newspaper notice are given as required by §34-60-108, C.R.S. However, the hearing can be held after the newspaper notice if all of the entities listed under Rule 503.b. waive the 20 day notice requirement.

303.d. **Revisions to Form 2 or Form 2A.** Prior to approval of the Form 2 or Form 2A permit application, minor revisions or requested information may be provided by contacting the COGCC staff. After approval, any substantive changes shall be submitted for approval on a Form 2 or Form 2A. A Sundry Notice, Form 4, shall be submitted, along with supplemental information requested by the Director, when non-substantive revisions are made after approval, and no additional fee shall be imposed.

303.e. **Incomplete applications.** Applications for Permit-to-Drill, Form 2, or Oil and Gas Location Assessments, Form 2A, which are submitted without the required attachments, the proper signature, or the required information, shall be considered incomplete and shall not be reviewed or approved. The COGCC staff shall notify the applicant in not more than ten (10) days of its receipt of the application of such inadequacies, except that the Director shall notify the applicant of inadequacies within three (3) business days of its receipt where the proposed Oil and Gas Location is covered by an accepted Comprehensive Drilling Plan. The applicant shall then have thirty (30) days from the date that it was contacted to correct or provide requested information, otherwise the application shall be considered withdrawn and the fee shall not be refunded.

303.f. **Information requests after completeness determination.** Subsequent to deeming an Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A,

complete, the Director may request from the operator additional information needed to complete review of and make a decision on such an application. Such an information request shall not affect an operator's ability to request a hearing pursuant to Rule 303.e seventy-five (75) days from the date the Form 2 or Form 2A was originally determined to be complete pursuant to Rule 303.h.

303.g. Permit expiration.

- (1) Applications for Permit-to-Drill, Form 2. Approval of a Form 2 shall become null and void if drilling operations on the permitted well are not commenced within two (2) years after the date of approval. The Director shall not approve extensions to Applications for Permit-to-Drill, Form 2.
- (2) Oil and Gas Location Assessments, Form 2A. If construction operations are not commenced on an approved Oil and Gas Location within three (3) years after the date of approval, then the approval shall become null and void. The Director shall not approve extensions to Oil and Gas Location Assessments, Form 2A.

303.h. Permits in areas pending Commission hearing. The Director may withhold the issuance of any Applications for Permit-to-Drill, Form 2, for any well or proposed well that is located in an area for which an application has been filed, or which the Commission has sought, by its own motion, to establish drilling units. The hearing thereon shall be held at the next meeting of the Commission, or as soon as practicable before an Administrative Law Judge or Hearing Officer.

303.i. Special circumstances for permit issuance without notice or consultation. The Director may issue a permit at any time in the event that an operator files a sworn statement and demonstrates therein to the Director's satisfaction that:

- (1) The operator had the right or obligation under the terms of an existing contract to drill a well; and the owner or operator has a leasehold estate or a right to acquire a leasehold estate under said contract which will be terminated unless the operator is permitted to immediately commence the drilling of said well; or
- (2) Due to exigent circumstances (including a recent change in geological interpretation), significant economic hardship to a drilling contractor will result or significant economic hardship to an operator in the form of drilling stand by charges will result.

In the event the Director issues a permit under this rule, the operator shall not be required to meet obligations to Surface Owners, local governmental designees, the Colorado Department of Public Health and Environment, or Colorado Parks and Wildlife under Rule 305 (except Rules 305.f.(4) and 305.f.(6), for which compliance will still be required) and 306. The Director shall report permits granted in such manner to the Commission at regularly scheduled monthly hearings.

303.j. Special circumstances for withholding approval of Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A.

- (1) The Director may withhold approval of any Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, for any proposed well or Oil and Gas Location when, based on information supplied in a written complaint submitted by any party with standing under Rule 522.a.(1), other than a local governmental designee, or by staff analysis, the Director has reasonable cause to believe the proposed well or Oil and Gas Location is in material violation of the Commission's rules, regulations, orders or statutes, or otherwise presents an imminent threat to

public health, safety and welfare, including the environment, or a material threat to wildlife resources. Any such withholding of approval shall be limited to the minimum period of time necessary to investigate and dismiss the complaint, or to resolve the alleged violation or issue. If the complaint is dismissed or the matter resolved to the dissatisfaction of the complainant, such person may consult with the parties identified in Rule 503.b.(7).

- (2) In the event the Director withholds approval of any Application for Permit-To-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, under this Rule 303.j., an operator may ask the Commission to issue an emergency order rescinding the Director's decision.

303.k. **Suspending approved Application for Permit-To-Drill, Form 2.** Prior to the spudding of the well, the Director shall suspend an approved Application for Permit-to-Drill, Form 2, if the Director has reasonable cause to believe that information submitted on the Application for Permit-to-Drill, Form 2 was materially incorrect. Under the circumstances described in Rule 303.i.(1) or (2), an operator may ask the Commission to issue an emergency order rescinding the Director's decision.

303.l. **Reclassification of stratigraphic well.** If a test for productivity is made in a stratigraphic well, the well must be reclassified as a well drilled for oil or gas and is subject to all of the rules and regulations for well drilled for oil or gas, including filing of reports and mechanical logs.

303.m. **Provisions for avoiding mine sites.** Any person holding, or who has applied for, a permit issued or to be issued under §34-33-101 to 137, C.R.S., may at their election, notify the Director of such permit or application. Such notice shall include the name, mailing address and facsimile number of such person and designate by legal description the life-of-mine area permitted, or applied for, with the Division of Reclamation, Mining, and Safety. As soon as practicable after receiving such notice and designation, the Director shall inform the party designated therein each time that an Application for Permit-to-Drill, Form 2, is filed with the Director which pertains to a well or wells located or to be located within said life-of-mine area as designated. The provisions of Rule 303.i.(1) and (2) will not be applicable to this rule.

304. FINANCIAL ASSURANCE REQUIREMENTS

Prior to drilling or assuming the operations for a well an operator shall provide financial assurance in accordance with the 700 Series rules. When an operator's existing wells are not in compliance with the 700 Series, the Director may withhold action on an Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, until such time as a hearing on the permit application is held by the Commission. Such hearing shall be held at the next regularly scheduled Commission hearing, or as soon as practicable before an Administrative Law Judge or Hearing Officer.

305A. LOCAL GOVERNMENT NOTIFICATION AND CONSULTATION FOR LARGE UMA FACILITIES

a. **Notice of Intent to Construct a Large UMA Facility.** Subject to the exceptions specified in subsection 305A.e., an operator proposing a Large UMA Facility shall deliver a written Notice of Intent to Construct a Large UMA Facility not less than 90 days prior to initiating the Form 2A process with the Commission and before the operator has finalized a specific location with the Surface Owner as follows:

- (1) The Notice must be delivered to:

A. The local government with land use authority over the proposed location of a Large UMA Facility; and

B. The Surface Owner of the lands on which a Large UMA Facility is proposed.

(2) The operator must deliver the Notice by hand delivery; certified mail, return-receipt requested; electronic mail, return receipt requested; or by other delivery service with receipt confirmation unless an alternative method of notice is pre-approved by the Director.

b. Content of Notice of Intent to Construct a Large UMA Facility. A Notice of Intent to Construct a Large UMA Facility shall include the following information:

(1) A description and depiction of the proposed Oil and Gas Location and the planned facilities;

(2) A description of the siting rationale for proposing to locate the facility within the Urban Mitigation Area, including a description of other sites considered and the reasons such alternate sites were rejected; and

(3) An offer to consult with the local government with land use authority over the proposed location to seek agreement regarding siting the Large UMA Facility, considering alternative locations and potential best management practices.

c. Consultation between the Operator and the Local Government with Land Use Authority.

If the local government with land use authority over the proposed Large UMA Facility accepts an operator's offer to consult in writing within 30 days of receipt of a Notice of Intent to Construct a Large UMA Facility, the operator shall consult in good faith regarding siting of, and best management practices to be employed at, the proposed location.

(1) The operator will invite the Surface Owner to participate in the local government consultation so the Surface Owner's siting requests and concerns can be considered.

(2) The Director will participate in the consultation process between the local government and the operator at the request of either.

(3) If the local government and operator are unable to reach agreement regarding the location for a proposed Large UMA Facility, the operator shall offer in writing to engage in mediation with the local government.

A. If the local government agrees to mediation, the operator and the local government shall jointly select a mediator or mediators and equally share the cost of mediation.

B. Upon selection of a mediator(s), the mediation shall conclude within 45 days unless the operator and local government agree to an extension of time.

C. The Director is not a party to the mediation, but at the request of either the local government or the operator, the Director shall provide technical assistance to the parties or the mediator to the extent the Director is able.

(4) This Rule 305A.c. does not prescribe any particular form of consultation or local land use planning or approval process.

d. **Meeting with the Surface Owner.** Within 30 days of receiving the Notice of Intent to Construct a Large UMA Facility, the Surface Owner of the lands on which the operator proposes to locate a Large UMA Facility may request a meeting with the operator and Director regarding siting of the proposed Large UMA Facility. The Director will schedule the meeting.

e. **Exceptions to Large UMA Facility Notification and Consultation Process.**

(1) An operator proposing a Large UMA Facility is not required to provide a Notice of Intent to Construct a Large UMA Facility or to engage in the consultation processes described in Rule 305A.a.-d. in any of the following circumstances:

A. The local government with land use authority over the proposed location of a Large UMA Facility has opted out of the Rule 305A notification and consultation processes. A local government may opt out of the Rule 305A notification and consultation processes by notifying the Director in writing that the local government does not wish to receive Notices of Intent to Construct Large UMA Facilities for such Facilities proposed within its jurisdiction.

B. The operator and the local government with land use authority over the proposed location of a Large UMA Facility have an existing agreement regarding siting of oil and gas locations and the proposed Large UMA Facility is within the scope of the agreement. An operator relying on this exception shall submit a copy of relevant provisions of the agreement with its Form 2A as required by Rule 303.b.(3)K. to demonstrate compliance with Rule 305A.

C. The Large UMA Facility is proposed to be located within an approved 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.), and which expressly governs the location of Wells or Production Facilities on the surface estate. An operator relying on this exception shall submit a copy of relevant portions of the plan and approval by the local government with its Form 2A as required by Rule 303.b.(3)K. to demonstrate compliance with Rule 305A.

D. The Location of the Large UMA Facility is within acreage identified as an oil and gas operations area included in an approved "Application for Development" as that is defined under §24-65.5-101, et. seq., C.R.S. An operator relying on this exception shall submit a copy of relevant portions of the plan and approval by the local government with its Form 2A as required by Rule 303.b.(3)K. to demonstrate compliance with Rule 305A.

(2) For a Form 2A submitted pursuant to (1)B., (1)C, or (1)D. of this Rule 305A.e., the Director within 30 days may verify with the local government with land use authority that the proposed Large UMA Facility is within the scope of the cited agreement or development plan. If, after conferring with the local government with land use authority and the operator, the Director determines the proposed Large UMA Facility is not within the scope of the cited agreement the Director will reject the Form 2A and notify the operator that it must comply with Rule 305A.a.-d.

(3) All Rule 604.c.(4) requirements apply to all Large UMA Facilities regardless of whether a proposed Large UMA Facility is excepted from the Rule 305A.a.-d. requirements pursuant to this Rule 305A.e.

f. Initiating the Form 2A Process.

- (1) An operator may initiate the Form 2A process by submitting its pre-application notices pursuant to Rule 305.a. once any of the following occur:
 - A. The operator and the local government with land use authority reach agreement regarding a proposed Large UMA Facility's site.
 - B. The operator asserts the proposed Large UMA Facility is subject to an exception pursuant to Rule 305A.e.
 - C. The local government with land use authority waives the Rule 305A procedures in writing.
 - D. The local government with land use authority fails to respond in writing within 30 days of receiving the Notice of Intent to Construct a Large UMA Facility.
 - E. At least 90 days have passed since the local government with land use authority received a written Notice of Intent to Construct a Large UMA Facility and the local government and the operator have engaged in consultation pursuant to Rule 305A.c., but have not reached agreement. In these cases, the operator may initiate the Form 2A process with its preferred site, but must state on the Form 2A that the local government does not agree with the site for the proposed Large UMA Facility. A Form 2A submitted under these circumstances will be docketed for a Commission hearing as follows:
 - i. The Director will notify the operator and local government with land use authority when the Director's technical review is complete and will confirm whether an agreement has been reached regarding the site for the proposed location.
 - ii. If an agreement has been reached, the Director will issue a decision on the Form 2A.
 - iii. If an agreement has not been reached, the Director will notice the Form 2A for a Commission hearing.
 - aa. Such a hearing shall be expedited but will be held only after both the 20 days' notice and the newspaper notice are given as required by §34-60-108, C.R.S. However, the hearing can be held after the newspaper notice if all of the entities listed under Rule 503.b. waive the 20-day notice requirement.
 - bb. The hearing will be conducted pursuant to Rule 528.a. For purposes of the hearing, the operator will be the Applicant and the local government with land use authority may intervene as a matter of right.
- (2) The Director will reject a Form 2A submitted for a Large UMA Facility if the documentation submitted with the Form 2A pursuant to Rule 303.b.(3)K. does not demonstrate compliance with Rule 305A for the proposed Large UMA Facility.

305. FORM 2 AND 2A APPLICATION PROCEDURES

a. Pre-application notifications.

- (1) Urban Mitigation Area Notice to Local Government. For proposed Oil and Gas Locations within an Urban Mitigation Area, an Operator shall notify the local government in writing that it intends to apply for an Oil and Gas Location Assessment. The operator will provide a Notice of Intent to Conduct Oil and Gas Operations to the Local Governmental Designee in those jurisdictions that have designated an LGD or to the local government planning departments in jurisdictions that have not designated an LGD no less than 30 days before the operator submits a Form 2A, Oil and Gas Location Assessment, to the Director. The notice shall include a general description of the proposed Oil and Gas Facilities, the location of the proposed Oil and Gas Facilities, the anticipated date operations (by calendar quarter and year) will commence, and that an additional notice pursuant to Rule 305.c. will be sent by the Operator. This notice shall serve as an invitation to the local government to engage in discussions with the Operator regarding proposed operations and timing, local government jurisdictional requirements, and opportunities to collaborate regarding site development. A local government may waive its right to notice under this provision at any time by providing written notice to an Operator and the Director. The notice requirement of this subpart does not apply to local governments that received notice and accepted the offer to consult pursuant to Rule 305A.a.

- (2) Exception Zone and Buffer Zone Setback Notice to the Surface Owner and Building Unit Owners. For Oil and Gas Locations proposed within the Exception Zone or Buffer Zone Setback, Operators shall notify the Surface Owner and the owners of all Building Units that a permit to conduct Oil and Gas Operations is being sought no less than 30 days before the operator submits the Form 2A, Oil and Gas Location Assessment, to the Director. The Operator may rely on the county assessor tax records to identify the persons entitled to receive the Notice. Notice shall include the following:
 - A. The Operator's contact information;
 - B. The location and a general description of the proposed Well or Oil and Gas Facilities;
 - C. The anticipated date operations will commence (by calendar quarter and year);
 - D. The Local Governmental Designee's (LGD) contact information;
 - E. Notice that the Building Unit owner may request a meeting to discuss the proposed operations by contacting the LGD or the Operator; and
 - F. A "Notice of Comment Period" will be sent pursuant to Rule 305.c. when the public comment period commences.

- (3) Large UMA Facility Notice to Proximate Local Governments. For a proposed Large UMA Facility, an operator shall notify any home rule or statutory city, town, territorial charter city, combined city and county, or county (for purposes of this section "Proximate Local Governments") within 1,000 feet of the proposed site that a permit to construct a Large UMA Facility is being sought not less than 45 days prior to submitting a Form 2A, Oil and Gas Location Assessment, to the Director.

A local government may waive its right to notice under this provision at any time by providing written notice to the operator and the Director.

- A. The Notice shall include the following: the operator's contact information; a description of the location and a general description of the proposed Large UMA Facility; and state that the Proximate Local Government may provide comments as provided in Rule 305.d.
- B. The Director will respond in writing to any Proximate Local Government comments regarding specific best management practices reasonably related to potential significant adverse impacts to public health, safety and welfare, including the environment and wildlife resources, that are within the Commission's jurisdiction to remedy for the proposed Large UMA Facility.

(4) Notice to School, Child Care Center, and School Governing Body.

- A. An operator will notify any relevant school or child care center, and school governing body, of a proposed oil and gas location within one-thousand, three hundred, twenty (1,320) feet or less from:
 - i. The property line of a parcel currently owned by the school, child care center, or school governing body as identified through county assessor records;
 - ii. The property line of a parcel considered a future school facility as identified on the final approved plat that may be obtained from the planning department of the relevant local government; or
 - iii. What reasonably appears to be a school facility (regardless of property ownership) based on the operator's review of current aerial maps that show surface development or surveys of the area.
- B. The operator will provide a pre-application Notice of Intent to Conduct Oil and Gas Operations to the principal or senior administrator of the school and to all applicable school governing bodies no less than 30 days before the operator submits the Form 2A, Oil and Gas Location Assessment, to the Director.
- C. The Notice will include:
 - i. The operator's contact information;
 - ii. The location and general description of the proposed oil and gas location, including the School Facilities Map as required under Rule 303.b.(3)U;
 - iii. The Local Governmental Designee's (LGD) contact information;
 - iv. The anticipated date, by calendar year and quarter, that construction will begin and the expected schedule of drilling and completion activities;
 - v. Whether the operator anticipates the proposed wells or production facilities will be subject to the mitigation measures in Rule 604.c.;

- vi. Whether the oil and gas location, wells, or production facilities are subject to a memorandum of understanding or other agreement with, or approval from, the relevant local government regarding location;
 - vii. Notice that the school governing body for the school facility or child care center may request a consultation to discuss the proposed operations by contacting the operator, and that the Director may be invited to any meeting. A school or child care center may delegate the consultation process to the principal or senior administrator of the school or child care center in proximity to the oil and gas location; and
 - viii. Notice that the school, child care center, or school governing body may submit comments regarding the proposed oil and gas location to the Commission as part of the Rule 305.d. public comment period.
- D. A school governing body may waive the right to notice for it and all schools within the area subject to the school governing body's oversight under this provision at any time by providing written notice to the operator and the Director.

b. Posting Form 2A and Form 2.

- (1) **Form 2A.** Upon receipt of an Oil and Gas Location Assessment, Form 2A, the Director shall, as provided by Rule 303, determine if the application is complete and, if so, post such Form 2A on the Commission's website. The Commission shall provide concurrent electronic notice of such posting to the relevant Local Governmental Designee (LGD) and the Colorado Parks and Wildlife (where consultation is triggered pursuant to Rule 306.c) and the Colorado Department of Public Health and Environment (where consultation is triggered pursuant to Rule 306.d). The website posting shall clearly indicate:
- A. The date on which the Form 2A was posted;
 - B. The date by which public comments must be received to be considered;
 - C. The address(es) to which the public may direct comments; and
 - D. Where the proposed Oil and Gas Location is covered by an accepted Comprehensive Drilling Plan, directions for review of the Plan.
- (2) **Form 2.** If an Application for Permit-to-Drill, Form 2, is concurrently filed with a Form 2A, that fact shall be noted in the posting provided herein. If a Form 2 is subsequently filed, only a summary notice of such filing, indicating that a Form 2A covering the well has been previously accepted or approved, shall be posted, with concurrent notice to the local governmental designee and, where consultation with one of those agencies is triggered, the Colorado Parks and Wildlife or Colorado Department of Public Health and Environment.
- 305.c. **Completeness determination and comment period notifications.** Upon receipt of a completeness determination from the Director, an Operator shall notify the persons specified herein of their opportunity to meet with the Operator pursuant to Rule 306 and submit written comments about the proposed Oil and Gas Location to the Director, the LGD, and the Operator, and shall provide information about the Oil and Gas Location as follows:

(1) **Oil and Gas Location Assessment Notice (“OGLA Notice”).**

A. Parties to be noticed:

- i. Surface Owners;
- ii. Owners of all Building Units within the Exception Zone Setback; and
- iii. Owners of surface property within five hundred (500) feet of the proposed Oil and Gas Location, for proposed Oil and Gas Locations not subject to Rule 318A or 318B.

The operator may rely on the tax records of the assessor for the county in which the affected lands are located to identify the persons entitled to receive the OGLA Notice.

B. The OGLA Notice shall be delivered by hand; certified mail, return-receipt requested; electronic mail, return receipt requested; or by other delivery service with receipt confirmation unless an alternative method of notice is pre-approved by the Director.

C. The OGLA Notice shall include:

- i. The Form 2A itself (without attachments);
- ii. A copy of the information required under Rule 303.b.(3).C, 303.b.(3).D, 303.b.(3).F, and 303.b.(3).J.i.;
- iii. The COGCC’s information sheet on hydraulic fracturing treatments except where hydraulic fracturing treatments are not going to be applied to the well in question;
- iv. Instructions on how Building Unit owners can contact their Local Governmental Designee;
- v. An invitation to meet with the Operator before Oil and Gas Operations commence on the proposed Oil and Gas Location;
- vi. An invitation to provide written comments to the LGD, the Operator and to the Director regarding the proposed Oil and Gas Operations, including comments regarding the mitigation measures or Best Management Practices to be used at the Oil and Gas Location.

(2) **Buffer Zone Notice.** A “Notice of Comment Period” shall be provided by postcard to owners of Building Units within the Buffer Zone. The operator may rely on the county assessor tax records to identify the persons entitled to receive the Buffer Zone Notice. Notice shall include the following information:

- A. The Operator’s contact information;
- B. The Local Governmental Designee’s contact information;
- C. The COGCC’s website address and telephone number;

- D. The location of the proposed Oil and Gas Facilities and the anticipated date operations will commence (by month and year);
- E. An invitation to meet with the Operator before Oil and Gas Operations commence on the proposed Oil and Gas Location;
- F. An invitation to provide written comments to the LGD, the Operator and to the Director regarding the proposed Oil and Gas Operations, including comments regarding the mitigation measures or Best Management Practices to be used at the Oil and Gas Location.

(3) **Appointment of agent.** The Surface Owner or Building Unit owner may appoint an agent, including its tenant, for purposes of subsequent notice and for consultation or meetings under Rule 306. Such appointment shall be made in writing to the operator and must provide the agent's name, address, and telephone number.

(4) **Tenants.** With respect to notices given under this Rule 305, it shall be the responsibility of the notified Surface Owner or Building Unit owner to give notice of the proposed operation to the tenant farmer, lessee, or other party that may own or have an interest in any crops or surface improvements that could be affected by such proposed operation.

(5) **Waiver.** Any of the notices required herein may be waived in writing by the Surface Owner, its agent, or the Local Governmental Designee, provided that a waiver by a Surface Owner or its agent shall not prevent the Surface Owner or any successor-in-interest to the Surface Owner from rescinding that waiver if such rescission is in accordance with applicable law.

305.d. **Comment period.** The Director shall not approve a Form 2A, or any associated Form 2, for a proposed Well or Production Facility during the comment period, and shall accept and immediately post on the Commission's website any comments received from the public, the Local Governmental Designee, the Colorado Department of Public Health and Environment, or Colorado Parks and Wildlife regarding the proposed Oil and Gas Location.

(1) The comment period for a Form 2 or a Form 2A for an Oil and Gas Location that is not a Large UMA Facility is 20 days from posting pursuant to Rule 305.b.

A. The Director shall extend the comment period to 30 days upon the written request during the 20-day comment period by the Local Governmental Designee, the Colorado Department of Public Health and Environment, Colorado Parks and Wildlife, the Surface Owner, or an owner of surface property who receives notice under Rule 305.c.(1)A.iii.

B. For Oil and Gas Locations proposed within an Urban Mitigation Area or within 500 feet of a Building Unit, the Director shall extend the comment period to not more than 40 days upon the written request of the Local Governmental Designee received within the original 20-day comment period.

(2) For a Large UMA Facility, the comment period is 40 days from posting pursuant to Rule 305.b.

(3) At the Director's sole discretion, the comment periods identified above may be extended or re-opened for a period not to exceed 20 days.

- (4) The Director shall post notice of an extension granted under this provision on the COGCC website within 24 hours of receipt of the extension request.

305.e. **Permit approval.** Upon the conclusion of the comment period and, where applicable, consultation with the Local Governmental Designee, Colorado Parks and Wildlife or Colorado Department of Public Health and Environment pursuant to Rules 306.b, 306.c. or 306.d, respectively, the Director may attach technically feasible and economically practicable conditions of approval to the Form 2 or Form 2A as the Director deems necessary to implement the provisions of the Act or these rules pursuant to Commission staff analysis or to respond to legitimate public health, safety, or welfare concerns expressed during the comment period. Provided, that an applicant under Rule 503 who claims that such a condition is not technically feasible, economically practicable, or necessary to implement the provisions of the Act or these rules, or to respond to legitimate public health, safety, or welfare concerns shall have the burden of proof on that issue before the Commission.

- (1) **Notice of decision.** Upon making a decision on an Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, the Director shall promptly provide notification of the decision and any conditions of approval to the operator and to any party with standing to request a hearing before the Commission pursuant to Rule 503.b, unless such a party has waived in writing its right to such notice and the Director has been provided a copy of such waiver.

- (2) **Suspension of approval.** If a party, Surface Owner or local government requests a hearing before the Commission pursuant to Rule 503.b on an Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, then it shall notify the Director in writing within ten (10) days after the issuance of the decision, setting forth the basis for the objection. Upon receipt of such an objection, the Director shall suspend the approval of the Form 2 or Form 2A and set the matter for an expedited adjudicatory hearing. Such a hearing shall be expedited but will only be held after both the 20 days' notice and the newspaper notice are given as required by Section 34-60-108, C.R.S. However, the hearing can be held after the newspaper notice if all of the entities listed under Rule 503.b waive the 20-day notice requirement. If such an objection is not received, the permit shall issue as proposed by the Director.

- (3) **Appeal.** If the approval of a Form 2 or Form 2A is not suspended as provided for herein, the issuance of the approved Form 2 or Form 2A by the Director shall be deemed a final decision of the Commission, subject to judicial appeal.

305.f. **Statutory Notice to Surface Owners.** Not less than thirty (30) days in advance of commencement of operations with heavy equipment for the drilling of a well, operators shall provide the statutorily required notice to the well site Surface Owner(s) as described below and the Local Governmental Designee in whose jurisdiction the well is to be drilled. Notice to the Surface Owner may be waived in writing by the Surface Owner.

- (1) Surface Owner Notice is not required on federal- or Indian-owned surface lands.
- (2) Surface Owner Notice shall be delivered by hand; certified mail, return-receipt requested; or by other delivery service with receipt confirmation. Electronic mail may be used if the Surface Owner has approved such use in writing.

- (3) The Surface Owner Notice must provide:
- A. The operator's name and contact information for the operator or its agent;
 - B. A site diagram or plat of the proposed well location and any associated roads and production facilities;
 - C. The date operations with heavy equipment are expected to commence;
 - D. A copy of the COGCC Informational Brochure for Surface Owners;
 - E. A postage-paid, return-addressed post card whereby the Surface Owner may request consultation pursuant to Rule 306; and,
 - F. A copy of the COGCC Onsite Inspection Policy (See Appendix or COGCC website), where the Oil and Gas Location is not subject to a Surface-Use Agreement.
- (4) **Notice of subsequent well operations.** An operator shall provide to the surface owner or agent at least seven (7) days advance notice of subsequent well operations with heavy equipment that will materially impact surface areas beyond the existing access road or well site, such as recompleting or stimulating the well.
- (5) **Notice during irrigation season.** If a well is to be drilled on irrigated crop lands between March 1 and October 31, the operator shall contact the Surface Owner or agent at least fourteen (14) days prior to commencement of operations with heavy equipment to coordinate drilling operations to avoid unreasonable interference with irrigation plans and activities.
- (6) **Final reclamation notice.** Not less than thirty (30) days before any final reclamation operations are to take place pursuant to Rule 1004, the operator shall notify the Surface Owner. Final reclamation operations shall mean those reclamation operations to be undertaken when a well is to be plugged and abandoned or when production facilities are to be permanently removed. Such notice is required only where final reclamation operations commence more than thirty (30) days after the completion of a well.

305.g. **Location Signage.** The Operator shall, concurrent with the Surface Owner Notice, post a sign not less than two feet by two feet at the intersection of the lease road and the public road providing access to the well site, with the name of the proposed well, the legal location thereof, and the estimated date of commencement. Such sign shall be maintained until completion operations at the well are concluded.

305.h. **Buffer Zone Move-In, Rig-Up Notice.** At least 30 days, but no more than 90 days, before the Move-In, Rig-Up of a drilling rig, the operator shall provide Move-In, Rig-Up ("MIRU") Notice to all Building Unit owners within the Buffer Zone if: (i) it has been more than one year since the previous notice or since drilling activity last occurred, or (ii) notice was not previously required.

- (1) The operator may rely on the county assessor tax records to identify the persons entitled to MIRU Notice. MIRU Notice shall be delivered by hand; certified mail, with return-receipt requested; electronic mail, with return receipt requested; or by other delivery service with receipt confirmation.
- (2) The MIRU Notice must include:

- A. A statement informing the Building Unit owner that the operator intends to Move-In and Rig-Up a drilling rig to drill wells within 1000 feet of their Building Unit;
- B. The operator's contact information;
- C. The legal location of the proposed wells (Quarter-Quarter, Section, Township, Range, County);
- D. The approximate street address of the proposed well locations (Street Number, Name, City);
- E. The name and number of the proposed wells, including the API Number if the APD has been approved or the eForm Document Number if the APD is pending approval;
- F. The anticipated date (Day, Month, Year) the drilling rig will move in and rig up; and
- G. The COGCC's website address and telephone number.

(3) A Building Unit owner entitled to receive MIRU Notice may waive their right in writing at any time.

(4) An operator may request an exception to this Rule and provide MIRU Notice less than 30 days prior to Move-In, Rig-Up of the drilling rig for good cause.

306. CONSULTATION AND MEETING PROCEDURES. Following the notifications provided for in Rule 305.c, an Operator shall comply with the following consultation and meeting procedures:

a. **Surface owners.** The Operator shall consult in good faith with the Surface Owner, or the Surface Owner's appointed agent as provided for in Rule 305 in locating roads, production facilities, and well sites, or other oil and gas operations, and in preparation for reclamation and abandonment. Such consultation shall occur at a time mutually agreed to by the parties prior to the commencement of operations with heavy equipment upon the lands of the Surface Owner. The Surface Owner or appointed agent may comment on preferred locations for wells and associated production facilities, the preferred timing of oil and gas operations, and mitigation measures or Best Management Practices to be used during Oil and Gas Operations.

(1) **Information provided by operator.** When consulting with the Surface Owner or appointed agent, the operator shall furnish a description or diagram of the proposed drilling location; dimensions of the drill site; topsoil management practices to be employed; and, if known, the location of associated production or injection facilities, pipelines, roads and any other areas to be used for oil and gas operations (if not previously furnished to such Surface Owner or if different from what was previously furnished).

(2) **Waiver.** The Surface Owner or the Surface Owner's appointed agent may waive, permanently or otherwise, their right to consult with the operator at any time. Such waiver must be in writing, signed by the Surface Owner, and submitted to the operator.

306.b. **Local governments.**

- (1) Local governments that have appointed a Local Governmental Designee and have indicated to the Director a desire for consultation shall be given an opportunity to consult with the Applicant and the Director on an Application for Permit-to-Drill, Form 2, or an Oil and Gas Location Assessment, Form 2A, for the location of roads, Production Facilities and Well sites, and mitigation measures or Best Management Practices during the comment period under Rule 305.d.
- (2) Within fourteen (14) days of being notified of a Form 2 or a Form 2A completeness determination pursuant to Rule 305.c, the Local Governmental Designee may notify the Commission and the Colorado Department of Public Health and Environment by electronic mail of its desire to have the Colorado Department of Public Health and Environment consult on a proposed Oil and Gas Location, based on concerns regarding public health, safety, welfare, or impacts to the environment.
- (3) For proposed Oil and Gas Locations within Exception Zone Setback or Urban Mitigation Areas, the Operator shall attend an informational meeting with Building Unit owners within the Exception Zone Setback or Urban Mitigation Area if the LGD requests such a meeting. Such informational meetings may be held on an individual basis, in small groups, or in larger community meetings and shall be held at a convenient place and time.

306.c. **Colorado Parks and Wildlife.**

(1) **Consultation to occur.**

- A. Subject to the provisions of Rule 1202.d, Colorado Parks and Wildlife shall consult with the Commission, the Surface Owner, and the Operator on an Oil and Gas Location Assessment, Form 2A, where:
 - i. Consultation is required pursuant to a provision in the 1200-Series of these rules;
 - ii. The operator seeks a variance from a provision in the 1200-Series of these rules; or
 - iii. Colorado Parks and Wildlife requests consultation because the proposed Oil and Gas Location would be within areas of known occurrence or habitat of a federally threatened or endangered species, as shown on the Colorado Parks and Wildlife Species Activity Mapping (SAM) system.
- B. The Commission shall consult with Colorado Parks and Wildlife when an operator requests a modification of an existing Commission order to increase well density or otherwise proposes to increase well density to more than one (1) well per forty (40) acres, or the Commission develops a basin-wide order involving wildlife or wildlife-related environmental concerns or protections.
- C. Notwithstanding the foregoing, the requirement to consult with Colorado Parks and Wildlife may be waived by Colorado Parks and Wildlife at any time.

(2) **Procedure.**

- A. The operator shall provide:

- i. A description of the oil and gas operation to be considered, including location;
 - ii. Any other relevant available information on the oil and gas operation, the affected wildlife resource, or the provision(s) of the 1200-Series Rules upon which the consultation is based; and
 - iii. Proposed mitigation for the affected wildlife resource.
- B. The Commission shall take into account the information submitted by the operator consistent with Rule 1202.c.
- C. The operator, the Commission, the Surface Owner, and Colorado Parks and Wildlife shall have forty (40) days to conduct the consultation called for in this section. Such consultation shall begin concurrent with the start of the public comment period. If no consultation occurs within such 40-day period, the requirement to consult shall be deemed waived, and the Director shall consider the operator's application on the basis of the materials submitted by the operator.

(3) Result of consultation under Rule 306.c.

- A. As a result of consultation called for in this subsection, Colorado Parks and Wildlife may make written recommendations to the Commission on conditions of approval necessary to minimize adverse impacts to wildlife resources. Where applicable, Colorado Parks and Wildlife may also make written recommendations on whether a variance request should be granted, under what conditions, and the reasons for any such recommendations.
- B. **Agreed-upon conditions of approval.** Where the operator, the Director, Colorado Parks and Wildlife, and the Surface Owner agree to conditions of approval for Oil and Gas Locations as a result of consultation, these conditions of approval shall be incorporated into approvals of an Oil and Gas Location Assessment, Form 2A, or an Application for Permit-to-Drill, Form 2, where applicable.
- C. **Permit-specific conditions.** Where the consultation called for in this subsection results in permit-specific conditions of approval to minimize adverse impacts to wildlife resources, the Director shall attach such permit-specific conditions only with the consent of the affected Surface Owner.
- D. **Standards for consultation and initial decision.** Following consultation and subject to subsection C above and Rule 1202.c, the Director shall decide whether to attach conditions of approval to a Form 2A or Form 2, where applicable. In making this decision, the Director shall apply the criteria of Rule 1202.
- E. **Notification of decision to consulting agency.** Where consultation occurs under Rule 306.c, the Director shall provide to Colorado Parks and Wildlife the conditions of approval for the Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, on the same day that he or she announces a decision to approve the application.

306.d. **Colorado Department of Public Health and Environment.**

(1) **Consultation to occur.**

A. The Commission shall consult with the Colorado Department of Public Health and Environment on an Application for Permit-to-Drill, Form 2, or an Oil and Gas Location Assessment, Form 2A, where:

i. Within 14 days of notification pursuant to Rule 305, the Local Governmental Designee requests the participation of the Colorado Department of Public Health and Environment in the Commission's consideration of an Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, based on concerns regarding public health, safety, welfare, or impacts to the environment;

ii. The operator seeks from the Director a variance from, or consultation is otherwise required or permitted under, a provision of one of the following rules intended for the protection of public health, safety, welfare, or the environment:

aa. Rule 317B. Public Water System Protection;

bb. Rule 325. Underground Disposal of Water;

cc. Rule 603. Statewide Location Requirements for Oil and Gas Facilities, Drilling, and Well Servicing Operations;

dd. Rule 604. Setback and Mitigation Measures for Oil and Gas Facilities, Drilling, and Well Servicing Operations;

ee. Rule 608. Coalbed Methane Wells;

ff. Rule 805. Odors and Dust;

gg. 900-Series E&P Waste Management; or

hh. Rule 1002.f. Stormwater Management.

All requests for variances from these rules must be made at the time an operator submits a Form 2A.

iii. The operator submits an Application for an Oil and Gas Location Assessment, Form 2A, for a Large UMA Facility.

B. The Commission shall consult with the Colorado Department of Public Health and Environment when an operator requests a modification of an existing Commission order to increase well density or otherwise proposes to increase well density to more than one (1) well per forty (40) acres, or the Commission develops a basin-wide order that can reasonably be anticipated to have impacts on public health, welfare, safety, or environmental concerns or protections.

- C. Notwithstanding the foregoing, the requirement to consult with the Colorado Department of Public Health and Environment may be waived by the Colorado Department of Public Health and Environment at any time.

(2) Procedure.

- A. Where required, the Commission and the Colorado Department of Public Health and Environment shall have forty (40) days to conduct the consultation called for in this section. Such consultation shall begin concurrent with the start of the public comment period. If no consultation occurs within such 40-day period, the requirement to consult shall be waived, and the Director shall consider the operator's application on the basis of the materials submitted by the operator.
- B. The consultation called for in this section shall focus on identifying potential impacts to public health, safety, welfare, or the environment from activities associated with the proposed Oil and Gas Location, and development of conditions of approval or other measures to minimize adverse impacts.
- C. Where consultation occurs pursuant to Rule 306.d.(1).A, it may include:
 - i. Review of the permit application;
 - ii. Discussions with the local governmental designee to better understand local government's concerns;
 - iii. Discussions with the Commission, operator, Surface Owner, or those potentially affected; and
 - iv. Review of public comments.
- D. Where consultation occurs pursuant to Rule 306.d.(1).A.ii, the Colorado Department of Public Health and Environment shall have the opportunity to:
 - i. Review the permit application, the request for variance, and the basis for the request; and
 - ii. Discuss the request with the operator, the surface owner, and the Commission.
- E. Where consultation occurs pursuant to Rule 306.d.(1).B, the Colorado Department of Public Health and Environment shall have the opportunity to:
 - i. Review the well-density increase application or draft Commission order; and
 - ii. Discuss the request with the operator or proponent, the Commission, and the local governmental designee.

(3) Results of consultation under Rule 306.d.

- A. As a result of consultation called for in this subsection, the Colorado Department of Public Health and Environment may make written

recommendations to the Commission on conditions of approval necessary to protect public health, safety, and welfare or the environment. Such recommendations may include, but are not limited to, monitoring requirements or best management practices. Where applicable, the Colorado Department of Public Health and Environment may also make written recommendations on whether a variance request should be granted, under what conditions, and the reasons for any such recommendations.

- B. **Agreed-upon conditions of approval.** Where the operator, the Director, the Colorado Department of Public Health and Environment, and the Surface Owner agree to conditions of approval for Oil and Gas Locations as a result of consultation, these conditions of approval shall be incorporated into approvals of an Oil and Gas Location Assessment, Form 2A, or Applications for Permit-to-Drill, Form 2, where applicable.
- C. **Standards for consultation and Director decision.** Following consultation, the Director shall decide whether to attach conditions of approval recommended by the Colorado Department of Public Health and Environment to a Form 2A or Form 2, where applicable. This decision shall minimize significant adverse impacts to public health, safety, and welfare, including the environment, consistent with other statutory obligations.
- D. **Notification of decision to consulting agency.** Where consultation occurs under Rule 306.d, the Director shall provide to the Colorado Department of Public Health and Environment the conditions of approval for the Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, on the same day that he or she announces a decision to approve the application.

306.e. **Meetings with Building Unit Owners Within a Buffer Zone Setback.**

- (1) **Meetings with Building Unit Owners.** An Operator shall be available to meet with Building Unit owners who received an OGLA Notice or a Buffer Zone Notice pursuant to Rule 305.c. and requested a meeting regarding the proposed Oil and Gas Location. Operators shall also be available to meet with such Building Unit owners if requested to do so by the Local Governmental Designee and such meetings shall comply with Rule 306.b.(3). Such informational meetings may be held on an individual basis, in small groups, or in larger community meetings.
- (2) **Information provided by operator.** When meeting with Building Unit owners or their appointed agent(s) pursuant to subsection (1), above, the Operator shall provide the following information: the date construction is anticipated to begin; the anticipated duration of pad construction, drilling and completion activities; the types of equipment anticipated to be present on the Location; and the operator's interim and final reclamation obligation. In addition, the Operator shall present a description and diagram of the proposed Oil and Gas Location that includes the dimensions of the Location and the anticipated layout of production or injection facilities, pipelines, roads and any other areas to be used for oil and gas operations. The Operator and Building Unit owners shall be encouraged to discuss potential concerns associated with Oil and Gas Operations, such as security, noise, light, odors, dust, and traffic, and shall provide information on proposed or recommended Best Management Practices or mitigation measures to eliminate, minimize or mitigate those issues.

- (3) **Waiver.** The Building Unit owner or agent may waive, permanently or otherwise, the foregoing meeting requirements. Any such waiver shall be in writing, signed by the owner or agent, and shall be submitted by the Building Unit owner or agent to the operator and the Director.
- (4) **Mitigation Measures.** Operators will consider all legitimate concerns related to public health, safety, and welfare raised during informational meetings or in written comments and, in consultation with the Director and Local Governmental Designee if the LGD so requests, will add relevant and appropriate Best Management Practices or mitigation measures as Conditions of Approval into the Form 2A and any associated Form 2s.
- (5) **Operator Certification.** The Director shall not approve a Form 2A, Oil and Gas Location Assessment, until the operator certifies it has complied with the meeting requirements of this Rule 306.e.
- 306.f. **Final reclamation consultation.** In preparing for final reclamation and plugging and abandonment, the operator shall use its best efforts to consult in good faith with the affected Surface Owner (or the tenant when the Surface Owner has requested that such consultation be made with the tenant). Such good faith consultation shall allow the Surface Owner (or appointed agent) the opportunity to provide comments concerning preference for timing of such operations and all aspects of final reclamation, including, but not limited to, the desired final land use and seed mix to be applied.
- 306.g. **Tenants.** Operators shall have no obligation to consult with tenant farmers, lessees, or any other party that may own or have an interest in any crops or surface improvements that could be affected by the proposed operation unless the Surface Owner appoints such person as its agent for such purposes. Nothing shall prevent the Surface Owner from including a tenant in any consultation, whether or not appointed as the Surface Owner's agent.
- 306.h. **School, Child Care Center, and School Governing Body.** The operator will offer to consult with the school governing body that received notice pursuant to Rule 305.a.(4). During the consultation, the school governing body may identify additional discrete facilities or areas it considers a school facility or child care center, and the operator will provide information regarding best management practices, operations, traffic management, and phases of development for the proposed oil and gas location. The operator and school governing body are encouraged to share information regarding operations and mitigation to attempt agreement regarding school facility and child care center setbacks.

307. COGCC Form 4. SUNDRY NOTICES

The Sundry Notice, Form 4, is a multipurpose form which shall be used by an operator to request approval from or provide notice to the Director as required by rule or when no other specific form exists, i.e., well name or number change. The rules requiring the use of the Sundry Notice, Form 4, are listed in Appendix I.

308A. COGCC Form 5. DRILLING COMPLETION REPORT

a. Preliminary Drilling Completion Report, Form 5

- (1) If drilling is suspended prior to reaching total depth and does not recommence within 90 days, an Operator will submit a "Preliminary" Drilling Completion Report, Form 5 within the next 10 days.

- (2) **Information Requirements.** The “Preliminary” Drilling Completion Report, Form 5 will include the following information:
- A. The date drilling activity was suspended;
 - B. The reason for the suspension;
 - C. The anticipated date and method of resumption of drilling; and
 - D. The details of all work performed to date, including all the information required in Rule 308A.b.(2) that has been obtained.
- (3) A “Final” Form 5 will be submitted after reaching total depth as required by Rule 308A.b.

308A.b. Final Drilling Completion Report, Form 5

- (1) A “Final” Drilling Completion Report, Form 5, will be submitted within 60 days of rig release after drilling, sidetracking, or deepening a Well to total depth. In the case of continuous, sequential drilling of multiple wells on a pad, the Final Form 5 will be submitted for all the wells within 60 days of rig release for the last Well drilled on the pad.
- (2) **Information Requirements.** The “Final” Drilling Completion Report, Form 5 will include the following information:
- A. A cement job summary for every casing string set or required by permit conditions will be attached to the form. The cement summary report will include cement reports and charts related to cement placement, which will include:
 - i. Daily operations summary; and
 - ii. Cement verification reports from the cementing contractor.
 - B. All logs run, open-hole and cased-hole, electric, mechanical, mud, or other, will be reported and submitted as specified here:
 - i. A digital image file (PDF, TIFF, PDS, or other format approved by the Director) of every log run will be attached to the form. The digital image file of the cement bond log will include a variable density display.
 - ii. A digital data file (LAS, DLIS, or other format approved by the Director) of every log run, with the exception of mud logs and cement bond logs, will be attached to the form.
 - C. All drill stem tests will be reported and test results will be attached to the form.
 - D. All cores will be reported and the core analyses attached to the form. If core analyses are not yet available, the Operator will note this on the Form 5 and provide a copy of the analyses as soon as it is available, via a Sundry Notice, Form 4.
 - E. Any directional survey will be attached to the form and will meet the requirements set forth in Rule 321.

- F. The latitude and longitude coordinates of the “as drilled” well location will be reported on the form. The latitude and longitude coordinates will be in decimal degrees to an accuracy and precision of five decimals of a degree using the North American Datum (NAD) of 1983 (e.g. latitude 37.12345, longitude -104.45632). If GPS technology is utilized to determine the latitude and longitude, all GPS data will meet the requirements set forth in Rule 215. The Operator will report the accuracy value expressed in meters and the date of the GPS measurement on the Form 5.
 - G. The bradenhead pressure action threshold, which is calculated as 30% of the true vertical depth (TVD) in feet of the surface casing shoe expressed in psig.
- (3) The Operator will submit a Drilling Completion Report, Form 5, within 30 days of the completion of well operations in which the casing or cement in the wellbore is changed. Changes to the wellbore casing or cement configuration include, but are not be limited to, the operations listed in Rule 317.e.(9). The Drilling Completion Report, Form 5 will include the information required in 308A.b.(2). The form will include the following attachments:
- A. Daily operations summary;
 - B. Cement verification reports from the contractor; and
 - C. Cement bond log(s) if run by rule, choice, or as a required condition of the repair approval, submitted pursuant to Rule 308A.b.(2).B.

308B. COGCC Form 5A. COMPLETED INTERVAL REPORT

308B.a. The Operator will submit the Completed Interval Report, Form 5A, within 30 days after a formation is completed (successful or not); after a formation is temporarily abandoned or permanently abandoned; after a formation is recompleted, reperforated, or restimulated; and after a formation is commingled.

308B.b. The Operator will report the details of hydraulic fracturing treatment, acidizing stimulation, or other stimulation, including the fluid volumes and items required on the Form 5A.

308B.c. In order to resolve completed interval information uncertainties, the Director may require an operator to submit further information in an additional Completed Interval Report, Form 5A.

308C. CONFIDENTIALITY

Upon submittal of a Sundry Notice, Form 4, request by the operator, completion reports, including Drilling Completion Reports, Form 5 and Completed Interval Reports, Form 5A, and mechanical logs of exploratory or wildcat wells shall be marked “confidential” by the Director and kept confidential for six (6) months after the date of completion, unless the operator gives written permission to release such logs at an earlier date.

309. COGCC Form 7. OPERATOR'S MONTHLY REPORT OF OPERATIONS

- a. Operators shall report all existing oil and gas wells that are not plugged and abandoned on the Operator's Monthly Report of Operations, Form 7, within 45 days after the end of each month. A well must be reported every month from the month that it is spud until it has been reported for one month as abandoned. Each formation that is completed in a well

shall be reported every month from the time that it is completed until it has been abandoned and reported for one month as abandoned. The reported volumes shall include all fluids produced during flowback, initial testing, and completion of the well.

- b. The volume of specific fluids injected into a Class II Underground Injection Control well shall be reported on an Operator's Monthly Report of Operations, Form 7, within 45 days after the end of each month. The specific Class II fluids reported on Form 7 are produced fluids and any gas or fluids used during enhanced recovery unit operations. Produced fluids include, but are not limited to, produced water and fluids recovered during drilling, casing cementing, pressure testing, completion, workover, and formation stimulation of all oil and gas wells including production, exploration, injection, service and monitoring wells.

Injection of any other Class II fluids requires separate volume reporting on a Form 14, as described in Rule 316A.

310. COGCC Form 8. OIL AND GAS CONSERVATION LEVY

On or before March 1, June 1, September 1 and December 1 of each year, every producer or purchaser, whichever disburses funds directly to each and every person owning a working interest, a royalty interest, an overriding royalty interest, a production payment and other similar interests from the sale of oil or natural gas subject to the charge imposed by §34-60-122(1) (a) C.R.S., 1973, as amended, will file a return with the Director showing by operator, the volume of oil, gas or condensate produced or purchased during the preceding calendar quarter, including the total consideration due or received at the point of delivery. No filing will be required when the charge imposed is zero mill (\$0.0000) per dollar value.

The levy will be an amount fixed by order of the Commission. The levy amount may, from time to time, be reduced or increased to meet the expenses chargeable against the oil and gas conservation and environmental response fund. The present charge imposed, as of October 1, 2020, is \$0.0015 per dollar value

311. COGCC Form 6. WELL ABANDONMENT REPORT

- a. **Notice of Intent to Abandon , Form 6.** Prior to the abandonment of a well, a Well Abandonment Report, Form 6 – Notice of Intent to Abandon, will be submitted to, and approved by, the Director. The Form 6 - Notice of Intent to Abandon will be completed and attachments included to fully describe the proposed abandonment operations. This includes the proposed depths of mechanical plugs and casing cuts; the proposed depths and volumes of all cement plugs; the amount, size and depth of casing and junk to be left in the Well; the volume, weight, and type of fluid to be left in the wellbore between cement or mechanical plugs; and the nature and quantities of any other materials to be used in the plugging. The Operator will provide a current wellbore diagram and a wellbore diagram showing the proposed plugging procedure with the Form 6. If the Well is not plugged within six months of approval, the operator will file a new Form 6 – Notice of Intent to Abandon.

- b. **Subsequent Report of Abandonment, Form, 6.**

(1) Within 30 days after abandonment, the Well Abandonment Report, Form 6 - Subsequent Report of Abandonment, will be filed with the Director. The abandonment details will include an account of the manner in which the abandonment or plugging work was performed. Copies of any casing pressure test results and downhole logs run during plugging and abandonment will be submitted with Form 6. Additionally, plugging verification reports detailing all procedures are required. A Plugging Verification Report will be submitted for each person or contractor actually setting the plugs. The Form 6 - Subsequent Report of Abandonment, and the Plugging Verification Reports will detail the depths of mechanical plugs and casing cuts, the depths and

volumes of all cement plugs, the amount, size, and depth of casing and junk left in the Well, the volume and weight of fluid left in the wellbore and the nature and quantities of any other materials used in the plugging. Plugging Verification Reports will conform with the Operator's report and both will show that plugging procedures are at least as extensive as those approved by the Director.

- (2) The Director will review an Operator's Well Abandonment Report, Form 6 - Subsequent Report of Abandonment, plugging records, and the well file to evaluate the abandonment or plugging work performed. The Director will approve the form or identify deficiencies for the Operator to correct and may require one of the following:
 - A. Surface or subsurface monitoring programs after the Well has been plugged and abandoned, if a subsurface or surface release occurred or may occur;
 - B. Re-entering the Well to complete additional remediation or plugging and abandonment work; or
 - C. Any other actions necessary to ensure proper plugging and abandonment of the Well.
- (3) If the Operator does not take actions necessary to correct deficiencies, the Director may issue a corrective action pursuant to Rule 208.

- c. **Re-Plugging.** A Well Abandonment Report, Form 6 – Notice of Intent to Abandon, will be submitted to, and approved by, the Director prior to the re-entry of a plugged and abandoned Well for the purpose of re-plugging the Well. A Well Abandonment Report, Form 6 - Subsequent Report of Abandonment will be filed with the Director within 30 days of the completion of the re-plugging operations. These forms will be submitted with all the information required above and any additional information required by current policy.
- d. **As-Drilled Location.** For all Wells being plugged, the Operator will report the latitude and longitude coordinates of the “as drilled” Well location on the Form 6. When plugging a Well for which this data has been obtained and submitted to the Commission previously, the Operator will submit this data on the Form 6 – Notice of Intent to Abandon. When plugging a Well for which this data has not yet been obtained and submitted to the Commission, the Operator will determine the “as drilled” location prior to plugging and submit the location on the Form 6 – Subsequent Report of Abandonment. The latitude and longitude coordinates will be in decimal degrees to an accuracy and precision of five decimals of a degree using the North American Datum (NAD) of 1983 (e.g. latitude 37.12345, longitude -104.45632). If the Operator uses GPS technology to determine the latitude and longitude, all GPS data will meet the requirements set forth in Rule 215. The Operator will report the accuracy value expressed in meters and the date of the GPS measurement on the Form 6.

312. COGCC Form 10. CERTIFICATE OF CLEARANCE AND/OR CHANGE OF OPERATOR

- a. Each operator of any oil or gas well completed after April 30, 1956, shall file with the Director, within thirty (30) days after initial sale of oil or gas a Certificate of Clearance and/or Change of Operator, Form 10, in accordance with the instructions appearing on such form, for each well producing oil or gas or both oil and gas. A Form 10 shall be filed for any well from which oil, gas or other hydrocarbon is being produced.

A Form 10 shall be filed within thirty (30) days should the oil transporter (first purchaser) and/or the gas gatherer (first purchaser) change. In addition, within fifteen (15) days of an operator change for any well, a Form 10 shall be filed with a filing and service fee as set by the Commission. (See Appendix III)

- b. Each operator of a Class II injection well shall file a new Form 10 with the Director within 30 days of the transfer of ownership.
- c. Whenever there shall occur a change in the producer or operator filing the certificate under Rule 312.a. hereof, or whenever there shall occur a change of transporter from any well within the State, a new Form 10 shall be executed and filed within fifteen (15) days in accordance with the instructions appearing on such form. In the case of temporary use of oil for well treating or stimulating purposes, no new form need be executed. In the case of other temporary change in transporter involving the production of less than one (1) month, the producer or operator may, in lieu of filing a new certificate, notify the Commission and the transporter authorized by the certificate on file with the Commission by letter of the estimated amount to be moved by the temporary transporter and the name of such temporary transporter. A copy of such notice shall also be furnished such temporary transporter.
- d. In no instance shall the temporary transporter move any quantity greater than the estimated amount shown in said notice.
- e. The certificate, when properly executed and approved by the Commission, shall constitute authorization to the pipeline or other transporter to transport the authorized volume from the well named therein; provided that this section shall not prevent the production or transportation in order to prevent waste, pending execution and approval of said certificate. Permission for the transportation of such production shall be granted in writing to the producer and transporter.
- f. The certificate shall remain in force and effect until:
 - (1) The producer or operator filing the certificate is changed; or
 - (2) The transporter is changed; or
 - (3) The certificate is canceled by the Commission.
- g. A copy of each Form 10 to be filed hereunder shall be sent by the Director to those local governmental designees who so request.
- h. It is the operator's responsibility to mail approved copies of the Certificate of Clearance and/or Change of Operator, Form 10, to the transporter and/or gatherer for each well listed.
- i. A Form 10, Change of Operator is required within 15 days of the transfer of ownership of production facilities including off-location flowlines and crude oil transfer lines. A Form 10 is not required for gas gathering systems, gas processing plants, and underground gas storage facilities, which are governed by Rule 313B.

313. COGCC Form 11. MONTHLY REPORT OF GASOLINE OR OTHER EXTRACTION PLANT

All operators of gasoline or other extraction plants shall make monthly reports to the Director on Form 11 Such forms shall contain all information required thereon and shall be filed with the Director on or before the twenty-fifth (25th) day of each month covering the preceding month.

313A. COGCC Form 11. MONTHLY REPORT OF GASOLINE OR OTHER EXTRACTION PLANT

All operators of gasoline or other extraction plants must make monthly reports to the Director on a Form 11. Such forms must contain all information required thereon and must be filed with the Director on or before the twenty-fifth (25th) day of each month covering the preceding month.

313B. COGCC Form 12. GAS GATHERING SYSTEMS, PROCESSING OR STORAGE FACILITY REGISTRATION/CHANGE OF OPERATOR

- a. 30 days after placing a new gas gathering system, a new gas compressor station, a new gas processing plant, or a new underground gas storage facility into service, an operator must submit a Gas Facility Registration, Form 12. The following information must be included:

- (1) The name and type, of system or facility.
- (2) The legal location (quarter-quarter, section, township, range, county) of a gas compressor station or a gas processing plant or legal location description (quarter-quarter, section, township, range, county) of the geographic area covered by the gas gathering system, or an underground gas storage facility.
- (3) The latitude and longitude of a gas compressor station or a gas processing plant or a representative latitude and longitude near the center of a gas gathering system, or an underground gas storage facility.
- (4) A facility layout drawing of a gas compressor station, a gas processing plant or an underground gas storage facility and the surrounding topography.
- (5) A topographic map or a geographic area map covering the gathering system that sufficiently shows the gathering line's route, section, township and range lines, waterways, public roadways, county lines and municipal boundaries.

- b. The operator of an unregistered gas gathering system, gas compressor station, gas processing plant, or underground gas storage facility existing prior to May 1, 2018, must submit a Form 12 – Registration no later than October 31, 2019.

The operator of a registered gas gathering system, gas compressor station, gas processing plant, or underground gas storage facility existing prior to May 1, 2018, must submit a Gas Facility Registration, Form 12 no later than October 31, 2019 that includes the information specified in Section a.(1) – (5) above.

- c. The operator of an existing gas gathering system, gas processing plant, gas compressor station, or underground storage facility must report annually the addition or removal of any gathering pipelines report on a Gas Facility Registration, Form 12. The operator of an existing underground storage facility must report annually the expansion or decommissioning of more than 10% of the capacity of such facility on a Gas Facility Registration, Form 12.
- d. Within 30 days of transfer of ownership of a gas gathering system, gas compressor station, gas processing plant, or an underground gas storage facility, an operator must submit a Gas Facility Registration/Change of Operator, Form 12. Documentation confirming transfer of ownership must be attached to the Form 12. All records related to the installation, repair, and monitoring are to be transferred to the new operator.

314. COGCC Form 17. BRADENHEAD TEST REPORT

The Operator will submit results of bradenhead tests to the Director within 10 days of completing the test either by filing a Form 17 or by another method approved by the Director or Commission. The Operator will include a wellbore diagram if not previously submitted or if the wellbore

configuration has changed. The Director may request that the Operator collect samples for analysis of the bradenhead gas and liquid along with production gas. The Operator will submit the results of any gas and liquid analysis collected using a Form 43.

315. REPORT OF RESERVOIR PRESSURE TEST

Where the Director believes it is necessary to prevent waste, protect correlative rights, or prevent a significant adverse impact, the Director may require subsurface pressure measurements. Whenever such measurements are made, results shall be reported on a Sundry Notice, Form 4, within twenty (20) days after completion of tests, or submitted on any company form approved by the Director containing the same information.

316A. COGCC Form 14. NON-PRODUCED WATER INJECTION

a. Form 14A. AUTHORIZATION OF SOURCE OF CLASS II WASTE FOR DISPOSAL

Prior approval of a Form 14A, Authorization of Source of Class II Waste for Disposal, is required for the injection of Class II waste (other than the fluids specifically described in Rules 308B and 309) into any formation in a dedicated Class II Underground Injection Control well. Examples include, but are not limited to, ground water recovered during a remediation project or chemical treatments. The Form 14A shall include a description of the nature and source of the injected fluids, the types of chemicals used to treat the injected fluids, and the date of initial fluid injection for new injection wells. The Form 14A must be submitted and approved for a new disposal facility and for any changes in the source of Class II waste for an existing facility.

b. Form 14. MONTHLY REPORT OF NON-PRODUCED WATER INJECTED

- i. Operators engaged in the injection of Class II waste (other than the fluids specifically described in Rules 308B and 309) into any formation in a dedicated Class II Underground Injection Control well shall submit a Form 14, Monthly Report of Non-Produced Water Injected within 45 days after the end of each month. This report shall include the type and amount of waste received from transporters.
- ii. Operators of simultaneous injection wells shall, by March 1 of each year, report to the Director the calculated injected volume for the previous year by month on a Form 14.
- iii. Operators of gas storage projects shall, by March 1 of each year, report to the Director the amount of gas injected and withdrawn for the previous year and the amount of gas remaining in the reservoir as of December 31 of that year.

316B. COGCC Form 21. MECHANICAL INTEGRITY TEST

Not less than 10 days prior to the performance of a mechanical integrity test, the Director shall be notified with a Field Operations Notice, Form 42 – Mechanical Integrity Test, of the scheduled date on which the test will be performed. Results of any mechanical integrity test shall be submitted on Form 21, Mechanical Integrity Test, within 30 days after the test. The Form 21 shall be completely filled out except for Part II, which is required only for injection wells. An original copy of the pressure chart shall be submitted with every Form 21.

316C. COGCC Form 42. FIELD OPERATIONS NOTICE

Operators will submit a Form 42, Field Operations Notice, as designated below and in accordance with a Condition of Approval on any Form 2, Application for Permit to Drill; Form 2A, Oil and Gas Location Assessment; Form 4, Sundry Notice; Form 6, Well Abandonment Report; or any other approved form.

- a. **Notice of Intent to Conduct Hydraulic Fracturing Treatment.** Operators shall give at least 48 hours advance written notice of intent to the Commission of a hydraulic fracturing treatment at any well. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Hydraulic Fracturing Treatment. The Commission shall provide prompt electronic notice of such intention to the relevant local governmental designee (LGD).
- b. **Notice of Spud.** Operators shall give at least 48 hours advance written notice of intent to the Commission of a surface hole spud on any well. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Spud. The Commission shall provide prompt electronic notice of such intention to the relevant local governmental designee (LGD).
- c. **Notice of Construction or Major Change.** Operators shall give at least 48 hours advance written notice of intent to the Commission of a construction or major change at any Well, Oil and Gas Location, or Oil and Gas Facility. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Construction or Major Change.
- d. **Notice to Run and Cement Casing.** If required by policy or condition of approval, Operators shall give at least 24 hours advance written notice of intent to the Commission to run and cement casing on any well. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice to Run and Cement Casing.
- e. **Notice of Formation Integrity Test.** If required by policy or condition of approval, Operators shall give at least 24 hours advance written notice of intent to the Commission of a formation integrity test on any well. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Formation Integrity Test.
- f. **Notice of Mechanical Integrity Test.** Operators shall give at least 10 day advance written notice of intent to the Commission of a mechanical integrity test on any well. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Mechanical Integrity Test.
- g. **Notice of Start of Plugging Operations.** Operators will give at least 48 hours advance written notice to the Commission prior to mobilizing for plugging any Well. Such notice will be provided on a Field Operations Notice, Form 42 - Start of Plugging Operations.
- h. **Notice of Blow Out Preventer Test.** If required by policy or condition of approval, Operators shall give at least 24 hours advance written notice of intent to the Commission of a blow out preventer test at any well. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Blow Out Preventer Test.
- i. **Notice of Site Ready for Reclamation Inspection.** Operators shall give written notice to the Commission of a site ready for reclamation inspection at any well, well pad or production facility. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Site Ready for Reclamation Inspection.
- j. **Notice of Pit Liner Installation.** Operators shall give at least 48 hours advance written notice of intent to the Commission of a pit liner installation at any facility. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Pit Liner Installation.
- k. **Notice of Significant Lost Circulation.** Operators shall give written notice to the Commission of significant lost circulation at any well within 24 hours. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Significant Lost Circulation.
- l. **Notice of High Bradenhead Pressure During Stimulation.** Operators will give written notice to the Commission of high bradenhead pressure during stimulation at any Well within

24 hours of measuring the high pressure. Such notice will be provided on a Field Operations Notice, Form 42 - Notice of High Bradenhead Pressure During Stimulation.

- m. **Notice of Completion of Form 2/2A Permit Conditions.** If required by policy or condition of approval, Operators shall give written notice to the Commission of completion of Form 2 or 2A permit conditions at any well, Oil and Gas Location, or Oil and Gas facility. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Completion of Form 2/2A Permit Conditions.
- n. **Notice of Inspection Corrective Actions Performed.** Operators shall give written notice to the Commission of inspection corrective actions performed at any well, Oil and Gas Location, or Oil and Gas facility. Such notice shall be provided on a Field Operations Notice, Form 42 - Notice of Inspection Corrective Actions Performed.
- o. **Notice of Return to Service.** Operators must provide at least 48 hours advance written notice to the Director as required by the 1100-Series Rules and Rule 326.
- p. **Abandonment of Flowline.** Operators must provide written notice to the Commission before undertaking or after completing abandonment of flowlines in accordance with Rule 1105.

317. GENERAL DRILLING RULES

Unless altered, modified, or changed for a particular field or formation upon hearing before the Commission the following will apply to the drilling or deepening of all wells:

- 317.a. **Blowout Prevention Equipment ("BOPE").** The Operator will take all necessary precautions for keeping a Well under control during drilling, deepening, re-entering, recompleting, workovers, or plugging. The Operator will indicate the BOPE, if any, on the Application for Permit to Drill, Deepen, Re-enter, or Recomplete and Operate (Form 2), as well as any known subsurface conditions (e.g. under or over-pressured formations). The Operator will ensure the working pressure of any BOPE exceeds the anticipated surface pressure to which it may be subjected, assuming a partially evacuated hole with a pressure gradient of 0.22 psi/ft. For BOPE requirements in Designated Setback Locations, see Rule 604.c.(2). For statewide BOPE specification, inspection, operation and testing requirements, see Rule 603.e.
 - (1) The Commission may designate specific areas, fields or formations as requiring certain BOPE. Any such proposed designation will occur by notice describing the area, field, or formation in question and will be given to all Operators of record within such area or field and by publication. The proposed designation, if no protest is timely filed, will be placed on the Commission consent agenda for its next regularly scheduled meeting following the month in which such notice was given. The matter will be approved or heard by the Commission in accordance with Rule 531. Such designation will be effective immediately upon approval by the Commission, except as to any previously-approved Form 2. If a protest is timely filed, the designation will be heard by the Commission in accordance with the 500 Series Rules.
 - (2) Pursuant to Rule 317.a.(1), the Director may condition approval of any application for permit to drill by requiring BOPE which the Director determines to be necessary for keeping the well under control. Should the Operator object to such condition of approval, the Commission will hear the matter at the next regularly scheduled meeting of the Commission, subject to the notice requirements of Rule 507.

- 317.b. **Bottom Hole Location.** Unless authorized by the provisions of Rule 321, Operators will drill all Wells so that the horizontal distance between the bottom of the hole and the location at the top of the hole will be at all times a practical minimum.
- 317.c. **Requirement to Post Permit at the Rig.** The Operator will post a copy of the approved Application for Permit-to-Drill, Form 2, in a conspicuous place on the drilling rig or workover rig.
- 317.d. **Requirement to Provide Spud Notice.** An Operator will provide advance notice to the Director on a Field Operations Notice, Form 42, no less than 48 hours prior to spudding a Well.
- 317.e. **Drilling Fluid, Casing, and Cement Program to Isolate Hydrocarbon Formations and Groundwater and for Well Control.**
- (1) The casing and cementing plan for each Well will prevent migration of oil, gas, and water within potential flow zones from one formation to another behind the casing.
 - (2) The casing and cementing plan will ensure groundwater penetrated by the wellbore will be isolated from the infiltration of hydrocarbons or water from other formations penetrated by the wellbore. At a minimum, the Director will require that the operator's casing and cement plan for a Well will isolate groundwater with fully-cemented surface casing or a combination of fully-cemented surface casing and stage cement for other casing string(s) across the groundwater and to a depth 50 feet below the groundwater and to 50 feet above it or to surface, in formations that meet the following standards:
 - A. Groundwater that has been classified pursuant to 5 C.C.R. § 1002-41 as Domestic Use – Quality, Agricultural Use – Quality, Surface Water Quality Protection, or Potentially Usable Quality; and
 - B. Groundwater that has not been classified pursuant to 5 C.C.R. § 1002-41, and with total dissolved solids (TDS) less than 10,000 mg/l.
 - C. Only the version of Colorado Department of Public Health and Environment, Water Quality Control Commission (WQCC), Regulation Number 41, The Basic Standards for Ground Water, 5 C.C.R. § 1002-41, *et seq.* published in the Colorado Register on June 10, 2020 applies to this Rule 317.e; later versions do not apply. A copy of 5 C.C.R. § 1002-41 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, 5 C.C.R. § 1002-41 may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and is available at <https://www.sos.state.co.us/CCR/RegisterHome.do>.
 - (3) **Surface casing where subsurface conditions are unknown.** In areas where pressure and formations are unknown, surface casing will be run for well control to reach a depth approved by the Director that is a minimum depth of 10% of true vertical depth (TVD) of the deepest point of the planned well (or as required by Commission order) and will be of sufficient size to permit the use of an intermediate string or strings of casings. Surface casing will be set in or through an impervious formation and will be cemented by pump and plug or displacement or other approved method with sufficient cement to fill the annulus to the top of the hole, all in accordance with reasonable requirements of the Director. In the D–J Basin Fox Hills Protection Area surface casing will be set in accordance with Rule 317A. (See also subpart 5).

(4) **Surface casing where subsurface conditions are known.** For wells drilled in areas where subsurface conditions have been established by drilling experience, surface casing, size at the operator's option, will be set and cemented to the surface by the pump and plug or displacement or other approved method at a depth approved by the Director, and for well control, to a minimum depth of 10% of true vertical depth (TVD) of the deepest point of the planned well (or as required by Commission order). In the D–J Basin Fox Hills Protection Area surface casing will be set in accordance with Rule 317A. (See also subpart 5).

(5) **Alternate isolation by stage cementing.**

- A. In areas where groundwater is of such depth as to make it impractical to set the full amount of surface casing necessary to comply fully with the requirement to isolate groundwater, the Director may approve isolation by stage cementing behind the intermediate and/or production casing so as to accomplish the required result.
- B. If either the top or bottom depths, or the concentration of TDS in identified groundwater are uncertain or unknown based on available sources of pertinent information as described in Rule 303.a.(5).F:
 - i. The Operator will collect site-specific data sufficient to ensure compliance with all casing and cementing requirements of this Rule 317.e, and submit that information in its casing and cementing plan or in an amended plan that is approved by the Director before the Operator completes the well; or
 - ii. The Operator's casing and cementing plan will provide for extending surface casing or cementing behind intermediate and/or production casing to isolate all groundwater where TDS concentrations are uncertain or unknown. To isolate groundwater, where the top or bottom depth of groundwater is unknown or uncertain the Operator's casing and cementing plan will provide for:
 - I. Extending surface casing and cement from the surface to 50 feet below the lowest bottom depth;
 - II. Stage cementing behind intermediate and/or production casing to 50 feet above the highest top or 50 feet below the lowest bottom depth; or
 - III. Extending primary production cement from the bottom of the casing to 50 feet above the highest top that is not otherwise isolated by surface casing and cement or alternate stage cement and casing string.
- C. If groundwater not identified in the casing and cementing plan is encountered after setting the surface casing with either (a) a TDS concentration less than 10,000 mg/l, or (b) unknown or uncertain TDS concentration, the Operator will isolate the groundwater by stage cementing the intermediate and/or production casing with a solid cement plug extending from 50 feet below the groundwater to 50 feet above the groundwater, with the Director's approval. In such cases the Operator will submit an amended casing and cementing plan reflecting the groundwater and stage cementing within 20 days.
- D. In the D–J Basin Fox Hills Protection Area any stage cementing will occur only in accordance with Rule 317A. If the stage cement is not circulated to surface, a cement bond log will be run to determine the top of the stage cement to ensure aquifers are protected.

- (6) All hole intervals drilled prior to reaching the base of the surface casing or as required by permit condition will be drilled with air, fresh water, or a fresh water-based bentonitic drilling mud. Any other additives will be reviewed and approved by the Director prior to use.
- (7) All casing cemented in a well will be steel casing.
- (8) Prior to placing casing in the hole, the Operator will ensure the casing has been tested to verify integrity. An Operator may:
 - A. For new pipe only, use the mill test pressure.
 - B. Hydrostatically pressure test the casing with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the Well; or
 - C. Use a casing evaluation tool.
- (9) Prior written approval from the Director on a Form 4, Sundry Notice, is required before commencing any of the following operations:
 - A. Pumping cement down the bradenhead access to the annulus between the production casing (or intermediate casing, if present) and surface casing;
 - B. All routine or planned casing repair operations; or
 - C. Any other changes to the casing or cement in the wellbore.
- (10) In the case of unforeseen casing repairs during well operations, the Operator will obtain oral approval from the Director, and will immediately submit a Form 4, Sundry Notice, confirming the repairs and approval.
- (11) An Operator will submit a Drilling Completion Report, Form 5, within 30 days of the completion of the operations listed above, per Rule 308A.b.(3).
- (12) Prior written approval from the Director on a Form 4, Sundry Notice, is required before changing the gross interval of perforations in a completed formation, including into a formation designated as a common source of supply. A Completed Interval Report, Form 5A will be submitted within 30 days of the Gross Interval Change, pursuant to Rule 308B.

317.f. Cementing.

- (1) Operators will use the pump and plug method. An Operator will use a top plug to reduce contamination of cement from the displacement of fluid. An Operator will use a bottom plug or other Director-approved isolation technique or equipment to reduce contamination from drilling mud within the casing.
- (2) Unless the Director approves otherwise,
 - A. The diameter of the drilled hole in which surface casing will be set and cemented will be at least 1.5 inches greater than the nominal outside diameter of the casing the operator will install.

- B. All other casing will be set and cemented with at least 0.84 inches between the nominal outside diameter of the casing being cemented and the previously set casing's inside nominal diameter.
- (3) The Operator will design and place cement in a manner that inhibits channeling of the cement in the annular space outside of the casing being cemented. During placement of cement, the Operator will monitor pump rates to verify the rates remain within design parameters and ensure displacement meets the design. The Operator will monitor the cementing process to ensure proper cement densities are maintained.
 - (4) When cement is required, the Operator will use a cement slurry that isolates all groundwater, hydrocarbon, corrosive, potential flow, or hydrogen sulfide zones.
 - (5) The Operator will prepare cement slurry to:
 - A. The designed density;
 - B. Minimize free fluid content, to the extent practicable;
 - C. Ensure cement slurry free water separation will not exceed 3 milliliters per 250 milliliters of cement; and
 - D. Ensure the cement mix water chemistry is appropriate for the cement slurry design.
 - (6) The Operator or cement services provider will test a cement mixture at a rate that is the most frequent of every 6 months or when there is a change in operating conditions, cement type, or cement vendor.
 - A. The test will be on representative samples of the cement and additives.
 - B. The Operator will make cement test data available to the Director upon request.

317.g. **Casing Centralization.**

- (1) **Surface casing.** At a minimum, the Operator will centralize casing as follows:
 - A. Within 120 feet of the of the surface;
 - B. At the casing shoe;
 - C. Above and below a stage collar or diverting tool, if run; and
 - D. Every fourth joint.
 - E. The Operator may implement an alternative centralization plan for surface casing if approved by the Director.
- (2) **Production and intermediate casing.** The Operator will provide adequate centralization or other methods to achieve cementing objectives in accordance with the permitted well design.

317.h. **Wellbore Circulation.** Prior to cementing, the Operator will clean and condition the wellbore to control gas flow, foster adequate cement displacement, and ensure a bond between cement, casing, and the wellbore.

317.i. Surface and Intermediate Casing Cementing.

- (1) The Operator will ensure that all surface and intermediate casing cement required under this rule achieves a minimum compressive strength of 300 psi after 24 hours and 800 psi after 72 hours measured at 800 psi confining pressure and 95° Fahrenheit or at the minimum expected downhole temperature.
- (2) The Operator will cement all surface casing with a continuous column from the bottom of the casing to the surface.
- (3) After thorough circulation of the wellbore as required by Rule 317.h., the Operator will pump cement behind the intermediate casing to at least 500 feet above the top of the shallowest known production horizon and as required in Rule 317. The Operator will allow cement placed behind the surface and intermediate casing to set a minimum of 8 hours or until 300 psi calculated compressive strength is developed, whichever occurs first, prior to commencing drilling operations. If the surface casing cement level falls below the surface or if there is evidence of inadequate cement coverage, the Operator will consult with the Director and, upon request, provide and implement a corrective action plan prior to drilling ahead.

317.j. Production Casing Cementing.

- (1) The operator will ensure that all cement required under this Rule 317 placed behind production casing achieves a minimum compressive strength of at least 300 psi after 24 hours and of at least 800 psi after 72 hours both measured at 800 psi at either 95° Fahrenheit or at the minimum expected downhole temperature.
- (2) After thorough circulation of a wellbore as required by Rule 317.h., the Operator will pump cement behind the production casing to the shallower of: 500 feet above the top of the shallowest uncovered known producing horizon, isolation of specific geologic intervals specified in the permit, or isolation of any other zone as required by Rule 317.e.

317.k. Surface Casing Pressure Testing.

- (1) Prior to drilling out below the surface casing shoe, the Operator will successfully pressure test the surface casing for a minimum 30-minute duration and to a minimum of 1,500 psi or to a pressure that will determine if the casing has adequate mechanical integrity to meet the well design and construction objectives.
- (2) If the surface casing is exposed to more than 360 rotating hours after reaching total depth or the depth of the next casing string, the Operator will verify the integrity of the surface casing before running the next casing string by using a casing evaluation tool, conducting a mechanical integrity test, or using an equivalent casing evaluation method submitted to and approved by the Director through a Sundry Notice, Form 4.

317.l. Intermediate Casing Pressure Testing.

- (1) Prior to drilling out below the intermediate casing shoe, the Operator will successfully pressure test the intermediate casing to ensure integrity is adequate to meet well design and construction objectives. The Operator will perform the pressure test for a minimum 30-minute duration and to a minimum of 1,500 psi unless otherwise approved by the Director.

- (2) The Operator will monitor the well's bradenhead pressure during any pressure test conducted pursuant to Rule 317.l.

317.m. Production Casing and Stimulation String Pressure Testing.

- (1) Prior to stimulation, the Operator will successfully pressure test the production casing or stimulation string, if used. The Operator will pressure test from the wellhead to a minimum depth of 200 feet above the true vertical depth (TVD) of the top perforations.
- (2) For production casing that will be exposed to stimulation and the stimulation string, the Operator will perform the pressure test for a minimum of 30 minutes and to a minimum of 500 psi greater than the maximum surface pressure anticipated to be imposed during the stimulation.
- (3) For wells that are not stimulated and production casing that will not be exposed to the stimulation, the Operator will perform the pressure test for a minimum of 30 minutes and to a minimum of 500 psi greater than the maximum anticipated surface pressure.
- (4) The Operator will monitor the Well's bradenhead pressure during any pressure test conducted pursuant to Rule 317.m.

317.n. Casing Pressure Test Monitoring and Success Criteria for all Casing Strings.

- (1) An Operator has successfully conducted a pressure test when:
 - A. The surface pressure does not change more than 5% from the initial test pressure;
 - B. The pressure does not change more than 1% during the last 5 minutes of the test; and
 - C. The bradenhead pressure does not change more than 5% during the test when testing the intermediate or production casings.
- (2) In the event of an indication that a Well no longer has mechanical integrity, the Operator may not conduct stimulation on any Well on the Oil and Gas Location until the Operator has determined the Well has mechanical integrity. If a Well intervention is necessary, the Operator will obtain verbal approval from the Director for the intervention and authorization to proceed with the stimulation.

317.o. Isolation when Drilling Operations Are Suspended Before Running Production Casing. In the event drilling operations are suspended before production casing is run, the Operator will notify the Director immediately and will take adequate and proper precautions to prevent migration of oil, gas, and water between formations in the open hole until drilling resumes or the well is plugged and abandoned.

317.p. Flaring of Gas During Drilling and Notice to Local Emergency Dispatch. Any gas escaping from the well during drilling operations will be, so far as practicable, conducted to a safe distance from the well site and burned. The Operator will notify the local emergency dispatch as provided by the Local Governmental Designee of any such flaring. Such notice will be given prior to the flaring if the flaring can be reasonably anticipated, and in all other cases as soon as possible but in no event more than 2 hours after the flaring occurs.

317.q. Protection of Productive Strata During Deepening Operations. If a Well is deepened for the purpose of producing oil and gas from a lower stratum, such deepening to and

completion in the lower stratum will be conducted in such a manner as to protect all upper productive strata.

- 317.r. **Requirement to Evaluate Disposal Zones for Hydrocarbon Potential.** If a Well is drilled as a disposal well then the disposal zone will be evaluated for hydrocarbon potential. The proposed hydrocarbon evaluation method will be submitted in writing and approved by the Director prior to implementation. The productivity results will be submitted to the Director upon completion of the Well.
- 317.s. **Requirement to Log Well.** For all new drilling operations, the Operator will run a minimum of a resistivity log with gamma-ray or other petrophysical log(s) approved by the Director that adequately describe the stratigraphy of the wellbore. A cement bond log, capable of generating a variable density display, will be run on all production casing or, in the case of a production liner, the intermediate casing, when these casing strings are run. The Operator will submit these logs and all other logs run with the Drilling Completion Report, Form 5. The Operator will run open-hole logs or equivalent cased-hole logs at depths that adequately verify the setting depth of surface casing and any groundwater coverage. These requirements will not apply to unlogged open-hole completion intervals.
- 317.t. **Remedial Cementing.** If cement coverage in any casing string does not satisfy the requirements of Rule 317.e., the Director may apply a condition of approval for Application for Permit-to-Drill, Form 2, to require remedial cementing and a cement bond log or other cement evaluation tool before recompletion, reentering, or deepening operations consistent with the provisions for isolating groundwater and hydrocarbon bearing zones in this Rule 317.
- 317.u. **Statewide Wellbore Collision Prevention.** An Operator will perform an anti-collision evaluation of all active (producing, shut in, or temporarily abandoned) offset wellbores that have the potential of being within 150 feet of a proposed Well prior to drilling operations for the proposed Well. The Operator will give notice to all offset Operators prior to drilling.
- 317.v. **Statewide Setback for Hydraulic Fracturing Treatment.**
- (1) No portion of a proposed wellbore that will be treated by hydraulic fracturing may be located within 150 feet of an existing (producing, shut-in, or temporarily abandoned) or permitted interval of an oil and gas wellbore that has been or will be treated by hydraulic fracturing belonging to another Operator without the signed written consent of the Operator of the encroached upon wellbore. The Operator will attach any signed written consents to the Application for Permit-to-Drill, Form 2 for the proposed wellbore.
 - (2) The Operator will measure the distance between the proposed and offset wellbores using the directional survey for drilled wellbores and the deviated drilling plan for permitted wellbores, or as otherwise reflected in the Commission's well records. The Operator will measure the distance from the perforation or mechanical isolation device.
- 317.w. **Notice Prior to Hydraulic Fracturing Treatment.** At least 90 days prior to the anticipated commencement of hydraulic fracturing treatment, the Operator of the wellbore that will be stimulated by hydraulic fracturing treatment will provide notice of hydraulic fracturing treatment commencement to all Operators of offset wells that were identified pursuant Rule 303.a.(5)G.i.
- 317.x. **Offset Wellheads and Surface Equipment.** Prior to hydraulic fracturing treatments, the Operator will ensure offset existing wells within 1,500 feet of the wellbore to be hydraulically fractured that are producing, shut-in, or temporarily abandoned have surface equipment (wellhead and master valve) rated to a pressure adequate to contain anticipated surface

pressures that could occur from the proposed hydraulic fracturing treatment. For offset wells that do not have adequately rated surface equipment, the Operator may instead use downhole mechanical isolation above perforations in the objective formation to prevent unanticipated migration of pressure.

- 317.y. **Consent to Offset Well Mitigation.** When an offset well and a proposed well are under different operatorship, the Operator of the offset well will not refuse to have the offset well appropriately mitigated to meet the requirements of the Commission's Rules necessary to ensure protection of public health, safety, welfare, the environment, and wildlife resources.
- 317.z. **Communication Prevention.** An Operator will take all necessary measures to prevent communication along any known conduits between a wellbore's hydraulic fracturing-treated interval and groundwater.
- 317.aa. **Surface Equipment Used in Hydraulic Fracturing Treatment.** Prior to beginning a hydraulic fracturing treatment, the Operator will rig up and pressure test any surface equipment exposed to hydraulic fracturing treatment pressure. The Operator will test for the proposed hydraulic fracturing treatment design and, at a minimum, to 110% of the maximum anticipated surface hydraulic fracturing treating pressure. The test will ensure an appropriate safety factor and prevent fluid losses.
- 317.bb. **Hydraulic Fracturing Treatment Monitoring:** The operator will monitor and record hydraulic fracturing treatment parameters including but not limited to the following list:
- (1) Surface injection pressure (psig);
 - (2) Slurry rate (bpm);
 - (3) Proppant concentration (ppg);
 - (4) Fluid rate (bpm);
 - (5) Identities, rates, and concentrations of additives used; and
 - (6) All other annuli pressures or volumes measured at the surface.

317A. SPECIAL DRILLING RULES - D-J BASIN FOX HILLS PROTECTION AREA

The following special drilling rules shall apply to wells in the D-J Basin Fox Hills Protection Area as defined in the 100 Series of the Rules and Regulations:

- a. **Surface Casing - Minimum Requirements for Well Control.** In all wells drilled within the D-J Basin Fox Hills Protection Area, surface casing shall be run to a minimum depth of five percent (5%) of the projected total depth to which the well is to be drilled, provided that in no event shall the surface casing be run to a depth less than two hundred (200) feet. The Director may, on a case-by-case basis, grant variances in this five percent (5%) requirement where the Director finds that the well is a development well in which pressures can be accurately predicted and finds that, based upon those predictions, the five percent (5%) requirement should be varied to achieve effective well control. In all cases, however, the actual depth at which the surface casing is set shall be calculated to position the casing seat to a depth within a competent formation (preferably shale) which will contain the maximum pressure to which the casing will be exposed during normal drilling operations.

b. **Surface Casing - Aquifer Protection.** For purposes of aquifer protection, surface casing must be set as follows in wells which are not exploratory wells:

- (1) Surface casing shall be run to a depth at least fifty (50) feet below the Fox Hills transition zone in wells drilled within Townships 5 South through 5 North, Ranges 65 West through 70 West or within Townships 3 North through 5 North, Range 64 West.
- (2) With respect to Townships 5 South through 5 North, Ranges 58 West through 63 West, Townships 5 South through 2 North, Range 64 West; and Township 6 South, Ranges 65 West through 70 West, in all wells located within one (1) mile of a permitted producing water well, surface casing shall be set to a depth sufficient to protect the deepest permitted producing water well within such one mile area. Said depth shall be at least fifty (50) feet below the depth of the base of the aquifer from which said deepest water well is producing, or fifty (50) feet below the base of the Fox Hills Transition Zone if such deepest water well produces from the Fox Hills Aquifer.

Upon the request of the operator, the Director (or the Commission upon appeal) may grant a variance to the requirements of this subparagraph b. upon a showing to the Director, or the Commission upon appeal, that the variance does not violate the basic intent of said requirements. For such variance purpose, the basic intent of said requirements is stated to be to provide reasonable aquifer protection for the water well(s) which are permitted by the State of Colorado Division of Water Resources and are currently producing in the area potentially affected by the oil or gas well to be drilled.

c. **Exploratory Wells.** For purposes of the D–J Basin Fox Hills Protection Area only, the term exploratory well means any well:

- (1) Which targets the classically demonstrated zones with limited geographic extent such as channel, bar, valley fill and levee type sandstones that were deposited prior to the x-bentonite time stratigraphic event; or
- (2) Which can be demonstrated to be separated from a known producing horizon by a dry hole; or
- (3) Which can be demonstrated to be targeted to a horizon which is geologically separate from the producing horizon in an offsetting producing well, or
- (4) Which the Director, or the Commission upon appeal, may define as an exploratory well by variance, it being the basic intent of this definition that the requirements of subparagraph b. not operate to discourage the drilling of high risk wells.

317B. PUBLIC WATER SYSTEM PROTECTION

a. **Definitions.** For purposes of this Rule 317B:

- (1) **Drilling, Completion, Production and Storage (“DCPS”) Operations** means operations at (i) well sites for the drilling, completion, recompletion, workover, or stimulation of wells or chemical and production fluid storage, and (ii) any other oil and gas location at which production facilities are operated. DCPS Operations excludes roads, gathering lines, and routine operations and maintenance.

- (2) **Existing Oil and Gas Location** means an oil and gas location, excluding roads, and gathering lines, permitted or constructed prior to the later of May 1, 2009 for federal land or April 1, 2009 for all other land or the date that the oil and gas location becomes subject to Rule 317B by virtue of its proximity to a Classified Water Supply Segment.
- (3) **New Oil and Gas Location** means an oil and gas location, excluding roads and gathering lines, that is not an existing oil and gas location.
- (4) **New Surface Disturbance** means surface disturbance that expands the area of surface covered by an oil and gas location beyond that initially disturbed in the construction of the oil and gas location.
- (5) **Non-Exempt Linear Feature** means a road or gathering line that is not necessary to cross a stream or connect or access a well or a gathering line.

b. Applicability Determination.

- (1) Rule 317B is applicable to DCPS Operations within Surface Water Supply Areas. The applicability of Rule 317B will be determined by reviewing the Public Water System Surface Water Supply Area Map, attached as part of Appendix VI, or by entering information into the Public Water System Surface Water Supply Area Applicability Determination Tool, also located on the Commission website.
- (2) The Public Water Systems subject to the protections of this Rule 317B are those listed in Appendix VI. Any additions or deletions to the Public Water Systems listed in Appendix VI or the Public Water System Surface Water Supply Area Map, also located in Appendix VI, shall be by Commission rulemaking, as provided in Rule 529.
- (3) DCPS Operations at New Oil and Gas Locations within a Surface Water Supply Area will be subject to the requirements in Rules 317B.c, 317B.d, or 317B.e based on the buffer zones defined in Table 1, below. DCPS Operations at Existing Oil and Gas Locations within a Surface Water Supply Area at which no new surface disturbance has occurred after the date Rule 317B became applicable to that oil and gas location will be subject to the requirements in Rule 317B.f.(1) based on the buffer zones defined in Table 1. DCPS Operations at Existing Oil and Gas Locations within a Surface Water Supply Area at which new surface disturbance has occurred after the date Rule 317B became applicable to that oil and gas location will be subject to the requirements in Rule 317B.f.(2) based on the buffer zones defined in Table 1.
- (4) For Classified Water Supply Segments that are perennial and intermittent streams, buffer zones shall be determined by measuring from the ordinary high water line of each bank to the near edge of the disturbed area at the oil and gas location at which the DCPS Operations will occur.
- (5) The buffer zones shall apply only to DCPS Operations located on the surface. The buffer zones shall not apply to subsurface boreholes and equipment or materials contained therein. The buffer zones shall not apply to DCPS Operations located in an area that does not drain to a classified water supply segment protected by this Rule 317B.

TABLE 1. Buffer Zones Associated with DCPS Operations.

Zone	Classified Water Supply Segments (ft)
Internal Buffer	0 - 300
Intermediate Buffer	301 - 500
External Buffer	501 - 2,640

c. Requirements for DCPS Operations Conducted at New Oil and Gas Locations in the Internal Buffer Zone.

DCPS Operations conducted and Non-Exempt Linear Features located at New Oil and Gas Locations within a Surface Water Supply Area may not occur in whole or in part within the Internal Buffer Zone identified in Table 1 unless a variance is granted pursuant to Rule 502.b and consultation with the Colorado Department of Public Health and Environment occurs pursuant to Rule 306.d and a Form 2A or Form 2 with appropriate conditions of approval has been approved, or the Director has approved a Comprehensive Drilling Plan pursuant to Rule 216 that covers the operation. In determining appropriate conditions of approval for such operations, the Director shall consider the extent to which the conditions of approval are required to prevent impacts to the Public Water System.

(1) The Commission shall grant a variance if the operator demonstrates that:

A. The proposed DCPS Operations and applicable best management practices and operating procedures will result in substantially equivalent protection of drinking water quality in the Surface Water Supply area; and

B. Either:

i. Conducting the DCPS Operation outside the Internal Buffer Zone would pose a greater risk to public health, safety, or welfare, including the environment and wildlife resources, such as may be the case where conducting the DCPS Operations outside the Internal Buffer Zone would require construction in steep or erosion-prone terrain or result in greater surface disturbance due to an inability to use infrastructure already constructed such as roads, well sites, or pipelines; or

ii. Conducting DCPS Operations beyond the Internal Buffer Zone is technically infeasible and prevents the operator from exercising its mineral rights.

(2) At a minimum, for any DCPS Operation at a New Oil and Gas Location within the Internal Buffer Zone, the Director shall include as conditions of approval in the Form 2A, Form 2, or Comprehensive Drilling Plan, the requirements of Rule 317B.d.

d. Requirements for DCPS Operations at New Oil and Gas Locations in the Intermediate Buffer Zone.

The following shall be required for all DCPS Operations at New Oil and Gas Locations within a Surface Water Supply Area and in the Intermediate Buffer Zone as defined in Table 1.

- (1) Pitless drilling systems;
- (2) Flowback and stimulation fluids contained within tanks that are placed on a well pad or in an area with downgradient perimeter berming;
- (3) Berms or other containment devices shall be constructed in compliance with Rule 604.c.(2)G around crude oil, condensate, and produced water storage tanks; and
- (4) When sufficient water exists in the Classified Water Supply Segment, collection of baseline surface water data consisting of a pre-drilling surface water sample collected immediately downgradient of the oil and gas location and follow-up surface water data consisting of a sample collected at the same location three (3) months after the conclusion of any drilling activities and operations or completion. The sample parameters shall include:
 - A. pH;
 - B. Alkalinity;
 - C. Specific conductance;
 - D. Major cations/anions (chloride, fluoride, sulfate, sodium);
 - E. Total dissolved solids;
 - F. BTEX/GRO/DRO;
 - G. TPH;
 - H. PAH's (including benzo(a)pyrene); and
 - I. Metals (arsenic, barium, calcium, chromium, iron, magnesium, selenium).

Current applicable EPA-approved analytical methods for drinking water must be used and analyses must be performed by laboratories that maintain state or nationally accredited programs.

Copies of all test results described above shall be provided to the Commission and the potentially impacted Public Water System(s) within three (3) months of collecting the samples. In addition, the analytical results and surveyed sample locations shall be submitted to the Commission in an electronic data deliverable format.

- (5) Notification of potentially impacted Public Water Systems within fifteen (15) stream miles downstream of the DCPS Operation prior to commencement of new surface disturbing activities at the site.
- (6) An emergency spill response program that includes employee training, safety, and maintenance provisions and current contact information for downstream Public Water System(s) located within fifteen (15) stream miles of the DCPS Operation, as well as the ability to notify any such downstream Public Water System(s) with intake(s) within fifteen (15) stream miles downstream of the DCPS operations.

In the event of a spill or release, the operator shall immediately implement the emergency response procedures in the above-described emergency response program.

If a spill or release impacts or threatens to impact a Public Water System, the operator shall notify the affected or potentially affected Public Water System(s) immediately following discovery of the release, and the spill or release shall be reported to the Commission in accordance with Rule 906.b.(3), and to the Environmental Release/Incident Report Hotline (1-877-518-5608) in accordance with Rule 906.b.(4).

e. Requirements for DCPS Operations at New Oil and Gas Locations within the External Buffer Zone.

The following shall be required when DCPS Operations are conducted at New Oil and Gas Locations within a Surface Water Supply Area and in the External Buffer Zone as defined in Table 1.

- (1) Pitless drilling systems or containment of all drilling flowback and stimulation fluids pursuant to Rule 904; and
- (2) When sufficient water exists in the Classified Water Supply Segment, collection of baseline surface water data consisting of a pre-drilling surface water sample collected immediately downgradient of the oil and gas location and follow-up surface water data consisting of a sample collected at the same location three (3) months after the conclusion of any drilling activities and operations or completion. The sample parameters shall include:
 - A. pH;
 - B. Alkalinity;
 - C. Specific conductance;
 - D. Major cations/anions (chloride, fluoride, sulfate, sodium);
 - E. Total dissolved solids;
 - F. BTEX/GRO/DRO;
 - G. TPH;
 - H. PAH's (including benzo(a)pyrene); and
 - I. Metals (arsenic, barium, calcium, chromium, iron, magnesium, selenium).

Current applicable EPA-approved analytical methods for drinking water must be used and analyses must be performed by laboratories that maintain state or nationally accredited programs.

Copies of all test results described above shall be provided to the Commission and the potentially impacted Public Water System(s) within three (3) months of collecting the samples. In addition, the analytical results and surveyed sample locations shall be submitted to the Commission in an electronic data deliverable format.

- (3) Notification of potentially impacted Public Water Systems within fifteen (15) stream miles downstream of the DCPS Operation prior to commencement of new surface disturbing activities at the site.
- (4) An emergency spill response program that includes employee training, safety, and maintenance provisions and current contact information for downstream Public Water System(s) located within fifteen (15) stream miles of the DCPS Operation, as well as the ability to notify any such downstream Public Water System(s) with intake(s) within fifteen (15) stream miles downstream of the DCPS operations.

In the event of a spill or release, the operator shall immediately implement the emergency response procedures in the above-described emergency response program.

If a spill or release impacts or threatens to impact a Public Water System, the operator shall notify the affected or potentially affected Public Water System(s) immediately following discovery of the release, and the spill or release shall be reported to the Commission in accordance with Rule 906.b.(3), and to the Environmental Release/Incident Report Hotline (1-877-518-5608) in accordance with Rule 906.b.(4).

f. Requirements for DCPS Operations at Existing Oil and Gas Locations.

- (1) Existing Oil and Gas Locations and DCPS Operations at Existing Oil and Gas Locations within a Surface Water Supply Area and within zones specified in Table 1 shall be subject to the following requirements instead of the requirements of Rules 317B.c, 317B.d, or 317B.e provided that no new surface disturbance at the Existing Oil and Gas Location occurs after the later of May 1, 2009 for federal land or April 1, 2009 for all other land or the date Rule 317B became applicable to the oil and gas location:
 - A. Collection of surface water data from a Classified Water Supply Segment consisting of a sample collected immediately downgradient of the oil and gas operation will occur by the latest of June 1, 2009, within six (6) months after the date Rule 317B became applicable to the oil and gas location, or when sufficient water exists in the stream:
 - i. pH;
 - ii. Alkalinity;
 - iii. Specific conductance;
 - iv. Major cations/anions (chloride, fluoride, sulfate, sodium);
 - v. Total dissolved solids;
 - vi. BTEX/GRO/DRO;
 - vii. TPH;
 - viii. PAH's (including benzo(a)pyrene); and
 - ix. Metals (arsenic, barium, calcium, chromium, iron, magnesium, selenium).

Current applicable EPA-approved analytical methods for drinking water must be used and analyses must be performed by laboratories that maintain state or nationally accredited programs.

Copies of all test results described above shall be provided to the Commission and the potentially impacted Public Water System(s) within three (3) months of collecting the samples. In addition, the analytical results and surveyed sample locations shall be submitted to the Commission in an electronic data deliverable format.

- B. An emergency spill response program that includes employee training, safety, and maintenance provisions and current contact information for downstream Public Water System(s) located within fifteen (15) stream miles of the DCPS Operation, as well as the ability to notify any such downstream Public Water System(s) with intake(s) within fifteen (15) stream miles downstream of the DCPS Operations.

In the event of a spill or release, the operator shall immediately implement the emergency response procedures in the above-described emergency response program.

If a spill or release impacts or threatens to impact a Public Water System, the operator shall notify the affected or potentially affected Public Water System(s) immediately following discovery of the release, and the spill or release shall be reported to the Commission in accordance with Rule 906.b.(3), and to the Environmental Release/Incident Report Hotline (1-877-518-5608) in accordance with Rule 906.b.(4).

- C. Operators shall employ and maintain Best Management Practices, as necessary, to comply with this rule.

- (2) Existing Oil and Gas Locations and DCPS Operations at Existing Oil and Gas Locations within a Surface Water Supply Area and within zones specified in Table 1 for which new surface disturbance occurs on or after the later of May 1, 2009 for federal land or on or after April 1, 2009 for all other land or the date Rule 317B became applicable to the oil and gas location shall be subject to the requirements of Rule 317B.f.(3) instead of the requirements of Rules 317B.c, 317B.d, or 317B.e where the additional new surface disturbance is addressed in a Comprehensive Drilling Plan accepted pursuant to Rule 216, or if:

- A. The new disturbance from the DCPS Operation will not increase the existing disturbed area prior to interim reclamation by more than one hundred (100) percent up to a maximum of three (3) acres, and
- B. The new surface disturbance occurs in a direction away from the stream or no closer to the stream if moving away from the stream would result in more damaging surface disturbance such as location on a steep slope, in an area of high soil erosion potential, or in a wetland.

- (3) Where the provisions of Rule 317B.f.(2) apply, the following zone requirements shall apply:

- A. For all zones, the requirements of Rule 317B.f.(1), except that the sampling parameters in Rule 317B.f.(1).A shall occur no later than six (6) months

after commencing the DCPS Operations at the Existing Oil and Gas Location.

B. For External and Intermediate Buffer Zones: pitless drilling systems or containment of drilling, flowback, and stimulation fluids with impervious liners, as provided in Rule 904.

C. For Internal Buffer Zones:

- i. Pitless drilling systems;
- ii. Flowback and stimulation fluids contained within tanks and placed on a well pad or in an area with downgradient perimeter berming;
- iii. Berms constructed in compliance with Rule 604.c.(2)G around all crude oil, condensate, and produced water tanks; and
- iv. Notification of potentially impacted Public Water Systems within fifteen (15) stream miles downstream of the DCPS Operation prior to commencement of new surface disturbing activities at the site.

318. LOCATION OF WELLS

All wells drilled for oil or gas to a common source of supply shall have the following setbacks:

- a. **Wells 2,500 feet or greater in depth.** A well to be drilled two thousand five hundred (2,500) feet or greater shall be located not less than six hundred (600) feet from any lease line, and shall be located not less than one thousand two hundred (1,200) feet from any other producible or drilling oil or gas well when drilling to the same common source of supply, unless authorized by order of the Commission upon hearing.
- b. **Wells less than 2,500 feet in depth.** A well to be drilled to less than a depth of two thousand five hundred (2,500) feet below the surface shall be located not less than two hundred (200) feet from any lease line, and not less than three hundred (300) feet from any other producible oil or gas well, or drilling well, in said source of supply, except that only one producible oil or gas well in each such source of supply shall be allowed in each governmental quarter-quarter section unless an exception under Rule 318.c. is obtained.
- c. **Exception locations.** The Director may grant an operator's request for a well location exception to the requirements of this rule or any order because of geologic, environmental, topographic or archaeological conditions, irregular sections, a surface owner request, or for other good cause shown provided that a waiver or consent signed by the lease owner toward whom the well location is proposed to be moved, agreeing that said well may be located at the point at which the operator proposes to drill the well and where correlative rights are protected. If the operator of the proposed well is also the operator of the drilling unit or unspaced offset lease toward which the well is proposed to be moved, waivers shall be obtained from the mineral interest owners under such lands. If waivers cannot be obtained from all parties and no party objects to the location, the operator may apply for a variance under Rule 502.b. If a party or parties object to a location and cannot reach an agreement, the operator may apply for a Commission hearing on the exception location.

d. **Exemptions to Rule 318.**

- (1) This rule shall not apply to authorized secondary recovery projects.

(2) This rule shall apply to fracture or crevice production found in shale, except from fields previously exempted from this rule.

(3) In a unit operation, approved by federal or state authorities, the rules herein set forth shall not apply except that no well in excess of two thousand five hundred (2,500) feet in depth shall be located less than six hundred (600) feet from the exterior or interior (if there be one) boundary of the unit area and no well less than two thousand five hundred (2,500) feet in depth below the surface shall be located less than two hundred (200) feet from the exterior or interior (if there be one) boundary of the unit area unless otherwise authorized by the order of the Commission after proper notice to owners outside the unit area.

e. **Wells located near a mine.** No well drilled for oil or gas shall be located within two hundred (200) feet of a shaft or entrance to a coal mine not definitely abandoned or sealed, nor shall such well be located within one hundred (100) feet of any mine shaft house, mine boiler house, mine engine house, or mine fan; and the location of any proposed well shall insure that when drilled it will be at least fifteen (15) feet from any mine haulage or airway.

318A. GREATER WATTENBERG AREA SPECIAL WELL LOCATION, SPACING AND UNIT DESIGNATION RULE

a. **GWA, GWA wells, GWA windows and unit designations.** The Greater Wattenberg Area ("GWA") is defined to include those lands from and including Townships 2 South to 7 North and Ranges 61 West to 69 West, 6th P.M. In the GWA, operators may utilize the following described surface drilling locations ("GWA windows") to drill, twin, deepen, or recomplete a well ("GWA well") and to commingle any or all of the Cretaceous Age formations from the base of the Dakota Formation to the surface:

(1) A square with sides four hundred (400) feet in length, the center of which is the center of any governmental quarter-quarter section ("400' window"); and,

(2) A square with sides eight hundred (800) feet in length, the center of which is the center of any governmental quarter section ("800' window").

(3) Absent a showing of good cause, which shall include the existence of a surface use or other agreement with the surface owner authorizing a surface well location outside of a GWA window, all surface wellsites shall be located within a GWA window.

(4) Unit designations.

A. 400' window. When completing a GWA well in a 400' window to a spaced formation, the operator shall designate drilling and spacing units in accordance with existing spacing orders.

B. 800' window. When completing a GWA well in an 800' window, whether in spaced or unspaced formations, the operator shall: (i) designate drilling and spacing units in accordance with existing spacing orders where units are not smaller than a governmental quarter section; or (ii) form a voluntary drilling and spacing unit consisting of a governmental quarter section; or (iii) where designating a drilling and spacing unit smaller than a governmental quarter section, secure waiver(s) from the operator or from the mineral owners (if the operator is also the holder of the mineral lease) of the lands in the governmental quarter section that are not to be included in the spacing unit; or (iv) apply to the Commission to form an alternate unit or to respace the area.

- C. Unspaced areas and wellbore spacing units. When completing a GWA well to an unspaced formation, the operator shall designate a drilling and spacing unit not smaller than a governmental quarter-quarter section if such well is proposed to be located greater than four hundred sixty (460) feet from the quarter-quarter section boundary in which it is located. If a well is proposed to be located less than four hundred sixty (460) feet from the governmental quarter-quarter section boundary, a wellbore spacing unit ("wellbore spacing unit") for such well shall be comprised of the governmental quarter-quarter sections that are located less than four hundred sixty (460) feet from the wellbore regardless of section or quarter section lines.
- D. Horizontal GWA well. Where a drilling and spacing unit does not exist for a horizontal well, a horizontal wellbore spacing unit shall be designated by the operator for each proposed horizontal well. The horizontal wellbore spacing unit may be of different sizes and configurations depending on lateral length and orientation but shall be comprised of the governmental quarter-quarter sections in which the wellbore lateral penetrates the productive formation as well as any governmental quarter-quarter sections that are located less than four hundred sixty (460) feet from the completed interval of the wellbore lateral regardless of section or quarter section lines. However, if the horizontal component of the horizontal wellbore is located entirely within a GWA window, the operator shall designate a drilling and spacing unit in accordance with subsections a.(4)A. and a.(4)B. of this rule. A horizontal wellbore spacing unit may overlap portions of another horizontal wellbore spacing unit or other wellbore spacing unit designated in accordance with subsection a.(4)C. GWA horizontal wells and horizontal wellbore spacing units shall be subject to the notice and hearing procedures as provided for in Rule 318A.e.(6).
- b. **Recompletion/commingling of existing wells.** Any GWA well in existence prior to the effective date of this rule, which is not located as described above, may also be utilized for deepening to or recompletion in any Cretaceous Age formation and for the commingling of production therefrom.
- c. **Surface locations.** Prior to the approval of any Application for Permit-to-Drill submitted for a GWA well, the proposed surface well location shall be reviewed in accordance with the following criteria:
- (1) A new surface well location shall be approved in accordance with Commission rules when it is less than fifty (50) feet from an existing surface well location.
 - (2) When the operator is requesting a surface well location greater than fifty (50) feet from a well (unless safety or mechanical considerations of the well to be twinned or topographical or surface constraints justify a location greater than fifty (50) feet), the operator shall provide a consent to the exception signed by the surface owner on which the well is proposed to be located in order for the Director to approve the well location administratively.
 - (3) If there is no well located within a GWA window but there is an approved exception location well located outside of a GWA window that is attributed to such window, the provisions of subsections (1) and (2) of this subsection c. shall be applicable to such location.

d. **Prior wells excepted.** This rule does not alter the size or configuration of drilling units for GWA wells in existence prior to the effective date of this rule. Where deemed necessary by an operator for purposes of allocating production, such operator may allocate production to any drilling and spacing unit with respect to a particular Cretaceous Age formation consistent with the provisions of this rule.

e. **GWA infill.**

(1) **Interior infill wells.** Additional bottom hole locations for the “J” Sand, Codell and Niobrara Formations are hereby established greater than four hundred sixty (460) feet from the outer boundary of any existing 320-acre drilling and spacing unit (“interior infill wells”). Pursuant to the well location provisions of subsection a., above, interior infill well locations shall be reached by utilizing directional drilling techniques from the GWA windows.

A. If a bottom hole location for an interior infill well is proposed to be located less than four hundred sixty (460) feet from the outer boundary of an existing drilling and spacing unit, a wellbore spacing unit as defined in a.(4)C., above, shall be designated by the operator for such well.

B. If a bottom hole location for an interior infill well is proposed to be located greater than four hundred sixty (460) feet from an existing 80-acre or existing 320-acre drilling and spacing unit, the spacing unit for such well shall conform to the existing 80-acre or existing 320-acre drilling and spacing unit.

(2) **Boundary wells.** Additional bottom hole locations for the “J” Sand, Codell and Niobrara Formations are hereby established less than four hundred sixty (460) feet from the outer boundary of a 320-acre governmental half section or from the outer boundary of any existing 320-acre drilling and spacing unit (“boundary wells”). A wellbore spacing unit as defined in a.(4)C., above, shall be designated by the operator for such well.

(3) **Additional producing formations.** An operator wanting to complete an interior infill well or boundary well in a formation other than the “J” Sand, Codell, or Niobrara Formations (“additional producing formation”) must request an exception location prior to completing the additional producing formation. The spacing unit dedicated to the exception location shall comply with subsections (1) or (2), above, as appropriate.

(4) Existing production facilities. To the extent reasonably practicable, operators shall utilize existing roads, pipelines, tank batteries and related surface facilities for all interior infill wells and boundary wells.

(5) Notice and hearing procedures. For proposed boundary wells, wellbore spacing units, and additional producing formations provided by this subsection e., and for proposed horizontal wells and horizontal wellbore spacing units as provided by 318A.a.(4)D., the following process shall apply:

A. Notice shall be given by certified mail by the operator of a proposed boundary well, wellbore spacing unit, horizontal well or horizontal wellbore spacing unit to all Owners in the proposed wellbore spacing unit. Notice shall be given by certified mail by the operator of a proposed additional producing formation to all Owners in cornering and contiguous spacing units of the requested completion and the proposed spacing unit; if the additional producing formation is unspaced only the Owner in the proposed spacing unit needs to

be notified. Notice for a boundary well, wellbore spacing unit, horizontal well or horizontal wellbore spacing unit shall include a description of the wellbore orientation, the anticipated spud date, the size and shape of the proposed wellbore spacing unit (with depiction attached), the proposed surface and bottom hole locations, identified by footage descriptions, and the survey plat. For proposed horizontal wells and horizontal wellbore spacing units, the operator shall also identify by footage descriptions, the location at which the wellbore penetrates the target formation.

- B. Each owner shall have a 30 day period after receipt of such notice to object in writing to the operator. The written objection must be based upon a claim that the notice provided by the operator does not comply with the informational requirements of subsection A., above, and/or a technical objection that either waste will be caused, correlative rights will be adversely affected, or that the operator is not an "owner", as defined in the Act, of the mineral estate(s) through which the wellbore penetrates within the target formation. Specific facts must form the basis for such objection. The objecting party shall provide a copy of the written objection to the Director.
- C. If an objection pursuant to subsection B. is timely received, the operator may seek a hearing before the Commission on the objection. The objecting party will bear the burden of proving that the notice provided by the operator does not comply with the informational requirements of subsection A., above, that the operator is not an owner, as defined by the Act, and/or the approval of the boundary well location, wellbore spacing unit, horizontal well, horizontal wellbore spacing unit or additional producing formation would either create waste or adversely affect the objecting party's correlative rights. The objection may be presented to an Administrative Law Judge or Hearing Officer. After hearing the objection, the Administrative Law Judge or Hearing Officer may issue a recommended order that sets forth whether the objection shall stand or be dismissed.
- D. If the objection stands, the Commission may either enter an order approving or denying the proposed boundary well location, wellbore spacing unit, horizontal well location, horizontal wellbore spacing unit or additional producing formation, with or without conditions. Such conditions may be requisites for the Application for Permit-to-Drill, Form 2, if the operator chooses to proceed with an Application for Permit-to-Drill, Form 2, relative to the proposed boundary well, wellbore spacing unit, horizontal well, horizontal wellbore spacing unit or additional producing formation. If the objection is dismissed, the operator shall treat the objection as withdrawn and otherwise proceed with subsection E. below.
- E. Absent receipt of a timely objection pursuant to subsections A. and B., above, the Director may administratively approve the boundary well, wellbore spacing unit, horizontal well, horizontal wellbore spacing unit or additional producing formation. A location plat evidencing the well location, wellbore spacing unit, or additional producing formation and applicable spacing unit shall be submitted to the Director together with copies of any surface waivers and a certification that no timely objections were received. An Application for Permit-to-Drill, Form 2, specifically identifying that a boundary well, wellbore spacing unit, horizontal well, horizontal wellbore spacing unit or additional producing formation is proposed, shall also be filed with the Director in accordance with Rule 303 within 90 days of the expiration of the 30 day notice period or such notice shall be deemed withdrawn. Should such notice be withdrawn or deemed withdrawn, the proposed operator shall not submit another notice for

the same well or wellbore spacing unit within 45 days of the date the original notice is withdrawn or deemed withdrawn.

f. Groundwater baseline sampling and monitoring.

(1) Applicability and effective date.

- A. This Rule 318A.f. 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.
- B. This Rule 318A.f. does not apply to an existing Oil or Gas Well that is re-permitted for use as a Dedicated Injection Well.
- C. 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).

(2) **Sampling Locations.**

- A. Initial baseline samples and a subsequent monitoring sample shall be collected from one (1) Available Water Source in the governmental quarter section in which a new Oil and Gas Well, the first well on a Multi-Well Site, or a Dedicated Injection Well is located. If a sampling location has previously been established within the governmental quarter section, and sampled within the prior sixty (60) months before spudding, no initial baseline sample is required.
- B. If there is no Available Water Source within the governmental quarter section where a proposed new Oil and Gas Well, Multi-Well Site, or Dedicated Injection Well is located, then an Available Water Source from a previously unsampled governmental quarter section within a 1/2 mile radius of the Oil and Gas well, Multi-Well Site, or Dedicated Injection Well, if any, shall be sampled. Once a sample location is established in a governmental quarter section, no additional sample locations are required for that governmental quarter section.
- C. If there is more than one Available Water Source in the governmental quarter section or, if applicable, within the half-mile radius around the Oil and Gas Well, the first well on a Multi-Well Site, or a Dedicated Injection Well, the sample location shall be selected based on the following criteria:
 - i. Proximity. Available Water Sources closest to the proposed Oil or Gas Well, a Multi-Well Site, or a Dedicated Injection Well are preferred.
 - ii. Type of Water Source. Well maintained domestic water wells are preferred over other Available Water Sources.

- iii. Multiple identified aquifers available. Where multiple defined aquifers are present, sampling the deepest identified aquifer is preferred.
- iv. 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).

(3) **Exceptions.** Prior to spudding, an operator may request an exception from the requirements of this Rule 318.A.f. by filing a Sundry Notice (Form 4) for the Director's review and approval if:

- A. No Available Water Sources are located within the governmental quarter section or a previously unsampled quarter section within a 1/2 mile radius of a proposed Oil and Gas Well, Multi-Well Site, or Dedicated Injection Well;
- B. The only Available Water Sources are determined to be unsuitable pursuant to subpart (4)B.ii.dd, above. An operator seeking an exception on this ground shall document the condition of the Available Water Sources it has deemed unsuitable; or
- C. 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.
- D. 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 318A.e.(4) shall be deemed approved.

(4) **Timing of Sampling.**

- A. Except as provided in subpart (4)B.i, above, initial sampling shall be conducted within 12 months prior to setting conductor pipe in an Oil and Gas Well or the first well on a Multi-Well Site, or commencement of drilling a Dedicated Injection Well.
- B. One subsequent sampling event shall be conducted at the initial (or previously established) sample location between six (6) and twelve (12) 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 (4)D.ii.

- (5) 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. Upon request, an operator shall provide its sampling protocol to the Director.
- (6) **Initial Baseline Sampling Analysis.** The initial baseline sampling required pursuant to subpart (4)D.i 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 Source shall be surveyed in accordance with Rule 215.
- (7) **Subsequent Sampling Analysis.** Subsequent sampling to meet the requirements of subpart (4)D.ii 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.
- (8) **Methane Detections.** 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.
- (9) **BTEX or TPH Detections.** The Operator shall notify the Director immediately if BTEX compounds or TPH are detected in a water sample.
- (10) **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 location, and the field observations shall be submitted to the Director in an electronic data deliverable format.
- A. 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.

B. Upon request, the Director shall also make the analytical results and surveyed Water Source location 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.

(11) **Liability.** The sampling results obtained to satisfy the requirements of this Rule 318A.f., 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.

g. **Limit on locations.** This rule does not limit the number of formations that may be completed in any GWA drilling and spacing unit nor, subject to subsection c., above, does it limit the number of wells that may be located within the GWA windows.

h. **GWA water sampling.** The Director may apply appropriate drilling permit conditions to require water well sampling near any proposed GWA wells in accordance with the guidelines set forth in subsection f., above.

i. **Waste Management.** In conjunction with filing an Oil and Gas Location Assessment, Form 2A, the operator shall include a waste management plan meeting the general requirements of Rule 907.a.

j. **Exception locations.** The provisions of Rule 318.c. respecting exception locations shall be applicable to GWA wells, however, absent timely objection, boundary wells, wellbore spacing units, and additional producing formations shall be administratively approved as provided in subsection e.(6) above.

k. **Correlative rights.** This rule shall not serve to bar the granting of relief to owners who file an application alleging abuse of their correlative rights to the extent that such owners can demonstrate that their opportunity to produce Cretaceous Age formations from the drilling locations herein authorized does not provide an equal opportunity to obtain their just and equitable share of oil and gas from such formations.

l. **Supersedes orders and policy.** Subject to paragraph d. above, this rule supersedes all prior Commission drilling and spacing orders affecting well location and density requirements of GWA wells. Where the Commission has issued a specific order limiting the number of horizontal wells permitted in a drilling and spacing unit, the well density in such unit shall be governed by that order.

m. The landowner notice provision for the owner(s) of surface property within five hundred (500) feet of the proposed oil and gas location under Rule 305.e. shall not apply to any such locations that are subject to the provisions of this subsection 318A.

318B. Yuma/Phillips County Special Well Location Rule

a. This Special Well Location Rule (“WLR”) governs wells drilled to and completed in the Niobrara Formation for the following lands:

Township 1 North Range 44 West: Sections 7, 18, 19, 30 through 33 Range 45 West: Sections 7 through 36 Range 46 West: Sections 4 through 9 Range 47 West: All Range 48 West: All

Township 2 North Range 46 West: All Range 47 West: All Range 48 West: All

Township 3 North Range 45 West: Sections 1 through 18 Range 46 West: All
Range 47 West: All Range 48 West: All

Township 4 North Range 45 West: All Range 46 West: All Range 47 West: All
Range 48 West: All

Township 5 North Range 45 West: All Range 46 West: All Range 47 West: All
Range 48 West: All

Township 6 North Range 45 West: All Range 46 West: All Range 47 West: All
Range 48 West: All

Township 7 North Range 45 West: All Range 46 West: All Range 47 West: All

Township 8 North Range 45 West: All Range 46 West: All Range 47 West: All

Township 9 North Range 45 West: Sections 19 through 36 Range 46 West: Sections
19 through 36 Range 47 West: Sections 19 through 36

Township 1 South Range 44 West: Sections 3 through 10, 16 through 21, 27 through
34 Range 45 West: Sections 3 through 5 Range 46 West: Sections 4 through 9,
16 through 36 Range 47 West: All Range 48 West: All

Township 2 South Range 44 West: Sections 3 through 6 Range 45 West: Section
7: W½, Section 18: W½, Section 19: All Range 46 West: Sections 1 through 24
Range 47 West: All Range 48 West: All

Township 3 South Range 48 West: All

Township 4 South Range 48 West: All

Within the WLR Area, operators may conduct drilling operations to the Niobrara Formation as follows:

- (1) Four (4) Niobrara Formation wells may be drilled in any quarter section.
- (2) No more than one (1) well may be located in any quarter section.
- (3) No minimum distance shall be required between wells producing from the Niobrara Formation in any quarter section
- (4) Wells shall be located at least three hundred (300) feet from the boundary of said quarter section, and wells located outside any drilling units already established by the Commission in the WLR Area prior to this WLR's effective date (July 30, 2006) shall, in addition, be located at least three hundred (300) feet from any lease line. Further, wells shall be located not less than nine hundred (900) feet from any producible well drilled to the Niobrara Formation prior to this WLR's effective date (July 30, 2006) located in a contiguous or cornering quarter section unless exception is approved by the Director.

- b. Any well drilled to the Niobrara Formation in the WLR Area prior to the effective date (July 30, 2006) of this WLR which is legally located when this WLR becomes effective but is not located as listed above shall be treated as properly located for purposes of this WLR.
- c. This WLR does not alter the size or configuration of any drilling units already established by the Commission in the WLR Area prior to this WLR's effective date (July 30, 2006).
- d. This WLR shall not serve to bar the granting of relief to owners who file an application alleging abuse of their correlative rights to the extent that such owners can demonstrate that their opportunity to produce from the Niobrara Formation at locations herein authorized does not provide an equal opportunity to obtain their just and equitable share of oil and gas from such formation.
- e. Well exception locations to this WLR shall be subject to the provisions of Rule 318.c.
- f. This WLR is a well location rule and supersedes existing Commission orders in effect at the time of its adoption only to the extent that the existing orders relate to permissible well locations and the number of wells that may be drilled in a quarter section. Commission orders in effect when this Rule 318B. is adopted nonetheless apply with respect to the size of drilling units already established by the Commission in the WLR Area. This WLR is not intended to establish well spacing. Accordingly, when an area subject to Rule 318B. is otherwise unspaced, it does not act to space the area but instead provides the permissible locations for any new Niobrara Formation wells. Similarly, Rule 318B. does not affect production allocation for existing or future wells. An operator may allocate production in accordance with the applicable lease, contract terms or established drilling and spacing units recognizing the owner's right to apply to the COGCC to resolve any outstanding correlative rights issues.
- g. The landowner notice provisions for owner(s) of surface property within five hundred (500) feet of the proposed oil and gas location under Rule 305.e shall not apply to any such locations that are subject to the provisions of this Rule 318B.

319. ABANDONMENT

The requirements for abandoning a Well are as follows:

319.a. Plugging

- (1) An Operator will plug a dry or abandoned well, seismic, core, or other exploratory hole, in such a manner that oil, gas, water, or other substance will be confined to the formation in which it originally occurred, isolating all zones specified in Rule 317.e., and zones identified and approved on the Notice of Intent to Abandon, Form 6. If the wellbore is not static before setting a plug in an open hole or after casing is removed from the wellbore, then the Operator will circulate any produced fluids from the wellbore and will fill the wellbore with wellbore fluids sufficient to maintain a balance or overbalance of the producing formation. Wellbore fluids will be in a static state prior to pumping balanced cement plugs, unless the Operator is placing the cement plug as a preliminary step to counteract a high pressure or a lost circulation zone before establishing a static state. The Operator will fill intervals between plugs with wellbore fluids of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling such interval. If mud is necessary to maintain wellbore fluids in a static state prior to setting plugs, the Operator will use a minimum mud weight of 9 pounds per gallon. The Operator will use water spacers both ahead of and behind balanced plug cement slurry to minimize cement contamination by any wellbore fluids that are incompatible with the cement slurry. Any cement plug will be a minimum of 100 feet in length and will extend a minimum of 100 feet above

each zone to be isolated. The material an Operator uses in plugging, whether cement, mechanical plug, or some other equivalent method approved in writing by the Director, will be placed in the Well in a manner to permanently prevent migration of oil, gas, water, or other substance from the formation in which it originally occurred. Cement will conform to the requirements in Rule 317.f. The operator will ensure the slurry design achieves a minimum compressive strength of 300 psi after 24 hours and 800 psi after 72 hours measured at 95° Fahrenheit, or at the minimum expected downhole temperature, and at 800 psi confining pressure.

- (2) The Operator will have the option as to the method of placing cement in the hole by (a) dump bailer, (b) pumping a balanced cement plug through tubing or drill pipe, (c) pump and plug, or (d) equivalent method approved by the Director prior to plugging. Unless prior approval is given, all wellbores will have water, mud or other approved fluid between all plugs.
- (3) An Operator will not place substances of any nature or description other than that normally used in plugging operations in any Well at any time during plugging operations. An Operator will submit all final reports of plugging and abandonment on a Well Abandonment Report, Form 6, and include a job log or cement verification report from the plugging contractor specifying the type of fluid used to fill the wellbore, type and slurry volume of API Class cement used, date of work, and depth the plugs were placed.
- (4) An Operator may not pull surface casing from any Well unless authorized by the Director.
- (5) All abandoned Wells will have a plug or seal placed in the casing and all open annuli from a depth of 50 feet to the surface of the ground or the bottom of the cellar in the hole in such manner as not to interfere with soil cultivation or other surface use. For below-grade markers, the Operator will fit the top of the casing with a screw cap or a steel plate welded in place with a weep hole. For above-grade markers, the Operator will fit the top of the casing with a screw cap or a steel plate welded in place with a weep hole, and a permanent monument that will be a pipe not less than four inches in diameter and not less than 10 feet in length, of which four feet will be above ground level and the remainder embedded in cement or welded to the surface casing. Whether a below-grade or an above-grade marker is used, the Operator will inscribe the marker with the well's legal location, well name and number, and API Number. The Operator will not cap or seal the well until 5 days after placing the last plug to allow monitoring for successful plugging and will cap or seal the well within 90 days after placing the last plug.
- (6) The Operator will obtain approval from the Director of the plugging method prior to plugging, and will notify the Director of the estimated time and date the plugging operation of any Well is to commence, and identify the depth and thickness of all known sources of groundwater. The Operator will verify the placement of the plug required at the base of groundwater and the placement of any other plug specified by the Director by tagging or by an alternative method approved by the Director. For good cause shown, the Director may require that a cement plug be tagged if a cement retainer or bridge plug is not used. If requested by the Operator, the Director will furnish written follow-up documentation for a requirement to tag cement plugs.
- (7) **Wells Converted for Water Supply.** When the well, seismic, core, or other exploratory hole to be plugged may safely be used as a water supply well, and such utilization is desired by the Surface Owner, the well need not be filled above the required sealing plug set below groundwater; provided that written authority for such use is secured from the Surface Owner and, in such written authority, the Surface Owner assumes

the responsibility to plug the well upon its abandonment as a water well in accordance with the Commission's Rules. Such written authority and assumption of responsibility will be filed with the Commission, provided further that the Surface Owner furnishes a copy of the permit for a water well approved by the Division of Water Resources.

319.b. Temporary Abandonment.

- (1) A Well may be temporarily abandoned after passing a successful mechanical integrity test pursuant to Rule 326 upon approval of the Director, for a period not to exceed 6 months provided the hole is cased or left in such a manner as to prevent migration of oil, gas, water, or other substance from the formation or horizon in which it originally occurred. All temporarily abandoned Wells will be closed to the atmosphere with a swedge and valve or packer, or other approved method. The well sign shall remain in place. If an Operator requests temporary abandonment status in excess of 6 months the Operator shall state the reason for requesting such extension and state plans for future operation. A Sundry Notice, Form 4, or other form approved by the Director, will be submitted annually stating the method the well is closed to the atmosphere and plans for future operation. Subsequent mechanical integrity tests will be required at the frequency specified in Rule 326.
- (2) The manner in which the Well is to be maintained should be reported to the Commission, and bonding requirements, as provided for in Rule 304, kept in force until such time as the Well is permanently abandoned.
- (3) An Operator will abandon any Well which has ceased production or injection and is incapable of production or injection and any hole determined to be dry within 6 months thereafter unless the Well passes a successful mechanical integrity test pursuant to Rule 326, and the time is extended by the Director upon application by the owner. The application will indicate why the Well is temporarily abandoned and future plans for utilization. In the event the well is covered by a blanket bond, the Director may require an individual plugging bond on the temporarily abandoned well. Subsequent mechanical integrity tests will be required at the frequency specified in Rule 326. Gas storage wells are to be considered active at all times unless physically plugged.

320. LIABILITY

The owner and operator of any well drilled for oil or gas production or injection purposes, or any seismic, core, or other exploratory holes, whether cased or uncased, shall be liable and responsible for the plugging thereof in accordance with the rules and regulations of the Commission regardless of whether the cost of such plugging and abandonment exceeds the amount of security as set forth in Rule 304.

321. DIRECTIONAL DRILLING

321.a. Deviated Drilling Plan.

- (1) If an Operator intends to drill a deviated (directional, highly deviated, or horizontal) wellbore utilizing controlled directional drilling methods, the Operator will prepare a deviated drilling plan that includes sufficient data to describe the location of the wellbore in three dimensions from not greater than 500 feet below the surface of the ground to total depth.
- (2) The Operator will file the deviated drilling plan with the Application for Permit-to-Drill, Form 2 in a format approved by the Director.

321.b. Directional Survey for a Deviated Wellbore.

- (1) For an intentionally drilled deviated wellbore the Operator will perform a directional survey of the wellbore in a manner to gather sufficient data to describe the location of the wellbore in three dimensions and from not greater than 500 feet below the surface of the ground to total depth.
- (2) The directional survey will be included with the Drilling Completion Report, Form 5, and in a format approved by the Director.

321.c. Inclination Survey for a Non-deviated Wellbore.

- (1) For a newly drilled non-deviated wellbore or for the re-entry, recompletion or deepening of an existing wellbore, the operator will perform an inclination survey of the wellbore and file the inclination survey with the Drilling and Completion Report, Form 5.
- (2) The first shot point of such inclination survey will be made at a depth not greater than 500 feet below the surface, and succeeding shot points will be made either at 500-foot intervals or at the nearest drill bit change thereto, but will not exceed 1,000 feet apart. The inclination survey may be made either during the normal course of drilling or after the well has reached total depth. A directional survey meeting the requirements of Rule 321.b. may be filed in lieu of an inclination survey.
- (3) In the event a Form 5 is not required for re-entry, recompletion or deepening of an existing wellbore, the Operator will file the inclination survey with a Sundry Notice, Form 4.
- (4) The survey will be provided in a format approved by the Director.

321.d. Wellbore Setback Compliance. The Operator will ensure that the wellbore complies with the setback requirements in the Commission's orders or Rules prior to producing the well.

322. COMMINGLING

The commingling of production from multiple formations or wells is encouraged in order to maximize the efficient use of wellbores and to minimize the surface disturbance from oil and gas operations. Commingling may be conducted at the discretion of an operator, unless the Commission has issued an order or promulgated a rule excluding specific wells, geologic formations, geographic areas, or field from commingling in response to an application filed by a directly and adversely affected or aggrieved party or on the Commission's own motion.

This rule supercedes the procedural requirements to establish commingling and allocation contained in any Commission order as of the effective date of this rule, but does not supersede any allocation made under such order.

323. OPEN PIT STORAGE OF OIL OR HYDROCARBON SUBSTANCES

Storage of oil or any other produced liquid hydrocarbon substance in earthen pits or reservoirs is considered to constitute waste, except in emergencies where such substances cannot be otherwise contained. In such cases, these substances must be reclaimed and such storage eliminated as soon as practicable after the emergency is controlled, unless special permission to delay or continue is obtained from the Director.

324A. POLLUTION

- a. The operator shall take precautions to prevent significant adverse environmental impacts to air, water, soil, or biological resources to the extent necessary to protect public health, safety and welfare, including the environment and wildlife resources, taking into consideration cost-effectiveness and technical feasibility to prevent the unauthorized discharge or disposal of oil, gas, E&P waste, chemical substances, trash, discarded equipment or other oil field waste.
- b. No operator, in the conduct of any oil or gas operation shall perform any act or practice which shall constitute a violation of water quality standards or classifications established by the Water Quality Control Commission for waters of the state, or any point of compliance established by the Director pursuant to Rule 324D. The Director may establish one or more points of compliance for any event of pollution, which shall be complied with by all parties determined to be a responsible party for such pollution.
- c. No owner, in the conduct of any oil or gas operation, shall perform any act or practice which shall constitute a violation of any applicable air quality laws, regulations, and permits as administered by the Air Quality Control Commission or any other local or federal agency with authority for regulating air quality associated with such activities.
- d. No injection shall be authorized pursuant to Rule 325 or Rule 401 unless the person applying for authorization to conduct the injection activities demonstrates that those activities will not result in the presence in an underground source of drinking water of any physical, chemical, biological or radiological substance or matter which may cause a violation of any primary drinking water regulation in effect as of July 12, 1982 and found at 40 C.F.R. Part 141, or may otherwise adversely affect the health of persons. An underground source of drinking water is an aquifer or its portion:
 - (1) A which supplies any public water system; or
 - B which contains a sufficient quantity of ground water to supply a public water system; and
 - (i) currently supplies drinking water for human consumption; or
 - (ii) contains fewer than 10,000 milligrams per liter total dissolved solids; and
 - (2) which is not an exempted aquifer.
- e. No person shall accept water produced from oil and gas operations, or other oil field waste for disposal in a commercial disposal facility, without first obtaining a Certificate of Designation from the County in which such facility is located, in accord with the regulations pertaining to solid waste disposal sites and facilities as promulgated by the Colorado Department of Public Health and Environment.

324B . EXEMPT AQUIFERS

- a. **Criteria for aquifer exemption.** An aquifer or a portion thereof may be designated by the Director or the Commission as an exempted aquifer, in connection with the filing of an application pursuant to Rule 325, or Rule 401, and after notification to the Colorado Department of Public Health and Environment, Water Quality Control Division, if it meets the following criteria
 - (1) It does not currently serve as a source of drinking water, and either subparagraph (2) or (3) below apply;

- (2) It cannot now and will not in the future serve as a source of drinking water because:
- A. It is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a person filing an application pursuant to Rule 325, or Rule 401, to contain minerals or hydrocarbons that, considering their quantity and location, are expected to be commercially producible; or
 - B. It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or
 - C. It is so contaminated that it would be economically or technologically impractical to render the water fit for human consumption;
- (3) The total dissolved solids content of the ground water is more than three thousand (3,000) and less than ten thousand (10,000) milligrams per liter and it is not reasonably expected to supply a public water system.

- b. **Aquifer exemption public notice.** If an aquifer exemption is required as part of an injection permit process, the injection well applicant shall apply for an aquifer exemption. This application shall contain data and information which show that applicable aquifer exemption criteria set forth in Rule 324B.a. are met. After evaluation of the application and prior to designating an aquifer or a portion thereof as an exempted aquifer, the Director shall publish a notice of proposed designation in a newspaper of general circulation serving the area where the aquifer is located. The notice shall identify such aquifer or portion thereof which the Director proposes to designate as exempted, and shall state that any person who can make a showing to the Director that the requested designation does not meet the criteria set forth in Rule 324B.a. may request the Commission to hold a hearing thereon.
- c. **Evaluation of written requests for public hearing.** Written requests for a public hearing before the Commission shall be reviewed and evaluated by the Director in consultation with the applicant to determine if the criteria set forth in Rule 324B.a. have been met. If, within thirty (30) days after publication of the notice, the Commission receives a hearing request for which the Director determines the criteria set forth in Rule 324B.a. have not been met, the Commission shall hold such a hearing in accordance with the provisions of §34-60-108, C.R.S., 1973, as amended, and shall make a final determination regarding designation.
- d. **Aquifer exemption designation.** If, within thirty (30) days after publication of the notice described in subparagraph b. above, the Commission does not receive a hearing request or receives a hearing request for which the Director determines the criteria set forth in Rule 324B.a. have been met, said aquifer or portion thereof shall be considered exempted thirty (30) days after publication of the notice.

324C. QUALITY ASSURANCE FOR CHEMICAL ANALYSIS

For the purpose of application for a permit for all wells authorized under Rule 325 and Rule 401, collection and analysis of water samples must comply with the Commission's approved quality assurance project plan.

324D. CRITERIA TO ESTABLISH POINTS OF COMPLIANCE

In determining a point of compliance, the Director shall take into consideration recommendations of the operator or any responsible party or parties, if applicable, including technical and economic feasibility, together with the following factors:

- a. The classified use established by the Water Quality Control Commission, for any groundwater or surface water which will be impacted by contamination. If not so classified, the Director shall consider the quality, quantity, potential economic use and accessibility of such water;
- b. The geologic and hydrologic characteristics of the site, such as depth to groundwater, groundwater flow, direction and velocity, soil types, surface water impacts, and climate;
- c. The toxicity, mobility, and persistence in the environment of contaminants released or discharged from the site;
- d. Established wellhead protection areas;
- e. The potential of the site as an aquifer recharge area; and
- f. The distance to the nearest permitted domestic water well or public water supply well completed in the same aquifer affected by the event.
- g. The distance to the nearest permitted livestock or irrigation water well completed in the same aquifer affected by the event.

325. UNDERGROUND DISPOSAL OF WATER

- a. No person shall commence operations for the underground disposal of water, or any other fluids, into a Class II well, or any well regulated by the Commission, nor shall any person commence construction of such a well, without having first obtained written authorization for such operations from the Director. Persons wishing to obtain authorization to conduct underground disposal activities shall file with the Director an Underground Injection Formation Permit Application, Form 31 and an Injection Well Permit Application, Form 33. If the disposal well is to be drilled, this application shall be submitted concurrently with the Application for Permit-to-Drill, Form 2, along with a service and filing fee to be determined by the Commission. (See Appendix III)
- b. **Withholding approval of underground disposal of water.** The Director may withhold the issuance of a permit and the granting of approval of any Underground Injection Formation Permit Application, Form 31 and any Injection Well Permit Application, Form 33 for any proposed disposal well when the Director has reasonable cause to believe that the proposed disposal well could result in a significant adverse impact on the environment or public health, safety and welfare. In the event such approval is not granted, the Director shall immediately advise the operator and bring the matter to the Commission at its next regularly scheduled hearing, or as soon as practicable before an Administrative Law Judge or Hearing Officer.
- c. The application for a dedicated injection well shall include the following information:
 - (1) The name, description and depth of the formation into which water is to be injected, and all underground sources of drinking water which may be affected by the proposed operation. A water analysis of the injection formation (if the total dissolved solids of the injection formation is determined to less than ten thousand (10,000) milligrams per liter, the aquifer must be exempted in accordance with Rule 322B.). The fracture pressure or fracture gradient of the injection formation.
 - (2) A base plat covering the area within one-quarter (1/4) mile of the proposed disposal well showing location of the proposed disposal well or wells and the location of all oil and gas wells, domestic and irrigation wells of public record and the identification of all oil and gas wells currently producing from the proposed injection

zone within one-half (1/2) mile of the disposal zone. The names, addresses and holdings of all surface and mineral owners as defined in C.R.S. 34-60-103 (7), within one-quarter (1/4) mile of the proposed disposal well or wells, or all owners of record in the field if a field-wide system is proposed. These owners shall be specifically outlined and identified on the base plat. A list of all domestic and irrigation wells of public record, within one-quarter (1/4) mile of the proposed disposal well or wells, including their location and depth. (This information may be obtained at the Colorado Division of Water Resources.) Remedial action shall be required for any well within one-quarter (1/4) mile of the proposed disposal well or wells in which the injection zone is not adequately confined. The applicant shall include information regarding the need for remedial action on any well(s) penetrating the injection zone within one-quarter (1/4) mile of the proposed disposal well or wells, which the applicant may or may not operate and a plan for the performance of any such remedial work. A copy of all plans and specifications for the system and its appurtenances.

- (3) A resistivity log, run from the bottom of the surface casing to total depth of the disposal well or wells or any well within one (1) mile together with a log from that well that can be correlated with the injection well. If the disposal well is to be drilled, a description of the typical stratigraphic level of the disposal formation in the disposal well or wells, and any other available logging or testing data, on the disposal well or wells.
- (4) A full description of the casing in the disposal well or wells. This shall include any information available on any remedial cement work performed to any casing string. This shall also include a schematic drawing showing all casing strings with cement volumes and tops, existing or as proposed, plug back total depth, depth of any existing open or squeezed perforations, setting depths of any bridge plugs existing or proposed, planned perforations in the injection zone, tubing and packer size and setting depth. A diagram of the surface facility showing all pipelines and tanks associated with the system. A listing of all leases connected directly by pipelines to the system.
- (5) A listing of all sources of water, by lease and well, to be injected shall be submitted on a Source of Produced Water for Disposal, Form 26.
- (6) Any proposed stimulation program.
- (7) The minimum and maximum amount of water to be injected daily with anticipated injection pressures. Maximum injection pressure will be set by the Director upon approval.
- (8) The names and addresses of those persons notified by the applicant, as required by subparagraph i. of this rule.

d. The application for a simultaneous injection well shall include the following:

- (1) The name, description and depth of the formation into which water is to be injected, and all underground sources of drinking water which may be affected by the proposed operation. A water analysis of the injection formation (if the total dissolved solids of the injection formation is determined to be less than ten thousand (10,000) milligrams per liter, the aquifer must be exempted in accordance with Rule 324B.); a water analysis from the producing formation; and go fracture pressure or fracture gradient of the injection formation.

- (2) A base plat covering the area within one-quarter (1/4) mile of the proposed well showing the location of the proposed well or wells and the location of all oil and gas wells, domestic and irrigation wells of public record and the identification of all oil and gas wells currently producing from the proposed injection zone within one-half (1/2) mile of the disposal zone and the names, addresses and holdings of all mineral owners as defined in §34-60-103 (7), C.R.S., within one-quarter (1/4) mile of the proposed disposal well or wells, or all owners of record in the field if a field-wide system is proposed. These owners shall be specifically outlined and identified on the base plat. Remedial action shall be required for any well within one-quarter (1/4) mile of the proposed well or wells in which the injection zone is not adequately confined. The applicant shall include information regarding the need for remedial action on any well(s) penetrating the injection zone within one-quarter (1/4) mile of the proposed disposal well or wells, which the applicant may or may not operate and a plan for the performance of any such remedial work and a copy of all plans and specifications for the system and its appurtenances.
- (3) A resistivity log, run from the bottom of the surface casing to total depth of the disposal zone or such log from a well within one (1) mile together with a log from that well that can be correlated with the simultaneous injection well. If the simultaneous injection well is to be drilled, a description of the typical stratigraphic level of the injection formation in the simultaneous injection well or wells, and any other available logging or testing data, on the simultaneous injection well or wells.
- (4) A full description of the casing in the simultaneous injection well or wells. This shall include any information available on any remedial cement work performed to any casing string. This shall also include a schematic drawing showing all casing strings with cement volumes and tops, existing or as proposed, plug back total depth, depth of any existing open or squeezed perforations, setting depths of any bridge plugs existing or proposed, planned perforations in the injection zone, downhole pump setting depth and any tubing and or packer size and setting depth.
- (5) Any proposed stimulation program.
- (6) The amount of water to be injected daily.
- (7) Downhole pump specifications, together with a calculation of maximum discharge pressure created under proposed wellbore configuration. Downhole pump configurations shall be designed to inject below the injection zone fracture gradient.
- (8) The names and addresses of those persons notified by the applicant, as required by subparagraph j. of this rule.

The following rules shall apply to both dedicated injection well and simultaneous injection well applications.

- e. **Mechanical integrity testing requirement.** Prior to application approval, the proposed disposal well must satisfactorily pass a mechanical integrity test in accordance with Rule 326.
- f. **Commercial disposal well requirements.** Prior to application approval, the appurtenant commercial disposal well operations shall comply with the requirements of Rules 706, 707, and 712.

- g. **Multiple well applications.** Application may be made to include the use of more than one (1) disposal well on the same lease, or on more than one (1) lease. Wherever feasible and applicable, the application shall contemplate a coordinated plan for the entire field.
- h. The designated operator of a unitized or cooperative project shall execute the application.
- i. Notice of the application for a dedicated injection well shall be given by the applicant by registered or certified mail or by personal delivery, to each surface owner and owner as defined in §34-60-103(7), C.R.S., within one-quarter (1/4) mile of the proposed well or wells and to owners and operators of oil and gas wells producing from the injection zone within one-half (1/2) mile of the disposal well or to owners of cornering and contiguous units where injection will occur into the producing zones, whichever is the greater distance.
- j. Notice of the application for a simultaneous injection well shall be given by the applicant by registered or certified mail or by personal delivery, to each owner as defined in §34-60-103(7), C.R.S., within one-quarter (1/4) mile of the proposed well or wells and to owners and operators of oil and gas wells producing from the injection zone within one-half (1/2) mile of the disposal well or to owners of cornering and contiguous units where injection will occur into the producing zones, whichever is the greater distance.
- k. A copy of the notice of application shall be included with the disposal application filed with the Commission, and the applicant shall certify that notice by registered or certified mail or by personal delivery, to each of the owners specified in subparagraphs i. and j., has been accomplished.
- l. **Notice of application requirements.** The notice shall briefly describe the disposal application and include legal location, proposed injection zone, depth of injection, and other relevant information. The notice shall state that any person who would be directly and adversely affected or aggrieved by the authorization of the underground disposal into the proposed injection zone may file, within 15 days of notification, a written request for a public hearing before the Commission, provided such request meets the protest requirements specified in subparagraph m. of this rule. The notice shall also state that additional information on the operation of the proposed disposal well may be obtained at the Commission office.
- m. **Evaluation of written requests for public hearing.** Written requests for public hearing before the Commission by a person, notified in accordance with subparagraphs i. and j. of this rule, who may be directly and adversely affected or aggrieved by the authorization of the underground disposal into the proposed injection zone, shall be reviewed and evaluated by the Director in consultation with the applicant. Written protests shall specifically provide information on:
 - (1) Possible conflicts between the injection zone's proposed disposal use and present or future use as a source of drinking water or present or future use as a source of hydrocarbons, or
 - (2) Operations at the well site which may affect potential and current sources of drinking water.
- n. **Dedicated injection well public notice.** The Director shall publish a notice of the proposed disposal permit for dedicated injection wells in a newspaper of general circulation serving the area where the well(s) is (are) located. The notice shall briefly describe the disposal application and include legal location, proposed injection zone, depth of injection and other relevant information. Comment period on the proposed disposal application shall end thirty (30) days after date of publication. If any data, information, or arguments submitted during the public comment period appear to raise substantial questions concerning potential

impacts to the environment, public health, safety and welfare raised by the proposed disposal well permit the Director may request that the Commission hold a hearing.

- o. **Injection application deadlines.** If all of the data or information necessary to approve the disposal application has not been received within six (6) months of the date of receipt, the application will be withdrawn from consideration. However, for good cause shown, a ninety (90) day extension may be granted, if requested prior to the date of expiration.

326. MECHANICAL INTEGRITY TESTING

For the purpose of this rule, a mechanical integrity test of a well is a test to determine if there is a significant leak in the well's casing, tubing, or mechanical isolation device, or if there is significant fluid movement into an underground source of drinking water through vertical channels adjacent to the wellbore.

a. **Injection Wells** - A mechanical integrity test shall be performed on all injection wells.

- (1) The mechanical integrity test shall include one of the following tests to determine whether significant leaks are present in the casing, tubing, or mechanical isolation device:
 - A. Isolation of the tubing-casing annulus with a packer set at 100 feet or less above the highest open injection zone perforation, unless an alternate isolation distance is approved in writing by the Director. The pressure test shall be with liquid or gas at a pressure of not less than 300 psi or the average injection pressure, whichever is greater, and not more than the maximum permitted injection pressure; or
 - B. The monitoring and reporting to the Director, on a monthly basis for 60 consecutive months, of the average casing-tubing annulus pressure, following an initial pressure test; or
 - C. Any equivalent test or combination of tests approved by the Director.
- (2) The mechanical integrity test shall include one of the following tests to determine whether there are significant fluid movements in vertical channels adjacent to the well bore:
 - A. Cementing records which shall only be valid for injection wells in existence prior to July 1, 1986;
 - B. Tracer surveys;
 - C. Cement bond log or other acceptable cement evaluation log;
 - D. Temperature surveys; or
 - E. Any other equivalent test or combination of tests approved by the Director.
- (3) No person shall inject fluids via a new injection well unless a mechanical integrity test on the well has been performed and supporting documents including Mechanical Integrity Test, Form 21, submitted and approved by the Director. Verbal approval may be granted for continuous injection following a successful test.

(4) Following the performance of the initial mechanical integrity test required by subparagraph (3), additional mechanical integrity tests shall be performed on each type of injection well as follows:

A. Dedicated injection well. As long as it is used for the injection of fluids, mechanical integrity tests shall be performed at the rate of not less than one test every five years, except as specified by subparagraph C below. Five year periods shall commence on the date the initial mechanical integrity test is performed or the date any mechanical integrity test specified in subparagraph C below.

B. Simultaneous injection well. No additional tests will be required after the initial mechanical integrity test.

C. All injection wells. A new mechanical integrity test shall be performed after any casing repairs, after resetting the tubing or mechanical isolation device, or whenever the tubing and/or mechanical isolation device is moved during workover operations.

b. **Shut-in Wells** - All shut-in wells shall pass a mechanical integrity test.

(1) A mechanical integrity test shall be performed on each shut-in well within two years of the initial shut-in date.

(2) Subsequently, a mechanical integrity test shall be performed on each shut-in well on 5 year intervals from the date the initial mechanical integrity test was performed, as long as the well remains shut-in.

(3) The mechanical integrity test for a shut-in well shall be performed after: isolating the wellbore with a bridge plug or similar approved isolating device set 100 feet or less above the highest open perforation. The pressure test shall be with liquid or gas at an initial, stabilized surface pressure of not less than 300 psi surface pressure or any equivalent test or combination of tests approved by the Director.

(4) Not less than 48 hours prior to returning an inactive, shut-in well to production or injection, an operator must submit a Field Operations Notice, Form 42 – Notice of Return to Service, to the Director of the scheduled date for returning the well to production or injection to allow the Commission to inspect.

c. **Temporarily Abandoned Wells** – All temporarily abandoned wells shall pass a mechanical integrity test.

(1) A mechanical integrity test shall be performed on each temporarily abandoned well within 30 days of temporarily abandoning the well.

(2) Subsequently, a mechanical integrity test shall be performed on each temporarily abandoned well on five year intervals from the date of the initial mechanical integrity test was performed, as long as the well remained temporarily abandoned.

(3) The mechanical integrity test for a temporarily abandoned well shall be performed after isolating the wellbore with a bridge plug or similar approved isolating device set 100 feet or less above the highest open perforation. The pressure test shall be liquid or gas at an initial, stabilized surface pressure of not less than 300 psi surface pressure or any equivalent test or combination of tests approved by the Director.

- (4) Not less than 48 hours prior to returning an inactive, temporarily abandoned well to production or injection, an operator must submit a Field Operations Notice, Form 42 – Notice of Return to Service, to the Director of the scheduled date for returning the well to production or injection to allow the Commission to inspect the installation of equipment or conduct of the mechanical intervention.
- d. **Waiting-on-completion and Suspended Operations Wells** – A mechanical integrity test shall be performed on each waiting-on-completion well within two years of setting the production casing. A mechanical integrity test shall be performed on each suspended operations well within two years of setting any casing string and suspending operations prior to reaching permitted total depth.
- e. Not less than 10 days prior to the performance of any mechanical integrity test required by this rule, any person required to perform the test shall notify the Director with a Form 42, Field Operations Notice, Mechanical Integrity Test, of the scheduled date and time when the test will be performed.
- f. All wells shall maintain mechanical integrity.
- (1) All non-injection wells which lack mechanical integrity, as determined through a mechanical integrity test or other means, shall be repaired or plugged and abandoned within six months. If an operator has performed a mechanical integrity test within the two years required for shut-in wells or the 30 days required for temporarily abandoned wells by this Rule, they will have six months from the date of the unsuccessful test to make repairs or plug and abandon the well. If the operator has not performed a mechanical integrity test within the required time frames in Rule 326.b.(1) and 326.c.(1), they will not be given an additional six months in the event of an unsuccessful test.
- (2) All injection wells which fail a mechanical integrity test, or which are determined through any other means to lack mechanical integrity, shall be shut-in immediately.
- g. Mechanical integrity test pressure loss or gain must not exceed 10% of the initial stabilized surface pressure over a test period of 15 minutes. The test may be repeated if the pressure loss or gain is determined to be the result of compression related to gas dissolution from the fluid column or temperature effects related to the fluid used to load the column. Wells that do not satisfy this test requirement are considered to lack mechanical integrity and are subject to the requirements of Rule 326.d.

327. WELL CONTROL

The operator shall take all reasonable precautions, in addition to fully complying with Rule 317 to prevent any oil, gas or water well from flowing uncontrolled and shall take immediate steps and exercise due diligence to bring under control any such well.

The operator shall report all uncontrolled events to the Director as soon as practicable, but no later than 24 hours following the incident. Within 15 days after these occurrences the operator shall submit a Spill Report, Form 19, and/or a Well Control Report, Form 23, as appropriate, for reportable spills/releases or kicks while drilling, providing all details required on the forms. The Director shall maintain these written reports in a central file.

328. MEASUREMENT OF OIL

The volume of all oil production from a lease or a production unit shall be measured and recorded prior to removal from the lease or production unit. The volume of production of oil shall be computed

in terms of barrels of clean oil on the basis of properly calibrated meter measurements or tank measurements of oil-level differences, made and recorded to the nearest one-quarter (1/4) inch of one hundred percent (100%) capacity tables, subject to the following corrections in items a., b., and c. below. This rule shall be used consistently with standards established by the American Society for Testing and Materials (ASTM), the American Petroleum Institute (API) Manual of Petroleum Measurement Standards, the American Gas Association (AGA), the Gas Processors Association (GPA), or other applicable standards-setting organizations, and pursuant to contractual rights or obligations. Only those editions of standards cited within this rule shall apply to this rule; later amendments do not apply. The material cited 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 publication depository library.

- a. **Correction for Impurities.** The percentage of impurities (water, sand and other foreign substances not constituting a natural component part of the oil) shall be determined to the satisfaction of the Director, and the observed gross volume of oil shall be corrected to exclude the entire volume of such impurities.
- b. **Temperature Correction.** The observed volume of oil corrected for impurities shall be further corrected to the standard volume of sixty degrees Fahrenheit (60° F) in accordance with ASTM D-1250 Table 7, or any close approximation thereof approved by the Director.
- c. **Gravity Determination.** The gravity of oil at sixty degrees Fahrenheit (60° F). shall be determined in accordance with ASTM D-1250 Table 5, or any close approximation thereof approved by the Director.
- d. **Tank Gauging.** Measurement by tank gauging must be completed in accordance with industry standards as specified in:
 - (1) The API Manual of Petroleum Measurement Standards, Chapter 3.1A Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, (Second Edition, August 2005) and no later editions;
 - (2) The API Manual of Petroleum Measurement Standards, Chapter 3.1B Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, (Second Edition, June 2001) and no later editions;
 - (3) The API Manual of Petroleum Measurement Standards, Chapter 3.1A Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, (Second Edition, August 2005) and no later editions;
 - (4) The API Manual of Petroleum Measurement Standards Chapter 18.1 - Custody Transfer - Section 1-Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck (Second Edition, April 1997) and no later editions, or
 - (5) The API Manual of Petroleum Measurement Standards Chapter 18.2, Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods, (First Edition, July 2016) and no later editions.
 - (6) The API Manuals identified in (1) through (6) above are 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, the API Manuals may be examined at any state publications depository library and is available from API at 1220 L Street, NW Washington, DC 20005-4070, 1-202-682-8000.

- e. **Metering Station.** Measurement shall be completed in accordance with industry standards as specified in API CH. 4 Proving Systems (Section 2, Third Edition September 2003 and Section 8, First Edition November 1995), API CH. 5 Metering (CH. 5.1 Fourth Edition October 2005, CH. 5.2 Third Edition October 2005, CH. 5.3 Fifth Edition September 2005, CH. 5.4 Second Edition July 2005, CH. 5.5 Second Edition July 2005, and CH. 5.6 First Edition October 2002), API CH. 7 Temperature Determination (First Edition June 2001), API CH. 8 Sampling (CH. 8.1 Third Edition October 1995 and CH. 8.2 Second Edition October 1995), and the API CH. 12, Calculation of Quantities (CH. 12.1 Part 1 Second Edition November 2001).
- f. **LACT Meters.** Measurement utilizing LACT units shall be in accordance with industry specifications or standards as specified in API SPEC. 6.1, Lease Automatic Custody Transfer Systems (Second Edition May 1991).
- g. **Sales Reconciliation.** In order to facilitate the resolution of questions regarding the payment of proceeds or sales reconciliation from a well, a payee may submit a Form 37 to the payor requesting additional information concerning the payee's interest in the well, price of the oil sold, taxes applied to the sale of oil, differences in well production and well sales, and other information as described in § 34-60-118.5, C.R.S. The payor shall return the completed form to the payee within sixty (60) days of receipt. Submittal of this form to the payor shall fulfill the requirement for "written request" described in § 34-60-118.5(2.5), C.R.S., and is a prerequisite to filing a complaint with the Commission. The payor shall use its best efforts to consult in good faith with the payee to resolve disputes regarding payment of proceeds or sales reconciliation.

A Form 37 requesting information concerning payment of proceeds may be submitted by the payee at any time. A Form 37 requesting information concerning sales volume reconciliation shall be submitted by the payee within one year of receipt of payment or the notification of a revised payment. The Commission may act to prohibit or terminate any abuse of the reconciliation process, such as the submittal by a payee of multiple repeated requests for sales volume reconciliation regarding the same well. Such action by the Commission may include, but is not limited to, relieving the payor from its obligation to answer the request and limiting or prohibiting the payee's submittal of additional requests.

329. MEASUREMENT OF GAS

The volume of all gas produced from a lease or a production unit shall be measured and recorded prior to removal from the lease or production unit. Production of gas of all kinds shall be measured by meter unless otherwise agreed to by the Director. For computing volume of gas to be reported to the Commission, the standard pressure base shall be fourteen point seventy-three (14.73) psia, regardless of atmospheric pressure at the point of measurement, and the standard temperature base shall be sixty degrees Fahrenheit (60° F). All volumes of gas to be reported to the Commission shall be adjusted by computation to these standards, regardless of pressures and temperatures at which the gas was actually measured, unless otherwise authorized by the Director. This rule shall be used consistently with standards established by the American Society for Testing and Materials (ASTM), the American petroleum Institute (API) Manual of Petroleum Measurement Standards, the American Gas Association (AGA), the Gas Processors Association (GPA), or other applicable standards-setting organizations, and pursuant to contractual rights and obligations. Only those editions of standards cited within this rule shall apply to this rule; later amendments do not apply. The material cited 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 publication depository library.

- a. **Metering Station.** Installation and operation of gas measurement stations shall be in accordance with industry standards as specified in API CH. 14.3, Orifice Measurement

(Part 2, Fourth Edition April 2000 and Part 3, Third Edition August 1992 and Part 4, Third Edition November 1992); API CH. 21.1, Electronic Measurement (gas) (First Edition September 1993); AGA Report #7, Turbine Measurement (January 2006); AGA Report #9, Ultrasonic Measurement (April 2007); and AGA Report #11, Coriolis Measurement (January 2003).

- b. **Metering Equipment.** The devices used to measure the differential, line pressure, and temperature shall have accepted accuracy ratings established in industry standards as specified in API CH. 22, Testing Protocol Standards (CH. 22.1 First Edition November 2006 and CH. 22.2 First Edition August 2005).
- c. **Meter Calibration.** Meters shall be calibrated annually unless more frequent calibration is required by contractual obligations or by the Director. All calibration reports shall be created, maintained, and made available as operation records pursuant to Rule 205. In the event two consecutive meter calibrations exceed a 2% error, the operator shall report the test results to the Director who may require the operator to show cause why the meter should not be replaced.
- d. **Gas Quality.** The heating value of produced natural gas shall be representative of the flowing gas stream at the lease or unit boundary, as determined by chromatographic analysis of a sample obtained in close proximity to the volume measurement device and shall be reported on an Operator's Monthly Report of Operations, Form 7. Gas sampling and analysis shall occur annually unless more frequent sampling is required by contractual obligations or by the Director. Gas sampling, gas chromatography, and the resulting analysis data shall be in accordance with industry standards as specified in API CH. 14.1, Gas Sampling (Fifth Edition February 2006); GPA 2166, Gas Sampling (Revised 2005); GPA 2261, Gas Analysis (Revised 2000); GPA 2286, Extended Analysis; GPA 2145, Gas Physical Properties (Revised 2003); and GPA 2172, Gas Heating Value (Revised 1996).
- e. **Sales Reconciliation.** In order to facilitate the resolution of questions regarding the payment of proceeds or sales reconciliation from a well, a payee may submit a Form 37 to the payer requesting additional information concerning the payee's interest in the well, price of the gas sold, taxes applied to the sale of gas, differences in well production and well sales, and other information as described in § 34-60-118.5, C.R.S. The payer shall return the completed form to the payee within sixty (60) days of receipt. Submittal of this form to the payer shall fulfill the requirement for "written request" described in § 34-60-118.5(2.5), C.R.S., and is a prerequisite to filing a complaint with the Commission. The payer shall use its best efforts to consult in good faith with the payee to resolve disputes regarding payment of proceeds or sales reconciliation.

A Form 37 requesting information concerning payment of proceeds may be submitted by the payee at any time. A Form 37 requesting information concerning sales volume reconciliation shall be submitted by the payee within one year of receipt of payment or the notification of a revised payment. The Commission may act to prohibit or terminate any abuse of the reconciliation process, such as the submittal by a payee of multiple repeated requests for sales volume reconciliation regarding the same well. Such action by the Commission may include, but is not limited to, relieving the payer from its obligation to answer the request and limiting or prohibiting the payee's submittal of additional requests.

330. MEASUREMENT OF PRODUCED AND INJECTED WATER

- a. The volume of produced water shall be computed and reported in terms of barrels on the basis of properly calibrated meter measurements or tank measurements of water-level differences, made and recorded to the nearest one-quarter (1/4) inch of one hundred (100%) percent capacity tables. If measurements are based on oil/water ratios, the oil/water ratio must be based on a production test performed during the last calendar year.

Other equivalent methods for measurement of produced water may be approved by the Director.

- b. The volume of water injected into a Class II dedicated injection well shall be computed and reported in term of barrels on the basis of properly calibrated meter measurements or tank measurements of water-level differences made and recorded to the nearest one-quarter (1/4) inch of one hundred percent (100%) capacity tables. If water is transported to an injection facility by means other than direct pipeline, measurement of water is required by a properly calibrated meter
- c. The volume of water injected and produced in simultaneous injection wells shall be computed and reported in terms of barrels on the basis of calculated pump volumes, on the basis of property calibrated meter measurements, or on the basis of a produced gas to water ratio based on an annual production test.

331. VACUUM PUMPS ON WELLS

The installation of vacuum pumps or other devices for the purpose of imposing a vacuum at the wellhead or on any oil or gas bearing reservoir may be approved by the Director upon application therefore, except as herein provided. The application shall be accompanied by an exhibit showing the location of all wells on adjacent premises and all offset wells on adjacent lands, and shall set forth all material facts involved and the manner and method of installation proposed. Notice of the application shall be given by the applicant by registered or certified mail, or by delivering a copy of the application to each producer within one-half (1/2) mile of the installation.

In the event no producer within one-half (1/2) mile of the installation or the Commission itself files written objection or complaint to the application within fifteen (15) days of the date of application, then the application shall be approved, but if any producer within one-half (1/2) mile of said installation or the Commission itself files written objection within fifteen (15) days of the date of application, then a hearing shall be held as soon as practicable.

332. USE OF GAS FOR ARTIFICIAL GAS LIFTING

Gas may be used for artificial gas lifting of oil where all such gas returned to the surface with the oil is used without waste. Where the returned gas is not to be so used, the use of gas for artificial gas lifting of oil is prohibited unless otherwise specifically ordered and authorized by the Commission upon hearing.

333. SEISMIC OPERATIONS

- a. **COGCC Form 20, Notice of Intent to Conduct Seismic Operations.** Seismic operations require an approved Form 20 which shall be submitted to the Director prior to commencement of shothole drilling or recording operations. An informational copy of the Form 20 shall be filed by the operator with the local governmental designee at or before the time of filing with the Director. Any change of plans or line locations may be implemented without Director approval provided that after such change is performed, the Director shall receive written notice of the change within five (5) days.

A map shall be included with the notice. This map shall be at a scale of at least 1:48,000 showing sections, townships and ranges and providing the location of the proposed seismic lines, including source and receiver line locations.

The Notice of Intent to Conduct Seismic Operations, Form 20, shall be in effect for six (6) months from the date of approval. An extension of time may be granted upon written request submitted prior to the expiration date.

b. **Surface owner consultation.** Prior to the commencement of any seismic operation, a good faith effort shall be made to consult with all surface owners of the lands included in the seismic project area.

c. **Exploration requiring the drilling of shotholes:**

(1) **Explosive storage.** All explosives shall be legally and safely stored and accounted for in magazines when not in use in accordance with relevant regulations of the Alcohol, Tobacco and Firearms Division of the Federal Department of the Treasury.

(2) **Blasting safety setbacks.** Blasting shall be kept a safe distance from a building, water well or spring, unless by special written permission of the surface owner or lessee, according to the following minimum setback distances:

CHARGES IN LBS. GREATER THAN	CHARGES IN LBS. UP TO AND INCLUDING	MINIMUM SETBACK DISTANCE IN FEET
0	2	200
2	5	300
5	6	360
6	7	420
7	8	480
8	9	540
9	10	600
10	11	649
11	12	696
12	13	741
13	14	784
14	15	825
15	16	864
16	17	901
17	18	936
18	19	969
19	20	1000
20		1320

(3) Prior to any shothole drilling, the operator shall contact the Utility Notification Center of Colorado (CO 811).

(4) **Drilling and plugging.** The following guidelines shall be used to plug shotholes unless the operator can demonstrate that another method will provide adequate protection to ground water quality and movement and long-term land stability:

A. Any slurry, drilling fluids, or cuttings which are deposited on the surface around the seismic hole shall be raked or otherwise spread out to at least within one (1) inch of the surface, such that the growth of the natural grasses or foliage shall not be impaired.

- B. All shotholes shall be preplugged or anchored to prevent public access if not immediately shot. In the event the preplug does not hold, seismic holes shall be properly plugged and abandoned as soon as practical after the shot has been fired. However, a fired hole shall not be left unplugged for more than thirty (30) days without approval of the Director. In no event shall shotholes be left open, but shall be covered with a tin hat or other similar cover until they are properly plugged. The hats shall be imprinted with the seismic contractor's name or identification number or mark.
 - C. The hole shall be filled to a depth of approximately three (3) feet below ground level by returning the cuttings to the hole and tamping the returned cuttings to ensure the hole is not bridged. A non-metallic perma-plug either imprinted or tagged with the operator name or the identification number or mark described in the notice of intent shall be set at a depth of three (3) feet, and the remaining hole shall be filled and tamped to the surface with cuttings and native soil. A sufficient mound of native soil shall be left over the hole to allow for settling.
 - D. When non-artesian water is encountered while drilling seismic shotholes, the holes shall be filled from the bottom up with a high grade coarse ground bentonite to ten (10) feet above the static water level or to a depth of three (3) feet from the surface; the remaining hole shall be filled and tamped to the surface with cuttings and native soil, unless the operator otherwise demonstrates that use of another suitable plugging material may be substituted for bentonite without harm to ground water resources.
 - E. If artesian flow (water rising above the depth at which encountered) is encountered in the drilling of any seismic hole, cement or high grade coarse ground bentonite shall be used to seal off the water flow with the selected material placed from the bottom of the hole to the surface or at least fifty (50) feet above the top of the water-bearing material, thereby preventing cross-flow between aquifers, erosion or contamination of fresh water supplies. Said holes shall be plugged immediately.
- d. **COGCC Form 20A, Completion Report for Seismic Operations.** A Form 20A shall be submitted to the Director within sixty (60) days after completion of the project. The report shall include: maps (with a scale not less than 1:48,000) showing the location of all receiver lines, energy source lines and any shotholes. Shotholes encountering artesian flow shall be indicated on the map.

If the program included any shotholes, then the completion report shall be accompanied by the following:

- (1) a certification by the party responsible for plugging the holes that all shotholes are plugged as prescribed by these rules and approved by the Director, and
- (2) the latitude and longitude of each shothole location. The latitude and longitude coordinates shall be referenced in decimal degrees to an accuracy and precision of five decimals of a degree using the North American Datum (NAD) of 1983 (e.g.; latitude 37.12345 N, longitude 104.45632 W) or reported in other form as approved by the Director. If GPS technology is utilized to determine the latitude and longitude, all GPS data shall meet the requirements set forth in Rule 215. a. through h.

e. **Bonding Requirements.** The company submitting the Notice of Intent to Conduct Seismic Operations, Form 20, shall file financial assurance in accordance with Rule 705. prior to the commencement of operations. The bond shall remain in effect until a request is made by the company to release the bond for the following reasons:

(1) The shotholes have been properly plugged and abandoned, and source and receiver lines have been reclaimed in accordance with this Rule 333., and

(2) There are no outstanding complaints received from surface owners that have not been investigated by the Director and addressed as provided for in Rule 522.

f. **Reclamation requirements.** Upon completion of seismic operations the surface of the land shall be restored as nearly as practicable to its original condition at the commencement of seismic operations. Appropriate reclamation of disturbed areas will vary depending upon site specific conditions and may include compaction alleviation and revegetation. All flagging, stakes, cables, cement, mud sacks or other materials associated with seismic operations shall be removed.

334. PUBLIC HIGHWAYS AND ROADS

All persons subject to the act and these rules and regulations while using public highways or roads shall be subject to the State Vehicles and Traffic Laws pursuant to Title 42, C.R.S. and the State Highway and Roads Laws, Title 43, C.R.S., pertaining to the use of public highways or roads within the state.

335. COGCC Form 15. EARTHEN PIT REPORT/PERMIT

An Earthen Pit Report/Permit, Form 15, shall be submitted for approval by the Director in accordance with Rule 903.

336. COGCC Form 18. COMPLAINT REPORT

Any party who wishes to file a complaint regarding oil and gas operations is encouraged to submit a Form 18. The Director shall investigate any complaint and determine what, if any, action shall be taken in accordance with Rule 522.

337. COGCC Form 19. SPILL/RELEASE REPORT

A spill or release of E&P waste or produced fluids shall be reported to the Director on a Spill/Release Report, Form 19 pursuant to the reporting requirements in Rule 906.

338. RESERVED

339. RESERVED

340. COGCC Form 27. SITE INVESTIGATION AND REMEDIATION WORKPLAN

Site Investigation and Remediation Workplan, Form 27, shall be submitted when required in accordance with Rule 909.

341. BRADENHEAD MONITORING DURING WELL STIMULATION OPERATIONS

341.a. Equipment Requirements.

- (1) The Operator will equip bradenhead access on all Wells to the annulus between the production and surface casing as well as any intermediate casing with appropriate fittings to allow safe and convenient determination of pressure and fluid flow.
- (2) To allow for Commission visual inspection at all times, all valves use for annular pressure monitoring will remain exposed and will not be buried. An Operator may use a rigid housing to protect the valves so long as the housing can be easily opened or removed by the Operator upon request.
- (3) These equipment requirements apply to all Wells, regardless of function.

341.b. **Bradenhead Monitoring.** The Operator will monitor all Wells at a Director-indicated frequency for aspects of well integrity necessary to protect public health, safety, welfare, the environment, including groundwater, potential flow zones, and formations, and wildlife resources and in accordance with this Rule 341.

(1) **After Rig Release, Prior to Stimulation.** An Operator will monitor all annular casing pressures on a monthly basis. If at any point the bradenhead monitoring pressure is greater than 30% of the true vertical depth (TVD) in feet of the surface casing shoe expressed in psig, the Operator will contact the Director before proceeding with stimulation to determine whether mitigation or other measures are necessary to ensure isolation consistent with the Commission's Rules.

(2) **During Hydraulic Fracturing Treatment.**

- A. An Operator will confine the placement of all stimulation fluids to the objective formations during hydraulic fracturing treatment to the extent practicable.
- B. During hydraulic fracturing treatment operations, an Operator will continuously monitor and record bradenhead annulus pressure on all wells being stimulated.
- C. If intermediate casing has been set on the well stimulated by hydraulic fracturing treatment, an Operator will monitor and record the pressure in the annulus between the intermediate casing and the production casing during stimulation operations.
- D. During hydraulic fracturing treatment operations, an Operator will monitor the bradenhead annulus and casing pressures for all wells within 300 feet of the wellbore being stimulated.
- E. If at any time during hydraulic fracturing treatment operations, the bradenhead annulus pressure in psig in the well being stimulated or any well being monitored has a bradenhead pressure exceeding 30% of the true vertical depth (TVD) in feet of the surface casing shoe expressed in psig, or the Operator has reason to suspect any potential failure of the production casing or stimulation string, the operator will:
 - i. Safely and quickly discontinue the stimulation and dissipate the annular pressure.
 - ii. Notify the Director as soon as practicable but no later than 24 hours following the occurrence with a Form 42, Field Operations Notice, Notice of High Bradenhead Pressure During Stimulation.

- iii. Perform diagnostic testing on the well and related equipment as is necessary to determine: (i) whether such a failure has actually occurred; (ii) if the pressure observations can be accounted for due to thermal expansion or pressure “ballooning” of the casing; or (iii) the presence or absence of a downhole failure or whether a migration pathway has actually occurred. The Operator will perform diagnostic testing as soon as is reasonably practical after Operator has reasonable cause to know of or suspect any such failure.
 - I. If the Operator does not identify a downhole failure or a migration pathway, the Operator will notify the Director of the results. The Director will timely grant approval to proceed with stimulation and may do so orally.
 - II. If the Operator identifies a downhole failure or migration pathway, the Operator will consult with the Director and, upon request, provide and implement a corrective plan prior to continuing any further stimulation operations on the Well and any additional Well on the Oil and Gas Location.
- iv. Submit a Sundry Notice, Form 4, providing all details, including whether a downhole failure or migration pathway occurred, cause of the high pressure or suspected failure, and corrective measures taken within 15 days after the occurrence.

(3) **Thirty Days After Hydraulic Fracturing Treatment.** For the first 30 days after hydraulic fracturing treatment or completion, an Operator will monitor and record production casing pressure and all annular casing pressures for a well on a daily basis, at a minimum.

(4) **Through the Remaining Life of the Well.** For all Wells in the state, an Operator will monitor and record production casing pressure and all annular casing pressures on a monthly basis or at a Director-approved frequency. If a Well's bradenhead pressure is greater than 30% of the true vertical depth (TVD) in feet of the surface casing shoe expressed in psig, or a lower threshold set by a Commission Order, or if a Well flows liquids or continuous gas from the bradenhead annulus, an operator will

- A. Report the bradenhead pressure to the Director on a Form 17, Bradenhead Test;
- B. Take immediate action to remedy such an annular pressure; and
- C. Perform diagnostic testing to determine if the annular casing pressure is sustained. An Operator will report diagnostic testing results to the Director on a Sundry Notice, Form 4, within 60 days of submitting a Form 17 pursuant to Rule 341.b.(4)A. If the diagnostic testing confirms sustained casing pressure, an Operator will develop and implement a pressure management plan and provide the plan with the Sundry Notice.

(5) **Records.** An Operator will keep bradenhead monitoring records required by Rule 341.b. available for inspection by the Director for a minimum of 5 years after the monitoring was performed.

341.c. **Annual Bradenhead Testing and Reporting.** For all Wells other than coalbed methane wells, an operator will perform an annual bradenhead test and submit the data to the Director on a Form 17 or other Director-approved method. For coalbed methane wells, an Operator will perform bradenhead testing in accordance with Rule 608.e.

341.d. **Bradenhead Test Observations.**

- (1) If an Operator observes a deficiency, the Operator will immediately take action to address the deficiency. Actions taken may include the Operator performing diagnostic testing on the Well to determine whether a deficiency does exist and the best method of repair or if a pressure management plan is needed.
- (2) The Director may impose a remediation plan if a deficiency exists, and if imposed, the Operator will implement an approved remediation plan or pressure management plan and report results within 30 days or as required by the approved plan.
- (3) If the Operator is not able to effectively address the deficiency or implement a pressure management plan, the Operator will plug and abandon the well within 6 months of discovering the deficiency.

**UNIT OPERATIONS, ENHANCED RECOVERY PROJECTS,
AND STORAGE OF LIQUID HYDROCARBONS**

401. AUTHORIZATION

- a. No person shall perform any enhanced recovery operations, cycling or recycling operations including the extraction and separation of liquid hydrocarbons from natural gas in connection therewith, or operations for the storage of gaseous or liquid hydrocarbons, nor shall any person carry on any other method of unit or cooperative development or operation of a field or a part of either, without having first obtained written authorization from the Commission to perform the aforementioned activities or operations. No person shall commence construction of a well for use in either enhanced recovery operations or for storage of gaseous or liquid hydrocarbons without having first obtained written authorization from the Commission to do so. These provisions shall not apply to existing gas storage projects or to projects that have received approval of the Federal Energy Regulatory Commission; provided however, that a copy of such application and approval shall be submitted to the Commission and made a part of their records.

- b. Persons wishing to obtain such authorization shall file an application for authorization with the Commission. The application may be filed by any one or more of the parties involved, or by the operator of the project for which authorization is sought. The application shall include the following:
 - (1) A plat showing the area involved, together with the well or wells, including drilling wells, dry and abandoned wells located thereon, all properly designated. If the plan of operation involves injection of fluids for enhanced recovery operations, or storage of liquid hydrocarbons, such plat shall show the names of owners of record within one-quarter (1/4) mile of the injection well or wells indicating whether they are surface owners, mineral interest owners, or working interest owners. The application shall also include information regarding the need for remedial action on wells penetrating the injection zone within one-quarter (1/4) mile of each injection well and a plan for the performance of any such remedial work.

 - (2) A full description of the particular operation for which authorization is required.

 - (3) Copies of the unit or co-operative agreement and operating agreement, unless these agreements have already been provided to the Commission.

 - (4) Where injection of fluids for enhanced recovery operations or storage of liquid hydrocarbons is proposed, the application shall also contain:
 - A. the name, description, thickness and depth of the following formations: those from which wells are producing or having produced; those which will receive any fluids to be injected; those capable of limiting the movement of any fluids to be injected;

 - B. the name and the depth to the bottom of all underground sources of drinking water which may be affected by the proposed activity or operation;

 - C. a resistivity log, run from the bottom of the surface casing to total depth of the injection well or wells, or a resistivity log of any well within one (1) mile together with a log from that well that can be correlated with a similar log of the injection well. If the injection well is to be drilled, a description of the

typical stratigraphic level of the injection formation and any other available logging or testing data;

- D. a description of the casing of the injection well or wells or the proposed casing program, including a schematic drawing of the surface and subsurface construction details of the system and a full description of cement jobs already in place or proposed;
- E. a statement specifying the type of fluid to be injected, chemical analysis of the fluid to be injected, the source of the fluid, the estimated amounts to be injected daily, the anticipated injection pressures, water analysis of receiving formation, any available data on the compatibility of the fluid with the receiving formations and known or calculated fracture gradient (maximum authorized surface injection pressure will be set by the Director);
- F. a description of any proposed stimulation program;
- G. the name and address of the operator or operators of the project and those persons notified by the applicant.

(5) This Rule does not apply to gas storage projects in existence on August 18, 1986.

402. NOTICE AND DATE OF HEARING

Upon the filing of any application, the Commission shall issue notice thereof, as provided by the Act and these regulations. Said application shall be set for public hearing at such time as the Commission may fix.

403. ADDITIONAL NOTICE

If injection of fluids is proposed by said application, in addition to the notice required by the Act, a copy of such application shall be given in person or by first class mail to each owner of record of the reservoir involved within one-quarter (1/4) mile of the proposed intake well or wells. Such delivery, whether in person or by mail, shall take place on or before the date the application is filed. An affidavit shall be attached to the application showing the parties to whom the notice has been given and their addresses.

404. CASING AND CEMENTING OF INJECTION WELLS

Wells used for injection of fluids into the producing formation shall be cased with safe and adequate casing or tubing so as to prevent leakage, and shall be so set or cemented that damage will not be caused to oil, gas or fresh water resources. (Each injection well must satisfactorily pass a mechanical integrity test in accord with Rule 326 prior to injection.)

405. NOTICE OF COMMENCEMENT AND DISCONTINUANCE OF INJECTION OPERATIONS

The following provisions shall apply to all injection projects whether or not they are approved by the Commission:

- a. Immediately upon the commencement of injection operations, the operator shall notify the Commission of the injection date.
- b. Within ten (10) days after the discontinuance of injection operations the operator shall notify the Commission of the date of such discontinuance and the reasons therefore.

- c. When any well in an approved enhanced recovery unit operation is converted to or from an injection status, notice shall be given on a Sundry Notice, Form 4, within thirty (30) days.
- d. Before any intake well shall be plugged, notice shall be given to the Commission by the owner of said well, and the same procedure shall be followed in the plugging of such well as is provided for the plugging of oil and gas wells.

RULES OF PRACTICE AND PROCEDURE

501. APPLICABILITY OF RULES OF PRACTICE AND PROCEDURE

- a. **General.** These rules will be known and designated as “Rules of Practice and Procedure before the Oil and Gas Conservation Commission of the State of Colorado,” and will apply to all proceedings before the Commission. These rules will be liberally construed to secure just, speedy, and inexpensive determination of all issues presented to the Commission.
- b. **Prohibition of abuse.** Notwithstanding any provision of these rules, the Commission, Director, or Administrative Law Judge or Hearing Officer will, upon its own motion or upon the motion of a party to a proceeding, act to prohibit or terminate any abuse of process by an applicant, protestant, intervenor, witness, or party offering a statement pursuant to Rule 510 in a proceeding. Such action may include, but is not limited to; summary dismissal of the application, protest, intervention, or other pleading; limitation or prohibition of harassing or abusive testimony; limitation or prohibition of excessive motion filing; restricted discovery; and finding a party in contempt. Grounds for such action may include, but are not limited to, the use of the Commission's procedures for reasons of obstruction and delay; misrepresentation in pleadings or testimony; or, other inappropriate or outrageous conduct that is deemed by the Commission, Director, or Administrative Law Judge or Hearing Officer to be an abuse of process.
- c. **Judicial review.** Any rule, regulation, or final order of the Commission, or any approval of an Application for Permit-to-Drill, Form 2, or Oil and Gas Location Assessment, Form 2A, by the Director for which a hearing is not requested within ten (10) days pursuant to Rule 305.e.(2), will be subject to judicial review in accordance with the provisions of the Administrative Procedure Act, §§24-4-101 to -108, C.R.S. The statutory time period for filing a notice of appeal from any Commission decision will commence pursuant to §24-4-106(4), C.R.S.

502. PROCEEDINGS NOT REQUIRING THE FILING OF AN APPLICATION

- a. **Commission's own motion.** The Commission may, on its own motion, initiate proceedings upon any questions relating to conservation of oil and gas or the conduct of oil and gas operations in the State of Colorado, or to the administration of the Act, by notice of hearing or by issuance of an emergency order without notice of hearing. Such emergency order will be effective upon issuance and will remain effective for a period not to exceed fourteen (14) days. Notice of an emergency order will be given as soon as possible after issuance.
- b. **Variances.**
- (1) Variances to any Commission rules, regulations, or orders may be granted in writing by the Director without a hearing upon written request by an operator to the Director, or by the Commission after hearing upon application. The operator or the applicant requesting the variance will make a showing that it has made a good faith effort to comply, or is unable to comply with the specific requirements contained in the rules, regulations, or orders, from which it seeks a variance, including, without limitation, securing a waiver or an exception, if any, and that the requested variance will not violate the basic intent of the Oil and Gas Conservation Act.
 - (2) No variance to the rules and regulations applicable to the Underground Injection Control Program will be granted by the Director without consultation with the U.S. Environmental Protection Agency, Region VIII, Waste Water Management Division Director.
 - (3) The Director will report any variances granted at the monthly Commission hearing following the date on which such variance was granted.

503. ALL OTHER PROCEEDINGS COMMENCED BY FILING AN APPLICATION

a. All proceedings that may require a Commission decision, including those recommended orders that become the decision of the Commission, other than those initiated by the Commission or a variance request submitted to the Director, may only be commenced by filing a formal application with the Commission electronically in a manner as determined by the Director. All operators' applications will include the operator's name and identification number; the type of application being submitted, all applicable formations, the location of applicable lands (including county, field name, Township / Range / Section, and nearby public crossroads) and map of the same; and the name and contact information (including email) for an operator representative designated to receive questions, protests, and interventions. The application will also set forth in reasonable detail the relief requested and the legal and factual grounds for such relief. The application will be executed by a person with authority to do so on behalf of the applicant, and the contents thereof will be verified by a party with sufficient knowledge to confirm the facts contained therein. The originally signed application will be maintained by the filing party. The electronically submitted application, and all subsequent documents submitted, will be considered a Commission official public record.

With the exception of those from state and local government agencies, each application will be accompanied by a docket fee established by the Commission (see Appendix III), except applications seeking an Order Finding Violation or an emergency order.

b. Applications to the Commission may be filed by the following applicants:

- (1) For purposes of applications for the creation of drilling units, applications for additional wells within existing drilling units, other applications for modifications to existing drilling unit orders, or applications for exceptions to Rule 318, only those owners within the proposed drilling unit, or within the existing drilling unit to be affected by the application, may be applicants.
- (2) For purposes of applications for involuntary pooling orders made pursuant to §34-60-116, C.R.S., or applications for unitization made pursuant to §34-60-118, C.R.S., only those owners within the proposed unit to be pooled or unitized may be applicants.
- (3) For purposes of seeking an Order Finding Violation, only the Director may be an applicant.
- (4) For purposes of seeking a variance from the Commission, only the operator, mineral owner, surface owner or tenant of the lands which will be affected by such variance, other state agencies, any local government within whose jurisdiction the affected operation is located, or any person who may be directly and adversely affected or aggrieved if such variance is not granted, may be an applicant.
- (5) For purposes of seeking a hearing pursuant to Rules 216.f.(4), 303.c.(2), 303.j.(2), or 604.a.(6)A only the operator seeking approval of the Application for Permit-to-Drill, Form 2, or an Oil and Gas Location Assessment, Form 2A, may be the applicant.
- (6) For purposes of seeking a hearing on approval of an Application for Permit-to-Drill, Form 2, or an Oil and Gas Location Assessment, Form 2A, under Rule 305.e.(2), only the following may be the applicant:
 - A. The operator;
 - B. The surface owner, solely to raise alleged noncompliance with Commission rules or statute, or to allege potential adverse impacts to public health, safety, and welfare, including the environment and wildlife resources, that are within the Commission's jurisdiction to remedy; and

C. The relevant local government, provided that the hearing will be conducted in similar fashion as is specified in Rules 508.j, 508.k, and 508.l with respect to a public issues hearing. It will be the burden of the local government to bring forward evidence sufficient for the Commission to make the preliminary findings specified in Rule 508.j at the outset of such hearing.

(7) For purposes of seeking a hearing on provisions related to measurement pursuant to Rule 328 or 329., only the mineral interest owner may be the applicant.

(8) For purposes of seeking a hearing for an order limiting surface density pursuant to Rule 1202.d.(5), only the operator will be the applicant.

(9) For purposes of seeking a hearing on a school facility or child care center setback determination pursuant to Rule 604.a.(6)B., only the operator or school governing body may be the applicant.

(10) For purposes of seeking relief or a ruling from the Commission on any other matter not described in (1) through (9) above, only those who have demonstrated that they would be directly and adversely affected or aggrieved by a Commission ruling, and that any injury or threat of injury sustained would be entitled to legal protection under the Act, may be an applicant.

c. Unless the Commission otherwise orders, all matters submitted to the Commission for adjudication will automatically be assigned to an Administrative Law Judge or Hearing Officer. An assignment to an Administrative Law Judge or Hearing Officer shall encompass all issues of fact and law concerning the matter unless the Commission specifies otherwise in a written order. Notwithstanding the foregoing, the following will be considered by the Commission:

(1) Approval of Comprehensive Drilling Plans filed pursuant to Rule 216;

(2) Applications seeking a hearing pursuant to Rules 216.f.(4), 303.j.(2), or 604.a.(6);

(3) Variance requests to the Commission filed pursuant to Rule 502.b; and

(4) Rulemaking proceedings held in accordance with Rule 529.

d. The Commission, Director, Administrative Law Judge, or Hearing Officer may require any additional information necessary pursuant to these rules to ensure the application is complete on its face. The Commission, Director, Administrative Law Judge, or Hearing Officer may issue an order rejecting an application if the application is found to be without merit. The rejection of an application shall be in writing and constitute a final agency order that is subject to judicial review.

e. A party filing an application may amend its application at any time prior to notice being sent consistent with Rule 507. A material amendment is a change that alters the requested relief of the original application, requires notice to additional persons, or as otherwise determined by the Commission, Administrative Law Judge, or Hearing Officer. If the application requires a material amendment, the Commission, Administrative Law Judge, or Hearing Officer may in its discretion dismiss the application.

f. Applications subject to the requirements for local public forums under Rule 508.a. will be accompanied by a proposed plan (the "Proposed Plan") to address protection of public health, safety, and welfare, including the environment and wildlife resources, and a description of the current surface occupancy/use. The Proposed Plan will include the rules and regulations of the Commission as they are applied to oil and gas operations in the application lands along with any procedures or conditions the applicant will voluntarily follow to address the protection of public health, safety, and welfare, including the environment and wildlife resources.

g. After the filing of an application, the matter will be set for hearing and notice of that hearing will be given.

- h. As necessary, Commission staff will evaluate all applications and prepare an evaluation, which may include a recommendation on the merits of the application. Any such evaluation or recommendation will be part of the administrative record to be considered by the Commission, Administrative Law Judge, or Hearing Officer.
- i. In order to continue to receive copies of the pleadings filed in a specific proceeding a party who receives notice of the application will file with the Commission a protest or intervention in accordance with these rules.
- j. Subsequent to the initiation of a proceeding, all pleadings filed by any party will reference the docket number assigned to such proceeding. Each pleading will include a certificate of service identifying the document served and filed with the Commission and that the pleading was served on all persons who filed a protest or intervention in accordance with these rules, by mailing a copy thereof, first-class postage prepaid, to the last known mailing address of the person to be served, or by personal delivery, or by electronic mail, or in a manner determined by the Director.

504. DOCKET NUMBER OF PROCEEDINGS

Upon the acceptance of an application, the Secretary of the Commission will assign it a docket number. All subsequent pleadings and filings will contain the same docket number. Any pleading or filing submitted without a docket number could lead to delayed processing or rejection.

505. REQUIREMENT OF PUBLIC HEARING

Before the Commission adopts any rule or regulation, or enters any order, or amendment thereof or grants any variance pursuant to Rule 502., the Commission, Administrative Law Judge, or Hearing Officer will hold a public hearing, scheduled in accordance with Rule 506. at such time and place as may be prescribed by the Commission, Administrative Law Judge, or Hearing Officer. Any party will be entitled to be heard as provided in these rules and regulations. The foregoing will not apply to recommended orders of non-protested matters, the issuance of an emergency order, Notice of Alleged Violation, or Cease and Desist Order.

506. HEARING DATE/CONTINUANCE

- a. All applications will be docketed for hearing before the Commission, Administrative Law Judge, or Hearing Officer. The date of hearing will depend upon hearing availability, but will be set at the earliest practicable time. No application may be heard until the applicant has complied with all notice, evidentiary and other application requirements set forth in the Commission's rules.
- b. The Commission, Administrative Law Judge, or Hearing Officer will grant the first request by an applicant for a continuance of any unprotested application. The Commission, Administrative Law Judge, or Hearing Officer will have the discretion to grant subsequent requests for a continuance of an unprotested application. The Commission, Administrative Law Judge, or Hearing Officer may at any time discontinue granting continuances of an application or dismiss an application in a written order subject to an exception pursuant to Rule 532.
- c. In all rulemaking proceedings, hearings will be held in accordance with Rule 529.
- d. The Commission, Director, Secretary, Administrative Law Judge, or Hearing Officer may for good cause cancel or continue any hearing to another date. Any continuance of a hearing will not extend the filing deadline for the filing of protests or interventions in accordance with Rule 509, or any other required deadline under these Rules, unless otherwise ordered by the Commission, Director, Administrative Law Judge, or Hearing Officer.
- e. When a Commission hearing is scheduled for multiple days the Secretary may estimate the time and date that a given matter may be heard by the Commission. The Commission may, in its discretion, change the

proposed hearing docket, including the time or date of any scheduled hearing. It will be the responsibility of the participating parties and attorneys to be present when the Commission hears the matter.

507. NOTICE FOR HEARING

a. General notice provisions.

- (1) When any proceeding has been initiated, the Commission will require a copy of the application, together with a notice of such proceeding, to be provided to all persons specified in the relevant sections of Rules 507.b. and 507.c. at least sixty (60) days in advance of the noticed hearing date. Notice will be provided in accordance with the requirements of §34-60-108(4), C.R.S., and will be drafted by the Secretary. A signed, electronic copy will be provided to the applicant in sufficient time for delivery to those who require notice. The application and notice will be provided directly by the applicant, using the applicant's return address.
- (2) The applicant is responsible for service and publication of required notices, including any related costs. No later than thirty (30) days before the noticed hearing date, the applicant will submit to the Secretary a certificate of service demonstrating that the applicant served a copy of the application and notice on all persons entitled to notice pursuant to these rules. The certificate of service will include a list of all persons who received a copy of the application and notice. The applicant will enjoy a rebuttable presumption that it has properly served notice on persons entitled to notice of the proceeding. Also no later than thirty (30) days before the noticed hearing date, the applicant will submit to the Secretary a notarized affidavit providing assurance that the applicant published a copy of the notice in relevant newspapers, and the date of publication for each newspaper used. The applicant is not required to submit a notarized proof of publication from the newspapers, or copies of the publications, unless a concern with publication is raised. Service of process by publication to unknown addresses will occur through five weeks of publication ending at the protest deadline, at least thirty (30) days prior to the noticed hearing date.
- (3) The Secretary will give notice to any person who has filed a request to be placed on the Commission's general email notification list. Notice by publication or notice provided pursuant to the Commission's general email list does not confer interested party status on any person.

b. Notice for specific applications.

- (1) **Applications affecting drilling units.** For purposes of applications for the creation of drilling units, applications for additional wells within existing drilling units or other applications for modifications of or exceptions to existing drilling unit orders (except for applications for well exception locations to existing orders which are addressed in subsection (5) of this rule) the application and notice will be served on the owners within the proposed drilling unit or within the existing drilling unit to be affected by the applications.
- (2) **Applications for involuntary pooling.** For purposes of applications for involuntary pooling orders made pursuant to §34-60-116, C.R.S., the application and notice will be served on those persons who own any interest in the mineral estate, whether leased or unleased, of the tracts to be pooled, except owners of an overriding royalty interest.
- (3) **Applications for unitization.** For purposes of applications for unitization made pursuant to §34-60-118, C.R.S., the application and notice will be served on those persons who own any interest in the mineral estate underlying the tract or tracts to be unitized and the owners within one-half (1/2) mile of the tract or tracts to be unitized.
- (4) **Applications changing certain well location setbacks.** For purposes of applications that change the permitted minimum setbacks for established drilling and spacing units, the application and notice

will be served on those owners of contiguous or cornering tracts who may be affected by such change.

(5) **Applications for well location exception.** For purposes of applications made for exceptions to Rule 318, exceptions to legal locations within drilling and spacing units, or for an exception location to an existing order, the application and notice will be served on the owners of any contiguous or cornering tract toward which the well location is proposed to be moved, provided that when the applicant owns any interest covering such tract, the person who owns the mineral estate underlying the tract covered by such lease will also be notified. If there is more than one owner within a single drilling unit and the owners have designated a party as the operator on their behalf, notice will be presumed sufficient if served upon the designated operator of the affected formation.

(6) **All other applications.** For any application not specified above, the Secretary has discretion to determine who is entitled to receive the application and notice, based on legal interest and potential impact.

(7) **Orders related to violations.** With respect to the resolution of a Notice of Alleged Violation (NOAV) through an Administrative Order by Consent (AOC), and to applications for an Order Finding Violation (OFV), the application (if any) and notice will be provided to a relevant complainant (if any), to the violator, responsible party, or operator, as applicable; and by publication in accordance with §34-60-108(4), C.R.S.

c. **Notice to local government, Colorado Department of Public Health and Environment, and Colorado Parks and Wildlife.** For purposes of intervention pursuant to Rule 509, the application and notice will also be given to the relevant local governmental designee, the Colorado Department of Public Health and Environment, and the Colorado Division of Parks and Wildlife for applications made under subsections b.(1) and (3) of this rule, at the same time that notice is provided under this rule.

d. **Notice to the Colorado State Board of Land Commissioners.** The application and notice will also be given to the Colorado State Board of Land Commissioners for all applications where the Colorado State Board of Land Commissioners maintains a mineral ownership included in the application lands. This requirement does not apply to enforcement applications.

508. LOCAL PUBLIC FORUMS, HEARINGS ON APPLICATIONS FOR INCREASED WELL DENSITY AND PUBLIC ISSUES HEARINGS.

a. **Applicability of rule.** The provisions of this Rule 508 only apply to the applications that would result in more than one (1) well site or multi-well site per forty (40) acre nominal governmental quarter-quarter section or that request approval for additional wells that would result in more than one (1) well site or multi-well site per forty (40) acre nominal governmental quarter-quarter section, within existing drilling units, not previously authorized by Commission order (together, for purposes of this rule, an “application for increased well density” or “application”).

b. Local public forum.

(1) The rules and regulations of the Commission as they are applied to oil and gas operations are expected to adequately address impacts to public health, safety and welfare, including the environment and wildlife resources, which may be raised by an application for increased well density.

(2) A local public forum may, however, be convened to consider potential issues related to public health, safety, and welfare, including the environment and wildlife resources, that may be raised by an application for increased well density that may not be completely addressed by these rules or the Proposed Plan submitted pursuant to Rule 503.c.

- A. A local public forum will be convened on the Commission's own motion, or upon request from the local governmental designee or the applicant.
- B. A local public forum may be convened at the Director's discretion, or upon receipt of a request for a local public forum from a citizen of the county(ies) in which the application area is situated, after the Director's consideration of the following factors:
 - (i) The size of the application area and the number and density of surface location requested;
 - (ii) The population density of the application area;
 - (iii) The distribution of Indian, federal and fee lands within the application area;
 - (iv) The level of current or past public interest in increased well density in the vicinity of the application area;
 - (v) Whether the application is limited to the deepening or recompletion of existing wells, or directional drilling from existing surface locations; and
 - (vi) Whether the application is limited to an exploratory unit formed for involuntary pooling purposes.
- (3) The Director will notify the local governmental designee, the Colorado Department of Public Health and Environment, and the Colorado Parks and Wildlife of any application for increased well density no later than seven (7) days after receipt of such application. If the local governmental designee elects to require a local public forum it will notify the Director of its decision within seven (7) days of receipt of notice of the application.
- (4) The Director will notify the applicant of any decision to convene a local public forum no later than fourteen (14) days after receipt of the application.

c. Local public forums on federal and Indian lands.

- (1) If the surface and the minerals of the application area are comprised in their entirety of federal or Indian lands, no local public forum will be convened because potential impacts to the environment or public health, safety, and welfare on such lands are subject to federal or tribal requirements. All proceedings on any application for increased well density on federal or Indian lands will be conducted to comply with the obligations contained in any intergovernmental or tribal memoranda of understanding governing the conduct of oil and gas operations on federal or Indian lands.
- (2) If the application area is comprised in part of federal or Indian lands, the Director will consult with the appropriate federal or Indian authorities before scheduling any public forum on the application. Insofar as the application includes federal or Indian lands, proceedings thereon will be conducted in accordance with this rule and any obligations contained in any intergovernmental or tribal memoranda of understanding governing the conduct of oil and gas operations on federal or Indian lands.
- (3) The Director will notify the appropriate federal and Indian authorities of any local public forum to be convened to evaluate the application area that includes federal or Indian lands. Federal or Indian participation in the local public forum may include, without limitation, presentation of the most recent applicable resource management plan(s) and any environmental assessment(s) or environmental impact statement(s) that cover or include all or any portion of the application area.

d. Notice of the local public forum.

- (1) Within seven (7) days from the date the applicant receives notice from the Director that a local public forum will be convened, the applicant will submit to the Director a list of the surface owners within the application area. In determining the identity and address of a surface owner for the purpose of giving all notices under this rule the records of the assessor for the county in which the lands are situated may be relied upon.
- (2) At least twenty-one (21) days before the date of the local public forum the Director will mail to the listed surface owners notice thereof.
- (3) Within fourteen (14) days of receipt of an application for increased well density the Director will, by regular or electronic mail or by facsimile copy, provide to the local governmental designee(s), the Colorado Department of Public Health and Environment, and the Colorado Parks and Wildlife notice of the local public forum or notice that, based on the factors in Rule 508.b.(2).B above, the Director will not conduct a local public forum.
- (4) At least fourteen (14) days before the date of the local public forum the Director will publish notice thereof in a newspaper of general circulation in the county or counties where the application lands are located.
- (5) The notice for the local public forum will state that the forum is being conducted to consider any issues raised by the application that may affect public health, safety, and welfare, including the environment and wildlife resources that are not addressed by the rules or the Proposed Plan.
- (6) Within seven (7) days of receipt of an application for increased well density, the Director will post a description of such application on the Commission website.

e. Timing and location of the local public forum.

- (1) As soon as practicable after publication of notice, but at least fourteen (14) days prior to the scheduled Commission hearing on the application, the Director will conduct the local public forum at a location reasonably proximate to the lands affected by the application. In the alternative, if the hearing is to be held at a location reasonably proximate to the lands affected by the application, the local public forum will be replaced by the presentation of statements in accordance with Rule 510. during the hearing on the application.
- (2) The Director will immediately notify the applicant of the scheduled time and location of the local public forum.
- (3) To the extent practicable, the local public forum will be scheduled to accommodate the Director or the Director's designee, the participants, and the applicant.
- (4) If the application area is comprised of lands located in more than one jurisdiction, the Director will coordinate the local public forum to provide for a single forum at a location reasonably proximate to the lands affected by the application.

f. Conduct of the local public forum.

- (1) An Administrative Law Judge or Hearing Officer will preside over the local public forum. The Administrative Law Judge or Hearing Officer will provide to the participants an explanation of the purpose of the local public forum and how the Commission may use the information obtained from the local public forum. The purpose of the local public forum is to address the sufficiency of the rules or the Proposed Plan with respect to protection of public health, safety, and welfare, including the environment and wildlife resources.

- (2) The conduct of the local public forum will be informal, and participants will not be required to be sworn, represented by attorneys, or subjected to cross examination.
- (3) Attendance or participation at the local public forum by a Commissioner will not constitute a violation of Rule 514.
- (4) The applicant will participate in the local public forum and present information related to the application.
- (5) The Director will create a record of the local public forum by video-tape, audio-tape, or by court reporter. Such record will be made available to all Commissioners for review prior to the hearing on the application and may be relied upon in making a decision to convene a public issues hearing.

g. Statements. The local public forum will be conducted to allow elected officials, local government personnel, and citizens to express concerns not completely addressed by the rules or the Proposed Plan or make statements regarding the potential impacts from applications for increased well density that relate to public health, safety, and welfare, including the environment and wildlife resources. Issues raised in the local public forum may include the following:

- (1) Impact to local infrastructure;
- (2) Impact to the environment;
- (3) Impact to wildlife resources;
- (4) Impact to ground water resources;
- (5) Potential reclamation impact; and
- (6) Other impact to public health, safety, and welfare

The local public forum will be limited to matters that are within the jurisdiction of the Commission.

h. Report to the Commission. At the conclusion of the local public forum the Administrative Law Judge or Hearing Officer will prepare and submit to the Commission a report of the proceedings. A copy of the report will be made available, no later than seven (7) days prior to the hearing on the application, to the Commissioners, the applicant, the Colorado Department of Public Health and Environment or the Colorado Parks and Wildlife if it consulted on the application, any affected local government and the public and will be posted on the Commission website. The report on the local public forum presented to the Commission will be included in the administrative record for the application, taking into consideration the nature of the local public forum process.

i. Conduct of the hearing on the application for increased well density.

- (1) The hearing on the application will be conducted in accordance with Rule 528.
- (2) The Commission will approve or deny the application based solely on the application's technical merits in accordance with §34-60-116, C.R.S.
- (3) The Administrative Law Judge or Hearing Officer for any local public forum will present to the Commission the report of the local public forum.
- (4) At the conclusion of the hearing on the application, the Commission will consider and decide whether to convene a public issues hearing based on the local public forum or statements made under Rule 510. and any motions to intervene, and the Commission may:

- A. Approve the application without condition;
- B. Approve the application with conditions based on the technical testimony presented at the hearing on the application;
- C. Approve the application, and with the applicant's consent, attach to the order on the application conditions the Commission determines are necessary to address issues related to public health, safety, or welfare, including the environment and wildlife resources;
- D. Approve the application and stay its effective date to convene a public issues hearing in accordance with Rule 508.j.; or
- E. Deny the application.

(5) If the Commission orders a public issues hearing it will set the public issues hearing for the next regularly scheduled Commission meeting unless the applicant requests at a prehearing conference, and the Commission agrees, to convene the public issues hearing immediately following the hearing on the application.

j. **Public issues hearing.** Upon a request by an applicant, protestant, intervenor, or on the Commission's own motion, a public issues hearing will be convened provided the Commission makes the following preliminary findings:

(1) That the public issues raised by the application reasonably relate to potential significant adverse impacts to public health, safety and welfare, including the environment and wildlife resources, that are within the Commission's jurisdiction to remedy;

(2) That the potential impacts were not adequately addressed by:

A. In the case of an application for increased well density, the application or by the Proposed Plan;
or

B. In the case of an Application for Permit-to-Drill, by such permit; and

(3) That the potential impacts are not adequately addressed by the rules and regulations of the Commission.

k. **Conduct of the public issues hearing.**

(1) The rules and regulations of the Commission will apply to all participants in the public issues hearing.

(2) The public issues hearing will be conducted, to the extent practicable, in accordance with Rule 528.

(3) After the public issues hearing the Commission may attach conditions to its order on the application to protect public health, safety, and welfare, including the environment and wildlife resources, as are warranted by the relevant testimony and that are not otherwise addressed by these rules and regulations and the Proposed Plan. In addition, the Commission may, without limitation:

A. Direct the applicant to amend its Proposed Plan for Commission review and approval for all or a portion of the application area to address specific issues related to public health, safety, and welfare, including the environment and wildlife resources, including any identified impacts of increased well density within all or a portion of the application area, rather than on a single well basis.

B. Include in any order a provision to allow the Director discretion to attach specific conditions to individual well permits as the Commission determines are reasonable and necessary to protect public health, safety, and welfare, including the environment and wildlife resources.

(4) Any plan or conditions imposed by Commission order that would affect federal or Indian lands will take into account conditions imposed by the federal or Indian authorities and any federal environmental analysis in order to facilitate regulatory consistency and minimize duplicative regulatory efforts.

(5) Any plan or conditions imposed will take into account cost effectiveness and technical feasibility, and will not be applied to prevent the drilling of new wells per se.

I. The Director and the Commission will use best efforts to comply with the provisions of this Rule 508.; however, any deviation from this rule will not invalidate the Commission's action on the local public forum, the application for increased well density, or the public issues hearing.

509. PROTESTS/INTERVENTIONS/PARTICIPATION IN ADJUDICATORY PROCEEDINGS

a. The applicant and persons who have filed with the Commission a timely and proper protest or intervention pursuant to this rule will have the right to participate formally in any adjudicatory proceeding.

(1) Description of affected interest:

A. Those who have demonstrated that they would be directly and adversely affected or aggrieved by a Commission ruling, and that any injury or threat of injury sustained would be entitled to legal protection under the Act, will be considered protestants. A protest will include information to demonstrate that the person is a protestant under these rules for the protest to be accepted. If determined by the Commission, Administrative Law Judge, or Hearing Officer that a person is not a protestant, any statement provided will be considered a written comment submitted pursuant to Rule 510.

B. Intervention may be granted by right or by permission.

(i) Intervention by right will be granted to the relevant local government; to the Colorado Department of Public Health and Environment solely to raise environmental or public health, safety, and welfare concerns; and to the Colorado Division of Parks and Wildlife solely to raise concerns about adverse impacts to wildlife resources.

(ii) Those who have demonstrated to the satisfaction of the Commission, Administrative Law Judge, or Hearing Officer that an intervention would serve the public interest may be recognized as a permissive intervenor. The Commission, Administrative Law Judge, or Hearing Officer, at their discretion, may limit the scope of the permissive intervenor's participation at the hearing.

(2) The protest or intervention will be filed with the Commission, and served on the applicant's counsel, if the applicant is represented by counsel, within thirty (30) days after notice of an adjudicatory proceeding. If the applicant is not represented by counsel, service will be made on the applicant. Service is made by electronic means. If electronic means are unavailable, service will be made by first class mail. Service is complete upon e-mailing or mailing. As per Rule 506.d., any continuance of a hearing will not extend the filing deadline for the filing of protests or interventions.

(3) All protest or intervention pleadings will include:

A. The application docket number;

- B. A general statement of the factual or legal basis for the protest or intervention based on the application;
 - C. A statement of the relief requested, which must be within the Commission's jurisdiction;
 - D. A description of the intended presentation including a list of proposed witnesses;
 - E. A time estimate to hear the protest or intervention; and
 - F. A certificate of service attesting that the pleading has been served on the applicant and any other party which has filed a protest or intervention in the proceeding.
- b. The Commission, Director, Administrative Law Judge, or Hearing Officer may require any additional information necessary pursuant to these rules to ensure the protest, or intervention is complete on its face.
- c. All pleadings filed pursuant to this rule will be submitted electronically in a manner determined by the Director, and will be accompanied by a docket fee established by the Commission (see Appendix III). The docket fee will be refunded if an intervention is denied. In cases of extreme hardship, the docket fee may be waived at the discretion of the Commission.
- d. If the application is contested, the Commission, Director, Administrative Law Judge, or Hearing Officer, at their discretion, may direct the parties to engage in a prehearing conference in accordance with Rule 527. A prehearing conference may result in a continuance of the hearing, or bifurcation of hearing issues as determined by the Director, Administrative Law Judge, or Hearing Officer.
- e. **Participation at the hearing.**
- (1) Adjudicatory hearings will be conducted in accordance with Rule 528. and any applicable prehearing orders of the Commission, Administrative Law Judge, or Hearing Officer.
 - (2) Testimony and cross-examination by a protestant or intervenor will be limited to those issues that reasonably relate to the interests that the protestant or intervenor seeks to protect, and which may be adversely affected by an order of the Commission, as determined by the presiding trier of fact whether it be the Commission, Administrative Law Judge or Hearing Officer.

510. STATEMENTS AT HEARING

- a. Any person may make an oral statement at a hearing or submit a written statement, according to instructions available on the COGCC website, prior to or at any hearing that relates to the proceeding before the Commission, Administrative Law Judge, or Hearing Officer. Written statements will be provided to the Commission Administrative Law Judge, or Hearing Officer, Applicant, Protestors, and Intervenors (if a docket number is specified in the statement). The Commission, Administrative Law Judge, or Hearing Officer at its discretion, may limit the length of any oral statement or restrict repetitive statements. In an adjudicatory hearing, an oral statement will be excluded from the record unless:
- (1) The statement is made under oath; and
 - (2) The parties to the hearing are allowed to cross-examine the maker of the statement.

Statements at hearing provide a means for interested persons to encourage the Commission, Administrative Law Judge, or Hearing Officer to consider such topics and issues that may not have been sufficiently raised by the Parties. Statements that are general in nature, cumulative summaries, or specifically address consideration of an academic or policy concern, will be weighted accordingly. The trier of fact is the decision-maker regarding the appropriate weight of all evidence presented, including public statements.

- b. The Commission, at its discretion, may accept a sworn written statement into the record of an adjudicatory hearing with due regard to the fact the statement was not subject to cross-examination.
- c. The parties to the hearing will have the right to object to inclusion of any statement under this Rule 510. into the record. The Commission will note the objection for the record. If the Commission accepts the basis for excluding the 510 statement from the record the substance of the statement will not be considered by the Commission in making a decision on the matter at issue.

511. UNCONTESTED HEARING APPLICATIONS

- a. If a matter is uncontested, the applicant may request, approval without a hearing based on an Administrative Law Judge's or Hearing Officer's review of the merits of the verified application and the supporting exhibits. If the Director does not recommend approval of the application without hearing, the applicant may request an administrative hearing before an Administrative Law Judge or Hearing Officer on the application. For purposes of this rule an uncontested matter will mean any application that is not subject to a protest or an intervention objecting to the relief requested in the application and will include matters in which all interested parties have consented in writing to the granting of the application without a hearing.
- b. Uncontested matters may be reviewed or heard administratively by an Administrative Law Judge or Hearing Officer and recommended for approval on the Commission's consent agenda. From time to time, uncontested applications recommended for approval by an Administrative Law Judge or Hearing Officer may be of special interest to the Commission and may be recommended by the Director for presentation to the Commission.
- c. Applications where an Administrative Law Judge or Hearing Officer review of sworn written testimony and exhibits is appropriate. An applicant will submit the documents described in (1) through (6) below to the Commission electronically in a manner as determined by the Director at least thirty (30) days after notice of an adjudicatory proceeding. The Administrative Law Judge or Hearing Officer will determine if additional evidence is needed on a case-by-case basis. If the application lacks sufficient information or evidence, the application may be continued at the Administrative Law Judge or Hearing Officer's discretion.
 - (1) One (1) written request for approval under Rule 511. briefly describing reasons the application may be a candidate for recommendation for approval without a hearing based on review of the merits of the verified application and the supporting exhibits (rather than necessitating an administrative hearing before an Administrative Law Judge or Hearing Officer);
 - (2) Sworn written testimony, of relevant witnesses verifying land, geologic, engineering, public health, safety, welfare, environment and wildlife facts and accompanied by attachments or exhibits that adequately support and is specific to the relief requested in the application, along with resumes/curricula vitae for each witness;
 - (3) A statement, signed under oath, from a person having knowledge of the stated facts, attesting to the facts stated in the written testimony and any attachments or exhibits. The sworn statement need not be notarized, but it will contain language indicating that the signatory is affirming that submitted testimony and supporting documents are true and correct to the best of the signatory's knowledge and belief and, if applicable, that they were prepared by the signatory or under the signatory's supervision;
 - (4) A sworn statement that is a summary of the testimony to support the relief requested in the application, including a request to take administrative notice of repetitive general, technical, or scientific evidence, where appropriate;
 - (5) One (1) set of exhibits which will contain relevant highlights in bullet-point format on each exhibit; and

- (6) A draft proposed order, if requested by the Administrative Law Judge or Hearing Officer, with findings of fact and conclusions of law related to land, geology, engineering, public health, safety, welfare, environment and wildlife and other appropriate subjects to support the relief requested in the application. Reference to testimony, exhibits, and previous Commission orders will be included as findings in the draft proposed order.
- d. Applications where an administrative hearing before an Administrative Law Judge or Hearing Officer is appropriate. An applicant will submit the following documents to the Commission electronically in a manner as determined by the Director at least seven (7) days prior to the administrative hearing.
- (1) Resumes/curricula vitae for all witnesses;
 - (2) A written summary of the testimony to support the relief requested in the application, including a request to take administrative notice of repetitive general, technical, or scientific evidence, where appropriate;
 - (3) Exhibits which will contain relevant highlights in bullet-point format on each exhibit; and
 - (4) A draft proposed order providing land, geology, engineering, public health, safety, welfare, environment and wildlife, and other appropriate findings to support the relief requested in the application. Reference to previous testimony, exhibits, and orders will be included as findings in the draft proposed order.

512. COMMISSION MEMBERS REQUIRED FOR HEARINGS AND/OR DECISIONS

Five (5) members of the Commission constitute a quorum for the transaction of business. Testimony may be taken and oath or affirmation administered by any member of the Commission, or by counsel to the Commission if the Commission Chair so delegates.

513. GEOGRAPHIC AREA PLANS

- a. **Purpose.** Geographic Area Plans are intended to enable the Commission to adopt basin-specific rules that promote the purposes of the Act.
- b. **Scope.** Geographic Area Plans will cover an entire oil and gas field or geologic basin, likely encompassing the activities of multiple operators, in multiple sub-basins or drainages, over a period of ten (10) years or more.
- c. **Procedure.**
 - (1) The Commission's adoption of a Geographic Area Plan will follow Rule 529.
 - (2) The Commission may initiate a Geographic Area Plan for a basin by publishing notice of its intent to do so, and it may adopt a Geographic Area Plan after a public hearing, which will include submittal of information from the public and public testimony. In addition to any other publication requirements in these rules, notice will be published in a newspaper of local circulation in the area covered by the Geographic Area Plan and provided to the local governmental designee(s).
 - (3) In adopting a Geographic Area Plan, the Commission will consult with the Colorado Department of Public Health and Environment, Colorado Parks and Wildlife, and local governmental designee(s). The Commission will also consider any local government comprehensive plans or other local government long-range planning tools.
 - (4) The Geographic Area Plan may include alternative development scenarios, designate units, adopt spacing orders, implement sampling or monitoring plans, or require consolidation of facilities within the area covered by the Plan subject to the Act.

514. RESERVED

515. EX PARTE COMMUNICATIONS

- a. The following provisions will be applied in any adjudicatory proceeding before the Commission, Administrative Law Judge, or a Hearing Officer.
- (1) No person will make or knowingly cause to be made to any member of the Commission, Administrative Law Judge, or a Hearing Officer an ex parte communication concerning the merits of a proceeding for which an application has been filed.
 - (2) No Commissioner, Administrative Law Judge, or Hearing Officer will make or knowingly cause to be made to any interested person an ex parte communication concerning the merits of a proceeding which has been noticed for hearing.
 - (3) A Commissioner, Administrative Law Judge, or Hearing Officer who receives, or who makes, or knowingly causes to be made, a communication prohibited by this rule will place on the public record of proceeding:
 - A. All such written communications and any responses thereto; and
 - B. Memoranda stating the substance of any such oral communications and any responses thereto.
 - (4) Upon receipt of a communication knowingly made or knowingly caused to be made by a person in violation of this rule, the Commission, Administrative Law Judge, or a Hearing Officer may require the person to show cause why their claim or interest in the proceeding should not be dismissed, denied, or otherwise adversely affected on account of such violation.
 - (5) If staff is a party to an adjudicatory proceeding they are subject to the provisions of this Rule 515(a).
- b. Oral or written communication with individual Commission members is permissible in a rulemaking proceeding. If such information is relied upon in final decision-making it will be made part of the record by the Commission. After the rulemaking record is closed new information that is intended for the rulemaking record will be presented to the Commission as a whole upon approval of a request to reopen the rulemaking record.
- c. This rule will not limit the right to challenge a decision of the Commission, Administrative Law Judge, or a Hearing Officer on the grounds of bias or prejudice due to any ex parte communication.

516. STANDARDS OF CONDUCT

- a. The purpose of this rule is to ensure that the Commission's decisions are free from personal bias and that its decision-making processes are consistent with the concept of fundamental fairness. The provisions of this rule are in addition to the requirements for Commission members set forth in §24-18-108.5, C.R.S. This rule should be construed and applied to further the objectives of fair and impartial decision making. To achieve these standards Commissioners, Administrative Law Judges, and Hearing Officers should:
- (1) Discharge their responsibilities with high integrity.
 - (2) Respect and comply with the law. Their conduct, at all times, should promote public confidence in the integrity and impartiality of the Commission.
 - (3) Not lend the prestige of the office to advance their own private interests, or the private interests of others, nor should they convey, or permit others to convey, the impression that special influence can be brought to bear on them.

b. Conflicts of interest. A conflict of interest exists in circumstances where a Commissioner, Administrative Law Judge, or Hearing Officer has a personal or financial interest that prejudices that Commissioner's, Administrative Law Judge's, or Hearing Officer's ability to participate objectively in an official act.

- (1) A Commissioner, Administrative Law Judge, or a Hearing Officer will disclose the basis for a potential conflict of interest to the Commission and others in attendance at the hearing before any discussion begins or as soon thereafter as the conflict is perceived. A conflict of interest may also be raised by other Commissioners, the applicant, any protestant or intervenor, or any member of the public.
- (2) In response to an assertion of a conflict of interest, a Commissioner may withdraw or the Director may designate an alternate Administrative Law Judge or Hearing Officer. If the Commissioner does not agree to withdraw, the other Commissioners, after discussion and comments from any party to the proceeding, will vote on whether a conflict of interest exists. Such vote will be binding on the Commissioner disclosing the conflict.
- (3) In determining whether there is a conflict of interest that warrants withdrawal, the Commission members, Administrative Law Judge, or Hearing Officer will take the following into consideration:
 - A. Whether the official act will have a direct economic benefit on a business or other undertaking in which the Commissioner, Administrative Law Judge, or Hearing Officer has a direct or substantial financial interest.
 - B. Whether the potential conflict will result in the Commissioner, Administrative Law Judge, or Hearing Officer not being capable of judging a particular controversy fairly on the basis of its own circumstances.
 - C. Whether the potential conflict will result in the Commissioner, Administrative Law Judge, or Hearing Officer having an unalterably closed mind on matters critical to the disposition of the proceeding.

c. Discharge of duties. In the performance of their official duties, the Commission will apply the following standards:

- (1) To be faithful to and constantly strive to improve their competence in regulatory principles, and to be unswayed by partisan interests, public clamor, or fear of criticism.
- (2) To maintain order and decorum in the proceedings before them.
- (3) To be patient, dignified and courteous to litigants, witnesses, lawyers, and others with whom the Commission deals in an official capacity, and to require similar conduct of attorneys, staff, and others subject to their direction and control.
- (4) To afford to every person who is legally interested in a proceeding, or their attorney, full right to be heard according to law.
- (5) To diligently discharge their administrative responsibilities, maintain professional confidence in Commission administration, and facilitate the performance of the administrative responsibilities of other staff officials.

517. REPRESENTATION AT ADMINISTRATIVE AND COMMISSION HEARINGS

a. Natural persons may appear on their own behalf and represent themselves at hearings before the Commission, and persons allowed to make oral or written statements may do so without counsel. Pro se participants will be subject to these rules and regulations.

b. Except as provided in a. and c. of this rule, representation at hearings before the Commission will be by attorneys licensed to practice law in the State of Colorado, and provided that any attorney duly admitted to practice law in a court of record of any state or territory of the United States or in the District of Columbia, but not admitted to practice in Colorado, who appears at a hearing before the Commission may, upon motion, be admitted for the purpose of that hearing only, if that attorney has associated for purposes of that hearing with any attorney who:

(1) Is admitted to practice law in Colorado;

(2) Is a resident or maintains a law office within Colorado; and

(3) Is personally appearing with the applicant in the matter and in all proceedings connected with it.

The resident attorney will continue in the case unless other resident counsel is submitted. Any notice, pleading, or other paper may be served upon the resident attorney with the same effect as if personally served on the non-resident attorney within this state. Resident counsel will be present before the Commission unless otherwise ordered by the Commission.

c. The Commission has the discretion to allow representation by a corporate officer or director of a community organization, a closely held entity, a citizens' group duly authorized under Colorado law, or if a limited liability corporation, the member/manager in the following circumstances:

(1) Where the agency is adopting a rule of future effect;

(2) Local public forums; or

(3) When an individual is appearing on behalf of a closely held corporation as provided in §13-1-127, C.R.S.

d. Unless a non-attorney is appearing pro se or pursuant to §13-1-127, C.R.S., or the Director is participating pursuant to Rule 528.c., a non-attorney will not be permitted to examine or cross-examine witnesses, make objections or resist objections to the introduction of testimony, or make legal arguments.

518. SUBPOENAS

The Commission may, through the Secretary, Administrative Law Judge, or a Hearing Officer, issue subpoenas requiring attendance of witnesses and the production of books, papers, and other instruments to the same extent and in the same manner and in accordance with the Colorado Rules of Civil Procedure. A party seeking a subpoena will submit the form of the subpoena to the Secretary for execution. Upon execution, the party requesting the subpoena has the responsibility to serve the subpoena in accordance with the Rules of Civil Procedure. Upon receipt of an objection to any discovery issued under this Rule, the Commission, Secretary, Administrative Law Judge, or a Hearing Officer has the discretion to limit the scope of the discovery sought to matters that are within the scope of the Commission's jurisdiction under the Act, or otherwise.

519. APPLICABILITY OF COLORADO COURT RULES AND ADMINISTRATIVE NOTICE

a. The Colorado Rules of Civil Procedure apply to Commission proceedings unless they are inconsistent with Commission Rules or the Colorado Oil and Gas Conservation Act, or as the Administrative Law Judge or Hearing Officer may otherwise direct on the record during prehearing proceedings or by written order.

b. In general, the rules of evidence applicable before a trial court without a jury will be applicable, providing that such rules may be relaxed, where, by so doing, the ends of justice will be better served.

(1) To promote uniformity in the admission of evidence, the Commission, Administrative Law Judge, or Hearing Officer to the extent practical, will observe and conform to the Colorado Rules of Evidence applicable in civil non-jury cases in the district courts of Colorado.

- (2) When necessary to ascertain facts affecting substantial rights of the parties to a proceeding, the Commission, Administrative Law Judge, or Hearing Officer may receive and consider evidence not admissible under the Rules of Evidence, if the evidence possesses probative value commonly accepted by reasonable and prudent persons in the conduct of their affairs.
- (3) Informality in any proceeding or in the manner of taking testimony will not invalidate any Commission order, decision, rule, or regulation.

c. **Administrative notice.** The Commission, Administrative Law Judge, or Hearing Officer may take administrative notice of:

- (1) Constitutions and statutes of any state and of the United States;
- (2) Rules, regulations, official reports, decisions, and orders of state and federal administrative agencies;
- (3) Decisions and orders of federal and state courts;
- (4) Reports and other documents in the files of the Commission;
- (5) Matters of common knowledge and undisputed technical or scientific fact;
- (6) Matters that may be judicially noticed by a Colorado district court in a civil non-jury case; and
- (7) Matters within the expertise of the Commission.

520. RESERVED

521. SERVICE UNDER RULES 522 AND 523

- a. The Director will serve a Notice of Alleged Violation, a Notice of Hearing of an enforcement action or an Order Finding Violation on the operator or the operator's designated agent and other parties as necessary by personal delivery or by certified mail, return receipt requested, to the address the operator has on file with the Commission pursuant to Rule 302.
- b. All other documents in enforcement cases will be served on all parties pursuant to Rule 503.g.
- c. Notice to a Complainant pursuant to Rule 522.b.(2) may be served by confirmed electronic mail (unless previously objected to by a party) or by first class mail to the address provided. Where notice is sent electronically, notice is perfected when sent. Where notice is sent by first class mail, notice is perfected five (5) days after mailing.
- d. A Petition for Review by a Complainant pursuant to Rule 522.b. will be served on the operator or the operator's designated agent to the address on file with the Commission by: confirmed electronic mail followed by a copy sent by first class mail; personal delivery; or certified mail, return receipt requested. All other documents in a Petition for Review proceeding will be served on all parties electronically (unless previously objected to by a party). Where sent by electronic copy, service is perfected once sent.
- e. In emergency situations, a Cease and Desist Order may be served by confirmed electronic or facsimile copy, followed by a copy served on the operator or the operator's designated agent by personal delivery or by certified mail, return receipt requested, to the address the operator has on file with the Commission pursuant to Rule 302. In non-emergency situations, a Cease and Desist Order may be served by certified mail as described above in this subpart.
- f. Service of certified mail on an operator is perfected under this Rule at the earliest of:

- (1) The date the operator receives the notice;
- (2) The date shown on the return receipt, if signed on behalf of the operator; or
- (3) Five (5) days after mailing.

522. PROCEDURES FOR ALLEGED VIOLATIONS

a. **Identification of Alleged Violations.** If, on the Director's own initiative or based on a complaint, the Director has reasonable cause to believe that a violation of the Act, or of any Commission rule, order, or permit has occurred, the Director will require the operator to remedy the violation and may commence an enforcement action seeking penalties by issuing a Notice of Alleged Violation (NOAV). Reasonable cause requires, at least, physical evidence of the alleged violation, as verified by the Director.

b. Complainant's Rights and Responsibilities.

- (1) The following persons (Complainant) may make a complaint to the Director requesting that an NOAV be issued:
 - A. The mineral owner;
 - B. The surface owner or tenant of the lands upon which the alleged violation occurred;
 - C. Other state agencies;
 - D. The local government with jurisdiction over the lands upon which the alleged violation took place;
or
 - E. Any person who is directly and adversely affected or aggrieved as a result of the alleged violation and whose interest is entitled to legal protection under the Act.
- (2) The Director will investigate all complaints made pursuant to Rule 522.b.(1), to the extent the Director believes is sufficient, to determine whether reasonable cause for an alleged violation exists. The Director will notify the Complainant of the determination pursuant to Rule 521.
 - A. If the Director determines no violation occurred, the Director will notify the operator, and no further action will be taken.
 - B. If the Director determines a violation may have occurred, the Director may resolve the matter without seeking penalties pursuant to subpart 522.c.(1) or initiate an enforcement action seeking penalties pursuant to subpart 522.d.
- (3) If a complaint specifically results in the issuance of an NOAV, a Complainant who has filed a written complaint on a Complaint Report, Form 18, will be given fourteen (14) days to comment on the terms of a draft proposed settlement of the NOAV, if any, pursuant to subpart 522.e.(1).
- (4) A Complainant who has filed a written complaint on a Complaint Report, Form 18 may file a Petition for Review requesting the Commission to hear the Complainant's objections to:
 - A. The Director's decision not to issue an NOAV for an alleged violation specifically identified in the written complaint; or
 - B. The settlement terms of a final proposed Administrative Order by Consent (AOC) settling an alleged violation arising directly from the written complaint.

- (5) Complainants must file a Petition for Review application with the Commission within twenty-eight (28) days of receiving the Director's decision not to issue an NOAV or a final proposed AOC. Applications filed later than twenty-eight (28) days following receipt will not be considered.
- A. A Petition for Review will set forth in reasonable detail the legal arguments and facts the Complainant contends demonstrate that the Director's decision not to issue an NOAV or the Director's proposed settlement of the alleged violation was clearly erroneous.
 - B. A Petition for Review may include a request for a continuance of the hearing based on actual, compelling evidence, which has been gathered by the Complainant after the Director's contested decision, that the Director should conduct additional investigation. An Administrative Law Judge or Hearing Officer will determine whether a continuance is warranted.
 - C. A Complainant must serve its Petition for Review on the operator pursuant to Rule 521 within seven (7) days following filing of the Petition.
 - D. The operator and the Director may file and serve responses within twenty-one (21) days after receipt of a Petition for Review.
 - E. The Petition for Review and all subsequent filings must be filed with the Commission electronically in a manner as determined by the Director.
- (6) Unless continued pursuant to Rule 522.b.(5)B., a Petition for Review will be heard not less than thirty-five (35) days following filing of the Petition for Review.
- A. The Petition for Review hearing will be limited to evidence and information entered into the record prior to the Director's contested decision. No party to the Petition for Review hearing may present evidence or information that was not previously presented to the Director. The Commission, Administrative Law Judge, or Hearing Officer retains discretion to continue a Petition for Review hearing to direct staff to conduct additional investigation or receive and consider additional information.
 - B. Discovery will not be permitted prior to the Petition for Review hearing.
 - C. It is the Complainant's burden to show the Director's action was clearly erroneous.
 - (i) If the Complainant meets this burden, the Commission, Administrative Law Judge, or Hearing Officer may remand the matter to the Director for further proceedings, set the matter for an Order Finding Violation Hearing, or order other such relief deemed just and reasonable.
 - (ii) If the Complainant fails to meet this burden, the Commission, Administrative Law Judge, or Hearing Officer will deny the Petition for Review, and if being heard by the Commission, the Commission may also act on the final proposed AOC pursuant to Rules 522.e.(1)C and D.
 - D. Parties may make a statement at the hearing. The Commission's, Administrative Law Judge's, or Hearing Officer's consideration of a Petition for Review will proceed as follows:
 - (i) Determination if any Commissioner, the Administrative Law Judge, or the Hearing Officer has a conflict;
 - (ii) Introduction and background by Staff;

- (iii) Presentation by the Complainant;
- (iv) Presentation by any intervenor;
- (v) Response by the operator, if any;
- (vi) Response by Staff, if any;
- (vii) Rebuttal by the Complainant, if any; and
- (viii) Commission, Administrative Law Judge, or Hearing Officer decision.

c. Resolution of Alleged Violations without Penalties.

- (1) When the Director has reasonable cause to believe a violation has occurred, the Director may resolve the alleged violation without seeking a penalty if all of the following apply:
 - A. The rule allegedly violated is not a Class 3 rule and the degree of actual or threatened impact is minor or moderate under the Commission's Penalty Schedule, Rule 523.c.(1);
 - B. The operator has not received a previous Warning Letter or Corrective Action Required Inspection Report regarding the same violation;
 - C. The Director determines the alleged violation can be corrected without undue delay; and
 - D. The operator timely performs all corrective actions required by the Director and takes any other actions necessary to promptly return to compliance.
- (2) The Director retains discretion to seek penalties for any violation of the Act, or a Commission rule, order, or permit, even if all of the factors in subpart 522.c.(1) apply.
- (3) When the Director determines it is appropriate to resolve an alleged violation pursuant to subpart 522.c.(1), the Director may issue the operator either a Warning Letter or Corrective Action Required Inspection Report that identifies the provisions of the Act, or Commission Rules, orders, or permits allegedly violated, the facts giving rise to the alleged violation, any corrective actions required to resolve the violation, and a schedule for conducting the corrective actions.
 - A. If the operator timely performs required corrective actions and otherwise returns to compliance, the alleged violation will be resolved and the matter closed without further action.
 - B. If the operator fails to fully perform all corrective actions required by a Warning Letter or a Corrective Action Required Inspection Report, or otherwise fails to return to compliance within the timeframe specified by the Director, the Director may initiate an enforcement action seeking penalties pursuant to subpart 522.d. for any unresolved alleged violation.

d. Enforcement Actions Seeking Penalties for Alleged Violations. When the Director determines subpart 522.c.(1) does not apply or otherwise elects to seek penalties for an alleged violation, the Director will commence an enforcement action by issuing a Notice of Alleged Violation (NOAV).

- (1) **Content of an NOAV.** An NOAV will identify the provisions of the Act, or Commission rules, orders, or permits allegedly violated and will contain a short and plain statement of the facts alleged to constitute each alleged violation. The NOAV may propose appropriate corrective action and an abatement schedule required by the Director to correct the alleged violation. The NOAV may propose a specific penalty amount or refer generally to Rule 523.
- (2) **Answer.** An answer to an NOAV must be filed within twenty-eight (28) days of the operator's receipt of an NOAV, unless an exception or extension is granted by the Director. An answer will, at a minimum, discuss the allegations contained in the NOAV, responding to each; identify corrective actions taken in response to the NOAV, if any; and identify facts known to the operator at the time that are relevant to the operator's response to the alleged violations. If the operator fails to file an answer within twenty-eight (28) days, the Director may request the Commission, Administrative Law Judge, or Hearing Officer enter a default judgment.
- (3) **Procedural matters.**
 - A. Service of an NOAV constitutes commencement of an enforcement action or other proceeding for purposes of §34-60-115, C.R.S.
 - B. Issuance of an NOAV does not constitute final agency action for purposes of judicial review.
 - C. A monetary penalty for a violation may only be imposed by Commission order.
 - D. The Secretary of the Commission will docket enforcement actions for hearing by issuing a Notice and Application for Hearing pursuant to Rule 507.

e. Resolution of Enforcement Actions.

- (1) **Administrative Order by Consent.** An enforcement action may be provisionally resolved by agreement between the operator and the Director except as provided in subpart 522.e.(2).
 - A. A proposed agreement to resolve an enforcement action will be memorialized in an Administrative Order by Consent (AOC) executed by the Director and the operator. An AOC will be noticed for review by an Administrative Law Judge, or Hearing Officer.
 - B. A Complainant who has filed a written complaint on a Complaint Report, Form 18, will be informed of the terms of a draft proposed AOC resolving alleged violations arising directly out of their written complaint and will be given fourteen (14) days to comment on the draft settlement terms before the AOC is finalized and presented to an Administrative Law Judge, or Hearing Officer for a recommended order approving it. The Director will provide a copy of the final proposed AOC to the Complainant. A Complainant who objects to the finalized settlement terms proposed for an alleged violation arising directly from their written complaint may file a Petition for Review pursuant to Rule 522.b.
 - C. AOCs that are not subject to a pending Complainant's Petition for Review will be reviewed by an Administrative Law Judge or Hearing Officer to issue a recommended order. Recommended orders on AOCs will be issued no sooner than fifteen (15) days prior to the next regularly scheduled Commission hearing. A recommended AOC becomes the decision of the Commission within twenty (20) days after service upon the parties, unless the Commission stays the recommended order on the AOC within that time or parties file an exception to the recommended order.
 - D. If the Commission stays the recommended AOC, the Commission may
 - (i) remand the matter to the Director for further proceedings; or

(ii) direct the parties to appear before the Commission for hearing.

(2) Order Finding Violation.

A. An enforcement action may not be resolved by the Director and must be heard by an Administrative Law Judge or Hearing Officer, unless the Commission directs otherwise, when:

(i) The Director alleges the operator is responsible for gross negligence or knowing and willful misconduct that resulted in an egregious violation;

(ii) The Director alleges the operator has engaged in a pattern of violations; or

(iii) The Commission sets an OFV hearing pursuant to 522.b. (6) C. (i).

B. Commencing an OFV hearing

(i) The Director will commence an OFV hearing for enforcement actions governed by subpart 522.e. (2) A. by filing a Notice and Application for Mandatory OFV Hearing.

(ii) Order Finding Violation hearings for enforcement actions not governed by subpart 522.e. (2) A. are commenced by service of the NOAV and Notice and Application for Hearing. The Director is not required to file a separate application for an OFV hearing. An OFV hearing will commence on the date stated in the Notice and Application for Hearing, as amended by applicable pre-hearing orders, or as amended by the Director, unless the parties have agreed to and executed an AOC not less than seven (7) days prior to the scheduled hearing date.

(iii) The Commission may conduct an OFV hearing on its own motion, with notice pursuant to Rule 507., if it believes the Director has failed to enforce a provision of the Act, or a Commission rule, order, or permit.

C. OFV hearing procedures

(i) OFV prehearing procedures are governed by Rule 527. The Director may convene a prehearing conference pursuant to Rule 527. within a reasonable time after serving a Notice and Application for Hearing.

(ii) OFV hearings are *de novo* proceedings governed by Rule 528.

(iii) If the Director initiates the OFV hearing, a Complainant may submit a Rule 510 statement or move to intervene by permission of the Commission Administrative Law Judge or Hearing Officer pursuant to Rule 509.a. (2)C.

(3) **Rescinding an NOAV.** If, after issuance of an NOAV to an operator, the Director no longer has reasonable cause to believe a violation of the Act, or of any Commission rule, order, or permit occurred, the Director will rescind the NOAV in writing.

f. **Failure to Comply with Commission Orders.** An operator's failure to diligently implement corrective action pursuant to an AOC, OFV, or other Commission order constitutes an independent violation which may subject the operator to additional penalties or corrective action requirements.

g. **Cease and Desist Orders.**

- (1) The Commission or the Director, may issue a Cease and Desist Order when an operator's alleged violation of the Act, or a Commission rule, order, or permit, or failure to take required corrective action creates an emergency situation. If the Cease and Desist Order is entered by the Director, it will be reported to the Commission not later than the next regularly scheduled Commission hearing, unless the matter is heard pursuant to the expedited procedure under §34-60-121(5)(b), C.R.S.
- (2) The Cease and Desist Order will be served pursuant to Rule 521. within seven (7) days after it is issued.
- (3) The Cease and Desist Order will state the provisions of the Act, or Commission rules, orders, or permits alleged to have been violated, and will contain a short and plain statement of the facts alleged to constitute the violation, the time by which the acts or practices cited are required to cease, and any corrective action the Commission or the Director elects to require of the operator.
- (4) Any protest by an operator of a Cease and Desist Order will be heard by the Commission pursuant to §34-60-121(5)(b), C.R.S. An operator's protest of a Cease and Desist Order will not stay the order pending a Commission hearing on the matter, unless the operator obtains an injunction enjoining enforcement of the Cease and Desist Order.
- (5) If an operator fails to comply with a Cease and Desist Order, the Commission may request the attorney general to bring suit pursuant to §34-60-109, C.R.S.

523. PROCEDURES FOR ASSESSING PENALTIES

- a. **General.** An operator who violates the Act, or a Commission rule, order, or permit may be subject to a penalty imposed by Commission order. Penalties will be calculated based on the Act and this Rule 523. The Commission's Enforcement Guidance and Penalty Policy also provides non-binding guidance to the Commission and interested persons evaluating a penalty for an alleged violation.
- b. **Days of Violation.** The duration of a violation presumptively will be calculated in days as follows:

- (1) A reporting or other minor violation not involving actual or threatened significant adverse impacts begins on the day that the report should have been made or other required action should have been taken, and continues until the report is filed or the required action is commenced to the Director's satisfaction.
- (2) All other violations begin on the date the violation was discovered or should have been discovered through the exercise of reasonable care and continue until the appropriate corrective action is commenced to the Director's satisfaction.

With respect to violations that result in actual or threatened adverse impacts to public health, safety, and welfare, including the environment and wildlife resources, commencing appropriate corrective action includes, at a minimum:

- A. Performing immediate actions necessary to assess and evaluate the actual or threatened adverse impacts; and
- B. Performing all other near-term actions necessary to stop, contain, or control actual or threatened adverse impacts in order to prevent, minimize, or mitigate damage to public health, safety, and welfare, including the environment and wildlife resources. Such actions may include, without limitation, stopping or containing a spill or release of E&P Waste; establishing well control after a loss of control event; removing E&P Waste resulting from surface spills or releases; installing fencing or other security measures to limit access (including wildlife access) to affected areas; providing alternative water supplies; notifying affected landowners, local governments, and other persons or businesses; and, in cases of actual adverse impacts, mobilizing all resources necessary to fully and completely remediate the affected environment.

(3) A penalty will be assessed for each day the evidence shows a violation continued.

(4) The number of days of violation does not include any period necessary to allow the operator to engage in good faith negotiation with the Commission regarding an alleged violation if the operator demonstrates a prompt, effective, and prudent response to the violation.

c. **Penalty Calculation.** The base penalty for each violation will be calculated based on the Commission's Penalty Schedule which considers the severity of the potential consequences of a violation of a specific rule combined with an assessment of the degree of actual or threatened adverse impact to public health, safety, and welfare, including the environment and wildlife resources. The maximum daily penalty cannot exceed \$15,000 per day per violation.

(1) **Penalty Schedule.** The Commission's Penalty Schedule is the following matrix that establishes a daily penalty based on the classification of the rule violation (Class 1, 2, or 3) and the degree of actual or threatened adverse impact resulting from the violation (minor, moderate, or major).

		Rule Classification		
		Class 1: Paperwork or other ministerial rules, a violation of which presents no direct risk or threat of harm to public health, safety, and welfare, including the environment and wildlife resources.	Class 2: Rules related at least indirectly to protecting public health, safety, and welfare, including the environment and wildlife resources, a violation of which presents a possibility of distinct, identifiable actual or threatened adverse impacts to those interests.	Class 3: Rules directly related to protecting public health, safety, and welfare, including the environment and wildlife resources, a violation of which presents a significant probability of actual or threatened adverse impacts to those interests.
Degree of threatened or actual impact to public health, safety, welfare, the environment, or wildlife	Major: Actual significant adverse impacts	\$5,000	\$10,000	\$15,000
	Moderate: Threat of significant adverse impacts, or moderate actual adverse impacts	\$1,500	\$5,000	\$10,000
	Minor: No actual adverse impact and little or no threat of adverse impacts	\$200	\$2,500	\$5,000

(2) **Degree of actual or threatened adverse impact.** The base penalty for a violation may be increased based on the degree of actual or threatened adverse impact to public health, safety, and welfare, including the environment and wildlife resources resulting from the violation. The Commission, Administrative Law Judge, or Hearing Officer will determine the degree of actual or threatened adverse impact to public health, safety, and welfare, including the environment and wildlife resources, based on the totality of circumstances in each case. The Commission, Administrative Law Judge, or Hearing Officer will consider the following, non-exclusive, list of factors in making its determination:

A. Whether and to what degree the environment and wildlife resources were adversely affected or threatened by the violation. This factor considers the existence, size, and proximity of potentially impacted livestock, wildlife, fish, soil, water, air, and all other environmental resources.

B. Whether and to what degree Waters of the State were adversely affected or threatened by the

violation.

- C. Whether and to what degree drinking water was adversely affected or threatened by the violation.
- D. Whether and to what degree public or private property was adversely affected or threatened by the violation.
- E. The quantity and character of any E&P waste or non-E&P waste that was actually or threatened to be spilled or released.
- F. Any other facts relevant to an objective assessment of the degree of adverse impact to public health, safety, or welfare, including the environment and wildlife resources.

(3) **Penalty Adjustments for Aggravating and Mitigating Factors.** The Commission, Administrative Law Judge, or Hearing Officer may increase a penalty up to the statutory daily maximum amount if it finds any of the aggravating factors listed in subpart A., below, exist. The Commission, Administrative Law Judge, or Hearing Officer may decrease a penalty if it finds that the violator cooperated with the Commission and other agencies with respect to the violation and that any of the mitigating factors listed in subpart B., below, exist.

A. Aggravating factors:

- (i) The violator acted with gross negligence or knowing and willful misconduct.
- (ii) The violation resulted in significant waste of oil and gas resources.
- (iii) The violation had a significant negative impact on correlative rights of other parties.
- (iv) The violator was recalcitrant or uncooperative with the Commission or other agencies in correcting or responding to the violation.
- (v) The violator falsified reports or records.
- (vi) The violator benefited economically from the violation, in which case the amount of such benefit will be taken into consideration.
- (vii) The violator has engaged in a pattern of violations.
- (viii) The violation led to death or serious injury.

B. Mitigating factors:

- (i) The violator self-reported the violation.
- (ii) The violator demonstrated prompt, effective and prudent response to the violation, including assistance to any impacted parties.
- (iii) The cause of the violation was outside of the violator's reasonable control and responsibility, or is customarily considered to be force majeure.
- (iv) The violator made a good faith effort to comply with applicable requirements prior to the Commission learning of the violation.

(v) The cost of correcting the violation reduced or eliminated any economic benefit to the violator, excluding circumstances in which increased costs stemmed from non-compliance.

(vi) The violator has demonstrated a history of compliance with the Act, and Commission rules, orders, and permits.

(4) **Penalty adjustments based on duration of violation.** In its discretion, the Commission, an Administrative Law Judge, or Hearing Officer may decrease the daily penalty amounts for violations of long duration to ensure the total penalty is appropriate to the nature of the violation.

d. Pattern of Violations, Gross Negligence, or Knowing and Willful Misconduct.

(1) The Director will apply for an Order Finding Violation hearing when the Director determines an operator has:

A. Engaged in a pattern of violations; or

B. Acted with gross negligence or knowing and willful misconduct that resulted in an egregious violation.

(2) If the Commission, Administrative Law Judge, or Hearing Officer finds after hearing that an operator is responsible for the conduct described in subparagraph d.(1), the Commission, Administrative Law Judge, or Hearing Officer may suspend an operator's Certification of Clearance, withhold new drilling or oil and gas location permits, or both. Such suspension will last until such time as the violator demonstrates to the satisfaction of the Commission that the operator has brought each violation into compliance and that any penalty assessed, which is not subject to judicial review, has been paid at which time the Commission may vacate the order.

(3) The Commission, Administrative Law Judge, or Hearing Officer will consider an operator's history of violations of the Act, or Commission rules, orders, or permits, and any other factors relevant to objectively determining whether an operator has engaged in a pattern of violations. For an operator's history of violations, the Commission, Administrative Law Judge, or Hearing Officer may only consider violations confirmed by Commission order through an AOC or OFV.

e. Voluntary disclosure.

(1) An operator who maintains a regulatory compliance program and voluntarily discloses to the Director a violation of the Act, or any Commission rule, order, or permit discovered as a direct result of such a program, will have a rebuttable presumption of a penalty reduction of at least 35% for a disclosed violation, if:

A. The disclosure is made promptly after the operator learns of the violation as a result of its regulatory compliance program;

B. The operator cooperates with the Director regarding investigation of the disclosed violation; and

C. The operator has achieved or commits to achieve compliance within a reasonable time and pursues compliance with due diligence.

(2) This presumption will not apply if:

A. The disclosure or the regulatory compliance program was engaged in for fraudulent purposes;

B. The disclosed violation was part of a pattern of violations; or

C. The disclosed violation was egregious and the result of the operator's gross negligence or knowing and willful misconduct.

(3) If the Director determines that any of the factors in subpart (1) are not met or that the factors in subpart (2) are met, the Director may consider the fact that the operator self-reported the violation as a mitigating factor under Rule 523.c.(3)B.(i).

f. **Public Projects.** In its discretion, the Commission, Administrative Law Judge, or Hearing Officer may allow an operator to satisfy a penalty in whole or in part by a Public Project that the operator is not otherwise legally required to undertake. The costs of the Public Project may offset the penalty amount dollar for dollar, or by some other ratio determined by the Commission. A Public Project must provide tangible benefit to public health, safety and welfare, or the environment or wildlife resources. The Commission favors Public Projects that benefit the persons or communities most directly affected by a violation, or that provide education or training to local government entities, first responders, the public, or the regulated community related to the violation.

g. **Payment of penalties.** An operator will pay a penalty imposed by Commission order, by certified funds, within thirty (30) days of the effective date of the order, unless the Commission grants a longer period or unless the operator files for judicial appeal, in which event payment of the penalty will be stayed pending resolution of such appeal. An operator's obligations to comply with the provisions of a Commission order requiring compliance with the Act, or Commission rules, orders, or permits will not be stayed pending resolution of an appeal, except by court order.

524. DETERMINATION OF RESPONSIBLE PARTY

In all cases initiated by the Commission or at the request of the Director, it will be the burden of the Director to present sufficient evidence to the Commission, Administrative Law Judge, or Hearing Officer to determine responsible party status. In all other cases, the applicant will have the burden to present sufficient evidence to the Commission, Administrative Law Judge, or Hearing Officer to determine responsible party status.

- a. A hearing may be initiated on the Commission's own motion, upon application, or at the request of the Director to decide responsible party status upon at least twenty-one (21) days' notice to the potentially responsible parties.
- b. Potentially responsible parties will be those persons that have or should have submitted Registration for Oil and Gas Operation, Form 1, or that have or should have submitted financial assurance for oil and gas operations pursuant to requirements of the 700-Series Rules.
- c. Potentially responsible parties will provide to the Commission, Director, Administrative Law Judge, or Hearing Officer such information as the Commission, Director, Administrative Law Judge, or Hearing Officer may reasonably require in making such determination.
- d. The Commission, Administrative Law Judge, or Hearing Officer will make the determination under this section without regard to any contractual assignments of liability or other legal defenses between parties.
- e. An operator will enjoy a rebuttable presumption against mitigation liability under §34-60-124(7), C.R.S., for ongoing significant adverse environmental impacts where the violation which led to such impacts was committed by a predecessor operator and where the operator has conducted an environmental investigation, with reasonable due diligence, of the environmental condition of the particular asset or activity and such investigation did not reveal such significant adverse environmental impacts. The failure to report any condition which is causing such impacts, upon subsequent knowledge by the operator, will negate the rebuttable presumption against mitigation liability.

- f. Where multiple persons are determined to be responsible parties, they will share in the mitigation liability in proportion to their respective shares of production, respective periods of ownership or respective contributions to the problem, or any other factors as may serve the interests of fairness.
- g. The determination of responsible party status and mitigation liability will require a showing that the responsible party conducted operations that have resulted in or have threatened to cause a significant adverse environmental impact to any air, water, soil, or biological resource based on the conduct of oil or gas operations in contravention of any then applicable historic provisions of the Act or rules, whether or not the Commission has entered an Order Finding Violation.

525. PERMIT-RELATED PENALTIES

- a. If the Commission determines, after a hearing, that an operator failed to perform any required corrective action/abatement or failed to comply with a Cease and Desist Order issued by the Commission or the Director with regard to violation of a permit provision, the Commission may issue an order suspending, modifying, or revoking a permit or permits authorizing the operation. The order will provide the condition(s) which must be met by the operator for reinstatement of the permit(s). An operator which is subject to an order that suspends, modifies, or revokes a permit or permits will continue the affected operations only for the purpose of bringing them into compliance with the permit(s) or modified permit(s), and will do so under the supervision of the Director. Once the condition for reinstatement has been met to the satisfaction of the Director and any fine not subject to judicial review or appeal has been paid, the Director will inform the Commission, and the Commission, if in agreement, will reinstate the permit(s).
- b. Whenever the Commission or the Director has evidence that an operator is responsible for a pattern of violation of any provision of the Act, or of any rule, permit, or order of the Commission, the Commission or the Director will issue a notice to such operator to appear for a hearing before the Commission. If the Commission finds, after such hearing, that a knowing and willful pattern of violation exists, it may issue an order which will prohibit the issuance of any new permits to such operator. When such operator demonstrates to the satisfaction of the Commission that it has brought each of the violations into compliance and that any fine not subject to judicial review or appeal has been paid, such order denying new permits will be vacated.

526. ADMINISTRATIVE HEARINGS IN UNCONTESTED MATTERS

- a. As to applications where there has been no protest or intervention filed with the Commission in accordance with Rule 509., and where the Administrative Law Judge or Hearing Officer has not issued a written recommended order approving the application, the application may be heard administratively. The date and time of the administrative hearing will be scheduled for the mutual convenience of the applicant and the Administrative Law Judge or Hearing Officer. The administrative hearing may be conducted prior to the protest or intervention date, but no recommended order will issue until the Administrative Law Judge or Hearing Officer has fully considered any timely and properly filed protest or intervention.
- b. One or more duly appointed Administrative Law Judges or Hearing Officer's may hear the application at the administrative hearing. Administrative hearings will proceed informally in a meeting format. The applicant may present its case using exhibits and witnesses. All witnesses will be sworn. At the conclusion of the administrative hearing, the Administrative Law Judge or Hearing Officer will make a decision concerning approval or denial of the application and so inform the applicant. The Administrative Law Judge or Hearing Officer will put such decision in a written report to the Commission containing findings of fact, conclusions of law, if any, and a recommended order. If the Administrative Law Judge or Hearing Officer's recommended order is a denial or qualified approval of the application, the applicant will be entitled to file an exception.

527. PREHEARING PROCEDURES FOR CONTESTED ADJUDICATORY PROCEEDINGS BEFORE THE COMMISSION

- a. The Commission encourages the use of prehearing conferences between parties to a contested matter in order to facilitate settlement, narrow the issues, identify any stipulated facts, resolve any other pertinent issues, and reduce the hearing time. A prehearing conference will be conducted at the direction of the Commission, Director, an Administrative Law Judge, or Hearing Officer upon receipt of a protest or an intervention, or upon the request of the applicant or any person who has filed a protest or intervention. For matters in which a staff analysis has been prepared, the Director will participate in the prehearing conference to advise the parties of the content of the preliminary staff analysis. The prehearing conference will be conducted under the following general guidelines.
- b. The Director, Administrative Law Judge, or Hearing Officer will preside over any prehearing conference and rule on preliminary matters in any pending proceeding.
- c. The Secretary, Administrative Law Judge, or Hearing Officer will notify the applicant and any person who has filed a protest or intervention of the prehearing conference, and will direct the attorneys for the parties, and pro se parties, to appear in order to expedite the hearing or settle issues, or both.
- d. All parties will be prepared to discuss all procedural and substantive issues, and will be authorized to make binding commitments.
- e. Preparation should include advance study of all materials filed and materials obtained through discovery.
- f. Failure of any person to attend the prehearing conference, after being notified of the date, time, and place, will be a waiver of any objection and will be deemed to be a concurrence to any agreement reached, or to any order or ruling made at the prehearing conference, including the entry of a default judgment or the dismissal of a protest.
- g. A prehearing statement may be required of any party.
- h. At any prehearing conference, the following matters may be considered:
 - (1) Offers of settlement or designation of issues;
 - (2) Simplification of and establishment of a list or summary of the issues;
 - (3) Bifurcation of issues for hearing purposes;
 - (4) Admissions as to, or stipulations of facts not remaining in dispute or the authenticity of documents;
 - (5) Limitation of the number of fact and expert witnesses;
 - (6) Limitation on methods and extent of discovery, and a discovery schedule;
 - (7) Disposition of procedural motions; and
 - (8) Other matters raised by the parties, the Commission, Administrative Law Judge, or Hearing Officer.
- i. At any prehearing conference, the following information may be required:
 - (1) An exchange and acceptance of service of exhibits proposed to be offered in evidence, and establishment of a list of exhibits to be offered;
 - (2) Establishment of a list of witnesses to be called and anticipated testimony times; and
 - (3) A timetable for the completion of discovery, if discovery is allowed.

- j. The Administrative Law Judge or Hearing Officer will reduce to writing any agreement reached or orders issued at a prehearing conference. The Administrative Law Judge or Hearing Officer may require parties to submit proposed findings or orders.
- k. It is the intent of this rule that a prehearing order will be binding upon the participating parties.
- l. Subsequent to the prehearing conference and prior to the hearing on a contested matter, the parties will each prepare and submit to the Administrative Law Judge or Hearing Officer a recommended order to consider for adoption at the time of hearing.

528. CONDUCT OF ADJUDICATORY HEARINGS

a. **Contested applications.** Every party will have the right to present its case by oral and/or documentary evidence. The following will be the order of presentation unless otherwise established by the Commission, Administrative Law Judge, or Hearing Officer:

- (1) Determination of whether any Commission members, the Administrative Law Judge, or Hearing Officer have a conflict of interest;
- (2) If before the Commission, presentation of any prehearing order;
- (3) If before the Commission, presentation of any motions and disposition of procedural matters;
- (4) If before the Commission, presentation of any stipulations;
- (5) Opening statement by the applicant;
- (6) Opening statements by the respondent (and intervenor, if any);
- (7) Presentation of the case-in-chief by the applicant;
- (8) Presentations by respondent (and intervenor, if any);
- (9) Presentation of statements under Rule 510., if any;
- (10) Presentation of staff analysis, if requested by the Commission, Administrative Law Judge, or Hearing Officer;
- (11) Rebuttal by the applicant;
- (12) Rebuttal by the respondent (and intervenor, if any);
- (13) Closing statement by the applicant;
- (14) Closing statements by the respondent (and intervenor, if any);
- (15) Rebuttal closing statement by the applicant;
- (16) Upon motion and for good cause shown, the Commission, Administrative Law Judge, or Hearing Officer may permit surrebuttal;
- (17) Closing of the record.

b. **Uncontested applications not approved administratively.** For uncontested applications not approved administratively pursuant to Rule 526., the applicant may present evidence in support of its application to

the Commission. The order of presentation will be as follows, unless otherwise established by the Commission, Administrative Law Judge, or Hearing Officer:

- (1) Determination of whether any Commission members have a conflict of interest;
- (2) Presentation of staff analysis, if requested by the Commission. The Commission, at its discretion or upon request of the Director, may defer staff testimony until all of the evidence has been presented;
- (3) Presentation of the case-in-chief by the applicant;
- (4) Closing statement by the applicant;
- (5) Closing of the record.

c. **Enforcement hearings.** In order to assure that all parties are afforded due process of law, the Commission will permit all parties to an enforcement hearing to present evidence and argument, and to conduct cross-examination. The enforcement matter will be heard by the Commission, Administrative Law Judge, or Hearing Officer. The order of presentation in a hearing for an enforcement matter will be as follows, unless otherwise established by the Commission, Administrative Law Judge, or Hearing Officer:

- (1) Determination of whether any Commission members, the Administrative Law Judge, or Hearing Officer have a conflict of interest;
- (2) Opening statements by all parties;
- (3) Presentation by the Director;
- (4) Presentation by any intervenor;
- (5) Presentation by the operator;
- (6) Rebuttal by the Director;
- (7) Rebuttal by any intervenor;
- (8) Rebuttal by the operator;
- (9) Closing statements;
- (10) Finding regarding existence of violation;
- (11) If the Commission, Administrative Law Judge, or Hearing Officer first determines by a preponderance of the evidence that a violation or violations exist, presentation by the Director of any recommended fine or permit-related penalty, and/or recommended corrective action/abatement to be taken by the operator;
- (12) Presentation of statements under Rule 510., if any;
- (13) Response by the intervenor;
- (14) Response by any operator;
- (15) Rebuttal by the Director;
- (16) Closing statements;

(17) Closing of the record.

- d. **Closing of record.** At the conclusion of closing statements, the record will be closed to the presentation of any further evidence, testimony, or statements, except as such may occur in response to questions from the Commission, Administrative Law Judge, or Hearing Officer.
- e. **Witnesses.** Each witness will take an oath or affirmation before testifying. After a witness has testified, the applicant, the protestant or participating intervenors, and any Commissioner may cross-examine that witness in the order established by the chairperson of the Commission. If the hearing is before an Administrative Law Judge or Hearing Officer, the Administrative Law Judge or Hearing Officer may ask questions during or after witness testimony or, cross-examine the witness.
- f. **Limitations of testimony.** Where two or more protestants or intervenors have substantially similar interests and positions, the Commission, Administrative Law Judge, or Hearing Officer may limit cross-examination or argument on motions and objections to fewer than all the intervenors. The Commission may also limit testimony to avoid undue delay, waste of time or needless presentation of cumulative evidence.

529. PROCEDURES FOR RULEMAKING PROCEEDINGS

- a. **Initiation of rulemaking.** The Commission may initiate rulemaking on its motion or in response to an application filed by any person, including at the request of the Director.
- b. **Applications for rulemaking.** Any person may petition the Commission to initiate rulemaking. All applications for rulemaking will contain the following information:
 - (1) The name, address, and telephone number of the person requesting the rulemaking;
 - (2) A copy of the rule proposed in the application and a general statement of the reasons for the requested rule; and
 - (3) A proposed statement of the basis and purpose for the rule.
- c. **Notice of proposed rulemaking.** All rulemaking hearings of the Commission will be noticed by publication in the Colorado Register not less than twenty-one (21) days prior to the hearing and as otherwise specified in the Administrative Procedure Act, §24-4-103, C.R.S.
- d. **Development of proposed rules.** Prior to the notice of proposed rulemaking, the Commission or Director will establish a representative group of participants with an interest in the subject of the rulemaking as provided by §24-4-103(2), C.R.S. The Commission or Director may also use informal procedures to gather information, including, but not limited to public forums, investigation by Commission staff, and formation of rulemaking teams. Commissioners may participate in such informal proceedings.
- e. **Content of notice.** The notice will state the time, date, place, and general subject matter of the hearing to be held. It may include a statement indicating whether an informal public meeting will be held, the time, date, place, and general purpose of the meeting, any special procedures the Commission deems appropriate for the particular rulemaking proceeding and a statement encouraging public participation. The notice will state that the proposed regulations will be available upon request from the office of the Commission, the date of availability, and any fee. The notice will include a short and plain statement which summarizes the intended action and states generally the basis and purpose of the rules.
- f. **The rulemaking hearing.** The Commission will hold a formal public hearing before promulgating any rules or regulations. At that hearing, the Commission will afford any person an opportunity to submit data, views or arguments. The Commission may limit such testimony or presentation of evidence at its discretion and may prohibit repetitive, irrelevant, or harassing testimony.

g. Conduct of rulemaking hearings.

- (1) The Commission encourages any person to participate at rulemaking hearings. The times at which the public may participate will be determined at the discretion of the Commission. The Commission may, at its discretion, limit the amount of time a person may use to comment or make public statements. Oaths will not be required for public participation.
- (2) The Commission encourages witnesses to make plain, brief, and simple statements of their positions. It also encourages submittal of written statements prior to hearing, with only an oral summary of such a statement at the hearing.
- (3) The order of presentation at a rulemaking hearing will be as established by the Commission at the hearing.
- (4) The Commission has the discretion to continue rulemaking hearings by announcement at the rulemaking hearing without republishing the proposed rules.

530. INVOLUNTARY POOLING PROCEEDINGS

- a. An application for involuntary pooling pursuant to §34-60-116, C.R.S., may be filed at any time by an owner who owns, or has secured the consent of the owners of, more than forty-five (45) percent of the mineral interests to be pooled within a drilling and spacing unit established by Commission order, prior to or after drilling of a well, but no later than ninety (90) days in advance of the hearing date for which the applicant proposes the matter be heard by the Commission, as per Rule 506.a. Mineral interests that are owned by a person who cannot be located by the applicant through reasonable diligence are not included for purposes of determining whether the forty-five (45) percent mineral interests threshold is met.
- b. The Commission must receive evidence that owners were tendered a good faith, reasonable offer to lease or participate no less than ninety (90) days prior to an involuntary pooling hearing. An application for involuntary pooling may be filed concurrently with the sending of a good faith, reasonable offer to lease or participate. While an application for involuntary pooling may be filed at any time prior to or after the drilling of a well, any involuntary pooling order issued will be retroactive to the date the application is filed with the Commission unless the payor agrees otherwise.
 - (1) For purposes of this Rule 530, “good faith” means a state of mind consisting in observance of reasonable commercial standards of fair dealing in oil and gas operations, and absence of intent to defraud or seek unconscionable advantage.
- c. Upon a showing by the applicant that it has complied with these rules, the Commission may deem an owner to be a nonconsenting owner in the area to be pooled if:
 - (1) After receiving an offer to participate and given at least sixty (60) days to review the offer, the owner does not elect in writing to consent to participate in the cost of the well concerning which the pooling order is sought. The offer to participate must include the following information, at a minimum:
 - A. The location and objective depth of the well.
 - (i) Directional wells will include the estimated Measured Depth and True Vertical Depth (MD, TVD), and
 - (ii) Horizontal wells will include the estimated Measured Depth, True Vertical Depth, and Lateral Length (MD, TVD, LL);
 - B. The estimated drilling and completion cost of the well (both the total cost and the owner’s share);

- C. The estimated spud date for the well or range of time within which spudding is to occur; and
- D. Contact information for an operator representative who will be available to answer owner questions.

An authority for expenditure prepared by the operator and containing the information required above, together with additional information deemed appropriate by the operator may satisfy these obligations.

- (2) After receiving a good faith offer to lease and given at least sixty (60) days to review the offer, the unleased owner has failed to accept or refused a reasonable offer to lease. In determining whether a good faith, reasonable offer to lease has been tendered under §34-60-116(7)(d), C.R.S., the Commission will consider the lease terms listed below for the drilling and spacing unit in the application and for all cornering and contiguous units, and additional leases where necessary to obtain a representative sample of the lease market:

- A. Date of lease and primary term or offer with acreage in lease;
- B. Annual rental per acre;
- C. Bonus payment or evidence of its non-availability;
- D. Mineral interest royalty; and
- E. Such other lease terms as may be relevant.

Additionally, for an offer to lease to be considered reasonable and have been made in good faith, the offer must be written in clear and neutral language and include information on which the offered price can be determined to be fair.

- d. A nonconsenting owner will be subject cost recovery pursuant to §34-60-116(7)(b), C.R.S.
- e. All offers to lease or participate must include contact information for a representative of the applicant to answer questions and the Commission's brochure describing its pooling procedures and the owner's options related to pooling.

531. CONSENT AGENDA

- a. Regular hearings will be held before the Commission on such days as may be set by the Commission.
- b. The Secretary may place on the consent agenda those uncontested matters recommended by an Administrative Law Judge or Hearing Officer for approval if a recommended order has not become the final agency action pursuant to Rule 532.b. prior to the next regularly scheduled hearing of the Commission.
 - (1) All matters on the consent agenda may be presented individually or in groups. All matters within a group will be voted on together, without deliberation and without the necessity of reading into the record the individual items. However, any Commissioner may request clarification from the Director or from the attorney or other representative of the applicant for any matter on the consent agenda.
 - (2) Any Commissioner may remove a matter from the consent agenda prior to voting thereon.
 - (3) Any matter removed from the consent agenda will be heard at the end of the remaining agenda, if practicable and agreeable to the applicant, or, if not, scheduled for hearing at the next regularly scheduled meeting of the Commission.

532. DECISIONS, ORDERS AND EXCEPTIONS

a. Interim Decisions.

- (1) Interim decisions are issued after an application is set for hearing, but are not recommended orders that may become a final decision of the Commission.
- (2) Interim decisions shall not be subject to exceptions. However, any aggrieved party or rulemaking participant may challenge the matters determined in an interim decision in exceptions to a recommended order.
- (3) Nothing in this rule prohibits a motion for clarification of an interim decision set forth in an interim decision.

b. **Recommended Orders.** After due consideration of written statements, oral statements, the testimony, the evidence, and the arguments presented at hearing, the Administrative Law Judge, or Hearing Officer will make a written recommended order based upon evidence in the record, consistent with the Act and any rule, permit, or order made pursuant thereto. Recommended orders will be issued no sooner than fifteen (15) days prior to the next regularly scheduled Commission hearing. The Administrative Law Judge or Hearing Officer will promptly transmit to the Commission and the parties the record and exhibits of the proceeding and a written recommended order. The recommended order becomes a final agency action if no exceptions are filed within twenty (20) days after service upon the parties and the Commission does not stay the recommended order on its own motion.

c. **Exceptions.** A recommended order becomes the Commission's final order unless, within twenty (20) days or such additional time as the Commission may allow, any party files exceptions to the recommended order or the Commission orders the recommended order to be stayed. A stay of a recommended order does not automatically extend the period for filing exceptions or a motion for an extension of time to file exceptions. If exceptions are timely filed, the recommended order is stayed until the Commission rules upon them. Parties may file responses to exceptions within fourteen (14) days following service of the exceptions.

- (1) A party wishing to file exceptions may shall request a transcript within seven (7) days of the date of the recommended order. The requesting party shall bear the cost of the preparation of the transcript.
- (2) The Commission will conduct a review upon the same record before the Administrative Law Judge or Hearing Officer, and a de novo review of the law.
- (3) The Commission may, upon its own motion or upon the motion of a party, order oral argument regarding exceptions. The Secretary shall set the time allotted for argument. The Commission may terminate argument whenever, in its judgment, further argument is unnecessary. The party filing exceptions is entitled to open and conclude the argument. Arguments will be limited to issues raised in the exceptions, unless the Commission orders otherwise.

d. An Administrative Law Judge's or Hearing Officer's recommended order shall be an initial decision for purposes of filing an exception pursuant to the state Administrative Procedure Act.

533. Commission Findings and Order

a. After due consideration of written statements, oral statements, the testimony, and the arguments presented at hearing before the Commission, the Commission will make its findings and written order, based upon evidence in the record and, as appropriate, consistent with the Act and any rule, permit, or order made pursuant thereto.

b. On behalf of the Commission, the Secretary will enter Commission orders within thirty (30) days of the Commission decision, as per §34-60-108(7), C.R.S.

- c. Orders will be final upon Commission approval, and effective for purposes of judicial review on the date of electronic delivery or mailing. Commission approval occurs twenty (20) days after the recommended order is served upon the parties, or when the Commission issues its order.

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

603.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 precautions and requirements are as follows:

(1) An Operator will:

- A. Design drilling fluid in conjunction with operating procedures and surface equipment to prevent the blowout of any Well until the well has been placed into production;
- B. Maintain adequate supplies of drilling fluid of sufficient weight and other acceptable characteristics;
- C. Perform drilling fluid tests as necessary to ensure well control;
- D. Maintain adequate drilling fluid testing equipment on the location at all times;
- E. Monitor wellbore fluid levels to ensure well control at all times, including when running or pulling pipe;
- F. Monitor mud pit levels visually or mechanically during the drilling process; and
- G. Install and operate mud-gas separation equipment as necessary.

(2) The Director will have access to the drilling fluid records related to the fluid's properties used to control the Well (fluid type, density, viscosity, fluid loss control, and other rheological properties),

and will be allowed to request or conduct any essential tests on the drilling fluid used in the drilling or recompletion of a well. The Operator will retain all records for a period of 5 years.

- (3) When the conditions and tests indicate a need for a change in the drilling fluid program in order to ensure control of the Well, the Operator will use due diligence in modifying the program.
- (4) An Operator will maintain well control using blowout preventer systems and/or diverter systems for Wells drilled with air, nitrogen, or foam.
- (5) The Operator will install blowout prevention equipment 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.
- (6) When required, blowout prevention equipment will be in accordance with API Standard 53: "Well Control Equipment Systems for Drilling Wells," 5th Edition (December 2018). Only the 5th Edition of the API Standard applies to this rule; later amendments do not apply. All material incorporated by reference in this rule are 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.
- (7) Drilling after setting the surface casing will not proceed until blowout prevention equipment is tested and found to be serviceable. Low pressure and high pressure tests will be performed. Test pressure, test duration, and test frequency will be in accordance with API Standard 53: "Well Control Equipment Systems for Drilling Wells," 5th Edition (December 2018), except that the minimum low pressure for a low pressure test will be 250 psi. Test pressure loss will 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 will be no unexplainable pressure loss at the end of the test.
- (8) While in service, blowout prevention equipment will be inspected daily and a preventer operating test will be performed on each round trip, but not more than once every 24 hour period. Notation of operating tests will be made on the daily report.
- (9) All pipe fittings, valves and unions placed on or connected with blowout prevention equipment, well casing, wellhead, drill pipe, or tubing will have a working pressure rating suitable for the maximum anticipated surface pressure and will be in good working condition as per generally accepted industry standards. The Operator will equip wellhead assemblies to monitor pressure containing annuli at surface, unless exempted by the Director.
- (10) Blowout prevention equipment will include pipe rams, blind rams, annular preventer, or other equipment that enable closure on the pipe being used. The choke line(s) and kill line(s) will be anchored, tied or otherwise secured to prevent whipping resulting from pressure surges.
- (11) The Operator will inspect and service the wellhead, tree, and related surface control equipment to maintain pressure control throughout the life of the Well.
- (12) The Operator will conduct pressure testing of the casing string in accordance with Rule 317.
- (13) An Operator will complete a formation integrity test (FIT) after drilling out below the surface casing shoe and any intermediate casing shoes for a minimum of 1 Well on each Oil and Gas Location if:
 - A. The fracture gradient of the formation at the casing shoe is unknown; or
 - B. The test is necessary to demonstrate:

- i. The casing shoe integrity is sufficient to contain the anticipated wellbore pressures of the penetrated formations;
 - ii. Flow paths to the formations above the casing shoe do not exist; or
 - iii. The casing shoe is competent to handle an influx of formation fluid or gas.
 - C. An Operator will submit a plan to the Director for approval if a FIT does not demonstrate the requirements as stated by Rule 603.e.(13)B.
 - D. The Operator will perform the FIT before drilling 20 feet or less of new hole, unless otherwise ordered by the Commission.
- (14) 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.
- (15) 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.
- (16) Drilling contractors shall place a sign or marker at the point of intersection of the public road and rig access road.
- (17) 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.
- (18) Each Operator will have a functioning emergency response plan that provides for the effective management of emergency situations that arise from oil and gas operations.
- 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

608.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 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.

608.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 water 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 two or 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 water 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 ratio (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.

608.c. Coal outcrop and coal mine monitoring.

- (1) If the CBM well is within 2 miles of the outcrop of the stratigraphic contact between the coal-bearing formation and the underlying formation, or within 2 miles of an active, inactive, or abandoned coal mine, the Operator will 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 will 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 will submit the results of the outcrop or mine monitoring to the Commission and the Surface Owner within 3 months of its completion of the field work. The analytical data will also be submitted to the Director in an electronic data deliverable format.
- (3) If a gas seep is identified during the survey, the Director will advise the Surface Owner(s), 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 §§ 34-1-103 & 24-65.1-103, C.R.S.

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

If such a water feature is identified, then the Operator will 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 will submit the results of the spring or water seep monitoring to the Commission and the landowner within 3 months of its completion of the field work. The analytical data will also be submitted to the Director in an electronic data deliverable format.

- 608.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.
- 608.e. **Bradenhead Testing.** An Operator of a coalbed methane well will comply with Rule 341, except as modified by this Rule. The appropriate regulatory agency will determine remedial requirements. The bradenhead testing requirement will not apply if the operator demonstrates to the satisfaction of the Director annular cement coverage greater than 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 50 feet above the base of the surface casing, and zonal isolation is confirmed by two consecutive bradenhead tests that the Operator conducts at least 12 months apart. Before beginning a bradenhead test, the Operator will shut-in the bradenhead annulus for a minimum shut-in period of 7 days.
- 608.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 will 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 subsection 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.

FINANCIAL ASSURANCE AND OIL AND GAS CONSERVATION AND ENVIRONMENTAL RESPONSE FUND

701. SCOPE

The rules in this series pertain to the provision of financial assurance by operators to ensure the performance of certain obligations imposed by the Oil and Gas Conservation Act (the Act), §34-60-106 (3.5), (11), (12) and (17) C.R.S., as well as the use of the Oil and Gas Conservation and Environmental Response Fund, §34-60-124 C.R.S., as a mechanism to plug and abandon orphan wells, perform orphaned site reclamation and remediation, and to conduct other authorized environmental activities.

702. General.

Operators are required to provide financial assurance to the Commission to demonstrate that they are capable of fulfilling the obligations imposed by the Act, as described in this series. Except as otherwise specified herein, a surety bond, in a form and from a company acceptable to the Commission, is an approved method of providing financial assurance. Any other method of providing financial assurance identified in §34-60-106(13), C.R.S., shall be submitted to the Commission for approval, and shall be equivalent to the protection provided by a surety bond and may require detailed Commission review on an ongoing basis, including the use of third party consultants, the reasonable expense for which shall be charged to the operator proposing such alternative financial assurance.

- a. When the Director has reasonable cause to believe that the Commission may become burdened with the costs of fulfilling the statutory obligations described herein because an operator has demonstrated a pattern of non-compliance with oil and gas regulations in this or other states, because special geologic, environmental, or operational circumstances exist which make the plugging and abandonment of particular wells more costly, or due to other special and unique circumstances, the Director may petition the Commission for an increase in any individual or blanket financial assurance required in this series.
- b. The requirements of this series do not apply to situations where financial assurance has been provided to federal or Indian agencies for operations regulated solely by such agencies.

703. Surface owner protection.

Operators shall provide financial assurance to the Commission, prior to commencing any operations with heavy equipment, to protect surface owners who are not parties to a lease, surface use or other relevant agreement with the operator from unreasonable crop loss or land damage caused by such operations. The determination that crop loss or land damage is unreasonable shall be made by the Commission after the affected surface owner has filed an application in accordance with the 500 Series rules. Financial assurance for the purpose of surface owner protection shall not be required for operations conducted on state lands when a bond has been filed with the State Board of Land Commissioners.

The financial assurance required by this section shall be in the amount of two thousand dollars (\$2,000) per well for non-irrigated land, or five thousand dollars (\$5,000) per well for irrigated land. In lieu of such individual amounts, operators may submit statewide, blanket financial assurance in the amount of twenty five thousand dollars (\$25,000). Relief granted by the Commission upon application by a surface owner pursuant to this section may include an order requiring the operator to conduct corrective or remedial action, and any monetary award for unreasonable crop loss or land damage that cannot be remediated or corrected is not limited to the amount of the operator's financial assurance hereunder.

704. Centralized E&P waste management facilities.

An operator which makes application for an offsite, centralized E&P waste management facility shall, upon approval and prior to commencing construction, provide to the Commission financial assurance in an amount equal to the estimated cost necessary to ensure the proper reclamation, closure, and abandonment of such facility as set forth in Rule 908.g, or in an amount voluntarily agreed to with the Director, or in an amount to be determined by order of the Commission. Operators of centralized E&P waste management facilities permitted prior to May 1, 2009 on federal land and April 1, 2009 for all other land shall, by July 1, 2009, comply with Rule 908.g and this Rule 704. This section does not apply to underground injection wells and multi-well pits covered under Rules 706 and 707.

705. Seismic operations.

Any operator submitting a Notice of Intent to Conduct Seismic Operations, Form 20, shall, prior to commencing such operations, provide financial assurance to the Commission in the amount of twenty five thousand dollars (\$25,000) statewide blanket financial assurance to ensure the proper plugging and abandonment of any shot holes and any necessary surface reclamation.

706. Soil protection and plugging and abandonment.

Prior to commencing the drilling of a well, an operator shall provide financial assurance to the Commission to ensure the protection of the soil, the proper plugging and abandonment of the well, and the reclamation of the site in accordance with the 300 Series of drilling regulations, the 900 Series of E&P waste management, the 1000 Series of reclamation regulations, and the 1100 Series of flowline regulations.

- a. The financial assurance required by this section shall be in the amount of ten thousand dollars (\$10,000) per well for wells less than three thousand (3,000) feet in total measured depth and twenty thousand dollars (\$20,000) per well for wells greater than or equal to three thousand (3,000) feet in total measured depth.
- b. In lieu of such per-well amount, an operator may submit statewide blanket financial assurance in the amount of sixty thousand dollars (\$60,000) for the drilling and operation of less than one hundred (100) wells, or one hundred thousand dollars (\$100,000) for the drilling and operation of one hundred (100) or more wells.
- c. All oil and gas wells, excluding domestic gas wells, with financial assurance posted prior to May 1, 2009 for federal land and April 1, 2009 for all other land, as well as all new domestic gas wells, must have financial assurances in compliance with this Rule 706 in place on July 1, 2009. Under Rule 502.b.(1), an operator may seek a variance from these financial assurance requirements under appropriate circumstances.

707. Inactive wells

- a. To the extent that an operator's inactive well count exceeds such operator's financial assurance amount divided by ten thousand dollars (\$10,000) for inactive wells less than three thousand (3,000) feet in total measured depth or twenty thousand dollars (\$20,000) for inactive wells greater than or equal to three thousand (3,000) feet in total measured depth, such additional wells shall be considered "excess inactive wells." For each excess inactive well, an operator's required financial assurance amount under Rule 706 shall be increased by ten thousand dollars (\$10,000) for inactive wells less than three thousand (3,000) feet in total measured depth or twenty thousand dollars (\$20,000) for inactive wells greater than or equal to three thousand (3,000) feet in total measured depth. This requirement shall be modified or waived if the Commission approves a plan submitted by

the operator for reducing such additional financial assurance requirement, for returning wells to production in a timely manner, or for plugging and abandoning such wells on an acceptable schedule.

In determining whether such plan is acceptable, the Commission shall take into consideration such factors as: the number of excess inactive wells; the cost to plug and abandon such wells; the proportion of such wells to the total number of wells held by the operator; any business reason the operator may have for shutting-in or temporarily abandoning such wells; the extent to which such wells may cause or have caused a significant adverse environmental impact; the financial condition of the operator; the capability of the operator to manage such plan in an orderly fashion; and the availability of plugging and abandonment services. If an increase in financial assurance is ordered pursuant to this subsection, the operator may, at its option and in compliance with these 700 Series rules, submit new financial assurance or supplement its existing financial assurance.

- b. Operators shall identify and list any shut-in or temporarily abandoned wells on their monthly production/injection report. In addition, when equipment is removed from a well so as to render it temporarily abandoned, operators shall file a Sundry Notice, Form 4, with the Commission within thirty (30) days describing such activity.
- c. Any person, other than the operator, who causes equipment from a well to be removed so as to render it temporarily abandoned shall, prior to conducting such activity, file a notice of intent to remove equipment and receive the approval of the Director. The Director may condition such approval on concurrent plugging and abandonment of the well or on provision of the financial assurance required of operators in this series.

708. General Liability Insurance.

All operators shall maintain general liability insurance coverage for property damage and bodily injury to third parties in the minimum amount of one million dollars (\$1,000,000) per occurrence. Such policies shall include the Commission as a "certificate holder" so that the Commission may receive advance notice of cancellation.

709. Financial assurance.

All financial assurance provided to the Commission pursuant to this Series shall remain in-place until such time as the Director determines an operator has complied with the statutory obligations described herein, or until such time as the Director determines that a successor-in-interest has filed satisfactory replacement financial assurance, at which time the Director shall provide written approval for release of such financial assurance. Whenever an operator fails to fulfill any statutory obligation described herein, and the Commission undertakes to expend funds to remedy the situation, the Director shall make application to the Commission for an order calling or foreclosing the operator's financial assurance.

- a. Operators and third party providers of financial assurance shall be served with a copy of such application pursuant to Rule 503. and shall be accorded an opportunity to be heard thereon. Any third party provider of financial assurance which subsequently fails to comply with a Commission order to make such financial assurance available shall be considered an unacceptable provider of any new financial assurance to operators in Colorado, until such time as it applies for and receives an order of reinstatement. This provision shall be stayed by the filing of a judicial appeal. In addition, the Commission may institute suit to recover such monies.

- b. If an operator's financial assurance is called or foreclosed by the Commission, the called or foreclosed amount shall be deposited in the Oil and Gas Conservation and Environmental Response Fund to be expended by the Director for the purposes referenced in Rule 701., and an overhead recovery fee of ten percent (10%) of the funds expended by the Director as direct costs shall be charged against any excess of the financial assurance over such costs. Any remainder of such financial assurance after such cost recovery shall be returned to its provider. In no circumstances will the liability of a third party provider of financial assurance exceed the face amount of such financial assurance.
- c. If an operator's financial assurance is called or foreclosed by the Commission, such operator's Certificates of Clearance, Form 10, are forthwith suspended and no sales of gas or oil shall be allowed, except as may be allowed by the Commission order, until such time as the operator's financial assurance has been replaced or restored.
- d. The Director shall not approve a new Operator Registration, Form 1, or a new Certificate of Clearance, Form 10, when wells are sold or transferred until the successor operator has filed satisfactory financial assurance under the 700-Series Rules.

710. Reserved.

711. Gas gathering, gas processing and underground gas storage facilities.

Operators of gas gathering, gas processing, or underground gas storage facilities must provide statewide blanket financial assurance to ensure compliance with the 900 Series rules in the amount of fifty thousand dollars (\$50,000), or in an amount voluntarily agreed to with the Director, or in an amount determined by order of the Commission. Operators of small systems gathering or processing less than five (5) MMSCFD per day may provide individual financial assurance in the amount of five thousand dollars (\$5,000).

712. Produced water transfer systems.

Operators of produced water transfer systems must provide statewide blanket financial assurance to ensure compliance with the 900 Series rules in the amount of fifty thousand dollars (\$50,000), or in an amount voluntarily agreed to with the Director, or in an amount determined by order of the Commission. Operators of small systems transferring less than seven hundred (700) barrels of water per day may provide individual financial assurance in the amount of five thousand dollars (\$5,000).

713. Surface facilities and structures appurtenant to Class II Commercial Underground Injection Control wells.

Operators of Class II commercial Underground Injection Control (UIC) wells shall be required to provide financial assurance to ensure compliance with the 900-Series Rules in the amount of fifty-thousand dollars (\$50,000) for each facility, or in an amount voluntarily agreed to with the Director, or in an amount to be determined by order of the Commission. The financial assurance required by this Rule 712 shall apply to the surface facilities and structures appurtenant to the Class II commercial injection well and used prior to the disposal of E&P wastes into such well and shall be in place by July 1, 2009. The financial assurance requirements for the plugging and abandonment of Class II commercial UIC wells are specified in Rule 706.

AESTHETIC AND NOISE CONTROL REGULATIONS

801. INTRODUCTION

The rules and regulations in this section are promulgated to control aesthetics and noise impacts during the drilling, completion and operation of oil and gas wells and production facilities. Any Colorado county, home rule or statutory city, town, territorial charter city or city and county may, by application to the Commission, seek a determination that the rules and regulations in this section, or any individual rule or regulation, shall not apply to oil and gas activities occurring within the boundaries, or any part thereof, of any Colorado county, home rule or statutory city, town, territorial charter city or city and county, such determination to be based upon a showing by any Colorado county, home rule or statutory city, town, territorial charter city or city and county that, because of conditions existing therein, the enforcement of these rules and regulations is not necessary within the boundaries of any Colorado county, home rule or statutory city, town, territorial charter city or city and county for the protection of public health, safety and welfare.

802. NOISE ABATEMENT

- a. The goal of this rule is to identify noise sources related to oil and gas operations that impact surrounding landowners and to implement cost-effective and technically-feasible mitigation measures to bring oil and gas facilities into compliance with the allowable noise levels identified in subsection c. Operators should be aware that noise control is most effectively addressed at the siting and design phase, especially with respect to centralized compression and other downstream “gas facilities” (see definition in the 100 Series of these rules).
- b. Oil and gas operations at any well site, production facility, or gas facility shall comply with the following maximum permissible noise levels.

ZONE	7:00 am to next 7:00 pm	7:00 pm to next 7:00 am
Residential/Agricultural/Rural	55 db(A)	50 db(A)
Commercial	60 db(A)	55 db(A)
Light industrial	70 db(A)	65 db(A)
Industrial	80 db(A)	75 db(A)

The type of land use of the surrounding area shall be determined by the Director in consultation with the Local Governmental Designee taking into consideration any applicable zoning or other local land use designation. In the hours between 7:00 a.m. and the next 7:00 the noise levels permitted above may be increased ten (10) dB(A) for a period not to exceed fifteen (15) minutes in any one (1) hour period. The allowable noise level for periodic, impulsive or shrill noises is reduced by five (5) dB (A) from the levels shown.

- (1) Except as required pursuant to Rule 604.c.(2)A., operations involving pipeline or gas facility installation or maintenance, the use of a drilling rig, completion rig, workover rig, or stimulation is subject to the maximum permissible noise levels for industrial zones.

- (2) In remote locations, where there is no reasonably proximate occupied structure or Designated Outside Activity Area, the light industrial standard may be applicable.
- (3) Pursuant to Commission inspection or upon receiving a complaint from a nearby property owner or local governmental designee regarding noise related to oil and gas operations, the Commission shall conduct an onsite investigation and take sound measurements as prescribed herein.

802.c. The following provide guidance for the measurement of sound levels and assignment of points of compliance for oil and gas operations:

- (1) Sound levels shall be measured at a distance of three hundred and fifty (350) feet from the noise source. At the request of the complainant, the sound level shall also be measured at a point beyond three hundred fifty (350) feet that the complainant believes is more representative of the noise impact. If an oil and gas well site, production facility, or gas facility is installed closer than three hundred fifty (350) feet from an existing occupied structure, sound levels shall be measured at a point twenty-five (25) feet from the structure towards the noise source. Noise levels from oil and gas facilities located on surface property owned, leased, or otherwise controlled by the operator shall be measured at three hundred and fifty (350) feet or at the property line, whichever is greater.

In situations where measurement of noise levels at three hundred and fifty (350) feet is impractical or unrepresentative due to topography, the measurement may be taken at a lesser distance and extrapolated to a 350-foot equivalent using the following formula:

$$db(A)_{DISTANCE\ 2} = db(A)_{DISTANCE\ 1} - 20 \times \log_{10} (distance\ 2/distance\ 1)$$

- (2) Sound level meters shall be equipped with wind screens, and readings shall be taken when the wind velocity at the time and place of measurement is not more than five (5) miles per hour.
- (3) Sound level measurements shall be taken four (4) feet above ground level.
- (4) Sound levels shall be determined by averaging minute-by-minute measurements made over a minimum fifteen (15) minute sample duration if practicable. The sample shall be taken under conditions that are representative of the noise experienced by the complainant (e.g., at night, morning, evening, or during special weather conditions).
- (5) In all sound level measurements, the existing ambient noise level from all other sources in the encompassing environment at the time and place of such sound level measurement shall be considered to determine the contribution to the sound level by the oil and gas operation(s).

802.d. In situations where the complaint or Commission onsite inspection indicates that low frequency noise is a component of the problem, the Commission shall obtain a sound level measurement twenty-five (25) feet from the exterior wall of the residence or occupied structure nearest to the noise source, using a noise meter calibrated to the db(C) scale. If this reading exceeds 65 db(C), the Commission shall require the operator to obtain a low frequency noise impact analysis by a qualified sound expert, including identification of any reasonable

control measures available to mitigate such low frequency noise impact. Such study shall be provided to the Commission for consideration and possible action.

802.e. Exhaust from all engines, motors, coolers and other mechanized equipment shall be vented in a direction away from all Building Units.

802.f. All Oil and Gas Facilities with engines or motors which are not electrically operated that are within four hundred (400) feet of Building Units shall be equipped with quiet design mufflers or equivalent. All mufflers shall be properly installed and maintained in proper working order.

803. LIGHTING

To the extent practicable, site lighting shall be directed downward and inward and shielded so as to avoid glare on public roads and Building Units within one thousand (1000) feet.

804. VISUAL IMPACT MITIGATION

Production facilities, regardless of construction date, which are observable from any public highway shall be painted with uniform, non-contrasting, non-reflective color tones (similar to the Munsell Soil Color Coding System), and with colors matched to but slightly darker than the surrounding landscape.

805. ODORS AND DUST

a. **General.** Oil and gas facilities and equipment shall be operated in such a manner that odors and dust do not constitute a nuisance or hazard to public welfare.

b. **Odors.**

(1) Compliance.

A. Oil and gas operations shall be in compliance with the Department of Public Health and Environment, Air Quality Control Commission, Regulation No. 2 Odor Emission, 5 C.C.R. 1001-4, Regulation No. 3 (5 C.C.R. 1001-5), and Regulation No. 7 Section XVII.B.1 (a-c) and Section XII.

B. No violation of Rule 805.b.(1) shall be cited by the Commission, provided that the practices identified in Rule 805.b.(2) are used.

(2) Production Equipment and Operations.

A. **Crude Oil, Condensate, and Produced Water Tanks.** All crude oil, condensate, and produced water tanks with uncontrolled actual emissions of volatile organic compounds (VOC) of five (5) tons per year (tpy) or greater, located within 1,320 feet of a Building Unit, or a Designated Outside Activity Area shall use an emission control device capable of achieving 95% control efficiency of VOC and shall obtain a permit as required by Colorado Department of Public Health and Environment, Air Pollution Control Commission Regulation as set forth in 805. b. (1).

- B. **Glycol Dehydrators.** All glycol dehydrators with uncontrolled actual emissions of VOC of five (5) tpy or greater, located within 1,320 feet of a Building Unit , or a Designated Outside Activity Area shall use an emission control device capable of achieving 90% control efficiency of VOC and shall obtain a permit as required by Colorado Department of Public Health and Environment, Air Pollution Control Commission Regulation as set forth in 805.b.(1).

- C. **Pits.** Pits with uncontrolled actual emissions of VOC of five (5) tpy or greater shall not be located within 1,320 feet of a Building Unit, or a Designated Outside Activity Area. For the purposes of this section, compliance with Rule 902.c is required. Operators may provide site-specific data and analyses to COGCC staff establishing that pits potentially subject to this subsection do not have a potential to emit VOC of five (5) tpy or greater.

- D. **Pneumatic Devices.** Low- or no-bleed pneumatic devices must be used when existing pneumatic devices are replaced or repaired, and when new pneumatic devices are installed.

(3) **Well completions.**

- A. Green completion practices are required on oil and gas wells where reservoir pressure, formation productivity, and wellbore conditions are likely to enable the well to be capable of naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD to the surface against an induced surface backpressure of five hundred (500) psig or sales line pressure, whichever is greater. Green completion practices are not required for exploratory wells, where the wells are not sufficiently proximate to sales lines, or where green completion practices are otherwise not technically and economically feasible.

- B. Green completion practices shall include, but not be limited to, the following emission reduction measures:
 - i. The operator shall employ sand traps, surge vessels, separators, and tanks as soon as practicable during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment.

 - ii. Well effluent during flowback and cleanout operations prior to encountering hydrocarbon gas of salable quality or significant volumes of condensate may be directed to tanks or pits (where permitted) such that oil or condensate volumes shall not be allowed to accumulate in excess of twenty (20) barrels and must be removed within twenty-four (24) hours. The gaseous phase of non-flammable effluent may be directed to a flare pit or vented from tanks for safety purposes until flammable gas is encountered.

 - iii. Well effluent containing more than ten (10) barrels per day of condensate or within two (2) hours after first encountering hydrocarbon gas of salable quality shall be directed to a

combination of sand traps, separators, surge vessels, and tanks or other equipment as needed to ensure safe separation of sand, hydrocarbon liquids, water, and gas and to ensure salable products are efficiently recovered for sale or conserved and that non-salable products are disposed of in a safe and environmentally responsible manner.

- iv. If it is safe and technically feasible, closed-top tanks shall utilize backpressure systems that exert a minimum of four (4) ounces of backpressure and a maximum that does not exceed the pressure rating of the tank to facilitate gathering and combustion of tank vapors. Vent/backpressure values, the combustor, lines to the combustor, and knock-outs shall be sized and maintained so as to safely accommodate any surges the system may encounter.
- v. All salable quality gas shall be directed to the sales line as soon as practicable or shut in and conserved. Temporary flaring or venting shall be permitted as a safety measure during upset conditions and in accordance with all other applicable laws, rules, and regulations.

C. An operator may request a variance from the Director if it believes that using green completion practices is infeasible due to well or field conditions, or would endanger the safety of wellsite personnel or the public.

D. In instances where green completion practices are not technically feasible, operators shall employ Best Management Practices (BMPs) to reduce emissions. Such BMPs shall consider safety and shall include measures or actions to minimize the time period during which gases are emitted directly to the atmosphere, and monitoring and recording the volume and time period of such emissions.

805.c. **Fugitive dust.** Operators shall employ practices for control of fugitive dust caused by their operations. Such practices shall include but are not limited to the use of speed restrictions, regular road maintenance, restriction of construction activity during high-wind days, and silica dust controls when handling sand used in hydraulic fracturing operations. Additional management practices such as road surfacing, wind breaks and barriers, or automation of wells to reduce truck traffic may also be required if technologically feasible and economically reasonable to minimize fugitive dust emissions.

E&P WASTE MANAGEMENT

901. INTRODUCTION

- a. **General.** The rules and regulations of this series establish the permitting, construction, operating and closure requirements for pits, methods of E&P waste management, procedures for spill/release response and reporting, and sampling and analysis for remediation activities. The 900 Series rules are applicable only to E&P waste, as defined in § 34-60-103(4.5), C.R.S., or other solid waste where the Colorado Department Of Public Health And Environment has allowed remediation and oversight by the Commission.
- b. **COGCC reporting forms.** The reporting required by the rules and regulations of this series shall be made on forms provided by the Director. Alternate forms may be used where equivalent information is supplied and the format has been approved by the Director.
- c. **Additional requirements.** Whenever the Director has reasonable cause to believe that an operator, in the conduct of any oil or gas operation, is performing any act or practice which threatens to cause or causes a violation of Table 910-1 and with consideration of water quality standards or classifications established by the Water Quality Control Commission ("WQCC") for waters of the state, the Director may impose additional requirements, including but not limited to, sensitive area determination, sampling and analysis, remediation, monitoring, permitting and the establishment of points of compliance. Any action taken pursuant to this Rule shall comply with the provisions of Rules 324A. through D. and the 500 Series rules.
- d. **Alternative compliance methods.** Operators may propose for prior approval by the Director alternative methods for determining the extent of contamination, sampling and analysis, or alternative cleanup goals using points of compliance.
- e. **Sensitive area determination.** When the operator or Director has data that indicate an impact or threat of impact to ground water or surface water, the Director may require the operator to make a sensitive area determination and that determination shall be subject to the Director's approval. The sensitive area determination shall be made using appropriate geologic and hydrogeologic data to evaluate the potential for impact to ground water and surface water, such as soil borings, monitoring wells, or percolation tests that demonstrate that seepage will not reach underlying ground water or waters of the State and impact current or future uses of these waters. Operators shall submit data evaluated and analysis used in the determination to the Director.
- f. **Sensitive area operations.** Operations in sensitive areas shall incorporate adequate measures and controls to prevent significant adverse environmental impacts and ensure compliance with the concentration levels in Table 910-1, with consideration to WQCC standards and classifications.

902. PITS - GENERAL AND SPECIAL RULES

- a. Pits used for exploration and production of oil and gas shall be constructed and operated to protect public health, safety, and welfare and the environment, including soil, waters of the state, and wildlife, from significant adverse environmental, public health, or welfare impacts from E&P waste, except as permitted by applicable laws and regulations.
- b. Pits shall be constructed, monitored, and operated to provide for a minimum of two (2) feet of freeboard at all times between the top of the pit wall at its point of lowest elevation and the fluid level of the pit. A method of monitoring and maintaining freeboard shall be employed.

Any unauthorized release of fluids from a pit shall be subject to the reporting requirements of Rule 906.

- c. Any accumulation of oil or condensate in a pit shall be removed within twenty-four (24) hours of discovery. Operators shall use skimming, steam cleaning of exposed liners, or other safe and legal methods as necessary to maintain pits in clean condition and to control hydrocarbon odors. Only de minimis amounts of hydrocarbons may be present unless the pit is specifically permitted for oil or condensate recovery or disposal use. A Form 15, Earthen Pit Report/Permit, may be revoked by the Director and the Director may require that the pit be closed if an operator repeatedly allows more than de minimis amounts of oil or condensate to accumulate in a pit. This requirement is not applicable to properly permitted and properly fenced, lined, and netted skim pits that are designed, constructed, and operated to prevent impacts to wildlife, including migratory birds.
- d. Where necessary to protect public health, safety and welfare or to prevent significant adverse environmental impacts resulting from access to a pit by wildlife, migratory birds, domestic animals, or members of the general public, operators shall install appropriate netting or fencing.
- e. Pits used for a period of no more than three (3) years, or more than three (3) years if the Director has issued a variance, for storage, recycling, reuse, treatment, or disposal of E&P waste or fresh water, as applicable, may be permitted in accordance with Rule 903 to service multiple wells, subject to Director approval.
- f. Unlined pits shall not be constructed on fill material.
- g. Except as allowed under Rule 904.a, unlined pits shall not be constructed in areas where pathways for communication with ground water or surface water are likely to exist.
- h. Produced water shall be treated in accordance with Rule 907 before being placed in a production pit.
- i. Operators shall utilize appropriate biocide treatments to control bacterial growth and related odors as needed.

903. PIT PERMITTING/REPORTING REQUIREMENTS

- a. An Earthen Pit Report/Permit, Form 15, shall be submitted to the Director for prior approval for the following pits:
 - (1) All production pits.
 - (2) Special purpose pits except those reported under Rule 903.b.(1) or Rule 903.b.(2).
 - (3) Drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 10,000 ppm TPH or chloride concentrations at total well depth exceeding 15,000 ppm.
 - (4) Multi-well pits containing produced water, drilling fluids, or completion fluids that will be recycled or reused, except where reuse consists only of moving drilling fluids from one (1) oil and gas location to another such location for reuse there.
- b. An Earthen Pit Report/Permit, Form 15, shall be submitted within thirty (30) calendar days after construction for the following:

- (1) Special purpose pits used in the initial phase of emergency response.
 - (2) Flare pits where there is no risk of condensate accumulation.
- c. An Earthen Pit Report/Permit, Form 15, shall not be required for drilling pits using water-based bentonitic drilling fluids with concentrations of TPH and chloride below those referenced in Rule 903.a.(3).
 - d. An Earthen Pit Report/Permit, Form 15, shall be completed in accordance with the instructions in Appendix I. Failure to complete the form in full may result in delay of approval or return of form.
 - e. The Director shall endeavor to review any properly completed Earthen Pit Report/Permit, Form 15, within thirty (30) calendar days after receipt. In order to allow adequate time for pit permit review and approval, operators shall submit an Earthen Pit Report/Permit, Form 15, at the same time as the Application for Permit-to-Drill, Form 2, is submitted. The Director may condition permit approval upon compliance with additional terms, provisions, or requirements necessary to protect the waters of the state, public health, or the environment.

904. PIT LINING REQUIREMENTS AND SPECIFICATIONS

- a. Pits that were constructed before May 1, 2009 on federal land, or before April 1, 2009 on other land, shall comply with their permit conditions and the rules in effect at the time of their construction. The following pits shall be lined if they are constructed on or after May 1, 2009 on federal land, or on or after April 1, 2009 on other land:
 - (1) Drilling pits designed for use with fluids containing hydrocarbon concentrations exceeding 10,000 ppm TPH or chloride concentrations at total well depth exceeding 15,000 ppm.
 - (2) Production pits, other than skim pits, unless the operator demonstrates to the Director's satisfaction that the quality of the produced water is equivalent to or better than that of the underlying groundwater or the operator can clearly demonstrate by substantial evidence, such as by appropriate percolation tests, that seepage will not reach the underlying aquifer or waters of the state at contamination levels in excess of applicable standards. Subject to Rule 901.c, this requirement shall not apply to such pits in Huerfano or Las Animas Counties constructed before May 1, 2011, or to such pits in Washington, Yuma, Logan, or Morgan counties constructed before May 1, 2013.
 - (3) Special purpose pits, except emergency pits constructed during initial emergency response to spills/releases, or flare pits where there is no risk of condensate accumulation.
 - (4) Skim pits.
 - (5) Multi-well pits used to contain produced water, drilling fluids, or completion fluids that will be recycled or reused, except where reuse consists only of moving drilling fluids from one oil and gas location to another such location for reuse there. Subject to Rule 901.c, this requirement shall not apply to multi-well pits used to contain produced water in Huerfano or Las Animas Counties constructed before May 1, 2011, or to multi-well pits used to

contain produced water in Washington, Yuma, Logan, or Morgan counties constructed before May 1, 2013.

(6) Pits at centralized E&P waste management facilities and UIC facilities.

b. The following specifications shall apply to all pits that are required to be lined by rule or by permit condition:

(1) Materials used in lining pits shall be of a synthetic material that is impervious, has high puncture and tear strength, has adequate elongation, and is resistant to deterioration by ultraviolet light, weathering, hydrocarbons, aqueous acids, alkali, fungi or other substances in the produced water.

(2) All pit lining systems shall be designed, constructed, installed, and maintained in accordance with the manufacturers' specifications and good engineering practices.

(3) Field seams must be installed and tested in accordance with manufacturer specifications and good engineering practices. Testing results must be maintained by the operator and provided to the Director upon request.

c. The following specifications shall also apply to pits that are required to be lined, except those at centralized E&P waste management facilities, unless an oil and gas operator demonstrates to the satisfaction of the Director that a liner system offering equivalent protection to public health, safety, and welfare, including the environment and wildlife resources, will be used:

(1) Liners shall have a minimum thickness of twenty-four (24) mils. The synthetic or fabricated liner shall cover the bottom and interior sides of the pit with the edges secured with at least a twelve (12) inch deep anchor trench around the pit perimeter. The anchor trench shall be designed to secure, and prevent slippage or destruction of, the liner materials.

(2) The foundation for the liner shall be constructed with soil having a minimum thickness of twelve (12) inches after compaction covering the entire bottom and interior sides of the pit, and shall be constructed so that the hydraulic conductivity shall not exceed 1.0×10^{-7} cm/sec after testing and compaction. Compaction and permeability test results measured in the laboratory and field must be maintained by the operator and provided to the Director upon request.

(3) As an alternative to the soil foundation described in Rule 904.c.(2), the foundation may be constructed with bedding material that exceeds a hydraulic conductivity of 1.0×10^{-7} cm/sec, if a double synthetic liner system is used; however, the bottom and sides of the pit shall be padded with soil or synthetic matting type material and shall be free of sharp rocks or other material that are capable of puncturing the liner. Each synthetic liner shall have a minimum thickness of twenty-four (24) mils.

d. The following specifications shall also apply to pits used at centralized E&P waste management facilities, unless an oil and gas operator demonstrates to the satisfaction of the Director that a liner system offering equivalent protection to public health, safety, and welfare, including the environment and wildlife resources, will be used:

(1) Liners shall have a minimum thickness of sixty (60) mils. The synthetic or fabricated liner shall cover the bottom and interior sides of the pit with the edges secured with at least a twelve (12) inch deep anchor trench around the pit perimeter. The anchor

trench shall be designed to secure, and prevent slippage or destruction of, the liner materials.

- (2) The foundation for the liner shall be constructed with soil having a minimum thickness of twenty-four (24) inches after compaction covering the entire bottom and interior sides of the pit, and shall be constructed so that the hydraulic conductivity shall not exceed 1.0×10^{-7} cm/sec after testing and compaction. Compaction and permeability test results measured in the laboratory and field must be maintained by the operator and provided to the Director upon request.
 - (3) As an alternative to the soil foundation described in Rule 904.d.(2), a secondary liner consisting of a geosynthetic clay liner, which is a manufactured hydraulic barrier typically consisting of bentonite clay or other very low permeability material, supported by geotextiles or geomembranes, which are held together by needling, stitching, or chemical adhesives, may be used.
- e. In Sensitive Areas, the Director may require a leak detection system for the pit or other equivalent protective measures, including but not limited to, increased record-keeping requirements, monitoring systems, and underlying gravel fill sumps and lateral systems. In making such determination, the Director shall consider the surface and subsurface geology, the use and quality of potentially-affected ground water, the quality of the produced water, the hydraulic conductivity of the surrounding soils, the depth to ground water, the distance to surface water and water wells, and the type of liner.

905. CLOSURE OF PITS, AND BURIED OR PARTIALLY BURIED PRODUCED WATER VESSELS.

- a. Drilling pits shall be closed in accordance with the 1000-Series Rules.
- b. Pits not used exclusively for drilling operations, buried or partially buried produced water vessels, and emergency pits shall be closed in accordance with an approved Site Investigation and Remediation Workplan, Form 27. The workplan shall be submitted for prior Director approval and shall include a description of the proposed investigation and remediation activities in accordance with Rule 909. Emergency pits shall be closed and remediated as soon as the initial phase of emergency response operations are complete or process upset conditions are controlled.
 - (1) Operators shall ensure that soils and ground water meet the concentration levels of Table 910-1.
 - (2) **Pit evacuation.** Prior to backfilling and site reclamation, E&P waste shall be treated or disposed in accordance with Rule 907.
 - (3) Liners shall be disposed as follows:
 - A. **Synthetic liner disposal.** Liner material shall be removed and disposed in accordance with applicable legal requirements for solid waste disposal.
 - B. **Constructed soil liners.** Constructed soil liner material may be removed for treatment or disposal, or, where left in place, the material shall be ripped and mixed with native soils in a manner to alleviate compaction and prevent an impermeable barrier to infiltration and ground water flow and shall meet soil standards listed in Table 910-1.

- (4) Soil beneath the low point of the pit must be sampled to verify no leakage of the managed fluids. Soil left in place shall meet the standards listed in Table 910-1.
- c. **Discovery of a spill/release during closure.** When a spill/release is discovered during closure operations, operators shall report the spill/release on the Spill/Release Report, Form 19, in accordance with Rule 906. Leaking pits and buried or partially buried produced water vessels shall be closed and remediated in accordance with Rules 909. and 910.
- d. **Unlined drilling pits.** Unlined drilling pits shall be closed and reclaimed in accordance with the 1000 Series rules and operators shall ensure that soils and ground water meet the concentration levels in Table 910-1.

906. SPILLS AND RELEASES

- a. **General.** Operators shall, immediately upon discovery, control and contain all spills/releases of E&P waste, gas, or produced fluids to protect the environment, public health, safety, and welfare, and wildlife resources. Operators shall investigate, clean up, and document impacts resulting from spills/releases as soon as practicable. The Director may require additional activities to prevent or mitigate threatened or actual significant adverse environmental impacts on any air, water, soil or biological resource, or to the extent necessary to ensure compliance with the concentration levels in Table 910-1, with consideration to WQCC ground water standards and classifications.
- b. **Reporting spills or releases of E&P Waste, gas, or produced fluids.**
 - (1) Report to the Director. Operators shall report a spill or release of E&P Waste, gas, or produced fluids that meet any of the following criteria to the Director verbally or in writing as soon as practicable, but no more than twenty-four (24) hours after discovery for A.-C., below, or no more than six (6) hours after discovery for D., below (the "Initial Report").
 - A. A spills/release of any size that impacts or threatens to impact any waters of the state, a residence or occupied structure, livestock, or public byway;
 - B. A spill/release in which one (1) barrel or more of E&P Waste or produced fluids is spilled or released outside of berms or other secondary containment;
 - C. A spill/release of five (5) barrels or more regardless of whether the spill/release is completely contained within berms or other secondary containment; or
 - D. A Grade 1 Gas Leak. For a Grade 1 Gas Leak from a flowline, the operator also must submit the COGCC Spill/Release Report, Form 19, document number on a Flowline Report, Form 44 for the Grade 1 Gas Leak.
 - (2) The Initial Report to the Director shall include, at a minimum,
 - A. The location of the spill/release;
 - B. Documentation that the operator provided additional party notifications as required by (6)-(9);
 - C. A description of any threat to waters of the state, residences or occupied structures, livestock, air quality, or public byway from the spill/release; and
 - D. Any information available to the Operator about the type and volume of fluid or

waste involved, including whether it is controlled or uncontrolled at the time of submitting the Initial Report.

- (3) If the Initial Report was not made by submitting a COGCC Spill/Release Report, Form 19 the Operator must submit a Form 19 with the Initial Report information as soon as practicable but not later than 72 hours after discovery of the spill/release unless extended by the Director.
 - (4) In addition to the Initial Report to the Director, the Operator shall make a supplemental report on Form 19 not more than 10 calendar days after the spill/release is discovered that includes an 8 1/2 x 11 inch topographic map showing the governmental section and location of the spill or an aerial photograph showing the location of the spill; all pertinent information about the spill/release known to the Operator that has not been reported previously; and information relating to the initial mitigation, site investigation, and remediation measures conducted by the Operator.
 - (5) The Director may require further supplemental reports or additional information.
 - (6) Notification to the local government. In addition to the Initial Report to the Director, as soon as practicable, but not more than 24 hours after discovery of a spill/release of E & P Waste, gas, or produced fluids reportable under Rule 906.b.(1)A or B, above, an Operator shall provide verbal or written notification to the entity with jurisdiction over emergency response within the local municipality if the spill/release occurred within a municipality or the local county if the spill/release did not occur within a municipality. The notification shall include, at a minimum, the information provided in the Initial Report to the Director.
 - (7) Notification to the Surface Owner. In addition to the Initial Report to the Director, within 24 hours after discovery of a spill/release of E & P Waste, gas, or produced fluids reportable under Rule 906.b.(1)A or B, an Operator shall provide verbal notification to the affected Surface Owner or the Surface Owner's appointed tenant. If the Surface Owner cannot be reached within 24 hours, the Operator shall continue good faith efforts to notify the Surface Owner until notice has been provided. The verbal notification shall include, at a minimum, the information provided in the Initial Report to the Director.
 - (8) Report to Environmental Release/Incident Report Hotline. A spill/release of any size which impact or threaten to impact any surface water supply area shall be reported to the Director and to the Environmental Release/Incident Report Hotline (1-877-518-5608). Spills and releases that impact or threaten a surface water intake shall be verbally reported to the emergency contact for that facility immediately after discovery.
 - (9) Reporting chemical spills or releases. Chemical spills and releases shall be reported in accordance with applicable state and federal laws, including the Emergency Planning and Community Right-to-Know Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Oil Pollution Act, and the Clean Water Act, as applicable.
- c. **Remediation of spills/releases.** When threatened or actual significant adverse environmental impacts on any air, water, soil or other environmental resource from a spill/release exist or when necessary to ensure compliance with the concentration levels in Table 910-1 with consideration to WQCC ground water standards and classifications, the Director may require operators to submit a Site Investigation and Remediation Workplan, Form 27.
- (1) Such spills/releases shall be remediated in accordance with Rules 909 and 910.

- (2) The operator shall make good faith efforts to notify and consult with the affected Surface Owner, or the Surface Owner's appointed tenant, prior to commencing operations to remediate E&P waste from a spill/release in an area not being utilized for oil and gas operations. Such efforts shall not unreasonably delay commencement of remediation approved by the Director.

d. Spill/release prevention.

- (1) **Secondary containment.** Secondary containment structures shall be sufficiently impervious to contain discharged material. Secondary containment that was constructed before May 1, 2009 on federal land, or before April 1, 2009 on other land, shall comply with the rules in effect at the time of construction. Secondary containment constructed on or after May 1, 2009 on federal land, or on or after April 1, 2009 on other land shall be constructed or installed around all tanks containing oil, condensate, or produced water with greater than 3,500 milligrams per liter (mg/l) total dissolved solids (TDS) and shall be sufficient to contain the contents of the largest single tank and sufficient freeboard to contain precipitation. Operators are also subject to tank and containment requirements under Rules 603. and 604. This requirement shall not apply to water tanks with a capacity of fifty (50) barrels or less.
- (2) **Spill/release evaluation.** Operators shall determine and document the cause of a spill/release of E & P Waste or produced fluids and, to the extent practicable, identify and timely implement measures to prevent spills/releases due to similar causes in the future.

907. MANAGEMENT OF E&P WASTE

a. General requirements.

- (1) **Operator obligations.** Operators shall ensure that E&P waste is properly stored, handled, transported, treated, recycled, or disposed to prevent threatened or actual significant adverse environmental impacts to air, water, soil or biological resources or to the extent necessary to ensure compliance with the concentration levels in Table 910-1, with consideration to WQCC ground water standards and classifications.
- (2) E&P waste management activities shall be conducted, and facilities constructed and operated, to protect the waters of the state from significant adverse environmental impacts from E&P waste, except as permitted by applicable laws and regulations.
- (3) **Reuse and recycling.** To encourage and promote waste minimization, operators may propose plans for managing E&P waste through beneficial use, reuse, and recycling by submitting a written management plan to the Director for approval on a Sundry Notice, Form 4, if applicable. Such plans shall describe, at a minimum, the type(s) of waste, the proposed use of the waste, method of waste treatment, product quality assurance, and shall include a copy of any certification or authorization that may be required by other laws and regulations. The Director may require additional information.

b. Waste transportation.

- (1) E&P waste, when transported off-site within Colorado for treatment or disposal, shall be transported to facilities authorized by the Director or waste disposal facilities approved to receive E&P waste by the Colorado Department of Public Health and

Environment. When transported to facilities outside of Colorado for treatment or disposal, E&P waste shall be transported to facilities authorized and permitted by the appropriate regulatory agency in the receiving state.

(2) **Waste generator requirements.** Generators of E&P waste that is transported off-site shall maintain, for not less than five (5) years, copies of each invoice, bill, or ticket and such other records as necessary to document the following requirements A through F:

- A. The date of the transport;
- B. The identity of the waste generator;
- C. The identity of the waste transporter;
- D. The location of the waste pickup site;
- E. The type and volume of waste; and
- F. The name and location of the treatment or disposal site.

Such records shall be signed by the transporter, made available for inspection by the Director during normal business hours, and copies thereof shall be furnished to the Director upon request.

c. Produced water.

(1) **Treatment of produced water.** Produced water shall be treated prior to placement in a production pit to prevent crude oil and condensate from entering the pit.

(2) **Produced water disposal.** Produced water may be disposed as follows:

- A. Injection into a Class II well, permitted in accordance with Rule 325.;
- B. Evaporation/percolation in a properly permitted pit;
- C. Disposal at permitted commercial facilities;
- D. Disposal by roadspreading on lease roads outside sensitive areas for produced waters with less than 3,500 mg/l TDS when authorized by the surface owner and in accordance with an approved waste management plan per Rule 907.a.(3). Roadspreading of produced waters shall not impact waters of the state, shall not result in pooling or runoff, and the adjacent soils shall meet the concentration levels in Table 910-1. Flowback fluids shall not be used for dust suppression.
- E. Discharging into state waters, in accordance with the Water Quality Control Act and the rules and regulations promulgated thereunder.
 - i. Operators shall provide the Colorado discharge permit number, latitude and longitude coordinates, in accordance with Rule 215.f, of the discharge outfall, and sources of produced water on a Source of Produced Water for Disposal, Form 26, and shall include a U.S.G.S. topographic map showing the location of the discharge outfall.

- ii. Produced water discharged pursuant to this subsection (2).E. may be put to beneficial use in accordance with applicable state statutes and regulations governing the use and administration of water.

F. Evaporation in a properly lined pit at a centralized E&P waste management facility permitted in accordance with Rule 908.

- (3) **Produced water reuse and recycling.** Produced water may be reused for enhanced recovery, drilling, and other approved uses in a manner consistent with existing water rights and in consideration of water quality standards and classifications established by the WQCC for waters of the state, or any point of compliance established by the Director pursuant to Rule 324D.
- (4) **Mitigation.** Water produced during operation of an oil or gas well may be used to provide an alternative domestic water supply to surface owners within the oil or gas field, in accordance with all applicable laws, including, but not limited to, obtaining the necessary approvals from the WQCD for constructing a new “waterworks,” as defined by Section 25-1-107(1)(X)(II)(A), C.R.S. Any produced water not so used shall be disposed of in accordance with subsection (2) or (3). Providing produced water for domestic use within the meaning of this subsection (4) shall not constitute an admission by the operator that the well is dewatering or impacting any existing water well. The water produced shall be to the benefit of the surface owner within the oil and gas field and may not be sold for profit or traded.

d. Drilling fluids.

- (1) **Recycling and reuse.** Drilling pit contents may be recycled to another drilling pit for reuse consistent with Rule 903.
- (2) **Treatment and disposal.** Drilling fluids may be treated or disposed as follows:
 - A. Injection into a Class II well permitted in accordance with Rule 325;
 - B. Disposal at a commercial solid waste disposal facility; or
 - C. Land treatment or land application at a centralized E&P waste management facility permitted in accordance with Rule 908.
- (3) **Additional authorized disposal of water-based bentonitic drilling fluids.** Water-based bentonitic drilling fluids may be disposed as follows:
 - A. Drying and burial in pits on non-crop land. The resulting concentrations shall not exceed the concentration levels in Table 910-1, below; or
 - B. Land application as follows:
 - i. **Applicability.** Acceptable methods of land application include, but are not limited to, production facility construction and maintenance, and lease road maintenance.
 - ii. **Land application requirements.** The average thickness of water-based bentonitic drilling fluid waste applied shall be no more than three (3) inches prior to incorporation. The waste shall be applied to prevent ponding or erosion and shall be incorporated as a beneficial amendment into the native soils within ten (10) days of

application. The resulting concentrations shall not exceed those in Table 910-1.

- iii. **Surface owner approval.** Operators shall obtain written authorization from the surface owner prior to land application of water-based bentonitic drilling fluids.
 - iv. **Operator obligations.** Operators shall maintain a record of the source, the volume, and the location where the land application of the water-based bentonitic drilling fluid occurred. Upon the Director's written request, this information shall be provided within five (5) business days, in a format readily reviewable by the Director. Operators with control and authority over the wells from which the water-based bentonitic drilling fluid wastes are obtained retain responsibility for the land application operation, and shall diligently cooperate with the Director in responding to complaints regarding land application of water-based bentonitic drilling fluids.
 - v. **Approval.** Prior Director approval is not required for reuse of water-based bentonitic drilling fluids for land application as a soil amendment.
- e. **Oily waste.** Oily waste includes those materials containing crude oil, condensate or other E&P waste, such as soil, frac sand, drilling fluids, and pit sludge that contain hydrocarbons.
- (1) Oily waste may be treated or disposed as follows:
 - A. Disposal at a commercial solid waste disposal facility;
 - B. Land treatment onsite; or
 - C. Land treatment at a centralized E&P waste management facility permitted in accordance with Rule 908.
 - (2) Land treatment requirements:
 - A. In the case of a reportable spill, Operators shall submit a Site Investigation and Remediation Workplan, Form 27, for prior approval by the Director. Treatment shall thereafter be completed in accordance with the workplan and Rules 909. and 910.
 - B. Free oil shall be removed from the oily waste prior to land treatment.
 - C. Oily waste shall be spread evenly to prevent pooling, ponding, or runoff.
 - D. Contamination of stormwater runoff, ground water, or surface water shall be prevented.
 - E. Biodegradation shall be enhanced by disking, tilling, aerating, or addition of nutrients, microbes, water or other amendments, as appropriate.
 - F. Land-treated oily waste incorporated in place or beneficially reused shall not exceed the concentrations in Table 910-1.

- G. When land treatment occurs in an area not being utilized for oil and gas operations, operators shall obtain prior written surface owner approval. When land treatment occurs on an approved Oil and Gas Location prior to completion of interim reclamation or on the surface disturbance remaining after interim reclamation, notice shall be provided to the surface owner.
 - H. Land treatment shall be conducted in a manner that does not preclude compliance with reclamation rules 1003 and 1004.
- f. **Other E&P Waste.** Other E&P waste such as workover fluids, tank bottoms, pigging wastes from pipelines, and gas gathering, processing, and storage wastes may be treated or disposed of as follows:
- (1) Disposal at a commercial solid waste disposal facility;
 - (2) Treatment at a centralized E&P waste management facility permitted in accordance with Rule 908;
 - (3) Injection into a Class II injection well permitted in accordance with Rule 325; or
 - (4) An alternative method proposed in a waste management plan in accordance with rule 907.a.(3) and approved by the Director.

907A. MANAGEMENT OF NON-E&P WASTE

- a. Certain wastes generated by oil and gas-related activities are non-E&P wastes and are not exempt from regulation as solid or hazardous wastes. These wastes need to be properly identified and disposed of in accordance with state and federal regulations.
- b. Certain wastes generated by oil and gas-related activities can either be E&P wastes or non-E&P wastes depending on the circumstances of their generation.
- c. The hazardous waste regulations require that a hazardous waste determination be made for any non-E&P solid waste. Hazardous wastes require storage, treatment, and disposal practices in accordance with 6 C.C.R. 1007-3. All non-hazardous/non-E&P wastes are considered solid waste which require storage, treatment, and disposal in accordance with 6 C.C.R. 1007-2.

908. CENTRALIZED E&P WASTE MANAGEMENT FACILITIES

- a. **Applicability.** Operators may establish non-commercial, centralized E&P waste management facilities for the treatment, disposal, recycling or beneficial reuse of E&P waste. This rule applies only to non-commercial facilities, which means the operator does not represent itself as providing E&P waste management services to third parties, except as part of a unitized area or joint operating agreement or in response to an emergency. Centralized facilities may include components such as land treatment or land application sites, pits, and recycling equipment.
- b. **Permit requirements.** Before any person shall commence construction of a centralized E&P waste management facility, such person shall file with the Director an application on Form 28 and pay a filing and service fee established by the Commission (see Appendix III), and obtain the Director's approval. The application shall contain the following:
 - (1) The name, address, phone and fax number of the operator, and a designated contact person.

- (2) The name, address, and phone number of the surface owner of the site, if not the operator, and the written authorization of such surface owner.
- (3) The legal description of the site.
- (4) A general topographic, geologic, and hydrologic description of the site, including immediately adjacent land uses, a topographic map of a scale no less than 1:24,000 showing the location, and the average annual precipitation and evaporation rates at the site.

(5) Centralized facility siting requirements.

- A. A site plan showing drainage patterns and any diversion or containment structures, and facilities such as roads, fencing, tanks, pits, buildings, and other construction details.
 - B. Scaled drawings of entire sections containing the proposed facility. The field measured distances from the nearer north or south and nearer east or west section lines shall be measured at ninety (90) degrees from said section lines to facility boundaries and referenced on the drawing. A survey shall be provided including a complete description of established monuments or collateral evidence found and all aliquot corners.
 - C. The facility shall be designed to control public access, prevent unauthorized vehicular traffic, provide for site security both during and after operating hours, and prevent illegal dumping of wastes. Appropriate measures shall also be implemented to prevent access to the centralized facility by wildlife or domestic animals.
 - D. Centralized facilities shall have a fire lane of at least ten (10) feet in width around the active treatment areas and within the perimeter fence. In addition, a buffer zone of at least ten (10) feet shall be maintained within the perimeter fire lane.
 - E. Surface water diversion structures, including, but not limited to, berms and ditches, shall be constructed to accommodate a one hundred (100) year, twenty four (24) hour event. The facility shall be designed and constructed with a run-on control system to prevent flow onto the facility during peak discharge and a run-off control system to contain the water volume from a twenty-five (25) year, twenty-four (24) hour storm.
- (6) **Waste profile.** For each type of waste, the amounts to be received and managed by the facility shall be estimated on a monthly average basis. For each waste type to be treated, a characteristic waste profile shall be completed.
- (7) **Facility design and engineering.** Facility design and engineering data, including plans and elevations, design basis, calculations, and process description.
- A. Geologic data, including, but not limited to:
 - i. Type and thickness of unconsolidated soils;
 - ii. Type and thickness of consolidated bedrock, if applicable;
 - iii. Local and regional geologic structures; and

iv. Any geologic hazards that may affect the design and operation of the facility.

B. Hydrologic data, including, but not limited to:

- i. Surface water features within two (2) miles;
- ii. Depth to shallow ground water and major aquifers;
- iii. Water wells within one (1) mile of the site boundary and well depth, depth to water, screened intervals, yields, and aquifer name;
- iv. Hydrologic properties of shallow ground water and major aquifers including flow direction, flow rate, and potentiometric surface;
- v. Site location in relation to the floodplain of nearby surface water features;
- vi. Existing quality of shallow ground water; and
- vii. An evaluation of the potential for impacts to nearby surface water and ground water.

C. Engineering data, including, but not limited to:

- i. Type and quantity of material required for use as a liner, including design components;
- ii. Location and depth of cut for liners;
- iii. Location, dimensions, and grades of all surface water diversion structures;
- iv. Location and dimensions of all surface water containment structures; and
- v. Location of all proposed facility structures and access roads.

(8) **Operating plan.** An operating plan, including, but not limited to:

- A. A detailed description of the method of treatment, loading rates, and application of nutrients and soil amendments;
- B. Dust and moisture control;
- C. Sampling;
- D. Inspection and maintenance;
- E. Emergency response;
- F. Record-keeping;
- G. Site security;

- H. Hours of operation;
- I. Noise and odor mitigation; and
- J. Final disposition of waste. Where treated waste will be beneficially reused, a description of reuse and method of product quality assurance shall be included.

(9) Ground water monitoring.

A. Water Wells.

Water samples shall be collected from water wells known to the operator or registered with the Colorado State Engineer within a one (1) mile radius of the proposed facility and shall be analyzed to establish baseline water quality. Analytical parameters shall be selected based upon the proposed waste stream and shall include, at a minimum, all major cations and anions, total dissolved solids, iron and manganese, nutrients (nitrates, nitrites, selenium), benzene, toluene, ethylbenzene, xylenes, pH, and specific conductance. Operators shall use reasonable good faith efforts to identify and obtain access to such water wells for the purpose of collecting water samples. If access cannot be obtained, then the operator shall notify the Director of the wells for which access was not obtained and sampling of such wells by the operator shall not be required. Not conducting sampling because access to water wells cannot be obtained shall not be grounds for denial of the proposed facility.

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

B. Site-specific monitoring wells.

- i. Where applicable, the Director shall require ground water monitoring to ensure compliance with the concentration levels in Table 910-1 and WQCC standards and classifications by establishing points of compliance, unless an oil and gas operator demonstrates to the satisfaction of the Director that an alternative method offering equivalent protection of public health, safety, and welfare, including the environment and wildlife resources, can be employed and provided the operator employs a dual liner with a leak detection system that provides for immediate leak detection from the uppermost liner. All monitoring well construction must be completed in accordance with the State Engineer's regulations on well construction, "Water Well Construction Rules" (2 C.C.R. 402-2).
- ii. Where monitoring is required, the direction of flow, ground water gradient and quality of water shall be established by the installation of a minimum of three (3) monitor wells, including an up-gradient well and two (2) down-gradient wells that will serve as points of compliance, or other methods authorized by the Director.

- (10) Surface water monitoring.** Where applicable, the Director shall require baseline and periodic surface water monitoring to ensure compliance with WQCC surface water

standards and classifications. Operators shall use reasonable good faith efforts to obtain access to such surface water for the purpose of collecting water samples. If access cannot be obtained, then the operator shall notify the Director of the surface water for which access was not obtained and sampling of such surface water by the operator shall not be required. Not conducting sampling because access to surface water cannot be obtained shall not be grounds for denial of the proposed facility.

- (11) **Contingency plan.** A contingency plan that describes the emergency response operations for the facility, 24-hour contact information for the person who has authority to initiate emergency response actions, and an outline of responsibilities under the joint operating agreement regarding maintenance, closure, and monitoring of the facility.
- c. **Permit approval.** The Director shall endeavor to approve or deny the properly completed permit within thirty (30) days after receipt and may condition permit approval as necessary to prevent any threatened or actual significant adverse environmental impact on air, water, soil or biological resources or to the extent necessary to ensure compliance with the concentration levels in Table 910-1, with consideration to WQCC ground water standards and classifications.
- d. **Financial assurance.** The operator of a centralized E&P waste management facility shall submit for the Director's approval such financial assurance as required by Rule 704. prior to issuance of the operating permit.
- e. **Facility modifications.** Throughout the life of the facility the operator shall submit proposed modifications to the facility design, operating plan, permit data, or permit conditions to the Director for prior approval.
- f. **Annual permit review.** To ensure compliance with permit conditions and the 900 Series rules, the facility permit shall be subject to an annual review by the Director. To facilitate this review, the operator shall submit an annual report summarizing operations, including the types and volumes of waste actually handled at the facility. The Director may require additional information.

g. Closure.

- (1) **Preliminary closure plan.** A general preliminary plan for closure shall be submitted with the Centralized E&P Waste Management Facility Permit, Form 28. The preliminary closure plan shall include, but not be limited to:
 - A. A general plan for closure and reclamation of the entire facility, including a description of the activities required to decommission and remove all equipment, close and reclaim pits, dispose of or treat residual waste, collect samples as needed to verify compliance with soil and ground water standards, implement post-closure monitoring, and complete other remediation, as required.
 - B. An estimate of the cost to close and reclaim the entire facility and to conduct post-closure monitoring. Cost estimates shall be subject to review by the Director.
- (2) **Final closure plan.** A detailed Site Investigation and Remediation Workplan, Form 27, shall be submitted at least sixty (60) days prior to closure for approval by the Director. The workplan shall include, but not be limited to, a description of the

activities required to decommission and remove all equipment, close and reclaim pits, dispose of or treat residual waste, collect samples as needed to verify compliance with soil and ground water standards, implement post-closure monitoring, and complete other remediation, as required.

- h. Operators may be subject to local requirements for zoning and construction of facilities and shall provide copies of any approval notices, permits, or other similar types of notifications for the facility from local governments or other agencies to the Director for review prior to issuance of the operating permit.

909. SITE INVESTIGATION, REMEDIATION, AND CLOSURE

- a. **Applicability.** This section applies to the closure and remediation of pits other than drilling pits constructed pursuant to Rule 903.a.(3); investigation, reporting and remediation of spills/releases; permitted waste management facilities including treatment facilities; plugged and abandoned wellsites; sites impacted by E&P waste management practices; or other sites as designated by the Director.

b. General site investigation and remediation requirements.

- (1) **Sensitive Area Determination.** Operators shall complete a sensitive area determination in accordance with Rule 901.e.
- (2) **Sampling and analyses.** Sampling and analysis of soil and ground water shall be conducted in accordance with Rule 910. to determine the horizontal and vertical extent of any contamination in excess of the concentrations in Table 910-1.
- (3) **Management of E&P waste.** E&P waste shall be managed in accordance with Rule 907.
- (4) **Pit evacuation.** Prior to backfilling and site reclamation, E&P waste shall be treated or disposed in accordance with Rule 907. and the 1000 Series rules.
- (5) **Remediation.** Remediation shall be performed in a manner to mitigate, remove, or reduce contamination that exceeds the concentrations in Table 910-1 in order to ensure protection of public health, safety, and welfare, and to prevent and mitigate significant adverse environmental impacts. Soil that does not meet concentrations in Table 910-1 shall be remediated. Ground water that does not meet concentrations in Table 910-1 shall be remediated in accordance with a Site Investigation and Remediation Workplan, Form 27.
- (6) **Reclamation.** Remediation sites shall be reclaimed in accordance with the 1000 Series rules for reclamation.

- c. **Site Investigation And Remediation Workplan, Form 27.** Operators shall prepare and submit for prior Director approval a Site Investigation and Remediation Workplan, Form 27, for the following operations and remediation activities:

- (1) Unlined pit closure when required by Rule 905.
- (2) Remediation of spills/releases in accordance with Rule 906.
- (3) Land treatment of oily waste in accordance with Rule 907.e.

- (4) Closure of centralized E&P waste management facilities in accordance with Rule 908.g.
 - (5) Remediation of impacted ground water in accordance with Rule 910.b.(4).
- d. **Multiple sites.** Remediation of multiple sites may be submitted on a single workplan with prior Director approval.
- e. **Closure.**
- (1) Remediation and reclamation shall be complete upon compliance with the concentrations in Table 910-1, or upon compliance with an approved workplan.
 - (2) **Notification of completion.** Within thirty (30) days after conclusion of site remediation and reclamation activities operators shall provide the following notification of completion:
 - A. Operators conducting remediation operations in accordance with Rule 909.b. shall submit to the Director a Site Investigation and Remediation Workplan, Form 27, containing information sufficient to demonstrate compliance with these rules.
 - B. Operators conducting remediation under an approved workplan shall submit to the Director, by adding or attaching to the original workplan, information sufficient to demonstrate compliance with the workplan.
- f. **Release of financial assurance.** Financial assurance required by Rule 706. may be held by the Director until the required remediation of soil and/or ground water impacts is completed in accordance with the approved workplan, or until cleanup goals are met.

910. CONCENTRATIONS AND SAMPLING FOR SOIL AND GROUND WATER

- a. **Soil and groundwater concentrations.** The concentrations for soil and ground water are in Table 910-1. Ground water standards and analytical methods are derived from the ground water standards and classifications established by WQCC.
- b. **Sampling and analysis.**
- (1) **Existing workplans.** Sampling and analysis for sites subject to an approved workplan shall be conducted in accordance with the workplan and the sampling and analysis requirements described in this rule.
 - (2) **Methods for sampling and analysis.** Sampling and analysis for site investigation or confirmation of successful remediation shall be conducted to determine the nature and extent of impact and confirm compliance with appropriate concentration levels in Table 910-1.
 - A. **Field analysis.** Field measurements and field tests shall be conducted using appropriate equipment, calibrated and operated according to manufacturer specifications, by personnel trained and familiar with the equipment.
 - B. **Sample collection.** Samples shall be collected, preserved, documented, and shipped using standard environmental sampling procedures in a manner to ensure accurate representation of site conditions.

- C. **Laboratory analytical methods.** Laboratories shall analyze samples using standard methods (such as EPA SW-846 or API RP-45) appropriate for detecting the target analyte. The method selected shall have detection limits less than or equal to the concentrations in Table 910-1.
- D. **Background sampling.** Samples of comparable, nearby, non-impacted, native soil, ground water or other medium may be required by the Director for establishing background conditions.

(3) Soil sampling and analysis.

- A. **Applicability.** If soil contamination is suspected or known to exist as a result of spills/releases or E&P waste management, representative samples of soil shall be collected and analyzed in accordance with this rule.
- B. **Sample collection.** Samples shall be collected from areas most likely to have been impacted, and the horizontal and vertical extent of contamination shall be determined. The number and location of samples shall be appropriate to the impact.
- C. **Sample analysis.** Soil samples shall be analyzed for contaminants listed in Table 910-1 as appropriate to assess the impact or confirm remediation. The analytical parameters shall be selected based on site-specific conditions and process knowledge and shall be agreed to and approved by the Director.
- D. **Soil impacted by produced water.** For impacts to soil due to produced water, samples from comparable, nearby non-impacted native soil shall be collected and analyzed for purposes of establishing background soil conditions including pH and electrical conductivity (EC). Where EC of the impacted soil exceeds the level in Table 910-1, the sodium adsorption ratio (SAR) shall also be determined.
- E. **Soil impacted by hydrocarbons.** For impacts to soil due to hydrocarbons, samples shall be analyzed for TPH or organic compounds per Table 910-1 as determined by site-specific conditions and process knowledge..

(4) Ground water sampling and analysis.

- A. **Applicability.** Operators shall collect and analyze representative samples of ground water in accordance with these rules under the following circumstances:
 - (i) Where ground water contamination is suspected or known to exceed the concentrations in Table 910-1;
 - (ii) Where impacted soils are in contact with ground water; or
 - (iii) Where impacts to soils extend down to the high water table.
- B. **Sample collection.** Samples shall be collected from areas most likely to have been impacted, downgradient or in the middle of excavated areas. The number and location of samples shall be appropriate to determine the horizontal and vertical extent of the impact. If the concentrations in Table 910-1 are exceeded, the direction of flow and a ground water gradient shall

be established, unless the extent of the contamination and migration can otherwise be adequately determined.

C. **Sample analysis.** Ground water samples shall be analyzed for benzene, toluene, ethylbenzene, xylene, and API RP-45 constituents, or other parameters appropriate for evaluating the impact. The analytical parameters shall be selected based on site-specific conditions and process knowledge and shall be agreed to and approved by the Director.

D. **Impacted ground water.** Where ground water contaminants exceed the concentrations listed in Table 910-1, operators shall notify the Director and submit to the Director for prior approval a Site Investigation and Remediation Workplan, Form 27, for the investigation, remediation, or monitoring of ground water to meet the required concentrations in Table 910-1.

911. PIT, BURIED OR PARTIALLY BURIED PRODUCED WATER VESSEL, BLOWDOWN PIT, AND BASIC SEDIMENT/TANK BOTTOM PIT MANAGEMENT REQUIREMENTS PRIOR TO DECEMBER 30, 1997.

a. **Applicability.** This rule applies to the management, operation, closure and remediation of drilling, production and special purpose pits, buried or partially buried produced water vessels, blowdown pits, and basic sediment/tank bottom pits put into service prior to December 30, 1997 and unlined skim pits put into service prior to July 1, 1995. For pits constructed after December 30, 1997 and skim pits constructed after July 1, 1995, operators shall comply with the requirements contained in Rules 901. through 910.

b. **Inventory.** Operators were required to submit to the Director no later than December 31, 1995, an inventory identifying production pits, buried or partially buried produced water vessels, blowdown pits, and basic sediment/tank bottom pits that existed on June 30, 1995. The inventory required operators to provide the facility name, a description of the location, type, capacity and use of pit/vessel, whether netted or fenced, lined or unlined, and where available, water quality data. Operators who have failed to submit the required inventory are in continuing violation of this rule.

c. Sensitive area determination.

(1) For unlined production and special purpose pits constructed prior to July 1, 1995 and not closed by December 30, 1997, operators were required to determine whether the pit was located within a sensitive area in accordance with the Sensitive Area Determination Decision Tree, Figure 901-1 (now Rule 901.e.) and submit data evaluated and analysis used in the determination to the Director on a Sundry Notice, Form 4. In December 2008, Figure 901-1 was deleted from the 900-Series Rules.

(2) For steel, fiberglass, concrete, or other similar produced water vessels that were buried or partially buried and located in sensitive areas prior to December 30, 1997, operators were required to test such vessels for integrity, unless a monitoring or leak detection system was put in place.

d. The following permitting/reporting requirements applied to pits constructed prior to December 30, 1997:

(1) A Sundry Notice, Form 4, including the name, address, and phone number of the primary contact person operating the production pit for the operator, the facility

name, a description of the location, type, capacity and use of pit, engineering design, installation features and water quality data, if available, was required for the following:

A. Lined production pits and lined special purpose pits constructed after July 1, 1995.

B. Unlined production pits constructed prior to July 1, 1995 which are lined in accordance with Rule 905. by December 30, 1997.

(2) An Application For Permit For Unlined Pit, Form 15 was required for the following:

A. Unlined production pits and special purpose pits in sensitive areas constructed prior to July 1, 1995, and not closed by December 30, 1997.

B. Unlined production pits outside sensitive areas constructed after July 1, 1995 and not closed by December 30, 1997.

(3) An Application For Permit For Unlined Pit, Form 15 and a variance under Rule 904.e.(1). (repealed, now Rule 502.b.) was required for unlined production pits and unlined special purpose pits in sensitive areas constructed after July 1, 1995.

(4) A Sundry Notice, Form 4 was required for unlined production pits outside sensitive areas receiving produced water at an average daily rate of five (5) or less barrels per day calculated on a monthly basis for each month of operation constructed prior to December 30, 1997.

e. The Director may have established points of compliance for unlined production pits and special purpose pits and for lined production pits in sensitive areas constructed after July 1, 1995.

f. Closure requirements.

(1) Operators of production or special purpose pits existing on July 1, 1995 which were closed before December 30, 1997, were required to submit a Sundry Notice, Form 4, within thirty (30) days of December 30, 1997. The Sundry Notice, Form 4 shall include a copy of the existing pit permit, if a permit was obtained, and a description of the closure process.

(2) Pits closed prior to December 30, 1997 were required to be reclaimed in accordance with the 1000 Series rules. Pits closed after December 30, 1997 shall be closed in accordance with the 900 Series rules and reclaimed in accordance with the 1000 Series rules.

(3) Operators of steel, fiberglass, concrete or other similar produced water vessels buried or partially buried and located in sensitive areas were required to repair or replace vessels and tanks found to be leaking. Operators shall repair or replace vessels and tanks found to be leaking. Operators shall submit to the Director a Sundry Notice, Form 4, describing the integrity testing results and action taken within thirty (30) days of December 30, 1997.

(4) Closure of pits and steel, fiberglass, concrete or other similar produced water vessels, and associated remediation operations conducted prior to December 30, 1997 are not subject to Rules 905., 906., 907., 909. and 910.

912. VENTING OR FLARING NATURAL GAS

- a. The unnecessary or excessive venting or flaring of natural gas produced from a well is prohibited.
- b. Except for gas flared or vented during an upset condition, well maintenance, well stimulation flowback, purging operations, or a productivity test, gas from a well shall be flared or vented only after notice has been given and approval obtained from the Director on a Sundry Notice, Form 4, stating the estimated volume and content of the gas. The notice shall indicate whether the gas contains more than one (1) ppm of hydrogen sulfide. If necessary to protect the public health, safety or welfare, the Director may require the flaring of gas.
- c. Gas flared, vented or used on the lease shall be estimated based on a gas-oil ratio test or other equivalent test approved by the Director, and reported on Operator's Monthly Report of Operations, Form 7.
- d. Flared gas that is subject to Sundry Notice, Form 4, shall be directed to a controlled flare in accordance with Rule 903.b.(2) or other combustion device operated as efficiently as possible to provide maximum reduction of air contaminants where practicable and without endangering the safety of the well site personnel and the public.
- e. Operators shall notify the local emergency dispatch or the local governmental designee of any natural gas flaring. Notice shall be given prior to flaring when flaring can be reasonably anticipated, or as soon as possible, but in no event more than two (2) hours after the flaring occurs.

**Table 910-1
CONCENTRATION LEVELS¹**

Contaminant of Concern	Concentrations
Organic Compounds in Soil	
TPH (total volatile and extractable petroleum hydrocarbons)	500 mg/kg
Benzene	0.17 mg/kg²
Toluene	85 mg/kg²
Ethylbenzene	100 mg/kg²
Xylenes (total)	175 mg/kg²
Acenaphthene	1,000 mg/kg²
Anthracene	1,000 mg/kg²
Benz(a)anthracene	0.22 mg/kg²
Benzo(b)fluoranthene	0.22 mg/kg²
Benzo(k)fluoranthene	2.2 mg/kg²
Benzo(a)pyrene	0.022 mg/kg²
Chrysene	22 mg/kg²
Dibenzo(a,h)anthracene	0.022 mg/kg²
Fluoranthene	1,000 mg/kg²
Fluorene	1,000 mg/kg²
Indeno(1,2,3,c,d)pyrene	0.22 mg/kg²
Naphthalene	23 mg/kg²
Pyrene	1,000 mg/kg²
Organic Compounds in Ground Water	
Benzene	5 µg/l³
Toluene	560 to 1,000 µg/l³
Ethylbenzene	700 µg/l³
Xylenes (Total)	1,400 to 10,000 µg/l^{3,4}
Inorganics in Soils	
Electrical Conductivity (EC)	<4 mmhos/cm or 2x background

Sodium Adsorption Ratio (SAR)	<12 ⁵
pH	6-9
Inorganics in Ground Water	
Total Dissolved Solids (TDS)	<1.25 x background ³
Chlorides	<1.25 x background ³
Sulfates	<1.25 x background ³
Metals in Soils	
Arsenic	0.39 mg/kg ²
Barium (LDNR True Total Barium)	15,000 mg/kg ²
Boron (Hot Water Soluble)	2 mg/l ³
Cadmium	70 mg/kg ^{3,6}
Chromium (III)	120,000 mg/kg ²
Chromium (VI)	23 mg/kg ^{2,6}
Copper	3,100 mg/kg ²
Lead (inorganic)	400 mg/kg ²
Mercury	23 mg/kg ²
Nickel (soluble salts)	1,600 mg/kg ^{2,6}
Selenium	390 mg/kg ^{2,6}
Silver	390 mg/kg ²
Zinc	23,000 mg/kg ^{2,6}
Liquid Hydrocarbons in Soils and Ground Water	
Liquid hydrocarbons including condensate and oil	Below detection level

COGCC recommends that the latest version of EPA SW 846 analytical methods be used where possible and that analyses of samples be performed by laboratories that maintain state or national accreditation programs.

¹ Consideration shall be given to background levels in native soils and ground water.

² Concentrations taken from CDPHE-HMWMD Table 1 Colorado Soil Evaluation Values (December 2007).

³ Concentrations taken from CDPHE-WQCC Regulation 41 - The Basic Standards for Ground Water.

⁴ For this range of standards, the first number in the range is a strictly health-based value, based on the WQCC's established methodology for human health-based standards. The second number in the range is a maximum contaminant level (MCL), established under the Federal Safe Drinking Water Act which has been determined to be an acceptable level of this chemical in public water supplies, taking treatability and laboratory detection limits into account. The WQCC intends that control requirements for this chemical be implemented to attain a level of ambient water quality that is at least equal to the first number in the range except as follows:

1) where ground water quality exceeds the first number in the range due to a release of contaminants that occurred prior to September 14, 2004 (regardless of the date of discovery or subsequent migration of such contaminants) clean-up levels for the entire contaminant plume shall be no more restrictive than the second number in the range or the ground water quality resulting from such release, whichever is more protective, and 2) whenever the WQCC has adopted alternative, site-specific standards for the chemical, the site-specific standards shall apply instead of these statewide standards.

⁵ Analysis by USDA Agricultural Handbook 60 method (20B) with soluble cations determined by method (2). Method (20B) = estimation of exchangeable sodium percentage and exchangeable potassium percentage from soluble cations. Method (2) = saturated paste method (note: each analysis requires a unique sample of at least 500 grams). If soils are saturated, USDA Agricultural Handbook 60 with soluble cations determined by method (3A) saturation extraction method.

⁶ The table value for these inorganic constituents is taken from the CDPHE-HMWMD Table 1 Colorado Soil Evaluation Values (December 2007). However, because these values are high, it is possible that site-specific geochemical conditions may exist that could allow these constituents to migrate into ground water at levels exceeding ground water standards even though the concentrations are below the table values. Therefore, when these constituents are present as contaminants, a secondary evaluation of their leachability must be performed to ensure ground water protection.

RECLAMATION REGULATIONS

1001. INTRODUCTION

- a. **General.** The rules and regulations of this series establish the proper reclamation of the land and soil affected by oil and gas operations and ensure the protection of the topsoil of said land during such operations. The surface of the land shall be restored as nearly as practicable to its condition at the commencement of drilling operations.
- b. **Additional requirements.** Notwithstanding the provisions of the 1000 Series rules, when the Director has reasonable cause to believe that a proposed oil and gas operation could result in a significant adverse environmental impact on any air, water, soil, or biological resource, the Director shall conduct an onsite inspection and may request an emergency meeting of the Commission to address the issue.
- c. **Surface owner waiver of 1000-Series Rules.** The Commission shall not require compliance with Rules 1002. (except Rules 1002.e.(1), 1002.e.(4), and 1002.f, for which compliance will continue to be required), Rule 1003, or Rule 1004 (except Rules 1004.c.(4) and 1004.c.(5), for which compliance will continue to be required), if the operator can demonstrate to the Director's or the Commission's satisfaction both that compliance with such rules is not necessary to protect the public health, safety and welfare, including prevention of significant adverse environmental impacts, and that the operator has entered into an agreement with the surface owner regarding topsoil protection and reclamation of the land. Absent bad faith conduct by the operator, penalties may only be imposed for non-compliance with a Commission order issued after a determination that, notwithstanding such agreement, compliance is necessary to protect public health, safety and welfare. Prior to final reclamation approval as to a specific well, the operator shall either comply with the rules or obtain a variance under Rule 502.b. This rule shall not have the effect of relieving an operator from compliance with the 900 Series Rules.

1002. SITE PREPARATION AND STABILIZATION

- a. Effective June 1, 1996:
 - (1) **Fencing of drill sites and access roads on crop lands.** During drilling operations on crop lands, when requested by the surface owner, the operator shall delineate each drillsite and access road on crop lands constructed after such date by berms, single strand fence, or other equivalent method in order to discourage unnecessary surface disturbances.
 - (2) **Fencing of reserve pit when livestock is present.** During drilling operations where livestock is in the immediate area and is not fenced out by existing fences, the operator, at the request of the surface owner, will install a fence around the reserve pit.
 - (3) **Fencing of well sites.** Subsequent to drilling operations, where livestock is in the immediate area and is not fenced out by existing fences, the operator, at the request of the surface owner, will install a fence around the wellhead, pit, and production equipment to prevent livestock entry.
- b. **Soil removal and segregation.**
 - (1) **Soil removal and segregation on crop land.** As to all excavation operations undertaken after June 1, 1996 on crop land, the operator shall separate and store soil horizons separately from one another and mark or document stockpile locations to facilitate subsequent reclamation. When separating soil horizons, the operator shall segregate horizons based upon noted changes in physical characteristics such as organic content,

color, texture, density, or consistency. Segregation will be performed to the extent practicable to a depth of six (6) feet or bedrock, whichever is shallower.

- (2) **Soil removal and segregation on non crop-land.** As to all excavation operations undertaken after July 1, 1997 on non-crop land, the operator shall separate and store the topsoil horizon or the top six (6) inches, whichever is deeper, and mark or document stockpile locations to facilitate subsequent reclamation. When separating the soil horizons, the operator shall segregate the horizon based upon noted changes in physical characteristics such as organic content, color, texture, density, or consistency.
 - (3) **Horizons too rocky or too thin.** When the soil horizons are too rocky or too thin for the operator to practicably segregate, then the topsoil shall be segregated to the extent possible and stored. Too rocky shall mean that the soil horizon consists of greater than thirty five percent (35%) by volume rock fragments larger than ten (10) inches in diameter. Too thin shall mean soil horizons that are less than six (6) inches in thickness. The operator shall segregate remaining soils on crop land to the extent practicable to a depth of three (3) feet below the ground surface or bedrock, whichever is shallower, based upon noted changes in physical characteristics such as color, texture, density or consistency and such soils shall be stockpiled to avoid loss and mixing with other soils.
- c. **Protection of soils.** All stockpiled soils shall be protected from degradation due to contamination, compaction and, to the extent practicable, from wind and water erosion during drilling and production operations. Best management practices to prevent weed establishment and to maintain soil microbial activity shall be implemented.
- d. **Drill pad location.** The drilling location shall be designed and constructed to provide a safe working area while reasonably minimizing the total surface area disturbed. Consistent with applicable spacing orders and well location orders and regulations, in locating drill pads, steep slopes shall be avoided when reasonably possible. The drill pad site shall be located on the most level location obtainable that will accommodate the intended use. If not avoidable, deep vertical cuts and steep long fill slopes shall be constructed to the least percent slope practical. Where feasible, operators shall use directional drilling to reduce cumulative impacts and adverse impacts on wildlife resources.
- e. **Surface disturbance minimization.**
- (1) In order to reasonably minimize land disturbances and facilitate future reclamation, well sites, production facilities, gathering pipelines, and access roads shall be located, adequately sized, constructed, and maintained so as to reasonably control dust and minimize erosion, alteration of natural features, removal of surface materials, and degradation due to contamination.
 - (2) Operators shall avoid or minimize impacts to wetlands and riparian habitats to the degree practicable.
 - (3) Where practicable, operators shall consolidate facilities and pipeline rights-of-way in order to minimize adverse impacts to wildlife resources, including fragmentation of wildlife habitat, as well as cumulative impacts.
 - (4) **Access roads.** Existing roads shall be used to the greatest extent practicable to avoid erosion and minimize the land area devoted to oil and gas operations. Roadbeds shall be engineered to avoid or minimize impacts to riparian areas or wetlands to the extent practicable. Unavoidable impacts shall be mitigated. Road crossings of streams shall be designed and constructed to allow fish passage, where practicable and appropriate. Where feasible and practicable, operators are encouraged to share access roads in

developing a field. Where feasible and practicable, roads shall be routed to complement other land usage. To the greatest extent practicable, all vehicles used by the operator, contractors, and other parties associated with the well shall not travel outside of the original access road boundary. Repeated or flagrant instance(s) of failure to restrict lease access to lease roads which result in unreasonable land damage or crop losses shall be subject to a penalty under Rule 523.

f. Stormwater management.

- (1) All oil and gas locations are subject to the Best Management Practices requirements of Rule 1002.f.(2). In addition, upon the termination of a construction stormwater permit issued by the Colorado Department of Public Health and Environment for an oil and gas location, such oil and gas location is subject to the Post-Construction Stormwater Program requirements of Rule 1002.f.(3), except that such requirements are not applicable to Tier 1 Oil and Gas Locations.
- (2) Oil and gas operators shall implement and maintain Best Management Practices (BMPs) at all oil and gas locations to control stormwater runoff in a manner that minimizes erosion, transport of sediment offsite, and site degradation. BMPs shall be maintained until the facility is abandoned and final reclamation is achieved pursuant to Rule 1004. Operators shall employ BMPs, as necessary to comply with this rule, at all oil and gas locations, including, but not limited to, well pads, soil stock piles, access roads, tank batteries, compressor stations, and pipeline rights of way. BMPs shall be selected based on site-specific conditions, such as slope, vegetation cover, and proximity to water bodies, and may include maintaining in-place some or all of the BMPs installed during the construction phase of the facility. Where applicable based on site-specific conditions, operators shall implement BMPs in accordance with good engineering practices, including measures such as:
 - A. **Covering materials and activities and stormwater diversion** to minimize contact of precipitation and stormwater runoff with materials, wastes, equipment, and activities with potential to result in discharges causing pollution of surface waters.
 - B. **Materials handling and spill prevention procedures and practices** implemented for material handling and spill prevention of materials used, stored, or disposed of that could result in discharges causing pollution of surface waters.
 - C. **Erosion controls** designed to minimize erosion from unpaved areas, including operational well pads, road surfaces and associated culverts, stream crossings, and cut/fill slopes.
 - D. **Self-inspection, maintenance, and good housekeeping procedures and schedules** to facilitate identification of conditions that could cause breakdowns or failures of BMPs. These procedures shall include measures for maintaining clean, orderly operations and facilities and shall address cleaning and maintenance schedules and waste disposal practices. In conducting inspections and maintenance relative to stormwater runoff, operators shall consider seasonal factors, such as winter snow cover and spring runoff from snowmelt, to ensure site conditions and controls are adequate and in place to effectively manage stormwater.
 - E. **Spill response procedures** for responding to and cleaning up spills. The necessary equipment for spill cleanup shall be readily available to personnel. Spill Prevention, Control, and Countermeasure plans incorporated by reference must be identified in the Post-Construction Stormwater Management Program specified in Rule 1002.f.(3).

- F. **Vehicle tracking control practices** to control potential sediment discharges from operational roads, well pads, and other unpaved surfaces. Practices could include road and pad design and maintenance to minimize rutting and tracking, controlling site access, street sweeping or scraping, tracking pads, wash racks, education, or other sediment controls.
- (3) Operators of oil and gas facilities shall develop a Post-Construction Stormwater Program in compliance with this section no later than the time of termination of stormwater permits issued by the Colorado Department of Public Health and Environment for construction of oil and gas facilities.
- A. The Post-Construction Stormwater Program shall reflect good faith efforts by operators to select and implement BMPs intended to serve the purposes of this rule. BMPs shall be selected to address potential sources of pollution which may reasonably be expected to affect the quality of discharges associated with the ongoing operation of production facilities during the post-construction and reclamation operation of the facilities. Pollutant sources that must be addressed by BMPs, if present, include:
- i. Transport of chemicals and materials, including loading and unloading operations;
 - ii. Vehicle/equipment fueling;
 - iii. Outdoor storage activities, including those for chemicals and additives;
 - iv. Produced water and drilling fluids storage;
 - v. Outdoor processing activities and machinery;
 - vi. Significant dust or particulate generating processes;
 - vii. Erosion and vehicle tracking from well pads, road surfaces, and pipelines;
 - viii. Waste disposal practices;
 - ix. Leaks and spills; and
 - x. Ground-disturbing maintenance activities.
- B. The Post-Construction Stormwater Program shall be developed, supervised, documented, and maintained by a qualified person(s) with training or prior work experience specific to stormwater management. Employees and subcontractors shall be trained to make them aware of the BMPs implemented and maintained at the site and procedures for reporting needed maintenance or repairs. Documentation shall include a description of the BMPs selected to ensure proper implementation, operation, and maintenance.
- C. Facility-specific maps, installation specification, and implementation criteria shall also be included when general operating procedures and descriptions are not adequate to clearly describe the implementation and operation of BMPs.

1003. INTERIM RECLAMATION

- a. **General.** Debris and waste materials other than *de minimis* amounts, including, but not limited to, concrete, sack bentonite and other drilling mud additives, sand plastic, pipe and cable, as well as equipment associated with the drilling, re-entry, or completion operations shall be removed. All E&P waste shall be handled according to the 900 Series rules. All pits, cellars, rat holes, and other bore holes unnecessary for further lease operations, excluding the drilling pit, will be backfilled as soon as possible after the drilling rig is released to conform with surrounding terrain. On crop land, if requested by the surface owner, guy line anchors shall be removed as soon as reasonably possible after the completion rig is released. When permanent guy line anchors are installed, it shall not be mandatory to remove them. When permanent guy line anchors are installed on cropland, care shall be taken to minimize disruption or cultivation, irrigation, or harvesting operations. If requested by the surface owner or its representative, the anchors shall be specifically marked, in addition to the marking required below, so as to facilitate farming operations. 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. In addition, all well sites and surface production facilities shall be maintained in accordance with Rule 603.j.
- b. **Interim reclamation of areas no longer in use.** All disturbed areas affected by drilling or subsequent operations, except areas reasonably needed for production operations or for subsequent drilling operations to be commenced within twelve (12) months, shall be reclaimed as early and as nearly as practicable to their original condition or their final land use as designated by the surface owner and shall be maintained to control dust and minimize erosion to the extent practicable. As to crop lands, if subsidence occurs in such areas additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable. Interim reclamation shall occur no later than three (3) months on crop land or six (6) months on non-crop land after such operations unless the Director extends the time period because of conditions outside the control of the operator. Areas reasonably needed for production operations or for subsequent drilling operations to be commenced within twelve (12) months shall be compacted, covered, paved, or otherwise stabilized and maintained in such a way as to minimize dust and erosion to the extent practicable.
- c. **Compaction alleviation.** All areas compacted by drilling and subsequent oil and gas operations which are no longer needed following completion of such operations shall be cross-ripped. On crop land, such compaction alleviation operations shall be undertaken when the soil moisture at the time of ripping is below thirty-five percent (35%) of field capacity. Ripping shall be undertaken to a depth of eighteen (18) inches unless and to the extent bed rock is encountered at a shallower depth.
- d. **Drilling pit closure.** As part of interim reclamation, drilling pits shall be closed in the following manner:
- (1) **Drilling pit closure on crop land and within 100-year floodplain.** On crop land or within the 100-year floodplain, water-based bentonitic drilling fluids, except *de minimis* amounts, shall be removed from the drilling pit and disposed of in accordance with the 900 Series rules. Operators shall ensure that soils meet the concentration levels of Table 910-1, above. Drilling pit reclamation, including the disposal of drilling fluids and cuttings, shall be performed in a manner so as to not result in the formation of an impermeable barrier. Any cuttings removed from the pit for drying shall be returned to the pit prior to backfilling, and no more than *de minimis* amounts may be incorporated into the surface materials. After the drilling pit is sufficiently dry, the pit shall be backfilled. The backfilling of the drilling pit shall be done to return the soils to their original relative positions. Closing and reclamation of drilling pits shall occur no later than three (3) months after drilling and completion activities conclude.

- (2) **Drilling pit closure on non-crop land.** All drilling fluids shall be disposed of in accordance with the 900 Series rules. Operators shall ensure that soils meet the concentration levels of Table 910-1, above. After the drilling pit is sufficiently dry, the pit shall be backfilled. Materials removed from the pit for drying shall be returned to the pit prior to the backfilling. No more than *de minimis* amounts may be incorporated into the surface materials. The backfilling of the drilling pit will be done to return the soils to their original relative positions so that the muds and associated solids will be confined to the pit and not squeezed out and incorporated in the surface materials. Closure and reclamation of drilling pits shall occur no later than six (6) months after drilling and completion activities conclude, weather permitting.
- (3) **Minimum cover.** On crop lands, a minimum of three (3) feet of backfill cover shall be applied over any remaining drilling pit contents. As to both crop lands and non-crop lands, during the two (2) year period following drilling pit closure, if subsidence occurs over the closed drilling pit location additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable.

e. **Restoration and revegetation.** When a well is completed for production, all disturbed areas no longer needed will be restored and revegetated as soon as practicable.

- (1) **Revegetation of crop lands.** All segregated soil horizons removed from crop lands shall be replaced to their original relative positions and contour, and shall be tilled adequately to re-establish a proper seedbed. The area shall be treated if necessary and practicable to prevent invasion of undesirable species and noxious weeds, and to control erosion. Any perennial forage crops that were present before disturbance shall be re-established.
- (2) **Revegetation of non-crop lands.** All segregated soil horizons removed from non-crop lands shall be replaced to their original relative positions and contour as near as practicable to achieve erosion control and long-term stability, and shall be tilled adequately in order to establish a proper seedbed. The disturbed area then shall be reseeded in the first favorable season following rig demobilization. Reseeding with species consistent with the adjacent plant community is encouraged. In the absence of an agreement between the operator and the affected surface owner as to what seed mix should be used, the operator shall consult with a representative of the local soil conservation district to determine the proper seed mix to use in revegetating the disturbed area. In an area where an operator has drilled or plans to drill multiple wells, in the absence of an agreement between the operator and the affected surface owner, the operator may rely upon previous advice given by the local soil conservation district in determining the proper seed mixes to be used in revegetating each type of terrain upon which operations are to be conducted.

Interim reclamation of all disturbed areas no longer in use shall be considered complete when all ground surface disturbing activities at the site have been completed, and all disturbed areas have been either built on, compacted, covered, paved, or otherwise stabilized in such a way as to minimize erosion to the extent practicable, or a uniform vegetative cover has been established that reflects pre-disturbance or reference area forbs, shrubs, and grasses with total percent plant cover of at least eighty percent (80%) of pre-disturbance levels or reference areas, excluding noxious weeds. Re-seeding alone is not sufficient.

- (3) **Interim reclamation completion notice, Form 4.** The operator shall submit a Sundry Notice, Form 4, which describes the interim reclamation procedures and any associated mitigation measures performed, any changes, if applicable in the landowner's designated final land use, and at a minimum four (4) photographs taken during the growing season facing each cardinal direction which document the success of the interim reclamation and one (1) photograph which documents the total cover of live perennial vegetation of

adjacent or nearby undisturbed land or the reference area. Each photograph shall be identified by date taken, well name, GPS location, and direction of view.

- f. **Weed control.** During drilling, production, and reclamation operations, all disturbed areas shall be kept as free of all undesirable plant species designated to be noxious weeds as practicable. Weed control measures shall be conducted in compliance with the Colorado Noxious Weed Act, C.R.S. §35-5.5-115 and the current rules pertaining to the administration and enforcement of the Colorado Noxious Weed Act. It is recommended that the operator consult with the local weed control agency or other weed control authority when weed infestation occurs. It is the responsibility of the operator to monitor affected and reclaimed lands for noxious weed infestations. If applicable, the Director may require a weed control plan.

1004. FINAL RECLAMATION OF WELL SITES AND ASSOCIATED PRODUCTION FACILITIES

- a. **Well sites and associated production facilities.** Upon the plugging and abandonment of a well, all pits, mouse and rat holes and cellars shall be backfilled. All debris, abandoned gathering line risers and flowline risers, and surface equipment shall be removed within three (3) months of plugging a well. All access roads to plugged and abandoned wells and associated production facilities shall be closed, graded and recontoured. Culverts and any other obstructions that were part of the access road(s) shall be removed. Well locations, access roads and associated facilities shall be reclaimed. As applicable, compaction alleviation, restoration, and revegetation of well sites, associated production facilities, and access roads shall be performed to the same standards as established for interim reclamation under Rule 1003. All other equipment, supplies, weeds, rubbish, and other waste material shall be removed. 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. All such reclamation work shall be completed within three (3) months on crop land and twelve (12) months on non-crop land after plugging a well or final closure of associated production facilities. The Director may grant an extension where unusual circumstances are encountered, but every reasonable effort shall be made to complete reclamation before the next local growing season.
- b. **Production and special purpose pit closure.** The operator shall comply with the 900 series rules for the removal or treatment of E&P waste remaining in a production or special purpose pit before the pit may be closed for final reclamation. After any remaining E&P waste is removed or treated, all such pits must be back-filled to return the soils to their original relative positions. As to both crop lands and non-crop lands, if subsidence occurs over closed pit locations, additional topsoil shall be added to the depression and the land shall be re-leveled as close to its original contour as practicable.
- c. **Final reclamation threshold for release of financial assurance.** Successful reclamation of the well site and access road will be considered completed when:
- (1) On crop land, reclamation has been performed as per Rules 1003 and 1004, and observation by the Director over two growing seasons has indicated no significant unrestored subsidence.
 - (2) On non-crop land, reclamation has been performed as per Rules 1003 and 1004, and disturbed areas have been either built on, compacted, covered, paved, or otherwise stabilized in such a way as to minimize erosion to the extent practicable, or a uniform vegetative cover has been established that reflects pre-disturbance or reference area forbs, shrubs, and grasses with total percent plant cover of at least eighty percent (80%) of pre-disturbance or reference area levels, excluding noxious weeds, as determined by the Director through a visual appraisal. The Director shall consider the total cover of live

perennial vegetation of adjacent or nearby undisturbed land, not including overstory or tree canopy cover, having similar soils, slope and aspect of the reclaimed area.

- (3) Disturbances resulting from flow line installations shall be deemed adequately reclaimed when the disturbed area is reasonably capable of supporting the pre-disturbance land use.
 - (4) A Sundry Notice Form 4, has been submitted by the operator which describes the final reclamation procedures, any changes, if applicable, in the landowner's designated final land use, and any mitigation measures associated with final reclamation performed by the operator, and
 - (5) A final reclamation inspection has been completed by the Director, there are no outstanding compliance issues relating to Commission rules, regulations, orders, permit conditions or the act, and the Director has notified the operator that final reclamation has been approved.
- d. Final reclamation of all disturbed areas shall be considered complete when all activities disturbing the ground have been completed, and all disturbed areas have been either built upon, compacted, covered, paved, or otherwise stabilized in such a way as to minimize erosion, or a uniform vegetative cover has been established that reflects pre-disturbance or reference area forbs, shrubs, and grasses with total percent plant cover of at least eighty percent (80%) of pre-disturbance or reference area levels, excluding noxious weeds, or equivalent permanent, physical erosion reduction methods have been employed. Re-seeding alone is not sufficient.
- e. **Weed control.** All areas being reclaimed shall be kept as free as practicable of all undesirable plant species designated to be noxious weeds. Weed control measures shall be conducted in compliance with the Colorado Noxious Weed Act, C.R.S. §35-5.5-115 and the current rules pertaining to the administration and enforcement of the Colorado Noxious Weed Act. It is recommended that the operator consult with the local weed control agency or other weed control authority when weed infestation occurs. It is the responsibility of the operator to monitor affected and reclaimed lands for noxious weed infestations. If applicable, the Director may require a weed control plan.

FLOWLINE REGULATIONS (1100 Series)

1101. REGISTRATION REQUIREMENTS

1101.a. Flowline and Crude Oil Transfer Line Statuses.

- (1) Pre-Commissioned Status means a constructed flowline or crude oil transfer line that:
 - A. Has not been connected or opened to sources of oil, condensate, produced water, or natural gas;
 - B. Is isolated from active status assets;
 - C. Does not contain oil, condensate, produced water, or natural gas; and
 - D. Is OOSLAT.
- (2) Active Status means a flowline or crude oil transfer line that is connected or open to sources of oil, condensate, produced water, or natural gas or is not in the pre-commissioned, out-of-service, or abandoned status, or contains these products.
- (3) Out-of-Service Status means a flowline or crude oil transfer line that is associated with an inactive well or the operator has ceased normal operations. For an out of service line, the operator must:
 - A. Isolate or disconnect it from sources of oil, condensate, produced water, or natural gas;
 - B. Evacuate all hydrocarbons and produced water to ensure the line is safe and inert and depressurize the line; and
 - C. apply OOSLAT.
- (4) Abandoned Status means a flowline or crude oil transfer line that has been permanently removed from service in accordance with Rule 1105.

1101.b. Off-Location Flowline Registration.

- (1) An operator must register every off-location flowline either individually or as part of a flowline system. An operator may register individual off-location flowlines or a flowline system by submitting a Flowline Report, Form 44, to the Director within 90 days after the flowline or flowline system is placed in active status. An off-location flowline registered as part of a produced water transfer system is not subject to this requirement.
- (2) Registration Requirements. For off-location flowlines registered pursuant to this section, operators must include the following information:
 - A. Geographic Information System (GIS) data that includes the flowline alignment and the following attributes: fluid type, pipe material type, and pipe size. GIS data must be submitted in the North American Datum of 1983 (NAD 83) and in a format approved by the Director;
 - B. Bedding materials used in construction;
 - C. Pipe material;

- D. Maximum flowline diameter;
 - E. Fluids that will be transferred;
 - F. The maximum anticipated operating pressure, testing pressure, test date and chart of successful pressure test;
 - G. Identify and describe the starting and ending oil and gas locations;
 - H. Description of corrosion protection;
 - I. Description of the integrity management system utilized in accordance with Rule 1104.f.; and
 - J. Description of the construction method used for public by-ways, road crossings, sensitive wildlife habitats, sensitive areas, and natural and manmade watercourses (i.e., open trench, bored and cased, or bored only), if applicable.
- (3) For off-location flowlines in existence prior to May 1, 2018, and already registered with the Commission, operators must submit, on or before December 1, 2020, a Flowline Report, Form 44, that includes:
- A. A description of the corrosion protection;
 - B. A description of the integrity management system utilized in accordance with Rule 1104.f.; and
 - C. Geographic Information System (GIS) data that includes the flowline alignment and the following attributes: fluid type, pipe material type, and pipe size. GIS data must be submitted in the North American Datum of 1983 (NAD 83) and in a format approved by the Director. The GIS data for these off-location flowlines must be the most accurate data possible without using invasive methods and a minimum horizontal positional accuracy of +/- 25 feet.
- (4) Within 90 days of modifying the alignment of a registered off-location flowline, the operator must report the change to the Director by submitting a Flowline Report, Form 44.
- (5) If a document is executed after May 1, 2018, that grants a right of access or easement to locate an off-location flowline on lands, then either the document itself or a memorandum or notice of such document must be recorded by the operator in the office of the county clerk and recorder of the county where the lands are located. If the document contains a legal description or map of the access or easement, then the memorandum or notice must include the legal description or map. Upon the surface owner's request, the operator shall provide a copy of the recorded document to the surface owner.

1101.c. Domestic Tap Registration.

- (1) Within 90-days of installation or discovery of a domestic tap connected to the operator's flowline, an operator must submit a Flowline Report, Form 44, to the Director to register the tap. The registration must include the latitude and longitude of the flowline or wellhead connection for the domestic tap and the street address or the latitude and longitude of the point of delivery.
- (2) For domestic taps installed after May 1, 2018, an operator must register the domestic tap

pursuant to subpart (1) and notify the domestic tap owner in writing that the domestic tap must:

- A. Be locatable by a tracer line or location device placed adjacent to or in the trench of the domestic tap to facilitate locating it, and a tracer wire or metallic device for locating must be resistant to corrosion damage;
 - B. Be installed by a licensed plumber;
 - C. Have properly-sized regulators at the point the tap connects to the operator's flowline and at the point the tap delivers gas to the dwelling or structure where the gas is utilized;
 - D. Include all necessary piping to accommodate appropriate odorization and equipment to control vapor content and gas utilization metering;
 - E. Be installed using materials designed for gas service and appropriate cover and bedding material in accordance with industry standards; and
 - F. Have markers that are installed and maintained at the point the domestic tap connects to the operator's flowline and at the point it delivers gas to the dwelling or structure where the gas is utilized consistent with Rule 1102.g.
- (3) An operator must supply odorant to the domestic tap owner at the time of installation until abandonment of the domestic tap.
- (4) Within 30 days of realigning, abandoning, discovering, or receiving notification that a registered domestic tap has been re-aligned or abandoned, the operator must report the change to the Director by submitting a Flowline Report, Form 44.

1101.d. Crude Oil Transfer Line and Produced Water Transfer System Registration.

- (1) **Registration.** At least 10 days before beginning construction of a crude oil transfer line or produced water transfer system, an operator must register it by submitting a Flowline Report, Form 44, to the Director. A produced water transfer system registered as part of a flowline system is not subject to this requirement. An operator may register multiple crude oil transfer lines using a single Form 44 to register those lines as a system.

For a crude oil transfer line or produced water transfer system constructed before May 1, 2018, and already registered with the Commission, operators must submit:

- A. Geographic Information System (GIS) data as required by (2)A., below, on or before December 1, 2020; and
 - B. Update any information required by (2)B., below, to the extent such information becomes known by the operator or can be acquired from such relevant records in the possession of the operator or its immediate predecessor in interest.
- (2) **As-built Specifications.** For a crude oil transfer line or produced water transfer system, the operator must submit a Flowline Report, Form 44, within 90 days of placing it into active status to include the following information:
- A. Geographic Information System (GIS) data that includes the flowline or crude oil transfer line alignment, isolation valves, and the following attributes: fluid type, pipe material type, and pipe size. GIS data shall be submitted in the North American Datum of 1983 (NAD 83) and in a format approved by the Director;

B. Specifications:

- i. Bedding materials used in construction;
- ii. Fluids that will be transferred;
- iii. The maximum anticipated operating pressure, testing pressure, test date, and chart of successful pressure test;
- iv. The pipe description (i.e., maximum size, grade, wall thickness, coating, standard dimension ratio, and material);
- v. The burial depth of the crude oil transfer line or produced water transfer system;
- vi. Description of corrosion protection;
- vii. Description of the integrity management system utilized in accordance with Rule 1104.f.;
- viii. Description of the construction method used for public by-ways, road crossings, sensitive wildlife habitats, sensitive areas and natural and manmade watercourses (i.e., open trench, bored and cased, or bored only); and
- ix. Copy of the operator's crude oil leak protection and monitoring plan prepared in accordance with 1104.g. If an operator has previously filed with the Director a current copy of its leak protection and monitoring plan it may cross reference the oil and gas facility or location for which the leak protection and monitoring plan was previously filed with reference to the API number, facility identification number, or COGCC document number.

C. An affidavit of completion stating the operator designed and installed the crude oil transfer line or produced water transfer system in compliance with the 1100 Series rules.

- (3) Within 90 days of modifying the alignment of a registered crude oil transfer line, the operator must report the change to the Director by submitting a Flowline Report, Form 44.
- (4) For produced water transfer systems that have had system alignment changes during the preceding year, an operator must submit a Flowline Report, Form 44, by May 1st of each year to report the new alignment.
- (5) If a document is executed after May 1, 2018, that grants a right of access or easement to locate a crude oil transfer line or produced water system on lands, then either the document itself or a memorandum or notice of such document must be recorded by the operator in the office of the county clerk and recorder of the county where the lands are located. If the document contains a legal description or map of the access or easement, then the memorandum or notice must include the legal description or map. Upon the surface owner's request, the operator shall provide a copy of the recorded document to the surface owner.

1101.e. Disclosure of Form 44 Data.

- (1) The Director will make Geographic Information System (GIS) data for off-location flowlines, crude oil transfer lines, and produced water transfer systems available through a publicly accessible online map viewer. Line attributes available to the public through the online map viewer will include the spatial location, operator, fluid type, pipe material type, and pipe size. Online map viewer data only will be available at scales greater than or equal to 1:6,000. Any

person may view spatial data at scales less than 1:6,000 for an individual parcel at the Commission's office.

- (2) Upon request from a local governmental designee(s), and subject to executing a confidentiality agreement and the provisions of the Colorado Open Records Act, the Commission will provide to the local government all Geographic Information System (GIS) data submitted through Flowline Reports, Form 44s, for all off-location flowlines, crude oil transfer lines and produced water transfer systems. The local government may only reproduce or publish data that the Commission makes publicly available through its website. A local government may share more specific data in person than that which the Commission makes publicly available, but the information must be treated as confidential and may not be reproduced or published.
- (3) Except as provided in parts (1) and (2), above, the Commission will keep all such Geographic Information System (GIS) data confidential to the extent allowed by the Colorado Open Records Act.

1102. FLOWLINE AND CRUDE OIL TRANSFER LINE REQUIREMENTS

1102.a. **Material.** Materials for pipe and pipe components must be:

- (1) Able to maintain the structural integrity of the flowline or crude oil transfer line under anticipated operating temperature, pressure, and other operating conditions; and
- (2) Compatible with the substances to be transported.

1102.b. **Applicable Technical Standards.** Each component of a flowline or crude oil transfer line installed or repaired must meet one of the following standards appropriate for the component:

- (1) American Society of Mechanical Engineers (ASME), Pipeline Transportation Systems for Liquids and Slurries, 2016 Edition (ASME B31.4-2016), and no later editions of the standard. ASME B31.4-2016 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, ASME B31.4-2016 may be examined at any state publications depository library and is available to purchase from the ASME. The ASME can be contacted at Two Park Avenue, New York, NY 10016-5990, 1-800-843-2763;
- (2) ASME Gas Transmission and Distribution Piping Systems, 2016 Edition (ASME B31.8-2016), and no later editions of the standard. ASME B31.8-2016 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, ASME B31.8-2016 may be examined at any state publications depository library and is available to purchase from the ASME. The ASME can be contacted at Two Park Avenue, New York, NY 10016-5990, 1-800-843-2763;
- (3) ASME Process Piping, 2016 Edition (ASME 31.3-2016), and no later editions of the standard. ASME 31.3-2016 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, ASME 31.3-2016 may be examined at any state publications depository library and is available to purchase from the ASME. The ASME can be contacted at Two Park Avenue, New York, NY 10016-5990, 1-800-843-2763;
- (4) API Specification 15S, Spoolable Reinforced Plastic Line Pipe, Second Edition, March 2016 (API Specification 15S), and no later editions of the standard. API Specification 15S 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,

API Specification 15S may be examined at any state publications depository library and is available from API at 1220 L Street, NW Washington, DC 20005-4070, 1-202-682-8000;

- (5) API RP 15TL4 (R2018) Recommended Practice for Care and Use of Fiberglass Tubulars, Second Edition. March 1999 together with API Specification 15HR, High-pressure Fiberglass Line Pipe, Fourth Edition, February 2016 (API Specification 15HR), and no later editions of the standards. API RP 15TL4 and API Specification 15HR are 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, API RP 15TL4 and API Specification 15HR may be examined at any state publications depository library and are available from API at 1220 L Street, NW Washington, DC 20005-4070, 1-202-682-8000;
- (6) API RP 15TL4 (R2018) Recommended Practice for Care and Use of Fiberglass Tubulars, Second Edition, March 1999, together with API Specification 15LR (R2013), Low Pressure Fiberglass Line Pipe and Fittings, Seventh Edition, August 2001 (API Specification 15LR), and no later editions of the standards. API RP 15TL4 and API Specification 15LR are 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, API RP 15TL4 and API Specification 15LR may be examined at any state publications depository library and are available from API at 1220 L Street, NW Washington, DC 20005-4070, 1-202-682-8000; or
- (7) ASME "Repair of Pressure Equipment and Piping" (ASME PCC-2-2018) and no later editions of the standard. The ASME 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. Additionally, the standard may be examined at any state publications depository library. The ASME standard is available to purchase from ASME at Two Park Avenue, New York, NY 10016-5990, 1-800-843-2763.

1102.c. **Design.** Each component of a flowline or crude oil transfer line must be designed to:

- (1) Prevent failure by minimizing internal or external corrosion and the effects of transported fluids;
- (2) Withstand maximum anticipated operating pressures and other internal loadings without impairment;
- (3) Withstand anticipated external pressures and loads that will be imposed on the pipe after installation;
- (4) Allow for line maintenance, periodic line cleaning, and integrity testing; and
- (5) Have adequate controls and protective equipment to prevent it from operating above the maximum operating pressure.

1102.d. **Installation.**

- (1) Installation crews must be trained in flowline or crude oil transfer line installation practices for which they are tasked to perform.
- (2) All workers performing welding on steel flowline or steel crude oil transfer lines in pressure service, must be certified in accordance with:
 - A. API Standard 1104, Welding of Pipelines and Related Facilities, Twenty First Edition, September 2013 and no later editions of the standard. API Standard 1104 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, API Standard 1104 may be examined at any state publications depository library and is available from API at 1220 L Street, NW Washington, DC 20005-4070, 1-202-682-8000; or

- B. ASME BPV Code 2017 Section IX - Welding, Brazing and Fusing Qualification and no later editions of the code. The Section 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, the ASME BPV Code may be examined at any state publications depository library The ASME BPV Code is available to purchase from the ASME at Two Park Avenue, New York, NY 10016-5990, 1-800-843-2763.
- (3) Non-destructive testing of welds for newly constructed steel off-location flowlines or steel crude oil transfer lines must be done in accordance with one of the following:
- A. Those standards established by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration pursuant to 49 C.F.R. § 192.243 and 49 C.F.R. § 195.234, in existence as of the date of this regulation, and no later amendments. 49 C.F.R. § 192.243 and 49 C.F.R. § 195.234 are 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, 49 C.F.R. § 192.243 and 49 C.F.R. § 195.234 may be found at <https://www.phmsa.dot.gov>; or
 - B. One of the standards set forth in Rule 1102.b. or Rule 1102.d.(2)A. and B., above.
- (4) Non-destructive testing is not required for repairs of existing steel off-location flowlines or steel crude oil transfer lines.
- (5) No pipe or other component may be installed unless it has been visually inspected at the site of installation to ensure that it is not damaged.
- (6) Off-location flowlines and crude oil transfer lines must be locatable by a tracer line or location device placed adjacent to or in the trench of a buried nonmetallic flowline or crude oil transfer line. Any installed tracer wire or metallic device for locating must be resistant to corrosion damage. Caution tape must be placed in the trench above the line and a minimum of one foot below grade. Metallic locatable caution tape may be used to satisfy both the tracer and caution tape requirements, if designed to be a location device.
- (7) Flowlines or crude oil transfer lines must be installed in a manner that minimizes interference with agriculture, land under construction, structures, road and utility construction, wildlife resources, the introduction of secondary stresses, and the possibility of damage to the pipe.
- (8) The pipe must be handled in a manner that minimizes stress and avoids physical damage to the pipe during stringing, joining, or lowering in. During the lowering in process the pipe string must be properly supported so as not to induce excess stresses on the pipe or the pipe joints or cause weakening or damage to the outer surface of the pipe.
- (9) Flowlines or crude oil transfer lines that cross a municipality, county, or state graded road must be bored unless the responsible governing agency specifically permits the operator to open cut the road.
- (10) Flowlines and crude oil transfer lines must be installed pursuant to the manufacturer's specifications. In the absence of applicable manufacturer's specifications, the following requirements apply:

- A. Flowline or crude oil transfer line trenches must be constructed to allow the line to rest on undisturbed native soil and provide continuous support along the length of the pipe;
 - B. Trench bottoms must be free of rocks greater than two inches in diameter, debris, trash, and other foreign material not required for flowline or crude oil transfer line installation; and
 - C. Over excavated trench bottoms must be backfilled with appropriate material and compacted prior to installation of the pipe to provide continuous support along the length of the pipe.
- (11) The width of the trench must provide adequate clearance on each side of the pipe. Trench walls must be excavated to ensure minimal sloughing of sidewall material into the trench. Subsoil from the excavated trench must be stockpiled separately from previously stripped topsoil.
- (12) A flowline or crude oil transfer line trench must be backfilled in a manner that provides firm support under the pipe and prevents damage to the pipe and pipe coating from equipment or from the backfill material. Sufficient backfill material must be placed in the pipe springline to provide long-term support for the pipe. Backfill material that will be within two feet of the pipe must be free of rocks greater than two inches in diameter and foreign debris. Backfilling material must be compacted as appropriate during placement in a manner that provides support for the pipe and reduces the potential for damage to the pipe and pipe joints.
- (13) Flowlines and crude oil transfer lines that traverse sensitive wildlife habitats or sensitive areas, such as wetlands, streams, or other surface waterbodies, must be installed in a manner that minimizes impacts to these areas.

1102.e. Cover for Subsurface Flowlines and Crude Oil Transfer Lines.

- (1) All installed flowlines and crude oil transfer lines must have cover sufficient to protect them from damage. On cropland, all flowlines must have a minimum cover of three (3) feet.
- (2) Where an underground structure, geologic, or other uncontrollable condition prevents a flowline or crude oil transfer line from being installed with minimum cover, or when there is a written agreement between the surface owner and the operator specifying flowline cover depth of less than minimum cover, it may be installed with less than minimum cover or above-ground, if:
 - A. The exposed pipe and components are designed to withstand anticipated conditions;
 - B. The operator installs it in compliance with manufacturer's specifications; and
 - C. The operator installs it in a manner to withstand anticipated external loads.
- (3) Operators must protect above-ground flowlines or crude oil transfer lines, or associated above-ground equipment, from vehicular traffic by installing the lines a safe distance from public roads or installing barricades.

1102.f. Top Soil Management and Reclamation.

- (1) Site preparation and stabilization must be performed in accordance with Rule 1002 for trenches greater than eight inches in width. This requirement to segregate and backfill topsoil does not apply to trenches which are eight inches or less in width. Operator must make reasonable efforts to install flowlines or crude oil transfer lines parallel to crop irrigation rows on flood irrigated land.

- (2) All trenches must be maintained in order to correct subsidence and reasonably minimize erosion.
- (3) Interim and final reclamation, including revegetation, must be performed in accordance with the applicable 1000 Series rules.

1102.g. Marking.

- (1) Where crossing public rights-of-way or utility easement crossings, an operator must install and maintain markers that identify the location of flowlines or crude oil transfer lines. These markers must be placed in a manner to reduce the possibility of damage or interference with surface use but need not be placed where impracticable or if the landowner does not grant permission.
- (2) Operators must install a marker consistent with the version of 49 C.F.R. § 195.410 in existence as of the date of this regulation and does not include later amendments, or the marker must include the following language:

"Warning", "Caution" or "Danger" followed by the words "gas or petroleum (or name of gas or fluid transported) in the flowline (or crude oil transfer line)" along with the name of the operator and the telephone number where the operator can be reached at all times. The letters must be legible, written on a background of sharply contrasting color and on each side with at least one (1) inch high with one-quarter (¼) inch stroke.

49 C.F.R. § 195.410 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, the regulation may be examined at any state publications depository library or found at <https://www.phmsa.dot.gov>.

1102.h. Inspection. Before placing a newly constructed line into active status, a crude oil transfer line or off-location flowline must be inspected by a third-party inspector who is trained in the installation of crude oil transfer lines or off-location flowlines.

- (1) A line constructed of welded steel pipe must be inspected by a third-party inspector who is: a Professional Engineer registered with the State of Colorado, working under the supervision of a Professional Engineer registered with the State of Colorado, a National Welding Inspection School Certified Pipeline Welding Inspector (CPWI), an American Welding Society Certified Welding Inspector (CWI), a National Welding Inspection School Certified Hydrotest Inspector, a National Association of Corrosion Engineers Certified Coating Inspector (Level 1 or higher), or an API Certified Pipeline Inspector.
- (2) A line constructed of materials other than welded steel pipe must be inspected by a third-party inspector who is: a Professional Engineer registered with the State of Colorado, working under the supervision of a Professional Engineer registered with the State of Colorado, or who has been trained on proper installation techniques by the pipe manufacturer or their representative, if available.
- (3) The operator must maintain inspection records, including at a minimum:
 - A. The third-party inspector's certification that the crude oil transfer line was installed as prescribed by the manufacturer's specifications and in accordance with the requirements of the 1100 Series rules; and
 - B. The third-party inspector's certification qualifications.

1102.i. Maintenance.

- (1) Each operator must take reasonable actions to prevent failures and leakage, and minimize corrosion of flowlines and crude oil transfer lines.
- (2) Whenever an operator discovers any condition that could adversely affect the safe and proper operation of a flowline or crude oil transfer line, the operator must correct the condition as soon as possible. However, if the condition presents an immediate hazard to persons or property, the operator may not operate the affected segment until the operator has corrected the condition.
- (3) If the flowline or crude oil transfer line lacks integrity, the operator must immediately investigate, report, and remediate any Spills or Releases in accordance with the 900 Series rules.
- (4) While conducting maintenance, an operator must take reasonable precautions to prevent unintentional releases of pressure or fluid.

1102.j. Repair.

- (1) Each operator must make repairs in a safe manner that prevents injury to persons and damage to equipment and property.
- (2) An operator may not use any pipe, valve, or fitting to repair a flowline or crude oil transfer line unless the component meets the installation requirements of the 1100 Series rules for the repaired segment. For a flowline or crude oil transfer line installed prior to May 1, 2018 that undergoes a major modification or change in status after May 1, 2018, the segment repaired must satisfy all applicable requirements of the 1100 Series rules before an operator can return the flowline or crude oil transfer line to active status.
- (3) An operator may not install or operate any pipe, valve, or fitting for replacement or repair of a flowline or crude oil transfer line unless it is designed to the maximum anticipated operating pressure.
- (4) An operator must verify the integrity of any replaced or repaired segment of flowline or crude oil transfer line before returning it to use.
- (5) An operator must conduct a repair in accordance with the manufacturer's specifications or an applicable technical standard identified in Rule 1102.b.
- (6) Each segment of pipe, valve, or fitting that is found to leak or is unsafe must be replaced or repaired before returning it to service.
- (7) While conducting a repair, an operator must take reasonable precautions to prevent unintentional releases of pressure or fluid.

1102.k. Operating requirements.

- (1) No flowline or crude oil transfer line may be in active status and operated until it has demonstrated compliance with Rule 1104, Integrity Management.
- (2) The maximum operating pressure for a flowline or crude oil transfer line may not exceed the manufacturer's specifications of the pipe or the manufacturer's specifications of any other component of it, whichever is less.

1102.l. Corrosion control.

- (1) All coated pipe for underground service must be electronically inspected prior to installation

using coating deficiency (i.e. scratch, bubble, and “holiday”) detectors to check for any faults not observable by visual examination. The detector must operate in accordance with manufacturer’s specifications and at a voltage level appropriate for the electrical characteristics of the flowline or crude oil transfer line being tested. During installation all joints, fittings, and tie-ins must be coated with materials compatible with the coatings on the pipe. Coating materials must:

- A. Be designed to mitigate corrosion of the buried pipe;
 - B. Have sufficient adhesion to the metal surface to prevent under-film migration of moisture;
 - C. Be sufficiently ductile to resist cracking;
 - D. Have enough strength to resist damage due to handling and soil stress;
 - E. Support any supplemental cathodic protection; and
 - F. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.
- (2) Cathodic protection systems must meet or exceed the minimum criteria set forth in the National Association of Corrosion Engineers (NACE) standard practice SP0169-2007 (formerly RP0169), Control of External Corrosion on Underground or Submerged Metallic Piping Systems, 2007 Edition (NACE SP0169-2007), and no later editions of the standard. NACE SP0169-2007 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, NACE SP0169-2007 may be examined at any state publications depository library and is available to purchase from the NACE. The NACE can be contacted at 15835 Park Ten Place, Houston, Texas 77084, 1-281-228-6200.
- (3) An operator must take prompt remedial action to correct any abnormal internal corrosion. Remedial action may include increased pigging, using corrosion inhibitors, coating the internal flowline or crude oil transfer line (e.g. an epoxy paint or other plastic liner), or a combination of these actions.

1102.m. **Record Keeping.** An operator must maintain records of flowline or crude oil transfer line size, route, materials, maximum anticipated operating pressure, pressure or other integrity test results, inspections, repairs, integrity management documentation, applicable technical standard(s) used, design, installation, cover for subsurface flowlines and crude oil transfer lines, top soil management and reclamation, marking, maintenance and corrosion control, until the operator submits abandonment information pursuant to Rule 1105.f. If an operator relies upon manufacturer’s specifications, it is the operator’s responsibility to ensure the appropriate specifications are available upon request by the Commission. These records are to be transferred with a change of operator.

1102.n. **One Call participation.** Every operator with underground facilities, as defined in §9-1.5-102(7), C.R.S., including wells and below-ground flowlines and crude oil transfer lines, must become a Tier One member of the Utility Notification Center of Colorado (CO 811) and participate in Colorado’s One Call notification system, the requirements of which are established by §9-1.5-101., C.R.S. et seq.

- (1) An operator with underground facilities must confirm its CO 811 membership when submitting an Operator Registration, Form 1, Change of Operator, Form 10, Gas Facility Registration, Form 12, or Flowline Report, Form 44.

- (2) An operator that does not have underground facilities is exempt from the CO 811 membership requirement.
- (3) Within 30 days of completing an asset purchase, a transfer, construction or relocation of a flowline or crude oil transfer line, an operator must update the operator's location information with CO 811.
- (4) An operator's registration with the Commission grants the Director permission to access information the operator submits to CO 811 about its oil and gas facilities.

1102.o. Requirements for shut-in or out of service off-location flowline or crude oil transfer line for inspection.

- (1) For an active status off-location flowline or crude oil transfer line that has been shut-in, meaning that the line contains fluids associated with oil and gas operations, but is not flowing fluids, for more than 90 days, the operator must:
 - A. Apply a tag out device to each riser associated with the line;
 - B. Continue to comply with the integrity management requirements of Rule 1104;
 - C. Pressure test the off-location flowline or crude oil transfer line in accordance with Rule 1104.h. before returning the line to operation; and
 - D. Not less than 48 hours prior to pressure testing, submit notice with a Field Operations Notice, Form 42 – Notice of Return to Service, to the Director of the scheduled date for the pressure test to allow the Commission to inspect during the pressure test.
- (2) For an off-location flowline or a crude oil transfer line that has been out of service for more than 90 days, the operator must:
 - A. Within 120 days of applying OOSLAT, submit a Flowline Report, Form 44, to the Director identifying the off-location flowline or crude oil transfer line or segment thereof that has been taken out of service and the outcome of the most recent integrity management test.
 - B. Pressure test the off-location flowline or crude oil transfer line in accordance with Rule 1104.h. before returning the line to active status; and
 - C. Not less than 48 hours prior to pressure testing, submit notice with a Field Operations Notice, Form 42 – Notice of Return to Service, to the Director of the scheduled date for the pressure test to allow the Commission to inspect during the pressure test.

1103. FLOWLINE AND CRUDE OIL TRANSFER LINE VALVES

1103.a. Isolation valve repair and maintenance.

- (1) Operators must annually conduct one of the following maintenance operations on all isolation valves:
 - A. Perform a function test; or
 - B. Maintain the isolation valve in accordance with its manufacturer's specifications.
- (2) Operators must repair or replace isolation valves that are not fully operable.

- (3) On-location manifold, peripheral and process piping flowlines are exempt from the annual maintenance operations set forth in this section Rule 1103.a.(1).

1103.b. Any valve, flange, fitting or other component that is connected to a flowline or crude oil transfer line must have a manufacturer's specification rating that is equal to or greater than the maximum anticipated operating pressure.

1103.c. For all flowlines or crude oil transfer lines constructed after May 1, 2018, an isolation valve must be installed at each of the following locations before being placed into active status:

- (1) On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency;
- (2) On each flowline or crude oil transfer line entering or leaving a breakout tank in a manner that permits isolation of the breakout tank from other facilities;
- (3) At locations along a flowline or crude oil transfer line that will minimize damage or pollution from accidental discharge of hydrocarbons or E&P Waste, as appropriate for the terrain in open country or for populated areas;
- (4) On each side of a flowline or crude oil transfer line crossing a Rule 317B Public Water System defined water supply or a waterbody that is more than 100 feet (30 meters) wide from high-water mark to high-water mark; and
- (5) On each side of a flowline or crude oil transfer line crossing a reservoir storing water for human consumption.

1103.d. Flowlines and crude oil transfer lines constructed before May 1, 2018, must be retrofitted with isolation valves at each of the locations identified in Rule 1103.c.(1)-(5) by October 31, 2019. On-location manifold, peripheral and process piping flowlines are exempt from the retrofit provisions set forth in this section 1103.d.

1103.e. Check Valve Installation Requirements.

- (1) Where an operator produces two or more wells through a common flowline, separator, or manifold, the operator must equip each flowline leading from a well to the common flowline, crude oil transfer line, separator, or manifold with a check valve or other comparable reverse flow prevention mechanism.
- (2) The check valve or other comparable reverse flow prevention mechanism must be installed to permit fluids to move from the well to the common flowline, crude oil transfer line, separator, or manifold and to prevent any fluid from entering the well through the flowline.
- (3) The operator must keep all check valves or other comparable reverse flow mechanisms in good working order.
- (4) Upon the Director's request, operators must test the operation of the check valve or other comparable reverse flow mechanism.
- (5) The requirements set forth in subsection (1) and (2) above, apply only to those check valves or comparable reverse flow mechanisms installed after May 1, 2018. Existing check valves or comparable reverse flow mechanisms must comply with subsection (3) and (4) above.

1104. INTEGRITY MANAGEMENT

1104.a. Initial Pressure Testing Requirements.

- (1) Within 90 days prior to placing any newly installed segment of flowline or crude oil transfer line into active status, an operator must test the line to at least maximum anticipated operating pressure and demonstrate integrity.
- (2) If an operator successfully completes an initial pressure test for an off-location flowline or crude oil transfer line, but does not place the line into active status within 90 days, the line may remain in pre-commissioned status and will not require an additional initial pressure test if:
 - A. The operator applied best practices to protect the line's integrity for the time between completing the successful initial pressure test and placing the line into active status; and
 - B. The operator submits a Field Operations Notice, Form 42 – Notice of Return to Service, to the Director of the scheduled date for placing the line into active status not less than 48 hours prior to placing the line into service.
- (3) In conducting tests, each operator must ensure that reasonable precautions are taken to protect its employees and the general public.
- (4) The operator may use a hydrostatic test or conduct the test using inert gas or wellhead pressure sources and well bore fluids, including gas, in accordance with one of the applicable standards set forth in Rule 1104.h.(1) below.

1104.b. **Testing upon request.** An operator will conduct an integrity test of any segment of flowline or crude oil transfer line at any time upon request of the Director.

1104.c. **Integrity Management for Active Status Below-ground Dump Lines.** An operator must verify integrity of below-ground dump lines by performing an annual static-head test and a monthly audio, visual, olfactory (AVO) detection survey of the entire line.

1104.d. **Integrity Management for Active Status Above-ground On-location Flowlines.** An operator must verify the integrity of above-ground on-location flowlines by performing a monthly audio, visual, olfactory (AVO) detection survey of the entire flowline.

1104.e. Integrity Management for Active Status Below-Ground On-location Flowlines.

- (1) For any below-ground on-location flowlines not subject to Rule 1104.c. or d., above, an operator must adhere to one of the following integrity management programs:
 - A. A pressure test to maximum anticipated operating pressure every three years;
 - B. Smart pigging conducted every three years;
 - C. Continuous pressure monitoring; or
 - D. Annual instrument monitoring conducted pursuant to Rule 1104.j.(2).
- (2) If an operator elects to use smart pigging to comply with this section, the smart pig must be able to measure flowline wall thickness, and measure for flowline defects that could affect integrity, including measurement of metal loss. If no Geographic Information System (GIS) data of the flowline exists, the smart pig will have GPS capabilities to the extent such capabilities do not materially compromise the ability of the smart pig to conduct the integrity testing required

by this section.

1104.f. Integrity Management for Active Status Off-Location Flowlines and Crude Oil Transfer Lines.

- (1) For active status off-location flowlines and crude oil transfer lines, but not including off-location produced water flowlines, operators must adhere to one of the following integrity management programs:
 - A. An annual pressure test to maximum anticipated operating pressure;
 - B. Continuous pressure monitoring;
 - C. Smart pigging conducted every three years; or
 - D. Annual instrument monitoring conducted pursuant to Rule 1104.j.(2).
- (2) For active status off-location below-ground produced water flowlines, operators must adhere to one of the following integrity management programs:
 - A. An annual pressure test to maximum anticipated operating pressure;
 - B. Continuous pressure monitoring; or
 - C. Smart pigging conducted every three years.
- (3) For active status above-ground off-location produced water flowlines, operators may use any of the options listed in Rule 1104.f.(2), or monthly AVO inspections.
- (4) If an operator elects to use smart pigging to comply with this section, the smart pig must be able to measure flowline wall thickness, and measure for flowline defects that could affect integrity, including measurement of metal loss. If no geodatabase file of the flowline exists, the smart pig will have GPS capabilities to the extent such capabilities do not materially compromise the ability of the smart pig to conduct the integrity testing required by this section.

1104.g. Leak protection, detection, and monitoring.

- (1) All crude oil transfer line operators must prepare and file with the Director a leak protection and monitoring plan with their registration.
- (2) All crude oil transfer line operators must develop and maintain a plan to coordinate the assessment of all inflow and outflow data. The plan must provide for the assessment of inflow and outflow data between the production facility operator, the crude oil transfer line operator, and the operator at the point or points of disposal, storage, or sale. Upon discovery of a material data discrepancy, the discovering party is to notify all other appropriate parties and take action to determine the cause. The crude oil transfer line operator is to retain a record of all material data discrepancies.

1104.h. Pressure Test Requirements.

- (1) Initial Pressure Test.
 - A. Before putting an off-location flowline or crude oil transfer line into active status, the successful initial pressure test must be conducted for a minimum of four hours or in compliance with the manufacturer's specifications and in accordance with one of the following applicable standards.

- i. American Society of Mechanical Engineers (ASME), Process Piping, 2016 Edition (ASME 31.3-2016) and no later edition;
 - ii. ASME Pipeline Transportation Systems for Liquids and Slurries, 2016 Edition (ASME B31.4-2016) and no later edition;
 - iii. ASME Gas Transmission and Distribution Piping Systems, 2016 Edition (ASME B31.8-2016) and no later edition;
 - iv. API Specification 15S, Spoolable Reinforced Plastic Line Pipe, Second Edition, March 2016 (API Specification 15S) and no later edition;
 - v. API RP 15TL4 (R2018) Recommended Practice for Care and Use of Fiberglass Tubulars, Second Edition, March 1999, together with API Specification 15HR, High-pressure Fiberglass Line Pipe, Fourth Edition, February 2016 (API Specification 15HR), and no later editions;
 - vi. 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 (6th Ed., February 1, 2013) (API RP 1110) and no later edition; or
 - vii. ASTM F2164-13, Standard Practice for Field Leak Testing of Polyethylene (PE) and Crosslinked Polyethylene (PEX) Pressure Piping Systems Using Hydrostatic Pressure, and no later edition, or manufacturer's specifications and must test the line to at least maximum anticipated operating pressure.
- B. The ASME, API and ASTM standards identified in A. above are 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, the standards may be examined at any state publications depository library. The ASME standards are available to purchase from the ASME at Two Park Avenue, New York, NY 10016-5990, 1-800-843-2763. The API standard is available to purchase from the API at 1220 L Street, NW Washington, DC 20005-4070, 1-202-682-8000. The ASTM standard is available to purchase from the ASTM at ASTM International, West Conshohocken, PA, 19428-2959, 1-877-909-2786.
- C. Before putting an on-location flowline into active status, the initial pressure test must be conducted in compliance with the manufacturer's specifications or in accordance with one of the applicable standards identified in Rule 1104.h.(1)A.
- D. The initial pressure test can be hydrostatic or the test fluid can be the produced fluids of oil, condensate, produced water, or natural gas or inert gas in accordance with the applicable sections of the above-mentioned standards.
- E. A successful initial pressure test must demonstrate that the flowline or crude oil transfer line does not leak.
- (2) **Annual and Triennial Pressure Testing Requirements.** For annual or triennial pressure tests conducted to meet the requirements of Rules 1104.e and 1104.f:
- A. A pressure test must test to at least the maximum operating pressure and run for at least 30 minutes once the fluid pressure has stabilized.
 - B. The test can be hydrostatic or the test fluid can be the produced fluids of oil, produced water or natural gas.

- C. A successful test will demonstrate the flowline or crude oil transfer line does not leak, that pressure loss does not exceed 10%, and the fluid pressure is stable for the last five minutes of the pressure test.

1104.i. **Continuous Pressure Monitoring Requirements.** An operator's continuous pressure monitoring program must meet API RP 1175 "Pipeline Leak Detection Program Management" (2017), and no later editions of the standard, and ensure:

- (1) Pressure data are monitored continuously, i.e., 24 hours per day and 7 days a week, and the monitoring is sufficiently sophisticated to identify flowline or crude oil transfer line integrity or pressure anomalies;
- (2) Systems are capable of being shut-in for repairs immediately upon discovery of a suspected leak, either through automation or a documented, manual process;
- (3) The operator documents the continuous monitoring program, including suspected or identified integrity failures and how the operator will maintain and repair flowlines or crude oil transfer lines; and
- (4) The API RP 1175 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, API RP 1175 may be examined at any state publications depository library and is available from API at 1220 L Street NW, Washington, DO 20005-4070, 1-202-682-8000.

1104.j. **Audio, Visual and Olfactory (AVO) Detection Survey or Alternative Survey Requirements.**

- (1) When performing an AVO detection survey, an operator must survey the entire flowline length using audio, visual and olfactory techniques to detect integrity failures, leaks, spills, or releases, or signs of a leak, spill, or release like stressed vegetation or soil discoloration.
- (2) Instrument Monitoring Method (IMM). Where the regulations permit, an operator also may conduct a survey using an instrument monitoring method capable of detecting integrity failures, leaks, spills or releases, or signs of a leak, spill or release.
- (3) For either survey method, an operator must document the date and time of the survey, the detection methodology and technology, if any, used and the name of the employee who conducted the survey.

1104.k. **Integrity Failure Investigation.**

- (1) If the integrity management program indicates that a flowline or crude oil transfer line has or has had an integrity failure, the operator must investigate the cause of the failure, investigate whether the failure resulted in a spill or release of liquids, produced water, or gas, and repair any failure as required by Rule 1102.j.
- (2) If the failure resulted in a spill or release of liquids, produced water or gas, the operator must comply with the 900 Series Rules.

1105. ABANDONMENT

1105.a. A flowline or crude oil transfer line remains subject to all of the requirements in Rules 1101 through 1104 until the operator completes all abandonment requirements set forth below.

1105.b. Upon removing a flowline or crude oil transfer line from use with the intent to abandon, an operator must immediately apply OOSLAT to the risers. OOSLAT must stay in place at all times during the process of abandoning the flowline or crude oil transfer line until the operator removes the riser.

1105.c. **Isolation.** When abandoning a flowline or crude oil transfer line, operators must permanently remove a flowline or crude oil transfer line from operation by physically separating it from all sources of fluids or pressure within the time frame set forth in Section 1004.a.

1105.d. **Pre-abandonment notice requirements for flowline or crude oil transfer line for inspection.** Operators must remove the flowline or crude oil transfer line and its risers, the riser associated with cathodic protection, and above-ground equipment, except where abandonment in place is less impactful as articulated in subparts (2) and (3).

(1) For on-location flowlines, the operator must submit notice to the Director of the scheduled date for commencing abandonment with a Field Operations Notice, Form 42 – Abandonment of Flowlines no less than 30 days before the operator will commence abandonment.

(2) If the off-location flowline or crude oil transfer line will be removed or abandoned in place pursuant to one of the following exceptions, the operator must submit notice to the Director of the scheduled date for commencing abandonment that includes appropriate documentation. The operator must submit the notice and appropriate documentation no less than 30 days before the operator will commence abandonment. The Director may review the notice, if necessary, to determine whether the proposed abandonment process is less impactful to public health, safety, welfare, the environment and wildlife resources. The Director's determination, if any, must be completed within 30 days of receiving the notice. Abandonment in place is allowed pursuant to the process in this section if:

- A. A surface owner agreement executed by a surface owner allows abandonment in place;
- B. The line is subject to the jurisdiction of the federal government, and the relevant federal agency directs abandonment in place;
- C. The flowline or crude oil transfer line is co-located with other active pipelines or utilities or is in a recorded right of way;
- D. Removal of the flowline or crude oil transfer line would cause significant damage to natural resources, including wildlife resources, topsoil, or vegetation;
- E. The flowline or crude oil transfer line is in a restricted surface occupancy area or sensitive wildlife habitat;
- F. The flowline or crude oil transfer line or a segment of the line crosses or is within 30 feet of a public road, railroad, bike path, public right of way, utility corridor, or active utility or pipeline crossing;
- G. The flowline or crude oil transfer line or a segment of the line crosses or is within 30 feet of or under a river, stream, lake, pond, reservoir, wetlands, watercourse, waterway, or spring; or
- H. The operator demonstrates and quantifies that the removal of the flowline or crude oil transfer line will cause significant emissions of air pollutants.

(3) An operator may request abandonment in place for off-location flowlines or crude oil transfer lines for reasons other than those articulated in section (2). The operator must request abandonment in place by submitting to the Director a Flowline Report, Form 44, no less than

30 days before the operator plans to commence abandonment. The Flowline Report must include documentation demonstrating that abandonment in place, considering any mitigation measures or best management practices, will be less impactful to public health, safety, welfare, the environment, and wildlife resources than removal. The Director may not approve the request for abandonment in place for the line or a portion thereof unless the Director finds that abandonment in place causes less impacts to public health, safety, welfare, the environment, and wildlife resources than removal.

- (4) Unless waived, the operator must provide notice to the surface owner and the relevant local government simultaneously with submitting notice to the Director pursuant to this Rule 1105.d. The local government or surface owner must provide their comments to the Director within 15 days of receipt, regarding the proposed abandonment's impacts to public health, safety, welfare, the environment, and wildlife resources.

1105.e. **Abandonment in place requirements.** For a flowline or crude oil transfer line abandoned in place, the operator must:

- (1). Evacuate the flowline or crude oil transfer line of any hydrocarbons or produced water to ensure the line is safe and inert;
- (2). Deplete the flowline or crude oil transfer line to atmospheric pressure;
- (3). Cut the flowline's or crude oil transfer line's risers to three (3) feet below grade or to the depth of the flowline or crude oil transfer line, whichever is shallower;
- (4). Seal the ends of the flowline or crude oil transfer line below grade;
- (5). Remove above-ground cathodic protection and equipment associated with the riser; and
- (6). Include pressure test results conducted in the prior 12 months as well as identification of any document numbers for a COGCC Spill/Release Report, Form 19, associated with the abandoned line with the Flowline Report, Form 44, submitted pursuant to Rule 1105.f.(2); and
- (7). For an off-location flowline or crude oil transfer line abandoned in place pursuant to Rule 1105.d.(2), the operator must submit documentation supporting the applicable reason for abandonment in place with the Flowline Report, Form 44, submitted pursuant to Rule 1105.f.(2).

1105.f. **Abandonment Verification.** Within 90 days of an operator completing abandonment requirements for a flowline or crude oil transfer line, an operator must submit:

- (1) A Field Operations Notice, Form 42 – Abandonment of Flowlines, to the Director for an on-location flowline. If the operator conducted a pressure test as part of the abandonment, a copy of the pressure test shall be submitted with the Report of Abandonment, Form 6 – Subsequent.
- (2) A Flowline Report, Form 44, to the Director for an off-location flowline or crude oil transfer line, which must include:
 - A. Geographic Information System (GIS) data that includes line alignment, if such GIS data has not been submitted to the Commission for the line;
 - B. An account of the manner in which the abandonment work was performed;
 - C. Copies of any pressure test results run as part of the abandonment shall be submitted with the Form 44 for off-location flowlines and crude oil transfer lines; and

D. If the line was abandoned in place, verification performed by a third party who:

- i. Observed that the abandonment requirements of Rule 1105.e.(1)-(4) were met; and
- ii. Is a Professional Engineer registered with the State of Colorado, working under the supervision of a Professional Engineer registered with the State of Colorado, or has specific training and experience abandoning lines in accordance with the requirements of Rule 1105.

1105.g. The Director will provide a Field Operations Notice, Form 42 – Abandonment of Flowlines, for an on-location flowline abandonment or a Flowline Report, Form 44, filed pursuant to Rule 1105.f. for an off-location flowline or crude oil transfer line abandonment to the appropriate Local Governmental Designee and CO 811.

PROTECTION OF WILDLIFE RESOURCES

1201. IDENTIFICATION OF WILDLIFE SPECIES AND HABITATS

Prior to the preparation of a Comprehensive Drilling Plan or the submittal of a Form 2A for a proposed new oil and gas location, an operator shall review the Sensitive Wildlife Habitat map and the Restricted Surface Occupancy map maintained by the Commission on its website and attached as Appendices VII and VIII to determine whether the proposed oil and gas location falls within Sensitive Wildlife Habitat or a Restricted Surface Occupancy area. The operator shall include this determination in the Form 2A or Comprehensive Drilling Plan.

1202. CONSULTATION

- a. The purpose of consultation under Rule 306.c is to allow the Director to determine whether conditions of approval are necessary to minimize adverse impacts from the proposed oil and gas operations in the identified sensitive wildlife habitat or restricted surface occupancy area, in an order increasing well density, or in a basin-wide order involving wildlife resource issues and to evaluate requests for variances from the provisions of the 1200-Series Rules. For purposes of this rule, minimize adverse impacts shall mean wherever reasonably practicable, to (i) avoid adverse impacts from oil and gas operations on wildlife resources, (ii) minimize the extent and severity of those impacts that cannot be avoided, (iii) mitigate the effects of unavoidable remaining impacts, and (iv) take into consideration cost-effectiveness and technical feasibility with regard to actions taken and decisions made to minimize adverse impacts to wildlife resources, consistent with the other provisions of the Act.
- b. Unless excepted as set forth in Rule 1202.d, when a proposed new oil and gas location is located in sensitive wildlife habitat or a restricted surface occupancy area, the Colorado Parks and Wildlife shall consult with the operator, the surface owner, and the Director in accordance with Rule 306.c. prior to approval of a Form 2A to identify possible conditions of approval.
- c. Any conditions of approval resulting from such consultation shall be guided by the list of Best Management Practices for Wildlife Resources maintained on the Commission website. In selecting conditions of approval from such Best Management Practices or other sources, the Director shall consider the following factors, among other considerations:
 - (1) The Best Management Practices for the producing geologic basin in which the oil and gas location is situated;
 - (2) Site-specific and species-specific factors of the proposed new oil and gas location;
 - (3) Anticipated direct and indirect effects of the proposed oil and gas location on wildlife resources;
 - (4) The extent to which conditions of approval will promote the use of existing facilities and reduction of new surface disturbance;
 - (5) The extent to which legally accessible, technologically feasible, and economically practicable alternative sites exist for the proposed new oil and gas location;
 - (6) The extent to which the proposed oil and gas operations will use technology and practices which are protective of the environment and wildlife resources;

- (7) The extent to which the proposed oil and gas location minimizes surface disturbance and habitat fragmentation;
- (8) The extent to which the proposed oil and gas location is within land used for residential, industrial, commercial, agricultural, or other purposes, and the existing disturbance associated with such use; and
- (9) Permit conditions, lease terms, and surface use agreements that predate December 11, 2008.

d. Consultation under Rule 306.c shall not be required if:

- (1) The Director or Commission has previously approved a Form 2A or Comprehensive Drilling Plan which includes the proposed new oil and gas location;
- (2) The Colorado Parks and Wildlife has previously approved, in writing, a wildlife mitigation plan or other wildlife protection or conservation plan that remains in effect for the area that includes the proposed new oil and gas location and the oil and gas location is in compliance with such plan;
- (3) The operator demonstrates that the identified habitat and/or species, where applicable, is not in fact present to support the identified species and use, such as where the proposed oil and gas location is located in a high density area, designated pursuant to Rule 603.b, or within an incorporated homeowners association or city or town limits;
- (4) The proposed new well would involve a one-time increase in surface disturbance of one (1) acre or less per well site at or immediately adjacent to an existing well site;
- (5) The operator applies for and obtains a Commission order pursuant to Rule 503 providing that there will not be more than three (3) well sites per section, with ground disturbing activity during the period from January 1 to March 31 (or other biologically appropriate alternative period up to ninety (90) consecutive days as determined by the Director for bighorn sheep winter range, elk production areas, bald or golden eagle nest or roost sites, columbian or plains sharp-tailed grouse production areas, greater or Gunnison sage grouse production areas, black-footed ferret release areas, or lesser prairie chicken production areas) limited to one (1) such well site, as determined by the Director. This exemption from consultation shall not apply to operations in occupied greater sage grouse sensitive wildlife habitat in Moffat, Routt, or Jackson Counties or in occupied Gunnison sage grouse sensitive wildlife habitat in Delta, Mesa, Gunnison, San Miguel, Dolores, or Montezuma Counties;
- (6) The Director grants a variance pursuant to Rule 502.b; or
- (7) The Colorado Parks and Wildlife waives the consultation requirement.

e. No permit-specific condition of approval for wildlife habitat protection under this rule shall be imposed without surface owner consent, including any permit-specific conditions for wildlife habitat protection that modify, add to, or differ materially from the general operating requirements in Rules 1203 and 1204. If the surface owner fails to consent to any such permit-specific condition of approval, then the parties shall consult with the surface owner regarding alternative conditions of approval acceptable to the surface owner.

1203. GENERAL OPERATING REQUIREMENTS IN SENSITIVE WILDLIFE HABITAT AND RESTRICTED SURFACE OCCUPANCY AREAS

a. **General Operating Requirements.** Within sensitive wildlife habitat and restricted surface occupancy areas, operators shall comply with the operating requirements listed below.

- (1) During pipeline construction for trenches that are left open for more than five (5) days and are greater than five (5) feet in width, install wildlife crossovers and escape ramps where the trench crosses well-defined game trails and at a minimum of one quarter (1/4) mile intervals where the trench parallels well-defined game trails.
- (2) Inform and educate employees and contractors on wildlife conservation practices, including no harassment or feeding of wildlife.
- (3) Consolidate new facilities to minimize impact to wildlife.
- (4) Minimize rig mobilization and demobilization where practicable by completing or recompleting all wells from a given well pad before moving rigs to a new location.
- (5) To the extent practicable, share and consolidate new corridors for pipeline rights-of-way and roads to minimize surface disturbance.
- (6) Engineer new pipelines to reduce field fitting and reduce excessive right-of-way widths and reclamation.
- (7) Use boring instead of trenching across perennial streams considered critical fish habitat.
- (8) Treat waste water pits and any associated pit containing water that provides a medium for breeding mosquitoes with Bti (*Bacillus thuringiensis v. israelensis*) or take other effective action to control mosquito larvae that may spread West Nile Virus to wildlife, especially grouse.
- (9) Use wildlife appropriate seed mixes wherever allowed by surface owners and regulatory agencies.
- (10) Mow or brushhog vegetation where appropriate, leaving root structure intact, instead of scraping the surface, where allowed by the surface owner.
- (11) Limit access to oil and gas access roads where approved by surface owners, surface managing agencies, or local government, as appropriate.
- (12) Post speed limits and caution signs to the extent allowed by surface owners, Federal and state regulations, local government, and land use policies, as appropriate.
- (13) Use wildlife-appropriate fencing where acceptable to the surface owner.
- (14) Use topographic features and vegetative screening to create seclusion areas, where acceptable to the surface owner.
- (15) Use remote monitoring of well production to the extent practicable.
- (16) Reduce traffic associated with transporting drilling water and produced liquids through the use of pipelines, large tanks, or other measures where technically feasible and economically practicable.

- b. **Exceptions.** If the operator believes that any of the foregoing operating requirements should be waived for any proposed oil and gas location, it shall so specify in a Form 2A for Director consideration.

1204. OTHER GENERAL OPERATING REQUIREMENTS

- a. The operating requirements identified below shall apply in all areas.

- (1) In black bear habitat west of Interstate 25 and on Raton Mesa east of Interstate 25, operators shall install and utilize bear-proof dumpsters and trash receptacles for food-related trash at all facilities that generate such trash.
- (2) In designated Cutthroat Trout habitat, as identified on the Colorado Parks and Wildlife Species Activity Mapping (SAM) system, operators shall disinfect water suction hoses and water transportation tanks withdrawing from or discharging into surface waters (other than contained pits) used previously in another river, lake, pond, or wetland and discard rinse water in an approved disposal facility. Disinfection practices shall be repeated after completing work or before moving to the next water body. Disinfection may be performed by removing mud and debris and then implementing one of the following practices:
 - A. Spray/soak equipment with a disinfectant solution capable of killing whirling disease spores; or
 - B. Spray/soak equipment with water greater than 140 degrees Fahrenheit (140° F) for at least 10 minutes.
- (3) To minimize adverse impacts to wildlife resources, plan new transportation networks and new oil and gas facilities to minimize surface disturbance and the number and length of oil and gas roads and utilize common roads, rights of way, and access points to the extent practicable, consistent with these rules, an operator's operational requirements, and any requirements imposed by federal and state land management agencies, local government regulations, and surface use agreements and other surface owner requirements, and taking into account cost effectiveness and technical feasibility.
- (4) Establish new staging, refueling, and chemical storage areas outside of riparian zones and floodplains.
- (5) Use minimum practical construction widths for new rights-of-way where pipelines cross riparian areas, streams, and critical habitats.

- b. **Exceptions.** If the operator believes that any of the foregoing operating requirements should be waived for any proposed oil and gas location, it shall so specify in a Form 2A for Director consideration.

1205. REQUIREMENTS IN RESTRICTED SURFACE OCCUPANCY AREAS

- a. Operators shall avoid Restricted Surface Occupancy areas to the maximum extent technically and economically feasible when planning and conducting new oil and gas development operations, except:
- (1) When authorized following consultation under Rule 306.c.(3);
 - (2) When authorized by a Comprehensive Drilling Plan;

- (3) Upon demonstration that the identified habitat is not in fact present;
 - (4) When specifically exempted by the Colorado Parks and Wildlife; or
 - (5) In the event of situations posing a risk to public health, safety, welfare, or the environment.
- b. As set forth in Rule 1205.a, new ground disturbing activities are to be avoided in Restricted Surface Occupancy areas, including construction, drilling and completion, non-emergency workovers, and pipeline installation activity, to minimize adverse impacts to wildlife resources. Production, routine maintenance, repairs and replacements, emergency operations, reclamation activities, or habitat improvements are not prohibited in Restricted Surface Occupancy areas. Notwithstanding the foregoing, non-emergency workovers, including uphole recompletions, may be performed with prior approval of the Director on a schedule that minimizes adverse impacts to the species for which the restricted surface occupancy area exists.
- c. **Applicability.** The requirements of Rule 1205 are not applicable to Applications for Permit-to-Drill, Form 2, or Oil and Gas Location Assessments, Form 2A, which are approved prior to May 1, 2009 on federal land or April 1, 2009 on all other land. The requirements of Rule 1205 are also not applicable until January 1, 2010, for any proposed oil and gas location in a Restricted Surface Occupancy area where the operator has in good faith initiated and is diligently pursuing consultation on the proposed oil and gas location begun prior to May 1, 2009 on federal land or April 1, 2009 on all other land, pursuant to Rule 306.c or Rule 216.