RULES AND REGULATIONS

DEFINITIONS
(100 Series)

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

AFFECTED PERSON means any person who satisfies the requirements of Rule 507.a.

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.

AVOID ADVERSE IMPACTS means to differentially select alternative locations, practices, or methods for Oil and Gas Operations based on site-specific circumstances, so that those operations will not cause quantifiable direct, indirect, or cumulative adverse impacts to the potentially affected resource(s). Avoidance may include a no action alternative.

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

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

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

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.

CDPHE means the Colorado Department of Public Health and Environment.

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 means a facility, other than a commercial disposal facility regulated by CDPHE, 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 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 Multi-Well Pit that meets the standards of Rules 909.g.(2)–(3).

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 means a list of the Chemical Products (including 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 will 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 means 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 Regulation Number 31, Basic Standards and Methodologies for Surface Water Regulations, 5 C.C.R. § 1002-31 ("WQCC Regulation 31"), except for ephemeral streams. Specific determinations of segments classified for the water supply use are documented in the WQCC's basin regulations, 5 C.C.R. §§ 1002-32–38. Only the versions of WQCC Regulations 31–38 that are in effect as of January 15, 2021 apply; later versions do not apply. WQCC Regulations 31–38 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, WQCC Regulations 31–38 may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and are available at https://www.colorado.gov/pacific/cdphe/water-quality-control-commission-regulations.

CLASS II UIC WELL means Wells which inject Fluids:

a. Which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection; and

b. For enhanced recovery of oil or natural gas.

COMMENCEMENT OF PRODUCTION OPERATIONS means the date that product consistently flows to a sales line, Gathering Line, or Tank from a Well.

COMMERCIAL DISPOSAL WELL means a Class II UIC Well that receives Class II Exploration and Production Waste from multiple non-owner Operators.

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

COMPENSATORY MITIGATION PLAN means a plan submitted pursuant to Rule 1203.b to offset the direct and Unavoidable Adverse indirect Impacts to Wildlife Resources from Oil and Gas Operations. A Compensatory Mitigation Plan may be one component of a Wildlife Mitigation Plan submitted pursuant to Rules 304.c.(17) & 1201.b.

COMPLETED WELL means a Well in which oil or gas is produced through wellhead equipment from the producing interval(s) after the production string has been installed.

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 AREA PLAN means a plan created by one or more Operator(s) covering future Oil and Gas Operations and addressing cumulative impacts in a defined geographic area.

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.

CONFINING LAYER means that portion of a separate stratigraphic layer that acts as an effective impermeable barrier to the vertical migration of gases or other fluids into any separate strata or zones that contain groundwater.

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.

CPW means the Colorado Division of Parks and Wildlife.

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.

CUTTINGS TRENCH means a depression used specifically for the onsite storage and disposal of dried cuttings generated from drilling a Well.

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.

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.

DIRECTOR'S RECOMMENDATION means the Director's written recommendation to the Commission about whether to approve or deny an Oil and Gas Development Plan pursuant to Rule 306, or whether to approve or deny a Comprehensive Area Plan pursuant to Rule 314.g.

DISPROPORTIONATELY IMPACTED COMMUNITY means communities of color, low-income, or indigenous populations in the state that potentially experience disproportionate environmental or socioeconomic impacts and risks, as described in § 25-7-105(1)(e)(III), C.R.S. For purposes of the Commission's Rules, Disproportionately Impacted Communities are identified as:

a. A U.S. Census block group in which more than 50% of the population meets the definition of a "minority population" pursuant to the U.S. Environmental Protection Agency's ("EPA") Technical Guidance for Assessing Environmental Justice in Regulatory Analysis (June 2016). Only the June 2016 edition of EPA's Technical Guidance for Assessing Environmental Justice in Regulatory Analysis applies to this definition; later amendments do not apply. All materials incorporated by reference in this definition 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, CO 80203. In addition, these materials may be examined at the U.S. Environmental Protection Agency, Region 8, 1595 Wynkoop Street, Denver, CO 80202, and are available online at https://www.epa.gov/sites/production/files/2016-06/documents/ejtg_5_6_16_v5.1.pdf.

b. A. U.S. Census block group in which the percentage of the population that meets the definition of a "minority population" pursuant to the EPA's Technical Guidance for Assessing Environmental Justice in Regulatory Analysis, as incorporated by reference in subpart a, exceeds the percentage of the minority population of the county.

c. A U.S. Census block group in which the median household income as identified by the U.S. Census Bureau's American Community Survey ("ACS") is less than or equal to 200% of the federal poverty guideline for a household of three pursuant to the U.S. Department of Health and Human Services ("DHHS") Poverty Guidelines. Only the 2015–2019 version of the ACS data applies to this definition; later amendments do not apply. Only the 2020 DHHS Poverty Guidelines apply to this definition; later amendments do not apply. The U.S. Census Bureau's 2015–2019 ACS data and the DHHS 2020 Poverty Guidelines 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, CO 80203. In addition, the 2015–2019 version of the ACS data may be examined at the U.S. Census Bureau's Headquarters at 4600 Silver Hill Road, Washington, DC 20233, and may be accessed online at www.census.gov/data/developers/data-sets/acs-5year.html. The 2020 DHHS Poverty Guidelines may be examined at the Hubert H. Humphrey Building, 200 Independence Avenue, S.W., Washington, DC 20201, and may be accessed online at https://aspe.hhs.gov/poverty-guidelines.

d. A U.S. Census block group in which 20% or more of the population is classified as linguistically isolated pursuant to the U.S. Census Bureau's ACS, as incorporated by reference in subpart c.

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 AND SPACING UNIT means, consistent with § 34-60-116, C.R.S., lands allocated by the Commission to a single Well or multiple Wells for mineral development under a spacing order.

> **WELLBORE SPACING UNIT** means a Drilling and Spacing Unit for a single Well where the unit overlaps at least one existing Drilling and Spacing Unit or Wellbore Spacing Unit.

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

EPA means the U.S. Environmental Protection Agency.

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.

FLARING means the combustion of natural gas during upstream Oil and Gas Operations, excluding gas that is intentionally used for onsite processes.

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.

FLOWBACK means the process of allowing Fluids and entrained solids to flow from a Well following Stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the Well into production. The term Flowback also means the Fluids and entrained solids that emerge from a Well during the Flowback process.

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.
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> **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:
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> > **Production Line** means a flowline connecting a separator to a meter, LACT, or gathering line;
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> > **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;
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> > **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.
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> **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.

FLUID means any material or substance which flows or moves whether in a semisolid, liquid, or gas form or state.

FORMAL CONSULTATION PROCESS means a process for soliciting and receiving meaningful input from the consulting party or parties, with opportunity for in-person meetings to allow for back-and-forth discussion, and a good faith effort to incorporate feedback from the consulting party or parties.

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.

GEOLOGIC HAZARD is defined in § 24-65.1-103(8), C.R.S.

GOVERNMENTAL AGENCY means any federal, state, tribal, or local governmental entity.

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:

a. Any School, nursing facility as defined in § 25.5-4-103(14), C.R.S., hospital, life care institution 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;

b. An operating Child Care Center as defined in § 26-6-102(5), C.R.S.; or

c. A multifamily dwelling unit with four or more units.

HIGH PRIORITY HABITAT means habitat areas identified by Colorado Parks and Wildlife where measures to Avoid, Minimize, and Mitigate Adverse Impacts to wildlife have been identified to protect breeding, nesting, foraging, migrating, or other uses by wildlife. Maps showing, and spatial data identifying, the individual and combined extents of the High Priority Habitats will be provided by CPW and attached to this Rule as Appendix VII. The Commission will provide the maps on its website. The extent of these High Priority Habitat areas is subject to update on a periodic but no more frequent than annual basis and will be modified only through the Commission's rulemaking process described in Rule 529. Notice of such rulemaking proceeding will be provided by January 15 of each year.

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.

INJECTION ZONE means a geological formation, group of formations, or part of a formation receiving Fluids through a Class II UIC Well.

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.

INVESTIGATION-DERIVED WASTE means those materials generated during site investigation and Remediation activities, including but not limited to personal protective equipment, soil cuttings, drilling mud, purged Groundwater, decontamination fluids, and disposable or consumable equipment and supplies.

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 means the disposal method by which treated E&P Waste is spread upon and mixed into soils.

LAND TREATMENT means the method by which E&P Waste is treated *ex situ* at the land surface 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, or adding 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.

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 means, as provided by § 34-60-106(2.5), C.R.S., providing necessary and reasonable protections to reduce the extent, severity, significance, or duration of Unavoidable direct, indirect, and cumulative Adverse Impacts to public health, safety, welfare, the environment, or Wildlife Resources from Oil and Gas Operations.

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.

MITIGATE ADVERSE IMPACTS means, with respect to Wildlife Resources, measures that compensate for Unavoidable direct, indirect, and cumulative Adverse Impacts and loss of such resources from Oil and Gas Operations, including, as appropriate, habitat replacement, on- or off-site habitat enhancement, habitat banking, or financial payment in lieu of habitat replacement or enhancement to compensate for the loss of habitat and ensure that wildlife populations are protected.

MULTI-WELL PITS means Pits used for treatment, storage, recycling, reuse, or disposal of E&P Wastes generated from more than one Well.

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.

NOXIOUS WEED is defined in § 35-5.5-103(16), C.R.S.

OIL AND GAS DEVELOPMENT PLAN means a plan to develop oil or gas resources at one or more Oil and Gas Locations, consistent with the requirements of Rule 303.

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.

OILY WASTE means those materials containing unrefined petroleum hydrocarbons in concentrations in excess of the concentration levels in Table 915-1. Oily waste may include crude oil, condensate, or other materials such as soil, frac sand, drilling fluids, cuttings, and Pit sludge that contain hydrocarbons.

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 anthropogenic contamination or other degradation of the physical, chemical, biological, or radiological integrity of air, water, soil, or biological resources that is not authorized or allowed by the Commission's Rules or applicable regulations promulgated by another federal, state, or Local Government agency.

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.

PRINCIPAL AGENT means the Operator representative authorized to accept and be served with notice from the Commission, or from other persons authorized under the Act.

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 EVALUATION means an evaluation of production potential for determination of requirements for infrastructure capacity and equipment sizing.

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.

PRODUCTIVITY TEST means a test for determination of a reservoir's ability to produce economic quantities of oil or gas.

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.

PROXIMATE LOCAL GOVERNMENT means any Local Government with land use authority within 2,000 feet of a proposed Working Pad Surface.

PUBLIC WATER SYSTEM ("PWS") means a system to provide to the public water for human consumption through pipes or other constructed conveyances, if such systems have at least 15 service connections or regularly serve an average of at least 25 individuals daily at least 60 days out of the year or the entity that administers such a system. The definition of PWS includes:

a. Any collection, treatment, storage, and distribution facilities under control of the PWS operator of such system and used primarily in connection with such system; and

b. Any collection or pretreatment storage facilities not under such control, which are used primarily in connection with such system.

The definition of PWS does not include any "special irrigation district," as defined in the Colorado Water Quality Control Commission's ("WQCC") Colorado Primary Drinking Water Regulations, 5 C.C.R. § 1002-11:11.3(77) ("WQCC's Primary Drinking Water Regulations"). Only the version of the WQCC's Primary Drinking Water Regulations that are in effect as of January 15, 2021 applies; later versions do not apply. WQCC's Primary Drinking Water Regulations 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, WQCC's Primary Drinking Water Regulations may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and are available at https://www.colorado.gov/pacific/cdphe/water-quality-control-commission-regulations.

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.

REFILE means a permit application filed for an expired or nearly expired permit for proposed Oil and Gas Operations that were not conducted during the valid term of the previously approved permit.

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 where existing or proposed Oil and Gas Operations occur.

REMEDIATION means 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 915-1 and other applicable Groundwater 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. Each individual residence within a building will be counted as one Residential Building Unit.

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.

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.

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.

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.

UIC AQUIFER means a geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

UNAVOIDABLE ADVERSE IMPACTS means direct, indirect, or cumulative adverse impacts to public health, safety, welfare, the environment, or Wildlife Resources that are not entirely eliminated through the application of alternative location selection or other methods designed to Minimize Adverse Impacts from Oil and Gas Operations.

UNDERGROUND SOURCE OF DRINKING WATER means a UIC Aquifer or its portion:

a. Which supplies any Public Water System;

b. Which contains a sufficient quantity of Groundwater to supply a Public Water System; and

(1) Currently supplies drinking water for human consumption; or

(2) Contains fewer than 10,000 mg/l total dissolved solids;

c. Which is not an exempted Aquifer.

UNDESIRABLE PLANT SPECIES are those species that possess unwanted or harmful characteristics. Undesirable plant species include, but are not limited to: Noxious Weeds; non-native invasive species that replace or inhibit the establishment of native vegetation; native or non-native species that create monocultures or are overly dominant; species that by their presence reduce species diversity in vegetation communities; species that reduce or hinder agricultural productivity; species that exacerbate wind or water erosion; and species that increase fire risk.

UPSET CONDITION means a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction.

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.

VENTING means allowing natural gas to escape into the atmosphere, but does not include:

a. The emission of gas from devices, such as pneumatic devices and pneumatic pumps, that are designed to emit as part of normal operations if such emissions are not prohibited by AQCC Regulation No. 7, as incorporated by reference in Rule 901.b;

b. Unintentional leaks that are not the result of inadequate equipment design; and

c. Natural gas escaping from, or downstream of, a Tank unless: 1) there is no separation occurring at equipment upstream of the Tank; 2) the separation equipment is not sufficiently sized to capture the entrained gas; or 3) the natural gas is sent to the Tank during circumstances when the gas cannot be sent to the Gathering Line or the combustion equipment used to Flare the gas is not operating.

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 RECORDS means all records related to the drilling, redrilling, deepening, repairing, plugging or abandoning of a Well, all other Well operations, and all alterations to casing and cement.

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 MITIGATION PLAN means a document submitted pursuant to Rules 304.c.(17) and 1201.b for an Oil and Gas Location within High Priority Habitat that describes the implementation of operating requirements pursuant to Rules 1202.a, 1202.b, & 1202.c, as well as any mitigation requirements pursuant to Rules 1202.d & 1203. A Compensatory Mitigation Plan to offset the direct and Unavoidable Adverse indirect Impacts to Wildlife Resources pursuant to Rule 1203.b may be a component of the Wildlife Mitigation Plan.

WILDLIFE PROTECTION PLAN means a document submitted pursuant to Rules 304.c.(17) & 1201.a for Oil and Gas Locations outside of High Priority Habitat that describes the implementation of operating requirements pursuant to Rule 1202.a at the proposed Oil and Gas Location.

WILDLIFE RESOURCES means fish, wildlife, and their aquatic and terrestrial habitats used for all life stages, including reproduction, rearing of young and foraging, and the migration corridors and seasonal ranges necessary to sustain robust wildlife populations.

WORKING PAD SURFACE means the portion of an Oil and Gas Location that has an improved surface upon which Oil and Gas Operations take place.

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 PROVISIONS
200 SERIES

201. EFFECTIVE SCOPE OF RULES AND REGULATIONS

a. The Commission's Rules are promulgated to regulate Oil and Gas Operations in a manner to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations. Except as set forth in Rule 201.d, the Commission's Rules are effective throughout the State of Colorado, and are in force in all pools and fields, unless the Commission amends, modifies, alters, or enlarges them through orders or Rules that apply to specific individual Pools or Fields.

b. Compliance. The Operator of any Oil and Gas Location, Oil and Gas Facility, Well, or any seismic, core, or other exploratory holes, whether cased or uncased, will comply with all applicable Commission Rules, and will ensure compliance by their contractors and subcontractors.

c. Nothing in the Commission's Rules constrains the legal authority conferred to Local Governments by §§ 29-20-104, 30-15-401, C.R.S., or any other statute. Local Government regulations may be more protective or stricter than state requirements.

d. These rules will not apply to:

(1) Indian trust Lands and minerals; or

(2) The Southern Ute Indian Tribe within the exterior boundaries of the Southern Ute Indian Reservation. The Commission's Rules will 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.

e. The State of Colorado will 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, pursuant to Sec. 5, Public Law No. 98-290 (1984).

f. Severability. If any portion of the Commission's Rules are found to be invalid, unconstitutional, or otherwise enjoined or overturned through judicial review, the Commission intends for the remaining portion of the Commission's Rules to remain in force and effect.

g. Incorporated Materials. Where referenced herein, the Commission's Rules incorporate by reference material originally published elsewhere. Such incorporation does not include later amendments to or editions of the referenced material. Pursuant to § 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. Copies of the complete text and information regarding how the incorporated material may be obtained or examined are available at the Commission's office located at 1120 Lincoln Street, Suite 801, Denver, Colorado 80203.

202. OFFICE AND DUTIES OF DIRECTOR

The office of Director of the Commission is hereby created. The Director is responsible for all Commission staff functions. The Director serves as the custodian of the Commission's records. Additional duties of the Director will be as determined from time to time by the Chair.

203. OFFICE AND DUTIES OF SECRETARY

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

204. INSPECTION POWERS

The Director has the right at all reasonable times to go upon and inspect any Oil and Gas Location, Oil and Gas Facility, disposal facility, or transporter facility, and any associated records, for the purpose of making any investigation or conducting any tests to ascertain compliance with the provisions of the Act or the Commission's Rules or any special Field rules. Any findings of a Commission Rule violation will be reported to the Commission.

205. OPERATOR REGISTRATION

a. Form 1, Registration for Oil and Gas Operations. Prior to the commencement of their 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, will, for purposes of the Act, file a Form 1, Registration for Oil and Gas Operations with the Director. 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 Form 1, will do so immediately. Any entity providing Financial Assurance for oil and gas Operators in Colorado will file a Form 1 with the Director. All changes of address of any party required to file a Form 1 will be reported via a new Form 1.

b. Form 1A, Designation of Agent.

(1) All Operators will file a Form 1A, Designation of Agent to designate:

A. A Principal Agent, who is an employee of the Operator; and

B. One or more agents that the Operator approves to serve as its representative(s).

(2) Form 1A designations will remain in effect until terminated in writing via a new Form 1A.

(3) All changes to the Form 1A will be immediately reported via a new Form 1A.

206. RECORDKEEPING AND ACCESS TO RECORDS

a. As required by the Commission's Rules, or upon request by the Director or the Commission, all Operators will submit the required or requested record, information, form, or data in the form or format specified by the Director, which may include a digital (electronic) only format. Information required by the Commission's Rules or requested by the Director will be submitted at the time prescribed in the Commission's Rules or specified by the Director. If the requested document is not within the Operator's possession, the Director may extend the response time. Confidential information will be protected pursuant to Rule 223.

b. All producers, Operators, transporters, refiners, gasoline or other extraction plant operators, initial purchasers of oil and gas within this State, and any other persons or entities subject to regulation under the Commission's Rules will keep accurate and complete records as required by the Commission's Rules. The Director and the Commission will have access to these records upon request. Such records include, but are not limited to:

(1) Any record required to be retained by any of the Commission's Rules;

(2) All reports required by the Commission's Rules to be filed with the Director or Commission;

(3) Natural gas meter calibration reports;

(4) Oil meter calibration reports;

(5) Well Records; and

(6) All such records and reports related to Oil and Gas Operations regulated by the Commission as may be requested by the Director or the Commission.

c. Well Records will show all the formations penetrated, the content and quality of oil, gas, or water in each formation tested, the grade, weight, size, and setting depth of casing, the type and volume of cement used in drilling the Well, and any other information obtained in the course of a Well operation.

(1) **Well Records Confidentiality.** An Operator may request confidentiality for a Wildcat (Exploratory) Well by submitting a Form 4, Sundry Notice. If the Director determines that the Well qualifies as a Wildcat (Exploratory) Well, the Form 5, Drilling Completion Report, Form 5A, Completed Interval Report, Form 7, Operator's Monthly Report of Operations, and all logs run will be considered confidential geological or geophysical data pursuant to § 24-72-204(3)(a)(IV), C.R.S., and will be kept confidential for 6 months after the date of Well completion, unless the Operator gives written permission to release the information at an earlier date.

d. Chemical Inventories.

(1) Operators will maintain a Chemical Inventory for each Chemical Product used or stored on an Oil and Gas Location, including but not limited to use in or storage for downhole drilling, completion, Stimulation, workover operations, and production operations, during a quarterly reporting period, organized by Well Site, in an amount exceeding 500 pounds.

(2) The 500 pound reporting threshold in Rule 206.d.(1) is based on the cumulative maximum amount of a Chemical Product present at the Oil and Gas Location during the quarterly reporting period. Entities maintaining Chemical Inventories under this section will update these inventories quarterly throughout the life of the Well Site.

(3) Operators will maintain the records covered by Rule 206.d in a readily retrievable format at the Operator's local field office.

e. **Transfer of Records.** All records and reports required by the Commission's Rules will be transferred to and maintained by any subsequent Operator.

f. Maintenance of Records.

(1) Unless otherwise specified by the Commission's Rules, Operators will maintain and keep all records, reports, and underlying data required by the Commission's Rules for a period of 5 years.

(2) Operators will maintain and keep Chemical Inventories and Well Records for 5 years after the plugging and abandonment of the applicable Well.

(3) Operators will maintain and keep Chemical Inventories for 5 years after the closure of an Oil and Gas Location.

207. REPORTS

Any report required under the Commission's Rules or requested by the Director or the Commission will be timely filed, accurate, complete, and comply with the requirements set forth in the Commission's Rules or any requirement set by the Director or the Commission.

208. CHEMICAL DISCLOSURE

a. Upon request by the Director, the Commission, a Relevant Local Government, Governmental Agency, an emergency responder, or a health professional, the Operator, vendor, or service provider will provide a list of the chemical constituents, including the specific identity and concentration of each constituent, contained in a Chemical Product.

(1) Such request may be made as a result of a spill or release, a complaint from a potentially adversely Affected Person, or when necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) Disclosure of the Chemical constituents contained in a Chemical Product will only be made to a health professional when requested for the purpose of diagnosis or treatment of an individual who may have been exposed to a Chemical used at an Oil and Gas Location.

b. **Trade Secret Chemical Product.** The Operator, vendor, or service provider will submit a Form 41, Trade Secret Claim of Entitlement to designate the information provided under Rule 208.a as a Trade Secret Chemical Product. Upon the Director's approval of the Trade Secret Chemical Product designation, the information will be considered confidential pursuant to § 24-72-204(3)(a)(IV), C.R.S., and will be exempt from disclosure on the Chemical Disclosure Registry form.

(1) The Form 41 will include the following contact information: claimant's name, authorized representative, mailing address, and phone number with respect to trade secret claims. If such contact information changes, the claimant will immediately submit a new Form 41 to the Commission with updated information.

(2) If the Director denies the Form 41, the Director will immediately notify and confer with the Operator, vendor, or service provider that submitted the Form 41 regarding the designation before requiring the information to be disclosed pursuant to Rule 208.c.

c. **Hydraulic Fracturing Chemical Disclosure.**

(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 will, with the exception of information approved as a Trade Secret Chemical Product pursuant to Rule 208.b, furnish the Operator with any information needed for the Operator to complete the Chemical Disclosure Registry form and post the form on the Chemical Disclosure Registry. The information will 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.** 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 will complete the Chemical Disclosure Registry form and post the form on the Chemical Disclosure Registry, including:

A. The Operator name;

B. The date of the Hydraulic Fracturing Treatment;

C. The county in which the Well is located;

D. The API number for the Well;

E. The Well name and number;

F. The longitude and latitude of the wellhead;

G. The true vertical depth of the Well;

H. 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;

I. 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;

J. Each Chemical intentionally added to the Base Fluid;

K. The maximum concentration, in percent by mass, of each Chemical intentionally added to the Base Fluid; and

L. The Chemical Abstract Service number for each Chemical intentionally added to the Base Fluid, if applicable.

(3) **Ability to Search for Information.** The Chemical Disclosure Registry will allow the Director and the public to search and sort the registry for Colorado information by geographic area, ingredient, Chemical Abstract Service Number, time period, and Operator.

209. TESTS AND SURVEYS

a. **Tests and Surveys.** When deemed necessary and reasonable, the Commission authorizes the Director to require that tests or surveys be made to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. If the Commission's Rules do not provide a timeline for conducting the test or survey, the Director will designate the time allowed to the Operator for compliance.

b. If the Director requires an Operator to take action pursuant to Rules 209.a or 218.g, the Operator may appeal the Director's decision to the Commission pursuant to Rule 503.g.(10). The matter will not be assigned to an Administrative Law Judge pursuant to Rule 503.h. The Commission will hear the appeal at its next regularly scheduled meeting. Operators will continue to comply with any requirements identified by the Director pursuant to Rule 209.a until the Commission makes a decision on the appeal. The Commission may uphold the Director's decision if the Commission determines the Director had reasonable cause to determine that an Operator's actions impacted or threatened to impact public health, safety, welfare, the environment, and wildlife resources, and that the action required by the Director was necessary and reasonable to address those impacts or threatened impacts. If an Operator does not appeal the Director's decision pursuant to this Rule 209.b, the Director will report the decision at the next regularly scheduled Commission hearing.

c. Bradenhead Test Areas.

(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 providing 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 pursuant to Rule 519.

C. If a protest is timely filed, the Commission will hear the proposed designation pursuant to the Commission's 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.

210. CORRECTIVE ACTION

a. The Director or Commission will require correction of any condition necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, or any condition that the Director or Commission has reasonable cause to believe is in violation of the Commission's Rules. The Director or Commission may exercise its discretion to set forth the manner in which the condition is to be remedied.

b. When a Field Inspection Report includes a corrective action, upon completion of that corrective action the Operator will submit to the Director a Field Inspection Report Resolution Form ("FIRR").

211. PLUGGING AND ABANDONMENT OF WELLS AND CLOSURE OF OIL AND GAS FACILITIES AND LOCATIONS

a. An Operator of a Well will Plug and Abandon the Well if the Commission, following a hearing pursuant to Rule 503, determines that Plugging and Abandoning is reasonable and necessary to protect or minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources, or when the Well is no longer used or useful.

b. An Operator of an Oil and Gas Location will permanently close an Oil and Gas Location or Oil and Gas Facility if the Commission, following a hearing pursuant to Rule 503, determines that such closure is necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources, or when the Oil and Gas Location or Oil and Gas Facility is no longer used or useful.

212. ISOLATION OF COAL SEAMS AND GROUNDWATER

In the conduct of Oil and Gas Operations each Owner or Operator 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.

213. NOTICE TO THE DIRECTOR AND COMMISSION

a. Any notice required to be filed with the Commission will be filed in the manner and time set forth by the Commission's Rules.

b. Emergency Situations.

(1) In case of an Emergency Situation where the delay caused by providing written notice to the Director would endanger public health, safety, welfare, the environment, or wildlife resources, any notice or information required by the Commission's Rules may be given to the Director orally.

(2) If notice or information is provided orally in the event of an Emergency Situation, Operators will provide to the Director the same information in writing at the earliest possible time but no later than 3 days following the Emergency Situation, unless a Commission Rule establishes a different timeframe. In the case of such an Emergency Situation, the Director or Commission may approve the responsive operation or change to an approved operation orally, which will be later confirmed in writing.

(3) If public health, safety, welfare, the environment, or wildlife resources are threatened, the Operator responsible for the operation causing such threat will immediately notify the Director, Relevant and Proximate Local Governments, and Surface Owner electronically and orally.

214. NAMING OF FIELDS

All oil and gas Fields discovered in the State subsequent to the adoption of the Commission's Rules will be named by the Director or at the Director's direction.

215. FORM 29, LOCAL GOVERNMENT INFORMATION

a. Local Governmental Designee. Each Local Government that designates an office for the purposes set forth in the 100 Series will provide the Commission written notice of such designation, including the name, address, telephone number, electronic mail address, local emergency dispatch, and other emergency numbers of the Local Government. It will be the responsibility of such Local Governmental Designee to:

(1) Provide comment on any pending Form 2A, Oil and Gas Location Assessment for which the Local Government is a Relevant or Proximate Local Government;

(2) 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 employees, officials, and offices of the Local Government; and

(3) Submit a confidentiality agreement to the Director via a Form 29, Local Government Information to request the Geographic Information System ("GIS") data submitted through Form 12, Gas Facility Registration/Change of Operator and Form 44, Flowline Report.

b. Contact Information for Notification. To facilitate accurate notification from the Commission or the Director to Local Governments, a Local Government may provide their electronic mail address to the Director via a Form 29.

c. If a Local Government, except for a special district, does not provide information pursuant to Rules 215.a or 215.b, then the Director will use reasonable best efforts to identify the appropriate contact person to provide the Local Government notice required by the Commission's Rules. The Director will only provide notice to special districts that request to receive notice pursuant to Rules 215.a & b.

216. 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:

a. GPS instruments are differential grade.

b. GPS instruments are capable of 1-meter horizontal positional accuracy after differential correction.

c. The Operator will report an accuracy value (in meters) or position dilution of precision ("PDOP") value with all submitted GPS data. Accuracies of 1.0 meter or less and PDOP readings of 6.0 or less are acceptable.

d. Elevation mask (lowest acceptable height above the horizon) will be no less than 15 degrees.

e. Latitude and longitude coordinates will be provided in decimal degrees with an accuracy and precision of 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 will be held for a period of 3 years.

g. Measurements will 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.

217. FORM 8, OIL AND GAS CONSERVATION LEVY

a. 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., will file a Form 8, Oil and Gas Conservation Levy with the Director and remit the levy payment. The Form 8 will show, 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 Form 8 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.

b. 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.

218. FORM 9, TRANSFER OF OPERATORSHIP

a. Definitions.

(1) For the purposes of this Rule 218, "Transferable Items" include but are not limited to:

A. Approved, unexpired Form 2, Application for Permit; Form 2A; Form 15, Earthen Pit Report/Permit; and Form 28, Centralized E&P Waste Management Facility Permit (collectively "Permits");

B. Wells;

C. Oil and Gas Locations;

D. Oil and Gas Facilities;

E. Off-Location Flowlines;

F. Open Remediation projects;

G. Unresolved Spills and Releases;

H. Unresolved Field Inspection Reports with outstanding corrective actions;

I. Unresolved warning letters;

J. Unresolved Notices of Alleged Violation; and

K. Any item listed in Rule 218.a.(1).A–(J) that is related in the Commission's records to another Transferable Item proposed for transfer.

(2) For purposes of this Rule 218, the term "Selling Operator" means the Operator of record for any Transferable Items at the time a Form 9 - Intent is filed.

(3) For purposes of this Rule 218, the term "Buying Operator" means the successor-in-interest entity to which Transferable Items will be transferred through the Form 9 process.

(4) For purposes of Rule 218, the term "Prior Operator" means an Operator other than the Selling Operator that was a previous Operator of record for any Transferable Items.

b. Form 9, Transfer of Operatorship – Intent. A Selling Operator will notify the Commission about the transfer of any Transferable Item associated with its Oil and Gas Operations to a Buying Operator by filing a Form 9, Transfer of Operatorship – Intent, with the Commission at least 30 days, or as soon as practicable, before the anticipated transfer date. The Form 9 – Intent will include the Selling Operator's understanding of the following information at the time the Selling Operator submits the Form 9 – Intent to the Commission, which may change prior to the closing date of the transaction:

(1) The name of the Buying Operator;

(2) The anticipated date for the transfer of all Transferable Items;

(3) The complete anticipated list of Transferable Items that are proposed for transfer;

(4) The complete list of any Transferable Items that are related in the Commission's records to a Transferable Item listed pursuant to Rule 218.b.(3) but are not proposed for transfer;

(5) The estimated amount of Financial Assurance required by the Commission's Rules that the Buying Operator will submit to the Commission prior to the anticipated date of transfer identified in Rule 218.b.(2);

(6) **Attached Attestations.** An attestation signed by the Selling Operator and the Buying Operator attesting to all contents of the Form 9 – Intent; and

(7) If the proposed transfer is subject to a non-disclosure or confidentiality agreement between the Selling Operator and the Buying Operator, the Selling Operator will indicate on the Form 9 – Intent that the proposed transfer is considered confidential, and the Director will keep the Form 9 – Intent and any other associated information confidential pursuant to § 24-72-204(3)(a)(IV), C.R.S., until the Form 9, Transfer of Operatorship – Subsequent is filed.

c. The Selling Operator will remit with the Form 9 – Intent the filing fee provided in Appendix III.

d. **Form 9, Transfer of Operatorship – Subsequent.**

(1) When a transaction subject to a Form 9 – Intent becomes final, the Buying Operator will submit a Form 9 – Subsequent within 7 days of closing. The Form 9 – Subsequent will include:

A. The effective date of transfer;

B. The complete list of Transferable Items that:

i. Were transferred to the Buying Operator;

ii. Are related in the Commission's records to a Transferable Item listed pursuant to Rule 218.d.(1).B.i but were not transferred, and:

aa. Whether the Selling Operator retained responsibility for compliance with the Commission's Rules for any Transferable Item listed pursuant to Rule 218.d.(1).B.ii; or

bb. Whether a Prior Operator retained responsibility for compliance with the Commission's Rules for any Transferable Item listed pursuant to Rule 218.d.(1).B.ii; and

iii. Were listed on the Form 9 – Intent pursuant to Rules 218.b.(3) & (4) but were not transferred to the Buying Operator upon closing, and:

aa. Whether the Selling Operator retained responsibility for compliance with the Commission's Rules for any Transferable Item listed pursuant to Rule 218.d.(1).B.iii; or

bb. Whether a Prior Operator retained responsibility for compliance with the Commission's Rules for any Transferable Item listed pursuant to Rule 218.d.(1).B.iii.

C. **Attached Attestations.**

i. An attestation signed by the Selling Operator and the Buying Operator attesting to all contents of the Form 9 – Subsequent;

ii. If applicable, an attestation signed by the Selling Operator attesting that the Selling Operator retains responsibility for compliance with the Commission's Rules for any Transferable Item listed in Rules 218.d.(1).B.ii.aa or 218.d.(1).B.iii.aa; and

iii. An attestation signed by the Buying Operator that the Buying Operator notified the Relevant Local Government in which any Transferable Item is located of the completed transaction in writing.

D. Subsequent Liability.

i. For Transferable Items listed in Rule 218.d.(1).B.i an acknowledgment that upon the effective date of transfer, that the Buying Operator assumes all responsibility for compliance with the Act, the Commission's Rules, and all terms and conditions of existing Permits and Commission orders for the Transferable Items;

ii. For Transferable Items listed in Rules 218.d.(1).B.ii or iii, an acknowledgment that the Buying Operator may be or may become responsible for compliance with the Act, the Commission's Rules, and all terms and conditions of existing Permits and Commission orders if the Buying Operator takes any action, or fails to take any action, that would cause such Transferable Item to be out of compliance with the Act, the Commission's Rules, and all terms and conditions of existing Permits and Commission orders; and

iii. For Transferable Items not listed in Rule 218.d.(1).B.i–iii but related in the Commission's records, an acknowledgment that the Commission will presume that the Transferable Item was transferred, and that the Buying Operator is responsible for compliance with the Act, the Commission's Rules, and all terms and conditions of existing Permits and Commission orders for the Transferable Items.

(2) If an anticipated transaction that is the subject of a Form 9 – Intent does not occur, the Selling Operator will notify the Director in writing. The Director will withdraw the Form 9 – Intent.

e. The Director will review the Form 9 – Intent and Form 9 – Subsequent upon receipt. The Director will approve the Form 9 – Intent and Form 9 – Subsequent within 45 business days of when all of the following have occurred:

(1) The Director has determined that all Permits described in Rule 218.d.(1).B.i subject to the proposed transfer comply with the Commission's current Rules in effect at the time of the proposed transfer;

(2) If a Permit described in Rule 218.d.(1).B.i. is not in compliance with the Act, the Commission's Rules, and all terms and conditions of existing Permits and Commission orders on the date of transfer, the Director has determined that the Selling Operator, Buying Operator, or Prior Operator has submitted a satisfactory plan to bring such Permit into compliance;

(3) The Director has determined that the Form 9 – Intent and Form 9 – Subsequent are complete and comply with this Rule 218; and

(4) The Buying Operator has submitted the Financial Assurance required by the Commission's Rules.

f. The Director may deny the Form 9 – Intent and Form 9 – Subsequent and the Selling Operator will remain responsible for compliance with the Commission's Rules for the proposed Transferable Items:

(1) If the Form 9 – Intent or Form 9 – Subsequent fail to satisfy Rules 218.b or 218.d;

(2) If the Selling Operator did not remit the filing fee required by Rule 218.c;

(3) If the Buying Operator fails to submit the Financial Assurance required by the Commission's Rules; or

(4) If the Buying Operator does not submit a Form 9 – Subsequent within 120 days following the anticipated date for transfer identified in Rule 218.b.(1).

g. If a Buying Operator operates a Well or Wells for 60 days or more without obtaining the Director's approval of a Form 9 – Intent and Form 9 – Subsequent, the Director may require all such Wells to be shut-in, consistent with the Well shut-in safety requirements of Rule 434. All such Wells will remain shut-in until a Form 9 – Intent and Form 9 - Subsequent are approved by the Director. An Operator that objects to a shut-in order may request an expedited hearing before the Commission pursuant to the expedited appeal procedures described in Rule 209.b.

h. The Director will not approve a Form 10, Certificate of Clearance submitted by the Buying Operator for a transferred Well unless there is an approved Form 9 – Intent and 9 – Subsequent.

i. A Form 9 is not required for the change of operator of gas gathering systems, gas processing plants, and underground gas storage facilities, which are governed by Rule 220.c.

219. FORM 10, CERTIFICATE OF CLEARANCE

a. The Operator of a Well will file with the Director a Form 10, Certificate of Clearance to designate the transporter(s) and gatherer(s), as applicable, for the Well. The certificate, when properly executed and approved by the Commission, constitutes authorization to the Pipeline or other transporter to transport the authorized Fluid from the Well named therein; provided that this section will not prevent the production or transportation in order to prevent waste, pending execution, and approval of said certificate.

b. Within 30 days after initial sale of oil or gas, each Operator of a new Well will file a Form 10 with the Director for the Well.

c. The Operator of a Well will file a new Form 10 to change the transporter or gatherer for the Well within 30 days of the change.

(1) In the case of other transporter temporary changes involving the production of less than 1 month, the Operator will notify the Director via a Form 10 indicating the dates of the temporary changes.

(2) In the case of temporary use of oil for Well treating or stimulating purposes, a new Form 10 is not required.

d. A new Operator will file a new Form 10 within 30 days of the date the Director approves the Form 9 – Subsequent pursuant to Rule 218.e.

e. Operators will pay the filing fee provided in Appendix III when filing a Form 10.

f. The Form 10 will remain in force and effect until:

(1) The Operator of the Well is changed;

(2) The transporter or gatherer is changed; or

(3) The certificate is suspended by the Commission.

g. It is the Operator's responsibility to provide electronic or paper copies of the approved Form 10 to the transporter or gatherer for each Well listed.

220. FORM 12, GAS FACILITY REGISTRATION/CHANGE OF OPERATOR

a. Facility Registration. The Operator of a new gas gathering system, a new gas compressor station, a new gas processing plant, or a new underground gas storage facility will submit a Form 12, Gas Facility Registration/Change of Operator, within 30 days of placing the new facility into service. The following information will be included:

(1) The name and type of system or facility;

(2) For a gas compressor station or a gas processing plant, the latitude and longitude of the southeast corner of the facility and the legal location by quarter-quarter, section, township, range, and county;

(3) For a gas gathering system or an underground gas storage facility, latitude and longitude of a point near the center of the system or facility, and a description of the geographic area by section, township, range, and county;

(4) For a gas compressor station, a gas processing plant, or an underground gas storage facility, a facility layout drawing;

(5) For an underground gas storage facility, a certification of federal approval, if applicable; and

(6) For a gas gathering system, GIS data that includes the gathering line alignment, isolation valves, and the following attributes:

A. Fluid type;

B. Pipe material type; and

C. Type size.

D. GIS data will be submitted in the NAD of 1983 and in a format approved by the Director. Information submitted pursuant to this Rule 220.a.(6) will be disclosed at the same mapping scale provided in and kept confidential pursuant to the procedures in Rule 1101.e.

b. Annual Reports. For a gas gathering system, gas processing plant, gas compressor station, or underground storage facility that has had any Gathering Lines added or removed during the preceding year, the Operator will submit a Form 12 by May 1st of each year to report the changes made during the prior calendar year. For an underground storage facility that has had an expansion or reduction of its capacity of more than 10% during the preceding year, the Operator will submit a Form 12 by May 1st of each year to report the changes made during the prior calendar year.

c. Change of Operator. The previous or new Operator of a gas gathering system, gas compressor station, gas processing plant, or an underground gas storage facility, will submit a Form 12 within 30 days of change of Operator. Documentation confirming transfer of ownership will be attached to the Form 12.

d. Gas Storage Projects. The Commission's 800 Series Rules do not apply to Gas Storage Wells and underground gas storage facilities.

221. PUBLIC HIGHWAYS AND ROADS

All persons subject to the Act and the Commission's Rules are subject to the State Vehicles and Traffic Laws pursuant to Title 42, C.R.S., and the State Transportation Laws, Title 43, C.R.S., pertaining to the use of public highways or roads within the state for Oil and Gas Operations.

222. FORM 18, COMPLAINT REPORT

a. A complaint regarding Oil and Gas Operations is filed by submitting a Form 18, Complaint Report.

b. The Director will investigate any complaint and determine what, if any, action will be taken pursuant to Rule 524.

223. CONFIDENTIAL INFORMATION

a. If an Operator seeks to submit information that is listed as confidential in Rule 223.b below, the Operator will:

(1) Confer with the Director prior to submitting the information to verify that it qualifies as confidential pursuant to the Commission's Rules. If the Director determines that the documents or submissions are not confidential, the Operator need not submit the information after the conferral process, unless required to do so by a Commission Rule.

(2) If associated with a form submittal, submit the information as a confidential attachment to a form, not on a form itself.

(3) Submit both a redacted and non-redacted version of the confidential information, unless the Director confirms orally or in writing that a non-redacted version does not need to be submitted. The non-redacted version will be labeled **CONFIDENTIAL** in a conspicuous location at the top of the document.

b. Confidential information may include:

(1) Monetary amounts, payment terms, drilling obligations, or personal information listed on Surface Use Agreements;

(2) Monetary amounts, payment terms, drilling obligations, or personal information listed on oil and gas leases;

(3) Monetary amounts, payments, or personal information listed in a right-of-way or easement agreement;

(4) Information concerning ongoing commercial negotiations regarding potential or planned routing and location of off-lease midstream gathering system infrastructure and information concerning landowner negotiations for which rights-of-way have not yet been obtained;

(5) Confidential geological or geophysical Well Records pertaining to Wildcat (Exploratory) Wells for a 6 month period pursuant to §§ 24-72-204(3)(a)(IV) & 34-60-106(1)(b), C.R.S.;

(6) Information about a proposed transfer of permits and assets pursuant to Rule 218.b.(7);

(7) Sensitive wildlife habitat information that the Operator is required to hold in confidence by other federal, state, or tribal regulatory agencies;

(8) Sensitive cultural information that the Operator is required to hold in confidence by other federal, state, or tribal regulatory agencies;

(9) Sensitive Public Water System information if the Public Water System administrator requests that it be held in confidence;

(10) Hydraulic fracturing chemicals pursuant to Rule 208;

(11) Personal medical information submitted on a Form 22, Accident Report; and

(12) Other information that the Operator designates as confidential if the Director concurs that the information meets the confidentiality provisions of the Colorado Open Records Act.

PERMITTING PROCESS
300 SERIES

301. GENERAL REQUIREMENTS FOR APPROVAL, CHANGES TO OPERATIONS, AND FILING FEES FOR OIL AND GAS OPERATIONS

a. Approval. All operations governed by any regulation in this Series require written approval of the Commission, or Director where applicable. The Commission or Director, where applicable, will approve operations only if they protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, and protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations. Operators will obtain the Commission's or Director's, where applicable, approval through the procedures provided in this and such other applicable Commission Rules. The Commission, or Director, where applicable, may require any conditions of approval that are determined to be necessary and reasonable to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, or to protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

b. Denial. The Commission may deny an Oil and Gas Development Plan, and the Commission or Director may deny Oil and Gas Operations if it does not comply with the Commission's Rules or the Act.

c. Changes to Approved Oil and Gas Development Plans.

(1) Operators will file any proposed change to an approved Oil and Gas Development Plan with the Director in writing through a Form 4, Sundry Notice. The Form 4 will be posted to the Commission's website at least 14 days prior to approval or denial of the requested change.

(2) The Director will determine what applications, forms, and information are required for the review and approval of the proposed change, and whether:

A. The proposed change is significant and requires Commission approval;

B. The proposed change requires consultation with the Colorado Department of Public Health and Environment ("CDPHE") or Colorado Division of Parks and Wildlife ("CPW"); or

C. The proposed change will not alter the basis upon which the Oil and Gas Development Plan is approved and can be administratively approved by the Director.

(3) The Operator will not begin work until the Director or Commission provides written approval.

(4) The Director or Commission will only approve changes that comply with the Commission's Rules.

(5) Notice of a Director-approved change to an Oil and Gas Development Plan will be posted to the Commission's website.

d. Filing Fees. Operators will pay filing fees at the time of applying for a Form 2A, Oil and Gas Location Assessment; Form 2, Application for Permit-to-Drill; Drilling and Spacing Unit; Oil and Gas Development Plan; or Comprehensive Area Plan ("CAP") (see Appendix III). Wells drilled for stratigraphic information only will be exempt from paying the filing fee.

e. The Director or Commission may request any information necessary and reasonable to make a final determination of approval or denial on any permit application before the Commission. In such information requests, the Director or Commission will provide the reasoning for the request and a reasonable timeframe for the applicant to provide the information.

f. Coordination with Local Governments and Federal Agencies.

(1) Purpose. The Commission, Local Governments, and federal surface management agencies all share authority to require permits for the surface impacts of Oil and Gas Operations. Recognizing that each permitting authority brings its own, unique expertise in reviewing a permit, the Commission supports creating coordinated, efficient processes among the permitting authorities.

(2) Concurrent Permitting. Where possible, the Commission prefers Operators to follow the concurrent permit review process pursuant to Rule 303.a.(6).A to allow each permitting authority to coordinate sharing its unique expertise and standards.

(3) Pre-Application Consultation. Prior to an Operator submitting an Oil and Gas Development Plan or Form 2A to the Commission, at the request of the Relevant Local Government or federal agency, the Director will participate in a Formal Consultation Process with the Relevant Local Government or federal agency and the Operator to discuss Oil and Gas Location siting, alternative location analysis, Best Management Practices, conditions of approval, anticipated milestones and events in the state and federal or local permitting processes, opportunities for collaboration, and other related topics regarding the Operator's planned development within the Relevant Local Government's or federal agency's jurisdiction.

(4) Sequential Permitting. An Operator may pursue a permit from the federal government or a Relevant Local Government before applying for an Oil and Gas Development Plan pursuant to Rule 303.

A. If the Operator chooses to seek a permit from the federal government or a Relevant Local Government before applying for an Oil and Gas Development Plan, during the course of the federal or Local Government permit review process, for any proposed location that meets one or more of the criteria in Rule 304.b.(2).B the Operator may submit an alternative location analysis to the Director that meets the criteria of Rule 304.b.(2).C.

B. If the Operator provides the Director with an alternative location analysis pursuant to Rule 301.f.(4).A, the Director will participate in a Formal Consultation Process with the Operator and the Relevant Local Government or federal agency about the proposed alternative locations prior to the Operator submitting a permit application to the Commission.

C. To promote the resolution of issues to the extent possible, a Relevant Local Government or federal agency may request that the Director participate as a referral agency in a Formal Consultation Process about proposed alternative locations for any location that meets the criteria of Rule 304.b.(2).B. If the Director receives such a request, the Operator will provide the Director with an alternative location analysis that meets the criteria of Rule 304.b.(2).C that may be used as a basis for the Formal Consultation Process. If the Director receives such a request, the Director will use best efforts to identify any potential conflicts, differences, or concerns that may exist regarding the proposed location(s) and the Commission's Rules.

302. LOCAL GOVERNMENTS

a. Nothing in the Commission's Rules constrains the legal authority conferred to Local Governments by §§ 24-65.1-101 *et seq.*, 29-20-104, 30-15-401, C.R.S., or any other statute, to regulate surface Oil and Gas Operations in a manner that is more protective or stricter than the Commission's Rules.

b. **Local Government Siting Information.** With their Oil and Gas Development Plan, or, if applicable, with their Form 2A or Drilling and Spacing Unit application, Operators will submit to the Director certification that:

(1) The Relevant Local Government does not regulate the siting of Oil and Gas Locations;

(2) The Relevant Local Government regulates the siting of Oil and Gas Locations, and has denied the siting of the proposed Oil and Gas Location;

(3) The Relevant Local Government regulates the siting of Oil and Gas Locations, and the proposed Oil and Gas Location does not meet any of the criteria listed in Rule 304.b.(2).B; or

(4) The Relevant Local Government regulates the siting of Oil and Gas Locations, and the proposed Oil and Gas Location meets one or more of the criteria listed in Rule 304.b.(2).B.

c. **Director's Review of Local Government Siting Information.**

(1) For proposed Oil and Gas Locations listed in Rule 302.b.(1), the Director will conduct a siting review pursuant to the Commission's 300 Series Rules.

(2) For proposed Oil and Gas Locations listed in Rule 302.b.(2), the Commission will not approve the proposed Oil and Gas Location without a hearing before the Commission, rather than an Administrative Law Judge or Hearing Officer.

(3) For proposed Oil and Gas Locations listed in Rule 302.b.(3), the Director will defer to the Relevant Local Government's siting disposition.

(4) For proposed Oil and Gas Locations listed in Rule 302.b.(4), the Operator will submit an alternative location analysis pursuant to Rule 304.b.(2).

d. With their Oil and Gas Development Plan, or, if applicable, with their Form 2A, Operators will state whether the proposed Oil and Gas Location is subject to the requirements of § 24-65.1-108, C.R.S., because it is located in an area designated as one of state interest.

e. **Notice to Relevant and Proximate Local Governments.** An Operator will notify any Relevant and Proximate Local Governments that it plans to submit an Oil and Gas Development Plan no less than 30 days prior to submitting an Oil and Gas Development Plan. The notice will comply with the procedural and substantive requirements of Rules 303.e.(2) & (3).

f. **Local Government Waiving Authority.**

(1) At any time, a Local Government may, by providing written notice to the Director on a Form 29, Local Government Information, and any relevant Operators:

A. Waive its right to receive notice under any or all of the Commission's Rules; or

B. Certify that it chooses not to regulate the siting of Oil and Gas Locations.

(2) The Commission will maintain a list of Local Governments that have certified to the Director that they have chosen not to regulate the siting of Oil and Gas Locations, or receive any category of notice otherwise required by the Commission's Rules. This list will be posted on the Commission's website.

(3) A Local Government may withdraw a waiver or certification at any time by providing written notice to an Operator and the Director on a Form 29. Upon receiving such notice, the Director will immediately remove the Local Government from the Rule 302.f.(2) list on the Commission's website.

g. Local Government Consultation. Within 45 days after an Operator provides notice of a proposed Oil and Gas Development Plan, and prior to the Director making a Director's Recommendation that the Commission approve or deny the Oil and Gas Development Plan, Relevant Local Governments or Proximate Local Governments may request, and will be provided, an opportunity to consult with the Operator and the Director. The Director or Operator will promptly schedule a Formal Consultation Process meeting. Nothing in this Rule 302.g precludes a Local Government from providing comments on a proposed Oil and Gas Development Plan or Form 2A during the Rule 303.d public comment period. Topics for Formal Consultation Process meeting will include, but not be limited to:

(1) The location of access roads, Production Facilities, and Wells; and

(2) Necessary and reasonable measures to avoid, minimize, and mitigate adverse impacts to public health, safety, welfare, the environment, or wildlife resources.

303. PROCEDURAL REQUIREMENTS FOR OIL AND GAS DEVELOPMENT PLANS

a. Components of an Oil and Gas Development Plan Application. Prior to commencing Oil and Gas Operations at an Oil and Gas Location that meets the criteria of Rule 304.a, an Operator will have an approved Oil and Gas Development Plan. An Operator will submit to the Commission the following:

(1) An application with the Hearings Unit for a hearing on the proposed Oil and Gas Development Plan, pursuant to Rule 503.g.(1). If the Oil and Gas Development Plan includes lands to be spaced, the Oil and Gas Development Plan application will include an application for and request for hearing on the proposed Drilling and Spacing Unit(s) pursuant to Rules 305 & 503.g.(2). For at least one portion of a mineral tract within the proposed Oil and Gas Development Plan, the applicant will provide documentation as described in Rule 305.a.(2).L, showing the applicant's status as an Owner.

(2) A Form 2A that meets all requirements of Rule 304 for each proposed Oil and Gas Location.

(3) Payment of the full filing fee required by Rule 301.d.

(4) Any other relevant information that the Director determines is necessary and reasonable to determine whether the proposed operation meets the Commission's Rules and protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources. The Director will provide the Operator with the reason for the request in writing.

(5) Cumulative Impacts Data Evaluation Repository.

A. Purpose. This Rule 303.a.(5) is intended to provide data for the Commission's cumulative impacts data evaluation repository. The Commission intends to use the data, in cooperation with CDPHE and other partners, to undertake basin-wide, statewide, and other studies to evaluate and address cumulative impacts to relevant resources at appropriate scales pursuant to Rules 304.c.(19) or 904.

B. Resource Impacts. The Operator will submit a Form 2B, Cumulative Impacts Data Identification that provides quantitative and qualitative data to evaluate incremental adverse and beneficial contributions to cumulative impacts caused by Oil and Gas Operations associated with the proposed Oil and Gas Development Plan, including any measures the Operator will take to avoid, minimize, or mitigate any adverse impacts:

i. **Air Resources.** A quantitative evaluation of the incremental increase in the pollutants listed below, estimated for the entire proposed Oil and Gas Development Plan. The emissions estimates will include both stationary and mobile sources of emissions during all pre-production activities, and both stationary and mobile sources of emissions for the first year of production based on all proposed wells and equipment.

aa. Oxides of nitrogen (NO_x);

bb. Carbon monoxide (CO);

cc. Volatile Organic Compounds (VOCs);

dd. Methane (CH_4);

ee. Ethane (C_2H_6);

ff. Carbon dioxide (CO_2); and

gg. Nitrous oxide (N_2O).

ii. **Public Health.** An evaluation of incremental adverse impacts to public health due to Oil and Gas Operations associated with the proposed Oil and Gas Development Plan, including:

aa. A quantitative evaluation of the incremental increase in total hazardous air pollutant emissions estimated for the entire proposed Oil and Gas Development Plan. The emissions estimates will include both stationary and mobile sources of emissions during all pre-production activities, and both stationary and mobile sources of emissions for the first year of production based on all proposed wells and equipment.

bb. A quantitative evaluation of the incremental increase in specific hazardous air pollutant emissions with known health impacts, estimated for the entire proposed Oil and Gas Development Plan. The emissions estimates will include both stationary and mobile sources of emissions during all pre-production activities, and both stationary and mobile sources of emissions for the first year of production based on all proposed wells and equipment:

1. Benzene;

2. Toluene;

3. Ethylbenzene;

4. Xylenes;

5. n-Hexane;

6. 2,2,4-Trimethylpentane (2,2,4-TMP);

7. Hydrogen sulfide (H_2S);

8. Formaldehyde; and

9. Methanol.

cc. A qualitative evaluation of any potential acute or chronic, short- or long-term incremental impacts to public health as a result of such emissions.

dd. Whether the proposed Oil and Gas Development Plan includes any proposed Oil and Gas Locations within a Disproportionately Impacted Community.

iii. Water Resources.

aa. For any proposed Oil and Gas Development Plan that includes proposed Oil and Gas Locations that will be listed as a sensitive area for water resources, or are within 2,640 feet of a surface Water of the State, the total planned on-location storage volume (measured in Barrels (bbls)) of:

1. Oil;

2. Condensate;

3. Produced water; and

4. Other volumes of stored hydrocarbons, Chemicals, or E&P Waste Fluids.

bb. An evaluation and identification of potential contaminant migration pathways and likely distances from the proposed Oil and Gas Locations to the nearest downstream riparian corridors, wetlands, and surface Waters of the State. If the Operator identifies any such contaminant migration pathways, the Operator will provide a qualitative evaluation of the baseline conditions in the riparian corridor, wetland, or surface Water of the State.

cc. A qualitative evaluation of potential impact to any Public Water System intake.

dd. A qualitative evaluation of measures the Operator proposes to take to reduce water use, including reusing and recycling produced water.

ee. A quantitative evaluation of the anticipated volume of all surface water and Groundwater to be used, including the percentage of the total volume that is anticipated to be reused or recycled water, consistent with Rules 304.c.(18).A & C.

iv. Terrestrial and Aquatic Wildlife Resources and Ecosystems. A quantitative or, where quantitative information is not reasonably available, a qualitative evaluation of potential impacts to Wildlife Resources as a result of Oil and Gas Operations associated with the proposed Oil and Gas Development Plan, including:

aa. List of High Priority Habitats within 1 mile; and

bb. Total acreage of new or expanded surface disturbance associated with the proposed Oil and Gas Development Plan, including:

1. A breakdown (by acreage) of the types of current land use;

2. The number of acres of new or expanded surface disturbance within High Priority Habitat.

v. Soil Resources.

aa. A quantitative evaluation of incremental adverse impacts to topsoil as a result of surface disturbance associated with the proposed Oil and Gas Development Plan; and

bb. A qualitative evaluation of incremental adverse impacts on ecosystems, including any vegetative communities, as a result of Oil and Gas Operations associated with the proposed Oil and Gas Development Plan.

vi. Public Welfare. A qualitative or quantitative evaluation of incremental adverse impacts to public welfare as a result of Oil and Gas Operations associated with the proposed Oil and Gas Development Plan, that addresses each of the following potential sources of impacts to public welfare, over both a short-term and long-term timeframe:

aa. Noise;

bb. Light;

cc. Odor;

dd. Dust; and

ee. Recreation and scenic values.

C. Surrounding Oil and Gas Impacts. On the Form 2B, the Operator will identify Oil and Gas Locations in proximity to each of the proposed Oil and Gas Locations associated with the proposed Oil and Gas Development Plan. Specifically, on the Form 2B, the Operator will identify:

i. The total number of active, permitted, and proposed Oil and Gas Locations within a 1 mile radius of each of the proposed Oil and Gas Locations, including those permitted by the Relevant Local Government, even if a permit application has not yet been submitted to the Commission for the same location.

ii. The cumulative total of the acreage that is currently disturbed or is planned to be disturbed to construct the active and proposed Oil and Gas Locations associated with the Oil and Gas Development Plan within a 1 mile radius of each of the proposed Oil and Gas Locations, and the source(s) used to calculate the total acreage, which may include:

aa. Any relevant field observation or measurements; or

bb. The Commission's electronic location files.

iii. The total number of oil and gas Wells within a 1 mile radius of each of the proposed Oil and Gas Locations that are:

aa. Active;

bb. Permitted but not drilled;

cc. Proposed; and

dd. Plugged and Abandoned.

iv. The total volume of produced hydrocarbon and produced water storage that exists and is proposed at the active and proposed Oil and Gas Locations associated with the Oil and Gas Development Plan within a 1 mile radius of each of the proposed Oil and Gas Locations, and the sources used to calculate the storage volumes.

D. Other Industrial Impacts. On the Form 2B, the Operator will identify existing industrial facilities within a 1 mile radius of each of the proposed Oil and Gas Locations associated with the proposed Oil and Gas Development Plan, including:

i. A map or aerial photo, if necessary, showing the proposed Oil and Gas Location(s) and the industrial facilities; and

ii. A general description of the use or operation of the industrial facilities.

(6) Permitting Coordination Notifications.

A. If an Operator is concurrently seeking a permit from the Commission and a federal agency or a Relevant Local Government for one or more locations within the proposed Oil and Gas Development Plan, the Operator may engage the Director in the federal agency or Relevant Local Government process. The Relevant Local Government or federal agency may also request that the Director engage in the Relevant Local Government process or federal agency process. If the Operator, Relevant Local Government, or federal agency requests the Director's engagement, the Operator will:

i. Notify the Director that it is concurrently seeking a permit from the Relevant Local Government or federal agency permitting process on the Form 2A at the time the Operator submits the proposed Oil and Gas Development Plan;

ii. Identify any potential conflicts or differences between agency standards for each of the respective permitting authorities on the Form 2A; and

iii. Promptly notify the Director in writing of subsequent milestones and events in the Local Government or federal agency permitting process, including but not limited to:

aa. Submission of documents;

bb. On-site inspections;

cc. Public comment deadlines;

dd. Hearings and public meetings; or

ee. Issuance of final decisions.

B. If an Operator has already obtained a permit from a federal agency or a Relevant Local Government for one or more locations within the proposed Oil and Gas Development Plan, the Operator will submit the federal agency's or Relevant Local Government's final decision documents approving the siting and any related surface disturbance as an attachment to the Form 2A for that location.

i. If a Relevant Local Government has already approved the siting of one or more Oil and Gas Locations proposed as part of an Oil and Gas Development Plan, and the Director determines that it will recommend that the Commission deny the proposed Oil and Gas Development Plan based on an alternative location analysis process pursuant to Rule 304.b.(2), the Director will notify the Relevant Local Government and the Operator prior to issuing a Recommendation pursuant to Rule 306.

ii. For a proposed Oil and Gas Location on federal surface or mineral estate for which the relevant federal agency has already approved one or more Application(s) for Permit to Drill, the Operator will submit any environmental analysis or analyses conducted for the Application(s) for Permit to Drill pursuant to the National Environmental Policy Act.

(7) A certification that all components of the Oil and Gas Development Plan have been submitted. The Operator will submit a Form 2C, Oil and Gas Development Plan Certification, to certify the submission of all components of the Oil and Gas Development Plan, and to identify all components of the application.

(8) If an Operator proposes multiple Oil and Gas Locations, and the Director determines that the number of proposed locations, geographic scope, or high number of adjacent or nearby Oil and Gas Development Plans submitted by the same Operator would be more appropriately considered as a CAP, the Director may request a meeting with the Operator to evaluate whether the proposed Oil and Gas Development Plan(s) should be re-submitted as a CAP application pursuant to Rule 314.

b. Completeness Determination. After the Operator certifies pursuant to Rule 303.a.(7) that all required components of the Oil and Gas Development Plan have been submitted, the Director will use best efforts to review the application materials within 30 days to determine if they are complete.

(1) If the proposed Oil and Gas Development Plan is complete, the Director will approve the Form 2C and issue a completeness determination to the Operator via electronic mail.

(2) A completeness determination does not constitute approval or denial of an Oil and Gas Development Plan, nor does it convey any rights to conduct any surface-disturbing activities.

(3) At any time, before or after the Director makes a completeness determination, the Director or the Commission may request any relevant information necessary and reasonable to make a final determination of approval or denial on an Oil and Gas Development Plan. The Operator will provide any requested information before the Commission makes a final decision to approve or deny the Oil and Gas Development Plan. The Director will provide the Operator with the reason for the request in writing.

(4) If the Director determines that an application is incomplete, the Director will notify the Operator in writing of any such inadequacies. The Operator will have 90 days from the date that it was contacted to correct or provide requested information, otherwise the Director will deny the Form 2C, and all components of the application will be considered withdrawn and the Oil and Gas Development Plan filing fee will not be refunded.

(5) The Director will submit the completeness determination to the Hearings Unit, where it will be part of the record before the Commission on the Oil and Gas Development Plan application.

c. Revisions to an Oil and Gas Development Plan Application.

(1) At any time prior to the Director making a completeness determination, the Operator may request changes to its Oil and Gas Development Plan or provide additional or different information by contacting the Director.

(2) After the Director makes a completeness determination, the Operator may only make material changes to its Oil and Gas Development Plan application with the Director's approval, which may require re-noticing the application pursuant to Rules 303.e and 503.g.(1), and reopening the public review and consultation period pursuant to Rule 303.d.

d. Public Review and Consultation.

(1) **Public Comment Period.** When the Director makes a completeness determination by approving a Form 2C, the Oil and Gas Development Plan application components, exemptions granted pursuant to Rule 304.d, and supporting materials will be posted to the Commission's website. The website posting will provide:

A. The date by which public comments must be received to be considered, which is:

i. 45 days from the date the Oil and Gas Development Plan was posted if the Oil and Gas Development Plan includes any proposed Oil and Gas Locations within 2,000 feet of a Residential Building Unit, High Occupancy Building Unit, or School Facility within a Disproportionately Impacted Community; and

ii. 30 days from the date the Oil and Gas Development Plan was posted for all other Oil and Gas Development Plans; and

B. The mechanism for the public to provide comments.

(2) **Notification for Consultation.** At the same time the Director posts materials to the Commission's website pursuant to Rule 303.d.(1), the Director will provide electronic notice of such posting to:

A. The Relevant Local Government(s);

B. All Proximate Local Government(s);

C. CPW;

D. CDPHE, if consultation will occur pursuant to Rule 309.f; and

E. Public Water System administrators, if consultation will occur pursuant to Rule 309.g.

(3) **Confidentiality.** If the Operator designates any portion of its Oil and Gas Development Plan application as "confidential" pursuant to Rule 223, then the Director will post only the redacted version when the Oil and Gas Development Plan application is posted.

e. Notice.

(1) **Who Receives Notice.** The Operator will provide notice of the completeness determination within 7 days to:

A. All Owners of minerals to be developed by the Oil and Gas Development Plan except that no notice is required for minerals already subject to a federal Unit Agreement pursuant to 43 C.F.R. § 3180.

B. All Surface Owners, Building Unit owners, and residents, including tenants of both residential and commercial properties, within 2,000 feet of any Working Pad Surface included in the Oil and Gas Development Plan. Notice to tenants may be accomplished by sending the notice to the residences addressed to "Current Resident."

C. The Colorado State Land Board (if a mineral owner).

D. The U.S. Bureau of Land Management (if any federal entity is mineral owner).

E. The Southern Ute Indian Tribe (for applications involving minerals within the exterior boundary of the Tribe's reservation that are subject to the Commission's jurisdiction pursuant to Rule 201.d.(2)).

F. All Schools, Child Care Centers, and School Governing Bodies pursuant to Rule 309.d.

G. Police, fire departments, emergency service agencies, and first responder agencies responsible for ensuring public safety in all areas within 2,000 feet of any Working Pad Surface included in the Oil and Gas Development Plan.

H. The administrator of any Public Water System that operates:

i. A surface water Public Water System intake that is 15 stream miles or less downstream from the proposed Working Pad Surface;

ii. A groundwater under the direct influence of surface water ("GUDI") Public Water System supply well within 2,640 feet of the proposed Working Pad Surface; and

iii. A Public Water System supply well completed in a Type III Aquifer within 2,640 feet of the proposed Working Pad Surface.

(2) **Substance of Notice.** Notice provided by the Operator pursuant to this section will include:

A. An introductory letter including:

i. The Operator's contact information including its electronic mail address, phone number, and physical address(es) to which the public may direct questions and comments;

ii. The contact information for the Relevant Local Government;

iii. The Commission's website address and main telephone number;

iv. The location of all proposed Oil and Gas Locations; and

v. The anticipated date that each phase of operations will commence (by month and year).

B. A description of the proposed Oil and Gas Development Plan, including:

i. How many Wells and Locations are proposed;

ii. The proposed construction schedule by quarter and year;

iii. A description of each operational phase of development and what to expect during each phase;

iv. Proposed haul routes and traffic volume associated with each phase of operations; and

v. A description of any variances requested pursuant to Rule 502.

C. The Commission's information sheet about the procedural steps involved with the Director's and Commission's review of Oil and Gas Development Plans;

D. The Commission's information sheet about the Commission's public comment process and the relevant deadlines;

E. The Commission's information sheet about Hydraulic Fracturing Treatments, unless Hydraulic Fracturing Treatments will not be utilized at any Well within the proposed Oil and Gas Development Plan;

F. Other information that the Director identifies in the completeness determination as necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources;

G. The Commission's information sheet about how the public may view the status of the proposed Oil and Gas Development Plan application on the Commission's website; and

H. Information on how the public may learn more details about and ask questions about the Oil and Gas Development Plan prior to the closure of the public comment period.

I. All written information provided pursuant to Rule 303.e.(2) will also be provided in all languages spoken by 5% or more of the population in all census block groups within 2,000 feet of each proposed Oil and Gas Location within the Oil and Gas Development Plan.

(3) **Procedure for Providing Notice.** Notice will be delivered by one of the following mechanisms:

A. Hand delivery, with confirmation of receipt;

B. Certified mail, return-receipt requested;

C. Electronic mail, with electronic receipt confirmation; or

D. By other delivery service with receipt confirmation.

f. Publication of Comments. The Director will post public comments on the Commission's website according to applicable guidance.

g. Extension of Comment Period. The Director may extend or reopen the comment period for up to an additional 30 days for a proposed Oil and Gas Development Plan and 45 days for a proposed CAP if the Director determines an extension or reopening is reasonable in order to obtain public input.

h. Drilling and Spacing Unit Applications. When an Oil and Gas Development Plan includes an application for a new Drilling and Spacing Unit or to amend an existing Drilling and Spacing Unit, the Drilling and Spacing Unit application will be noticed and subject to the petition process set forth in Rules 504.b.(2) & 507.

304. FORM 2A, OIL AND GAS LOCATION ASSESSMENT APPLICATION

a. Submitting Form 2A. Operators will submit a completed Form 2A, Oil and Gas Location Assessment as part of their Oil and Gas Development Plan application, as required by Rule 303.a.(2). Operators will submit and obtain approval of a Form 2A prior to:

(1) Surface disturbance at a site previously undisturbed by Oil and Gas Operations;

(2) Surface disturbance for purposes of expanding an existing Working Pad Surface or Oil and Gas Location; or

(3) Any significant change to the design and operation of an Oil and Gas Location, including but not limited to the addition of a Well or a Pit, except an Emergency Pit or a lined Plugging Pit. The Director will determine if a Form 2A is required for significant changes at an existing Oil and Gas Location made in response to new requirements or regulations from other state or federal agencies or the Relevant Local Government.

b. Information Requirements. All Form 2As will include the following information, unless otherwise provided in a Commission Order approving a CAP pursuant to Rule 314.

(1) Local Government Siting Information. The Operator will comply with the certification requirements of Rule 302.b.

(2) Alternative Location Analysis.

A. Applicability. This Rule 304.b.(2) applies to any proposed Oil and Gas Location:

i. That meets any of the criteria listed in Rule 304.b.(2).B, unless the Director determines in the completeness determination that an alternative location analysis is not necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources. The Director may not waive the alternative location analysis requirement for any Oil and Gas Location that meets the criteria listed in Rule 304.b.(2).B.i–iii.

ii. For which the Director or Commission determines that an alternative location analysis is necessary to evaluate whether the proposed Oil and Gas Location reasonably protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

iii. Within the exterior boundaries of the Southern Ute Indian Reservation and subject to the Commission's jurisdiction pursuant to Rule 201.d.(2), if the Southern Ute Indian Tribe objects to the proposed Oil and Gas Location, or requests an alternative location analysis.

B. Alternative Location Analysis Criteria. An Operator will perform an alternative location analysis if:

i. The proposed Working Pad Surface is within 2,000 feet of 1 or more Residential Building Units or High Occupancy Building Units;

ii. The proposed Working Pad Surface is less than 2,000 feet from a School Facility or Child Care Center;

iii. The proposed Working Pad Surface is within 1,500 feet of a Designated Outside Activity Area;

iv. The proposed Working Pad Surface is less than 2,000 feet of a municipal or county boundary, and the Proximate Local Government objects to the location or requests an alternative location analysis;

v. The proposed Working Pad Surface is within a Floodplain;

vi. Unless waived by the applicable Public Water System(s), the proposed Oil and Gas Location is within:

aa. A surface water supply area as defined in Rule 411.a.(1); or

bb. Within 2,640 feet of a Public Water System supply well that is completed in a Type III Aquifer or is a groundwater under the direct influence of surface water well as defined in Rule 411.b.(1);

vii. The proposed Oil and Gas Location is within the boundaries of, or is immediately upgradient from, a mapped, visible, or field-verified wetland or riparian corridor;

viii. The proposed Oil and Gas Location is within High Priority Habitat and the Operator did not obtain a waiver from CPW through a pre-application consultation;

ix. The Operator is using or intends to use a Surface Owner protection bond pursuant to Rule 703 to access the proposed Oil and Gas Location; or

x. The proposed Working Pad Surface is within 2,000 feet of a Residential Building Unit, High Occupancy Building Unit, or School Facility located within a Disproportionately Impacted Community.

C. Contents of an Alternative Location Analysis. If an alternative location analysis is required, the Operator will prepare a narrative analysis that identifies all potential alternate locations from which the targeted minerals can be accessed that may be considered for siting of the Oil and Gas Location. Operators will also submit the following information:

i. One or more maps or recent aerial images showing:

aa. The proposed area of mineral development;

bb. The Operator's proposed Oil and Gas Location;

cc. All technically feasible alternative locations;

dd. All proximal existing and permitted Oil and Gas Locations;

ee. All relevant jurisdictional boundaries;

ff. All Disproportionately Impacted Communities within 2,000 feet of each Oil and Gas Location analyzed in the alternative location analysis;

gg. A reference coordinate (latitude/longitude); and

hh. All Rule 304.b.(2).B criteria met by the proposed location and any alternative location(s) shown.

ii. For each alternative location evaluated, a table showing all information required by Rules 304.b.(3).A & B.

iii. A data table for the proposed Oil and Gas Location and each alternative location, with all measurements made from each proposed Working Pad Surface, that lists the following information:

aa. All Rule 304.b.(2).B criteria met.

bb. For proposed Oil and Gas Locations within or within 2,000 feet of a Disproportionately Impacted Community:

1. The distance to the nearest Building Unit, High Occupancy Building Unit, and School;

2. A description of the community outreach efforts conducted by the Operator prior to preparing the alternative location analysis, including whether the Operator made information available in languages other than English based on the linguistic needs of the community, questions and Operator responses to questions from residents of the Disproportionately Impacted Community, and any public meetings conducted (including location, time of day, and whether interpreters were requested and provided) with residents of the Disproportionately Impacted Community;

3. The number and description of existing Oil and Gas Locations, Oil and Gas Facilities, and Wells also within 2,000 feet of any Residential Building Unit, High Occupancy Building Unit, or School Facility within 2,000 feet of any proposed Oil and Gas Location analyzed in the Alternative Location Analysis.

cc. Distance to any municipal or county boundaries that are within 2,000 feet, and the names of the Proximate Local Government(s).

dd. **Relevant Local Government Information.** For each alternative location analyzed, the:

1. Name of the Relevant Local Government;

2. The Relevant Local Government's land use or zoning designation;

3. The Relevant Local Government's permitting process; and

4. The status of each Relevant Local Government's permit process, if applicable.

ee. Current land use, and plans for future land use at and proximal to each identified location.

ff. Distance to nearest wetland, surface water, surface water supply area as defined in Rule 411.a.(1), or Public Water System supply well that is completed in a Type III Aquifer or is a groundwater under the direct influence of surface water well as defined in Rule 411.b.(1).

gg. Distance to nearest High Priority Habitat.

hh. Anticipated method of right-to-construct and surface ownership.

D. The Director may request that the Operator provide any additional information or analyze additional locations for the Oil and Gas Location if the Director believes that additional analysis or information is necessary for the Director's and Commission's review of the public health, safety, welfare, environmental, and wildlife impacts of the locations the Operator analyzes.

(3) Cultural Distances.

A. A table showing the distance and approximate bearing from the edge of the Working Pad Surface of the proposed or existing Oil and Gas Location to the edge or corner of the nearest building, Residential Building Unit, High Occupancy Building Unit, and School Facility; the nearest boundary of a Designated Outside Activity Area; the nearest Residential Building Unit, High Occupancy Building Unit, or School Facility within a Disproportionately Impacted Community within 2,000 feet of the proposed Working Pad Surface; the boundary of the nearest Disproportionately Impacted Community; and the nearest public road, above ground utility, railroad, and property line.

B. A table showing the number of Building Units, Residential Building Units, High Occupancy Building Units, School properties, School Facilities, and Designated Outdoor Activity Areas within the following radii of the Working Pad Surface:

i. 0–500 feet;

ii. 501–1,000 feet; and

iii. 1,001–2,000 feet.

C. A current aerial image depicting the information in the tables in Rules 304.b.(3).A & B.

(4) Location Pictures. The Operator will attach to the Form 2A photographs as described in this Rule 304.b.(4). The photographs will depict the staked location and its surroundings. Each photograph will be identified by date taken, Well or location name, and direction of view. The field of view of each photograph will be shown on a current aerial image, also attached. Operators will provide location photographs in sufficiently high resolution so that details of current surrounding land use may be readily discerned. Operators will attach one of the following photograph options:

A. A minimum of 4 color photographs showing the staked location and its surroundings from each cardinal direction, with no significant gaps between fields of view;

B. A minimum of 2 panoramic photographs of the location and its surroundings covering a full 360° around the location; or

C. Photographs of the locations and its surroundings taken from an unmanned aerial vehicle.

(5) **Site Equipment List.** A list of major equipment components to be used in conjunction with drilling and operating the Well(s), including but not limited to, all Tanks, Pits, flares, combustion equipment, separators, and other ancillary equipment.

(6) **Flowline Descriptions.** A description of the proposed location, size, and material of any Flowlines, including Off-Location Flowlines.

(7) **Drawings.** Operators will provide the drawings, maps, and figures required below in a suitable size, scale, and electronic format for the Director to conduct a review. If multiple drawings are required to convey the required information, then the Operator will provide them in a logical manner. All drawings, maps, and figures will include a scale bar and north arrow, the Operator's name, the site name, and other information as necessary to identify the attachment as part of the Oil and Gas Development Plan. Aerial imagery used for base maps will be current.

A. **Location Drawings.** A scaled drawing and scaled aerial photograph showing the approximate outline of the Oil and Gas Location and Working Pad Surface and all visible improvements within 2,000 feet of the proposed Oil and Gas Location (as measured from the proposed edge of the Working Pad Surface), with a horizontal distance and approximate bearing from the Working Pad Surface. If there are no visible improvements within 2,000 feet of a proposed Oil and Gas Location, the Operator will specify this on the Form 2A. Visible improvements will include, but not be limited to:

i. All buildings and Building Units, with High Occupancy Building Units identified;

ii. Publicly maintained roads and trails, including their names;

iii. Fences;

iv. Above-ground utility lines;

v. Railroads;

vi. Pipelines or Pipeline markers;

vii. Mines;

viii. Oil and gas Wells and associated Production Facilities;

ix. Injection Wells and associated facilities;

x. Plugged oil and gas Wells, including dry holes;

xi. Known water wells; and

xii. Known sewers with manholes.

B. Layout Drawings. Location construction and operations layout drawings, location construction, and operations cross-section plots including location and finish grades and operations facility layout drawings. These drawings will include, as applicable to the proposed Oil and Gas Location:

i. The Working Pad Surface and surrounding disturbed area making up the entirety of the Oil and Gas Location;

ii. A preliminary drill rig layout;

iii. Preliminary Well completion and Stimulation layout;

iv. If a Well is proposed to be hydraulically fractured, a preliminary layout drawing of the Flowback equipment, including the equipment and connections to comply with reduced emission completion requirements pursuant to Rule 903.c.(1); and

v. The location of all existing and proposed Oil and Gas Facilities listed on the Form 2A.

C. Wildlife Habitat Drawing. A drawing, map, or aerial image depicting High Priority Habitat within 1 mile of the Working Pad Surface.

D. Preliminary Process Flow Diagrams. Process flow diagrams depicting:

i. Flowback operations; and

ii. Oil and gas production operations.

E. Hydrology Map. A topographic map showing the horizontal distance and approximate bearing from the Oil and Gas Location to:

i. All surface Waters of the State within 2,640 feet of the proposed Working Pad Surface. The map will indicate which surface water features are downgradient;

ii. All Water Sources within 2,640 feet of the proposed Working Pad Surface;

iii. Any Public Water System facilities, including intakes, wells, storage facilities, recharge areas, and treatments plants within 2,640 feet of the Working Pad Surface;

iv. Rule 411 buffer zones within 2,640 feet of the Working Pad Surface; and

v. Any surface waters within 2,640 feet of the Working Pad Surface that are 15 stream miles upstream of a Public Water System intake.

F. Access Road Map. A U.S. Geological Survey topographic map, or scaled aerial photograph showing the access route from the nearest publicly maintained road to the proposed Oil and Gas Location, and identifying any new access roads constructed as part of the Oil and Gas Development Plan. The map will clearly identify any Residential Building Units within 2,000 feet of the access road for this Oil and Gas Location.

G. Related Location and Flowline Map. A U.S. Geological Survey topographic map, or scaled aerial photograph showing:

i. All existing, approved, and proposed Oil and Gas Locations within 2,000 feet of the area affected by the proposed Oil and Gas Development Plan;

ii. All proposed Flowline corridors, including Off-Location Flowline corridors, to or from the proposed Oil and Gas Location and to or from associated Oil and Gas Facilities.

H. Directional Well Plat. If the proposed Oil and Gas Location includes one or more directional Wells, a map showing the surface hole location and the proposed wellbore trajectory with the top of the productive zone and bottom-hole location for each Well.

I. Geologic Hazard Map. A map identifying any Geologic Hazards within a 1 mile radius of the proposed Working Pad Surface. For any identified Geologic Hazard that extends beyond the 1 mile radius, a second map scaled to show the extent of that hazard in relation to the proposed Oil and Gas Location.

J. Disproportionately Impacted Communities Map. If the proposed Oil and Gas Location is within 2,000 feet of a Residential Building Unit, High Occupancy Building Unit, or School Facility located within a Disproportionately Impacted Community, a map or aerial photo showing the spatial relationship between the proposed Oil and Gas Location and the building(s) identified, and the boundaries of the census block group that meets the 100 Series definition of a Disproportionately Impacted Community.

(8) Geographic Information System ("GIS") Data. GIS polygon data to describe the boundaries of the entire proposed Oil and Gas Location and the Working Pad Surface.

(9) Land Use Description. A narrative description of the current land use(s), the Relevant Local Government's land use or zoning designation, any applicable federal land use designations for proposed Oil and Gas Locations on federal surface estate, and the landowner's designated final land use(s) for the purpose of determining Reclamation standards.

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

B. Reference Area Data. If the final land use includes rangeland, forestry, recreation, or wildlife habitat, then a Reference Area will be selected and documented. The Operator will also submit the following information:

i. Reference Area Map. A topographic map or aerial image showing the location of the Reference Area with respect to the proposed Oil and Gas Location including latitude and longitude of Reference Area; and

ii. Reference Area Pictures. 5 color photographs of the Reference Area, including 4 taken from each cardinal direction, and 1 taken from above the Reference Area. Each photograph will be identified by date taken, Well or Oil and Gas Location name, and direction of view. The photographs will be taken during the peak growing season and will clearly depict vegetation cover and diversity. To ensure that the photographs accurately depict vegetation during peak growing season, these photographs may be submitted up to 12 months after the Form 2A. Photographs of the Reference Area may be taken from an unmanned aerial vehicle, provided such aerial images are collected at a sufficient resolution to provide specific vegetation information.

iii. A table of the dominant vegetation within the Reference Area.

(10) **NRCS Map Unit Description.** A Natural Resources Conservation Service ("NRCS") soil map unit description.

(11) **Best Management Practices.** A description of any Operator-proposed, site specific Best Management Practices that the Operator commits to perform as part of the implementation of the Oil and Gas Development Plan, including any Best Management Practices, conditions of approval, or stipulations required by an approved federal permit.

(12) **Surface Owner Information.**

A. Contact information for the Surface Owner(s); and

B. A redacted version of the Surface Use Agreement or a memorandum describing the Surface Use Agreement that includes a description of the lands subject to the agreement, signatures of the parties to the agreement, dates of signature, and any provisions of the agreement that are relevant to the Form 2A.

(13) **Proximate Local Government Information.** Contact information for any Proximate Local Governments.

(14) **Wetlands.** If a federal, state, or local government agency requires a permit or sets other substantive standards for direct or indirect impacts to a wetland, including but not limited to the discharge of dredged or fill material during the construction of a proposed Oil and Gas Location, access roads to the Oil and Gas Location, or Pipeline corridors associated with the Oil and Gas Location, evidence that the Operator has complied with the agency's substantive standards, sought any required permits, and whether the permit(s) have been issued.

(15) **Schools and Child Care Centers.** If the proposed Oil and Gas Location is within 2,000 feet of a School Facility, Future School Facility, or Child Care Center, a statement indicating whether the School Governing Body requested consultation.

c. **Plans.** All Form 2As will include site-specific plans that demonstrate compliance with the Commission's Rules for the operation of the proposed Oil and Gas Location in a manner that is protective of and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources. Each Form 2A will include the following plans, unless otherwise provided in a Commission Order approving a CAP pursuant to Rule 314.

(1) **Emergency Spill Response Program.** For operations within 2,640 feet of a groundwater under the direct influence of surface water well or Type III Well or surface water that is 15 miles or less upstream from a Public Water System(s) intake, an emergency spill response program consistent with the requirements of Rules 411.a.(4).B, 411.b.(5).B, & 602.j.

(2) **Noise Mitigation Plan.** A noise mitigation plan consistent with the requirements of Rule 423.a.

(3) **Light Mitigation Plan.** A light mitigation plan consistent with the requirements of Rule 424.a.

(4) **Odor Mitigation Plan.** An odor mitigation plan consistent with the requirements of Rule 426.a.

(5) Dust Mitigation Plan. A dust mitigation plan consistent with the requirements of Rule 427.a.

(6) Transportation Plan. If the Relevant Local Government requires a transportation plan or an equivalent traffic planning document, the transportation plan submitted to the Relevant Local Government. If the Relevant Local Government does not require a transportation plan, the Director may request information regarding haul routes, traffic volumes, and Best Management Practices to avoid, minimize, and mitigate impacts from traffic associated with the Oil and Gas Location.

(7) Operations Safety Management Program. An operations safety management program consistent with the requirements of Rule 602.d.

(8) Emergency Response Plan. An emergency response plan consistent with the requirements of Rule 602.j.

(9) Flood Shut-In Plan. If located in a Floodplain, a shut-in plan consistent with the requirements of Rule 421.b.(1).

(10) Hydrogen Sulfide Drilling Operations Plan. If operating in zones known or suspected to contain hydrogen sulfide gas (“H_2S”), a H_2S drilling operations plan consistent with the requirements of Rule 612.d.

(11) Waste Management Plan. A waste management plan consistent with the requirements of Rule 905.a.(4).

(12) Gas Capture Plan. A gas capture plan or commitment consistent with the requirements of Rule 903.e.

(13) Fluid Leak Detection Plan. A fluid leak detection plan.

(14) Topsoil Protection Plan. A topsoil protection plan consistent with the requirements of Rule 1002.c.

(15) Stormwater Management Plan. A stormwater management plan consistent with the requirements of Rule 1002.f.

(16) Interim Reclamation Plan. An interim reclamation plan consistent with the requirements of Rule 1003.

(17) Wildlife Plan. A Wildlife Protection Plan or Wildlife Mitigation Plan consistent with the requirements of Rule 1201.

(18) Water Plan. A plan identifying the planned source of water for drilling and completion operations including:

A. The planned source and volume of all surface water and Groundwater to be used and the coordinates of the planned source of water;

B. The seller’s name and address if water is to be purchased;

C. If recycled or reused water is anticipated to be used, a description of the source of that water, background concentrations of chemicals listed in Table 437-1, anticipated method of transporting the water, and anticipated volumes to be used in addition to the reuse and recycling plan requirements of Rule 905.a.(3); and

D. If fresh water is anticipated to be used, a description of why the Operator does not intend to use recycled or reused water.

(19) **Cumulative Impacts Plan.** A plan documenting how the Operator will address cumulative impacts to resources identified pursuant to Rule 303.a.(5) that includes:

A. A description of all resources to which cumulative adverse impacts are expected to be increased;

B. A description of specific measures taken to avoid or minimize the extent to which cumulative adverse impacts are increased;

C. A description of all measures taken to mitigate or offset cumulative adverse impacts to any of the resources; and

D. Additional information determined to be reasonable and necessary to the evaluation of cumulative impacts by the Operator, the Director, CDPHE, CPW, or the Relevant Local Government.

(20) **Community Outreach Plan.** For Oil and Gas Locations proposed within 2,000 feet of a Residential Building Unit, High Occupancy Building Unit, or School Facility located within a Disproportionately Impacted Community, a consultation, outreach, and engagement plan that includes:

A. A description of any measures taken to directly mitigate adverse impacts to the Disproportionately Impacted Community;

B. Certification that written materials have been and will be provided in all languages spoken by 5% or more of the population in the census block group where the proposed Oil and Gas Location is located and those census block groups within 2,000 feet of the proposed Oil and Gas Location; and

C. The proposed date, time, and location of any public meeting(s) that are held at a location in close proximity to the Disproportionately Impacted Community. The Operator will provide child care and interpretation services at such a public meeting upon request.

(21) **Geologic Hazard Plan.** If the Operator identifies any Geologic Hazards pursuant to Rule 304.b.(7).I, the Operator will submit a Geologic Hazard plan describing proposed mitigation measures.

d. **Lesser Impact Areas.** The Director may exempt an Operator from submitting any of the information required by Rule 304.b, or any plan required by Rule 304.c, under the following circumstances:

(1) If the Operator requests an exemption from the Director based on evidence showing the information or plan is unnecessary because:

A. The impacted resource or resource concern are not present in the area; or

B. Impacts to the resource will be so minimal as to pose no concern.

(2) Operators may request an exemption from the Director in writing, without proceeding through the ordinary Rule 502 variance process. A request for an exemption will be provided with the Form 2A at the time the form is submitted.

(3) The Director may grant an exemption as part of the completeness determination if the Director concurs with the Operator that providing the information or plan is unnecessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources.

(4) If the Director grants an exemption, the Commission may nevertheless request the information or plan subject to the exemption, or related information, if the Commission determines that reviewing the information or plan is necessary to protect and minimize adverse impacts.

e. Substantially Equivalent Information.

(1) The Operator may submit substantially equivalent information or plans developed through a Local Government land use process in lieu of providing information or plans required by Rules 304.b & 304.c. Nothing in this Rule 304.e.(1) precludes the Director or Commission from requiring the Operator to submit information or plans otherwise required by Rules 304.b or 304.c because the Director or Commission determines that the information or plans developed through the Local Government land use process are not equivalent.

(2) For proposed Oil and Gas Locations on federal surface or mineral estate for which an Operator has submitted environmental analysis pursuant to Rule 303.a.(6).B.ii, the Operator may provide references to equivalent information in the federal environmental analysis in lieu of providing information or plans required by Rules 304.b & 304.c, including the alternative location analysis required by Rule 304.b.(2). Nothing in this Rule 304.e.(2) precludes the Director or Commission from requiring the Operator to submit information or plans otherwise required by Rules 304.b or 304.c because the Director or Commission determines that the federal environmental analysis is not equivalent.

305. APPLICATION FOR A DRILLING AND SPACING UNIT

a. Procedural Requirements.

(1) Operators seeking to create a new Drilling and Spacing Unit, or to modify an existing Drilling and Spacing Unit, will file a Drilling and Spacing Unit pursuant to Rule 503.g.(2). If the proposed Drilling and Spacing Unit is part of an Oil and Gas Development Plan application, the Drilling and Spacing Unit application will be included with the hearing application for that Oil and Gas Development Plan.

(2) All Drilling and Spacing Unit applications will include the following information:

A. Certification that the Operator has complied with the Local Government siting disposition requirements of Rule 302.b.

B. Certification that the operations in the Drilling and Spacing Unit will be conducted in a reasonable manner to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

C. The unit boundary and interwell completion setback distances.

D. All existing Oil and Gas Locations and associated Wells that are developing the same formation in the application lands. The application will discuss what the Operator intends to do with the existing Oil and Gas Locations and Wells.

E. The wellbore orientation for all horizontal Wells in the proposed unit.

F. Whether there are existing units and Wells within the proposed application lands and what the disposition of those existing units and Wells in those existing units will be under the proposed application.

G. The Oil and Gas Locations that are proposed for the unit. If an Operator has applied for a Form 2A, the Operator will identify its document number. If the Form 2A has already been approved, the Operator will identify its Location ID number.

H. The total number of proposed Wells for the unit.

I. Any additional information as may be required to support the requested prayer for relief.

J. All prior orders that implicate the prayer for relief.

K. Certification that satisfies the requirements of Rule 505.a.

L. For at least one portion of a mineral tract within the proposed unit, documentation showing the applicant's status as an Owner within the unit. Acceptable forms of documentation include, but are not limited to:

i. Mineral deed or memorandum;

ii. Mineral lease or memorandum; or

iii. Any other agreement confirming the applicant's right to drill into and produce from a Pool, or a memorandum of such agreement.

M. For federal minerals, certification that the Operator will comply with any applicable federal unit agreement or communitization agreement requirements.

b. Standards for Approval. In determining whether to recommend that the Commission approve or deny a proposed Drilling and Spacing Unit, the Director will consider whether the proposed Drilling and Spacing Unit:

(1) Protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources;

(2) Prevents waste of oil and gas resources;

(3) Avoids the drilling of unnecessary Wells; and

(4) Protects correlative rights.

306. DIRECTOR'S RECOMMENDATION ON THE OIL AND GAS DEVELOPMENT PLAN

a. When the Director May Issue a Recommendation. The Director will not make a Recommendation to the Commission about whether to approve or deny any Oil and Gas Development Plan until:

(1) The Director has fully reviewed the Oil and Gas Development Plan and all supporting application materials and has obtained all information necessary to evaluate the proposed operation and its potential impacts on public health, safety, welfare, the environment, and wildlife resources;

(2) The Director has reviewed and commented on the Drilling and Spacing Unit application, if submitted with the Oil and Gas Development Plan;

(3) The public comment period has ended and the Director has considered all substantive public comments received, including comments from the Relevant Local Government(s) or Proximate Local Government(s);

(4) If applicable, CPW, CDPHE, and Public Water System consultations have been completed and submitted to the Director; and

(5) The Director determines that the Operator has provided adequate Financial Assurance as required by the Commission's 700 Series Rules for both the proposed Oil and Gas Development Plan and all existing facilities owned by the Operator.

b. Director's Recommendation.

(1) **Approval.** The Director may Recommend that the Commission approve an Oil and Gas Development Plan that:

A. Complies with all requirements of the Commission's Rules; and

B. In the Director's judgment, protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) **Conditions of Approval.**

A. The Director may Recommend that the Commission add conditions to the approval that are necessary and reasonable to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

B. For any proposed Oil and Gas Development Plan that includes proposed Oil and Gas Locations that have already been approved by the federal agency or agencies, the Director will consider environmental analyses and federal stipulations and conditions of approval before Recommending any additional conditions of approval.

(3) **Denial.** If the Director determines that an application does not provide necessary and reasonable protections for, or minimize adverse impacts to, public health, safety, welfare, the environment, and wildlife resources, or fails to meet the requirements of the Commission's Rules, the Director may Recommend that the Commission deny the Oil and Gas Development Plan.

c. Notice of Recommended Decision. Upon making a Recommendation that the Commission approve or deny an Oil and Gas Development Plan, the Director will post the written basis for the Director's Recommendation on the Commission's website, file its Recommendation with the Hearings Unit, and notify the following persons electronically in a manner determined by the Director:

(1) The Surface Owner(s) whose contact information was provided pursuant to Rule 304.b.(12).A;

(2) The Operator;

(3) The Relevant Local Government(s);

(4) All Proximate Local Governments;

(5) CDPHE, if consultation occurred subject to Rule 309.f;

(6) CPW, if consultation occurred subject to Rule 309.e;

(7) Public Water System(s), if consultation occurred pursuant to Rule 309.g;

(8) The Colorado State Land Board (if a mineral owner);

(9) The appropriate federal agency (if any federal entity is mineral owner); and

(10) Any person or entity that has provided a comment electronically pursuant to Rule 303.d.(1).

d. If the Director does not issue a Recommendation within 120 days of a completeness determination, the Operator may move for a hearing before the Commission, Administrative Law Judge, or Hearing Officer. At such hearing, the Director will provide an explanation of the status of the Director's review of the Oil and Gas Development Plan and any reasons for delay. For an Oil and Gas Development Plan within an approved CAP, the Operator may move for a hearing if the Director does not issue a Recommendation within 90 days of a completeness determination.

307. COMMISSION CONSIDERATION OF THE OIL AND GAS DEVELOPMENT PLAN

a. Director's Recommendation. Upon receipt of the Director's Recommendation on an Oil and Gas Development Plan, it will be considered by the Commission pursuant to Rule 510, and Rules 508 & 509, as appropriate. The Commission will consider whether to delegate consideration of an Oil and Gas Development Plan to an Administrative Law Judge or Hearing Officer, except that the Commission will not delegate:

(1) The Director's Recommendation of denial to an Administrative Law Judge or Hearing Officer; or

(2) Consideration of an Oil and Gas Development Plan that the Director Recommends approving, but includes one or more proposed Oil and Gas Locations that have been denied by a Relevant Local Government.

b. Commission's Consideration of Director's Recommendation.

(1) **Approval.** The Commission may approve an Oil and Gas Development Plan that complies with all requirements of the Commission's Rules, and protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources. The Commission may add any conditions to the approval of an Oil and Gas Development Plan that it determines are necessary and reasonable to ensure compliance with all requirements of the Commission's Rules or to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) **Denial.** If the Commission determines that an Oil and Gas Development Plan does not provide necessary and reasonable protections for, or minimize adverse impacts to, public health, safety, welfare, the environment, and wildlife resources, or fails to meet the requirements of the Commission's Rules, the Commission may deny the Oil and Gas Development Plan. The Commission will identify in the record the basis for the denial.

(3) **Stay.** If the Commission determines that additional information or analysis, including an alternative location analysis or an analysis of additional locations if an alternative location analysis was already conducted, is necessary for it to make a decision to approve or deny an Oil and Gas Development Plan, it may stay consideration of the Oil and Gas

Development Plan for further consideration until the Director or Operator can provide the Commission with the additional information or analysis necessary to consider the Oil and Gas Development Plan. The Commission may set or extend reasonable deadlines for the Director or Operator to provide the additional information or analysis to the Commission.

c. Final Agency Action. The Commission's decision to approve or deny an Oil and Gas Development Plan will constitute final agency action. The Commission's decision to stay an Oil and Gas Development Plan for further consideration will not constitute final agency action.

308. FORM 2, APPLICATION TO DRILL, DEEPEN, RE-ENTER, OR RECOMPLETE, AND OPERATE

a. Submitting Form 2. If the Commission approves an Operator's Oil and Gas Development Plan, or if the Operator's Form 2A and Drilling and Spacing Unit, where applicable, were approved prior to the effective date of this Rule, then the Operator will submit and obtain the Director's approval of a complete Form 2, Application for Permit to Drill, before taking any of the actions listed in Rules 308.a.(1)–(6) below. The Form 2 will detail the Operator's plans to:

(1) Drill any Well;

(2) Deepen any existing Well;

(3) Re-enter, complete, and operate any plugged Well (except for re-entry to re-plug will require a Form 6, Notice of Intent to Abandon pursuant to Rule 434);

(4) Recomplete and operate any existing Well;

(5) Drill a sidetrack from any Well; or

(6) Convert a stratigraphic Well into a production Well.

b. Information Requirements. All Form 2s require the following information.

(1) Every Form 2 will specify the distance between the Well and wall or corner of the nearest building, Building Unit, public road, above ground utility, railroad, and property line.

(2) **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.

(3) 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.

(4) **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:

A. 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.

B. For irregular, partial, or truncated sections, dimensions will be furnished to completely describe the entire section(s) containing the proposed Well.

C. 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 pursuant to Rule 216.

D. 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 will meet the requirements set forth in Rule 216.

E. The Well location plat will include the proposed top of the productive zone and the bottom hole location. The plat will be in a suitable size and scale for the Director to conduct a review. If the wellbore penetrates multiple sections, the Well location plat will depict every section penetrated by the wellbore.

F. A map legend.

G. A north arrow.

H. A bar scale.

I. The ground elevation.

J. The basis of the elevation (how it was calculated or its source).

K. The basis of bearing or interior angles used.

L. Complete description of monuments and collateral evidence found; all aliquot corners used will be described.

M. The legal land description by section, township, range, principal meridian, baseline, and county.

N. Operator name.

O. Well name and Well number.

P. Date of completion of scaled drawing.

(5) **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 410.a.

(6) **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 408.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 408.e.(5) to ensure isolation of all such Groundwater. The casing and cementing plan will also identify the distance between the objective formation to be hydraulically fractured and Groundwater with less than 10,000 milligrams per liter total dissolved solids, and indicate whether a confining layer exists in a separate stratigraphic layer between those zones.

(7) Statewide Offset Well Evaluation.

A. 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.

B. The Operator will attach any consents obtained pursuant to Rule 408.u.(1) to the Form 2.

C. The Operator will provide notice pursuant to Rule 408.v.

(8) 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:

A. 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.

B. 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.

(9) With their Form 2, Operators will state whether the proposed Well is subject to the requirements of § 24-65.1-108, C.R.S., because it is located in an area designated as one of state interest.

c. Administrative Approval or Denial of the Form 2.

(1) The Director may approve a Form 2 that complies with all requirements of the Commission's Rules, and protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

A. The Director may add any conditions of the approval to a Form 2 that are necessary and reasonable to ensure compliance with all requirements of the Commission's Rules or to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

B. The Director will review the Oil and Gas Location where the Well is located to ensure that necessary and reasonable conditions of approval are applied to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) The Director may deny any Form 2 that does not meet all requirements of the Commission's Rules, or does not provide necessary and reasonable protections for, or minimize adverse impacts to, public health, safety, welfare, the environment, and wildlife resources. The Director will put forth the reason for the denial. If the Director denies a Form 2, the Operator has the right for a hearing in front of the Commission at an upcoming hearing.

(3) The Director may request, and an Operator will provide upon request, any relevant information necessary and reasonable to determine whether to approve or deny a Form 2. The Director will provide the Operator with the reason for the request.

(4) The Director will endeavor to review Form 2 applications in a timely and efficient manner. If the Director does not complete review within 90 days of an Operator submitting a Form 2, the Operator may move for a hearing before the Commission, Administrative Law Judge, or Hearing Officer. At such hearing, the Director will provide an explanation of the status of the Director's review of the Form 2 and any reasons for delay.

d. Changes to Form 2. Prior to approval of the Form 2, minor revisions or requested information may be provided by contacting the Director. After approval, any substantive changes will be submitted for approval on a Form 2. A Form 4 will be submitted, along with supplemental information requested by the Director, when non-substantive revisions are made after approval, and no additional fee will be imposed.

309. CONSULTATION

a. Unless otherwise specified below, all consultations required by Rule 309 will occur within 45 days after the Director posts the completeness determination on the Commission's website pursuant to Rule 303.d.(1), except that consultations will occur within 60 days for proposed Oil and Gas Development Plans or Form 2As located within a Disproportionately Impacted Community.

b. Surface Owners. The Operator will consult in good faith with the Surface Owner or the Surface Owner's appointed agent about the location of all surface disturbances, and in preparation for Reclamation and abandonment. The Surface Owner or appointed agent may submit relevant comments to the Director about any Oil and Gas Development Plan pursuant to Rule 303.d.(1).

(1) **Information Provided by Operator.** When consulting with the Surface Owner or appointed agent, the Operator will furnish, in writing:

A. All the information required for a complete Oil and Gas Development Plan;

B. The expected date of commencement of operations;

C. Topsoil management practices to be employed; and

D. The location of associated roads, Production Facilities, infrastructure, and any other areas to be used for Oil and Gas Operations.

(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 will be in writing and signed by the Surface Owner.

(3) Operators will conduct Oil and Gas Operations in a manner that accommodates the Surface Owner by minimizing intrusion upon and damage to the surface of the land.

c. Building Unit Owners and Tenants. An Operator will be available to meet for a Formal Consultation Process with residents (including owners and tenants) of Building Units located within 2,000 feet of the proposed Working Pad Surface. Building Unit Owners, their agents, their tenants, or a Relevant or Proximate Local Government may request such a meeting.

(1) **Information Provided by Operator.** When meeting with Building Unit owners or their appointed agent(s) or tenants, the Operator will provide the following information:

A. The date construction is anticipated to begin;

B. The anticipated duration of pad construction, drilling, and completion activities;

C. The types of equipment anticipated to be present on the proposed Oil and Gas Locations;

D. The Operator's interim and final Reclamation obligation;

E. A description and diagram of the proposed Oil and Gas Locations that includes the dimensions of the proposed Oil and Gas Location and the anticipated layout of production or injection facilities, Pipelines, roads, and any other areas to be used for Oil and Gas Operations;

F. Information relevant to potential health, safety, welfare, and environmental impacts associated with Oil and Gas Operations, including but not limited to security, noise, light, odors, dust, and traffic; and

G. Information about proposed Best Management Practices or mitigation measures to avoid, minimize, or mitigate those impacts.

(2) **Waiver.** The Building Unit owner, agent, or tenant may waive, permanently or otherwise, their respective right to receive notice pursuant to the Commission's Rules. Any such waiver will be in writing, signed by the owner, agent, or tenant.

(3) The Operator and the Director will consider all concerns related to public health, safety, welfare, the environment, and wildlife resources raised by Building Unit owners, their agents, or tenants during the Formal Consultation Process, including concerns raised during informational meetings or in written comments. The Operator will provide a written response to all such concerns to the Director as an attachment to the Form 2A prior to the Director making a Recommendation pursuant to Rule 306.

(4) All information provided pursuant to this Rule 309.c will also be provided in all languages spoken by 5% or more of the population in the census block group(s) within 2,000 feet of each proposed Oil and Gas Location within the Oil and Gas Development Plan.

d. Schools, Child Care Centers, and School Governing Bodies.

(1) No less than 30 days before the Operator submits an Oil and Gas Development Plan, an Operator will provide a pre-application notice of intent to conduct Oil and Gas Operations to any relevant School, Child Care Center, and School Governing Body within 2,000 feet as measured from the Working Pad Surface to:

A. The property line of a parcel currently owned by the School, Child Care Center, or School Governing Body as identified through county assessor records;

B. 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 Local Government; or

C. 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.

(2) The Notice will include:

A. The Operator's contact information;

B. The location and general description of the proposed Oil and Gas Location, including the cultural distances table as required under Rule 304.b.(3), and drawings, maps, and figures required under Rule 304.b.(7).

C. The Relevant Local Government contact information;

D. The anticipated date, by calendar year and quarter, that construction will begin and the expected schedule of drilling and completion activities;

E. A description of the status of the Relevant Local Government's siting disposition, if applicable;

F. 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 Governing Body or Child Care Center may delegate the consultation process to the principal or senior administrator of a School or Child Care Center in proximity to the proposed Oil and Gas Location; and

G. 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 303.d.(1) public comment period.

(3) A School Governing Body may waive the right to receive notice under this provision for the School Governing Body and all Schools within the area subject to the School Governing Body's oversight at any time by providing written notice to the Operator.

(4) The Operator, School Governing Body, or Director may initiate consultation pursuant to this Rule 309. 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 relevant information regarding planned measures to avoid, minimize, or mitigate adverse impacts to the School Facility or Child Care Center.

e. Colorado Parks and Wildlife.

(1) **The Purpose of Consultation.** The purpose of consultation with CPW is to provide the Director the information necessary to determine whether an application protects Wildlife Resources and whether conditions of approval are necessary to Avoid, Minimize, or Mitigate Adverse Impacts to Wildlife Resources associated with High Priority Habitats, and protect against adverse impacts to Wildlife Resources resulting from Oil and Gas Operations. Factors that CPW may take into consideration during consultation include, but are not limited to, the following:

A. Anticipated adverse impacts of the proposed Oil and Gas Operations on Wildlife Resources;

B. The extent to which the proposed siting of facilities Avoids or Minimizes Adverse Impacts;

C. The extent to which the proposed Oil and Gas Operations incorporate the use of existing facilities, roads, and Pipeline corridors and limit new surface disturbance and habitat fragmentation;

D. The extent to which the proposed Oil and Gas Operations use technology and Best Management Practices which are protective of Wildlife Resources, including but not limited to seasonal construction and drilling limitations, noise limitations, remote operations, equipment disinfection, and transporting and storing liquids through Pipelines and large Tanks or other measures to reduce traffic volumes;

E. The extent to which the proposed Oil and Gas Operations are within land used or designated to be used for residential, industrial, commercial, agricultural, or other purposes, and the existing wildlife disturbance associated with such use; and

F. The extent to which the proposed Oil and Gas Operations occur on federal or private lands for which the use and access of the lands in question may already be incorporated into a federal planning document, or the private Surface Owner designates the use of the land based on the function and utility of multiple use designations.

(2) **When Consultation Must Occur.** The Operator will consult with the Surface Owner (unless the Surface Owner has waived their right to participate pursuant to Rule 309.e.(4).C) and with CPW about a Form 2A, Oil and Gas Development Plan, CAP, or other matter where:

A. A proposed Oil and Gas Location or associated new access road, utility, or Pipeline corridor falls within High Priority Habitat, a State Park, or a State Wildlife Area;

B. A proposed Oil and Gas Location or associated new access road, utility, or Pipeline corridor falls within federally designated critical habitat or an area with a known occurrence for a federal or Colorado threatened or endangered species;

C. A proposed Oil and Gas Location or associated new access road, utility, or Pipeline corridor falls within an existing conservation easement established wholly or partly for wildlife habitat;

D. CPW requests consultation or because consultation is necessary to Avoid, Minimize, or Mitigate reasonably foreseeable direct, indirect, or cumulative Adverse Impacts to Wildlife Resources from a Form 2A, Oil and Gas Development Plan, CAP, or other matter where consultation is not otherwise required;

E. The Operator seeks a variance pursuant to Rule 502 from a provision in the Commission's 1200 Series Rules, or from wildlife-specific conditions of approval or Best Management Practices approved on a Form 2A; or

F. The Director determines that consultation would assist the Director in determining whether to recommend approving or denying an Oil and Gas Development Plan or CAP.

G. Notwithstanding the foregoing, the requirement to consult with CPW may be waived by CPW at any time. Any waiver will be based on a written finding by CPW that consultation is not necessary to protect Wildlife Resources from quantifiable adverse direct, indirect, or cumulative impacts from Oil and Gas Operations.

(3) When Consultation is Not Required. Consultation will not be required if:

A. The Director has previously approved a Form 2A or CAP and associated Wildlife Protection Plan or Wildlife Mitigation Plan that addresses the proposed Oil and Gas Location and the proposed operations are in compliance with previously approved plans.

B. CPW has previously approved, in writing, a Wildlife Protection Plan, Wildlife Mitigation Plan, or other conservation plan that remains in effect for the area that includes the proposed Oil and Gas Operations and the Oil and Gas Location is in compliance with such plan.

C. The Operator demonstrates and CPW agrees in writing that:

i. The identified habitat and species triggering the consultation is no longer present and unlikely to return to the area; or

ii. The proposed Oil and Gas Location is within an area either primarily or completely developed for residential, agricultural, commercial, or industrial use that makes the area incompatible with wildlife habitat.

D. The proposed new Oil and Gas Location would involve a one-time increase in surface disturbance of 1 acre or less contiguous with an existing Oil and Gas Location with a Wildlife Mitigation Plan or other conservation plan that remains in effect for the area.

E. A Commission Order limits the density of Oil and Gas Locations within a Drilling and Spacing Unit to 1 per section, and the Order includes a Wildlife Mitigation Plan or other conservation plan that remains in effect for the area.

(4) Procedures for Consultation.

A. The Operator will provide:

i. The Oil and Gas Development Plan or CAP, if applicable, or for consultations that do not involve an Oil and Gas Development Plan or CAP, a description of the proposed Oil and Gas Operations, including their location and the phasing and duration of operations consistent with Rules 303 & 304, and, if applicable Rule 314; and

ii. Any other relevant available information about the proposed Oil and Gas Operations and the affected Wildlife Resources, including the wildlife habitat drawing pursuant to Rule 304.b.(7).C and information required by Rule 1201.

B. The Operator, the Director, the Surface Owner, and CPW will have 60 days to conduct the consultation required by this Rule 309.e, recognizing that pre-consultation or consultation with Relevant Local Governments or federal land management agencies may shorten the process. The time period for consultation will begin at the start of the Rule 303.d.(1) or 314.f.(1).A public comment period, or when an Operator requests a variance. If the Operator has made no reasonable accommodation for consultation within such 60-day period, the Director will have discretion to postpone making a decision about an Oil and Gas Development Plan or CAP in order to allow consultation to occur if the Director believes the information from consultation is necessary to determine how to protect and Avoid, Mitigate, and Minimize Adverse Impacts to Wildlife Resources.

C. The Surface Owner may waive its right to participate in the consultation and is not obligated to provide access to its surface for such consultation. If access to the surface is not granted, the Operator will arrange a consultation meeting with CPW at a mutually agreeable time and location and the consultation will be based on best available data.

(5) Result of Consultation.

A. As a result of consultation required by this Rule 309.e, CPW may make written recommendations to the Director about how to protect Wildlife Resources and conditions of approval that are necessary and reasonable to Avoid, Minimize, or Mitigate direct, indirect, and cumulative Adverse Impacts to Wildlife Resources from Oil and Gas Operations pursuant to Rules 1202 & 1203.

B. CPW may also recommend, in writing, that the Commission deny an Oil and Gas Development Plan, Form 2A, Wildlife Protection Plan, Wildlife Mitigation Plan, Compensatory Mitigation Plan, or CAP due to reasonably foreseeable risks or Adverse Impacts to Wildlife Resources that cannot be Avoided, Minimized, or Mitigated to the extent necessary to protect these resources from Oil and Gas Operations.

C. Except for Rule 1202.c, CPW may waive, in writing, any operating or mitigation requirements otherwise required by Rules 1202 or 1203 based on CPW's analysis of potential Unavoidable Adverse Impacts.

D. For Rule 1202.c:

i. CPW may waive the application of and the Director may grant an exception to Rule 1202.c.(1).R for any new ground disturbance that meets the criteria of Rule 1202.c between 300 feet and 500 feet from the Ordinary High Water Mark ("OHWM") of cutthroat trout designated crucial habitat, and native fish and other native aquatic species conservation waters, if the Operator adheres to the following Best Management Practices:

aa. Contain Flowback and Stimulation Fluids in Tanks that are placed on a Working Pad Surface in an area with downgradient perimeter berming;

bb. Construct lined berms or other lined containment devices pursuant to Rule 603.o around any new crude oil, condensate, and produced water storage Tanks that are installed after January 15, 2021;

cc. Inspect the Oil and Location on a daily basis, unless the approved Form 2A provides for different inspection frequency or alternative method of compliance;

dd. Maintain adequate Spill response equipment at the Oil and Gas Location during drilling and completion operations; and

ee. Not construct or utilize any Pits, except that Operators may continue to utilize existing Pits that were properly permitted, constructed, operated, and maintained in compliance prior to January 15, 2021.

ii. CPW may waive the application of and the Director may grant an exception to Rule 1202.c.(1).S:

aa. For perennial streams, if the Operator adheres to the following Best Management Practices for any new ground disturbance that meets the criteria of Rule 1202.c between 300 feet and 500 feet from the OHWM of sportfish management waters:

1. Contain Flowback and Stimulation Fluids in Tanks that are placed on a Working Pad Surface in an area with downgradient perimeter berming;

2. Construct lined berms or other lined containment devices pursuant to Rule 603.o around any new crude oil, condensate, and produced water storage Tanks that are installed after January 15, 2021;

3. Inspect the Oil and Location on a daily basis, unless the approved Form 2A provides for different inspection frequency or alternative method of compliance;

4. Maintain adequate Spill response equipment at the Oil and Gas Location during drilling and completion operations; and

5. Not construct or utilize any Pits, except that Operators may continue to utilize existing Pits that were properly permitted, constructed, operated, and maintained in compliance prior to January 15, 2021.

bb. For ephemeral and intermittent streams, if the Operator adheres to the following Best Management Practices:

1. Contain Flowback and Stimulation Fluids in Tanks that are placed on a Working Pad Surface in an area with downgradient perimeter berming;

2. Construct lined berms or other lined containment devices pursuant to Rule 603.o around any new crude oil, condensate, and produced water storage Tanks that are installed after January 15, 2021;

3. Inspect the Oil and Location on a daily basis, unless the approved Form 2A provides for different inspection frequency or alternative method of compliance;

4. Maintain adequate Spill response equipment at the Oil and Gas Location during drilling and completion operations; and

5. Not construct or utilize any Pits, except that Operators may continue to utilize existing Pits that were properly permitted, constructed, operated, and maintained in compliance prior to January 15, 2021.

iii. CPW may waive the application of Rule 1202.c.(1).T.

iv. CPW may waive the application of and the Director may grant an exception to Rule 1202.c.(1) for a proposed location within an approved CAP that includes preliminary siting approval pursuant to Rule 314.b.(5).

E. Where applicable, CPW may also make written recommendations on whether a variance request pursuant to Rule 502 should be granted, under what conditions, and the reasons for any such recommendations, including requests for variances from Rule

1202.c.(1).Q–S. The Commission will consider the written recommendations of CPW and the relevant federal land management agency, if applicable, including recommended or final federal stipulations and conditions of approval.

(6) Conditions of Approval.

A. If the Director agrees that the conditions of approval or denial as recommended by CPW are necessary and reasonable to Avoid, Minimize, or Mitigate Adverse Impacts to Wildlife Resources, the Director will incorporate CPW's recommended conditions into the Director's Recommendation on an Oil and Gas Development Plan, Form 2A, or CAP.

B. The Director will not incorporate conditions of approval to Avoid, Minimize, or Mitigate Adverse Impacts to Wildlife Resources into the Director's Recommendation without consent of the affected Surface Owner. This provision does not apply to conditions of approval to Avoid, Minimize, or Mitigate Adverse Impacts to Wildlife Resources that do not directly impact the affected Surface Owner's property or use of that property including, but not limited to, off-site compensatory mitigation requirements.

C. If the Director determines that any conditions of approval or denial as recommended by CPW are not necessary to Avoid, Minimize, or Mitigate Adverse Impacts to Wildlife Resources, the Director will explain the grounds for the disagreement in the Director's Recommendation.

D. The Commission will determine whether to follow CPW's recommendation when making a final decision to approve or deny an Oil and Gas Development Plan or CAP.

(7) Notification of Decision to Consulting Agency. Where consultation occurs, the Director will provide the Director's Recommendation to CPW on the same day that it posts the decision to the Commission's website pursuant to Rule 306.c. CPW may petition the Commission to review the Director's Recommendation.

f. Consultation with CDPHE.

(1) When Consultation Will Occur.

A. The Director will consult with CDPHE if:

i. At any time during the Local Government consultation and comment period, a Local Government requests the participation of CDPHE in the Director's consideration of an Oil and Gas Development Plan or CAP based on concerns regarding public health, safety, welfare, or impacts to the environment; or

ii. An Operator requests a variance from the Commission pursuant to Rule 502 from a provision of Rules 303, 304, 314, 408.e, 411, 426, 427, 604, 615, 801, 802, 803.g, 803.h, 806.c, or the Commission's 900 Series Rules as part of an Oil and Gas Development Plan, Form 2A, CAP, or UIC Aquifer exemption application.

B. The Director may request consultation about any Oil and Gas Development Plan or CAP if the Director reasonably believes that consultation with the CDPHE would assist the Director in understanding the potential risks to public health, safety, welfare, or the environment.

C. The Director will consult with CDPHE if CDPHE requests consultation.

D. Notwithstanding the foregoing, the requirement to consult with CDPHE may be waived by CDPHE at any time.

(2) Procedure for Consultation.

A. The time period for consultation with CDPHE will begin at the start of the Rule 303.d.(1) public comment period, or when an Operator requests a variance from a Rule listed in Rule 309.f.(1).A.ii. If the public comment period is extended by the Director or the Commission, then the CDPHE consultation period may also be extended for the same amount of time that the public comment period is extended. Following conclusion of the initial consultation period, the Director may reopen a new consultation period with CDPHE if information pertaining to the Oil and Gas Development Plan or CAP changes or new evidence arises related to the public health or environmental impacts of the Oil and Gas Development Plan or CAP. The Director may extend the consultation period by 60 days upon the request of CDPHE if additional time is necessary to avoid, minimize, or mitigate adverse environmental impacts.

B. The consultation required by this Rule 309.f will focus on identifying potential impacts to public health, safety, welfare, or the environment from activities associated with the proposed Oil and Gas Development Plan or CAP, and development of conditions of approval or other measures to avoid, minimize, or mitigate those potential adverse impacts.

C. The consultation process may include, but is not limited to:

i. Review of the relevant Oil and Gas Development Plan or CAP application, variance request, Well-density application, or draft Commission regulation;

ii. Discussions with the Relevant Local Government(s) and Proximate Local Government(s) to better understand the Local Governments' concerns;

iii. Discussions with the Commission, Operator, Surface Owner, Surface Owner's tenant, emergency responders, School officials, hospital administrators, Public Water System administrators, or any other potentially Affected Person; and

iv. Review of public comments.

(3) Results of Consultation.

A. As a result of consultation called for by this Rule 309.f, CDPHE may make written recommendations to the Director about conditions of approval necessary and reasonable to protect public health, safety, welfare, or the environment. Such recommendations may include, but are not limited to, monitoring requirements or Best Management Practices. CDPHE may also recommend that the Commission deny an Oil and Gas Development Plan or CAP if necessary and reasonable to protect public health, safety, welfare, or the environment. Where applicable, CDPHE may also make written recommendations about whether a variance request should be granted or denied and the reasons for any such recommendations.

B. **Standards for Consultation and Director Decision.** If the Director agrees that the conditions of approval recommended by CDPHE are necessary and reasonable to protect public health, safety, welfare, or the environment, the Director will incorporate CDPHE's recommended conditions into approvals of an Oil and Gas Development Plan or CAP. If the Director determines that any conditions of approval recommended by CDPHE are not necessary and reasonable to protect public health, safety, welfare, or the environment, the Director will explain the grounds for the disagreement in the Director's Recommendation. The Commission will determine whether to follow CDPHE's recommendation when making a final decision to approve or deny an Oil and Gas Development Plan or CAP.

C. Notification of Decision to Consulting Agency. Where consultation occurs, the Director will provide the Director's Recommendation to CDPHE on the same day that it announces the decision. CDPHE may petition the Commission to review the Director's Recommendation.

g. Public Water Systems.

(1) The Operator will engage in a Formal Consultation Process with all Public Water Systems that receive notice pursuant to Rule 303.e.(1).H, unless the Public Water System waives its right to consultation.

(2) **Groundwater Monitoring.** Among other topics, consultations pursuant to Rule 309.g will address whether groundwater monitoring should occur pursuant to Rule 411.b.(4).B.

310. SUSPENDING APPROVED OIL AND GAS DEVELOPMENT PLANS

The Director may suspend an approved Oil and Gas Development Plan or any associated Drilling and Spacing Units, Form 2As, or Form 2s if the Director has reasonable cause to believe that information submitted on an application was materially incorrect. An Operator may petition the Commission to review the Director's decision. The Commission will hear the petition at its next regularly scheduled hearing.

311. EXPIRATION

a. Except as otherwise specified by Rule 314.b.(2), Oil and Gas Development Plans are valid for 3 years. The following expirations will occur 3 years from the approval date of the Oil and Gas Development Plan:

(1) If drilling operations have not commenced for a permitted Well, the Form 2 for the undrilled Well will be null and void.

(2) If drilling operations have not commenced at any Wells on an Oil and Gas Location, the Form 2A(s) for that Oil and Gas Location, any associated Production Facilities designed to serve only that Location, and the associated Form 2s will be null and void;

(3) If drilling operations have not commenced for any permitted Well in a Drilling and Spacing Unit, the Drilling and Spacing Unit order will be vacated, and any associated Form 2As and Form 2s will become null and void; or

(4) If drilling operations have not commenced for any permitted Well subject to an Oil and Gas Development Plan, the Oil and Gas Development Plan will expire, the Drilling and Spacing Unit orders will be vacated, and the associated Form 2As and Form 2s will be null and void.

b. Extensions. The Commission or Director will not approve extensions for an Oil and Gas Development Plan, a Drilling and Spacing Unit, a Form 2A, or a Form 2.

c. Applications and Refile Forms After Expiration. Oil and Gas Development Plans, Drilling and Spacing Unit applications, Refile Form 2As, and Refile Form 2s may be filed within 60 days prior to expiration or anytime following expiration and are subject to the Commission's Rules in effect at the time of submission.

d. **Remedy.** Any built Oil and Gas Location for which a Form 2A expires pursuant to Rule 311.a will be subject to final Reclamation pursuant to the Commission's 1000 Series Rules.

312. SUBSEQUENT OPERATIONS ON EXISTING WELLS

a. The Operator will submit and obtain the Director's approval of a Form 4 before conducting any subsequent Well operations involving heavy equipment, except for routine Well maintenance.

b. **Verbal Approval.** If during the course of the subsequent operations or routine Well maintenance the Operator determines that additional subsequent operations involving heavy equipment that are not routine maintenance are necessary, the Operator may obtain verbal approval from the Director to conduct the subsequent operations. If the Operator obtains verbal approval from the Director, the Operator will submit a Form 4 to obtain written approval from the Director within 7 days.

c. **Information Requirements.** The Form 4 will describe the details of the proposed work.

d. **Approval of Subsequent Well Operations.** The Director may approve a Form 4 that complies with all requirements of the Commission's Rules, and protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(1) The Director may add any conditions of the approval to a Form 4 that are necessary and reasonable to ensure compliance with all requirements of the Commission's Rules, or to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) The Director will review the Oil and Gas Location where the Well is located to ensure that necessary and reasonable conditions of approval are applied to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

e. **Notice Requirements.** An Operator will provide notice of operations covered by Rule 312.a to the Surface Owner pursuant to Rule 412.a.(4).

313. FORM 20, PERMIT TO CONDUCT SEISMIC OPERATIONS

a. **Submitting Form 20.** Operators, or, if applicable, seismic survey contractors, will submit and obtain approval of a Form 20, Permit to Conduct Seismic Operations prior to commencement of seismic operations, including shothole drilling and recording operations.

b. **Information Requirements.** The Form 20 will include the following:

(1) A map in a suitable size and scale to show the proposed project boundary, energy source locations, and receiver locations with sections, townships and ranges, county and municipal boundaries, and High Priority Habitat.

(2) GIS data for the proposed project boundary, energy source points, and receiver locations in a format approved by the Director.

(3) Any Relevant Local Government permits, as required in Rule 313.c.

(4) Any traffic control plan, as required in Rule 313.d.

(5) Any plan or measures to protect and minimize impacts to Wildlife Resources developed in coordination with CPW.

(6) Reclamation plan.

c. Local Government Permits. Operators will obtain all required Relevant Local Government permits prior to commencing seismic operations. Operators will submit copies of the Relevant Local Government permits with their Form 20 applications.

d. Traffic Control and Load Limits. If the Relevant Local Government approval fails to address traffic control and load limits then Operators will include the following information in traffic control plans submitted with their Form 20 applications:

(1) If the seismic operations will utilize vibroseis units, confirmation that the Relevant Local Government allows vibroseis units to travel and operate on the public roadways identified in the survey area;

(2) The load limits of all public roads within the survey area; and

(3) A detailed traffic control plan for any activity in a public right-of-way.

e. Director's Decision.

(1) The Director may approve the Form 20 if it complies with the Commission's Rules and protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) The Director may deny the Form 20 if it does not comply with the Commission's Rules or if it does not adequately protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

f. Changes to a Form 20. Operators or seismic survey contractors will file any proposed change to an approved Permit to Conduct Seismic Operations on a Form 20.

g. Form 20 Expiration. An approved Form 20 will expire 6 months from the date of approval.

h. Refile Form 20. Operators or seismic survey contractors may submit a Refile Form 20 for approval of a previously permitted seismic project that was not conducted during the valid term of the previously approved Form 20. The Refile Form 20 will comply with Rule 314.

i. Operators will provide a copy of the approved Form 20 to the Relevant Local Government.

314. COMPREHENSIVE AREA PLANS

a. Purpose of Comprehensive Area Plans.

(1) The Commission intends for Comprehensive Area Plans ("CAPs") to facilitate evaluating and addressing cumulative impacts from oil and gas development in a broad geographic area by identifying plans for one or more Operators to develop Oil and Gas Locations within a region while avoiding, minimizing, and mitigating impacts to public health, safety, welfare, the environment, and wildlife resources in the region through systematic planning of infrastructure location, Best Management Practices, and centralizing facilities.

(2) The Commission intends to create incentives for Operators to develop CAPs by conveying an exclusive right to operate in the area covered by the CAP for an appropriate duration of time.

(3) The Commission encourages Operators to develop CAPs. The Commission may direct the Director to meet with an Operator to discuss whether submission of a CAP is appropriate. The Director may request a meeting with an Operator to discuss whether submission of a CAP is appropriate pursuant to Rule 303.a.(8).

b. Rights Conveyed.

(1) If the Commission approves a CAP, the approved CAP will convey the exclusive right to develop the oil and gas formation or formations that are the subject of the CAP within the CAP's geographic boundaries for the duration of the CAP as specified by Rule 314.c.

(2) Approved Oil and Gas Development Plans, Drilling and Spacing Units, Form 2As, and Form 2s within an approved CAP will not expire until the CAP expires pursuant to Rule 314.c, but will expire at the time the CAP expires.

(3) If the Commission approves a CAP, the Operator need not separately evaluate cumulative impacts for each individual Oil and Gas Development Plan proposed within the CAP, as would otherwise be required by Rule 303.a.(5).

(4) Expedited review of associated Oil and Gas Development Plans pursuant to Rule 306.d.

(5) Preliminary siting approval of future Oil and Gas Locations within the CAP if the Operator meets the informational requirements of Rule 314.e.(11) and the consultation requirements of Rule 314.f.(4).A.iii.

A. An Operator seeking preliminary siting approval through a CAP will submit the information identified in Rule 314.e.(11) as part of its CAP application.

B. If an Operator receives preliminary siting approval, the Operator need not submit an alternative location analysis pursuant to Rule 304.b.(2) as part of the Form 2A application for any associated Form 2A applications.

C. If an Operator receives preliminary siting approval, as an attachment to the Form 2A application for any associated Form 2A applications, the Operator will submit a description of any changes to the surrounding land use, or future land use changes contemplated in a Local Government planning document, from between the time the CAP was approved and the time the Form 2A is submitted.

D. Preliminary siting approval pursuant to Rule 314 does not guarantee that the Commission will ultimately approve any associated Form 2As within an approved CAP.

(6) Approval of a CAP does not constitute approval of an Oil and Gas Development Plan, Drilling and Spacing Unit, Form 2A, or Form 2. Operators will submit all Oil and Gas Development Plans, Drilling and Spacing Unit applications, Form 2As, and Form 2s as ordinarily required by the Commission's Rules for all locations and Wells within an approved CAP. However, during the course of consultation about a CAP pursuant to Rule 314.f.(4), a consulting entity may waive future consultations for subsequently submitted Oil and Gas Development Plans and other permits that are associated with the CAP.

c. Duration. Approved CAPs will expire 6 years after the date the Commission approves the CAP, unless the Commission issues an Order to approve a different duration or extend the duration pursuant to Rules 314.c.(1) & (2).

(1) **Initial Approval for Longer Duration.** The Commission may approve a different duration based on a request in the CAP application materials. Such a request will include:

A. A reasonable and consistent development schedule for fully developing minerals subject to the CAP;

B. A reasonable and consistent development schedule for building appropriate infrastructure and a description of how that infrastructure will facilitate avoiding, minimizing, or mitigating potential adverse impacts to public health, safety, welfare, the environment, or wildlife resources, including but not limited to emissions reductions strategies;

C. A description of why the proposed duration is consistent with any long-term land use planning documents for each Relevant Local Government; and

D. A description of any planned mitigation for adverse impacts to Wildlife Resources within the boundaries of the proposed CAP.

(2) Extensions.

A. The Commission may extend the duration of the CAP if the Operator submits an application pursuant to Rule 503.g.(8), and the Operator demonstrates that:

i. It has diligently pursued development of the mineral resources within the CAP; and

ii. No significant surface land use changes have occurred within the CAP that would substantially alter the cumulative impacts of the CAP on relevant resources.

B. The Commission may approve or deny the extension of the CAP following a hearing pursuant to Rule 510. The Commission may extend the CAP by any duration it determines is necessary and reasonable to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

C. If the Commission approves an extension of the CAP, the Operator may re-apply for another extension, subject to the procedures of this Rule 314.c.(2).

d. Submission Procedure.

(1) One or more Operators (collectively, the “Operator”) may apply for a CAP at any time by submitting the application materials specified in Rule 314.e electronically pursuant to Rule 503.g.(8).

(2) The Operator will coordinate with the Director and submit all information necessary for the Director and Commission to fully evaluate the CAP’s cumulative impacts on public health, safety, welfare, the environment, and wildlife resources.

(3) At any time after a CAP application is submitted, the Director may request any information necessary to review the CAP application. The Operator will provide all requested information before the Director issues the Director’s Recommendation.

(4) When the Director has obtained all information necessary to fully review the CAP’s cumulative impacts on public health, safety, welfare, the environment, and wildlife resources, the Director will make a completeness determination.

(5) **Requests to Stay Other Applications.** An Operator may include a request for preliminary relief in its CAP application that the Commission put a hold on taking final action on Oil and Gas Development Plan and Drilling and Spacing Unit applications related to minerals subject to the proposed CAP while the Commission and Director conduct their review of the CAP application.

A. Such a request will include the mineral ownership information required pursuant to Rule 314.e.(9).

B. If the CAP application includes such a request for relief, the Secretary will notice the request for relief for expedited hearing pursuant to Rule 503.a at the time the Director issues the completeness determination.

C. Mineral Owners within the proposed CAP may file a petition protesting the requested relief pursuant to Rule 507.

e. Informational Requirements for Comprehensive Area Plan. At a minimum, the Operator will submit the following materials as components of its CAP application:

(1) Contact Information.

A. The name, telephone number, and e-mail address for the primary contact person about the CAP for each Operator.

B. The name, telephone number, and e-mail address of every Relevant Local Government within the CAP's boundaries.

C. The name, telephone number, and e-mail address for all Local Governments with land use authority within and within 2,000 feet of the CAP's boundaries.

D. Contact information for all persons who will receive notice pursuant to Rule 314.f.(1).C.

(2) Fees. Payment of the full filing and service fee required by Rule 301.d.

(3) Maps.

A. A topographic map in a suitable size and scale for the Director to conduct a review showing the area proposed for the CAP and proposed Oil and Gas Locations.

B. Maps or descriptions of all publicly maintained roads, Operator-proposed haul routes, and proposed access road locations.

C. Maps or descriptions of proposed Gathering Line and Flowline infrastructure.

D. Maps or descriptions of proposed utility lines.

E. A description of plans for electrification of proposed Oil and Gas Operations.

F. One or more detailed maps showing all High Priority Habitats and federally designated critical habitats for threatened and endangered species within the CAP's boundaries. Operators will rely upon best available information when assessing wildlife habitat within the CAP's boundaries and may provide supplemental site-specific published reports or wildlife surveys.

G. One or more detailed maps generally delineating existing Building Units within the proposed CAP's boundaries and specifically delineating all High Occupancy Building Units and Designated Outside Activity Areas.

H. One or more detailed maps delineating surface ownership within the proposed CAP's boundaries.

I. One or more detailed maps showing characteristics of known Groundwater within the proposed CAP's boundaries, including but not limited to depth of the water table, depths of known Groundwater formations, and characteristics of the Groundwater including salinity.

J. One or more maps identifying areas defined as Disproportionately Impacted Communities.

K. One or more detailed maps showing all riparian areas, Floodplains, Waters of the State, and Public Water System facilities within the proposed CAP boundaries.

L. A map showing existing, permitted, and proposed Oil and Gas Locations that are within the proposed CAP boundaries but not subject to the proposed CAP.

(4) **GIS Data.** GIS polygon data to describe the CAP's external boundaries.

(5) **Density of Wells.** The proposed subsurface density of Wells within the boundaries of the CAP.

(6) **Consolidation of Oil and Gas Locations.** The proposed density of Oil and Gas Locations within the boundaries of the CAP (reported in Oil and Gas Locations per section). This should include a narrative proposal, with maps and appropriate supporting documentation, demonstrating the Operator's plan to consolidate Oil and Gas Locations to the maximum extent possible within the boundaries of the CAP.

(7) **Timing of Operations**. A narrative proposal, explaining the anticipated timing for building infrastructure and developing proposed Oil and Gas Locations.

(8) **Infrastructure Planning.** A narrative proposal, with appropriate supporting documentation, demonstrating the Operator's plan to consolidate infrastructure within the CAP, the timeline for installing any new infrastructure relative to the planned construction dates for the proposed Wells, and a discussion of any approvals necessary for the infrastructure to be built.

(9) **Mineral Rights.** A map and narrative that:

A. Demonstrates the location of the minerals the Operator owns or has secured the consent of mineral Owners to develop; and

B. Describes the percentage of minerals the Operator owns or has secured the consent of mineral Owners to develop.

(10) **Evaluating and Addressing Cumulative Impacts.** The Operator will provide quantitative and qualitative data to evaluate incremental adverse impacts and beneficial contributions to each resource listed below that are likely to be caused by Oil and Gas Operations associated with the proposed CAP. Data will include a summary of Best Management Practices or other measures the Operator will employ to avoid, minimize, and mitigate impacts to each resource.

A. **Air Resources.** A quantitative evaluation of the projected incremental increase in emissions of the pollutants listed below, estimated for each year of and five years after the proposed CAP's duration. The emissions estimate will include both stationary and mobile sources of emissions during both pre-production activities and emissions during full production. The evaluation will include any emissions reductions due to the Operator's Plugging and Abandonment of existing oil and gas Wells within the CAP boundaries for the year when the plugging operation occurs.

i. Oxides of Nitrogen (NO_x);

ii. Carbon monoxide (CO);

iii. Volatile Organic Compounds (VOCs);

iv. Methane (CH_4);

v. Ethane (C_2H_6);

vi. Carbon dioxide (CO_2); and

vii. Nitrous oxide (N_2O).

B. Public Health and Safety. A quantitative evaluation of incremental increase in emissions of the categories of pollutants listed below, estimated for each year of and five years after the proposed CAP's duration. The emissions estimate will include both stationary and mobile sources of emissions during both pre-production activities and emissions during full production. The evaluation will include any emissions reductions due to the Operator's Plugging and Abandonment of existing oil and gas Wells within the CAP boundaries for the year when the plugging operation occurs. The evaluation will also include a qualitative evaluation of potential public health and safety risks associated with these emissions.

i. Total hazardous air pollutants;

ii. Specific hazardous air pollutants with known health impacts, including:

aa. Benzene;

bb. Toluene;

cc. Ethylbenzene;

dd. Xylenes;

ee. n-Hexane;

ff. 2,2,4-Trimethylpentane (2,2,4-TMP);

gg. Hydrogen sulfide (H_2S);

hh. Formaldehyde; and

ii. Methanol.

C. Water Resources.

i. For any CAP that includes a proposed Oil and Gas Location that will be listed as a sensitive area for water resources or is within 2,640 feet of a surface Water of the State, the total planned on-location storage volume of (measured in Barrels (bbls)) of:

aa. Oil;

bb. Condensate;

cc. Produced water; and

dd. Other volumes of stored hydrocarbons, Chemicals, or E&P Waste Fluids.

ii. The Operator will identify and evaluate potential contaminant migration pathways and likely distances from Oil and Gas Locations that may be proposed within the CAP to the nearest downstream riparian corridors, wetlands, and surface Waters of the State. If the Operator identifies any such contaminant migration pathways:

aa. The Operator will provide a qualitative evaluation of the baseline conditions in the riparian corridor, wetland, or surface Water of the State; and

bb. Identify Best Management Practices to avoid, minimize, or mitigate potential adverse impacts to the identified riparian corridors, wetlands, and surface waters of the State.

iii. A qualitative evaluation of potential impacts to, and a summary of Best Management Practices or other measures to avoid, minimize, or mitigate adverse impacts to the following categories of Public Water System intakes and wells within the boundaries of the CAP:

aa. Surface water supply areas as defined in Rule 411.a.(1);

bb. Public Water System supply wells that are groundwater under the direct influence of surface water wells or Type III wells as defined in Rule 411.b.(1); and

cc. Any surface water Public Water System intakes within 15 stream miles downstream of the CAP boundaries.

iv. A qualitative evaluation of the potential for erosion and sedimentation to adversely impact water quality, and a summary of Best Management Practices or other measures to avoid, minimize, or mitigate adverse impacts.

v. The total volume of water the Operator plans to use (measured in bbls), an inventory of the sources from which the Operator intends to obtain the water, and estimated volumes, from each of the following sources:

aa. Freshwater from any Groundwater source;

bb. Freshwater from any lake or stream source;

cc. Freshwater from any domestic water source;

dd. Reclaimed water from a municipal source; and

ee. Recycled or reused E&P Waste.

vi. A qualitative evaluation of the Operator's plan for recycling or disposal of Flowback water and produced water, and the estimated volumes (measured in bbls) of each planned method.

D. Terrestrial and Aquatic Wildlife and Ecosystem Resources. A quantitative evaluation of potential impacts to Wildlife Resources as a result of Oil and Gas Operations associated with the proposed CAP, including:

i. Total acreage of maximum new or expanded surface disturbance associated with the proposed CAP;

ii. Total acreage disturbed after interim Reclamation associated with the proposed CAP;

iii. A breakdown (by acreage) of the types of current land use; and

iv. The number of acres of new or expanded surface disturbance within High Priority Habitat.

E. Soil Resources.

i. A qualitative evaluation of incremental adverse impacts to topsoil as a result of surface disturbance associated with the proposed CAP;

ii. A qualitative evaluation of incremental adverse impacts on ecosystems, including any vegetative communities, as a result of Oil and Gas Operations associated with the proposed CAP; and

iii. A quantitative evaluation of any Reclamation activities associated with the Plugging and Abandonment of existing Wells or closure of existing Oil and Gas Locations within the proposed CAP's boundaries.

F. Public Welfare. A qualitative or quantitative evaluation of incremental adverse impacts to public welfare as a result of Oil and Gas Operations associated with the proposed CAP, that addresses each of the following potential sources of impacts to public welfare, over both a short-term and long-term timeframe. The evaluation will include any compensatory or other offset beneficial impacts.

i. Traffic;

ii. Noise;

iii. Light;

iv. Odor;

v. Dust; and

vi. Recreation and scenic values.

G. Disproportionately Impacted Communities. The census block groups of any Disproportionately Impacted Communities within the CAP.

(11) Siting Information. If the Operator seeks preliminary siting approval pursuant to Rule 314.b.(5), the Operator will submit the following information:

A. Alternative location analyses that meet the criteria of Rule 304.b.(2).C for each proposed future Oil and Gas Location within the CAP.

B. For each proposed future Oil and Gas Location within the CAP, the information required by Rules 304.b.(3), (4), (7), & (8).

C. Either:

i. The applicable long-term or comprehensive land use plan for each Local Government within the CAP, that identifies current and planned future land uses for all areas within the CAP for the proposed full duration of the CAP; or

ii. Certification that each Relevant Local Government agrees with each proposed Oil and Gas Location within its boundaries.

D. An Operator seeking preliminary siting approval pursuant to Rule 314.b.(5) will consult with the Director during the course of the Director's review of the CAP application to determine whether the informational and plan requirements of Rules 304.b. and 304.c are substantially satisfied by the information contained in the CAP.

E. An Operator seeking preliminary siting approval pursuant to Rule 314.b.(5) will provide notice of the CAP application to Building Unit owners and tenants within 2,000 feet of each proposed Oil and Gas Location.

(12) Completeness Certification. A certification that the Operator has submitted all materials required by this Rule 314.e.

f. Public Review Process.

(1) Notice.

A. When the Director issues a completeness determination pursuant to Rule 314.d.(4), the Director will post the CAP application and all supporting materials to the Commission's website. The website posting will provide:

i. The date by which public comments must be received to be considered; and

ii. The mechanism for the public to provide comments.

B. Confidentiality. If the Operator designates any portion of its CAP application as "confidential" pursuant to Rule 223, then the Director will post only the redacted version when the CAP is posted to the Commission's website.

C. Within 5 days of the Director issuing the completeness determination, the Operator will provide notice to the following:

i. All Owners of minerals that would be developed under the CAP;

ii. All Surface Owners of the Operator's proposed Oil and Gas Locations;

iii. All Local Governments within the CAP's boundaries;

iv. All Local Governments within 2,000 feet of the CAP's boundaries;

v. CDPHE;

vi. CPW;

vii. The Colorado State Land Board (if it owns any minerals or surface estate within the CAP);

viii. The appropriate federal agency (if any federal entity owns minerals or surface estate within the CAP);

ix. The Southern Ute Indian Tribe (if the CAP involves any minerals within the exterior boundary of the Tribe's reservation where both the surface and oil and gas estates are owned in fee by persons or entities other than the Tribe);

x. All High Occupancy Building Units, Child Care Centers, and the School Governing Body of any Schools located within the CAP's boundaries; and

xi. All Public Water Systems that operate facilities within the CAP's boundaries.

D. **Procedure for Providing Notice.** The Operator will provide notice required by Rule 314.f.(1).C by one of the following mechanisms:

i. Hand delivery, with confirmation of receipt;

ii. Certified mail, return-receipt requested;

iii. Electronic mail, with electronic receipt confirmation; or

iv. By other delivery service with receipt confirmation.

(2) **Comments.**

A. The Commission will only consider comments received within 60 days from the date the CAP is posted on the Commission's website.

B. The Director will post on the Commission's website all comments received unless they contain confidential information.

C. Upon request or by the Director's own initiative, the Director may extend the comment period by any duration determined to be reasonable in order to obtain relevant public input.

(3) **Public Meeting.** An Operator will hold at least 1 informational meeting with all persons or entities entitled to notice pursuant to Rule 314.f.(1).C.

A. **Timing of Meeting.** The informational meeting will be held during the open public comment period, with sufficient time for the attendees to make comment on the CAP application based on information received. The meeting will be held at a date and time reasonable for most invitees to attend.

B. **Language Access.** All written and oral information provided at a public meeting will also be provided in all languages spoken by 5% or more of the population in any census block groups within or adjacent to the proposed CAP.

C. **Content of Meeting.** The Operator will provide at a minimum the following information:

i. The schedule of operations;

ii. Maps and figures of the CAP area boundary and all Oil and Gas Locations subject to the CAP; and

iii. Anticipated Best Management Practices to be employed during the term of the CAP to minimize adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations.

D. The Operator will provide to the Director a summary of the meeting, attendees, questions and concerns expressed, responses, and anticipated Best Management Practices designed to minimize and mitigate impacts.

(4) **Consultation.** Consultation about a CAP will allow the consulting entities to provide input about the cumulative impacts associated with the CAP, timing of operations, consolidation of infrastructure, and conveying the right of Operatorship in the area of the CAP. Consultation about a CAP is intended to be limited to these topics, and is not a replacement for consultation otherwise required for individual Oil and Gas Development Plans.

A. Local Governments.

i. During the public comment period, the Director will engage in a Formal Consultation Process with all Local Governments within the CAP and Local Governments within 2,000 feet of the CAP's boundaries, unless any Local Government waives its right to consultation.

ii. The Local Government Formal Consultation Process will include any relevant topics identified by the Local Government, but will address at least:

aa. The current land use of all areas within the CAP's boundaries, and all future planned land uses of areas within the CAP's boundaries over the anticipated duration of the CAP; and

bb. Cumulative traffic impacts.

iii. If an Operator seeks preliminary siting approval pursuant to Rule 314.b.(5), the Formal Consultation Process will address whether the proposed future Oil and Gas Locations are consistent with the long-term or comprehensive land use plan for all Local Governments within the CAP's boundaries for the duration of the CAP.

B. CPW.

i. During the public comment period, the Director will engage in a Formal Consultation Process with CPW, unless CPW waives its right to consultation.

ii. The Formal Consultation Process with CPW may address any relevant topic, but will address the proposed CAP's cumulative impacts on Wildlife Resources and measures to avoid, minimize, and mitigate those impacts.

C. CDPHE.

i. During the public comment period, the Director will engage in a Formal Consultation Process with CDPHE, unless CDPHE waives its right to consultation.

ii. The Formal Consultation Process with CDPHE may address any relevant topic, but will address the proposed CAP's cumulative impacts on public health and the environment, including air quality, water quality, Public Water System supplies, and E&P Waste disposal.

D. Federal Government. For proposed CAPs that include federally-owned or managed surface or mineral estate, the Director will engage in a Formal Consultation Process with the applicable federal agency or agencies, unless the agency or agencies waives their right to consultation.

g. Director's Recommendation on the Comprehensive Area Plan.

(1) When the Director May Issue a Recommendation. The Director will not make a Recommendation to the Commission about whether to approve or deny any CAP until after:

A. The Director has fully reviewed the CAP and all supporting application materials and has obtained all information necessary to evaluate the proposed operations and their potential cumulative impacts on public health, safety, welfare, the environment, and wildlife resources.

B. The public comment period has ended, including conducting a public meeting pursuant to Rule 314.f.(3), and the Director has considered all substantive public comments received.

C. The Director has completed the Formal Consultation Process with all Local Governments identified in Rule 314.f.(4).A, CPW, CDPHE, and any federal agency identified in Rule 314.f.(4).D, unless any such entity waives its right to consultation.

(2) Director's Recommendation.

A. Approval. The Director may Recommend that the Commission approve a CAP that:

i. Complies with all requirements of the Commission's Rules; and

ii. Protects and minimizes adverse cumulative impacts to public health, safety, welfare, the environment, and wildlife resources.

B. Denial. If the Director determines that a CAP does not meet the requirements of Rule 314, or provide necessary and reasonable protections for, or minimize adverse impacts to, public health, safety, welfare, the environment, and wildlife resources, or fails to meet the requirements of the Commission's Rules, the Director may Recommend that the Commission deny the CAP.

(3) Notice of Director's Recommendation. Upon issuing the Director's Recommendation, the Director will post the written basis for the Director's Recommendation on the Commission's website, and notify the following persons electronically in a manner determined by the Director:

A. The Operator;

B. All Local Governments within the CAP;

C. Local Governments within 2,000 feet of the CAP's boundaries;

D. CDPHE;

E. CPW;

F. The Colorado State Land Board (if it owns any minerals or surface estate within the CAP);

G. The appropriate federal agency (if any federal entity owns minerals or surface estate within the CAP); and

H. Any person or entity that has provided a comment electronically pursuant to Rule 512.

(4) **Petition for Review of the Director's Recommendation.** CPW, CDPHE, any Local Government within the CAP or Local Governments within 2,000 feet of the CAP's boundaries, and any Owners of minerals within the boundaries of the CAP may petition the Commission to review the Director's Recommendation. Petitions of the Director's Recommendation will comply with Rule 507.

(5) If the Director does not issue a Recommendation within 180 days of a completeness determination pursuant to Rule 314.d.(4), the Operator may move for a hearing before the Commission, Administrative Law Judge, or Hearing Officer. At such hearing, the Director will provide an explanation of the status of the Director's review of the CAP and any reasons for delay.

h. Commission's Consideration of a Comprehensive Area Plan.

(1) If the Director recommends approval of a CAP, the CAP will be heard by the Commission pursuant to Rules 509 & 510.

(2) If the Director recommends the denial of the CAP, the Operator may petition the Director's Recommendation to the Commission. The petition will be filed and heard pursuant to Rules 507 & 510.

(3) **Approval.** The Commission may approve a CAP that complies with all requirements of the Commission's Rules and protects and minimizes adverse cumulative impacts to public health, safety, welfare, the environment, and wildlife resources.

(4) **Denial.** If the Commission determines that a CAP does not provide necessary and reasonable protections for, or minimize adverse impacts to, public health, safety, welfare, the environment, and wildlife resources, or fails to meet the requirements of the Commission's Rules, the Commission may deny the CAP. The Commission will identify in the record the basis for the denial.

(5) **Stay.** If the Commission determines that additional information or analysis is necessary for it to make a decision to approve or deny a CAP, it will issue an order staying consideration of the CAP for further consideration until the Director or Operator can provide the Commission with the additional information or analysis necessary to consider the CAP. The Commission may set or extend reasonable deadlines for the Director or Operator to provide additional information or analysis to the Commission.

(6) **Final Agency Action.** The Commission's decision to approve or deny a CAP will constitute final agency action. The Commission's decision to stay a CAP for further consideration will not constitute final agency action.

(7) **Changes to an Approved CAP.** Changes to an approved CAP will be approved or denied by the Commission, after appropriate notice, consultation pursuant to Rule 314.f.(4) and Director review. The Director will have discretion to determine appropriate notice and consultation requirements based on the scale and nature of the changes.

OPERATIONS AND REPORTING
400 SERIES

401. LOCATION OF WELL COMPLETIONS

All Wells drilled for oil or gas will have the following completion setbacks:

a. Well Completions 2,500 Feet or Greater in Depth. A Well completion 2,500 feet or greater below the surface will be located not less than 600 feet from any lease line and not less than 1,200 feet from any other existing or permitted Well completion in the same common source of supply, unless authorized by order of the Commission or an exception under Rule 401.c is obtained.

b. Well Completions Less than 2,500 Feet in Depth. A Well completion less than 2,500 feet below the surface will be located not less than 200 feet from any lease line and not less than 300 feet from any other existing or permitted Well completion in the same common source of supply, except that only one Well completion in each such source of supply will be allowed in each governmental quarter-quarter section unless authorized by order of the Commission or an exception under Rule 401.c is obtained.

c. Exception Locations.

(1) Operators may request in writing from the Director an exception to the Well completion location 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. The Operator will submit the written exception location request and waivers pursuant to Rule 401.c.(2).B, as attachments to the Form 2, Application for Permit to Drill.

(2) The Director will not approve an exception request unless the Operator:

A. Demonstrates in sufficient detail that correlative rights are protected; and

B. Submits with its request one of the following waivers authorizing the encroachment:

i. If the proposed Well completion encroaches upon an unspaced lease, a waiver will be signed by the Owner unless Rule 401.c.(2).B.iii applies.

ii. If the proposed Well completion encroaches upon a unit, a waiver will be signed by all Owners within the unit, unless Rule 401.c.(2).B.iii applies.

iii. If the Operator of the proposed Well is the Owner of an encroached-upon unspaced lease, or of a lease within an encroached-upon unit, a waiver will be signed by the leased mineral interest Owners.

d. Exemptions to Rule 401.

(1) Rule 401 does not apply to authorized secondary or tertiary recovery projects;

(2) Rule 401 does not apply to Wells completed in fractured shale reservoirs in fields discovered prior to 1964; and

(3) In a unit operation approved by federal or state authorities, these Well completion location requirements apply to the exterior or interior (if one exists) boundary of the unit area unless otherwise authorized by Commission order after proper notice to Owners outside the unit area.

e. Wells Located Near a Mine. No Well will be located within 200 feet of a shaft or entrance to a coal mine not definitely abandoned or sealed, nor will such Well be located within 100 feet of any mine shaft house, mine boiler house, mine engine house, or mine fan; and the location of any proposed Well will ensure that when drilled it will be at least 15 feet from any mine haulage or airway.

402. GREATER WATTENBERG AREA SPECIAL WELL LOCATION AND UNIT DESIGNATION RULE

a. 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.

b. As of January 15, 2021, the GWA special Well location, spacing, and unit designation Rule 318A is no longer in effect and future operations and development within the GWA will be subject to all of the Commission's Rules and orders.

c. Wellbore Spacing Units created under Rule 318A prior to January 15, 2021 will remain in effect unless the Form 2 expires without spud.

d. A proposed Oil and Gas Location within the GWA with a valid Form 2A, Oil and Gas Location Assessment may be constructed prior to the expiration of the current Form 2A. If not constructed prior to the expiration of the current Form 2A, the proposed Oil and Gas Location will be resubmitted as part of an Oil and Gas Development Plan.

e. A proposed Well within the GWA with a valid Form 2 may be drilled prior to the expiration of the current Form 2. If the Well is not drilled prior to the expiration of the current Form 2, the proposed Well will be resubmitted as part of an Oil and Gas Development Plan.

403. YUMA/PHILLIPS COUNTY SPECIAL WELL LOCATION RULE

a. This Special Well Location Rule ("Yuma 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

b. Within the Yuma WLR area, Operators may conduct drilling operations to the Niobrara Formation as follows:

(1) 4 Niobrara Formation Wells may be drilled in any quarter section;

(2) No more than 1 Well may be located in any quarter quarter section;

(3) No minimum distance will be required between Wells producing from the Niobrara Formation in any quarter section; and

(4) Wells will be located at least 300 feet from the boundary of said quarter section, and Wells located outside any drilling units established by the Commission in the Yuma WLR area prior to July 30, 2006 will, in addition, be located at least 300 feet from any lease line. Further, Wells will be located not less than 900 feet from any producible Well drilled to the Niobrara Formation prior to July 30, 2006, located in a contiguous or cornering quarter section unless an exception is approved by the Director.

c. Any Well drilled to the Niobrara Formation in the Yuma WLR area prior to July 30, 2006, but not located as described in Rule 403.b will be treated as properly located for purposes of this Rule 403.

d. This Yuma WLR does not alter the size or configuration of any drilling units established by the Commission in the Yuma WLR area prior to July 30, 2006.

e. This Yuma WLR will 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.

f. Well exception locations to this Yuma WLR will be subject to the provisions of Rule 401.c.

g. This Yuma 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 is adopted nonetheless apply with respect to the size of drilling units already established by the Commission in the Yuma WLR area. This Yuma WLR is not intended to establish Well spacing. Accordingly, when an area subject to Rule 403 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 403 does not affect production allocation for existing or future Wells. An Operator may allocate production pursuant to the applicable lease, contract terms or established Drilling and Spacing Units recognizing the Owner's right to apply to the Commission to resolve any outstanding correlative rights issues.

404. FORM 4, SUNDRY NOTICES

a. The Form 4, Sundry Notice is a multipurpose form which will be used by an Operator to request approval from or provide notice to the Director pursuant to the Commission's Rules or when no other specific form exists.

b. An Operator will comply with Rule 301.c for any Form 4 submitted to propose a change to an approved Oil and Gas Development Plan.

c. An Operator will comply with Rule 304.a for any Form 4 submitted to propose a change to an approved Form 2A.

d. If an Operator submits a Form 4 proposing a change to a previously approved noise, light, odor, or dust plan pursuant to Rules 423.a, 424.a, 426.a, or 427.a, the Director may approve the proposed change only if it provides equally protective or more protective standards to avoid, minimize, or mitigate adverse impacts from noise, light, odor, or dust.

405. FORM 42, FIELD OPERATIONS NOTICE

Operators will submit a Form 42, Field Operations Notice, as designated below and pursuant to a condition of approval on any Form 2; Form 2A; Form 4; Form 6, Well Abandonment Report; or any other approved form. No Form 42 may be submitted more than 2 weeks prior to the scheduled activity, unless a longer timeframe is specified by another Commission Rule. Each Form 42 that notifies the Commission of a forthcoming activity will describe the estimated duration (which may be expressed as a range) for the proposed activity if it is anticipated to last for longer than one day.

a. **Notice of Intent to Conduct Seismic Operations.** Operators will provide the Commission written notice 2 business days in advance of the commencement of Seismic Operations. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Intent to Conduct Seismic Operations. The Commission will provide prompt electronic notice of such intention to the Relevant Local Government.

b. **Notice of Construction or Major Change.** Operators will provide the Commission written notice 2 business days in advance of commencing construction or a major change at any Oil and Gas Location or Oil and Gas Facility. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Construction or Major Change. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government and CPW.

c. **Notice of Pit Liner Installation.** Operators will provide the Commission written notice 2 business days in advance of a Pit liner installation at any facility. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Pit Liner Installation.

d. **Notice of Completion of Form 2/2A Permit Conditions.** If required by a condition of approval, Operators will provide the Commission written notice of completion of Form 2 or 2A permit conditions at any Well, Oil and Gas Location, or Oil and Gas Facility. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Completion of

Form 2/2A Permit Conditions. The Commission will provide prompt electronic notice of such completion to CPW for any completions of Form 2A permit conditions for Oil and Gas Locations located in High Priority Habitat.

e. Notice of Move-In, Rig-Up.

(1) For operations with a drilling rig, Operators will provide the Commission written notice 2 business days in advance of the operation on a Form 42, Field Operations Notice – Notice of Move-In and Rig-Up on an Oil and Gas Location.

(2) For planned operations with a work-over rig, Operators will provide the Commission written notice 2 business days in advance of the operation on a Form 42, Field Operations Notice – Notice of Move-In and Rig-Up on an Oil and Gas Location.

(3) For unplanned operations with a work-over rig, Operators will provide the Commission written notice within 1 business day after commencement of the operation on a Form 42, Field Operations Notice – Notice of Move-In and Rig-Up on an Oil and Gas Location.

(4) For any operation identified in Rules 405.e.(1)–(3), the Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government and the Division of Water Resources.

f. Notice of Spud. Operator will provide the Commission written notice 2 business days in advance of spudding the surface hole on any Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Spud. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government.

g. Notice to Run and Cement Casing. If required by condition of approval, Operators will provide the Commission written notice 24 hours in advance of running and cementing casing on any Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice to Run and Cement Casing.

h. Notice of Blow Out Preventer Test. If required by condition of approval, Operators will provide the Commission written notice 24 hours in advance of conducting a blow out preventer test at a Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Blow Out Preventer Test.

i. Notice of Significant Lost Circulation. Within 24 hours of significant lost circulation at any Well, Operators will provide the Commission written notice of the event. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Significant Lost Circulation.

j. Notice of Formation Integrity Test. If required by condition of approval, Operators will provide the Commission written notice 24 hours in advance of conducting a formation integrity test on any Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Formation Integrity Test.

k. Notice of Intent to Conduct Hydraulic Fracturing Treatment. Operators will provide the Commission written notice 48 hours in advance of conducting a Hydraulic Fracturing Treatment at any Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Hydraulic Fracturing Treatment. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government, the Air Pollution Control Division, and the Division of Water Resources.

l. Notice 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 Form 42, Field Operations Notice – Plugging Operations. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government.

m. 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 Form 42, Field Operations Notice – Notice of High Bradenhead Pressure During Stimulation.

n. Notice of Mechanical Integrity Test. Operators will provide the Commission written notice 10 days in advance of conducting a mechanical integrity test on a Well. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Mechanical Integrity Test.

o. Notice of Remedial Cementing Operations. Operators will provide the Commission written notice 48 hours in advance of the commencement of remedial cementing operations. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Remedial Cementing Operations.

p. Notice of Return to Service. Operators will provide the Director with at least 48 hours advance written notice as required by Rules 1104.A.(2).b and 417. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Return to Service.

q. Notice of H_2S on an Oil and Gas Location. Within 48 hours after receipt of a laboratory gas stream analysis showing the presence of hydrogen sulfide ("H_2S") on an Oil and Gas Location, Operators will provide the Commission written notice of the analysis. Such notice will be provided on a Form 42, Field Operations Notice – Notice of H_2S on an Oil and Gas Location. The Commission will provide prompt electronic notice of such analysis to CPW.

r. Abandonment of Flowline. Operators will provide written notice to the Commission before undertaking and after completing abandonment of on-location Flowlines pursuant to Rule 1105. Such notice will be provided on a Form 42, Field Operations Notice – Abandonment of Flowlines. The Commission will provide prompt electronic notice of such intention to the Relevant Local Government.

s. Well Liquids Unloading. Operators will provide the Director with advance written notice before undertaking Well liquids unloading, as required by Rule 903.d.(1).E. Such notice will be provided on a Form 42, Field Operations Notice – Notice of Well Liquids Unloading. The Commission will provide prompt electronic notice of such notice to the Relevant Local Government. The Operator will submit the Form 42 – Notice of Well Liquids Unloading no later than:

(1) 48 hours prior to conducting Well liquids unloading; or

(2) As soon as possible prior to conducting Well liquids unloading if 48 hours notice would require an alternative or extended Well liquids unloading practice that increases emissions.

t. Groundwater Baseline Sampling and Monitoring. Operators will provide immediate notice to the Director on a Form 42, Field Operations Notice – Water Sample Reporting upon receipt of any analytical results that meet any of the conditions described in Rules 615.e.(4).C & D.

406. GENERAL OIL AND GAS LOCATION CONSTRUCTION RULES

a. Operators will construct Oil and Gas Locations in conformance with the approved Form 2A and all applicable and approved Form 4s.

b. Requirement to Provide Construction Notice. An advance notice will be provided to the Director on a Form 42 – Notice of Construction or Major Change no less than 2 business days prior to commencement of operations with heavy equipment for the construction of an Oil and Gas Location. The Form 42 will include an estimated duration for the proposed construction activity, which may be expressed as a range. The Commission will provide prompt electronic notice of such intention to the Relevant and Proximate Local Government and to CPW.

c. Requirement to Post Location Assessment at the Location. A copy of the approved Form 2A, and any Form 4 modifying the approved Form 2A, will be posted in a protected and conspicuous place on location upon commencement of operations with heavy equipment until the conclusion of interim Reclamation.

d. Location Signage. The Operator will, concurrent with the Rule 412 Surface Owner notice, post a sign not less than 2 feet by 2 feet at the intersection of the lease road and the public road providing access to the Oil and Gas Location, with the name of the proposed Well or Oil and Gas Location, the legal location thereof, and the estimated date of commencement of construction. Such sign will be maintained until Well completion operations and construction operations at the Oil and Gas Location are concluded.

e. Conductors.

(1) An Operator will secure conductors and cellars to prevent accidental access by people, livestock, or wildlife when active work on that conductor is not occurring.

(2) If artesian flows are encountered when a conductor is preset, the Operator will isolate the conductor with cement from the base of the conductor to the anticipated bottom of the cellar by the pump and plug or displacement method. The Operator will file a Form 4 – Report of Work Done, Other: Conductor Artesian Flow for the Oil and Gas Location to document the artesian flow and cementing operation.

(3) If the Operator has not drilled the Well for which the conductor was set within 30 days after setting the conductor, or after rig demobilization and move off (whichever is later), the Operator will have 15 days to comply with the following safety standards for maintaining a preset conductor:

A. Weld a plate on the top of the conductor pipe that remains in place until the conductor is opened for drilling;

B. Cover and fence all rat holes, mouse holes, and cellars with materials sufficient to prevent accidental access by people, livestock, or wildlife and;

C. Maintain all fencing and covers.

(4) If the Operator has not drilled the Well within 3 months of setting the conductor on Crop Land locations or within 6 months on rangeland then the Operator will plug the conductor and perform Reclamation as follows:

A. Cut the conductor pipe four feet below ground level;

B. Fill the conductor pipe with material that is clean, inert, and free from contaminants;

C. Seal the conductor pipe with either a cement plug and a screw cap or a cement plug and a welded steel plate, and backfill the hole to ground level;

D. Remove the cellar ring;

E. Within 30 days of the plugging, submit a Form 4 – Report of Work Done, Other: Plugged Conductor for the Oil and Gas Location, to report the plugging of the conductor(s), that includes photo documentation demonstrating compliance with Rules 406.e.(4).A–D, above; and

F. Perform Reclamation pursuant to either Rule 1003 or Rule 1004.

407. FORM 45, LOCATION CONSTRUCTION REPORT

a. An Operator will submit a Form 45, Location Construction Report within 45 days of completion of interim Reclamation for a new or modified Oil and Gas Location.

b. The Form 45 will include the following information:

(1) Geographic Information System ("GIS") polygon data to describe the as-built boundaries of the entire Oil and Gas Location and of the Working Pad Surface;

(2) A surveyed as-built layout drawing of the Oil and Gas Facilities and Production Facilities, and other temporary and permanent equipment on the location;

(3) A proposed anticipated schedule, by month and year, of the operation phases planned for 1 year following the date the Form 45 is submitted; and

(4) A description of all conductors that have been set, including:

A. Well name and Well number, and API number if the Well has an approved Form 2;

B. Latitude and longitude of the conductor. If Global Positioning System ("GPS") technology is utilized to determine the latitude and longitude, all GPS data will meet the requirements set forth in Rule 216; and

C. Conductor setting depth, pipe description (including diameter and weight/foot, if applicable), cement volume, and cement job summary (if applicable).

408. 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:

a. Closed Loop Drilling. Closed loop drilling is required except where only water-based bentonitic drilling Fluids will be used, the wellbore will not penetrate salt-bearing formations, the Pit will not be in contact with shallow Groundwater, and the Pit will not be located within 2,000 feet of any Building Unit, a lined drilling Pit system may be used.

b. Bottom Hole Location. Unless authorized by the provisions of Rule 410, 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.

c. Requirement to Post Permit at the Rig. The Operator will post a copy of the approved Form 2 in a conspicuous place on the drilling rig or workover rig.

d. Requirement to Provide Spud Notice. An Operator will provide advance notice to the Director on a Form 42 – Notice of Spud, no less than 2 business days prior to spudding a Well.

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.* in effect as of January 15, 2021 applies to this Rule 408.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.colorado.gov/pacific/cdphe/water-quality-control-commission-regulations.

(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 pursuant to reasonable requirements of the Director.

(4) **Surface Casing Where Subsurface Conditions Are Known.** For Wells drilled in areas where subsurface conditions have been established by drilling experience, surface casing, sized 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 TVD of the deepest point of the planned Well (or as required by Commission order).

(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 308.b.(6):

i. The Operator will collect site-specific data sufficient to ensure compliance with all casing and cementing requirements of this Rule 408.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:

aa. Extending surface casing and cement from the surface to 50 feet below the lowest bottom depth;

bb. Stage cementing behind intermediate and/or production casing to 50 feet above the highest top or 50 feet below the lowest bottom depth; or

cc. 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.

(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 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 confirming the repairs and approval.

(11) An Operator will submit a Form 5, Drilling Completion Report, within 30 days of the completion of the operations listed above, pursuant to Rule 414.b.(3).

(12) Prior written approval from the Director on a Form 4 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 Form 5A, Completed Interval Report, will be submitted within 30 days of the gross interval change, pursuant to Rule 416.

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; and

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.

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.

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.

i. Surface and Intermediate Casing Cementing.

(1) The Operator will ensure that all surface and intermediate casing cement required under this Rule 405.i achieves a minimum compressive strength of 300 psi after 24 hours and 800 psi after 72 hours measured at 800 psi confining pressure and 95º 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 408.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 408. 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.

j. Production Casing Cementing.

(1) The Operator will ensure that all cement required under this Rule 408 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 408.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 408.e.

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 Form 4.

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 408.l.

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 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 408.m.

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.

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.

p. 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.

q. Requirement to Evaluate Disposal Zones for Hydrocarbon Potential. If a Well is drilled as a disposal Well then the Injection 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.

r. 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 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.

s. Remedial Cementing. If cement coverage in any casing string does not satisfy the requirements of Rule 408.e, the Director may apply a condition of approval for 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 408.

t. 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.

u. 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 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.

v. 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 308.b.(7).A.

w. 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.

x. 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 and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

y. 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.

z. 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 Treatment pressure. The test will ensure an appropriate safety factor and prevent Fluid losses.

aa. 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.

409. REPORT OF RESERVOIR PRESSURE TEST. Where the Director believes it is necessary to prevent waste, protect correlative rights, or to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, the Director may require subsurface pressure measurements. Whenever such measurements are made, results will be reported on a Form 13, Bottom Hole Pressure, within 20 days after completion of tests, or submitted on any company form approved by the Director containing the same information.

410. DIRECTIONAL DRILLING

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 Form 2 in a format approved by the Director.

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 Form 5, and in a format approved by the Director.

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 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 410.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 Form 4.

(4) The survey will be provided in a format approved by the Director.

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.

411. PUBLIC WATER SYSTEM PROTECTION

a. Surface Water Supply Areas.

(1) Definition. A Surface Water Supply Area is the buffer zones listed in Rule 411.a.(1).B surrounding a Classified Water Supply Segment that includes 5 stream miles upstream from a Public Water System surface water intake.

A. Calculating Buffer Zone Distances. Operators will identify buffer zones by measuring from the ordinary high-water mark of a Classified Water Supply Segment to the nearest edge of the Working Pad Surface.

B. Buffer Zones.

i. The internal buffer zone is located between 0 and 1,000 feet hydraulically upgradient from a Classified Water Supply Segment.

ii. The intermediate buffer zone is located between 1,001 and 1,500 feet hydraulically upgradient from a Classified Water Supply Segment.

iii. The external buffer zone is located between 1,501 and 2,640 feet hydraulically upgradient from a Classified Water Supply Segment.

C. The buffer zones identified by Rule 411.a.(1).B. may be modified by the Commission as a component of reviewing a proposed Oil and Gas Development Plan pursuant to Rule 307 or a hearing pursuant to Rule 503.a to include additional tributaries, including ephemeral streams, if the Director, Public Water System, or CDPHE demonstrate that modification is necessary to protect the Public Water System surface water intake from risks of spills or releases. In making such a determination, the Commission will consider whether Best Management Practices the Operator proposes to employ will provide sufficient protections to tributaries such that modifying the buffer zones is not necessary.

(2) Protections. Operators will comply with the standards established in Rules 411.a.(2).A–C below for the buffer zone in which the Working Pad Surface is proposed or located, and with all standards for zones farther from the Classified Water Supply Segment.

A. Internal Buffer Zone.

i. After January 15, 2021, Operators will not conduct any new surface disturbance within the internal buffer zone of a Surface Water Supply Area identified in Rule 411.a.(1).B.i.

ii. Operators of any existing Oil and Gas Locations located within the internal buffer zone of a Surface Water Supply Area identified in Rule 411.a.(1).B.i will submit a Form 2A to the Director prior to conducting any new surface disturbing activities, or a Form 4 prior to conducting any subsequent well operations pursuant to Rule 312 or making significant changes to the Oil and Gas Operations at the existing locations.

aa. The Director will review the Form 4 and may add any conditions of approval necessary and reasonable to protect public health, safety, welfare, the environment, and wildlife resources from potential impacts of the surface disturbance, subsequent well operations, or significant changes.

bb. If an Operator proposes to construct an access road, pipeline, or other necessary infrastructure, the Operator will describe the necessity of the proposed infrastructure on the Form 4, and the Director will evaluate whether the proposed infrastructure is necessary for ongoing Oil and Gas Operations.

cc. The Operator will provide the Form 4 to the administrator of all potentially impacted Public Water Systems at the same time Operator submits the Form 4 to the Director.

iii. Only the Commission may grant a variance to Rules 411.a.(2).A.i & ii. If an Operator seeks a variance from Rules 411.a.(2).A.i or ii, the Operator will consult with CDPHE and the Public Water System prior to the Commission holding a hearing to grant or deny the variance pursuant to Rule 502.b. The Commission will only grant a variance to Rules 411.a.(2).A.i or ii if the Operator demonstrates that the proposed Oil and Gas Operations and applicable Best Management Practices and operating procedures will result in substantially equivalent protection of drinking water quality for the Surface Water Supply Area. If the relevant Public Water System(s) agree to waive the requirements of Rules 411.a.(2).A.i or ii, the Operator will provide evidence of the waiver to the Commission. A waiver from all relevant Public Water Systems will create a presumption that a variance will be granted if the Operator also demonstrates that Best Management Practices and operating procedures will result in substantially equivalent protection of drinking water quality.

B. Intermediate Buffer Zone. After January 15, 2021, at all new and existing Oil and Gas Locations within a Surface Water Supply Area intermediate buffer zone identified in Rule 411.a.(1).B.ii, in addition to the protections required by Rule 411.a.(2).C, Operators will:

i. Contain Flowback and Stimulation fluids in Tanks that are placed on a Working Pad Surface in an area with downgradient perimeter berming;

ii. Construct lined berms or other lined containment devices pursuant to Rule 603.o around any new crude oil, condensate, and produced water storage Tanks that are installed after January 15, 2021;

iii. Inspect the Oil and Location on a daily basis, unless a Form 2A approved prior to January 15, 2021 provides for less frequent inspections pursuant to any prior Commission Rule;

iv. Maintain adequate Spill response equipment at the Oil and Gas Location during drilling and completion operations; and

v. Not construct or utilize any Pits, except that Operators may continue to utilize existing Pits that were properly permitted, constructed, operated, and maintained in compliance prior to January 15, 2021.

C. External Buffer Zone. After January 15, 2021, at all new and existing Oil and Gas Locations in the Surface Water Supply Area external buffer zone identified in Rule 411.a.(1).B.iii, Operators will:

i. Utilize pitless drilling systems; and

ii. Conduct baseline surface water sampling prior to drilling or completing any new Wells, or re-completing or restimulating any existing Well.

aa. **Sampling Location.** Operators will sample from the Classified Water Supply Segment immediately downgradient of the Oil and Gas Location.

bb. **Sampling Timing.** Operators will take one sample prior to drilling a Well, and at least one follow-up sample from the same location 90 days after the Wells at the Oil and Gas Location are completed.

cc. **Sampling Methods.** Operators will obtain analysis of the water samples from laboratories that maintain state or nationally accredited programs and utilize currently-applicable EPA-approved analytical methods.

dd. **Reporting Data.** Operators will submit a Form 43, Analytical Sample Submittal to the Commission containing the results of each sample analysis within 60 days of collecting the sample. Operators will simultaneously submit the Form 43 to the administrator of all potentially impacted Public Water Systems.

ee. **Analytes.** Operators will analyze samples collected pursuant to this Rule 411.a.(2).C.ii for the following constituents:

1. pH;

2. Alkalinity (total bicarbonate and carbonate as $CaCO_3$);

3. Specific conductance;

4. Major cations (calcium, iron, magnesium, manganese, potassium, sodium);

5. Major anions (bromide, chloride, fluoride, sulfate, nitrate and nitrate as N, and phosphorus);

6. Total dissolved solids;

7. BTEX compounds (benzene, toluene, ethylbenzene, and total xylenes);

8. Diesel Range Organics (DRO – C_{10} to C_{36}) and Gasoline Range Organics (GRO – C_6 to C_{10});

9. Polycyclic Aromatic Hydrocarbons (including those listed as Organic Compounds in Soils in Table 915-1); and

10. Metals (including those listed as Metals in Soils in Table 915-1).

(3) **Consultation.** If an Operator submits a Form 2A for a proposed Oil and Gas Location within a Surface Water Supply Area identified in Rule 411.a.(1), the Operator will engage in a Formal Consultation Process with any potentially impacted Public Water System pursuant to Rule 309.g. The Formal Consultation Process will address any additional Best Management Practices that should be applied for the protection of the Public Water System. If the Public Water System determines that the proposed Oil and Gas Location may impact ephemeral streams upstream and in direct hydraulic communication with a Surface Water Supply Area, the Formal Consultation Process will address the necessity of applying setbacks or mitigation measures to ephemeral streams.

(4) **Spill and Release Notification & Emergency Response.**

A. **Applicability.** This Rule 411.a.(4) applies to Operators of all new and existing Oil and Gas Locations with a Working Pad Surface within 2,640 feet of surface water that is 15 miles or less upstream from a surface water Public Water System intake.

B. **Emergency Response Plan Requirements.** Emergency response plans maintained by Operators pursuant to Rule 602.j will include current contact information for the administrators of all Public Water Systems with a surface water intake within 15 miles downstream.

C. **Spill and Release Notification.** No later than when the Operator provides the Director with notice pursuant to Rule 912.b.(1), the Operator will notify the administrators of all Public Water Systems with a surface water intake within 15 miles downstream in the event of a Spill or Release if the Spill or Release is reportable pursuant to Rule 912.b.(1).A and has the potential to impact the Public Water System.

b. **Groundwater Under the Direct Influence of Surface Water & Type III Aquifer Wells.**

(1) **Definitions.**

A. Groundwater Under the Direct Influence of Surface Water ("GUDI") means any water beneath the surface of the ground with:

i. Significant occurrence of insects or other macro-organisms, algae, or large-diameter pathogens such as Giardia lamblia or Cryptosporidium; or

ii. Significant and relatively rapid shifts in water characteristics such as turbidity, temperature, conductivity, or pH, which closely correlate to climatological or surface water conditions.

B. Groundwater Under the Direct Influence of Surface Water Well ("GUDI Well") means a Public Water System that is supplied by a well under the direct influence of surface water.

C. Type III Aquifer means an Aquifer that consists of unconsolidated geologic material including alluvial, colluvial or other unconsolidated materials, as defined in the Colorado State Board of Examiners of Water Well Construction and Pump Installation Contractors, Rules and Regulations for Water Well Construction, Pump Installation, Cistern Installation, and Monitoring and Observation Hole/Well Construction, 2 C.C.R. § 402-2:5.2.2.3 (2020) (hereinafter "State Engineer's Water Well Construction and Permitting Rules"). Only the January 15, 2021 version of the State Engineer's Water Well Construction and Permitting Rules applies to this Rule; later amendments do not apply. All materials 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, the State Engineer's Water Well Construction and Permitting Rules are available from the State Engineer's Office, 1313 Sherman St., Suite 821, Denver, CO 80203, and are available online at https://dwr.colorado.gov/services/well-construction-inspection#water-well-construction-rules. Type III Aquifers may contain localized impermeable layers that do not act as hydraulic boundaries between distinct Aquifers. A common example of a Type III Aquifer is an alluvial Aquifer.

D. Type III Well means a Public Water System supply well completed in a Type III Aquifer.

(2) Buffer Zones.

A. The internal buffer zone is located between 0 and 1,000 feet from a GUDI Well or Type III Well.

B. The intermediate buffer zone is located between 1,001 and 1,500 feet from a GUDI Well or Type III Well.

C. The external buffer zone is located between 1,501 and 2,640 feet from a GUDI Well or Type III Well.

(3) Protections. Operators will comply with the standards established below for the buffer zone in which the Working Pad Surface is proposed or located and with all standards for zones farther from the GUDI Well or Type III Well.

A. Internal Buffer Zone.

i. After January 15, 2021, Operators will not conduct any new surface disturbance within the internal buffer zone of a GUDI Well or Type III Well identified in Rule 411.b.(2).A.

ii. Only the Commission may grant a variance to Rule 411.b.(3).A.i. If an Operator seeks a variance from Rule 411.b.(3).A.i, the Operator will consult with CDPHE and the Public Water System prior to the Commission holding a hearing to grant or deny the variance pursuant to Rule 502.b. The Commission will only grant a variance to Rule 411.b.(3).A.i if the Operator demonstrates that the proposed Oil and Gas Operations and applicable Best Management Practices and operating procedures will result in substantially equivalent protection of drinking water quality for the GUDI Well or Type III Well. If the relevant Public Water System(s) agree to waive the requirements of Rule 411.b.(3).A.i, the Operator will provide evidence of the waiver to the Commission. A waiver from all relevant Public Water System(s) will create a presumption that a variance will be granted if the Operator also demonstrates that Best Management Practices and operating procedures will result in substantially equivalent protection of drinking water quality.

iii. Operators of new Oil and Gas Locations within the internal buffer zone of a GUDI Well or Type III Well identified in Rule 411.b.(2).A will adhere to all requirements for operations within the internal buffer zone of a Surface Water Supply Area pursuant to Rule 411.a.(2).A.

B. **Intermediate Buffer Zone.** After January 15, 2021, Operators of new Oil and Gas Locations within the internal buffer zone of a GUDI Well or Type III Well identified in Rule 411.b.(2).B will adhere to all requirements for operations within the intermediate buffer zone of a Surface Water Supply Area pursuant to Rule 411.a.(2).B.

C. **External Buffer Zone.** After January 15, 2021, Operators will utilize pitless drilling systems at all new and existing Oil and Gas Locations within the external buffer zone of a GUDI Well or Type III Well identified in Rule 411.b.(2).C.

(4) **Consultation.** If an Operator submits a Form 2A for a proposed Oil and Gas Location within 2,640 feet of a GUDI Well or Type III Well, the Operator will engage in a Formal Consultation Process with the administrator of the Public Water System that operates the GUDI Well or Type III Well pursuant to Rule 309.g. The Formal Consultation Process will address:

A. Any Best Management Practices that should be applied;

B. Whether Groundwater monitoring is necessary. Although the Operator and Public Water System may determine that Groundwater monitoring is necessary in other circumstances, at a minimum Groundwater monitoring will be necessary if:

i. The Public Water System determines that Groundwater monitoring is necessary;

ii. Installation of one or more Groundwater monitoring wells does not pose significant, unusual, or unique risks of contamination to the Aquifer; and

iii. Suitable locations for one or more Groundwater monitoring wells exist between the proposed Oil and Gas Location and the GUDI Well or Type III Well and in other appropriate locations to determine groundwater gradient; and

C. Whether protection of recharge facilities is necessary. If the Public Water System determines that the proposed Oil and Gas Location may impact engineered structures that enable recharge to the Public Water System in the vicinity of a GUDI Well or Type III Well, the Formal Consultation Process will address the necessity of applying setbacks or mitigation measures to such recharge facilities.

(5) Spill and Release Notification & Emergency Response.

A. Applicability. This Rule 411.b.(5) applies to Operators of all new and existing Oil and Gas Locations with a Working Pad Surface within 2,640 feet of a GUDI Well or Type III Well.

B. Emergency Response Plan Requirements. Emergency response plans maintained by Operators pursuant to Rule 602.j will include current contact information for the administrators of all Public Water Systems with a GUDI Well or Type III Well within 2,640 feet of the Working Pad Surface.

C. Spill and Release Notification. No later than when the Operator provides notice to the Director pursuant to Rule 912.b.(1), the Operator will notify the administrators of all Public Water Systems with a GUDI Well or Type III Well within 2,640 feet of a Spill or Release that is reportable pursuant to Rules 912.b.(1).A, F, G, or J.

(6) Reporting Groundwater Monitoring Data. If Groundwater monitoring is required pursuant to Rule 411.b.(4).B, the Operator will submit a Form 43 to report data from the monitoring well(s) for each of the analytes listed in Rule 411.a.(2).C.ii.ee at a frequency specified as a condition of approval on the Operator's Form 2A.

412. SURFACE OWNER NOTICE

a. Statutory Notice to Surface Owners. Not less than 30 days in advance of commencement of operations with heavy equipment for the drilling of a Well, Operators will provide the statutorily required notice to the Well Site Surface Owner(s) as described below and the Relevant Local Government. 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 will 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 will 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; and

E. A postage-paid, return-addressed post card whereby the Surface Owner may request consultation pursuant to Rule 309.

(4) Notice of Subsequent Operations. An Operator will provide to the Surface Owner or the Surface Owner's appointed agent and the Relevant Local Government at least 7 days advance notice of subsequent operations with a rig or heavy equipment that will materially impact surface areas beyond the existing access road or Oil and Gas Location, including but not limited to all operations listed in Rule 312.a.

(5) **Notice During Irrigation Season.** If a Well is to be drilled on irrigated Crop Land or may interfere with other agricultural activities, the Operator will contact the Surface Owner or agent at least 14 days prior to commencement of operations with heavy equipment to coordinate drilling operations to avoid unreasonable interference with irrigation plans and agricultural activities.

(6) **Final Reclamation Notice.** Not less than 30 days before any final Reclamation operations are to take place pursuant to Rule 1004, the Operator will notify the Surface Owner. Final Reclamation operations will 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 30 days after the completion of a Well.

b. Move-In, Rig-Up Notice.

(1) At least 30 Days, but no more than 90 days, before moving in and rigging up a drilling rig, the Operator will provide Move-In, Rig-Up ("MIRU") Notice to all Surface Owners, Building Unit owners and tenants within 2,000 feet of the Working Pad Surface if:

A. It has been more than one year since the previous notice or since drilling activity last occurred, or

B. Notice was not previously required.

(2) The Operator may rely on the county assessor tax records to identify Building Unit Owners within 2,000 feet of the Working Pad Surface receiving the MIRU Notice.

(3) The Operator will provide notice to the physical address of all parcels of land within 2,000 feet of the Working Pad Surface receiving the MIRU Notice.

(4) MIRU Notice will be delivered by hand; certified mail, with return-receipt requested; electronic mail, with return receipt requested, delivery confirmation, or by other delivery service with delivery confirmation.

(5) The MIRU Notice will include:

A. A statement informing the Building Unit Owner and tenant that the Operator intends to move in and rig up a drilling rig to drill Wells within 2,000 feet of their Building Unit;

B. The Operator's contact information where it may be reached 24-hours a day;

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 Form 2 has been approved or the eForm Document Number if the Form 2 is pending approval;

F. The anticipated date (day, month, year) the drilling rig will move in and rig up;

G. The Commission's website address and telephone number; and

H. The estimated duration of time (which may be a range) that the drilling rig will be onsite and an indication of whether multiple drilling operations are planned for the Oil and Gas Location.

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

(7) An Operator may request an exception to this Rule and provide MIRU Notice less than 30 days prior to moving in and rigging up a drilling rig for good cause.

413. FORM 7, OPERATOR'S MONTHLY REPORT OF OPERATIONS

a. Operators will report all existing oil and gas Wells that are not Plugged and Abandoned on the Form 7, Operator's Monthly Report of Operations within 45 days after the end of each month. A Well will 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 will 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 will include all Fluids produced during Flowback, initial testing, completion, and production of the Well.

b. Operators will report the volume of produced Fluids and any gas or Fluids used during enhanced recovery unit operations injected into a Class II UIC Well on a Form 7 within 45 days after the end of each month. 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 Wells including production, exploration, injection, service and monitoring wells.

c. Operators will report the volume of any non-produced Class II Fluids not listed in Rule 413.b injected into a Class II UIC Well on a Form 14, Monthly Report of Non-Produced Water Injected pursuant to Rule 808.b.

414. FORM 5, DRILLING COMPLETION REPORT

a. Form 5, Preliminary Drilling Completion Report.

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

(2) **Information Requirements.** The Form 5, Preliminary Drilling Completion Report 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 414.b.(2) that has been obtained.

(3) A Form 5, Final Drilling Completion Report will be submitted after reaching total depth as required by Rule 414.b.

b. Form 5, Final Drilling Completion Report.

(1) A Form 5, Final Drilling Completion Report 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 Form 5, Final Drilling Completion Report 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 Form 5, Final Drilling Completion Report 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 Form 4.

E. Any directional survey will be attached to the form and will meet the requirements set forth in Rule 410.

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 216. 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 TVD in feet of the surface casing shoe expressed in psig.

(3) The Operator will submit a 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 limited to, the operations listed in

Rule 408.e.(5). The Form 5 will include the information required by Rule 414.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 414.b.(2).B.

415. COMMINGLING

a. 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 without prior Commission approval, unless:

(1) The Operator proposes to conduct commingling at an existing Well through a procedure that requires prior Director approval pursuant to Rule 312.a; or

(2) The Commission has issued an order or promulgated a Rule excluding specific Wells, geologic formations, geographic areas, or Fields from commingling in response to an application filed by a directly and adversely affected or aggrieved party or on the Commission's own motion.

b. This Rule 415 supersedes the procedural requirements to establish commingling and allocation contained in any Commission order as of the effective date of this Rule 415, but does not supersede any allocation made under such order.

416. FORM 5A, COMPLETED INTERVAL REPORT

a. The Operator will submit the Form 5A, Completed Interval Report for a formation within 30 days after the following operations:

(1) Any Stimulation or re-stimulation;

(2) Any Productivity Test (successful or not), if there is no Stimulation;

(3) Any reperforation or change in the perforated interval if there is no Stimulation;

(4) Commingling with another formation;

(5) Temporary abandonment; or

(6) Permanent abandonment of the formation if the Well is not to be abandoned.

b. The Operator will report the details of any Stimulation performed including, but not limited to, Hydraulic Fracturing Treatment and acidizing Stimulation.

c. In order to resolve completed interval information uncertainties, the Director may require an Operator to submit further information in an additional Form 5A.

417. 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 through vertical channels to other formations.

a. Injection Wells. A mechanical integrity test will be performed on all injection Wells.

(1) The mechanical integrity test will 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 will 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;

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 will include one of the following tests to determine whether there are significant Fluid movements in vertical channels adjacent to the wellbore:

A. Cementing records which will 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 will inject fluids via a new injection Well unless a mechanical integrity test on the Well has been performed and supporting documents including Form 21, Mechanical Integrity Test, submitted and approved by the Director. Oral approval may be granted for continuous injection following a successful test.

(4) Following the performance of the initial mechanical integrity test required by Rule 417.a.(3), additional mechanical integrity tests will be performed on each type of injection Well as follows:

A. Class II UIC Well. As long as it is used for the injection of Fluids, mechanical integrity tests will be performed at the rate of not less than 1 test every 5 years, except as specified by Rule 417.a.(4).C below. Five year periods will commence on the date the initial mechanical integrity test is performed or the date of a mechanical integrity test specified in Rule 417.a.(4).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 will be performed after any casing repairs, after resetting the tubing or mechanical isolation device, or whenever the tubing or mechanical isolation devise is moved during workover operations.

(5) All injection Well mechanical integrity tests will be witnessed by the Director.

b. Shut-in Wells. All Shut-in Wells will pass a mechanical integrity test.

(1) A mechanical integrity test will be performed on each Shut-in Well within 2 years of the initial shut-in date.

(2) Subsequently, a mechanical integrity test will 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 will 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 will 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 will submit a 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 will pass a mechanical integrity test.

(1) A mechanical integrity test will be performed on each Temporarily Abandoned Well within 30 days of temporarily abandoning the well.

(2) Subsequently, a mechanical integrity test will be performed on each Temporarily Abandoned Well on 5 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 will 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 will 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 will submit a 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. Suspended Operations and Waiting on Completion Wells. A mechanical integrity test will be performed on Suspended Operations Wells and Waiting On Completion Wells as described in this Rule 417.d.

(1) A mechanical integrity test will be performed on each Suspended Operations Well within 2 years of setting any casing string and suspending operations prior to reaching permitted total depth.

(2) A mechanical integrity test will be performed on each Waiting On Completion Well within 2 years of setting production casing.

(3) Subsequently, a mechanical integrity test will be performed on each Suspended Operations Well and Waiting On Completion Well on 5 year intervals from the date that the initial mechanical integrity test was performed, as long as the Well remains in a suspended operations or waiting on completion status.

(4) The mechanical integrity test for a Suspended Operations Well and Waiting On Completion Well will be performed to verify integrity of the casing string being tested. The pressure test will 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.

e. Not less than 10 days prior to the performance of any mechanical integrity test required by this Rule 417, any person required to perform the test will notify the Director with a Form 42 – Mechanical Integrity Test, of the scheduled date and time when the test will be performed.

f. All Wells will maintain mechanical integrity. All Wells which lack mechanical integrity, as determined through a mechanical integrity test, or other means, will be repaired or Plugged and Abandoned within 6 months. If an Operator has performed a mechanical integrity test within the 2 years required for Shut-in Wells or the 30 days required for Temporarily Abandoned Wells by this Rule, the Operator will have 6 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 Rules 417.b.(1) & c.(1), the Operator will not be given an additional 6 months in the event of an unsuccessful test.

g. Mechanical integrity test pressure loss or gain will 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 417.f.

418. FORM 21, MECHANICAL INTEGRITY TEST

a. Results of all mechanical integrity tests, including tests that show a lack of integrity, will be submitted on Form 21, Mechanical Integrity Test, within 30 days after the test.

b. A mechanical integrity test that shows the Well lacks integrity is considered a failed test.

c. The Form 21 will be completely filled out except for Part II, which is required only for injection Wells. An original copy of the pressure chart will be submitted with every Form 21.

419. BRADENHEAD MONITORING, TESTING, AND REPORTING

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 used 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.

b. Bradenhead Monitoring. The Operator will monitor all Wells at a Director-indicated frequency for aspects of Well integrity necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, including Groundwater, Potential Flow Zones, and formations and pursuant to this Rule 419.

(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 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 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 – 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.

aa. 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.

bb. 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 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 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 Report;

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 Form 4 within 60 days of submitting a Form 17 pursuant to Rule 419.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 Form 4.

(5) **Records.** An Operator will keep Bradenhead monitoring records required by Rule 419.b available for inspection by the Director for a minimum of 5 years after the monitoring was performed.

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 pursuant to Rule 614.e.

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.

420. 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, Bradenhead Test Report 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.

421. STATEWIDE FLOODPLAIN REQUIREMENTS

a. When operating within a defined Floodplain, the following requirements apply to new Oil and Gas Locations and Wells:

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

(2) Effective June 1, 2015, new Wells will 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.

(3) Effective June 1, 2015, new Oil and Gas Locations will 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.

b. When operating within a defined Floodplain, the following requirements apply to all Wells, Tanks, separation equipment, containment berms, Production Pits, Special Purpose Pits, and Flowback Pits:

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

(2) All Tanks, including partially buried Tanks, and separation equipment will be anchored to the ground. Anchors will be engineered to support the Tank and separation equipment and to resist flotation, collapse, lateral movement, or subsidence.

(3) Containment berms around Tanks will be constructed of steel rings or another engineered technology that provides equivalent protection from floodwaters and debris.

(4) Production Pits, Special Purpose Pits (other than Emergency Pits), and Flowback Pits containing E&P Waste are prohibited within a defined Floodplain.

422. LOCAL GOVERNMENT WELFARE PROTECTION STANDARDS

Operators will comply with all Relevant Local Government requirements, including regulations that may be more protective or stricter than the Commission's Rules.

423. NOISE

a. Operators will submit a noise mitigation plan that demonstrates one or more proposed methods of meeting the maximum permissible noise levels described by this Rule 423 as an attachment to their Form 2As, as required by Rule 304.c.(2). An Operator may submit substantially equivalent information or plans developed through a Local Government land use process or federal process in lieu of the information required by this Rule 423.a unless the Director or Commission determines that the information or plan developed through the Local Government land use process or federal process is not equivalent. The noise mitigation plan will include at least the following information:

(1) An explanation of how the Operator will comply with the maximum permissible noise levels specified in Rule 423.b.(1). This is to include a description of methods to design acoustical mitigation measures or choose/site equipment appropriately such that the Operator has a reasonable expectation of compliance.

(2) Estimated duration of each stage of operation, including drilling, completion, Flowback, production, and an estimate of the noise levels of each stage of operation;

(3) Reference to topographical considerations of noise and noise propagation at the proposed Oil and Gas Location;

(4) Description of Best Management Practices and best engineering practices for measuring and mitigating noise levels and an implementation schedule for such technology.

(5) For proposed Oil and Gas Locations with a Working Pad Surface within 2,000 feet of one or more Residential Building Units, at least one, and no more than six noise points of compliance where monitors will be located. Operators will identify noise points of compliance using the following criteria:

A. Provide one noise point of compliance in each direction in which a Residential Building Unit is located within 2,000 feet of the proposed Working Pad Surface.

B. Noise points of compliance will be located at least 350 feet from the Working Pad Surface, and no less than 25 feet from the exterior wall of the Residential Building Unit that is closest to the Working Pad Surface. If a Surface Owner or tenant refuses to provide the Operator with access to install a noise monitor, then the noise point of compliance will be located at either the next-closest Residential Building Unit or an alternative location approximately the same distance and direction from the Working Pad Surface.

b. A preliminary plan for how the Operator will conduct background ambient noise surveys to establish baseline conditions for noise levels on the site, for both A-scale and C-scale noise. The Director may require as a condition of approval on the Form 2A that the Operator conduct the background ambient noise survey between 30 and 90 days prior to start of construction and update the plan accordingly based on the results. Operators will conduct baseline noise surveys at the noise points of compliance identified pursuant to Rule 423.a.(5). When an Operator conducts a background ambient survey the Operator will follow the same approach as outlined in Rule 423.c.(7) and over a 72-hour period, including at least 24 hours between 10:00 p.m. on a Friday and 4:00 a.m. on a Monday. Operators will record any significant weather events and take those events into account when establishing the baseline. A single cumulative daytime ambient noise level and a single cumulative nighttime ambient noise level will be established by taking the logarithmic average of all daytime or nighttime 1-hour Leq values measured and in accordance with the sound level data collection requirements pursuant to the maximum permissible noise levels.

(1) All Oil and Gas Operations will comply with the following maximum permissible noise levels in Table 423-1 unless otherwise required by Rule 423. The Director may require Operators to comply with a lower maximum permissible noise level based on the consultation process with Relevant and Proximate Local Governments, CDPHE, or CPW pursuant to Rules 302.g, 309.e, & 309.f.

Table 423-1 – Maximum Permissible Noise Levels

LAND USE DESIGNATION	**7:00 am to next 7:00 pm**	**7:00 pm to next 7:00 am**
Residential/ Rural/State Parks & State Wildlife Areas	55 db(A)	50 db(A)
Commercial/Agricultural	60 db(A)	55 db(A)
Light Industrial	70 db(A)	65 db(A)
Industrial	80 db(A)	75 db(A)
All Zones	60 db(C)	60 db(C)

(2) Unless otherwise required by Rule 423, drilling or completion operations, including Flowback:

A. In Residential/Rural or Commercial/Agricultural, maximum permissible noise levels will be 60 db(A) in the hours between 7:00 p.m. to 7:00 a.m. and 65 db(A) in the hours between 7:00 a.m. to 7:00 p.m.; and

B. In all zones maximum permissible noise levels will be 65 db(C) in the hours between 7:00 p.m. to 7:00 a.m. and 65 db(C) in the hours between 7:00 a.m. to 7:00 p.m.

(3) The basis for determining land use designation pursuant to Table 423-1 will be the Relevant Local Government's land use or zoning designation. The Director may consult with a Relevant or Proximate Local Government to identify the type of land use of the Oil and Gas Location and its surrounding area, taking into consideration any applicable zoning or other local land use designation.

A. To protect public health, safety, and welfare, the Director may require Operators to comply with a lower maximum permissible noise level in areas zoned industrial, light industrial, or commercial, if the Oil and Gas Facility will be within 2,000 feet of a Residential Building Unit or High Occupancy Building Unit.

B. In a noise mitigation plan submitted pursuant to Rule 423.a, an Operator may request a higher maximum permissible noise level than would otherwise be allowed by Table 423-1, if the Operator demonstrates that both the Relevant and any Proximate Local Governments agree to the higher maximum permissible noise level. The Director may apply that higher maximum permissible noise level as long as the requested level is protective of public health, safety, and welfare, and wildlife.

(4) When operating in High Priority Habitat, Operators will consult CPW and, on federal lands, the Bureau of Land Management, or United States Fish and Wildlife Service, to determine the acceptable noise limits and monitoring protocols.

(5) Operators may exceed the noise levels in Table 423-1 as measured at the nearest noise point of compliance if all affected Surface Owners and tenants agree in writing to the higher noise limit requested by the Operator.

(6) Unless otherwise required by Rule 423.b.(7), during the hours between 7:00 a.m. and the next 7:00 p.m. the maximum permissible noise levels listed in Table 423-1 may be increased 10 dB(A) for a period not to exceed 15 minutes in any 1-hour period. The increase is permissible only for a 1 hour period during any 12 hours.

(7) Operators will reduce periodic, impulsive, or shrill noise by 5 dB(A) below the levels in Table 423-1. For periodic, shrill, and impulsive noise within 1000 feet of a Residential Building Unit, Operators will minimize noise that can be readily eliminated through maintenance, equipment modification, or other readily available procedures.

(8) Pursuant to Commission inspection or upon receiving a complaint from a Local Government, or a Surface Owner or tenant of a property within 2,000 feet of an Oil and Gas Facility regarding noise related to Oil and Gas Operations, the Commission will conduct an onsite investigation and take sound measurements using the methods prescribed for Operators in Rule 423.c.

c. To demonstrate compliance with Tables 423-1 and 423-2 Operators will measure sound levels according to the following standards:

(1) During pre-production activities and ongoing operations lasting longer than 24 consecutive hours such as drilling, completion, recompletion, Stimulation, and Well maintenance, in areas zoned residential or within 2,000 feet of a Building Unit, Operators will take continuous sound measurements from each noise point of compliance designated pursuant to Rule 423.a.(5).

(2) Monitoring Procedures.

A. In response to a complaint or at the Director's request, Operators will measure sound levels at 25 feet from the complainant's occupied structure towards the noise source for low frequency (dbC) indicated issues. For high frequency (dbA) measurement will be at the nearest point of compliance. For equipment installed at Oil and Gas Locations subject to a Form 2A approved prior to January 15, 2021, after the Commencement of Production Operations, no single piece of equipment will exceed the maximum permissible noise levels listed in Table 423-1 as measured at a point 350 feet from the equipment generating the noise in the direction from which the complaint was received.

B. In situations where measurement of noise is unrepresentative due to topography or any other issue, Operators or the Commission may take the measurement at the nearest noise point of compliance, or at a different distance and extrapolate it to 25 feet from the complainant's residence (dbC) or the complainant's property line (dbA) using the following formula:

db(A) distance 2 = db(A) distance 1 – 20 x log 10 (distance 2/distance 1) db(C) distance 2 = db(C) distance 1 – 20 x log 10 (distance 2/distance 1)

(3) Operators will equip sound level meters with wind screens that are in good working order, and will take readings when the wind velocity at the time and place of measurement is not more than 5 miles per hour. In determining an Oil and Gas Operation's contribution to sound levels, the Director will consider wind readings that exceed 5 mph.

(4) Operators will take sound level measurements 5 feet above ground level.

(5) Operators will determine sound levels by averaging logarithmic minute-by-minute measurements made over a minimum 1-hour sample duration.

(6) All sound meters will be type II meters at a minimum. All measurements will be reported using LeqA (fast) and LeqC (slow). Meters will be field calibrated pre-survey and post survey. Continuous surveys will be field calibrated pre-survey and post survey and pursuant to the manufacturer's recommended interval. All survey equipment will be inspected at time of calibration for compliance with the Commission's Rules.

(7) Operators will take samples under conditions that are representative of the noise experienced by the complainant (*e.g.*, at night, morning, evening, or during special weather conditions).

(8) If a Building Unit, High Occupancy Building Unit, High Priority Habitat, or Designated Outside Activity Area is built or designated after an Oil and Gas Development Plan or Form 2A is approved, the Operator of the Oil and Gas Location need not comply with Rule 423.c with respect to the newly built or designated Building Unit, High Occupancy Building Unit, High Priority Habitat, or Designated Outside Activity Area.

(9) Operators will maintain records to demonstrate compliance with this Rule 423.c, and will submit the records to the Director upon request.

d. Cumulative Noise. All noise measurements will be cumulative.

(1) Noise measurements taken at noise points of compliance designated pursuant to Rule 423.a.(5) will take into account ambient noise, rather than solely the incremental increase of noise from the facility targeted for measurement.

(2) At new or substantially modified Oil and Gas Locations where ambient noise levels at noise points of compliance designated pursuant to Rule 423.a.(5) already exceed the noise thresholds identified in Table 423-1, then Operators will be considered in compliance with Rule 423, unless at any time their individual noise contribution, measured pursuant to Rule 423.c, increases noise above ambient levels by greater than 5 dBC and 5 dBA between 7:00 p.m. and 7:00 a.m. or 7 dBC and 7 dBA between 7:00 a.m. and 7:00 p.m. This Rule 423.d.(2) does not allow Operators to increase noise above the maximum cumulative noise thresholds specified in Table 423-2 after the Commencement of Production Operations.

(3) After the Commencement of Production Operations, if ambient noise levels already exceed the maximum permissible noise thresholds identified in Table 423-1, under no circumstances will new Oil and Gas Operations or a significant modification to an existing Oil and Gas Operations raise cumulative ambient noise above:

Table 423-2 – Maximum Cumulative Noise Levels

LAND USE	7:00 am to next 7:00 pm	7:00 pm to next 7:00 am
Residential /Rural/State Parks/State Wildlife Areas	65 db(A)	60 db(A)
Commercial/Agricultural	70 db(A)	65 db(A)
Light Industrial	80 db(A)	75 db(A)
Industrial	90 db(A)	85 db(A)
All Zones	75 db(C)	70 db(C)

e. If Oil and Gas Operations result in persistent noise that adversely impacts public welfare, the Director may require the Operator to take action pursuant to Rule 901.a.

424. LIGHTING

a. Operators will submit a light mitigation plan as an attachment to their Form 2As, pursuant to Rule 304.c.(3). An Operator may submit substantially equivalent information or plans developed through a Local Government land use process or federal process in lieu of the information required by this Rule 424.a unless the Director or Commission determines that the information or plan developed through the Local Government land use process or federal process is not equivalent.

(1) All light mitigation plans will be signed by a person with relevant expertise in light mitigation techniques and design.

(2) All light mitigation plans will address:

A. A pre-production facility lighting plan demonstrating one or more proposed methods of ensuring compliance with Rule 424.c, and:

i. That provides adequate lighting to ensure safety during active operations involving personnel; and

ii. The proposed anticipated location, mounting, height, and orientation of all outdoor lighting fixtures on the site during pre-production activities.

iii. Nothing in this Rule 424.a.(2).A prevents an Operator from using ad hoc temporary portable lighting when necessary for safety reasons during pre-production activities, provided that the Operator otherwise complies with the standards in Rules 424.b–f.

B. A Production Facility lighting plan demonstrating one or more proposed methods of ensuring compliance with Rules 424.d & e, and:

i. The location, mounting, height, and orientation of all outdoor lighting fixtures on the site;

ii. A table that calculates the total lumen output of all fixtures combined; and

iii. Cut sheets of light fixtures that demonstrate Backlight, Uplight, and Glare (“BUG”) rating, lumen output, and fully shielded design; and

iv. For any location with a Building Unit within 2,000 feet, a photometric plan estimating or calculating the illuminance, measured in lux, 100 feet outside the facility boundary;

C. The Operator's capability of meeting all requirements of this Rule 424 through one or more proposed methods;

D. The location of the resources and receptors listed in Rules 424.c & d; and

E. Square footage of the Working Pad Surface for purposes of demonstrating compliance with Rule 424.d.(2).

b. Lighting Standards.

(1) Operators will direct site lighting downward and inward, such that no light shines above a horizontal plane passing through the center point light source.

(2) Operators will use appropriate technology within fixtures that obscures, blocks, or diffuses the light to reduce light intensity outside the boundaries of the Oil and Gas Facility.

(3) Operators will use Best Management Practices to minimize light pollution and obtrusive lighting, which may include, but are not limited to:

A. Minimizing lighting when not needed using timers or motion sensors;

B. Using full cut-off lighting;

C. Using lighting colors that reduce light intensity; and

D. Using low-glare or no-glare lighting.

c. Pre-Production Facility Lighting.

(1) At all Oil and Gas Facilities with active operations involving personnel, Operators will provide sufficient on-site lighting to ensure the safety of all persons on or near the site.

(2) If the facility has a noise barrier, Operators will locate the facility lighting beneath the noise barrier, except for drilling rig lights, which will be shielded and pursuant to Federal Aviation Administration permit requirements if applicable. Operators will take precautions to ensure that lights do not shine out of openings in the noise barrier.

(3) Prior to the Commencement of Production Operations, Operators will take all necessary and reasonable precautions to ensure that lighting from Oil and Gas Facilities does not unnecessarily impact the health, safety, and welfare of any of the following:

A. Persons occupying Building Units within 2,000 feet of the Oil and Gas Facility;

B. Motorists on roads within 2,000 feet of the Oil and Gas Facility; and

C. Wildlife occupying any High Priority Habitat within 2,000 feet of the Oil and Gas Facility.

d. Production Phase Facility Lighting When Personnel Are On-Site.

(1) After the Commencement of Production Operations, at all Oil and Gas Facilities with active operations involving personnel, Operators will provide sufficient on-site lighting to ensure the safety of all persons on or near the site.

(2) After the Commencement of Production Operations, when active operations involving personnel are occurring, Oil and Gas Facilities will not exceed the following maximum permissible light levels.

LAND USE	**Lumens per square foot of Working Pad Surface**
Residential /Rural/State Parks/State Wildlife Areas/High Priority Habitat/Wilderness Areas/National Park/National Monument	1.25
Commercial/Agricultural	2.5
Light Industrial	5.0
Industrial	7.5

(3) The basis for determining land use designation pursuant to be Rule 424.d.(2) will be the Relevant Local Government's land use or zoning designation. The Director may consult with a Relevant or Proximate Local Government to identify the type of land use of the Oil and Gas Location and its surrounding area, taking into consideration any applicable zoning or other local land use designation.

A. To protect public safety and welfare, the Director may require Operators to comply with a lower maximum permissible light level in areas zoned industrial, light industrial, or commercial, if the Oil and Gas Facility will be within 2,000 feet of a Residential Building Unit or High Occupancy Building Unit.

B. The Director may require Operators to comply with a lower maximum permissible light level based on the consultation process with Relevant and Proximate Local Governments, CDPHE, or CPW required by Rules 302.g, 309.e, & 309.f.

C. In a light mitigation plan submitted pursuant to Rule 424.a, an Operator may request a higher maximum permissible light level than would otherwise be allowed by Rule 424.d.(2), if the Operator demonstrates that both the Relevant and any Proximate Local Governments agree to the higher maximum permissible light level. The Director may apply that higher maximum permissible light level as long as the requested level is protective of public safety, public welfare, and wildlife.

e. Production Phase Facility Lighting When Personnel Are Not On-Site. After the Commencement of Production Operations, Operators will minimize continuous on-site lighting when personnel are not present.

f. Cumulative Light Impacts. Operators will develop site lighting to reduce cumulative nighttime light intensity from all Oil and Gas Facilities to 4 lux at any Residential Building Unit or High Occupancy Building Unit within 1 mile of any Oil and Gas Facility, measured at 5.5 feet above grade in a direct line of sight to the brightest light fixture onsite.

425. VISUAL IMPACT MITIGATION

a. Commission Visual Impact Mitigation Standards.

(1) Unless the Commission approves an alternate method of visual impact mitigation, all permanent equipment at new and existing Oil and Gas Facilities, regardless of construction date, which are observable from any public highway, road, or publicly-maintained trail, will 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.

(2) If requested to do so during consultation with the Relevant Local Government, the Surface Owner, or a Building Unit owner pursuant to Rules 302.g, 309.b, or 309.c, an Operator will orient new Oil and Gas Facilities in a direction to reduce the contrast between the Oil and Gas Facilities and the surrounding landscape. If multiple receptors to visual impacts may be present, the Operator will describe its efforts to use orientation to minimize impacts on all potential receptors.

b. Oil and Gas Facilities located on the surface of federal lands will be painted and oriented as directed by the appropriate federal agency.

c. Operators will use Best Management Practices to avoid, minimize, and mitigate visual impacts consistent with any Relevant Local Government's regulations.

426. ODORS

a. For proposed Working Pad Surfaces within 2,000 feet of a Building Unit or Designated Outside Activity Area, Operators will submit an odor mitigation plan as an attachment to their Form 2As, as required by Rule 304.c.(4). An Operator may submit substantially equivalent information or plans developed through a Local Government land use process or federal process in lieu of the information required by this Rule 426.a unless the Director or Commission determines that the information or plan developed through the Local Government land use process or federal process is not equivalent. All odor mitigation plans will address:

(1) How the Operator will comply with all requirements of this Rule 426 through one or more proposed methods; and

(2) All Best Management Practices the Operator will use to reduce odors.

b. Operators will conduct all Oil and Gas Operations at all Oil and Gas Facilities in a manner that minimizes odors outside the boundaries of the Oil and Gas Location.

c. In areas within 2,000 feet of a Building Unit or Designated Outside Activity Area, Operators will use current and appropriate Best Management Practices to minimize odors.

d. Complaint System.

(1) Upon Director request, the Operator(s) of the Oil and Gas Facility or Facilities subject to the complaint will provide within 24 hours the Director, the Relevant or Proximate Local Government, and the complainant (should the complainant request notification) with a complete description of all activities occurring at the facility during the timeframe specified in the complaint.

(2) The Director may require the Operator(s) of the Oil and Gas Facility or Facilities subject to the complaint to take necessary and reasonable actions to reduce odors, including, but not limited to, conducting air sampling to measure volatile organic compounds.

e. **Cumulative Odors.** The Commission or Director may require Operators to adopt additional Best Management Practices as conditions of approval or through guidance to minimize odors in areas with high concentrations of oil and gas activities that may expose one or more Building Units or Designated Outside Activity Areas to odors from oil and gas sources.

427. DUST

a. Operators will submit a dust mitigation plan for all Oil and Gas Operations on Oil and Gas Locations and lease access roads, that demonstrates one or more methods of meeting the requirements of this Rule 427 as an attachment to their Form 2As, as required by Rule 304.c.(5). An Operator may submit substantially equivalent information or plans developed through a Local Government land use process or federal process in lieu of the information required by this Rule 427.a unless the Director or Commission determines that the information or plan developed through the Local Government land use process or federal process is not equivalent. Such plans will include at least the following information:

(1) Soil type;

(2) Proposed vehicle speed limit to minimize dust;

(3) Total area of soil disturbance (in acres);

(4) Whether access roads are paved;

(5) Number of anticipated truck trips during each stage of wellpad construction, drilling, completion, and production;

(6) A plan for suppressing fugitive dust caused solely by wind; and

(7) A list of Best Management Practices that will be used. Such practices may include, but are not limited to:

A. The use of speed restrictions;

B. Regular road maintenance; and

C. Restricting construction activity during high wind days.

b. Operators will minimize fugitive dust caused by their operations, or dust originating from areas disturbed by their Oil and Gas Operations that becomes windborne.

(1) If at any time, an Operator is not in compliance with this Rule 427.b, the Operator will cease ongoing truck traffic or other operations causing fugitive dust, until the Operator has performed dust suppression activities that the Director determines substantially and adequately control dust. If an Operator disagrees with the Director's determination, it may appeal to the Commission pursuant to Rule 901.a.(3).

(2) Compliance with a dust minimization plan submitted pursuant to Rule 427.a does not relieve an Operator of complying with this Rule 427.b.

c. Applying Dust Suppressant.

(1) Operators will not use any of the following fluids for dust suppression:

A. Produced water;

B. E&P Waste or hazardous waste;

C. Crude oil or any oil not specifically designed for road maintenance;

D. Solvents; and

E. Any process Fluids.

(2) Operators will use only fresh water (potable or non-potable) to conduct dust suppression activities within 300 feet of the ordinary high-water mark of any water body.

(3) Operators will maintain safety data sheets ("SDS") for any chemical-based dust suppressant, and make the SDS available immediately upon request to the Director and to the Local Government. Operators will maintain SDS for any chemical-based dust suppressant until the site passes final site Reclamation, and transfer the records upon transfer of property ownership.

d. Within 2,000 feet of Building Units, or High Priority Habitat, the Commission may require additional dust control measures as a condition of approval, including, but not limited to:

(1) Constructing wind breaks and barriers;

(2) Automation of Wells to reduce truck traffic;

(3) Road or facility surfacing; and

(4) Soil stockpile stabilization measures.

e. Cumulative Dust Impacts. Based on review of dust mitigation plans submitted pursuant to Rule 427.a, the Commission may require Operators to adopt additional dust mitigation requirements to reduce cumulative dust impacts, based on the following considerations:

(1) The number of anticipated truck trips for the Oil and Gas Facility seeking Commission approval combined with the number of anticipated truck trips at any other Oil and Gas Locations within a 1-mile radius during the same time period;

(2) Whether the truck traffic for the Oil and Gas Facility seeking Commission approval will use any of the same unpaved roads as truck traffic for any other Oil and Gas Facility; and

(3) Whether there are other major sources of dust in the area, which may or may not be Oil and Gas Facilities, which will result in the area bearing a cumulative dust risk that could harm public health, safety, welfare, the environment, or wildlife resources, including impacts to plants, such as burial or significant damage to photosynthetic processes.

428. WELL CONTROL

a. The Operator will take all reasonable precautions, in addition to fully complying with Rule 417 to prevent any oil, gas or water well from flowing uncontrolled during Well operations and will take immediate steps and exercise due diligence to bring under control any such Well.

b. For controlled drilling events, a "significant" Well control event is a kick managed by shutting in the Well to circulate out the kick.

c. **Form 23, Well Control Report.** The Operator will report all uncontrolled events and any significant controlled events during a Well operation to the Director as soon as practicable, but no later than 24 hours following the incident. Within 15 days after these occurrences, the Operator will submit a Form 23, Well Control Report.

d. If required, the Operator will submit a Form 19, Spill/Release Report, for reportable Spills or Releases providing all details required on the form.

429. MEASUREMENT OF OIL

a. **General Standards.**

(1) **Measurement and Recording.** The volume of all oil production from a lease or a production unit will be measured and recorded prior to removal from the lease or production unit. The volume of production of oil will 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 1/4 inch of 100% capacity tables, subject to the following corrections in Rules 429.b & c below.

(2) **Incorporation by Reference.** This Rule 429 will be used consistently with standards established by the ASTM International ("ASTM"), the American Petroleum Institute ("API") Manual of Petroleum Measurement Standards, the American Gas Association ("AGA"), GPA Midstream ("GPA"), or other applicable standards-setting organizations, and pursuant to contractual rights or obligations. Only those editions of standards in effect as of January 15, 2021 apply to this Rule, later amendments do not apply. All materials incorporated by reference in this Rule 429 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. The materials may also be examined at any state publications depository library if the materials are not available online for free. In addition, these materials are available from the organizations at:

A. ASTM, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 19428-2959; https://www.astm.org/.

B. API, 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001-5571; https://www.api.org/.

C. AGA, 400 North Capitol Street, NW, Suite 450, Washington, DC 20001; https://www.aga.org/.

D. GPA, 6060 American Plaza, Suite 700, Tulsa, OK 74135, https://gpamidstream.org/.

b. **Correction for Impurities.** The percentage of impurities (water, sand, and other foreign substances not constituting a natural component part of the oil) will be determined to the satisfaction of the Director, and the observed gross volume of oil will be corrected to exclude the entire volume of such impurities.

c. Temperature Correction. The observed volume of oil corrected for impurities will be further corrected to the standard volume of sixty degrees Fahrenheit (60° F) pursuant to ASTM D1250-19e1, Standard Guide for Use of the Joint API and ASTM Adjunct for Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils (May 1, 2019), as incorporated by reference pursuant to Rule 429.a.(2) ("ASTM D1250"), or any close approximation thereof approved by the Director.

d. Gravity Determination. The gravity of oil at 60° F will be determined pursuant to Table 5 of ASTM D-1250, as incorporated by reference in Rule 429.c, or any close approximation thereof approved by the Director.

e. Tank Gauging. Measurement by Tank gauging will be completed pursuant to industry standards as specified in:

(1) API, Manual of Petroleum Measurement Standards, Chapter 3.1A: Standard Practice for the Manual Gauging of Petroleum and Petroleum Products (Third Edition, December 2018), as incorporated by reference pursuant to Rule 429.a.(2);

(2) API, Manual of Petroleum Measurement Standards, Chapter 3.1B: Standard Practice for the Manual Gauging of Petroleum and Petroleum Products (Third Edition, April 2018), as incorporated by reference pursuant to Rule 429.a.(2);

(3) API, Manual of Petroleum Measurement Standards, Chapter 18.1: Custody Transfer, Section 1: Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck (Third Edition, May 2018), as incorporated by reference pursuant to Rule 429.a.(2); or

(4) 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), as incorporated by reference pursuant to Rule 429.a.(2).

f. Metering Station. Measurement will be completed pursuant to industry standards as specified in the following chapters of the API Manual of Petroleum Measurement Standards, as incorporated by reference pursuant to Rule 429.a.(2):

(1) API, Manual of Petroleum Measurement Standards, Chapter 4: Proving Systems:

A. Chapter 4.2: Displacement Provers (Third Edition, September 2003, reaffirmed March 2011); and

B. Chapter 4.8: Operation of Proving Systems (Second Edition, September 2013);

(2) API, Manual of Petroleum Measurement Standards, Chapter 5: Metering:

A. Chapter 5.1: General Considerations for Measurement by Meters (Fourth Edition, September 2005, reaffirmed July 2016, including June 2008 and June 2011 errata);

B. Chapter 5.2: Measurement of Liquid Hydrocarbons by Displacement Meters (Third Edition, October 2005, reaffirmed July 2015);

C. Chapter 5.3: Measurement of Liquid Hydrocarbons by Turbine Meters (Fifth

Edition, September 2005, reaffirmed August 2014, including July 2009 Addendum 1);

D. Chapter 5.4: Accessory Equipment for Liquid Meters (Fourth Edition, September 2005, reaffirmed August 2015, including May 2015 errata);

E. Chapter 5.5: Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems (Second Edition, July 2005, reaffirmed August 2015); and

F. Chapter 5.6: Measurement of Liquid Hydrocarbons by Coriolis Meters (First Edition, October 2002, reaffirmed November 2013);

(3) API, Manual of Petroleum Measurement Standards, Chapter 7: Temperature Determination:

A. Chapter 7.1: Liquid-in-Glass Thermometers (Second edition, August 2017);

B. Chapter 7.2: Portable Electronic Thermometers (Third edition, May 2018);

C. Chapter 7.3: Fixed Automatic Tank Temperature Systems (Second edition, October 2011, reaffirmed December 2016); and

D. Chapter 7.4: Dynamic Temperature Measurement (Third edition, January 2018);

(4) API, Manual of Petroleum Measurement Standards, Chapter 8: Sampling:

A. Chapter 8.1: Standard Practice for Manual Sampling of Petroleum and Petroleum Products (Fifth Edition, September 2019); and

B. Chapter 8.2: Standard Practice for Automatic Sampling of Petroleum and Petroleum Productions (Fourth Edition, November 2016); and

(5) API, Manual of Petroleum Measurement Standards, Chapter 12, Calculation of Petroleum Quantities:

A. Chapter 12.1.1: Calculation of Static Petroleum Quantities, Part 1—Upright Cylindrical Tanks and Marine Vessels (Fourth Edition, February 2019).

g. **LACT Meters.** Measurement utilizing LACT units will be pursuant to industry specifications or standards as specified in API, Manual of Petroleum Measurement Standards, Chapter 6.1, Lease Automatic Custody Transfer (LACT) Systems (Second Edition, May 1991, reaffirmed December 2017), as incorporated by reference pursuant to Rule 429.a.(2).

h. **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, Payment of Proceeds – Sales Volume Reconciliation Payer Contact Form to the payer 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 payer will return the completed form to the payee within 60 days of receipt. Submittal of this form to the payer will 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 will use its best efforts to consult in good faith with the payee to resolve disputes regarding payment of proceeds or sales reconciliation.

i. A Form 37 requesting information concerning payment of proceeds or sales volume reconciliation may be submitted by the payee at any time. The Commission may act to prohibit or terminate any abuse of the reconciliation process.

j. Meter Calibration.

(1) Meters will be calibrated annually unless more frequent calibration is required by contractual obligations or by the Director. All calibration reports will be created, maintained, and made available as operation records pursuant to Rule 206. In the event two consecutive meter calibrations exceed a 2% error, the Operator will report the test results to the Director who may require the Operator to show cause why the meter should not be replaced.

(2) The Operator will conspicuously post and maintain the date of the last meter calibration in a legible condition at each meter at all times.

430. MEASUREMENT OF GAS

a. General Standards.

(1) Measurement and Reporting. The volume of all gas produced from a lease or a production unit will be measured and recorded prior to removal from the lease or production unit. Production of gas of all kinds will 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 will be 14.73 psia, regardless of atmospheric pressure at the point of measurement, and the standard temperature base will be 60° F. All volumes of gas to be reported to the Commission will 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.

(2) Incorporation by Reference. This Rule 430 will be used consistently with standards established by the ASTM, API, AGA, GPA, or other applicable standards-setting organizations, as incorporated by reference pursuant to Rule 429.a.(2), and pursuant to contractual rights and obligations.

b. Metering Station. Installation and operation of gas measurement stations will be pursuant to industry standards, as incorporated by reference pursuant to Rule 429.a.(2):

(1) API, Manual of Petroleum Measurement Standards, Chapter 14.3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-Edged Orifice Meters:

A. Part 2: Specification and Installation Requirements (Fifth Edition, March 2016 including March 2017 and January 2019 errata);

B. Part 3: Natural Gas Applications (Fourth Edition, November 2013); and

C. Part 4: Background, Development, Implementation Procedure, and Example Calculations (Fourth Edition, October 2019);

(2) API, Manual of Petroleum Measurement Standards, Chapter 21.1: Flow Measurement Using Electronic Metering Systems—Electronic Gas Measurement (Second Edition, February 2013);

(3) AGA, Report #7: Measurement of Natural Gas by Turbine Meters (January 2006);

(4) AGA, Report #9: Measurement of Gas by Multipath Ultrasonic Meters (July 2017); and

(5) AGA, Report #11: Measurement of Natural Gas by Coriolis Meter (February 2013).

c. Metering Equipment. The devices used to measure the differential, line pressure, and temperature will have accepted accuracy ratings established in industry standards as specified in API, Manual of Petroleum Measurement Standards, Chapter 22: Testing Protocols, as incorporated by reference pursuant to Rule 429.a.(2):

(1) Chapter 22.1: General Guidelines for Developing Testing Protocols for Devices Used in the Measurement of Hydrocarbon Fluids, (Second Edition, August 2015, including November 2018 Addendum 1); and

(2) Chapter 22.2: Testing Protocols—Differential Pressure Flow Measurement Devices (Second Edition, April 2017).

d. Meter Calibration.

(1) Meters will be calibrated annually unless more frequent calibration is required by contractual obligations or by the Director. All calibration reports will be created, maintained, and made available as operation records pursuant to Rule 206. In the event two consecutive meter calibrations exceed a 2% error, the Operator will report the test results to the Director who may require the Operator to show cause why the meter should not be replaced.

(2) The Operator will conspicuously post and maintain the date of the last meter calibration in a legible condition at each meter at all times.

e. Gas Quality. The heating value of produced natural gas will 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 will be reported on a Form 7. Gas sampling and analysis will occur annually unless more frequent sampling is required by contractual obligations or by the Director. Gas sampling, gas chromatography, and the resulting analysis data will be pursuant to industry standards, as incorporated by reference pursuant to Rule 429.a.(2):

(1) API, Manual of Petroleum Measurement Standards, Chapter 14.1: Collecting and Handling of Natural Gas Samples for Custody Transfer (Seventh Edition, May 2016, including August 2017 Addendum 1 and Errata 1);

(2) GPA, Standard 2166, Obtaining Natural Gas Samples for Analysis by Gas Chromatography (Fifth Edition, January 2017);

(3) GPA, Standard 2261, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (2019 Edition, January 2019);

(4) GPA, Standard 2286, Method for the Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Program Gas Chromatography (September 2014);

(5) GPA, Standard 2145, Table of the Physical Properties for Hydrocarbons and Other Compounds of Interest to Natural Gas and Natural Gas Liquids Industries (January

2016); and

(6) GPA, Standard 2172, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (February 2020).

f. **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 will return the completed form to the payee within 60 days of receipt. Submittal of this form to the payer will 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 will use its best efforts to consult in good faith with the payee to resolve disputes regarding payment of proceeds or sales reconciliation.

g. A Form 37 requesting information concerning payment of proceeds or requesting information concerning sales volume reconciliation may be submitted by the payee at any time. The Commission may act to prohibit or terminate any abuse of the reconciliation process.

431. MEASUREMENT AND REPORTING OF PRODUCED, REUSED, RECYCLED, AND INJECTED WATER

a. The volume of produced water will 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 1/4 inch of 100% capacity tables, or another method approved by the Director. If measurements are based on oil/water ratios, the oil/water ratio will 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. The volume of produced water will be reported on the Form 7.

b. On the Form 5 and the Form 5A Operators will report the volume in Barrels of the following Fluids used in drilling operations and Stimulation, respectively:

(1) Total Fluids;

(2) Fresh water; and

(3) Recycled or reused Fluids that offset the use of fresh water.

c. The volume of water injected into a Class II UIC Well will 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 1/4 inch of 100% capacity tables, or another method approved by the Director. If water is transported to an injection facility by means other than direct Pipeline, measurement of water is required by a properly calibrated meter. The Operator will conspicuously post and maintain the date of the last meter calibration in a legible condition at each meter at all times. The volume of injected water will be reported on the Form 7.

d. The volume of water injected and produced in Simultaneous Injection Wells will 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. The volumes of injected and produced water will be reported on the Form 7.

432. VACUUM PUMPS ON WELLS

a. 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 will be accompanied by an exhibit showing the location of all Wells on adjacent premises and all offset Wells on adjacent lands, and will set forth all material facts involved and the manner and method of installation proposed. Notice of the application will be given by the Applicant by registered or certified mail, or by delivering a copy of the application to each producer within 1/2 mile of the installation.

b. If no objection to a Rule 432.a application is filed by a producer within 1/2 mile of the installation, or by the Director, within 15 days of the date of application, the Director will approve the application. If an objection is filed by any producer within 1/2 mile of the installation, or the Director, the application will be brought to the Commission for hearing pursuant to Rule 510.

433. 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.

434. ABANDONMENT

The requirements for abandoning a Well are as follows:

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 408.e, and zones identified and approved on the Form 6, Well Abandonment Report – Notice of Intent to Abandon. 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 408.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 Form 6 and include an operations summary 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 pursuant to 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.

b. Temporary Abandonment.

(1) A Well may be temporarily abandoned after passing a successful mechanical integrity test pursuant to Rule 417 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 will remain in place. If an Operator requests temporary abandonment status in excess of 6 months the Operator will state the reason for requesting such extension and state plans for future operation. A 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 417.

(2) The manner in which the Well is to be maintained should be reported to the Commission, and bonding requirements, as provided for in the Commission's 700 Series Rules, kept in force until the permanent Plugging and Abandonment of the Well.

(3) An Operator will abandon any Well that 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 417, 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 417. Gas Storage Wells are to be considered active at all times unless physically plugged.

435. FORM 6, WELL ABANDONMENT REPORTS

a. Form 6, Notice of Intent to Abandon. Prior to the abandonment of a Well, a Form 6, Well Abandonment Report – 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.

(1) The Director may add any conditions of the approval to a Form 6 – Notice of Intent to Abandon that are necessary and reasonable to ensure compliance with all requirements of the Commission's Rules or to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) The Director will review the Oil and Gas Location where the Well is located to ensure that necessary and reasonable conditions of approval are applied to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(3) **Notice Requirements.** An Operator will provide notice of plugging operations to the Surface Owner pursuant to Rule 412.a.(4).

b. Form 6, Subsequent Report of Abandonment.

(1) Within 30 days after abandonment, the Form 6, Well Abandonment Report – 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 the 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 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 perform remedial cement work 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 210.

c. Re-Plugging. A Form 6 – Notice of Intent to Abandon will be submitted to, and approved by, the Director pursuant to Rules 435.a.(1)–(3) prior to the re-entry of a Plugged and Abandoned Well for the purpose of re-plugging the Well. A 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 216. The

Operator will report the accuracy value expressed in meters and the date of the GPS measurement on the Form 6.

436. SEISMIC OPERATIONS, NOTICE, CONSULTATION AND REPORTING

a. Surface Owner and Tenant Notice. At least 5 business days prior to commencing Seismic Operations, the Operator will notify all Surface Owners and tenants of the lands included within the seismic project boundary.

(1) Notice will include:

A. A description of the work being performed;

B. A detailed schedule of the operations;

C. Phone numbers that are monitored 24/7 and email addresses for the company and contractors performing the work; and

D. All safety precautions employed by the Operator and any safety precautions and information that Surface Owners and tenants should be aware of.

(2) Operators will provide notice to each Surface Owner or tenant individually by letter or door hanger.

(3) Operators are encouraged to post notice of planned Seismic Operations on neighborhood, community, or municipal websites. Operators are also encouraged to coordinate notice through Relevant Local Governments, home-owners' associations, or neighborhood associations. However, such additional notice will not relieve the Operator of its responsibilities under Rule 436.a.

b. Utility Owner Notice and Consultation. Prior to the commencement of any Seismic Operation, Operators will notify and consult with owners of all subsurface utilities, including gas service lines, gas transmission lines, electric, phone, cable, water, storm sewer, sanitary sewer, fiber optic lines, water wells, or other buried utilities in the area.

(1) Operators will locate all utilities prior to performing the survey.

(2) Operators will meet or consult with the utility operator to determine safe peak vibration limits (when vibroseis will be used) and setback distances from buried utilities. Operators will retain documentation demonstrating that they consulted with all utility Operators and that the utility agreed to specific peak vibration limits and setback distances (both laterally and vertically) for the utilities.

c. Upon a request from the Director, and within 5 days of said request, Operators will provide documentation demonstrating that they complied with Rules 436.a. & b.

d. Vibration Limits.

(1) Operators will determine in advance safe setback distances from both surface structures and subsurface utilities and structures.

(2) Operators will perform real time monitoring during vibroseis operations to verify and document that variable particle velocity versus frequency standards published in the U.S. Bureau of Mines, Report of Investigations 8507 (November 1980) are not exceeded. Only the 1980 version of U.S. Bureau of Mines' Report of Investigations

8507 applies; later versions do not apply. U.S. Bureau of Mines' Report of Investigations 8507 is available for 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, U.S. Bureau of Mines' Report of Investigations 8507 may be examined at the U.S. Department of the Interior, Office of Surface Mining Reclamation and Enforcement, 3 Parkway Center Pittsburgh, PA 15220, and is available at https://www.osmre.gov/resources/blasting/docs/USBM/RI8507BlastingVibration1989.pdf.

(3) Unless a lower limit is required by a utility owner or a Relevant Local Government, a peak vibration limit of 0.75 inches per second ("ips") will apply to surface structures and 2.0 ips will apply to subsurface utilities and structures.

e. Seismic Operations Requiring the Drilling of Shotholes.

(1) **Explosive Storage.** Operators will safely store and account for all explosives pursuant to local, state, and federal rules.

(2) **Blasting Safety Setbacks.** Operators will keep blasting a safe distance from a Building Unit, water well, or spring, 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

CHARGES IN LBS. GREATER THAN	CHARGES IN LBS. UP TO AND INCLUDING	MINIMUM SETBACK DISTANCE IN FEET
18	19	969
19	20	1000
20	n/a	1320

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

(4) **Drilling and Plugging.** Operators will adhere to the following standards for plugging shotholes unless the Operator obtains a variance pursuant to Rule 502 by demonstrating that another method will provide adequate protection to Groundwater 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 will be raked or otherwise spread out to at least within 1 inch of the surface, such that the growth of the natural grasses or foliage will not be impaired.

B. All shotholes will be preplugged or anchored to prevent public access if not immediately shot.

i. If a preplug does not hold, seismic holes will be properly Plugged and Abandoned as soon as practical after the shot has been fired. In no case will Operators leave a shothole unplugged for more than 30 days without the Director's approval.

ii. Shotholes will not be left open. Operators will cover shotholes with a tin hat or other similar cover until it can be properly plugged. The hats will be imprinted with the seismic contractor's name or identification number or mark.

C. Operators will fill holes to a depth of approximately 3 feet below ground level by returning the cuttings to the hole and tamping the returned cuttings to ensure the hole is not bridged.

i. Operators will set a non-metallic perma-plug either imprinted or tagged with the Operator's name or the identification number or mark described in the Form 20, Permit to Conduct Seismic Operations at a depth of 3 feet.

ii. Operators will fill the remaining hole and tamp it to the surface with cuttings and native soil. Operators will leave a sufficient mound of native soil over the hole to allow for settling.

D. If Operators encounter non-artesian Groundwater while drilling seismic shotholes:

i. Operators will fill the holes from the bottom up with a high-grade coarse ground bentonite to 10 feet above the static water level or to a depth of 3 feet from the surface.

ii. Operators will fill the remaining hole and tamp it to the surface with cuttings and native soil, unless the Operator otherwise demonstrates to the Director's satisfaction that use of another suitable plugging material may be substituted for bentonite without harm to Groundwater resources.

E. If artesian Groundwater (Groundwater rising above the depth at which encountered) is encountered in the drilling of any seismic hole, cement or high grade coarse ground bentonite will 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 50 feet above the top of the water-bearing material, thereby preventing cross-flow between Groundwater, erosion, or contamination of fresh water supplies. Such holes will be plugged immediately.

f. Form 20A, Completion Report for Seismic Operations.

(1) If any portion of the seismic project is conducted, the Operator will submit a Form 20A, Completion Report for Seismic Operations to the Director within 60 days after completion of the permitted seismic project.

(2) The Form 20A will include the following:

A. A map in a suitable size and scale to show the actual project boundary, energy source locations, and receiver locations with sections, townships, and ranges, county and municipal boundaries, and High Priority Habitat.

B. GIS data for the actual project boundary, energy source points, and receiver locations in a format approved by the Director.

C. The results of the real time monitoring required by Rule 436.d.(2).

(3) If the program included any shotholes, the Form 20A will include:

A. Any shotholes encountering artesian water on the map;

B. A certification by the party responsible for plugging the holes that all shotholes are plugged as prescribed by the Commission's Rules; and

(4) If the permitted seismic project is not conducted prior to the expiration of the Form 20, the Operator will submit a Form 20A within 30 days of said expiration certifying that no Seismic Operations were conducted. If an Operator submits a Refile Form 20 within 30 days of the expiration of the Form 20, a Form 20A certifying no Seismic Operations were conducted is not required.

g. Financial Assurance Requirements. The Operator will file Financial Assurance pursuant to Rule 705 prior to submitting the Form 20. The Financial Assurance will remain in effect until the following conditions have been met:

(1) The Operator has submitted and the Director has approved the Form 20A for all Seismic Operations covered by the Financial Assurance;

(2) All shotholes have been properly Plugged and Abandoned, and all surface disturbance has been reclaimed pursuant to Rule 436.h;

(3) All complaints received from Surface Owners have been investigated, addressed, and resolved by the Director pursuant to Rule 524;

(4) The Operator has submitted a written request for release of Financial Assurance to the Director; and

(5) The Reclamation required by Rule 436.h has been completed.

h. **Reclamation Requirements.** Upon completion of Seismic Operations, the Operator will restore the surface of the land as nearly as possible 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, trash, or other materials associated with Seismic Operations will be removed.

437. Hydraulic Fracturing Chemical Additives.

a. **Effective Date.** After January 15, 2021, Operators will not use the chemicals listed in Table 437-1 as additives in Hydraulic Fracturing Fluid.

b. This Rule 437 does not prevent Operators from recycling or reusing produced water that has naturally occurring, trace amounts of chemicals listed in Table 437-1.

c. For any chemical constituent listed in Table 437-1 for which Table 915-1 also provides a standard, the concentration in recycled or reused produced water will be below the Table 915-1 standard, or the unconcentrated naturally occurring background level, whichever is greater.

TABLE 437-1. Chemical Additives Prohibited in Hydraulic Fracturing Fluid

Ingredient Name	CAS #
Benzene	71-43-2
Lead	7439-92-1
Mercury	7439-97-6
Arsenic	740-38-2
Cadmium	7440-43-9
Chromium	7440-47-3
Ethylbenzene	100-41-4
Xylene	1330-20-7
1,3,5-trimethylbenzene	108-67-8
1,4-dioxane	123-91-1
1-butanol	71-36-3
2-butoxyethanol	111-76-2
N,N-dimethylformamide	68-12-2
2-ethylhexanol	104-76-7
2-mercaptoethanol	60-24-2
benzene, 1,1’-oxybis-,tetrapropylene derivatives, sulfonated, sodium salts (BOTS)	119345-04-9
butyl glycidyl ether	8-6-2426
Quaternary ammonium compounds, dicoco alkyldimethyl, chlorides (QAC)	61789-77-3
Bis hexamethylene triamine penta methylene phosphonic acid (BMPA)	35657-77-3
Diethylenetriamine penta (methylene- phosphonic acid) (DMPA)	15827-60-8
FD&C blue no. 1	3844-45-9
Tetrakis (triethanolaminato) zirconium (IV) (TTZ)	101033-44-7

RULES OF PRACTICE AND PROCEDURE
500 SERIES

501. APPLICABILITY OF RULES OF PRACTICE AND PROCEDURE

a. General. The Commission’s 500 Series 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. The Commission’s Rules will be liberally construed to secure the just, speedy, and inexpensive determination of all issues presented to the Commission, Administrative Law Judges, and Hearing Officers.

b. Prohibition of Abuse. Notwithstanding any provision of the Commission’s Rules, the Commission, 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, petitioner, witness, or party offering a statement pursuant to Rule 512 in a proceeding. Such action may include, but is not limited to: summary dismissal of the application, petition, 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, Administrative Law Judge, or Hearing Officer to be an abuse of process.

c. Before the Commission adopts any Rule or regulation, 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 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 the Commission’s Rules. The foregoing will not apply to recommended orders of uncontested matters, the issuance of an Emergency Order, Notice of Alleged Violation (“NOAV”), or Cease and Desist Order.

d. Judicial Review. Any Rule, regulation, permit, or final order of the Commission, whether approved by the Director or the Commission, is subject to judicial review pursuant to the provisions of the Administrative Procedure Act, §§ 24-4-101–108, C.R.S. The statutory time period for filing a notice of appeal from any Commission decision commences pursuant to § 24-4-106(4), C.R.S.

502. VARIANCES

a. Variances. Requests for variances to any of the Commission’s Rules or orders will be filed with the Commission.

b. Director Recommended Variances. Variances seeking relief from the ministerial application of a Commission Rule or order may be recommended for approval by the Director. If the application for a variance is uncontested, the Commission will consider the Director’s recommendation pursuant to Rule 508. If the Director determines that an application for a variance is not ministerial or implicates public health, safety, welfare, the environment, or wildlife resources, the Director will refer the application to the Commission for hearing pursuant to Rule 510.

(1) Variances Sought from Commission. Variances to any of the Commission’s Rules or orders not applied for pursuant to Rule 502.b may be granted by the Commission after a hearing upon the application.

(2) For purposes of seeking a variance from the Commission, only the Operator or an Applicant authorized by the Commission's Rules may file an application seeking the Commission's approval of a variance.

c. The Operator or the Applicant requesting a variance pursuant to Rule 502.a will make a showing that:

(1) It has made a good faith effort to comply, or is unable to comply, with the specific requirements contained in the Commission's Rule or order from which it seeks a variance, including, without limitation, securing a waiver or an exception, if any;

(2) That the requested variance will not violate the basic intent of the Act;

(3) The requested variance is necessary to avoid an undue hardship;

(4) Granting the variance will result in no net adverse impact to public health, safety, welfare, the environment, or wildlife resources; and

(5) The requested variance contains reasonable conditions of approval or other mitigation measures to avoid, minimize, or mitigate adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

d. No variance to the Commission's 800 Series Rules will be granted without consultation with the EPA.

e. Notice of all granted variances also will be posted on the Commission's website.

503. APPLICATIONS FOR A HEARING BEFORE THE COMMISSION

a. Commission's Own Motion. The Commission may, on its own motion, initiate proceedings upon any question relating to 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 15 days. Notice of an Emergency Order will be given as soon as practicable after issuance.

b. All proceedings that require a Commission decision, other than those initiated by the Commission, will be commenced by filing an application for a hearing before the Commission.

c. All applications will include at a minimum:

(1) The Applicant's name and email address;

(2) If the Applicant is an Operator registered with the Commission, the Operator's Commission identification number;

(3) Identification of the type of application submitted;

(4) All geologic formations, if necessary for adjudication of the application;

(5) The location of applicable lands (including county, Field name, Township / Range / Section, and nearby public crossroads) and map of the same;

(6) The name and contact information (including email) for an Operator or Applicant representative designated to receive questions and petitions;

(7) A description of the relief requested, set forth in reasonable detail;

(8) The legal and factual grounds for the requested relief;

(9) A prayer for relief;

(10) If applicable, the name, mailing address, phone number, and email address of the Applicant's legal counsel;

(11) The name of each person entitled to receive notice of the application under the Commission's Rules; and

(12) Any information required by the Commission's Rules that is specific to the application.

d. All applications 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.

e. The originally signed application will be maintained by the filing party. The electronically submitted application, and all subsequent documents submitted, are Commission public records.

f. Each application, except those filed by a Governmental Agency or the Commission, will be accompanied by a docket fee established by the Commission (see Appendix III).

g. Commission Application Types. The following applications may be filed with the Commission for adjudication:

(1) **Oil and Gas Development Plan.** An Oil and Gas Development Plan application will satisfy the requirements set forth in Rule 303. Only an Owner or Operator within the proposed Oil and Gas Development Plan may file an Oil and Gas Development Plan.

(2) **Drilling Units.** Pursuant to Rule 305, applications for the creation of drilling units, additional Wells within existing drilling units, other applications for modifications to existing drilling unit orders, or applications for exception locations not subject to Rule 401.c. Only an Owner or Operator within the proposed or existing unit may file an application pursuant to this Rule 503.g.(2).

(3) **Pooling and Unitization Applications.** A statutory pooling application filed pursuant to § 34-60-116, C.R.S., or a unitization application filed pursuant to § 34-60-118, C.R.S. Unitization applications will satisfy the information requirements set forth in Rule 505. Statutory pooling applications will satisfy the information requirements set forth in Rules 505 & 506.

(4) **Order Finding Violation.** An Order Finding Violation ("OFV") application will include the NOAV. Only the Director may be the Applicant for an OFV.

(5) **Payment of Proceeds.** A payment of proceeds application will satisfy the information requirements set forth in Rules 429 or 430, and will be submitted on a Form 38, Payment of Proceeds Hearing Request.

(6) **School and Child Care Center Setbacks.** A School and Child Care Center setback application will satisfy the information requirements set forth in Rule 604.a.(3).

(7) **Petition for Review.** A complainant's Petition for Review will satisfy the requirements of Rule 524.e.

(8) **Comprehensive Area Plan.** A Comprehensive Area Plan will satisfy the requirements of Rule 314. Only an Owner or Operator may file a Comprehensive Area Plan.

(9) **Variances.** An application for a variance will satisfy the requirements of Rule 502.

(10) Any person may seek relief or a ruling from the Commission on any other matter not described in Rule 503.g.(1)–(9) above. Rulemaking petitions are not relief or rulings covered by this Rule 503.g.(10) and may be filed by any person pursuant to Rule 529.b.

h. Unless provided for in the Commission's Rules, or 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 will 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 Area Plans filed pursuant to Rule 314;

(2) Applications seeking a hearing pursuant to Rules 604.a.(3) or 604.b.(4);

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

(4) Rulemaking proceedings held pursuant to Rule 529.

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

j. A party filing an application may amend its application at any time prior to notice being sent consistent with Rule 504. A material amendment is a change that substantially 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.

k. Upon the acceptance of an application:

(1) Commission Staff will assign the application a docket number; and

(2) The matter will be set for hearing, and notice of that hearing will be given pursuant to Rule 504.

l. The Commission, Administrative Law Judge, or Hearing Officer will grant the first request by an Applicant for a continuance of any uncontested application. The Commission, Administrative Law Judge, or Hearing Officer has discretion to grant or deny subsequent requests for a continuance of an uncontested application.

m. Commission Staff will evaluate all applications, which may include a recommendation on the merits of the application. Any such recommendation will be part of the administrative record to be considered by the Commission, Administrative Law Judge, or Hearing Officer.

n. 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 parties, pursuant to Rule 522.

504. 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 504.b–f at least 60 days in advance of the noticed hearing date. Notice will be provided pursuant to 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. The Applicant is responsible for service and publication of required notices, including any related costs.

A. If the application is for an Oil and Gas Development Plan, the Operator will comply with the notice provisions of Rule 303.e prior to a hearing on the Oil and Gas Development Plan.

(2) No later than 30 days before the noticed hearing date, the Applicant will submit to the Secretary:

A. A certificate of service demonstrating that the Applicant served a copy of the application and notice on all persons entitled to notice pursuant to the Commission's Rules. The certificate of service will include a list of all persons who received a copy of the application and notice, including identification of mailed notices returned to the Applicant as undeliverable; and

B. A notarized affidavit providing assurance that the Applicant published a copy of the notice in a newspaper of general circulation in the county where the land affected is situated, 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 Rule 507 petition deadline, at least 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.

(4) Notice by publication or notice by electronic mail provided pursuant to this subsection does not confer Affected Person status on any person.

b. Notice for Specific Applications.

(1) **Applications for Oil and Gas Development Plans.** Oil and Gas Development Plan applications will be served on all persons identified in Rules 303.d.(2) and 303.e.(1).

(2) **Applications related to Drilling Units.** For purposes of applications for drilling units, additional Wells within existing drilling units, or other applications for modifications of, or exceptions to, existing drilling unit orders but not including applications subject to Rule 504.b.(6), the application and notice will be served on the leasehold interest owners and any unleased mineral Owners within the proposed drilling unit or within the existing drilling unit to be affected by the applications. The persons identified in Rule 303.d.(2) will also receive notice of such an application.

(3) **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.

(4) **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 mile of the tract or tracts to be unitized.

(5) **Applications Changing Certain Well Completion Setbacks.** For purposes of applications that change the ordered minimum Well completion setbacks for Drilling and Spacing Unit boundaries, the application and notice will be served on those Owners of Cornering and Contiguous Units or tracts who may be affected by such change, 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.

(6) **Applications for Well Completion Exception.** For purposes of applications for exceptions to Rules 401.a & b not granted pursuant to Rule 401.c, the application and notice will be served on the Owners of any Cornering and Contiguous Units or tracts upon which the Well completion location is encroaching, provided that when the Applicant owns any interest covering such tract or unit, the person who owns the mineral estate underlying the tract covered by such lease will also be notified.

(7) **Applications for Variances.** For purposes of requesting a variance pursuant to Rule 502, the application and notice will be served on the Director and the Relevant Local Government. Upon review of the application, the Director may request, and the Secretary has discretion to require, that notice be served on any necessary person based on the person’s potential legal interest or the potential impact of the variance. A necessary person may include but is not limited to a potentially impacted Governmental Agency, potentially impacted Surface Owner, or other potentially impacted person. For any variance requested as part of an application subject to Rules 504.b.(1)–(6), no additional notice will be required.

(8) **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.

(9) **Orders Related to Violations.** With respect to the resolution of an NOAV, the application and notice will be provided to a relevant complainant (if any), to the alleged violator or alleged Responsible Party, or Operator, as applicable, and by publication pursuant to § 34-60-108(4), C.R.S.

c. **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.

d. **Notice to Colorado Parks and Wildlife.** The application and notice will also be given to CPW for all applications where CPW maintains a mineral ownership included in the application lands.

e. Notice to Tribal Governments. The application and notice will also be given to the Southern Ute Indian Tribe or the Ute Mountain Ute Tribe for all applications involving minerals within the exterior boundary of either tribe's reservation where both the surface and oil and gas estates are owned in fee by persons or entities other than the Tribe.

f. Notice to the Bureau of Land Management. The application and notice will also be given to the Bureau of Land Management for all applications where the Bureau of Land Management maintains or manages a mineral or surface ownership included in the application lands.

505. EVIDENCE IN SUPPORT OF AN APPLICATION

Applicants seeking relief under Rules 503.g.(1)–(7) will submit the documents described in Rules 505.a–e below to the Commission with its application. The Commission, 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 Commission, Administrative Law Judge, or Hearing Officer's discretion.

a. Sworn written testimony, of relevant witnesses verifying land, geologic, engineering, public health, safety, welfare, the environment, and wildlife facts, or such other facts and testimony as may be required by the Commission's Rules. Geologic and engineering written testimony are not required for a statutory pooling application filed pursuant to Rule 503.g.(3), or a variance application filed pursuant to Rule 502.a. Such testimony will be accompanied by attachments or exhibits that adequately support and are specific to the relief requested in the application, along with resumes/curricula vitae for each witness.

b. 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.

c. 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.

d. 1 set of exhibits which will contain relevant highlights in bullet-point format on each exhibit.

e. 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, the environment and wildlife, and other appropriate subjects to support the relief requested in the application. Geologic and engineering evidence are not required for a Rule 503.g.(3) order. Reference to testimony, exhibits, and previous Commission orders will be included as findings in the draft proposed order.

506. INVOLUNTARY POOLING APPLICATIONS

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 45% 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 90 days in advance of the date the matter is to be heard by the Commission, pursuant to Rule 510. 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 45% mineral interest threshold is met.

b. The Commission will receive evidence that Owners were tendered a good faith, reasonable offer to lease or participate no less than 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 506, "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 the Commission's 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 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 will 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", and "LL");

B. The estimated drilling and completion cost in dollars 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.

(2) 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.

(3) If, after receiving a good faith offer to lease and given at least 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 pursuant to § 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.

(4) For an offer to lease to be considered reasonable and have been made in good faith, the offer will 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 to cost recovery pursuant to § 34-60-116(7)(b), C.R.S.

e. All offers to lease or participate will 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.

507. CONTESTED HEARING APPLICATIONS

a. A person who may be adversely affected or aggrieved by an application may submit a petition to the Commission as an Affected Person to participate formally as a party in an adjudicatory proceeding. The petition will set forth a brief and plain statement of the facts which entitle that person to be admitted and the matters that the person claim should be decided. The Commission, Administrative Law Judge, or Hearing Officer may admit any person or agency as a party to the proceeding for limited purposes.

(1) Federal agencies, state agencies, tribal governments, Relevant Local Governments, and special districts with legal authority over the application are Affected Persons.

(2) For purposes of an application filed pursuant to Rule 503.g.(1), Surface Owners and residents (including owners and tenants) of Building Units located within 2,000 feet of a proposed Working Pad Surface are Affected Persons.

(3) For all persons other than those listed in Rules 507.a.(1) & (2), the person's petition will:

A. Identify an interest in the activity that is adversely affected by the proposed activity;

B. Allege such interest could be an injury-in-fact if the application is granted; and

C. Demonstrate that the injury alleged is not common to members of the general public.

(4) When determining if a person is an Affected Person all relevant factors will be considered, including, but not limited to, the following:

A. Whether the interest claimed is one protected or adversely affected by the application;

B. Whether a reasonable relationship exists between the interest claimed and the activity regulated;

C. Likely impacts and magnitude of impacts of the regulated activity on the health, safety, welfare, or use of property of the person;

D. Likely impacts of the regulated activity on the impacted natural resources or wildlife used or enjoyed by the person; or

E. For a Governmental Agency not identified in Rule 507.a.(1), its legal authority over or interest in the issues relevant to the application.

b. For purposes of an application filed pursuant to Rule 503.g.(2), only a mineral Owner within the unit, Relevant Local Government, CDPHE, or CPW may file a petition.

c. A petition filed by the Relevant Local Government, CDPHE, or CPW will be granted.

d. The petition will be filed with the Commission and served on the Applicant's counsel, if the Applicant is represented by counsel, at least 30 days before the hearing. If the Applicant is not represented by counsel, service will be made on the Applicant.

e. Pursuant to Rule 510.l, the filing deadline for the filing of petitions may be extended for good cause upon any continuance of a hearing.

f. All petitions will include:

(1) The application docket number;

(2) A general statement of the factual or legal basis for the petition based on the application;

(3) A statement and support for why the person filing the petition meets the definition of an Affected Person;

(4) A statement of the relief requested;

(5) A written description of the case the Affected Person plans to present to the Commission including a list of proposed witnesses;

(6) A time estimate to hear the petition;

(7) A certificate of service attesting that the pleading has been served on the Applicant and any other party in the proceeding; and

(8) If applicable, the name, mailing address, phone number, and email address of the petitioner's legal counsel or the petitioner themselves if not represented by legal counsel.

g. The Commission, Administrative Law Judge, or Hearing Officer may require any additional information necessary pursuant to the Commission's Rules to ensure the petition is complete. The Commission, Administrative Law Judge, or Hearing Officer has the discretion to summarily dismiss without prejudice any petition that does not meet the informational requirements set forth in this Rule.

508. UNCONTESTED HEARING APPLICATIONS

a. If a matter is uncontested, the Applicant may request from the Commission, Administrative Law Judge, or Hearing Officer 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 request to approve the application without hearing is not approved, the applicant may request an administrative hearing before an Administrative Law Judge or Hearing Officer on the application. For purposes of this Rule 508, an uncontested matter will mean any application that is not subject to a petition objecting to the relief requested in the application and additionally will include matters in which all interested parties have consented in writing to the granting of the application without a hearing.

b. 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.

509. PREHEARING PROCEDURES FOR CONTESTED APPLICATIONS

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, Administrative Law Judge, or Hearing Officer upon receipt of a petition, an enforcement matter, or upon the request of the Applicant or any person who has filed a petition. For matters in which staff is a party or a staff analysis has been prepared, the Director will participate in the prehearing conference to advise the parties of the content of staff's analysis. The prehearing conference will be conducted under the following general guidelines.

b. The Commission, Administrative Law Judge, or Hearing Officer will enter a case management order that establishes:

(1) The hearing schedule;

(2) The filing deadlines;

(3) Whether discovery is permitted; and

(4) Any other procedural matters.

c. An Administrative Law Judge or Hearing Officer will preside over any prehearing conference and rule on preliminary matters.

d. The Secretary, Administrative Law Judge, or Hearing Officer will notify the Applicant and any person who has filed a petition of the prehearing conference, and will direct the attorneys for the parties, and parties who are not represented by an attorney, to appear in order to expedite the hearing, settle issues, or both.

e. All parties will be prepared to discuss all procedural and substantive issues and will be authorized to make binding commitments.

f. Preparation should include advance study of all materials filed and, if discovery is permitted pursuant to Rule 509.b.(3), such materials obtained through discovery.

g. Failure of a party to attend any hearing other than a rulemaking hearing, 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 hearing, including the entry of a default judgment or the dismissal of a petition.

h. A prehearing statement may be required of any party.

i. 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) If a party seeks additional discovery beyond what was permitted by Rule 509.b.(3), a 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.

j. 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.

k. 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.

l. It is the intent of this Rule 509 that a prehearing order will be binding upon the participating parties.

m. Subsequent to the prehearing conference and prior to the hearing on a contested matter, the parties may be asked to each prepare and submit to the Administrative Law Judge or Hearing Officer a recommended order to consider for adoption at the time of hearing.

510. HEARINGS

a. The Applicant, as the proponent of the order, has the burden of proof. Any party to the proceeding has the right to present its case or defense, including any affirmative defenses, by oral and documentary evidence, submit rebuttal evidence, and to conduct cross examination as the Commission, Administrative Law Judge, or Hearing Officer determines is required for the full and true disclosure of the facts.

b. 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.

c. A case management order, issued by the Commission, Administrative Law Judge, or Hearing Officer, will govern all hearings, including rulemaking hearings.

d. Administrative Hearings in Uncontested Applications.

(1) As to applications where there has been no petition filed with the Commission pursuant to Rule 507, 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 date a petition filed pursuant to Rule 507.d is filed, but no recommended order will issue until the Administrative Law Judge or Hearing Officer has fully considered any timely and properly filed petition.

(2) An Administrative Law Judge or Hearing Officer 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.

e. Hearings in Contested Applications. Every party will have the right to present its case at hearing by oral and documentary evidence. A case management order, issued by the Commission, Administrative Law Judge, or Hearing Officer, will govern the hearing of a contested application.

f. Order Finding Violation Hearing.

(1) An OFV hearing will be held before the Commission, Administrative Law Judge, or Hearing Officer when:

A. The enforcement matter cannot be resolved through an Administrative Order by Consent ("AOC"); and

B. For any enforcement actions governed by Rule 525.d.(1).

(2) OFV hearings for enforcement actions not governed by Rule 525.d.(1) 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, unless continued by the Commission, Administrative Law Judge, or Hearing Officer.

(3) The Commission may commence an OFV hearing on its own motion, with notice pursuant to Rule 504, if it believes the Director has failed to enforce a provision of the Act, or a Commission Rule, order, or permit.

(4) OFV hearings are *de novo* proceedings.

g. Hearing on Complainant's Petition for Review.

(1) The Commission's hearing on a complainant's Petition for Review pursuant to Rule 524.c will be limited to evidence and information entered into the record prior to the Director's contested decision, and any evidence or information received and considered by the Director following an order from the Commission, Administrative Law Judge, or Hearing Officer. No party to the Petition for Review hearing may present evidence or information that was not previously presented to the Director.

(2) It is the complainant's burden to show the Director's action was clearly erroneous.

A. If the Commission, Administrative Law Judge, or Hearing Officer finds that the Director's action was clearly erroneous, they may remand the matter to the Director for further proceedings, or order other such relief deemed just and reasonable.

B. If the complainant fails to meet its burden, the Commission, Administrative Law Judge, or Hearing Officer will deny the Petition for Review, and act on the final proposed AOC pursuant to Rule 523.d.(1).C.

h. Rulemaking Hearings. All rulemaking proceedings will be held pursuant to Rule 529.

i. Witnesses. Any witness at a hearing will take an oath or affirmation before testifying. After a witness has testified, the Applicant, the petitioner, 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.

j. Limitations of Testimony.

(1) Testimony and cross-examination by a petitioner will be limited to those issues that reasonably relate to the interests that the petitioner seeks to protect, and which may be adversely affected by an order of the Commission, as determined by the Commission, Administrative Law Judge, or Hearing Officer.

(2) Where two or more petitioners 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 petitioners. The Commission may also limit testimony to avoid undue delay, waste of time, or needless presentation of cumulative evidence.

k. 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.

l. The Commission, Secretary, Administrative Law Judge, or Hearing Officer may for good cause cancel, stay, or continue any hearing to another date. Upon continuance of a hearing, the deadline for filing a petition to contest an application pursuant to Rule 507, or any other required deadline under the Commission's Rules, maybe extended for good cause by the Commission, Administrative Law Judge, or Hearing Officer.

m. 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.

511. LOCAL PUBLIC HEARING

a. Any person may request the Commission hold a local public hearing to gather feedback from the local community, including elected officials and Local Government officials, on a proposed Oil and Gas Development Plan or Comprehensive Area Plan. The Commission will decide whether to grant all requests for a Local Public Hearing. The Commission has discretion to decline a request for a Local Public Hearing, or in the alternative hold the local public hearing at the Commission's offices. The Commission may choose to hold a Local Public Hearing on its own motion. The Commission also has the discretion to designate a single Commissioner, Administrative Law Judge, or Hearing Officer to preside at the local public hearing.

b. A request for a local public hearing will be in writing, and will include the docket number for the relevant plan. The request for a local public hearing will state with reasonable specificity the reasons why the Commission should hold a local public hearing.

c. The conduct of a local public hearing will be informal, and participants will not be required to be sworn in prior to making a statement, represented by attorneys, or subjected to cross-examination.

d. The Applicant may participate in the local public hearing and present information related to the application.

e. The Director will create a record of the local public hearing by video recording, audio recording, or court reporter. Such record will be available to all Commissioners for review prior to the hearing on the Plan application.

f. Issues raised in a local public hearing may include any topic relevant to the proposed Oil and Gas Development Plan or Comprehensive Area Plan.

512. PUBLIC COMMENT

a. The Commission may accept oral or written comments from the public about any matter during a time specified for general public comment by the Commission.

b. If the Commission, Administrative Law Judge, or Hearing Officer receives public comments concerning an adjudicatory proceeding to be heard, the public comments will be included in the administrative record for the adjudicatory proceeding.

c. Parties to a proceeding may not provide public comment in that proceeding; they are not considered part of the public for comment purposes.

513. COMMISSION MEMBERS REQUIRED FOR HEARINGS AND/OR DECISIONS

A majority of the voting Commissioners constitutes a quorum and is required 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.

514. STANDARDS OF CONDUCT

a. The purpose of this Rule 514 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 514 are in addition to the requirements for Commission members set forth in § 24-18-101 *et seq.*, C.R.S. This Rule 514 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; and

(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 person's ability to participate objectively in an official act.

(1) A Commissioner, Administrative Law Judge, or 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 petitioner, any parties to the proceeding, 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 will vote on whether a conflict of interest exists. Such vote will be binding on the Commissioner with 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; and

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 its official duties, the Commission, Administrative Law Judge, and Hearing Officer will apply the following standards:

(1) To be faithful to and constantly strive to improve its competence in statutory and 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 it;

(3) To be patient, dignified, and courteous, and to require similar conduct of attorneys, staff, and others subject to its direction and control;

(4) To afford to every person who is legally interested in a proceeding full right to be heard according to law; and

(5) To diligently discharge its administrative responsibilities, maintain professional confidence in Commission administration, and facilitate the performance of the administrative responsibilities of other staff officials.

515. REPRESENTATION AT ADMINISTRATIVE AND COMMISSION HEARINGS

a. Natural persons may appear on their own behalf and represent themselves at hearings before the Commission. Participants who are not represented by legal counsel are subject to the Commission's Rules.

b. Persons allowed to make oral or written statements pursuant to Rule 512 may do so, on their own behalf or on behalf of an organization or entity they are duly authorized to represent, without counsel.

c. Except as provided in Rules 515 a, b, & d, representation at hearings before the Commission will be by attorneys licensed to practice law in the State of Colorado. 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; and

(2) Is a resident of Colorado; or

(3) Maintains a law office within Colorado.

d. The Commission will allow representation by a corporate officer or director of a community organization, a closely held entity, a citizens' group, or if a limited liability corporation, the member or manager in the following circumstances:

(1) Rulemakings;

(2) Local public hearings; or

(3) When an individual is appearing on behalf of a closely held corporation pursuant to § 13-1-127, C.R.S.

e. Unless a non-attorney is appearing pursuant to Rules 515.a, b, or d, or the Director is participating pursuant to Rules 510.f or g, 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.

516. SUBPOENAS

The Commission, Administrative Law Judge, or Hearing Officer may 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 pursuant to the Colorado Rules of Civil Procedure. A party seeking a subpoena will submit the form of the subpoena for execution. Upon execution, the party requesting the subpoena has the responsibility to serve the subpoena pursuant to the Colorado Rules of Civil Procedure.

517. APPLICABILITY OF COLORADO COURT RULES AND ADMINISTRATIVE NOTICE

a. The Colorado Rules of Civil Procedure apply to Commission proceedings unless they are inconsistent with the Commission's Rules or the 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 Colorado Rules of Evidence applicable before a trial court without a jury will be applicable in matters before the Commission, 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, tribe, and of the United States;

(2) Rules, regulations, official reports, decisions, and orders of local, state, and federal administrative agencies;

(3) Decisions and orders of federal and state courts;

(4) Commission and Commission Staff reports, data, files, documents, and records;

(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 case; and

(7) Matters within the expertise of the Commission or Commission Staff.

d. Upon receipt of an objection to any discovery issued pursuant to Rule 509.b.(3), the Commission, Administrative Law Judge, or 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.

518. ELECTRONIC FILING

a. All applications, pleadings, petitions, or documents filed pursuant to the Commission’s Rules will be submitted electronically in a manner determined by the Director.

b. All applications, pleadings, petitions, or documents filed pursuant to the Commission’s Rules will be accompanied by a docket fee established by the Commission (see Appendix III). No docket fees will be assessed on filings made by Commission Staff or Governmental Agencies. The docket fee will be refunded if a petition is denied. In cases of hardship, the Commission or Director may, in its discretion waive the docket fee.

519. 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 520.b.

(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.

520. INTERIM DECISIONS, RECOMMENDED 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. A Hearing Officer or Administrative Law Judge's decision on a motion to dismiss is an interim decision, unless an application is dismissed in part or in its entirety.

(2) Interim decisions will 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 520.a 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 Commission Rule, permit, or order made pursuant thereto. The Administrative Law Judge or Hearing Officer will promptly transmit electronically 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 20 days after service upon the parties and the Commission does not stay the recommended order on its own motion.

c. Exceptions. Pursuant to § 34-60-108(9), C.R.S., a recommended order becomes the Commission's final order unless, within 20 days or such additional time as the Commission may allow, any party or person whose petition to participate in the matter was denied 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 14 days following service of the exceptions.

(1) 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.

(2) The Commission may, upon its own motion or upon the motion of a party, order oral argument regarding exceptions. The Secretary will 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 or Hearing Officer's recommended order will be an initial decision for purposes of filing an exception pursuant to the state Administrative Procedure Act.

521. 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 Commission Rule, permit, or order made pursuant thereto.

b. Commission orders will be entered within 30 days after the hearing pursuant to § 34-60-108(7), C.R.S. Orders will be final upon Commission approval and effective for purposes of judicial review on the date of electronic delivery or mailing.

522. SERVICE

a. A person filing any application, petition, pleading, or other document will serve a copy, including all supporting attachments or exhibits, on every other party in the docketed matter. Service of all pleadings or other documents will be accomplished electronically in a manner determined by the Director.

b. Enforcement Documents. The Director will serve an NOAV, a Notice of Hearing of an enforcement action, or an OFV 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 205. All other documents in enforcement cases will be served electronically in a manner determined by the Director.

c. Complainant. Notice to a complainant 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 5 days after mailing.

d. Petitions for Review. A Petition for Review by a complainant will be served on the Operator or the Operator's Designated Agent to the address on file with the Commission electronically in a manner as determined by the Director. If the complainant is unable to serve the Petition for Review electronically, the complainant will serve it by certified mail, return receipt requested. A complainant will serve its Petition for Review on the Operator within 7 days following filing of the petition. All other documents in a Petition for Review proceeding will be served on all parties electronically (unless previously objected to by a party).

e. Cease and Desist Orders. In Emergency Situations, a Cease and Desist Order may be served electronically in a manner as determined by the Director, 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 205.

f. Service by Certified Mail. When service is accomplished through certified mail it will be perfected at the earliest of:

(1) The date of receipt;

(2) The date shown on the return receipt; or

(3) 5 days after mailing.

g. Service by First Class Mail. If a party or person lacks access to file or receive documents electronically in a manner as determined by the Director, service will be made by first class mail. When service is accomplished through first class mail, it is perfected 5 days after mailing. Service by first class mail may not be substituted for service by certified mail when service by certified mail is required by Commission Rule or the Act.

523. ENFORCEMENT

a. Identification of Alleged Violations. If, on the Director's own initiative or based on a complaint, reasonable cause exists to believe that a violation of the Act or any Commission Rule, order, or permit has occurred, the Director will require the Operator to remedy the violation and may commence an enforcement action by issuing an NOAV. Reasonable cause requires, at least, evidence of the alleged violation, as verified by the Director.

b. Resolution of Alleged Violations without Penalties.

(1) When the Director has reasonable cause to believe a violation of the Act or any Commission Rule, order, or permit has occurred, the Director may resolve the alleged violation without seeking a penalty if all of the following apply:

A. The Commission Rule allegedly violated is not a Class 3 rule and the degree of actual or threatened impact is minor or moderate pursuant to the Commission's Penalty Schedule, Rule 525.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 Rule 523.b.(1) apply.

c. Enforcement Actions Seeking Penalties for Alleged Violations. When the Director determines that Rule 523.b.(1) does not apply or otherwise elects to seek penalties for an alleged violation, the Director will commence an enforcement action by issuing an NOAV.

(1) Content of an NOAV. An NOAV will identify the provisions of the Act or Commission's 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.

(2) Answer. An answer to an NOAV will be filed within 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 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. Resolution of Enforcement Actions.

(1) Administrative Order by Consent. Except as provided in Rule 523.d.(2), an enforcement action is resolved upon the Commission's entry of an order approving an agreement between the Operator and the Director or by a recommended order becoming a final decision of the Commission.

A. A proposed agreement to resolve an enforcement action will be memorialized in an AOC executed by the Director and the Operator.

B. A complainant who has filed a written complaint on a Form 18, Complaint Report, 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 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 final proposed AOC may file a Petition for Review pursuant to Rule 524.c.

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. A recommended order on an AOC becomes the decision of the Commission within 20 days after service upon the parties, unless the Commission stays the recommended order on the AOC within that time.

D. If the Commission stays the recommended order on the 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) Orders Finding Violation.

A. An enforcement action may not be resolved by the Director and will 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 violation resulted in the death or serious injury of a person;

iii. The Director alleges the Operator has engaged in a pattern of violations; or

iv. The Commission sets an OFV hearing pursuant to Rule 510.f.(3).

e. Rescinding an NOAV. If, after issuance of an NOAV 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 that may result in an NOAV, additional penalties, or corrective action requirements.

524. COMPLAINANT ENFORCEMENT MATTERS

a. Any person may make a complaint using the Form 18 to the Director alleging that a violation of the Act or any Commission Rule, order, or permit has occurred. The Director will investigate all complaints made pursuant to this Rule to the extent the Director believes sufficient grounds exist to warrant an investigation.

b. The Director will notify the complainant of whether an investigation will be conducted.

(1) If the Director determines no violation occurred, the Director will notify the Operator and the complainant, and no further action will be taken.

(2) If the Director determines a violation may have occurred, the Director may initiate and resolve the enforcement action pursuant to Rule 523.

(3) If a complaint specifically results in the issuance of an NOAV, a complainant who has filed a written complaint on a Form 18 will be given 14 days to comment on the terms of a draft proposed settlement of the NOAV, if any, before the AOC is signed and presented to an Administrative Law Judge or Hearing Officer for a recommended order approving it.

c. A complainant who has filed a written complaint on a Form 18 may file a Petition for Review requesting the Commission hear the complainant's objections to:

(1) The Director's decision not to issue an NOAV for an alleged violation specifically identified in the written complaint; or

(2) The settlement terms of a final proposed AOC that settles an alleged violation arising directly from the Form 18.

d. Complainants will file a Petition for Review application with the Commission within 28 days of service of the Director's decision.

e. A Petition for Review will set forth in reasonable detail the legal arguments and facts the complainant contends demonstrate that the Director's decision was clearly erroneous.

(1) A Petition for Review may include a request for a continuance of the enforcement hearing on the AOC. Such a request will be based on actual, compelling evidence, which has been gathered by the complainant after the Director's contested decision, and will explain why the Director should further investigate the circumstances surrounding the alleged violation. The Commission, Administrative Law Judge, or Hearing Officer will determine whether a continuance is warranted, and whether to direct Staff to conduct additional investigation or receive and consider additional information.

(2) An Administrative Law Judge or Hearing Officer will issue a case management order that establishes the deadlines for filing responses to the Petition for Review.

(3) Discovery will not be permitted prior to the Petition for Review hearing.

f. Unless otherwise continued, a Petition for Review will be heard within 42 days following filing of the Petition for Review.

525. ASSESSING PENALTIES IN ENFORCEMENT MATTERS

a. General. If the Commission finds that an Operator has violated the Act or a Commission Rule, order, or permit, the Commission may issue an order imposing a penalty. Penalties will be calculated based on the Act and this Rule 525. 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.

(3) With respect to violations that result in actual or threatened adverse impacts to public health, safety, welfare, 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 protect and minimize adverse impacts to public health, safety, welfare, 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.

(4) A penalty will be assessed for each day the evidence shows a violation continued.

(5) 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 impacts to public health, safety, welfare, the environment, and wildlife resources. Pursuant to § 34-60-121(1)(a), C.R.S., the maximum daily penalty cannot exceed $15,000 per day per violation.

(1) **Penalty Schedule.** The Commission's Penalty Schedule is set forth in the following matrix. The matrix 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, welfare, the environment, and wildlife resources.	Class 2: Rules related at least indirectly to protecting and minimizing adverse impacts to public health, safety, welfare, 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 and minimizing adverse impacts to public health, safety, welfare, 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 resources	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, welfare, 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, welfare, 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, soil, water, air, and all other natural or 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. Whether any persons were harmed or whether there was a threat to the health, safety, and welfare of any persons; and

G. Any other facts relevant to an objective assessment of the degree of adverse impact to public health, safety, welfare, 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 Rule 525.c.(3).A, 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 Rule 525.c.(3).B 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's Rules, orders, and permits.

(4) **Penalty Adjustments Based on Duration of Violation.** In its discretion, the Commission, 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 OFV hearing when the Director determines an Operator has:

A. Engaged in a pattern of violations;

B. Acted with gross negligence or knowing and willful misconduct that resulted in an egregious violation; or

C. Engaged in an activity that resulted in death or serious injury.

(2) If the Commission, Administrative Law Judge, or Hearing Officer finds after hearing that an Operator is responsible for the conduct described in Rule 525.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's 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) The Director may consider a penalty reduction for a violation of the Act or any Commission Rule, order, or permit voluntarily disclosed by an Operator if:

A. The disclosure is made promptly after the Operator discovers the violation;

B. The Operator discovered the violation independent of, and unrelated to a Commission inspection or an NOAV;

C. The Operator cooperates with the Director regarding investigation of the disclosed violation; and

D. The Operator has achieved or commits to achieve compliance within a reasonable time and pursues compliance with due diligence.

(2) The Director may not consider a penalty reduction if:

A. The disclosure is made for fraudulent purposes;

B. The disclosed violation is 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 Rule 525.e.(1) are not met or that the factors in Rule 525.e.(2) are met, the Director may consider the fact that the Operator self-reported the violation as a mitigating factor pursuant to Rule 525.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 will provide tangible benefit to public health, safety, welfare, 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 unless otherwise agreed to, within 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's Rules, orders, or permits will not be stayed pending resolution of an appeal, except by court order.

526. DETERMINATION OF RESPONSIBLE PARTY

The Director will have evidence to supports its allegations against an Operator. If the Director initiates an enforcement proceeding against an Operator, the Operator may raise as an affirmative defense that another person is the Responsible Party for the alleged violation. If the Operator raises an affirmative defense that a different person is the Responsible Party, it will provide credible evidence to support its affirmative defense.

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 21 days' notice to the potentially Responsible Parties.

b. Potentially Responsible Parties will be those persons that have or should have submitted a Form 1, Registration for Oil and Gas Operations, or that have or should have submitted Financial Assurance for Oil and Gas Operations pursuant to requirements of the Commission's 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. If an Operator raises an affirmative defense that another person is the Responsible Party, the Operator raising the affirmative defense will identify the person alleged to be the Responsible Party, and provide that person with notice concurrent with filing an Answer to an NOAV.

e. The Commission, Administrative Law Judge, or Hearing Officer will make the determination under this section without regard to any contractual or legal disputes between the parties regarding assignments of liability or other legal defenses.

f. Each Responsible Party will be liable only for a proportionate share of any costs imposed under this Rule, and will not be held jointly and severally liable for such costs.

g. The Commission, Administrative Law Judge, or Hearing Officer will find Responsible Party status and mitigation liability if the Responsible Party conducted operations that resulted in or threatened to cause an adverse impact to public health, safety, welfare, the environment, or wildlife resources in contravention of any then applicable provision of the Act or Commission Rule, or order of the Commission, or of any permit.

527. PERMIT-RELATED PENALTIES

a. If the Commission determines, after a hearing, that an Operator failed to perform any required corrective action, 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 will 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 violations of any provision of the Act or of any Commission Rule, order, or permit, 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 violations 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.

528. CEASE AND DESIST ORDERS

a. The Commission or the Director may issue a Cease and Desist Order when an Operator's alleged violation of the Act or Commission Rule, order, or permit, or failure to take required corrective action or other authorized activity that 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.

b. The Cease and Desist Order will be served pursuant to Rule 522.e within 7 days after it is issued.

c. The Cease and Desist Order will state the provisions of the Act or Commission's 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.

d. An objection by an Operator to a Cease and Desist Order will be heard by the Commission pursuant to § 34-60-121(5)(b), C.R.S. An Operator's objection to 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.

e. After the issuance of a Cease and Desist Order, the Director may require amendment to or suspension of a permit associated with the Cease and Desist Order if necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. No amendment or suspension of a permit may occur without notice and hearing before the Commission.

f. 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.

529. RULEMAKING PROCEEDINGS

a. Initiation of Rulemaking. The Commission may initiate rulemaking on its own motion or in response to an application filed by any person, including the Director. Whether to conduct a rulemaking lies within the discretion of the Commission. A rulemaking may address regulations statewide, or in a more limited geographic area such as a specific geologic basin or Field.

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;

(3) The Commission's statutory authority to enact the proposed rule; and

(4) 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 20 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 pursuant to § 24-4-103(2), C.R.S. The Commission or Director may also use other means 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.

(1) **Colorado Parks and Wildlife Consultation.** For new basin-wide orders or modifications of existing basin-wide or Field-wide orders, on issues pertaining to Wildlife Resources or wildlife-related environmental concerns or protections, or for development acreage that intersects High Priority Habitat, the Commission will consult with CPW during the stakeholder process.

(2) The Director will consult with the CDPHE when the Commission develops a regulation that can reasonably be anticipated to have impacts on public health, welfare, safety, or the environment.

(3) The Director will consult with the CDPHE when an Operator requests a modification of an existing Commission order to increase Well density or otherwise proposes a Well density of more than 1 Well per 40 acres.

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, and the date of availability. The notice will include a short and plain statement that 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, including oral testimony or presentations, 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. In its discretion, the Commission may allow only pre-filed written testimony and oral testimony or presentations at a rulemaking 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. EX PARTE COMMUNICATIONS

a. The following provisions will be applied in any adjudicatory proceeding before the Commission, Administrative Law Judge, or Hearing Officer.

(1) No person will make or knowingly cause to be made to any member of the Commission, Administrative Law Judge, or 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 that 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 530, the Commission, Administrative Law Judge, or 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 530.a.

b. Oral or written communication with individual Commission members is permissible in a rulemaking proceeding. The Commission will make any communication presented to or considered by an individual Commissioner part of the record. 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 530 will not limit the right to challenge a decision of the Commission, Administrative Law Judge, or Hearing Officer on the grounds of bias or prejudice due to any ex parte communication.

SAFETY AND FACILITY OPERATIONS REGULATIONS
600 SERIES

601. INTRODUCTION

The Commission's Rules in this 600 Series are promulgated to protect the health, safety, and welfare of the general public during all Oil and Gas Operations. They do not apply to practices regulated by the federal Occupational Safety and Health Act of 1970. For information about safety regulations applicable to industry personnel, contact the U.S. Department of Labor, Occupational Safety and Health Administration ("OSHA"), Regional Administrator, Colorado Region VIII, 1244 Speer Blvd, Suite 551, Denver, CO 80204, 720-264-6550, or visit https://www.osha.gov/contactus/bystate/CO/areaoffice.

602. GENERAL SAFETY REQUIREMENTS

Operators will operate and maintain all Oil and Gas Facilities in a safe manner. Operators will train their employees in the safe conduct of all job responsibilities, including safe operation and location of all equipment. An Operator will ensure that all contractors, subcontractors, and persons directly under the Operator's control on an Oil and Gas Location or at an Oil and Gas Facility receive adequate training and are aware of the hazards presented by the Operator's Oil and Gas Operations.

a. Operators will familiarize their employees, contractors, and subcontractors with the Commission's Rules as they relate to the person's job functions.

b. Operators are responsible for training all employees so that operations can be conducted in a safe and workmanlike manner at all times. Such training will include at a minimum the review and training on standard operating procedures and best management practices for each job function.

c. Operators are responsible for ensuring that operations are conducted with due regard for the safety of employees, for the preservation and conservation of property, and for protecting and minimizing adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

d. Operators will establish and maintain a written operations safety management program for all Oil and Gas Operations. The operations safety management program will establish operational practices and procedures for safety and will include at a minimum a:

(1) Change management program; and

(2) Pre-Startup safety program for all new and existing Oil and Gas Locations.

e. Employees, contractors, and subcontractors will immediately report unsafe and potentially dangerous conditions to their supervisor and any such conditions will be remedied as soon as practicable.

f. In the event of a situation that requires operations to cease due to an imminent threat to safety, the Director may order a safety shut-in of an Oil and Gas Location until the imminent threat to safety is resolved. If the Director requires an Operator to take action pursuant to Rule 602.f, the Operator may appeal the Director's decision to the Commission pursuant to Rule 503.g.(10). The matter will not be assigned to an Administrative Law Judge pursuant to Rule 503.h. The Commission will hear the appeal at its next regularly scheduled meeting. Operators will continue to comply with any requirements identified by the Director pursuant to Rule 602.f until the Commission makes a decision on the appeal. The Commission may uphold the

Director's decision if the Commission determines the Director had reasonable cause to determine that an Operator's actions posed an imminent threat to safety, and that the action required by the Director was necessary and reasonable to address those impacts or threatened impacts. If an Operator does not appeal the Director's decision pursuant to this Rule 602.f, the Director will report the decision at its next regularly scheduled hearing.

g. Operators will notify the Director and the Local Government of the applicable jurisdiction of reportable safety events at an Oil and Gas Facility. Reportable safety events include:

(1) Any accidental fire, explosion, detonation, uncontrolled release of pressure, or loss of Well control, vandalism or terrorist activity, or any accidental or natural event that damages equipment or otherwise alters an Oil and Gas Facility so as to create a significant Spill or Release, fire hazard, unintentional public access, or any other condition that threatens public safety;

(2) Any accident or natural event at an Oil and Gas Facility that results in a reportable injury as defined by the U.S. Department of Labor, Occupational Safety and Health Administration ("OSHA"), 29 C.F.R. § 1904.39 (2021). Only the January 15, 2021 version of OSHA's 29 C.F.R. § 1904.39 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, 29 C.F.R. § 1904.39 (2021) is available from OSHA's Office of Regional Administrator, Colorado Region VIII, 1244 Speer Blvd, Suite 551, Denver, CO 80204, and is available online at https://www.osha.gov/laws-regs/regulations/standardnumber/1904/1904.39;

(3) Any Spill or Release of hazardous Chemicals reportable to another state or federal agency, or a Grade 1 Gas Leak; and

(4) Any accident or natural event at an Oil and Gas Facility that results in:

A. An injury to a member of the general public that requires medical treatment; or

B. Damage to lands, structures, or property on or off the Oil and Gas Location.

h. Operators will provide initial notification of a reportable safety event described in Rule 602.g.(1)–(4) above, as soon as practicable, but no more than 6 hours after the safety event. A Form 22, Accident Report, will be submitted to the Director within 3 days of the reportable safety event.

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

i. Where unsafe or potentially dangerous conditions exist at an Oil and Gas Location and first responders or Commission Staff are on-site, the Operator will respond to and be present at the Location with first responders or Commission Staff.

j. Each Operator will have a functioning emergency response plan that provides for the effective management of situations that may arise from Oil and Gas Operations. All existing and proposed Oil and Gas Locations will have an emergency response plan in place that has been coordinated with, and approved by, the local emergency response agency. The plan may be developed to cover all Oil and Gas Locations within a Field or geographical area so long as the emergency response agency agrees.

(1) After the initial emergency response plan has been coordinated with, reviewed by, and approved by the local emergency response agency, the emergency response plan will then be reviewed and updated at intervals designated by the local emergency response agency.

(2) After approval of a Form 9, Transfer of Operatorship pursuant to Rule 218.e, the Buying Operator will coordinate with the local emergency response agency to update the emergency response plan as appropriate.

k. Vehicles not necessary for drilling, production, servicing, or seismic operations will be located a minimum distance of 100 feet from the wellbore, or a distance equal to the height of the derrick or mast, whichever is greater. Operators will take equivalent safety measures where terrain, location, or other conditions do not permit this minimum distance.

l. Existing Production Facilities are exempt from the provisions of the Commission's Rules with respect to minimum distance requirements and setbacks unless they are found by the Director to be unsafe.

m. Operators will provide self-contained physically secured sanitary facilities during drilling operations and at any other similarly staffed Oil and Gas Location or Oil and Gas Facility, and ensure that waste remains contained within the sanitary facilities.

603. OPERATIONAL AND SAFETY REQUIREMENTS

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 Form 2, Application for Permit to Drill, 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 pounds per square inch ("psi") per foot.

(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. The matter will be approved or heard by the Commission pursuant to Rule 519. 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 pursuant to the Commission's 500 Series Rules.

(2) Pursuant to this Rule 603.a, the Director may condition the approval of any Form 2 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 504.

b. Rig Floor Safety Valve Requirements. During drilling or Well servicing operations there will 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.

c. Well Servicing Operations.

(1) **Pressure Check Requirements.** Prior to commencing Well servicing operations, the Well will be checked for pressure and steps taken to remove pressure or to ensure that operations may be safely conducted under pressure.

(2) BOPE.

A. Adequate BOPE equipment will be used on all Well servicing operations.

B. Backup stabbing valves will be required on Well servicing operations during reverse circulation. Valves will be pressure tested before each Well servicing operation using low-pressure air or Fluid or high-pressure Fluid.

(3) All Well servicing operations will be conducted in accordance with American Petroleum Institute ("API") Recommended Practice ("RP") 54, Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operations, Third Edition Reaffirmed, January 2013. Only the Third Edition of API's RP 54 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

(4) 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.

(5) 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.

(6) 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.

(7) An Operator will maintain Well control using BOPE systems and/or diverter systems for Wells drilled with air, nitrogen, or foam.

(8) The Operator will install BOPE when there is any indication that a Well will flow, either through prior records, present Well conditions, or the planned Well work, or special orders of the Commission.

(9) When required, BOPE will be in accordance with API Standard 53: "Well Control Equipment Systems for Drilling Wells," 5th Edition (December 2018). Only the 5th Edition of API Standard 53 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

(10) Drilling after setting the surface casing will not proceed until BOPE 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), as incorporated by reference in Rule 603.c.(9), 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 BOPE being tested, then there will be no unexplainable pressure loss at the end of the test.

(11) While in service, BOPE 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.

(12) All pipe fittings, valves, and unions placed on or connected with BOPE, 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.

(13) BOPE 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.

(14) The Operator will inspect and service the wellhead, tree, and related surface control equipment to maintain pressure control throughout the life of the Well.

(15) The Operator will conduct pressure testing of the casing string pursuant to Rule 408.

(16) 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 the FIT does not demonstrate the requirements of Rule 603.c.(16).B.

D. The Operator will perform the FIT before drilling 20 feet or less of new hole, unless otherwise ordered by the Commission.

(17) 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.

(18) BOPE for drilling operations will consist of (at a minimum):

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

B. **Rig Without Kelly.** Double ram with blind ram and pipe ram.

C. **Trained Personnel.**

i. During drilling operations there will be at least 2 persons at the Well Site that have successfully completed an International Association of Drilling Contractors certified Well control training, or have completed a Director-approved BOPE training.

ii. All rig employees will have adequate understanding of and be able to operate the BOPE system. New employees will be trained in the operation of BOPE systems**.**

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

d. **Well Consolidation.** Where necessary and reasonable, Operators will consolidate new Wells to create multi-Well pads, including shared locations with other Operators to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

e. **Development from Existing Oil and Gas Locations.** Where possible, Operators will develop multiple reservoirs by drilling from existing Oil and Gas Locations or by multiple completions or commingling in existing wellbores.

f. **Pit Level Indicators.** Pit level indicators will be used for mud Tanks and Drilling Pits.

g. **Drill Stem Tests.** Closed chamber drill stem tests will be allowed. All other drill stem tests require Director approval.

h. **Fencing Requirements.** Unless otherwise requested by the Surface Owner, Oil and Gas Locations or Oil and Gas Facilities will be adequately fenced to restrict access by unauthorized persons, if determined necessary by the Director. However, all pumps and Pits will be adequately fenced to prevent access by unauthorized persons.

i. **Loadlines.** All loadlines will be bullplugged or capped.

j. **Guy Line Anchors.** All guy line anchors left buried for future use will be identified by a marker of bright color not less than 4 feet in height and not greater than 1 foot east of the guy line anchor.

k. **Tank Specifications.** All newly installed or replaced crude oil and condensate storage Tanks will be designed, constructed, and maintained pursuant to the National Fire Protection Association ("NFPA") Code 30, Flammable and Combustible Liquids Code (2018 version). The Operator will maintain written records verifying proper design, construction, and maintenance, and will make these records available for inspection by the Director. Only the 2018 version of NFPA Code 30 applies to this Rule; later amendments do not apply. All materials incorporated by reference in this Rule are available for public inspections during normal business hours from the Public Room Administrator at the office of the Commission, 1120 Lincoln Street, Suite 801, Denver, CO 80203. In addition, these materials are available from the NFPA, 1 Batterymarch Park, Quincy, MA, 02169-7471.

l. **Access Roads.** At the time of construction, all leasehold roads will be constructed to accommodate all weather access by local emergency vehicles, and will be maintained in a stable condition.

m. **Well Site Cleared.** Within 90 days after a Well is Plugged and Abandoned, the Well Site will be cleared of all non-essential equipment, trash, and debris. For good cause shown, a reasonable extension of time may be granted by the Director. The Operator will request prior approval for this extension on a Form 4, Sundry Notice.

n. **Identification of Plugged and Abandoned Wells.** The Operator will identify the location of the wellbore with a permanent monument pursuant to Rule 434.a.(5).

o. **Secondary Containment.** Operators will design, construct, and maintain secondary containment devices around new and significantly modified crude oil, condensate, and produced water storage Tanks.

(1) Operators will design secondary containment structures to be sufficiently sized to contain at least 150% of the volume of the largest single Tank within the containment.

(2) Operators will construct secondary containment of steel, or other engineered material, designed and installed to prevent leakage and resist degradation from erosion or routine operation.

(3) To prevent leakage, Operators will line secondary containment areas with an impervious synthetic or engineered liner that underlays all primary containment vessels including partially buried vessels. The liner will be sufficiently impervious so that any discharge from a primary containment system will not escape containment before cleanup occurs. The liner will be attached to secondary containment and any equipment penetrating the liner will have a sealed connection.

(4) Secondary containment will prevent Spills or Releases from primary containment vessels, process vessels, or pipelines from migrating horizontally or vertically prior to clean-up.

(5) For locations within 500 feet and upgradient of a surface water body or wetland, tertiary containment, such as a compacted earthen berm, is required around Production Facilities.

(6) No potential ignition sources, aside from fired vessels ("FV"), will be installed inside the secondary containment area. Any electrical equipment installations inside the bermed area will 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 (including January 2014 errata), and the current national electrical code as adopted by the State of Colorado. Only the 3rd edition (including January 2014 errata) of API RP 500 applies to this Rule; later amendments do not apply. The materials 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, CO 80203. In addition, these materials are available from API, 1220 L Street NW, Washington, DC 20005-4070, and from the Department of Regulatory Agencies, Colorado Electrical Board, 1560 Broadway, Suite 110, Denver, CO 80202.

604. SETBACKS and SITING REQUIREMENTS

a. Well Location Requirements.

(1) At the time the Well is drilled, a Well will be located not less than 200 feet from buildings, public roads, above ground utility lines, or railroads.

(2) At the time a Form 2A, Oil and Gas Location Assessment is filed, a Well will be located not less than 150 feet from a surface property line. The Commission 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). The Operator will submit an exception location request letter stating the reasons for the exception and a signed waiver(s) from the offset Surface Owner(s) with the Form 2A for the proposed Oil and Gas Location where the Well will be drilled. Such signed waiver will be filed in the office of the county clerk and recorder of the county where the Well will be located.

(3) No Working Pad Surface will be located 2,000 feet or less from a School Facility or Child Care Center.

A. If the Operator and School Governing Body disagree as to whether a proposed Working Pad Surface is 2,000 feet or less from a School Facility or Child Care Center, the Commission will hear the matter in the course of considering the proposed Oil and Gas Development Plan. At the hearing, the Operator will demonstrate that the Working Pad Surface is more than 2,000 feet from any School Facility or Child Care Center.

B. Any hearing required under Rule 604.b.(3).A will be held at a location reasonably proximate to the lands affected by the proposed Oil and Gas Development Plan.

(4) No Working Pad Surface will be located less than 500 feet from 1 or more Residential Building Units not subject to a Surface Use Agreement or waiver, that includes informed consent from all Building Unit owner(s) and tenant(s) explicitly agreeing to the proposed Oil and Gas Location siting.

b. Siting Requirements for Proposed Oil and Gas Locations Near Residential Building Units and High Occupancy Building Units. No Working Pad Surface will be located more than 500 feet and less than 2,000 feet from 1 or more Residential Building Units or High Occupancy Building Units unless one or more of the following conditions are satisfied:

(1) The Residential Building Unit owners and tenants and High Occupancy Building Unit owners and tenants within 2,000 feet of the Working Pad Surface explicitly agree with informed consent to the proposed Oil and Gas Location;

(2) The location is within an approved Comprehensive Area Plan that includes preliminary siting approval pursuant to Rule 314.b.(5) or an approved Comprehensive Drilling Plan;

(3) Any Wells, Tanks, separation equipment, or compressors proposed on the Oil and Gas Location will be located more than 2,000 feet from all Residential Building Units or High Occupancy Building Units; or

(4) The Commission finds, after a hearing pursuant to Rule 510, that the proposed Oil and Gas Location and conditions of approval will provide substantially equivalent protections for public health, safety, welfare, the environment, and wildlife resources, including Disproportionately Impacted Communities. The Commission will base its finding on information including but not limited to:

A. The Director's Recommendation on the Oil and Gas Location pursuant to Rule 306.b;

B. The extent to which the Oil and Gas Location design and any planned Best Management Practices, preferred control technologies, and conditions of approval avoid, minimize, and mitigate adverse impacts, considering:

i. Geology, technology, and topography;

ii. The location of receptors and proximity to those receptors; and

iii. The anticipated size, duration, and intensity of all phases of the proposed Oil and Gas Operations at the proposed Oil and Gas Location.

C. The Relevant Local Government's consideration or disposition of a land use permit for the location, including any siting decisions and conditions of approval identified as appropriate by the Relevant Local Government;

D. The Operator's alternative location analysis conducted pursuant to Rule 304.b.(2), or an alternative location analysis performed for the Relevant Local Government that the Director has accepted as substantially equivalent pursuant to Rule 304.e;

E. Related Oil and Gas Location siting and infrastructure proposed as a component of the same Oil and Gas Development Plan as the proposed Oil and Gas Location;

F. How Oil and Gas Facilities associated with the proposed Oil and Gas Location are designed to avoid, minimize, and mitigate impacts on Residential Building Units and High Occupancy Building Units; or

G. The Operator's actual and planned engagement with nearby residents and businesses to consult with them about the planned Oil and Gas Operations.

605. SIGNAGE REQUIREMENTS FOR OIL AND GAS OPERATIONS

a. Oil and Gas Location Signage. For new Oil and Gas Locations, from the time of construction until Reclamation is complete, the Operator will post a sign at the entrance to an Oil and Gas Location that includes the:

(1) Oil and Gas Location name;

(2) Commission's assigned Oil and Gas Location identification number (ID #);

(3) The Operator's telephone number where it may be reached at all times; and

(4) Telephone number(s) for local emergency services (911 where available).

b. Road Signage Requirements During Drilling Operations.

(1) Concurrent with or prior to Move-In, Rig-Up ("MIRU"), the Operator or its contractor will place a sign or marker at the point of intersection of the public road and rig access road, and the sign will be maintained until the drill rig is released.

(2) The sign placed during drilling operations will identify the public road to be used in accessing the rig, along with all necessary emergency numbers, and will be posted in a conspicuous place at the drilling rig.

c. Drilling, Hydraulic Fracturing Treatment, Flowback, and Recompletion Operations.

(1) Directional signs, no less than 3 square feet and no more than 6 square feet in size, will be provided during drilling, Hydraulic Fracturing Treatment, Flowback, and recompletion operations by the Operator or contractor.

(2) Such signs will be at locations sufficient to advise emergency crews where drilling, Hydraulic Fracturing Treatment, Flowback, and recompletion operations are taking place. At a minimum, such locations will include:

A. The first point of intersection of a public road and the rig access road; and

B. Thereafter at each intersection of the rig access route, except where the route to the Oil and Gas Location is clearly obvious to uninformed third parties.

(3) Signs not necessary to meet other obligations under the Commission's Rules will be removed as soon as practicable after the operation is complete.

d. Well Signage Requirements.

(1) Within 60 days after a new Well is Completed, including each Well on a Multi-Well Site, or an existing sign is replaced or modified, a permanent sign will be conspicuously located at the wellhead and will identify:

A. The Well name;

B. The API number; and

C. Its legal location, including the quarter/quarter section.

(2) When no associated Tank battery is present at the Oil and Gas Location, the following additional information is required on the Well sign:

A. Name of the Operator;

B. Telephone number at which the Operator can be reached at all times;

C. Telephone number for local emergency services (911 where available); and

D. The public road used to access the Well.

(3) **Multi-Well Locations.** On a multi-Well location the information required by Rule 605.d.(2) may be placed on one sign with dimensions as described in Rule 605.e.(2).

(4) If a Well is a known source of hydrogen sulfide gas, it will be marked accordingly.

e. Tank Battery Signage.

(1) Within 60 days after the installation of a Tank battery, a permanent, conspicuous sign will be located at the battery.

(2) The Tank battery sign will be no less than 3 square feet and no more than 6 square feet, and will provide:

A. Name of the Operator;

B. Telephone number at which the Operator can be reached at all times;

C. Telephone number for local emergency services (911 where available);

D. The public road used to access the Tank battery site;

E. Well name(s) and API number(s) associated with the Tank battery and the legal location of the Well(s); and

F. Location, including the quarter/quarter section, of the Tank battery.

(3) If an Oil and Gas Location is a known source of hydrogen sulfide gas, it will be marked accordingly.

f. Centralized E&P Waste Management Facility Signage.

(1) The main point of access to a Centralized E&P Waste Management Facility will be marked by a sign captioned:

"(Operator name) E&P Waste Management Facility, Permit #."

Such sign will be no less than 3 square feet and no more than 6 square feet and will provide:

A. A phone number at which the Operator can be reached at all times;

B. A phone number for local emergency services (911 where available);

C. The public road used to access the facility; and

D. The legal location, including quarter/quarter section, of the facility.

(2) If a Centralized E&P Waste Management Facility is a known source of hydrogen sulfide gas, it will be marked accordingly.

g. General Sign Requirements.

(1) No sign required under this Rule 605 will be installed at a height exceeding 6 feet.

(2) Operators will ensure that signs are well maintained and legible, and will replace damaged or vandalized signs within 30 days of discovery that the sign is no longer legible or is damaged.

(3) Upon the Director's approval of a Form 9 the Buying Operator will have 60 days to replace or update all signs at the Oil and Gas Location so that the signs comply with Rule 605.

h. Tank and Container labels.

(1) All Tanks with a capacity of 10 Barrels or greater will 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. NFPA label or equivalent globally harmonized label.

(2) Lettering on all new Tanks, and on any reapplied or modified labels, will be legible from a distance of 100 feet.

(3) 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, will retain the markings, placards, and labels on the Container. Such markings, placards, and labels will be retained on the Container until it is sufficiently cleaned of residue and purged of vapors to remove any potential hazards.

606. EQUIPMENT, WEEDS, WASTE, AND TRASH REQUIREMENTS.

a. The storage, placement, or maintenance of equipment, vehicles, trailers, commercial products, Chemicals, drums, totes, Containers, materials, and all other supplies not necessary for use on an Oil and Gas Locations is prohibited.

(1) This prohibition applies to the Operator and all contractors.

(2) An Operator may request a variance pursuant to Rule 502 for a Surface Owner to use portions of the Oil and Gas Location, provided such use does not interfere with safe operations, access to equipment, Reclamation requirements, or emergency response capabilities. Such use cannot cause degradation to the site.

(3) This prohibition does not apply to emergency response trailers and associated equipment staged on an Oil and Gas Location for emergency response purposes.

b. No maintenance of equipment or vehicles is permitted at an Oil and Gas Location unless immediately necessary to allow for the continuation of active Oil and Gas Operations.

c. Oil and Gas Locations will be kept free of all Undesirable Plant Species.

d. Trash.

(1) Operators will properly dispose of all trash, rubbish, and other waste materials as non-hazardous/non-E&P solid waste, pursuant to Rule 906.c.

(2) No trash, waste, rubbish, or other materials will be burned or buried at an Oil and Gas Location.

(3) All trash, rubbish, and other waste material will be properly contained until removed from the Oil and Gas Location. At no time will trash, debris, or rubbish be placed or remain on the ground.

A. Appropriate Containers are Containers that prevent leakage of Fluids, and are capable of containing waste materials in all weather conditions.

B. Appropriate Containers will be designed, maintained, and operated to exclude wildlife.

607. EQUIPMENT ANCHORING REQUIREMENTS

All equipment at an Oil and Gas Location in a Geologic Hazard area will be anchored. Anchors will be engineered to support the equipment and to resist flotation, collapse, lateral movement, or subsidence. Anchoring requirements in Floodplains are governed by Rule 421.b.(2).

608. OIL AND GAS FACILITIES

a. Production Liquid Storage Tanks.

(1) Atmospheric Tanks used for produced Fluids storage will be built in accordance with the following standards as applicable. Only those editions of standards incorporated by reference in Rules 608.a.(1).A–F apply; later amendments do not apply. All materials incorporated by reference in this Rule 608.a.(1) 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070, and from Underwriters Laboratories, Inc., 100 Technology Drive, Broomfield, CO 80021.

A. Underwriters Laboratories, Inc., No. UL-142, Standard for Steel Above Ground Tanks for Flammable and Combustible Liquids, 10th Edition (May 17, 2019);

B. API Standard No. 650, Welded Steel Tanks for Oil Storage, 13th Edition (March 2020);

C. API Standard No. 12B, Bolted Tanks for Storage of Production Liquids, 16th Edition (November 2014);

D. API Standard No. 12D, Field Welded Tanks for Storage of Production Liquids, 12th Edition (June 2017);

E. API Standard No. 12F, Shop Welded Tanks for Storage of Production Liquids, 13th Edition (January 2019); or

F. API Standard No. 12P, Specification for Fiberglass Reinforced Plastic Tanks, 4th edition (August 2016), only for produced water.

(2) Tanks used for produced Fluids storage will be located at least 2 diameters from the boundary of the property on which the Tank is built. Where the property line is a public right of way, the Tanks will be 2/3 of the diameter from the nearest side of the public right of way or easement.

A. Tanks with less than 3,000 Barrels capacity will be located at least 3 feet apart.

B. Tanks with 3,000 or more Barrel capacity will be located at least 1/6 the sum of the diameters apart. When the diameter of one Tank is less than 1/2 the diameter of the adjacent Tank, the Tanks will be located at least 1/2 the diameter of the smaller Tank apart.

(3) All production Tanks greater than 60 gallons will conform to minimum standards of NFPA Code 30, 2018 Edition unless otherwise specified. Only the 2018 version of NFPA Code 30 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from the NFPA, 1 Batterymarch Park, Quincy, MA, 02169-7471.

(4) At the time of installation, Tanks will be a minimum of 200 feet from any building.

(5) Unless equipped with a fired heater, Tanks will be a minimum of 75 feet from a FV or heater-treater ("HT"). No ancillary equipment that has potential ignition sources will be installed or used inside the secondary containment area.

(6) Tanks will be a minimum of 50 feet from a separator, Well test unit, or other non-fired equipment. Non-fired vapor recovery towers, transfer pumps, vapor line knockouts, and LACT units are exempt from this requirement.

(7) Tanks will be a minimum of 75 feet from a compressor with a rating of greater than or equal to 200 horsepower.

(8) Tanks will be a minimum of 75 feet from a wellhead.

(9) Gauge hatches on atmospheric Tanks used for crude oil storage will be closed, latched, and sealed at all times when not being actively accessed by trained personnel. Tanks will function as sealed and ventless with gas released only through a vapor control system or properly sized pressure relief valve.

(10) Tank Venting Standards.

A. All Tank Venting systems will be designed, constructed, and operated in accordance with API Standard 2000, Venting Atmospheric and Low Pressure Storage Tanks, 7th edition, March 2014. Only the 7th Edition of the API standard applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from API at 1220 L Street, NW Washington, DC 20005-4070.

B. Except for individual blowdown lines used to depressurize Tanks prior to opening gauge hatches, vent lines from individual Tanks will be joined and ultimate discharge will be directed away from the loading racks and FV pursuant to API RP 12R-1, Installation, Operation, Maintenance, Inspection, and Repair of Tanks in Production Service, 6th Edition, March 2020. Only the 6th Edition of API RP 12R-1 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

C. During drilling, completion, production, and storage operations, all sealed Tanks will be designed for a minimum of 4 ounces of backpressure. Vent/back pressure valves, the combustor, lines to the combustor, and knock-outs will be sized and maintained so as to safely accommodate any surge the system may encounter. Operators will properly maintain, and periodically test, Tank seals to ensure that they provide the required back pressure and prevent emissions.

(11) During hot oil treatments on Tanks containing 35 degrees or higher API gravity oil, hot oil units will be located a minimum of 100 feet from any Tank being serviced.

(12) **Labeling of Tanks.** All Tanks and Containers will be labeled pursuant to Rule 605.h.

(13) All open-topped Tanks will be equipped with screens or other appropriate equipment to prevent entry by wildlife, including birds and bats.

(14) **Change in Service.** Tanks undergoing change in service will be emptied, cleaned, and re-labeled for the new use (if any). Operators will manage all waste generated during change in service pursuant to Rule 906.

b. Fired Vessel, Heater-Treater, and Separation Equipment.

(1) Fired vessels (“FV”) including heater-treaters (“HT”) will be minimum of 50 feet from separators or Well test units.

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

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

(4) FV-HT will be a minimum of 75 feet from a Well.

(5) At the time of installation, FV-HT will be a minimum of 200 feet from a Residential Building Unit.

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

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

(8) All separation equipment will be designed, constructed and maintained according to API Spec 12J, Specification for Oil and Gas Separators, 8th edition, October 2008. Only the 8th Edition (2008) of API Spec 12J applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials and are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

c. Special Equipment. The Director may require an Operator to employ special equipment to protect public safety.

(1) All Wells located within 500 feet of a Residential Building Unit will be equipped with an automatic isolation valve that will shut the Well in when a sudden change of pressure, either a rise or drop, occurs. Automatic isolation valves will be designed so they are fail safe.

(2) Isolation valves required by Rule 608.c.(1) will be electronic or activated by a secondary gas source supply, and will be inspected at least every 3 months to ensure the valves are in good working order and that the secondary gas supply has volume and pressure sufficient to activate the isolation valve.

d. Static Charge, Lightning, and Stray Current Requirements. All equipment will be designed and operated in a manner to prevent accumulation of static charge pursuant to API RP 2003, Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents, 8th Edition, September 2015. Only the 8th Edition (2015) of API RP 2003 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

e. Mechanical Conditions. All Production Facilities, valves, pipes, fittings, and vessels will be securely fastened or sealed, inspected at regular intervals, and maintained in good mechanical condition. All equipment will be engineered, operated, and maintained within the manufacturer's recommended specifications.

f. Buried or Partially Buried Tanks, Vessels, or Structures.

(1) Buried or partially buried Tanks, vessels, or structures used for storage of produced Fluids and E&P Waste will be properly designed, constructed, installed, and operated in a manner to prevent leaks, contain materials safely, and according to manufacturer specifications.

(2) Buried or partially buried Tanks, vessels, or structures will be underlain by an impermeable synthetic or engineered liner that extends to the surface and ties into the secondary containment. In lieu of an impermeable liner, double walled Tanks may be used to meet the requirements of this Rule 608.f.(2).

(3) Operators will inspect or test buried or partially buried Tanks, vessels, or structures for leaks at least annually. Operators will maintain records documenting tests conducted pursuant to this Rule 608.f.(3) for 5 years, and provide the records to the Director upon request.

(4) If any leaks are detected, Operators will repair or replace the Tank, vessel, or structure to prevent future Spills or Releases of E&P Waste. Operators will report, investigate, and remediate any Spill or Release pursuant to Rules 912 & 913.

g. Fluid Handling Equipment. Any piece of Fluid handling equipment that is not a Tank or Flowline, including temporary equipment, and regardless of the volume the equipment is designed to hold, will have either general secondary containment around the equipment, or a written Spill contingency plan. The written Spill contingency plan will include at least the following standards:

(1) A written commitment of manpower, equipment, and materials required to expeditiously control and contain all discharged Fluids;

(2) A schedule and protocol for periodic visual inspection or testing flow-through process vessels and associated components (such as dump valves) for leaks, corrosion, or other conditions that could lead to a discharge;

(3) Procedures for taking corrective action or making repairs to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge; and

(4) Procedures for prompt removal, Remediation, and reporting, if required, for any accumulations of discharges.

609. INSPECTIONS

a. Unless otherwise specified by the Commission's Rules, Operators will inspect Oil and Gas Locations as set forth below. Operators will promptly investigate, and if appropriate, repair, replace, or remediate any malfunctioning equipment or process. If an Operator takes action to address any malfunctioning equipment or process identified during an inspection, the Operator will maintain documentation of the action taken, and provide it to the Director upon request. The Operator will submit documentation of the results of all Tank system inspections to the Director upon request.

b. Tank and Process Vessel Inspections. All in-service Tanks and process vessels will be inspected and maintained pursuant to one of the following applicable standards:

(1) For Tanks that are built to meet API Standard 650, as incorporated by reference in Rule 608.a.(1).B, or are greater than 30 feet in diameter, API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction, (Fifth Edition, Including Addendum 1 (2018), Addendum 2 (2020), and Errata 1 (2020)). Only the fifth edition (2018, including 2020 Addendum 2 and Errata 1) of API Standard 653 apply; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

(2) For all other Tanks, either:

A. API Standard 12R1, Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service (6th edition March 2020). Only the 6th edition (March 2020) of API Standard 12R1 applies; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070; or

B. Steel Tank Institute ("STI") SP001, Standard for the Inspection of Aboveground Storage Tanks (January 2018). Only the January 2018 version of STI SP001 applies; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from STI, 944 Donata Court, Lake Zurich, IL 60047.

(3) For process vessels, API Standard 510, Pressure Vessel Inspector (10th edition May 2014). Only the 10th Edition (May 2014) of API Standard 510 applies to this Rule; later amendments do not apply. API Standard 510 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, CO 80203. In addition, these materials may be examined at any state publications depository library and is available from API at 1220 L Street, NW Washington, DC 20005-4070.

c. Out of Service Tanks and Process Vessels. Out of service Tanks and process vessels are not subject to the inspection standards in Rule 609.b. Operators will:

(1) Isolate or disconnect the Tank or process vessel from sources of oil, condensate, produced water, or natural gas;

(2) Depressurize and evacuate all hydrocarbons and produced water from the Tank or process vessel and test the interior of the Tank or process vessel to show that it is safe for designated entry, cleaning, or repair work.;

(3) Apply OOSLAT; and

(4) Equip any openings in the Tank or process vessel with screens or other appropriate equipment to prevent entry by wildlife, including birds and bats.

d. **Audio Visual Olfactory Inspections.** Operators will conduct Audio, Visual, Olfactory ("AVO") inspections of all Oil and Gas Facilities, at the same inspection frequency required by the Air Quality Control Commission Regulation 7, 5 C.C.R. §§ 1001-9:D.I.E.2.c.viii–ix & 1001-9:D:II.C.1.d (2021) ("AQCC Regulation 7"). Only the version of the AQCC Regulation 7 in effect as of January 15, 2021 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, AQCC Regulation 7 is available from the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and is available online at https://www.colorado.gov/pacific/cdphe/aqcc-regs. When performing an AVO inspection, an Operator will survey the Oil and Gas Facility using audio, visual, and olfactory techniques to detect failures, leaks, Spills, or Releases, or signs of a leak, Spill, or Release.

610. FIRE PREVENTION AND PROTECTION

a. Gasoline-fueled engines will be shut down during fueling operations.

b. Operators will comply with all Division of Oil and Public Safety regulations during handling, connecting, and transfer operations involving liquefied petroleum gas ("LPG"), 7 C.C.R. § 1101-15, *et seq*. Only the version of the Division of Oil and Public Safety's LPG Regulations, 7 C.C.R. § 1101-15, *et seq.* in effect as of January 15, 2021 apply to this Rule; later versions do not apply. All materials 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, CO 80203. In addition, these materials are from the Division of Oil and Public Safety, 633 17th St., Suite 500, Denver, CO 80202, and are available online at https://www.colorado.gov/pacific/ops/RegulationsStatutes.

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

(1) Be adequately vented to the outside air;

(2) Have 2 unobstructed exits leading from the building in different directions if the building is in excess of 500 square feet;

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

(4) Be identified as a hazard and appropriate warning signs posted.

d. Flammable liquids will not be stored within 50 feet of the wellbore, except for the fuel in the tanks of operating equipment or supply for injection pumps.

e. LPG Tanks larger than 250 gallons and used for heating purposes will be placed as far as practicable from and parallel to the adjacent side of the rig or wellbore as terrain and location configuration permit. Installation will be consistent with provisions of NFPA Code 58, Liquid Petroleum Gas Code (2020 edition). Only the 2020 edition of NFPA Code 58 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from the NFPA, 1 Batterymarch Park, Quincy, MA, 02169-7471.

f. Smoking is prohibited within 150 feet of the wellbore, on any drilling or workover site, at an Oil and Gas Location with a producing Well or a Well that is undergoing Hydraulic Fracturing Treatment or Flowback, or in the vicinity of operations which constitute a fire hazard. Such locations will be conspicuously posted with a sign, “No Smoking or Open Flame.”

g. No matches, smoking equipment, or source of ignition will be carried into “No Smoking or Open Flame” areas.

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

i. Only approved heaters for Class I Division 2 areas, as designated by 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 (including January 2014 errata), will be permitted on an Oil and Gas Location or near Oil and Gas Facilities. The safety features of these heaters will not be altered. Only the 3rd edition, including January 2014 errata, of API RP 500 applies to this Rule; later editions do not apply. All materials 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, CO 80203. In addition, these materials are available from API, 1220 L Street, NW, Washington, DC 20005-4070.

j. Combustible materials such as oily rags and waste will be stored in covered metal Containers.

k. **Control of Fire Hazards.** Any material not in use that might constitute a fire hazard will be removed a minimum of 25 feet from the wellhead(s), Tanks, and separator(s). Any electrical equipment installations inside the secondary containment areas will comply with API RP 500 classifications and comply with the current national electrical code as adopted by the State of Colorado. Only the 3rd edition (including January 2014 errata) of API RP 500 applies to this Rule; later amendments do not apply. API RP 500 and Colorado’s current national electrical code 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, CO 80203. In addition, these materials are available from API, 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.

l. Material used for cleaning will have a flash point of not less than 100 degrees Fahrenheit. For limited special purposes, a lower flash point cleaner may be used when it is specifically required and will be handled with extreme care.

m. Firefighting equipment will not be tampered with and will not be removed other than for 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 will be properly drained or properly protected from freezing.

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

o. Fire protection equipment will be periodically inspected, and maintained in good operating condition at all times.

p. Firefighting equipment will be readily available near all welding operations. When welding, cutting, or other hot work is performed a person will be designated as a fire watch. The area surrounding the work will be inspected at least 1 hour after the hot work is completed.

q. Portable fire extinguishers will be tagged showing the date of last inspection, maintenance, or recharge. Inspection and maintenance procedures will comply with NFPA Code 10, Standards for Portable Fire Extinguishers (2018). Only the 2018 Edition of NFPA Code 10 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from NFPA, 1 Batterymarch Park, Quincy, MA, 02169.

r. All employees, contractors, and subcontractors will be shown the location of fire control equipment including, but not limited to Fluid guns, water hoses, and fire extinguishers, and trained in the use of such equipment. They will also be familiar with the procedure for requesting emergency assistance as terrain and location configuration permit.

611. AIR AND GAS DRILLING

a. Drilling compressors (air or gas) will 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 will be laid in as nearly a straight line as possible from the wellbore and be a minimum of 150 feet in length. The line will be securely anchored.

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

d. All combustible material will 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 will be of adequate strength to withstand at least the maximum discharge pressure of the compressors used, and will be checked daily for any evidence of damage or weakness.

612. HYDROGEN SULFIDE GAS

a. General.

(1) Operators will avoid any uncontrolled release or hazardous accumulation of hydrogen sulfide (“H_2S”) gas. If releases or hazardous accumulations of H_2S cannot be avoided, or during upset conditions or malfunctions, Operators will employ mitigation measures to reduce potential harms to safety.

(2) **Scope.** To protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources, Operators will comply with this Rule 612 where oil and gas exploration and production occurs in areas known or reasonably expected to contain H_2S.

b. Radius of Exposure Calculation. When an Operator is conducting drilling, workover, completion, or production operations in a geologic zone where the Operator knows or reasonably expects to encounter, or a laboratory gas analysis detects, H_2S in the gas stream at concentrations at or above 100 parts per million ("ppm"), the Operator will calculate the radius of exposure to any Building Unit, High Occupancy Building Unit, or Designated Outside Activity Area.

(1) Radius of exposure will be calculated pursuant to Bureau of Land Management ("BLM") Onshore Order No. 6 (Jan. 22, 1991). Only the 1991 version of Onshore Order 6 applies to this Rule; later amendments do not apply. All materials 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, CO 80203. In addition, these materials are available from the BLM Colorado State Office, 2850 Youngfield St., Lakewood, CO 80215, and are available online at https://www.blm.gov/sites/blm.gov/files/energy_onshoreorder6.pdf.

(2) If insufficient data exists to calculate a radius of exposure, the Operator will assume the radius of exposure is 3,000 feet.

(3) Operators will perform gas stream laboratory analysis if any concentration of H_2S of 20 ppm or greater is detected by using field measurement devices during drilling, completion, or production operations. Operators will report any gas stream laboratory analysis greater than 1 ppm H_2S to the Director and the Relevant and Proximate Local Government(s). If the Operator ever detects H_2S concentrations greater than 1 ppm, the Operator will repeat gas stream laboratory analysis annually.

c. H_2S Public Protection Plan. A public protection plan is required if:

(1) The 100 ppm radius of exposure is greater than 50 feet and there is a Building Unit, High Occupancy Building Unit, or Designated Outside Activity Area within the radius of exposure;

(2) The 100 ppm radius of exposure is equal to or greater than 3,000 feet and includes any publicly-maintained road; or

(3) The Director determines that a public protection plan is necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources.

d. H_2S Drilling Operations Plan.

(1) When proposing to drill a Well in areas where H_2S gas can reasonably be expected to be encountered, Operators will submit a H_2S drilling operations plan with their Form 2, unless the plan was already submitted with their Form 2A, pursuant to Rule 304.c.(10).

(2) Operators will prepare the H_2S drilling operations plan pursuant to BLM Onshore Order No. 6, as incorporated by reference in Rule 612.b.(1).

e. Designated H_2S Locations. If an Operator ever measures H_2S gas stream concentrations of 100 ppm or greater at a Well, the Well is a designated H_2S location. All designated H_2S locations will be designed and operated in accordance with BLM Onshore Order No. 6, as incorporated by reference in Rule 612.b.(1). Designated H_2S locations will have:

(1) Signs indicating the presence of H_2S not less than 200 feet or more than 500 feet from the entrance of the location;

(2) H_2S monitoring with audible and visible alarms at 10 ppm of H_2S;

(3) At least one wind indicator; and

(4) With landowner approval, adequate fencing.

f. Operations in Designated H_2S Locations.

(1) In a designated H_2S location, Operators will employ a secondary means of immediate Well control at all Wells that are known to have H_2S through use of a christmas tree or downhole completion equipment. The equipment will allow downhole accessibility (reentry) under pressure for permanent Well control. When the presence of H_2S is detected during drilling in formations not tested, completed, or produced, the Operator will report depth intervals, concentrations measured at surface or within drilling Fluid, and the control measures used.

(2) At Oil and Gas Locations producing gas with greater than 100 ppm H_2S, Operators will monitor all storage Tanks. Any headspace field measurement or laboratory analysis greater than 500 ppm H_2S, or 10 ppm H_2S in ambient air, will require mitigation measures to control and minimize accumulation within the storage Tank.

(3) All operations at an Oil and Gas Location with potential H_2S concentrations greater than 100 ppm will:

A. Use equipment that can withstand the effects and stress of H_2S;

B. Be conducted pursuant to American National Standards Institute ("ANSI")/National Association of Corrosion Engineers ("NACE") Standard MR0175/ISO 15156-2015-SG, Petroleum and natural gas industries – Materials for use in H_2S-containing environments in oil and gas production (2015), or some other Director approved standard for selection of metallic equipment. Only the 2015 version of ANSI/NACE Standard MR0175/ISO 15156-2015-SG 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, CO 80203. In addition, these materials are available from NACE International, 15835 Park Ten Pl, Houston, TX 77084; and

C. If applicable, use adequate protection by chemical inhibition or such other methods that control or limit H_2S's corrosive effects.

(4) Operators in designated H_2S locations will conduct a laboratory analysis of the gas stream for H_2S at least monthly. If the H_2S concentration increases by greater than 25%, the Operator will recalculate the radius of exposure and notify the Director and the Relevant and Proximate Local Government(s).

g. Operator Reports of H_2S.

(1) Operators will report on a Form 42, Field Operations Notice – Notice of H_2S on an Oil and Gas Location any laboratory analysis indicating the presence of H_2S gas to the Director within 48 hours. Upon receipt of the Form 42, the Director will notify the Relevant and Proximate Local Government(s).

(2) If a laboratory analysis indicates any concentrations of H_2S gas greater than 100 ppm in the gas stream, or headspace field measurement or laboratory analysis greater than 500 ppm H_2S, or 10 ppm H_2S in ambient air, the Operator will report such findings to the Director on a Form 4, including the information required in Rules 612.b–d, as applicable, within 45 days.

h. Unless deemed an immediate operational need for safety reasons and the release does not pose a risk to public safety, Operators may only intentionally release H_2S gas with prior Director approval of a Form 4. The Form 4 will include a proposed air monitoring plan for H_2S. If combustion or Flaring is proposed, the air monitoring plan will include a SO_2 by-product detection plan.

i. If an intentional release of H_2S gas occurs due to Upset Conditions or malfunctions, the Operator will notify the Director, the Relevant and Proximate Local Government(s), and the local emergency response agency orally within 24 hours, followed by the filing of a Form 4 within 5 days.

j. All H_2S monitoring, mitigation, and safety equipment will be maintained and functioning in good working order at all times.

k. Temporary Abandonment of a H_2S Well.

(1) Prior to temporarily abandoning a Well with potential concentrations of greater than 100 ppm H_2S in its gas stream, the Operator will file a Form 4, Notice of Temporarily Abandoned Status to obtain the Director's approval.

(2) Operators will install a cast iron bridge plug and maintain H_2S monitoring and telemetry equipment when temporarily abandoning a Well with potential concentrations of greater than 100 ppm H_2S in its gas stream.

613. GRADE 1 GAS LEAK REPORTING

An Operator will initially report to the Director a Grade 1 Gas Leak from a Flowline pursuant to Rule 912.b.(1).D and will submit the Form 19, Spill/Release Report document number on the Form 44, Flowline Report for the Grade 1 Gas Leak.

614. COALBED METHANE WELLS

a. Assessment and Monitoring of Plugged and Abandoned Wells Within 1/4 mile of Proposed Coalbed Methane Well.

(1) Based upon examination of Commission and other publicly available records, Operators will identify all Plugged and Abandoned Wells located within 1/4 mile of a proposed coalbed methane ("CBM") Well. The Operator will assess the risk of leaking gas or water to the ground surface or into subsurface water resources, taking into account plugging and cementing procedures described in any recompletion or Plug and Abandonment report filed with the Commission. The Operator will notify the Director of the results of the assessment of the plugging and cementing procedures. The Director will review the assessment and take appropriate action to pursue further investigation and Remediation if warranted and pursuant to the Colorado Oil and Gas Conservation and Environmental Response Fund.

(2) Operators will conduct a soil gas survey at all Plugged and Abandoned Wells located within 1/4 mile of a proposed CBM Well prior to production from the proposed CBM Well and again 1 year and thereafter every 3 years after production has commenced. Operators will submit the results of the soil gas survey to the Director within 3 months of conducting the survey.

b. 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, then prior to drilling the CBM Well, the Operator will determine whether there are gas seeps, springs, or water seeps that discharge from the coal-bearing formation in the area by:

A. Making a good faith effort to obtain the access necessary to survey the outcrop or mine;

B. Reviewing publicly available geologic and hydrogeologic data; and

C. Interviewing the Surface Owner(s).

(2) If a gas seep is identified during the survey, then the Operator will survey its location and areal extent pursuant to Rule 216, and determine the concentration of the soil gas. If possible, the Operator will collect a sample of gas from the seep for compositional analysis and stable isotope analysis of the gas pursuant to 615.e.(4). Thereafter, the Operator will inspect the gas seep, survey its areal extent, and measure soil gas concentrations annually, if access can be obtained. Within 3 months of its completion of the field work, the Operator will submit the results of the outcrop or mine monitoring to the Director in an electronic data deliverable format via a Form 43, Analytical Sample Submittal and, if necessary, via a Form 4. The Operator will concurrently provide the same information to the Surface Owner.

(3) If a spring or water seep is identified during the survey, then the Operator will survey its location and areal extent pursuant to Rule 216, measure the flow rate, photograph the feature, and collect and analyze a water sample pursuant to Rule 615.e. Thereafter, the Operator will inspect the spring or water seep, survey its areal extent, and measure its flow rate annually, if access can be obtained. Within 3 months of its completion of the field work, the Operator will submit the results of the outcrop or mine monitoring to the Director in an electronic data deliverable format via a Form 43 and, if necessary, via a Form 4. The Operator will concurrently provide the same information to the Surface Owner.

(4) If a gas seep is identified during the survey, the Director will advise the Surface Owner(s), Relevant 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 pursuant to § 24-65.1-103, C.R.S.

c. Prior to Producing – Static Bottom-Hole Pressure Survey. Prior to producing the Well, the Operator will obtain a static bottom-hole pressure test on at least the first Well drilled on a government quarter section. The survey will 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 will be reported on a Form 13, Bottom Hole Pressure, and submitted with the Form 5A, Completed Interval Report, 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.

d. CBM Monitoring. If a conventional gas Well or Plugged and Abandoned Well exists within 1/4 mile of a proposed CBM Well, then in addition to the water sources described in Rule 615.b, the 2 closest water wells within a 1/2 mile radius of the conventional gas Well or the Plugged and Abandoned Well will be sampled pursuant to Rules 615.c–f.

(1) If possible, the water wells selected should be on opposite sides of the conventional gas Well or the Plugged and Abandoned Well not exceeding a 1/2 mile radius. If water wells on opposite sides of the conventional gas Well or the Plugged and Abandoned Well cannot be identified, then the 2 closest wells within a 1/2 mile radius of the conventional gas Well or the Plugged and Abandoned Well will be sampled.

(2) If 2 or more conventional Wells or Plugged and Abandoned Wells are located within 1/4 mile of the proposed CBM Well, then the conventional Well or the Plugged and Abandoned Well closest to a proposed CBM Well will be used for selecting water wells for sampling.

(3) If there are no conventional gas Wells or Plugged and Abandoned Wells located within a 1/4 mile radius of the proposed CBM Well this Rule 614.d will not apply.

e. Bradenhead Testing. An Operator of a CBM Well will comply with Rule 419, except as modified by this Rule 614.e. 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.

615. GROUNDWATER BASELINE SAMPLING AND MONITORING

a. Applicability and Effective Date.

(1) This Rule applies to oil Wells, gas Wells (“Oil and Gas Wells”), Multi-Well Sites, and Class II UIC Wells for which a Form 2, or Form 4, Notice to Recomplete, is submitted or pending on or after January 15, 2021. Oil and Gas Wells, Multi-Well Sites, and Class II UIC Wells operating under a Form 2 approved prior to January 15, 2021, will continue to follow the sampling protocols required by their permits at the time that the Form 2 was approved.

(2) Nothing in this Rule 615 is intended, and will not be construed, to preclude or limit the Director from requiring Groundwater sampling or monitoring at other Production Facilities consistent with other applicable Commission Rules, including but not limited to the oil and gas location assessment process, and other processes in place pursuant to the Commission’s 900 Series Rules (Form 15, Earthen Pit Report/Permit, Form 27, Site Investigation and Remediation Workplan, and Form 28, Centralized E&P Waste Management Facility Permit).

(3) An Operator may elect, or the Director may require an Operator to install one or more Groundwater monitoring wells to satisfy, in full or in part, the requirements of Rule 615.b, but installation of monitoring wells is not required under this Rule 615.

b. Sampling Locations. Initial baseline samples and subsequent monitoring samples will be collected from all Available Water Sources, up to a maximum of 4, within a 1/2 mile radius of a proposed Oil and Gas Well, Multi-Well Site, or Class II UIC Well. If more than 4 Available Water Sources are present within a 1/2 mile radius of a proposed Oil and Gas Well, Multi-Well Site, or Class II UIC Well, the Operator will select the 4 sampling locations based on the following criteria:

(1) **Proximity.** Available Water Sources closest to the proposed Oil and Gas Well, Multi-Well Site, or Class II UIC Well are required.

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

(3) **Orientation of Sampling Locations.** To the extent Groundwater flow direction is known or reasonably can be inferred, sample locations from both down-gradient 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 Class II UIC Well.

(4) **Multiple Identified Aquifers Available.** Where multiple defined Aquifers are present, sampling the deepest and shallowest identified Aquifers is required.

(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 615 by filing a Form 4 for the Director's review and approval if:

(1) No Available Water Sources are located within 1/2 mile of a proposed Oil and Gas Well, Multi-Well Site, or Class II UIC Well;

(2) The only Available Water Sources are determined to be unsuitable pursuant to Rule 615.b.(5). An Operator seeking an exception on this ground will 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 pursuant to this Rule 615.c.(3) will document the efforts used to obtain access from the owners of suitable Water Sources.

(4) If the Director takes no action on the Form 4 within 10 business days of receipt, the requested exception from the requirements of this Rule 615.c will be deemed approved.

d. Timing of Sampling.

(1) Initial sampling will be conducted within 12 months prior to setting conductor pipe in a Well or if no conductor is present prior to spudding the first Well on a Multi-Well Site, or commencement of drilling a Class II UIC Well.

(2) **Subsequent Monitoring.** One subsequent sampling event will be conducted at the initial sample locations between 6 and 12 months, and a second subsequent sampling event will be conducted between 60 and 72 months following completion of the Well or Class II UIC Well, or the last Well on a Multi-Well Site. Additional subsequent samples will be collected every 5 years (57 to 63 month interval) for the life of the Well. A post abandonment sample will be collected 6 to 12 months after the Oil and Gas Well has been Plugged and Abandoned. Wells that are drilled and abandoned without ever producing hydrocarbons are exempt from subsequent monitoring sampling under this Rule 615.d.(2).

(3) **Previously Sampled Water Sources.** In lieu of conducting the initial sampling required pursuant to Rule 615.d.(1), or the second subsequent sampling event required pursuant to

Rule 615.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 Rule 615.d.(1), or any subsequent sampling event required pursuant to Rule 615.d.(2);

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 Rules 615.e.(1) & (2), below; and

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

(4) The Director may require additional sampling at any time as a result of information indicating a potential change in or impact to groundwater.

e. Sampling Procedures and Analysis.

(1) Sampling and analysis will be conducted in conformance with an accepted industry standard pursuant to Rule 913.b.(2). A model Sampling and Analysis Plan ("COGCC Model SAP") will be posted on the Commission's website, and will be updated periodically to remain current with evolving industry standards. Sampling and analysis conducted in conformance with the COGCC Model SAP will be deemed to satisfy the requirements of this Rule 615.e.(1). Upon request, an Operator will provide its sampling protocol to the Director.

(2) The analyses for samples collected as required by Rule 615 will include:

A. pH;

B. Specific conductance;

C. Total dissolved solids ("TDS");

D. Dissolved gases (methane, ethane, and propane);

E. Alkalinity (total, bicarbonate, and carbonate as $CaCO_3$);

F. Major anions (bromide, chloride, fluoride, sulfate, nitrate and nitrite as N, and phosphorus);

G. Major cations (calcium, iron, magnesium, manganese, potassium, and sodium);

H. Other elements (barium, boron, selenium, and strontium);

I. Presence of bacteria (iron related, sulfate reducing, and slime forming);

J. Total petroleum hydrocarbons ("TPH") as total volatile hydrocarbons (C_6 to C_{10}) and total extractable hydrocarbons (C_{10} to C_{36}); and

K. BTEX compounds (benzene, toluene, ethylbenzene, and xylenes ("BTEX")).

(3) Field observations such as odor, water color, sediment, bubbles, and effervescence as well as the presence or absence of H_2S gas will be documented. The location of the sampled Water Sources will be surveyed pursuant to Rule 216.

(4) Dissolved Gas Detections. If a free or dissolved gas (methane, ethane, or propane) 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 gas will be performed to determine gas type.

A. The compositional analysis should include:

i. hydrogen;

ii. argon;

iii. oxygen;

iv. carbon dioxide;

v. nitrogen;

vi. methane (C1);

vii. ethane (C2);

viii. ethene (C2H4);

ix. propane (nC3);

x. isobutane (iC4);

xi. butane (nC4);

xii. isopentane (iC5);

xiii. pentane (nC5);

xiv. hexanes +;

xv. Specific gravity; and

xvi. British Thermal Units (BTU).

B. Stable isotope analyses should include:

i. delta D of C1;

ii. delta 13C ofC1;

iii. delta 13C of C2;

iv. delta 13C of C3;

v. delta 13C of iC4 (if available);

vi. delta 13C of nC4 (if available);

vii. delta 13C of iC5 (if available);

viii. delta 13C of nC5 (if available); and

ix. delta 13C of CO_2.

C. The Operator will notify the Director by submitting a Form 42, Field Operations Notice – Water Sample Reporting, with a copy sent to the owner of the water well immediately if:

i. The test results indicated thermogenic or a mixture of thermogenic and biogenic gas;

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

iii. The methane concentration is detected at or above 10 mg/l.

D. The Operator will notify the Director immediately by Form 42 – Water Sample Report and provide a copy of the Form 42 – Water Sample Report and the test results to the water well owner, if BTEX compounds or TPH are detected in a water sample.

f. **Sampling Results.** Copies of all final laboratory analytical results will be provided to the Director and the water well owner or landowner within 3 months of collecting the samples. The analytical results including PDF of lab results, the surveyed sample Water Source locations, and the field observations will be submitted to the Director in an electronic data deliverable format approved by the Director along with a PDF of the lab report via Form 43.

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

g. Upon request, the Director will also make the analytical results and surveyed Water Source locations available to the Local Government of the jurisdiction in which the groundwater samples were collected, in the same electronic data deliverable format.

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.

UNDERGROUND INJECTION FOR DISPOSAL AND ENHANCED RECOVERY PROJECTS
800 SERIES

801. CLASS II UNDERGROUND INJECTION CONTROL WELLS

a. A Class II Underground Injection Control Well ("Class II UIC Well") will not be authorized if the proposed Well or operations will result in the presence of any physical, chemical, biological, or radiological substance or matter in an Underground Source of Drinking Water that may adversely affect the health of persons or cause a violation of any of the U.S. Environmental Protection Agency's National Primary Drinking Water Regulations, 40 C.F.R. § 141. Only the version of 40 C.F.R. § 141 in effect as of January 15, 2021 applies to this Rule; later amendments do not apply. 40 C.F.R. § 141 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, and at the U.S. Environmental Protection Agency, Region 8, 1595 Wynkoop St, Denver, CO 80202, and is available online at https://www.epa.gov/sites/production/files/2015-11/documents/howepargulates_cfr-2003-title40-vol20-part141_0.pdf.

b. A Class II UIC Well will not be authorized if the proposed Well or operations will result in the presence of any physical, chemical, biological, or radiological substance or matter that will cause a violation of any applicable domestic or agricultural use standards as adopted in 5 C.C.R. § 1002-41 ("WQCC Regulation 41") or 5 C.C.R. § 1002-42 ("WQCC Regulation 42"). Only the versions of WQCC Regulations 41 & 42 that are in effect as of January 15, 2021 apply to this rule; later amendments do not apply. WQCC Regulations 41 & 42 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, and at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and are available online at https://www.colorado.gov/pacific/cdphe/water-quality-control-commission-regulations.

c. Class II UIC Wells will not be permitted in areas where they would inject into a formation that is separated from any Underground Source of Drinking Water by a Confining Layer with known open faults or fractures that would allow flow between the Injection Zone and Underground Source of Drinking Water within the area of review.

d. Injection Zones will not be permitted within 300 feet in a vertical dimension from the top of any Precambrian basement formation.

e. An Operator will not inject any Fluids or other contaminants into a UIC Aquifer that meets the definition of an Underground Source of Drinking Water unless EPA has approved a UIC Aquifer exemption as described in Rule 802.e.

802. UIC AQUIFER EXEMPTIONS

a. Purpose. UIC Aquifer exemptions are required for an Operator to inject Fluids into a formation containing Groundwater with total dissolved solids ("TDS") concentration less than 10,000 milligrams per liter ("mg/l"). The Commission or Director will not designate UIC Aquifers if they have a TDS concentration less than 3,000 mg/l.

b. Criteria for UIC Aquifer Exemptions. The Commission or the Director may designate a UIC Aquifer as exempt upon the filing of an application pursuant to Rules 803, 809, 810, or 811, and after coordination with CDPHE's Water Quality Control Division if it meets all of the following criteria:

(1) The UIC Aquifer does not currently serve as an Underground Source of Drinking Water or domestic water source, and is not classified for domestic use by the Water Quality Control Commission; and

(2) The Applicant demonstrates that the UIC Aquifer cannot now and will not in the future serve as a source of drinking water for one of the following reasons:

A. It is mineral, hydrocarbon, or geothermal energy producing, or can be demonstrated by filing an application pursuant to Rules 803, 809, 810, or 811 to contain minerals or hydrocarbons that, considering their quantity and location, are technologically feasible to develop and can be commercially produced; or

B. It is so contaminated that it would be economically or technologically impractical to render the water fit for human consumption; and

(3) The Applicant demonstrates that the UIC Aquifer cannot now and will not in the future serve as a source of agricultural water for one of the following reasons:

A. It is mineral, hydrocarbon, or geothermal energy producing, or can be demonstrated by filing an application pursuant to Rules 803, 809, 810, or 811 to contain minerals or hydrocarbons that, considering their quantity and location, are technologically feasible to develop and can be commercially produced; or

B. It is so contaminated that it would be economically or technologically impractical to render the water fit for agricultural use.

c. UIC Aquifer Exemption Public Notice. If a UIC Aquifer exemption is required as part of an injection permit application process, the Operator will apply for a UIC Aquifer exemption. The application will contain data and information that show the UIC Aquifer meets the exemption criteria set forth in Rule 802.b. After evaluation of the application and prior to designating a UIC Aquifer or a portion thereof as an exempted UIC Aquifer, the Director will publish a notice of proposed designation on the Commission's website and in a newspaper of general circulation serving the area where the UIC Aquifer is located. The Director will also provide notice of the proposed Aquifer exemption to the Relevant Local Government with land use authority above the proposed Injection Zone. The notice will identify the UIC Aquifer or portion thereof that the Director proposes to designate as exempted, and will state that any interested person may request a hearing before the Commission.

d. Evaluation of Written Requests for Public Hearing. Written requests for a public hearing before the Commission will be reviewed and evaluated by the Commission to determine if the criteria set forth in Rule 802.b have been met. If, within 30 days after publication of the notice, the Commission receives a timely hearing request, the Commission will hold such a hearing pursuant to Rule 510. If no request for hearing is filed within 30 days after publication of the notice, the UIC Aquifer or portion thereof will be considered exempted 30 days after publication of the notice.

e. Submission to EPA. If the Commission approves a UIC Aquifer exemption pursuant to Rule 802.d, the Director will promptly submit a formal request for approval of the exemption to EPA. A UIC Aquifer exemption is not effective until it receives final approval from EPA.

803. APPLICATION REQUIREMENTS FOR CLASS II UNDERGROUND INJECTION CONTROL WELLS

a. Unless otherwise noted in this Rule 803, the requirements of this Rule 803 apply to all new Class II UIC Wells, including disposal Wells, enhanced recovery Wells, Simultaneous Injection Wells, and Commercial Disposal Well Facilities.

b. Related Permitting Requirements.

(1) An Operator will submit an application for a Class II UIC Well at the same time it submits any permit applications required by the Commission's 300 Series Rules, including an Oil and Gas Development Plan, a Form 2A, Oil and Gas Location Assessment, or Form 2, Application for Permit to Drill.

(2) For proposals to convert an existing production Well into an injection Well that would not otherwise require the submission of an Oil and Gas Development Plan or Form 2A, the Operator will:

A. Submit a partial Form 2B, Cumulative Impacts Data Identification documenting the incremental adverse and beneficial impacts of the proposed conversion pursuant to Rules 303.a.(5).B.i, ii, & vi; and

B. If requested by the Director, submit a subset of the information or plans required by Rule 304 necessary to consider the incremental adverse and beneficial impacts of the conversion.

c. Multiple Disposal Well Applications. The Injection Zone radius for disposal Wells will not interfere with the Injection Zone radius of any other disposal Wells. This Rule 803.c will not apply to enhanced recovery floods.

d. Neither construction of nor operation of a Class II UIC Well will occur without the Director's approval of a Form 31, Underground Injection Formation Permit Application, and Form 33, Injection Well Permit Application.

(1) **Form 31, Underground Injection Formation Permit Application.** A Form 31 permits the Injection Zone and will be approved prior to completing an Injection Zone. A Form 31, Underground Injection Formation Permit Application – Intent, will be approved prior to sampling, Stimulating, and testing the Well(s). A Form 31, Underground Injection Formation Permit Application – Subsequent, will be approved prior to injection.

(2) **Form 33, Injection Well Permit Application.** A Form 33 permits the injection Well and will be approved prior to completing the Well. A Form 33, Injection Well Permit Application – Intent, will be approved prior to sampling, Stimulating, and testing the Well(s). A Form 33, Underground Injection Formation Permit Application – Subsequent, will be approved prior to injection.

e. Denial of Underground Disposal of Class II Exploration and Production Waste. If the Director determines that a proposed Class II UIC Well is not protective of public health, safety, welfare, applicable Colorado water quality standards, the environment, and wildlife resources, and will not protect against adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations, the Director will deny the Form 31 and any related Form 33 in writing. Pursuant to Rule 503.g.(10), the Operator may seek the Commission's review of the Director's rejection of a Form 31 and Form 33.

f. Maximum Allowable Injection Rate, Total Volume, and Surface Injection Pressure. The Director will set the maximum allowable injection rate, total volume, and surface injection pressure in the approved Form 31 – Subsequent and Form 33 – Subsequent.

(1) The Operator will perform seismic monitoring if the permitted injection rate for a disposal Well exceeds 10,000 Barrels of water per day. If requested by the Commission or Director, the Operator will perform seismic monitoring as reasonable and necessary for other injected Fluids. A traffic light protocol for seismicity associated with injection activities may be applied as a condition of approval.

(2) Except during hydraulic fracturing, the maximum allowable injection pressure will be set below the fracture gradient of the Injection Zone, as determined by a step-rate injection test in the Class II UIC Well, a step rate injection test in an offset Well completed in the same Injection Zone, or other test acceptable to the Director. The maximum allowable injection pressure will assure that the pressure in the Injection Zone during injection does not initiate new fractures or propagate existing fractures. Until a step-rate injection test is performed, the maximum allowable injection pressure will be set consistent with a formation pressure gradient of 0.6 pounds per square inch ("psi") per total vertical foot from surface to the uppermost injection perforation.

(3) Disposal Wells will initially be permitted for an injection volume based on a 1/4 mile radius from the completed interval in the Injection Zone. The 1/4 mile radius will be measured from the surface location(s) for proposed vertical disposal Well(s), or the completed portion of the wellbore(s) in the Injection Zone in drifted, directional, or horizontal disposal Wells. This Rule 803.f.(3) does not apply to enhanced oil recovery projects.

(4) Operators may submit a Form 4, Sundry Notice, requesting a disposal Well volume increase, such that the radius will increase to an injection volume based on a 1/2 mile radius from the completed interval in the Injection Zone. This Rule 803.f.(4) does not apply to enhanced oil recovery projects.

g. Form 31, Underground Injection Formation Permit Application – Intent. An application for a Class II UIC Well will include the following information:

(1) **Operator.** The Operator of the Class II UIC Well or the designated Operator of a unitized or cooperative project will execute the application.

(2) **Map and List of Addresses.** The parties listed in Rules 803.g.(2).A–B will be specifically outlined and identified on a base map, and a related list of addresses will be provided with the application.

A. All Surface Owners:

i. Within 1/2 mile of the surface location(s) for proposed vertical disposal Well(s);

ii. Within 1/2 mile of the completed portion of the wellbore(s) in the Injection Zone in directional, or horizontal disposal Wells; or

iii. If a Field-wide disposal system is proposed, all Surface Owners of record in the Field and within 1/2 mile of the unit or project boundary.

iv. For enhanced recovery projects, a map meeting the requirements of Rule 811.b.(8).

B. All mineral Owners:

i. Of all oil and gas Wells currently producing from the proposed Injection Zone within 1/2 mile of the surface location(s) for proposed vertical disposal Well(s);

ii. Within 1/2 mile of the completed portion of the wellbore(s) in the Injection Zone in drifted, directional, or horizontal disposal Wells; or

iii. For enhanced recovery projects, a map meeting the requirements of Rule 811.b.(8).

(3) Authorization for Surface Use.

A. To construct or recomplete a disposal Well or Simultaneous Injection Well at a surface location, the Operator will provide a Surface Use Agreement, unless the Owner or Operator of the disposal Well or Simultaneous Injection Well is also the Surface Owner.

B. To construct or recomplete an Enhanced Recovery Well at a surface location, the Operator will provide a Surface Use Agreement, a copy of a lease, or a unit operating agreement, unless the Owner or Operator of the Enhanced Recovery Well is also the Surface Owner.

C. For all Class II UIC Wells, Surface Use Agreement(s), leases, or unit operating agreements will state explicitly that the injected Fluids may contain E&P Waste from Oil and Gas Operations.

(4) Surface Facility Diagram and Process Flow Diagram. A diagram of the surface facility showing all Pipelines and Tanks associated with the system and a process flow diagram.

(5) Proposed Injection Program. The application will include a proposed injection program with the following:

A. An overall summary of the proposed injection program.

B. Geologic Formation Summary. A geologic formation summary for all Wells being converted to injection and all new injection Wells. For a new injection Well, the application may reference any available geophysical logging data from offset Well(s) within 1 mile of the proposed injection Well to estimate formation depths and thickness. Where there is limited available data from the local basin below the target formations, the Operator will provide a best estimate to the depth of the Precambrian basement. The geologic formation summary may consist of a stratigraphic chart starting from the surface, down to the proposed total depth of the Well, that includes the geologic formations present, along with the names, descriptions, depths, and thickness from the surface to the top of Precambrian basement of the following:

i. The formations which will receive any Fluids to be injected or zones that have already received injected Fluids;

ii. The overlying and underlying Confining Layers capable of limiting the movement of any Fluids to be injected;

iii. The formations from which oil and gas Wells are producing or have produced; and

iv. All Underground Sources of Drinking Water.

C. Injected Water Analysis. Laboratory analytical results from a representative water sample collected from the Fluid to be injected, addressing all analytes listed in and following all procedures required by Rules 909.j.(1)–(5). For an injection Well intended to serve production Wells not yet completed, the applicant may submit other available data regarding the expected quality of the Fluid to be injected. Within 90 days after the date of first production of a production Well that will send Fluids to the injection Well, the applicant will submit a laboratory analysis of a representative sample collected from the fluid to be injected.

D. **Injection Zone Analysis.** Laboratory analytical results from a representative water sample collected from the Injection Zone, addressing all analytes listed in and following all procedures required by Rules 909.j.(1)–(5). If the total dissolved solids of the Injection Zone is determined to be less than 10,000 mg/l, the Operator will seek a UIC Aquifer exemption pursuant to Rule 802. The Operator will evaluate disposal zones for hydrocarbon potential pursuant to Rule 408.q. For a new Class II UIC Well, the Applicant may provide any available representative water analysis from offset Well(s) completed in the same Injection Zone within 1 mile of the proposed injection Well for submission with a Form 31 – Intent. The Operator will submit a water analysis from the Injection Zone, collected from the disposal Well(s) in the application with the Form 31 – Subsequent after the Well(s) are completed.

E. A description of the compatibility of the injection Fluid with the Injection Zone.

F. A description of the source(s) of the Fluid and a description of the transport method from the source(s) to the injection Well(s).

G. A general description of the surface facilities, separation, and treatment processes.

H. The estimated volume to be injected daily.

I. The anticipated injection pressures and known or calculated fracture gradient.

(6) **Seismicity Evaluation.** The application will include a seismicity evaluation with the following information:

A. A geological and geophysical evaluation of known transmissive or sealing faults or shear zones within 12 miles of the proposed Class II UIC Well and the potential for induced seismicity during injection operations;

B. An exhibit of the historical seismic activity within 12 miles of the proposed injection Well;

C. An exhibit showing the potential for seismic activity within 12 miles of the proposed injection Well; and

D. A wellbore diagram of the Injection Zone depicting the Well's bottomhole location relative to the Precambrian basement.

(7) **Oil and Gas Well Map and List.**

A. The application will include a base map covering the area within 1 mile, as measured from the surface location(s) for proposed vertical disposal Well(s), or within 1 mile of the completed portion of the wellbore(s), projected to surface in plan view in the Injection Zone in drifted, directional, or horizontal disposal Wells. The base map will show the proposed injection wellbore(s), wellbore path(s), and all oil and gas Wells within a 1 mile radius of the injection wellbore(s). Labels on the map will identify all oil and gas Wells within 1 mile of the proposed injection wellbore(s) that are producing from the proposed Injection Zone at the time of the application.

B. For enhanced recovery projects, a map meeting the requirements of Rule 811.b.(8).

C. A list will provide additional details for all oil and gas Wells shown on the oil and gas Well map and their total depth, completed interval depths, completed formation names, and producing or injecting status at the time of application.

(8) **Water Wells Map and List.** The application will include a map and list of all water wells registered with the Division of Water Resources, within 1 mile of the proposed Class II UIC Well(s), including their location and depth.

(9) **Area of Review.** The application will include a review of all offset oil and gas Wells within 1/2 mile of proposed injection wellbore(s), describing existing isolation of Injection Zones, oil and gas production formations, Confining Layers, and Underground Sources of Drinking Water.

(10) **Remedial Corrective Action Plan.** The Applicant will include a remedial corrective action plan for any offset Well(s) within 1/4 mile of the proposed injection wellbore(s) in which the Injection Zone is not adequately plugged or otherwise isolated with cement to prevent flow into the offset Well(s). The remedial corrective action plan will describe the Applicant's plan for performance of any such remedial work to plug, re-plug, or provide remedial cement for the offset Wells, which the Applicant may or may not operate.

A. For a volume increase request pursuant to Rule 803.f.(1).C, the Applicant will provide a remedial corrective action plan for offset Wells within 1/2 mile of the proposed injection wellbore(s).

B. This Rule 803.g.(10) does not apply to enhanced oil recovery projects where an offset production Well is part of the enhanced oil recovery project.

(11) **Stimulation Program.** The application will include a summary of any proposed stimulation program.

(12) **Disposal Formation Hydrocarbon Evaluation.** For disposal Wells, the application will include the Operator's proposed method of evaluating hydrocarbon production potential of the proposed Injection Zone. This Rule 803.g.(12) will not apply to enhanced recovery wells.

(13) **Class II Waste Source List.** The application will include a listing of all potential sources of Class II E&P Waste to be injected on a Form 26, Source of Produced Water for Disposal, and Form 14A, Authorization of Source of Class II Waste for Disposal, as applicable.

(14) **Notice of Application.** A notice of application for an injection Well will be given by the Applicant by registered or certified mail or by personal delivery to the persons listed below. The application will include a certificate of service demonstrating that the Applicant served a copy of the application on all persons entitled to notice pursuant to the Commission's Rules. The certificate of service will include the names and addresses of those persons the Applicant notified, and the Applicant will certify that notice was given by registered or certified mail, or by personal delivery. The Applicant will provide notice to:

A. Surface Owners and mineral Owners with recorded ownership interests within 1/2 mile of the surface location of the proposed Class II UIC Well(s), the Relevant Local Government in which the injection Well(s) are located and any Local Government with land use authority within 1/2 mile of the surface location(s) for proposed vertical Well(s), or within 1/2 mile of the completed portion of the wellbore(s), projected to surface in plan view in the Injection Zone in drifted, directional, or Horizontal Wells.

B. For a volume increase request pursuant to Rule 803.f.(3), all persons and entities listed in Rule 803.g.(14).A within a 3/4 mile radius of the proposed injection wellbore(s).

C. Disposal Wells and Simultaneous Injection Wells. Owners and Operators of oil and gas Wells producing from the Injection Zone and the recorded mineral Owner of the Injection Zone within 1/2 mile of the surface location(s) for proposed vertical disposal Well(s), or within 1/2 mile of the completed portion of the wellbore(s), projected to surface in plan view in the Injection Zone in drifted, directional, or horizontal disposal Wells, and to mineral Owners of Cornering and Contiguous Units where injection will occur into the producing zones, whichever is the greater distance.

D. Enhanced Recovery Wells. If injection of Fluids is proposed for an enhanced recovery project, the Applicant will provide an entire copy of the application, by registered or certified mail or by personal delivery, to each mineral Owner of record of the reservoir involved within the unit and within 1/2 mile of the proposed unit boundary.

(15) Notice of Application Requirements. The notice of application will briefly describe the injection application and include legal location, proposed Injection Zone(s), depth of injection, and other relevant information.

A. The notice will specifically state that pursuant to Rule 507.a, any person who may be directly and adversely affected or aggrieved by the authorization of the underground injection into the proposed Injection Zone is entitled to file, within 30 days of notification, a written request for a public hearing before the Commission, provided such request meets the petition requirements specified in Rule 804.b.

B. The notice will state that additional information about the operation of the proposed Class II UIC Well may be obtained at the Commission's office and on the Commission's website. The notice will provide the appropriate Commission Staff contact information.

C. A copy of the notice of application will be included with the Form 31 – Intent filed with the Commission.

h. Form 31, Underground Injection Formation Permit Application – Subsequent. Within 30 days of a successful mechanical integrity test for a Class II UIC Well, the Operator will file a Form 31 – Subsequent, which will include the following information:

(1) Injection Zone Water Analysis. A water analysis from the Injection Zone, collected from the Class II UIC Well(s) in the application, addressing all analytes listed in and following all procedures required by Rules 909.j.(1)–(5).

(2) Geophysical Logs. Openhole resistivity and neutron/density Logs from the bottom of the surface casing to total depth of the Class II UIC Well, unless otherwise specified as a condition of approval on the Form 31 – Intent for the injection Well.

(3) Step Rate or Injectivity Test Documentation. If the Operator performs a step rate test or injectivity test, the Operator will submit the test results.

(4) Disposal Well Hydrocarbon Evaluation Results. Summary of the Operator's evaluation of Productivity Test results in the Injection Zone. This Rule 803.h.(4) will not apply to enhanced recovery wells.

i. Form 33, Injection Well Permit Application – Intent. The Operator will file a Form 33 – Intent, which will include the following information:

(1) Wellbore Diagram. An existing and proposed schematic drawing showing all casing strings with cement volumes and tops, plug back total depth, isolation devices, remedial cement work, depth of any existing open or squeezed perforations, setting depths of any existing or proposed bridge plugs, formation tops, planned perforations in the Injection Zone, tubing and packer size, and setting depth.

(2) Casing and Cementing Plan. The application will include a proposed casing and cement plan for the injection Well meets the requirements of Rule 308.b.(6). This will include any previous and proposed remedial cement work.

(3) Casing Integrity. For existing Wells proposed for conversion to a Class II UIC Well, the Operator will check the condition of the casing with a pipe analysis Log or a caliper Log and include a copy of the Log with the application.

j. Form 33, Injection Well Permit Application – Subsequent. After a Class II UIC Well is completed, recompleted, or after Injection Zones are temporarily abandoned, the Operator will file a Form 33 – Subsequent.

(1) The Form 33 – Subsequent will include the following as-constructed details:

A. **Wellbore Diagram.** A final schematic drawing showing all casing strings with cement volumes and tops, plug back total depth, isolation devices, depth of any existing open or squeezed perforations, setting depths of any bridge plugs, formation tops, perforations in the Injection Zone, tubing and packer size, and setting depths.

B. **Casing and Cementing.** Documentation of the final casing and cement in the Class II UIC Well, any existing remedial cement confirmed during the work, and remedial cement placed during the work.

C. **Cement Bond Log.** Unless already provided to the Commission, to determine if the cement has been placed to adequately isolate the Injection Zone, production zones, and Groundwater, a cement bond or other cement evaluation Log will be run and provided with this report as a means of verifying cementing records.

(2) Mechanical Integrity Testing Requirement. Prior to application approval, the proposed Class II UIC Well will satisfactorily pass a mechanical integrity test pursuant to Rule 417 and be witnessed by the Director.

k. Injection Application Deadlines. After a Form 31 – Intent and any related Form 33 – Intents have been approved, the Operator will submit all of the data or information necessary to approve the Form 31 – Subsequent or any related Form 33 – Subsequents within 6 months, or the application for a Form 31 – Subsequent or any related Form 33 – Subsequents will be withdrawn from consideration. However, for good cause shown, a 90-day extension may be granted, if requested in writing to the Director on a Form 4 prior to the date of expiration.

l. Notice of Commencement. Within 30 days after the commencement of injection operations, the Operator will submit a Form 5A, Completed Interval Report, to notify the Commission of the injection date.

m. Notice of Discontinuance. Within 10 days after the discontinuance of injection operations, the Operator will submit a Form 4 to notify the Commission of the date of such discontinuance, the reasons for the discontinuance, and the Operator's future plans for the Class II UIC Well. An Operator need not submit a notice of discontinuance for status changes to or from injection to production in enhanced recovery projects, and instead should submit a notice of status change pursuant to Rule 811.d.

n. Before plugging any Class II UIC Well, the Owner of the Well will provide notice to the Commission and will follow the same procedures for plugging a Class II UIC Well as the procedures for plugging oil and gas Wells pursuant to Rule 434.a.

804. NOTICE AND COMMENT FOR CLASS II UIC WELL APPLICATIONS

a. Injection Well Public Notice and Comment.

(1) When the Director determines that a proposed injection permit application is complete, the Director will publish a notice of the proposed injection permit application in a newspaper of general circulation serving the area where the injection Well(s) is (are) located, and also publish notice on the Commission's website. The Director will simultaneously provide notice to the Division of Water Resources.

(2) The notice will briefly describe the proposed injection permit application and include legal location, proposed Injection Zone, depth of injection, and other relevant information.

(3) The comment period for the proposed injection permit application will begin on the date that notice is published in a newspaper of general circulation, and will end 30 days after the date of such publication.

(4) During the public comment period, any interested person may electronically submit comments about the proposed injection permit application to the Commission.

(5) During the public comment period, any interested person may submit a written protest. For any proposed injection permit application that is not associated with a Form 2A or Oil and Gas Development Plan application, such a protest will also request a Commission hearing about the proposed injection permit application pursuant to Rule 503.g.(10). Such protests will be evaluated pursuant to Rule 804.b.

b. Evaluation of Written Requests for Public Hearing. Pursuant to Rule 507.a, written requests for public hearing before the Commission by a person who may be directly and adversely affected or aggrieved by the authorization of the proposed injection permit application will be reviewed and evaluated by the Commission. Written protests will specifically provide information about:

(1) Possible conflicts between the Injection Zone's proposed injection use and present or future use as a source of drinking water, agricultural water, or as a source of hydrocarbon production;

(2) How proposed operations at the Class II UIC Well site are not protective of potential and current sources of drinking water or agricultural water;

(3) How the proposed Class II UIC Well is not protective of applicable Colorado water quality standards or public health, safety, welfare, the environment, or wildlife resources; or

(4) How the application will not protect against adverse environmental impacts on any air, water, soil, or biological resource.

805. ANALYTICAL REQUIREMENTS FOR INJECTION FLUID ANALYSES

a. Collection and analysis of water samples required by Rules 803, 809, 810, or 811 will comply with the Commission's approved Underground Injection Control Quality Assurance Project Plan, effective October 8, 1997.

b. Water analyses will include total dissolved solids using routine EPA or oilfield methods.

c. If requested by the Director, the Operator will analyze samples for other constituents that may be present in the injection Fluids.

d. The Operator will report all analyses of water samples with the Electronic Data Deliverable ("EDD") through the Commission's Environmental Database on a Form 43, Analytic Sample Submittal.

806. TIMING OF INJECTION FLUID SAMPLING AND ANALYSIS

a. **Initial Analysis.** An injection Fluid analysis from a representative sample collected at the injection facility is required within 1 year of commencing injection after approval of an injection application.

b. **Periodic Analysis.** An injection Fluid analysis from a representative sample collected at the injection facility is required every 5 years after the initial analysis or 5 years after the most recent change of source analysis.

c. **Change of Source Analysis.** An injection Fluid analysis is required when there is a significant change in the quality of the injection Fluid and as required by Rule 807. The injection Fluid analysis will address all analytes listed in and follow all procedures required by Rules 909.j.(1)–(5).

807. FORM 26, SOURCE OF PRODUCED WATER FOR DISPOSAL

a. The Operator of a Class II UIC Well will submit a Form 26, Source of Produced Water for Disposal, before commencing injection into the Well(s).

b. The Operator of a Class II UIC Well will submit a new Form 26 within 90 days after any change in source water by addition of new source Wells or the deletion of existing source Wells.

808. NON-PRODUCED CLASS II EXPLORATION AND PRODUCTION WASTE INJECTION

a. **Form 14A, Authorization of Source of Class II Waste for Disposal.** The Operator of a Class II UIC Well will submit and obtain approval of a Form 14A, Authorization of Source of Class II Waste for Disposal, prior to the injection of Class II E&P Waste other than produced water, pursuant to Rule 413.b, into any formation in a Class II UIC Well.

(1) The Form 14A will include a description of the nature and source of the Fluids to be injected, the types of Chemicals used to treat such Fluids, and the proposed date of initial Fluid injection.

(2) The Operator will submit a Form 14A and obtain the Director's approval for any new disposal facility, and for any changes in the source of non-produced Class II waste for an existing facility.

(3) Examples of non-produced water are Fluids that are not classified as a hazardous waste at the time of injection, and include Fluids which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations.

b. **Form 14, Monthly Report of Non-Produced Water Injected.**

(1) The Operator engaged in the injection of approved non-produced Class II waste pursuant to Rule 808.a in a Class II UIC Well will submit a Form 14, Monthly Report of Non-Produced

Water Injected, within 45 days after the end of each month. This report will include the type and amount of Waste injected.

(2) The Operator of a Simultaneous Injection Well will, by March 1 of each year, report to the Director the calculated injected volume for the previous year, by month, on a Form 14.

809. SIMULTANEOUS INJECTION WELL APPLICATION REQUIREMENTS

a. Applications for new Simultaneous Injection Wells will:

(1) Satisfy the requirements of Rules 803, 804, 805, 806, 807, and 808.

(2) Include downhole pump specifications and a calculation of maximum discharge pressure created under proposed wellbore configuration. Downhole pump configurations will be designed to inject below the Injection Zone fracture gradient.

810. COMMERCIAL DISPOSAL WELLS AND FACILITIES

a. Applications for new Commercial Disposal Wells will:

(1) Satisfy the requirements of Rules 803, 804, 805, 806, 807, and 808.

(2) Meet the Financial Assurance requirements of Rules 706, 707, and 713.

b. Commercial Disposal Well Facilities will perform continuous seismic monitoring. The Operator will provide seismic monitoring data to the Director upon request.

811. ENHANCED RECOVERY INJECTION PROJECTS

a. No person will perform any enhanced recovery operations, cycling, or recycling operations, including the extraction and separation of liquid hydrocarbons from natural gas, nor will 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 following a hearing pursuant to Rule 503.g.(3). Enhanced recovery projects include at least one injection Well and one production Well, which may be the same Well for “huff and puff” style operations.

b. Hearing applications for new enhanced recovery injection projects will include the following information:

(1) Demonstration that the proposed project satisfies the requirements of Rules 803, 804, 805, 806, 807, and 808 unless otherwise noted in those Rules.

(2) Be filed by the Operator, or any one or more of the parties involved in the proposed enhanced recovery injection project.

(3) **Operator Contact.** The name, phone, email, and address of all Operators in the unit.

(4) **Unit and Operating Agreements.** A copy of the unit or co-operative agreement and operating agreement.

(5) **Multiple Well Applications.** An application may include the use of more than 1 injection or production Well on the same location, or on more than 1 location. The application will contemplate a coordinated plan for the entire Field.

(6) Unit Plan of Operations. This information will supplement the proposed injection program summary required by Rule 803. The plan of operations will describe how the enhanced recovery project will be operated as a system.

(7) Casing and Cementing for Enhanced Recovery Injection Wells. A casing and cement plan that meets the requirements of Rule 308.b.(6) to prevent leakage and damage to Groundwater, oil, or gas resources.

(8) Unit Area Owners Map. A map will show the names of Owners of record within the unit and within 1/2 mile of the unit boundary, indicating whether they are Surface Owners, mineral interest Owners, or working interest Owners.

(9) Unit Area Well Plat. A plat showing the boundary of the unit area, and the Class II UIC Well(s), all offset injection Wells, production Wells, Plugged and Abandoned Wells, and dry and abandoned Wells.

(10) Unit Area Water Wells Map and List. The application will include a map and list of all water wells registered with the Division of Water Resources, within the unit area and within 1/2 mile of the unit boundary, including their depth.

(11) Unit Area of Review. The application will include a review of all existing Wells within the unit area and within 1/4 mile of the unit boundary, describing existing isolation of Injection Zones, oil and gas production formations, Confining Layers, and Underground Sources of Drinking Water.

c. Notice and Date of Hearing for Enhanced Recovery Injection Projects. Upon the filing of an enhanced recovery injection project application, the Commission will issue a notice of hearing pursuant to Rule 503.a. The application will be set for public hearing at a time designated by the Commission.

d. Notice of Status Change. When any Well in an approved enhanced recovery unit operation is converted to or from an injection to production status, the Operator will provide notice on a Form 4 within 30 days.

ENVIRONMENTAL IMPACT PREVENTION
900 SERIES

901. GENERAL STANDARDS

a. Addressing Impacts and Potential Impacts to Public Health, Safety, Welfare, the Environment, and Wildlife Resources. Whenever the Director has reasonable cause to determine that an Operator, in the conduct of any Oil and Gas Operations, is impacting or threatening to impact public health, safety, welfare, the environment, or wildlife resources, the Director may require the Operator to take action to avoid, minimize, or mitigate the potential impacts to public health, safety, welfare, the environment, or wildlife resources, including but not limited to:

(1) Suspending operations or initiating immediate mitigation measures until the cause of the threat or potential threat to public health, safety, welfare, the environment, or wildlife resources is identified and the threat or potential threat to public health, safety, welfare, the environment, or wildlife resources is corrected.

(2) Submitting a Form 27, Site Investigation and Remediation Workplan, for site characterization, Remediation, monitoring, permitting, and the establishment of points of compliance.

(3) If the Director requires an Operator to take action pursuant to this Rule 901.a, the Operator may appeal the Director's decision to the Commission pursuant to Rule 503.g.(10). The matter will not be assigned to an Administrative Law Judge pursuant to Rule 503.h. The Commission will hear the appeal at its next regularly scheduled meeting. Operators will continue to comply with any requirements identified by the Director pursuant to this Rule 901.a until the Commission makes a decision on the appeal. The Commission may uphold the Director's decision if the Commission determines the Director had reasonable cause to determine that an Operator's actions impacted or threatened to impact public health, safety, welfare, the environmental, or wildlife resources, and that the action required by the Director was necessary and reasonable to avoid, minimize, or mitigate those impacts or threatened impacts.

b. Incorporation by Reference. Pursuant to § 24-4-103(12.5), C.R.S., the Commission incorporates by reference into these 900 Series Rules the following codes, standards, guidelines, and rules of other federal agencies, state agencies, and nationally recognized organizations and associations.

(1) Where Materials May Be Found.

A. Copies of all materials incorporated by reference 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.

B. Copies of all materials incorporated by reference are also available at the office or website of the agency or organization that issued the code, standard, guideline, or rule, as specified below.

C. Copies of any materials that are not available to the public on the internet for no cost may be examined at any state publications depository library.

(2) Current Version. Only the version of the code, standard, guideline, or rule in effect as of January 15, 2020, and no later amendments or editions of the code, standard, guideline, or rule are incorporated by reference, unless otherwise specified below.

(3) Materials Incorporated.

A. 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.* (hereinafter "WQCC Regulation 41"). Only the version of WQCC Regulation 41 in effect as of January 15, 2021 applies; later amendments do not apply. WQCC Regulation 41 may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and is available online at https://cdphe.colorado.gov/water-quality-control-commission-regulations.

B. Colorado Department of Public Health and Environment, Solid and Hazardous Waste Commission ("SHWC"), Regulations Pertaining to Solid Waste, 6 C.C.R. § 1007-2*, et seq.* (hereinafter "SHWC Solid Waste Regulations"). Only the version of the SHWC Solid Waste Regulations in effect as of January 15, 2021 applies; later amendments do not apply. The SHWC Solid Waste Regulations may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and are available online at https://cdphe.colorado.gov/solid-waste-regulations.

C. SHWC Regulations Pertaining to Hazardous Waste, 6 C.C.R. § 1007-3, *et seq.* (hereinafter "SHWC Hazardous Waste Regulations"). Only the version of the SHWC Hazardous Waste Regulations in effect as of January 15, 2021 applies; later amendments do not apply. The SHWC Hazardous Waste Regulations may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and are available online at https://cdphe.colorado.gov/hazardous-waste-regulations.

D. Colorado Department of Public Health and Environment, Air Quality Control Commission ("AQCC"), Regulation No. 7, Control of Ozone Via Ozone Precursors and Control of Hydrocarbons Via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides), 5 C.C.R. § 1001-9, *et seq.* (hereinafter "AQCC Regulation No. 7"). Only the version of AQCC Regulation No. 7 in effect as of January 15, 2021 applies; later amendments do not apply. AQCC Regulation No. 7 may be examined at the Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80246, and is available online at https://cdphe.colorado.gov/aqcc-regulations.

E. Colorado State Board of Examiners of Water Well Construction and Pump Installation Contractors, Rules and Regulations for Water Well Construction, Pump Installation, Cistern Installation, and Monitoring and Observation Hole/Well Construction, 2 C.C.R. § 402-2, *et seq.* (hereinafter "State Engineer's Water Well Construction and Permitting Rules"). Only the version of the State Engineer's Water Well Construction Rules in effect as of January 15, 2021 applies; later amendments do not apply. The State Engineer's Water Well Construction and Permitting Rules may be examined at the Colorado Division of Water Resources, 1313 Sherman St., Suite 821, Denver, CO 80203, and are available online at https://dwr.colorado.gov/services/well-construction-inspection.

F. U.S. Environmental Protection Agency, Test Methods for Evaluating Solid Waste: Physical/Chemical Methods (May 2019 edition) (hereinafter, "EPA SW-846"). Only the May 2019, "Update VI" edition of EP SW-846 applies to this rule; later amendments do not apply. EPA SW-846 may be examined at the U.S. Environmental Protection Agency, Region 8, 1595 Wynkoop St, Denver, CO 80202, and is available online at https://www.epa.gov/hw-sw846/sw-846-compendium.

G. U.S. Environmental Protection Agency, 40 C.F.R. § 60.5375a, What GHG and VOC standards apply to well affected facilities? (2016) (hereinafter, "40 C.F.R. § 60.5375a"). Only the version of 40 C.F.R. § 60.5375a that became effective on August 2, 2016 applies to this rule; later amendments do not apply. 40 C.F.R. § 60.5375a may be examined at the U.S. Environmental Protection Agency, Region 8, 1595 Wynkoop St, Denver, CO 80202, and is available online at https://www.govinfo.gov/content/pkg/FR-2016-06-03/pdf/2016-11971.pdf.

H. U.S. Environmental Protection Agency, Regional Screening Levels for Chemical Contaminants at Super Fund Sites (Nov. 18, 2020) (hereinafter, "EPA's RSLs"). Only the November 2020 version of EPA's RSLs applies; later amendments do not apply. EPA's RSLs may be examined at the U.S. Environmental Protection Agency, Region 8, 1595 Wynkoop St, Denver, CO 80202, and are available online at https://www.epa.gov/risk/regional-screening-levels-rsls-generic-tables.

I. Western Coordinating Committee on Nutrient Management, Soil, Plant and Water Reference Methods for the Western Region (4th edition, 2013). Only the 4th edition (2013) of the Soil, Plant and Water Reference Methods for the Western Region applies to this rule; later amendments do not apply. Soil, Plant and Water Reference Methods for the Western Region may be examined at the Soil Science Society of America, 5585 Guilford Road, Madison, WI 53711, and is available online at https://www.naptprogram.org/files/napt/publications/method-papers/western-states-methods-manual-2013.pdf.

J. Rocky Mountain Low-Level Radioactive Waste Board, Rules (Dec. 3, 2010). Only the 2010 version of the Rocky Mountain Low-Level Radioactive Waste Board's Rules apply to this Rule; later amendments do not apply. The Rocky Mountain Low-Level Radioactive Waste Board's Rules may be examined at Rocky Mountain Low-Level Radioactive Waste Board, 999 18th St., Suite 2400 S, Denver, CO 80202, and are available online at http://www.rmllwb.us/documents/Rules_12-3-10.pdf.

902. POLLUTION

a. Operators will prevent Pollution.

b. Operators will prevent adverse environmental impacts on any air, water, soil, or biological resource resulting from Oil and Gas Operations and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

c. Operators will prevent the unauthorized discharge or disposal of oil, condensate, gas, E&P Waste, Chemical substances, trash, discarded equipment, and other oil field waste.

d. No Operator, in the conduct of any Oil or Gas Operation, may violate numeric or narrative water quality standards or classifications established by the WQCC for Waters of the State, or any Point of Compliance established by the Director pursuant to Rule 914. The Director may require the Operator to establish one or more Points of Compliance for any event of Pollution, which will be complied with by all parties determined to be a Responsible Party for such Pollution.

e. No Operator, in the conduct of any Oil or Gas Operation, may violate any applicable air quality law, regulation, or permit 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.

f. No person may 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 accordance with the regulations pertaining to Solid Waste Disposal sites and facilities as promulgated by CDPHE.

903. VENTING OR FLARING NATURAL GAS

Venting and Flaring of natural gas represent waste of an important energy resource and pose safety and environmental risks. Venting and Flaring, except as specifically allowed in this Rule 903, are prohibited.

a. Notice to Local Governments and Emergency Responders.

(1) **Prior Notice.** As soon as practicable prior to, but no later than two hours before, any planned Flaring of natural gas allowed pursuant to this Rule 903, Operators will provide verbal, written, or electronic notice to the Relevant and Proximate Local Governments and to the local emergency response authorities.

(2) **Subsequent Notice.** In the event of Flaring due to an Upset Condition, Operators will provide verbal, or electronic notice as soon as possible, but no later than 12 hours, to the Relevant and Proximate Local Governments and to the local emergency response authorities.

(3) **Waiver.** Relevant and Proximate Local Governments and local emergency response authorities may waive their right to notice under this Rule 903.a at any time, pursuant to Rule 302.f.(1).A.

(4) **Recordkeeping.** Operators will maintain records of notice provided pursuant to this Rule 903.a, and provide the records to the Director upon request.

b. Emissions During Drilling Operations.

(1) Operators will capture or combust gas downstream of the mud-gas separator using best drilling practices while maintaining safe operating conditions.

(2) If capturing or combusting gas would pose safety risks to onsite personnel, Operators may Vent and will provide verbal notification to the Director within 12 hours and submit a Form 4, Sundry Notice within 7 days. The Operator need not seek a formal variance pursuant to Rule 502. A Form 23, Well Control Report may also be required if the criteria in Rule 428.c are met. If Venting pursuant to this Rule 903.b.(2) exceeds 24 hours, the Operator will seek the Director's approval to continue Venting.

(3) Combustors will be located a minimum of 100 feet from the nearest surface hole location and enclosed.

c. Emissions During Completion Operations.

(1) **Reduced Emission Completions Practices.** Operators will adhere to reduced emission completion practices as specified in 40 C.F.R. § 60.5375a, as incorporated by reference in Rule 901.b, on all newly Completed and re-completed oil and gas Wells regardless of whether the Well is hydraulically fractured, unless otherwise specified in this Rule 903.c.

(2) **Flowback Vessels.** Operators will enclose all Flowback vessels and adhere to the AQCC Regulation No. 7 standards for emission reduction from pre-production Flowback vessels as specified in 5 C.C.R. § 1001-9:D.VI.D, as incorporated by reference in Rule 901.b.

(3) Operators may Flare gas during completion operations with specific written approval from the Director under any of the following circumstances:

A. The Operator obtains the Director's approval to Flare through an approved gas capture plan pursuant to Rule 903.e;

B. The Operator submits, and the Director approves, a Form 4 allowing the Operator to Flare gas that would otherwise not be permitted pursuant to Rule 903.c.

i. On the Form 4 the Operator will explain why Flaring is necessary to Complete the Well, and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

ii. On the Form 4 the Operator will estimate anticipated Flaring volume and duration.

iii. On the Form 4 the Operator will explain its plan to connect the facility to a Gathering Line or otherwise utilize the gas in the future.

iv. The Director may approve a Form 4 requesting permission to Flare during completion if the Director determines that the Flaring is necessary to Complete the Well and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources; or

C. The Operator may direct gas to an emission control device and combust the gas if necessary to ensure safety or during an Upset Condition for a period not to exceed 24 cumulative hours. If Flaring pursuant to this Rule 903.c.(3).C exceeds 24 hours, the Operator will seek the Director's approval to continue Flaring. Within 7 days of the Flaring event, the Operator will submit a Form 4 reporting the Upset Condition or safety issues that resulted in the Flaring event and include the estimated volume of gas Flared.

d. Emissions During Production.

(1) After the Commencement of Production Operations at an Oil and Gas Location, Venting or Flaring of natural gas produced from any Completed Well is prohibited except under the following circumstances:

A. Gas Flared or Vented during an Upset Condition is allowed for a period necessary to address the upset, not to exceed 24 cumulative hours. Operators will maintain records of the date, cause, estimated volume of gas Flared or Vented, and duration of each Upset Condition resulting in Flaring or Venting, and will make such records available to the Director upon request.

B. Gas Vented during and as part of active and required maintenance and repair activity, including pipeline pigging, as long as the Venting is not prohibited by AQCC Regulation No. 7, 5 C.C.R. § 1001-9, as incorporated by reference in Rule 901.b. Operators will use operational best practices to minimize Venting during maintenance and repair activity.

C. If approved by the Director on a Gas Capture Plan pursuant to Rule 903.e, gas Flared during a Production Evaluation or Productivity Test for a period not to exceed 60 days.

D. Gas Vented during a Bradenhead test pursuant to Rule 419.

E. Any event of Well liquids unloading, as long as the Well liquids unloading employs best management practices to minimize hydrocarbon emissions as required by the AQCC Regulation No. 7, 5 C.C.R. § 1001-9, as incorporated by reference in Rule 901.b. Operators will capture or Flare gas escaping into the air during liquids unloading if the escape of the gas poses a risk to public health, safety, or welfare due to the risk of a fire, explosion, or inhalation. Pursuant to Rule 405.s, all Well liquids unloading, including swabbing, will be reported to the Director. The Operator will submit a Form 42, Field Operations Notice – Notice of Well Liquids Unloading, no less than:

i. 48 hours prior to conducting Well liquids unloading; or

ii. As soon as possible prior to conducting Well liquids unloading if 48 hours notice would require an alternative or extended Well liquids unloading practice that increases emissions.

F. Flaring or Venting approved pursuant to Rule 903.d.(3) or on a Form 4 prior to January 15, 2021.

(2) For any instance of Venting or Flaring permitted pursuant to Rules 903.d.(1).A–E for a period that exceeds 8 consecutive or 24 cumulative hours, the Operator will submit a Form 4 reporting:

A. The estimated or measured volume and content of gas Vented or Flared;

B. Gas analysis of the gas Vented or Flared, including hydrogen sulfide;

C. Explanation, rationale, and cause for the Venting or Flaring event; and

D. A description of any operational best practices used to minimize Venting during maintenance and repair activity.

(3) At Wells that have Commenced Production Operations prior to January 15, 2021 and that are Venting or Flaring natural gas because they are not connected to a natural gas Gathering Line or putting the natural gas to beneficial use, the Operator may request permission from the Director to Flare or Vent by submitting a gas capture plan via a Form 4 no later than the date the Operator's previously approved Form 4 expires and in no case later than January 15, 2022. If an Operator loses access to a Gathering Line after January 15, 2021, the Operator will submit a gas capture plan via a Form 4 within 30 days of losing the Gathering Line access. The Operator may not Flare or Vent pursuant to this Rule 903.d.(3) unless and until the Director approves the Form 4. The Director may approve a one-time request to Flare or Vent for a period not to exceed 12 months, if the Director determines that Flaring or Venting is necessary to produce the Well, will minimize waste, and will protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. For any such Form 4 submitted prior to January 15, 2022, the Director will not approve the one-time request to Flare or Vent to any date after January 15, 2022. The gas capture plan on the Form 4 will describe:

A. The estimated volume and content of the gas to be Flared or Vented;

B. Gas analysis including hydrogen sulfide for the subject Well;

C. For requests based on lack of available infrastructure, the Operator will state why the Well cannot be connected to infrastructure;

D. When the Well(s) will be connected to infrastructure, why the Operator commenced production of the Well before infrastructure was available, and whether the mineral Owner will be compensated for the Vented or Flared gas; and

E. Options for using the gas instead of Flaring or Venting, including to generate electricity, gas processing to recover natural gas liquids, or other options for using the gas.

(4) Measurement and Reporting.

A. Operators will measure the volume of all gas Vented, Flared, or used at an Oil and Gas Location by direct measurement or by estimating the volume of gas Vented, Flared or used. The volume of gas Vented, Flared, or used will be reported on a per Well basis on the Form 7, Operator's Monthly Report of Operations.

B. Operators will notify all mineral Owners of the volume of oil and gas that is Vented, Flared, or used on-lease. Operators will maintain records of such notice and provide the records to the Director upon request.

(5) All Flared gas will be combusted in an enclosed device equipped with an auto-igniter or continuous pilot light and a design destruction efficiency of at least 98% for hydrocarbons.

(6) Pits.

A. Pits Constructed After January 15, 2021.

i. Operators will design, construct, and operate new Pits that are within 2,000 feet of an existing Building Unit or Designated Outside Activity Area to emit less than 2 tons per year ("tpy") volatile organic compounds ("VOCs").

ii. Operators will design, construct, and operate new Pits within Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson, Larimer, and Weld Counties to emit less than 2 tpy VOCs.

iii. Operators will design, construct, and operate new Pits in locations that do not meet the criteria of Rules 903.d.(6).A.i–ii to emit less than 5 tpy VOCs, unless:

aa. The Pit is used for recycling or reuse of produced water, subject to the approval of a reuse and recycling plan pursuant to Rule 905.a.(3);

bb. The Operator utilizes a centralized water distribution system to minimize trucks used to transport produced water; and

cc. The Director approves the Operator's plan to minimize emissions pursuant to Rule 903.d.(6).A.iv based on consultation with the Air Pollution Control Division.

iv. Operators will design, construct, and operate new Pits to utilize control technology to minimize emissions to the extent reasonably achievable based on best available practices.

B. Pits Constructed Prior to January 15, 2021. After January 15, 2023, all Pits constructed prior to January 15, 2021 will be operated to emit less than 5 tpy VOCs, unless:

i. The Pit is used for recycling or reuse of produced water and the Pit utilizes control technology to minimize emissions to the extent reasonably achievable, and the Operator submits and obtains the Director's approval of a reuse and recycling plan that meets the requirements of Rule 905.a.(3); or

ii. The Operator submits a Form 15, Earthen Pit Report/Permit pursuant to Rule 903.a.(6).C demonstrating that a greater allowable rate of emissions from the Pit is reasonable and necessary, and the Director approves the Form 15 based on consultation with the Air Pollution Control Division.

C. Operators will provide the basis for their determination of applicability under Rule 903.d.(6) to the Director on a Form 15 submitted concurrently with the initial produced water quality analysis required by Rule 909.j. The basis for determination of applicability will:

i. State the Pit's estimated annual emissions in tpy VOCs;

ii. Describe the method used to estimate emissions; and

iii. If the Operator seeks an exception pursuant to Rules 903.d.(6).B.i or ii, describe the basis for why the exception should be granted.

e. Gas Capture Plans.

(1) Gas Capture Plan Submission.

A. On a Form 2A, Oil and Gas Location Assessment the Operator will commit to connecting to a gathering system by the Commencement of Production Operations, or submit a gas capture plan as an attachment to their Form 2A, pursuant to Rule 304.c.(12).

B. Gas capture plans will demonstrate compliance with the requirements of Rules 903.b–d and include the following information:

i. A description and map of the location of the closest or contracted natural gas gathering system or point of sale.

ii. The name of the company operating the closest or contracted natural gas gathering system.

iii. The Operator's plan for connecting their facility to a natural gas gathering system or otherwise putting gas to beneficial use, including:

aa. Discussion of potential rights of way issues;

bb. Construction schedules;

cc. Date of availability of the gas Gathering Line;

dd. Whether the nearest or contracted gas gathering system has capacity to accept the anticipated gas to be produced at the location at the time of application; and

ee. Options for beneficial use of natural gas that are alternatives to Flaring during production operations prior to connection to gas Gathering Lines, including, but not limited to: onsite use, natural gas liquid processing, electrical power generation, gas to liquid, reinjection for enhanced oil recovery, or other options.

iv. For a Wildcat (Exploratory) Well or if the Operator anticipates conducting a Production Evaluation or Productivity Test, a description of the planned Production Evaluation or Productivity Test and any issues related to the Operator's ability to connect to a gas Gathering Line.

v. Any anticipated safety risks that will require the Operator to allow gas to escape, rather than being captured or combusted during drilling operations, pursuant to Rule 903.b.(2).

vi. A description of operational best practices that will be used to minimize Venting during active and planned maintenance allowed pursuant to Rule 903.d.(1).B.

vii. Procedures the Operator will employ to reduce the frequency of Well liquids unloading events.

viii. Anticipated volumes of liquids and gas production and a description of how separation equipment will be sized to optimize gas capture.

(2) **Verification.** Operators will verify that their facility has been connected to a gathering line by submitting a Form 10, Certificate of Clearance pursuant to Rule 219.

(3) **Compliance.** If an Operator does not connect its facility to a gathering line or otherwise put gas to beneficial use as described in the Operator's Form 2A or gas capture plan, the Director may require the Operator to shut in a Well until it is connected to a Gathering Line or the gas is put to beneficial use. The Operator may request a Commission hearing pursuant to Rule 503.g.(10), however, the Well will remain shut in until the Commission's hearing occurs.

904. EVALUATING CUMULATIVE IMPACTS

a. No later than January 15, 2022, and annually thereafter, the Director will report the following information to the Commission based on consultation with CDPHE and the Department of Natural Resources:

(1) A report from the Director about data gathered regarding anticipated and existing impacts in the Cumulative Impacts Data Evaluation Repository ("CIDER"), including but not limited to data regarding impacts to Wildlife Resources, including High Priority Habitat, and a comparison of water volume data reported pursuant to Rules 303.a.(5).B iii.ee and 431.b;

(2) Information from the Air Pollution Control Division ("APCD") or Air Quality Control Commission ("AQCC") regarding the current status of the Greenhouse Gas Pollution Reduction Roadmap and any initiatives developed by the APCD and AQCC to achieve Colorado's statewide greenhouse gas emission reductions, and the role of Oil and Gas Operations in achieving the reduction targets for the oil and gas sector;

(3) Information from the APDC or AQCC regarding the information reported pursuant to AQCC Regulation No. 7 in the oil and gas emissions inventories;

(4) Information regarding ambient air quality standard attainment, trends, and contributions from Oil and Gas Operations, including ground-level ozone ambient air quality standards;

(5) Information regarding evolving or new innovative technologies or measures, including technologies and measures employed by Operators during the prior year, that may provide innovative methods to reduce emissions or otherwise avoid, minimize, or mitigate adverse cumulative impacts to public health, safety, welfare, the environment, or wildlife resources;

(6) Any reports prepared or published by other Governmental Agencies or academic research institutions that provide relevant information about avoiding, minimizing, or mitigating adverse cumulative impacts to public health, safety, welfare, the environment, or wildlife resources;

(7) Any additional information that is requested by the Commission or that the Director determines is relevant to avoiding, minimizing, or mitigating adverse cumulative impacts to public health, safety, welfare, the environment, and wildlife resources; and

(8) Any recommendations for future rulemakings, guidance, work groups, or studies to address cumulative impacts to public health, safety, welfare, the environment, or wildlife resources and any air, water, soil, or biological resources based on the information presented pursuant to Rules 904.a.(1)–(7).

b. As a condition of approving an Oil and Gas Development Plan pursuant to Rule 307.b.(1), the Commission may require an Operator to participate in studies evaluating cumulative impacts of oil and gas development that is related to an Oil and Gas Location approved pursuant to the Oil and Gas Development Plan, or the impacts of that Oil and Gas Location.

(1) The studies may be conducted in consultation with CDPHE, CPW, the Public Utilities Commission, the Colorado Energy Office, or other third parties.

(2) Participation in the study may involve providing data, conducting investigations, performing monitoring, or other methods of gathering data, supplying data to the Director, or providing the Director or other authorized party access to a physical location. An Operator participating in a study will provide all data and other information gathered as part of the study to the Director upon request. Participation in a study will not require an Operator to fund the study, unless the Operator chooses to provide funding voluntarily.

c. The Commission may establish an informational docket on its own motion pursuant to Rule 503.a. Through the informational docket, the Commission may solicit general or specific information necessary and reasonable to evaluate the cumulative impacts of Oil and Gas Operations. Participation in the informational docket will not require payment of a docket fee or filing fee.

905. MANAGEMENT OF E&P WASTE

a. General Requirements.

(1) **Operator Obligations.** Operators will ensure that E&P Waste is properly stored, handled, transported, treated, recycled, or disposed to prevent threatened or actual adverse environmental impacts to air, water, soil, or biological resources, or to the extent necessary to ensure compliance with the concentration levels in Table 915-1, radiation control standards, and WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

(2) **Protecting Waters of the State.** Operators will conduct E&P Waste management activities, and construct and operate all Oil and Gas Locations, to protect the Waters of the State from adverse environmental impacts caused by E&P Waste.

(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 Form 4, Form 15, or Form 28, Centralized E&P Waste Management Facility Permit. Such plans will describe, at a minimum:

A. The type(s) of waste;

B. The proposed volume and use of the waste;

C. The method of waste treatment and storage;

D. Recycled materials quality assurance;

E. Final disposition of the waste;

F. A copy of any certification or authorization that may be required by other laws and regulations;

G. A proposed timeline for reuse and recycling;

H. Beneficial use criteria;

I. Anticipated method of transporting waste; and

J. Any additional information requested by the Director.

(4) **Waste Management Plans.** Each Operator that generates E&P Waste as a result of their operations will prepare a comprehensive waste management plan detailing how the Operator will treat, characterize, manage, store, dispose, and transport all types of waste generated. The Director may require a waste management plan to include a description of proposed haul routes, including any applicable Local Government traffic requirements.

A. Operators will submit their waste management plans with their Form 2A pursuant to Rule 304.c.(11).

B. Operators will evaluate opportunities for reuse and recycling and may include a reuse and recycling plan, as described in Rule 905.a.(3) above, as part of the waste management plan.

C. If an Operator seeks to change its E&P Waste management practice, the Operator will update its waste management plan by submitting a revised waste management plan for the Director's approval or denial on a Form 4.

(5) Should evidence indicate that conditions at an active or closed Oil and Gas Location, Oil and Gas Facility, or Land Application site where produced Fluids and E&P Waste are currently or were previously generated, stored, treated, or disposed indicate contaminant concentrations in soils or Groundwater exceeding applicable standards, then the Commission authorizes the Director to require further investigation, Remediation, and Reclamation.

b. E&P Waste Transportation.

(1) **Off-Site Transportation Within Colorado.** Operators will only transport E&P Waste off-site within Colorado to facilities authorized by the Director, to permitted commercial waste disposal facilities, permitted commercial waste recycling facilities, or beneficial use sites approved to receive E&P Waste by CDPHE and the Relevant Local Government.

(2) **Off-Site Transportation Outside of Colorado.** Operators will only transport E&P Waste off-site for treatment or waste disposal outside of Colorado to facilities authorized and permitted by the appropriate regulatory agency in the receiving state. Operators will comply with the Rocky Mountain Low-level Radioactive Waste Board's Rules, as incorporated by reference in Rule 901.b.

(3) **Waste Generator Requirements.** Any Operator that generates E&P Waste that is transported off-site will maintain, for not less than 5 years, copies of each invoice, bill, or ticket, and such other records as necessary to document the requirements listed in Rules 905.b.(3).A–F. Such records will be signed by the transporter and provided to the Director upon request.

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.

c. Produced Water.

(1) **Treatment of Produced Water.** Operators will treat produced water prior to placing it in a production pit to prevent crude oil, condensate, or hydrocarbon sheen from entering the Pit.

(2) **Produced Water Disposal.** Produced water may be disposed as follows:

A. Injection into a Class II UIC Well, permitted pursuant to the Commission's 800 Series Rules, or a Class I well permitted by EPA;

B. Evaporation/percolation in a properly permitted Pit at an Oil and Gas Location, operated in accordance with permit conditions that will not cause a violation of any applicable WQCC Regulation 41 numeric or narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b;

C. Disposal at permitted commercial facilities;

D. Discharging into Waters of the State under the following conditions pursuant to the Water Quality Control Act and all applicable regulations.

i. Operators will provide the Colorado discharge permit number, latitude and longitude coordinates pursuant to Rule 216.e of the discharge outfall, and sources of produced water on a Form 26, Source of Produced Water for Disposal, and will include a U.S. Geological Survey topographic map showing the location of the discharge outfall.

ii. If the discharge outfall is not located immediately at the receiving water body, the Operator will prevent surface impacts such as erosion or contamination that can result from the produced water flowing across the land surface.

iii. Produced water discharged pursuant to this Rule 905.c.(2).D may be put to beneficial use in accordance with applicable state statutes and regulations governing the use and administration of water.

E. Evaporation in a properly lined Pit at a Centralized E&P Waste Management Facility permitted pursuant to Rule 907.

(3) **Produced Water Reuse and Recycling.** Operators may reuse produced water for enhanced recovery, drilling, completion, 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 914.

(4) **Mitigation.** Operators may use water produced during operation of an oil or gas Well to provide an alternative domestic water supply to Surface Owners within the oil or gas Field, pursuant to all applicable laws, including, but not limited to, obtaining the necessary approvals from the Water Quality Control Division for constructing a new "waterworks," as defined by § 25-1.5-203(1)(b)(II)(A), C.R.S. Any produced water not so used will be disposed of pursuant to Rules 905.c.(2) or (3). Providing produced water for domestic use within the meaning of this Rule 905.c.(4) will not constitute an admission by the Operator that the Well is dewatering or impacting any existing water well. The water produced will be to the benefit of the Surface Owner within the oil and gas Field and may not be sold for profit or traded.

(5) **Water Sharing Agreements.** Operators will submit agreements for sharing produced water for the Director's approval or denial no less than 60 days in advance of implementing the water sharing plan. The plan will be submitted as a waste management plan pursuant to Rule 905.a.(4).

d. **Drilling Fluids.**

(1) **Reuse and Recycling.** Operators may recycle drilling Pit contents for reuse at another drilling Pit that is properly permitted and operated pursuant to Rules 908, 909, & 910.

(2) **Treatment and Disposal.** Operators will treat or dispose of drilling Fluids through:

A. Injection into a Class II UIC Well permitted pursuant to the Commission's 800 Series Rules;

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 pursuant to Rule 907.

(3) **Additional Authorized Disposal of Water-Based Bentonitic Drilling Fluids.** Operators may dispose of water-based bentonitic drilling fluids through one of the following methods:

A. Drying and burial in Pits on Non-Crop Land, if:

i. The resulting concentrations will not exceed the concentration levels in Table 915-1; and

ii. The Director approves the Operator's plan for closing the Pit pursuant to a prior approved Form 27.

B. Land Application if permitted by a waste management plan approved by the Director pursuant to Rule 905.a.(4), and if the Operator complies with the following standards:

i. **Application Methods.** Acceptable methods of Land Application include, but are not limited to, Production Facility construction and maintenance, lease road maintenance, and offsite beneficial reuse, subject to Rule 905.a.(4).

ii. **Land Application Requirements.**

aa. The average thickness of water-based bentonitic drilling Fluid waste applied will be no more than 3 inches.

bb. Operators will incorporate the drilling Fluid waste through mechanical means into the uppermost soil horizon.

cc. The waste will be applied to prevent ponding or erosion and will be incorporated as a beneficial amendment into the native soils within 10 days of application.

dd. Operators will not apply water-based bentonitic drilling Fluids to Non-Crop Land.

ee. Prior to application, Operators will analyze water-based bentonitic drilling Fluid waste to ensure that concentrations of contaminants of concern in water-based bentonitic drilling Fluids do not exceed concentrations in Table 915-1.

ff. The results of sampling analysis demonstrating compliance with Table 915-1 will be provided to the Director upon request.

iii. **Surface Owner & Relevant Local Government Approval.** Operators will obtain written authorization from the Relevant Local Government, if required, and the Surface Owner prior to Land Application of water-based bentonitic drilling Fluids and provide the written authorization to the Director upon request.

iv. **Recordkeeping.** Operators will maintain records of the information listed in Rules 905.d.(3).B.iv.aa–cc for 5 years, pursuant to Rule 206.f. Operators will provide all such records to the Director within 5 days, upon request:

aa. The source of any water-based bentonitic drilling Fluids applied;

bb. The volume of any water-based bentonitic drilling Fluids applied; and

cc. The location where the Land Application of the water-based bentonitic drilling Fluid occurred.

v. **Operator Responsibility.** The Operator with control and authority over the Well(s) from which the water-based bentonitic drilling fluid wastes were obtained retains responsibility for the Land Application operation. All Operators will cooperate with the Director in responding to complaints regarding Land Application of water-based bentonitic drilling Fluids.

e. Oily Waste.

(1) **Treatment and Disposal.** Operators may treat or dispose of Oily Waste through one of the following methods:

A. Disposal at a commercial Solid Waste Disposal facility;

B. Land Treatment onsite pursuant to 905.e.(2); or

C. Land Treatment at a Centralized E&P Waste Management Facility permitted pursuant to Rule 907.

D. Onsite treatment, for Oily Waste other than Tank bottoms, using alternative methods described on a Form 27 submitted to the Director for prior approval.

(2) **Land Treatment Requirements.**

A. Prior to commencing any Land Treatment, Operators will submit and obtain approval of a Form 27. The Form 27 will include, at a minimum:

i. A site diagram depicting the location of the planned Land Treatment area;

ii. The duration of the planned treatment; and

iii. The Operator's plan for final disposition of the treated Oily Waste.

B. Operators will adhere to the approved plan provided with the Form 27 and Rules 907 and 915 when performing Land Treatment.

C. Operators will remove free oil from the Oily Waste prior to Land Treatment.

D. Operators will spread Oily Waste evenly to prevent pooling, ponding, and runoff.

E. Operators will prevent Pollution of Stormwater Runoff, Groundwater, and surface water.

i. Operators will establish stormwater controls and use Best Management Practices to prevent contaminated stormwater from leaving the Land Treatment area.

ii. Operators will establish Land Treatment areas where contaminant mobility, soil type, or depth to Groundwater prevent downward migration of contaminants that would cause a violation of any WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

iii. Operators will establish Land Treatment areas a minimum of 200 feet from the ordinary high water mark of a surface water.

iv. The Director may require the use of a liner beneath the Land Treatment area as a condition of approval on the Form 27, as appropriate.

F. Operators will enhance biodegradation by routine disking, tilling, aerating, or addition of nutrients, microbes, water or other amendments, at a predetermined frequency pursuant to the approved Form 27.

G. When Operators incorporate land-treated Oily Waste in place or beneficially reuse it, the treated waste may not exceed the cleanup concentrations in Table 915-1, including inorganic constituents and metals.

H. Surface Owner Consent.

i. If an Operator intends to conduct Land Treatment in an area not being utilized for Oil and Gas Operations, the Operator will obtain the Surface Owner's consent to conduct the Land Treatment operations on the Surface Owner's property, and provide a copy of the signed agreement with the Surface Owner to the Director with the Form 27 prior to proceeding with Land Treatment.

ii. If an Operator intends to conduct Land Treatment on an approved Oil and Gas Location prior to completion of interim Reclamation or on the surface disturbance remaining after interim reclamation, the Operator will provide notice to the Surface Owner at least 30 days before commencing the Land Treatment. Notice will, at a minimum, include a site diagram depicting the location of the planned Land Treatment area, the duration of the planned treatment, and planned final disposition of the waste.

I. Operators will conduct Land Treatment in a manner that does not preclude compliance with Rules 1003 and 1004.

J. Operators will not conduct Land Treatment of Oily Waste on an Oil and Gas Location after the final Well has been plugged. Oily Waste will be treated or disposed pursuant to Rules 905.e.1.(A) or (C).

K. Operators will conduct Land Treatment in a manner that achieves compliance with Table 915-1 concentrations in three years or less. If the treated waste does not comply with Table 915-1 within three years of the date of Land Treatment, the Operator will submit a Form 28 at least 90 days in advance of the 3-year anniversary of the Land Treatment Form 27 approval date. Failure to comply with Table 915-1 in 3 years or to submit a Form 28 will result in the requirement to immediately remove and properly dispose any remaining Oily Waste pursuant to Rules 905.e.1.(A) or (C).

f. **Other E&P Waste.** Operators may treat and dispose other E&P Waste, including but not limited to workover Fluids, Tank bottoms, pigging wastes from Pipelines, and gas gathering, processing, and storage wastes through one of the following methods:

(1) Disposal at a commercial Solid Waste Disposal facility;

(2) Treatment at a Centralized E&P Waste Management Facility permitted pursuant to Rule 907;

(3) Injection into a Class II UIC Well permitted pursuant to the Commission's 800 Series Rules; or

(4) An alternative method proposed in a waste management plan pursuant to Rule 905.a.(4) and approved by the Director.

g. **Drill Cuttings.** Operators will treat or dispose of drill cuttings through one of the following methods:

(1) **Oily Waste.** Operators will manage the following drill cuttings as Oily Waste pursuant to Rule 905.e:

A. Drill cuttings generated from oil-based drilling fluids;

B. Drill cuttings that exceed Table 915-1 concentrations for organic compounds in soil; and

C. Drill cuttings that have not been sampled and analyzed to demonstrate compliance with Table 915-1 for organic compounds in soil.

(2) **Drill Cuttings.** Operators will demonstrate compliance with Table 915-1 through sampling and analysis. Management of drill cuttings that exceed Table 915-1 for constituents listed under soil suitability for Reclamation by the methods listed below is subject to prior approval by the Director, pursuant to Rule 915.b. Operators may manage drill cuttings that comply with Table 915-1, are not Oily Waste, and are generated using water-based bentonitic drilling Fluids through one of the following methods:

A. Disposal at a commercial Solid Waste Disposal facility;

B. Disposal at a Centralized E&P Waste Management Facility permitted pursuant to Rule 907;

C. Subject to Surface Owner approval, Land Application as a beneficial soil amendment to native soil subject to a waste management plan approved pursuant to Rule 905.a.(4).

D. If permitted by Rule 1003.d, and subject to Surface Owner approval, drying and burial in on-location drilling Pits that are documented with a Form 27 submitted for prior Director approval for closure of the Pit; or

E. Subject to Surface Owner approval, and prior Director approval of a Form 27, burial in a Cuttings Trench.

906. MANAGEMENT OF NON-E&P WASTE

a. Certain wastes generated by Oil and Gas Operations that do not meet the 100 Series definition of E&P Waste are regulated as solid or hazardous wastes by CDPHE's Solid and Hazardous Waste Commission ("SHWC"). Operators will properly identify and dispose of these wastes pursuant to applicable state and federal regulations.

b. The SHWC Hazardous Waste Regulations, as incorporated by reference in Rule 901.b, require that a hazardous waste determination be made for any non-E&P solid waste. Operators will comply with all hazardous waste storage, treatment, and disposal requirements in the SHWC's Hazardous Waste Regulations, as incorporated by reference in Rule 901.b.

c. All non-hazardous/non-E&P Wastes are considered solid waste. Operators will comply with all storage, treatment, and disposal requirements in the SHWC's Solid Waste Regulations, as incorporated by reference in Rule 901.b.

d. Operators will not burn or bury non-E&P Waste on Oil and Gas Locations.

907. 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 907 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 E&P Waste Management Facilities may include components such as Land Treatment or Land Application sites, Pits, and recycling equipment.

b. Permit Requirements. Before any Operator commences construction of a Centralized E&P Waste Management Facility, the Operator will file and obtain the Director's approval of an application on a Form 28, Centralized E&P Waste Management Facility Permit, and pay a filing fee established by the Commission (see Appendix III). The Operator will submit a Form 28 application at the same time it submits any permit applications required by the Commission's 300 Series Rules, if any, including an Oil and Gas Development Plan or a Form 2A. In addition, the Form 28 will contain the following:

(1) The name, address, phone and email address of the Operator, and a designated contact person.

(2) The name, address, phone number, email address, and written authorization of the Surface Owner of the site, if not the Operator.

(3) The legal description of the site.

(4) A general topographic, geologic, and hydrologic description of the site, including immediately adjacent land uses and 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 E&P Waste Management 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 will be measured at 90 degrees from said section lines to facility boundaries and referenced on the drawing. A survey will be provided including a complete description of established monuments or collateral evidence found and all aliquot corners.

C. The facility will 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 will also be implemented to prevent access to the Centralized E&P Waste Management Facility by wildlife or domestic animals.

D. Centralized E&P Waste Management Facilities will have a fire lane of at least 10 feet in width around the perimeter of the active treatment areas and within the facility fencing. In addition, a buffer zone of at least 10 feet will be maintained within the perimeter fire lane.

E. Surface water diversion structures, including but not limited to berms and ditches, will be constructed to accommodate a 100-year, 24-hour storm event. The facility will 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 25-year, 24-hour storm event.

F. Operators will provide evidence that they have complied with any Relevant Local Government land use regulations and facility siting or construction or operation requirements.

G. Operators will not construct new Centralized E&P Waste Management Facilities within 2,000 feet of the nearest Building Unit or High Occupancy Building Unit, unless all Building Unit owners and tenants within 2,000 feet consent to a closer location.

(6) **Waste Profile.** For each type of waste, Operators will estimate the amounts to be received and managed by the facility on a monthly average basis. For each waste type to be treated, Operators will complete a characteristic waste profile, which will include analysis of representative waste samples by an accredited laboratory.

(7) **Facility Design and Engineering.** Facility design and engineering data, incorporating Best Management Practices, including plans and elevations, design basis, calculations, and process description. Facility design, engineering, and as-constructed plans will be reviewed and stamped by a Colorado Professional Engineer ("P.E.").

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. Water wells within 1 mile of the site boundary including, but not limited to, information such as well construction details, total depth, static water level, screened interval(s), yields, and Aquifer name(s).

ii. Surface water features within 2 miles;

iii. Site location in relation to the Floodplain of nearby surface water features;

iv. Depth to Groundwater, including specifically identifying the shallowest unconfined Groundwater and any underlying Groundwater formations;

v. Existing quality of the shallowest Groundwater;

vi. Hydrologic properties of the shallowest Groundwater at the location including flow direction, flow rate, and potentiometric surface; and

vii. An evaluation of the potential for impacts to nearby surface water and Groundwater.

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. Design of leak detection system for Pits or other containment systems;

iv. Location, dimensions, and grades of all surface water diversion structures;

v. Location and dimensions of all surface water containment structures; and

vi. Location of all proposed facility structures and access roads.

(8) **Operating Plan.** An operating plan, incorporating Best Management Practices, 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. Recordkeeping;

G. Site security;

H. Hours of operation;

I. Stormwater management plan;

J. Noise, visual impacts, and odor mitigation; and

K. Final disposition of waste. If the Operator intends to beneficially reuse treated waste, the Operator will describe the reuse and method of product quality assurance.

(9) Groundwater Monitoring.

A. Water Wells. Operators will collect water samples from water wells known to the Operator or registered with the Colorado State Engineer, following all protocols established by Rule 615, except that the Operator will collect water samples from known water wells within 1 mile of the proposed Centralized E&P Waste Management Facility. An Operator may request an exception from the requirements of this Rule 907.b.(9).A by submitting a Form 4 pursuant to Rule 615.c.

B. Site-Specific Monitoring Wells.

i. As a condition of approval, the Director may require the Operator to install site-specific monitoring wells to ensure compliance with the concentration levels in Table 915-1 and WQCC Regulation 41, as incorporated by reference in Rule 901.b, by establishing Points of Compliance.

ii. All monitoring well construction must be completed pursuant to the State Engineer’s Water Well Construction and Permitting Rules, as incorporated by reference in Rule 901.b.

iii. Where monitoring is required, the direction of flow, Groundwater gradient, and quality of water will be established by the installation of a minimum of 3 monitor wells, including an up-gradient well and 2 down-gradient wells that will serve as Points of Compliance, or other methods authorized by the Director.

iv. The Operator will propose for prior Director approval monitoring schedules, reporting schedules, and appropriate analyte lists.

(10) Surface Water Monitoring. Where applicable, the Director will require baseline and periodic surface water monitoring to ensure compliance with WQCC surface water standards and classifications, including narrative standards. Operators will 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 will notify the Director of the surface water for which access was not obtained and sampling of such surface water by the Operator will not be required.

(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, contact information of local emergency response authorities, and an outline of responsibilities under any joint operating agreement regarding maintenance, operations, closure, and monitoring of the facility.

c. Permit Review.

(1) Within 90 days of the submission for a Form 28, the Director will issue a determination about whether the Form 28 application is complete.

(2) The Director may approve the Centralized E&P Waste Management Facility permit if it protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources. The Director may require any conditions of approval that are determined to be necessary and reasonable to protect public health, safety, welfare, the environment, and wildlife resources, or to the extent necessary to ensure compliance with the concentration levels in Table 915-1, or WQCC Regulation 41 Groundwater standards and classifications, as incorporated by reference in Rule 901.b.

(3) The Director may deny a Centralized E&P Waste Management Facility permit if it does not adequately protect and minimize impacts to public health, safety, welfare, the environment, and wildlife resources.

d. Financial Assurance. The Operator of a Centralized E&P Waste Management Facility will submit for the Director's approval such Financial Assurance as required by Rule 704 prior to the Director issuing the operating permit.

e. Facility Modifications. Throughout the life of the facility, the Operator will submit proposed modifications to the facility design, operating plan, permit data, or permit conditions to the Director for prior approval through a Form 4.

f. Permit Expiration. The Form 28 will expire 3 years after approval if the Operator has not commenced construction of the permitted facility.

g. Annual Permit Review. To ensure compliance with permit conditions and the Commission's Rules, the facility permit will be subject to an annual review by the Director. To facilitate this review, the Operator will submit an annual report summarizing operations, including the types and volumes of waste handled at the facility. The Director may require additional information.

h. Closure.

(1) **Preliminary Closure Plan.** A general preliminary plan for closure will be submitted with the Form 28. The preliminary closure plan will 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 Groundwater 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 will be subject to review by the Director to verify that the financial assurance provided pursuant to Rules 907.d and 704 is appropriate.

(2) **Final Closure Plan.** The Operator will submit a detailed Form 27 at least 60 days prior to closure for approval or denial by the Director. The workplan will 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 Groundwater standards, implement post-closure monitoring, and complete other Remediation, as required.

908. PIT PERMITTING/REPORTING REQUIREMENTS

a. Operators will submit a Form 15, Earthen Pit Report/Permit to the Director for review and approval prior to constructing any of the following:

(1) All Production Pits;

(2) Special Purpose Pits except those listed in Rules 908.c.(1) or (2);

(3) Drilling Pits; and

(4) Multi-Well Pits, including those located at Centralized E&P Waste Management Facilities.

b. Operators will submit a Form 15, to the Director for review and approval prior to enlarging or otherwise modifying an existing properly permitted Pit.

c. Operators will submit a Form 15 within 30 days after constructing:

(1) Emergency Pits, Plugging Pits, and Workover Pits if they are used in the initial phase of an emergency response; and

(2) Cuttings Trenches approved on a Form 2A.

d. In order to allow adequate time for Pit permit review and approval, Operators will submit a Form 15 at the same time they submit a Form 2A or Oil and Gas Development Plan. The Director may condition approval of the Form 15 upon compliance with additional terms, provisions, or requirements necessary to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. The Director may deny a Form 15 if the Director determines it does not provide necessary and reasonable standards to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources. Notwithstanding the foregoing, no Form 15 will be approved until the associated Form 2A or Oil and Gas Development Plan is approved.

909. PITS – CONSTRUCTION AND OPERATION

a. Operators will ensure that the Pits they operate are:

(1) Properly permitted through a Form 15 approved by the Director, or registered in their names with an active Pit Facility ID;

(2) Accurately mapped; and

(3) Listed according to current facility records in the Commission's database. Operators may update facility records using a Form 15.

b. Operators will construct, maintain, and operate Pits used for exploration and production of oil and gas in a manner that protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources. Operators will operate and maintain Pits and Pit liners to prevent Spills and Releases.

c. Operators will construct, monitor, and operate Pits to provide for a minimum of 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. Operators will employ a method of monitoring and maintaining the freeboard. Operators will report any unauthorized Release of Fluids from a Pit pursuant to Rule 912.

d. Operators will not store oil or any other produced liquid hydrocarbon substance in earthen Pits or reservoirs, except in emergencies where such substances cannot be otherwise contained. Operators will remove the oil or produced hydrocarbons as soon as the emergency is controlled. Operators will submit a Form 15 for the Director's approval within 30 days of the emergency, pursuant to Rule 908.c.

e. No liquid hydrocarbons may be present in a Pit unless the Pit is specifically permitted as a Skimming/Settling ("Skim") Pit.

(1) Immediately upon discovery or notification, Operators will remove any accumulation of oil or condensate, including free product or hydrocarbon sheen, from a Pit. If the Operator is unable to immediately remove the accumulation, the accumulation will be removed within 24 hours of discovery.

(2) Operators will 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.

(3) If an Operator allows oil or condensate (free product or sheen) to accumulate in a Pit, then the Director may revoke the Operator's Form 15 and require the Operator to close and remediate the Pit.

f. Operators will fence and net or install CPW-approved exclusion devices on all new Pits pursuant to Rule 1202.a.(4).

g. Operators may use Multi-Well Pits for a period of no more than 3 years, unless:

(1) The Operator obtains a permit to operate the Multi-Well Pit pursuant to Rule 907 at a Centralized E&P Waste Management Facility;

(2) The Multi-Well Pit is located in Huerfano or Las Animas Counties and was constructed prior to May 1, 2011; or

(3) The Multi-Well Pit is located in Logan, Morgan, Washington, and Yuma Counties and was constructed prior to May 1, 2013.

(4) Based on evidence of risks to public health, safety, welfare, the environment, or wildlife resources, the Director may require an Operator to line, net, cover, fence, or close an existing Multi-Well Pit that is subject to Rules 909.g.(2) & (3), or submit a Form 28 for such a Multi-Well Pit.

h. Operators will treat produced water pursuant to Rule 905.c.(1) before placing it in a Production Pit.

i. Operators will utilize appropriate biocide treatments to control bacterial growth and related odors.

j. **Produced Water Quality Analyses.** Beginning January 15, 2021, Operators will submit an initial water quality analysis for produced water for each Well from which produced water is placed into a permitted or registered Pit, including Pits that were constructed prior to January 15, 2021.

(1) The water sample will be analyzed for the following:

A. pH;

B. Specific conductance;

C. Total dissolved and suspended solids (TDS and TSS);

D. Alkalinity (total, bicarbonate, and carbonate as $CaCO_3$);

E. Major anions (bromide, chloride, fluoride, sulfate, nitrate and nitrite as N, and phosphorus);

F. Major cations (calcium, iron, magnesium, manganese, potassium, and sodium);

G. Other elements (barium, boron, selenium, and strontium);

H. Naphthalene;

I. Total petroleum hydrocarbons ("TPH") as total volatile hydrocarbons (C_6 to C_{10}) and total extractable hydrocarbons (C_{10} to C_{36});

J. BTEX compounds (benzene, toluene, ethylbenzene, and xylenes); and

K. Radium (^{226}Ra and ^{228}Ra).

(2) **Subsequent Sampling and Analysis.** After initial sampling, Operators will collect and analyze subsequent samples at the following frequencies:

A. For lined Pits, Operators will collect and analyze a second confirmation sample during the period between 33 and 39 months after the initial sampling and analysis;

B. For unlined Pits:

i. Operators will collect and analyze samples on an annual basis after the initial sampling and analysis;

ii. If subsequent sampling and analysis indicates stable water quality over time, the Operator may request relief from further subsequent sampling and analysis by submitting a Form 4, which the Director will review and approve or deny;

C. For all Pits, Operators will collect and analyze a subsequent sample for any new Well that contributes water to the Pit;

D. For all Pits, Operators will collect and analyze a subsequent sample any time the Operator or Director has reason to believe the water quality in the Pit has changed; and

E. For all Pits, if subsequent sampling and analysis indicates variable water quality, the Director may require more frequent or additional sampling.

(3) Operators will submit all water quality analysis data using a Form 43, Analytical Sample Submittal, and will include suitable electronic data deliverable generated by the laboratory and PDF of lab reports within 3 months of sample collection. Results for the initial samples collected pursuant to Rule 909.j.(1) will be submitted no later than July 15, 2022, or prior to Pit closure, whichever is earlier.

(4) Operators will collect samples according to standard environmental procedures.

(5) Operators will analyze samples in an accredited laboratory using established methodologies. For those analytes with Groundwater threshold concentrations listed in WQCC Regulation 41, as incorporated by reference in Rule 901.b, the analytical technique will be capable of achieving, and will achieve, reporting limits at concentrations less than the WQCC Regulation 41 thresholds in the matrix submitted. The Director may review the analytical standard used for each analyte and may request the analysis be run by a different method.

(6) As an alternative to the sampling required by Rules 909.j.(1)–(5) the Operator transporting produced water produced from the same formation(s) in the same Field or unit to the same Pit may submit a Form 4 to request the Director's approval for an alternative sampling program to consolidate the number of samples required from the same formation(s).

910. PIT LINING REQUIREMENTS AND SPECIFICATIONS

a. Except for Cuttings Trenches and Pits constructed as an initial emergency response measure pursuant to Rule 908.c.(1), all Pits constructed after January 15, 2021 will be lined.

b. **Skim Pits.** Operators will not construct new Skim pits. All existing Skim Pits, regardless of date of construction, will be lined. For any unlined Skim Pits in existence on January 15, 2021, the

Operator will submit a Form 27 outlining the Operator's plan to delineate and remediate any associated impacts and a plan to either properly line or close the Pit. The Form 27 for an unlined Skim Pit must be submitted to the Director by April 1, 2021. If the Pit will be lined and returned to service, the Operator will also submit and obtain the Director's approval of a Form 15.

c. Operators will construct all Pits according to the following specifications:

(1) Materials used in lining Pits will 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 will be designed, constructed, installed, and maintained in accordance with the manufacturers' specifications and good engineering practices. Operators will maintain records demonstrating that the Operator followed manufacturers' specifications, and provide them to the Director upon request.

(3) Field seams will be installed and tested in accordance with manufacturer specifications and good engineering practices. Operators will maintain testing results, repair documentation (including the dates of tests and repairs), and provide them to the Director upon request.

d. Operators will construct all Pits, except those at Centralized E&P Waste Management Facilities, according to the following specifications:

(1) Liners will have a minimum thickness of 24 mils. The synthetic or fabricated liner will cover the bottom and interior sides of the Pit with the edges secured with at least a 12-inch deep anchor trench around the Pit perimeter. The anchor trench will be designed to secure, and prevent slippage or destruction of, the liner materials.

(2) The foundation for the liner will be constructed with material containing no sharp rocks, debris or other material that could puncture the liner. The foundation for the liner will have a minimum thickness of 12 inches after compaction, cover the entire bottom and interior sides of the Pit, and be constructed so that the hydraulic conductivity will not exceed 1.0×10^{-7} cm/sec after testing and compaction. Operators will maintain compaction and permeability test results measured in the laboratory and field and provide the results to the Director upon request.

(3) As an alternative to the soil foundation described in Rule 910.d.(2), Operators may construct the foundation 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 will be padded with soil or synthetic matting type material and will be free of sharp rocks or other material that are capable of puncturing the liner. Each synthetic liner will have a minimum thickness of 24 mils.

e. Operators will construct Pits used at Centralized E&P Waste Management Facilities according to the following specifications:

(1) Liners will have a minimum thickness of 60 mils. The synthetic or fabricated liner will cover the bottom and interior sides of the Pit with the edges secured with at least a 12-inch deep anchor trench around the Pit perimeter or in accordance with the liner manufacturer's specifications. The anchor trench will be designed to secure, and prevent slippage or destruction of, the liner materials.

(2) The foundation for the liner will be constructed with material containing no sharp rocks, debris, or other material that could puncture the liner. The foundation for the liner will have a minimum thickness of 24 inches after compaction, cover the entire bottom and interior sides of the Pit, and be constructed so that the hydraulic conductivity will not exceed 1.0 x 10^{-7} cm/sec after testing and compaction. Operators will maintain compaction and permeability test results measured in the laboratory and field and provide them to the Director upon request.

(3) As an alternative to the soil foundation described in Rule 910.e.(2), Operators may use 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.

(4) As an alternative to the soil foundation described in Rule 910.e.(2), Operators may use a double synthetic liner system. However, the bottom and sides of the Pit will be padded with soil or synthetic matting type material and will be free of sharp rocks or other materials that are capable of puncturing the liner. Each synthetic liner will have a maximum thickness of 60 mils.

(5) All Pits will be constructed and operated with a leak detection system.

f. The Director may require the use of additional liners or a leak detection system for the Pit or other equivalent protective measures, including but not limited to, increased recordkeeping requirements, monitoring systems, and underlying gravel filled sumps and lateral systems. In making such a determination, the Director will consider the site-specific information provided by the Operator, including but not limited to surface and subsurface geology, the presence and depth to Groundwater, the quality of the produced water, the hydraulic conductivity of the surrounding soils, the distance to surface water and water wells, and the type of liner.

911. CLOSURE OF OIL AND GAS FACILITIES

a. Operators will close all Oil and Gas Facilities, including Drilling Pits and Cuttings Trenches, in accordance with an approved Form 27.

(1) Operators will obtain the Director’s approval of the Form 27 prior to conducting any investigation or closure operations.

(2) The Form 27 will include a description of the proposed investigation and Remediation activities pursuant to Rule 913.

(3) Operators will close and remediate Emergency Pits as soon as the initial phase of emergency response operations is complete or any process Upset Conditions are controlled.

(4) Oil and Gas Facility closure pursuant to this Rule 911.a will be at the time of final site closure, Plugging and Abandonment, or decommissioning, unless the Director determines that a substantive change to the site requires a Form 27, or a reportable Spill or an historic impact is discovered during facility operation or removal.

b. Discovery of a Spill or Release During Closure. If an Operator discovers a Spill or Release during closure operations, the Operator will report the Spill or Release on a Form 19, Spill/Release Report, pursuant to Rule 912.

c. Pit Closure.

(1) Pit Evacuation. Operators will treat or dispose of E&P Waste pursuant to Rule 905 prior to backfilling and site Reclamation.

(2) Operators will collect a sufficient number of representative samples from locations beneath a Pit to demonstrate that no leakage of managed fluids has occurred. Operators will ensure that any soil left in place meets the cleanup concentrations listed in Table 915-1.

(3) Liner Disposal.

A. Synthetic Liner Disposal. Operators will remove and dispose of synthetic liners pursuant to all state and federal requirements for Solid Waste Disposal.

B. Constructed Soil Liners. Operators may remove constructed soil liner material for treatment or disposal. Alternatively, if an Operator leaves the constructed soil liner material in place, the Operator will rip the material and mix it with native soils in a manner to alleviate compaction and prevent an impermeable barrier to infiltration and Groundwater flow. Operators will demonstrate that the resulting material meets cleanup concentrations for contaminants of concern listed in Table 915-1.

912. SPILLS AND RELEASES

a. General.

(1) Immediately upon discovering any Spills or Releases of E&P Waste, produced Fluids, or unauthorized Releases of natural gas that meet the criteria of Rules 912.b.(1).H, I, or J, regardless of size or volume, Operators will control and contain the Spill or Release to protect and minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(2) Operators will investigate, clean up, and document impacts resulting from Spills and Releases as soon as the impacts are discovered.

(3) The Director may require the Operator to perform any action the Director determines to be necessary and reasonable to prevent or mitigate adverse impacts on any air, water, soil, or biological resource caused by a Spill or Release.

(4) Operators will document and maintain records to demonstrate compliance with the concentration levels in Table 915-1, and, if surface water or Groundwater are impacted, WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

(5) For any Spills or Releases that do not meet the reporting requirements of Rule 912.b, Operators will document cleanup efforts and provide documentation of the cleanup to the Director upon request.

b. Reporting Spills or Releases of E&P Waste, Gas, or Produced Fluids.

(1) Report to the Director. Operators will submit an initial report ("24 Hour Notification") of a Spill or Release of E&P Waste, natural gas, or produced Fluids that meet any of the following criteria to the Director verbally, via electronic mail, or on a Form 19, Spill/Release Report – Initial within 24 hours of discovery, unless otherwise specified below.

A. A Spill or Release of any size that impacts or threatens to impact any Waters of the State, Public Water System, residence or occupied structure, livestock, wildlife, or publicly-maintained road;

B. A Spill or Release in which 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 or Release of 5 Barrels or more of E&P Waste or produced Fluids regardless of whether the Spill or Release is completely contained within berms or other secondary containment.

D. Within 6 hours of discovery, a Grade 1 Gas Leak. For a Grade 1 Gas Leak from a Flowline, the Operator also must submit the Form 19 – Initial, document number on a Form 44, Flowline Report, for the Grade 1 Gas Leak.

E. The discovery of 10 cubic yards or more of impacted material resulting from a current or historic Spill or Release. Discovery and reporting will not be contingent upon confirmation samples demonstrating exceedance of Table 915-1 standards.

F. The discovery of impacted Waters of the State, including Groundwater. Discovery and reporting will not be contingent upon confirmation samples demonstrating exceedance of Table 915-1 standards. The presence of free product or hydrocarbon sheen on Groundwater or surface water is reportable. The presence of contaminated soil in contact with Groundwater or surface water is reportable.

G. A suspected or actual Spill or Release of any volume where the volume cannot be immediately determined, including a Spill or Release of any volume that daylights from the subsurface.

H. A Spill or Release resulting in vaporized hydrocarbon mists that leave the Oil and Gas Location or Off-Location Flowline right of way from an Oil and Gas Location and impacts or threatens to impact off-location property.

I. A Release of natural gas that results in an accumulation of soil gas or gas seeps.

J. A Release that results in natural gas in Groundwater.

(2) The 24 Hour Notification to the Director will include, at a minimum,

A. The specific location of the Spill or Release, including latitude and longitude;

B. Certification that the Operator provided additional party notifications as required by Rules 912.b.(7)–(10), below;

C. A description of any threat to Waters of the State, Public Water Systems, residences or occupied structures, livestock, wildlife, air quality, or publicly-maintained roads from the Spill or 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 the 24 Hour Notification.

(3) If the Operator did not submit the 24 Hour Notification through a Form 19 – Initial, the Operator will submit a Form 19 – Initial no less than 72 hours after discovery of the Spill or Release unless the Director extends the timeframe in writing.

(4) In addition to the Form 19 – Initial, the Operator will file a Form 19 – Supplemental not more than 10 days after the Spill or Release is discovered that includes:

A. A topographic map showing the governmental section and location of the Spill or Release, or an aerial photograph showing the location of the specific Spill or Release site.

B. All pertinent information about the Spill or Release known to the Operator that has not been reported previously, including photo documentation showing the source of the Spill or Release, the impacted area, and initial cleanup activity; and

C. Information relating to the initial mitigation, site investigation, and Remediation measures conducted by the Operator.

D. Global Positioning System data that meets the requirements of Rule 216 if latitude and longitude data provided pursuant to Rule 912.b.(2).A did not meet the requirements of Rule 216.

(5) The Director may require any Form 19 – Supplemental reports or information the Director determines are necessary.

(6) No later than 90 days after a Spill or Release is discovered, the Operator will have submitted, and obtained the Director's approval of either:

A. A Form 19 – Supplemental requesting closure pursuant to Rule 913.h and supported by adequate documentation to demonstrate that the Spill or Release has been fully cleaned up and complies with Table 915-1; or

B. A Form 27 if any of the criteria listed in Rules 912.b.(6).B.i–iii apply. If Remediation will continue under an approved Form 27, the Operator will also submit a Form 19 – Supplemental which requests closure of the Spill or Release and includes the Remediation project number assigned by the Director.

i. A Form 27 is required by the Commission's Rules;

ii. Cleanup or Remediation will continue for longer than 90 days after the Spill or Release was discovered; or

iii. The Director requests a Form 27.

(7) **Notification to Local Governments.** At the same time the Operator makes the 24 Hour Notification, the Operator will provide verbal or written notification to the entity with jurisdiction over emergency response within the local municipality if the Spill or Release occurred within a municipality or the local county if the Spill or Release did not occur within a municipality. The notification will include, at a minimum, the information listed in Rule 912.b.(2).

(8) **Notification to the Surface Owner.** The Operator will provide verbal or written notification to the affected Surface Owner or the Surface Owner's appointed tenant concurrent with providing the 24 Hour Notification.

A. If the Surface Owner cannot be reached within 24 hours, the Operator will continue to make good faith efforts to notify the Surface Owner until notice has been provided.

B. The verbal or written notification will include, at a minimum, the information listed in Rule 912.b.(2).

C. The Operator will document the notification including the name of the person contacted, phone number or email of contact, date, and time on the Form 19 – Initial and update the information as necessary on the Form 19 -- Supplemental.

(9) **Report to Environmental Release/Incident Report Hotline.** Operators will report a Spill or Release of any size that impacts or threatens to impact surface waters to the Director and to the Environmental Release/Incident Report Hotline (1-877-518-5608). Spills and Releases that impact or threaten a Public Water System intake, as described in Rules 411.a.(4) & 411.b.(5), will be verbally reported to the emergency contact for that facility concurrent with providing the 24 Hour Notification to the Director pursuant to Rule 912.b.(1).

(10) At the same time the Operator submits a Form 19 – Initial, the Operator will provide verbal or written notification to CPW if the Spill or Release occurred within 300 feet of surface Waters of the State, or within High Priority Habitat.

(11) **Reporting Chemical Spills or Releases.** Operators will report Chemical Spills and Releases pursuant to 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.

c. Remediation of Spills or Releases.

(1) The Director may require Operators to submit a Form 27 if the Director identifies any threatened or actual adverse impacts to any air, water, soil, wildlife, or other environmental resource from a Spill or Release, or if necessary to ensure compliance with the concentration levels in Table 915-1 and WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

(2) Not including initial emergency response operations, the Operator will notify and consult with any affected Surface Owners, or the Surface Owner's appointed tenant, prior to commencing operations to remediate a Spill or Release in an area not being utilized for Oil and Gas Operations. It is the Operator's burden to timely notify and negotiate access with the Surface Owner. Failure to do so will not relieve the Operator from its responsibility to commence or complete Remediation approved by the Director.

d. Spill and Release Prevention.

(1) Operators will determine and document the cause of a Grade 1 Gas Leak or Spill or Release of E&P Waste or produced Fluids. After identifying the cause, Operators will implement measures to prevent Spills or Releases due to similar causes in the future, and document all changes made.

(2) The Director may take enforcement action if a Spill occurs at any site subject to control of the same Operator as a result of similar causes identified in Rule 912.d.(1).

(3) Operators will provide documentation of the Spill or Release evaluation and any steps taken to prevent Spills or Releases due to similar causes in the future to the Director upon request.

e. Suspected Spill or Release Closure.

(1) Operators will submit a Supplemental Form 19 providing documentation that any suspected Spill or Release reported pursuant to Rule 912.b.(1).G did not exceed any applicable reporting thresholds. The Operator will clean up any actual Spill below the reporting threshold of Rule 912.b pursuant to the requirements of Rule 912.a.(5).

(2) If the suspected Spill or Release reported pursuant to Rule 912.b.(1).G did in fact exceed any reporting threshold identified in Rule 912.b.(1), the Operator will clean up the Spill pursuant to the requirements of Rule 912.c.

f. Changes of Operator. Within 60 days of the Director's approval of a Form 9, Transfer of Operatorship – Subsequent pursuant to Rule 218.e, the Buying Operator will submit a supplemental Form 19 designating the responsible Operator for each open Spill and Release.

913. SITE INVESTIGATION, REMEDIATION, AND CLOSURE

a. Applicability. This Rule 913 applies to the investigation, Remediation, and reporting required for Spills and Releases, Remediation projects, and decommissioning of Oil and Gas Facilities. All site investigation, Remediation, and closure operations will be conducted in accordance with the Commission's Rules, including the Commission's 1000 Series Rules.

b. General Site Investigation and Remediation Requirements.

(1) Site Investigation and Remediation Workplan. Operators will submit and obtain the Director's approval of a Form 27 whenever it is required by the Commission's Rules, prior to commencing the operations addressed by the Form 27.

(2) Sampling and Analyses. Operators will conduct sampling and analysis of soil and Groundwater pursuant to Rule 915 to determine the horizontal and vertical extent of any contamination in excess of the cleanup concentrations in Table 915-1 or in WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

A. Sampling and analyses will be required to profile E&P Waste, delineate extent of contamination, and confirm compliance with applicable standards upon completion of Remediation.

B. Laboratory method detection limits must be less than or equal to Table 915-1 or WQCC Regulation 41 standards, as incorporated by reference in Rule 901.b.

C. Composite sample results may be submitted for preliminary analysis and waste profiling. Discrete sample results will be required for confirmation sampling.

(3) Management of Investigation-Derived Waste. Investigation-Derived Waste will be managed pursuant to Rules 905 or 906.

(4) Pit Evacuation. Prior to site investigation and Remediation, E&P Waste will be treated or disposed pursuant to Rule 905.

(5) Remediation.

A. Remediation will be performed in a manner that reduces or removes contamination that exceeds the cleanup concentrations in Table 915-1 or in WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, and that protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

B. When conducting Remediation activities, Operators will conform to the following standards:

i. Operators will fence or cover open excavations to prevent access when sites are not attended.

ii. Operators will protect topsoil, consistent with the Commission's 1000 Series Rules.

iii. Operators will minimize surface disturbance.

iv. Operators will properly store, handle, and manage all E&P Waste to prevent contamination of stormwater, surface water, Groundwater, and soil.

v. If Remediation occurs within High Priority Habitat, the Operator will incorporate Best Management Practices protective of the relevant wildlife species or habitat in the Operator's Form 27.

C. Groundwater that does not meet the cleanup concentrations in Table 915-1 or WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, will be remediated pursuant to a Form 27.

(6) **Surface Reclamation.** If the Director approves the closure of a Remediation project, the Operator will reclaim the site(s) pursuant to the Commission's 1000 Series Rules.

c. **Form 27, Site Investigation and Remediation Workplan.** Operators will prepare and obtain the Director's approval of a Form 27 prior to conducting the following operations and Remediation activities:

(1) Pit or Cuttings Trench closure;

(2) Buried or partially buried vessel closure, which will be by removal;

(3) Remediation of Spills and Releases pursuant to Rule 912;

(4) Land Treatment of Oily Waste pursuant to Rule 905.e;

(5) Closure of Centralized E&P Waste Management Facilities pursuant to Rule 907.h;

(6) Remediation of impacted Groundwater pursuant to Rule 915.e.(3).D, and the contaminant concentrations in Table 915-1;

(7) Investigation and Remediation of natural gas in soil or Groundwater;

(8) When requested by the Director due to any potential risk to soil, Groundwater, or surface water; and

(9) Decommissioning of Oil and Gas Facilities.

d. **Implementation Schedule.** Each Form 27 will include a specific implementation schedule to complete investigation and Remediation.

(1) Operators will investigate impacts to soil, Groundwater, and surface water as soon as the impacts are discovered.

(2) Any change from the approved implementation schedule will be requested at least 14 days in advance, and the Operator may not make the change without the Director's approval.

e. **Reporting Schedule.** After initial approval of a Form 27, the Operator will provide quarterly update reports in a Supplemental Form 27 to document progress of site investigation and Remediation, unless an alternative reporting schedule has been requested by the Operator and approved by the Director. The Director may request a more frequent reporting schedule based on site-specific conditions.

(1) Operators may not change the reporting schedule without the Director's approval.

(2) By April 15, 2021, Operators of existing remediation projects approved prior to January 15, 2021 will submit a Supplemental Form 27 with a detailed project summary and status.

(3) For existing remediation projects approved prior to January 15, 2021, the Operator will adopt a quarterly reporting schedule unless a more frequent or specific reporting schedule was already approved by the Director.

f. **Discovery of a Spill or Release During Closure.** If a Spill or Release is discovered during facility closure operations, the Operator will report it to the Director on a Form 19 pursuant to Rule 912.

g. **Changes of Operator.** Within 60 days of the Director's approval of a Form 9 – Subsequent pursuant to Rule 218.e, the Buying Operator will submit a supplemental Form 27 designating the responsible Operator for all open Remediation projects.

h. **Closure.**

(1) Remediation will be considered complete when the Operator has demonstrated compliance with:

A. The cleanup concentrations in Table 915-1;

B. WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, if applicable; and

C. Any condition of approval of a Form 27.

(2) An Operator may request a variance pursuant to Rule 502 to comply with an alternative standard in lieu of one or more of the standards in Rules 913.h.(1).A & C. In addition to applying for a variance, the Operator will also submit a Form 27 demonstrating that their alternative clean-up process protects and minimizes adverse impacts to public health, safety, welfare, the environment, and wildlife resources.

(3) For contaminated groundwater where periodic monitoring has been required, closure may not occur until after 4 consecutive quarters of sampling and analysis demonstrating compliance with Table 915-1 and WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, if applicable.

(4) **Notification of Completion.** Within 30 days after conclusion of site Remediation activities:

A. Operators conducting Remediation operations pursuant to an approved Form 27 will submit to the Director a Supplemental Form 27 containing documentation sufficient to demonstrate compliance with the Commission's Rules.

B. Operators will coordinate with the Director through a Form 4 regarding additional surface Reclamation required by the Commission's 1000 Series Rules, if applicable.

i. **Release of Financial Assurance.** Financial Assurance required by Rule 706 may be held by the Director until the required Remediation of soil and/or Groundwater impacts is completed in accordance with the approved workplan, or until cleanup goals are met.

914. CRITERIA TO ESTABLISH POINTS OF COMPLIANCE

In determining a Point of Compliance, the Director will take into consideration recommendations of the Operator or any Responsible Party or Parties, if applicable, together with the following factors:

a. The classified use established by the WQCC, for any Groundwater or surface water that was impacted by contamination. If not so classified, the interim narrative standard applies, and the domestic and agricultural uses are to be protected;

b. The geologic and hydrologic characteristics of the site, such as depth to Groundwater, Groundwater flow, direction and hydraulic conductivity, soil types, surface water impacts, and any seasonal hydrologic variability;

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;

f. The distance to the nearest permitted domestic water well or Public Water System supply well completed in the same Aquifer affected by the event; and

g. The distance to the nearest permitted livestock or irrigation water well completed in the same Aquifer affected by the event.

915. CONCENTRATIONS AND SAMPLING FOR SOIL AND GROUNDWATER

a. Soil Concentrations. Operators will adhere to the concentrations for soil cleanup in Table 915-1. Operators will use Residential Soil Screening Level Concentrations as cleanup levels unless required otherwise by the Director. The Director will require adherence to the Protection of Groundwater Soil Screening Levels when a pathway to Groundwater exists. When the Director has reasonable cause to believe that oil and gas exploration-related compounds or parameters other than those listed in Table 915-1 may be present, the Director may require additional analyses of compounds included in the EPA RSLs, as incorporated by reference in Rule 901.b.

b. Soil Suitability for Reclamation. Operators will adhere to the concentrations for soil in Table 915-1 for restoring soil to the agronomic properties for electrical conductivity ("EC"), sodium adsorption ratio ("SAR"), pH, and boron for soils. Subject to prior approval by the Director, Operators may leave materials with elevated concentrations of EC, SAR, or pH *in situ*. In such cases, the Operator will provide a detailed Reclamation plan that includes, but is not limited to, soil analysis from adjacent undisturbed lands, revegetation techniques, site stabilization, and details of seeded species.

c. Groundwater Concentrations. Operators will adhere to the concentrations for Groundwater in Table 915-1. The Groundwater standards and analytical methods are derived from the Groundwater standards and classifications established by WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

d. Additional Groundwater Analyses. When the Director has reasonable cause to believe that oil and gas exploration-related compounds or parameters other than those listed in Table 915-1 may be present, the Director may require additional analyses beyond the list of compounds included in Table 915-1 for Groundwater including but not limited to:

(1) Any element, compound or parameter listed in Table A and Tables 1, 2, 3, and 4 of WQCC Regulation 41, as incorporated by reference in Rule 901.b.

(2) In accordance with the Narrative Standards of WQCC Regulation 41.5.A, any element, compound, or parameter not listed in Table A or Tables 1, 2, 3, and 4 of WQCC Regulation

41, as incorporated by reference in Rule 901.b, which alone or in combination with other substances, are in concentrations shown to be:

A. Carcinogenic, mutagenic, teratogenic, or toxic to human beings; or,

B. A danger to public health, safety, and welfare.

e. Sampling and Analysis. Analysis will be conducted using EPA SW-846 analytical methods, as incorporated by reference in Rule 901.b, or, with the Director's approval, other analytical methods published by nationally-recognized organizations. Analyses of samples will be performed by laboratories that maintain state or national accreditation programs. Operators will adhere to the specialized agricultural analytical methods where required pursuant to footnote 2 to Table 915-1. A lab with experience with agricultural analysis will be used.

(1) Methods for Sampling and Analysis. Sampling and analysis for site investigation or confirmation of successful Remediation will be conducted to determine the nature and extent of impact and confirm compliance with appropriate concentration levels in Table 915-1 and WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

A. Field Analysis. Field measurements and field tests will be conducted using appropriate equipment, calibrated and operated according to manufacturer specifications, by personnel trained and familiar with the equipment. Operators will provide all field measurements and tests to the Director upon request, including but not limited to field notes, field screening logs, soil boring logs, monitor well construction Logs, pump test reports, photographs, and soil vapor screening results.

B. Sample Collection. Samples will be collected, preserved, documented, and shipped or delivered to a laboratory under a chain-of-custody protocol using standard environmental sampling procedures in a manner to ensure accurate representation of site conditions.

C. Laboratory Analytical Methods. Laboratories will analyze samples using standard methods (including but not limited to EPA SW-846, as incorporated by reference in Rule 901.b) appropriate for detecting the target analyte. The method selected will have detection limits less than or equal to the cleanup concentrations in Table 915-1 and WQCC Regulation 41, as incorporated by reference in Rule 901.b.

D. Background Sampling. The Director may require the Operator to take site-specific samples, outside of the area disturbed by Oil and Gas Operations, of comparable, nearby, non-impacted, native soil, Groundwater or other media to establish background conditions.

(2) Soil Sampling and Analysis.

A. Applicability. If soil contamination is suspected or known to exist as a result of Spills or Releases or E&P Waste management, Operators will collect and analyze representative samples of soil pursuant to this Rule 915.e.(2).

B. Sample Collection. Samples will be collected from areas most likely to have been impacted, and the horizontal and vertical extent of contamination will be determined. The number and location of samples will be appropriate to determine the horizontal and vertical extent of the impact.

C. Sample Analysis. Operators will analyze soil samples for contaminants of concern listed in Table 915-1 as appropriate to assess the impact or confirm Remediation. If an

Operator believes it is appropriate to modify the list of contaminants of concern, the Operator will submit, and obtain the Director's approval of, a modified list of contaminants of concern through a Form 19 or Form 27, as applicable. The list will be based on site specific E&P Waste profile and process knowledge. Operators will analyze samples for additional contaminants of concern upon the Director's request.

D. Soil Background Determination. For impacts to soil due to E&P Waste, samples from comparable, nearby non-impacted native soil will be collected and analyzed for purposes of establishing background soil conditions including pH, EC, SAR, and other constituents as identified in the E&P Waste profile.

(3) Groundwater Sampling and Analysis.

A. Applicability. Operators will collect and analyze representative samples of Groundwater if:

i. Groundwater contamination is suspected or is known to exceed the concentrations in cleanup Table 915-1 or WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b;

ii. Impacted soils are in contact with Groundwater; or

iii. Impacts to soils extend down to the high water table.

B. Sample Collection. Operators will collect samples as soon as possible from areas most likely to have been impacted: immediately downgradient or in the middle of excavated areas in close proximity to the suspected source of the impact.

i. The number and location of samples will be appropriate to determine the horizontal and vertical extent of the impact.

ii. If the cleanup concentrations in Table 915-1 or WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, are exceeded, the direction of flow and a Groundwater gradient will be established.

iii. The Director may require the installation of temporary or permanent monitoring wells as necessary for sample collection. All monitoring wells will be constructed and permitted in accordance with the State Engineer's Water Well Construction and Permitting Rules, as incorporated by reference in Rule 901.b.

C. Sample Analysis. Operators will analyze Groundwater samples for constituents of concern listed in Table 915-1, or other parameters appropriate for evaluating the impact, to assess the impact or confirm Remediation. If an Operator believes it is appropriate to modify the list of constituents of concern, the Operator will submit, and obtain the Director's approval of, a modified list of constituents of concern through a Form 19 or Form 27, as applicable. The list will be based on site specific E&P Waste profile and process knowledge. Operators will analyze samples for additional constituents of concern upon the Director's request.

D. Impacted Groundwater. Pursuant to Rule 913.c.(6), if Groundwater contaminants exceed the concentrations listed in Table 915-1 or in WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b, Operators will notify the Director and submit to the Director for prior approval a Form 27 for the investigation, Remediation, or monitoring of

Groundwater to meet the required cleanup concentrations in Table 915-1 or in WQCC Regulation 41 numeric and narrative Groundwater quality standards and classifications, as incorporated by reference in Rule 901.b.

(4) Waste and Produced Fluids Sampling and Analysis. When required by the Director, Operators will collect samples necessary to adequately characterize the composition of produced oil, condensate, water, drilling Fluids, drill cuttings, production gases, Bradenhead gases, soil gas, and soil gas seeps. The Operator will submit, and obtain the Director's approval of the number of samples collected, the analyte lists, and analytical methods appropriate to the waste or production stream.

f. Remediations in Progress. For sites that are subject to an open Form 19 or Form 27 as of January 15, 2021, Operators may seek the Director's permission to comply with the version of Table 910-1 that was previously in effect, if Remediation is completed by January 15, 2022. If Remediation at a site subject to an open Form 19 or Form 27 is not completed by January 15, 2022, then the Operator will comply with the current version of Table 915-1.

Table 915-1
CLEANUP CONCENTRATIONS

Contaminant of Concern	Concentrations
Soil TPH (total volatile [C_6-C_{10}] and extractable [C_{10}-C_{36}] hydrocarbons)	500mg/kg
Soils and Groundwater - liquid hydrocarbons including condensate and oil	below visual detection limits
Soil Suitability for Reclamation	
Electrical conductivity (EC) (by saturated paste method)[1,2]	<4mmhos/cm
Sodium adsorption ratio (SAR) (by saturated paste method)[1,2,3]	<6
pH (by saturated paste method)[1,2]	6–8.3
boron (hot water soluble soil extract)[1,2,3]	2mg/l
Organic Compounds in Groundwater[4]	
benzene	5µg/l
toluene[5]	560 to 1,000µg/l
ethylbenzene	700µg/l
xylenes (sum of o-, m- and p- isomers = total xylenes)[5]	1,400 to 10,000µg/l
naphthalene	140µg/l
1,2,4-trimethylbenzene	67µg/l
1,3,5-trimethylbenzene	67µg/l
Groundwater Inorganic Parameters[4]	
total dissolved solids (TDS)[1]	<1.25 X local background
chloride ion[1]	250mg/l or <1.25 X local background
sulfate ion[1]	250mg/l or <1.25 X local background

Table 915-1 (continued)

Contaminant of Concern	Concentrations	
	Residential Soil Screening Level Concentrations (mg/kg)[7]	**Protection of Groundwater Soil Screening Level Concentrations (mg/kg) Risk Based (R) and MCL Based (M)[7,8]**
Organic Compounds in Soils[6, 9, 10]		
benzene	1.2	0.0026 (M)
toluene	490	0.69 (M)
ethylbenzene	5.8	0.78 (M)
xylenes (sum of o-, m- and p- isomers = total xylenes)	58	9.9 (M)
1,2,4-trimethylbenzene	30	0.0081 (R)
1,3,5-trimethylbenzene	27	0.0087 (R)
acenaphthene	360	0.55 (R)
anthracene	1800	5.8 (R)
benz(a)anthracene	1.1	0.011 (R)
benzo(b)fluoranthene	1.1	0.3 (R)
benzo(k)fluoranthene	11	2.9 (R)
benzo(a)pyrene	0.11	0.24 (M)
chrysene	110	9 (R)
dibenzo(a,h)anthracene	0.11	0.096 (R)
fluoranthene	240	8.9 (R)
fluorene	240	0.54 (R)
indeno(1,2,3-cd)pyrene	1.1	0.98 (R)
1-methylnaphthalene	18	0.006 (R)
2-methylnaphthalene	24	0.019 (R)
naphthalene	2	0.0038 (R)
pyrene	180	1.3 (R)
Metals in Soils[1, 6, 9, 10, 11]		
arsenic	0.68	0.29 (M)
barium	15000	82 (M)
cadmium	71	0.38 (M)
chromium (VI)	0.3	0.00067 (R)
copper	3100	46 (M)
lead	400	14 (M)
nickel	1500	26 (R)
selenium	390	0.26 (M)
silver	390	0.8 (R)
zinc	23000	370 (R)

Table 915-1 (continued) footnotes

[1] The Director will consider site-specific background concentrations or reference levels in native soils and Groundwater.

[2] Soil suitability thresholds for electrical conductivity ("EC"), pH, and sodium adsorption ratio ("SAR") in soils are based on use of saturated paste preparation methods, followed by analysis. Soil suitability thresholds for available boron are based on hot water soluble (or DPTA/sorbitol) extraction followed by analysis. Methods for preparation and analysis of the soil suitability parameters can be found in Soil, Plant, and Water Reference Methods for the Western Region, as incorporated by reference in Rule 901.b.

[3] With the Director's prior approval, SAR levels and the concentration for hot water soluble boron may be modified based on land use, depth, or characteristics of the vegetative community.

[4] Concentrations for Groundwater are taken from WQCC Regulation 41, as incorporated by reference in Rule 901.b.

[5] For toluene and xylenes (total), 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 Groundwater 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 will be no more restrictive than the second number in the range or the Groundwater 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 will apply instead of these statewide standards.

[6] Concentrations for organic compounds and metals in soils are taken from the November 2020 EPA Regional Screening Levels ("EPA RSLs") for Chemical Contaminants at Superfund Sites, as incorporated by reference in Rule 901.b.

[7] If there is no pathway for communication with Groundwater, then residential soil screening levels apply for organic compounds and metals. If the Director determines that a pathway to Groundwater exists, then the protection of Groundwater soil screening levels will apply, secondary to actual measured concentrations of the contaminants of concern in Groundwater.

[8] The letter "(R)" following a protection of Groundwater soil screening level indicates the concentration is derived from a risk-based approach. The letter "(M)" following a protection of Groundwater soil screening level indicates the concentration is derived from the drinking water MCL.

[9] If the method detection limit ("MDL") or practical quantitation limit ("PQL") for a pollutant is higher (less stringent) than a threshold concentration listed in Table 915-1, the Director may allow an Operator to substitute the MDL or PQL for the concentration listed in Table 915-1.

[10] The risk based cleanup concentrations for organic compounds in soils shown in Table 915-1 are taken from the EPA RSLs, as incorporated by reference in Rule 901.b, tables for Target Risk ("TR") = $1x10^{-6}$ and Target Hazard Quotient ("THQ")=0.1. The risk-based cleanup concentrations for metals in soils shown in Table 915-1 are taken from the EPA RSLs, as incorporated by reference in Rule 901.b, tables for TR=$1X10^{-6}$ and THQ=1. The EPA RSL Frequently Asked Questions pages suggest that the THQ=0.1 tables are appropriate when more than 1 compound of concern is to be considered as present or likely to be present as is typical in soils impacted with organic compounds in Spills or Releases of produced water or liquid hydrocarbons.

[11] The Director will consider Residential Soil Screening Level Concentrations up to 1.25 times site specific background levels for metals in soil.

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
1200 SERIES

1201. WILDLIFE PLANS

a. **Wildlife Protection Plan.** Proposed Oil and Gas Operations on new or amended Oil and Gas Locations requiring a new Form 2A, Oil and Gas Location Assessment outside of High Priority Habitat require a Wildlife Protection Plan that includes a description of the Rule 1202.a operating requirements applicable to the Oil and Gas Location. Wildlife Protection Plans may address multiple Oil and Gas Locations if supplemental site-specific information is provided as needed to meet Rule 1202.a operating requirements at each Oil and Gas Location. Wildlife Protection Plans do not require Colorado Parks and Wildlife ("CPW") consultation or approval.

b. **Wildlife Mitigation Plan.** Proposed Oil and Gas Operations on new or amended Oil and Gas Locations within High Priority Habitat require a Wildlife Mitigation Plan that includes a description of the Rule 1202.a operating requirements, and the additional operating and mitigation requirements in Rules 1201.b.(1)–(4), 1202, & 1203. Wildlife Mitigation Plans may address one or multiple Oil and Gas Locations. Pre-existing CPW-approved Wildlife Mitigation Plans in effect on January 15, 2021 may meet these requirements subject to written concurrence from CPW that the Wildlife Mitigation Plan satisfies the requirements of this Rule 1201.b. The Wildlife Mitigation Plan will include the following:

(1) A description of any pre-application consultation with CPW, which may include an alternative location analysis pursuant to Rule 304.b.(2).B.viii, or identifying site-specific measures to Avoid, Minimize, or Mitigate Adverse Impacts to Wildlife Resources;

(2) A description of Best Management Practices incorporated into the proposed Oil and Gas Operations that the Operator commits to implementing for the purposes of minimizing impacts to wildlife;

(3) A description of the Rule 1202.b operating requirements applicable to the Oil and Gas Location; and

(4) A description of the Rule 1203 mitigation commitments to offset Unavoidable Adverse Impacts to Wildlife Resources.

1202. OPERATING REQUIREMENTS

a. The operating requirements identified in this Rule 1202.a apply to Oil and Gas Operations statewide unless the Operator obtains a signed waiver from CPW and the Director or Commission approves a Form 4, Sundry Notice or Form 2A documenting the relief.

(1) In black bear habitat, Operators will install and utilize bear-proof dumpsters and trash receptacles for food-related trash at all facilities that generate trash.

(2) Operators will disinfect water suction hoses and water transportation Tanks withdrawing from or discharging into surface waters (other than contained Pits) used previously in another river, intermittent or perennial stream, lake, pond, or wetland and discard rinse water in an approved disposal facility. Disinfection practices will be repeated prior to completing work and before moving to the next water body. Disinfection will be performed by scrubbing and pre-rinsing equipment away from water bodies to remove all mud, plants, and organic materials and then by implementing one of the following practices:

A. Spray/soak equipment with a CPW-approved disinfectant solution capable of killing whirling disease spores and other aquatic nuisance species defined by CPW; or

B. Spray/soak equipment with water greater than 140° Fahrenheit for at least 10 minutes. All equipment and any compartments they contain will be completely drained and dried between each use.

(3) At new and existing Oil and Gas Locations, Operators will not situate new staging, refueling, or Chemical storage areas within 500 feet of the Ordinary High Water Mark ("OHWM") of any river, perennial or intermittent stream, lake, pond, or wetland.

(4) To prevent access by wildlife, including birds and bats, Operators will fence and net or install other CPW-approved exclusion devices on new Drilling Pits, Production Pits, and other Pits associated with Oil and Gas Operations that are intended to contain Fluids.

A. Such fencing and netting or other CPW-approved exclusion device will be installed within 5 days after the cessation of active drilling and completion activities and maintained until the Pit is removed from service and dried or closed pursuant to the Commission's 900 Series Rules.

B. The Director may require an operator to fence and net or install other CPW-approved exclusion devices on an existing Pit if the Director determines that the installation is necessary and reasonable to protect Wildlife Resources based on the analysis required by Rule 909.j, or other information that demonstrates additional protections for Wildlife Resources are appropriate.

C. Operators will properly maintain and repair all fences, nets, and CPW-approved exclusion devices required by this Rule 1202.a.(4).

(5) For trenches that are left open for more than 5 consecutive days during construction of Pipelines regulated pursuant to the Commission's 1100 Series Rules, Operators will install wildlife escape ramps at a minimum of one ramp per 1/4 mile of trench.

(6) When conducting interim and final Reclamation pursuant to Rules 1003 and 1004, Operators will use CPW-recommended seed mixes for Reclamation when consistent with the Surface Owner's approval and any local soil conservation district requirements.

(7) Operators will use CPW-recommended fence designs when consistent with the Surface Owner's approval and any Relevant Local Government requirements.

(8) Operators will conduct all vegetation removal necessary for Oil and Gas Operations outside of the nesting season for migratory birds (April 1 to August 31). For any vegetation removal that must be scheduled between April 1 to August 31, Operators may implement appropriate hazing or other exclusion measures prior to April 1 to avoid take of migratory birds. If hazing or other exclusion measures are not implemented, Operators will conduct pre-construction nesting migratory bird surveys within the approved disturbance area prior to any vegetation removal during the nesting season. If active nests are located, Operators will provide work zone buffers around active nests.

(9) Operators will treat Drilling Pits, Production Pits, and any other Pit associated with Oil and Gas Operations 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 Resources. Such treatment will be conducted in a manner which will not adversely affect aquatic Wildlife Resources.

(10) Operators will employ the following minimum Best Management Practices on new Oil and Gas Locations with a Working Pad Surface located between 500 feet and 1000 feet hydraulically upgradient from a High Priority Habitat identified in Rule 1202.c.(1).Q–S:

A. Contain Flowback and Stimulation Fluids in Tanks that are placed on a Working Pad Surface in an area with downgradient perimeter berming;

B. Construct lined berms or other lined containment devices pursuant to Rule 603.o around any new crude oil, condensate, and produced water storage Tanks that are installed after January 15, 2021;

C. Inspect the Oil and Location on a daily basis, unless the approved Form 2A provides for different inspection frequency or alternative method of compliance;

D. Maintain adequate Spill response equipment at the Oil and Gas Location during drilling and completion operations; and

E. Not construct or utilize any Pits, except that Operators may continue to utilize existing Pits that were properly permitted, constructed, operated, and maintained in compliance prior to January 15, 2021.

b. Operators will bore, rather than trench, Flowline and utility crossings of perennial streams identified as aquatic High Priority Habitat unless the Operator obtains a signed waiver from CPW and the Director or Commission approves a Form 4 or Form 2A documenting the relief. When installing culverts or bridges, such structures will not impact or prevent the passage of fish unless otherwise directed by CPW.

c. Except as specified pursuant to Rule 1202.c.(2), Operators will not conduct any new ground disturbance and Well work, including access road and pad construction, drilling and completion activities, and Flowline/utility corridor clearing and installation activities in the High Priority Habitats listed in Rule 1202.c.(1).

(1) High Priority Habitats subject to this Rule 1202.c include:

A. Columbian sharp-tailed grouse (within 0.6 miles of the lek site);

B. Greater prairie chicken (within 0.6 miles of the lek site);

C. Greater sage-grouse (within 1.0 miles of the lek site);

D. Gunnison sage-grouse (within 1.0 miles of the lek site);

E. Lesser prairie chicken (within 1.25 miles of the lek site);

F. Plains sharp-tailed grouse (within 0.4 miles of the lek site);

G. Bald eagle (within 0.25 miles of an active nest);

H. Ferruginous hawk (within 0.5 miles of an active nest);

I. Golden eagle (within 0.25 miles of an active nest);

J. Northern goshawk (within 0.5 miles of an active nest);

K. Peregrine falcon (within 0.5 miles of an active nest);

L. Prairie falcon (within 0.5 miles of an active nest);

M. Least tern production area;

N. Piping plover production area;

O. Townsend's big-eared bat, Mexican free-tailed bat, and myotis (within 350 feet of winter hibernacula);

P. Bighorn sheep production area;

Q. Waters identified by CPW as "Gold Medal" (within 500 feet of OHWM);

R. Cutthroat trout designated crucial habitat and native fish and other native aquatic species conservation waters (within 500 feet of OHWM);

S. Sportfish management waters not identified by CPW as "Gold Medal" (within 500 feet of OHWM); and

T. CPW-owned State Wildlife Areas and State Parks.

(2) This Rule 1202.c does not apply to:

A. Production operations at existing Oil and Gas Locations, including:

i. Routine maintenance, repairs, and replacements of Production Facilities that do not require a drilling or workover rig;

ii. Emergency operations;

iii. Spill and Release response;

iv. Ongoing Reclamation and site maintenance activities;

v. Habitat improvements that have been approved by CPW or the Commission to Mitigate Adverse Impacts to Wildlife Resources at existing facilities; or

vi. Commission- or Director-requested work.

B. Non-emergency workovers, including uphole recompletions, plugging operations, and site investigation and Remediation at existing Oil and Gas Locations, if:

i. The Operator has obtained prior approval from the Director;

ii. The Operator has consulted with CPW; and

iii. The Operator Minimizes Adverse Impacts to the species for which the High Priority Habitat exists.

C. Access road construction and Flowline/utility corridor clearing and installation activities within the High Priority Habitat identified in Rules 1202.c.(1).Q–S in association with an approved Form 2A may be allowed subject to Best Management Practices or other avoidance measures agreed to in consultation with CPW.

d. All Oil and Gas Development Plans submitted after January 15, 2021, including amendments to previously-approved Form 2As, that cause the density of Oil and Gas Locations to exceed 1 per square mile in the High Priority Habitats listed in Rule 1202.d require a CPW-approved Wildlife Mitigation Plan pursuant to Rule 1201.b or other CPW-approved conservation plan and compensatory mitigation for Wildlife Resources pursuant to Rule 1203. This Rule 1202.d applies to the following High Priority Habitat types:

(1) Bighorn sheep migration corridors and winter range;

(2) Elk migration corridors, production areas, severe winter range, and winter concentration areas;

(3) Mule deer migration corridors, severe winter range, and winter concentration areas;

(4) Pronghorn migration corridors and winter concentration areas;

(5) Greater sage-grouse priority habitat management areas;

(6) Columbian sharp-tailed grouse production areas;

(7) Greater prairie chicken production areas;

(8) Gunnison sage-grouse occupied habitat and production areas;

(9) Lesser prairie chicken focal areas; and

(10) Plains sharp-tailed grouse production areas.

1203. COMPENSATORY MITIGATION FOR WILDLIFE RESOURCES

a. In High Priority Habitats listed in Rule 1202.d, the Operator will complete compensatory mitigation to Mitigate direct and Unavoidable Adverse indirect Impacts pursuant to Rules 1203.b–d. Direct impacts to wildlife are unavoidable and occur from direct mortality or displacement during construction activities and habitat conversion to industrial facilities. Indirect impacts to wildlife occur over time from the cumulative functional habitat loss from fragmentation and modified habitat use as development density increases. Indirect Impacts may be Avoided or Minimized through the application of alternative siting and Rule 1202 operating requirements. The Director, after consultation with CPW, will have discretion to determine whether compensatory mitigation proposed by the Operator is sufficient to protect wildlife from direct and Unavoidable Adverse indirect Impacts. An Operator may fulfill the obligation to complete compensatory mitigation by:

(1) Completing or causing to be completed a project approved by CPW and the Director as described in a Compensatory Mitigation Plan pursuant to Rule 1203.b; or

(2) Paying a habitat mitigation fee to CPW, as provided by Rules 1203.c & 1203.d. Any fee pursuant to Rules 1203.c & 1203.d will be calculated to reimburse all reasonable and necessary direct and indirect costs that will be incurred by CPW in completing compensatory mitigation sufficient to offset the direct and Unavoidable Adverse indirect Impacts to Wildlife Resources caused by the proposed Oil and Gas Operations.

(3) The Director may grant an exception from the compensatory mitigation requirement set forth in this Rule 1203 after consulting with CPW pursuant to Rule 309.e.

b. If an Operator chooses to complete or cause to be completed compensatory mitigation to Mitigate the direct and Unavoidable Adverse indirect Impacts to Wildlife Resources:

(1) The Operator will submit a Compensatory Mitigation Plan to the Director with a level of detail commensurate with the scale, scope, intensity, and duration of the impacts to Wildlife Resources that includes, as appropriate:

A. Plan objectives or mitigation goal, including a description of how the plan will address equivalence, timeliness, duration, durability, and additionality;

B. Coordination and concurrence with CPW;

C. Site selection;

D. Site protection instrument;

E. Baseline information on Wildlife Resources;

F. Mitigation schedule and workplan;

G. Maintenance plan;

H. Performance standards;

I. Monitoring and reporting requirements;

J. Long-term management plan;

K. Adaptive management plan, if necessary;

L. Financial Assurances; and

M. Other information as required by the Director.

(2) The Director will consult with CPW about the adequacy of the proposed Compensatory Mitigation Plan.

(3) The Director may accept the Operator's Compensatory Mitigation Plan if it meets the criteria of Rule 1203.b.(1) and, in the Director's judgment, based on the consultation described in Rule 1203.b.(2), provides adequate compensation for direct and Unavoidable Adverse indirect Impacts to Wildlife Resources from the proposed Oil and Gas Operations.

c. **Direct Impact Habitat Mitigation Fee.** An Operator may fulfill its obligation to Mitigate direct Adverse Impacts to wildlife caused by new ground disturbance within High Priority Habitat types listed in Rule 1202.d by paying to CPW a habitat mitigation fee in the amount listed in Table 1203-1 no less than 30 days prior submitting a Form 42, Field Operations Notice – Notice of Construction or Major Change pursuant to Rule 405.b. The direct impact habitat mitigation fee is subject to update on a periodic but no more frequent than annual basis and will be modified only through the Commission's rulemaking process described in Rule 529. Notice of such rulemaking proceeding will be provided by January 15 of each year.

Table 1203-1 – Direct Impact Habitat Mitigation Fee

Total Disturbance Acres	Fee
1.0–10.99	$13,750
11.0+	Determined based on site-specific conditions and consultation with CPW

d. Indirect Impacts.

(1) In High Priority Habitats listed in Rule 1202.d with a density of Oil and Gas Locations less than 5 per square mile, CPW will recommend to the Director whether compensatory mitigation is required to address the Unavoidable Adverse indirect Impacts of habitat fragmentation caused by the proposed Oil and Gas Development Plan.

(2) When determining whether to recommend that compensatory mitigation be required for Unavoidable Adverse indirect Impacts on Wildlife Resources, factors that CPW may consider include, but are not limited to:

A. The existing landscape context, and extent to which the proposed Oil and Gas Operations are within land already used for residential, industrial, commercial, agricultural, or other purposes, and the existing wildlife disturbance associated with such land uses;

B. The estimated lifespan of the proposed Oil and Gas Operations;

C. The extent to which the proposed Oil and Gas Operations incorporate alternative siting of Oil and Gas Facilities or Oil and Gas Locations to Avoid and Minimize Adverse Impacts;

D. The extent to which the proposed Oil and Gas Operations incorporate the use of existing Oil and Gas Facilities, Oil and Gas Locations, roads, or Pipeline corridors to limit new surface disturbance and habitat fragmentation;

E. The extent to which the proposed Oil and Gas Operations use technology and practices which protect Wildlife Resources, including but not limited to:

i. Seasonal construction and drilling limitations;

ii. Noise limitations;

iii. Remote operations; or

iv. Measures to reduce traffic volumes, including but not limited to transport of liquids through the use of Pipelines and storage in large Tanks.

(3) If the Director determines that compensatory mitigation for Unavoidable Adverse indirect Impacts to Wildlife Resources is necessary, the Operator may fulfill its obligation to Mitigate the indirect Adverse Impacts of its proposed Oil and Gas Operations by either:

A. Completing or causing to be completed a project approved by CPW and the Director pursuant to Rule 1203.b; or

B. Paying an additional habitat mitigation fee to CPW.

(4) The Director will determine the amount of the fee for each proposed Oil and Gas Location based on CPW's estimate of costs to reimburse all reasonable and necessary expenditures to complete compensatory mitigation sufficient to offset the Unavoidable Adverse indirect Impacts to Wildlife Resources from the proposed disturbance.