COGCC and WOGCC Oil & Gas Regulatory Update

Rocky Mountain EHS Peer Group - January 21, 2021

JOST ENERGY LAW PC

Colorado SB 19-181:

State Regulatory Actions since 4/16/2019

- 500 Series Rulemaking – Complete
  - As directed by SB19-181, this rulemaking enables the use of administrative law judges and hearing officers to ensure the COGCC is properly processing applications.
- Flowline Rulemaking – Complete
  - Following the 2018 and SB 19-181 rule changes, additional public disclosure, inspection, and deactivation requirements were added.
- AQCC Regulation Number 7 & Regulation Number 3 - Complete
  - Reg 7 addresses control of Ozone, Volatile Organic Compounds and Nitrogen Oxide (NOx) emissions. Reg 3 addresses stationary source permitting and air pollutant emission notice requirements.
  - Second Reg 7 Rulemaking reduces actual emissions of NOx from stationary source engines and applies to existing natural gas fired reciprocating internal combustion engines and those placed in service, modified, or relocated after adoption.
- Wellbore Integrity Rulemaking - Complete
  - This rulemaking strengthened Groundwater protection requirements for all phases of oil and natural gas development.
- AQCC Regulation Number 22 - Complete
  - This rulemaking developed Colorado greenhouse gas reporting and emission reduction requirements.
- Mill Levy Rulemaking – Complete
  - This rulemaking increased the current mill levy from $0.0011 to $0.0015.
- Mission Change Rulemaking – Complete
  - 200-600, 800, 900 & 1200 Series Amendments Adopted November 23, 2020, effective January 15, 2021, in accordance with SB19-181 and the COGCC's mission to regulate oil and gas development to protect PHSWEW.
- AQCC GHG Reductions – Stakeholder Meetings in Process & Rulemakings in 2021
- COGCC Financial Assurance and Filing Fees – Will be noticed in 2021
- COGCC Mission Change Clean-Up & Map Updates – annual Rulemakings noticed in January every year to update HPH and DI Maps; potential "clean up" Rulemaking in 2021

SB 19-181:

Local Regulatory Actions since 4/16/2019

- Adams County:
  - 6-month moratorium passed in March 2019
  - Regulatory Update – Completed September 2019
  - Moratorium lifted in September 2019 after regulations passed
- Arapahoe County:
  - Working on Traffic Impact Fee
  - Currently updating oil and gas regulations
- Aurora:
  - Currently updating oil and gas regulations
- Broomfield:
  - Passed 6-month moratorium in May 2019 and have passed extensions to extend to June 4, 2021
  - May 2020, Broomfield passes 2,000' setbacks along with new zoning restrictions
  - Expected to develop further regulations
- Berthoud:
  - Passed first moratorium in May 2019 and it is still in effect today
  - First discussion of oil and gas code update in July 2020
- Boulder County:
  - Passed initial moratorium on June 28, 2019 and has continued to be extended in 6-month increments.
  - Updated oil and gas regulations – Effective December 2020
- City of Boulder:
  - Moratorium on oil and gas has been in place for over 7 years
  - Current moratorium set to expire at the end of 2020 unless extended

SB 19-181:

Local Regulatory Actions since 4/16/2019

- Commerce City:
  - Currently updating oil and gas regulations
- Erie:
  - Initially adopted moratorium in July 2018, extended on Jan. 22, 2019, then extended again on June 25, 2019 after SB19-181 was passed and expired in December 2020
  - Updated regulations in November 2020
- Fort Collins:
  - Currently updating regulations in 2021
- Lafayette:
  - Moratorium initially passed in November 2017 and has been continuously extended
  - Current moratorium set to expire May 31, 2021
- Larimer County:
  - Oil and Gas Task Force Charter formed March 2019
  - New oil and gas regulations approved April 2020

SB 19-181:

Local Regulatory Actions since 4/16/2019

- Lochbuie:
  - 6-Month Moratorium passed in August 2019, extended 3 months in January 2020, but repealed in February 2020
  - Updated several provisions of oil and gas code
- Longmont:
  - Environmental groups tried to reinstate Longmont's fracking ban which was struck down in 2016 and were denied
- Superior:
  - Enacted 6-month moratorium in January 2019, extended in July 2019 until April 2020
  - New regulations passed April 13, 2020 and moratorium expired
- Timnath:
  - 3-month moratorium passed April 2019 (not extended upon expiration)
  - Interim oil and gas regulations passed July 2019
- Weld County:
  - 1041 Designation – 2019
  - MOU w/COGCC – 2019
  - 1041 WOLGA Code Change
  - Location Assessment for Pipelines Change

25,000’ Overview of COGCC Mission Change Rules

- **100 Series**: New definitions for every Rule Series
- **200 Series**: Limitations on transfer of operatorship timing and liability
- **300 Series**: Full permitting process overhaul – Oil and Gas Development Plan, CAP, and LG approvals; Rule 318A WSU terminated
- **400 Series**: Operations, reporting and substantial Noise, Odor, Dust and Lighting modifications
- **500 Series**: Procedural modifications, standing and “affected person” allowances
- **600 Series**: Setbacks of 2,000 from 1 or more Building Units, 1 High Occupancy Building Unit or School
- **800 Series**: Modifications to UIC wells and aquifer exemptions
- **900 Series**: Overlapping jurisdiction with CDPHE; modifications to venting and flaring
- **1200 Series**: New regulations for High Priority Habitats; new plans for Form 2As

Hearings and Adoption Dates

- Hearings Started August 24, 2020 and ended November 23, 2020
  - Over 100 parties and 100’s of public comments in writing or verbal
- **200-600 Series Rules:** Preliminary Adopted on September 28, 2020
- **800 Series Rules**: Preliminarily Adopted on October 9, 2020
- **900 Series Rules**: Preliminary Adopted on November 5, 2020
- **1200 Series Rules**: Preliminary adopted on November 20, 2020
- **Full Set of 200-600, 800, 900 and 1200 Rules**: Adopted on November 23, 2020
- <u>**Effective Date of all Rules: January 15, 2021**</u>

200-Series:

Overview of Adopted Rules

- **Transfer of Permits**: require more financial assurance and expanded notice prior to Closing of transaction (Form 9 and Form 10)

- **Contractor Liability**: ensure Contractor compliance with rules

- **Tests & Surveys**: more authority to the Commission

- **Abandonment**: allow a Local Government to nominate a well to abandon; discretion to the Director to require a P&A; establish criteria to require a P&A

- **Chemical Disclosure**: reveal chemical identities; prohibit chemicals of concern

- **Director Discretion**: remains subjective and applies to many rules

Rule 201 – Scope of Rules

- **201.a. – Adopts SB19-181 Mission**: 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, and 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
- **201.b – Contractor Liability**: 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, <u>and will ensure compliance by their contractors and subcontractors</u>
- **201.c – Stricter LG Regulation**: 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

Rule 209 – Tests & Surveys

- **209.a**: 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, and 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
- If the Director requires an Operator to take action pursuant to Rules 209.a or 218.g, the Operator may <u>appeal</u> the Director's decision to the Commission pursuant to Rule 503.g.(10) (any person may seek relief or a ruling from the Commission) and the Commission will hear the appeal at its next regularly scheduled meeting
- The Commission may uphold the Director's decision if the Commission determines the Director had <u>reasonable cause to determine</u> that an Operator's actions impacted or threatened to impact public health, safety, and welfare, the environment, and wildlife resources, and that the action required by the Director was <u>necessary and reasonable</u> 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 its next regularly scheduled hearing

Rules 210 & 211 – Corrective Action, P&A, Closure

- **210.a**: The Director or Commission will require correction of any condition necessary to protect and minimize adverse impacts to public health, safety, and 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
- **211.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
- **211.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

Rule 223 – Confidential Information

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

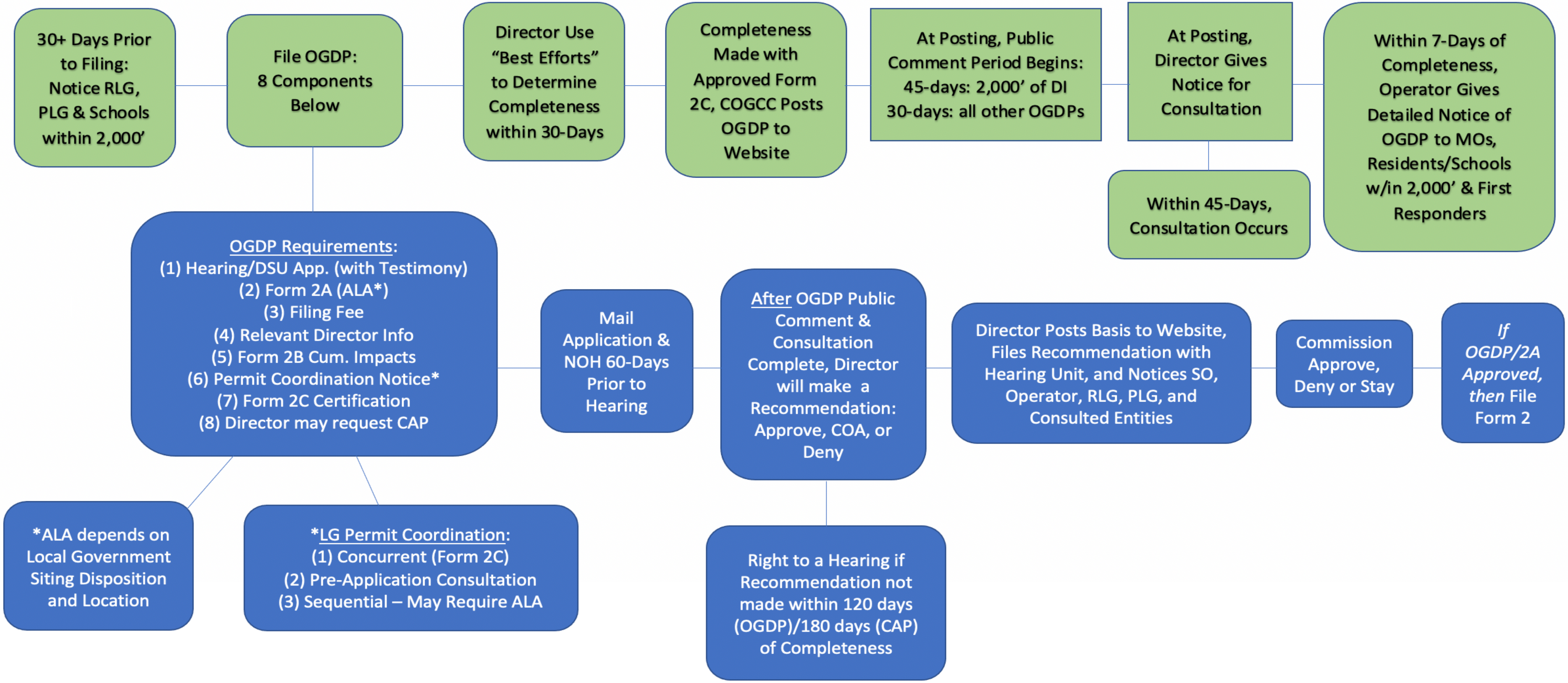
Effective Date & Impact on Pending Permits

- **Effective Date: January 15, 2021**

- Statement of Basis and Purpose provides:
  - Operators to notify Staff by **March 1, 2021** about which pending permit applications they intend to <u>replace</u> to comply with the newly adopted and amended Rules
  - Operators will have **6 months** from the effective date of the Mission Change Rules – **July 15, 2021** – to submit new Form 2As and Form 2s for in process, on hold or delayed permit applications
- COGCC intends to "delete" pending permits not in compliance
- Legal Concerns with "voluntary" notification of pending permits, COGCC "deletion" and no determinative outcome – effects potential future takings litigation

300 & 500-Series OGDP Process

Adopted COGCC Rules as of November 23, 2020



OGDP Components

Rule 303

1. Pre-Application Notice
2. Hearing Application for OGDP + Spacing Application(s) (if needed) + mineral ownership for one tract
3. Form 2A (including ALA if necessary and required Cumulative Impacts Plan) - Rule 304.e allows substantially equivalent information developed with a Local permit
4. Filing fee (Rule 301.d: at the time of filing a Form 2, Form 2A, DSU, OGDP and CAP)
5. Any relevant information that the Director determines is necessary and reasonable to determine whether the operation is protective
6. Cumulative Impacts Data Evaluation Repository (CIDER) – **NEW Form 2B -** Requirements: Air Resources, Public Health, Water Resources, Terrestrial and Aquatic Wildlife Resources, Soil and Ecosystem Resources, Public Welfare, surrounding O&G/Industrial impacts
7. Permit Coordination Notifications – **NEW Form 2C**, notification of concurrent Local/federal permit, conflicts, milestones, approved permit
8. Certification of Completeness – **NEW Form 2C**
9. If multiple Locations, Director may request a meeting with Operator to evaluate re-submittal as a CAP

15 Form 2A Requirements

Rule 304

1. Local Government Siting Information, including Rule 304.b.(2)B ALA Criteria;
2. Alternative Location Analysis;
3. Cultural Distances;
4. Location Pictures;
5. Site Equipment List;
6. Flowline Descriptions;
7. Drawings;
8. Geographic Information System (GIS) Data;
9. Land Use Description;
10. NRCS Map Unit Description;
11. Best Management Practices;
12. Surface Owner Information;
13. Proximate Local Government Information;
14. Wetlands;
15. Schools and Child Care Centers

21 Form 2A Plans

Rule 304.c

(1) Emergency Spill Response Program
(2) Noise Mitigation Plan
(3) Light Mitigation Plan
(4) Odor Mitigation Plan
(5) Dust Mitigation Plan
(6) Transportation Plan
(7) Operations Safety Management Program
(8) Emergency Response Plan
(9) Flood Shut-In Plan
(10) Hydrogen Sulfide Drilling Plan
(11) Waste Management Plan
(12) Gas Capture Plan
(13) Fluid Leak Detection Plan
(14) Topsoil Protection Plan
(15) Stormwater Management Plan
(16) Interim Reclamation Plan
(17) Wildlife Protection Plan
(18) Water Plan
(19) Cumulative Impacts Plan
(20) Community Outreach Plan
(21) Geologic Hazard Plan

Rule 308 – Form 2 Requirements

1. Distance between well and nearest RBU and other locations;
2. Wellbore Diagram;
3. Details re: deepen, re-enter, recomplete & sidetrack;
4. Well Location Plat;
5. Deviated Drilling Plan;
6. Casing and Cementing Plan (NEW with Wellbore Integrity Rules as of 11/2/2020);
7. Statewide Offset Well Evaluation;
8. Hydraulic Fracturing Treatment at Depths 2,000 feet or less;
9. Certification if well is subject to § 24-65.1-108, C.R.S (area of state interest)

Rules 311 & 312 – Expiration/Refiles & Subsequent Operations

- **311**: OGDPs are valid for 3 years; no extensions permitted; OGDPs, DSUs, refile Form 2s and 2As maybe filed 60 days prior to expiration subject to Commission's rules in effect at the time of submission
- **312**: Must obtain Director approval for a Form 4 before conducting subsequent operations with heavy equipment, *except* for routine Well maintenance
- May obtain verbal approval with a Form 4 within 7-days

400-Series:

Overview of Adopted Rules

- **Re-instated Wellbore Spacing Units**: part of OGDP in 300 Series
- **Exception Locations**: Allowances maintained in certain circumstances with 100% consent
- **Noise, Odor & Light**: more stringent regulations and receptor locations
- **Public Water Systems**: limitations on surface locations within buffer zones; can seek variance from COGCC with hearing
  - **Buffer Zones**
    - The internal buffer zone is located between 0 and 1,000 feet hydraulically upgradient from a Classified Water Supply Segment.
    - The intermediate buffer zone is located between 1,001 and 1500 feet hydraulically upgradient from a Classified Water Supply Segment.
    - The external buffer zone is located between 1501 and 2640 feet hydraulically upgradient from a Classified Water Supply Segment.

Rule 402 – GWA Rule

- **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

Rule 413, 414, 416 – Forms 7, 5, and 5A

- **413.a.**: Form 7, Operator’s Monthly Report of Operations - 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.
- **414.a.**: Form 5, Preliminary Drilling Completion Report - 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.
- **414.b.**: Form 5, Final Drilling Completion Report - 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 Final Form 5 will be submitted for all the Wells within 60 days of rig release for the last Well drilled on the pad.
- **416.a.**: 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

Rule 417, 418 – Mechanical Integrity Testing

- 417.a.: A mechanical integrity test will be performed on all injection Wells
- 417.b.: All Shut-in Wells will pass a mechanical integrity test
- 417.c.: All Temporarily Abandoned Wells will pass a mechanical integrity test
- 417.d.: A mechanical integrity test will be performed on Suspended Operations Wells and Waiting On Completion Wells as described in this section (417.d)
- 417.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, Field Operations Notice - Mechanical Integrity Test, of the scheduled date and time when the test will be performed
- 418: 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.

Rule 419, 420 – Bradenhead Testing

- **419.a.**: 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
- **419.b.**: 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, including Groundwater, Potential Flow Zones, and formations, and Wildlife Resources, and pursuant to this Rule 419
  - After Rig Release, Prior to Stimulation
  - During Hydraulic Fracturing Treatment
  - Thirty Days After Hydraulic Fracturing Treatment
  - Through the Remaining Life of the Well
- **420**: The Operator will submit results of Bradenhead tests to the Director within 10 days of completing the test either by filing a Form 17 or by another method approved by the Director or Commission

Rule 423 – Noise

- **423.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

- **423.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

Rule 423 – Noise

- **423.b.**: 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, the 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)

Rule 423 – Noise

- **423.b.**: 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.

- **423.c.**: 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 Rule 423.b.(1) as measured at a point 350 feet from the equipment generating the noise in the direction from which the complaint was received

- **423.d.**: All noise measurements will be cumulative

Rule 424 – Lighting

- **424.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
  - Plan must address pre-production lighting and production lighting
- **424.c. & d.**: 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
  - Maximum Permissible Light Levels for facilities based on land use
- **424.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

Rule 425, 426, 427 – Visual Impact Mitigation, Odors and Dust

- **425.a.**: 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
- **426.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
- **427.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)

Rule 434, 435 – Abandonment

- **434.a.**: 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.
  - 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
- **434.b.**: 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
- **435.a.**: Prior to the abandonment of a Well, a Well Abandonment Report, Form 6 – Notice of Intent to Abandon, will be submitted to, and approved by, the Director. The Form 6, Notice of Intent to Abandon will be completed and attachments included to fully describe the proposed abandonment operations
- **435.b.**: Within 30 days after abandonment, the Form 6 – Subsequent Report of Abandonment, will be filed with the Director

Rule 436 – Seismic Operations

- **436.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
- **436.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
- **436.f.**: Form 20A, Completion Report for Seismic Operations - 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
- **436.g.**: Financial Assurance Requirements - The Operator will file Financial Assurance pursuant to Rule 705 prior to submitting the Form 20
- **436.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

500-Series:

Overview of Adopted Rules

- **Standing**: expanded to Building Unit Owners and Tenants within 2,000’; automatic standing
- **Notice**: expanded to 2,000’ for Building Unit Owners, Tenants, HOBU and Schools
- **Variances**: Allowed but extremely limited use
- **Responsible Party**: modify burden of proof to place on party
- **Hearing and Application Filing Processes**: modified to require a form of hearing in almost every situation

Rule 502 – New Variance Criteria

- Requests for variances to any of the Commission's Rules or orders will be filed with the Commission
- 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
- 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

Rule 507 – Affected Person & Standing

- 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
- Federal agencies, state agencies, tribal governments, Relevant Local Governments, and special districts with legal authority over the application are Affected Persons
- 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
- 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
- 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 Governmental Agencies not identified in 507.a.(1), its legal authority over or interest in the issues relevant to the application

600-Series:

Overview of Adopted Rules

- **General and Operational Safety Requirements**: safe manner and applies to all contractors and subcontractors
- **Setbacks and Siting Requirements**: 2,000’ with off ramps
- **Signage Requirements**: OGL, Road, D&C, Well, Tank and Centralized E&P Waste Management
- **Waste, Weeds and Trash Requirements**: all prohibited
- **Oil and Gas Facilities – Tanks, Vessels**: building standard and siting requirements
- **Inspections**: Tank and Process Vessel Inspections, AVO (Audio, Visual, Olfactory) Inspections
- **Fire Prevention and Protection**: substantial requirements for fire controls
- **Hydrogen Sulfide Gas – Public Protection Plan**: radial calculation and notice to residents if present
- **CBM Wells**: Assessment and Monitoring
- **Groundwater Baseline Sampling and Monitoring:** applies statewide

Rule 604.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**

(1) At the time a Form 2A 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

Rule 604.a. - Well Location Requirements

(3) No Working Pad Surface will be located **2,000 feet or less from a School Facility or Child Care Center**

- 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
- 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

Rule 604.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 Development 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**

Rule 604.b. - Siting Requirements for Proposed Oil and Gas Locations Near Residential Building Units and High Occupancy Building Units

(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

Rule 612 – Hydrogen Sulfide Gas

- **612.a.**: Operators will avoid any uncontrolled release or hazardous accumulation of H2S and if releases or hazardous accumulations of H2S cannot be avoided, or during upset conditions or malfunctions, Operators will employ mitigation measures to reduce potential harms to safety

- **612.b.**: 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 H2S in the gas stream at concentrations at or above 100 parts per million the Operator will calculate the radius of exposure to any Building Unit, High Occupancy Building Unit, or Designated Outdoor Activity Area

Rule 612 – Hydrogen Sulfide Gas

- **612.c.**: An H2S 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 Outdoor Activity Area within the radius of exposure; or
  (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
- **612.d.**: When proposing to drill a Well in areas where H2S gas can reasonably be expected to be encountered, Operators will submit a H2S drilling operations plan with their Form 2, unless the plan was already submitted with their Form 2A, pursuant to Rule 304.c.(10) and the H2S drilling operations plan must be made pursuant to BLM Onshore Order No. 6. (Jan. 22, 1991)
- **612.e. and f.**: Designated H2S locations and procedures
- **612.g.**: Operators will report on a Form 42, Field Operations Notice any laboratory analysis indicating the presence of H2S gas to the Director within 48 hours
  - Upon receipt of the Form 42, the Director will notify the Relevant and Proximate Local Government

Rule 615 – Groundwater Baseline Sampling and Monitoring (Statewide)

- **615.a.**:
  - Applies to oil Wells, gas Wells, Multi-Well Sites, and Dedicated Injection 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 Dedicated Injection 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
  - 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
- **615.b.**:
  - 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 Dedicated Injection 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 Dedicated Injection Well, the Operator will select the 4 sampling locations based on several criteria: proximity, type of water source, orientation of sampling locations, multiple aquifers and condition of water source

Rule 615 – Groundwater Baseline Sampling and Monitoring (Statewide)

- **615.c.**: 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 there is no available water source
- **615.d.**: Timing of Sampling
  - 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 Dedicated Injection Well.
  - 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 Dedicated Injection 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.
  - Operator may rely on water sampling analytical results obtained from an Available Water Source within the sampling area if certain requirements are met
- **615.e.**: Sampling and analysis will be conducted in conformance with an accepted industry standard pursuant to Rule 913.b.(2). COGCC provides a model Sampling and Analysis Plan

800-Series:

Overview of Adopted Rules

- New definitions of UIC Aquifer and Underground Source of Drinking Water must align with the recently adopted Wellbore Integrity Rules and definition of Groundwater, as well as the SBP language for determination of presence of groundwater
- UIC request must be submitted with OGDP 300 Series Filings
- Director discretion remains through the Rules
- Changes in Underground Injection Permit requirements and new geological and geophysical evaluation of known faults within a 12-mile radius for EOR wells
- EOR addressed in 800 series rules – expanded definition of EOR

Rule 803 – Form 31 Permit – Seismicity Evaluation

- **803.g.(6):** 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.

900-Series:

Overview of Adopted Rules

- **902**: Prevention of Pollution
- **903**: Prohibition of Venting and Flaring except as provided in the Rule
- **904**: Annual Director Report of Cumulative Impact Data; Operator Participation in Studies
- **905 - 907**: Management of E&P and non-E&P Waste, Centralized E&P Waste Management Facility Requirements
- **908 – 910**: Pit Requirements
- **911**: Facility Closure Requirements
- **912**: Reporting/Remediation of Spills and Releases
- **913**: Site Investigation/Remediation/Closure Requirements
- **914**: Points of Compliance Criteria
- **915**: Soil/Groundwater Concentrations, New Table 915-1 Retroactive for Remediation Not Complete by 1/15/2022

Key Definitions of Venting and Flaring

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

Rule 903.a – Notice of Venting and Flaring

- Operator must give notice no later than 2 hours before any planned Flaring allowed by Rule 903 (verbal, written or electronic) to the RLG and PLG and local emergency response authorities

- If Flaring due to upset condition, Operator must provide verbal or electronic notice as soon as possible, but no later than 12 hours, to RLG and PLG and local emergency response

- RLG, PLG and local emergency response may <u>waive</u> notice

- Operator must maintain records of notice provided and provide to Director upon request

Rule 903.b – Emissions During Drilling

- Operators will capture or combust gas downstream of the mud-gas separator using best drilling practices while maintaining safe operating conditions

- 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

- Combustors will be located a minimum of 100 feet from the nearest surface hole location and enclosed

Rule 903.c – Emissions During Completions

- Must use reduced emission completion practices on all newly Completed and re-Completed Wells
- Must enclose all Flowback vessels and adhere to AQCC Reg 7 for emission reduction from pre-production Flowback vessels
- May Flare with written approval from the Director only under one of the following circumstances:
  (1) Obtain Director approval through an approved Gas Capture Plan (part of 2A)
  (2) Obtain an approved Form 4 (including anticipated Flaring volume and duration, plan to connect)
  (3) Combust at an emission control device if necessary to ensure safety during Upset Condition for a period not to exceed **24 cumulative hours**; must have Director approval over 24 hours; must submit a Form 4 within 7-days

Rule 903.d – Emissions During Production

- Prohibition of Venting and Flaring after Commencement of Production EXCEPT:
  (1) Upset Condition not to exceed 24 cumulative hours
  (2) Active and required maintenance and repair as long as not prohibited by AQCC Reg 7
  (3) Approved by the Director on a Gas Capture Plan for a Production Evaluation or Productivity Test not to exceed 60 days
  (4) During a Bradenhead Test
  (5) During Well Liquids Unloading with a Form 42 Notice no less than 48 hours prior to the unloading or as soon as possible prior to unloading
  (6) Approved on a Form 4 prior to January 15, 2021 (not to exceed 1/15/2022)

- For any Venting or Flaring done pursuant to an exception for a period that exceeds 8 consecutive or 24 cumulative hours, the Operator must submit a Form 4

Rule 903.d – Emissions for Unconnected Wells & Pits

- Wells that have Commenced Production prior to 1/15/2021 and are not connected to a gathering line or put to beneficial use may Vent or Flare with an approved Form 4, but Director will not approve a one-time request to Vent or Flare to any date after 1/15/2022
- New Pits within 2,000’ of a BU/DOAA or within Ozone non-attainment Counties must emit less than 2 tpy of VOCs – all other Pits must emit less than 5 tpy VOCs (unless used for recycling/reuse of produced water)
- Pits constructed prior to 1/15/2021 will emit less than 5 tpy VOCs (unless used for recycling/reuse of produced water)

Rule 903.e – Gas Capture Plans

- On a Form 2A, 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)
- Gas Capture Plans will demonstrate compliance with the requirements of Rules 903.b–d and include detailed information on the planned gathering system or putting gas to beneficial use
- Operator must certify that facility has been connected to a gathering line with a Form 10 Certificate of Clearance

Rule 904 – Cumulative Impacts

- No later than January 15, 2022, and annually thereafter, the Director will report detailed information to the Commission based on consultation with CDPHE and the Department of Natural Resources, including CIDER data, APCD GHG Roadmap data, Reg 7 data, ozone data, other reports/academic research, any relevant information on PHSWEW, and recommendations for future Rulemaking, Guidance, workgroups, and studies
- Commission may require an Operator to participate in studies to evaluate cumulative impacts as a condition of approving an OGDP
- Commission may establish an informational docket to solicit information to evaluate cumulative impacts

Rule 912: Spills and Releases

- 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 , **<u>within 24 hours</u>** of discovery, unless otherwise specified (ALSO notification to LG/SO):
    - Any size that impacts or threatens to impact any Waters of the State, PWS, residence, livestock, wildlife, or publicly-maintained road
    - 1 barrel or more of E&P Waste or produced fluids is spilled or released outside of berms or other secondary containment
    - 5 barrels or more of E&P Waste or produced Fluids regardless of whether the Spill or Release is completely contained
    - For a Grade 1 Gas Leak from a Flowline, the Operator must submit a Form 19 – Initial
    - The discovery of 10 cubic yards or more of impacted material resulting from a current or historic Spill or Release
    - The discovery of impacted Waters of the State, including Groundwater
    - A suspected or actual Spill or Release of any volume where the volume cannot be immediately determined
    - A Spill or Release resulting in vaporized hydrocarbon mists that leave the Location Flowline
    - A Release of natural gas that results in an accumulation of soil gas or gas seeps
    - A Release that results in natural gas in Groundwater

Rule 915: Soil and Groundwater Concentrations

- Operators will adhere to the concentrations for soil cleanup and Groundwater in Table 915-1.
- The Director will require adherence to the Protection of Groundwater Soil Screening Levels when a pathway to Groundwater exists (subject to a future Workgroup).
- 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.
- **SEE FOOTNOTES** in Table 915-1 (i.e., the Director will consider site-specific background concentrations or reference levels in native soils and Groundwater)

1200-Series:

Overview

- **New Required Plans**: new requirements for Compensatory Mitigation Plan, Wildlife Mitigation Plan (for locations within a High Priority Habitat) and Wildlife Protection Plan (for locations outside of a High Priority Habitat)
- **High Priority Habitat**: new definition and list of new habitats with no surface occupancy restrictions.
- **Rule 304**: required alternative location analysis if the Location is in a HPH and CPW has not granted a waiver
- **Rule 309**: CPW Consultation requirements
- **Rule 1202.c**: prohibition of new ground disturbance at new locations within listed HPH.
- **Rule 1202.d**: new requirement for a CPW-approved Wildlife Mitigation Plan for new OGDPs and amendments to existing Locations that exceed 1-square mile in HPH locations.
- **Rule 1203**: Compensatory Mitigation

Rule 1201: Wildlife Plans

- Proposed Oil and Gas Operations on new or amended Oil and Gas Locations requiring a new Form 2A, Oil and Gas Location Assessment <u>outside of High Priority Habitat</u> require a Wildlife Protection Plan
- Proposed Oil and Gas Operations on new or amended Oil and Gas Locations <u>within High Priority Habitat</u> require a Wildlife Mitigation Plan that includes a description of the Rule 1202.a operating requirements, and additional operating and mitigation requirements

Rule 1202.c: No New Ground Disturbance in HPH

Except as specified pursuant to Rule 1202.c.(2), Operators will not conduct any <u>new ground disturbance and Well work</u>, 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)

- **NOTE**: 3 new aquatic "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) and "S" (sportfish management waters not identified by CPW as "Gold Medal" - within 500 feet of OHWM)

Rule 1202.c: No New Ground Disturbance at HPH

Rule 1202.c does not apply to:

- Production operations at existing Oil and Gas Locations (including maintenance and emergency)
- Non-emergency workovers, including uphole recompletions, plugging operations, and site investigation and Remediation at existing Oil and Gas Locations with prior approval and CPW consultation
- Access road construction and Flowline/utility corridor clearing and installation activities within the High Priority Habitat identified in Rules 1202.c.(1).Q–S

Rule 1202.d: Big Game/Grouse Habitats

- 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

Rule 1203: Compensatory Mitigation

- 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. 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 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

Rule 1203: Compensatory Mitigation

- 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:

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

WOGCC

Statutory Pooling Update

W.S. 30-5-109

- HB 0014 – ENROLLED ACT NO. 14
  - An Act relating to oil and gas; amending the calculation of owners' shares for drilling units as specified; providing for the expiration of pooling orders under specified conditions; providing a royalty during payment of risk penalty; making conforming amendments; and providing for an effective date.
- Expiration date of pooling order
- Differentiating between "leased" and "unleased" nonconsenting owners
- Royalty rate during payment of risk penalty
- Second chance to elect to participate in the well
- Effective Date July 1, 2020

WOGCC

Statutory Pooling Update

W.S. 30-5-109(f)

A pooling order issued under this subsection shall expire twelve (12) months after issuance if the person authorized to drill and operate the well fails to commence operations within twelve (12) months of issuance of the pooling order.

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Statutory Pooling Update

W.S. 30-5-109(g)

- Statute distinguishes leased and unleased nonconsenting owners and apply different penalties for each owner class:
  - (g)(i): 100% of each such nonconsenting owner's share of the cost of any newly acquired surface equipment... (applies to ALL nonconsenting owners)
  - (g)(ii)(A): 300% of that portion of costs and expenses drilling, reworking, etc.... 200% of that portion of costs of newly acquired equipment in the well... "if the nonconsenting owner's tract or interest is subject to a lease or other contract for oil and gas development." (applies only to nonconsenting owners who hold a lease)

WOGCC

Statutory Pooling Update

W.S. 30-5-109(g)

- Statute distinguishes the first well drilled in a DSU and subsequent wells for unleased mineral interest owners:
  - (g)(ii)(B): For the first well.. 200% of that portion of costs and expenses drilling, reworking, etc.... 125% of that portion of costs of newly acquired equipment in the well... "if the nonconsenting owner's tract or interest is not subject to a lease or other contract for oil and gas development" (applies to unleased mineral owners)
  - (g)(ii)(C): For each subsequent well... 150% of that portion of costs and expenses drilling, reworking, etc.... 125% of that portion of costs of newly acquired equipment in the well... "if the nonconsenting owner's tract or interest is not subject to a lease or other contract for oil and gas development" (applies to unleased mineral owners)

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Statutory Pooling Update

W.S. 30-5-109(h)

- A nonconsenting owner of a tract or interest in a drilling unit "that is not subject to a lease or other contracts for oil and gas development" is entitled to a cost-free royalty interest equal to the greater of:
  - Sixteen percent 16%; or
  - The acreage weighted average royalty interest of the leased tracts within the drilling unit.

WOGCC

Statutory Pooling Update

W.S. 30-5-109(j)

- SECOND CHANCE TO ELECT TO PARTICIPATE IN THE WELL
- Within thirty (30) days after the producer has fully recovered his costs under subsection (g) of this section, the producer shall send notice to the nonconsenting owner to offer the nonconsenting owner the opportunity to participate under the pooling order as a working interest owner. The notice shall state that the nonconsenting owner may elect to participate in the pooling order or may elect to continue receiving the royalty specified in subjection (h) of this section;
- Within sixty (60) days after receiving notice, the nonconsenting owner shall inform the producer whether he wishes to make an election to participate under the pooling order as a working interest owner or continue receiving the royalty specified in subsection (h) of this section;
- If the nonconsenting owner fails to respond to the notice within the time specified in paragraph (ii) of this subsection, the nonconsenting owner shall be deemed to elect to continue receiving the royalty specified in subsection (h) of this section;
- Within five (5) business days after receiving notice of election from a nonconsenting owner or upon expiration of the time specified in paragraph (ii() of this subsection, the producer shall notify the commission regarding the nonconsenting owner's election or lack thereof.

Thank you!

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