GENERAL RULES AND REGULATIONS
CHAPTER 43-02-03

B. MISCELLANEOUS RULES

43-02-03-01. Definitions.

The terms used throughout this chapter have the same meaning as in North Dakota Century Code chapter 38-08 except:

1. "Adjusted allowable" means the allowable production a proration unit receives after all adjustments are applied.
2. "Allocated pool" is one in which the total oil or natural gas production is restricted and allocated to various proration units therein in accordance with proration schedules.
3. "Allowable production" means that number of barrels of oil or cubic feet of natural gas authorized to be produced from the respective proration units in an allocated pool.
4. "Barrel" means forty-two United States gallons [158.99 liters] measured at sixty degrees Fahrenheit [15.56 degrees Celsius] and fourteen and seventy-three hundredths pounds per square inch absolute [1034.19 grams per square centimeter].
5. "Barrel of oil" means forty-two United States gallons [158.99 liters] of oil after deductions for the full amount of basic sediment, water, and other impurities present, ascertained by centrifugal or other recognized and customary test.
6. "Bottom hole or subsurface pressure" means the pressure in pounds per square inch gauge under conditions existing at or near the producing horizon.
7. "Bradenhead gas well" means any well capable of producing gas through wellhead connections from a gas reservoir which has been successfully cased off from an underlying oil or gas reservoir.
8. "Casinghead gas" means any gas or vapor, or both gas and vapor, indigenous to and produced from a pool classified as an oil pool by the commission.
9. "Certified or registered mail" means any form of service by the United States postal service, federal express, Pitney Bowes, and any other commercial, nationwide delivery service that provides the mailer with a document showing the date of delivery or refusal to accept delivery.
10. "Commercial injection well" means one that only receives fluids produced from wells operated by a person other than the principal on the bond.

11. "Common purchaser for natural gas" means any person now or hereafter engaged in purchasing, from one or more producers, gas produced from gas wells within each common source of supply from which it purchases, for processing or resale.

12. "Common purchaser for oil" means every person now engaged or hereafter engaging in the business of purchasing oil in this state.

13. "Common source of supply" is synonymous with pool and is a common accumulation of oil or gas, or both, as defined by commission orders.

14. "Completion" means an oil well shall be considered completed when the first oil is produced through wellhead equipment into tanks from the ultimate producing interval after casing has been run. A gas well shall be considered complete when the well is capable of producing gas through wellhead equipment from the ultimate producing zone after casing has been run. A dry hole shall be considered complete when all provisions of plugging are complied with as set out in this chapter.

15. "Condensate" means the liquid hydrocarbons recovered at the surface that result from condensation due to reduced pressure or temperature of petroleum hydrocarbons existing in a gaseous phase in the reservoir.

16. "Cubic foot of gas" means that volume of gas contained in one cubic foot [28.32 liters] of space and computed at a pressure of fourteen and seventy-three hundredths pounds per square inch absolute [1034.19 grams per square centimeter] at a base temperature of sixty degrees Fahrenheit [15.56 degrees Celsius].

17. "Director" means the director of oil and gas of the industrial commission, the assistant director of oil and gas of the industrial commission, and their designated representatives.

18. "Enhanced recovery" means the increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool, which artificial means or application includes pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of:

    a. Aiding in the lifting of fluids in the well; or

    b. Stimulation of the reservoir at or near the well by mechanical, chemical, thermal, or explosive means.

19. "Exception well location" means a location which does not conform to the general spacing requirements established by the rules or orders of the commission but which has been specifically approved by the commission.

20. "Flow line" means a pipe or conduit of pipes used for the transportation, gathering, or conduct of a mineral from a wellhead to a separator, treater, dehydrator, tank battery, or surface reservoir.

21. "Gas lift" means any method of lifting liquid to the surface by injecting gas into a well from which oil production is obtained.

22. "Gas-oil ratio" means the ratio of the gas produced in cubic feet to a barrel of oil concurrently produced during any stated period.

23. "Gas-oil ratio adjustment" means the reduction in allowable of a high gas-oil ratio proration unit to conform with the production permitted by the limiting gas-oil ratio for the particular pool during a particular proration period.

24. "Gas transportation facility" means a pipeline in operation serving one or more gas wells for the transportation of natural gas, or some other device or equipment in like operation whereby natural gas produced from gas wells connected therewith can be transported.

25. "Gas well" means a well producing gas or natural gas from a common source of gas supply as determined by the commission.

26. "High gas-oil ratio proration unit" means a proration unit with a producing oil well with a gas-oil ratio in excess of the limiting gas-oil ratio for the pool.

~~26.~~27. "Inactive pipeline" means any underground gathering pipeline system or portion thereof that has been removed from service for more than one year.

~~27.~~28. "Injection or input well" means any well used for the injection of air, gas, water, or other fluids into any underground stratum.

~~28.~~29. "Injection pipeline" means a pipe or conduit of pipes used for the transportation of fluids, typically via an injection pump, from a storage tank or tank battery directly to an injection well.

~~29.~~30. "Limiting gas-oil ratio" means the gas-oil ratio assigned by the commission to a particular oil pool to limit the volumes of casinghead gas which may be produced from the various oil-producing units within that particular pool.

~~30.~~31. "Log or well log" means a systematic, detailed, and correct record of formations encountered in the drilling of a well, including commercial electric logs, radioactive logs, dip meter logs, and other related logs.

~~31.~~32. "Multiple completion" means the completion of any well so as to permit the production from more than one common source of supply.

~~32.~~33. "Natural gas or gas" means and includes all natural gas and all other fluid hydrocarbons not herein defined as oil.

~~33.~~34. "Occupied dwelling" or "permanently occupied dwelling" means a residence which is lived in by a person at least six months throughout a calendar year.

~~34.~~35. "Official gas-oil ratio test" means the periodic gas-oil ratio test made by order of the commission and by such method and means and in such manner as prescribed by the commission.

~~35.~~36. "Offset" means a well drilled on a forty-acre [16.19-hectare] tract cornering or contiguous to a forty-acre [16.19-hectare] tract having an existing oil well, or a well drilled on a one hundred sixty-acre [64.75-hectare] tract cornering or contiguous to a one hundred sixty-acre [64.75-hectare] tract having an existing gas well; provided, however, that for wells subject to a fieldwide spacing order, "offset" means any wells located on spacing units cornering or contiguous to the spacing unit or well which is the subject of an inquiry or a hearing.

~~36.~~37. "Oil well" means any well capable of producing oil or oil and casinghead gas from a common source of supply as determined by the commission.

~~37.~~38. "Operator" is the principal on the bond covering a well and such person shall be responsible for drilling, completion, and operation of the well, including plugging and reclamation of the well site.

~~38.~~39. "Overage or overproduction" means the amount of oil or the amount of natural gas produced during a proration period in excess of the amount authorized on the proration schedule.

~~39.~~40. "Potential" means the properly determined capacity of a well to produce oil, or gas, or both, under conditions prescribed by the commission.

~~40.~~41. "Pressure maintenance" means the injection of gas or other fluid into a reservoir, either to increase or maintain the existing pressure in such reservoir or to retard the natural decline in the reservoir pressure.

~~41.~~42. "Proration day" consists of twenty-four consecutive hours which shall begin at seven a.m. and end at seven a.m. on the following day.

~~42.~~43. "Proration month" means the calendar month which shall begin at seven a.m. on the first day of such month and end at seven a.m. on the first day of the next succeeding month.

~~43.~~44. "Proration schedule" means the periodic order of the commission authorizing the production, purchase, and transportation of oil or of natural gas from the various units of oil or of natural gas proration in allocated pools.

~~44.~~45. "Proration unit for gas" consists of such geographical area as may be prescribed by special pool rules issued by the commission.

~~45.~~46. "Recomplete" means the subsequent completion of a well in a different pool.

~~46.~~47. "Reservoir" means pool or common source of supply.

~~47.~~48. "Saltwater handling facility" means and includes any container and site used for the handling, storage, disposal of substances obtained, or used, in connection with oil and gas exploration, development, and production and can be a stand-alone site or an appurtenance to a well or treating plant.

~~48.~~49. "Shut-in pressure" means the pressure noted at the wellhead when the well is completely shut in, not to be confused with bottom hole pressure.

~~49.~~50. "Spacing unit" is the area in each pool which is assigned to a well for drilling, producing, and proration purposes in accordance with the commission's rules or orders.

51. "Stratigraphic test well" means any well or hole, except a seismograph shot hole, drilled for the purpose of gathering information ~~in connection with the oil and gas industry~~ with no intent to produce oil or gas from or inject into such well.

~~50.~~52. "Subsurface observation well" means a well used to observe subsurface phenomena, including the presence of carbon dioxide, pressure fluctuations, fluid levels and flow, temperature, and in situ water chemistry.

~~51.~~53. "Tank bottoms" means that accumulation of hydrocarbon material and other substances which settle naturally below crude oil in tanks and receptacles that are used in handling and storing of crude oil, and which accumulation contains basic sediment and water in an amount rendering it unsalable to an ordinary crude oil purchaser; provided, that with respect to lease production and for lease storage tanks, a tank bottom shall be limited to that volume of the tank in which it is contained that lies below the bottom of the pipeline outlet thereto.

~~52.~~54. "Treating plant" means any plant permanently constructed or portable used for the purpose of wholly or partially reclaiming, treating, processing, or recycling tank bottoms, waste oils, drilling mud, waste from drilling operations, produced water, and other wastes related to crude oil and natural gas exploration and production. This is not to be construed as to include saltwater handling and disposal operations which typically recover skim oil and solids from their operations, treating mud or cuttings at a well site during drilling operations, treating flowback water during completion operations at a well site, or treating tank bottoms at the well site or facility where they originated.

History: Amended effective January 1, 1983; May 1, 1992; July 1, 1996; December 1, 1996; September 1, 2000; July 1, 2002; January 1, 2008; April 1, 2014; October 1, 2016; April 1, 2018;

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-14. Access to sites and records.

The commission, director, and their representatives shall have access to all records wherever located. All owners, operators, drilling contractors, drillers, service companies, or other persons engaged in drilling, completing, producing, operation, or servicing oil and gas wells, pipelines, injection wells, stratigraphic test wells, subsurface observation wells, or treating plants shall permit the commission, director, and their representatives to come upon any lease, property, pipeline right-of-way, well, or drilling rig operated or controlled by them, complying with state safety rules, and to inspect the records and operation, and to have access at all times to any and all records. If requested, copies of such records must be filed with the commission. The confidentiality of any data submitted which is confidential pursuant to subdivision f of subsection 1 of North Dakota Century Code section 38-08-04 and section 43-02-03-31 must be maintained.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1992; May 1, 1994; April 1, 2014; October 1, 2016; ________

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

43-02-03-14.2. Oil and gas metering systems.

1. **Application of section.** This section is applicable to all allocation and custody transfer metering stations measuring production from oil and gas wells within the state of North Dakota, including private, state, and federal wells. If these rules differ from federal requirements on measurement of production from federal oil and gas wells, the federal rules take precedence.

2. **Definitions.** As used in this section:

   a. "Allocation meter" means a meter used by the producer to determine the volume from an individual well before it is commingled with production from one or more other wells prior to the custody transfer point.

   b. "Calibration test" means the process or procedure of adjusting an instrument, such as a gas meter, so its indication or registration is in satisfactorily close agreement with a reference standard.

   c. "Custody transfer meter" means a meter used to transfer oil or gas from the producer to transporter or purchaser.

   d. "Gas gathering meter" means a meter used in the custody transfer of gas into a gathering system.

   e. "Meter factor" means a number obtained by dividing the net volume of fluid (liquid or gaseous) passed through the meter during proving by the net volume registered by the meter.

   f. "Metering proving" means the procedure required to determine the relationship between the true volume of a fluid (liquid or gaseous) measured by a meter and the volume indicated by the meter.

3. **Inventory filing requirements.** The owner of ~~metering~~ meter proving equipment shall file with the ~~commission~~ director an inventory of all ~~meters used for custody transfer and allocation of production from oil or gas wells, or both~~conventional pipe provers or master-meter provers used to test the accuracy of oil meters. Inventories must be updated on an annual basis, and filed with the ~~commission~~ director on or before the first day of each year, or they may be updated as frequently as monthly, at the discretion of the operator. Inventories must include the following:

   ~~a. Well name and legal description of location or meter location if different.~~

   ~~b. North Dakota industrial commission well file number.~~

~~c.~~a. Meter information:

(1) ~~Gas meters~~Prover:

(a) ~~Make and model~~Type.

(b) ~~Differential, static, and temperature range~~Serial number.

(c) ~~Orifice tube size (diameter)~~Prover volume.

(d) ~~Meter station number~~Most recent water draw certificate.

(e) ~~Serial number.~~

(2) ~~Oil~~ Master meter~~s~~:

(a) Make and model.

(b) Size.

~~(c) Meter station number.~~

(c) Serial number.

(d) Master meter factor.

(e) Most recent meter proving certificate.

(3) An inventory of all meters used for custody transfer and allocation of production from oil and gas wells, or both shall be filed with the director upon request.

4. **Installation and removal of meters.** The ~~commission~~ director must be notified of all custody transfer meters placed in service. The owner of the custody transfer equipment shall notify the ~~commission~~ director of the date a meter is placed in service, the make and model of the meter, and the meter or station number. The ~~commission~~ director must also be notified of all metering installations removed from service. The notice must include the date the meter is removed from service, the serial number, and the meter or station number. The required notices must be filed with the ~~commission~~ director within thirty days of the installation or removal of a meter.

All allocation meters must be approved prior to installation and use. The application for approval must be on a facility sundry notice ~~(form 4 or form provided by the commission)~~ and shall include the make and model number of the meter, the meter or station number, the serial number, the well name, its location, and the date the meter will be placed in service.

Meter installations for measuring production from oil or gas wells, or both, must be constructed to American petroleum institute or American gas association standards or to meter manufacturer's recommended installation. Meter installations constructed in accordance with American petroleum institute or American gas association standards in effect at the time of installation shall not automatically be required to retrofit if standards are revised. The ~~commission~~ director will review any revised standards, and when deemed necessary will amend the requirements accordingly.

5. **Registration of persons proving or testing meters.** All persons engaged in meter proving or testing of oil and gas meters must be registered with the ~~commission~~ director. Those persons involved in oil meter testing, by flowing fluid through the meter into a test tank and then gauging the tank, are exempted from the registration process. However, such persons must notify the ~~commission~~ director prior to commencement of the test to allow a representative of the ~~commission~~ director to witness the testing process. A report of the results of such test shall be filed with the commission within thirty days after the test is completed. Registration must include the following:

   a. Name and address of company.

   b. Name and address of measurement personnel.

   c. Qualifications, listing experience or specific training.

   Any meter tests performed by a person not registered with the ~~commission~~ director will not be accepted as a valid test.

6. **Calibration requirements.** Oil and gas metering equipment must be proved or tested to American petroleum institute or American gas association standards or to the meter manufacturer's recommended procedure to establish a meter factor or to ensure measurement accuracy. The owner of a custody transfer meter or allocation meter shall notify the ~~commission~~ director at least ten days prior to the testing of any meter.

   a. Oil allocation meter factors shall be maintained within two percent of original meter factor. If the factor change between provings or tests is greater than two percent, meter use must be discontinued until successfully reproven after being repaired or replaced.

   b. Oil custody transfer meter factors must be maintained within one-quarter of one percent of the previous meter factor. If the factor change between provings or tests is greater than one-quarter of one percent, meter use must be discontinued until successfully reproven after being repaired or replaced.

   c. Copies of all oil allocation meter test procedures are to be filed with and reviewed by the ~~commission~~ director to ensure measurement accuracy.

   d. All gas meters must be tested with a minimum of a three-point test for static and differential pressure elements and a two-point test for temperature elements. The test reports must include an as-found and as-left test and a detailed report of changes.

   e. Test reports must include the following:

      (1) Company name of test contractor.

(2) Pipeline company name.

(3) Meter owner name.

~~(1)~~(4) Producer name.

~~(2)~~(5) Well or Central Tank Battery (CTB) name.

~~(3)~~(6) Well file number or Central Tank Battery (CTB) number.

~~(4) Pipeline company or company name of test contractor.~~

~~(5)~~(7) Test personnel's name.

~~(6)~~(8) Station or meter number.

f. Unless required more often by the director, minimum frequency of meter proving or calibration tests are as follows:

(1) Oil meters used for custody transfer shall be proved monthly for all measured volumes which exceed two thousand barrels per month. For volumes two thousand barrels or less per month, meters shall be proved at each two thousand barrel interval or more frequently at the discretion of the operator.

(2) Quarterly for oil meters used for allocation of production in a diverse ownership central production facility. Semiannually for oil meters used for allocation of production in a common ownership central production facility.

(3) Semiannually for gas meters used for allocation of production in a diverse ownership central production facility. Annually for gas meters used for allocation of production in a common ownership central production facility.

(4) Semiannually for gas meters in gas gathering systems.

(5) For meters measuring more than one hundred thousand cubic feet [2831.68 cubic meters] per day on a monthly basis, orifice plates shall be inspected semiannually, and meter tubes shall be inspected at least every five years to ensure continued conformance with the American gas association meter tube specifications.

(6) For meters measuring one hundred thousand cubic feet [2831.68 cubic meters] per day or less on a monthly basis, orifice plates shall be inspected annually.

g. Accuracy of all equipment used to test oil or gas meters must be traceable to the standards of the national institute of standards and technology. The equipment must be certified as accurate either by the manufacturer or an independent testing facility. The certificates of accuracy for all equipment used to test gas meters must be made available upon request. The owner of a conventional pipe prover or master meter prover shall notify the director at least ten days prior to the testing of any prover. Certification of the equipment must be updated as follows:

(1) Annually for all equipment used to test the pressure and differential pressure elements.

(2) Annually for all equipment used to determine temperature.

(3) Biennially for all conventional pipe provers.

(4) Annually for all master meters.

(5) Five years for equipment used in orifice tube inspection.

~~g.~~h. All meter test reports, including failed meter test reports, must be filed within thirty days of completion of proving or calibration tests unless otherwise approved. Test reports are to be filed on, but not limited to, all meters used for allocation measurement of oil or gas, ~~and~~ all meters used in ~~crude oil~~ custody transfer, conventional pipe provers, and master meter provers.

~~h.~~a. ~~Accuracy of all equipment used to test oil or gas meters must be traceable to the standards of the national institute of standards and technology. The equipment must be certified as accurate either by the manufacturer or an independent testing facility. The certificates of accuracy must be made available upon request. Certification of the equipment must be updated as follows:~~

~~(1) Annually for all equipment used to test the pressure and differential pressure elements.~~

~~(2)~~(1) ~~Annually for all equipment used to determine temperature.~~

~~(3)~~(1) ~~Biennially for all conventional pipe provers.~~

~~(4)~~(1) ~~Annually for all master meters.~~

~~(5)~~(1) ~~Five years for equipment used in orifice tube inspection.~~

7. **Variances.** Variances from all or part of this section may be granted by the ~~commission~~ director provided the variance does not affect measurement accuracy. All requests for variances must be on a facility sundry notice ~~(form 4)~~.

A register of variances requested and approved must be maintained by the ~~commission~~director.

History: Effective May 1, 1994; amended effective July 1, 1996; September 1, 2000; July 1, 2002; April 1, 2018; April 1, 2020;April 1, 2022;_________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-15. Bond and transfer of wells.

1. **Bond requirements.** Prior to commencing construction of a site or appurtenance or road access thereto, any person who proposes to drill a well for oil, gas, injection, or source well for use in enhanced recovery operations, shall submit to the ~~commission~~director~~,~~ and obtain ~~its~~ the approval of the director, a surety bond or cash bond. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The operator of such well shall be the principal on the bond covering the well. Each surety bond shall be executed by a responsible surety company authorized to transact business in North Dakota.

2. **Bond amounts and limitations.** The bond shall be in the amount of fifty thousand dollars when applicable to one well only. Wells drilled to a total depth of less than two thousand feet [609.6 meters] may be bonded in a lesser amount if approved by the director. When the principal on the bond is drilling or operating a number of wells within the state or proposes to do so, the principal may submit a bond conditioned as provided by law. Wells utilized for commercial injection operations must be bonded in the amount of one hundred thousand dollars. A blanket bond covering more than one well shall be in the amount of one hundred thousand dollars, provided the bond shall be limited to no more than six of the following in aggregate:

   a. A well that is a dry hole and is not properly plugged;

   b. A well that is plugged and the site is not properly reclaimed;

   c. A well that is abandoned pursuant to subsection 1 of North Dakota Century Code section 38-08-04 or section 43-02-03-55 and is not properly plugged and the site is not properly reclaimed; and

   d. A well that is temporarily abandoned under section 43-02-03-55 for more than seven years.

   If this aggregate of wells is reached, all well permits, for which drilling has not commenced, held by the principal of such bond are suspended. No rights may be exercised under the permits until the aggregate of wells drops below the required limit, or the operator files the appropriate bond to cover the permits, at which time the rights given by the drilling permits are reinstated. A well with an approved temporary abandoned status for no more than seven years shall have the same status as an oil, gas, or injection well. The commission may, after notice and hearing, require higher bond amounts than those referred to in this section. Such additional amounts for bonds must be related to the economic value of the well or wells and the expected cost of plugging and well site reclamation, as determined by the ~~commission~~director. The ~~commission~~ director may refuse to accept a bond or to add wells to a blanket bond if the operator or surety company has failed in the past to comply with statutes, rules, or orders relating to the operation of wells; if a civil or administrative action brought by the commission is pending against the operator or surety company; or for other good cause.

3. **Unit bond requirements.** Prior to commencing unit operations, the operator of any area under unitized management shall submit to the ~~commission~~director~~,~~ and obtain ~~its~~ the approval of the director, a surety bond or cash bond. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The operator of the unit shall be the principal on the bond covering the unit. The amount of the bond shall be specified by the commission in the order approving the plan of unitization. Each surety bond shall be executed by a responsible surety company authorized to transact business in North Dakota.

   Prior to transfer of a unit to a new operator, the commission, after notice and hearing, may revise the bond amount for a unit, or in the case when the unit was not previously bonded, the commission may require a bond and set a bond amount for the unit.

4. **Bond terms.** Bonds shall be conditioned upon full compliance with North Dakota Century Code chapter 38-08, and all administrative rules and orders of the commission. It shall be a plugging bond, as well as a drilling bond, and is to endure up to and including approved plugging of all oil, gas, and injection wells as well as dry holes. Approved plugging shall also include practical reclamation of the well site and appurtenances thereto. If the principal does not satisfy the bond's conditions, then the surety shall satisfy the conditions or forfeit to the commission the face value of the bond.

5. **Transfer of wells under bond.** Transfer of property does not release the bond. In case of transfer of property or other interest in the well and the principal desires to be released from the bond covering the well, such as producers, not ready for plugging, the principal must proceed as follows:

   a. The principal must notify the director, in writing, of all proposed transfers of wells at least thirty days before the closing date of the transfer. The director may, for good cause, waive this requirement.

      (1) The principal shall submit a schematic drawing identifying all lines owned by the principal which leave the constructed pad or facility and shall provide any details the director deems necessary.

      (2) The principal shall submit to the ~~commission~~ director a form 15 reciting that a certain well, or wells, describing each well by quarter-quarter, section, township, and range, is to be transferred to a certain transferee, naming such transferee, for the purpose of ownership or operation. The date of assignment or transfer must be stated and the form signed by a party duly authorized to sign on behalf of the principal.

      (3) On said transfer form the transferee shall recite the following: "The transferee has read the foregoing statement and does accept such transfer and does accept the responsibility of such well under the transferee's one-well bond or, as the case may be, does accept the responsibility of such wells under the transferee's blanket bond, said bond being tendered to or on file with the commission." Such acceptance must likewise be signed by a party authorized

to sign on behalf of the transferee and the transferee's surety.

b. When the ~~commission~~ director has passed upon the transfer and acceptance and accepted it under the transferee's bond, the transferor shall be released from the responsibility of plugging the well and site reclamation. If such wells include all the wells within the responsibility of the transferor's bond, such bond will be released by the ~~commission~~ director upon written request. Such request must be signed by an officer of the transferor or a person authorized to sign for the transferor. The director may refuse to transfer any well from a bond if any well on the bond is in violation of a statute, rule, or order. No abandoned well may be transferred from a bond unless the transferee has obtained a single well bond in an amount equal to the cost of plugging the well and reclaiming the well site.

c. The transferee (new operator) of any ~~oil, gas, or injection~~ well shall be responsible for the plugging and site reclamation of any such well and appurtenance thereto where the reclamation and restoration of land and water resources impacted by oil and gas development is in an inadequate reclamation status. For that purpose the transferee shall submit a new bond or, in the case of a surety bond, produce the written consent of the surety of the original or prior bond that the latter's responsibility shall continue and attach to such well. The original or prior bond shall not be released as to the plugging and reclamation responsibility of any such transferor until the transferee shall submit to the ~~commission~~ director an acceptable bond to cover such well. All liability on bonds shall continue until the plugging and site reclamation of such wells is completed and approved.

6. **Treating plant bond.** Prior to commencing site or road access construction, any person proposing to operate a treating plant must submit to the ~~commission~~ director and obtain ~~its~~ the approval of the director, a surety bond or cash bond. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The person responsible for the operation of the plant shall be the principal on the bond. Each surety bond shall be executed by a responsible surety company authorized to transact business in North Dakota. The amount of the bond must be as prescribed in section 43-02-03-51.3. It is to remain in force until the operations cease, all equipment is removed from the site, and the site and appurtenances thereto are reclaimed, or liability of the bond is transferred to another bond that provides the same degree of security. If the principal does not satisfy the bond's conditions, then the surety shall satisfy the conditions or forfeit to the commission the face value of the bond.

7. **Saltwater handling facility bond.** Prior to commencing site or road access construction, any person proposing to operate a saltwater handling facility that is not already bonded as an appurtenance shall submit to the ~~commission~~ director and obtain ~~its~~ the approval of the director, a surety bond or cash bond. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The person responsible for the operation of the saltwater handling facility must be the principal on the bond. Each surety bond must be executed by a responsible surety company authorized to transact business in North Dakota. The amount of the bond must be as prescribed in section 43-02-03-53.3. It is to remain in force until the operations cease, all equipment is removed from the site, and the site and appurtenances thereto

are reclaimed, or liability of the bond is transferred to another bond that provides the same degree of security. If the principal does not satisfy the bond's conditions, the surety shall satisfy the conditions or forfeit to the commission the face value of the bond. Transfer of property does not release the bond. The director may refuse to transfer any saltwater handling facility from a bond if the saltwater handling facility is in violation of a statute, rule, or order.

8. **Crude oil and produced water underground gathering pipeline bond.** The bonding requirements for crude oil and produced water underground gathering pipelines are not to be construed to be required on flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on piping utilized to connect wells, tanks, treaters, flares, or other equipment on the production facility.

    a. Any owner of an underground gathering pipeline transferring crude oil or produced water, after April 19, 2015, shall submit to the ~~commission~~ director and obtain ~~its~~ the approval of the director, a surety bond or cash bond prior to July 1, 2017. Any owner of a proposed underground gathering pipeline to transfer crude oil or produced water shall submit to the ~~commission~~ director and obtain ~~its~~ the approval of the director, a surety bond or cash bond prior to placing into service. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The person responsible for the operation of the crude oil or produced water underground gathering pipeline must be the principal on the bond. Each surety bond must be executed by a responsible surety company authorized to transact business in North Dakota. The bond must be in the amount of fifty thousand dollars when applicable to one crude oil or produced water underground gathering pipeline system only. Such underground gathering pipelines that are less than one mile [1609.34 meters] in length may be bonded in a lesser amount if approved by the director. When the principal on the bond is operating multiple gathering pipeline systems within the state or proposes to do so, the principal may submit a blanket bond conditioned as provided by law. A blanket bond covering one or more underground gathering pipeline systems must be in the amount of one hundred thousand dollars. The owner shall file with the director, as prescribed by the director, a geographical information system layer utilizing North American datum 83 geographic coordinate system and in an environmental systems research institute shape file format showing the location of all associated above ground equipment and the pipeline centerline from the point of origin to the termination point of all underground gathering pipelines on the bond. Each layer must include at least the following information:

        (1) The name of the pipeline gathering system and other separately named portions thereof;

        (2) The type of fluid transported;

        (3) The pipeline composition;

        (4) Burial depth; and

(5) Approximate in-service date.

b. The blanket bond covering more than one underground gathering pipeline system is limited to no more than six of the following instances of noncompliance in aggregate:

(1) Any portion of an underground gathering pipeline system that has been removed from service for more than one year and is not properly abandoned pursuant to section 43-02-03-29.1; and

(2) An underground gathering pipeline right-of-way, including associated above ground equipment, which has not been properly reclaimed pursuant to section 43-02-03-29.1.

If this aggregate of underground gathering pipeline systems is reached, the ~~commission~~ director may refuse to accept additional pipeline systems on the bond until the aggregate is brought back into compliance. The commission, after notice and hearing, may require higher bond amounts than those referred to in this section. Such additional amounts for bonds must be related to the economic value of the underground gathering pipeline system and the expected cost of pipeline abandonment and right-of-way reclamation, as determined by the ~~commission~~director. The ~~commission~~ director may refuse to accept a bond or to add underground gathering pipeline systems to a blanket bond if the owner or surety company has failed in the past to comply with statutes, rules, or orders relating to the operation of underground gathering pipelines; if a civil or administrative action brought by the commission is pending against the owner or surety company; if an underground gathering pipeline system has exhibited multiple failures; or for other good cause.

c. The underground gathering pipeline bond is to remain in force until the pipeline has been abandoned, as provided in section 43-02-03-29.1, and the right-of-way, including all associated above ground equipment, has been reclaimed as provided in section 43-02-03-29.1, or liability of the bond is transferred to another bond that provides the same degree of security. If the principal does not satisfy the bond's conditions, the surety shall satisfy the conditions or forfeit to the commission the face value of the bond.

d. Transfer of underground gathering pipelines under bond. Transfer of property does not release the bond. In case of transfer of property or other interest in the underground gathering pipeline and the principal desires to be released from the bond covering the underground gathering pipeline, the principal must proceed as follows:

(1) The principal shall notify the director, in writing, of all proposed transfers of underground gathering pipelines at least thirty days before the closing date of the transfer. The director, for good cause, may waive this requirement.

Notice of underground gathering pipeline transfer. The principal shall submit, as provided by the director, a geographical information system layer utilizing North American datum 83 geographic coordinate system and in an environmental systems research institute shape file format showing the location of all associated above ground equipment and the pipeline centerline from the point of origin to the termination point of all underground gathering pipelines to be transferred to a certain transferee, naming such transferee, for the purpose of ownership or operation. The date of assignment or transfer must be stated and the form 15pl signed by a party duly authorized to sign on behalf of the principal.

The notice of underground gathering pipeline transfer must recite the following: "The transferee has read the foregoing statement and does accept such transfer and does accept the responsibility of such underground gathering pipelines under the transferee's pipeline bond or, as the case may be, does accept the responsibility of such underground gathering pipelines under the transferee's pipeline systems blanket bond, said bond being tendered to or on file with the commission." Such acceptance must likewise be signed by a party authorized to sign on behalf of the transferee and the transferee's surety.

(2) When the ~~commission~~ director has passed upon the transfer and acceptance and accepted it under the transferee's bond, the transferor must be released from the responsibility of abandoning the underground gathering pipelines and right-of-way reclamation. If such underground gathering pipelines include all underground gathering pipeline systems within the responsibility of the transferor's bond, such bond will be released by the ~~commission~~ director upon written request. Such request must be signed by an officer of the transferor or a person authorized to sign for the transferor. The director may refuse to transfer any underground gathering pipeline from a bond if the underground gathering pipeline is in violation of a statute, rule, or order.

(3) The transferee (new owner) of any underground gathering pipeline is responsible for the abandonment and right-of-way reclamation of any such underground gathering pipeline. For that purpose the transferee shall submit a new bond or, in the case of a surety bond, produce the written consent of the surety of the original or prior bond that the latter's responsibility shall continue and attach to such underground gathering pipeline. The original or prior bond may not be released as to the abandonment and right-of-way reclamation responsibility of any such transferor until the transferee submits to the ~~commission~~ director an acceptable bond to cover such underground gathering pipeline. All liability on bonds continues until the abandonment and right-of-way reclamation of such underground gathering pipeline is completed and approved by the director.

9. **Geological storage facility bond requirements.** Before commencing injection operations, the operator of any storage facility shall submit to the ~~commission~~director~~,~~ and obtain ~~its~~ the approval of the director, a surety bond or cash bond in the amount

specified by the commission in the order approving the storage facility. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The operator of the storage facility shall be the principal on the bond covering the storage facility. Each surety bond must be executed by a responsible surety company authorized to transact business in North Dakota.

10. **Enhanced oil recovery potential well bond.** Before the director may approve a well for enhanced oil recovery potential status, the operator shall submit to the director and obtain the approval of the director, a blanket surety bond or cash bond in the amount of one hundred thousand dollars, provided the bond shall be limited to no more than six wells that have been inactive for more than twelve years. An alternative form of security may be approved by the commission after notice and hearing, as provided by law. The operator of such well shall be the principal on the bond covering the well. Each surety bond shall be executed by a responsible surety company authorized to transact business in North Dakota. Each such bond shall be subject to an annual review to determine if the bond amount is sufficient and the commission may, after notice and hearing, require a higher bond amount. Such additional amounts for bonds must be related to the economic value of the well or wells and the expected cost of plugging and well site reclamation, as determined by the director. The director may refuse to accept a bond or to add wells to an enhanced oil recovery potential blanket bond if the operator or surety company has failed in the past to comply with statutes, rules, or orders relating to the operation of wells; if a civil or administrative action brought by the commission is pending against the operator or surety company; or for other good cause.

~~10.~~11. **Bond termination.** The ~~commission~~ director shall, in writing, advise the principal and any sureties on any bond as to whether the plugging and reclamation is approved. If approved, liability under such bond may be formally terminated upon receipt of a written request by the principal. The request must be signed by an officer of the principal or a person authorized to sign for the principal.

~~11.~~12. **Director's authority.** The director is vested with the power to act for the commission as to all matters within this section, except requests for alternative forms of security, which may only be approved by the commission.

History: Amended effective April 30, 1981; March 1, 1982; January 1, 1983; May 1, 1990; May 1, 1992; May 1, 1994; July 1, 1996; December 1, 1996; September 1, 2000; July 1, 2002; May 1, 2004; January 1, 2006; April 1, 2012; April 1, 2014; October 1, 2016; April 1, 2018; April 1, 2020; April 1, 2022; ____________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-16. Application for permit to drill and recomplete.

Before any person shall begin any well-site preparation for the drilling of any well other than surveying and staking, such person shall obtain approval from the director. An application for permit to drill ~~(form 1 or form provided by the commission)~~ must be filed with the director, together with a permit fee of one hundred dollars. ~~Verbal approval may be given for site~~

~~preparation by the director in extenuating circumstances.~~ Site construction, or appurtenance or road access thereto, may not commence until such application is approved and a permit to drill is issued by the director. Verbal approval may be given for site preparation by the director in extenuating circumstances to include but not be limited to contractual obligations, an expiring lease, or an expiring right-of-way. The application must be accompanied by the bond pursuant to section 43-02-03-15 or the applicant must have previously filed such bond with the ~~commission~~ director, otherwise the application is incomplete. An incomplete application received by the ~~commission~~ director has no standing and will not be deemed filed until it is completed.

The application for permit to drill shall be accompanied by an accurate plat certified by a registered surveyor showing the location of the proposed well with reference to true north and the nearest lines of a governmental section, the latitude and longitude of the proposed well location to the nearest tenth of a second, the ground elevation, and the proposed road access to the nearest existing public road. Information to be included in such application shall be the proposed depth to which the well will be drilled, estimated depth to the top of important markers, estimated depth to the top of objective horizons, the proposed mud program, the proposed casing program, including size and weight thereof, the depth at which each casing string is to be set, the proposed pad layout, including cut and fill diagrams, and the proposed amount of cement to be used, including the estimated top of cement.

For wells permitted on new pads built after July 31, 2013, permit conditions imposed by the ~~commission~~ director may include, upon request of the owner of a permanently occupied dwelling within one thousand feet of the proposed well, requiring the location of all flares, tanks, and treaters utilized in connection with the permitted well be located at a greater distance from the occupied dwelling than the well head, if the location can be reasonably accommodated within the proposed pad location. If the facilities are proposed to be located farther from the dwelling than the well bore, the director can issue the permit without comment from the dwelling owner. The applicant shall give any such owners written notice of the proposed facilities personally or by certified mail, return receipt requested, and addressed to their last-known address listed with the county property tax department. The ~~commission~~ director must receive written comments from such owner within five business days of the owner receiving said notice. An application for permit must include an affidavit from the applicant identifying each owner's name and address, and the date written notice was given to each owner. The owner's notice must include:

1. A copy of North Dakota Century Code section 38-08-05.
2. The name, telephone number, and if available the electronic mail address of the applicant's local representative.
3. A sketch of the area indicating the location of the owner's dwelling, the proposed well, and location of the proposed flare, tanks, and treaters.
4. A statement indicating that any such owner objecting to the location of the flare, tanks, or treaters, must notify the ~~commission~~ director within five business days of receiving the notice.

Prior to the commencement of recompletion operations or drilling horizontally in the existing pool, an application for permit must be approved by the director. ~~Included in such~~Such application shall be ~~the notice of intention (form 4)~~filed to reenter a well by drilling horizontally, deepening, or plugging back to any source of supply other than the producing horizon in an existing well. Such notice shall include the name and file number and exact location of the well, the approximate date operations will begin, the proposed procedure, the estimated completed total depth, the anticipated hydrogen sulfide content in produced gas from the proposed source of supply, the weight and grade of all casing currently installed in the well unless waived by the director, the casing program to be followed, and the original total depth with a permit fee of fifty dollars. The director may deny any application if it is determined, in accordance with the latest version of ANSI/NACE MR0175/ISO 15156, that the casing currently installed in the well would be subject to sulfide stress cracking.

The applicant shall provide all information, in addition to that specifically required by this section, if requested by the director. The director may impose such terms and conditions on the permits issued under this section as the director deems necessary.

The director shall deny an application for a permit under this section if the proposal would cause, or tend to cause, waste or violate correlative rights. The director of oil and gas shall state in writing to the applicant the reason for the denial of the permit. The applicant may appeal the decision of the director to the commission.

A permit to drill automatically expires one year after the date it was issued, unless the well is drilling or has been drilled below surface casing. A permit to recomplete or to drill horizontally automatically expires one year after the date it was issued, unless such project has commenced. The director may extend a permit to drill and a permit to recomplete or drill horizontally for up to one year upon request.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1992; May 1, 1994; September 1, 2000; July 1, 2002; April 1, 2010; April 1, 2012; April 1, 2014; October 1, 2016; April 1, 2020; ___________

General Authority	Law Implemented
NDCC 38-08-05	NDCC 38-08-05

43-02-03-16.3. Recovery of a risk penalty.

The following govern the recovery of the risk penalty pursuant to subsection 3 of North Dakota Century Code section 38-08-08 and subsection 3 of North Dakota Century Code section 38-08-09.4:

1. An owner may recover the risk penalty under the provisions of subsection 3 of North Dakota Century Code section 38-08-08, provided the owner gives, to the owner from whom the penalty is sought, a written invitation to participate in the risk and cost of drilling a well, including reentering a plugged and abandoned well, or the risk and cost of reentering an existing well to drill deeper or a horizontal lateral. If the nonparticipating owner's interest is not subject to a lease or other contract for development, an owner seeking to recover a risk penalty must also make a good-faith attempt to have the unleased owner execute a lease.

a. The invitation to participate in drilling must be in writing and contain the following:

(1) The approximate surface location of the proposed or existing well, proposed completion and total depth, objective zone, and completion location if other than a vertical well.

(2) An itemization of the estimated costs of drilling and completion.

(3) The approximate date upon which the well was or will be spudded or reentered.

(4) A statement indicating the invitation must be accepted within thirty days of receiving it.

(5) Notice that the participating owners plan to impose a risk penalty and that the nonparticipating owner may object to the risk penalty by either responding in opposition to the petition for a risk penalty, or if no such petition has been filed, by filing an application or request for hearing with the commission.

(6) Drilling or spacing unit description.

b. An election to participate ~~must be in writing and~~ that must be received by the owner giving the invitation within thirty days of the participating party's receipt of the invitation.

c. An invitation to participate and an election to participate must be served personally, by mail requiring a signed receipt, or by overnight courier or delivery service requiring a signed receipt. Failure to accept mail requiring a signed receipt constitutes service.

d. An election to participate is only binding upon an owner electing or declining to participate if the well is spudded or reentry operations are commenced on or before ninety days after the date the owner extending the invitation to participate sets as the date upon which ~~a~~ an election response to the invitation is to be received. It also expires if the permit to drill or reenter expires without having been exercised. If an election to participate lapses, a risk penalty can only be collected if the owner seeking it again complies with the provisions of this section.

2. An owner may recover the risk penalty under the provisions of subsection 3 of North Dakota Century Code section 38-08-09.4, provided the owner gives, to the owner from whom the penalty is sought, a written invitation to participate in the unit expense. If the nonparticipating owner's interest is not subject to a lease or other contract for development, an owner seeking to recover a risk penalty must also make a good-faith attempt to have the unleased owner execute a lease.

a. The invitation to participate in the unit expense must be in writing and contain the following:

(1) A description of the proposed unit expense, including the location, objectives, and plan of operation.

(2) An itemization of the estimated costs.

(3) The approximate date upon which the proposal was or will be commenced.

(4) A statement indicating the invitation must be accepted within thirty days of receiving it.

(5) Notice that the participating owners plan to impose a risk penalty and that the nonparticipating owner may object to the risk penalty by either responding in opposition to the petition for a risk penalty, or if no such petition has been filed, by filing an application or request for hearing with the commission.

b. An election to participate ~~must be in writing and~~ that must be received by the owner giving the invitation within thirty days of the participating party's receipt of the invitation.

c. An invitation to participate and an election to participate must be served personally, by mail requiring a signed receipt, or by overnight courier or delivery service requiring a signed receipt. Failure to accept mail requiring a signed receipt constitutes service.

d. An election to participate is only binding upon an owner electing or declining to participate if the unit expense is commenced within ninety days after the date the owner extending the invitation request to participate sets as the date upon which ~~a~~ an election response to the request invitation is to be received. If an election to participate lapses, a risk penalty can only be collected if the owner seeking it again complies with the provisions of this section.

e. An invitation to participate in a unit expense covering monthly operating expenses shall be effective for all such monthly operating expenses for a period of five years if the unit expense identified in the invitation to participate is first commenced within ninety days after the date set in the invitation to participate as the date upon which ~~a~~ an election response to the invitation to participate must be received. An election to participate in a unit expense covering monthly operating expenses is effective for five years after operations are first commenced. If an election to participate in a unit expense comprised of monthly operating expenses expires or lapses after five years, a risk penalty may only be assessed and collected if the owner seeking the penalty once again complies with this section.

3. Upon its own motion or the request of a party, the commission may include in a pooling order requirements relating to the invitation to participate and election to participate, in which case the pooling order will control to the extent it is inconsistent with this section.

History: Effective December 1, 1996; amended effective May 1, 2004; January 1, 2006; January 1, 2008; April 1, 2010; April 1, 2012; April 1, 2014; April 1, 2020; __________

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04
NDCC 38-08-08

43-02-03-17. Sign on well and facility.

Every well and facility associated with the production, transportation, purchasing, storage, treating, or processing of oil, gas, and water except plugged wells shall be identified by a sign. The sign shall be of durable construction and the lettering thereon shall be kept in a legible condition. The wells on each lease or property shall be numbered in nonrepetitive sequence, unless some other system of numbering was adopted by the owner prior to the adoption of this chapter. Each sign must show the facility name or well name and number (which shall be different or distinctive for each well or facility), the name of the operator, current emergency phone number, file or facility number (if applicable), and the location by quarter-quarter, section, township, and range.

History: Amended effective January 1, 1983; May 1, 1992; September 1, 2000; April 1, 2014; October 1, 2016; April 1, 2018; _______

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

43-02-03-20. Sealing off strata.

During the drilling of any ~~oil or natural gas~~ well, all oil, gas, and water strata ~~above the producing horizon~~ shall be sealed or separated where necessary in order to prevent their contents from passing into other strata.

All freshwaters and waters of present or probable value for domestic, commercial, or stock purposes shall be confined to their respective strata and shall be adequately protected by methods approved by the ~~commission~~director. Special precautions shall be taken in drilling and plugging wells to guard against any loss of artesian water from the strata in which it occurs and the contamination of artesian water by objectionable water, oil, or gas.

All water shall be shut off and excluded from the various oil-bearing and gas-bearing strata which are penetrated. Water shutoffs shall ordinarily be made by cementing casing or landing casing with or without the use of mud-laden fluid.

History: Amended effective May 1, 1992; _________

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

43-02-03-21. Casing, tubing, and cementing requirements.

All wells drilled ~~for oil, natural gas, or injection~~ shall be ~~completed~~ constructed with strings of casing which shall be properly cemented at sufficient depths to adequately protect and isolate all formations containing water, oil, or gas or any combination of these; protect the pipe through salt sections encountered; and isolate the uppermost sand of the Dakota group.

Drilling of the surface hole shall be with freshwater-based drilling mud or other method approved by the director which will protect all freshwater-bearing strata. This includes water used during the cementing of surface casing for displacement. The surface casing shall consist of new or reconditioned pipe that has been previously tested to one thousand pounds per square inch [6900 kilopascals]. The surface casing shall be set and cemented at a point not less than fifty feet [15.24 meters] below the base of the Fox Hills formation. Sufficient cement shall be used on surface casing to fill the annular space behind the casing to the bottom of the cellar, if any, or to the surface of the ground. If the annulus space is not adequately filled with cement, the director shall be notified immediately. The operator shall diligently perform remedial work after obtaining approval from the director. All strings of surface casing shall stand cemented under pressure for at least twelve hours before drilling the plug. The term "under pressure" as used herein shall be complied with if one float valve is used or if pressure is otherwise held. Cementing shall be by the pump and plug method while the drilling rig is on the well or other methods approved by the director. ~~The director is authorized to require an~~ An appropriate accurate gauge shall be maintained on the surface casing of any well, not properly plugged and abandoned, to detect any buildup of pressure caused by the migration of fluids. Surface casing pressure shall be monitored and maintained to keep the hydrostatic pressure at the surface casing shoe below the pressure the formation integrity test was performed at.

Surface casing strings must be allowed to stand under pressure until the tail cement has reached a compressive strength of at least five hundred pounds per square inch [3450 kilopascals]. All filler cements utilized must reach a compressive strength of at least two hundred fifty pounds per square inch [1725 kilopascals] within twenty-four hours and at least three hundred fifty pounds per square inch [2415 kilopascals] within seventy-two hours. All compressive strengths on surface casing cement shall be calculated at a temperature of eighty degrees Fahrenheit [26.67 degrees Celsius].

Production or intermediate casing strings shall consist of new or reconditioned pipe that has been previously tested to two thousand pounds per square inch [13800 kilopascals]. Such strings must be allowed to stand under pressure until the tail cement has reached a compressive strength of at least five hundred pounds per square inch [3450 kilopascals]. All filler cements utilized must reach a compressive strength of at least two hundred fifty pounds per square inch [1725 kilopascals] within twenty-four hours and at least five hundred pounds per square inch [3450 kilopascals] within seventy-two hours, although in any horizontal well performing a single stage cement job from a measured depth of greater than thirteen thousand feet [3962.4 meters], the filler cement utilized must reach a compressive strength of at least two hundred fifty pounds per square inch [1725 kilopascals] within forty-eight hours and at least five hundred pounds per square inch [3450 kilopascals] within ninety-six hours. All compressive strengths on production or intermediate casing cement shall be calculated at a temperature found in the Mowry formation using a gradient of 1.2 degrees Fahrenheit per one hundred feet [30.48 meters] of depth plus eighty degrees Fahrenheit [26.67 degrees Celsius]. At a formation temperature at or in excess of two hundred thirty degrees Fahrenheit [110 degrees Celsius], cement blends must include additives to address compressive strength regression.

Each surface casing string shall be tested by application of pump pressure of at least one thousand pounds per square inch [6900 kilopascals] and each other casing string shall be tested by application of pump pressure of at least one thousand five hundred pounds per square inch

[10350 kilopascals] immediately after cementing, while the cement is in a liquid state, or the casing string must be pressure tested after all cement has reached five hundred pounds per square inch [3450 kilopascals] compressive strength. If, at the end of thirty minutes, this pressure has dropped more than ten percent, the casing shall be repaired after receiving approval from the director. Thereafter, the casing shall again be tested in the same manner. Further work shall not proceed until a satisfactory test has been obtained. The casing in a horizontal well may be tested by use of a mechanical tool set near the casing shoe after the horizontal section has been drilled.

All flowing wells must be equipped with tubing. A tubing packer must also be utilized unless a waiver from the director is obtained after demonstrating the casing will not be subjected to excessive pressure or corrosion. The packer must be set as near the producing interval as practicable, but in all cases must be above the perforations.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1992; July 1, 1996; January 1,1997; September 1, 2000; July 1, 2002; May 1, 2004; January 1, 2006; April 1, 2010; April 1, 2012;April 1, 2020; April 1, 2022; _________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-24. Pulling string of casing.

In pulling strings of casing from any ~~oil, gas, or injection~~ well, the space above the casing stub shall be kept and left full of fluid with adequate gel strength and specific gravity, cement, or combination thereof, to seal off all freshwater and saltwater strata and any strata bearing oil or gas not producing. No casing shall be removed without the prior approval of the director.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1992; _________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-27.1. Hydraulic fracture stimulation.

1. Prior to performing any hydraulic fracture stimulation, including refracs, through a frac string run inside the ~~intermediate~~ casing string:

   a. Remedial work is required to be performed on all casing strings deemed defective pursuant to section 43-02-03-22 prior to performance at the discretion of the director.

   ~~a.~~b. The frac string must be either stung into a liner with the hanger/packer located in cemented casing or run with a packer set at a minimum depth of one hundred feet [30.48 meters] below the top of cement or a minimum depth of one hundred feet [30.48 meters] below the top of the Inyan Kara formation, whichever is deeper.

   ~~b.~~c. The ~~intermediate~~ casing-frac string annulus must be pressurized and monitored during frac operations. ~~Prior to performing any refrac, a casing evaluation tool must be run to verify adequate wall thickness of the intermediate casing.~~ If there is a suspected frac string or casing failure, the operator of the well shall verbally notify the director as soon as practicable.

~~c.~~d. An adequately sized, function tested pressure relief valve must be utilized on the treating lines from the pumps to the wellhead, with suitable check valves to limit the volume of flowback fluid should the relief valve open. The relief valve must be set to limit line pressure to no more than eighty-five percent of the internal yield pressure of the frac string. An adequately sized, function tested pressure relief valve and an ~~adequate~~ adequately sized diversion line must be utilized to divert flow from the ~~intermediate~~ casing to a pit or containment vessel in case of frac string failure. The relief valve must be set to limit annular pressure to no more than eighty-five percent of the lowest internal yield pressure of the ~~intermediate~~ casing string or no greater than the pressure test on the intermediate casing, less one hundred pounds per square inch gauge, whichever is less.

~~d.~~e. The surface casing must be fully open and connected to a diversion line rigged to a pit or containment vessel.

~~e.~~f. An adequately sized, function tested remote operated frac valve must be utilized at a location on the christmas tree that provides isolation of the well bore from the treating line and must be remotely operated from the edge of the location or other safe distance.

~~f.~~g. Notify the director within twenty-four hours after the commencement of hydraulic fracture stimulation operations, in an electronic format approved by the director, identifying the subject well and verifying a frac string was run in the well.

~~g.~~h. Within sixty days after the hydraulic fracture stimulation is performed, the owner, operator, or service company shall post on the fracfocus chemical disclosure registry all elements made viewable by the fracfocus website.

2. Prior to performing any hydraulic fracture stimulation, including refracs, through ~~an~~ a ~~intermediate~~ casing string:

a. Remedial work is required to be performed on all casing strings deemed defective pursuant to section 43-02-03-22 prior to performance at the discretion of the director.

~~a.~~b. The maximum treating pressure shall be no greater than eighty-five percent of the American petroleum institute rating of the affected ~~intermediate~~ casing string.

~~b.~~c. Casing evaluation tools to verify adequate wall thickness of any affected ~~intermediate~~ casing string shall be run from the wellhead to a depth as close as practicable to one hundred feet [30.48 meters] above the completion formation and a visual inspection with photographs shall be made of the top joint of the ~~intermediate~~ casing and the wellhead flange. The visual inspection and photograph requirement may be waived by the director for good cause.

If the casing evaluation tool or visual inspection indicates wall thickness is below the American petroleum institute minimum or a lighter weight of ~~intermediate~~ casing than the well design called for, calculations must be made to determine the reduced pressure rating. If the reduced pressure rating is less than the anticipated treating pressure, a frac string shall be run inside the ~~intermediate~~ casing.

~~c.~~d. Cement evaluation tools to verify adequate cementing of each ~~intermediate~~ casing string shall be run from the wellhead to a depth as close as practicable to one hundred feet [30.48 meters] above the completion formation.

(1) If the cement evaluation tool indicates defective casing or cementing, a frac string shall be run inside the ~~intermediate~~ casing.

(2) If the cement evaluation tool indicates the ~~intermediate~~ casing string cemented in the well fails to satisfy section 43-02-03-21, a frac string shall be run inside the ~~intermediate~~ casing.

~~d.~~e. Each affected ~~intermediate~~ casing string and the wellhead must be pressure tested for at least thirty minutes with less than five percent loss to a pressure equal to or in excess of the maximum frac design pressure. If the pressure rating of the wellhead does not exceed the maximum frac design pressure, a wellhead and blowout preventer protection system must be utilized during the frac.

~~e.~~f. An adequately sized, function tested pressure relief valve must be utilized on the treating lines from the pumps to the wellhead, with suitable check valves to limit the volume of flowback fluid should be the relief valve open. The relief valve must be set to limit line pressure to no greater than the test pressure of the ~~intermediate~~ casing, less one hundred pounds per square inch [689.48 kilopascals].

~~f.~~g. The surface casing value must be fully open and connected to a diversion line rigged to a pit or containment vessel.

h. An adequately sized, function tested remote operated frac valve must be utilized between the treating line and the wellhead.

~~g.~~i. If there is a suspected casing failure, the operator of the well shall verbally notify the director as soon as practicable.

~~h.~~j. Notify the director within twenty-four hours after the commencement of hydraulic fracture stimulation operations, in an electronic format approved by the director, identifying the subject well and verifying all logs and pressure tests have been performed as required.

~~i.~~k. Within sixty days after the hydraulic fracture stimulation is performed, the owner, operator, or service company shall post on the fracfocus chemical disclosure registry all elements made viewable by the fracfocus website.

3. If during the stimulation, the pressure in the ~~intermediate~~ casing-surface casing annulus exceeds three hundred fifty pounds per square inch [2413 kilopascals] gauge, the owner or operator shall verbally notify the director as soon as practicable but no later than twenty-four hours following the incident.

History: Effective April 1, 2012; amended effective April 1, 2014; April 1, 2020; April 1, 2022; ________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-28. Safety regulation.

During drilling operations all oil wells shall be cleaned into a pit or tank, not less than forty feet [12.19 meters] from the derrick floor and one hundred fifty feet [45.72 meters] from any fire hazard.

All flowing oil wells must be produced through an approved oil and gas separator or emulsion treater of ample capacity and in good working order. No boiler, electric generator, flare, or treater shall be placed nearer than one hundred fifty feet [45.72 meters] to any producing well or oil tank as defined in Occupational Safety and Health Administration Standard 1910.106(a)(2). Placement as close as one hundred twenty-five feet [38.10 meters] may be allowed if a spark or flame arrestor is utilized on the equipment. Placement of an oil processing vessel as defined in American Society of Mechanical Engineers (ASME) Section VIII as close as sixty-five feet [19.8 meters] may be allowed if approved by the director. Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least one hundred fifty feet [45.72 meters] from the vicinity of wells and tanks. All waste shall be burned or disposed of in such manner as to avoid creating a fire hazard. All vegetation must be removed to a safe distance from any production or injection equipment to eliminate a fire hazard.

The director may require remote operated or automatic shutdown equipment to be installed on, or shut in for no more than forty days, any well that is likely to cause a serious threat of pollution or injury to the public health or safety.

Surface casing shall not be plumbed into the production flowline to relieve pressure without approval from the director.

No well shall be drilled nor production or injection equipment installed nor saltwater handling facility or treating plant constructed less than five hundred feet [152.40 meters] from an occupied dwelling unless agreed to in writing by the owner of the dwelling or authorized by order of the commission.

Subsurface pressure must be controlled during all drilling, completion, and well-servicing operations with appropriate fluid weight and pressure control equipment. The operator conducting any well hydraulic fracture stimulation shall give prior written notice, up to thirty-one days and not less than twenty-one days, to any operator of a well completed in the same or adjacent pool, if publicly available information indicates or if the operator is made aware, if the completion intervals are within two thousand six hundred and forty feet [804.67 meters] of one another. Notice must include twenty-four-hour emergency contact information, planned start and end dates, and contact information for scheduling updates.

History: Amended effective January 1, 1983; May 1, 1990; September 1, 2000; January 1, 2006; January 1, 2008; April 1, 2012; April 1, 2014; October 1, 2016; April 1, 2020;_________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-29. Well and lease equipment and gas gathering pipelines.

Wellhead and lease equipment with a working pressure at least equivalent to the calculated or known pressure to which the equipment may be subjected shall be installed and maintained. Equipment on producing wells shall be installed to facilitate gas-oil ratio tests, and static bottom hole or other pressure tests. Valves shall be installed and maintained in good working order to permit pressure readings to be obtained on both casing and tubing.

All newly constructed underground gas gathering pipelines must be devoid of leaks and constructed of materials resistant to external corrosion and to the effects of transported fluids. All such pipelines installed in a trench must be installed in a manner that minimizes interference with agriculture, road and utility construction, the introduction of secondary stresses, the possibility of damage to the pipe, and tracer wire shall be buried with any nonconductive pipes installed. When a trench for an underground gas gathering pipeline is backfilled, it 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.

1. The operator of any underground gas gathering pipeline placed into service on August 1, 2011, to June 30, 2013, shall file with the director, by January 1, 2015, a geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the location of the pipeline centerline. The operator of any underground gas gathering pipeline placed into service after June 30, 2013, shall file with the director, within one hundred eighty days of placing into service, a geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (~~Ersi~~Esri) shape file format showing the location of all compressor sites, buried drip tanks, and the pipeline centerline. An affidavit of completion shall accompany each layer containing the following information:

    a. A statement that the pipeline was constructed and installed in compliance with section 43-02-03-29.

    b. The outside diameter, minimum wall thickness, composition, internal yield pressure, and maximum temperature rating of the pipeline, or any other specifications deemed necessary by the director.

    c. The anticipated operating pressure of the pipeline.

    d. The type of fluid that will be transported in the pipeline and direction of flow.

e. Pressure to which the pipeline was tested prior to placing into service.

f. The minimum pipeline depth of burial.

g. In-service date.

h. Leak detection and monitoring methods that will be utilized after in-service date.

i. Pipeline name.

j. Accuracy of the geographical information system layer.

2. When an underground gas gathering pipeline or any part of such pipeline is abandoned, the operator shall leave such pipeline in a safe condition by conducting the following:

   a. Disconnect and physically isolate the pipeline from any operating facility or other pipeline.

   b. Cut off the pipeline or the part of the pipeline to be abandoned below surface at pipeline level.

   c. Purge the pipeline with fresh water, air, or inert gas in a manner that effectively removes all fluid.

   d. Remove cathodic protection from the pipeline.

   e. Permanently plug or cap all open ends by mechanical means or welded means.

3. Within one hundred eighty days of completing the abandonment of an underground gas gathering pipeline the operator of the pipeline shall file with the director a geographical information system layer utilization North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (~~Ersi~~Esri) shape file format showing the location of the pipeline centerline and an affidavit of completion containing the following information:

   a. A statement that the pipeline was abandoned in compliance with section 43-02-03-29.

   b. The type of fluid used to purge the pipeline.

4. Above ground pipeline markers shall be placed and maintained over each buried underground gas gathering pipeline or portion thereof at the discretion of the director when necessary to protect public health and safety.

The requirement to submit a geographical information system layer is not to be construed to be required on buried piping utilized to connect flares, tanks, treaters, or other equipment located entirely within the boundary of a well site or production facility.

History: Amended effective January 1, 1983; January 1, 2006; April 1, 2014; October 1, 2016; April 1, 2022; ________

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

43-02-03-29.1. Crude oil and produced water underground gathering pipelines.

1. Application of section. This section is applicable to all underground gathering pipelines designed for or capable of transporting crude oil or produced water from an oil and gas production facility for the purpose of disposal, storage, or for sale purposes. If these rules differ from the pipeline manufacturer's prescribed installation and operation practices, the pipeline manufacturer's prescribed installation and operation practices take precedence.

   The requirements in this section are not applicable to flow lines, injection pipelines, pipelines operated by an enhanced recovery unit for enhanced recovery unit operations, or on piping utilized to connect wells, tanks, treaters, flares, or other equipment located entirely within the boundary of a well site or production facility.

   If these rules differ from or are preempted by federal requirements on federally regulated pipelines, the federal rules take precedence. The pipeline owner shall provide sufficient documentation to the director confirming the pipeline is federally regulated.

2. Definitions. The terms used throughout this section apply to this section only.

   a. "Crude oil or produced water underground gathering pipeline" means an underground gathering pipeline designed or intended to transfer crude oil or produced water from a production facility for disposal, storage, or sale purposes.

   b. "New construction" means a new gathering pipeline installation project or an alteration or reroute of an existing gathering pipeline where the location, composition, size, design temperature, or design pressure changes.

   c. "Pipeline repair" is the work necessary to restore a pipeline system to a condition suitable for safe operations that does not change the design temperature or pressure.

   d. "Gathering system" is a group of connected pipelines which have been designated as a gathering system by the operator. A gathering system must have a unique name and must be interconnected.

   e. "In-service date" is the first date fluid was transported down the underground gathering pipeline for disposal, storage, or sale purposes after construction.

3. Notifications.

   a. The underground gathering pipeline owner shall notify the ~~commission, as provided by the~~ director, at least seven days prior to commencing new construction of any underground gathering pipeline. <u>The notice of intent to construct automatically expires after one year and for any project not built with one year; a new notice of intent to construct must be submitted.</u>

(1) The notice of intent to construct a crude oil or produced water underground gathering pipeline must include the following:

(a) The proposed date construction is scheduled to begin.

(b) A statement that the director will be verbally notified approximately forty-eight hours prior to commencing the construction.

(c) A geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the proposed route of the pipeline from the point of origin to the termination point.

(d) The proposed underground gathering pipeline design drawings, including all associated above ground equipment.

[1] The proposed pipeline composition, specifications (i.e. size, weight, grade, wall thickness, coating, and standard dimension ratio).

[2] The type of fluid to be transported.

[3] The method of testing pipeline integrity (e.g. hydrostatic or pneumatic test) prior to placing the pipeline into service.

[4] Proposed burial depth of the pipeline.

[5] The location and type of all road crossings (i.e. bored and cased or bored only).

[6] The location of all environmentally sensitive areas, such as wetlands, streams, or other surface waterbodies that the pipeline may traverse, if applicable.

b. The underground gathering pipeline owner shall file a sundry notice (form 4 or form provided by the ~~commission~~director) with the director providing ~~notifying~~ notification ~~the commission~~ of any underground gathering pipeline system or portion thereof that has been removed from service for more than one year.

c. If damage occurs to any underground gathering pipeline, flow line, or other underground equipment used to transport crude oil, natural gas, carbon dioxide, or water produced in association with oil and gas, during construction, operation, maintenance, repair, or abandonment of an underground gathering pipeline, the responsible party shall verbally notify the director immediately.

d. The pipeline owner shall file a sundry notice (form 4 or form provided by the ~~commission~~director) within thirty days of the in-service date reporting the date of first service.

4. Design and construction.

The following applies to newly constructed crude oil and produced water underground gathering pipelines, including tie-ins to existing systems:

a. Underground gathering pipelines must be devoid of leaks and constructed of materials resistant to external corrosion and to the effects of transported fluids.

b. Underground gathering pipelines must be designed in a manner that allows for line maintenance, periodic line cleaning, and integrity testing.

c. Installation crews must be trained in all installation practices for which they are tasked to perform.

d. Underground gathering pipelines must be installed in a manner that minimizes interference with agriculture, road and utility construction, the introduction of secondary stresses, and the possibility of damage to the pipe. Tracer wire must be buried with any nonconductive pipe installed.

e. Unless the manufacturer's installation procedures and practices provide guidance, pipeline trenches must be constructed to allow for the pipeline to rest on undisturbed native soil and provide continuous support along the length of the pipe. Trench bottoms must be free of rocks greater than two inches in diameter, debris, trash, and other foreign material not required for pipeline installation. If a trench bottom is over excavated, the trench bottom must be backfilled with appropriate material and compacted prior to installation of the pipe to provide continuous support along the length of the pipe.

   The width of the trench must provide adequate clearance on each side of the pipe. Trench walls must be excavated to ensure minimal sluffing of sidewall material into the trench. Subsoil from the excavated trench must be stockpiled separately from previously stripped topsoil.

f. Underground gathering pipelines that cross a township, county, or state graded road must be bored unless the responsible governing agency specifically permits the owner to open cut the road.

g. 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 in a manner that could impair its strength or reduce its serviceability.

h. 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.

i. When a trench for an underground gathering pipeline is backfilled, it 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 haunches of the pipe 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.

j. Cover depths must be a minimum of four feet [1.22 meters] from the top of the pipe to the finished grade. The cover depth for an undeveloped governmental section line must be a minimum of six feet [1.83 meters] from the top of the pipe to the finished grade.

k. Underground gathering pipelines that traverse environmentally sensitive areas, such as wetlands, streams, or other surface waterbodies, must be installed in a manner that minimizes impacts to these areas. Any horizontal directional drilling plan prepared by the owner or required by the director, must be filed with the ~~commission~~director, prior to the commencement of horizontal directional drilling.

l. Clamping or squeezing as a method of connecting any produced water underground gathering pipeline must be approved by the director. Prior to clamping or squeezing the pipeline, the owner shall file a sundry notice (form 4 or form provided by the ~~commission~~director) with the director and obtain approval of the clamping or squeezing plan. The notice must include documentation that the pipeline can be safely clamped or squeezed as prescribed by the manufacturer's specifications. Any damaged portion of a produced water underground gathering pipeline that has been clamped or squeezed must be replaced before it is placed into service.

5. Pipeline reclamation.

a. When utilizing excavation for pipeline installation, repair, or abandonment, topsoil must be stripped, segregated from the subsoils, and stockpiled for use in reclamation. "Topsoil" means the suitable plant growth material on the surface; however, in no event shall this be deemed to be more than the top twelve inches [30.48 centimeters] of soil or deeper than the depth of cultivation, whichever is greater.

b. The pipeline right-of-way must be reclaimed as closely as practicable to original condition. All stakes, temporary construction markers, cables, ropes, skids, and any other debris or material not native to the area must be removed from the right-of-way and lawfully disposed of.

c. During right-of-way reclamation all subsoils and topsoils must be returned in proper order to as close to the original depths as practicable. Right-of-way reclamation shall be completed within 180 calendar days of the pipeline being placed into service. An extension may be granted at the director's discretion.

d. The reclaimed right-of-way soils must be stabilized to prevent excessive settling, sluffing, cave-ins, or erosion.

e. The crude oil and produced water underground gathering pipeline owner is responsible for their right-of-way reclamation and maintenance until such pipeline is released by the ~~commission~~ director from the pipeline bond pursuant to section 43-02-03-15.

6. Inspection.

All newly constructed crude oil and produced water underground gathering pipelines must be inspected by third-party independent inspectors during all aspects of construction to ensure the pipeline is installed as prescribed by the manufacturer's specifications and in accordance with the requirements of this section. A list of all third-party independent inspectors and a description of each independent inspector's qualifications, certifications, experience, and specific training must be provided to the ~~commission~~ director upon request. A person may not be used to perform inspections unless that person has been trained and is qualified in the phase of construction to be inspected. The third-party independent inspector may not be an employee of the gathering pipeline owner/operator or the contractor hired to construct and install the pipeline. The number of third-party independent inspectors shall be adequate for the size of the pipeline construction project. Projects may be required by the director to have additional third-party independent inspectors present to ensure proper pipeline installation.

7. Associated pipeline facility.

No associated above ground equipment may be installed less than five hundred feet [152.40 meters] from an occupied dwelling unless agreed to in writing by the owner of the dwelling or authorized by order of the commission.

All associated above ground equipment used to store crude oil or produced water must be devoid of leaks and constructed of materials resistant to the effects of crude oil, produced water, brines, or chemicals that may be contained therein. The above materials requirement may be waived by the director for tanks presently in service and in good condition. Unused tanks and associated above ground equipment must be removed from the site or placed into service, within a reasonable time period, not to exceed one year.

Dikes must be erected around all produced water or crude oil tanks at any new facility prior to placing the associated underground gathering pipeline into service. Dikes must be erected and maintained around all crude oil or produced water tanks or above ground equipment, when deemed necessary by the director. Dikes as well as the base material under the dikes and within the diked area must be constructed of sufficiently impermeable material to provide emergency containment. Dikes must be of sufficient dimension to contain the total capacity of the largest tank plus one day's fluid throughput. The required capacity of the dike may be lowered by the director if the necessity therefor can be demonstrated to the director's satisfaction. Discharged crude oil or produced water must be properly removed and may not be allowed to remain standing within or outside of any diked areas.

The underground gathering pipeline owner shall take steps to minimize the amount of solids stored at the pipeline facility, although the remediation of such material may be allowed onsite, if approved by the director.

8. Underground gathering pipeline as built.

The owner of any underground gathering pipeline placed into service after July 31, 2011, shall file with the director, as prescribed by the director, within one hundred eighty days of placing into service, a geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the location of all associated above ground equipment and the pipeline centerline from the point of origin to the termination point. An affidavit of completion shall accompany each layer containing the following information:

a. A third-party inspector certificate that the pipeline was constructed and installed in compliance with section 43-02-03-29.1.

b. The outside diameter, minimum wall thickness, composition, and maximum temperature rating of the pipeline, or any other specifications deemed necessary by the director.

c. The maximum allowable operating pressure of the pipeline.

d. The specified minimum yield strength and internal yield pressure of the pipeline if applicable to the composition of pipe.

e. The type of fluid that will be transported in the pipeline.

f. Pressure and duration to which the pipeline was tested prior to placing into service.

g. The minimum pipeline depth of burial from the top of the pipe to the finished grade.

h. In-service date.

i. Leak protection and monitoring methods that will be utilized after in-service date.

j. Any leak detection methods that have been prepared by the owner.

k. The name of the pipeline gathering system and any other separately named portions thereof.

l. ~~Accuracy of the~~The geographical information system layer must be within twenty feet of horizontal accuracy.

9. Operating requirements.

The maximum operating pressure for all crude oil and produced water underground gathering pipelines may not exceed the manufacturer's specifications of the pipe or the manufacturer's specifications of any other component of the pipeline, whichever is less. The maximum operating pressure of any portion of an underground gathering system may not exceed the test pressure from the most recent integrity test demonstration following modification or repair for which it was tested.

The crude oil or produced water underground gathering pipeline must be equipped with adequate controls and protective equipment to prevent the pipeline from operating above the maximum operating pressure.

10. Leak protection, detection, and monitoring.

All crude oil and produced water underground gathering pipeline owners shall file with the ~~commission~~ director any leak protection and monitoring plan prepared by the owner or required by the director, pursuant to North Dakota Century Code section 38-08-27.

If any leak detection plan has been prepared by the owner, it must be submitted to the director.

All crude oil or produced water underground gathering pipeline owners shall develop and maintain a data sharing plan and file a copy with the director. The plan must provide for real-time sharing of data between the operator of the production facility, the crude oil or produced water underground gathering pipeline owner, and the operator at the point or points of disposal, storage, or sale. If a discrepancy in the shared data is observed, the party observing the data discrepancy shall notify all other parties and action must be taken to determine the cause. A record of all data discrepancies must be retained by the crude oil or produced water underground gathering pipeline owner. If requested, copies of such records must be filed with the ~~commission~~director.

11. Spill response.

All crude oil and produced water underground gathering pipeline owners shall maintain a spill response plan during the service life of any crude oil or produced water underground gathering pipeline. The plan should detail the necessary steps for an effective and timely response to a pipeline spill. The spill response plan should be tailored to the specific risks in the localized area. Response capabilities should address access to equipment and tools necessary to respond, as well as action steps to protect the health and property of impacted landowners, citizens, and the environment.

12. Corrosion control.

a. Underground gathering pipelines must be designed to withstand the effects of external corrosion and maintained in a manner that mitigates internal corrosion.

b. All metallic underground gathering pipelines installed must have sufficient corrosion control.

c. All coated pipe must be electronically inspected prior to placement using coating deficiency (i.e. holiday) detectors to check for any faults not observable by visual examination. The holiday detector must be operated in accordance with manufacturer's instructions and at a voltage level appropriate for the electrical characteristics of the pipeline system 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:

(1) Be designed to mitigate corrosion of the buried pipeline;

(2) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have enough strength to resist damage due to handling and soil stress;

(5) Support any supplemental cathodic protection; and

(6) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

d. Cathodic protection systems must meet or exceed the minimum criteria set forth in the National Association of Corrosion Engineers standard practice Control of External Corrosion on Underground or Submerged Metallic Piping Systems.

e. If internal corrosion is anticipated or detected, the underground gathering pipeline owner shall take prompt remedial action to correct any deficiencies, such as increased pigging, use of corrosion inhibitors, internal coating of the pipeline (e.g. an epoxy paint or other plastic liner), or a combination of these methods. Corrosion inhibitors must be used in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect.

13. Pipeline integrity.

A crude oil or produced water underground gathering pipeline owner may not operate a pipeline unless it has been pressure tested and demonstrated integrity. In addition, an owner may not return to service a portion of pipeline which has been repaired, replaced, relocated, or otherwise changed until it has demonstrated integrity.

a. The crude oil and produced water underground gathering pipeline owner shall notify the ~~commission~~ director at least forty-eight hours prior to commencement of any pipeline integrity test to allow a representative of the ~~commission~~ director to witness the testing process and results. The notice must include the pipeline integrity test procedure.

b. The crude oil and produced water underground gathering pipeline owner shall submit within sixty days of the underground gathering pipeline being placed into service the integrity test results which must include the following:

(1) The name of the pipeline gathering system and any other separately named portions thereof;

(2) The date of the test;

(3) The duration of the test;

(4) The length of pipeline which was tested;

(5) The maximum and minimum test pressure;

(6) The starting and ending pressure;

(7) A copy of the appropriately scaled chart recorder or digital log results;

(8) A geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the location of the centerline of the portion of the pipeline that was tested;

(9) A copy of the test procedure used; and

(10) A third-party inspector certificate summarizing the pipeline has been pressure tested and whether it demonstrated integrity, including the identification of any leaks, ruptures, or other integrity issues encountered, and an explanation for any substantial pressure gain or losses during the integrity test, if applicable.

c. All crude oil and produced water underground gathering pipeline owners shall maintain a pipeline integrity demonstration plan during the service life of any crude oil or produced water underground gathering pipeline. The director, for good cause, may require a pipeline integrity demonstration on any crude oil or produced water underground gathering pipeline.

14. Pipeline repair.

Each owner, in repairing an underground gathering pipeline or pipeline system, shall ensure that the repairs are made in a manner that prevents damage to persons or property.

An owner may not use any pipe, valve, or fitting, for replacement or repair of an underground gathering pipeline, unless it is designed to meet the maximum operating pressure.

a. At least forty-eight hours prior to any underground gathering pipeline repair or replacement, the underground gathering pipeline owner shall notify the ~~commission, as provided by the~~ director, except in an emergency.

b. Within one hundred eighty days of repairing or replacing any underground gathering pipeline the owner of the pipeline shall file with the director a geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the location of the centerline of the repaired or replaced pipeline and an affidavit of completion containing the following information:

(1) A statement that the pipeline was repaired in compliance with section 43-02-03-29.1.

(2) The reason for the repair or replacement.

(3) The length of pipeline that was repaired or replaced.

(4) Pressure and duration to which the pipeline was tested prior to returning to service.

c. Clamping or squeezing as a method of repair for any produced water underground gathering pipeline must be approved by the director. Prior to clamping or squeezing the pipeline, the owner shall file a sundry notice (form 4) with the director and obtain approval of the clamping or squeezing plan. The notice must include documentation that the pipeline can be safely clamped or squeezed as prescribed by the manufacturer's specifications. If an emergency requires clamping or squeezing, the owner or the owner's agent shall obtain verbal approval from the director and the notice shall be filed within seven days of completing the repair. Any damaged portion of a produced water underground gathering pipeline that has been clamped or squeezed must be replaced before it is returned to service.

15. Pipeline abandonment.

a. At least forty-eight hours prior to abandoning any underground gathering pipeline, the underground gathering pipeline owner shall notify the director verbally.

b. When an underground gathering pipeline or any part of such pipeline is abandoned as defined under subsection 1 of North Dakota Century Code section 38-08-02 after March 31, 2014, the owner shall leave such pipeline in a safe condition by conducting the following:

(1) Disconnect and physically isolate the pipeline from any operating facility, associated above ground equipment, or other pipeline.

(2) Cut off the pipeline or the part of the pipeline to be abandoned below surface at pipeline level.

(3) Purge the pipeline with fresh water, air, or inert gas in a manner that effectively removes all fluid.

(4) Remove cathodic protection from the pipeline.

(5) Permanently plug or cap all open ends by mechanical means or welded means.

(6) The site of all associated above ground equipment must be reclaimed pursuant to section 43-02-03-34.1.

(7) If the bury depth is not at least three feet below final grade, such portion of pipe must be removed.

c. Within one hundred eighty days of completing the abandonment of an underground gathering pipeline the owner of the pipeline shall file with the director a geographical information system layer utilizing North American datum 83 geographic coordinate system (GCS) and in an environmental systems research institute (Esri) shape file format showing the location of the pipeline centerline and an affidavit of completion containing the following information:

(1) A statement that the pipeline was abandoned in compliance with section 43-02-03-29.1.

(2) The type of fluid used to purge the pipeline.

(3) The date of pipeline abandonment.

(4) The length of pipeline abandoned.

16. Pipeline markers.

a. Above ground pipeline markers shall be placed and maintained over each buried crude oil or produced water underground gathering pipeline or portion thereof at the discretion of the director when necessary to protect public health and safety.

History: Effective October 1, 2016; amended effective April 1, 2020; April 1, 2022; ________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-31. Well log, completion, and workover reports.

After the plugging of a well, a plugging record (form 7) shall be filed with the director. After the completion of a well, recompletion of a well in a different pool, or drilling horizontally in an existing pool, a completion report (form 6 or form provided by the ~~commission~~director) shall be filed with the director. In no case shall oil or gas be transported from the lease prior to the filing of a completion report unless approved by the director. The operator shall cause to be run an open hole electrical, radioactivity, or other similar log, or combination of open hole logs, of the operator's choice, from which formation tops and porosity zones can be determined. The operator shall cause to be run a gamma ray log from total depth to ground level elevation of the well bore. Within six months of reaching total depth and prior to completing the well, the operator shall cause to be run a cement evaluation log from which the presence and quality of bonding of cement can be determined in every well in which production or intermediate casing has been set. The initial cement evaluation log shall be run without the addition of pressure at surface. The obligation to log may be waived or postponed by the director if the necessity therefor can be demonstrated to the director's satisfaction. Waiver will be contingent upon such terms and conditions as the director deems appropriate. All logs run shall be available to the director at the well site prior to proceeding with plugging or completion operations. All logs run shall be submitted to the director free of charge. Logs shall be submitted as one digital TIFF (tagged image file format) copy and one digital LAS (log ASCII) formatted copy, or a format approved by the director. In addition, operators shall file one copy of drill stem test reports and charts, formation water analyses, core analyses, geologic reports, and noninterpretive lithologic logs or sample descriptions if compiled by the operator.

All information furnished to the director on permits, except the operator name, well name, location, permit date, confidentiality period, spacing or drilling unit description, spud date, rig contractor, central tank battery number, any production runs, or volumes injected into an injection well, shall be kept confidential from the ~~time~~ date a request by the operator is received in writing until the six-month confidentiality period has ended. The six-month period shall commence on the date the well is completed or the date the written request is received, whichever is earlier. If the written request accompanies the application for permit to drill or is filed after permitting but prior to spudding, the six-month period shall commence on the date the well is spudded. The director may release such confidential completion and production data to health care professionals, emergency responders, and state, federal, or tribal environmental and public health regulators if the director deems it necessary to protect the public's health, safety, and welfare.

All information furnished to the director on recompletions, restimulation wells, or reentries, except the operator name, well name, location, permit date, confidentiality period, spacing or drilling unit description, spud date, rig contractor, any production runs, or volumes injected into an injection well, shall be kept confidential for not more than six months if requested by the operator in writing. The six-month period shall commence on the date the well is completed, recompleted, or restimulated or the date ~~the well was approved for recompletion or reentry~~ a request by the operator is received in writing, whichever is earlier. Any information furnished to the director prior to approval of the recompletion, restimulation, or reentry shall remain public.

Approval must be obtained on a well sundry ~~notice~~ form ~~(form 4)~~ from the director prior to perforating or recompleting a well in a pool other than the pool in which the well is currently permitted.

After the completion of any remedial work, or attempted remedial work such as plugging back or drilling deeper, acidizing, shooting, formation fracturing, squeezing operations, setting liner, perforating, reperforating, or other similar operations not specifically covered herein, a report on the operation shall be filed on a sundry notice (form 4) with the director. The report shall present a detailed account of all work done and the date of such work; the daily production of oil, gas, and water both prior to and after the operation; the shots per foot, size, and depth of perforations; the quantity of sand, crude, chemical, or other materials employed in the operation; and any other pertinent information or operations which affect the original status of the well and are not specifically covered herein.

Upon the installation of pumping equipment on a flowing well, or change in type of pumping equipment designed to increase productivity in a well, the operator shall submit a sundry notice (form 4) of such installation. The notice shall include all pertinent information on the pump and the operation thereof including the date of such installation, and the daily production of the well prior to and after the pump has been installed.

All forms, reports, logs, and other information required by this section shall be submitted within thirty days after the completion of such work, although a completion report shall be filed immediately after the completion or recompletion of a well in a pool or reservoir not then covered by an order of the commission.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1990; May 1, 1992; May 1, 1994; July 1, 1996; September 1, 2000; July 1, 2002; January 1, 2006; January 1, 2008; April 1, 2010; April 1, 2012; October 1, 2016; April 1, 2020; ______

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-34.1. Reclamation of surface.

1. Within a reasonable time, but not more than one year, after a well is plugged, or if a permit expires, has been canceled or revoked, or a treating plant or saltwater handling facility is decommissioned, the site, access road, and other associated facilities constructed shall be reclaimed as closely as practicable to original condition pursuant to North Dakota Century Code section 38-08-04.12. Prior to site reclamation, the operator or the operator's agent shall file a well sundry ~~notice~~ form ~~(form 4)~~ or facility sundry notice with the director and obtain approval of a reclamation plan. The operator or operator's agent shall provide a copy of the proposed reclamation plan to the surface owner at least ten days prior to commencing the work unless waived by the surface owner. Verbal approval to reclaim the site may be given. The notice shall include:

   a. The name and address of the reclamation contractor;

   b. The name and address of the surface owner and the date when a copy of the proposed reclamation plan was provided to the surface owner;

   c. A description of the proposed work, including topsoil redistribution and reclamation plans for the access road and other associated facilities; and

   d. Reseeding plans, if applicable.

   The commission will mail a copy of the approved notice to the surface owner.

   All equipment, waste, and debris shall be removed from the site. All pipelines shall be purged and abandoned pursuant to section 43-02-03-29.1. Flow lines shall be removed if buried less than three feet [91.44 centimeters] below final contour.

2. Gravel or other surfacing material shall be removed, stabilized soil shall be remediated, and the site, access road, and other associated facilities constructed for the well, treating plant, or saltwater handling facility shall be reshaped as near as practicable to original contour.

3. The stockpiled topsoil shall be evenly distributed over the disturbed area and, where applicable, the area revegetated with native species or according to the reasonable specifications of the appropriate government land manager or surface owner.

4. A site assessment may be required by the director, before and after reclamation of the site.

5. Within thirty days after completing any reclamation, the operator shall file a sundry notice with the director reporting the work performed.

6. The director, with the consent of the appropriate government land manager or surface owner, may waive the requirement of reclamation of the site and access road after a well is plugged or treating plant or saltwater handling facility is decommissioned. The ~~operator~~ director shall record documentation of the waiver with the recorder of the county in which the site or road is located.

History: Effective April 1, 2012; amended effective April 1, 2014; October 1, 2016; April 1, 2018; April 1, 2020; April 1, 2022; __________.

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-35. Conversion of mineral wells to freshwater wells.

Any person desiring to convert a mineral well to a freshwater well, as provided by North Dakota Century Code section 61-01-27, shall file an application for approval with the commission. The application must include, but is not limited to, the following:

1. If the well is to be used for other than individual domestic and livestock use, a conditional water permit issued by the ~~state water commission~~department of water resources.

2. An affidavit by the person desiring to obtain approval for the conversion stating that such person has the authority and assumes all liability for the use and plugging of the proposed freshwater well.

3. The procedure which will be followed in converting the mineral well to a freshwater well.

4. If the well is not currently plugged and abandoned, an affidavit must be executed by the operator of the well indicating that the parties responsible for plugging the mineral well have no objection to the conversion of the mineral well to a freshwater well.

If the commission, after notice and hearing, determines that a mineral well may safely be used as a freshwater well, the commission may approve the conversion.

History: Amended effective April 30, 1981; January 1, 1983; September 1, 1987; July 1, 2002; ________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-41. Subsurface pressure tests.

The operator shall make a subsurface pressure test on the discovery well of any new pool hereafter discovered and shall report the results thereof to the director within thirty days after the completion of such discovery well. Drill stem test pressures are acceptable. After the discovery of a new pool, each operator shall make additional subsurface pressure tests as directed by the director or provided for in field rules. All tests shall be made by a person qualified by both training and experience to make such tests and with an approved subsurface pressure instrument. All wells shall remain completely shut in for at least forty-eight hours prior to the test. The subsurface determination shall be obtained as close as possible to the ~~midpoint~~ top of the formation containing the productive interval of the reservoir. The report of the reservoir pressure test shall be filed on form 9a.

The director may shut in any well for failure to make such test as herein above described until such time as a satisfactory test has been made or satisfactory explanation given.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1992; September 1, 2000; _______

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-44. Metered casinghead gas.

All casinghead gas produced shall be reported monthly to the director in units of one thousand cubic feet [28.32 cubic meters] computed at a pressure of fourteen and seventy-three hundredths pounds per square inch absolute [1034.19 grams per square centimeter] at a base temperature of sixty degrees Fahrenheit [15.56 degrees Celsius]. Associated gas production may not be transported from a well premises or central production facility until its volume has been determined through the use of properly calibrated measurement equipment. All measurement equipment and volume determinations must conform to American gas association standards. The operator of a well shall notify the director within thirty days on a well sundry form of the connection date to a gas gathering system, the metering equipment, transporter, and purchaser of the gas. Any gas produced and used on lease for fuel purposes or flared ~~must~~ may be estimated or measured and shall be reported on a gas production report (form 5b) in accordance with section 43-02-03-52.1. Meters used to determine the used on lease or flared gas volumes should be installed and calibrated in accordance with American Petroleum Institute or American Gas Association standards or to the meter manufacturer's recommendations.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1992; July 1, 1996; September 1, 2000; ___________

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

43-02-03-48.1. Central production facility - Commingling of production.

1. The director shall have the authority to approve requests to consolidate production equipment at a central location. The applicant shall provide all information requested by the director. The director may impose such terms and conditions as the director deems necessary.

2. Commingling of <u>oil and gas</u> production from two or more wells in a central production facility is prohibited unless approved by the director. There are two types of central production facilities in which production from two or more wells is commingled that may be approved by the director.

   a. A central production facility in which all production going into the facility has common ownership. For purposes of this section, production with common ownership is defined as production from wells that do not have diverse ownership.

   b. A central production facility in which production going into the facility has diverse ownership. For purposes of this section, production with diverse ownership is defined as production from wells that are:

      (1) In different drilling or spacing units; and

      (2) Which have different mineral ownership.

3. The commingling of <u>oil and gas</u> production in a central production facility from two or more wells having common ownership may be approved by the director provided the production from each well can be accurately determined at reasonable intervals. Commingling of <u>oil and gas</u> production in a central production facility from two or more wells having diverse ownership may be approved by the director provided the production from each well is accurately metered prior to commingling. Commingling of <u>oil and gas</u> production in a central production facility from two or more wells having diverse ownership that is not metered prior to commingling may only be approved by the commission after notice and hearing.

   a. Common ownership central production facility. The application for permission to commingle oil<u>,</u> ~~and~~ gas<u>, or both</u> in a central production facility with common ownership must be submitted on a <u>facility</u> sundry notice ~~(form 4)~~ and shall include the following:

      (1) A plat or map showing thereon the location of the central facility and the name, well file number, and location of each well and flow lines from each well that will produce into the facility.

(2) A schematic drawing of the facility which diagrams the testing, treating, routing, and transferring of production. All pertinent items such as treaters, tanks, flow lines, valves, meters, recycle pumps, etc., should be shown.

(3) An affidavit executed by a person who has knowledge indicating that common ownership as defined above exists.

(4) An explanation of the procedures or method to be used to determine, accurately, individual well production at periodic intervals. Such procedures or method shall be performed at least once every three months.

~~(4)~~(5) List of all allocation meters to be used and the meter type.

A copy of all tests are to be filed with the director on a central tank battery well test form ~~11~~ within thirty days after the tests are completed.

b. Diverse ownership central production facility. The application for permission to commingle oil, ~~and~~ gas, or both in a central production facility having diverse ownership must be submitted on a facility sundry notice ~~(form 4)~~ and shall include the following:

(1) A plat or map showing thereon the location of the central facility and the name, well file number, and location of each well, and flow lines from each well that will produce into the facility.

(2) A schematic drawing of the facility which diagrams the testing, treating, routing, and transferring of production. All pertinent items such as treaters, tanks, flow lines, valves, meters, recycle pumps, etc., should be shown.

(3) The name of the manufacturer, size, and type of meters to be used. The meters must be proved at least once every three months and the results reported to the director within thirty days following the completion of the test.

(4) An explanation of the procedures or method to be used to determine, accurately, individual well production at periodic intervals. Such procedures or method shall be performed monthly.

~~(4)~~(5) List of all allocation meters to be used and the meter type.

A copy of all tests are to be filed with the director on a central tank battery well test form ~~11~~ within thirty days after the tests are completed.

4. The commingling of produced water in a central production facility from two or more wells may be approved by the director provided the produced water production can be accurately determined at reasonable intervals. The application for permission to commingle water in a central production facility must be submitted on a facility sundry notice and shall include the following:

a. A plat or map showing thereon the location of the central facility and the name, well file number, and location of each well, and flow lines from each well that will produce into the facility.

b. A schematic drawing of the facility which diagrams the testing, treating, routing, and transferring of production. All pertinent items such as treaters, tanks, flow lines, valves, meters, recycle pumps, etc., should be shown.

c. An explanation of the procedures or method to be used to determine, accurately, individual well production at periodic intervals. Such procedures or method shall be performed monthly.

d. List of all allocation meters to be used and the meter type.

~~4.~~5. Any changes to a previously approved central production facility must be reported on a facility sundry notice ~~(form 4)~~ and approved by the director.

History: Effective May 1, 1992; amended effective September 1, 2000; May 1, 2004; April 1, 2020; _________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-51.1. Treating plant permit requirements.

1. The treating plant permit application shall be submitted on form 1tp and shall include at least the following information:

   a. The name and address of the operator.

   b. An accurate plat certified by a registered surveyor showing the location of the proposed treating plant and the center of the site with reference to true north and the nearest lines of a governmental section. The plat shall also include the latitude and longitude of the center of the proposed treating plant location to the nearest tenth of a second, and the ground elevation. The plat shall also depict the outside perimeter of the treating plant and verification that the site is at least five hundred feet [152.4 meters] from an occupied dwelling.

   c. A schematic drawing of the proposed treating plant site, drawn to scale, detailing all facilities and equipment, including the size, location, and purpose of all tanks, the height and location of all dikes, the location of all flow lines, and the location of the topsoil stockpile. It shall also include the proposed road access to the nearest existing public road and the authority to build such access.

   d. Cut and fill diagrams.

   e. An affidavit of mailing identifying each owner of any permanently occupied dwellingwithin one-quarter mile of the proposed treating plant and certifying that such owner has been notified of the proposed treating plant.

   f. Appropriate geological data on the surface geology and its suitability for fluid containment.

g. Schematic drawings of the proposed diking and containment, including calculated containment volume and all areas underlain by a synthetic liner.

h. Monitoring plans and leak detection for all buried or partially buried structures and any concrete structure upon which waste or product is in direct contact.

i. The capacity and operational capacity of the treating plant.

j. A narrative description of the process and how the waste and recovered product streams travel through the treating plant.

k. A review of the surficial aquifers within one mile of the proposed treating plant site or surface facilities.

l. Any other information required by the director to evaluate the proposed treating plant or site.

2. Permits may contain such terms and conditions as the director deems necessary.

3. Any permit issued under this section may be revoked by the commission after notice and hearing if the permittee fails to comply with the terms and conditions of the permit, any directive of the director, or any applicable rule or statute. Any permit issued under this section may be suspended by the director for good cause.

4. Permits are transferable only with approval of the director.

5. Permits may be modified by the director.

6. A permit shall automatically expire one year after the date it was issued, unless dirtwork operations have commenced to construct the site. The director may extend a treating plant permit for up to one year upon request.

7. If the treating plant is abandoned and reclaimed, the permit shall expire and be of no further force and effect.

History: Effective April 1, 2014; amended effective October 1, 2016; April 1, 2020; ________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04

43-02-03-51.3. Treating plant construction and operation requirements.

1. Before construction of a treating plant, treating plant site, or access road begins, the operator shall file with the director a surety bond or cash bond conditioned upon compliance with all laws, rules and regulations, and orders of the commission. The bond amount shall be specified in the commission order authorizing the treating plant and shall be based upon the location, type, and capacity of the plant, processing method, and plan of operation for all plant waste approved in the commission order and shall be payable to the industrial commission. In no case shall the bond amount be set lower than fifty thousand dollars.

2. Treating plant sites and associated facilities or appropriate parts thereof shall be fenced if required by the director. All fences installed within or around any facility must be constructed in a manner that promotes emergency ingress and egress.

3. All storage tanks shall be kept free of leaks and in good condition. Storage tanks for saltwater shall be constructed of, or lined with, materials resistant to the effects of saltwater. Open tanks are allowed if approved by the director.

4. All waste, recovered solids, and recovered fluids shall be stored and handled in such a manner to prevent runoff or migration offsite.

5. Dikes of sufficient dimension to contain the total capacity of the maximum volume stored must be erected and maintained around all storage and processing tanks. Dikes as well as the base within the diked area must be lined with a synthetic impermeable liner to provide emergency containment unless waived by the director. All processing equipment shall be underlain by a synthetic impermeable material, unless waived by the director. The site shall be sloped and diked to divert surface drainage away from the site. The operations of the treating plant shall be conducted in such a manner as to prevent leaks, spills, and fires. All discharged fluids and wastes shall be promptly and properly removed and shall not be allowed to remain standing within the diked area or on the treating plant premises. All such incidents shall be properly cleaned up, subject to approval by the director. All such reportable incidents shall be promptly reported to the director and a detailed account of any such incident must be filed with the director in accordance with section 43-02-03-30.

6. A perimeter berm, at least six inches [15.24 centimeters] in height, must be constructed of sufficiently impermeable material to provide emergency containment around the treating plant and to divert surface drainage away from the site if deemed necessary by the director.

7. Within thirty days following construction or modification of a treating plant, a sundry notice (form 4) must be submitted detailing the work and the dates commenced and completed. The sundry notice must be accompanied by a schematic drawing of the treating plant site drawn to scale, detailing all facilities and equipment, including the size, location, and purpose of all tanks; the height and location of all dikes as well as a calculated containment volume; all areas underlain by a synthetic liner; any leak detection system installed; the location of all flowlines; the stockpiled topsoil location and its volume; and the road access to the nearest existing public road.

8. Immediately upon the commencement of treatment operations, the operator shall notify the director in writing of such date.

9. The operator of a treating plant shall provide continuing surveillance and conduct such monitoring and sampling as the director may require.

10. Storage pits, waste pits, or other earthen storage areas shall be prohibited unless authorized by an appropriate regulatory agency. A copy of said authorization shall be filed with the director.

11. Burial of waste at any treating plant site shall be prohibited. All residual water and waste, fluid or solid, shall be disposed of in an authorized facility.

12. The operator shall take steps to minimize the amount of residual waste generated and the amount of residual waste temporarily stored onsite. Solid waste shall not be stockpiled onsite unless authorized by an appropriate regulatory agency. A copy of said authorization shall be filed with the director.

13. If deemed necessary by the director, the operator shall cause to be analyzed any waste substance contained onsite. Such chemical analysis shall be performed by a certified laboratory and shall adequately determine if chemical constituents exist which would categorize the waste as hazardous by department of environmental quality standards.

14. Treating plants shall be constructed and operated so as not to endanger surface or subsurface water supplies or cause degradation to surrounding lands and shall comply with section 43-02-03-28 concerning fire hazards and proximity to occupied dwellings.

15. The beginning of month inventory, the amount of waste received and the source of such waste, the volume of oil sold, the amount and disposition of water, the amount and disposition of residue waste, fluid or solid, and the end of month inventory for each treating plant shall be reported monthly on form 5p with the director on or before the first day of the second succeeding month, regardless of the status of operations.

16. Records necessary to validate information submitted on form 5p shall be maintained in North Dakota.

17. All proposed changes to any treating plant must have prior approval by the director.

18. The operator shall comply with all applicable rules and orders of the commission. All rules in this chapter governing oil well sites shall also apply to any treating plant site.

19. The operator shall immediately cease operations if so ordered by the director for failure to comply with the statutes of North Dakota, commission rules or orders, or directives of the director.

History: Effective April 1, 2014; amended effective October 1, 2016; April 1, 2018; April 1, 2020; _________

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

43-02-03-53.1. Saltwater handling facility permit requirements.

1. A permit for construction of a saltwater handling facility, saltwater handling facility site, or access road must be approved by the director prior to construction. The saltwater handling facility permit application must be submitted on a facility sundry notice ~~(form 4)~~ and include at least the following information:

    a. The name and address of the operator.

b. An accurate plat certified by a registered surveyor showing the location of the proposed saltwater handling facility and the center of the site with reference to true north and the nearest lines of a governmental section. The plat also must include the latitude and longitude of the center of the proposed saltwater handling facility location to the nearest tenth of a second and the ground elevation. The plat also must depict the outside perimeter of the saltwater handling facility and verification that the site is at least five hundred feet [152.4 meters] from an occupied dwelling.

c. A schematic drawing of the proposed saltwater handling facility site, drawn to scale, detailing all facilities and equipment, including the size, location, and purpose of all tanks, the height and location of all dikes, the location of all flow lines, and the location and thickness of the stockpiled topsoil. The schematic drawing also must include the proposed road access to the nearest existing public road and the authority to build such access.

d. Cut and fill diagrams.

e. Schematic drawings of the proposed diking and containment, including calculated containment volume and all areas underlain by a synthetic liner, as well as a description of all containment construction material.

f. The anticipated daily throughput of the saltwater handling facility.

g. A review of the surficial aquifers within one mile of the proposed treating plant site or surface facilities.

h. Any other information required by the director to evaluate the proposed saltwater handling facility or site.

2. Permits may contain such terms and conditions as the director deems necessary.

3. Any permit issued under this section may be revoked by the commission after notice and hearing if the permittee fails to comply with the terms and conditions of the permit, any directive of the director, or any applicable rule or statute. Any permit issued under this section may be suspended by the director for good cause.

4. Permits are transferable only with approval of the director.

5. Permits may be modified by the director.

6. A permit automatically expires one year after the date it was issued, unless dirtwork operations have commenced to construct the site. <u>The director may extend a saltwater handling facility permit for up to one year upon request.</u>

7. If the saltwater handling facility is abandoned and reclaimed, the permit expires and is of no further force and effect.

History: Effective October 1, 2016; amended effective April 1, 2020; __________

General Authority
NDCC 38-08-04

Law Implemented
NDCC 38-08-04

43-02-03-55. Abandonment of wells, treating plants, underground gathering pipelines, or saltwater handling facilities - Suspension of drilling.

1. The removal of production equipment or the failure to produce oil or gas for one year constitutes abandonment of the well. The removal of production equipment or the failure to produce water from a source well for one year constitutes abandonment of the well. The removal of injection equipment or the failure to use an injection well for one year constitutes abandonment of the well. The removal of monitoring equipment from or the failure to use a subsurface observation well for one year constitutes abandonment of the well. The failure to plug a stratigraphic test hole within one year of reaching total depth constitutes abandonment of the well. The removal of treating plant equipment or the failure to use a treating plant for one year constitutes abandonment of the treating plant. The removal of saltwater handling facility equipment or the failure to use a saltwater handling facility for one year constitutes abandonment of the saltwater handling facility. An abandoned well must be plugged and its site must be reclaimed, an abandoned treating plant must be removed and its site must be reclaimed, and an abandoned saltwater handling facility must be removed and its site must be reclaimed, pursuant to sections 43-02-03-34 and 43-02-03-34.1. A well not producing oil or natural gas in paying quantities for one year may be placed in abandoned-well status pursuant to subsection 1 of North Dakota Century Code section 38-08-04. If an injection well is inactive for extended periods of time, the commission may, after notice and hearing, require the injection well to be plugged and abandoned. If an underground gathering pipeline is inactive for seven years, the commission may, after notice and hearing, require the pipeline to be properly abandoned pursuant to sections 43-02-03-29 and 43-02-03-29.1.

2. The director may waive for one year the requirement to plug and reclaim an abandoned well by giving the well temporarily abandoned status for good cause. ~~This status may only be given to wells that are to be used for purposes related to the production of oil and gas within the next seven years.~~ If a well is given temporarily abandoned status, the well's perforations must be isolated, the integrity of its casing must be proven, and its casing must be sealed at the surface, all in a manner approved by the director. The director may extend a well's temporarily abandoned status and each extension may be approved for up to one year. A fee of one hundred dollars shall be submitted for each application to extend the temporary abandonment status of any well. A surface owner may request a hearing to review ~~of~~ a well temporarily abandoned for at least seven years pursuant to subsection 1 of North Dakota Century Code section 38-08-04. ~~This~~Temporarily abandoned status for oil and gas wells may only be given to wells that are to be used for purposes related to the production of oil and gas within the next seven years.

3. The director may approve an oil well for enhanced oil recovery potential status if the subject oil well was completed with surface casing set and cemented to properly isolate the Fox Hills formation, additional strings of casing are properly cemented to adequately protect and isolate all formations containing water, oil, or gas or any

combination of these, protect the pipe through salt sections encountered, and isolate the uppermost sand of the Dakota group, and the director has deemed the subject well to have a potential use in an enhanced oil recovery project. If a well is given enhanced oil recovery potential status, the well's perforations must be isolated, the integrity of its casing must be proven, and its casing must be sealed at the surface, all in a manner approved by the director. A surface owner may request a hearing to review a well that has been on enhanced oil recovery potential status for at least twelve years, pursuant to subsection 1 of North Dakota Century Code section 38-08-04.

~~3~~4. In addition to the waiver in subsection 2, the director may also waive the duty to plug and reclaim an abandoned well for any other good cause found by the director. If the director exercises this discretion, the director shall set a date or circumstance upon which the waiver expires.

~~4~~5. The director may approve suspension of the drilling of a well. If suspension is approved, a plug must be placed at the top of the casing to prevent any foreign matter from getting into the well. When drilling has been suspended for thirty days, the well, unless otherwise authorized by the director, must be plugged and its site reclaimed pursuant to sections 43-02-03-34 and 43-02-03-34.1.

History: Amended effective April 30, 1981; January 1, 1983; May 1, 1990; May 1, 1992; August 1, 1999; January 1, 2008; April 1, 2010; April 1, 2012; April 1, 2014; October 1, 2016; April 1, 2018; April 1, 2020; April 1, 2022; _________

General Authority	Law Implemented
NDCC 38-08-04	NDCC 38-08-04