TITLE 16 ECONOMIC REGULATION

PART 1 RAILROAD COMMISSION OF TEXAS

CHAPTER 3 OIL AND GAS DIVISION

§3.1 Organization Report; Retention of Records; Notice Requirements

(a) Filing requirements.

(1) Except as provided under subsection (e) of this section, no organization, including any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the Commission shall perform such operations without having on file with the Commission an approved organization report and financial security as required by Texas Natural Resources Code §§91.103 - 91.1091. Operations within the jurisdiction of the Commission include, but are not limited to, the following:

(A) drilling, operating, or producing any oil, gas, brine, geothermal resource, spent brine return injection, brine mining injection, fluid injection, or oil and gas waste disposal well;

(B) transporting, reclaiming, treating, processing, or refining crude oil, gas and products, brine resources, or geothermal resources and associated minerals;

(C) discharging, storing, handling, transporting, reclaiming, or disposing of oil and gas waste, including hauling salt water for hire by any method other than pipeline;

(D) operating gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance or repressurizing plants, or recycling plants;

(E) recovering skim oil from a salt water disposal site;

(F) nominating crude oil;

(G) operating a directional survey company;

(H) cleaning a reserve pit;

(I) operating a pipeline;

(J) operating as a cementer approved for plugging wells, operating as a cementer cementing casing strings or liners, or operating a well service company performing well stimulation activities, including hydraulic fracturing; or

(K) operating an underground hydrocarbon or natural gas storage facility.

(2) The Commission shall notify organizations that perform operations not included in paragraph (1)(A) - (K) of this subsection of any additional activities subject to the jurisdiction of the Commission which require the filing of the organization report. Such notification shall make the provisions of this section applicable to such activities.

(3) Each organization performing activities subject to the jurisdiction of the Commission shall maintain a current organization report with the Commission until all duties, obligations, and liabilities incurred pursuant to Commission rules, the Natural Resources Code, Titles 3 (Subtitles A, B, C, and Chapter 111 of Subtitle D) and 5, Texas Health and Safety Code, Chapter 401; Texas Utilities Code, §121.201, and the Water Code, Chapters 26, 27, and 29, are fulfilled.

(4) The organization report shall contain the following information:

(A) the name, street address, mailing address, telephone number, and emergency after-hours telephone number of the organization;

(B) the plan of the business organization;

(C) for each officer, director, general partner, owner of more than 25% ownership interest, or trustee (hereinafter controlling entity) of the organization:

(i) that entity's or individual's full legal name, the name(s) under which such entity or individual conducts business in the State of Texas, and all assumed names;

(ii) the following:

(I) if the entity is an individual, his or her social security number. Any individual who does not have a valid social security number shall submit, at that person's option, either his or her valid driver's license or Texas State Identification number;

(II) if the entity is not an individual, the name and, at that person's option, either the valid driver's license, social security, or Texas Identification number of each officer, director, or other person, who, under Texas Natural Resources Code, §91.114, holds a position of ownership or control of the organization, or an active P-5 number for that entity. All controlling entities connected to an organization which are not individuals shall provide the identification of the individuals in ownership or control of those entities.

(iii) a street address different than that of the organization; and

(iv) if different from the mailing address of the organization, a mailing address;

(D) if a foreign or nonresident organization, the name and street address of a resident agent.

(E) the name of any non-employee agent that the organization authorizes to act for the organization in signing Oil and Gas Division certificates of compliance which initially designate the operator or change the designation of the operator. Organizations may designate non-employee agents to execute subsequent organization reports. That designation shall be authorized by the organization and not by a non-employee agent.

(5) Any organization may designate a resident agent with a street address different than that of the organization in place of submitting the street addresses of the three (if applicable) primary controlling entities of the organization. Any foreign or nonresident organization identified in paragraph (1) of this subsection shall designate and maintain a resident agent upon whom may be served any process, notice, or demand required or permitted by law to be served upon such entity by or on behalf of the Commission. Failure of such organization to designate and maintain a resident agent shall render the organization report invalid. (Reference Order Number 20-60,617, effective January 1, 1971.)

(6) Failure by any organization identified in paragraph (1) of this subsection to answer any subpoena, commission to take deposition, or directive to appear at a hearing served upon such organization by or on behalf of the Commission shall render the organization report invalid.

(7) An organization shall refile an organization report annually according to the schedule assigned by the Commission. Prior to the filing date, the Commission shall mail notification and information to each organization for update of the organization report file. An organization shall file an amended organization report within 15 days

after a change in any information required to be reported in the organization report. Only address changes may be made by letter.

(8) The Commission shall meet any requirement under statute or Commission rule for an order to be sent or notice to be given by the Commission to an organization by mailing the item to the organization's mailing address shown on the most recently filed organization report or the most recently filed letter notification of change of address. Notices sent by regular first-class mail shall be presumed to have been received if, upon arrival of the deadline for any response to the notice, the wrapper containing the notice has not been returned to the Commission. Any Commission action or proceeding for which notice is required shall go forward on the basis of the notice provided under this subsection, whether or not actual notice has been received. Service of notices and orders sent by certified mail is effective upon:

(A) acceptance of the item by any person at the address;

(B) initial failure to claim or refusal to accept the item by any person at the address prior to its eventual return to the Commission by the United States Postal Service; or

(C) return of the item to the Commission by the United States Postal Service bearing a notation such as "addressee unknown," "no forwarding address," "forwarding order expired," or any similar notation indicating that the organization's mailing address shown on the most recently filed organization report or address change notification letter is incorrect.

(9) An organization may also designate to the Commission in writing a specified address for all Commission correspondence relating to a particular district. If designated by an operator, this specified address shall be used in lieu of the organization address for any notices, other than hearing notices, pertaining to that district.

(10) The Commission may return, unapproved, to the organization address an organization report which is submitted to the Commission not fully completed according to the report's written instructions and not timely corrected. In the event that the Commission returns an organization report, all submitted financial assurances shall remain non-refundable. If an organization report approved by the Commission is found to contain information that was materially false at the time it was submitted for approval, the Commission may suspend or revoke the organization report after notice and opportunity for hearing.

(b) Record requirements. All entities who perform operations which are within the jurisdiction of the Commission shall keep books showing accurate records of the drilling, redrilling, or deepening of wells, the volumes of crude oil on hand at the end of each month, the volumes of oil, gas, brine, and geothermal resources produced and disposed of, together with records of such information on leases or property sold or transferred, and other information as required by Commission rules and regulations in connection with the performance of such operations, which books shall be kept open for the inspection of the Commission or its representatives, and shall report such information as required by the Commission to do so.

(c) Time frame. All organizations shall keep copies of records, forms, and documents which are required to be filed with the Commission, along with the supporting documents referred to in subsection (b) of this section, for a period of three years, or longer if required by another Commission rule, and any such copies may be disposed of at the discretion of such entities after the original records, forms, and documents have been on file with the Commission for the required period, except that particular documents shall be retained beyond the required period and until the resolution of pending Commission regulatory enforcement proceedings if the documents contain information material to the determination of any issues therein. All records, forms, and documents required to be filed with the Commission shall be filed in the same name, exactly as it appears on the organization report.

(d) Organization reports for operators of inactive wells.

(1) The Commission or its delegate may approve the organization report for an operator of an inactive well if the Commission or its delegate has approved an extension of the deadline for plugging the inactive well.

(2) The Commission or its delegate may conditionally approve an organization report if:

(A) the operator assumed responsibility for a well that was inactive at the time of the approval of the operator designation form for the well; and

(B) the Commission or its delegate approved the operator designation form for the inactive well less than six months prior to the date the operator is required to renew its organization report.

(3) The Commission or its delegate may revoke conditional approval of an organization report granted under paragraph (2) of this subsection after notice of opportunity for hearing if the operator has failed to meet any of the following requirements within six months after approval of the operator designation form:

(A) restoration of the well to active status as defined by Commission rule;

(B) plugging of the well in compliance with a Commission rule or order; or

(C) obtaining the approval of the Commission or its delegate of an extension of the deadline for plugging an inactive well.

(e) Issuance of permits to organizations without active organization reports.

(1) Notwithstanding contrary provisions of this section, the Commission or its delegate may issue a permit to an organization or individual that does not have an active organization report or does not ordinarily conduct activities under the jurisdiction of the Commission when the issuance of such a permit is determined to be necessary to implement a compliance schedule, or to remedy circumstances or a violation of a Commission rule, order, license, permit, or certificate of compliance relating to safety or the prevention of pollution. For permits issued under this subsection, the Commission or its delegate may impose special conditions or terms not found in like permits issued pursuant to other Commission rules. Any organization or individual who requests such a permit shall file an organization report and any other required forms for record-keeping purposes only. The report or form shall contain all information ordinarily required to be submitted to the Commission or its delegate.

(2) This section shall not limit the Commission's authority to plug or to replug wells or to clean up pollution or unpermitted discharges of waste under the jurisdiction

of the Commission.

(f) Each organization required to file an organization report under subsection (a) of this section or an affiliate of such an organization that performs operations within the jurisdiction of the Commission that files for federal bankruptcy protection shall provide written notice to the Commission of that action not later than the 30th day after the date the organization or the affiliate files for bankruptcy protection by submitting the notice to the Enforcement Section of the Office of General Counsel. All bankruptcy-related notices sent to the Commission shall be submitted in writing to that section. For the purpose of this section, affiliate means an organization that is effectively controlled by another.

(g) Neither the Commission nor its delegate may approve an organization report unless the organization has complied with the state registration requirements of the Secretary of State. A tax dispute with the Comptroller of Public Accounts shall not be a basis for disapproving an organization report.

(h) Pursuant to Texas Natural Resources Code, §91.706(b), if an operator uses or reports use of a well for production, injection, or disposal for which the operator's certificate of compliance has been canceled, the Commission or its delegate may refuse to renew the operator's organization report required by Texas Natural Resources Code, §91.142, until the operator pays the fee required by §3.78(b)(8) of this title (relating to Fees and Financial Security Requirements) and the Commission or its delegate issues the certificate of compliance required for that well.

Source Note: The provisions of this §3.1 adopted to be effective January 1, 1976; amended to be effective January 1, 1981, 5 TexReg 4990; amended to be effective February 22, 1986, 11 TexReg 701; amended to be effective December 7, 1987, 12 TexReg 4411; amended to be effective July 22, 1991, 16 TexReg 3767; amended to be effective July 1, 1992, 17 TexReg 4173; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective January 11, 2004, 29 TexReg 359; amended to be effective November 26, 2007, 32 TexReg 8452; amended to be effective September 13, 2010, 35 TexReg 8332; amended to be effective August 27, 2012, 37 TexReg 6538; amended to be effective February 18, 2025, 50 TexReg 835.

§3.2 Commission Access to Properties

(a) The commission or its representatives shall have access to come upon any lease or property operated or controlled by an operator, producer, or transporter of oil, gas, or geothermal resources, and to inspect any and all leases, properties, and wells and all records of said leases, properties, and wells.

(b) Designated agents of the commission are authorized to make any tests on any well at any time necessary for conservation regulation, and the owner of such well is hereby directed to do all things that may be required of him by the commission's agent to make such tests in a proper manner.

Source Note: The provisions of this §3.2 adopted to be effective January 1, 1976; amended to be effective January 30, 2007, 32 TexReg 287.

§3.3 Identification of Properties, Wells, and Tanks

Each property that produces oil, gas, or geothermal resources and each oil, gas, or geothermal resource well and tank, or other approved crude oil measuring facility where tanks are not utilized thereon, shall at all times be clearly identified as follows.

(1) A sign shall be posted at the principal entrance to each such property which shall show the name by which the property is commonly known and is carried on the records of the commission, the name of the operator, and the number of acres in the property.

(2) A sign shall be posted at each well site which shall show the name of the property, the name of the operator, and the well number.

(3) A sign shall be posted at or painted on each oil stock tank and on each remotely located satellite tank, or on each approved crude oil measuring facility where tanks are not utilized, that is located on or serving each property, which signs shall show, in addition to the information provided for in paragraph (1) of this section, the commission lease number for the formation from which oil in the tank, or in an approved crude oil measuring facility, is produced, and where oil from more than one formation is commingled in the same tank, or in an approved crude oil measuring facility, the sign shall show the number of the commission permit that authorized the commingling of the oil; provided that, if there is more than one tank in a battery which contains oil from only one formation or oil from different formations that is commingled pursuant to a single commingling permit, it will not be necessary for the sign to be posted at or painted on each tank if the sign posted at or painted on a tank in the battery shows the required information and clearly identifies, by tank number or otherwise, the tanks to which the information is applicable.

(4) If a well is separately completed in two or more producing formations, the wellhead valve and flow line serving each separate formation shall be identified by a metal tag or other lettering attached to or painted on either the valve or flow line which shows the name of the formation and identifies the completion string of casing or tubing, as for example "C" for casing; "UT" for upper tubing; "LT" for lower tubing, etc., each being preceded or followed by the name of the producing formation.

(5) The signs and identification required by this section shall be in the English language, clearly legible, and in the case of the signs required by paragraphs (1), (2), and (3) of this section shall be in letters and numbers at least one inch in height.

Source Note: The provisions of this §3.3 adopted to be effective January 1, 1976.

§3.4 Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms

(a) Lease name and number.

(1) All operators with oil and geothermal producing properties must ascertain from the appropriate proration schedule the lease number assigned to each separate lease, and thereafter include on each commission-required form or report the exact lease name and its number as they

appear on the current proration schedule for all leases.

(2) No commission-required form or report will be accepted until the form or report is properly completed, including both the lease name and lease number applicable thereto.

(3) If a lease has not been issued a lease number on the current proration schedule, the lease shall have assigned to it the exact lease name as shown on the form first submitted, and in addition thereto a lease number will be assigned at the same time the form reflecting the potential test is submitted and processed. Subsequent to the assignment of a lease number, such number together with the exact lease name as submitted on the appropriate form must appear on all future forms and reports submitted to the commission, the lease number and lease name as assigned by the commission to be evidenced to the operator on the face of the supplement establishing the allowable for the lease.

(b) Gas well identification numbers shall be assigned by the commission for each separate gas well completion, and such gas well identification number shall be used on all forms and reports required by and filed with the commission concerning operations for such well so long as it remains a gas well, such commission gas well identification number to be effective as provided in the following paragraphs.

(1) All operators having a gas well must ascertain from the appropriate current gas allowable schedule the commission gas well identification number assigned to each separate gas well completion, and thereafter include on each commission required form or report its exact well lease name and number and its commission gas well identification number as they appear on the current gas allowable schedule for all gas wells completed in the same reservoir.

(2) No commission-required form or report will be accepted until the form or report is properly completed, including both the well lease name and number and the commission gas well identification number applicable thereto.

(3) If a gas well has not been assigned a gas well identification number on the current gas allowable schedule, such well shall have assigned to it the exact well lease name and number as shown on the appropriate form and, in addition thereto, a gas well identification number will be assigned at the time the commission-required form is submitted and processed. After the assignment of a gas well identification number, such number together with the exact well lease name and number on the form first submitted, must appear on all future forms and reports submitted to the commission, the gas well lease name and gas well identification number as assigned by the commission to be evidenced to the operator on the face of the supplement establishing the initial allowable for such well.

Source Note: The provisions of this §3.4 adopted to be effective January 1, 1976.

§3.5 Application To Drill, Deepen, Reenter, or Plug Back

(a) Requirements for spacing, density, and units. An application for a permit to drill, deepen, plug back, or reenter any oil well, gas well, brine production well, or geothermal resource well shall be made under the provisions of §§3.37, 3.38, 3.39, 3.40, and/or 3.82 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; Assignment of Acreage to Pooled Development and Proration Units; and Brine Production Projects and Associated Brine Production Wells and Class V Spent Brine Return Injection Wells) (Statewide Rules 37, 38, 39, 40, and 82), or as an exception thereto, or under special rules governing any particular oil, gas, brine, or geothermal resource field or as an exception thereto and filed with the commission on a form approved by the commission. An application must be accompanied by any relevant information, form, or certification required by the Railroad Commission or a commission representative necessary to determine compliance with this rule and state law.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Application--Request by an organization made either on the prescribed form or electronically pursuant to procedures for electronic filings adopted by the commission for a permit to drill, deepen, plug back, or reenter any oil well, gas well, brine production well, or geothermal resource well.

(2) Commission--The Railroad Commission of Texas.

(3) Commission representative--A commission employee authorized to act for the commission. Any authority given to a commission representative is also retained by the commission. Any action taken by the commission representative is subject to review by the commission.

(c) Commencement of operations. Operations of drilling, deepening, plugging back, or reentering shall not be commenced until the permit has been granted by the commission and the waiting period, if any, has terminated, or authorization has been granted pursuant to subsection (d) of this section.

(d) Testing of existing wells in other reservoirs inside the casing. For an existing well, an operator may request authorization to commence operations to deepen inside the casing or plug back prior to the granting of a permit to deepen or plug back.

(1) This authorization shall be requested by submitting a request with the district office to deepen inside the casing or plug back. The request shall include:

(A) the operator name;

(B) the lease name;

(C) the lease number or gas identification number;

(D) well number;

(E) county;

(F) field name;

(G) a list of all reservoir(s) to be tested;

(H) the casing setting depth and the depth of the deepest reservoir to be tested;

(I) a plat showing the well location; and

(J) a statement as to whether or not the well location would require an exception to §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40) if completed in any of the reservoirs to be tested. If an exception would be required, the request shall also include a statement that all affected offsets have been given written notice of the intent to test with the opportunity to witness the testing and the offsets shall be identified on the plat.

(2) Operations of deepening inside the casing or plugging back shall not be commenced until the district office has reviewed and approved the request. Testing pursuant to this authorization shall be completed within 90 days from the date the district office approves the request.

(A) No reservoir tested pursuant to the provisions of this subsection shall be tested for more than 15 days.

(B) If the operator desires to place the well on production, the operator shall shut in the well, with no production being sold, and file a permit application for the tested reservoirs with the appropriate fees. If the permit application for the tested reservoirs requires an exception to §§3.37, 3.38, 3.39, and/or 3.40 of this title (relating to Statewide Spacing Rule; Well Densities; Proration and Drilling Units: Contiguity of Acreage and Exception Thereto; and Assignment of Acreage to Pooled Development and Proration Units) (Statewide Rules 37, 38, 39, and 40), no consideration will be given by the commission to the cost of recompleting and testing the well in determining whether or not to grant the exception.

(C) Within 30 days of completion of testing, the operator must either file an application for a permit to produce a reservoir tested pursuant to this subsection or file an amended completion report in accordance with §3.16 of this title (relating to Log and Completion or Plugging Report) (Statewide Rule 16) with a copy of the request signed by the district office and a statement that a permit to produce a tested reservoir is not being sought, or if the well has been plugged and abandoned, a plugging report including reservoir and perforation data. If a permit is not obtained for the tested reservoirs and/or an allowable is not assigned, the producer shall report all test production on Form PR, Monthly Production Report, filed for the last permitted reservoir in which the well was completed and may request authorization to sell the test production. The test production may be sold after such authorization is granted.

(e) Exploratory and specialty wells. An application for any exploratory well or cathodic protection well that penetrates the base of the fresh water strata, fluid injection well, injection water source well, disposal well, brine production well, brine solution mining well, spent brine return injection well, or underground hydrocarbon storage well shall be made and filed with the commission on a form approved by the commission. Operations for drilling, deepening, plugging back, or reentering shall not be commenced until the permit has been granted by the commission. For an exploratory well, an exception to filing such form prior to commencing operations may be obtained if an application for a core hole test is filed with the commission.

(f) Drilling permit fee. With each application or materially amended application, the applicant shall submit to the commission a nonrefundable fee as determined by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78).

(g) Expiration. Any permit to drill, deepen, plug back, or reenter granted by the commission expires no later than two years after the date of original approval.

(h) Plats. An application to drill, deepen, plug back, or reenter shall be accompanied by a neat, accurate plat, with a scale of one inch equals 1,000 feet. The plat for the initial well on the lease, pooled unit, or unitized tract shall show the entire lease, pooled unit, or tract, including all tracts being pooled. If necessary to show the entire lease, the scale may be one inch equals 2,000 feet. Plats for subsequent wells on a lease or pooled unit shall show at least the lease or pooled unit line nearest the proposed location and the nearest survey/section lines. The Division Director or the director's delegate may approve plats with other scales upon request.

(1) The lease shall be outlined on the plat using either a heavy line or crosshatching.

(2) For vertical wells, the plat shall include the following:

(A) the surface location of the proposed drilling site;

(B) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the surface location;

(C) perpendicular lines providing the distance in feet from the two nearest non-parallel lease lines to the surface location;

(D) a line providing the distance in feet from the surface location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

(E) a line providing the distance in feet from the surface location to the nearest oil, gas, or oil and gas well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir;

(F) the geographic location information, including the Latitude/Longitude or X/Y coordinates in the NAD 27, NAD 83, or WGS 84 coordinate system;

(G) a labeled scale bar; and

(H) northerly direction.

(3) For horizontal wells, the plat shall include the following:

(A) the surface location of the proposed drilling site, penetration point, first take point, last take point, and terminus location;

(B) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the surface location;

(C) perpendicular lines providing the distance in feet from the two nearest non-parallel lease lines to the surface location; if location is offlease, then provide the distance in feet from the two nearest non-parallel survey/section lines to the surface location;

(D) a line providing the distance in feet from the horizontal wellbore between and including the penetration point and the terminus location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be indicated. A line providing the distance in feet from the horizontal wellbore between and including the first take point and the last take point to the nearest point on the lease line shall be indicated. If there are multiple leases, pooled units and/or unitized tracts closer to the horizontal course(s) of the drainhole(s) than allowed by the applicable spacing rule, then the operator shall provide the distance in feet from the closest take point to each such tract;

(E) a line providing the distance in feet from the wellbore from the penetration point through the terminus location to the nearest oil, gas, or oil and gas well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir. A line providing the distance in feet from the wellbore between and including the first take point and the last take point to the nearest oil, gas, or oil and gas well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir;

(F) the geographic location information for the surface location of the well, including the Latitude/Longitude or X/Y coordinates in the NAD 27, NAD 83, or WGS 84 coordinate system;

(G) a labeled scale bar; and

(H) northerly direction.

(4) Requirements for plats as provided for in §3.11, §3.37, §3.38, and §3.86 of this title (relating to Inclination and Directional Surveys Required, Statewide Spacing Rule, Well Densities, and Horizontal Drainhole Wells) may supplement or replace the plat requirements set out above.

Source Note: The provisions of this §3.5 adopted to be effective January 1, 1976; amended to be effective September 1, 1983, 8 TexReg 3184; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective October 30, 1986, 11 TexReg 4214; amended to be effective February 24, 1992, 17 TexReg 1225; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective February 1, 2016, 41 TexReg 785; amended to be effective February 18, 2025, 50 TexReg 835.

§3.6 Application for Multiple Completion

(a) Authority will be granted to multicomplete a well in separate reservoirs that are not in communication without the necessity of notice and hearing on each separate application; provided, that an application for multiple completion on the form prescribed and the required accompanying data, as hereafter listed, is filed with the Engineering unit of the Commission's Permitting and Production Section for its consideration and approval.

(b) If the proposed zones of completion are not presently recognized by the commission as being acceptable for multicompletion approval, all data necessary to substantiate a conclusion by the commission that the proposed zones of completion are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein must be filed with the application.

(c) If the additional data furnished with the application is not considered by the commission to be sufficient to establish the proposed zones of completion as separate zones of production which are feasible and reasonably susceptible of having multicompleted and producing wells drilled thereto and therein, or if any party protests such an application, then, if an operator so elects, his application will be set for hearing.

(d) Multiple completion authority for a well will not be granted unless the following required data have been filed with the Engineering unit of the Commission's Permitting and Production Section:

(1) application for multiple completion properly executed and attested;

(2) electrical log or portion of the electric log of the well or a type electric log or a portion of the type electric log showing clearly thereon the subsurface location of the separate reservoirs claimed. Any electric log filed will be considered public information pursuant to §3.16 of this title (relating to Log and Completion Report (Statewide Rule 16);

(3) packer setting report where applicable;

(4) packer leakage test or communication test;

(5) diagrammatic sketch of the mechanical installation;

(6) letters of waiver from offset operators, or evidence that notice of application to multicomplete was given to said operators.

Source Note: The provisions of this §3.6 adopted to be effective January 1, 1976; amended to be effective February 28, 1986, 11 TexReg 545; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.7 Strata To Be Sealed Off

Whenever hydrocarbon, brine or geothermal resource fluids are encountered in any well drilled for oil, gas, brine, or geothermal resources in this state, such fluid shall be confined in its original stratum until it can be produced and utilized without waste. Each such stratum shall be adequately protected from infiltrating waters. Wells may be drilled deeper after encountering a stratum bearing such fluids if such drilling shall be prosecuted with diligence and any such fluids be confined in its stratum and protected as aforesaid upon completion of the well. The commission will require each such stratum to be cased off and protected, if in its discretion it shall be reasonably necessary and proper to do so.

Source Note: The provisions of this §3.7 adopted to be effective January 1, 1976; amended to be effective February 18, 2025, 50 TexReg 835.

§3.8 Water Protection

Effective July 1, 2025, the requirements of this section are incorporated in Chapter 4 of this title (relating to Environmental Protection), specifically Subchapter A (relating to Oil and Gas Waste Management).

Source Note: The provisions of this §3.8 adopted to be effective January 1, 1976; amended to be effective February 10, 1977, 2 TexReg 359; amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective May 1, 1984, 9 TexReg 1549; amended to be effective March 15, 1986, 11 TexReg 950; amended to be effective January 6, 1987, 11 TexReg 5091; amended to be effective December 1, 1987, 12 TexReg 4188; amended to be effective January 28, 1992, 17 TexReg 321; amended to be effective February 1, 1995, 19 TexReg 10345; amended to be effective October 25, 1995, 20 TexReg 8442; amended to be effective April 1, 1996, 20 TexReg 9423; amended to be effective July 10, 2000, 25 TexReg 6487; amended tobe *effective September 1, 2004, 29 TexReg 8271; amended to be effective April 15, 2013, 38 TexReg 2318; amended to be effective July 1, 2025, 50 TexReg 33.*

§3.9 Disposal Wells

Any person who disposes of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be responsible for complying with this section, Texas Water Code, Chapter 27, and Title 3 of the Natural Resources Code.

(1) General. Saltwater or other oil and gas waste, as that term is defined in the Texas Water Code, Chapter 27, may be disposed of, upon application to and approval by the commission, by injection into nonproducing zones of oil, gas, or geothermal resources bearing formations that contain water mineralized by processes of nature to such a degree that the water is unfit for domestic, stock, irrigation, or other general uses. Every applicant who proposes to dispose of saltwater or other oil and gas waste into a formation not productive of oil, gas, or geothermal resources must obtain a permit from the commission authorizing the disposal in accordance with this section. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(2) Geological requirements. Before such formations are approved for disposal use, the applicant shall show that the formations are separated from freshwater formations by impervious beds which will give adequate protection to such freshwater formations. The applicant must submit a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating that the use of such formation will not endanger the freshwater strata in that area and that the formations to be used for disposal are not freshwater-bearing.

(3) Application.

(A) The application to dispose of saltwater or other oil and gas waste by injection into a porous formation not productive of oil, gas, or geothermal resources shall be filed with the commission in Austin accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office.

(B) The applicant for a disposal well permit under this section shall include with the permit application a printed copy or screenshot showing the results of a survey of information from the United States Geological Survey (USGS) regarding the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed disposal well location.

(C) The commission may require an applicant for a disposal well permit under this section to provide the commission with additional information such as logs, geologic cross-sections, pressure front boundary calculations, and/or structure maps, to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval. Such conditions may include, but are not limited to, complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events in the area as demonstrated by information available from the USGS.

(4) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the published notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(5) Notice and opportunity for hearing.

(A) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one-half mile of the proposed disposal well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the municipal boundaries of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(B) In addition to the requirements of subsection (a)(5)(A) of this section, a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed disposal tract by mailing or delivering a copy of the application to each such surface owner.

(C) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water districts.

(D) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(E) Protested applications:

(i) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(ii) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(F) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) Subsequent commission action.

(A) A permit for saltwater or other oil and gas waste disposal may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(i) a material change of conditions occurs in the operation or completion of the disposal well, or there are material changes in the information originally furnished;

(ii) freshwater is likely to be polluted as a result of continued operation of the well;

(iii) there are substantial violations of the terms and provisions of the permit or of commission rules;

(iv) the applicant has misrepresented any material facts during the permit issuance process;

(v) injected fluids are escaping from the permitted disposal zone;

(vi) injection is likely to be or determined to be contributing to seismic activity; or

(vii) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(B) A disposal well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on Commission records.

(C) Voluntary permit suspension.

(i) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of paragraph (12)(D) of this section. The provisions of this subparagraph shall not apply to any well that is permitted as a commercial disposal well.

(ii) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under clause (i) of this subparagraph indicate that the well meets the performance standards of paragraph (12)(D) of this section.

(iii) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(iv) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of paragraph (12)(D) of this section or the permit. Further, during the period of permit suspension, the provisions of paragraph (11)(A) - (C) of this section shall not apply.

(v) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of paragraph (12)(D) of this section.

(7) Area of Review.

(A) Except as otherwise provided in this paragraph, the applicant shall review the date of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(B) The commission or its delegate may grant a variance from the area-of-review requirements of subparagraph (A) of this paragraph upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(i) the area affected by pressure increases resulting from injection operations;

(ii) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(iii) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(C) Persons applying for a variance from the area-of-review requirements of subparagraph (A) of this paragraph on the basis of factors set out in subparagraph (B)(ii) or (iii) of this paragraph for an individual well shall provide notice of the application to those persons given notice under the provisions of paragraph (5)(A) of this subsection. The provisions of paragraph (5)(D) and (E) shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(D) Notice of an application for an areal variance from the area-of-review requirements under subparagraph (A) of this paragraph shall be given on or before the date the application is filed with the commission:

(i) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(ii) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date of the application is filed with the commission, to the following:

(I) the manager of each underground water conservation district(s) in which the variance would apply, if any;

(II) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(III) the county clerk of each county in which the variance would apply; and

(IV) any other person or persons that the commission or its delegate determine should receive notice of the application.

(E) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(F) An areal variance granted under the provisions of this paragraph may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under subparagraph (A) of this paragraph pending issuance of a final order.

(8) Casing. Disposal wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, geothermal resources, or freshwater resources.

(9) Special equipment.

(A) Tubing and packer. Wells drilled or converted for disposal shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 100 feet above the top of the permitted interval. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

(B) Pressure valve. The wellhead shall be equipped with a pressure observation valve on the tubing and for each annulus of the well.

(C) Exceptions. The director may grant an exception to any provision of this paragraph upon proof of good cause. If the director denies an exception, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(10) Well record. Within 30 days after the completion or conversion of a disposal well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.

(11) Monitoring and reporting.

(A) The operator shall monitor the injection pressure and injection rate of each disposal well on at least a monthly basis, or on a more frequent basis as required by the commission under conditions described in paragraph (3)(C) of this section.

(B) The results of the monitoring shall be reported annually to the commission on the prescribed form, or on a more frequent basis as required by the commission under conditions described in paragraph (3)(C) of this section.

(C) All monitoring records shall be retained by the operator for at least five years.

(D) The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.

(12) Testing.

(A) Purpose. The mechanical integrity of a disposal well shall be evaluated by conducting pressure tests to determine whether the well tubing, packer, or casing have sufficient mechanical integrity to meet the performance standards of this rule, or by alternative testing methods under subparagraph (E) of this paragraph.

(B) Applicability. Mechanical integrity of each disposal well shall be demonstrated in accordance with provisions of subparagraph (D) and subparagraph (E) of this paragraph prior to initial use. In addition, mechanical integrity shall be tested periodically thereafter as described in subparagraph (C) of this paragraph.

(C) Frequency.

(i) Each disposal well completed with surface casing set and cemented through the entire interval of protected usable-quality water shall be tested for mechanical integrity at least once every five years.

(ii) In addition to testing required under clause (i), each disposal well shall be tested for mechanical integrity after every workover of the well.

(iii) A disposal well that is completed without surface casing set and cemented through the entire interval of protected usable-quality ground water shall be tested at the frequency prescribed in the disposal well permit.

(iv) The commission or its delegate may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with the requirements in clauses (i) and (ii) of this subparagraph. Such testing schedule shall not apply to a disposal well for which a disposal well permit has been issued but the well has not been drilled or converted to disposal.

(D) Pressure tests.

(i) Test pressure.

(I) The test pressure for wells equipped to dispose through tubing and packer shall equal the maximum authorized injection pressure or 500 psig, whichever is less, but shall be at least 200 psig.

(II) The test pressure for wells that are permitted for disposal through casing shall equal the maximum permitted injection pressure or 200 psig, whichever is greater.

(ii) Pressure stabilization. The test pressure shall stabilize within 10% of the test pressure required in clause (i) of this subparagraph prior to commencement of the test.

(iii) Pressure differential. A pressure differential of at least 200 psig shall be maintained between the test pressure on the tubing-casing annulus and the tubing pressure.

(iv) Test duration. A pressure test shall be conducted for a duration of 30 minutes when the test medium is liquid or for 60 minutes when the test medium is air or gas.

(v) Pressure recorder. Except for tests witnessed by a commission representative or wells permitted for disposal through casing, a pressure recorder shall be used to monitor and record the tubing-casing annulus pressure during the test. The recorder clock shall not exceed 24 hours. The recorder scale shall be set so that the test pressure is 30 to 70% of full scale, unless otherwise authorized by the commission or its delegate.

(vi) Test fluid.

(I) The tubing-casing annulus fluid used in a pressure test shall be liquid for wells that inject liquid unless the commission or its delegate authorizes the use of a different test fluid for good cause.

(II) The tubing-casing annulus fluid used in a pressure test shall contain no additives that may affect the sensitivity or otherwise reduce the effectiveness of the test.

(vii) Pressure test results. The commission or its delegate will consider, in evaluating the results of a test, the level of pollution risk that loss of well integrity would cause. Factors that may be taken into account in assessing pollution risk include injection pressure, frequency of testing and monitoring, and whether there is sufficient surface casing to cover all zones containing usable-quality water. A pressure test may be rejected by the commission or its delegate after consideration of the following factors:

(I) the degree of pressure change during the test, if any;

(II) the level of risk to usable-quality water if mechanical integrity of the well is lost; and

(III) whether circumstances surrounding the administration of the test make the test inconclusive.

(E) Alternative testing methods.

(i) As an alternative to the testing required in subparagraph (B) of this paragraph, the tubing-casing annulus pressure may be monitored and included on the annual monitoring report required by paragraph (11) of this section, with the authorization of the commission or its delegate and provided that there is no indication of problems with the well. Wells that are approved for tubing-casing annulus monitoring under this paragraph shall be tested in the manner provided under subparagraph (B) of this paragraph at least once every ten years after January 1, 1990.

(ii) The commission or its delegate may grant an exception for viable alternative tests or surveys or may require alternative tests or surveys as a permit condition.

(F) The operator shall notify the appropriate district office at least 48 hours prior to the testing. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

(G) A complete record of all tests shall be filed in duplicate in the district office on the appropriate form within 30 days after the testing.

(H) In the case of permits issued under this section prior to the effective date of this amendment which require pressure testing more frequently than once every five years, the commission's delegate may, by letter of authorization, reduce the required frequency of pressure tests, provided that such tests are required at least once every three years. The commission shall consider the permit to have been amended to require pressure tests at the frequency specified in the letter of authorization.

(13) Plugging. Disposal wells shall be plugged upon abandonment in accordance with §3.14 of this title (relating to Plugging).

(14) Penalties.

(A) Violations of this section may subject the operator to penalties and remedies specified in the Texas Water Code, Chapter 27, and the Natural Resources Code, Title 3.

(B) The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certification of Compliance; Severance) for violation of this section.

Source Note: The provisions of this §3.9 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective April 1, 1982, 7 TexReg 651; amended to be effective December 4, 1996, 21 TexReg 11361; amended to be effective August 4, 1998, 23 TexReg 7768; amended to be effective December 28, 1999, 24 TexReg 11711; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective November 17, 2014, 39 TexReg 8988.

§3.10 Restriction of Production of Oil and Gas from Different Strata

(a) General prohibition. Oil or gas shall not be produced from different strata through the same string of tubulars except as provided in this section. As used in this section, "different strata" means two or more different commission-designated fields, or one or more commission-designated fields and any other hydrocarbon reservoir.

(b) Exception. After notice and an opportunity for a hearing, the commission or its delegate may grant an exception to subsection (a) of this section to permit production from a well or wells commingling oil or gas or oil and gas from different strata, if commingled production will prevent waste or promote conservation or protect correlative rights.

(c) Notice of Application for Exception.

(1) Timing of Notice.

(A) The applicant shall give notice of each request for an exception by serving a copy of the application to commingle production on all affected operators at the same time the application is filed with the commission.

(B) Service shall be accomplished by delivering a copy of the application to the operator to be served, or to the operator's duly authorized representative, in person, by agent, by courier receipted delivery, by first class mail to the operator's mailing address as shown on the operator's most recently filed Form P-5 (Organization Report) or the most recently filed letter notification of change of address, or by such other manner as the commission may direct.

(2) Operators Presumptively Affected By Application.

(A) An initial exception to commingle production exclusively from different commission-designated fields is presumed to affect all operators in each of the commission-designated fields proposed to be produced through the same string of tubulars.

(B) An initial exception to commingle production from a commission-designated field with production from one or more hydrocarbon reservoirs that have not been designated by the commission as a field is presumed to affect all operators in each of the different commission-designated fields proposed to be produced through the same string of tubulars and all operators of adjacent tracts, and of tracts nearer to the well for which a commingling exception is sought than the longest applicable minimum lease-line distance.

(C) An exception to commingle production exclusively from the same commission-designated fields for which an initial commingling application has previously been granted is presumed to affect all operators of adjacent tracts, and of tracts nearer to the well for which a subsequent commingling exception is sought than the longest applicable minimum lease-line distance, who have a well completed in one or more of the commission-designated fields for which commingling is sought.

(D) An exception to commingle production from a commission-designated field and one or more hydrocarbon reservoirs in specified correlative intervals that have not been designated by the commission as fields, for which an initial commingling exception involving the same fields and hydrocarbon reservoirs has previously been granted, is presumed to affect all operators of adjacent tracts, and of tracts nearer to the well for which a commingling exception is sought than the longest applicable minimum lease-line distance.

(3) Notice Required Only to Affected Operators.

(A) Except as provided in subparagraph (B) of this paragraph, all operators described in paragraph (2)(A) - (D) of this subsection are affected by a requested exception to allow commingling and the applicant shall give each of them notice of the application as provided in paragraph (1)(A) of this subsection.

(B) The commission or its delegate may determine that an operator described in paragraph (2)(A) - (D) will be unaffected by a requested exception to allow commingling. This determination shall be made only upon the applicant's written request and provision to the commission of competent geological or engineering data establishing conclusively that commingling production as requested by the applicant will not physically interfere with the production of hydrocarbons by the operator for which an unaffected determination is requested. An applicant for an exception to allow commingling is not required to give notice of the application to an operator who has been determined to be unaffected as provided in this subparagraph.

(d) Commingled production. Commingled production of gas from different strata pursuant to subsection (b) of this section shall be considered production from a common source of supply for purposes of proration and allocation.

Source Note: The provisions of this §3.10 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective September 12, 1979, 4 TexReg 3082; amended to be effective May 14, 1996, 21 TexReg 3791.

§3.11 Inclination and Directional Surveys Required

(a) General. All wells shall be drilled as nearly vertical as possible by normal, prudent, practical drilling operations. Nothing in this section shall be construed to permit the drilling of any well in such a manner that the wellbore crosses lease and/or property lines (or unit lines in cases of pooling) without special permission.

(b) Inclination surveys.

(1) Requirements.

(A) An inclination survey made by persons or concerns approved by the commission shall be filed on a form prescribed by the commission for each well drilled or deepened with rotary tools, except as hereinafter provided, or when, as a result of any operation, the course of the well is changed. The first shot point of such inclination survey shall be made at a depth not greater than 500 feet below the surface of the ground, and succeeding shot points shall be made either at 500-foot intervals or at the nearest drill bit change thereto, but not to exceed 1,000 feet apart.

(B) Inclination surveys conforming to these requirements may be made either during the normal course of drilling or after the well has reached total depth. Acceptable directional surveys may be filed in lieu of inclination surveys.

(C) Copies of all directional or inclination surveys, regardless of the reason for which they are run, shall be filed as a part of or in addition to the inclination surveys otherwise required by this section. If computations are made from dipmeter surveys to determine the course of the wellbore in any portion of the surveyed interval, a report of such computations shall be required.

(D) Inclination surveys shall not be required in any well drilled to a total depth of 2,000 feet or less on a regular location at least 150 feet from the nearest lease line, provided the well is not intentionally deviated from the vertical in any manner whatsoever.

(E) Inclination surveys shall not be required on wells deepened with rotary tools if the well is deepened no more than 300 feet or the distance from the surface location to the nearest lease or boundary line, whichever is the lesser, and provided that the well was not intentionally deviated from the vertical at any time before or after the beginning of deepening operations.

(F) Inclination surveys will not be required on wells that are drilled and completed as dry holes and are permanently plugged and abandoned. If such wells are reentered at a later date and completed as producers or injection or disposal wells, inclination reports will be required and must be filed with the appropriate completion form for the well.

(G) Inclination survey filings will not be required on wells that are reentries within casing of previously producing wells if inclination data are already on file with the Railroad Commission of Texas (commission). If such data are not on file with the commission, the results of an inclination survey must be reported on the appropriate form and filed with the completion form, except as provided by subparagraph (D) of this paragraph.

(2) Reports.

(A) The report form shall be signed and certified by a party having personal knowledge of the facts therein contained. The report shall include a tabulation of the maximum drifts which could occur between the surface and the first shot point, and each two successive shot points, assuming that all of the unsurveyed hole between any two shot points has the same inclination as that measured at the lowest shot point, and the total possible accumulative drift, assuming that all measured angles of inclination are in the same direction.

(B) In addition, the report shall be accompanied by a certified statement of the operator, or of someone acting at his direction on his behalf, either:

(i) that the well was not intentionally deviated from vertical; or

(ii) that the well was deviated at random, with an explanation of the circumstances.

(C) The report shall be filed in the district office by attaching one copy to each appropriate completion form for the well.

(D) The commission may require the submittal of the original charts, graphs, or discs resulting from the surveys.

(c) Directional surveys.

(1) When required.

(A) When the maximum displacement indicated by an inclination survey is greater than the actual distance from the surface location to the nearest lease line or pooled unit boundary, it will be considered to be a violating well subject to plugging and to penalty action. However, an operator may submit a directional survey, run at his own expense by a commission approved surveying company, to show the true bottom hole location of the well to be within the prescribed limits. When such directional survey shows the well to be bottomed within the confines of the lease, but nearer to a well or lease line or pooled unit boundary than allowed by applicable rules, or by the permit for the well if the well has been granted an exception to §3.37 of this title (relating to Statewide Spacing Rule), a new permit will be required if it is established that the bottom hole location or completion location is not a reasonable location.

(B) Directional surveys shall be required on each well drilled under the directional deviation provisions of this section.

(C) No oil, gas, or geothermal resource allowable shall be assigned any well on which a directional survey is required under any provision of this section until a directional survey has been filed with and accepted by the commission.

(2) Filing and type of survey.

(A) Directional surveys required under this section must be run by competent surveying companies, approved by the commission, signed and certified by a person having actual knowledge of the facts, in the manner prescribed by the commission in accordance with §3.12 of this title (relating to Directional Survey Company Report).

(B) All directional surveys, unless otherwise specified by the commission, shall be either single shot surveys or multi-shot surveys with the shot points not more than 200 feet apart, beginning within 200 feet of the surface, and the bottom hole location must be oriented both to the surface location and to the lease lines (or unit lines in cases of pooling).

(C) If more than 200 feet of surface casing has been run, the operator may begin the directional survey immediately below the surface casing depth. However, if such method is used, the inclination drifts from the surface of the ground to the surface casing depth must be added cumulatively and reported on the appropriate form. This total shall be assumed to be in the direction least favorable to the operator, and such point shall be considered the starting point of the directional survey.

(d) Intentional deviation of wells.

(1) Definitions.

(A) Directional deviation--The intentional deviation of a well from vertical in a predetermined compass direction.

(B) Random deviation--The intentional deviation of a well without regard to compass direction for one of the following reasons:

(i) to straighten a hole which has become crooked in the normal course of drilling;

(ii) to sidetrack a portion of a hole because of mechanical difficulty in drilling.

(2) When permitted.

(A) Directional deviation. A permit for directionally deviating a well may be granted by the commission:

(i) for the purpose of seeking to reach and control another well which is out of control or threatens to evade control;

(ii) where conditions on the surface of the ground prevent or unduly complicate the drilling of a well at a regular location;

(iii) where conditions are encountered underground which prevent or unduly hinder the normal completion of the well;

(iv) where it can be shown to be advantageous from the standpoint of mechanical operation to drill more than one well from the same surface location to reach the productive horizon at essentially the same positions as would be reached if the several wells were normally drilled from regular locations prescribed by the well spacing rules in effect;

(v) for the purpose of drilling a horizontal drainhole; or

(vi) for other reasons found by the commission to be sufficient after notice and hearing.

(B) Random deviation. Permission for the random deviation of a well may be granted by the commission whenever the necessity for such deviation is shown, as prescribed in paragraph (3)(C) of this subsection.

(3) Applications for deviation.

(A) Applications for wells to be directionally deviated must specify on the application to drill both the surface location of the well and the projected bottom hole location of the well. On the plat, in addition to the plat requirements provided for in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the following shall be included:

(i) two perpendicular lines providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest points on the lease, pooled unit, or unitized tract line. If there is an unleased interest in a tract of the pooled unit or unitized tract that is nearer than the pooled unit or unitized tract line, the nearest point on that unleased tract boundary shall be used;

(ii) a line providing the distance in feet from the projected bottomhole location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

(iii) a line providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest oil, gas, or oil and gas well, identified by number, applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir; and

(iv) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the projected bottomhole location.

(B) If the necessity for directional deviation arises unexpectedly after drilling has begun, the operator shall give written notice by letter or telegram of such necessity to the appropriate district office and to the commission office in Austin, and upon giving such notice, the operator may proceed with the directional deviation. The commission may, at its discretion, accept written notice electronically transmitted. If the operator proceeds with the drilling of a deviated well under such circumstances, he proceeds at his own risk. Before any allowable shall be assigned to such well, a permit for the subsurface location of each completion interval shall be obtained from the commission under the provisions set out in the commission rules. However, should the operator fail to show good and sufficient cause for such deviation, no permit will be granted for the well.

(C) If the necessity for random deviation arises unexpectedly after the drilling has begun, the operator shall give written notice by letter or telegram of such necessity to the appropriate district office and to the commission office in Austin, and, upon giving such notice, the operator may proceed with the random deviation, subject to compliance with the provisions of this section on inclination surveys. The commission may, at its discretion, accept written notice electronically transmitted.

(e) Surveys on request of other operators. The commission, at the written request of any operator in a field, shall determine whether a directional survey, an inclination survey, or any other type of survey approved by the commission for the purpose of determining bottom hole location of wells, shall be made in regard to a well complained of in the same field.

(1) The complaining party must show probable cause to suspect that the well complained of is not bottomed within its own lease lines.

(2) The complaining party must agree to pay all costs and expenses of such survey, shall assume all liability, and shall be required to post bond in a sufficient sum as determined by the commission as security against all costs and risks associated with the survey.

(3) The complaining party and the commission shall agree upon the selection of the well surveying company to conduct the survey, which shall be a surveying company on the commission's approved list.

(4) The survey shall be witnessed by the commission, and may be witnessed by any party, or his agent, who has an interest in the field.

(5) Nothing in these rules shall be construed to prevent or limit the commission, acting on its own authority, from conducting spot checks and surveys at any time and place for the purpose of determining compliance with the commission rules and regulations.

(f) Penalties.

(1) False reports. The filing of a false or incorrect directional survey shall be grounds for cancellation of the well permit, for pipeline severance of the lease on which the well is located, for penalty action under the applicable statutes, and/or for such other and further action as may be appropriate.

(2) Other. The same penalties and actions as set forth in paragraph (1) of this subsection shall be assessable against any operator who refuses to comply with a commission order which issues under subsection (e) of this section.

Source Note: The provisions of this §3.11 adopted to be effective January 1, 1976; amended to be effective July 4, 1979, 4 TexReg 2197; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective May 23, 1990, 15 TexReg 2634; amended to be effective June 11, 2001, 26 TexReg 4088.

§3.12 Directional Survey Company Report

(a) For each well drilled for oil, gas, brine, or geothermal resources for which a directional survey report is required by rule, regulation, or order, the surveying company shall prepare and file the following information. The information shall be certified by the person having personal knowledge of the facts, by execution and dating of the data compiled:

(1) the name of the surveying company;

(2) the name of the individual performing the survey for the surveying company;

(3) the title or position the individual holds with the surveying company;

(4) the date on which the individual performed the survey;

(5) the type of survey conducted and whether the survey was multishot;

(6) a complete identification of the well, including the name of the operator of the well; the fee owner; the commission lease number, if assigned; the well number; the API number, and the drilling permit number, the land survey; the field name; and the county and state; and

(7) a notation that the survey was conducted from a depth of ____ feet to ____ feet.

(b) Each directional survey, with its accompanying certification and a certified plat on which the bottom hole location is oriented both to the surface location and to the lease lines (or unit lines in case of pooling) shall be mailed by registered, certified, or overnight mail direct to the commission in Austin by the surveying company making the survey. The surveying company may file electronically if the Commission has provided for such filing.

Source Note: The provisions of this §3.12 adopted to be effective January 1, 1976; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective October 27, 2008, 33 TexReg 8785; amended to be effective February 18, 2025, 50 TexReg 835.

§3.13 Casing, Cementing, Drilling, Well Control, and Completion Requirements

(a) General. Operators shall comply with this section for any wells that will be spudded on or after January 1, 2014.

(1) Intent. The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to

follow the intent of the section, using good engineering practices and the best currently available technology. In accordance with §3.17 of this title (relating to Pressure on Bradenhead), operators must notify the Commission of bradenhead pressure. The Commission will evaluate notices of bradenhead pressure on a case-by-case basis to determine further action and will provide guidance to assist operators in wellbore evaluation.

(2) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(A) Stand under pressure--To leave the hydrostatic column pressure in the well acting as the natural force without adding any external pump pressure. The provisions are complied with if a float collar and/or float shoe is used and found to be holding at the completion of the cement job.

(B) Zone of critical cement--

(i) For surface casing strings, the bottom 20% of the casing string, but no more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet or less.

(ii) For intermediate or production casing strings, the bottom 20% of the casing string or 300 vertical feet above the casing shoe or top of the highest proposed productive zone, whichever is less.

(C) Protection depth--Depth to which usable-quality water must be protected, as determined by the Groundwater Advisory Unit of the Oil and Gas Division, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(D) Productive zone--Any stratum known to contain oil, gas, brine, or geothermal resources in commercial quantities in the area.

(E) Gas/oil contact zone--A zone in an oil well in which natural gas, commonly known as gas cap gas, overlies and is in contact with crude oil in a reservoir.

(F) Bay well--Any well under the jurisdiction of the Commission as defined in §3.78(a)(5) of this chapter.

(G) Deputy director of Field Operations--The deputy director of Field Operations of the Oil and Gas Division or the deputy director's delegate.

(H) Director--The director of the Oil and Gas Division of the Railroad Commission of Texas or the director's delegate.

(I) District director--The Director of a Railroad Commission district office or the district director's delegate.

(J) Hydraulic fracturing treatment--A completion process involving treatment of a well by the application of hydraulic fracturing fluid under pressure for the express purpose of initiating or propagating fractures in a target geologic formation to enhance production of oil and/or natural gas. The term does not include acid treatment, perforation, or other non-fracture treatment completion activities.

(K) Land well--Any well subject to Commission jurisdiction as defined in §3.78(a)(6) of this chapter.

(L) Minimum separation well--A well in which hydraulic fracturing treatments will be conducted and for which:

(i) the vertical distance between the base of usable quality water and the top of the formation to be stimulated is less than 1,000 vertical feet;

(ii) the director has determined contains inadequate separation between the base of usable quality water and the top of the formation in which hydraulic fracturing treatments will be conducted; or

(iii) the director has determined is in a structurally complex geologic setting.

(M) Offshore well--Any well subject to Commission jurisdiction as defined by §3.78(a)(7).

(N) Potential flow zone--A zone designated by the director or identified by the operator using available data that needs to be isolated to prevent sustained pressurization of the surface casing/intermediate casing or production casing annulus sufficient to cause damage to casing and/or cement in a well such that it presents a threat to subsurface water or oil, gas, or geothermal resources. The Commission will maintain a list of known zones by district and county that are considered potential flow zones and make this information available to all operators. The Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.

(O) Zone with corrosive formation fluids--Any zone designated by the director or identified by the operator using available data containing formation fluids that are capable of negatively impacting the integrity of casing and/or cement or have a demonstrated trend of failure for similar casing and cement design in the field. The Commission will maintain a list of known zones by district and county that are considered zones with corrosive formation fluids, and make this information available to all operators. The Commission will revise this list as necessary based on information provided, or otherwise made available, to the Commission.

(P) Usable quality water--Water as defined in §3.30(e)(7)(B)(i) of this title (relating to Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)).

(3) Wellbore diameters.

(A) The diameter of the wellbore in which surface casing will be set and cemented shall be at least one and one-half (1.50) inches greater than the nominal outside diameter of casing to be installed, unless otherwise approved by the district director.

(B) For subsequent casing strings, the diameter of each section of the wellbore for which casing will be set and cemented shall be at least one (1) inch greater than the nominal outside diameter of the casing to be installed, unless otherwise approved by the district director. The district director may grant such approvals on an area basis.

(C) The casing diameter requirements in subparagraphs (A) and (B) of this paragraph do not apply to reentries, liners, and expandable casing.

(D) All float equipment, centralizers, packers, cement baskets, and all other equipment run into the wellbore on casing shall be consistent with the manufacturer's recommendations.

(4) Casing and cementing.

(A) All casing cemented in any well shall be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a casing evaluation tool may be employed. Casing meeting the performance standards set forth in API Specification 5CT: Specification for Casing and Tubing (or a Commission-approved equivalent standard) shall be used through the protection depth.

(B) The base cement shall meet the standards set forth in API Specification 10A: Specification for Cement and Material for Well Cementing or the American Society for Testing and Materials (ASTM) Specification C150/C150M, Standard Specification for Portland Cement (or a Commission-approved equivalent standard).

(C) Casing shall be cemented across and above all formations permitted for injection under §3.9 of this title (relating to Disposal Wells) at the time the well is completed, or cemented immediately above all formations permitted for injection under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) at the time the well is completed, in a well within one-quarter mile of the proposed well location, as follows:

(i) if the top of cement is determined through calculation, at least 600 feet (measured depth) above the permitted formations;

(ii) if the top of cement is determined through the performance of a temperature survey conducted immediately after cementing, 250 feet (measured depth) above the permitted formations;

(iii) if the top of cement is determined through the performance of a cement evaluation log, 100 feet (measured depth) above the permitted formations;

(iv) at least 200 feet into the previous casing shoe (or to surface if the shoe is less than 200 feet from the surface); or

(v) as otherwise approved by the district director.

(D) Casing shall be cemented across and above all productive zones, potential flow zones, and/or zones with corrosive formation fluids, as follows:

(i) if the top of cement is determined through calculation, across and extending at least 600 feet (measured depth) above the zones;

(ii) if the top of cement is determined through the performance of a temperature survey, across and extending 250 feet (measured depth) above the zones;

(iii) if the top of cement is determined through the performance of a cement evaluation log, across and extending 100 feet (measured depth) above the zones;

(iv) across and extending at least 200 feet into the previous casing shoe (or to the surface if the shoe is less than 200 feet from the surface); or

(v) as otherwise approved by the district director.

(E) Where necessary, the cement slurry shall be designed to control annular gas migration consistent with, or equivalent to, the standards in API Standard 65-Part 2: Isolating Potential Flow Zones During Well Construction.

(5) Casing testing before drillout. For surface and intermediate strings of casing, before drilling the cement plug, the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot. The maximum test pressure required, however, unless otherwise ordered by the Commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation that the condition has been corrected. The operator shall notify the district director of a failed test. In the event of a pressure test failure, completion operations may not re-commence until the district director approves a remediation plan, the operator successfully implements the plan, and the operator conducts a successful pressure test.

(6) Well control.

(A) Wellhead assemblies. After setting the conductor pipe on offshore wells or surface casing on land or bay wells, wellhead assemblies shall be used on wells to maintain surface control of the well at all times. Each component of the wellhead shall have a pressure rating equal to or greater than the anticipated pressure to which that particular component might be exposed during the course of drilling, testing, or producing the well.

(B) Well control equipment.

(i) An operator shall install a blowout preventer system or control head and other connections to keep the well under control at all times as soon as surface casing is set. When conductor casing is set and/or shallow gas is anticipated to be encountered, operators shall install a diverter system on the conductor casing. For bay and offshore wells, at a minimum, such systems shall include a double ram blowout preventer, including pipe and blind rams, an annular-type blowout preventer or other equivalent control system, and a shear ram.

(ii) For wells in areas with hydrogen sulfide, the operator shall comply with §3.36 of this title (relating to Oil, Gas, Brine, or Geothermal Resource Operation in Hydrogen Sulfide Areas).

(iii) Ram type blowout prevention equipment shall have a rated working pressure that equals or exceeds the maximum anticipated surface pressure of the well. Blowout preventer rams shall be of a proper size for the drill pipe being used or production casing being run in the well or shall be variable-type rams that are in the appropriate size range. Alternatively, an annular preventer may be used in lieu of casing/pipe rams or variable bore rams when running production casing provided the expected shut-in surface pressures would not exceed the tested pressure rating of the annular preventer.

(iv) Operators shall install a drill pipe safety valve to prevent backflow of water, oil, gas, or other formation fluids into the drill string.

(v) Operators shall install a choke line of sufficient size and working pressure.

(vi) When using a Kelly rig during drilling, the well shall be fitted with an upper Kelly cock in proper working order to close in the drill string below hose and swivel, when necessary for well control. A lower Kelly safety valve shall be installed so that it can be run through the blowout preventer. When needed for well control, the operator shall maintain at all times on the rig floor safety valves to include:

(I) full-opening safety valve; and

(II) inside blowout preventer valve with wrenches, handling tools, and necessary subs for all drilling pipe sizes in use.

(vii) All control equipment shall be consistent with API Standard 53: Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells. Control equipment shall be certified in accordance with API Standard 53 as operable under the product manufacturer's minimum operational specifications. Certification shall include the proper operation of the closing unit valving, the pressure gauges, and the manufacturer's recommended accumulator fluids. Certification shall be obtained through an independent company that tests blowout preventers, stacks and casings. Certification shall be performed every five (5) years and the proof of certification shall be made available upon request of the Commission.

(viii) All well control equipment shall be in good working condition at all times. All outlets, fittings, and connections on the casing, blowout preventers, choke manifold, and auxiliary wellhead equipment that may be subjected to wellhead pressure shall be of a material and construction to withstand or exceed the anticipated pressure. The lines from outlets on or below the blowout preventers shall be securely installed, anchored, and protected from damage.

(ix) In addition to the primary closing system, including an accumulator system, the blowout preventers shall have a secondary location for closure.

(x) Testing of blowout prevention equipment.

(I) Ram type blowout prevention equipment shall be tested to at least the maximum anticipated surface pressure of the well, but not less than 1,500 psi, before drilling the plug on the surface casing.

(II) Blowout prevention equipment shall be tested upon installation, after the disconnection or repair of any pressure containment seal in the blowout preventer stack, choke line, or choke manifold, limited to the affected component, with testing to occur at least every 21 days. When requested, the district director shall be notified before the commencement of a test.

(III) A record of each test, including test pressures, times, failures, and each mechanical test of the casings, blowout preventers, surface connections, surface fittings, and auxiliary wellhead equipment shall be entered in the logbook, signed by the person responsible for the test, and made available for inspection by the Commission upon request.

(C) Drilling fluid program.

(i) The characteristics, use, and testing of drilling fluid and conduct of related drilling procedures shall be designed to prevent the blowout of any well. Adequate supplies of drilling fluid of sufficient weight and other acceptable characteristics shall be maintained. Drilling fluid tests shall be performed as needed to ensure well control. Adequate drilling fluid testing equipment shall be kept on the drilling location at all times. Sufficient drilling fluid shall be pumped and maintained to ensure well control at all times, including when pulling drill pipe. Mud pit levels shall be visually or mechanically monitored during the drilling process. Mud-gas separation equipment shall be installed and operated as needed when abnormally pressured gas-bearing formations may be encountered. The Commission shall have access to the drilling fluid records and shall be allowed to conduct any essential tests on the drilling fluid used in the drilling or recompletion of a well. When the conditions and tests indicate a need for a change in the drilling fluid program in order to insure control of the well, the operator shall use due diligence in modifying the program.

(ii) Wells drilled with air shall maintain well control using blowout preventer systems and/or diverter systems.

(iii) All hole intervals drilled prior to reaching the base of protected water shall be drilled with air, fresh water or a fresh water based drilling fluid. No oil-based drilling fluid may be used until casing has been set and cemented to the protection depth.

(D) Diverter systems for bay and offshore wells. Any bay or offshore well that is drilled to and/or through formations where the expected reservoir pressure exceeds the hydrostatic pressure of the drilling fluid column shall be equipped to divert any wellbore fluids away from the rig floor. When the diverter system is installed, the diverter components including the sealing element, diverter valves, control systems, stations and vent lines shall be function and pressure tested. For drilling operations with a surface wellhead configuration, the system shall be function tested at least once every 24-hour period after the initial test. After all connections have been made on the surface casing or conductor casing, the diverter sealing element and diverter valves shall be pressure tested to a minimum of 200 psig. Subsequent pressure tests shall be conducted within seven days after the previous test. All diverter systems shall be maintained in working condition. No operator shall continue drilling operations if a test or other information indicates that the diverter system is unable to function or operate as designed.

(E) Casinghead.

(i) Requirements. All land and bay wells shall be equipped with casingheads of sufficient rated working pressure, with adequate connections and valves accessible at the surface, to allow pumping of fluid between any two strings of casing at the surface.

(ii) Casinghead test procedure. Any well showing sustained pressure on the casinghead, or leaking gas or oil between the surface casing and the next casing string, shall be tested in the following manner. The well shall be killed with water or mud and pump pressure applied. The casing shall be condemned if the pressure gauge on the casinghead reflects the applied pressure. After completing corrective measures, the casing shall be tested in the same manner. This method shall be used when the origin of the pressure cannot otherwise be determined.

(F) Christmas tree.

(i) All completed non-pumping wells shall be equipped with Christmas tree fittings and wellhead connections with a rated working pressure equal to, or greater than, the surface shut-in pressure of the well. The tubing shall be equipped with a master valve, but two master valves shall be used on all wells with surface pressures in excess of 5,000 psi. All wellhead connections shall be assembled and tested prior to installation by a fluid pressure equal to the test pressure of the fitting employed.

(ii) The Christmas tree for completed bay and offshore wells shall be equipped with either two master valves, one master valve and one wing valve, or two wing valves. All bay and offshore wells shall have at least five feet of spacing between the bottom of the Christmas tree and the surface of the water at high tide, where applicable. Any newly completed bay and offshore well or existing well on which the Christmas tree is being replaced shall be equipped with a back pressure valve wellhead profile at the flange where the tubing hangs on the Christmas tree.

(G) Storm choke and safety valve.

(i) Bay and offshore wells shall be equipped with a storm choke and/or safety valve installed in the tubing.

(ii) An operator may request approval to use a surface safety valve in lieu of a subsurface safety valve by filing with the appropriate district director a written request for such approval providing all pertinent information to support the exception.

(iii) The depth and type of the safety valve shall be reported in the "remarks" section of the appropriate completion report form required by §3.16 of this title (relating to Log and Completion or Plugging Report), after the well is completed or recompleted.

(7) Additional requirements for wells on which hydraulic fracturing treatments will be conducted.

(A) All casing strings or fracture tubing installed in a well that will be subjected to hydraulic fracturing treatments shall have a minimum internal yield pressure rating of at least 1.10 times the maximum pressure to which the casing strings or fracture tubing may be subjected.

(B) The operator shall pressure test the casing (or fracture tubing) on which the pressure will be exerted during hydraulic fracturing treatments to at least the maximum pressure allowed by the completion method. Casing strings that include a pressure actuated valve or sleeve shall be tested to 80 percent of actuation pressure for a minimum time period of five (5) minutes. A surface pressure loss of greater than 10 percent of the initial test pressure is considered a failed test. The casing required to be pressure tested shall be from the wellhead to at least the depth of the top of cement behind the casing being tested. The district director shall be notified of a failed test within 24 hours of completion of the test. In the event of a pressure test failure, no hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing).

(C) During hydraulic fracturing treatment operations, the operator shall monitor all annuli. The operator shall immediately suspend hydraulic fracturing treatment operations if the pressures deviates above those anticipated increases caused by pressure or thermal transfer and shall notify the appropriate district director within 24 hours of such deviation. Further completion operations, including hydraulic fracturing treatment operations, may not recommence until the district director approves a remediation plan and the operator successfully implements the approved plan.

(D) The following conditions also apply if the well is a minimum separation well, unless otherwise approved by the director:

(i) Cementing of the production casing in a minimum separation well shall be by the pump and plug method. The production casing shall be cemented from the shoe up to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface).

(ii) The operator shall pressure test the casing string on which the pressure will be exerted during stimulation to the maximum pressure that will be exerted during hydraulic fracturing treatment. The operator shall notify the district director within 24 hours of a failed test. No hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing).

(iii) The production casing for any minimum separation well shall not be disturbed for a minimum of eight hours after cement is in place and casing is hung-off, and in no case shall the casing be disturbed until the cement has reached a minimum compressive strength of 500 psi.

(iv) In addition to conducting an evaluation of cementing records and annular pressure monitoring results, the operator of a minimum separation well shall run a cement evaluation tool to assess radial cement integrity and placement behind the production casing. If the cement evaluation indicates insufficient isolation, completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan.

(v) The operator of a minimum separation well may request from the appropriate district director approval of an exemption from the requirement to run a cement evaluation tool. Such request shall include information demonstrating that the operator has:

(I) successfully set, cemented, and tested the casing for which the exemption is requested in at least five minimum separation wells by the same operator in the same operating field;

(II) obtained cement evaluation tool logs that support the findings of cementing records, annular pressure monitoring results or other tests demonstrating that successful cement placement was achieved to isolate productive zones, potential flow zones, and/or zones with corrosive formation fluids; and

(III) shown that the well for which the exemption is requested will be constructed and cemented using the same or similar techniques, methods, and cement formulation used in the five wells that have had successful cement jobs.

(8) Pipeline shut-off valves for bay and offshore wells. All bay and offshore gathering pipelines designed to transport oil, gas, condensate, or other oil or geothermal resource field fluids from a well or platform shall be equipped with automatically controlled shut-off valves at critical points in the pipeline system. Other safety equipment shall be in full working order as a safeguard against spillage from pipeline ruptures.

(9) Training for bay and offshore wells. All tool pushers, drilling superintendents, and operators' representatives (when the operator is in control of the drilling) shall be required to, upon request, furnish certification of satisfactory completion of an American Petroleum Institute (API) training program, an International Association of Drilling Contractors (IADC) training program, or other equivalent nationally recognized training program on well control equipment and procedures. The certification shall be renewed every two years by attending an API- or IADC-approved refresher course or a refresher course approved by the equivalent nationally recognized training program.

(10) Bottom-hole pressure surveys. The Commission may require bottom-hole pressure surveys of the various fields at such times as determined to be necessary. However, operators shall be required to take bottom-hole pressures only in those wells that are not likely to suffer damaging effects from the survey. Tubing and tubingheads shall be free from obstructions in wells used for bottom-hole pressure test purposes.

(b) Casing and cementing requirements for land wells and bay wells.

(1) Surface casing requirements for land wells and bay wells.

(A) Any proposal to set surface casing to a depth of 3,500 feet or greater shall require prior approval of the appropriate district director. A request for such approval shall be in writing and shall specify how the operator plans to maintain well control during drilling, and ensure successful circulation and adequate bonding of cement, and, if necessary, prevent upward migration of deeper formation fluids into protected water. The district director may grant approvals on an area basis.

(B) Amount required.

(i) An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Groundwater Advisory Unit of the Oil and Gas Division. Unless surface casing requirements are specified in field rules approved prior to the effective date of this rule, before drilling any well, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the district director. The district director may grant such approval on an area basis.

(ii) Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.

(C) Cementing. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or the operator's representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.

(D) Cement quality.

(i) Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

(ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed.

(iii) In addition to the minimum compressive strength of the cement, the free water content shall be minimized to the greatest extent practicable in the cement slurry to be used in the zone of critical cement. In no event shall the free water separation average more than two milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B-2: Recommended Practice for Testing Well Cements, inside the zone of critical cement, or more than six milliliters per 250 milliliters of cement tested outside the zone of critical cement.

(iv) The Commission may require a better quality of cement mixture to be used in any well or any area if conditions indicate that a better quality of cement is necessary to prevent pollution, isolate productive zones, potential flow zones, or zones with corrosive formation fluids or prevent a safety issue in the well.

(E) Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures in, or equipment and procedures equivalent to those in, API RP 10B-2, Recommended Practice for Testing Well Cements. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the Commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure.

(i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement.

(ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.

(F) Cementing report. Within 30 days of completion of the well, or within 90 days of cessation of drilling operations, whichever is earlier, a cementing report must be filed with the Commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the Commission. The operator of the well or the operator's duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the Commission.

(G) Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. All centralizers shall meet specifications in, or equivalent to, API spec 10D Specifications for Bow-Spring Casing Centralizers; API Spec 10 TR4, Technical Report on Considerations Regarding Selection of Centralizers for Primary Cementing Operations; and API RP 10D-2, Recommended Practice for Centralizer Placement and Stop Collar Testing.

(H) Alternative surface casing programs.

(i) An alternative method of fresh water protection may be approved upon written application to the appropriate district director. The operator shall state the reason for the alternative fresh water protection method and outline the alternate program for casing and cementing through the protection depth for strata containing usable-quality water. Alternative programs for setting more than specified amounts of surface casing for well control purposes may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be considered on an individual well basis only. The district director may approve, modify, or reject the proposed program. The district director shall deny the request if the operator has not demonstrated that the alternative casing plan will achieve the intent of this rule as described in subsection (a)(1) of this section. If the proposal is modified or rejected, the operator may request a review by the deputy director of field operations. If the proposal is not approved administratively, the operator may request a public hearing. An operator shall obtain approval of any alternative program before commencing operations.

(ii) Any alternate casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside this string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least 100 feet below the protection depth.

(iii) Any alternate casing program shall include pumping sufficient cement to fill the annular space from the shoe or multi-stage tool to the ground surface. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey or cement bond log. The appropriate district office shall be notified prior to running the required temperature survey or bond log. After the top of cement outside the casing is determined, the operator or the operator's representative shall contact the appropriate district director and obtain approval for the procedures to be used to perform any required additional cementing operations. Upon completion of the well, a cementing report shall be filed with the Commission on the prescribed form.

(iv) Before parallel (nonconcentric) strings of pipe are cemented in a well, surface or intermediate casing must be set and cemented through the protection depth.

(I) Mechanical integrity test of surface casing after drillout.

(i) If the surface casing is exposed to more than 360 rotating hours after reaching total depth or the depth of the next casing string, the operator shall verify the integrity of the surface casing by using a casing evaluation tool or conducting a mechanical integrity test or equivalent Commission-approved casing evaluation method, unless otherwise approved by the district director.

(ii) If a mechanical integrity test is conducted, the appropriate district office shall be notified at least eight hours before the test is conducted to give the district office an opportunity to witness the test. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director, and the surface casing shall be tested at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation of an acceptable pressure test. The appropriate district office shall be notified within 24 hours after a failed test. Completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan, and successfully re-tests the surface casing.

(2) Intermediate casing requirements for land wells and bay wells.

(A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet (measured depth) above the shoe. If any productive zone, potential flow zone, or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented;

(i) if the top of cement is determined through calculation, from the shoe up to a point at least 600 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;

(ii) if the top of cement is determined through performance of a temperature survey, from the shoe up to a point at least 250 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids;

(iii) if the top of cement is determined through performance of a cement evaluation log, from the shoe up to a point at least 100 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluid; or

(iv) to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface); or

(v) as otherwise approved by the district director.

(B) Top of cement. The calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title (relating to Log and Completion or Plugging Report).

(C) Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone, and/or zone with corrosive formation fluids make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively isolate and seal the zones to prevent fluid migration to or from such strata within the wellbore.

(3) Production casing requirements for land wells and bay wells.

(A) Centralizers. In deviated and horizontal holes, the operator shall provide centralization as necessary to ensure zonal isolation between the top of the interval to be completed and the shallower zones that require isolation.

(B) Cementing method. The production string of casing shall be cemented by the pump and plug method, or another method approved by the Commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive zone, potential flow zone and/or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such zones by one of the methods specified for intermediate casing in paragraph (2) of this subsection. A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating casing pressure tests. In the event that the distance from the casing shoe to the top of the shallowest productive zone, potential flow zone and/or zone with corrosive formation fluids make cementing, as required above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such zones, and prevent fluid migration to or from such zones within the wellbore. Uncemented casing is allowable within a producing reservoir provided the production casing is cemented in such a manner to effectively isolate and seal off that zone from all other productive zones in the wellbore as required by §3.7 of this title (relating to Strata To Be Sealed Off).

(C) Reporting of top of cement. Calculated or measured top of cement shall be indicated on the appropriate completion form required by §3.16 of this title.

(D) Isolation of gas/oil contact zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

(4) Tubing requirements for land wells and bay wells.

(A) Tubing requirements for oil wells. All flowing oil wells shall be equipped with and produced through tubing. When tubing is run inside casing in any flowing oil well, the bottom of the tubing shall be at a point not higher than 100 feet (vertical depth) above the top of the producing interval nor more than 50 feet (vertical depth) above the top of the liner, if a liner is used, or 100 feet (vertical depth) above the kickoff point in a deviated or horizontal well. In a multiple zone structure, however, when an operator elects to equip a well in such a manner that small through-the-tubing type tools may be used to perforate, complete, plug back, or recomplete without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, but not exceeding, 1,000 feet (vertical depth) above the top of the perforated or open-hole interval actually open for production into the wellbore.

(B) Alternate tubing requirements. Alternate programs requesting a temporary exception pursuant to subsection (d) of this section to omit tubing from a flowing oil well may be authorized on an individual well basis by the appropriate district director. The district director shall deny the request if the operator has not demonstrated that the alternative tubing plan will achieve the intent as described in subsection (a)(1) of this section. If the proposal is rejected, the operator may request a review by the director of field operations. If the proposal is not approved administratively, the operator may request a hearing. An operator shall obtain approval of any alternative program before commencing operations.

(c) Casing, cementing, drilling, and completion requirements for offshore wells.

(1) Casing. An offshore well shall be cased with at least three strings of pipe, in addition to such drive pipe as the operator may desire, which shall be set in accordance with the following program.

(A) Conductor casing. A string of new pipe, or reconditioned pipe with substantially the same characteristics as new pipe, shall be set and cemented at a depth of not less than 300 feet TVD (true vertical depth) nor more than 800 feet TVD below the mud line. Sufficient cement shall be used to fill the annular space back of the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations.

(B) Surface casing. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi) or reconditioned pipe that has been tested to an equal pressure. Sufficient cement shall be used to fill the annular space behind the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Surface casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations. In all cases, surface casing shall be set prior to drilling below 3,500 feet TVD. Minimum depths for surface casing are as follows.

(i) Surface Casing Depth Table.

Proposed Total Vertical Depth of Well	**Surface**
to 7,000 feet	25% of proposed total depth of well
7,000 - 10,000 feet	2,000 feet
10,000 and below	2,500 feet

(ii) Surface Casing test.

(I) Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling plug or initiating tests. Casing shall be tested by pump pressure to at least 1,000 psi. If, at the end of 30 minutes, the pressure shows a drop of 100 psi or more, the casing shall be condemned until the leak is corrected. A pressure test demonstrating a drop of less than 100 psi after 30 minutes constitutes confirmation that the condition has been corrected.

(II) After drillout, if the surface casing is exposed to more than 360 rotating hours, the operator shall verify the integrity of the casing using a casing evaluation tool, a mechanical integrity test, or an equivalent Commission-approved alternate casing evaluation methodology, unless otherwise approved by the district director.

(III) If a mechanical integrity test of the surface casing is conducted, the appropriate district office shall be notified a minimum of eight (8) hours before the test is conducted. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director, and the surface casing shall be tested at a minimum test pressure of 0.5 psi per foot multiplied by the true vertical depth of the surface casing up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% drop in pressure after 30 minutes constitutes confirmation of an acceptable pressure test. The operator shall notify the appropriate district office within 24 hours of a failed test. Operations may not re-commence until the district director approves a remediation plan and the operator implements the approved plan, and the operator successfully re-tests the surface casing.

(C) Production casing or oil string.

(i) The production casing or oil string shall be new or reconditioned pipe with a mill test of at least 2,000 psi that has been tested to an equal pressure.

(ii) After cementing, the production casing shall be tested by pump pressure to at least 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 150 psi or more, the casing shall be condemned. After corrective operations, the casing shall again be tested in the same manner.

(iii) Cementing of the production casing shall be by the pump and plug method. Sufficient cement shall be used to fill the calculated annular space above the shoe to isolate any productive zones, potential flow zones, or zones with corrosive formation fluids and to a depth that isolates abnormal pressure from normal pressure (0.465 psi per vertical foot of gradient). A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating tests.

(2) Operators shall comply with the well control requirements of subsection (a)(6) of this section.

(d) Exceptions or alternate programs. The director may administratively grant an exception or approve an alternate casing/tubing program required by this section provided that the alternate casing/tubing program will achieve the intent of the rule as described in subsection (a)(1) of this section and the following requirements are met:

(1) The request for an exception or alternate casing/tubing program shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(2) An administrative exception for tubing shall not exceed a period of 180 days. A request for an exception for tubing beyond 180 days shall require a Commission order.

Source Note: The provisions of this §3.13 adopted to be effective January 1, 1976; amended to be effective April 8, 1980, 5 TexReg 1152; amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective January 1, 1983, 7 TexReg 3982; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective January 11, 1991, 16 TexReg 39; amended to be effective August 13, 1991, 16 TexReg 4153; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective January 1, 2014, 38 TexReg 3542; amended to be effective February 18, 2025, 50 TexReg 835.

§3.14 Plugging

(a) Definitions and application to plug.

(1) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(A) Approved cementer--A cementing company, service company, or operator approved by the Commission or its delegate to mix and pump cement for the purpose of plugging a well in accordance with the provisions of this section. The term shall also apply to a cementing company, service company, or operator authorized by the Commission or its delegate to use an alternate material other than cement to plug a well.

(B) Funnel viscosity--Viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

(C) Groundwater conservation district--Any district or authority created under §52, Article III, or §59, Article XVI, Texas Constitution, that has the authority to regulate the spacing of water wells, the production from water wells, or both.

(D) Operator designation form--A certificate of compliance and transportation authority or an application to drill, deepen, recomplete, plug back, or reenter that has been completed, signed, and filed with the Commission or its delegate.

(E) Productive horizon--Any stratum known to contain oil, gas, or geothermal resources in producible quantities in the vicinity of an unplugged well.

(F) Related piping--The surface piping and subsurface piping that is less than three feet beneath the ground surface between pieces of equipment located at any collection or treatment facility. Such piping would include piping between and among headers, manifolds, separators, storage tanks, gun barrels, heater treaters, dehydrators, and any other equipment located at a collection or treatment facility. The term is not intended to refer to lines, such as flowlines, gathering lines, and injection lines that lead up to and away from any such collection or treatment facility.

(G) Reported production--Production of oil or gas, excluding production attributable to well tests, accurately reported to the Commission or its delegate on Form PR, Monthly Production Report.

(H) Serve notice on the surface owner or resident--To hand deliver a written notice identifying the well or wells to be plugged and the projected date the well or wells will be plugged to the surface owner, or resident if the owner is absent, at least three days prior to the day of plugging or to mail the notice by first class mail, postage pre-paid, to the last known address of the surface owner or resident at least seven days prior to the day of plugging.

(I) Usable quality water strata--All strata determined by the Groundwater Advisory Unit of the Oil and Gas Division to contain usable quality water.

(J) Written notice--Notice actually received by the intended recipient in tangible or retrievable form, including notice set out on paper and hand-delivered, facsimile transmissions, and electronic mail transmissions.

(2) The operator shall give the Commission notice of its intention to plug any well or wells drilled for oil, gas, or geothermal resources or for any other purpose over which the Commission has jurisdiction, except those specifically addressed in §3.100(e)(1) of this title (relating to Seismic Holes and Core Holes) (Statewide Rule 100), prior to plugging. The operator shall deliver or transmit the written notice to the district office on the appropriate form.

(3) The operator shall cause the notice of its intention to plug to be delivered to the district office at least five days prior to the beginning of plugging operations. The notice shall set out the proposed plugging procedure as well as the complete casing record. The operator shall not commence the work of plugging the well or wells until the proposed procedure has been approved by the district director or the director's delegate. The operator shall not initiate approved plugging operations before the date set out in the notification for the beginning of plugging operations unless authorized by the district director or the director's delegate. The operator shall notify the district office at least four hours before commencing plugging

operations and proceed with the work as approved. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location, and ready to commence plugging operations. Operations shall not be suspended prior to plugging the well unless the hole is cased and casing is cemented in place in compliance with Commission rules. The Commission's approval of a notice of intent to plug and abandon a well shall not relieve an operator of the requirement to comply with subsection (b)(2) of this section, nor does such approval constitute an extension of time to comply with subsection (b)(2) of this section.

(4) The surface owner and the operator may file an application to condition an abandoned well located on the surface owner's tract for usable quality water production operations. The application shall be made on Commission Form P-13, the Application of Landowner to Condition an Abandoned Well for Fresh Water Production.

(A) Standard for Commission Approval. Before the Commission will consider approval of an application:

(i) the surface owner shall assume responsibility for plugging the well and obligate himself, his heirs, successors, and assignees to complete the plugging operations;

(ii) the operator responsible for plugging the well shall place all cement plugs required by this rule up to the base of the usable quality water strata; and

(iii) the surface owner shall submit:

(I) a signed statement attesting to the fact that:

(-a-) there is no groundwater conservation district for the area in which the well is located; or

(-b-) there is a groundwater conservation district for the area where the well is located, but the groundwater conservation district does not require that the well be permitted or registered; or

(-c-) the surface owner has registered the well with the groundwater conservation district for the area where the well is located; or

(II) a copy of the permit from the groundwater conservation district for the area where the well is located.

(B) The duty of the operator to properly plug ends only when:

(i) the operator has properly plugged the well in accordance with Commission requirements up to the base of the usable quality water stratum;

(ii) the surface owner has registered the well with, or has obtained a permit for the well from, the groundwater conservation district, if applicable; and

(iii) the Commission has approved the application of surface owner to condition an abandoned well for fresh water production.

(5) The operator of a well shall serve notice on the surface owner of the well site tract, or the resident if the owner is absent, before the scheduled date for beginning the plugging operations. A representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served notice as required by this paragraph. The district director or the director's delegate may grant exceptions to the requirements of this paragraph concerning the timing of notices when a workover or drilling rig is already at work on location and ready to commence plugging operations.

(b) Commencement of plugging operations, extensions, and testing.

(1) The operator shall complete and file in the district office a duly verified plugging record, in duplicate, on the appropriate form within 30 days after plugging operations are completed. A cementing report made by the party cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(2) Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed unless the Commission or its delegate approves a plugging extension under §3.15 of this title (relating to Surface Equipment Removal Requirements and Inactive Wells).

(3) The Commission may plug or replug any dry or inactive well as follows:

(A) After notice and hearing, if the well is causing or is likely to cause the pollution of surface or subsurface water or if oil, gas, or other formation fluid is leaking from the well, and:

(i) neither the operator nor any other entity responsible for plugging the well can be found; or

(ii) neither the operator nor any other entity responsible for plugging the well has assets with which to plug the well.

(B) Without a hearing if the well is a delinquent inactive well and:

(i) the Commission has sent notice of its intention to plug the well as required by §89.043(c) of the Texas Natural Resources Code; and

(ii) the operator did not request a hearing within the period (not less than 10 days after receipt) specified in the notice.

(C) Without notice or hearing, if:

(i) the Commission has issued a final order requiring that the operator plug the well and the order has not been complied with; or

(ii) the well poses an immediate threat of pollution of surface or subsurface waters or of injury to the public health and the operator has failed to timely remediate the problem.

(4) The Commission may seek reimbursement from the operator and any other entity responsible for plugging the well for state funds expended pursuant to paragraph (3) of this subsection.

(c) Designated operator responsible for proper plugging.

(1) The entity designated as the operator of a well specifically identified on the most recent Commission-approved operator designation form filed on or after September 1, 1997, is responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning plugging of wells.

(2) As to any well for which the most recent Commission-approved operator designation form was filed prior to September 1, 1997, the entity designated as operator on that form is presumed to be the entity responsible for the physical operation and control of the well and to be the entity responsible for properly plugging the well in accordance with this section and all other applicable Commission rules and regulations concerning

plugging of wells. The presumption of responsibility may be rebutted only at a hearing called for the purpose of determining plugging responsibility.

(d) General plugging requirements.

(1) Wells shall be plugged to insure that all formations bearing usable quality water, oil, gas, or geothermal resources are protected. All cementing operations during plugging shall be performed under the direct supervision of the operator or his authorized representative, who shall not be an employee of the service or cementing company hired to plug the well. Direct supervision means supervision at the well site during the plugging operations. The operator and the cementer are both responsible for complying with the general plugging requirements of this subsection and for plugging the well in conformity with the procedure set forth in the approved notice of intention to plug and abandon for the well being plugged. The operator and cementer may each be assessed administrative penalties for failure to comply with the general plugging requirements of this subsection or for failure to plug the well in conformity with the approved notice of intention to plug and abandon the well.

(2) Cement plugs shall be set to isolate each productive horizon and usable quality water strata. Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division. The operator shall verify the placement of the plug required at the base of the deepest usable quality water stratum by tagging with tubing or drill pipe or by an alternate method approved by the district director or the district director's delegate.

(3) Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe. Cement plugs shall be placed by other methods only upon written request with the written approval of the district director or the director's delegate.

(4) All cement for plugging shall be an approved API oil well cement without volume extenders and shall be mixed in accordance with API standards. Slurry weights shall be reported on the cementing report. The district director or the director's delegate may require that specific cement compositions be used in special situations; for example, when high temperature, salt section, or highly corrosive sections are present. An operator shall request approval to use alternate materials, other than API oil well cement without volume extenders, to plug a well by filing with the director or the director's delegate a written request providing all pertinent information to support the use of the proposed alternate material and plugging method. The director or the director's delegate shall determine whether such a request warrants approval, after considering factors which include but are not limited to whether or not the well to be plugged was used as an injection or disposal well; the well's history; the well's current bottom hole pressure; the presence of highly pressurized formations intersected by the wellbore; the method by which the alternative material will be placed in the wellbore; and the compressive strength and other performance specifications of the alternative material to be used. The director or the director's delegate shall approve such a request only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources.

(5) Operators shall use only cementers approved by the director or the director's delegate, except when plugging is conducted in accordance with subparagraph (B)(ii) of this paragraph or paragraph (6) of this subsection. Cementing companies, service companies, or operators may apply for designation as approved cementers. Approval will be granted on a showing by the applicant of the ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this rule. An approved cementer is authorized to conduct plugging operations in accordance with Commission rules in each Commission district.

(A) A cementing company, service company, or operator seeking designation as an approved cementer shall file a request in writing with the district director of the district in which it proposes to conduct its initial plugging operations. The request shall contain the following information:

(i) the name of the organization as shown on its most recent approved organizational report;

(ii) a list of qualifications including personnel who will supervise mixing and pumping operations;

(iii) length of time the organization has been in the business of cementing oil and gas wells;

(iv) an inventory of the type of equipment to be used to mix and pump cement or other alternate materials as approved by the director or the director's delegate; and

(v) a statement certifying that the organization will comply with all Commission rules.

(B) No request for designation as an approved cementer will be approved until after the district director or the director's delegate has:

(i) inspected all equipment to be used for mixing and pumping cement or other alternate materials as approved by the director or the director's delegate; and

(ii) witnessed at least one plugging operation to determine if the cementing company, service company, or operator can properly mix and pump cement or other alternate materials as approved by the director or the director's delegate according to the specifications required by this rule.

(C) The district director or the director's delegate shall file a letter with the director or the director's delegate recommending that the application to be designated as an approved cementer be approved or denied. If the district director or the director's delegate does not recommend approval, or the director or the director's delegate denies the application, the applicant may request a hearing on its application.

(D) Designation as an approved cementer may be suspended or revoked for violations of Commission rules. The designation may be revoked or suspended administratively by the director or the director's delegate for violations of Commission rules if:

(i) the cementer has been given written notice by personal service or by registered or certified mail informing the cementer of the proposed action, the facts or conduct alleged to warrant the proposed action, and of its right to request a hearing within 10 days to demonstrate compliance with Commission rules and all requirements for retention of designation as an approved cementer; and

(ii) the cementer did not file a written request for a hearing within 10 days of receipt of the notice.

(6) An operator may request administrative authority to plug its own wells without being an approved cementer. An operator seeking such authority shall file a written

request with the district director and demonstrate its ability to mix and pump cement or other alternate materials as approved by the director or the director's delegate in compliance with this subsection. The district director or the director's delegate shall determine whether such a request warrants approval. If the district director or the director's delegate refuses to administratively approve this request, the operator may request a hearing on its request.

(7) The district director or the director's delegate may require additional cement plugs to cover and contain any productive horizon or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation. The tagging and/or pressure testing of any such plugs, or any other plugs, and respotting may be required if necessary to ensure that the well does not pose a potential threat of harm to natural resources.

(8) For onshore or inland wells, a 10-foot cement plug shall be placed in the top of the well, and casing shall be cut off three feet below the ground surface.

(9) Mud-laden fluid of at least 9-1/2 pounds per gallon with a minimum funnel viscosity of 40 seconds shall be placed in all portions of the well not filled with cement or other alternate material as approved by the director or the director's delegate. The hole shall be in static condition at the time the cement plugs are placed. The district director or the director's delegate may grant exceptions to the requirements of this paragraph if a deviation from the prescribed minimums for fluid weight or viscosity will insure that the well does not pose a potential threat of harm to natural resources. An operator shall request approval to use alternate fluid other than mud-laden fluid by filing with the district director a written request providing all pertinent information to support the use of the proposed alternate fluid. The district director or the director's delegate shall determine whether such a request warrants approval, and shall approve such a request only if the proposed alternate fluid will insure that the well does not pose a potential threat of harm to natural resources.

(10) Non-drillable material that would hamper or prevent reentry of a well shall not be placed in any wellbore during plugging operations, except in the case of a well plugged and abandoned under the provisions of §3.35 or §4.614(b) of this title (relating to Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned (Statewide Rule 35); and Authorized Disposal Methods, respectively). Pipe and unretrievable junk shall not be cemented in the hole during plugging operations without prior approval by the district director or the director's delegate.

(11) All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(12) The operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines that will not be actively used in the continuing operation of the lease within 120 days after plugging work is completed. Within the same 120 day period, the operator shall remove all such tanks, vessels, and related piping, remove all loose junk and trash from the location, and contour the location to discourage pooling of surface water at or around the facility site. The operator shall close all pits in accordance with the provisions of Chapter 4 of this title (relating to Environmental Protection), specifically Subchapter A (relating to Oil and Gas Waste Management). The district director or the director's delegate may grant a reasonable extension of time of not more than an additional 120 days for the removal of tanks, vessels and related piping.

(e) Plugging requirements for wells with surface casing.

(1) When insufficient surface casing is set to protect all usable quality water strata and such usable quality water strata are exposed to the wellbore when production or intermediate casing is pulled from the well or as a result of such casing not being run, a cement plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and 50 feet below the base of the deepest usable quality water stratum. This plug shall be evidenced by tagging with tubing or drill pipe. The plug shall be respotted if it has not been properly placed. In addition, a cement plug shall be set across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and below the shoe.

(2) When sufficient surface casing has been set to protect all usable quality water strata, a cement plug shall be placed across the shoe of the surface casing. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above the shoe and at least 50 feet below the shoe.

(3) If surface casing has been set deeper than 200 feet below the base of the deepest usable quality water stratum, an additional cement plug shall be placed inside the surface casing across the base of the deepest usable quality water stratum. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(4) Plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division.

(5) An operator may not remove, cause to be removed, or allow to be removed surface casing from a well at abandonment. This prohibition applies to wells drilled by cable tool and rotary rigs alike.

(f) Plugging requirements for wells with intermediate casing.

(1) For wells in which the intermediate casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum, but extend no less than 50 feet above and below the base of the deepest usable quality water stratum.

(2) For wells in which intermediate casing is not cemented through all usable quality water strata and all productive horizons, and if the casing will not be pulled, the intermediate casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division.

(g) Plugging requirements for wells with production casing.

(1) For wells in which the production casing has been cemented through all usable quality water strata and all productive horizons, a cement plug meeting the

requirements of subsection (d)(11) of this section shall be placed inside the casing and centered opposite the base of the deepest usable quality water stratum and across any multi-stage cementing tool. This plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest usable quality water stratum.

(2) For wells in which the production casing has not been cemented through all usable quality water strata and all productive horizons and if the casing will not be pulled, the production casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(3) The district director or the director's delegate may approve a cast iron bridge plug to be placed immediately above each perforated interval, provided at least 20 feet of cement is placed on top of each bridge plug. A bridge plug shall not be set in any well at a depth where the pressure or temperature exceeds the ratings recommended by the bridge plug manufacturer.

(4) Additionally, plugs shall be set as necessary to separate multiple usable quality water strata by placing the required plug at each depth as determined by the Groundwater Advisory Unit of the Oil and Gas Division.

(h) Plugging requirements for well with screen or liner.

(1) If practical, the screen or liner shall be removed from the well.

(2) If the screen or liner is not removed, a cement plug in accordance with subsection (d)(11) of this section shall be placed at the top of the screen or liner.

(i) Plugging requirements for wells without production casing and open-hole completions.

(1) Any productive horizon or any formation in which a pressure or formation water problem is known to exist shall be isolated by cement plugs centered at the top and bottom of the formation. Each cement plug shall have sufficient slurry volume to fill a calculated height as specified in subsection (d)(11) of this section.

(2) If the gross thickness of any such formation is less than 100 feet, the tubing or drill pipe shall be suspended 50 feet below the base of the formation. Sufficient slurry volume shall be pumped to fill the calculated height from the bottom of the tubing or drill pipe up to a point at least 50 feet above the top of the formation, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

(j) The district director or the director's delegate shall review and approve the notification of intention to plug in a manner so as to accomplish the purposes of this section. The district director or the director's delegate may approve, modify, or reject the operator's notification of intention to plug. If the proposal is modified or rejected, the operator may request a review by the director or the director's delegate. If the proposal is not administratively approved, the operator may request a hearing on the matter. After hearing, the examiner shall recommend final action by the Commission.

(k) Plugging horizontal drainhole wells. All plugs in horizontal drainhole wells shall be set in accordance with subsection (d)(11) of this section. The productive horizon isolation plug shall be set from a depth 50 feet below the top of the productive horizon to a depth either 50 feet above the top of the productive horizon, or 50 feet above the production casing shoe if the production casing is set above the top of the productive horizon. If the production casing shoe is set below the top of the productive horizon, then the productive horizon isolation plug shall be set from a depth 50 feet below the production casing shoe to a depth that is 50 feet above the top of the productive horizon. In accordance with subsection (d)(7) of this section, the Commission or its delegate may require additional plugs.

Source Note: The provisions of this §3.14 adopted to be effective January 1, 1976; amended to be effective February 29, 1980, 5 TexReg 499; amended to be effective January 1, 1983, 7 TexReg 3989; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective September 8, 1986, 11 TexReg 3792; amended to be effective November 9, 1987, 12 TexReg 3959; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective March 1, 1992, 17 TexReg 1227; amended to be effective September 1, 1992, 17 TexReg 5283; amended to be effective September 20, 1995, 20 TexReg 6931; amended to be effective September 14, 1998, 23 TexReg 9300; amended to be effective December 28, 1999, 24 TexReg 11711;amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective November 1, 2000, 25 TexReg 9924; amended to be effective January 9, 2002, 27 TexReg 139; amended to be effective July 28, 2003, 28 TexReg 5853; amended to be effective December 3, 2003, 28 TexReg 10747; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective September 13, 2010, 35 TexReg 8332; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective July 1, 2025, 50 TexReg 33.

§3.15 Surface Equipment Removal Requirements and Inactive Wells

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Active operation--Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer and that is not permitted as a disposal or injection well, the well remains inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least five barrels of oil for oil wells or 50 Mcf of gas for gas wells each month for at least three consecutive months, or until the well has reported production of at least one barrel of oil for oil wells or at least one Mcf of gas for gas wells each month for 12 consecutive months.

(2) Cost calculation for plugging an inactive well--The cost, calculated by the Commission or its delegate, for each foot of well depth plugged based on average actual plugging costs for wells plugged by the Commission for the preceding state fiscal year for the Commission Oil and Gas Division district in which the inactive well is located.

(3) Delinquent inactive well--An inactive well for which, after notice and opportunity for a hearing, the Commission or its delegate has not extended the plugging deadline.

(4) Enhanced oil recovery (EOR) project--A project that does not include a water disposal project and is:

(A) a Commission-approved EOR project that uses any process for the displacement of oil or other hydrocarbons from a reservoir other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process;

(B) a certified project described by Texas Tax Code, §202.054; or

(C) any other project approved by the Commission or its delegate for EOR.

(5) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid oil and gas lease or a recorded deed conveying a fee interest in the mineral estate.

(6) Inactive well--An unplugged well that has been spudded or has been equipped with cemented casing and that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months.

(7) Operator designation form--A certificate of compliance and transportation authority or an application to drill, recomplete, and reenter that has been approved by the Commission or its delegate.

(8) Physical termination of electric service to the well's production site--Disconnection of the electric service to an inactive well site at a point on the electric service lines most distant from the production site toward the main supply line in a manner that will not interfere with electrical supply to adjacent operations, including cathodic protection units.

(b) Plugging of inactive bay and offshore wells required.

(1) An operator of an existing inactive bay or offshore well as defined in §3.78 of this title (relating to Fees and Financial Security Requirements) must:

(A) restore the well to active operation as defined by Commission rule;

(B) plug the well in compliance with a Commission rule or order; or

(C) obtain the approval of the Commission or its delegate of an extension of the deadline for plugging an inactive bay or offshore well.

(2) The Commission or its delegate may not approve an extension of the deadline for plugging an inactive bay or offshore well if the plugging of the well is otherwise required by Commission rules or orders.

(c) Extension of deadline for plugging an inactive bay or offshore well. The Commission or its delegate may administratively grant an extension of the deadline for plugging an inactive bay or offshore well as defined by Commission rules if:

(1) the operator has a current organization report;

(2) the operator has, and on request provides, evidence of a good faith claim to a continuing right to operate the well;

(3) the well and associated facilities are otherwise in compliance with all Commission rules and orders; and

(4) for a well more than 25 years old, the operator successfully conducts and the Commission or its delegate approves a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural resources, including surface and subsurface water, oil, and gas.

(d) Plugging of inactive land wells required.

(1) An operator that assumes responsibility for the physical operation and control of an existing inactive land well must maintain the well and all associated facilities in compliance with all applicable Commission rules and orders and within six months after the date the Commission or its delegate approves an operator designation form must either:

(A) restore the well to active operation as defined by Commission rule;

(B) plug the well in compliance with a Commission rule or order; or

(C) obtain approval of the Commission or its delegate of an extension of the deadline for plugging an inactive well.

(2) The Commission or its delegate may not approve an extension of the deadline for plugging an inactive land well if the plugging of the well is otherwise required by Commission rules or orders.

(3) Except for an operator designation form filed for the purpose of a name change, the Commission or its delegate may not approve an operator designation form for an inactive land well until the operator satisfies the requirements of paragraph (1)(C) of this subsection.

(4) If an operator fails to restore the well to active operation as defined by Commission rule, plug the well in compliance with a Commission rule or order, or obtain an extension of the deadline for plugging an inactive well within six months after acquiring an inactive well, the Commission or its delegate may, after notice and opportunity for hearing, revoke the operator's organization report.

(5) The Commission or its delegate may approve an organization report that is delinquent or has been revoked if the Commission or its delegate simultaneously approves extensions of the deadline for plugging the operator's inactive wells.

(e) Extension of deadline for plugging an inactive land well. The Commission or its delegate may administratively grant an extension of the deadline for plugging an inactive land well if:

(1) the Commission or its delegate approves the operator's Application for an Extension of Deadline for Plugging an Inactive Well (Commission Form W-3X);

(2) the operator has a current organization report;

(3) the operator has, and on request provides evidence of, a good faith claim to a continuing right to operate the well;

(4) the well and associated facilities are otherwise in compliance with all Commission rules and orders; and

(5) for a well more than 25 years old, the operator successfully conducts and the Commission or its delegate approves a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural resources, including surface and subsurface water, oil, and gas.

(f) Application for an extension of deadline for plugging an inactive land well.

(1) This subsection does not apply to a bay well or an offshore well as those terms are defined in §3.78 of this title.

(2) An operator must include the following in an application for an extension of the deadline for plugging an inactive well:

(A) an affirmation made by an individual with personal knowledge of the physical condition of the inactive well pursuant to the provisions of Texas Natural Resources Code, §89.029 and §91.143, stating the following: that the operator has physically terminated electric service to the well's production site; and either:

(i) if the operator does not own the surface of the land where the well is located and the well has been inactive for at least five years but for less than 10 years as of the date of renewal of the operator's organization report, that the operator has emptied or purged of production fluids all piping, tanks, vessels, and equipment associated with and exclusive to the well; or

(ii) if the operator does not own the surface of the land where the well is located, and the well has been inactive for at least 10 years as of the date of renewal of the operator's organization report, that the operator has removed:

(I) all surface equipment and related piping, tanks, tank batteries, pump jacks, headers, fences, and firewalls; has closed all open pits; and has removed all junk and trash, as defined by Commission rule, associated with and exclusive to the well; and

(II) all equipment associated with providing electric service to the well's equipment production site, except for equipment owned by an electric utility, as defined by Section 31.002, Utilities Code; and

(B) documentation that the operator has satisfied at least one of the following requirements:

(i) for all inactive land wells that an operator has operated for more than 12 months, the operator has plugged or restored to active operation, as defined by Commission rule, 10% of the number of inactive land wells operated at the time of the last annual renewal of the operator's organization report;

(ii) if the operator is a publicly traded entity, for all inactive land wells, the operator has filed with the Commission a copy of the operator's federal documents filed to comply with Financial Accounting Standards Board Statement No. 143, Accounting for Asset Retirement Obligations, and an original executed Uniform Commercial Code Form 1 Financing Statement, filed with the Secretary of State, that names the operator as the "debtor" and the Railroad Commission of Texas as the "secured creditor" and specifies the funds covered by the documents in the amount of the cost calculation for plugging all inactive wells;

(iii) the filing of a blanket bond on Commission Form P-5PB(2), Blanket Performance Bond, a letter of credit on Commission Form P-5LC, Irrevocable Documentary Blanket Letter of Credit, or a cash deposit, in the amount of either the lesser of the cost calculation for plugging all inactive wells or $2 million;

(iv) for each inactive land well identified in the application, the Commission has approved an abeyance of plugging report and the operator has paid the required filing fee;

(v) for each inactive land well identified in the application, the operator has filed a statement that the well is part of a Commission-approved EOR project;

(vi) for each inactive land well identified in the application that is not otherwise required by Commission rule or order to conduct a fluid level or hydraulic pressure test of the well, the operator has conducted a successful fluid level test or hydraulic pressure test of the well and the operator has paid the required filing fee;

(vii) for each inactive land well identified in the application, the operator has filed Commission Form W-3X and the Commission or its delegate has approved a supplemental bond, letter of credit, or cash deposit in an amount at least equal to the cost calculation for plugging an inactive land well for each well specified in the application; or

(viii) for each time an operator files an application for a plugging extension and for each inactive land well identified in the application, the operator has filed Commission Form W-3X and the Commission or its delegate has approved an escrow fund deposit in an amount at least equal to 10% of the total cost calculation for plugging an inactive land well.

(g) Commission action on application for plugging extension.

(1) The Commission or its delegate shall administratively grant all applications for plugging extensions that meet the requirements of Commission rules.

(2) The Commission or its delegate may administratively deny an application for a plugging extension for an inactive well if the Commission or its delegate determines that:

(A) the applicant does not have an active organization report at the time the plugging extension application is filed;

(B) the applicant has not submitted all required filing fees and financial assurance for the requested plugging extension and for renewal of its organization report; or

(C) the applicant has not submitted a signed organization report for the applied-for extension year that qualifies for approval regardless of whether the applicant has complied with the inactive well requirements of this section.

(3) Except as provided in paragraph (2) of this subsection, if the Commission or its delegate determines that an organization report should be denied renewal solely because it does not meet the inactive well requirements of this section, a Commission delegate shall, within a reasonable time of not more than 14 days after receipt of the applicant's administratively complete organization report renewal packet, including all statutorily required fees and financial assurance:

(A) notify the operator of the determination;

(B) provide the operator with a written statement of the reasons for the determination; and

(C) notify the operator that it has 90 days from the expiration of its most recently approved organization report to comply with the requirements of this section.

(4) If, after the expiration of the 90-day period specified in paragraph (3)(C) of this subsection, the Commission or its delegate determines that the operator remains out of compliance with the requirements of this section, the Commission delegate shall mail the operator a written notice of this determination. The operator may request a hearing. If the operator fails to timely file a request for hearing and the required hearing fee, the Commission shall enter an order denying the plugging extension request and denying renewal of the operator's organization report without further notice or opportunity for hearing.

(5) To request a hearing, the operator must file a written request for hearing and the hearing fee of $4,500 with the Hearings Division, no later than 30 days from the date the written notice was mailed to the operator. In the request for hearing, the operator must identify by its assigned American Petroleum Institute (API) number each inactive well for which the operator is seeking a hearing to contest the determination that the well remains out of

compliance. At the time an operator files a request for hearing under this subsection, the operator shall provide a list of affected persons to be given notice of the hearing. Affected persons shall include the owners of the surface estate of each tract on which a well that is the subject of the hearing request is located, the director of the Commission's Enforcement Section, and the district director of each Commission district in which the wells are located. The applicant's failure to diligently prosecute a hearing requested under this subsection may result in the application being involuntarily dismissed for want of prosecution on the motion of any affected person or on the Commission's own motion.

(6) If an operator files a timely plugging extension application that is not properly administratively denied for the reasons specified in paragraph (2) of this subsection, then the operator's previously approved organization report shall remain in effect until the Commission approves its plugging extension application or enters a final order denying the application.

(h) Revocation of extension. The Commission or its delegate may revoke an extension of the deadline for plugging an inactive well if the Commission or its delegate determines, after notice and an opportunity for a hearing, that the applicant is ineligible for the extension under the Commission's rules or orders.

(i) Removal of surface equipment for land wells inactive more than 10 years. Requirements to remove surface equipment for land wells inactive more than 10 years do not excuse an operator from compliance with all other applicable Commission rules and orders including the requirements in Chapter 4 of this title (relating to Environmental Protection).

(1) An operator of an inactive land well must leave a clearly visible sign as required by §3.3 of this title (relating to Identification of Properties, Wells, and Tanks) at the wellhead of the well and must maintain wellhead control as required by §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements).

(2) An operator may not store surface equipment removed from an inactive land well on an active lease.

(3) An operator may be eligible for a temporary extension of the deadline for plugging an inactive land well or a temporary exemption from the surface equipment removal requirements if the operator is unable to comply with the requirements of subsection (f)(2)(A) of this section because of safety concerns or required maintenance of the well site and the operator includes with the application a written affirmation of the facts regarding the safety concerns or maintenance.

(4) An operator may be eligible for an extension of the deadline for plugging a well without complying with the surface equipment removal requirements for inactive land wells if the well is located on a unit or lease or in a field associated with an EOR project and the operator includes a statement in the written affirmation that the well is part of such a project. The exemption provided by this subsection applies only to the equipment associated with current and future operations of the project.

(j) Abeyance of plugging report.

(1) An operator that files an abeyance of plugging report must:

(A) pay an annual fee of $100 for each inactive land well covered by the report;

(B) use Commission Form W-3X on which the operator must specify the field and the covered wells within that field; and

(C) for each well, include a certification signed and sealed by a person licensed by the Texas Board of Professional Engineers or the Texas Board of Professional Geoscientists stating that the well has:

(i) a reasonable expectation of economic value in excess of the cost of plugging the well for the duration of the period covered by the report, based on the cost calculation for plugging an inactive well;

(ii) a reasonable expectation of being restored to a beneficial use that will prevent waste of oil or gas resources that otherwise would not be produced if the well were plugged; and

(iii) documentation demonstrating the basis for the affirmation of the well's future utility.

(2) Except as provided in paragraph (3) of this subsection, the Commission or its delegate may not transfer an abeyance of plugging report to a new operator of an existing inactive land well. The new operator of an existing inactive land well must file a new abeyance of plugging report or otherwise comply with the requirements of this subchapter not later than six months after the date the Commission or its delegate approves the new operator's request to be recognized as the operator of the well.

(3) The Commission or its delegate may transfer an abeyance of plugging report in the event of a change of name of an operator.

(k) Enhanced oil recovery (EOR) project.

(1) An inactive well is considered to be part of an EOR project if the well is located on a unit or lease or in a field associated with a Commission-approved EOR project.

(2) Except as provided in paragraph (3) of this subsection, the Commission and its delegate may not transfer a statement that an inactive well is part of an EOR project to a new operator of an existing inactive well. A new operator of an existing inactive well must file a new statement stating that the well is part of such an EOR project or otherwise comply with the provisions of this section not later than six months after the date the Commission or its delegate approves the new operator's request to be recognized as the operator of the well.

(3) The Commission or its delegate may transfer a statement that a well is part of an EOR project in the event of a change of name of an operator.

(l) Fluid level or hydraulic pressure test for inactive wells more than 25 years old.

(1) At least three days prior to the test, the operator must give the district office notice of the date and approximate time the operator intends to conduct a fluid level or hydraulic pressure test. The district office may require that a test be witnessed by a Commission employee. The district office may allow an operator to conduct a test even if notice of the test is provided to the district office fewer than three days prior to the test.

(2) No operator may conduct a test other than a fluid level or hydraulic pressure test without prior approval from the district director or the director's delegate.

(3) For each inactive well that is more than 25 years old and that has been inactive more than 10 years, the operator must perform either a fluid level test once every 12 months or a hydraulic pressure test once every five years and obtain the approval of the Commission or its delegate of the results of said tests.

(4) Notwithstanding the provisions of paragraph (1) of this subsection, an operator may conduct a hydraulic pressure test without prior approval from the district director or the director's delegate, provided that the operator gives the district office written notice of the date and approximate time for the test at least three days prior to the time the test will be conducted; the production casing is tested to a depth of at least 250 feet below the base of usable quality water strata or 100 feet below the top of cement behind the production casing, whichever is deeper; and the minimum test pressure is greater than or equal to 250 psig for a period of at least 30 minutes.

(5) Using Commission Form H-15, each operator must file in the Commission's Austin office the results of a successful fluid level test within 30 days of the date the test was performed. The results, if approved, are valid for a period of one year from the date of the test. Upon request by the Commission or its delegate, the operator must file the actual test data.

(6) Using Commission Form H-5 or Form H-15, each operator must file in the district office the results of a successful hydraulic pressure test, including the original pressure recording chart or its electronic equivalent, within 30 days of the date the test was performed. The results, if approved, are valid for a period of five years from the date of the test, unless the Commission or its delegate requires the operator to perform testing more frequently to ensure that the well does not pose a threat of harm to natural resources.

(7) An operator of an inactive well that is more than 25 years old may not return that inactive well to active operation unless the operator performs either a successful fluid level test of the well within 12 months prior to the return to activity or a successful hydraulic pressure test of the well within five years prior to the return to activity.

(m) Fluid level or hydraulic pressure test for inactive land well less than 25 years old.

(1) At least three days prior to the test, each operator must give the district office notice of the date and approximate time the operator intends to conduct a fluid level or hydraulic pressure test. The district office may require that a test be witnessed by a Commission employee. The district office may allow an operator to conduct a test even if notice of the test is provided to the district office fewer than three days prior to the test.

(2) No operator may conduct a test other than a fluid level or hydraulic pressure test without prior approval from the district director or the director's delegate.

(3) Notwithstanding the provisions of paragraph (1) of this subsection, an operator may conduct a hydraulic pressure test without prior approval from the district director or the director's delegate, provided that the operator gives the district office written notice of the date and approximate time for the test at least three days prior to the time the test will be conducted; the production casing is tested to a depth of at least 250 feet below the base of usable quality water strata or 100 feet below the top of cement behind the production casing, whichever is deeper; and the minimum test pressure is greater than or equal to 250 psig for a period of at least 30 minutes.

(4) An operator that files documentation of a fluid level test or a hydraulic pressure test for an inactive land well less than 25 years old in order to obtain a plugging extension must pay an annual fee of $50 for each well covered by the documentation.

(5) Using Commission Form H-15, each operator must file in the Commission's Austin office the results of a successful fluid level test within 30 days of the date the test was performed. The results, if approved, are valid for a period of one year from the date of the test. Upon request by the Commission or its delegate, the operator must file the actual test data.

(6) Using Commission Form H-5 or Form H-15, each operator must file in the district office the results of a successful hydraulic pressure test, including the original pressure recording chart or its electronic equivalent, within 30 days of the date the test was performed. The results, if approved, are valid for a period of five years from the date of the test, unless the Commission or its delegate requires the operator to perform testing more frequently to ensure that the well does not pose a threat of harm to natural resources.

(7) The Commission or its delegate may transfer documentation of the results of a fluid level or hydraulic pressure test to a new operator of an existing inactive land well that is less than 25 years old.

(n) Supplemental financial assurance.

(1) A supplemental bond, letter of credit, or cash deposit filed as part of an application for an extension for an inactive land well is in addition to any other financial assurance otherwise required of the operator or for the well.

(2) The Commission or its delegate may not transfer a supplemental bond, letter of credit, or cash deposit to a new operator of an existing inactive land well. A new operator of an existing inactive land well must file a new supplemental bond, letter of credit, or cash deposit or otherwise comply with the provisions of this section not later than six months after the date the Commission or its delegate approves an operator designation form.

(o) Escrow funds.

(1) An operator must deposit escrow funds with the Commission each time the operator files an application for an extension of the deadline for plugging an inactive well.

(2) The Commission or its delegate may release escrow funds deposited with the Commission only as prescribed by §3.78 of this title.

(p) Plugging more than 10% of inactive well inventory. If an operator plugs more than 10% of the number of inactive land wells during a 12-month organization report cycle, the Commission will count the number of plugged wells above 10% toward fulfillment of the 10% blanket option under subsection (f)(2)(B)(i) of this section during the next organization report cycle.

Source Note: The provisions of this §3.15 adopted to be effective September 13, 2010, 35 TexReg 8332; amended to be effective August 15, 2011, 36 TexReg 5096; amended to be effective July 2, 2012, 37 TexReg 4894; amended to be effective January 1, 2017, 41 TexReg 9465; amended to be effective December 8, 2025, 50 TexReg 7882.

§3.16 Log and Completion or Plugging Report

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Electric log--A density, sonic, or resistivity (except dip meter) log run over the entire wellbore.

(2) Drilling operation--A continuous effort to drill or

deepen a wellbore for which the commission has issued a permit.

(3) Operator--A person who assumes responsibility for the regulatory compliance of a well as shown by a form the person files with the commission and the commission approves.

(4) Well--A well drilled for any purpose related to exploration for or production or storage of oil or gas or brine or geothermal resources, including a well drilled for injection of fluids to enhance hydrocarbon recovery, injection of spent brine return fluids, disposal of produced fluids, disposal of waste from exploration or production activity, or brine mining.

(b) Completion and plugging reports.

(1) The operator of a well shall file with the commission the appropriate completion report within 90 days after completion of the well or within 150 days after the date on which the drilling operation is completed, whichever is earlier.

(2) The operator of a well shall file with the Commission an amended completion report within 30 days of any physical changes made to the well, such as any change in perforations, or openhole or casing records.

(3) If the well is a dry hole, the operator shall file with the commission an appropriate plugging report within 30 days after the well is plugged.

(c) Electric logs. Except as otherwise provided in this section, not later than the 90th day after the date a drilling operation is completed, the operator shall file with the commission a legible and unaltered copy of an electric log, except that where a well is deepened, a legible and unaltered copy of an electric log shall be filed if such log is run over a deeper interval than the interval covered by an electric log for the well already on file with the commission. In the event an electric log, as defined in this section, has not been run, subject to the commission's approval, the operator shall file a lithology log or gamma ray log of the entire wellbore. In the event no log has been run over the entire wellbore, subject to the commission's approval, the operator shall file the log which is the most nearly complete of the logs run. An electric log shall be filed with the commission electronically in a digital format acceptable to the commission, when the commission has the technological capability to receive the electronic filing. Nothing in this subsection requires an operator to run an electric log in conjunction with the drilling or deepening of a well.

(d) Delayed filing based on confidentiality. Each log filed with the commission shall be considered public information and shall be available to the public during normal business hours. If the operator of a well desires a log to be confidential, on or before the 90th day after the date a drilling operation is completed, the operator must submit to the Oil and Gas Division in Austin a written request for a delayed filing of the log. If a well is drilled on land submerged in state water, when filing such a request, the operator must retain the log and may delay filing such log for five years beginning from the date the drilling operation was completed. For any other well, the operator must retain the log and may delay filing such log for three years beginning from the date the drilling operation was completed. Logs must be filed with the commission within 30 days after the expiration of the confidentiality period.

(e) Sanctions. If an operator fails to file a completion report or log in accordance with the provisions of this section, the commission may refuse to assign an allowable to a well, set the allowable for such well at zero, and/or initiate penalty action pursuant to the Texas Natural Resources Code, Title 3.

Source Note: The provisions of this §3.16 adopted to be effective January 1, 1976; amended to be effective February 20, 1986, 11 TexReg 545; amended to be effective January 30, 2006, 31 TexReg 477; amended to be effective April 28, 2015, 40 TexReg 2273; amended to be effective February 23, 2016, 41 TexReg 1226; amended to be effective February 18, 2025, 50 TexReg 835.

§3.17 Pressure on Bradenhead

(a) All wells shall be equipped with a Bradenhead. Whenever pressure develops between any two strings of casing, the district office shall be notified immediately. No cement may be pumped between any two strings or pipe at the top of the hole, except after permission has been granted by the district office.

(b) Any well showing pressure on the Bradenhead, or leaking gas, oil, brine, or geothermal resource between the surface and the production or oil string shall be tested in the following manner. The well shall be killed and pump pressure applied through the tubing head. Should the pressure gauge on the Bradenhead reflect the applied pressure, the casing shall be condemned and a new production or oil string shall be run and cemented. This method shall be used when the origin of the pressure cannot be determined otherwise.

Source Note: The provisions of this §3.17 adopted to be effective January 1, 1976; amended to be effective February 18, 2025, 50 TexReg 835.

§3.18 Mud Circulation Required

When coming out of the hole with the drill pipe, drilling fluid shall be circulated until equalized, and a fill-up line shall be turned into the casing to insure a full load of fluid on the bottom of the hole at all times.

Source Note: The provisions of this §3.18 adopted to be effective January 1, 1976.

§3.19 Density of Mud-Fluid

In cable tool drilling, no operator shall drill into a known oil, gas, or geothermal resource producing formation with water from a higher formation in the hole, or with a sufficient head of water introduced into the hole to prevent gas blowing to the surface. The well shall either be allowed to blow until it has been drilled-in or it shall be drilled under a head of fluid whose weight shall average not less than 9 1/2 pounds per gallon; but in no case shall gas be allowed to blow for a longer period than three days after completion of the well. Mud-laden fluid used for protecting oil, gas, or geothermal resource bearing sands in upper formations while oil, gas, or geothermal resource is being produced from deeper formations shall have an average weight of not less than 91 pounds per gallon.

Source Note: The provisions of this §3.19 adopted to be effective January 1, 1976.

§3.20 Notification of Fire Breaks, Leaks, or Blow-outs

(a) General requirements.

(1) Operators shall give immediate notice of a fire, leak, spill, or break to the appropriate commission district office by telephone or telegraph. Such notice shall be followed by a letter giving the full description of the event, and it shall include the volume of crude oil, gas, geothermal resources, other well liquids, or associated products lost.

(2) All operators of any oil wells, gas wells, geothermal wells, pipelines receiving tanks, storage tanks, or receiving and storage receptacles into which crude oil, gas, or geothermal resources are produced, received, stored, or through which oil, gas, or geothermal resources are piped or transported, shall immediately notify the commission by letter, giving full details concerning all fires which occur at oil wells, gas wells, geothermal wells, tanks, or receptacles owned, operated, or controlled by them or on their property, and all such persons shall immediately report all tanks or receptacles struck by lightning and any other fire which destroys crude oil, natural gas, or geothermal resources, or any of them, and shall immediately report by letter any breaks or leaks in or from tanks or other receptacles and pipelines from which oil, gas, or geothermal resources are escaping or have escaped. In all such reports of fires, breaks, leaks, or escapes, or other accidents of this nature, the location of the well, tank, receptacle, or line break shall be given by county, survey, and property, so that the exact location thereof can be readily located on the ground. Such report shall likewise specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity (estimated, if no accurate measurement can be obtained, in which case the report shall show that the same is an estimate) of oil, gas, or geothermal resources, lost, destroyed, or permitted to escape. In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. (Reference Order Number 20-60,399, effective 9-24-70.)

(b) The report hereby required as to oil losses shall be necessary only in case such oil loss exceeds five barrels in the aggregate.

(c) Any operation with respect to the pickup of pipeline break oil shall be done subject to the following provisions. The provisions hereafter set out shall not apply to the picking up and the returning of pipeline break oil to the pipeline from which it escaped either at the place of the pipeline break, or at the nearest pipeline station to the break where facilities are available to return such oil to the pipeline; provided, that such operations are conducted by the pipeline operator at the time of the pipeline break and its repair; provided, further, that such authority as is herein granted for the picking up of pipeline break oil shall not relieve the operator of such pipeline of notifying the commission of such pipeline break, and the furnishing to the commission of the information required by the provisions set out in subsection (a) of this section for reporting such pipeline breaks.

(1) Any person desiring to pick up, reclaim, or salvage pipeline break oil, other than as provided in this subsection, shall obtain in writing a permit before commencing operations. All applications for permits to pick up, reclaim, or salvage such oil shall be made in writing under oath to the district office.

(2) Applications to pick up, reclaim, or salvage pipeline break oil shall state the location of such oil, the location of the break in the pipeline causing the leakage of such oil, the name of the pipeline, the owner thereof, and the date of the break.

(3) Pipeline break oil that is not returned to the pipeline from which it escaped shall be offered to the applicant to reclaim by the operator of such pipeline but shall be charged to such pipeline stock account.

Source Note: The provisions of this §3.20 adopted to be effective January 1, 1976.

§3.21 Fire Prevention and Swabbing

(a) No hydrocarbon flow tank, unless entirely buried, shall hereafter be placed nearer than 150 feet from any derrick, rig, building, power plant, or boiler of any description. The director of the Oil and Gas Division or his delegate may administratively grant exceptions to this requirement. If the director of the Oil and Gas Division declines to administratively grant, continue, or extend an exception, the operator shall move the hydrocarbon flow tank to the required distance or request a hearing on the matter. After hearing, the examiner shall recommend final action to the commission.

(b) No field working hydrocarbon tank having a capacity of 10,000 barrels or more shall be built nearer than 200 feet (measured from shell to shell) to any other like tank.

(c) No person engaged in the production, transportation, storage, handling, refining, reclaiming, processing, treating, or marketing of crude petroleum oil or the products or by-products thereof shall store, either permanently or temporarily, crude petroleum oil or the products and by-products thereof in open pits or earthen storage.

(d) All oil tanks where there is a gas hazard shall be gas tight and provided with proper gas vents.

(e) No forge or open light shall be placed inside the derrick of a well showing oil or gas.

(f) Boilers must be equipped with steam lines for fighting fire and must not be set nearer than 150 feet to any producing well.

(g) All wells shall be cleaned into a pit not less than 40 feet from the derrick floor and 150 feet from any fire hazard.

(h) No boiler or electric lighting generator shall be placed or remain nearer than 150 feet to any producing well or oil tank.

(i) Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least 150 feet from the vicinity of any well, tank, or pump station. All waste shall be burned or disposed of in such manner as to avoid creating a fire hazard.

(j) Dikes or fire walls shall not be required except such fire walls must be erected and kept around all permanent oil tanks, or battery of tanks, that are within the corporate limits of any city, town, or village; or where such tanks are closer than 500 feet to any highway or inhabited dwelling or closer than 1,000 feet to any school or church; or where such tanks are so located as to be deemed by the commission to be an objectionable hazard.

(k) Swabbing, bailing, or air jetting of wells is prohibited as a production method for wells unless the Commission has, after notice and hearing, granted an exception to this subsection. The Commission shall give notice of the hearing at least 10 days prior to the date of the hearing.

(1) An operator seeking an exception to allow swabbing, bailing, or air jetting of a well shall:

(A) provide the Commission with the names and mailing addresses of the mineral interest owners of record and surface owners of record of the lease on which a well for which an exception is sought is located;

(B) present evidence at the hearing establishing:

(i) the method of production proposed;

(ii) that any production is properly accounted for pursuant to §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil);

(iii) that the proposed exception is necessary to prevent waste or protect correlative rights;

(iv) that wellhead control is sufficient to prevent releases from the well;

(v) that no pollution of usable quality water or safety hazard will result from either the proposed production method or the condition of the well; and

(vi) that the operator possesses a continuing good faith claim to the right to operate the well.

(2) In addition to the information set out in paragraph (1) of this subsection, factors that the Commission may consider in ruling on a request for an exception include:

(A) whether the well has passed a mechanical integrity test within the preceding 12 months;

(B) the estimated monthly and cumulative production from the well if the requested exception is granted;

(C) whether production will be into an on-lease tank battery or a mobile tank;

(D) the adequacy of the financial assurance provided by the operator to assure that the well will be timely and properly plugged;

(E) whether production volume, fine sands in the reservoir, or other factors render pumping of the well impracticable;

(F) whether the reservoir from which the well produces contains hydrogen sulfide; and

(G) the operator's history of compliance with Commission rules.

(3) This section does not prohibit swabbing as a non-recurring method to start initial production, to test or clean out a well, or to restore a well to flowing or pumping status.

(l) Operation and maintenance of electrical power lines. An operator must construct, operate, and maintain an electrical power line serving a well site or other surface facility employed in operations incident to oil and gas development and production in accordance with the National Electrical Code published by the National Fire Protection Association and adopted by the Texas Department of Licensing and Regulation in §73.100 of this title (relating to Technical Requirements).

Source Note: The provisions of this §3.21 adopted to be effective January 1, 1976, amended to be effective October 3, 1980, 5 TexReg 3794; amended to be effective October 2, 2002, 27 TexReg 9149; amended to be effective September 13, 2010, 35 TexReg 8332.

§3.22 Protection of Birds

(a) If an operator who maintains a tank or pit does not take protective measures necessary to prevent harm to birds, the operator may incur liability under federal and state wildlife protection laws. Federal statutes, such as the Migratory Bird Treaty Act, provide substantial penalties for the death of certain species of birds due to contact with oil in a tank or pit. These penalties may include imprisonment. State statutes also protect certain species of birds. The Railroad Commission of Texas (commission) is cooperating with federal and state wildlife authorities in their efforts to protect birds.

(b) An operator must screen, net, cover, or otherwise render harmless to birds the following categories of open-top tanks and pits associated with the exploration, development, and production of oil and gas, including transportation of oil and gas by pipeline:

(1) open-top storage tanks that are eight feet or greater in diameter and contain a continuous or frequent surface film or accumulation of oil; however, temporary, portable storage tanks that are used to hold fluids during drilling operations, workovers, or well tests are exempt; and

(2) skimming pits or collecting pits that are used as skimming pits that are permitted under Chapter 4 of this title (relating to Environmental Protection), Subchapter A (relating to Oil and Gas Waste Management).

(c) If the commission finds a surface film or accumulation of oil in any other pit regulated under Chapter 4 of this title (relating to Environmental Protection), specifically Subchapter A (relating to Oil and Gas Waste Management), the commission will instruct the operator to remove the oil. If the operator fails to remove the oil from the pit in accordance with the commission's instructions or if the commission finds a surface film or accumulation of oil in the pit again within a 12-month period, the commission will require the operator to screen, net, cover, or otherwise render the pit harmless to birds. Before complying with this requirement, the operator will have a right to a hearing upon request. In addition to the enforcement actions specified by this subsection, the commission may take any other appropriate enforcement actions within its authority.

Source Note: The provisions of this §3.22 adopted to be effective September 1, 1991, 16 TexReg 2523; amended to be effective November 1, 1991, 16 TexReg 4737; amended to be effective July 1, 2025, 50 TexReg 33

§3.23 Vacuum Pumps

The installation of a vacuum pump or other device for the purpose of putting vacuum on any gas or oil-bearing formation, or the application of any vacuum to any gas or oil-bearing formation is prohibited, except as follows.

(1) If casinghead gas is utilized in a casinghead-gas plant, vacuum may be used, but no more than is sufficient to gather the gas and deliver it at the plant. In no event shall more than two points of vacuum (two inches of mercury) be used at the casinghead.

(2) In a field which is depleted or practically depleted vacuum may be used, but no vacuum pump shall be installed or used without a permit from the commission obtained upon application after notice to adjacent lease owners and operators and a public hearing on such application.

Source Note: The provisions of this §3.23 adopted to be effective January 1, 1976.

§3.24 Check Valves Required

(a) Where two or more wells are being produced through a common line, a common separator, or a common manifold, the flow lines leading from each well to such common line, common separator, or common manifold shall be equipped with a check valve or other means of shut-off which shall at all times be kept in good working order. The check valve or other means of shut-off shall be placed in each flow line above the surface of the ground and shall be located in the flow line as close to the wellhead connection as is practicable. Where a manifold system is employed in which each well produced through the manifold system has its own individual flow line leading from the wellhead to the manifold, then it shall be permissible for the check valve or other means of shut-off to be placed in the flow line near a point where the flow line enters the manifold system. The check valve or other means of shut-off must be above ground, and must be in the flow line serving the well and must be located between the wellhead and the point where the flow line connects with any other flow line, common separator, or common manifold. Each check valve or other means of shut-off shall be placed in the flow line serving the well so that it will permit the passage of fluids from the well and will act as a check to prevent any fluid from entering the well through the flow line from any outside source.

(b) Operator shall do all things necessary to keep the check valve or other means of shut-off in good working order, and operators, when requested by an agent of the commission, will test the check valve or other means of shut-off for leakage.

Source Note: The provisions of this §3.24 adopted to be effective January 1, 1976.

§3.25 Use of Common Storage

(a) Where oil and/or other liquid hydrocarbons are produced from two or more separate reservoirs or zones and separate proration schedules are published by the Commission for each reservoir or zone, the use of common storage is authorized as long as the requirements of §3.26 and §3.27 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil, and Gas to be Measured and Surface Commingling of Gas, respectively) are met. An operator utilizing common storage pursuant to this section shall not be required to file a separate Form P-4, Certificate of Compliance and Transportation Authority, for each reservoir or zone, but may file one form to authorize the transportation of oil or gas from all reservoirs or zones producing into common storage.

(b) A gatherer transporting oil from such common storage shall not be required to file a separate transporter's report for each separate reservoir or zone or each separate lease but shall file such report on a combined basis for the total amount of commingled oil in common storage.

(c) The operator of a lease or leases for which the Commission has authorized the use of common storage of oil produced from two or more reservoirs or zones and from two or more leases shall file Form PR, Monthly Production Report, for each separate reservoir or zone and/or for each separate lease and, in addition thereto, said operator shall file a report showing the data included on the individual reports on a combined basis for the total amount of commingled oil in common storage.

Source Note: The provisions of this §3.25 adopted to be effective January 1, 1976; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective February 25, 2019, 44 TexReg 812.

§3.26 Separating Devices, Tanks, and Surface Commingling of Oil

(a) Where oil and gas are found in the same stratum and it is impossible to separate one from the other, or when a well has been classified as a gas well and such gas well is not connected to a cycling plant and such well is being produced on a lease and the gas is utilized under Texas Natural Resources Code §§86.181 - 86.185, the operator shall install a separating device of approved type and sufficient capacity to separate the oil and liquid hydrocarbons from the gas.

(1) A separating device shall be kept in place as long as a necessity for it exists, and its use shall not be discontinued without the consent of the Commission.

(2) All oil and any other liquid hydrocarbons as and when produced shall be adequately measured pursuant to paragraphs (3) and (4) of this subsection before the same leaves the lease from which they are produced, except for gas wells where the full well stream is moved to a plant or central separation facility in accordance with §3.55 of this title (relating to Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering) (Statewide Rule 55) and the full well stream is measured, with each completion being separately measured, before the gas leaves the lease. If an operator commingles production pursuant to subsection (b) of this section, the operator shall comply with paragraphs (3) and (4) of this subsection but the operator is not required to measure the production stream before it leaves the lease.

(3) Sufficient tankage and separator capacity shall be provided by the producer to adequately take daily gauges of all oil and any other liquid hydrocarbons unless LACT equipment, installed and operated in accordance with the latest revision of American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 6.1 or another method approved by the Commission or its delegate, is being used to effect custody transfer.

(4) For Commission purposes, the measurement requirements of this section are satisfied by the use of coriolis or turbine meters or any other measurement device or technology that conforms to standards established, as of the time of installation, by the American Petroleum Institute (API) or the American Gas Association (AGA) for measuring oil or gas, as applicable, or approved by the Director of the Oil and Gas Division as an accurate measurement technology.

(b) Surface commingling of oil, gas, or oil and gas production from two or more tracts of land producing from the same Commission-designated reservoir or from one or more tracts of land producing from different Commission-designated reservoirs is permitted and authorized if:

(1) the operator measures the production stream from each tract and each Commission-designated reservoir separately before combining it with a stream from another tract or Commission-designated reservoir; or

(2) the tracts and Commission-designated reservoirs have identical working interest and royalty interest ownership in identical percentages.

(c) Production that complies with subsection (b) of this section is authorized even if the separator, metering, or storage is located off the tract or tracts. If production is surface commingled pursuant to subsection (b) of this section, the operator shall file Form P-17A, Application for Commingle Permit Pursuant to Rules 26 and/or 27.

(d) If an operator does not meet the requirements of subsection (b) of this section, the Commission may approve surface commingling of oil, gas, or oil and gas production from two or more tracts of land producing from the same Commission-designated reservoir or from one or more tracts of land producing from different Commission-designated reservoirs in order to prevent waste, to promote conservation, or to protect correlative rights.

(1) Administrative approval. After receipt of a completed Form P-17, the Commission may grant approval for surface commingling administratively when the tracts or Commission-designated reservoirs do not have identical working interest and royalty interest ownership in identical percentages and the Commission has not received a protest to an application within 21 days of notice of the application being mailed by the applicant to all working and royalty interest owners or, if publication is required, within 21 days of the date of last publication and the applicant provides:

(A) a method of allocating production to ensure the protection of correlative rights, in accordance with subsection (e) of this section; and

(B) an affidavit or other evidence that all working interest and royalty interest owners have been notified of the application by certified mail or have provided applicant with waivers of notice requirements; or

(C) in the event the applicant is unable, after due diligence, to provide notice by certified mail to all working interest and royalty interest owners, a publisher's affidavit or other evidence that the Commission's notice of application has been published once a week for two consecutive weeks in a newspaper of general circulation in the county or counties in which the tracts that are the subject of the application are located.

(2) Request for hearing. When the tracts or Commission-designated reservoirs do not have identical working interest and royalty interest ownership in identical percentages and a person entitled to notice of the application has filed a protest to the application with the Commission, the applicant may request a hearing on the application. The Commission shall give notice of the hearing to all working interest and royalty interest owners. The Commission may permit the commingling if the applicant demonstrates that the proposed commingling will protect the rights of all interest owners in accordance with subsection (e) of this section and will prevent waste, promote conservation or protect correlative rights.

(e) Reasonable allocation required. The applicant must demonstrate to the Commission or its designee that the proposed commingling of hydrocarbons will not harm the correlative rights of the working or royalty interest owners of any of the wells to be commingled. The method of allocation of production to individual interests must accurately attribute to each interest its fair share of aggregated production.

(1) In the absence of contrary information, such as indications of material fluctuations in the monthly production volume of a well proposed for commingling, the Commission will presume that allocation based on the daily production rate for each well as determined and reported to the Commission by semi-annual well tests will accurately attribute to each interest its fair share of production without harm to correlative rights. As used in this section, "daily production rate" for a well means the 24 hour production rate determined by the most recent well test conducted and reported to the Commission in accordance with §§3.28, 3.52, 3.53, and 3.55 of this title (relating to Potential and Deliverability of Gas Wells to be Ascertained and Reported, Oil Well Allowable Production, Annual Well Tests and Well Status Reports Required, and Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering).

(2) Operators may test commingled wells annually after approval by the Commission or the Commission's delegate of the operator's written request demonstrating that annual testing will not harm the correlative rights of the working or royalty interest owners of the commingled wells. Allocation of commingled production shall not be based on well tests conducted less frequently than annually.

(3) Nothing in this section prohibits allocations based on more frequent well tests than the semi-annual well test set out in paragraph (1) of this subsection. Additional tests used for allocation do not have to be filed with the Commission but must be available for inspection at the request of the Commission, working interest owners or royalty interest owners.

(4) Allocations may be based on a method other than periodic well tests if the Commission or its designee determines that the alternative allocation method will insure a reasonable allocation of production as required by this paragraph.

(f) An operator that commingles production from different Commission-designated reservoirs, whether under subsection (b) or (c) of this section, shall comply with §3.10 of this title (relating to Restriction of Production of Oil and Gas from Different Strata).

(g) An operator that commingles production, whether under subsection (b) or (c) of this section, shall review and correct any forms related to its commingle permit as necessary in order to maintain accurate information on file with the Commission.

(h) If oil or any other liquid hydrocarbon is produced from a lease or other property covered by the coastal or inland waters of the state, the liquid produced may, at the option of the operator, be measured on a shore or at a point removed from the lease or other property on which it is produced.

(i) Oil gravity tests and reports (Reference Order Number 20-55, 647, effective 4-1-66, and Reference Order Number 20-58, 528, effective 5-10-68.)

(1) Where individual lease oil production, or authorized commingled oil production, separator, treating, and/or storage vessels, other than conventional emulsion breaking treaters, are connected to a gas gathering system so that heat or vacuum may be applied prior to oil measurement for Commission-required production reports, the operator may, at the operator's option, apply heat or vacuum to the oil only to the extent the average gravity of the stock tank oil will not be reduced below a limiting gravity for each lease as established by an average oil gravity test conducted under the following conditions (Reference Order Number 20-55, 647, effective 4-1-66):

(A) the separator or separator system, which shall include any type vessel that is used to separate hydrocarbons, shall be operated at not less than atmospheric pressure;

(B) no heat shall be applied;

(C) the test interval shall be for a minimum of 24 hours, and the average oil gravity after weathering for not more than 24 hours shall then become the limiting gravity factor for applying heat or vacuum to unmeasured oil on the tested lease.

(2) Initial gravity tests shall be made by the operator when such separator, treating, and/or storage vessels are first used pursuant to this section. Subsequent tests shall be made at the request of either the Commission or any interested party; and such subsequent tests shall be witnessed by the requesting party. Any interested party may witness the tests.

(3) Each operator shall enter on the required production report the gravity of the oil delivered to market from the lease reported, and it is provided that should a volume of oil delivered to market from such lease separation facilities not meet the gravity requirement established by the described test, adjustment shall be made by charging the allowable of the lease on the relationship of the volume and the gravity of the particular crude.

(4) Where a conventional heater treater is required and is used only to break oil from an emulsion prior to oil measurement, this section will not be applicable; provided, however, that by this limitation on the section, it is not intended that excessive heat may be used in conventional heater treater, and in circumstances where such heater treater is connected to a gas gathering system and it is found by Commission investigation made on its own volition or on complaint of any interested party that excessive heat is used, either the provisions of this section or special restrictive regulation may be made applicable.

Source Note: The provisions of this §3.26 adopted January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective February 18, 1994, 19 TexReg 783; amended to be effective June 23, 1997, 22 TexReg 5747; amended to be effective May 1, 2000, 25 TexReg 3741; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective April 28, 2015, 40 TexReg 2275; amended to be effective February 25, 2019, 44 TexReg 812.

§3.27 Gas to be Measured and Surface Commingling of Gas

(a) All natural gas, except casinghead gas, produced from wells shall be measured, with each completion being measured separately, before the gas leaves the lease, and the producer shall report the volume produced from each completion to the Commission. For Commission purposes, the measurement requirements of this section are satisfied by the use of coriolis or turbine meters or any other measurement device or technology that conforms to standards established, as of the time of installation, by the American Petroleum Institute (API) or the American Gas Association (AGA) for measuring oil or gas, as applicable, or approved by the Director of the Oil and Gas Division as an accurate measurement technology. Exceptions to this provision may be granted by the Commission upon written application.

(b) All casinghead gas sold, processed for its gasoline content, used in a field other than that in which it is produced, or used in cycling or repressuring operations, shall be measured before the gas leaves the lease, and the producer shall report the volume produced to the Commission. Exceptions to this provision may be granted by the Commission upon written application.

(c) All casinghead gas produced in this state which is not covered by the provisions of subsection (b) of this section, shall be measured before the gas leaves the lease, is used as fuel, or is released into the air, based on its use or on periodic tests, and reported to the Commission by the producer. The volume of casinghead gas produced by wells exempt from gas/oil ratio surveys must be estimated, based on general knowledge of the characteristics of the wells. Exceptions to this provision may be granted by the Commission upon written application.

(d) Releases and production of gas at a volume or daily flow rate, commonly referred to as "too small to measure" (TSTM), which, due to minute quantity, cannot be accurately determined or for which a determination of gas volume is not reasonably practical using routine oil and gas industry methods, practices, and techniques are exempt from compliance with this rule and are not required to be reported to the Commission or charged against lease allowable production.

(e) The Commission may approve surface commingling of gas or oil and gas described in subsections (a), (b) or (c) of this section and produced from two or more tracts of land producing from the same Commission-designated reservoir or from one or more tracts of land producing from different Commission-designated reservoirs in accordance with §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil).

(f) In reporting gas well production, the full-well stream gas shall be reported and charged against each gas well for allowable purposes. All gas produced, including all gas used on the lease or released into the air, must be reported regardless of its disposition.

(g) If gas is produced from a lease or other property covered by the coastal or inland waters of the state, the gas produced may, at the option of the operator, be measured on a shore or at a point removed from the lease or other property from which it was produced.

(h) All natural hydrocarbon gas produced and utilized from wells completed in geothermal resource reservoirs shall be measured and allocated to each individual lease based on semiannual tests conducted on full well stream lease production.

(i) For purposes of this rule, "measured" shall mean a determination of gas volume in accordance with this rule and other rules of the Commission, including accurate estimates of unmetered gas volumes released into the air or used as fuel.

(j) No meter or meter run used for measuring gas as required by this rule shall be equipped with a manifold which will allow gas flow to be diverted or bypassed around the metering element in any manner unless it is of the type listed in paragraphs (1) or (2) of this subsection:

(1) double chambered orifice meter fittings with proper meter manifolding to allow equalized pressure across the meter during servicing;

(2) double chambered or single chambered orifice meter fittings equipped with proper meter manifolding or other types of metering devices accompanied by one of the following types of meter inspection manifolds:

(A) a manifold with block valves on each end of the meter run and a single block valve in the manifold complete with provisions to seal and a continuously maintained seal record;

(B) an inspection manifold having block valves at each end of the meter run and two block valves in the manifold with a bleeder between the two and with one valve equipped with provisions to seal and continuously maintained seal records;

(C) a manifold equipped with block valves at each end of the meter run and one or more block valves in the manifold, when accompanied by a documented waiver from the owner or owners of at least 60% of the royalty interest and the owner or owners of at least 60% of the working interest of the lease from which the gas is produced.

(k) Whenever sealing procedures are used to provide security in the meter inspection manifold systems, the seal records shall be maintained for at least three years at an appropriate office and made available for Commission inspection during normal working hours. At any time a seal is broken or replaced, a notation will be made on the orifice meter chart along with graphic representation of estimated gas flow during the time the meter is out of service.

(l) All meter requirements apply to all meters which are used to measure lease production, including sales meters if sales meter volumes are allocated back to individual leases.

(m) The Commission may grant an exception to measurement requirements under subsections (a), (b) and (c) of this section if the requirements of this subsection are met. An exception granted under this subsection will be revoked if the most recent well test or production reported to the Commission reflects a production rate of more than 20 MCF of gas per day or if any of the other requirements for an exception under this subsection are no longer satisfied. An applicant seeking an exception under this subsection must file an application establishing:

(1) the most recent production test reported to the Commission demonstrates that the gas well or oil lease for which an exception is sought produces at a rate of no more than 20 MCF of gas per day;

(2) an annual test of the production of the gas well or oil lease provides an accurate estimate of the daily rate of gas flow;

(3) the flow rate established in paragraph (2) of this subsection multiplied by the recorded duration determined by any device or means that accurately records the duration of production each month yields an accurate estimate of monthly production; and

(4) the operator of the pipeline connected to the gas well or oil lease concurs in writing with the application.

(n) Failure to comply with the provisions of this rule will result in severance of the producing well, lease, facility, or gas pipeline or in other appropriate enforcement proceeding.

Source Note: The provisions of this §3.27 adopted to be effective January 1, 1976; amended to be effective April 12, 1983, 8 TexReg 1019; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective June 23, 1997, 22 TexReg 5747; amended to be effective April 28, 2015, 40 TexReg 2275; amended to be effective February 25, 2019, 44 TexReg 812.

§3.28 Potential and Deliverability of Gas Wells to be Ascertained and Reported

As in effect on 12/8/2025.

(a) The information necessary to determine the absolute daily open flow potential of each producing associated or nonassociated gas well shall be ascertained, and a report shall be filed as required with the Commission within 90 days of completion of the well. The test shall be performed in accordance with the Commission's publication, Back Pressure Test for Natural Gas Wells, State of Texas, or other test procedure approved in advance by the Commission and shall be reported on the Commission's prescribed form. An operator may determine absolute open flow potential from a stabilized one-point test. For a one-point test, the well shall be flowed on a single choke setting until a stabilized flow is achieved, but not less than 72 hours. The shut-in and flowing bottom hole pressures shall be calculated in the manner prescribed for a four-point test. The Commission may authorize a one-point test of shorter duration for a well which is not connected to a sales line, but a test which is in compliance with this section must be conducted and reported after the well is connected before an allowable will be assigned to the well. Back-dating of allowables will be performed in accordance with §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable).

(b) After conducting the test required by subsection (a) of this section each operator of a gas well shall conduct an initial deliverability test and report the test results on the Commission's prescribed form not later than 90 days after completion of the well. If a 72-hour one-point back pressure test on a well connected to a sales line was conducted as provided in subsection (a) of this section, the same test may be used to determine initial deliverability, provided the test was conducted in accordance with subsection (c) of this section.

(1) After the initial deliverability test has been conducted, the following schedule for well testing applies:

(A) Nonassociated gas wells shall be tested semiannually.

(B) Associated gas wells described in §3.49(b) of this title (relating to Gas-Oil Ratio) shall be tested annually.

(C) Wells with current reported deliverability of 100 Mcf a day or less are not required to test as long as deliverability and production remain at or below 100 Mcf a day but are required to file Form G-10 according to the instructions on the form.

(D) Wells with a deliverability greater than 100 Mcf a day and less than or equal to 250 Mcf a day in fields without special field rules are not required to be tested as long as deliverability and production remain equal to or less than 250 Mcf a day.

(2) Notwithstanding any of the provisions in this section on frequency of testing, gas wells commingling liquid hydrocarbons before metering must comply with the testing provisions applicable to such wells.

(3) All deliverability tests shall be conducted in accordance with subsection (c) of this section and the instructions printed on the Form G-10. The results of each test shall be attested to by the operator or its appointed agent. The first purchaser or its representative upon request to the operator shall have the right to witness such tests. Gas meter charts, printouts, or other documents showing the actual measurement of the gas produced or other data required to be recorded during any deliverability test conducted under this subsection shall be preserved as required by §3.1 of this title (relating to Organization

Report; Retention of Records; Notice Requirements).

(4) In the event that the first purchaser and the operator cannot agree upon the validity of the test results, then either party may request a retest of the well. The first purchaser upon request to the operator shall have the right to witness the retest. If either party requests a representative from the Commission to witness a retest of the well, the results of a Commission-witnessed test shall be conclusive for the purposes of this section until the next regularly scheduled test of the well. In the event a retest is witnessed by the Commission, the retest shall be signed by the representative of the Commission.

(5) In the event that downhole remedial work or other substantial production enhancement work is performed, or if a pumping unit, compressor, or other equipment is installed to increase deliverability of a well subject to the Commission-witnessed testing procedure described in this subsection, a new test may be requested and shall be performed according to the procedure outlined in this subsection.

(c) Unless applicable special field rules provide otherwise or the director of the oil and gas division or the director's delegate authorizes an alternate procedure due to a well's producing characteristics, deliverability tests shall be performed as follows. Deliverability tests shall be scheduled by the producer within the testing period designated by the Commission, and only the recorded data specified by the Form G-10 is required to be reported. All deliverability tests shall be performed by producing the subject well at stabilized rates for a minimum time period of 72 hours. A deliverability test shall be conducted under normal and usual operating conditions using the normal and usual operating equipment in place on the well being tested, and the well shall be produced against the normal and usual line pressure prevailing in the line into which the well produces. The average daily producing rate for each 24-hour period, the wellhead pressure before the commencement of the 72-hour test, and the flowing wellhead pressure at the beginning of each 24-hour period shall be recorded. In addition, a 24-hour shut-in wellhead pressure shall be determined either within the six-month period prior to the commencement of the 72-hour deliverability test or immediately after the completion of the deliverability test. The shut-in wellhead pressure that was determined and the date on which the 24-hour test was commenced shall be recorded on Form G-10. Exceptions and extensions to the timing requirements for deliverability tests and shut-in wellhead pressure tests may be granted by the Commission for good cause. The flow rate during each day of the first 48 hours of the test must be as close as possible to the flow rate during the final 24 hours of the test, but must equal at least 75% of such flow rate. The deliverability of the well during the last 24 hours of the flow test shall be used for allowable and allocation purposes. If pipeline conditions exist such that a producer believes a representative deliverability test cannot be performed, the producer with pipeline notification may request in writing that the Commission use either of the following as the deliverability of record:

(1) the deliverability test performed during the previous testing period; or

(2) the maximum daily production from any of the 12 months prior to the due date of the test as determined by dividing the highest monthly production by the number of days in that month.

(d) After the initial deliverability test, an operator may elect not to perform and/or file a subsequent deliverability test for a well. In those cases, the Commission shall use the lesser of the following as the deliverability of record for the purpose of this section:

(1) the results of the most recent deliverability test on file with the Commission; or

(2) the maximum daily production from any of the 12 months prior to the due date of the test as determined by dividing the highest monthly production by the number of days in that month.

(e) Notwithstanding subsection (d) of this section, a deliverability test must be performed on a well in accordance with this section:

(1) at initial completion of the well;

(2) at recompletion of the well into a different regulatory field;

(3) at reclassification of the well from oil to gas;

(4) when the well is an inactive well as defined in §3.15 of this title (relating to Surface Equipment Removal Requirements and Inactive Wells) and the operator resumes production from the well;

(5) when the well is completed in a regulatory field where the allocation formula is based in whole or in part on the downhole pressure of the well, and that allocation formula is not suspended;

(6) when necessary to reinstate an allowable; or

(7) when required by Commission order, special field rule, or other Commission rule.

(f) If the deliverability of a well changes after a test is reported to the Commission, the deliverability of record for a well will be decreased upon receipt of a written request from the operator to reduce the deliverability of record to a specified amount. If the deliverability of a well increases, a retest must be conducted in the manner specified in this section and must be reported on Form G-10 before the deliverability of record will be increased.

(g) First purchasers with packages of gas dedicated entirely to a downstream purchaser shall coordinate testing with and provide test results to that downstream purchaser if requested by the downstream purchaser. In these cases, the downstream purchaser upon request to the operator shall have the right to witness all deliverability tests and retests.

(h) Tests of wells connected to a pipeline shall be made in a manner that no gas is flared, vented, or otherwise wastefully used.

Source Note: The provisions of this §3.28 adopted to be effective September 1, 1986, 11 TexReg 3680; amended to be effective October 12, 1998, 23 TexReg 10397; amended to be effective February 28, 2000, 25 TexReg 1592; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 1, 2017, 41 TexReg 9470.

§3.29 Hydraulic Fracturing Chemical Disclosure Requirements

(a) Definitions. The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Accredited laboratory--A laboratory as defined in Texas Water Code, §5.801.

(2) Additive--Any chemical substance or combination of substances, including a proppant, contained in a

hydraulic fracturing fluid that is intentionally added to a base fluid for a specific purpose whether or not the purpose of any such substance or combination of substances is to create fractures in a formation.

(3) Adjacent property--A tract of property next to the tract of property on which the subject wellhead is located, including a tract that meets only at a corner point.

(4) API number--A unique, permanent, numeric identifier assigned to each well drilled for oil or gas in the United States.

(5) Base fluid--The continuous phase fluid type, such as water, used in a particular hydraulic fracturing treatment.

(6) Chemical Abstracts Service--The division of the American Chemical Society that is the globally recognized authority for information on chemical substances.

(7) Chemical Abstracts Service number or CAS number--The unique identification number assigned to a chemical by the Chemical Abstracts Service.

(8) Chemical Disclosure Registry--The chemical registry website known as FracFocus developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

(9) Chemical family--A group of chemical ingredients that share similar chemical properties and have a common general name.

(10) Chemical ingredient--A discrete chemical constituent with its own specific name or identity, such as a CAS number, that is contained in an additive.

(11) Commission--The Railroad Commission of Texas.

(12) Delegate--The person authorized by the director to take action on behalf of the Railroad Commission of Texas under this section.

(13) Director--The director of the Oil and Gas Division of the Railroad Commission of Texas or the director's delegate.

(14) Health professional or emergency responder--A physician, physician's assistant, industrial hygienist, toxicologist, epidemiologist, nurse, nurse practitioner, or emergency responder who needs information in order to provide medical or other health services to a person exposed to a chemical ingredient.

(15) Hydraulic fracturing fluid--The fluid, including the applicable base fluid and all additives, used to perform a particular hydraulic fracturing treatment.

(16) Hydraulic fracturing treatment--The treatment of a well by the application of hydraulic fracturing fluid under pressure for the express purpose of initiating or propagating fractures in a target geologic formation to enhance production of oil and/or natural gas.

(17) Landowner--The person listed on the applicable county appraisal roll as owning the real property on which the relevant wellhead is located.

(18) Operator--An operator as defined in Texas Natural Resources Code, Chapter 89.

(19) Person--Natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(20) Proppant--Sand or any natural or man-made material that is used in a hydraulic fracturing treatment to prop open the artificially created or enhanced fractures once the treatment is completed.

(21) Requestor--A person who is eligible to request information claimed to be entitled to trade secret protection in accordance with Texas Natural Resources Code, §91.851(a)(5).

(22) Service company--A person that performs hydraulic fracturing treatments on a well in this state.

(23) Supplier--A company that sells or provides an additive for use in a hydraulic fracturing treatment.

(24) Total water volume--The total amount of water in gallons used as the carrier fluid for the hydraulic fracturing job. It may include recycled water and newly acquired water.

(25) Trade name--The name given to an additive or a hydraulic fracturing fluid system under which that additive or hydraulic fracturing fluid system is sold or marketed.

(26) Trade secret--Any formula, pattern, device, or compilation of information that is used in a person's business, and that gives the person an opportunity to obtain an advantage over competitors who do not know or use it. The six factors considered in determining whether information qualifies as a trade secret, in accordance with the definition of "trade secret" in the Restatement of Torts, Comment B to Section 757 (1939), as adopted by the Texas Supreme Court in *Hyde Corp. v. Huffines,* 314 S.W.2d 763, 776 (Tex. 1958), include:

(A) the extent to which the information is known outside of the company;

(B) the extent to which it is known by employees and others involved in the company's business;

(C) the extent of measures taken by the company to guard the secrecy of the information;

(D) the value of the information to the company and its competitors;

(E) the amount of effort or money expended by the company in developing the information; and

(F) the ease or difficulty with which the information could be properly acquired or duplicated by others.

(27) Well--A well as defined in Texas Natural Resources Code, Chapter 89.

(28) Well completion report--The report an operator is required to file with the Commission following the completion or recompletion of a well, if applicable, in accordance with §3.16(b) of this title (relating to Log and Completion or Plugging Report.)

(b) Applicability. This section applies to a hydraulic fracturing treatment performed on a well in the State of Texas for which the Commission has issued an initial drilling permit on or after February 1, 2012.

(c) Required disclosures.

(1) Supplier and service company disclosures.

(A) As soon as possible, but not later than 15 days following the completion of hydraulic fracturing treatment(s) on a well, the supplier or the service company must provide to the operator of the well the following information concerning each chemical ingredient intentionally added to the hydraulic fracturing fluid:

(i) each additive used in the hydraulic fracturing fluid and the trade name, supplier, and a brief description of the intended use or function of each additive in the hydraulic fracturing treatment;

(ii) each chemical ingredient subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2);

(iii) all other chemical ingredients not submitted under subparagraph (A) of this paragraph that were intentionally included in, and used for the purpose of creating, hydraulic fracturing treatment(s) for the well;

(iv) the actual or maximum concentration of each chemical ingredient listed under clause (i) or clause (ii) of this subparagraph in percent by mass; and

(v) the CAS number for each chemical ingredient, if applicable.

(B) The supplier or service company must provide the operator of the well a written statement that the specific identity and/or CAS number or amount of any additive or chemical ingredient used in the hydraulic fracturing treatment(s) of the operator's well is claimed to be entitled to protection as trade secret information pursuant to Texas Government Code, Chapter 552. If the chemical ingredient name and/or CAS number is claimed as trade secret information, the supplier or service company making the claim must provide:

(i) the supplier's or service company's contact information, including the name, authorized representative, mailing address, and telephone number; and

(ii) the chemical family, unless providing the chemical family would disclose information protected as a trade secret.

(2) Operator disclosures.

(A) On or before the date the well completion report for a well on which hydraulic fracturing treatment(s) was/were conducted is submitted to the Commission in accordance with §3.16(b) of this title, the operator of the well must complete the Chemical Disclosure Registry form and upload the form on the Chemical Disclosure Registry, including:

(i) the operator name;

(ii) the date of completion of the hydraulic fracturing treatment(s);

(iii) the county in which the well is located;

(iv) the API number for the well;

(v) the well name and number;

(vi) the longitude and latitude of the wellhead;

(vii) the total vertical depth of the well;

(viii) the total volume of water used in the hydraulic fracturing treatment(s) of the well or the type and total volume of the base fluid used in the hydraulic fracturing treatment(s), if something other than water;

(ix) each additive used in the hydraulic fracturing treatments and the trade name, supplier, and a brief description of the intended use or function of each additive in the hydraulic fracturing treatment(s);

(x) each chemical ingredient used in the hydraulic fracturing treatment(s) of the well that is subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2), as provided by the chemical supplier or service company or by the operator, if the operator provides its own chemical ingredients;

(xi) the actual or maximum concentration of each chemical ingredient listed under clause (x) of this subparagraph in percent by mass;

(xii) the CAS number for each chemical ingredient listed, if applicable; and

(xiii) a supplemental list of all chemicals and their respective CAS numbers, not subject to the requirements of 29 Code of Federal Regulations §1910.1200(g)(2), that were intentionally included in and used for the purpose of creating the hydraulic fracturing treatments for the well.

(B) If the Chemical Disclosure Registry known as FracFocus is temporarily inoperable, the operator of a well on which hydraulic fracturing treatment(s) were performed must supply the Commission with the required information with the well completion report and must upload the information on the FracFocus Internet website when the website is again operable. If the Chemical Registry known as FracFocus is discontinued or becomes permanently inoperable, the information required by this rule must be filed as an attachment to the completion report for the well, which is posted, along with all attachments, on the Commission's Internet website, until the Commission amends this rule to specify another publicly accessible Internet website.

(C) If the supplier, service company, or operator claim that the specific identity and/or CAS number or amount of any additive or chemical ingredient used in the hydraulic fracturing treatment(s) is entitled to protection as trade secret information pursuant to Texas Government Code, Chapter 552, the operator of the well must indicate on the Chemical Disclosure Registry form or the supplemental list that the additive or chemical ingredient is claimed to be entitled to trade secret protection. If a chemical ingredient name and/or CAS number is claimed to be entitled to trade secret protection, the chemical family or other similar description associated with such chemical ingredient must be provided. The operator of the well on which the hydraulic fracturing treatment(s) were performed must provide the contact information, including the name, authorized representative, mailing address, and phone number of the business organization claiming entitlement to trade secret protection.

(D) Unless the information is entitled to protection as a trade secret under Texas Government Code, Chapter 552, information submitted to the Commission or uploaded on the Chemical Disclosure Registry is public information.

(3) Inaccuracies in information. A supplier is not responsible for any inaccuracy in information that is provided to the supplier by a third party manufacturer of the additives. A service company is not responsible for any inaccuracy in information that is provided to the service company by the supplier. An operator is not responsible for any inaccuracy in information provided to the operator by the supplier or service company.

(4) Disclosure to health professionals and emergency responders. A supplier, service company or operator may not withhold information related to chemical ingredients used in a hydraulic fracturing treatment, including information identified as a trade secret, from any health professional or emergency responder who needs the information for diagnostic, treatment or other emergency response purposes subject to procedures set forth in 29 Code of Federal Regulations §1910.1200(i). A supplier, service company or operator must provide directly to a health professional or emergency responder, all information in the person's possession that is required by the health professional or emergency responder, whether or not the information may qualify for trade secret protection under subsection (e) of this section. The person disclosing information to a health professional or emergency responder must include with the disclosure, as soon as circumstances permit, a statement of the health professional's confidentiality obligation. In an emergency situation, the supplier, service company or operator must provide the information immediately upon request to the person who determines that the information is necessary for emergency response or treatment. The disclosures

required by this subsection must be made in accordance with the procedures in 29 Code of Federal Regulations §1910.1200(i) with respect to a written statement of need and confidentiality agreements, as applicable.

(d) Disclosures not required. A supplier, service company, or operator is not required to:

(1) disclose ingredients that are not disclosed to it by the manufacturer, supplier, or service company;

(2) disclose ingredients that were not intentionally added to the hydraulic fracturing treatment;

(3) disclose ingredients that occur incidentally or are otherwise unintentionally present which may be present in trace amounts, may be the incidental result of a chemical reaction or chemical process, or may be constituents of naturally occurring materials that become part of a hydraulic fracturing fluid; or

(4) identify specific chemical ingredients and/or their CAS numbers that are claimed as entitled to trade secret protection based on the additive in which they are found or provide the concentration of such ingredients, unless the Office of the Attorney General, or a court of proper jurisdiction on appeal of a determination by the Office of the Attorney General, determines that the information would not be entitled to trade secret protection under Texas Government Code, Chapter 552, if the information had been provided to the Commission.

(e) Trade secret protection.

(1) A supplier, service company, or operator is not required to disclose trade secret information, unless the Office of the Attorney General or a court of proper jurisdiction determines that the information is not entitled to trade secret protection under Texas Government Code, Chapter 552.

(2) If the specific identity and/or CAS number of a chemical ingredient, the concentration of a chemical ingredient, or both the specific identity and/or CAS number and concentration of a chemical ingredient are claimed or have been finally determined to be entitled to protection as a trade secret under Texas Government Code, Chapter 552, the supplier, service company, or operator, as applicable, may withhold the specific identity and/or CAS number, the concentration, or both the specific identity and/or CAS number and concentration, of the chemical ingredient from the information provided to the operator. If the supplier, service company, or operator, as applicable, elects to withhold that information, the supplier, service company, or operator, as applicable, must provide to the operator or the Commission, as applicable, information that:

(A) indicates that the specific identity and/or CAS number of the chemical ingredient, the concentration of the chemical ingredient, or both the specific identity and/or CAS number and concentration of the chemical ingredient are entitled to protection as trade secret information; and

(B) discloses the chemical family associated with the chemical ingredient; or

(C) discloses the properties and effects of the chemical ingredient(s), the identity of which is withheld.

(f) Trade secret challenge.

(1) The following persons may submit a request challenging a claim of entitlement to trade secret protection for any chemical ingredients and/or CAS numbers used in the hydraulic fracturing treatment(s) of a well:

(A) the landowner on whose property the relevant wellhead is located;

(B) the landowner who owns real property adjacent to property described in subparagraph (A) of this paragraph; or

(C) a department or agency of this state with jurisdiction over a matter to which the claimed trade secret information is relevant.

(2) A requestor must certify in writing to the director, over the requestor's signature, to the following:

(A) the requestor's name, address, and daytime phone number;

(B) if the requestor is a landowner, a statement that the requestor is listed on the county appraisal roll as owning the property on which the relevant wellhead is located or is listed on the county appraisal roll as owning property adjacent to the property on which the relevant wellhead is located;

(C) the county in which the wellhead is located; and

(D) the API number or other Railroad Commission of Texas identifying information, such as field name, oil lease name and number, gas identification number, and well number.

(3) A requestor may use the following format to provide the written certification required by paragraph (2) of this subsection:

REQUEST TO CHALLENGE CLAIM OF ENTITLEMENT
TO TRADE SECRET PROTECTION OF HYDRAULIC FRACTURING
TREATMENT CHEMICAL COMPOSITION

I, _______(name)_________, challenge the claim of entitlement to trade secret protection for portions of the chemicals or other substances used in the hydraulic fracturing treatment of the following well:

Operator name: ____
County name: ____
API number: ____
Field Name: ____
Railroad Commission oil lease name and number: ________________
Railroad Commission gas identification number: _________________
Well Number: ____

<u>The following is to be completed if the requestor is a landowner:</u>

I certify that I am listed on the appraisal roll as owning the property on which the relevant wellhead is located or I am listed on the appraisal roll as owning property adjacent to the property on which the relevant wellhead is located.

Name of requestor: ____

Mailing address of Requestor:

____

____

Phone number of requestor: ______________________________________

Email address of requestor (optional):

____

EMAIL ADDRESS: YOU ARE NOT REQUIRED TO PROVIDE AN EMAIL ADDRESS when completing and filing this form. Please be aware that information provided to any governmental body may be subject to disclosure pursuant to the Texas Public Information Act or other applicable federal or state legislation. IF YOU PROVIDE AN EMAIL ADDRESS, YOU AFFIRMATIVELY CONSENT TO THE RELEASE OF THAT EMAIL ADDRESS TO THIRD PARTIES. Other departments within the Railroad Commission also may use the email address you provide to communicate with you.

Signature of Requestor: ____

Date: ________________________

As in effect on 12/8/2025.

(4) A requestor must file a request no later than 24 months from the date the operator filed the well completion report for the well on which the hydraulic fracturing treatment(s) were performed. A landowner who owned the property on which the wellhead is located, or owned adjacent property, on or after the date the operator filed with the Commission the completion report for the subject well may challenge a claim of entitlement to trade secret protection within that 24-month period only. The Commission will determine whether or not the request has been received within the allowed 24-month period.

(5) If the Commission determines that the request has been received within the allowed 24-month period and the certification is properly completed and signed, the Commission will consider this sufficient for the purpose of forwarding the request to the Office of the Attorney General.

(6) Within 10 business days of receiving a request that complies with paragraph (2) of this subsection, the director must:

(A) submit to Office of the Attorney General, Open Records Division, a request for decision regarding the challenge;

(B) notify the operator of the subject well and the owner of the claimed trade secret information of the submission of the request to the Office of the Attorney General and of the requirement that the owner of the claimed trade secret information submit directly to the Office of Attorney General, Open Records Division, the claimed trade secret information, clearly marked "confidential," submitted under seal; and

(C) inform the owner of the claimed trade secret information of the opportunity to substantiate to the Office of the Attorney General, Open Records Division, its claim of entitlement of trade secret protection, in accordance with Texas Government Code, Chapter 552.

(7) If the Office of the Attorney General determines that the claim of entitlement to trade secret protection is valid under Texas Government Code, Chapter 552, if the information had been provided to the Commission, the owner of the claimed trade secret information shall not be required to disclose the trade secret information, subject to appeal.

(8) The request shall be deemed withdrawn if, prior to the determination of the Office of the Attorney General on the validity of the trade secret claim, the owner of the claimed trade secret information provides confirmation to the Commission and the Office of the Attorney General that the owner of the claimed trade secret information has voluntarily provided the information that is the subject of the request to the requestor subject to a claim of trade secret protection, or the requestor submits to the Commission and the Office of the Attorney General a written notice withdrawing the request.

(9) A final determination by the Office of the Attorney General regarding the challenge to the claim of entitlement of trade secret protection of any withheld information may be appealed within 10 business days to a district court of Travis County pursuant to Texas Government Code, Chapter 552.

(10) If the Office of the Attorney General, or a court of proper jurisdiction on appeal of a determination by the Office of the Attorney General, determines that the withheld information would not be entitled to trade secret protection under Texas Government Code, Chapter 552, if the information had been provided to the Commission, the owner of the claimed trade secret information must disclose such information to the requestor as directed by the Office of the Attorney General or a court of proper jurisdiction on appeal.

(g) Trade secret confidentiality. A health professional or emergency responder to whom information is disclosed under subsection (c)(4) of this section must hold the information confidential, except that the health professional or emergency responder may, for diagnostic or treatment purposes, disclose information provided under that subsection to another health professional, emergency responder, or accredited laboratory. A health professional, emergency responder, or accredited laboratory to which information is disclosed by another health professional or emergency responder under this subsection must hold the information confidential and the disclosing health professional or emergency responder must include with the disclosure, or in a medical emergency, as soon as circumstances permit, a statement of the recipient's confidentiality obligation pursuant to this subsection.

(h) Penalties. A violation of this section may subject a person to any penalty or remedy specified in the Texas Natural Resources Code, Title 3, and any other statutes administered by the Commission. The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) (Rule 73) for violation of this section.

Source Note: The provisions of this §3.29 adopted to be effective January 2, 2012, 36 TexReg 9307.

§3.30 Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)

(a) Need for agreement. Several statutes cover persons and activities where the respective jurisdictions of the RRC and the TCEQ may intersect. This rule is a statement of how the agencies implement the division of jurisdiction.

(1) Section 10 of House Bill 1407, 67th Legislature, 1981, which appeared as a footnote to the Texas Solid Waste Disposal Act, Texas Civil Statutes, Article 4477-7, provides as follows: On or before January 1, 1982, the Texas Department of Water Resources, the Texas Department of Health, and the Railroad Commission of Texas shall execute a memorandum of understanding that specifies in detail these agencies' interpretation of the division of jurisdiction among the agencies over waste materials that result from or are related to activities associated with the exploration for and the development, production, and refining of oil or gas. The agencies shall amend the memorandum of understanding at any time that the agencies find it to be necessary.

(2) Texas Health and Safety Code, §401.414, relating to Memoranda of Understanding, requires the Railroad Commission of Texas and the Texas Commission on Environmental Quality to adopt a memorandum of

understanding (MOU) defining the agencies' respective duties under Texas Health and Safety Code, Chapter 401, relating to radioactive materials and other sources of radiation. Texas Health and Safety Code, §401.415, relating to oil and gas naturally occurring radioactive material (NORM) waste, provides that the Railroad Commission of Texas shall issue rules on the management of oil and gas NORM waste, and in so doing shall consult with the Texas Natural Resource Conservation Commission (now TCEQ) and the Department of Health (now Department of State Health Services) regarding protection of the public health and the environment.

(3) Texas Water Code, Chapters 26 and 27, provide that the Railroad Commission and TCEQ collaborate on matters related to discharges, surface water quality, groundwater protection, underground injection control and geologic storage of carbon dioxide. Texas Water Code, §27.049, relating to Memorandum of Understanding, requires the RRC and TCEQ to adopt a new MOU or amend the existing MOU to reflect the agencies' respective duties under Texas Water Code, Chapter 27, Subchapter C-1 (relating to Geologic Storage and Associated Injection of Anthropogenic Carbon Dioxide).

(4) The original MOU between the agencies adopted pursuant to House Bill 1407 (67th Legislature, 1981) became effective January 1, 1982. The MOU was revised effective December 1, 1987, May 31, 1998, August 30, 2010, and again on May 1, 2012, to reflect legislative clarification of the Railroad Commission's jurisdiction over oil and gas wastes and the Texas Natural Resource Conservation Commission's (the combination of the Texas Water Commission, the Texas Air Control Board, and portions of the Texas Department of Health) jurisdiction over industrial and hazardous wastes.

(5) The agencies have determined that the revised MOU that became effective on May 1, 2012, should again be revised to further clarify jurisdictional boundaries and to reflect legislative changes in agency responsibility.

(b) General agency jurisdictions.

(1) Texas Commission on Environmental Quality (TCEQ) (the successor agency to the Texas Natural Resource Conservation Commission).

(A) Solid waste. Under Texas Health and Safety Code, Chapter 361, §§361.001 - 361.754, the TCEQ has jurisdiction over solid waste. The TCEQ's jurisdiction encompasses hazardous and nonhazardous, industrial and municipal, solid wastes.

(i) Under Texas Health and Safety Code, §361.003(34), solid waste under the jurisdiction of the TCEQ is defined to include "garbage, rubbish, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility, and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, municipal, commercial, mining, and agricultural operations and from community and institutional activities."

(ii) Under Texas Health and Safety Code, §361.003(34), the definition of solid waste excludes "material which results from activities associated with the exploration, development, or production of oil or gas or geothermal resources and other substance or material regulated by the Railroad Commission of Texas pursuant to Section 91.101, Natural Resources Code. . . ."

(iii) Under Texas Health and Safety Code, §361.003(34), the definition of solid waste includes the following until the United States Environmental Protection Agency (EPA) delegates its authority under the Resource Conservation and Recovery Act, 42 United States Code (U.S.C.) §6901, et seq., (RCRA) to the RRC: "waste, substance or material that results from activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants, or repressurizing plants and is a hazardous waste as defined by the administrator of the EPA. . . ."

(iv) After delegation of RCRA authority to the RRC, the definition of solid waste (which defines TCEQ's jurisdiction) will not include hazardous wastes arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants, or reservoir pressure maintenance or repressurizing plants. The term natural gas or natural gas liquids processing plant refers to a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. The term does not include a separately located natural gas treating plant for which the primary function is the removal of carbon dioxide, hydrogen sulfide, or other impurities from the natural gas stream. A separator, dehydration unit, heater treater, sweetening unit, compressor, or similar equipment is considered a part of a natural gas or natural gas liquids processing plant only if it is located at a plant the primary function of which is the extraction of natural gas liquids from field gas or fractionation of natural gas liquids. Further, a pressure maintenance or repressurizing plant is a plant for processing natural gas for reinjection (for reservoir pressure maintenance or repressurization) in a natural gas recycling project. A compressor station along a natural gas pipeline system or a pump station along a crude oil pipeline system is not a pressure maintenance or repressurizing plant.

(B) Water quality.

(i) Discharges under Texas Water Code, Chapter 26. Under the Texas Water Code, Chapter 26, the TCEQ has jurisdiction over discharges into or adjacent to water in the state, except for discharges regulated by the RRC. Upon delegation from the United States Environmental Protection Agency to the TCEQ of authority to issue permits for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code §26.131(a), the TCEQ has sole authority to issue permits for those discharges. For the purposes of TCEQ's implementation of Texas Water Code, §26.131, "produced water" is defined as all wastewater associated with oil and gas exploration, development, and production activities, except hydrostatic test water and gas plant effluent, that is discharged into water in the state, including waste streams regulated by 40 CFR Part 435.

(ii) Discharge permits existing on the effective date of EPA's delegation to TCEQ of NPDES permit authority for discharges of produced water, hydrostatic test water, and gas plant effluent. RRC permits issued prior to TCEQ delegation of NPDES authority shall remain effective until revoked or expired. Amendment or renewal of such permits on or after the effective date of delegation shall be pursuant to TCEQ's TPDES authority. The TPDES permit will supersede and replace the RRC permit. For facilities that have both an RRC permit and an EPA permit, TCEQ will issue the TPDES permit upon amendment or renewal of the RRC or EPA permit, whichever occurs first.

(iii) Discharge applications pending on the effective date of EPA's delegation to TCEQ of NPDES permit authority for discharges of produced water, hydrostatic test water, and gas plant effluent. TCEQ shall assume authority for discharge applications pending at the time TCEQ receives delegation from EPA. The RRC will provide TCEQ the permit application and any other relevant information necessary to administratively and technically review and process the applications. TCEQ will review and process these pending applications in accordance with TPDES requirements.

(iv) Storm water. TCEQ has jurisdiction over storm water discharges that are required to be permitted pursuant to Title 40 Code of Federal Regulations (CFR) Part 122.26, except for discharges regulated by the RRC. Discharge of storm water regulated by TCEQ may be authorized by an individual Texas Pollutant Discharge Elimination System (TPDES) permit or by a general TPDES permit. These storm water permits may also include authorizations for certain minor types of non-storm water discharges.

(I) Storm water associated with industrial activities. The TCEQ regulates storm water discharges associated with certain industrial activities under individual TPDES permits and under the TPDES Multi-Sector General Permit, except for discharges associated with industrial activities under the jurisdiction of the RRC.

(II) Storm water associated with construction activities. The TCEQ regulates storm water discharges associated with construction activities, except for discharges from construction activities under the jurisdiction of the RRC.

(III) Municipal storm water discharges. The TCEQ has jurisdiction over discharges from regulated municipal storm sewer systems (MS4s).

(IV) Combined storm water. Except with regard to storage of oil, when a portion of a site is regulated by the TCEQ, and a portion of a site is regulated by the EPA and RRC, storm water authorization must be obtained from the TCEQ for the portion(s) of the site regulated by the TCEQ, and from the EPA and the RRC, as applicable, for the RRC regulated portion(s) of the site. Discharge of storm water from a facility that stores both refined products intended for off-site use and crude oil in aboveground tanks is regulated by the TCEQ.

(v) State water quality certification. Under the Clean Water Act (CWA) Section 401 (33 U.S.C. Section 1341), the TCEQ performs state water quality certifications for activities that require a federal license or permit and that may result in a discharge to waters of the United States, except for those activities regulated by the RRC.

(vi) Commercial brine extraction and evaporation. Under Texas Water Code, §26.132, the TCEQ has jurisdiction over evaporation pits operated for the commercial production of brine water, minerals, salts, or other substances that naturally occur in groundwater and that are not regulated by the RRC.

(C) Injection wells. Under the Texas Water Code, Chapter 27, the TCEQ has jurisdiction to regulate and authorize the drilling, construction, operation, and closure of injection wells unless the activity is subject to the jurisdiction of the RRC. Injection wells under TCEQ's jurisdiction are identified in 30 TAC §331.11 (relating to Classification of Injection Wells) and include:

(i) Class I injection wells for the disposal of hazardous, radioactive, industrial or municipal waste that inject fluids below the lower-most formation which within 1/4 mile of the wellbore contains an underground source of drinking water;

(ii) Class III injection wells for the extraction of minerals including solution mining of sodium sulfate, sulfur, potash, phosphate, copper, uranium and the mining of sulfur by the Frasch process;

(iii) Class IV injection wells for the disposal of hazardous or radioactive waste which inject fluids into or above formations that contain an underground source of drinking water; and

(iv) Class V injection wells that are not under the jurisdiction of the RRC, such as aquifer remediation wells, aquifer recharge wells, aquifer storage wells, large capacity septic systems, storm water drainage wells, salt water intrusion barrier wells, and closed loop geothermal wells.

(2) Railroad Commission of Texas (RRC).

(A) Oil and gas waste.

(i) Under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, wastes (both hazardous and nonhazardous) resulting from activities associated with the exploration, development, or production of oil or gas or geothermal resources, including storage, handling, reclamation, gathering, transportation, or distribution of crude oil or natural gas by pipeline, prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel, are under the jurisdiction of the RRC, except as noted in clause (ii) of this subparagraph. These wastes are termed "oil and gas wastes." In compliance with Texas Health and Safety Code, §361.025 (relating to exempt activities), a list of activities that generate wastes that are subject to the jurisdiction of the RRC is found in §4.110 of this title (relating to Definitions) and at 30 TAC §335.1 (relating to Definitions), which contains a definition of "activities associated with the exploration, development, and production of oil or gas or geothermal resources." Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of oil and gas naturally occurring radioactive material (NORM) waste that constitutes, is contained in, or has contaminated oil and gas waste.

(ii) Hazardous wastes arising out of or incidental to activities associated with gasoline plants, natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants are subject to the jurisdiction of the TCEQ until the RRC is authorized by EPA to administer RCRA. When the RRC is authorized by EPA to administer RCRA, jurisdiction over such hazardous wastes will transfer from the TCEQ to the RRC.

(B) Water quality.

(i) Discharges. Under Texas Natural Resources Code, Title 3, and Texas Water Code, Chapter 26, the RRC regulates discharges from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, including transportation of crude oil and natural gas by pipeline, and from solution brine mining activities, except that on delegation to the TCEQ of NPDES authority for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code §26.131(a), the TCEQ has sole authority to issue permits for those discharges. Discharges regulated by the RRC into or adjacent to water in the state shall not cause a violation of the water quality standards. While water quality standards are established by the TCEQ, the RRC has the responsibility for enforcing any violation of such standards resulting from activities regulated by the RRC. Texas Water Code, Chapter 26, does not require that discharges regulated by the RRC comply with regulations of the TCEQ that are not water quality standards. The TCEQ and the RRC may consult as necessary regarding application and interpretation of Texas Surface Water Quality Standards.

(ii) Storm water. When required by federal law, authorization for storm water discharges that are under the jurisdiction of the RRC must be obtained through application for a National Pollutant Discharge Elimination System (NPDES) permit with the EPA and authorization from the RRC, as applicable.

(I) Storm water associated with industrial activities. Where required by federal law, discharges of storm water associated with facilities and activities under the RRC's jurisdiction must be authorized by the EPA and the RRC, as applicable. Under 33 U.S.C. §1342(l)(2) and §1362(24), EPA cannot require a permit for discharges of storm water from "field activities or operations associated with {oil and gas} exploration, production, processing, or treatment operations, or transmission facilities" unless the discharge is contaminated by contact with any overburden, raw material, intermediate product, finished product, byproduct, or waste product located on the site of the facility. Under Chapter 4 of this title (relating to Environmental Protection), specifically Subchapter A (relating to Oil and Gas Waste Management), the RRC prohibits operators from causing or allowing pollution of surface or subsurface water. Operators are encouraged to implement and maintain Best Management Practices (BMPs) to minimize discharges of pollutants, including sediment, in storm water to help ensure protection of surface water quality during storm events.

(II) Storm water associated with construction activities. Where required by federal law, discharges of storm water associated with construction activities under the RRC's jurisdiction must be authorized by the EPA and the RRC, as applicable. Activities under RRC jurisdiction include construction of a facility that, when completed, would be associated with the exploration, development, or production of oil or gas or geothermal resources, such as a well site; treatment or storage facility; underground hydrocarbon or natural gas storage facility; reclamation plant; gas processing facility; compressor station; terminal facility where crude oil is stored prior to refining and at which refined products are stored solely for use at the facility; a carbon dioxide geologic storage facility under the jurisdiction of the RRC; and a gathering, transmission, or distribution pipeline that will transport crude oil or natural gas, including natural gas liquids, prior to refining of such oil or the use of the natural gas in any manufacturing process or as a residential or industrial fuel. The RRC also has jurisdiction over storm water from land disturbance associated with a site survey that is conducted prior to construction of a facility that would be regulated by the RRC. Under 33 U.S.C. §1342(l)(2) and §1362(24), EPA cannot require a permit for discharges of storm water from "field activities or operations associated with {oil and gas} exploration, production, processing, or treatment operations, or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activities" unless the discharge is contaminated by contact with any overburden, raw material, intermediate product, finished product, byproduct, or waste product located on the site of the facility. Under Chapter 4 of this title (relating to Environmental Protection), specifically Subchapter A (relating to Oil and Gas Waste Management), the RRC prohibits operators from causing or allowing pollution of surface or subsurface water. Operators are encouraged to implement and maintain BMPs to minimize discharges of pollutants, including sediment, in storm water during construction activities to help ensure protection of surface water quality during storm events.

(III) Municipal storm water discharges. Storm water discharges from facilities regulated by the RRC located within an MS4 are not regulated by the TCEQ. However, a municipality may regulate storm water discharges from RRC sites into their MS4.

(IV) Combined storm water. Except with regard to storage of oil, when a portion of a site is regulated by the RRC and the EPA, and a portion of a site is regulated by the TCEQ, storm water authorization must be obtained from the EPA and the RRC, as applicable, for the portion(s) of the site under RRC jurisdiction and from the TCEQ for the TCEQ regulated portion(s) of the site. Discharge of storm water from a terminal facility where crude oil is stored prior to refining and at which refined products are stored solely for use at the facility is under the jurisdiction of the RRC.

(iii) State water quality certification. The RRC performs state water quality certifications, as authorized by the Clean Water Act (CWA) Section 401 (33 U.S.C. Section 1341) for activities that require a federal license or permit and that may result in any discharge to waters of the United States for those activities regulated by the RRC.

(C) Injection wells. The RRC has jurisdiction over the drilling, construction, operation, and closure of the following injection wells.

(i) Disposal wells. The RRC has jurisdiction under Texas Water Code, Chapter 27, over injection wells used to dispose of oil and gas waste. Texas Water Code, Chapter 27, defines "oil and gas waste" to mean "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources, waste arising out of or incidental to the underground storage of hydrocarbons other than storage in artificial tanks or containers, or waste arising out of or incidental to the operation of gasoline plants, natural gas processing plants, or pressure maintenance or repressurizing plants. The term includes but is not limited to salt water, brine, sludge, drilling mud, and other liquid or semi-liquid waste material." The term "waste arising out of or incidental to drilling for or producing of oil, gas, or geothermal resources" includes waste associated with transportation of crude oil or natural gas by pipeline pursuant to Texas Natural Resources Code, §91.101.

(ii) Enhanced recovery wells. The RRC has jurisdiction over wells into which fluids are injected for enhanced recovery of oil or natural gas.

(iii) Brine mining. Under Texas Water Code, §27.036, the RRC has jurisdiction over brine mining and may issue permits for injection wells.

(iv) Geologic storage of carbon dioxide. Under Texas Water Code, §27.011 and §27.041, and subject to the review of the legislature based on the recommendations made in the preliminary report described by Section 10, Senate Bill No. 1387, Acts of the 81st Legislature, Regular Session (2009), the RRC has jurisdiction over geologic storage of carbon dioxide in, and the injection of carbon dioxide into, a reservoir that is initially or may be productive of oil, gas, or geothermal resources or a saline formation directly above or below that reservoir and over a well used for such injection purposes regardless of whether the well was initially completed for that purpose or was initially completed for another purpose and converted.

(v) Hydrocarbon storage. The RRC has jurisdiction over wells into which fluids are injected for storage of hydrocarbons that are liquid at standard temperature and pressure.

(vi) Geothermal energy. Under Texas Natural Resources Code, Chapter 141, the RRC has jurisdiction over injection wells for the exploration, development, and production of geothermal energy and associated resources.

(vii) In situ tar sands. Under Texas Water Code, §27.035, the RRC has jurisdiction over the in situ recovery of tar sands and may issue permits for injection wells used for the in situ recovery of tar sands.

(c) Definition of hazardous waste.

(1) Under the Texas Health and Safety Code, §361.003(12), a "hazardous waste" subject to the jurisdiction of the TCEQ is defined as "solid waste identified or listed as a hazardous waste by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended (42 U.S.C. §6901, et seq.)." Similarly, under Texas Natural Resources Code, §91.601(1), "oil and gas hazardous waste" subject to the jurisdiction of the RRC is defined as an "oil and gas waste that is a hazardous waste as defined by the administrator of the United States Environmental Protection Agency under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (42 U.S.C. §§6901, et seq.)."

(2) Federal regulations adopted under authority of the federal Solid Waste Disposal Act, as amended by RCRA, exempt from regulation as hazardous waste certain oil and gas wastes. Under 40 Code of Federal Regulations (CFR) §261.4(b)(5), "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" are described as wastes that are exempt from federal hazardous waste regulations.

(3) A partial list of wastes associated with oil, gas, and geothermal exploration, development, and production that are considered exempt from hazardous waste regulation under RCRA can be found in EPA's "Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes," 53 FedReg 25,446 (July 6, 1988). A further explanation of the exemption can be found in the "Clarification of the Regulatory Determination for Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy, " 58 FedReg 15,284 (March 22, 1993). The exemption codified at 40 CFR §261.4(b)(5) and discussed in the Regulatory Determination has been, and may continue to be, clarified in subsequent guidance issued by the EPA.

(d) Jurisdiction over waste from specific activities.

(1) Drilling, operation, and plugging of wells associated with the exploration, development, or production of oil, gas, or geothermal resources. Wells associated with the exploration, development, or production of oil, gas, or geothermal resources include exploratory wells, cathodic protection holes, core holes, oil wells, gas wells, geothermal resource wells, fluid injection wells used for secondary or enhanced recovery of oil or gas, oil and gas waste disposal wells, and injection water source wells. Several types of waste materials can be generated during the drilling, operation, and plugging of these wells. These waste materials include drilling fluids (including water-based and oil-based fluids), cuttings, produced water, produced sand, waste hydrocarbons (including used oil), fracturing fluids, spent acid, workover fluids, treating chemicals (including scale inhibitors, emulsion breakers, paraffin inhibitors, and surfactants), waste cement, filters (including used oil filters), domestic sewage (including waterborne human waste and waste from activities such as bathing and food preparation), and trash (including inert waste, barrels, dope cans, oily rags, mud sacks, and garbage). Generally, these wastes, whether disposed of by discharge, landfill, land farm, evaporation, or injection, are subject to the jurisdiction of the RRC. Wastes from oil, gas, and geothermal exploration activities subject to regulation by the RRC when those wastes are to be processed, treated, or disposed of at a solid waste management facility authorized by the TCEQ under 30 TAC Chapter 330 are, as defined in 30 TAC §330.3(148) (relating to Definitions), "special wastes."

(2) Field treatment of produced fluids. Oil, gas, and water produced from oil, gas, or geothermal resource wells may be treated in the field in facilities such as separators, skimmers, heater treaters, dehydrators, and sweetening units. Waste that results from the field treatment of oil and gas include waste hydrocarbons (including used oil), produced water, hydrogen sulfide scavengers, dehydration wastes, treating and cleaning chemicals, filters (including used oil filters), asbestos insulation, domestic sewage, and trash are subject to the jurisdiction of the RRC.

(3) Storage of oil.

(A) Tank bottoms and other wastes from the storage of crude oil (whether foreign or domestic) before it enters the refinery are under the jurisdiction of the RRC. In addition, waste resulting from storage of crude oil at refineries is subject to the jurisdiction of the TCEQ.

(B) Wastes generated from storage tanks that are part of the refinery and wastes resulting from the wholesale and retail marketing of refined products are subject to the jurisdiction of the TCEQ.

(4) Underground hydrocarbon storage. The disposal of wastes, including saltwater, resulting from the construction, creation, operation, maintenance, closure, or abandonment of an "underground hydrocarbon storage facility" is subject to the jurisdiction of the RRC, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" have the meanings set out in Texas Natural Resources Code, §91.201.

(5) Underground natural gas storage. The disposal of wastes resulting from the construction, operation, or abandonment of an "underground natural gas storage

facility" is subject to the jurisdiction of the RRC, provided that the terms "natural gas" and "storage facility" have the meanings set out in Texas Natural Resources Code, §91.173.

(6) Transportation of crude oil or natural gas.

(A) Jurisdiction over pipeline-related activities. The RRC has jurisdiction over matters related to pipeline safety for pipelines in Texas, as referenced in §8.1 of this title (relating to General Applicability and Standards) pursuant to Chapter 121 of the Texas Utilities Code and Chapter 117 of the Texas Natural Resources Code. The RRC has jurisdiction over spill response and remediation of releases from pipelines transporting crude oil, natural gas, and condensate that originate from exploration and production facilities to the refinery gate. The RRC has jurisdiction over waste generated by construction and operation of pipelines used to transport crude oil, natural gas, and condensate on an oil and gas lease, and from exploration and production facilities to the refinery gate. The RRC is responsible for water quality certification issues related to construction and operation of pipelines used to transport crude oil, natural gas, and condensate on an oil and gas lease, and from exploration and production facilities to the refinery gate. The RRC has jurisdiction over waste generated by construction and operation of pipelines transporting carbon dioxide.

(B) Crude oil and natural gas are transported by railcars, tank trucks, barges, tankers, and pipelines. The RRC has jurisdiction over waste from the transportation of crude oil by pipeline, regardless of the crude oil source (foreign or domestic) prior to arrival at a refinery. The RRC also has jurisdiction over waste from the transportation by pipeline of natural gas, including natural gas liquids, prior to the use of the natural gas in any manufacturing process or as a residential or industrial fuel. The transportation wastes subject to the jurisdiction of the RRC include wastes from pipeline compressor or pressure stations and wastes from pipeline hydrostatic pressure tests and other pipeline operations. These wastes include waste hydrocarbons (including used oil), treating and cleaning chemicals, filters (including used oil filters), scraper trap sludge, trash, domestic sewage, wastes contaminated with polychlorinated biphenyls (PCBs) (including transformers, capacitors, ballasts, and soils), soils contaminated with mercury from leaking mercury meters, asbestos insulation, transite pipe, and hydrostatic test waters.

(C) The TCEQ has jurisdiction over waste from transportation of refined products by pipeline.

(D) The TCEQ also has jurisdiction over wastes associated with transportation of crude oil and natural gas, including natural gas liquids, by railcar, tank truck, barge, or tanker.

(7) Reclamation plants.

(A) The RRC has jurisdiction over wastes from reclamation plants that process wastes from activities associated with the exploration, development, or production of oil, gas, or geothermal resources, such as lease tank bottoms. Waste management activities of reclamation plants for other wastes are subject to the jurisdiction of the TCEQ.

(B) The RRC has jurisdiction over the conservation and prevention of waste of crude oil and therefore must approve all movements of crude oil-containing materials to reclamation plants. The applicable statute and regulations consist primarily of reporting requirements for accounting purposes.

(8) Refining of oil.

(A) The management of wastes resulting from oil refining operations, including spent caustics, spent catalysts, still bottoms or tars, and American Petroleum Institute (API) separator sludges, is subject to the jurisdiction of the TCEQ. The processing of light ends from the distillation and cracking of crude oil or crude oil products is considered to be a refining operation. The term "refining" does not include the processing of natural gas or natural gas liquids.

(B) The RRC has jurisdiction over refining activities for the conservation and the prevention of waste of crude oil. The RRC requires that all crude oil streams into or out of a refinery be reported for accounting purposes. In addition, the RRC requires that materials recycled and used as a fuel, such as still bottoms or waste crude oil, be reported.

(9) Natural gas or natural gas liquids processing plants (including gas fractionation facilities) and pressure maintenance or repressurizing plants. Wastes resulting from activities associated with these facilities include produced water, cooling tower water, sulfur bead, sulfides, spent caustics, sweetening agents, spent catalyst, waste hydrocarbons (including used oil), asbestos insulation, wastes contaminated with PCBs (including transformers, capacitors, ballasts, and soils), treating and cleaning chemicals, filters, trash, domestic sewage, and dehydration materials. These wastes are subject to the jurisdiction of the RRC under Texas Natural Resources Code, §1.101. Disposal of waste from activities associated with natural gas or natural gas liquids processing plants (including gas fractionation facilities), and pressure maintenance or repressurizing plants by injection is subject to the jurisdiction of the RRC under Texas Water Code, Chapter 27. However, until delegation of authority under RCRA to the RRC, the TCEQ shall have jurisdiction over wastes resulting from these activities that are not exempt from federal hazardous waste regulation under RCRA and that are considered hazardous under applicable federal rules.

(10) Manufacturing processes.

(A) Wastes that result from the use of natural gas, natural gas liquids, or products refined from crude oil in any manufacturing process, such as the production of petrochemicals or plastics, or from the manufacture of carbon black, are industrial wastes subject to the jurisdiction of the TCEQ. The term "manufacturing process" does not include the processing (including fractionation) of natural gas or natural gas liquids at natural gas or natural gas liquids processing plants.

(B) The RRC has jurisdiction under Texas Natural Resources Code, Chapter 87, to regulate the use of natural gas in the production of carbon black.

(C) Biofuels. The TCEQ has jurisdiction over wastes associated with the manufacturing of biofuels and biodiesel. TCEQ Regulatory Guidance Document RG-462 contains additional information regarding biodiesel manufacturing in the state of Texas.

(11) Commercial service company facilities and training facilities.

(A) The TCEQ has jurisdiction over wastes generated at facilities, other than actual exploration, development, or production sites (field sites), where oil and gas industry workers are trained. In addition, the TCEQ has jurisdiction over wastes generated at facilities where materials, processes, and equipment associated with oil and gas industry operations are researched, developed, designed, and manufactured. However, wastes generated from tests of materials, processes, and equipment at field sites are under the jurisdiction of the RRC.

(B) The TCEQ also has jurisdiction over waste generated at commercial service company facilities operated by persons providing equipment, materials, or services (such as drilling and work over rig rental and tank rental; equipment repair; drilling fluid supply; and acidizing, fracturing, and cementing services) to the oil and gas industry. These wastes include the following wastes when they are generated at commercial service company facilities: empty sacks, containers, and drums; drum, tank, and truck rinsate; sandblast media; painting wastes; spent solvents; spilled chemicals; waste motor oil; and unused fracturing and acidizing fluids.

(C) The term "commercial service company facility" does not include a station facility such as a warehouse, pipeyard, or equipment storage facility belonging to an oil and gas operator and used solely for the support of that operator's own activities associated with the exploration, development, or production activities.

(D) Notwithstanding subparagraphs (A) - (C) of this paragraph, the RRC has jurisdiction over disposal of oil and gas wastes, such as waste drilling fluids and NORM-contaminated pipe scale, in volumes greater than the incidental volumes usually received at such facilities, that are managed at commercial service company facilities.

(E) The RRC also has jurisdiction over wastes such as vacuum truck rinsate and tank rinsate generated at facilities operated by oil and gas waste haulers permitted by the RRC pursuant to Chapter 4 of this title (relating to Environmental Protection), specifically Subchapter A (relating to Oil and Gas Waste Management).

(12) Mobile offshore drilling units (MODUs). MODUs are vessels capable of engaging in drilling operations for exploring or exploiting subsea oil, gas, or mineral resources.

(A) The RRC and, where applicable, the EPA, the U.S. Coast Guard, or the Texas General Land Office (GLO), have jurisdiction over discharges from an MODU when the unit is being used in connection with activities associated with the exploration, development, or production of oil or gas or geothermal resources, except that upon delegation to the TCEQ of NPDES authority for discharges into surface water in the state of produced water, hydrostatic test water, and gas plant effluent resulting from the activities described in Texas Water Code, §26.131(a), the TCEQ shall assume RRC's authority under this subsection.

(B) The TCEQ and, where applicable, the EPA, the U.S. Coast Guard, or the GLO, have jurisdiction over discharges from an MODU when the unit is being serviced at a maintenance facility.

(C) Where applicable, the EPA, the U.S. Coast Guard, or the GLO has jurisdiction over discharges from an MODU during transportation from shore to exploration, development or production site, transportation between sites, and transportation to a maintenance facility.

(e) Interagency activities.

(1) Recycling and pollution prevention.

(A) The TCEQ and the RRC encourage generators to eliminate pollution at the source and recycle whenever possible to avoid disposal of wastes. Questions regarding source reduction and recycling may be directed to the TCEQ External Relations Division, or to the RRC. The TCEQ may require generators to explore source reduction and recycling alternatives prior to authorizing disposal of any waste under the jurisdiction of the RRC at a facility regulated by the TCEQ; similarly, the RRC may explore source reduction and recycling alternatives prior to authorizing disposal of any waste under the jurisdiction of the TCEQ at a facility regulated by the RRC.

(B) The TCEQ External Relations Division and the RRC will coordinate as necessary to maintain a working relationship to enhance the efforts to share information and use resources more efficiently. The TCEQ External Relations Division will make the proper TCEQ personnel aware of the services offered by the RRC, share information with the RRC to maximize services to oil and gas operators, and advise oil and gas operators of RRC services. The RRC will make the proper RRC personnel aware of the services offered by the TCEQ External Relations Division, share information with the TCEQ External Relations Division to maximize services to industrial operators, and advise industrial operators of the TCEQ External Relations Division services.

(2) Treatment of wastes under RRC jurisdiction at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K, (relating to Storage, Treatment, and Reuse Procedures for Petroleum-Substance Contaminated Soil).

(A) Soils contaminated with constituents that are physically and chemically similar to those normally found in soils at leaking underground petroleum storage tanks from generators under the jurisdiction of the RRC are eligible for treatment at TCEQ regulated soil treatment facilities once alternatives for recycling and source reduction have been explored. For the purpose of this provision, soils containing petroleum substance(s) as defined in 30 TAC §334.481 (relating to Definitions) are considered to be similar, but drilling muds, acids, or other chemicals used in oil and gas activities are not considered similar. Generators under the jurisdiction of the RRC must meet the same requirements as generators under the jurisdiction of the TCEQ when sending their petroleum contaminated soils to soil treatment facilities under TCEQ jurisdiction. Those requirements are in 30 TAC §334.496 (relating to Shipping Procedures Applicable to Generators of Petroleum-Substance Waste), except subsection (c) which is not applicable, and 30 TAC §334.497 (relating to Recordkeeping and Reporting Procedures Applicable to Generators). RRC generators with questions on these requirements should contact the TCEQ.

(B) Generators under RRC jurisdiction should also be aware that TCEQ regulated soil treatment facilities are required by 30 TAC §334.499 (relating to Shipping Requirements Applicable to Owners or Operators of Storage, Treatment, or Disposal Facilities) to maintain documentation on the soil sampling and analytical methods, chain-of-custody, and all analytical results for the soil received at the facility and transported off-site or reused on-site.

(C) The RRC must specifically authorize management of contaminated soils under its jurisdiction at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K. The RRC may grant such authorizations by rule, or on an individual basis through permits or other written authorizations.

(D) All waste, including treated waste, subject to the jurisdiction of the RRC and managed at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K will remain subject to the jurisdiction of the RRC. Such materials will be subject to RRC regulations regarding final reuse, recycling, or disposal.

(E) TCEQ waste codes and registration numbers are not required for management of wastes under the jurisdiction of the RRC at facilities authorized by the TCEQ under 30 TAC Chapter 334, Subchapter K.

(3) Processing, treatment, and disposal of wastes under RRC jurisdiction at facilities authorized by the TCEQ.

(A) As provided in this paragraph, waste materials subject to the jurisdiction of the RRC may be managed at solid waste facilities under the jurisdiction of the TCEQ once alternatives for recycling and source reduction have been explored. The RRC must specifically authorize management of wastes under its jurisdiction at facilities regulated by the TCEQ. The RRC may grant such authorizations by rule, or on an individual basis through permits or other written authorizations. In addition, except as provided in subparagraph (B) of this paragraph, the concurrence of the TCEQ is required to manage "special waste" under the jurisdiction of the RRC at a facility regulated by the TCEQ. The TCEQ's concurrence may be subject to specified conditions.

(B) A facility under the jurisdiction of the TCEQ may accept, without further individual concurrence, waste under the jurisdiction of the RRC if that facility is permitted or otherwise authorized to accept that particular type of waste. The phrase "that type of waste" does not specifically refer to waste under the jurisdiction of the RRC, but rather to the waste's physical and chemical characteristics. Management and disposal of waste under the jurisdiction of the RRC is subject to TCEQ's rules governing both special waste and industrial waste.

(C) If the TCEQ regulated facility receiving the waste does not have approval to accept the waste included in its permit or other authorization, individual written concurrences from the TCEQ shall be required to manage wastes under the jurisdiction of the RRC at TCEQ regulated facilities. Recommendations for the management of special wastes associated with the exploration, development, or production of oil, gas, or geothermal resources are found in TCEQ Regulatory Guidance document RG-3. (This is required only if the TCEQ regulated facility receiving the waste does not have approval to accept the waste included in its permit or other authorization provided by the TCEQ.) To obtain an individual concurrence, the waste generator must provide to the TCEQ sufficient information to allow the concurrence determination to be made, including the identity of the proposed waste management facility, the process generating the waste, the quantity of waste, and the physical and chemical nature of the waste involved (using process knowledge and/or laboratory analysis as defined in 30 TAC Chapter 335, Subchapter R (relating to Waste Classification)). In obtaining TCEQ approval, generators may use their existing knowledge about the process or materials entering it to characterize their wastes. Material Safety Data Sheets, manufacturer's literature, and other documentation generated in conjunction with a particular process may be used. Process knowledge must be documented and submitted with the request for approval.

(D) Domestic septage collected from portable toilets at facilities subject to RRC jurisdiction that is not mixed with other waste materials may be managed at a facility permitted by the TCEQ for disposal, incineration, or land application for beneficial use of such domestic septage waste without specific authorization from the TCEQ or the RRC. Waste sludge subject to the jurisdiction of the RRC may not be applied to the land at a facility permitted by the TCEQ for the beneficial use of sewage sludge or water treatment sludge.

(E) TCEQ waste codes and registration numbers are not required for management of wastes under the jurisdiction of the RRC at facilities under the jurisdiction of the TCEQ. If a receiving facility requires a TCEQ waste code for waste under the jurisdiction of the RRC, a code consisting of the following may be provided:

(i) the sequence number "RRCT";

(ii) the appropriate form code, as specified in 30 TAC Chapter 335, Subchapter R, §335.521, Appendix 3 (relating to Appendices); and

(iii) the waste classification code "H" if the waste is a hazardous oil and gas waste, or "R" if the waste is a nonhazardous oil and gas waste.

(F) If a facility requests or requires a TCEQ waste generator registration number for wastes under the jurisdiction of the RRC, the registration number "XXXRC" may be provided.

(G) Wastes that are under the jurisdiction of the RRC need not be reported to the TCEQ.

(4) Management of nonhazardous wastes under TCEQ jurisdiction at facilities regulated by the RRC.

(A) Once alternatives for recycling and source reduction have been explored, and with prior authorization from the RRC, the following nonhazardous wastes subject to the jurisdiction of the TCEQ may be disposed of, other than by injection into a Class II well, at a facility regulated by the RRC; bioremediated at a facility regulated by the RRC (prior to reuse, recycling, or disposal); or reclaimed at a crude oil reclamation facility regulated by the RRC: nonhazardous wastes that are chemically and physically similar to oil and gas wastes, but excluding soils, media, debris, sorbent pads, and other clean-up materials that are contaminated with refined petroleum products.

(B) To obtain an individual authorization from the RRC, the waste generator must provide the following information, in writing, to the RRC: the identity of the proposed waste management facility, the quantity of waste involved, a hazardous waste determination that addresses the process generating the waste and the physical and chemical nature of the waste, and any other information that the RRC may require. As appropriate, the RRC shall reevaluate any authorization issued pursuant to this paragraph.

(C) Once alternatives for recycling and source reduction have been explored, and subject to the RRC's individual authorization, the following wastes under the jurisdiction of the TCEQ are authorized without further TCEQ approval to be disposed of at a facility regulated by the RRC, bioremediated at a facility regulated by the RRC, or reclaimed at a crude oil reclamation facility regulated by the RRC: nonhazardous bottoms from tanks used only for crude oil storage; unused and/or reconditioned drilling and completion/workover wastes from commercial service company facilities; used and/or unused drilling and completion/workover wastes generated at facilities where workers in the oil and gas exploration, development, and production industry are trained; used and/or unused drilling and completion/workover wastes generated at facilities where materials, processes, and equipment associated with oil and gas exploration, development, and production operations are researched, developed, designed, and manufactured; unless other provisions are made in the underground injection well permit used and/or unused drilling and completion wastes (but not workover wastes) generated in connection with the drilling and completion of Class I, III, and V injection wells; wastes (such as contaminated soils, media, debris, sorbent pads, and other cleanup materials) associated with spills of crude oil and natural gas liquids if such wastes are under the jurisdiction of the TCEQ; and sludges from washout pits at commercial service company facilities.

(D) Under Texas Water Code, §27.0511(g), a TCEQ permit is required for injection of industrial or municipal waste as an injection fluid for enhanced recovery purposes. However, under §27.0511(h), the RRC may authorize a person to use nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals as an injection fluid for enhanced recovery purposes without obtaining a permit from the TCEQ. The use or disposal of radioactive material under this subparagraph is subject to the applicable requirements of Texas Health and Safety Code, Chapter 401.

(E) Under Texas Water Code, §27.026, by individual permit, general permit, or rule, the TCEQ may designate a Class II disposal well that has an RRC permit as a Class V disposal well authorized to dispose by injection nonhazardous brine from a desalination operation and nonhazardous drinking water treatment residuals under the jurisdiction of the TCEQ. The operator of a permitted Class II disposal well seeking a Class V authorization must apply to TCEQ and obtain a Class V authorization prior to disposal of nonhazardous brine from a desalination operation or nonhazardous drinking water treatment residuals. A permitted Class II disposal well that has obtained a Class V authorization from TCEQ under Texas Water Code, §27.026, remains subject to the regulatory requirements of both the RRC and the TCEQ. Nonhazardous brine from a desalination operation and nonhazardous drinking water treatment residuals to be disposed by injection in a permitted Class II disposal well authorized by TCEQ as a Class V injection well remain subject to the requirements of the Texas Health and Safety Code, the Texas Water Code, and the TCEQ's rules. The RRC and the TCEQ may impose additional requirements or conditions to address the dual injection activity under Texas Water Code, §27.026.

(5) Drilling in landfills. The TCEQ will notify the Oil and Gas Division of the RRC and the landfill owner at the time a drilling application is submitted if an operator proposes to drill a well through a landfill regulated by the TCEQ. The RRC and the TCEQ will cooperate and coordinate with one another in advising the appropriate parties of measures necessary to reduce the potential for the landfill contents to cause groundwater contamination as a result of landfill disturbance associated with drilling operations. The TCEQ requires prior written approval before drilling of any test borings through previously deposited municipal solid waste under 30 TAC §330.15 (relating to General Prohibitions), and before borings or other penetration of the final cover of a closed municipal solid waste landfill under 30 TAC §330.955 (relating to Miscellaneous). The installation of landfill gas recovery wells for the recovery and beneficial reuse of landfill gas is under the jurisdiction of the TCEQ in accordance with 30 TAC Chapter 330, Subchapter I (relating to Landfill Gas Management). Modification of an active or a closed solid waste management unit, corrective action management unit, hazardous waste landfill cell, or industrial waste landfill cell by drilling or penetrating into or through deposited waste may require prior written approval from TCEQ. Such approval may require a new authorization from TCEQ or modification or amendment of an existing TCEQ authorization.

(6) Coordination of actions and cooperative sharing of information.

(A) In the event that a generator or transporter disposes, without proper authorization, of wastes regulated by the TCEQ at a facility permitted by the RRC, the TCEQ is responsible for enforcement actions against the generator or transporter, and the RRC is responsible for enforcement actions against the disposal facility. In the event that a generator or transporter disposes, without proper authorization, of wastes regulated by the RRC at a facility permitted by the TCEQ, the RRC is responsible for enforcement actions against the generator or transporter, and the TCEQ is responsible for enforcement actions against the disposal facility.

(B) The TCEQ and the RRC agree to cooperate with one another by sharing information. Employees of either agency who receive a complaint or discover, in the course of their official duties, information that indicates a violation of a statute, regulation, order, or permit pertaining to wastes under the jurisdiction of the other agency, will notify the other agency. In addition, to facilitate enforcement actions, each agency will share information in its possession with the other agency if requested by the other agency to do so.

(C) The TCEQ and the RRC agree to work together at allocating respective responsibilities. To the extent that jurisdiction is indeterminate or has yet to be determined, the TCEQ and the RRC agree to share information and take appropriate investigative steps to assess jurisdiction.

(D) For items not covered by statute or rule, the TCEQ and the RRC will collaborate to determine respective responsibilities for each issue, project, or project type.

(E) The staff of the RRC and the TCEQ shall coordinate as necessary to attempt to resolve any disputes regarding interpretation of this MOU and disputes regarding definitions and terms of art.

(7) Groundwater.

(A) Notice of groundwater contamination. Under Texas Water Code, §26.408, effective September 1, 2003, the RRC must submit a written notice to the TCEQ of any documented cases of groundwater contamination that may affect a drinking water well.

(B) Groundwater protection letters. The RRC provides letters of recommendation concerning groundwater protection.

(i) For recommendations related to normal drilling operations, shot holes for seismic surveys, and cathodic protection wells, the RRC provides geologic interpretation identifying fresh water zones, base of usable-quality water (generally less than 3,000 mg/L total dissolved solids, but may include higher levels of total dissolved solids if identified as currently being used or identified by the

Texas Water Development Board as a source of water for desalination), and include protection depths recommended by the RRC. The geological interpretation may include groundwater protection based on potential hydrological connectivity to usable-quality water.

(ii) For recommendations related to injection, the RRC provides geologic interpretation of the base of the underground source of drinking water. The term "underground source of drinking water" is defined in 40 Code of Federal Regulations §146.3 (Federal Register, Volume 46, June 24, 1980).

(8) Emergency and spill response.

(A) The TCEQ and the RRC are members of the state's Emergency Management Council. The TCEQ is the state's primary agency for emergency support during response to hazardous materials and oil spill incidents. The TCEQ is responsible for state-level coordination of assets and services, and will identify and coordinate staffing requirements appropriate to the incident to include investigative assignments for the primary and support agencies.

(B) Contaminated soil and other wastes that result from a spill must be managed in accordance with the governing statutes and regulations adopted by the agency responsible for the activity that resulted in the spill. Coordination of issues of spill notification, prevention, and response shall be addressed in the State of Texas Oil and Hazardous Substance Spill Contingency Plan and may be addressed further in a separate Memorandum of Understanding among these agencies and other appropriate state agencies.

(C) The agency (TCEQ or RRC) that has jurisdiction over the activity that resulted in the spill incident will be responsible for measures necessary to monitor, document, and remediate the incident.

(i) The TCEQ has jurisdiction over certain inland oil spills, all hazardous-substance spills, and spills of other substances that may cause pollution.

(ii) The RRC has jurisdiction over spills or discharges from activities associated with the exploration, development, or production of crude oil, gas, and geothermal resources, and discharges from brine mining or surface mining.

(D) If TCEQ or RRC field personnel receive spill notifications or reports documenting improperly managed waste or contaminated environmental media resulting from a spill or discharge that is under the jurisdiction of the other agency, they shall refer the issue to the other agency. The agency that has jurisdiction over the activity that resulted in the improperly managed waste, spill, discharge, or contaminated environmental media will be responsible for measures necessary to monitor, document, and remediate the incident.

(9) Anthropogenic carbon dioxide storage. In determining the proper permitting agency in regard to a particular permit application for a carbon dioxide geologic storage project, the TCEQ and the RRC will coordinate by any appropriate means to review proposed locations, geologic settings, reservoir data, and other jurisdictional criteria specified in Texas Water Code, §27.041.

(f) Radioactive material.

(1) Radioactive substances. Under the Texas Health and Safety Code, §401.011, the TCEQ has jurisdiction to regulate and license:

(A) the disposal of radioactive substances;

(B) the processing or storage of low-level radioactive waste or NORM waste from other persons, except oil and gas NORM waste;

(C) the recovery or processing of source material;

(D) the processing of by-product material as defined by Texas Health and Safety Code, §401.003(3)(B); and

(E) sites for the disposal of low-level radioactive waste, by-product material, or NORM waste.

(2) NORM waste.

(A) Under Texas Health and Safety Code, §401.415, the RRC has jurisdiction over the disposal of NORM waste that constitutes, is contained in, or has contaminated oil and gas waste. This waste material is called "oil and gas NORM waste." Oil and gas NORM waste may be generated in connection with the exploration, development, or production of oil or gas.

(B) Under Texas Health and Safety Code, §401.412, the TCEQ has jurisdiction over the disposal of NORM that is not oil and gas NORM waste.

(C) The term "disposal" does not include receipt, possession, use, processing, transfer, transport, storage, or commercial distribution of radioactive materials, including NORM. These non-disposal activities are under the jurisdiction of the Texas Department of State Health Services under Texas Health and Safety Code, §401.011(a).

(3) Drinking water residuals. A person licensed for the commercial disposal of NORM waste from public water systems may dispose of NORM waste only by injection into a Class I injection well permitted under 30 TAC Chapter 331 (relating to Underground Injection Control) that is specifically permitted for the disposal of NORM waste.

(4) Management of radioactive tracer material.

(A) Radioactive tracer material is subject to the definition of low-level radioactive waste under Texas Health and Safety Code, §401.004, and must be handled and disposed of in accordance with the rules of the TCEQ and the Department of State Health Services.

(B) Exemption. Under Texas Health and Safety Code, §401.106, the TCEQ may grant an exemption by rule from a licensing requirement if the TCEQ finds that the exemption will not constitute a significant risk to the public health and safety and the environment.

(5) Coordination with the Texas Radiation Advisory Board. The RRC and the TCEQ will consider recommendations and advice provided by the Texas Radiation Advisory Board that concern either agency's policies or programs related to the development, use, or regulation of a source of radiation. Both agencies will provide written response to the recommendations or advice provided by the advisory board.

(6) Uranium exploration and mining.

(A) Under Texas Natural Resources Code, Chapter 131, the RRC has jurisdiction over uranium exploration activities.

(B) Under Texas Natural Resources Code, Chapter 131, the RRC has jurisdiction over uranium mining, except for in situ recovery processes.

(C) Under Texas Water Code, §27.0513, the TCEQ has jurisdiction over injection wells used for uranium mining.

(D) Under Texas Health and Safety Code, §401.2625, the TCEQ has jurisdiction over the licensing of source material recovery and processing or for storage, processing, or disposal of by-product material.

(g) Effective date. This Memorandum of Understanding, as of its July 15, 2020, effective date, shall supersede the prior Memorandum of Understanding among the agencies, dated May 1, 2012.

Source Note: The provisions of this §3.30 adopted to be effective May 31, 1998, 23 TexReg 5427; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective August 30, 2010, 35 TexReg 7728; amended to be effective May 1, 2012, 37 TexReg 2385; amended to be effective July 15, 2020, 45 TexReg 4503; amended to be effective July 1, 2025, 50 TexReg 33

§3.31 Gas Reservoirs and Gas Well Allowable

(a) General.

(1) Allowables of gas wells not currently assigned an allowable will not be made effective:

(A) prior to the well's completion or reclassification date; or

(B) more than 15 days prior to the date all reports or information necessary to the assignment of an allowable are received in the appropriate commission office.

(2) If a report or item of information necessary to the assignment of an allowable is not filed on time, there shall be a one-day allowable reduction for each day the report or information is late.

(b) Changes in gas well allowables.

(1) Changes in allowable of gas wells currently assigned an allowable will be effective on the date of the test or date of the change affecting the well's allowable (when the operator submits special tests or information), provided this is not more than 15 days prior to the date the special test or information is received in the appropriate Commission office.

(2) With respect to a multicompleted well, the allowable of the second and succeeding zones will be made effective no earlier than the date the last report or item necessary for the assignment of an allowable is received in the appropriate Commission office.

(3) When a well is recompleted as a gas well in a different field, any overproduction that has occurred in the old field must be made up before an allowable will be assigned in the new field.

(4) The maximum daily allowable for a horizontal drainhole gas well or a gas well in a designated unconventional fracture treated (UFT) field is set forth in §3.86(d)(4) and (5) of this title (relating to Horizontal Drainhole Wells).

(c) Requirements for gas wells in a field for which an allocation formula has been adopted.

(1) If acreage is a factor in the allocation formula, a certified plat showing the acreage assigned to the well for proration purposes shall be submitted. The plat must be accompanied by a statement that all of the acreage claimed can reasonably be considered productive of gas and that the distance limitations of the field rules have not been exceeded. If all of the acreage claimed is not contained in a single lease, a certificate of pooling authority must be submitted, on the appropriate commission form. If the distance limitations of the field rules are shown to have been exceeded, the plat must show the number of acres within and beyond the distance limitations. An operator may request an exception to the distance limitations which may be administratively approved by the commission or a commission designee if all the acreage can be considered productive. If approval of the request is declined or protest is received, the request may be set for hearing. If all of the acreage cannot be considered productive, the plat must also show the productive limit of the acreage. If a plat shows acreage in the unit in excess of the maximum number of acres permitted by the field rules, it will not be accepted.

(2) If bottom-hole or reservoir pressure is a factor in the allocation formula, it shall be submitted on the appropriate commission form and shall be measured at, or corrected to, the proper datum plane.

(3) If any other information, data or parameter is a factor in the allocation formula, it must be submitted on the appropriate commission form.

(d) Determining prorated reservoir allowable and lawful market demand.

(1) On or before the 25th day of each month, the commission will determine the lawful market demand for gas to be produced from each reservoir during the upcoming allowable month. The monthly reservoir allowable shall be equal to the lawful market demand for that reservoir. The lawful reservoir market demand for prorated reservoirs shall be equal to the adjusted reservoir market demand forecast adjusted by a forecast correction adjustment, and a commission adjustment (i.e., lawful reservoir market demand = adjusted reservoir market demand forecast + forecast correction adjustment + commission adjustment).

(A) Allowable month--The month during which allowables determined pursuant to this section will be effective.

(B) Adjusted reservoir market demand forecast--The sum of all operator reservoir market demand forecasts for a reservoir after any necessary downward adjustments have been made to individual operator reservoir market demand forecasts and optional operator forecasts so that no such forecast will exceed the total capability of the operator's wells for the reservoir during the allowable month.

(C) Operator reservoir market demand forecast--The sum of the operator's well forecasts for a reservoir determined by the commission pursuant to this subsection.

(i) The commission will determine a forecast for each well that will be active during the allowable month that:

(I) for prorated and limited wells is equal to the well's production during the same allowable month in the prior year; and

(II) for special or administrative special allowable wells is equal to the well's production during the most recently reported production month.

(ii) If the well had no reported production during the same allowable month in the prior year or if a special or administrative special allowable well had no reported production in the most recently reported production month, the forecast shall be equal to:

(I) the well's highest reported monthly production during any of the three most recently reported production months; or, if no production has been reported for those months;

(II) the well's capability.

(iii) Alternatively, the operator reservoir market demand forecast may be determined by an optional operator forecast.

(D) Optional operator forecast--The commission designated operator may file an optional market demand forecast for all of the operator's wells in the reservoir that is equal to the anticipated market demand for the production from the operator's wells in the field during the allowable month. The optional operator forecast for the operator's wells in the reservoir can be no greater than the total capability of the operator's wells or less than zero. An optional operator forecast must be filed by the 10th day of the month preceding the allowable month.

(E) Forecast correction adjustment--

(i) The February 1994 forecast correction adjustment shall be the reservoir market demand for November 1993 for all wells in a reservoir that are not administrative special allowable wells for February 1994, subtracted from the production reported for November 1993 for those wells;

(ii) The March 1994 forecast correction adjustment shall be the reservoir market demand for December 1993 for all wells in a reservoir that are not administrative special allowable wells for March 1994, subtracted from the production reported for December 1993 for those wells;

(iii) The April 1994 forecast correction adjustment shall be the reservoir market demand for January 1994 for all wells in a reservoir that are not administrative special allowable wells for April 1994, subtracted from the production reported for January 1994 for those wells;

(iv) For May 1994 and subsequent months, the forecast correction adjustment shall be equal to the total reservoir production from the most recent reported month, minus (total adjusted reservoir market demand forecast for the production month + supplemental change adjustment for that month + commission adjustment for that month), minus (production from all special and administrative special allowable wells minus allowable assigned to those special wells for that month).

(F) Supplemental change adjustment--Any adjustment to the reservoir allowable that is necessary to account for an automatic allowable revision in a prior month, a change of well or well test status during a prior month, the provisions of a final order modifying field or well production status, or any other ministerial change.

(G) Commission adjustment--Any other adjustments to the adjusted reservoir market demand forecast that the commission determines are necessary.

(2) The commission may reject or modify any optional operator forecast if it determines that the forecast is inaccurate or being used to manipulate the allocation of gas rather than to determine the reasonable market demand.

(e) Well capability.

(1) No gas well shall be given an initial allowable in excess of its capability.

(A) Except as provided in subparagraphs (B) and (C) of this paragraph, a well's capability is defined as the lesser of:

(i) the well's latest deliverability test on file with the commission; or

(ii) the well's highest monthly production during any of the three most recently reported production months.

(B) If a well is a special or an administrative special allowable well, its capability is defined as the lesser of:

(i) the well's latest deliverability test on file with the commission; or

(ii) the well's most recently reported monthly production.

(C) If a well is new to a reservoir and has been active for less than six months, its capability shall be defined as the well's latest deliverability test on file with the commission.

(2) An operator may submit a substitute capability determination for any well in a prorated field that represents the maximum monthly production capability of the well under normal operating conditions for a specific six-month period.

(A) The determination may be made on the basis of a well test or other acceptable information by a registered professional engineer who certifies that the determination was made by the engineer or under the supervision of the engineer, and that the capability has been determined in accordance with generally accepted engineering practices. Alternatively, the substitute capability determination may be made by an independent tester on the basis of a well test conducted in accordance with §3.28(c) of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported) (Statewide Rule 28). The request for a substitute capability must be submitted on the appropriate form.

(B) The commission or a commission designee may reject any substitute capability determination for good cause.

(C) The capability determined pursuant to this paragraph shall be used as the well's capability for a period of six months from the effective date of the determination unless:

(i) the operator files a written request that the substitute capability determination be cancelled. If such a request is submitted, the substitute capability may be cancelled by the commission or commission designee; or

(ii) an affected person files a protest alleging, with specificity, the inaccuracy or invalidity of the determination. If a protest is filed, the commission may set the matter for hearing. A protested substitute capability determination shall be effective on the intended effective date, unless the commission orders otherwise. If the commission determines that the protested substitute capability was incorrect, appropriate allowable or status adjustments will be made for the affected well.

(f) Fields operating under statewide rules. A statewide prorated field is any gas field in which no special field rules have been adopted and in which at least one well in the field has a current reported deliverability test of greater than 250 Mcf a day. Daily allowable production of gas from individual wells in a statewide prorated field shall be determined by allocating the allowable production among the individual wells in the proportion that each well's deliverability (based on the latest deliverability test of record) bears to the summation of the most recent reported deliverability tests of all wells producing from the same field. Allocated allowables shall be subject to the well capability provisions of this section.

(g) Definitions of prorated and nonprorated wells and fields.

(1) A prorated well is a well for which an allowable is determined by an allocation formula.

(2) A nonprorated well is a well for which an allowable is not determined by an allocation formula.

(3) A prorated field is a field that has two or more wells one of which is a prorated well.

(4) A nonprorated field is any field that is not a

prorated field.

(5) Statewide Exempt Fields:

(A) A statewide exempt field is any gas field in which no special field rules have been adopted and in which no well in the field has a current reported deliverability test of greater than 250 Mcf per day. Wells in statewide exempt fields shall be assigned allowables equal to their capacity to produce but in no event greater than 250 Mcf per day.

(B) In fields where special field rules exist and no well has a current deliverability test of greater than 250 Mcf per day, an operator may request statewide exempt field status. The request may be granted administratively by the commission or commission designee if the applicant provides the commission with a declaration, signed by all operators, subject to the false filing penalties provided for in the Texas Natural Resources Code, §91.143, stating all operators in the field agree to exempt status. If declarations are not provided from all operators in the field or if the commission or commission designee declines to grant any request administratively, the applicant may request a hearing. If a notice of intent to appear in protest of the application has not been filed by five days before the date of the hearing, then there shall be a presumption that each well's first purchaser has a market for 100% of the well's deliverability as determined by the most recent deliverability tests on file with the Commission and that granting exempt status to the field will not harm correlative rights or cause waste and exempt status will be granted. Wells in exempt fields with special rules shall be assigned allowables equal to their capability to produce but in no event greater than 250 Mcf per day. If 250 Mcf per day is exceeded by any well, the field will be changed to the existing special field rule allocation. Reinstatement of allocation formula may be initiated by the commission designee, or by one of the operators in the field.

(6) A limited well is a nonprorated well in a prorated field (other than a special or administrative special allowable well) with an allowable set below the maximum allowable it would receive under the allocation formula. A limited well shall be assigned an allowable at the rate that the well is capable of producing as determined by subsection (e) of this section.

(7) A special allowable well is a nonprorated well granted a fixed allowable by the commission after notice and hearing.

(8) An administrative special allowable well is a nonprorated well that has been granted an allowable pursuant to subsection (k) of this section.

(9) The maximum allowable for a well is the largest allowable that can be assigned under applicable rules. For a limited well, the maximum allowable is the allowable the well would receive under the allocation formula. For a special allowable well, the maximum allowable is the allowable assigned pursuant to paragraph (7) of this subsection. For administrative special allowable wells, the maximum allowable is 100 Mcf/day for wells qualifying as administrative special wells under subsection (k)(1) of this section and is the allowable the well would receive under the allocation formula for wells qualifying as administrative special allowable wells under subsection (k)(2) of this section. Additionally, for administrative special allowable wells in prorated gas fields without special field rules, the maximum allowable is 250 Mcf a day. For a well in a one well field, the maximum allowable is the well's deliverability based on the latest deliverability test of record. For an associated gas well, the maximum allowable is the gas well allowable calculated by §3.49(b)(1) or (2) of this title (relating to Gas-Oil Ratio) (Statewide Rule 49).

(h) Allowable adjustments and balancing provisions for nonprorated wells.

(1) A nonprorated well shall not be allowed to accumulate underproduction. However, a limited well shall be entitled to accumulate underage up to the well's capability each month.

(2) If the most recent production figures reported to the commission show a nonprorated well to be overproduced, the alllowable will be revised to cover overproduction that is in excess of the well's accumulated underproduction, up to the maximum allowable. A nonprorated well with accumulated overproduction will be assigned a supplemental allowable that will balance the accumulated overproduction or a supplemental allowable equal to the well's maximum allowable, whichever is smaller.

(3) The allowable for wells in nonprorated fields, except for special and administrative special allowable wells, shall be limited to the lesser of:

(A) the well's maximum allowable;

(B) the well's capability as determined by subsection (e) of this section.

(4) The initial allowable for special and administrative special allowable wells shall be the least of the well's:

(A) capability;

(B) its amount of production during the most recently reported production month; or

(C) the amount provided for by the allocation formula.

(i) Balancing provisions for overproduction and underproduction of gas for wells completed in prorated gas fields.

(1) Balancing provisions for prorated fields. Except as provided in subsection (h) of this section or as necessary to prevent waste or protect correlative rights, balancing provisions will be applied for wells completed in prorated gas fields.

(2) Balancing periods. For the purpose of computing and balancing overproduction and underproduction in prorated gas fields, the dates 7 a.m., March 1, and 7 a.m., September 1, are to be known as balancing dates; and the six-month periods beginning 7 a.m., March 1, and ending 7 a.m., September 1, and beginning 7 a.m., September 1, and ending 7 a.m., March 1, will be considered as separate entities and will be known as "balancing periods."

(3) Balancing provision for 49(b) fields. The balancing provisions may be applied by commission action after notice and hearing to fields where the well allowables are determined by §3.49(b) of this title (relating to Gas-Oil Ratio) (Statewide Rule 49(b)).

(4) Underproduction.

(A) If during the balancing period a prorated gas well or a limited well does not produce as much gas as is allocated to it by the commission, the operator of the well shall be permitted to carry such underproduction forward to the next succeeding balancing period as future allowable credit to be produced during that period.

(B) The amount of underproduction to be carried forward into any new balancing period as allowed production during such new balancing period shall consist of the actual underproduction that accrued in the balancing period immediately preceding such new balancing period; and the accumulative well status as to underproduction, will be adjusted on each balancing date accordingly. An operator may request that underproduction not balanced during a second balancing period be carried forward to subsequent balancing periods. The operator's request must include evidence of increased market demand that will allow underproduction to be produced in the subsequent balancing period. The request may be granted administratively by the commission or a commission designee if the request was filed no later than the last day of the balancing period following the date the underproduction is canceled, the operator has given at least 21 days notice to all other operators in the field and the first purchaser of gas from the subject well, and no protest to the request has been filed. The request may also be approved administratively if the operator provides written waivers of objection from all to whom notice would be given as an alternative to notice and absence of protest. If the commission or a commission designee declines to grant administratively the request, the operator may request a hearing.

(5) Overproduction.

(A) Subject to the following prescribed conditions, the operator of a gas well, may produce the well in excess of the monthly allowable allocated to the well. No well shall in any one month be produced at a rate in excess of its underproduction plus twice its monthly allowable without obtaining approval from the commission prior to the due date for the production report for the overproduced month. A well which is balanced or overproduced may not in any one month produce an amount in excess of twice its monthly allowable without obtaining approval from the commission prior to the due date for the production report for the overproduced month. A well which is balanced or overproduced will not be granted such authority for more than two months in any six month balancing period.

(B) A well overproduced as of a balancing date, which was also overproduced on the balancing date immediately preceding and remained overproduced for the entire period between the two balancing dates, shall be shut-in until the overproduction, existent as of the later of such two balancing dates, is made up. Upon request by an operator, the commission may grant authority to produce such a well at a fractional part of its monthly allowable (reduced rate) until its production and allowable are in balance. The commission or a commission designee may determine the permissible rate.

(C) If a protest is received or the commission declines to approve a request to produce at a reduced rate, the operator of a well which under the provisions of subparagraph (B) of this paragraph is required to be shut-in, may request a hearing before the commission to determine whether shutting-in the well would damage it. Notice of the hearing will be given to all operators in the field and the first purchaser of the subject well. If, after consideration of the evidence submitted at the hearing, the commission finds that the well would be damaged if shut-in, the commission may allow the overproduction charged against it to be made up at a lesser rate than it would be made up if the well were shut-in. The commission or a commission designee may determine the permissible rate pending the result of the hearing.

(D) Except where a well is shut-in to make up overproduction or is producing at a reduced rate, overproduction existent as of any balancing date shall be made up at any time during the next period; i.e., a specified fractional part of the overproduction need not be made up during each month of that balancing period, so long as all of such overproduction is made up during that balancing period.

(j) Suspension of allocation formula.

(1) The commission or a commission designee may administratively suspend the allocation formula for a particular gas field if:

(A) each operator from that field has a market, for 100% of the deliverability, as determined by the deliverability tests on file with the commission, for its respective wells; and

(B) all operators in the field consent to suspension of the formula.

(2) Suspension of the allocation formula may be initiated by the commission or a commission designee, or by one of the operators in the field. The commission or a commission designee will determine which fields are appropriate for suspension utilizing the criteria of paragraph (1) of this subsection. The allocation formula may be administratively suspended if the applicant provides the commission with a declaration, subject to the false filing penalties provided for in the Natural Resources Code, §91.143, from all operators in the field stating that they have a market for 100% of the deliverability of their wells. If the commission or a commission designee declines to administratively suspend the allocation formula, the applicant may request a hearing as provided for in paragraph (4) of this subsection.

(3) Reinstatement of the allocation formula may be initiated by the commission, commission designee, or by one of the operators in the field.

(A) If, for any month, the market for gas production from a well in a field with a suspended allocation formula is less than 100% of the well's deliverability as determined by the deliverability tests on file with the commission, the operator of the field must inform the commission or a commission designee; upon such notification, the commission or commission designee will, with prior notice to the operators in the field, reinstate the allocation formula.

(B) The allocation formula will be reinstated at the request of an operator from a field with a suspended allocation formula or at any time the commission deems reinstatement necessary to protect correlative rights or prevent waste.

(4) If the commission or a commission designee reinstates the allocation formula or denies a request to suspend or reinstate the allocation formula in a particular field, the applicant may request a hearing. In addition to the criteria set forth in paragraph (1) of this subsection, the commission will consider whether suspension or reinstatement is necessary to prevent waste or protect correlative rights. An applicant may also request a hearing when unable to obtain written consent from all operators in a field pursuant to subparagraph (1)(B) of this subsection.

(5) Suspension of the allocation formula will balance the field's production status at zero, and provide for a 100% capacity allowable.

(k) Administrative Special Allowable.

(1) A well which has a deliverability, capability, and six consecutive months of production of 100 Mcf per day

or less, and the well is not producing in a 49(b) field, will be assigned an administrative special allowable pursuant to subsection (h) of this section. Additionally, a well which has a deliverability, capability, and six consecutive months of production of 250 Mcf a day or less, and the well is producing in a prorated field without special field rules, will be assigned an administrative special allowable pursuant to subsection (h) of this section.

(2) A well, other than an administrative special allowable well defined in paragraph (1) of this subsection, in a prorated field whose average monthly production during the last six consecutive months falls below the cutoff percentage (determined by the commission at the monthly statewide hearing) of the well's top allowable averaged over that six-month period, will be assigned an administrative special allowable pursuant to subsection (h) of this section. The initial cutoff percentage is 70% and will remain at 70% until changed in accordance with this subparagraph. Administrative special allowable wells under this subsection will remain administrative special allowable wells until:

(A) they overproduce the top allowable available under the applicable allocation formula; or

(B) they receive a substitute capability pursuant to subsection (e) of this section; or

(C) the commission resets the cutoff percentage below the well's average production level for the last six consecutive months.

Source Note: The provisions of this §3.31 adopted to be effective September 1, 1986, 11 TexReg 3680; amended to be effective July 1, 1992, 17 TexReg 3236; amended to be effective September 20, 1993, 18 TexReg 5977; amended to be effective January 11, 1994, 19 TexReg 71; amended to be effective May 19, 1997, 22 TexReg 4065; amended to be effective October 20, 1997, 22 TexReg 10311; amended to be effective February 1, 2016, 41 TexReg 785.

§3.32 Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Fugitive emissions--Releases of gas from lease production, gathering, compression, or gas plant equipment components, including emissions from valve stems, pressure relief valves, flanges and connections, gas-operated valves, compressor and pump seals, pumping well stuffing boxes, casing-to-casing bradenheads subject to the provisions of §3.17 of this title (relating to Pressure on Bradenhead), pits, and sumps, that cannot reasonably be captured and sold or routed to a vent or flare.

(2) Gathering system--Facilities employed to collect, compress, and transport gas to another gas gathering system, a gas plant, compression facility, or transmission line.

(3) Lease production facilities--Production, separation, treating, compression, flowlines, storage, and other production handling equipment employed on a lease in the production of gas, condensate, and oil.

(4) Low pressure separator gas--Gas separated or liberated from a gas-liquid stream in a low pressure separation facility. Low pressure separation facilities include but are not limited to separators, treaters, free water knockouts, and other associated equipment.

(5) Tank vapors--Gas which evolves from oil, condensate, or water when placed in a gunbarrel or storage tank.

(b) Activities authorized by this section may be subject to rules and regulations promulgated by the United States Environmental Protection Agency under the federal Clean Air Act or the Texas Commission on Environmental Quality under the Texas Clean Air Act.

(c) General Provisions. All gas from any oil well, gas well, gas gathering system, gas plant or other gas handling equipment shall be utilized for purposes and uses authorized by law, except as provided in this section. This section does not apply to gas transmission or gas distribution facilities or operations.

(d) Exempt Gas Releases.

(1) Releases of gas that are not readily measured by devices routinely used in the operation of oil wells, gas wells, gas gathering systems, or gas plants, such as meters, are not required by the commission to be reported or charged against lease allowable production and are not subject to the remaining requirements of this section. Releases of gas exempt from the requirements of this section under this paragraph include, but are not limited to, the following:

(A) tank vapors from crude oil storage tanks, gas well condensate storage tanks, or salt water storage tanks, including makeup gas for gas blanket maintenance;

(B) fugitive emissions of gas;

(C) amine treater, glycol dehydrator flash tank and/or reboiler emissions;

(D) blowdown gas from flow lines, gathering lines, meter runs, pressurized vessels, compressors, or other gas handling equipment for construction, maintenance or repair;

(E) gas purged from compressor cylinders or other gas handling equipment for startup;

(F) gas released at a wellsite during drilling operations and prior to the completion date of the well, including gas produced during air or gas drilling operations or gas which must be separated from drilling fluids using a mud-gas separator, or mud-degasser; or

(G) gas released at a wellsite during initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, well maintenance or repair operations.

(2) Notwithstanding the foregoing, the commission or the commission's delegate may require the flaring of releases of gas not readily measured by devices routinely used in the operation of oil wells, gas wells, gas gathering systems, or gas plants, such as meters, if the commission or the commission's delegate determines that flaring is required for safety reasons.

(e) Gas Releases to be Burned in a Flare.

(1) Except as otherwise provided in subsections (d), (f)(1)(B) and (C), (g)(2), or an exception granted under subsection (h) of this section, all gas releases of greater than 24 hours duration authorized under the provisions of this section shall be burned in a flare if the gas can be burned safely. All gas releases of 24 hours' duration or less authorized under the provisions of this section may be vented to the air if flaring is not required for safety reasons or by other regulation and the gas can be safely vented.

(2) Gas releases authorized under this section must be

managed in accordance with the provisions of §3.36 of this title (relating to Oil, Gas, Brine, or Geothermal Resource Operation in Hydrogen Sulfide Areas) when applicable.

(3) An exception to the requirements of this subsection may be granted under subsection (h) by the commission or the commission's delegate to allow the venting of gas to the air for releases of greater than 24 hours' duration if the operator presents information that shows the gas cannot be both safely and continuously burned in a flare, and the gas can be safely vented.

(4) Notwithstanding the provisions of paragraph (1) of this subsection or an exception granted under subsection (h), the commission or the commission's delegate may require that the gas be flared if flaring is required for safety reasons.

(f) Gas Releases in Oil and Gas Production Operations.

(1) The following releases of gas resulting from routine oil and gas production operations are necessary in the efficient drilling and operation of oil and gas wells and are hereby authorized subject to the requirements of subsection (e) of this section. The released gas shall be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported and charged against lease allowable production.

(A) Gas may be released for a period not to exceed ten producing days after initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, well maintenance or repair operations.

(B) Gas from a well that must be unloaded or cleaned-up to atmospheric pressure may be vented to the air for periods not to exceed 24 hours in one continuous event or a total of 72 hours in one calendar month.

(C) In the event of a full or partial shutdown by a gas gathering system, compression facility, or gas plant, gas from a lease production facility served by that gas gathering system, compression facility or gas plant may be released for a period not to exceed 24 hours. The operator shall notify the appropriate commission district office by telephone or facsimile as soon as reasonably possible after the release of gas begins. An operator may continue the release by flaring or by venting of the gas, if flaring is not required for safety reasons or by other regulation, beyond the initial 24-hour period, pending commission approval or denial of a request for an administrative exception under subsection (h) of this section. The operator shall file the request with the commission by the end of the next full business day following the first 24 hours of the release unless the deadline is extended by the commission or the commission's delegate.

(D) Hydrocarbon gas contained in the waste stream from a membrane unit or molecular sieve used to remove carbon dioxide, hydrogen sulfide, or other contaminants from a gas stream may be released, provided that at least 85% of the hydrocarbon gas in the inlet gas stream is recovered and directed to a legal use.

(E) Low pressure separator gas, not to exceed 15 mcfd of hydrocarbon gas per gas well or 50 mcfd of hydrocarbon gas per commission-designated oil lease or commingling point for commingled operations, may be released.

(2) The commission or the commission's delegate may administratively grant or renew an exception to the requirements or limitations of this subsection subject to the requirements of subsection (h) to allow additional releases of gas if the operator of a well or production facility presents information to show the necessity for the release. The volume of gas that is released must be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported on the appropriate commission form and shall be charged to the operator's allowable production. Necessity for the release includes, but is not limited to, the following situations:

(A) Cleaning a well of solids or fluids or both for more than ten producing days following initial completion, recompletion in another field, or workover operations in the same field, including but not limited to perforating, stimulating, deepening, cleanout, or well maintenance or repair operations;

(B) Unloading excess formation fluid buildup in a wellbore for periods in excess of 24 hours in one continuous event or 72 hours total in one calendar month;

(C) Volumes of low pressure gas that can be measured with devices routinely used in oil and gas exploration, development, and production operations and that are not directed by an operator to a gas gathering system, gas pipeline, or other marketing facility, or other purposes and uses authorized by law due to mechanical, physical, or economic impracticability;

(D) For casinghead gas only, the unavailability of a gas pipeline or other marketing facility, or other purposes and uses authorized by law; or

(E) Avoiding curtailment of gas production which will result in a reduction of ultimate recovery from a gas well or oil reservoir.

(g) Gas releases from gas gathering system, gas plant or gas handling operations.

(1) The operator of a gas gathering system, gas plant, gas compressor facility or other gas handling equipment not directly associated with lease production of gas, shall not intentionally allow gas to be released for a period of more than 24 hours after the start of an upset condition. The operator shall notify the appropriate commission district office by telephone or facsimile as soon as reasonably possible after the release of gas begins. The volume of gas that is released must be measured or estimated in accordance with §3.27 of this title (relating to Gas To Be Measured and Surface Commingling of Gas) and reported on the appropriate commission form. The provisions of this subsection do not apply to accidental releases which are subject to or reported pursuant to any other commission rule.

(2) The commission or the commission's delegate may administratively grant or renew an exception to the requirements or limitations of this subsection and allow additional releases of gas for a period greater than 24 hours if the operator presents information that shows the necessity for the release. An operator may continue the release by flaring or by venting of the gas, if flaring is not required for safety reasons or by other regulation, beyond the initial 24-hour period pending commission consideration of a request for an administrative exception under subsection (h) of this section. The request for exception is to be filed with the commission by the end of the next full business day following the first 24 hours of the release unless the deadline is extended by the commission or the commission's delegate. The following

are examples of situations that may qualify for an exception under this paragraph:

(A) gas gathering system or gas plant construction, repairs or maintenance;

(B) gas plant turnaround; or

(C) emergency situations.

(h) Exceptions. The commission or the commission's delegate may administratively grant an exception authorized by this section provided that the requirements of this subsection are met.

(1) The request for an exception shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(2) An administrative exception shall not exceed a period of 180 days.

(3) The 180-day limitation shall not apply for volumes of gas less than or equal to 50 mcf of hydrocarbon gas per day for each gas well, commission-designated oil lease, or commingled vent or flare point.

(4) Requests for exceptions for more than 180 days and for volumes greater than 50 mcf of hydrocarbon gas per day shall be granted only in a final order signed by the commission.

(5) A request for an exception to cover an operating emergency, system upset, or other unplanned condition may be submitted by facsimile transmission or other means, provided that an original signed request is accompanied by the fee required by subsection (h)(1) of this section and is received by the commission within three working days of the facsimile transmission request.

(6) Exceptions shall be issued to the operator of a gas well or commission-designated oil lease or commingling point for commingled operations and to the operator of a processing plant or other facility subject to this section.

(7) Exceptions are not transferable upon a change of operatorship. Operators shall have 90 days from the date of commission approval of a transfer of operatorship to review existing exceptions to this section and, if continuation of the exception is needed, to make application for a new exception. The existing exception and existing authority shall remain in effect during the 90-day review period. If an operator files an application and fee for a new exception before the 90-day review period expires and the 90-day review period expires before the commission acts on the application, the operator is authorized to continue to operate under the existing authority pending final commission action on the application.

(8) One application for exception to the requirements of this section may be filed for multiple releases from gas wells, commission-designated oil leases, gas gathering systems, gas compressors or other gas handling facilities when the release of gas is the result of a full or partial shut-down of a gas gathering system, gas plant, gas compressor or other gas handling facility under subsection (f)(1)(C) or (g)(1). Each well, lease or facility must be clearly identified by the applicant and a single fee paid under §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(i) Renewal and Amendment of Exceptions.

(1) The commission or the commission's delegate may renew an exception authorized by this section. An administrative renewal by the commission's delegate may not exceed a period of 180 days.

(2) A renewal shall be based upon a showing by the operator of a well, lease, or other facility subject to this section, that the conditions for which the initial exception or latest renewal was granted have not significantly changed despite a good-faith attempt by the operator to direct the gas to or utilize the gas for purposes and uses authorized by law.

(3) An operator shall file an application and fee for renewal of an exception with the commission 21 days prior to expiration of the existing exception authority. The request for renewal shall be accompanied by the fee required by §3.78(b)(5) of this title (relating to Fees and Financial Security Requirements).

(4) If an operator files an application, accompanied by the required fee, for renewal of an existing exception to the requirements of this section at least 21 days before the expiration of the existing exception and the existing authority expires before the commission acts on the application, the operator is authorized to continue to operate under the existing authority pending final commission action on the application.

(5) The request by an operator to amend an existing exception will require a new application for exception if the amendment will result in a material change of the previously granted exception.

(6) Material changes include, but are not limited to, the following:

(A) Change of operator of the well or facility subject to this section; and

(B) An increase in volume of gas to be released or an extension of the duration of an exception greater than that provided for in subsection (h) of this section.

(j) Opportunity for hearing.

(1) An operator may request a hearing on any application for an exception or exception renewal required by this section.

(2) An operator may request a hearing on any request for administrative approval of an exception or exception renewal that has been denied by the commission or the commission's delegate.

Source Note: The provisions of this §3.32 adopted to be effective December 4, 1996, 21 TexReg 11367; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective February 18, 2025, 50 TexReg 835.

§3.33 Geothermal Resource Production Test Forms Required

(a) A production test form, with all information requested thereon filled in, shall be filed in the district office not later than 10 days after the test is completed. Production operations shall not be commenced before the test form is filed and the commission grants authority to initiate operations.

(b) The initial production test form for any new completion or recompletion must be accompanied by the well record.

Source Note: The provisions of this §3.33 adopted to be effective January 1, 1976.

§3.34 Gas To Be Produced and Purchased Ratably

(a) Definitions. The following words and terms, when used in this section and in §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule

31) shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affiliate--A person or entity that owns, is owned by, or is under common ownership with another person or entity to the extent of 50% or more or that otherwise controls or is controlled by another person or entity. Affiliates of a common entity are also affiliates of each other. A person or entity that purchases gas solely for purposes other than resale shall not be considered an affiliate, and an interstate pipeline, as defined in the Natural Gas Policy Act of 1978, §2(15) (15 United States Code §3301 et seq.), shall not be considered an affiliate of an intrastate pipeline.

(2) Commission designee--A Railroad Commission employee authorized to act for the commission. Any authority given to a commission designee is also retained by the commission. Any action taken by the commission designee is subject to review by the commission.

(3) Downstream purchaser--One that purchases natural gas for resale and is not a first purchaser.

(4) First purchaser or initial purchaser--The first purchaser of natural gas produced from a well. A first purchaser and any affiliate of the purchaser that transports any natural gas it purchases from a well by use of the same pipeline system used by the first purchaser of which it is an affiliate shall be treated as a single first purchaser for purposes of ratability requirements; provided, however, that an affiliate that is purchasing and accepting deliveries pursuant to a special marketing program that is in compliance with this section, shall be treated as a separate first purchaser; and, provided further that the designation of such affiliate as a separate first purchaser is reviewable by the commission and may be disallowed upon a showing that the designation was for purposes of circumventing this section. Any affiliate may file forms in its own name.

(5) Pipeline system--A network of physically connected pipelines that are operated as a single unit under normal conditions.

(A) A first purchaser's pipeline system is that portion of a physical segment of a pipeline that the first purchaser owns.

(B) If a first purchaser does not own the pipeline it uses to transport its gas, the first purchaser's pipeline system shall include all the wells from which it purchases that are on the pipeline system of the transport pipeline.

(C) A first purchaser may not segregate its purchases from any one field into two or more pipeline systems by transporting on another pipeline gas that it purchases as a first purchaser if the first purchaser is also purchasing as a first purchaser from the same field and transporting on a pipeline that it owns.

(D) A first purchaser may not segregate its purchases from any one field into two or more pipeline systems by executing gas exchange agreements.

(E) Any of a first purchaser's pipeline systems which serve a common customer or common customers in a common geographic location shall be operated in a manner to avoid unjust or unreasonable discrimination in takes as between those systems.

(F) A first purchaser shall not segregate its physically connected pipelines that are capable of being operated as a single unit under normal conditions into two or more pipeline systems or designate a gathering system as a separate system for purposes of circumventing this section.

(6) Prorated gas field--A reservoir or field in which an allocation formula is in effect.

(b) General provisions. This section is promulgated to promote and maintain ratable production of natural gas and to require production in compliance with priority categories established by the commission for the purposes of preventing waste, including production in excess of market demand, protecting correlative rights, preventing discrimination, and conserving the natural resources of this state. An operator shall not produce in excess of its ratable share of the market demand as determined by this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31). An operator shall produce ratably as set out in subsection (e) of this section and shall produce in compliance with subsection (i) of this section which establishes priority categories of natural gas. Because production is dictated by pipeline capacity and market demand, pipelines are an integral part of production regulation. The requirements imposed on pipelines by this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) are enforced to assist in the regulation of production and provide the only method by which such production regulation can be enforced and market demand met as required by statutory law. A first purchaser shall not discriminate between different wells from which it purchases in the same field, nor shall it discriminate unjustly or unreasonably between separate fields. The provisions of this section requiring ratable production and purchasing of gas apply to purchase and production from wells from which a first purchaser is purchasing on its pipeline system.

(c) Designation of pipeline system. A first purchaser shall, on or before a date designated by the commission or a commission designee, designate its pipeline system(s) and shall identify its affiliates that use the same pipeline system, including an affiliate operating a special marketing program that is in compliance with subsection (k) of this section. A pipeline system designation must identify the physical segment of pipeline that constitutes the pipeline system and identify by Railroad Commission of Texas lease and/or identification number and field the wells on that pipeline system from which the first purchaser is purchasing. A change in pipeline system designation is not required to add or delete well connections. The designation of a pipeline system cannot be changed by a first purchaser without prior approval by the commission or a commission designee. Approval of a change in pipeline system designation cannot be given without prior notice of the requested designation given by the first purchaser to affected operators of wells on the system(s) for which a change in designation is sought. A hearing to determine the proper designation of a first purchaser's pipeline system may be called by the commission, or may be requested by a first purchaser or by an operator filing a complaint. The burden of proof in the hearing shall be on the first purchaser.

(d) Operators who use produced gas. Any person who purchases natural gas at the wellhead, at a common point within a field or fields or at the outlet of a processing or treating plant must determine if it is the initial purchaser.

(e) Production guidelines. An operator shall produce without discrimination between its wells in the same field on the same first purchaser's pipeline system and without unjust or unreasonable discrimination between its wells in separate fields on the same first purchaser's pipeline system. An operator shall apportion a first purchaser's delivery requests ratably to its wells in each field on the same first purchaser's pipeline system without discrimination in the same manner as provided in this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) and shall not produce in excess of its ratable share of the market demand as its share is determined by those rules. An operator shall produce in compliance with the priority categories of gas production established by the commission in subsection (i) of this section.

(f) Purchases from different fields.

(1) In making purchases and accepting deliveries between fields, a first purchaser of natural gas that purchases and accepts delivery of gas from more than one field on its same pipeline system must accept from each field a consistent percentage of the portion of the aggregate deliverability as determined by the deliverability tests and total gas limits that it is entitled to purchase from all wells from which it purchases on its pipeline system, unless the purchaser can demonstrate a just and reasonable basis for discriminating between fields.

(2) Natural gas purchases from a well by a first purchaser that uses another first purchaser's pipeline system to transport its gas and sells the gas purchased on that pipeline system solely to the first purchaser that owns the transport pipeline must be treated as first purchases of gas by the first purchaser that owns the transport pipeline.

(g) Purchases within a field.

(1) In making purchases and accepting deliveries within fields, a first purchaser of natural gas that purchases and accepts delivery of gas from different gas wells in the same priority category (see subsection (i) of this section) in the same field on its same pipeline system shall purchase and accept from the wells from which it purchases in the field a consistent percentage of the portion that it is entitled to purchase of the maximum allowable that a well is entitled to under the field's allocation formula. If purchases and deliveries from different wells in the same field become nonratable, the first purchaser shall consider commission-assigned underproduction and overproduction to establish an appropriate pattern of purchases or acceptance of deliveries to restore ratability.

(2) Natural gas purchases from a well by a first purchaser that uses another first purchaser's pipeline system to transport its gas and sells the gas purchased on that pipeline system solely to the first purchaser that owns the transport pipeline must be treated as first purchases of gas by the first purchaser that owns the transport pipeline.

(3) Purchases and deliveries of casinghead gas shall be based on the well's gas limit as specified in §3.49 of this title (relating to Gas-Oil Ratio) (Statewide Rule 49) as provided in subsection (h) of this section. Overproduction and underproduction of gas is administered by the provisions of §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31). A first purchaser shall not reduce purchases from a limited well as described in §3.31(g)(5) until all prorated gas wells from which it purchases in the field connected to its same pipeline system are ratably reduced to the assigned allowable of the limited well. Below that point, purchases from all prorated wells and limited wells should be reduced ratably by purchasing and accepting delivery of the same percentage of the portion that it is entitled to purchase of the maximum allowable established for the well by the field's allocation formula. If purchases and deliveries from different wells in the same field become nonratable, the first purchaser shall consider commission-assigned underproduction and overproduction in establishing an appropriate pattern of purchases or acceptances of deliveries to restore ratability. When purchases of gas described in subsection (i)(2) or (5) of this section are to be reduced, they shall be reduced ratably within each priority category.

(h) Casinghead gas reductions. When purchases and deliveries of casinghead gas described in subsection (i)(1) or (3) of this section are to be reduced, each well's share of the reduction shall be calculated by multiplying the total reduction by the fractional share that each well's gas limit bears to the arithmetic sum of the aggregate gas limits of all wells in the field from which the first purchaser has been purchasing on its same pipeline system. In calculating its reduction of a well, a first purchaser shall use that portion of the gas limits that it is entitled to purchase. A well operating under net gas/oil ratio authority shall produce no more gas than its gas limit as it would be reduced by the previously mentioned procedure absent the net gas/oil ratio authority.

(i) Priority categories. First purchasers of gas shall satisfy their pipeline system demand for gas by purchasing and accepting delivery of gas from the following priority categories in ascending numerical order. Lower priority category gas is gas from a higher numerical category. A first purchaser shall not within its pipeline system curtail gas from a priority category if the purchaser is purchasing and accepting delivery of lower priority category gas as a first purchaser on its same pipeline system. A first purchaser's purchases and acceptance of delivery of first, second, or third priority category gas under an obligation to purchase and accept delivery from the tailgate of a plant processing gas to extract liquids, or from a gathering system that purchases from wells and is required by contract or by its physical connections to sell its gas entirely to the purchaser, whether or not these purchases are made as a first purchaser, shall not be curtailed if the first purchaser is purchasing and accepting delivery of lower priority category gas as a first purchaser on its same pipeline system. If curtailed, the curtailment must be ratable with like priority category gas which the first purchaser is purchasing and accepting delivery of from wells on its same pipeline system.

(1) First priority shall be given to casinghead gas produced from certified tertiary recovery projects approved by the commission and secondary recovery projects involving water injection, gas injection, or pressure maintenance approved by the commission to prevent waste.

(2) Second priority shall be given to gas from special allowable wells as defined in §3.31(g)(6) of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31) granted special allowable status after the effective date of this section to prevent physical waste. Wells classified as special allowable wells pursuant to notice and hearing prior to the effective date of this section

shall be given second priority unless a new determination is made that the special allowable status is not necessary to prevent physical waste.

(3) Third priority shall be given to the remainder of casinghead gas so that gas produced in association with oil production shall not be wastefully vented and oil production shall not be unnecessarily curtailed. Gas recovered from a landfill or sewage process shall also be given third priority.

(4) Fourth priority shall be given to gas from wells classified under §3.49(b) of this title (relating to Gas-Oil Ratio) (Statewide Rule 49), but only to the extent of one full allowable for multiple 49(b) wells.

(5) Fifth priority shall be given to gas from administrative special allowable wells as defined in §3.31(g)(7) of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31) to gas from special allowable wells as described in §3.31(g)(6) granted that status prior to the effective date of this section (see paragraph (2) of this subsection) without notice and hearing, and to gas from special allowable wells granted that status by the commission subsequent to the effective date of this section after notice and hearing for other reasons than to prevent physical waste.

(6) Sixth priority shall be given to the remainder of gas well gas, including limited wells (see subsection (g) of this section).

(j) Prohibition against discriminating in favor of purchaser's own production. A first purchaser of natural gas may not discriminate between or against natural gas of a similar kind or quality in favor of its own production or production in which it may be directly or indirectly interested in whole or in part.

(k) Special marketing programs. If a first purchaser elects to qualify an affiliate as a separate first purchaser, the first purchaser may designate the affiliate as a special marketing program. The special marketing program must comply with the following with respect to the purchase and acceptance of delivery of natural gas.

(1) For purposes of this subsection, an affiliated first purchaser is the special marketing program purchaser's affiliate whose pipeline is being used to transport the gas in the special marketing program.

(2) Each and every special marketing program offer to purchase gas must be made without discrimination within a field and without unjust or unreasonable discrimination between fields to all operators for all wells on the pipeline system of the affiliated first purchaser from which the affiliated first purchaser has been purchasing and accepting delivery of gas as a first purchaser. The offer must also be made for all first, second, and third priority category gas on the affiliated first purchaser's pipeline system which it has been purchasing and accepting for delivery under an obligation to purchase and accept delivery from the tailgate of a plant processing gas to extract liquids or from a gathering system that purchases from wells and is required by contract or by its physical connections to sell its gas entirely to the affiliated first purchaser, whether or not those purchases were made as a first purchaser.

(3) It is unreasonably discriminatory, and therefore prohibited, for the offer to purchase gas in the special marketing program, or for any release of gas for sale in the special marketing program to require release of any claims under any existing contract or require modification of any existing contract provisions other than a release of the gas for sale in the special marketing program or a requirement of a volume-for-volume basis for gas taken in the special marketing program to be credited against the contract from which gas is released for sale in the special marketing program, if the credit provision is limited to the period of actual participation in the special marketing program. Nothing in this paragraph shall prohibit an operator of any well from offering terms inconsistent with these provisions. The making of an offer which is not accepted shall not affect rights under existing contracts.

(4) If a well producing priority category 1, 2, or 3 gas is shut in or curtailed, and waste, as defined in the Texas Natural Resource Code, Title 3, is found by the commission to exist, neither a special marketing program purchaser nor its affiliated first purchaser may purchase lower priority category gas until all the priority Category 1, 2, and 3 gas is taken and resulting waste is prevented. The commission shall expedite determination of waste, and may enter an emergency, temporary, or interim order upon application and affidavit proof that waste is occurring. The application and affidavit proof must be accompanied by supporting documentation, including data on well performance, and a statement that the application and affidavit proof has been served on the first purchaser(s) of the subject well(s) and any affiliated special marketing program purchaser using the first purchaser(s) same pipeline system on or before the date the application and affidavit proof has been mailed or delivered to the commission, with the opportunity for the first purchaser to respond within five days of service or of commission receipt, whichever is latest.

(5) The affiliated first purchaser must continue in compliance with this section to purchase and accept delivery from the wells for which the offer was made and not accepted.

(6) With respect to the purchase of gas from those that accept an offer made pursuant to this subsection, the special marketing program purchaser must comply with this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) as a separate first purchaser.

(7) It is not the objective of this subsection to abrogate any existing contract rights or obligations.

(l) Sellers' complaint procedure. Any operator or nonoperator that is denied by the first purchaser in violation of this section or §3.28 or §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) the opportunity to produce a well's ratable share of gas or opportunity for a well to participate in a special marketing program may file a complaint with the commission and request the commission to direct the first purchaser to end the discriminatory practices. A complainant may request a hearing regarding alleged discriminatory practices or to determine whether a first purchaser is or has, through gas exchange agreements or through actions of its affiliate(s), denied an operator a reasonable opportunity to market its gas.

(m) Purchasers' complaint procedure. If after reasonable notice by the purchaser, an operator fails to comply with a first purchaser's request to reduce production ratably in compliance with this section and §3.28 and §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) the purchaser may file a complaint with the commission and request the commission to direct the operator to comply with the purchaser's requests to reduce production ratably. The complainant or the operator may request the commission to take further action, including setting the issue for hearing.

(n) Hardship exceptions. If the operation of this section or §3.28 or §3.31 of this title (relating to Potential and Deliverability of Gas Wells To Be Ascertained and Reported, and Gas Reservoirs and Gas Well Allowable) (Statewide Rules 28 and 31) causes undue hardship, the commission may, after proper notice and hearing, grant an exception or take appropriate action, including action to prevent waste or protect correlative rights.

(o) Severability provisions. If any provision of this section or its application to any person or circumstance is held invalid, the invalidity shall not affect other provisions or applications of the section which can be given effect without the invalid provisions or appreciation, and the provisions of the section are declared to be severable.

Source Note: The provisions of this §3.34 adopted to be effective September 1, 1986, 11 TexReg 3691; amended to be effective March 2, 1987, 12 TexReg 536; amended to be effective September 8, 1987, 12 TexReg 2860; amended to be effective February 29, 1988, 13 TexReg 838; amended to be effective July 1, 1992, 17 TexReg 3236; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.35 Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned

(a) Abandonment of radioactive source.

(1) Immediate notice of the loss of a radioactive source shall be filed by the operator with the commission designating the location, by county, survey name and abstract number, lease name and well number, distances from survey boundaries and Lambert Coordinates.

(2) Procedures for recovery of the lost radioactive source will be furnished to the commission and such radioactive source shall not be declared abandoned until all reasonable effort has been expended to retrieve the tool.

(3) The operator shall erect, under supervision of the commission, a standardized permanent surface marker as a visual warning to any person who may reenter the hole for any reason, showing that it contains a radioactive source. This marker shall contain the following information: well name, commission number, surface location, name of the operator, name of the lease, the source or material abandoned in the well, the total depth of the well, the depth at which the source is abandoned, the plug back depth, the date of the abandonment of the source, the activity of the source, and a warning not to drill below the plug back depth.

(b) Abandonment procedures.

(1) Wells in which radioactive sources are abandoned shall be mechanically equipped so as to prevent either accidental or intentional mechanical disintegration of the radioactive source.

(A) Sources abandoned in the bottom of the well shall be covered with a substantial standard color dyed (red iron oxide) cement plug on top of which a whipstock or other approved deflection device shall be set. The dye is to alert the reentry operator prior to encountering the source.

(B) Upon abandoning the well in which a logging source has been cemented in place behind a casing string above total depth, a standard color dyed cement plug shall be placed opposite the abandoned source and a whipstock or other approved deflection device placed on top of the plug.

(C) In the event the operator finds that after expending a reasonable effort, because of hole conditions, it is not possible to abandon the source as prescribed in subparagraphs (A) and (B) of this paragraph, he shall seek commission approval to an alternate abandonment procedure.

(D) When a logging source must be abandoned in a producing zone, a standard color dyed cement plug shall be set and a whipstock or other approved deflection device placed above to direct the sidetrack at least 15 feet away from the source.

(2) Upon permanent abandonment of any well in which a radioactive source is left in the hole, and after removal of the wellhead, a permanent plaque shall be attached to the top of the casing left in the hole in such a manner that reentry cannot be accomplished without disturbing the plaque. This plaque shall serve as a visual warning to any person reentering the hole that a radioactive source has been abandoned in place in the well. The plaque shall contain the trefoil radiation symbol with a radioactive warning and shall be constructed of a long-lasting material such as monel, stainless steel, or brass, in accordance with specifications established by the commission. The plugging report filed with the commission shall identify the well as an abandoned radioactive source well, and shall show compliance with the procedures required by this section.

(3) The commission will maintain a current listing of all abandoned radioactive source wells, and each district office will keep such a list for radioactive source wells in that district.

Source Note: The provisions of this §3.35 adopted to be effective January 1, 1976.

§3.36 Oil, Gas, Brine, or Geothermal Resource Operation in Hydrogen Sulfide Areas

(a) Applicability. Each operator who conducts operations as described in paragraph (1) of this subsection shall be subject to this section and shall provide safeguards to protect the general public from the harmful effects of hydrogen sulfide. This section applies to both intentional and accidental releases of hydrogen sulfide.

(1) Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon, brine, or geothermal fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon, brine, or geothermal fluids that contain gas in the system which has hydrogen sulfide as a constituent of the gas, to the extent as specified in subsection (c) of this section, general provisions.

(2) This section shall not apply to:

(A) operations involving processing oil, gas, or hydrocarbon fluids which are either an industrial modification or products from industrial modification, such as refining, petrochemical plants, or chemical plants;

(B) operations involving gathering, storing, and transporting stabilized liquid hydrocarbons;

(C) operations where the concentration of hydrogen sulfide in the system is less than 100 ppm.

(b) Definitions.

(1) Industrial modification--This term is used to identify those operations related to refining, petrochemical plants, and chemical plants. The term does not include field processing such as that performed by gasoline plants and their associated gathering systems.

(2) Stabilized liquid hydrocarbon--The product of a production operation in which the entrained gaseous hydrocarbons have been removed to the degree that said liquid may be stored at atmospheric conditions.

(3) Radius of exposure--That radius constructed with the point of escape as its starting point and its length calculated as provided for in subsection (c)(2) of this section.

(4) Area of exposure--The area within a circle constructed with the point of escape as its center and the radius of exposure as its radius.

(5) Public area--A dwelling, place of business, church, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that can expect to be populated.

(6) Public road--Any federal, state, county, or municipal street or road owned or maintained for public access or use.

(7) Sulfide stress cracking--The cracking phenomenon which is the result of corrosive action of hydrogen sulfide on susceptible metals under stress.

(8) Facility modification--Any change in the operation such as an increase in throughput, in excess of the designed capacity, or any change that would increase the radius of exposure.

(9) Public infringement--This shall mean that a public area and/or a public road, or both, has been established within an area of exposure to the degree that such infringement would change the applicable provisions of this rule to those operations responsible for creating the area of exposure.

(10) Potentially hazardous volume of hydrogen sulfide--A volume of hydrogen sulfide gas of such concentration that:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road; or

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road; or

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(11) Contingency plan--A written document that shall provide an organized plan of action for alerting and protecting the public within an area of exposure prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(12) Reaction-type contingency plan--A preplanned, written procedure for alerting and protecting the public, within an area of exposure, where it is impossible or impractical to brief in advance all of the public that might possibly be within the area of exposure at the moment of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(13) Definition of referenced organizations and publications.

(A) ANSI--American National Standard Institute, 1430 Broadway, New York, New York 10018, Table I, Standard 253.1-1967.

(B) API--American Petroleum Institute, 300 Corrigan Tower Building, Dallas, Texas 75201, Publication API RP-49, Publication API RP-14E, Sections 1.7(c), 2.1(c) 4.7.

(C) ASTM--American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103, Standard D-2385-66.

(D) GPA--Gas Processors Association, 1812 First Place, Tulsa, Oklahoma 74120, Plant Operation Test Manual C-1, GPA Publication 2265-68.

(E) NACE--National Association of Corrosion Engineers, P.O. Box 1499, Houston, Texas 77001, Standard MR-01-75.

(F) DOT--Department of Transportation, Office of Pipeline Safety, 400 Seventh Street, S.W., Washington, D.C. 20590, Title 49, Code of Federal Regulations, Parts 192 and 195.

(G) OSHA--Occupational Safety and Health Administration, United States Department of Labor, 200 Constitution Avenue, NW, Washington D.C. 20270, Title 29, Code of Federal Regulations, Part 1910.145(c)(4)(i).

(H) RRC--Railroad Commission of Texas, Gas Utilities Division, P.O. Drawer 12967, Capitol Station, Austin, Texas 78711, Gas Utilities Dockets 446 and 183.

(c) General provisions.

(1) Each operator shall determine the hydrogen sulfide concentration in the gaseous mixture in the operation or system.

(A) Tests shall be made in accordance with standards as set by ASTM Standard D-2385-66, or GPA Plant Operation Test Manual C-1, GPA Publication 2265-68, or other methods approved by the commission.

(B) Test of vapor accumulation in storage tanks may be made with industry accepted colormetric tubes.

(2) For all operations subject to this section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations, or by other methods that have been approved by the commission.

(A) For determining the location of the 100 ppm radius of exposure: x = [(1.589) (mole fraction H_2 S)(Q)] to the power of (.6258).

(B) For determining the location of the 500 ppm radius of exposure: x = [(0.4546) (mole fraction H_2 S)(Q)] to the power of (.6258). Where x = radius of exposure in feet; Q = maximum volume determined to be available for escape in cubic feet per day; H_2 S = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

(3) The volume used as the escape rate in determining the radius of exposure shall be that specified in subparagraph (A) - (E) of this paragraph, as applicable.

(A) The maximum daily volume rate of gas containing hydrogen sulfide handled by that system element for which the radius of exposure is calculated.

(B) For existing gas wells, the current adjusted open-flow rate, or the operator's estimate of the well's capacity to flow against zero back-pressure at the wellhead shall be used.

(C) For new wells drilled in developed areas, the escape rate shall be determined by using the current adjusted open-flow rate of offset wells, or the field average current adjusted open-flow rate, whichever is larger.

(D) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14.65 pounds per square inch (psia) and 60 degrees Fahrenheit.

(E) For intentional releases from pipelines and pressurized vessels, the operator's estimate of the volume and release rate based on the gas contained in the system elements to be de-pressured.

(4) For the drilling of a well in an area where insufficient data exists to calculate a radius of exposure, but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed. A lesser-assumed radius may be considered upon written request setting out the justification for same.

(5) Storage tank provision: storage tanks which are utilized as a part of a production operation, and which are operated at or near atmospheric pressure, and where the vapor accumulation has a hydrogen sulfide concentration in excess of 500 ppm, shall be subject to the following.

(A) No determination of a radius of exposure shall be made for storage tanks as herein described.

(B) A warning sign shall be posted on or within 50 feet of the facility to alert the general public of the potential danger.

(C) Fencing as a security measure is required when storage tanks are located inside the limits of a townsite or city, or where conditions cause the storage tanks to be exposed to the public.

(D) The warning and marker provision, paragraph (6)(A)(i), (ii), and (iv) of this subsection.

(E) The certificate of compliance provision, subsection (d)(1) of this section.

(6) All operators whose operations are subject to this section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following.

(A) Warning and marker provision.

(i) For above-ground and fixed surface facilities, the operator shall post, where permitted by law, clearly visible warning signs on access roads or public streets, or roads which provide direct access to facilities located within the area of exposure.

(ii) In populated areas such as cases of townsites and cities where the use of signs is not considered to be acceptable, then an alternative warning plan may be approved upon written request to the commission.

(iii) For buried lines subject to this section, the operator shall comply with the following.

(I) A marker sign shall be installed at public road crossings.

(II) Marker signs shall be installed along the line, when it is located within a public area or along a public road, at intervals frequent enough in the judgment of the operator so as to provide warning to avoid the accidental rupturing of line by excavation.

(III) The marker sign shall contain sufficient information to establish the ownership and existence of the line and shall indicate by the use of the words "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the federal Department of Transportation shall satisfy the requirements of this provision. Marker signs installed prior to the effective date of this section shall be acceptable provided they indicate the existence of a potential hazard.

(iv) In satisfying the sign requirement of clause (i) of this subparagraph, the following will be acceptable.

(I) Sign of sufficient size to be readable at a reasonable distance from the facility.

(II) New signs constructed to satisfy this section shall use the language of "Caution" and "Poison Gas" with a black and yellow color contrast. Colors shall satisfy Table I of American National Standard Institute Standard 253.1-1967. Signs installed to satisfy this section are to be compatible with the regulations of the federal Occupational Safety and Health Administration.

(III) Existing signs installed prior to the effective date of this section will be acceptable if they indicate the existence of a potential hazard.

(B) Security provision.

(i) Unattended fixed surface facilities shall be protected from public access when located within 1/4 mile of a dwelling, place of business, hospital, school, church, government building, school bus stop, public park, town, city, village, or similarly populated area. This protection shall be provided by fencing and locking, or removal of pressure gauges and plugging of valve opening, or other similar means. For the purpose of this provision, surface pipeline shall not be considered as a fixed surface facility.

(ii) For well sites, fencing as a security measure is required when a well is located inside the limits of a townsite or city, or where conditions cause the well to be exposed to the public.

(iii) The fencing provision will be considered satisfied where the fencing structure is a deterrent to public access.

(C) Materials and equipment provision.

(i) For new construction or modification of facilities (including materials and equipment to be used in drilling and workover operations) completed or contemplated subsequent to the effective date of this section, the metal components shall be those metals which have been selected and manufactured so as to be resistant to hydrogen sulfide stress cracking under the operating conditions for which their use is intended, provided that they satisfy the requirements described in the latest editions of NACE Standard MR-01-75 and API RP-14E, sections 1.7(c), 2.1(c), 4.7. The handling and installation of materials and equipment used in hydrogen sulfide service are to be performed in such a manner so as not to induce susceptibility to sulfide stress cracking. Other materials which are nonsusceptible to sulfide stress cracking, such as fiberglass and plastics, may be used in hydrogen sulfide service provided such materials have been manufactured and inspected in a manner which will satisfy the latest published, applicable industry standard, specifications, or recommended practices.

(ii) Other materials and equipment (including materials and equipment used in drilling and workover operations) which are not included within the provision of clause (i) of this subparagraph may be used for hydrogen sulfide service provided:

(I) such materials and equipment are proved, as the result of advancements in technology or as the result of control and knowledge of operating conditions (such as temperature and moisture content), to be suitable for the use intended and where such usage is technologically acceptable as good engineering practice; and

(II) the commission has approved the use of said materials and equipments for the specific uses after written application.

(iii) Existing facilities (including materials in present common usage for drilling and workover operations in hydrogen sulfide areas) which are in operation prior to the effective date of this section, and where there has been no failure of existing equipment attributed to sulfide stress cracking, shall satisfy the requirements of this section.

(iv) In the event of a failure of any element of an existing system as the result of hydrogen sulfide stress cracking, the compliance status of the system shall be determined by the commission after the operator has submitted to the commission a detailed written report on the failure.

(7) All operations subject to subsection (a) of this section shall be subject to the additional control and equipment safety provision, paragraph (8) of this subsection, and the contingency plan provision, paragraph (9) of this subsection, if any of the following conditions apply:

(A) the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a "public area" except a public road;

(B) the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road;

(C) the 100 ppm radius of exposure is greater than 3,000 feet.

(8) Control and equipment safety provision. Operators subject to this provision shall install safety devices and maintain them in an operable condition or shall establish safety procedures designed to prevent the undetected continuing escape of hydrogen sulfide. For intentional releases of a potentially hazardous volume of hydrogen sulfide gas, the gas must be flared unless permission to vent is obtained from the commission or its delegate. Venting will be allowed only upon a showing that the venting will not pose an unreasonable risk of harm to the public.

(9) Contingency plan provision.

(A) All operators whose operations are subject to this provision shall develop a written contingency plan complete with all requirements before hydrogen sulfide operations are begun.

(B) The purpose of the contingency plan shall be to provide an organized plan of action for alerting and protecting the public prior to an intentional release, or following the accidental release of a potentially hazardous volume of hydrogen sulfide.

(C) The contingency plan shall be activated prior to an intentional release, or immediately upon the detection of an accidental release of a potentially hazardous volume of hydrogen sulfide.

(D) Conditions that might exist in each area of exposure shall be considered when preparing a contingency plan.

(E) The plan shall include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency.

(F) The plan shall include procedures for requesting assistance and for follow-up action to remove the public from an area of exposure.

(G) The plan shall include a call list which shall include the following as they may be applicable:

(i) local supervisory personnel;

(ii) county sheriff;

(iii) Department of Public Safety;

(iv) city police;

(v) ambulance service;

(vi) hospital;

(vii) fire department;

(viii) doctors;

(ix) contractors for supplemental equipment;

(x) district Railroad Commission office;

(xi) the appropriate regional office of the Texas Commission on Environmental Quality or its successor agencies;

(xii) other public agencies.

(H) The plan shall include a plat detailing the area of exposure. The plat shall include the locations of private dwellings or residential areas, public facilities, such as schools, business locations, public roads, or other similar areas where the public might reasonably be expected within the area of exposure.

(I) The plan shall include names and telephone numbers of residents within the area of exposure, except in cases where the reaction plan option has been approved by the commission in accordance with subparagraph (L) of this paragraph.

(J) The plan shall include a list of the names and telephone numbers of the responsible parties for each of the possibly occupied public areas, such as schools, churches, businesses, or other public areas or facilities within the area of exposure.

(K) The plan shall include provisions for advance briefing of the public within an area of exposure. Such advance briefing shall include the following elements:

(i) the hazards and characteristics of hydrogen sulfide;

(ii) the necessity for an emergency action plan;

(iii) the possible sources of hydrogen sulfide within the area of exposure;

(iv) instructions for reporting a gas leak;

(v) the manner in which the public will be notified of an emergency;

(vi) steps to be taken in case of an emergency.

(L) In the event of a high density of population, or the case where the population density may be unpredictable, a reaction type of plan, in lieu of advance briefing for public notification, will be acceptable. The reaction plan option must be approved by the commission.

(M) The plan shall include additional support information, if applicable, such as:

(i) location of evacuation routes;

(ii) location of safety and life support equipment;

(iii) location of hydrogen sulfide containing facilities;

(iv) location of nearby telephones and/or other means of communication; and

(v) special instructions for conditions at a particular installation such as local terrain and the effect of various weather conditions.

(N) The Railroad Commission District Office shall be notified as follows if the contingency plan is activated:

(i) 12 hours in advance of an intentional release or as soon as a decision is made to release if such decision could not reasonably have been made more than 12 hours prior to the release;

(ii) immediately in the case of an accidental release;

(iii) as soon as possible before or after an unplanned intentional release made in an emergency situation to prevent a possible uncontrolled release.

(O) The retention of the contingency plan shall be as follows.

(i) The plan shall be available for commission inspection at the location indicated on the certificate of compliance.

(ii) The plan shall be retained at the location which lends itself best to activation of the plan.

(P) In the event that, due to particular situations, a contingency plan cannot be developed consistent with the provisions of this paragraph, relating to the contingency plan, then the operator may develop an adjusted plan to fit the situation, and submit same with the certificate of compliance. Approval of the certificate of compliance so submitted will constitute approval of the contingency plan.

(Q) The plan shall be kept updated to insure its current applicability.

(10) Injection provision.

(A) Injection of fluids containing hydrogen sulfide shall not be allowed under the conditions specified in this provision unless first approved by the commission after public hearing:

(i) where injection fluid is a gaseous mixture, or would be a gaseous mixture in the event of a release to the atmosphere, and where the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a public area except a public road; or, if the 500 ppm radius of exposure is in excess of 50 feet and includes any part of a public road; or if the 100 ppm radius of exposure is 3,000 feet or greater;

(ii) where the hydrogen sulfide content of the gas or gaseous mixture to be injected has been increased by a processing plant operation.

(B) Each project involving the injection of gas or gaseous mixtures containing hydrogen sulfide which does not require a public hearing prior to receiving commission approval specified in this provision shall nevertheless be subject to the other provisions of this section to the extent that such provisions are applicable to such project.

(11) In addition to any other requirements of this section, drilling and workover operations, and gasoline plant sites where the 100 ppm radius of exposure is 50 feet or greater shall be subject to the following.

(A) Protective breathing equipment shall be maintained in two or more locations at the site.

(B) Wind direction indicators shall be installed at strategic locations at or near the site and be readily visible from the site.

(C) Automatic hydrogen sulfide detection and alarm equipment that will warn of the presence of hydrogen sulfide gas in concentrations that could be harmful shall be utilized at the site.

(12) Drilling provision. Drilling and workover operations where the 100 ppm radius of exposure includes a public area or is 3,000 feet or greater shall be subject to the following additional provisions.

(A) Protective breathing equipment shall be maintained at the well site and shall be sufficient to allow for well control operations.

(B) The operator shall provide a method of igniting the gas in the event of an uncontrollable emergency.

(C) The operator shall install a choke manifold, mud-gas separator, and flare line, and provide a suitable method for lighting the flare.

(D) Secondary remote control of blowout prevention and choke equipment to be located away from the rig floor at a safe distance from the wellhead.

(E) Drill stem testing of hydrogen sulfide zones is permitted only in daylight hours.

(F) The Railroad Commission district office shall be notified of the intention to conduct a drill stem test of a formation containing hydrogen sulfide in sufficient concentration to meet the requirements of this provision.

(G) A certificate of compliance shall be required on each well subject to this provision even if well is located on certificated lease.

(H) Full compliance with all the requirements of this provision must be satisfied before the well is drilled to a depth that is within 1,000 feet of the hydrogen sulfide zone. Alternate depths may be approved in advance by the appropriate commission district office.

(I) API Publication RP-49 is referenced as a suggested guideline for drilling and workover of wells subject to this provision.

(J) Blowout preventers and well control systems shall be pressure tested at or near compliance depth or at depth of nearest bit change prior to reaching compliance depth. The appropriate Railroad Commission district office must be notified at least four hours prior to the test.

(13) Training requirement provision.

(A) Each operator whose operations contain hydrogen sulfide in excess of 100 ppm shall train its employees working in the affected areas in hydrogen sulfide safety.

(B) Each operator shall require all service companies working in affected areas to utilize only those service company personnel who have been trained in accordance with the provisions of subparagraphs (C) and (D) of this paragraph. Written certification to the operator by the service company that only those service company personnel who have been trained in accordance with the training requirement provision will be utilized in affected areas complies with this provision. For this provision, service company shall mean any company actually performing work at well sites, gasoline plant sites, or on pipelines, where such work could allow the escape of hydrogen sulfide gas.

(C) The training of all personnel working in the affected areas shall include the following elements:

(i) hazards and characteristics of hydrogen sulfide;

(ii) safety precautions;

(iii) operation of safety equipment and life support system.

(D) On-site supervisory personnel shall be additionally trained in the following:

(i) effect of hydrogen sulfide on metal components in the system;

(ii) corrective action and shutdown procedures, and when drilling a well, blowout prevention, and well control procedures;

(iii) must have full knowledge of the requirements of the contingency plan, when such plan is required.

(E) Training schedules and course outlines shall be provided to the commission personnel upon request for the purpose of commission review to determine compliance with the provisions of subparagraphs (C) and (D) of this paragraph.

(14) Accident notification. Operators shall immediately notify the appropriate Railroad Commission District Office of any accidental release of hydrogen sulfide gas of sufficient volume to present a hazard and of any hydrogen sulfide related accident.

(d) Reports required.

(1) Certificate of compliance provision. A certificate of compliance shall be submitted for operations subject to any provision of this section. The following shall apply to the certificate of compliance provision of the section.

(A) The certificate of compliance shall certify that operator has complied or will comply with applicable provisions of this section.

(B) The certificate of compliance shall be filed in triplicate in the commission district office where the operation is located.

(C) The certificate of compliance shall certify that existing operations subject to this section to be in compliance will be in compliance as specified in an attached schedule, or, for new or modified facilities, will be in compliance upon completion.

(D) An approved certificate of compliance will permit an operator to perform all activities described in the certificate without additional filing of approval; provided that, consistent with subsection (c)(12)(G) of this section, a certificate of compliance will be required on each well subject to the provisions of subsection (c)(12)(G) of this section.

(E) A new or amended certificate of compliance shall be required if there is a change in public exposure caused by public infringement of an existing radius of exposure resulting in a change in the applicable provisions of this section, not described by the existing certificate. The operator shall file the new or amended certificate within 30 days after such infringement.

(F) A new or amended certificate of compliance shall be required if there is modification of an existing operation or facility which increases the radius of exposure in a public area, or results in a change in the applicable provisions of this section not described by the existing certificate. The operator shall file the new or amended certificate at least 30 days prior to initiating the operation or construction.

(G) The operator shall file a certificate of compliance 30 days prior to commencement of a drilling or workover operation on wells where a certificate of compliance is required for that well by provisions of this section (wells drilled on noncertificated leases or wells with a 100 ppm radius of exposure greater than 3,000 feet).

(H) In case of extenuating circumstances, an operator may file a certificate of compliance with an attached written explanation for those cases where waiver of 30-day prior filing is requested. In such cases, the approval of the certificate of compliance will constitute authority to proceed.

(I) The certificate of compliance shall be prepared and executed by a party who, through training and experience, is qualified to make such certification.

(J) The certificate of compliance will be in effect until conditions are altered in a manner that would require amending the "certificate." The operator shall notify the commission within 30 days following cessation or abandonment of operations in a certificated area.

(K) The certificate of compliance required by the provisions of this order for an existing system are due in the district office as soon as is reasonably possible, and no later than September 1, 1976, and as applicable for new or modified operations.

(L) A certificate of compliance may cover a single operation or multiple operations located in an area, a field, or a group of fields within a commission district. The description of the type of operation as indicated on the form must be sufficiently complete to the degree that it is obvious what element of an operation is to be covered by the certificate. All Railroad Commission identification numbers for each element of the system must be shown on the certificate and must be identified as to the type of operation.

(M) Certificates are nontransferable, and a new operator of a system or any acquired element of a system or operation shall be required to certificate that operation. Operator of a certificated system shall notify the commission in writing when the system or any operating part has been transferred to another operator. An amended certificate shall be required should any change occur that would add or delete a Railroad Commission identification number covered by the certificate.

(N) Each operator shall maintain a current master list of all his operations for which a certificate of compliance is in effect and shall submit such list for inspection upon request by the commission.

(2) Completion report provision.

(A) The operator shall report on the initial completion report for new oil or gas wells the hydrogen sulfide concentrations of the wellhead gas for all wells where the hydrogen sulfide concentration is equal to or exceeds 100 ppm.

(B) The drilling of a well in an area which would require the submission of a certificate of compliance (Form H-9) shall have noted on the drilling application (Form W-1) that such certification has been filed.

(3) Releases of, and accidents related to, hydrogen sulfide. The operator shall furnish a written report to the district office within ten days of any accidental release of hydrogen sulfide gas of sufficient volume to present a hazard and of any hydrogen sulfide related accident, whether it be from an accidental or intentional release.

(e) Exception provision. Any application for exception to the provisions of this section should specify the provisions to which exception is requested, and set out in detail the basis on which the exception is to be requested.

Source Note: The provisions of this §3.36 adopted January 1, 1976; amended to be effective September 1, 1976, 1 TexReg 1517; amended to be effective September 15, 1985, 10 TexReg 2069; amended to be effective April 7, 1995, 20 TexReg 2285; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective February 18, 2025, 50 TexReg 835.

§3.37 Statewide Spacing Rule

(a) Distance requirements.

(1) No well for oil, gas, or geothermal resource shall hereafter be drilled nearer than 1,200 feet to any well completed in or drilling to the same horizon on the same tract or farm, and no well shall be drilled nearer than 467 feet to any property line, lease line, or subdivision line; provided the commission, in order to prevent waste or to

prevent the confiscation of property, may grant exceptions to permit drilling within shorter distances than prescribed in this paragraph when the commission shall determine that such exceptions are necessary either to prevent waste or to prevent the confiscation of property.

(2) When an exception to this section is desired, application shall be made by filing the proper fee as provided in §3.78 of this title (relating to Fees and Financial Security Requirements) and the appropriate form according to the instructions on the form, accompanied by a plat as described in subsection (c) of this section. A person acquainted with the facts pertinent to the application shall certify that all facts stated in it are true and within the knowledge of that person.

(A) When an exception to only the minimum lease-line spacing requirement is desired, the applicant shall file a list of the mailing addresses of all affected persons, who, for tracts closer to the well than the greater of one-half of the prescribed minimum between-well spacing distance or the minimum lease-line spacing distance, include:

(i) the designated operator;

(ii) all lessees of record for tracts that have no designated operator; and

(iii) all owners of record of unleased mineral interests.

(B) When an exception to the minimum between-well spacing requirement of this section is desired, the applicant is required to file the mailing addresses of those persons identified in subparagraph (A)(i)-(iii) of this paragraph for each adjacent tract and each tract nearer to the well than the greater of one-half the prescribed minimum between-well spacing distance or the minimum lease-line spacing.

(3) An exception may be granted pursuant to subsection (h)(2) of this section, or after a public hearing held after at least 10 days notice to all persons described in paragraph (2) of this subsection. At any such hearing, the burden shall be on the applicant to establish that an exception to this section is necessary either to prevent waste or to prevent the confiscation of property. For purposes of giving notice of an application for an exception, the commission will presume that every person described in paragraph (2) of this subsection will be affected by the application, unless the Oil and Gas Division director or the director's delegate determines they are unaffected. Such determination will be made only upon written request and a showing by the applicant that:

(A) competent, conclusive geological or engineering data indicate that no drainage of hydrocarbons from the particular tract(s) subject to the request will occur due to production from the applicant's proposed well; and

(B) notice to the particular operator(s), lessee(s) of record, or owner(s) of record of unleased mineral interest would be unduly burdensome or expensive.

(4) If, after diligent efforts, the applicant is unable to ascertain the name and address of one or more persons required by this subparagraph to be notified, then the applicant shall notify such persons by publishing notice of the application in a form approved by the Commission. The applicant shall publish the notice once each week for two consecutive weeks in a newspaper of general circulation in the county where the well will be located. The first publication shall be published at least 14 days before the protest deadline in the notice of application. The applicant shall file with the Commission a publisher's affidavit or other evidence of publication.

(b) The distances mentioned in subsection (a) of this section are minimum distances to provide standard development on a pattern of one well to each 40 acres in areas where proration units have not been established.

(c) In filing an application for an exception to the distance requirements of this section, in addition to the plat requirements in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the applicant shall attach to each copy of the form a plat that:

(1) shows to scale the property on which the exception is sought; all other applied for, permitted, and completed oil, gas, or oil and gas wells in the same field and reservoir on said property; and all adjoining surrounding properties and completed wells in the same field and reservoir within the prescribed minimum between-well spacing distance of the applicant's well;

(2) shows the entire lease, pooled unit, or unitized tract indicating the names and offsetting properties of all affected offset operators;

(3) corresponds to the listing required under subsection (a)(2) of this section;

(4) is certified by a person acquainted with the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(d) In the interest of protecting life and for the purpose of preventing waste and preventing the confiscation of property, the commission reserves the right in particular oil, gas, and geothermal resource fields to enter special orders increasing or decreasing the minimum distances provided by this section.

(e) No well drilled in violation of this section without special permit obtained, issued, or granted in the manner prescribed in said section, and no well drilled under such special permit or on the commission's own order which does not conform in all respects to the terms of such permit shall be permitted to produce either oil, gas, or geothermal resources and any such well so drilled in violation of said section or on the commission's own order shall be plugged.

(f) No operator shall commence the drilling of a well, either on a regular location or on a Rule 37 exception location, until first having been notified by the commission that the regular location has been approved, or that the Rule 37 exception location has been approved. Failure of an operator to comply with this subsection will cause such well to be closed in and the holding up of the allowable of such well.

(g) Subdivision of property.

(1) In applying Rule 37 (Statewide Spacing Rule) of statewide application and in applying every special rule with relation to spacing in every field in this state, no subdivision of property made subsequent to the adoption of the original spacing rule will be considered in determining whether or not any property is being confiscated within the terms of such spacing rule, and no subdivision of property will be regarded in applying such spacing rule or in determining the matter of confiscation if such subdivision took place subsequent to the promulgation and adoption of the original spacing rule.

(2) Any subdivision of property creating a tract of such size and shape that it is necessary to obtain an exception to the spacing rule before a well can be drilled thereon is a

voluntary subdivision and not entitled to a permit to prevent confiscation of property if it were either:

(A) segregated from a larger tract in contemplation of oil, gas, or geothermal resource development; or

(B) segregated by fee title conveyance from a larger tract after the spacing rule became effective and the voluntary subdivision rule attached.

(3) The date of attachment of the voluntary subdivision rule is the date of discovery of oil, gas, or geothermal resource production in a certain continuous reservoir, regardless of the subsequent lateral extensions of such reservoir, provided that such rule does not attach in the case of a segregation of a small tract by fee title conveyance which is not located in an oil, gas, or geothermal resource field having a discovery date prior to the date of such segregation.

(4) The date of attachment of the voluntary subdivision rule for multiple reservoir fields located in the same structural feature and separated vertically but not laterally (i.e., the multiple reservoirs overlap geographically at least in part), shall be the same date as that assigned to the earliest discovery well for such multiple reservoir structure.

(5) If a newly discovered reservoir is located outside the then productive limits of any previously discovered reservoirs and is classified by the commission as a newly discovered field, then the date of discovery of such newly found reservoir remains the date of attachment for the voluntary subdivision rule, even though subsequent development may result in the extension of such newly discovered reservoir until it overlies or underlies older reservoirs with prior discovery dates.

(6) The date of attachment of the voluntary subdivision rule for a reservoir that has been developed through expansion of separately recognized fields into a recognized single reservoir and is merged by commission order is the earliest discovery date of production from such merged reservoir, and that date will be used subsequent to the date of merger of the fields into a single field.

(7) The date of attachment of the voluntary subdivision rule for a reservoir under any special circumstance which the commission deems sufficient to provide for an exception may be established other than as prescribed in this section, so that innocent parties may have their rights protected.

(h) Exceptions to Rule 37.

(1) An order granting exception to Rule 37 wherein protest is had shall carry as its last paragraph the following language: It is further ordered by the commission that this order shall not be final until 20 days after it is actually mailed to the parties by the commission; provided that if a motion for rehearing of the application is filed by any party at interest within such 20-day period, this order shall not become final until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the commission. Permits issued pursuant to paragraph (2) of this subsection shall be issued without the 20-day waiting period.

(2) The director of the Oil and Gas Division or a delegate of the director may issue an exception permit for drilling, deepening, or additional completion, recompletion, or reentry in an existing well bore if:

(A) a notice of at least 10 days has been given, and no protest has been made to the application; or

(B) written waivers of objection are received from all persons to whom notice would be given pursuant to subsection (a)(2) of this section.

(3) Applications filed for drilling, deepening, or additional completion, recompletion, or reentry will be processed and permit issued in accordance with this regulation, subject to the commission's discretion to set any application for hearing. If the director or a delegate of the director declines to grant an application, the operator may request a hearing.

(i) Rule 37 permits.

(1) Unless otherwise specified in a permit or in a final order granting an exception to this section, permits issued by the commission for completions requiring an exception to this section shall expire two years from the effective date of the permit unless drilling operations are commenced in good faith within the two-year permit period. The permit period will not be extended.

(2) So long as a Rule 37 exception is in litigation, the two-year permit period will not commence. On final adjudication and decree from the last court of appeal the two-year permit period will commence, beginning on the date of final decree.

(j) Once an application for a spacing exception has been denied, no new application shall be entertained except on changed conditions. Changed conditions in the commission's administration of its Spacing Rule 37 and amendments thereto applicable to the various special fields and reservoirs of Texas and in passing upon applications for permits under said rule and amendments shall include, among other things, the following.

(1) Any material changes in the physical conditions of the producing reservoir under the tract under consideration or under the area surrounding said tract which would materially affect the recovery of oil, gas, or geothermal resource from the given tract.

(2) Any material changes in the distribution or allocation of allowable production in the area surrounding the tract under consideration which would materially affect or tend to affect the recovery of oil, gas, or geothermal resource from the given tract.

(3) Any additional permits granted by the commission for wells drilled in the area surrounding or on offset tracts to the tract under consideration which would materially affect or tend to affect the recovery of oil, gas, or geothermal resource from the given tract.

(4) Any additional facts or evidence thereof materially affecting or tending to affect the recovery of oil, gas, or geothermal resource from the applicant's tract, or the property rights of applicant, which were not known of and considered by the commission at any previous hearing or application thereon.

(k) Exceptions to Statewide Rule 37 apply to the total depth for which the permit is granted or if special field rules are applicable, an exception to the spacing rule shall be granted only for the reservoir or reservoirs or applicable depth to which the well is projected. Subsequent recompletion of the well to reservoirs other than that covered by the permit issued would be granted only after the filing and processing of a new application.

(l) Salt dome oil or gas fields.

(1) The provisions of this section shall not apply to certain approved salt dome oil or gas fields. An application for classification as a salt dome oil or gas field shall include the following:

(A) geological evidence proving that an oil or gas field is a piercement-type salt dome, that faulting has caused the producing formation to be at a 45 angle or greater, and that each well is likely to be completed in a separate reservoir;

(B) establishment, by plat or otherwise, of the probable productive limits of the salt dome area;

(C) certification that notice of the application for salt dome classification with evidence included has been given to all operators in the field or, if a new field, in accordance with subsection (a)(2) of this section; and

(D) a list of persons notified and the date notice was mailed.

(2) The director of the Oil and Gas Division, or the director's delegate, may administratively grant an application for salt dome classification if the evidence proves that the oil or gas field is a salt dome.

(3) The operator may request a hearing if the director of the Oil and Gas Division, or the director's delegate, declines to approve an application. If an application is protested within 10 days of notice, it will be set for hearing. After hearing, the examiner shall recommend final commission action.

(4) The amendment providing for administrative approval of salt dome oil and gas fields does not alter the status of those fields previously approved and listed in this section.

(m) Wells that were deviated, whether intentionally or otherwise, prior to April 1, 1949, and are bottomed on the lease where permitted, are legal wells. The Rule 37 department will develop the record in each reapplication for such deviated wells so that the commission can determine the condition of each such well. The following will be adduced from sworn testimony and authenticated data at each such hearing.

(1) That such well was deviated before April 1, 1949. Proof of completion of the well prior to that date and its subsequent producing status is not adequate proof of deviation.

(2) That such well was completed on the lease where the surface location was permitted. Such bottom hole location must be proven by the submission of an acceptable authenticated directional survey.

(3) That such bottom hole location is one that either is not in direct violation of a condition or limitation placed in the permit to drill, or is not in violation of a specific commission order. Example: Denial order for a Rule 37 application for a comparable location.

(4) That the present operator of such well or its predecessor has not filed either a false inclination or a false directional survey with the commission.

(5) A well that is either bottomed off the lease, deviated after April 1, 1949, drilled in direct violation of a specific condition or limitation placed in the Rule 37 permit, or is in violation of a specific commission order, is an illegal well and it shall not be permitted, and such well where permit is refused shall not be considered a replaceable well under commission replacement-well regulation.

(6) The provisions of this section do not preclude an operator from applying for approval of the bottom hole location of a deviated well as a reasonable location under the rules and regulations now applicable, provided, that such bottom hole location shall not be approved unless the applicant proves that a vertical projection of the permitted surface location for such well is within the productive limits of the reservoir.

Source Note: The provisions of this §3.37 adopted to be effective January 1, 1976; amended to be effective November 4, 1981, 6 TexReg 3911; amended to be effective May 7, 1982, 7 TexReg 1624; amended to be effective June 1, 1989, 14 TexReg 1586; amended to be effective May 23, 1990, 15 TexReg 2634; amended to be effective September 15, 1997, 22 TexReg 8973; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective March 18, 2019, 44 TexReg 1437.

§3.38 Well Densities

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission designee--Director of the Oil and Gas Division or any Commission employee designated in writing by the director or the Commission.

(2) Drilling unit--The acreage assigned to a well for drilling purposes.

(3) Proration unit--The acreage assigned to a well for the purpose of assigning allowables and allocating allowable production to the well.

(4) Substandard acreage--Less acreage than the smallest amount established for standard or optional drilling units.

(5) Surplus acreage--Substandard acreage within a lease, pooled unit, or unitized tract that remains unassigned after the assignment of acreage to each applied for, permitted, or completed well in a field, in an amount equaling or exceeding the amount established for standard or optional drilling units. Surplus acreage is distinguished from the term "tolerance acreage," in that tolerance acreage is defined in context with proration regulation, while surplus acreage is defined by this rule only in context with well density regulation.

(6) Tolerance acreage--Acreage within a lease, pooled unit, or unitized tract that may be assigned to a well for proration purposes pursuant to special field rules in addition to the amount established for a prescribed or optional proration unit.

(b) Density requirements.

(1) General prohibition. No well shall be drilled on substandard acreage except as hereinafter provided.

(2) Standard units.

(A) The standard drilling unit for all oil, gas, and geothermal resource fields wherein only spacing rules, either special, country regular, or statewide, are applicable is hereby prescribed to be the following.

Spacing Rule	Acreage Requirement
(1) 150 - 300	02
(2) 200 - 400	04
(3) 330 - 660	10
(4) 330 - 933	20
(5) 467 - 933	20
(6) 467 - 1200	40

(7) 660 - 1320	40

(B) The spacing rules listed in subparagraph (A) of this paragraph are not exclusive. If any spacing rule not listed in subparagraph (A) of this subsection is brought to the attention of the commission, it will be given an appropriate acreage assignment.

(c) Development to final density. An application to drill a well for oil, gas, or geothermal resource on a drilling unit composed of surplus acreage, commonly referred to as the "tolerance well," may be granted as regular when the operator seeking such permit certifies to the commission in a prescribed form the necessary data to show that such permit is needed to develop a lease, pooled unit, or unitized tract to final density, and only in the following circumstances:

(1) when the amount of surplus acreage equals or exceeds the maximum amount provided for tolerance acreage by special or county regular rules for the field, provided that this paragraph does not apply for a lease, pooled unit, or unitized tract that is completely developed with optional units and the special or county regular rules for the field do not have a tolerance provisions expressly made applicable to optional proration units;

(2) if the special or county regular rules for the field do not have a tolerance provision expressly made applicable to optional proration units, when the amount of surplus acreage equals or exceeds one-half of the smallest amount established for an optional drilling unit; or

(3) if the applicable rules for the field do not have a tolerance provision for the standard drilling or proration unit, when the amount of surplus acreage equals or exceeds one-half the amount prescribed for the standard unit.

(d) Applications involving the voluntary subdivision rule.

(1) Density exception not required. An exception to the minimum density provision is not required for the first well in a field on a lease, pooled unit, or unitized tract composed of substandard acreage, when the leases, or the drillsite tract of a pooled unit or unitized tract:

(A) took its present size and shape prior to the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to Statewide Spacing Rule)); or

(B) took its present size and shape after the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to Statewide Spacing Rule)) and was not composed of substandard acreage in the field according to the density rules in effect at the time it took its present size and shape.

(2) Density exception required. An exception to the density provision is required, and may be granted only to prevent waste, for a well on a lease, pooled unit, or unitized tract that is composed of substandard acreage and that:

(A) took its present size and shape after the date of attachment of the voluntary subdivision rule (§3.37(g) of this title (relating to the Statewide Spacing Rule)); and

(B) was composed of substandard acreage in the field according to the density rules in effect at the time it took its present size and shape.

(3) Unit dissolution.

(A) If two or more separate tracts are joined to form a unit for oil or gas development, the unit is accepted by the Commission, and the unit has produced hydrocarbons in the preceding twenty (20) years, the unit may not thereafter be dissolved into the separate tracts with the rules of the commission applicable to each separate tract if the dissolution results in any tract composed of substandard acreage for the field from which the unit produced, unless the Commission approves such dissolution.

(B) The Commission shall grant approval only after application, notice, and an opportunity for hearing. The applicant seeking the unit dissolution shall provide a list of the names and addresses of all current lessees and unleased mineral interest owners of each tract within the joined or unitized tract at the time the application is filed. The Commission shall give notice of the application to all current lessees and unleased mineral interest owners of each tract within the joined or unitized tract. Additionally, if one or more wells on the unitized tract has produced from the field within the 12-month period prior to the application, the applicant shall include on the list all affected persons described in subsection (h)(1)(A) of this section, and the Commission shall give notice of the application to these affected persons.

(C) A Commission designee may grant administrative approval if the Commission designee determines that granting the application will not result in the circumvention of the density restrictions of this section or other Commission rules, and if either:

(i) written waivers are filed by all affected persons; or

(ii) no protest is filed within the time set forth in the notice of application.

(e) Application involving unitized areas with entity for density orders. An exception to the minimum density provision is not required for a well in a unitized area for which the commission has granted an entity for density order, if the sum of all applied for, permitted, or completed producing wells in the field within the unitized area, multiplied by the applicable density provision, does not exceed the total number of acres in the unitized area. The operator must indicate the docket number of the entity for density order on the application form.

(f) Exceptions to density provisions authorized. The Commission, or Commission designee, in order to prevent waste or, except as provided in subsection (d)(2) of this section, to prevent the confiscation of property, may grant exceptions to the density provisions set forth in this section. Such an exception may be granted only after notice and an opportunity for hearing.

(g) Filing requirements.

(1) Application. An application for permit to drill shall include the fees required in §3.78 of this title (relating to Fees and Financial Security Requirements) and shall be certified by a person acquainted with the facts, stating that all information in the application is true and complete to the best of that person's knowledge.

(2) Plat. When filing an application for an exception to the density requirements of this section, in addition to the plat requirements in §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5), the applicant shall attach to each copy of the application a plat that:

(A) depicts the lease, pooled unit, or unitized tract, showing thereon the acreage assigned to the drilling unit for the proposed well and the acreage assigned to all current applied for, permitted, or completed oil, gas, or oil and gas wells in the same field or reservoir which are located within the lease, pooled unit, or unitized tract;

(B) on large leases, pooled units, or unitized tracts, if the established density is not exceeded as shown on the face of the application, outlines the acreage assigned to the well for which the permit is sought and the immediately adjacent wells on the lease, pooled unit, or unitized tract;

(C) on leases, pooled units, or unitized tracts from which production is secured from more than one field, outlines the acreage assigned to the wells in each field that is the subject of the current application;

(D) corresponds to the listing required under subsection (g)(1)(A) of this section.

(E) is certified by a person acquainted with the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(3) Substandard acreage. An application for a permit to drill on a lease, pooled unit, or unitized tract composed of substandard acreage must include a certification in a prescribed form indicating the date the lease, or the drillsite tract of a pooled unit or unitized tract, took its present size and shape.

(4) Surplus acreage. An application for permit to drill on surplus acreage pursuant to subsection (c) of this section must include a certification in a prescribed form indicating the date the lease, pooled unit, or unitized tract took its present size and shape.

(5) Certifications. Certifications required under paragraphs (3) and (4) of this subsection shall be filed on Form W-1A, Substandard Acreage Certification.

(A) The operator shall file the Form W-1A with the drilling permit application and shall indicate the purpose of filing. The operator shall accurately complete all information required on the form in accordance with instructions on the form.

(B) The operator shall list the field or fields for which the substandard acreage certification applies in the designated area on the form. If there are more than three fields for which the certification applies, the operator shall attach additional Forms W-1A and shall number the additional pages in sequence.

(C) The operator shall file the original Form W-1A with the Commission's Austin office and a copy with the appropriate district office, unless the operator files electronically.

(D) The operator or the operator's agent shall certify the information provided on the Form W-1A is true, complete, and correct by signing and dating the form, and listing the requested identification and contact information.

(E) Failure to timely file the required information on the appropriate form may result in the dismissal of the application.

(h) Procedure for obtaining exceptions to the density provisions.

(1) Filing requirements. If a permit to drill requires an exception to the applicable density provision, the operator must file, in addition to the items required by subsection (g) of this section:

(A) a list of the names and addresses of all affected persons. For the purpose of giving notice of application, the Commission presumes that affected persons include the operators and unleased mineral interest owners of all adjacent offset tracts, and the operators and unleased mineral interest owners of all tracts nearer to the proposed well than the prescribed minimum lease-line spacing distance. The Commission designee may determine that such a person is not affected only upon written request and a showing by the applicant that:

(i) competent, convincing geological or engineering data indicate that drainage of hydrocarbons from the particular tracts subject to the request will not occur due to production from the proposed well; and

(ii) notice to the particular operators and unleased mineral interest owners would be unduly burdensome or expensive;

(B) engineering and/or geological data, including a written explanation of each exhibit, showing that the drilling of a well on substandard acreage is necessary to prevent waste or to prevent the confiscation of property;

(C) additional data requested by the Commission designee.

(2) Notice of application. Upon receipt of a complete application, the Commission will give notice of the application by mail to all affected persons for whom signed waivers have not been submitted. If, after diligent efforts, the applicant is unable to ascertain the name and address of one or more persons required by this subsection to be notified, then the applicant shall notify such persons by publishing notice of the application in a form approved by the Commission. The applicant shall publish the notice once each week for two consecutive weeks in a newspaper of general circulation in the county where the well will be located. The first publication shall be published at least 14 days before the protest deadline in the notice of application. The applicant shall file with the Commission a publisher's affidavit or other evidence of publication.

(3) Approval without hearing. If the Commission designee determines, based on the data submitted, that a permit requiring an exception to the applicable density provision is justified according to subsection (f) of this section, then the Commission designee may issue the exception permit administratively if:

(A) signed waivers from all affected persons were submitted with the application; or

(B) notice of application was given in accordance with this subsection and no protest was filed within 21 days of the notice; or

(C) no person appeared to protest the application at a hearing scheduled pursuant to paragraph (4)(A) of this subsection.

(4) Hearing on the application.

(A) If a written protest is filed within 21 days after the notice of application is given in accordance with paragraph (2) of this subsection, the application will be set for hearing.

(B) If the application is not protested and the Commission designee determines that a permit requiring an exception to the applicable density provision is not justified according to subsection (f) of this section, the operator may request a hearing to consider the application.

(i) Duration. A permit is issued as an exception to the applicable density provision shall expire two years from the effective date of the permit; unless drilling operations are commenced in good faith within the two year period.

(j) The requirements for density exceptions for wells in a designated unconventional fracture treated (UFT) field are set forth in §3.86(k) of this title (relating to Horizontal Drainhole Wells).

Source Note: The provisions of this §3.38 adopted to be effective November 1, 1989, 14 TexReg 5255; amended to be effective April 21, 1997, 22 TexReg 3404; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective February 13, 2002, 27 TexReg 906; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective February 1, 2016, 41 TexReg 785; amended to be effective March 18, 2019, 44 TexReg 1437 .

§3.39 Proration and Drilling Units: Contiguity of Acreage and Exception Thereto

(a) Proration and drilling units established for individual wells drilled or to be drilled shall consist of acreage which is contiguous.

(b) An exception to the contiguous acreage provision may be granted at the operator's request if acreage that is to be included in the proration or drilling unit is separated by a long, narrow right-of-way tract.

Source Note: The provisions of this §3.39 adopted to be effective January 1, 1976.

§3.40 Assignment of Acreage to Pooled Development and Proration Units

(a) An operator may pool acreage, in accordance with appropriate contractual authority and applicable field rules, for the purpose of creating a drilling unit or proration unit by filing an original certified plat delineating the pooled unit and a Certificate of Pooling Authority, Form P-12, according to the following requirements:

(1) Each tract in the certified plat shall be identified with an outline and a tract identifier that corresponds to the tract identifier listed on Form P-12.

(2) The operator shall provide information on Form P-12, accurately and according to the instructions on the form.

(A) The operator shall separately list each tract committed to the pooled unit by authority granted to the operator.

(B) For each tract listed on Form P-12, the operator shall state the number of acres contained within the tract. The operator shall indicate by checking the appropriate box on Form P-12 if, within an individual tract, there exists a non-pooled and/or unleased interest.

(C) The operator shall state on Form P-12 the total number of acres in the pooled unit. The total number of acres in the pooled unit shall equal the sum of all acres in each tract listed. The total acreage shown on Form P-12 shall only include tracts in which the operator holds a leased or ownership interest in the minerals or other contractual authority to include the tract in the pooled unit.

(D) If a pooled unit contains more tracts than can be listed on a single Form P-12, the operator shall file as many additional Forms P-12 as necessary to list each pooled tract individually. The additional Forms P-12 shall be numbered in sequence.

(E) The operator shall provide the requested identification and contact information on Form P-12.

(F) The operator shall certify the information on Form P-12 by signing and dating the form.

(3) Failure to timely file the required information on the certified plat or Form P-12 may result in the dismissal of the W-1 application. "Timely" means within three months of the Commission notifying the operator of the need for additional information on the certified plat and/or Form P-12.

(4) The operator shall file Form P-12 and a certified plat in the following instances:

(A) with the drilling permit application when two or more tracts are joined to form a pooled unit for Commission purposes;

(B) with the initial completion report if any information reported on Form P-12 has changed since the filing of the drilling permit application;

(C) to designate a pooled unit formed after a completion report has been filed; or

(D) to designate a change in a pooled unit previously recognized by the Commission. The operator shall file any changes to a pooled unit in accordance with the requirements of §3.38(d)(3) of this title (relating to Well Densities).

(b) If a tract to be pooled has an outstanding interest for which pooling authority does not exist, the tract may be assigned to a unit where authority exists in the remaining undivided interest provided that total gross acreage in the tract is included for allocation purposes, and the certificate filed with the Commission shows that a certain undivided interest is outstanding in the tract. The Commission may not allow an operator to assign only the operator's undivided interest out of a basic tract where a nonpooled interest exists.

(c) The nonpooled undivided interest holder retains the development rights in the basic tract. If the development rights are exercised, the Commission grants authority to develop the basic tract, and the well is completed as a producing well on the basic tract, then the entire interest in the basic tract and any interest pooled with another tract shall be assigned to the well on the basic tract for allocation purposes. Splitting of an undivided interest in a basic tract between two or more wells on two or more tracts is not acceptable.

(d) Multiple assignment of acreage is not permitted, except as provided in subsection (e) of this section. Multiple assignment of acreage is defined as the assignment of the same surface acreage to more than one well in a field. However, this limitation shall not prevent the reformation of development or proration units so longas:

(1) no multiple assignment of acreage occurs; and

(2) such reformation does not violate other conservation regulations.

(e) In unconventional fracture treated (UFT) fields defined in §3.86 of this title (relating to Horizontal Drainhole Wells), multiple assignment of acreage is permissible as follows:

(1) Assignment of acreage to both a horizontal well and a vertical well for drilling and development or for allocation of allowable is permissible. The field density rules apply independently to horizontal wells and vertical wells. Acreage assigned to horizontal wells shall not count against acreage assigned to vertical wells, and acreage assigned to vertical wells shall not count against acreage assigned to horizontal wells.

(A) Acreage assigned to horizontal wells for drilling and development or for allocation of allowable shall be permissible so long as the horizontal well density complies with §3.38 of this title and/or special field rules, as applicable. For the purposes of this section, stacked lateral wells as defined in §3.86(a)(10)of this title are not considered assignment of acreage to multiple horizontal wells.

(B) Acreage assigned to vertical wells for drilling and development or for allocation of allowable shall be permissible so long as the vertical well density complies with §3.38 of this title and/or special field rules, as applicable.

(2) Where ownership of the right to drill or produce from a tract in a UFT field is divided horizontally, acreage may be assigned to more than one well provided that the wells having the same wellbore profile are not completed in the same ownership interval. For purposes of this section "divided horizontally" means that ownership of the right to drill or produce has been separated into depth intervals defined by total vertical depth, depth relative to a specific geological contact, or some other discriminator. A tract may be "divided horizontally" even where one operator has the right to drill or produce multiple intervals on the same tract of land in the same field.

(A) To apply for multiple assignment of acreage under this subsection, the operator's drilling permit application shall indicate the upper and lower limits of the operator's ownership interval. The interval shown on the drilling permit application is measured as the total vertical depth from the surface.

(B) No more than 15 days prior to filing its drilling permit application, the applicant shall identify any well, including any wells permitted but not yet drilled or completed, that is located within one-half mile of the applicant's proposed wellbore between the first and last take points and, upon identification of all applicable wells, send written notice of its application to the P-5 address of record of the Commission-designated operator of the wells determined to fall within the one-half mile radius. The applicant shall attach to the notice a certified plat that clearly depicts the projected path of the wellbore and the one-half mile radius surrounding the wellbore from the first take point to the last take point. Copies of the notice, service list, and certified plat shall be filed with the drilling permit application.

(C) If any person entitled to notice under this subsection did not receive notice, that person may request a hearing. If the Commission determines at a hearing that the applicant did not provide the notice as required by this subsection, the Commission may cancel the permit.

(D) To mitigate the potential for wellbore collisions, the applicant shall provide copies of any directional surveys to the persons entitled to notice under this subsection, upon request, within 15 days of the applicant's receipt of a request.

(E) Where ownership of the right to drill or produce from a tract in a UFT field is divided horizontally, the field density rules for the field will apply separately to each ownership interval, such that proration units on a tract above and below a division of ownership are accounted for separately.

(F) Field rules that allow assignment of acreage to more than one well in UFT fields are superseded by this rule amendment, as of the effective date of this amendment, March 3, 2020. If, prior to the effective date of this amendment, an operator has assigned acreage to more than one well pursuant to previous field rules, such multiple assignment remains valid. After March 3, 2020, multiple assignment of acreage is not permissible unless the applicant complies with the requirements of this subsection. The Commission will not consider any applications for field rules regarding multiple assignment of acreage in UFT fields until two years after March 3, 2020.

(3) Upon request by the Commission, an operator shall provide non-confidential information verifying that the well was completed in the interval indicated on its drilling permit application.

(f) Upon an operator's written request and for good cause shown, the director or the director's delegate may resolve an existing instance of multiple assignment of acreage. If such a request is administratively denied, the operator shall have a right to request a hearing to review the denial.

(g) If an operator does not qualify for multiple assignment of acreage under subsection (e) of this section, acreage cannot be assigned to more than one well unless the operator is granted an exception after a public hearing held after notice to all persons described in paragraph (2) of this subsection.

(1) An operator applying for an exception must show:

(A) an exception is necessary to prevent waste, prevent confiscation, or protect correlative rights; and

(B) the wells are not completed in the same ownership interval.

(2) If an exception is sought for a well in a UFT field, the operator shall file with its application for an exception the names and mailing addresses of persons described in §3.86(k)(2), relating to Horizontal Drainhole Wells. If an exception is sought for any other well, the operator shall file with its application for an exception the names and mailing addresses of all the operators and unleased mineral interest owners of all adjacent offset tracts, and the operators and unleased mineral interest owners of all tracts nearer to the proposed well than the prescribed minimum lease-line spacing distance. In the event the applicant is unable after due diligence to locate the whereabouts of any person to whom notice is required by this subsection, the applicant shall publish notice of this application pursuant to §1.43 of this title (relating to Notice by Publication).

(3) To mitigate the potential for wellbore collisions, the applicant shall provide copies of any directional surveys to the persons entitled to notice under this subsection, upon request, within 15 days of the applicant's receipt of a request.

(h) If an offset, overlying, or underlying operator, or a lessee or unleased mineral interest owner determines that any operator has assigned identical acreage to two or more concurrently producing wells in violation of this section, the operator or owner may file a complaint with the Hearings Division to request that a hearing be set to consider the issues raised in the complaint. If the Commission determines after a hearing on the complaint that acreage has been assigned in violation of this section, the Commission may curtail or cancel the allowable production rate for any affected wells and/or may cancel the Certificate of Compliance (Form P-4) for any affected wells for failure to comply with this section.

(i) An operator shall file Form P-16, Acreage Designation, with each drilling permit application and with each completion report for horizontal wells in any field and for all wells in designated UFT fields as defined in §3.86 of this title. An operator assigning surface acreage to more than one well pursuant to subsection (g) of this section shall file Form P-16, Acreage Designation, with each drilling permit application and with each completion report. The operator may file Form P-16 with each drilling permit application and with each completion report for all other wells. The operator may also file proration unit plats for individual wells in a field.

Source Note: The provisions of this §3.40 adopted to be effective January 1, 1976; amended to be effective January 9, 2002, 27 TexReg 150; amended to be effective February 1, 2016, 41 TexReg 785; amended to be effective March 3, 2020, 45 TexReg 1387.

§3.41 Application for New Oil or Gas Field Designation and/or Allowable

(a) The commission shall assign a new field designation and/or discovery allowable after an operator furnishes to the commission's Austin office proper evidence, other than horizontal distance, proving that a well is a new discovery. An operator shall include the following in the application:

(1) a legible area map, drawn to scale, preferably on white paper, which shows the following:

(A) all oil, gas, and abandoned wells within at least a 2 1/2-mile radius of the well claimed to be a discovery well;

(B) the producing intervals of all pertinent oil and gas wells identified in subparagraph (A) of this paragraph;

(C) all commission-recognized fields within a 2 1/2-mile radius of the well claimed to be a discovery well, that are presently active or were active in the past, identified by commission-assigned field names, names of the producing formations, and approximate average depth of the producing interval;

(D) the total depth of all wells identified in subparagraph (A) of this paragraph that penetrated the subject zone;

(E) scale, legend, and name of person who prepared the map;

(2) a complete legible electric log of the well. However, an operator is not required to file a complete electric log if the operator has filed all other required data, a portion of the log showing the top and bottom of the proposed reservoir interval, log headings, and applicable scales, and satisfactorily proves discovery as a new reservoir. Any electric log filed shall be considered public information pursuant to §3.16 of this title (relating to Log and Completion or Plugging Report) (Statewide Rule 16).

(3) a bottom-hole pressure for oil wells, submitted on the appropriate form. This bottom-hole pressure may be determined by a pressure build-up test, drill stem test, or wire- line formation tester. Calculations based on fluid level surveys or calculations made on flowing wells using shut-in wellhead pressures may be used if no test data is available.

(4) a subsurface structure map and/or cross section(s), if separation is based on structural differences, including faulting and pinch-outs. The structure map shall show the contour of the top of the producing formation and the line(s) of cross section. The cross section(s) shall be prepared from comparable electric logs (not tracings) with the wells, producing formation, and hydrocarbon reservoir identified. The engineer or geologist who prepared the map and cross section shall sign them.

(5) reservoir pressure measurements or calculations, if separation is based on pressure differentials.

(6) core data, drillstem test data, cross sections of nearby wells, and/or production data estimating the fluid level, if separation is based on differences in fluid levels. The operator shall obtain the fluid level data within 10 days of the potential test date.

(b) The staff may require additional data deemed necessary to make a determination. Deviation from the requirements of subsection (a) of this section may be allowed at the staff's discretion.

(c) The director, oil and gas, may administratively grant an application if all required data is submitted with the form prescribed, and the evidence proves that the new reservoir is effectively separated from any other reservoir previously shown to be productive.

(d) If the director of the Oil and Gas Division, or the director's delegate, declines administratively to grant an application, the operator may request a hearing. If the commission receives the hearing request within 10 days of the date of the notice of administrative denial of the application, the commission shall schedule a hearing. After hearing, the examiner shall recommend final commission action.

Source Note: The provisions of this §3.41 adopted to effective January 1, 1976; amended to be effective July 24, 1980, 5 TexReg 2859; amended to be effective February 28, 1986, 11 TexReg 545; amended to be effective January 4, 1999, 24 TexReg 131.

§3.42 Oil Discovery Allowable

(a) The commission shall determine the discovery allowable rate for oil wells proven to be completed in a new and separate reservoir from the following discovery allowable schedule.

Scale of Allowables		
Interval of Depth	Daily Well Allowable	
	Onshore	**Offshore**
0 - 999	100 barrels	300 barrels
1,000 - 1,999	100 barrels	300 barrels
2,000 - 2,999	100 barrels	300 barrels
3,000 - 3,999	100 barrels	300 barrels
4,000 - 4,999	130 barrels	330 barrels
5,000 - 5,999	160 barrels	360 barrels
6,000 - 6,999	200 barrels	400 barrels
7,000 - 7,999	270 barrels	470 barrels
8,000 - 8,999	340 barrels	540 barrels
9,000 - 9,999	440 barrels	640 barrels
10,000 - 10,499	510 barrels	710 barrels
10,500 - 10,999	590 barrels	790 barrels
11,000 - 11,499	670 barrels	870 barrels
11,500 - 11,999	750 barrels	950 barrels
12,000 - 12,499	830 barrels	1,030 barrels
12,500 - 12,999	910 barrels	1,110 barrels
13,000 - 13,499	1,000 barrels	1,200 barrels
13,500 - 13,999	1,100 barrels	1,300 barrels
14,000 - 14,499	1,200 barrels	1,400 barrels
14,500 - 14,999	1,360 barrels	1,560 barrels
15,000 - 15,499	1,520 barrels	1,720 barrels
15,500 - 15,999	1,760 barrels	1,960 barrels

(b) Duration and exemption from market demand limitation.

(1) Onshore. Each oil well completed in an oil reservoir determined by the commission to be a new onshore oil field onshore may receive, as a maximum daily, its discovery allowable, exempt from market demand limitation, for a period of 24 months (36 months for depth intervals deeper than 10,000 feet) from the date of assignment of the oil allowable to such discovery well or until the 11th oil well has been completed therein, whichever occurs first.

(2) Offshore. Each oil well completed in an oil reservoir determined by the commission to be a new offshore oil field may receive, as a maximum daily allowable, its discovery oil allowable, exempt from market demand limitation, for a period of 24 months (36 months for depth intervals deeper than 10,000 feet) from the date of assignment of the oil allowable to such discovery well or until the sixth oil well has been completed therein, whichever occurs first.

(c) The director or the director's delegate shall review the production performance of discovery wells to evaluate whether waste is occurring due to the discovery allowable. If the director or the director's delegate believes waste is or may be occurring, the director or the director's delegate may request any additional relevant information from the operator and may set the matter for hearing to allow the commission to determine if the discovery allowable should be lowered to prevent waste.

Source Note: The provisions of this §3.42 adopted to be effective January 1, 1976; amended to be effective August 6, 1980, 5 TexReg 2930; amended to be effective November 28, 1989, 14 TexReg 6006; amended to be effective January 4, 1999, 24 TexReg 131.

§3.43 Application for Temporary Field Rules

(a) The commission will accept applications for temporary field rule hearings for oil, gas, or geothermal resource fields after the first well has been completed.

(b) When requesting such hearings, the applicant must furnish the commission a list of the names and addresses of all operators holding leases on land touching the tract on which the discovery well is located. The applicant must list the names and addresses of the owners of the abutting unleased land.

(c) Temporary field rules will apply until permanent field rules are adopted.

Source Note: The provisions of this §3.43 adopted to be effective January 1, 1976.

§3.45 Oil Allowables

(a) Oil allowable yardsticks.

(1) 1947 allowable yardstick. The following schedule allowable shall be assigned all wells according to depth of the reservoir and proration unit size authorized by the commission upon expiration of the discovery allowable, if discovery of the field occurred prior to January 1, 1965, provided that paragraph (3) of this subsection does not apply.

Depth	10 Ac.	20 Ac.	40 Ac.
0 - 1,000	18	28	
1,000 - 1,500	27	37	57
1,500 - 2,000	36	46	66
2,000 - 3,000	45	55	75
3,000 - 4,000	54	64	84
4,000 - 5,000	63	73	93
5,000 - 6,000	72	82	102
6,000 - 7,000	81	91	111
7,000 - 8,000	91	101	121
8,000 - 8,500	103	113	133
8,500 - 9,000	112	122	142
9,000 - 9,500	127	137	157
9,500 - 10,000	152	162	182
10,000 - 10,500	190	210	230
10,500 - 11,000		225	245
11,000 - 11,500		255	275
11,500 - 12,000		290	310
12,000 - 12,500		330	350
12,500 - 13,000		375	395
13,000 - 13,500		425	445
13,500 - 14,000		480	500
14,000 - 14,500		540	560

(2) 1965 allowable yardstick. The following schedule allowable shall be assigned all wells according to depth of the reservoir and proration unit size authorized by the commission upon expiration of the discovery allowable, if discovery of the field occurred on or after January 1, 1965.

Depth	10 Ac.	20 Ac.	40 Ac.	80 Ac.	160 Ac.
0 - 2,000	21	39	74	129	238
2,000 - 3,000	22	41	78	135	249
3,000 - 4,000	23	44	84	144	265
4,000 - 5,000	24	48	93	158	288
5,000 - 6,000	26	52	102	171	310
6,000 - 7,000	28	57	111	184	331
7,000 - 8,000	31	62	121	198	353
8,000 - 8,500	34	68	133	215	380
8,500 - 9,000	36	74	142	229	402

9,000 - 9,500	40	81	157	250	435
9,500 - 10,000	43	88	172	272	471
10,000 - 10,500	48	96	192	300	515
10,500 - 11,000		106	212	329	562
11,000 - 11,500		119	237	365	621
11,500 - 12,000		131	262	401	679
12,000 - 12,500		144	287	436	735
12,500 - 13,000		156	312	471	789
13,000 - 13,500		169	337	506	843
13,500 - 14,000		181	362	543	905
14,000 - 14,500		200	400	600	1,000

(3) Exception. Wells in fields discovered prior to January 1, 1965, whose discovery allowables either have expired or will expire subsequent to July 1, 1964, upon expiration of the discovery allowable, may be assigned allowable pursuant to the 1965 yardstick, if such allowables exceed those which would be assigned pursuant to the 1947 yardstick, or if the proration unit size authorized by the commission is not provided for in the 1947 yardstick. It is provided that any adjustment made in allowable assignment pursuant to this paragraph shall not be made prior to the effective date of this order. Retroactive adjustment shall not be allowed.

(4) Texas offshore allowable yardstick.

Depth	40 Ac.	80 Ac.	160 Ac.
0 - 2,000	200	330	590
2,000 - 3,000	220	360	640
3,000 - 4,000	245	400	705
4,000 - 5,000	275	445	785
5,000 - 6,000	305	490	865
6,000 - 7,000	340	545	950
7,000 - 8,000	380	605	1,050
8,000 - 9,000	420	665	1,150
9,000 - 10,000	465	730	1,260
10,000 - 11,000	515	800	1,380
11,000 - 12,000	565	875	1,500
12,000 - 13,000	620	950	1,625
13,000 - 14,000	675	1,030	1,750
14,000 - 15,000	735	1,115	1,880

(5) The maximum daily allowable for a horizontal drainhole oil well or an oil well in a designated unconventional fracture treated (UFT) field is set forth in §3.86(d)(4) and (5) of this title (relating to Horizontal Drainhole Wells).

(b) Assignment of allowables for wells under statewide rules.

(1) All wells completed in fields operating under statewide rules which were assigned the 20-acre yardstick allowable prior to the adoption of the new spacing rule on October 1, 1962, will be continued at the same allowable rate unless, after notice and hearing, special rules or other special orders are adopted that would provide for a higher producing rate. Any new well completed in such a reservoir will be given the same allowable rate as is assigned the other wells even though it has been drilled as a regular location under the new statewide spacing rule and density rule.

(2) All wells completed in fields operating under statewide rules that are presently on discovery status or

have had discovery status terminated subsequent to the adoption of the new state spacing rule on October 1, 1962, will be given the 40-acre yardstick allowable, until such time as a change is ordered by the commission.

(c) Production of marginal wells.

(1) To artificially curtail the production of any "marginal well" below the marginal limit prior to its ultimate plugging and abandonment is hereby declared to be waste, and no rule or order of the Railroad Commission of Texas, or other constituted legal authority shall be entered requiring restriction of the production of any "marginal well" as defined in this chapter.

(2) Application of paragraph (1) of this subsection shall be confined to unrestricted operating conditions which accord with established operating rules of the commission, and shall be subject to all operating conditions designed to prevent waste imposed by the commission, which conditions apply to all wells alike. (Reference Order Number 20-54,115, effective January 1, 1965.)

Source Note: The provisions of this §3.45 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective February 1, 2016, 41 TexReg 785.

§3.46 Fluid Injection into Productive Reservoirs

(a) Permit required. Any person who engages in fluid injection operations in reservoirs productive of oil, gas, or geothermal resources must obtain a permit from the commission. Permits may be issued when the injection will not endanger oil, gas, or geothermal resources or cause the pollution of freshwater strata unproductive of oil, gas, or geothermal resources. Permits from the commission issued before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission.

(b) Filing of application.

(1) Application.

(A) An application to conduct fluid injection operations in a reservoir productive of oil, gas, or geothermal resources shall be filed in Austin on the form prescribed by the commission accompanied by the prescribed fee. On the same date, one copy shall be filed with the appropriate district office. The form shall be executed by a party having knowledge of the facts entered on the form.

(B) The applicant shall file the freshwater injection data form if fresh water is to be injected.

(C) The applicant for a disposal well permit under this section shall include with the permit application a printed copy or screenshot showing the results of a survey of information from the United States Geological Survey (USGS) regarding the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed disposal well location.

(D) The commission may require an applicant for a disposal well permit under this section to provide the commission with additional information such as logs, geologic cross-sections, pressure front boundary calculations, and/or structure maps, to demonstrate that fluids will be confined if the well is to be located in an area where conditions exist that may increase the risk that fluids will not be confined to the injection interval. Such conditions may include, but are not limited to, complex geology, proximity of the basement rock to the injection interval, transmissive faults, and/or a history of seismic events in the area as demonstrated by information available from the USGS.

(2) Commercial disposal well. An applicant for a permit to dispose of oil and gas waste in a commercial disposal well shall clearly indicate on the application and in the notice of application that the application is for a commercial disposal well permit. For the purposes of this rule, "commercial disposal well" means a well whose owner or operator receives compensation from others for the disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the well, and the primary business purpose for the well is to provide these services for compensation.

(c) Notice and opportunity for hearing.

(1) The applicant shall give notice by mailing or delivering a copy of the application to affected persons who include the owner of record of the surface tract on which the well is located; each commission-designated operator of any well located within one half mile of the proposed injection well; the county clerk of the county in which the well is located; and the city clerk or other appropriate city official of any city where the well is located within the corporate limits of the city, on or before the date the application is mailed to or filed with the commission. For the purposes of this section, the term "of record" means recorded in the real property or probate records of the county in which the property is located.

(2) In addition to the requirements of subsection (c)(1), a commercial disposal well permit applicant shall give notice to owners of record of each surface tract that adjoins the proposed injection tract by mailing or delivering a copy of the application to each such surface owner.

(3) If, in connection with a particular application, the commission or its delegate determines that another class of persons should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class. Such classes of persons could include adjacent surface owners or underground water conservation districts.

(4) In order to give notice to other local governments, interested, or affected persons, notice of the application shall be published once by the applicant in a newspaper of general circulation for the county where the well will be located in a form approved by the commission or its delegate. The applicant shall file with the commission in Austin proof of publication prior to the hearing or administrative approval.

(5) Protested applications:

(A) If a protest from an affected person or local government is made to the commission within 15 days of receipt of the application or of publication, whichever is later, or if the commission or its delegate determines that a hearing is in the public interest, then a hearing will be held on the application after the commission provides notice of hearing to all affected persons, local governments, or other persons, who express an interest, in writing, in the application.

(B) For purposes of this section, "affected person" means a person who has suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor, and includes surface owners of property on which the well is located and commission-designated operators of wells located within one-half mile of the proposed disposal well.

(6) If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the commission's delegate denies administrative approval, the applicant shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(d) Subsequent commission action.

(1) An injection well permit may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:

(A) a material change of conditions occurs in the operation or completion of the injection well, or there are material changes in the information originally furnished;

(B) fresh water is likely to be polluted as a result of continued operation of the well;

(C) there are substantial violations of the terms and provisions of the permit or of commission rules;

(D) the applicant has misrepresented any material facts during the permit issuance process;

(E) injected fluids are escaping from the permitted injection zone;

(F) for a disposal well permit under this section, injection is likely to be or determined to be contributing to seismic activity; or

(G) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

(2) An injection well permit may be transferred from one operator to another operator provided that the commission's delegate does not notify the present permit holder of an objection to the transfer prior to the date the lease is transferred on commission records.

(3) Voluntary permit suspension.

(A) An operator may apply to temporarily suspend its injection authority by filing a written request for permit suspension with the commission in Austin, and attaching to the written request the results of an MIT test performed during the previous three-month period in accordance with the provisions of subsection (j)(4) of this section. The provisions of this paragraph shall not apply to any well that is permitted as a commercial injection well.

(B) The commission or its delegate may grant the permit suspension upon determining that the results of the MIT test submitted under subparagraph (A) of this paragraph indicate that the well meets the performance standards of subsection (j)(4) of this section.

(C) During the period of permit suspension, the operator shall not use the well for injection or disposal purposes.

(D) During the period of permit suspension, the operator shall comply with all applicable well testing requirements of §3.14 of this title (relating to plugging, and commonly referred to as Statewide Rule 14) but need not perform the MIT test that would otherwise be required under the provisions of subsection (j)(4) of this section or the permit. Further, during the period of permit suspension, the provisions of subsection (i)(1) - (3) of this section shall not apply.

(E) The operator may reinstate injection authority under a suspended permit by filing a written notification with the commission in Austin. The written notification shall be accompanied by an MIT test performed during the three-month period prior to the date notice of reinstatement is filed. The MIT test shall have been performed in accordance with the provisions and standards of subsection (j)(4) of this section.

(e) Area of Review.

(1) Except as otherwise provided in this subsection, the applicant shall review the data of public record for wells that penetrate the proposed disposal zone within a 1/4 mile radius of the proposed disposal well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the disposal zone into freshwater strata. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(2) The commission or its delegate may grant a variance from the area-of-review requirements of paragraph (1) of this subsection upon proof that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface. Such a variance may be granted for an area defined both vertically and laterally (such as a field) or for an individual well. An application for an areal variance need not be filed in conjunction with an individual permit application or application for permit amendment. Factors that may be considered by the commission or its delegate in granting a variance include:

(A) the area affected by pressure increases resulting from injection operations;

(B) the presence of local geological conditions that preclude movement of fluid that could endanger freshwater strata or the surface; or

(C) other compelling evidence that the variance will not result in a material increase in the risk of fluid movement into freshwater strata or to the surface.

(3) Persons applying for a variance from the area-of-review requirements of paragraph (1) of this subsection on the basis of factors set out in paragraph (2)(B) or (C) of this subsection for an individual well shall provide notice of the application to those persons given notice under the provisions of subsection (c)(1) of this section. The provisions of subsection (c) of this section shall apply in the case of an application for a variance from the area-of-review requirements for an individual well.

(4) Notice of an application for an areal variance from the area-of-review requirements under paragraph (1) of this subsection shall be given on or before the date the application is filed with the commission:

(A) by publication once in a newspaper having general circulation in each county, or portion thereof, where the variance would apply. Such notice shall be in a form approved by the commission or its delegate prior to publication and must be at least three inches by five inches in size. The notice shall state that protests to the application may be filed with the commission during the 15-day period following the date of publication. The notice shall appear in a section of the newspaper containing state or local news items;

(B) by mailing or delivering a copy of the application, along with a statement that any protest to the application should be filed with the commission within 15 days of the date the application is filed with the commission, to the following:

(i) the manager of each underground water conservation district in which the variance would apply, if any;

(ii) the city clerk or other appropriate official of each incorporated city in which the variance would apply, if any;

(iii) the county clerk of each county in which the variance would apply; and

(iv) any other person or persons that the commission or its delegate determines should receive notice of the application.

(5) If a protest to an application for an areal variance is made to the commission by an affected person, local government, underground water conservation district, or other state agency within 15 days of receipt of the application or of publication, whichever is later, or if the commission's delegate determines that a hearing on the application is in the public interest, then a hearing will be held on the application after the commission provides notice of the hearing to all local governments, underground water conservation districts, state agencies, or other persons, who express an interest, in writing, in the application. If no protest from an affected person is received by the commission, the commission's delegate may administratively approve the application. If the application is denied administratively, the person(s) filing the application shall have a right to hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(6) An areal variance granted under the provisions of this subsection may be modified, terminated, or suspended by the commission after notice and opportunity for hearing is provided to each person shown on commission records to operate an oil or gas lease in the area in which the proposed modification, termination, or suspension would apply. If a hearing on a proposal to modify, terminate, or suspend an areal variance is held, any applications filed subsequent to the date notice of hearing is given must include the area-of-review information required under paragraph (1) of this subsection pending issuance of a final order.

(f) Casing. Injection wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) in such a manner that the injected fluids will not endanger oil, gas, or geothermal resources and will not endanger freshwater formations not productive of oil, gas, or geothermal resources.

(g) Special equipment.

(1) Tubing and packer. Wells drilled or converted for injection shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 200 feet below the known top of cement behind the long string casing but in no case higher than 150 feet below the base of usable quality water. For purposes of this section, the term "tubing" refers to a string of pipe through which injection may occur and which is neither wholly nor partially cemented in place. A string of pipe that is wholly or partially cemented in place is considered casing for purposes of this section.

(2) Pressure valve. The wellhead shall be equipped with a pressure observation valve on the tubing and for each annulus of the well.

(3) Exceptions. The commission or its delegate may grant an exception to any provision of this paragraph upon proof of good cause. If the commission or its delegate denies an exception, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(h) Well record. Within 30 days after the completion or conversion of an injection well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.

(i) Monitoring and reporting.

(1) The operator shall monitor the injection pressure and injection rate of each injection well on at least a monthly basis, or on a more frequent basis for a disposal well permitted under this section as required by the commission under conditions described in subsection (b)(1)(D) of this section.

(2) The results of the monitoring shall be reported annually, or on a more frequent basis for a disposal well permitted under this section as required by the commission under conditions described in subsection (b)(1)(D) of this section, to the commission on the prescribed form.

(3) All monitoring records shall be retained by the operator for at least five years.

(4) The operator shall report to the appropriate District Office within 24 hours any significant pressure changes or other monitoring data indicating the presence of leaks in the well.

(j) Testing.

(1) Purpose. The mechanical integrity of an injection well shall be evaluated by conducting pressure tests to determine whether the well tubing, packer, or casing have sufficient mechanical integrity to meet the performance standards of this rule, or by alternative testing methods under paragraph (5) of this subsection.

(2) Applicability. Mechanical integrity of each injection well shall be demonstrated in accordance with provisions of paragraphs (4) and (5) of this subsection prior to initial use. In addition, mechanical integrity shall be tested periodically thereafter as described in paragraph (3) of this subsection.

(3) Frequency.

(A) Each injection well completed with surface casing set and cemented through the entire interval of protected usable-quality water shall be tested for mechanical integrity at least once every five years.

(B) In addition to testing required under subparagraph (A), each injection well shall be tested for mechanical integrity after every workover of the well.

(C) An injection well that is completed without surface casing set and cemented through the entire interval of protected usable-quality ground water shall be tested at the frequency prescribed in the injection permit.

(D) The commission or its delegate may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with the requirements in subparagraph (A) and subparagraph (B) of this paragraph. Such testing schedule shall not apply to an injection well for which an injection well permit has been issued but the well has not been drilled or converted to injection.

(4) Pressure tests.

(A) Test pressure.

(i) The test pressure for wells equipped to inject through tubing and packer shall equal the maximum authorized injection pressure or 500 psig, whichever is less, but shall be at least 200 psig.

(ii) The test pressure for wells that are permitted for injection through casing shall equal the maximum permitted injection pressure or 200 psig, whichever is greater.

(B) Pressure stabilization. The test pressure shall stabilize within 10% of the test pressure required in subparagraph (A) of this paragraph prior to commencement of the test.

(C) Pressure differential. A pressure differential of at least 200 psig shall be maintained between the test pressure on the tubing-casing annulus and the tubing pressure.

(D) Test duration. A pressure test shall be conducted for a duration of 30 minutes when the test medium is liquid or for 60 minutes when the test medium is air or gas.

(E) Pressure recorder. Except for tests witnessed by a commission representative or wells permitted for injection through casing, a pressure recorder shall be used to monitor and record the tubing-casing annulus pressure during the test. The recorder clock shall not exceed 24 hours. The recorder scale shall be set so that the test pressure is 30 to 70% of full scale, unless otherwise authorized by the commission or its delegate.

(F) Test fluid.

(i) The tubing-casing annulus fluid used in a pressure test shall be liquid for wells that inject liquid unless the commission or its delegate authorizes use of a different test fluid for good cause.

(ii) The tubing-casing annulus fluid used in a pressure test shall contain no additives that may affect the sensitivity or otherwise reduce the effectiveness of the test.

(G) Pressure test results. The commission or its delegate will consider, in evaluating the results of a test, the level of pollution risk that loss of well integrity would cause. Factors that may be taken into account in assessing pollution risk include injection pressure, frequency of testing and monitoring, and whether there is sufficient surface casing to cover all zones containing usable-quality water. A pressure test may be rejected by the commission or its delegate after consideration of the following factors:

(i) the degree of pressure change during the test, if any;

(ii) the level of risk to usable-quality water if mechanical integrity of the well is lost; and

(iii) whether circumstances surrounding the administration of the test make the test inconclusive.

(5) Alternative testing methods.

(A) As an alternative to the testing required in paragraph (2) of this subsection, the tubing-casing annulus pressure may be monitored and included on the annual monitoring report required by subsection (i) of this section, with the authorization of the commission or its delegate and provided that there is no indication of problems with the well. Wells that are approved for tubing-casing annulus monitoring under this paragraph shall be tested in the manner provided under paragraph (3) of this subsection at least once every ten years after January 1, 1990.

(B) The commission or its delegate grant an exception for viable alternative tests or surveys or may require alternative tests or surveys as a permit condition.

(6) The operator shall notify the appropriate district office at least 48 hours prior to the testing. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

(7) A complete record of all tests shall be filed in duplicate in the district office within 30 days after the testing.

(8) In the case of permits issued under this section prior to the effective date of this amendment which require pressure testing more frequently than once every five years, the commission's delegate may, by letter of authorization, reduce the required frequency of pressure tests, provided that such tests are required at least once every three years. The commission shall consider the permit to have been amended to require pressure tests at the frequency specified in the letter of authorization.

(k) Area Permits. A person may apply for an area permit that authorizes injection into new or converted wells located within the area specified in the area permit. For purposes of this subsection, the term "permit area" shall mean the area covered or proposed to be covered by an area permit. Except as specifically provided in this subsection, the provisions of subsections (a) - (j) of this section shall apply in the case of an area permit and all injection wells converted, completed, operated, or maintained in accordance with that permit. Except as otherwise specified in the area permit, once an area permit has been issued, the operator may apply to operate individual wells within the permit area as injection wells as specified in paragraph (3) of this subsection.

(1) An application for an area permit must be accompanied by an application for at least one injection well. The applicant must:

(A) identify the maximum number of injection wells that will be operated within the permit area;

(B) identify the depth(s) of usable-quality water within the permit area, as determined by the Groundwater Advisory Unit of the Oil and Gas Division;

(C) for each existing well in the permit area that may be converted to injection under the area permit, provide a wellbore diagram that specifies the casing and liner sizes and depths, packer setting depth, types and volumes of cement, and the cement tops for the well. A single wellbore diagram may be submitted for multiple wells that have the same configuration, provided that each well with that type of configuration is identified on the wellbore diagram and the diagram identifies the deepest cement top for each string of casing among all the wells covered by that diagram.

(D) provide a wellbore diagram(s) showing the type(s) of completion(s) that will be used for injection wells drilled after the date the application for the area permit is filed, including casing and liner sizes and depths and a statement indicating that such wells will be cemented in accordance with the cementing requirements of §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements) (Statewide Rule 13);

(E) identify the type or types of fluids that are proposed to be injected into any well within the permit area;

(F) identify the depths from top to bottom of the injection interval throughout the permit area;

(G) specify the maximum surface injection pressure for any well in the permit area covered by the area permit;

(H) specify the maximum amount of fluid that will be injected daily into any individual well within the permit area as well as the maximum cumulative amount of fluid that will be injected daily in the permit area;

(I) in lieu of the area-of-review required under subsection (e) of this section and subject to the area-of-review variance provisions of subsection (e) of this section, review the data of public record for wells that penetrate the proposed injection interval within the permit area and the area 1/4 mile beyond the outer boundary of the permit area to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the injection interval into freshwater strata. The applicant shall identify in the application the wells which appear from the review of such public records to be unplugged or improperly plugged and any other unplugged or improperly plugged wells of which the applicant has knowledge. The applicant shall also identify in the application the date of plugging of each abandoned well within the permit area and the area 1/4 mile beyond the outer boundary of the permit area; and

(J) furnish a map showing the location of each existing well that may be converted to injection under the area permit and the location of each well that the operator intends, at the time of application, to drill within the permit area for use for injection. The map shall be keyed to identify the configuration of all such wells as described in subparagraphs (C) and (D) of this paragraph.

(2) In lieu of the notice required under subsection (c)(1) of this section, notice of an area permit shall be given by providing a copy of the area permit application to each surface owner of record within the permit area; each commission-designated operator of a well located within one-half mile of the permit area; the county clerk of each county in which all or part of the permit area is located; and the city clerk or other appropriate city official of any incorporated city which is located wholly or partially within the permit area, on or before the date the application is mailed to or filed with the commission. Notice of an application for an area permit shall also be given in accordance with the requirements of subsection (c)(2). If, in connection with a particular application, the commission or its delegate determines that another class of persons, such as adjacent surface owners or an appropriate underground water conservation district, should receive notice of the application, the commission or its delegate may require the applicant to mail or deliver a copy of the application to members of that class.

(3) Once an area permit has been issued and except as otherwise provided in the permit, no notice shall be required when an application for an individual injection well permit for any well covered by the area permit is filed.

(4) Prior to commencement of injection operations in any well within the permit area, the operator shall file an application for an individual well permit with the commission in Austin. The individual well permit application shall include the following:

(A) the well identification and, for a new well, a location plat;

(B) the location of any well drilled within 1/4 mile of the injection well after the date of application for the area permit and the status of any well located within 1/4 mile of the injection well that has been abandoned since the date the area permit was issued, including the plugging date if such well has been plugged;

(C) a description of the well configuration, including casing and liner sizes and setting depths, the type and amount of cement used to cement each casing string, depth of cement tops, and tubing and packer setting depths;

(D) an application fee in the amount of $100 per well; and

(E) any other information required by the area permit.

(5) An individual well permit may be issued by the commission or its delegate in writing or, if no objection to the application is made by the commission or its delegate within 20 days of receipt of the application, the individual well permit shall be deemed issued.

(6) All individual injection wells covered by an area permit must be permitted in accordance with the requirements of this subsection and converted or completed, operated, maintained, and plugged in accordance with the requirements of this section and the area permit.

(l) Gas storage operations. Storage of gas in productive or depleted reservoirs shall be subject to the provisions of §3.96 of this title (relating to Underground Storage of Gas in Productive or Depleted Reservoirs).

(m) Plugging. Injection wells shall be plugged upon abandonment in accordance with §3.14 of this title (relating to Plugging).

(n) Penalties.

(1) Violations of this section may subject the operator to penalties and remedies specified in Title 3 of the Natural Resources Code and any other statutes administered by the commission.

(2) The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) for violation of this section.

Source Note: The provisions of this §3.46 adopted to be effective January 1, 1976; amended to be effective April 1, 1982, 7 TexReg 655; amended to be effective January 1, 1994, 18 TexReg 8871; amended to be effective December 4, 1996, 21 TexReg 11361; amended to be effective April 7, 1998, 23 TexReg 3432; amended to be effective August 4, 1998, 23 TexReg 7768; amended to be effective December 28, 1999, 24 TexReg 11711; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective November 17, 2014, 39 TexReg 8988.

§3.47 Allowable Transfers for Saltwater Injection Wells

An allowable transfer will not be authorized for a well converted from oil production to saltwater disposal; however, an operator may make application to use the well for dual-purpose waterflood and saltwater disposal if injection is into an oil productive zone, and it is shown that the water injection will not injure the reservoir but will probably be of benefit to the reservoir as a secondary recovery program even though the beneficial effect of the water injection cannot be readily determined.

Source Note: The provisions of this §3.47 adopted to be effective January 1, 1976.

§3.48 Capacity Oil Allowables for Secondary or Tertiary Recovery Projects

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Capacity oil allowable--The allowable assigned from time to time by the director of the Oil and Gas Division or the director's delegate to an oil lease or unit engaged in a secondary or tertiary recovery program, that is consistent with the ability of the lease or unit to produce and that will prevent the occurrence of overproduced status for the lease or unit. Capacity oil allowables encompass and supercede what the Railroad Commission formerly designated as waterflood allowables.

(2) Offsetting operators and unleased mineral interest owners affected by the application--All offsetting operators and unleased mineral interest owners to the lease or unit except for those offsetting operators and unleased mineral owners the director of the Oil and Gas Division or the director's delegate determines to be unaffected by the application.

(b) Application. The director of the Oil and Gas Division or the director's delegate may grant a capacity oil allowable for a lease or unit, to the operator of a secondary or tertiary recovery project, when evidence of production increase in response to the secondary or tertiary recovery project is noted. The operator's application for a capacity oil allowable shall consist of:

(1) a written request that shall contain a statement indicating that all offsetting operators and unleased mineral interest owners affected by the application have been sent a copy of the complete application, and a list of such offsetting operators and unleased mineral interest owners indicating the date that notification was sent;

(2) evidence of the operator's participation in the subject secondary or tertiary recovery project;

(3) a plat indicating all producing wells and injection wells on the lease or unit and all offsetting operators and unleased mineral interest owners to the lease or unit;

(4) if available, signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application; and

(5) a production graph illustrating both increased production and volumes of water or other substances used in the secondary or tertiary recovery project that have been injected on the lease or unit since initiation of the secondary or tertiary recovery project.

(c) Notice and hearing. If the operator does not submit signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, there shall be a minimum of 21 days notice of the application for a capacity oil allowable; provided that, if the operator requests a hearing to consider the application, such hearing shall be held only after at least 10 days notice. If the director of the Oil and Gas Division or the director's delegate declines to approve the initial application, or if a protest is received by the Oil and Gas Division within the prescribed notice period, the operator may request a hearing to show that the capacity oil allowable is necessary either to prevent waste or to protect correlative rights. Any hearing held pursuant to this section shall be held only after at least 10 days notice. If the operator submits signed waivers of objection from all offsetting operators and unleased mineral interest owners affected by the application, or if no protest is received by the Oil and Gas Division within the 21-day notice period, or if no protestant appears at a hearing to consider an application for a capacity oil allowable, the capacity oil allowable may be granted administratively by the director of the Oil and Gas Division or the director's delegate if the application establishes that the capacity oil allowable is necessary to ensure maximum recovery from the secondary or tertiary recovery project.

(d) Temporary basis. A capacity oil allowable may be granted on a temporary basis by the director of the Oil and Gas Division or the director's delegate upon receipt of a complete application indicating that an immediate allowable increase is necessary to ensure maximum recovery from the secondary or tertiary recovery project. If a hearing is held to consider the application, any capacity oil allowable previously granted on a temporary basis under this section will remain in effect until a signed order of the Railroad Commission is issued in the matter. If the commission order denies the application, or if an applicant fails to request a hearing to consider a protested application, additional production resulting from the capacity oil allowable granted on a temporary basis will be treated as overproduction.

Source Note: The provisions of this §3.48 adopted to be effective March 28, 1988, 13 TexReg 1257.

§3.49 Gas-Oil Ratio

(a) Any oil well producing with a gas-oil ratio in excess of 2,000 cubic feet of gas per barrel of oil produced shall be allowed to produce daily only that volume of gas obtained by multiplying its maximum daily oil allowable, as determined by the allocation formula applicable to the well, by 2,000. The gas volume thus obtained shall be known as the daily gas limit of the well. The daily oil allowable of the well shall then be determined by dividing its daily gas limit, obtained as provided in this section, by its producing gas-oil ratio in cubic feet per barrel of oil produced.

(b) Any gas well producing from the same reservoir in which oil wells are completed and producing shall be allowed to produce daily only that amount of gas which is the volumetric equivalent in reservoir displacement of the gas and oil produced from the oil well in the reservoir that withdraws the maximum amount of gas in the production of its daily oil allowable.

(1) The following formula shall be used in the determination of the allowable of a gas well producing with a gas-oil ratio of 100,000 or more.

$$Q = A\left(r_1 - r_2 + \frac{199.3\ PrB}{TrZ}\right)$$

Where:

Q = Gas well allowable, cubic feet per day at 14.65 PSIA and 60° F.

A = Top oil well allowable, barrels per day at 60° F.

r_1 = Permissible gas-oil ratio applicable to reservoir, cubic feet at 14.65 PSIA and 60° F. per barrel at 60° F.

r_2 = Cubic feet of gas dissolved in one (1) barrel of oil at average reservoir conditions, cubic feet at 14.65 PSIA and 60° F. per barrel at 60° F.

Pr = Average reservoir pressure at gas-oil contact, PSIA.

Tr = Average reservoir temperature at gas-oil contact, degrees Rankine.

B = Formation volume factor of reservoir oil at average reservoir conditions, dimensionless.

Z = Deviation factor of gas from ideal gas laws at average reservoir pressure and temperature, dimensionless.

(2) The following formula shall be used in the determination of the allowable of a gas well producing with a gas-oil ratio of less than 100,000 under the provisions of the rule stated.

$$Q = \frac{A\left(r_1 - r_2 + \frac{199.3\,PrB}{TrZ}\right)}{1 - \frac{r_2}{r_3} + \frac{199.3\,PrB}{r_3\,TrZ}}$$

Where:

r_3 = Gas-oil ratio of gas well, cubic feet at 14.65 PSIA and 60° F. per barrel at 60° F. Other symbols are as above.

(3) The allowable for an associated gas well as determined by this subsection shall be limited to the lesser of:

(A) the gas well allowable as calculated by paragraph (1) or (2) of this subsection;

(B) the well's capability as determined by §3.31(e) of this title (relating to Gas Reservoirs and Gas Well Allowable) (Statewide Rule 31); or

(C) the highest monthly production during those months averaged to a daily amount for wells that reported production during any of the three most recently reported production months.

(c) The necessary reservoir data shall be obtained from the file of the most recent MER hearing or shall be estimated by the commission unless more recent information is submitted by the operators.

(d) If the gas produced from an oil reservoir is returned to the same reservoir from which it was produced, only the volume of gas not returned to the reservoir shall be considered in applying the rule stated.

(e) Associated gas wells.

(1) Subsection (b) of this section will not be applicable to associated gas wells in reservoirs for which unlimited net gas-oil ratio authority has been granted for oil wells, where such net gas is defined as total gas produced less gas diverted to legal uses; however, this subsection does not apply to reservoirs where net gas is defined as total gas produced less gas returned to the reservoir from which it was produced, or where special field rules have been adopted for associated gas wells, or where a total gas volume limitation is placed upon the oil well producing under a net ratio, except that each associated gas well in such a reservoir shall be entitled to an additional gas voidage not to exceed the limitation placed upon the net ratio authority granted and the facts are shown on the current oil proration schedule for the field.

(2) Allowables for associated gas wells producing from reservoirs that are subject to an unlimited net gas-oil ratio authority will be dropped from the associated gas well schedule, effective that date such an unlimited net gas-oil ratio is authorized for any oil well in such reservoir.

(f) All gas-oil ratios determined by test or allocation shall be reported on the oil well status report form in accordance with instructions thereon and the provisions of §3.53(a) of this title (relating to Annual Well Tests and Well Status Reports Required).

(g) Allowables.

(1) No well shall have its allowable curtailed below the allowable fixed by the applicable field rules and the general statewide market demand order, unless such well is incapable of producing this allowable on a calendar day basis.

(2) Any well that has a gas-oil ratio in excess of the prescribed ratio for the field in which it is located will have its schedule daily allowable penalized due to such ratio.

Source Note: The provisions of this §3.49 adopted to be effective January 1, 1976; amended to be effective July 1, 1992, 17 TexReg 3236; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.50 Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain Railroad Commission approval and certification of enhanced oil recovery (EOR) projects pursuant to Texas Tax Code, §202.052, §202.054, and §202.0545.

(b) Applicability.

(1) This section applies to:

(A) new EOR projects and the change from secondary EOR projects to tertiary projects which qualify as new EOR projects, and which begin active operation on or after September 1, 1989; and

(B) expansions of existing EOR projects.

(2) An EOR project may not qualify as an expansion if the project has qualified as a new EOR project under this section.

(c) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Active operation--The start and continuation of a fluid injection program for a secondary or tertiary recovery project to enhance the displacement process in the reservoir. Applying for permits and moving equipment into the field alone are not considered active operations.

(2) Anthropogenic carbon dioxide--Carbon dioxide produced as a result of human activities.

(3) Commission--The Railroad Commission of Texas.

(4) Commission representative--A commission employee authorized to act for the commission. Any authority given to a commission representative is also retained by the commission. Any action taken by the commission representative is subject to review by the commission.

(5) Comptroller--The Comptroller of Public Accounts.

(6) Enhanced oil recovery project (EOR)--The use of any process for the displacement of oil from the reservoir other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process. This term does not include pressure maintenance or water disposal projects.

(7) Existing enhanced recovery project--An EOR project that has begun active operation but was not approved by the Commission as a new EOR project.

(8) Expanded enhanced recovery project or expansion--The addition of injection and producing wells, the change of injection pattern, or other commission approved operating changes to an existing enhanced oil recovery project that will result in the recovery of oil that would not otherwise be recovered.

(9) Fluid injection--Injection through an injection well of a fluid (liquid or gaseous) into a producing formation as part of an EOR project.

(10) Incremental production--The volume of oil produced by an expanded enhanced recovery project in excess of the production decline rate established under conditions before expansion of an existing enhanced recovery project.

(11) Oil recovery from an enhanced recovery project--The oil produced from the designated area the commission certifies to be affected by the project.

(12) Operator--The person recognized by the commission as being responsible for the actual physical operation of an EOR project and the wells associated with the EOR project.

(13) Positive production response--Occurs when the rate of oil production from wells within the designated area affected by an EOR project is greater than the rate that would have occurred without the project.

(14) Pressure maintenance--The injection of fluid into the reservoir for the purpose of maintaining the reservoir pressure at or near the bubble point or other critical pressure wherein fluid injection volumes are not sufficient to refill existing reservoir voidage in the approved project area and displace oil that would not be displaced by primary recovery operations.

(15) Primary recovery--The displacement of oil from the reservoir into the wellbore(s) by means of the natural pressure of the oil reservoir, including artificial lift.

(16) Production decline rate--The projected future oil production from a project area as extrapolated by a method approved by the commission.

(17) Recovered oil tax rate--The tax rate provided by the Tax Code, §202.052(b).

(18) Secondary recovery project--An enhanced recovery project that is not a tertiary recovery project.

(19) Termination--Occurs when the approved fluid injection program associated with an EOR project stops or is discontinued.

(20) Tertiary recovery project--An EOR project using a tertiary recovery method (as defined in the federal June 1979 energy regulations referred to in the Internal Revenue Code of 1986, §4993, or approved by the United States secretary of the treasury for purposes of administering the Internal Revenue Code of 1986, §4993, without regard to whether that section remains in effect) including those listed as follows:

(A) Alkaline (or caustic) flooding--An augmented waterflooding technique in which the water is made chemically basic as a result of the addition of alkali metals.

(B) Carbon dioxide augmented waterflooding--Injection of carbonated water, or water and carbon dioxide, to increase waterflood efficiency.

(C) Cyclic steam injection--The alternating injection of steam and production of oil with condensed steam from the same well or wells.

(D) Immiscible carbon dioxide displacement--Injection of carbon dioxide into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained.

(E) In situ combustion--Combustion of oil in the reservoir, sustained by continuous air injection, to displace unburned oil toward producing wells.

(F) Microemulsion, or micellar/emulsion, flooding--An augmented waterflooding technique in which a surfactant system is injected in order to enhance oil displacement toward producing wells. A surfactant system normally includes a surfactant, hydrocarbon, cosurfactant, an electrolyte and water, and polymers for mobility control.

(G) Miscible fluid displacement--An oil displacement process in which gas or alcohol is injected into an oil reservoir, at pressure levels such that the injected gas or alcohol and reservoir oil are miscible. The process may include the concurrent, alternating, or subsequent injection of water. The injected gas may be natural gas, enriched natural gas, a liquefied petroleum gas slug driven by natural gas, carbon dioxide, nitrogen, or flue gas. Gas cycling, i.e., gas injection into gas condensate reservoirs, is not a miscible fluid displacement technique nor a tertiary enhanced recovery technique within the meaning of this section.

(H) Polymer augmented waterflooding--Augmented waterflooding in which organic polymers are injected with the water to improve a real and vertical sweep efficiency.

(I) Steam drive injection--The continuous injection of steam into one set of wells (injection wells) or other injection source to effect oil displacement toward and production from a second set of wells (production wells).

(21) Water disposal project--The injection of produced water into the reservoir for the purpose of disposing of the produced water wherein the water injection volumes are not sufficient to refill existing reservoir voidage in the approved project area and displace oil that would not be displaced by primary recovery operations.

(d) Application requirements. To qualify for the recovered oil tax rate the operator shall:

(1) submit an application for approval on the appropriate form. All applications must be filed at the Commission's Austin office. The form shall be executed and certified by a person having knowledge of the facts entered on the form. If an application is already on file under the Natural Resources Code, Chapter 101, Subchapter B, or for approval as a tertiary recovery project for purposes of the Internal Revenue Code of 1986, §4993, the operator may file a new EOR project and area designation application if the active operation of the project does not begin before the application under this section is approved by the Commission;

(2) submit all necessary forms to the Oil and Gas Division and provide the Commission with any relevant information required to administer this section such as: area plats showing the proposed project area and all injection and producing wells within the area, production and injection history, planned enhanced oil recovery procedures, and any other pertinent data;

(3) obtain a unitization agreement if required for purposes of carrying out the project under the Natural Resources Code, Chapter 101, Subchapter B. The Commission may not approve the project unless the unitization is approved; and

(4) submit an application on the appropriate form and obtain the necessary permits to conduct fluid injection operations pursuant to §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) (Statewide Rule 46), if such permits have not already been obtained.

(e) Concurrent applications. The operator may file concurrently:

(1) an application for approval of a new or expanded EOR project under this section, together with;

(2) an application for approval of a unitization agreement for purposes of carrying out the enhanced oil recovery project under the Natural Resources Code, §§101.001 et seq.; or

(3) an application for approval for certification of the project as a tertiary recovery project.

(f) Opportunity for hearing. A commission representative may administratively approve the application. If the commission representative denies administrative approval, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the commission.

(g) Approval and certification.

(1) Project approval. In order to be eligible for the recovered oil tax rate as provided in the Tax Code, §202.052(b), the operator shall apply for and be granted Commission approval of a new EOR project or an expansion of an existing EOR project, prior to commencing active operation of the new project or expanded project. For a project to be approved the operator shall:

(A) prove that it qualifies as an EOR project;

(B) designate the area to be affected by the project and obtain Commission approval of the designation; and

(C) if production from the wells within the project area is reported with production from wells not in the project area, designate the method to account for and report production from the project area.

(2) Positive production response certificate.

(A) The operator of an EOR project that meets the requirements of this section shall demonstrate to the Commission a positive oil production response before the operator can receive Commission certification of such a positive production response. The certification date may be any date desired by the operator, subject to Commission approval, following the date on which a positive oil production response first occurred. The operator shall apply for a positive production response certificate within three years of project approval for secondary projects, and within five years of project approval for tertiary projects, to qualify for the recovered oil tax rate. The oil produced from the designated area of a new EOR project or incremental oil produced from the designated area of an expanded EOR project after the date of certification of a positive production response is eligible for the recovered oil tax rate. The operator shall apply to the comptroller pursuant to the Tax Code, §202.052 and §202.054, to qualify for the recovered oil tax rate.

(B) The application for positive response certification shall include:

(i) production and injection graphs with supporting tabular data illustrating a positive production response and volumes of water or other substances that have been injected on the designated area since the initiation of the new or the expanded EOR project;

(ii) a plat of the affected area showing all injection and producing wells, with completion dates; and

(iii) any other data requested by the Oil and Gas Division.

(C) The application for the positive production response certificate shall be processed administratively. If the Commission representative denies administrative approval, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the Commission.

(h) Annual reporting.

(1) The operator shall file an annual report on the appropriate form with the Oil and Gas Division each year the project remains eligible for the reduced severance tax rate. This form shall be filed within 30 days of the first anniversary of the date that the Commission acted on the EOR positive production response certification application

and annually thereafter.

(2) The report shall contain the following:

(A) Commission certification date of positive production response;

(B) monthly volume of injected fluid(s) and anthropogenic carbon dioxide;

(C) number of well(s) used for injection;

(D) monthly production of oil, gas, and water;

(E) number of active producing wells; and

(F) any other relevant information requested by the Oil and Gas Division.

(i) Reduced or enlarged areas. The operator may apply for reduced or enlarged project area certification if the application for reduction or enlargement is received prior to the filing of an application for positive production response certification of the original enhanced oil recovery project.

(j) Termination and penalty. Upon approval by the Commission and the comptroller, the recovered oil tax rate shall continue for a maximum of 10 years, unless the project is sooner terminated. If the project is terminated prior to the 10-year period, the operator shall notify the Commission and the comptroller in writing within 30 days after the last day of active operations. Failure to so notify may result in civil penalties, interest, and the tax due. If the Commission determines a project has been terminated or there is action that affects the tax rate, it shall notify the comptroller immediately in writing.

(k) Additional tax rate reduction for enhanced recovery projects using anthropogenic carbon dioxide.

(1) Subject to the limitations provided by Texas Tax Code, §202.0545, until the later of the seventh anniversary of the date that the Comptroller of Public Accounts first approves an application for a tax rate reduction under this subsection or the effective date of a final rule adopted by the United States Environmental Protection Agency regulating carbon dioxide as a pollutant, the producer of oil recovered through an EOR project that qualifies under Texas Tax Code, §202.054, for the recovered oil tax rate provided by Texas Tax Code, §202.052(b), is entitled to an additional 50 percent reduction in that tax rate if in the recovery of the oil the EOR project uses carbon dioxide that:

(A) is captured from an anthropogenic source in this state;

(B) would otherwise be released into the atmosphere as industrial emissions;

(C) is measurable at the source of capture; and

(D) is sequestered in one or more geological formations in this state following the EOR process.

(2) In the event that a portion of the carbon dioxide used in the EOR project is anthropogenic carbon dioxide that satisfies the criteria of paragraph (1) of this subsection and a portion of the carbon dioxide used in the project fails to satisfy the criteria of paragraph (1) of this subsection because it is not anthropogenic, the tax reduction provided by paragraph (1) of this subsection shall be reduced to reflect the proportion of the carbon dioxide used in the project that satisfies the criteria of paragraph (1) of this subsection.

(3) To qualify for the tax rate reduction under this subsection, the operator shall:

(A) apply for a certification from the Commission if carbon dioxide used in the project is to be sequestered in an oil or natural gas reservoir; and

(B) apply to the Comptroller of Public Accounts for the reduction and include with the application any information and documentation that the comptroller may require.

(4) To qualify for the additional reduced recovered oil tax rate under this subsection the operator shall:

(A) submit an application for certification to the Commission's Austin Office for approval on the appropriate form that is executed and certified as provided for on the form; and

(B) provide the Commission with:

(i) plats showing the proposed project area and all wells within the area;

(ii) production and injection history;

(iii) planned enhanced oil recovery procedures;

(iv) information to demonstrate that the carbon dioxide to be injected is anthropogenic and a description of the method(s) of capturing and measuring the captured carbon dioxide at the source;

(v) a description of the planned sequestration program reasonably expected to ensure that at least 99% of the sequestered carbon dioxide will remain sequestered for at least 1,000 years;

(vi) planned monitoring and verification measures, including the planned duration of such measures, that will be employed to demonstrate that the sequestration program is performing as expected; and

(vii) any other pertinent information requested by the Commission.

(5) The Commission may issue the certification for the reduced tax rate under this subsection only if the Commission finds that, based on substantial evidence, there is a reasonable expectation that:

(A) the operator's planned sequestration program will ensure that at least 99 percent of the anthropogenic carbon dioxide sequestered will remain sequestered for at least 1,000 years; and

(B) the operator's planned sequestration program includes appropriately designed monitoring and verification measures that will be employed for a period sufficient to demonstrate whether the sequestration program is performing as expected.

(6) The operator is responsible for making application to the Comptroller of Public Accounts for the additional tax rate reduction.

(7) The additional tax rate reduction under this subsection does not apply and the operator will be required to repay the amount of tax that would have been imposed in the absence of this subsection if the operator's sequestration program or the operator's monitoring and verification measures differ substantially from the planned program approved by the Commission.

(8) In conjunction with the Annual Report required to be filed under subsection (h) of this section, an operator shall submit information concerning the operator's monitoring and verification measures results as proposed in the application for certification to demonstrate whether the sequestration program is performing as expected. In the event that the operator's sequestration program, including monitoring and verification measures, differs substantially from the program certified by the Commission under subsection (k) (5) of this section, the operator shall include with the Annual Report a written description of any material changes in the sequestration program.

(9) A Commission representative may administratively approve or deny an application for certification. If the Commission representative administratively denies an application, the applicant shall have the right to a hearing upon request. After hearing, the examiner shall recommend final action by the Commission.

Source Note: The provisions of this §3.50 adopted to be effective February 20, 1990, 15 TexReg 652; amended to be effective March 18, 1992, 17 TexReg 1615; amended to be effective November 17, 1993, 18 TexReg 7922; amended to be effective April 6, 1998, 23 TexReg 3435; amended to be effective October 12, 2003, 28 TexReg 8585; amended to be effective January 7, 2008, 33 TexReg 114.

§3.51 Oil Potential Test Forms Required

(a) A completed potential test form shall be filed with the Commission not later than the deadline for filing completion reports under §3.16 of this title (relating to Log and Completion or Plugging Report). If the operator fails to file a potential test in an acceptable form prior to the deadline for filing completion reports as specified under §3.16 of this title, then the effective date of the allowable resulting from the test shall not extend back more than 30 days prior to the date that the test form, properly completed, is filed with the Commission. This 30-day provision shall govern regardless of whether the potential test is taken during the month in which it is received by the Commission or any prior month.

(b) The initial potential test form for any new completion or recompletion must be accompanied by the well record.

Source Note: The provisions of this §3.51 adopted to be effective January 1, 1976; amended to be effective February 1, 2016, 41 TexReg.

§3.52 Oil Well Allowable Production

(a) The daily allowable production of any lease or property shall not include production based upon the daily potential production of the field or area in which such well is located unless such well is actually on production, and such lease or property shall share in the total allowable production of the field or area, only to the extent of such well's actual ability to produce from day to day regardless of the rated potential production thereof according to the commission schedules.

(b) Production of a well in any one day shall not exceed 110% of the top well allowable as fixed by applicable rules and orders. Production and runs from a lease during the monthly allowable period shall not exceed 105% of the monthly allowable for the well or wells on the lease. However, the volume of oil that is produced and removed from the producing property as tolerance production shall be treated as overproduction and overruns shall be made up during the next succeeding month.

(c) All oil allowable volumes shall be measured in a manner consistent with §3.71 of this title (relating to Pipeline Tariffs) (Statewide Rule 71).

(d) A newly completed well coming into production during a proration period will be gauged either by a commission agent, or pipeline gauger if a commission agent is not available, if an offset lease owner witnesses the gauge taken by the pipeline gauger. The allowable production of such newly completed well shall be in addition to the existing total allowable production of the field as previously ascertained. The well whose allowable is thus fixed shall take its ratable share of production at the next succeeding schedule date according to rule.

(e) All oil produced from any well governed by any proration order of the commission shall be charged against the allowable daily production of such well regardless of the disposition which is made of the oil so produced.

(f) The operator of any lease or unitized area in the State of Texas may be permitted to produce the total allowable for any such lease or unitized area subject to the following provisions:

(1) The operator must submit an application to produce that total allowable on a lease or unit production basis to the commission with a plat showing the subject lease or unit as well as the adjacent properties thereto. Such plat shall identify properly all properties and wells. The applicant shall give written notice to all operators in the field when application is made for permission to produce on a lease basis in a field. If no protest is received by the commission within 15 days of the date of mailing, the application may be granted by administrative action. If protest is received, notice will be given and the matter set for hearing.

(2) The total daily allowable of the lease or unit shall be initially established as an allowable equal to the sum of the current allowables for all wells on the lease or unit. The allowable credited to any new or existing well may be increased to the top well allowable permitted by subsequently filing a new potential test on that well. The maximum total daily allowable of the lease or unit will be equal to the sum of the scheduled top allowables assignable to each well for its proration unit.

(3) The total daily allowable of the lease or unit may be produced in any quantity from any well or combination of wells with the exception that wells nearer than a regular location from a lease or unit line shall not be permitted to produce more than their normal allowables and wells at a distance of a regular location from a lease or unit line shall not be produced at a rate of more that two times the top allowable for such well unless waivers of objection to rates in excess of this limit have been obtained from the operators of wells offsetting the well.

(4) Annual well test or allocation:

(A) An annual well test, or an allocation pursuant to §3.53(a)(2) of this title (relating to Annual Well Tests and Well Status Reports Required) shall be made and reported on the oil well status report form on each lease or unit property to which a lease production basis has been granted showing an individual well test or allocation on each oil well on the property made during the prescribed test period determined by the commission. Annual well tests may be witnessed by offset operators. An offset operator that desires to witness an annual well test shall give the testing operator written notice of its desire to witness the next scheduled annual well test of a specific well. A testing operator that has received prior written notice that an offset operator desires to witness an annual well test shall give that offset operator at least 24 hours advance notice of the date of the next annual well test for that well. The Commission will use the test or allocation data in the preparation of the oil proration schedule. The total schedule daily lease allowable shall be the sum of the individual well allowables as determined under applicable rules and the lease production basis shall be designated on the oil proration schedule by an appropriate symbol. All wells on the lease for which an allowable is requested shall have their production volumes reported pursuant to §3.53(a).

(B) Any producing well with a gas-oil ratio in excess of that permitted by the applicable rules shall have its daily allowable calculated by dividing the producing gas-oil ratio into the daily gas limit of the well.

(5) The Commission shall continue to require special tests in cases of commingled production where individual lease apportionment is determined by this method. Other special tests may be required as the Commission deems necessary.

(6) In the event that the monthly gas production of the lease or unit exceeds the permissible monthly lease gas limit, the volume of gas in excess of the lease gas limit shall be considered overproduction and must be made up by underproduction of the lease gas limit. Whenever the overproduced amount equals the next month's lease gas limit the overproduced amount shall immediately be reduced to zero by shutting in the lease or by other means acceptable to the Commission.

(7) The East Texas Field is excluded from the provisions of this section.

(g) Administrative cancelation of overproduction.

(1) An operator may request in writing to the Commission that overproduction for a specific lease be canceled. The request shall include a listing of the names and addresses of all offsetting operators in the same field as the lease for which the request is filed.

(2) Upon receipt of an operator's written request:

(A) Commission staff shall determine whether the operator's wells on the specified lease are in compliance with Commission rules excluding rules pertaining to overproduction.

(B) If the wells are found to be in compliance, the Commission staff shall send written notice to offset operators as identified in the request advising them of the request and giving them not less than 15 days to file a written objection to the request.

(C) If no objection to the request is received, the overproduction on the lease requested by the operator shall be canceled.

(D) If objection to the request is received or if Commission staff determines that the operator's wells are not in compliance with Commission rules excluding rules pertaining to overproduction, then the requested cancelation shall not be administratively approved. The operator may request that the matter be scheduled for public hearing pursuant to Tex. Nat. Res. Code §86.090. The burden of proof shall be on the applicant operator.

Source Note: The provisions of this §3.52 adopted to be effective January 1, 1976; amended to be effective May 1, 1991, 16 TexReg 2095; amended to be effective February 18, 1994, 19 TexReg 783; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective January 10, 2000, 25 TexReg 79; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective February 1, 2016, 41 TexReg 785.

§3.53 Annual Well Tests and Well Status Reports Required

(a) Oil wells.

(1) Unless otherwise provided for in this section, each operator of producing oil wells shall annually test each producing oil well for a 24-hour period during the test period specified on the well status report form and shall record all oil, gas and water volumes resulting from the test on the form.

(2) For any oil well capable of producing no more than five barrels of oil per 24-hour period, the operator of such well may report the required oil, gas and water volumes based on an allocation of that well's production on a prorated daily basis, rather than an actual well test. This option of using production allocation instead of actual well tests does not apply to surface-commingled wells, swabbed wells, the East Texas Field or the following Panhandle fields: Panhandle Carson County Field (Field Number 68845-001); Panhandle Collingsworth County Field (Field Number 68859-001); Panhandle Gray County Field (Field Number 68873-001); Panhandle Hutchison County Field (Field Number 68887-001); Panhandle Moore County field (Field Number 68901-001); Panhandle Potter County Field (Field Number 68915-001); and Panhandle Wheeler County Field (Field Number 68929-001).

(3) Each operator of a well or wells listed in the oil proration schedule shall file with the commission an oil well status report form in accordance with instructions on the form. All wells on a lease, and injection and disposal wells, must be reported.

(4) Changes in oil well status filed between regularly scheduled oil well status surveys shall be submitted on oil well status report forms in accordance with instructions thereon.

(b) Gas wells. Each operator of a gas well producing liquid hydrocarbons shall file with the commission gas well status reports in accordance with instructions thereon.

Source Note: The provisions of this §3.53 adopted to be effective January 1, 1976; amended to be effective November 21, 1980, 5 TexReg 4419; amended to be effective February 13, 1997, 22 TexReg 1313; amended to be effective January 10, 2000, 25 TexReg 79.

§3.54 Gas Reports Required

(a) Gas processing plant report. As soon after the first day of each calendar month as practicable, and never later than the 25th day of each calendar month, the operator of each plant manufacturing or extracting liquid hydrocarbons, including gasoline, butane, propane, condensate, kerosene, or other derivatives from natural gas, or refinery or storage vapors, shall file, in duplicate, in the Austin office, a report concerning the operation of the plant during the immediately preceding month, which must contain the data and information required on the form.

(b) Pressure maintenance and repressuring plant report.

(1) As soon after the first day of each month as practicable, but never later than the 15th day of each calendar month, the operator of each plant that returns natural gas to oil or gas producing reservoirs, or both, for the purpose of maintaining pressure or repressuring an oil or gas reservoir, but is not reporting such gas on any other commission approved form, shall file in duplicate in the district office a report concerning the operation of the plant during the immediately preceding month, which must contain the data and information required on the form.

(2) Pressure maintenance.

(A) The operator of each pressure-maintenance or repressuring plant shall file the report although no liquid hydrocarbons are recovered.

(B) The term "pressure-maintenance plant" or "repressuring plant" as used herein means any equipment or device, mechanical or otherwise, used for the purpose of returning any natural gas, residue gas from a gas processing plant, including plant and storage vapors, to an underground oil reservoir if the plant is operated as a separate unit. If pressure maintenance or repressuring operations are conducted as an integral part of a gas processing plant extracting, manufacturing, or recovering liquid hydrocarbons from natural gas or vapors, or both, the operations shall be reported by the operator of the processing plant.

(c) Producer's report of condensate and/or crude oil produced from gas wells. As soon as practicable after the first day, and never later than the last day of the calendar month, subsequent to the period of the report, the operator of each gas well from which liquids are recovered on the lease shall file the required form.

(d) Carbon black plant report. As soon as practicable after the first day and never later than the 15th day of each calendar month, each operator of a carbon black plant shall file a report. The report shall cover the operation of the plant for the immediately preceding month and shall be filed in duplicate in the district office.

(e) Monthly gas production report. As soon after the first day of each month as practicable, and never later than the last day of the calendar month, subsequent to the period of the report, every operator producing natural gas from wells classified as either gas wells or oil wells by the commission, except those expressly exempted by the commission shall file a report on the required form.

Source Note: The provisions of this §3.54 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective May 7, 1991, 16 TexReg 2297.

§3.55 Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering

(a) When the full well stream from a gas well is moved to a plant or central separation facilities, and the liquid hydrocarbons produced by two or more wells are commingled without being measured or metered from each gas well, the operator of each well so producing shall periodically file with the commission, as provided for in this section, a report showing the following information for each well:

(1) the specific gravity of the gas at 60 degrees Fahrenheit, after the removal of the liquid hydrocarbons;

(2) the API gravity corrected to 60 degrees Fahrenheit of the liquid hydrocarbons removed;

(3) the number of stock tank barrels of liquid hydrocarbons (corrected to 60 degrees Fahrenheit) recovered per 1,000 standard cubic feet of gas.

(b) Tests.

(1) The tests necessary for this report shall be made by one or more of the following methods:

(A) conventional mechanical separation;

(B) low temperature separation;

(C) split stream method;

(D) in accordance with AGA-NGAA Testing Code 101-43.

(2) The tests shall be made semiannually, or quarterly if contracts for royalty payments require quarterly tests. Semiannual tests must be made during the first and third or second and fourth quarters of the year. If a contract for royalty payments requires quarterly tests, the tests shall be made during each quarter. Both semiannual and quarterly tests may be made during any month of the quarter if the same (first, second, or third) month of each quarter is used thereafter for any well.

(c) The results of each test shall be submitted in duplicate on the appropriate commission form to the proper commission district office not later than the 15th day of each month following the month in which the test is made. The tests shall be required when the conditions set out in the first paragraph of this section exist, regardless of whether or not the conditions are an exception to §3.26 of this title (relating to Separating Devices, Tanks, and Surface Commingling of Oil) (Statewide Rule 26). The tests shall not be required, however, in any reservoir in which 100% of the operating and royalty ownership has been unitized.

(d) This section does not purport to alter any procedure for periodic tests of gas wells that has previously been approved by the commission. If test periods agreed upon by the interested parties have not been approved by the commission, and if the periods agreed upon differ from the test periods provided for in this section, alternative testing periods may be approved by the commission upon application.

Source Note: The provisions of this §3.55 adopted to be effective January 1, 1976; amended to be effective March 10, 1986, 11 TexReg 901; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.56 Scrubber Oil and Skim Hydrocarbons

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings unless the context clearly indicates otherwise:

(1) Identifiable liquid hydrocarbons--Volume of scrubber oil/skim hydrocarbons that is received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons can be clearly identified.

(2) Producing property--A location from which hydrocarbons are being produced that has been assigned a lease identification number by the Commission and which is used in reporting production.

(3) Scrubber oil--Liquid hydrocarbons which accumulate in lines that are transporting casinghead gas and which are captured at the inlet to a gas processing plant.

(4) Skim hydrocarbons--Oil and condensate which accumulate during produced water disposal operations.

(5) Tolerance--The amount of skim hydrocarbons that may be recovered before the produced water disposal system operator must allocate to the producing property.

(6) Unidentifiable liquid hydrocarbons--Scrubber oil/skim hydrocarbons received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons cannot be identified.

(b) Disposition of scrubber oil, skim hydrocarbons, and identifiable liquid hydrocarbon volumes.

(1) Scrubber oil. Any scrubber oil that has not been returned to a producing property by the end of a monthly report period shall be reported by the operator of the gas

plant on the monthly plant report, Form R-3 (Monthly Report for Gas Processing Plants). The unidentifiable liquid hydrocarbons recovered and reported on Form R-3 may be disposed of at the point of accumulation. The accepted Form R-3 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(2) Skim hydrocarbons.

(A) All unidentifiable liquid hydrocarbons recovered by a single operator or multiple operator produced water disposal system shall be reported on the Form P-18 (Skim Oil/Condensate Report) for each reporting period.

(B) The unidentifiable liquid hydrocarbons recovered and reported on Form P-18 may be disposed of at the point of accumulation. The accepted Form P-18 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(C) Unidentifiable liquid hydrocarbons recovered by a single operator produced water disposal system shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period.

(D) Unidentifiable liquid hydrocarbons recovered by a multiple operator produced water disposal system in excess of a tolerance ratio of one barrel of liquid hydrocarbons for each 2,000 barrels of produced water received shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period. The produced water disposal system operator shall notify the operator of each producing property of any allocations to that property by furnishing a copy of the allocations as shown on Form P-18 (Skim Oil/Condensate Report).

(E) The operator of each producing property shall report the volume of liquid hydrocarbons allocated to the producing property as production from the property on Form PR, Monthly Production Report. The volume allocated back shall be shown as skim oil or skim condensate on the form.

(3) Identifiable liquid hydrocarbon volumes.

(A) Identifiable liquid hydrocarbon volumes returned to the producing property during the reporting period in which the volume is received at the gas plant/produced water disposal facility shall not be reported to the Commission by the gas plant/facility operator. The gas plant/produced water disposal facility operator shall notify the appropriate Commission district office by telephone prior to the return of such volumes. The movement of these volumes back to the producing property shall comply with §3.85 of this title (relating to Manifest to Accompany Each Transport of Liquid Hydrocarbons by Vehicle), commonly referred to as Statewide Rule 85.

(B) Identifiable volumes not returned to the producing property shall be reported to the Commission and to the operator of the producing property on Form R-3 or Form P-18 as prescribed in paragraph (1) or (2) of this subsection. Volumes shall be specifically credited to the appropriate producing property. The operator of the producing property shall report the disposition of such identifiable volumes as either skim hydrocarbons or scrubber oil on the appropriate production report.

Source Note: The provisions of this §3.56 adopted to be effective January 10, 2000, 25 TexReg 80; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 30, 2007, 32 TexReg 287.

§3.57 Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials

Effective July 1, 2025, the requirements of this section are incorporated in Chapter 4 of this title (relating to Environmental Protection), specifically Subchapter A (relating to Oil and Gas Waste Management).

Source Note: The provisions of this §3.57 adopted to be effective April 11, 1990, 15 TexReg 1693; amended to be effective June 1, 1998, 23 TexReg 5656; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective July 1, 2025, 50 TexReg 33

§3.58 Certificate of Compliance and Transportation Authority; Operator Reports

(a) Certificate of Compliance and transportation authority.

(1) Each operator who seeks to operate any well subject to the jurisdiction of the Commission shall file with the commission's Austin office a commission form P-4 (certificate of compliance and transportation authority) for each property on which the wells are located certifying that the operator has complied with Texas Natural Resources Code, Title 3; Texas Water Code, §26.131; and Texas Water Code, Chapter 27, and orders, rules, and regulations of the commission pursuant to Texas Natural Resources Code, Title 3; Texas Water Code, §26.131; and Texas Water Code, Chapter 27, in respect to the property. The Commission form P-4 establishes the operator of an oil lease, gas well, or other well; certifies responsibility for regulatory compliance, including plugging wells in accordance with §3.14 of this title (relating to plugging); and identifies gatherers, purchasers, and purchasers' commission-assigned system codes authorized for each well or lease. Operators shall file form P-4 for new oil leases, gas wells, or other wells; recompletions; reclassifications of wells from oil to gas or gas to oil; consolidation, unitization or subdivision of oil leases; or change of gatherer, gas purchaser, gas purchaser system code, operator, field name or lease name. When an operator files a form P-4, the oil and gas division shall review the form for completeness and accuracy. The Commission may require an operator who files a form P-4 for the purpose of changing the designation of an operator for a lease or well to provide to the Commission evidence that the transferee has the right to operate the lease or well. Except as otherwise authorized by the Commission, a transporter (whether the operator or someone else) shall not transport the oil, gas, or geothermal resources from such property until the Commission has approved the certificate of compliance and transportation authority. No certificate of compliance designating or changing the designation of an operator will be approved that is signed, either as transferor or transferee, by a non-employee agent of the organization unless the organization has filed with the commission, on its organization report, the name of the non-employee agent it has authorized to sign such certificates of compliance on its behalf.

(2) An approved certificate of compliance and transportation authority shall bind the operator until

another operator files a subsequent certificate and the Commission has approved the subsequent certificate and transferred the property on commission records to the subsequent operator.

(3) The appropriate district office or the Austin office may grant temporary authority for an operator to use a transporter not authorized for a particular property in order to take care of production and prevent waste. The operator shall secure such temporary authority in writing from the appropriate district office or the Austin office before the oil or condensate is moved. In an emergency situation the operator may secure such temporary authority verbally but shall notify the district office in writing within 10 days after the oil or condensate is moved. An emergency situation exists when oil or condensate must be moved off a lease because it poses an imminent threat to the public health and safety, or when the threat of waste is imminent. The operator shall also furnish copies of such authorization or notification to the regular transporter and to the temporary transporter.

(4) If an applicant wishes to assume operator status for a property, but is unable to obtain the signature of the previous operator on the certificate of compliance and transportation authority, the applicant shall file with the oil and gas division in Austin a completed form P-4 signed by a designated officer or agent of the applicant, along with an explanatory letter and legal documentation of the applicant's right to operate the property. Prior to approval of such an application, the office of the general counsel will notify the last known operator of record, if such operator's address is available, affording such operator an opportunity to protest.

(b) Monthly production report (oil, natural gas and geothermal resources). For each calendar month, each operator who is a producer of crude oil, natural gas or geothermal resources shall file with the commission a report for each of the operator's producing properties. Operators shall file such reports on commission Form PR, Monthly Production Report, or commission Form GT-2 (producer's monthly report of geothermal wells). These commission forms report monthly production and disposition of oil and condensate, and casinghead gas and gas well gas (Form PR) and geothermal resources (Form GT-2). On or before the last day of the month subsequent to the period of the report, the operator shall file the original form with the Austin office, and one copy with the transporter taking the oil, gas or geothermal resources from the property if requested by the transporter.

(c) Recovered load oil.

(1) The operator of each lease from which load oil is recovered shall file the original and one copy of commission form P-3 (authority to transport recovered load or frac oil) with the district office, and another copy with the transporter prior to running the load oil. Form P-3 requires a producer to report the quantity of recovered load or frac oil to be transported from a particular lease and to identify the transporter. The form P-3 (authority to transport recovered load or frac oil) filed by the operator shall be the authority for the transporter to run the quantity of recovered load or frac oil stated in the form.

(2) The provisions of this subsection apply only to oil that has been obtained from a source other than the lease on which it is used. "Recovered load oil or frac oil," as that term is used herein, is any oil or liquid hydrocarbons used in any operation in an oil or gas well, and which has been recovered as a merchantable product.

(d) Subdivision and consolidation of oil leases.

(1) An operator seeking to subdivide or consolidate existing oil leases shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). Form P-6 identifies the leases to be subdivided or consolidated as well as the resulting leases. Two plats shall be filed with form P-6, one showing the boundaries of the lease(s) before and one showing the boundaries of the lease(s) after the subdivision or consolidation.

(2) An operator seeking to subdivide an existing oil lease that it operates or to assume operatorship of fewer than all of the wells on an oil lease shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to subdivide an oil lease may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules.

(3) An operator seeking to consolidate two or more existing oil leases that it operates shall file and obtain approval of a commission form P-4 (certificate of compliance and transportation authority) and a commission form P-6 (request for permission to subdivide or consolidate oil lease(s)). A request to consolidate two or more oil leases may be approved administratively if the commission staff determines that approval of the request will not cause waste, harm correlative rights, or result in the circumvention of commission rules and:

(A) the mineral and royalty ownership of the leases proposed for consolidation is identical in all respects;

(B) the operator has obtained a surface commingling exception permit pursuant to §3.26 of this title (relating to separating devices, tanks, and surface commingling of oil) that authorizes commingling of production from all of the leases proposed for consolidation; or

(C) the operator has filed and obtained approval of a valid commission form P-12 (certificate of pooling authority) authorizing pooling of all of the leases proposed for consolidation.

Source Note: The provisions of this §3.58 adopted to be effective January 1, 1976; amended to be effective February 23, 1979, 4 TexReg 436; amended to be effective May 9, 1988, 13 TexReg 2026; amended to be effective May 22, 2000, 25 TexReg 4512; amended to be effective May 12, 2002, 27 TexReg 3756; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective November 26, 2007, 32 TexReg 8452.

§3.59 Oil and Gas Transporter's Reports

(a) General. The commission may, from time to time, require oil and gas pipeline companies to make reports to the commission showing wells connected with their lines during any month, the amount of production taken therefrom, names of parties from whom oil and gas are purchased, and the amount of oil or gas purchased therefrom.

(b) Daily report. The commission may, in case of overproduction or for any other reason which it deems urgent, require oil and gas pipe line companies to furnish daily reports of the amount of oil or gas purchased or taken from different wells or parties.

(c) Weekly stock report. Rescinded by Order Number 20-57,970, effective 11-16-67.

(d) Monthly transportation and storage report.

(1) Each gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall file with the commission on or before the last day of each calendar month a report showing the required information concerning the transportation operations of such gatherer, transporter, or storer for the next preceding month. Such form is incorporated in and made a part of this section.

(2) The original of the report, covering all of the operations of the gatherer, transporter, storer, and/or handler of crude oil or products, or both, shall be filed in the Austin office of the commission. One copy of the report shall be filed in each district office in which the gatherer, transporter, storer, and/or handler of crude oil or products, or both, operates, but may include only the information pertaining to the operations in that district in which it is filed.

(3) The written instructions appearing on said form are incorporated in and made a part of this section, and all of the data and information on the form shall be reported and arranged on the form as required by the form.

(4) No gatherer, transporter, storer, and/or handler of crude oil shall remove crude oil from any property unless such property is identified by a sign posted in compliance with §3.3(3) of this title (relating to Identification of Properties, Wells, and Tanks).

(5) The provisions of this section shall not apply to the operator of any refinery, processing plant, blending plant, or treating plant to which §3.60 of this title (relating to Refinery Reports) applies if the operator has filed the required form.

(e) Annual report.

(1) Each common carrier pipeline shall make and file with the commission, at its Austin office, an annual report for each calendar year. The report must show the names of the officers, directors, and stockholders, and the residence of each; the amount of capital stock and bonded indebtedness outstanding; the results of financial operations; the sources of revenue; and the expenditures, assets and liabilities, and statistical data of oil transported; and such other information as may be deemed pertinent by the commission concerning the carrier's transactions in the performance of services under its charter provisions relative to the transportation of crude petroleum in the State of Texas.

(2) The annual report must be made to the commission on the form prescribed and furnished by the commission; and must be returned complete, under oath, within 30 days after the receipt of the forms from the commission.

(3) For all purposes applicable under these rules and regulations the "Classification of Investment for Pipe Lines, Pipe Line Operating Revenues, and Pipe Line Operating Expenses" prescribed by the Interstate Commerce Commission and effective on January 1, 1915, is adopted and made a part of these rules for the use of all common carrier pipelines subject to the provisions of that act of the legislature, being Chapter 30 of the Regular Session of the 35th Legislature, State of Texas.

Source Note: The provisions of this §3.59 adopted to be effective January 1, 1976.

As in effect on 12/8/2025.

§3.60 Refinery Reports

On or before the 15th day of each calendar month, the operator of each refinery, processing plant, blending plant or treating plant, and/or other plant situated within the state that processes or manufactures a product, except those gas processing plants for which another form is required by §3.54(a) of this title (relating to Gas Reports Required), shall file with the commission a report covering the operations of the refinery or plant during the preceding month. The report must contain the data and information required to be reported on the form.

Source Note: The provisions of this §3.60 adopted to be effective January 1, 1976.

§3.61 Refinery and Gasoline Plants

(a) The operator of each refinery in the state shall use tanks for measuring the crude oil and products taken into the refinery and the finished products of the refinery.

(b) No refinery or gasoline plant shall be operated without a certificate of compliance on a form supplied by the commission and approved by it, which shall be in effect for a period of 12 months, but may be renewed for one or more additional 12-month period. The operator must equip the plant with tanks and proper metering facilities.

(c) Measuring facilities for the accurate measurement of the volume of each type of gas taken into a natural gasoline plant shall be installed and used by the operator of the gasoline plant. Meters must be provided and used for measuring separately the dry sweet natural gas, the dry sour natural gas, casinghead gas, and refinery vapors taken into each plant. Accurate meters must be installed and used in each gasoline plant in which is processed dry gas (as distinguished from casinghead gas) so that all disposals of residue gas from such natural gasoline plant are accurately accounted for. Adequate devices should likewise be installed and used in each gasoline plant at which casinghead gas exclusively, or casinghead gas and refinery vapors only are processed, for the purpose of making approximate estimates of the volume of residue gas produced from such plant; such devices may consist either of meters, pilot tubes, pressure recording gauges, or manometers, through which measurements may be made from which reasonably accurate estimates of volume can be made.

(d) Measuring natural gasoline.

(1) Adequate tanks or meters of standard or approved types must be provided for measuring accurately all finished products of natural gasoline plants.

(2) The operator of each natural gasoline plant shall meter separately the volume of dry sweet natural gas, dry sour natural gas, casinghead gas, and refinery vapors that are taken into each natural gasoline plant.

(3) The operator of each natural gasoline plant in which dry natural gas (as distinguished from casinghead gas) is processed shall use metering facilities so that all disposition of residue gas from such natural gasoline plants are accurately accounted for. The operator of each natural gasoline plant in which casinghead gas exclusively, or casinghead gas and refinery vapors only, are processed shall install and use measuring devices, consisting either of meters, pitot tubes, pressure recording gauges, or manometers, with which measurements may be made of

the residue gas disposition from the plant.

(4) The operator of each natural gasoline plant shall provide and use tanks or meters of standard or approved type for measuring each finished product of the plant.

Source Note: The provisions of this §3.61 adopted to be effective January 1, 1976.

§3.62 Cycling Plant Control and Reports

(a) The operator of each cycling plant shall use tanks for measuring the crude oil, condensate, or other liquid hydrocarbons taken into or extracted by the cycling plant.

(b) The operator of each cycling plant shall meter the following separately:

(1) all gas taken into the plant from statutory gas wells;

(2) all casinghead gas taken into the cycling plant;

(3) all gas used for plant fuel;

(4) all gas taken by pipe lines or for domestic or commercial uses;

(5) all gas, including flash vapors, vented directly or indirectly to the air.

(c) Gas used for lifting water by jetting, or used in turbines and subsequently vented to the air or burned in a flare, shall be accurately metered and reported by the operator as vented on the appropriate form.

(d) No cycling plant shall be permitted to vent any gas taken into the plant from statutory gas wells; however, the venting of a volume of flash vapors not to exceed 2.0% of the volume of gas taken into said plant shall be considered to be compliance.

(e) No gas shall be used for plant operation that is not burned in boilers, heaters, or internal combustion engines in a reasonably efficient manner, and no raw gas or residue gas shall be used for plant fuel if any flash vapors are being vented or flared.

(f) No cycling plant shall be operated without a certificate of compliance. The appropriate form submitted to the commission and approved by it shall be in effect for a period of 12 months, but may be renewed for one or more periods of 12 months. The certificate of compliance shall be revoked if an inspection reveals noncompliance.

Source Note: The provisions of this §3.62 adopted to be effective January 1, 1976.

§3.63 Carbon Black Plant Permits Required

(a) Each operator of a carbon black plant shall make application for a permit to operate the plant, using the appropriate form.

(b) No person shall operate a plant for the burning of natural gas in the manufacture of carbon black without a permit authorizing the operation of the plant.

(c) Each 12 months the commission, on application, may grant a permit to each of the operators of carbon black plants for a period of 12 months.

Source Note: The provisions of this §3.63 adopted to be effective January 1, 1976.

§3.65 Critical Designation of Natural Gas Infrastructure

(a) Definitions.

(1) In this section, the term "energy emergency" means any event that results in firm load shed or has the potential to result in firm load shed required by the reliability coordinator of a power region in Texas. An event that has the "potential to result in firm load shed" is when the reliability coordinator of a power region in Texas has issued an Energy Emergency Alert Level 1 or 2.

(2) In this section, the term "critical customer information" means the information required on Commission Form CI-D and any attachments.

(3) In this section, "any volume of gas indicated in Mcf/day" means the average daily production from the well's six most recently filed monthly production reports. Wells without six months of production reports shall average the production from the well's production reports on file with the Commission or use the production volume from the well's initial potential test or deliverability test if the well has not yet filed a production report.

(4) In this section, the term "electricity supply chain map" means the electricity supply chain map produced by the Texas Electricity Supply Chain Security and Mapping Committee.

(5) In this section, the term "Director" means the Director of the Critical Infrastructure Division or the director's delegate.

(6) In this section, the term "EOR project" means an enhanced oil recovery project as defined in §3.50(c)(6) of this title (relating to Enhanced Oil Recovery Projects-Approval and Certification for Tax Incentive) with at least one injection well permitted under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) whether or not the project has received Commission approval or certification under §3.50 of this title.

(b) Critical designation criteria. The following facilities are designated critical during an energy emergency:

(1) Critical Gas Supplier. The following facilities are designated a critical gas supplier:

(A) gas wells producing gas in excess of 250 Mcf/day;

(B) oil leases producing casinghead gas in excess of 500 Mcf/day, except for EOR projects provided the EOR project consumes more energy than it produces calculated by comparing the amount of electricity used to the amount of gas produced both in Million British Thermal Units (MMBTU);

(C) gas processing plants;

(D) natural gas pipelines and pipeline facilities including associated compressor stations and control centers;

(E) local distribution company pipelines and pipeline facilities including associated compressor stations and control centers;

(F) underground natural gas storage facilities;

(G) natural gas liquids transportation and storage facilities; and

(H) saltwater disposal facilities including saltwater disposal pipelines.

(2) Critical Customer. A critical customer is a critical gas supplier that requires electricity delivered by an electric entity to operate. A critical customer is required to provide critical customer information pursuant to subsection (f) of this section to the electric entities described in §25.52(h) of this title (relating to Reliability and Continuity of Service) and Texas Utilities Code §38.074(b)(1) so that those electric entities may prioritize the facilities in accordance with Texas Utilities Code §38.074(b)(2) and (b)(3). Priority for load shed purposes during an energy emergency is described by §25.52(h)(2)

of this title and any guidance issued thereunder by the Public Utility Commission.

(c) Request for critical designation if not designated critical in subsection (b) of this section. A facility that is not designated critical under subsection (b) of this section may write to the Commission to apply to be designated critical if the facility's operation is required in order for another facility designated critical to operate. The applicant shall include objective evidence that the facility's operation is required for another facility designated critical in subsection (b) of this section to operate. The director will review the application and if the application is approved, the facility shall submit Form CI-D. If the request is denied, the applicant may request a hearing.

(d) Acknowledgment of critical status. Except as provided by subsection (e) of this section, an operator of a facility designated as critical under subsection (b) or (c) of this section shall acknowledge the facility's critical status by filing Form CI-D as provided in this subsection. In the year 2022, the Form CI-D acknowledgment shall be filed bi-annually by January 15, 2022, and either September 1, 2022, or 30 days from the date the map is produced by the Texas Electricity Supply Chain Security and Mapping Committee, whichever is later. Beginning in 2023, the Form CI-D acknowledgment shall be filed bi-annually by March 1 and September 1 of each year.

(e) Critical designation exception.

(1) A facility listed in subsection (b) of this section that is not included on the electricity supply chain map produced by the Texas Electricity Supply Chain Security and Mapping Committee may apply for an exception. An applicant shall demonstrate with objective evidence a reasonable basis and justification in support of the application. The Director of the Critical Infrastructure Division will administratively approve or deny a request for an exception. If the request is denied, the Division will notify the applicant and the applicant may request a hearing to challenge the denial. The party requesting the hearing shall have the burden of proof.

(2) Examples of a reasonable basis and justification for which an exception may be granted include, but are not limited to, the following:

(A) All of the natural gas produced at the facility is consumed on site;

(B) All of the natural gas produced, processed, or delivered by the facility is consumed outside of this state;

(C) The facility does not provide gas for third-party use;

(D) For saltwater disposal facilities and saltwater disposal pipelines, the facility or pipeline does not support a facility designated critical in subsection (b)(1)(A)-(G) of this section; or

(E) The electric entity delivering electricity to the facility has provided notice that the facility's request for critical designation status was rejected, denied, or otherwise disapproved by the electric utility; provided, however, that the electric utility communicated its determination in writing, and the decision was for reasons other than the lack of correct identifying information or other administrative reasons.

(3) An applicant for exception shall submit a Form CI-X exception application that identifies each facility for which an exception is requested. The Form CI-X shall be accompanied by an exception application fee. The amount of the fee is $150 as established in Chapter 81, Texas Natural Resources Code.

(A) In the year 2022, the Form CI-X exception application shall be filed bi-annually by January 15, 2022, and either September 1, 2022, or 30 days from the date the map is produced by the Texas Electricity Supply Chain Security and Mapping Committee, whichever is later. Beginning in 2023, the Form CI-X exception application shall be filed bi-annually by March 1 and September 1 of each year.

(B) Once an operator has an approved Form CI-X on file with the Commission, the operator is not required to pay the $150 exception application fee when the operator updates the facilities identified on its Form CI-X.

(f) Providing critical customer information. A critical customer shall provide the critical customer information to the electric entities described in §25.52 of this title and Texas Utilities Code §38.074(b)(1) unless the critical customer is granted an exception under subsection (e) of this section. The critical customer information shall be provided in accordance with §25.52 of this title. The operator shall certify on its Form CI-D that it has provided the critical customer information to its electric entity.

(g) Confidentiality of information filed pursuant to this section. A person filing information with the Commission that the person contends is confidential by law shall notify the Commission on the applicable form. If the Commission receives a request under the Texas Public Information Act (PIA), Texas Government Code, Chapter 552, for materials that have been designated confidential, the Commission will notify the filer of the request in accordance with the provisions of the PIA so that the filer can take action with the Office of the Attorney General to oppose release of the materials.

(h) Exceptions not transferable. Exceptions are not transferable upon a change of operatorship. When a facility is transferred, both the transferor operator and the transferee operator shall ensure the transfer is reflected on each operator's Form CI-D or Form CI-X when the applicable form update is submitted in accordance with the bi-annual filing timelines in subsections (d) and (e) of this section. If the facility has an exception under subsection (e) of this section, the exception shall remain in effect until the next bi-annual filing deadline. If the transferee operator seeks to continue the exception beyond that time period, the transferee operator shall indicate the transferred facility on the Form CI-X pursuant to subsection (e) of this section.

(i) Failure to file or provide required information. An operator who fails to comply with this section may be subject to penalties under §3.107 of this title (relating to Penalty Guidelines for Oil and Gas Violations).

Source Note: The provisions of this §3.65 adopted to be effective December 20, 2021, 46 TexReg 8688; amended to be effective November 21, 2022, 47 TexReg 7661.

§3.66. Weather Emergency Preparedness Standards

(a) Applicability.

(1) In accordance with Texas Natural Resources Code §86.044, this section applies to a gas supply chain facility that is:

(A) included on the electricity supply chain map created under Texas Utilities Code §38.203; and

(B) designated as critical in §3.65 of this title, relating to Critical Designation of Natural Gas

Infrastructure.

(2) In accordance with Texas Utilities Code §121.2015, this section applies to a gas pipeline facility that:

(A) directly serves a natural gas electric generation facility operating solely to provide power to the electric grid for the Electric Reliability Council of Texas (ERCOT) power region or for the ERCOT power region and an adjacent power region; and

(B) is included on the electricity supply chain map created under Texas Utilities Code §38.203.

(b) Definitions. In this section, the following definitions apply.

(1) Critical component--Any component, including components on equipment rented or leased from a third party, that is susceptible to weather-related interruptions, such as those caused by freezing temperatures, freezing precipitation, or extreme heat, the occurrence of which is likely to significantly hinder sustained operation of the gas pipeline or gas supply chain facility.

(2) Gas pipeline facility--A pipeline or pipeline facility regulated by the Commission under Texas Utilities Code Chapter 121.

(3) Gas supply chain facility--A facility that is:

(A) used for producing, treating, processing, pressurizing, storing, or transporting natural gas, as well as handling waste produced;

(B) not primarily used to support liquefied natural gas pretreatment, liquefaction, or regasification facilities in the business of exporting or importing liquefied natural gas to or from foreign countries;

(C) otherwise regulated by the Commission under Subtitle B of Title 3, Texas Natural Resources Code; and

(D) not regulated by the Commission under Texas Utilities Code Chapter 121.

(4) Major weather-related forced stoppage--A weather-related forced stoppage during a weather emergency that is the result of the deliberate disregard of this section or that results in:

(A) a loss of production exceeding 5,000 Mcf of natural gas per day per oil lease;

(B) a loss of production exceeding 5,000 Mcf of natural gas per day per gas well;

(C) a loss of gas processing capacity exceeding 200 MMcf per day;

(D) a loss of storage withdrawal capacity exceeding 200 MMcf per day; or

(E) a loss of transportation capacity exceeding 200 MMcf per day.

(5) Repeated weather-related forced stoppage--When a gas supply chain facility or a gas pipeline facility has more than one major weather-related forced stoppage or weather-related forced stoppage violation within a 12-month period.

(6) Sustained operation--Safe operation of a gas supply chain facility or a gas pipeline facility such that the facility does not experience a major weather-related forced stoppage or weather-related forced stoppage in production, treating, processing, storage, or transportation of natural gas.

(7) Weather emergency--Weather conditions such as freezing temperatures, freezing precipitation, or extreme heat in the facility's county or counties that result in an energy emergency as defined by §3.65 of this title. A weather emergency does not include weather conditions that cannot be reasonably mitigated such as tornadoes, floods, or hurricanes.

(8) Weatherization--The iterative cycle of preparedness for sustained operation during weather emergencies that includes:

(A) correcting critical component failures that occurred during previous weather emergencies;

(B) installing equipment to mitigate weather-related operational risks; and

(C) internal inspection, self-assessment, and implementation of processes to identify, test, and protect critical components.

(9) Weather-related forced stoppage--An unanticipated and/or unplanned outage in the production, treating, processing, storage, or transportation of natural gas that is caused by weather conditions such as freezing temperatures, freezing precipitation, or extreme heat and occurs during a weather emergency.

(c) Weather emergency preparedness standards for a gas supply chain facility or a gas pipeline facility.

(1) By December 1st of each year, a gas supply chain facility operator or a gas pipeline facility operator shall implement weather emergency preparation measures intended to:

(A) ensure the sustained operation of a gas supply chain facility or a gas pipeline facility during a weather emergency; and

(B) correct known major weather-related forced stoppages and weather-related forced stoppages that prevented sustained operation of a facility because of previous weather emergencies.

(2) Weather emergency preparation measures required by paragraph (1) of this subsection shall include:

(A) providing training on weather emergency preparations and operations to relevant operational personnel;

(B) consideration of the risk to the health and safety of employees and protection of the environment; and

(C) weatherization of the facility using methods a reasonably prudent operator would take given the type of facility, the age of the facility, the facility's critical components, the facility's location, and weather data for the facility's county or counties such as data developed for the Commission by the state climatologist. The Commission will periodically publish weatherization practices and may include weather data developed for the Commission by the state climatologist.

(d) Weather Emergency Readiness Attestation. By December 1 of each year, an operator of a gas supply chain facility or a gas pipeline facility shall submit to the Commission a Weather Emergency Readiness Attestation that:

(1) is signed by an authorized representative of the operator entity attesting, under penalties prescribed in Texas Natural Resources Code §91.143, that:

(A) the operator implemented the required weather emergency preparation measures described in subsection (c) of this section;

(B) the information and statements made in the Weather Emergency Readiness Attestation are true, correct, and complete to the best of the attestor's knowledge;

(C) the representative is authorized to sign the attestation on behalf of the operator entity; and

(D) the Weather Emergency Readiness Attestation was prepared by the authorized representative or under the authorized representative's supervision and direction;

(2) includes an attachment describing all activities engaged in by the operator to implement the requirements of subsection (c) of this section, including a description of the weatherization methods utilized by the operator to weatherize each type of facility; and

(3) for the Weather Emergency Readiness Attestation due December 1, 2022, also describes corrective actions taken to mitigate known major weather-related forced stoppages and weather-related forced stoppages that prevented sustained operation of a facility because of previous weather emergencies.

(e) Inspection of gas supply chain facilities and gas pipeline facilities. Beginning December 1, 2022, the Commission will inspect facilities to ensure compliance with this section and will prioritize inspections of oil leases and gas wells producing greater than 5,000 Mcf per day of natural gas and facilities storing, processing, or transporting greater than 200 MMcf per day of natural gas. The Commission will further prioritize inspections in descending order in accordance with a facility's production volume or storage, processing, or transportation capacity.

(f) Notifications and other requirements for gas supply chain facilities and gas pipeline facilities.

(1) An operator of a gas supply chain facility or a gas pipeline facility that experiences either of the following during a weather emergency shall notify the Commission immediately through the Critical Infrastructure Division's notification portal if the stoppage is not resolved within 24 hours of discovery of the stoppage:

(A) a weather-related forced stoppage; or

(B) a forced stoppage caused by a loss of electricity.

(2) An operator of a gas supply chain facility or gas pipeline facility that experiences either of the following during a weather emergency shall, within one hour of discovery of the stoppage, contact the Commission through the Critical Infrastructure Division's 24-hour emergency telephone number. Subsequent to the phone call, the operator shall submit a notification through the Critical Infrastructure Division's notification portal:

(A) a major weather-related forced stoppage; or

(B) a forced stoppage caused by a loss of electricity that results in the same volume of loss in natural gas production, withdrawal capacity, processing capacity, or transportation capacity as a major weather-related forced stoppage.

(3) The notification of the major weather-related forced stoppage or weather-related forced stoppage may include information such as any third-party issues that may have directly contributed to the stoppage, if applicable.

(4) A gas supply chain facility or a gas pipeline facility that is determined to have experienced repeated weather-related forced stoppages or major weather-related forced stoppages in sustained operation during a weather emergency shall comply with this paragraph. Upon notice from the Commission that the facility is required to comply with this paragraph, the facility's operator shall contract with a person with related experience to assess the facility's weather emergency preparation measures, plans, procedures, and operations. The person with related experience shall not be an employee of the facility or its affiliate and shall not have participated in any assessments of the facility for at least the previous five years, unless the facility's operator can document that no other persons with related experience are reasonably available for engagement. Within the timeframe provided by the Commission, the operator shall submit to the Commission a written assessment prepared by the person and the facility operator's corrective action plan in compliance with the terms in the Commission's notice that the facility is required to comply with this paragraph.

(g) Enforcement.

(1) Violation of this section by a gas supply chain facility operator. If a major weather-related forced stoppage or weather-related forced stoppage was caused by a gas supply chain facility's failure to adhere to the requirements of this section, the facility's operator will be subject to an enforcement action. A gas supply chain facility operator will be given notice and opportunity for a hearing for alleged violations of this section. The notice will be sent by certified mail and state the facts or conduct alleged to comprise the violation. The notice will give the operator 30 days from receipt to request a hearing. Pursuant to Texas Natural Resources Code §86.044 and §§86.222-.224, if after notice and opportunity for a hearing, the Commission determines that an operator has violated this section and the violation is not remedied in a reasonable amount of time, the Commission shall notify the Office of the Attorney General of Texas of the violation in accordance with Texas Natural Resources Code §86.222. The table in this paragraph contains a classification system to be used under Texas Natural Resources Code §86.222 for violations of this section. The penalty for each violation may be up to $1,000,000.

Figure: 16 TAC §3.66(g)(1) ***[See Figure at the end of this document.]***

(2) Violation of this section by a gas pipeline facility operator.

(A) If a major weather-related forced stoppage or weather-related forced stoppage was caused by a gas pipeline facility's failure to adhere to the requirements of this section, the facility's operator will be subject to an enforcement action. A gas pipeline facility operator will be given notice and opportunity for a hearing for alleged violations of this section. The notice will be sent by certified mail and state the facts or conduct alleged to comprise the violation. The notice will give the operator 30 days from receipt to request a hearing. Pursuant to Texas Utilities Code §121.2015, if after notice and opportunity for a hearing, the Commission determines that an operator has violated this section and the violation is not remedied in a reasonable amount of time, the Commission shall report the violation to the Office of the Attorney General of Texas. Pursuant to Texas Utilities Code §121.206, the Commission shall assess an administrative penalty for a violation of this section, which may be up to $1,000,000 for each offense. Each day a violation continues constitutes a separate offense.

(B) In accordance with Texas Utilities Code §121.206(d), the Commission will use the table in paragraph (1) of this subsection in assessing penalties for a violation of this section. The penalty amounts contained in the table in paragraph (1) of this subsection are provided solely as guidelines to be considered by the Commission in determining the amount of administrative penalties for violations of Texas Utilities Code, Chapter 121, Subchapter E, or a safety standard or other rule prescribed or adopted under that subchapter. The establishment of these penalty guidelines shall in no way limit the

Commission's authority and discretion to cite violations and assess administrative penalties. The Commission retains full authority and discretion to cite violations of Texas Utilities Code, Chapter 121, Subchapter E, or a safety standard or other rule prescribed or adopted under that subchapter, and to assess administrative penalties in any amount up to the statutory maximum when warranted by the facts in any case, regardless of inclusion in or omission from this section. The penalty calculation worksheet shown in the table in paragraph (1) of this subsection lists the typical penalty amounts for certain violators, the circumstances justifying enhancements of a penalty, and the circumstances justifying a reduction in a penalty.

(h) Confidentiality. If a gas supply chain facility operator or a gas pipeline facility operator filing information required by this section contends certain information is confidential by law, the operator shall file a complete version of the required information and a version for public inspection in which the confidential information has been redacted. If the Commission receives a request under the Texas Public Information Act (PIA), Texas Government Code, Chapter 552, for materials that have been designated confidential, the Commission will notify the filer of the request in accordance with the provisions of the PIA so that the filer can take action with the Office of the Attorney General to oppose release of the materials.

Source Note: The provisions of this §3.66 adopted to be effective September 19, 2022, 47 TexReg 5781

§3.70 Pipeline Permits Required

(a) Each operator of a pipeline or gathering system, other than an operator excluded under §8.1(b)(4) of this title (relating to General Applicability and Standards), subject to the jurisdiction of the Commission, shall obtain a pipeline permit, to be renewed annually, from the Commission as provided in this rule. Production or flow lines that are subject to §8.1(a)(1)(B) and (D) of this title must comply with this section. All other production or flow lines as defined in this subsection are exempt from complying with this section. A production or flow line is piping used for production operations that generally occur upstream of gathering or other pipeline facilities. For the purposes of this subsection, piping used in "production operations" means piping used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids, and includes the following processes:

(1) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement; and

(2) associated production compression, gas lift, gas injection, or fuel gas supply.

(b) To obtain a new pipeline permit or to amend a permit because of a change of classification, an operator shall file an application for a pipeline permit on the Commission's online permitting system. The operator shall include or attach the following documentation and information:

(1) the contact information for the individual who can respond to any questions concerning the pipeline's construction, operation or maintenance;

(2) the requested classification and purpose of the pipeline or pipeline system as a common carrier, a gas utility or a private line;

(3) a sworn statement from the pipeline applicant providing the operator's factual basis supporting the classification and purpose being sought for the pipeline, including, if applicable, an attestation to the applicant's knowledge of the eminent domain provisions in Texas Property Code, Chapter 21, and the Texas Landowner's Bill of Rights as published by the Office of the Attorney General of Texas;

(4) documentation to provide support for the classification and purpose being sought for the pipeline, if applicable; and

(5) any other information requested by the Commission.

(c) To renew an existing permit, to amend an existing permit for any reason other than a change in classification, or to cancel an existing permit, an operator shall file an application for a pipeline permit on the Commission's online filing system. The operator shall include or attach:

(1) the contact information for the individual who can respond to any questions concerning the pipeline's construction, operation, or maintenance; change in operator or ownership; or other change including operator cessation of pipeline operation;

(2) a statement from the pipeline operator confirming the current classification and purpose of the pipeline or pipeline system as a common carrier, a gas utility or a private line, if applicable; and

(3) any other information requested by the Commission.

(d) Upon receipt of a complete permit application, the Commission has 30 calendar days to issue, amend, or deny the pipeline permit as filed. If the Commission determines that the application is incomplete, the Commission shall promptly notify the applicant of the deficiencies and specify the additional information necessary to complete the application. Upon receipt of a revised application, the Commission has 30 calendar days to determine if the application is complete and issue, amend, or deny the pipeline permit as filed.

(e) If the Commission is satisfied from the application and the documentation and information provided in support thereof, and its own review, that the proposed line is or will be laid, equipped, managed and operated in accordance with the laws of the state and the rules and regulations of the Commission, the permit may be granted. The pipeline permit, if granted, shall classify the pipeline as a common carrier, a gas utility, or a private pipeline based upon the information and documentation submitted by the applicant and the Commission's review of the application.

(f) This rule applies to applications made for new pipeline permits and to amendments, renewals, and cancellations of existing pipeline permits. The classification of a pipeline under this rule applies to extensions, replacements, and relocations of that pipeline.

(g) The Commission may delegate the authority to administratively issue pipeline permits.

(h) The pipeline permit, if granted, shall be revocable at any time after a hearing, held after 10 days' notice, if the Commission finds that the pipeline is not being operated in accordance with the laws of the state and the rules and regulations of the Commission including if the permit is not renewed annually as required in subsection (a) of this section.

(i) Each pipeline operator shall pay an annual fee based on the pipeline operator's permitted mileage of pipeline not later than April 1 of each year.

(1) For purposes of calculating the mileage fee, the Commission will categorize pipelines into two groups.

(A) Group A includes transmission and gathering pipelines that are required by Commission rules to have a valid T-4 permit to operate and are subject to the regulations in 49 CFR Parts 192 and 195, such as natural gas transmission and storage pipelines, natural gas gathering pipelines defined as Type A, Type B, or Type C in 49 CFR §192.8, hazardous liquids transmission and storage pipelines, regulated rural hazardous liquids gathering pipelines under 49 CFR §195.11, and hazardous liquid low-stress rural pipelines under 49 CFR §195.12.

(B) Group B includes pipelines that are required by Commission rules to have a valid T-4 permit to operate but are only subject to the reporting requirements in 49 CFR Parts 191 and 195 such as Type R gathering pipelines as defined in 49 CFR §192.8, and reporting-regulated-only gathering lines as defined in 49 CFR §195.15.

(2) An operator of a Group A pipeline shall pay an annual fee of $20 per mile of pipeline based on the number of miles permitted to that operator as of December 31 of each year.

(3) An operator of a Group B pipeline shall pay an annual fee of $10 per mile of pipeline based on the number of miles permitted to that operator as of December 31 of each year.

(4) Any pipeline distance that is a fraction of a mile will be considered as one mile and will be assessed a $20 or $10 fee, as appropriate.

(5) Fees due to the Commission for mileage transferred from one operator to another operator pursuant to subsection (o) of this section will be captured in the next mileage fee to be calculated on the following December 31 and paid by the new operator.

(j) Each pipeline operator shall pay a $500 permit processing fee for each new permit application and permit renewal. Each operator shall file the annual renewals as follows:

(1) Companies with names beginning with letters A through C shall file in February;

(2) Companies with names beginning with letters D through E shall file in March;

(3) Companies with names beginning with letters F through L shall file in April;

(4) Companies with names beginning with letters M through P shall file in May;

(5) Companies with names beginning with letters Q through T shall file in June; and

(6) Companies with names beginning with letters U through Z and companies with names beginning with numerical values or other symbols shall file in July.

(k) Each operator shall comply with the following:

(1) If a permit is transferred, in the Commission fiscal year of the transfer the acquiring operator shall renew that permit in its designated month pursuant to subsection (j) of this section. If the acquiring operator receives a transferred permit in a Commission fiscal year and its renewal month has already passed, the acquiring operator shall pay the renewal fee upon transfer.

(2) If an operator adds a new permit and pays the new permit fee, the operator is not required to pay the renewal fee for that permit in the same Commission fiscal year.

(3) If an operator adds a new permit after its renewal month has passed, the new permit shall be renewed the following Commission fiscal year in the operator's designated month pursuant to subsection (j) of this section.

(l) A pipeline operator who fails to renew a permit on or before the renewal deadline which is the last day of the operator's required filing month as specified in subsection (j) of this section shall pay a late-filing fee as follows:

(1) $250, if the renewal application is received within 30 calendar days after the renewal deadline date;

(2) $500, if the renewal application is received more than 30 calendar days and no more than 60 calendar days after the renewal deadline date; and

(3) $700, if the renewal application is received more than 60 calendar days after the renewal deadline date.

(4) If the renewal application is not received within 90 calendar days of the renewal deadline date, the Commission may assess a penalty and/or revoke the operator's permit in accordance with subsection (h) of this section.

(m) A pipeline operator with a total mileage of 50 miles or less of pipeline who fails to pay the annual mileage fee as specified in subsection (i) of this section shall pay a late-filing fee as follows:

(1) $125, if the fee is received within 30 calendar days of April 1;

(2) $250, if the fee is received more than 30 calendar days and no more than 60 calendar days after April 1; and

(3) $350, if the fee is received more than 60 calendar days after April 1.

(4) If the fee is not received within 90 calendar days of April 1, the Commission may assess a penalty and/or revoke the operator's permit in accordance with subsection (h) of this section.

(n) A pipeline operator with a total mileage of more than 50 miles of pipeline who fails to pay the annual mileage fee shall pay a late-filing fee as follows:

(1) $250, if the fee is received within 30 calendar days of August 31 for the initial year that the requirement is in effect and April 1 for each subsequent year;

(2) $500, if the fee is received more than 30 calendar days and no more than 60 calendar days after August 31 for the initial year that the requirement is in effect and April 1 for each subsequent year; and

(3) $700, if the fee is received more than 60 calendar days after August 31 for the initial year that the requirement is in effect and April 1 for each subsequent year.

(4) If the fee is not received within 90 calendar days of August 31 for the initial year that the requirement is in effect or April 1 for each subsequent year, the Commission may assess a penalty and/or revoke the operator's permit in accordance with subsection (h) of this section.

(o) A pipeline operator who has been issued a permit and is transferring the pipeline or a portion of the pipeline included on the permit to another operator shall file a notification of transfer with the Commission within 30 days following the transfer. The transferee and transferor operators shall file a fully executed Form T-4B as a notification of transfer. The Commission may use a fully executed Form T-4B to remove the pipeline that is the subject of the transfer from the transferor operator and assign the mileage to the transferee operator for calculation of the annual mileage fee. The transferee operator shall amend its permit to include the pipeline or portion of the pipeline within 30 days following the Commission's approval of the transfer or the operator may be subject to a penalty for operating without a permit pursuant to subsection (p) of this section.

(1) A transferee operator may file a Form T-4B signed only by the transferee operator as a notification of transfer with the Commission only upon presenting to the Commission for its review, concurrently with Form T-4B:

(A) evidence that the transferee operator made a good faith effort to procure the transferor operator's signature; and

(B) documentation establishing that the transferee operator has a legal right to operate the pipeline.

(2) Prior to approving a single-signature Form T-4B filed pursuant to paragraph (1) of this subsection, the Commission shall issue notice to the transferor operator, providing the operator 15 days to contest the transfer and request a hearing. Upon receipt of a timely response requesting a hearing, the matter shall be referred to the Hearings Division for adjudication as a contested case.

(p) A pipeline operator who operates a pipeline without a permit, with an expired permit, or who otherwise fails to comply with this section, may be assessed a penalty as prescribed in §8.135 of this title (relating to Penalty Guidelines for Pipeline Safety Violations).

(q) Interstate pipelines are exempt from the fee requirements of this section.

(r) Beginning December 9, 2024, operators shall comply with the following.

(1) All gas permits shall be amended to include all gas gathering pipelines defined as Type A, Type B, Type C, or Type R in 49 CFR §192.8. The permit amendments shall be filed on the Commission's online permitting system by March 31, 2025. The amendment shapefile shall indicate each segment as Type A, Type B, Type C, or Type R, and include any other information requested by the Commission.

(2) A gas permit will not be eligible for renewal if the permit has not been amended by March 31, 2025, in accordance with paragraph (1) of this subsection. If the gas permit does not have any gas gathering pipelines to be amended or added, the operator shall include with its 2025 renewal submission a statement on the submitted cover letter attesting to that fact. The Commission may request additional information as necessary to confirm the statement.

Source Note: The provisions of this §3.70 adopted to be effective August 25, 2003, 28 TexReg 6816; amended to be effective March 1, 2015, 39 TexReg 9969; amended to be effective June 25, 2018, 43 TexReg 4169; amended to be effective January 6, 2020, 45 TexReg 119; amended to be effective December 9, 2024, 49 TexReg 9958

§3.71 Pipeline Tariffs

Every person owning, operating, or managing any pipeline, or any part of any pipeline, for the gathering, receiving, loading, transporting, storing, or delivering of crude petroleum as a common carrier shall be subject to and governed by the following provisions. Common carriers specified in this section shall be referred to as "pipelines," and the owners or shippers of crude petroleum by pipelines shall be referred to as "shippers."

(1) All marketable oil to be received for transportation. By the term "marketable oil" is meant any crude petroleum adapted for refining or fuel purposes, properly settled and containing not more than 2.0% of basic sediment, water, or other impurities above a point six inches below the pipeline connection with the tank. Pipelines shall receive for transportation all such "marketable oil" tendered; but no pipeline shall be required to receive for shipment from any one person an amount exceeding 3,000 barrels of petroleum in any one day; and, if the oil tendered for transportation differs materially in character from that usually produced in the field and being transported therefrom by the pipeline, then it shall be transported under such terms as the shipper and the owner of the pipeline may agree or the commission may require.

(2) Basic sediment, how determined--temperature. In determining the amount of sediment, water, or other impurities, a pipeline is authorized to make a test of the oil offered for transportation from an average sample from each such tank, by the use of centrifugal machine, or by the use of any other appliance agreed upon by the pipeline and the shipper. The same method of ascertaining the amount of the sediment, water, or other impurities shall be used in the delivery as in the receipt of oil. A pipeline shall not be required to receive for transportation, nor shall consignee be required to accept as a delivery, any oil of a higher temperature than 90 degrees Fahrenheit, except that during the summer oil shall be received at any atmospheric temperature, and may be delivered at like temperature. Consignee shall have the same right to test the oil upon delivery at destination that the pipeline has to test before receiving from the shipper.

(3) "Barrel" defined. For the purpose of these sections, a "barrel" of crude petroleum is declared to be 42 gallons of 231 cubic inches per gallon at 60 degrees Fahrenheit.

(4) Oil involved in litigation, etc.--indemnity against loss. When any oil offered for transportation is involved in litigation, or the ownership is in dispute, or when the oil appears to be encumbered by lien or charge of any kind, the pipeline may require of shippers an indemnity bond to protect it against all loss.

(5) Storage. Each pipeline shall provide, without additional charge, sufficient storage, such as is incident and necessary to the transportation of oil, including storage at destination or so near thereto as to be available for prompt delivery to destination point, for five days from the date of order of delivery at destination.

(6) Identity of oil, maintenance of oil. A pipeline may deliver to consignee either the identical oil received for transportation, subject to such consequences of mixing with other oil as are incident to the usual pipeline transportation, or it may make delivery from its common stock at destination; provided, if this last be done, the delivery shall be of substantially like kind and market value.

(7) Minimum quantity to be received. A pipeline shall not be required to receive less than one tank car-load of oil when oil is offered for loading into tank cars at destination of the pipeline. When oil is offered for transportation for other than tank car delivery, a pipeline shall not be required to receive less than 500 barrels.

(8) Gathering charges. Tariffs to be filed by a pipeline shall specify separately the charges for gathering of the oil, for transportation, and for delivery.

(9) Measuring, testing, and deductions (reference Special Order Number 20-63,098 effective June 18, 1973).

(A) Except as provided in subparagraph (B) of this paragraph, all crude oil tendered to a pipeline shall be gauged and tested by a representative of the pipeline prior to its receipt by the pipeline. The shipper may be present or represented at the gauging or testing. Quantities shall be computed from correctly compiled tank tables showing 100% of the full capacity of the tanks.

(B) As an alternative to the method of measurement provided in subparagraph (A) of this paragraph, crude oil and condensate may be measured and tested, before transfer of custody to the initial transporter, by:

(i) lease automatic custody transfer (LACT) equipment, provided such equipment is installed and operated in accordance with the latest revision of American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 6.1, or;

(ii) any device or method, approved by the commission or its delegate, which yields accurate measurements of crude oil or condensate.

(C) Adjustments to the quantities determined by the methods described in subparagraphs (A) or (B) of this paragraph shall be made for temperature from the nearest whole number degree to the basis of 60 degrees Fahrenheit and to the nearest 5/10 API degree gravity in accordance with the volume correction Tables 5A and 6A contained in API Standard 2540, American Society for Testing Materials 01250, Institute of Petroleum 200, first edition, August 1980. A pipeline may deduct the basic sediment, water, and other impurities as shown by the centrifugal or other test agreed upon by the shipper and pipeline; and 1.0% for evaporation and loss during transportation. The net balance shall be the quantity deliverable by the pipeline. In allowing the deductions, it is not the intention of the commission to affect any tax or royalty obligations imposed by the laws of Texas on any producer or shipper of crude oil.

(D) A transfer of custody of crude between transporters is subject to measurement as agreed upon by the transporters.

(10) Delivery and demurrage. Each pipeline shall transport oil with reasonable diligence, considering the quality of the oil, the distance of transportation, and other material elements, but at any time after receipt of a consignment of oil, upon 24 hours' notice to the consignee, may offer oil for delivery from its common stock at the point of destination, conformable to paragraph (6) of this section, at a rate not exceeding 10,000 barrels per day of 24 hours. Computation of time of storage (as provided for in paragraph (5) of this section) shall begin at the expiration of such notice. At the expiration of the time allowed in paragraph (5) of this section for storage at destination, a pipeline may assess a demurrage charge on oil offered for delivery and remaining undelivered, at a rate for the first 10 days of $.001 per barrel; and thereafter at a rate of $.0075 per barrel, for each day of 24 hours or fractional part thereof.

(11) Unpaid charges, lien for and sale to cover. A pipeline shall have a lien on all oil to cover charges for transportation, including demurrage, and it may withhold delivery of oil until the charges are paid. If the charges shall remain unpaid for more than five days after notice of readiness to deliver, the pipeline may sell the oil at public auction at the general office of the pipeline on any day not a legal holiday. The date for the sale shall be not less than 48 hours after publication of notice in a daily newspaper of general circulation published in the city where the general office of the pipeline is located. The notice shall give the time and place of the sale, and the quantity of the oil to be sold. From the proceeds of the sale, the pipeline may deduct all charges lawfully accruing, including demurrage, and all expenses of the sale. The net balance shall be paid to the person lawfully entitled thereto.

(12) Notice of claim. Notice of claims for loss, damage, or delay in connection with the shipment of oil must be made in writing to the pipeline within 91 days after the damage, loss, or delay occurred. If the claim is for failure to make delivery, the claim must be made within 91 days after a reasonable time for delivery has elapsed.

(13) Telephone-telegraph line--shipper to use. If a pipeline maintains a private telegraph or telephone line, a shipper may use it without extra charge, for messages incident to shipments. However, a pipeline shall not be held liable for failure to deliver any messages away from its office or for delay in transmission or for interruption of service.

(14) Contracts of transportation. When a consignment of oil is accepted, the pipeline shall give the shipper a run ticket, and shall give the shipper a statement that shows the amount of oil received for transportation, the points of origin and destination, corrections made for temperature, deductions made for impurities, and the rate for such transportation.

(15) Shipper's tanks, etc.--inspection. When a shipment of oil has been offered for transportation the pipeline shall have the right to go upon the premises where the oil is produced or stored, and have access to any and all tanks or storage receptacles for the purpose of making any examination, inspection, or test authorized by this section.

(16) Offers in excess of facilities. If oil is offered to any pipeline for transportation in excess of the amount that can be immediately transported, the transportation furnished by the pipeline shall be apportioned among all shippers in proportion to the amounts offered by each; but no offer for transportation shall be considered beyond the amount which the person requesting the shipment then has ready for shipment by the pipeline. The pipeline shall be considered as a shipper of oil produced or purchased by itself and held for shipment through its line, and its oil shall be entitled to participate in such apportionate.

(17) Interchange of tonnage. Pipelines shall provide the necessary connections and facilities for the exchange of tonnage at every locality reached by two or more pipelines, when the commission finds that a necessity exists for connection, and under such regulations as said commission may determine in each case.

(18) Receipt and delivery--necessary facilities for. Each pipeline shall install and maintain facilities for the receipt and delivery of marketable crude petroleum of shippers at any point on its line if the commission finds that a necessity exists therefor, and under regulations by the commission.

(19) Reports of loss from fires, lightning, and leakage.

(A) Each pipeline shall immediately notify the commission district office, electronically or by telephone, of each fire that occurs at any oil tank owned or controlled by the pipeline, or of any tank struck by lightning. Each pipeline shall in like manner report each break or leak in any of its tanks or pipelines from which more than five barrels escape. Each pipeline shall file the required information with the commission in accordance with the appropriate commission form within 30 days from the date of the spill or leak.

(B) No risk of fire, storm, flood, or act of God, and no risk resulting from riots, insurrection, rebellion, war, or act of the public enemy, or from quarantine or authority of law or any order, requisition or necessity of the government of the United States in time of war, shall be borne by a pipeline, nor shall any liability accrue to it from any damage thereby occasioned. If loss of any crude oil from any such causes occurs after the oil has been received for transportation, and before it has been delivered to the consignee, the shipper shall bear a loss in such proportion as the amount of his shipment is to all of the oil held in transportation by the pipeline at the time of such loss, and the shipper shall be entitled to have delivered only such portion of his shipment as may remain after a deduction of his due proportion of such loss, but in such event the shipper shall be required to pay charges only on the quantity of oil delivered. This section shall not apply if the loss occurs because of negligence of the pipeline.

(C) Common carrier pipelines shall mail (return receipt requested) or hand deliver to landowners (persons who have legal title to the property in question) and residents (persons whose mailing address is the property in question) of land upon which a spill or leak has occurred, all spill or leak reports required by the commission for that particular spill or leak within 30 days of filing the required reports with the commission. Registration with the commission by landowners and residents for the purpose of receiving spill or leak reports shall be required every five years, with renewal registration starting January 1, 1999. If a landowner or resident is not registered with the commission, the common carrier is not required to furnish such reports to the resident or landowner.

(20) Printing and posting. Each pipeline shall have paragraphs (1) - (19) of this section printed on its tariff sheets, and shall post the printed sections in a prominent place in its various offices for the inspection of the shipping public. Each pipeline shall post and publish only such rules and regulations as may be adopted by the commission as general rules or such special rules as may be adopted for any particular field.

(21) Immediately upon the publication of its tariffs, and each subsequent amendment thereof, each pipeline is requested to file one copy with the commission.

(22) Records.

(A) Each person operating crude oil gathering, transportation, or storage facilities in the state must maintain daily records of the quantities of all crude oil moved from each oil field in the state, and such records shall also show separately for each field to whom delivery is made, and the quantities so delivered.

(B) The information contained in the records thus required to be kept must be reported to the commission by the gatherers, transporters, and handlers at such times and in such manner as may be required by the commission.

Source Note: The provisions of this §3.71 adopted to be effective August 25, 2003, 28 TexReg 6816.

§3.72 Obtaining Pipeline Connections

(a) A common carrier pipeline transporting crude oil in Texas, upon application for connection and offer of crude oil by a producer or persons owning unconnected lease batteries, shall connect such lease batteries in the following instances:

(1) when such request is made for connection of lease batteries in the general area served by a common carrier, which is an affiliate or subsidiary of a common purchaser, as defined in the Texas Natural Resources Code, §111.081; and

(2) within individual fields, when any common carrier possesses the only pipeline serving such field or common reservoir and request is made for connection of an unconnected lease battery in the field, provided, that for just cause a common carrier pipeline may apply for an exception. If proper application has been made for such connection and the common carrier pipeline refuses to connect the unconnected lease battery, a complaint for failure to connect may be filed with the commission by the person seeking the connection. The complaining person may allege discrimination or noncompliance with the provisions of this subsection or the appropriate section(s) of the Texas Natural Resources Code.

(b) Whether the matter comes to the commission either as an application for exception by the pipeline or on a complaint for failure to connect, at least 10 days' notice shall be given to all interested parties, after which the hearing shall be held. At the hearing, the commission may require and consider, among other factors, evidence relating to ability of the pipeline carrier to transport the quality of oil, the market or lack of market for the proffered oil, and the period required to return the capital investment for the connection. It is not its intention to limit, nor does the commission herein limit, the consideration by it of any facts with respect to a claim of violation of, or of any facts that may constitute a cause of action for violation of, any of the provisions of Texas Natural Resources Code, §§11.001-11.136, whether enumerated in this section or not.

Source Note: The provisions of this §3.72 adopted to be effective August 25, 2003, 28 TexReg 6816.

§3.73 Pipeline Connection; Cancellation of Certificate of Compliance; Severance

(a) No pipeline or other carrier shall be connected with any well subject to the jurisdiction of the Commission until the operator of the well provides the pipeline or other carrier with a certificate from the Commission that the rules in this title have been complied with. This section shall not prevent a temporary connection with any well in order to take care of production and prevent waste until the operator has a reasonable time, not to exceed 30 days from the date of such connection, within which to obtain such certificate. For purposes of this section, the term "Commission" means the Railroad Commission of Texas, the Director of the Oil and Gas Division, or the Director's delegate.

(b) No pipeline operator shall physically disconnect its facilities from or cease providing pipeline services to any well or lease without first obtaining:

(1) written consent of the well or lease operator for the proposed disconnect or termination; or

(2) written permission from the Commission. This section does not apply to temporary suspensions of service authorized under other rules in this title or attributable to maintenance, safety, or product quality issues.

(c) If the pipeline operator is unable to obtain the written consent of the well or lease operator to physically disconnect from or cease providing service to the well or lease, or the well or lease operator objects to the proposed physical disconnect or termination of service, and the pipeline operator still desires to physically disconnect from or cease providing service to the well or lease, the pipeline operator shall file an application with the Commission requesting permission to physically disconnect its facilities from or cease providing service to the well or lease. An affected well or lease operator may object to physical disconnection or cessation of service and file a complaint with the Commission under this subsection.

(1) The pipeline operator shall file its application with the Commission at least 30 days prior to the date on which the pipeline operator desires to make the physical disconnection or cease providing service. On the same date as the pipeline operator files its application with the Commission, the pipeline operator shall send a copy of the application to the operator of the well or lease affected by the application by certified mail, return receipt requested. The application shall identify the well operator and pipeline operator, identify each lease or well involved, and provide sufficient information to allow the Commission to make a determination pursuant to paragraph (4) of this subsection.

(2) If the operator of the well or lease does not file with the Commission a written objection to the application within 28 days following the filing of the application, the Commission shall administratively approve or deny the application and shall notify the pipeline operator and the well or lease operator of the decision by certified mail, return receipt requested. Following such notification, either party shall have 21 days to file a written request for hearing. If neither party files a timely request for hearing, the administrative approval or denial shall be deemed final.

(3) If either party files a timely request for hearing, the Commission shall refer the application to the Office of General Counsel docket services to be set for hearing within 60 days following the date of referral.

(4) In determining whether or not to approve a request to physically disconnect from or cease providing service to a well or lease, the Commission may consider relevant factors, including but not limited to:

(A) operational integrity of the pipeline facilities;

(B) operational integrity of the equipment on the well or lease;

(C) cost of continued operation of the physical connection or service;

(D) risk to public safety, human health and the environment;

(E) availability of alternative transportation;

(F) protection of correlative rights; and

(G) prevention of waste.

(d) The Commission may shut in and seal any well, and cancel any certificate of compliance if it appears that the operator of a well has violated or is violating, in connection with the operation of the well, any statutes, rules in this title, permits, or orders of the Commission. Upon receipt of information that indicates operations are being conducted in violation of statutes, rules in this title, or a Commission permit or order, the Commission shall send a notice letter to the operator directing the operator to correct the violation. The letter shall state the facts or conduct alleged to warrant the shut-in and sealing of the well, and cancellation of the certificate of compliance. The letter shall give the operator an opportunity to show compliance with the statutes, rules in this title, or Commission permits or orders. The letter shall be sent by registered or certified mail, and shall indicate the time within which compliance shall be demonstrated or achieved. The time period allowed for the operator to achieve compliance shall not be less than 10 days from the date the notice letter is sent.

(e) Within the time period set out in the notice letter, the operator shall either demonstrate compliance or correct the violation, and notify the Commission of its action.

(f) If the violation is not corrected within the time period set out in the notice letter, the Commission may shut in and seal the well, and cancel the certificate of compliance.

(g) If a certificate of compliance has been cancelled, the Commission may not issue a new certificate of compliance until the owner or operator of the property covered by the certificate of compliance submits to the Commission a reissuance fee as required by §3.78 of this title (relating to Fees and Financial Security Requirements) (Statewide Rule 78); and

(1) the property covered by the certificate is brought into compliance with the statutes, rules in this title, and Commission permits and orders; or

(2) the Commission determines that there are just and equitable grounds for reissuing the certificate.

(h) Pursuant to Texas Natural Resources Code, §91.705, upon notice from the Commission to any operator of a pipeline or other carrier connected to any well subject to the jurisdiction of the Commission that the certificate of compliance applicable to the well has been canceled by the Commission, the operator of the pipeline or other carrier shall disconnect from or suspend service to the well and shall not reconnect to or resume service to that well until a new certificate of compliance has been issued by the Commission. Pursuant to Texas Natural Resources Code, §85.3855, failure to comply with this subsection may subject a person to a penalty of up to $10,000 per violation.

(i) Pursuant to Texas Natural Resources Code, §91.706(a), upon notice from the Commission that a certificate of compliance as to any well has been canceled as provided in this section, the operator of such well shall not use that well for production, injection, or disposal until a new certificate of compliance with respect to the well has been issued by the Commission as provided in this section. Pursuant to Texas Natural Resources Code, §85.3855, failure to comply with this subsection may subject a person to a penalty of up to $10,000 per violation.

(j) Pursuant to Texas Natural Resources Code, §91.706(b), if an operator uses or reports use of a well for production, injection, or disposal for which the operator's certificate of compliance has been canceled, the Commission may refuse to renew the operator's organization report required by Texas Natural Resources Code, §91.142, until the operator pays the fee required pursuant to §3.78(b)(8) of this title (relating to Fees and Financial Security Requirements) and the Commission issues the certificate of compliance required for that well.

(k) The provisions of this section shall be cumulative of other Commission actions and procedures relating to violations of state statutes or Commission permits, rules, and orders, including the authority of the Commission to immediately shut in a well or lease, or to direct the operator to shut in a well or lease, when an emergency exists due to pollution or an imminent threat of harm to people or property.

Source Note: The provisions of this §3.73 adopted to be effective October 28, 2003, 28 TexReg 9241; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective November 26, 2007, 32 TexReg 8452; amended to be effective February 18, 2025, 50 TexReg 835.

§3.76 Commission Approval of Plats for Mineral Development

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Minerals--Oil and/or gas.

(2) Operations site--A surface area of two or more acres that an owner of a possessory mineral interest may use to explore for and produce minerals, which is located in whole or in part within a qualified subdivision, and designated on the subdivision plat.

(3) Possessory mineral interest--A mineral interest that includes the right to use the land surface for exploration and production of minerals.

(4) Qualified subdivision--A tract of land not more than 640 acres:

(A) that is located in a county having a population in excess of 400,000, or in a county having a population in excess of 140,000 that borders a county having a population in excess of 400,000 or located on a barrier island;

(B) that has been subdivided in a manner authorized by law by the surface owners for residential, commercial, or industrial use; and

(C) that contains an operations site for each separate 80 acres within the 640-acre tract and provisions for road and pipeline easements to allow use of the operations sites.

(5) Barrier island--An island bordering on the Gulf of Mexico and entirely surrounded by water.

(b) As provided in subsections (e) and (f) of this section, the surface owners of a parcel of land may restrict use of the surface by the possessory mineral owners if the tract is a qualified subdivision and if a plat of the subdivision has been approved by the Railroad Commission after notice and hearing and filed with the clerk of the county in which the qualified subdivision is to be located.

(c) An application for a hearing under this section must be made in writing and mailed or delivered to the director of the Oil and Gas Division. The application must include:

(1) a jurisdictional statement setting out the facts stated in subsection (a)(4)(A) and (B) of this section;

(2) a statement that the applicant has authority to represent and represents all surface owners of land contained in the proposed qualified subdivision;

(3) the names and addresses of all owners of possessory mineral interests and all mineral lessors of land contained in the proposed qualified subdivision;

(4) a plat of the proposed subdivision showing each proposed 80-acre tract with its operations site, road easements, and pipeline easements and a legible copy thereof no larger than 8 1/2 inches by 11 inches;

(5) a concise description of mineral development in the area, including the number of oil and/or gas wells within 2.5 miles of the boundary of the proposed qualified subdivision and the depths at which each well is completed;

(6) a list of all the Railroad Commission designated oil and/or gas fields, if any, which underlie the proposed qualified subdivision; including the spacing and density requirements. If no Railroad Commission designated fields underlie the qualified subdivision, the application should so state.

(d) The Railroad Commission shall, on proper notice to the applicant and owners of possessory mineral interests and mineral lessors of land contained in the proposed qualified subdivision, hold a hearing on the application to determine the adequacy of the number and location of operations sites and road and pipeline easements. At the hearing on the application, evidence may be presented by the applicant and the owners of possessory mineral interests and mineral lessors. The applicant must carry the burden of proof. After considering the evidence, the commission may approve, reject, or amend the application to ensure that the mineral resources of the subdivision may be fully and effectively developed.

(e) An owner of a possessory mineral interest within a Railroad Commission approved qualified subdivision may use only the surface contained in designated operations sites for exploration, development, and production of minerals and only the designated easements as necessary to adequately use the operations sites.

(f) The owner of the possessory mineral interest may drill wells or extend well bores from an operations site or from a site outside of the qualified subdivision to bottomhole locations vertically beneath the surface of parts of the qualified subdivision other than the operation sites. Such drilling is subject to other applicable commission rules and regulations, and is permissible only to the extent that the operations do not unreasonably interfere with the use of the surface of the qualified subdivision outside the operations site.

(g) Subsections (e) and (f) of this section cease to apply to a subdivision if, by the third anniversary of the date on which the order of the commission becomes final:

(1) the surface owner has not commenced actual construction of roads or utilities within the qualified subdivision; and

(2) a lot within the qualified subdivision has not been sold to a third party.

(h) All or any portion of a qualified subdivision may be amended, replatted, or abandoned by the surface owner. An amendment or replat, however, may not alter, diminish, or impair the usefulness of an operations site or appurtenant road or pipeline easement unless the amendment or replat is approved by the commission. Railroad Commission approval of a replat or amendment may be administratively granted by the director of the Oil and Gas Division, or his delegate, upon submission of items required in subsection (c) of this section and after notice and opportunity for hearing has been afforded to all possessory mineral interest owners and mineral lessors of land contained within the original and/or replatted or amended qualified subdivision.

Source Note: The provisions of this §3.76 adopted to be effective July 10, 2000, 25 TexReg 6487.

§3.78 Fees and Financial Security Requirements

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Violation--Noncompliance with a Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(2) Outstanding violation--A violation for which:

(A) either:

(i) a Commission order finding a violation has been entered and all appeals have been exhausted; or

(ii) an agreed order between the Commission and the organization relating to a violation has been entered; and

(B) one or more of the following conditions still exist:

(i) the conditions that constituted the violation have not been corrected;

(ii) all administrative, civil, and criminal penalties, if any, relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid; or

(iii) all reimbursements of any costs and expenses assessed by the Commission relating to the violation of such Commission rules, orders, licenses, permits, or certificates have not been paid.

(3) Commercial facility--A facility whose owner or operator receives compensation from others for the storage, reclamation, treatment, or disposal of oil field fluids or oil and gas wastes that are wholly or partially trucked or hauled to the facility and whose primary business purpose is to provide these services for compensation if:

(A) the facility is permitted under §3.8 of this title (relating to Water Protection);

(B) the facility is permitted under §3.57 of this title (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials);

(C) the facility is permitted under §3.9 of this title (relating to Disposal Wells) and a collecting pit permitted under §3.8 is located at the facility; or

(D) the facility is permitted under §3.46 of this title (relating to Fluid Injection into Productive Reservoirs) and a collecting pit permitted under §3.8 is located at the facility.

(4) Financial security--An individual performance bond, blanket performance bond, letter of credit, or cash deposit filed with the Commission.

(5) Bay well--Any well under the jurisdiction of the Commission for which the surface location is either:

(A) located in or on a lake, river, stream, canal, estuary, bayou, or other inland navigable waters of the state and which requires plugging by means other than conventional land-based methods, including, but not limited to, use of a barge, use of a boat, dredging, or building a causeway or other access road to bring in the necessary equipment to plug the well; or,

(B) located on state lands seaward of the mean high tide line of the Gulf of Mexico in water of a depth at mean high tide of not more than 100 feet that is sheltered from the direct action of the open seas of the Gulf of Mexico.

(6) Land well--Any well subject to Commission jurisdiction for which the surface location is not in or on inland or coastal waters.

(7) Offshore well--Any well subject to Commission jurisdiction for which the surface location is on state lands in or on the Gulf of Mexico, that is not a bay well.

(8) Officers and owners--Any persons owning or controlling an organization including officers, directors, general partners, sole proprietors, owners of more than 25% ownership interest, any trustee of an organization, and any person determined by a final judgment or final administrative order to have exercised control over the organization.

(9) Letter of credit--An irrevocable letter of credit issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party bank authorized under state or federal law to do business in Texas; and

(C) renewed and continued in effect until the conditions of the letter of credit have been met or its release is approved by the Commission or its authorized delegate.

(10) Bond--A surety instrument issued:

(A) on a Commission-approved form;

(B) by and drawn on a third party corporate surety authorized under state law to issue surety bonds in Texas; and

(C) renewed and continued in effect until the conditions of the bond have been met or its release is approved by the Commission or its authorized delegate.

(11) Well-specific plugging insurance policy--An insurance policy that:

(A) is approved by the Texas Department of Insurance;

(B) is issued by an insurer authorized under state law to issue a well-specific plugging insurance policy in Texas;

(C) names the Commission as the owner and contingent beneficiary of the policy;

(D) names a primary beneficiary who agrees to plug the specified well bore;

(E) is fully prepaid and cannot be canceled or surrendered;

(F) provides that the policy continues in effect until the well bore has been plugged as required by the Commission;

(G) provides that benefits will be paid when, but not before, the specified well bore has been plugged; and

(H) provides that benefits that will equal or exceed:

(i) $2 per foot for each foot of well depth for land wells;

(ii) $60,000 for bay wells; or

(iii) $100,000 for offshore wells.

(12) Director--The director of the Commission's Oil and Gas Division or the director's delegate.

(13) Escrow funds--Funds deposited with the Commission as part of an application for a plugging extension for an inactive land well.

(14) Groundwater protection determination letter--A letter of determination stating the total depth of surface casing required for a well in accordance with Texas Natural Resources Code, §91.011.

(b) Filing fees. The following filing fees are required to be paid to the Railroad Commission.

(1) With each application or materially amended application for a permit to drill, deepen, plug back, or reenter a well, the applicant shall submit to the Commission a nonrefundable fee of:

(A) $200 if the proposed total depth of the well is 2,000 feet or less;

(B) $225 if the proposed total depth of the well is greater than 2,000 feet but less than or equal to 4,000 feet;

(C) $250 if the proposed total depth of the well is greater than 4,000 feet but less than or equal to 9,000 feet; or

(D) $300 if the proposed total depth of the well is greater than 9,000 feet.

(2) An application for a permit to drill, deepen, plug back, or reenter a well will be considered materially amended if the amendment is made for a purpose other than:

(A) to add omitted required information;

(B) to correct typographical errors; or

(C) to correct clerical errors.

(3) An applicant shall submit an additional nonrefundable fee of $150 when requesting that the Commission expedite the application for a permit to drill, deepen, plug back, or reenter a well.

(4) With each individual application for an exception to any rule or rules in this chapter, the applicant shall submit to the Commission a nonrefundable fee of $150, except as provided in paragraph (5) of this subsection.

(5) With each application for an exception to any rule or rules in this chapter that includes an exception to §3.37 of this title (relating to Statewide Spacing Rule) (Statewide Rule 37) or §3.38 of this title (relating to Well Densities) (Statewide Rule 38), the applicant shall submit a nonrefundable fee of $200.

(6) With each application for an oil and gas waste disposal well permit, the applicant shall submit to the Commission a nonrefundable fee of $100 per well.

(7) With each application for a fluid injection well permit, the applicant shall submit to the Commission a nonrefundable fee of $200 per well. Fluid injection well means any well used to inject fluid or gas into the ground in connection with the exploration or production of oil or gas other than an oil and gas waste disposal well.

(8) If a certificate of compliance for a well or a lease has been canceled for violation of one or more Commission rules, the operator shall submit to the Commission a nonrefundable fee of $300 for each severance or seal order issued for the well or lease before the Commission may reissue the certificate pursuant to §3.58 of this title (relating to Certificate of Compliance and Transportation Authority; Operator Reports) (Statewide Rule 58).

(9) With each application for issuance, renewal, or material amendment of an oil and gas waste hauler's permit, the applicant shall submit to the Commission a nonrefundable fee of $100.

(10) With each Natural Gas Policy Act (15 United States Code §§3301-3432) application, the applicant shall submit to the Commission a nonrefundable fee of $150.

(11) Hazardous waste generation fee. A person who generates hazardous oil and gas waste, as that term is defined in §3.98 of this title (relating to Standards for Management of Hazardous Oil and Gas Waste), shall pay to the Commission the fees specified in §3.98(z).

(12) Inactive well extension fee.

(A) For each well identified by an operator in an application for a plugging extension based on the filing of an abeyance of plugging report on Commission Form W-3X, the operator must pay to the Commission a non-refundable fee of $100.

(B) For each well identified by an operator in an application for a plugging extension based on the filing of a fluid level or hydraulic pressure test that is not otherwise required to be filed by the Commission, the operator must pay to the Commission a non-refundable fee of $50.

(13) Groundwater protection determination letters.

(A) With each individual request for a groundwater protection determination letter, the applicant shall submit to the Commission a nonrefundable fee of $100.

(B) With each individual application for an expedited letter of determination stating the total depth of surface casing required for a well in accordance with Texas Natural Resources Code, §91.0115(b), the applicant shall submit to the Commission a nonrefundable fee of $75, in addition to the fee required by subparagraph (A) of this paragraph.

(14) An operator must make a check or money order for any of the aforementioned fees payable to the Railroad Commission of Texas. If the check accompanying an application is not honored upon presentment, the Commission or its delegate may suspend or revoke the permit issued on the basis of that application, the allowable assigned, the exception to a statewide rule granted on the basis of the application, the certificate of compliance reissued, or the Natural Gas Policy Act category determination made on the basis of the application.

(15) If an operator submits a check that is not honored on presentment, the operator shall submit the payment in the form of a credit card, cashier's check, or cash.

(c) Organization Report Fee. An organization report required by Texas Natural Resources Code, §91.142, shall be accompanied by a fee as follows:

(1) for an operator of:

(A) not more than 25 wells, $300;

(B) more than 25 but not more than 100 wells, $500; or

(C) more than 100 wells, $1,000;

(2) for an operator of one or more natural gas pipelines, $225;

(3) for an operator of one or more of the following service activities: pollution cleanup contractor; directional surveying; approved cementer for plugging wells; a cementer of casing strings or liners; or physically moving or storing crude or condensate, $300;

(4) for an operator of one or more liquids pipelines, $625;

(5) for an operator of all other service activities, or facilities, $500;

(6) for an operator with multiple activities, a total fee equal to the sum of the separate fees applicable to each category of service activity, facility, pipeline, or number of wells operated shall be submitted, provided that the total fee for an operator of wells shall not exceed $1,125; and

(7) for an entity not currently performing operations under the jurisdiction of the Commission, $300.

(d) Financial security. Except for those operators exempted under subsection (g)(7) of this section, any person, including any firm, partnership, joint stock association, corporation, or other organization, required by Texas Natural Resources Code, §91.142, to file an organization report with the Commission must also file financial security in one of the following forms:

(1) an individual performance bond;

(2) a blanket performance bond; or

(3) a letter of credit or cash deposit in the same amount as required for an individual performance bond or blanket performance bond.

(e) Forms for financial security and insurance policies.

Operators shall submit well-specific plugging insurance policies, bonds and letters of credit on forms prescribed by the Commission.

(f) Filing deadlines for financial security and insurance policies. Operators shall submit required financial security or well-specific plugging insurance policies at the time of filing an initial organization report, as a condition of the issuance of a permit to drill, recomplete or reenter, upon yearly renewal, or as otherwise required under this section.

(g) Amount of financial security. An operator required to file financial security under subsection (d) of this section shall file financial security described in this subsection.

(1) Types and amounts of financial security required.

(A) A person operating one or more wells may file an individual performance bond, letter of credit, or cash deposit in an amount equal to the sum of $2.00 for each foot of total well depth for each well operated, excluding any well bore included in a well-specific plugging insurance policy.

(B) A person operating one or more wells may file a blanket bond, letter of credit, or cash deposit to cover all wells for which a bond, letter of credit, or cash deposit is required in an amount equal to the sum of the base amount determined by the total number of wells operated excluding any well bores and/or permits issued to drill, recomplete, or reenter wells included in a well-specific plugging insurance policy. A person performing multiple operations shall be required to file only one blanket bond, letter of credit, or cash deposit unless the person is operating a commercial facility, in which case the person also shall comply with the financial security requirements of subsection (l) of this section. The financial security amount shall be at least the base amount determined by the total number of wells operated or $25,000, whichever is greater. After excluding any well bores and/or permits issued to drill, recomplete or reenter wells included in a well-specific plugging insurance policy, the base amount is determined as follows:

(i) The base amount for a person operating 10 or fewer wells or performs other operations shall be $25,000.

(ii) The base amount for a person operating more than 10 but fewer than 100 wells shall be $50,000.

(iii) The base amount for a person operating 100 or more wells shall be $250,000.

(2) Additional financial security for bay wells.

(A) All operators of bay wells shall file additional financial security of no less than $60,000 in addition to any other financial security that is required under this section for any other Commission-regulated activities.

(B) For each bay well that is not currently producing oil or gas and has not produced oil or gas within the past 12 months, including injection and disposal wells, the operator shall file additional financial security of $60,000, unless the well bore is included in a well-specific plugging insurance policy that provides benefits of at least $60,000. An operator shall not be required to file additional financial security in addition to the $60,000 amount set under subparagraph (A) of this paragraph if the operator operates only a single inactive bay well.

(C) In the case of a bay well that has been inactive for 12 consecutive months or longer and that is not used for disposal or injection, the well shall remain subject to the provisions of subparagraph (B) of this paragraph, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(3) Additional financial security for offshore wells.

(A) All operators of offshore wells and operators of both bay wells and offshore wells shall file additional financial security of no less than $100,000 in addition to any other financial security that is required under this section for any other Commission regulated activities.

(B) For each offshore well that is not currently producing oil or gas and has not produced oil or gas within the past 12 months, including injection and disposal wells, the operator shall file an additional amount of financial security of $100,000, unless the well bore is included in a well-specific plugging insurance policy that provides benefits of at least $100,000. An operator shall not be required to file additional financial security in addition to the $100,000 amount set under subparagraph (A) of this paragraph if the operator operates only a single inactive offshore well.

(C) In the case of an offshore well that has been inactive for 12 consecutive months or longer and that is not used for disposal or injection, the well shall remain classified as inactive for purposes of this section, regardless of any minimal activity, until the well has reported production of at least 10 barrels of oil for oil wells or 100 mcf of gas for gas wells each month for at least three consecutive months.

(4) Reduction of the additional financial security that is required for bay and/or offshore wells. An operator may request a reduction of either the additional $60,000 in financial security required for all operators of bay wells, or the additional $100,000 in financial security required for all operators of offshore wells and operators of both bay wells and offshore wells.

(A) The director may administratively approve the reduction if the operator provides documentation that it currently has acceptable financial assurance in place to satisfy any financial assurance requirements established by local authorities. The operator must show that the bond or other form of financial assurance can be called on by or assigned to the Commission under the following circumstances:

(i) a well is likely to pollute or is polluting any ground or surface water or is allowing the uncontrolled escape of formation fluids from the strata in which they were originally located; or

(ii) a well is not being maintained in compliance with Commission rules or state law relating to plugging or the prevention or control of pollution; or

(iii) the operator has failed to renew and maintain an organization report filing as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements) and this section.

(B) If the director administratively denies a requested reduction, the operator may request a hearing to determine whether the reduction should be granted.

(5) Reduction in additional financial security required for bay and/or offshore wells that are not actively producing oil and natural gas. An operator may request that Commission consider a reduction in any additional financial security requirement for the operation of bay and/or offshore wells that are not actively producing oil and natural gas or that are used for disposal or injection in an amount not to exceed the remainder of 25% of the operator's certified net worth based on the independently

audited calculation for the most recently completed fiscal year minus the Commission's estimate of the operator's total plugging liability for all of the operator's active bay and/or offshore wells.

(A) The director may administratively grant a full or partial reduction if the operator meets the following criteria:

(i) the operator has either five or fewer bay and offshore wells or at least half of the operator's bay and offshore wells are actively producing oil and natural gas;

(ii) the operator provides to the Commission certification of its net worth from an independent auditor that has employed generally accepted accounting principles to confirm the operator's stated net worth based on the most recently available and independently audited calculation;

(iii) the reduction is less than or equal to the remainder of 25% of the operator's certified net worth minus the Commission's estimate of the operator's total plugging liability for all of the operator's active bay and offshore wells;

(iv) none of the operator's wells or operations, including any land-based wells, have been found by Commission staff to be violating or to have violated any Commission rule that resulted in pollution or in any hazard to the health or safety of the public in the last 12 months.

(B) If the director administratively denies the requested reduction, an operator may request a hearing to determine if a full or partial reduction should be granted.

(C) The operator may also request a hearing to challenge the Commission's presumed estimate of the operator's plugging liability for bay and offshore wells as applied to any additional financial security required for any inactive bay and offshore wells. The operator shall present clear and convincing evidence that the estimated plugging liability is less than the amount estimated by the Commission. Notice of the hearing shall be provided by the Commission to the owners of the surface estate and the owners of the mineral estate for any well that is a subject of the requested hearing, and all other affected persons as identified by the operator or otherwise required by the Commission.

(6) Persons with non-well operations not exempted under paragraph (7) of this subsection. A person performing other operations who is not an operator of wells and who is not a person whose only activity is as a first purchaser, survey company, gas nominator, gas purchaser or well plugger shall file financial security in the amount of $25,000.

(7) Persons exempt from financial security requirements. No financial security is required of a person who is not an operator of wells if the person's only activity is as a first purchaser, survey company, salt water hauler, gas nominator, gas purchaser and/or well plugger.

(8) Persons with both well and non-well operations. If a person is engaged in more than one activity or operation, including well operation, for which financial security is required, the person is not required to file financial security for each activity or operation in which the person is engaged. The person is required to file financial security only in the greatest amount required for any activity or operation in which the person engages. The financial security filed covers all of the activities and operations for which financial security is required. The provisions of this paragraph do not exempt a person from the financial security required under subsection (l) of this section.

(9) Financial security amounts are the minimum amounts required by this section to be filed. A person may file a greater amount if desired.

(h) Financial security conditions. Any bond, letter of credit, or cash deposit required under this section is subject to the conditions that the operator will plug and abandon all wells and control, abate, and clean up pollution associated with the oil and gas operations and activities covered under the required financial security in accordance with applicable state law and permits, rules, and orders of the Commission. This section does not apply to a well-specific plugging insurance policy.

(i) Conditions for cash deposits and escrow funds. Operators must tender cash deposits and escrow funds in United States currency or certified cashiers check only. The Commission or its delegate will place all cash deposits and escrow funds in a special account within the Oil and Gas Regulation and Cleanup Fund account. The Commission or its delegate will deposit any interest accruing on cash deposits and escrow funds into the Oil and Gas Regulation and Cleanup Fund pursuant to Texas Natural Resources Code, §81.067. The Commission or its delegate may not refund a cash deposit until either financial security is accepted by the Commission or its delegate as provided for under this section or an operator ceases all activity. The Commission or its delegate may release escrow funds to the current operator of the well only if the well for which the operator tendered the escrow funds is either restored to active status or plugged in accordance with Commission rules. In the event that the well is plugged through the use of state funds, the Commission may collect from the escrow account in the amount necessary to reimburse the state for any expenditure.

(j) Well or lease transfer.

(1) The Commission shall not approve a transfer of operatorship submitted for any well or lease unless the operator acquiring the well or lease has on file with the Commission financial security in an amount sufficient to cover both its current operations and the wells or leases being transferred.

(2) Any existing financial security covering the well or lease proposed for transfer shall remain in effect and the prior operator of the well remains responsible for compliance with all laws and Commission rules covering the transferred well until the Commission approves the transfer.

(3) A transfer of a well or lease from one entity to another entity under common ownership is a transfer for the purposes of this section.

(4) The Commission may approve a transfer of operatorship submitted for any well bore included in a well-specific plugging insurance policy if the transfer meets all other Commission requirements.

(k) Reimbursement liability. Filing any form of financial security does not extinguish a person's liability for reimbursement for the expenditure of state oilfield clean-up funds pursuant to Texas Natural Resources Code, §89.083 and 91.113.

(l) Financial security for commercial facilities. The provisions of this subsection shall apply to the holder of any permit for a commercial facility.

(1) Application.

(A) New permits. Any application for a new or amended commercial facility permit filed after the original effective date of this subsection shall include:

(i) a written estimate of the maximum dollar amount necessary to close the facility prepared in accordance with the provisions of paragraph (4) of this subsection that shows all assumptions and calculations used to develop the estimate;

(ii) a copy of the form of the bond or letter of credit that will be filed with the Commission; and

(iii) information concerning the issuer of the bond or letter of credit as required under paragraph (5) of this subsection including the issuer's name and address and evidence of authority to issue bonds or letters of credit in Texas.

(B) Existing permits. Within 180 days of the original effective date of this subsection, the holder of any commercial facility permit issued on or before the original effective date of this subsection shall file with the Commission the information specified in subparagraph (A)(i) - (iii) of this paragraph.

(2) Notice and hearing.

(A) New permits. For commercial facility permits issued after the original effective date of this subsection, the provisions of §3.8 or §3.57 of this title (relating to Water Protection; and Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials), as applicable, regarding notice and opportunity for hearing, shall apply to review and approval of financial security proposed to be filed to meet the requirements of this subsection.

(B) Existing permits. Notice of filing of information required under paragraph (1)(B) of this subsection shall not be required. In the event approval of the financial security proposed to be filed for a commercial facility operating under a permit in effect as of the original effective date of this subsection is denied administratively, the applicant shall have the right to a hearing upon written request. After hearing, the examiner shall recommend a final action by the Commission.

(3) Filing of instrument.

(A) New permits. A commercial facility permitted after the original effective date of this subsection may not receive oil field fluids or oil and gas waste until a bond or letter of credit in an amount approved by the Commission or its delegate under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with the Commission.

(B) Existing permits. Except as otherwise provided in this subsection, after one year from the original effective date of this section, a commercial facility permitted on or before the original effective date of this subsection may not continue to receive oil field fluids or oil and gas waste unless a bond or letter of credit in an amount approved by the Commission or its delegate under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the Commission or its delegate.

(C) Extensions for existing permits. On written request and for good cause shown, the Commission or its delegate may authorize a commercial facility permitted before the original effective date of this subsection to continue to receive oil field fluids or oil and gas waste after one year after the original effective date of this section even though financial security required under this subsection has not been filed. In the event the Commission or its delegate has not taken final action to approve or disapprove the amount of financial security proposed to be filed by the owner or operator under this subsection one year after the original effective date of the section, the period for filing financial security under this subsection is automatically extended to a date 45 days after such final Commission action.

(4) Amount.

(A) Except as provided in subparagraphs (B) or (C) of this paragraph, the amount of financial security required to be filed under this subsection shall be an amount based on a written estimate approved by the Commission or its delegate as being equal to or greater than the maximum amount necessary to close the commercial facility, exclusive of plugging costs for any well or wells at the facility, at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit, but shall in no event be less than $10,000.

(B) The owner or operator of one or more commercial facilities may reduce the amount of financial security required under this subsection for one such facility by the amount, if any, it filed as financial security under subsection (g)(6) of this section. The full amount of financial security required under subparagraph (A) of this paragraph shall be required for the remaining commercial facilities.

(C) Except for the facilities specifically exempted under subparagraph (D) of this paragraph, a qualified professional engineer licensed by the State of Texas shall prepare or supervise the preparation of a written estimate of the maximum amount necessary to close the commercial facility as provided in subparagraph (A) of this paragraph. The owner or operator of a commercial facility shall submit the written estimate under seal of a qualified licensed professional engineer to the Commission as required under paragraph (1) of this subsection.

(D) A facility permitted under §3.57 of this title (relating to Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials) that does not utilize on-site waste storage or disposal that requires a permit under §3.8 of this title (relating to Water Protection) is exempt from subparagraph (C) of this paragraph.

(E) Notwithstanding the fact that the maximum amount necessary to close the commercial facility as determined under this paragraph is exclusive of plugging costs, the proceeds of financial security filed under this subsection may be used by the Commission to pay the costs of plugging any well or wells at the facility if the financial security for plugging costs filed with the Commission is insufficient to pay for the plugging of such well or wells.

(5) Issuer and form.

(A) Bond. The issuer of any commercial facility bond filed in satisfaction of the requirements of this subsection shall be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection shall provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the Commission or its delegate.

(B) Letter of credit. Any letter of credit filed in satisfaction of the requirements of this subsection shall be issued by and drawn on a bank authorized under state or federal law to operate in Texas. The letter of credit shall be an irrevocable, standby letter of credit subject to the requirements of Texas Business and Commerce Code, §§5.101-5.118. The letter of credit shall provide that it will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is authorized by the Commission or its delegate.

(m) Effect of outstanding violations.

(1) Except as provided in paragraph (2) of this subsection, the Commission shall not accept an organization report or an application for a permit or approve a certificate of compliance for a well or a lease submitted by an organization if:

(A) the organization has outstanding violations; or

(B) an officer or owner of the organization, as defined in subsection (a) of this section, was, within seven years preceding the filing of the report, application, or certificate, an officer or owner of an organization and during that period, the organization committed a violation that remains an outstanding violation.

(2) The Commission shall accept a report or application or approve a certificate filed by an organization covered by paragraph (1) of this subsection if:

(A) the conditions that constituted the violation have been corrected or are being corrected in accordance with a schedule agreed to by the organization and the Commission;

(B) all administrative, civil, and criminal penalties, and all plugging and cleanup costs incurred by the state relating to those conditions have been paid or are being paid in accordance with a schedule agreed to by the organization and the Commission; and

(C) the report, application or certificate is in compliance with all other requirements of law and Commission rules.

(3) All fees tendered in connection with a report or application that is rejected under this subsection are nonrefundable.

(n) Mandatory surcharges. The Commission adopts this subsection pursuant to Texas Natural Resources Code, §81.070, to impose reasonable surcharges as necessary on fees collected by the Commission that are required to be deposited to the credit of the Oil and Gas Regulation and Cleanup Fund, as provided by Texas Natural Resources Code, §81.067, in an amount sufficient to enable the Commission to recover the costs of performing the functions specified by Texas Natural Resources Code, §81.068, from those fees and surcharges. This subsection establishes the methodology the Commission shall use to determine the amount of the surcharge on each fee, as required by Texas Natural Resources Code, §81.070(c).

(1) For all fees subject to a surcharge under this section, the Commission shall employ a projected cost-based recovery methodology derived from budgeted cost projections approved by the Legislature in the General Appropriations Act, which is dependent upon revenue projections issued by the Comptroller in the most recent Biennial Revenue Estimate. In establishing the surcharge amounts, the Commission shall consider the factors and values set forth in the following subparagraphs.

(A) The Commission shall ascertain the time required to complete the regulatory work associated with the activity in connection with which the surcharge is imposed using the number of full-time equivalent positions (FTEs) appropriated by the Legislature for that purpose during the applicable biennium, multiplied by the work hours in a fiscal year, divided by the anticipated number of permit applications processed in a fiscal year.

(B) The Commission shall use the number of P-5 Organization Reports as a proxy to determine the number of individual or entities from which the Commission's costs may be recovered. An Organization Report is required to be filed and renewed annually by any organization, including any person, firm, partnership, corporation, or other organization, domestic or foreign, operating wholly or partially within this state, that performs operations within the jurisdiction of the agency.

(C) The Commission shall determine how the surcharge will affect operators considered to be large, based on operating more than 10,000 oil or gas wells; operators considered to be medium, based on operating more than 1,000 oil or gas wells, but fewer than 10,000 wells; and operators considered to be small, based on operating fewer than 1,000 oil or gas wells.

(D) The Commission shall consider the balance of the Oil and Gas Regulation and Cleanup Fund at the beginning of the fiscal year in which the surcharge is assessed.

(E) The Commission shall assume that the Legislature intended that the agency's oil and gas regulatory program should be self-funded. The Commission shall maintain an adequate balance in the Oil and Gas Regulation and Cleanup Fund such that the regulatory program can withstand a decrease in industry activity without sacrificing the health and public safety aspects of its regulatory work, while also having funds available to respond to any emergency related to oil and gas activity throughout the state. The Commission shall also maintain a fund balance that is within the statutory fund limits as determined by the Legislature.

(2) The Commission shall consider the factors set forth in paragraph (1) of this subsection to determine the surcharge applicable to all fees deposited to the Oil and Gas Regulation and Cleanup Fund in the following manner:

(A) the Commission shall first apply the premise that the oil and gas regulatory program should be self-funded;

(B) the Commission shall then apply a cost-based recovery analysis to the funding levels determined by the Legislature. The Commission shall rely primarily on these two factors, but shall also review all factors and values set forth in subparagraph (A) of this paragraph; and

(C) the Commission will apply the surcharge rate to all applicable fees as detailed in paragraph (3) of this subsection.

(3) Based on the factors and methodology set forth in this subsection, the Commission has determined that a surcharge rate of 150 percent will be necessary on all fees required to be deposited to the credit of the Oil and Gas Regulation and Cleanup Fund.

(4) The Commission shall review the surcharge rate determination under this subsection periodically but not less than each biennium to confirm that the imposed surcharge is reasonable.

Source Note: The provisions of this §3.78 adopted to be effective July 10, 2000, 25 TexReg 6487; amended to be effective November 1, 2000, 25 TexReg 9924; amended to be effective June 11, 2001, 26 TexReg 4088; amended to *be effective January 9, 2002, 27 TexReg 139; amended to be effective October 12, 2003, 28 TexReg 8890; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective December 19, 2005, 30 TexReg 8426; amended to be effective November 26, 2007, 32 TexReg 8452; amended to be effective September 13, 2010, 35 TexReg 8332; amended to be effective May 1, 2012, 37 TexReg 1315; amended to be effective August 27, 2012, 37 TexReg 6538; amended to beeffective December 16, 2013, 38 TexReg 9010; amended to be effective February 1, 2016, 41 TexReg 792; amended to be effective February 18, 2025, 50 TexReg 835.*

§3.79 Definitions

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Adjacent estuarine zones--This term embraces the area inland from the coast line of Texas and is comprised of the bays, inlets, and estuaries along the gulf coast.

(2) By-product--Any element found in a geothermal formation which when brought to the surface is not used in geothermal heat or pressure inducing energy generation.

(3) Casinghead gas--Any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil.

(4) Commission--The Railroad Commission of Texas.

(5) Common reservoir--Any oil, gas, or geothermal resources field or part thereof which comprises and includes any area which is underlaid, or which from geological or other scientific data or experiments or from drilling operations or other evidence appears to be underlaid by a common pool or accumulation of oil, gas, or geothermal resources.

(6) Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit. Whenever the conditions of pressure and temperature differ from the standard in this definition, conversion of the volume from these conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation.

(7) District office--The commission-designated office for the geographic area in which the property or act subject to regulation is located or arises.

(8) Dry gas--Any natural gas produced from a stratum that does not produce crude petroleum oil.

(9) Exploratory well--Any well drilled for the purpose of securing geological or geophysical information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources, except coal and uranium, and includes what is commonly referred to in the industry as "slim hole tests," "core hole tests," or "seismic holes." For regulations governing coal exploratory wells, see Chapter 12 of this title (relating to Coal Mining Regulations), and for regulations governing uranium exploratory wells, see Chapter 11, Subchapter C of this title (relating to Surface Mining and Reclamation Division, Substantive Rules--Uranium Mining).

(10) Gas lift--Gas lift by the use of gas not in solution with oil produced.

(11) Gas well--Any well:

(A) which produces natural gas not associated or blended with crude petroleum oil at the time of production;

(B) which produces more than 100,000 cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon; or

(C) which produces natural gas from a formation or producing horizon productive of gas only encountered in a wellbore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.

(12) Gatherer--Includes any pipeline, truck, motor vehicle, boat, barge, or person authorized to gather or accept oil, gas, or geothermal resources from lease production or lease storage.

(13) Geothermal energy and associated resources--

(A) All products of geothermal processes, embracing indigenous steam, hot water and hot brines, and geopressured water;

(B) Steam and other gases, hot water and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations;

(C) Heat or other associated energy found in geothermal formations;

(D) Any by-product derived from them.

(14) Geothermal resource well--A well drilled within the established limits of a designated geothermal field.

(A) A geopressured geothermal well must be completed within a geopressured aquifer.

(B) A geopressured aquifer is a water-bearing zone with a pressure gradient in excess of 0.5 pounds per square inch per foot and a temperature gradient in excess of 1.6 degrees Fahrenheit per 100 feet of depth.

(15) Marginal well--Any oil well which is incapable of producing its maximum capacity of oil except by pumping, gas lift, or other means of artificial lift, and which well so equipped is capable, under normal unrestricted operating conditions, of producing such daily quantities of oil as herein set out, as would be damaged, or result in a loss of production ultimately recoverable, or cause the premature abandonment of same, if its maximum daily production were artificially curtailed. The following described wells shall be deemed "marginal wells" in this state.

(A) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 10 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a depth of 2,000 feet or less.

(B) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 20 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 2,000 feet and less in depth than 4,000 feet.

(C) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 25 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 4,000 feet and less in depth than 6,000 feet.

(D) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 30 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 6,000 feet and less in depth than 8,000 feet.

(E) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 35 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 8,000 feet. (Reference Order Number 20-59,200, effective May 1, 1969.)

(16) Natural gas or gas--These terms shall have the same meaning, as used in the rules, regulations, or forms of the commission.

(17) Natural gasoline--Gasoline manufactured from casinghead gas or from any natural gas.

(18) Oil well--Any well which produces one barrel or more crude petroleum oil to each 100,000 cubic feet of natural gas.

(19) Operator--A person, acting for himself or as an agent for others and designated to the commission as the one who has the primary responsibility for complying with its rules and regulations in any and all acts subject to the jurisdiction of the commission.

(20) Person--Any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, and a fiduciary or representative of any kind.

(21) Product--Includes refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, casinghead gasoline, natural gas gasoline, gas oil, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum, and/or any and all liquid products or by-products derived from crude petroleum oil or gas, whether hereinabove enumerated or not.

(22) Sour gas--Any natural gas containing more than 1 1/2 grains of hydrogen sulphide per 100 cubic feet or more than 30 grains of total sulphur per 100 cubic feet, or gas which in its natural state is found by the commission to be unfit for use in generating light or fuel for domestic purposes.

(23) Sweet gas--All natural gas except sour gas and casinghead gas.

(24) Texas offshore--This term embraces the area in the Gulf of Mexico seaward of the coast line of Texas comprised of:

(A) the three league area confirmed to the State of Texas by the Submerged Land Act (43 United States Code §§1301-1315); and

(B) the area seaward of such three league area owned by the United States.

(25) Transportation or to transport--The movement of any crude petroleum oil or products of crude petroleum oil or the products of either from any receptacle in which any such crude petroleum or products of crude petroleum oil or the products of either has been stored to any other receptacle by any means or method whatsoever, including the movement by any pipeline, railway, truck, motor vehicle, barge, boat, or railway tank car. It is the purpose of this definition to include the movement or transportation of crude petroleum oil and products of crude petroleum oil and the products of either by any means whatsoever from any receptacle containing the same to any other receptacle anywhere within or from the State of Texas, regardless of whether or not possession or control or ownership change.

(26) Transporter or transporting agency--Includes any common carrier by pipeline, railway, truck, motor vehicle, boat, or barge, and/or any person transporting oil or a product by pipeline, railway, truck, motor vehicle, boat, or barge.

(27) Underground source of drinking water--An aquifer or its portion which is not an exempt aquifer as defined in 40 Code of Federal Regulations §146.4 and which:

(A) supplies any public water system; or

(B) contains a sufficient quantity of ground water to supply a public water system; and

(i) currently supplies drinking water for human consumption; or

(ii) contains fewer than 10,000 milligrams per liter (mg/l) total dissolved solids.

Source Note: The provisions of this §3.79 adopted to be effective August 25, 2003, 28 TexReg 6816; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.80 Commission Oil and Gas Forms, Applications, and Filing Requirements

(a) Forms. Forms required to be filed at the Commission shall be those prescribed by the Commission. A complete set of all Commission forms required to be filed at the Commission shall be kept by the Commission secretary and posted on the Commission's web site. Notice of any new or amended forms shall be issued by the Commission. For any required or discretionary filing, an organization may either file the prescribed form on paper or use any electronic filing process in accordance with subsections (e) or (f) of this section, as applicable. The Commission may at its discretion accept an earlier version of a prescribed form, provided that it contains all required information and meets the requirements of subsection (e)(3) of this section.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission--The Railroad Commission of Texas.

(2) Electronic filing process--An electronic transmission to the Commission in a prescribed form and/or format authorized by the Commission and completed in accordance with Commission instructions.

(3) Form--A printed or typed paper document or electronic submission, including any necessary instructions, with blank spaces for insertion of required or requested specific information.

(4) Organization--Any person, firm, partnership, joint stock association, corporation, or other organization, domestic or foreign, operating wholly or partially within

this state, acting as principal or agent for another, for the purpose of performing operations within the jurisdiction of the Commission.

(5) Position of ownership or control--A person holds a position of ownership or control in an organization if the person is:

(A) an officer or director of the organization;

(B) a general partner of the organization;

(C) the owner of an organization which is a sole proprietorship;

(D) the owner of more than a 25 percent ownership interest in the organization; or

(E) the designated trustee of the organization.

(6) Violation--Non-compliance with a statute, Commission rule, order, license, permit, or certificate relating to safety or the prevention or control of pollution.

(c) Organization eligibility. The Commission may not accept an organization report or an application for a permit, or approve a certificate of compliance if:

(1) the organization that submitted the report, application, or certificate violated a statute or Commission rule, order, license, certificate, or permit that relates to safety or the prevention or control of pollution; or

(2) any person who holds a position of ownership or control in the organization has, within the seven years preceding the date on which the report, application, or certificate is filed, held a position of ownership or control in another organization, and during that period of ownership or control the other organization violated a statute or Commission rule, order, license, permit, or certificate that relates to safety or the prevention or control of pollution.

(d) Violations. An organization has committed a violation if there is either a Commission order against an organization finding that the organization has committed a violation and all appeals have been exhausted or an agreed order entered into by the Commission and an organization relating to an alleged violation, and:

(1) the conditions that constituted the violation or alleged violation have not been corrected;

(2) all administrative, civil and criminal penalties, if any, relating to the violation or agreed settlement relating to an alleged violation have not been paid; or

(3) all reimbursements of costs and expenses, if any, assessed by the Commission relating to the violation or to the alleged violation have not been collected.

(e) Authorization and standards for electronic filing.

(1) An organization may file electronically any form for which the Commission has provided an electronic version, provided that the organization pays all required filing fees and complies with all requirements, including but not limited to security procedures, for electronic filing.

(2) The Commission deems an organization that files electronically or on whose behalf is filed electronically any form, as of the time of filing, to have knowledge of and to be responsible for the information filed on the form, pursuant to the statutory requirements, restrictions, and standards found in and pertaining to:

(A) Texas Natural Resources Code, Title 3 (oil and gas well drilling, production, and plugging);

(B) Texas Natural Resources Code, Title 5 (geothermal resources);

(C) Texas Natural Resources Code, Title 11 (hazardous liquids storage);

(D) Texas Utilities Code, Chapter 121, Subchapter I (sour gas pipeline facilities);

(E) Texas Water Code, §26.131 (discharge permits);

(F) Texas Water Code, Chapter 27 (class II injection and disposal wells and class III brine mining wells);

(G) Texas Water Code, Chapter 29 (oil and gas waste haulers);

(H) Texas Health and Safety Code, §401.415 (oil and gas naturally occurring radioactive material (NORM) waste); and

(I) Texas Administrative Code, Title 16, Chapter 3 (Oil and Gas Division) and Chapter 4 (Environmental Protection).

(3) All forms that an organization submits or that are submitted on behalf of an organization shall be transmitted in the manner prescribed by the Commission that is compatible with its software, equipment, and facilities.

(4) The Commission may provide notice electronically to an organization of, and may provide an organization the ability to confirm electronically, the Commission's receipt of a form submitted electronically by or on behalf of that organization.

(5) The Commission deems that the signature of an organization's authorized representative appears on each form submitted electronically by or on behalf of the organization, as if this signature actually appears, as of the time the form is submitted electronically to the Commission.

(6) The Commission holds each organization responsible, under the penalties prescribed in Texas Natural Resources Code, §91.143, for all forms, information, or data that an organization files or that are filed on its behalf. The Commission charges each organization with the obligation to review and correct, if necessary, all forms or data that an organization files or that are filed on its behalf.

(f) Other electronic transmissions. The Commission may at its discretion accept other documents or data electronically transmitted.

Source Note: The provisions of this §3.80 adopted to be effective June 11, 2001, 26 TexReg 4088; amended to be effective April 12, 2004, 29 TexReg 3612; amended to be effective July 12, 2004, 29 TexReg 6633; amended to be effective October 11, 2004, 29 TexReg 9533; amended to be effective April 3, 2006, 31 TexReg 2846; amended to be effective January 30, 2007, 32 TexReg 287; amended to be effective January 7, 2008, 33 TexReg 114; amended to be effective September 12, 2011, 36 TexReg 5835; amended to be effective July 7, 2014, 39 TexReg 5148.

§3.81 Class III Brine Mining Injection Wells

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of the activity sought to be permitted, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Brine mining facility or facility--The brine mining injection well, and the pits, tanks, fresh water wells, pumps, and other structures and equipment that are or will be used in conjunction with the brine mining injection well.

(3) Brine mining injection well--A Class III UIC well used to inject fluid for the purpose of extracting brine by

the solution of a subsurface salt formation. The term "brine mining injection well" does not include a well used to inject fluid for the purpose of leaching a cavern for the underground storage of hydrocarbons or the disposal of waste, or a well used to inject fluid for the purpose of extracting sulphur by the thermofluid mining process.

(4) Commission--The Railroad Commission of Texas.

(5) Director--The director of the Oil and Gas Division or a staff delegate designated in writing by the director of the Oil and Gas Division or the commission.

(6) Existing brine mining injection well--A brine mining injection well in which injection operations began prior to the effective date of this section.

(7) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose.

(8) New brine mining injection well--A brine mining injection well in which injection operations begin on or after the effective date of this section.

(9) Permit--A written authorization issued by the commission under this section for the operation of a brine mining injection well.

(10) Person--A natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust partnership, association, or any other legal entity.

(11) Pollution--The alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation or property or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(b) Prohibitions.

(1) Unauthorized injection. No person may operate a brine mining injection well without obtaining a permit from the commission under this section. No person may begin constructing a new brine mining injection well until the commission has issued a permit to operate the well under this section and a permit to drill, deepen, plug back, or reenter the well under §3.5 of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(2) Fluid migration. No person may operate a brine mining injection well in a manner that allow fluids to escape from the permitted injection zone. If fluids are migrating from the permitted injection zone, the operator shall immediately cease injection operations.

(3) Falsifying documents and tampering with gauges. No person may knowingly make any false statement, representation, or certification in any application, report, record, or other document submitted or required to be maintained under this section or under any permit issued pursuant to this section, or falsify, tamper with, or knowingly render inaccurate any monitoring device or method required to be maintained under this section or under any permit issued pursuant to this section.

(c) Standards for permit issuance. A permit may be issued only if the commission determines that the operation of the brine mining injection well will not result in the pollution of fresh water. All permits issued under this section will contain the conditions required by subsections (f) and (g) of this section, and all other conditions reasonably necessary to prevent the pollution of fresh water.

(d) Permit application.

(1) Duty to apply. Any person who operates or proposes to operate a brine mining injection well shall file a permit application with the commission in Austin within the time provided in paragraph (2) of this subsection. The applicant shall mail or deliver a copy of the application to the appropriate district office on the same day the application is mailed or delivered to the commission in Austin. A permit application will be considered filed with the commission on the date it is received by the commission in Austin.

(2) Time to apply.

(A) Any person who proposes to operate a new brine mining injection well shall file a permit application at least 180 days before the date on which injection is to begin, unless a later date has been authorized by the director.

(B) Any person who is operating an existing brine injection well shall file a permit application within 90 days of the effective date of this section.

(C) Any person who has obtained a permit under this section and who wishes to continue to operate the brine mining injection well after the permit expires shall file an application for new permit at least 180 days before the existing permit expires, unless a later date has been authorized by the director.

(3) Who applies. When a brine mining facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit.

(4) Application requirements for all applicants. All applicants shall submit the following information, using application forms supplied by the commission:

(A) name, mailing address, and location of the brine mining facility for which the application is submitted;

(B) the operator's name, mailing address, telephone number, and status as federal, state, private, public, or other entity, and a statement indicating whether the operator is the owner of the facility;

(C) the proposed uses for the brine mined at the facility;

(D) a listing of all permits or construction approvals for the facility received or applied for under federal or state environmental programs;

(E) a topographic map, or other map if the topographic map is unavailable, extending one mile beyond the property boundaries of the facility, depicting the facility and those springs, other surface water bodies, drinking water wells, and other wells listed in public records or otherwise known to the applicant within 1/4 mile of the facility property boundary;

(F) a plat showing the oil and gas operators of the tract on which the facility is located and the tracts adjacent to the tract on which the facility is located. On the plat or on a separate sheet attached to the plat, the applicant shall list the names and addresses of the oil and gas operators;

(G) a plat showing the surface ownership of the tract on which the facility is located and the tracts adjacent to the tract on which the facility is located. On the plat or on a separate sheet attached to the plat, the applicant shall list the names and addresses of the surface owners, as determined from the current county tax rolls or other reliable sources, and shall identify the source of the list. If the director determines that, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more surface owners, the director may waive the requirements of this subparagraph with respect to those surface owners;

(H) a map with surveys marked showing the type, location, and depth of all wells of public record within a 1/4 mile radius of the brine mining injection well that penetrate the salt formation. The applicant shall attach the following information to the map:

(i) a tabulation of the wells showing the dates the wells were drilled and the present status of the wells; and

(ii) plugging records for plugged and abandoned wells and completion records for other wells;

(I) a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the depth to which fresh water strata should be protected;

(J) a complete electric log of the brine mining injection well or a nearby well. On the log, the applicant shall identify the geologic formations between the land surface and the top of the salt formation and the depths at which they occur;

(K) a drawing of the surface and subsurface construction details of the brine mining injection well;

(L) the proposed maximum daily injection rate and maximum injection pressure;

(M) the proposed injection procedure;

(N) the proposed mechanical integrity testing procedure;

(O) the source of mining water to be used at the facility. If the source is groundwater, the following information must be included:

(i) the groundwater formation name;

(ii) an depth of the groundwater formation; and

(iii) an analysis of the groundwater;

(P) the direction of the hydraulic gradient in the area; and

(Q) the proposed groundwater monitoring plan, or an alternate plan for assuring that fluids are not escaping from the permitted injection zone.

(5) Additional information. The applicant shall submit any other information required on the application form supplied by the commission. In addition to the information reported on the application form, the applicant shall submit, at the director's request, any other information the commission may reasonably require to assess the brine mining injection well and to determine whether to issue a permit.

(e) Signatories to applications and reports.

(1) Applications. All applications shall be signed as follows:

(A) for a corporation, by a responsible corporate officer. A responsible corporate officer means a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy-making or decision-making functions for the corporation; or

(B) for a partnership or sole proprietorship, by a general partner or the proprietor, respectively.

(2) Reports. All reports required by permits and other information requested by the commission shall be signed by a person described in paragraph (1) of this subsection or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(A) the authorization is made in writing by a person described in paragraph (1) of this subsection;

(B) the authorization specifies an individual or position having responsibility for the overall operation of the regulated facility; and

(C) the authorization is submitted to the commission before or together with any report of information signed by the authorized representative.

(3) Certification. Any person signing a document under paragraph (1) or (2) of this subsection shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or who are directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information."

(f) Conditions applicable to all permits. The conditions specified in this subsection apply to all permits.

(1) Duty to comply. The operator shall comply with all conditions of the permit. Any permit noncompliance is grounds for enforcement action, for permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application.

(2) Duty to reapply. If the operator wishes to continue a permitted activity after the expiration date of the permit, the operator shall apply for and obtain a new permit.

(3) Need to halt or reduce activity not a defense. It is not a defense for an operator in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

(4) Duty to mitigate. The operator shall take all reasonable steps to minimize and correct any adverse effect on the environment resulting from noncompliance with the permit.

(5) Proper operation and maintenance. The operator shall at all times properly operate and maintain all facilities and systems of treatment and control, and related appurtenances, that are installed or used by the operator to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up and auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

(6) Permit actions. The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the operator for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

(7) Property rights. The permit does not convey any property rights of any sort, or any exclusive privilege.

(8) Duty to provide information. The operator shall also furnish to the commission, within a time specified by the commission, any information that the commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The operator shall also furnish to the commission, upon request, copies of records required to be kept under the conditions of the permit.

(9) Inspection and entry. The operator shall allow any

member or employee of the commission, on proper identification, to:

(A) enter upon the premises where a regulated activity is conducted or where records are kept under the conditions of the permit;

(B) have access to and copy, during reasonable working hours, any records required to be kept under the conditions of the permit;

(C) inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under the permit; and

(D) sample or monitor any substance or parameter for the purpose of assuring compliance with the permit or as otherwise authorized by the Texas Water Code, §27.071, or the Texas Natural Resources Code, §91.1012.

(10) Monitoring and records.

(A) Samples and measurements taken for the purpose of monitoring must be representative of the monitored activity.

(B) The operator shall retain records of all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for at least three years from the date of the sample, measurement, report, or application. This period may be extended by request of the commission at any time.

(C) Records of monitoring information must include the date, exact place, and time of the sampling or measurements; the individual(s) who performed the sampling or measurements; the date(s) analyses were performed; the individual(s) who performed the analyses; the analytical techniques or methods used; and the results of the analyses.

(11) Signatory requirements. All reports and other information submitted to the commission shall be signed and certified in accordance with subsection (e) of this section.

(12) Reporting requirements.

(A) The operator shall notify the commission as soon as possible of any planned physical alteration or addition to the facility.

(B) The operator shall give advance notice to the commission of any planned changes in the facility that may result in noncompliance with permit requirements.

(C) Monitoring results shall be reported at the intervals specified in the permit.

(D) Reports of compliance or noncompliance with the requirements contained in any compliance schedule of the permit shall be submitted no later than 30 days after each scheduled date.

(E) The operator shall report to the commission any noncompliance that may endanger human health or the environment.

(i) An oral report shall be made to the appropriate district office immediately after the operator becomes aware of the noncompliance. A written report shall be filed with the Austin office within five days of the time the operator becomes aware of the noncompliance. The written report must contain the following information:

(I) a description of the noncompliance and its cause;

(II) the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue; and

(III) steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(ii) Information that shall be reported under this subparagraph includes the following:

(I) any monitoring or any other information that indicates that any contaminant may endanger fresh water; or

(II) any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between fresh water strata.

(F) The operator shall report any noncompliance not reported under subparagraphs (C), (D), and (E) of this paragraph at the time monitoring reports are submitted. The report must contain the information listed in subparagraph (E) of this paragraph.

(G) If the operator becomes aware that it failed to submit any relevant facts or submitted incorrect information in a permit application or a report to the commission, the operator shall promptly submit the relevant facts or correct information.

(13) Transfers. The permit is not transferable to any person except by modification, or revocation and reissuance, to change the name of the operator and incorporate other necessary requirements.

(14) Completion report. Injection operations may not begin in any new brine mining injection well until the operator has submitted a completion report to the director, and the director has reviewed the completion report and found the well in compliance with the conditions of the permit.

(15) Workovers. The operator shall notify the appropriate district office at least 48 hours before performing any workover or corrective maintenance operations that involve the removal of the tubing or well stimulation.

(16) Mechanical integrity.

(A) No person may perform injection operations in a brine mining injection well that lacks mechanical integrity. A well has mechanical integrity if:

(i) there is not significant leak in the casing; and

(ii) there is no significant fluid movement into fresh water strata through vertical channels adjacent to the wellbore.

(B) For any existing brine mining injection well, mechanical integrity must be demonstrated annually. For any new brine mining injection well, mechanical integrity must be demonstrated before injection operations begin and annually thereafter. In addition, for all brine mining injections wells, mechanical integrity must be demonstrated after any workover that involves the removal of the tubing.

(C) To demonstrate the absence of a significant leak in the casing, the operator shall conduct a fluid pressure test in accordance with the following procedures:

(i) the operator shall submit a written test procedure to the commission in Austin at least 15 days before the test;

(ii) the operator shall notify the district office orally at least 48 hours before the test;

(iii) the operator shall perform the test using the test procedure submitted prior to the testing unless otherwise instructed by the commission; and

(iv) the operator shall file a complete record of the test with the commission in Austin within 30 days after the test.

(D) In lieu of an annual fluid pressure test, the operator may monitor the pressure of a hydrocarbon pad or blanket contained in the annulus space of the well, provided the operator has obtained written approval from the director prior to using this method.

(E) One of the following methods shall be used to demonstrate the absence of significant fluid movement into fresh water strata through vertical channels adjacent to the wellbore:

(i) the results of a temperature or noise log; or

(ii) where the nature of the casing precludes the use of the logging techniques prescribed in clause (i) of this subparagraph, cementing records demonstrating the presence of adequate cement to prevent such movement.

(F) The director may allow the use of a method of demonstrating mechanical integrity other than one listed in subparagraphs (C), (D), and (E) of this paragraph with the approval of the administrator of the Environmental Protection Agency obtained pursuant to 40 Code of Federal Regulations §146.8(d).

(G) Mechanical integrity must be demonstrated to the satisfaction of the director. In conducting and evaluating the results of a mechanical integrity test, the operator and the director will apply procedures and standards generally accepted in the industry. In reporting the results of a mechanical integrity test, the operator must include a description of the method and procedures used. In evaluating the results, the director will review monitoring and other test data submitted since the previous mechanical integrity test.

(17) Notice of conversion or abandonment. The operator shall notify the commission at such times as the permit requires before conversion or abandonment of the well.

(18) Plugging. Within one year after cessation of brine mining injection operations, the operator shall plug the well in accordance with §3.14(a) and (c) - (h) of this title (relating to Plugging) (Rule 14(a) and (c) - (h)). For good cause, the director may grant a reasonable extension of time in which to plug the well if the operator submits a proposal that describes actions or procedures to ensure that the well will not endanger fresh water during the period of the extension.

(g) Other permit conditions. In addition to the conditions required in all permits, the commission will establish conditions, as required on a case-by-case basis, to provide for and assure compliance with the requirements specified in this subsection.

(1) Duration. Permits will be effective for a term up to the operating life of the facility. The commission will review each permit issued pursuant to this section at least once every five years to determine whether cause exists for modification, revocation and reissuance, or termination of the permit.

(2) Operating requirements. Permits will prescribe operating requirements, which will at a minimum specify that:

(A) except during well stimulation, injection pressure at the wellhead may not exceed a maximum calculated to assure that the injection pressure does not initiate new fractures or propagate existing fractures in the injection zone; and

(B) in no case may the injection pressure initiate fractures in the confining zone or cause the escape of injection or formation fluids from the injection zone.

(3) Monitoring requirements. Permits will specify the following monitoring requirements:

(A) requirements concerning the proper use, maintenance, and installation, when appropriate, of monitoring equipment or methods;

(B) requirements concerning the type, intervals, and frequency of monitoring sufficient to yield data representative of the monitored activity, including continuous monitoring when appropriate; and

(C) requirements to report monitoring results with a frequency dependent on the nature and effect of the monitored activity, but in no case less than quarterly.

(4) Construction requirements. Permits will specify construction requirements to assure that the injection operations will not endanger fresh water. Changes in construction requirements during construction may be approved by the director as minor modifications of the permit. No such changes may be physically incorporated into the construction of the well prior to approval of the modifications by the director.

(A) An existing brine mining injection well shall achieve compliance with the construction requirements according to a compliance schedule established as soon as possible and in no case later than one year after the effective date of the permit. The permit will require the operator to submit a written compliance report within 30 days after compliance has been achieved.

(B) A new brine mining injection well must be cased and cemented in accordance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements), (Rule 13), provided, however, that the operator shall set and cement surface casing in accordance with the letter obtained from the Groundwater Advisory Unit of the Oil and Gas Division pursuant to subsection (d)(4)(I) of this section regardless of the total depth of the well. No alternative program for setting less surface casing will be authorized.

(C) Appropriate logs and other tests must be conducted during the drilling and construction of a new brine mining injection well. A descriptive report interpreting the results of such logs and tests must be prepared by a knowledgeable log analyst and submitted to the director. The logs and tests appropriate to each well will be determined based on the depth, construction, and other characteristics of the well, the availability of similar data in the area, and the need for additional information that may arise from time to time as the construction of the well progresses.

(5) Financial responsibility. It shall be a permit condition that the operator maintain financial responsibility and resources to plug and abandon the brine mining injection well. The operator shall show evidence of such financial responsibility to the commission by submitting a surety bond or letter of credit in a form prescribed by the commission. Such bond or letter of credit shall be maintained until the well is plugged in accordance with subsection (f)(18) of this section.

(6) Corrective action. For all known wells that penetrate the injection zone within a 1/4 mile radius of the brine mining injection well and are improperly completed, plugged, or abandoned, the commission will consider requiring corrective action to prevent movement of fluid into fresh water strata.

(A) In determining the need for corrective action, the commission will consider the following factors: nature and volume of injected fluid; nature of native fluids; potentially affected population; geology; hydrology; history of the injection operation; completion and plugging records; abandonment procedures in effect at the time a well was abandoned; and hydraulic connections with fresh water.

(B) For an existing brine mining injection well requiring corrective action, any permit issued will include a compliance schedule leading to compliance with corrective action requirements. The compliance schedule will require compliance as soon as possible and in no case later than one year after the effective date of the permit. The permit will require the operator to submit a written compliance report within 30 days after all required corrective action has been taken.

(C) For a new brine mining injection well, the operator may not begin injection operations until all required corrective action has been taken.

(h) Modification, revocation and reissuance, and termination of permits. A permit may be modified, revoked and reissued, or terminated by the commission either upon the written request of any interested person, including the operator, or upon the commission's initiative, but only for the reasons and under the conditions specified in this subsection. Except for minor modifications made under paragraph (2) of this subsection, the commission will follow the applicable procedures in subsection (i) of this section. In the case of a modification, the commission may request additional information or an updated application. In the case of a revocation and reissuance, the commission will require a new application. If a permit is modified, only the conditions subject to modification are reopened. The term of a permit may not be extended by modification. If a permit is revoked and reissued, the entire permit is reopened and subject to revision, and the permit is reissued for a new term.

(1) Modification, or revocation and reissuance. The following are causes for modification, or revocation and reissuance:

(A) material and substantial alterations or additions to the facility occurred after permit issuance and justify permit conditions that are different or absent in the existing permit;

(B) the commission receives new information;

(C) the standards or regulations on which the permit was based have been changed by promulgation of amended standards or regulations or by judicial decision after the permit was issued;

(D) the commission determines good cause exists for modifying a compliance schedule, such as a act of God, strike, flood, materials shortage, or other event over which the operator has little or no control and for which there is no reasonably available remedy;

(E) cause exists for terminating a permit under paragraph (3) of this subsection, and the commission determines that modification, or revocation and reissuance, is appropriate; or

(F) a transfer of the permit is proposed.

(2) Minor modifications. With the operator's consent, the director may make minor modifications to a permit administratively, without following the procedures of subsection (i) of this section. Minor modifications may only:

(A) correct clerical or typographical errors, or clarify any description or provision in the permit, provided that the description or provision is not changed substantively;

(B) require more frequent monitoring or reporting;

(C) change construction requirements provided that any changes shall comply with the requirements of subsection (g)(4) of this section; or

(D) allow a transfer of the permit where the director determines that no change in the permit is necessary other than a change in the name of the operator, provided that a written agreement between the current operator and the new operator containing a specific data for the transfer of permit responsibility, coverage, and liability has been submitted to the commission.

(3) Termination. The following are causes for terminating a permit during its term, or for denying a permit renewal application:

(A) the operator fails to comply with any condition of the permit or this section;

(B) the operator fails to disclose fully all relevant facts in the permit application or during the permit issuance process, or misrepresents any relevant fact at any time;

(C) a material change of conditions occurs in the operation or completion of the well, or there are material changes in the information originally furnished;

(D) the commission determines that the permitted injection endangers human health or the environment, or that pollution of fresh water is occurring or is likely to occur as a result of the permitted injection; or

(E) fluids are escaping from the permitted injection zone.

(i) Permitting procedures.

(1) Review of applications. Upon receipt of an application for a permit, the director will review the application for completeness. Within 30 days after receipt of the application, the director will notify the applicant in writing whether the application is complete or deficient. A notice of deficiency will state the additional information necessary to complete the application, and a date for submitting this information. The application will be deemed withdrawn if the necessary information is not received by the specified date, unless the director has extended this date upon request of the applicant. Upon timely receipt of the necessary information, the director will notify the applicant that the application is complete. The director will not begin processing a permit until the application is complete.

(2) Permit denial. If the director administratively denies a permit application, a notice of administrative denial will be mailed to the applicant. The applicant will have a right to a hearing on request. If the applicant requests a hearing, the notice of administrative denial will be subject to the same procedures as a draft permit prepared under paragraph (3) of this subsection.

(3) Draft permits.

(A) A draft permit will be prepared when the director tentatively decides:

(i) to issue a permit;

(ii) to modify, or revoke and reissue, a permit; or

(iii) to terminate a permit, in which case the director will prepare a notice of intent to terminate, which is a type of draft permit.

(B) A draft permit will contain all proposed permit conditions.

(4) Fact sheets. The director will prepare a fact sheet to accompany every draft permit that the director finds is the subject of widespread public interest or raises important issues. The fact sheet will briefly set forth the principal facts and the significant factual, legal, methodological, and policy questions considered in preparing the draft permit. The fact sheet will include information satisfying the requirements of 40 Code of Federal Regulations §124.8(b).

(5) Notice.

(A) The commission will give notice when a draft permit is prepared under paragraph (3) of this subsection, and when a hearing is scheduled under paragraph (7) of this subsection.

(B) Notice will be given by the methods specified in this subparagraph.

(i) A copy of the notice will be mailed to the following persons:

(I) any agency that the commission knows has issued or is required to issue a permit for the same facility under any federal or state environmental program;

(II) the United States Environmental Protection Agency;

(III) persons on a mailing list developed according to 40 Code of Federal Regulations §124.10(c)(1)(viii);

(IV) any unit of local government having jurisdiction over the area where the facility is or is proposed to be located, and each state agency having any authority under state law with respect to the construction or operation of the facility;

(V) the operator; and

(VI) any oil and gas operators or surface owners required to be listed in the application under subsection (d)(4)(F) and (G) of this section. If, pursuant to subsection (d)(4)(G), the director waived the requirement to list certain surface owners in the application, the applicant shall notify such persons by publishing the notice. The notice shall be published by the applicant once each week for two consecutive weeks in a newspaper of general circulation for the county where the facility is located. The applicant shall file proof of publication with the commission in Austin.

(ii) The notice shall be published by the applicant at least once in a newspaper of general circulation for the county where the facility is located. The applicant shall file proof of publication with the commission in Austin.

(C) Notices will include information satisfying the requirements of 40 Code of Federal Regulations §124.10(d) and the Texas Government Code, Chapter 2001.

(D) A copy of any draft permit, fact sheet, and application will be mailed to the persons notified under subparagraph (B)(i)(I) and (II) of this paragraph, and to any other person upon request. The applicant will be mailed a copy of any draft permit and fact sheet.

(E) The Texas Commission on Environmental Quality, the Texas Water Development Board, the Texas Department of Health, the Texas Parks and Wildlife Department, the United States Fish and Wildlife Service, other state and federal agencies with jurisdiction over fish, shellfish, and wildlife resources, the Advisory Council on Historic Preservation, state historic preservation officers, and other appropriate government authorities will be given opportunity to receive copies of notices, applications, draft permits, and fact sheets.

(6) Comments and requests for hearing. Notice of a draft permit will allow at least 30 days for public comment. During the public comment period, any interested person may submit written comments on the draft permit and may request a hearing if one has not already been scheduled.

(7) Hearings on draft permits.

(A) A hearing will be held:

(i) when the director finds, on the basis of requests, a significant degree of public interest in a draft permit;

(ii) when an applicant or an affected person requests a hearing on a draft permit; or

(iii) when an operator requests a hearing on a draft permit prepared when the director tentatively decides to modify, revoke and reissue, or terminate a permit.

(B) The commission may hold a hearing at its discretion, for instance, when a hearing might clarify one or more issues involved in the permit decision.

(C) Notice of a hearing will be given at least 30 days before the hearing. The public comment period under paragraph (6) of this subsection will automatically be extended to the close of any hearing under this paragraph.

(8) Administrative approval. After the close of the public comment period, the director may issue, modify, revoke and reissue, or terminate a permit administratively if no hearing is required under paragraph (7) of this subsection.

(9) Response to comments. When a final permit is issued, the commission will respond in writing to comments received during the public comment period. The response will be made available to the public and will:

(A) specify which provisions, if any, of the draft permit have been changed in the final permit, and the reasons for the changes; and

(B) briefly describe and respond to all significant comments on the draft permit raised during the public comment period, or during any hearing on the draft permit.

(j) Commission review of administrative actions. Administrative actions performed by the director or commission staff pursuant to this section are subject to review by the commissioners.

(k) Federal regulations. All references to the Code of Federal Regulations in this section are references to the 1987 edition of the Code. The following federal regulations are adopted by reference and can be obtained at the William B. Travis Building, 1701 North Congress Avenue, Austin, Texas 78711: 40 Code of Federal Regulations §§124.8(b), 124.10(c)(1)(viii), 124.10(d), and 146.8(d). Where the word "director" is used in the adopted federal regulations, it should be interpreted to mean "commission."

(l) Effective date. This section becomes effective upon approval of the commission's Class III Underground Injection Control (UIC) Program for brine mining injection wells by the United States Environmental Protection Agency under the Safe Drinking Act, §1422 (42 United States Code §300h-1).

Source Note: The provisions of this §3.81 adopted to be effective August 25, 2003, 28 TexReg 6816; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective February 18, 2025, 50 TexReg 835.

§3.82 Brine Production Projects and Associated Brine

Production Wells and Class V Spent Brine Return Injection Wells.

(a) Scope and purpose.

(1) This section contains the regulations for:

(A) brine production projects and the associated brine production wells for the extraction of elements, minerals, mineral ions, salts, or other useful substances, including, but not limited to, lithium, lithium ions, lithium chloride, halogens or halogen salts, from a subsurface formation but not including oil, gas, or any product of oil or gas, as defined by Section 85.001 of the Natural Resources Code, or fluid oil and gas waste, as defined by Section 122.001 of the Natural Resources Code; and

(B) Class V spent brine return injection wells used in association with brine production projects for the reinjection of the spent brine.

(2) This section applies regardless of whether the well was initially completed for the purpose of brine production or Class V spent brine return injection or was initially completed for another purpose and is converted for brine production or Class V spent brine return injection.

(3) The operator of a brine production project, including associated brine production wells and Class V spent brine return injection wells, shall comply with the requirements of this section as well as with all other applicable Commission rules and orders.

(4) Any pipelines, flowlines, storage, or any other brine containers at the brine production project shall be constructed, operated, and maintained such that they will not leak or cause an unauthorized discharge to surface or subsurface waters.

(5) This section does not apply to Class III brine mining injection wells regulated under §3.81 of this title (relating to Class III Brine Mining Injection Wells).

(6) This section does not apply to the creation, operation, or maintenance of an underground hydrocarbon storage cavern in a salt formation regulated under §3.95 of this title (relating to Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations) and §3.97 of this title (relating to Underground Storage of Gas in Salt Formations).

(7) This section does not apply to the injection of fluids that meet the definition of a hazardous waste under 40 CFR Part 261.

(8) Subsection (d) of this section establishes statewide field rules for brine production fields including assignment of acreage, well spacing, and density provisions to promote the regular development of brine resources in a manner that does not damage the reservoir.

(9) If a provision of this section conflicts with any provision or term of a Commission order or permit, the provision of such order or permit controls, provided that the provision satisfies the minimum requirements for EPA's Class V Underground Injection Control (UIC) program.

(10) If a provision of this section conflicts with a provision of another Commission rule referenced in this section, the provision of this section controls.

(b) Definitions. The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of activity sought to be permitted, has suffered, or faces a substantial risk of suffering, concrete or actual injury or economic damage other than as a member of the general public. A competitor is not an affected person unless it has suffered, or faces a substantial risk of suffering, actual harm to its interest in real property or waste of substantial recoverable substances.

(2) Application--The Commission form for applying for a permit, including any additions, revisions or modifications to the forms, and any required attachments.

(3) Aquifer--A geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

(4) Area of review (AOR)--The brine production project area unless an exception obtained pursuant to this section results in an injection well location closer than one-half mile to the boundary of the brine production project area, in which case the area of review is a one-half mile radius around the injection well location.

(5) Brine--Saline water, whether contained in or removed from an aquifer, which may contain brine resources or other naturally-occurring substances such as entrained oil or gas, including hydrogen sulfide gas. The term does not include brine produced as an incident to the production of oil and gas.

(6) Brine field--A formation or the correlative depth interval designated in the field designation or rules that contains brine resources.

(7) Brine production project--A project the purpose of which is the extraction of brine resources from a brine field. The term includes brine production wells, Class V spent brine return injection wells, monitoring wells, brine flowlines, and any equipment associated with the project.

(8) Brine production project area--The surface extent of the land assigned to a brine production project, as indicated on the plat required by subsection (e)(3)(N) of this section.

(9) Brine production project permit--A permit authorizing a brine production project issued by the Commission pursuant to this section.

(10) Brine production well--A well drilled or recompleted for the exploration or production of brine resources that is part of a brine production project.

(11) Brine resource--Elements, minerals, salts, or other useful substances dissolved or entrained in brine, including, but not limited to, lithium, lithium ions, lithium chloride, halogens, or other halogen salts, but not including oil, gas, or any product of oil or gas. The term does not include brine extracted pursuant to §3.81 of this title (relating to Class III Brine Mining Injection Wells).

(12) Cementing--The operation whereby a cement slurry is pumped into a drilled hole and/or forced behind casing.

(13) Class V spent brine return injection well--A well into which brine produced by a brine production project is re-injected into the same brine field from which it was withdrawn after the brine resources have been extracted. The term does not include a Class I, II, III, IV, or VI UIC well.

(14) Code of Federal Regulations (CFR)--The codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the federal government.

(15) Commission--The Railroad Commission of Texas.

(16) Confining zone--A geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above or below the brine field.

(17) Contaminant--Any physical, chemical, biological,

or radiological substance or matter in water.

(18) Corrective action--Methods to assure that wells within the area of review do not serve as conduits for the movement of fluids from the brine field and into or between USDWs, including the use of corrosion resistant materials where appropriate.

(19) Director--The Director of the Oil and Gas Division of the Railroad Commission of Texas or the Director's delegate.

(20) Electric log--A density, sonic, or resistivity (except dip meter) log run over the entire wellbore.

(21) EPA--The United States Environmental Protection Agency.

(22) Exempted aquifer--An aquifer or its portion that meets the criteria in the definition of USDW but which has been exempted according to the procedures in 40 CFR §144.7.

(23) Fault--A surface or zone of rock fracture along which there has been displacement.

(24) Flow rate--The volume per time unit given to the flow of gases or other fluid substance which emerges from an orifice, pump, turbine or passes along a conduit or channel.

(25) Fluid--Any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state.

(26) Formation--A body of consolidated or unconsolidated rock characterized by a degree of lithologic homogeneity which is prevailingly, but not necessarily, tabular and is mappable on the earth's surface or traceable in the subsurface.

(27) Formation fluid--Fluid present in a formation under natural conditions as opposed to introduced fluids such as drilling mud.

(28) Fracture pressure--The pressure that, if applied to a subsurface formation, would cause that formation to physically fracture or result in initiation or propagation of fractures.

(29) Good faith claim--A factually supported claim based on a recognized legal theory to a continuing possessory right in an estate that includes the brine resources sought to be extracted through a brine production well.

(30) Injection well--A well into which fluids are being injected.

(31) Interested person--Any person who expresses an interest in an application, permit, or Class V spent brine return injection well.

(32) Limited English-speaking household--A household in which all members 14 years and older have at least some difficulty with English.

(33) Lithology--The description of rocks on the basis of their physical and chemical characteristics.

(34) Mechanical integrity--A Class V spent brine return injection well has mechanical integrity if:

(A) there is no significant leak in the casing, tubing, or packer (internal mechanical integrity); and

(B) there is no significant fluid movement into a USDW through channels adjacent to the injection well bore as a result of operation of the injection well (external mechanical integrity).

(35) Operator--A person, acting for itself or as an agent for others and designated to the Commission as the one who has the primary responsibility for complying with its rules and regulations in any and all acts subject to the jurisdiction of the Commission.

(36) Packer--A device lowered into a well to produce a fluid-tight seal.

(37) Person--A natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(38) Plugging--The act or process of stopping the flow of water, oil, or gas into or out of a formation through a borehole or well penetrating that formation.

(39) Plugging record--A systematic listing of permanent or temporary abandonment of water, oil, gas, test, exploration and waste injection wells. The listing may contain a well log, description of amounts and types of plugging material used, the method employed for plugging, a description of formations which are sealed and a graphic log of the well showing formation location, formation thickness, and location of plugging structures.

(40) Pollution--The alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation or property or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(41) Pressure--The total load or force per unit area acting on a surface.

(42) Schedule of compliance--A schedule of remedial measures included in a permit, including an enforceable sequence of interim requirements (for example, actions, operations, or milestone events) leading to compliance with the applicable statutes and regulations.

(43) Spent brine--Brine produced from a brine production well from which brine resources have been extracted. Spent brine may include non-hazardous process water and other additives used to facilitate brine resource extraction or reinjection.

(44) Surface casing--The first string of well casing to be installed in the well.

(45) Total dissolved solids--The total dissolved (filterable) solids as determined by use of the method specified in 40 CFR part 136.

(46) Transmissive fault or fracture--A fault or fracture that has sufficient permeability and vertical extent to allow fluids to move beyond the confining zone.

(47) Underground injection--Well injection.

(48) UIC--Underground injection control.

(49) UIC Program--The Underground Injection Control program under Part C of the Safe Drinking Water Act, including an "approved State program" as defined in 40 CFR §144.3.

(50) Underground source of drinking water (USDW)--An aquifer or its portion which is not an exempted aquifer and which:

(A) supplies any public water system; or

(B) contains a sufficient quantity of ground water to supply a public water system and either:

(i) currently supplies drinking water for human consumption; or

(ii) contains fewer than 10,000 milligrams per liter total dissolved solids.

(51) Well--A bored, drilled, or driven shaft whose depth is greater than the largest surface dimension, or a dug hole whose depth is greater than the largest surface dimension.

(52) Well injection--The subsurface emplacement of fluids through a well.

(53) Well plug--A watertight and gastight seal installed in a borehole or well to prevent movement of fluids.

(54) Workover--An operation in which a down-hole component of a well is repaired or the engineering design of the well is changed. Workovers include operations such as sidetracking, the addition of perforations within the permitted injection interval, and the addition of liners or patches. For the purposes of this section, workovers do not include well stimulation operations.

(c) General requirements.

(1) A brine production project and all associated brine production wells and Class V spent brine return injection wells shall be permitted in accordance with the requirements of this section. No person may construct or operate such wells without a permit under this section.

(2) Applications and reports shall be signed in accordance with this paragraph.

(A) Applications. All applications shall be signed as follows:

(i) for a corporation, by a responsible corporate officer. A responsible corporate officer means a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy-making or decision-making functions for the corporation; or

(ii) for a partnership or sole proprietorship, by a general partner or the proprietor, respectively.

(B) Reports. All reports required by permits and other information requested by the Commission shall be signed by a person described in subparagraph (A) of this paragraph or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(i) the authorization is made in writing by a person described in subparagraph (A) of this paragraph;

(ii) the authorization specifies an individual or position having responsibility for the overall operation of the regulated brine production project; and

(iii) the authorization is submitted to the Commission before or together with any report of information signed by the authorized representative.

(C) Certification. Any person signing a document under subparagraph (A) or (B) of this paragraph shall make the following certification: "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or who are directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information."

(3) Operators of all Class V spent brine return injection wells shall re-inject spent brine into the brine field from which the brine was produced.

(4) All brine production wells and Class V spent brine return injection wells shall be drilled and completed or recompleted, operated, maintained, and plugged in accordance with the requirements of this section and the brine production project permit.

(5) The Commission shall assign each brine production project a Commission lease number. All brine project operators shall ascertain from the appropriate schedule the lease number assigned to each separate brine production project, and thereafter include on each Commission-required form or report the exact brine production project name and its assigned number as they appear on the current schedule for all leases.

(6) An applicant for or permittee of a brine production project and associated wells shall comply with the requirements of this chapter, including but not limited to:

(A) §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements);

(B) §3.5 of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back);

(C) §3.11 of this title (relating to Inclination and Directional Surveys Required);

(D) §3.12 of this title (relating to Directional Survey Company Report);

(E) §3.16 of this title (relating to Log and Completion or Plugging Reports)

(F) §3.17 of this title (relating to Pressure on Bradenhead)

(G) §3.18 of this title (relating to Mud Circulation Required);

(H) §3.19 of this title (relating to Density of Mud-Fluid);

(I) §3.36 of this title (relating to Oil, Gas, Brine, or Geothermal Resource Operation in Hydrogen Sulfide Areas);

(J) §3.80 of this title (relating to Commission Oil and Gas Forms, Applications, and Filing Requirements); and

(K) Chapter 4 of this title (relating to Environmental Protection).

(7) In addition to the requirements of §3.13 of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements), all wells associated with a brine production project shall use casing and cement designed to withstand the anticipated pressurization and formation fluids that are capable of negatively impacting the integrity of casing and/or cement such that it presents a threat to USDWs or oil, gas, or geothermal resources.

(8) All operators of wells drilled and operated in association with a brine production project shall comply with the requirements of §3.14 of this title (relating to Plugging), §3.15 (relating to Surface Equipment Removal Requirements and Inactive Wells), and §3.35 (relating to Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned), except that the operator shall plug all wells associated with a brine production project and remove all wastes, storage vessels, and equipment from the site within one year of cessation of brine production project operations.

(9) All operators of wells drilled and operated in association with a brine production project shall comply with the requirements of §3.78 of this title (relating to Fees and Financial Security Requirements), as the requirements are applicable to brine production projects, except that, prior to spudding, the operator shall provide financial security in an amount estimated to plug each well in the brine production project after cessation of brine production project operations. Notwithstanding the provisions of §3.78(i) of this title, for an operator of a brine production project who has satisfied its financial security requirements by filing a cash deposit, the Commission shall refund to the operator the amount estimated to plug

each well following its plugging if the amount of the deposit remaining after the refund would be sufficient to plug all remaining wells in the brine production project.

(10) No person may knowingly make any false statement, representation, or certification in any application, report, record, or other document submitted or required to be maintained under this section or under any permit issued pursuant to this section, or falsify, tamper with, or knowingly render inaccurate any monitoring device or method required to be maintained under this section or under any permit issued pursuant to this section.

(d) Spacing, acreage, density and field rules; exceptions.

(1) Spacing. All brine production wells and Class V spent brine return injection wells shall be completed within the brine production project area and no less than one-half mile from the boundary of the brine production project area and no less than one-half mile from any interest within the brine production project area that is not participating in the project, unless special field rules provide different spacing requirements or the applicant obtains an exception to this paragraph pursuant to paragraph (4) of this subsection.

(2) Acreage and density.

(A) An applicant for a brine production project permit shall designate and assign to the project acreage within the applicable brine field and indicate the total number of acres in the permit application required by subsection (e)(3) of this section. The minimum acreage is 1,280 acres per brine production well included in the brine production project unless special field rules provide different well density requirements or the applicant obtains an exception to this paragraph pursuant to paragraph (4) of this subsection.

(B) Upon completion of a brine production well in a brine production project area and filing the completion report with the Commission, the applicant shall file a plat assigning acreage in the brine production project area to each brine production well. The total number of acres assigned to the brine production project area divided by the total number of brine production wells shall equal or exceed 1,280 acres unless special field rules provide different well density requirements or the applicant obtains an exception to the density requirements pursuant to paragraph (4) of this subsection.

(C) An applicant shall not assign more than 5,120 acres in a brine field to a brine production well unless special field rules provide for different limits.

(D) The two farthermost points of acreage assigned to a well shall not exceed 23,760 feet unless special field rules provide for a different limit, and the acreage assigned shall include all productive portions of the wellbore.

(E) Multiple assignment of the same acreage in a brine field to more than one brine production well is not permitted. However, this limitation shall not prevent the reformation of brine production projects so long as:

(i) no multiple assignment of acreage occurs; and

(ii) such reformation does not violate other regulations.

(F) The acreage included in a brine production project area shall consist of acreage for which the operator has a good faith claim to produce brine resources.

(i) Non-contiguous acreage included in the same brine production project area may not be separated by greater than the minimum spacing distance for wells provided by paragraph (1) of this subsection, as altered by any applicable special field rules.

(ii) An operator may obtain an exception to the contiguity requirements of clause (i) of this subparagraph pursuant to paragraph (4)(C) of this subsection.

(G) The acreage limits provided by this paragraph are the minimum and maximum amounts of acreage in a brine field that may be assigned to an individual well at the operator's election and shall not be construed as a limit on the sizes of either a brine production project area or a pooled unit for production of brine resources.

(3) Brine field designation and field rules.

(A) Application for new brine field designation. A new brine field designation may be made by the Commission after a hearing after notice to all operators of brine production wells within a two-and one-half-mile radius of the brine discovery well. The applicant shall provide proper evidence proving that a well is completed in a new field.

(i) The applicant shall submit a legible area map, drawn to scale, which shows the following:

(I) all oil, gas, brine production, and abandoned wells within at least a two-and one-half-mile radius of the brine well claimed to be a discovery well;

(II) the producing intervals of all wells identified in subclause (I) of this clause;

(III) all Commission-recognized fields within a two and one-half mile radius of the brine well claimed to be a discovery well identified by Commission-assigned field names, names of the producing formations, and approximate average depth of the producing interval;

(IV) the total depth of all wells identified in subclause (I) of this clause that penetrated the top of the proposed new field; and

(V) scale, legend, and name of person who prepared the map.

(ii) The applicant shall submit a list of the names and addresses of all operators of wells within a two-and one-half-mile radius of the brine discovery well.

(iii) The applicant shall submit a complete electric log of the brine well. If the applicant contends the electric log is confidential by law, the applicant shall mark the log confidential. If the Commission receives a request under the Texas Public Information Act (PIA), Texas Government Code, Chapter 552, for logs that have been designated confidential, the Commission will notify the filer of the request in accordance with the provisions of the PIA so that the filer can take action with the Office of the Attorney General to oppose release of the log.

(iv) The applicant shall submit a bottom-hole pressure for brine production wells submitted on the appropriate form. This bottom-hole pressure may be determined by a pressure build-up test, drill stem test, or wire-line formation tester. Calculations based on fluid level surveys or calculations made on flowing wells using shut-in wellhead pressures may be used if no test data is available.

(v) The applicant shall submit a subsurface structure map and/or cross sections, if separation is based on structural differences, including faulting and pinch-outs. The structure map shall show the contour of the top of the brine field and the lines of cross section. The cross sections shall be prepared from comparable electric logs (not tracings) with the wells, producing formation, and brine field identified. The engineer or geologist who prepared the map and cross section shall sign and seal them.

(vi) The applicant shall submit reservoir pressure measurements or calculations, if separation is based on pressure differentials.

(vii) The applicant shall submit core data, drillstem test data, cross sections of nearby wells, and/or production data estimating the fluid level, if separation is based on differences in fluid levels. The applicant shall obtain the fluid level data within 10 days of the potential test date.

(viii) The applicant shall submit evidence that demonstrates that the new brine field is effectively separated from any other brine field or oil or gas field previously shown to be commercially productive.

(B) Temporary brine field rules.

(i) The Commission will accept applications for temporary brine field rule hearings for brine fields after the first well has been completed in a brine field.

(ii) When requesting such hearings, the applicant shall furnish the Commission with a list of the names and addresses of all operators of wells within a two-and one-half-mile radius of the brine discovery well.

(iii) At the hearing on the adoption of temporary brine field rules, the applicant bears the burden of establishing that each of the proposed temporary brine field rules is reasonably expected to protect freshwater resources, protect correlative rights, prevent waste of recoverable brine resources, and promote the production of additional brine resources in an orderly and efficient manner.

(iv) Temporary brine field rules shall remain effective until:

(I) 18 months after adoption; or

(II) permanent brine field rules are adopted.

(C) Permanent brine field rules.

(i) After temporary brine field rules have been effective in a brine field for at least 12 months, the operator of a brine production well in the brine field subject to temporary brine field rules or the Commission may request a hearing to adopt permanent brine field rules for the brine field in which the operator's well is located.

(ii) An operator requesting a hearing to adopt permanent brine field rules shall furnish the Commission a list of all operators within a two-and one-half-mile radius of the brine discovery well.

(iii) If permanent field rules are not adopted, temporary field rules adopted under subparagraph (B) of this paragraph expire after 18 months and the statewide field requirements of this section apply to operations within the applicable brine field.

(4) Exceptions to spacing, density, and contiguity requirements.

(A) An exception to paragraph (1) of this subsection or paragraph (2)(A) - (C) of this subsection may be granted after at least 21 days' notice to all persons described in subparagraph (B) of this paragraph. An exception to paragraph (2)(F) of this subsection may be granted after at least 21 days' notice to all persons described in subparagraph (C) of this paragraph. If no person entitled to notice protests the request for an exception, the Commission may grant the exception administratively. If the Commission receives a timely protest, the Director shall forward the request for an exception to the Hearings Division to conduct a hearing. At a hearing on an exception, the burden shall be on the applicant to establish that an exception to this section is necessary either to prevent waste or to protect correlative rights.

(B) In addition to the notice required under subsection (f) of this section, an applicant seeking an exception to the spacing or density requirements shall file with its application the names and mailing addresses of the following persons for tracts within the minimum spacing distance for the proposed well and the brine field:

(i) the designated operator;

(ii) all lessees of record for tracts with no designated operator; and

(iii) all owners of record of unleased mineral interests.

(C) In addition to the notice required under subsection (f) of this section, an applicant seeking an exception to the contiguity requirements of paragraph (2)(F) of this subsection shall file with its application the names and mailing addresses of the following persons for tracts located between the non-contiguous portions of its proposed project area that are farther apart than the minimum spacing distance for wells in the brine field:

(i) the designated operator;

(ii) all lessees of record for tracts with no designated operator; and

(iii) all owners of record of unleased mineral interests.

(D) If, after diligent efforts, the applicant is unable to ascertain the name and address of one or more persons required by this paragraph to be notified, then the applicant shall notify such persons by publishing notice of the application in a form approved by the Commission. The applicant shall publish the notice once each week for two consecutive weeks in a newspaper of general circulation in the county or counties in which the brine production project well will be located. The first publication shall be published at least 14 days before the protest deadline in the notice of application.

(e) Brine production project permit application.

(1) Any person who proposes to operate a brine production project shall submit to the Director an application for a brine production project permit. The application shall be made under this section or under special field rules governing the particular brine field, or as an exception thereto, and filed with the Commission on a form approved by the Commission.

(2) An application for a brine production project permit shall be accompanied by an application for at least one injection well and shall include the information required by paragraph (3) of this subsection, as applicable. The applicant is not required to submit permit applications for the other individual brine production and Class V spent brine return injection wells at the time the applicant submits its application for a brine production project permit. Unless otherwise specified in the brine production project permit, once the brine production project permit has been issued, the operator may operate additional brine production wells and Class V spent brine return injection wells as part of the brine production project. The operator shall obtain permits for those wells prior to commencing operations. Requirements for obtaining a Class V spent brine return injection well permit are specified in paragraph (4) of this subsection. Notice in addition to the notice required for the brine production project by subsection (f) of this section is not required for the individual wells unless the operator requests an exception

to the spacing, density, or acreage requirements or additional notice is required by the permit.

(3) An application for a brine production project permit shall comply with the requirements of this paragraph.

(A) The application shall include the name, mailing address, and physical location of the brine production project for which the application is submitted.

(B) The application shall include the applicant's name, mailing address, telephone number, P-5 Organization Report number, and a statement indicating whether the applicant operator is the owner of the brine production project.

(C) The application shall specify the proposed use or uses for the brine produced by the project.

(D) The application shall specify the estimated maximum number of brine production wells and Class V spent brine return injection wells that will be operated within the brine production project.

(E) The application shall designate the total number of acres included in the proposed brine production project area, which shall equal not less than 1,280 acres per brine production well unless special field rules provide otherwise.

(F) The application shall specify the brine field from which the brine will be produced and spent brine reinjected, including the top and bottom depths of the field throughout the area of review.

(G) The application shall include complete electric logs of representative brine production wells and Class V spent brine return injection wells or complete electric logs of representative nearby wells. On the logs, the applicant shall identify and indicate the depths of the geologic formations between the land surface and the top of the brine field.

(H) The application shall include wellbore diagrams showing the completions that will be used for brine production wells and Class V spent brine return injection wells, including casing and liner sizes and depths and a statement indicating that such wells will be drilled, cased, cemented, and completed in accordance with the requirements of §3.13 of this title as those requirements may be revised by this section. The statement shall also include information to demonstrate that the casing and cement used in the completion of each brine production well and each Class V spent brine return injection well is designed to withstand the anticipated pressurization and formation fluids that are capable of negatively impacting the integrity of casing and/or cement such that it presents a threat to USDWs or oil, gas, or geothermal resources. The wellbore diagrams shall show the proposed arrangement of the downhole well equipment and specifications of the downhole well equipment. A single wellbore diagram may be submitted for multiple wells that have the same configuration, provided that each well with that type of configuration is identified on the wellbore diagram and the diagram identifies the deepest cement top for each string of casing among all the wells covered by that diagram.

(I) The application shall include information to characterize the brine field from which the brine will be produced and into which the spent brine will be reinjected, including the following:

(i) an isopach map showing thickness and areal extent of the brine field;

(ii) lithology, grain mineralogy, and matrix cementing of the brine field;

(iii) effective porosity of the brine field and the method used to determine effective porosity;

(iv) vertical and horizontal permeability of the brine field and the method used to determine permeability;

(v) the occurrence and extent of natural fractures and solution features within the brine production project;

(vi) chemical and physical characteristics of the fluids contained in the brine field that may potentially impact casing or cement;

(vii) the bottom hole temperature and pressure of the brine field;

(viii) formation fracture pressure of the brine field, the method used to determine fracture pressure and the expected direction of fracture propagation. Calculations demonstrating injection of spent brine into the proposed brine field shall not exceed the fracture pressure gradient and information showing injection into the brine field will not initiate fractures through the confining zone;

(ix) a description of the proposed well stimulation program, if applicable, including a description of the stimulation fluids, and a determination that the well stimulation will not compromise containment of the brine field;

(x) the vertical distance separating the top of the brine field from the base of the lowest USDW;

(xi) a demonstration, such as geologic maps and cross-sections, that the brine field into which the spent brine will be injected is the same formation from which the brine will be produced; and

(xii) any other information necessary to characterize the brine field.

(J) The application shall include information to characterize the proposed confining zone, including the following:

(i) the geological name and the top and bottom depths of the formation making up the confining zone;

(ii) an isopach map showing thickness and areal extent of the confining zone;

(iii) lithology, grain mineralogy, and matrix cementing of the confining zone;

(iv) the vertical distance separating the top of the confining zone from the base of the lowest USDW; and

(v) any other information necessary to characterize the confining zone.

(K) The application shall include the proposed operating data, including the following:

(i) the maximum daily brine production rate;

(ii) the maximum daily injection rate and maximum injection pressure; and

(iii) the proposed test procedure to be used to determine mechanical integrity of the Class V spent brine return injection wells.

(L) The application shall include a letter from the Geologic Advisory Unit of the Commission's Oil and Gas Division stating that the use of the brine field for the injection of spent brine will not endanger usable quality water or USDWs.

(M) The application shall include an accurate plat with surveys of a scale sufficient to legibly show the entire extent of the area of review. The plat shall include the following:

(i) the area of review outlined on the plat using either a heavy line or crosshatching;

(ii) the location, to the extent anticipated at the time of the application, of each well within the brine production project area that the applicant intends to use for the brine production project including each existing well that may be converted to brine production or Class V spent brine return injection, each well the applicant intends to drill for brine production, each well the applicant intends to drill for project monitoring, and each Class V spent brine return injection well. If the wells are horizontal or deviated wells, the plat shall include the surface location of the proposed drilling site, penetration point, perforated casing or open hole through which brine will be produced or reinjected, terminus location, and a line showing the distance in feet from the perimeter of the area of review to the nearest point of extraction or injection on the lateral leg of the horizontal well;

(iii) the type, location, and depth of all wells of public record within the area of review that penetrate the top of the brine field. The applicant shall include the following information with the map:

(I) a tabulation of the wells showing the dates the wells were drilled and the current status of the wells;

(II) completion records for all wells and plugging records for plugged and abandoned wells; and

(III) a corrective action plan for any known wells in the area of review that penetrate the brine field and that may allow fluid migration into USDWs from the brine field for which the applicant cannot demonstrate proper completion, plugging, or abandonment. The Director may approve a phased corrective action plan;

(iv) the geographic location information of the wells, including the Latitude/Longitude decimal degree coordinates in the WGS 84 coordinate system, a labeled scale bar, and indication of the northerly direction; and

(v) a certification by a person knowledgeable of the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data.

(N) The application shall include a plat showing:

(i) the outline of the brine production project area;

(ii) the operators of tracts in the brine production project area and tracts adjacent to the brine production project area;

(iii) owners of all leases of record for tracts that have no designated operator in the brine production project area and within the brine field;

(iv) owners of record of unleased mineral interests within the brine field for tracts in the brine production project area;

(v) surface owners of tracts in the brine production project area; and

(vi) the names and addresses of all persons listed in clause (ii) through (v) of this subparagraph. If the names and addresses of the persons in clause (ii) through (v) of this subparagraph cannot be included on the plat, the applicant shall include the names and addresses on a separate sheet attached to the plat. The applicant shall determine the names and addresses of the surface owners from the current county tax rolls or other reliable sources and shall identify the source of the list. If the Director determines that, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more surface owners, the Director may waive the requirements of this subparagraph with respect to those surface owners.

(O) The application shall include a subsurface structure map and/or cross sections, including faulting and pinch-outs. The structure map shall show the contour of the top of the brine field and the lines of cross section. The cross sections shall be prepared from comparable electric logs (not tracings) and shall identify the wells, brine field, and any hydrocarbon reservoir.

(P) The application shall include a printed copy or screenshot showing the results of a survey of information from the United States Geological Survey (USGS) regarding the locations of any historical seismic events within a circular area of 100 square miles (a circle with a radius of 9.08 kilometers) centered around the proposed injection well location.

(Q) The application shall include a certification that the applicant has a good faith claim to produce the brine resources for the tracts included in the brine production project area.

(R) The application shall include a proposed plugging and abandonment plan.

(S) The applicant shall ensure that, if required under Texas Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, or Chapter 1002, relating to Texas Geoscientists Practice Act, respectively, the geologic and hydrologic evaluations required under this section are conducted by a licensed professional engineer or geoscientist who shall affix the appropriate seal on the resulting report of such evaluations.

(T) The application shall include any other information the Director may reasonably require to enable the Commission to determine whether to issue a permit for the brine production project, including the associated brine production wells and Class V spent brine return injection wells.

(4) Prior to commencement of injection operations into any Class V spent brine return injection well within the brine production project area, the operator shall file an application for an individual well permit with the Commission in Austin. The individual well permit application shall include the following:

(A) the well identification and, for a new well, a location plat;

(B) the location of any well drilled within one-half mile of the injection well after the date of application for the brine production project permit and the status of any well located within one-half mile of the injection well that has been abandoned since the date the brine production project permit was issued, including the plugging date if such well has been plugged;

(C) a description of the well configuration, including casing and liner sizes and setting depths, the type and amount of cement used to cement each casing string, depth of cement tops, and tubing and packer setting depths;

(D) a description of any additives used in the brine production project and reinjected with the spent brine into the Class V spent brine return well;

(E) an application fee in the amount of $100 per well; and

(F) any other information required by the brine production project permit.

(5) Criteria for exempted aquifers. An aquifer or a portion thereof which meets the criteria for an "underground source of drinking water" may be determined under 40 CFR §144.7 to be an "exempted aquifer" if it meets the criteria in paragraphs (a) through (c) of 40 CFR §146.4. The Commission adopts 40 CFR

§144.7 and §146.4 by reference, effective February 18, 2025.

(6) All individual Class V spent brine return injection wells covered by a brine production project permit shall be completed, operated, maintained, and plugged in accordance with the requirements of subsection (j) of this section and the brine production project permit.

(f) Notice and hearing.

(1) Notice to certain communities. The applicant shall identify whether any portion of the AOR encompasses an Environmental Justice (EJ) or Limited English-Speaking Household community using the most recent U.S. Census Bureau American Community Survey data. If the AOR incudes an EJ or Limited English-Speaking Household community, the applicant shall conduct enhanced public outreach activities to these communities, including a public meeting. Efforts to include EJ and Limited English-Speaking Household communities in public involvement activities in such cases shall include:

(A) published meeting notice in English and the identified language (e.g., Spanish);

(B) comment forms posted on the applicant's webpage and available at the public meeting in English and the identified language;

(C) interpretation services accommodated upon request;

(D) English translation of any comments made during any comment period in the identified language; and

(E) to the extent possible, public meeting venues near public transportation.

(2) Notice. The applicant for a brine production project permit shall give notice of the application as follows.

(A) Persons to notify. The applicant for a brine production project permit shall notify:

(i) operators on tracts adjacent to the brine production project area;

(ii) owners of all leases of record for tracts that have no designated operator in the brine production project area and within the brine field;

(iii) owners of record of unleased mineral interests in the brine production project area and within the brine field;

(iv) all surface owners identified on the plat described in subsection (e)(3)(N)(v) of this section;

(v) the city clerk or other appropriate city official of a city for which any portion falls within the brine production project area;

(vi) the county clerk of any county or counties for which any portion falls within the brine production project area; and

(vii) any other person designated by the Director.

(B) Method of notice.

(i) The applicant for a brine production project permit shall mail or deliver to persons listed in subparagraph (A) of this paragraph notice of the brine production project permit application in a form approved by the Commission. The applicant shall provide notice after staff determines than an application is complete pursuant to subsection (g)(1) of this section.

(ii) The applicant shall publish notice of the brine production project permit application in a form approved by the Commission. The applicant shall publish the notice once each week for two consecutive weeks in a newspaper of general circulation of any county or counties for which any portion falls within the brine production project area. The first notice shall be published at least 14 days before the protest deadline in the notice of application. The applicant shall file with the Commission a publisher's affidavit or other evidence of publication.

(C) Contents of notice. The notice shall be made using the form prescribed by the Commission, which shall include the following information:

(i) the county or counties within which the brine production project area is located;

(ii) a copy of the plat required by subsection (e)(3)(M) of this section;

(iii) the name of the brine field;

(iv) the depth to the top of the brine field;

(v) the proposed life of the brine production project; and

(vi) a statement that an affected person may file a protest within 30 days of the date of the notice and any interested person may submit comments to the Commission within 30 days of the date of the notice.

(D) Notice of Class V spent brine return injection wells. Once an applicant complies with the notice required to obtain a brine production project permit and the permit has been issued, no notice shall be required when filing an application for an individual injection well permit for any Class V spent brine return injection well covered by the brine production permit unless otherwise provided in the permit or unless the individual injection well has an exception such that the injection well is located closer than one-half mile from the boundary of the brine production project, in which case notice shall be provided to any new entity located within the area of review for the injection well.

(E) Notice of brine production well. Once an applicant complies with the notice required to obtain a brine production permit and the permit has been issued, no notice shall be required when filing an application for an individual brine production well permit for any brine production well covered by the brine production permit unless otherwise provided in the permit or unless an exception is requested.

(3) Comments, protests, and requests for hearing. Notice of an application will allow at least 30 days for public comment. Beginning on the date of the notice, any affected person has 30 days to protest the application, and any interested person has 30 days to submit written comments.

(4) Hearings.

(A) The Commission shall hold a hearing when:

(i) the Commission receives a written protest from an affected person within 30 days after notice of the application is given in accordance with this subsection;

(ii) the Director denies the application and the operator requests a hearing within 30 days of the notice of administrative denial;

(iii) the Director issues the permit and the operator requests a hearing to contest certain permit conditions; or

(iv) the Director determines that a hearing is in the public interest.

(B) Notice of a hearing will be given at least 30 days before the hearing. The public comment period under paragraph (3) of this subsection will automatically be extended to the close of any hearing under this paragraph.

(C) At any hearing, the burden shall be on the applicant.

(D) After hearing, the administrative law judge and technical examiner shall recommend final Commission action.

(g) Commission action on permit applications.

(1) Permitting procedures.

(A) Initial permit application review. Upon receipt of an application for a permit, the Director will review the application for completeness. Within 30 days after receipt of the application, the Director will notify the applicant in writing whether the application is complete or deficient. A notice of deficiency will state the additional information necessary to complete the application, and a date for submitting this information. The application will be deemed withdrawn if the necessary information is not received by the specified date, unless the Director has extended this date upon request of the applicant. Upon timely receipt of the necessary information, the Director will notify the applicant that the application is complete. The Director will not begin processing a permit until the application is complete.

(B) Administrative action on application. When no timely protest is received from an affected person, the Director may administratively grant an application for a brine production project permit, including the associated wells, if the applicant provides sufficient evidence to demonstrate that the brine production project will not endanger USDWs or human health or the environment.

(2) Application for an amended permit. The permittee shall file an application to amend a brine production project permit if the permittee wishes to make substantial changes such as change the exterior boundaries of, or maximum number of wells authorized in, the brine production project area or alter permit conditions.

(3) Permit application denial. If the Director administratively denies a permit application, a notice of administrative denial will be mailed to the applicant. The applicant will have a right to a hearing on request. At any such hearing, the burden shall be on the applicant. After hearing, the administrative law judge and technical examiner shall recommend final Commission action.

(h) Modification, revocation and reissuance, and termination of permits. A permit may be modified, revoked and reissued, or terminated by the Commission either upon the written request of the operator or upon the Commission's initiative, but only for the reasons and under the conditions specified in this subsection. Except for minor modifications made under paragraph (2) of this subsection, the Commission will follow the applicable procedures in paragraph (1) of this subsection. In the case of a modification, the Commission may request additional information or an updated application. In the case of a revocation and reissuance, the Commission will require a new application. If a permit is modified, only the conditions subject to modification are reopened. The term of a permit may not be extended by modification. If a permit is revoked and reissued, the entire permit is reopened and subject to revision, and the permit is reissued for a new term.

(1) Modification, or revocation and reissuance. The following are causes for modification, or revocation and reissuance:

(A) when material and substantial alterations or additions to the brine production project occur after permit issuance and justify permit conditions that are different or absent in the existing permit;

(B) the Commission receives new information;

(C) the standards or regulations on which the permit was based have been changed by promulgation of amended standards or regulations or by judicial decision after the permit was issued;

(D) the Commission determines good cause exists for modifying a compliance schedule, such as an act of God, strike, flood, materials shortage, or other event over which the operator has little or no control and for which there is no reasonably available remedy;

(E) cause exists for terminating a permit under paragraph (3) of this subsection, and the Commission determines that modification, or revocation and reissuance, is appropriate; or

(F) a transfer of the permit is proposed.

(2) Minor modifications. With the permittee's consent, the Director may make minor modifications to a permit administratively, without following the procedures of paragraph (1) of this subsection. Minor modifications may only:

(A) correct clerical or typographical errors, or clarify any description or provision in the permit, provided that the description or provision is not changed substantively;

(B) require more frequent monitoring or reporting;

(C) change construction requirements provided that any changes shall comply with the requirements of subsection (j)(4) of this section; or

(D) allow a transfer of the permit where the Director determines that no change in the permit is necessary other than a change in the name of the permittee, provided that a written agreement between the current permittee and the new permittee containing a specific date for the transfer of permit responsibility, coverage, and liability has been submitted to the Commission.

(3) Termination. The following are causes for terminating a permit during its term, or for denying a permit renewal application:

(A) the permittee fails to comply with any condition of the permit or this section;

(B) the permittee fails to disclose fully all relevant facts in the permit application or during the permit issuance process, or misrepresents any relevant fact at any time;

(C) a material change of conditions occurs in the operation or completion of the well, or there are material changes in the information originally furnished; or

(D) the Commission determines that the permitted injection endangers human health or the environment, or that pollution of USDWs is occurring or is likely to occur as a result of the permitted injection.

(4) Duty to provide information. The permittee shall also furnish to the Commission, within a time specified by the Commission, any information that the Commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The permittee shall also furnish to the Commission, upon request, copies of records required to be kept under the conditions of the permit.

(i) Permit conditions.

(1) Access by Commission. The permittee shall allow any member or employee of the Commission, on proper identification, to:

(A) enter upon the premises where a regulated activity is conducted or where records are kept under the conditions of the permit;

(B) have access to and copy, during reasonable working hours, any records required to be kept under the conditions of the permit;

(C) inspect any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under the permit; and

(D) sample or monitor any substance or parameter for the purpose of assuring compliance with the permit or as otherwise authorized by the Texas Water Code, §27.071, or the Texas Natural Resources Code, §91.1012.

(2) Commission testing. The Commission may make any tests on any well at any time necessary for regulation of wells under this section, and the operator of such wells shall comply with any directives of the Commission to make such tests in a proper manner.

(3) Duty to comply. The permittee shall comply with all conditions of the permit. Any permit noncompliance is grounds for enforcement action, for permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application.

(4) Need to halt or reduce activity not a defense. It is not a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

(5) Duty to mitigate. The permittee shall take all reasonable steps to minimize and correct any adverse effect on the environment resulting from noncompliance with the permit.

(6) Proper operation and maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control, and related appurtenances, that are installed or used by the permittee to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate permittee staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up and auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

(7) Property rights. The permit does not convey any property rights of any sort, or any exclusive privilege. However, a valid permit is a property interest that may not be modified, suspended, or revoked without due process of law.

(8) Financial assurance. The permit shall require the permittee to maintain financial responsibility and resources to plug and abandon all brine mining production wells and Class V spent brine return injection wells and to remove all wastes, storage vessels, and equipment from the site within one year of cessation of brine production operations. The permittee shall show evidence of such financial responsibility to the Director in accordance with the requirements of §3.78 of this title by submitting a cash deposit, an individual performance bond, a blanket performance bond, or letter of credit in a form prescribed by the Commission. Such cash deposit, bond, or letter of credit shall be maintained until the well is plugged in accordance with paragraph (16) of this subsection.

(9) Duration. A permit issued under this section is effective for the duration of the brine production project. The Commission will review each permit issued pursuant to this section at least once every five years to determine whether just cause exists for modification, revocation and reissuance, or termination of the permit. The Commission may modify, revoke and reissue, or terminate a permit for just cause only after notice and opportunity for a hearing.

(10) Transfers. A brine production project permit is not transferable to any person except by modification, or revocation and reissuance of the permit to change the name of the permittee and incorporate other necessary requirements associated with the permittee name change.

(11) Permit renewal. Any person who has obtained a permit under this section and who wishes to continue to operate the brine production project and brine production wells after the permit expires shall file an application for a new permit at least 180 days before the existing permit expires, unless a later date has been authorized by the Director.

(12) Permit actions. The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

(13) Compliance with permit. All brine production wells and Class V spent brine return injection wells shall be drilled, converted, completed, operated, or maintained in accordance with the brine production project permit.

(14) Monitoring and records.

(A) Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

(B) The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for at least five years from the date brine production ceases. This period may be extended by the Commission at any time.

(C) Records of monitoring information shall include the date, exact place, and time of the sampling or measurements; the individuals who performed the sampling or measurements; the dates analyses were performed; the individuals who performed the analyses; the analytical techniques or methods used; and the results of the analyses.

(15) Reporting and record retention.

(A) The permittee shall submit to the Director, within the time specified by the Director, any information that the Director may reasonably request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept under the conditions of the permit.

(B) The permittee shall retain records of all information required by the permit for at least five years from the date brine production ceases. This period may be extended by request of the Commission at any time.

(C) The permittee shall file a report of the volumes of brine, oil, and gas produced by each brine production well during the preceding month. The permittee shall report the volumes of brine production on a form designated by the Commission. The permittee shall report oil or gas volumes on the Form PR, Monthly Production Report. Each report shall be filed with the Commission on or before the last day of the month following the period covered by the report.

(D) The permittee shall notify the Director at such times as the permit requires before conversion or abandonment of a well associated with a brine production project.

(E) The permittee shall report to the Commission any noncompliance, including any spills or leaks from brine receptacles or pipelines, that may cause waste or confiscation of property or endanger surface or subsurface water, human health or the environment.

(i) An oral report shall be made to the appropriate district office immediately after the permittee becomes aware of the noncompliance.

(ii) A written report shall be filed with the Director and the appropriate district office within five days of the time the permittee becomes aware of the noncompliance. The written report shall contain the following information:

(I) a description of the noncompliance and its cause;

(II) the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue; and

(III) steps planned or taken to reduce, eliminate, and prevent recurrence of the noncompliance.

(F) If the permittee becomes aware that it failed to submit any relevant facts or submitted incorrect information in a permit application or a report to the Commission, the permittee shall promptly submit the relevant facts or correct information.

(16) Plugging. The operator of a brine production project shall plug all wells associated with the brine production project in accordance with the provisions of §3.14 of this title, except that the well shall be plugged within one year after cessation of the brine production project. For good cause, the Director may grant a reasonable extension of time in which to plug the wells if the operator submits a proposal that describes actions or procedures to ensure that the wells will not endanger USDWs during the period of the extension.

(17) Identification. Each property that produces brine resources and each well associated with a brine production project and tank shall at all times be clearly identified as follows.

(A) A sign shall be posted at the principal entrance to each such property which shall show the name by which the property is commonly known and is carried on the records of the Commission, the name of the permittee, and the number of acres in the property.

(B) A sign shall be posted at each well site which shall show the name of the property, the name of the permittee, and the well number.

(C) A sign shall be posted at or painted on each tank that is located on or serving each property, which signs shall show, in addition to the information provided for in subparagraph (A) of this paragraph, the Commission lease number for the formation from which brine in the tank is produced.

(D) The signs and identification required by this section shall be in the English language, clearly legible, and in the case of the signs required by subparagraphs (A), (B), and (C) of this paragraph shall be in letters and numbers at least one inch in height.

(18) Dikes or berms. Dikes or berms shall be erected and maintained around all permanent tanks, or battery of tanks, that are:

(A) within the corporate limits of any city, town, or village;

(B) closer than 500 feet to any highway or inhabited dwelling;

(C) closer than 1,000 feet to any school or church; or

(D) so located as to be deemed by the Commission to be an objectionable hazard.

(19) Additional conditions. The Commission reserves the right to include additional permit conditions if it determines the conditions are necessary to ensure compliance with the requirements in this section and to prevent waste, prevent the confiscation of property, or prevent pollution.

(j) Additional permit conditions for Class V spent brine return injection wells. In addition to the conditions in subsection (i) of this section, Class V spent brine return injection wells shall be subject to the following.

(1) Unauthorized injection prohibited. No person may operate a Class V spent brine return injection well without obtaining a permit from the Commission under this section. No person may begin constructing a new Class V spent brine return injection well until the Commission has issued a permit to drill, deepen, plug back, or reenter the well under §3.5 of this title and a permit to operate the injection well under this section.

(2) Injected fluid restricted to brine field. No person may operate a Class V spent brine return injection well in a manner that allows fluids to escape into USDWs from the brine field from which it was produced. If fluids from a Class V spent brine return injection well are migrating out of the brine field into USDWs, the permittee shall immediately cease injection operations in the well or wells most proximate to the location where fluids have been detected in USDWs and perform the necessary corrective action or plug the injection well.

(3) Permit standards. No person may operate a Class V spent brine return injection well in a manner that allows fluid to escape from the permitted brine field or the movement of fluids containing any contaminant into USDWs, if the presence of that contaminant may cause a violation of any primary drinking water regulation or may otherwise adversely affect the health of persons. If injected fluids migrate into USDWs, or cause formation fluid to migrate into USDWs, the permittee shall immediately cease injection operations. All permits for Class V spent brine return injection wells issued under this section shall include the conditions required by this section and any other conditions reasonably necessary to prevent the pollution of USDWs.

(4) Construction requirements for Class V spent brine return injection wells. All Class V spent brine mining injection wells shall be drilled and completed or recompleted, operated, maintained, and plugged in accordance with the requirements of this section and the Class V spent brine return injection well permit.

(A) Permits shall specify drilling and construction requirements to assure that the injection operations shall not endanger USDWs. No changes to the construction of a well may be physically incorporated into the construction of the well prior to approval of the modifications by the Director.

(B) In addition to the casing and cementing requirements of §3.13 of this title, the operator shall:

(i) for all newly drilled Class V spent brine return injection wells, drill a sufficient depth into the brine field to ensure that when the well is logged prior to setting the long string the operator will be able to identify the top of the brine field and verify that the fluid will be injected only into the brine field;

(ii) set and cement surface casing from at least 100 feet below the lowermost base of usable quality water as defined by the Geologic Advisory Unit to the surface, regardless of the total depth of the well;

(iii) set and cement long string casing at a minimum from the top of the brine field to the surface unless the Director approves an alternate completion for good cause; and

(iv) determine the integrity of the cement by a cement bond log.

(C) In order to provide the Commission with an opportunity to witness the setting and cementing of the surface casing and production casing (long string) and running of cement bond logs, the operator shall provide at least 48 hours' notice to the appropriate Commission district office.

(D) Appropriate logs and other tests shall be conducted during the drilling and construction of a Class V spent brine return injection well to verify the depth to the top of the brine field, adequacy of cement behind the casing strings, and injectivity and fracture pressure of the brine field. A descriptive report interpreting the results of such logs and tests shall be prepared by a knowledgeable log analyst and submitted to the Director. The logs and tests appropriate to each well shall be determined based on the depth, construction, and other characteristics of the well, the availability of similar data in the area, and the need for additional information that may arise as the construction of the well progresses.

(E) The well shall be equipped with tubing and packer set within 100 feet of the top of the brine field.

(F) The wellhead shall be equipped with a pressure observation valve on the tubing and for each annulus of the well.

(G) Injection operations may not begin in any new Class V spent brine return injection well until the operator has submitted a completion report to the Director, and the Director has reviewed the completion report and found the well to be in compliance with this section and the conditions of the permit. If the permittee has not received notice from the Director that the well is in compliance with this section and the permit within 45 days of submission of the completion report, the permittee may begin injection operations.

(5) Operating requirements. Class V spent brine return injection well permits will prescribe operating requirements, which shall at a minimum specify the following.

(A) All Class V spent brine return injection shall be into the same brine field from which the brine was extracted by the brine production wells.

(B) All injection shall be through tubing set on a packer. The packer shall be set within 100 feet of the top of the permitted injection interval. The Director will consider granting exceptions to this requirement for good cause and when the proposed completion of the well would still result in the protection of underground sources of drinking water and confinement of injected fluids. For wells that are approved for casing injection, the operator shall perform a casing pressure test against a temporary packer/plug to demonstrate mechanical integrity of the long string casing.

(C) Except during well stimulation, injection pressure at the wellhead shall not exceed the maximum pressure calculated to assure that the injection pressure does not initiate new fractures or propagate existing fractures in the brine field and in no case may the injection pressure initiate fractures in the confining zone or cause the escape of injection or formation fluids from the brine field.

(D) The operator shall fill the annulus between the tubing and long string casing with a corrosion inhibiting fluid. All injection wells shall maintain an annulus pressure sufficient to indicate mechanical integrity unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs. The annulus pressure shall be monitored by a pressure chart or digital pressure gauge. The operator shall provide the Director with a written report and explanation of any change in annulus pressure that would indicate a leak or lack of mechanical integrity within 15 days of detecting the change in pressure. The Commission will consider any deviations that cannot be explained by factors such as temperature fluctuations or a reasonable margin of error to be an indication of the possibility of a significant leak and/or the possibility of significant fluid movement into a formation containing a USDW. An unsatisfactory explanation may result in a requirement that the well be tested for mechanical integrity.

(E) For each workover of an injection well, the operator shall notify the appropriate Commission district office at least 48 hours prior to the beginning of the workover or corrective maintenance operations that involve the removal of the tubing or well stimulation, and a mechanical integrity test shall be run on the well after the workover is completed if the packer is unseated during the workover.

(6) Corrective action. For all known wells in the area of review that penetrate the top of the brine field for which the operator cannot demonstrate proper completion, plugging, or abandonment, the Director will require corrective action if necessary to prevent movement of fluid into USDWs. Corrective action may be phased, if a phased corrective action plan has been approved by the Director.

(7) Mechanical integrity of Class V spent brine return injection wells.

(A) Mechanical integrity required. No person may perform injection operations in a Class V spent brine return injection well that lacks mechanical integrity. A well has mechanical integrity if:

(i) there is no significant leak in the casing (internal mechanical integrity); and

(ii) there is no significant fluid movement into a USDW through vertical channels adjacent to the wellbore (external mechanical integrity).

(B) Mechanical integrity shall be demonstrated to the satisfaction of the Director. In conducting and evaluating the results of a mechanical integrity test, the operator and the Director shall apply procedures and standards generally accepted in the industry. In reporting the results of a mechanical integrity test, the operator shall include a description of the method and procedures used. In evaluating the results, the Director will review monitoring and other test data submitted since the previous mechanical integrity test.

(C) Internal mechanical integrity. The permittee shall provide for a demonstration of internal mechanical integrity of the wellhead, casing, tubing, and annular seal assembly if present, using either a pressure test at a surface pressure of not less than 100 psig above the maximum expected operating surface pressure of the well or an equivalent test approved by the Director. The permittee shall provide a recording device to record the pressures measured during a mechanical integrity test.

(D) External mechanical integrity. The permittee shall use one of the following methods to demonstrate the absence of significant fluid movement into USDWs through vertical channels adjacent to the Class V spent brine return injection wellbore:

(i) the results of a temperature or noise log; or

(ii) where the nature of the casing precludes the use of the logging techniques prescribed in clause (i) of this subparagraph, cementing records demonstrating the presence of adequate cement to prevent such movement.

(E) Alternate methods. The Director may allow the use of a method of demonstrating mechanical integrity other than the methods listed in subparagraphs (C) and (D) of this paragraph with the approval of the administrator of EPA obtained pursuant to 40 CFR §146.8(d).

(F) Calibration of pressure gauges. A permittee shall calibrate all pressure gauges used in mechanical integrity demonstrations according to the manufacturer's recommendations. A copy of the calibration certificate shall be submitted to the Director at the time of demonstration and every time the gauge is calibrated. A pressure gauge shall have a resolution so as to allow detection of at least one-half of the maximum allowable pressure change.

(G) Timing of mechanical integrity testing.

(i) Both internal and external mechanical integrity shall be demonstrated before injection operations begin.

(ii) Internal mechanical integrity shall be demonstrated annually thereafter and after any workover that involves the removal of the tubing.

(iii) External mechanical integrity shall be demonstrated every five years.

(iv) The Director may require mechanical integrity testing if the Director has reason to believe that the well lacks mechanical integrity.

(H) Notice of testing. The permittee shall notify the appropriate Commission district office orally at least 48 hours before performance of a mechanical integrity test.

(I) Reporting of testing. The permittee shall file a complete record of the test with the Commission in Austin within 30 days after the test. A copy of the pressure record shall accompany the report. The report shall include evaluation of the test results by a person qualified to provide such an evaluation. Reports of mechanical integrity demonstrations using downhole logs shall be accompanied by an interpretation of the log by a person qualified to make such interpretations.

(J) Failure to demonstrate mechanical integrity.

(i) A well shall maintain mechanical integrity. If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity is suspected during operation, the permittee shall halt injection immediately unless the Director allows continued injection because the permittee establishes that injection can continue without endangering USDWs. Report of the failure of mechanical integrity shall be made orally to the Director within 24 hours from the time the permittee becomes aware of the failure.

(ii) A written plan to restore mechanical integrity shall be submitted to the Director within 15 days of the failure to demonstrate mechanical integrity. The plan shall include a schedule and description of corrective action and a schedule for re-testing or plugging the well. The corrective action proposed in the plan shall be designed such that the completion of the well will comply with this section. The Director may witness any mechanical integrity demonstration.

(iii) All wells that fail to pass a mechanical integrity test shall be repaired or plugged and abandoned within 90 days of the failure date. The 90-day timeline may be extended by the Director for good cause. The well shall be shut-in immediately after failure to pass the mechanical integrity test and shall remain shut-in until it passes a mechanical integrity test or is plugged and abandoned.

(K) Testing deviations. The Commission will consider any deviations during testing that cannot be explained by factors such as temperature fluctuations or by the margin of error for the test used to determine mechanical integrity to be an indication of the possibility of a significant leak and/or the possibility of significant fluid movement into a formation containing a USDW.

(8) Monitoring and records.

(A) Monitoring requirements. Permits shall specify the following monitoring requirements:

(i) the proper use, maintenance, and installation of monitoring equipment or methods;

(ii) the type, intervals, and frequency of monitoring sufficient to yield data representative of the monitored activity, including continuous monitoring when appropriate;

(iii) the reporting of monitoring results with a frequency dependent on the nature and effect of the monitored activity, but in no case less than annually; and

(iv) any samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

(B) Record retention. The operator shall retain records of all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation, copies of all reports required by the permit, and records of all data used to complete the permit application, for at least five years from the date brine production ceases. This period may be extended by request of the Commission at any time.

(C) Monitoring record contents. Records of monitoring information shall include the date, exact place, and time of the sampling or measurements; the individuals who performed the sampling or measurements; the dates analyses were performed; the individuals who performed the analyses; the analytical techniques or methods used for the analyses; and the results of the analyses.

(D) Signatory requirements. All reports and other information submitted to the Commission shall be signed and certified in accordance with subsection (c)(2) of this section.

(E) Reporting requirements.

(i) The operator shall notify the Commission and obtain Commission approval in advance of any planned changes to the brine production project, including any physical alternation or addition to the project and any change that may result in non-compliance with permit conditions.

(ii) Monitoring results shall be reported at the intervals specified in the permit.

(iii) Reports of compliance or noncompliance with the requirements contained in any schedule of compliance shall be submitted no later than 30 days after each scheduled date.

(iv) The operator shall report to the Commission any noncompliance that may endanger USDWs, human health, or the environment.

(I) An oral report shall be made to the appropriate Commission district office immediately after the operator becomes aware of the noncompliance.

(II) A written report shall be filed with the Director within five days of the time the operator becomes aware of the noncompliance. The written report shall contain the following information:

(-a-) a description of the noncompliance and its cause;

(-b-) the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue; and

(-c-) steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(v) Information that shall be reported under this subparagraph includes the following:

(I) any monitoring or any other information that indicates that any contaminant may endanger USDWs; and

(II) any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between USDWs.

(F) Reporting errors. If the operator becomes aware that it failed to submit any relevant facts or report any noncompliance, or that it submitted incorrect information in a permit application or a report to the Director, then the operator shall promptly submit the relevant facts, report of noncompliance, or correct information as applicable. A report of noncompliance shall contain the information listed in subparagraph (E) of this paragraph.

(9) Notice of workovers. The operator shall notify the appropriate Commission district office at least 48 hours before performing any workover or corrective maintenance operations that involve the unseating of the packer or well stimulation.

(10) Additional conditions. The Commission may establish additional conditions on a case-by-case basis as required to provide for and assure compliance with the requirements specified in this section.

(k) Violations; penalties.

(1) Any well drilled or operated in violation of this section without a permit issued under this section shall be plugged.

(2) Violations of this section may subject the operator to penalties and remedies specified in the Texas Water Code, Chapter 27, and the Natural Resources Code, Title 3.

(3) The certificate of compliance for a brine production well may be revoked in the manner provided in subsections §3.73(d)-(g), (i)-(k) of this title (relating to Pipeline Connection; Cancellation of Certification of Compliance; Severance) for violations of this section.

(l) Commission review of administrative actions. Administrative actions performed by the Director or Commission staff pursuant to this section are subject to review by the commissioners.

(m) Federal regulations. All references to the CFR in this section are references to the 1987 edition of the Code. The following federal regulations are adopted by reference and can be obtained at the William B. Travis Building, 1701 North Congress Avenue, Austin, Texas 78711: 40 CFR §§124.8(b), 124.10(c)(1)(viii), 124.10(d), and 146.8(d). Where the word "director" is used in the adopted federal regulations, it should be interpreted to mean "commission."

(n) Effective date. For the regulations pertaining to Class V spent brine return injection wells, this section becomes effective upon approval of the Commission's Class V Underground Injection Control (UIC) Program for spent brine return injection wells by the USEPA under the Safe Drinking Water Act, §1422 (42 United States Code §300h-1). For all other regulations, this section becomes effective as provided in Section 2001.001 et seq. of the Texas Government Code.

Source Note: The provisions of this §3.82 adopted to be effective February 18, 2025, 50 TexReg 835.

§3.83 Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain commission certification of a wellbore as a two-year inactive well or three-year inactive well in order to qualify for the tax exemptions provided for in the Tax Code, §§201.053, 202.052, and 202.056.

(b) Definitions.

(1) Two-year inactive well--A well that has not produced any hydrocarbons in more than one calendar month in the two years prior to the date of certification by the Commission under this section.

(2) Three-year inactive well--A well that has not produced any hydrocarbons in more than one calendar month in the three years prior to the date of certification by the commission under this section.

(3) Eligible well--Wells eligible under this section include those that:

(A) were previous producing or injection wells that have not been plugged or abandoned; or

(B) have been plugged and abandoned; or

(C) are active injection wells.

(4) Well--A wellbore with single or multiple completions.

(c) Certification. The commission or its delegate may certify a well as a two-year inactive well or a three-year inactive well. If the commission or its delegate declines to certify a well administratively, the operator affected by this action may request a hearing.

(d) Revocation of Certification. Certification of a two-year inactive well or a three-year inactive well may be revoked by the commission for cause which includes, but is not limited to, receipt of information by the commission that a certified well produced hydrocarbons in more than one calendar month in the applicable two or three years prior to certification, or if production from other wells is credited to the two-year inactive well or the three-year inactive well, or if a certified well is reported to the commission to be capable of production but is not capable of production. The Comptroller of Public Accounts will be notified of any revocation.

(e) Certified Wells.

(1) Three-year inactive wells. The commission may not certify a three-year inactive well under this section after February 29, 1996. Prior to applying to the Comptroller of Public Accounts for the tax incentives listed in subsection (a) of this section, the operator of a three-year inactive certified well shall file with the commission a test report showing productive capability for the well. Production is presumed to begin on this well test date. The certification remains with the well in the event of a change of operator or ownership.

(2) Two-year inactive wells. The commission may not designate a two-year inactive well under this section after February 28, 2010. An application for two-year inactive well certification shall be made during the period of September 1, 1997, through August 31, 2009, to qualify for the tax exemption. Certification will be issued upon the filing of a test report showing the well's capability and an approval of application for certification. Production is presumed to begin on the well test date as reported on the appropriate report. The certification shall remain with the well in the event of a change of operator or ownership.

Source Note: The provisions of this §3.83 adopted to be effective November 23, 1993, 18 TexReg 8195; amended to be effective January 10, 1996, 20 TexReg 11119; amended to be effective July 21, 1998, 23 TexReg 7363; amended to be effective September 10, 2001, 26 TexReg 6869.

§3.84 Gas Shortage Emergency Response

(a) The purpose of this section is to provide a means for a producer or purchaser to increase production and takes from wells in a field in response to an increase in demand caused by unforeseen events. This section outlines the commission's mechanisms for both determining that a gas shortage emergency exists, and responding to a gas shortage emergency.

(b) The commission may, after notice and hearing, determine that a gas shortage emergency exists or has existed. The commission may also determine the duration of the emergency at such hearing. The commission shall issue notice when it has determined that a gas shortage emergency exists, or has existed, and when it determines the gas shortage emergency has ended or will end. In determining whether a gas shortage emergency exists or has existed, the commission shall consider any relevant information, including, but not limited to, the following:

(1) notification from gas storage facilities that they are attaining maximum gas withdrawal rates;

(2) notification from a gas utility, distributor, transporter, producer or purchaser that gas shortages have occurred or are anticipated; and

(3) weather data.

(c) Upon the commission's finding that a gas shortage emergency exists, or has existed, producers or purchasers shall be authorized to meet the increased demand for the duration of the gas shortage emergency as determined by the commission regardless of a well's assigned allowable or allowable status.

(d) If inequities occur as a result of production authorized by subsection (c) of this section, an adjustment shall be made at the hearing in which production reported for the month of the gas shortage emergency is considered in setting future allowables. Such adjustment shall include the assignment of additional allowable to adequately protect correlative rights. The commission may determine the maximum amount of the supplemental allowable by multiplying the number of days of the gas shortage emergency period by the difference between the well's capability (as defined in §3.31 of this title (relating to Gas Reservoirs and Gas Well Allowable)) and the assigned allowable.

Source Note: The provisions of this §3.84 adopted to be effective September 13, 1994, 19 TexReg 6853; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.85 Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Cargo manifest--One or more documents that together contain the information required by subsection (c) of this section. That part of a manifest which contains information unique to the particular transport being described (such as date and time of removal) must be part of a book, tablet, or series, wherein the documents are sequentially numbered.

(2) Commission--The Railroad Commission of Texas.

(3) Facility--Any place used to store, process, refine, reclaim, dispose of, or treat liquid hydrocarbons.

(4) Lease--A well producing oil, gas, or oil and gas, and any group of contiguous wells producing oil, gas, or oil and gas of any number operated as a producing unit.

(5) Liquid hydrocarbons--Unrefined oil or condensate, and refined oil or condensate to be blended with unrefined liquid hydrocarbons.

(6) Oil tanker vehicle--A motor vehicle licensed for highway use on a public highway or used on a public highway:

(A) that is equipped with, carrying, pulling, or otherwise transporting an assembly, compartment, tank, or other container that is used for transporting, hauling, or delivering liquids; and

(B) that is being used to transport liquid hydrocarbons on a public highway.

(7) Public highway--A way or place of whatever nature open to the use of the public as a matter of right for the purpose of vehicular travel, even if the way or place is temporarily closed for the purpose of construction, maintenance, or repair.

(8) Transporter--Each gatherer, storer, or other handler of liquid hydrocarbons who moves or transports those liquid hydrocarbons by truck or other motor vehicle, provided however, that the provisions of this rule do not apply to:

(A) common carriers as defined in the Natural Resources Code, Chapter 111; or

(B) the movement of salt water, brine, sludge, drilling mud, or other liquid or semiliquid material if the commission has authorized the entity to move such material and such material contains less than 7.0% liquid hydrocarbon, by volume, or if not authorized by the commission, the movement is not for hire and the material moved does not contain more than 7.0% liquid hydrocarbons by volume.

(b) A cargo manifest must be carried in each oil tanker vehicle transporting liquid hydrocarbons on a public highway in this state and must be presented on request for inspection as provided by subsection (f) of this section.

(c) For each load of liquid hydrocarbons loaded onto and transported by an oil tanker vehicle, the cargo manifest must include:

(1) an identification of the lease or facility from which the liquid hydrocarbons were removed, which must include:

(A) the lease or facility name; and

(B) the name of the operator of the lease or facility;

(2) the total quantity of liquid hydrocarbons removed from the lease or facility and loaded onto the oil tanker vehicle; provided that for purposes of indicating quantity on the copy of the manifest left with the lease operator, top and bottom gauges will suffice. On the other copies, an estimate in barrels must be included;

(3) the date and hour when the liquid hydrocarbons were removed from the lease or facility and loaded onto the oil tanker vehicle;

(4) the identity of the transporter which must include;

(A) the company or individual transporter's name and address;

(B) the oil tanker vehicle driver's name; and

(C) a unique number for the oil tanker vehicle that for a truck tractor and semitrailer type oil tanker vehicle must include unique vehicle numbers for both truck tractor and semitrailer; and

(5) the intended point of destination for the liquid hydrocarbons, including the name of the receiving facility.

(d) Copy of manifest to be left at the lease.

(1) A copy of the cargo manifest must be left at the lease or facility from which the liquid hydrocarbons were removed or delivered to the lease or facility operator, his agent, or his representative.

(2) The requirements of this section may be met by leaving a separate document at the lease or facility from which the liquid hydrocarbons were removed or by delivering to the lease or facility operator a separate document that includes information required under subsection (c)(1)-(3) and (4)(A) and (B) this section.

(3) If more than one load of liquid hydrocarbons is removed from a single tank or other container of liquid hydrocarbons within a period of 24 consecutive hours, subsection (c)(2) and (3) of this section may be met for purposes of this section by a separate document that includes:

(A) the total quantity of liquid hydrocarbons removed;

(B) the date and hour the first load was removed; and

(C) the date and hour the last load was removed.

(4) If the operator of a facility requires that a transporter leave at the facility or deliver to the operator a document other than the transporter's cargo manifest, a transporter may meet the requirements of this section by leaving those specified documents at an agreed location or delivering the document to the operator.

(e) After the delivery of all liquid hydrocarbons in an oil tanker vehicle is completed, the cargo manifest must be maintained in the records of the transporter for a period of not less than two years from the date the liquid hydrocarbons are removed from the oil tanker vehicle.

(f) Upon request from a commission agent or other law enforcement official the transporter must produce the cargo manifest for inspection immediately, whether it is on an oil tanker vehicle or in the records of the transporter. Copies of cargo manifests must be filed with the commission, upon request from the commission.

(g) Companies or individuals who do not have organization reports (Form P-5) on file with the Railroad Commission, as required by §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirement (commonly referred to as Statewide Rule 1)), may not issue cargo manifests.

(h) Every truck or other vehicle covered by this section shall bear on both sides thereof the name of the company or individual responsible for such transportation, the number of the vehicle, and the number of the certificate or permit authorizing the service. In the case of vehicles not for hire, this number shall be the company's organizational report (P-5) number. The identifying signs shall be printed in letters not less than two inches in height, in sharp color contrast to the background, and shall be plainly legible for a distance of at least 50 feet.

Source Note: The provisions of this §3.85 adopted to be effective August 25, 2003, 28 TexReg 6816.

§3.86 Horizontal Drainhole Wells

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Correlative interval--The depth interval designated by the field rules or by new field designation on Form P-7 (New Field Designation).

(2) First take point--The take point in a horizontal drainhole well nearest to the point where the drainhole penetrates the top of the correlative interval. The first take point may be at a location different from the penetration point.

(3) Horizontal drainhole--That portion of the wellbore drilled in the correlative interval, between the penetration point and the terminus.

(4) Horizontal drainhole displacement--The calculated horizontal displacement of the horizontal drainhole from the first take point to the last take point.

(5) Horizontal drainhole well--Any well that is developed with one or more horizontal drainholes having a horizontal drainhole displacement of at least 100 feet.

(6) Last take point--The take point in a horizontal drainhole well nearest the terminus. The last take point may be at a location different from the terminus.

(7) Nonperforation zone (NPZ)--A portion of a horizontal drainhole well within the field between the first take point and the last take point that the operator has intentionally designated as containing no take points pursuant to the spacing requirements in §3.37 of this title (relating to Statewide Spacing Rule).

(8) Penetration point--The point where the drainhole penetrates the top of the correlative interval.

(9) Record well--The single horizontal drainhole within a stacked lateral well designated by the operator as the record well for reporting purposes.

(10) Stacked lateral well--A horizontal drainhole well in which the following conditions are met:

(A) there are two or more horizontal drainhole wells on the same lease, pooled unit, or unitized tract at different depths within the correlative interval for the field;

(B) the horizontal drainholes are drilled from different surface locations;

(C) all take points of a stacked lateral well's horizontal drainholes are within a rectangular area the width of which is 660 feet, and the length of which is 1.2 times the distance between the first and last take points of the record well;

(D) all horizontal drainholes are tested independently and have the same classification (i.e., gas or oil). Only horizontal drainholes of the same classification are eligible to be designated as a stacked lateral well; and

(E) there is only one operator for the stacked lateral well.

(11) Take point in a horizontal drainhole well--Any point along a horizontal drainhole where oil and/or gas can be produced from the correlative interval.

(12) Terminus--The farthest point required to be surveyed along the horizontal drainhole from the penetration point and within the correlative interval.

(13) Unconventional fracture treated (UFT) field--A field designated by the Commission under subsection (i) of this section for which horizontal well development and hydraulic fracture treatment (as defined in §3.29(a)(15) and (16) of this title (relating to Hydraulic Fracturing Chemical Disclosure Requirements)) must be used in order to recover resources from all or a part of the field and which may include the drilling of vertical wells along with the drilling of horizontal wells.

(b) Drainhole spacing.

(1) No take point on a horizontal drainhole shall be located nearer than 1,200 feet (horizontal displacement), or other between-well spacing requirement under applicable rules for the field, to any take point along any other horizontal drainhole in another well, or to any other well completed or permitted in the same field on the same lease, pooled unit, or unitized tract.

(2) No take point on a horizontal drainhole shall be located nearer than 467 feet, or other lease-line spacing requirement under applicable rules for the field, from any property line, lease line, or subdivision line.

(3) All wells developed with horizontal drainholes shall otherwise comply with §3.37 of this title (relating to Statewide Spacing Rule), or other applicable spacing rules.

(4) If the drilling permit application indicates that there will be one or more NPZs, then the as-drilled plat filed after completion of the well shall be certified by a person with knowledge of the facts pertinent to the application that the plat is accurately drawn to scale and correctly reflects all pertinent and required data. In addition to the information required under subsection (f) of this section, the certified as-drilled plat shall include:

(A) the as-drilled track of the wellbore;

(B) the location of each take point on the wellbore;

(C) the boundaries of any wholly or partially unleased tracts within the distance permitted under §3.37 of this title or applicable special field rules of the wellbore; and

(D) notations of the shortest distance from each wholly or partially unleased tract within the distance permitted under §3.37 of this title or applicable special field rules of the wellbore to the nearest take point on the wellbore.

(5) To comply with the spacing requirements set forth in paragraph (3) of this subsection, the take-points along the as-drilled location of a properly permitted horizontal drainhole shall fall within a rectangle established as follows:

(A) two sides of the rectangle are parallel to the permitted drainhole and 50 feet or 10% of the minimum distance to any property line, lease line or subdivision line, whichever is greater, on either side of the drainhole; and

(B) the other two sides of the rectangle are perpendicular to the sides described in subparagraph (A) of this paragraph, with one of those sides passing through the permitted first take point and the other side passing through the permitted last take point.

(6) Prior to perforating the wellbore within an approved NPZ, the operator must amend the permit to authorize perforations within the originally-approved NPZ.

(c) Well densities. All wells developed with horizontal drainholes shall comply with §3.38 of this title (relating to Well Densities) or other applicable density rules.

(d) Proration and drilling units.

(1) Acreage may be assigned to each horizontal drainhole well for the purpose of allocating allowable oil or gas production up to the amount specified by applicable rules for a proration unit for a vertical well plus the additional acreage assignment as provided in this paragraph.

Additional Acreage Assignment
For Fields with a Density Rule of 40 Acres or Less

Horizontal Drainhole Displacement, ft	Additional Acreage Allowed, acres
100 to 585	20
586 to 1,170	40
1,171 to 1,755	60
1,756 to 2,340	80
2,341 to 2,925	100
2,926 to 3,510	120
etc. - 585 ft increments	etc. - 20 acre increments

As in effect on 12/8/2025.

Additional Acreage Assignment
For Fields with a Density Rule Greater Than 40 Acres

Horizontal Drainhole Displacement, ft	Additional Acreage Allowed, acres
150 to 827	40
828 to 1,654	80
1,655 to 2,481	120
2,482 to 3,308	160
3,309 to 4,135	200
4,136 to 4,962	240
etc. - 827 ft increments	etc. - 40 acre increments

(2) Assignment of acreage to proration and drilling units for horizontal drainhole wells shall comply with §3.40 of this title (relating to Assignment of Acreage to Pooled Development and Proration Units).

(3) All proration and drilling units shall consist of continuous and contiguous acreage and proration units shall consist of acreage that can be reasonably considered to be productive of oil or gas.

(4) The maximum daily allowable assigned to a horizontal well shall comply with the table in subsection (d)(1) of this section and the maximum daily allowable specified by paragraph (5) of this subsection, unless special field rules specify different requirements for acreage or maximum daily allowable.

(5) The maximum daily allowable for a horizontal drainhole well in a designated UFT field shall be 100 barrels of oil for each acre that is assigned to an oil well for allowable purposes, or 600 Mcf of gas for each acre that is assigned to a gas well for allowable purposes. This paragraph does not affect suspension of the allocation formula under §3.31(j) of this title (relating to Gas Reservoirs and Gas Well Allowable). The maximum daily allowable for a horizontal drainhole well in a field that has not been designated as a UFT field shall be determined by multiplying the applicable allowable for a vertical well in the field with a proration unit containing the maximum acreage authorized by the applicable rules for the field, exclusive of tolerance acreage, by a fraction:

(A) the numerator of which is the acreage assigned to the horizontal drainhole well for proration purposes; and

(B) the denominator of which is the maximum acreage authorized by the applicable field rules for proration purposes, exclusive of tolerance acreage. The daily oil allowable shall be adjusted in accordance with §3.49(a) of this title (relating to Gas-Oil Ratio), when applicable.

(6) All points on the horizontal drainhole from the first take point to the terminus shall be within the proration and drilling unit. If the penetration point is located on an offsite tract, the conditions prescribed in subsection (g) of this section shall be met before the drilling permit application is submitted to the Commission.

(e) Multiple drainholes allowed.

(1) A single well may be developed with more than one horizontal drainhole originating from a single vertical wellbore.

(2) A horizontal drainhole well developed with more than one horizontal drainhole shall be treated as a single well.

(3) The horizontal drainhole displacement used for calculating additional acreage assignment for a well completed with multiple horizontal drainholes shall be the horizontal drainhole displacement of the longest horizontal drainhole plus the projection of any other horizontal drainhole on a line that extends in a 180 degree direction from the longest horizontal drainhole.

(f) Stacked lateral wells.

(1) For oil and gas wells, stacked lateral wells within the correlative interval for the field may be considered a single well for density and allowable purposes, at an operator's discretion. If an operator chooses to designate horizontal drainholes as a stacked lateral well, the operator shall designate:

(A) one horizontal drainhole within the stacked lateral well as the record well. An operator may change the record well designation to another wellbore by filing amended drilling permit applications and completion reports for the previous and the new record well; and

(B) all points, from the first take point to the last take point, of the record well for a stacked lateral well are within the proration and drilling unit designated for that well. Notwithstanding paragraph (4) of this subsection, all points from the first take point to the last take point of any other horizontal drainhole comprising the stacked lateral well are not required to be within the proration and drilling unit designated for the record well so long as they otherwise comply with the requirements of this section and any applicable lease line spacing rules.

(2) For the purpose of assigning additional acreage to the stacked lateral well, the horizontal drainhole displacement shall be calculated based on the distance from the first take point to the last take point in the horizontal drainhole for the record well, regardless of the horizontal drainhole displacement of other horizontal drainholes of the stacked lateral well.

(3) Each surface location of a stacked lateral well shall be permitted separately and assigned an API number. When applying for a drilling permit for a stacked lateral well, the operator shall:

(A) identify each surface location of such well as a stacked lateral well on the Form W-1 drilling permit application;

(B) identify on the plat any other existing, or applied for, horizontal drainholes comprising the stacked lateral well being permitted; and

(C) depict on the plat a rectangle described in subsection (a)(10)(C) of this section indicating the lateral boundaries of the stacked lateral well.

(4) Each horizontal drainhole of a stacked lateral well shall comply with: the applicable minimum spacing distance under §3.37 of this title or any applicable special field rules for any lease, pooled unit or property line; and the applicable minimum between well spacing distance under §3.37 of this title or any applicable special field rules for any different well, including all horizontal drainholes of any other stacked lateral well, on the same lease or pooled unit in the field. An operator may seek an exception to §3.37 or §3.38 of this title for stacked lateral wells in accordance with the Commission's rules in this chapter or any applicable special field rule. There are no maximum or minimum distance limitations between horizontal drainholes of a stacked lateral well in a vertical direction.

(5) An operator shall file separate completion forms for each surface location of the stacked lateral well. An operator shall also file a certified plat showing the as-drilled location for each surface location of a stacked lateral well. The certified as-drilled plat shall:

(A) show each horizontal drainhole from each surface location; and

(B) depict on the plat a rectangle described in subsection (a)(10)(C) of this section indicating the lateral boundaries of the stacked lateral well.

(6) In addition to the record well, each surface location of a stacked lateral well shall be listed on the proration schedule, but no allowable shall be assigned for an individual surface location. Each surface location of a stacked lateral well shall be required to have a separate well status report (Form G-10 or Form W-10, as applicable) and the sum of all horizontal drainhole test rates shall be reported as the test rate for the record well.

(7) An operator shall report all production from horizontal drainholes included as a stacked lateral well on the production report that includes the record well. Production reported for a record well shall equal the total production from all of the horizontal drainholes comprising the stacked lateral well. An operator shall measure the production from each surface location of a stacked lateral well. An operator shall measure the full well stream with the measurement adjusted for the allocation of condensate based on the gas to liquid ratio established by the most recent Form G-10 test rate for that surface location. The gas and condensate production shall be identified by individual API number, and recorded and reported on the "Supplementary Attachment to Form PR".

(8) If the field is designated as absolute open flow (AOF) pursuant to §3.31(j) of this title and that designation is removed, the Commission shall assign a single gas allowable to each record well classified as a gas well. The assigned allowable may be produced from any one, all, or a combination of the horizontal drainholes that constitute the stacked lateral well.

(9) An operator shall file Form W-3A, Notice of Intention to Plug and Abandon, and Form W-3, Well Plugging Report, for each horizontal drainhole within the stacked lateral well as required by §3.14 of this title (relating to Plugging).

(10) In order to maintain a single operator of record for a stacked lateral well, a certificate of compliance changing the designation of an operator for a horizontal drainhole in a stacked lateral well pursuant to §3.58 of this title (relating to Certificate of Compliance and Transportation Authority; Operator Reports) may only be approved if certificates of compliance designating the same operator have been filed for all horizontal drainholes within the stacked lateral well.

(11) An operator may remove a horizontal drainhole from a designated stacked lateral well by filing an amended drilling permit application and a completion report. If the horizontal drainhole being removed is the record well for the stacked lateral and there are still multiple horizontal drainholes remaining within the designated stacked lateral well, then the operator shall designate a new record well for the stacked lateral well prior to removing the existing record well from the designated stacked lateral well.

(g) Drilling applications and required reports.

(1) Application. Any intent to develop a new or existing well with horizontal drainholes must be indicated on the application to drill. An application for a permit to drill a horizontal drainhole shall include the fees required by §3.78 of this title (relating to Fees and Financial Security Requirements), and shall be certified by a person acquainted with the facts, stating that all information in the application is true and complete to the best of that person's knowledge. If the penetration point on the proposed horizontal drainhole is located on an offsite tract, the following conditions shall be met prior to submission of the application to drill:

(A) The applicant shall give written notice by certified mail, return receipt requested, to all mineral owners of any offsite tracts through which the proposed wellbore path traverses from the point of penetration. The notice shall identify the proposed well, include a plat clearly depicting the projected path of the entire wellbore, and allow the party notified not less than 21 days to object to the proposed offsite tract penetration. Notice of offsite tract penetration is not required if:

(i) written waivers of objection are received by the applicant from all mineral owners of any offsite tracts and the waivers are attached to the drilling permit application; or

(ii) the applicant is the only mineral owner of any offsite tracts.

(B) For purposes of this subsection, the mineral owners of any offsite tracts through which the proposed wellbore path traverses from the point of penetration include:

(i) the designated operator;

(ii) all lessees of record for any offsite tracts which have no designated operator; and

(iii) all owners of unleased mineral interests where there is no designated operator or lessee.

(C) In the event the applicant is unable after due diligence to locate the whereabouts of any person to whom notice is required by this subsection, the applicant shall publish notice of this application pursuant to Chapter 1 of this title (relating to Practice and Procedure).

(D) If any mineral owner of an offsite tract objects to the location of the penetration point, the applicant may request a hearing to demonstrate the necessity of the location of the penetration point of the well to prevent waste or to protect correlative rights.

(E) If any person specified in subparagraph (B) of this paragraph did not receive notice as required in subparagraph (A) of this paragraph, that person may request a hearing. If the Commission determines at a hearing that the applicant did not provide the notice as required by subparagraph (A) of this paragraph, the Commission may cancel the permit.

(F) To mitigate the potential for wellbore collisions, the applicant shall provide copies of any directional surveys to the parties entitled to notice under this section, upon request, within 15 days of the applicant's receipt of a request.

(2) Drilling unit plat. The application to drill a horizontal drainhole shall be accompanied by a plat as required by §3.5(h) of this title (relating to Application to Drill, Deepen, Reenter, or Plug Back).

(A) For fields that require a proration unit plat, in addition to the plat requirements provided for in §3.5(h) of this title, the plat shall include the lease, pooled unit or unitized tract, showing the acreage assigned to the drilling unit for the proposed well and the acreage assigned to the drilling units for all current applied for, permitted, or completed oil, gas, or oil and gas wells on the lease, pooled unit, or unitized tract.

(B) An amended drilling permit application and plat shall be filed after completion of the horizontal drainhole well if the Commission determines that the drainhole as drilled is not reasonable with respect to the drainhole represented on the plat filed with the drilling permit application. A horizontal drainhole, as drilled, shall be considered reasonable with respect to the drainhole represented on the plat filed with the drilling permit application if the take points on the as-drilled plat comply with subsection (b)(4) and (5) of this section and with any applicable lease line spacing rules.

(3) Directional survey. A directional survey from the surface to the farthest point drilled on the horizontal drainhole shall be required for all horizontal drainholes. The directional survey and accompanying reports shall be conducted and filed in accordance with §3.11 and §3.12 of this title (relating to Inclination and Directional Surveys Required, and Directional Survey Company Report, respectively). No allowable shall be assigned to any horizontal drainhole well until an acceptable directional survey and survey plat has been filed with the Commission.

(4) Proration unit plat. The required proration unit plat must depict the lease, pooled unit, or unitized tract, showing the acreage assigned to the proration unit for the horizontal drainhole well, the acreage assigned to the proration units for all wells on the lease, pooled unit, or unitized tact, and the path, penetration point, take points, and terminus of all drainholes. No allowable shall be assigned to any horizontal drainhole well until an acceptable proration unit plat has been filed with the Commission. Proration unit plats are not required for wells in a designated UFT field. However, an operator of a well in a designated UFT field may file a proration unit plat along with Form P-16. Designated UFT fields have no maximum diagonal limit.

(5) As-drilled plat. An as-drilled plat is required for each horizontal drainhole well. The as-drilled plat for each horizontal drainhole well shall show the surface location, actual wellbore path, penetration point, terminus, and first and last take points of the horizontal drainhole. If the drilling permit for the horizontal drainhole well is approved with one or more NPZs, the as-drilled plat shall show the nearest take point on either side of each NPZ.

(6) Plat requirements. All plats required by this section shall be prepared using blue or black ink and shall include a certification by a professional land surveyor registered in accordance with Texas Occupations Code, Chapter 1071, relating to Land Surveyors, or by a registered professional engineer registered in accordance with Texas Occupations Code, Chapter 1001, relating to Professional Engineers.

(h) Exceptions and procedure for obtaining exceptions.

(1) The Commission may grant exceptions to this section in order to prevent waste, prevent confiscation, or to protect correlative rights.

(2) If a permit to drill a horizontal drainhole requires an exception to this section, the notice and opportunity for hearing procedures for obtaining exceptions to the density provisions prescribed in §3.38 of this title shall be followed as set forth in §3.38(h) of this title.

(3) For notice purposes, the Commission presumes that for each adjacent tract and each tract nearer to any point along the proposed or existing horizontal drainhole than the prescribed minimum lease-line spacing distance, affected persons include:

(A) the designated operator;

(B) all lessees of record for tracts that have no designated operator; and

(C) all owners of record of unleased mineral interests.

(i) UFT field designation criteria, application and approval procedures.

(1) Criteria for UFT field designation.

(A) Administrative UFT field designation. To be designated administratively as a UFT field, a field shall have the following characteristics:

(i) the *in situ* permeability of at least one distinct producible interval within the field is 0.1 millidarcies or less prior to hydraulic fracture treatment, as determined by core data or other supporting data and analysis; and

(ii) as to producing wells for which the Commission issued the initial drilling permit on or after February 1, 2012, that have been completed in the field, either:

(I) there are at least five such wells of which at least 65% were drilled horizontally and completed using hydraulic fracture treatment; or

(II) there are at least twenty-five such wells drilled horizontally and completed using hydraulic fracture treatment.

(B) Alternative UFT field designation obtained through evidentiary hearing. If an applicant demonstrates in a hearing that reservoir characteristics exist other than the characteristics specified in subparagraph (A) of this paragraph such that horizontal drilling and hydraulic fracture treatment must be used in order to recover the resources from all or a part of the field and that UFT field designation will promote orderly development of the field, the hearings examiner may recommend to the Commission that the field be designated as a UFT field.

(2) Procedures for UFT field designation.

(A) Commission motion to designate a UFT field. The Commission may on its own motion propose that a field be designated as a UFT field upon written notice of the motion to all operators in the field.

(i) If no written objection is filed within 21 days after the date the notice is issued, Commission staff may present a recommendation to the Commission regarding designation of the field as a UFT field.

(ii) If the Commission receives a timely filed written objection, the Commission shall notify the operators in the field that an objection was received and allow any operator in the field 21 days to request a hearing. Pursuant to paragraph (1)(B) of this subsection, the operator requesting the hearing shall bear the burden of proof at the hearing. If no request to set the matter for hearing is received from an operator in the field, the Commission may either dismiss the matter or set the matter for hearing on its own motion. If the matter is set for hearing on the Commission's motion, the proponents of UFT field designation shall bear the burden of proof.

(B) Operator application for UFT designation.

(i) An operator may propose that a field be designated as a UFT field by submitting an application to the Commission that includes an affirmative statement that the field qualifies for designation as a UFT field and providing core data or other supporting data and analysis in support of that affirmative statement.

(ii) If, on review of the completed application, Commission staff determines that the field meets the criteria in paragraph (1)(A) of this subsection, Commission staff shall notify all operators in the field that a UFT field designation order may be presented to the Commission for approval not less than 21 days after the date the notice is issued unless the Commission receives a written objection. If the applicant provides written waivers of objection from all operators in the field, then notice to the operators in the field shall not be required.

(iii) If the Commission receives a timely filed written objection to the notice of the proposal to designate the field as a UFT field, or if Commission staff determines that the field does not qualify for designation as a UFT field, then the applicant for UFT field designation may request that the application be set for hearing.

(iv) If the applicant requests a hearing, the Commission shall send a notice of hearing to all operators in the field proposed for designation as a UFT field at least 15 days in advance of the hearing.

(v) Following a hearing on the request, the hearings examiner may present a recommendation to the Commission regarding the request to designate the field as a UFT field.

(j) Effect of special field rules for UFT fields.

(1) Special field rules for a UFT field shall prevail over all conflicting provisions of this chapter.

(2) The Commission may on its own motion or on the motion of an operator in a field call a hearing to review the current special field rules applicable in a field that is designated or proposed to be designated as a UFT field and request amendment or rescission of any portion of the current field rules, in conjunction with such designation, so that the field is regulated with the appropriate combination of special field rules and the rules in this chapter to effectively and efficiently protect correlative rights and/or prevent waste.

(3) The following provisions shall apply with respect to specific amendments to the special field rules for a UFT field.

(A) A special field rule amendment hearing is not required for the following amendments:

(i) reduction of the standard and/or optional density to one-half of the existing standard and/or optional density;

(ii) deletion of the between-well spacing rule; or

(iii) replacement of the allowable provided by special field rules with the allowable provided by §3.31 of this title, §3.45 of this title (relating to Oil Allowables), and subsection (d)(4) and (5) of this section.

(B) To request one or more of the amendments listed in subparagraph (A) of this paragraph, the operator shall submit to the Commission a request for amendment and engineering and/or geological data to support the requested amendments. For each exhibit submitted, the operator shall include a written explanation showing that the requested amendment will result in the protection of correlative rights and/or the prevention of waste.

(C) Upon receipt of a request for amendment, the Commission shall provide notice of the request to all operators in the field. If no written objection is filed within 21 days after the date the notice is issued, Commission staff may present a recommendation to the Commission regarding the requested amendment. If the Commission receives a timely filed written objection, the applicant may request a hearing to establish through the submission of competent evidence that the requested amendment is necessary for continued development of a designated UFT field, and will result in the protection of correlative rights and/or prevention of waste.

(k) Exceptions to §3.38 for a well in a UFT field. To request an exception to §3.38 of this title for a well in a UFT field:

(1) The operator shall submit to the Commission a written request for an exception to §3.38 of this title. The operator shall clearly state on the drilling permit application whether the density exception is sought under this subsection or through the provisions of §3.38 of this title.

(2) The Commission shall send written notice of the request for an exception to §3.38 of this title filed under this subsection to any designated operators, lessees of record for tracts that have no designated operator, and all owners of unleased mineral interests:

(A) within 600 feet from the location of a vertical well completed within the UFT field; or

(B) within 600 feet from any take point on a horizontal well within the UFT field correlative interval.

(3) Persons who have received notice pursuant to paragraph (2) of this subsection shall have 21 days from the date of issuance of the notice to file a written objection with the Commission.

(4) If no timely filed written objection is received by the Commission, the applicant provides written waivers from all persons entitled to notice under paragraph (2) of this subsection, or there are no persons entitled to notice, then the application may be approved administratively without the requirement of filing supporting data.

(5) If a timely filed written objection is received by the Commission, the applicant may request a hearing, at which the applicant shall show that the proposed exception to §3.38 of this title is necessary to effectively drain an area of the UFT field that will not be effectively drained by existing wells or to prevent waste or confiscation. Notice of a hearing for a protested exception application under

§3.38 of this title for a well in a UFT field will be provided to those persons entitled to notice of such an application as specified in paragraph (2) of this subsection.

(6) Permits granted pursuant to paragraphs (1) - (5) of this subsection shall be issued as exceptions to §3.38 of this title.

(7) Nothing in this subsection prevents an operator from electing to apply for and obtain a density exception under the provisions of §3.38 of this title rather than the provisions of paragraphs (1) - (6) of this subsection.

(l) Tubing requirements for completions in UFT fields. An operator of a flowing oil well in a UFT field may obtain a six-month exception to the requirement in §3.13(b)(4)(A) of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements) that flowing oil wells shall be produced through tubing. The exception may be granted administratively. A revised completion report shall be filed once the oil well has been equipped with the required tubing string to reflect the actual completion configuration.

(1) For good cause shown, including a showing that the well is flowing at a pressure in excess of 300 psig surface wellhead flowing pressure, an operator may obtain from the District Director one or more extensions to the six month exception. Each extension shall be no more than six months in duration. If the request for an extension is denied, the operator may request a hearing. If a hearing is requested, the exception shall remain in effect pending final Commission action on the request for an extension.

(2) This subsection applies to new drills, reworks, recompletions, or new fracture stimulation treatments for any flowing oil well in the field.

Source Note: The provisions of this §3.86 adopted to be effective June 1, 1990, 15 TexReg 2635; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective June 11, 2001, 26 TexReg 4088; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective February 1, 2016, 41 TexReg 785.

§3.91 Cleanup of Soil Contaminated by a Crude Oil Spill

(a) Terms. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Free oil--The crude oil that has not been absorbed by the soil and is accessible for removal.

(2) Sensitive areas--These areas are defined by the presence of factors, whether one or more, that make an area vulnerable to pollution from crude oil spills. Factors that are characteristic of sensitive areas include the presence of shallow groundwater or pathways for communication with deeper groundwater; proximity to surface water, including lakes, rivers, streams, dry or flowing creeks, irrigation canals, stock tanks, and wetlands; proximity to natural wildlife refuges or parks; or proximity to commercial or residential areas.

(3) Hydrocarbon condensate--The light hydrocarbon liquids produced in association with natural gas.

(b) Scope. These cleanup standards and procedures apply to the cleanup of soil in non-sensitive areas contaminated by crude oil spills from activities associated with the exploration, development, and production, including transportation, of oil or gas or geothermal resources as defined in §4.110 of this title (relating to Definitions). For the purposes of this section, crude oil does not include hydrocarbon condensate. These standards and procedures do not apply to hydrocarbon condensate spills, crude oil spills in sensitive areas, or crude oil spills that occurred prior to the effective date of this section. Cleanup requirements for hydrocarbon condensate spills and crude oil spills in sensitive areas will be determined on a case-by-case basis. Cleanup requirements for crude oil contamination that occurred wholly or partially prior to the effective date of this section will also be determined on a case-by-case basis. Where cleanup requirements are to be determined on a case-by-case basis, the operator must consult with the appropriate district office on proper cleanup standards and methods, reporting requirements, or other special procedures.

(c) Requirements for cleanup.

(1) Removal of free oil. To minimize the depth of oil penetration, all free oil must be removed immediately for reclamation or disposal.

(2) Delineation. Once all free oil has been removed, the area of contamination must be immediately delineated, both vertically and horizontally. For purposes of this paragraph, the area of contamination means the affected area with more than 1.0% by weight total petroleum hydrocarbons.

(3) Excavation. At a minimum, all soil containing over 1.0% by weight total petroleum hydrocarbons must be brought to the surface for disposal or remediation.

(4) Prevention of stormwater contamination. To prevent stormwater contamination, soil excavated from the spill site containing over 5.0% by weight total petroleum hydrocarbons must immediately be:

(A) mixed in place to 5.0% by weight or less total petroleum hydrocarbons; or

(B) removed to an approved disposal site; or

(C) removed to a secure interim storage location for future remediation or disposal. The secure interim storage location may be on site or off site. The storage location must be designed to prevent pollution from contaminated stormwater runoff. Placing oily soil on plastic and covering it with plastic is one acceptable means to prevent stormwater contamination; however, other methods may be used if adequate to prevent pollution from stormwater runoff.

(d) Remediation of soil.

(1) Final cleanup level. A final cleanup level of 1.0% by weight total petroleum hydrocarbons must be achieved as soon as technically feasible, but not later than one year after the spill incident. The operator may select any technically sound method that achieves the final result.

(2) Requirements for bioremediation. If on-site bioremediation or enhanced bioremediation is chosen as the remediation method, the soil to be bioremediated must be mixed with ambient or other soil to achieve a uniform mixture that is no more than 18 inches in depth and that contains no more than 5.0% by weight total petroleum hydrocarbons.

(e) Reporting requirements.

(1) Crude oil spills over five barrels. For each spill exceeding five barrels of crude oil, the responsible operator must comply with the notification and reporting requirements of §3.20 of this title (relating to Notification of Fire Breaks, Leaks, or Blow-outs) and submit a report on a Form H-8 to the appropriate district office. The following information must be included:

(A) area (square feet), maximum depth (feet), and volume (cubic yards) of soil contaminated with greater than 1.0% by weight total petroleum hydrocarbons;

(B) a signed statement that all soil containing over 1.0% by weight total petroleum hydrocarbons was brought to the surface for remediation or disposal;

(C) a signed statement that all soil containing over 5.0% by weight total petroleum hydrocarbons has been mixed in place to 5.0% by weight or less total petroleum hydrocarbons or has been removed to an approved disposal site or to a secure interim storage location;

(D) a detailed description of the disposal or remediation method used or planned to be used for cleanup of the site;

(E) the estimated date of completion of site cleanup.

(2) Crude oil spills over 25 barrels. For each spill exceeding 25 barrels of crude oil, in addition to the report required in paragraph (1) of this subsection, the operator must submit to the appropriate district office a final report upon completion of the cleanup of the site. Analyses of samples representative of the spill site must be submitted to verify that the final cleanup concentration has been achieved.

(3) Crude oil spills of five barrels or less. Spills into the soil of five barrels or less of crude oil must be remediated to these standards, but are not required to be reported to the commission. All spills of crude oil into water must be reported to the commission.

(f) Alternatives. Alternatives to the standards and procedures of this section may be approved by the commission for good cause, such as new technology, if the operator has demonstrated to the commission's satisfaction that the alternatives provide equal or greater protection of the environment. A proposed alternative must be submitted in writing and approved by the commission.

Source Note: The provisions of this §3.91 adopted to be effective November 1, 1993, 18 TexReg 6835; amended to be effective July 1, 2025, 50 TexReg 33

§3.93 Water Quality Certification Definitions

(a) The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) 401 certification--A certification issued by the commission, under the authority of the Federal Clean Water Act, §401, that a federal permit that may result in a discharge to waters of the United States is consistent with applicable state and federal water quality laws and regulations.

(2) Commission--The Railroad Commission of Texas or its designee.

(3) Department of the Army permits--Individual or general permits or letters of permission issued by the U.S. Army Corps of Engineers under the authority of the Federal Clean Water Act, §404, or the Rivers and Harbors Act of 1899, §9 and §10, United States Code, Title 33, §402 and §403.

(4) District engineer--The U.S. Army Corps of Engineers representative responsible for administering and enforcing federal laws and regulations, including processing and issuance of permits, under the jurisdiction of the U.S. Army Corps of Engineers.

(5) Federal Clean Water Act--United States Code, Title 33, Chapter 26.

(6) NPDES permit--A permit issued by the regional administrator under the authority of the Federal Clean Water Act, §402, Title 33, United States Code, §1342. NPDES permits can either be individual or general permits.

(7) Permitting agency--Any agency of the federal government to which application is made for any permit to conduct an activity that may result in any discharge into waters of the United States.

(8) Person--A natural person, corporation, organization, government or governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(9) Pollutant--Any constituent that contaminates or alters the physical, thermal, chemical, or biological quality of water so as to be harmful, detrimental, or injurious to humans, animal life, vegetation, or property or to the public health, safety, or welfare, or that impairs the usefulness or the public enjoyment of the water for any lawful purpose.

(10) Regional administrator--The administrator of the United States Environmental Protection Agency, Region 6.

(11) Water quality standards--Texas Surface Water Quality Standards, Title 30, Texas Administrative Code, Chapter 307.

(12) Waters of the United States--Interstate waters, the territorial seas, and waters that would or could affect interstate commerce, including tributaries of such waters and adjacent wetlands, as defined in Title 33, Code of Federal Regulations, Part 328.

(b) Certification Required. No person may conduct any activity subject to the jurisdiction of the commission pursuant to a Department of the Army permit or an NPDES permit if the activity may result in a discharge into waters of the United States within the boundaries of the State of Texas, unless the commission has first issued a certification or waiver of certification under this section.

(c) Request for Certification. The regional administrator, district engineer, or the permit applicant may submit a request for certification to the commission.

(1) Request by Applicant. If the permit applicant requests certification, the applicant shall submit to the commission:

(A) a copy of the completed permit application and any amendments thereto;

(B) a list on a map or on a separate sheet attached to a map of the names and addresses of owners of tracts of land adjacent to the site where the proposed activity would occur and, where the activity may result in a discharge to watercourse other than the Gulf of Mexico or a bay, the owners of each waterfront tract between the potential discharge point and 1/2 mile downstream of the potential discharge point, except for those waterfront tracts within the corporate limits of an incorporated city, town, or village;

(C) a request for certification; and

(D) for Department of the Army permits in the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), a description of the acreage proposed to be filled, if any.

(2) Request by EPA or the Corps. Except as provided in subsection (d)(1) of this section, a request for certification submitted by the regional administrator or the district engineer shall contain the information specified in this paragraph:

(A) a copy of the public notice;

(B) a request for certification;

(C) for NPDES permits, a copy of the draft permit, if available; and

(D) for Department of the Army permits in the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), a description of the acreage proposed to be filled, if any.

(3) Request for Additional Information. Where the commission believes more information is required to accomplish review of a request for certification, the commission shall notify the applicant or the permitting agency and request such information. In response to such a notification from the commission, the applicant or the permitting agency shall submit such materials as the commission finds necessary for review of the request for certification. Except as otherwise provided, such information shall be provided within ten days of issuance of a request for additional information by the commission.

(d) Notice of Request for Certification.

(1) Joint Notice. Notice of a request for certification shall be made using a joint mailed notice issued by the U.S. Army Corps of Engineers or the U.S. Environmental Protection Agency after agreements with those agencies have been reached regarding the content of the notice and the persons entitled to notice in Texas. When a joint notice is issued by either the U.S. Army Corps of Engineers or the U.S. Environmental Protection Agency, the requirements of subsection (c)(2) of this section do not apply.

(2) Notice by Applicant. If a joint notice is not used as provided in paragraph (1) of this subsection, the applicant must mail notice of the request for certification on or before the date the request for certification is filed with the commission. Such notice shall include the information required in paragraph (3) of this subsection. The applicant shall provide notice by first class mail to:

(A) the owners of land adjacent to the tract upon which the activity is proposed to take place, and where the activity may result in a discharge to a watercourse other than the Gulf of Mexico or a bay, the surface owners of each waterfront tract between the potential discharge point and 1/2 mile downstream of the potential discharge point, excluding owners of those waterfront tracts within the corporate limits of an incorporated city, town, or village;

(B) the mayor and health authorities of any city or town in which the proposed activity will be located or that is within 1/2 mile downstream of the potential discharge;

(C) the county judge and health authorities of any county in which the proposed activity will be located or that is within 1/2 mile downstream of the potential discharge;

(D) the Texas Commission on Environmental Quality (TCEQ) or its successor agencies;

(E) the Texas Parks and Wildlife Department;

(F) the U.S. Environmental Protection Agency, Region 6;

(G) the U.S. Fish and Wildlife Service; and

(H) for a proposed activity within the coastal management program boundary as defined under Title 31, Texas Administrative Code §503.1 (Coastal Management Program Boundary), the Secretary of the Coastal Coordination Council.

(3) Contents of Notice. Any notice provided as required in paragraph (2) of this subsection shall contain:

(A) the applicant's name and mailing address, together with the name and mailing address of the party conducting the activity, if different from the applicant;

(B) a brief written description of the activity;

(C) a statement that the applicant is seeking certification from the commission under the Federal Clean Water Act, §401;

(D) a statement that any comments concerning the request for certification may be submitted in writing to the assistant Director of Environmental Services, Railroad Commission, 1701 North Congress Avenue, P.O. Box 12967, Austin, Texas 78711-2967, on or before the deadline for submission of written public comments, which, absent special circumstances, shall be at least 30 days after the date notice is mailed; and

(E) a statement that a copy of the permit application is available for review in the office of the federal permitting agency.

(4) Emergency Actions. When the division engineer for the U.S. Army Corps of Engineers authorizes emergency procedures and it is in the public interest to provide a certification in less than 30 days, the commission may waive the notice and hearing requirements under this section and issue a final determination. For emergency actions within the coastal zone, as described in 31 TAC §503.1 (Coastal Management Program Boundary), the commission may only issue a final determination if the emergency action is consistent with the provisions of 31 TAC §501.14(j) (7) (Policies for Specific Activities and Coastal Natural Resource Areas).

(e) Public Comments.

(1) Written Comments. The commission shall consider all comments related to the water quality impacts of the proposed activity that are submitted to the commission in writing prior to the deadline for submission of comments.

(2) Public Meetings. The commission shall hold a meeting to receive public comment on a request for certification if the commission finds that such a meeting is in the public interest. If the commission holds a meeting to receive public comment on a request for certification, the commission shall notify the applicant by first class mail not less than ten days before the date set for the public meeting that a meeting to receive public comment will be held on the request for certification. The commission will also provide notice by first-class mail or by personal service to all of the persons identified under subsection (d) (2) of this section and the federal permitting agency at least ten days prior to the public meeting. The notice of public meeting shall identify the federal permit application; the date, time, place, and nature of the public meeting; the legal authority and jurisdiction under which the public meeting is to be held; the applicant's proposed action; the requirements for submitting written comments; the method for obtaining additional information; and such other information as the commission deems necessary. The notice to the federal permitting agency shall also estimate the additional time necessary to consider the request for certification and shall state that the commission is not waiving certification.

(f) Commission Review of Requests for Certification. After expiration of the time for receipt of public comments, the commission shall determine whether the proposed activity for which a request for certification has been received will result in any discharge into waters of the United States within the boundaries of the State of Texas, and if so, whether the proposed activity will comply with all applicable water quality requirements. Applicable water quality requirements include, but are not limited to, state water quality standards, and any other applicable water quality requirements. For an activity within the boundary of the Texas Coastal Management Program (CMP), applicable state water quality requirements include the enforceable goals and policies of the CMP, Title 31, Texas Administrative Code, Chapter 501.

(g) Final Action.

(1) Issuance of Final Determination. A final determination on a request for certification of an NPDES or Department of the Army permit shall be issued by the commission within 15 days from the close of the public comment period, unless the regional administrator or the district engineer, in consultation with the commission, finds that unusual circumstances require a longer time. If the commission does not act upon the request for certification within 15 days from the close of the public comment period or within a longer time granted by the regional administrator or the district engineer, the commission will be deemed to have waived certification. Notwithstanding any contrary provisions of this paragraph, in unusual circumstances the commission may elect to delay acting upon a request for certification of an NPDES permit until after a review of the draft permit.

(2) Notification of Final Determination. The commission shall notify the applicant, the regional administrator or district engineer, and any person so requesting of its final determination. Such final determination shall waive, grant, grant conditionally or deny certification. The notification of a final determination shall be in writing and shall include:

(A) the name and address of the applicant;

(B) a statement of conditions that are necessary to ensure compliance with the applicable water quality requirements;

(C) when the state certifies a draft permit instead of a permit application, any condition required to ensure compliance with applicable water quality requirements shall be identified, citing the federal or state law references upon which that condition is based. Failure by the commission to provide such a citation waives its right to certify with respect to that condition;

(D) for NPDES permits, a statement of the extent to which each condition of the draft permit can be made less stringent without the concurrence of the commission; and

(E) a statement of the basis for the commission's determination to waive certification, grant certification, grant conditional certification, or deny certification.

(3) Statement of Basis.

(A) If a waiver of certification is made, the statement of basis for the commission's determination shall explain that the waiver is based on a determination that no discharge will result from the activity or that the activity does not fall within the commission's jurisdiction or that the commission expressly waives its authority to act on a request for certification for other reasons.

(B) If a certification or conditional certification is made, the statement of basis for the commission's determination shall include either a statement that there is reasonable assurance that the activity will be conducted in a manner which will not violate any applicable water quality requirements or a statement of conditions, including monitoring conditions, that the commission deems necessary to assure that the discharge will not violate applicable water quality requirements.

(C) If a denial of certification is made, the statement of basis for the commission's determination will explain why the commission has determined that the proposed activity will result in a violation of applicable water quality requirements.

(4) Limitation. The commission shall not condition or deny certification of an NPDES permit on the grounds that state law allows a less stringent permit condition.

(5) Request for Hearing. If the commission's final determination denies certification, the applicant may request a hearing on the final determination. If the commission's final determination grants a conditional certification and the applicant disagrees with one or more of such conditions, the applicant may request a hearing on the final determination. A request for a hearing must be filed within 15 days after the commission issues its final determination. The commission shall provide notice of the hearing to each of the parties provided notice of the final determination as provided in paragraph (2) of this subsection. After hearing, the examiner shall recommend a final action by the commission.

(h) Penalties. Violations of this section may subject a person to penalties and remedies specified in the Texas Natural Resources Code, Title 3, and any other statutes administered by the commission. The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) (Statewide Rule 73) for violation of this section.

Source Note: The provisions of this §3.93 adopted to be effective October 25, 1995, 20 TexReg 8445; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.95 Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed in an application for a storage facility permit or for amendment or modification of an existing storage facility permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Brine string--The uncemented tubing through which highly saline water flows into or out of a hydrocarbon storage well during hydrocarbon withdrawal or injection operations.

(3) Cavern--The storage space created in a salt formation by solution mining.

(4) Commission--The Railroad Commission of Texas.

(5) Emergency shutdown valve--A valve that automatically closes to isolate a hydrocarbon storage wellhead from surface piping in the event of specified conditions that, if uncontrolled, may cause an emergency.

(6) Fire detector--A device capable of detecting the presence of a flame or the heat from a fire.

(7) Fresh water--Water having bacteriological,

physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose. For purposes of this section, brine associated with the creation, operation, and maintenance of an underground hydrocarbon storage facility is not considered fresh water.

(8) Hydrocarbon storage well or storage well--A well, including the storage wellhead, casing, tubing, borehole, and cavern, used for the injection or withdrawal of liquid or liquefied hydrocarbons into or out of an underground hydrocarbon storage facility.

(9) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(10) Liquid or liquefied hydrocarbons--Crude oil and products, derivatives, or byproducts of oil or gas that are:

(A) liquid under standard conditions of temperature and pressure;

(B) liquefied under the temperatures and pressures at which they are stored; or

(C) stored under conditions that necessitate the use of displacement fluids to withdraw them from storage.

(11) Operator--The person recognized by the Commission as being responsible for the physical operation of an underground hydrocarbon storage facility, or such person's authorized representative.

(12) Owner--The person recognized by the Commission as owning all or part of a storage facility, or such person's authorized representative.

(13) Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(14) Pollution--Alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(15) Process or transfer area--Any area at an underground hydrocarbon storage facility where hydrocarbons are physically altered by equipment, including dehydrators, compressors, and pumps, or where hydrocarbons are transferred to or from trucks, rail cars, or pipelines.

(16) Storage wellhead--Equipment installed at the surface of the wellbore, including the casinghead and tubing head, spools, block or wing valves, and instrument flanges. Spool pieces must have a length of less than six feet to be considered a part of the storage wellhead.

(17) Surface piping--Any pipe within a storage facility that is directly connected to a storage well, outboard of the wellhead emergency shutdown valve and used to transport product, brine, or fresh water to or from a storage well whether such pipe is above or below ground level.

(18) Underground hydrocarbon storage facility or storage facility--A facility used for the storage of liquid or liquefied hydrocarbons in an underground salt formation, including surface and subsurface rights, appurtenances, and improvements necessary for the operation of the facility.

(b) Permit required.

(1) General. No person may create, operate, or maintain an underground hydrocarbon storage facility without obtaining a permit from the Commission. A permit issued by the Commission for such activities before the effective date of this section shall continue in effect until revoked, modified, or suspended by the Commission, or until it expires by its terms. The provisions of this section apply to permits for underground hydrocarbon storage facility operations issued prior to the effective date of this section, except as specifically provided in this section.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a Commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application.

(1) Information required. An application for a permit to create, operate, or maintain an underground hydrocarbon storage facility shall be filed with the Commission by the owner or operator, or proposed owner or operator, on the prescribed form. The application shall contain the information necessary to demonstrate compliance with the applicable state laws and Commission regulations.

(2) Permit amendment. An application for amendment of an existing underground hydrocarbon storage facility permit shall be filed with the Commission:

(A) prior to any planned enlargement of a cavern in excess of the permitted cavern capacity by solution mining;

(B) when required in accordance with paragraph (3) of this subsection;

(C) prior to the drilling of any additional hydrocarbon storage wells;

(D) prior to any increase in the volume of liquid or liquefied hydrocarbons stored in the cavern in excess of the permitted storage volume; or

(E) any time that conditions at the storage facility deviate materially from conditions specified in the permit or the permit application.

(3) Increase in capacity. The owner or operator of a storage facility shall notify the Commission if information indicates that the capacity of a cavern exceeds the permitted cavern capacity by 20% or more. Such notification shall be made in writing to the Commission within 10 days of the date that the owner or operator knows or has reason to know that the cavern capacity exceeds the permitted capacity by 20% or more. The notification shall include a description of the information that indicates that the permitted cavern capacity has been exceeded, and an estimate of the current cavern capacity. Upon receipt of such information, the Commission or its designee may take any one or more of the following actions:

(A) require the permittee to comply with a compliance schedule that lists measures to be taken to ensure that conditions at the storage facility do not pose a danger to life or property, and that no waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water occurs;

(B) require the permittee to file an application to amend the underground hydrocarbon storage facility permit;

(C) modify, cancel, or suspend the permit as provided in subsection (f) of this section; or

(D) take enforcement action.

(4) Related activities. An application for a permit to store saltwater or brine in a pit or to dispose of saltwater or other oil and gas waste arising out of or incidental to the creation, operation, or maintenance of an underground

hydrocarbon storage facility shall be filed in accordance with applicable Commission requirements.

(d) Standards for underground storage zone.

(1) Geologic, construction, and operating performance. An underground hydrocarbon storage facility may be created, operated, or maintained only in an impermeable salt formation in a manner that will prevent waste of the stored hydrocarbons, uncontrolled escape of hydrocarbons, pollution of fresh water, and danger to life or property. Natural gas storage operations are not authorized under the provisions of this section. A permit under §3.97 of this title (relating to Underground Storage of Gas in Salt Formations) is required to convert from storage of liquid or liquefied hydrocarbons to storage of natural gas in an underground salt formation.

(2) Fresh water strata. The applicant must submit with the application a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the depth to which fresh water strata occur at each storage facility.

(e) Notice and hearing.

(1) Notice requirements. The applicant shall, no later than the date the application is mailed to or filed with the Commission, give notice of an application for a permit to create, operate, or maintain an underground hydrocarbon storage facility, or to amend an existing storage facility permit, by mailing or delivering a copy of the application form to:

(A) the surface owner of the tract where the storage facility is located or is proposed to be located;

(B) the surface owner of each tract adjoining the tract where the storage facility is located or is proposed to be located;

(C) each oil, gas, or salt leaseholder, other than the applicant, of the tract on which the storage facility is located or is proposed to be located;

(D) each oil, gas, or salt leaseholder of any tract adjoining the tract on which the storage facility is located or is proposed to be located;

(E) the county clerk of the county where the storage facility is located or is proposed to be located; and

(F) if the storage facility is located or proposed to be located within city limits, the city clerk or other appropriate city official.

(2) Publication of notice. Notice of the application, in a form approved by the Commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county or counties where the facility is or is proposed to be located. The applicant shall file proof of publication prior to any hearing on the application or administrative approval of the application.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons shall require an examination of the county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the Commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. A permit application for a new underground hydrocarbon storage facility will be considered for approval only after notice and hearing. The Commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the Commission.

(5) Hearing on permit amendments.

(A) An application for an amendment to an existing storage facility permit may be approved administratively if the Commission receives no protest from a person notified pursuant to the provisions of paragraph (1) of this subsection, or from any other affected person.

(B) If the Commission receives a protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the Commission, or of the date of the third publication, whichever is later, or if the Commission determines that a hearing is in the public interest, then the applicant will be notified that the application cannot be approved administratively. The Commission will schedule a hearing on the application upon written request of the applicant. The Commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the Commission.

(C) If the application is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the Commission.

(f) Modification, cancellation, or suspension of a permit.

(1) General. Any permit may be modified, suspended, or canceled after notice and opportunity for hearing if:

(A) a material change in conditions has occurred in the operation, maintenance, or construction of the storage facility, or there are material deviations from the information originally furnished to the Commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) fresh water is likely to be polluted as a result of continued operation of the facility;

(C) there are material violations of the terms and provisions of the permit or Commission regulations;

(D) the applicant has misrepresented any material facts during the permit issuance process; or

(E) injected fluids are escaping or are likely to escape from the storage facility.

(2) Imminent dangers. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the Commission or its designee may immediately suspend a storage facility permit until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All operations at the facility shall cease upon suspension of a permit under this paragraph.

(g) Transfer of permit. A storage facility permit may not be transferred without the prior approval of the Commission or its designee. Until such transfer is approved by the Commission or its designee, the proposed transferee may not conduct any activities otherwise authorized by the permit. The following procedure shall be followed when requesting approval for transfer of a permit.

(1) Request. Prior to transferring either ownership or operation of a storage facility, the permittee shall file a request for transfer of the permit with the Commission. Such request may not be filed unless a completed Form P-4, signed by both the permittee and the proposed transferee, has been filed with the Commission.

(2) Approval. The Commission, or its designee, shall approve the transfer of a storage facility permit, provided:

(A) the proposed transferee is not the subject of any unsatisfied Commission enforcement order at the time of the request for permit transfer; and

(B) there are no existing violations of any Commission regulation, order, or permit at the storage facility at the time of the request for permit transfer that have been documented by the Commission, or its employees, unless the proposed transferee agrees to correct the violations according to a compliance schedule approved by the Commission, or its designee.

(3) Good cause. Notwithstanding paragraph (2) of this subsection, for good cause shown the Commission or its designee may require public notice and opportunity for hearing prior to taking action on a request for transfer of a permit. Such request may be denied after notice and opportunity for hearing if the Commission or its designee finds that transfer of the permit would not be in the public interest.

(h) Safety. The following safety requirements shall apply to all underground hydrocarbon storage facilities, except as specifically provided otherwise, provided, however, that the provisions of this subsection shall not apply to any hydrocarbon storage well that is out of service and disconnected from all surface piping. Notwithstanding the compliance time periods specified in this subsection, a new storage facility permitted under this section must have all required safety measures and equipment in place before commencement of storage operations at the facility. All storage facilities that are permitted on the effective date of this section must have such safety measures and equipment in place within the period of time specified. Further, until such a facility has all the safety measures and devices required by paragraphs (2) - (7) and (13) - (16) of this subsection in place, the facility must have an attendant on site at all times. Notwithstanding the compliance time periods specified in paragraph (2)(B) of this subsection, no storage well in active service may be operated without a fully functional emergency shutdown valve unless in compliance with specified conditions of paragraph (2)(C) of this subsection.

(1) Monitoring of injection and withdrawal operations. All hydrocarbon injection and withdrawal activities shall be continuously monitored by an individual who is trained and experienced in such activities. Any facility that is unattended during injection and withdrawal activities shall have company personnel on call at all times. On-call personnel must be able to reach the facility within 30 minutes from the time a potential problem at the storage facility is noted by the individual monitoring the injection or withdrawal activities.

(2) Storage wellhead.

(A) The storage wellhead shall be designed, operated, and maintained to contain the contents of the storage well and protect against loss of stored product.

(B) Within five years of the effective date of this section, the operator shall have installed emergency shutdown valves between the storage wellhead and the product and brine surface piping of each hydrocarbon storage well and, if required under paragraph (3) of this subsection, between the storage wellhead and fresh water surface piping of the well. Within one year of the effective date of the section, an operator may request an exception to the storage wellhead configuration or compliance date of this subparagraph and propose an alternative configuration or workover schedule for approval by the Commission or its designee. A storage well that is out of service and is disconnected from surface piping shall be exempt from this requirement until reactivated for active hydrocarbon storage. Emergency shutdown valves shall meet the following requirements.

(i) Each emergency shutdown valve shall be capable of activation at each storage well, at the on-site control center if one exists, at the remote control center if one exists, and at a location that is reasonably anticipated to be accessible to emergency response personnel at any facility that does not have an on-site control center that is attended 24 hours per day.

(ii) Each emergency shutdown valve shall be an automatic fail-closed valve that automatically closes when there is a loss of pneumatic pressure, hydraulic pressure, or power to the valve.

(iii) Each emergency shutdown valve shall be closed and opened at least monthly.

(iv) Each emergency shutdown valve system shall be tested at least twice each calendar year at intervals not to exceed 7 1/2 months. The test shall consist of activating the actuation devices, checking the warning system, and observing the valve closure.

(C) If an emergency shutdown valve system fails to operate as required, the storage well shall be immediately shut in until repairs are completed, unless:

(i) a backup emergency shutdown valve is in operation on the same piping; or

(ii) an attendant is posted at the well site to provide immediate manual shut-in.

(D) The requirements of this paragraph do not apply to underground hydrocarbon storage facilities storing only crude oil.

(3) Product, brine, and fresh water surface piping.

(A) Product surface piping shall be designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well. For facilities with hazardous materials surface piping under the administrative authority of the Safety Division of the Railroad Commission of Texas, for the purposes of this section, product surface piping extends from the wellhead emergency shutdown valve to the first pressure regulation device, including a manual, motor-operated, or emergency shutdown valve.

(B) Brine surface piping shall be designed for the maximum brine wellhead pressure and to transport, under emergency conditions, product to the brine system gas vapor control system described in paragraph (6) of this subsection unless:

(i) a secondary emergency shutdown valve is in operation on the brine surface piping; and

(ii) the brine surface piping between the wellhead emergency shutdown valve and the secondary emergency shutdown valve is designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well.

(C) Fresh water surface piping, if any, must be equipped with a wellhead emergency shutdown valve unless it is:

(i) disconnected from the wellhead; or

(ii) connected to brine surface piping outboard of the wellhead emergency shutdown valve; or

(iii) designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well; and has an internal diameter of less than or equal to two inches; and an attendant is posted at the well site to provide immediate manual shut-in when in use.

(D) Fresh water piping designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well and with an internal diameter of less than or equal to two inches is exempt from the requirement that an emergency shutdown valve be located on the wellhead or separated from the wellhead by a spool no longer than six feet.

(4) Overfill detection and automatic shut-in methods.

(A) The requirements of this paragraph shall not apply to an underground hydrocarbon storage facility storing only crude oil.

(B) The requirements of this paragraph shall not apply to a storage well that is out of service and disconnected from surface piping until the well is reconnected for hydrocarbon storage.

(C) Within one year of the effective date of this section, each storage cavern shall have at least two of the following redundant devices or methods in operation:

(i) a safety casing or annular tubing string filled with a non-volatile fluid and equipped with a pressure sensor switch set to automatically close all emergency shutdown valves in response to a preset pressure;

(ii) a preset pressure sensor switch or transducer on the brine piping that is set to automatically close all emergency shutdown valves in response to a preset pressure. This pressure sensor or transducer may be used in conjunction with weep hole(s) on a safety string that is concentric with the brine string, or in conjunction with weep hole(s) on the brine string;

(iii) a device on the brine string or brine piping that detects hydrocarbon in the brine by physical or chemical characteristics and that is set to automatically close all emergency shutdown valves in response to hydrocarbon detection;

(iv) an instrument that detects a rapid increase in the brine flow rate indicative of hydrocarbon in the brine and that is set to automatically close all emergency shutdown valves in response to a preset flow rate or differential flow rate; or

(v) an alternate device or method approved by the Commission or its designee.

(5) Leak detectors.

(A) The provisions of subparagraphs (B) - (D) of this paragraph shall not apply to underground hydrocarbon storage facilities storing only crude oil.

(B) A leak detector shall be installed and in operation at the wellhead of each hydrocarbon storage well and at each process and transfer area and each surface vessel area that contains liquid or liquefied hydrocarbons. These leak detectors shall be integrated with the warning system required in paragraph (13)(A) of this subsection.

(C) Leak detectors shall be installed and in operation at four locations that are evenly spaced around the perimeter of the brine pit(s).

(D) Leak detectors shall be tested twice each calendar year at intervals not to exceed 7 1/2 months and, when defective, repaired or replaced within 10 days.

(6) Brine system gas vapor control.

(A) The provisions of this paragraph shall not apply to underground hydrocarbon storage facilities storing only crude oil.

(B) Gas vapor control devices shall be installed and in operation at each brine pit system to ignite or capture hydrocarbon vapors that are heavier than air. Control devices shall consist of at least one of the following:

(i) a flare on the brine system upstream from the brine discharge point;

(ii) a hydrocarbon liquid knockout vessel and degasifier;

(iii) pilot lights on the berm of each brine pit; or

(iv) an alternative method designed to provide a reliable, localized point of ignition to prevent the formation of a vapor cloud.

(C) Brine system gas vapor control systems shall be inspected twice each calendar year at intervals not to exceed 7 1/2 months.

(7) Fire detection devices or methods and fire control systems.

(A) Fire detection devices or methods shall be installed and in operation at all process and transfer areas. Fire detection devices or methods specified in this paragraph shall be integrated with the warning system required in paragraph (13)(A) of this subsection. Fire detection shall consist of at least one of the following:

(i) fire detectors;

(ii) heat sensors, including meltdown and fused devices; or

(iii) camera surveillance at facilities that are attended at an on-site control room 24 hours per day.

(B) Fire detectors shall be tested twice each calendar year at intervals not to exceed 7 1/2 months and, when defective, repaired or replaced within 10 days.

(C) Within three years of the effective date of this section, each storage wellhead in active storage service shall have fire suppression capability designed to aid in personnel rescue and for equipment protection and cooling. Within one year of the effective date of this section, the operator may request an exception to the schedule or fire suppression requirement of this subparagraph and propose an alternative schedule or means of protection from wellhead fire for approval of the Commission or its designee.

(8) Emergency response plan. Each storage facility shall submit to the Commission a written emergency response plan. The plan shall address spills and releases, fires, fire suppression capability, explosions, loss of electricity, and loss of telecommunication services. The plan shall describe the storage facility's emergency response communication system, procedures for coordination of emergency communication and response activities with local emergency planning committees and other local authorities, use of warning systems, procedures for citizen and employee emergency notification and

evacuation, and employee training. The initial plan must be designed based upon the existing safety measures at the facility. The plan shall be updated as changes in safety features at the facility occur, or as the Commission or its designee requires. The plan shall include a plat of the facility that shows the location of wells, processing areas, loading racks, brine pits, and other significant features at the site. A copy of the plan shall be provided to the local emergency response planning committee and to any other local governmental entity that submits a written request for a copy of the plan to the operator. Copies of the plan shall also be available at the storage facility and at the company headquarters.

(9) Notification of emergency or uncontrolled release.

(A) Emergency response personnel. Each operator shall notify the county sheriff's office, the county emergency management coordinator, and any other appropriate public officials, which are identified in the emergency response plan, of any emergency that could endanger nearby residents or property. Such emergencies include, but are not limited to, an uncontrolled release of hydrocarbons from a storage well, or a leak or fire at any area of the storage facility. The operator shall give notice as soon as practicable following the discovery of the emergency. At the time of the notice, the operator shall report an assessment of the potential threat to the public.

(B) Commission. The operator shall report to the appropriate Commission district office as soon as practicable any emergency, significant loss of fluids, significant mechanical failure, or other problem that increases the potential for an uncontrolled release. The operator shall file with the Commission within 30 days of the incident a written report on the root cause of the incident. The operator shall file with the Commission within 90 days of the incident a written report that describes the operational changes, if any, that have been or will be implemented to reduce the likelihood of a recurrence of a similar incident. An operator may request that the Commission grant, for good cause, a reasonable amount of additional time to file a written report on the root cause of the incident.

(10) Public education. Each facility operator shall establish a continuing educational program to inform residents within a one-mile radius of a hydrocarbon storage facility of emergency notification and evacuation procedures.

(11) Annual emergency drill. Annually, each operator shall conduct a drill that tests response to a simulated emergency. Written notice of the drill shall be provided to the appropriate Commission district office, the county emergency management coordinator, and the county sheriff's office at least seven days prior to the drill. Local emergency response authorities shall be invited to participate in all such drills. The operator shall file a written evaluation of the drill and plans for improvements with the appropriate district office and the county emergency management coordinator within 30 days after the date of the drill.

(12) Employee safety training.

(A) Each operator shall prepare and implement a plan to train and test each employee at each underground hydrocarbon storage facility on operational safety to the extent applicable to the employee's duties and responsibilities. The facility's emergency response plan shall be included in the training program.

(B) Each operator shall hold a safety meeting with each contractor prior to the commencement of any new contract work at an underground hydrocarbon storage facility. Emergency measures, including safety and evacuation measures specific to the contractor's work, shall be explained in the contractor safety meeting.

(13) Warning systems and alarms.

(A) All leak detectors, fire detectors, heat sensors, pressure sensors, and emergency shutdown instrumentation shall be integrated with warning systems that are audible and visible in the local control room and at any remote control center. The circuitry shall be designed so that failure of a detector or heat sensor, excluding meltdown and fused devices, to function will activate the warning.

(B) A manually operated alarm shall be installed at each attended storage facility. The alarm shall be audible in areas of the facility where personnel are normally located.

(14) Wind socks. At least one wind sock that is visible at any time from any normal work location within the storage facility shall be installed at the facility.

(15) Barriers. Barriers designed to prevent unintended impact by vehicles and equipment shall be placed around above-grade hydrocarbon piping, hydrocarbon process equipment, and surface hydrocarbon storage vessels in areas where vehicles may normally be expected to travel or within 100 feet of a public road.

(16) Wellhead, surface piping, and associated valves. All wellhead equipment, product, fresh water, and brine surface piping, and associated valves shall be designed, installed, and operated in accordance with engineering standards to the expected service conditions to which the piping and equipment will be subjected.

(i) Cavern capacity and configuration.

(1) Crude oil storage. The provisions of this subsection shall not apply to underground hydrocarbon storage facilities where only crude oil is stored.

(2) Before storage operations begin. The capacity and configuration of each hydrocarbon storage cavern (both salt domes and bedded salt) shall be determined by sonar survey before storage operations begin in a newly completed cavern.

(3) Salt domes. The capacity and configuration of each salt dome hydrocarbon storage cavern shall be determined by sonar survey at least once every 10 years.

(4) Bedded salt. The configuration of the roof of each hydrocarbon storage cavern in bedded salt shall be determined by downhole log or an alternate method approved by the Commission or its designee at least once every five years.

(5) Filing results. Sonar and roof monitoring survey results shall be filed with the Commission within 30 days after the survey.

(6) Out-of-service caverns. A sonar or roof monitoring survey is not required for a cavern that is out of service. A sonar or roof monitoring survey shall be performed before any cavern that has been out of service is returned to service, unless the provisions of paragraph (2) of this subsection apply.

(j) Well completion, casing, and cementing. Hydrocarbon storage wells shall be cased and the casing strings cemented to prevent fluids from escaping to the surface or into fresh water strata, or otherwise escaping and causing waste or endangering public safety or the environment.

(1) New wells.

(A) All hydrocarbon storage wells drilled in salt domes after the effective date of this section shall have at least two casing strings cemented into the salt formation. Sufficient cement shall be used to fill the annular space outside the casing from the casing shoe to the ground surface, or from the casing shoe to a point at least 200 feet above the shoe of the previous casing string.

(B) All hydrocarbon storage wells in bedded salt drilled after the effective date of this section shall have all casing strings cemented with sufficient cement to fill the annular space outside each casing string from the casing shoe to the ground surface.

(2) Well completion report. A well completion report shall be filed in accordance with the instructions on the form prescribed by the Commission within 30 days after a storage well is completed and before solution mining to create the cavern begins.

(k) Operating requirements.

(1) Operating pressure. The operating pressure of each hydrocarbon storage well shall not exceed the permitted maximum allowable operating pressure for that well. The permitted maximum allowable operating pressure is that pressure specified in the Commission permit or order, or, if not specified in the permit or order, that pressure stated in the application or the application for amendment to a permit or order. The maximum operating pressure at the shoe of the lowermost cemented casing shall not exceed 0.8 pounds per square inch per foot of depth.

(2) Volume of hydrocarbons stored. The quantity of hydrocarbons stored in a cavern shall not exceed the permitted maximum storage volume for that cavern. The permitted maximum hydrocarbon storage volume is that volume specified in the Commission permit or order, or, if not specified in the permit or order, that volume stated in the application or the application for amendment to a permit or order.

(l) Monitoring requirements.

(1) Pressures. Each hydrocarbon storage well shall be equipped with pressure sensors that continuously monitor and display wellhead pressures on both the product and brine sides of the wellhead at the control room. Each hydrocarbon storage well with a safety string shall be equipped with a pressure sensor and the sensor shall continuously monitor the pressure on the safety string at the wellhead.

(2) Pressure gauges. Each hydrocarbon storage well shall be equipped with gauges on both the brine and hydrocarbon sides of the wellhead.

(3) Volumes injected and withdrawn. The volume of hydrocarbons injected into and withdrawn from each hydrocarbon storage well shall be measured by:

(A) flow meter for each well; or

(B) an alternate method approved by the Commission or its designee.

(4) Measurement performance. The accuracy of hydrocarbon volume measurement devices or methods required under paragraph (3) of this subsection shall be verified at least once each year by a person who is not an officer or employee of the owner or operator, or any affiliate of the owner or operator. For purposes of this section, an affiliate is any person or entity that owns, is owned by, or is under common ownership with the owner or the operator. In the case of meters, verification includes witnessing meter calibration or proving conducted by the owner or operator or an affiliate of the owner or operator.

(5) Data recording. Within three years of the effective date of this section, operators shall have installed and have functioning equipment to electronically record all liquid and gas pressures, volumes, and flow rates at a frequency of at least once per minute, and all actuations of the emergency shutdown valve.

(m) Reporting. The operator shall report maximum wellhead pressures on the hydrocarbon and brine sides of each hydrocarbon storage well and the net volumes of hydrocarbons injected into and withdrawn from each hydrocarbon storage well in accordance with the instructions on the annual report form prescribed by the Commission.

(n) Operations, construction, and maintenance records retention.

(1) Hydrocarbon injection and withdrawal data.

(A) The operator shall retain for at least three months all electronic records of hydrocarbon storage well pressures, flow rates, and hydrocarbon volumes injected into and withdrawn from each well, and the hydrocarbon inventory of each cavern. These electronic data shall be recorded at a frequency of at least once per minute.

(B) The operator shall retain for at least five years the records, reported to the Commission under subsection (m) of this section, of maximum monthly wellhead pressures on the hydrocarbon and brine sides of each hydrocarbon storage well and the monthly net volumes of hydrocarbons injected into and withdrawn from each hydrocarbon storage well. These electronic data shall be recorded at a frequency of at least once per day.

(2) Records retention. The operator shall retain for at least five years the records of measurement performance under subsection (l)(4) of this section; and testing of safety devices under subsection (h) of this section. Records of any test of a safety device required under subsection (h) of this section shall be available for on-site inspection within 10 days of the date of the test.

(3) Construction and maintenance data. The operator shall retain for the life of the facility documents and records pertaining to the drilling, mining, completion, major repairs, and workovers of storage wells and testing of storage well integrity, and shall transfer all such documents and records to any new owner and/or new operator of the facility.

(4) Extension during investigation. Any documents or records that contain information pertinent to the resolution of any pending regulatory enforcement proceeding shall be retained beyond the prescribed retention until the resolution of such proceeding.

(o) Testing and maintenance.

(1) Integrity tests for wells in salt domes with a single casing string. Each hydrocarbon storage well drilled into a salt dome and having a single casing string cemented to the surface shall have the casing inspected by mechanical, ultrasonic, or magnetic methods at least once every five years and after each workover that involves physical changes to the cemented casing string.

(2) Integrity tests for wells other than those in salt domes with a single casing string. Each hydrocarbon storage well shall be tested for integrity prior to being placed into service, at least once every five years, and after each workover that involves physical changes to any cemented casing string. The following requirements apply

to all such integrity tests.

(A) A hydrocarbon storage well shall be tested for integrity by the nitrogen-brine interface method or an alternative approved by the Commission, or its designee.

(B) A test procedure shall be filed with the Commission for approval at least 10 days before the test date.

(C) The operator shall notify the district office at least five days prior to conducting any integrity test.

(D) A complete record of each integrity test shall be filed in duplicate with the district office within 30 days after testing is completed. The record shall include a chronology of the test, copies of all downhole logs, storage well completion information, pressure readings, volume measurements, temperature logs and readings, and an explanation of the test results that addresses the precision of the test in terms of a calculated leak rate.

(E) Storage well pressures shall be allowed to stabilize to a rate of change of less than 10 psi in 24 hours before the testing period begins.

(3) Storage wellhead and casing. Storage wellhead components and casing shall be inspected at least once every 10 years for corrosion, cracks, deformations or other conditions that may compromise integrity and that may not be detected by the five-year test. The operator may request an extension of up to five years from the Commission for good cause. Factors the Commission may consider in determining good cause pursuant to this paragraph include by are not limited to the age, location, and configuration of the well; well and facility history; operator compliance record; operator efforts to comply with this subsection; and accuracy of inventory control.

(4) Product, fresh water, and brine surface piping. Within one year of the effective date of this section, the operator shall submit a piping integrity management plan for approval by the Commission or its designee. Within three years of the effective date of this section, or in conjunction with the storage well integrity testing, all product, freshwater, and brine surface piping shall be maintained according to the facility's piping integrity management plan.

(5) Alternative monitoring. An operator may request the Commission or its designee to approve storage well pressure monitoring as an alternative to integrity testing for hydrocarbon storage wells that are out of storage service. An out-of-service storage well must be tested for integrity according to the procedures specified in paragraph (2) of this subsection before it may be returned to storage service.

(p) Plugging.

(1) Plug on abandonment. A hydrocarbon storage well shall be plugged upon permanent abandonment in a manner approved by the Commission or its designee. A proposal for plugging shall be submitted to the Commission in Austin for approval or modification prior to plugging. Following approval of a plugging plan, the operator shall file a notification of intent to plug at least five days prior to commencement of plugging operations. A plugging report shall be filed with the Commission in Austin within 30 days after plugging.

(2) Alternative monitoring. As an alternative to plugging a hydrocarbon storage well that has been permanently deactivated, an operator may request approval by the Commission or its designee of a plan to convert the storage well to a monitor well. A pressure monitoring plan must be submitted to the Commission along with the request to convert the storage well to a monitoring well.

(q) Penalties.

(1) Penalties. Violations of this section may subject the operator to penalties and remedies specified in the Texas Natural Resources Code, Titles 3 and 11, and other statutes administered by the Commission.

(2) Certificate of compliance. The certificate of compliance for any underground hydrocarbon storage facility may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance).

(r) Applicability of other Commission rules and orders. The owner or operator of an underground hydrocarbon storage facility is not relieved by this section of compliance with any other requirement of Chapters 3, 4, 7, or 8 of this title (relating to Oil and Gas Division; Environmental Protection; Gas Services Division; or Pipeline Safety Regulations).

Source Note: The provisions of this §3.95 adopted to be effective January 1, 1994, 18 TexReg 8871; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 30, 2007, 32 TexReg 289; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.96 Underground Storage of Gas in Productive or Depleted Reservoirs

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed an application for an underground gas storage project permit or an amendment or modification of an existing underground gas storage project permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Commission--The Railroad Commission of Texas.

(3) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose.

(4) Leak detector--A device capable of detecting by chemical or physical means the presence of hydrocarbon vapor or the escape of vapor through a small opening.

(5) Gas storage or underground gas storage--Storage of natural gas or other gaseous material in a productive or depleted reservoir, exclusive of gas injection for enhanced recovery.

(6) Gas storage project--All surface and subsurface rights, appurtenances, and improvements necessary for conducting underground gas storage operations in a gas storage reservoir.

(7) Gas storage well or storage well--A well used to inject or withdraw natural gas or other gaseous material stored in a productive or depleted reservoir, exclusive of a well used to inject gas for enhanced recovery.

(8) Operator--The person recognized by the commission as being responsible for the physical operation of a gas storage project, or such person's authorized representative.

(9) Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(10) Pollution--Alteration of the physical, chemical, or

biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(11) Productive or depleted reservoir--A subsurface sand, stratum, or formation that is productive of, or has previously produced, oil, gas, or geothermal resources.

(b) Permit required.

(1) General. No person may operate a gas storage project without obtaining a permit from the commission. A permit issued by the commission for operation of a gas storage project before the effective date of this section shall continue in effect until revoked, modified, or suspended by the commission, or until it expires according to its terms. The provisions of this section apply to gas storage projects permitted prior to the effective date of this section, except as otherwise specifically provided.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application. An application to operate a gas storage project shall be filed with the commission by the owner or operator or proposed owner or operator. The application shall include the following:

(1) compliance with safety requirements--information demonstrating compliance with the provisions of subsection (i) of this section;

(2) request for reservoir designation--a request for designation of a productive or depleted reservoir as a gas storage reservoir, supported by the following:

(A) information demonstrating that the reservoir is suitable for gas storage; and

(B) information demonstrating the amount of recoverable native gas remaining in the reservoir;

(3) compliance with standards for injection wells--information demonstrating compliance with the provisions of subsections (j), (k), and (l) of this section for each gas injection well. The requirements of this paragraph do not apply to wells used for gas withdrawal only;

(4) water protection letter--a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the depth to which fresh water strata occur in the project area;

(5) public interest--a request that the commission issue an order containing the findings described in the Texas Natural Resources Code, §91.174(a), if such an order is desired by the applicant;

(6) fees--the fees required under §3.78 of this title (relating to Fees and Financial Security Requirements) for each gas storage well in the storage project that will be used for injection.

(d) Permit amendment. An application for amendment of an existing gas storage project permit shall be filed with the commission as specified in paragraphs (1) - (4) of this subsection.

(1) Expansion of reservoir. An application for permit amendment shall be filed prior to expanding the areal extent of the gas storage reservoir.

(2) Increase in pressure. An application for permit amendment shall be filed prior to increasing the gas storage reservoir pressure above the maximum permitted pressure.

(3) Adding storage wells. An application for permit amendment shall be filed prior to adding additional gas storage wells to the project.

(4) Material deviation. An application for permit amendment shall be filed at any time that conditions at the storage project deviate materially from the conditions specified in the permit or permit application.

(e) Standards for storage reservoir. A gas storage project shall be operated only in a productive or depleted reservoir in a manner that will prevent waste of oil, gas, or geothermal resources, uncontrolled escape of gases, pollution of fresh water, and danger to life or property.

(f) Notice and hearing.

(1) Notice requirements. By no later than the date the application is mailed to or filed with the commission, the applicant shall give notice of an application for a permit to operate a gas storage project, or to amend an existing storage project permit, by mailing or delivering a copy of the application to:

(A) each mineral interest owner, other than the applicant, of the proposed gas storage reservoir;

(B) each leaseholder of minerals lying above or below the proposed gas storage reservoir;

(C) each leaseholder of minerals offsetting the proposed gas storage reservoir;

(D) each owner or leaseholder of any portion of the surface overlying the proposed gas storage reservoir;

(E) the clerk of the county or counties where the proposed gas storage reservoir is located; and

(F) the city clerk or other appropriate city official where the proposed gas storage reservoir is located within city limits.

(2) Publication of notice. Notice of the application for an original or amended gas storage project permit, in a form approved by the commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county where the gas storage project is located. The applicant shall file proof of publication of the notice prior to any hearing on the application or administrative approval.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain the names and addresses of such persons shall require an examination of county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. An application for a new gas storage project permit will be considered for approval only after notice and hearing. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(5) Hearing on permit amendments.

(A) If the commission receives a protest regarding an application for amendment of a gas storage project permit from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the commission, or of the date of the third publication, whichever is later, or if the commission or its designee determines that a hearing is in the public interest, then the applicant will be notified that the application for amendment cannot be administratively approved. The commission will schedule a hearing on the application upon request of the applicant. The commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the commission.

(B) If the commission receives no protest regarding an application for amendment of a gas storage project permit from a person notified pursuant to paragraph (1) of this subsection or from any other affected person, the application may be approved administratively.

(C) If the application for amendment of a gas storage project permit is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the commission.

(g) Modification, cancellation, or suspension of a permit.

(1) General. A permit may be modified, suspended, or canceled after notice and opportunity for hearing under any of the following circumstances:

(A) a material change in conditions has occurred in the operation of the gas storage project, or there are material deviations from the information originally furnished to the commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) fresh water is likely to be polluted as a result of the continued operation of the gas storage project;

(C) there are material violations of the terms and provisions of the permit or of applicable commission orders or regulations;

(D) the applicant has misrepresented material facts during the permit issuance process; or

(E) injected fluids are escaping or are likely to escape from the storage project.

(2) Imminent danger. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is imminent, the commission or its designee may immediately suspend a permit for underground gas storage until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All underground gas storage operations shall cease upon suspension of a permit under this paragraph.

(h) Transfer of permit. A gas storage project permit may be transferred from one operator to another operator if both of the following requirements are met.

(1) Notice. Written notice of intended permit transfer is submitted to the commission at least 15 days prior to the date the transfer takes place.

(2) No objection. The commission or its designee does not notify the present permit holder of an objection to the transfer prior to the transfer date stated in the notification in paragraph (1) of this subsection.

(i) Safety requirements for gas storage projects.

(1) Leak detectors.

(A) Within two years of the effective date of this section, leak detectors shall be installed and in operation at each gas storage well that is located 100 yards or less from a residence, commercial establishment, church, school, or small, well-defined outside area, and at each structurally enclosed compressor site. For purposes of this section, the term "small, well-defined outside area" means an area such as a playground, recreation area, outdoor theater, or other place of public assembly that is occupied by 20 or more persons on at least five days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive.

(B) Each leak detector required under this paragraph shall be tested twice each calendar year at intervals not to exceed 7-1/2 months and, when defective, repaired or replaced within 10 days.

(2) Warning systems. Within two years of the effective date of this section, all leak detectors required in paragraph (1) of this subsection shall be integrated with warning systems that are audible and visible in the control room and at any remote control center. The circuitry shall be designed so that failure of a detector or pressure monitor to function will activate the warning.

(3) Emergency response plan. Within six months of the effective date of this section, each operator shall submit to the commission a safety plan that includes emergency response procedures, provisions to provide security against unauthorized activity, and gas release detection and prevention measures. The plan shall include a description of and be designed for the residential, commercial, and public land use in the proximity of the gas storage project. The initial plan must be designed based upon the existing safety measures at the facility. The plan shall be updated as changes in safety features at the facility occur, or as the commission or its designee requires. Copies of the plan shall be available at the storage facility and at the company headquarters.

(4) Safety training. Within six months of the effective date of this section, each operator shall prepare and implement a plan to train and test each employee at each gas storage project on operational safety and emergency response procedures to the extent applicable to the employee's duties and responsibilities. The plan shall be incorporated into the plan addressing the requirements of the United States Department of Transportation and Occupational Safety and Health Administration. Each operator shall hold a safety meeting with each contractor prior to the commencement of any new contract work at a gas storage project. Emergency measures specific to the contractor's work shall be explained in the contractor safety meeting.

(5) Gas withdrawal wells exempt. Gas storage wells that will be used only for gas withdrawal are exempt from the requirements of paragraphs (1) and (2) of this subsection.

(j) Area of review. The applicant shall review the data of public record for wells that penetrate the portion of the gas reservoir that falls within the area proposed to be designated as the gas storage reservoir, and those wells that penetrate the gas reservoir within 1/4 mile of the outer boundary of the proposed gas storage reservoir, to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids from the gas storage reservoir. The applicant shall identify in the application any wells which appear from such review of public records to be unplugged or improperly plugged, and any other unplugged or improperly plugged wells of which the applicant has actual knowledge.

(k) Casing. Gas storage wells shall be cased and the casing cemented in compliance with §3.13 of this title (relating to Casing, Cementing, Drilling, and Completion Requirements).

(l) Special equipment.

(1) Tubing and packer. New wells drilled or converted for injection of gases after April 1, 1982, shall be equipped with tubing set on a mechanical packer. Packers shall be set no higher than 200 feet below the known top of cement behind the long string casing but in no case higher than 150 feet below the base of fresh water.

(2) Pressure observation valve. The wellhead shall be equipped with a pressure observation valve on the tubing and each annulus of the well.

(3) Exceptions. An exception to any provision of this subsection may be granted administratively upon a showing of good cause. If a request for an exception is administratively denied, the operator shall have a right to a hearing upon request. After hearing, the examiner shall recommend a final action by the commission.

(m) Well record. Within 30 days after the completion, conversion, or recompletion of a gas storage well, the operator shall file in duplicate in the district office a complete record of the well on the appropriate form which shows the current completion.

(n) Monitoring and reporting.

(1) Wellhead pressure. The wellhead pressure of each gas storage well shall be continuously recorded, continuously monitored electronically, or controlled by a preset high-low pressure sensor switch.

(2) Pressure reporting. Information regarding wellhead pressures for each gas storage well shall be reported annually to the commission on the prescribed form.

(3) Gas metering. The total volume of gas injected into and withdrawn from the storage project shall be metered through a master meter.

(4) Record retention. All wellhead pressure records, gas metering records, and leak detector test results shall be retained by the operator for at least five years.

(5) Reporting of leaks. The operator shall report to the appropriate district office the discovery of any pressure changes or other monitoring data that indicate the presence of leaks in the well or the lack of confinement of the injected gases to the gas storage reservoir. Such report shall be made orally as soon as practicable following the discovery of the leak, and shall be confirmed in writing within five working days.

(6) Gas volume reports. On or before the last day of each month, the operator of each gas storage project that stores gas to supply a public utility shall file with the commission a report showing the volume of gas placed into storage and the volume of gas removed from storage at the project during the preceding month. The report shall also state the total volume of gas stored on the first and last days of the preceding month. This report shall be filed in a format acceptable to the commission.

(o) Integrity testing.

(1) Prior to commencing operations. Before beginning gas injection operations, the operator shall pressure test the long string casing, or the tubing-casing annulus if the well is equipped with tubing set in a packer. Gas storage wells in which injection occurs through casing shall be tested at the maximum authorized injection pressure. Gas storage wells in which injection occurs through tubing and packer shall be tested at no less than 500 psig.

(2) Subsequent tests. Each gas storage well shall be pressure tested in the manner provided in paragraph (1) of this subsection at least once every five years to determine if there are leaks in the casing, tubing, or packer. The commission, or its designee, may prescribe a schedule and mail notification to operators to allow for orderly and timely compliance with this requirement.

(3) Alternatives to testing. As an alternative to the testing required in paragraph (2) of this subsection, the tubing-casing annulus pressure may be monitored and monitoring results described in the annual monitoring report required by subsection (n) of this section, provided that there is no indication of problems with the well. The commission, or its designee, may also grant an exception for other viable alternative tests or surveys.

(4) District office notification. The operator shall notify the appropriate district office at least 48 hours prior to conducting the test required in paragraphs (1) or (2) of this subsection. Testing shall not commence before the end of the 48-hour period unless authorized by the district office.

(5) Test records. A complete record of all tests shall be filed in duplicate with the district office within 30 days after the testing.

(6) Gas withdrawal wells exempt. Gas storage wells that shall be used only for gas withdrawal are excluded from the requirements of this subsection.

(p) Plugging. Gas storage wells shall be plugged upon abandonment in accordance with §3.14 of this title (relating to Plugging).

(q) Penalties.

(1) General. Violations of this section may subject the operator to penalties and remedies specified in the Texas Natural Resources Code, Title 3; Texas Civil Statutes, Article 6053-3; and other statutes administered by the commission.

(2) Certificate of compliance. The certificate of compliance for any oil, gas, or geothermal resource well may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) for violation of this section.

(r) Applicability of other commission rules.

(1) General. The operator of a gas storage project must comply with the requirements of Chapters 7 and 8 of this title (relating to Gas Services Division, and Pipeline Safety Regulations) for both pipelines and associated facilities, and other applicable commission rules and orders.

(2) Signs. Each location at which gas storage activities take place, including each gas storage well, shall be identified by a sign that meets the requirements specified in §3.3(a)(1), (2), and (5) of this title (relating to Identification of Properties, Wells, and Tanks). In addition, each sign shall include a telephone number where the operator, or a representative of the operator, can be

reached in the event of an emergency.

Source Note: The provisions of this §3.96 adopted to be effective January 1, 1994, 18 TexReg 8871; amended to be effective July 10, 2000, 25 TexReg 6487; amended to be effective September 1, 2004, 29 TexReg 8271; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.97 Underground Storage of Gas in Salt Formations

(a) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--A person who, as a result of actions proposed in an application for a storage facility permit or amendment or modification of an existing storage facility permit, has suffered or may suffer actual injury or economic damage other than as a member of the general public.

(2) Cavern--The storage space created in a salt formation by solution mining.

(3) Commission--The Railroad Commission of Texas.

(4) Emergency shutdown valve--A valve that automatically closes to isolate a gas storage wellhead from surface piping in the event of specified conditions that, if uncontrolled, may cause an emergency.

(5) Fresh water--Water having bacteriological, physical, and chemical properties that make it suitable and feasible for beneficial use for any lawful purpose. For purposes of this section, brine associated with the creation, operation, and maintenance of an underground gas storage facility is not considered fresh water.

(6) Gas storage well or storage well--A well, including the storage wellhead, casing, tubing, borehole, and cavern used for the injection or withdrawal of natural gas or any other gaseous substance into or out of an underground gas storage facility.

(7) Leak or fire detector--A device capable of detecting by chemical or physical means the presence of stored product gas or the escape of stored product gas or the presence of flame or heat of a fire.

(8) Operator--The person recognized by the Commission as being responsible for the physical operation of an underground gas storage facility, or such person's authorized representative.

(9) Owner--The person recognized by the Commission as owning all or part of an underground gas storage facility, or such person's authorized representative.

(10) Person--A natural person, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(11) Pollution--Alteration of the physical, chemical, or biological quality of, or the contamination of, water that makes it harmful, detrimental, or injurious to humans, animal life, vegetation, or property, or to public health, safety, or welfare, or impairs the usefulness or the public enjoyment of the water for any lawful or reasonable purpose.

(12) Storage wellhead--Equipment installed at the surface of the wellbore, including the casinghead and tubing head, spools, block or wing valves, and instrument flanges. Spool pieces must have a length less than six feet to be considered a part of the storage wellhead.

(13) Surface piping--Any pipe within a storage facility that is directly connected to a storage well, outboard of the wellhead emergency shutdown valve and used to transport gas, brine, or fresh water to or from a storage well whether such pipe is above or below ground level.

(14) Underground gas storage facility or storage facility--A facility used for the storage of natural gas or any other gaseous substance in an underground salt formation, including surface and subsurface rights, appurtenances, and improvements necessary for the operation of the facility.

(b) Permit required.

(1) General. No person may create, operate, or maintain an underground gas storage facility without obtaining a permit from the Commission. A permit issued by the Commission for such activities before the effective date of this section shall continue in effect until revoked, modified, or suspended by the Commission, or until it expires according to its terms. The provisions of this section apply to permits to conduct gas storage operations issued prior to the effective date of this section, except as otherwise specifically provided.

(2) Conflict with other requirements. If a provision of this section conflicts with any provision or term of a Commission order, field rule, or permit, the provision of such order, field rule, or permit shall control.

(c) Application.

(1) Information required. An application for a permit to create, operate, or maintain an underground gas storage facility shall be filed with the Commission by the owner or operator, or the proposed owner or operator, on the prescribed form. The application shall contain the information necessary to demonstrate compliance with applicable state laws and Commission regulations.

(2) Permit amendment. An application for amendment of an existing underground gas storage facility permit shall be filed with the Commission:

(A) prior to any planned enlargement of a cavern in excess of the permitted cavern capacity by solution mining;

(B) when required in accordance with paragraph (3) of this subsection;

(C) prior to the drilling of any additional storage wells;

(D) prior to an increase in the maximum operating pressure above the permitted pressure; or

(E) any time that conditions at the storage facility deviate materially from the conditions specified in the permit or permit application.

(3) Increase in capacity. The owner or operator of a storage facility shall notify the Commission if information indicates that the capacity of a cavern exceeds the permitted cavern capacity by 20% or more. Such notification shall be made in writing to the Commission within 10 days of the date that the owner or operator of the storage facility knows or has reason to know that the cavern capacity exceeds the permitted capacity by 20% or more. The notification shall include a description of the information that indicates that the permitted cavern capacity has been exceeded, and an estimate of the current cavern capacity. Upon receipt of such information, the Commission or its designee may take any one or more of the following actions:

(A) require the permittee to comply with a compliance schedule that lists measures to be taken to ensure that conditions at the storage facility do not pose a danger to life or property, and that no waste of gas, uncontrolled escape of gas, or pollution of fresh water occurs;

(B) require the permittee to file an application to amend the underground gas storage facility permit;

(C) modify, cancel, or suspend the permit as provided in subsection (f) of this section; or

(D) take enforcement action.

(d) Standards for underground storage zone.

(1) Geologic, construction, and operating performance. An underground gas storage facility may be created, operated, or maintained only in an impermeable salt formation in a manner that will prevent waste of the stored gases, uncontrolled escape of gases, pollution of fresh water, and danger to life or property. This section does not authorize storage of liquid or liquefied hydrocarbons in an underground salt formation. A permit under §3.95 of this title (relating to Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations) is required to convert from storage of natural gas to storage of liquid or liquefied hydrocarbons in an underground salt formation.

(2) Fresh water strata. The applicant must submit with the application a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the depth to which fresh water strata occur at each storage facility.

(e) Notice and hearing.

(1) Notice requirements. The applicant shall, no later than the date the application is mailed to or filed with the Commission, give notice of an application for a permit to create, operate, or maintain an underground hydrocarbon storage facility, or to amend an existing storage facility permit, by mailing or delivering a copy of the application form to:

(A) the surface owner of the tract where the storage facility is located or is proposed to be located;

(B) the surface owner of each tract adjoining the tract where the storage facility is located or is proposed to be located;

(C) each oil, gas, or salt leaseholder, other than the applicant, of the tract on which the storage facility is located or is proposed to be located;

(D) each oil, gas, or salt leaseholder of any tract adjoining the tract on which the storage facility is located or is proposed to be located;

(E) the county clerk of the county or counties where the storage facility is located or is proposed to be located; and

(F) if the storage facility is located or is proposed to be located within city limits, the city clerk or other appropriate city official.

(2) Publication of notice. Notice of the application, in a form approved by the Commission or its designee, shall be published by the applicant once a week for three consecutive weeks in a newspaper of general circulation in the county where the storage facility is or is proposed to be located. The applicant shall file proof of publication prior to any hearing on the application or administrative approval of the application.

(3) Notice by publication. The applicant shall make diligent efforts to ascertain the name and address of each person identified under paragraph (1)(A) - (D) of this subsection. The exercise of diligent efforts to ascertain names and addresses of such persons shall require an examination of the county records where the facility is located and an investigation of any other information of which the applicant has actual knowledge. If, after diligent efforts, the applicant has been unable to ascertain the name and address of one or more persons required to be notified under paragraph (1)(A) - (D) of this subsection, the notice requirements for those persons are satisfied by the publication of the notice of application as required in paragraph (2) of this subsection. The applicant must submit an affidavit to the Commission specifying the efforts that were taken to identify each person whose name and/or address could not be ascertained.

(4) Hearing required for new permits. A permit application for a new underground gas storage facility will be considered for approval only after notice and hearing. The Commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the Commission.

(5) Hearing on permit amendments.

(A) An application for an amendment to an existing storage facility permit may be approved administratively if the Commission receives no protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person.

(B) If the Commission receives a protest from a person notified pursuant to paragraph (1) of this subsection or from any other affected person within 15 days of the date of receipt of the application by the Commission, or of the date of the third publication, whichever is later, or if the Commission determines that a hearing is in the public interest, then the applicant will be notified that the application cannot be approved administratively. The Commission will schedule a hearing on the application upon written request of the applicant. The Commission will give notice of the hearing to all affected persons, local governments, and other persons who express, in writing, an interest in the application. After hearing, the examiner shall recommend a final action by the Commission.

(C) If the application is administratively denied, a hearing will be scheduled upon written request of the applicant. After hearing, the examiner shall recommend a final action by the Commission.

(f) Modification, cancellation, or suspension of a permit.

(1) General. Any permit may be modified, suspended, or canceled after notice and opportunity for hearing if:

(A) a material change in conditions has occurred in the operation, maintenance, or construction of the storage facility, or there are material deviations from the information originally furnished to the Commission. A change in conditions at a facility that does not affect the safe operation of the facility or the ability of the facility to operate without causing waste of hydrocarbons or pollution is not considered to be material;

(B) pollution of fresh water is likely as a result of continued operation of the storage facility;

(C) there are material violations of the terms and provisions of the permit or Commission regulations;

(D) the applicant has misrepresented any material facts during the permit issuance process; or

(E) injected fluids are escaping or are likely to escape from the storage facility.

(2) Imminent danger. Notwithstanding the provisions of paragraph (1) of this subsection, in the event of an emergency that presents an imminent danger to life or property, or where waste of hydrocarbons, uncontrolled escape of hydrocarbons, or pollution of fresh water is

imminent, the Commission or its designee may immediately suspend a storage facility permit until a final order is issued pursuant to a hearing, if any, conducted in accordance with the provisions of paragraph (1) of this subsection. All operations at the facility shall cease upon suspension of a permit under this paragraph.

(g) Transfer of permit. A storage facility permit may not be transferred without the prior approval of the Commission, or its designee. Until such transfer is approved by the Commission or its designee, the proposed transferee may not conduct any activities authorized by the permit. The following procedure shall be followed when requesting approval for transfer of a permit.

(1) Request. Prior to transferring either ownership or operation of a storage facility, the permittee shall file with the Commission a request for transfer of the permit. Such a request may not be filed unless a completed Form P-4, signed by both the permittee and the proposed transferee, has been filed with the Commission.

(2) Approval. The Commission, or its designee, shall approve the transfer of a storage facility permit, provided:

(A) the proposed transferee is not the subject of any unsatisfied Commission enforcement order at the time of the request for permit transfer; and

(B) there are no existing violations of any Commission regulation, order, or permit at the storage facility at the time of the request for permit transfer that have been documented by the Commission, or its employees, unless the proposed transferee agrees to correct the violations according to a compliance schedule approved by the Commission, or its designee.

(3) Good cause. Notwithstanding paragraph (2) of this subsection, for good cause shown the Commission, or its designee, may require public notice and opportunity for hearing prior to taking action on a request for transfer of a permit. Such request may be denied after notice and opportunity for hearing if the Commission or its designee finds that transfer of the permit would not be in the public interest.

(h) Safety. The following safety requirements shall apply to all underground gas storage facilities, provided, however, that the provisions of this subsection shall not apply to any natural gas storage well that is out of service and disconnected from surface piping. Notwithstanding the compliance time periods specified in this subsection, a new underground gas storage facility permitted under this section must have all required safety measures and equipment in place before commencement of storage operations at the facility. All existing storage facilities must have such safety measures and equipment in place within the period of time specified. Notwithstanding the compliance time periods specified in paragraph (2)(B) of this subsection, no storage well in active service may be operated without a fully functional emergency shutdown valve unless in compliance with specified conditions of paragraph (2)(C) of this subsection.

(1) Monitoring of injection and withdrawal operations. All gas injection and withdrawal activities shall be continuously monitored by an individual who is experienced and trained in such activities. Any facility that is unattended during injection and withdrawal activities shall have company personnel on call at all times. On-call personnel must be able to reach the facility within 30 minutes from the time a potential problem is noted by the individual monitoring the injection or withdrawal activities.

(2) Storage wellhead.

(A) The storage wellhead must be designed, operated, and maintained to contain the contents of the storage well and protect against loss of stored product.

(B) Within five years of the effective date of this section, the operator shall have installed emergency shutdown valves between the wellhead and the gas injection/withdrawal surface piping of each storage well and between the wellhead and any brine or fresh water surface piping. Within one year of the effective date of this section, the operator may request an exception to the storage wellhead configuration or compliance date of this subparagraph and propose an alternative configuration or workover schedule for approval by the Commission or its designee. A storage well that is out of service and is disconnected from surface piping shall be exempt from this requirement until reactivated for active gas storage. Emergency shutdown valves shall meet the following requirements:

(i) Each emergency shutdown valve shall be capable of activation at each storage well, at the on-site control center if one exists, at the remote control center if one exists, and at a location that is reasonably anticipated to be accessible to emergency response personnel at any facility that does not have an on-site control center that is attended 24 hours per day.

(ii) Each emergency shutdown valve shall be an automatic fail-closed valve that automatically closes when there is a loss of pneumatic or hydraulic pressure on, or power to, the valve or when the maximum operating pressure under subsection (k) of this section is exceeded.

(iii) Each emergency shutdown valve shall be closed and opened at least monthly.

(iv) Each emergency shutdown valve system shall be tested at least twice each calendar year at intervals not to exceed 7 1/2 months. The test shall consist of activating the actuation devices, checking the warning system, and observing the valve closure.

(C) If an emergency shutdown valve system fails to operate as required, the well shall be immediately shut in until repairs are completed, unless:

(i) a backup emergency shutdown valve is in operation on the same piping; or

(ii) an attendant is posted at the well site to provide immediate manual shut-in.

(3) Gas, brine, and fresh water surface piping.

(A) Gas surface piping shall be designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well. For facilities with hazardous materials surface piping under the administrative authority of the Safety Division of the Railroad Commission of Texas, for the purposes of this section, gas surface piping extends from the wellhead emergency shutdown valve to the first pressure regulation device, including a manual, motor-operated, or emergency shutdown valve.

(B) Brine piping, if any, shall be designed for the maximum brine wellhead pressure and to transport, under emergency conditions, gas to a gas control system if the operator is solution mining while the gas storage well is in active storage service, unless:

(i) a secondary emergency shutdown valve is in operation on the brine surface piping; and

(ii) the brine surface piping between the wellhead emergency shutdown valve and the secondary emergency shutdown valve is designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well.

(C) Fresh water surface piping, if any, must be equipped with an emergency shutdown valve unless it is:

(i) disconnected from the wellhead; or

(ii) connected to the brine surface piping outboard of the wellhead emergency shutdown valve; or

(iii) designed for the maximum allowable operating pressure on the hydrocarbon side of the well; and has an internal diameter of less than or equal to two inches; and an attendant is posted at the well site to provide immediate manual shut-in when in use.

(D) Fresh water piping designed for the permitted maximum allowable operating pressure on the hydrocarbon side of the well and with an internal diameter of less than or equal to two inches, is exempt from the requirement that an emergency shutdown valve be separated from the wellhead by a spool no longer than six feet.

(4) Cavern debrining and solution mining operations.

(A) Within one year of the effective date of this section, each storage well shall have two or more of the following redundant devices or methods in operation during cavern debrining operations or during solution mining operations that are conducted with gas in storage in the same cavern. These devices are designed to prevent the release of gas into the brine and fresh water systems connected to the well during cavern debrining operations or during solution mining operations that are conducted with gas in storage in the same cavern. Gas release prevention shall consist of at least two of the following redundant devices or methods:

(i) emergency shutdown valves equipped with pressure sensor switches or transducers set to automatically close emergency shutdown valves on the brine side of the wellhead and on the fresh water piping, if any, in response to preset pressures on the brine and fresh water piping of the well;

(ii) weep hole(s) on the brine return string in conjunction with a preset pressure sensor switch or transducer on the brine piping that is set to automatically close emergency shutdown valves on the brine side of the wellhead and on the fresh water piping, if any, in response to a preset pressure;

(iii) a device on the brine return string or brine piping that detects hydrocarbon in the brine by physical or chemical characteristics and that is set to automatically close emergency shutdown valves on the brine side of the wellhead and on the fresh water piping, if any, in response to hydrocarbon detection;

(iv) an instrument that detects a rapid increase in the brine flow rate indicative of hydrocarbon in the brine and that is set to automatically close emergency shutdown valves on the brine side of the wellhead and on the fresh water piping, if any, in response to a preset flow rate or differential flow rate; or

(v) an alternative device or method approved by the Commission.

(B) Solution mining of a cavern may occur while gas is in storage, provided that the injection of fresh water and the injection of gas do not occur simultaneously within the same cavern.

(5) Leak or fire detectors.

(A) Within two years of the effective date of this section, a leak or fire detector shall be installed and in operation at each gas storage well and each structurally enclosed compressor site.

(B) Leak or fire detectors shall be tested twice each calendar year at intervals not to exceed 7 1/2 months, and, when defective, repaired or replaced within 10 days. Leak or fire detectors shall be integrated with warning systems required in paragraph (6)(A) of this subsection.

(6) Warning systems and alarms.

(A) Within two years of the effective date of this section, all leak or fire detectors and sensors or methods that actuate the emergency shutdown valve shall be integrated with warning systems that are audible and visible in the control room and at any remote control center. The circuitry shall be designed so that failure of a leak or fire detector to function will activate the warning.

(B) A manually operated audible alarm shall be installed at each attended storage facility. The alarm shall be audible in areas of the facility where personnel are normally located.

(7) Emergency response plan. Each storage facility shall submit to the Commission a written emergency response plan. The plan shall address gas releases, fires, fire suppression capability, explosions, loss of electricity, and loss of telecommunication services. The plan shall describe the facility's emergency response communication system, procedures for coordination of emergency communication and response activities with local authorities, use of warning systems, procedures for citizen and employee emergency notification and evacuation, and employee training. The plan shall also include a plat of the facility showing the locations of wells, processing areas, and other significant features at the facility. The initial plan must be designed based upon the existing safety measures at the facility. The plan shall be updated as changes in safety features at the facility occur, or as the Commission or its designee requires. A copy of the plan shall be provided to the local emergency response committee and to any other local governmental entity that submits a written request for a copy of the plan to the operator. Copies of the plan shall also be available at the storage facility and at the company headquarters.

(8) Notification of emergency or uncontrolled release.

(A) Emergency response personnel. Each operator shall notify the county sheriff's office, the county emergency management coordinator, and any other appropriate public officials which are identified in the emergency response plan of any emergency that could endanger nearby residents or property. Such emergencies include, but are not limited to, an uncontrolled release of hydrocarbons from a storage well or a leak or fire at any area of the storage facility. The operator shall give notice as soon as practicable following the discovery of the emergency. At the time of the notice, the operator shall also report an assessment of the potential threat to the public.

(B) Commission. The operator shall report to the appropriate Commission district office as soon as practicable any emergency, significant loss of gas or fluids, significant mechanical failure, or other problem that increases the potential for an uncontrolled release. The operator shall file with the Commission within 30 days of the incident a written report on the root cause of the incident. Within 90 days of the incident, the operator shall file with the Commission a written report that describes the operational changes, if any, that have been or will be implemented to reduce the likelihood of a recurrence of a similar incident. An operator may request that the Commission grant, for good cause, a reasonable amount of additional time to file a written report on the root cause of the incident.

(9) Annual emergency drill. Annually, each operator shall conduct a drill that tests response to a simulated emergency. Written notice of the drill shall be provided to the appropriate Commission district office, the county emergency management coordinator, and the county sheriff's office at least seven days prior to the drill. Local emergency response authorities shall be invited to participate in all such drills. The operator shall file a written evaluation of the drill and plans for improvements with the appropriate district office and the county emergency management coordinator within 30 days after the date of the drill.

(10) Employee safety training.

(A) Each operator shall prepare and implement a plan to train and test each employee at each underground gas storage facility on operational safety to the extent applicable to the employee's duties and responsibilities. The facility's emergency response plan shall be included in the training program.

(B) Each operator shall hold a safety meeting with each contractor prior to the commencement of any new contract work at an underground gas storage facility. Emergency measures, including safety and evacuation measures specific to the contractor's work, shall be explained in the contractor safety meeting.

(11) Fire suppression capability.

(A) Within three years of the effective date of this section, each operator shall have fire suppression capability designed to aid in personnel rescue and equipment protection and cooling.

(B) Within one year of the effective date of this section, the operator may request an exception to the schedule or fire suppression requirement of this paragraph and propose an alternative schedule or means of protection from wellhead fire for approval of the Commission or its designee.

(12) Wellhead, piping, and associated valves. All wellhead surface piping and associated valves shall be designed, installed, and operated in accordance with engineering standards to the expected service conditions to which the piping and equipment will be subjected.

(13) Barriers. Within one year of the effective date of this section, barriers designed to prevent unintended impact by vehicles and equipment shall be placed around above grade hydrocarbon piping, hydrocarbon process equipment where vehicles may normally be expected to travel, or within 100 feet of a public road.

(i) Cavern capacity and configuration.

(1) Before storage operations begin. The capacity and configuration of each gas storage cavern (both salt domes and bedded salt) shall be determined by sonar survey before storage operations begin in a newly completed cavern.

(2) Salt domes. The capacity and configuration of each salt dome gas storage cavern shall be determined by sonar survey before a cavern that has been out of service is returned to service, provided, however, that a sonar survey shall not be required on a cavern that is being returned to service if a sonar survey of that cavern has been run at any time during the previous 10 years.

(3) Bedded salt. The configuration of the roof of each gas storage cavern in bedded salt shall be determined by downhole log or an alternate method approved by the Commission, or its designee, at least once every five years.

(4) Filing of results. Sonar and roof monitoring survey results shall be filed with the Commission within 30 days after the survey.

(5) Out-of-service caverns. A sonar or roof monitoring survey is not required for a cavern that is out of service. A sonar or roof monitoring survey shall be performed before any such cavern that has been out of service is returned to service, unless the provisions of paragraph (2) of this subsection apply.

(6) Verification. Sonar surveys performed before debrining shall be verified by metering the volume of the displaced brine.

(j) Well completion, casing, and cementing. Gas storage wells shall be cased and the casing strings cemented to prevent gases from escaping to the surface or into fresh water strata, or otherwise escaping and causing waste or endangering public safety or the environment.

(1) New wells.

(A) All gas storage wells drilled in salt domes after the effective date of this section shall have at least two casing strings cemented into the salt formation. Sufficient cement shall be used to fill the annular space outside the casing from the casing shoe to the ground surface, or from the casing shoe to a point at least 200 feet above the shoe of the previous casing string.

(B) All gas storage wells drilled in bedded salt after the effective date of this section shall have all casing strings cemented with sufficient cement to fill the annular space outside each casing string from the casing shoe to the ground surface.

(2) Well completion report. A well completion report shall be filed in accordance with the instructions on the form prescribed by the Commission within 30 days after a storage well is completed and before solution mining to create the cavern begins.

(k) Operating pressure.

(1) Not to exceed maximum. The operating pressure of each gas storage well shall not exceed the permitted maximum allowable operating pressure for that well. The permitted maximum allowable operating pressure is that pressure specified in the Commission permit or order, or, if not specified in the permit or order, that pressure stated in the application or the application for amendment to a permit or order.

(2) At casing seat. The maximum operating pressure at the casing seat shall not exceed 0.85 pounds per square inch per foot of depth.

(l) Monitoring requirements.

(1) Gas pressure. Gas pressure on the injection/withdrawal casing or tubing or piping connected thereto shall be equipped with a pressure sensor to continuously monitor the wellhead pressure. Pressure sensors shall be integrated electronically with the warning systems, alarms, and emergency shutdown valve actuation system as required in subsection (h)(2)(B) and (h)(6)(A) of this section.

(2) Pressure observation valves. The injection/withdrawal casing or tubing shall be equipped with a pressure observation valve and gauge. The wellhead shall be equipped with a pressure observation valve on

each casing annulus so that a gauge may be installed for pressure monitoring.

(3) Volumes injected and withdrawn. The volume of gas injected into and withdrawn from each storage well shall be measured by:

(A) flow meter for each well; or

(B) an alternate method approved by the Commission.

(4) Meter calibration. Meters that measure the volume of gas into storage and out of storage shall be recalibrated at least once each year.

(5) Data recording. Within three years of the effective date of this section, operators shall have installed and have functioning equipment to electronically record all liquid and gas pressures and injection volumes and rates at a frequency of at least once per minute, and all actuations of the emergency shutdown valve.

(m) Reporting.

(1) Monthly reports. On or before the last day of each month, the operator of each facility that stores gas to supply a public utility shall file with the Commission a report showing the volume of gas placed into storage and the volume of gas removed from storage at the storage facility, during the preceding month. The report shall also state the total volume of gas in storage on the first and last days of the preceding month. This report shall be filed in a format acceptable to the Commission or its designee.

(2) Annual reports. The operator shall file annually a status report for each storage well in accordance with the instructions on the form prescribed by the Commission.

(n) Operations, construction, and maintenance records retention.

(1) Operations data.

(A) The operator shall retain for at least three months all electronic records of storage well pressures, volumes of gases injected and withdrawn, and the inventory of gas in storage. These electronic data shall be recorded at a frequency of at least once per minute.

(B) The operator shall retain for at least five years the records reported to the Commission under subsection (m). These electronic data shall be recorded at a frequency of at least once per day.

(2) Records retention. The operator shall retain for at least five years the records of measurement performance under subsection (l)(4) of this section; and testing of safety devices under subsection (h) of this section. Records of any test of a safety device required under subsection (h) of this section shall be available for on-site inspection within 10 days of the date of the test.

(3) Construction and maintenance data. The operator shall retain for the life of the facility documents and records pertaining to the drilling, mining, completion, repair and workover of storage wells and the testing of storage well integrity, and shall transfer all such documents and records to any new owner and/or new operator of the facility.

(4) Extension during investigation. The operator shall retain beyond the prescribed retention period any documents or records that contain operational data pertaining to the resolution of any pending regulatory enforcement proceedings until the resolution of such proceedings.

(o) Testing and maintenance.

(1) Integrity tests. Each gas storage well shall be tested for integrity prior to being placed into service, at least once every five years, and after each workover that involves physical changes to any cemented casing string. The following requirements apply to such integrity tests.

(A) A test procedure shall be filed with the Commission for approval at least 10 days before the test date.

(B) The initial test conducted on a well prior to placing it into service shall be performed using the nitrogen-interface test method or an alternative method approved by the Commission or its designee.

(C) The integrity test required to be conducted at least once every five years on a well that has gas in storage may be performed using pressure monitoring, provided:

(i) the wellhead pressure is stabilized such that the effects of ambient temperature on pressure have overtaken the effects of the last injection or withdrawal on pressure;

(ii) a downhole temperature log is run at the beginning and at the end of the test period;

(iii) the test period is a minimum of 72 hours; and

(iv) the net gas volume change for the test period is calculated.

(D) The operator shall notify the district office at least five days prior to conducting any integrity test.

(E) A complete record of each integrity test shall be filed in duplicate with the district office within 30 days after testing is completed. The record shall include a chronology of the test, copies of all downhole logs, storage well completion information, pressure readings, volume measurements, temperature logs and readings, and an explanation of the test results that addresses the precision of the test in terms of a calculated leak rate.

(2) Alternative monitoring. An operator may request the Commission or its designee to approve well pressure monitoring as an alternative to integrity testing for storage wells that are out of gas storage service. An out-of-service well shall be tested for integrity by the nitrogen-interface method before it may be returned to storage service.

(3) Storage wellhead and casing. Storage wellhead components and casing shall be inspected at least once every 15 years for corrosion, cracks, deformations, or other conditions that may compromise integrity and that may not be detected by the five-year test. The operator may request an extension of up to five years from the Commission for good cause. Factors the Commission may consider in determining good cause pursuant to this paragraph include by are not limited to the age, location, and configuration of the well; well and facility history; operator compliance record; operator efforts to comply with this subsection; and accuracy of inventory control.

(4) Fresh water, brine, and gas surface piping. Within one year of the effective date of this section, the operator shall submit a piping integrity management plan for approval by the Commission or its designee. Within three years of the effective date of this section, or in conjunction with the storage well integrity testing, all gas, freshwater, and brine surface piping shall be maintained according to the facility's piping integrity management plan.

(p) Plugging.

(1) Plug on abandonment. A gas storage well shall be plugged upon permanent abandonment in a manner approved by the Commission or its designee. A proposal for plugging shall be submitted to the Commission in Austin for approval or modification prior to plugging. Following approval of a plugging plan, the operator shall file notification of intent to plug at least five days prior to

commencement of plugging operations. A plugging report shall be filed with the Commission within 30 days after plugging.

(2) Alternative monitoring. As an alternative to plugging a gas storage well that has been permanently deactivated, an operator may request approval by the Commission or its designee of a plan to convert the well to a monitor well. A pressure monitoring plan must be submitted to the Commission along with the request to convert the well to a monitoring well.

(q) Penalties.

(1) Penalties. Violations of this section may subject the operator to penalties and remedies specified in Texas Natural Resources Code, Title 3; Texas Utilities Code, Chapter 121; and other statutes administered by the Commission.

(2) Certificate of compliance. The certificate of compliance for any underground gas storage facility may be revoked in the manner provided in §3.73 of this title (relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance) for violation of this section.

(r) Applicability of other Commission rules and orders. The owner or operator of an underground gas storage facility is not relieved by this section of compliance with any other requirement of Chapters 3, 4, 7, or 8 of this title (relating to Oil and Gas Division; Environmental Protection; Gas Services Division; or Pipeline Safety Regulations).

Source Note: The provisions of this §3.97 adopted to be effective January 1, 1994, 18 TexReg 8871; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective January 30, 2007, 32 TexReg 289; amended to be effective July 2, 2012, 37 TexReg 4892.

§3.98 Standards for Management of Hazardous Oil and Gas Waste

(a) Purpose. The purpose of this section is to establish standards for management of hazardous oil and gas waste.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Activities associated with the exploration, development, and production of oil or gas or geothermal resources--Activities associated with:

(A) the drilling of exploratory wells, oil wells, gas wells, or geothermal resource wells;

(B) the production of oil, gas, or geothermal resources, including:

(i) activities associated with the drilling of injection water source wells that penetrate the base of usable quality water;

(ii) activities associated with the drilling of cathodic protection holes associated with the cathodic protection of wells and pipelines subject to the jurisdiction of the commission to regulate the production of oil, gas, or geothermal resources;

(iii) activities associated with natural gas or natural gas liquids processing plants or reservoir pressure maintenance or repressurizing plants;

(iv) activities associated with any underground natural gas storage facility, provided the terms "natural gas" and "storage facility" shall have the meanings set out in Texas Natural Resources Code, §91.173;

(v) activities associated with any underground hydrocarbon storage facility, provided the terms "hydrocarbons" and "underground hydrocarbon storage facility" shall have the meanings set out in Texas Natural Resources Code, §91.201; and

(vi) activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil or gas prior to the refining of such oil or prior to the use of such gas in any manufacturing process or as a residential or industrial fuel;

(C) the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission to regulate the exploration, development, and production of oil or gas or geothermal resources; and

(D) the discharge, storage, handling, transportation, reclamation, or disposal of waste or any other substance or material associated with any activity listed in subparagraphs (A) - (C) of this paragraph.

(2) Administrator--The administrator of the United States Environmental Protection Agency, or the administrator's designee.

(3) Authorized facility--Either:

(A) an authorized recycling or reclamation facility; or

(B) an authorized treatment, storage, or disposal facility.

(4) Authorized recycling or reclamation facility--A facility permitted in accordance with the requirements of 40 CFR, Parts 270 and 124 or Part 271, if required, at which hazardous waste that is to be recycled or reclaimed is managed and whose owner or operator is subject to regulation under:

(A) 40 CFR, §261.6(c) or an equivalent state program (concerning facilities that recycle recyclable materials); or

(B) 40 CFR, Part 266, Subparts C (concerning recyclable materials used in a manner constituting disposal), F (concerning recyclable materials used for precious metal recovery), or G (concerning spent lead-acid batteries being reclaimed), or an equivalent state program.

(5) Authorized representative--The person responsible for the overall operation of all or any part of a facility or generation site.

(6) Authorized treatment, storage, or disposal facility--A facility at which hazardous waste is treated, stored, or disposed of that:

(A) has received either:

(i) a permit (or interim status) in accordance with the requirements of 40 CFR, Parts 270 and 124 (EPA permit); or

(ii) a permit (or interim status) from a state authorized in accordance with 40 CFR, Part 271; and

(B) is authorized under applicable state or federal law to treat, store, or dispose of that type of hazardous waste. If a hazardous oil and gas waste is destined to a facility in an authorized state that has not yet obtained authorization from the EPA to regulate that particular hazardous waste, then the designated facility must be a facility allowed by the receiving state to accept such waste and the facility must have a permit issued by the EPA to manage that waste.

(7) Centralized Waste Collection Facility or CWCF--A facility that meets the requirements of subsection (m)(3) of this section.

(8) Certification--A statement of professional opinion

based upon knowledge and belief.

(9) CFR--Code of Federal Regulations.

(10) CESQG--A conditionally exempt small quantity generator, as described in subsection (f)(1) of this section (relating to generator classification and accumulation time).

(11) Commission--The Railroad Commission of Texas or its designee.

(12) Container--Any portable device in which material is stored, transported, treated, disposed of, or otherwise handled.

(13) Contaminated media--Soil, debris, residues, waste, surface waters, ground waters, or other materials containing hazardous oil and gas waste as a result of a discharge or clean-up of a discharge.

(14) Department of Transportation or DOT--The United States Department of Transportation.

(15) Designated facility--An authorized facility that has been designated on the manifest by the generator pursuant to the provisions of subsection (o)(1) of this section (relating to general manifest requirements).

(16) Discharge or hazardous waste discharge--The accidental or intentional spilling, leaking, pumping, pouring, emitting, emptying, or dumping of hazardous waste into or on any land or water.

(17) Disposal--The discharge, deposit, injection, dumping, spilling, leaking, or placing of any hazardous waste into or on any land or water so that such waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

(18) Disposal facility--A facility or part of a facility at which hazardous waste is intentionally placed into or on any land or water, and at which waste will remain after closure.

(19) Elementary neutralization unit--A device consisting of a tank, tank system, container, transport vehicle, or vessel that is used for neutralizing wastes that are hazardous wastes:

(A) only because they exhibit the characteristic of corrosivity under the test referred to in subsection (e)(1)(D)(ii) of this section (relating to characteristically hazardous wastes); or

(B) they are identified in subsection (e)(1)(D)(i) of this section (relating to listed hazardous wastes) only because they exhibit the corrosivity characteristic.

(20) Empty container--A container or an inner liner removed from a container that has held any hazardous waste and that meets the requirements of 40 CFR, §261.7(b).

(21) Environmental Protection Agency or EPA--The United States Environmental Protection Agency.

(22) EPA Acknowledgment of Consent--The cable sent to the EPA from the United States Embassy in a receiving country that acknowledges the written consent of the receiving country to accept the hazardous waste and describes the terms and conditions of the receiving country's consent to the shipment.

(23) EPA hazardous waste number--The number assigned by the EPA to each hazardous waste listed in 40 CFR, Part 261, Subpart D, and to each characteristic identified in 40 CFR, Part 261, Subpart C.

(24) EPA identification number or EPA ID Number--The number assigned by the EPA to each hazardous waste generator, transporter, and treatment, storage, or disposal facility.

(25) EPA Form 8700-12--The EPA form that must be completed and delivered to the commission in order to obtain an EPA ID number.

(26) Executive director of the TCEQ--The executive director of the TCEQ or the executive director's designee.

(27) Facility--All contiguous land, including structures, other appurtenances, and improvements on the land, used for recycling, reclaiming, treating, storing, or disposing of hazardous waste. A facility may consist of several treatment, storage, or disposal operational units (e.g., one or more landfills, surface impoundments, or combinations thereof).

(28) Generate--To produce hazardous oil and gas waste or to engage in any activity (such as importing) that first causes a hazardous oil and gas waste to become subject to regulation under this section.

(29) Generation site--

(A) Excluding sites addressed in subparagraphs (B) (relating to pipelines) and (C) (relating to gas plants) of this paragraph, any of the following operational units that are owned or operated by one person and other sites at which hazardous oil and gas waste is generated or where actions first cause a hazardous oil and gas waste to become subject to regulation, including but not limited to:

(i) all oil and gas wells that produce to one set of storage or treatment vessels, such as a tank battery, the storage or treatment vessels, associated flowlines, and related land surface;

(ii) an injection or disposal site, that is not part of a generation site described in subparagraph (A)(i) of this paragraph, its related injection or disposal wells, associated injection lines, and related land surface;

(iii) an offshore platform; or

(iv) any other site, including all structures, appurtenances, or other improvements associated with that site that are geographically contiguous, but which may be divided by public or private right-of-way, provided the entrance and exit between the properties is at a cross-roads intersection, and access is by crossing as opposed to going along, the right-of-way.

(B) In the case of a pipeline system (other than a field flowline or injection line system), an equipment station (such as a pump station, breakout station, or compressor station) or any other location along a pipeline (such as a drip pot, pigging station, or rupture), together with any and all structures, other appurtenances, and improvements:

(i) that are geographically contiguous with or are physically related to an equipment station or other location described in this paragraph, but excluding any pipeline that connects two or more such stations or locations;

(ii) that are owned or operated by one person; and

(iii) at which hazardous oil and gas waste is produced or where actions first cause a hazardous oil and gas waste to become subject to regulation.

(C) A natural gas treatment or processing plant or a natural gas liquids processing plant.

(30) Generator--Any person, by generation site, whose act or process produces hazardous oil and gas waste or whose act first causes a hazardous oil and gas waste to become subject to regulation under this section, or such person's authorized representative.

(31) Geothermal energy and associated resources Geothermal energy and associated resources as defined in

Texas Natural Resources Code, §141.003(4).

(32) Hazardous oil and gas waste--Any oil and gas waste determined to be hazardous under the provisions of subsection (e) of this section (relating to hazardous waste determination).

(33) Hazardous oil and gas waste constituent--A hazardous waste constituent of hazardous oil and gas waste.

(34) Hazardous waste--A hazardous waste, as defined in 40 CFR, §261.3, including a hazardous oil and gas waste.

(35) Hazardous waste constituent--A constituent that caused the administrator to list a hazardous waste in 40 CFR, Part 261, Subpart D, or a constituent listed in table 1 of 40 CFR, §261.24.

(36) International shipment--The transportation of hazardous oil and gas waste into or out of the jurisdiction of the United States.

(37) Land disposal--The placement in or on the land, except as otherwise provided in 40 CFR, Part 268, including placement in a landfill, surface impoundment, waste pile, injection well, land treatment facility, salt dome formation, salt bed formation, or underground mine or cave, or placement in a concrete vault or bunker intended for disposal purposes.

(38) LQG--A large quantity generator, as described in subsection (f)(3) of this section (relating to generator classification and accumulation time).

(39) Management--The systematic control of the collection, source separation, storage, transportation, processing, treatment, recovery, and disposal of hazardous waste.

(40) Manifest--The shipping document required pursuant to the provisions of subsection (o) of this section (relating to manifests).

(41) Manifest document number--The 12-digit identification number assigned to a generator by the EPA, plus a unique five-digit document number assigned to the manifest by the generator, or preprinted on the manifest, for recording and reporting purposes.

(42) Oil and gas waste--Waste generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources, or the solution mining of brine. Until delegation of authority under RCRA to the commission by EPA, the term "oil and gas waste" shall exclude hazardous waste arising out of or incidental to activities associated with natural gas treatment or natural gas liquids processing plants and reservoir pressure maintenance or repressurizing plants.

(43) On-site--At the generation site.

(44) Operator--The person responsible for the overall operation of a facility.

(45) Owner--The person who owns a facility or part of a facility.

(46) P-5 operator number--The number assigned by the commission to each person who conducts any of the activities specified in §3.1 of this title (relating to Organization Report; Retention of Records; Notice Requirements) within the State of Texas.

(47) Person--An individual, firm, joint stock company, corporation, organization, government, governmental subdivision or agency, business trust, estate, trust, partnership, association, or any other legal entity.

(48) Pressure maintenance plant or repressurizing plant--A plant for processing natural gas for reinjection (for reservoir pressure maintenance or repressurizing) in a natural gas recycling project. These terms do not include a compressor station along a natural gas pipeline system or a pump station along a crude oil pipeline system.

(49) Primary exporter--Any person who is required to originate the manifest for a shipment of hazardous waste in accordance with 40 CFR, Part 262, Subpart B, or equivalent state provision, that identifies a treatment, storage, or disposal facility in a receiving country as the facility to which the hazardous waste will be sent and any intermediary arranging for the export.

(50) Receiving country--A foreign country to which a hazardous waste is sent for the purpose of treatment, storage, or disposal (except short-term storage incidental to transportation).

(51) Reclaim--To process to recover a usable product or to regenerate.

(52) Recycle--To beneficially use, reuse, or reclaim hazardous waste.

(53) Reportable quantity--The quantity of a hazardous substance released in a 24-hour period that must be reported under the provisions of 40 CFR, Part 117 (for spills to water) or Part 302 (any spill).

(54) Resource Conservation and Recovery Act or RCRA--The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended, 42 USC §6901, et seq.

(55) Reuse--To employ hazardous waste as an ingredient in an industrial process to make a product (other than recovery of distinct components of hazardous waste as separate end products) or effective substitution of hazardous waste for a commercial product used in a particular function or application.

(56) Sludge--Any solid, semi-solid, or liquid waste generated from a wastewater treatment plant or water supply treatment plant, or air pollution control facility, exclusive of the treated effluent from a wastewater treatment plant.

(57) Solid waste--Any waste identified in 40 CFR, §261.2.

(58) Solution mined brine--Brine extracted from a subsurface salt formation through dissolution of salt in the formation.

(59) SQG--A small quantity generator, as described in subsection (f)(2) of this section (relating to generator classification and accumulation time).

(60) State--Any of the 50 states that compose the United States, the District of Columbia, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands.

(61) Storage--The holding of hazardous waste for a temporary period (excluding storage at the site of generation during the applicable accumulation time period specified in subsection (f) of this section), at the end of which the hazardous waste is recycled, reclaimed, treated, disposed of, or stored elsewhere.

(62) Tank--A stationary device designed to contain an accumulation of hazardous waste that is constructed primarily of non-earthen materials (e. g., wood, concrete, steel, plastic) that provide structural support.

(63) Tank system--A tank and its associated ancillary equipment and containment system.

(64) TCEQ--The Texas Commission on Environmental

Quality or its successor agencies.

(65) Totally enclosed treatment facility--A facility for the treatment of hazardous waste that is directly connected to an industrial production process and that is constructed and operated in a manner that prevents the release of any hazardous waste or hazardous waste constituent into the environment during treatment (e.g., a pipe in which waste acid is neutralized).

(66) Transfer facility--Any transportation-related facility including loading docks, parking areas, storage areas, and other similar areas where shipments of hazardous waste are held during the normal course of transportation.

(67) Transport vehicle--A motor vehicle or rail car used for the transportation of cargo. Each cargo-carrying body (trailer, railroad freight car, etc.) is a separate transport vehicle.

(68) Transportation--The movement of hazardous waste by air, rail, highway, or water.

(69) Transporter--A person engaged in the off-site transportation of hazardous waste.

(70) Treatment--Any method, technique, or process, including neutralization, designed to change the physical, chemical, or biological character or composition of any hazardous waste so as to neutralize such waste, to recover energy or material resources from the waste, or to render such waste non-hazardous or less hazardous, safer to transport, store, or dispose of, amenable for recovery or storage, or reduced in volume. The term does not include any activity that might otherwise be considered treatment that is exempt from regulation under this section (such as neutralization of caustic or acidic fluids in an elementary neutralization unit).

(71) TCEQ-Form 0311--The TCEQ Uniform Hazardous Waste Manifest form. This form can be obtained from the commission.

(72) United States--The 50 states, the District of Columbia, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands.

(73) Used Oil--Any oil that has been refined from crude oil, or any synthetic oil, that has been used and as a result of such use is contaminated by physical or chemical impurities.

(74) Vessel--Every description of watercraft used or capable of being used as a means of transportation on the water. The term does not include a structure that is or is designed to be, permanently affixed to one location, or a drilling or workover vessel that is stationary or fixed for the performance of its primary function.

(75) Waste--Any solid waste, as that term is defined in 40 CFR, §261.2.

(76) Wastewater treatment unit--A device (such as a hydrostatic test water treatment unit) that:

(A) is a tank or tank system comprising part of a wastewater treatment facility that is subject to regulation under either §§402 or 307(b) of the Clean Water Act, 33 USC §§1342 or 1317(b); and

(B) receives and treats or stores an influent wastewater that is a hazardous waste, that generates and accumulates a wastewater treatment sludge that is a hazardous waste, or treats or stores a wastewater treatment sludge that is a hazardous waste.

(77) Water (bulk shipment)--The bulk transportation of hazardous waste that is loaded or carried on board a vessel without containers or labels.

(c) Applicability.

(1) General.

(A) This section applies to any person who generates hazardous oil and gas waste and to any person who transports hazardous oil and gas waste.

(B) An owner or operator of a treatment, storage, or disposal facility regulated by the TCEQ's industrial and hazardous waste program, shall be subject to the standards for generators of hazardous waste found in Title 30, Texas Administrative Code, Chapter 335, Subchapter C (TCEQ standards for generators) if the facility generates a new waste that contains hazardous oil and gas waste and waste regulated by the TCEQ's industrial and hazardous waste program.

(2) Requirements Cumulative. The provisions of this section are in addition to applicable provisions contained in any other section, order, policy, rule, or statutory authority of the commission. In the event of a conflict between this section and any other section, order, policy, or rule of the commission, this section shall control.

(d) General Prohibitions. No person may cause, suffer, allow, or permit the collection, handling, storage, transportation, treatment, or disposal of hazardous oil and gas waste in a manner that would violate the provisions of this section.

(e) Hazardous Waste Determination.

(1) Determination. A person who generates a waste shall determine if such waste is hazardous oil and gas waste as provided in this subsection. A hazardous oil and gas waste is a waste that:

(A) is defined in subsection (b) of this section (relating to definitions) as an oil and gas waste;

(B) is not described in 40 CFR, §261.4(a) (which describes wastes that are not considered solid wastes);

(C) is not described in 40 CFR, §261.4(b) (which describes solid wastes that are exempt from regulation under RCRA Subtitle C); and

(D) is identified as a hazardous waste either:

(i) in 40 CFR, Part 261, Subpart D (regarding listed hazardous wastes); or

(ii) in 40 CFR, Part 261, Subpart C (regarding characteristically hazardous wastes), as determined either:

(I) by testing the waste:

(-a-) in accordance with methods described in 40 CFR, Part 261, Subpart C; or

(-b-) in accordance with an equivalent method approved by the administrator under 40 CFR, §260.21; or

(II) by applying knowledge of the hazard characteristics of the waste in light of the materials or processes used.

(2) Land Ban. Each LQG and SQG shall determine whether the hazardous oil and gas waste it generates is prohibited from land disposal under the provisions of 40 CFR, Part 268. If the waste is prohibited from land disposal, the LQG or SQG must comply with all applicable provisions of 40 CFR, Part 268 (concerning management of land ban wastes) prior to disposing of such waste.

(3) Exclusions and Exemptions.

(A) Notwithstanding the provisions of subsection (e)(1) of this section, in the event the administrator determines, in accordance with the provisions of 40 CFR, §260.22, that a particular oil and gas waste that is considered a hazardous oil and gas waste because it meets criteria set out in subsection (e)(1)(D)(i) of this section (relating to listed hazardous wastes) should not be considered a hazardous waste, such waste shall be exempt from regulation under this section.

(B) Notwithstanding the provisions of subsection (e)(1) of this section the following are exempt from regulation under this section:

(i) any oil and gas waste described in 40 CFR, §261.6(a)(2) (concerning recyclable materials) that is managed as provided in applicable provisions of 40 CFR, Part 266, Subparts C - H, and 40 CFR, Parts 270 and 124;

(ii) any oil and gas waste described and recycled, reclaimed, or reused as provided in 40 CFR, §261.6(a)(3) (concerning recyclable materials);

(iii) used oil that is not considered a hazardous waste under the provisions of 40 CFR, §279.10(b) and that is managed as provided in 40 CFR, Part 279;

(iv) dielectric fluid containing polychlorinated biphenyls (PCBs) and electric equipment containing such fluid that are regulated under 40 CFR, Part 761 and that are hazardous only because they exhibit the characteristic of toxicity for D018-D043 under the test required under subsection (e)(1)(D)(ii) of this section (relating to characteristically hazardous wastes);

(v) debris, as that term is defined in 40 CFR, §268.2, that is an oil and gas waste:

(I) that contains or contained a hazardous oil and gas waste listed in 40 CFR, Part 261, Subpart D or that exhibits or exhibited a hazardous waste characteristic identified in 40 CFR, Part 261, Subpart C; and

(II) that has been treated using one of the required destruction technologies specified in Table 1 of 40 CFR, §268.45 or that is determined by the administrator to be no longer contaminated with hazardous oil and gas waste; and

(vi) hazardous oil and gas waste remaining in an empty container.

(f) Generator Classification and Accumulation Time.

(1) Conditionally Exempt Small Quantity Generator.

(A) To be classified as a conditionally exempt small quantity generator (CESQG) during any calendar month, a generator of hazardous oil and gas waste must:

(i) generate no more than 100 kilograms (220.46 pounds) of hazardous oil and gas waste in that calendar month; and

(ii) accumulate no more than 1,000 kilograms (2204.60 pounds) of hazardous oil and gas waste on-site at any one time.

(B) Except as provided in subsection (f)(5) of this section, a CESQG must comply with all requirements of this section applicable to CESQGs.

(C) If a CESQG generates in one calendar month, or accumulates on-site at any one time, more than a total of one kilogram (2.20 pounds) of any acute hazardous waste listed in 40 CFR, §261.31, 261.32 or 261.33(e) or a total of 100 kilograms (220.46 pounds) of contaminated media resulting from the clean up of a discharge into or on any land or water of any acute hazardous waste listed in 40 CFR, §261.31, 261.32, or 261.33(e), all such acute hazardous wastes must be managed as though generated by an LQG. The LQG accumulation time period for such acute hazardous wastes shall begin at such time as the maximum quantity specified in this subparagraph is exceeded.

(2) Small Quantity Generator.

(A) To be classified as a small quantity generator (SQG) in any calendar month, a generator of hazardous oil and gas waste must:

(i) generate less than 1,000 kilograms (2204.60 pounds) of hazardous oil and gas waste in that calendar month;

(ii) not allow any particular quantity of hazardous oil and gas waste to remain on-site for a period of more than:

(I) 180 days from the date that particular quantity was generated; or

(II) 270 days from the date that particular quantity was generated, but only if the waste must be transported or offered for transport to a treatment, storage, or disposal facility that is located a distance of 200 miles or more from the point of generation; and

(iii) not accumulate more than 6,000 kilograms (13,227.60 pounds) of hazardous oil and gas waste on-site at any one time.

(B) An SQG must accumulate all hazardous oil and gas waste in tanks or containers that meet the requirements of this section and, except as provided in subsection (f)(5) of this section, comply with all requirements of this section applicable to SQGs.

(C) The accumulation period specified in subsection (f)(2)(A)(ii) of this section may be extended an additional 30 days if the commission, at its sole discretion, determines that unforeseen, temporary, and uncontrollable circumstances require that hazardous oil and gas waste remain on-site for a longer time period.

(3) Large Quantity Generators.

(A) Any generator of hazardous oil and gas waste not classified as a CESQG or SQG is classified as a large quantity generator (LQG).

(B) An LQG must accumulate hazardous oil and gas waste in tanks or containers that meet the requirements of this section and, except as provided in subsection (f)(5) of this section, comply with all other requirements of this section applicable to LQGs.

(C) An LQG shall not accumulate any particular quantity of hazardous oil and gas waste on-site for more than 90 days from the date that particular quantity was generated, unless an extension to such 90-day period has been granted in accordance with the provisions of subsection (f)(4)(D) of this section.

(D) The 90-day accumulation period specified in subsection (f)(4)(C) of this section may be extended an additional 30 days if the commission, at its sole discretion, determines that unforeseen, temporary, and uncontrollable circumstances require that hazardous oil and gas waste remain on-site for longer than 90 days.

(4) Accumulation in Containers at the Point of Generation.

(A) Notwithstanding the foregoing provisions of subsection (f) of this section, an LQG or SQG may accumulate in containers up to 55 gallons of hazardous oil and gas waste or a total of one quart of acute hazardous wastes listed in 40 CFR, §261.33(e) without having to manage such hazardous oil and gas waste in accordance with the accumulation time limits applicable to LQGs or SQGs or with the provisions of subsections (q) (relating to preparedness and prevention), (r) (relating to contingency plan and emergency procedures), (s) (relating to personnel training), (t) (relating to standards for use of containers), and (u) (standards for use of tank systems) of this section, provided that the requirements of subsection (f)(4)(B) of this section are met.

(B) All hazardous oil and gas waste subject to the exemption of subsection (f)(4)(A) of this section must be accumulated in containers that:

(i) are at a location that is:

(I) under the control of the generator; and

(II) at or near the point of generation;

(ii) meet the applicable requirements of 40 CFR, §§265.171, 265.172, and 265.173(a) (concerning container condition, compatibility of waste with container, and closing containers); and

(iii) are marked with the words "Hazardous Waste" or with other words that identify the contents of the containers.

(C) If the amount of hazardous waste accumulated on-site at or near the point of generation exceeds the maximum amount specified in subsection (f)(4)(A) of this section, the generator must, with respect to such excess waste, comply with all applicable provisions of this section within three days of the date that such maximum amount is exceeded.

(5) Episodic Generation. Except as otherwise provided in this paragraph, if a generator's classification varies from one month to another, the hazardous oil and gas waste generated during any particular month shall be managed in accordance with the requirements applicable to the generator's classification for that month.

(A) If hazardous oil and gas waste generated by a generator who is classified as a CESQG during a particular month is mixed with waste generated in a month during which the generator is considered an LQG, the mixture shall be managed in accordance with the standards applicable to LQGs.

(B) If hazardous oil and gas waste generated by a generator who is classified as a CESQG during a particular month is mixed with waste generated in a month during which the generator is considered an SQG, the mixture shall be managed in accordance with the standards applicable to SQGs.

(C) If hazardous oil and gas waste generated by a generator who is classified as an SQG during a particular month is mixed with waste generated in a month during which the generator is considered an LQG, the mixture shall be managed in accordance with the standards applicable to LQGs.

(g) Notification. A person who is considered an LQG or SQG under the provisions of this section must notify the commission of the activities of such person that are subject to the provisions of this section and obtain an EPA ID number by filing the prescribed form (currently EPA Form 8700-12) with the commission. Such notification must be made upon the later of 90 days after the effective date of this section or within ten days of the date that the LQG or SQG becomes subject to the provisions of this section.

(h) Preparedness and Prevention.

(1) General. In addition to all other applicable requirements of this section, all generators of hazardous oil and gas waste shall employ reasonable and appropriate measures (considering the nature and location of the facility and the types and quantities of hazardous oil and gas waste maintained at the site) in the operation and maintenance of his or her generation site to minimize the possibility of a fire, explosion, or any unplanned sudden or non-sudden release of hazardous oil and gas wastes or hazardous oil and gas waste constituents to air, soil, or surface water that could threaten human health or the environment.

(2) LQGs and SQGs. LQGs and SQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart C (concerning preparedness and prevention).

(i) Contingency Plan and Emergency Procedures.

(1) LQGs. LQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart D (concerning contingency plan and emergency procedures).

(2) SQGs. SQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions of 40 CFR, §262.34(d)(5) (concerning emergency response).

(j) Personnel Training. LQGs who accumulate hazardous oil and gas waste at the generation site must comply with the provisions applicable to owners or operators of 40 CFR, §265.16 (concerning personnel training).

(k) Standards for Use of Containers.

(1) LQGs. LQGs accumulating hazardous oil and gas waste in containers must:

(A) comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart I (concerning use and management of containers);

(B) clearly mark each container being used to accumulate hazardous oil and gas waste on-site, in a manner and location visible for inspection, with the date accumulation of such hazardous oil and gas waste begins; and

(C) clearly label or mark each container being used to accumulate hazardous oil and gas waste on-site with the words "Hazardous Waste."

(2) SQGs. SQGs accumulating hazardous oil and gas waste in containers must:

(A) comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart I, except §265.176 (concerning distance from property lines);

(B) clearly mark each container being used to accumulate hazardous oil and gas waste on-site, in a manner and location visible for inspection, with the date accumulation of such hazardous oil and gas waste begins; and

(C) clearly label or mark each container being used to accumulate hazardous oil and gas waste on-site with the words "Hazardous Waste."

(3) CESQGs. The provisions of this paragraph apply to CESQGs only.

(A) Hazardous oil and gas waste generated by a CESQG may be mixed with non-hazardous waste even though the resultant mixture exceeds the quantity limitations of subsection (f)(1) of this section, unless the mixture exhibits any of the hazardous waste characteristics of the hazardous oil and gas waste in the mixture, as determined under subsection (e)(1)(D)(ii) of this section.

(B) If a CESQG's wastes are mixed with used oil, the mixture is subject to the requirements 40 CFR, Part 279 if the mixture is destined to be burned for energy recovery. Any material produced from such a mixture by processing, blending, or other treatment is also so regulated if it is destined to be burned for energy recovery.

(l) Standards for Use of Tank Systems.

(1) LQGs. LQGs accumulating hazardous oil and gas waste in tanks must:

(A) comply with the provisions applicable to owners or operators of 40 CFR, Part 265, Subpart J, except §265.197(c) and §265.200;

(B) comply with the provisions applicable to owners or operators of 40 CFR, §265.111 and §265.114 (concerning closure performance standards and disposal of contaminated equipment and media); and

(C) clearly label or mark each tank being used to accumulate hazardous oil and gas waste with the words "Hazardous Waste."

(2) SQGs. SQGs accumulating hazardous oil and gas waste in tanks must:

(A) comply with the provisions of 40 CFR, §265.201 (concerning accumulation of waste in tanks by small quantity generators); and

(B) clearly label or mark each tank being used to accumulate hazardous oil and gas waste with the words "Hazardous Waste."

(m) Disposition of Hazardous Oil and Gas Waste.

(1) On-site Treatment, Storage, Disposal, Recycling, and Reclamation. Except as otherwise specifically provided in this section, no person may treat, store, dispose of, recycle, or reclaim any hazardous oil and gas waste on-site.

(2) Transport to Authorized Facility.

(A) Except as otherwise specifically provided in this section and subject to all other applicable requirements of state or federal law, a generator of hazardous oil and gas waste must send his or her waste to one of the following categories of facilities for treatment, storage, disposal, recycling, or reclamation:

(i) an authorized recycling or reclamation facility;

(ii) an authorized treatment, storage, or disposal facility;

(iii) a facility located outside the United States, provided that the requirements of subsection (v)(1) of this section (relating to exports of hazardous waste) are met;

(iv) a transfer facility, provided that the requirements of subsection (w)(3) of this section are met;

(v) if the waste is generated by a CESQG, a facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste; or

(vi) if the waste is generated by a CESQG, a centralized waste collection facility (CWCF) that meets the requirements of paragraph (3) of this section.

(B) Notwithstanding any contrary provision of this subsection, hazardous oil and gas wastes may be treated or stored on-site in an elementary neutralization unit or a totally enclosed treatment facility. If a hazardous oil and gas waste that is ignitable under 40 CFR, §261.21 (other than DOO1 High TOC Subcategory wastes defined in 40 CFR, §268.42, Table 2) or that is corrosive under 40 CFR, §261.22 is being treated in an elementary neutralization unit or a wastewater treatment unit to remove the characteristic before land disposal, the owner or operator must comply with the requirements of 40 CFR, §264.17(b).

(C) While waste is being accumulated on-site in accordance with the provisions of subsection (f) of this section, a generator may treat hazardous oil and gas waste on-site in tanks or containers that comply with the applicable provisions of subsections (k) and (l) of this section.

(D) For purposes of Chapter 4 of this title (relating to Environmental Protection), specifically Subchapter A (relating to Oil and Gas Waste Management), the manifest for shipment of hazardous oil and gas waste to a designated facility (a facility designated on the manifest by the generator pursuant to the provisions of subsection (o)(1) of this section) shall be deemed commission authorization for disposal at a facility permitted by another agency or another state.

(3) Centralized Collection of Hazardous Oil and Gas Waste.

(A) Centralized Waste Collection Facility. Provided that the requirements of this paragraph are met, a person may maintain at a CWCF hazardous oil and gas waste that is generated:

(i) by that person; and

(ii) at sites where that person is considered a CESQG under the provisions of this section.

(B) Prior to receipt of oil and gas hazardous waste generated off-site, a person who operates a CWCF must register with the commission by filing with the commission a notice that includes the following information:

(i) a map showing the location of the CWCF and each individual hazardous oil and gas waste generation site that may contribute waste to the collection facility. In lieu a map, the person who operates the CWCF may provide to the commission the name and lease number, field name and number, or other identifying information acceptable to the commission, of the CWCF and each generation site that may contribute waste to the collection facility;

(ii) the person's P-5 operator number; and

(iii) the EPA ID number for the CWCF, if any.

(C) All hazardous oil and gas waste received at the CWCF must be kept in closed containers that are marked with the words "Hazardous Waste."

(D) A person operating a CWCF shall not maintain at the CWCF at any one time more than 5,000 kilograms of hazardous oil and gas waste or more than five quarts of any hazardous oil and gas waste that is listed in 40 CFR, §261.33(e) (acute hazardous waste).

(n) EPA ID Numbers.

(1) Generators. No LQG or SQG may transport or offer for transportation any hazardous oil and gas waste until such generator has obtained an EPA ID number by filing the prescribed form (currently EPA Form 8700-12) with the commission.

(2) Transporters. No LQG or SQG may allow his or her hazardous oil and gas waste to be transported by a transporter that does not have an EPA ID number.

(3) Treatment, Storage, or Disposal Facilities. Except in the case of facilities specified in subsection (m)(2)(A)(iii), (vi), and (v) of this section, no LQG or SQG may send his or her hazardous oil and gas waste to a treatment, storage, or disposal facility unless that facility:

(A) is a designated facility as defined in this section; and

(B) has an EPA ID number.

(o) Manifests.

(1) General Requirements.

(A) Except as provided in subsection (o)(1)(E) of this section, each time an LQG or SQG transports hazardous oil and gas waste or offers hazardous oil and gas waste for transportation to an authorized facility, such generator must prepare a manifest form. If the waste was generated in the State of Texas and is being transferred to an authorized facility located within the State of Texas, the generator shall use the form prescribed by the TCEQ. If the authorized facility is located outside the State of Texas, the generator must refer to subsection (o)(2) of this section to determine which manifest form to use.

(B) The generator must specify on the manifest one authorized facility to handle the hazardous oil and gas waste described on the manifest (the "primary designated facility").

(C) The generator may also specify on the manifest one alternate authorized facility to handle the hazardous oil and gas waste (the "alternate designated facility") in the event an emergency prevents delivery of the hazardous oil and gas waste to the primary designated facility.

(D) If the transporter is unable to deliver the hazardous oil and gas waste to the primary designated facility or the alternate designated facility, the generator must either specify another authorized facility to which the hazardous oil and gas waste can be delivered or instruct the transporter to return the hazardous oil and gas waste to the generator. If the generator specifies another authorized facility to which the hazardous oil and gas waste can be delivered, the generator shall instruct the transporter to revise the manifest to show this facility as the designated facility (see subsection (w)(6) of this section relating to transporter's inability to deliver waste).

(E) An SQG is not required to comply with the provisions of this subsection (relating to manifests) if:

(i) the SQG's hazardous oil and gas waste is reclaimed under a contractual agreement (the "hazardous waste reclamation agreement") pursuant to which:

(I) the type of hazardous oil and gas waste and frequency of shipments are specified in the agreement; and

(II) the vehicle used to transport the hazardous oil and gas waste to the hazardous waste reclamation facility and to deliver regenerated material back to the generator is owned and operated by the hazardous waste reclamation facility;

(ii) the SQG maintains a copy of the hazardous waste reclamation agreement in his or her files for a period of at least three years after termination or expiration of the reclamation agreement; and

(iii) the SQG complies with the provisions of 40 CFR, §268.7(a)(10) (concerning land ban wastes subject to tolling agreements) if the waste is determined to be prohibited from land disposal under subsection (e)(2) of this section (relating to land ban wastes).

(2) Manifests Required for Out-of-State Domestic Shipments.

(A) If the hazardous oil and gas waste was generated within the United States, but outside the State of Texas, and is being transported to an authorized facility located within the State of Texas, the generator must use the form prescribed by the TCEQ.

(B) If the hazardous oil and gas waste was generated within the State of Texas and is being transported to an authorized facility located within the United States but outside the State of Texas (the "consignment state"), the manifest specified by the consignment state shall be used. If the consignment state does not specify a particular manifest form for use, then the generator shall use the form prescribed by the TCEQ.

(3) Number of Copies. The manifest must consist of at least the number of copies that will provide the generator, each transporter, and the owner or operator of the designated facility with one copy each for their records and one additional copy to be returned to the generator by the owner or operator of the designated facility to which the waste was delivered (in accordance with the provisions of 40 CFR, §264.71 and §265.71, or state equivalent).

(4) Use of the Manifest.

(A) The generator must:

(i) sign the manifest certification by hand;

(ii) obtain the handwritten signature of the initial transporter and date of acceptance of the shipment by the initial transporter on the manifest;

(iii) retain one copy of the manifest signed by the initial transporter until the copy signed by the operator of the designated facility (in accordance with 40 Code of Federal Regulations §264.71, §265.71, or state equivalent) is received;

(iv) give the transporter the remaining copies of the manifest; and

(v) obtain one copy of the manifest, signed by the owner or operator of the designated facility that received the hazardous oil and gas waste, and retain that copy for three years from the date the hazardous oil and gas waste was accepted for shipment by the initial transporter.

(B) For shipments of hazardous oil and gas waste within the United States solely by water (bulk shipments only), the generator must send three copies of the manifest, dated and signed in accordance with the provisions of paragraph (4)(A) of this subsection (relating to use of the manifest), to either:

(i) the owner or operator of the designated facility; or

(ii) if exported by water, the last water transporter expected to handle the hazardous oil and gas waste in the United States. Copies of the manifest are not required for each transporter.

(C) For rail shipments of hazardous oil and gas waste within the United States that originate at the generation site, the generator must send at least three copies of the manifest, dated and signed in accordance with the provisions of paragraph (4)(A) of this subsection (relating to use of the manifest), to:

(i) the next non-rail transporter, if any;

(ii) the designated facility, if transported solely by rail; or

(iii) if exported by rail, the last rail transporter expected to handle the hazardous oil and gas waste in the United States.

(D) For shipments of hazardous oil and gas waste to a designated facility located outside the State of Texas and in an authorized state that has not yet obtained authorization from the EPA to regulate that particular waste as hazardous, the generator must determine that the owner or operator of the designated facility agrees to sign and return the manifest to the generator (in accordance with the applicable provisions of 40 CFR, §264.71 or §265.71), and that any out-of-state transporter agrees to comply with the applicable requirements of subsection (w)(4) of this section (relating to manifest requirements for transporters).

(p) Packaging. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, an LQG or SQG must package the hazardous oil and gas waste in accordance with the applicable DOT packaging regulations set out in 49 CFR, Parts 173, 178, and 179.

(q) Labeling. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must label each package that contains hazardous oil and gas waste in accordance with the applicable DOT regulations set out in 49 CFR, Part 172.

(r) Marking.

(1) General. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must mark each package that contains hazardous oil and gas waste in accordance with the applicable DOT regulations set out in 49 CFR, Part 172.

(2) Non-Bulk Packaging. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must mark each package that contains hazardous oil and gas waste and is of a size specified in 40 CFR, §262.32(b) (110 gallons or less), with the following words and information. Such words and information must be displayed in accordance with the applicable requirements of 49 CFR, 172.304. The generator must include his or her name and address and the manifest document number in the appropriate space: HAZARDOUS WASTE--Federal Law Prohibits Improper Disposal. If found, contact the nearest police or public safety authority or the U.S. Environmental Protection Agency. Generator's Name and Address: ______________________ Manifest Document Number: __________________________

(s) Placarding. Before transporting hazardous oil and gas waste or offering hazardous oil and gas waste for transportation off-site, LQGs and SQGs must placard the vehicle or vehicles used to transport such hazardous oil and gas waste, or offer to the initial transporter the appropriate placards. Appropriate placards shall be determined according to DOT regulations set out in 49 CFR, Part 172, Subpart F.

(t) Recordkeeping.

(1) Waste Determination. Each LQG and SQG shall keep records of any and all test results, waste analyses, or other determinations made in accordance with subsection (e) of this section (relating to hazardous waste determination), for at least three years from the date that the waste was last sent to an authorized facility.

(2) Annual Reports. A copy of all reports required in subsection (u)(1) of this section (relating to annual reports), shall be retained by the generator for a period of at least three years from the due date of the report.

(3) Exception Reports. A copy of all reports required under subsection (u)(2) of this section (relating to exception reports), shall be retained by the generator for a period of at least three years from the due date of the report.

(4) Inspection Reports. A copy of each inspection report required under this section shall be retained by the generator for a period of at least three years from the due date of the report.

(5) Extension. The periods of record retention specified in subsection (t)(1) - (4) of this section are extended automatically during the course of any unresolved enforcement action regarding the regulated activity or upon request by the commission.

(u) Reporting.

(1) Annual Reports. Any generator who is classified as an LQG or SQG during any calendar month of a calendar year shall prepare and submit a single copy of an annual report to the commission on the annual reporting form prescribed by the commission, Form H-21. The report shall be filed on or before the first day of March of the following calendar year and shall be accompanied by the fee assessed under the provisions of subsection (z) of this section. The annual report shall contain a certification signed by the generator. The annual report shall cover activities occurring at the generation site during the month(s) of the reporting year that the site was classified as a small or large quantity generation site, and shall include the following information:

(A) the name of the generator followed by the generator's P-5 operator number in parentheses, the EPA ID number for the generation site, and the address of the generation site or other site-identifying information (such as the lease number, unit number, or T-4 number (in the case of pipelines));

(B) the calendar year covered by the report;

(C) the name, EPA ID number, if any, and address for each authorized facility within the United States to which hazardous oil and gas waste was shipped during the year;

(D) the name and EPA ID number of each transporter used during the year for shipments to an authorized facility within the United States;

(E) a description, EPA hazardous waste number (from 40 CFR, Part 261, Subpart C or D), United States DOT hazard class, and quantity of each hazardous oil and gas waste shipped to an authorized facility within the United States. This information must be listed by the EPA ID number of each facility to which hazardous oil and gas waste was shipped. If the waste was shipped to an authorized facility that does not have an EPA ID number, the type of facility (reclamation or recycling) must be designated on the report;

(F) a description of the efforts undertaken during the year to reduce the volume and toxicity of hazardous oil and gas waste generated; and

(G) a description of the changes in volume and toxicity of hazardous oil and gas waste actually achieved during the year in comparison to previous years, to the extent such information is available.

(2) Exception Reports.

(A) An LQG who does not receive a copy of the manifest with the handwritten signature of the owner or operator of the designated facility within 35 days from the date the hazardous oil and gas waste was accepted by the initial transporter for shipment must contact the transporter and, if necessary, the owner or operator of the designated facility to determine the status of the hazardous oil and gas waste shipment.

(B) An LQG must submit an exception report to the commission if he or she has not received a copy of the manifest with the handwritten signature of the owner or operator of the designated facility within 45 days from the date the hazardous oil and gas waste was accepted by the initial transporter for shipment. The exception report must include:

(i) a legible copy of the manifest for that shipment of hazardous oil and gas waste for which the generator does not have confirmation of delivery; and

(ii) a letter signed by the generator explaining the efforts taken to locate the hazardous oil and gas waste and the results of those efforts.

(C) An SQG who does not receive confirmation of delivery of hazardous oil and gas waste by receipt of a copy of the manifest with the handwritten signature of the owner or operator of the designated facility within 60 days from the date the hazardous oil and gas waste was accepted by the initial transporter for shipment, must submit to the commission an exception report. The exception report must include:

(i) a legible copy of the manifest for which the generator does not have confirmation of delivery; and

(ii) a notation, either typed or handwritten, indicating that the generator has not received confirmation of delivery of the shipment to the designated facility.

(D) In the case of interstate shipments of hazardous oil and gas waste for which a manifest has not been returned within 45 days of acceptance of the hazardous oil and gas waste for shipment by the initial transporter, an LQG or SQG shall notify the appropriate regulatory agency of the state in which the designated facility is located, and the appropriate regulatory agency of each state in which the shipment may have been delivered, that the manifest has not been received. If a state required to be notified under this section has not received interim or final authorization pursuant to the RCRA, the LQG or SQG shall notify the administrator that the manifest has not been returned.

(3) Additional Reporting. The commission may require any generator of hazardous oil and gas waste to furnish additional reports concerning the quantities and disposition of hazardous oil and gas waste generated.

(v) Additional Requirements Applicable to International Shipments.

(1) Exports.

(A) Any person who exports hazardous oil and gas waste to a foreign country must comply with the requirements of 40 CFR, Part 262, Subpart E.

(B) Primary exporters of hazardous oil and gas waste generated within the State of Texas must submit to the commission a copy of the annual report submitted to the administrator in compliance with 40 CFR, §262.56.

(2) Imports. Any person who imports hazardous oil and gas waste generated outside the United States into the State of Texas shall be considered the generator of such hazardous oil and gas waste for the purposes of this section. Such person must comply with the applicable provisions of this section, except that:

(A) the name and address of the foreign generator and the importer's name, address, and EPA ID number shall be substituted on the manifest in place of the generator's name, address, and EPA ID number;

(B) the importer or the importer's agent must sign and date the certification and obtain the signature of the initial transporter in place of the generator's certification statement on the manifest; and

(C) the importer shall use the manifest form prescribed by the TCEQ.

(w) Standards Applicable to Transporters of Hazardous Oil and Gas Waste. The following standards apply to persons who transport hazardous oil and gas waste generated by LQGs and SQGs. The requirements of this subsection do not apply in the case of hazardous oil and gas waste generated by CESQGs.

(1) Scope.

(A) This subsection establishes standards for persons transporting hazardous oil and gas waste from the generation site to any designated facility. The provisions of this section do not apply with respect to on-site movements of hazardous oil and gas waste.

(B) In addition to the provisions of this subsection, a transporter must comply with standards applicable to generators of hazardous oil and gas waste if he or she mixes hazardous oil and gas wastes of different DOT shipping descriptions by placing them into a single container. If a transporter mixes a hazardous oil and gas waste with a hazardous waste that is not considered a hazardous oil and gas waste, the transporter must comply with the standards applicable to generators of hazardous wastes found at Title 30, Texas Administrative Code, Chapter 335, Subchapter C (the TCEQ's standards for generators of hazardous waste).

(2) Permits and EPA ID Numbers. No transporter may transport hazardous oil and gas waste unless he or she has an EPA ID number. The transporter may obtain an EPA ID number by filing the prescribed form (currently EPA Form 8700-12) with the appropriate regulatory entity (either EPA, TCEQ, the commission, or another state).

(3) Transfer Facility Requirements. No transporter may store manifested hazardous oil and gas waste at a transfer facility for any period of time unless:

(A) the hazardous oil and gas waste is packaged in containers that meet the requirements of subsection (p) of this section (relating to packaging); and

(B) the hazardous oil and gas waste is stored at the transfer facility for no longer than ten days.

(4) Manifest Requirements.

(A) A transporter may not accept hazardous oil and gas waste for shipment from a generator unless it is accompanied by a manifest signed in accordance with the provisions of subsection (o)(4) of this section (relating to use of the manifest).

(B) Before transporting hazardous oil and gas waste, the transporter must sign and date the manifest acknowledging acceptance of the hazardous oil and gas waste from the generator. The transporter must return a signed copy of the manifest to the generator before leaving the generation site.

(C) The transporter must ensure that the manifest accompanies the shipment of hazardous oil and gas waste. In the case of exports, the transporter must ensure that a copy of the EPA Acknowledgment of Consent is attached to the manifest.

(D) A transporter may not accept hazardous oil and gas waste for export from a primary exporter or other person if:

(i) the transporter knows that the shipment does not conform to the EPA Acknowledgment of Consent; or

(ii) except in the case of shipments by rail, an EPA Acknowledgment of Consent is not attached to the manifest (or shipping paper in the case of exports by water (bulk shipment)).

(E) A transporter who delivers a hazardous oil and gas waste to another transporter or to the designated facility must:

(i) obtain the date of delivery and the handwritten signature of the other transporter or of the owner or operator of the designated facility on the manifest;

(ii) retain one copy of the manifest in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping); and

(iii) give the remaining copies of the manifest to the accepting transporter or owner or operator of the designated facility.

(F) The requirements of subsection (w)(4)(C), (D), (E), and (G) of this section do not apply to water (bulk shipment) transporters if:

(i) the hazardous oil and gas waste is delivered by water (bulk shipment) to the designated facility;

(ii) a shipping paper containing all the information required on the manifest (excluding the EPA ID numbers, generator certification, and signatures) and, for exports, an EPA Acknowledgment of Consent, accompanies the hazardous oil and gas waste;

(iii) the delivering transporter obtains the date of delivery and handwritten signature of the owner or operator of the designated facility on either the manifest or the shipping paper;

(iv) the person delivering the hazardous oil and gas waste to the initial water (bulk shipment) transporter obtains the date of delivery and signature of the water (bulk shipment) transporter on the manifest and forwards it to the designated facility; and

(v) a copy of the shipping paper or manifest is retained by each water (bulk shipment) transporter in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping).

(G) For shipments involving rail transportation, the requirements of subsection (w)(4)(C), (D), (E), and (F) of this section do not apply and the following requirements do apply:

(i) when accepting hazardous oil and gas waste from a non-rail transporter, the initial rail transporter must:

(I) sign and date the manifest acknowledging acceptance of the hazardous oil and gas waste;

(II) return a signed copy of the manifest to the non-rail transporter;

(III) forward at least three copies of the manifest to:

(-a-) the next non-rail transporter, if any;

(-b-) the designated facility, if the shipment is delivered to that facility by rail; or

(-c-) the last rail transporter designated to handle the hazardous oil and gas waste in the United States; and

(IV) retain one copy of the manifest and rail shipping paper in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping);

(ii) rail transporters must ensure that a shipping paper containing all the information required on the manifest (excluding the EPA ID numbers, generator certification, and signatures) and, for exports, an EPA Acknowledgment of Consent, accompanies the hazardous oil and gas waste at all times;

(iii) when delivering hazardous oil and gas waste to the designated facility, a rail transporter must:

(I) obtain the date of delivery and handwritten signature of the owner or operator of the designated facility on the manifest or the shipping paper (if the manifest has not been received by the facility); and

(II) retain a copy of the manifest or signed shipping paper in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping);

(iv) when delivering hazardous oil and gas waste to a non-rail transporter, a rail transporter must:

(I) obtain the date of delivery and the handwritten signature of the next non-rail transporter on the manifest; and

(II) retain a copy of the manifest in accordance with the provisions of subsection (w)(7) of this section (relating to recordkeeping);

(v) before accepting hazardous oil and gas waste from a rail transporter, a non-rail transporter must sign and date the manifest and provide a copy to the rail transporter.

(H) Transporters who transport hazardous oil and gas waste out of the United States must:

(i) indicate on the manifest the date the hazardous oil and gas waste left the United States;

(ii) sign the manifest and retain one copy in accordance with the provisions of subsection (v)(1) of this section;

(iii) return a signed copy of the manifest to the generator; and

(iv) give a copy of the manifest to a United States customs official at the point of departure from the United States.

(I) A transporter accepting hazardous oil and gas waste for shipment from an SQG need not comply with the requirements of subsection (w)(4) and (7) of this section provided that:

(i) the hazardous oil and gas waste is being transported pursuant to a reclamation agreement that meets the requirements of subsection (o)(1)(E) of this section;

(ii) the transporter records, on a log or shipping paper, the following information for each shipment:

(I) the name, address, and EPA ID number of the generator of the hazardous oil and gas waste;

(II) the quantity of hazardous oil and gas waste accepted;

(III) all DOT required shipping information;

(IV) the date the hazardous oil and gas waste is accepted;

(iii) the transporter carries this record when transporting the hazardous oil and gas waste to the reclamation facility; and

(iv) the transporter retains these records for a period of at least three years after termination or expiration of the agreement.

(5) Delivery of Waste. The transporter must deliver the entire quantity of hazardous oil and gas waste accepted from a generator or a transporter to:

(A) the primary designated facility;

(B) the alternate designated facility, if the hazardous oil and gas waste cannot be delivered to the primary designated facility because an emergency prevents delivery;

(C) the next designated transporter; or

(D) for exports, the location designated in the EPA Acknowledgment of Consent.

(6) Inability to Deliver Waste. If the hazardous oil and gas waste cannot be delivered as provided in subsection (w)(5) of this section the transporter must contact the generator for further directions and must revise the manifest according to the generator's instructions.

(7) Recordkeeping.

(A) A transporter of hazardous oil and gas waste must keep a copy of the manifest signed by the generator, himself or herself, and the next transporter or the owner or operator of the designated facility for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter.

(B) For shipments delivered to the designated facility by water (bulk shipment), each water (bulk shipment) transporter must retain a copy of the shipping paper containing all the information required in 40 CFR, §263.20(e)(2) for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter.

(C) For shipments of hazardous oil and gas waste by rail within the United States:

(i) the initial rail transporter must keep a copy of the manifest and shipping paper with all the information required in 40 CFR, §263.20(f)(2) for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter; and

(ii) the final rail transporter must keep a copy of the signed manifest (or the shipping paper if signed by the designated facility in lieu of the manifest) for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter.

(D) A transporter who transports hazardous oil and gas waste out of the United States must keep, for a period of three years from the date the hazardous oil and gas waste was accepted by the initial transporter, a copy of the manifest indicating that the hazardous oil and gas waste left the United States.

(E) The periods of retention referred to in subsection (w)(7) of this section are extended automatically during the course of any unresolved enforcement action regarding the regulated activity or upon request by the commission.

(x) Discharges.

(1) Reporting Requirements.

(A) Commission. A person subject to regulation under this section shall immediately notify the commission upon discovery of any discharge in which a reportable quantity of a hazardous oil and gas waste is discharged. Such notification shall be made by contacting the appropriate commission district office.

(B) Federal. Persons subject to regulation under this section shall comply with applicable reporting requirements of 40 CFR, Parts 117, 263, and 302.

(2) Initial Response.

(A) Immediate Action. Upon discovery of a discharge of hazardous oil and gas waste, the generator or transporter must take appropriate immediate action to protect human health and the environment (e.g., notify local authorities, where appropriate, and dike the discharge area).

(B) Permitting Exemption. The prohibition of on-site treatment, storage, disposal, recycling, or reclamation activities in subsection (m)(1) of this section does not apply to activities performed by a person engaged in treatment or containment activities during immediate response to a discharge of hazardous oil and gas waste; an imminent and substantial threat of a discharge of hazardous oil and gas waste; or a discharge of a substance which, when discharged, would become a hazardous oil and gas waste, provided that:

(i) any hazardous oil and gas waste associated with such discharge is managed in accordance with applicable provisions of subsections (h) (relating to preparedness and prevention), (i) (relating to personnel training), (k) (relating to standards for use of containers), and (l) (standards for use of tank systems) of this section; and

(ii) the applicable discharge reporting requirements of subsection (x) of this section are complied with.

(C) Continued Measures. The provisions of subparagraph (B) of this paragraph do not apply to activities that continue or are initiated after the immediate response is over. Such activities are subject to all applicable requirements of this section.

(3) Discharge Clean Up.

(A) The generator or transporter shall recover as much as of the spilled material as can be recovered by ordinary physical means as soon as possible after discovery of the spill.

(B) The generator or transporter shall clean up the site at which the discharge occurred to background levels as soon as reasonably possible. As an alternative to clean-up to background levels, the generator or transporter must take such action as may be required or approved by the commission so that the hazardous oil and gas waste discharge no longer presents a hazard to human health or the environment, taking into consideration the geology and hydrology of the discharge site, the nature and quantity of the hazardous oil and gas waste discharged, and the present and anticipated future use of the discharge site.

(C) If an official (state or local government or a federal agency) acting within the scope of his or her official responsibilities determines that immediate removal of the hazardous oil and gas waste associated with a discharge is necessary to protect human health or the environment, that official may authorize the removal of the hazardous oil and gas waste by transporters who do not have EPA ID numbers and without the preparation of a manifest.

(y) Emergency Permits.

(1) General. Notwithstanding any other provision of this section, the commission may authorize by emergency permit the treatment, storage, or disposal of hazardous oil and gas waste where the commission finds that a discharge of hazardous oil and gas waste poses a danger to life or property.

(2) Requirements. An emergency permit:

(A) may be oral or written. If oral, a written permit must be issued within five days of issuance of the oral permit;

(B) shall have a term of not more than 90 days;

(C) shall clearly specify the manner and location of authorized treatment, storage, and disposal activities;

(D) may be terminated by the commission without notice if the commission determines that termination is appropriate to protect human health and the environment;

(E) shall incorporate, to the extent possible and not inconsistent with the emergency situation, all applicable requirements of 40 CFR, Parts 264, 266, and 270; and

(F) shall be accompanied by a public notice published in a daily or local newspaper of general circulation in the area affected by the activity and broadcast over local radio stations. The notice shall include:

(i) the name and address of the office granting the emergency authorization;

(ii) the name and location at which the permitted activities will take place;

(iii) a brief description of the hazardous oil and gas wastes involved;

(iv) a brief description of the actions authorized and reasons for authorization of such actions; and

(v) the duration of the emergency permit.

(z) Fees.

(1) Base fee.

(A) Except as provided in subparagraph (B) of this paragraph:

(i) each generator who is classified as an LQG during any calendar month of a calendar year shall pay to the commission a base annual fee for generation of hazardous oil and gas waste of $1,000;

(ii) each generator who is not classified as an LQG during any calendar month of a calendar year, but is classified as an SQG during a calendar month of that calendar year, shall pay to the commission a base annual fee for generation of hazardous oil and gas waste of $200; and

(iii) no annual fee for generation of hazardous oil and gas waste shall be assessed against a generator who is classified as a CESQG during all months of the entire calendar year in which he or she generates hazardous oil and gas waste.

(B) For purposes of determining the base fee as provided in subparagraph (A) of this paragraph, generator classification shall be determined after excluding quantities of hazardous oil and gas waste generated in connection with a spill or discharge, including contaminated soil, media, and debris, if, within 30 days after discovery of such spill or discharge, the generator files a one-page typewritten report with the commission that describes:

(i) the nature and quantity of spilled or discharged material;

(ii) the reason for or cause of the spill or discharge; and

(iii) the steps that have been or will be taken by the generator to minimize the likelihood of a similar spill or discharge at that site.

(2) Additional fee. The base annual fee determined according to the provisions of paragraph (1) of this subsection shall be doubled if less than 50% of the hazardous oil and gas wastes generated at the site during the entire calendar year are recycled, reused or reclaimed. For purposes of calculating the percentage of hazardous oil and gas wastes that are recycled, reused, or reclaimed, hazardous oil and gas wastes excluded from regulation under this section by the provisions of subsection (e)(3)(B)(i) - (iii) of this section (relating to exclusions and exemptions from hazardous oil and gas waste classification) and subsection (m)(2)(B) of this section (relating to elementary neutralization units, totally enclosed treatment facilities, and wastewater treatment units) shall be included in the quantity of hazardous oil and gas waste recycled, reused, or reclaimed. The wastes excluded from regulation under this section under the provisions of subsections (e)(3)(B)(i) - (iii) and (m)(2)(B) of this section shall not be included when calculating the quantity of waste generated for purposes of determining generator classification.

(3) Fee payment. The base fee and any additional fee assessed under this subsection shall be paid to the commission on or before the first day of March of the year following the calendar year in which the waste was generated. Fees assessed under this subsection shall be tendered to the commission with the annual report (see subsection (u)(1) of this section).

(aa) Penalties. A person subject to regulation under this section is subject to the penalties prescribed in the Texas Natural Resources Code if such person does not comply with the requirements of this section.

(bb) Federal Regulations. All references to the Code of Federal Regulations (CFR) in this section are references to the 1994 edition of the Code, as amended through November 7, 1995. The following federal regulations are adopted by reference and copies can be obtained at the William B. Travis Building, 1701 North Congress, Austin, Texas 78711: 40 CFR, Parts 116, 117, 124, 264, 266, 268, 270, 271, 279, and 302; 40 CFR, Part 261, Subparts A, C, and D; 40 CFR, Part 262, Subparts B and E; 40 CFR, Part 265, Subparts C, D, I, and J (except §265.197(c) and §265.200); 40 CFR, §§260.21, 260.22, 262.34(d)(5), 265.16, 265.111, 265.114, and 265.201; 49 CFR, Parts 172, 173, 178, and 179; and 49 CFR, §171.15 and §171.16. Words and terms used in the federal regulations adopted by reference shall have the meanings given in the federal regulations adopted by reference or in 40 CFR, §260.10, unless otherwise specified. Where the term "State Director" is applicable in the federal regulations adopted by reference, it should be interpreted to mean "commission."

Source Note: The provisions of this §3.98 adopted to be effective April 1, 1996, 20 TexReg 9423; amended to be effective May 4, 1999, 24 TexReg 3313; amended to be effective September 10, 2001, 26 TexReg 6870; amended to be effective November 24, 2004, 29 TexReg 10728; amended to be effective July 1, 2025, 50 TexReg 33

§3.99 Cathodic Protection Wells

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Cathodic protection well--Any well drilled for the purpose of installing one or more anodes to prevent corrosion of a facility associated with the production of oil, gas, or geothermal resources, such as a well casing, storage and separation facility, or pipeline.

(2) Project area--The geographic area in which a related group of cathodic protection wells is drilled.

(3) Protection depth--Depth or depths at which usable quality water must be protected or isolated, as determined by the Groundwater Advisory Unit of the Oil and Gas Division, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(4) Commission--The Railroad Commission of Texas or its authorized representative.

(b) Exemption. Any cathodic protection well that is drilled to a depth of 30 feet or less is not subject to the requirements of this section.

(c) Determination of protection depth. Before drilling any cathodic protection well, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth or depths.

(d) Drilling permits.

(1) Wells that do not penetrate any protection depth. A cathodic protection well that does not penetrate any protection depth does not require a drilling permit.

(2) Wells that penetrate any protection depth. A cathodic protection well that penetrates any protection depth must be drilled in accordance with the requirements

of §3.5(g) of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(e) Completion.

(1) Timing. A cathodic protection well must be completed as soon as possible after it is drilled.

(2) Wells that do not penetrate any protection depth. A cathodic protection well that does not penetrate any protection depth must be completed in accordance with subparagraph (A) or (B) of this paragraph.

(A) The operator must place at least a 10-foot cement or bentonite plug at the top of the well. The top of the plug shall be no less than three feet below the surface, and the remainder of the hole between the top of the plug and the surface shall be filled with drill cuttings or native soil.

(B) Alternative completion procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(3) Wells that penetrate any protection depth. A cathodic protection well that penetrates any protection depth must be completed in accordance with subparagraph (A) or (B) of this paragraph.

(A) The operator must either set and cement casing to the deepest protection depth penetrated or center a 100-foot cement plug across each protection depth penetrated and must place at least a 10-foot cement or bentonite plug at the top of the well. The top of the plug shall be no less than three feet below the surface, and the remainder of the hole between the top of the plug and the surface shall be filled with drill cuttings or native soil.

(B) Alternative completion procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(f) Physical requirements for bentonite plugging materials. Bentonite materials used to plug cathodic protection wells shall be derived from naturally occurring, untreated, high swelling sodium bentonite that is composed of at least 85% montmorillonite clay and that meets the International Association of Geophysical Contractors (IAGC) recommended geophysical industry standard dated January 24, 1992, for the physical characteristics of bentonite used in seismic shot hole plugging.

(g) Reporting. Within 30 days of completion of the last well in a project area, the operator shall submit a letter to the commission stating that each cathodic protection well in the project area has been completed in accordance with subsection (e) of this section. The letter must include the completion date for each well, the name and address of the operator, and the drilling permit and API numbers of the well, if applicable. A plat of the project area identifying cathodic protection well locations, counties, survey lines, scale, and northerly direction must be attached. In addition, a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth or depths must be attached.

(h) Abandonment. Upon abandonment of a cathodic protection well, any wires or vent pipe must be cut off at the top of the 10-foot surface plug, and the vent pipe must be securely capped or plugged.

Source Note: The provisions of this §3.99 adopted to be effective July 21, 1992, 17 TexReg 4877; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective January 1, 2014, 38 TexReg 3542.

§3.100 Seismic Holes and Core Holes

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Seismic hole--Any hole drilled for the purpose of securing geophysical information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources.

(2) Core hole--Any hole drilled for the purpose of securing geological information to be used in the exploration or development of oil, gas, geothermal, or other mineral resources, except coal or uranium. For regulations governing coal exploratory wells, see Chapter 12 of this title (relating to Coal Mining Regulations), and for regulations governing uranium exploratory wells, see Chapter 11, Subchapter C of this title (relating to Surface Mining and Reclamation Division, Substantive Rules--Uranium Mining).

(3) Project area--The geographic area in which an exploratory survey involving one or more seismic holes or core holes is carried out.

(4) Protection depth--Depth or depths at which usable quality water must be protected or isolated, as determined by the Groundwater Advisory Unit of the Oil and Gas Division, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(5) Operator--The person who contracts for the services of a seismic crew or core hole drilling contractor or, if the seismic survey or core hole testing is not performed on a contract basis, but is performed by an exploration and production company or by a geophysical contractor for speculative purposes, the person who drills the seismic holes or core holes.

(6) Commission--The Railroad Commission of Texas or its authorized representative.

(b) Exemption. Any seismic hole or core hole drilled to a depth of 20 feet or less is not subject to the requirements of this section.

(c) Determination of protection depth. Before drilling any seismic hole or core hole in a project area, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth or depths in the project area.

(d) Drilling permits.

(1) Holes that do not penetrate any protection depth. A seismic hole or core hole that does not penetrate any protection depth does not require a drilling permit.

(2) Holes that penetrate any protection depth. A seismic hole or core hole that penetrates any protection depth requires a drilling permit to satisfy the requirements for exploratory wells described in §3.5(g) of this title (relating to Application To Drill, Deepen, Reenter, or Plug Back) (Statewide Rule 5).

(e) Plugging.

(1) Holes that do not penetrate any protection depth. A seismic hole or core hole that does not penetrate any protection depth must be plugged in accordance with subparagraph (A) or (B) of this paragraph. Seismic holes must be plugged after the hole is loaded with explosives. Core holes must be plugged immediately after completion

of coring the hole.

(A) The operator shall adequately plug the hole by filling it from total depth to a depth of no more than 16 feet below the surface with drill cuttings and/or bentonite. Immediately above the drill cuttings and/or bentonite, the operator shall place a bentonite plug no less than 10 feet in length. A plastic cap imprinted with the name of the operator shall be set above the bentonite plug no less than three feet below the surface. The remainder of the hole shall be filled with drill cuttings or native soil. All precautions should be taken to prevent bentonite from bridging over.

(B) Alternative plugging procedures and materials may be utilized when the operator has demonstrated to the commission's satisfaction that the alternatives will protect usable quality water.

(2) Holes that penetrate any protection depth. A seismic hole or core hole that penetrates any protection depth must be plugged in accordance with the requirements of §3.14 of this title (relating to Plugging) (Statewide Rule 14) and a plastic cap imprinted with the name of the operator shall be set in the hole no less than three feet below the surface.

(f) Physical requirements for bentonite plugging materials. Bentonite materials used to plug seismic or core holes shall be derived from naturally occurring, untreated, high swelling sodium bentonite that is composed of at least 85% montmorillonite clay and that meets the International Association of Geophysical Contractors (IAGC) recommended geophysical industry standard dated January 24, 1992, for the physical characteristics of bentonite used in seismic shot hole plugging.

(g) Reporting.

(1) Holes that do not penetrate any protection depth. Within 30 days of plugging the last hole in the project area, the operator shall submit a letter to the commission stating that each seismic hole or core hole in the project area has been plugged in accordance with subsection (e)(1) of this section. The letter must include the plugging date for each hole and the name and address of the operator. A plat of the project area identifying seismic or core hole locations, counties, survey lines, scale, and northerly direction must be attached. A United States Geological Survey map of the project area with hole locations marked will satisfy the plat requirement. In addition, a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth or depths must be attached.

(2) Holes that penetrate any protection depth. For any seismic or core hole that penetrates any protection depth, a plugging record shall be filed in accordance with §3.14 of this title (relating to Plugging) (Statewide Rule 14).

Source Note: The provisions of this §3.100 adopted to be effective September 1, 1992, 17 TexReg 5283; amended to be effective August 25, 2003, 28 TexReg 6816; amended to be effective July 2, 2012, 37 TexReg 4892; amended to be effective January 1, 2014, 38 TexReg 3542.

§3.101 Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells

(a) Purpose. This section specifies the procedure by which an operator can obtain a Railroad Commission of Texas certification that natural gas from a particular gas well qualifies as high-cost natural gas under the Texas Tax Code, Chapter 201, Subchapter B, §201.057(a)(2)(A) and that such gas is exempt from or eligible for a reduction of the severance tax imposed by the Texas Tax Code, Chapter 201.

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Commission--The Railroad Commission of Texas.

(2) Completion--The act of making a well capable of producing gas from a particular commission designated or new field.

(3) Completion date--The date on which a well is first made capable of producing oil or gas from a particular commission-designated or new field, as shown on the completion report filed by the operator with the commission.

(4) Comptroller--The Comptroller of Public Accounts of the State of Texas.

(5) Data-point well--A well that has been tested and/or produced in the proposed tight gas formation; and, from the test results or other data, applicant provides a measured or calculated in situ permeability and/or a measured or calculated pre-stimulation stabilized flow rate against atmospheric pressure.

(6) Director--The director of the Oil and Gas Division or the director's delegate. Any authority given to the director in this section is also retained by the commission. Any action taken by the director pursuant to this section is subject to review by the commission.

(7) High-cost gas--Natural gas which the commission finds to be:

(A) produced from any gas well, if production is from a completion which is located at a depth of more than 15,000 feet;

(B) produced from geopressured brine;

(C) occluded natural gas produced from coal seams;

(D) produced from Devonian shale; or

(E) produced from designated tight formations or produced as a result of production enhancement work.

(8) Operator--The person responsible for the actual physical operation of a gas well.

(9) Spud date--The date of commencement of drilling operations, as shown on commission records.

(c) Applicability.

(1) A severance tax exemption is available for high-cost gas produced from a well that is spudded or completed between May 24, 1989, and September 1, 1996. Eligible high-cost gas shall be exempt from the tax imposed by the Texas Tax Code, Chapter 201, during the period from September 1, 1991, through August 31, 2001.

(2) A severance tax reduction is available for high-cost gas produced from a well that is spudded or completed after August 31, 1996. Eligible high-cost gas shall be entitled to a reduction of the tax imposed by the Texas Tax Code, Chapter 201, for the first 120 consecutive calendar months beginning on the first day of production or until the cumulative value of the tax reduction equals 50% of the drilling and completion costs incurred for the well, whichever occurs first. The amount of tax reduction is determined pursuant to the Texas Tax Code, §201.057(c). If the application for certification is submitted to the Commission after January 1, 2004, the total allowable credit for taxes paid for reporting periods before the date the application is filed may not exceed the total tax paid on

the gas that otherwise qualified for the exemption or tax reduction and that was produced during the 24 consecutive calendar months immediately preceding the month in which the application for certification under this section was filed with the Commission.

(3) The plug back or deepening of an existing wellbore qualifies as a completion under this section. When the plug back or deepening is completed prior to September 1, 1996, the gas produced may qualify for a tax exemption. When the plug back or deepening is completed after August 31, 1996, the gas produced may qualify for a tax reduction. The plug back or deepening qualifies as a completion if:

(A) it is the initial completion in a commission-designated or newly discovered field that has not been previously produced from that wellbore; or

(B) the operator can demonstrate that the strata between the former completion and the new completion contain a minimum of 20 vertical feet of impermeable strata; or

(C) the operator submits the results of bottom hole pressure surveys, gas analyses or other methods or calculations comparing the new completion with previous completions in the wellbore that were in existence prior to May 24, 1989. The application shall include an explanation of the engineering principles, calculations, and reasoning to show that the gas to be produced from the applied-for completion could not have been produced from any completion in existence prior to May 24, 1989.

(4) If the operator determines that a gas well previously certified as producing high-cost gas no longer produces high-cost gas or if the operator takes any action or discovers any information that affects the eligibility of gas for an exemption or tax reduction under Texas Tax Code, §201.057, the operator shall notify the Commission in writing within 30 days after such an event occurs.

(5) If the Commission determines that a gas well previously certified as producing high-cost gas no longer produces high-cost gas or if the commission takes any action or discovers any information that affects the eligibility of gas for an exemption or tax reduction under Texas Tax Code, §201.057, the Commission shall notify within 48 hours, in writing, the comptroller and the operator.

(d) Application procedure.

(1) An application for a state severance tax exemption or tax reduction for a gas well may be made only by the operator of that well. The operator shall file one copy of the required application form, one copy of the required attachments specified in subsection (e)(1) - (6) of this section and any additional information deemed necessary by the Commission to clarify, explain and support the required attachments. Submission of legible copies of required attachments shall comply if the application includes a statement, signed by the operator, that the attachments are true and correct copies of the documents originally filed with the Commission. However, the Commission may require an operator to file certified copies of required attachments or other documents from Commission files if necessary for a certification.

(2) Filings and correspondence on high-cost gas state severance tax applications shall be addressed to the Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, Attention: High-Cost Gas Severance Tax Section. No filings may be made at the district offices.

(e) Application requirements for individual well certifications. To qualify for the severance tax exemption or tax reduction, the operator shall prove that the gas produced is high-cost gas by providing the following information:

(1) Applications for wells producing deep high-cost gas shall include:

(A) the completed applicable commission form; and

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well.

(2) Applications for wells producing geopressured brine shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) a bottom-hole pressure test report and other information establishing the initial reservoir pressure gradient; and

(D) evidence to establish that, before production, the gas from the well was in solution in a brine aquifer with at least 10,000 parts of dissolved solids per million parts of water.

(3) Applications for wells producing coal seam gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well if the gas is produced through a wellbore, or a detailed description of the production process if the gas is not produced through a wellbore;

(C) a radioactivity, electric or other log which will define the coal seams or, if such logs are not reasonably available, a detailed lithologic description of the gas-producing interval; and

(D) evidence to establish that the natural gas was produced from coal seams.

(4) Applications for wells producing Devonian shale gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) an environmentally corrected, calibrated gamma ray log with values greater than 100 API units over the Devonian age stratigraphic section, or a gamma ray log with superimposed indications of the shale base line and the gamma ray index of 0.7 over this section or, if the gamma ray log is not reasonably available, a driller's log or similar report indicating the general characteristics of the strata penetrated and the corresponding depths at which they are encountered throughout the Devonian age stratigraphic section;

(D) information which calculates the percentage of footage of the producing interval which is not Devonian shale as indicated by the gamma ray log, driller's log, or similar report;

(E) information which demonstrates that the percentage of potentially disqualifying nonshale footage for the stratigraphic section selected is equal to or less than 5.0% of the Devonian stratigraphic age interval; and

(F) reference to a standard stratigraphic chart or text establishing that the producing interval is a shale of Devonian age.

(5) Applications for wells producing designated tight formation gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) specific reference to the commission docket number assigned to the applicable designated tight formation area certification along with a copy of the map with the subject well location shown, which outlines the designated tight formation area approved by the commission.

(6) Applications for wells producing production enhancement gas shall include:

(A) the completed applicable commission form;

(B) copies of all Gas Well Back Pressure Test, Completion or Recompletion Reports and Logs ever filed on the subject well;

(C) a description of the production enhancement work that has been performed on the well, including the dates the work was commenced and completed, or that will be performed on the well;

(D) an itemized statement of costs incurred in performing the production enhancement work, including copies of invoices and bills for such work, or, if the work has not yet been completed, estimates of such costs;

(E) a statement estimating, for a five-year test period beginning from the month in which the application is filed, the increase in gas production resulting from the application of production enhancement work;

(F) calculations showing that the projected increase in revenue does not exceed 200% of the §103 price;

(G) the renegotiated price;

(H) a copy of that portion of the sales contract that authorizes collection of the renegotiated price; and

(I) the properly executed statement under oath made by the purchaser of natural gas which states that there is a reasonable basis for the statements and estimates made by the applicant.

(f) Application requirements for tight formation area certifications.

(1) If justification for an individual well application is based on a tight formation certification and the well is not located within a geographical area that has been previously certified as a designated tight formation area or the well is not completed in a formation interval that has been previously certified as a designated tight formation by the Federal Energy Regulatory Commission under the Natural Gas Policy Act or by the Railroad Commission of Texas, the operator shall first apply for a tight formation area designation.

(2) An applicant requesting a tight formation area designation shall submit a written request to the High-Cost Gas Severance Tax Section, at the address given in subsection (d)(2) of this section, for a certification that a named formation or a specific portion thereof is a tight formation. The applicant shall supply a list of the names and addresses of all affected persons. For purposes of this subsection, "affected persons" means all operators of all wells listed on the current proration schedule for the applicable field or fields located within the proposed designated area. The applicant shall mail or deliver a copy of the prescribed, completed notice of application form to all affected persons, and if required, shall publish the notice of application in accordance with §1.46 of this title (relating to Notice by Publication in Oil and Gas and Surface Mining and Reclamation Nonrulemaking Proceedings), as found in the Commission's General Rules of Practice and Procedure (16 Texas Administrative Code Chapter 1). Notice of application forms may be obtained by contacting the Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, Attention: High-Cost Severance Tax Section. Before the application may be approved, the applicant shall submit a letter certifying that all affected persons were sent a copy of the notice of application, and the date on which the notice of application was sent.

(3) In addition to the written request and list of affected persons, the applicant shall submit the following information in duplicate:

(A) a geographical and geological description of the formation, including:

(i) a map with an outline of the geographical limits of the formation in and around the requested area, with the proposed designated areal boundaries shown, with counties, surveys and abstracts identified and with the locations clearly identified for all wells inside the requested area that have penetrated the proposed formation; all wells (i.e., those that penetrated the proposed formation) shown on the map inside the requested area shall include either the commission's gas well identification number or the API number (if available);

(ii) a list of the counties involved, abstract numbers, survey names, geologic formation markers, and any other descriptive information that will aid in identifying the subject formation including an estimate of the number of acres within the requested area; and

(iii) a structure map contoured on the top of the formation and a cross-section to depict upper and lower limits of the proposed formation, or specific portion thereof.

(B) engineering and geological exhibits, including a written explanation of each, to establish the following:

(i) that the in situ permeability throughout the proposed formation or specific portion thereof is 0.1 millidarcies or less, as determined by geometric mean or median analysis of available data from all wells that either have been tested or are completed in the proposed formation within the requested area. If no in situ permeability estimates are provided for wells that are in the requested area and have been tested and/or are completed in the proposed formation, an explanation shall be provided;

(ii) that the pre-stimulation stabilized production rate against atmospheric pressure at the wellhead, as determined by a geometric mean or median analysis of available data from all wells within the requested area that either have been tested and/or are completed in the proposed formation or specific portion thereof, does not exceed the production rate listed in the following table:

If the average depth to the top of the formation (in feet)		The maximum allowable production rate (in thousand cubic feet per day) may not exceed-
exceeds-	but does not exceed-	
0	1,000	44
1,000	1,500	51
1,500	2,000	59
2,000	2,500	68
2,500	3,000	79
3,000	3,500	91
3,500	4,000	105
4,000	4,500	122
4,500	5,000	141
5,000	5,500	163
5,500	6,000	188
6,000	6,500	217
6,500	7,000	251
7,000	7,500	290
7,500	8,000	336
8,000	8,500	388
8,500	9,000	449
9,000	9,500	519
9,500	10,000	600
10,000	10,500	693
10,500	11,000	802
11,000	11,500	927
11,500	12,000	1,071
12,000	12,500	1,238
12,500	13,000	1,432
13,000	13,500	1,655
13,500	14,000	1,913
14,000	14,500	2,212
14,500		2,557

(iii) that no well drilled into the formation is expected to produce, without stimulation, more than five barrels of crude oil per day; and

(iv) that the requested designated area does not extend beyond a two and one-half mile radius drawn from any data point well.

(g) Commission action on applications for individual well certifications and for tight formation area designations.

(1) Each application, for an individual well certification, shall be assigned a docket number identifying it as a severance tax application. A notice of receipt shall be sent to the applicant, indicating the assigned docket number and receipt date. All further correspondence shall include this docket number.

(2) The director may administratively approve the individual well certification applications if the forms and information submitted by the operator establish that the gas qualifies as high-cost gas eligible for the severance tax exemption or tax reduction. If the director denies

administrative approval, the applicant shall have the right to a hearing.

(3) If Commission staff finds that the data submitted with the tight formation area designation applications are complete and comply with the requirements set out in subsection (f)(3) of this section and if no protest to the application is filed within 21 days of the notice, the application shall be presented to the Commission for approval. If Commission staff finds the data submitted are incomplete, or indicate the area does not qualify, or if a protest is filed within the 21-day notice period, the applicant shall request a hearing to have the application considered. If the applicant does not request such a hearing or if the applicant fails to appear at a requested hearing, the application shall be dismissed. Any such hearing shall be held only after at least 10 days' notice by the Commission to all affected persons as defined in subsection (f)(2) of this section. If no protestant appears at the hearing, and/or if the application and any evidence presented at the hearing establishes that the subject formation meets the requirements for a tight formation certification, the application shall be presented to the Commission for approval.

(h) Reporting. To qualify for the exemption or tax reduction provided by Texas Tax Code, §201.057(a)(2)(A), all persons responsible for paying the tax shall apply with the comptroller after receiving a copy of the Commission's certification letter. The application shall contain the Commission's letter certifying that the well produces or will produce high-cost gas, a completed copy of the Commission's application for certification form and a completed copy of the applicable Comptroller of Public Accounts' form. To obtain the maximum tax exemption or tax reduction, the application shall be filed with the comptroller at the later of the 180th day after the first day of production or the 45th day after the certification by the Commission. If the application is not filed by the applicable deadline, the tax exemption or reduction will be reduced by 10% for the period beginning on the 180th day after the first day of production and ending on the date on which the application is filed with the comptroller.

Source Note: The provisions of this §3.101 adopted to be effective January 11, 1995, 19 TexReg 10351; amended to be effective September 15, 1997, 22 TexReg 8974; amended to be effective August 13, 2001, 26 TexReg 6009; amended to be effective October 12, 2003, 28 TexReg 8585.

§3.102 Tax Reduction for Incremental Production

(a) Purpose. The purpose of this section is to provide a procedure by which an operator can obtain a 50% severance tax reduction for five years on the incremental oil and casinghead gas production from a qualifying lease.

(b) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Oil lease--A commission-designated oil lease to which the commission has assigned an identifying number.

(2) Production--Barrels of oil (including barrels of gas liquids reported as production monthly on the appropriate form) plus casinghead gas, where six thousand cubic feet of gas is the equivalent of one barrel of oil, expressed in barrels of oil equivalent (BOE).

(3) Baseline production--An oil lease's average BOE monthly production during the four highest months of production in the time period from January 1, 1996, through December 31, 1996.

(4) Incremental production--Production from a qualifying lease in excess of baseline production.

(5) Incremental production technique--

(A) any secondary or tertiary production enhancement technique;

(B) any primary production enhancement technique that an operator certifies required an expenditure of at least $5,000 to cause increased production.

(6) Qualifying lease--A lease is a qualifying lease provided that:

(A) the commission has designated the lease as an oil lease and has assigned to it an identifying number;

(B) production from the lease, measured by dividing the sum of lease production during the four-month period used to compute the baseline production by the sum of the number of well-days during the same four-month period, is no more than seven barrels of oil equivalent per day per well, excluding gas flared pursuant to the rules of the commission; and

(C) after the operator performs an incremental production technique, the lease shows incremental production for four of five consecutive months on or after September 1, 1997, and before December 31, 1998.

(7) Incremental ratio--The amount of a qualifying lease's average monthly incremental production during the four-month period used to meet the definition of a qualifying lease divided by its average monthly total production during the same four-month period.

(8) Qualified incremental production--A qualifying lease's total monthly production multiplied by the incremental ratio.

(9) Well-day--One well producing hydrocarbons for one day.

(c) Qualification for the tax reduction. An operator of a qualifying lease is entitled to a 50% tax reduction on that lease's qualified incremental production for five years provided that:

(1) The operator of a qualifying lease applies to the commission for a determination of an incremental ratio before February 11, 1999;

(2) The commission certifies an incremental ratio;

(3) The operator provides to the state comptroller the certified incremental ratio; and

(4) The operator applies to the state comptroller for the tax relief provided by this section not later than one year after the date the commission certifies the incremental ratio for a qualifying lease.

(d) Request for hearing. If the request for certification of an incremental ratio is denied administratively, or if the operator does not agree with the administrative determination of the amount of the incremental ratio, the applicant may request a hearing. The request for a hearing must be filed within 20 days after the date on which notice of the administrative decision is mailed to the operator. The commission shall provide notice of the hearing to the applicant and to any other affected person named by the applicant. After hearing, the examiner shall recommend final action by the commission.

Source Note: The provisions of this §3.102 adopted to be effective June 23, 1998, 23 TexReg 6437.

§3.103 Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared

(a) Purpose. The purpose of this section is to provide a procedure by which an operator may obtain commission certification that the operator markets gas that was previously released into the air for 12 months or more pursuant to §3.32 of this title (relating to Gas Well Gas and Casinghead Gas Shall Be Used for Legal Purposes). Certification under this section is voluntary.

(b) Definitions. The following terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Oil lease--A commission-designated oil lease to which the commission has assigned an identifying number as listed on the monthly oil proration schedule at the time an application is filed under this rule.

(2) Oil well--A wellbore completed in a commission-designated field and assigned to an oil lease as listed on the monthly oil proration schedule at the time an application for certification is filed under this rule.

(c) Eligibility. An operator shall be eligible to receive the tax exemption on marketed casinghead gas for the life of an oil well or oil lease as listed on the oil proration schedule at the time an application for certification is filed under this rule if:

(1) the operator previously released the casinghead gas from an oil well or oil lease into the air for 12 months or more pursuant to §3.32 of this title; and

(2) the operator marketed the gas no earlier than June 1, 1997, in accordance with §3.32 of this title.

(d) Certification.

(1) An operator may apply for commission certification on the appropriate form. The completed form shall be accompanied by information necessary to establish:

(A) prior release into the air of casinghead gas for 12 months or more during a period of 13 consecutive months pursuant to §3.32 of this title; and

(B) such gas has generated taxable proceeds subject to the severance tax as a result of being marketed on or after September 1, 1997.

(2) The director of the commissions's Oil and Gas Division, or the director's delegate, may administratively approve or deny a request for certification.

(3) If the director of the commission's Oil and Gas Division or the director's delegate denies the request, the operator may request a hearing by filing such a request in writing within 15 days after the postmarked date of the notice of the administrative denial.

(4) If the operator fails to appear at the hearing without good cause, the request for certification shall be dismissed.

(5) Filings and correspondence concerning the application for certification shall be addressed to the Railroad Commission, P.O. Box 12967, Austin, Texas 78711-2967, Attention: Permitting/Production Services Section.

(e) Application to the Comptroller. After the commission issues the certification provided for in subsection (d) of this section, the operator may apply to the Comptroller of Public Accounts to receive the tax exemption.

(f) Termination of Authorization to Release Gas. On the date the commission issues the certification provided for in subsection (d) of this section, either by administrative action or by commission order, the volume of casinghead gas authorized to be released into the air as an exception obtained pursuant to §3.32(h) of this title shall be reduced to the volume of casinghead gas not subject to the certification. If all of the volume of casinghead gas authorized to be released under an exception is certified for purposes of the tax exemption, the exception shall no longer apply, and shall automatically terminate as of the date of certification.

Source Note: The provisions of this §3.103 adopted to be effective August 4, 1998, 23 TexReg 7770.

§3.106 Sour Gas Pipeline Facility Construction Permit

(a) Definitions. The following words and terms when used in this section shall have the following meanings, unless the context clearly indicates otherwise.

(1) Affected person--The owner or occupant of real property located in the area of influence of the proposed route of a sour gas pipeline facility. If the final proposed route of the pipeline is unknown at the time of application, then an affected person is any person who owns or occupies real property located within the area of influence associated with any possible pipeline route identified by the applicant. For purposes of this definition, the owner shall be the owner of record as of the final day to protest an application. The occupant shall be the occupant as of the final day to protest an application.

(2) Applicant--A person who has filed an application for a permit to construct a sour gas pipeline facility, or a representative of that person.

(3) Application--Application for a Permit to Construct a Sour Gas Pipeline Facility, and all required attachments.

(4) Area of influence--Area along a sour gas pipeline facility represented by all possible areas of exposure using the 100 ppm radius.

(5) Construction of a facility--Any activity conducted during the initial construction of a pipeline including the removal of earth, vegetation, or obstructions along the proposed pipeline right-of-way. The term does not include:

(A) surveying or acquiring the right-of-way;

(B) clearing the right-of-way with the consent of the owner;

(C) repairing or maintaining an existing sour gas pipeline facility; or

(D) installing valves or meters or other devices or fabrications on an existing pipeline if such devices or fabrication do not result in an increase in the area of influence.

(6) Extension of a sour gas pipeline facility--An addition to an operating sour gas pipeline facility regardless of ownership of the addition.

(7) Nominal pipe size--The industry convention for naming pipe. Six inch nominal size pipe corresponds to pipe with an approximate inner diameter of six inches. The actual inner diameter varies based on the wall thickness of the pipe.

(8) Person--An individual, partnership, firm, corporation, joint venture, trust, association, or any other business entity, a state agency or institution, county, municipality, school district, or other governmental subdivision.

(9) Preliminary contingency plan--A contingency plan containing all of the elements required for a contingency plan under §3.36 of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas),

except that:

(A) the plan need not contain the list of names and telephone numbers of residents within the area of influence if required under §3.36(c)(9)(I) of this section. In lieu of this list of names and telephone numbers, the plan shall contain a detailed explanation of the manner in which the names and telephone numbers of residents within the area of influence will be compiled prior to commencement of operations;

(B) the plat detailing the area of influence may be:

(i) the detailed plat required under §3.36(c)(9)(H);

(ii) a plat containing the information required under §3.36(c)(9)(H), that identifies residential, business, and industrial areas with an estimate of the number of people that may be within any such areas; or

(iii) one or more aerial photographs covering the area and providing the information required under §3.36(c)(9)(H); and

(C) a fixed pipeline route need not be specified in the preliminary plan provided the preliminary plan identifies the boundaries of the area within which the pipeline will be constructed and provided that all public notices of the application required under this section note such boundaries and identify the potential area of influence as the total area encompassed by the area of influence associated with all possible pipeline routes.

(10) Sour gas pipeline facility--A pipeline and ancillary equipment that:

(A) contains a concentration of 100 parts per million or more of hydrogen sulfide;

(B) is located outside the tract of production; and

(C) is subject to the requirements of §3.36 of this title.

(11) Tract of production--The surface area which overlies the area encompassed by a mineral lease or unit from which oil, gas, or other minerals are produced if such area is treated by the Oil and Gas Division of the commission as a single tract.

(12) 100 ppm radius--The 100 parts per million radius of exposure as calculated in §3.36(c)(1) - (3) of this title (relating to oil, gas, or geothermal resource operation in hydrogen sulfide areas) for the sour gas pipeline facility.

(b) Permit Required; Exceptions. No person may commence construction of a facility within this State without a permit if the facility is initially used as a sour gas pipeline facility except for the following:

(1) an extension of an existing sour gas pipeline facility that at the time of construction of the extension is in compliance with §3.36 of this title (relating to oil, gas, or geothermal resource operation in a hydrogen sulfide area) if:

(A) the extension is not longer than five miles;

(B) the nominal pipe size is not larger than six inches; and

(C) the operator causes to be delivered to the Safety Division written notice of construction of the extension not later than 24 hours before the start of construction;

(2) a new gathering system that operates at a working pressure of less than 50 pounds per square inch gauge;

(3) an extension of a gathering system which operates at a working pressure of less than 50 pounds per square inch gauge;

(4) an interstate gas pipeline facility, as defined by 49 U.S.C. §60101, that is used for the transportation of sour gas; or

(5) replacement of all or part of a sour gas pipeline facility if the area of influence of the replaced portion of the facility does not increase so as to include a public area, as defined in §3.36(b)(5) of this title, not included in the area of influence of the portion of the replaced sour gas pipeline facility.

(c) Filing and Assignment of Docket Number. Upon filing of an application with the Oil and Gas Division, staff will assign a docket number to the application and will notify the applicant of the assigned docket number. Staff will also assign and provide a docket number to a person who submits a notice of intent to file an application.

(d) Application. A complete application consists of:

(1) a properly completed application Form PS-79, with the original signature, in ink, of the applicant;

(2) if applicant desires notification under subsection (h)(1) by electronic mail, a written request for electronic mail notification and the applicant's electronic mail address;

(3) a plat which meets the requirements of subsection (f)(4) of this section and identifies the boundaries of surveys and blocks or sections as appropriate within the area of influence;

(4) a copy of the applicant's Application for Permit to Operate a Pipeline, Form T-4, if applicable, including all attachments; and

(5) a copy of the completed application for a Statewide Rule 36 Certificate of Compliance, Form H-9, including any attachment required under §3.36 of this title. A preliminary contingency plan may be filed in lieu of a contingency plan if required under §3.36 of this title.

(e) Notice.

(1) For each county that contains all or part of the area of influence of a proposed sour gas pipeline facility, the applicant shall:

(A) cause to be delivered to the county clerk no later than the first date of publication in that county a copy of the items described in subsection (d)(1) - (3) of this section;

(B) publish notice of its application in a newspaper of general circulation in each county that contains all or a portion of the area of influence of the proposed sour gas pipeline facility. Such notice shall meet the requirements of subsection (f) of this section and be published in a section of the newspaper containing news items of state or local interest.

(2) Final action may not be taken on any application under this section until proof of notice, evidenced as follows, is provided:

(A) a return receipt from each county clerk with whom an application form and plat is required to be filed pursuant to paragraph (1) of this subsection; and

(B) the full page or pages of the newspaper containing the published notice required under paragraph (2) of this subsection including the name of the paper, the date the notice was published, and the page number.

(f) The published notice of application shall be at least three inches by five inches in size, exclusive of the plat, and shall contain the following:

(1) the name, business address, and telephone number of the applicant and of the applicant's authorized representative, if any;

(2) a description of the geographic location of the sour gas pipeline facility and the area of influence, to the extent not clearly identified in the plat required to be published in

subsection (f)(4) of this section;

(3) the following statement, completed as appropriate: "This proposed pipeline facility will transport sour gas that contains 100 parts per million, or more, of hydrogen sulfide. A copy of application forms and a map showing the location of the pipeline is available for public inspection at the offices of the (insert County name) County Clerk, located at the following address: (insert address of County Clerk). Any owner or occupant of land located within the area of influence of the proposed sour gas pipeline facility desiring to protest this application can do so by mailing or otherwise delivering a letter referring to the application (by docket number if available) and stating their desire to protest to: Docket Services, Office of General Counsel, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967. Protests shall be in writing and received by Docket Services not later than (specify 30th day after the first date notice of the application is to be published). The letter shall include the name, address, and telephone number of every person on whose behalf the protest is filed and shall state the reasons each such person believes that he or she is the owner or occupant of property within the area of influence of the proposed pipeline facility. It is recommended that a copy of this notice be included with the letter."; and

(4) a plat identifying:

(A) the location of the pipeline facility;

(B) area of influence;

(C) north arrow;

(D) scale;

(E) geographic subdivisions appropriate for the scale; and

(F) by inset or otherwise, landmarks or other features such as roads and highways in relation to the proposed route of the sour gas pipeline facility. These landmarks or other features shall be of sufficient detail to allow a person to reasonably ascertain whether an owned or occupied property that is within the area of influence of the proposed sour gas pipeline facility. Examples of acceptable plats are included in this subsection.

NOTICE OF APPLICATION FOR PIPELINE PERMIT

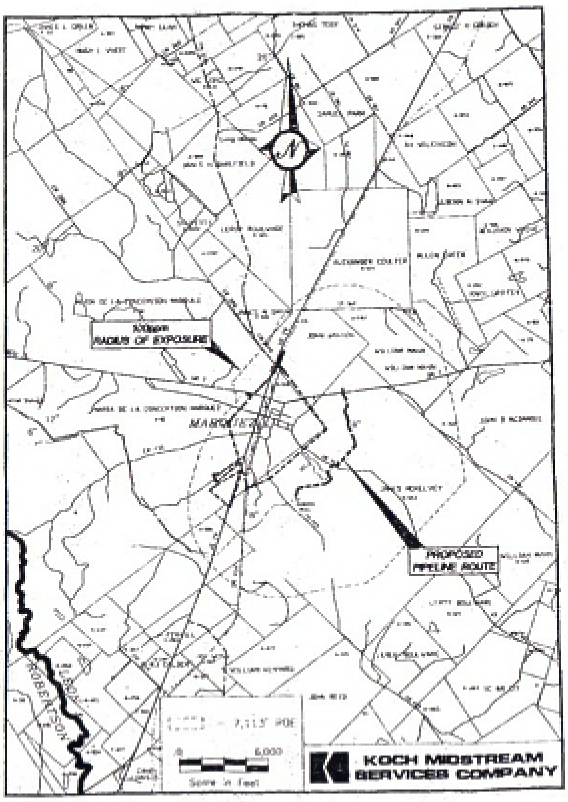
Koch Midstream Services Company, 606 S. Shelby St., Carthage, Texas 76533, has applied to the Railroad Commission of Texas for a permit to construct a 2.05 miles buried pipeline in Leon County, Texas, to gather natural gas containing hydrogen sulfide (Sour Gas). In the event of a leak, the radius of exposure of hydrogen sulfide for 100 parts per million (ppm) could extend 7113 feet on either side of the pipeline based on methods outlined in the 16 Texas Administration Code 3.36(2). The radius of exposure included parts of U.S. Hwy. 79 and extends northeasterly thru Marquez city limits. The applicant proposes to construct pipeline beginning 7,836 ft. southeasterly of a point of intersection of U.S. Hwy. 79 and State Hwy. 7 extending northeasterly 2.05 miles ending 5,808 ft. of a point of intersection of U. S. Hwy. 79 and State Hwy. 7. The city limits of Marquez are shown on the plat. The southwestern end of the pipeline will interconnect with a 8" sour gas pipeline owned and operated by the applicant. The pipeline will be constructed and operated in accordance with rules and regulations adopted by the Railroad Commission of Texas specifying construction material and methods for the safe operation of sour gas pipelines.

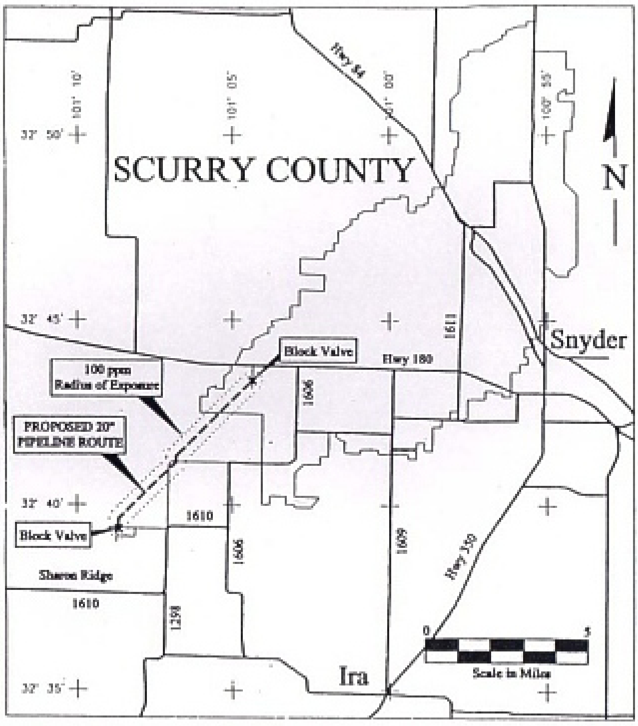
This proposed pipeline facility will transport sour gas that contains more than 100 ppm of hydrogen sulfide. A copy of this application is available for public inspection at the offices of the Leon County Clerk, located at the following address: the corner of Cass Street and St. Mary Street in Centerville, Texas.

Any owner or occupant of land located within 100 ppm radius of exposure of the proposed sour gas pipeline facility desiring to protest this application can do so by mailing or otherwise delivering a letter referring to Gas Utilities Docket (GUD) No. 8899 and stating their desire to protest to:

Docket Services
Office of General Counsel
Railroad Commission of Texas
P. O. Box 12967
Austin, Texas 78711-2967

Protests must be received no later than September 19, 1998. It is recommended that a copy of this notice be included with the letter. Additional information concerning the protest procedure can be obtained by calling (512) 463-7017 or by visiting\\www.rrc.state.tx.us\ on the Internet. For more information regarding this permit application you may contact Rob Koenig, Koch Midstream Services Company, 606 S. Shelby Street, Carthage, Texas 75633, Telephone: (903) 693-5172 ext. 2542.





NOTICE OF APPLICATION FOR PIPELINE PERMIT

PennzEnergy Exploration & Production, L.L.C., 4632 W Hwy 180, Snyder, Texas 79549, has applied to the Railroad Commission of Texas for a permit to construct 7.5 miles of 20" buried pipeline in Scurry County, Texas to gather produced gas at the Sharon Ridge Canyon Unit, Tank Battery 5. The gas transported within the proposed gas gathering line will contain concentrations of Hydrogen Sulfide greater than 100 ppm. In the event of a leak, the radius of exposure of Hydrogen Sulfide for 100 ppm could extend 1,577 feet on either side of the pipeline based on methods outlined in 16 Texas Administration Code 3.36. The radius of exposure of Hydrogen Sulfide for 500 ppm could extend 720 feet on either side of the pipeline. The proposed sour gas pipeline will be located in Scurry County as shown on the plat. The pipeline will be constructed and operated in accordance with rules and regulations adopted by the Railroad Commission of Texas specifying construction material and methods for the safe operation of sour gas pipelines. A copy of the application is available at the office of the Scurry County Clerk, located at 1806 25th Street, Snyder, Texas 79549.

Any owner or occupant of land located within the 100 ppm radius of exposure of the proposed sour gas pipeline desiring to protest can do so by mailing or otherwise delivering a letter referring to Gas Utilities Docket Number 8937 and stating their desire to protest:

Docket Services
Office of General Counsel
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

Protests must be received no later than May 1, 1999. It is recommended that a copy of this notice be included with the letter.

(g) Protests. Affected persons have standing to file a protest to an application. In the event the final proposed pipeline route is not known at the time of application, any person who owns or occupies real property located within the area of influence identified in the application shall have standing to file a protest to an application. All such protests shall:

(1) be in writing and filed at the commission no later than the 30th day after the notice is published in a newspaper in the county in which the person filing the protest owns or occupies real property;

(2) state the name, address, and telephone number of every person on whose behalf the protest is being filed; and

(3) include a statement of the facts on which the person filing the protest relies to conclude that each person on whose behalf the protest is being filed is an affected person, as defined in subsection (a)(1) of this section.

(h) Division Review.

(1) Within 14 days of receipt of the application, the commission's designee will provide notice to the applicant that the application is either complete and accepted for filing, or incomplete and specify the additional information required for acceptance. Such notice shall be provided in writing by mail or by electronic mail if the applicant submits with the application a written request that communications regarding application completeness or deficiencies be communicated by electronic mail and provides an accurate electronic mail address. The application shall be completed within 30 days of notification that the application is incomplete or such longer time as may be requested by the applicant, in writing, and approved by the commission's designee. If the application is not completed within the specified time period, the commission's designee shall send notice of intent to deny the application to the applicant. Within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the applicant may request a hearing on the application as it exists at that time. If a request for hearing is not filed within ten days of issuance of a notice of intent to deny the application for failure to complete the application, the application shall be dismissed without prejudice by the commission's designee.

(2) The commission's designee shall make a written recommendation as to whether the materials to be used in and method of construction and operation of a proposed sour gas pipeline facility comply with the rules and safety standards of the commission if the application is not protested, by the latter of the 14th day after the end of the 30-day protest period or the 14th day after the day notice of a complete application is issued.

(3) If, pursuant to subsection (i) of this section, a hearing is held, the staff may introduce evidence relating to the materials to be used in and method of construction and operation of a proposed sour gas pipeline facility.

(4) In determining whether or not the materials to be used in and method of construction and operation of a proposed sour gas pipeline facility comply with the rules and safety standards of the commission, relevant provisions of §3.36 and §3.70 of this title (relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas, and Pipeline Permits Required, respectively) shall be considered. If applicable, Chapter 8 of this title (relating to Pipeline Safety Regulations) shall also be considered.

(5) If no affected person files a protest with the commission by the 30th day after the date notice of application was published, the commission's designee shall either make a written recommendation that the permit be issued, that the permit be granted subject to specific conditions required to ensure compliance with applicable laws and regulations, or that the permit be denied. If the commission's designee recommends that the permit be conditionally granted or be denied, the reasons for such recommendation shall be explained. If the commission's designee recommends that the application be conditionally granted or be denied, the applicant shall have a right to a hearing upon written request received no later than 15 days after the date of issuance of notice of conditional grant or denial.

(i) Hearing.

(1) A hearing shall be convened to consider an application for a sour gas pipeline construction permit if:

(A) a protest is timely filed by an affected person;

(B) a request is timely filed by the applicant; or

(C) the commission so elects on its own motion.

(2) The Office of General Counsel shall assign an examiner who shall conduct a hearing in accordance with the procedural requirements of Texas Government Code, Chapter 2001 (the Administrative Procedure Act), and Chapter 1 of this title (relating to the general rules of practice and procedure).

(3) The commission shall convene a hearing not later than the 60th day after a protest is filed, the applicant submits a request for hearing, or the commission gives notice of intent to convene a hearing on its own motion. If the application is not complete as of the date the request for hearing is filed or notice of hearing issued, the 60-day time period for convening a hearing shall not begin to run until such time as notice of a complete application is issued unless the hearing is held pursuant to the provisions of subsection (h)(1). If the hearing is held pursuant to the provisions of subsection (h)(1), the hearing will be held within 60 days of receipt of a request for hearing.

(4) In any hearing convened to consider an application, the applicant has the burden of showing that the materials to be used in and method of construction and operation comply with the applicable rules and safety standards adopted by the commission.

(j) Order.

(1) An order approving an application shall include a finding that the materials to be used in and method of construction and operation of the facility comply with the applicable rules and safety standards adopted by the commission. If an application meets all the requirements of §3.70 of this title, relating to Pipeline Permits Required, including the requirements of §3.36 of this title, relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas, the order may approve the certificate of compliance (Form H-9) or grant the pipeline permit or both.

(2) An order denying an application shall state the reason or reasons for the denial.

(3) In the case of an application for which a hearing is conducted, the commission will render a decision not later than the 60th day after the date on which the hearing is finally closed.

(4) If no hearing is held on an application, the commission will render a decision as soon as practicable but not later than the 60th day after the staff prepares its written recommendation in accordance with subsection (h)(2) and (4).

Source Note: The provisions of this §3.106 adopted to be effective May 1, 2000, 25 TexReg 3741; amended to be effective November 24, 2004, 29 TexReg 10728.

§3.107 Penalty Guidelines for Oil and Gas Violations

(a) Policy. Improved safety and environmental protection are the desired outcomes of any enforcement action. Encouraging operators to take appropriate voluntary corrective and future protective actions once a violation has occurred is an effective component of the enforcement process. Deterrence of violations through penalty assessments is also a necessary and effective component of the enforcement process. A rule-based enforcement penalty guideline to evaluate and rank oil- and natural gas-related violations is consistent with the central goal of the Commission's enforcement efforts to promote compliance. Penalty guidelines set forth in this section will provide a framework for more uniform and equitable assessment of penalties throughout the state, while also enhancing the integrity of the Commission's enforcement program.

(b) Only guidelines. This section complies with the requirements of Texas Natural Resources Code, §81.0531 and §91.101, which provides the Commission with the authority to adopt rules, enforce rules, and issue permits relating to the prevention of pollution. The penalty amounts shown in the tables in this section are provided solely as guidelines to be considered by the Commission in determining the amount of administrative penalties for violations of provisions of Texas Natural Resources Code, Title 3; Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; or the provisions of a rule adopted or order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29. This rule does not contemplate automatic enforcement. Violations can be corrected by operators before being referred to legal enforcement.

(c) Commission authority. The establishment of these penalty guidelines shall in no way limit the Commission's authority and discretion to cite violations and assess administrative penalties. The guideline minimum penalties listed in this section are for the most common violations cited; however, this is neither an exclusive nor an exhaustive list of violations that the Commission may cite. The Commission retains full authority and discretion to cite violations of Texas Natural Resources Code, Title 3; including Nat. Res. Code §91.101, which provides the Commission with the authority to adopt rules, enforce rules, and issue permits relating to the prevention of pollution; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; and the provisions of a rule adopted or an order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29, and to assess administrative penalties in any amount up to the statutory maximum when warranted by the facts in any case, regardless of inclusion in or omission from this section.

(d) Factors considered. The amount of any penalty requested, recommended, or finally assessed in an enforcement action will be determined on an individual case-by-case basis for each violation, taking into consideration the following factors:

(1) the person's history of previous violations;

(2) the seriousness of the violation;

(3) any hazard to the health or safety of the public; and

(4) the demonstrated good faith of the person charged.

(e) Typical penalties. Regardless of the method by which the guideline typical penalty amount is calculated, the total penalty amount will be within the statutory limit.

(1) A guideline of typical penalties for violations of Texas Natural Resources Code, Title 3; the provisions of Texas Water Code, Chapters 26, 27, and 29, that are administered and enforced by the Commission; and the provisions of a rule adopted or an order, license, permit, or certificate issued under Texas Natural Resources Code, Title 3, or Texas Water Code, Chapters 26, 27, and 29, are

set forth in Table 1.

Table 1. Penalty Guideline

Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty Amount or Range
16 TAC §3.2	Commission denied access	$1,000
16 TAC §3.3	failure to comply with well sign requirements	$500
16 TAC §3.3	failure to comply with entrance sign requirements	$1,000
16 TAC §3.3	failure to comply with tank battery sign requirements	$1,000
16 TAC §3.5(a)	no drilling permit approved	$5,000
16 TAC §3.5(a)	no drilling permit: no application filed	$10,000
16 TAC §3.8(b)	pollution of surface or subsurface water	$1,000 minimum
16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: dry pit area	$500 base penalty plus $0.30/sq. ft.
16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: wet pit area	$500 base penalty plus $0.50/sq. ft.
16 TAC §3.8(d)(2)	use of prohibited pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.
16 TAC §3.8(d)(2)	use of prohibited pits: salt water or other fluid area	$2,500 base plus $0.75 sq. ft.
16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.
16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: salt water or other fluid pit area	$2,500 base plus $0.75 sq. ft.
16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: dry	$2,500
16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: wet	$5,000
16 TAC §3.9(1)	no permit to dispose or inject	$5,000
16 TAC §3.9(9)(A)	failure to comply with tubing and packer requirements	$2,000
16 TAC §3.9(9)(B)	no pressure observation valve	$1,000 per valve
16 TAC §3.9(12)	no test, failed test, or no Form H-5	$5,000
16 TAC §3.13(b)(1)(B)	open casing/tubing	$1,000 to $5,000
16 TAC §3.13(b)(1)(C)	failure to comply with wellhead control requirements	$5,000
16 TAC §3.13(b)(2)	failure to comply with surface casing requirements	$2,000
16 TAC §3.14(a)(2)	failure to file Form W-3A	$2,500
16 TAC §3.14(a)(3)	failure to notify of setting plugs	$1,500
16 TAC §3.14(b)(1)	failure to file Form W-3	$5,000
16 TAC §3.14(b)(2)	failure to plug onshore well	$2,000 plus $1/ft. of total depth
16 TAC §3.14(b)(2)	failure to plug bay, estuary, or inland waterway well	$15,000 plus $2 per foot of total depth, subject to statutory maximum
16 TAC §3.14(b)(2)	failure to plug offshore well	$50,000 plus $5 per foot of total depth, subject to statutory maximum
16 TAC §3.14(d)(1)-(11)	failure to follow general plugging requirement	$1,000
16 TAC §3.14(d)(12)	failure to remove miscellaneous loose junk and trash	$1,000
16 TAC §3.14(d)(12)	failure to remove tanks, vessels, and related piping	$2,500
16 TAC §3.14(d)(12)	failure to empty tanks, vessels, and related piping	$5,000
16 TAC §3.15(l)(7)	failure to test prior to reactivating well	$1,000
16 TAC §3.15(f)(2)(A)	failure to disconnect electricity	$5,000
16 TAC §3.15(f)(2)(A)	failure to purge vessels	$7,500
16 TAC §3.15(f)(2)(A)	failure to remove equipment	$10,000
16 TAC §3.16(b) and (c)	failure to file completion records/logs	$2,500
16 TAC §3.17	Bradenhead violations: no valve; no access; or pressure on it	$1,000 to $2,500
16 TAC §3.20(a)(1)	failure to notify of incident	$2,500 to $5,000
16 TAC §3.21(a)-(i)	improper fire prevention	$1,000
16 TAC §3.21(j)	failure to comply with dike/firewall requirements	$2,500
16 TAC §3.21(k)	swabbing without authority	$1,000 per well
16 TAC §3.21(l)	failure to comply with electric power line requirements	$2,000
16 TAC §3.22	no nets	compliance
16 TAC §3.35(a)	failure to notify of lost logging tool	$5,000
16 TAC §3.35(b)	failure to properly abandon lost logging tool	$5,000
16 TAC §3.36(c)(5)(B)	improper storage tank signs in a non-public area	$1,000
16 TAC §3.36(c)(5)(B)	improper storage tank signs in a public area	$2,000
16 TAC §3.36(c)(6)(A)	improper entry signs in a non-public area	$1,000
16 TAC §3.36(c)(6)(A)	improper entry signs in a public area	$2,000
16 TAC §3.36(c)(6)(A)	improper entry signs in a populated public area	$5,000
16 TAC §3.36(c)(6)(B)	failure to fence specific area at a well	$5,000

As in effect on 12/8/2025.

Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty Amount or Range
16 TAC §3.36(c)(6)(B)	failure to fence specific area at a battery	$10,000
16 TAC §3.36(c)(6)(C)	materials provision	$2,500
16 TAC §3.36(c)(8)	failure to maintain H_2S equipment	$5,000
16 TAC §3.36(c)(9)(Q)	failure to update contingency plan	$2,500
16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	more than 6 hours up to 12 hours-$5,000
16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	12 hours or more-$10,000
16 TAC §3.36(c)(14)	failure to notify of H_2S release	more than 6 hours up to 12 hours-$5,000
16 TAC §3.36(c)(14)	failure to notify of H_2S release	12 hours or more-$10,000
16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; no injury	$5,000
16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; injury or death	$10,000
16 TAC §3.36(c)(12)(F)	failure to notify of drill stem test in H_2S formation	$2,000
16 TAC §3.36(c)(13)	failure to have H_2S trained personnel	$5,000 per person
16 TAC §3.36(d)(1)(E)	failure to file Form H-9; non-public area	$1,000
16 TAC §3.36(d)(1)(E)	failure to file Form H-9; public area	$10,000
16 TAC §3.36(d)(2)	failure to identify well as sour on completion report	$10,000
16 TAC §3.36(d)(3)	intentional failure to file written report of H_2S release	$3,000
16 TAC §3.36(d)(3)	failure to file written report of emergency H_2S release	$5,000
16 TAC §3.46(a)	no permit to dispose or inject	$5,000
16 TAC §3.46(g)(1)	failure to comply with tubing and packer requirements	$2,000
16 TAC §3.46(g)(2)	no pressure observation valve	$1,000 per valve
16 TAC §3.46(j)	no test, failed test, or no Form H-5	$5,000
16 TAC §3.57	reclamation plant operation violation	$1,000
16 TAC §3.65(c), (d), or (f)	failure to file Form CI-D or Form CI-X	$1,000
16 TAC §3.65(g)	failure to provide critical customer information	$2,500
16 TAC §3.73(a)	failure to notify of pipeline connection	$1,000
16 TAC §3.73(h)	reconnecting, transporting from well/lease without approved Form P-4	$1,000 minimum; see Table 1A for additional amount
16 TAC §3.73(j)	reporting, producing, injecting, disposing without approved Form P-4	$1,000 minimum; see Table 1A for additional amount
16 TAC §3.81	failure to comply with brine mining injection well operation requirements	$1,000
16 TAC §3.95	failure to comply with underground salt formation liquid or liquefied hydrocarbon storage facility operation requirements	$2,000
16 TAC §3.96	failure to comply with underground productive or depleted reservoir gas storage facility operation requirements	$2,000
16 TAC §3.97	failure to comply with underground salt formation gas storage facility operation requirements	$2,000
16 TAC §3.98	failure to comply with hazardous waste disposal operation requirements	$2,000
16 TAC §3.99(d)(2)	failure to comply with protection/isolation of usable quality water requirements	$2,500 per well
16 TAC §3.99(e)	failure to comply with cathodic protection well construction requirements	$1,000 per well
16 TAC §3.99(g)	failure to file completion report	$1,000 per well
16 TAC §3.100(d)(2)	failure to permit seismic/core holes penetrating usable quality water	$1,000 per hole
16 TAC §3.100(f)	failure to properly plug seismic/core holes	$1,000 per hole
16 TAC §3.100(g)	failure to file final survey report	$5,000 per survey
16 TAC §3.106(b)	commenced construction of a sour gas pipeline facility without a permit	$10,000
16 TAC §3.106(e)	published notice with egregious errors/omissions	$5,000
16 TAC §3.106(f)	provided pipeline plat with egregious errors/omissions	$5,000
Tex. Nat. Res. Code, §91.143	false filing	$1,000 per form

(2) Guideline penalties for violations of §3.73 of this title, relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance, include additional penalty amounts that are based on four components. In combination, these four components yield the factor by which an additional penalty amount of $1,000 is multiplied. The various combinations of the components are set forth in Table 1A.

(A) The first component is the length of the violation. A low rating means the violation has been in existence less than three months. A medium rating means the violation has been outstanding for more than three months and up to one year. A high rating means the violation has been outstanding for more than one year.

(B) The second component is production value. A low rating means the value of the production is less than $5,000. A medium rating means the value of the production is more than $5,000 and up to $100,000. A high rating means the value of the production is more than $100,000.

(C) The third component is the number of unresolved severances. A low rating means there are fewer than two unresolved severances. A medium rating means there are more than two and up to six unresolved severances. A high rating means there are more than six unresolved severances.

(D) The fourth component is the basis of the severance. The letter "N" indicates that the severance is not pollution related. The letter "Y" indicates that the severance is pollution related.

Table 1A. Calculation of Additional Guideline Penalty Amounts for Violations of 16 Tex. Admin. Code §3.73, relating to Pipeline Connection; Cancellation of Certificate of Compliance; Severance

Length of Violation **Low: < 3 mos.** **Medium:** **High: > 1 yr.**	**Production Value** **Low: < $5,000** **Medium:** **High: > $100,000**	**Unresolved Severances** **Low: < 2** **Medium:** **High: > 6**	**Basis of Severance** **N: non-pollution related** **Y: pollution related**	**Factor**
low	low	low	N	1.0
low	low	medium	N	1.5
low	low	high	N	1.5
low	medium	low	N	1.5
low	medium	medium	N	3.5
low	medium	high	N	5.0
low	high	low	N	4.5
low	high	medium	N	7.0
low	high	high	N	7.5
medium	low	low	N	1.5
medium	low	medium	N	2.5
medium	low	high	N	3.5
medium	medium	low	N	3.5
medium	medium	medium	N	5.0
medium	medium	high	N	8.0
medium	high	low	N	8.5
medium	high	medium	N	9.0
medium	high	high	N	10.0
high	low	low	N	2.5
high	low	medium	N	3.5
high	low	high	N	3.5
high	medium	low	N	4.5
high	medium	medium	N	7.5
high	medium	high	N	8.0
high	high	low	N	10.0
high	high	medium	N	10.0
high	high	high	N	10.0
low	low	low	Y	1.5
low	low	medium	Y	2.0
low	low	high	Y	2.5
low	medium	low	Y	3.0
low	medium	medium	Y	5.0
low	medium	high	Y	7.5
low	high	low	Y	5.0
low	high	medium	Y	8.0
low	high	high	Y	8.5
medium	low	low	Y	2.0
medium	low	medium	Y	3.5
medium	low	high	Y	7.0
medium	medium	low	Y	7.0

Length of Violation Low: < 3 mos. Medium: High: > 1 yr.	Production Value Low: < $5,000 Medium: High: > $100,000	Unresolved Severances Low: < 2 Medium: High: > 6	Basis of Severance N: non-pollution related Y: pollution related	Factor
medium	medium	medium	Y	7.5
medium	medium	high	Y	8.5
medium	high	low	Y	9.0
medium	high	medium	Y	9.5
medium	high	high	Y	10.0
high	low	low	Y	3.0
high	low	medium	Y	4.0
high	low	high	Y	5.0
high	medium	low	Y	5.0
high	medium	medium	Y	8.5
high	medium	high	Y	9.0
high	high	low	Y	10.0
high	high	medium	Y	10.0
high	high	high	Y	10.0

(f) Penalty enhancements for certain violations. For violations that involve threatened or actual pollution; result in threatened or actual safety hazards; or result from the reckless or intentional conduct of the person charged, the Commission may assess an enhancement of the guideline penalty amount. The enhancement may be in any amount in the range shown for each type of violation as shown in Table 2.

Table 2. Penalty Enhancements

Evidentiary Factors	Threatened or Actual Pollution	Safety Hazard	Severity of Violation
Agricultural land or sensitive wildlife habitat	$1,000 to $5,000		
Endangered or threatened species	$2,000 to $10,000		
Bay, estuary or marine habitat	$5,000 to $25,000		
Minor freshwater source (minor aquifer, seasonal watercourse)	$2,500 to $7,500		
Major freshwater source (major aquifer, creeks, rivers, lakes and reservoirs)	$5,000 to $25,000		
Impacted residential/public areas		$1,000 to $15,000	
Hazardous material release		$2,000 to $25,000	
Reportable incident/accident		$5,000 to $25,000	
Well in H_2S field		up to $10,000	
Time out of compliance			$100 to $2,000 / month
Reckless conduct of operator			double total penalty
Intentional conduct of operator			triple total penalty

(g) Penalty enhancements for certain violators. For violations in which the person charged has a history of prior violations within seven years of the current enforcement action, the Commission may assess an enhancement based on either the number of prior violations or the total amount of previous administrative penalties, but not both. The actual amount of any penalty enhancement will be determined on an individual case-by-case basis for each violation. The guidelines in Tables 3 and 4 are intended to be used separately. Either guideline may be used where applicable, but not both.

Table 3. Penalty enhancements based on number of prior violations within seven years

Number of violations in the seven years prior to action	Enhancement amount
One	$1,000
Two	$2,000
Three	$3,000

As in effect on 12/8/2025.

Four	$4,000
Five or more	$5,000

Table 4. Penalty Enhancements based on total amount of prior penalties within seven years

Total administrative penalties assessed in the seven years prior to action	**Enhancement amount**
Less than $10,000	$1,000
Between $10,000 and $25,000	$2,500
Between $25,000 and $50,000	$5,000
Between $50,000 and $100,000	$10,000
Over $100,000	10% of total amount

(h) Penalty reduction for accelerated settlement before hearing. The recommended monetary penalty for a violation may be reduced by up to 50% if the person charged agrees to an accelerated settlement before the Commission conducts an administrative hearing to prosecute a violation. Once the hearing is convened, the opportunity for the person charged to reduce the basic monetary penalty is no longer available. The reduction applies to the basic penalty amount requested and not to any requested enhancements.

(i) Demonstrated good faith. In determining the total amount of any monetary penalty requested, recommended, or finally assessed in an enforcement action, the Commission may consider, on an individual case-by-case basis for each violation, the demonstrated good faith of the person charged. Demonstrated good faith includes, but is not limited to, actions taken by the person charged before the filing of an enforcement action to remedy, in whole or in part, a violation or to mitigate the consequences of a violation.

(j) Penalty calculation worksheet. The penalty calculation worksheet shown in Table 5 lists the guideline minimum penalty amounts for certain violations; the circumstances justifying enhancements of a penalty and the amount of the enhancement; and the circumstances justifying a reduction in a penalty and the amount of the reduction.

Table 5. Penalty Calculation Worksheet

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
1	16 TAC §3.2	Commission denied access	$1,000	$
2	16 TAC §3.3	failure to comply with well sign requirements	$500	$
3	16 TAC §3.3	failure to comply with entrance sign requirements	$1,000	$
4	16 TAC §3.3	failure to comply with tank battery sign requirements	$1,000	$
5	16 TAC §3.5(a)	no drilling permit: filed but not approved	$5,000	$
6	16 TAC §3.5(a)	no drilling permit: no application filed	$10,000	$
7	16 TAC §3.8(b)	pollution of surface or subsurface water	$1,000 minimum	$
8	16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: dry pit area	$500 base penalty plus $0.30/sq. ft.	$
9	16 TAC §3.8(d)(1)	improper disposal of oil and gas waste; enhance for actual or threatened pollution: wet pit area	$500 base penalty plus $0.50/sq. ft.	$
10	16 TAC §3.8(d)(2)	use of prohibited pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.	$
11	16 TAC §3.8(d)(2)	use of prohibited pits: salt water or other fluid area	$2,500 base plus $0.75 sq. ft.	$
12	16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: fresh water pit area	$2,500 base plus $0.25 sq. ft.	$
13	16 TAC §3.8(d)(4)(G)(i)(I), (II)	reserve pits: salt water or other fluid pit area	$2,500 base plus $0.75 sq. ft.	$
14	16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: dry	$2,500	$
15	16 TAC §3.8(d)(4)(G)(i)(III), (IV)	workover and other pits: wet	$5,000	$
16	16 TAC §3.9(1)	no permit to dispose or inject	$5,000	$
17	16 TAC §3.9(9)(A)	failure to comply with tubing and packer requirements	$2,000	$
18	16 TAC §3.9(9)(B)	no pressure observation valve	$1,000 per valve	$
19	16 TAC §3.9(12)	no test, failed test, or no Form H-5	$5,000	$
20	16 TAC §3.13(b)(1)(B)	open casing/tubing	$1,000 to $5,000	$
21	16 TAC §3.13(b)(1)(C)	failure to comply with wellhead control requirements	$5,000	$
22	16 TAC §3.13(b)(2)	failure to comply with surface casing requirements	$2,000	$
23	16 TAC §3.14(a)(2)	failure to file Form W-3A	$2,500	$
24	16 TAC §3.14(a)(3)	failure to notify of setting plugs	$1,500	$
25	16 TAC §3.14(b)(1)	failure to file Form W-3	$5,000	$
26	16 TAC §3.14(b)(2)	failure to plug onshore well	$2,000 plus $1/ft. of total depth	$
27	16 TAC §3.14(b)(2)	failure to plug bay, estuary, or inland waterway well	$15,000 plus $2 per foot of total	$

As in effect on 12/8/2025.

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
			depth, subject to statutory maximum	
28	16 TAC §3.14(b)(2)	failure to plug offshore well	$50,000 plus $5 per foot of total depth, subject to statutory maximum	$
29	16 TAC §3.14(d)(1)-(11)	failure to follow general plugging requirement	$1,000	$
30	16 TAC §3.14(d)(12)	failure to remove miscellaneous loose junk and trash	$1,000	$
31	16 TAC §3.14(d)(12)	failure to remove tanks, vessels, and related piping	$2,500	$
32	16 TAC §3.14(d)(12)	failure to empty tanks, vessels, and related piping	$5,000	$
33	16 TAC §3.15(l)(7)	failure to test prior to reactivating well	$1,000	$
34	16 TAC §3.15(f)(2)(A)	failure to disconnect electricity	$5,000	$
35	16 TAC §3.15(f)(2)(A)	failure to purge vessels	$7,500	$
36	16 TAC §3.15(f)(2)(A)	failure to remove equipment	$10,000	$
37	16 TAC §3.16(b) and (c)	failure to file completion records/logs	$2,500	$
38	16 TAC §3.17	Bradenhead violations: no valve; no access; or pressure on it	$1,000 to $2,500	$
39	16 TAC §3.20(a)(1)	failure to notify of incident	$2,500 to $5,000	$
40	16 TAC §3.21(a)-(i)	improper fire prevention	$1,000	$
41	16 TAC §3.21(j)	failure to comply with dike/firewall requirements	$2,500	$
42	16 TAC §3.21(k)	swabbing without authority	$1,000 per well	$
43	16 TAC §3.21(l)	failure to comply with electric power line requirements	$2,000	$
44	16 TAC §3.22	no nets	compliance	
45	16 TAC §3.35(a)	failure to notify of lost logging tool	$5,000	$
46	16 TAC §3.35(b)	failure to properly abandon lost logging tool	$5,000	$
47	16 TAC §3.36(c)(5)(B)	improper storage tank signs in a non-public area	$1,000	$
48	16 TAC §3.36(c)(5)(B)	improper storage tank signs in a public area	$2,000	$
49	16 TAC §3.36(c)(6)(A)	improper entry signs in a non-public area	$1,000	$
50	16 TAC §3.36(c)(6)(A)	improper entry signs in a public area	$2,000	$
51	16 TAC §3.36(c)(6)(A)	improper entry signs in a populated public area	$5,000	$
52	16 TAC §3.36(c)(6)(B)	failure to fence specific area at a well	$5,000	$
53	16 TAC §3.36(c)(6)(B)	failure to fence specific area at a battery	$10,000	$
54	16 TAC §3.36(c)(6)(C)	materials provision	$2,500	$
55	16 TAC §3.36(c)(8)	failure to maintain H_2S equipment	$5,000	$
56	16 TAC §3.36(c)(9)(Q)	failure to update contingency plan	$2,500	$
57	16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	more than 6 hours up to 12 hours-$5,000	$

As in effect on 12/8/2025.

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
58	16 TAC §3.36(c)(9)(N)	failure to notify of H_2S contingency plan activation	12 hours or more-$10,000	$
59	16 TAC §3.36(c)(14)	failure to notify of H_2S release	more than 6 hours up to 12 hours-$5,000	$
60	16 TAC §3.36(c)(14)	failure to notify of H_2S release	12 hours or more-$10,000	$
61	16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; no injury	$5,000	$
62	16 TAC §3.36(c)(11)-(12), except (12)(F)	failure to follow requirements at drill/workover site; injury or death	$10,000	$
63	16 TAC §3.36(c)(12)(F)	failure to notify of drill stem test in H_2S formation	$2,000	$
64	16 TAC §3.36(c)(13)	failure to have H_2S trained personnel	$5,000 per person	$
65	16 TAC §3.36(d)(1)(E)	failure to file Form H-9; non-public area	$1,000	$
66	16 TAC §3.36(d)(1)(E)	failure to file Form H-9; public area	$10,000	$
67	16 TAC §3.36(d)(2)	failure to identify well as sour on completion report	$10,000	$
68	16 TAC §3.36(d)(3)	intentional failure to file written report of H_2S release	$3,000	$
69	16 TAC §3.36(d)(3)	failure to file written report of emergency H_2S release	$5,000	$
70	16 TAC §3.46(a)	no permit to dispose or inject	$5,000	$
71	16 TAC §3.46(g)(1)	failure to comply with tubing and packer requirements	$2,000	$
72	16 TAC §3.46(g)(2)	no pressure observation valve	$1,000 per valve	$
73	16 TAC §3.46(j)	no test, failed test, or no Form H-5	$5,000	$
74	16 TAC §3.57	reclamation plant operation violation	$1,000	$
75	16 TAC §3.65(c), (d), or (f)	failure to file Form CI-D or Form CI-X	$1,000	$
76	16 TAC §3.65(g)	failure to provide critical customer information	$2,500	$
77	16 TAC §3.73(a)	failure to notify of pipeline connection	$1,000	$
78	16 TAC §3.73(h)	reconnecting, transporting from well/lease without approved Form P-4	$1,000 minimum; see Table 1A for additional amount	$
79	16 TAC §3.73(j)	reporting, producing, injecting, disposing without approved Form P-4	$1,000 minimum; see Table 1A for additional amount	$
80	16 TAC §3.81	failure to comply with brine mining injection well operation requirements	$1,000	$
81	16 TAC §3.95	failure to comply with underground salt formation liquid or liquefied hydrocarbon storage facility operation requirements	$2,000	$
82	16 TAC §3.96	failure to comply with underground productive or depleted reservoir gas storage facility operation requirements	$2,000	$
83	16 TAC §3.97	failure to comply with underground salt formation gas storage facility operation requirements	$2,000	$
84	16 TAC §3.98	failure to comply with hazardous waste disposal operation requirements	$2,000	$
85	16 TAC §3.99(d)(2)	failure to comply with protection/isolation of usable quality water requirements	$2,500 per well	$
86	16 TAC §3.99(e)	failure to comply with cathodic protection well construction requirements	$1,000 per well	$

As in effect on 12/8/2025.

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalty Tally
87	16 TAC §3.99(g)	failure to file completion report	$1,000 per well	$
88	16 TAC §3.100(d)(2)	failure to permit seismic/core holes penetrating usable quality water	$1,000 per hole	$
89	16 TAC §3.100(f)	failure to properly plug seismic/core holes	$1,000 per hole	$
90	16 TAC §3.100(g)	failure to file final survey report	$5,000 per survey	$
91	16 TAC §3.106(b)	commenced construction of a sour gas pipeline facility without a permit	$10,000	$
92	16 TAC §3.106(e)	published notice with egregious errors/omissions	$5,000	$
93	16 TAC §3.106(f)	provided pipeline plat with egregious errors/omissions	$5,000	$
94	Tex. Nat. Res. Code, §91.143	false filing	$1,000 per form	$
95	Tex. Nat. Res. Code, §89.029	false filing	$1,000 to $25,000	$
96	**Subtotal of guideline penalty amounts from Table 1 (lines 1-95, inclusive)**			$
97	**Reduction for settlement before hearing: up to 50% of line 96 amt.**		________%	$
98	**Subtotal: amount shown on line 96 less applicable settlement reduction on line 97**			$
	Penalty enhancement amounts for threatened or actual pollution from Table 2			
99	Agricultural land or sensitive wildlife habitat		$1,000 to $5,000	$
100	Endangered or threatened species		$2,000 to $10,000	$
101	Bay, estuary or marine habitat		$5,000 to $25,000	$
102	Minor freshwater source (minor aquifer, seasonal watercourse)		$2,500 to $7,500	$
103	Major freshwater source (major aquifer, creeks, rivers, lakes and reservoirs)		$5,000 to $25,000	$
	Penalty enhancement amounts for safety hazard from Table 2			
104	Impacted residential/public areas		$1,000 to $15,000	$
105	Hazardous material release		$2,000 to $25,000	$
106	Reportable incident/accident		$5,000 to $25,000	$
107	Well in H_2S field		up to $10,000	$
	Penalty enhancement amounts for severity of violation from Table 2			
108	Time out of compliance		$100 to $2,000 each month	$
109	**Subtotal: amount shown on line 98 plus all amounts on lines 99 through 108, inclusive**			$
	Penalty enhancements for culpability of person charged from Table 2			
110	Reckless conduct of operator		double line 108 amount	$
111	Intentional conduct of operator		triple line 108 amount	$
	Penalty enhancements for number of prior violations within past seven years from Table 3			
112	One		$1,000	$
113	Two		$2,000	$

As in effect on 12/8/2025.

	Oil & Gas Rule/Statute	General Description	Guideline Minimum Penalty from Table 1	Penalt y Tally
114	Three		$3,000	$
115	Four		$4,000	$
116	Five or more		$5,000	$
Penalty enhancements for amount of penalties within past seven years from Table 4				
117	Less than $10,000		$1,000	$
118	Between $10,000 and $25,000		$2,500	$
119	Between $25, 000 and $50,000		$5,000	$
120	Between $50,000 and $100,00		$10,000	$
121	Over $100,000		10% of total amt.	$
122	**Subtotal: Line 98 amt. plus amts. on line 110 and/or 111 plus the amt. shown on any line from 112 through 121, inclusive**			$
123	**Reduction for demonstrated good faith of person charged**			$
124	**TOTAL PENALTY AMOUNT: amount on line 122 less any amount shown on line 123**			$

Source Note: The provisions of this §3.107 adopted to be effective August 27, 2012, 37 TexReg 6540; amended to be effective December 20, 2021, 46 TexReg 8688;amended to be effective December 8, 2025, 50 TexReg 7882.

Figure: 16 TAC §3.66(g)(1)

Classification System

<table>
<tr><th colspan="2">Violation Factors</th><th>Factor Value</th><th>Points Tally</th></tr>
<tr><td colspan="2">Oil lease or gas well facility out of compliance with §3.66 produces an average of 5,000 Mcf or more of natural gas per day</td><td>4</td><td></td></tr>
<tr><td colspan="2">Oil lease or gas well facility out of compliance with §3.66 produces an average of 1,000 Mcf or more per day but less than 5,000 Mcf of natural gas per day</td><td>3</td><td></td></tr>
<tr><td colspan="2">Oil lease or gas well facility out of compliance with §3.66 produces an average of 500 Mcf or more per day but less than 1,000 Mcf of natural gas per day</td><td>2</td><td></td></tr>
<tr><td colspan="2">Oil lease or gas well facility out of compliance with §3.66 produces an average of 250 Mcf or more per day but less than 500 Mcf of natural gas per day</td><td>1</td><td></td></tr>
<tr><td colspan="2">Gas processing plant, underground gas storage, or gas pipeline facility out of compliance with §3.66 that resulting in a loss of processing, storage withdrawal, or transportation of 200 MMcf or more of natural gas per day</td><td>4</td><td></td></tr>
<tr><td colspan="2">Gas processing plant, underground gas storage, or gas pipeline facility out of compliance with §3.66 that results in a loss of processing, storage withdrawal, or transportation capacity 100 MMcf or more per day but less than 200 MMcf of natural gas per day</td><td>3</td><td></td></tr>
<tr><td colspan="2">Gas processing plant, underground gas storage, or gas pipeline facility out of compliance with §3.66 that results in a loss of processing, storage withdrawal, or transportation capacity of less than 100 MMcf of natural gas per day</td><td>2</td><td></td></tr>
<tr><td colspan="2">Actual Hazard to health, safety, or economic welfare of the public</td><td>5</td><td></td></tr>
<tr><td colspan="2">Potential hazard to health, safety, or economic welfare of the public</td><td>2</td><td></td></tr>
<tr><td rowspan="4">Time out of compliance (calculated as days the operator fails to remedy a violation noted in a Commission notice of violation)</td><td>90 days or greater</td><td>4</td><td></td></tr>
<tr><td>60 days or more but less than 90 days</td><td>3</td><td></td></tr>
<tr><td>30 days or more but less than 60 days</td><td>2</td><td></td></tr>
<tr><td>5 days or more but less than 30 days</td><td>1</td><td></td></tr>
<tr><td colspan="2">Reckless conduct of operator</td><td>3</td><td></td></tr>
<tr><td colspan="2">Intentional conduct of operator</td><td>5</td><td></td></tr>
<tr><td colspan="2">Repeat violations based on operator's history of compliance</td><td>3</td><td></td></tr>
<tr><td colspan="2">Good faith effort to remedy violation</td><td>-2</td><td></td></tr>
<tr><td colspan="2">No effort to remedy violation</td><td>5</td><td></td></tr>
<tr><td colspan="2">During the weather emergency in which the facility's violation occurred, the operator had no reduction in the natural gas supplied to the Texas electricity supply chain</td><td>-3</td><td></td></tr>
</table>

As in effect on 12/8/2025.

During the weather emergency in which the facility's violation occurred, the operator of a saltwater disposal well had no reduction in saltwater disposal capacity made available to Texas electricity supply chain facilities.	-3	
		Total
		Penalty maximum per violation
15 points or more = Class A violation		$More than 5,000[1]
10-14 points = Class B violation		$5,000
5-9 points = Class C violation		$4,000
1-4 points = Class D violation		$3,000

[1] Pursuant to Natural Resources Code §86.222, the required classification system shall provide that a penalty in an amount that exceeds $5,000 may be recovered only if the violation is included in the highest class of violations in the classification system.

As in effect on 12/8/2025.