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Oil and Gas Regulatory Update

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RULE A-2: GENERAL HEARING PROCEDURES

a) Execution and Filing

1) All applications, except for applications filed by the Director, shall be in writing and state the interests of the application and the general nature of the order requested. Fourteen copies of the application, including exhibits, shall be filed with the Commission Director’s office located in Little Rock, Arkansas (“Director’s Office”). The application shall be deemed filed when it is received by the Director’s Office.

2) All fourteen (14) copies of the applications, including exhibits, except for those filed by the Director, must be received in the Director’s Office at least twenty (20) days prior to the first day of regularly scheduled hearing. If the applicant or his/her representative files an electronic version (a .pdf file labeled by the assigned docket number) of the application, including exhibits, on an electronic storage device approved by the Director a minimum of twenty (20) days prior to the first day of the regularly scheduled hearing, the fourteen (14) copies of the applications, including exhibits must be received in the Director’s office eighteen (18) days prior to the first day of the regularly scheduled hearing.

3) Every application shall be signed by the applicant or his/her representative and his/her address shall be stated thereon. The signature of the applicant or his/her representative constitutes a certificate by him/her that he/she has read the petition and that to the best of his/her knowledge, information and belief there is good ground to support the same.

4) Unless otherwise provided by General Rule of the Commission, each application, except for applications filed by the Director, shall be accompanied by a five hundred dollar ($500.00) filing fee made payable to the Arkansas Oil and Gas Commission.

5) The applicant shall also submit a check payable to the Arkansas Oil and Gas Commission in an amount approved by the Commission, not to exceed two dollars ($2.00) per name of persons named in the application, whose address are known as well as addresses for other persons that the applicant seeks to provide a copy of the order. The applicant shall also provide mailing labels for each person named in the application whose address is known, as well as any other person that the applicant seeks to provide a copy of the order. If the address of the person is unknown, the Applicant shall provide a statement to that affect. All mailing labels shall be provided within three (3) days after the date of the hearing.

6) If after the application is filed, and prior to the hearing date, the Director finds the application deficient relative to the requirements of subsections a) 1) through 4) above, the Director shall return the application to the applicant with a statement as to the deficiencies.

7) If after the application is filed, and prior to the hearing date, the Director determines that additional facts, data, records, or other information are necessary to fully evaluate the application, the Director may require the applicant to submit such necessary facts, data, records or other information.

8) Amendments may be filed at the time of the hearing. However, any amendments filed prior to the hearing date shall be submitted at least ten (10) days prior to the hearing date, and contain a written statement or a clear indication as to what the amendment is being amended. Any application that is substantially amended, as determined by the
Commission, regardless of the time of the amendment, may be continued until the next hearing of the Commission.

b) Notice of Hearing

1) The Applicant shall prepare a notice of hearing which shall be issued in the name of the Arkansas Oil and Gas Commission. Such notice shall include a statement pertaining to the legal authority for the hearing; the name of the applicant; the legal description of the property or unit; a statement of the requested action; a listing of interested parties; the time, date and location of the hearing; the Commission assigned docket number; and the contact information of the Commission offices. The notice shall also state that any interested person may file an entry of appearance in the hearing by submitting such entry of appearance in writing to the Hearing Officer or Director, and that thereafter such person shall be deemed a party of record in the proceeding.

2) Unless otherwise provided by the Brine Act found in Ark. Code Ann. § 15-76-201 et. seq. or General Rule of the Commission, the Applicant shall serve such notice in the following manner:

A) By mailing such notice by U.S. Postal service, first-class mail, directed to all interested parties at their last known addresses at least ten (10) days prior to the date of the hearing, but not more than thirty (30) days prior to the date of the hearing; and

B) By publication of such notice for at least one (1) day, with the notice appearing at least ten (10) days prior to the date of the hearing, but not more than thirty (30) days prior to the date of the hearing, in the newspaper of general circulation published in each county containing some portion of the land identified in the application.

c) Emergency Hearings

In the event an emergency is found to exist by the Commission which in its judgment requires the making, changing, renewal or extension of an order, special rule, or regulation, without first having a hearing, such emergency order shall have the same validity as if a hearing with respect to the same had been held after due notice. The emergency order permitted by this section shall remain in force until the date of the next regular Commission hearing set to be held after the emergency rule, regulation or order was issued, or sixty days from its effective date in accordance with the Brine Act found in Ark. Code Ann. § 15-76-307, and, in any event, it shall expire when any order made after due notice and hearing with respect to the subject matter of such emergency order becomes effective.

d) Pre-Hearing Conferences

1) Upon his/her own motion, or the motion of a party of record, the Hearing Officer, as designated by the Commission, may convene a meeting of the parties or their counsel in order to:

A) Simplify the factual and legal issues presented by the hearing request;

B) Receive stipulations, admissions of fact and the contents and authenticity of documents;
C) Exchange lists of witnesses the parties intend to have testify and copies of all documents the parties intend to introduce into evidence at the hearing; and

D) Discuss and resolve such other matters as may tend to expedite the disposition of the hearing request and to assure a just conclusion thereof.

2) Pre-hearing conferences may be held by telephone conference if such procedure is acceptable to all parties.

e) Hearings

1) Every hearing shall be held on a date and at a location established by the Commission, and conducted by a Hearing Officer designated by the Commission. The Hearing Officer shall take all necessary actions to avoid delay, to maintain order and to develop a clear and complete record, and shall have all powers necessary and appropriate to conduct a fair hearing and to render a decision on the petition, including but not limited to the following:

A) To administer oaths and affirmations;

B) To receive relevant evidence;

C) To regulate the course of the hearing and the conduct of the parties and their counsel therein;

D) To consider and rule upon procedural requests;

E) To examine witnesses and direct witnesses to testify, limit the number of times any witness may testify, limit repetitive or cumulative testimony and set reasonable limits on the amount of time each witness may testify; and

(F) To require the production of documents or subpoena the appearance of witnesses, either on the Hearing Officer's own motion or for good cause shown on motion of any party of record. The Hearing Officer may require that relevant documents be produced to any party of record on his/her own motion or for good cause shown on motion of any party of record.

2) Every person appearing shall enter his/her appearance by stating his/her name and address. Thereafter, such person shall be deemed a party of record.

3) All participants in the hearing shall have the right to be represented by an attorney licensed to practice law in the State of Arkansas. An attorney appearing in a representative capacity in any proceeding hereunder shall file a written notice of appearance identifying his or her name, address and telephone number, and identifying the party represented.

4) The Hearing Officer shall allow all parties to present statements, testimony, evidence and argument as may be relevant to the proceeding.

5) The Director, or his/her designee, may appear at any public hearing and shall have the opportunity to question parties or otherwise elicit such information as is necessary to reach a decision on the application.
GENERAL RULES AND REGULATIONS

6) Preliminary Matters: Where applicable, the following shall be addressed prior to receiving evidence:

A) The applicant may offer preliminary exhibits, including documents necessary to present the issues to be heard, notices, proof of publication and orders previously entered in the cause.

B) Rulings may be made by the Hearing Officer on any pending motions.

C) Any other preliminary matters appropriate for disposition prior to presentation of evidence.

7) Every hearing shall be conducted in accordance with the Commission’s rules and applicable laws of this State.

f) Evidence

1) Admissibility: A party shall be entitled to present his/her case by oral or documentary evidence, to submit rebuttal evidence, and to conduct such cross-examination as may be required for a full and true disclosure of the facts. Any oral or documentary evidence may be received, but the presiding Hearing Officer may exclude evidence which is irrelevant, immaterial or unduly prejudicial or repetitious. However, the erroneous ruling on the admissibility of evidence shall not of itself invalidate any rule, regulation or order.

2) Official Notice: Official notice may be taken of any material fact not appearing in evidence in the record if the circuit courts of this State could take judicial notice of such fact. In addition, notice may be taken of generally recognized technical or scientific facts within the Commission’s specialized knowledge.

3) Order of Proof: The applicant shall open the proof. Other parties of record shall be heard immediately following the petitioner. The Hearing Officer or Director or his/her designee, as well as any Commissioner may examine any witnesses. In all cases, the Hearing Officer shall designate the order of proof and may limit the scope of examination or cross-examination.

4) Briefs: The Hearing Officer may require or allow parties to submit written briefs to the Hearing Officer within 10 days after the close of the hearing or within such other time as the Hearing Officer shall determine as being consistent with the Commission’s responsibility for an expeditious decision.

g) Recording of Proceedings; Testimony

The Commission shall provide a certified court reporter to take down the testimony and preserve a record of all proceedings at the hearing. Any person testifying shall be required to do so under oath. However, relevant unsworn statements, comments and observations by any interested person may be heard and considered by the Commission as such and included in the record.

h) Postponement or Continuance of Hearing

Any hearing may be postponed or continued for due cause by the Hearing Officer upon his/her own motion or upon the motion of a party to the hearing. A motion filed by a party to the hearing shall set forth facts attesting that the request for continuance is not solely for the purpose of delay. All parties involved in a hearing shall avoid undue delay caused by repetitive postponements or
continuances so that the subject matter of the hearing may be resolved expeditiously. The Applicant may postpone or continue the hearing of an application for three consecutive regularly scheduled Commission meetings without prior approval of the Hearing Officer. After the third consecutive postponement, the application shall be dismissed, unless the Hearing Officer allows an exception for due cause, and the applicant shall be required to re-file in accordance with applicable General Rules in order for an application to be scheduled for a hearing.

i) Default

If a party, after proper service of notice, fails to appear at the pre-hearing conference or at a hearing, and if no continuance is granted, the Commission may then proceed to make its decision in the absence of such party. If the failure to appear at such pre-hearing conference or hearing is due to an emergency situation beyond the parties' control, and the Commission is notified of such situation on or before the scheduled pre-hearing conference or hearing, the Hearing Officer may continue or post-pone the pre-hearing conference or hearing. Emergency situations include sudden unavailability of counsel, sudden illness of a party or his representative, or similar situations beyond the parties' control.

j) Voting

1) In order for the Commission to adopt a motion approving an application as applied for, or as amended by either the applicant or a Commissioner, there must be:

A) A quorum present;

B) A majority of the votes cast must be in favor of the motion outlining the proposed order; and

C) At least five (5) votes cast must be in favor of the motion outlining the proposed order.

2) If a motion approving the application as applied for, or as modified by either the applicant or a Commissioner does not receive the votes required in subparagraphs i) A) through C) above, and no subsequent or substitute motion receives the votes required in subparagraphs i) A) through C) above, then the application shall be deemed to be denied by the Commission.

3) If an application is deemed to be denied by the Commission in accordance with subparagraph i) 2) above, the Commission shall enter an order of denial, which may be appealed as a final decision under the Arkansas Administrative Procedures Act found in Ark. Code Ann. § 25-15-201 et. seq.

4) Nothing in this subparagraph shall limit the Commission’s authority to continue any application for due cause.

k) Commission’s Order--Final Administrative Decision

Within 30 days of the close of the hearing record, the Commission shall issue findings of fact, conclusions of law and final administrative decision of the Commission signed by the Director. The Commission shall have continuing jurisdiction for the purposes of enforcement, and/or modifications or amendments to the provisions of all orders. Any appeals shall be governed by the Administrative Procedures Act found in Ark. Code Ann. § 25-15-201 et. seq.
l) Notice of Order--Recordation

Within 30 days after an order has been issued, a copy of such order shall be mailed by the Commission to each interested party at his/her last known address or his/her attorney of record, and filed in accordance with the Administrative Procedures Act found in Ark. Code Ann. § 25-15-201 et. seq.

m) Official Record

In every case of adjudication, the official record shall be compiled in accordance with the Administrative Procedures Act found in Ark. Code Ann. § 25-15-201 et. seq.

RULE A-3: ADDITIONAL REQUIREMENTS FOR SPECIFIC TYPES OF HEARINGS

a) Abandoned Well and Emergency Response Hearings

1) Unless otherwise specified below, General Rule A-2 shall apply to all abandoned well and emergency response hearing proceedings pursuant to Ark. Code Ann. § 15-72-217.

2) The Director shall only provide notice to the permit holder named in the application, in accordance with General Rule A-2 (b) (2).

3) The Director shall have the burden of proof at the hearing. A decision shall be supported by a substantial evidence standard.

b) Integration Hearings

1) Unless otherwise specified below, General Rule A-2 shall apply to all drilling unit integration proceedings.

2) Commencement of Action

Where the oil or gas rights within a drilling unit are separately owned and the owners of those rights have not voluntarily agreed to integrate or pool those rights to develop the oil or gas, an owner may petition the Commission for an order integrating those rights, pursuant to Ark. Code Ann. § 15-72-302 and §15-72-303. The application for an order integrating interests shall contain the following:

A) The name and address of the applicant;

B) The applicant’s reasons for desiring to integrate the separately owned interests;

C) A legal land description of the drilling unit sought to be established;

D) A geologic report of the area where the proposed drilling unit is to be located indicating the potential presence of reservoirs;

E) If the application is for the integration of an exploratory drilling unit, as contemplated by Ark. Code Ann. § 15-72-302:

   i) the names of all owners named in the application who have not agreed to integrate their interests in the right to drill and produce oil or gas, or both, in the proposed drilling unit as of the date of filing the petition, as disclosed by the records in the office of the clerk for the county or counties in which the drilling unit is situated, and;

   ii) a statement that the persons who own at least an undivided fifty percent (50%) interest in the right to drill and produce oil or gas or both, from the total proposed unit agree thereto at the time of the filing of the application;

F) If the application is for the integration of an established drilling unit, as contemplated by Ark. Code Ann. § 15-72-303, and created in accordance with applicable Commission Orders or General Rules; the names of all owners named in the application who have not agreed to integrate their interests in the right to
drill and produce oil or gas, or both, in the proposed drilling unit as of the date of filing the petition, as disclosed by the records in the office of the clerk for the county or counties in which the drilling unit is situated;

G) Unleased mineral owners.

i) A resume of efforts showing that the applicant has exercised due diligence, to locate each unleased mineral owner, and that a bona fide effort was made to reach an agreement with each owner as to how the unit would be developed, as follows:

aa) Due diligence, regarding non-industry owners (persons who are not actively involved in the oil and gas business) means, except for good cause shown, to be determined at the discretion of the Commission, that the Applicant attempted to contact said owners and that bona fide efforts to reach an agreement commenced at least sixty (60) days prior to the date of the hearing; and that there are sufficient contacts to show that the Applicant has exhausted all reasonable efforts to reach an agreement. However, the Applicant shall not be required to contact an owner that the Applicant is precluded by law from contacting, or an owner who has expressly stated that the Applicant is not to contact said owner.

bb) Due diligence, regarding industry owners (person who as an active business practice are involved in the oil and gas business) means that the Applicant has provided industry owners notice, including an Authorization for Expenditure (“AFE”) and Well Proposal, prior to filing the integration application.

ii) An affidavit indicating what the highest and/or best cash bonus and royalty terms that the Applicant has knowledge of that have been offered and accepted, or contracted for, for any acreage within the unit(s) where the well is located (as defined in Section (a)(2) of General Rule B-3), including any acreage within the unit(s) subject to leases or other agreements with a fee mineral owner covering lands located in more than one unit. If this information changes prior to the hearing, the Applicant shall inform the Commission of any changes. If no affidavit is provided prior to or at the time of the hearing, the Applicant shall provide sworn testimony as to the highest and/or best cash bonus and royalty terms that the Applicant has knowledge of that have been offered and accepted, or contracted for, for any acreage within the unit(s) where the well is located (as defined in Section (a)(2) of General Rule B-3), including any acreage within the unit(s) subject to leases or other agreements with a fee mineral owner covering lands located in more than one unit.

H) Uncommitted Leasehold Working Interest Owners.

A resume of efforts showing that the applicant has exercised due diligence, to locate each uncommitted leasehold working interest owner and that a bona fide effort, was made to reach an agreement with each owner as to how the unit would be developed, by providing the uncommitted leasehold working interest owners
notice, including an AFE and Well Proposal, prior to filing the integration application.

I) Any other information relevant to protect correlative rights of the parties sought to be affected by the order.

c) Appeal of Director’s Decision.

1) Any interested party may appeal a permit denial, any enforcement action, or rule interpretation decision made by the Director to the Commission.

2) Unless otherwise specified below, General Rule A-2 shall apply to all hearings requested to appeal a decision of the Director.

3) The application to appeal a Director’s decision shall be accompanied by a two hundred and fifty dollar ($250.00) filing fee.

d) Exceptional Well Location

1) Unless otherwise specified below, General Rule A-2 shall apply to all hearings for an application which has been referred to the Commission in accordance with General Rule B-40, or for which General Rule B-40 is not applicable.

2) The application shall include proof of notice to each owner within the unit in which the well is located and within the units offsetting the boundary line or lines, or in the case of wells in uncontrolled fields within the boundaries of mineral lease lines and the offsetting lease(s), which shall be encroached upon by the exceptional well location.

3) If the application has been referred to the Commission in accordance with General Rule B-40, no application fee is required to be submitted with the application.

e) Authority to Commingle and Additional Completions

1) Unless otherwise specified below, General Rule A-2 shall apply to all hearings for which the applicant has requested a hearing for an application which has been denied in accordance with General Rule D-18 or General Rule D-19, or for which General Rules D-18 or D-19 are not applicable.

2) If the applicant requests the hearing in accordance with General Rule D-18, the application shall include proof of notice to all offset operators in all adjacent units.

3) If the applicant requests the hearing in accordance with General Rule D-19, the application shall include proof of notice to all working interest owners in the subject unit and all offset operators in all adjacent established units including all working interest owners in the offset unit where the operator is the same as the applicant.

f) Establishment of Field Rules

1) Unless otherwise specified below, General Rule A-2 shall apply to all hearings for the creation of field rules, as provided by General Rule B-38.
2) The application shall include proof of notice to each owner, as defined in Ark. Code Ann. § 15-72-102 (9), within the proposed unit(s) in which the well(s) is/are located and within all units offsetting the boundary line or lines of the proposed unit(s).

3) The application shall include a geologic report of the proposed field, specifying the geologic setting of the proposed field and including at a minimum a completion report of the discovery and other wells located within the proposed field, a type geophysical log from a well(s) in the proposed field and a structure and isopach map of the productive zone(s) within the proposed field.

(Source: 1991 rule book; amended April 13, 2008; amended December 14, 2008; amended July 17, 2009)
RULE A-5: ENFORCEMENT PROCEDURES

a) Definitions:

1) “Commission” shall mean the Arkansas Oil and Gas Commission, on which the Director serves as secretary, but is a non-voting member.

2) “Director” shall mean the Commission Director of Production and Conservation.

3) “Regulated Entity” shall mean all operators, owners, producers or persons subject to Commission regulatory authority.

4) “UIC” shall mean the Underground Injection Control program of the Federal Safe Drinking Water Act.

b) Any regulated entity engaged in the drilling, operation or plugging of any production, injection, or other well or drill hole regulated by the Commission; or the operation of any crude oil or gas production or injection facility; or the operation of any natural gas line or crude oil flowline regulated by the Commission; or transporter by tank truck of any oilfield production or completion fluid; or seismic activity; or any other activity regulated by the Commission, is subject to this rule for violation of any oil, gas and/or brine statutes, or any rule, regulation, or permit condition of the Commission.

c) In accordance with Ark. Code Ann. § 15-72-103(c) or § 15-76-303(c), any person knowingly and willfully aiding or abetting any other person in the violation of any statute relating to the conservation of oil, gas and/or brine, or the violation of any provision of the state oil, gas and/or brine statutes, or any rule, regulation, order, or permit condition, shall be subject to the same penalties as are prescribed herein for the regulated entity.

d) Notice of Non-Compliance

1) A Notice of Non-Compliance may be issued when any regulated entity is in non-compliance with any requirement of the Arkansas oil, gas and/or brine statutes, or rules, regulations, orders, or any permit condition, and:

   A) That the non-compliance was not caused by the regulated entity’s deliberate action;

   B) That any action necessary to abate the non-compliance was commenced immediately and was or will be completed within a specified date certain, as established by the Director, or his or her designee, not to exceed thirty (30) days from the date of the determination that the regulated entity was determined to be in non-compliance; and

   C) That the non-compliance has not caused and cannot reasonably be expected to cause significant environmental harm or damage to property.
2) The notice of non-compliance shall be documented in writing and, delivered via first class mail to the regulated entity or to the regulated entity’s representative as reported on the AOGC Form 1 Organization Report. The written notification shall indicate the nature and circumstances of the non-compliance, and the time within which and the means by which the non-compliance is to be abated.

3) If abatement was not completed as specified in the written notification, the Director, or his or her designee, may issue a formal Notice of Violation in accordance with subparagraph (e) below.

4) The provisions of this subparagraph (d), shall not apply to the following types of incidents, which may require a Notice of Violation to be issued in accordance with subparagraph (e) below:

   A) Conducting any regulated activity specified in paragraph (b) above prior to issuance or re-issuance of the appropriate Commission permit or authority;

   B) Operating an annular or casing injection/disposal well or a well with pressure on the annulus;

   C) Failure to maintain required performance bond or pay annual well fees;

   D) Failure to establish mechanical integrity on any UIC well prior to operation, or failure to repair any UIC well following failure of mechanical integrity;

   E) Commencing any work or activity on a well or its related production facility or well site that has been placed in the Abandoned and Orphan Well Plugging Program;

   F) Failure to provide emergency response for a crude oil or saltwater spill;

   G) Improper discharge or disposal of produced fluids; or

   H) Operating a well in violation of spacing requirements or permit conditions.

e) Notice of Violation(s)

1) A Notice of Violation may be issued, by the Director or his or her designee, when any regulated entity is in violation of any requirements of the Arkansas oil, gas, and/or brine statutes, or rules, regulations, orders, or any permit conditions of the Commission. Unless otherwise determined by the Commission after notice and a hearing, a regulated entity shall not be held responsible by the Commission for violations of oil, gas and/or brine statutes, or rules, regulations, or permit conditions of the Commission in the absence of the issuance of an underlying Notice of Violation.

2) The Notice of Violation shall be in writing and contain:

   A) A statement regarding the nature of the violation, including a citation to the specific section of the oil, gas and/or brine statutes, or any rule, regulation, order or permit condition of the Commission alleged to have been violated;
B) The suggested action needed to abate the violation including any appropriate remedial measures to prevent future violations;

C) The time within which the violation should be abated; and

D) A notice of any civil penalties, as specified in subparagraph g) below, the Director will request to be issued by the Commission.

E) A notice of any civil penalties for violations of natural gas line regulations under United States Department of Transportation, Office of Pipeline Safety jurisdiction in accordance with appropriate federal regulation specified in 49 CFR 190.223, the Director will request to be issued by the Commission.

3) The Notice of Violation may include a well, lease, or unit cessation requirement for the following types of violations:

A) Violation of production allowable;

B) Failure to maintain required well specific performance bond;

C) Drilling or operating, without a Commission permit or permit transfer, a well required to be permitted or transferred;

D) Operating a well that has been determined to be abandoned by the Commission;

E) Failure to plug a leaking well or a well ordered to be plugged by the Commission;

F) Operating an annular or casing injection/disposal well;

G) Operating a UIC Class II or V well with a failed mechanical integrity test;

H) Operating a UIC Class II or V well with pressure on the annulus indicating tubing and/or casing failure;

I) Failure to provide emergency response or remediate a crude oil or produced water spill;

J) Improper disposal or discharge of produced fluids; or

K) Any other violation for which a cessation requirement is authorized by an oil, gas and/or brine statute, or rule, regulation, order or permit condition.

4) The Notice of Violation may also include a state-wide cessation requirement for the following types of violations:

A) Failure to maintain required blanket financial assurance as specified in General Rule B-2;

B) Failure to pay annual well fees as specified in General Rule B-2;
C) Failure to pay any monies due the Abandoned and Orphaned Well Plugging Fund as specified in General Rule G-1; or

D) Failure to comply with the provisions of General Rule B-42, or General Rule E-3.

E) Any other violation for which a state-wide cessation requirement is authorized by an oil, gas and/or brine statute, or rule, regulation, order or permit condition.

5) The Director, or his or her designee, shall send via certified mail the Notice of Violation to the regulated entity, or the regulated entity’s representative as reported on the AOGC Form 1 Organization Report, charged with the violation(s), or provide personal delivery of a copy of the notice to the regulated entity, or the regulated entity’s representative.

6) The regulated entity charged with the violation(s) may request a Director’s Review of the Notice of Violation and provide the Director, in writing, any information in mitigation of the violation(s) on or before thirty (30) calendar days of the mailing or personal delivery of the original Notice of Violation, unless a shorter time period is specified in the Notice of Violation for instances where there is a condition that creates an imminent danger to the health or safety of the public or threatens significant environmental harm or damage to the property. Such written information may include a proposed alternative to the required action needed to abate the violation(s). Upon receipt of such information from the regulated entity, the Director, shall conduct a review.

7) During the review, the Director may consider any of the following criteria in reaching a Final Director’s Decision regarding the violation(s):

A) The regulated entity’s history of previous violations, including violations at other locations and under other permits;

B) The seriousness of the violation, including any irreparable harm to the environment or damage to property;

C) The degree of culpability of the regulated entity; and

D) The existence of any additional conditions or factors in aggravation or mitigation of the violation, including information provided by the regulated entity.

8) Upon completion of the review, the Director shall issue a Final Director’s Decision to:

A) affirm the violation; or

B) vacate the violation; or

C) amend or modify the type of violation and abatement requirements specified in the violation; or

D) establish probationary or permanent modification or conditions to any underlying permit related to the violation, which may include special monitoring or reporting requirements; or
E) enter into a settlement agreement to extend the amount of time provided to complete remedial actions necessary to abate the violations or reduce the amount of the requested assessed civil penalty.

9) The Final Director’s Decision shall be delivered to the regulated entity, or the regulated entity’s representative, as reported on the AOGC Form 1 Organization Report, via first class mail. The Final Director’s Decision may be appealed to the Commission by filing an application in accordance with General Rule A-2, A-3, and other applicable hearing procedures. The application to appeal the Final Director’s Decision is required to be received by the Director within thirty (30) days of the mailing of the Final Director’s Decision. The application shall state the reason for the appeal and shall be scheduled to be heard by the Commission in accordance with General Rule A-2, A-3, and other applicable hearing procedures.

10) A Notice of Violation for which a Director’s Review has not been requested, shall become a final administrative decision of the Commission thirty (30) days following the mailing of the Notice of Violation.

11) A Final Director’s Decision not appealed to the Commission within thirty (30) days of mailing of the Final Director’s Decision shall become a final administrative decision of the Commission.

12) All violations specified in a Notice of Violation(s) which have become a final administrative decision in accordance with subparagraph e) 10), a Final Director’s Decision which has become a final administrative decision of the Commission in accordance with subparagraph e) 11), or by Order of the Commission, shall be fully abated within the time frame specified in the original Notice of Violation, Final Director’s Decision, or Order of the Commission. No further permits or authorities shall be issued to the regulated entity until all outstanding violations specified in a Notice of Violation which has become a final administrative decision in accordance with subparagraph e) 10), a Final Director’s Decision which has become a final administrative decision of the Commission in accordance with subparagraph e) 11), or by Order of the Commission have been fully abated.

f) In addition to the issuance of a Notice of Violation(s), the Director may initiate further enforcement proceedings, as provided for in statute, as follows:


2) The revocation of a certificate of clearance on a state-wide basis, as provided for in Ark. Code Ann. § 15-71-110 (11);

3) The filing of a civil complaint in a court of competent jurisdiction in the County where the violation occurred, as provided for in Ark. Code Ann. § 15-72-108 or § 15-76-304;


g) Civil Penalties
1) The Director shall determine whether to request the assessment of civil penalties based on failure to comply with the applicable abatement requirements for violations issued under subparagraphs (g) (2) and (3) below. The Director shall determine whether to request the assessment of civil penalties for violations issued under subparagraphs (g) (4) and (5) below. If a civil penalty is requested by the Director, the Regulated Entity may voluntarily agree to the assessment and pay the civil penalty as requested or modified by the Director, or the Director or his designee may file an application, in accordance with General Rule A-2, A-3, and other applicable hearing procedures, to request the issuance of the requested civil penalty by the Commission. The maximum amount of the Director’s requested civil penalty shall be computed as provided in subparagraphs (g) (2) through (5) below. However, the Commission is not bound by the Director’s request, or the amounts provided below, and may impose civil penalties of up to the maximum amounts permitted by law.

2) Administrative violations, defined as failure to file required reports and forms and to provide required notices (excluding spill notice), including, but not limited to regulated activities such as, the failure to file production and well reports or other reports required by Commission rules, regulations, orders or permit conditions; failure to notify the Commission before the setting of surface casing, or the plugging of a well; failure to maintain required performance bond in force for the wells under permit; or pay annual well fees within the specified time. The Director may request the assessment of up to $1000 per administrative violation and up to $1000 per day for each day the violation remains unabated after the specified compliance date. The per administrative violation civil penalty request shall be calculated as follows:

A) No previous violation of the same rule: $250. One previous violation of the same rule: $500. Two or more previous violations of the same rule: $1000. The fourth and each subsequent violation of the same rule shall be considered a significant violation in accordance with subparagraph g) 4) below.

B) The time frame used for determining previous violations shall be limited to the regulated entity’s violation record for the preceding three full calendar years before the issuance of the violation.

3) Operating violations, defined as failure to maintain compliance with Commission rules on well drilling and operation, and production facility, pipeline and seismic operations and/or commencing operations requiring a permit prior to issuance or re-issuance of the required permit or authority. These operations include, but are not limited to regulated activities such as, operating a well or natural gas pipeline system without the proper permit or transfer of ownership, failure to maintain a well or crude oil flow line in a leak-free condition, failure to comply with non-jurisdictional natural gas pipeline requirements, failure to notify of a spill occurrence, failure to maintain containment dikes, or operating an Exploration and Production Fluid Transportation System without a proper permit. Multiple incidents of the same violation against a regulated entity on the same occasion shall not be considered separate violations. The Director may request the assessment of up to $2500 per operating violation and up to $2500 per day for each day the violation remains unabated after the specified compliance date, with the exception that operating violations as specified in Ark. Code Ann. § 15-76-303 are limited to a maximum of $1,000 per operating violation. The per operating violation civil penalty shall be calculated as follows:
A) No previous violation of the same rule $500. One previous violation of the same rule, $750; two or more previous violations of the same rule, $1000. The fourth and each subsequent violation of the same rule shall be considered a significant violation in accordance with subparagraph g) 4) below.

B) The time frame used for determining previous violations shall be limited to the regulated entity’s violation record for the preceding three full calendar years before the issuance of the violation; plus

C) If the violation had a low degree of probability to cause environmental impact to soil and/or land surface, vegetation or crops, surface water, groundwater, livestock or wildlife, add $250; or, if the violation had a high degree of probability to cause environmental impact to soil and/or land surface, vegetation or crops, surface water, groundwater, livestock or wildlife, add $500; or, if the violation caused environmental impact to soil and/or land surface, vegetation or crops, surface water, groundwater, livestock or wildlife, add $1000, or

D) If the violation created a hazard to the safety of any person, such as the contamination of a potable water well or emission of hydrogen sulfide gas, add $2000.

4) Except as limited in Ark. Code Ann. § 15-76-303, or as otherwise provided in subparagraphs g) 5) or 6) below, significant violations may result in a request by the Director or his or her designee, of a civil penalty of up to $2500 per violation and up to $2500 per day for each day of the violation for the following types of violations: failure to comply with the provisions of General Rule A-7, failure to comply with well spacing provisions, operating a UIC well without a proper permit, operating an annular or casing injection/disposal well, operating a UIC well prior to establishing mechanical integrity, operating a UIC well with a failed mechanical integrity test, operating a UIC well with pressure on the annulus, failure to provide emergency response or remediate a crude oil or produced water spill, or the improper disposal or discharge of produced fluids. The per violation civil penalty shall be computed as follows:

A) An initial amount of $1000; plus

B) One or more previous violations of the same type: add $500 per violation; plus

C) If the violation caused environmental impact to surface water, ground water or wildlife: add $1000, or if the violation created a hazard to the safety of any person, such as the contamination of a potable water well or emission of hydrogen sulfide gas: add $1500.

D) The time frame used for determining previous violations shall be limited to the regulated entity’s violation record for the preceding three full calendar years before the issuance of the violation.

5) In accordance with Ark. Code Ann. §15-72-103, the Director, or his or her designee, may request a civil penalty of up to $100,000 for any person who transports a liquid or other substance and violates a rule, regulation, or order of the commission by dumping or
disposing of the liquid or other substance improperly or without authorization at a well or well site.

6) The Director, or his or her designee, may request any amount in civil penalties authorized by applicable federal law for violations of the United States Department of Transportation, Office of Pipeline Safety jurisdictional natural gas line requirements.

h) All civil penalties assessed and paid to the Commission shall be deposited in the Commission operating fund. Additionally, all civil penalties assessed and paid, for violations specified in Ark. Code Ann. § 15-72-202 shall be turned into the general fund of the county where the violation occurred to be used on roads, bridges, and highways at the discretion of the county court.
RULE B-1: APPLICATION TO DRILL A PRODUCTION WELL

a) Definitions:

1) “Production Well” means a well drilled, deepened, or re-entered after plugging, for the exploration or production of oil and/or gas or brine; or a well drilled, deepened or re-entered after plugging for a water supply for use in connection with an enhanced oil recovery project.

2) “Deepen” for a cased well means an operation whereby a well is drilled to a measured depth below the cement casing shoe. For an open hole completion, “Deepen” means an operation whereby a well is drilled below the original measured depth of the well.

3) “Drill” means the commencement of an operation to either set conductor pipe or the moving in a drilling rig capable of drilling to a depth to set the requisite amount of surface casing and spudding the well, if conductor pipe is not used.

4) “Permit Holder” means the person to whom the permit is issued and is responsible for all regulatory requirements relative to the production well.

5) “Re-enter” means an operation whereby access to a previously plugged wellbore is re-established for any purpose including replugging.

6) “Shale Operations” means drilling activities relating to the production of gas and other petroleum hydrocarbons from directed at an unconventional shale gas formation in a county listed in Arkansas General Rule B-43(c) or (d). “Shale Operations” does not include: (i) the periodic inspection, maintenance, or repair of completion activities; (ii) preparatory activities such as inspection, surveying, or staking; or (iii) drilling additional wells, redrilling, or recompletion operations on an existing drilling pad if the operator does not expand the existing pad. For purposes of this rule, “Shale Operations” does include well site construction operations.

67) “Spud” means the commencement of drilling a wellbore to a depth to set the requisite amount of surface casing.

b) Permit Application Procedures for a Permit to Drill, Deepen or Re-enter a Production Well

1) No person shall drill, deepen, or re-enter a plugged production well, without a permit. A copy of the permit shall be posted on site prior to a well being spud or the commencement of deepening or re-entering operations.

2) The Permit Holder is required to provide notice to the surface owner in accordance with Ark Code Ann. § 15-72-203.
A) If notice is required in accordance with Ark Code Ann § 15-72-203 (c) and entry upon the surface owner’s surface estate is required on or after the effective date of this rule, the notice shall contain:

   i) the proposed date Shale Operations will commence; and 

   ii) the location of the proposed well and the pad location, including the section, township, range, and plat of the pad location, if available; and 

   iii) a statement that the Permit Holder has a pending or approved drilling permit for the proposed Shale Operations on the surface owner's property and that the permit shall be available for inspection by the surface owner on request by the surface owner; and 

   iv) the name, address, telephone number, fax number, and electronic mailing address of the Permit Holder or the Permit Holder's agent.

B) The Notice shall be sent by certified United States mail or delivered personally, to the surface owner at the address of the surface owner stated in the public records of the county collector of the county in which the surface owner’s property is located, at least fourteen (14) days before the Permit Holder proposes to begin Shale Operations on the surface owner’s property.

C) After written notice of the Permit Holder's intent to begin Shale Operations is given under this subsection, a Permit Holder is not required to give any other notice to begin, conduct, or complete Shale Operations on the surface owner’s property.

D) Written notice under this subsection is:

   i) presumed delivered three (3) days after mailing by certified mail;

   ii) effective immediately upon hand delivery;

E) Written notice is not required:

   i) for emergency situations in which the Shale Operations are required to protect the public health and safety or the environment; or

   ii) if a surface owner has a contractual relationship with a Permit Holder or the Permit Holder’s agent that specifies when or how the Permit Holder shall give notice regarding the beginning of Shale Operations.

F) After receipt of a written notice of the Permit Holder's intent to begin Shale Operations under this subsection, the surface owner shall not make
alterations to a proposed drilling location to interfere with the Shale Operations for which the surface owner received the notice.

G) The provisions of subparagraphs b) 2) A) through F) above do not supersede, modify, or supplant the notice provisions of General Rule B-42.

3) The Permit Holder shall notify the appropriate Commission Regional Office by telephone, or other approved method, a minimum of twenty-four (24) hours prior to a well being spud or the commencement of deepening or re-entering operations. Commission staff may conduct site inspections as deemed necessary.

4) No production well may be drilled at a surface location other than that specified on the permit, except that if a Permit Holder has commenced drilling operations and the production well is lost due to adverse drilling conditions prior to surface casing being set, the Permit Holder may request an amendment of the permit without a fee for the new location, provided the production well remains on the same surface owners’ property where the production well was originally permitted. The Director may approve the commencement of drilling operations prior to the filing of an amended permit. Movement of the production well location off the original surface owners’ property, or after surface casing has been set, requires the filing of a new permit application, along with a new permit fee and plat. Drilling may not commence prior to the issuance of a new permit.

5) Application for a permit to drill, deepen or re-enter a plugged production well shall be made on forms prescribed by the Director. The application shall be executed under penalties of perjury, accompanied by a non-refundable permit fee of $300.00; and the permit shall not be issued until any required financial assurance in accordance with General Rule B-2 is submitted and approved.

6) If the application does not contain all of the required information or required documents, the Director, or his designee, shall notify the applicant in writing. The notification shall specify the additional information or documents necessary for an evaluation of the application, and shall advise the applicant that the application will be deemed denied unless the information or documents are received within sixty (60) days following the date of mailing or personal delivery of the notification.

7) Permits shall automatically expire six (6) months from the date of issuance, unless commencement of the drilling, deepening or re-entry of plugged production well operations authorized by the permit has occurred, which are to be continued with due diligence, but not to exceed 1 year from the date of commencement of the drilling, deepening or re-entry of plugged production well operations authorized by the permit, at which time the production well shall be plugged or a new permit application, along with a new permit fee and plat, must be filed.

8) Permits for the drilling, deepening or re-entry of plugged production well are not transferable prior to the completion of drilling operations and the setting of surface casing. A new permit application, along with a new permit fee and plat must be filed.
9) The permit application to drill, deepen or re-enter a plugged production well shall include at a minimum:

A) The proposed name of the production well.

B) The surveyed location and ground elevation of the production well. A survey is not required for a deepened production well, or a re-entered plugged production well, if the original production well location was surveyed and shown on the original production well permit application. If the application is for a horizontal production well, the surface location and proposed bottom hole location of the lateral portion of the horizontal production well shall be shown. If applicable, a Form 25 must be submitted for horizontal production wells where the costs and production are to be shared between drilling units in accordance with General Rule B-43 or B-44, or a Form 5 must be submitted for a location exception in accordance with General Rule B-40.

C) A plat showing:
   i) The exact location of the production well proposed to be drilled, deepened or re-entered; an outline of the proposed drilling unit and/or leasehold, whichever is applicable, unless the production well is a wildcat well; and the distance from the production well to the nearest section lines, drilling unit lines and or lease lines, whichever is applicable; and
   ii) If the production well is located within a controlled oil or gas field, the plat shall also include the location of all producing wells completed or producing within the same common source of supply in the drilling unit and/or leasehold.

D) The name of the proposed drilling contractor.

E) The proposed depth of the production well, and the name of the deepest geologic formation to be tested.

10) The application for a permit to drill, deepen or re-enter a plugged production well shall be signed by a person authorized to sign for such owner as specified on the Organizational Report filed in accordance with General Rule B-13.

11) The applicant must be authorized to do business in the State or Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission.

12) If the applicant satisfies the requirements of all applicable statutes and this Rule, a permit shall be issued, and in no circumstances be unduly withheld, unless:

A) The applicant has falsified or otherwise misstated any material information on or relative to the permit application;
B) No further permits or authorities may be issued in accordance with General Rule A-5.

c) Production Well Drilling Permit Revocation Procedures

1) The Director may revoke a production well drilling permit if the Permit Holder fails to meet permit conditions as specified in the production well drilling permit, the production well permit was issued in error, or the Permit Holder falsified or otherwise misstated any material information in the application form.

2) The Director shall notify the Permit Holder of the production well drilling permit in writing. Following the revocation notice the Permit Holder is required to plug the production well. The Permit holder shall have thirty (30) days from the date of the production well drilling permit to appeal the Director’s Decision to revoke the production well drilling permit in accordance with General Rule A-2, A-3. and other applicable hearing procedures. Drilling or production may not commence or continue during the appeal process. A revocation of a production well drilling permit for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the revocation.
RULE B-43: ESTABLISHMENT OF DRILLING UNITS FOR GAS PRODUCTION FROM CONVENTIONAL AND UNCONVENTIONAL SOURCES OF SUPPLY OCCURRING IN CERTAIN PROSPECTIVE AREAS NOT COVERED BY FIELD RULES

(a) For purposes of this rule, unconventional sources of supply shall mean those common sources of supply that are identified as the Fayetteville Shale, the Moorefield Shale, and the Chattanooga Shale Formations, or their stratigraphic shale equivalents, as described in published stratigraphic nomenclature recognized by the Arkansas Geological Survey or the United States Geological Survey.

(b) For purposes of this rule, conventional sources of supply shall mean all common sources of supply that are not defined as unconventional sources of supply in section (a) above.

(c) This rule is applicable to all occurrences of conventional and unconventional sources of supply in Arkansas, Cleburne, Conway, Cross, Faulkner, Independence, Jackson, Lee, Lonoke, Monroe, Phillips, Prairie, St. Francis, Stone, Van Buren, White and Woodruff Counties, Arkansas and shall be called the “section (c) lands”. The development of the conventional and unconventional sources of supply within the section (c) lands shall be subject to the provisions of this rule.

(d) This rule is further applicable to all occurrences of unconventional sources of supply in Crawford, Franklin, Johnson, and Pope Counties, Arkansas and shall be called the “section (d) lands”. The development of the unconventional sources of supply within the section (d) lands shall be subject to the provisions of this rule. For purposes of this rule, the section (d) lands and the section (c) lands may collectively be referred to as the “covered lands”.

(e) All Commission approved Fayetteville Shale and non-Fayetteville Shale fields that are situated within the section (c) lands and that are in existence on the date this rule is adopted (collectively, the “existing fields”), are abolished and the lands heretofore included within the existing fields are included within the section (c) lands governed by this rule. Further, all amendments that added the Fayetteville Shale Formation to previously established fields for conventional sources of supply occurring in the section (d) lands are abolished and continuing development of the Fayetteville Shale and other unconventional sources of supply in these lands shall be governed by the provisions of this rule. All existing individual drilling units however, contained within the abolished fields shall remain intact.

(f) All drilling units established for conventional and unconventional sources of supply within the section (c) lands and all drilling units established for unconventional sources of supply within the section (d) lands shall be comprised of single governmental sections, typically containing an area of approximately 640 acres in size. Each drilling unit shall be characterized as either an “exploratory drilling unit” or an “established drilling unit”. An “exploratory drilling unit” shall be defined as any drilling unit that is not an established drilling unit. An “established drilling unit” shall be defined as any drilling unit that contains a well that has been drilled and completed in a conventional or unconventional
source of supply (a “subject well”), and for which the operator or other person responsible for the conduct of the drilling operation has filed, with the Commission, all appropriate documents in accordance with General Rule B-5, and been issued a certificate of compliance. Upon the filing of the required well and completion reports for a subject well and the issuance of a certificate of compliance with respect thereto, the exploratory drilling unit upon which the subject well is located and all contiguous governmental sections shall be automatically reclassified as established drilling units.

(g) The filing of an application to integrate separately owned tracts within an exploratory drilling unit, as defined in Section (f) above and as contemplated by A.C.A. § 15-72-302(e), is permissible, provided that one or more persons who collectively own at least an undivided fifty percent (50%) interest in the right to drill and produce oil or gas, or both, from the total acreage assigned to such exploratory drilling unit support the filing of the application. In determining who shall be designated as the operator of the exploratory drilling unit that is being integrated, the Commission shall apply the following criteria:

1) Each integration application shall contain a statement that the applicant has sent written notice of its application to integrate the drilling unit to all working interest owners of record within such drilling unit. This notice shall contain a well proposal and AFE for the initial well and may be sent at the same time the integration application is filed.

2) If any non-applicant working interest owner in the drilling unit owns, or has the written support of one or more working interest owners that own, separately or together, at least a fifty percent (50%) working interest in the drilling unit, such non-applicant working interest owner may (i) object to the applicant being named operator (a “section (g) operator challenge”) or (ii) file a competing integration application (a “section (g) competing application”) that challenges any aspect of the original integration application for such drilling unit. Any contested matter that is limited to a section (g) operator challenge shall be heard at the Commission hearing that was originally scheduled for such integration application. Any contested matter that involves the filing of a section (g) competing application shall be postponed until the next month’s regularly scheduled Commission hearing if postponement is requested by either competing applicant.

3) If a party desiring to be named operator of a drilling unit is supported by a majority-in-interest of the total working interest ownership in the drilling unit (the “majority owner”), the majority owner shall be designated unit operator.

4) In the event two parties desiring to be named operator own, or have the written support of one or more working interest owners that own, exactly, an undivided 50% share of the drilling unit and either a section (g) operator challenge is submitted or a section (g) competing application is filed, operatorship shall be determined by the Commission, based on the factors it deems relevant and the evidence submitted by the parties or as otherwise provided by subsequent rule.

5) If the person designated as operator by the Commission in the adjudication of a section (g) operator challenge or a section (g) competing application does not commence actual drilling operations on the drilling unit within the twelve (12) month period set out in the integration order, such operator shall not be entitled
to be designated as operator under the subsequent integration of such drilling unit unless (i) the operator’s failure to commence such drilling operations was due to force majeure, or (ii) a majority-in-interest of the total working interest ownership in the drilling unit (excluding such designated operator) support such operator.

(h) The filing of an application to integrate separately owned tracts within an established drilling unit, as defined in Section (f) above and as contemplated by A.C.A. § 15-72-303 is permissible, without a minimum acreage requirement, provided that one or more persons owning an interest in the right to drill and produce oil or gas, or both, from the total acreage assigned to such established drilling unit requests such integration. In determining who shall be designated as the operator of the established drilling unit that is being integrated, the Commission shall apply the following criteria:

1) Each integration application shall contain a statement that the applicant has sent written notice of its application to integrate the drilling unit to all working interest owners of record within such drilling unit. This notice shall contain a well proposal and AFE for the initial well and may be sent at the same time the integration application is filed.

2) Any non-applicant working interest owner in the drilling unit may object to the applicant being named operator (a “section (h) operator challenge”). In addition, if an objecting party owns, or has the written support of one or more working interest owners that own, separately or together, a larger percentage working interest in the drilling unit than the applicant, such objecting party may file a competing integration application (a “section (h) competing application”) that challenges any aspect of the original integration application for such drilling unit. Any contested matter that is limited to a section (h) operator challenge shall be heard at the Commission hearing that was originally scheduled for such integration application. Any contested matter that involves the filing of a section (h) competing application shall be postponed until the next month’s regularly scheduled Commission hearing if postponement is requested by either competing applicant.

3) If a party desiring to be named operator of a drilling unit is a majority owner (as defined in subsection (g)(3) above), the majority owner shall be designated unit operator.

4) If a party desiring to be named operator of a drilling unit is not a majority owner, but is supported by the largest percentage interest of the total working interest ownership in the drilling unit (the “plurality owner”), there shall be a rebuttable presumption that the plurality owner shall be designated unit operator. If a section (h) operator challenge to a plurality owner being designated unit operator is submitted by a party that owns, or has the written support of one or more owners that own, separately or together, the next largest percentage share of the working interest ownership in the drilling unit (the “minority owner”), the Commission may designate the minority owner operator if the minority owner is able to show that, based on the factors the Commission deems relevant and the evidence submitted by the parties, the Commission should designate the minority owner as unit operator.
5) If two or more parties that desire to be named operator own, or have the support of one or more working interest owners that own, separately or together, the same working interest ownership in the drilling unit, operatorship shall be determined by the Commission, based on the factors it deems relevant and the evidence submitted by the parties or as otherwise provided by subsequent rule.

6) If the person designated as operator by the Commission in the adjudication of a section (h) operator challenge or a section (h) competing application does not commence actual drilling operations on the drilling unit within the twelve (12) month period set out in the integration order, such operator shall not be entitled to be designated operator under the subsequent integration of such drilling unit unless (i) the original operator’s failure to commence drilling operations on the initial well was due to force majeure, or (ii) a majority-in-interest of the total working interest ownership in the drilling unit (excluding the original operator) support the original operator.

(i) The well spacing for wells drilled in drilling units for unconventional sources of supply within the covered lands are as follows:

1) Each well location (as defined in Section (a)(2) of General Rule B-3) shall be at least 560 feet from any drilling unit boundary line;

2) Each well location (as defined in Section (a)(2) of General Rule B-3) shall be at least 560 feet from any other well in the same common source of supply that extends across or encroaches upon drilling unit boundaries unless all owners, as defined in Ark. Code Ann. (1987) § 15-72-102(9), in all units consent in writing to a well closer than 560 feet. Consent may be given prior to the drilling of a well, while a well is being drilled, or after a well has been drilled, but prior to commencement of production.

3) Each well location (as defined in Section (a)(2) of General Rule B-3) shall be at least 448 feet, an allowed 20% variance, from all other well locations in the same common source of supply within an established drilling unit, unless all owners, as defined in Ark. Code Ann. (1987) § 15-72-102(9), in the unit consent in writing to a well closer than 448 feet. Consent may be given prior to the drilling of a well, while a well is being drilled, or after a well has been drilled, but prior to commencement of production.

4) No more than 16 wells may be drilled per 640 acres for each separate unconventional source of supply within an established drilling unit; and

5) Applications for exceptions to these well location provisions, relative to a drilling unit boundary or other location in a common source of supply, may be brought before the Commission.

(j) The well spacing for wells drilled in drilling units for conventional sources of supply within the section (c) lands are as follows:

1) Only a single well completion will be permitted to produce from each separate conventional source of supply within each established drilling unit, unless additional completions are approved in accordance with General Rule D-19;
2) Each well location (as defined in Section (a) 2) of General Rule B-3) shall be at least 1120 feet from any drilling unit boundary line;

3) Well completions located closer than 1120 feet from all established drilling unit boundaries, shall be subject to approval in accordance with General Rule B-40; and

4) Applications for exceptions to these well location provisions, relative to a drilling unit boundary or other location in a common source of supply, may be brought before the Commission.

(k) The casing programs for all wells drilled in exploratory and established drilling units established by this rule and occurring in the covered lands specified by this rule shall be in accordance with General Rule B-15.

(l) Wells completed in and producing from only conventional sources of supply, as defined in Section (b), shall be subject to the initial and annual testing provisions of General Rule D-16 and production allowable provisions of General Rule D-16 21. Wells completed in and producing from only unconventional sources of supply, as defined in Section (a), shall not be subject to the initial and annual testing and test reporting provisions of General Rule D-16 and allowable provisions of General Rule D-21. except that the initial test shall apply to those wells which produce with a reduction in the allowable due to an encroachment penalty. All required initial and annual tests may be performed without the presence of a Commission representative following notice as provided for in General Rule D-16. There shall be no production allowable established for wells producing from unconventional sources of supply located within the covered lands. Wells completed in and producing from only unconventional sources of supply, within the covered lands, shall report on a form prescribed by the Director, the highest twenty-four (24) hour production rate during the first forty (40) days of production, which form shall be filed within sixty (60) days of the date of first production from the well.

(m) The commingling of completions for unconventional and/or conventional sources of supply within each well situated on an established drilling unit, shall be subject to the provisions and approval process outlined in General Rule D-18. If an unconventional source of supply is approved to be commingled with a conventional source of supply within a well situated on an established drilling unit, the well shall be subject to the production allowable provisions of General Rule D-16 21.

(n) The reporting requirements of General Rule B-5 shall apply to all wells subject to the provisions of this rule. In addition, the operator of each such well shall be required to file monthly gas production reports in accordance with General Rule D-8.

(o) The Commission specifically retains jurisdiction to consider applications brought before the Commission from a majority in interest of all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), in two or more adjoining drilling units seeking the authority to drill, produce and/or share the costs of and the proceeds of production from one or more separately metered wells that extend across or encroach upon drilling unit boundaries and that are drilled and completed in one or more unconventional sources of supply within the covered lands. All such applications shall contain a proposed agreement on
the formula for the sharing of costs, production and royalty from the affected drilling units.

1) **Encroaching Wells.** If a well encroaches upon but does not cross the drilling unit boundary of an adjoining drilling unit (an “encroaching well”), the Commission shall not consider the encroached upon drilling unit to be held by production from the encroaching well.

2) **Administrative Approval of Wells that Extend Across or Encroach Upon Drilling Unit Boundaries.** If the majority in interest of all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), within each drilling unit agree to share a proposed well, a well that is being drilled, or a well which has been drilled, but prior to commencement of production, between two or more adjoining drilling units which are all integrated or are 100% leased utilizing the below methodology for sharing of costs, production and royalty among the affected drilling units, the Director or his designee is authorized to approve the application administratively, if the following conditions are met:

A. The application provides proof that:

   i) There is at least one well located, as defined in subsection (a)(2) of General Rule B-3, at a non-exceptional well location and located entirely within each included drilling unit that is producing or capable of producing gas; or

   ii) Within twelve (12) months following the date the well for which administrative approval is granted is spud, there will be at least one well located, as defined in subsection (a)(2) of General Rule B-3, at a non-exceptional well location and located entirely within each included drilling unit that is either a well that is producing gas, or a well that is capable of producing gas and awaiting connection to a pipeline; or

   iii) There is at least one well or a combination of multiple wells, including cross unit wells and/or encroaching wells located, as defined in subsection (a)(2) of General Rule B-3, within each included drilling unit that have a total combined perforated lateral length within the drilling unit of not less than 4160 feet, and are producing or are capable of producing gas; or

   iv) Within twelve (12) months following the date the well for which administrative approval is granted is spud, there will be at least one well or a combination of multiple wells, including cross unit wells and/or encroaching wells located, as defined in subsection (a)(2) of General Rule B-3, within each included drilling unit that have a total combined perforated lateral length within the drilling unit of not less than 4160 feet, and are producing or are capable of producing gas and awaiting connection to a pipeline; or
v) At least seventy five percent (75%) of the fee mineral ownership within each included drilling unit that does not contain one or more wells satisfying the requirements of subpart 2)A.i) or subpart 2)A. iii) above agree in writing to the well; and

B. Notice has been given to all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9) and no objections were received by the Director in accordance with subsection 2) I) below; and

C. The application includes detailed plat maps indicating current well locations and potential future well development plans in all included drilling units.

D. If administrative approval is granted, based upon either or both of subsection 2)A.ii) or iv) above, and the applicant fails to satisfy one of the conditions specified in subsection 2)A.ii) or iv) above, the drilling permit and all other authorities for the well shall be automatically revoked, and the well shall be shut in, unless the applicant has filed a request in accordance with General Rule A-2, A-3, and other applicable hearing procedures prior to the expiration of the time period specified in such subsections, or the Commission otherwise approves the application.

E. The method for sharing the costs of and the proceeds of production from one or more separately metered wells shall be based on acreage allocation as follows:

   i) An area measured 560 feet along and on both sides of the entire length of the horizontal perforated section of the well, and including an area formed by a 560 feet radius from the beginning point of the perforated interval, and a 560 feet radius from the ending point of the perforated interval shall be calculated for each such separately metered well (the “calculated area”).

   ii) Each calculated area shall be allocated and assigned to each drilling unit according to that portion of the calculated area occurring within each drilling unit.

F. Each such application for utilizing the above methodology shall be submitted on a form prescribed by the Director of Production and Conservation, accompanied by an application fee of $500.00 and include the name and address of each owner, as defined in Ark. Code Ann. (1987) § 15-72-102(9), within each of the drilling units in which the proposed well is to be drilled and/or completed.

G. Concurrently with the filing of an application utilizing the above methodology, the applicant shall send to each owner specified in subsection 2)F. above a notice of the application filing and verify such mailing by affidavit, setting out the names and addresses of all owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), and the date(s) of mailing.
H. Any owner, as defined by Ark. Code Ann. (1987) § 15-72-102(9), noticed in accordance with subsection 2) G) above shall have the right to object to the granting of such application within fifteen (15) days after the receipt of the application by the Commission. Each objection must be made in writing and filed with the Director. If a timely written objection is filed as herein provided, then the applicant shall be promptly furnished a copy and such application shall be denied. If the application is denied under this section, the applicant may request to have the application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing requirements, except that no additional filing fee is required.

I. An application may be referred to the Commission for determination when the Director deems it necessary that the Commission make such determination for the purpose of protecting correlative rights of all parties, in order to prevent waste, or for any other reason. Promptly upon such determination, and not later than fifteen (15) days after receipt of the application, the Director shall give the applicant written notice, citing the reason(s) for referral to the full Commission for determination. If the application is referred under this section, the applicant shall file a request for a hearing, in accordance with General Rules A-2 and A-3, and other applicable hearing requirements, except that no additional filing fee is required.

J. If the Director has not notified the applicant of the determination to refer the application to the Commission within the fifteen (15) day period in accordance with the foregoing provisions, and if no objection is received at the office of the Commission within the fifteen (15) days as provided for in subsection 2)I, the application shall be approved and a drilling permit issued.

K. Upon receipt of the drilling permit, the applicant shall give the other owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), written notice that the drilling permit has been issued. The owners, as defined by Ark. Code Ann. (1987) § 15-72-102(9), who have not previously made an election, shall have fifteen (15) days after receipt of said notice within which to make an election to participate in the well or be deemed as electing non-consent and subject to the non-consent penalty set out in the existing Joint Operating Agreement(s) covering their respective drilling unit or units.

L. Following completion of the well and prior to the issuance of the Certificate of Compliance to commence production, the final location of the perforated interval shall be submitted to the Director to verify the proposed portion of the calculated area occurring within each drilling unit as specified in subsection 2) E) above.

3) Filing of Affidavit. The Applicant shall also file an affidavit or other document showing the calculated area allocated and assigned to each drilling unit, according to the final calculation of the area, occurring within each drilling unit.
with the Director and in the real estate property records in all counties where any portion of the drilling units are located.

(p) The Commission shall retain jurisdiction to consider applications, brought before the Commission, from a majority in interest of working interest owners in two or more adjoining governmental sections seeking the authority to combine such adjoining governmental sections into one drilling unit for the purpose of developing one or more unconventional sources of supply. In any such multi-section drilling unit, production shall be allocated to each tract therein in the same proportion that each tract bears to the total acreage within such drilling unit.

(q) The Commission shall retain jurisdiction to consider applications, brought before the Commission, from a majority in interest of working interest owners in a drilling unit seeking the authority to omit any lands from such drilling unit that are owned by a governmental entity and for which it can be demonstrated that such governmental entity has failed or refused to make such lands available for leasing.
RULE B-44: ESTABLISHMENT OF DRILLING UNITS FOR GAS PRODUCTION FROM ALL SOURCES OF SUPPLY OCCURRING IN CERTAIN PRODUCING AREAS IN FRANKLIN, LOGAN, SCOTT, SEBASTIAN AND YELL COUNTIES

(a) Definitions:

(1) “Unconventional Sources of Supply” shall mean those common sources of supply that are identified as the Fayetteville Shale, the Moorefield Shale, and the Chattanooga Shale Formations, or their stratigraphic shale equivalents, as described in published stratigraphic nomenclature recognized by the Arkansas Geological Survey or the United States Geological Survey.

(2) “Conventional Sources of Supply” shall mean all common sources of supply that are not defined as unconventional sources of supply in section (a)(1) above or the Middle Atoka as defined in section (a)(4) below, or a tight gas formation as defined in section (a)(3) below.


(4) “Middle Atoka” shall mean the tight gas formation that is the stratigraphic equivalent, from the top of the Basham Formation to the base of Borum Formation, which includes the Hartford Series, within the covered lands specified in section (b) below.

(b) This rule is applicable to all sources of supply occurring in the “covered lands,” except the Hartshorne Coal Formation or any other coal formation. The development of these sources of supply within the covered lands shall be subject to the provisions of this rule. The covered lands are specified as follows:

(1) Sections 19-36, T7N R28W; Sections 1-3 and 11, T6N, R29W all in Franklin County;

(2) Sections 19-36 T7N R27W; Sections 19-36 T7N R26W; Sections 13-36 T7N R25W; Sections 13-36 T7N R24W; Sections 13-36 T7N R23W; all of T6N R28W; all of T6N R27W; all of T6N R26W; all of T5N R29W; all of T5N R28W; all of T5N R27W; all of T5N R26W; all of T5N R25W; all of T4N R29W; Sections 1-12 T4N R28W; Sections 1-12 T4N R27W; Sections 1-12 T4N R26W all in Logan County and those portions of T6N R25W, T6N R24W and T6N R23W located in Logan County;

(3) That portion of T5N R30W, T4N R29W, T4N R28W, T4N R27W, and T4N R26W located in Scott County; and all of T4N R30W in Scott County;

(4) Sections 31-36 T7N R31W; Sections 31 and 32 T7N R30W; all of T6N R32W; all of T6N R31W; all of T6N R30W; all of T5N R32W; all of T5N R31W; all of
T4N R32W and all of T4N R31W in Sebastian County and that portion of T6N R29W and T5N R30W located in Sebastian County;

(5) All of T5N R25W; all of T5N R24W; all of T5N R23W; all of T4N R25W; all of T4N R24W; all of T4N R23W; All of T6N R22W; all of T5N R22W; all of T4N R22W all in Yell County and those portions of T6N R25W, T6N R24W, T6N R23W located in Yell County;

(6) After notice and hearing, the Commission shall retain jurisdiction to expand the covered lands above, to include other lands proven to possess production characteristics similar to the lands initially contained within the covered lands.

(c) The Commission shall retain jurisdiction, after notice and hearing, to determine which other formations, in addition to the Middle Atoka, qualify as tight gas formations within the covered lands.

(d) All Commission approved fields, except those applicable to the Hartshorne Coal Formation or any other coal formation, that are situated within the covered lands and that are in existence on the date this rule is adopted (collectively, the “existing fields”), are abolished and the lands heretofore included within the existing fields are included within the covered lands governed by this rule. However, all existing portions of the abolished fields which are not included in the covered lands, those portions of the fields shall remain intact and operate under the existing field rules for that field or upon order of the Commission may be joined to other existing adjacent fields. All existing individual drilling units however, contained within the abolished fields shall remain intact.

(e) All drilling units established for sources of supply within the covered lands shall be comprised of single governmental sections, typically containing an area of approximately 640 acres in size, unless a different size and/or configuration is approved for any unit or units by Order of the Commission. Each drilling unit shall be characterized as either an “exploratory drilling unit” or an “established drilling unit”. An “exploratory drilling unit” shall be defined as any drilling unit that is not an established drilling unit. An “established drilling unit” shall be defined as any drilling unit that contains a well that has been drilled and completed in any source of supply (a “subject well”), and for which the operator or other person responsible for the conduct of the drilling operation has filed, with the Commission, all appropriate documents in accordance with General Rule B-5, and has been issued a certificate of compliance. Upon the filing of the required well and completion reports for a subject well and the issuance of a certificate of compliance with respect there, the exploratory drilling unit upon which the subject well is located and all contiguous governmental sections shall be automatically reclassified as established drilling units. All existing “exploratory drilling units” contiguously located to drilling units with established production at the time this rule is adopted, shall be automatically reclassified as established drilling units.

(f) The filing of an application to integrate separately owned tracts within an exploratory drilling unit, as defined in Section (e) above and as contemplated by A.C.A. § 15-72-302(e), is permissible, provided that one or more persons who own at least an undivided fifty percent (50%) interest in the right to drill and produce oil or gas, or both, from the total acreage assigned to such exploratory drilling unit agree. In determining who shall be designated as the operator of the exploratory drilling unit that is being integrated, the Commission shall apply the following criteria:
1) Each integration application shall contain a statement that the applicant has sent written notice of its application to integrate the drilling unit to all working interest owners of record within such drilling unit. This notice shall contain a well proposal and AFE for the initial well and may be sent at the same time the integration application is filed.

2) If any non-applicant working interest owner in the drilling unit owns, or has the written support of one or more working interest owners that own, separately or together, at least a fifty percent (50%) working interest in the drilling unit, such non-applicant working interest owner may (i) object to the applicant being named operator (a “section (f) operator challenge”) or (ii) file a competing integration application (a “section (f) competing application”) that challenges any aspect of the original integration application for such drilling unit. Any contested matter that is limited to a section (f) operator challenge shall be heard at the Commission hearing that was originally scheduled for such integration application. Any contested matter that involves the filing of a section (f) competing application shall be postponed until the next month’s regularly scheduled Commission hearing if postponement is requested by either competing applicant.

3) If a party desiring to be named operator of a drilling unit is supported by a majority-in-interest of the total working interest ownership in the drilling unit (the “majority owner”), the majority owner shall be designated unit operator.

4) In the event two parties desiring to be named operator own, or have the written support of one or more working interest owners that own, exactly, an undivided 50% share of the drilling unit and either a section (f) operator challenge is submitted or a section (f) competing application is filed, operatorship shall be determined by the Commission, based on the factors it deems relevant and the evidence submitted by the parties or as otherwise provided by subsequent rule.

5) If the person designated as operator by the Commission in the adjudication of a section (f) operator challenge or a section (f) competing application does not commence actual drilling operations on the drilling unit within the twelve (12) month period set out in the integration order, such operator shall not be entitled to be designated as operator under the subsequent integration of such drilling unit unless (i) the operator’s failure to commence such drilling operations was due to force majeure, (ii) a majority-in-interest of the total working interest ownership in the drilling unit (excluding such designated operator) support such operator.

(g) The filing of an application to integrate separately owned tracts within an established drilling unit, as defined in Section (e) above and as contemplated by A.C.A. § 15-72-303 is permissible, without a minimum acreage requirement, provided that one or more persons owning an interest in the right to drill and produce oil or gas, or both, from the total acreage assigned to such established drilling unit requests such integration. In determining who shall be designated as the operator of the established drilling unit that is being integrated, the Commission shall apply the following criteria:

1) Each integration application shall contain a statement that the applicant has sent written notice of its application to integrate the drilling unit to all working interest owners of record within such drilling unit. This notice shall contain a well proposal and AFE for the initial well and may be sent at the same time the integration application is filed.
interest owners of record within such drilling unit. This notice shall contain a well proposal and AFE for the initial well and may be sent at the same time the integration application is filed.

2) Any non-applicant working interest owner in the drilling unit may object to the applicant being named operator (a “section (g) operator challenge”). In addition, if an objecting party owns, or has the written support of one or more working interest owners that own, separately or together, a larger percentage working interest in the drilling unit than the applicant, such objecting party may file a competing integration application (a “section (g) competing application”) that challenges any aspect of the original integration application for such drilling unit. Any contested matter that is limited to a section (g) operator challenge shall be heard at the Commission hearing that was originally scheduled for such integration application. Any contested matter that involves the filing of a section (g) competing application shall be postponed until the next month’s regularly scheduled Commission hearing if postponement is requested by either competing applicant.

3) If a party desiring to be named operator of a drilling unit is a majority owner (as defined in subsection (f) (3) above), the majority owner shall be designated unit operator.

4) If a party desiring to be named operator of a drilling unit is not a majority owner, but is supported by the largest percentage interest of the total working interest ownership in the drilling unit (the “plurality owner”), there shall be a rebuttable presumption that the plurality owner shall be designated unit operator. If a section (g) operator challenge to a plurality owner being designated unit operator is submitted by a party that owns, or has the written support of one or more owners that own, separately or together, the next largest percentage share of the working interest ownership in the drilling unit (the “minority owner”), the Commission may designate the minority owner operator if the minority owner is able to show that, based on the factors the Commission deems relevant and the evidence submitted by the parties, the Commission should designate the minority owner as unit operator.

5) If two or more parties that desire to be named operator own, or have the support of one or more working interest owners that own, separately or together, the same working interest ownership in the drilling unit, operatorship shall be determined by the Commission, based on the factors it deems relevant and the evidence submitted by the parties or as otherwise provided by subsequent rule.

6) If the person designated as operator by the Commission in the adjudication of a section (g) operator challenge or a section (g) competing application does not commence actual drilling operations on the drilling unit within the twelve (12) month period set out in the integration order, such operator shall not be entitled to be designated operator under the subsequent integration of such drilling unit unless (i) the original operator’s failure to commence drilling operations on the initial well was due to force majeure, (ii) a majority-in-interest of the total working interest ownership in the drilling unit (excluding the original operator) support the original operator.
(h) The well spacing for wells drilled in exploratory and established drilling units for all unconventional sources of supply within the covered lands are as follows:

1) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 560 feet from any drilling unit boundary line, unless an exception is approved in accordance with subparagraph (p) below or in accordance with General Rule B-40;

2) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 560 feet from other well locations within an established drilling unit, within common sources of supply, unless an exception to this rule is approved by the Commission, following notice and hearing.

(i) The well spacing for wells drilled in exploratory and established drilling units for the Middle Atoka, and any other tight gas formation source of supply within the covered lands are as follows:

1) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 560 feet from any drilling unit boundary line, unless an exception is approved in accordance with subparagraph (p) below or in accordance with General Rule B-40;

2) Each well location, as defined in General Rule B-3 (a)(2) shall be at least 560 feet from other well locations within an established drilling unit, unless the common sources of supply are stratigraphically different named intervals, approved in accordance with subparagraph (i) (3) below, or an exception to this rule is approved by the Commission, following notice and hearing.

3) Application for approval of well locations less than 560 feet from other well locations within an established unit, for common sources of supply from stratigraphically different named intervals, shall be submitted on a form prescribed by the Director, and contain, at a minimum, the following information:

A) The location of the unit;

B) The location or proposed location of all wells being encroached upon, showing the productive zones in each well;

C) A cross-section, containing the location or proposed location of all wells being encroached upon, demonstrating the productive zone will be from stratigraphically different named intervals;

D) In addition, each application shall provide proof of written notice to all owners, as defined in Ark. Code Ann. § 15-72-102(9), in the subject unit;

E) The notice shall contain at a minimum, the name of the applicant, the name and location of the encroaching wells, and instructions as to the filing with the Director written objections
within fifteen (15) days after receipt of the application by the Director.

F) Any owner noticed in accordance with sub-paragraph i) 3) E) above shall have the right to object to the granting of such application within fifteen (15) days after receipt of the application by the Director.

G) If an objection is not received within fifteen (15) days after the receipt of the application, and that the productive zone will be from stratigraphically different named intervals, the Director shall approve the application.

H) If an objection is received, or if the application does not satisfy the requirements of this Rule and is denied by the Director, the Applicant may request to have the matter placed, in accordance with General Rules A-2, A-3 and other established procedures, on the docket of a regularly scheduled Commission hearing.

(j) The well spacing for wells drilled in exploratory and established drilling units for the Upper Atoka and the Freiburg conventional sources of supply within the covered lands are as follows:

1) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 560 feet from any drilling unit boundary line, unless an exception is approved in accordance with subparagraph (p) below or in accordance with General Rule B-40;

2) Each well location, as defined in General Rule B-3 (a)(2) shall be at least 560 feet from other well locations within an established drilling unit, within common sources of supply, unless an exception to this rule is approved by the Commission, following notice and hearing.

(k) The well spacing for wells drilled in exploratory and established drilling units for all other conventional sources of supply within the covered lands are as follows:

1) Only a single well completion will be permitted to produce from each separate conventional source of supply within each exploratory or established drilling unit, unless additional completions are approved in accordance with General Rule D-19;

2) Each well location, as defined in General Rule B-3 (a)(2), shall be at least 1120 feet from any drilling unit boundary line, unless an exception is approved in accordance with subparagraph (p) below or General Rule B-40;

(l) The casing programs for all wells drilled in exploratory and established drilling units established by this rule, and occurring in the covered lands specified by this rule, shall be in accordance with General Rule B-15 or other applicable General Rules.

(m) Wells completed in and producing from all sources of supply, within the covered lands, shall be subject to the testing and production allowable provisions of General Rule D-16
and allowable provisions of General Rule D-21, except that unconventional sources of supply shall not be subject to an allowable.

(n) The commingling of completions in all sources of supply, within each well, shall be subject to the provisions in General Rule D-18.

(o) The reporting requirements of General Rule B-5 shall apply to all wells subject to the provisions of this rule. In addition, the operator of each such well shall be required to file monthly gas production reports, on a Form approved by the Director, no later than 45 days after the last day of each month.

(p) The Commission specifically retains jurisdiction to consider applications brought before the Commission from a majority in interest of working interest owners in two or more adjoining exploratory or established drilling units seeking the authority to drill, produce and share the costs of and the proceeds of production from a separately metered well that extends across or encroaches upon drilling unit boundaries and that are drilled and completed in one or more sources of supply within the covered lands. All such applications shall contain a proposed agreement on the formula for the sharing of costs, production and royalty from the affected drilling units.

1) However, if the majority in interest of working interest owners agree to share a proposed well between two or more adjoining drilling units, which have been previously integrated, utilizing the below methodology for sharing of costs, production and royalty among the affected drilling units, or if the well encroaches upon the drilling unit boundaries specified by this rule, the Director or his designee is authorized to approve the application administratively utilizing the following methodology:

   A) The sharing of well costs and the proceeds of production from one or more separately metered wells, between the affected drilling units, shall be based on an allocation based on an area (acreage) calculation as specified below.

   B) For horizontal wells, an area (equal to the setback footage for that source of supply as specified in section (h), (i), (j) or (k) above) along and on both sides of the entire length of the horizontal perforated section of the well, and including an area formed by a radius (equal to the setback footage for that source of supply as specified in section (h), (i), (j) or (k) above) from the beginning point of the perforated interval and from the ending point of the perforated interval. The area formed shall be calculated for each such separately metered well and referred to as the “calculated area”.

   C) For vertical wells, an area (equal to the setback footage for that source of supply as specified in section (h), (i), (j) or (k) above) extending around the perforated interval as defined in General Rule B-3, shall be calculated for each such separately metered well and referred to as the “calculated area”.
D) Each calculated area shall be allocated and assigned to each drilling unit according to that portion of the calculated area occurring within each drilling unit.

2) Each such application for utilizing the above methodology shall be submitted on a form prescribed by the Director of Production and Conservation, accompanied by an application fee of $500.00 and include the name and address of each owner, as defined in A.C.A. § 15-72-102(9), within each of the drilling units in which the proposed well is to be drilled and/or completed.

3) Concurrently with the filing of an application utilizing the above methodology, the applicant shall send to each owner specified in subsection (p)(2) above a notice of the application filing and verify such mailing by affidavit, setting out the names and addresses of all owners and the date(s) of mailing.

4) Any owner noticed in accordance with subsection (p)(3) above shall have the right to object to the granting of such application within fifteen (15) days after the receipt of the application by the Commission. Each objection must be made in writing and filed with the Director. If a timely written objection is filed as herein provided, then the applicant shall be promptly furnished a copy and the application shall be denied. If the application is denied under this section, the applicant may request to have the application referred to the Commission for determination, in accordance with applicable state laws and General Rules A-2 and A-3, except that no additional filing fee is required.

5) An application may be referred to the Commission for determination when the Director deems it necessary that the Commission make such determination for the purpose of protecting correlative rights of all parties. Promptly upon such determination, and not later than fifteen (15) days after receipt of the application, the Director shall give the applicant written notice, citing the reason(s) for denial of the application under this rule and the referral to the full Commission for determination, in accordance with applicable state laws and General Rules A-2 and A-3.

6) If the Director has not notified the applicant of the determination to refer the application to the Commission within the fifteen (15) day period in accordance with the foregoing provisions, and if no objection is received at the office of the Commission within the fifteen (15) days as provided for in subsection (p)(4), the application shall be approved and a drilling permit issued.

7) Upon receipt of the drilling permit, the applicant shall give the other working interest parties written notice that the drilling permit has been issued. The working interest parties, who have not previously made an election, shall have 15 days after receipt of said notice within which to make an election to participate in the well or be deemed as electing non-consent and subject to the non-consent penalty set out in the existing Joint Operating Agreement(s) covering their respective drilling unit or units.

8) Following completion of the well and prior to the issuance by the Commission of the Certificate of Compliance to commence production, the final location of the perforated interval shall be submitted to the Commission to verify the proposed
portion of the calculated area occurring within each drilling unit as specified in subsection (p)(1) above.

(q) The Commission shall retain jurisdiction to consider applications, brought before the Commission, from a majority in interest of working interest owners in two or more adjoining governmental sections seeking the authority to combine such adjoining governmental sections into one drilling unit for the purpose of developing one or more unconventional sources of supply. In any such multi-section drilling unit, production shall be allocated to each tract therein in the same proportion that each tract bears to the total acreage within such drilling unit.

(r) The Commission shall retain jurisdiction to consider applications, brought before the Commission, from a majority in interest of working interest owners in a drilling unit seeking the authority to omit any lands from such drilling unit that are owned by a governmental entity and for which it can be demonstrated that such governmental entity has failed or refused to make such lands available for leasing.
RULE B-45: ESTABLISHMENT OF WELL SET-BACK REQUIREMENTS FOR DRY GAS PRODUCTION WELLS OCCURRING IN ESTABLISHED FIELDS IN CRAWFORD, FRANKLIN, JOHNSON, LOGAN, MADISON, POPE, SCOTT, YELL, SEBASTIAN AND WASHINGTON COUNTIES

a) Applicability

1) Except as provided in subparagraph a) 2) below, this rule applies to all controlled sources of supply, as defined in Ark Code Ann. § 15-71-107, occurring within any existing field created by an order of the Commission within Crawford, Franklin, Johnson, Logan, Madison, Pope, Scott, Yell, Sebastian and Washington Counties.

2) This rule does not apply to:

A) The Hartshorne Coal Formation or any other coal formation;

B) Any uncontrolled conventional source of supply occurring within the Commission established fields covered by this rule;

C) Any source of supply governed by General Rule B-43, or

D) Any source of supply governed by General Rule B-44.

3) After notice and hearing, the Commission shall retain jurisdiction to extend the provisions of this rule to any new fields established by the Commission.

4) This rule applies to wells in which controlled and uncontrolled sources of supply are commingled.

b) Definitions

1) “Encroachment Footage” shall mean the actual footage of the New or Existing PRU from the drilling unit boundary, when that footage is less than the Setback Footage specified by rule.

2) “Existing PRU” shall mean a production reporting unit, which is either an individual producing zone or approved commingled producing zones within a dry natural gas well which was previously productive prior to the effective date of this rule.

3) “FUB” shall mean distance from a drilling unit boundary line.

4) “New PRU” shall mean a production reporting unit, which is either an individual producing zone (in a newly drilled dry natural gas well or a new zone in an existing dry natural gas well) or approved commingled producing zones within a dry natural gas well which becomes productive after the effective date of this rule.

5) “Penalty Allowable” shall mean the PRU Deliverability of the New or Existing
PRU, subject to a Penalty Factor, a New or Existing PRU is allowed to produce and sell on a per day basis.

6) “Penalty Factor” shall mean the factor which is multiplied by the New or Existing PRU to impose a penalty (or reduction) upon the PRU Deliverability.

7) "PRU Deliverability" shall mean the measured volume of dry natural gas from an Existing or New PRU under normal operating conditions for that Existing or New PRU as determined by the IOPT or Production Test.

8) “Setback Footage” shall mean the required minimum distance a New or Existing PRU must be from the drilling unit boundary.

c) After the effective date of this rule, the Setback Footage for all drilling units subject to this rule shall be as follows:

1) For all existing drilling units with a Setback Footage that is less than 660 feet, the Setback Footage shall remain unchanged.

2) For all existing drilling units with a Setback Footage that is 660 feet or greater, the revised Setback Footage shall be re-established to 660 feet.

d) After the effective date of this rule, any Existing PRU not subject to a Penalty Allowable may produce at the PRU Deliverability.

e) After the effective date of this rule, any New PRU not subject to a Penalty Allowable may produce at the PRU Deliverability.

f) The Penalty Allowable, for any Existing or New PRU, after the effective date of this rule shall be determined as follows:

1) For any Existing PRU where the Setback Footage is equal to or greater than 660 feet, and where the Setback Footage has been re-established to 660 feet in accordance with subparagraph c) 2) above, the previously imposed penalty on the allowable established prior to the adoption of this rule shall be removed and the Existing PRU allowed to produce at the PRU Deliverability.

2) For any Existing PRU where there is Encroachment Footage, and where the Setback Footage has been re-established to a 660 feet in accordance with subparagraph c) 2) above, the previously imposed penalty on the allowable established prior to the adoption of this rule shall be re-calculated based on the revised Setback Footage of 660 feet in order to calculate the Penalty Allowable, except that any Existing PRU that has a re-calculated Penalty Allowable of less than 75 MCFD shall be assigned a Penalty Allowable of 75 MCFD.

3) For any Existing PRU, where the Setback Footage remains unchanged in accordance with subparagraph c) 1) above, the Penalty Allowable established prior to the adoption of this rule shall remain in effect, except that any Existing PRU that has a re-calculated Penalty Allowable of less than 75 MCFD shall be assigned a Penalty Allowable of 75 MCFD.
4) No New PRU may be located less than 660 feet FUB where the Setback Footage
has been re-established to a 660 feet in accordance with subparagraph c) 2)
above, or closer than the applicable Setback Footage that remained unchanged in
accordance with subparagraph c) 1) above, unless approved in accordance with
General Rule B-40, or an alternative is approved by the Commission after notice
and hearing.

g) In accordance with subparagraph f) 2) above, the Penalty Allowable shall be calculated as
follows:

1) If the Encroachment Footage encroaches upon only one boundary of said drilling
unit, the Penalty Allowable shall be the greater of 75 MCFD or calculated as
follows:

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\text{Penalty Allowable} = \text{PRU Deliverability} \times \text{Penalty Factor} \times \left(\frac{\text{Encroachment Footage}}{\text{Setback Footage}}\right) \times \frac{\text{proposed drilling unit acreage}}{640 \text{ acres or applicable established drilling unit acreage}}
\]

2) If the Encroachment Footage encroaches upon two boundaries of said drilling
unit, then the Penalty Allowable shall be the greater of 75 MCFD or the
cumulative of the penalties calculated as follows:

\[
\text{Penalty Allowable} = \text{PRU Deliverability} \times \text{Penalty Factor} \left(\frac{1 + \text{2nd Encroachment Footage}}{\text{Setback Footage}} - 1\right) \times \frac{\text{proposed drilling unit acreage}}{640 \text{ acres or applicable established drilling unit acreage}}
\]

h) Sales in Excess of the Penalty Allowable

1) An Existing or New PRU subject to a Penalty Allowable in accordance with this
rule shall have an annual balancing date of July 1, where the preceding 12 month
(July 1 – June 30) sales must be reconciled with the preceding 12 month Penalty
Allowable to determine if the PRU had excess sales.

2) An Existing or New PRU subject to a Penalty Allowable which has sales in
excess of the assigned Penalty Allowable must be shut-in on the annual balancing
date of July 1 and remain shut-in until all excess sales is eliminated. The shut-in
period shall be determined by dividing the excess sales by the Penalty Allowable.

3) Any Existing or New PRU subject to a Penalty Allowable which has excess sales
on the annual balancing date of July 1 and which fails to shut-in within 30 days
after the July 1, may be subject to a civil penalty not to exceed two thousand five
hundred dollars ($2,500.00) per day for every day the PRU produced beyond the
30 day period, and may be subject to further enforcement actions in accordance
a) Applicability

This rule shall only apply to dry natural gas wells for which it is necessary to determine the PRU Deliverability in accordance with General Rules A-7, B-43, B-44, D-19, D-21, or the request of the Director, or his designee, to conduct a back pressure test on a dry natural gas well.

b) Definitions

1) “Existing PRU” shall mean a production reporting unit, which is either an individual sources of supply or approved commingled producing zones within a dry natural gas well which was previously productive prior to the effective date of this rule.

2) “IOPT” shall mean an Initial One-Point Test performed to determine PRU Deliverability.

3) “New PRU” shall mean a production reporting unit, which is either an individual producing zone (in a newly drilled dry natural gas well or a new zone in an existing dry natural gas well) or approved commingled producing zones within a dry natural gas well which becomes productive after the effective date of this rule.

4) “Permit Holder” shall mean the person to whom the permit is issued and is responsible for all regulatory requirements relative to the production well.

5) “Production Test” shall mean any One-Point Test that is performed to determine PRU Deliverability which occurs after a successful One-Point Test has been performed.

6) "PRU Deliverability" shall mean the measured volume of dry natural gas from an Existing or New PRU under normal operating conditions for that Existing or New PRU as determined by the IOPT or Production Test.

c) An IOPT shall be conducted for any New PRU for the purpose of determining the PRU Deliverability. If a New PRU cannot be tested to determine the PRU Deliverability, a written explanation setting forth in detail the reasons why such IOPT cannot be obtained shall be submitted, along with a request for an alternative methodology to determine the PRU Deliverability.

d) Further Production Testing of an Existing or New PRU following an IOPT is not required except for purposes of retesting at the request of the Permit Holder to establish a penalty allowable in accordance with General Rule D-21, determining marginal well status for severance tax purposes in accordance with General Rule A-7, an additional completion request in accordance with D-19, or if requested by the Director or his designee.

e) IOPT or Production Testing Requirements:
1) Notice – The Permit Holder of the PRU shall provide notice in the manner prescribed by the Director, or his designee, at least seventy-two (72) hour notice in advance of an IOPT or a Production Test.

2) When to Conduct Test – The Permit Holder shall conduct the IOPT within ten (10) calendar days of commencement of production of a New PRU. The Director, or his designee, shall retain the right to require a re-test of an Existing or New PRU at any time. Additionally, the Permit Holder shall have the right to request a retest of an Existing or New PRU at any time.

3) Filing of Documents – The Permit Holder shall submit the results of the IOPT or Production Test within ten (10) business days of the test date.

4) AOGC Staff Witness – The IOPT is required to be witnessed by a representative of the AOGC unless the Permit Holder is notified by the AOGC that the test shall not be witnessed. Production tests for purposes of establishing marginal well determination, in accordance with General Rule A-7, are required to be witnessed by a representative of the AOGC. AOGC staff witness will be subject to notice by the Permit Holder in accordance with subparagraph (e) (1) above and subject to availability of an AOGC staff witness. All tests shall be conducted during normal working hours of the Commission unless otherwise approved by the Director or his designee.

f) Testing Methodology – An IOPT or Production Test shall be conducted to determine the PRU Deliverability. All tests shall be reported on a form prescribed by the Director, or his designee, and conducted as follows:

1) Before a test is started, the wellbore should be cleared of any accumulated fluids.

2) The Dry Natural Gas from the Existing or New PRU shall be flowed through the production facilities into the pipeline for a minimum of 24 hours. All flow rate measurements shall be obtained by the use of an orifice meter or other authorized metering device in good operating condition previously approved the Director or his designee.

3) Should the flow rate not be obtained to determine PRU Deliverability, the Permit Holder shall provide a written explanation setting forth in detail the reasons why such flow rate could not be obtained in accordance with this procedure. The Director, or his designee, may authorize an alternative method to determine PRU Deliverability.
a) Definitions


2) Non-Jurisdictional Pipeline means any onshore natural gas pipeline, including but not limited to flowlines, production lines, or gathering lines, not under jurisdiction of Federal Regulation 49 CFR Part 192 as amended, which is within the jurisdiction of the Arkansas Oil and Gas Commission in accordance with Ark. Code Ann. § 15-71-110 as amended.

3) Perennial Stream means: a stream that has flowing water year-round during a typical year, the water table is located above the stream bed for most of the year, groundwater is the primary source of water for stream flow, and runoff from rainfall is a supplemental source of water for stream flow.

4) Pipeline Operator means any person who owns or operates and is responsible for the construction, operation and maintenance of a natural gas pipeline which transports natural gas from the well within the jurisdiction of the Arkansas Oil and Gas Commission in accordance with Ark Code Ann. § 15-71-110 as amended.

b) Applicability

1) For purposes of this Rule, the jurisdiction of the Arkansas Oil and Gas Commission, as specified in Ark Code Ann. Ann. § 15-71-110 as amended, extends and includes:

   A) The production process or production facility as defined in Ark Code Ann. § 15-71-110 as amended; or

   B) A natural gas pipeline or associated facility whose owner is not affiliated with an Arkansas natural gas public utility and the majority owner is either a production company or an affiliate of a production company.

2) Every Pipeline Operator transporting natural gas by pipeline from the well is subject to the applicable provisions of this rule. Natural gas pipelines from the well, to a custodial transfer meter located on the well pad, are exempt from the provisions of this rule.

c) General Requirements for all Jurisdictional and Non-Jurisdictional Pipelines:

1) Each Pipeline Operator shall apply, on a form prescribed by the Director, for an initial statewide permit to construct and operate a natural gas pipeline system. The initial permit application shall contain at a minimum the following:

   A) Name, address and contact information for the Pipeline Operator;

   B) Map, or other media acceptable to the Director, showing the location of all natural gas pipelines from the producing wells through any production or
processing equipment or treating facility, and to the termination point of the jurisdiction of the Arkansas Oil and Gas Commission, including all public road, railroads and perennial stream crossings;

C) A determination as to what pipelines are jurisdictional;

D) Submission of the applicable permit fee as follows:

   (i) no permit fee is required for 1 mile or less, provided the pipeline does not cross a public road, railroad or perennial stream.

   (ii) less than 50 miles of pipeline, including pipelines in (c)(1)(D)(i) above which cross public roads, railroads or perennial streams - $500.00

   (iii) 50 miles to less than 100 miles of pipeline - $1,500.00

   (iv) 100 miles to less than 250 miles of pipeline - $2,500.00

   (v) 250 miles or more of pipelines - $5,000.00

2) Each Pipeline Operator shall be required to submit an annual permit renewal by January 31 of each year.

3) The renewal permit shall include a revised pipeline map showing any new pipeline additions constructed during the previous year, an annual report on a form prescribed by the Director, along with a permit renewal fee in accordance with paragraph (c)(1)(D) above. The renewal permit shall also contain the Pipeline Operator’s determination as to which pipelines are jurisdictional.

4) Each Pipeline Operator shall submit a Notice of Construction or Repair, on a form prescribed by the Director, prior to commencing construction or within 48 hours after completing repair, for each segment or project length of pipeline constructed during the year. The Notice shall indicate the location and extent of the natural gas pipelines to be constructed or repaired.

5) Each Pipeline Operator shall notify the Director, or his or her designee, within 24 hours of exceeding any natural gas pipeline’s established maximum allowable operating pressure. This shall be submitted on a form prescribed by the Director.

6) Each Pipeline Operator shall submit a Notice of Incident, on a form prescribed by the Director for each incident of release due to natural gas pipeline failure which results in:

   A) A death or personal injury requiring in-patient hospitalization; or

   B) A total cost of repair, including the value of natural gas lost, of ten thousand dollars ($10,000) or more; or

   C) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of subparagraphs (A) or (B) above.
d) Requirements for all Non-Jurisdictional Pipelines

1) Each Pipeline Operator shall submit a Notice of Incident, on a form prescribed by the Director for each incident of release due to natural gas pipeline failure which results in total cost of repair, including the value of natural gas lost, of fifty ten thousand dollars ($510,000) or more.

21) All pipelines crossing any stream or stream bed shall comply with applicable state and federal rules and regulations. Additionally, any stream crossing of perennial streams, constructed on or after December 16, 2007, shall maintain a minimum of fifty (50) feet of undisturbed stream bank for the protection of the stream. However, the fifty (50) feet of undisturbed stream bank requirement may be modified by the Director provided that the Pipeline Operator provides proof that the Pipeline Operator has received approval for the crossing from a state or federal agency.

32) Each Pipeline Operator shall place and maintain appropriate signage at all natural gas pipeline crossings of public roads and railroads. The marker should include the words “Warning”, “Caution” or “Danger” followed by the words “Gas Pipeline” along with the Pipeline Operator’s name and telephone number where the Pipeline Operator can be reached at all times.

43) Each Pipeline Operator which operates natural gas pipelines within the limits of any incorporated or unincorporated city, town or village, shall be a member of a qualified one-call program.

54) All natural gas pipelines, constructed after the effective date of this rule, shall be buried at least twenty-four (24) inches below ground surface, or in accordance with other applicable state or federal laws.

e) Requirements for Jurisdictional Pipelines

1) All Jurisdictional Pipelines shall be in compliance with construction, operation and maintenance requirements contained in Federal Regulations 49 CFR Part 192 Subpart A thru Subpart O P as amended, which are herein incorporated by reference.

2) All Jurisdictional Pipelines shall be subject to the applicable enforcement provisions of Federal Regulation 49 CFR Part 190 as amended, which are herein incorporated by reference.

3) All Jurisdictional Pipelines shall be subject to the applicable incident and other reporting requirements contained in Federal Regulation 49 CFR Part 191 as amended, which are herein incorporated by reference, and all such reports shall be submitted to the Arkansas Oil and Gas Commission.

4) All Pipeline Operator of Jurisdictional Pipelines shall be subject to the applicable drug and alcohol testing requirements contained in Federal Regulation 49 CFR Part 199 as amended, which are herein incorporated by reference.

5) All Jurisdictional Pipelines which contain over 100 PPM hydrogen sulfide shall also be subject to the provisions of subparagraph (f) below, unless the provisions of
Additional Requirements for All Pipelines Containing 100 PPM or Greater Hydrogen Sulfide.

1) Construction, Operating and Maintenance Requirements:

A) All pipeline materials must be chemically compatible with any natural gas transported by the natural gas pipeline and such pipeline shall maintain structural integrity under the anticipated temperatures and environmental conditions for which the natural gas pipeline may be exposed, and

B) All piping must be of sufficient thickness or must be installed with adequate protection to withstand anticipated external pressures and loads that will be imposed on the pipe after installation, and

C) No natural gas pipeline may be operated after new construction, repair or relocation until it has been successfully tested for at least one hour with a minimum pressure of 1.25 times the maximum operating pressure to substantiate the maximum operating pressure with all leaks located and eliminated, and

D) All metallic natural gas pipelines must be adequately protected from both external and internal corrosion and the pPipeline oOperator is required to submit an annual report, by March 31st of every year for the preceding calendar year, of the effectiveness of the company’s corrosion program, with such protection efforts performed by an independent contractor specializing in the control of corrosion.

2) Each pPipeline oOperator shall prepare, maintain and follow for each natural gas pipeline, a manual of written procedures for conducting operations, maintenance activities and emergency response. This plan must be reviewed and updated as often as necessary. A review must be conducted annually but not to exceed 15 months between reviews.

3) Each pPipeline oOperator shall have a procedure for continuing surveillance of its facilities and take appropriate action regarding, failures, corrosion and operating conditions.

4) Each pPipeline oOperator must develop and carry out a damage prevention program to prevent damage to its natural gas pipelines from excavation activities. Each pPipeline oOperator shall be a member of the state wide “one-call” system. The plan must have a method of communicating to excavators in the area where the natural gas pipeline is located of the existence of the natural gas pipeline, provide a means of receiving and recording notification of planned excavation activities, provide for temporary marking of the natural gas pipeline and inspection of the natural gas pipeline when the pPipeline oOperator has reason to believe it could be damaged by excavation activities.

5) Each pPipeline oOperator shall establish written procedures to minimize the hazards resulting from a natural gas pipeline emergency event. Each plan must include at a minimum:
A) Methods of receiving and identifying an event which requires immediate response; and

B) Methods for establishing and maintaining adequate communication with appropriate emergency response and public officials; and

C) Methods for determining safe areas related to evacuation and security during an event; and

D) Methods for training employees of their duties and responsibilities during an event.

6) Each pipeline operator shall develop and implement a written continuing public awareness plan which includes provisions for educating the public, appropriate governmental organizations and persons engaged in excavation activities. Use of a one-call notification prior to conducting excavation, possible hazards associated with unintended releases from the natural gas pipeline, physical indications that such a release may have occurred, steps that should be taken for the safety of the public, procedures for reporting such an event. The program must include activities to advise affected municipalities, schools, businesses and residents along the pipeline right of way. The program and media used must be as comprehensive as necessary to reach all areas in which the pipeline operator shall transport gas.

7) Each pipeline operator shall establish procedures for analyzing accidents and failures for the purpose of determining the cause of the failure and minimizing the possibility of subsequent reoccurrence.

8) Each pipeline operator shall not operate any natural gas pipeline at a pressure that exceeds the documented pressure at which the natural gas pipeline may be safely operated.

9) Each pipeline operator shall have a patrol program to observe surface conditions on and adjacent to its pipeline right-of-way for indications of leaks, construction activity, erosion, condition of signage, conditions at public road and railroad crossings and other factors affecting safety and operation of the pipeline. Patrols shall be conducted and documented at least twice each calendar year, not to exceed 7 ½ months between patrols.

10) Each pipeline operator shall maintain appropriate pipeline markers at all public road and railroad crossings and along the pipeline at intervals necessary to identify the location of the buried pipeline. The marker should include the words “Warning”, “Caution” or “Danger” followed by the words “Gas Pipeline” along with the pipeline operator’s name and telephone number where the pipeline operator can be reached at all times.

11) Each pressure relieving device in a compressor station, pressure limiting station or regulator station must be inspected, tested and operated at the pipelines maximum operating pressure, once each calendar year and not to exceed 15 months to determine proper operation.

12) Each remote controlled shutdown device must be inspected and tested once each calendar year and not to exceed 15 months to determine proper operation.
13) Each line valve that serves to block a segment of pipeline and or might be used in an emergency, must be inspected and partially operated once each calendar year and not to exceed 15 months.

14) Each pipeline operator shall maintain records associated with operation and maintenance of the pipeline required in this section.

15) Each natural gas pipeline abandoned in place must be disconnected from all sources of gas, purged of gas, filled with freshwater or inert material and sealed at both ends. When a pipeline is being purged all efforts must be taken to (i) prevent the formation of a hazardous mixture of gas and air, (ii) ensure that all safety equipment necessary is present, (iii) remove all non-essential persons from the area and (iv) ensure the public is adequately protected.
RULE D-21: PROCEDURES FOR DETERMINING THE PRODUCTION ALLOWABLE FOR DRY NATURAL GAS PRODUCTION WELLS

a) Applicability

This rule shall only apply to dry natural gas wells for which it is necessary to determine the PRU Deliverability in accordance with General Rules B-43, B-44 and other applicable General Rules, Field Rules or Commission Orders. This rule shall not apply to any PRU subject to provisions of General Rule B-45.

b) Definitions

1) “Allowable” shall mean the PRU Deliverability for a New or Existing PRU is allowed to produce and sell on a per day basis.

2) “Encroachment Footage” shall mean the actual footage of the New or Existing PRU from the drilling unit boundary, when that footage is less than the Setback Footage specified by rule.

3) “Existing PRU” shall mean a production reporting unit, which is either an individual producing zone or approved commingled producing zones within a dry natural gas well which was previously productive prior to the effective date of this rule.

4) “New PRU” shall mean a production reporting unit, which is either an individual producing zone (in a newly drilled dry natural gas well or a new zone in an existing dry natural gas well) or approved commingled producing zones within a dry natural gas well which becomes productive after the effective date of this rule.

5) “Penalty Allowable” shall mean the PRU Deliverability of the New or Existing PRU, subject to a Penalty Factor, a New or Existing PRU is allowed to produce and sell on a per day basis.

6) “Penalty Factor” shall mean the factor which is multiplied by the New or Existing PRU to impose a penalty (or reduction) upon the PRU Deliverability.

7) "PRU Deliverability" shall mean the measured volume of dry natural gas from an Existing or New PRU under normal operating conditions for that Existing or New PRU as determined by the IOPT or Production Test conducted in accordance with General Rule D-16.

8) “Setback Footage” shall mean the required minimum distance a New or Existing PRU must be from the drilling unit boundary.

9) “FUB” shall mean distance from a drilling unit boundary line.
RULE D-21: PROCEDURES FOR DETERMINING THE PRODUCTION ALLOWABLE FOR DRY NATURAL GAS PRODUCTION WELLS

a) Applicability

This rule shall only apply to dry natural gas wells for which it is necessary to determine the PRU Deliverability in accordance with General Rules B-43, B-44 and other applicable General Rules, Field Rules or Commission Orders. This rule shall not apply to any PRU subject to provisions of General Rule B-45.

b) Definitions

1) “Allowable” shall mean the PRU Deliverability for a New or Existing PRU is allowed to produce and sell on a per day basis.

2) “Encroachment Footage” shall mean the actual footage of the New or Existing PRU from the drilling unit boundary, when that footage is less than the Setback Footage specified by rule.

3) “Existing PRU” shall mean a production reporting unit, which is either an individual producing zone or approved commingled producing zones within a dry natural gas well which was previously productive prior to the effective date of this rule.

4) “New PRU” shall mean a production reporting unit, which is either an individual producing zone (in a newly drilled dry natural gas well or a new zone in an existing dry natural gas well) or approved commingled producing zones within a dry natural gas well which becomes productive after the effective date of this rule.

5) “Penalty Allowable” shall mean the PRU Deliverability of the New or Existing PRU, subject to a Penalty Factor, a New or Existing PRU is allowed to produce and sell on a per day basis.

6) “Penalty Factor” shall mean the factor which is multiplied by the New or Existing PRU to impose a penalty (or reduction) upon the PRU Deliverability.

7) "PRU Deliverability" shall mean the measured volume of dry natural gas from an Existing or New PRU under normal operating conditions for that Existing or New PRU as determined by the IOPT or Production Test conducted in accordance with General Rule D-16.

8) “Setback Footage” shall mean the required minimum distance a New or Existing PRU must be from the drilling unit boundary.

9) “FUB” shall mean distance from a drilling unit boundary line.
c) Any New or Existing PRU, not subject to a Penalty Factor in accordance with subparagraph f) below, shall be subject to an allowable as follows:

1) A New or Existing PRU shall have an allowable determined as follows: Allowable = PRU Deliverability x (proposed drilling unit acreage ÷ 640 acres or applicable established drilling unit acreage)

2) A New or Existing PRU with a PRU Deliverability of less than 75 MCFD shall have an allowable determined as follows: Allowable = 75 MCFD. PRU Deliverability of less than 75 MCFD shall be demonstrated by either:

A) Conducting a test utilizing the methodology specified in General Rule D-16; or

B) Utilizing the most recent six month average daily rate of production for the PRU under actual operating conditions calculated by dividing the total gas reported by the number of days produced during the applicable six month period.

d) Any New or Existing PRU subject to a Penalty Allowable, the Penalty Allowable shall be determined as calculated as follows:

1) If the Encroachment Footage encroaches upon only one boundary of said drilling unit, the Penalty Allowable shall be the greater of 75 MCFD or calculated as follows:

Penalty Allowable = PRU Deliverability x Penalty Factor (Encroachment Footage ÷ Setback Footage) x proposed drilling unit acreage ÷ 640 acres or applicable established drilling unit acreage.

2) If the Encroachment Footage encroaches upon two boundaries of said drilling unit, then the Penalty Allowable shall be the greater of 75 MCFD or the cumulative of the penalties calculated as follows:

Penalty Allowable = PRU Deliverability x Penalty Factor [(1st Encroachment Footage + 2nd Encroachment Footage) ÷ Setback Footage -1] x proposed drilling unit acreage ÷ 640 acres or applicable established drilling unit acreage.

e) Sales in Excess of the Penalty Allowable

1) An Existing or New PRU subject to a Penalty Allowable in accordance with this rule shall have an annual balancing date of July 1, where the preceding 12 month (July 1 – June 30) sales must be reconciled with the preceding 12 month Penalty Allowable to determine if the PRU had excess sales.

2) An Existing or New PRU subject to a Penalty Allowable which has sales in excess of the assigned Penalty Allowable must be shut-in on the annual balancing date of July 1 and remain shut-in until all excess sales is eliminated. The shut-in period shall be determined by dividing the excess sales by the Penalty Allowable.
3) Any Existing or New PRU subject to a Penalty Allowable which has excess sales on the annual balancing date of July 1 and which fails to shut-in within 30 days after the July 1, may be subject to a civil penalty not to exceed two thousand five hundred dollars ($2,500.00) per day for every day the PRU produced beyond the 30 day period, and may be subject to further enforcement actions in accordance with General Rule A-5, and Ark. Code Ann. § 15-72-401 through 15-72-406.
General Rule D-22 - Requirements for Lease Rights Gas Supply Lines

a) Definitions

1) “Director” shall mean the Director of the Oil and Gas Commission.

2) “Lease Rights Gas Supply Line” shall mean a pipeline, under jurisdiction of the Arkansas Oil and Gas Commission (“AOGC”) as defined in Ark. Code Ann. § 15-71-110, which transports natural gas from a Well Operator Connection, located at a natural gas well, or other natural gas production equipment located upstream of the production meter on the well location to a single end user.

3) “Lease Rights Gas Supply Line Operator” shall mean a Lease Rights Gas Supply Line owner who has an agreement authorizing natural gas supply, who accesses directly from the Well Operator Connection, and who owns or operates and is responsible for the construction, operation and maintenance of a Lease Rights Gas Supply Line.

4) “Lease Rights Gas” shall mean the gas owned and controlled by the Lease Rights Gas Supply Line Operator once it passes the Well Operator Connection.

5) “Well Operator Connection” shall mean the point at which the Operator provided access point connects to the Lease Rights Gas Supply Line and at which point the control of the gas by the Operator terminates and is assumed by the Lease Rights Gas Supply Line Operator.

b) All Lease Rights Gas Supply Lines located downstream of a production meter at the natural gas well or other natural gas production equipment located on the well location, and which is under the jurisdiction of AOGC as defined in Ark. Code Ann. § 15-71-110, are not subject to the provisions of this rule, but shall be subject to all other applicable Federal and State rules and regulations governing natural gas pipelines.

c) All new Lease Rights Gas Supply Lines originating at a Well Operator Connection, constructed after the effective of this rule, are subject to the provisions of this rule at the time of construction.

d) Within ninety (90) days of the effective date of this Rule, for all existing Lease Rights Gas Supply Lines, the Operators providing a Well Operator Connection shall provide the Director with a list of names and addresses of the legally entitled recipients of the Lease Rights Gas, as reflected in the records of the Operator. The Director shall send a letter to each Lease Rights Gas Supply Line Operator notifying them of the requirements of this Rule.

e) Within six (6) months from the date the notification letter was sent in accordance with subparagraph (d) above, all Lease Rights Gas Supply Line Operators existing at the time this Rule is adopted, shall document compliance with items 1 through 6 below, by the submission of documentation to the Director or his or her designee demonstrating compliance. If the Lease Rights Gas Supply Line Operator fails to submit the required
documentation demonstrating compliance with items 1 through 6 below, or if the Lease Rights Gas Supply Line Operator fails to comply with items 1 through 6 below, the Director or his or her designee may authorize the Operator to disconnect the Lease Rights Gas Supply Line until such time as the Lease Rights Gas Supply Line Operator is in full compliance with the provisions of this Rule. The Lease Rights Gas Supply Line Operator shall:

1) Utilizing the services of a plumber licensed by the State of Arkansas, properly install one or more properly-sized regulator(s) on the Lease Rights Gas Supply Line at the Well Operator Connection point and all necessary piping to accommodate appropriate odorization, gas utilization metering equipment, and a properly-sized regulator at the dwelling or structure where the natural gas is utilized. All materials used shall be designed for natural gas service and provide structural integrity where necessary;

2) Utilizing the services of a plumber licensed by the State of Arkansas, properly install an excess flow valve on the Lease Rights Gas Supply Line as close to the Well Operator Connection as feasible;

3) Utilizing the services of a plumber licensed by the State of Arkansas, properly install appropriate dehydration and odorization facilities on the Lease Rights Gas Supply Line downstream from the Well Operator Connection;

4) Utilizing the services of a plumber licensed by the State of Arkansas, properly install a new Lease Rights Gas Supply Line or test an existing Lease Rights Gas Supply Line, as follows:

   A) New Lease Rights Gas Supply Lines shall be constructed of steel or plastic which is designed, manufactured and intended for natural gas service in accordance with industry standards. Each newly constructed gas supply line must be tested and free of leaks prior to placing into service. Each test shall be at a pressure of fifty (50) psig for a period of thirty (30) minutes. All piping shall be installed in a manner which will minimize strain or external loading. If plastic pipe is used, it shall be installed so as to minimize tensile stresses and must have a tracer wire or means of locating the pipe while underground. Tracer wire may not be wrapped around the plastic pipe and contact with the pipe should be avoided with at least two (2) inches between the wire and the Lease Rights Gas Supply Line;

   B) All newly constructed Lease Rights Gas Supply Lines shall be buried and have a minimum of eighteen (18) inches of cover or greater if necessary to not pose a safety hazard to surface activities conducted along the Lease Rights Gas Supply Line right-of-way;

   C) All existing Lease Rights Gas Supply Lines must be pressure tested in accordance with e) 4) A) above; and

   D) All repairs or relocation of a Lease Rights Gas Supply Line must be performed by a plumber licensed by the State of Arkansas and be in accordance with all applicable above provisions.
5) Install and maintain signage within the line of sight along the Lease Rights Gas Supply Line, with such signs to include words 1” in height and ¼” in stroke “WARNING – DANGER – NATURAL GAS PIPELINE”, and including the name, address and 24-hour contact information of the Lease Rights Gas Supply Line Operator; and

6) Provide the Director, or his or her designee, and the Operator written notification of the name, address, and telephone number that should be used to notify the Lease Rights Gas Supply Line Operator of any emergency condition. The Lease Rights Gas Supply Line Operator shall ensure that this information is kept current with the Director, or his or her designee, and the Operator.

f) The Lease Rights Gas Supply Line Operator shall, utilizing the services of a plumber licensed by the State of Arkansas, inspect the Lease Rights Gas Supply Line and associated equipment on an annual basis, make proper repairs as necessary and provide evidence of such inspection and repair to both the Operator and the Director or his or her designee.

g) Produced fluids collected by the Lease Rights Gas Supply Line Operator shall be removed from the site and disposed in accordance with applicable Arkansas Oil and Gas Commission and Arkansas Department of Environmental Quality rules and regulations. Produced fluids shall not be discharged onto the ground surface or into waters of the state. Any spill of produced fluids shall be remediated in accordance with applicable Arkansas Oil and Gas Commission and Arkansas Department of Environmental Quality rules and regulations.

h) All Lease Rights Gas Supply Lines existing at the time this Rule is adopted which are servicing multiple domestic or end users are prohibited, and within six (6) months from the date the notification letter sent in accordance with subparagraph (d) above, the Lease Rights Gas Supply Line Operator shall reconfigure the Lease Rights Gas Supply Line to only allow for a single domestic or end user per Lease Rights Gas Supply Line.

i) Lease Rights Gas Supply Lines Operators shall maintain compliance with the provisions of this Rule. If a Lease Rights Gas Supply Line Operator fails to comply with the provisions of this Rule, the Director or his or her designee shall give Notice of the Violation, in accordance with General Rule A-5, to the Lease Rights Gas Supply Line Operator. The Lease Rights Gas Supply Line Operator shall have thirty (30) days to comply with the Notice of Violation. If the Lease Rights Gas Supply Line Operator fails to comply or properly request a review or appeal in accordance with General Rule A-5, then the Director or his or her designee may authorize the Operator to disconnect the Lease Rights Gas Supply Line until such time as the Lease Rights Gas Supply Line Operator is in full compliance with the provisions of this Rule. Any appeal of a Director’s Decision for a Notice of Violation issued in accordance with this subparagraph shall not be subject to the filing fee required in accordance with General Rule A-2 or A-3.

j) Lease Rights Gas Supply Line Operators are no longer subject to the provisions of this rule if the well, where the Well Operator Connection is located, is transferred to the Lease Rights Gas Supply Line Operator in accordance with General Rule B-11.