Department of Natural Resources
Office of Conservation

Advanced Notice of Proposed Rulemaking and
Solicitation of Comments

LAC 43:XIX Chapter 1 – General Provisions
LAC 43:XIX Chapter 2 – Additional Requirements for Water Operations
LAC 43:XIX Chapter 11 – Required Use of Storm Chokes

As part of the ongoing efforts to promote oil and gas exploration and production activities while protecting public health, safety and the environment, the Office of Conservation is considering regulatory amendments intended to reduce the potential for oil and gas operations to impact public health, safety and the environment.

These amendments revise the operational and safety requirements for the drilling, completion, and workover of oil and gas wells in Louisiana and most were jointly developed by representatives from regulatory, industry, and academic sectors. Recognizing that the State of Louisiana includes many different operating environments and well types, an attempt was made to employ a tiered approach to regulatory requirements whenever possible.

Based on the number and complexity of regulatory changes being considered, the Department of Natural Resources – Office of Conservation is hereby seeking comments from all interested parties on the proposed rule amendments being considered along with information on the potential fiscal and economic impacts of such rules on all affected parties. This information will be invaluable to this Office as the rule development process continues.

Written comments addressing these issues are due no later than 4:30 p.m., September 20, 2012, and should be submitted to Chris Sandoz, Engineering Division, Office of Conservation, Louisiana Department of Natural Resources, P. O. Box 94275, Baton Rouge, LA 70804-9275 or by Fax to (225) 342-2584.

Title 43
NATURAL RESOURCES
Part XIX. Office of Conservation—General Operations
Subpart 1. Statewide Order No. 29-B

Chapter 1. General Provisions

§101. Definitions

A. Unless the context otherwise requires, the words defined in this Section shall have the following meanings when found in this Chapter ~~order~~.

Agent—the director of the Division of Minerals, the chief engineer thereof, or any of the district managers or their aides.

Completion Operations — the work conducted to establish production from a well after the production casing string or liner has been set, cemented, and pressure-tested.

Conductor Pipe — pipe ordinarily used for the purpose of supporting unconsolidated surface deposits.

Cubic foot of gas — the amount of gaseous hydrocarbons contained in a cubic foot of space at the base temperature of 60 degrees F and an absolute pressure of 14.4 lbs./sq. in. plus 10 oz./sq. inch, which temperature and pressure are referred to as the base temperature and pressure, respectively.

Department—the Department of Natural Resources, Office of Conservation of the state of Louisiana.

District Manager—the head of any one of the districts of the state under the ~~Division of Minerals~~ Office of Conservation, and as used herein, refers specifically to the manager within whose district the well or wells are located.

Drive Pipe — pipe ordinarily used for the purpose of supporting unconsolidated surface deposits.

Incapable of Flow — a condition in which reservoir pressure has declined to a point at which a well no longer produces by means of natural energy; or a well from which flow is mechanically impossible. These conditions must be satisfied at all times during and at the completion of the operations being conducted while the tree is removed.

Intermediate Casing — casing used as protection against caving of heaving formations or for isolation of abnormally pressured formations or when other means are not adequate for the purpose of segregating upper oil, gas or water-bearing strata.

Liner – a string of pipe used to case open hole below existing casing which extends from the setting depth up into another string of casing, but which does not extend to the surface.

Office — the Department of Natural Resources, Office of Conservation of the State of Louisiana.

Production Casing — casing used for the purpose of segregating the horizon from which production is obtained and affording a means of communication between such horizons and the surface.

Surface Casing – casing used to protect shallow fresh-water sands.

Underground Source of Drinking Water (USDW) - for the purpose of administering these rules and regulations is defined in LAC 43:XIX.403.B.

Water Location—Inland Lakes and Bays—any water location in the coastal zone area as defined in R.S. 49:214.27 except in a field designated as offshore by the Commissioner.

Water Location—Offshore—any water location in a field designated as offshore by the Commissioner.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Adopted by the Department of Conservation (August 1943), amended by the Department of Natural Resources, Office of Conservation, LR 37:

§103. Application to Drill

A. …

1. An application to drill a well with a surface location that is within 1,000 feet of an Interstate highway, state highway, or residential or commercial area within the limits of an incorporated city, town or village shall be accompanied by an emergency action plan. The district manager may, at his discretion, require the submission of an emergency action plan for any well.

~~1~~2. Applicants that receive a drilling permit for a well located within 1,000 feet of an Interstate highway, state highway, or residential or commercial area within the limits of an incorporated city, town or village shall furnish a copy of the approved drilling permit, emergency action plan and the certified location plat to the appropriate state and local authorities, including all emergency responders.

B. – E. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Adopted by the Department of Conservation (August 1943), amended (August 1958), (August 1961), (May 1973), amended by the Department of Natural Resources, Office of Conservation, LR 34:2639 (December 2008), LR 37.

§105. All Other Applications

A. All applications for permits to repair (except ordinary maintenance operations), abandon (plug and abandon), acidize, hydraulically fracture stimulate, deepen, perforate, perforate and squeeze, plug (plug back), plug and perforate, plug back and side-track, plug and squeeze, pull casing, side-track, squeeze, squeeze and perforate, workover, cement casing or liner as workover feature, or when a well is to be killed or directionally drilled, shall be made to the district office on Form ~~MD-11~~DM-4R and a proper permit shall be received from the district manager before work is started. A description of the work done under the above recited work permits shall be furnished on the reverse side of the Well History and Work Resume Report (Form WH-1), which form shall be filed with the district office of the ~~Department~~ Office of Conservation in which the well is located within 20 days after the completion or recompletion of the well. At least 12 hours prior notice of the proposed operations shall be given the district manager ~~and~~/or his designee ~~an offset operator in order that one of them may witness the work. If the district manager fails to appear within 12 hours, the work may be witnessed by the offset operator, but failing in this, the~~

~~work need not be held up longer than 12 hours. This rule shall not deter an operator from taking immediate action in an emergency to prevent damage.~~

B. When a service company, other than the drilling contractor, cements, perforates or acidizes, either before or after completion of a well, the service company shall furnish the district manager with legible exact copies of reports furnished the owner of the well.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Adopted by the Department of Conservation (August 1943), amended (August 1958), amended by the Department of Natural Resources, Office of Conservation, LR 37:

§109. Casing Program

A. General Requirements

1. The operator shall case and cement all wells with a sufficient number of strings of casing and quantity and quality of cement in a manner necessary to prevent fluid migration in and around the wellbore, protect the underground source of drinking water (USDW) from contamination, support unconsolidated sediments, prevent waste of resources, and otherwise provide a means of control of the formation pressures and fluids.

2. The operator shall install casing necessary to withstand collapse, burst, tensile, and other stresses that may be encountered and the well shall be cemented in a manner which will anchor and support the casing. Safety factors in casing program design shall be of sufficient magnitude to provide optimum well control while drilling and to assure safe operations for the life of the well.

3. Formation Integrity Tests

a. A formation integrity test must be conducted below the surface casing or liner and all intermediate casings or liners. The district manager may require a formation integrity test at the conductor casing shoe if warranted by local geologic conditions or the planned casing setting depth. Each formation integrity test must be conducted after drilling at least 10 feet but no more than 50 feet of new hole below the casing shoe and must be tested to either the formation leak-off pressure or to a pressure equivalent to 0.5 ppg above the anticipated drilling fluid weight at the setting depth of the next casing string. All test results and hole-behavior observations made during the course of drilling related to formation integrity and pore pressure shall be recorded in the driller's report.

4. Prolonged Drilling Operations

a. If drilling operations continue for more than 30 days within a casing string run to the surface:

i. Drilling operations must be stopped as soon as practicable, and the effects of the prolonged operations on continued drilling operations and the life of the well evaluated. At a minimum, the operator shall conduct a caliper or pressure test of the casing;

ii. If casing integrity as determined by the evaluation has deteriorated to a level below minimum safety factors, the casing must be repaired or another casing string run. Approval from the district manager shall be obtained prior to any casing repair activity.

~~A~~B. Drive or Conductor Pipe. ~~Conductor pipe is that pipe ordinarily used for the purpose of supporting unconsolidated surface deposits.~~ The use and removal of conductor pipe or drive pipe during the drilling of any oil and gas well shall be at the option of the operator.

~~B~~C. Surface Casing

1. Surface casing shall be set at a depth which provides full protection of the USDW. Where no danger of pollution of fresh water sources exists, the minimum amount of surface or~~f~~ first-intermediate casing to be set shall be determined from Table 1 hereof.

Table 1 – Surface Casing			
Total Depth of Contact	**Casing Required**	~~**Number of Sacks Cement**~~	**Min. Surface Casing Test Pressure (lbs. per sq. in.)**
0-2500	100	~~200 or circulate to surf*~~	300
2500-3000	150	~~500 "~~	600

Table 1 – ~~Surface Casing~~			
Total Depth of Contact	**Casing Required**	**~~Number of Sacks Cement~~**	**Min. Surface Casing Test Pressure (lbs. per sq. in.)**
3000-4000	300	~~500 "~~	600
4000-5000	400	~~500 "~~	600
5000-6000	500	~~500 "~~	750
6000-7000	800	~~500 "~~	1000
7000-8000	1000	~~500 "~~	1000
8000-9000	1400	~~500 "~~	1000
9000-Deeper	1800	~~500 "~~	1000

~~**Circulate to the Surface* shall mean the calculated amount of cement necessary to fill the theoretical annular space plus 10 percent.~~

a. Alternative methods of USDW protection may be approved by the District Manager.~~In known low-pressure areas, exceptions to the above may be granted by the commissioner or his agent. If, however, in the opinion of the commissioner, or his agent, the above regulations shall be found inadequate, and additional or lesser amount of surface casing and/or cement or test pressure shall be required for the purpose of safety and the protection of fresh water sands~~.

2. Surface casing shall be cemented with a sufficient volume of cement to insure cement returns to the surface. If no returns are seen at the surface, a top-off job must be performed.

~~2~~3. Surface casing shall be tested before drilling the plug, float equipment, or guide shoe by applying a minimum pump pressure as set forth in Table 1 ~~after at least 200 feet of the mud-laden fluid has been displaced with water at the top of the column~~. If at the end of 30 minutes the pressure gauge shows a drop of 10 percent of test pressure as outlined in Table 1, the operator shall be required to take such corrective measures as will insure that such surface casing will hold said pressure for 30 minutes without a drop of more than 10 percent of the test pressure. The provisions of Paragraph ~~D~~E.~~7~~6, below, for the producing casing, shall also apply to the surface casing.

~~3~~4. Cement shall be allowed to stand a minimum of 12 hours under pressure before initiating test or drilling plug, float equipment, or guide shoe. Under pressure is complied with if one float valve is used or if pressure is held otherwise.

~~C~~D. Intermediate Casing/Drilling Liner

1. ~~Intermediate casing is that casing used as protection against caving of heaving formations or when other means are not adequate for the purpose of segregating upper oil, gas or water-bearing strata.~~ Intermediate casing/drilling liner shall be set when required by abnormal pressure or other well conditions. The provisions of Paragraphs E.2 through E.8 below, for the production casing, shall also apply to the intermediate casing.

2. If an intermediate casing string is deemed necessary by the district manager for the prevention of underground waste, such regulations pertaining to a minimum setting depth, quality of casing, ~~and~~ cementing and testing ~~of sand~~, shall be determined by the ~~department~~ Office of Conservation after due hearing. ~~The provisions of Paragraph D.7 below, for the producing casing, shall also apply to the intermediate casing.~~

3. If a drilling liner is used, the following minimum requirements must be met:

a. the liner-lap point must be at least 300 feet above the previous casing shoe. Any liner-lap less than 300 feet must be approved by the District Manager;

b. the cement shall be tested prior to drilling out the shoe by a fluid entry test to determine whether a seal between the liner top and next larger casing string has been achieved. The fluid entry test shall be conducted in a manner which induces a pressure drop at the liner top equivalent to 0.5 ppg below the estimated pore pressure at the liner top;

c. the drilling liner (and liner-lap) shall be tested to a pressure at least equal to the anticipated pressure to which the liner will be subjected to during the formation-integrity test below that liner shoe, or subsequent liner shoes if set. Testing shall be in accordance with LAC 43:XIX.109.A.3.

~~D~~E. Product~~ing~~ion ~~Oil String~~ Casing/Production Liner

~~1. Producing or oil string is that casing used for the purpose of segregating the horizon from which production is obtained and affording a means of communication between such horizons and the surface.~~

~~2~~1. The ~~producing string of~~ production casing shall consist of new or reconditioned casing, tested at mill test pressure or as otherwise designated by the ~~department~~ Office of Conservation ~~and set at a sufficient depth to cut off all gas formations above the oil-saturated horizon in which the well is to be completed. The position of the oil horizon shall be determined by coring, testing or electrical logging, or other satisfactory method, and the producing string of casing shall be bottomed and cemented at a point below the gas/oil contact if determinable and practicable~~.

~~3~~2. Cement shall be by the pump-and-plug method, or another method approved by the department. ~~Sufficient cement shall be used to fill the calculated annular space behind the casing to such a point, as in the opinion of the district manager, local conditions require to protect the producing formations and all other oil and gas formations occurring above~~ The production casing/production liner shall be cemented using a sufficient volume of cement to fill the calculated casing annulus to at least 500 feet above all known hydrocarbon bearing formations to insure isolation of all known hydrocarbon formations and abnormally pressured formations, but in ~~every~~ no case~~, no~~ shall less cement ~~shall~~ be used than the calculated amount necessary to fill the ~~annular space~~ casing/liner annulus to a point 500 feet above the shoe or the top of the liner whichever is less.

~~4~~3. The amount of cement to be left remaining in the casing, until the requirements of Paragraph 5 below have been met, shall be not less than 20 feet. This shall be accomplished through the use of a float-collar, or other approved or practicable means~~, unless a full-hole cementer, or its equivalent, is used~~.

~~5~~4. Cement shall be allowed to stand a minimum of 12 hours under pressure and a minimum total of 24 hours before initiating test or drill plug in the producing or oil string. Under pressure is complied with if one or more float valves are employed and are shown to be holding the cement in place, or when other means of holding pressure is used. When an operator elects to perforate and squeeze or to cement around the shoe, he may proceed with such work after 12 hours have elapsed after placing the first cement.

~~6~~5. Before drilling the plug in the producing string of casing, the casing shall be tested by pump pressure, as determined from Table 2 hereof.~~, after 200 feet of mud-laden fluid in the casing has been displaced by water at the top of the column.~~

Table 2. Intermediate and Production~~ing~~ Casing

~~String Pressure~~ Set Depth ~~Set~~	~~No. of Sacks of Cement~~	~~Producing~~ Min. Test Pressure (lbs. per sq. in.)
2000-3000'	~~200*~~	800
3000-6000'	~~300*~~	1000
6000-9000'	~~500*~~	1200
9000-and deeper	~~500*~~	1500

~~*But in every case no less cement shall be used than the calculated amount necessary to fill the annular space to a point 500 feet above the shoe.~~

a. If at the end of 30 minutes the pressure gauge shows a drop of 10 percent of the test pressure or more, the operator shall be required to take such corrective measures as will insure that the producing string of casing is so set and cemented that it will hold said pressure for 30 minutes without a drop of more than 10 percent of the test pressure on the gauge.

~~7~~6. If a production liner is used, the following minimum requirements must be met:

a. the liner-lap point must be at least 300 feet above the previous casing shoe. Any liner-lap less than 300 feet must be approved by the District Manager.;

b. the cement shall be tested prior to drilling out the shoe by a fluid entry test to determine whether a seal between the liner top and next larger casing string has been achieved. The fluid entry test shall be conducted in a manner which induces a pressure drop at the liner top equivalent to 0.5 ppg below the estimated pore pressure at the liner top;

c. the production liner (and liner-lap) shall be tested to a pressure at least equal to the anticipated pressure to which the liner will be subjected to during the formation-integrity test below that liner shoe, or subsequent liner shoes if set. Testing shall be in accordance with LAC 43:XIX.109.A.3.

7. If the ~~c~~Commissioner's agent is not present at the time designated by the operator for inspection of the casing tests of the producing string, the operator shall have such tests witnessed, preferably by a contractor or an offset operator. An affidavit of test, on the form prescribed by the ~~Department~~ Office of Conservation, signed by the operator and witness, shall be furnished to the district office of the ~~Department~~ Office of Conservation showing that

the test conformed satisfactorily to the above mentioned regulations before proceeding with the completion. If test is satisfactory, normal operations may be resumed immediately.

8. If ~~the~~ any test is unsatisfactory, the operator shall not proceed with the completion of the well until a satisfactory test has been obtained.

F. Cement Top Verification

1. To ensure isolation of hydrocarbon bearing formations and to demonstrate compliance with the minimum cementing requirements of LAC 43:XIX.109.E.2, operators shall monitor returns and displacement pressures during all casing cementing operations.

2. Operators shall confirm top of cement in cases where abnormal displacement pressures and/or lost circulation occur during casing cementing operations.

3. Should an operator be unable to confirm the placement of cement in accordance with the requirements of LAC 43:XIX.109.E.2, the operator shall submit an evaluation plan to the District Manager to demonstrate that the cement placement provides protection of the USDW and prevents waste of hydrocarbon resources and/or well control complications in the subject well or in adjacent wells.

4. Cementing and wireline records demonstrating the presence of the required annulus cement top shall be retained by the operator for a period of two years.

~~E~~G. Tubing and Completion

1. Well-completion operations means the work conducted to establish the production of a well after the production-casing string has been set, cemented, and pressure-tested.

2. Prior to engaging in well-completion operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date, time, and attendees of safety meetings shall be recorded and available for review by the Office of Conservation.

~~1~~3. A valve, or its equivalent, tested to a pressure of not less than the calculated bottomhole pressure of the well, shall be installed below any and all tubing outlet connections.

4. No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

~~2~~5. When a well develops a casing pressure, upon completion, equivalent to more than three-quarters of the internal pressure that will develop the minimum yield point of the casing, such well shall be required by the district manager to be killed, and a tubing packer to be set so as to keep such excessive pressure off the casing.

~~F~~H. Wellhead Connections.

1. Wellhead connections shall be tested prior to installation at a pressure indicated by the district manager in conformance with conditions existing in areas in which they are used. Whenever such tests are made in the field, they shall be witnessed by an agent of the department. Tubing and tubingheads shall be free from obstructions in wells used for bottomhole pressure test purposes.

2. When the tree is installed, the wellhead shall be equipped so that all annuli can be monitored for sustained casing pressure. If sustained casing pressure is observed on a well, the operator shall immediately notify the district manager.

3. Wellhead, tree, and related equipment shall have a pressure rating greater than the shut-in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Promulgated by the Department of Conservation (August 1943), amended (February 1951), (August 1958), amended by the Department of Natural Resources, Office of Conservation, LR 25:1523 (August 1999), LR 37:.

§111. Diverter Systems and Blowout Preventers

A. Diverter System. A diverter system shall be required when drilling surface hole in areas where drilling hazards are known or anticipated to exist. The district manager may, at his discretion, require the use of a diverter system on any well. In cases where it is required, a diverter system consisting of a diverter sealing element, diverter lines, and control systems must be designed, installed, used, maintained, and tested to ensure proper diversion of gases, water, drilling fluids, and other materials away from facilities and personnel. The diverter system shall be designed to incorporate the following elements and characteristics:

1. dual diverter lines arranged to provide for maximum diversion capability;

2. at least two diverter control stations. One station shall be on the drilling floor. The other station shall be in a readily accessible location away from the drilling floor;

3. remote-controlled valves in the diverter lines. All valves in the diverter system shall be full-opening. Installation of manual or butterfly valves in any part of the diverter system is prohibited;

4. minimize the number of turns in the diverter lines, maximize the radius of curvature of turns, and minimize or eliminate all right angles and sharp turns;

5. anchor and support systems to prevent whipping and vibration;

6. rigid piping for diverter lines. The use of flexible hoses with integral end couplings in lieu of rigid piping for diverter lines shall be approved by the district manager.

B. Diverter Testing Requirements

1. When the diverter system is installed, the diverter components including the sealing element, diverter valves, control systems, stations and vent lines shall be function ~~and pressure~~ tested.

2. For drilling operations with a surface wellhead configuration, the system shall be function tested at least once every 24-hour period after the initial test.

3. After nippling-up on conductor casing that has been cemented in place, the diverter sealing element and diverter valves are to be pressure tested to a minimum of 200 psig. Subsequent pressure tests are to be conducted within seven days after the previous test.

4. Function tests and pressure tests shall be alternated between control stations.

5. Recordkeeping Requirements

a. Pressure and function tests are to be recorded in the driller's report ~~and certified (signed and dated) by the operator's representative~~.

b. The control station used during a function or pressure test is to be recorded in the driller's report.

c. Problems or irregularities during the tests are to be recorded along with actions taken to remedy same in the driller's report.

d. All reports pertaining to diverter function and/or pressure tests are to be retained for inspection at the wellsite for the duration of drilling operations.

C. BOP Systems. The operator shall specify and insure that contractors design, install, use, maintain and test the BOP system to ensure well control during drilling, and completion, workover, recompletion, abandonment and all other appropriate operations unless otherwise exempted. During drilling operations, ~~T~~the surface BOP stack shall be installed before drilling below surface casing. The BOP stack shall consist of the appropriate number of ram-type preventers and/or annular type preventers necessary to control the well under all potential conditions that might occur during the operations being conducted including when the drillstring or workstring has been removed from the well. The pipe rams shall be of proper size(s) to fit the drill pipe in use. The use of annular-type preventers in conjunction with ram-type preventers is encouraged.

1. The requirements of LAC 43:XIX.111.C-H~~I~~ shall not be applicable for wells drilled to or completed in the Nacatoch Formation in the Caddo Pine Island field.

2. The requirements of LAC 43:XIX.111.C-H shall not be applicable for abandonment operations where the well is incapable of flow. For the purposes of this paragraph, a well that is "incapable of flow" shall be defined as a well in which reservoir pressure has declined to a point at which the well no longer produces by means of natural energy; or a well from which flow is mechanically impossible. These conditions must be satisfied at all times during and at the completion of the operations being conducted with the tree removed.

3. The requirements of LAC 43:XIX.111.C-H shall not be applicable for wireline operations conducted with a tree in place. All wireline perforating operations and all other wireline operations where communication exists between the completed hydrocarbon-bearing zone(s) and the wellbore shall use a lubricator assembly containing at

least one wireline valve. When the lubricator is initially installed on the well, it shall be successfully pressure tested to the expected shut-in surface pressure.

~~2~~4. The ~~c~~Commissioner of conservation, following a public hearing, may grant exceptions to the requirements of LAC 43:XIX.111.C-~~I~~H.

D. BOP Working Pressure. The working pressure rating of any BOP component, excluding annular-type preventers, shall exceed the maximum anticipated surface pressure (MASP) to which it may be subjected.

E. BOP Auxiliary Equipment. Depending on the type of operation and well conditions, ~~A~~all BOP systems shall be equipped and provided with the ~~following~~ auxiliary equipment specified in Table 1 or Table 2 hereof. When required, the auxiliary equipment must meet the minimum requirements specified in Paragraphs 1 through 8 below.

Table 1 – BOP Auxiliary Equipment Requirements – Drilling Operations			
Pore Pressure Gradient	**≤ 0.5 psi/ft**		**> 0.5 psi/ft**
Total Depth (TVD)	**≤10,000’**	**>10,000’**	**Any Depth**
Equipment Type			
Accumulator System	Optional	Required	Required
Secondary BOP Control Station	Optional	Required	Required
Kill and choke outlets w/ 2 valves on each line	Optional	Required	Required
Upper and Lower Kelly Cock/Kelly-type valve	Required	Required	Required
Drill string safety valve	Required	Required	Required
Casing safety valve	Required	Required	Required
RAM locking devices	Required*	Required*	Required*

Table 2 – BOP Auxiliary Equipment Requirements – Completion, Workover & Recompletion			
Well Condition	**Incapable of Flow**	**Capable of Flow**	
Plugback Total Depth (TVD)	**Any Depth**	**≤10,000’**	**>10,000’**
Equipment Type			
Accumulator System	Optional	Optional	Required
Secondary BOP Control Station	Optional	Optional	Required
Upper and Lower Kelly Cock/Kelly-type valve	Required**	Required**	Required**
Work string safety valve	Required	Required	Required
RAM locking devices	Required*	Required*	Required*

*Required if RAM-type preventers are used.
** Required if a kelly or top-drive is used in completion, workover/recompletion, or abandonment operations.

1. If required, ~~A~~ the hydraulically actuated accumulator system ~~which~~ shall provide 1.5 times volume of fluid capacity to close and hold closed all BOP components, with a minimum pressure of 200 psig above the pre-charge pressure without assistance from a charging system.

~~2~~a. A backup to the primary accumulator-charging system, supplied by a power source independent from the power source to the primary, which shall be sufficient to close all BOP components and hold them closed.

~~3~~b. Accumulator regulators supplied by rig air without a secondary source of pneumatic supply shall be equipped with manual overrides or other devices to ensure capability of hydraulic operation if the rig air is lost.

~~4~~2. If required, ~~A~~at least one operable remote BOP control station in addition to the one on the drilling floor shall be used. This control station shall be in a readily accessible location away from the drilling floor. If a BOP control station does not perform properly, operations shall be suspended until that station is operable.

~~5~~3. If required, ~~A~~ a drilling spool with side outlets shall be installed, if side outlets are not provided in the body of the BOP stack, to provide for separate kill and choke lines.

~~6~~4. If required, ~~C~~choke and kill lines shall each be equipped with two full-opening valves. At least one of the valves on the choke line and the kill line shall be remotely controlled. In lieu of remotely controlled valves, two readily-accessible manual valves may be installed provided that a check valve is placed between the manual valves and the pump. The valves must have a working pressure rating equal to or greater than the working pressure rating of the connection to which they are attached, and must be installed between the well control stack and the choke or kill line.

~~7~~5. A valve installed below the swivel (upper kelly cock), essentially full-opening, and a similar valve installed at the bottom of the kelly (lower kelly cock). A wrench to fit each valve shall be stored in a location readily accessible to the drilling crew. If drilling with a mud motor and utilizing drill pipe in lieu of a Kelly, you must install one Kelly valve above, and one strippable kelly valve below the joint of pipe used in place of a Kelly. On a top-drive system equipped with a remote-controlled valve, you must install a strippable Kelly-type valve below the remote-controlled valve.

~~8~~6. An essentially full-opening drill-string safety valve in the open position on the rig floor shall be available at all times while drilling operations are being conducted. This valve shall be maintained on the rig floor to fit all connections that are in the drill string. A wrench to fit the drill-string safety valve shall be stored in a location readily accessible to the drilling crew.

~~9~~7. A safety valve shall be available on the rig floor, in the open position, assembled with the proper connection to fit the casing string being run in the hole.

~~10~~8. Locking devices installed on the ram-type preventers.

F. BOP Maintenance and Testing Requirements

1. The BOP system shall be visually inspected on a daily basis.

2. Pressure tests (low and high pressure) of the BOP system are to be conducted at the following times and intervals:

a. during a shop test prior to transport of the BOPs to the drilling location. Shop tests are not required for equipment that is transported directly from one well location to another;

b. immediately following installation of the BOPs;

c. within 14 days of the previous BOP pressure test. Exceptions may be granted by the district manager in cases where a trip is scheduled to occur within 2 days after the 14-day testing deadline;

d. before drilling out each string of casing or liner (The district manager may require that a conservation enforcement specialist witness the test prior to drilling out each casing string or liner);

e. not more than 48 hours before a well is drilled to a depth that is within 1000 feet of a hydrogen sulfide zone (The district manager may require that a conservation enforcement specialist witness the test prior to drilling to a depth that is within 1000 feet of a hydrogen sulfide zone);

f. when the BOP tests are postponed due to well control problem(s), the BOP test is to be performed on the first trip out of the hole, and reasons for postponing the testing are to be recorded in the driller's report.

g. following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly.

3. Low pressure tests (200-300 psig) of the BOP system (choke manifold, kelly valves, drill-string safety valves, etc.) are to be performed at the times and intervals specified in LAC 43:XIX.111.F.2. in accordance with the following provisions.

a. Test pressures are to be held for a minimum of five minutes.

b. Variable bore pipe rams are to be tested against the largest and smallest sizes of pipe in use, excluding drill collars and bottom hole assembly.

c. Bonnet seals are to be tested before running the casing when casing rams are installed in the BOP stack.

4. High pressure tests of the BOP system are to be performed at the times and intervals specified in LAC 43:XIX.111.F.2 in accordance with the following provisions.

a. Test pressures are to be held for a minimum of five minutes.

b. Ram-type BOP's, choke manifolds, and associated equipment are to be tested to their rated working pressure ~~of the equipment~~, or the rated working pressure of the wellhead equipment, or 500 psi greater than the calculated maximum anticipated surface pressure (MASP) for the applicable section of the hole.

c. Annular-type BOPs are to be tested to 70% of their rated working pressure ~~of the equipment~~, or the rated working pressure of the wellhead equipment, or the maximum anticipated surface pressure (MASP) for the applicable section of the hole.

5. The annular and ram-type BOPs with the exception of the blind-shear rams are to be function tested every seven days between pressure tests. All BOP test records should be certified (signed and dated) by the operator's representative.

~~a. Blind-shear rams are to be tested at all casing points and at an interval not to exceed 30 days.~~

6. If the BOP equipment does not hold the required pressure during a test, the problem must be remedied and a retest of the affected component(s) performed.

7. If a control station is not functional, operations shall be suspended until that station is operable.

G. BOP Record Keeping. The time, date and results of pressure tests, function tests, and inspections of the BOP system are to be recorded in the driller's report and are to be retained for inspection at the wellsite for the duration of drilling operations.

H. BOP Well Control Drills. Weekly well control drills with each drilling crew are to be conducted during a period of activity that minimizes the risk to drilling operations. The drills must cover a range of drilling operations, including drilling with a diverter (if applicable), on-bottom drilling, and tripping. Each drill must be recorded in the driller's report and is to include the time required to close the BOP system, as well as, the total time to complete the entire drill.

I. Well Control Safety Training. In order to ensure that all drilling personnel understand and can properly perform their duties prior to drilling wells which are subject to the jurisdiction of the Office of Conservation, the operator shall require that contract drilling companies provide and/or implement the following:

1. periodic training for drilling contractor employees and on-site operator representatives which ensures that employees maintain an understanding of, and competency in, well control practices;

2. procedures to verify adequate retention of the knowledge and skills that the contract drilling employees and on-site operator representative need to perform their assigned well control duties.

J. Well Control

1. The operator must take necessary precautions to keep the well under control at all times and must:

a. Monitor and evaluate well conditions to minimize the potential for the well to flow or kick;

b. Have a person onsite during drilling operations who represents the operator's interests and can fulfill the operator's responsibilities;

c. Continuously monitor the well during all operations and ensure that the well is not left unattended at any time unless the well is shut in and secured with blowout preventers (BOPs), bridge plugs, cement plugs, or packers.

d. Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment.

2. Whenever drilling operations are interrupted, a downhole safety device must be installed, such as a cement plug, bridge plug, or packer. The device must be installed at an appropriate depth within a properly cemented casing string or liner.

a. Among the events that may cause interruption to drilling operations are:

i. evacuation of the drilling crew;

ii. inability to keep the drilling rig on location; or

iii. repair to major drilling or well-control equipment.

3. If the diverter or BOP stack is nippled down while waiting on cement, it must be determined, before nippling down, when it will be safe to do so based on knowledge of formation conditions, cement composition, effects of nippling down, presence of potential drilling hazards, well conditions during drilling, cementing, and post cementing, as well as past experience.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.

HISTORICAL NOTE: Adopted by the Department of Conservation (August 1943), amended by the Department of Natural Resources, Office of Conservation, LR 34:2640 (December 2008), LR 37:.

§112. Hydrogen Sulfide Operations

A. Applicability. Each operator who conducts operations as described in paragraph 1 of this subsection shall be subject to this section and this section shall apply to both controlled and accidental releases of hydrogen sulfide.

1. Operations including drilling, working over, producing, injecting, gathering, processing, transporting, and storage of hydrocarbon fluids that are part of, or directly related to, field production, transportation, and handling of hydrocarbon fluids that have hydrogen sulfide as a constituent.

2. This section shall not apply to:

a. Refineries, petrochemical plants, or chemical plants;

b. Operations where the concentration of hydrogen sulfide in the system is less than 100 ppm.

B. General Provisions.

1. Each operator shall determine the hydrogen sulfide concentration in the operation.

a. Tests shall be made in accordance with standards as set by ASTM Standard D-2385-66, or GPA Plant Operation Test Manual C-1, GPA Publication 2265-68, or successor standard.

b. Test of vapor accumulation in storage tanks may be made with industry accepted colormetric tubes.

2. For all operations subject to this section, the radius of exposure shall be determined, except in the cases of storage tanks, by the following Pasquill-Gifford equations. Where X = radius of exposure in feet; Q = maximum volume determined to be available for escape in cubic feet per day; H_2S = mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

a. For determining the location of the 100 ppm radius of exposure: X = [(1.589) (mole fraction H_2S) (Q)] to the power of (0.6258).

b. For determining the location of the 500 ppm radius of exposure: X = [(0.4546) (mole fraction H_2S) (Q)] to the power of (0.6258).

c. The volume used as the escape rate in determining the radius of exposure shall be that specified in clause i-iii of this subparagraph, as applicable.

i. The maximum daily volume rate of gas containing hydrogen sulfide handled by that system element for which the radius of exposure is calculated.

ii. For existing wells or new wells drilled in existing fields, the operator's estimate of the well's capacity to flow against zero back-pressure at the wellhead shall be used.

iii. For controlled releases from pipelines and pressurized vessels, the operator's estimate of the volume and release rate based on the gas contained in the system to be de-pressured.

3. For the drilling of a well in an area (wildcat field) where insufficient data exists to calculate a radius of exposure, but where hydrogen sulfide may be expected, then a 100 ppm radius of exposure equal to 3,000 feet shall be assumed.

4. Storage tanks which are utilized as a part of a production operation, which are operated at or near atmospheric pressure and where the vapor accumulation has a hydrogen sulfide concentration in excess of 500 ppm, shall be subject to the following.

a. No determination of a radius of exposure shall be made for storage tanks as herein described.

b. A warning sign shall be posted on or within 50 feet of the facility to alert the general public of the potential danger.

c. Fencing as a security measure is required when storage tanks are located inside the limits of a city, town, or village.

d. A clearly visible warning sign posted in accordance with local governing authority on all roads that provide direct access to such tanks. Warning signs shall comply with the provisions of paragraph 5.a.ii.

e. The certificate of compliance provision, Subsection C.1 of this Section.

f. Storage tanks shall be located not less than 600 feet from existing water wells, public area or any public road.

g. A sign reading "Self-contained Breathing Apparatus is Required Beyond this Point if Hatches are to be Opened" shall be located at the foot of the catwalk stairs.

h. Vented gas from storage tanks shall be flared unless a vapor recovery system is used to control tank vapor emissions. Where vapor recovery systems are used a flare line shall be available for emergency use.

i. Truck vapor return or recovery lines are required to be located at the tank battery loadout line and shall be utilized when transferring oil or condensate.

5. All operators whose operations are subject to this section, and where the 100 ppm radius of exposure is in excess of 50 feet, shall be subject to the following.

a. Warning and marker signs.

i. For facilities over water, the operator shall display warning signs clearly visible from all points of approach to such facility.

ii. For land surface facilities, the operator shall post, in accordance with local governing authority, clearly visible warning signs at or within 50 feet of the facility and on access roads or public roads which provide direct access to facilities.

iii. Warning signs shall use the language of "Caution" and "Poison Gas" with a black and yellor color contrast. Colors shall satisfy Table I of ANSI Standard Z53.1-1967.

iv. Wind direction indicators shall be installed at strategic locations at or near the site and be readily visible from the site.

v. Automatic hydrogen sulfide detection equipment having visual and audible alarms that will warn of the presence of hydrogen sulfide gas in concentrations that could be harmful shall be utilized at the site. The operator shall maintain this equipment in an operable condition and shall establish procedures designed to prevent the undetected continuing escape of hydrogen sulfide.

vi. All lines within a public area or within 50 feet of a public road shall be buried at least three feet below ground level and the operator of all buried lines shall comply with the following.

(a) A marker sign shall be installed at public road crossings.

(b) Marker signs shall be installed along the line at intervals frequent enough to provide warning to avoid the accidental rupturing of line by excavation.

(c) The marker sign shall contain sufficient information to establish the ownership and existence of the line and shall indicate by the use of the words "Poison Gas" that a potential danger exists. Markers installed in compliance with the regulations of the federal Department of Transportation, Office of Pipeline Safety (Title 49, Code of Federal Regulations, Parts 192 and 195) shall satisfy the requirements of this provision.

b. Security provisions.

i. Unattended surface facilities and wellsites shall be protected from public access when located within ¼ mile of a public area. This protection shall be provided by fencing and locking. For the purpose of this provision, surface lines shall not be considered as a surface facility.

ii. The fencing provisions will be considered satisfied where the fencing structure is a deterrent to public access.

c. Materials and equipment provision.

i. All facilities including materials and equipment to be used in drilling and workover operations shall be constructed from those metals which have been selected and manufactured so as to be resistant to hydrogen sulfide stress cracking under the operating conditions for which their use is intended, provided that they satisfy the requirements described in the latest editions of NACE Standard MR-01-75 and API RP-14E, sections 1.7(c), 2.1(c), 4.7. The handling and installation of materials and equipment used in hydrogen sulfide service are to be performed in such a manner so as not to induce susceptibility to sulfide stress cracking.

ii. Any equipment utilizing natural gas that contains hydrogen sulfide as a fuel shall be equipped with a system to prevent emission of the fuel gas to the atmosphere in the event of a pilot failure or flameout. Exhaust gas stack height shall be not less than 20 feet from ground level or the floor of the highest manned deck of multi-story facilities whichever is greater.

iii. Emergency relief valves on any gas processing equipment shall have a line for conveying the released gases or vapors to a flare.

iv. For releases of a potentially hazardous volume of hydrogen sulfide gas, the gas must be flared.

d. Personal Protection Equipment

i. Protective breathing equipment shall be maintained at the site.

6. All operations subject to subsection A of this section shall be subject to the additional contingency plan provision, paragraph 7 of this subsection, if any of the following conditions apply:

a. the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a public area except a public road;

b. the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road;

c. the 100 ppm radius of exposure is greater than 3,000 feet.

7. Contingency plan provision.

a. All operators whose operations are subject to this provision shall develop a written contingency plan complete with all requirements before hydrogen sulfide operations are begun.

b. The purpose of the contingency plan shall be to provide an organized plan of action for alerting and protecting the public prior to a controlled release, or upon detection of an accidental release of a potentially hazardous volume of hydrogen sulfide.

c. The contingency plan shall be activated prior to a controlled release, or immediately upon the detection of an accidental release of a potentially hazardous volume of hydrogen sulfide.

d. Conditions that might exist in each area of exposure shall be considered when preparing a contingency plan.

e. The plan shall include instructions and procedures for alerting the general public and public safety personnel of the existence of an emergency.

f. The plan shall include procedures for requesting assistance and for follow-up action to remove the public from an area of exposure.

g. The plan shall include a call list which shall include the following as they may be applicable:

i. Local company supervisory personnel;

ii. Parish sheriff and other local law enforcement agencies;

iii. Office of State Police Hazardous Materials Hotline;

iv. Local Governing Authority;

v. Local emergency medical services including hospitals and doctors;

vi. Fire department;

vii. Contractors for supplemental equipment;

viii. District Manager – Office of Conservation;

ix. U. S. Coast Guard.

h. The plan shall include a plat detailing the area of exposure. The plat shall include the locations of private dwellings or residential areas, public facilities, such as schools, business locations, public roads, other similar areas where the public might reasonably be expected within the area of exposure and areas of low elevation where hydrogen sulfide may accumulate.

i. The plan shall include names and telephone numbers of residents within the area of exposure except in cases where the reaction plan option pursuant to §228.B.8.l applies.

j. The plan shall include a list of the names and telephone numbers of the responsible parties for each of the possibly occupied public areas, such as schools, churches, business, or other public areas or facilities within the area of exposure.

k. The plan shall include provisions for advance briefing of the public within an area of exposure. Such advance briefing shall include the following elements:

i. the necessity for an emergency action plan;

ii. the hazards and characteristics of hydrogen sulfide;

iii. the possible sources of hydrogen sulfide within the area of exposure;

iv. instructions for reporting a gas leak;

v. the manner in which the public will be notified of an emergency;

vi. steps to be taken in case of an emergency.

l. In the event of a high density of populations, or the case where the population density may be unpredictable, a reaction type of plan, in lieu of advance briefing for public notification, will be acceptable.

m. The plan shall include additional site specific information, such as:

i. location of evacuation routes;

ii. location of safety and life support equipment;

iii. location of hydrogen sulfide containing facilities;

iv. location of nearby telephones and/or other means of communication; and

v. special instructions for conditions such as local terrain and the effect of various weather conditions.

n. Notification to parties identified in the contingency plan shall be as follows:

i. immediately in the case of an accidental release;

ii. at least 12 hours in advance of a controlled release or as soon as a decision is made to release if such decision could not reasonable have been made more than 12 hours prior to the release.

o. The retention of the contingency plan shall be as follows:

i. The plan shall be available for inspection by an agent of the Office of Conservation at the location indicated on the certificate of compliance.

ii. The plan shall be retained at the location which lends itself best to activation of the plan.

p. The plan shall be kept updated to insure its current applicability.

8. Drilling provision. Drilling and workover operations where the 100 ppm radius of exposure includes a public area or is 3,000 feet or greater shall be subject to the following additional provisions.

a. Protective breathing equipment shall be maintained at the well site and shall be sufficient to allow for well control operations.

b. The operator shall provide a method of igniting the gas in the event of an uncontrollable emergency.

c. The operator shall install a choke manifold, mud-gas separator, and flare line, and provide a suitable method for lighting the flare.

d. Full compliance with all the requirements of this provision must be satisfied before the well is drilled to a depth that is within 1,000 feet of the hydrogen sulfide zone.

C. Reports required.

1. Certificate of compliance provision.

a. A certificate of compliance shall be submitted to the district manager in duplicate for operations subject to any provision of this section.

b. The certificate of compliance shall certify that existing operations subject to this section to be in compliance or will be in compliance as specified in an attached schedule, or, for new or modified facilities, will be in compliance upon completion.

c. A certificate of compliance will permit an operator to perform all activities described in the certificate provided that a certificate of compliance will be required on each well subject to the provisions of subsection C.1.f. of this section.

d. An amended certificate of compliance shall be required if there is a change in public exposure caused by public infringement of an existing radius of exposure. The operator shall file the amended certificate within 30 days after such infringement.

e. An amended certificate of compliance shall be required if there is modification of an existing operation or facility which increases the radius of exposure in a public area. The operator shall file the amended certificate prior to initiating the operation or construction.

f. The operator shall file a certificate of compliance prior to commencement of a drilling or workover operation on wells if any of the following conditions apply:

i. the 100 ppm radius of exposure is in excess of 50 feet and includes any part of a public area except a public road;

ii. the 500 ppm radius of exposure is greater than 50 feet and includes any part of a public road;

iii. the 100 ppm radius of exposure is greater than 3,000 feet.

g. The operator of any operation subject to a certificate of compliance shall maintain such operation in compliance with the provisions of such certificate and this section until a certificate of abandonment is filed in duplicate with the district manager.

h. The certificate of compliance required by the provisions of this section for an existing operation shall be filed in duplicate with the district manager as soon as is reasonably possible, and no later than 90 days after the effective date of this order. For new facilities the operator shall file such certificate prior to initiating the operation or construction.

i. A certificate of compliance is nontransferable. Any new operator of an existing operation subject to the provisions of this section shall be required to file a certificate for such operation.

2. The operator shall furnish a written report to the district manager within ten days of any release of a potentially hazardous volume of hydrogen sulfide gas.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Promulgated by the Department of Conservation (August 1943), amended (February 1951), (August 1958), amended by the Department of Natural Resources, Office of Conservation, LR 25:1523 (August 1999), LR 37:.

§117. Drilling Fluids

A. ~~The inspectors and engineers of the Department~~ Office of Conservation representatives shall have access to the mud records of any drilling well, except those records which pertain to special muds and special work with respect to patentable rights or trade secrets, and shall be allowed to conduct any essential test or tests on the mud used in the drilling of a well. When the conditions and tests indicate a need for a change in the mud or drilling fluid program in order to insure proper control of the well, the district manager shall require the operator or company to use due diligence in correcting any objectionable conditions.

B. Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in all anticipated conditions and circumstances.

C. When circulating, the drilling fluid must be tested at least once each work shift or more frequently if conditions warrant. The tests must conform to industry-accepted practices and, at a minimum, include density, and viscosity. The district manager may require additional tests for monitoring and maintaining drilling fluid quality, prevention of downhole equipment problems and for kick detection. The test results must be recorded in the drilling fluid report.

D. Kick Prevention and Detection

1. While drilling, a safe drilling margin or kick tolerance of at least 0.5 ppg must be maintained. The kick tolerance shall be determined periodically as either mud weight or total depth increases. When this safe margin cannot be maintained, drilling operations must be suspended until the situation is remedied.

2. Before starting out of the hole with drill pipe, the drilling fluid must be properly conditioned. A volume of drilling fluid equal to the annular volume must be circulated with the drill pipe just off-bottom. This practice may be omitted if documentation in the driller's report shows:

a. No indication of formation fluid influx before starting to pull the drill pipe from the hole;

b. The weight of returning drilling fluid is within 0.2 pounds per gallon of the drilling fluid entering the hole;

3. When coming out of the hole with drill pipe, the annulus must be filled with drilling fluid before the hydrostatic pressure decreases by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure.

4. A mechanical, volumetric, or electronic device must be used to measure the drilling fluid required to fill the hole.

5. Controlled rates must be used to run and pull drill pipe and downhole tools so as not to swab or surge the well.

6. When there is an indication of swabbing or influx of formation fluids, appropriate measures must be taken to control the well. Circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom.

7. The test fluids in the hole must be circulated or reverse circulated before pulling drill-stem test tools from the hole. If circulating out test fluids is not feasible, with an appropriate kill weight fluid test fluids may be bullhead out of the drill-stem test string and tools.

E. Drilling Fluid Quantities

1. Quantities of drilling fluid and drilling fluid materials must be maintained and replenished at the drill site as necessary to ensure well control. These quantities must be determined based on known or anticipated drilling conditions, rig storage capacity, weather conditions, and estimated time for delivery.

2. The daily inventories of drilling fluid and drilling fluid materials must be recorded, including weight materials and additives in the drilling fluid report.

3. If there are not sufficient quantities of drilling fluid and drilling fluid material to maintain well control, the drilling operations must be suspended.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Adopted by the Department of Conservation (August 1943), amended by the Department of Natural Resources, Office of Conservation, LR 37:.

Title 43
NATURAL RESOURCES
Part XIX. Office of Conservation―General Operations
Subpart 1. Statewide Order No. 29-B

Chapter 2. Additional Requirements for Water Locations

§201. Applicability

A. In addition to the requirements set forth in Chapter 1 of this Subpart, all oil and gas wells being drilled or completed at a water location within the state and which are spud or on which workover operations commence on or after the effective date of this rule shall comply with this Chapter. For the purposes of determining the applicability of this Chapter, a water location is defined as a location which requires the use of a barge, jack-up platform or fixed platform to support the drilling, workover, or completion rig.

B. Unless otherwise stated herein, nothing within this Chapter shall alter the obligation of oil and gas operators to meet the requirements of Chapter 1 of this Subpart.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 37:

§203. Application to Drill

A. An application to drill a well at a water location shall be accompanied by an emergency action plan.

B. Applicants that receive a drilling permit for a well at a water location shall furnish a copy of the approved drilling permit, emergency action plan and the certified location plat to the appropriate federal, state and local authorities.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 37:

§205. Rig Movement and Reporting

A. The Operator must report the movement of all drilling and workover rig units on and off locations to the appropriate District Manager with the rig name, well serial number and expected time of arrival and departure.

B. Prior to moving a rig onto location, the operator shall provide the appropriate District Office with an electronic copy via email or on a disk of the associated drilling rig's Spill Prevention Control (SPC) plan that is required by DEQ pursuant to the provisions of Part IX of Title 33 of the Louisiana Administrative Code or any successor rule. To satisfy this requirement, an SPC plan which was previously submitted to this Office may be referenced at the time of rig movement notification, provided no substantive changes have been made.

C. Drilling operations on a platform with producing wells or other hydrocarbon flow must comply with the following:

1. An emergency shutdown station must be installed near the driller's console.

2. All producible wells located in the affected wellbay must be shut in below the surface and at the wellhead when:

a. a mobile offshore drilling unit (MODU) moves within 500 feet of the target platform;

b. a drilling unit is moved or skid between wells on a platform;

c. a rig or related equipment is moved on and off a platform. This includes rigging up and rigging down activities.

3. Production may be resumed once the MODU is in place, secured, and ready to begin drilling operations.

D. The movement of rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving well-completion rigs and related equipment, unless otherwise approved by the District Manager. A closed surface-controlled subsurface safety valve of the pump-through type may be used in lieu of the pump-through-type tubing plug, provided that the surface control has been locked out of operation. The well from which the rig or related equipment is to be moved shall also be equipped with a back-pressure valve prior to removing the blowout preventer (BOP) system and installing the tree.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 37:

§207. Casing Program

A. General Requirements

1. All tubulars and cement shall meet or exceed API manufacturing specifications. Cementing jobs shall be designed so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out of the casing or before commencing completion operations.

2. Centralizers shall be used to ensure adequate cement bond and hydraulic isolation of productive formations and the USDW. At a minimum the following requirements must be met:

a. Surface casing shall be centralized by means of placing centralizers in the following manner.

i. A centralizer shall be placed on every third joint from the shoe to at least 500’ above the shoe, with one centralizer being placed on each of the lowermost three joints of casing.

b. Intermediate and production casing, and drilling and production liners shall be centralized by means of a centralizer placed every third joint from the shoe to at least 500 feet above the shoe and across all potentially productive intervals to at least 100 feet above and below each interval. Additionally, one centralizer shall be placed on each of the lowermost three joints of casing.

c. Intermediate and production casing, and drilling and production liners run in the horizontal portion of a well shall be centralized by means of a centralizer placed on every third joint from the top of the target formation to at least 500 feet above the target formation.

B. Tubing and Completion

1. New wells completed as flowing or gas-lift wells shall be equipped with a minimum of one master valve and one surface safety valve, installed in the tree, downstream of the master valve.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 37:

§209. Blowout Prevention – Drilling Operations

A. BOP and kick detection equipment for drilling activity at a water location shall be designed and utilized, as necessary, to control the well under all potential conditions that might occur during the operations being conducted and at minimum, shall include the components specified in Table 1.

Table 1 – Minimum BOP Equipment Requirements – Drilling Operations			
Maximum Pore Pressure Gradient for Open-hole Section	**≤ 0.5 psi/ft**		**> 0.5 psi/ft**
Total Depth (TVD)	**≤10,000’**	**>10,000’**	**Any Depth**
Equipment Type			
Annular	Required	Required	Required
Pipe Ram	Required (1)	Required (2)	Required (2)
Blind Ram	Required	Required	Required
Shear Ram	Optional	Optional	Required
Accumulator System	Required	Required	Required
Secondary Accumulator Charging System	Optional	Required	Required
Secondary BOP Control Station	Optional	Required	Required

Table 1 – Minimum BOP Equipment Requirements – Drilling Operations			
Maximum Pore Pressure Gradient for Open-hole Section	**≤ 0.5 psi/ft**		**> 0.5 psi/ft**
Total Depth (TVD)	**≤10,000'**	**>10,000'**	**Any Depth**
Equipment Type			
Kill and choke outlets w/ 2 valves on each line	Required	Required	Required
Upper and Lower Kelly Cock/Kelly-type valve	Required	Required	Required
Drill string safety valve	Required	Required	Required
Casing safety valve	Required	Required	Required
RAM locking devices	Required	Required	Required
Fill-up line	Required	Required	Required
Hole-fill Volume Measuring Device/Trip Tank	Required	Required	Required
Pit Level Change Indicator / Return Flow Indicator*	Required	Required	Required
Mud Gas Detection Equipment*	Required	Required	Required
Mud Gas Separator/Degasser	Required	Required	Required

* Equipment must include visual and audible warning devices.

1. Annular-type and ram-type BOP components shall be hydraulically controlled.

2. Drilling activity with a tapered drill string shall require the installation of two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide, at minimum, two sets of rams capable of sealing around the larger-size drill string and one set of pipe rams capable of sealing around the smaller-size drill string.

3. A set of hydraulically-operated combination rams may be used for the blind rams and shear rams.

4. All connections used in the surface BOP system must be flanged, including the connections between the well control stack and the first full-opening valve on the choke line and the kill line.

5. The Commissioner of Conservation, following a public hearing in accordance with La. R.S. 30:6, may grant exceptions to the requirements of LAC 43:XIX.209.A.

B. BOP Auxiliary Equipment. All BOP systems shall be equipped and provided with the equipment specified in Table 1.hereof. When required, the auxiliary equipment must meet the minimum requirements specified in LAC 43:XIX.111.E.1-8.

C. BOP Maintenance and Testing Requirements. The BOP system shall be tested and maintained in accordance with the requirements of LAC 43:XIX.111.F.

D. BOP Record Keeping. The time, date and results of pressure tests, function tests, and inspections of the BOP system are to be recorded in the driller's report. All pressure tests shall be recorded on an analog chart or digital recorder. All documents are to be retained for inspection at the wellsite for the duration of drilling operations and are to be retained in the operator's files for a minimum period of six months, or if a well control incident occurred during drilling activities, documents shall be retained for a period of not less than two years.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 37:

§211. Blowout Prevention - Completion, Workover/Recompletion, and Abandonment Operations

A. Definitions. When used in this section, the following terms shall have the meanings given below.

Completion Operations — the work conducted to establish production from a well after the production casing string has been set, cemented, and pressure-tested.

Expected Surface Pressure—the highest pressure predicted to be exerted upon the surface of a well. In calculating expected surface pressure, reservoir pressure as well as applied surface pressure must be considered.

Routine Operations—any of the following operations conducted on a well with the tree installed including cutting paraffin, removing and setting pump-through-type tubing plugs, gas-lift valves, and subsurface safety valves which can be removed by wireline operations, bailing sand, pressure surveys, swabbing, scale or corrosion treatment, caliper and gauge surveys, corrosion inhibitor treatment, removing or replacing subsurface pumps, through-tubing logging, wireline fishing, and setting and retrieving other subsurface flow-control devices.

Workover Operations—the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of a well.

B. Prior to engaging in well-workover operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date, time and attendees of safety meetings shall be recorded and available for review.

C. BOP system components for completion, workover/recompletion, and abandonment operations that are conducted with the production tree removed shall be designed and utilized, as necessary, to control the well under all potential conditions that might occur during the operations being conducted and at minimum, shall include the components specified in Table 1.

Table 1 – Minimum BOP Equipment Requirements – Operations with Production Tree Removed

Well Condition	**Incapable of Flow**	**Capable of Flow**	
Plug Back Total Depth	**Any Depth**	**<10,000’**	**>10,000’**
Equipment Type			
Annular	Optional	Required	Required
Pipe Ram	Required (1)	Required (1)	Required (1)
Blind Ram	Required	Required	Required
Shear Ram	Optional	Optional	Required
Accumulator System	Optional	Required	Required
Secondary Accumulator Charging System	Optional	Optional	Required
Secondary BOP Control Station	Optional	Optional	Required
Kill and choke outlets w/ 2 valves on each line	Optional	Required	Required
Upper and Lower Kelly Cock/Kelly-type valve	Required*	Required*	Required*
Work string safety valve	Required	Required	Required
RAM locking devices	Required	Required	Required
Fill-up line	Optional	Optional	Required
Hole-fill Volume Measuring Device/Trip Tank	Required	Required	Required
Pit Level Change Indicator / Return Flow Indicator**	Optional	Optional	Required

*Required if a kelly or top-drive is used.

**Equipment must include visual and audible warning devices.

1. Annular-type and ram-type BOP components shall be hydraulically controlled.

2. A set of hydraulically-operated combination rams may be used for the blind rams and shear rams.

3. BOP Auxiliary Equipment. All BOP systems shall be equipped and provided with the equipment specified in Table 1 hereof. When required, the auxiliary equipment must meet the minimum requirements specified in LAC 43:XIX.111.E.1-8.

4. When well-workover operations are conducted on a well with the tree removed, an emergency shutdown system (ESD) manually controlled station shall be installed near the driller’s console or well-servicing unit operator’s work station, except when there is no other hydrocarbon-producing well or other hydrocarbon flow on the platform.

D. The minimum BOP-system components for well-workover operations with the tree in place and performed through the wellhead inside of conventional tubing using small-diameter jointed pipe (usually 3/4 inch to 1 1/4 inch) as a work string, i.e., small-tubing operations, shall include one set of pipe rams, and one set of blind rams.

1. An essentially full-opening work-string safety valve in the open position on the rig floor shall be available at all times while well-workover operations are being conducted. This valve shall be maintained on the rig floor to fit all connections that are in the work string. A wrench to fit the work-string safety valve shall be stored in a location readily accessible to the workover crew.

E. The minimum BOP-system components for well-workover operations with the tree in place and performed by moving tubing or drill pipe in or out of a well under pressure utilizing equipment specifically designed for that purpose, i.e., snubbing operations, shall use hydraulically operated components and shall include one set of pipe rams and two sets of stripper-type pipe rams with spacer spool.

F. For coiled tubing operations with the production tree in place, the BOP system components shall be hydraulically operated and include a stripper or annular-type well control component, one set of blind rams, one set of shear rams, one set of two-way slip rams, one set of pipe rams;

1. A set of combination rams may be used for the blind rams and shear rams.

2. A set of combination rams may be used for the two-way slip rams and the pipe rams.

3. A dual check valve assembly must be attached to the coiled tubing connector at the downhole end of the coiled tubing string for all coiled tubing well-workover operations. Exceptions to the check valve requirement may be granted by the District Manager.

4. The hydraulic-actuating system must provide sufficient accumulator capacity to close-open-close each component in the BOP stack. This cycle must be completed with at least 200 psi above the pre-charge pressure without assistance from a charging system.

5. The coiled tubing connector must be tested to a low pressure of 200 to 300 psi, followed by a high pressure test to the rated working pressure of the connector or the expected surface pressure, whichever is less. The dual check valve must be successfully pressure tested to the rated working pressure of the connector, the rated working pressure of the dual check valve, expected surface pressure, or the collapse pressure of the coiled tubing, whichever is less.

6. The following additional requirements apply when the anticipated surface pressures are greater than 3,500 psi:

a. an additional set of blind/shear rams located as close to the tree as practical.

b. a kill line and a separate choke line. Each line shall be equipped with two full-opening valves and at least one of the valves must be remotely controlled. A manual valve shall be used instead of the remotely controlled valve on the kill line if a check valve is installed between the two full-opening manual valves and the pump or manifold. The valves shall have a working pressure rating equal to or greater than the working pressure rating of the connection to which they are attached, and shall be installed between the well control stack and the choke or kill line. The kill line shall be connected to a pump or manifold. The kill line inlet on the BOP stack shall not be used for taking fluid returns from the wellbore.

c. All connections used in the surface BOP system from the tree to the uppermost required ram must be flanged, including the connections between the well control stack and the first full-opening valve on the choke line and the kill line.

G. Wireline/Slickline Operations. The operator shall comply with the following requirements during routine, as defined in Subsection A of this section, and non-routine wireline workover operations:

1. Wireline operations shall be conducted so as to minimize leakage of well fluids. Any leakage that does occur shall be contained to prevent pollution.

2. All wireline perforating operations and all other wireline operations where communication exists between the completed hydrocarbon-bearing zone(s) and the wellbore shall use a lubricator assembly containing at least one wireline valve.

3. When the lubricator is initially installed on the well, it shall be successfully pressure tested to the expected shut-in surface pressure.

H. BOP Maintenance and Testing Requirements. The BOP system shall be tested and maintained in accordance with the requirements of LAC 43:XIX.111.F.

1. Test pressures must be recorded during BOP and coiled tubing tests on a pressure chart, or with a digital recorder. All documents are to be retained for inspection at the well site for the duration of operations and are to be retained in the operator's files for a minimum period of six months, or if a well control incident occurred during the operations, documents shall be retained for a period of not less than two years.

I. The commissioner may grant an exception to any provision of this section that requires specific equipment upon proof of good cause. For consideration of an exception, the operator must show proof of the unavailability of properly sized equipment and demonstrate that anticipated surface pressures minimize the potential for a loss of well control during the proposed operations. All exception requests must be made in writing to the commissioner and include documentation of any available evidence supporting the request.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 37:

§213. Drilling Fluid Handling Areas

A. In drilling fluid handling areas where dangerous concentrations of combustible gas may accumulate and where natural ventilation is inadequate, a ventilation system, gas monitors and safety equipment must be installed and maintained in accordance with the following minimum requirements.

1. A ventilation system capable of replacing the air once every 5 minutes or 1.0 cubic feet of air-volume flow per minute, per square foot of area, whichever is greater.

a. If a mechanical ventilation system does not run continuously, then it must activate when gas detectors indicate the presence of 1 percent or more of combustible gas by volume.

2.Gas detectors must be tested and recalibrated quarterly. No more than 90 days may elapse between tests.

3. Explosion-proof or pressurized electrical equipment to prevent the ignition of explosive gases;

a. Where air is used for pressuring equipment, the air intake must be located outside of and as far as practicable from hazardous areas.

4. Alarms that activate when the mechanical ventilation system fails.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 37:

Title 43
NATURAL RESOURCES
Part XIX. Office of Conservation—General Operations
Subpart 4. Statewide Order No. 29-B-a

Chapter 11. Required Use of ~~Storm Chokes~~ Subsurface Safety Valves (SSSV)

§1101. Scope

A. Order establishing rules and regulations concerning the required use of ~~storm chokes~~ SSSV to prevent blowouts or uncontrolled flow in the case of damage to surface equipment.

AUTHORITY NOTE: Promulgated in accordance with Act 157 of the Legislature of 1940.
HISTORICAL NOTE: Adopted by the Department of Conservation, March 15, 1946, amended March 1, 1961, amended and promulgated by the Department of Natural Resources, Office of Conservation, LR 20:1127 (October 1994), amended LR 37:.

§1103. Applicability

A. All wells capable of flow with a surface pressure in excess of 100 pounds, falling within the following categories, shall be equipped with a ~~storm chokes~~ SSSV's:

1. any locations inaccessible during periods of storm and/or floods, including spillways;
2. located in bodies of water being actively navigated;
3. located in wildlife refuges and/or game preserves;
4. located within 660 feet of railroads, ship channels, and other actively navigated bodies of water;
5. located within 660 feet of state and federal highways in Southeast Louisiana, in that area East of a North-South line drawn through New Iberia and South of an East-West line through Opelousas;
6. located within 660 feet of state and federal highways in Northeast Louisiana, in that area bounded on the West by the Ouachita River, on the North by the Arkansas-Louisiana line, on the East by the Mississippi River, and on the South by the Black and Red Rivers;
7. located within 660 feet of the following highways:
   a. U.S. Highway 71 between Alexandria and Krotz Springs;
   b. U.S. Highway 190 between Opelousas and Krotz Springs;
   c. U.S. Highway 90 between Lake Charles and the Sabine River;
8. located within the corporate limits of any city, town, village, or other municipality.

AUTHORITY NOTE: Promulgated in accordance with Act 157 of the Legislature of 1940.
HISTORICAL NOTE: Adopted by the Department of Conservation, March 15, 1946, amended March 1, 1961, amended and promulgated by Department of Natural Resources, Office of Conservation, LR 20:1128 (October 1994), amended LR 37:.

§1104. General Requirements for ~~Storm Choke~~ Subsurface Safety Valve (SSSV) Use at Water Locations

A. ~~This Section only applies to oil and gas wells at water locations~~. All SSSV used at water locations as defined in LAC 43:XIX.201.A must be inspected, installed, used, maintained, and tested in accordance with American Petroleum Institute Recommended Practice 14B, "Recommended Practice for Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems" as amended.

B. ~~A~~ SSSV Installation ~~shall be designed, installed, used, maintained, and tested to ensure reliable operation~~.

1. The device shall be installed at a depth of 100 feet or more below the seafloor within two days after production is established.

2. Until a SSSV is installed, the well shall be attended in the immediate vicinity so that emergency actions may be taken while the well is open to flow. ~~During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface safety device has been installed in the well.~~

3. The well shall not be open to flow while the SSSV is removed, except when flowing of the well is necessary for a particular operation such as cutting paraffin, bailing sand, or similar operations.

~~4. All SSSV's must be inspected, installed, used, maintained, and tested in accordance with American Petroleum Institute Recommended Practice 14B, Recommended Practice for Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems.~~

C. Testing requirements

~~1. All SSSVs must be inspected, installed, maintained, and tested in accordance with API RP 14B, Recommended Practice for Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems.~~

~~2~~1. ~~Testing requirements.~~ Each SSSV installed in a well shall be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced at intervals not exceeding 6 months for those valves not installed in a landing nipple and 12 months for those valves installed in a landing nipple.

~~3~~2. Records must be retained for a period of 2 years for each safety device installed.

3. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating ~~subsurface safety device~~ SSSV has been installed in the well.

~~C~~D. Temporary removal for routine operations.

1. Each wireline or pumpdown-retrievable SSSV may be removed, without further authorization or notice, for a routine operation which does not require the approval of Form DM-4R,

2. The well shall be identified by a sign on the wellhead stating that the SSSV has been removed. If the master valve is open, a trained person shall be in the immediate vicinity of the well to attend the well so that emergency actions may be taken, if necessary.

3. A platform well shall be monitored, but a person need not remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended or a pump-through plug installed in the tubing at least 100 feet below the mud line and the master valve closed, unless otherwise approved by the district manager.

4. Each operator shall maintain records indicating the date a SSSV is removed, the reason for its removal, and the date it is reinstalled.

~~D~~E. Emergency Action. In the event of an emergency, such as an impending storm, any well not equipped with a ~~subsurface safety device~~ SSSV and which is capable of natural flow shall have the device properly installed as soon as possible with due consideration being given to personnel safety.

~~E. Design and Operation~~

~~1. All SSSVs must be inspected, installed, maintained, and tested in accordance with API RP 14B, Recommended Practice for Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems.~~

~~2. Testing requirements. Each SSSV installed in a well shall be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced at intervals not exceeding 6 months for those valves not installed in a landing nipple and 12 months for those valves installed in a landing nipple.~~

~~3. Records must be retained for a period of 2 years for each safety device installed.~~

AUTHORITY NOTE: Promulgated in accordance with Act 157 of the Legislature of 1940.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 37:.

§1105. Waivers

A. Onshore Wells. Where the use of ~~storm chokes~~ subsurface safety valves (SSSV) would unduly interfere with normal operation of a well, the District Manager may, upon submission of pertinent data, in writing, waive the requirements of this order.

B. Offshore Wells

1. The district manager, upon submission of pertinent data, in writing explaining the efforts made to overcome the particular difficulties encountered, may waive the use of a ~~subsurface safety valve~~ SSSV under the following circumstances, and may, in his discretion, require in lieu thereof a surface safety valve:

a. where sand is produced to such an extent or in such a manner as to tend to plug the tubing or make inoperative the ~~subsurface safety valve~~ SSSV;

b. when the flowing pressure of the well is in excess of 100 psi but is inadequate to activate the ~~subsurface safety valve~~ SSSV;

c. where flow rate fluctuations or water production difficulties are so severe that the ~~subsurface safety valve~~ SSSV would prevent the well from producing at its allowable rate;

d. where mechanical well conditions do not permit the installation of a ~~subsurface safety valve~~ SSSV;

e. in such other cases as the district manager may deem necessary to grant an exception.

2. Under the following circumstances no formal approval is necessary. However, each company will maintain records indicating the date a subsurface safety valve is removed, the reason for its removal, and the date it is reinstalled:

a. when the flowing pressure of the well is 100 psi or less;

b. when it is necessary to perform routine maintenance and service work; to clean up completions and recompletions in wells where a subsurface safety valve would otherwise be in service.

AUTHORITY NOTE: Promulgated in accordance with Act 157 of the Legislature of 1940.
HISTORICAL NOTE: Adopted by the Department of Conservation, March 1, 1961, amended March 15, 1961, amended and promulgated by Department of Natural Resources, Office of Conservation, LR 20:1128 (October 1994), amended LR 37:.