ConocoPhillips

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September 27, 2016

Alaska Oil and Gas Conservation Commission
333 W. 7th Ave #100
Anchorage, Alaska, 99501-3539

RE: Comments on Proposed Regulation Changes

Dear Commissioners:

ConocoPhillips Alaska, Inc., ("ConocoPhillips") respectfully submits the attached comments in response to the Notice of Proposed Changes in Regulations of the Alaska Oil and Gas Conservation Commission dated July 20, 2016 ("Notice").

In the Notice, the Commission invited the submission of questions about the proposed regulation changes, and ConocoPhillips submitted a written list of questions on September 15. Having answers to those questions would help us better understand the objective of some of the proposals, which in turn would help us comment on how the objective might be achieved without unnecessary costs, burdens, or adverse consequences.

ConocoPhillips sees merit in many of the proposed changes, and we support the goal of updating and clarifying the regulations. Several of the proposed regulation changes, however, could have material adverse impacts to oil and gas producers. ConocoPhillips submits the attached comments to help improve the proposals, and we would welcome further constructive interaction with the AOGCC after the initial hearing and to help ensure the best final result. We think it is important that the AOGCC hold a public workshop or a second hearing before adopting the final rules in this regulatory package.

Thank you for the opportunity to comment on the proposed regulation changes.

Regards,

Erik Keskula
Manager, North Slope Development

ConocoPhillips Alaska, Inc.

Comments on AOGCC Proposed Regulation Changes

September 27, 2016

25.022 Notice of Ownership. Our only comment on this proposed change is that because the proposal relates to information about an *operator* rather than an *owner*, it seems Section 25.020, which applies to operators, would be a better place to codify the new language, promoting organizational clarity.

Proposed Regulation 20 AAC 25.030 Casing and Cementing: Paragraph (d)(5). The proposed changes in paragraph (d)(5) would modify the current requirement for cementing so that it applies to 500 *vertical* feet. The current regulation refers to 500 feet without specifying vertical feet or measured feet. Historically, AOGCC has approved cementing with 500' *measured depth* (MD) of cement above hydrocarbon zones and the production casing shoe. This has historically proven to provide zonal isolation for hydrocarbon zones, hydraulic fracturing fluids and EOR / waterflood fluids thus demonstrating, in our view, that current practices under the existing regulations have been working adequately.

The proposed change to specify *vertical* feet is unnecessary and could create additional risk in achieving zonal isolation. This is particularly pertinent for the type of well typically drilled on the North Slope. Wells currently being drilled at Alpine and Kuparuk are directionally drilled horizontal wells from a multi-well pad. These types of wells usually require a long geometrically complicated intermediate casing run. By increasing the cement height, there is a significant risk in breaking down a weak interval and losing returns as spider plot and the example below will illustrate.

Equivalent Circulating Density (ECD) is the effective density of the circulating fluid in the wellbore, which is the sum of the hydrostatic pressure imposed by the static fluid column and the friction pressure. A critical factor when cementing casing is ensuring this ECD does not increase to a point where a weak zone can fracture. This can lead to lost circulation and increase the risk to successful zonal isolation. Increasing the cement height to 500' True Vertical Depth (TVD) above hydrocarbon zones leads to an increase in ECD when pumping cement and the increased risk to zonal isolation.

Well CD5-03 is a good example of a typical well drilled on the North Slope and it illustrates the effect on ECD of increasing cement height to 500' TVD above the casing shoe.

Figure 1 is a spider plot of the CD5 pad illustrating the long directional wells on CD-5 and highlights the CD5-03 well path.

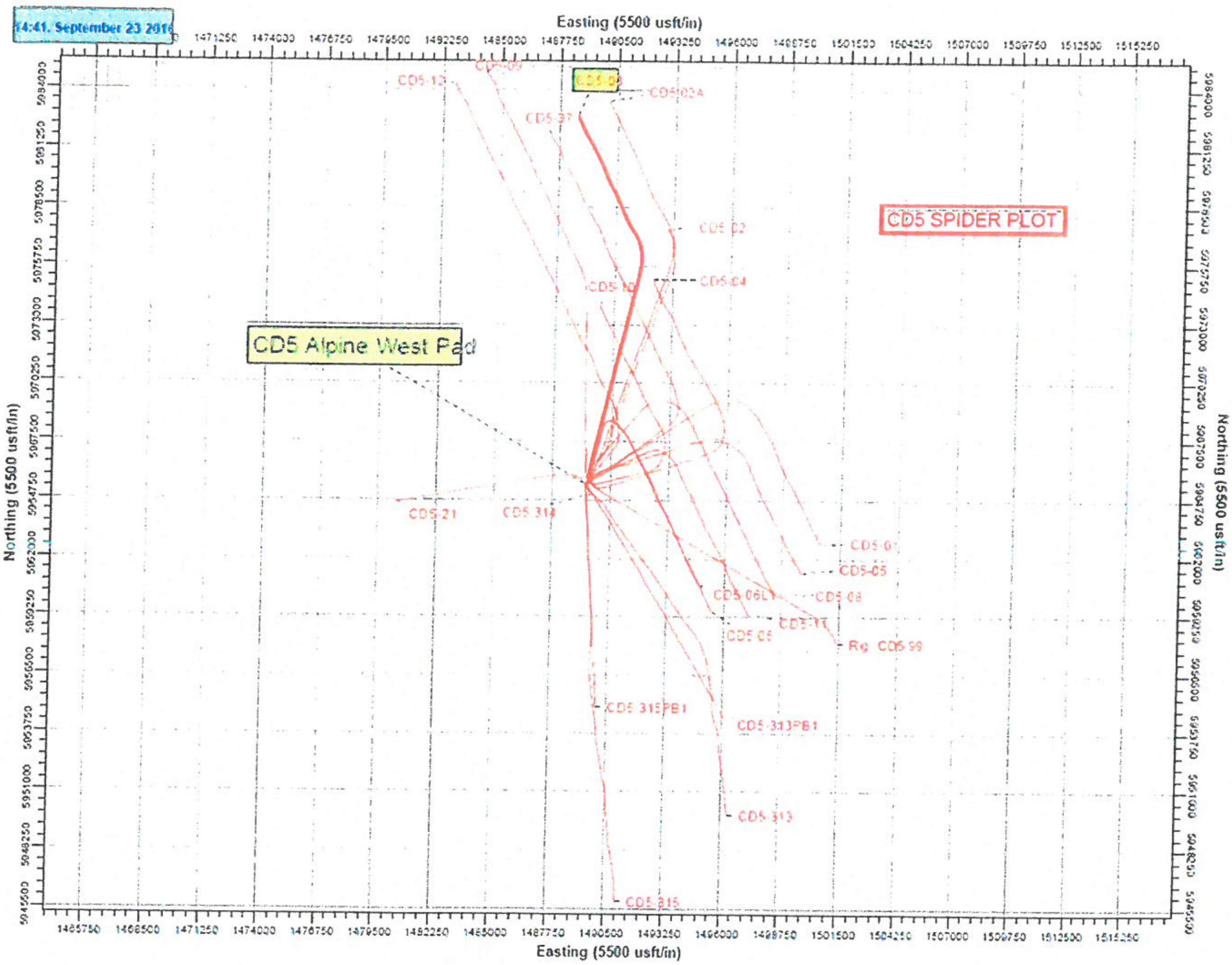

Figure 1

Figures 2-3 are section views of the of CD5-03 well bore showing the key geologic markers, actual Top of Cement (TOC) and 500' TVD of cement above the Alpine A-Sand:

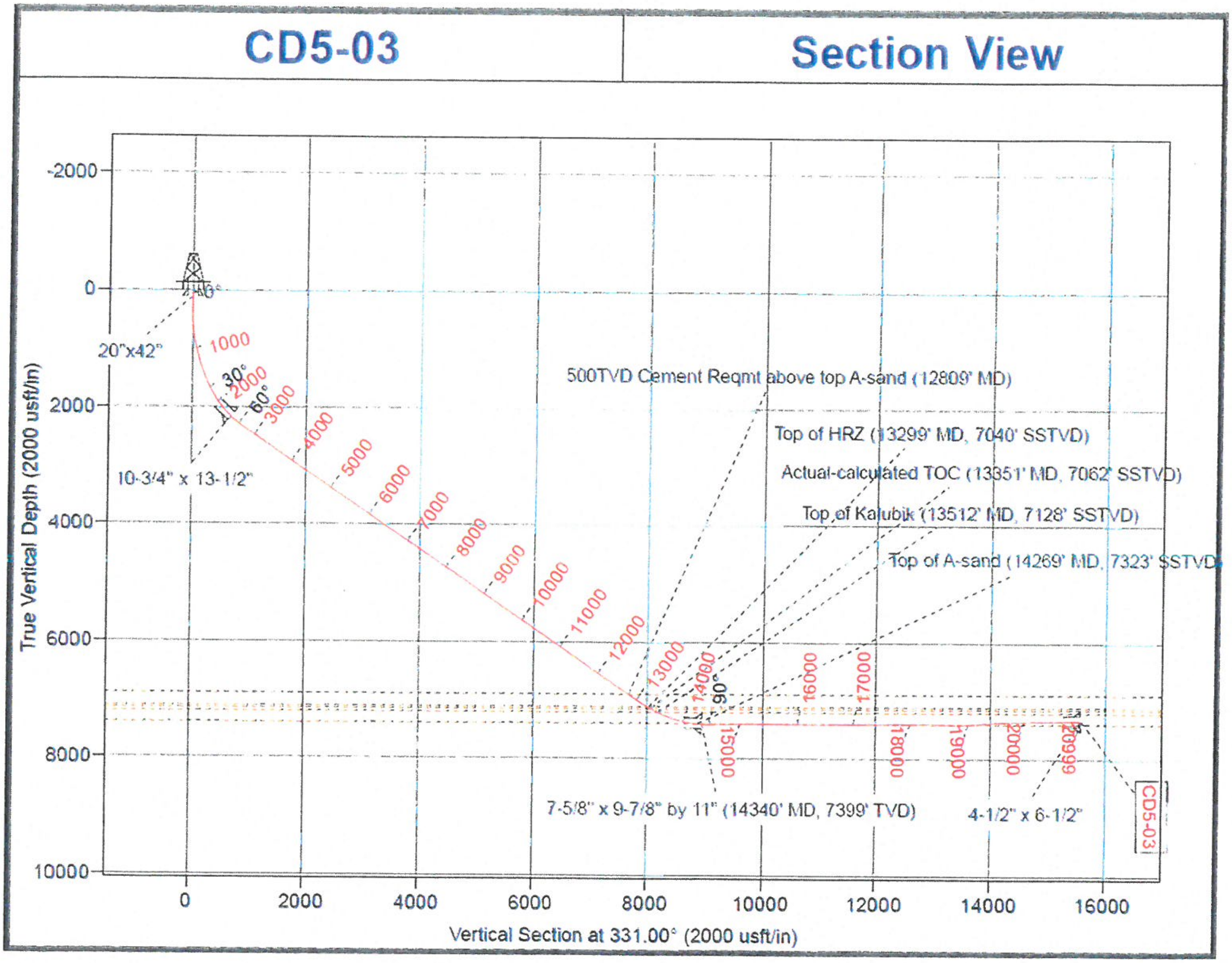

Figure 2

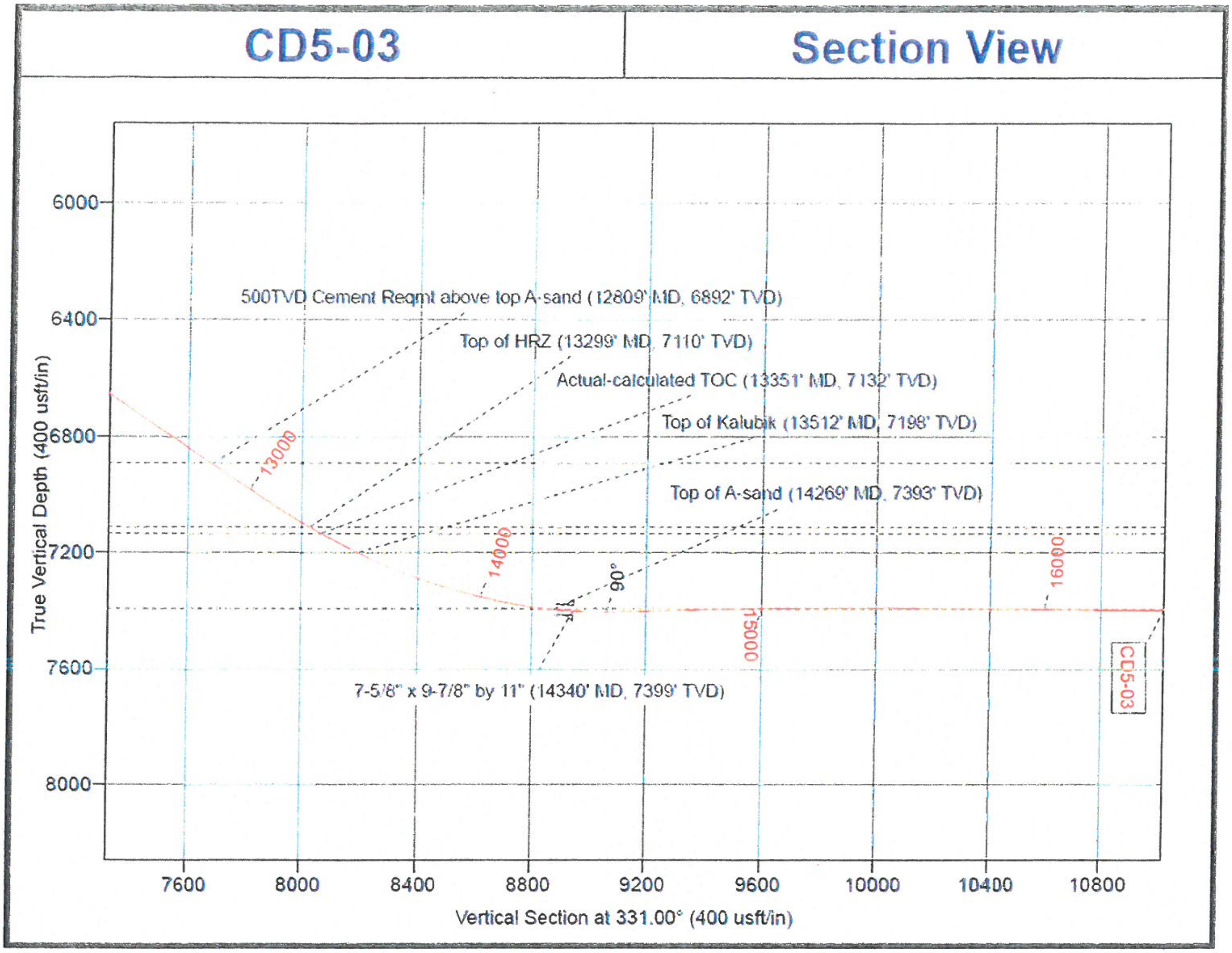
CD5-03
Section View
500TVD Cement Reqmt above top A-sand (12809' MD, 6892' TVD)
Top of HRZ (13299' MD, 7110' TVD)
Actual-calculated TOC (13351' MD, 7132' TVD)
Top of Kalubik (13512' MD, 7198' TVD)
Top of A-sand (14269' MD, 7393' TVD)
7-5/8" x 9-7/8" by 11" (14340' MD, 7399' TVD)
13000
14000
15000
16000
90°
CD5-03
True Vertical Depth (400 usft/in)
6000
6400
6800
7200
7600
8000
7600
8000
8400
8800
9200
9600
10000
10400
10800
Vertical Section at 331.00° (400 usft/in)

Figure 3

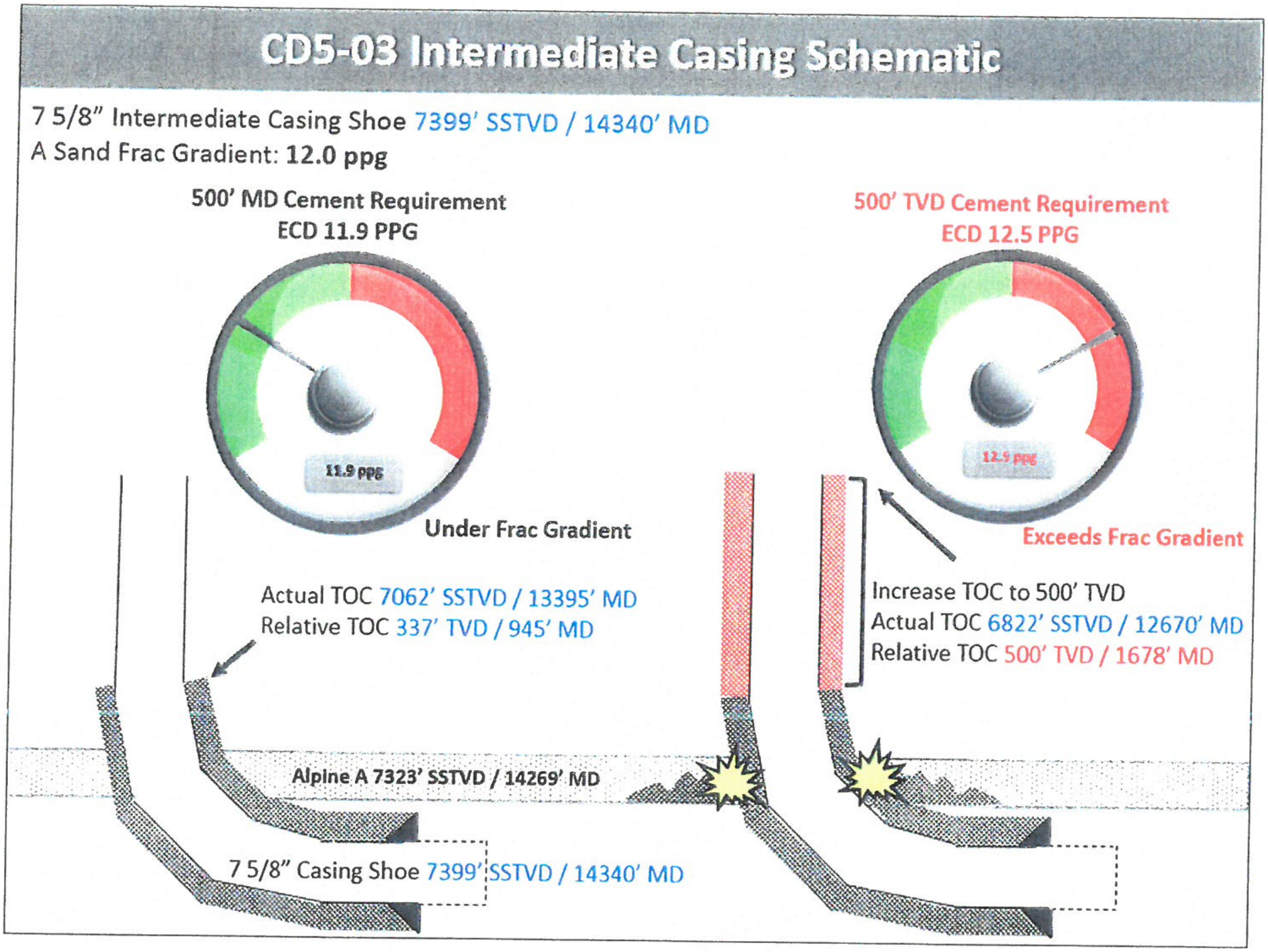

Figure 4

As Figure 4 shows, increasing the TOC on CD5-03 to 500' TVD above the Alpine A Sand would almost double the length of the cement column. This would result in an increase in ECD at the 7-5/8" shoe from 11.9 PPG to 12.5 PPG, which likely would cause a breakdown of and lost circulation in the Alpine A Sand. In this illustration, the result of trying to cement to 500' TVD to comply with the proposed regulation would be a step backward, undermining the objective of zonal isolation rather than improving it.

ConocoPhillips has reviewed the Texas Railroad Commission regulations on casing cementing, found in Texas Administrative Code Title 16 Part 1 Chapter 3.13 Casing, Cementing, Drilling, Well Control, and Completion Requirements. In Section 3.13(a)(4), on casing and cementing, Texas requires from 100' MD to 600' MD of cement above the permitted zone, depending on the type of log that is run to qualify the cement. The Texas Administrative Code Title 16 Part 1 Chapter 3.13 are provided as Exhibit 1 to these comments. We are not aware of any requirement in Texas or any other another jurisdiction requiring cementing to 500' TVD.

ConocoPhillips sees no improvement to zonal isolation that would result from increasing the amount of cement pumped to 500' TVD above the intermediate casing shoe. As demonstrated in the example provided, increasing the amount of cement pumped on intermediate casing to 500' TVD above the casing shoe or hydrocarbon zone increases the ECD's at the casing shoe and increases the risk of losing circulation while pumping the cement. Therefore, ConocoPhillips recommends continuing with the current AOGCC practice for cementing of the intermediate casing of 500'MD above a hydrocarbon zone or casing shoe.

Proposed Regulation 20 AAC 25.030 Casing and Cementing: Paragraph (d)(8). The proposed language for a new paragraph (d)(8) appears to be entirely redundant of the regulations in 20 AAC 25.283. ConocoPhillips opposes repetition and redundancy in the regulations when it is not required to serve a specific purpose, and we see no purpose for it here. Over time, redundancy tends to lead to divergent interpretations, complexity and confusion rather than simplicity and clarity. The existing regulatory requirements for permitting hydraulic fracturing operations are adequately clear as stated in section 283. We recommend rejection of the proposed subsection (d)(8).

Proposed Regulation 20 AAC 25.030 Casing and Cementing: Subsection (e). The Commission has proposed a change in this section to add a casing pressure test limit based on casing internal yield pressure. ConocoPhillips believes there is a better way to address the underlying issue, and our proposal would avoid the problems that would be caused by the Commission's proposal. In our view, the Commission's apparent objective could better be accomplished by changing the required casing test pressure to the Maximum Potential Surface Pressure (MPSP).

MPSP is described in 20 AAC 25.005(c)(4)(A) as the maximum downhole pressure that may be encountered with a pressure gradient to surface of 0.1 psi per foot of true vertical depth. Testing to the maximum potential pressure would be a sufficiently protective and conservative requirement. As AOGCC is proposing, changing the casing test pressure to 50% of the casing internal yield could unnecessarily increase the testing requirement above the maximum potential pressure, and even exceed the rating of the BOPE. This change could also increase the wear and tear on the BOPE and lead to lower reliability in this critical safety system.

ConocoPhillips sees no technical benefit by changing the casing test pressure to 50% of the casing internal yield pressure when doing so would require testing above the MPSP. We believe testing to MPSP is more reasonable, and therefore we recommend testing the casing to MPSP instead of casing internal yield pressure.

Proposed Regulation 20 AAC 25.071 Logs and Geologic Data. The proposed changes in this section update the requirements in part based on contemporary practice, but retain a requirement for paper copies, which is burdensome, expensive, and unnecessary.

ConocoPhillips recommends removing the requirement for a reproduced copy, and adopting the language proposed in paragraph (b)(8) for all prior paragraphs. This would reduce the level of QC/QA required, because the data can be delivered electronically more expeditiously and the accuracy can be validated in one QC pass. Operators work with digital electronic formats. Paper copies are seldom available, and are costly to obtain, handle and store. We are not aware of any practical requirement for the retention of paper copies.

25.556 Orders Expiration. The AOGCC has proposed short-term, automatic expirations for conservation, area injection, and other types of orders. ConocoPhillips strongly opposes this proposal and urges the AOGCC to refrain from adopting such an onerous rule without greater consultation with affected operators, including potentially a public workshop to discuss the objective the Commission seeks to achieve with the proposal and less burdensome alternatives to the current proposal.

Durability of governing rules is very important, in part because field development plans with investments in capital, staffing and training are based on the rules. Operators and the Commission both put a lot of time and effort into adopting rules that are suitable to last, but also have flexibility to accommodate reasonably anticipated changes over time. In our view, this system is working adequately. The purpose of keeping abreast of potentially significant changes is also served by regular reporting under regulations and orders, and by the fact that operators commonly seek adjustments to existing orders, which provides an opportunity for the Commission to seek information or raise issues of potential concern under existing orders.

We recognize that in some cases rules may need to be changed either to improve the rule or to adjust to changed circumstances. We believe both the Commission and affected stakeholders have options for rule changes under existing regulations, including 20 AAC 25.460, .520 and .540. The existing regulations at 20 AAC 25.520(c), for example, provide that the "commission will, in its discretion, amend pool orders in accordance with the procedures set forth in 20 AAC 25.540." The operator and any affected owner, or other interested party has the right to request amendment of an area injection order or conservation order at any time through existing AOGCC processes.

In case of automatic expiration, which we oppose, we see a high risk of new and unnecessary problems. If for any reason a conservation order is not renewed before expiration, for example, the pool would presumably cease to exist as a regulatory matter, putting the operator in a position of possibly having to cease drilling operations, injection, and possibly even production to the detriment of the State as a whole. Given the sheer number of existing orders, and the significant additional burden this rule would impose on the Commission's staff, the possibility of missing deadlines is not remote. This level of uncertainty and potential instability will not reduce waste, protect correlative rights or maximize ultimate recovery, or serve any identifiable regulatory purpose. Instead, automatic expiration and the additional administrative process of required renewal will drive up costs, and could potentially affect project economics.

Even if no deadline for renewal were ever missed, the proposal would impose a very significant increase in burden and cost on operators of existing fields. Preparing an application to the AOGCC for an order is a very substantial undertaking in terms of operator staff time and resources. Having to undertake a similar effort not just on initial orders and occasional modifications, but on every order no less than every five years, would have the effect of a highly burdensome increase in regulatory compliance costs, with not correlative public benefit.

We see no basis for a one-size-fits-all prescription for rules to expire in five years. We also see no adequate justification for imposing unilaterally on operators a burden of proving to the Commission on such a short time frame that existing orders ought to remain in effect. We believe a more sensible approach is to retain the existing system in which orders are crafted to be durable, but remain subject to modification at the Commissions discretion. In some cases, an early review might be appropriate; in others, a requirement to regularly renew an order would be a waste of effort that could be put to better use.

If the Commission is firm in its belief that some change in this area is necessary – which is not clear to ConocoPhillips – we seek an opportunity to work with the Commission on ideas for a more flexible, less burdensome approach.

ConocoPhillips Proposal for new 20 AAC 25.015(c). Although the Commission has not proposed change to this regulation, ConocoPhillips would like to take this opportunity to recommend a regulatory change that we think would be an improvement to the rules governing a change in a drilling program. Our recommendation is to add a new subsection (c) to 20 AAC 25.015, to read as follows: "Notwithstanding (a) and (b) of this section, Commission approval is not required if the only change to a through-tubing drilling operation is a change in the kick-off point with no vertical change in objective formation greater than 500 feet."

Exhibit 1

LexisNexis®

1 of 1 DOCUMENT

TEXAS ADMINISTRATIVE CODE

*** This document reflects all regulations in effect as of August 31, 2016 ***

TITLE 16. ECONOMIC REGULATION
PART 1. RAILROAD COMMISSION OF TEXAS
CHAPTER 3. OIL AND GAS DIVISION

Go to the Texas Administrative Code Archive Directory

16 TAC § 3.13 (2016)

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

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

(1) Intent. The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. In accordance with § 3.17 of this title (relating to Pressure on Bradenhead), operators must notify the Commission of bradenhead pressure. The Commission will evaluate notices of bradenhead pressure on a case-by-case basis to determine further action and will provide guidance to assist operators in wellbore evaluation.

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

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

(B) Zone of critical cement-- (i) For surface casing strings, the bottom 20% of the casing string, but no more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet or less. (ii) For intermediate or production casing strings, the bottom 20% of the casing string or 300 vertical feet above the casing shoe or top of the highest proposed productive zone, whichever is less.

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

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

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

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

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

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

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

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

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

(L) Minimum separation well--A well in which hydraulic fracturing treatments will be conducted and for which: (i) the vertical distance between the base of usable quality water and the top of the formation to be stimulated is less than 1,000 vertical feet; (ii) the director has determined contains inadequate separation between the base of usable quality water and the top of the formation in which hydraulic fracturing treatments will be conducted; or (iii) the director has determined is in a structurally complex geologic setting.

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

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

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

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

(3) Wellbore diameters.

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

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

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

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

(4) Casing and cementing.

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

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

(C) Casing shall be cemented across and above all formations permitted for injection under § 3.9 of this title (relating to Disposal Wells) at the time the well is completed, or cemented immediately above all formations permitted for injection under § 3.46 of this title (relating to Fluid Injection into Productive Reservoirs) at the time the well is completed, in a well within one-quarter mile of the proposed well location, as follows: (i) if the top of cement is determined through calculation, at least 600 feet (measured depth) above the permitted formations; (ii) if the top of cement is determined through the performance of a temperature survey conducted immediately after cementing, 250 feet (measured depth) above the permitted formations; (iii) if the top of cement is determined through the performance of a cement evaluation log, 100 feet (measured depth) above the permitted formations; (iv) at least 200 feet into the previous casing shoe (or to surface if the shoe is less than 200 feet from the surface); or (v) as otherwise approved by the district director.

(D) Casing shall be cemented across and above all productive zones, potential flow zones, and/or zones with corrosive formation fluids, as follows: (i) if the top of cement is determined through calculation, across and extending at least 600 feet (measured depth) above the zones; (ii) if the top of cement is determined through the performance of a temperature survey, across and extending 250 feet (measured depth) above the zones; (iii) if the top of cement is determined through the performance of a cement evaluation log, across and extending 100 feet (measured depth) above the zones; (iv) across and extending at least 200 feet into the previous casing shoe (or to the surface if the shoe is less than 200 feet from the surface); or (v) as otherwise approved by the district director.

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

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

(6) Well control.

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

(B) Well control equipment. (i) An operator shall install a blowout preventer system or control head and other connections to keep the well under control at all times as soon as surface casing is set. When conductor casing is set and/or shallow gas is anticipated to be encountered, operators shall install a diverter system on the conductor casing. For bay and offshore wells, at a minimum, such systems shall include a double ram blowout preventer, including pipe and blind rams, an annular-type blowout preventer or other equivalent control system, and a shear ram. (ii) For wells in areas with hydrogen sulfide, the operator shall comply with § 3.36 of this title (relating to Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas). (iii) Ram type blowout prevention equipment shall have a rated working pressure that equals or exceeds the maximum anticipated surface pressure of the well. Blowout preventer rams shall be of a proper size for the drill pipe being used or production casing being run in the well or shall be variable-type rams that are in the appropriate size range. Alternatively, an annular preventer may be used in lieu of casing/pipe rams or variable bore rams when running production casing provided the expected shut-in surface pressures would not exceed the tested pressure rating of the annular preventer. (iv) Operators shall install a drill pipe safety valve to prevent backflow of water, oil, gas, or other formation fluids into the drill string. (v) Operators shall install a choke line of sufficient size and working pressure. (vi) When using a Kelly rig during drilling, the well shall be fitted with an upper Kelly cock in proper working order to close in the drill string below hose and swivel, when necessary for well control. A lower Kelly safety valve shall be installed so that it can be run through the blowout preventer. When needed for well control, the operator shall maintain at all times on the rig floor safety valves to include:

(I) full-opening safety valve; and

(II) inside blowout preventer valve with wrenches, handling tools, and necessary subs for all drilling pipe sizes in use. (vii) All control equipment shall be consistent with API Standard 53: Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells. Control equipment shall be certified in accordance with API Standard 53 as operable under the product manufacturer's minimum operational specifications. Certification shall include the proper operation of the closing unit valving, the pressure gauges, and the manufacturer's recommended accumulator fluids. Certification shall be obtained through an independent company that tests blowout preventers, stacks and casings. Certification shall be performed every five (5) years and the proof of certification shall be made available upon request of the Commission. (viii) All well control equipment shall be in good working condition at all times. All outlets, fittings, and connections on the casing, blowout preventers, choke manifold, and auxiliary wellhead equipment that may be subjected to wellhead pressure shall be of a material and construction to withstand or exceed the anticipated pressure. The lines from outlets on or below the blowout preventers shall be securely installed, anchored, and protected from damage. (ix) In addition to the primary closing system, including an accumulator system, the blowout preventers shall have a secondary location for closure. (x) Testing of blowout prevention equipment.

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

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

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

(C) Drilling fluid program. (i) The characteristics, use, and testing of drilling fluid and conduct of related drilling procedures shall be designed to prevent the blowout of any well. Adequate supplies of drilling fluid of sufficient weight and other acceptable characteristics shall be maintained. Drilling fluid tests shall be performed as needed to ensure well control. Adequate drilling fluid testing equipment shall be kept on the drilling location at all times. Sufficient drilling fluid shall be pumped and maintained to ensure well control at all times, including when pulling drill pipe. Mud pit levels shall be visually or mechanically monitored during the drilling process. Mud-gas separation equipment shall be installed and operated as needed when abnormally pressured gas-bearing formations may be encountered. The Commission shall have access to the drilling fluid records and shall be allowed to conduct any essential tests on the drilling fluid used in the drilling or recompletion of a well. When the conditions and tests indicate a need for a change in the drilling fluid program in order to insure control of the well, the operator shall use due diligence in modifying the program. (ii) Wells drilled with air shall maintain well control using blowout preventer systems and/or diverter systems. (iii) All hole intervals drilled prior to reaching the base of protected water shall be drilled with air, fresh water or a fresh water based drilling fluid. No oil-based drilling fluid may be used until casing has been set and cemented to the protection depth.

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

(E) Casinghead. (i) Requirements. All land and bay wells shall be equipped with casingheads of sufficient rated working pressure, with adequate connections and valves accessible at the surface, to allow pumping of fluid between any two strings of casing at the surface. (ii) Casinghead test procedure. Any well showing sustained pressure on the casinghead, or leaking gas or oil between the surface casing and the next casing string, shall be tested in the following manner. The well shall be killed with water or mud and pump pressure applied. The casing shall be condemned if the pressure gauge on the casinghead reflects the applied pressure. After completing corrective measures, the casing shall be tested in the same manner. This method shall be used when the origin of the pressure cannot otherwise be determined.

(F) Christmas tree. (i) All completed non-pumping wells shall be equipped with Christmas tree fittings and wellhead connections with a rated working pressure equal to, or greater than, the surface shut-in pressure of the well. The tubing shall be equipped with a master valve, but two master valves shall be used on all wells with surface pressures in excess of 5,000 psi. All wellhead connections shall be assembled and tested prior to installation by a fluid pressure equal to the test pressure of the fitting employed. (ii) The Christmas tree for completed bay and offshore wells shall be equipped with either two master valves, one master valve and one wing valve, or two wing valves. All bay and offshore wells shall have at least five feet of spacing between the bottom of the Christmas tree and the surface of the water at high tide, where applicable. Any newly completed bay and offshore well or existing well on which the Christmas tree is being replaced shall be equipped with a back pressure valve wellhead profile at the flange where the tubing hangs on the Christmas tree.

(G) Storm choke and safety valve. (i) Bay and offshore wells shall be equipped with a storm choke and/or safety valve installed in the tubing. (ii) An operator may request approval to use a surface safety valve in lieu of a subsurface safety valve by filing with the appropriate district director a written request for such approval providing all pertinent information to support the exception. (iii) The depth and type of the safety valve shall be reported in the "remarks" section of the appropriate completion report form required by § 3.16 of this title (relating to Log and Completion or Plugging Report), after the well is completed or recompleted.

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

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

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

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

(D) The following conditions also apply if the well is a minimum separation well, unless otherwise approved by the director: (i) Cementing of the production casing in a minimum separation well shall be by the pump and plug method. The production casing shall be cemented from the shoe up to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface). (ii) The operator shall pressure test the casing string on which the pressure will be exerted during stimulation to the maximum pressure that will be exerted during hydraulic fracturing treatment. The operator shall notify the district director within 24 hours of a failed test. No hydraulic fracturing treatment may be conducted until the district director has approved a remediation plan, and the operator has implemented the approved remediation plan and successfully re-tested the casing (or fracture tubing). (iii) The production casing for any minimum separation well shall not be disturbed for a minimum of eight hours after cement is in place and casing is hung-off, and in no case shall the casing be disturbed until the cement has reached a minimum compressive strength of 500 psi. (iv) In addition to conducting an evaluation of cementing records and annular pressure monitoring results, the operator of a minimum separation well shall run a cement evaluation tool to assess radial cement integrity and placement behind the production casing. If the cement evaluation indicates insufficient isolation, completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan. (v) The operator of a minimum separation well may request from the appropriate district director approval of an exemption from the requirement to run a cement evaluation tool. Such request shall include information demonstrating that the operator has:

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

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

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

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

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

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

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

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

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

(B) Amount required. (i) An operator shall set and cement sufficient surface casing to protect all usable-quality water strata, as defined by the Groundwater Advisory Unit of the Oil and Gas Division. Unless surface casing requirements are specified in field rules approved prior to the effective date of this rule, before drilling any well, an operator shall obtain a letter from the Groundwater Advisory Unit of the Oil and Gas Division stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the district director. The district director may grant such approval on an area basis. (ii) Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.

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

(D) Cement quality. (i) Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi. (ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed. (iii) In addition to the minimum compressive strength of the cement, the free water content shall be minimized to the greatest extent practicable in the cement slurry to be used in the zone of critical cement. In no event shall the free water separation average more than two milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B-2: Recommended Practice for Testing Well Cements, inside the zone of critical cement, or more than six milliliters per 250 milliliters of cement tested outside the zone of critical cement. (iv) The Commission may require a better quality of cement mixture to be used in any well or any area if conditions indicate that a better quality of cement is necessary to prevent pollution, isolate productive zones, potential flow zones, or zones with corrosive formation fluids or prevent a safety issue in the well.

(E) Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures in, or equipment and procedures equivalent to those in, API RP 10B-2, Recommended Practice for Testing Well Cements. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the Commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure. (i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement. (ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.

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

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

(H) Alternative surface casing programs. (i) An alternative method of fresh water protection may be approved upon written application to the appropriate district director. The operator shall state the reason for the alternative fresh water protection method and outline the alternate program for casing and cementing through the protection depth for strata containing usable-quality water. Alternative programs for setting more than specified amounts of surface casing for well control purposes may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be considered on an individual well basis only. The district director may approve, modify, or reject the proposed program. The district director shall deny the request if the operator has not demonstrated that the alternative casing plan will achieve the intent of this rule as described in subsection (a)(1) of this section. If the proposal is modified or rejected, the operator may request a review by the deputy director of field operations. If the proposal is not approved administratively, the operator may request a public hearing. An operator shall obtain approval of any alternative program before commencing operations. (ii) Any alternate casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside this string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least

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

(I) Mechanical integrity test of surface casing after drillout. (i) If the surface casing is exposed to more than 360 rotating hours after reaching total depth or the depth of the next casing string, the operator shall verify the integrity of the surface casing by using a casing evaluation tool or conducting a mechanical integrity test or equivalent Commission-approved casing evaluation method, unless otherwise approved by the district director. (ii) If a mechanical integrity test is conducted, the appropriate district office shall be notified at least eight hours before the test is conducted to give the district office an opportunity to witness the test. The operator shall use a chart of acceptable range (20% - 80% of full scale) or an electronic equivalent approved by the district director, and the surface casing shall be tested at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the true vertical depth in feet of the casing string by a factor of 0.5 psi per foot up to a maximum of 1,500 psi for a minimum of 30 minutes. A pressure test demonstrating less than a 10% pressure drop after 30 minutes constitutes confirmation of an acceptable pressure test. The appropriate district office shall be notified within 24 hours after a failed test. Completion operations may not re-commence until the district director approves a remediation plan and the operator successfully implements the approved plan, and successfully re-tests the surface casing.

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

(A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet (measured depth) above the shoe. If any productive zone, potential flow zone, or zone with corrosive formation fluids is open to the wellbore above the casing shoe, the casing shall be cemented; (i) if the top of cement is determined through calculation, from the shoe up to a point at least 600 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids; (ii) if the top of cement is determined through performance of a temperature survey, from the shoe up to a point at least 250 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluids; (iii) if the top of cement is determined through performance of a cement evaluation log, from the shoe up to a point at least 100 feet (measured depth) above the top of the shallowest productive zone, potential flow zone, or zone with corrosive formation fluid; or (iv) to a point at least 200 feet (measured depth) above the shoe of the next shallower casing string that was set and cemented in the well (or to surface if the shoe is less than 200 feet from the surface); or (v) as otherwise approved by the district director.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Display Image (ii) Surface Casing test.

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

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

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

(C) Production casing or oil string. (i) The production casing or oil string shall be new or reconditioned pipe with a mill test of at least 2,000 psi that has been tested to an equal pressure. (ii) After cementing, the production casing shall be tested by pump pressure to at least 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 150 psi or more, the casing shall be condemned. After corrective operations, the casing shall again be tested in the same manner. (iii) Cementing of the production casing shall be by the pump and plug method. Sufficient cement shall be used to fill the calculated annular space above the shoe to isolate any productive zones, potential flow zones, or zones with corrosive formation fluids and to a depth that isolates abnormal pressure from normal pressure (0.465 psi per vertical foot of gradient). A float collar or other means to stop the cement plug shall be inserted in the casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating tests.

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

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

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

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

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

NOTES:

CROSS-REFERENCES: This Section cited in *16 TAC § 3.9*, (relating to Disposal Wells); *16 TAC § 3.15*, (relating to Surface Casing To Be Left in Place); *16 TAC § 3.46*, (relating to Fluid Injection into Productive Reservoirs); 16 TAC § 3.77, (relating to Brine Mining Injection Wells); *16 TAC § 3.96*, (relating to Underground Storage of Gas in Productive or Depleted Reservoirs); *16 TAC § 3.81*, (relating to Brine Mining Injection Wells).