



RAILROAD COMMISSION OF TEXAS OIL AND GAS DIVISION

February 29, 2016

Robert E. Warren
Vice President – Onshore Operations
International Association of Drilling Contractors (IADC)
10370 Richmond Avenue, Suite 760
Houston, Texas 77042

Re: Concerns with Well Control Requirements of the Railroad Commission's
Statewide Rule 13

Dear Mr. Warren:

This letter is in response to your letters dated June 14, 2014, and July 15, 2015, requesting clarification of well control requirements in the Commission's Statewide Rule 13 (16 Tex. Admin. Code §3.13), relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements, as amended effective January 1, 2014. The final clarification document is attached and will be included on the Commission's Rule 13 webpage at <http://www.rrc.state.tx.us/oil-gas/compliance-enforcement/rule-13-geologic-formation-info/>.

I appreciate the assistance you and your members have provided to us throughout the review and discussion of the rule language and intent.

Sincerely,

A handwritten signature in black ink, appearing to read "Leslie Savage".

Leslie Savage, Assistant Director
Technical Permitting
Oil and Gas Division

REVISED STATEWIDE RULE 13 – CLARIFICATION OF WELL CONTROL ISSUES

The Railroad Commission (Commission) has received requests for clarification of certain issues relating to the reference in revised Statewide Rule 13 to certain API publications of standards and recommended practices for well control and well control equipment. The Commission has developed the following responses to address those issues for which clarification has been requested.

GENERAL ISSUES

ISSUE: Section §3.13(a)(6)(B)(vii) states that: “All control equipment shall be consistent with API Standard 53: Recommended Practices for BOP 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.” At the time the Commission proposed the amendments to Rule 13, API listed this publication under “Recommended Practice 53” (see <http://publications.api.org/Exploration-Production.aspx>). API has since revised this publication (4th Edition, November, 2012) and deleted the reference to “recommended practices” in the title. Please clarify this issue.

RESPONSE: The publication states that: “API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized.” The introduction to this publication further states that: “This standard does not present all of the operating practices that can be employed to successfully install and operate blowout prevention systems in drilling, completions and well testing operations. Practices set forth herein are considered acceptable for accomplishing the job as described; however, equivalent alternative installations and practices can be used to accomplish the same objectives.” Therefore, as a compendium of “recommended practices,” API concedes the need for the exercise of sound engineering and operating practices when considering well control equipment, testing and operations.

In drafting §3.13(a)(6)(B)(vii), the Commission very carefully selected the phrase “consistent with API Standard 53: Recommended Practices for BOP Equipment Systems for Drilling Wells” to preserve the flexibility already built into this publication and to accommodate flexibility with respect to sound engineering and operations that are necessary and prudent. To that end, the rule requires operations and equipment that are “consistent with” Standard 53 and good engineering and operating practices to ensure that operators are able to maintain well control.

SPECIFIC ISSUES

ISSUE: Section 3.13(a)(6)(B)(vii) states that: “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 years and the proof of certification shall be made available upon request of the commission.” API

Standard 53 does not use the term “certified” with respect to well control equipment. Please clarify this issue.

RESPONSE: Both API Recommended Practices 53 (3rd Edition, March 1997) and API Standard 53 (4th Edition, 2012) include the term “certification.” However, the term is used in association with a manufacturer’s certification or an NACE certification. Neither publication requires “certification” of control equipment as operable. In addition, the Commission did not include a definition for “certify” or “certification” in the most recent amendments to Rule 13. Therefore, the requirement in §3.13(a)(6)(B)(ii) to “certify” control equipment “in accordance with Standard 53 as operable” will need to be clarified prior to implementation and enforcement. The Commission will review this language in future amendments of Rule 13.

ISSUE: API Standard 53, Section 6.2.1.1 states that choke and kill systems must be designed, manufactured, and installed in accordance with API 16C, “Specification for Choke and Kill Systems.” API 16C, Section 1.4.2 states that valves and other equipment must have an API 6A minimum product specification level of “PSL 3” and minimum material class “EE,” which means that any choke manifold in Texas using API 6A valves built to PSL 1 or PSL 2, and material class DD valves are no longer acceptable (although revisions to API 16C are expected to allow DD material class valves.) Any drilling rig in Texas with choke manifold valves, kill line valves, chokes, choke line valves and other equipment not meeting this requirement for minimum PSL 3 and EE trim would need to be replaced with new (different) equipment at great cost and time. API 6A PSL Level I valves are safe and reliable and, if such a valve fails to seal, there are commonly other valves (redundancy) in the system to maintain well control. Please clarify this issue.

RESPONSE: As noted, the rule only requires that the choke and kill systems be consistent with API Standard 53 and that the practices in API Standard 53 are “considered acceptable for accomplishing the job as described; however, equivalent alternative installations and practices can be used to accomplish the same objectives.”

ISSUE: API Standard 53, Section 6.1.2.11.A. states that: “[A] minimum Class 4 BOP stack arrangement shall be installed for 10K pressure rated systems, with a minimum of one blind ram or a BSR capable of shearing and sealing the drill pipe in use.” This could mean that a two ram stack with one annular is no longer sufficient for a 10K rated blowout preventer system. The decision on the number of BOPs should be a risk-based decision for the well to be safely drilled, rather than a function of the pressure rating of the equipment that a rig might happen to have on hand. Please clarify this issue.

RESPONSE: API Standard 53, Section 6.1.1.1 states that: “Every installed ram BOP shall have, as a minimum, a working pressure equal to the maximum anticipated surface pressure (MASP) to be encountered.” The BOP Stack Classification should be determined by the MASP of the well, not by the Pressure Rating of the equipment being utilized.

ISSUE: API Standard 53, Section 6.1.2.12. states that: “A Class 5 BOP arrangement or greater shall be installed for 15K and greater pressure rated systems. The minimum requirements for a Class 5 BOP stack arrangement shall include one annular, one BSR, and two pipe rams. The fifth device may be a ram or annular type preventer, whichever is desired. A risk assessment shall be performed to identify ram placements and configurations, and taking into account annular and large tubular(s) for well control management.” Blinding shear rams are now required on 15K BOP stacks. It does not matter what well is being drilled, just the rated working pressure of the BOP stack. Such a decision for shear rams at the expense of a cavity that might include a more reliable blind ram to close on an open well bore should be a risk-based decision. Please clarify this issue.

RESPONSE: API Standard 53, Section 6.1.1.1 states that: “Every installed ram BOP shall have, as a minimum, a working pressure equal to the maximum anticipated surface pressure (MASP) to be encountered.” The BOP Stack Classification should be determined by the MASP of the well, not by the Pressure Rating of the equipment being utilized.

ISSUE: API Standard 53, Section 6.3.11.2.5. states that: “All rigid or flexible lines between the control system and BOP stack shall meet the fire test requirements of AD 16D, including end connections, and shall have RWP equal to the RWP of the BOP control system.” While many rigs have rigid piping, fire testing is not generally performed on this piping. Please clarify whether piping must be fire tested, particularly in situations with walking rigs where the piping and flexible hoses are long distance from the wellbore. Please clarify this issue.

RESPONSE: Section 10.1.2.1 of API 16D: This provision would be satisfied if the flexible control lines to a surface-mounted BOP stack or diverter, located in a division one (1) area, as defined by API RP 500(area classification), are capable of containing the hose rated working pressure in a flame temperature of 1300°F (700°C) for a 5-minute period.

ISSUE: Please clarify the intent of the references in revised Rule 13 to API 16C in API Standard 53 Section 6.2.3.1.4, Section 6.2.4.2.4, Section 7.2.1.1, and Section 7.2.3.1.4. API 16C covers flexible choke and kill lines and API 16C-licensed facilities for flexible choke and kill lines are currently limited to six facilities, only one of which is in the United States. With limited manufacture options for API 16C hoses, deliveries take a long time and pricing is very high. There are many companies that produce choke and kill hoses that are not API 16C products. There is a similar concern with API Standard 53, Section 4.12.1., which states that: “Marking and storage of sealing components of BOP systems shall be in accordance with API 6A, API 16A, or API 17D, as applicable, including identification marking of ring gaskets, bolts, nuts, clamps, and elastomeric seals.”

RESPONSE: As noted above, equivalent alternative installations and practices can be used to accomplish the same objectives.

ISSUE: API Standard 53, Section 6.2.2.9 states that: “A minimum of two remotely operated chokes shall be installed on choke manifold systems rated 10K and greater. The choke control panel shall have two independent control valves, one each for the two remotely operated chokes.” Many 10K choke manifolds have one manual choke, one center run, and one remotely controlled hydraulic choke. Many operators rent chokes because of varying preferences on makes and models. The addition of a second hydraulic choke would require plumbing changes and space. This requirement includes no review of the well to be drilled and risk associated with same. A 10K choke manifold might have been used on a well that only requires a 5K BOP stack. Where a 5K choke manifold may have required only one hydraulic choke, now that choke manifold is required to have two, resulting in additional time and cost to many independent operators and drilling contractors in Texas. Please clarify this issue.

RESPONSE: Section 6.2.2.9 does not apply to wells with a MASP less than 10,000 PSI. Wells with a maximum anticipated surface pressure less than 10,000 PSI must have a minimum of one remotely operated choke.

ISSUE: API Standard 53, Section 6.2.2.18 states that: “[T]he choke control station shall include all instruments necessary to furnish an overview of well control operations. This includes the ability to monitor and control such items as stand pipe pressure, casing pressure, and monitor pump strokes.” Please clarify how such items would be controlled at the choke control station.

RESPONSE: Section 6.2.2.18 states that the choke control station must include all instruments necessary to furnish an overview of well control operations, including the ability to “monitor” and, therefore, be able to control such items as stand pipe pressure, casing pressure and monitor pump strokes, not to control from the choke control station.

ISSUE: API Standard 53, Section 6.3.10.6 states that: “All control system analog pressure gauges shall be calibrated to one percent of full scale at least every three years.” A requirement to test to one percent is excessive. Please clarify the requirement under revised Rule 13 as a result of incorporation of API Standard 53 by reference. Please clarify this issue.

RESPONSE: Calibration to OEM specifications would be acceptable. Equipment owners must ensure that the calibration of the control system analog pressure gauges is included in their inspection and maintenance program.

ISSUE: Please clarify the requirements relating to the reference to API 16D in Section 6.3.1.1., relating to control systems for surface BOP stacks. The requirements for pump time and closing time in API Standard 53 also fit around current 16D equipment requirements and many control systems were built before API 16D existed. Please clarify this issue.

RESPONSE: As noted above, §3.13 only requires that an operator’s equipment and practices be consistent with Standard 53, which states that equivalent alternative installations and practices can be used to accomplish the same objectives. Equipment that is operating must meet the version of 16D or relevant design at the time of manufacture.

ISSUE: API Standard 53, Section 6.3.9.4 that states that: “The precharge pressure shall be measured prior to BOP stack deployment and adjusted in accordance with the manufacturer-specified API 16D method (A, B, or C),” using the control system manufacturer-supplied surface base pressure, adjusted for operating temperature as required, and shall be documented and retained at the rig site. The calculated precharge pressures along with documentation supporting nonoptimal precharge pressures (if used) shall be filed with the well-specific data package. See Annex C for examples of accumulator precharge calculations.” Full compliance with this requirement would be an undue burden. Please clarify this issue.

RESPONSE: The Commission considers BOP Stack Deployment to be the original commissioning of new equipment.

ISSUE: API Standard 53, Section 6.4.6.1 states that a trip tank shall be installed and used on all wells. Such a requirement would remove the possibility of a rig filling the hole from main mud tanks on shallow rigs or spudder type rigs that just drill the surface interval before a larger rig is used to drill the more critical parts of the well. This should be an engineering based decision and is not necessary on all rigs. Please clarify this issue.

RESPONSE: As noted above, §3.13 only requires that an operator’s equipment and practices be consistent with Standard 53. The Commission understands that not all well sections would require trip tanks. As noted above, equivalent alternative installations and practices can be used to accomplish the same objectives.

ISSUE: API Standard 53, Section 6.4.7.1 states that: “Pit volume measuring systems, complete with audible and visual alarms, shall be installed.” Section 6.4.7.3 states that: “A pit volume totalizer system shall be installed and used on all rigs.” Section 6.4.8.1 states that: “A flow rate sensor mounted in the flow line shall be installed for early detection of formation fluid entering the wellbore or a loss of returns.” Such instrumentation systems and pit volume systems might be rental items only used during

the more critical portions of a more critical well. By referencing API Standard 53, the Commission is now requiring these systems on all wells at all times, including a rig that only drills and sets conductor pipe. Such a decision should be based on risks and the drilling engineer's assessment of the requirements of well that is being drilled. Please clarify this issue.

RESPONSE: As noted above, §3.13 only requires that an operator's equipment and practices be consistent with Standard 53. The Commission understands that not all well sections would require pit volume measuring systems, pit volume totalizers, and flow rate sensors. As noted above, equivalent alternative installations and practices can be used to accomplish the same objectives.

ISSUE: What is the benefit of API Standard 53, Section 6.5.3.1.5., which states that: "Actuation times shall be recorded in a database for evaluating trends (see sample worksheets in Annex A)"?

RESPONSE: Actuation times should be monitored and recorded. However, recording in a database is not necessary.

ISSUE: API Standard 53, Section 6.5.3.4.3 states that: "Chamber pressure tests shall be performed and charted as follows: a) At least once yearly, b) When equipment is repaired or remanufactured, c) In accordance with equipment owner's PM program." Requiring the test to be charted and the frequency is burdensome. Please clarify this issue.

RESPONSE: Chamber pressure tests shall at a minimum be performed when equipment is remanufactured and the results recorded; however, charting is not necessary. From a practical standpoint, a chamber test is effectively performed each time the BOP is pressure tested or function tested.

ISSUE: Footnote "d" to Table 2 in API Standard 53 states that the MGS requires a onetime hydrostatic test during manufacturing or upon installation and that subsequent welding on the MGS vessel shall require an additional hydrostatic test to be performed. However, not all MGS are pressure vessels and OEM repair procedures may not require hydrostatic testing. Please clarify how this testing is to be performed for MGS that are not pressure vessels and for repair procedures that do not require hydrostatic testing. Also please clarify if hydrostatic testing requires holding pressure on the vessel.

RESPONSE: If the MGS is a pressure vessel, hydrostatic testing may be appropriate; however, OEM recommended repair and testing procedures should be followed. If the MGS is not a pressure vessel, testing in accordance with the manufacturer's recommendations is appropriate and sufficient.

ISSUE: For accumulator drawdown tests, API Standard 53, Section 6.5.6.2.2 states that: "This test shall be performed after the initial nipple-up of BOPs, after any repairs that required isolation/partial isolation of the system, or every 6 months from previous test, using the following example (see Annex A)." Subsection (g) states that "Record the final accumulator pressure. The final accumulator pressure shall be equal to or greater than 200 psi (1.38 MPa) above precharge pressure." Note 1 states that: "When performing the accumulator drawdown test, wait a minimum of 1 hour from the time you initially charged the accumulator system from precharge pressure to operating pressure. Failure to wait sufficient time may result in a false positive test." Please clarify this issue, as a requirement to wait an hour for the drawdown test is not a common practice in industry.

RESPONSE: The Commission agrees that the one hour waiting period is recommended, but not mandatory.

ISSUE: API Standard 53, Section 6.5.8.6.1 states that poor boy degasser/mud-gas separation systems equipment owner's PM program must include removal of inspection plates and clearing of debris. This requirement will require welding inspection plates to existing poor boy degassers. Operators have expressed concern about the safety of welding in proximity to flammable gases and/or liquids. Please clarify this issue.

RESPONSE: The Commission interprets this section to require removal of the inspection plate only if an inspection plate exists. Any method of ensuring that the degassers are clear of debris would be acceptable.

ISSUE: API Standard 53, Section 6.5.8.2.6 states that: "After the initial pressure test is completed, all bolts shall then be rechecked for proper torque." If the initial torque is applied per specification, and pressure test achieved, it should not be necessary to recheck for proper torque. Please clarify this issue.

RESPONSE: The Commission agrees that, if the bolts were torqued to specifications upon initial installation, rechecking the bolts is not necessary after the initial pressure test. However, bolts may be re-torqued after subsequent BOP tests.

ISSUE: API Standard 53, Section 6.5.10.1.2 states that: "The equipment owner shall be responsible for retaining records and documentation within the previous 2 year period at the rig site.", and "6.5.10.6.4 Pressure and function test reports shall be retained for a minimum of 2 years at the rig site, and copies of these documents shall be retained at a designated offsite location." Section 7.6.11.1.2 states that: "The equipment owner shall be responsible for retaining records and documentation within the previous 2 year period at the rig site." This is a new requirement and that movement of equipment from rig to rig makes this complicated and not feasible. Most records are kept at the office. Please clarify this issue.

RESPONSE: Only the most recent pressure and function test reports must be kept at the rig site or an off-site location.

ISSUE: API Standard 53, Section 6.5.10.5.3 states that: "Equipment malfunctions or failures shall be reported in writing to the equipment manufacturer in accordance with Annex B" and Section 6.5.10.5.4 states that: "The equipment owner shall maintain a log of BOP and control system failures. The log shall provide a description and history of the item that failed along with the corrective action. The failure log shall be limited to items used for wellbore pressure control and equipment used to function this equipment." Please clarify what is meant by a failure and what needs to be reported to the equipment manufacturer.

RESPONSE: The Commission interprets this language to mean that the equipment owner should notify the original equipment manufacturer(s) when there is a well control event that causes damage to equipment, harm to personnel, or reportable release to environment, and the failure of their equipment is attributable to the event.