API Std 53 - Blowout Prevention Equipment Systems for Drilling Wells

Standard	Edition	Section	Inquiry #	Question	Reply
53	4th Edition, Nov. 2012	4.4.3	53-01-16	**Question 1: In reference to API Standard 53 requirement 4.4.3, are pressure-energized ring gaskets required for Surface BOP Choke Manifolds?** **Question 2: Is API 6A, 16A and 16C considering change to the design requirements based on the exclusion of non-pressure energized ring gaskets in API Standard 53 4.4.3?**	**Reply 1: Yes.** **It has been noted that there are requirements within the standard (4.4.3 & 6.2.2.2) that are not requirements within the equipment design specifications.** **Reply 2: This question falls outside the scope of S53 and does not meet the requirements for submitting a technical inquiry. You may consider submitting your question directly to each of the task groups for the documents you reference in the question.**
53	4th Edition, Nov. 2012	6.1.2.12	53-03-15	**Referring to Section 6.1.2.12, can a surface BOP stack arrangement with one annular, one blind shear ram, and two pipe rams, with the fifth device being optional, be considered a Class 5 stack arrangement?**	**No; a Class 5 surface BOP stack arrangement must contain five devices at a minimum. The stack must contain one annular, one blind shear ram, two pipe rams, and the fifth device can be an annular or pipe ram.**
53	4th Edition, Nov. 2012	6.2	53-05-15	**With regards to API STD 53, I am seeking further clarification as to whether a by-pass line is required on a surface BOP choke and kill manifold. Section 6.2 which refers to the general scope of a choke and kill does not mention a by-pass line. The sizing is mentioned in considerations and the by-pass lines are also indicated on the examples.** **But I interpret examples and considerations as not mandatory. Is this correct?**	**Yes, the bleed line (line that by-passes the chokes) is optional.**
53	4th Edition, Nov. 2012	6.2	53-06-15	**Is this bleed line (that bypasses the chokes) a mandatory line to have on a surface choke and kill manifold???**	**No, the bleed line (line that by-passes the chokes) is optional.**
53	4th Edition, Nov. 2012	6.2	53-07-15	**Can you please advise if a by-pass line is require on surface choke and kill manifolds.**	**No, the bleed line (line that by-passes the chokes) is optional.**
53	4th Edition, Nov. 2012	6.2.2.4	53-02-16	**Minimum nominal inside diameter (ID) for lines downstream of the chokes shall be equal to or greater than the nominal connection size of the choke inlet and outlet.** **Question 1: The way this is written; it is conceivable that you could have a 4-1/16" line entering the choke & kill manifold; reducing to 3-1/16" at choke bore inlet and then maintain 3-1/16" downstream of chokes.** **Do you concur?** **Question 2: Why is it API concern if an operator wants to have a 2-1/16" outlet after the buffer tank to go to strip tank, etc?**	**Reply 1: Yes** **Reply 2: Unfortunately, the question you have asked is not in a format that is acceptable for developing a response. Specifically, API only addresses questions phrased in the form such that the answer is "yes" or "no". Please review the guidance for submitting questions to API at:** **http://mycommittees.api.org/standards/techinterp/transpipe/default.as**
53	4th Edition, Nov. 2012	6.2.2.4	53-11-16	**Regarding para 6.2.2.4 This paragraph states "Minimum nominal inside diameter (ID) for lines downstream of the chokes shall be equal to or greater than the nominal connection size of the choke inlet and outlet." This paragraph does not state how far downstream the piping needs to comply with this.**	**The lines downstream of the chokes utilized to flow well fluids during well control operations shall maintain the minimum nominal ID until it enters the next system (mud gas separator, overboard line, etc.).**

53	4th Edition, Nov. 2012	6.2.2.8 6.2.2.9	53-14-14	Background: A drilling contractor has a well control system with BOPs, choke and kill manifolds rated at 10,000 psi. The equipment is being used on a 5000 psi well head. The choke manifold has one remote operated drilling choke. Question 1: Referencing 6.2.2.8 and 6.2.2.9, is it correct that the equipment is technically de rated to 5000 psi for the wellhead? Question 2: Is only one remote operated choke is required?	Reply 1: API 53 does not address de-rating. For the specific well mentioned in this question, the equipment can only be tested to 5000 psi (see 6.5.3.2.6). Reply 2: Yes
53	4th Edition, Nov. 2012	6.2.3.2.2	53-02-14	Referring to Section 6.2.3.2.2, can you please clarify further the meaning of the size range shown and your interpretation of nominal diameter?	The intent is that the pipe ID be as close as practical to the ID of the valves.
53	4th Edition, Nov. 2012	6.3.1.1 7.3.1.1 7.4.1.1	53-[illegible]-13	Background: When a piece of equipment is built to an API equipment specification it complies with the specification at the time it was built. If it is repaired or remanufactured, it may be brought up to the latest edition of the equipment specification if possible. Therefore, in service equipment on a rig may not comply with all of the requirements of the latest edition of the relevant equipment specification. API 53, Section 2 (Normative References), states "For undated references (no date included in the listing), the latest edition of the referenced document applies". Sections 6.3.1.1, 7.3.1.1, and 7.4.1.1 state "Control systems for subsea BOP stacks shall be designed, manufactured, and installed in accordance with API 16D". API 53 also states in various sections that you shall meet API 16D, Method A, B, or C for precharge calculations, which is calling out a specific requirement of API 16D. Question: Do Sections 6.3.1.1, 7.3.1.1, and 7.4.1.1 require in-service control systems to always be 100% in compliance with the latest API 16D, or are these sections referring only to specific requirements of 16D like the precharge?	The intent is that compliance with the normative references applies at the time the rig is built and/or the BOP system or components are installed. This can also be affected by a contractual agreement or regulatory requirements.
53	4th Edition, Nov. 2012	6.2.3.2.2	53-09-13	Section 6.2.3.2.2 a) advises what the minimum nominal I.D. for choke lines by pressure rating only. For pressure rated systems 10K and above, is a 3 in. nominal I.D. choke line required for 4-inch. and 7-inch. through-bore BOP equipment?	No; 4-inch up to, but not including 7 1/16-inch. bore equipment, is not addressed in API 53 or API 16A.
53	4th Edition, Nov. 2012	6.2.3.2.2.b	53-08-16	Section 7.2.2.11 states "The bleed line (if installed, the line that bypasses the chokes) shall be..." Section 6.2.3.2.2.b states "The bleed line (the line that bypasses the chokes) shall be...". It does not contain the "if installed" language, but it is sub-headed under 6.2.3.2 Other Considerations for Choke Lines. Is a bleed line to bypass the choke lines REQUIRED on choke manifold assemblies on surface BOP installations?	No, the bleed line (line that by-passes the chokes) is optional (reference previous interpretations 53-05-15, 53-06-15 and 53-07-15).

This intepretation has been rendered invalid as a result of publication of API S53, 4th Edition, Addendum 1 in July 2016. Therefore this interpretation has been withdrawn as a result of these updated requirements.

53	4th Edition, Nov. 2012	6.3.5	53-12-13	**Is API 53, Sections 6.3.5.4 and 6.3.5.5 saying that the pumps need to be checked on the initial test and the subsequent tests, only on the initial test, or only when the equipment owner's PM program requires it?**	**Yes; the intent of 6.3.5.4 and 6.3.5.5 is to conduct the test at pre-deployment, initial latch-up, and not-to-exceed six months. Any other testing is at the discretion of the equipment owner or other applicable requirements that fall outside of API 53.**
53	4th Edition, Nov. 2012	6.2.3	53-12-14	**Referencing 6.2.3, there are some cases where we can't have a straight exit lines after buffer chamber at choke manifold because of the position or space to flare pits on the rig's location. Following the recommendations that we have for choke and kill bends, can we use that for the choke manifold exit lines before buffer chamber?**	**See 6.4.11 for vent line recommendations.**
53	4th Edition, Nov. 2012	6.3.11.2.5 7.3.13.2.5 7.4.8.2.5 7.3.11.2.5	53-03-13	**A drilling contractor has a new rig with a subsea MUX stack and subsea conventional stack (for weight on older wellheads). They have stated that the drape hose are below the moonpool and that the shielding is more for wave motion than fire rating. The moon pool conduit lines are hard pipe. Sections 6.3.11.2.5, 7.3.13.2.5, 7.4.8.2.5, and 7.3.13.2.5 are ambiguous with respect to the requirement of fire retardant hoses. It is our understanding that the requirement in [illegible] makes no [illegible] and hence the hoses should not be fire retardant. The note in Std 53 indicates that the API requirement assumes that a fire in the moonpool would burn out the conduit hoses and hence trigger the deadman system if the electrical signals are also lost. For our deepwater semis however, it is not likely that the hoses are affected by a fire in the moonpool as the hoses are hanging below bottom box of the rig. There is no requirement in the API of how short time the hoses should sustain a fire, and hence the design will not be a proper form of weak link design. Can you clarify if a fire retarded hose for the conduit line and hot line will fulfil the requirements in Std 53?**	**Keep in mind that API 16D is the specification for control systems; do not confuse the requirements of API 16D with those of API 16C (choke and kill systems). Additionally, Section 6.3.11.2.5 applies only to surface BOP's. The intent in API 53 is to provide a weak link between the control system and the BOP because the fire retardant properties would be counter to the intended purpose of the emergency system. Since there are many vessel designs in operation it is not practical to have a different option for each. Sections 7.3.18 and 7.3.19 require floating rigs to have an autoshear and deadman respectively, therefore should be interpreted as: "Rigid conduit and hot line supply hoses between the control system and the BOP shall NOT be fire retardant".**

This intepretation has been rendered invalid as a result of publication of API S53, 4th Edition, Addendum 1 in July 2016. Therefore this interpretation has been withdrawn as a result of these updated requirements and replaced with the following interpretation.

53	4th Edition, Nov. 2012	6.3.11.2.5 7.3.13.2.5 7.4.8.2.5 7.3.13.2.5	53-03-13	**A drilling contractor has a new rig with a subsea MUX stack and subsea conventional stack (for weight on older wellheads). They have stated that the drape hose are below the moonpool and that the shielding is more for wave motion than fire rating. The moon pool conduit lines are hard pipe.** **Sections 6.3.11.2.5, 7.3.13.2.5, 7.4.8.2.5, and 7.3.13.2.5 are ambiguous with respect to the requirement of fire retardant hoses. It is our understanding that the requirement in 7.3.13.2.5 takes precedence and hence the hoses should not be fire retardant.** **The note in Std 53 indicates that the API requirement assumes that a fire in the moonpool would burn out the conduit hoses and hence trigger the deadman system if the electrical signals are also lost. For our deepwater semis however, it is not likely that the hoses are affected by a fire in the moonpool as the hoses are hanging below bottom box of the rig. There is no requirement in the API of how short time the hose should sustain a fire, and hence the design will not be a proper form of weak link design.** **Can you clarify if a fire retarded hose for the conduit line and hot line will fulfil the requirements in Std 53?**	**Section 6.3.11.2.5 applies only to surface BOP's.** **API 53 is making the fire retardant requirement of API 16D not required for the control lines and hot line supply between the control system and BOP. The intent is to provide a weak link between the control system and the BOP because the fire retardant properties would be counter to the intended purpose of the emergency system. Since there are many vessel designs in operation it is not practical to have a different option for each.**

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53	4th Edition, Nov. 2012	6.3.8	53-16-14	**In reference to 6.3.8 on response time and 7.6.5.1.1 on function tests, if a system includes a high pressure shear circuit (used for emergencies) and a regulated shear circuit, which circuit should be used to determine if closing times are met, the high pressure shear circuit that would be used in a well control event, or, the regulated circuit with lower pressure?**	**Response times shall be met by at least one of the surface/subsea power circuits. See 6.3.8.4, 7.3.10.4, and 7.4.6.5.4.**
53	4th Edition, Nov. 2012	6.3.8	53-16-14	**In reference to 6.3.8 on response time and 7.6.5.1.1 on function tests, if a system includes a high pressure shear circuit (used for emergencies) and a regulated shear circuit, which circuit should be used to determine if closing times are met, the high pressure shear circuit that would be used in a well control event, or, the regulated circuit with lower pressure?**	**Response times shall be met by at least one of the surface/subsea fluid supplies. See 6.3.8.4, 7.3.10.4, and 7.4.6.5.4.**
53	4th Edition, Nov. 2012	6.5.2.2.1	53-03-16	**On page 33 of the standard under 6.5.2.2.1 is stated "Inspection practices and procedures vary and are outside the scope of this document."** **Question 1: Does API have a document that states the frequency of inspections performed?** **Question 2: Or a document that goes in depth as to what level of service is required for Onshore BOPs?**	**Reply 1: Yes, API Standard 53 discusses frequency of inspections, but not the practices and procedures. For surface BOP systems see Section 6.5.7.** **Reply 2: No.**

53	4th Edition, Nov. 2012	6.5.3	53-01-14	**Referring to Table 2 and Table 3 in 6.5.3, do the terms "upstream and downstream" mean that the pressure test must be carried out in both directions (bi-direction) on all the valves?**	**Section 6.5.3.2.13 requires valves that are required to seal against flow from both directions be tested from both directions.**
53	4th Edition, Nov. 2012	6.5.3.2	53-14-16	**BOPE should be pressure tested with low pressure and then high pressure. API 53 doesn't clarify if it low pressure must be bled off before we conduct high pressure test. Can we, without bleeding off low pressure, increase the pressure from 200 psi to high pressure value and conduct the test in this way?**	**Yes, it is allowable to increase to the high pressure test immediately following the low pressure test (250 psi to 350 psi) without bleeding the test pressure off.**
53	4th Edition, Nov. 2012	6.5.3.4	53-07-16	**Do the ram preventers and Annular preventer require Pressure Testing each time before the equipment is put into operational service on the wellhead if it has not exceeded intervals of 21 days.**	**Yes.**
53	4th Edition, Nov. 2012	6.5.3.4.1	53-05-13	**We are seeking a clarification of Section 6.5.3.4.1. Our drilling rig is skidding about every six to seven days and our operator is asking us to only do a connection test on our BOP stack every time we nipple up to start drilling the new well, but we won’t be exceeding the 21 day maximum required to test the BOP stack. Is this acceptable?**	**No; all of the items listed in 6.5.3.4.1 shall be followed to be in compliance with API 53.**
53	4th Edition, Nov. 2012	6.5.3.4.1	53-05-16	**If a lease/pad contained 5 wells ready for a completion rig to conduct work, would it be a requirement to perform a full BOP test on each Well (Broken connections, Hardlines, Pipe Rams, Blind Rams, Annular) upon installation of the BOP to each Wellhead, if the previous BOP test was still within 21 days.**	**Yes.**
53	4th Edition, Nov. 2012	6.5.3.4.1	53-06-16	**The operator has asked for reduction in Pressure Testing Operations. Section 3.1.59 - The periodic application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment of system. Does this mean all ram preventers and Annular preventer must be pressure tested every time the BOP is installed on a wellhead?**	**Yes, 6.5.3.4.1 provides the frequency for pressure testing.**

53	4th Edition, Nov. 2012	6.5.3.6	53-19-16	**Question 1: Do we need a gage with our digital recorder (12" circular) for testing purposes?** **Question 2: Or do need just the digital recorder?** **Question 3: If the answer to Question 1 is "yes", do we need to calibrate both of them?**	**Reply 1: Yes, this gauge may be analog or digital. If a data acquisition system is utilized, a gauge would not be required (6.5.3.6.1).** **Reply 2: No.** **Reply 3: Yes.**
53	4th Edition, Nov. 2012	6.5.3.6.2	53-08-13	**Background: Section 6.5.3.6.2 states analog pressure measurements shall be made at not less than 25% and not more than 75% of the full pressure span of the gauge. We currently have chart recorder with a range of 30,000 psi and would like to perform pressure test of 3,000 psi, which represent 10% of the maximum range of our chart recorder. These tests are to perform integrity test of our operating chambers of various equipment's. Our customer refers to Section 6.5.3.6.2 regarding the pressure test and does not want to pursue the test and require replacement of the chart recorder.** **Question: If I refer to section 6.5.3.6.3 which states electronic pressure gauges and chart recorder or data acquisition systems shall be used within the manufacturer's specified range, am I still operating within range?**	**Yes, only if the chart recorder is electronic (e.g. uses a pressure transducer), and the test pressures are within the manufacturer's specified range, it conforms to API 53.**
53	4th Edition, Nov. 2012	6.5.3.8.8	53-16-16	**Question: At what frequency shall the electrical power to the UPS and the rig air be isolated:** **• Each function test?** **• Or prior to operations?**	**A frequency for this test is not defined. This will be clarified in the next edition of Standard 53.**
53	4th Edition, Nov. 2012	6.5.4	53-02-15	**In reference to API Standard 53 requirements in 6.5.4.3 and 6.5.4.5, is the smallest OD pipe to include tubulars that are considered part of the bottom hole assembly?**	**No; see 6.1.2.2 a).**
53	4th Edition, Nov. 2012	6.5.8.2.6 7.6.9.5.6	53-23-16	**After the initial pressure test is completed, all bolts shall then be rechecked for proper torque.** **Request clarification on all bolts. Currently, common practice is to re-check torque only on the disassembled component(s) after the initial pressure test. Torque is not re-checked on components that were not disassembled.**	**7.6.9.5.6 and 6.5.8.2.6 were intended to be completed on newly made up connections.**

53	4th Edition, Nov. 2012	6.5.8.3	53-13-16	**This section refers to assemblies.** **Question 1: Are the requirements intended for individual parts as well?** **Question 2: If yes, that makes sense.** **If it only means assemblies, that leads to two follow up questions.** **a) what constitutes an assembly?** **(ie: if I sell you a ram block by itself that's a part, but If I ship it with the seals installed is that an assembly??)** **b) What requirements exist around single replacement parts? I don't see them mentioned separately elsewhere.**	**Reply 1: This section provides requirements for assemblies.** **Reply 2a: Assemblies are defined by the equipment manufacturer.** **Reply 2b: See 6.1.4.4 and 7.1.4.4.**
53	4th Edition, Nov. 2012	7.2.2.18	53-04-14	**Background: Section 7.2.2.18 states, "The choke control station shall include all instruments necessary to furnish an overview of the well control operations. This includes the ability to monitor and control such items as standpipe pressure, casing pressure, and monitor pump strokes, etc."** **Question: Does 7.2.2.18 require the stations where the manual chokes will be controlled (i.e. at the choke manifold) to have the instruments necessary for carrying out the well control operations such as the drill pipe pressure gauge, casing pressure, and pump stroke counter?**	**The choke control station in this section (and 6.2.2.18 as well) is intended to be the same as a drilling choke control console system as defined in API 16C, Section 10.9, i.e. the function of the remote hydraulic choke control system is to provide reliable control of the drilling choke from one or more remote locations with the sensitivity and resolution required to perform all well control procedures that the choke valve is designed to provide. It is not the intent to require pump stroke counters on a manual choke.**
53	4th Edition, Nov. 2012	7.2.3.1.1	53-11-18	**Background: Section 7.2.3.1.1 states "... flow targets or fluid cushions shall be used at short radius bends, on block ells, and tees." Section 7.2.3.1.2 states "Short radius pipe bends (R/d < 10) shall be targeted or have fluid cushions installed in the direction of expected flow or in both directions if bidirectional flow is expected,..." For subsea BOP Stacks, it is common practice to use short radius bends (or kickouts) at the riser termination adapter and directly above the choke/kill test or isolation valves on the LMRP. These kickouts would be connected to the choke/kill flexible hoses or flex loops. Due to space restrictions on the stack, these kickouts do not have a fluid cushion/target located directly at the bend. Instead, the cushion/target is generally located at the end of the choke or kill line when the flow changes direction at the lowermost well control valves. The choke/kill pipework from the kickout to the lowest valve is made as straight as possible for this run.** **Question 1: Does a fluid cushion flange installed at the lowest well control valve (leading into the wellbore below the lowest choke or kill ram) meet the requirement of 7.2.3.1.1 for "shall be used at short radius bends"?** **Question 2: Is it required to have a cushion/target directly at a short radius bend?** **Question 3: Can the cushion/target be further down the choke/kill piping, if no 90° changes in direction are made between the short radius bend and the cushion/target (as stated in 7.2.3.1.2)?**	**Reply1: Yes.** **Reply 2: Yes.** **Reply 3: No.**

This intepretation has been rendered invalid as a result of publication of API S53, 4th Edition, Addendum 1 in July 2016. Therefore this interpretation has been withdrawn as a result of these updated requirements and replaced with the following interpretation.

53	4th Edition, Nov. 2012	7.2.3.1.1	53-11-13	**Question 1: Does a fluid cushion flange installed at the lowest well control valve (leading into the wellbore below the lowest choke or kill ram) meet the requirement of 7.2.3.1.1 for "shall be used at short radius bends"?** **Question 2: Is it required to have a cushion/target directly at a short radius bend?**	**Reply1: Yes.** **Reply 2: No, but if R/D<10, the equipment owner's PM program shall include an inspection for erosion at the pipe bends at least every two years.**

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53	4th Edition, Nov. 2012	7.2.3.1.1	53-11-14	**Is it acceptable to use a special 90 degree elbow with a thickness more than 10 mm greater than the straight pipe instead of target block?**	**No; the standard does not currently allow this alternative.**
53	4th Edition, Nov. 2012	7.2.3.1.1	53-11-14	**Is it acceptable to use a special 90 degree elbow with a thickness more than 10 mm greater than the straight pipe instead of target block?**	**Yes, with the provision that the equipment owner's PM program include an inspection for erosion at the pipe bends at least every two years.**

This intepretation has been rendered invalid as a result of publication of API S53, 4th Edition, Addendum 1 in July 2016. Therefore this interpretation has been withdrawn as a result of these updated requirements.

53	4th Edition, Nov. 2012	7.2.3.1.2	53-05-14	**Referencing 7.2.3.1.2, for short radius bends (R/d < 10), ninety-degree block ells, and tees, can the fluid cushions requirement be replaced with annual inspection of wall thickness and or internal bore scoping since there is no past failure existing in these components and provided the component wall thickness and internal surface condition remains intact?**	**No; API 53 does not currently allow alternatives to fluid cushions**

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53	4th Edition, Nov. 2012	7.2.3.1.2	53-10-14	**Is it the intent of 7.2.3.1.2, that the flex loops on the LMRP, mainly the area directly under the kick-outs on the riser adapter, and the riser adapters themselves have either large radius bends or targeted ells? Typically on many BOPs, the first bend in the flex loop, as you come out of the riser adapter and begin spiraling down the flex loop, is a bend that has a radius less than 10 times the ID of the choke or kill pipe. Also the riser adapter is typically supplied with short radius bend kick-outs.**	**The requirement is written such that it covers the flex loops and riser adapter kick-out subs.**

53	4th Edition, Nov. 2012	7.2.3.1.2	53-10-14	**Is it the intent of 7.2.3.1.2, that the flex loops on the LMRP, mainly the area directly under the kick-outs on the riser adapter, and the riser adapters themselves have either large radius bends or targeted ells? Typically on many BOPs, the first bend in the flex loop, as you come out of the riser adapter and begin spiraling down the flex loop, is a bend that has a radius less than 10 times the ID of the choke or kill pipe. Also the riser adapter is typically supplied with short radius bend kick-outs.**	**Yes. When R/d > 10 is not possible, the equipment owner's PM program shall include an inspection for erosion at the pipe bends at least every two years.**
53	4th Edition, Nov. 2012	7.2.3.1.2	53-21-16	**Item 7.2.3.1.2 states that short radius bends on choke and kill lines must be targeted or have fluid cushion to minimize erosion** **Question 1: Is there any requirement for the length of the cushion zone?** **Question 2: Would be acceptable a length of 4 inches, or equal to pipe internal diameter, whichever is higher?** **Question 3: Is it acceptable to use fluid cushion made of pipes welded perpendicularly instead of a block?**	**Reply 1: No, there are no design requirements for the fluid cushion.** **Reply 2: API cannot answer this question. There is no choke or kill fluid cushion design requirements within Std 53.** **Reply 3: API cannot answer this question. There is no choke or kill fluid cushion design requirements within Std 53.**
53	4th Edition, Nov. 2012	7.2.3.2.9	[illegible]	**Background: Regarding Section 7.2.3.2.9, I would like to address the issue of the 12 inch spools between the choke and kill valve bodies and the BOP body. The spool pieces were originally added by the manufacturer to extend the position of the choke and kill bodies away from the BOP. This added length prevented damage to the valves and BOP bonnet doors during maintenance. Without the spool pieces the doors could not be opened fully, thus adding the potential to damage the door face during ram block installation and removal. Since the original design of the BOP the manufacturer has manufactured an extended neck valve body design. But it must be noted there are problems with this design. With the addition of a welded spool to the valve body alignment becomes critical. If the welded extension is not square to the flange and to the valve body, proper alignment can never be achieved. This also adds the probability that the valves are no longer interchangeable within the system. Example, if the lower inner and outer choke body is prepared and fitted in place; potentially it could not be moved to a different valve position without remanufacturing the associated choke and kill pipework. If the valve in fact is moved to a different position and the original pipework is utilized, it could allow the associated flanges to be out of position and over stressed after installation. We believe the use of the short spools is the better solution, and reduces the exposure to leak via a ring gasket, due to possible over stress of the flange connections, if a valve is replaced.** **Question: We request an interpretation of API 53 to allow the use of spools between the BOP and choke and kill valves.**	**API does not grant deviations to the requirements stated in its standard; we can only issue interpretations in response to questions concerning the meaning of the requirements. Your comments have been forwarded to the task group responsible for API 53 for consideration as a future revision to the standard.**

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53	4th Edition, Nov. 2012	7.2.3.2.9	53-14-13	Is the intent of Clause 7.2.3.2.9 to prohibit a properly designed spacer spool between the BOP outlet on the body and the failsafe valves and spacer spools for the drill-through wall of the choke and kill lines on the stack and spools?	Yes; API 53 does not allow for use of spools between the BOP outlet and the choke and kill valves.
53	4th Edition, Nov. 2012	7.3.10	53-02-13	Background: A particular rig with casing shear rams has response time of 51 seconds. When asked about the required closing time in API 53 for subsea casing shear rams, I stated "45 seconds, the same as pipe rams." Rig personnel believed that the requirements in 7.2.10 do not apply to casing shear rams because they do not seal and thus are not considered a BOP. Question: Are casing shear rams required to comply with the closing times stated in 7.3.10?	Yes. Tables 6 and 7 require the well to be secured in 90 seconds or less. If a casing shear ram is part of that sequence then it shall be within that same timeline to achieve a secure well.
53	4th Edition, Nov. 2012	7.3.12.8	53-20-16	For functions with varying pressure ranges it is impossible to comply with the 25%-75% gauge rule. The Overshot Packer and the Flowline Seals (just an example but it applies to more functions) can sometimes be run down to as low as 200 psi and as high as 1,500 psi. To meet the API Standard 53 requirement on 7.3.12.8, you would need to operate with a gauge with a high end of 2,000 psi which would make your low end 500 psi (25% of 2000), which is above our low range for the function (200 psi). To meet the API Standard 53 requirement on 7.3.12.8, you would need to operate with a gauge with a high end of 2,000 psi which would make your low end 500 psi (25% of 2000), which is above our low range for the function (200 psi). Use two different gauges?	The intent is not to require two gauges for normal operations; the intent is for two gauges required for testing only. However, two gauges would be required to meet the requirement with a span that exceeds the 25%-75%.
53	4th Edition, Nov. 2012	7.4.6.4.2	53-22-16	The API 53 has contraditory procedures to do the drawdown test. In section 7.4.6.4.2 says that you should close and open the largest volume annular plus four smallest operation volume ram-type BOP, excluding test ram. However, the section 7.6.8.2.2 d) request the largest annular plus the four smallest volume PIPE ram preventers. Which one should I use for the BOP from background?	For drawdown testing, 7.6.8.2.2 must be followed.

53	4th Edition, Nov. 2012	7.4.9.10 7.4.9.11	53-04-15	**Question 1: In reference to the requirement of 7.4.9.11, is it permissible for the system to display no previous status upon restoration of power?** **Question 2: In reference to the requirement of 7.4.9.11, is it permissible for the system to change the state of a BOP operator upon restoration of power, and display the changed position? Example – unlocking a locked pipe ram?** **Question 3: In reference to the requirement of 7.4.9.11, API 16D requires not displaying the last position when an electrical power loss in the surface panel(s) could result in an incorrect indication (5.2.5.4). Please confirm the API 16D requirement takes precedence and either include the requirement in API S53 or delete the design requirement in API S53.**	**Reply 1: No, unless displaying the previous status could result in an incorrect indication (API 16D 5.2.5.4 & 5.4.5).** **Reply 2: No.** **Reply 3: See response to question 1.**
53	4th Edition, Nov. 2012	7.4.16.1	53-01-15	**Question 1: If a stack-mounted accumulator system (sized per API 16D, Method C, for closing of shear ram(s) only) is utilized to meet the ROV closing time requirement, and is shared with a deadman and autoshear system, shall it include a ROV recharging function to comply with 7.4.16.1.2?** **Question 2: Shall the stack-mounted accumulator option include a regulated circuit to actuate critical functions listed in 7.4.16.1.1 if they have a rated working pressure below the accumulator's charged pressure?** **Question 3: A failure of the deadman or autoshear may be the reason for needing to conduct BOP ROV intervention. If a shared system fails, shall the BOP ROV intervention system include functions to isolate these systems so recharging of the accumulator system is possible?**	**Reply 1: API 53 does not address this issue.** **Reply 2: The source of hydraulic fluid shall have necessary pressure and flow rate to operate these functions", as stated in 7.4.16.1.2, and "All critical functions shall meet the closing time requirements in 7.4.6.5.4", as stated in 7.4.16.1.6.** **Reply 3: API 53 does not address this issue.**
53	4th Edition, Nov. 2012	7.4.16.1.1	53-18-16	**It is not clear in 7.4.16.1.1 whether shear ram 'OPEN', pipe ram 'OPEN', and ram locks 'UNLOCK' are considered critical functions as they are not included in Table 6.** **Question 1: Are shear ram 'OPEN', pipe ram 'OPEN', and ram locks 'UNLOCK' considered critical functions?** **Question 2: Are the items on the list below inclusive of API Standard 53 critical functions?** **• Each Shear Ram 'CLOSE'** **• Blind Shear Ram Locks 'LOCK'** **• One Pipe Ram 'CLOSE' and 'LOCK'** **• LMRP Connector 'UNLATCH'**	**Reply 1: No.** **Reply 2: Yes.**

53	4th Edition, Nov. 2012	7.4.16.2.2	53-04-13	**Background: I have a four-ram stack (one blind shear and three pipe rams). I have an acoustic pod that closes the blind shear rams, closes a hang-off ram, and disconnects the LMRP. The acoustic pod is capable of operating critical functions, just not all of them.** **Section 7.4.16.2.2 states "the acoustic control system should be capable of operating critical functions", with the term "critical functions" being defined in 7.4.16.1.1 as each shear ram, one pipe ram, ram locks, and unlatching of the LMRP connector.** **Question: Is the intent of 7.4.16.2 to require the acoustic pod to operate all critical functions, specifically every shear ram?**	**No; this provision is implemented with a "should" and therefore is a recommendation.**
53	4th Edition, Nov. 2012	Table 7	53-07-13	**Question: Are the blind shear ram closing times stated in Table 7 to mean if pipe is in the BOP it must shear and seal in 45 seconds, and if drill pipe is not in the BOP, the ram must close in 45 seconds with sufficient pressure that could have sheared the drill pipe had it been in the BOP?**	**Table 7 is a function test requirement without pipe in the stack.** **7.6.6.5 states BSRs and/or CSRs shall not be tested when pipe is in the stack.** **7.4.16.1.2 states the source of hydraulic fluid shall have necessary pressure and flow rate to operate these functions.** **The intent is to secure the wellbore in 45 seconds or less with or without pipe in the stack, but the test with pipe in the stack is not a requirement of Standard 53.**
53	4th Edition, Nov. 2012	7.6.5.1	53-09-14	**Referencing 7.6.5.1, for BOP functioning/intervention via a ROV, does the 45 second requirement in Table 6 and Table 7 apply to an open bore or for a BOP with pipe in it?**	**Testing referred to in Table 6 and Table 7 is intended to be conducted with an open hole for shear rams (see 7.6.6.5) and with pipe in the stack for pipe rams.**
53	4th Edition, Nov. 2012	7.6.5.2.13 Table 10	53-08-15	**Question 1: Does each of the valves in the C&K manifold (about 35 valve) need to be pressure tested in both directions?** **Question 2: Or does each of the valves in the C&K manifold need to be pressure tested from wellbore direction only?** **Question 3: Or does each of the valves in the C&K manifold need just 1 each shell test in 15k & 10k side?** **We heard same test need to be done each 21days during operation**	**Reply 1: No. Valves that are required to seal against flow from both directions, shall be pressure tested from both directions.** **Reply 2: No, see above.** **Reply 3: Shell testing of choke manifold equipment is a manufacturing requirement. See API Specification 16C second edition 7.5.12.** **See API Standard 53 7.6.5.4.2.d & Table 10.**

53	4th Edition, Nov. 2012	7.6.5.3	53-07-14	**Question 1: Are all "pre-deployment" and "prior to deployment" requirements of API 53 to be completed after a LMRP or BOP retrieval for repair before re-deploying to the same well for continued operation.** **Question 2: Alternatively, does "pre-deployment" and "prior to deployment" refer to deployment following between-well-maintenance and prior to new operations?"**	**Reply 1: No; a function test of the BOP control system shall be performed following the disconnection or repair, limited to the affected component, as stated in 7.6.5.4.3.** **Reply 2: Yes.**
53	4th Edition, Nov. 2012	7.6.6.3	53-17-16	**I do not understand the intent to pressure test annular(s) and VBR(s) on the largest and smallest OD drill pipe to be used in well drilling program on surface.** **Should be enough to test only with the smallest OD drill pipe as stated in 7.6.6.4 on subsea test?**	**No, 7.6.6.3 shall be followed for the pre-deployment test.** **The intent is to verify the full range of variable BOP sealing elements prior to deployment.**
53	4th Edition, Nov. 2012	7.6.6.9	53-13-14	**In section 7.6.6.9 it requires testing on the ram locks only during pre-deployment testing. What about the 21 day testing regimen?**	**The use of ram locks is not required for subsequent testing. Section 7.6.6.10 states "The BSR(s) and the hang-off ram BOP shall be pressure tested with locks in the locked position and closing and locking pressure vented, during the initial subsea test only."**
53	4th Edition, Nov. 2012	7.6.6.17	53-04-16	**Question 1: In reference to 7.6.6.17, is totally impractical to suggest that a surge bottle can be installed adjacent to the annular preventer if contingency well control procedures include stripping operations as this implies that a bottle may be used on some wells and not on others. Would it not be better to simply state that an annular surge bottle is optional for subsea use?** **Question 2: Per the Standard, would it be better to state that the surge bottle is optional than simply deleting 7.6.6.17? Stating that it is optional is clear. Deleting the statement could be interpreted as an error.**	**Reply 1: This is a question based on an opinion and does not meet the requirements for technical interpretation. Note that a surge bottle is not required per this standard, as the statement utilizes the word "can" which allows the possibility without inferring it is a requirement. Depending on system configuration and plumbing, a surge bottle may improve stripping capability. Use of other equipment may accomplish the same result as a surge bottle.** **Reply 2: See response above. However your comment will be considered during the next revision of the document.**
53	4th Edition, Nov. 2012	Table 9	53-10-16	**Question 1: Is it acceptable to pressure test a riser connector to 70% as like an SBOP after breaking this connection, if the wellhead RWP is 15 000psi and the anticipated wellhead pressure is just over 10 000psi?** **Question 2: Is it acceptable to complete function test and drawdown test then split the LMRP off the BOP and change riser connector, choke and kill gaskets then deploy? Confirmation required please.**	**Reply 1: No.** **Reply 2: No.**

53	4th Edition, Nov. 2012	Table 9	53-12-16	**We are doing pre deployment testing according to S53 table 9 (page 86), my question relates to table 10 (subsea testing) and the interpretation of “initial pressure test, upon landing the BOP”** **Question 1: Shall this be understood in the most conservative way, that one shall first do a full pre-deployment test, run BOP, and then repeat all testing again after landing on a wellhead?** **Question 2: Or could the pre-deployment test (as long as BOP is run within reasonable time, say a week) be considered as the initial pressure test (with WH connector pressure test and full function test after landing)?**	**Reply 1: The testing listed in Table 10 shall be conducted after initial latch-up.** **Reply 2: No.**
53	4th Edition, Nov. 2012	7.6.8.2	53-15-16	**Question 1: The drawdown test requirement outlined in section 7.6.8.2 for drawdown testing, after the completion of the drawdown test, do we require to perform a pump up test for the system to confirm the pumps capability, or we are only required to perform the drawdown test and confirm the minimum pressure?** **Question 2: The pump capability test is required to be done based on table 9 for predeployment testing, does the system need to be bled down to precharge pressure prior to performing the test or only the pressure after the drawdown test which is as a minimum should be 200 psi over precharge pressure?**	**Reply 1: No, 7.6.8.2 does not require a pump capability test.** **Reply 2: Yes, the pressure is required to be bled down to precharge pressure.**
53	4th Edition, Nov. 2012	7.6.8.2.2	53-09-16	**Section 7.6.8.2.2 Requires a main accumulator system drawdown on initial land out and every 6 months there after. The requirement does NOT mention the pump efficiency test specifically but does refere to Annex "A" which DOES include a pump systems test . I am referring to a test to determine if the pumps meet the requirements of 7.4.5 which, consequently does NOT have a frequency stated but because the annex references both requirements rigs have assumed they have the same testing frequency requirements. This prolongs the time in which the system is incapable of carrying out an EDS.** **Upon landing the BOP , in addition to the drawdown test, is the pump systems test - timing top off from precharge- required?**	**No.**

53	4th Edition, Nov. 2012	7.6.8.3	53-15-13	**Question 1: Referring to 7.6.8.3, do the following meet the intent of "the greatest consuming emergency sequence (excluding hydraulic connectors) supplied by the dedicated emergency accumulators shall be discharged"?** **a) Operating HP shear functions by the primary control system that are supplied by the emergency accumulators?** **b) Operating HP shear functions through an ROV flying lead supplied by the emergency accumulators?** **c) Flowing a volume of fluid by an ROV flying lead supplied by the emergency accumulators into a measured test apparatus?** **d) Conducting the greatest consuming deadman or autoshear sequence?** **Question 2: If the greatest sequence includes a hydraulic timer, is the hydraulic timing volume required to be included in this test?** **Question 3: If the answer to Question 2 is yes, can it be simulated by another function?** **Question 4: If well hopping, does the test at initial landing only have to be completed after connection to the first well?**	**Reply 1: Item a) does not meet the intent of 7.6.8.3 because it refers to a primary control system function. Items b) through d) do meet the intent of 7.6.8.3.** **Reply 2: Yes, all involved volumes shall be included.** **Reply 3: Yes.** **Reply 4: Yes, if the hydraulic supply system remains intact during the hopping operation.**
53	4th Edition, Nov. 2012	7.6.9.3.1	53-06-14	**Background: We have one rig where the COCs of the subsea components expired at the end of last year (2013), however; the components have been in storage for more than two years and only been in service for 740 days. All equipment is fully functional and documents of testing and annual inspection are well maintained.** **Question 1: Referencing 7.6.9.3.1, does the term "At least every 5 years" begin on the component COC date or on the date that the component is put in service?** **Question 2: Referencing 7.6.9.3.1, does API 53 require the COCs of this equipment to be active if the equipment owner's PM program requirements include all subsea equipment to be inspected annually and/or every five year by a competent person(s) (the frequency of inspection is derived from the equipment as owner collects and analyzes condition based data (including performance data) and the result of the inspection meets the equipment owner's PM program and the manufacturer's guidelines?**	**Reply 1: Neither; it begins from the date the equipment was last "inspected for repair or remanufacturing, in accordance with equipment owner's PM program and the manufacturer's guidelines".** **Reply 2: No, API 53 does not require COCs.**

This intepretation has been rendered invalid as a result of publication of API S53, 4th Edition, Addendum 1 in July 2016. Therefore this interpretation has been superceded as a result of these updated requirements and replaced with the following interpretation.

53	4th Edition, Nov. 2012	7.6.9.3.1	53-06-14	**Background: We have one rig where the COCs of the subsea components expired at the end of last year (2013), however; the components have been in storage for more than two years and only been in service for 740 days. All equipment is fully functional and documents of testing and annual inspection are well maintained.** **Question: Referencing 7.6.9.3.1, does API 53 require the COCs of this equipment to be active if the equipment owner's PM program requirements include all subsea equipment to be inspected annually and/or every five year by a competent person(s) (the frequency of inspection is derived from the equipment as owner collects and analyzes condition based data (including performance data) and the result of the inspection meets the equipment owner's PM program and the manufacturer's guidelines?**	**Reply: No, API 53 does not require COCs.**
53	4th Edition, Nov. 2012	7.6.9.3.3	53-03-14	**Background: Section 7.6.9.3.3 states certain equipment shall undergo a critical inspection (internal/external visual, dimensional, NDE, etc.) annually, or upon recovery if exceeding 1 year: e.g. shear blades, bonnet bolts (or other bonnet/door locking devices), ram shaft buttonfoot, welded studs, ram cavities, and ram blocks. The actual dimensions shall be verified against the manufacturer's allowable tolerances.** **Question 1: Was the intent to be a requirement for the listed example equipment?** **Question 2: Does API 53 specify who determines which inspection method is used?**	**Reply 1: Yes, the example equipment listed shall be inspected at a minimum.** **Reply 2: Yes; Section 7.6.9.3.1 states inspections shall be performed in accordance with the equipment owner's preventive maintenance program.**
53	4th Edition, Nov. 2012	7.6.9.3.4	53-08-14	**Section 7.6.9.3.4 states inspections shall be performed by a competent person(s). Must this "competent person (workshop)" have the certification or permission of the manufacturer to fulfill the repairs?**	**No; these are not required by API 53. See 3.1.20 for the definition of a competent person.**
53	4th Edition, Nov. 2012	7.6.11.7.6	53-01-12	**Section 7.1.3.6 requires a subsea BOP on a non-moored (ie DP) semi to have two shear rams. Is the expectation that both shear rams are capable of shearing the drill pipe in use at the maximum anticipated wellbore pressure, or does only one need to be capable of shearing in these conditions?** **The confusion arises out of the wording in 7.6.11.7.6 which states "Consider one set of shear rams capable of shearing drill pipe and tubing that might be across the stack at MEWSP."**	**If the first shear is activated it would be expected to experience the worse conditions. The second shear or closure may not be shearing, but just closing and sealing.** **Two shearing rams must be capable of shearing the pipe and only one is required to be capable of sealing the wellbore. It is preferred that this be achieved on the first attempt but the BOP system must be prepared to at least shear on the first closure and seal on the second.** **It was not the intent of the committee that the second closure be capable of shearing the pipe and sealing the wellbore.**

This intepretation has been rendered invalid as a result of publication of API S53, 4th Edition, Addendum 1 in July 2016. Therefore this interpretation has been withdrawn as a result of these updated requirements.