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Supplement
Well Control Equipment Subunit Boundaries

SafeOCS
OBSERVE REPORT PREVENT

REVISION LOG

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WCE Subunit Boundaries

Overview

Well control equipment (WCE) systems are comprised of a combination of several subunits, serving to control the flow of wellbore fluids during oil and gas drilling and other well operations. API Standard 53 lists several subsystems required for such operations: blowout preventers (BOPs), choke and kill lines, choke manifolds, control systems, and auxiliary equipment.[1] The WCE data collection scope also includes the diverter system, whose primary purpose is to safely divert an uncontrolled flow away from the rig to give the crew additional time to evacuate, and the riser system, which serves as a running tool for the BOP stack, transports the drilling and wellbore fluids from the bottom of the well to the surface, carries the hydraulic conduit lines for the supply of pressurized fluid to the BOP controls, and carries the choke and kill lines connecting the BOP stack with the choke manifold.

This supplement provides descriptions of each of the WCE subunits identifying the following:

- BOP stack system
- BOP control systems (primary, secondary, and emergency)
- Riser system
- Diverter system
- Choke manifold system
- Auxiliary equipment

Choke and kill lines are discussed in the context of the riser system. Example schematic drawings are included at the end.

[1] API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012. See section 1.1 for a discussion of BOP equipment systems.

The Subsea BOP Stack

The subsea BOP stack, shown in Figure E, shall[2] provide a means to do the following:

- Close and seal on the drill pipe, tubing, casing, or liner and allow circulation.
- Close and seal on an open hole and allow volumetric well control operations.
- Strip the drill string.
- Hang-off the drill pipe on a ram BOP and control the wellbore.
- Shear the drill pipe, tubing, or wireline in use.
- Disconnect the riser from the BOP Stack. Circulate across the BOP stack to a choke manifold.

Subsea BOP stacks shall be class 5 (10,000 psi or greater maximum anticipated wellhead pressure (MAWHP))[3] or greater with:

- Minimum of one annular preventer
- Minimum of two pipe rams
- A minimum of two sets of shear rams, one of which must be able to seal. (Moored rigs can have only one set of shear rams after conducting a risk assessment.)

Subsea BOP stack mounted choke and kill lines provide redundancy as well as multiple access points to the BOP stack and allow for well control operations as follows:

- Circulating down one line and up the other line.
- Circulating down the drill pipe and up either or both lines.
- Pumping down one or both lines.
- Allow well pressure monitoring.

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[2] All shall statements in this section refer to API Standard 53 requirements.

[3] BOP stack classifications are per API Standard 53.

- All outlets connected to the BOP stack shall have two valves, all of which are remote controlled.

The BOP stack includes the ram and annular BOPs, drilling spools, adaptor spools, and the side outlet valves. Additional components not explicitly mentioned in API Standard 53 are required for the system to work.

The Surface BOP Stack

The surface BOP Stack, shown in Figure G, shall[4] provide a means to do the following:

- Close and seal on the drill pipe, tubing, casing, or liner, and allow circulation.
- Close and seal on an open hole and allow volumetric well control operations.
- Strip the drill string.
- Shear the drill pipe or tubing when blind shear rams are installed.
- Circulate across the BOP stack to a choke manifold.

BOP stacks are classed[5] according to pressure requirements from a class 2 BOP stack (which, for a maximum anticipated surface pressure (MASP) of 3,000 psi, would include one blind ram plus one pipe ram or one annular BOP) to a class 5 BOP Stack (which, for a MASP of 10,000 psi or greater, includes at least one annular, one BSR, and two pipe rams, and the fifth BOP can be either an annular or a ram).

Surface BOP stack choke and kill systems provide access points to the BOP stack and allow the following:

- Circulating down the kill line and up the choke line.
- Circulating down the drill pipe and up the choke line.
- Pump down the kill line.

[4] All shall statements in this section refer to API Standard 53 requirements.

[5] BOP stack classifications are per API Standard 53.

- Allow well pressure monitoring.
- All outlets connected to the BOP stack shall have two valves, one of which must be remote controlled.

The Subsea BOP Control System

Per API Standard 53, subsea BOP control systems must have the following, unless otherwise noted: redundant control pods, an autoshear emergency control system, a deadman emergency control system, an ROV intervention secondary control system, an acoustic secondary control system (optional for all subsea systems), and an emergency disconnect sequence (EDS) (mandatory for all stacks run from a dynamically-positioned vessel but optional for moored vessels).

The API Standard 53 minimal requirements stated above do not specify the full range of equipment/components available and in use today. Not only do current systems allow for full control from various panels, but they also provide readbacks in the form of position, inclination angles, flow meter readings, pressures, temperatures, alarms, and various system fault messages, both live and logged. Much of this information is also sent, through secure communications, to the shore bases for further monitoring or troubleshooting purposes.

The Primary BOP Control System

The primary BOP control system (example schematic shown in Figure A) includes all the functions that can be operated or monitored from any one of multiple panels on the rig (e.g., the driller's control panel, toolpusher's control panel, or subsea maintenance panel). Each of these panels can operate all the BOP stack functions. Any one of these panels can send a signal to the two identical control pods, each of which receives the signal but only the active pod responds to it. The other pod is fully redundant to the active pod and on standby for immediate use if required. These control pods, mounted on the LMRP, decode the multiplexed signals from the surface, and send the hydraulic fluid at the required pressure to the commanded function. The control pods each have independent MUX (multiplex) control cables from the surface panels. The BOP stack also has (at least) two independent hydraulic supplies, adding to the levels of redundancy throughout.

Even though the two control pods and multiple panels provide full redundancy of control to the BOP stack, there are some events that could prevent the rig personnel from affecting those controls. These include an inadvertent disconnect of the LMRP from the lower stack, the loss of the marine riser, or even the loss of the rig itself. In anticipation of one of these incidents occurring, the subsea BOP stacks are outfitted with additional control equipment.

The BOP Emergency Control System

The emergency control system, shown in Figure B, includes the automated controls such as deadman and autoshear. These systems can command the function sequences necessary to seal the well automatically, independent of the primary control system components, if the power and signals to both pods are simultaneously lost (autoshear), or if the LMRP is disconnected, either deliberately or accidentally, from the lower BOP stack (deadman).

The Secondary BOP Control System

The secondary control system includes BOP stack framework-mounted interface control panels such that the remotely operated vehicle (ROV) can connect to the BOP stack to operate certain functions externally. The secondary control system, shown in Figure C, also includes an (optional[6]) acoustic control interface with a stand-alone control pod. This secondary control system allows for the operation of selected BOP stack functions via one of two redundant transponders that send and receive coded audio signals transmitted through the water from either the rig or a portable control unit.

Figure D shows a typical example of a control system arrangement for the shear rams. The shear rams in this example can be closed from seven different sources. This means that they

[6] Optional, in this case, refers only to the installation of the equipment. If an acoustic control system is installed and mentioned on the permit to drill, then it is expected to be fully functional.

must be tested from seven different sources, and every function reduces the remaining life of the seals.

The Surface BOP Control System

The BOP control system for a surface stack, shown in Figure F, is usually a simple closed loop direct hydraulic system. The HPU pressurizes the hydraulic fluid from the reservoir tank, which it stores in the surface accumulator. The accumulator feeds a pressure regulator, which then directs the fluid to a control manifold. This manifold supplies the individual valves for each function which then direct the fluid directly to the BOPs and valves. When a function such as the annular is operated, the fluid on the close side of the annular is returned to the reservoir. Other than having two remote control panels to operate the manifold valves, there is essentially no redundancy. The surface shear ram has only one close supply line, but it is always accessible.

The Riser System

The marine drilling riser system includes all components from the top of the BOP stack to the bottom of the diverter. On a subsea system, this includes a quantity (string) of riser joints to suit the rig. A 12,000-foot capable rig that uses 75-foot joints will have 160 joints of riser, plus a set of “pup” joints which have similar specifications but are a mixture of shorter lengths to allow the correct overall measurements to be reached.

Figure J shows an example schematic for a riser joint. Each joint has a “pin” on one end and a “box” on the other. The pin end has male stabs for the main tube and all of the auxiliary lines. The box end is the female side of the connections and contains individual redundant seals for each line. The pin is stabbed into the box and then, depending on the style of riser there may be bolt, dogs, or a breech lock to join the joints together. The majority of deepwater riser joints will be enclosed in buoyancy modules to reduce the “wet” weight of the riser and help to keep the riser string in-tension.

Above the riser joints is the telescopic joint. This is used how it sounds, a special joint of riser with a larger bore outer barrel at the bottom and an inner barrel at the top with two redundant sealing units in the middle. The outer barrel connects to the riser string, and the inner barrel connects to the diverter completing a sealed conduit from the BOP stack to the mud treatment equipment on the rig. The telescopic joint is required to accommodate the heaving action of the rig riding the tide and waves while in operation.

Pressure tests of the choke and kill lines are carried out during stack deployment; the choke and kill lines, which form a circuit between the BOP stack and the choke manifold, can only be tested when they are all properly connected. Because the complete circuit can involve passing through up to 12,000 feet of water, sections of these lines are attached to the marine riser joints which are each typically between 75 and 90 feet long. One of these riser joints connects directly to the top of the BOP stack and, when this has been lowered through the rig, additional joints are connected until the BOP stack reaches the wellhead. To reach the deepwater rig's maximum depth this could involve 160 x 75-foot joints of riser, with one line on each side, totaling 320 tests that could be required during this phase. It is, however, normal practice to only test the choke and kill lines after every tenth joint to reduce the overall time required. In addition to these pressure tests, the submerged electronic components of the BOP control system are scrutinized as the hydrostatic pressure affecting them increases with the depth (c. 5,350 psi at 12,000 feet).

The Diverter System

The diverter equipment, shown in Figure I, is mounted underneath the rig floor rotary table and, on a subsea system, provides the interface between the drilling riser and the drilling fluid (mud) systems. The components include the diverter housing, the diverter assembly, overboard and flowline valves, and pipework. A surface system does not have a riser per se; instead, they have several overshot spools to connect from the top of the annular to the diverter. The use and operation of the diverter systems are similar for both subsea and surface WCE systems.

Mud is pumped down the drill pipe to provide the primary well control in the form of hydrostatic pressure, to lubricate and cool the drill bit, and to carry cuttings back to the surface. In normal circumstances, the return flow travels up to the diverter housing, then through the flowline valve, down the flowline, and on to the mud treatment center, where it is cleaned and treated before being circulated back into the well.

In the event of a shallow gas kick or a blowout, the diverter packing unit would be closed to prevent the flow from reaching the rig floor. Activating the packer to the closed position automatically fires a sequence to close the flowline valve and to open the overboard lines simultaneously to prevent a closed system because the diverter is, by definition, not a blowout preventer. Rather, it is a safety device intended to give the people on the drill floor vital minutes to evacuate in case of an emergency.

The Choke Manifold System

The choke manifold system, shown in Figure H, is an arrangement of piping, valves, chokes, and pressure sensors used to control pressurized fluids coming out of the well. The manifolds are designed to allow drilling or for wellbore fluids to be evacuated from the well and safely directed to the proper location. During a well kill operation, this could involve drawing heavy mud (drilling fluid) from the mud pits via the standpipe manifold and pumping it down the kill line. With a BOP closed, the gas-cut mud, or simply the lighter mud, is directed up the choke line and back to the manifold. When the fluid reaches the manifold, it is directed through a remotely adjustable choke designed to restrict the flow and thus control the pressure coming out of the well.

Typically, the valves and piping downstream of the chokes are rated for lower pressure than those on the upstream side. The lower pressure fluid can then be directed to the burner boom, overboard lines, mud-gas separator, or one of the trip tanks, as required. The mud-gas separator (MGS) is typically a large vertical vessel, fitted with internal baffles, used to remove undesired gas from drilling mud when it returns to surface while circulating the well. The mud enters the tank from the top and hits the baffles inside the tank separating the gas, which flows freely up the vent pipe from the mud, which is routed back to the mud tanks (pits) for reuse.

All choke manifolds have at least two chokes for redundancy purposes. If the choke becomes blocked during a well kill operation, it is relatively easy to redirect the flow through the (an) alternate choke with minimal disruption. The functional requirements for the choke manifold are essentially the same for both subsea and (≥10,000psi) surface systems. However, the surface systems are often less versatile in the possible routings through the manifold.

The Auxiliary Equipment

Per API Standard 53, the auxiliary equipment includes the components listed in Table 1. The table is annotated to describe the equipment and identify whether it applies to subsea or surface WCE systems.

Table 1: Auxiliary Equipment

COMPONENT		USE
Similar equipment used on both subsea and surface WCE systems		
1	Kelly valves	Valves used within the drill string.
2	Drill pipe safety valves	
3	Inside BOP	
4	Float valves	
5	Trip tank	Part of the mud (drilling fluid) flow.
6	Pit volume measurement and recording devices	
7	Flow rate sensor	
8	Poor boy degasser	Part of the mud flow, but specifically used for removing gas from the mud.
9	Mud gas separator	
10	Mechanical type degasser	
11	Flare/vent lines	
12	Standpipe choke	
13	Top drive equipment	Mechanism that rotates the drill pipe when directing mud down the drill string.
Equipment specific to subsea WCE systems		
14	Guide frames	Part of the subsea stack framework.
15	Slope indicators	
16	Pin connector / hydraulic latch	No longer in common use, but formerly used on a well where shallow gas was expected, to guide the gas to the rig instead of aerating the water and reducing the buoyancy below the rig.
17	Mud booster line	One of the riser auxiliary lines that allows additional mud to be pumped into the riser at the top of the BOP stack to help lift the drill cuttings up the large bore of the riser main tube.

18	Hydraulic supply line	Auxiliary lines on the riser used to carry the water-based BOP control fluid from the surface accumulators down to the subsea BOP stack.
19	Riser tensioning support ring	Remotely latched mechanism used to attach the hydro-pneumatic riser tensioners to the drilling riser.

SOURCE: U.S. DOT, BTS, SafeOCS Program.

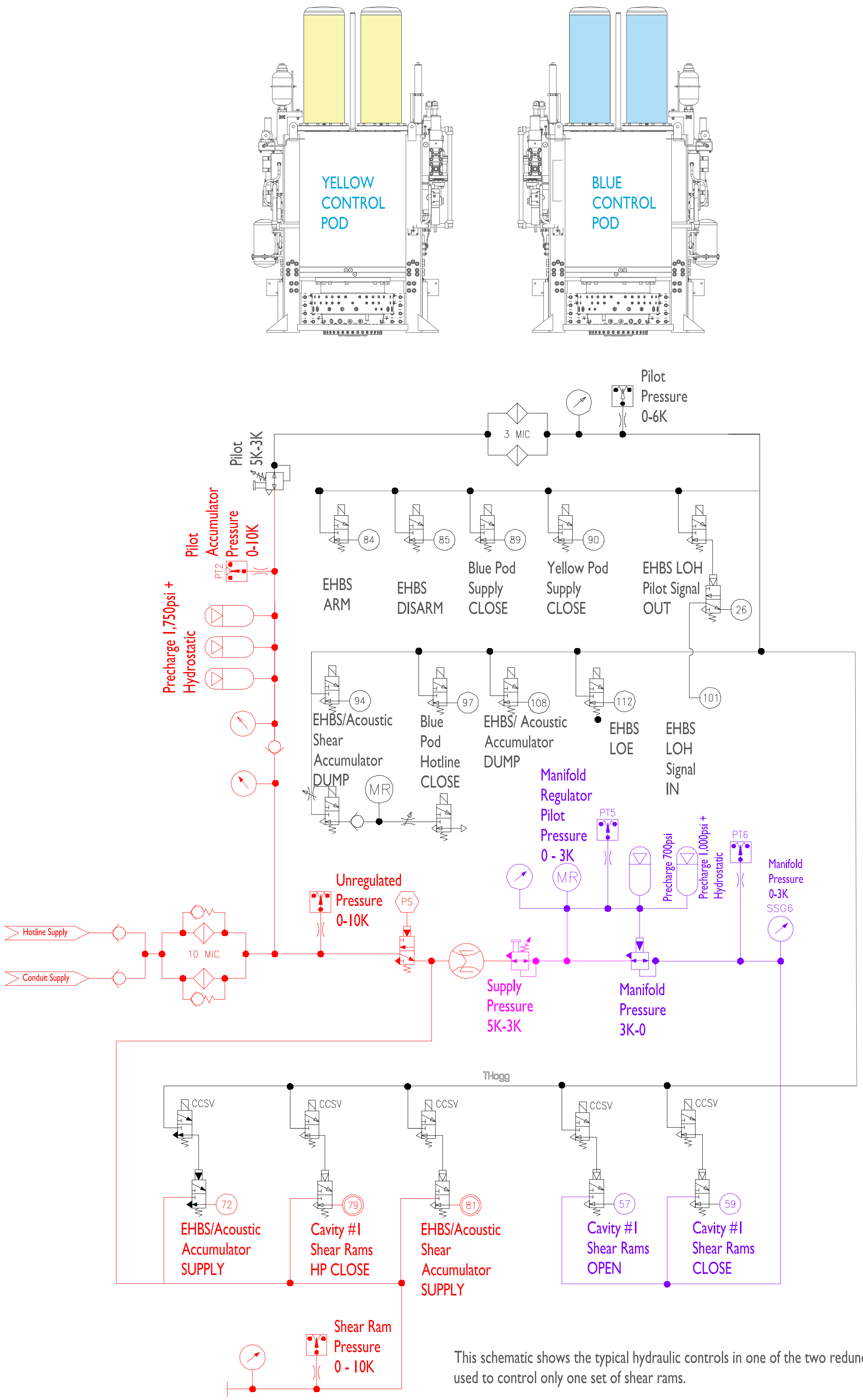
EXAMPLE SCHEMATICS

The following pages present example schematics referenced above.

- Figure A: Example Schematic for Subsea Primary Control System – Shear Ram
- Figure B: Example Schematic for Emergency Deadman/Autoshear System
- Figure C: Example Schematic for Secondary Acoustic Control System
- Figure D: Example Schematic for Subsea Shear Ram Control System Arrangement
- Figure E: Example Schematic for Subsea BOP Stack
- Figure F: Example Schematic for Surface BOP Stack Control System
- Figure G: Example Schematic for Surface BOP Stack
- Figure H: Example Schematic for Choke Manifold
- Figure I: Example Schematic for Diverter System
- Figure J: Example Schematic for Riser Joint

Example Schematic Drawings

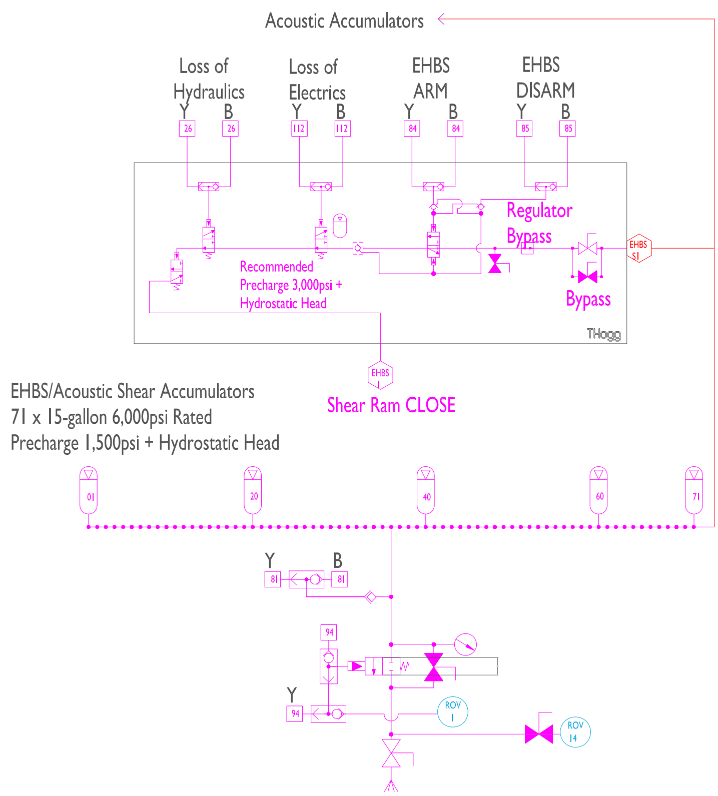
Figure A. Example Schematic for Subsea Primary Control System - Shear Rams



This schematic shows the typical hydraulic controls in one of the two redundant pods. used to control only one set of shear rams.

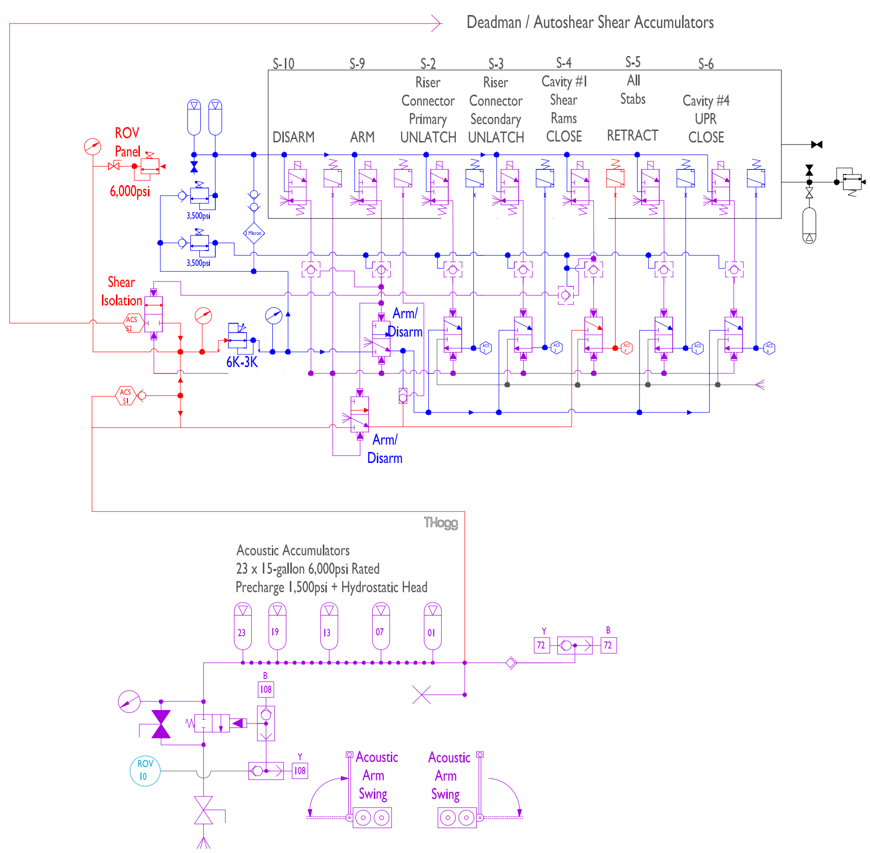
(SOURCE: US DOT, BTS, SafeOCS Program)

Figure B. Example Schematic for Emergency Deadman/Autoshear Control



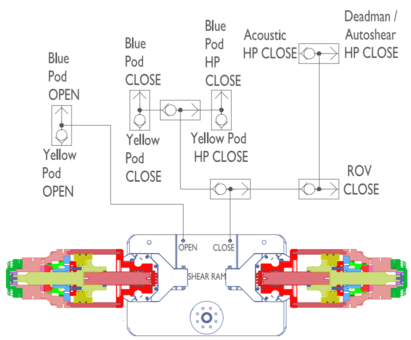
(SOURCE: US DOT, BTS, SafeOCS Program)

Figure C. Example Schematic for Secondary Acoustic Control System



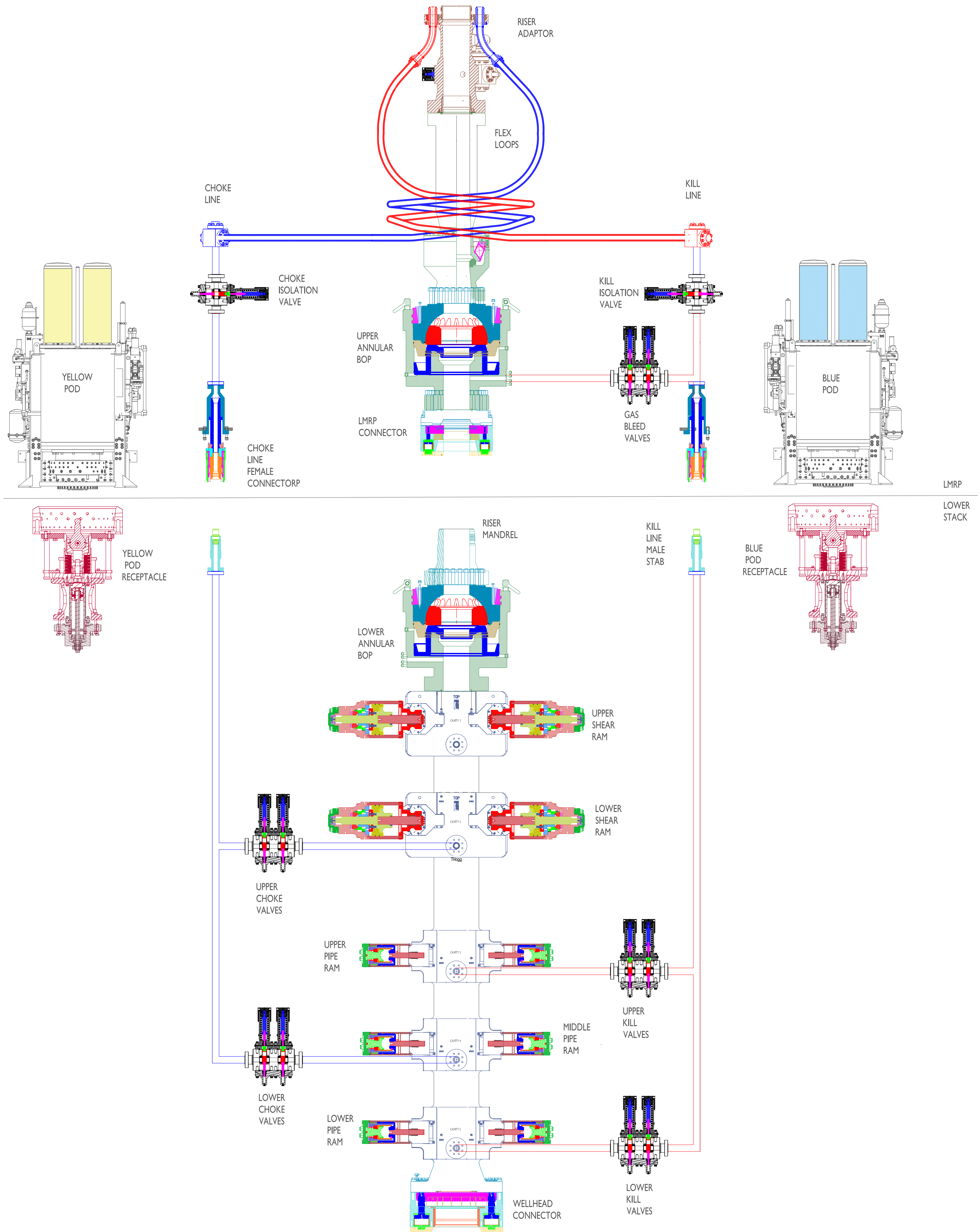
(SOURCE: US DOT, BTS, SafeOCS Program)

Figure D. Example Schematic for Subsea Shear Ram Control System Arrangement



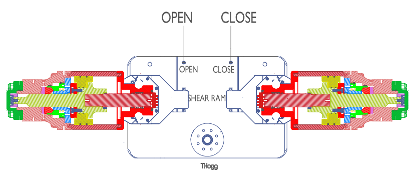
(SOURCE: US DOT, BTS, SafeOCS Program)

Figure E. Example Schematic for Subsea BOP Stack



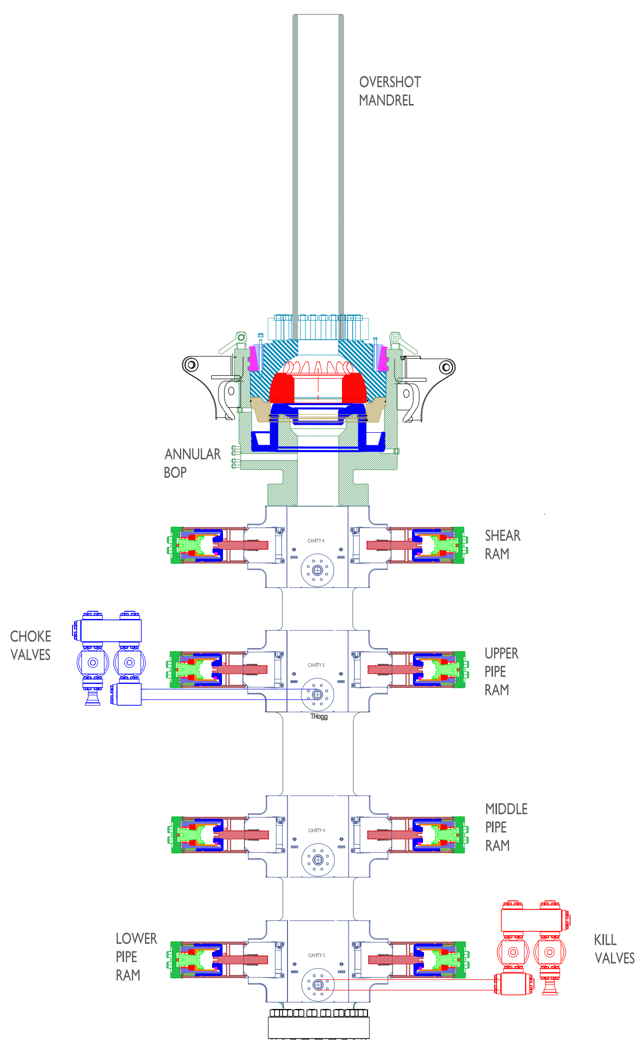
(SOURCE: US DOT, BTS, SafeOCS Program)

Figure F. Example Schematic for Surface BOP Stack Control System



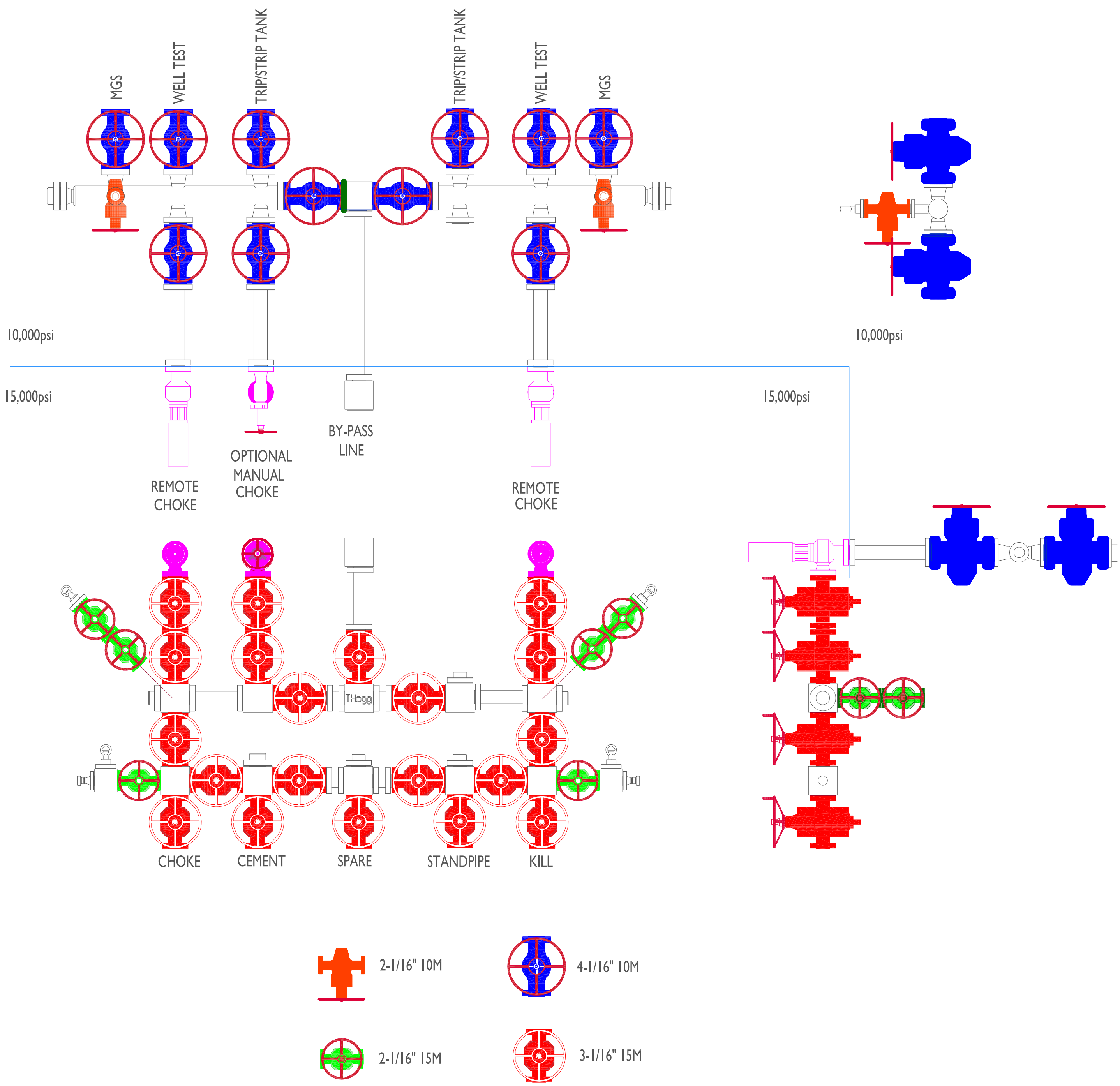
(SOURCE: US DOT, BTS, SafeOCS Program)

Figure G. Example Schematic for Surface BOP Stack



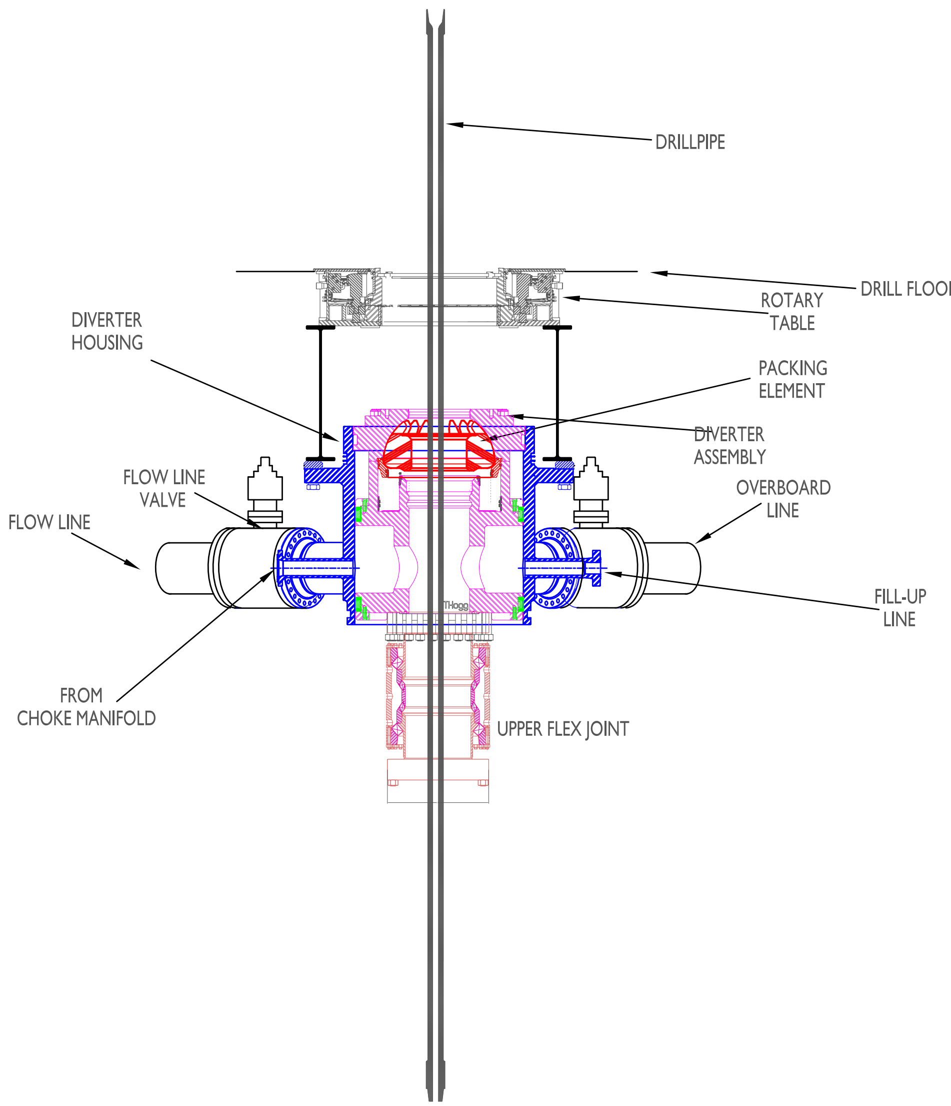
(SOURCE: US DOT, BTS, SafeOCS Program)

Figure H. Example Schematic for Choke Manifold



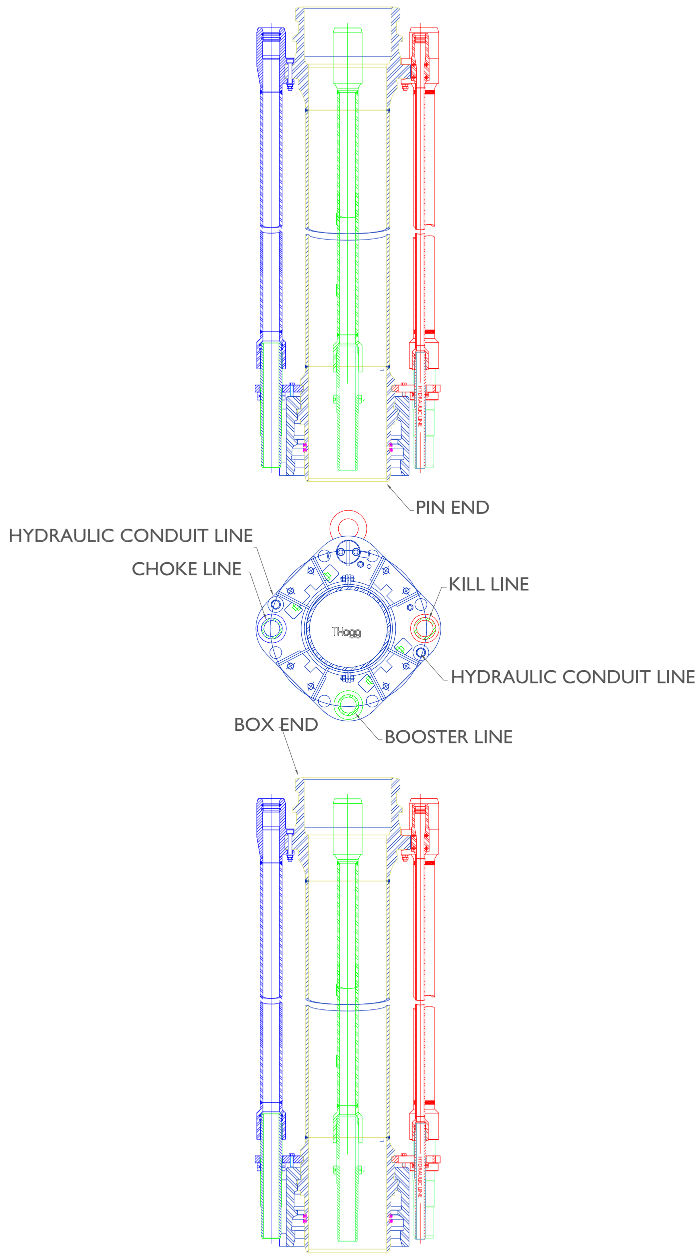
(SOURCE: US DOT, BTS, SafeOCS Program)

Figure I. Example Schematic for Diverter System



(SOURCE: US DOT, BTS, SafeOCS Program)

Figure J. Example Schematic for Riser Joints



(SOURCE: US DOT, BTS, SafeOCS Program)