EXHIBIT # 1893

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Appendix H. Description of the BOP Stack and Control System

Introduction

This appendix describes the major components on a blowout preventer (BOP) system and specifically provides a description of *Deepwater Horizon* BOP stack, lower marine riser package (LMRP) and control system. Applicable standards are also described.

The BOP system is safety critical, and is an integral part of the drilling system. On a subsea drilling system, the BOP system is located between the wellhead and the riser. It is designed to assist in well control and to rapidly shut in the well in the event that the well starts to flow due to an influx of formation fluids. In addition to its primary function of providing the final barrier during loss of well control, the BOP system is used for a range of routine operational tasks, such as casing pressure and formation strength tests.

Three major components of the BOP system are:

- The LMRP.
- The BOP stack.
- The control system.

The BOP system comprises individual BOPs (ram and annular) and the valves and piping (kill and choke lines) that are used to maintain control of pressure in a wellbore. The BOPs and valves are hydraulically operated. A typical BOP system for deepwater use has five to six ram-type preventers and one or two annular-type preventers:

- Variable bore rams (VBRs) are designed to close and seal around drill pipe.
- Blind shear rams (BSRs) are designed to close and seal the wellbore, shearing the drill pipe if it is present.
- Casing shear rams (CSRs) are designed to shear casing without sealing the wellbore.
- Annular preventers are positioned above ram preventers, since they are not typically rated to working pressures as high as those of the ram preventers. Annular preventers are designed to close around a wide range of tubular sizes and can seal the wellbore if no pipe is present.

Figure 1 is a schematic representation of *Deepwater Horizon* BOP system.

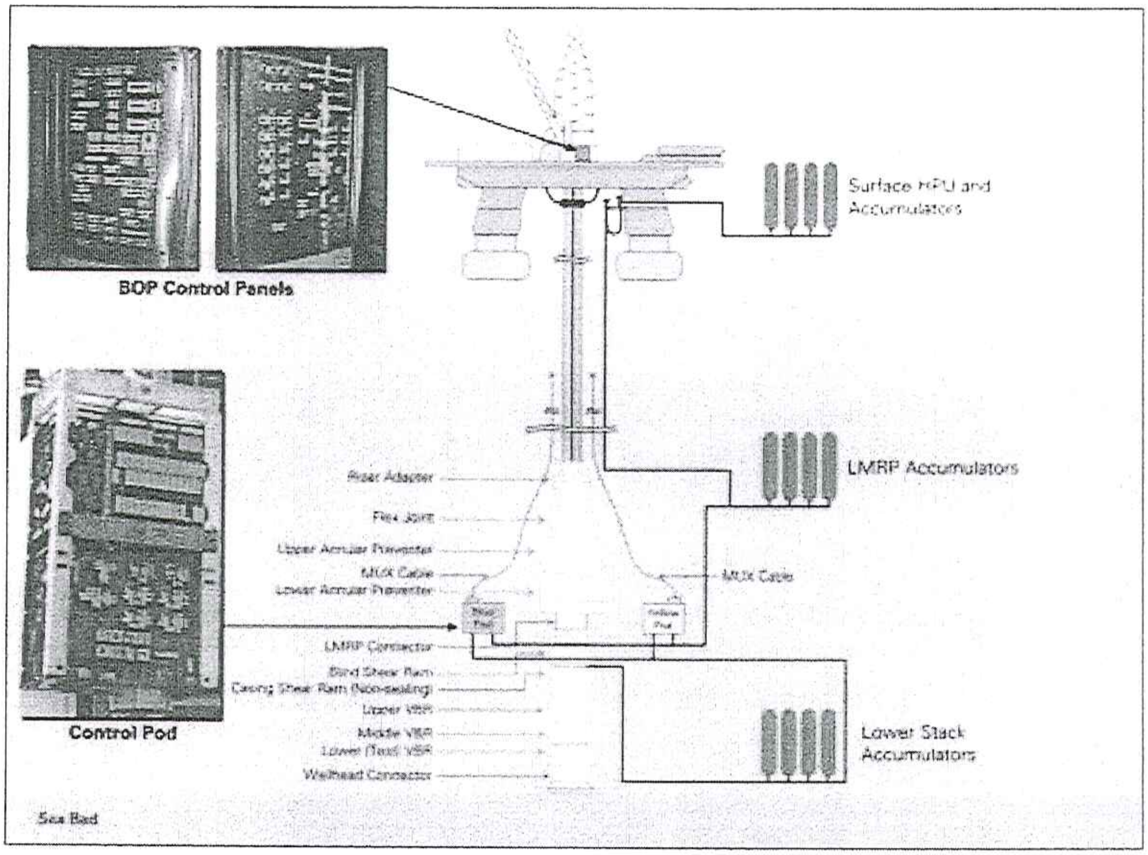

Figure 1. A Schematic Representation of Deepwater Horizon BOP System.

2 Detailed Description

As described in the Cameron *BOP Operation and Maintenance Manual*, the BOP system on *Deepwater Horizon* was a "TL BOP Guidelineless Stack, 18 3/4 in., 15,000 psi system." *Figure 2* shows a simplified diagram of the BOP and a photograph of it in the moon pool on the rig.

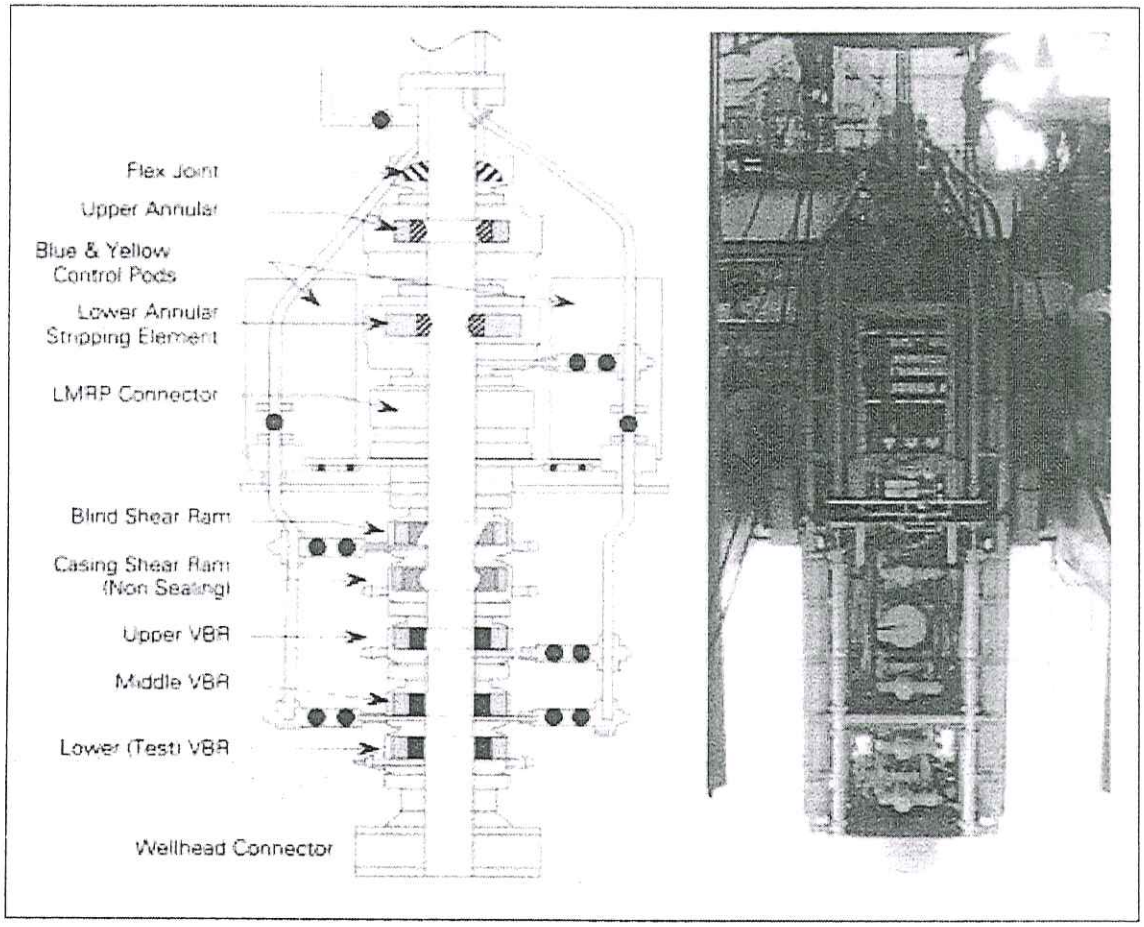

Figure 2. Diagram and Photo of *Deepwater Horizon* BOP System.

The BOP stack was attached to the wellhead with a hydraulically operated, high-pressure wellhead connector manufactured by Vetco (18 3/4 in., 15,000 psi type 'SHD-H4'). A Flexjoint™ riser adapter (manufactured by Oil States) assembly attached the LMRP to the marine drilling riser. The LMRP had a Cameron 18 3/4 in., 10,000 psi type 'HC' hydraulically-actuated connector at its lower end, giving it the ability to disconnect from the BOP stack and allowing retrieval back to surface.

2.1 LMRP Details

Figure 3 shows the major components of the LMRP. The following discussion and item numbers reference this figure.

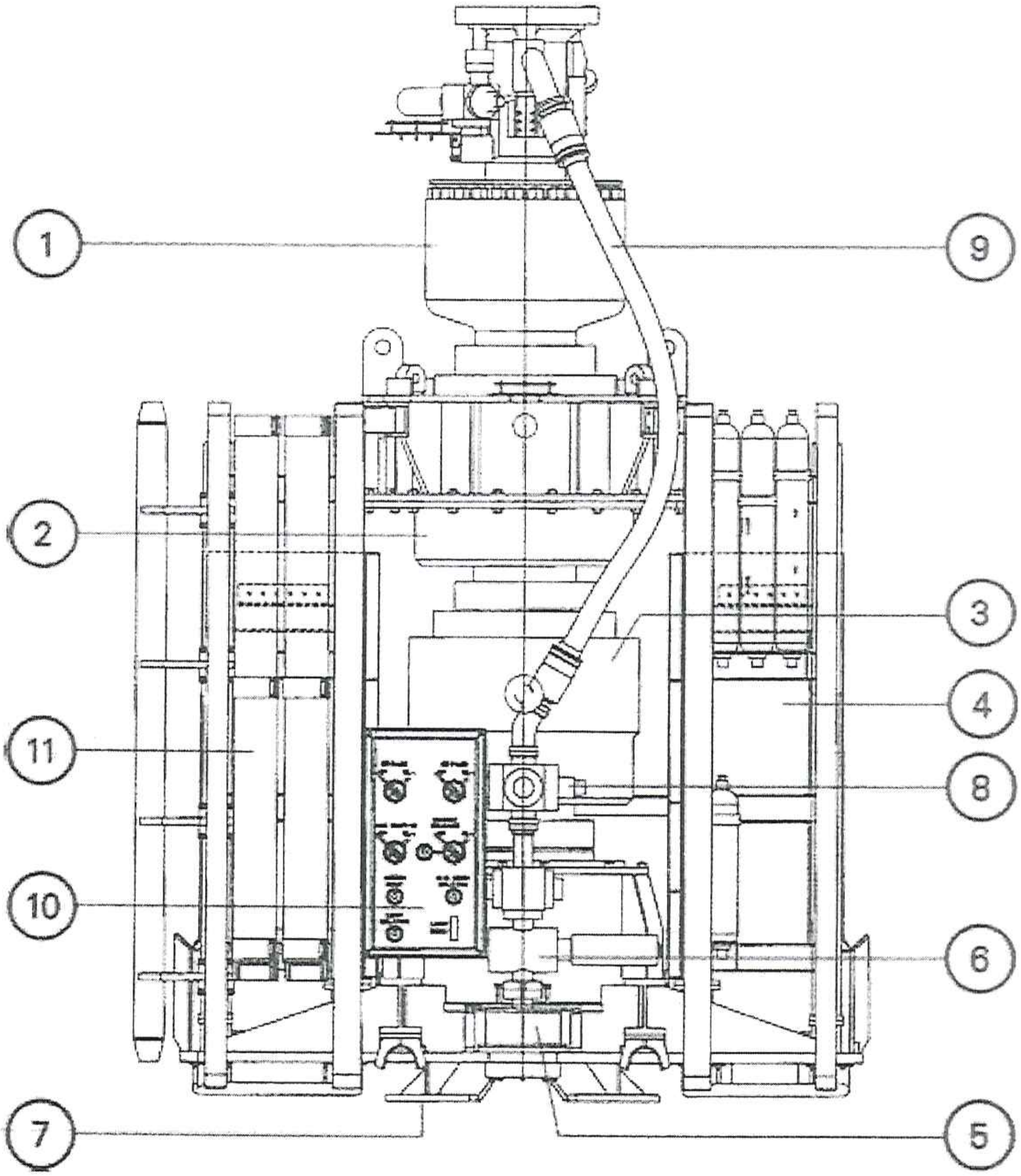

Figure 3. LMRP Assembly.

(1) Flexjoint™ Riser Adapter

The Flexjoint™ riser adapter assembly was the uppermost component in the LMRP. The adapter contained a 5,000 psi flexible joint that allowed for the deflection of the marine drilling riser from the vertical axis of the BOP stack. The Flexjoint™ device was manufactured by Oil States and had the ability to handle up to 10° of angular deflection at any heading.

The assembly also had a mud boost line port that allowed mud to be pumped into the marine drilling riser to boost cuttings back to the surface (through the marine drilling riser). The riser flange connection at the top of the adapter located immediately above the Flexjoint™ provided a load-carrying connection point between the marine drilling riser and the LMRP and provided the connection between the external service lines on the marine drilling riser and the LMRP and BOP stack. These external service lines were the choke, kill, hydraulic conduit (subsea control system hydraulic supply) and mud boost lines.

(2) Upper Annular Preventer

The upper annular preventer was a Cameron 18 3/4 in., 10,000 psi type 'DL' BOP. This annular preventer was used to seal the wellbore annulus while drill pipe and/or casing was being run through the LMRP and BOP stack. The packing element installed in the upper annular preventer was rated for 10,000 psi when closed around a pipe or 5,000 psi when closed on an open hole.

(3) Lower Annular Preventer

The lower annular preventer was a Cameron 18 3/4 in., 10,000 psi type 'DL' BOP. This annular preventer was rated for 10,000 psi when it was purchased, according to the Cameron *BOP Operation and Maintenance Manual*. At the time of the accident, the lower annular preventer was configured with a stripping packer with an element having a pressure rating of 5,000 psi when closed around drill pipe. The stripping packer was designed to allow drill pipe tool joint stripping (raising and lowering) without damaging the packer or the drill pipe tool joint. According to Cameron's documentation, the stripping packer design was tested to 5,000 psi on 5 1/2 in. and 6 5/8 in. drill pipe.

(4) Control Pods

Two Cameron 'Mark II' electro-hydraulic multiplex (MUX) control pods provided control function and communication between the subsea LMRP and BOP stack components and the surface control system. These pods were designated as the blue pod and the yellow pod. A spare pod that was held on the rig was designated as the white pod.

(5) Choke and Kill Connectors

Cameron 3 1/16 in., 15,000 psi choke and kill connectors were hydraulically operated connectors. These connectors provided high-pressure connections between the choke and kill lines on the LMRP and the BOP stack.

(6) Choke and Kill Line Isolation Valves

Two Cameron 3 1/16 in., 15,000 psi gate valves with fail safe 'open' hydraulic operators were used to isolate the choke and kill lines.

(7) LMRP Connector

A Cameron 18 3/4 in., 10,000 psi type 'HC' connector was used to provide a connection between the bottom of the LMRP and the top of the BOP stack. The hydraulically-actuated connector permitted separation of the marine drilling riser from the BOP stack for retrieval of the marine drilling riser and the LMRP. This allowed the BOP control pods to be retrieved to surface for repair, while leaving the BOP stack shut-in on the well. This connector also allowed the marine drilling riser and the LMRP to be disconnected from the BOP stack in the event of loss of rig dynamic-position station keeping (i.e., rig drift-off or drive-off). This type of disconnect is referred to as an emergency disconnect sequence (EDS). This connector had the ability to disconnect from the BOP stack with up to a 10° vertical misalignment.

(8) Gas Bleed Valves

The gas bleed valves were Cameron dual body gate valves, 3 1/16 in., 15,000 psi with fail safe close hydraulic operators. The purpose of these valves was to allow residual gas to be circulated from the LMRP and BOP stack after a well kill operation.

(9) Choke and Kill Flexible Lines

Two flexible steel choke and kill lines, 3 1/16 in. inner diameter (ID), 15,000 psi provided flexibility in the LMRP choke and kill system around the Flexjoint™ riser adapter.

(10) ROV Interface Control Panel

The remotely operated vehicle (ROV) interface control panel allowed select functions on the LMRP to be operated using ROV intervention.

(11) LMRP Hydraulic Accumulators

Four 60-gallon, 5,000 psi accumulator bottles supplemented the hydraulic fluid volume and pressure being supplied to the subsea hydraulic control pods' BOP system through the rigid conduit line on the riser from the surface pump and accumulator system.

2.2 BOP Stack Details

The BOP stack comprises high-pressure (15,000 psi) components. *Figure 4* shows the arrangement of the BOP stack and its major components. The following discussion and item numbers reference this figure.

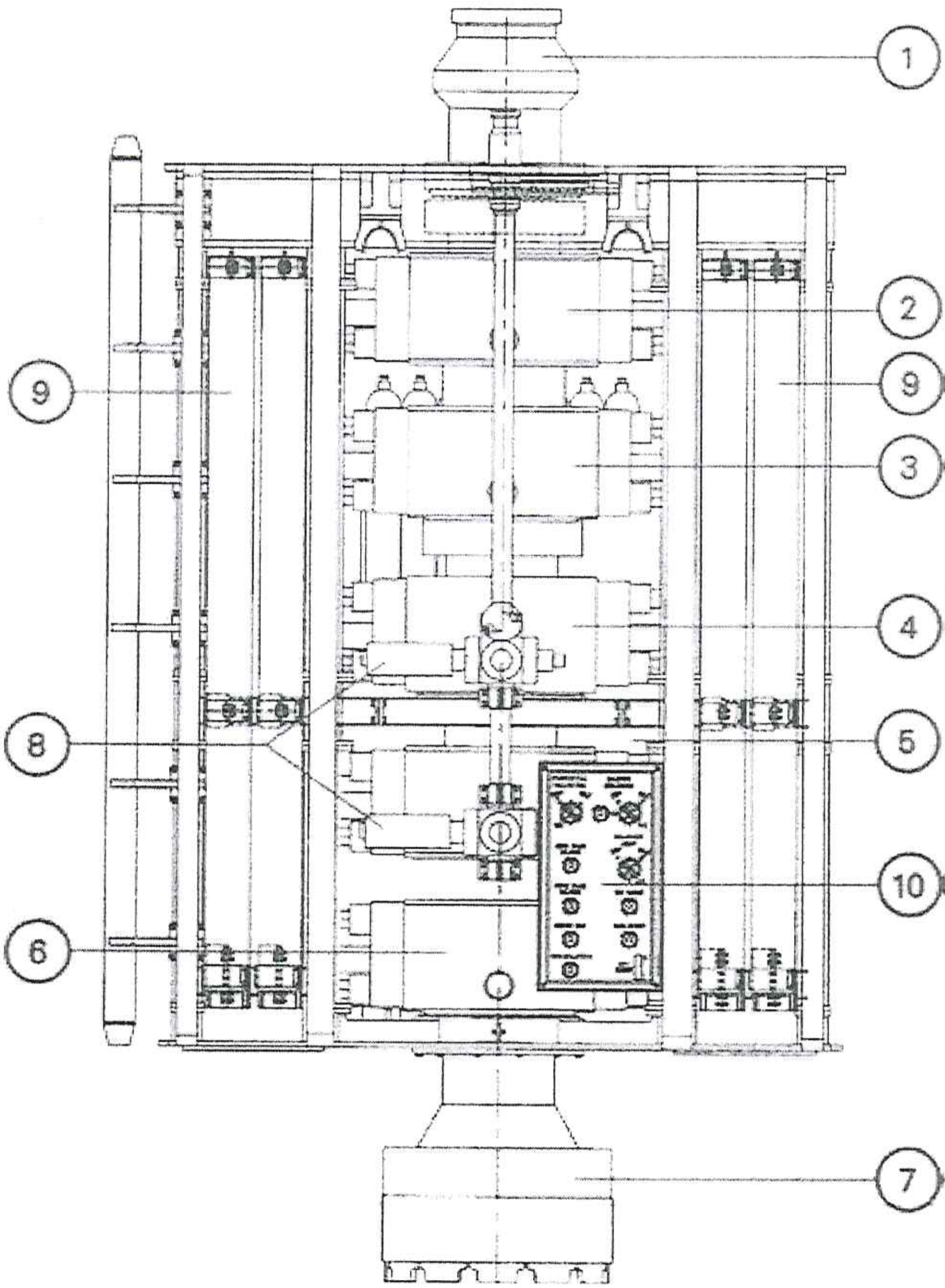

Figure 4. BOP Stack.

(1) LMRP Mandrel

The LMRP mandrel was an 18 3/4 in., 10,000 psi mandrel with a top hub profile that is suitable for connection with the LMRP connector (Cameron hub). The mandrel provided a full-bore, high-pressure connection between the BOP stack and the LMRP.

(2) Blind Shear Ram

The BSR was a Cameron 18 3/4 in., 15,000 psi type 'TL' double ram preventer. The upper cavity of this ram preventer was fitted with Cameron type 'shearing blind rams' that were used to cut the drill pipe (if present) and seal the wellbore. This preventer could be actuated in two modes: under 3,000 psi closing pressure (blind shear), or 4,000 psi closing pressure (high-pressure blind shear). The upper cavity was fitted with Cameron standard ram bonnets (which contained the actuating pistons) and 'ST' locks (which could be used to hold the closed rams in position).

(3) Casing Shear Ram

The lower cavity of this preventer was fitted with Cameron 'Super Shear' rams. These rams were capable of cutting drill pipe, casing and tool joints, but they could not seal the wellbore. The cavity was fitted with Cameron 'Super Shear' bonnets that could not be locked after they were closed.

(4) Upper Pipe Ram

The upper pipe ram was a Cameron 18 3/4 in., 15,000 psi type 'TL' single ram preventer. This ram preventer was fitted with Cameron VBRs that were capable of closing and sealing on tubulars that had an outer diameter (OD) between 3 1/2 in. and 6 5/8 in., and it was fitted with Cameron 'standard' ram bonnets and ST locks.

(5) Middle Pipe Ram

The middle pipe ram was a Cameron 18 3/4 in., 15,000 psi type 'TL' double ram preventer. The upper cavity of this ram preventer was fitted with Cameron VBRs that were capable of closing and sealing tubulars that had an OD between 3 1/2 in. and 6 5/8 in. and it was fitted with Cameron 'standard' ram bonnets and ST locks.

(6) Lower Pipe Ram

The lower cavity of this preventer was fitted with inverted Cameron VBRs that were capable of closing and sealing on tubulars that had an OD between 3 1/2 in. and 6 5/8 in. and sealing the wellbore pressure from above the ram. This pipe ram was referred to as the 'test ram,' and it was fitted with Cameron 'standard' ram bonnets and ST locks.

(7) Wellhead Connector

The wellhead connector was a Vetco 18 3/4 in., 15,000 psi, type 'SHD-H4' wellhead connector. This hydraulically-actuated connector was used to connect the BOP stack to the top of the 18 3/4 in., 15,000 psi subsea wellhead housing.

(8) Choke and Kill Line Valves

The choke and kill line valves consisted of four Cameron dual body gate valves that were 3 1/16 in., 15,000 psi with fail safe 'close' hydraulic operators. These valve assemblies were used to isolate the choke and kill line piping connections to the BOP rams.

(9) BOP Stack Hydraulic Accumulators

Eight 80-gallon, 5,000 psi accumulators on the BOP stack were dedicated to the three emergency operations (autoshear, automatic mode function [AMF] and EDS) of the BSRs and the CSRs. (Refer to Figure 1.) The accumulator bottles were also used for the normal closing operation of the high-pressure BSRs and the high-pressure CSRs. These accumulators stored hydraulic fluid at 5,000 psi and received their supply from the rigid conduit line through subsea pods that were mounted on the LMRP. The maximum operating pressure for the high-pressure BSRs and high-pressure CSRs was reduced to 4,000 psi by manually-set hydraulic regulators.

(10) ROV Interface Control Panel

The ROV interface control panel was located on the BOP system to allow ROV intervention to operate select BOP functions.

3 Electro-hydraulic Control System

The operation of *Deepwater Horizon* BOP system was controlled by a Cameron 'Mark II' electro-hydraulic MUX control system.

The BOP system's annular preventers, ram preventers, connectors and valves were hydraulically actuated. The hydraulic power was delivered by a hydraulic power unit (HPU) located on the rig. The HPU charged the surface accumulators to 5,000 psi and provided hydraulic fluid through a 3 1/2 in. OD rigid conduit line and an auxiliary 1 in. OD hot line hose to the BOP.

The rigid conduit line was the primary hydraulic fluid supply. The hot line supplied hydraulic fluid to the BOP control system while the BOP system was being deployed to, or retrieved from, the sea bed. The rigid conduit line and the hot line terminated at the conduit valve package (CVP) on the LMRP. From the CVP, the hydraulic fluid was directed to either the yellow or the blue pod (depending on which pod was selected by the operator on the rig) to be the active pod. Only one pod was required at any given time for the BOP hydraulic system to function, and that pod was the only one that received hydraulic fluid supply. However, the other (redundant) pod received electrical commands and energized the solenoid valves simultaneously with the active pod.

The control system primarily consisted of two control stations on the rig: the driller's control panel (located in the driller's cabin), and the toolpusher's control panel (located on the bridge). Each control panel contained two programmable logic controllers (PLCs) on two independent control networks (A and B) and two independent power distribution networks (A and B). The control and power networks supplied power and communications to the surface equipment and to the two subsea electronic module (SEM) housings located in each pod. The SEM received commands from the surface system to energize or de-energize the appropriate solenoid valves. Each SEM housing contained two independent PLCs, which were designated as SEM A and SEM B.

Figure 5 shows the major components contained within the SEM housing:

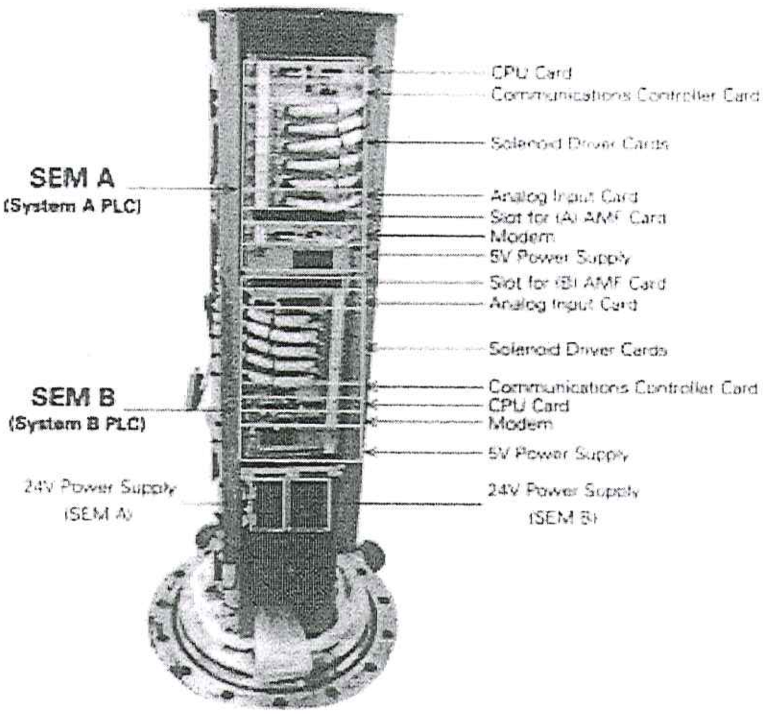

Figure 5. SEM Housing Located in Each Pod.
(Typical Cameron 'Mark I' SEM [not from *Deepwater Horizon*].)

Full duplex modems (using a Cameron proprietary custom protocol) carried communication from the surface to the SEMs. Two independent MUX cables (designated yellow and blue, corresponding to the two pods) carried power and communications subsea.

Both SEMs contained:

- Two power supplies (converting 230-volt AC power from surface to 24-volt DC and 5-volt DC).
- A modem.
- A central processing unit.
- Solenoid driver modules.
- An analog input module.
- An automated mode function (AMF) card.
- Batteries (27-volt DC and 9-volt DC) used for powering the AMF in the event that the surface power supply failed.

The operator selected the pod and SEM that would use the surface hydraulic supply to operate the BOP system. If the operator selected 'blue pod—SEM A,' the blue pod would have had hydraulic supply from the surface, and SEM A would have been selected (within the blue pod's SEM housing) to provide the operator with the information displayed on the control panels. The event logger on the rig continuously recorded electronic data from all four SEMs and all surface panels.

The selected SEM operated the solenoid valves, which in turn provided hydraulic pilot signals to the various hydraulic control valves located in the subsea control pod. Pilot signals acted as a hydraulic switch to operate larger hydraulic components.

Each solenoid contained two coils (A and B). As each function was activated from the surface, a command was issued to both the yellow and the blue pods, then to both SEMs in each pod. Four solenoid coils were energized for every valve operated.

When a solenoid valve was energized in the active pod, the valve opened and allowed the hydraulic fluid supply to enter the specified hydraulic circuit to operate the selected equipment on the BOP system.

The SEM also had the ability to monitor and transmit any measured data from instruments within the pod and on the BOP system (e.g., hydraulic control pressures, hydrostatic pressure, choke and kill line pressure, wellbore pressure and inclinometer measurements) to surface. This information assisted the operator in making decisions regarding BOP system operation.

4 Applicable Industry Standards

Deepwater Horizon BOP stack, LMRP and control system components were manufactured, assembled and factory-acceptance tested from 2000–2001. The stack assembly, along with the BOP control system, was installed and commissioned aboard *Deepwater Horizon* in 2001, and it remained with the rig for its entire working life.

The pressure containing and controlling components (i.e., ram preventers, annular preventers, connectors and choke and kill valves) were designed, manufactured and factory tested in accordance with the applicable requirements of the American Petroleum Institute (API) *Spec 16* and API *Spec 6A*. These API standards also included the requirements of the National Association of Corrosion Engineers (NACE) *MR 0175* (requirements for operating in a sour gas environment), the American Society of Mechanical Engineers (ASME) standards (for welding procedure qualification and welder qualification) and various other industry standards.

Industry standards did not exist for some components of the BOP system. In these cases, the component designer and manufacturer defined standards to which the components were designed, manufactured and factory tested prior to delivery.

The testing required by API standards for BOP components and gate valves was static testing, as opposed to dynamic testing (i.e., simulating a well flowing condition).

The arrangement of the LMRP and BOP stack components was also consistent with the *Code of Federal Regulations* (CFR) for oil and gas drilling in the U.S. Offshore Continental Shelf. (Refer to *30 CFR, Chapter II, Subpart D.*)

5 Applicable BP Standards

Table 1 shows a comparison between *Deepwater Horizon* BOP stack configuration and BP's *Engineering Technical Practice (ETP) GP 10-10, Well Control Engineering.*

Table 1. Comparison Between *Deepwater Horizon* BOP Stack Configuration and BP's *ETP GP 10-10.*

Section	Excerpt from BP's ETP *(GP 10-10)*	*Deepwater Horizon* BOP Stack Configuration
7.5.2	As arranged from top to bottom, the minimum BOP configuration shall be required for wells where a wellhead pressure of over 5,000 psi is possible, is: ▪ Two annular preventers, one of which is retrievable on lower marine riser package. ▪ Four ram type preventers. ▪ Outlets for choke and kill lines. There shall be a minimum of three inlets/outlets. Where there are four inlets/outlets, one shall be below the lowermost ram. Where there are three inlets/outlets, the single kill or choke line connection shall not be below the lowermost ram.	*Deepwater Horizon* BOP system had two annular preventers on the retrievable LMRP and five ram type preventers on the BOP stack. Two of the ram type preventers were not configured for sealing wellbore pressure: the casing shear rams did not seal, and the lower pipe rams had a test ram configuration that would only seal pressure from above the ram. A BP dispensation was approved in 2004 to "convert bottom pipe ram on the *Deepwater Horizon* BOP to a test ram."
7.5.3	A sealing shear ram shall be required. The limitations of its shearing capacity should be known and understood, and a documented risk assessment shall be in place to address any such limitations.	A sealing shear ram (BSR) was included in the stack. The BSR capability was verified in the yard during rig commissioning when 5 1/2 in., 21.9 ppf pipe was sheared at 2,900 psi. The BSR also successfully sheared 6 5/8 in. drill pipe when an EDS function was executed in June 2003.
7.5.5	The BOP stack shall contain a pipe ram that can close on every size of drill pipe and tubing that comprises a significant length of the total string. Where tubular accessories (e.g., cables, clamps, screens, etc.) may compromise a shear ram or pipe ram seal, then appropriate procedures and contingencies shall be in place to mitigate this risk.	*Deepwater Horizon* BOP stack had two VBR-equipped ram preventers that were capable of closing on 3 1/2" to 6 5/8" OD pipe and sealing wellbore pressure.
7.5.6	The lowermost ram shall be preserved as a master component and only used to close in the well when no other ram is available for this purpose.	*Deepwater Horizon* BOP stack had the lowermost ram converted to a test ram. The middle pipe ram was capable of satisfying this requirement.
7.5.7	Ram type preventers shall have remotely or automatically operated ram lock systems fitted.	*Deepwater Horizon* BOP stack was equipped with remotely operated ram locks on the BSRs, pipe rams and test ram. The casing shear ram was not equipped with a ram lock.