United States District Court
Eastern District of Louisiana

In re: Oil Spill by the Oil Rig Deepwater Horizon in the Gulf of Mexico on April 20, 2010,

MDL No. 2179

EXPERT REPORT OF FORREST EARL SHANKS II

ON

BOP DESIGN

October 17, 2011

CONFIDENTIAL

TREX-40008

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1. SCOPE OF WORK

My name is Earl Shanks. I have been retained by BP with respect to the April 20, 2010 incident ("the incident") on the Transocean *Deepwater Horizon* ("DWH") mobile offshore drilling unit ("MODU"). I was asked to analyze the available evidence to evaluate the sufficiency of the design of the DWH's blowout preventer ("BOP") and its components. I was also asked to evaluate the impact of any design deficiencies with respect to the BOP stack.

I have reviewed and/or relied on the materials that are cited in this report and exhibits, including but not limited to the documents and testimony listed in Appendix A to this report. I have also relied on my experience in the oil industry, my education, and my experience on the BP Incident Investigation Team.

2. SUMMARY OF OPINIONS

Based on the evidence that I have reviewed and the analyses that I have performed, I have reached the following opinions in this case to a reasonable degree of engineering certainty:

- Cameron's Shear Blind Ram ("*SBR*")[1] design, which is the model of blind shear rams used in the DWH BOP, was designed and intended to shear 5-1/2" drill pipe located in an 18-3/4" wellbore.
- When the BSRs were activated the drill pipe was positioned in the wellbore such that the Cameron *SBR*s were not capable of sealing the well.
- The *SBR*s failed to cut the drill pipe and seal the well when they were activated because the pipe was located at the side of the wellbore, and outside of the shearing and sealing zone of the *SBR*s.
- The DWH blind shear rams were first activated when the Autoshear pin was cut on April 22, 2010.
- If the AMF/Deadman system had activated the blind shear rams immediately after the first explosions occurred on April 20, 2010, the BOP would have sheared the drill pipe and sealed the well.
- Except for the above problems regarding off-center drill pipe, the DWH's BOP was suitable for the Macondo well, and no alternative features were necessary.

3. QUALIFICATIONS

I have over 35 years of experience working in the offshore oil and gas drilling industry in areas including the design, analysis, implementation, and operation of offshore drilling

[1] Because of the similarity of the acronyms for general blind shear rams (BSR) and Cameron's Shear Blind Ram (*SBR*) blind shear ram model, I will use italics when discussing Cameron's *SBR* model that was used on the DWH BOP.

equipment. My experience over this time has been primarily focused on subsea equipment, including BOPs, for use in deepwater drilling. I am a named inventor on four patents relating to riser and choke system technologies, and I have authored numerous publications relating to offshore and deepwater drilling equipment and operations.[2]

3.1. Professional Background

Much of my 35 years of experience in the offshore oil and gas drilling industry relates directly to subsea blowout preventers ("BOPs"). As the Manager System Engineering for SEDCO Inc. in the 1970s and 1980s, I was responsible for the design, manufacture, and installation of drilling systems, including the BOP and well control systems, for 29 new build and upgrade MODUs.

As the Drilling Technology Group Leader for MODU Drilling Technology at Mobil Oil, I provided worldwide technical support for Mobil's MODU drilling activities and was responsible for acquiring and developing technology to drill to water depths of 7,500 feet. I was also responsible for designing and building drilling equipment to operate in deepwater, high water current environments.

As the MEPTEC Drilling Group Leader for Special Drilling Technologies, I had responsibility for reviewing BOP capabilities for specific wells and for ensuring any needed modifications or upgrades were performed.

As the Director of Technology Development for Transocean from 1998 to 2003, I was responsible for monitoring and evaluating technological developments relevant to the oil and gas industry and for the development of new technology.

From 2004 to 2010, I worked with DTC, an engineering company that provides engineering consulting services to various oil and gas companies. During this time, I worked as a contractor with several groups within BP. The projects that I worked for BP included a project with Hydril to design a high pressure wellhead and BOP, providing subsea equipment support (risers, BOPs) for the Drilling Excellence Group, and riser design verification for new rig builds.

In April of 2010, BP requested my assistance on its relief well team for Macondo. On June 1, 2010, I was asked to participate in BP's investigation into the *Deepwater Horizon* incident as a BOP subject matter expert. As part of BP's investigation team I provided technical support for the investigation into the BOP. My participation in BP's internal investigation ended in September 2010.

I am currently Oceaneering's Chief Technologist for Oceaneering Intervention Engineering. In this role, my primary responsibility is to support the BOP controls group in the development of new technology and equipment. I am also Oceaneering's representative on industry groups such as American Petroleum Institute ("API") and International Association of Drilling Contractors ("IADC").

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[2] See my current resume attached as Appendix B.

During my career, I have also participated in several industry organizations and committees. For instance, at the request of the State Department, I served on a Commerce Department COCOM Committee. On this committee, I evaluated defense sensitive technologies relating to subsea equipment and MODU lifting capacity. I have served as the co-chairman on an IADC committee that wrote Guidelines for Surface BOP Planning and Operations. I have also participated in an effort by API to write a technical report on the design verification of High Pressure High Temperature ("HPHT") drilling equipment and am the Chairman of the Design Verification effort of API's Task Group for Protocols for Equipment Rated Greater than 15 ksi.

3.2. Educational Background

Before attending college, I served in the United States Marine Corps. During my service, I spent a year in Vietnam and received multiple Commendations. After being honorably discharged, I attended the University of Houston and earned a Bachelor's degree in Mechanical Engineering in 1972. The following year I earned a Master's degree in Mechanical Engineering from Oklahoma State University.

3.3. Retention for This Matter

In 2010, I was retained by BP to work on this litigation. For my services in this matter I am being compensated at my customary hourly rate of $250 per hour. My compensation does not depend in any way on the outcome of this litigation. I have not testified as an expert witness either at trial or in deposition in the last 4 years. I have provided a list of my publications in my resume attached as Appendix B.

4. BACKGROUND

4.1. BOPs General Discussion

4.1.1. BOPs Are Critical Safety Equipment.

Blowout preventers ("BOPs") are critical safety equipment, especially in offshore deepwater drilling operations, where the wellhead may be thousands of feet underwater and inaccessible to the drilling crew. BOPs are used in routine drilling and well control operations, and are also called on if the need arises in emergency situations, as they were on the *Deepwater Horizon*. BOPs are often the last physical barrier protecting against a blowout in emergency situations. Therefore, drilling contractors like Transocean and lease operators like BP rely on BOPs to operate and perform as intended.

Cameron's Engineering Bulletins, which provide guidance to Cameron customers, describe the conditions for which Cameron designs its BOPs, including the blind shear rams. Cameron's Engineering Bulletin on its *SBR* ram design, which was used on the DWH BOP, addresses the use of *SBR*s to shear drill pipe in emergency situations:[3]

[3]Cameron Engineering Bulletin 538D, CAM_CIV_0003124.

> If emergency conditions make it necessary to shear the drill pipe, the closing SBRs will cut the pipe and seal the wellbore whether the fish (the lower section of cut pipe) is suspended on the lower pipe rams or dropped. If the fish is not dropped, the lower shear ram will bend the cut pipe over a shoulder and away from the front face of the lower shear ram, which then seals against the packer in the upper shear ram.

4.1.2. BOPs Comprise Several Components.

A subsea BOP sits on the sea floor at the top of the well and consists of two main sections: the lower marine riser package ("LMRP") and the lower BOP. BOPs consist of several individual preventer elements that fall into two general types: annulars and rams. Annulars contain a large rubber ring that is essentially squeezed shut to seal on different sizes of drill pipe when compressed. Rams utilize two opposing pistons that come together to perform various functions: variable bore rams ("VBRs") use rubber inserts ("packers") to create a seal around the drill pipe; BSRs contain shearing blades to cut the pipe and elastomeric elements to seal the well after shearing; and casing shear rams ("CSRs") can shear casing and larger pipe than BSRs, but cannot seal the well.

The below figure shows the BOP from the *Deepwater Horizon*:

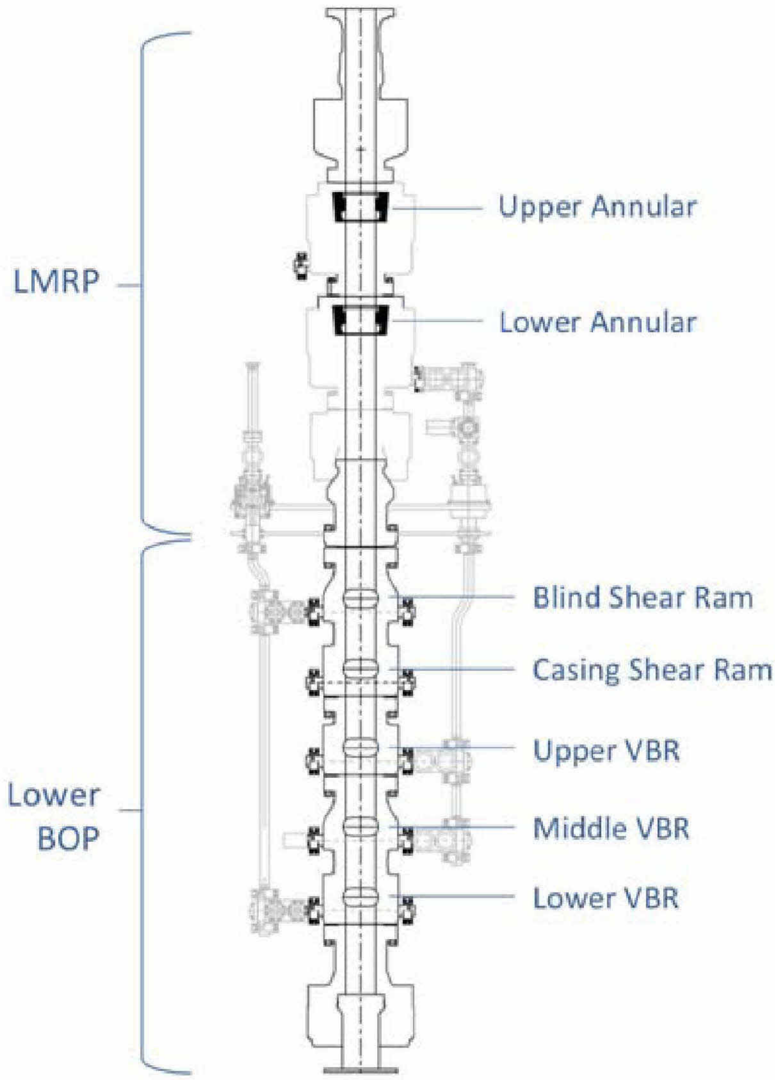

Figure 1 The DWH BOP

The DWH BOP contained two annulars located on the LMRP, as shown in Figure 1. The DWH's BOP utilized three types of rams, each with a different purpose. These rams were located on the lower BOP and included 3 sets of VBRs, 1 set of CSRs, and 1 set of BSRs. The DWH's VBRs could seal against drill pipe ranging in diameter from 3-1/2" to 6-5/8".[4]

[4]One of the DWH BOP's VBRs was converted to a "test ram." This means the VBR was inverted so that it could seal against pressure from above, but not pressure from below.

4.1.3. Drilling Contractors and Leasehold Operators Rely on BOPs to Function as Intended and Designed.

Drilling contractors, like Transocean, and lease operators, like BP, recognize that BOPs are used in emergency situations. For example, Transocean's President and CEO, Steve Newman, stated as follows in written answers to the U.S. Congress:[5]

> **"A blowout preventer (BOP) is a series of large valves that are positioned on top of a well to provide secondary pressure control of a well. BOPs are designed to quickly shut off the flow of oil or natural gas in the case of a kick or blowout during drilling operations, which is a sudden, uncontrolled release of pressure from below the sea floor."**

Therefore, drilling contractors and operators rely on BOPs to function as designed. This includes relying on the blind shear rams ("BSRs") to shear pipe and seal a well when the pipe size and pressures encountered are within parameters supplied by the manufacturer.

4.2. Development of the DWH's BOP Configuration and Design

The DWH's BOP design used a configuration and components that were at or above the industry standard. The configuration was a 5-ram cavity stack with a blind shear ram, casing shear ram and three pipe rams (later, two pipe rams and one test ram). This was a standard configuration that was widely used even up to the day of the incident.[6]

The lower BOP stack (which includes the blind shear ram, casing shear ram, and variable bore rams) was pressure rated to 15,000 psi, which was the maximum available pressure rating for these components of a subsea stack. The LMRP (which includes the annulars) was pressure rated to 10,000 psi, which was the maximum available pressure rating for annulars. The lower annular stripping packer was pressure rated to 5,000 psi. The blind shear rams were Cameron's *SBR* design, a standard design at the time, and which is still sold by Cameron.[7]

The DWH high pressure shear system had a supply pressure of 5,000 psi, used accumulator bottles rated for 6,000 psi, and a regulated supply to the shear rams of 4,000 psi, which was the maximum hydraulic pressure of the ram bonnets. The DWH BOP stack was also rated by Cameron to a 10,000 foot water depth.[8]

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[5] MDL Ex. 2016 at p. 99.

[6] TRN-MDL00272700 at 720-22; CAM_CIV_0311314 at 317.

[7] M. Whitby, 7-18-2011 dep.tr. at 340:17-341:3.

[8] D. McWhorter 7-8-2011 dep. tr. at 577:25-578:5.

4.2.1. BP Entered a Contract with Transocean for the DWH's Services

In 1998, BP's predecessor Vastar Resources, Inc. (which was acquired by BP and will be referred to as "BP" herein) contracted with Transocean's predecessor R&B Falcon Drilling Company (which was acquired by Transocean and will be referred to as "Transocean" herein) for the lease and construction of the Transocean rig *Deepwater Horizon* ("DWH").[9] Transocean owned and built the DWH. [10]

The division of BOP-related responsibilities during the design of the DWH is consistent with my experience working with rig builds and rig upgrades. In my experience, many of the significant responsibilities among the parties are usually described in the contracts between the involved parties. As discussed below, Vastar Resources (later BP) specified certain functional requirements for the BOP, but relied on Cameron and Transocean for BOP implementation and design, and Transocean was ultimately responsible for providing adequate equipment. In my experience, this is a common division of responsibilities during a rig build.

BP's contract with Transocean contained certain specifications regarding functional aspects of the DWH's BOP, such as that it must be designed to drill wells in water depths up to 10,000 feet. The contract specified certain basic criteria for the stack configuration, ram type preventers, and annular type preventers. Regarding the stack configuration, the contract said:[11]

E.2.4 STACK CONFIGURATION
(Blind/Shear/Pipe/Variable)

Upper Shear r: Cavity 5	SSCSR (Less than or equal to 13-5/8")
Lower shear r: Cavity 4	: BSR
Middle Upper Cavity 3	: VBR
Middle Lower Cavity 2	: VBR
Lower rams Cavity 1	: LFPR
Position of side outlets - kill	
Upper	: Below BSR (Cavity #4)
Lower	: Below LFPR (Cavity #1)

[9]Drilling Contract, MDL Ex. 4271.

[10]Drilling Contract, MDL Ex. 4271 at BP-HZN-MBI00021464, 73.

[11]Drilling Contract, MDL Ex. 4271 at BP-HZN-MBI00021538.

The contract contained the following specifications regarding the ram type preventers:[12]

E.2.3 RAM TYPE PREVENTERS

Preventers:		
Quantity	no.:	5
Bore size	inch:	18.3/4"
Working Pressure	psi:	15000
Make	:	CAMERON or equivalent
Model	:	TYPE TI
Type (single/double)	:	Double x2 , Single x 1
Stack Configuration	:	A1, A2, CL, SSCSR BSR, VBR, VBR.LFPR,CH
Ram locks	yes/no:	YES
Preventer connection type - top	:	CX18 (BX-164 Option Available)
Preventer connection type - bottom	:	CX18 (BX-164 Option Available)
Side outlets	yes/no:	YES
Size	inch:	3.1/16
Connection type	:	No. 6 CAMERON CLAMP AX GROOVE
Super/Shear rams:		Less than or equal to 13-5/8"
Quantity	no.:	1 set
Blind/Shear rams:		
Quantity	no.:	1 set
Variable rams:		
Quantity	no.:	1 set
Size range (max/min)	inch/inch:	Customer to advise
Quantity	no.:	1 set
Size range (max/min)	inch-inch:	Customer to advise
Pipe rams:		
Quantity	no.:	1 set
Size	inch:	Customer to advse

Regarding the blind shear rams, the contract simply specified that the BOP would have one set of blind shear rams with a working pressure of 15,000 psi for an 18-3/4" wellbore, and that the make of the blind shear rams would be Cameron or an equivalent. The contract contained the following specifications regarding the annular type preventers:[13]

E.3.2 ANNULAR TYPE PREVENTER (LMRP)

Size		inch:	18-3/4"
Qty.		no:	2
Working pressure		psi:	10000
Make/Type	(2*70.5=141" Total Heig|	:	CAMERON TYPE DL

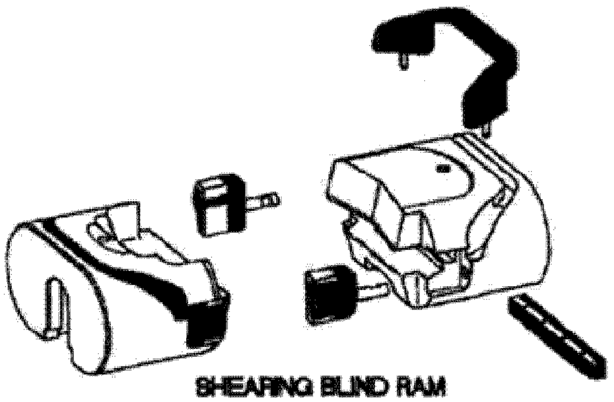
The drilling contract did not specify details such as the specific design of the blind shear rams, including the shape or dimensions of the shearing and sealing surfaces. I have not seen any evidence indicating BP or Transocean participated in the design of the blind shear ram

[12]Drilling Contract, MDL Ex. 4271 at BP-HZN-MBI00021538.

[13]Drilling Contract, MDL Ex. 4271 at BP-HZN-MBI00021539.

blocks that were used on the Deepwater Horizon. Rather, the Cameron *SBR* model (blind shear rams) that was used on the DWH was a well-known model that was designed long before the drilling contract, as shown by this Cameron Engineering Bulletin showing the *SBR* blocks in October 1998:[14]

PROPERTY OF	DRAWN BY	DATE	REVISION	Engineering Bulletin
CAMERON	B.C. Williams	Oct 29, 1998	A1	EB 852D
	APPROVED BY	DATE		
	Melvin F. Whitby	Oct 30, 1998		Page 1 of 17



SHEARING BLIND RAM

In fact, Cameron received a United States patent for the same or a similar design in 1979:

United States Patent [19] [11] **4,132,267**
Jones [45] **Jan. 2, 1979**

[54] **PIPE SHEARING RAM ASSEMBLY FOR BLOWOUT PREVENTER**

[75] Inventor: **Marvin R. Jones**, Houston, Tex.

[73] Assignee: **Cameron Iron Works, Inc.**, Houston, Tex.

3,736,982 6/1973 Vujasinovic .... 251/1 A X
3,817,326 6/1974 Meynier 166/55

Primary Examiner—Ernest R. Purser
Assistant Examiner—Richard E. Favreau
Attorney, Agent, or Firm—Vinson & Elkins

[14]MDL Ex. 3183; M. Whitby, 7-19-2011 dep. tr. at 398:23 to 400:5.

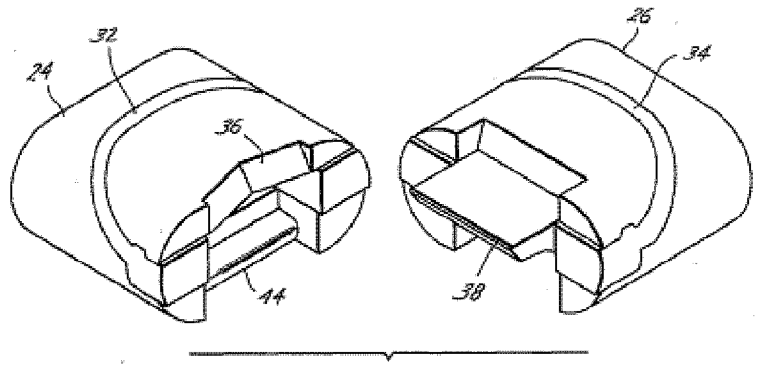


Fig. 4

BP's contract with Transocean contained several additional provisions requiring Transocean to provide sufficient drilling and safety equipment, including the BOP.[15]

14.1 REPRESENTATION OF DRILLING UNIT
The Drilling Unit shall be fully equipped as specified in Exhibit B and shall meet the requirements of Exhibit G, and shall be adequate to drill and complete wells in the Operating Area to the depths as specified in Article 14.2 hereof and in water depths as specified in Article14.3. CONTRACTOR represents that the Drilling Unit satisfies all requirements of Articles 14.1.1, 14.4 and 14.6, and is capable of operating to its full capacity as rated by the

manufacturer. CONTRACTOR shall maintain the Drilling Unit at optimal operating condition, in accordance with good oilfield practices throughout the duration of the CONTRACT.

14.2 MAXIMUM DRILLING DEPTH RATING
CONTRACTOR represents that the Drilling Unit is mechanically capable of drilling wells to the depth specified in Exhibit B-1.

14.3 MAXIMUM WATER DEPTH RATING
CONTRACTOR represents that the Drilling Unit is mechanically capable of drilling wells in water depths and during environmental conditions, as specified in Exhibit B-1.

[15]Drilling Contract, MDL Ex. 4271 at BP-HZN-MBI-00021477-79, 572.

14.5 APPLICABLE LAWS
Subject to Article 2.3.4, CONTRACTOR represents that during the Contract Period, the Drilling Unit is outfitted, conformed, and equipped to meet all applicable laws, rules, requirements, and regulations promulgated by the U.S. Coast Guard, the U.S. Environmental Protection Agency, the United States of America Department of the Interior as well as any other agency, bureau, or department of the U.S. federal, territorial possession, state, municipal, or local governments, any political subdivisions thereof, having jurisdiction over the operations in U. S. federal waters.

As can be seen in the examples above, Transocean as the "contractor" was responsible for ensuring that the DWH and its equipment satisfied the requirements of the contract (14.1), including drilling depth (14.2), water depth (14.3), and was responsible for ensuring that the DWH equipment met all relevant regulations.

Transocean's President and CEO, Steve Newman, testified that the DWH's BOP was Transocean equipment, and that Transocean was responsible for maintaining it:[16]

Q. Transocean is responsible for the maintenance of the BOP, correct?

A. Yes

Q. And Transocean was responsible for the BOP on the Deepwater Horizon, correct?

A. The BOP on the Deepwater Horizon is a piece of Transocean equipment, and we are responsible for the maintenance of that piece of equipment.

The drilling contract also specifically stated that Transocean was responsible for furnishing the DWH with a blowout preventer that complied with MMS regulations:[17]

Category I

Furnished by CONTRACTOR, paid by CONTRACTOR

1.20 Blowout preventers, choke and kill lines, ring gaskets, controls, handling, testing tools and spare parts as required set out in Exhibit "B-2".

1.30 All equipment shall comply with MMS regulations.

Mr. Newman confirmed in his deposition testimony that Transocean was responsible for providing a BOP that complied with MMS regulations:[18]

[16]S. Newman 9-30-2011 dep. tr. at 138:22 to 139:6.

[17]Drilling Contract, MDL Ex. 4271 at BP-HZN-MBI-00021571-72.

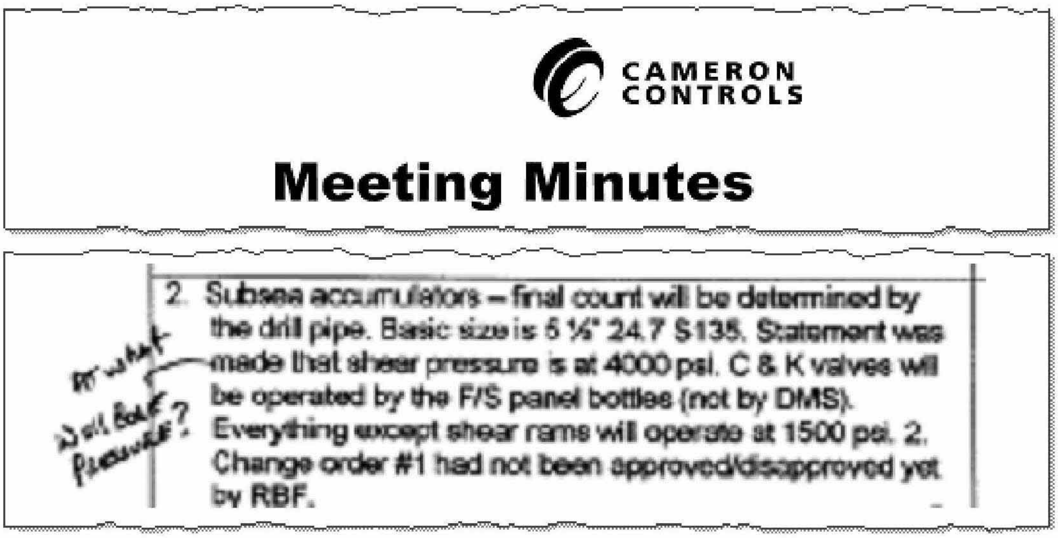
> **Q. You would agree that Transocean supplied the BOP and it was Transocean's responsibility that that BOP comply with MMS regulations, correct?**
>
> A. Yes

In my experience, it is common in a contractor-operator relationship for the contractor to be responsible for the provision, maintenance and operation of drilling equipment such as BOPs, in a way that meets industry and regulatory standards.

4.2.2. BP Monitored the Progress of the BOP Design by Cameron and Transocean.

Beginning in June 1999, Cameron, Transocean and BP representatives attended weekly Progress Meetings regarding the blowout preventer.[19] These were typically attended by several representatives from each of Transocean and Cameron, and one or two representatives from BP. The Rig Files for the DWH contain the Progress Meeting minutes.[20]

Early on in the Progress Meetings, the attendees discussed issues regarding shearability. For example, the July 7, 1999 Meeting Minutes indicate a discussion regarding shearing pressures for 5-1/2", S-135 drill pipe, the type of drill pipe that was in the DWH BOP on the day of the incident:[21]



CAMERON CONTROLS

Meeting Minutes

2. Subsea accumulators – final count will be determined by the drill pipe. Basic size is 5 ½" 24.7 S135. Statement was made that shear pressure is at 4000 psi. C & K valves will be operated by the F/S panel bottles (not by DMS). Everything except shear rams will operate at 1500 psi. 2. Change order #1 had not been approved/disapproved yet by RBF.

At what well bore pressure?

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[18]S. Newman, 9-30-2011 dep. tr. at 150:19-23.

[19]BP-HZN-2179MDL01155528 at 555-56 (June 9, 1999 "Kick off Meeting Minutes for RBS-8D".)

[20]BP-HZN-2179MDL01155528 - 01156159.

[21]Vastar Rig Files Vol. 1, BP-HZN-2179MDL01155528 at 540.

These minutes, along with the hand written note on the side asking "at what wellbore pressure?" indicate that the meeting participants were focused on the ability of the BOP to shear at anticipated pressure levels. The notes for the following week's meeting on July 14, 1999, indicate that RBF (Transocean's predecessor) was going to internally consider and determine operating pressure:[22]

CAMERON CONTROLS

Meeting Minutes

7. RBF will discuss desired operating pressure internally and provide an answer so that exact bottle count can be determined.	RBF

The Progress Meeting minutes for late 1999 and early 2000 show that Cameron and Transocean continued to focus on and be the center of shearability issues, including repeated mentions of regarding shearability charts for the DWH. The DWH Rig File contains a shearability chart from Mel Whitby of Cameron that indicates that it was printed on October 22, 1999.[23] The table indicates that at a wellbore pressure of 10,000 psi, the required pressure to shear 5", S-135 pipe is 3,368 psi, within the shearing capabilities of the blind shear rams. The drill pipe on the DWH was 5.5", not 5", and the November 3, 1999 Progress Meeting minutes contain an "Action Item" of "Revised Shearing Capability Chart to be provided by Cameron."[24] This action item was on the Progress Meeting minutes for November 10,[25] and on November 17, the Progress Meeting minutes contained an entry that "Shear capability chart to be provided via e-mail to everyone" as Cameron's responsibility.[26] On the same day, John Kotria of Cameron distributed a shear chart via email that showed the same shear pressure requirement of 3,368 psi for 5.5" S-135 drill pipe at 10,000 psi.[27]

The Progress Meeting minutes for November 24 and December 1, 8, and 15 each contain entries that state "Shear chart to be updated with 5" pipe," and list Cameron as responsible for

[22]BP-HZN-2179MDL01155528 at 535.

[23]BP-HZN-2179MDL01155528 at 5979.

[24]BP-HZN-2179MDL01155528 at 5922-23.

[25]BP-HZN-2179MDL01155528 at 5916-917.

[26]BP-HZN-2179MDL001155528 at 903-904.

[27]BP-HZN-2179MDL001155528 at 5913-15.

the action.[28] The Progress Meeting minutes for January 5, 2000 state, "Shear chart to be updated and redistributed with 5-1/2" pipe," with Cameron again listed as responsible for this action.[29] The Progress Meeting Minutes for January 12, 2000 state "Shear chart to be updated and redistributed with 5-1/2 38# pipe info," with Al Sheppard of Cameron having responsibility for the action.[30]

The minutes from the January 19, 2000 meeting state "Shear chart has been updated and redistributed with 5-1/2" 38# pipe," which is a heavier pipe than used on the DWH on the day of the incident.[31] The rig file does not contain the distribution of this table in connection with these minutes.[32] In the February 2, 2000 Progress Meeting minutes, one of the topics was "Shear chart current revision to be distributed via email," listing Cameron employee Irving Schneider as responsible and a due date of February 4.[33] The February 9 Progress Meeting minutes reflect that this action was completed, but do not include the updated chart.[34]

During the meetings discussed above, the participants also considered whether to design the system to provide 3,500 or 4,000 psi to the high pressure shear operator.[35] They ultimately chose 4,000 psi,[36] despite the increased challenges of fitting enough accumulator bottles on the stack. The only reason to provide 4,000 psi instead of 3,500 psi to the *SBR* high pressure shear operator is to increase shearing capacity. The DWH high pressure shear system had a supply

[28]BP-HZN-2179MDL01155528 at 5879-80; 5886-87; 5892-93; 5901-02.

[29]BP-HZN-2179MDL01155528 at 5849-50.

[30]BP-HZN-2179MDL01155528 at 5844-46.

[31]BP-HZN-2179MDL01155528 at 5790-91.

[32]At another place in the rig file, there is a shear chart that includes 5-1/2", 38 pound heavy weight drill pipe. The shearing pressure at 10,000 psi wellbore pressure on that chart is not legible. BP-HZN-2179MDL001155528 at 5632.

[33]BP-HZN-2179MDL01155528 at 5771-72.

[34]BP-HZN-2179MDL01155528 at 5769-70.

[35]For example, see BP-HZN-2179MDL01155528 at 56152-53.

[36]I am aware that the Plaintiffs in this case claim that BP was responsible for BOP design. While BP established certain functional specifications and reviewed certain design materials, the Progress Meeting minutes and other documents show that Cameron and Transocean had primary roles in designing the BOP and, especially with respect to Cameron, its components. M. Whitby, 7-19-2011 dep. tr. at 451:4-6 ("We design in accordance with 16A and the customer requirements as they're delivered to us"). In my experience, this is typical of the relationships between BOP manufacturers, who have design expertise; drilling contractors, who have operational expertise; and lease operators, whose requirements in specialized technical areas like blowout preventers are often based on more functional criteria.

pressure of 5,000 psi, used accumulator bottles rated for 6,000 psi, and a regulated supply to the shear rams of 4,000 psi.[37]

On March 1, 1999, in response to Transocean's request for proposals for the DWH rig BOP, Cameron submitted a quotation for a 15,000 psi rated lower BOP stack using Cameron's *SBR* model blind shear rams.[38]

0470
RAM SUBASSY, UPPER SBR 18-3/4" 15000 WP
'T' AND 'TL' BOP, API 16A, ABS AND
DNV CERTIFICATION, WITH CAMRAM PACKERS
AND TOP SEAL.

0480
RAM SUBASSY, LOWER SBR 18-3/4" 15000 WP
'T' AND 'TL' BOP, API 16A, ABS AND
DNV CERTIFICATION, WITH CAMRAM PACKERS
AND TOP SEAL.

The *SBR* model proposed by Cameron was ultimately used in the DWH's BOP. On the day of the incident, the blind shear rams in the DWH BOP were still Cameron's *SBR* model, which Cameron was still offering and selling to its customers.

4.2.3. Shearing Tests Performed by Cameron Demonstrated that the DWH Blind Shear Rams Could Shear 5-1/2" Drill Pipe.

4.2.3.1. April 2000 Shear Test.

On April 11, 2000, Cameron performed a shear test on 5-1/2" 24.7 ppf S-135 drill pipe, using the *SBR* blind shear ram blocks that were installed on the DWH BOP and pipe that would be used on the DWH.[39] This was in compliance with Cameron EB 702D's recommendation that shear testing using the actual BOP and tubular in question be performed.[40]

The April 11, 2000 test was attended by three representatives from RBF (Transocean), four from Cameron, and one from Vastar (BP).[41] The shear test used the same, if not slightly

[37] MDL Ex. 1164 at 38.

[38] MDL Ex. 4276 at TRN-HCEC-00077386.

[39] Although I do not discuss it here, Cameron and Transocean also conducted several successful tests of the DWH's casing shear rams. Vastar Rig Files Vol. 2, BP-HZN-2179MDL01155049 at 01155064; MDL Ex. 3951 at CAM_CIV_0223330.

[40] EB 702D, MDL Ex. 1199 at CAM_CIV_0003187.

[41] CAM_CIV_0025645-25660, at 25648.

heavier, drill pipe that was in the BOP during the April 20, 2010 incident. During this test the pipe sheared at a pressure of 2,700 psi.[42] After the shear, the *SBR*s were successfully pressure tested to 15,000 psi. Below is a summary from the testing report:

CAMERON

ENGINEERING REPORT ABSTRACT

REPORT NUMBER: 2728 DATED: May 17, 2000

TITLE: R&B Deepwater Horizon Project 18-3/4" 15M TL Super Shear Rams (SSRs) & Shear Blind Rams (SBRs) Shear Test

ABSTRACT: A set of 18-3/4" 15M TL SSRs and 18-3/4" 15M TL SBRs were shear tested in Cameron's Berwick facility in Louisiana. The SBRs sheared 5-1/2" OD, 24.7 lb/ft, S-135 drill pipe with a ram closing pressure of 2700 psi. The SBRs were pressure tested to low, 200-300 psi, and high, 15,000 psi, wellbore pressure to confirm the rams' seal integrity after shearing. The SBRs were in good condition after shearing the pipe and sealing wellbore pressure. The SSRs sheared two sizes

The 2,700 psi shear test result is slightly below the pressure that would be calculated from Cameron's shear formula, which is found in Cameron Engineering Bulletin ("EB") 702D (2,857 psi). Cameron's shear formula is deliberately conservative by using the maximum pressures that Cameron has recorded in its decades of testing:[43]

> What we wanted to do is we wanted to -- to look at the plot of all of the -- the shear tests that we conducted for a specific grade of pipe, and then we wanted our calculation not to estimate the mean. We wanted it to be at the top so that all the datapoints were -- were at or below that line.

Even though the 2,700 psi result from the April 2000 shear test is below the shear pressure in Cameron's EB 702D, it is still artificially high. This is because the 2,700 psi from the April 2000 test is only a measure of the ***ram closing*** pressure, not the ***net shearing*** pressure.[44] The shear rams close as hydraulic fluid presses on the close side of a piston. As the

[42]MDL Ex. 3951 at CAM_CIV_0223330; CAM_CIV_0025645-25660, at 25657. The text of the report in one place states that the shearing pressure was only 2,300 psi, but this appears to be an error. Based on the chart, the closing pressure at shear was 2,700 psi.

[43]D. McWhorter 7-8-2011 dep. tr. at 401:5-403:17.

[44]CAM_CIV_0025645-25660 at 25657.

piston moves, pressure on the other (open) side of the piston builds, which resists the closing pressure. This resisting pressure must be accounted for in order to accurately determine true shearing pressure.

In the below figure of the relevant portion of the DWH hydraulic operating system, the hydraulic fluid blue on the close side of the piston is shaded blue, and fluid on the open side of the piston is shaded red. As more fluid enters the blue close area from two inlets and moves the piston, fluid in the red open area is forced out through one outlet, causing resistance:

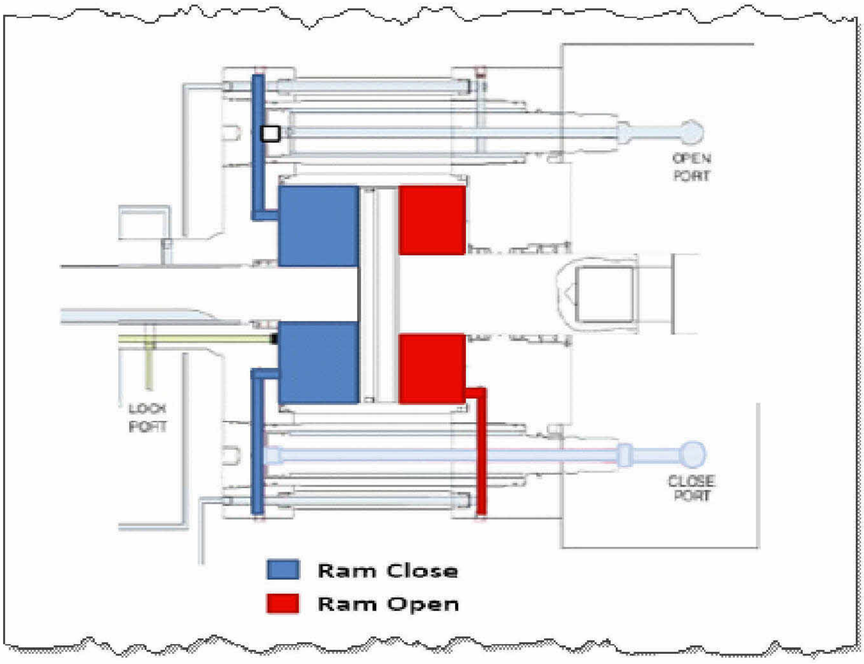

Figure 2 Blind Shear Ram Open and Close Hydraulic Diagram

Cameron's testing protocol for the April 11, 2000 shear test called for the opening line pressure to be measured and recorded, but this data was not included in the produced test report:[45]

> 2. The opening, closing, and wellbore pressure lines each shall be minimally equipped with a pressure gauge and connected to a chart recorder. Test pressures must be recorded during the duration of the shear test.

The pressure on the open side can be significant, and can offset the closing pressure from between several hundred psi up to more than one thousand psi. The below graph from a shear test of a high pressure test illustrates this point well. In that test the net shear pressure, after

[45] CAM_CIV_0025645-60 at 25655.

accounting for the open pressure, was 1,165 psi lower than the pressure on the shear close line only:

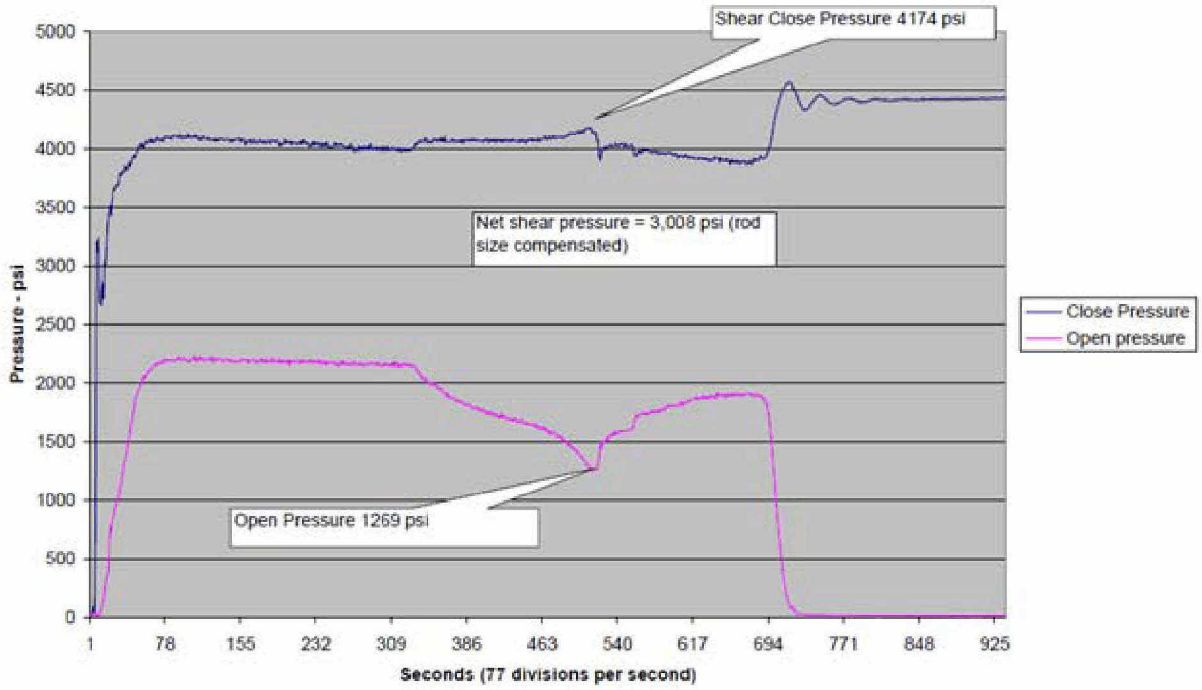

Figure 3 Example of Open Pressure During Shearing Test

The open side pressure in the above example was on a higher pressure system than the DWH, but I would still expect the open side pressure of the DWH to be several hundred psi.

4.2.3.2. August 1999 Shear Test

Cameron also reported the results of additional testing to Transocean and BP. The April 11, 1999 Progress Meeting minutes state that Cameron performed shear tests on 5-1/2" 24.7 ppf drill pipe in the Cameron test lab on August 6, 1999. This is the same pipe that was in the DWH BOP on the day of the incident. The pipe sheared at 2,178 psi:[46]

2. The following are the Shear Pressures required to shear on the surface using SBR'S based on the shear tests conducted on 8/6/99 at the Cameron test lab: 2178 Psi for 5-1/2" 24.7 lb/ft 3630 Psi for 5-1/2" 38 lb/ft RB Falcon to discuss the DMS with Vastar and finalize the accumulator bottle requirements for the stack by next meeting on 8/18/99.	RBF

[46] 8/11/99 Meeting Minutes, MDL Ex. 3951.

These results appear to be reasonable and consistent with accounting for open line pressure. Cameron's Director of Engineering Technology testified that customers ought to be able to rely on Cameron shearing tests as a validation that a blind shear ram can shear a certain type of pipe and seal the well.[47]

> **Q. So in that situation, users of the BOP should be able to rely on the fact that the BOP would, in fact, shear that pipe of casing, according to your shearing document?**
>
> A. It is a validation.
>
> **Q. Okay. And not only shear, but as long as it was that same quality, it ought to also seal?**
>
> (objection)
>
> A. The test procedure would involve a shear and a pressure test.
>
> **Q. Because that's what it's supposed to do, right?**
>
> (objection)
>
> A. That is the intent of the test.

This means that Cameron's shear test provided Transocean and BP with an understanding of the shear limitations of Cameron's *SBR* model blind shear rams. In my experience, this would be the sort of information that a drilling contractor and leasehold operator would rely upon for understanding shear limitations of the shearing rams.

4.2.3.3. September 2001 Shear Tests

As part of its rig acceptance audit for the *Deepwater Horizon*, BP required an additional shearing test beyond the April 2000 Factory Acceptance Test ("FAT"), using the combined DWH BOP and control system:[48]

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[47] M. Whitby 7-19-2011 dep. tr. at 521:9-22.

[48] TRN-MDL-01622406.

bp

Deepwater Horizon – Omission Profile
Integrated Acceptance Test

6th November 2002

REF	OBSERVATION	RECOMMENDATION	AUDIT TEAM ADVISED COMPLETION	ASSET ACCEPTANCE OR CHANGE	ACTUAL COMPLETION DATE	SIGNED OFF BY
[redacted]	The rig has not carried out drill pipe or casing shear tests on the combined BOP/BOP control system. Only FAT on the BOP has been carried out.	The rig must carry out successful BOP drill pipe and casing shear tests. Failure to do so imports an unacceptable business risk into BP's GoM deepwater business.	Prior to going onto the BP location *Rig crew after re-coil test*		09/20/01	DEC 7

The test protocol specified by Transocean called for the use of the DWH's 5-1/2" drill pipe.[49] The shear testing was completed on September 20, 2001.[50]

4.2.4. Transocean Had Policies Regarding Suitability of the BOP, Including Its Shearing Capability.

In addition to the drilling contract and the Progress Meeting minutes discussed above, there are other documents and testimony that indicate that Transocean had responsibility for the suitability of the BOP, including its shearing ability. For example, Geoff Boughton, Transocean's Subject Matter Expert for Subsea Systems and Equipment, testified that BP looks to Transocean and the BOP manufacturer for such information, which is consistent with my experience:[51]

> **Q. Or let me rephrase it. Do you look to BP for the shear calculations?**
>
> A. Normally, BP looks to us and the manufacturer for the shear calculations.

Transocean also has its own policies regarding well control and BOPs, and in my experience and opinion it is reasonable for BP to expect Transocean to comply with its policies. For example, Transocean's Well Control Handbook establishes certain BOP requirements, such as requiring that "[t]he pipe rams, shear ram, spool pieces, gate valves and any component attached to the BOP stack must have a working pressure rating that exceeds the maximum anticipated surface pressure under 'worst case' operating conditions."[52] Maximum anticipated

[49]MDL Ex. 4637; F01128-E05274830.

[50]TRN-MDL-01622406.

[51]G. Boughton 7-20-2011 dep. tr. at 66:1-5.

[52]Well Control Handbook, MDL Ex. 1454 at TRN-MDL-00287036.

surface pressure, or MASP, is a factor in considering the ability for a BOP to shear pipe and seal a well, and is a calculation that Transocean's Well Control Handbook states that it must perform.[53] I discuss the calculation of MASP in more detail later in the report.

Transocean's Handbook also provides requirements for the shearing capability of the blind shear rams, requiring that "[t]he blind/shear rams must be capable of shearing the highest grade and heaviest drill pipe on the rig (HWDP excluded) and sealing of the well in one operation."[54] It further discloses that Transocean's "rig personnel must known the capabilities (i.e., what size and grade of pipe can be sheared) and operating parameters of the shear rams installed in the rig's BOP stack."[55]

Although I have not seen information indicating that Transocean calculated the MASP for the Macondo well, as is required by its Handbook,[56] Transocean knew the MASP that was included in the Macondo APD,[57] and Paul Johnson, Transocean's Rig Manager Performance for the *Deepwater Horizon*, testified that that he did check the adequacy of the BOP against the anticipated pressures and temperatures of the Macondo well and that there were no issues:[58]

> **Q. So BP would provide you the maximum anticipated surface pressure and then you would evaluate whether or not the well control equipment would function within that range?**
>
> A. Yes.

There is no evidence that Transocean ever communicated to BP that the DWH's BOP did not satisfy Transocean's own requirements or that it was unsuitable for the Macondo well. Nor is there any evidence that Transocean had any conversations with BP recommending the use of different blind shear ram blades on the DWH's BOP.[59] Therefore, it was reasonable for BP to expect that Transocean's BOP met Transocean's policy requirements and was suitable for the Macondo well.

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[53]Well Control Handbook, MDL Ex. 1454 at TRN-MDL-00286798.

[54]MDL Ex. 1454 at TRN-MDL-00287041.

[55] Well Control Handbook, MDL Ex. 1454 at TRN-MDL-00286908.

[56]G. Boughton 7-20-2011 dep. tr. at 266:8-269:3; Well Control Handbook, MDL Ex. 1454 at TRN-MDL-00286777, 286797-99; MDL Ex. 3324 (forwarding Macondo APD with MASP calculations from Transocean's Senior Toolpusher to Assistant Driller).

[57] J. O. McWhorter 7-20-2011 dep. tr. at 297:9-15 (stating that reviewed Macondo well APD).

[58] P. Johnson 3-28-2011 dep. tr. at 392:24-395:20.

[59]B. Ambrose 7-19-2011 dep. tr. at 665:10-15.

4.2.5. Other Factors Support the Adequacy of the DWH BOP Design.

4.2.5.1. There Was a Successful EDS in June 2003.

The DWH's BOP was designed with an Emergency Disconnect Sequence ("EDS"), which performed a sequence of operations to shear the drill pipe in the BOP, seal the wellbore, and disconnect the LMRP from the lower BOP stack. The purpose of the EDS was to allow the rig to safely disconnect from the BOP stack if for some reason the rig was unable to maintain its location over the well.

In June 2003, the DWH rig successfully used the EDS system to shear drill pipe and disconnect from the lower BOP stack when the rig was unable to keep up with high winds and currents and began moving off location.[60] At the time the EDS was initiated, the blind shear rams sheared the drill pipe that was in the BOP and sealed the well.[61] Based on drilling reports from the date of the incident, I understand that the drill pipe that was sheared was 6-5/8", 33 ppf, S-135 drill pipe.[62] With this type of pipe and at the pressure conditions at the time of the EDS, Cameron's EB 702D predicts a shearing pressure of 4,519 psi using the pipe weight method and 4,881 psi using the pipe dimension method. Both of these predicted shearing pressures exceed the maximum shearing pressure of 4,000 psi available to the DWH BOP's blind shear rams. This again demonstrates the conservatism of Cameron's EB 702D calculation for shearing capacity.

4.2.5.2. Transocean Has Concluded That the DWH BOP was suitable for Macondo.

Transocean employee Bill Ambrose testified that Cameron designed the *SBR* blocks, and that Transocean believes the DWH BOP was suitable for Macondo:[63]

[60] MDL Ex. 1890; F. Abbassian 5-4-2011 dep. tr. at 630:11-631:18; R. Ezell 4-28-2011 dep. tr. at 582:2-584:14; TRN-MDL-00505381.

[61] TRN-MDL-00069825 at 832-33; TRN-MDL-00001641 at 677-78; BP-HZN-2179MDL00912924 at 988.

[62] TRN-MDL-00069825 at 832-33; TRN-MDL-00001641 at 677-78; BP-HZN-2179MDL00912924 at 988.

[63] W. Ambrose 7-18-2011 dep. tr. at 169:6-18.

> **Q. Does -- is Transocean aware of any evaluations of the suitability of the blind shear rams on the DEEPWATER HORIZON as it was designed?**
>
> A. We -- it was designed in accordance with API, so the design rests with Cameron, but it was designed according to the specification.
>
> **Q. Does Transocean have a position whether the blind shear rams on the DEEPWATER HORIZON, as designed, were suitable for use at the Macondo Well?**
>
> A. They were.

Transocean has also said:[64]

> **Q. I think we were on 29, and I was asking you whether Transocean was aware of any device or equipment that would have had a better chance than the DEEPWATER HORIZON's BOP assembly of controlling the influx of hydrocarbons from the Macondo Well.**
>
> A. No, I don't believe we know of any other equipment.

Because Transocean did not believe that there were any design problems with the DWH's BOP and that it was suitable for the Macondo well, I have seen no indication that Transocean warned BP of any issues with the BOP, including a warning that Cameron's *SBR* model blades had an issue shearing off-center pipe.

4.2.5.3. At the Time of the Incident, Cameron Still Offered the *SBR* Design.

At the time of the incident, Cameron's *SBR* design was a current model that was offered for sale by Cameron. Therefore, at the time of the incident, BP and Transocean would not have had any reason to think that the *SBR* design was obsolete or otherwise insufficient for the purpose for which it was purchased. Cameron still sells the *SBR* design that was used on the DWH's BOP and has not made any changes to the design. [65]

[64] W. Ambrose 7-18-2011 dep. tr. at 207:20-208:2.

[65] M. Whitby 7-18-2011 dep. tr. at 340:17-341:1.

4.3. Events During the Macondo Well Incident Regarding BOP Activation

On the day of the incident, the DWH had finished drilling the Macondo well, and for reasons beyond the scope of this report, hydrocarbons entered the wellbore and traveled towards the surface.

Based on data that is available, the BOP's upper annular was activated at 21:41 in response to mud overflowing onto the rig floor.[66] Drill pipe pressure data indicates that the upper annular remained engaged, without sealing the well, for approximately five minutes.[67] This condition would have resulted in the rapid erosion of the upper annular's elastomeric sealing element. Just before 21:47 the drill pipe pressure, which had been increasing due to the engagement of the upper annular, began to decrease. This likely represents the failure of the upper annular's sealing element, the reduced hydraulic pressure available to the upper annular due to VBR activation, or both. At approximately 21:47, the drill pipe pressure rapidly increased from 1,200 to 5,730 psi. This was likely the result of the upper and/or middle VBRs sealing around the drill pipe. The explosions occurred at 21:49, and the real time data feed ended around the same time. The following chart, based on the Sperry Sun data, identifies the events discussed above:

[66] Sperry Sun Pressure data, MDL Ex. 604; MDL Ex. 620; BP-HZN-BLY00061169; C. Pleasant 3-14-2011 dep. tr. at 81:19-83:2; DNV Report, MDL Ex. 1164 at p. 4, 27; DNV Report, MDL Ex. 1165 at p. F-142; BP Internal Investigation Report, Appx. W.

[67] Sperry Sun Pressure data, MDL Ex. 604; MDL Ex. 620; BP-HZN-BLY00061169.

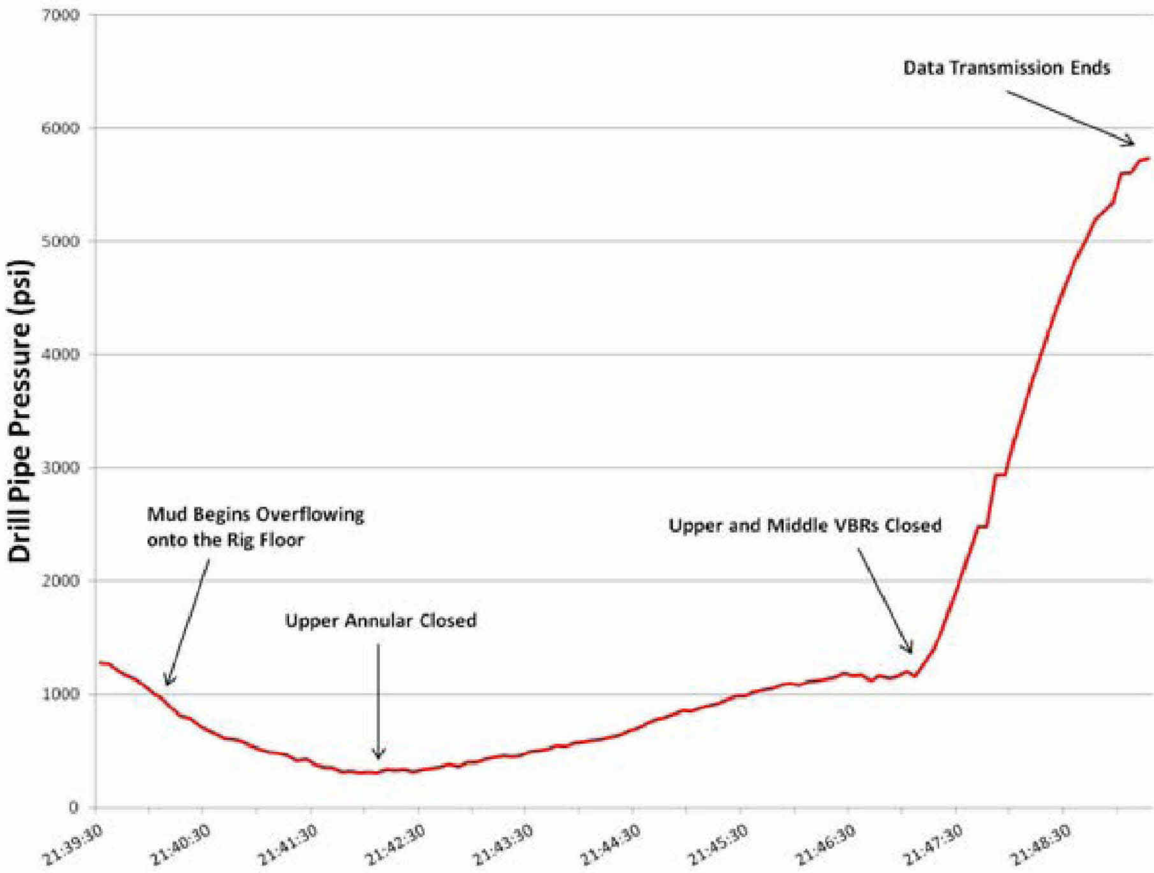

Figure 4 Sperry Sun Drill Pipe Pressure Data

Based on the testimony in this case, the recorded pressure readings from the drill pipe, observations during ROV interventions, and the condition of the BOP when it was retrieved, it appears that when the explosions occurred at 21:49, the upper annular, upper pipe ram VBRs[68] and middle pipe ram VBRs[69] were closed. The elastomeric element of the upper annular would have been significantly or completely eroded from the five minutes in which it was engaged but did not seal the well. The evidence does not indicate that any of the lower annular, casing shear rams ("CSRs") or blind shear rams were activated at the time of the explosions.

[68] The upper VBRs were found closed when the BOP was retrieved, and there is no way to close the VBRs through ROV intervention.

[69] During ROV intervention, the pressure increased immediately when the ROV first pumped hydraulic fluid into the middle VBR. DNV Appendix F, MDL Ex. 1165 at F-142; MDL Ex. 6138; BP-HZN-2179MDL02172464.

5. OPINIONS

5.1. The BOP Failed To Seal the Well During the Macondo Well Incident.

5.1.1. The Annular Failed to Seal the Well Because It Was Closed on a Tool Joint.

The first operation of the BOP by the Transocean rig crew in response to the blowout was to close the upper annular, which based on the Sperry Sun drill pipe data and hydraulic modeling occurred at 21:41. Based on the drill pipe pressure readings, the annular did not seal on the drill pipe, but continued attempting to seal for the next five minutes until 21:47. The reason that the annular did not seal is that there was a tool joint located in the annular, which prevented the annular from forming a seal around the pipe. Pictures from the forensic examination reveal that the tool joint in the upper annular contains significant erosion:

Figure 5 Picture of "Tool Joint A" and Upper End of Segment 1-B-1.

The upper annular was rated to a close pressure of 10,000 psi. If the tool joint was not located in the upper annular when it was activated, the annular should have closed in the well based on the pressures measured in the wellbore.

Transocean's drill crew should have positioned the drill pipe across the BOP stack to avoid a tool joint being across any of the BOP preventers, including the annulars. This is common industry practice. As discussed below, based on the available data and hydraulic analyses, the forces of the well from below were inadequate to push the drill pipe upward at the time the annular was closed. This means, in contrast to industry practice, Transocean's drill crew had positioned a tool joint across the upper annular, which prevented this annular from forming a full seal when activated during the Macondo well incident.

5.1.2. The Blind Shear Rams Failed To Shear the Drill Pipe and Seal the Well Because the Drill Pipe Was Located on the Side of the Wellbore.

As discussed below, several theories have been proposed regarding the timing and circumstances of the blind shear rams' activation on or after April 20, 2010. In any case, it is known that the blind shear rams were activated but did not shear the drill pipe and seal the well as intended.

The data from the forensic examination of the BOP and the pipe that was located inside of it at the time of the incident indicates that the pipe was off-center at the time that the blind shear rams were activated. Based on the DNV's forensic examination of the drill pipe and ram blocks, I agree with this conclusion. For example, the below alignment of the pipe that was across the blind shear rams, as well as the ram blocks themselves, strongly support the conclusion that the drill pipe was off-center when the blind shear rams were activated.

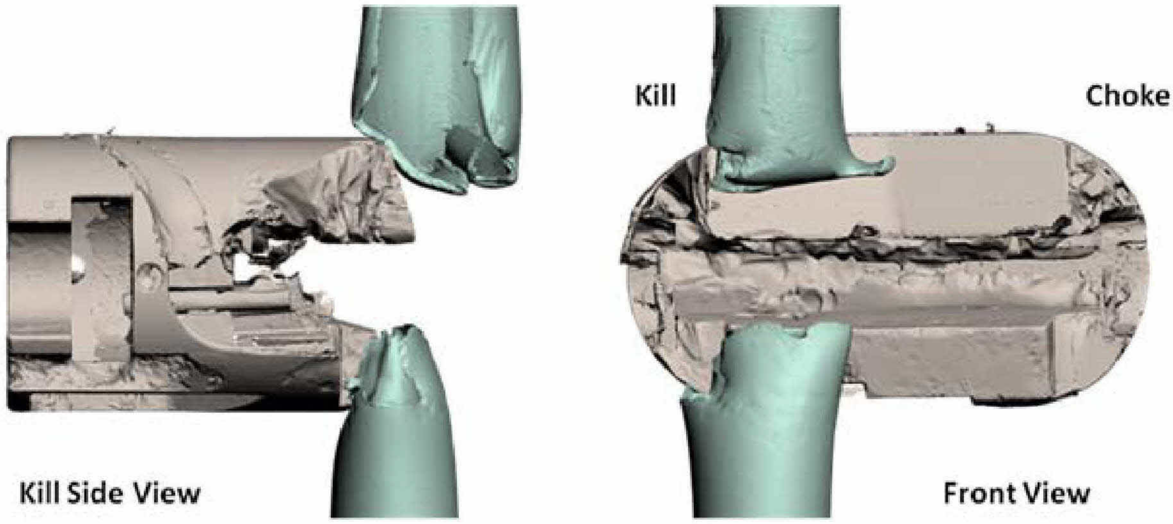

Figure 6. Pipe Segments and BSR Rams Indicate Off-Center Location

The drill pipe ends would look differently if they had been sheared by the blind shear rams as intended. Specifically, the pipe ends are not deformed as uniformly or symmetrically as would be expected if they had been sheared normally. This suggests an abnormal symmetry in the shearing force, which is explained by one side of the pipe being outside of the cutting surface of the ram blocks. They also lack the fold-over on the bottom segment in a normal *SBR* cut. The below images of drill pipe that has been sheared by Cameron blind shear rams illustrate the expected symmetry and fold-over [70]

[70]CAM_CIV_0335363.

Figure 7 Normal Shear: Ends Display Uniformity, Symmetry

Figure 8 Normal Shear: Lower Segment Contains Fold-over

The erosion patterns on the laser scanned images of the DWH *SBR* blocks also suggest that the pipe was located on the side of the wellbore. The below images of both blind shear ram blocks illustrate that the cutting surface of the bottom block extends further than that of the upper block.

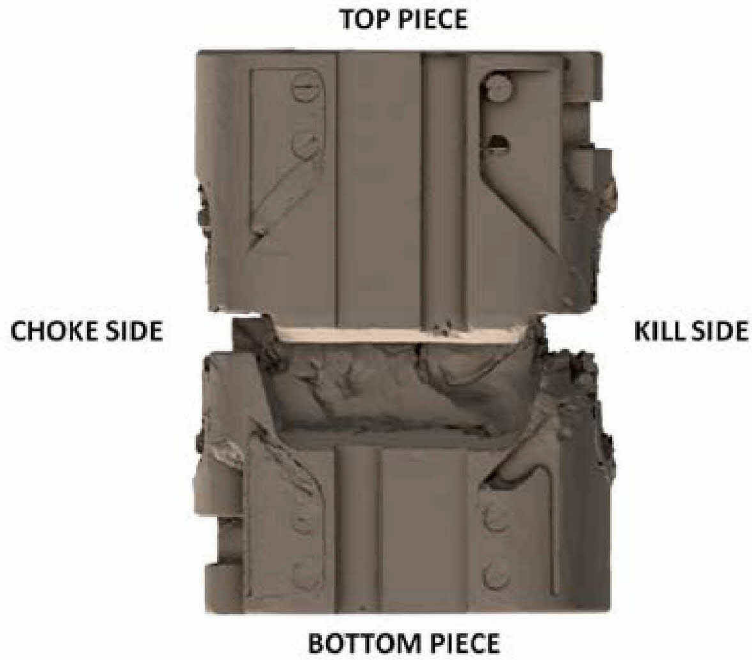

Figure 9 Closed DWH *SBR* Ram Blocks, Bottom View

In the below image of just the lower *SBR* ram, the shearing surface on the kill side, where the pipe was located, is completely eroded, while the shearing surface on the choke side has suffered some erosion, but is largely structurally intact. The pipe against the kill side would have constrained the flow and resulted in the greater erosion seen in the image:

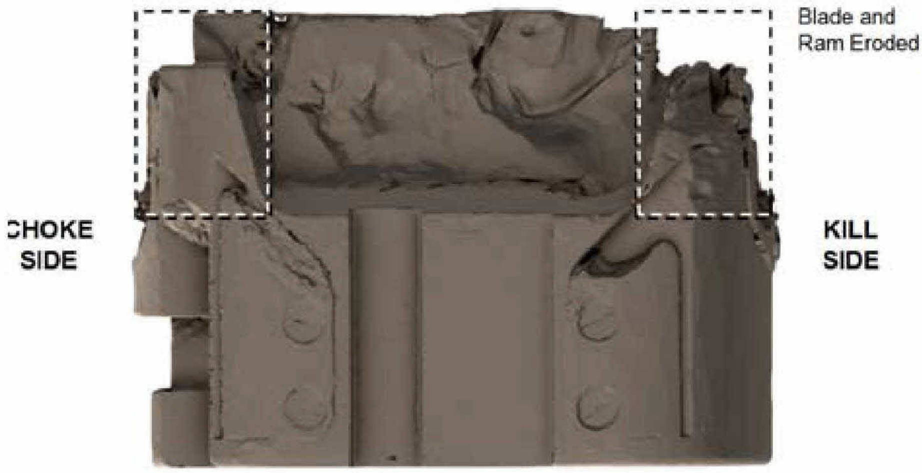

Figure 10 Lower DWH *SBR* Ram Block, Bottom View

It is my opinion that the BSRs did not shear the drill pipe and seal the well because the drill pipe was located at the side of the wellbore when it was sheared. The BOP wellbore was

18-3/4" in diameter. The cutting surfaces of Cameron's *SBR* model blades are 17-7/8" on the lower blade, and 15-1/4" for the upper blade.[71] This is illustrated by a view looking from above the *SBR* model blind shear rams:

Figure 11 DWH *SBR* Ram Blocks, Top View

Modeling performed by DNV, and which was relied upon by Mr. Childs,[72] indicates that the geometries of these cutting surfaces will result in an inability to shear drill pipe and seal the wellbore at the pressures stated by Cameron.[73] Even before compensating for wellbore pressure, the model predicts that with an off-center pipe, the *SBR* ram blocks will stall out 2.2" from closing at or before 5,280 psi is applied.[74] This is well above the shearing pressure advised by Cameron's EB 702D,[75] and more than the 4,000 psi available from the high pressure shear circuit.

[71]D. McWhorter 07-08-2011 dep. tr. at 709:14 to 710:20.

[72]Childs Report at 23.

[73]DNV Addendum at p. 21 ("With an applied equivalent pressure of 5,280 psi (which is greater than the available hydraulic pressure), the upper and lower BSR blocks were 2.8 inches from being fully closed.")

[74]Addendum to Final DNV Report, p. 21. Additional Finite Element Analysis modeling that I had performed confirms that the pressure needed to shear off-center drill pipe is substantially higher than the pressures advised by Cameron, and above the operating pressure limitations of the DWH's high pressure shear circuit.

[75] See discussion of shearing below.

5.1.2.1. The Drill Pipe Was Pushed Off Center by the Falling of the Traveling Block Assembly.

With the upper annular and upper VBR closed, the drill pipe would have been centered approximately 19.5 feet above and 7 feet below the blind shear rams.[76] Under these conditions (a 5-1/2" diameter drill pipe constrained at points approximately 27 feet apart), the segment of drill pipe located in the BOP would have been very rigid, and would have required a tremendous amount of force in order to locate the drill pipe against the wellbore at the blind shear rams. Although there was no significant force directly acting on the pipe in a radial (sideways) direction, the off-center location could have been caused by buckling as a result of pressure from an axial (above or below) direction.

Mr. Childs relies on DNV's calculation of the axial load required in order to induce the buckling that occurred.[77] The DNV report calculated the required force at 113,568 lbs.[78] DNV calculated that such a force would cause elastic (temporary) buckling that could have caused the drill pipe to be off-center in the blind shear rams.

The force that buckled the drill pipe, however, caused plastic (permanent) deformation of the drill pipe in at least segments 39 and 1-B-1. Laser scan images of both segments reveal a curvature in each of these segments.[79]

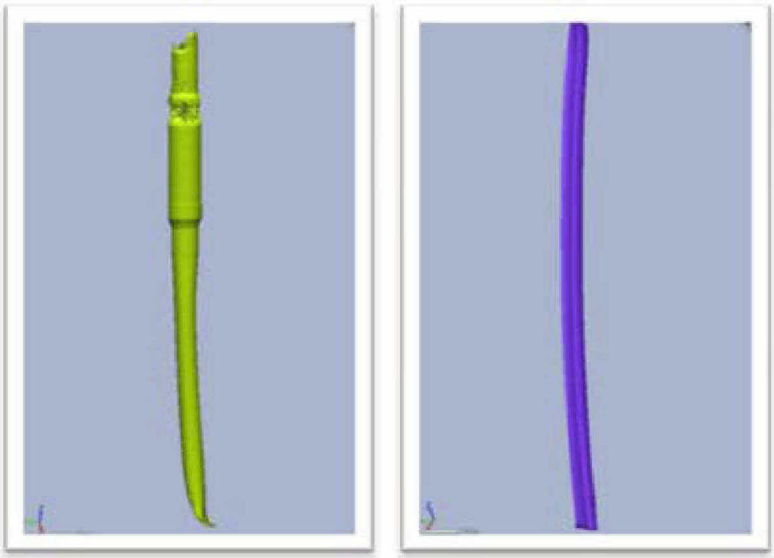

Figure 12 Laser Scan Images of Pipe Segments 1-B-1 (Left) and 39 (Right)

[76]BOP schematic, TRN-MDL-02170944.

[77]Childs Report at p. 14.

[78]DNV Report, MDL Ex. 1164 at p. 151. These calculations have been replicated with similar results.

[79]DNV Report, MDL Ex. 1164 at p. 91 (noting that "This segment of drill pipe [1-B-1] had a curvature in its length.")

As demonstrated in Figure 13 below, aligning segments 39 and 1-B-1 according to marks on the pipe where they separated, shows a continuous and significant curvature in the same direction, indicating that the deforming force affected the pipe above and below the upper annular.

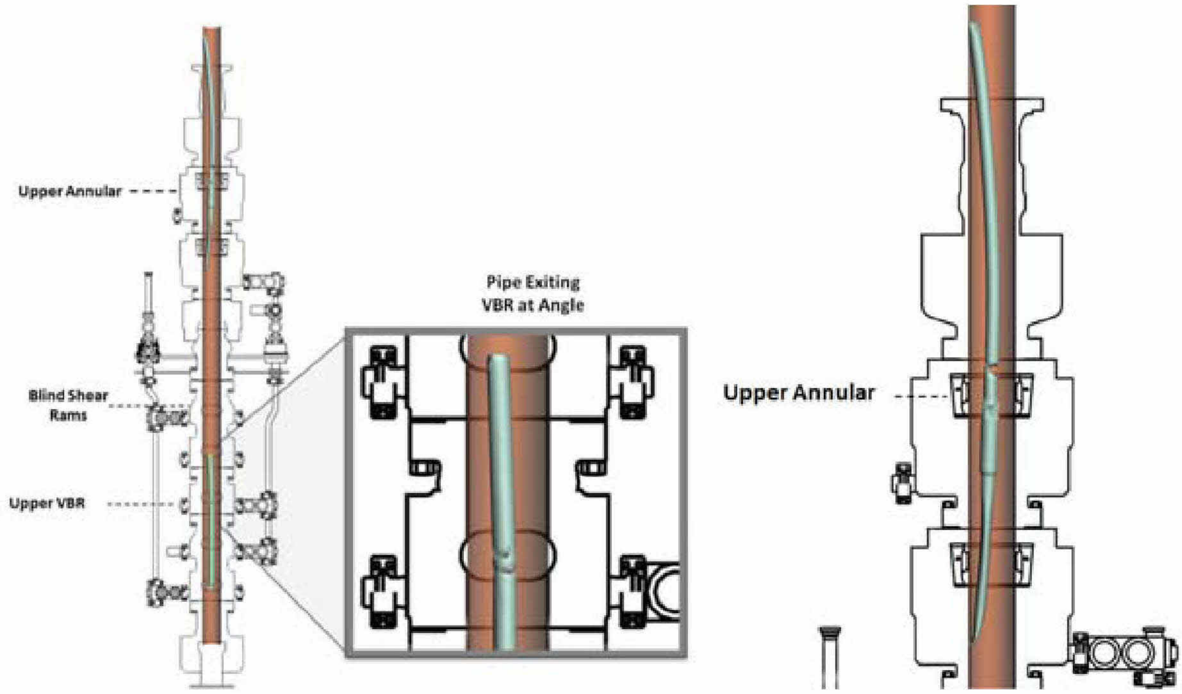

Figure 13 Pipe Segments 39 and 1-B-1 Aligned in the Wellbore

In my opinion, the likely source of such a force would have been the DWH's traveling block assembly falling. The traveling block is comprised of a set of large diameter sheaves and a large block and tackle pulley assembly that is suspended from the crown of the drilling derrick by 14-16 strands of heavy gauge steel cable. It also includes the top drive, which is the powerful motor used to turn the drill string during drilling operations. The lower portion of the top drive is attached to the top of the drill pipe. The traveling block assembly travels up and down on guide rails in the derrick. The DWH's traveling block assembly weighed approximately 190,000 lbs.[80] The below image shows the DWH's travelling block assembly inside the derrick.

[80]Sperry Sun data, MDL Ex. 604; BP-HZN-BLY00061169.

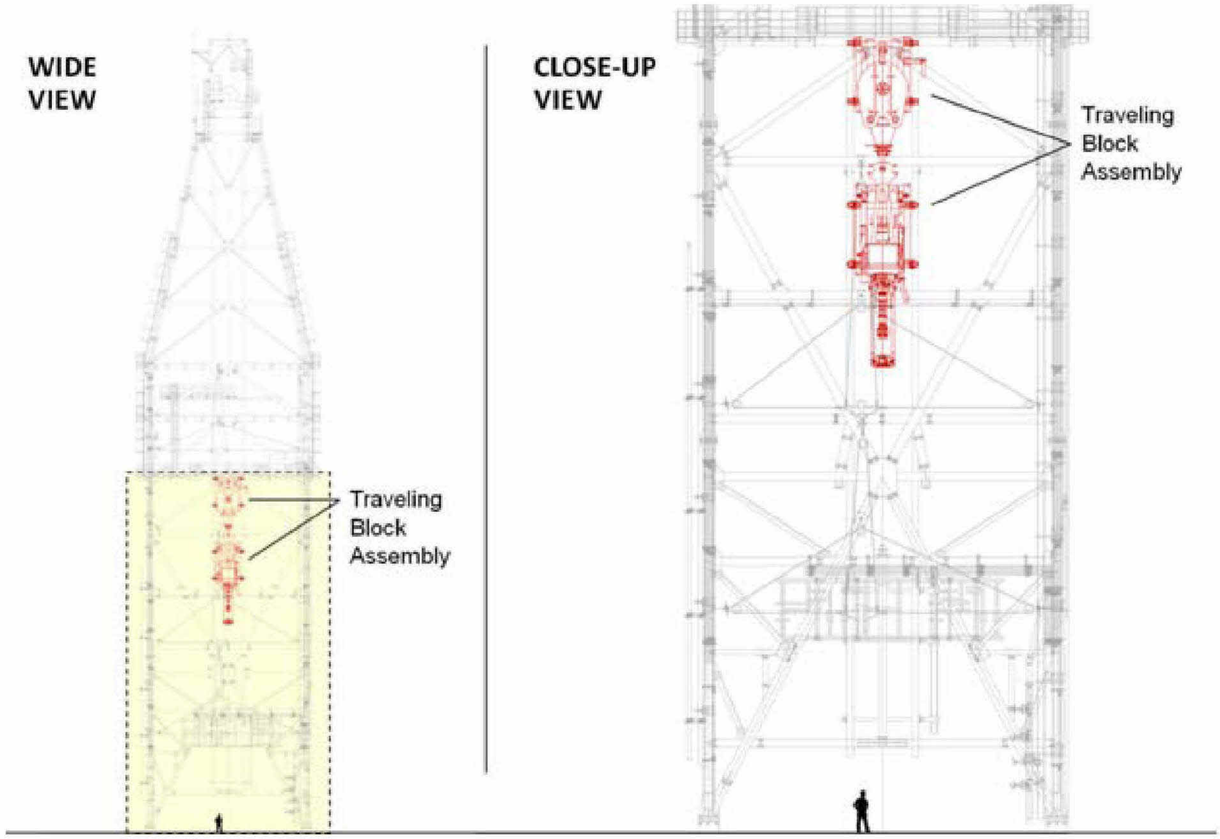

Figure 14 Schematic Drawing of DWH Traveling Block Assembly

Transocean employee Daun Winslow, an Operations Manager Performance who was on the DWH on April 20, 2010, testified that after the explosions, as people were boarding the lifeboats, he saw the traveling block assembly fall:[81]

[81]D. Winslow 4-20-2011 dep. tr. at 199:14-200:11.

Q. Now, was there a time that the top drive fell?

A. When we went down to the -- the lifeboats -- and, you know, I was looking back and I was just mesmerized by the magnitude of this fire. I -- you know, the -- on the right-hand side would have been the port lifeboat. There was somebody yelling, we got to get out of here, we got to get out of here. And I thought, we got plenty of time. And it was about that time that I seen the traveling blocks and equipment fall in the derrick. And the 100 feet of drill line, the two-inch drill line -- it's that big around, it's steel, you know, and it just unraveled. And the blocks fell down. You couldn't hear them falling over the noise, you know, with the drill string weight. And the blocks are probably 150', 160,000 pounds of steel, and it didn't make any noise. So at that time I said -- away you go is what I said. The port lifeboat launched.

The force of the travelling block falling would have been significant. The traveling block weighed approximately 190,000 lbs, and the drill string above the BOP weighed almost another 200,000 lbs.[82] The height of the block assembly was almost 27 feet above the drilling floor.[83] The riser, which was held in tension with the DWH, would have constrained lateral movement of the drill pipe so that, aside from the helical buckling of the pipe inside the riser, the downward force of the falling blocks and drill pipe would have been transferred down the drill pipe.

The closed VBRs would have provided substantial resistance to the force of the drill pipe and traveling block assembly. Forces at the VBRs resisting the downward pressure would have included the friction caused by the rams pressing the packers into the drill pipe (with sufficient force to seal the well), additional pressure and increased friction caused by the compression of the rubber packers due to the pressure differential above and below the VBRs, and any upward pressure on the pipe caused by the friction of the flowing hydrocarbons and the pressure below the VBRs. Calculations of the friction caused by the closed VBRs indicate that the closed upper and middle VBRs would have created frictional forces that would have resisted approximately 359,000 lbs of vertical force.[84]

In addition to the calculated resistance that the VBRs would have provided, the physical evidence indicates that the drill pipe located in the VBRs did not move substantially. Specifically, locations of the markings on the drill pipe from BOP elements match the dimensions of the BOP itself. This suggests that there was no substantial upward or downward movement of the pipe after the erosion caused by the upper annular.

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[82] As hydrocarbons rose through the wellbore and the riser, the hanging weight of the drill pipe would have increased due to the loss of buoyancy from the decreased density of the fluid inside of the riser and wellbore.

[83] Sperry Sun block position data, MDL Ex. 604; MDL Ex. 620; BP-HZN-BLY00061169.

[84] Appendix C provides a calculation of the frictional forces created by the VBRs.

5.1.2.1. The Theory That the Drill Pipe Was Forced Off-Center By a Force from Below Is Unsubstantiated.

I have reviewed the report of Transocean's expert, Greg Childs. Mr. Childs' report theorizes that a force from below caused the drill pipe to elastically buckle (the "force from below theory"), and as discussed below, force a tool joint of the drill pipe into the upper annular.

Mr. Childs' report states that before the incident, there was a tool joint just below the upper annular.[85] The report also states that right before the annular was closed, there was just enough frictional force from the well flow between the casing and the drill pipe to move the tool joint up and into the annular.[86] Once the upper annular was closed, Mr. Childs' report then theorizes that an upward force on the drill pipe was caused by the pressure from the well.[87] The report concludes that 113,000 lbs of axial force was required to buckle the pipe at the blind shear rams, when the pipe is centered at the upper annular and upper VBR. Mr. Childs' report calculates that the upward pressure on the drill pipe exceeded 150,000 lbs, but as will be shown below, was erroneously calculated.[88]

5.1.2.1.1. The "Force From Below" Theory Conflicts with the Physical Evidence.

One of the problems with the "force from below" theory is that it conflicts with the available physical evidence. As an initial matter, the "force from below theory" of Mr. Childs' report relies on the upper annular to provide the necessary resistance to the purported buckling force from below.[89] The curvature of segment 39, which was located immediately *above* the annular, shows that the buckling force that caused the plastic deformation was also present above the annular:

[85] Childs Report at 20. Annulars are not supposed to be closed on tool joints because, among other reasons, it is likely to form a poor seal.

[86] Childs Report at 20.

[87] Childs Report at 14.

[88] Childs Report at 14.

[89] Childs Report at 14, 21.

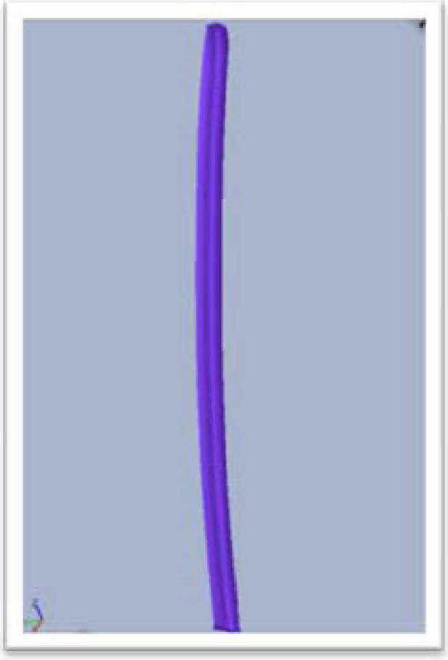

Figure 15 Plastic Deformation of Pipe Segment 39

Additionally, the calculations and models from Mr. Childs' report are for *elastic* buckling. As shown above, the drill pipe contains *plastic* deformation, which requires more force than elastic buckling. As discussed next, there was not enough force from below to make it past the closed VBRs even for elastic buckling, much less plastic deformation.

5.1.2.1.2. The "Force From Below" Theory Does Not Generate Enough Force from Below.

A significant problem with the "force from below" theory is that there was not enough force from below either to move the tool joint up into the annular (meaning that the tool joint was already improperly positioned there when the kick began), or to buckle the pipe once the VBRs were closed.

According to the calculations submitted with Mr. Childs' report, 51,000 lbs of upward force was required to lift the drill pipe one foot at the BOP.[90] To show this force, Mr. Childs' report presents a table that shows axial force, which they calculate as a function of the quantity of flow and pressure drop.[91] The axial force chart shows that between "minute 4" and "minute 5," which corresponds with 21:43 to 21:44, the axial force became enough to lift the drill string

[90] Childs Report at n. 37; Stress Engineering Services, Inc, *Hydraulic Analysis of the Macondo Well Prior to the Incident of April 20, 2010*, Rev. 1, April 27, 2011, at Appx. G, p. 141.

[91] Stress Engineering Services, Inc, *Hydraulic Analysis of the Macondo Well Prior to the Incident of April 20, 2010*, Rev. 1, April 27, 2011, at Appx. G, p. 225-230.

into the annular.[92] However, as illustrated in the below figure, drill pipe pressure data indicates that by 21:43, the annular was already closed so tightly around the drill pipe that it was causing the well pressure to increase.

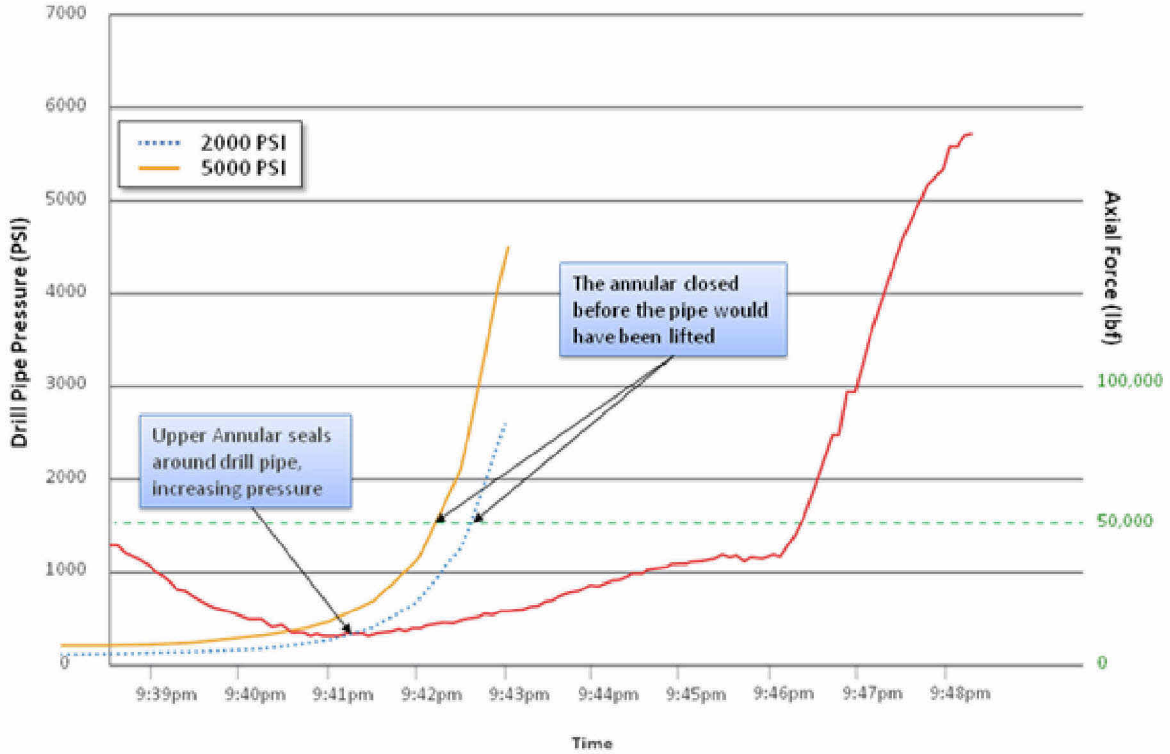

Figure 16 The Annular Closed Before Transocean's Predicted Lift

Additionally, there would not have been enough upward force to buckle the drill pipe after the VBRs were closed. As mentioned above, a minimum of 113,000 lbs of net upward force was necessary to sufficiently buckle the drill pipe. Mr. Childs calculates that the pressure differential above and below the VBRs resulted in approximately 166,000 lbs of upward force.[93] However, this calculation ignores the tremendous friction created by the closed and sealed

[92] Childs Report at Figure 15. The axial force charts of Mr. Childs' report stop at "minute 5" (21:44) even though the information from which the axial forces were derived (i.e., Stress Engineering's calculation of flow) go to "minute 8" (21:47). Stress Engineering Services, Inc, *Hydraulic Analysis of the Macondo Well Prior to the Incident of April 20, 2010*, Rev. 1, April 27, 2011, at Appx. G, p. 225-230. If the axial forces are calculated beyond "minute 5" (21:44) to "minute 8" (21:47), the axial forces would reach impossible levels (several million pounds of upward force). Because the axial force calculations result in impossible forces if extended even a couple of minutes in time, these calculations are unreliable.

[93] Childs Report at p. 26.

VBRs, which would have completely isolated the pipe above the VBRs from the axial forces below.[94]

According to Cameron's EB 859, the VBRs that were on the DWH can "hangoff" (*i.e.*, hold up) 350,000 lbs of force when closed on a 5-1/2" pipe and when a tool joint of the drill pipe is resting on the VBRs.[95] There was not a tool joint in the VBRs, but calculations of the friction caused by the closed VBRs on the drill pipe indicate that the closed upper and middle VBRs would have created frictional forces that would have resisted approximately 359,000 lbs of vertical force.[96] This amount of frictional force from the VBRs would have been more than enough to completely isolate the 166,000 lbs of force from below. In sum, because the closed VBRS would have prevented any transfer of force from below the VBRs to the drill pipe above the VBRs, the force from the well could not have buckled the drill pipe above the closed VBRs.

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[94] Stress Engineering's report, referenced in Mr. Childs' report, expresses that it assumes zero friction at the VBRs. Childs Report at p. 14, Figure 9; Stress Engineering, Structural Analysis of the Macondo #252 Work String, May 26, 2010, p. 28 ("The seal is assumed frictionless and does not provide vertical restraint.")

[95] CAM_CIV_0270293 to 299, at 297.

[96] See the attached Appendix C.

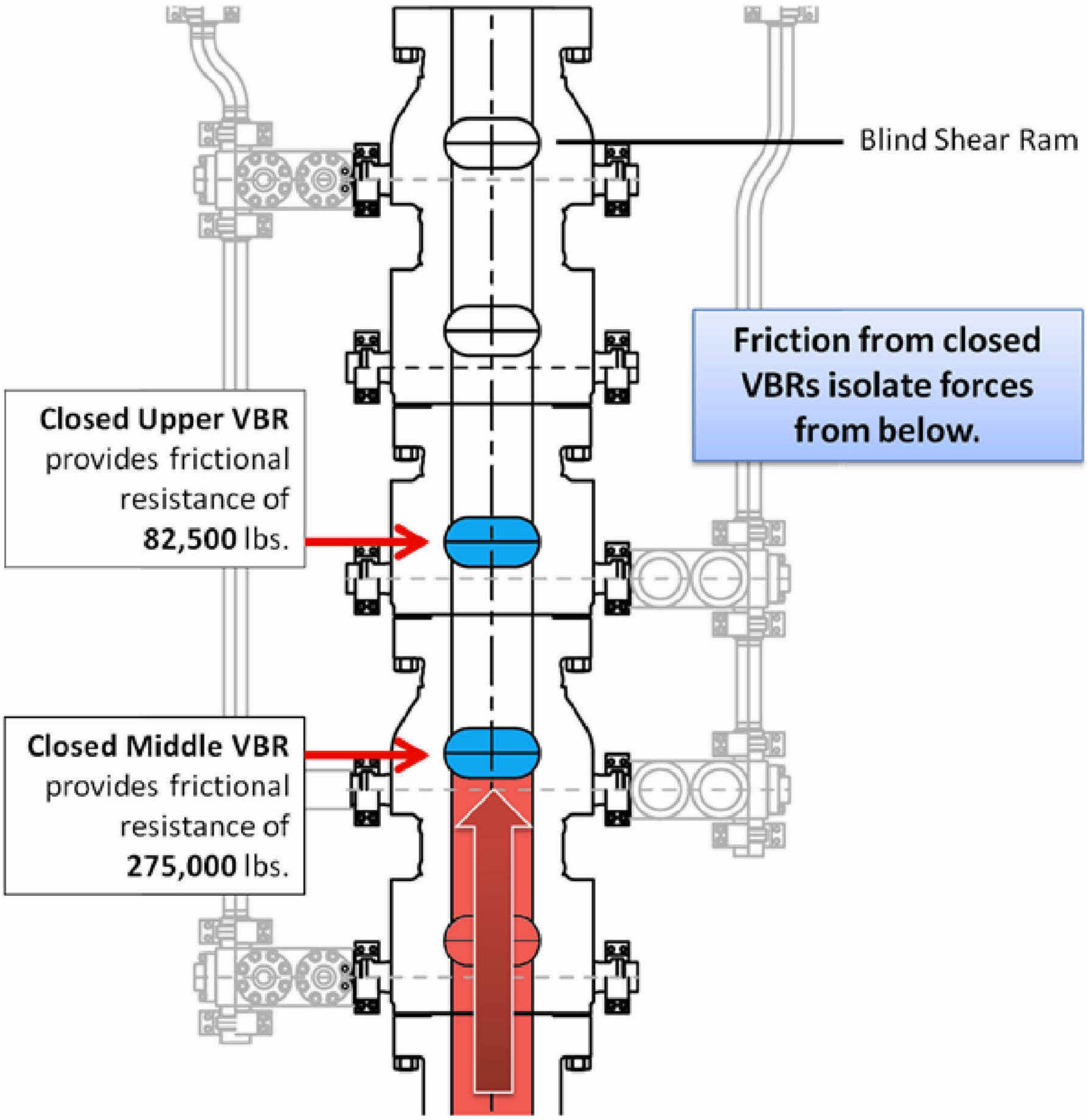

Figure 17 Friction from Closed VBRs Isolated Force from Below

5.1.2.2. Drag Load Charts of Mr. Childs' Report Confirm That There Is Not Enough Force to Support the "Force From Below" Theory.

The Stress Engineering analysis that Mr. Childs' report relies upon contains drag load charts that show the compressive force experienced by the drill pipe after the annular and VBRs are closed. This was done to determine the available force to buckle the drill pipe between the upper annular and upper VBR.[97] Stress Engineering did not need to use the five scenarios it used in its drag load charts, however, because the force at depth 0 ft, meaning the force at the rig, is

[97] Stress Engineering, Inc: Structural Analysis of the Macondo #252 Work String at 7.

known. Specifically, this force at the rig is the tension measured by the hook load. In the chart below, which shows drag loading prior to closure of the VBRs, I have added a red line that shows the proper load based on the known weight of the hook load at the surface:

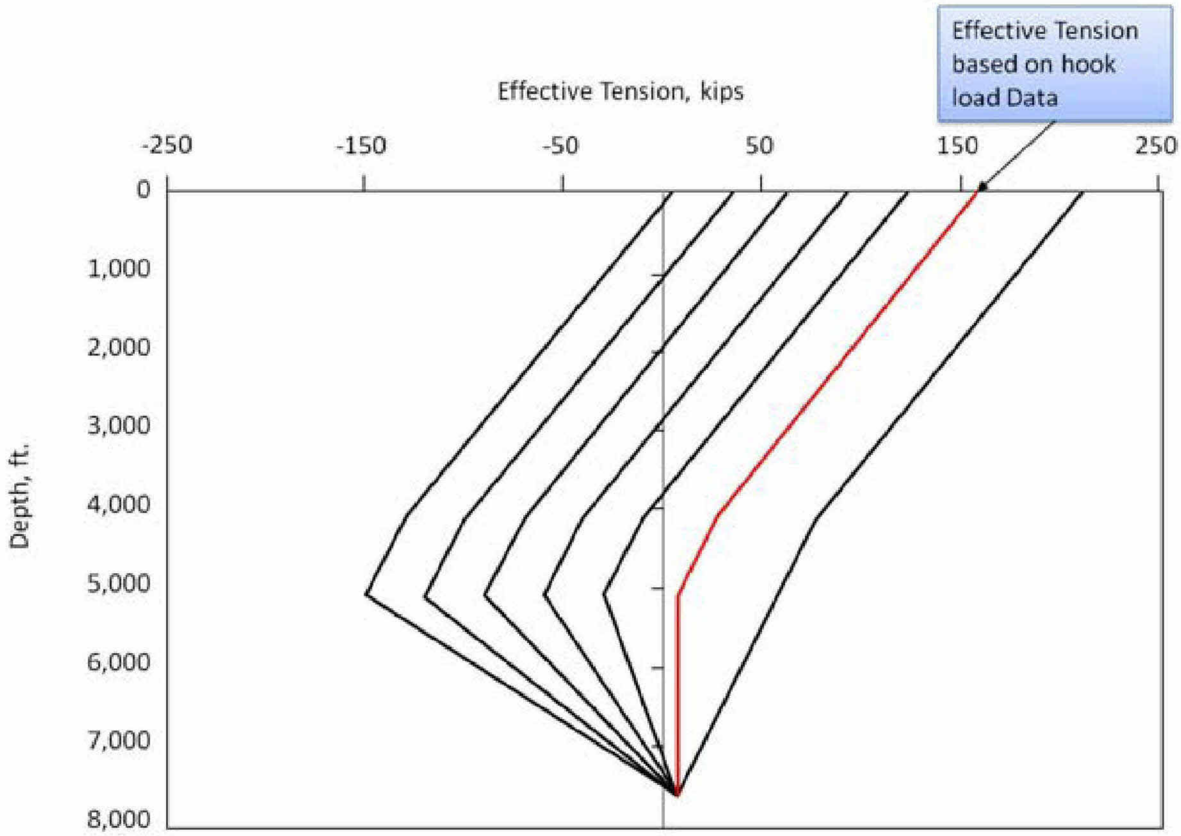

Figure 18 Recreation of Stress Engineering's Effective Tension Graph

At the time that the Sperry Sun data was lost, the hook load was measured as approximately 350,000 lbs.[98] Subtracting off the known weight of the traveling block assembly, which was approximately 190,000 lbs,[99] the downward force experienced at the top of the drill string was approximately 160,000 lbs. This means that the effective tension at depth 0 ft was approximately 160,000 lbs. Using 160,000 lbs as the proper basis for the drag load charts confirms that the tension experienced in the pipe at the BOP was not even negative, much less the minimum -50,000 lbs (-50 kips) needed to lift the drill pipe into the annular.

Using the same starting point in the below chart, which shows drag load after closing the VBRs, it is confirmed that under Transocean's theory and models, the required 113,000 lbs that it claims is necessary to buckle the pipe between the annular and VBR was not present.

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[98] Sperry Sun data, MDL Ex. 604; MDL Ex. 620; BP-HZN-BLY00061169.

[99] Sperry Sun data, MDL Ex. 604; BP-HZN-BLY00061169.

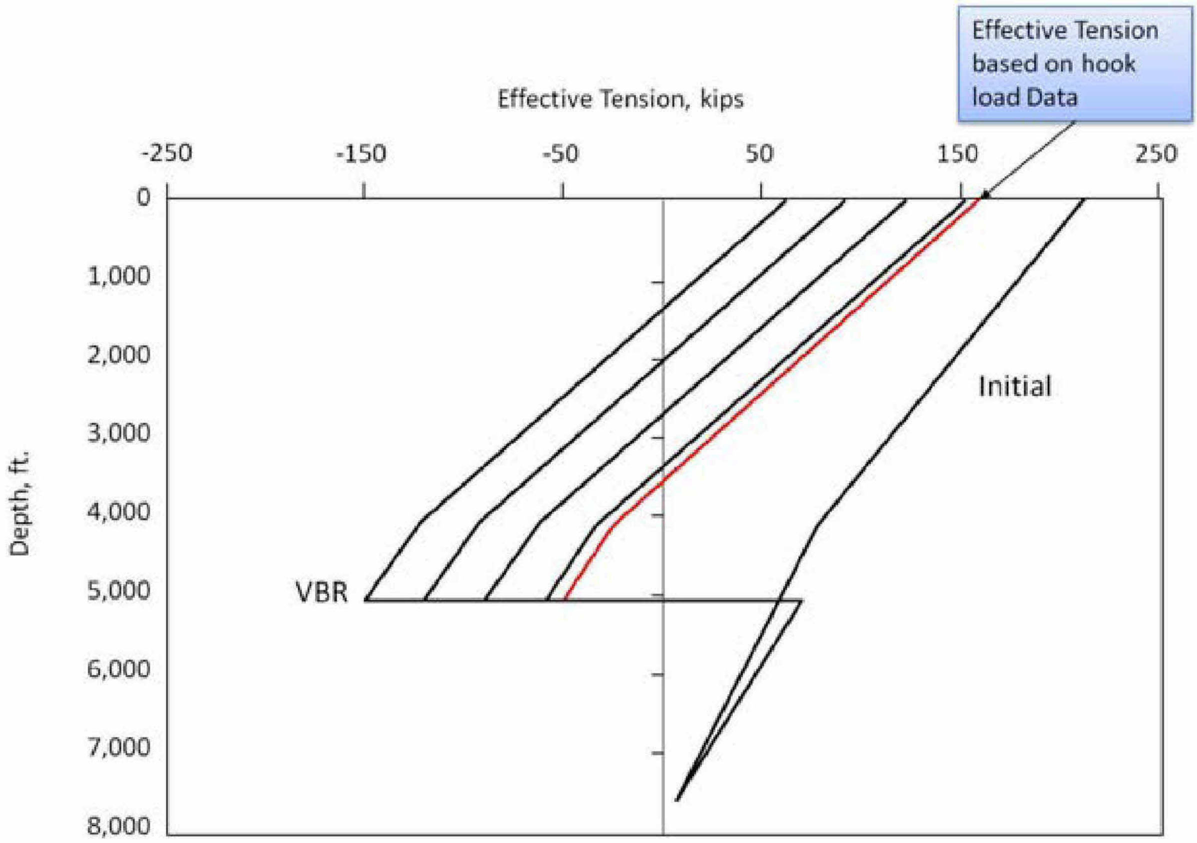

Figure 19 Recreation of Stress Engineering's Effective Tension Graph

5.1.2.3. The Rig Drift Theory Does Not Adequately Explain the Buckled Drill Pipe.

Dr. Rory Davis' report, submitted on behalf of the United States, theorizes that the drill pipe was buckled due to the DWH drifting off location after the explosions destroyed the engines and the DWH's ability to maintain position.[100] This rig drift theory, however, does not take several factors into account, and does not reconcile with the available evidence.

As an initial matter, the rig drift theory does not explain the plastic deformation in the drill pipe. Additionally, this theory only discusses the relatively longer distance between the blind shear rams and the upper annular (20 feet), but does not take into account the centering force of the much shorter distance (7 feet) between the blind shear rams and the upper VBRs. The rig drift theory also does not take into account the rigidity of the drill pipe located between the upper annular and upper VBRs that would result from being centered at those locations.

To be plausible, the rig drift theory requires that the blind shear rams closed on April 22, when the Autoshear pin was cut. At the time that the AMF/Deadman fired (the other event that has been theorized as to when the blind shear rams closed), the DWH would not have drifted a

[100] Davis Report at 14.

sufficient distance—*i.e.*, the explosions that would have satisfied the conditions for AMF/Deadman activation also caused the DWH to lose its engines and ability to hold position. ROV footage near the time of the Autoshear cutting shows that there was a substantial angle between the riser and the top of the BOP. The rig drift theory, however, does not explain how the angle of the pipe from the riser (20 feet above the blind shear rams) would have caused the pipe at the blind shear rams to be sufficiently off-center when the pipe was centered 7 feet below at the upper VBR.

The rig drift also does not account for the condition of the pipe above the upper annular, which would have been severely eroded and possibly separated.[101] This severe erosion would have reduced or eliminated the ability of the DWH or the drill pipe above the annular to affect the positioning of the pipe below the annular.

5.2. The Design of the BOP Was Adequate for the Macondo Well.

At the time the DWH was designed and built, Cameron was widely considered by many BOP experts, including myself, as the premier BOP manufacturer in the world. As I discussed earlier, the DWH BOP used an industry standard configuration, and many of its components were rated at the highest pressures available.

5.2.1. The DWH BSRs Could have Sheared the Pipe and Sealed the Well if the Drill Pipe Had Been Centered

Cameron's EB 702D provides a formula for determining the shear pressure required to shear specific sizes and grades of drill pipe at a given wellbore pressure.[102] This formula "is derived from the **maximum** recorded shear force that Cameron has experienced in a test environment for a given drilling tubular size and material designation."[103] Cameron has also explained that this calculation is conservative and it expects actual shearing pressure to be lower than what is calculated.[104]

If the drill pipe had been centered in the wellbore, Cameron's *SBR* model blind shear rams should have sheared the pipe and sealed the well. In the below sections, I explain why the Cameron *SBR* model blind shear rams were capable of shearing centered drill pipe at either of the two times at which it has been suggested that the blind shear rams closed: upon satisfaction of the AMF/Deadman conditions, and the cutting of the Autoshear pin (which I conclude is when the blind shear rams closed).

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[101] Based on a visual examination of images of the bottom section of segment 39, the pipe experienced a tensile fracture, followed by substantial pressure that curled a portion of the broken segment inward. The DWH sank hours after the Autoshear pin was cut.

[102] EB 702D, MDL Ex. 1199 at CAM_CIV_0003184.

[103] Product Advisory #12114 - EB 702D Update, MDL Ex. 3168 (emphasis in original).

[104] D. McWhorter 7-8-2011 dep. tr. at 676:6-20; M. Whitby 7-18-2011 dep. tr. at 324:7-22.

5.2.1.1. The Cameron *SBR* Model Blind Shear Rams Could Have Sheared the Drill Pipe if the AMF/Deadman Had Operated.

Mr. Childs' report states that the AMF/Deadman fired after the explosions at 21:49. At that time, drill pipe pressure data and other evidence shows that the VBRs had sealed the annulus, isolating the BSRs from the pressure below. The wellbore pressure at the blind shear rams at that time is believed to be slightly over 1,000 psi based on Transocean's calculation of the density of fluid in the riser.[105] Under these conditions, because the weight of seawater (8.54 ppg) is greater than the weight of the fluid in the riser, the pressure advised by Cameron EB 702D to shear at the BOP would be 176 psi ***less*** than the pressure advised for shearing at the surface with no wellbore pressure.[106] Notably, if the AMF/Deadman had activated immediately after the explosions as designed, the drill pipe would have been centered, because it would not yet have been forced off-center by the traveling block and drill pipe falling.[107]

Using Cameron's calculations from EB 702D, the required pressure for shearing the pipe under these circumstances would be 2,681 psi (2,857 psi -176 psi).[108] Using the April 2000 shear test from the DWH, the estimated pressure needed for shearing would be 2,524 psi (2,700 psi -176 psi). As discussed below, both of these numbers are well within the maximum pressure that was supplied to the Cameron *SBR* model blind shear rams (4,000 psi). According to

[105] Childs Report at footnotes 37-39 (citing to Stress Engineering Services Inc. Hydraulic Analysis of Macondo #252 Well Prior to Incident of April 20, 2010, Revision 1, April 27, 2010 at pp. 141-142, Appendix C, and 144 respectively.) The Stress Engineering analysis calculates a hydrocarbon density of 3 ppg (pp. 139 and 144) when the VBRs were closed, and that hydrocarbons reached the top of the riser at 21:47 (p. 139). The BP Incident Investigation Team's modeling of well conditions calculates a similar wellbore pressure. *See* BP Incident Investigation Report, Appendix W, *Report-Dynamic Simulations Deepwater Horizon Incident BP*, at Fig. 3.35 (showing "Pressure Above BOP" at 21:50 just above 1,000 psi, and falling fast.)

[106] Hydrostatic head of water at 5,000 feet minus hydrostatic head of fluid in the riser divided the closing ration (6.7) = approximately 176 psi in the open direction.

[107] When the explosions on the rig occurred, they severed the MUX cables which provide electrical communications and power from the rig to the BOP control pods. The MUX cables, as is normal on most rigs, were routed through the moon pool area. Because the MUX cables were severed from the explosions in the moon pool, the conditions for activation of the AMF/Deadman system were satisfied. It has been suggested that the MUX cables should have been protected from explosions or routed through another area of the rig to avoid potential explosions in the moon pool area. However, protecting the MUX cables from an explosion by rerouting them or protecting them in an enclosure would defeat the purpose of the AMF/Deadman system, which is to ensure automatic closure of the blind shear rams in an emergency event. If the cables had been intact when the rig crew attempted to activate the EDS, the blind shear rams would have closed, but it cannot be expected that after an explosion that the crew would be able to activate the EDS. Instead, the AMF/Deadman system is designed to ensure the blind shear rams close in such an event. Further, with respect to running the MUX cables through the moon pool, the MUX cables must be routed through the moon pool to connect to the riser, which supports the weight of the cables. I am not aware of any rigs that route the MUX cables in any way other than through the moon pool, and thus this is industry practice.

[108] The calculation that achieves this result is discussed earlier.

Cameron documents, the actual pressure needed would be even less, however, because internal pipe pressure "will reduce the required shearing pressure by the introduction of hoop stresses."[109]

Transocean witnesses also testified that the blind shear rams could have sheared the pipe in the BOP at the time of the incident. Geoff Boughton, Transocean's Subject Matter Expert, subsea Equipment, testified that "the drill pipe in the BOP at the time was shearable by the blind shear rams."[110] Bob Walsh, an engineer in Transocean's new builds group and a member of its investigation team, testified similarly:[111]

> **Q. Did the Drill Team do any modeling or analysis to evaluate whether the blind shear rams could have sheared the drill pipe on April 20th if it had not been off-center and outside the shearing zone?**
>
> A. Yes.
>
> **Q. And what was the conclusion of the Transocean Investigation Team?**
>
> A. Shearing -- shearing calculations were done that indicated we would have sheared the pipe.

5.2.1.2. The Cameron *SBR* Model Blind Shear Rams Could Have Sheared the Drill Pipe When the Autoshear Pin Was Cut.

On April 22, 2010, at approximately 07:48, the Autoshear pin on the DWH BOP was cut during ROV intervention efforts. The Autoshear system was designed to activate the blind shear rams upon unintentional separation of the LMRP from the lower BOP, and the cutting of the Autoshear pin manually activated this system. As I discuss above, the evidence indicates that this was the point when the blind shear rams were first activated and closed.

After the explosions on the rig at approximately 21:49 on April 20, 2010, the EDS button was pushed on the bridge.[112] However, there is no evidence the EDS system was actually activated because the LMRP did not disconnect from the lower BOP stack at this time. I understand that deficiencies with both of the control pods of the DWH BOP prevented the AMF/Deadman system from activating the blind shear rams, when the conditions for activation of this system were satisfied shortly after the first explosions on the rig.

Additionally, as discussed above, because the drill pipe would have been centered when the AMF/Deadman conditions were met of the evening of April 20, before the traveling block

[109] CAM_CIV_0334582 at 4765.

[110] G. Boughton, 7-20-2011 dep. tr. at 109:5-11.

[111] R. Walsh, 8-24-2011 dep. tr. at 173:5-15.

[112] C. Pleasant 3-14-2011 dep. tr. at 55:6-58:10.

fell, and given that the system had sufficient shearing pressure, the blind shear rams should have sheared the pipe and sealed the well if they were activated at this time.

The cutting of the Autoshear pin was the next opportunity for the blind shear rams to fire, and the evidence indicates that this is when these rams actually closed. First, numerous eyewitnesses of the live ROV feed when the Autoshear pin was cut reported seeing the BOP stack move immediately after the pin is cut.[113] I have watched the ROV videos and have seen the same movement.[114] This movement would have been the result of the release of thousands of pounds of pressure when the blind shear rams are activated.

Mr. Childs' report challenges that the blind shear rams were closed by the activation of the Autoshear pin. He bases this claim on the fact that he did not observe the approximately 30 gallons of hydraulic fluid that would have been released with a blind shear ram activation. Mr. Childs' source is the ROV footage from the Autoshear pin cutting operation.[115] Figure 20 below shows the ROV field of view at the time that the Autoshear pin was cut, as well as the location of the vent where the hydraulic fluid would have exited. The venting fluid would not have been seen in the ROV video because the location of the venting was outside of the ROV's field of view, on another side of the BOP. Also, the hydraulic fluid in the BOP was only slightly colored, would have exited the BOP away from where the ROV was located, and would have dissipated quickly.

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[113] A. Emmerson 9-28-2011 dep. tr. at 259:6-261:9; D. Winslow 4-20-2011 dep. tr. at 254:2-255:11; MDL Ex. 4794 at TRN-INV-02861650-51.

[114] Oceaneering Millennium 37 ROV video from April 22, 2010, BP-HZN-2179MDL03772302.

[115] Childs Report at p. 30.

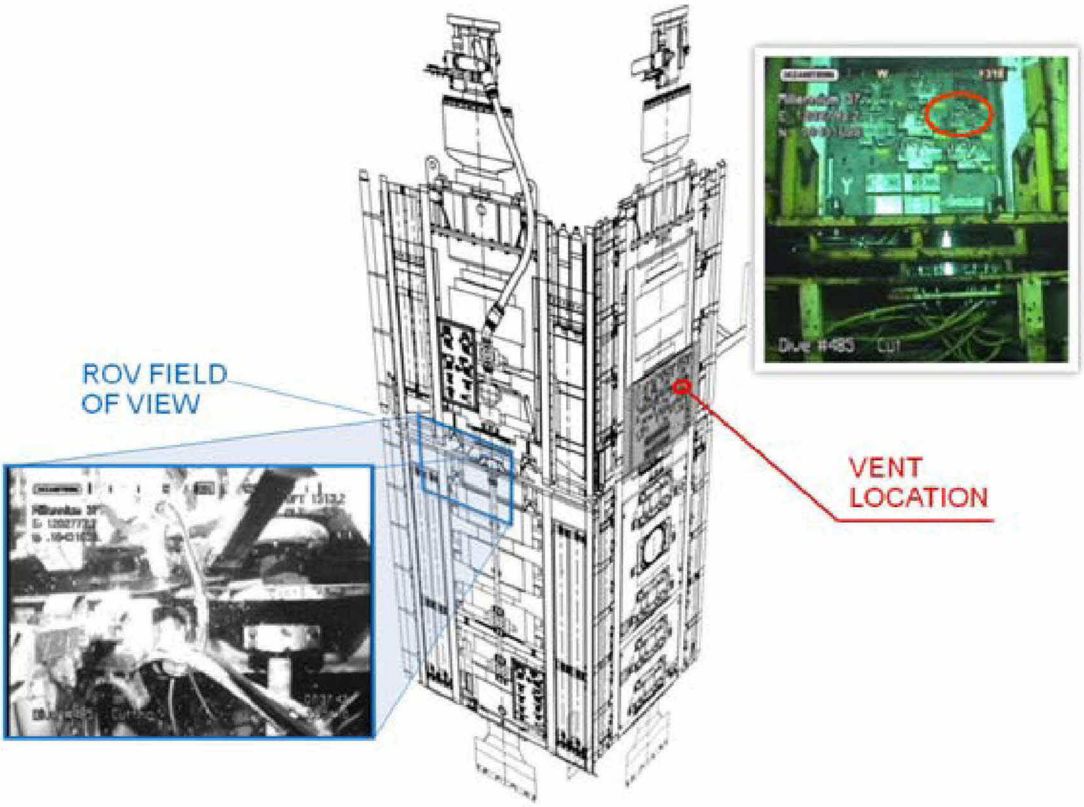

Figure 20 Location of ROV Field of View and Hydraulic Fluid Vent Location

Second, during later ROV intervention efforts the high pressure shear circuit close side pressured up immediately after leaks that were identified were fixed.[116] This also indicates that the rams were already closed.

If the VBRs were sealed against the drill pipe when the Autoshear pin was cut, the wellbore pressure would have been the same as when the AMF/Deadman conditions were met. The blind shear rams had more than the 2,681 psi advised to shear using Cameron's conservative EB 702D under these conditions.

If the VBRs were not sealed against the drill pipe when the Autoshear pin was cut, the wellbore pressure would have been approximately 8,300 psi, which would have corresponded with a pressure of 3,764 psi shearing pressure under EB 702D. Using the April 2000, 2,700 psi shearing test (which did not account for opening pressure), the required pressure would have been 3,564 psi. Using the August 1999 Cameron 2,178 psi shearing test that appears to have accounted for opening pressure, the required pressure would have been 3,190 psi. The figure below shows these shearing pressures.

[116] MDL Ex. 6138; DNV Report Appendix F at F-134 - F-137.

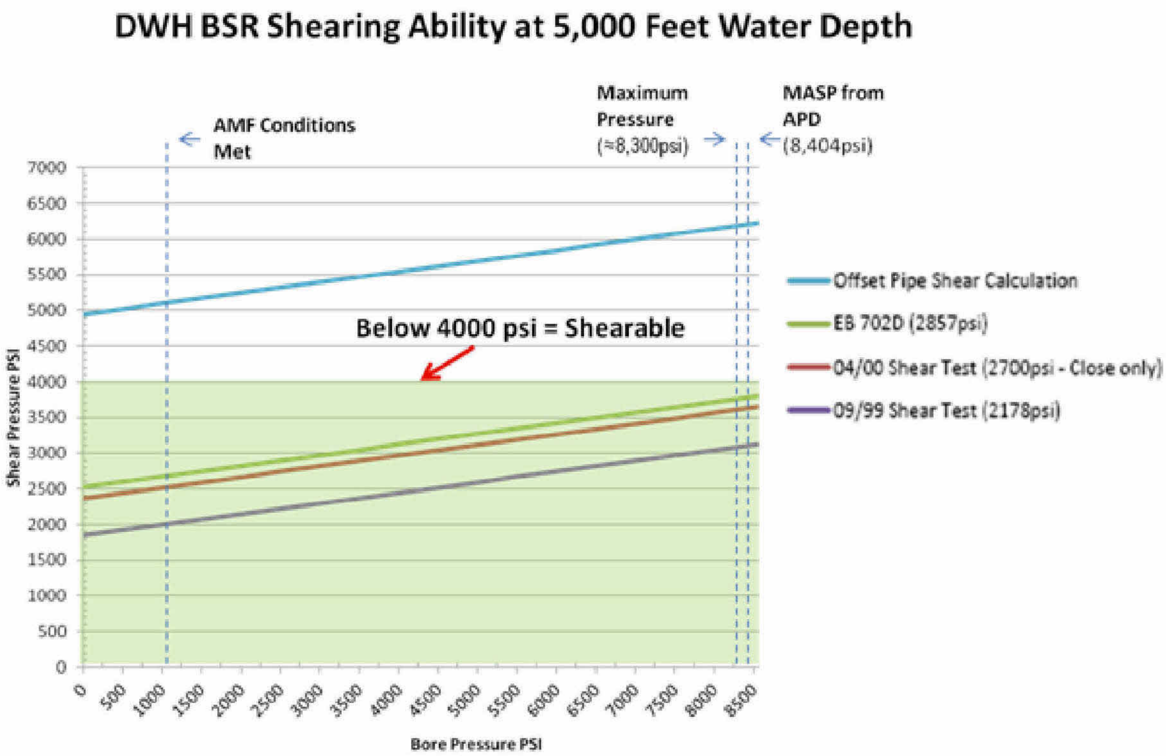

Figure 21 DWH BSR Shearing Ability at 5,000 Feet Water Depth

The above figure calculates the shearing pressures necessary to shear 5-1/2" S-135 drill pipe at various wellbore pressures using the following reference points:

- The September 1999 shear test performed by Cameron (2,178 psi)
- The April 2000 shear test (2,700 psi closing pressure)
- EB 702D's calculations (2,857 psi)
- The calculation of force necessary to shear off-center pipe[117] (5,280 psi)

The chart uses the formula from Cameron EB 702D to account for changes in wellbore pressure. Three relevant wellbore pressures are marked for their relevance in this case: the pressure time at which the AMF/Deadman conditions were met; the maximum wellbore pressure calculated by hydraulic modeling from data on the day of the incident; and the MASP reported in BP's APD for the Macondo well.

[117] This number is based on modeling data and reflects shearing only. Addendum to Final DNV Report, MDL Ex. 3124 at 21.

In the above table, points in the green-shaded area are within the shearing ability of the DWH's BSRs' 4,000 psi high pressure shear circuit. Notably, with the exception of the off-center pipe, all of the other cases are within the 4,000 psi shear pressure capability of the DWH's BSRs. Because the DWH had available pressure that exceeded these requirements, if the drill pipe had been centered, the Cameron *SBR* model blind shear rams were capable of shearing the pipe and sealing the well if not for the off-center drill pipe.

5.2.1.3. The DWH BOP Blind Shear Rams Were Capable of Shearing 5-1/2" Drill Pipe at MASP for the Macondo Well.

MASP, as discussed above, is a calculation that is considered in the evaluation of casing and rig equipment. In the Application for Bypass that was submitted for the Macondo well on March 15, 2010, the MASP at the wellhead for the Macondo well was calculated to be 8,404 psi.[118]

Based on my calculations using Cameron's EB 702D formula, and as shown above in Figure 21, at this MASP at the wellhead for the Macondo well, the DWH's BOP had sufficient shearing capacity to shear the 5-1/2" drill pipe that was across the blind shear rams at the time of the incident.[119] If the drill pipe had been centered in the BOP, when the DWH's blind shear rams were activated, according to Cameron's EB 702D formula, they would have sheared the drill pipe and sealed the well at this wellbore pressure.[120]

Mr. Perkins' expert report contends that the MASP calculation for the Macondo well submitted with the APD was erroneous because it used a 50/50 mud/gas ratio rather than a 100% gas column to the surface. I disagree. First, I note that the APD for the Macondo well specifically included the calculations that were used to calculate the MASP at the wellhead, and explicitly identifies the use of a 50/50 mud/gas ratio.[121] MMS, therefore, knew that MASP at the wellhead for the Macondo well was calculated with a 50/50 mud/gas ratio, and approved it. Similarly, MMS approved other APDs for wells drilled by the DWH that used a 50/50 mud/gas ratio to calculate MASP at the wellhead.[122] Second, in my experience, MASP should be calculated with what should be reasonably expected for the well to produce, which would not be a 100% gas column. In this regard, a 50/50 mud/gas ratio for calculating MASP is not uncommon in the industry, and I am aware of other operators, such as Shell, that use a similar

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118 MDL Ex. 1339; MDL Ex. 7004. The original APD for the Macondo well disclosed a MASP at the wellhead of 7,990 psi. MDL Ex. 6171.

119 *See also* D. McWhorter 7-8-2011 dep. tr. at 665:1-678:4.

120 The BOP also had sufficient pressure ratings for the Macondo well at MASP. The ram preventers on the BOP were all rated to 15,000 psi and the upper annular was rated to 10,000 psi. *See* C. Pleasant 3-14-2011 dep. tr. at 321:8-16; Drilling Contract, MDL Ex. 4271 at BP-HZN-MBI00021538.

121 MDL Ex. 1339.

122 Kodiak APD, BP-HZN-2179MDL03547166; Tiber APD, BP-HZN-2179MDL00871315.

ratio when calculating MASP at the wellhead. I note that it is generally known in the industry that the deeper a well is drilled in the Gulf of Mexico, the higher the ratio of oil to gas.

Based on modeling work performed by Add Energy, the calculation of MASP as submitted in the APD is also shown to be conservative. In its report entitled "Dynamic Simulations Deepwater Horizon Incident," Add Energy created a dynamic model of the conditions in the DWH's riser and wellbore leading up to and immediately following the blowout and explosions on the DWH rig.[123] This modeling shows that for the sequence of events that occurred (the upper annular closing at 21:41, but the annulus not being sealed until the VBRs closed at 21:47), the maximum pressure that was experienced below the BOP was approximately 8,300 psi.[124] This shows that the MASP reported in the APD to MMS was close to the actual maximum pressure that could have been experienced at the BOP, but was still conservative.

5.2.2. Because the BOP Was Adequate for the Macondo Well, No Alternative Features Were Needed.

As a general matter, if the BOP satisfies the operational requirements of the drilling operations that the rig is conducting, the drilling contractor, who would generally be responsible for modifying the BOP if necessary, would not seek to modify the BOP to add features or replace existing features. With every modification to a BOP, there is the opportunity for adding complexity or causing unintended consequences, which could impair the BOP's performance.[125] In other words, if the BOP is working as intended, it is best, as a general matter, to leave the BOP alone. Below I discuss some of the additional features that have been raised in this case for the DWH BOP.

5.2.2.1. DVS Rams

The DVS is a blind shear ram model offered by Cameron. The DVS differs from the *SBR* design used on the DWH BOP in two relevant respects. First, the DVS design uses two "V" shaped blades, whereas the *SBR* design uses one "V" shaped blade and one flat blade. This allows the DVS blades to shear pipe at lower pressures than the *SBR* blades. Second, the DVS blades are slightly wider than the *SBR* blades.

There may have been several reasons why Cameron offered in its proposal the *SBR* design for the DWH BOP's blind shear rams. First, the *SBR* blind shear ram design was Cameron's standard blind shear ram design.[126] This was still true even on April 20, 2010. For example, a Cameron communication indicates that 36 of the 38 subsea BOP stacks that Cameron

[123] ae add energy: Dynamic Simulations Deepwater Horizon Incident.

[124] ae add energy: Dynamic Simulations Deepwater Horizon Incident at 56.

[125] MDL Ex. 3186 at p. 36 ("The increased design complexity of modern-day BOPs can come at a price. While high-tech solutions may seem desirable, the intricate mechanical components that may result must be considered, along with other factors, such as possible leak paths and redundancy of critical seals.").

[126] MDL Ex. 3183 at CAM_CIV_0003212.

sold between 2005 and 2010 used the *SBR* design.[127] Second, during the design of the DWH BOP system, a problem with the DVS rams was discovered. This problem resulted in damage to the blades during shearing and required a redesign of the DVS blades.[128] Third, Cameron's Engineering Bulletin "Shear Ram Product Line," which was published in 1998, shortly before the DWH BOP was designed, compared the *SBR* and DVS designs, but did not recommend using one over the other, or suggest that only the DVS design could shear pipe that was located in certain portions of the wellbore.[129] The Engineering Bulletin simply noted differences between the designs.

There was no apparent need before the incident to replace the *SBR* blind shear rams on the DWH BOP with the DVS blades. Although the use of two "V" shaped blades on the DVS rams is more efficient than the *SBR* design, and allows the DVS rams to shear a given pipe at lower pressure than the *SBR* rams,[130] the greater efficiency of the DVS rams was not needed for shearing the 5-1/2" drill pipe on the Macondo well, as discussed above.

5.2.2.2. CDVS Rams

The CDVS is another model of blind shear ram blades offered by Cameron. This design also differs from the *SBR* design used on the DWH BOP in two main aspects. First, like the DVS design, the CDVS design uses two "V" shaped blades. Second, unlike the *SBR* design the CDVS blades extend across the full width of the wellbore.

The CDVS design was not offered by Cameron until after the DWH BOP was designed and manufactured.[131] The CDVS rams were not installed on the DWH BOP likely for reasons similar to why the DVS rams were not installed, but also that the CDVS rams were designed to be used for shearing logging cable, not drill pipe.[132] Also, as discussed above, the increased shearing efficiency of the CDVS design was not needed on the DWH BOP. Also, BP would not have had a reason to request the replacement of the *SBR* blades with CDVS blades because Cameron and Transocean never indicated the blade width of the *SBR* rams could pose a problem. Additionally, on April 20, 2010, the CDVS design was under a Cameron "Safety Alert" due to reports it had problems operating at or near 15,000 psi.[133] Because of this problem, Cameron

[127] CAM_CIV_0311314 at 317.

[128] BP-HZN_2179MDL01155528 at 564.

[129] MDL Ex. 3183 at CAM_CIV_0003210.

[130] Cameron Engineering Bulletin 852D (MDL Ex. 3183), at CAM_CIV_0003210. Cameron's Engineering Bulletin also provides that the *SBR* design provides "longer packer fatigue life" than the DVS design.

[131] D. McWhorter 7-7-2011 dep. tr. at 148:13-17; M. Whitby 7-18-2011 dep. tr. at 354:10-17.

[132] M. Whitby 7-19-2011 dep. tr. at 649:14-650:23.

[133] D. McWhorter 7-7-11 dep. tr. at 152:14-153:8; Cameron Safety Alert 22258, CAM_CIV_0012644; Transocean Equipment Alert, TRN-INV-0032368; Cameron Field Performance Report 221928, CAM_CIV_0375743; Cameron Field Performance Report 221870, CAM_CIV_0375738.

lowered the fatigue life and working pressure of the CDVS to 10,000 psi. This meant use of the CDVS rams would have ***reduced*** the operating pressure of the DWH blind shear rams from 15,000 psi to 10,000 psi.

5.2.2.3. Two Sets of Blind Shear Rams / 6 BOP Stack

The configuration of the DWH BOP with a 5 ram cavity stack and 1 blind shear ram was industry standard from its commissioning through the incident, and complied with MMS regulations. The standard subsea BOP during this time included only one blind shear ram. A 1999 study by SINTEF Industrial Management for MMS depicted the standard subsea BOP as follows:[134]

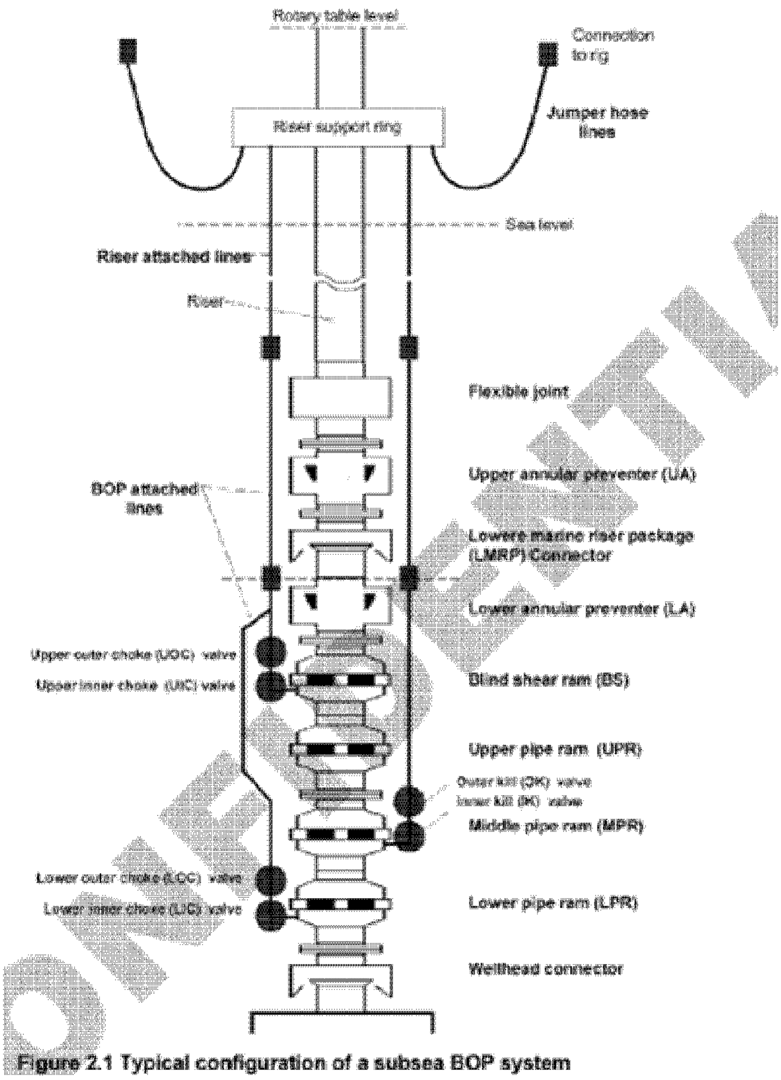

Figure 22 Typical Configuration of a Subsea BOP

[134] TRN-MDL00272700 at 722.

This SINTEF report also provided detailed BOP stack configuration information for 26 of the BOPs considered in the study. Of these 26 BOPs, 25 had four BOP cavities and one blind shear ram.[135] A 2004 study for MMS by West Engineering Services also noted that the majority of BOP stacks had a single blind shear ram.[136] Even through 2010, the use of a single blind shear ram was standard on Cameron BOPs.[137] According to an internal Cameron communication, of the 38 subsea BOP stacks that Cameron sold between 2005 and 2010, 36 contained only a single blind shear ram.[138]

In addition to being a standard configuration, the use of a 5 BOP cavity stack with 1 blind shear ram complied with MMS regulations on BOP stack configuration. These regulations stated:[139]

> (b) Your subsea BOP stack must include at least four remote-controlled, hydraulically operated BOPs consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams.

Also, a second blind shear ram would not have been able to shear the off-center pipe. A second blind shear ram on the DWH would have been located above the first blind shear ram. The below illustration, which shows a second blind shear ram cavity in a model of buckling force, shows that at the location of the second blind shear ram, the pipe would have been further off-center and held more firmly against the wellbore:

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135 TRN-MDL00272700 at 720.

136 MDL Ex. 3174 at p. 3-6.

137 CAM_CIV_0311314 at 317.

138 CAM_CIV_0311314 at 317.

139 30 C.F.R. § 250.442.

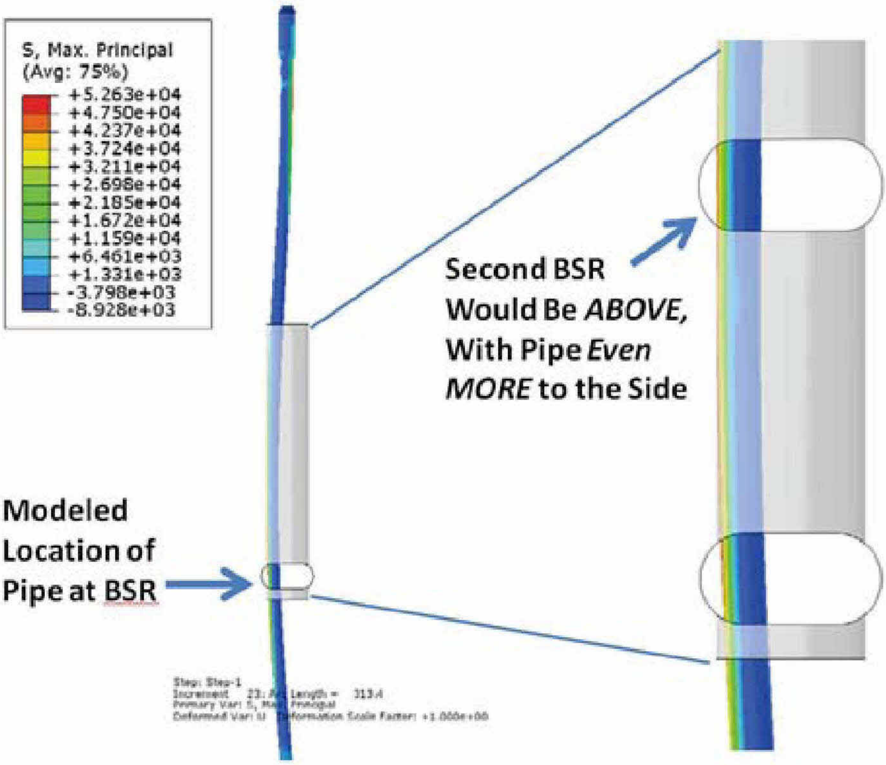

Figure 23 Pipe at Second Blind Shear Ram Would Have Been More Off-Center

5.2.2.4. 5,000 psi Ram Bonnets

At the time the DWH was designed and manufactured, the highest rated blind shear ram bonnets Cameron offered were rated to 4,000 psi.[140] These are the bonnets that were used on the DWH BOP. Although Cameron later developed ram bonnets rated to 5,000 psi, this feature was not needed on the DWH BOP.[141] The DWH BOP's blind shear rams were capable of shearing the 5-1/2" drill pipe used on the Macondo well, including at the well's MASP. The blind shear rams failed to shear the drill pipe because it was off-center and could not be sheared and sealed by the *SBR* rams, not because the rams lacked sufficient shearing pressure.

5.2.2.5. Tandem Boosters

Tandem boosters are a feature that can be included on a BOP stack that increase the shearing force available to the blind shear rams. This feature was not needed on the DWH BOP because, as discussed above, it was designed with sufficient shearing capacity to shear the 5-1/2" drill pipe in the BOP at the MASP for the Macondo well. Also, the addition of tandem boosters to the DWH BOP was not practical. As shown on Cameron's "Shear Ram Product Line"

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[140] D. McWhorter 7-7-2011 dep. tr. at 136:23-25.

[141] G. Boughton 7-20-2011 dep. tr. at 223:21-25.

Engineering Bulletin, tandem boosters were not a standard feature on most BOP stacks around the time when the DWH BOP was designed and manufactured.[142] After its design and construction, the addition of tandem boosters was not practical because substantial structural modifications to the rig would have been needed to fit the BOP stack with tandem boosters in the moon pool, which was deemed impractical when Transocean considered adding tandem boosters to the BOP of the *Deepwater Horizon*'s sister vessel, the *Deepwater Nautilus*.[143] Additional accumulator volume would also have been needed as tandem boosters roughly double the amount of hydraulic fluid needed to close the blind shear rams. These additional accumulators and associated piping would have added potential leak paths to the BOP system, would have complicated maintenance, and would have required structural modifications to the DWH in order to accommodate the BOP on the deck for transport and maintenance.[144]

5.2.2.6. Acoustic back-up system

An acoustic back-up system is a feature that can be included with a BOP that potentially allows communication to the BOP to activate functions through acoustic signals when other means of communication with the BOP are lost. Inclusion of this feature on rigs in the Gulf of Mexico is uncommon.[145] For example, as of April 20, 2010, Transocean had no rigs in the Gulf of Mexico with acoustic back-up systems.[146] Acoustic back-up systems serve the same function as an AMF/Deadman system, so there is no need for an acoustic system if the AMF/Deadman system is properly maintained and functional.

Further, even if the DWH BOP had included an acoustic back-up system, it is unknown whether such a system would have worked as these systems are known to have reliability issues. For example, Transocean's CEO, Steve Newman, was not aware of a situation where an acoustic backup system was used to control a well during a loss-of-well-control event.[147] West Engineering noted in its report "Evaluation of Secondary Intervention Methods in Well Control" that "[a]coustic interference caused by the noise of a flowing well may make operation unreliable."[148] This report further stated that "[a]coustic systems are not recommended because they tend to be very costly, and there is insufficient data available on system reliability in the presence of a mud or gas plume."[149] An ExproSoft memorandum on acoustic system reliability also noted that "[r]elying on an acoustic system with a ROV back-up seems questionable. …

[142] MDL Ex. 3183 at CAM_CIV_0003212.

[143] G. Boughton 7-20-2011 dep. tr. at 120:19-121:19; 225:8-23; 344:12-346:12.

[144] G. Boughton 7-20-2011 dep. tr. at 225:8-226:3.

[145] D. McWhorter 7-7-2011 dep. tr. at 125:14-126:10.

[146] G. Boughton 7-20-2011 dep. tr. at 230:23-231:6.

[147] S. Newman 9-30-2011 dep. tr. at 54:19-55:4.

[148] MDL Ex. 3298 at TRN-MDL-00495001.

[149] MDL Ex. 3298 at TRN-MDL-00495005.

[F]or transmitting an emergency signal that starts a shear and disconnect sequence it seems dubious. … The probability of an acoustic system failure seems fairly high and a back-up emergency system that can be activated fast enough should be evaluated."[150] Even after the DWH incident, a Joint Industry Task Force organized by the IADC and API recommended that the reliability of acoustic back-up systems be further studied before it would recommend the use of such systems.[151]

6. CLOSING STATEMENT

This report represents my analysis and opinions, which have been prepared to a reasonable level of professional and engineering certainty. Should additional information become available, I reserve the right to supplement and/or revise any of my analysis and opinions. If requested, I can and will competently testify regarding the contents, analysis, and opinions in this report.

[150] MDL Ex. 5166 at CAM_CIV_0406944.

[151] MDL Ex. 3958 at CAM_CIV_0223962; M. Whitby 7-18-2011 dep. tr. at 367:16-372:18.

Respectfully submitted,

Forest Earl Shanks II

Appendix A:

Materials Considered

Beginning Bates number	Ending Bates number	Description
		Access to all depositions and exhibits
BP-HZN-2179MDL00088245	BP-HZN-2179MDL00088413	Vastar Resources, Inc. Deepwater Horizon Rig Files, 6.0 BOP Equipment, Volume 3
BP-HZN-2179MDL00251266	BP-HZN-2179MDL00251270	4.20.2010 Drilling Report
BP-HZN-2179MDL03547166	BP-HZN-2179MDL03547210	Kodiak APD - excerpt from
BP-HZN-2179MDL00871315	BP-HZN-2179MDL00871360	APD approval.pdf
BP-HZN-2179MDL00871315	BP-HZN-2179MDL00871360	KC102 #1 Application for Permit to Drill a New Well
BP-HZN-2179MDL00912924	BP-HZN-2179MDL00913033	Tubular Bells Drilling Program.doc
BP-HZN-2179MDL01009020	BP-HZN-2179MDL01009074	Well Control.pdf
BP-HZN-2179MDL01155049	BP-HZN-2179MDL01155346	Vastar Resources, Inc. Deepwater Horizon Rig Files, 6.0 BOP Equipment, Volume 2
BP-HZN-2179MDL01155528	BP-HZN-2179MDL01156159	Vastar Resources, Inc. Deepwater Horizon Rig Files, 6.0 BOP Equipment, Volume 1
BP-HZN-2179MDL01819480	BP-HZN-2179MDL01819529	Handwritten notes
BP-HZN-2179MDL02172464	BP-HZN-2179MDL02172464	DW Horizon IMT ROV Ops Notes_September 19.xls
BP-HZN-2179MDL03547166	BP-HZN-2179MDL03547210	Appendix B: Application for Permit to Drill (APD)
BP-HZN-2179MDL03547166	BP-HZN-2179MDL03547379	MC 727 #2 Application for Permit to Drill
BP-HZN-2179MDL03772302	BP-HZN-2179MDL03772302	Oceaneering Millennium 37 ROV video from April 22, 2010
BP-HZN-2179MDL03772304	BP-HZN-2179MDL03772304	C-Innovation video from April 22, 2010
BP-HZN-BLY00000001	BP-HZN-BLY00000193	Deepwater Horizon Accident Investigation Report
BP-HZN-BLY00061169	BP-HZN-BLY00061169	Sperry Sun data from 4/5/2010 through 4/20/2010
BP-HZN-BLY00063669	BP-HZN-BLY00063683	Approval.pdf
BP-HZN-MBI00137274	BP-HZN-MBI00137304	Responder Logbook
BP-HZN-MBI00167826	BP-HZN-MBI00167826	ROV footage
BP-HZN-MBI00171007	BP-HZN-MBI00171038	Responder Logbook
CAM_CIV_0003123	CAM_CIV_0003130	Shearing Blind Rams -- Operations, Care, and Maintenance / Drilling Engineering EB 538 D / Revision C1
CAM_CIV_0012644	CAM_CIV_0012646	Safety Alert 22258 / Reduced Fatigue Life of Packer for 18-3/4 15K Type T/TL BOP CDVS Ram & 18-3/4 10/15K Type UII BOP CDVS Ram
CAM_CIV_0012830	CAM_CIV_0012831	Cameron Ram BOP Cavity in Service Acceptance Criteria / Engineering Bulletin EB 905 D / Revision A1

CAM_CIV_0025645	CAM_CIV_0025660	Engineering Report Abstract / Report Number: 2728 / R&B Deepwater Horizon Project 18-3/4" 15M TL Super Shear Rams (SSRs) & Shear Blind Rams (*SBR*s) Shear Test
CAM_CIV_0070269	CAM_CIV_0070270	Design File Cover Sheet & Table of Content / Design File No. DF-005108 / Rev A01
CAM_CIV_0070271	CAM_CIV_0070271	Design Input
CAM_CIV_0070272	CAM_CIV_0070287	Sales Order Acknowledgement / Sale Order: 50/V25/60198329
CAM_CIV_0070288	CAM_CIV_0070288	Design Output
CAM_CIV_0070289	CAM_CIV_0070292	Cameron - Houston, Texas / Product Engineering Part/Document Audit Report / Entry Number: 2113587-10
CAM_CIV_0070293	CAM_CIV_0070297	Cameron - Houston, Texas / Product Engineering Part/Document Audit Report / Entry Number: 2113587-07
CAM_CIV_0070298	CAM_CIV_0070298	Assembly 18.3/4" 15M BOP Double "TL" with ST-Lock W/SEQ VLV / SK-120036-05
CAM_CIV_0070299	CAM_CIV_0070299	Assembly 18-3/4" 15,000 'TL', Double BOP W/ST-Lock and Seq. Valve / SK-013970-02
CAM_CIV_0070300	CAM_CIV_0070300	Body
CAM_CIV_0070301	CAM_CIV_0070313	18 3/4" 15M TL BOP Body Analysis Standard
CAM_CIV_0070314	CAM_CIV_0070314	DIM. Drawing - Body, 18-3/4" 15M# 'TL' W/Special NPT and Sae Flange Prep on Open & Close Port
CAM_CIV_0070315	CAM_CIV_0070315	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2011729-01
CAM_CIV_0070316	CAM_CIV_0070316	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2011727-01
CAM_CIV_0070317	CAM_CIV_0070318	Machine Detail - Body, 18-3/4" 15M# 'TL' BOP, W/Special Flange Prep, on Open & Close Port / X-103151-02
CAM_CIV_0070319	CAM_CIV_0070320	Machine Detail - Body, 18-3/4" 15M# 'TL' BOP, W/Special NPT and Sae Flange Prep on Open & Close Port / X-103151-03
CAM_CIV_0070321	CAM_CIV_0070321	Bonnet
CAM_CIV_0070322	CAM_CIV_0070328	Table 26 Formulas for Maximum Deflection and Maximum Stress in Flat Plates with Straight Boundaries and Constant Thickness
CAM_CIV_0070329	CAM_CIV_0070329	Operating Piston

CAM_CIV_0070330	CAM_CIV_0070332	18 3/4" 15M TL BOP Operating Piston Analysis Standard
CAM_CIV_0070333	CAM_CIV_0070333	Sub-Assembly, Operating Piston to Function W/Sequence Valve 18-3/4" 15M# 'TL' BOP
CAM_CIV_0070334	CAM_CIV_0070334	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2010388-05
CAM_CIV_0070335	CAM_CIV_0070335	DAP234IFS.mcd
CAM_CIV_0070336	CAM_CIV_0070336	Machine Detail, Operating Piston for Housing Locking Screw 18.3/4" 15M "TL" BOP / X-102270-05
CAM_CIV_0070337	CAM_CIV_0070337	Mach. Detail, Operating Piston to Function W/Sequence Valve 18-3/4" 15M# "TL" BOP / X-102270-03
CAM_CIV_0070338	CAM_CIV_0070338	Bonnet Bolt
CAM_CIV_0070339	CAM_CIV_0070342	18 3/4" 15M TL BOP Bonnet Bolt Analysis Standard
CAM_CIV_0070343	CAM_CIV_0070343	Bonnet Bolt F/18-3/4" 15M# 'TL' BOP
CAM_CIV_0070344	CAM_CIV_0070344	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2010401-02
CAM_CIV_0070345	CAM_CIV_0070345	Piston Ram Change
CAM_CIV_0070346	CAM_CIV_0070348	18 3/4" 15M TL BOP Ram Change Piston Analysis Standard
CAM_CIV_0070349	CAM_CIV_0070349	Piston, RAM Change, 18-3/4"-15M# 'TL' BOP
CAM_CIV_0070350	CAM_CIV_0070350	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2010391-02
CAM_CIV_0070351	CAM_CIV_0070351	Cylinder Ram Change
CAM_CIV_0070352	CAM_CIV_0070355	18 3/4" 15M TL BOP Ram Change Cylinder Analysis Standard
CAM_CIV_0070356	CAM_CIV_0070356	Cylinder, RAM Change, 18-3/4"-15M# 'TL' BOP
CAM_CIV_0070357	CAM_CIV_0070357	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2010393-02
CAM_CIV_0070358	CAM_CIV_0070358	Cylinder Head
CAM_CIV_0070359	CAM_CIV_0070361	18 3/4" 15M TL BOP Cylinder Head Analysis Standard
CAM_CIV_0070362	CAM_CIV_0070362	Operating Cylinder
CAM_CIV_0070363	CAM_CIV_0070366	18 3/4" 15M TL BOP Operating Cylinder Analysis Standard
CAM_CIV_0070367	CAM_CIV_0070367	Cylinder, Operating Piston, 18-3/4" 15M# 'TL' BOP

CAM_CIV_0070368	CAM_CIV_0070368	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2010389-02
CAM_CIV_0070369	CAM_CIV_0070369	Design Review / Design Fiel #: DF-005108-01
CAM_CIV_0070370	CAM_CIV_0070370	Stud DBL Ended
CAM_CIV_0070371	CAM_CIV_0070373	18 3/4" 15M TL BOP Operator Cylinder Studs Analysis Standard
CAM_CIV_0070374	CAM_CIV_0070374	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 22011346-26-01
CAM_CIV_0070375	CAM_CIV_0070375	Tandem Booster
CAM_CIV_0070376	CAM_CIV_0070448	Cameron Design Approval Package / Package Number: 5024-279-001
CAM_CIV_0070449	CAM_CIV_0070449	Super Shear
CAM_CIV_0070450	CAM_CIV_0070450	DAP268-HSG-SS.mcd
CAM_CIV_0070451	CAM_CIV_0070458	DAP237HSG-SS.mcd
CAM_CIV_0070459	CAM_CIV_0070465	Working.rpt
CAM_CIV_0070466	CAM_CIV_0070471	Test.rpt
CAM_CIV_0070472	CAM_CIV_0070472	DAP268-BON-SS.mcd
CAM_CIV_0070473	CAM_CIV_0070475	DAP245BON-SS.mcd
CAM_CIV_0070476	CAM_CIV_0070476	DAP268-OP-SS.mcd
CAM_CIV_0070477	CAM_CIV_0070478	DAP245OP-SS.mcd
CAM_CIV_0070479	CAM_CIV_0070479	DAP268-CH-SS.mcd
CAM_CIV_0070480	CAM_CIV_0070481	DAP245CH-SS.mcd
CAM_CIV_0070482	CAM_CIV_0070482	DAP268-CS-SS.mcd
CAM_CIV_0070483	CAM_CIV_0070484	DAP245CS-SS.mcd
CAM_CIV_0070485	CAM_CIV_0070485	DAP268-SS-SS.mcd
CAM_CIV_0070486	CAM_CIV_0070487	DAP245SS-SS.mcd
CAM_CIV_0070488	CAM_CIV_0070489	Sub-Assembly, Bonnet 28", Externally Ported Super Shear Ram, End Cap W/ Polypak GRV, 18-3/4 15M, 'TL' BOP / SK-019369-02
CAM_CIV_0070490	CAM_CIV_0070490	DIM. DWG-Super Shear Housing 18-3/4" TL BOP
CAM_CIV_0070491	CAM_CIV_0070491	DIM. DWG-Super Shear Bonnet 18-3/4" TL BOP
CAM_CIV_0070492	CAM_CIV_0070492	DIM. DWG-Super Shear Piston 18-3/4" TL BOP
CAM_CIV_0070493	CAM_CIV_0070493	DIM. DWG-Super Shear End Cap 18-3/4" TL BOP
CAM_CIV_0070494	CAM_CIV_0070494	Section III Bills of Materials

CAM_CIV_0070495	CAM_CIV_0070495	DAP268-PIS.mcd
CAM_CIV_0070496	CAM_CIV_0070497	DAP245OP.mcd
CAM_CIV_0070498	CAM_CIV_0070498	DAP268-RCC.mcd
CAM_CIV_0070499	CAM_CIV_0070500	DAP245RCC.mcd
CAM_CIV_0070501	CAM_CIV_0070501	DAP268-OC.mcd
CAM_CIV_0070502	CAM_CIV_0070504	DAP245OC
CAM_CIV_0070505	CAM_CIV_0070505	Rams
CAM_CIV_0070506	CAM_CIV_0070517	18-3/4" 15M BOP *SBR* Rams Analysis Standard
CAM_CIV_0070518	CAM_CIV_0070531	18-3/4" 15M BOP 5.0" Pipe Rams Analysis Standard
CAM_CIV_0070532	CAM_CIV_0070533	Product Engineering Part/Document Audit Report / Entry Number: 2163089-07
CAM_CIV_0070534	CAM_CIV_0070535	Product Engineering Part/Document Audit Report / Entry Number: 2010407-01
CAM_CIV_0070536	CAM_CIV_0070537	Product Engineering Part/Document Audit Report / Entry Number: 2163582-01
CAM_CIV_0070538	CAM_CIV_0070539	Product Engineering Part/Document Audit Report / Entry Number: 2010374-03
CAM_CIV_0070540	CAM_CIV_0070540	Machining Detail, Pipe Ram Charted Drawings -01 thru -23 18.75"-10/15M Type-T-B.O.P. / X-24153
CAM_CIV_0070541	CAM_CIV_0070541	Mach. Det. Conn. Rod Slot, 18-3/4" 15M# 'T' & 'TL' BOP Ram Body / X-023806-01
CAM_CIV_0070542	CAM_CIV_0070542	Mach. Detail, Operating Piston to Function W/Sequence Valve 18-3/4" 15M# "TL' BOP / X-102270-03
CAM_CIV_0070543	CAM_CIV_0070543	Machine Detail, Button, 18-3/4 10M-15M, T BOP / X-23985-01
CAM_CIV_0070544	CAM_CIV_0070557	18-3/4" 15M TL BOP 6-5/8" Pipe Hangoff Ram Analysis Standard
CAM_CIV_0070558	CAM_CIV_0070570	18-3/4" 15M TL BOP 7-5/8" to 3-1/2" VBR Ram Analysis Standard
CAM_CIV_0070571	CAM_CIV_0070572	Product Engineering Part/Document Audit Report / Entry Number: 644575-01-00-01
CAM_CIV_0070573	CAM_CIV_0070574	Product Engineering Part/Document Audit Report / Entry Number: 2010407-01
CAM_CIV_0070575	CAM_CIV_0070576	Product Engineering Part/Document Audit Report / Entry Number: 2163091-01

CAM_CIV_0070577	CAM_CIV_0070578	Product Engineering Part/Document Audit Report / Entry Number: 644575-01
CAM_CIV_0070579	CAM_CIV_0070580	Product Engineering Part/Document Audit Report / Entry Number: 644575-01-00-02
CAM_CIV_0070581	CAM_CIV_0070594	18-3/4" 15M TL BOP 6-5/8" x 5" Flexpacker NR Ram Analysis Standard
CAM_CIV_0070595	CAM_CIV_0070595	Machine Detail-Hangoff Ram Body 18-3/4 15M 'T' and 'TL' BOP 6-5/8X5 Flexpacker NR / X-208738-01
CAM_CIV_0070596	CAM_CIV_0070596	Mach. Detail, Operating Piston to Function W/Sequence Valve 18-3/4" 15M# "TL' BOP / X-102270-03
CAM_CIV_0070597	CAM_CIV_0070597	Mach. Det. Conn. Rod Slot, 18-3/4" 15M# 'T' & 'TL' BOP Ram Body / X-023806-01
CAM_CIV_0070598	CAM_CIV_0070598	Machine Detail, Button, 18-3/4 10M-15M, T BOP / X-23985-01
CAM_CIV_0070599	CAM_CIV_0070599	Molding Detail - Flexpacker 18-3/4" 10/15M UII BOP Double Plate for 6-5/8" to 5" Pipe OD / X-103945-01
CAM_CIV_0070600	CAM_CIV_0070601	Product Engineering Part/Document Audit Report / Entry Number: 2163767-01
CAM_CIV_0070602	CAM_CIV_0070602	Product Engineering Part/Document Audit Report / Entry Number: 2163768-01
CAM_CIV_0070603	CAM_CIV_0070603	18 3/4" 15M TL BOP DVS Shear Ram Analysis Standard
CAM_CIV_0070604	CAM_CIV_0070614	18-3/4" 15M TL BOP DVS Shear Ram Analysis Standard
CAM_CIV_0070615	CAM_CIV_0070615	Machine Detail - Ram Body, Lower Double V-Shear (DVS) 18-3/4 15M 'T' and 'TL' BOP / X-208167-01
CAM_CIV_0070616	CAM_CIV_0070616	Machine Detail - Ram Body, Upper Double V-Shear (DVS) 18-3/4 15M 'T' and 'TL' BOP / X-208166-01
CAM_CIV_0070617	CAM_CIV_0070617	Mach. Detail, Operating Piston to Function W/Sequence Valve 18-3/4" 15M# "TL" BOP / X-102270-03
CAM_CIV_0070618	CAM_CIV_0070618	Mach. Det. Conn. Rod Slot, 18-3/4" 15M# 'T' & 'TL' BOP Ram Body / X-023806-01
CAM_CIV_0070619	CAM_CIV_0070619	Machine Detail, Button, 18-3/4 10M-15M, T BOP / X-23985-01
CAM_CIV_0070620	CAM_CIV_0070621	Cameron - Houston, Texas / Product Engineering Part/Document Audit Report / Entry Number: 2232813-02

CAM_CIV_0070622	CAM_CIV_0070623	Cameron - Houston, Texas / Product Engineering Part/Document Audit Report / Entry Number: 2232813-01
CAM_CIV_0070624	CAM_CIV_0070637	18-3/4" 15M TL BOP 5-1/2" Pipe Rams Analysis Standard
CAM_CIV_0070638	CAM_CIV_0070640	18-3/4" 15M TL BOP 4-1/2" Pipe Rams Analysis Standard
CAM_CIV_0070641	CAM_CIV_0070641	Machining Detail, Pipe Ram 18-3/4 10/15M "T" BOP / X-24153
CAM_CIV_0070642	CAM_CIV_0070642	Inspection Ref. Data, Ram Body, 18-3/4"-5M# "TL" BOP (All Pipe Sizes) / X-102427-01
CAM_CIV_0070643	CAM_CIV_0070643	Machining Detail, Pipe Ram Charted Drawings -01 thru -23 18.75"-10/15M Type -T- B.O.P. / X-24153
CAM_CIV_0070644	CAM_CIV_0070644	Mach. Det. Conn. Rod Slot, 18-3/4" 15M# 'T' & 'TL' BOP Ram Body / X-023806-01
CAM_CIV_0070645	CAM_CIV_0070645	Mach. Detail, Operating Piston to Function W/Sequence Valve 18-3/4" 15M# "TL' BOP / X-102270-03
CAM_CIV_0070646	CAM_CIV_0070646	Machine Detail, Button, 18-3/4 10M-15M, T BOP / X-23985-01
CAM_CIV_0070647	CAM_CIV_0070647	Design Validation
CAM_CIV_0070648	CAM_CIV_0070648	Certificate of Conformance New Manufacture
CAM_CIV_0070649	CAM_CIV_0070649	Test Report BOP Type
CAM_CIV_0070650	CAM_CIV_0070650	Certificat De Test
CAM_CIV_0070651	CAM_CIV_0070651	Certificat De Test
CAM_CIV_0070652	CAM_CIV_0070663	Bonnet Test Report
CAM_CIV_0070664	CAM_CIV_0070665	Test Report BOP Type
CAM_CIV_0070666	CAM_CIV_0070674	Bonnet Test Report
CAM_CIV_0070675	CAM_CIV_0070675	Engineering Report Abstract / Report Number: 3548 / DVS Ram for 18-3/4"-15M TL BOP Temperature Qualification
CAM_CIV_0070676	CAM_CIV_0070676	Engineering Report Abstract / Report Number: 3549 / *SBR* Ram for 18-3/4"-15M TL BOP Temperature Qualification
CAM_CIV_0070677	CAM_CIV_0070686	Appendix I / Sealing Characteristics
CAM_CIV_0070687	CAM_CIV_0070687	Engineering Report Abstract / Report Number: 3629 / 18-15M TL *SBR* Fatigue Test
CAM_CIV_0070688	CAM_CIV_0070688	Engineering Report Abstract / Report Number: 2728 / R&B Deepwater Horizon Project 18-3/4" 15M TL Super Rams (SSRs) & Shear Blind Rams (*SBR*s) Shear Test

CAM_CIV_0070689	CAM_CIV_0070689	Engineering Report Abstract / Report Number: 3628 / 18-15M TL DVS Shear Ram Fatigue & Shear Test
CAM_CIV_0070690	CAM_CIV_0070690	Engineering Report Abstract / Report Number: 3702 / 5 to 3-1/2 VBR for 18-3/4-15K TL BOP API 16A Fatigue Test
CAM_CIV_0070691	CAM_CIV_0070691	Engineering Report Abstract / Report Number: 3119 / 183/4"-15M TL BOP CDVS Rams Fatigue Testing
CAM_CIV_0070692	CAM_CIV_0070692	Engineering Report / E.R.No. 1784 / Fatigue Test of 5" Fixed Bore Ram Packers in an 18-3/4"-15,000 Psi T BOP on 5" Diameter Pipe
CAM_CIV_0070693	CAM_CIV_0070693	Engineering Report / E.R.No. 1729 / Stripping Life of 5" Pipe Ram 18-3/4" T Ram Assemblies -- 3000 Psi Well Bore Pressure -- 1500 Psi Closing Pressure
CAM_CIV_0070694	CAM_CIV_0070695	Hangoff Test of 5" Fixed Bore Pipe Rams for 18-3/4"-15M T BOP / Revision A1 / Engineering Test Report Summary TR-1060 D
CAM_CIV_0070696	CAM_CIV_0070696	Engineering Report Abstract / Report Number: 2148 / Hangoff Test, 5" Diameter Pipe, 18-3/4" 15M T BOP 7-5/8" to 3-1/2" VBRs
CAM_CIV_0070697	CAM_CIV_0070697	Engineering Report Abstract / Report Number: 1899 / API 16A Ram Access Test on the Cameron 18-3/4"-15M T BOP
CAM_CIV_0070698	CAM_CIV_0070698	Engineering Report Abstract / Report Number: 2088 / Scaled BOP Operational Characteristics Test Data Per API SPEC 16A, First Edition, November 1, 1986
CAM_CIV_0070699	CAM_CIV_0070699	Engineering Report Abstract / Report Number: 3558 / VBR Ram for 18-3/4" -15M TL BOP Temperature Qualification
CAM_CIV_0070700	CAM_CIV_0070700	Design Verification
CAM_CIV_0070701	CAM_CIV_0070701	18 3/4"-15,000 PSI TL BOP
CAM_CIV_0070702	CAM_CIV_0070705	Type Approval Certificate No. D-3062
CAM_CIV_0070706	CAM_CIV_0070709	Addendum to TAC D-3062
CAM_CIV_0070710	CAM_CIV_0070713	Type Approval Certificate No. D-3160
CAM_CIV_0070714	CAM_CIV_0070714	Facility Type: Self Elevating Unit / Facility Names: West Juno (Cameron SO#1227952) / Shipyard,Hull Numbers: Keppel Fels Ltd. Singapore, B312 / Review Activity: Extension of Approval of BOP & RAM Assemblies
CAM_CIV_0070715	CAM_CIV_0070716	Independent Review Certificate No.: HOE-569769A/2010

CAM_CIV_0070717	CAM_CIV_0070718	Independent Review Certificate No.: HOE-569769B/2010
CAM_CIV_0070719	CAM_CIV_0070719	Design Changes
CAM_CIV_0070720	CAM_CIV_0070720	Engineering Report Abstract / Report Number: 3558 / VBR Ram for 18-3/4" - 15M TL BOP Temperature Qualification
CAM_CIV_0070721	CAM_CIV_0070721	Engineering Report Abstract / Report Number: 3549 / *SBR* Ram for 18-3/4" - 15M TL BOP Temperature Qualification
CAM_CIV_0070722	CAM_CIV_0070722	Engineering Report Abstract / Report Number: 3548 / DVS Ram for 18-3/4" - 15M TL BOP Temperature Qualification
CAM_CIV_0070723	CAM_CIV_0070723	Engineering Report Abstract / Report Number: 3629 / 18-15M TL *SBR* Fatigue Test
CAM_CIV_0070724	CAM_CIV_0070724	Engineering Report Abstract / Report Number: 3628 / 18-15M TL DVS Shear Ram Fatigue & Shear Test
CAM_CIV_0070725	CAM_CIV_0070728	Design Improvement to 18-3/4"-15M TL BOP Operating Piston Buttons
CAM_CIV_0070729	CAM_CIV_0070730	Design File Cover Sheet & Table of Content / Design File No. DF-005052-01 / Rev A1
CAM_CIV_0070731	CAM_CIV_0070731	Design Input
CAM_CIV_0070732	CAM_CIV_0070733	Drilling Engineering Design and Development Planning / DF-005052-01
CAM_CIV_0070734	CAM_CIV_0070734	Design Output
CAM_CIV_0070735	CAM_CIV_0070740	Cameron - Houston, Texas / Product Engineering Part/Document Audit Report / Entry Number: 2163588-09
CAM_CIV_0070741	CAM_CIV_0070741	Assembly 18-3/4" 10/15M 'DL' Annular BOP W/ Anti-Rotation Key / SK-013908-03
CAM_CIV_0070742	CAM_CIV_0070750	Calculations for the "DL" BOP Body
CAM_CIV_0070751	CAM_CIV_0070751	DIM. Drawing Body, 18-3/4" 10M# PSI WP 'DL' Annular BOP
CAM_CIV_0070752	CAM_CIV_0070752	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2011702-01
CAM_CIV_0070753	CAM_CIV_0070753	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2011689-01
CAM_CIV_0070754	CAM_CIV_0070754	18 3/4" - 10M 'D' BOP' Body Analysis w/3 1/16" Dia. Horizontal Hole through Bottom Plate
CAM_CIV_0070755	CAM_CIV_0070755	Post1 Linearized Stress Listing
CAM_CIV_0070756	CAM_CIV_0070756	Post1 Linearized Stress Listing

CAM_CIV_0070757	CAM_CIV_0070757	Post1 Linearized Stress Listing
CAM_CIV_0070758	CAM_CIV_0070758	Post1 Linearized Stress Listing
CAM_CIV_0070759	CAM_CIV_0070762	18 3/4"-10M DBOP Body W/ 10 ksi Bore, 931 Kip Tens & 2,014 Ft-Kip BM
CAM_CIV_0070763	CAM_CIV_0070763	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2011698-01
CAM_CIV_0070764	CAM_CIV_0070764	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2011695-01
CAM_CIV_0070765	CAM_CIV_0070766	Calculations for the "DL" BOP Piston
CAM_CIV_0070767	CAM_CIV_0070767	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2011655-01
CAM_CIV_0070768	CAM_CIV_0070769	Calculations for the "DL" BOP Outer Cylinder Head
CAM_CIV_0070770	CAM_CIV_0070770	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 2011653-01
CAM_CIV_0070771	CAM_CIV_0070771	Calculations for "Lock Ring Teeth", 18-3/4" 10M DL Annular BOP
CAM_CIV_0070772	CAM_CIV_0070772	Dimensional Drawing Lock Ring, 18-3/4" 10M# 'DL' Annular BOP
CAM_CIV_0070773	CAM_CIV_0070773	Cooper Cameron Corporation Houston, Texas / Engineering Bill of Material / Entry Number: 699337-21
CAM_CIV_0070774	CAM_CIV_0070774	18 3/4-10M WP DBOP Body W/Hub 8' Floor
CAM_CIV_0070775	CAM_CIV_0070777	18-3/4 10M DBOP Piston
CAM_CIV_0070778	CAM_CIV_0070778	'D' BOP / Packer Volume Studies
CAM_CIV_0070779	CAM_CIV_0070781	18" -10M # Type 'DL' BOP
CAM_CIV_0070782	CAM_CIV_0070786	Insert 18 3/4-10M DL Packer
CAM_CIV_0070787	CAM_CIV_0070787	Engineering Bill of Material Explosion / Entry Number: 644853-01-10-01
CAM_CIV_0070788	CAM_CIV_0070788	Engineering Bill of Material Explosion / Entry Number: 644853-01-10-01
CAM_CIV_0070789	CAM_CIV_0070790	Index / Design Approval Package / DAP Number: DAP-246-01 / 18-10M DL Annular BOP
CAM_CIV_0070791	CAM_CIV_0070791	DAP246-BDY.mcd
CAM_CIV_0070792	CAM_CIV_0070800	Calculations for the "DL" BOP Body
CAM_CIV_0070801	CAM_CIV_0070801	18 3/4" - 10M 'D' BOP' Body Analysis w/3 1/16" Dia. Horizontal Hole through Bottom Plate

CAM_CIV_0070802	CAM_CIV_0070802	Post1 Linearized Stress Listing
CAM_CIV_0070803	CAM_CIV_0070803	Post1 Linearized Stress Listing
CAM_CIV_0070804	CAM_CIV_0070804	Post1 Linearized Stress Listing
CAM_CIV_0070805	CAM_CIV_0070805	Post1 Linearized Stress Listing
CAM_CIV_0070806	CAM_CIV_0070809	18 3/4"-10M DBOP Body W/ 10 ksi Bore, 931 Kip Tens & 2,014 Ft-Kip BM
CAM_CIV_0070810	CAM_CIV_0070810	DAP246-TOP.mcd
CAM_CIV_0070811	CAM_CIV_0070822	Calculations for the "DL" BOP top Plate
CAM_CIV_0070823	CAM_CIV_0070823	DAP246-PIS.mcd
CAM_CIV_0070824	CAM_CIV_0070825	Calculations for the "DL" BOP Piston
CAM_CIV_0070826	CAM_CIV_0070826	DAP246-OCH.mcd
CAM_CIV_0070827	CAM_CIV_0070828	Calculations for the "DL" BOP Outer Cylinder Head
CAM_CIV_0070829	CAM_CIV_0070829	DAP246-LR.mcd
CAM_CIV_0070830	CAM_CIV_0070831	Calculations for "Lock Ring Teeth", 18-3/4" 10M DL Annular BOP
CAM_CIV_0070832	CAM_CIV_0070832	18-3/4" 10M# 'DL' Annular BOP W/Anti-Rotation Key / SK-013908-03
CAM_CIV_0070833	CAM_CIV_0070833	DIM. Drawing Body, 18-3/4" 10M# PSI WP 'DL' Annular BOP
CAM_CIV_0070834	CAM_CIV_0070834	DIM. DWG-Top 18-3/4" -10M DL Flgd Btm X Stdd Top
CAM_CIV_0070835	CAM_CIV_0070835	DIM. DWG-Piston 18-3/4" -10M DL
CAM_CIV_0070836	CAM_CIV_0070836	DIM. DWG-Outer Cylinder Head 18-3/4" -10M DL
CAM_CIV_0070837	CAM_CIV_0070837	Dimensional Drawing Lock Ring, 18-3/4" 10M# 'DL' Annular BOP
CAM_CIV_0070838	CAM_CIV_0070838	Closing Pressure Required by 18-10 D/DL Annular
CAM_CIV_0070839	CAM_CIV_0070839	Design Validation
CAM_CIV_0070840	CAM_CIV_0070841	Engineering Test Specification
CAM_CIV_0070842	CAM_CIV_0070842	Strain - Gauge Tests (1st Run) / 18 3/4" - 10,000# W.P. Studded X Studded Type D BOP
CAM_CIV_0070843	CAM_CIV_0070844	18 3/4 10 KSI 'D' BOP
CAM_CIV_0070845	CAM_CIV_0070846	18 3/4 - 10M 'D' BOP at 15000 PSI Finite Element / Strains in (Illegible), Stress in KPSI
CAM_CIV_0070847	CAM_CIV_0070856	Untitled
CAM_CIV_0070857	CAM_CIV_0070860	Untitled

CAM_CIV_0070861	CAM_CIV_0070869	18 3/4 - 10000 D BOP Strain Gage Test Top Bore Hoop Strain CH-18, 19
CAM_CIV_0070870	CAM_CIV_0070871	Untitled
CAM_CIV_0070872	CAM_CIV_0070872	Engineering Report Abstract / Report Number: 1955 / Stripping Life Test - Standard 18-3/4" - 10M Annular Packer
CAM_CIV_0070873	CAM_CIV_0070873	Engineering Report Abstract / Report Number: 3600 / 18-3/4: 10M Annular, Cold Temperature Test
CAM_CIV_0070874	CAM_CIV_0070874	Engineering Report Abstract / Report Number: 3311 / Sealing Performance Test, 18-3/4" 10M DL Annular for BP Paul B Loyd Junior Flat Packs at Cold Temperature
CAM_CIV_0070875	CAM_CIV_0070875	Engineering Report Abstract / Report Number: 3221 / 18-3/4" 10M DL Annular High Temperature Test
CAM_CIV_0070876	CAM_CIV_0070876	Engineering Report Abstract / Report Number: 3043 / 18-3/4"-10M D/DL Annular Packer/Donut Assembly Fatigue Testing
CAM_CIV_0070877	CAM_CIV_0070877	Engineering Report Abstract / Report Number: 3221 / 18-3/4" 10M DL Annular High Temperature Test
CAM_CIV_0070878	CAM_CIV_0070878	Engineering Report Abstract / Report Number: 3320 / 18-3/4" 10M Type' D/DL' Annular Assembly with M1-84 Compound with no Post Cure Qualification Fatigue Test
CAM_CIV_0070879	CAM_CIV_0070879	Engineering Report Abstract / Report Number: 3311 / Sealing Performance Test, 18-3/4" 10M DL Annular for BP Paul B Loyd Junior Flat Packs at Cold Temperature
CAM_CIV_0070880	CAM_CIV_0070880	Engineering Report Abstract / Report Number: ER-3653 / Fatigue Test on 18 3/4"-10M Annular Assembly with Molded Bore
CAM_CIV_0070881	CAM_CIV_0070881	Engineering Report Abstract / Report Number: 3600 / 18 3/4"-10M DL Annular, Cold Temperature Test
CAM_CIV_0070882	CAM_CIV_0070882	Engineering Report Abstract / Report Number: ER-3769 / Fatigue Test on 18 3/4"-10M D/DL Annular Assembly Manufactured with Compound M1-85 Mixed by Gold Key
CAM_CIV_0070883	CAM_CIV_0070883	Design Review & Verification
CAM_CIV_0070884	CAM_CIV_0070884	18 3/4" -10,000 D/DL Annular BOP Product Requirements
CAM_CIV_0070885	CAM_CIV_0070887	Type Approval Certificate No. D-2999

CAM_CIV_0070888	CAM_CIV_0070889	Independent Review Certificate No: HOE-318920/2008
CAM_CIV_0070890	CAM_CIV_0070890	Design Changes
CAM_CIV_0070891	CAM_CIV_0070891	Engineering Report Abstract / Report Number: 3043 / 18 3/4"-10M D/DL Annular Packer/Donut Assembly Fatigue Testing
CAM_CIV_0070892	CAM_CIV_0070892	Engineering Report Abstract / Report Number: 3320 / 18 3/4"-10M Type 'D/DL' Annular Assembly with M1-84 Compound with no Post Cure Qualification Fatigue Test
CAM_CIV_0070893	CAM_CIV_0070893	Engineering Report Abstract / Report Number: ER-3653 / Fatigue Test 18 3/4"-10M Annular Assembly with Molded Bore
CAM_CIV_0070894	CAM_CIV_0070894	Engineering Report Abstract / Report Number: ER-3769 / Fatigue Test on 18 3/4"-10M D/DL Annular Assembly Manufactured with Compound M1-85 Mixed by Gold Key
CAM_CIV_0270293	CAM_CIV_0270299	Cameron Engineering Bulletin 859
CAM_CIV_0311314	CAM_CIV_0311318	R: Rigs w/Cameron BOP stack with 2 shear ram cavities
CAM_CIV_0334582	CAM_CIV_0334767	02_TLBOP with ST-Locks.pdf
CAM_CIV_0335363	CAM_CIV_0335363	CC-TLBOP-ST-06 Accessories and Options.ppt
CAM_CIV_0357411	CAM_CIV_0357474	Engineering Report Abstract / Report Number: 3815 / 18-3/4 15K TL cDVS Ram Fatigue Test
CAM_CIV_0375738	CAM_CIV_0375741	Field Performance Reports - FPR Number 221870.pdf
CAM_CIV_0375743	CAM_CIV_0375746	Field Performance Reports - FPR Number 221928.pdf
N/A	N/A	Joint Cover Memo and BOEM Report
N/A	N/A	Republic of the Marshall Islands Investigation Report
N/A	N/A	Expert Report of Gregg Perkin (PSC)
N/A	N/A	Expert Report of Rory Davis (US)
N/A	N/A	30 CFR 250.442 and 30 CFR 250.443
N/A	N/A	30 C.F.R. 250.442(b)
N/A	N/A	2011-09-23 Expert Report of Greg Childs (Transocean).pdf
N/A	N/A	30 CFR 250.413
N/A	N/A	FEA drill pipe buckling and shearing models and associated files
N/A	N/A	Macondo Well Incident, Cameron 18-3/4" - 15,000 TL-BOP, Calculation of vertical friction of 5-1/2" Drill Pipe in 6-5/8" - 3-1/2" Variable Bore Pipe Rams (VBRs)

PSC-MDL2179-005060	PSC-MDL2179-005259	DNV Report Vol. I
PSC-MDL2179-005260	PSC-MDL2179-005610	DNVReport Vol. II
TRN-INV-00032368	TRN-INV-00032372	DOC-00008012 HQS_OPS_EAL_BOPR_005.pdf
TRN-INV-01747442	TRN-INV-01747659	Transocean Investigation Report Vol. 1.pdf
TRN-INV-01747660	TRN-INV-01748295	Transocean Investigation Report Vol. 2.pdf
TRN-MDL-00001641	TRN-MDL-00001680	
TRN-MDL-00049105	TRN-MDL-00049519	RBS 8D - Multiplex BOP Control System Volume 1 - System Manual, Maintenance Valves & Regulators
TRN-MDL-00069825	TRN-MDL-00069837	
TRN-MDL-00272700	TRN-MDL-00272832	SINTEF Report
TRN-MDL-00501351	TRN-MDL-00501374	Technical Information Bulletin
TRN-MDL-00505381	TRN-MDL-00505418	Transocean DP Incident Summary and Analysis
TRN-MDL-01622406	TRN-MDL-01622529	bp Omission Profile 042902_.doc
TRN-MDL-02170944	TRN-MDL-02170945	SK-019490-04.DWG

Appendix B:

Resumé of Forrest Earl Shanks II

FORREST EARL SHANKS II

Professional Experience

October 17, 2011

SUMMARY OF KEY PROFESSIONAL/TECHNICAL SERVICES

- BOP and Controls Safety Critical Systems Evaluation
- Drilling Technology Evaluation and Development
- Offshore Drilling Operations Support
- Riser and BOP Stack and Controls Specification for Deepwater and Harsh Environment Applications
- HPHT BOP and Well Control Equipment Design and Evaluation
- Detailed Machine Design – Design, Review, Evaluation plus Failure Analysis
- Teaching Offshore Drilling Operations – MetOcean, Stability, Marine Structures and Equipment, Drilling Equipment, and Drilling Operations
- Mobil Offshore Drilling Unit (MODU) Design Specifications and Operability Inspections for Floaters and Jack-ups
- Riser Analysis for all types of MODU's, jack-ups to ultra-deepwater floaters
- Station Keeping Analysis for moored and dynamic positioned MODU's
- J-Lay Flowlines From MODU Design and Evaluation
- Marine Drilling Riser Assurance Assessment

GENERAL PROFESSIONAL SUMMARY

Mr. Shanks has varied experience in the design, analysis, implementation, and operation of equipment used on offshore drilling vessels. His assignments have ranged from the detailed design engineering of subsea and deck equipment, the use and maintenance of drilling equipment offshore, operations drilling superintendent, to the management of major projects for offshore drilling rig operations. He has spent the majority of his career working on the development and application of new subsea technology, especially deepwater. He has also gained experience in the design, development and installation of subsea production systems. He pioneered Slim Hole drilling technology for Mobil and proved the technology with a test well in Dallas and two exploration discovery wells in the Bolivia jungle.

Oceaneering International – April 2011 to Present
Chief Technologist, Oceaneering Intervention Engineering (OIE)
He reports to the Vice President of OIE who is responsible for multiple Product Groups and supports technical activities within the various groups.

BOP Controls Group
Primary responsibility for 2011 has been the support of the BOP Controls Group within OIE. Mr. Shanks has managed the development of several new products and worked with the BOP Controls Management to explore new product lines and new business opportunities.

Consulting to the Offshore Industry, May 2004 – March 2011
Working through Deepwater Technology Company, DTC, a deepwater consulting company, Mr. Shanks has worked on several projects for BP for the last 6 years.

Review and Recommendations for BOP Safety Systems
Before leaving his consulting position at BP, he reviewed rigs under contract to BP for their shearing (Blind/Shear and Casing Shear) capability and the design of their safety critical systems (emergency disconnect sequence, deadman and autoshear systems) and worked with the BP Rig Teams and Contractors to determine if any upgrades were required.

BOP and BOP Controls Investigation
Reviewed and provided technical support for the internal BOP investigation of the Horizon incident.

HPHT Well Control Equipment
He participated in a High Pressure and High Temperature (HPHT) project and was responsible for the design of well control equipment for working pressures to 25,000 psi. The project produced preliminary designs for 20,000 and 25,000 psi Ram BOP bodies and completed the Detailed Engineering Phase during first half 2009. In addition to the BOP's, vessel and other well control equipment have been specified and detailed upgrade procedures have been written for several deepwater MODU drilling vessels. The next Phase of the HPHT Project was to manufacture and qualify an 18 3/4" - 20,000 psi Ram BOP; however the project was terminated in mid-2009.

Marine Drilling Riser Assurance Assessment
Review the design and fatigue assessment of a new marine drilling riser system for two new drillships, Thunder Horse PDQ, and various other rigs presently under contract. Participate in the writing of a standard practice for reviewing new and existing marine drilling riser systems.

API Recommended Practice 6HP and PER15K
As part of his HPHT Project efforts, he has participated in an effort by API to write a technical report on the design verification of HPHT equipment, originally called API RP 6HP. API has consolidated the on-going HPHT efforts. Design Verification, Design Validation, and the HPHT Materials Group have been joined into one Task Group, Protocols for Equipment Rated Greater than 15 KSI, PER15K. Mr. Shanks is the Chairman of the Design Verification effort of the Task Group. The end result will be an API Technical Report. The timing for the draft report is June 2010 with the API balloting process on-going the rest of the year.

Deepwater J-Lay of Flowlines from a MODU
The other project which has been completed, for BP, is the design of using an existing deepwater drilling vessel to J-Lay flowlines in water depths to 10,000 ft. He was the primary author of a Preliminary Engineering Study during the summer of 2004. The conclusions in this report lead to a

detailed design project performed by GMC for 18 months. Mr. Shanks supported the technical efforts of this project spending approximately 15% of his time on the project.

TRANSOCEAN, October 1998 – October 2003
Director Technology Development

The job responsibilities focus on three main areas.

- Participate in the development of new technology in Transocean projects.
- Provide a means Transocean retains lessons learned from these projects.
- Keep up with the most current technology inside and outside the oil and gas industry.
- Co-Chairman for a IADC Committee writing Guidelines for Surface BOP Planning and Operations

Major topics evaluated for technical and economic feasibility include:

- Novel Free Standing Riser designed for possible installation on the Enterprise Class drillship
- Surface BOP designs for application with and without a seafloor isolation system. In addition to design studies, reliability studies were performed comparing to conventional and various arrangements of Surface BOP systems.
- A major study was conducted on improving the reliability of deepwater Mux BOP Control Systems. The goal was to design and prove a system could be built to go 5 years between major maintenance.
- Surface BOP applications for use on dynamically positioned drilling vessels.
- New technologies were continually evaluated to determine industry and Transocean rig fleet impact. These technologies include expandable tubulars, casing drilling, connectionless casing, lightweight risers, and many more.
- Mud Lift drilling technologies were continually evaluated for all active JIP's including DeepVision, Conoco Hydril, Shell, Mauer, and PSL.
- Various J-Lay methods from drilling vessels were analyzed. Engineering designs were performed to show feasibility.
- Casing and liner drilling methods were evaluated for application on offshore drilling units including jack-ups and floaters.
- Connectionless casing designs were evaluated including laser and induction welding.

MOBIL OIL, AUGUST 1985 – SEPTEMBER 1998
Team Leader for the Technical Rig Upgrade Project

The Tranche 6 Project was initiated in 1992 to determine feasibility; the drilling area is a harsh environment area with deepwater, 5000 feet, and high ocean currents. The drilling conditions will be as severe as have been drilled in the offshore industry. Working on a suitcase project basis, Mr. Shanks supported the preparations of MNSL to drill their deepwater acreage West of the Shetland Islands. During 1995, a series of Definition Engineering Studies were performed to determine the requirements of the drilling rig and specify what upgrades and additional equipment would be necessary to safely and efficiently drill in the area. The engineering studies utilized Mobil and outside contractors to accomplish the results. The 1996 and early 1997 efforts were dedicated to preparing final design details and awarding contracts to supply equipment upgrades and construct additional equipment. The first Tranche 6 well was spudded June 1998.

MEPTEC Drilling Group Leader – Special Drilling Technologies

Mr. Shanks was a Group Leader in the MEPTEC Drilling Group responsible for Special Drilling Technologies. The group was formed in 1992.

- Teaching Instructor for Mobil's Offshore Floating Drilling Courses worldwide
- The group was responsible for Offshore Drilling Technical Support and emerging technologies for drilling in general.
- Responsible for reviewing BOP capabilities for the specific wells to be drilled and responsible for any BOP modifications or upgrades.
- He performed all riser and mooring analysis for MODU drilling applications worldwide.
- Responsible for writing several drilling vessel performance requirements for evaluation prior to contract award.

Drilling Superintendent

Mr. Shanks was responsible for Mobil Drilling's research in Slim Hole Technology. A test well was drilled at Mobil's Research Lab during the first quarter of 1991. The test well provided practical hands on experience with the technology and provided a slim hole test laboratory to perform extensive borehole hydraulics tests and practice well control techniques. The information gained from the test well was utilized to plan two exploration wells in the Madre De Dios Block in Northern Bolivia. Mr. Shanks was the Drilling Superintendent for the two wells in Bolivia. He spent most of 1991 living in Santa Cruz, Bolivia as the Mobil responsible representative in Bolivia for the two well Slim Hole Program.

Drilling Technology Group Leader – MODU Drilling Technology

Mr. Shanks was a Group Leader in the Drilling Technology Section of Mobil's Drilling Operations Group responsible for MODU Drilling Technology. The Group was formed in 1987. Drilling Technology supported Mobil's drilling activities on a world-wide basis. The primary activities of the Floating Drilling Group were:

- Provide worldwide technical support for Mobil's MODU drilling activities.
- Head a Mobil technical team of various technical capabilities to inspect and evaluate MODU vessels to meet project requirements prior to contract award.
- Acquire and develop in-house technology and capability to drill in 7500 ft. of water by year-end 1989. This effort will be followed by 10,000 ft. capability.
- Recruited by State Department to serve on a Commerce Department COCOM Committee with permission from Mobil. Obtained Secret clearance to make recommendations on defense sensitive technical equipment which should be shared with NATO friendly and un-friendly countries. His specialty on the committee was Deepwater MODU's (lifting capacity) and subsea equipment.
- Wrote the new Mobil Offshore Floating Drilling Course Manual and taught the course worldwide when needed.
- Designed and build equipment to drill in 2700-ft. water depth with the influence of the Gulf Stream (6 kts). This project combined deepwater and high current technology. This was an18 month and a 10 man-year technology project. It required detailed analysis of the mooring, riser and BOP Stack to withstand the current effects.
- Wrote a pre-contract award document for floating drilling operations which details the minimum acceptance standards for Mobil Drilling worldwide.

- Chairman of the Technical Engineering Development Committee (TEDCOM) for the National Science Foundation (and other countries) funded Ocean Drilling Project. This committee was technical oversight on the technical aspects of the project managed by Texas A&M.

Subsea Development Engineer

While working at Mobil's Offshore R&D group in Dallas for two years, 1985 to 1987, Mr. Shanks worked on various projects. These included:

- Writing the control system specifications and performing customer quality control and acceptance testing for the Ness Field subsea development in the North Sea.
- Writing the installation procedures for Mobil's Deepwater Production Riser.
- A re-design and operation's test of a specialty bilge pump used on Mobil's Subsea Atmospheric System.
- Work on various subsea production schemes to meet the needs of Mobil Exploration and Production needs world-wide.

SEDCO Inc., April 1976 – July 1985

Manager Systems Engineering

While at SEDCO, during 1976 - 1985, he was Manager of the Systems Engineering group (1981-1985). Systems Engineering had responsibilities for Special Projects for SEDCO and its customers, as well as the operational engineering support of the surface and subsurface drilling equipment. During the nine and one half years at SEDCO he worked on various significant projects and also worked offshore as an equipment engineer on the SEDCO 709. These projects include:

- Responsible for the specification, design, manufacture, delivery, and installation of 29 new build and up-grade MODU drilling systems including BOP and well control systems. These included jack-up and floating drilling units. Four of the units were Multiplex electro-hydraulic deepwater systems.
- Involvement in the design, development and operation of the drilling equipment to be used in 6000 ft of water for the drilling vessels Sedco 471, 472, 709, and 710. All of which are capable of drilling dynamically positioned in deepwater.
- Deepwater Blowout Preventer Recovery - A mechanical problem on the SEDCO 471 BOP allowed the lower half of the BOP to be dropped in 3150 ft. of water off Australia. Designed and supervised the construction of the recovery tools in about 30 days which retrieved the BOP in less than two days.
- Piling Installation from a Dynamic Stationed Drillship - Eight pilings, 5 ft. diameter, 2 1/2 in. wall, 92 ft. long, were installed in the North Sea by the SEDCO 445 DP drillship using an underwater hammer. Responsible for the design, modification, and use of the equipment onboard the SEDCO 445.
- Subsea Choke (patented) - Designed, built, and tested the first subsea drilling choke for use on an offshore dynamically positioned drilling vessel. Patented.
- Riser Recoil Prevention System (patented) - Responsible for the design, installation, and testing of the first of its kind riser recoil preventer systems used on the SEDCO 471, 472, 709, and 710 dynamically positioned drilling vessels
- Ocean Drilling Project - Design of 30,000 ft. drill string, and the design of a bending restrictor for drill pipe to allow for vessel roll of $\pm$ 7 degrees for drilling (rotating) and survival of $\pm$ 10 degrees, plus various other tools for the project.

- Other Projects - The design and testing of a new generation of high current drilling equipment including riser fairings, riser restraint system, and techniques for safe operation of drilling vessels in the high currents around the world.

VETCO Offshore in Ventura, California, January 1975 - April 1976
Design Engineer
While at VETCO he was responsible for designing of deepwater State of the Art subsea marine systems. His designs included high strength riser couplings (patented), rotating tension rings using fluid bearings, and new methods for subsea production using subsea tree clusters. He was the first in-house engineer to use finite element analysis (FEA) for equipment design. He also was the first to use and set up the capability to use strain gauges to validate design stress in prototype equipment designs.

Baylor Company, January 1974 - January 1975
Design Engineer
His first job out of school was with the Baylor Company in Houston, Texas. At the Baylor Company he was a design engineer and was responsible for the design of components for use on 3 in. chain mooring windlasses for semisubmersibles, various components on thrusters which are used for dynamic positioning of drilling vessels, and a new design riser coupling for use in deepwater applications. On a field assignment he was the responsible mechanical engineer to start up the SEDCO 704 mooring windlass' in Halifax harbor in 1974. Designed, built and tested a new design drilling riser connector.

Education

Master of Science, Mechanical Engineering, Oklahoma State University, 1973 (Pi Tau Sigma)
Bachelor of Science, Mechanical Engineering, University of Houston, 1972
High School, John Tyler High School, Tyler, Texas

Military

United States Marine Corps
Active duty July 1968 to Jan 1970, Viet Nam all of 1969
Combat Marine Rifleman, MOS 0311, Several Commendations, one with Valor

Hobbies

- Metal working in small home machine shop. Experienced in the use of machine tools including lathe and mill work.
- Hunting and other shooting sports, Golf, Scuba Diving, Riding Motorcycles,
- Collecting and working on classic cars

Patents

"Variable Incompressible Buoyancy for Ultra-Deepwater Risers", Mobil, 1998
"Subsea Drilling Choke System", SEDCO, 1979

"Riser Recoil Preventer System", SEDCO 1980
“Pipe Connector (Riser)”, Vetco Offshore, 1978

Publications and Presentations

DRILLING SAFETY RULES - WELL CONTROL EQUIPMENT - BOP and CONTROLS
Earl Shanks, Oceaneering; Frank Gallander, Chevron
Offshore Compliance Forum, September 2011, Galveston, TX

EQUIPMENT ADVANCES and NEW LEGISLATION EFFECTS
Earl Shanks, Oceaneering
IADC Well Control of the Americas, August 2011, San Antonio, Texas

SEAFLOOR ISOLATION DEVICE for SURFACE BOP SPAR DRILLING
Earl Shanks, DTC; Ross Fraser, ATP; Margaret Buckley, DTC
OTC Panel Discussion/Presentation, May 2010, Houston, TX

RECOMMENDED PRACTICE for EQUIPMENT with PRESSURE RATING GREATER than 15,000 PSI
Earl Shanks, DTC: Kenneth Young, Mohr Engineering Services
World Oil HPHT Drilling and Completions Conference, 2-3 April 2008, Houston, TX

DEVELOPMENT OF A 20,000 PSI WELL CONTROL SYSTEM FOR ULTRA-DEEPWATER
Earl Shanks, DTC
IADC Well Control Conference of the Americas, Aug 2007, Galveston, TX

RIG OF THE FUTURE
Earl Shanks, DTC; Scott McGrath, Transocean
SPE 2006 ATW, Strategies and Solutions for HPHT Drilling and Completions, Galveston, TX

UPDATED DESIGN METHODS FOR HPHT EQUIPMENT
Kenneth Young, Chris Alexander, Richard Biel, Stress Engineering Services; Earl Shanks, DTC
IADC Deepwater Drilling Conference, Oct 2005, Rio de Janeiro

A REVIEW OF HIGH CURRENT OPERATIONS AND EQUIPMENT
Earl Shanks, Riddle Steddum, Transocean
10th Annual India Oil and Gas Review Symposium & International Exhibition, 2003 Bombay India

EVALUATING THE ECONOMICS FOR USING DYNAMICALLY POSITIONED DRILLING VESSELS OR MOORED VESSELS FOR FLOATING DRILLING OPERATIONS, Earl Shanks, Jim Sikes, John May, Transocean
10th Annual India Oil and Gas Review Symposium & International Exhibition, 2003 Bombay, India

DEEPWATER BOP CONTROL SYSTEMS-A LOOK AT RELIABILITY ISSUES
Earl Shanks, Transocean; Andrew Dykes, Marc Quilici, John Pruitt, ABS Consulting
OTC 15194, 2003

SURFACE BOP RELIABILITY ISSUES FOR DEEPWATER FLOATING DRILLING RIGS, Earl Shanks, Jim Schroeder, Transocean Sedco Forex, John Pruitt, ABS Consulting, IADC World Drilling 2002, Madrid, Spain

SURFACE BOP FOR DEEPWATER MODERATE ENVIRONMENT DRILLING OPERATIONS FROM A FLOATING DRILLING UNIT, Earl Shanks, Jim Schroeder, Bill Ambrose, Riddle Steddum, Transocean Sedco Forex, OTC Houston 2002

A NEW GENERATION OF A FIELD DEVELOPMENT DRILLSHIP
Earl Shanks, Don Ray, and Andy Cates Transocean Sedco Forex
ETCE 2000/Drill-10093 ETCE-OMAE Conference February 2000

AN OVERVIEW OF PREPARATIONS FOR DRILLING AT A HIGH CURRENT, DEEP WATER SITE: TRANCHE 6 WEST OF SHETLAND, Earl Shanks, Iain Graham, Frank DelloStritto, SNAME Conference, Houston, Texas February 1997.

SLIM HOLE ADVANCEMENTS ALLOW ECONOMIC OFFSHORE EXPLOITATION, Earl Shanks, Petroleum Engineer International July 1995.

DEEPWATER PREPARATION FOR RIG OPTIONS/AVAILABILITY, F. E. Shanks, Mobil Oil, Caspian Oil And Gas Conference, 1994

SLIM HOLE EXPLORATION REQUIRES PROPER TECHNICAL PREPARATION,
F. E. Shanks II., Mobil, K. R. Williams, Longyear, SPE Conference 1993.

THE LOOP CURRENT EXPERIENCE - EWING BANK 871, D.B. Lewis, J.B. Adams, F.E. Shanks, D. Szabo, Mobil, JPT, September 1991.

HIGH CURRENT, DEEPWATER DRILLING EXPERIENCES, F. E. Shanks, Sedco Inc., SPE/IADC Conference, 1985.

DEEPWATER HIGH CURRENTS CALL FOR SPECIAL EQUIPMENT (Part 1), Earl Shanks, World Oil, July 1983.

DRILLING HIGH-CURRENT LOCATIONS REQUIRES SPECIAL PREPARATION (Part 2), Earl Shanks, World Oil, August 1983.

THE 15,000 PSI BOP SYSTEM FOR OFFSHORE DRILLING, Earl Shanks, Jack Nabors, Jon Gean, Offshore Technology Conference, 1982.

BOP RECOVERY IN 3,000 FOOT WATER DEPTH, Forrest E. Shanks, Earl G. Miko, Offshore Technology Conference, 1981.

EXPERIENCE DRILLING DEEPWATER HIGH CURRENT AREAS, F. E. Shanks, D. S. Hammett, H. L. Zinkgraf, Offshore Technology Conference, 1979.

FLUID BEARINGS USED IN ROTATING TENSION RINGS, Earl Shanks, Ron Weber, Ed Larralde, Vetco Offshore, Offshore Technology Conference, 1976.

<u>Appendix C</u>:

Calculation of vertical friction on 5-1/2” Drill Pipe in 6-5/8” - 3-1/2” Variable Bore Pipe Rams (VBRs)

MACONDO WELL INCIDENT

Cameron 18-3/4" - 15,000 TL-BOP

Calculation of vertical friction on 5-1/2" Drill Pipe
in 6-5/8" - 3-1/2" Variable Bore Pipe Rams (VBRs)

Objective:

To establish likely vertical friction force on the DP with the two upper sets of VBRs closed around the pipe under the well bore conditions at the time of incident.
The calculations assume the full well bore pressure differential across the middle VBRs and hydrostatic pressure from the riser acting on the upper VBRs.

References:

- Cameron VBR analysis CAM_CIV_0070558
- MDL2179-EX-00001164 (DNV Report Vol. I)
- The Stress Engineering Services Analysis of the DWH Work String Appendix 'C', page 29.
- Coefficients of friction, Rubber - Steel and Steel - Steel:
  * Various Engineering Handbooks on http://www
  * http://www.raib.gov.uk/cms_resources.cfm?file=/091029_R272009_RRV.pdf, pg 26
  * http://deepblue.lib.umich.edu/bitstream/2027.42/6373/5/bac8280.0001.001.pdf, pg 19
  * Mr. Roller: http://www.mrroller.com/index.cfm?page=_geninfo

The following calculations are done with MathCad 13.

Input variables:

Symbols and relevant input variables are the same as in Cameron's analysis for this size VBRs (CAM_CIV_00705581).

Operator Cylinder Diameter: $dia_{op} := 18.044$ [In]

Connecting Rod Diameter: $dia_{cr} := 6.743$ [In]

Tail Rod Diameter: $dia_{tr} := 4.623$ [In]

Operator Cylinder Area: $A_{op} := \frac{\pi}{4} \cdot dia_{op}^2$

$A_{op} = 255.7$ [In2]

Connecting Rod Area: $A_{cr} := \frac{\pi}{4} \cdot dia_{cr}^2$

$A_{cr} = 35.7$ [In2]

Tail Rod Area: $A_{tr} := \frac{\pi}{4} \cdot dia_{tr}^2$

$A_{tr} = 16.8$ [In2]

Hydraulic Closing Pressure: $P_{os} := 1500$ [psi] Diff. pressure vs. sea pressure.

Water depth: $h_w := 5000$ [ft]

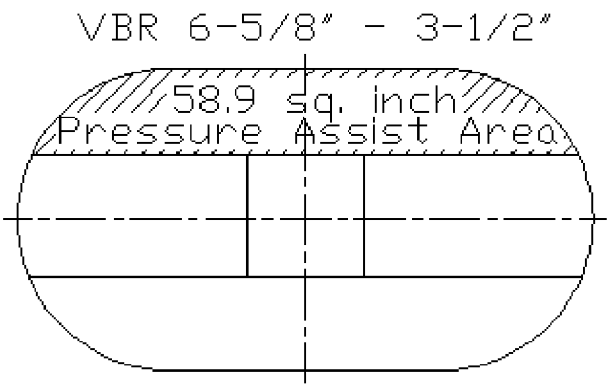
Density of seawater: $\rho_{sw} := 8.5787$ [lb/gal]

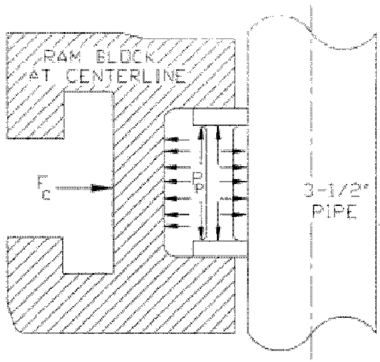
Hydrostatic pressure from sea: $P_w := \rho_{sw} \cdot h_w \cdot 0.05195$

$P_w = 2.228 \times 10^3$ [psi]

Variable Bore Rams:

The VBR is a variable bore ram design. It is designed to seal when closed on 7-5/8" to 3-1/2" diameter pipe. The packers implement the use of plate ribs to prevent/reduce extrusion of the rubber during service when used with different pipe sizes. When the rams are closed on pipe, the extrusion plate ribs are pushed into the packer.





Front Face Unbalanced Area: $A_f := 58.887$ [In^2] Ref. CAM_CIV_0070558 3.f on page 4

Rubber Area of Packer: $A_R := 103.046$ [In^2] Ref. CAM_CIV_0070558 4.c on page 6

Forces on middle VBRs:

Well bore Differential Pressure: (across middle VBRs) $P_{wbm} := 8000$ [psi] Ref. SES Analysis of the DWH Work String, Appendix 'C', page 29

Closing force from Hydr. Operator: $F_{Owp} := (A_{op} - A_{tr}) \cdot P_{os} + A_{tr} \cdot P_w - A_{cr} \cdot P_{wbm}$

$F_{Owp} = 1.101 \times 10^5$ [lbf]

Total Closing Force on Ram at well bore differential pressure and operating system pressure:

Closing Force upper VBRs: $F_{cm} := F_{Owp} + A_f \cdot P_{wbm}$

$F_{cm} = 5.812 \times 10^5$ [lbf]

Forces on upper VBRs:

Well bore Hydrostatic Pressure: $P_{wbu} := 500$ [psi] Ref. SES Analysis of the DWH Work String, Appendix 'C', page 29

Closing force from Hydr. Operator at hydrostatic pressure in well bore: $F_{Ohp} := (A_{op} - A_{tr}) \cdot P_{os} + A_{tr} \cdot P_w - A_{cr} \cdot P_{wbu}$

$F_{Ohp} = 3.779 \times 10^5$ [lbf]

Total Closing Force on Ram at hydrostatic well bore pressure and operating system pressure:

Closing Force upper VBRs: $F_{cu} := F_{Ohp} + 0.0$ (i.e. No diff. pressure across upper VBRs.

$F_{cu} = 3.779 \times 10^5$ [lbf]

Rubber Pressure in middle VBR Packers:

The total closing force on a ram is opposed by the same force from the opposite ram through the packers. The total closing force is then the projection of the packer force in a plane perpendicular to the ram and operator axis.
The pressure in the rubber is created by the force from the operator plus the force from the unbalanced area of the ram (pressure assist area) and the well bore pressure.

Rubber Pressure from Closing Force: $P_{Rm} := \frac{F_{cm}}{A_R} + P_{wbm}$

$P_{Rm} = 13640$ [psi]

Rubber Pressure in upper VBR Packers:

Rubber Pressure from Closing Force: $P_{Ru} := \frac{F_{cu}}{A_R} + P_{wbu}$

$P_{Ru} = 4168$ [psi]

Clamping Force on Drill Pipe:

The total clamping or crimping force on the drill pipe through a set of VBRs is the sum of contact force from the rubber and the contact force from the anti extrusion plates or fingers all around the DP.

Drill Pipe Diameter:	$DP_{od} := 5.50$	[In]	
Packer Slot Height:	$h_{pack} := 4.727$	[In]	Ref. CAM_CIV_0070558 page 4
Anti Extrusion Plate Thickness:	$t_{aep} := 0.5$	[In]	(assumption)
Anti Extrusion Plate OD:	$AE_{od} := DP_{od} + 3$		(assumption)
	$AE_{od} = 8.5$	[In]	
Rubber Contact Area:	$A_{rca} := \pi \cdot DP_{od} \cdot \left(h_{pack} - 2 \cdot t_{aep}\right)$		
	$A_{rca} = 64.398$	[In2]	
AEP Contact Area to DP:	$A_{aep} := \pi \cdot DP_{od} \cdot 2 \cdot t_{aep}$		
	$A_{aep} = 17.279$	[In2]	

Clamping Force from middle VBRs on Drill Pipe:

Rubber Clamping Force on DP: $F_{rcm} := A_{rca} \cdot P_{Rm}$

$F_{rcm} = 8.784 \times 10^{5}$ [lbs]

The rubber pressure acts on the OD of the anti extrusion plates that are then pushed into contact with the DP and thereby create a clamping force steel against steel.

AEP Clamping Force on DP: $F_{aepm} := AE_{od} \cdot P_{Rm}$

$F_{aepm} = 1.159 \times 10^{5}$ [lbs]

Clamping Force from upper VBRs on Drill Pipe:

Rubber Clamping Force on DP: $F_{rcu} := A_{rca} \cdot P_{Ru}$

$F_{rcu} = 2.684 \times 10^{5}$ [lbs]

AEP Clamping Force on DP: $F_{aepu} := AE_{od} \cdot P_{Ru}$

$F_{aepu} = 3.543 \times 10^{4}$ [lbs]

Force to pull or push DP through VBRs:

The force to pull or push the DP trough the closed VBRs has to overcome the friction created by the contact force (clamping) from the VBR Packers. The clamping force is the sum of the contact force from the rubber and the contact force from the anti extrusion fingers or plates.
The friction is calculated based on a worst case basis (i.e. low friction) to evaluate the likelihood of DP buckling between the VBR and the ABOP. The following is therefore based on sliding and lubricated friction (oil based mud and hydrocarbons contaminated with sand, etc.) .

The following coefficient of friction has been found in "Rail Accident Report", report 27/2009 Web site http://www.raib.gov.uk/cms_resources.cfm?file=/091029_R272009_RRV.pdf, pg 26

Condition	'Steel-on-steel' μ values	'Rubber on steel' μ values
Dry	0.1 to 0.3	0.6 to 0.9
Wet	0.1	0.12

Table 3: indicative coefficient of friction values

The following coefficient of friction has been found on web site http://www.mrroller.com/index.cfm?page=_geninfo

Rubber against steel:	Coefficient of friction:
Dry sliding friction	0.70
Wet (water) sliding friction	0.30
Lubricated sliding friction	0.1 – 0.2

In this application with oil based mud and high contact pressure a coefficient of 0.2 is probably a minimum. However, the high contact force may create a much higher cof as discussed in several papers published.

Coefficients of friction for steel against steel normally found in engineering handbooks are:

Steel against steel:	Coefficient of friction:
Dry sliding friction	0.10
Lubricated sliding friction	0.10
Dry static friction	0.15
Lubricated static friction	0.12

Selected values for coefficient of friction:

Coefficient of friction for Rubber against Steel: $\mu_{rs} := 0.3$

Coefficient of friction for Steel against Steel: $\mu_{ss} := 0.1$

Required axial force to buckle the drill pipe:

According to the DNV report, Volume I, the required axial force for the drill pipe to buckle is about 113,560 lbf for a length equal to the distance between the upper VBR and the upper ABOP (27,3 ft).

Buckling force: $F_B := 113568$ [lbf] Ref. MDL2179-EX-00001164 DNV Report Vol. I, page 151

Friction force from middle VBR on Drill Pipe:

Force to overcome Friction: $F_{Fm} := F_{rcm} \cdot \mu_{rs} + F_{aepm} \cdot \mu_{ss}$

$F_{Fm} = 275116$ [lbf]

Friction force from upper VBR on Drill Pipe:

Force to overcome Friction: $F_{Fu} := F_{rcu} \cdot \mu_{rs} + F_{aepu} \cdot \mu_{ss}$

$F_{Fu} = 84060$ [lbf]

Required upward force to buckle the drill pipe:

The required upward force from the drill pipe below the VBRs for buckling to take place between the closed upper VBR and the closed upper ABOP will then be the sum of required buckling force plus the friction through the closed VBRs.

$$F_{Upw} := F_B + F_{Fm} + F_{Fu}$$

$F_{Upw} = 472744$ [lbf]