IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF LOUISIANA

In re: Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico, on April 20, 2010,	* * * *	**MDL 2179**
	*	**SECTION J**
This Document Applies To:	* *	
No. 10-2771, In re: The Complaint and Petition of Triton Asset Leasing GmbH, et al.	* * *	**JUDGE BARBIER**
and	* *	**MAG. JUDGE SHUSHAN**
No. 10-4536, United States of America v. BP Exploration & Production, Inc., et al.	* *	

FINDINGS OF FACT AND CONCLUSIONS OF LAW

PHASE TWO TRIAL

Pursuant to Federal Rule of Civil Procedure 52(a), the Court enters these Findings of Fact and Conclusions of Law relative to the Phase Two trial. If any finding is in truth a conclusion of law or any conclusion stated is in truth a finding of fact, it shall be deemed so, labels notwithstanding.

CONTENTS

I. INTRODUCTION AND PROCEDURAL HISTORY

1. This multidistrict litigation arises from the April 20, 2010, blowout, explosions, fire, and subsequent oil spill involving the mobile offshore drilling unit DEEPWATER HORIZON (sometimes referred to as "HORIZON") and the well, known as Macondo, it had drilled in the Gulf of Mexico approximately fifty miles from the Louisiana coast.

2. Presented here is an abridged version of the procedural history for this multidistrict litigation. The reader is directed to the Findings of Fact and Conclusions of Law for the Phase One trial ("Phase One Findings") for a more thorough account of the procedural history.[1]

3. The Court has held thus far two major trial proceedings. Further trials are planned, including a "Penalty Phase" scheduled to begin on January 20, 2015.

4. The "Phase One" trial was held between February 25, 2013 and April 17, 2013 and consisted of twenty-nine trial days. It addressed fault determinations relating to the loss of well control, the ensuing explosion and fire, the sinking of the HORIZON, and the initiation of the release of oil. After the Phase One trial, the parties submitted memoranda, responses, and proposed findings of fact and conclusions of law.

5. A "Phase Two" trial was then held from September 30, 2013 to October 18, 2013 and consisted of twelve trial days. Phase Two was divided into two segments: "Source Control" and "Quantification." Source Control concerned issues pertaining to the conduct or omissions relative to stopping the discharge of hydrocarbons. The Quantification segment addressed the amount of oil actually released into the Gulf of Mexico. As with the Phase One trial, the parties

[1] Rec. Doc. 13381, 21 F. Supp. 3d 657 (E.D. La. 2014).

submitted post-trial memoranda, responses, and proposed findings of fact and conclusions of law.

6. On September 4, 2014, the Court issued the Phase One Findings,[2] which were revised slightly and re-issued on September 9, 2014.[3] BP subsequently moved to amend the Phase One Findings or for a new trial, which the Court denied on November 13, 2014.[4]

7. The Phase One Findings made numerous factual and legal determinations, only a few of which are mentioned here.

8. With respect to the United States' action for civil penalties under the Clean Water Act's ("CWA")[5] against BP Exploration & Production, Inc. ("BPXP"),[6] the Court found that the discharge of oil was the result of BPXP's gross negligence and willful misconduct. Consequently, the Court concluded that BPXP was subject to a higher maximum penal amount than would apply in the absence of such conduct. However, the Court did not determine the actual penal amount in the Phase One Findings.

9. The Phase One Findings also made fault allocations under general maritime law. The Court attributed 67% of the fault for the blowout, explosion, and oil spill to two BP entities, BPXP and BP America Production Company ("BPAPC"). Transocean (meaning Transocean Holdings LLC, Transocean Deepwater Inc., and Transocean Offshore Deepwater Drilling Inc.) and Halliburton (meaning Halliburton Energy Service, Inc. and Halliburton's Sperry division) bore 30% and 3% of the fault, respectively.

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[2] Rec. Doc. 13355.

[3] Rec. Doc. 13381, 21 F. Supp. 3d 657 (E.D. La. 2014).

[4] Rec. Doc. 13644.

[5] *See* 33 U.S.C. § 1321(b)(7). Citations to statutes or regulations refer to the version applicable on April 20, 2010, unless otherwise stated.

[6] BPXP was not the only party against whom the United States initially sought to enforce CWA penalties. However, because of various rulings, settlements, and stipulations, the claim against BPXP was the only CWA claim at issue during the Phase One trial.

10. Although the Phase One Findings found that certain BP employees acted recklessly, which would normally warrant punitive damages under general maritime law, the Court concluded that, under the circumstances, Fifth Circuit precedent barred the imposition of punitive damages against BPXP and BPAPC. The Phase One Findings found that Transocean's and Halliburton's misconduct did not exceed ordinary negligence; thus, these parties also did not face punitive damages.

11. The Court turns now to the issues presented in the Phase Two trial.

II. Source Control Segment

A. Parties to the Source Control Segment

12. The Source Control segment was tried as a bench trial that began on September 30, 2013, and concluded on October 3, 2013. Participants were the "Aligned Parties" on one side and the BP entities on the other.

13. The Aligned Parties consisted of private plaintiffs and claimants-in-limitation (represented by the Plaintiffs' Steering Committee or "PSC"), the States of Alabama and Louisiana, the Transocean entities (Transocean Offshore Deepwater Drilling Inc., Transocean Holdings LLC, Transocean Deepwater Inc., and Triton Asset Leasing GmbH), and Halliburton Energy Services, Inc.

14. The BP entities were BPXP, BPAPC, and BP p.l.c. (collectively "BP" for purposes of the Source Control segment).

B. Stipulated Facts; Timeline of Source Control Events

15. The parties to the Source Control segment stipulated to certain facts,[7] providing a timeline of source control events. The Court has reproduced these stipulations in paragraphs 16 to 212, below.[8]

i. Terms and Definitions

16. **BOEMRE** - Bureau of Ocean Energy Management, Regulation and Enforcement. This term refers to the federal agency responsible for overseeing the development of energy and mineral resources on the Outer Continental Shelf. This agency was formerly known as Minerals Management Service and is now known as Bureau of Safety and Environmental Enforcement (BSEE) and Bureau of Ocean Energy Management (BOEM).

17. **BOP** - This term refers to the Blowout Preventer used in conjunction with the DEEPWATER HORIZON.

18. **BOP-on-BOP** - This term refers to a contemplated operation to place a second BOP on the DEEPWATER HORIZON BOP.

19. **CDP** - Containment and Disposal Project. This term refers to the efforts to develop and install two Free-Standing Risers in the Gulf of Mexico connected to Floating Production Storage and Offloading ("FPSO") vessels, as a method to contain hydrocarbons flowing from the MC 252 Well.

20. **COFFERDAM** - This term refers to the large metal containment dome that was modified for use in deepwater and utilized in May 2010 in an attempt to contain the flow of hydrocarbons from the end of the parted riser. At the top of the cofferdam, a pipe would channel hydrocarbons to the DISCOVERER ENTERPRISE, a vessel on the surface.

[7] Rec. Doc. 7076.

[8] The Court has omitted citations from the stipulated facts and altered certain fonts to be consistent with the rest of these Findings of Fact and Conclusions of Law. Brackets indicate edits or additional commentary by the Court.

21. **DDII** – DEVELOPMENT DRILLER II. This term refers to Transocean's Mobile Offshore Drilling Unit that drilled the backup intercept relief well beginning on May 16, 2010, until standing down.

22. **DDIII** – DEVELOPMENT DRILLER III. This term refers to Transocean's drilling rig that drilled the first intercept relief well beginning on May 2, 2010, and concluding on September 19, 2010.

23. **FEDERAL SCIENCE TEAM -** This term refers to working groups composed of scientists employed by the Department of Energy labs, at the request of Secretary Chu, including Sandia, Lawrence Livermore, and Los Alamos, as well as scientists from the U.S. Geological Survey, who participated in analysis of source control options. (This term excludes non-governmental Science Advisors who provided advice to Secretary Chu.)

24. **FOSC** - Federal On-Scene Coordinator. This term refers to the federal official designated by the U.S. Coast Guard to coordinate and direct response efforts and coordinate all other efforts at the scene of a discharge or release of oil.

25. **FSR** - Free-Standing Riser. This term refers to a type of riser that is suspended in the water via an air can and suction pile, which allows for rapid connection to and disconnection from a Floating, Production, Storage and Offloading Vessel, used as part of the CDP.

26. **ICS -** Incident Command System. This term refers to a standardized on-scene incident management concept designed specifically to allow responders to adopt an integrated organizational structure scalable to the complexity and demands of any single incident or multiple incidents without being hindered by jurisdictional boundaries.

27. **INDUSTRY REPRESENTATIVES** - This term refers generally to representatives from various companies within the industry, such as BP, Transocean, Cameron,

Wild Well Control, Exxon, and others, who, as appropriate, attended meetings of various project teams focused on the options to capture and/or contain oil flowing from the MC 252 Well and to shut in the MC 252 well.[9]

28. **JUNK SHOT** - This term refers to the operation by which bridging material was injected into the DEEPWATER HORIZON BOP either from the surface or via a subsea manifold as part of the Top Kill operation. This procedure was formally known as "Top Kill Procedure for MC 252-1 Contingency: Alternative LCM Pills."

29. **LMRP** - Lower Marine Riser Package. With respect to the DEEPWATER HORIZON, this term refers to the LMRP that was connected to the BOP and contained the control pods and annular preventers.

30. **LMRP TOP HAT # 4** - This term refers to a containment dome, smaller than the Cofferdam, placed on top of the DEEPWATER HORIZON's LMRP and used to collect and flow hydrocarbons up to the DISCOVERER ENTERPRISE after the DEEPWATER HORIZON's riser was cut off above the LMRP in June 2010.

31. **MC 252 WELL** - This term refers to the exploratory well that was being drilled by the Transocean MARIANAS and DEEPWATER HORIZON rigs in Mississippi Canyon, Block 252 on the outer continental shelf in the Gulf of Mexico. Mississippi Canyon, Block 252 was leased by MMS to BP, Anadarko, and MOEX.

32. **MOMENTUM KILL** - This term refers to the operation by which drilling fluid was pumped into the DEEPWATER HORIZON's BOP at a high rate of speed in an attempt to overcome the flow of hydrocarbons as part of the Top Kill operation.

[9] The use of this term in a specific stipulation does not indicate the participation, or level of participation, of any particular industry company or individual unless otherwise noted. Nor do the parties intend the use of this term to imply whether or not the activities undertaken with industry representatives complied with industry standards.

33. **MMS** - Minerals Management Service. This term refers to the legacy or former federal agency within the U.S. Department of Interior whose name was first changed to BOEMRE and then to BESE and BOEM.

34. **NIC** - National Incident Commander. This term refers to the title and role held by Admiral Thad Allen (ret.) as the senior Federal official overseeing and coordinating the DEEPWATER HORIZON response.

35. **OIL SPILL RESPONSE PLAN** - This term refers to BP's 2009 Regional Oil Spill Response Plan – Gulf of Mexico. BP's 2009 Regional Oil Spill Response Plan – Gulf of Mexico was submitted to MMS for approval on June 29, 2009 and was approved on July 21, 2009.

36. **PEER ASSIST -** This term refers to the process used by project teams to receive evaluations from individuals inside and outside BP for the identification and mitigation of a project's potential risks.

37. **RESPONSE** – This term refers to efforts to control the source of hydrocarbons from the MC 252 Well and collect or contain hydrocarbons from the MC 252 Well, but excludes efforts to contain hydrocarbons from open water and shorelines.

38. **RISER TOP HAT** – This term refers to a containment dome, smaller than the Cofferdam, to be placed at the end of the DEEPWATER HORIZON's riser and used to collect and flow hydrocarbons up to the DISCOVERER ENTERPRISE.

39. **RITT** - Riser Insertion Tube Tool. This term refers to the device inserted into the end of the DEEPWATER HORIZON riser and used to flow and collect hydrocarbons to the DISCOVERER ENTERPRISE in May 2010.

40. **ROV** - Remote Operated Vehicle. This term refers to the tethered underwater vehicles used to perform tasks at or near the sea floor.

41. **SIMOPS** - Simultaneous Operations. This term refers to the coordination of all surface vessels during the Response.

42. **SOURCE CONTROL COMMAND POST** - This term refers to the Incident Command Post established at BP's offices in Houston for the purpose of addressing source control planning and operations.

43. **STATIC KILL** – This term refers to the hydrostatic control procedure, implemented after installation of the 3-ram Capping Stack, by which mud was pumped through the choke and kill manifold to kill the MC 252 Well and prepare it for cementing.

44. **TEAM** – This term refers to project teams formed by BP to work on specific source control efforts. In each instance, the efforts of the project team were organized, directed and led by a representative of BP. Every project team was comprised of multiple individuals from both inside and outside BP.[10]

45. **TOP KILL** - This term refers to the operations comprised of the Momentum Kill and Junk Shot attempted in May 2010 as a means to kill the MC 252 Well.

46. **TRANSOCEAN DEEPWATER HORIZON MODU** - This term refers to the Mobile Offshore Drilling Unit that was used to drill the MC 252 Well prior to April 20, 2010, and which subsequently sank following an explosion and fire.

47. **UAC or UC -** Unified Area Command or Unified Command. This term refers to the organization established to oversee the management of the Macondo spill and had the

[10] The use of this term in a specific stipulation does not indicate the participation, or level of participation, of any particular industry company or individual unless otherwise noted. Nor does the use of this term in a specific stipulation indicate that any particular individual working with a Team participated in or agreed with any decision of recommendation of the Team or that any particular individual working with a Team assisted in the preparation of any procedure.

authority to set overall strategy and priorities, allocate critical resources according to priorities, ensure the incident was properly managed, and ensure that objectives were met and strategies followed. The Unified Command consisted of the FOSC, the State On Scene Coordinators, and the On Scene Coordinators for BP and Transocean.[11]

ii. Response Framework

48. The Oil Pollution Act, 33 U.S.C. § 2701 et seq.; Federal Water Pollution Act, 33 U.S.C § 1251 et seq.; and the National Contingency Plan, 40 C.F.R. § 300 et seq., established the legal framework for the coordination of the efforts to control the source of the oil. These statutes and regulations authorize the Federal On-Scene Coordinator (FOSC) to direct and monitor all Federal, State and private actions. Efforts to coordinate the response were also governed by Homeland Security Presidential Directive 5 (HSPD-5). HSPD-5 designates the Secretary of the Homeland Security as the Principal Federal Officer for domestic incident management.[12]

49. At all times, the FOSC was an employee of the U.S. Department of Homeland Security.

50. The Incident Command System (ICS) was the organizational structure used by the Department of Homeland Security to execute oil spill response efforts at the MC 252 Well.[13]

51. Captain Joseph Paradis, as Captain of the Marine Safety Unit in Morgan City, Louisiana, was the designated FOSC. Because Captain Paradis was on leave at the time of the April 20, 2010, explosion, CDR Patrick Ropp was Acting FOSC for the first 24 hours.

[11] The decisions of the UAC were not required to be unanimous, therefore, when this term is used in a stipulation reflecting a decision or action by the UAC, the stipulation is not intended to ascribe involvement or agreement by any specific members of the UAC to that decision or action.

[12] By virtue of this stipulation, the parties do not intend to stipulate whether or not these statutory and regulatory provisions, or HSPD-5, were always followed in connection with the response, nor whether other statutory, regulatory, common law, and general maritime law not listed in this stipulation are part of the applicable legal framework.

[13] By virtue of this stipulation the parties do not intend to stipulate whether or not the ICS protocols were always followed in connection with the response.

52. On April 23, 2010, the commander of Coast Guard District 8, Rear Admiral Mary Landry, became the FOSC for the DEEPWATER HORIZON response.

53. On April 23, 2010, Admiral Landry established the Unified Area Command (UAC) for the DEEPWATER HORIZON response at the Shell Training and Conference Center in Robert, Louisiana.

54. On April 23, 2010, BP's Houston offices were recognized by the UAC as an Incident Command Post working on source control.

55. On April 29, 2010, the DEEPWATER HORIZON incident was declared a Spill of National Significance ("SONS").

56. On May 1, 2010, Coast Guard Commandant Admiral Thad Allen was designated as the National Incident Commander (NIC).

57. On June 1, 2010, Rear Admiral James Watson succeeded Admiral Landry as the FOSC.

58. On June 17, 2010, the UAC headquarters was moved to New Orleans.

59. On July 12, 2010, Rear Admiral Paul Zukunft succeeded Admiral Watson as the FOSC.

60. Generally, at 6:00 a.m. and 6:00 p.m. daily, federal representatives at the Source Control Command Post in Houston participated in Joint Handover Meetings conducted by BP's Incident Commander.

61. Generally, at 6:30 a.m. and 4:30 p.m. daily, federal representatives of the Unified Command attended source control project team meetings.

62. Generally, at 7:00 a.m. and 5:30 p.m. daily, the UAC convened an area command meeting with Incident Commanders from each of the Incident Command Posts.

63. Generally, at 8:00 a.m. and 5:00 p.m. daily, the team working on containment options met to discuss the status of planning and implementation.

64. Generally, at 8:00 a.m. daily, BP executives convened a conference call with Department of Interior Secretary Ken Salazar or his representative and senior federal officials involved with source control oversight to review progress on source control and operations planning. By May 12, 2010, Department of Energy Secretary Steven Chu or his representative participated in these briefings.

65. Generally, at 8:30 a.m. daily, Simultaneous Operations (SIMOPS) meetings were held to coordinate movements of vessels operating in the vicinity of the Macondo well.

66. Generally, at 3:00 p.m. daily, the Houston Source Control Command Post held meetings to define and review the incident objectives, strategies, tactics, and to develop upcoming plans.

67. A Federal Science Team was convened by Secretary of Energy Chu and Secretary of Interior Salazar to, among other things, assist in reviewing and analyzing source control procedures developed at the Source Control Command Post in Houston.

iii. Events of April 20 – April 30, 2010

68. On April 20, 2010, at 9:51 p.m. CDT, an explosion occurred on the DEEPWATER HORIZON MODU located in the Gulf of Mexico approximately 42 miles southeast of Venice, Louisiana. BP activated its Oil Spill Response Plan and began assembling resources, inside and outside of BP, to respond to the incident.

69. As of April 20, 2010, a ROV hydraulic line was connected to the inverted test ram rather than the middle pipe ram. [[14]]

[[14] The Phase One Findings described the BOP's various sealing and shearing components. *See* Phase One Findings ¶¶ 370-380. The stipulated facts and the Phase One Findings use different names for some of these

70. On April 21, 2010, a Remotely Operated Vehicle (ROV) attempted to activate the DEEPWATER HORIZON's Blow-Out Preventer (BOP) to close in the well. The ROV used a "hot stab" procedure to create a hydraulic connection in an attempt to close the middle pipe rams. The ROV pump failed and it was returned to the surface for repairs. An ROV also attempted to cut the autoshear trigger pin.[[15]] The team working on BOP intervention efforts was later led by then-BP Vice President of Operations, Harry Thierens.

71. On April 21, 2010, BP began to develop plans for drilling both a shallow and a deep intercept relief well using the DISCOVERER ENTERPRISE and the DEVELOPMENT DRILLER III (DDIII). The relief wells team was led by then-BP Vice President of Drilling & Completions for Gulf of Mexico Deepwater, Pat O'Bryan.

72. On April 22, 2010, ROVs made four attempts to activate the DEEPWATER HORIZON's BOP and thereby shut in the well by (a) cutting the electrical wires to simulate the DEEPWATER HORIZON BOP's automatic mode function, also known as the "deadman" operation; (b) attempting to activate the autoshear function; (c) using a "hot stab" procedure to close the blind shear ram; and (d) again attempting to activate the autoshear function. The autoshear pin was successfully cut.

73. On April 22, 2010, at 10:22 a.m. CDT, the DEEPWATER HORIZON sank in the Gulf of Mexico.

74. On April 22, 2010, a ROV discovered two sources of hydrocarbon release. It was later determined that one release point was the end of the DEEPWATER HORIZON riser, and the other was the end of the drill pipe that extended from the riser. [Footnote omitted]

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components. Here, "inverted test ram" and "middle pipe ram" correspond to "test rams" and "middle variable bore rams" in the Phase One Findings. *See id.* ¶¶ 379-380.]

[[15] "Autoshear" is a function designed to automatically close the BOP's blind shear rams if the LMRP detached from the lower BOP stack. *See id.* ¶ 384. Cutting the Autoshear trigger pin (referred to in the Phase One Findings as the "Autoshear plunger") should manually activate Autoshear without detaching the LMRP. *See id.* ¶ 385.]

75. By April 23, 2010, cofferdams, pollution domes, and a capping stack were identified as potential source control options for the MC 252 Well.

76. On April 24, 2010, plans for drilling intercept relief wells changed from drilling one shallow relief well and one deep relief well to drilling two deep relief wells.

77. On April 25, 2010, a Team led by then-BP Vice President of Drilling and Completions, North America Gas SPU, Mark Patteson, began planning for Top Kill.

78. On April 25, 2010, two attempts were made to actuate the DEEPWATER HORIZON BOP's middle pipe rams by using a ROV hot stab procedure as well as by using a portable subsea accumulator system.

79. On April 26, 2010, an exploration plan for the relief well to be drilled by the DDIII was approved by MMS/BOEMRE.

80. On April 26, 2010, an attempt was made to actuate the DEEPWATER HORIZON BOP's middle pipe ram using a portable subsea accumulator system.

81. On April 26, 2010, in an effort to seal the well, two unsuccessful attempts were made to close the DEEPWATER HORIZON BOP's blind shear rams[[16]] using a portable subsea accumulator system.

82. On April 26, 2010, ROVs repaired leaks in the DEEPWATER HORIZON BOP's control systems.

83. On April 26, 2010, applications for permits to drill (APD) were made to MMS/BOEMRE for the first and second deep relief wells.

[[16] The blind shear rams were designed to shear pipe passing through the BOP and seal the well. *See id.* ¶¶ 376-377.]

84. On April 27, 2010, the Team focusing on capping solutions held its first formal meeting. The capping team was led initially by Harry Thierens and later by then-BP VP of Drilling & Completion, Centralized Development Organization, Richard Lynch.

85. On April 27, 2010, an unsuccessful attempt was made to close the DEEPWATER HORIZON BOP's casing shear ram[[17]] using high pressure fluid.

86. On April 27, 2010, MMS/BOEMRE approved the APD for the first relief well using the DDIII.

87. On April 28, 2010, an additional point of hydrocarbon release was discovered to have developed through a hole at the kink in the riser above the DEEPWATER HORIZON's LMRP [Lower Marine Riser Package].

88. On April 28, 2010, two unsuccessful attempts were made to close the DEEPWATER HORIZON BOP's casing shear rams.

89. On April 28, 2010, a thermal survey of the BOP choke and kill lines found no flow through those lines.

90. On April 29, 2010, attempts were made to close the DEEPWATER HORIZON BOP's casing shear rams and blind shear rams.

91. On April 30, 2010, planning to cap the end of the drill pipe through the use of a slip on wellhead valve assembly began.

iv. <u>Events of May 1 – May 30, 3010</u>

92. On May 1, 2010, an attempt was made to close the DEEPWATER HORIZON LMRP's upper annular.[[18]]

[[17] The casing shear rams were designed to shear through pipe passing through the BOP, but, unlike the blind shear rams, do not seal the well upon closure. *See id.* ¶ 378.]

[[18] The upper and lower annular preventers are components in the LMRP designed to seal the annular space between the drill pipe and the BOP wellbore. *See id.* ¶374.]

93. On May 2, 2010, attempts were made to close the DEEPWATER HORIZON LMRP's lower annular.

94. On May 2, 2010, the DDIII arrived on location to begin drilling the first intercept relief well, located approximately one-half mile from the MC 252 Well.

95. On May 2, 2010, the DDIII spudded the first intercept relief well.

96. On May 3, 2010, additional attempts were made to close the DEEPWATER HORIZON LMRP's upper and lower annular preventers.

97. On May 3, 2010, a procedure was developed to remove the yellow pod from the DEEPWATER HORIZON's LMRP for use in Top Kill.

98. On May 5, 2010, the slip-on wellhead valve assembly was installed on the drill pipe protruding from the end of the riser and was closed off, stopping the flow of hydrocarbons emanating from the drill pipe.

99. On May 5, 2010, an attempt was made to actuate the DEEPWATER HORIZON BOP's middle pipe rams.

100. On May 5, 2010, the yellow pod from the DEEPWATER HORIZON's BOP LMRP was removed and brought to the surface in order to be modified for the Top Kill Operation.

101. On May 5, 2010, construction of the Cofferdam was completed. The Cofferdam was then loaded on board a vessel and shipped to site.

102. On May 5, 2010, the procedure for placement of the cofferdam was approved.

103. On May 6, 2010, a Peer Assist was held to evaluate Junk Shot and Momentum Kill.

104. On May 6-7, 2010, the Cofferdam was lowered and positioned over the leak at the end of the DEEPWATER HORIZON riser. While it was being lowered, hydrate crystals formed inside of the Cofferdam which prevented its successful placement over the leaking riser.

105. On May 8, 2010, the concept of the riser insertion tube tool ("RITT") as a means to collect hydrocarbons was identified by a Team working on near-term containment options led by Richard Lynch.

106. On May 9, 2010, the Riser Top Hat plan was developed to include the addition of methanol to the dome to prevent the formation of hydrate crystals.

107. On May 10, 2010, the Junk Shot manifold was lowered to the sea floor.

108. On May 11, 2010, a riser and LMRP were deployed from the DISCOVERER ENTERPRISE in order to prepare for the potential use of one of the Riser Top Hats or the RITT to collect the flow of hydrocarbons by the DISCOVERER ENTERPRISE.

109. On May 11, 2010, a Peer Assist was held to evaluate the BOP-on-BOP and capping options.

110. On May 11, 2010, construction of the RITT was completed and preparations were made to transport it to the MC 252 Well.

111. On May 12, 2010, a Riser Top Hat was deployed from the VIKING POSEIDON to the sea bed.

112. On May 14, 2010, a Peer Assist was held to evaluate the Top Preventer concept, which encompassed both a 2-ram capping stack and BOP-on-BOP option.

113. On May 13, 2010, the Containment and Disposal Project (CDP) Team, led by then-BP Vice President of Engineering and HSSE, Centralized Development Organization, Kevin Kennelley, held its initial Kick-Off meeting.

114. On May 15, 2010, construction began on the FSR #1 [Free-Standing Riser] that was part of the CDP.

115. On May 15, 2010, MMS/BOEMRE approved the APD for the second relief well, allowing the DDII to begin drilling operations.

116. On May 15, 2010, the RITT was run to depth and inserted into the end of the DEEPWATER HORIZON's leaking riser. Thereafter, hydrocarbons were transported to the DISCOVERER ENTERPRISE for the collection of oil and flaring of gas.

117. On May 16, 2010, the DDII began drilling the second relief well.

118. On May 17, 2010, jumper lines were installed between the Junk Shot manifold and the DEEPWATER HORIZON BOP's choke and kill lines.

119. On May 18, 2010, the DEEPWATER HORIZON LMRP's yellow pod was reinstalled in preparation for Top Kill.

120. On May 25, 2010, the RITT was removed from the end of the DEEPWATER HORIZON's riser to prepare for the upcoming Top Kill.

121. On May 25, 2010, the "Top Kill Procedure for MC252-1 Momentum Kill Pumping Operations" was approved.

122. On May 25, 2010, the "Top Kill Procedure for MC252-1 Contingency: Alternative LCM Pills," also known as the Junk Shot, was approved.

123. On May 25, 2010, the "Top Kill Procedure for MC252-1 Momentum Cementing Operations" was approved.

124. On May 26, 2010, from the Q4000, Momentum Kill was commenced by pumping heavy drilling mud through the DEEPWATER HORIZON BOP's choke and kill lines.

125. On the evening of May 26, 2010, a second attempt at Momentum Kill was commenced by pumping heavy drilling mud through the DEEPWATER HORIZON BOP's choke and kill lines.

126. On May 26, 2010, shortly after the second attempt, a third attempt to kill the MC 252 Well was made, which included pumping both heavy mud and bridging material (Junk Shot) through the DEEPWATER HORIZON BOP's choke and kill lines.

127. On May 27, 2010, a fourth attempt to kill the MC 252 Well was made, which included pumping both heavy mud and bridging material (Junk Shot) through the DEEPWATER HORIZON BOP's choke and kill lines.

128. On May 27, 2010, a fifth attempt was made to kill the MC 252 Well, which included pumping both heavy mud and bridging material (Junk Shot) through the DEEPWATER HORIZON BOP's choke and kill lines.

129. On May 28, 2010, a sixth and final attempt was made to kill the MC 252 Well, which included pumping both heavy mud and bridging material (Junk Shot) through the DEEPWATER HORIZON BOP.

130. On May 29, 2010, the decision was made not to move forward with the BOP-on-BOP option.[[19]]

131. On May 30, 2010, an EverGreen burner in France was procured to allow the Q4000 to flare hydrocarbons from the MC 252 Well.

132. On May 31, 2010, BP and members of the Federal Science Team agreed that one interpretation of the analysis and diagnostics from the Top Kill indicated an issue with well integrity.

[[19] BOP-on-BOP refers to a contemplated operation to place a second BOP on the DEEPWATER HORIZON BOP.]

v. Events of June 1 – June 30, 2010

133. On June 1, 2010, a ROV cut the auxiliary lines surrounding the DEEPWATER HORIZON's riser and then cut the DEEPWATER HORIZON's riser at or near the sea floor in preparation for installing the LMRP Top Hat # 5 (one of several Top Hat designs developed for this effort) above the DEEPWATER HORIZON's LMRP.

134. On June 1, 2010, using a diamond saw, a ROV attempted to cut the riser above the DEEPWATER HORIZON's LMRP in preparation for installing the LMRP Top Hat # 5. The saw got stuck.

135. On June 2, 2010, the EverGreen burner intended to flare hydrocarbons on board the Q4000 arrived in Louisiana.

136. On June 2, 2010, attempts were made to remove the diamond saw.

137. On June 3, 2010, ROV-operated super shears successfully cut the riser from the DEEPWATER HORIZON's LMRP.

138. On June 3, 2010, the LMRP Top Hat #4 was installed above the DEEPWATER HORIZON's LMRP. LMRP Top Hat #4 was used instead of LMRP Top Hat #5 due to the jagged cut of the riser by the super shears.

139. On June 3, 2010, the LMRP Top Hat #4 began directing hydrocarbons to the DISCOVERER ENTERPRISE for collection of oil and flaring of gas.

140. On June 6, 2010, the manifold intended for use for the CDP was shipped to the MC 252 Well location.

141. On June 7, 2010, as part of the CDP system, construction began on FSR #2 [Free-Standing Riser].

142. On June 12-13, 2010, a suction pile was installed to anchor the CDP FSR # 1. The CDP manifold was installed on the seabed to prepare for flowing hydrocarbons to the HELIX PRODUCER I.

143. On June 15, 2010, installation of the CDP FSR # 1 was initiated.

144. On June 16, 2010, the EverGreen burning system aboard the Q4000 commenced flaring operations of both oil and gas flowing from the DEEPWATER HORIZON BOP's choke lines through a manifold deployed on the sea floor.

145. On June 21, 2010, installation of the CDP FSR # 1 was completed.

146. On June 24, 2010, Vector Magnetics conducted the first ranging run for the relief well being drilled by the DDIII at 16,270 feet (ft.) measured depth (MD).

147. On June 25, 2010, Vector Magnetics conducted a second ranging run for the relief well being drilled by the DDIII at 16,395 ft. MD.

148. On June 27, 2010, Vector Magnetics conducted a third ranging run for the relief well being drilled by the DDIII at 16,520 ft. MD.

149. On June 29, 2010, a Peer Assist was held to review the well intercept and cementing procedures for the relief well operations.

150. On June 29, 2010, Vector Magnetics conducted a fourth ranging run for the relief well being drilled by the DDIII at 16,595 ft. MD.

151. On June 30, 2010, the transition spool and the 3-ram Capping Stack were both completed and passed a System Integration Test after a failed pressure/temperature sensor was replaced with a Teledyne Cormon dual pressure transducer/single temperature sensor calibrated and rated to 15,000 psi. The 3-ram Capping Stack was transported to [Port Fourchon]. The flange splitter system required to install the spool was completed and scheduled to undergo a system integration test.

vi. Events of July 1 – July 31, 2010

152. On July 1, 2010, the transition spool and 3-ram Capping Stack arrived at [Port Fourchon] and were prepared for transfer to the DISCOVERER INSPIRATION for delivery to the MC 252 Well.

153. On July 2, 2010, Vector Magnetics conducted a fifth ranging run for the relief well being drilled by the DDIII at 17,438 ft. MD.

154. On July 2, 2010, the System Integration Test for the flange splitter was completed.

155. On July 2, 2010, the DISCOVERER ENTERPRISE commenced installation of the flex joint straightening tool to remedy the 2.5 degree flex joint angle.

156. On July 3, 2010, Vector Magnetics conducted a sixth ranging run for the relief well being drilled by the DDIII at 17,638 ft. MD.

157. On July 3, 2010, the transition spool and 3-ram Capping Stack were transferred to the DISCOVERER INSPIRATION.

158. On July 3, 2010, the flex joint straightening tool decreased the flex joint angle by 1 percent.

159. On July 4, 2010, the flex joint straightening tool completed alignment of the flange and flex joint to accept the 3-ram Capping Stack.

160. On July 4, 2010, the procedure for installing a 3-ram Capping Stack was approved and preparations continued for the installation of the 3-ram Capping Stack.

161. On July 4, 2010, the 3-ram Capping Stack was successfully tested to 10,000 psi and the deployment assembly was installed.

162. On July 4, 2010, Vector Magnetics conducted a seventh ranging run for the relief well being drilled by the DDIII at 17,703 ft. MD.

163. On July 5, 2010, Vector Magnetics conducted an eighth ranging run for the relief well being drilled by the DDIII at 17,674 ft. MD.

164. On July 8, 2010, Vector Magnetics conducted a ninth ranging run for the relief well being drilled by the DDIII at 17,765 ft. MD.

165. On July 8, 2010, the NIC sent a letter to Bob Dudley[[20]] requesting, *inter alia*, that BP provide certain information in order for the NIC "to approve the[] potential actions" regarding installation of the 3-ram Capping Stack. Specifically, Admiral Allen requested information regarding the timeline and decision points in the capping operations; source control contingency plans; a plan for pressure testing the well; a relief well timeline; and a plan for management of oil reaching the surface.

166. On July 9, 2010, the 1,200 ft. flex hose intended to connect the junk shot manifold to the CDP manifold was landed and – after the repair of a leak near the choke and kill manifold – was successfully pressure tested.

167. On July 9, 2010, the removal of the LMRP Top Hat #4 and installation of the 3-ram Capping Stack was approved.

168. On July 10, 2010, production of hydrocarbons through the LMRP Top Hat #4 to the DISCOVERER ENTERPRISE was stopped, and the LMRP Top Hat #4 was removed from its location to allow for the installation of the 3-ram Capping Stack. The Q4000 continued to flare hydrocarbons.

169. On July 10, 2010, Vector Magnetics conducted a tenth ranging run for the relief well being drilled by the DDIII at 17,799 ft. MD.

[[20] Bob Dudley was the president and chief executive officer of BP's Gulf Coast Restoration Organization from June 23 to September 30, 2010. On October 1, 2010, Mr. Dudley succeeded Tony Hayward as BP's group chief executive.]

170. On July 11, 2010, the overshot tool removed the riser flange from the DEEPWATER HORIZON LMRP flexible joint flange in order to prepare for the installation of the 3-ram Capping Stack. Following the riser stub removal and drill pipe assessment, the transition spool piece was installed on the DEEPWATER HORIZON's LMRP.

171. On July 11, 2010, procedures regarding shutting in the well and testing its integrity were sent to the Houston Source Control Command Post.

172. On July 12, 2010, seismic data was collected for analysis by DOE, DOI, BP, and the Federal Science Team in order to determine current well integrity.

173. On July 11-12, the procedures to shut in the well and test its integrity were approved.

174. On July 12, 2010, the DISCOVERER INSPIRATION landed the 3-ram Capping Stack onto the transition spool piece.

175. On July 12, 2010, Vector Magnetics conducted an eleventh ranging run for the relief well being drilled by the DDIII at 17,829 ft. MD.

176. On July 12, 2010, the CDP FSR #1 and manifold system began flowing hydrocarbons to the HELIX PRODUCER I.

177. On July 13, 2010, the planned shut-in was delayed at the request of Secretary of Energy Chu to allow further consideration of well integrity.

178. On July 14, 2010, shutting in the well to test its integrity for a maximum duration of 48 hours was approved.

179. On July 14, 2010, the procedure to shut in the well began by closing the gas vent valve on the DEEPWATER HORIZON LMRP and the upper kill line on the BOP, such that the Q4000 and HELIX PRODUCER I stopped collecting hydrocarbons.

180. On July 14, 2010, the 3-ram Capping Stack's middle ram was closed, diverting all flow to the 3-ram Capping Stack's choke and kill outlets.

181. On July 14, 2010, while shutting in the well, a leak was discovered in the 3-ram Capping Stack's choke connector.

182. On July 15, 2010, the choke isolation valve upstream of the leaking choke connector on the 3-ram Capping Stack was closed, with hydrocarbons flowing only through the 3-ram Capping Stack's kill side outlet.

183. On July 15, 2010, the 3-ram Capping Stack's choke connector was replaced. The choke side outlet was temporarily reopened. Production of hydrocarbons to the Q4000 and HELIX PRODUCER I through the DEEPWATER HORIZON LMRP and BOP temporarily resumed.

184. On July 15, 2010, the 3-ram Capping Stack's kill and choke side outlets were closed and the MC 252 Well was shut in at approximately 2:24 p.m. CDT.

185. On July 15, 2010, well integrity monitoring and testing commenced once the well was shut in.

186. On July 16, 2010, Vector Magnetics conducted a twelfth ranging run for the relief well being drilled by the DDIII at 17,836 ft. MD.

187. On July 16, 2010, the NIC issued a letter permitting BP to keep the well shut in and continue testing its integrity beyond 48 hours.

188. On July 17, 2010, BP and the National Oceanic & Atmospheric Administration initiated a series of acoustic surveys to monitor the wellhead and seafloor for leaks that might indicate a loss of well integrity.

189. On July 18, 2010, Vector Magnetics conducted a thirteenth ranging run for the relief well being drilled by the DDIII at 17,862 ft. MD.

190. On July 18, 2010, development continued on the Hydrostatic Control Procedure, also known as Static Kill.

191. On July 20, 2010, a Peer Assist was held to review operations to recover the DEEPWATER HORIZON BOP and permanently abandon the MC 252 Well.

192. On July 20, 2010, BP presented the Federal Science Team with a Hydrostatic Control Procedure.

193. On July 23, 2010, some source control efforts, including relief well drilling, were temporarily suspended due to Tropical Storm Bonnie.

194. On July 24, 2010, the DDIII recommenced relief well drilling.

195. On July 26, 2010, the DDII recommenced relief well drilling.

196. On July 27, 2010, the "Hydrostatic Control for MC252-1 Hydrostatic Control Procedure," also known as Static Kill, was approved.

vii. <u>Events of August 1 – August 31, 2010</u>

197. On August 3, 2010, the Q4000 commenced the Static Kill operation by pumping drilling mud through the choke and kill manifold into the MC 252 Well via the choke side of the DEEPWATER HORIZON BOP.

198. On August 5, 2010, the Q4000 pumped cement into the MC 252 Well through the DEEPWATER HORIZON BOP via the choke and kill manifold.

199. On August 6, 2010, Vector Magnetics conducted a fourteenth ranging run for the relief well being drilled by the DDIII at 17,878 ft. MD.

200. On August 6, 2010, a pressure test was performed on the cement plug set in the MC 252 Well during the Static Kill operation to determine if the cement was successfully placed.

201. On August 7, 2010, a second pressure test was undertaken to confirm the results of the August 6 test. These tests confirmed that the cement plug placement was successful.

202. On August 8, 2010, Vector Magnetics conducted a fifteenth ranging run for the relief well being drilled by the DDIII at 17,907 ft. MD.

203. On August 12, 2010, a near ambient pressure test was initiated to determine that the cement plug successfully sealed off the MC 252 Well.

204. On August 19-21, 2010, a 48-hour ambient pressure test confirmed that the cement plug set during the Static Kill operation sealed the MC 252 Well.

viii. Events of September 1 – September 19, 2010

205. On September 2, 2010, the DISCOVERER ENTERPRISE removed the 3-ram Capping stack from the DEEPWATER HORIZON BOP.

206. On September 3-4, 2010, the Q4000 removed the DEEPWATER HORIZON BOP from the wellhead and brought it to Michoud, Louisiana.

207. On September 4, 2010, the DDII installed its BOP on the MC 252 wellhead.

208. On September 14, 2010, Vector Magnetics conducted a sixteenth ranging run for the relief well being drilled by the DDIII at 17,934 ft. MD.

209. On September 16, 2010, Vector Magnetics conducted a seventeenth ranging run for the relief well being drilled by the DDIII at 17,982 ft. MD.

210. On September 16, 2010, the relief well drilled by the DDIII intersected the MC 252 Well's annulus at approximately 17,977 ft. MD and remained in contact with the annulus to 17,984 ft. MD.

211. On September 17, 2010, the DDIII cemented the annulus of the MC 252 Well.

212. On September 19, 2010, the NIC stated that the MC 252 Well was killed.

C. Findings on Disputed Issues

213. There is no dispute that the source control effort between May and September 2010 was a massive and complex undertaking. BP's entire Gulf of Mexico resources became focused on the response, which included subsea, surface, and onshore intervention efforts. The response saw collaboration between BP as the designated responsible party, numerous Government agencies, major oil and gas companies such as Exxon, Shell, and Chevron, oil and gas service companies, and members of academia. Ultimately, BP spent over $1.6 billion on source control.

214. As reflected in the Stipulated Facts, the Macondo well was successfully shut in on July 15, 2010, 86 days after the blowout began on April 20, via a capping stack that was landed on top of the LMRP.

215. The Aligned Parties contend there were two major flaws relative to source control that delayed the successful capping of the well. First, the Aligned Parties claim that BP consciously disregarded the need to prepare for a subsea blowout in deepwater, despite the foreseeability of such an event. Second, the Aligned Parties assert that BP intentionally misrepresented the rate at which hydrocarbons flowed from the well, which caused decision-makers to attempt source control methods that had no chance of success, namely, Top Kill, while abandoning other methods that were viable, namely, BOP-on-BOP.

216. The Aligned Parties do not agree entirely over what consequences should flow from these alleged failures. The PSC, Alabama, and Louisiana urge that BP's source control failures warrant the imposition of punitive damages on BP, including the parent entity, BP p.l.c., particularly when the Phase Two evidence is considered with the Phase One evidence. Transocean and Halliburton argue a different point: that BP's source control errors made it a

superseding cause of the oil spill, which exculpates Transocean and Halliburton of their Phase One liability.

217. BP contested all of these positions with counter-evidence and arguments.

i. BP's Oil Spill Response Plan

218. Federal regulations required that BP, as the leaseholder and designated operator of the Macondo well, submit an oil spill response plan to the MMS for approval.[21] The plan had to demonstrate that BP could "respond quickly and effectively whenever oil is discharged from [its] facility."[22] The MMS further required that the plan "[b]riefly describe the general procedures that have been developed and instituted . . . to ensure that the source of the discharge is controlled as soon as possible after a spill occurs."[23] The MMS had to approve BP's oil spill response plan before drilling operations could commence.[24]

219. When the blowout occurred, BP had a spill response plan in place that contained more than 500 pages. Nevertheless, this plan said very little about source control for a blowout in deepwater. It focused instead on containment and collection of oil once it reached the surface.

220. BP's deepwater source control plan amounted to three points: (1) attempt to shut in the well by using ROV's to activate the DEEPWATER HORIZON's BOP, (2) drill a relief well, and (3) stand up a team of experts to address the situation.

221. As Dr. Tony Hayward, the Group CEO of BP p.l.c. at the time of the blowout, explained, BP had identified a subsea deepwater blowout as one of the highest risks for the company.[25] BP considered the BOP to be the "last line of defense" against a deepwater

[21] 30 C.F.R. § 254.1.
[22] *Id.*
[23] TREX 11753.12 (Notice to Lessees and Operators, Effective Oct. 26, 2006).
[24] 30 C.F.R. § 245.2.
[25] Hayward Dep. 166:10-:18.

blowout.[26] In the event the BOP failed to stop a deepwater blowout, BP's only existing plan to kill a subsea deepwater blowout was to drill a relief well, which could take on the order of three months.[27]

222. BP did not have access to a pre-built capping stack prior to the blowout. During the response, BP fabricated several intervention techniques including the cofferdam, RITT, numerous top hats, and the capping stack.

223. The Aligned Parties assert that the evidence reflects that if BP had properly prepared for a deepwater blowout, with a capping stack available on April 20, 2010, the well could have been shut in within 24 days.

224. The scientific principles and materials necessary for designing and creating capping stacks were available prior to the HORIZON/Macondo blowout and known to BP. As BP's counsel acknowledged during trial, "[W]hile it was feasible and practical to have a type of capping device, for deepwater operations, there were no capping stacks specifically designed for deepwater blowouts."[28] The technology to build a capping stack was available, and it would have saved time if BP had built or at least planned for a deepwater capping stack prior to the blowout.[29]

225. Nevertheless, federal regulations did not specifically require companies to have, or to have access to, a prebuilt deepwater capping stack before the HORZION/Macondo blowout. Indeed, prior to drilling the Macondo well, BP had submitted its oil spill response plan to the MMS for review and approval, and the MMS approved same.

[26] Hayward Dep. 234:15-:19.
[27] Hayward Dep. 256:1-:14.
[28] Phase Two Tr. 530:7-10.
[29] Phase Two Tr. 693:12-695:17 (Dupree).

226. The evidence shows that it was not industry practice to have a pre-built capping stack prior to the HORIZON/Macondo blowout.

227. The Court finds that BP's oil spill response plan, including the limited source control aspects, complied with federal regulations and industry practice existing at the time.

ii. <u>BP's Flow Rate Misrepresentations</u>

228. There is no dispute that BP lied about the amount of oil that flowed from the well. The evidence shows that BP repeatedly told government officials that its best estimate for flow rate was 5,000 barrels of oil per day, while BP's internal documents showed there was little basis for this estimate and actual flow rates were significantly higher. Indeed, BP pled guilty to obstruction of Congress, 18 U.S.C. § 1505, for making such misrepresentations in response to a Congressional Committee inquiry. BP has admitted that it

> falsely suggested, in its May 24, 2010 letter [to a Committee of the United States House of Representatives], that the Unified Command's flow rate estimate of 5,000 barrels of oil per day ("BOPD") was the "most scientifically informed judgment" and that subsequent flow rate estimates had "yielded consistent results." In fact, as set forth above, BP had multiple internal documents with flow rate estimates that were significantly greater than 5,000 BOPD that it did not share with the Unified Command.[30]

229. Nevertheless, it has not been shown that BP's misrepresentations regarding flow rate delayed the capping of the well or otherwise adversely affected source control efforts.

230. When it came to source control, BP could not act unilaterally. The Unified Command[31] had the ultimate approval authority for source control operations. BP would propose possible source control solutions, but the decision to move forward with any of them rested with the federal Government. The Government also had its own scientists who independently evaluated data and BP's proposals.

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[30] *United States v. BP Exploration & Production Inc. et al.*, No. 12-292, Rec. Doc. 2-1, Ex. A ¶ 5 (E.D. La. Nov. 15, 2012).

[31] *See supra* paragraph 47.

231. The Aligned Parties contend that BP's misrepresentations and omissions regarding flow rate led to the prioritization of Top Kill over other source-control methods, especially BOP-on-BOP. In other words, the Government would not have approved Top Kill had BP not underestimated the flow rate, claim the Aligned Parties.

232. Top Kill was an effort to kill the well by pumping mud and bridging material into the HORIZON's BOP with the intent to force mud down the wellbore and preclude flow from the reservoir. It consisted of two elements: (1) injecting various bridging materials into the BOP to restrict flow ("Junk Shot"), and (2) immediately pumping mud into the BOP to overcome the momentum of the flow ("Momentum Kill").

233. Contrary to the Aligned Parties' contentions, the weight of the evidence does not show that Government decision-makers relied on BP's flow rate misrepresentations when they approved Top Kill.

234. For example, Dr. Marcia McNutt, director of the Government's Flow Rate Technical Group testified that no one in the Government had any confidence in BP's 5,000 barrels per day estimate.[32] Dr. Thomas Hunter, Co-Director of the Federal Science Team, testified that the 5,000 barrels per day estimate "did not make a significant difference in our engagement of the top kill, because . . . our conclusions was we didn't know what the flow was."[33] Admiral Mary Landry, the Federal On-Scene Coordinator from April 23, 2010 until June 1, 2010, testified that the Government was aware that multiple uncertainties surrounded the 5,000 barrels per day estimate and that the Government's Flow Rate Technical Group was stood up to provide a more accurate estimate.[34]

[32] McNutt Dep. 438-39.
[33] Hunter Dep. 684:11- :14.
[34] Landry Dep. 699-701.

235. Furthermore, it has not been shown that implementing Top Kill before other alternatives was an unreasonable action under the circumstances.

236. Top Kill had fewer risks than other alternatives, particularly the BOP-on-BOP procedure. For example, a key concern during source control was wellbore integrity. If a particular intervention created too much pressure in the wellbore, burst disks in the well casing could rupture. This could lead to a casing broach and underground blowout (where hydrocarbons escape into the surrounding rock formation rather than travelling up the well, BOP, and riser segment) and perhaps a surface broach (where hydrocarbons migrate through the seafloor to the sea), making the situation worse. It was determined that these risks were greater with the BOP-on-BOP option than with Top Kill.

237. Another benefit to Top Kill was that if the procedure failed, it would still be possible to attempt a BOP-on-BOP operation. On the other hand, if the Unified Command pursued a BOP-on-BOP operation first and it was not successful, attempting Top Kill would be more difficult, perhaps impossible.

238. The Aligned Parties also contend that BP knew that Top Kill could not succeed if the float rate exceeded 15,000 barrels of oil per day and that BP knew that the flow rate exceeded this limit. The weight of the evidence also does not support this argument. While 15,000 barrels of oil per day may have been the limit for a procedure that relied on only Momentum Kill, the Junk Shot aspect of Top Kill made success a possibility even if flow was above 15,000 barrels of oil per day. Notably, one of the Top Kill attempts appeared to work momentarily, but ultimately failed.

239. The Aligned Parties further claim that BP's flow rate misrepresentations continued after Top Kill when it told the Government that Top Kill failed because the well's

burst disks had previously ruptured and mud was pumped out the well instead of all the way down the production casing. This, claim the Aligned Parties, caused Government decision-makers to abandon entirely the BOP-on-BOP capping procedure and focus instead on containment. The Aligned Parties assert that if BP had revealed the real reason Top Kill failed—that the flow of oil was too great and the flow path too large—the Government would have moved forward with BOP-on-BOP and capped the well much sooner.

240. Again, the weight of the evidence does not support the Aligned Parties' arguments. BP presented three explanations for why Top Kill failed, one of which was related to flow from the well. Although BP pushed the burst disk theory as the only "plausible" explanation and the other two as merely "possible," the evidence does not show that BP was dishonest in its evaluation and explanation. Furthermore, the Government's scientists independently analyzed the Top Kill data and, though they believed alternate explanations were more likely, could not rule out the burst disk theory. Ultimately, both BP and the Government determined that the well integrity concerns were too great to attempt the BOP-on-BOP procedure.

241. At bottom, there were several risks associated with the BOP-on-BOP procedure that either did not exist or could be mitigated with other options. The Court finds that, given the information known at the time, there were genuine concerns that attempting BOP-on-BOP shut in could make matters substantially worse. Moreover, it cannot be said that the decisions made and actions taken post-blowout were unreasonable.

D. Conclusions[35]

242. As set forth in Part II.C.ii., it has not been shown that BP's flow rate misrepresentations delayed or adversely affected source control, nor has it been shown that BP's post-blow out source control actions were unreasonable.

243. This leaves the issue of BP's source control planning, discussed in Part II.C.i.

244. As noted above, the Court finds that BP's source control plan complied with then-existing federal regulations and industry practice.

245. The Aligned Parties urge that compliance with a federal regulation and industry custom does not necessarily prove that one has met the legal standard or preclude a finding of gross negligence, recklessness, etc. This view is correct in the abstract. For example, it is possible for an entire industry to unduly delay in adopting new and available devices.[36] Still, compliance with federal regulations and industry custom is a relevant consideration that tends to weigh against culpability.

246. There is evidence that arguably could lead a factfinder to conclude that BP was negligent in its source control preparation. However, simple negligence is not at issue here. Consequently, the Court does not determine whether or not BP was negligent in its source control preparation.

247. Instead, the questions the Court must resolve are (1) whether, considering both the Phase One and Phase Two evidence, any of the BP entities engaged in such extreme, extra-negligent conduct that would warrant punitive damages, or (2) whether BP's source control conduct makes it a superseding cause of the oil spill or otherwise warrants additional fault allocated to BP.

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[35] This section is simply labeled "Conclusions," as opposed to "Conclusions of Law" or "Conclusions of Fact." Whether a conclusion is legal or factual shall be determined by its substance.

[36] *See The T.J. Hooper*, 60 F.2d 737, 740 (2d Cir. 1932).

248. As to the first question, the Court finds that punitive damages are not warranted. The Court finds that BP was not grossly negligent, reckless, willful, or wanton in its source control planning. A major factor in this determination is the fact that BP's source control plan complied with federal regulations and industry practice. And while the Court does not determine whether or not BP's source control plan was merely negligent, even if the Court found that BP was negligent in its source control planning, that finding would not combine with the Phase One conclusions to result in a finding of extra-negligent conduct beyond which has already been found.

249. The Court similarly concludes that BP's conduct does not make it a superseding cause of the oil spill, nor does BP's conduct warrant a reallocation of comparative fault among BP, Transocean, and Halliburton.

250. In short, the evidence in the Source Control segment does not change the Court's conclusions from Phase One.

III. QUANTIFICATION SEGMENT

251. The CWA imposes a civil penalty upon "[a]ny person who is the owner, operator, or person in charge of any vessel, onshore facility, or offshore facility from which oil . . . is discharged in violation of paragraph (3) . . . ."[37] The maximum amount of this civil penalty is determined in part by the volume of oil discharged.[38] More specifically, the CWA multiplies the number of barrels[39] of oil by a certain dollar value[40] to arrive at the maximum penal amount.

[37] 33 U.S.C. § 1321(b)(7)(A).

[38] *See id.* § 1321(b)(7)(A),(D).

[39] The CWA defines a "barrel" as "42 United States gallons at 60 degrees Fahrenheit." *Id.* § 1321(a)(13). The parties further agree that a barrel should be measured at surface pressure (1 atmosphere), rather than the pressure in the reservoir, which is much higher than surface pressure and would yield a greater quantity of oil. The parties disagree, however, over how to convert from reservoir barrels to "stock tank barrels." Nevertheless, when the Court refers to a certain number of "barrels" of oil, it means "stock tank barrels," i.e., 42 U.S. gallons at 60 degrees Fahrenheit and 1 atmosphere pressure.

The Court must also consider certain equitable factors before determining the final amount of the CWA penalty.[41]

252. On February 22, 2012, the Court ruled on motions for partial summary judgment and held that BPXP and Anadarko Petroleum Corporation are liable for civil penalties under the CWA, because they co-owned an offshore facility—the Macondo well—from which oil discharged.[42]

253. The purpose of the Quantification segment was for the parties to present evidence on the amount of oil that actually released into the Gulf of Mexico due to the DEEPWATER HORIZON/Macondo well incident. The Quantification segment was tried as a bench trial beginning on October 7, 2013 and concluding on October 18, 2013.

254. The parties to the Quantification segment were the United States as plaintiff and BPXP and Anadarko Petroleum Corporation as defendants. BPXP and Anadarko Petroleum Corporation are collectively referred to as "BP" for purposes of the Quantification segment.[43]

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[40] The amount of this multiplier is determined by whether the defendant acted with "gross negligence or willful misconduct" or less culpable conduct (e.g., negligence). *See id.* § 1321(b)(7)(A),(D); *see also* 40 C.F.R. § 19.4; 33 C.F.R. § 27.3.

[41] *See* 33 U.S.C. § 1321(b)(8) ("In determining the amount of a civil penalty under paragraphs (6) and (7), the . . . court . . . shall consider the seriousness of the violation or violations, the economic benefit to the violator, if any, resulting from the violation, the degree of culpability involved, any other penalty for the same incident, any history of prior violations, the nature, extent, and degree of success of any efforts of the violator to minimize or mitigate the effects of the discharge, the economic impact of the penalty on the violator, and any other matters as justice may require."). The Court will consider these factors as part of the Penalty Phase trial set for January 20, 2015.

[42] Order and Reasons [As to the Cross-Motions for Partial Summary Judgment Regarding Liability under the CWA and OPA] at 23-24, Rec. Doc. 5809, 844 F. Supp. 2d 746, 761 (E.D. La. 2012). A panel of the Fifth Circuit Court of Appeals affirmed this ruling on June 4, 2014, and again on November 5, 2014. *In Re Deepwater Horizon*, 753 F.3d 570 (5th Cir. 2014); *In Re Deepwater Horizon*, 772 F.3d 350 (5th Cir. 2014). On January 9, 2015, the Fifth Circuit denied BPXP's and Anadarko's requests for rehearing en banc.

In the Phase One Findings, this Court further found that BPXP was an "operator" and "person in charge" of both the offshore facility (the Macondo well) and the vessel (the DEEPWATER HORIZON) for purposes of the CWA. Phase One Findings ¶¶ 537-38, Rec. Doc. 13381, 21 F. Supp. 3d 657, 746 (E.D. La. 2014).

[43] BPXP is the only BP entity the United States sued under the CWA. The United States originally sued two Anadarko entities—Anadarko Petroleum Corporation and Anadarko Exploration & Production LP—but later stipulated that it would not seek any CWA penalties from Anadarko Exploration & Production LP. *See* Rec. Doc. 5930 ¶ 2. The United States also brought CWA claims against MOEX Offshore 2007 LLC and certain Transocean entities, but settled with those parties prior to trial.

255. The parties stipulated that during the spill response 810,000 barrels of oil were collected without contacting any ambient sea water ("Collected Oil"). Thus, while the parties present estimates of the total volume of oil that left the reservoir, they agree that 810,000 barrels should not be used to calculate the statutory maximum penalty under the CWA.

256. The testifying experts presented widely varying estimates of the cumulative discharge and used different techniques to reach their conclusions. Most experts who opined on the cumulative discharge provided both a range of possible estimates and a "best estimate." Others provided only a range. The testifying experts' estimates are listed here[44]:

Expert (By order of appearance)	**Estimate of Cumulative Discharge** (In millions of stock tank barrels of oil) (Does not account for Collected Oil)
Ronald Dykhuizen (USA)	Best Estimate: 5.0 Range: 3.5 to 6.0
Stewart Griffiths (USA)	Best Estimate: 5.0 Range: 4.3 to 5.5
Mohan Kelkar (USA)	Range: 4.5 to 5.4
Mehran Pooladi-Darvish (USA)	Range: 5.0 to 5.3
Martin Blunt (BP)	Best Estimate: 3.26 Range: 2.9 to 3.7
Alain Gringarten (BP)	Range: 2.4 to 3.0

257. Ultimately, the United States proposed that 5.0 million barrels of oil exited the reservoir, resulting in a net discharge of 4.19 million barrels once adjusted for the Collected Oil.

258. BP estimated that 3.26 million barrels of oil released from the reservoir, resulting in a net discharge of 2.45 million.

259. BP and the United States also presented competing theories of how the rate of discharge changed over the course of the spill.

[44] Dr. Paul Hsieh was called as a fact witness by the United States and testified about some of the work he did during the response. As part of this work, Dr. Hsieh developed a reservoir model that estimated daily flow rates and cumulative discharge. Dr. Hsieh did not testify as an expert, however.

260. BP theorized that the discharge began at a relatively low rate, as compared to the United States' estimates, and that the rate of discharge increased over time. BP proposed that cement in the well, certain BOP components, and the riser kink above the LMRP initially created restrictions that impeded the flow of oil. As these restrictions eroded—which, according to BP, occurred gradually over a period of at least 35 days—the rate of discharge steadily increased. By mid-May, BP estimates the flow rate was between 24,900 and 34,900 barrels of oil per day. On July 15, the final day of the spill, BP estimates oil was flowing around 45,000 barrels of oil per day.

261. The United States presented the competing theory that neither the cement nor the riser created significant obstacles to flow. As to the components within the BOP that did impede flow, the United States believes these restrictions eroded rapidly and did not provide any significant resistance after a few days. The United States contended instead that the primary factor affecting the rate of discharge was reservoir depletion, meaning the rate of discharge was highest near the beginning of the spill period—when the reservoir was highly pressurized—and slowly declined over time. For example, the United States estimates that the rate of discharge was roughly 60,000 barrels of oil per day on or around May 27, which decreased to around 53,000 barrels of oil per day by mid-July.

262. The evidence pertaining to the Quantification segment was voluminous, dense, highly technical, and conflicting. The Court received not only live testimony, but also reviewed the parties' expert reports, deposition excerpts submitted in lieu of live testimony, post trial memoranda, and proposed findings of fact and conclusions of law.

263. Both sides presented evidence to support their cumulative flow estimates, and each mounted effective attacks on the other's calculations.

264. There is no way to know with precision how much oil discharged into the Gulf of Mexico. There was no meter counting off each barrel of oil as it exited the well. The experts used a variety of methods to estimate the cumulative discharge. None of these were perfect. Because data from the well is limited, every expert had to make some assumptions while performing his calculations.

265. The Court will use Dr. Martin Blunt's testimony to illustrate the type of evidence and arguments presented during the Quantification segment.

266. Dr. Blunt, one of BP's experts, used a material balance analysis to arrive at a cumulative discharge estimate of 3.26 million stock tank barrels. Under this analysis, cumulative flow (Np) is the product of three variables: initial volume of oil connected to the well (N); compressibility of the rock and fluids in the reservoir (c); and change in reservoir pressure (Δp):

$$Np = N \text{ x } c \text{ x } \Delta p$$

267. Dr. Blunt calculated N to be 112 million stock tank barrels. To arrive at this number, Dr. Blunt first determined the total volume of oil in the entire reservoir, which he derived from seismic data collected before the well was drilled. He then evaluated what portion of the total oil was actually connected to the well and not compartmentalized by geologic faults or sedimentary discontinuities. To do this, Dr. Blunt estimated the size of the connected area, which he determined by analyzing the distance at which a pressure signal from the well hits boundaries of the reservoir. The pressure signal analysis depends heavily on permeability—the ability of oil to flow in the reservoir formation—another variable that had to be determined. After determining the size of the connected area, Dr. Blunt calculated how much oil was in that

area, as opposed to outside the connected area. Dr. Blunt then used a single-stage flash process to convert his estimate for connected oil from reservoir barrels to stock tank barrels.[45]

268. Compressibility, c, describes how easy or hard it is for a body to change its size and shape when acted upon by pressure. The more compressible the rock, the greater the cumulative discharge under the material balance analysis. Dr. Blunt's value for c was 6.35 microsips. To reach this number, he relied on compression testing performed on rotary sidewall core samples extracted from the reservoir.

269. Change in pressure, Δp, is the difference between the initial measured reservoir pressure and the final reservoir pressure. If everything is held constant, the greater the change in the pressure, the more oil was released. The initial pressure was measured on April 12, 2010. After a well is shut in, pressure will build up until it equalizes, providing final pressure. Final pressure was not measured in this instance because pressure was still building when the well was cemented, cutting off the ability to monitor pressure. Therefore, Dr. Blunt estimated the final equilibrium pressure by using pressure readings taken at the capping stack following shut in and then predicting the additional increase in pressure after the well was cemented. Because pressure at the capping stack (located near the seafloor) is different from the pressure at the reservoir, Dr. Blunt also had to convert the capping stack pressure readings to down-hole values. Ultimately, Dr. Blunt determined Δp to be 1,367 psi.

270. The United States criticized several aspects of Dr. Blunt's calculation and presented a competing version of the material balance analysis through its expert, Dr. Kelkar, who used different values for some of the inputs. The United States attacked, among other things, Dr. Blunt's inputs for permeability, rock compressibility, and fluid separation (the

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[45] *See supra* note 39.

manner in which reservoir barrels are converted to stock tank barrels).[46] Of these, compressibility was perhaps the most contested issue.

271. The United States' used 12 microsips as its value for compressibility, noting that BP relied on this number during the response and represented it to be the "most likely" case. The United States further contended that the rock core testing that generated the 6.35 value was flawed and unreliable. The United States pointed out that of the 44 rock samples collected from the Macondo well, 21 were in such a fragile state they could not be used for rock mechanics testing; therefore, only the "strongest" cores were tested, leading to a sampling bias that underestimated compressibility. Ultimately, only three of these samples were actually tested for compressibility, constituting less than one percent of the reservoir's thickness at the Macondo well, claimed the United States. Moreover, the United States argued that the orientation of the cores in the lab tests did not match the orientation of compaction in the reservoir, a consequence of using rotary sidewall cores to collect reservoir samples. Because the Macondo reservoir is anisotropic—meaning the physical properties of the rock has different values depending on the direction in which it is measured—the tests likely under-predicted compressibility. The United States asserted that conventional (or whole) coring is the most accurate method in the industry to take rock samples and the only method appropriate for compressibility testing. The United States raised other arguments about the compressibility testing which are not recounted here.

272. Again, the Court presents this discussion to illustrate the type of evidence and arguments presented at trial. Each side ably demonstrated the shortcomings of the other's evidence.

273. After weighing all of the evidence and considering all of the arguments, the Court finds that 4.0 million barrels of oil released from the reservoir. After deducting the Collected Oil

[46] *See supra* note 39.

from this amount per the parties' stipulation, the Court finds for purposes of calculating the maximum possible civil penalty under the CWA that 3.19 million barrels of oil discharged into the Gulf of Mexico.

IV. SUMMARY

274. BP was not grossly negligent, reckless, willful, or wanton in its source control planning and preparation. Assuming without deciding that BP's source control plan was negligent, that finding would not alter any of the fault determinations from Phase One.

275. It has not been shown that BP's flow rate misrepresentations delayed the capping of the well or otherwise adversely affected source control. It has not been shown that the post-blowout source control decisions or actions were unreasonable.

276. In short, nothing from the Source Control segment alters the Court's findings and conclusions from Phase One.

277. The Court finds that 4.0 million barrels of oil released from the reservoir. After deducting the Collected Oil from this amount per the parties' stipulation, the Court finds for purposes of calculating the maximum possible civil penalty under the CWA that 3.19 million barrels of oil discharged into the Gulf of Mexico.

Signed in New Orleans, Louisiana, this 15th day of January, 2015.

United States District Judge