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 No. 2179**
	§	**SECTION: J**
	§	**JUDGE BARBIER**
Applies to: No. 10-2771, and All Cases	§	**MAG. JUDGE SHUSHAN**

<u>THE ALIGNED PARTIES' PROPOSED PHASE TWO FINDINGS OF FACT</u>

NOW INTO COURT, come Plaintiffs, Claimants-in-Limitation, including the State of Alabama and the State of Louisiana, through Plaintiffs' Co-Liaison Counsel, Coordinating Counsel for the States, the Plaintiffs' Steering Committee, and the PSC Phase Two Trial Team; Transocean Offshore Deepwater Drilling Inc., Transocean Holdings LLC, Transocean Deepwater Inc., Triton Asset Leasing GmbH; and Halliburton Energy Services, Inc., and collectively file these Proposed Findings of Fact.

<u>PLEADINGS AND EVIDENCE BEFORE THE COURT</u>

On September 30, 2013, the Court called this matter for trial. In accordance with Federal Rule of Civil Procedure 52, and based upon the evidence presented during Phase One and Phase Two of this limitations trial, the Aligned Parties propose the following findings of fact. The parties will file separate proposed conclusions of law. The Aligned Parties incorporate herein, as if stated in full, the parties' Stipulated Facts Concerning Source Control Events (Rec. Doc. 7076), filed on August 8, 2012. If the Court determines that any finding of fact is more appropriately a conclusion of law, the parties respectfully request the Court to consider the "fact" a conclusion of law.[1]

[1] Citations to the record are identified as follows: (1) citations to trial testimony are noted by the first initial of the witness's first name, followed by his or her last name, a reference to P1 for Phase One testimony or P2 for Phase Two testimony, then page and line, (*e.g.*, M. Bly, P1 TT 863:1-15); (2) citations to trial exhibits are noted as "TREX-" followed by the exhibit number; (3) citations to demonstrative exhibits are noted as "D-" demonstrative number; and (4) citations to deposition testimony are identified by the first initial of the witness's first name, followed by his or her last name, then page and line (*e.g.*, Depo. of S. Douglas, 93:1-5). In the event the deposition page numbering between volumes is not sequential, the Aligned Parties will identify the requisite volume number as necessary. Citations to any pleadings filed with the Court are identified by record docket number and case number.

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PROPOSED FINDINGS OF FACT

I. Phase Two Proceedings

A. Proceedings Leading To The Phase Two Trial.

1. This litigation arose out of the April 20, 2010, blowout of the Macondo well and the resulting explosion and fire on the Mobile Offshore Drilling Unit ("MODU") *Deepwater Horizon* as it was preparing to temporarily abandon the well. Macondo was an exploratory well drilled in Block 252, Mississippi Canyon, on the Outer Continental Shelf ("OCS") approximately 50 miles south of Louisiana. *See In re Oil Spill by the Oil Rig Deepwater Horizon in the Gulf of Mexico*, 808 F. Supp. 2d 943, 947 (E.D. La. 2011). Eleven men died in the explosion and many others were injured. *Id*. On April 22, after burning for two days, the *Deepwater Horizon* sank into the Gulf of Mexico. *In re Oil Spill by the Oil Rig Deepwater Horizon in the Gulf of Mexico*, 844 F. Supp. 2d 746, 748 (E.D. La. 2012). Oil flowed from the Macondo well into the Gulf until July 15, 2010, when the well was capped. *Id*.

2. Four Transocean entities, Transocean Offshore Deepwater Drilling Inc., Transocean Holdings LLC, Transocean Deepwater Inc. and Triton Asset Leasing GmbH (collectively, "Transocean"), commenced this action by filing a Limitation action under the Shipowner's Limitation of Liability Act, 46 U.S.C. §§ 30501, *et seq*. (the "Act"). Rec. Doc. 1, (2:10-cv-02771-CJB-SS). Under the Act, each of the Transocean entities seeks to limit its liability to the value of the vessel, *i.e*., the *Deepwater Horizon*, or the owner's interest in the vessel and/or to be exonerated from liability.

3. Pursuant to court orders directing that all persons claiming damages for any losses, injuries or destruction of property occasioned by the voyage of the *MODU Deepwater Horizon* be filed in the Limitation proceeding, Rec. Docs. 9-10 (2:10-cv-02771-CJB-SS),

numerous claims were filed in this action. *See, e.g.*, Rec. Docs. 288-300 (2:10-cv-02771-CJB-SS).

4. In August 2010, the Judicial Panel on Multidistrict Litigation also consolidated before this Court numerous individual lawsuits stemming from the April 20, 2010 oil spill. *In re: Oil Spill by the Oil Rig Deepwater Horizon in the Gulf of Mexico*, on April 20, 2010, 731 F. Supp. 2d 1352, 1353 (J.P.M.L. 2010). The lawsuits included claims for the deaths of the 11 individuals, numerous claims for personal injury and various claims for environmental and economic damages. *In re Oil Spill by the Oil Rig Deepwater Horizon in the Gulf of Mexico*, 808 F. Supp. 2d at 947.

5. Phase One was tried as a bench trial before this Court beginning on February 25, 2013, and concluding on April 17, 2013.

B. <u>Phase Two Proceedings.</u>

6. Phase Two was divided into two segments: the Source Control segment and the Quantification segment.

7. The Source Control segment was tried as a bench trial before this Court beginning on September 30, 2013, and concluding on October 3, 2013. The parties to that trial were Transocean, Halliburton Energy Services, Inc., ("HESI") the Plaintiffs Steering Committee representing the private plaintiffs, and the States of Alabama and Louisiana (collectively the "Aligned Parties") on one side, and the BP Defendants on the other side.

8. The Quantification segment was tried as a bench trial before this Court beginning on October 7, 2013, and concluding on October 17, 2013. The parties to that trial were the United States on one side, and the BP Defendants and the Anadarko Defendants on the other side.

9. These Proposed Findings of Fact are submitted with respect to the Source Control Segment.

C. Summary Of Findings.

10. BP knew for at least two decades before drilling Macondo that the risks of a deepwater blowout were high, that the consequences were grave and that it was utterly unprepared to respond to the flow of oil at its source in the event of a blowout. In fact, BP's top management considered a deepwater blowout the highest of BP's risks in the Gulf of Mexico and among the highest risks for BP's entire Exploration and Production Unit. BP's top management acquired this knowledge from multiple sources, including its in-house engineers, its outside technical experts to whom BP would turn in the event of a deepwater blowout, and industry associations that warned in guidances, manuals and conferences that a deepwater blowout was likely and that when it occurred the environmental and other consequences would be catastrophic. Yet, armed with this knowledge, BP management spent no money or resources on source control planning. In sum, BP did nothing to prepare to control the source of a deepwater blowout, and residents and businesses around the Gulf of Mexico have paid the price.

11. As an industry leader in deepwater drilling in the Gulf of Mexico, BP had the responsibility and unique obligation to be a leader in deepwater drilling safety and source control planning. BP management failed. BP drilled Macondo without a plan to mitigate the consequences of a deepwater blowout despite knowing that the drilling operation was in the "high risk" zone according to its own internal Major Accident Risk assessment. That Major Accident Risk matrix is designed to halt any project that falls in the high risk zone; a high risk project may go forward only if approved by BP management.

12. Knowing the high risk nature of deepwater drilling generally, and the additional high risks of drilling Macondo specifically, BP management allowed the well to be drilled

without any source control plan or equipment in place. The only pre-explosion "plan" in place was BP's Oil Spill Response Plan ("OSRP"). BP's witnesses, including its highest officers, testified that the OSRP was not, and was not intended to be, a source control plan. One by one, they admitted that BP in fact did not have a source control plan and that all BP had in place was a "plan" to begin planning if and when a deepwater blowout occurred. These BP officers admitted that the only "tools" BP had in place to address a deepwater blowout were remote-operated vehicle ("ROV") intervention, which they knew was unlikely to work in a deepwater blowout situation, and the drilling of relief wells, a process they knew would take between 90 to 150 days to complete. BP's top management knew before drilling Macondo that BP had no capability to immediately stop the flow of oil in the event of a blowout and that the risks of that event were high. But in keeping with BP's CEO "every dollar counts" mantra, BP proceeded to drill Macondo despite countless advance warnings that the risks of that operation could be, and ultimately were, catastrophic.

13. In the weeks following the April 20, 2010 blowout, BP repeatedly lied about the amount of oil that was flowing from the Macondo well. BP told Government officials in the Unified Command, Congress, and the public that the flow rate was just 5,000 barrels of oil per day ("BOPD"). In fact, BP had many internal flow rate estimates that were substantially greater, but that were not distributed outside of BP. BP's lies were no accident; they were the result of a policy and practice—enforced by high-level BP executives—that that flow rate information was not to be distributed externally, or even shared internally within BP.

14. Unaware of BP's internal analyses–which repeatedly called into question the 5,000 BOPD estimate that BP was defending publicly—Government decision-makers adopted 5,000 BOPD as the official public estimate

15. BP's misrepresentations concerning the flow rate had a critical impact on the source control effort and particularly on the decisions to attempt the Top Kill source control strategy and to abandon a capping strategy when Top Kill failed.

16. Top Kill had two components. In the "momentum kill," drilling mud was pumped from vessels down the choke and kill lines into the BOP in an attempt to overcome the flow of hydrocarbons. In the "Junk Shot," bridging material such as balls, rubber, or rope was pumped into the BOP in an attempt to clog the open orifices in the BOP and stop the flow of hydrocarbons. Correctly understanding the flow rate was critical to evaluating both the likelihood of success and the reasons for failure of both procedures.

17. BP did not tell Unified Command officials that it knew, before Top Kill was approved, that the momentum kill (one of the two procedures that comprised the Top Kill) would not succeed if the flow exceeded 15,000 BOPD. Instead, BP told the Unified Command and the public that the Top Kill procedure was a "slam dunk" with a chance of success of 60% to 80%. This contrived success rate was unsupported by any probability analysis or testing and was, in fact, contradicted by available evidence.

18. Top Kill was not a risk-free option. The procedure itself endangered human lives and the support vessels on the surface, and the procedure carried the risk of increasing the flow from the well, causing an underground blowout and jeopardizing the relief wells.

19. Top Kill failed because the flow rate was too high and the orifice was too large. During the Top Kill attempts, a BP employee communicated internally to a senior BP engineering executive that Top Kill was failing because the flow rate was too high and the orifice was too large. After the Top Kill failed, BP's contractors concluded that Top Kill failed because the orifice was too large and the flow rate was too high and informed BP of this analysis.

20. But on May 29, 2010, BP instead told the Unified Command that the only "plausible" explanation for the operation's failure was that the collapse disks in the 16-inch casing had opened and allowed Top Kill fluid and hydrocarbons to escape into the formation.

21. BP's misrepresentation—claiming that the only plausible explanation for the failure of Top Kill was the open collapse disks—directly led to the abandonment of the BOP-on-BOP option. The BOP-on-BOP option was ready and could have safely and effectively capped the well by mid-May to early June. The various risks presented by the BOP-on-BOP option were mitigated, did not constitute a reasonable basis to favor Top Kill over BOP-on-BOP, and would not have prevented the BOP-on-BOP strategy from being successful.

22. BP's decision not to prepare to control the source of a deepwater blowout and its intentional misrepresentations to Unified Command, Federal response authorities, and the public, directly caused the Macondo well to flow for weeks—and possibly months—longer.

II. BP Was In Charge Of And Was Expected To Prepare For Post-Spill Source Control.

23. BP was the Operator of the Macondo well and the Responsible Party for the Macondo oil spill. Depo. of A. Hayward, 481:2-6, 481:8-11 (BP CEO testifying "[w]e were clearly a responsible party under the OPA 1990 Regulations"); Depo. of E. Bush, 30:20-31:2 (BP 30(b)(6) representative testifying that BP was the Responsible Party); Depo. of B. Domangue, 213:16-19, 213:24-214:7 (BP accepted the designation of Responsible Party); Depo. of L. Herbst, 451:13-15 (MMS Regional Director for Gulf of Mexico testifying: "Q. Who was the well operator for the MC252 well? A. BP.").

24. As the Operator and the Responsible Party, BP was responsible for source control. Depo. of T. Allen, 110:2-20 (agreeing with statement in Federal On-Scene Coordinator Report that "source control had to be achieved through the Responsible Party"); Depo. of M. Landry,

490:13-16 (testifying that it was BP's obligation as the Responsible Party to secure the source of the spill); Depo. of L. Herbst, 451:22-452:1 (operator has the responsibility to control the source); Depo. of E. Bush, 30:20-31:2 (BP 30(b)(6) witness agreeing that "[u]nder the Regulations in place . . . BP had a responsibility to control the source of an oil spill"); Depo. of D. Suttles, 199:9-11, 199:14-21, 199:23-25, 200:3 (BP's Unified Area Commander testifying that "[i]n the Gulf of Mexico, the lease operator has the responsibility for the response," which "[o]n DEEPWATER HORIZON . . . was BP."); Depo. of D. Suttles, 530:22-24, 531:2-7 ("as the operator . . . we were responsible for . . . responding to the spill if it occurred"); E. Ziegler, P2 TT 516:4-10, 516:23-24, 517:24-518:4.

25. BP was aware before the spill began that as the Responsible Party, it had the responsibility to respond to the spill. As a BP employee instructed BP incident commanders just five days before the blowout, "[i]t's the RP's Spill" and "[t]he [Coast Guard] enters a response with the idea that they are there to assist the RP, unless you give them the impression that you are incompetent, then they will take over." TREX-10304.001 (April 15, 2010 email from BP's Earnest Bush); Depo. of E. Bush, 88:22-89:1, 89:3-90:6 ("it's something I already knew, but wanted to reinforce it with my Incident Commanders"); TREX-5335.001; *see also* Depo. of M. Landry, 94:7-95:14; Depo. of J. Rohloff, 111:5-112:20, 112:23-113:3, 113:7-12, 113:15-21, 113:24-114:1; *see* Depo. of S. Chu, 223:24-224:2, 224:4-12, 224:15-19 ("[W]e're here to help you.").

26. The evidence shows that the Government relied upon BP for post-spill source control efforts. BP, not the Government, was responsible for identifying, developing and implementing source control techniques. Depo. of L. McKay, 476:20-477:17, 478:12-479:21, 479:23-480:20, 489:7-12, 489:14-15, 491:9-492:19, 492:21, 520:20-23, 646:21-647:1, 647:17-

648:20, 651:24-652:2, 652:4-7; Depo. of D. McWhorter, 11/15/2012, 125:3-9; Depo. of D. McWhorter, 11/16/2012, 456:12-16; *see* TREX-7372; E. Ziegler P2 Expert Report, TREX-11578R-v2.043-.045 (BP is solely responsible for source control for the BP operated well); *see also* J. Dupree, P2 TT 698:11-13 (Unified Command was dependent upon BP to provide accurate information); Depo. of S. Chu, 188:9-16; Depo. of M. Landry, 94:7-95:14, 230:7-15 ("I would look to [BP] . . . as the Responsible Party."); Depo. of M. Landry, 321:10-15 ("I relied on the work of BP through Doug Suttles as the Lead Person for BP.").

27. The Federal On-Scene Coordinator's Report confirms that:

> As sub-sea drilling systems are not an area of Coast Guard cognizance and expertise, the Federal On-Scene Coordinator (FOSC) was unfamiliar with the technology and capabilities of the deepwater drilling industry. Neither the Coast Guard nor any other federal agency had experience with a massive deep water spill. Ultimately, source control had to be achieved through the Responsible Party (RP).

TREX-9105 at 21-22.

28. The Coast Guard's Report on Preparedness echoes this statement, as follows:

> The Federal Government has neither the skilled personnel nor the appropriate equipment to respond independently to an oil blowout in deep water and must rely wholly on the responsible party.

TREX-9124.118; TREX-9099.118; *see also* Depo. of M. Landry, 579:12-580:13, 580:15-21 (BP, not the Government, had all of the information regarding reservoir permeability, the gas/oil ratio, the oil viscosity, measured flow pressure at the base of the BOP, and the reservoir skin); J. Wilson, P2 TT 121:15-21, 122:7-10; *see also* Depo. of M. McNutt, 464:18-23, 465:1-3, 465:6-7 (Government Officials, including the head of the Flow Rate Technical Group, were outside BP's "circle of trust").

29. Not only was source control BP's responsibility, BP failed to be transparent with the representatives of the Federal Government during the response. The Federal On Scene

Coordinator experienced "a lack of transparency by the RP on source control." TREX-9105 at 47. Senior BP Management "made major decisions outside the [Incident Command Structure]." *Id*. Even after the Incident Command raised this concern, and insisted on attending the daily meetings, "it remained apparent that key strategic and tactical planning occurred behind closed doors by RP personnel without government participation." *Id*.

30. Within the Houston Incident Command Post, BP was giving active direction and establishing what steps were going to be taken at what time. Depo. of G. Boughton, 100:5-13. "BP was driving the bus." Depo. of G. Boughton, 204:18-23, 205:1-9, 390:14-21.

31. It was BP's decision, for example, to eliminate the use of the *Enterprise*'s BOP as an option for capping the well, on or around May 10, 2010. R. Turlak, P2 TT 340:19-25; *see also, e.g.*, TREX-7104.0003 ("BP has decided to go another route.").

32. Particularly during the pre-Top Kill phase of the response, the Government "look[ed] to BP to secure the source" while providing a limited amount of Government oversight. Depo. of M. Landry, 496:19-497:13, 497:15-22; *see also* Depo. of M. Landry, 445:11-19 ("BP proffered several proposals for Source Control . . . over the course of the time I was FOSC, and MMS was the approving authority, and we signed off . . . [.]"); *see also* Depo. of T. Allen, 21:15-18, 21:20 (National Incident Commander testifying that Government acted primarily in an oversight role); Depo. of G. Boughton, 100:5-13, 204:18-23, 205:1-9 ("certainly after the first couple of days . . . it was quite clear that it was BP's operation"); Depo. of G. Boughton, 390:4-6, 390:8-13, 390:14-21 ("when I arrived over there, it was apparent that BP was calling the shots"); Depo. of A. Hayward, 481:2-6, 481:8-11 ("we . . . led, in conjunction with the Coast Guard, the biggest response . . . ever mounted"); Depo. of L. McKay, 651:24-652:2, 652:4-7, 653:1-5, 653:7-13, 653:15-16 ("Q. That doesn't make any sense after the well blows out

to say, oh, the Coast Guard is the one responsible for everything that happens from here on out …? A. … I don't think we've said that."); Depo. of E. Bush, 89:16-19 (BP's Rule 30(b)(6) witness testifying: "Q. So it's not the Federal Government's job to respond. It's the responsibility–Responsible Party's job to respond, right? A. It is our job."); Depo. of D. McWhorter, 11/15/2012, 125:3-9 (Cameron employee who worked at the source control incident command post testifying that BP was in charge of the response effort); Depo. of D. McWhorter, 11/16/2012, 456:5-7, 456:9-16 (BP in consultation with the Government controlled the prioritization of intervention methods).

33. Contemporaneous accounts confirm that during the period leading up to the Top Kill, BP was making the key source control decisions subject to receiving Government approval. *See* TREX-9154.002 (member of Secretary Chu's team writing on May 20, 2010 that "It is clear that BP is making the decisions right now"); TREX-9125.002 (May 4, 2010 government meeting notes stating that "[a]ll decision making, particularly about whether to make a physical intervention in the damaged well, was clearly BP's sole responsibility").

34. The Government's level of involvement in source control changed over time. As Tom Hunter, co-head of the United States' Science Team, explained "before the top kill, we had a very defined role, as exhibited by . . . the fact that we were working on diagnostics . . . and trying to understand the well situation." Depo. of T. Hunter, 626:23-627:15. After the Top Kill, the relationship changed because of the Top Kill's failure. As Hunter testified, "the view [was] that we needed a different . . . path forward, that the Government had a significant role in deciding that path forward—and agreeing that that was the right path forward, became a very present concern." Depo. of T. Hunter, 627:22-628:9; *see also* Depo. of S. Chu, 182:21-183:2, 183:4-16 (describing his "evolving role" in the response that began with "diagnosing the

condition of the BOP" and later was "brought into more and more conversations about the control of the well itself"). As described *infra*, even when the NIC representative attempted to participate in the internal BP post-Top Kill analysis meeting, BP refused to let him enter.

35. It was not until after the failed Top Kill that the Federal government was able to fully participate in the source control decision-making process. TREX-9105 at 47 ("This changed in late May 2010 when the NIC representative vigorously insisted on participating in an internal RP meeting to assess the failed top kill, establishing a new paradigm. From that point forward, the government played a significant role in overarching source control planning and assessment.").

36. While the Government did sign off on BP's source control decisions, the Government's ability to provide meaningful oversight of these decisions depended on BP's willingness to provide the Government with complete and accurate information. *See* Depo. of S. Chu, 188:17-21 ("Q. And getting complete and accurate information from BP was important to you as a scientist for you to do your job, correct? A. Correct."); Depo. of M. Landry, 573:2-4, 573:6 ("Q. So you, as the Government, would need to rely on BP to supply you with that internal well data, correct? . . . A. That's correct."). BP failed to provide complete and accurate information on which the Government depended and which it believed it was receiving. *See infra*, Section XIV-XVII.

III. BP Held Itself Out As An Industry Leader In Deepwater Drilling.

37. BP "considers itself a leader in the industry." Depo. of L. McKay, 42:5-7; TREX-6298 at 12 ("[W]e are the leading deepwater producer.").

38. In 2009, BP was recognized as an "industry leader" in the Gulf of Mexico. Depo. of A. Hayward, 209:17-210:4.

39. A continual push into the deeper waters of the Gulf was a key BP business strategy. TREX 120174.3; TREX 120174.4; TREX 120174.5. This expansion was due to advances in technology that allowed BP to drill into "new deeper water geography and new deeper geology." TREX 120174.4.

40. Starting in 1975, with the first well in 1,000 feet of water, BP pushed out into deeper waters. TREX-9098.010. By 1994, operators were drilling wells in approximately 3,000 feet of water; by 1998, wells were drilled in nearly 4,000 feet of water, expanding to 5,000 feet by 2000. BP itself pushed the boundary to nearly 7,000 feet by 2003. By 2010, BP ranked first in terms of net leases in the Gulf of Mexico. TREX-120174.3; R. Bea P2 Expert Report, TREX-11750R.3-.4; *see also* Depo. of L. McKay, 42:13-15.

41. BP was "pushing the technology frontier to unlock the future as we go deeper, with higher pressures and more challenged (*sic*) reservoir conditions." TREX-120174.5. The company observed, "[t]echnology will be the key to the future and given BP's track record of successfully pushing the technology frontier we are confident that these challenges can be met." TREX 120174.7.

42. "BP is happiest," Anthony Hayward, BP plc's Chief Executive Officer, stated "doing the tough stuff that others cannot or choose not to do." From the company's roots in Edwardian days, "it is the same frontier spirit that is evident today as we develop the deep waters of Angola, the Gulf of Mexico and Egypt." TREX-6015 at 3 (Annual Meeting, April 17, 2008).

IV. Knowing The Risk, BP Did Not Prepare For Source Control Of A Deepwater Well Blowout.

A. BP Knew The Significant Risk Of An Uncontrolled Deepwater Blowout in the Gulf of Mexico Far In Advance Of The Macondo Incident.

43. Deepwater activity had increased dramatically in the twenty years prior to 2005. TREX-9098.10. The risk of a blowout increases in deepwater, and BP knew source control

procedures were more difficult. *See* TREX-5053.0007. BP was aware of the risk posed by "uncontrolled flow during drilling, completion or well intervention activities" and the potential to create "a loss of well control. . . release of hydrocarbons and potential environmental damage. . . fire and explosion." TREX-4171.

44. BP management knew that an uncontrolled blowout in a subsea environment was a very significant risk long before Macondo. Depo. of L. McKay, 594:18-19, 22-595:10; Depo. of J. Rohloff, 52:17-23; *see also* Depo. of D. Suttles, 247:10-14, 281:18-23. BP management identified a deepwater well blowout in the Gulf of Mexico as part of a group-wide risk assessment. Depo. of A. Hayward, 234:16-25; Depo. of C. Holt, 45:25-46:2, 46:6-9. A deepwater blowout was "the highest risk in the Gulf of Mexico, and one of the highest risks for the Exploration and Production Unit." Depo. of A. Hayward, 196:10-18; *see also* Depo. of A. Inglis, 125:3-8. In fact, BP considered an uncontrollable deepwater well blowout to be the highest level process safety risk in BP's entire worldwide operation. TREX-4171; Depo. of D. Suttles, 724:10-16, 724:19-20, 724:22-25.

45. As documented in 2004, BP was aware of the "risk to its existing operations from a catastrophic loss of [well] containment." *See* Depo. of D. Suttles, 205:4-206:23, 207:1-3, 5-7; TREX-2287.003. Andrew Frazelle, BP's Wells Operation Manager for the Gulf of Mexico at the time of the incident, "certainly knew, prior to April 20th, 2010, of the risk of a blowout" and understood that the consequences of an uncontrolled blowout could be severe. Depo. of A. Frazelle, 11:17-12:7, 160:11-18, 219:8-15; *see also* Depo. of L. McKay, 89:21-90:10, 90:22-91:1, 91:3-4.

46. Statistically, drilling in the Gulf of Mexico accounts for 67% of the wells drilled worldwide but 95% of all blowout incidents. TREX-7264.0019 (Lloyd's Register report on 2009

blowout frequencies). In contrast, "the North Sea [accounts for] 5% of the incidents and about 33% of the wells" drilled worldwide. *Id*. "'This indicates a blowout frequency for the GoM [Gulf of Mexico], which is about nine times higher than for the North Sea.'" *Id*.

47. Based on these statistics, BP knew the risks and should have prepared for a source control response to a deepwater blowout, especially in the Gulf of Mexico.

48. BP's Major Accident Risk Process document ("MAR") identified the probabilities of experiencing a "leak" (blowout) during exploratory drilling of a High Pressure–High Temperature well as about 2/1000 per well per year. TREX-4152.050. A 2009 SINTEF blowout frequency study identified a similar blowout frequency as 1/1000 per well or about 4/1000 per well per year. TREX-7192.006; TREX-4156.006. Given that there is approximately a 50% failure rate of the BSRs to seal such a well, BP knew that the risk of an uncontrolled blowout in a deepwater High Pressure-High Temperature well, like Macondo, doubled. TREX-5054.003; *see* TREX-6299.010.

49. As early as 2001, BP personnel specifically considered the following situation, predicting, almost a decade in advance, an event strikingly similar to what would happen at Macondo:

> **Situation:**
>
> *Horizon* has driven off
>
> Well is flowing at 100,000 – 300,000 bbls / day
>
> BOP is open – no rams closed
>
> Do not know if Dead-man has actuated or not
>
> ROV flow rate for override is 0.12 GPM
>
> **Question:**

> Can we close the shear rams with the ROV over-ride without further damage to the BOP at 100, 200 & 300BPD flow rate?
>
> **Answer:**
>
> No.

TREX-4423; D-20050.

50. "As the industry advances into deepwater exploration, the risks of blow out increase, due to difficulties related to kick detection and control procedures under deepwater conditions." TREX-5053.007. For example:

- A 1996 study reported that, while deepwater wells accounted for only 2% of the wells drilled, they accounted for 8% of the blowouts;
- A 2001 study reported a total of 117 BOP failures in the 83 wells observed between 1997 and 1998, with many kicks occurring in narrow margin wells like Macondo;
- An Mineral Management Service ("MMS") study in 2007 reported 39 blowouts between 1992 and 2006 on the OCS;

G. Perkin P2 Expert Report, TREX-11464R.25-.26.

51. Moreover, due to the size and nature of the reservoirs and the length of time it would take to drill a relief well, deepwater projects in the Gulf of Mexico were known to have potential consequences significantly greater than blowouts in shallow water. "The higher consequences of an uncontrolled deepwater blowout therefore require substantially lower likelihoods to be deemed an acceptable risk." R. Bea P2 Expert Report, TREX-11750R.12. Application of the available data to BP's MAR Matrix rendered the likelihood of a deepwater blowout–and the associated consequences–an "Unacceptably High Risk." R. Bea P2 Expert Report, TREX-11750R.18; *see also* R. Bea, P2 TT 425:15-427:24.

52. "A loss of well control in connection with deepwater drilling" was foreseeable to BP, as recognized by Dennis Johnson, BP's Manager of Crisis and Continuity Management and Emergency Response. Depo. of D. Johnson, 133:17-19, 22. An uncontrolled blowout resulting

in the release of oil into the environment is a "foreseeable" scenario that is to be planned and prepared for. *See* Depo. of D. Johnson, 132:22-24, 133:2-6, 9; *see also* Depo. of A. Inglis, 142:21-24, 143:1-7.

53. BP also knew the magnitude of the hazard and the risk at Macondo before it started to drill the well, having calculated the worst case scenario flow rate of 162,000 BOPD for the Macondo well in its Initial Exploration Plan for Macondo. Depo. of C. Holt, 45:25-46:2, 46:6-9; TREX-6299; TREX-768.098; Depo. of A. Inglis, 133:23-134:6. The purpose of identifying a worst-case scenario is to assure the MMS that the operator can handle such a scenario. Depo. of A. Inglis, 132:22-133:5, 133:7-15, 18-22.

54. BP fully understood the risk of a deepwater blowout and the need to prepare to mitigate such an event.

B. BP Failed To Undertake Or Underwrite Any Effort To Prepare For Source Control. BP Had No Plan.

1. *BP Spent No Time Planning For, Nor Did BP Have The Necessary Tools For, Deepwater Source Control.*

55. Hayward admitted that BP "certainly didn't have all of the tools" that were necessary to shut in the well, and "[w]e didn't have a capping stack that would go instantly into place. We didn't have some of the things that you would ideally want." Depo. of A. Hayward, 343:2-20. Hayward also admitted that BP's "ability to intervene in the subsea was not in any way, shape, or form complete." Depo. of A. Hayward, 254:14-17, 254:19-255:4. BP's Vice President of Exploration for the Gulf of Mexico and Deputy Incident Commander, David Rainey agreed that prior to the blowout, BP "clearly" did not have "the equipment to handle . . . the type of catastrophe [presented] when it began" drilling the Macondo well. Depo. of D. Rainey, 258:14-17.

56. BP did not have the tools it needed because it had no "pre-approved plans" for source control once the BOP failed. *See* Depo. of J. Wellings, 247:1-6, 247:8; *see* Depo. of R. Lynch, 183:21-184:4; *see* Depo. of C. Holt, 63:24-64:4, 64:7-14, 64:17-20.

57. BP's corporate representative testified that BP had not identified any equipment for use in the subsea to control the source of a deepwater blowout other than the drilling of a relief well. Depo. of J. Rohloff, 48:7-11, 48:13-17; *see also* Depo. of R. Lynch, 201:15-20.

58. The only written pre-incident plan that BP had in place was its OSRP, which set out in a single bullet point that the "plan" was to **begin** the planning process **after** such a blowout occurred. TREX-769.179 (BP OSRP, Section 6(c)); R. Bea P2 Expert Report, TREX-11750R.4; Depo. of J. Rohloff, 47:6-11, 47:13-17, 47:20-24, 48:2-11, 48:13-49:1, 275:3-276:5; *see also* R. Bea P2 Rebuttal Report, TREX-11751R.7 (plan is limited to the first 48 hours). BP admitted this "plan" was not a source control plan. *See infra* at Section V.

59. BP's pre-spill preparation was a "think about it . . . when it happens plan[,]" *i.e.*, a plan to make a plan. R. Bea, P2 TT 440:25-441:7; Depo. of A. Hayward, 255:5-21; Depo. of C. Holt, 32:19-33:19, 33:22, 43:3-10, 43:13-18, 43:20-21, 44:18-20, 44:23-45:4, 45:11-14, 45:18-21, 45:24, 63:24-64:4, 64:7-14, 64:17-65:6, 65:8-12, 65:14-18; TREX-2433.022; D-20043.

60. "A spill is not the right time to conduct Research and Development" for Source Control operations. Depo. of T. Hunter, 511:10-14, 511:24-512:4. BP had no solutions available to immediately stem the flow of hydrocarbons from Macondo. Depo. of T. Hunter, 50:12-51:13, 51:16; TREX-9689.005.

2. *BP Spent No Money Developing Source Control Plans, Procedures or Equipment Prior To The Macondo Incident.*

61. BP did not spend a single dollar on research and development for source control plans, procedures or equipment prior to the Macondo blowout. R. Bea, P2 TT 446:4-449:9; E.

Ziegler, P2 TT 518:12-25; D-20052; D-20053; D-20054; D-20055; D-20056; D-20057; D-20058. BP spent no time or money preparing to stop a deepwater blowout at its source. Depo. of L. McKay, 102:21-103:9, 104:22-105:11, 105:13; TREX-6021; *see also* TREX-9104; TREX-2296.

62. BP was spending at least $17 billion per year on Exploration & Production and approximately $600 million per year on drilling technology research and development. TREX-2295. Specifically, in 2009, BP spent several hundred million dollars on research and development of exploration and production worldwide, yet BP spent no money on research related to source control. Depo. of A. Inglis, 161:1-162:21.

63. BP admitted, through its Rule 30(b)(6) designee James Rohloff, who also served as BP's *Thunderhorse* Offshore Leadership Team Manager, that it was unaware of any funds ever being allocated to identify ways to shut in a deepwater well subsea other than through the use of a BOP. Depo. of J. Rohloff, 102:14-19, 102:23, 138:19-139:13, 139:16, 140:25-141:6, 141:8-25, 142:3-6.

64. BP admitted that it "had neither allocated, budgeted, approved, distributed nor spent funds researching, testing, designing, building or planning" for the various source control options that were developed during the Macondo response. TREX-9349.004-.006.

65. Andrew Inglis, the CEO of BP Exploration and Production, Inc. and member of the board of BP, plc, admitted that "[i]n terms of . . . containment activities . . . there wasn't any research going on" and that BP spent "zero dollars" in preparation for containment of a deepwater spill. Depo. of A. Inglis, 162:9-21; R. Bea, P2 TT 446:4, 448:10-449:9; D-20057; D-20058; *see* D-20059.

66. As the Chief Operating Officer of BP Exploration and Production, Inc., Douglas Suttles had no idea that BP had spent zero dollars on the research of oil spill cleanup technologies prior to the Macondo blowout. Depo. of D. Suttles, 22:7-11; 585:9-14, 273:13-17, 273:20-23, 276:20-22, 277:5-8. Specifically, before the Macondo incident, BP did not research or develop capping stack technology. Depo. of C. Holt, 621:13-17, 621:20-24, 622:1-2; TREX-9104.004-.006; Depo of D. Suttles, 253:25-254:14.

67. BP's attitude toward spending such funds was reflected in public speeches by Anthony Hayward, who was both CEO and the top of the safety command structure for BP. Depo. of A. Hayward, 27:15-21, 27:23-24, 347:2-8. Upon becoming CEO, Hayward gave a speech in September 2007 outlining plans to "slash management layers from eleven to seven, redeploy some staff and remove others to kick start an oil group he believed [had] become over-cautious." Depo. of A. Hayward, 108:9-23. Hayward used the phrase "every dollar counts" to emphasize cost-reduction within BP. Depo. of A. Hayward, 113:1, 115: 3-16, 116:13-117:4; TREX-6016 at 5. Just five days prior to the Macondo blowout, Hayward delivered a speech in which he stated, "[T]he drive to increase efficiency and reduce costs remains a key focus for everyone at BP." Depo. of A. Hayward, 118:25-119:6; *see* TREX-6016.

68. The vast amount of money BP was required to spend post-Macondo was due to BP's failure to have a source control plan in the first place. E. Ziegler, P2 TT 566:23-567:5; *see also* J. Dupree, P2 TT 694:1-5 ("[B]uilding a capping stack wouldn't be a significant amount of money considering the amount of money that we spent in the deepwater."); *see also* E. Ziegler, P2 TT 566:23-567:11 ("If BP says–and I wouldn't disagree with them—that they spent a lot of money and a lot of time and a lot of man-hours and a lot of effort on creating that capping

situation, then that's all the more reason, if it's going to take so long, to have this plan before you ever drill the well.").

3. *BP Refused To Provide Any Training On Deepwater Source Control.*

69. BP provided no training on how to conduct a deepwater source control operation. R. Bea P2 Expert Rebuttal Report, TREX-11751R.7; E. Ziegler, P2 TT 504:4-6; Depo. of E. Bush, 31:13-24; Depo. of A. Frazelle, 219:16-18, 219:20-220:2, 220:4; Depo. of J. Rohloff, 26:23-27:5, 27:21-28:10, 30:8-31:3, 31:6-7, 104:17-24, 105:1; Depo. of J. Wellings, 82:15-83:10, 83:12-14; E. Ziegler, P2 TT 504:4-6. Additionally, BP "did not have someone who provided source control expertise to the Oil Spill Plan." Depo. of E. Bush, 12:1-8.

70. The technical experts within BP had no preparation or experience on what to do in the event of a deepwater blowout. Depo. of A. Frazelle, 219:16-18, 219:20-220:2, 220:4; Depo. of J. Wellings, 82:15-83:10, 83:12-14; R. Bea P2 Expert Rebuttal Report, TREX-11751R.7.

71. BP's Well Capping Team Leader, James Wellings, was not trained in deepwater blowout source control, and BP's Source Control leader, James Dupree, had no training in well kill operations. Depo. of J. Wellings, 82:19-83:1; J. Dupree, P2 TT 702:9-21. BP's corporate representative on source control testified that BP's operators were not trained on deepwater blowout source control. Depo. of E. Bush, 31:3-24.

72. Before the Macondo incident, BP had not conducted any deepwater blowout source control drills. Depo. of J. Rohloff, 292:18-293:2; D-20052; Depo. of E. Bush, 35:17-21, 37:2-38:16. The limited source control drills that were conducted did not address a Macondo-type situation. Depo. of J. Wellings, 82:19-83:6; Depo. of E. Bush, 31:13-24. BP "never conducted a full-fledged drill on a well that was flowing." Depo. of M. Patteson, 11/23/2013, 66:19-20, 66:25-67:2.

73. BP's employees were asked to do a job they had not been taught or trained to do. *See* E. Ziegler, P2 TT 504:4-6.

V. BP's OSRP And Its January 2010 Deepwater SPU Well Control Response Guide Were Not Source Control Plans.

74. Earnest Bush, BP's Crisis and Continuity Management/Emergency Response Advisor, was responsible for managing the OSRP and all surrounding regulations. Depo. of E. Bush, 10:2-11:15. Bush admitted that the OSRP "is not—not about source control." Depo. of E. Bush, 21:4-14, 27:24-28:16. With respect to a plan to control the source of a spill, Bush stated, "I don't know where that plan is," never saw it and did not know what the plan was. Depo of E. Bush, 67:24-68:12, 100:5-15, 105:20-106:3. Bush did not know if a written source control plan existed on April 20, 2010. Depo. of E. Bush, 106:16-18. Bush also admitted that, although the regulations regarding oil spill response plans have not changed since the incident, BP's current OSRP contains a much more detailed discussion of potential source control efforts. Depo. of E. Bush, 28:11-16, 65:6-19; TREX-10267. Bush further admitted that he lacked expertise in source control during deepwater blowouts. Depo. of E. Bush, 22:20-23:13.

75. Other BP officials likewise admitted that its OSRP was not a source control plan. *See* Depo. of A. Hayward, 255:11-21; Depo. of D. Suttles, 281:24-282:2, 282:8-16; TREX-11578R-v2.022; *see also* R. Bea, P2 TT 441:5-7. Rather, BP's OSRP dealt with how to respond to an oil spill on the surface and was designed solely to collect oil on the surface while a relief well was drilled. Depo. of E. Bush, 15:2-18, 27:24-28:16, 63:25-64:4; 105:20-106:9; TREX-769.179. BP's OSRP addressed only oil clean-up and containment once the oil reached the surface and did not have a specific source control plan to stop the flow at the wellhead. Depo. of E. Bush, 15:15-22, 17:15-20; 63:20-22, 63:25-64:4 ("This plan was not meant to address source control."); Depo. of A. Hayward, 255:5-21 ("[W]e did not have a plan to intervene to prevent

flow . . . until the relief well was there."), 256:1-5, 256:8-10 ("[BP's plan] was to contain the oil on the surface using spill response capability on the surface and to drill a relief well."); Depo. of D. Suttles, 218:10-20, 218:23-219:8. BP's OSRP was designed to allow continued uncontrolled flow while BP tried to determine, in the midst of crisis, how to shut in the well and stop the flow. Depo. of L. McKay, 49:25-50:9; Depo. of E. Bush, 148:19-22; TREX-11227.

76. Although BP designated source control as its highest response priority, only one page in its 600-page OSRP mentioned source control. Depo. of E. Bush, 11:20-25, 14:6-15:24; TREX-769.0179. Section 6C, titled "Source Control," contains only one relevant bullet point that addresses its source control plan to plan, as follows:

> In the event the spill source cannot be controlled by the facility operator or remotely with a safety system, **BP will activate the Oil Spill Response Plan and assemble a team of technical experts to respond to the situation.** The team will be comprised of personnel familiar with the facility including production superintendents, foremen, facility engineers, and production and/or drilling engineers. The Deputy Incident Commander or Operations Section Chief will be responsible for monitoring information produced by the team, as well as their progress, and reporting the results to the Incident Commander.

TREX 769.0179 (emphasis added); *see also* Depo. of E. Bush, 14:6-15:24.

77. Further, BP lacked a Macondo-specific source control plan. R. Bea, P2 TT 486:8-15; *see* TREX-769; Depo. of E. Bush, 15:2-18.

78. James Dupree, who was in charge of BP's source control efforts after the incident, never even referred to BP's OSRP at any time during the response. J. Dupree, P2 TT 703:23-704:12.

79. Even the Chief Operating Officer of BP Exploration and Production, who led BP's group crisis response and was BP's most senior member on the Unified Area Command ("Unified Command"), admitted that he did not interact with OSRP experts. Depo. of D. Suttles,

503:17-504:16. Suttles was not even aware of whether the OSRP contained a plan for stopping the flow of a deepwater well. Depo. of D. Suttles, 202:2-7, 202:20-203:1.

80. Prior to the Macondo blowout, no one—either internally or externally—provided source control expertise to the OSRP team. Depo. of E. Bush, 11:16-17, 11:20-25. Bush was not aware of any of the technical experts listed in the OSRP having expertise in how to kill a well releasing an uncontrolled flow of oil in a deepwater blowout. Depo. of E. Bush, 94:8-13. The OSRP did not contain any reference to engineered, designed, dressed and staged equipment for source control. *See* TREX-769; Depo. of D. Suttles, 518:22-519:5, 519:8-18. Additionally, although BP's Drilling and Operations Practice Guide required BP to prepare a well-specific source control guide for Macondo, BP did not prepare a well-specific control guide. R. Bea, P2 TT 432:8-12.

81. BP's January 2010 Deepwater SPU Well Control Response Guide, ("Response Guide"), was also not a source control plan. The Response Guide noted that it "is applicable for the BP Gulf of Mexico Deepwater Business Unit[.] It is a guide to ensure that an organized Source Control response to a well control event is brought swiftly and efficiently into action." TREX-2386.0009. This Response Guide would normally cover the first 48 hours and is not a "how-to-fix-it manual." M. Mazzella, P2 TT 779:4-22; TREX-2386.0009. Like the OSRP, BP's Response Guide is not a source control manual and does not identify the different options for source control in the event of a blowout. M. Mazzella, P2 TT 781:7-15.

82. "The oil spill response plan . . . [is] a piece of paper. Paper does not stop a well from flowing. If you want to cap a well, for example, you need to have a cap." E. Ziegler, P2 TT 524:12-18.

83. While BP's OSRP was reviewed and approved by the MMS, the MMS did not review BP's internal policies and guidelines on how to intervene and stop a blowout. TREX-9099 at 29 ("The regulations do not, however, address subsea containment of oil, nor do they require discussions on spill abatement such as well intervention or drilling of relief wells."). As observed by the US 30(b)(6) representative, "they were not prepared to respond." Depo. of L. Herbst, 348:14-17, 348:20-22.

84. Indeed, the OSRP prepared and submitted by BP was primarily intended to "interface with external BP groups to protect [BP's] reputation, financial integrity, and license to operate." TREX-11603.0004; R. Bea P2 Rebuttal Report, TREX-11751R.8.

85. In the end, BP's only "plan" was to activate the BOP through ROVs, call well control specialists and wait for a relief well to be completed. Depo. of E. Bush, 15:2-18, 121:17-122:3; Depo. of A. Hayward, 255:11-22; Depo. of D. Suttles, 342:15-20, 520:17-521:7, 521:10-11, 521:13-22; *see* TREX-769.0179; *see* TREX-2407. BP had no readily available intervention options other than to use ROV intervention or drill a relief well. TREX-769.0179; TREX-8886; TREX-10166; Depo. of A. Hayward, 255:11-21; Depo. of D. Suttles, 520:17-521:7, 521:10-11, 521:13-22. Because a relief well could have taken 90 to 150 days or even longer to stop the flow, a plan for quicker intervention options was needed. Depo. of D. Barnett, 198:9-14, 198:16; Depo. of D. Suttles, 203:11-22, 203:25-204:6; *see also* R. Bea P2 Expert Report, TREX-11750R.3; *id*. at 11750R.34.

VI. BP's Failure To Have A Source Control Plan In Place Prior To Macondo Resulted In A Substantial Delay In Shutting In The Well.

86. BP knew that source control would take a long time in the absence of a proper plan and the necessary equipment. In fact, the day after the blowout, Lamar McKay, Chairman and President of BP America and BP's liaison to the United States Congress, sent a message to

Doug Suttles acknowledging that Macondo "will play out for a long while." TREX-2433.012. BP knew that relief wells would take months to intercept a deepwater blowout. *See* Depo. of J. Wellings, 52:25-53:1, 53:3-16.

A. BP Had To Create A Source Control Plan "On The Fly."

87. Given the admitted lack of utility of BP's OSRP, BP left itself with no quickly deployable solution in the event of a disaster. Depo. of E. Bush, 27:24-28:10; Depo. of A. Hayward, 254:14-17, 254:19-256:5, 256:8-18, 621:17-19, 621:21. BP's attempts to contain the Macondo blowout were improvised and made up on a day-to-day basis. TREX-2402; Depo. of A. Hayward, 258:9-22, 262:10-19, 343:2-10. BP's failure to anticipate a subsea blowout necessitated the efforts to design, build and use such source control technologies. *See* TREX-2291; Depo. of D. Suttles, 246:9-19.

88. Examples of source control methods that BP had to fabricate during the spill response included the cofferdam conversion to a pollution dam, the RITT, numerous top hats and the capping stack. Depo. of D. Barnett, 325:23-326:4, 326:6-13, 326:15-16; Depo. of D. Suttles, 296:14-297:1, 520:2-6. Each intervention technique BP attempted during Macondo (Cofferdam, Top Kill, Top Hat, Capping Stack, etc.) was being considered by BP's experts for the very first time. TREX-9098.007 ("None of the subsea containment strategies used had even been attempted in water depths similar to those of Macondo.").

89. Because BP "didn't have the equipment" in place "to attack a Macondo-type event," it "had to engineer many things simultaneously on the fly." M. Mazzella, P2 TT 707:18-24. "We didn't have the equipment to attack a Macondo-type event," conceded BP's head of the source control efforts, James Dupree. J. Dupree, P2 TT 707:18-24. "That's why we had to engineer so many things simultaneously on the fly." *Id*.

90. Charles Holt, a leader of BP's Source Control effort, admitted that BP was essentially creating plans on how to kill the well as they went along. Depo. of C. Holt, 43:14-18, 43:20-25, 44:18-20, 44:23; TREX-11232. BP knew well in advance of drilling Macondo that the proper time to create a plan is not in the middle of a crisis but instead prior to a crisis. *See* Depo. of C. Holt, 45:11-14, 45:18-21, 45:24. The very purpose of a plan is to manage a crisis. Depo. of D. Johnson, 132:8-11, 14.

91. BP admitted that pre-planning would have been beneficial: "having plans in place beforehand . . . would have been of benefit." Depo. of C. Holt, 342:22-24, 343:2-8. BP's efforts to design, build and use source control technologies "on the fly" were made necessary by the failure to anticipate and plan for a subsea blowout. TREX-2291.001; Depo. of D. Suttles, 246:9-19. Dupree agreed that there is no substitute for planning and preparation for the worst case scenario, "no matter how good you think you are or how safe you feel." J. Dupree, P2 TT 705:17-706:1. BP's only plan, its OSRP, did not contain source control plans and procedures and, thus, was insufficient to address a spill of this magnitude. Depo. of J. Wellings, 247:1-6, 247:8; Depo. of R. Lynch, 183:21-184:4; Depo. of C. Holt, 63:24-64:4, 64:7-14, 64:17-20.

92. BP could not stop the flow at its source and admitted that it needed to significantly enhance subsea intervention capability in deepwater. TREX-9096; TREX-5051.012; Depo. of L. McKay, 89:21-90:4. BP had a limited pre-developed deepwater strategy and capability in subsea containment. TREX-7354.002; Depo. of L. McKay, 89:21-90:4.

93. As stated by expert Edward Ziegler, BP was not prepared to handle the response to a deepwater blowout because it did not have an effective and robust Source Control plan for Macondo. E. Ziegler, P2 TT 518:15-17; *see also* E. Ziegler, P2 TT 524:12-18; E. Ziegler P2 Expert Report, TREX-11578R. 23-.28.

94. Prior to drilling Macondo, BP acknowledged the likelihood of "analysis paralysis" in stressful situations. *See* TREX-120061.4; TREX-120061.9. "Analysis paralysis" is an industry term used to describe a situation where an organization lacks a concrete plan and is forced to make decisions more slowly and often incorrectly. *See* E. Zeigler P2 Expert Report, TREX-11578R.24.

95. A May 29, 2010 email among Cameron employees described this very situation: "Paralysis by analysis. Situation normal." TREX-10072.004; TREX-10072.4.1.HESI. Cameron employees observed BP's source control activities at Macondo and expressed frustration with BP's inadequate plan to achieve source control, using descriptions such as "[p]aralysis by analysis," "running this show like a game of Scrabble," "[b]y morning they will have enough letters to attempt a new word," and "[t]hey have no clue what to do next, simply running around like chickens with their heads cut off." TREX-10072.3.2.HESI. BP knew such frustrations and observations would occur without an effective plan in place. E. Ziegler, P2 TT 519:7-520:23.

96. As stated at the 2008 International Oil Spill Conference, "[o]il spill response readiness is not done in one set of tasks. Instead, readiness evolves from recognizing the need for preparedness, to allocating resources to address the issue, and gaining participation." R. Bea, P2 TT 440:3-12; TREX-11400 at 18 TREX-11400 at 28; D-20041

B. <u>With Preparation, The Spill Could Have Likely Been Stopped Within Weeks, If Not Days.</u>

97. The evidence establishes that, had BP prepared for a deepwater blowout, with an available capping device, the well could have likely been shut in within 24 days or less. *See* TREX-9573.3 (a deepwater drill was conducted using a capping stack built after the Macondo blowout, and the well was capped in 4.77 days); *see* E. Ziegler, P2 TT 544:13-20 (from the point in time at which BP had a capping device, it could have shut in the Macondo well in as little as

seven days); *see* TREX-9345.066 (the time to land and close in a capping stack can be accomplished in one to three weeks); *see* TREX-9564.002 (providing an estimate of 24 days from onset of incident to install a capping stack); *see* G. Perkin P2 Expert Report, TREX-11464R.7 (had a properly designed and assembled capping stack been made prior to the incident, the uncontrolled flow could have been arrested in a matter of weeks); J. Dupree, P2 TT 695:18-696:25. In September of 2010, in a presentation to BOEMRE, Wild Well Control, Inc. stated that in the event of a future Macondo-type event, capping could be accomplished within one to three weeks. TREX-2402.008-9; TREX-2403.066; Depo. of A. Inglis, 667:16-669:3; Depo. of D. Suttles, 320:19-321:21, 323:1-9, 323:13-15, 324:2-16, 325:18-326:19.

98. BP's first source control attempt was to try to actuate the BOP with ROVs. J. Dupree, P2 TT 602:11-603:7; Depo. of L. McKay, 37:22-24, 38:1-9. BP continued its ROV attempts at least until May 5, 2010. TREX-9550.008; Depo. of H. Thierens, 203:13-25, 205:13-22, 206:17-207:6.

99. Well before it began drilling Macondo, BP knew that its attempts at ROV intervention to close the BSR would be ineffective against dynamic flow conditions seen at Macondo. *See* TREX-1166.084-.085; *see also* TREX-4423. In 2001, a BP engineering team developed a hypothetical in order to assess a ROV's ability to close the *Deepwater Horizon*'s BSR and seal the well in the event of an uncontrolled blowout strikingly similar to the Macondo incident. TREX-4423. At that time, BP concluded that high flow rates and dynamic flow conditions would "wash out" or erode the BSR's elastomeric elements before it would seal. TREX-4423.

100. Similarly, in 2003, the US MMS retained West Engineering to evaluate "secondary intervention" methods in source control situations. *See* TREX-1166.084-.085. West

Engineering came to the same conclusion as BP in 2001-that ROV intervention could not be relied upon for secondary intervention once a well is flowing. R. Bea, P2 TT 444:10-445:11; D-20050; D-20051; Depo. of L. McKay, 34:20-35:7, 35:9-13, 35:15-36:15, 36:17-20; *see* TREX-1166; TREX-7348.084-.085. In its 2003 report, West noted that dynamic flow conditions from the well combined with slow ROV pump rates would lead to BSR elastomer seal damage. TREX-1166.029; TREX-7348.029. The 2003 West study determined that an operator's reliance on ROV systems as the sole means of securing the well has a high probability of failure. TREX-1166.068; TREX-7348.068.

101. Ultimately, as predicted by its own prior findings and those of West Engineering, BP's source control attempts to close the BSR with ROVs failed to shut in the well. *See* TREX-4423; *see also* Rec. Doc. 7076, ¶25, 34, 43 (2:10-md-02179-CJB-SS) (Agreed Stipulations).

102. With a proper plan and a pre-fabricated capping device, BP could have shut in the well in an ideal minimum of seven days. E. Zeigler, P2 TT 544:13-546:15, 548:3-16; *see* TREX-5385; TREX-9345; TREX-9562; D-26009A.

VII. BP Should Have Immediately Utilized Some Type Of Capping Device To Stop The Flow Of Oil.

A. Capping Devices Are Defined Functionally.

103. Capping devices are defined functionally as devices that mechanically shut off flow from a well. E. Ziegler, P2 TT 526:18-527:2 ("The capping device is the method to shut off the flow from a well."); *see e.g.*, TREX-11625.0025 ("Capping means, in simple terms, to put a cap on a blowing well."). The name of the device is irrelevant—whether called a "blowout preventer," "BOP," pre-made "stack," "valve," or "Christmas tree," the function of the capping device, as described in industry publications and documents, is to be able to control the source. E. Ziegler, P2 TT 527:16-528:17.

104. BP expert Iain Adams refers to the functional definition of a capping stack as a "BOP-like device." I. Adams P2 Expert Report, TREX-011737R.012. Adams further admits that "a capping stack consists of either a purpose built or modified BOP stack." TREX-011737R.016. Similarly, U.S. Secretary of Energy Steven Chu referred to the capping stack as a "mini BOP." Depo. of S. Chu, 274:4-275:7. Stress Engineering Principal Engineer Kenneth Bhalla agreed that the capping stack is similar to a mini BOP. Depo. of K. Bhalla, 27:23-28:15.

B. <u>BP Knew For More Than Two Decades That Capping Devices Are Best Available Technology For Controlling Deepwater Blowouts.</u>

105. BP failed to pay attention to engineering analysis and industry direction over the course of two decades that pointed to well capping solutions as the best available source control options. *See* TREX-9827, TREX-9828, TREX-11625; D-20039.

106. "Well capping techniques have been applied both on land and offshore locations and have historically proven successful in regaining well control in shorter durations and are preferred over the more time-consuming alternative of drilling a relief well." TREX-9346.002. Capping devices have existed and been used in the industry for decades. Depo. of L. Herbst, 360:22-25, 361:2-8; E. Ziegler, P2 TT 531:5-532:8, 535:1-9; Depo. of D. Barnett, 154:16-159:16, 159:18-161:12; *see also* Depo. of L. Herbst, 393:8-24, 394:1.

107. Capping device technology is feasible, well proven and not novel. J. Dupree, P2 TT 693:10-25; Depo. of L. Herbst, 328:5-10; E. Ziegler, P2 TT 531:5-532:8, 535:1-9. Prior to the Macondo blowout, "[c]apping devices were feasible;" "[y]ou could put together a capping device out of available existing parts." E. Ziegler, P2 TT 531:5-532:8, 535:1-9. The Macondo Capping Stack was assembled using current technology and "off-the-shelf" equipment. E. Ziegler, P2 TT 532:12-533:2, 557:4-8; *see also* E. Ziegler, P2 TT 544:13-20 (capping devices were feasible and readily available to assemble); Depo. of L. Herbst, 360:22-25, 361:2-20; Depo.

of D. McWhorter, 11/16/2012, 451:24-452:1, 452:3-13; G. Perkin, P2 Expert Rebuttal Report, TREX-11465R.3 (a BP Peer Assist of the BOP-on-BOP option in early May determined these options were feasible, could be managed safely and had a high probability of success). The MMS Regional Director for Gulf of Mexico Operations, Lars Herbst testified that "most of the equipment is established oilfield equipment and it is how you assemble that equipment." Depo. of L. Herbst, 363:13-22.

108. In response to U.S. Secretary of the Interior Ken Salazar's request for ideas from the industry after the Macondo event, Apache Corporation responded on April 30, 2010, "[i]f the LMRP can be removed from the BOP, **conventional wisdom** would suggest that another subsea BOP could be placed on top of the *Horizon*'s BOP in order to close the well in." E. Ziegler, P2 TT 538:10-539:1; TREX-011581.1.1.HESI (emphasis added). In fact, Apache listed two deepwater operators who had capping devices pre-built for drilling offshore Brazil. TREX-011581.0002. This "conventional wisdom" was based on decades of industry guidance.

109. In 1991, the Drilling Engineers Association published a Joint Industry Blowout Control Report ("DEA-63") predicting that: (1) off-shore drilling would proceed into ultra deepwater, high pressure reservoirs with increased blowout risks, (2) the consequence of a blowout of a high pressure reservoir would be severe, (3) because of the greater blowout risk, diligent preparation and planning to rapidly abate source flow was critical to the industry as a whole, and (4) underwater well capping would be an essential element for any blowout mitigation. R. Bea, P2 TT 433:5-21; *see* TREX-11625; D-20026. BP's predecessor, Amoco, participated in the DEA-63 study. TREX-11625.0018.

110. One of the directives of the study was "the development of vertical intervention and capping techniques for deepwater blowouts." TREX-11625.0016. The publication includes

a section on "Capping / Shut-in." TREX-11625.0025. As noted in the report, "The most logical approach to controlling pollution from a subsea blowout is to contain and collect the blowout effluent at the source of the spill." TREX 11625.0363. Notably, the maximum drilling depths at the time of the report were only around 1,500 feet. *See e.g.*, R. Bea P2 Report, TREX-11750R.025; TREX-6299.006.

111. While DEA-63 informed BP that the risks of a deepwater blowout increase substantially with depth and that the consequences of such an event would be catastrophic, the Association concluded that the second phase of the project was not immediately necessary because "1991 was a decade away from the time [industry] would move into ultra deepwater encountering the high pressure or high temperature or high productivity areas. So that intervening 10 years was to be the 10 years industry would use to be properly prepared to face or manage the risks they would encounter in the 2000s." R. Bea, P2 TT 435:2-436:23.

112. DEA-63 forecast a blowout scenario nearly identical to Macondo. The Study diagrams a disabled, severed riser and a blowing out well; the BOP is slightly leaning, a kink is in the riser above the BOP leaking hydrocarbons and a broken riser is leaking hydrocarbons into the ocean. *See* TREX-11625; R. Bea P2 TT 435:7-11; D-20031. The Study proposed that, in such an event, "Procedures may be developed to 'strip' new BOP components over a subsea blowing well. Capping stacks composed of BOPs, pump-in spools, hydraulically-operated valves and other devices are used routinely to kill onshore blowouts." TREX-11625.0403. The report even offers a depiction of the installation of capping devices. TREX-11625.0414-.0418. Yet in the twenty years between the publication of DEA-63 and the Macondo blowout, BP did nothing to study or to develop these procedures. Depo. of D. Barnett, 201:25-202:6, 202:8-10, 202:12-20.

113. In 1998, the International Association of Drilling Contractors ("IADC") published a set of Deepwater Well Control Guidelines that emphasized the consequences of a deepwater blowout and the need for Blowout Contingency Plans for deepwater drilling. *See* TREX-7353. Specifically, the IADC Guidelines advised operators to "identify, locate and negotiate for specialized well control equipment in advance" for both surface and subsea. TREX-7353.362.

114. These IADC guidelines noted that "the identification of potential hazards and the development of a systematic response have rightfully become essential elements in sound business practice." TREX-7353.353. "The methodology associated with this hazard identification and response strategy formulation is often referred to as the Blowout Contingency Plan." TREX-7353.353. A Blowout Contingency Plan would address source control and detail "the equipment and services likely to be required in the event of a major deepwater blowout, as well as recognized equipment compatibility issues related to source control." TREX-7353.361; TREX-7353.372. The IADC recommended that "blowouts on land and in shallow water can be reviewed to further develop the list of probable deepwater blowout scenarios." TREX-7353.379.

115. The IADC warned that "the consequences which result from a sustained blowout in a deepwater environment will be far-reaching and could, conceivably, have a lasting impact on public perception." TREX-7353.353. It also warned that the availability of deepwater well control measures was not advancing fast enough. R. Bea, P2 TT 437:7-17; *see* TREX-7353; *see also* TREX-11625; D-20033; D-20034; D-20035.

116. The guidelines included the very diagrams from DEA-63 depicting the use of a capping intervention to stop a deepwater blowout nearly identical to Macondo. TREX 7353.381-386; Depo. of L. McKay, 75:5-11, 75:13-17, 75:19-22, 75:24-76:2. They instructed the study of

vertical intervention scenarios "to allow development of detailed kill plans with contingency plans for problem areas within each scenario." TREX-7353.379.

117. The IADC guidelines focused on the Gulf of Mexico. TREX-7353.2.

118. In 1999, an MMS-funded study titled Final Report of the PCCI Marine and Environmental Engineering on Oil Spill Containment, Remote Sensing and Tracking for Deepwater Blowouts: Status of Existing and Emerging Technology was released. *See* TREX-5053. This study concluded, "[a]s the industry advances into deepwater exploration, the risks of blowout increase, due to difficulties related to kick detection and control procedures under deepwater conditions." TREX-5053.007. The PCCI contains a blowout scenario very similar to what occurred at the Macondo blowout. TREX-2297.024-.025; Depo. of D. Suttles, 288:8-289:11.

119. In 2003, the Society of Petroleum Engineers ("SPE") and the IADC held a conference on Well Control Procedures. *See* TREX-6299. As part of that conference, the organizations recognized that virtually no work had been done regarding deepwater blowout control since the 1991 Drilling Engineers Association "DEA-63" report nearly 13 years before. TREX-6299.006. They noted the likelihood of a deepwater blowout was high and that technology within the industry was lagging behind. R. Bea, P2 TT 438:18-439:11; TREX-6299.006; TREX-6299.011; D-20038. The direct questions posed were, "[w]hat about blowout containment procedures?. . . . Have they been keeping up with the current technology?" TREX-6299.006. The report specifically noted that an ultra-deep water blowout of 5,000 feet or more was statistically "likely to happen" and asked, "[a]re [w]e [r]eady?" TREX-6299.011; Depo. of A. Inglis, 106:19-25, 107:7-16, 112:21-113:5; *see also* R. Bea, P2 TT 438:18-439:11.

120. The 2003 conference called for continued research on deepwater drilling blowout intervention techniques in light of the fact that current considerations are based on shallower deepwater drilling up to 1500 feet deep. TREX-6299.006. The Macondo well was drilled at 5,000 feet, yet BP never invested in any such research and development efforts. *See* TREX-9104; R. Bea, P2 TT 447:24-449:9; E. Ziegler, P2 TT 518:12-25; D-20057; D-20058; Depo. of L. McKay, 102:21-103:9, 104:22-105:11, 105:13; *see* TREX-6021; Depo. of A. Inglis, 162:9-21.

121. Subsequently, the SPE and IADC released Paper No. 92626: "Modeling Ultra-Deepwater Blowouts and Dynamic Kills and the Resulting Blowout Control Best Practices Recommendations" (2005). D-20039. This industry paper recognized and advised that "capping" was the first option to shut-in an offshore blowout. R. Bea, P2 TT 439:12-17; D-20039. Specifically, the authors warned that, as the industry was "breaching new frontiers, specifically ultra-deep waters (5,000 ft or more of water depth), new blowout control measures are necessary." D-20039.

122. In 2005, a separate paper was published by Dr. Ole Rygg, the technical expert whom BP hired, utilized and relied upon for the creation of flow modeling which BP hid from Unified Command. *See* TREX-9239. Dr. Rygg recognized that:

> In evaluation of emergency response for a drilling operation, onshore or offshore, one essential element is the pre-evaluation of the possibility of regaining control of a blowing well. Even though the probability of a blowout might be small, the consequences with respect to safety, cost and pollution could be catastrophic.

TREX-9239.001.

123. Despite all this information and knowledge long before Macondo, BP did not prepare for a deepwater blowout, as set forth herein.

C. <u>BP, As Well As Others In The Industry, Has Utilized Capping Devices For Decades And Understood Their Feasibility And Desirability For Well Capping Solutions.</u>

124. BP admits that capping stacks are used in land-based operations for well control events and are not a new technology. Depo. of A. Frazelle, 220:5-11, 220:13-14; Depo. of L. McKay, 20:3-8, 20:10-21. The scientific principles and materials necessary for designing and creating capping stacks were available prior to the Macondo blowout and known to BP. Depo. of A. Inglis, 164:18-165:13; Depo. of D. Rainey, 261:19-262:9; Depo. of L. McKay, 20:3-8, 20:10-21; J. Dupree, P2 TT 693:10-12, 694:1-5. Indeed, capping devices have been used in the industry for decades. E. Ziegler, P2 TT 531:5-532:8, 535:1-9; Depo. of L. Herbst, 327:18-22, 328:1-10, 359:3-7, 359:11-23, 360:6-25, 361:2-8.

125. BP knew, prior to April 2010, that devices like capping stacks existed, were superior to drilling a relief well, and were considered Best Available and Safest Technology ("BAST") in other environments. *See* TREX-9346; *see also* TREX-7354, TREX-9828. At least nine years before the Macondo blowout, BP had determined that well capping constituted not only BAST, but the **best available technology** ("BAT") for source control of a blowout, stating, "[t]he best options for subsea blowout spill control seem to be technologies to facilitate vertical intervention to contain the flow using well control techniques." TREX-5053.006; *see* TREX-11263; *see* 9346 at 4; *see* TREX-11264; *see* R. Bea, P2 TT 438:1-3; D-20036. In 2001, BP's Alaska division concluded that well capping devices constituted BAT for blowout source control. *See* TREX-9171; *see* TREX-9346; TREX-9828.001; R. Bea, P2 TT 438:4-14; D-20037. As BP admitted in its Best Available Technology (BAT) Analysis Well Blowout Source Control, "[a]fter evaluating the two primary methods of regaining well control during a blowout scenario (Well Capping and Relief Well Drilling), BPXA believes Well Capping constitutes the BAT for source control." TREX-9827.001. "Historical evidence," the company acknowledged, "clearly

indicates well capping has greater reliability and application for well control compared to that of relief well drilling." TREX-9346 at 4; *see* TREX-9827.004; *see* TREX-9828.

126. BP's Gulf of Mexico Deepwater SPU Well Control Response Guide specifically identified capping stack solutions as a Level 3: Phase 2–Well Control Response and described "sourcing capping and related equipment," including a capping stack. TREX-2386.001; TREX-2386.092.

127. Further support for BP's knowledge of the well capping solution is BP's Master Services Agreement with Wild Well Control, Inc. for emergency well control planning prevention and response. *See* TREX-11467. A capping stack was optional under the Master Services Agreement and required BP to enter into a separate contract if it chose to have one available. TREX-11467.0089; R. Bea, P2 TT 506:9-19. An unlimited number of capping stack configurations was available through a Wild Well Control, Inc. subsidiary. TREX-11467.0089. However, BP did not contract with Wild Well Control, Inc. to have a capping stack available. *See* TREX-11467. BP never approached Wild Well Control, Inc. to develop or create a capping stack for use in a deepwater well. Depo. of D. Barnett, 154:16-159:16, 159:18-161:12.

128. Cameron Vice President David McWhorter explained that capping stacks have long been used successfully by the industry as a method of source control. Cameron's own BOPs had been used as capping stack solutions as early as the 1980s and were actually used to cap wells in Kuwait, in essentially the same manner as what was used on Macondo. Depo. of D. McWhorter, 11/15/2012, 175:3-178:22; G. Perkin P2 Expert Report, TREX-11464R.28; E. Ziegler P2 Expert Report, TREX-11578R.37.

129. At least two capping-type operations had been previously conducted in deep water: (1) a blowout in Malaysia in 1988, and (2) the *Jim Cunningham* incident in the eastern

Mediterranean in 2004, where a BOP-on-BOP process was utilized. R. Turlak, P2 TT 318:8-22; E. Ziegler, P2 TT 537:18-538:8. A capping device was also used for the PEMEX blowout in the Gulf of Mexico decades before the Macondo blowout. Depo. of M. Mason, 214:12-22.

130. Shell and Senta Drilling reportedly had capping devices available for a deepwater project off the coast of Brazil. E. Ziegler P2 Expert Report, TREX-11578R.37.

131. By its own admission, BP "could have built a capping stack" prior to the spill. J. Dupree, P2 TT 693:4-25. Doug Suttles, Chief Operating Officer of BP Exploration and Production, knew no reason why a capping stack could not have been built prior to the Macondo blowout. Depo. of D. Suttles, 22:7-11; 585:9-14, 228:6-9, 228:12-14. BP could have had a deepwater capping stack "ready and available" prior to the incident but chose not to do so. J. Dupree, P2 TT 692:14-694:5; Depo. of A. Frazelle, 219:1-3, 5-18, 20-24, 219:20-220:2, 220:4-11, 220:13-14, 223:15-21; Depo. of A. Hayward, 343:13-20, 344:8-12, 15-16; *see also* P2 TT 530:7-10 (statement of BP Counsel that "it was feasible and practical to have a type of capping device for deepwater operations").

132. In addition, from a cost perspective, "building a capping stack wouldn't be a significant amount of money considering the amount of money that we spent in the deepwater." J. Dupree, P2 TT 694:1-5.

133. BP's counsel acknowledged during trial, "[t]o be clear, it is not BP's position that capping devices in general were not feasible. . . . Our position is that, while 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."

134. Further proof that pre-built and pre-incident planning for the use of a capping device is the fact that BP now has several capping devices available for worldwide deployment

in the event of another deepwater blowout. J. Dupree, P2 TT 695:18-696:6; Depo. of A. Frazelle, 225:13-14, 225:16-226:1; E. Ziegler, P2 TT 530:11-15. BP has named its current capping system the Global Deepwater Well Cap and Tooling Package. TREX-11259. These purpose-built capping devices are sited in Houston and elsewhere for rapid deployment. TREX-10640; TREX-11259 at 1 ("BP has its capping packaged, staged and ready to be deployed. The equipment sits in a giant cathedral-ceilinged warehouse in the dusty, sprawling port of Houston."); Depo. of A. Frazelle, 225:13-14, 225:16-226:1, 226:3-6 ("BP has a capping stack that is available for worldwide deployment."); E. Ziegler, P2 TT 530:11-15. There is no reason BP could not have had such a device and a plan for its use prior to Macondo.

D. <u>Landing Capping Devices, Including The One That Shut In Macondo, Is A Routine Operation In The Industry.</u>

135. Landing capping devices is a routine operation in the industry. E. Ziegler, P2 TT 539:13-540:17, 565:2-13, 566:5-16; D-26007.

136. On July 12, 2010, the three-ram Capping Stack was landed. E. Ziegler, P2 TT 539:13-540:17; D-26007; Rec. Doc. 7076, ¶127 (2:10-md-02179-CJB-SS); Depo. of D. Suttles, 231:14-19. The video from the actual capping operation (D-26007) demonstrated that, despite flow from the well, setting the capping stack was a "routine operation" that happens "many places in the world almost every day in the deepwater industry." E. Ziegler, P2 TT 539:2-541:24; D-26007. The capping process was relatively easy. E. Ziegler, P2 TT 540:17; D-26007. For instance, there was a small white hose was "not even buffeted" when it was near the flow, and "[t]here were no hydrates." E. Ziegler, P2 TT 540:2-541:1; D-26007. The video showed that "[t]he ROVs that don't have a great deal of pushing force are helping to center the capping device." E. Ziegler, P2 TT 540:3-5; D-26007. The video further showed that "[w]ith the well flowing at whatever rate it's flowing at, the [capping] device is simply pushed over, centered on

the well." E. Ziegler, P2 TT 540:5-7; D-26007. BP could have assessed this situation in mid-May by deploying ROVs with cameras to confirm adequate visibility. E. Ziegler, P2 TT 539:2-541:24; D-26007.

E. <u>BP Began Designing Capping Devices Immediately After The Macondo Incident.</u>

137. That capping stacks were a well-known solution prior to Macondo is further evidenced by the fact that BP immediately began developing such a solution after the blowout occurred. As early as April 23, 2010, BP identified a capping stack as a source control option for the Macondo well, and capping procedures had begun to be distributed by April 26. Rec. Doc. 7076 at ¶28 (2:10-md-02179-CJB-SS); *see also* Rec. Doc. 7076 at ¶32-36 (2:10-md-02179-CJB-SS); T. Smith, P2 TT 877:18-24. BP internally discussed the idea of a capping device within a week of the blowout. TREX-2291; TREX-3919; Depo. of D. Suttles, 231:8-18; Depo. of A. Inglis, 664:1-8, 665:18-668:1. Wild Well Control, BP's own source control expert, almost immediately proposed using a capping device as a solution for shutting in the well. TREX-3918; E. Ziegler, P2 TT 542:3-544:4. As of April 27, 2010, Wild Well Control had already provided BP with a well capping procedure involving a two-ram capping device. E. Ziegler, P2 TT 542:3-543:24; TREX-3918.

138. As discussed in more detail in Section XVIII below, had BP chosen to implement these early plans with respect to the BOP-on-BOP operation, the well could have been shut in about May 10, 2010, thereby preventing as much as 60 days of flow. *See supra*, Section XVIII; E Ziegler, P2 TT 548:3-16.

VIII. BP Ignored The Source Control Experts And Specialists It Assembled.

139. In accordance with Section 6C of BP's OSRP, BP "assemble[d] a team of technical experts to respond to the situation." TREX-769.179. However, after assembling the

teams, BP ignored the advice of those source control experts and specialists. *See* TREX-3918; *see* TREX-10072; *see* TREX-10611; *see* TREX-10612; *see* TREX-10613; *see* TREX-10620; Depo. of D. Barnett, 168:1-169:17, 190:13-20. Wild Well Control, Inc., Cameron, Anadarko and Transocean all believed the best source control option for the Macondo well was the BOP-on-BOP and/or capping stack solution. *See* TREX-10514; *see* TREX-3922; *see* TREX-10884. BP nevertheless abandoned these capping solutions. *See* TREX-4405; *see* TREX-10894; *see* TREX-11232; Rec. Doc. 7076, ¶83 (2:10-md-02179-CJB-SS).

140. Prior to the blowout, BP had a contract with Wild Well Control, Inc., in which BP represented that it "will have fully developed emergency response procedures" and which specified that capping stacks were optional and not included in the contract. TREX-11467.66.1.PSC; TREX-11467.89.1.PSC.

141. Members of the capping team group assembled by BP, including representatives from various entities such as Transocean and Wild Well Control, Inc., were in favor of the capping stack as of mid-May. Depo. of G. Boughton, 83:3-85:2, 85:8-15. Wild Well Control provided BP with a well capping procedure involving a two-ram capping device using pre-existing technology and equipment by April 27, 2010. E. Ziegler, P2 TT 542:3-543:24; TREX-3918.1.1.HESI. The leader of the well capping team, BP's James Wellings, was in favor of the capping stack from the very beginning. Depo. of G. Boughton, 80:19-81:8. Yet BP chose to de-prioritize this option in favor of other suggestions, such as Top Kill.

142. On May 29, 2010, the decision was made not to move forward with the BOP-on-BOP option. Rec. Doc. 7076, ¶83 (2:10-md-02179-CJB-SS). BP abandoned the BOP-on-BOP solution that would have primarily used equipment that was either already available on drilling

rigs or that could have been modified long before the capping stack installed in mid-July 2010 was ready to install. *See* TREX-4405; TREX-10894; TREX-11232.

143. Pat Campbell, the CEO of Wild Well Control, Inc. testified that there were multiple additional times where BP ignored Wild Well Control, Inc.'s opinion on the proper course of action during the response. Depo. of P. Campbell, 7/13/2011, 40:18-23.

144. Wild Well Control, Inc., a company that has shut in thousands of wells on land and offshore, participated in numerous source control activities as BP's contractor. Depo. of D. Barnett, 25:4-20, 173:9-11. A Wild Well Control, Inc. employee described the relationship between BP and the source control experts as "a 3 ring circus with an incredible amount of disconnect between the various groups." TREX-10627.0001; Depo. of D. Barnett, 288:11-289:19.

145. Employees of Wild Well Control, Inc. were frustrated and concerned about BP's decision not to follow Wild Well Control, Inc.'s advice. Depo. of D. Barnett, 117:13-21, 117:23-118:11, 118:14-21, 118:23. For example, BP abandoned two capping operations that Wild Well Control, Inc. recommended to BP, the capping stack and the BOP-on-BOP, in mid-May 2010. Depo. of D. Barnett, 161:13-162:1, 162:2-25, 163:2-8, 163:10, 163:12-22; Depo. of B. Domangue, 248:15-249:5. The BOPs from the *Discoverer Enterprise* and *Development Driller II* ("*DDII*") were both considered for use in the BOP-on-BOP option. Depo. of D. Barnett, 162:2-25; 163:2-8; 163:10; 163:12-22. BP's decision to abandon the BOP-on-BOP option went counter to Wild Well Control, Inc.'s advice. Depo. of D. Barnett, 163:12-22. Wild Well Control, Inc. was not aware of anything on the *DDII* BOP which would have delayed or prevented installation on the *Deepwater Horizon* BOP. Depo. of D. Barnett, 313:21-24, 314:1-10.

146. On the other hand, BP did go forward with the Top Kill, contrary to the specialists' opinions regarding its efficacy. Wild Well Control, Inc. had been opposed to the Top Kill and did not believe a Top Kill by itself would work to kill the well. Depo. of D. Barnett, 118:24-25, 119:3-19, 180:23-181:2. David Barnett, Vice President of Engineering for Wild Well Control Inc., did not have confidence in being able to control a well with the Top Kill. Depo. of D. Barnett, 103:10-23, 103:25-104:11, 104:13-19, 104:22-106:14, 106:16-107:5. Indeed, Top Kills are rarely performed "[b]ecause it's obvious that their chances of success are not very high." Depo. of D. Barnett, 180:5-19.

147. With respect to the junk shot component of the Top Kill, Wild Well Control, Inc.'s President, Pat Campbell, a member of the Peer Assist Group, was involved in meetings and discussions regarding the junk shot. Campbell noted that no one outside of BP involved in the Peer Assist thought that a junk shot was a good idea. Depo. of P. Campbell, 7/12/2011, 366:22-367:6, 367:25-368:14; D-20018; *see also* TREX-3917. Campbell's testimony that "[t]he inside diameter of the flexible lines and the choke and the kill lines were 3-inch ID, so what we saw was a very generous flow path," described the conditions that made the junk shot difficult, *i.e.*, that due to the size of the choke and kill lines, they were restricted to shooting small objects into a large flow path. G. Perkin, P2 TT 201:2-202:11; Depo. of P. Campbell, 7/12/2011, 368:15-369:2; D-20018. According to Campbell, the Momentum Kill had a very low likelihood of success, and PSC expert Gregg Perkin saw nothing that would cause him to disagree with Campbell. Depo. of P. Campbell, 7/13/2011, 11:18-12:12; G. Perkin, P2 TT 202:18-203:12; D-20019.

IX. BP's Lack Of Planning Led To Improvised, Failed, Or Misguided Efforts, Wasting Significant Time.

148. Many of the source control methods BP attempted were improvised, untested and deemed to have a high risk of failure. *See* TREX-10514.001 ("Everything [BP] ha[s] done so far is an experiment."); TREX-3922; TREX-11227. Each additional method involved some delay due to the different operations required. Depo. of T. Hunter, 97:18-24, 98:1-5.

149. BP's lack of a source control plan resulted in significant delays and prolonged the length of the spill. *See supra*, Section IV-VI; *see also infra* at XVIII.

X. BP's Failure To Have A Plan In Place Allowed For The "Siloing" Of Information And The Failure To Provide Full Disclosure To Others.

150. It is important to generate and collect information relevant to source control decision-making and to share this data in a transparent process. E. Ziegler, P2 TT 552:25-553:2. The information must get to the people who need it, as inaccurate data can slow the process and lead to poor decisions. E. Zeigler, P2 TT 553:3-12. The data process must be straightforward to be effective. *Id*.

151. Inaccurate information during the Macondo response affected source control responses because it slowed the process and caused wrong turns. E. Ziegler, P2 TT 553:7-12. BP exhibited "poor communication" and challenges in ensuring that the information flow was timely and accurate. TREX-10625.001; Depo. of D. Barnett, 278:20-24, 279:1-8, 10-17.

152. BP's flow rate misrepresentations provide numerous examples of the "siloing" of key information concerning source control data, arising from or facilitated by the lack of a genuine source control plan. BP's effort to conceal flow rate estimates, both internally and externally, is not good engineering practice. J. Wilson, P2 TT 118:24-119:19. BP's misrepresentations concerning the Macondo flow rate are examined in greater detail below. *See infra*, Sections XIII-XVIII.

XI. BP Violated Applicable Regulations Requiring It To Be Prepared To Handle And Respond To A Worst-Case Scenario Blowout.

153. Pursuant to 30 C.F.R. § 254.1, BP, as the leaseholder and operator of the Macondo well, was required to submit a spill-response plan to the Government. TREX-11422.014; Depo. of D. Barnett, 269:9-11. BP "was ultimately responsible for conducting operations at Macondo in a way that ensured the safety and protection of personnel, equipment, natural resources and the environment." TREX-11422.014. As 30 C.F.R. § 254.5(c) states, "[n]othing in this part relieves [the operator] from taking all appropriate actions necessary to immediately abate the source of a spill and remove any spills of oil." R. Bea, P2 TT 442:9-15; E. Ziegler, P2 TT 516:4-10, 516:23-24; Depo. of L. Herbst, 315:21-24, 451:9-15, 452:10-13, 452:15, 454:5-7; D-20046.

154. MMS regulations required BP to be able to control the well, *i.e.*, to be able to accomplish source control at all times. *See* 30 C.F.R. § 254.15. Yet BP had no source control plan designed to meet the regulatory requirement in 30 C.F.R. §254.5. BP's regional response plan was inadequate. TREX-9096.007; Depo. of L. Herbst, 349:5-11, 349:13. BP was utterly unprepared to respond to the actual flow rate from the Macondo well or to a worst-case scenario. TREX-9096.002; TREX-9098.007; Depo. of L. Herbst, 348:14-17, 348:20-22, 412:22-23, 412:25-413:2; D-20048. Further, BP "did not have someone who provided source control expertise to the Oil Spill Plan." Depo. of E. Bush, 12:1-8.

155. MMS Regional Director for the Gulf of Mexico, Lars Herbst, testified that it was BP's obligation under the regulations to abate the source as quickly as possible and that the MMS "expected [BP] to be able to contain a deepwater blowout." Depo. of L. Herbst, 398:11-13, 398:15-16. In certifying its OSRP, BP verified that it had "the capability to respond to the maximum extent practicable to a worst-case discharge." TREX-768.098.

156. The MMS did not review or approve BP's capability (or lack thereof) to immediately abate the spill at its source. Rather, it accepted BP's certification in the Initial Exploration Plan that:

> BP Exploration & Production, Inc. has the capability to respond, to the maximum extent practicable, to a worst-case discharge [162,000 barrels per day], or a substantial threat of such a discharge, resulting from the activities proposed in our Exploration Plan.

TREX-768.098; *see also* TREX-6181.026 (Certification of Capability).

157. BP's estimate of 162,000 BOPD as a worst-case uncontrolled flow from a blowout of Macondo fell within its stated and certified capability to respond to a worst-case spill in the Gulf of Mexico, as set forth in its Gulf of Mexico Regional Oil Spill Plan. TREX-10301.007. BP officially stated that it had "the capability to respond, to the maximum extent practicable, to a worst-case discharge, or a substantial threat of such a discharge, resulting from the activities proposed in BP's Exploration Plan." TREX-768.098; R. Bea, P2 TT 442:16-443:5; D-20047.

158. The Government expected BP to have the capability to shut in a blowout in a much shorter time frame than 87 days. Depo. of L. Herbst, 302:24-303:8, 397:17-398:13, 398:15-22 ("[BP] did not, obviously, contain [the flow] as quick as our expectations were."). MMS's "expectations went beyond what was written in the [OSRP]." R. Bea, P2 TT 463:24-464:4; Depo. of L. Herbst, 397:17-398:13, 398:15-22. Herbst was quite clear that BP failed to meet the Government's expectations in its ability to respond to a deepwater blowout; he testified that BP was supposed to be able to contain a deepwater blowout but failed. Depo. of L. Herbst, 398:1-13, 398:15-22.

XII. Federal Regulation Required BP To Employ Best Available and Safest Technology.

159. As the operator of the Macondo Well, BP was obligated to use BAST. 30 C.F.R. §250.105, 107 and 401(a); *see also* E. Ziegler P2 Expert Report, TREX-11578R-v2.020; E.

Ziegler Expert Rebuttal Report, TREX-11579R-v2.004. BAST means the safest technologies that are determined to be economically feasible. 30 C.F.R. § 250.105. The use of BAST is required in order to keep a well under control in the Gulf of Mexico. 30 C.F.R. § 250.401(a).

160. Despite having identified pre-fabricated, dedicated capping stacks as the best available technology in its Alaskan drilling, BP failed to request any such capping stack be built prior to drilling the Macondo Well; thus, none was ready when the well blew out. TREX-9828.001.

161. The goal of process safety, including mitigation, is to reduce risks of a major system failure to a level that is As Low as Reasonably Practicable ("ALARP"). TREX-11750R.9. Unlike BAST, which requires the best technology be used at all times, the ALARP standard looks primarily at the end results, permitting balancing between prevention and mitigation provided that balance ensures the operation is in the "safe" zone. R. Bea P2 Expert Report, TREX-11750R.12. BP required "[a]ll risks [to] be managed to a level which is as low as reasonably practicable." D-20022. BP also operated Macondo outside of ALARP. R. Bea, P2 TT 428:22-429:1; R. Bea P2 Expert Report, TREX-11750R.12

162. PSC expert Robert Bea reviewed BP's MAR and concluded that Macondo belonged in A5, using documentation provided by BP. R. Bea, P2 TT 426:14-427:19, 429:2-21; D-20023. Bea disagreed with BP's assessment of the Macondo, which placed the Macondo on the MAR in the C4 category, as documented in BP's January 2010 Integrity Management Report. R. Bea, P2 TT 430:8-24. The reason Bea disagreed with BP's assessment was BP's failure to properly evaluate consequences. *Id.* While BP identified the potential cost from an incident at Macondo as between $100 million and $1 billion, Bea found that the cost would substantially exceed $10 billion. *Id.* But even BP's flawed Category C4 analysis placed the Macondo drilling

operation in the "high" risk zone and above the Group Reporting Line, thus requiring BP management approval before the Macondo project could be implemented. R. Bea P2 Expert Report, TREX-011750R.17-.22; *see also* D-20023; D-20024.

163. BP consciously disregarded well-publicized studies and its own internal knowledge indicating that blowout rates for deepwater wells were higher than those of other wells and remarkably, placed the risk of a deepwater blowout at "essentially zero." TREX-9099.118-.119; *see also* TREX-6299.011. Coupled with BP's decision to focus almost entirely on prevention in lieu of mitigation, Macondo fell well outside of the ALARP process safety system. Depo. of A. Hayward, 276:25-277:5, 277:7-10; *see* TREX-120061.12.

164. As a result, BP had no mitigation barriers in place—not in the form of a plan and not in the form of actual, readied equipment. *See* R. Bea P2 Expert Report, TREX-011750R.14.

XIII. BP Misrepresented And Concealed Its Flow Rate Estimates.

A. BP Admitted In Its Guilty Plea It Withheld High Flow Rate Estimates From The Unified Command.

165. On November 15, 2012, BP pled guilty to "corruptly, that is, with an improper purpose, endeavor[ing] to influence, obstruct, and impede the due and proper exercise of the power of inquiry under which an inquiry and investigation was being had by a Committee of the United States House of Representatives into the amount of oil flowing from the Macondo Well ('flow rate') through . . . omissions and false and misleading statements in its May 24, 2010 response ('Markey Response') to the Committee on Energy and Commerce." TREX-52673 at 16 ("BP Guilty Plea").

166. The May 24 Markey Response referred to in the BP Guilty Plea attached a memo (which also had attachments) that was authored by BP former vice president David Rainey ("Rainey Memo").

167. Doug Suttles sent this same Rainey Memo to Unified Command on May 19, 2010. *See* TREX-3218 (Rainey Memo); *see* TREX-1651-Cured (Markey Response attaching Rainey Memo).

168. The first factual allocution in support of BP's Guilty Plea states, "BP, through a former vice president, withheld information and documents relating to multiple flow-rate estimates prepared by BP engineers that showed flow rate far higher than 5,000 BOPD, including as high as 96,000 BOPD." TREX-52673 at 16 (BP Guilty Plea).

169. The BP estimates underlying the first factual allocution are those generated by a group of BP engineers led by BP Vice President of Base Management Mike Mason in early May 2010. *See* TREX-11160, TREX-11135, TREX-10185, TREX-11136 (documents dated in early May 2010, originating from individuals in Mike Mason's group, which contain spreadsheets with upper-end values of between 95,000 and 96,000); *see* TREX-9441, TREX-11169 ("Holistic System Report," using data as of May 6, 2010, containing flow rates of up to 96,000 BOPD). These estimates of up to 96,000 BOPD are also contained in a PowerPoint presentation attached to a May 11, 2010 email from Mike Mason to members of his modeling group. That email references an intra-BP meeting at which Andy Inglis, CEO of BP Exploration and Production, was shown flow rates ranging from 14,000 to 96,000 BOPD. *See* TREX-9156 (May 11 presentation).

170. The second factual allocution states, "BP, through a former vice president, withheld information and documents relating to internal flow-rate estimates he prepared using the Bonn Agreement analysis, that showed flow rates far higher than 5,000 BOPD, and that went as high as 92,000 BOPD." TREX-52673 at 16 (BP Guilty Plea).

171. The BP estimates underlying the second factual allocution were those of former BP vice president David Rainey. Rainey's flow-rate estimates for April 27, 2010 using the Bonn Agreement analysis indicated flow rates at a "low," "best guess," and "high" range of 2,783, 17,328, and 92,028 BOPD, respectively. TREX-3213 at 4 (Rainey Bonn Agreement analysis); *see also* TREX-3214.003 (same).

172. BP's plea also addresses the fraudulent nature of BP and Rainey's surface expression modeling of the flow rate. The third factual allocution states, "BP, through a former vice president, falsely represented that the flow-rate estimates included in the Response were the product of the generally-accepted ASTM methodology. At the time that this false representation was made, BP's former vice president knew that those estimates were the product of a methodology he devised after, among other things, a review of a Wikipedia entry about oil spill estimation." TREX-52673 at 17 (BP Guilty Plea).

173. David Rainey testified at deposition that he located the "Metcalf & Eddy" protocol, which he used to evaluate the flow rate estimates that were submitted to Congress and to Unified Command, on the Internet, by "googl[ing] 'oil spill volumes from surface observations'" and locating on Wikipedia a reference to a scientific paper of that name. With regard to his estimation charts, Rainey testified, "the parameters that are given here sort of came off the Wikipedia page but referred to in Metcalf & Eddy." Depo. of D. Rainey, 143:17-144:08; *see* TREX-3211. Rainey testified he developed a "hybrid" methodology by combining the Wikipedia-entry Metcalf & Eddy standards with the ASTM standards. Depo. of D. Rainey, 148:13-149:4, 154:22-155:20; *see* TREX-3213-Cured (Rainey estimates).

174. The fourth factual allocution states, "BP, through a former vice president, falsely represented that the flow-rate estimates included in the Markey Response had played 'an

important part' in Unified Command's decision on April 28, 2010, to raise its own flow-rate estimate to 5,000 BOPD. At the time this false representation was made, BP's former vice president knew that those flow-rate estimates had not played 'an important part' in Unified Command's decision to raise its flow-rate estimates and had not even been distributed outside of BP prior to that decision." TREX-52673 at 17 (BP Guilty Plea).

175. As described in more detail below, the Unified Command's decision to raise its flow rate estimate from 1,000 BOPD to 5,000 BOPD was in fact based on a representation by BP's Doug Suttles to Rear Admiral Mary Landry, who also served as the Federal On Scene Coordinator ("FOSC") for the spill response, that BP's range of flow rates was between 1,000 and 5,000 BOPD, with 2,500 BOPD being BP's "best estimate." Depo. of M. Landry, 25:2-26:6, 192:8-193:1.

176. The fifth factual allocution states, "BP falsely suggested, in its May 24, 2010 letter, 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." TREX-52673 at 17. (BP Guilty Plea).

177. This factual allocution has particular significance for this case because it constitutes an admission by BP that the company withheld high internal flow rate estimates not only from Congress, but also from Unified Command–the body that reviewed and approved of BP's source control recommendations. J. Dupree, P2 TT 596:11-20 ("The process for authorizing a source control operation was that we would prepare the recommended operation and write the detailed procedures and discuss the operation. And then we would recommend that

to the Unified Command . . . [.] We would recommend the options; they would approve it."). BP's admission establishes that in performing those functions, Unified Command lacked material flow rate information in BP's possession. As explained below, source control procedures recommended by BP depended on the rate of flow. Therefore the ability of Unified Command to evaluate those procedures' likelihood of success was undermined by BP's concealment of flow rate information.

178. Numerous BP internal documents confirm BP's fifth factual allocution. These BP internal documents contain flow rate estimates based on hydraulic modeling that were significantly higher than 5,000 BOPD. J. Wilson, P2 TT 123:15-19; D-25015C (Chart of BP Flow Rate Modeling: April 21, 2010–May 31, 2010); J. Wilson P2 Expert Report, TREX-11900.0038-.0051 (Appendix A). As described in more detail *infra*, BP shared with Unified Command only a select few of its modeling runs, describing targeted rates of 5,000 BOPD as the "most likely model" and higher rates almost exclusively as "worst case discharges." *See, e.g.*, TREX-9155 (May 10 Letter); TREX-3218 (May 19 Rainey Memo); *see also infra*, Sections XIII.C—XIII.M. BP failed to share numerous intermediate flow rates and its own engineers' concerns about the 5,000 BOPD estimate.

179. The sixth factual allocution states, "[o]n or about June 25, 2010, in a BP letter to Congressman Markey, BP's former vice president inserted language that falsely stated that BP's worst case discharge estimate was raised from 60,000 BOPD to 100,000 BOPD after subsequent 'pressure data was obtained from the BOP stack.' At the time this false representation was made, BP's former vice president knew that the 100,000 BOPD figure was not first derived after subsequent pressure data had been obtained, but instead, he had been aware of a 100,000 BOPD worst case discharge since as early as on or about April 21, 2010." TREX-52673 at 17, 18.

180. The BP flow rate estimates underlying the sixth factual allocution are those performed by BP reservoir engineers in early April 2010 and sent to BP's David Rainey. TREX-3063 (email from Walt Bozeman to David Rainey, *et al*., dated April 21, 2010, calculating worst case discharge of 100,000 BOPD).

B. <u>Unified Command Relied On BP's Representations In Announcing A 5,000 BOPD Flow Rate Estimate.</u>

181. BP's misrepresentations about flow rate led directly to the Government's announcement of an official flow rate estimate of just 5,000 BOPD.

182. On April 23, 2010, Admiral Landry of the Coast Guard was named the Federal On Scene Coordinator. She held that position until May 31, 2010. Depo. of M. Landry, 395:7-13.

183. On April 24, 2010, Admiral Landry announced through the Unified Command that the flow rate from the well was 1,000 BOPD. Depo. of M. Landry, 103:24-104:4. BP provided that estimate to Landry through her assistant Captain Hanzalik. *Id*. at 110:24-111:1, 111:6-13; *see also* Depo. of L. Herbst, 181:18-182:10, 182:12-16 ("[A]s I recall, the 1,000 barrels per day … was actually an estimate that–that BP had made, and the federal government at that particular point accepted that number.").

184. On April 28, 2010, Admiral Landry announced the flow rate was 5,000 BOPD. Depo. of M. Landry, 181:15-24.

185. Admiral Landry had a "vivid recollection" of the origin of Unified Command's 5,000 BOPD flow rate figure. *Id*. at 23:13-19. Charlie Henry, the Unified Command's Scientific Support Coordinator and NOAA Director of GoM Disaster Response Center, had informed Admiral Landry that NOAA believed the flow rate was much greater than 1,000 BOPD–the official estimate at the time–based on overflight data and their other work. Consistent with

"standard procedure in a spill," Admiral Landry then approached the Responsible Party, BP, for its estimation of the flow rate. *Id*. at 188:14-189:6. In particular, Landry spoke with Doug Suttles, BP's lead representative at Unified Command, and asked him for BP's estimate of the flow. *Id*. at 24:9-24. Landry informed Suttles that NOAA was saying the number was higher than 1,000 BOPD. *Id*. at 191:24-192:02.

186. On April 28, Admiral Landry, Charlie Henry of NOAA, and Doug Suttles of BP held a meeting in BP's offices at Unified Command. Suttles told Admiral Landry that as a result of a conversation he had with a woman in BP's Houston office, BP's new range was 1,000 to 5,000 BOPD. *Id*. at 25:2-26:6. Admiral Landry recalled that Suttles drew the range on an easel, inserted a line for 2,500 BOPD in the middle of the range, and said words to the effect of, "'We estimate it to be 2,500. That's our best estimate.'" *Id*. at 192:8-193:1; *see also* Depo. of M. Landry, 565:13-566:3; TREX-9628.0001 (drawing by Admiral Landry during deposition of her recollection of Suttles's proffered range).

187. Admiral Landry informed Suttles that she was going to "go with the higher number" in BP's proffered range–*i.e.*, 5,000 BOPD. Depo. of M. Landry, 193:2-14; *see also* Depo. of M. Landry, 311:22-312:1, 312:4-19 ("The way the process would work is that … the Responsible Party proffered a number, and NOAA acquiesced to my using that number…."); *id*. at 570:10-19 (Henry "rolled his eyes" at 2,500 BOPD); *id*. at 233:18-234:8 ("I got Doug Suttles telling me he thinks it's 2500 per day . . . [.] And I got–I have Charlie Henry telling me he thinks it's more than that.").

188. Suttles did not object to Admiral Landry announcing 5,000 BOPD as the Unified Command estimate. Depo. of M. Landry, 570:10-571:3.

189. Later that day, Admiral Landry publicly announced that Unified Command's revised flow rate estimate was 5,000 BOPD–the flow rate BP had represented as its high-end number. Depo. of M. Landry, 25:22-26:6.

190. In announcing the revised Unified Command estimate of 5,000 BOPD, Admiral Landry, in her words, "relied on the work of BP through Doug Suttles as the Lead Person for BP." Depo. of M. Landry, 321:10-15. Admiral Landry's expectation on the morning of April 28 was that BP would provide her directly with "every estimate or model that they had performed" regarding the oil emitted from the Macondo well. *Id*. at 230:7-15 ("Q: … And were you looking to BP as of the morning of April 28th to provide you with every estimate or model that they had performed regarding how much oil is being emitted from the Macondo Well? A: I would look to them to be—yes. I would look to them for providing me—as the Responsible Party, they should be providing me with all [the] information they have."); *Id*. at 232:1-3 ("Q: … And who was it—to whom was it that BP was to be providing that information? A: Me."). If BP had had flow rate ranges significantly different from the 1,000 to 5,000 BOPD range, Admiral Landry would have wanted to know those flow rate ranges. *Id*. at 573:7-12.

191. Although BP has attempted to minimize its role in the announcement of a 5,000 BOPD estimate, the evidence does not support BP's position. An internal BP email written by Doug Suttles less than a month after the April 28 announcement confirms that BP played an important role in this flow rate estimate. *See* TREX-150106.0001 (Email from Doug Suttles dated May 21, 2010, stating, "Also note that the 5000 BOPD with a wide uncertainty range was a rate agreed by NOAA, Coast Guard and BP very early in the spill. I notice on the bottom of this note we are saying this was a NOAA estimate. That is not correct and continues to create an issue with NOAA and the CG.").

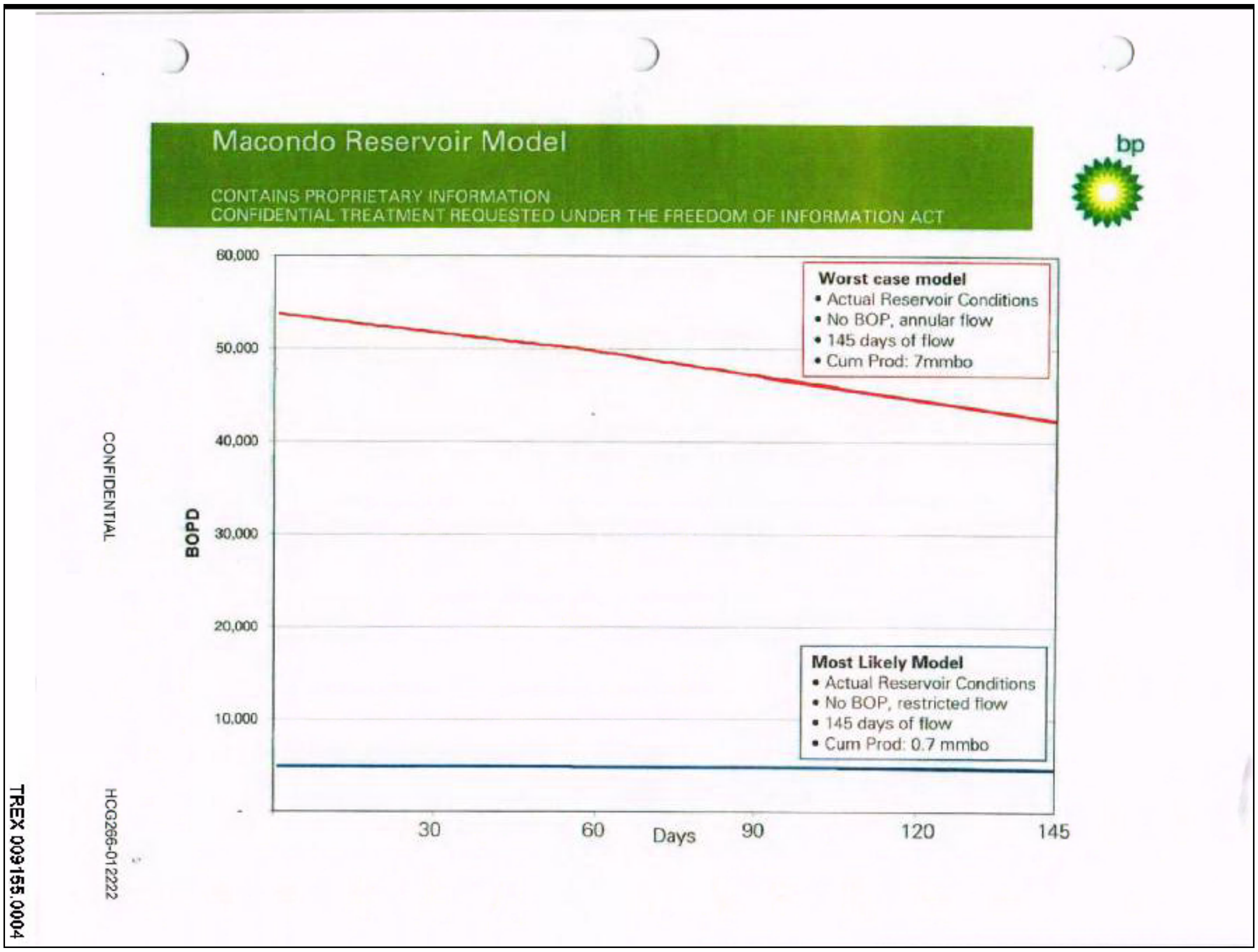
192. Admiral Landry also testified that while she relied on NOAA to assess the volume of oil on the surface and its trajectory based on projected currents and weather patterns, she did not look to NOAA for an amount of "flow rate out of the wellhead." As she explained, "It's not in their lane. That's not their expertise." Depo. of M. Landry, 80:23-81:22; *see also id*. at 226:1-9 ("Q. And at some point in time, did you begin to look to NOAA to estimate the flow rate? … Q. … at any point while you were the [Federal On Scene Coordinator]? A. No.").

193. This 5,000 BOPD estimate remained Unified Command's official flow rate until the Flow Rate Technical Group ("FRTG")–which was not created until May 19, 2010–released its first preliminary estimate of a lower bound of 12,000 to 19,000 BOPD on May 27, 2010. TREX-11902 (May 27, 2010 Press Release of FRTG Rates).

194. Once collection efforts began in June, the FRTG's estimated flow rate range continued to stair-step upward, reaching 35,000 to 60,000 BOPD on June 15, 2010. TREX-9660.

C. <u>BP Misrepresented The Flow Rate To Unified Command On May 10.</u>

195. On May 10, 2010, for example, Doug Suttles sent a letter to Unified Command leaders Admiral Landry, Admiral Allen, Lars Herbst of MMS, and Admiral Neffenger, regarding the "Potential Productive Capacity of the Maconda [*sic*] Well." TREX-9155 (May 10 Letter). In a chart attached to the letter, BP labeled a line depicting 55,000 BOPD, and decreasing over time, as the "worst case model." More importantly, BP labeled a line depicting 5,000 BOPD as its "Most Likely Model." TREX-9155.0004.



196. Admiral Landry understood from the chart attached to BP's May 10 letter that BP believed the most likely model of the flow rate was 5,000 BOPD. TREX-9155.0004; Depo. of M. Landry, 583:24-584:3. She also believed that the worst-case "full stream well capacity of the well" would be 55,000 BOPD, but that–as set forth in BP's letter–"[t]his would be extremely rare and represents a theoretical downside." *Id*. at 581:19-25; TREX-9155.0003.

197. Admiral Landry believed that BP's May 10 letter was providing her a complete picture of BP's flow rate analysis and not omitting any material information. *Id*. at 582:1-5.

198. Admiral Allen, who also received Doug Suttles' May 10 letter, testified at deposition that he also understood the letter to purport to set forth BP's "most likely model" of

flow rate using "actual reservoir conditions." Depo. of T. Allen, 554:15-18, 565:5-9, 565:11-13, 565:15.

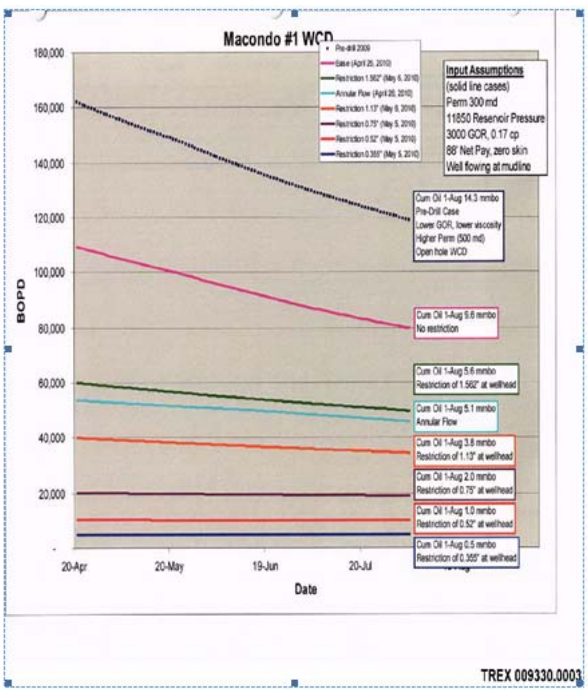
199. BP represented the flow rates in its May 10 Letter as being based on reservoir modeling, which is a type of hydraulic modeling. TREX-150110.0001 (May 10 email from Jasper Peijs to Doug Suttles describing flow rates as "reservoir models based on mass balance"); A. Ballard, P2 TT 957:21-958:6.

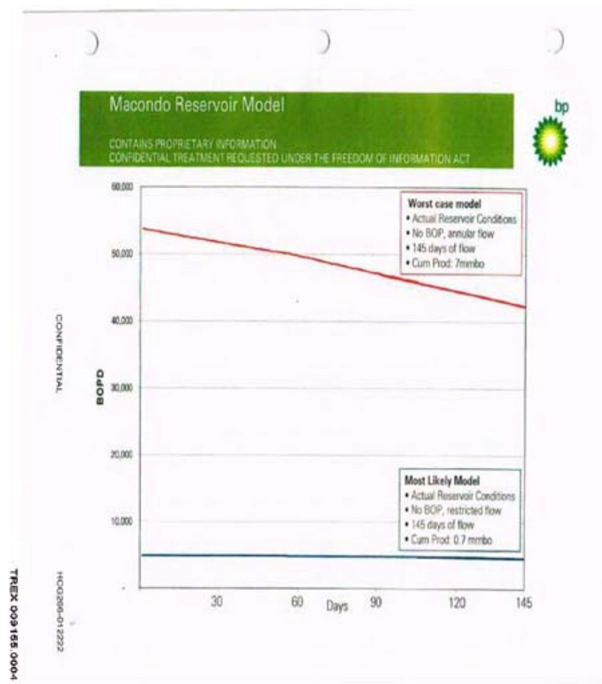
200. However, BP's expert and BP Engineering Team Lead at *Thunderhorse*, Adam Ballard, in his capacity as a Corporate Representative for BP on flow rate estimates, testified at deposition that "no one during [April 28 to May 27, 2010] was estimating or had made an estimate of the flow rate using hydraulic modeling and pressure measurements," and agreed that no one could have come to the conclusion that 5,000 BOPD was BP's "most likely" model based on BP's hydraulic modeling. Depo. of A. Ballard, 490:19-491:6, 491:9-13. Ballard likewise testified at trial that hydraulic modeling could not support a "most likely model" of 5,000 BOPD on May 10. A. Ballard, P2 TT 953:25-954:4 ("Q. Nor could they justify with hydraulic modeling a representation on May 10 of a most likely model of 5,000 barrels per day, could they, sir? A. From a hydraulic modeling, as I said, I don't think you could come up with a likely estimate of what the flow rate was.").

201. The flow rates depicted in BP's May 10 Letter were in fact the product of BP doctoring more comprehensive charts showing many more flow rates, not only above 5,000 but also above 55,000 BOPD. J. Wilson, P2 TT 109:16-111:1; D-25011A (power point demonstrative illustrating "editing" of BP's internal flow rate charts).

202. At the request of Jasper Peijs, who was an executive assistant to BP CEO of Exploration and Production Andy Inglis, BP Reservoir Engineer Kelly McAughan ran a number of simulations at eight different flow rates. TREX-9157 (McAughan WCD plots from May 5).

203. McAughan sent those charts to Peijs with an invitation to "edit freely." TREX-9330.0001. Peijs did. He deleted six of the estimates: 10,000, 20,000, 40,000, 60,000, 109,000, and 162,000 BOPD, and left only 5,000 and 55,000 BOPD. TREX-11906 (excel spreadsheet illustrating Peijs's editing of charts). Peijs then labeled 55,000 BOPD the "Worst case model" and 5,000 BOPD the "Most Likely Model," and sent the edited chart to Doug Suttles to incorporate into his May 10 Letter. TREX-11907 (Peijs sends edited chart to Doug Suttles); TREX-9155 (May 10 Letter from Suttles to Unified Command).





204. Admiral Landry testified that she did not expect BP to "edit out" its various flow rate estimates, and that she did not want BP to "edit freely" the flow rate estimates that it provided to her. Depo. of M. Landry, 605:5-8, 605:10-21.

D. BP Misrepresented The Flow Rate To Unified Command On May 19.

205. On May 19, BP's Suttles sent to Unified Command the fraudulent Rainey Memo.

206. Suttles told Unified Command the Rainey Memo contained BP's "most recent work on flow rate estimation." TREX-3218.0001 (cover email to Unified Command). The Rainey Memo reaffirmed BP's "best guess" of 5,000 to 6,000 BOPD based on surface expression modeling. One of the eight attachments stated that 5,707 BOPD was BP's "Best Guess" estimate as of May 17, 2010. TREX-3218.0001 (May 19 Rainey Memo); TREX-3218.15.1.TO (callout of 5,707 BOPD as BP's "Best Guess").

207. In fact, this memo did not—contrary to Suttles' claim—contain BP's "most recent work on flow rate estimation" because it failed to disclose numerous flow rate estimates generated by BP, including:

- An April 28 memo, in which BP purported to model "the whole system from reservoir to sea in order to bound the answers on flowrate," that contained rates as high as 65,171 BOPD. TREX-5063.
- An April 30 power point slide deck, which showed flow rates as high as 146,000 BOPD. TREX-9359.
- May 9 "blowout rates," calculated by Dr. Rygg of Add Energy, ranging from 37,000 to 87,000 BOPD. TREX-9266.
- A May 11 power point slide deck, showing flow rates as high as 96,000 BOPD. TREX-9156.
- A mid-May visual estimate performed by Trevor Hill of 20,000 to 25,000 BOPD. Depo. of T. Hill, 394:8-395:5, 424:19-22, 424:24-425:4.
- A May 14 visual estimate performed by Dr. Rygg of 40,000 reservoir BOPD through the riser alone. TREX-8866 (Email from Ole Rygg to Kurt Mix, May 10, 2010, "Current flow out of riser").

208. Although the May 19 memo did reference higher flow rates, it characterized these rates using phrases like "Maximum Discharge Calculation," "absolute worst case flow rate[s]," "worst case theoretical flow, and "low probability worst cases." TREX-3218.0006-.0007; *see*

also TREX-3218.0016 (60,000 BOPD is a "worst case theoretical flow"); TREX-3218.0017 (55,000 BOPD and 100,000 BOPD "low probability worst cases" if BP has "incorrectly modeled the restrictions").

E. <u>BP Repeatedly And Publicly Misrepresented The Flow Rate As 5,000 BOPD.</u>

209. BP officials repeatedly stated in public and to Unified Command that 5,000 BOPD was BP's best estimate.

210. Throughout late April and May 2010, BP stood behind the Unified Command 5,000 BOPD estimate and repeatedly characterized 5,000 BOPD as the best estimate of flow from the Macondo well. D-25018A (listing fourteen separate representations by BP that 5,000 BOPD or below was the "best estimate" of the flow rate, or words to that effect); A. Ballard, P2 TT 989:14-21 (BP expert Ballard acknowledging he was "aware that there were some communications about 5,000 being an estimate"); *Id*. at 996:8-15 (Ballard agreeing that "the timeline that you showed earlier [D-25018A], those were the different communications from BP").

211. On April 29, Doug Suttles appeared on numerous morning television shows and called 1,000 to 5,000 BOPD a "best estimate" and a "reasonable estimate." He called 5,000 BOPD a "best estimate" on Good Morning America on both May 14 and May 21, and on NPR on May 22. Suttles also characterized 5,000 BOPD as the "best estimate" at Unified Command Press Briefings on May 17 and May 21. BP also referred to 5,000 BOPD as its "current estimate" or "currently estimated rate" in its 6-K filings. D-25018A (demonstrative titled "BP: 5,000 BOPD 'Best Estimate'"). Even while it was misrepresenting the flow rate publicly and to Unified Command, BP de-prioritized measuring the flow rate. For example, BP internally considered—and rejected—using a device which would have provided an accurate flow rate from the Macondo well. Depo. of T. Knox, 437:24-438:7; TREX-9547.

F. BP Misrepresented The Flow Rate To National Labs Scientists.

212. Between May 13 and May 16, 2010, BP engineers met with National Labs scientists. During those meetings, BP engineers asked National Labs scientists to validate certain of BP's modeling. TREX-10340.

213. On May 13, National Labs scientists requested from BP "a case" for the flow rate advocated by Professor Stephen Wereley, who had claimed that the flow rate was 70,000 BOPD. They were told by BP employee Chris Cecil that BP had no such case. TREX-10793 at 2 (original notes of BP's Chris Cecil from May 13 meeting). This was false, as BP did have cases for 70,000 BOPD assuming flow was up the production casing. *See, e.g.*, TREX-9156.0005 (May 11 Mason presentation); Depo. of M. Mason, 347:24-348:3, 348:6-10 (acknowledging that BP "could have provided a case up the tubing string . . . for 70,000, or roughly 70,000 barrels a day"). After BP fraudulently led the National Labs scientists to believe the 70,000 BOPD estimate had no support in BP's modeling, a BP employee and a National Labs scientist agreed to base their analysis on 5,000 BOPD as the "best-controlled estimate." TREX-10793 at 2 (original notes of BP's Chris Cecil with handwritten changes by Mike Mason).

214. BP engineer Mike Mason reviewed Cecil's notes from the meeting where Cecil had stated BP did not have a case for 70,000 BOPD. He added a qualifier to Cecil's notes, altering them to read that BP could not provide such a rate "for the **annular flow cases**." TREX-10793 at 2 (emphasis added). This alteration made it appear as though the statement Cecil made at the meeting was accurate, when in fact it was not. Mason suggested the annotation even though **he did not attend the meeting** and thus had no basis for believing the original notes were inaccurate or limited to annular flow cases. *Id.* (original Cecil notes with handwritten modification); TREX-10340.0003; Depo. of M. Mason, 340:1-16 (acknowledging his name is not listed as an attendee at the meeting; stating "I don't think I did" attend the meeting); *id.* at

349:1-10 (acknowledging handwriting on TREX-10793 as his own); *id*. at 350:2-4 (agreeing he was the one who suggested the annotation).

215. BP explicitly told National Labs' scientists to assume 5,000 BOPD, and only gave them four days to perform their calculations to validate BP's models. On May 16, BP Head of Subsea Discipline, Paul Tooms sent the National Labs a series of questions. Question two asked the scientists to assume a flow rate of 5,000 BOPD. TREX-9131.0002; Depo. of T. Hunter, 538:13-20. National Labs scientists responded to this question internally with concerns. One scientist wrote, "I am wary of question 2. It looks like they are feeding us a desired solution to the question. I.e. [*sic*] They are prescribing a response to rebut media." TREX-9153.0001. Another responded that BP had set up the questions in such a way, "by giving us the data Thursday afternoon and requiring an answer by Sunday afternoon, that there are very few analysis options[.] . . . So they sort of have a self fulfilling prophesy [*sic*]; they have posed the questions in such a way that we effectively have to use the same analysis method that they used. So it's not surprising we will likely get the same answers . . .[.]" *Id*.

216. BP expert Adam Ballard contends that BP provided "federal responders" with "data needed to perform hydraulic modeling." A. Ballard P2 Expert Report, TREX-11905R.016-.017. However, at least with respect to National Labs scientists, that data was only provided alongside assurances that BP agreed 5,000 BOPD was the "best-controlled estimate." TREX-10793 at 2 (original Cecil notes). As set forth above, BP's representations directly to the National Labs scientists were reinforced by BP's repeated claims to both Unified Command and the public that 5,000 BOPD was its best estimate of the flow rate.

217. When BP told the National Labs to assume a 5,000 BOPD flow rate, BP did not share all its assumptions of how to make that "case" for 5,000 BOPD. As summarized in the

May 11 PowerPoint presentation to Andy Inglis, on a slide entitled "The Case for 5000 BOPD at 3800 psi," the assumptions required to obtain a flow rate of only 5,000 BOPD include a "high" skin value of 25, a reservoir thickness of only 10 or 12 feet, and a low permeability value of 170 millidarcies. TREX-9156.0008; Depo. of T. Hunter, 580:2-582:6, 582:8 ("Q. Okay. Now, when BP told the Labs on May 16th to assume a flow rate of 5,000 barrels of oil per day for purposes of answering … BP's questions, did BP share the assumptions that are shown on Slide 7 [of TREX-9156] with the Labs? A: I'm confident that the answer to that is 'No.'").

G. <u>BP Misrepresented The Flow Rate To Its Contractors.</u>

218. BP failed to inform Transocean, HESI, and other contractors that the Top Kill would not be successful if the flow rate from the Macondo well was greater than 15,000 BOPD. Depo. of R. Vargo, 8/22/2012, 98:1-9, 98:11-13, 98:15-21, 278:22-280:18, 284:15-22, 284:24-285:6.

219. Such misrepresentations in the context of source control operations slowed the source control process and exacerbated existing problems. E. Ziegler, P2 TT 553:7-12.

220. BP told HESI that it should assume the flow rate from the Macondo well was approximately 5,000 BOPD and never informed HESI that its own personnel and consultants had consistently modeled much higher flow rate estimates. Depo. of R. Vargo, 8/22/2012, 56:11-15, 138:21-25.

221. In addition to intentionally withholding flow rate data from its contractors, BP failed to share a variety of other pertinent information during the source control efforts. For example, BP never communicated to HESI that it had initially prioritized the BOP-on-BOP intervention method over the Top Kill. Depo of R. Vargo, 8/22/2012, 109:21-111:1, 111:3-111:5. Nor did BP communicate to HESI that a capping stack was a feasible course of action to shut in the well before going forward with the Top Kill. Depo. of R. Vargo, 8/22/2012, 111:6-9,

111:11. Finally, BP did not share with Transocean its reasons for shelving the BOP-on-BOP option. R. Turlak, P2 TT 358:19-21.

H. Despite Uncertainties, BP Had The Capability To Model Potential Flow Rates From The Well, And Indeed Did So In Order To Inform Source Control Efforts.

222. Over the course of late April and May 2010, BP engineers performed a wide number of computer simulations examining the range of potential flow rates from the well. J. Wilson, P2 TT 81:6-16. BP engineers and contractors had sufficient tools and information to model flow rates from the Macondo well. J. Wilson P2 Expert Report, TREX-11900.0008. They employed conventional petroleum reservoir and well modeling software packages, such as PROSPER, OLGA, and WELLCAT. Depo. of T. Lockett, 69:10-70:19; Depo. of M. Mason, 41:25-42:4, 42:14-21, 90:6-8, 90:10-17; J. Wilson P2 Expert Report, TREX-11900.0008.

223. BP's flow rate estimates were highly reliable for source-control decision-making. J. Wilson, P2 TT 89:14-16.

224. The evidence overwhelmingly shows that BP's modeling produced multiple ranges of potential flow rate estimates.

225. To begin with, multiple BP witnesses testified that BP modeled potential flow rate ranges. BP modeler Mike Mason testified that he asked people working under him during the response to investigate the potential flow rates from the Macondo well. Depo. of M. Mason, 78:7-15, 80:9-14, 80:16 ("Q: Yeah. When we're talking about the range of potential flow rates, is it accurate to summarize that work as varying the–the modeling parameters across a wide range to try and figure out the–the range of potential flow rates from the Macondo Well? A: Yes."). BP's Flow Assurance Engineering Technical Authority, Trevor Hill also agreed that by April 2010, there were several groups looking at flow modeling at BP, and their work allowed for estimates of flow rate ranges. Depo. of T. Hill, 445:19-25, 446:2-4. BP's 30(b)(6) witness

and BP Community Practice Leader for Integrated Asset Modeling Simon Bishop confirmed that BP did "a wide range of activity calculating a range of modeled rates from the well" to inform decision making regarding source control activities. Depo. of S. Bishop, 74:7-75:21. BP executive Andy Inglis also testified that BP employees worked on flow rate assessment at Unified Command as well as in Houston. Depo. of A. Inglis, 310:24-311:2, 311:11-312:10.

226. Contemporaneous documents also confirm that BP's engineering groups used modeling "in order to bound the answers on flowrate." TREX-5063.1.1.TO (Email from Trevor Hill to Gordon Birrell, dated April 28, 2010, attaching "Modeling of system flow behaviour"). This was possible because BP had high-quality estimates of the reservoir, fluid properties, and as-built, engineered infrastructure of the well. J. Wilson P2 Expert Report, TREX-11900.0008.

227. BP engineers themselves expressed that they "had good confidence" in certain parameters, including reservoir pressure, seabed water pressure, fluid properties, and the diameter of the riser. TREX-5063.4.1.TO (Email from Trevor Hill to Gordon Birrell, dated April 28, 2010, attaching "Modeling of system flow behaviour").

228. A BP group led by Mike Mason confirmed that BP was both modeling potential flow rates and that these modeled rates were reliable. A frequently asked question ("FAQ") attached to a May 11, 2010 presentation posed the question: "[w]hat gives you confidence in your understanding of the data?" Mason's team responded:"–[w]e know the pressure beneath the BOP[;] Reservoir: properties, fluid characteristics, pressure, depths[;] current state of the BOP[;] geometries in the well[.] . . .**[W]ith this data we can anticipate the expected range of rates**." TREX-9156.12.1.TO (emphasis added).

229. The Mason team's FAQ answer and other BP documents make clear that, even though there were certain parameters that BP was less certain about, BP was able to "bound the answer on flowrate." TREX-5063.1.1.TO; J. Wilson, P2 TT 94:2-8.

230. Notwithstanding this evidence, BP employee, 30(b)(6) representative, and expert Dr. Adam Ballard has testified that BP performed no flow rate estimates at all. For example, Ballard–in his capacity as BP's 30(b)(6) witness on flow rate estimates–testified that BP did not "predict[], estimat[e], characteriz[e], or measure[e] the daily amount of hydrocarbons from the Macondo well" between April 20 and July 15 (other than a single calculation Ballard performed after the capping stack was installed). Depo. of A. Ballard, 477:8-23, 477:25-478:25.

231. Dr. Ballard's testimony that BP did not have flow rate estimates is contradicted by BP's admission in its guilty plea that it had "withheld information and documents relating to **multiple flow-rate estimates**." TREX-52673 at 16 (emphasis added). And if Dr. Ballard's testimony that BP had no basis for coming up with a likely flow rate estimate were credited, A. Ballard, P2 TT 953:25-954:4, then BP's representation to Admiral Landry on May 10, 2010 that 5,000 was its "Most Likely Model" of the flow rate was plainly false. TREX-9155.0004.

I. BP's Internal Modeling Generated Flow Rates Exceeding 5,000 BOPD And Even 15,000 BOPD.

232. During the Response, BP had four different engineering groups exploring the flow rate from the Well: Flow Assurance, Petroleum Engineers, Reservoir Engineers, and the Hydraulic Kill Team. J. Wilson, P2 TT 83:9-16, 84:3-17, 85:9-24; D-25013B (BP Organization Chart of Modeling Groups).

233. Contrary to Dr. Ballard's testimony, all of these groups performed hydraulic modeling related to flow rate. J. Wilson, P2 TT 85:25-86:3.

234. Consistent with BP's guilty plea, the evidence shows that these hydraulic modeling efforts generated flow rates significantly higher than the 5,000 BOPD estimate BP repeatedly represented was its best estimate of the flow rate. D-25015C (demonstrative titled, "BP Flow Rate Modeling: April 21, 2010–May 31, 2010").

235. BP Reservoir Engineers performed the earliest modeling immediately after the blowout by modifying a pre-drill modeling case for the Macondo Well. J. Wilson P2 Expert Report, TREX-11900.0015. One day after the accident, BP Reservoir Engineers informed BP executive and BP Deputy Area Commander David Rainey that the worst-case discharge from the well could be 100,000 BOPD. TREX-3063 (email from Walt Bozeman to David Rainey, et al., dated April 21, 2010, calculating worst-case discharge of 100,000 BOPD).

236. The Reservoir Engineers also created forecasts of flow rates over time. These forecasts accounted for reservoir depletion. By assuming a restriction at the wellhead, the Reservoir Engineers could vary the flow rate and explore total discharge over time for a range of rates. TREX-9330.0004. The flow rates forecasted by this group ranged from 5,000 to 109,000 BOPD.

237. As noted above, the Flow Assurance Engineers ran models to "bound the answers on flowrate." Their analysis yielded a range of 2,523 to 65,171 BOPD. TREX-5063.

238. BP Expert Dr. Ballard testified that Mr. Hill and Dr. Lockett, BP's Flow Assurance Engineers, were using an "infinite productivity index" to obtain the results in TREX 5063. A. Ballard, P2 TT 936:16-937:5. However, the face of the document stated that the engineers in fact used "three illustrative values:" a productivity index of 1, an index of 10, and then the maximum capacity of the system. TREX-5063.4.6.BP (Modeling of system flow behavior memo). Neither the scenario that assumed a productivity index of 1 nor the case that

assumed a productivity index of 10 were based on an "infinite productivity index." And with an orifice of just one inch, a productivity index of 10 was sufficient to produce a flow rate of more than 20,000 BOPD. TREX-5063.0005 (Graph).

239. The assumed productivity index of 10 was overly optimistic. BP's Reservoir Engineers calculated a productivity index of 50 for the Macondo well. TREX-9480 (email from Walt Bozeman to Kurt Mix and Robert Bodek, April 21, 2010, "Macondo Info" stating: "We are calculating a PI of 50 bbl/psi."); J. Wilson P2 Expert Report, TREX-11900.0038.

240. BP's Petroleum Engineers, led by Mike Mason, modeled various scenarios and generated flow rate ranges as high as 96,000 BOPD. TREX-9156.0005. Notably, other than a targeted case for 5,000 BOPD, the result of that modeling was, at its lowest, 14,000 BOPD. TREX-9156.0006 ("Partial Reservoir Exposed" case); TREX-9156.8.1.TO ("The Case for 5,000 BOPD at 3800 psi").

241. BP derived the targeted "[c]ase for 5,000 BOPD" by changing the modeling inputs, such as the skin, size of reservoir, and permeability, to determine "what would be the condition in the well in order that 5,000 barrels a day were a rate from the well." Depo. of S. Bishop, 278:8-17, 280:9-14; TREX-9156.8.1.TO.

242. When BP modelers obtained flow rates of 5,000 BOPD or below, it was frequently because they had targeted those rates by changing the resistances. J. Wilson, P2 TT 101:9-25. These adjustments were not based on any empirical data about the well. *Id*. at 102:1-4.

243. BP's Hydraulic Kill Team used the OLGA software to model flow rates. J. Wilson P2 Expert Report, TREX-11900.0018-.0019. Dr. Ole Rygg of the blowout consulting firm Add Energy was a part of this team. J. Wilson, P2 TT 96:5-14.

244. Dr. Rygg modeled "blowout rates" for the Macondo well using a pressure measurement of 3800 psi obtained from the bottom of the BOP stack on May 9, 2010. *Id*. at 96:15-97:3. This measurement substantially reduced the uncertainty in BP's flow modeling. *Id*. at 97:4-9. Rygg's modeling generated flow rates of 37,000 BOPD for annular flow, 55,000 BOPD for casing flow, and 74,000 BOPD for flow up both casing and annular space. TREX-9266.0002 (email from Ole Rygg to BP's Kurt Mix, May 9, 2010, attaching "Blowout Rates"). The rates at 3800 psi assumed "current restrictions/measured" pressure, and thus were not worst case scenarios. *Id*.

245. Two other BP contractors were involved in calculating flow. Morten Emilsen of Add Energy, who was involved in the investigation effort, concluded the well was "very prolific" with a blowout potential of 70,000 BOPD. On May 13, 2010, Emilsen emailed BP that, based on a fully open reservoir, the Macondo well's IPR was "high" and indicated "a very prolific reservoir." Depo. of M. Emilsen, 109:19-25. In a May 21, 2010 slidepack that Emilsen sent to BP, Emilsen estimated a "blowout potential" of 70,000 stock tank barrels per day. *Id*. at 111:22-112:3; TREX-7247.0002. He also performed simulations for blowouts to seabed with restrictions in the BOP; based on the 3800 psi measured BOP pressure, a full 86 feet of net pay, and a casing flow path, Emilsen generated a flow rate of 54,000 stock tank barrels per day. Depo. of M. Emilsen, 110:17-111:3; TREX-7219.0030. These estimates were included in his May 31 draft report. Depo. of M. Emilsen, 297:13-298:5; TREX-7270 at 27. Emilsen did not model a flow rate of 5,000 barrels per day. Depo. of M. Emilsen, 290:19-22.

246. BP also failed to inform the Government that, prior to the Top Kill operation, HESI had submitted a report to BP concerning the cementing portion of the Top Kill which

reported a minimum well flow rate of 30,000 BOPD. Depo. of K. Cook, 590:15-591:4; Depo. of L. Herbst, 564:6-11, 564:13-19, 564:21-565:4; Depo. of M. Sogge, 431:7-10, 431:12-16.

247. Flow rate was a necessary input in HESI's WellCat temperature modeling. Depo. of R. Vargo, 8/22/2012, 131:23-132:19, 139:8-140:11. But HESI was unable to successfully perform its WellCat modeling with a flow rate input of 5,000 BOPD. Depo. of R. Vargo, 8/22/2012, 228:9-230:4. To accurately match the known data in its model, in mid-May 2010, HESI used a flow rate of 30,000 BOPD as an input in its WellCat modeling. Depo. of R. Vargo, 8/22/2012, 131:23-132:19.

248. HESI's GoM Regional Manager for Cementing Richard Vargo not only emailed this report to BP, but also hand-carried a copy and spoke to BP engineers about the rate. Depo. of R. Vargo, 8/22/2012, 134:13-136:19. After HESI discussed its modeling with BP's Western Hemisphere Cementing Sector Specialist Erick Cunningham, Cunningham approved HESI's use of a 30,000 BOPD flow rate in its WELLCAT modeling for purposes of the post-Top Kill cement job. Depo. of R. Vargo, 8/22/2012, 139:8-17. However, BP did not inform HESI that it had already determined that the dynamic kill would not succeed if the flow rate was 15,000 BOPD or greater. Depo. of R. Vargo, 8/22/2012, 91:8-15.

J. <u>BP Employees And Contractors Expressed Concerns Internally About The 5,000 BOPD Estimate.</u>

249. On May 15, 2010, the head of the Petroleum Engineering flow rate work group Mike Mason wrote an email directly to Andy Inglis, CEO of BP Exploration and Production. Mason told Inglis, "We should be very cautious standing behind a 5,000 BOPD figure as our modelling [*sic*] shows that this well could be making anything up to ~100,000 BOPD depending on a number of unknown variables. . . . We can make the case for 5,000 BOPD only based on

certain assumptions and in the absence of other information, such as a well test." TREX-3220.0001 (email from Mike Mason to Andy Inglis, May 15, 2010, "Macondo Oil Rate").

250. In response to this email, Jasper Peijs, Andy Inglis's executive assistant, called Mason into a meeting and told him, as Mason recalled at deposition, "[n]ext time you have an idea or a thought like this E-mail note, we would appreciate it if you would walk over and discuss it with us." Mason asked him what the "problem" was with the email and Peijs responded, "It's the big number." Mason understood that to be a reference to the 100,000 BOPD number in his May 15 email. Depo. of M. Mason, 320:1-321:15.

251. On May 16, 2010, Dr. Rygg emailed BP's Trevor Hill that the new pressure reading of 3800 psi could mean that restrictions at the wellhead were giving way and thus that there was "less chance of ever being able to do a dynamic [T]op [K]ill." He also wrote, "Be aware that we are working on the 5000 [BOPD] case. That could be too optimistic." TREX-9250.0002-.0003.

252. Hill forwarded the email to BP's Tim Lockett, who replied to Hill on May 17: "The apparent reliance in Ole's email on the 5 mbd [5,000 BOPD] number, which has little if no origin, is concerning. From all the different ways we have looked at flowrate, 5 mbd would appear to err on the low side." TREX-9250.0002.

253. Dr. Lockett confirmed at deposition that by May 17, he was of the opinion that 5,000 BOPD had little or no origin and erred on the low side. Depo. of T. Lockett, 385:23-386:1, 386:3-10.

254. Indeed, by mid-May numerous BP engineers had made estimates of flow rates higher than 5,000 BOPD by watching video footage and estimating velocity of the plume out of the riser. Dr. Rygg wrote BP engineer Kurt Mix on May 10 that he did not think it could be

ruled out that the flow was on the order of 40,000 BOPD out of the end of the riser alone–i.e., not including the leak from the kink at the riser above the BOP. TREX-8866 (Email from Ole Rygg to Kurt Mix, May 10, 2010, "Current flow out of riser"). Dr. Rygg testified this number was in reservoir barrels, rather than stock tank barrels. But according to expert Dr. John Wilson that would still yield a flow rate of 16,400 BOPD through the end of the riser. J. Wilson P2 Expert Report, TREX-11900.0032.

255. Around May 15, Trevor Hill made a visual estimate of 20,000 to 25,000 BOPD from the riser, which he later revised downward to 15,000-20,000 BOPD. Depo. of T. Hill, 394:8-395:5, 424:19-22, 424:24-425:4.

256. By mid-May, Hill no longer believed 5,000 BOPD was BP's best estimate of flow. Hill also testified that he was not aware of anyone at BP who believed in mid-May that 5,000 BOPD was the best estimate. *Id*. at 393:22-394:7, 402:5-8, 402:10. Other BP employees and consultants also expressed concerns that the 5,000 BOPD was too low. Depo. of T. Hill, 402:5-8, 402:10, 483:18-484:18, 484:20-22, 484:24-485:2, 485:4-5, 486:12-17, 486:19-24, 487:1-488:10, 488:12-489:1, 489:18-490:9, 490:11-21, 490:23-491:5; A. Ballard, P2 TT 993:17, 993:23-994:3, 994:9-995:6, 995:10-24, 996:8-15; D-25013B.

257. Hill failed to share his flow rate estimate with Government scientists. Depo. of T. Hill, 396:6-22, 396:24-397:12, 397:14-21, 397:23-398:12, 398:14-399:2, 399:5-14, 416:10-416:14, 430:2-11, 430:13-21, 430:23-431:7, 431:9-19, 431:22-432:3, 432:6, 432:25-433:5, 433:8-10.

K. <u>BP Intentionally Concealed Its Flow Rate Estimates, Both Internally And Externally.</u>

258. On April 22, 2010, a BP employee wrote that another modeler had adjusted his model and estimated 82,000 BOPD. He was told, "we already have had difficult discussions

with the USCG [Coast Guard] on the numbers. Please tell Alistair not to communicate to anyone on this." The employee wrote back, "Yes, he knows about confidentiality." TREX-8656.

259. On April 30, 2010, a BP contractor asked BP for its "best estimate" of flow to perform plume modeling. He was told, "NOTE: Confidential information. For the first run, use 70,000 bpd. For the second run, 35,000 bpd." TREX-9629.

260. On May 5 and 6, 2010, in connection with the flow rate modeling performed by Kelly McAughan for Jasper Peijs, Andy Inglis, and Tony Hayward, Peijs told McAughan, "This information is sensitive, so please do not forward." TREX-9157.0001.

261. On May 6, 2010, McAughan forwarded the plots to another member of her team, with the request that "like Jasper said please don't pass around." *Id*.

262. As noted above, when BP's Mike Mason e-mailed Andy Inglis on May 15 that "[w]e should be very cautious standing behind a 5,000 BOPD figure as our modeling shows that this well could be making anything up to ~100,000 BOPD …," he was told by Inglis's executive assistant that the next time he had a thought like the "the big number," he should walk over and discuss it with them in person. Depo. of M. Mason, 320:1-321:15; TREX-3220. The implicit message BP delivered to Mason was that he should not put high flow rate estimates in writing.

263. There is in fact evidence that "the big number" was subsequently removed from an internal BP document called the "Holistic System Analysis." A May 8, 2010 version of the Holistic System Analysis, circulated to Mike Mason, stated: "This modelling [*sic*] indicates a wide range of potential flow-rates. Flow behind casing (currently considered most likely) yields a feasible range of 2,000-47,000 stbpd, with a worst case of 52,000 stbpd. Unconstrained flow through the inside of the production casing string could reach 96,000 stbpd, but this is considered an unlikely rate." TREX-9441 (May 8 Holistic Systems Analysis).

264. BP removed the 96,000 stbpd estimate from the May 20, 2010 version of its Holistic Systems Analysis. This version stated: "This modelling [*sic*] yields a wide range of potential flow rates. Flow behind casing (currently considered most likely) yields a feasible range of 2,000-47,000 stbpd. Unconstrained flow (no restriction through reservoir, well bore or downstream of well head) through the inside of the production casing string shows a much higher maximum value." TREX-11170 at 8 (May 20 Holistic Systems Analysis).

265. BP also sought to limit the distribution of an internal BP Technical Memo, dated May 14, 2010, that discussed potential issues that might arise during the Top Kill operations. Depo. of A. Frazelle, 242:19-243:25, 244:2-13, 244:15-245:14; TREX-5361 at 1, 4 (May 16, 2010, email stating "this is BP confidential, please do not forward or share" and attaching memo that said in part, "Of concern is whether this surface pressure, or additional hydrostatic pressure exerted during a top-kill operation, has the potential to rupture burst-disks …").

266. On May 16, 2010, BP flow modeler Trevor Hill asked Farah Saidi, a member of BP's Flow Assurance team, what the flow rate was through the RITT tool. Saidi responded that "rates are confidential and I was told by Mike Brown not to write anything about it. . . ." TREX-9474.

267. Saidi testified that she recalled being instructed by BP's Vice President of Drilling and Completions Richard Lynch not to forward the rates to anyone. Depo. of F. Saidi, 407:2-19, 408:2-11.

268. On May 17, 2010, BP's Expert Adam Ballard himself was told by BP executive Richard Lynch that BP was "not releasing any information that can be related to rate," and that "[w]e remain in a position where no flow related information can be released internally or

externally." TREX-9475.3.1.TO.Ballard; TREX-9475.2.1.TO; A. Ballard, P2 TT 1000:7-1001:16; Depo. of A. Ballard, 292:9-20, 292:23-293:19, 294:15-23, 297:9-16.

269. On May 18, 2010, BP's engineering manager for the Containment and Disposal Project was also told by BP engineer Mike Brown that the oil rate was "[v]ery tight information." TREX-9475.1.2.TO; A. Ballard, P2 TT 1001:21-1002:12.

270. On May 27, 2010, BP's Rupen Doshi sent an email that stated in part: "Just want to make it clear that **NO ONE** is to get the data files from the Top Kill method that is being pumped from yesterday or today except for Paul Toom's [*sic*] group. This order comes directly from [BP's] Bill Kirton and Charles Holt." TREX-6195; Depo. of P. Tooms, 6/16/2011, 304:3-304:23, 304:25-305:17; TREX-9164. BP's Jace Larrison responded that same day: "We will continue to load into PI and will provide **NO** data access to anyone and will wait for Paul Tooms to give approval for each users access." TREX-6195; TREX-9164.0002; Depo. of P. Tooms, 6/16/2011, 304:3-23, 304:25-305:17. Doshi responded: "I am sure you can imagine how tight hole [*sic*] this is going to be." TREX-9164.0001; Depo. of P. Tooms, 6/16/2011, 304:3-23, 304:24-305:17. Tooms replied that "[t]he purpose of the note was meant to put a limit on the people outside the circle of trust getting the data." TREX-9164.0001.

271. Government officials were unaware that BP employees were instructing others within BP to limit information shared with the Government. Depo. of M. McNutt, 462:13-14, 462:22-463:20, 463:23-464:9, 464:11-23, 465:1-3, 465:6-7; TREX-9164.

272. BP also told its contractors not to share information. For example, BP instructed Schlumberger not to share any hydrocarbon recovery reports or flow-related details with anyone outside of BP. Depo. of A. DeCoste, 244:14-246:19; TREX-10481. Although Schlumberger was aware that MMS was interested in knowing flow rates and cumulative collection amounts,

Depo. of A. DeCoste, 63:17-21, Schlumberger provided collection rate numbers only to BP – consistent with BP's instructions to Schlumberger. Depo. of. A. DeCoste, 63:22-24.

273. BP employees also testified they were not given other teams' calculations or estimates. For example, BP's Mike Mason was not given and was unaware of: (1) Dr. Rygg's visual calculations of 40,000 BOPD based on a video of flow from the riser, Depo. of M. Mason, 314:6-11, 314:13-15, (2) Kelly McAughan's worst case discharge plots, Depo. of M. Mason, 407:17-20, 22-24, or (3) the OLGA modeling performed by Kurt Mix and William Burch, Wild Well Control Inc. engineer, in late April with cases up to 146,000 BOPD. TREX-10488; Depo. of M. Mason, 412:23-413:6. Dr. Lockett similarly testified that he had never seen the Hydraulic Kill Team's memo that incorporated Dr. Rygg's "blowout rates," *see* Depo. of T. Lockett, 432:15-18, TREX-9159, or Mike Mason's May 11 PowerPoint slides. *See* Depo. of T. Lockett, 432: 22-24; TREX-9156.

274. During the time when it was concealing flow rate information, BP was aware that the financial consequences, including fines and penalties, based on the amount of hydrocarbons released from the Macondo well could be severe. Depo. of M. Mason, 521:22-522:15, 523:7-15; TREX-10871.0068.

L. <u>BP Did Not Share Its Internal Estimates And Analyses With Government Officials And Scientists Prior To The Top Kill.</u>

275. Notwithstanding the doubts expressed by many BP employees about the 5,000 BOPD estimate and BP's own internal modeling showing flows far above 5,000 BOPD, BP concealed its concerns and its higher flow rates from government officials at Unified Command and National Labs scientists.

276. Numerous government officials testified that BP did not give them, nor did they otherwise receive, BP's flow rate estimates.

277. Admiral Landry testified that BP did not provide her with:

- Mike Mason's May 11 power point presentation, which showed flow rates as high as 96,000 BOPD. TREX-9156 (Mason May 11 Presentation); Depo. of M. Landry, 616:15-19, 616:21-617:1.

- BP's well control modeling from April 29, 2010, which contained flow rate worst case estimates as high as 146,000 BOPD. TREX-9359 (BP Macondo Well Control Modeling, April 29, 2010); Depo. of M. Landry, 608:2-8, 608:10-13, 608:15-19.

- Dr. Rygg's "blowout rates" of 37,000 to 87,000 BOPD that he sent to Kurt Mix on May 9. TREX-9266; Depo. of M. Landry, 590:23-25.

- Charts prepared by Kelly McAughan on May 5 and 6, which McAughan had sent to Jasper Peijs with the message that he could "edit freely." TREX-9157; TREX-9158; Depo. of M. Landry, 603:22-25.

- A visual estimate of flow from video, conducted by Dr. Rygg, on the order of 40,000 reservoir barrels per day. TREX-8866; Depo. of M. Landry, 600:2-7.

278. BP also failed to inform Admiral Landry that BP engineers expressed doubts internally about the 5,000 BOPD estimate. Depo. of M. Landry, 586:24-587:15, 593:10-12, 593:14-17, 593:20-594:1.

279. After being shown BP's internal flow rate modeling that BP did not share with her during the response, Admiral Landry testified that "BP was not being transparent." *Id*. at 642:10-12, 642:15-18, 642:21-23.

280. Secretary Chu testified that BP did not provide him with:

- The April 28 memorandum in which BP engineers "bound the answers on flowrate" and generated rates as high as 65,171 BOPD. Secretary Chu stated that this document "would have been relevant, again, in evaluating things like dynamic top kills." TREX-5063; Depo. of S. Chu, 214:24-215:1, 215:3-6, 215:8-10.

- The May 11 Mike Mason PowerPoint slides showing flow rates as high as 96,000 BOPD. Secretary Chu testified these slides would have been helpful to him in providing advice to decision makers about source control decisions. TREX-9156; Depo. of S. Chu, 217:7-10, 217:14-19, 217:21, 218:8-11, 218:14-18.

- Dr. Rygg's May 9 "blowout rates" showing ranges from 37,000 to 87,000 BOPD. TREX-9266; Depo. of S. Chu, 228:4-8. When asked whether that document would have helped him "in providing advice to the decision makers about source control strategies," Secretary Chu answered, "[y]es." *Id*. at 228:9-12, 228:14.

281. Secretary Chu confirmed that BP did not provide him, nor his team, with the BP internal flow rate documents that he was shown at deposition. *Id*. at 232:2-4, 232:6-8.

282. After having seen BP's internal flow rate modeling at deposition, Secretary Chu agreed that BP's restricting flow information internally and externally was not the type of behavior that engenders trust. Secretary Chu also agreed that this would not be the working relationship that would be the most effective in controlling the flow. *Id*. at 223:24-224:2, 224:4-12, 224:15-21, 224:23-225:3.

283. Lars Herbst of MMS testified that he did not know BP had performed flow modeling. BP also did not give him:

- The flow rates of up to 65,171 BOPD contained in BP's April 28 memo that "bound the answers on flow rate." TREX-5063; Depo. of L. Herbst, 535:21-536:5.

- BP's well control modeling from April 29, 2010, which contained flow rate worst case estimates as high as 146,000 BOPD. TREX-9359 (BP Macondo Well Control Modeling, April 29, 2010); Depo. of L. Herbst, 545:7-20.

- Dr. Rygg's modeling of blowout rates between 37,000 and 87,000 BOPD. TREX-9266; Depo. of L. Herbst, 550:21-25.

- Documents or information evidencing BP's approval of HESI's use of a 30,000 BOPD flow rate estimate in its WELLCAT modeling for the Top Kill cement job. *Id*. at 564:6-11, 564:13.

284. Science Advisor to Secretary Salazar and Head of FRTG, Dr. McNutt testified that BP was not "a willing partner" when it came to flow rate. She stated, "[t]here was this tenseness … it was almost kind of a – a chill in the room when flow rate issues came up." Depo. of M. McNutt, 433:4-6, 433:8-13.

285. In particular, BP never told McNutt that the flow rate could be up to 100,000 BOPD. *Id*. at 436:1-4, 436:7-11, 436:14. BP also did not inform McNutt of Dr. Rygg's modeled flow rates of 37,000 to 87,000 BOPD. TREX-9267 (May 11 Add Energy Presentation); Depo. of M. McNutt, 497:6-17, 497:19-498:14.

286. After being shown BP's internal flow rate documents at her deposition, Dr. McNutt testified, "I guess I'm not in the circle of trust." *Id*. at 464:18-23. McNutt also testified, "it does not appear that BP was as forthcoming with their own understanding of flow rate as I could have expected." *Id*. at 534:22-25, 535:4-13.

287. BP did not give Admiral Allen:

- BP's May 11 PowerPoint slides with flow rates of up to 96,000 BOPD. Depo. of T. Allen, 572:11-13, 572:20-573:5.
- The charts by BP's Kelly McAughan dated May 5 and 6, upon which the May 10 letter was based. TREX-9157; TREX-9158; Depo. of T. Allen, 578:2-6, 578:9-12, 580:21-22, 580:24, 581:10-12.
- A memo dated May 9 to BP's Jonathon Sprague from Kurt Mix, Bill Burch, and Ole Rygg, which incorporated Dr. Rygg's blowout rates of 37,000 to 87,000 BOPD. TREX-9159; Depo. of T. Allen, 583:25-584:23, 585:1-13.

288. Dr. Tom Hunter, former Director of Sandia National Labs and the head of the Federal Science Team, testified that in May 2010, BP never notified or provided him with any information that the flow rate was greater than 15,000 BOPD, the level at which the dynamic Top Kill would fail. Depo. of T. Hunter, 498:25-499:3, 499:5-7.

289. Dr. Hunter testified that BP did not share flow rate information "in any major way." *Id*. at 561:2-5, 561:7-11. He did not recall "any provision of flow rate information in – during the period in – in the month of May . . . by direct request or otherwise." *Id*. at 567:1-9.

290. A contemporaneous document confirms Dr. Hunter's recollection that BP failed to share flow rate information with him in May 2010. Hunter had asked BP, "[w]hat data is

available on flow rate?" TREX-9915.0003 (Email from Ruban Chandran to Tom Hunter, May 21, 2010, "BP: Q&As"). BP's May 21, 2010 response to Dr. Hunter disclosed only the amount of barrels of oil collected by the RITT tool–1,400 to 3,000 BOPD. *Id.*; Depo. of T. Hunter, 527:23-528:1, 528:14-19. BP did not provide Hunter with any of its own reservoir modeling. *Id.* at 528:2-4. It did not share with Hunter any flow rate analyses using video of the flow. *Id.* at 528:5-8. BP also did not disclose the doubts BP's employees had about the 5,000 BOPD estimate. *Id.* at 528:9-11, 528:13. Dr. Hunter testified that he likely had not intended for BP to limit its answer to RITT collection data. *Id.* at 562:22-563:2, 563:4-8 (". . . the question was flow rate, not RITT flow rate").

291. BP also failed to disclose to Dr. Hunter:

- BP's April 28 analysis that "bound the answers on flowrate" and that generated flow rates of up to 65,171 BOPD. TREX-5063; Depo. of T. Hunter, 565:15-566:7. Dr. Hunter stated this would have been "valuable" and "important." *Id.* at 566:14-17, 566:20-25.

- Dr. Rygg's video estimate of the plume at 40,000 reservoir barrels per day. *Id.* at 588:15-589:18, 589:20-25, 590:2.

- Information that BP's modeling had shown the flow rate could be up to 100,000 BOPD. *Id.* at 572:22-573:5.

292. BP gave neither Dr. Hunter nor the National Labs:

- The charts created by Kelly McAughan on May 5 and 6, upon which BP's May 10 letter to Admiral Landry was based. TREX-9157; TREX-9158; Depo. of T. Hunter, 558:5-7, 559:24-560:3.

- The May 11 Mike Mason modeling presentation showing flow rates of up to 96,000 BOPD. TREX-9156; Depo. of T. Hunter, 576:21-577:7, 579:13-19.

- A May 9 memo containing Dr. Rygg's blowout rates of 37,000 and 87,000 BOPD. TREX-9159; Depo. of T. Hunter, 596:10-18, 597:19-25, 598:2-3.

- The National Labs were also not aware that BP had approved HESI's use of a 30,000 BOPD flow rate in its simulations supporting the Top Kill. *Id.* at 600:18-21.

M. <u>BP Executives And Employees Acknowledged That They Did Not Share BP's Internal Flow Rate Analyses With Government Officials Or Scientists Prior To The Top Kill.</u>

293. BP executives and employees testified that they did not share BP's internal flow rate modeling with government officials or scientists prior to the Top Kill.

294. On May 13, BP's Mike Mason wrote to BP's Jasper Peijs regarding a meeting he had that morning with scientists from the National Labs. He concluded his email with the statement: "unless pushed I am holding off with any other data until afterwards." TREX-9326 at 1.

295. The record shows that at least one type of data Mason held off in providing to the Government was BP's internal flow rate estimates. Mason does not have a clear recollection of providing, and does not recall anyone else providing, the National Labs team with his modeling results. TREX-10799 (May 10 Results of Riser and Umbilical Modeling); Depo. of M. Mason, 450:3-5, 450:7-10, 450:12; TREX-9156 (May 11 Presentation); Depo. of M. Mason, 455:18-21, 456:3-5, 456:7. Mason also testified that he did not recall providing, and did not recall anyone else providing, the National Labs scientists with Trevor Hill's visual estimate of flow, (*id*. at 404:9-12, 404:15-25, 405:3-6), Dr. Rygg's visual estimate of flow, (*id*. at 405:7-11, 405:14, 405:22-25, 406:2), Dr. Rygg's modeled blowout rates, (*id*. at 406:3-7, 406:10-14, 406:17-24), Kelly McAughan's worst case discharge plots, (*id*. at 407:17-20, 407:22-408:4, 408:7-9), or the hydraulic kill team's rates incorporating Dr. Rygg's work, (*id*. at 408:25-409:9).

296. On May 16, Mike Mason had his BP colleague Tony Liao, a BP Senior Petroleum Engineer, perform a depletion calculation to determine the amount of flow needed to account for a 700 psi pressure decrease that had registered on the PT-B gauge at the bottom of the BOP. Liao reported back that the rate required was 86,600 BOPD. TREX-9313 at 1; Depo. of M. Mason, 288:13-289:5.

297. Mason forwarded that result to BP executives James Dupree and Gordon Birrell, Technology Vice President for Operations, HSE, and Engineering. TREX-9313.0001. Dupree testified at trial that he did not share this 86,600 BOPD flow rate with National Labs scientists, even though he met with them that same day. J. Dupree, P2 TT 691:10-15.

298. As noted above, in mid-May, BP's Trevor Hill made a visual estimate of flow of 20,000-25,000 BOPD, which he later revised downward to 15,000-20,000 BOPD. Hill testified that he communicated his estimates to BP's Paul Tooms, but not to government officials, National Labs scientists, or FRTG members. Depo. of T. Hill, 396:6-22, 396:24, 425:9-18. Hill also did not provide Government officials with his estimates of up to 65,171 BOPD that he and Tim Lockett generated in order to "bound the answers on flowrate." *Id*. at 470:2-6, 470:8-10; *see also* TREX-5063. Nor did Hill provide Tim Lockett's "best estimate" tables with flow rates of up to 37,704 BOPD to the Government. Depo. of T. Hill, 483:7-11; *see also* TREX-9446.

299. In mid-May 2010, BP's Hill suggested in writing to BP's Tooms that the Government's FRTG should have access to all "information and insights available to BP," which would in turn benefit BP by ensuring accurate flow rate estimates and valuable design information for the dynamic well kill and collection options. Depo. of T. Hill, 428:6-25, 430:2-11, 430:13-21, 430:23-431:4, 433:21-434:5; TREX-11186. Hill requested permission to release additional video clips and to offer his support to the FRTG. But Hill received no response to his suggestions and ultimately did not carry out this work. Depo. of T. Hill, 273:7-25, 274:2-15, 434:6-14, 434:17-435:2, 435:4-19, 435:22-436:6, 436:10-20, 436:23-438:17, 438:20-439:1, 439:3-8, 439:10-21, 439:23-440:1. Hill also offered to act as BP's contact with the FRTG. BP instead assigned BP executive David Rainey as the BP contact, although Hill had much more

experience regarding fluid flow than Rainey (a geologist). Depo. of T. Hill, 289:19-290:13, 290:15-16, 290:18-22, 290:25-291:7, 291:10-12, 291:15.

XIV. Government Officials And Scientists Relied On BP For Flow Rate Information.

A. Government Officials And Scientists Did Not Have Access To The Same Amount Or Type Of Information That BP Had.

300. The Government relied on BP for internal proprietary data about the well. Depo. of M. Landry, 573:2-4, 573:6. The Government did not have access to BP's internal proprietary well data as of April 28, 2010 or as of May 10, 2010, the date of Suttles' letter to Admiral Landry. TREX-9155; Depo. of M. Landry, 572:7-19, 579:12-580:13, 580:15-581:9. Unified Command did not have information regarding the well permeability, gas-oil ratio, viscosity, measured flowing pressure, skin, or other restrictions, unless and until it was provided by BP. *See id*. at 579:12-580:13, 580:15-581:9.

301. Secretary Chu testified that he and his Science Advisors also did not have access to BP's proprietary information in the mid-May timeframe. Secretary Chu and his team did not have access to fluid properties, permeability, viscosity, gas-oil ratio, rock compressibility, or amount of exposed reservoir. Depo. of S. Chu, 210:14-16, 210:18-211:11.

302. Lars Herbst testified that as of May 1, MMS did not know the production index for the Macondo well. Depo. of L. Herbst, 536:25-537:3. The MMS only had data from "offset wells"–*i.e*., different wells than Macondo; it did not have access to the reservoir characteristics for the MC 252 well, such as permeability and porosity. *Id*. at 537:4-538:3.

B. The Internal Flow Rate Analyses That BP Withheld From The Government Were Material Information For Source Control.

303. Admiral Landry expected BP to provide her with "every estimate or model that they had performed regarding how much oil is being emitted from the Macondo well." She testified that "as the Responsible Party, they should be providing me with all the information

they have." Depo. of M. Landry, 230:7-15, 511:14-17, 511:19 (Q: "Did BP have an obligation to provide the Coast Guard with any and all estimates it had regarding flow rate throughout the entire response effort?" A: "Yes."). Landry believed BP had a "responsibility for . . . being forthcoming with whatever information they had and what was going on with the flow rate." Depo. of M. Landry, 80:8-19. The BP executives she looked to for information were Doug Suttles, David Rainey, and Richard Lynch. *Id*. at 84:11-21.

304. Secretary of Energy Steven Chu's role was to analyze information and data and provide that analysis to decision-makers. Depo. of S. Chu, 186:6-10, 186:12. Secretary Chu viewed BP's internal analysis of the flow rate as being material to his work on source control. As he testified, "having an accurate flow rate number [would have been] important to providing accurate scientific support to the decision makers in source control strategies." *Id*. at 192:24-193:16. Secretary Chu also explained that if BP had had flow rates in the 40, 50, or 60,000 BOPD range, he would consider that material information he did not receive. *Id*. at 205:21-25, 206:2-5, 206:7-19, 206:21-23.

305. Secretary Chu considered BP's own internal estimates of the flow rate particularly relevant to his analysis of the Top Kill operation. Secretary Chu testified: "I would have certainly have liked to [have] seen how they were estimating flows as it was relevant to well control such as top kill." Depo. of S. Chu, 212:21-213:1, 213:3-6.

306. Dr. McNutt testified she "absolutely" would have wanted to see Dr. Rygg's modeling for BP, and stated, "We systematically found that modeling was very helpful in decision-making throughout DEEPWATER HORIZON." Depo. of M. McNutt, 587:14-18, 587:22-588:5, 588:8-9.

307. Lars Herbst testified that if BP had permeability and porosity estimates for Macondo as of May 1, it would have been very helpful for that information to have been shared with him. Depo. of L. Herbst, 538:9-16. Herbst also expected BP to share any core sample data that it had with him. *Id*. at 538:17-22.

308. According to Dr. Tom Hunter of the Federal Science Team, flow rate data would have been "important information" for the source control intervention techniques. Depo. of T. Hunter, 567:10-16. Dr. Hunter testified that all data and information related to the spill should have been made readily available to the United States Government. *Id*. at 522:5-22.

309. Commander Richard Brannon of the U.S. Coast Guard expected that BP management would be transparent and forthright with flow rate modeling results. Depo. of R. Brannon, 108:1-4; 108:20-109:3; 109:8-23.

C. BP's Disclosure Of Certain Worst Case Discharge Estimates Did Not Ameliorate The Harm Caused By Its Failure To Share Numerous Flow Rate Estimates With The Government.

310. BP has argued that Government officials did not rely on the 5,000 BOPD estimate because BP shared certain worst-case discharge estimates with the Government. For the reasons explained below, the evidence does not support BP's argument.

311. Initially, BP's position does not account for the fact that when BP shared worst-case discharge information with the Government, BP discouraged the Government from viewing these worst-case estimates as realistic possibilities. For example, BP's May 10 letter to Admiral Landry stated that the 55,000 BOPD estimate was the "worst case," "represents a theoretical downside," and was based on assumed parameters that "would be extremely rare." TREX-9155 at 3. The MMS's Lars Herbst understood that when BP shared a high-end estimate of 40,000 BOPD, that was a worst-case discharge estimate and not a likely estimate of what the actual flow rate was at the time. Depo. of L. Herbst, 194:23-195:2, 195:5-9.

312. Moreover, the evidence described above establishes that Government officials like Admiral Landry and Secretary Chu expected BP to share all of its flow rate information and view the totality of BP's flow rate modeling as material. These Government officials did not testify that they were only looking to BP for its worst-case discharge estimates.

313. BP itself understood the significance of non-worst-case-scenario flow rate estimates to Government officials. As set forth above, BP included a "most likely model" in its May 10 letter to Admiral Landry, described its range of potential flow rates of 1,000 to 5,000 BOPD in its April 28 meeting with Admiral Landry, and repeatedly represented that 5,000 BOPD was its "best estimate" of the flow rate. BP proffered no testimony explaining why BP would repeatedly stand behind 5,000 BOPD if the only number that mattered was a worst-case scenario discharge estimate.

314. BP's position that only worst-case discharge estimates mattered for purposes of source control is belied by testimony of BP's own 30(b)(6) witness, Charles Holt. Mr. Holt claimed that in planning for the Top Kill, BP relied on a flow rate estimate of 5,000 BOPD – i.e., not the worst-case discharge estimate of the flow. Depo. of C. Holt, 481:4-7, 481:10-16, 481:18 ("Q. And what estimates was BP relying on [when BP engaged in the first dynamic kill]? What was the number? A. 5,000 barrels a day.").

315. The testimony of government witnesses shows that BP's position that only worst-case discharge estimates mattered confuses two separate issues. At deposition, Admiral Landry distinguished between two different components of oil spill response: (1) how the Coast Guard "prepare[d] for the volume of oil that could be emitted and reach shore," for which worst-case discharge estimates are important, (Depo. of M. Landry, 499:25-500:9), and (2) "source of spill" operations, for which accurate flow rate information is relevant. *Id*. at 503:19-23; *see id*. 489:14-

22 (distinguishing between "securing the source" and "the larger response"); *id*. at 167:17-168:17 (testifying that the "response effort to the oil spill" is "different from Source Control. It's different from the work of MMS oversighting Source Control."). Admiral Landry made clear that for source control operations – as distinguished from oil spill response operations – accurate flow rate information (not just worst-case discharge assumptions) is critical: "[y]ou want to know as accurate as possible the flow rate, in executing Source Control operations." *Id*. at 559:23-560:1, 560:3-5. Admiral Allen similarly testified that flow rate information was consequential "[a]s it relates to the pressure in the well, and the various procedures associated with capping[,] containment, and so forth, and the potential integrity of the wellbore itself." Depo. of T. Allen, 515:25-516:5.

D. Government Officials Did Not Rely On Early Government "Guesstimates" Or The Flow Rate Technical Group When They Approved BP's Recommendation To Proceed With The Top Kill.

316. BP's position that government officials did not rely on BP's repeated representations defending the 5,000 BOPD flow rate estimate because government employees made their own estimates of the flow rate does not find support in the record. As described above, BP—as the operator of the well—had, and knew it had, superior knowledge and access to information regarding the condition of the well, the BOP, the reservoir, and the Macondo fluid properties. BP was well aware that Government officials relied on BP for this type of proprietary information. Moreover, BP repeatedly stood by 5,000 BOPD throughout April and May 2010 and 5,000 BOPD remained the official estimate up through the beginning of the Top Kill.

317. BP relies on an April 26, 2010 email drafted by two NOAA scientists. The email, which has the subject line "Leakrate Guesstimate," states that the scientists looked at video of flow exiting what they estimated was a 2 foot diameter hole which they "figure[d]" was "coming

out … at about 1 foot per second." Based on some simple calculations, they came up with a flow rate of 64,426 BOPD, which they converted to 48,320 barrels per day. TREX-8895.

318. There is no evidence that any high-level government response official received this "Leakrate Guesstimate" at the time, or that it was given any credence. In fact, the evidence suggests just the opposite. Admiral Landry testified that she did not have knowledge during the response of any NOAA estimates assessing flow from the wellhead. Depo. of M. Landry, 81:23-82:6. More generally, during her tenure as Federal On Scene Coordinator, Admiral Landry did not look to NOAA to estimate the flow rate from the well because "[t]hat's not their expertise." *Id*. at 80:23-81:22; 226:1-9. Further, there is no contemporaneous evidence that BP officials believed BP did not need to share flow rate data on the theory that the Government had access to the information necessary to calculate flow rates.

319. Even if Admiral Landry had received this "Leakrate Guesstimate" generated by two employees at NOAA, BP subsequently represented to the Government on April 28, May 10, May 19, and May 24 that its best estimate of the flow was 5,000 BOPD (or even 2,500 BOPD in the case of the April 28 estimate). TREX-9628 at 1 (drawing by Landry at her deposition recalling Suttles's line from 1,000 to 5,000 BOPD with a line at 2500); TREX-9155 (May 10 Letter); TREX-3218 (May 19 Rainey Memo); TREX-1651 (May 24 Markey Response); Depo. of M. Landry, 192:8-193:1 (describing Landry's recollection of the April 28 estimate). Given BP's superior access to information and Admiral Landry's views about NOAA's expertise on flowrate estimation, it would have been reasonable in this situation for Admiral Landry to believe BP's representations of 5,000 BOPD over a "Leakrate Guesstimate" from NOAA.

320. BP has also referred the Court to two emails involving members of the FRTG as evidence that the Government did not rely on BP's flow rate representations.

321. Before describing the emails, it is useful to recount the history of the FRTG.

322. The FRTG was not chartered until May 19, 2010, just one week before the Top Kill began. Depo. of M. Sogge, 23:24-24:11. Prior to that, there is no evidence that there was a government agency or group charged with flow rate estimation or that any such government entity attempted to model flow rates in a systematic way. As noted above, when Admiral Landry announced 5,000 BOPD as the official estimate on April 28, she relied on BP's claim that 5,000 BOPD was its upper estimate of the flow rate.

323. The process of standing up the FRTG–which included both government and non-government employees in a variety of fields of expertise–took a period of at least several days. Dr. McNutt, for example, was not appointed to lead the FRTG until May 23, 2010–just three days before the Top Kill began. Depo. of M. McNutt, 138:19-139:6, 139:24-140:9.

324. After the FRTG teams were created, FRTG members faced difficulties obtaining the data that they needed from BP, which delayed their efforts to come up with a flow rate estimate. Dr. McNutt testified that the FRTG's flow rate estimation efforts were delayed "because we got very poor data from BP." *Id*. at 141:8-14; *see also id*. at 154:11-155:6, 223:8-10, 223:14-224:3. William Lehr, NOAA Senior Scientist and Head of the FRTG's Plume Team, testified that early on, the Plume Team did not receive "the quality of the video that the Team needed to do a proper PIV." Depo. of W. Lehr, 495:14-18. According to Lehr, the delay in getting quality video "definitely delayed the ability [of the Plume Team] to make the estimates." *Id*. at 495:19-22. The first official Plume Team estimate – generated on May 27, 2010, a day after the Top Kill began – "was delayed because [the team] didn't get the quality of video." *Id*. at 495:23-496:3, 496:5-14. Other Plume Team members thought that the video BP shared was "atrocious" and "pretty much useless." *Id*. at 496:21-497:4, 497:6-10, 497:12-17.

325. Additionally, the FRTG's Reservoir Modeling Team was unable to acquire BP's proprietary reservoir data without agreeing to complex nondisclosure provisions required by BP. As a result, the Reservoir Modeling Team was delayed in beginning their work and did not have a flow rate estimate until June 15, 2010. Depo. of M. McNutt, 305:8-19.

326. The FRTG did not announce its first flow rate estimate range until May 27, 2010, a day after the Top Kill began. In light of the limited data the FRTG had by that point, the FRTG was only able to release lower bound numbers of 12,000 to 19,000 BOPD. TREX-9655 (May 27 Press Conference).

327. In support of its position that government officials did not rely on BP's 5,000 BOPD representation, BP relies on two internal FRTG emails. The first is a May 23 email chain between Dr. Marcia McNutt and a member of the FRTG in which the FRTG member suggested that there was agreement on a range of 5,000 to 80,000 BOPD. TREX-8868. Second, BP relies on a May 25 email written by Dr. McNutt, in which she wrote: "[s]o for example, I don't have the exact numbers yet, but we might say something like, 'Multiple lines of scientific evidence agree that the rate of release is at least 14,000 to 20,000 barrels of oil per day.'" TREX-9652.

328. There is no evidence that either email was shared with government officials who were reviewing BP's Top Kill effort, much less that these government officials relied upon these to the exclusion of BP's flow rate representations. The evidence, rather, is to the contrary.

329. The significance of flow rates to the Top Kill—which began just 1 to 3 days after these emails were written—was intentionally misstated to the FRTG. BP represented to Dr. McNutt, the head of the FRTG, in the lead-up to the Top Kill, that the Top Kill's likelihood of success did not depend on the flow rate. Depo. of M. McNutt, 412:20-413:1, 413:3-7, 413:11, 417:6-12, 417:15.

330. Both emails pre-date the FRTG's first public announcement of a flow rate range and were drafted while the FRTG was still in its infancy–*i.e.*, less than a week after the FRTG was chartered. The emails are preliminary discussions, and the FRTG did not adopt the flow rate ranges as its estimates. Dr. McNutt testified at deposition that it was not until May 25–just one day before the Top Kill began–that the FRTG began to have comfort in the lower bound range that it announced on May 27. Depo. of M. McNutt, 415:9-11, 415:14-416:5.

331. The May 23 email relied upon by BP indicates that in order to narrow the potential flow rate ranges, the FRTG was in need of information in the possession of BP. TREX-8868.0002 ("With better information, information that is available to BP, we believe that we can significantly reduce this range."). That is consistent with the evidence, described above, that the FRTG's ability to expeditiously generate flow rate ranges depended on information from BP that BP did not provide in a timely manner.

332. Even if the FRTG had distributed these preliminary discussions to government officials, there is no evidence that they would have reversed the perception created by BP's repeated representations to the Government that the flow rate was 5,000 BOPD–and there is little reason to believe that they would have had such an effect. In this respect, it is notable that on May 23, BP's David Rainey told Dr. McNutt that BP's best estimate of the flow rate was still 5,000 BOPD. Depo. of M. McNutt, 434:3-13. Just a day before, BP's Doug Suttles told the public during an interview on NPR that BP did not "think the rate's anywhere near that high" when asked to assume that the flow rate was 30,000 BOPD. TREX-11900.0033.

XV. BP Misrepresented The Top Kill's Chances Of Success.

333. On May 16, 2010, BP met with Government officials and recommended attempting the "Top Kill," a source control operation that involved pumping mud (the "momentum kill") into the flowing well and injecting junk (the "junk shot") into the *Deepwater*

Horizon BOP to attempt to stop the flow of the well. The Government approved BP's recommendation, and on May 26-28, 2010, BP attempted the Top Kill six times. All six attempts failed. Before attempting the Top Kill, BP knew that the momentum kill could not succeed at a flow rate of 15,000 BOPD or greater and that the junk shot was very unlikely to succeed. Nevertheless, BP told the Government that the Top Kill was a "slam dunk" and had a 60-80% chance of success. BP also failed to inform Government officials at Unified Command and National Incident Command—the officials approving the operation—that the momentum kill could not succeed at a flow rate of 15,000 BOPD or greater. To those whom this was disclosed, it had little impact. Because BP misrepresented the flow rate as 5,000 BOPD, warnings of failure at 15,000 BOPD did not create alarm. BP's omissions and misrepresentations corrupted the source control decision-making process before, during and after the implementation of Top Kill.

A. **<u>BP Recommended The Top Kill Procedure On May 16, 2010 And Attempted It Unsuccessfully On May 26-28, 2010.</u>**

334. The Top Kill operation was an effort to stop the flow of hydrocarbons from the Macondo well in May 2010. The operation combined two strategies. First, the "momentum kill" (sometimes referred to as "dynamic kill")—a procedure by which drilling fluid (or "mud") was pumped from vessels on the ocean surface down through the choke and kill lines of the *Deepwater Horizon* BOP in an attempt to overcome the flow of hydrocarbons. Rec. Doc. 7076, ¶77-78 (2:10-md-02179-CJB-SS) (Agreed Stipulations). Robert Grace, a well control consultant who worked for BP during the response, explains in his Blowout and Well Control Handbook, that "the momentum kill is a procedure where two fluids collide, and the one with the greater momentum wins. If the greater momentum belongs to the fluid from the blowout, the blowout continues. If the greater momentum belongs to the kill fluid, the well is controlled." TREX-

21176.0269 (Robert Grace, Blowout and Well Control Handbook); Depo. of C. Holt, 170:4-10 (Grace was a well control consultant for BP).

335. The second component of Top Kill was the "junk shot," an operation that involved pumping bridging material, or "junk," such as balls, rubber, or rope, from a vessel on the surface into the *Deepwater Horizon* BOP through its choke and kill lines. The hope was that these objects would plug or partially clog the leaks in the BOP or the riser, thereby reducing the flow rate to a level where the momentum kill could succeed. Rec. Doc. 7076 (2:10-md-02179-CJB-SS) (Agreed Stipulations-Definition of "JUNK SHOT"); G. Perkin, P2 TT 197:6-20; J. Dupree, P2 TT 615:18-617:5.

336. On May 16, 2010, BP held a "*Deepwater Horizon* Review" meeting with Government officials including Secretaries Salazar and Chu, Admiral Allen, and Tom Hunter. At that meeting, BP recommended that BP proceed with the Top Kill operation. TREX-142819N at 3-4 (BP's "Recommendation" was to perform "a Dynamic/Momentum Kill"); J. Dupree, P2 TT 618:25-620:4; Depo. of C. Holt, 72:10-14, 73:5-10, 73:12-15, 323:19-24 (BP recommended the Top Kill to Unified Command). The Government approved BP's recommendation. Depo. of C. Holt, 73:16-19.

337. BP attempted the Top Kill six times between May 26 and May 28, 2010. The first two Top Kill attempts consisted of the momentum kill alone; the other four attempts involved both the momentum kill and the junk shot. All six attempts failed. Rec. Doc. 7076, ¶77-82 (2:10-md-02179-CJB-SS) (Agreed Stipulations; describing the six failed Top Kill attempts); *see also* Depo. of A. Hayward, 264:1-19.

B. <u>The Top Kill's Chance Of Success Was Dependent On The Flow Rate From The Well.</u>

338. The Top Kill's success was dependent upon flow rate. The momentum kill portion is flow rate sensitive by definition. For the momentum kill to succeed, the momentum of the fluid pumped into the well must exceed the momentum of the fluid coming out of the well. TREX-21176.0269 (Robert Grace's Blowout and Well Control Handbook). Because the momentum of each fluid is defined by the density of the fluid and the flow rate, the momentum kill's chance of success depended on the flow rate from the well; if the flow rate was greater than the momentum of the fluid pumped in, momentum kill would fail. J. Wilson, P2 TT 82:10-24, 124:23-125:8; J. Dupree, P2 TT 653:2-7; I. Adams, P2 TT 1097:14-1099:24.

339. The junk shot was also affected by the flow rate. The junk shot worked by pumping "junk" into the well in the hope that it would adhere to the openings, decreasing the orifice size and thereby the flow rate. *See* M. Mazzella, P2 TT 806:18-807:2 (bridging material "slows the flow, stems the flow, and enables you to do a Momentum Kill"). If the flow rate was so high that it expelled the junk before it could adhere to the openings, or if the junk could not sufficiently reduce the level of the flow, Top Kill would fail. I. Adams, P2 TT 1101:14-1102:3; J. Wilson, P2 TT 125:9-15, 171:14-22, 172:24-173:20, 175:5-17; Depo. of S. Chu, 307:4-7, 307:9-22 (both the momentum kill and the junk shot "are dependent on flow rate" and the junk shot's chances "would certainly depend on the flow" because "the idea of junk shot was it would—if there were large holes, if you will, or orifices where a lot of the oil would be coming out, that the junk shot would partially clog those orifices, slow down at least temporarily the amount of oil coming out that would help in the dynamic kill").

340. BP submitted a junk shot procedure for Government approval that expressly used BP's false "best estimate" flow rate assumption of 5,000 BOPD to estimate an effective orifice

size of "0.4-in to 0.64-in." TREX-9148.0005 ("Current BOP analysis (pressure and ram location) suggests that Blind Shear Rams and/or the Casing Shear Rams are closed, but passing with a leak area of 0.4-in to 0.64-in equivalent throat diameter (**based on 5,000-bpd total flow**)." (emphasis added)). That projected orifice size impacted the likelihood of Top Kill's success; a larger orifice size (meaning a higher flow rate) could negate the junk shot's ability to enable a successful momentum kill. *See* I. Adams, P2 TT 1122:3-9; Depo. of P. Campbell, 7/12/2011, 368:15-369:10.

341. BP knew that Top Kill's success was dependent upon flow rate. As BP flow assurance engineer, Tim Lockett, testified: "I formed the view in May 2010 that Top Kill could be deployed and be either successful in killing the well or not successful in killing the well, depending on the flow rate from the well." Depo. of T. Lockett, 404:15-16, 404:18-22. Prior to the Top Kill attempts, James Dupree stated that "the kill could struggle if rates are significantly higher than the current estimates [of 5,000 BOPD]." TREX-140914.0002. BP contractors also recognized that the flow rate was critical to the Top Kill's chances of success. Depo. of D. Barnett, 35:6-11 ("Q. All right. So, in other words, to-to plan for a top kill, a momentum kill, you have to put in some factor for flow rate? You have to have some information concerning flow rate, correct? A. Yes, you do."); Depo. of R. Vargo, 8/22/2012, 54:19-55:3 (agreeing that flow rate was important when planning for Top Kill in determining how to successfully do this or if it can even be successfully done).

C. <u>BP Learned On May 16 That The Momentum Kill Could Not Succeed At A Flow Rate Of 15,000 BOPD Or Higher.</u>

342. Ole Rygg, a principal at Add Energy who worked as a BP consultant, conducted modeling to determine the conditions under which the momentum kill could succeed. Depo. of C. Holt, 161:24-25, 162:2-5, 162:7-11; A. Ballard, P2 TT 994:4-8.

343. On May 16, 2010—the same day that BP recommended the Top Kill to the Government—Dr. Rygg reported to BP that the momentum kill could not succeed as planned if the flow rate from the well was 15,000 BOPD or higher. TREX-8537 (May 16 email and presentation from Ole Rygg); Depo. of O. Rygg, 203:10-24; 205:14-206:11, 261:24-262:13; 264:18-265:10, 265:17-24; 273:3-9; *see also* Depo. of C. Holt, 179:25-180:11 ("The modeling that had been done said that with the limitation of 50 barrels per minute and a flow rate of 50,000—15,000 barrels or more, that the dynamic kill would not be successful."); I. Adams P2 Expert Report, TREX-11737R.0008 ("Modelling (*sic*) was undertaken during the response that indicated if the responders could pump 50 barrels per minute of mud into the *Deepwater Horizon*'s BOP, such a momentum kill could successfully kill the well if it was flowing at 5,000 barrels per day, but not if it was flowing at 15,000 barrels per day."); TREX-9245.0002 (Summary Points from the Kill the Well on Paper Discussion, 18 May 2010: "Modeling indicates that a dynamic kill cannot be successfully executed if the oil flow rate is 15000 STBpd."); J. Wilson, P2 TT 101:2-8.

344. Wild Well Control also performed modeling to assess Top Kill, which—just like Dr. Rygg's modeling—showed a 15,000 BOPD limit on the momentum kill. Depo. of C. Holt, 468:16-22, 468:25-469:3, 469:5-16, 469:19-25, 470:2-8 (testimony of BP's corporate representative regarding Top Kill modeling that Wild Well Control's model also showed that BP's dynamic kill could not succeed at a 15,000 barrel per day flow rate).

345. No other modeling, witness, or evidence contradicts the conclusion that the momentum kill could not succeed at flow rates of 15,000 BOPD or more, and Dr. Rygg's modeling was the only flow rate modeling that BP ultimately used in conjunction with the Top Kill. Depo. of C. Holt, 315:14-18, 315:20-316:6 (testimony of BP's corporate representative

regarding Top Kill modeling that the Add Energy modeling was the only flow rate model BP used with regard to the Top Kill); I. Adams, P2 TT 1100:19-22 ("Q. You [didn't] do any modeling of your own to show that momentum kill could succeed when the well was flowing 15,000 or more, [did] you? A. No."); *Id*. at 1101:4-6 ("Q. Your report doesn't claim that a momentum kill could work if the well is flowing above 23,000 barrels a day, does it? A. No, it doesn't."); J. Wilson, P2 TT 81:24-82:9; D-25019 (Wilson Opinion: "BP knew or should have known from its modeling efforts that the top kill was very likely to fail because the well flow rate exceeded a 15,000 BOPD threshold rate.").

346. As discussed above, in the weeks prior to the Top Kill, BP generated numerous internal flow rate estimates that exceeded 15,000 BOPD. In fact, BP knew from its internal modeling that the well could be flowing at over 100,000 BOPD—approximately 7 times higher than the 15,000 BOPD limit on the momentum kill. *See supra* Section XIII. Because BP knew that the flow rate very likely exceeded 15,000 BOPD, Dr. Rygg's conclusion that the momentum kill could not succeed at a flow rate over 15,000 BOPD revealed to BP that the Top Kill was doomed to failure. J. Wilson, P2 TT 81:24-82:9; J. Wilson P2 Expert Report, TREX-11900.0035 ("BP knew or should have known from its modeling efforts that the Top Kill was very likely to fail because the well flow rate exceeded a 15,000 barrel oil per day threshold rate."). BP told the Government the opposite. *See infra* at XV.F.

347. Consistent with what BP knew prior to the Top Kill, when BP's Tom Knox looked back at the Top Kill data in July 2010, he wrote to his BP colleague Trevor Hill, "I have convinced myself that it was always doomed to failure" because "I don't think we could get enough mud into the well to kill it." TREX-9532.

D. <u>BP Knew The Junk Shot Was Unlikely To Succeed.</u>

348. BP also knew that the junk shot was unlikely to succeed. On May 7, 2010, a Peer Assist Team assembled by BP and comprised of well control specialists, industry experts, petroleum engineering academics, and BP source control leaders met to analyze the potential success of the junk shot portion of Top Kill. These experts agreed that: "[j]unk shots are often not successful." TREX-10506.0004 (Peer Assist Report); TREX-3917.0001-.0002 (Peer Assist Participants); M. Mazzella, P2 TT 787:6-23, 790:16-791:8 (identifying experts on team); *Id*. at 793:25-794:6 (confirming that this was one of the team's "nearly unanimous top 10 findings."); G. Perkin, P2 TT 199:18-25 (Peer Assist team concluded that "junk shots are not often successful"). This conclusion was one of the Peer Assist Team's "nearly unanimous" "Top Ten Findings" regarding the junk shot. TREX-10506.0003-.0004 (Peer Assist Report). BP's James Dupree and Mark Mazzella, BP's Segment Engineering Technical Authority for Well Control, were members of the Peer Assist Team that made this finding. Mazzella confirmed that "the consensus" of the three groups that participated in the Peer Assist was "that these findings were unanimous." M. Mazzella, P2 TT 793:13-18. Mazzella also confirmed that the Peer Assist team members had experience working on "hundreds of wells . . . where Junk Shots were attempted." *Id*. at 794:7-14. Thus, by May 7, 2010, BP knew that the expert consensus was that junk shots are often not successful. TREX-10506.0004; Depo. of C. Holt, 145:8-16.

349. Pat Campbell, the President of Wild Well Control and a participant on the Peer Assist Team, agreed. Mr. Campbell testified that none of the people on the Peer Assist Team—outside of the BP employees—thought the junk shot was "a good idea," and, if it had been up to him, he would not have attempted the junk shot. Depo. of P. Campbell, 7/12/2011, 290:21-291:14, 367:25-368:14; *see also id.* at 136:19-25 (Campbell did not choose the junk shot and did not think it had much chance of working). As Mr. Campbell explained: the "very generous

flow path" through the BOP and the observations of what was "being expelled" out of the BOP suggested that BP could not significantly impede the flow by pumping junk through the 3-inch internal diameter choke and kill lines. *Id*. at 368:15-369:2; *see also* G. Perkin, P2 TT 197:11-198:4, 201:22-202:11 (because the choke and kill lines had an internal diameter of only three inches, BP was "restricted to shooting small objects . . . in an attempt to try to stop up a large flow path"). According to Mr. Campbell, "the flow path was likely too large for the junk shot to work." Depo. of P. Campbell, 7/13/2011, 11:18-12:12.

350. Although a junk shot had never been performed in deepwater, BP did not perform any modeling supporting the junk shot's probability of success. Depo. of C. Holt, 145:17-19, 145:23-146:4, 147:3-5, 145:7-8, 343:9-16, 343:19-24; Depo. of O. Rygg, 208:1-3; J. Dupree, P2 TT 712:8-20; J. Wilson, P2 TT 124:15-19, 173:6-20. BP therefore had no junk shot modeling that provided any basis for BP to claim that the Top Kill was a "slam dunk" or had a high percentage likelihood of success.

E. <u>BP Knew That The Combination Of The Momentum Kill And The Junk Shot Was Very Unlikely To Succeed.</u>

351. In addition to BP's knowledge that the individual components were likely to fail, BP knew that the Top Kill operation as a whole was unlikely to succeed. Prior to the Top Kill, Wild Well Control – which BP had hired to provide source control expertise – advised BP that the junk shot in combination with the momentum kill "had a very low likelihood of success." Depo. of P. Campbell, 7/13/2011, 11:18-12:12; Depo. of D. Barnett, 25:4-7 (Wild Well was involved in a number of the source control efforts at Macondo). Wild Well Control's David Barnett, whose "major area[] of involvement" in the response "was the planning and implementation of the kill operations," including the Top Kill, recalled that "we expressed our lack of confidence that the top kill would be successful." *Id*. at 25:12-20, 105:4-12.

F. <u>BP Falsely Told The Government And The Public That The Top Kill Was A "Slam Dunk" And Had A 60-80% Likelihood Of Success.</u>

352. Despite knowing that Top Kill was very unlikely to succeed, BP told the Government and the public that its chances of success were high. BP told Secretary Chu that the Top Kill was a "slam dunk," that BP was "confident that it was going to work," and that BP had the capability to "overwhelm" the flow that was coming up from the well. Depo. of S. Chu, 206:2-5, 206:7-13, 308:9-11, 308:13-16.

353. Similarly, BP represented to Secretary Salazar that the Top Kill had an 80% probability of success. TREX-11317.0001 ("BP probability of success-80 percent on result and schedule."); *see also* TREX-10742.0005 (May 30 email observing that BP engineers had "predicted such a high chance of success with the top-kill").

354. BP also assured the public that the Top Kill was likely to succeed. BP CEO Tony Hayward told reporters: "[w]e rate the probability of success between 60 and 70 percent." TREX-150307N. A BP talking points memo generated after Top Kill failed acknowledges that BP represented before Top Kill occurred that "there was a 60-70% chance of the top kill working." TREX-10532 at 2 (May 29 talking points Q&A).

355. BP's claims about Top Kill's likelihood of success had no basis and were contradicted by what BP knew. G. Perkin, P2 TT 205:8-11, 206:5-7, 207:5-9; J. Wilson, P2 TT 128:1-10; *see also supra* Section XV.B-E (Top Kill likely to fail; Junk Shot likely to fail, momentum kill certain to fail at flow rates of 15,000 BOPD and above). Charles Holt, testifying on behalf of BP, admitted that he had not seen any analysis that predicted the Top Kill had a 70% chance of success and did not "recall probabilities being assigned to this." Depo. of C. Holt, 457:8-14. James Dupree, who oversaw BP's source control operations, also could not explain or defend BP's representations regarding the Top Kill's likelihood of success. Mr. Dupree testified

that nobody ever asked him to estimate the Top Kill's chance of success, and as far as he was aware, "we never calculated [a] chance of success." J. Dupree, P2 TT 722:25-723:13. He testified that he "certainly wouldn't have represented" the Top Kill's likelihood of success as 60-70%. *Id*. at 712:21-713:3. Similarly, BP's Mark Patteson, BP's Wells Manager for North America and the Top Kill team leader, testified that he had never asked for or seen any probability analysis for the Top Kill. He had "no idea" what the 60-70% probability estimate was based on. Depo. of M. Patteson, 1/24/2013, 264:3-13.

G. <u>BP Did Not Disclose The 15,000 BOPD Limit To Key Government Officials Who Had To Sign Off On The Top Kill.</u>

356. In addition to lying to the Government about Top Kill's likelihood of success, BP failed to tell Government decision-makers that the momentum kill would fail at flow rates of 15,000 BOPD and above. Key Government decision-makers–including Unified Commander Admiral Mary Landry, National Incident Commander Rear Admiral Thad Allen, Secretary of Energy Steven Chu, MMS Regional Director Lars Herbst, FRTG Leader Dr. Marcia McNutt, and National Incident Command Representative at the Houston Incident Command Post Admiral Kevin Cook–testified that they were never informed of the 15,000 BOPD limit. Depo. of M. Landry, 446:24-447:2, 447:4, 493:23-494:3, 708:12-17, 708:9, 708:2-17; Depo. of T. Allen, 52:17-53:11, 517:6-16, 517:19-518:6; Depo. of S. Chu, 303:25-304:6, 304:8-17, 306:20-25, 307:2-3; Depo. of L. Herbst, 440:20-23, 441:17-21, 444:25-445:5; Depo. of M. McNutt, 195:18-20, 195:24-196:3, 412:20-413:1, 413:3-7, 413:11-13, 413:24-414:6, 414:8-10, 414:12-24, 417:6-12, 417:15, 419:17-420:2, 420:5, 422:23-423:4, 423:7-10, 423:12-20; Depo. of K. Cook, 470:10-12, 470:16-471:1, 471:5, 473:15-474:12, 553:21-554:2, 555:1-15, 555:7-8, 560:23-561:10, 561:12.

357. Far from informing these Government officials that there was a flow rate at which the momentum kill could not succeed, Secretary Chu testified that BP "tried to argue, compellingly, that it would work." Depo. of S. Chu, 303:25-304:6, 304:8-17, 306:20-25, 307:2-3. Likewise, Dr. McNutt testified at her deposition that the 15,000 BOPD limit was the "exact opposite" of what BP had told her about the Top Kill not being dependent on flow rate. Depo. of M. McNutt, 195:18-20, 195:24-196:3, 412:20-413:1, 413:3-7, 413:11-13, 413:24-414:6, 414:8-10, 414:12-24, 417:6-12, 417:15, 419:17-420:2, 420:5, 422:23-423:4, 423:7-10, 423:12-20; TREX-8553 at 1; *see also* J. Wilson, P2 TT 176:15-177:2.

358. BP, testifying through its corporate representative Charles Holt, admitted that "BP had a responsibility to inform Admiral Allen," and "BP also had a responsibility to inform Admiral Landry" of the 15,000 BOPD limit. Depo. of C. Holt, 174:14-16, 174:19-23, 174:25. Because BP failed to carry out this responsibility, Government officials who were involved in deciding whether to approve the Top Kill and signing off on the Top Kill procedures were unaware of the 15,000 BOPD limit. TREX-8983 at 1 (Momentum Kill Pumping procedure signed by Landry and Herbst); TREX-9148.0001 (Junk Shot procedure signed by Landry); TREX-9149 at 1 (Momentum Kill Cementing procedure signed by Herbst); J. Wilson, P2 TT 169:13-22, 176:15-177:2.

H. <u>The 15,000 BOPD Limit On The Momentum Kill Was Relevant To Source Control, And Government Decision-Makers Testified That It Should Have Been Disclosed To Them.</u>

359. The Government officials who BP failed to inform of the 15,000 BOPD limit on the momentum kill agreed that it was important information that mattered to source control and should have been disclosed to them by BP.

360. Mr. Herbst explained that BP informing him about the 15,000 BOPD limit would have been "very helpful" to him in deciding whether to sign off on the Top Kill procedure. Depo. of L. Herbst, 441:17-25, 442:2-5.

361. Dr. McNutt similarly testified that it "would have been helpful" if BP had told the Government about the 15,000 BOPD limit. Depo. of M. McNutt, 414:18-24, 415:2-5, 415:8.

362. Likewise, Admiral Landry testified that she would have expected BP to share the 15,000 BOPD limit with her personally because she "would want to know all the details [she] could, going into Source Control" in order to manage the risks, prevent a subsea blowout, and choose the method most likely to succeed. Depo. of M. Landry, 493:23-494:3, 558:25-559:5, 559:7-21.

363. When asked whether BP should have told him about the 15,000 BOPD limit, Admiral Allen explained that he wanted "to have as much information as possible" and if he had learned of the 15,000 BOPD limit, he would have looked at it and asked for an explanation to better understand it. Depo. of T. Allen, 53:2-14, 53:16-54:2, 54:5-7.

364. Similarly, Admiral Cook testified that his "goal at every juncture" was "to try and bring out the best information," and if BP had brought the 15,000 BOPD limit to his attention, he would have made sure "it was included in the analysis," "vetted properly," and "considered in the final decision" of whether to perform the Top Kill instead of the BOP-on-BOP. Depo. of K. Cook, 561:20-24, 562:2-7, 568:21-23, 569:2-17, 569:19, 569:21, 569:23-24, 570:1-7. If BP had told him of the 15,000 BOPD limit, "it would have been honestly evaluated" as part of his decision on whether to approve the Top Kill procedure. *Id.* at 561:13-16, 561:18-19.

I. <u>When BP Shared The 15,000 BOPD Limit With Government Scientists, It Did Not Disclose That Its Internal Flow Rates Greatly Exceeded 15,000 BOPD.</u>

365. Although BP shared the 15,000 BOPD limit with certain lower level Government scientists in a meeting known as the Kill The Well On Paper Discussion, BP did not disclose at that meeting that BP had estimated flow rates far in excess of 15,000 BOPD. TREX-9245 (meeting summary notes, which do not mention BP's internal flow rate estimates above 15,000 BOPD); Depo. of O. Rygg, 210:8-17, 210:19-211:2, 211:4, 271:9-16 (Dr. Rygg did not recall any discussion at the Kill the Well on Paper meeting that BP had internal flow rate estimates greater than 15,000 BOPD). Without information regarding estimated flow rates over 15,000 BOPD, BP's disclosure of the 15,000 BOPD limit to the Government scientist was meaningless.

366. In fact, in light of BP's claims that 5,000 BOPD was its best estimate of the flow rate, when BP disclosed the 15,000 BOPD limit during the Kill The Well On Paper Discussion, it gave the false and misleading impression that the Top Kill was likely to succeed. According to the written summary of that discussion, BP told meeting participants that while the dynamic kill could not succeed at a flow rate of 15,000 BOPD, "[m]odeling indicates that a . . . dynamic kill can be achieved for a well flowing oil at a rate of 5000 STBpd if the pressure in most of the flowing wellbore is above the bubble point." TREX-9245.0002.

J. <u>BP Compounded Its Misrepresentations About Flow Rate By Misrepresenting The Impact Of A Large Pressure Drop On the Likely Success Of Top Kill.</u>

367. During the response efforts, BP collected wellhead pressure readings from a gauge at the bottom of the BOP. J. Dupree, P2 TT 648:13-19. As of May 8, 2010, BP measured the pressure at the base of the BOP to be 3,800 psi. On May 15, BP measured the pressure at the base of the BOP to be 3,100 psi, a 700 psi drop in the measured pressure. TREX-144843.0010 (BP presentation noting "decrease of 700 psi in one week); TREX-9315 (BP graph showing

measured pressure drop); J. Wilson P2 Expert Report, TREX-11900.0010 ("As of at least May 8, a wellhead pressure measurement of approximately 3,800 psi was available to the BP engineers from a PT-B pressure gauge at the base of the BOP.").

368. BP knew that this pressure drop could indicate an increased flow rate from the well and a reduction in the restrictions that had been creating back-pressure at the wellhead. TREX-9313.0003 (hydraulic depletion modeling report); *see also* A. Ballard, P2 TT 970:23-971:15; TREX-9310 at 3 (BP Technical Note showing that production rate required to achieve measured pressure drop was ~87,000 BOPD). BP's James Dupree admitted at trial that he had received an internal BP report, which had explained the pressure drop based on a high flow rate, and had informed him "that to have a 700 psi depletion, it would take a flow rate of 86,600 barrels per day." J. Dupree, P2 TT 690:15-691:4, 692:2-8; TREX-9313.0001. (BP report on pressure drop)

369. BP also knew that if the measured pressure drop signified an increased flow rate and a reduction in the restrictions, there would be "less chance of ever being able to do a dynamic top kill, since the required rate through the stack to achieve the required pressure drop is to[o] high." TREX-9250.0002; TREX-130491.0001 (May 16 emails from Ole Rygg); *see also* I. Adams, P2 TT 1122:7-1123:1 (agreeing that the momentum kill's likelihood of success would decrease and the junk shot would not work "if the hole eroded to the extent it was so large that you couldn't bridge that with the junk you could pump down the line"). Thus, BP understood that the 700 psi measured pressure drop could mean that the Top Kill was less likely than ever to succeed. *See* TREX-9250.0002 (May 17 email from BP hydraulic modeler Tim Lockett stating that when he first learned about the pressure drop, his "first thought" was "this is bad news," as he believed it indicated "reduced restriction within the BOP"); *Id.*; *see also* TREX-130491.0001

(May 16 emails from Dr. Rygg to BP explaining the possibility that "the reduction in the wellhead pressure is due to an increased flow rate since the restrictions at the wellhead is giving away [sic]."); I. Adams, P2 TT 1121:22-1122:6 (Rygg's statement meant that the pressure drop could indicate erosion had enlarged the size of the hole in the BOP and the flow rate had increased); J. Wilson, P2 TT 126:20-127:2 (Dr. Rygg's email is "suggesting that if the pressure drops, it's because there's less resistance to flow.").

370. When BP recommended the Top Kill to the Government on May 16, 2010, however, BP told the government the opposite. BP represented that as a result of the pressure drop, "[t]he likelihood of a successful dynamic or momentum kill increased significantly." TREX-144843.0010.

371. Mr. Dupree testified that BP presented the pressure drop as a positive development because "if the pressure at the base of the BOP is falling, it's an indication that the well is weakening. It's getting weaker and weaker. Therefore, the success – what we're saying here is the success of a mud kill starts [to] dramatically go up." J. Dupree, P2 TT 646:14-647:4. However, Mr. Dupree admitted that he did not inform the Government that he had learned that very same day—May 16—that the pressure drop might mean that the flow rate was as high as 86,600 BOPD. TREX-9313.0003 (hydraulic modeling report); J. Dupree, P2 TT 691:5-15, 692:5-12.

K. <u>BP's Misrepresentations And Omissions Regarding Flow Rates Materially Impacted The Government's Analysis Of The Top Kill.</u>

372. Knowing flow rate estimates is critical to effective source control decision-making. G. Perkin, P2 TT 196:7-16; Depo. of T. Allen, 514:16-18, 514:20-515:3, 515:7-516:5, 637:20-23, 637:25-638:13, 638:15-19 (developing "accurate and scientifically grounded flow rate information" was "vital," "fundamentally important," "relevant," and "consequential" to

source control, as flow rate "relates to the pressure in the well, and the various procedures associated with capping containment, and . . . the potential integrity of the wellbore itself"); Depo. of M. Mason, 51:18-52:2 (flow rate information "was an important aspect of how to – how we would kill the well"); TREX-8553 at 2 (Summary points from the Kill the Well on Paper Discussion: "Knowledge of the flow rate is needed to inform the probability of not succeeding with the dynamic well kill."); TREX-9239 (Rygg article: "In the analyzing phase, a well control simulator should actively be used to predict the current flow situation in the well including . . . rates.").

373. Government officials involved in source control would have liked BP to give to them BP's flow rate modeling and to have been afforded the opportunity to make source control decisions with complete information. Depo. of S. Chu, 186:6-10, 186:12-20, 186:22-187:4, 187:6-12, 187:14-16; Depo. of K. Cook, 568:16-20 ("Q. And wouldn't you expect, as the United States Government, that BP would be sharing with you their best information as it relates to the flow rate estimate? A. I would."); Depo. of R. Brannon, 109:8-23 (BP's flow rate modeling "would have been good to have" as it was relevant to "the closure of the well"); J. Wilson, P2 TT 169:23-170:10.

374. According to USGS Director Marcia McNutt, "an earlier accurate estimate of flow rate might have accelerated full containment." TREX-9673.

375. Secretary Chu agreed and testified that in hindsight, BP's actions did not create "the working relationship that would be the most effective in controlling the—the flow." Depo. of S. Chu, 198:8-23, 198:25-199:2, 224:20-21, 224:23-225:3. Secretary Chu explained that knowing about BP's internal flow rate estimates would have made a difference in the Government's analysis of the Top Kill. Secretary Chu testified that BP's internal estimates of

flow rate would have been "material" to his analysis of the Top Kill. *Id*. at 194:6-22, 194:24-196:2, 199:24-200:2, 200:4-9, 205:21-25; *see id*. at 212:21-213:1, 213:3-6 ("I would have certainly have liked to [have] seen how they were estimating flows as it was relevant to well control such as top kill."). If BP had internal estimates of flow rates in the 40,000-60,000 BOPD range, that would be "material information that [he] did not receive," and if BP had given him that information, he "would have had more discussions about the feasibility" of the Top Kill operation. *Id*. at 206:2-5, 206:7-19, 206:21-23. If BP had told Secretary Chu that flow rate was in the range of 40,000 barrels per day or greater, Secretary Chu would have given the Top Kill "a lot more thought and calculations," would have had "more discussion as to whether it would be advisable to go forward" with the Top Kill, and would have been less likely to advise pursuing the Top Kill. *Id*. at 204:2-9, 204:12-205:1, 205:4-20. If he had known BP's range of flow rate estimates, Secretary Chu might have recommended against the Top Kill. At a minimum, he would have had "much more serious discussions" about the Top Kill's probability of success. *Id*. at 230:18-22, 230:25-231:7, 231:10-21, 231:24-232:1.

376. Government witnesses repeatedly testified that accurate flow rate estimates were important for analyzing source control strategies. Depo. of T. Allen, 514:16-18, 514:20-515:3, 515:7-516:5, 635:25-636:4, 637:20-23, 637:25-638:13, 638:15-19; Depo. of R. Brannon, 109:8-23, Depo. of S. Chu, 186:6-10, 186:12-20, 186:22-187:4, 187:6-12, 187:14-17, 194:6-22, 194:24-196:2, 199:24-200:2, 200:4-9, 205:21-25; Depo. of T. Hunter, 107:24-108:5, 108:7-13, 566:14-17, 566:20-567:24; Depo. of M. Landry, 500:10-14, 500:16-17, 502:15-503:7, 503:9, 503:19-23, 504:7-20, 558:14-20, 558:22-559:5, 559:7-560:1, 560:3-5; Depo. of M. McNutt, 22:8-22, 23:2-12, 449:19-24, 450:1-2, 450:4-11, 512:16-21, 512:24-513:4.

L. <u>Because BP Executives Did Not Share Flow Rate Information–Even Within BP–BP Engineers Designed The Top Kill Based On The Flawed Assumption That The Flow Rate Was Only 5,000 BOPD.</u>

377. BP did not share accurate information about flow rate even within BP. *See supra* Section XIII.K. This policy of siloing and withholding flow rate information meant that many BP employees engaged in source control operations were not fully informed about BP's estimated flow rate ranges. As a result, the Top Kill was designed based on the flawed assumption that the flow rate was only 5,000 BOPD.

378. Mark Mazzella, BP's Segment Engineer Technical Authority for well control, led the Top Kill but BP management did not provide him with all of BP's internal flow rate modeling data. M. Mazzella, P2 TT 810:6-8. Thus, while he knew people were working on modeling the flow rate, he explained that "[w]hat those inputs and outputs looked like, I don't have any knowledge of." *Id*. at 810:23-811:6. No one told Mazzella what the modeled flow rate ranges were, how the modeling was done, or who was doing the modeling. *Id*. at 811:19-21.

379. BP also did not tell Mark Patteson, BP's designated "lead in the top kill effort," about important flow rate information, including the flow rate limit on the momentum kill. During the response, Patteson did not see the Kill the Well on Paper summary points, nor did he see Dr. Rygg's May 16 email to Mr. Mix concluding that the dynamic kill would fail at a flow rate of 15,000 BOPD. Depo. of M. Patteson, 1/23/2013, 144:8-11; Depo. of M. Patteson, 1/24/2013, 84:4-6, 84:11-18, 84:23-24, 91:12-18, 91:23, 91:25, 92:3, 92:5-7; TREX-11401 at 2, 8 (BP organizational chart showing Patteson as Top Kill lead). Patteson testified that if he had been told that the Top Kill would not work under certain conditions, and he was aware those conditions existed, he "would have suggested that we not attempt this." Depo. of M. Patteson, 1/23/2013, 308:23-309:2, 309:7-11.

380. BP, through its corporate representative Charles Holt, testified that when the Top Kill procedure was initiated on May 26, 2010, the flow rate "estimates that were agreed to by all parties at that time were a number on the order of 5,000 barrels a day" and that BP was "relying on" a 5,000 barrel a day estimate in implementing Top Kill. Depo. of C. Holt, 481:4-7, 481:10-16, 481:18, 485:17-20, 485:22-486:2, 486:4-5, 486:8-11.

381. The signed junk shot procedure also shows that the junk shot was designed based on a 5,000 BOPD flow rate estimate. TREX-9148.0005 (junk shot procedure stating that the flow path is "0.4-in to 0.64-in equivalent throat diameter (based on 5,000-bpd total flow")); *see also* Rec. Doc. 7076, ¶75 (2:10-md-02179-CJB-SS) (Agreed Stipulations); I. Adams, P2 TT 1107:6-23, 1108:15-1109:5.

382. Mr. Lockett, a BP flow assurance engineer who had cautioned against relying on the 5,000 BOPD estimate, testified that it would have been a mistake for BP to plan the Top Kill based on a 5,000 BOPD flow rate estimate. Mr. Lockett explained that BP's planning should have taken "a wider view of possible flow rates than one number, 5,000 barrels per day." If Mr. Lockett had known that BP was relying on a 5,000 BOPD estimate in planning for the Top Kill, he would have expressed the same concerns he articulated in the email in which he wrote that "[f]rom all the different ways we have looked at flowrate, 5 mbd would appear to err on the low side." Depo. of T. Lockett, 391:3-19, 391:21-392:1, 392:3-12, 393:3-7, 393:10-13; TREX-9250.0002.

XVI. BP Knew The Top Kill Was A Dangerous Operation That Could Make The Source Control Situation Worse.

383. BP contends that it conducted source control according to a "do no harm" or "don't make it worse" principle and elected to attempt the Top Kill because it was consistent with that principle. J. Dupree, P2 TT 596:25-597:25, 659:17-22, 730:2-6. But, before attempting the

Top Kill, BP knew that the Top Kill was a dangerous option that could make the situation worse. BP knew that the Top Kill could endanger human lives, damage vessels on the surface, increase the flow from the well, cause an underground blowout, and jeopardize the relief wells. BP attempted the hopeless Top Kill in spite of these critical risks.

A. <u>BP Knew That The Top Kill Was Dangerous And Could Negatively Impact Other Source Control Options.</u>

384. Before attempting Top Kill, BP knew that it was a dangerous operation that posed serious risks to the safety of the people involved. A document listing the "top 3 risks by procedure from HAZIDs of Top Kill Activities" shows that the Top Kill could result in "personnel injury or fatality" and "significant damage to the surface vessels." TREX-8533 at 1; *see also* TREX-142710N at 13 (BP presentation identifying "People, Pressure, SIMOPS" as one of the "Top Risks" of the Top Kill); TREX-10509 at 7 (BP's May 7 Source Control Update showing that the junk shot had been "reviewed with industry experts" and was "a high risk option" with "High" "Associated risks"); TREX-8541 at 4 (concluding that the Top Kill would be "very problematic" and the BOP-on-BOP should therefore "be prioritized" above the Top Kill). Depo. of R. Vargo, 8/22/2012, 59:10-21 (the "risk to people getting hurt . . . was definitely a top risk"); *id*. at 99:4-7, 99:9-16, 100:24-102:15, 102:17-103:16, 103:18-104:17, 104:19-22, 105:1-107:21, 107:25-108:6, 108:11-111:1, 111:3-5, 280:6-18 (Top Kill put at risk both people and the well).

385. BP also knew that the Top Kill operation posed risks to the integrity of the well and could result in a subsea broach or underground blowout. On May 7, 2010, a Peer Assist team comprised of well control specialists, industry experts, petroleum engineering academics, and BP source control leaders—including James Dupree and Mark Mazzella—reported its "nearly unanimous," "consensus" finding that if BP successfully plugged the well with the junk

shot, a subsea broach could result. TREX-10506.0004 (Top Ten Findings, finding #2, of Peer Assist Report); TREX-10506.0003 ("These Key findings are nearly unanimous messages delivered from the three groups of the Peer Assist Team"); M. Mazzella, P2 TT 792:18-793:18 (confirming that the Peer Assist report contains the "consensus" of the three groups involved in the Top Kill peer review); TREX-3917.0001-.0002 (Peer Assist Participants list); M. Mazzella, P2 TT 787:6-23, 790:16-791:8 (discussing expertise of Peer Assist team members). Consistent with that finding, the Peer Assist Report concluded that "significant risk is present," and one of the "potential regrets with the Junk Shot or kill operation" was to "lose containment through the casing," which could result in "underground flow." TREX-10506.0002; TREX-10506.0004; *see also* TREX-8532 at 1 (May 14 BP Technical Memo concluding that Top Kill posed a risk of rupturing the burst disks, exposing the formation to excessive pressure, fracturing the formation, and causing a broach to seabed); TREX-10507 at 4-5 (May 14 BP Top Kill Evaluation concluding that "the Junk Shot and Momentum Kill operations could jeopardize the overall integrity of the well system" and "result in additional flow volume or an underground blowout"; and showing that Top Kill's "High Level Risks" included "Compromise casing integrity," "Potential for underground blowout," and "Potential for seafloor broach"); TREX-9940.0003; TREX-9940.0012 (May 14 BP Top Kill presentation showing that rupturing the burst disks was a possible "Regret" of the Top Kill operation; and listing "Well Integrity Compromised" and "Broach to seabed" as "High Level Risks" of the Top Kill); TREX-142710N at 13 (May 23 BP presentation identifying "Broach at the Seabed" as one of the Top Kill's "Top Risks"); TREX-8533 at 1-2 (showing that Top Kill procedures could result in "failure of burst disks & fracturing formation" and "potential for underground blowout."); J. Dupree, P2 TT 715:2-6 (admitting that the junk shot threatened to burst the rupture disks in the well); I. Adams, P2 TT 1050:23-1051:19

(conceding that of the risks posed by the Top Kill, "the damage to well integrity was a very significant one, and the potential downsides were significant," because if the rupture disks had burst during the Top Kill, a subsea broach could have resulted).

386. BP also knew that the Top Kill could jeopardize the relief well operation. TREX-9940.0012 (May 14 BP Top Kill presentation listing "Jeopardizing Relief Well" among Top Kill's "High Level Risks"); TREX-142710N at 13 (May 23 BP presentation identifying "Impact Relief Well Success" as one of the "Top Risks" of the Top Kill); J. Dupree, P2 TT 715:2-6 (the junk shot threatened to impact the relief well). If the Top Kill had resulted in a subsea broach and there were multiple hydrocarbon outlet points, the potential success of the relief well would be compromised. TREX-10507 at 4 (Top Kill Evaluation observing that the "[f]ailure of critical well integrity components" as a result of the Top Kill "could jeopardize drilling of the relief wells"); J. Dupree, P2 TT 643:6-647:13 (explaining how a subsea broach with multiple outlet points would "really complicate[] the potential success of the relief well"); I. Adams, P2 TT 1055:2-24 (the Top Kill could jeopardize the relief wells by compromising well integrity).

387. BP also knew that the Top Kill posed a risk of eroding restrictions in the BOP or riser and thereby increasing the flow rate from the well. TREX-10506.0002 (May 7 Peer Assist Report identifying "Blow riser top – remove restriction/increase flow" as one of the "potential regrets with the Junk Shot or kill operation"); TREX-142710N at 13 (May 23 BP presentation identifying "Do Not Kill Well, More Oil Flowing" due to "Erosion/Kink" as one of the "Top Risks" of the Top Kill); TREX-8533 at 1-2 (document showing that Top Kill could result in "increased flow"); Depo. of C. Holt, 108:1-10 (removing restrictions and increasing flow was a risk); Depo. of R. Vargo, 8/22/2012, 50:8-10 (the Top Kill risked increasing the well flow). A May 14 BP presentation showed that even if only the momentum kill were pumped, a possible

"Regret" would be: "Erode orifice and flow increases." TREX-9940.0002-.0003; TREX-10508 at 4 (May 14 Top Kill Evaluation listing same risk). Likewise, the summary points from the Kill the Well on Paper discussion concluded, "The dynamic kill operation is likely to put solids-laden fluid at a substantial rate through the BOP stack and riser, which may erode restrictions." TREX-8553 at 1. The junk shot also posed a risk of dramatically increasing the flow rate. As shown in BP's May 7 Source Control Update, the junk shot posed a "Major Risk" of creating "unrestricted flow." TREX-10509 at 7.

B. BP's Misrepresentations To Its Contractors, Including Transocean And HESI, Needlessly Placed People In Harm's Way.

388. The Top Kill operation posed numerous risks, including the risk of increasing flow from the well by eroding the kink in the riser, of compromising casing integrity, of fracturing the formation by rupturing the burst disks and of causing serious physical injuries to the many workers tasked with performing the Top Kill. Depo of R. Vargo, 8/22/2012, 50:1-7, 51:2-52:25, 55:4-11, 59:1-18.

389. Because of the numerous and serious risks associated with the Top Kill, these risks should have been accepted only if the operation had a good probability of being successful. Depo. of R. Vargo, 8/22/2012, 90:9-15. BP knew that the Top Kill was all risk, no reward in light of its awareness that the flow rate was greater than 15,000 BOPD and that the dynamic kill would not be successful if the flow rate was greater than 15,000 BOPD. Depo. of R. Vargo, 8/22/2012, 96:25-97:3, 97:5-97:8, 97:10.

390. In source control efforts, if a potential operation offers only a low chance for success, it should not be attempted because such operations can give rise to new risks and potentially unsolvable problems. G. Perkin, P2 TT 196:17-197:2.

391. BP's decision to proceed with the Top Kill despite its knowledge that it would not be successful also needlessly delayed efforts that had a chance of successfully shutting in the Macondo well. Depo. of R. Vargo, 8/22/2012, 103:13-16, 103:18-104:14. In short, BP made the incident worse.

XVII. BP Misrepresented The Reason For The Top Kill's Failure, Which Caused The BOP-On-BOP To Be Abandoned And Significantly Delayed The Capping Of The Well.

A. BP Misrepresented The Reason For The Top Kill's Failure.

1. *BP Knew That Top Kill Would Fail If The Flow Rate Was Too High.*

392. As discussed above, BP knew in advance of the Top Kill that the operation's success or failure depended on the flow rate and the orifice size. *See supra* Section XV.B. In particular, BP knew that the momentum kill would fail at flow rates at 15,000 BOPD or more. *See supra* Section XV.C. And BP understood that the substantial majority of its modeled flow rates were above this 15,000 BOPD threshold. *See id*. BP also knew that the junk shot would fail at high flow rates and if the orifice size was too large. *See supra* Section XV.B; Section XV.D.

393. These facts–known to BP before the Top Kill–are relevant not only to an assessment of BP's recommendation to move forward with the Top Kill, but also must be taken into account in considering what BP knew after the Top Kill failed when it presented to the Government its explanation for the Top Kill's lack of success.

2. *During And After Top Kill, BP Employees And Contractors Stated That The Operation Was Failing Because The Flow Rate Was Too High And The Orifice Was Too Large.*

394. During Top Kill, BP employees realized that it was failing for the reasons predicted–*i.e.*, because the flow rate from the well was at least 15,000 BOPD.

395. On the second night of the procedure, a BP employee leading the operation communicated to a senior BP executive involved in the response that the Top Kill was not succeeding because the flow rate was too high and the orifice was too large. Specifically, on May 27, 2010, Kurt Mix of BP sent Jon Sprague, a Senior BP Engineering Executive who was BP's Drilling Engineer Manager for GoM, a text message explaining that they had "[p]umped over 12800 bbl of mud today plus 5 separate [*sic*] bridging pills" and the Top Kill operation was failing because there was "[t]oo much flow rate—over 15000 [BOPD] and too large an orfice [*sic*]." TREX-9160; *see* D-25013B.

396. Other BP employees also understood that the Top Kill likely failed because the flow rate was too high and the orifice was too large. *See* G. Perkin, P2 TT 216:13-17. Mark Mazzella, BP's well control authority, believed the Top Kill was unsuccessful because "the hole we were trying to plug up was just too big." *See* D-20070.

397. On May 29, 2010, Thomas Selbekk—a BP contractor—communicated to Kurt Mix of BP that modeling indicated that the Top Kill failed because there was "not enough restriction at surface to create enough pressure to force the mud into the well." TREX-9265 at 1.

398. After Top Kill was concluded, BP's contractor, Wild Well Control, analyzed why the procedure failed and provided this analysis to BP. Wild Well Control concluded that Top Kill failed because the flow path was too large (and hence the flow too high) and could not be blocked. David Barnett, the vice president of Wild Well Control, testified that the team members evaluating Top Kill's failure reached a consensus that disagreed with BP's claim that open rupture disks caused Top Kill to fail. Depo. of D. Barnett, 121:11-13, 121:15-23, 121:25-122:2. He stated that "everyone was in fairly close agreement that it was simply a matter of the flow path was too big." Depo. of D. Barnett, 121:11-13, 121:15-23, 121:25-122:2, 237:7-20, 239:8-

242:24; I. Adams, P2 TT 1123:2—1125:25. Wild Well Control concluded that "the flow path through the BOP was too large to either plug with the debris [from the junk shot], or certainly to create enough frictional pressure by just pumping alone. Depo. of D. Barnett, 120:4-9; *see also* G. Perkin, P2 TT 209:1-12.

399. On May 31, 2010, Wild Well Control prepared and sent to BP a memo titled "Summary & Conclusions From Top Kill Efforts 26-28 May 2010." TREX-10632 (email from David Barnett to Mark Mazzella and Mark Patteson). The memo observed, "Given the lack of response while pumping very large bridging material . . . , it is apparent that the geometry of the pathway(s) inside the BOP is quite large." TREX-10632; G. Perkin, P2 TT 207:14-208:6; I. Adams, P2 TT 1125:10-20; *see also* Depo. of D. Barnett, 119:23-121:5, 121:11-13, 121:15-23, 121:25-122:2, 237:7-20, 239:8-240:16.

B. <u>BP Excluded Government Officials From Its Discussions About Top Kill's Failure.</u>

400. Following the final Top Kill attempt, BP internally analyzed the data collected during the Top Kill. Depo. of L. Herbst, 239:17-240:23. Senior BP executives Andy Inglis and James Dupree attended this internal meeting at BP's Houston headquarters, but Government officials were not invited. *Id*. at 242:8-9, 242:13-20, 487:7-16.

401. While BP officials were meeting, Lars Herbst—head of the MMS— knocked on the door of the room where BP was meeting and asked permission for him and Admiral Cook to participate in the meeting. BP representatives told Herbst that the two Government representatives could not participate and they were "not allowed entry at that time." Depo. of L. Herbst, 239:17-240:23, 241:3-242:7, 488:22-489:12. BP officials told Herbst that "they needed their own time to assess the information." Depo. of L. Herbst, 243:16-21, 489:13-20. BP's rejection of Herbst's request to sit in on its internal Top Kill Analysis was "the last [Herbst] heard

about it until [he] sat down at a briefing regarding [BP's] results and their analysis of the results." Depo. of L. Herbst, 241:18-242:7.

C. Despite Knowledge To The Contrary, BP Misrepresented On May 29, 2010 That Open Collapse Disks Were The Only Plausible Explanation For Top Kill's Failure.

402. After its internal meeting, BP formally presented its explanation for the failure of the Top Kill to Government officials on May 29, 2010. TREX-9162; Depo. of L. Herbst, 447:6-18; Depo. of C. Holt, 183:25-184:7, 185:21-24, 186:1-4; Depo. of K. Cook, 137:1-20. At this meeting, Paul Tooms of BP presented three scenarios as "possible" explanations for the operation's failure—two of which BP said were "not plausible." TREX-11614.0005-0010 (May 29, 2010 Top Kill Analysis presentation); J. Dupree, P2 TT 716:19-23; Depo. of C. Holt, 188:4-12, 189:16-190:7; Depo. of L. Herbst, 491:14-25, 492:2-17, 492:19-495:8 ; Depo. of K. Cook, 138:18-139:11. None of the scenarios expressly identified flow rate or orifice size as the reason for the operation's failure. *Id.*

403. Instead, BP told the Government that only one scenario (Scenario #3) was a "plausible" explanation for the failure of Top Kill—that the collapse disks in the casing had opened before the rig sank such that the Top Kill mud had flowed through those disks into the formation. TREX-11614; G. Perkin, P2 TT 211:2-19; J. Dupree, P2 TT 716:21-717:7; I. Adams, P2 TT 1128:2-14; Depo. of M. McNutt, 458:1-460:18; Depo. of K. Cook, 158:3-8, 158:11-15, 573:13-18, 573:21-574:2; Depo. of C. Holt, 546:3-10; Depo. of L. Herbst, 447:19-22, 447:24-448:14, 494:16-495:8.

404. Government officials who attended the meeting repeatedly confirmed that BP presented failed rupture disks as the only plausible explanation for the Top Kill's failure. *See* Depo. of K. Cook, 156:25-157:10, 157:12-17, 157:20-158:8, 158:11-24, 159:2-12 ("Q. Okay. So . . . you would agree with me that BP is not telling Admiral Allen here, that for sure the rupture

disks have failed but, rather, that there is a concern that they have failed, and if they have failed, there are consequences, right? A. I'm agreeing that's what it says. **I'm telling you, from being there, that the context was that there was no other plausible scenario being presented, only that one for the failure of top kill**." (emphasis added)); Depo. of L. Herbst, 494:16-21 ("Q. In fact, BP presented this failed rupture disks scenario as the only plausible scenario for explaining the top kill's failure; is that right? A. From what I recall, that was the only one, yes.").

405. In reality, the rupture disks did not blow out, and there is no "evidence the rupture disks were open." Depo. of T. Allen, 70:15-25; I. Adams, P2 TT 1135:2-1136:1.

D. BP's Misrepresentations Regarding The Only "Plausible" Reason For Top Kill's Failure Caused The Abandonment Of The BOP-On-BOP Option.

406. BP's May 29, 2010 presentation to the Government ended with a recommendation to abandon the BOP-on-BOP option. The last slide in BP's PowerPoint deck was titled "Conclusions & Path Forward." TREX-11614.0012. This slide stated that "[i]f there is a path open to formation" – *i.e.*, BP's only plausible scenario for the Top Kill's failure – "then containment is the preferred option" – in other words collection of oil, rather than capping, was BP's recommended path forward. BP's final slide also represented that "[s]hutting the well in (via BOP on BOP) is likely to lead to broaching." *Id*. BP recommended that in light of its interpretation of the Top Kill data, the BOP-on-BOP should not be the next step. TREX-9412.0001-.0002 (May 20, 2010 email from Bernard Looney to Admiral Allen forwarding BP's rationale for abandoning BOP-on-BOP); J. Dupree, P2 TT 675:18-676:17; I. Adams, P2 TT 1128:21-1129:3.

407. Consistent with BP's recommendation, directly following BP's presentation to the Government on May 29, 2010, the decision was made to abandon the BOP-on-BOP option. Rec. Doc. 7076, ¶83 (2:10-md-02179-CJB-SS) (Stipulated Facts); Depo. of C. Holt, 459:1-10; G.

Perkin, P2 TT 213:23-25; I. Adams, P2 TT 1126:22-1127:2, 1158:13-15. Both Government and BP witnesses testified that the decision to abandon the BOP-on-BOP was caused by BP's representation to the Government that the failed rupture disks were the only plausible explanation for Top Kill's failure. Depo. of L. Herbst, 495:22-496:3; Depo. of C. Holt, 209:2-5, 209:7 ("Q. And as a result of what BP offered at the time as the most likely reason [for Top Kill's failure], the BOP on BOP option was removed as an option, correct? A. Yes, that was—that's correct."); I. Adams, P2 TT 1069:5-9 ("Coming out of Top Kill, the concern was that a new, well, a new concern was identified, and as a result BOP-on-BOP was removed from the table."; *see also* G. Perkin P2 Expert Report, TREX-11464R.23-24; I. Adams, P2 TT 1095:20-1096:1; I. Adams P2 Expert Report, TREX-11737R.0015.

408. Internal Government correspondence confirms that BP's misrepresentations about the cause of the Top Kill's failure caused the abandonment of the BOP-on-BOP. Before the presentation, Dr. Marcia McNutt sent an email to Secretary Salazar at 10:41 a.m. titled "some thoughts on past steps and next steps." At this point, Dr. McNutt still considered the possibility of using a BOP-on-BOP as one of "two longer-term solutions for producing the well until one or the other of the relief wells can effect a bottom kill." TREX-9653.0001. After she heard BP's presentation, at 3:23 p.m., McNutt wrote another email to Secretary Salazar and Secretary Chu with different conclusions: "[A]ny attempt to shut in this well from above strongly risks over pressuring deep formations with the hydrocarbons and causing an uncontainable blowout to the sea floor," and "[t]he best way forward is flow containment and bottom kill." TREX-9656.0001.

409. Likewise, at 3:50 p.m., Admiral Cook sent Admiral Allen an email titled "BP Briefing On Way Forward." He stated, "Meeting completed," and, among other points, notified

Admiral Allen that based on BP's presentation, "BOP on BOP not advisable, now or in the future, because of rupture disk issue. . . . Again a potential broaching scenario." TREX-9411.

410. As a result of BP's misrepresentation, the decision was made to shift the focus from capping to containment (i.e., the collection of oil). I. Adams, P2 TT 1128:21-24; Depo. of K. Cook, 150:15-151:5 ("Q. Okay. So based on the potential risk of a subsea broach . . . there was a recommendation to move to a containment approach, right? A. . . . . coming out of this meeting, the integrity of the well became a driver.").

411. Because the BOP-on-BOP was abandoned, the *Developmental Driller II* and its BOP were reassigned to drilling operations on the second relief well. TREX-9412.0002 (May 30, 2010 email from Bernard Looney to Admiral Allen: "[a]s a result, the 'BOP on BOP' option has been discontinued. The *DDII* is consequently returning to drilling operations.").

412. After the BOP-on-BOP option was shelved, BP continued to represent to the government that open collapse disks were the only plausible explanation for the Top Kill's failure and did not mention the possibility that the operation failed because of excessive flow rate. On May 31, 2010, Mr. Dupree and Phil Pattillo, Technical Authority and Advisor to BP, made another presentation to Secretary Salazar, Dr. McNutt, and other government officials titled "*Deepwater Horizon* Review." J. Dupree, P2 TT 671:3-20; TREX-150306N at 1. The agenda for this presentation included "Diagnostics & Analysis" for the Top Kill. TREX-150306N at 2. This version of the presentation did not mention or describe any other plausible explanations for the Top Kill. Instead, it concluded that "[a]n event-related rupture of a collapse disk can be conjectured," TREX-150306N at 6, and that, as a result, "[s]hutting the well in (via BOP on BOP) is no longer a viable option[.]" TREX-150306N at 7. Nothing in the presentation

mentioned the possibility that the Top Kill operation failed because of flow rate or orifice size. TREX-150306N.

E. The Government Did Not Independently Analyze Top Kill Results Before The BOP-On-BOP Was Abandoned.

413. Before the May 29, 2010 meeting, the Government did not have the data necessary to conduct an independent analysis of why the Top Kill failed or to question BP's explanation. The Government "had access to data realtime as it was . . . coming through"–that is, it could see data flashing across the screen in a control room, but it did not have "the data to go back and . . . analyze." Depo. of L. Herbst, 239:17-240:23, 488:9-21.

414. Nor did the Government have the expertise to analyze the failure of the Top Kill. As Rear Admiral Cook explained, BP—the experts—represented to the Government that the only plausible explanation for the failure was the failed ruptured disks and the Government did not have the information or the expertise to disagree. Depo. of K. Cook, 159:-2-12 ("Q. And you agreed with [BP's May 29 analysis] at the time? A. Yeah, I—I didn't have the expertise to not agree . . . [.] So I really wasn't concerning myself with the details of the final analysis. If that's what the Experts were saying, then we're going to move on to something else.").

415. The Government did not commission an independent analysis of the Top Kill data until after the BOP-on-BOP option had been abandoned on May 29, 2010. On May 30, 2010, Secretary Chu sent an email to a number of Government officials, including Tom Hunter and Marcia McNutt. Secretary Chu wrote, "I would like to get the lab analysis folks to independently analyze the top kill data and see if they come to the same conclusion as BP: namely the fact that at 70+ bpm, the pressure in the BOP never exceed 6300 psi is reasonable evidence that mud was likely flowing through the seal assembly and out the rupture disks." TREX-11477.0001. Until this request on May 30, 2010, the Government was relying on

representations by BP about the Top Kill data. G. Perkin, P2 TT 300:6-22 ("Q. So given the fact that Secretary Chu didn't even request an independent analysis until May 30, what was Dr. McNutt relying upon when she said 'There's strong evidence of collapsed rupture disks.'? A. BP. Q. And all the other documents that you were shown about communications between scientists before May 30 and before the analysis was done had to be relying upon what? A. BP.").

F. <u>The Government Proposed The Well Integrity Test To Reassess The Accuracy Of BP's Claims About The Rupture Disks, And After The Well Was Shut In, The Test Showed That BP's Representations Were False.</u>

416. The Government's involvement in the source control effort increased significantly after the Top Kill's failure. As Secretary Chu explained: "[i]n the early part of May there was a —we were listening and trying to evaluate based on that, but certainly after the [failure of Top Kill] and after the postmortem, that's where [the Government] began to be much more critical about what BP planned to do, because I think there was a feeling that perhaps their evaluation was—should be more deeply looked at." Depo. of S. Chu, 308:17-18, 308:20-309:2.

417. Over the period of the next six weeks, the Government began to doubt the veracity of BP's claim about the failure of Top Kill. On June 14, 2010, Secretary Chu asked BP to reevaluate whether shut-in was a viable option by implementing a well integrity test in conjunction with the implementation of the capping stack to be used for containment purposes. TREX-142679.0002; J. Dupree, P2 TT 682:21-684:21.

418. The well integrity test determined that the formation was intact after the capping stack was used to shut in the well on July 15, 2010. Rec. Doc. 7076, ¶137-138 (2:10-md-02179-CJB-SS) (Stipulated Facts); J. Dupree, P2 TT 686:5-9. Data collected during the Well Integrity Test on July 15, 2010 proved that BP's representations about the reason for the Top Kill's failure were false. Depo. of C. Holt, 204:5-8, 204:12-15 ("Q. Today flow rate is much more likely to be the reason top kill failed than any of the three scenarios offered, correct? A. The information

that we have today, flow rate would have been a—or is a most likely reason why top kill didn't—wasn't successful."); I. Adams, P2 TT 1131:16-1132:3, 1134:22-1136:17. Data gathered during the well integrity test revealed that, in fact, the rupture disks were intact and that the well had integrity. J. Dupree, P2 TT 717:8-11 ("Q. You agree today the collapse disk had nothing to do with the Top Kill failure, correct? A. Yes. Because later on we find out, certainly through killing the well, that the rupture disks were indeed intact."); Depo. of C. Holt, 196:14-17, 196:19-22 ("Q. BP would agree with me that you—that it knows today that failure of the rupture disks was most likely not the reason why the top kill failed, correct? A. In knowledge of the wellbore integrity that we had with the eventual kill, the rupture disks did not contribute to the failure of the top kill effort.").

XVIII. The BOP-On-BOP Would Have Safely And Effectively Capped The Well Long Before July 15.

419. BP had an alternative to the Top Kill that would have safely and effectively capped the well weeks before the capping stack finally was used to shut in the well: the BOP-on-BOP option. This BOP-on-BOP option was ready as early as mid-May and certainly by early June. Moreover, the BOP-on-BOP would have succeeded in closing in the well. Although BP today contends that the BOP-on-BOP had risks, BP's own contemporaneous analysis found that this capping strategy could be managed safely and was superior to the capping stack that ultimately was used to cap the well.

A. The BOP-On-BOP Was Ready Between Mid-May And Early June.

1. *The BOP-On-BOP Option Was Developed In Late April And Early May 2010.*

420. Within a few days of April 20, 2010, representatives from BP, Transocean, Cameron and Wild Well Control, met at BP's offices to discuss capping solutions. R. Turlak, P2 TT 373:12-17. On April 27, 2010, Wild Well Control provided BP with a project memo that

raised "Well Capping" and "Installation of Capping Stack on existing BOP" as options that should be considered. The memo also included a summary of procedures for installation of a capping stack onto the existing BOP. Depo. of A. Inglis, 663:15-665:13; TREX-3918. The capping option was at the top of the list when the ROV intervention team realized that they were running out of options. Depo. of G. Boughton, 318:2-322:5.

421. On April 27, 2010, the capping team, composed of engineers from BP, Transocean, Cameron, Vetco and Wild Well Control, focused on capping solutions held its first formal meeting and began work. Rec. Doc. 7076, ¶37 (2:10-md-02179-CJB-SS); Depo. of D. Suttles, 231:8-18; TREX-10527 (Well Capping Team); R. Turlak, P2 TT 329:6-13, 364:23-25. The capping team's "assignment was to work on BOP-on-BOP, as well as the capping stack." *Id*. at 329:14-19.

422. BP's Jim Wellings was in charge of the capping team. Depo. of J. Wellings, 18:8-14, 18:16; R. Turlak, P2 TT 329:20-21. Wellings wanted to pursue the BOP-on-BOP option. Depo. of J. Wellings, 203:7-8, 203:10-13 ("I wanted to do it, yeah."); *see also* R. Turlak, P2 TT 330:1-3 ("Q: Was [Wellings] enthusiastic about the BOP-on-BOP option? A: He knew we had to get something done, and he wanted to move ahead."). Rob Turlak, Transocean's Manager of Subsea Engineering and Well Control, along with other Transocean engineers, was a member of the capping team. *Id*. at 329:6-13.

423. By April 28, 2010, the capping team was evaluating capping the well by placing a second BOP on top of the *Horizon*'s lower BOP. TREX-145113.57.1.TO (Turlak calendar) ("Look at Stack on Stack.").

424. Around April 29th, Transocean's Geoff Boughton procured the two-ram Hydril BOP used in the capping stack from Transocean's Amelia yard. Depo. of G. Boughton, 318:2-

319:9. Transocean also managed to find "several" HC connectors, for connecting the capping devices to the *Horizon* lower BOP, "in short order." Depo. of J. Wellings, 279:12-280:10.

425. An April 30, 2010 BP presentation details plans to cap the Macondo well using the BOP from the *Discoverer Enterprise*. TREX-11402.0002-.0003 (MC 252 # 1 Well Capping Sequence). The riser on top of the LMRP would be "cut and removed." TREX-11402.0003. The *Enterprise* would then latch and lift the *Horizon* LMRP off of the *Horizon* stack. TREX-11402.0005-.0006 (MC 252 # 1 Well Capping Sequence). After removing any drill pipe stub from the top of the *Horizon* lower BOP, TREX-11402.0007 (MC 252 # 1 Well Capping Sequence), the *Enterprise* BOP would be lowered on riser joints, and latched onto the *Horizon* lower BOP. TREX-11402.0010 (MC 252 # 1 Well Capping Sequence). Next, the "Enterprise Closes her Shear Rams–Flow is stopped." TREX-11402.0011 (MC 252 # 1 Well Capping Sequence).

426. In order to attach to the *Horizon* lower BOP, the Enterprise BOP needed a Cameron HC connector at the bottom of the stack. Changing out the bottom component of a BOP stack is "a common thing to do." R. Turlak, P2 TT 331:15-332:7.

427. In addition to changing the connector at the bottom of the *Enterprise* stack, the capping team "had to get two riser joints and cut twelve 8-inch holes in the main tube of the riser and actually plug the end of that particular riser joint because[.] [T]he concern was … as [they] were lowering the Enterprise . . . , [they] didn't want to get that oil and gas coming straight up the riser back to the surface." *Id*. at 332:8-24.

428. For redundancy, the capping team "did a second riser joint the same way." *Id*. They added a third riser above those two joints that "could flood the riser, so that once we were at depth [they] wouldn't collapse …the main tube." *Id*. The capping team verified with riser

manufacturer Vetco that this perforated riser would support the weight of the second BOP. *Id*. at 333:24-334:9.

429. By May 3, 2010, maintenance on the *Enterprise* BOP was "finished" and the team was "waiting on [the] HC connector to start BOP testing." TREX-11229.0002; Depo. of J. Wellings, 146:3-11 ("I would take that to mean that they finished doing the maintenance on it."); *see also id*. 145:12-23 (explaining that the May 5 meeting minutes attached to a May 3 email are "probably" May 3 meeting minutes). BP's HAZID for the BOP-on-BOP procedure notes that as of May 6, 2010, "Testing of [the] Enterprise BOP prior to deployment" was "completed." TREX-9787.0013 (BP BOP-on-BOP HAZID) ("Testing completed.").

430. On May 5, 2010, capping team leader Jim Wellings forwarded a detailed animation of the planned procedures for landing the *Deepwater Enterprise* BOP on the *Horizon* lower BOP. TREX-4310.0001 (May 5 Wellings email attaching wellcap2.wmv); *see also* D-25010 (native version of animation from TREX-4310).

431. Upon removal of the LMRP, the animation depicted "drill pipe sticking out of the lower BOP stack." R. Turlak, P2 TT 337:8-10; D-25010 (native version of animation from TREX-4310).

432. As of the date Wellings sent the animation, the capping team's plan for any drill pipe in the lower BOP stack was to "use an ROV with a saw cutter attached to the bottom of the ROV and go in and grasps [*sic*] the adapted spool and the saw was going to cut off the drill pipe." R. Turlak, P2 TT 337:11-16. The procedure is depicted in the animation, and the saw depicted in the animation was "ready to go." *Id*. at 337:17-21; D-25010; Depo. of G. Boughton, 406:10-13.

433. By early May, the capping team had identified hydrate formation as a potential risk of connecting the *Enterprise* BOP. The plan to mitigate that risk was to "just pump[] glycol down the kill line," or "open[] one of the side outlet valves and pump[] [glycol]." R. Turlak, P2 TT 339:6-14.

434. Transocean's engineering group also had run "a BOP on–BOP engineering study to make sure that was going to be safe to operate the *Enterprise* on top of the *Horizon*'s BOP," and verify that the weight of the second BOP would not present any problems. Depo. of G. Boughton, 103:22-104:20.

435. As of May 6-7, 2010, the *Enterprise* BOP was "[j]ust a matter of days" from being finished and deployed. R. Turlak, P2 TT 340:16-18; *see also* TREX-6112 (5/7/10 BP Gantt chart showing well closed in on 5/15); Depo. of G. Boughton, 73:10-74:13 (*Enterprise* BOP-on-BOP was "ready to go by the–I'm guessing–I'm going to say the 10th of May, the first couple weeks of May, somewhere in that time frame."); Depo. of G. Boughton, 79:11-13 (well could have been capped in mid-May).

436. The specialized riser joints were constructed the first week of May and were ready by the "the 10th of May, somewhere in there." *Id*. at 326:24-327:4. The Cameron HC connector required to fasten the *Enterprise* stack to the *Horizon*'s lower BOP "was on board the rig by May 10th." *Id*. at 327:5-10; *see also id*. 327:11-18 (Boughton did not remember Transocean waiting for any parts or equipment for the *Deepwater Enterprise* stack as of May 10). As Mr. Turlak recalled, as of May 10 "the only thing left to do was to put the HC collet connector on the bottom and test it." R. Turlak, P2 TT 384:11-21. To the best of his knowledge, the Enterprise BOP had been tested by May 10th. *Id.*

2. *The Enterprise BOP-On-BOP Option Could Have Been Implemented By Mid-May.*

437. Around May 10, BP took the *Enterprise* off the BOP-on-BOP project, and shifted the project to the BOP on the *DDII*. R. Turlak, P2 TT 340:19-25; TREX-145113.0061 (Turlak calendar) ("Well Cap Team now wants to look at DD II for running onto *Horizon* lower BOP."); TREX-10894 (5/10/10 MacKay email re: DD II–USE FOR PULLING DWH LMRP & CAPPING WELL WITH DD II BOP) ("Basically we need to be prepared to use the *DDII* as an alternative to the *Enterprise* BOP onto DEH [*sic*] Lower BOP . . . .").

438. Only two days after the switch to the *DDII*, BP's Jim Wellings wrote that the "Enterprise option BOP on BOP [was] ready to go." TREX-11230 (5/12/10 Wellings email re: Update on *DDII* BOP on BOP and Capping Stack).

439. Wellings corroborated this assessment in a later email, writing that "[w]e were in a position early on to install a cap and the decision was made to do the top kill first." TREX-8542.0001 (8/26/10 Wellings email re: Jim Wellings Way Forward).

440. More than two years later, Wellings testified that he "just miswrote the email" in TREX-8542. Depo. of J. Wellings, 160:8-12. In light of the unambiguous text of both TREX-11230 and TREX-8542, as well other corroborating evidence showing the BOP-on-BOP could have been implemented by mid-May (*see supra* XVIII.A), Wellings' testimony on this point is not credible.

441. Consistent with Wellings' contemporaneous email, Rob Turlak testified that the *Enterprise* BOP "should have been ready to go on–by the 12th [of May]." R. Turlak, P2 TT 386:6-11; *see also* G. Perkin, P2 TT 274:2-11 ("But in my mind, [the *Enterprise*] BOP was ready to go. If BP had specified they wanted a venting feature on that BOP, they should have made it known early on and that could have been accommodated."); Depo. of G. Boughton, 73:10-74:13,

79:11-13 (testifying that the *Enterprise* BOP-on-BOP was "ready to go" in the first couple of weeks of May).

442. Although the *Enterprise* BOP did not include a subsea choke for venting excess pressure, there was no evidence presented at trial that BP viewed venting as a requirement for the BOP-on-BOP strategy before the middle of May. As discussed below, the evidence shows BP first raised venting as a concern on or about May 15, 2010.

443. Moreover, because it is undisputed that the well was not flowing up the annulus and hydrocarbons were therefore not in communication with the rupture disks, the absence of a **subsea** choke on the *Enterprise* BOP-on-BOP would have made no difference to the BOP-on-BOP's effectiveness. While the need for venting was not discussed until after the switch to the *DDII*, the *Enterprise* was always capable of venting to **surface** through the choke manifold on the *Enterprise* vessel itself. R. Turlak, P2 TT 340:13-15 (*Enterprise* had venting capability); R. Turlak, P2 TT 346:19-21; Depo. of J. Wellings, 441:1-4, 441:6-25; Depo. of J. Wellings, 493:12-17; *see also* Depo. of D. McWhorter, 11/16/2012, 520:3-521:3, 521:5-6 (explaining the venting *Enterprise*'s capability: "[t]he choke and kill lines run up the riser string into a permanently-installed choke manifold on the rig. So there was already a choke in place on the rig."). "[A]ll the elements would be there" to vent hydrocarbons or vent flow. Depo. of D. McWhorter, 11/16/2012, 520:22-521:3, 521:5-6.

444. In fact, the *Enterprise* had unique processing capabilities that made it particularly well suited to handle any hydrocarbons that had to be vented up to the rig. TREX-11245 at 1 (5/16/10 Olsen email re: *DDII* BOP with Choke Venting Capability) ("[i]n case of venting the well, [the *Deepwater Enterprise*] is the better rig. It has a full test and crude oil storage spread and this system is ready."); *see also* R. Turlak, P2 TT 340:5-12 (*Enterprise* "had the capability of

bringing the oil and gas to surface, separating the oil and also flaring off the gas, which is exactly what it did during the – when they were in the collection mode in late May.").

445. Thus, if BP had chosen to implement the *Enterprise* BOP-on-BOP option on or about May 12–the date BP's Wellings wrote that this option was "ready to go," the absence of a subsea choke likely would not have prevented the *Enterprise* BOP-on-BOP from being installed and successfully capping the well. TREX-11230.

446. In short, the weight of the evidence shows that BP could have capped the well using the *Enterprise* BOP-on-BOP option as early as mid-May 2010, two months before the capping stack shut in the well.

3. *By Mid-May, A BP-Led Peer Assist Team Found That The BOP-On-BOP Option Was Feasible And Could Be Managed Safely.*

447. On May 13, BP conducted a Top Preventer Peer Assist to review both "removing the Horizon LMRP and running the DDII BOP on the Horizon lower stack," and "running a Double Ram preventer [the two-ram capping stack] on top of the Horizon Flex Joint." TREX-11235 at 1 (MC 252 Top Preventer Peer Assist); Depo. of J. Wellings, 220:4-18. "Specifically," the purpose of the Peer Assist was to "[a]ssess the feasibility and risks associated with both operations and determine the significance of these risks," and "[e]xamine the contingencies and confirm that these are sufficient and effective." TREX-11235 at 1 (MC 252 Top Preventer Peer Assist). BP presented risks previously identified by the capping team, to see if the peer assist team could identify other risks. Depo. of J. Wellings, 223:24-224:7; TREX-11235 at 3 (MC 252 Top Preventer Peer Assist).

448. The Peer Assist team included engineers from BP, Cameron, Transocean, ExxonMobil, Oceaneering, and Wild Well Control. TREX-11235 at 1-2 (MC 252 Top Preventer Peer Assist); TREX-10505.0025 (Peer Assist Participants).

449. The Peer Assist concluded that (a) it "believe[d] that the BOP on BOP operation is feasible and can be managed safely" TREX-10505.0005 (MC 252 Top Preventer Peer Assist Recommendations); (b) the "[k]ey risks had all been identified–no significant additional risks [were] identified by [the] review team" *id*.; and (c) an "[a]mazing amount of work [had] been done – great job in short time." *Id*.

450. BP engineers agreed with the Peer Assist team's assessment that BOP-on-BOP was feasible and could be managed safely. Depo. of J. Wellings, 111:18-112:10, 112:12-17 (BP's head of the Capping Team testifying that the "[BOP-on-BOP] was obviously a feasible solution that we presented, and we worked through and mitigated the risks involved. . . . I certainly thought it was a feasible solution."); *id*. at 238:14-16 (agreeing that the operational risks identified in the peer assist are manageable); Depo. of C. Holt, 87:18-21, 87:24-88:2, 88:4-5 (BP's 30(b)(6) witness testifying, "It says you can do it with the identified mitigation of the risk.").

451. Cameron, a Peer Assist participant, also agreed that as of the middle of May 2010, the BOP-on-BOP operation was feasible and could be managed safely. Depo. of D. McWhorter, 11/16/2012, 451:24-452:13 ("[I]t's a matter of a simple connection, simple physics, as far as connecting the BOP on top of the–the *Horizon* BOP.").

4. ***Despite BP's Decision To Switch From The Enterprise To The DDII For The BOP-On-BOP, The BOP-On-BOP Strategy Still Could Have Been Implemented In Mid-To-Late May.***

452. BP's decision to switch from the *Enterprise* to the *DDII* for the BOP-on-BOP strategy required re-doing work that had already been completed for the Enterprise BOP. R. Turlak, P2 TT 341:21-342:24; TREX-11230 (5/12/10 Wellings email re: Update on *DDII* BOP on BOP and Capping Stack) ("All the simulations, DP evaluation, riser analysis, etc. done on the Enterprise [would] have to be re-done for the *DDII*.").

453. Even following the shift from the *Enterprise* to the *DDII*, numerous emails – as well as record testimony–establish that the plan was to implement the BOP-on-BOP option by approximately May 18, 2010. *See* TREX-10879 (5/14/10 O'Bryan email re: Priority for Completion of BOP Work on the *DDII*) ("bop on bop is the priority"); *see also* TREX-4405.0001 (5/11/10 Wellings email re: DD2 stack G/A/ dwg) ("I reviewed with Andy Ingles [*sic*] yesterday and they want to have this in the water next week."); TREX-145008.0001 (5/14/10 Olsen email re: IMPORTANT – Priority for Completion of BOP Work on the *DDII*) ("BP wants us to be ready for running BOP's on Tuesday."); R. Turlak, P2 TT 343:10-15 ("[O]n the 18th, they wanted to be ready to run the BOP."); TREX-144963.0001-.0002 (5/15/10 Olsen email attaching Project plan for Stack on Stack with DD II) ("All centered around a Tuesday BOP run . . . ."); TREX-9431.0003 (5/15/10 Mark Shepard (USCG) email noting that BOP-on-BOP "could proceed next Thursday," May 20).

454. As of May 15, 2010, Transocean's "onshore activities" in support of the BOP-on-BOP effort were "progressing well." TREX-144963.0001 (5/15/10 Olsen email attaching Project plan for Stack on Stack with DD II). Transocean "had already gotten the riser taken care of. The plugs for the riser, the plates were made, and the connectors were on their way." R. Turlak, P2 TT 344:15-18.

5. *When BP First Raised Venting Excess Pressure As A Requirement In Mid-May, Transocean Identified Multiple Venting Options For The BOP-On-BOP Within Days.*

455. On May 15, the capping team "had a meeting with Hydril BOP representatives at BP['s] office regarding what is required to install a Choke on the *DDII* BOP which would allow 'venting' off of excess pressure once the *DDII* BOP has been landed and latched onto the DWH Lower BOP." TREX-144961.1.1.TO (callout from 5/15/10 MacKay email re: *DDII* BOP with Choke Venting Capability).

456. BP did not raise venting as a requirement for the BOP-on-BOP strategy until on or about May 15. Capping team member Rob Turlak did not remember hearing a concern from BP about venting prior to May 15, 2010. R. Turlak, P2 TT 346:19-21. And BP's Jim Wellings testified that the need for a venting option was not discussed until after the switch from the Enterprise to the *DDII*. *See* Depo. of J. Wellings, 441:1-4, 441:6-25, 493:12-17.

457. Although BP's decision to add a venting option delayed the BOP-on-BOP strategy, the evidence overwhelmingly shows that it was still ready for implementation by late May or early June 2010–still a month-and-a-half before the Capping Stack stopped the flow of hydrocarbons from Macondo.

458. By May 17, 2010, two days after BP had first raised the venting concern, Transocean had identified three "[p]ossible solutions to the challenge" of venting from the *DDII* BOP. TREX-145021.0001 (5/17/10 Olsen email re: Conference call this AM to discuss DD2 BOP venting).

459. The first option was to attach a double-block valve on one of the BOP's side outlets, and attach a subsea choke to that valve. *Id*.; R. Turlak, P2 TT 347:5-25. This method was ultimately used with the three-ram capping stack to shut in the well. Depo. of D. McWhorter, 11/15/2012, 33:8-11 (agreeing that a Cameron CC40 choke was used to shut in the Macondo well).

460. Mr. Turlak testified that if he had been told to do so on April 28, when the capping team first looked at BOP-on-BOP options, he could have designed a choke. R. Turlak, P2 TT 346:22-25. BP's capping team leader Jim Wellings agreed that a subsea choke "could have been installed on the ENTERPRISE." Depo. of J. Wellings, 442:1-12.

461. The next option was "venting back up through the choke–choke line and back up to surface and going through the choke and kill line manifold." R. Turlak, P2 TT 348:1-12; TREX-145021.0001 (5/17/10 Olsen email re: Conference call this AM to discuss DD2 BOP venting).

462. Like the *Enterprise*, the *DDII* stack had surface venting capabilities, without the need for any further modification. Depo. of D. McWhorter, 11/16/2012, 520:3-521:3, 521:5-6 (explaining that "any fully functioning BOP stack that would have been deployed on top of the Macondo stack, as was visualized in the BOP-on-BOP option, would have actually already had a choke attached to it"); *see also* R. Turlak, P2 TT 348:1-12 (explaining, with a model of the BOP, the surface venting option).

463. The third venting option was to use a "choke manifold on the seabed with a Coflex [hose] jumper from the BOP stack to the manifold." R. Turlak, P2 TT 348:13-349:10; TREX-11245 at 1 (5/16/10 Olsen email re: *DDII* BOP with Choke Venting Capability). BP told Transocean it wanted to pursue this third option upon learning "that the subsea choke was not going to be able to be retrievable." R. Turlak, P2 TT 348:13-349:10.

464. To "connect a Coflexip hose [to the BOP], [a double-block valve would be] turned at a 45-degree angle to come out of the BOP stack frame, and a mini collet connecter would attached to[the valve] and be hydraulically operated to latch on and a Coflexip hose [would be] connected to it to connect to the subsea manifold where they could vent or produce back up to the surface." R. Turlak, P2 TT 348:13-349:10. Transocean and Cameron designed and constructed the "simple" 45-degree angle block valve for this option "in about four days." *Id.* at 349:11-23; D-25025 (45-degree angle valve).

465. A fourth venting option for the BOP-on-BOP would have been immediately available for either the *Enterprise* or the *DDII*: gradually closing the different variable bore rams within the second BOP to incrementally reduce flow. "[M]onitoring the pressure under these closed pipe ram[s] with respect to disk pressure thresholds should have been possible and achievable." G. Perkin P2 Expert Rebuttal Report, TREX-11465R.3.

6. *Although BP's Mid-May Request For A Subsea Venting Option Delayed The BOP-On-BOP Option, The Modified BOP-On-BOP Was Ready By Late May Or Early June.*

466. BP's mid-May request for venting options delayed deployment of both the *DDII* BOP and the capping stack. R. Turlak, P2 TT 356:25-357:6 ("[T]he DD II was going to be run on the Tuesday, the 18th. Then after we found–found out that they wanted venting, that was going to delay it, ..."); *see also* TREX-144986.0001 (5/27/10 Olsen email re: Planning for Triple Cap Stack and BOP outlet) ("It is not going to be acceptable to do more changes now. The team has spend [*sic*] 2 weeks on this and we need to draw a line in the sand if [BP] shall have any thing to run any time soon.").

467. Although BP's changed plans delayed the BOP-on-BOP option, a variety of evidence shows that it was still ready–with the requested subsea venting capability–by late May or early June.

468. On May 18, Transocean estimated that a venting solution for either the capping stack or the *DDII* BOP was "about 10-14 days away." TREX-144951.0001 (5/18/10 Olsen email); R. Turlak, P2 TT 352:5-13 (agreeing that his view at the time was consistent with the email); *see also* I. Adams, P2 TT 1147:10-16 (agreeing that 10-14 days "was a reasonable, if optimistic, estimate"); I. Adams P2 Expert Rebuttal Report, TREX-11738R.006 (same). BP's expert Iain Adams did not "think [this] was an unrealistic date . . . ." I. Adams, P2 TT 1148:4-8;

TREX-144954.0001 (5/17/10 Olsen email re: BOP on BOP Plan) (estimating 12 days); R. Turlak, P2 TT 350:21-23 (agreeing that the total of about 12 days seems reasonable).

469. In a May 23 letter to Admiral Landry, BP's Doug Suttles represented that having the *DDII* "ready to run their BOP on top of the *Deepwater Horizon* BOP" was a "prerequisite[] for the Top Kill Operation." TREX-142700.0002-.0003 (5/23/10 Suttles letter to Landry re: Top Kill Operation). He also told Admiral Landry that "Removal of the Riser and LMRP from the top of the *Deepwater Horizon* BOP," and "Installation of the *Development Driller II* BOP onto the *Deepwater Horizon* BOP," were "expected to take one week." TREX-142700.0003 (5/23/10 Suttles letter to Landry re: Top Kill Operation).

470. Consistent with those estimates, BP's internal schedule from May 19 projected that installation of the *DDII* BOP would be complete on June 3. TREX-11236 at 2 (5/19/10 *DDII* BOP on *Horizon* BOP schedule).

471. On May 24, Jim Wellings circulated a schematic of the "Subsea Choke Manifold for venting," that would be used either with the *DDII* BOP or the capping stack. TREX-145038.0001 (5/24/10 Wellings email re: 3:30 Mtg on BOP Venting moved to 5:30); R. Turlak, P2 TT 353:6-12 ("[I]t was the piping and instrumentation drawing for the venting system that we were going to use on – either way, on the DD II or the capping stack."). In the same email chain, BP's Mike Brown said that the subsea choke manifold "will be ready to ship Thursday pm [May 27]." TREX-145038.0001 (5/24/10 Wellings email re: 3:30 Mtg on BOP Venting moved to 5:30); R. Turlak, P2 TT 353:13-17.

472. A guidance frame was not used to land the capping stack, and would not have been needed to land a second BOP on the *Horizon* BOP. *See* D-26007 (video of capping stack

landing); R. Turlak, P2 TT 397:18-22 ("I don't know how something that weighs 40,000 pounds is going to guide something that weighs 700,000 pounds.").

473. In any event, by May 26 a guidance frame had "been designed, built and shipped to the *DD2* for installation." TREX-4319.0001 (5/26/10 Sneddon email re: BOP Guidance Frame); Depo. of G. Boughton, 553:22-554:2.

474. On May 27, 2010, BP issued the formal written BOP-on-BOP procedure for review. TREX-140700.0002 (BOP on BOP Capping Procedures for MC-252 #1); I. Adams P2 Expert Report, TREX-11737R.0013-.0014.

475. As of that date, Transocean's internal project plan projected that the *DDII* BOP would be "ready to run" on June 6, 2010. TREX-144986.0001-.0002 (5/27/10 Olsen email re: Planning for Triple Cap Stack and BOP outlet). Mr. Turlak agreed that June 6 was "a realistic completion time, even with all the modifications that were being asked for." R. Turlak, P2 TT 357:15-18.

476. BP's projection from the same date similarly estimated that the BOP-on-BOP installation would be complete on June 7, 2010. TREX-144985.0002 (5/27/10 Roberts email re: *DDII* BOP on *Horizon* BOP 5-27.ZIP).

477. BP's Gantt chart, dated "29-May 0900," projected that the well would be shut in with the *DDII* BOP on June 6, 2010. TREX-11261N.2.BP (BOP on BOP Gantt Chart).

478. Later that day (May 29, 2010), "the decision was made not to move forward with the BOP-on-BOP option." Rec. Doc. 7076, ¶83 (2:10-md-02179-CJB-SS) (Agreed Stipulations); Depo. of R. Brannon, 148:2-8, 148:10-12 ("On May 29th, [BOP-on-BOP] was taken off the table. BOP on BOP was–was not a–was not an option."); Depo. of C. Holt, 209:2-5, 209:7

(conceding that BOP-on-BOP was removed as an option because of BP's May 29th presentation regarding the "most likely reason" for Top Kill failure).

479. After learning from BP's Wellings that "BP has decided to go another route and will not be doing the BOP for a while," Mr. Turlak was surprised: "We were so close. We had come a long way from the *Enterprise* and the *DD II*, and then the *DD II* with the venting option, had the equipment ready, and then their decision not to do it." R. Turlak, P2 TT 358:6-18; TREX-7104.0003 (5/30/10 Wellings email re: Thanks For the Good Work BOP on BOP and Capping Stack Team) ("[W]e will be disbanding the BOP on BOP team for now. Thanks again for the hard work and long hours of coming up with a brilliant plan and inspired contingencies."). BP never explained to Mr. Turlak why it shelved the BOP-on-BOP. R. Turlak, P2 TT 358:19-21.

480. BP's Wellings conceded that the *DDII* BOP "was ready to install the end of May with the subsea choke and the additional blind shear ram." Depo. of J. Wellings, 183:3-4, 183:6-11; *see also id*. at 182:10-15 ("[I]t was ready to install, basically, by the end of May."). Wellings made clear that when the BOP-on-BOP was abandoned, "it was worked to fruition," and "[t]here wasn't any more work to be done." *Id*. at 193:6-14.

481. Charles Holt, BP's 30(b)(6) witness for the BOP-on-BOP effort, similarly believed the BOP-on-BOP was ready to splash by May 30, 2010. Depo. of C. Holt, 18:2-17, 66:1-10, 231:8-11, 231:13-16.

482. In sum, while BP's mid-May request to add a venting option and its decision to switch from the *Enterprise* BOP to the *DDII* BOP delayed the capping of the well, the evidence demonstrates that even with BP's requested modifications, the *DDII* BOP could have shut in the well by late May or early June, at the latest.

B. <u>The BOP-On-BOP Would Have Been Equally Effective As The Capping Stack That Succeeded In Shutting In The Well.</u>

483. The capping stack used to shut in the well was the functional equivalent of a second BOP.

484. Rob Turlak explained that the capping stack used at Macondo was essentially the "same thing" as a BOP. R. Turlak, P2 TT 362:16-20 ("MR. LI: We're just explaining that the capping stack and the BOP are the same thing. THE COURT: I think you've established that. The witness has said that right? THE WITNESS: Yes, sir.").

485. Like the three-ram capping stack that successfully shut in the well on July 15, 2010, the *Enterprise* BOP and the *DDII* BOP were equipped with redundant, Hydril blind shear rams. I. Adams, P2 TT 1157:12-18, 1157:22-25; I. Adams P2 Expert Rebuttal Report, TREX-11738R.011.

486. During the successful shut-in on July 15, only one of the capping stack's three Hydril blind shear rams was closed. Rec. Doc. 7076, ¶133 (2:10-md-02179-CJB-SS) (Agreed Stipulations) (describing middle ram closure).

487. Because the *Enterprise* BOP and the *DDII* BOP both contained two Hydril blind shear rams, the success of the capping stack's Hydril blind shear ram is compelling evidence that the Enterprise BOP and the *DDII* BOP would have closed in the well successfully.

488. To the extent there were differences between the BOP-on-BOP and the capping stack, BP's peer assist concluded that the BOP-on-BOP was "the preferred option" among the proposed capping solutions. TREX-6212.0001; Depo. of J. Wellings, 232:25-233:8; Depo. of C. Holt, 85:1-13, 85:16-23; *see also* TREX-4405.0001 (5/11/10 Trent Fleece (BP) email re: DD2 stack G/A dwg) ("I'm more than available to make [BOP-on-BOP] happen, I think its [*sic*] our best shot.").

489. By May 17, the capping team had concluded that BOP-on-BOP "is the clear choice among the alternative capping/diversion scenarios." TREX-10611.0001 (5/17/10 Pat Campbell email re Updated BOP on BOP Schedule); Depo. of D. Barnett, 172:11-16.

490. Both the *Enterprise* BOP and the *DDII* BOP were readily available. Jim Wellings testified that "early on, we realized that they – the BOP on BOP, we already had all the control systems in place 'cause it's coming–it's attached to a rig that's already been working; whereas, the–the capping stack connected to the–to the rising BOP after the LMRP was removed, there was–there was a significant amount of–of construction and work that had to be done." Depo. of J. Wellings, 131:16-19, 131:21-132:14; *see also* Depo. of D. Barnett, 177:24-178:2, 178:4-13, 178:15 (BOP-on-BOP was preferred because "[i]t was immediately available. It required no fabrication, testing, construction of controls and–so it was–it was an expedient solution, and it had the advantages of already having an–an existing Control System.").

491. To provide venting capabilities, a subsea choke assembly, like the Cameron choke used on the capping stack to shut-in the well, "could have been" attached to the BOP-on-BOP. Depo. of D. McWhorter, 11/16/2012, 519:21-520:3, 521:5-13, 521:15-16.

492. Like the capping stack, the BOP-on-BOP gave the capping team the option of attaching venting technologies to the side outlet on a ram. R. Turlak, P2 TT 350:1-5.

493. The *Enterprise* and *DDII* BOPs each had 12 side outlets. One could vent from any of those outlets. R. Turlak, P2 TT 327:24-328:8. The BOPs also had a double-block valve connected to an outlet on the upper annular, which provided another venting option. *Id*. at 328:9-329:2.

494. The BOP-on-BOP offered twice as many ram cavities (six) as the three-ram capping stack. While the *DDII* BOP and the *Enterprise* BOP in their standard configurations had

two blind shear rams, they each had six ram cavities. Therefore, the BOP-on-BOP strategy gave BP the option of deploying as many as six blind shear rams–twice as many as were ultimately available on the capping stack. *Id*. at 338:23-339:5, 341:10-20.

495. BP's suggestion that the capping stack offered advantages over the BOP-on-BOP with respect to collection and containment is not supported by the record. Both the *DDII* and *Enterprise* BOPs could have been configured to collect oil. Depo. of D. Barnett, 177:24-178:2, 178:4-10 (BOP–on-BOP gave the option of capturing oil through the choke and kill lines); R. Turlak, P2 TT 340:5-12 (Enterprise "had the capability of bringing the oil and gas to surface, separating the oil and also flaring off the gas, which is exactly what it did during the – when they were in the collection mode in late May"); Depo. of G. Boughton, 548:12-549:23 (modifications to the *DDII* BOP would have allowed containment); E. Ziegler P2 Expert Report, TREX-11578-v2.042 ("BP should and could have contained, collected, stored, and transported and sold the liquid hydrocarbons while capping/venting equipment was being place, and/or while relief wells are drilled.").

496. The subsea manifold was designed for use with either the second BOP or the three-ram capping stack and allowed for production to the surface. TREX-145038.3 (diagram of subsea manifold); R. Turlak, P2 TT 348:13-349:10.

497. In short, like the three-ram capping stack, the *DDII* BOP and the *Enterprise* BOP would have successfully shut-in the well.

C. <u>The BOP-On-BOP Option Had Been Used Successfully Before.</u>

498. Capping devices have "been used in the industry for decades." E. Ziegler, P2 TT 531:5-532:8.

499. BOPs were used by well control contractors to cap uncontained wells during the first Gulf War. Depo. of D. McWhorter, 11/15/2012, 176:23-179:4.

500. Other earlier incidents demonstrated "that the technology and the application of setting a BOP-on-BOP in deeper water from a floating rig was achievable and existed as a technique in the industry." E. Ziegler, P2 TT 538:2-8.

501. As early as 2001, BP's Alaska division "believe[d] well capping constitutes the BAT [Best Available Technology] for source control of a blowout." TREX-9828 at 1 (BP Exploration (Endicott) Oil Discharge Prevention and Contingency Plan: Best Available Technology). BP recognized nearly a decade before the blowout that "[h]istorical evidence clearly indicates well capping has greater reliability and application for well control compared to that of relief well drilling. Well capping response times account for an approximate 50 percent reduction in blowout durations when compared to that of relief well drilling." TREX-9828 at 4.

D. <u>BP Engineers And Contractors–Including WWC, Cameron, And Transocean –Supported The BOP-On-BOP Option.</u>

502. Many of the parties involved in the source control efforts, including BP engineers, Transocean, BP's other contractors, and the United States, supported the BOP-on-BOP option to cap the well.

503. BP capping team leader Jim Wellings acknowledged that BOP-on-BOP "would have closed in the well." Depo. of J. Wellings, 210:1-5; *see also* Depo. of A. Frazelle, 433:14-16, 433:18 (agreeing that BOP-on-BOP "was a credible option for containing a well"); Depo. of D. Barnett, 314:3-10 ("I'm not aware of anything on the *DDII* BOP stack that would preclude us from using it to install on top of the *Horizon* BOP stack.").

504. "One way or another," Transocean was advocating "capping the BOP, whether it was the *Enterprise*, the capping BOP. Whatever method anybody wanted to do, we were amply prepared to do it." Depo. of G. Boughton, 324:3-12; TREX-10884 (5/9/10 Bobillier email re:

Best possible options forward) (concluding "that stabbing the DEN bop on top of the Horizon bop (after removing the LMRP) is the best of our options").

505. Wild Well Control similarly wanted to pursue the BOP-on-BOP option in May. Depo. of D. Barnett, 163:15-17; *id*. at 172:24-173:8 ("[A]mong the option that we had to place anything on the Well to stem the flow, [BOP-on-BOP] was the best choice we had at the time.").

506. The BOP-on-BOP option also "appealed to [Cameron] greatly with the knowledge that we had and the understanding of the equipment that was available in the area, that that was–that was something that needed to be near the top of the list." Depo. of D. McWhorter, 11/16/2012, 456:22-25, 457:2-7. Of the source control options, BOP-on-BOP "was the quickest," explained Cameron's 30(b)(6) representative David McWhorter "The equipment was—was there. It was on station. The modification was–was minimal." *Id*. at 473:21-474:15.

507. Even Anadarko admitted that "Drilling 101 would have been to immediately cut the Riser and pull the LMRP." TREX-150042.0001 (6/3/10 email from Anadarko's Nancy Seiler discussing BOP-on-BOP options).

508. Following the failure of the Top Kill and the shelving of the BOP-on-BOP option, Stuart Nelson at Cameron wrote "I would have thought they would have needed that BOP on BOP solution more than ever now. It if was up to me I would have done that in the very beginning. Everything they have done so far is an experiment. Releasing the LMRP, cutting the drill pipe and installing a new BOP is the way it was designed to work in the first place." TREX-10514.0001 (5/30/10 Stuart Nelson (Cameron) email re: BP *Horizon*–BOP Pressure Relief Manifold).

509. Moreover, BOP-on-BOP was a top priority for the United States from "sometime shortly" after April 20. Depo. of K. Cook, 524:13-15, 524:17; *see also* Depo. of P. Tooms,

6/17/2011, 477:13-16 (BP executive Tooms's personal suggestion to the United States was that BP should have attempted BOP-on-BOP).

E. <u>The BOP-On-BOP Was A Superior Option To The Top Kill.</u>

510. As discussed in Section XV, BP had little if any reason to believe the Top Kill operation would be successful. The Top Kill operation had numerous risks, including the risk of subsea broach, further erosion of the *Horizon* BOP and a resulting increase in hydrocarbon flow from the well, and the inherent dangers to human safety and life of using high pressure equipment. *See* Section XV.

511. BP's first draft of the "Top Kill Evaluation," dated May 14, 2010, recommended that "[t]he option of installing the *DDII* stack on top of the Horizon stack should be prioritized above the Q4000 operation for executing the kill operation." TREX-8541 at 4 ("Top Kill Evaluation," Revision A); Depo. of M. Patteson, 1/23/2013, 174:23-175:10. The evaluation noted that "[t]he complexity of the current wellbore configuration makes a top kill with the Q4000 very problematic," and that "the Junk Shot and Momentum Kill operations could jeopardize the over integrity of the well system." TREX-8541 at 4 ("Top Kill Evaluation," Revision A). "Failure of critical well integrity components could result in additional flow volume or an underground blowout that could jeopardize drilling of the relief wells." *Id*.

512. BP subsequently removed from its Top Kill Evaluation document the recommendation that "[t]he option of installing the *DDII* stack on top of the *Horizon* stack should be prioritized above the Q4000 operation for executing the kill operation." TREX-8541; *see also* TREX-10508 ("Top Kill Evaluation," Revision C); Depo. of C. Holt, 127:3-128:1, 128:14-18. BP's 30(b)(6) witness on the Top Kill and the BOP-on-BOP was unable to recall why this recommendation was removed. Depo. of C. Holt, 129:2-12. 129:14-20, 129:23-130:9,

130:12-17, 130:19-131:4 ("I don't recall why that was removed out of this particular document.").

513. BP knew that the Top Kill posed "the risk that the injection of bridging materials could completely block the flow of hydrocarbons through the BOP." I. Adams P2 Expert Report, TREX-11737R.0009; TREX-9148.0005 (Top Kill Procedure for MC252-1 Contingency: Alternative LCM Pills). However, BP's approved procedures for the Junk Shot did not describe any contingencies to manage the well's pressure in the event that the Junk Shot completely stopped the flow. TREX-9148.

514. In contrast, the BOP-on-BOP option–as explained above–had multiple venting capabilities. *See e.g.*, G. Perkin P2 Expert Report, TREX-11464R.24 ("A BOP-on-BOP or a Capping Stack solution would have allowed for the control of pressure with the ability to bleed pressure off through the Choke and Kill Lines."); *see also* Depo. of J. Wellings, 210:6-8, 210:10 (confirming that if pressure built up after the second BOP was attached, the BOP-on-BOP option had mechanisms in place to relieve that pressure).

515. Also, the success of Top Kill was heavily dependent on flow rate. *See supra* Section XV.B. In contrast, the BOP-on-BOP was not constrained by flow. Even at a projected flow rate of 70,000 barrels per day, the upward force from the well would not interfere with landing a second BOP. TREX-10517 at 2 (5/2/10 email from Chris Matrice at Stress Engineering) (explaining that the force from the plume "is relatively low as far as thrust is concerned"); Depo. of J. Wellings, 461:7-12; R. Turlak, P2 TT 379:8-21 ("[T]he force from that velocity based on stress engineering's work, it was the–the force would be very little . . . [.]").

516. Capping the well with a second BOP also would not have prevented a later Top Kill attempt. As a BP engineer pointed out during the response, a Top Kill could be attempted

through the capping BOP's choke and kill lines. TREX-10542 (5/8/10 Fleece email re: BOP on BOP); Depo. of J. Wellings, 173:9-16; *see also* TREX-10543 at 22 (Analysis of Well Containment and Control Attempts in the Aftermath of the Deepwater Blowout in MC252) ("Before attempting the top kill, responders should have considered installing equipment, like the capping stack, that could be used to contain enough pressure to shut-in the well."); Depo of C. Holt, 617:6-17, 617:20-618:2, 618:4-7, 618:19-25, 619:2-3 (agreeing that the concept expressed in TREX-10543 at 22 is the same as in Mr. Fleece's May 8 proposal).

517. While Top Kill indisputably failed, a second BOP almost certainly would have successfully shut in the well. *See supra* Section XVIII.A-C.

518. In short, capping the well with a second BOP was a superior option to the Top Kill. G. Perkin P2 Expert Report, TREX-11464R.31 ("BP prioritized the Top Kill and Junk Shot procedures over the BOP-on-BOP solution to shut-in the Well knowing that the BOP-on-BOP solution was the best available technology and most effective solution to shut-in the Well.").

F. BP's Repeated Attempts To Force A Hard Shut-In Were Inconsistent With Its Stated Concerns About The Burst Disks.

519. BP's contentions regarding casing design have been inconsistent between Phase One and Phase Two.

520. In Phase One, BP claimed that the rupture disks had no impact on source control. D. Lewis P1 Expert Report, TREX-8098 at 6, 23 ("The rupture disks were not a weak link in the system;" "[I] do not believe that the use of rupture disks . . . interfered with well-kill operations;" rejecting "Mr. Pritchard's report . . . that [the rupture disks] caused the post April 20 well control efforts to be compromised").

521. Yet in Phase Two, BP alleges that the rupture disks were the primary driver of all source control decisions and the cause of its failure to implement timely source control

alternatives. Depo. of A. Frazelle, 236:13-15, 236:17-237:01, 699:14-20; Depo. of K. Cook, 162:9-15, 573:13-18, 573:21-574:16, 574:19-575:5; Depo. of M. Landry, 634:20-23, 635:25-636:10, 636:12; Depo. of P. Tooms, 157:7-25; TREX-009412.002; TREX-009413; TREX-0011797R.95; I. Adams, P2 TT 1050:20-1052:15, 1069:22-1070:12; J. Dupree, P2 TT 674:12-675:20; G. Perkin, P2 TT 223:1-227:1.

522. But rupture disks would never have been a concern during the response had the casing string not contained rupture disks in the first place. Depo. of A. Frazelle, 237:7-10, 237:12-20. BP designed the Macondo well to include rupture disks to alleviate certain concerns about well integrity during production of the well. TREX-5853; TREX-5861 at 252; TREX-000001 at 76.

523. However, BP has offered no evidence that it ever considered what impact the inclusion and placement of those rupture disks might have on source control efforts during an uncontrolled blowout.

524. Moreover, BP's Phase Two position is inconsistent with its actions immediately following the blowout. BP claimed early on in the source control efforts that well integrity was an issue. If BP was concerned about well integrity and the possibility of a subsea broach, any early efforts to cause a hard shut-in were unreasonable and illogical. TREX-11579R-v2.008. As early as April 24, 2010, BP expressed concerns that ROV interventions could result in a hard shut-in and cause a subsea broach. Depo. of A. Frazelle, 415:14-17, 415:19-416:9, 707:19-708:4, 708:6-11, 708:13-709:4; Depo. of H. Thierens, 679:02-680:21; TREX-6095; TREX-11578R-v2.032; TREX-11579R-v2.006-008. Furthermore, BP's attempted Top Kill procedure in conjunction with the Junk Shot would have had the same effect as a hard shut-in. TREX-11579R-v2.006-008; I. Adams, P2 TT 1050:20-1053:16; D-23793A. These attempts to perform

a hard shut-in of the well are incongruent with BP's stated concerns regarding well integrity and a subsea broach, which caused the abandonment of the BOP-on-BOP operation as a source control option. Depo. of D. Suttles, 509:08-510:25; TREX-11579R-v2.008; G. Perkin, P2 TT 222:19-223:15, 223:19-227:1, 255:18-22; D-20017.

525. BP should have considered source control before deciding to use rupture disks. *See* TREX-7059 at 1-2 (rupture disks "is all that we can fund;" "please call if your capital situation changes and we can do the right thing"); E. Ziegler, P2 TT 522:9-19 ("You need to make the calculations about things that affect the integrity of the well during source control before you drill the well so that you can plan your source control").

G. **<u>The Potential Risks Of The BOP-On-BOP Were Planned For And Effectively Mitigated.</u>**

526. During trial, BP suggested that there were a number of purported "risks" associated with the BOP-on-BOP option. However, each had been mitigated prior to BP's elimination of the BOP-on-BOP option on May 29, and there can be no dispute that the BOP-on-BOP was abandoned as a result of BP's claims about the reason for the Top Kill failure–*i.e.*, the collapse disks – and not because of the risks of LMRP removal, hydrate mitigation, or the other concerns that BP highlighted at trial. Depo. of C. Holt, 207:21-23, 208:1-5, 209:2-5, 209:7, (conceding that BOP-on-BOP was removed as an option because of BP's May 29th presentation regarding the "most likely reason" for Top Kill failure). Depo. of L. Herbst, 495:22-496:3; TREX-9354 at 7 ("Shutting the well in (via BOP on BOP) is no longer a viable option.").

527. As a general matter, BP's litigation position regarding the risks of BOP-on-BOP is contradicted by the conclusions its own engineers reached during the response effort.

528. Around May 14, 2010, BP's peer assist team concluded that the BOP-on-BOP option "is feasible and can be managed safely," and that the "[k]ey risks had all been identified."

TREX-10505.0005 (MC 252 Top Preventer Peer Assist Recommendations); *see also* Depo. of A. Frazelle, 657:10-19 ("I still agree with that statement.").

529. BP's Jim Wellings, the head of the capping team, also testified that the capping team had "worked through and mitigated the risks involved . . . [.] I certainly thought it was a feasible solution." Depo. of J. Wellings, 111:18-112:10, 112:12-17. Wellings also confirmed that the operational risks identified in the peer assist could be managed. *See id*. at 238:14-16; Depo. of C. Holt, 87:18-21, 87:24-88:2, 88:4-5 ("It says you can do it with the identified mitigation of the risk.").

530. Charles Holt, BP's 30(b)(6) witness for BOP-on-BOP, didn't "recall any conversations that said that the BOP on BOP would not be possible." *Id*. at 221:7-11, 221:13-16. "From an operations perspective, it was something that – that [BP] believed that we could manage the risk around." *Id*. at 221:17-20, 221:22-24.

1. *The Low Risk Of Rupture Disk Failure Could Be Mitigated By The BOP-On-BOP's Numerous Venting Options.*

531. BP's main argument at trial about the BOP-on-BOP option was that it posed an undue risk to the rupture disks and of causing a subsea broach.

532. Initially, it is now clear that the rupture disks were not open and that hydrocarbons were not flowing up the annulus where the rupture disks were located. I. Adams, P2 TT 1134:22-1136:1. Thus, if the BOP-on-BOP had been used, it would not have caused a disk failure or broaching to the seabed.

533. BP's argument that perceived risks of a disk failure justified favoring Top Kill over the BOP-on-BOP option does not stand up to scrutiny. First, as explained *supra* in Section XVIII.A., BP did not raise a concern about venting excess pressure to avoid rupture disk failure

until on or about May 15, 2010. Thus, concerns about disk failure or broaching cannot explain BP's decision not to implement the BOP-on-BOP option prior to May 15, 2010.

534. Even after May 15, BP knew that the chance of burst disks failure during shut-in was low. On May 16, BP engineers calculated that the shut in pressure would be 8,400 to 8,900 psi, and that even the high-end of this range was still "below the 16" burst disk rupture pressure by 1,000 psi +/-." TREX-10512 at 15-16; TREX-10507 at 7 (May 14 BP document stating at the maximum pressure "the Burst Disk will not fail").

535. BP concluded by May 22 that "there is less than a 4 % chance of burst disk failure if the well is shut-in and no other preventative activities are taken." TREX-10531.0003 (5/22/10 BP Technical Note Entitled "Probability of Rupture Disk Failure during shut-in"). BP's analysis found a sub-4% chance of burst disk failure if "no other preventative activities are taken." *Id*.

536. But BP knew by May 22, as discussed above in Section XVIII.A, 2, 5, 6, that the BOP-on-BOP had numerous options for preventing burst disk failure and broaching. The BOP-on-BOP's pressure venting options were similar to (if not superior to) the venting capabilities of the capping stack that safely shut in the well. These venting capabilities effectively eliminated the already low risk that the BOP-on-BOP option would cause rupture disk failure or broaching to the seabed upon shut-in. G. Perkin P2 Expert Report, TREX-11464R.24 ("A BOP-on-BOP or a Capping Stack solution would have allowed for the control of pressure with the ability to bleed pressure off through the Choke and Kill Lines."); *see also* Depo. of J. Wellings, 210:6-8, 210:10 (agreeing that if pressure built up after the second BOP was attached, the BOP-on-BOP option had mechanisms in place to relieve that pressure).

537. Moreover, the risk of a subsea broach impacting the relief well efforts could have been mitigated by cementing casing into the relief well below the depth of a potential broach,

just as BP suggested as a mitigation option for the Top Kill. J. Dupree, P2 TT 661:11-662:12 (explaining how BP mitigated the risk of impacting the relief well prior to Top Kill).

2. *Any Risks Of LMRP Removal Had Been Mitigated.*

538. At trial, BP argued that the removal of the *Horizon* LMRP – a step in the BOP-on-BOP installation procedures–posed undue risks and justified favoring Top Kill over BOP-on-BOP, but that claim does not withstand scrutiny.

539. The Cameron LMRP on the *Horizon* stack is designed to be lifted safely off the lower BOP when the BOP stack is subsea. Depo. of D. McWhorter, 11/16/2012, 514:9-515:15. As Cameron's 30(b)(6) representative testified, "[T]he LMRP is actually designed to be taken off the BOP." Depo. of D. McWhorter, 11/15/2012, 143:3-8; *see also* TREX-10514 at 1 (5/30/10 Stuart Nelson (Cameron) email re: BP *Horizon*–BOP Pressure Relief Manifold ("Releasing the LMRP, cutting the drill pipe, and installing a new BOP is the way it was designed to work in the first place."). Thus, LMRP removal "could have been done." Depo. of D. McWhorter, 11/15/2012, 143:3-16.

540. BP's own peer assist for the BOP-on-BOP examined the risk of LMRP removal. That contemporaneous analysis found that problems with LMRP removal posed a "low probability" risk. TREX-10505 at 5 (BP Peer Assist Presentation).

541. BP's claims today about the risk of LMRP removal are also undercut by the fact that BP prepared and approved "Lower Marine Riser (LMRP) Removal Procedures." Unified Command likewise approved these LMRP removal procedures by May 25, 2010. TREX-141123.0001 (Macondo: Lower Marine Riser (LMRP) Removal Procedures for MC-252 #1).

542. The procedures contained contingencies for pulling the LMRP if the LMRP failed to release from the lower BOP. TREX-141123.0012 (Macondo: Lower Marine Riser (LMRP) Removal Procedures for MC-252 #1); I. Adams, P2 TT 1154:16-24.

3. *BP Had Also Addressed Alleged Drill Pipe Risks.*

543. During trial, BP raised a specific concern about risks associated with drill pipe being found in the *Horizon* BOP.

544. But according to BP's Well Operations Manager Andrew Frazelle, who was a member of the BOP-on-BOP peer assist team, "debris inside the BOP" was not a concern "because of numerous ways for removal of that debris." Depo. of A. Frazelle, 254:19-23; TREX-6212.0025 (Peer Assist Participants).

545. For example, "[t]he contingency procedure for cutting drill pipe sticking out of the *Deepwater Horizon* BOP after the removal [of the LMRP] was approved May 27." I. Adams Expert Report, TREX-011737R.13. The approved LMRP removal procedures explained that diamond wire saws on ROVs would be used to cut any drill pipe that was found in between the *Deepwater Horizon* lower BOP and LMRP. TREX-141123.0007 (Macondo: Lower Marine Riser (LMRP) Removal Procedures for MC-252 #1) ("Two Diamond Wire Saws will be located on the [ROV] which will be used to cut Drill Pipe/Casing stub proud of the DWH stack when the DWH LMRP is pulled (if required).").

546. BP used a demonstrative at trial that purported to show that ROVs would have had difficulty reaching a piece of drill pipe located between the *Deepwater Horizon*'s lower BOP and LMRP. *See* D-23769.1.1. BP, however, introduced no contemporaneous exhibits that showed a lack of ROV access to drill pipe was actually a concern during the response. To the contrary, the BP-led peer assist and the BP-approved LMRP Removal Procedures do not mention any risk associated with ROVs being unable to reach the drill pipe because of inadequate clearance. TREX-10505 (BP Peer Assist Presentation); TREX-141123 (LMRP Removal Procedures).

547. Moreover, BP failed to present any expert testimony substantiating the demonstrative's suggestion that ROVs would have had difficulty accessing and cutting any drill pipe found between the two BOP structures.

548. Further mitigating any risk of LMRP removal, as of April 29, 2010, there was evidence the casing shear rams had closed and had sheared whatever was across them. Depo. of D. McWhorter, 11/16/2012, 507:25-508:16; TREX-10080.0030 (Don King notes from 4/29/10) ("[s]hear event happened"). David McWhorter was present during the closing of the casing shear rams, and observed a reduction in flow from the closing of the casing shear rams. Depo. of D. McWhorter, 11/16/2012, 446:22-447:9.

549. After closure of the casing shear rams, "the problem of – of a drill pipe tethering the LMRP to the formation can largely be disregarded" because the rams would have sheared any pipe at that point. Depo. of D. McWhorter, 11/16/2012, 509:13-14, 509:16-20, 510:16-20 (agreeing that "the problem of whether or not there's something inside the wellbore is no longer present after the casing shear rams close"). From the subsequent investigation, there is no dispute that the casing shear ram "did close" and "did cut the pipe." *Id*. at 515:22-516:2.

550. BP has also suggested that drill pipe could damage the connector on top of the *Deepwater Horizon*'s lower BOP that the *DDII* or *Enterprise* BOP's would latch onto. At the BP-led peer assist, however, the risks of "Connector Damage" and "Seal Damage" during LMRP removal were identified and detailed "Contingency Procedures" for the "Correction of Leak in the Interface Connection between *DDII* and *DWH* BOPs" were developed. TREX-10505 at 24 (MC 252 Top Preventer Peer Assist Recommendations); TREX-140700.0014 (BOP on BOP Capping Procedures). BP presented no evidence at trial that its procedures were inadequate to mitigate the risk of connector damage.

551. Also, LMRP removal may not have been necessary. Mr. Perkin explained that the LMRP would not necessarily have to be removed for the BOP-on-BOP operation. G. Perkin, P2 TT 268:18-22. "You could build a crossover between the – if you cut off the riser, you remove the flex joint, you can make an adapter between the two." *Id*. BP expert Iain Adams also suggested that "[p]robably landing [the second BOP] on the flex joint could probably have been engineered . . . ." I. Adams, P2 TT 1088:9-24.

4. *The Weight Of The Second BOP Also Did Not Pose An Undue Risk.*

552. BP's purported concerns about the weight of a second BOP stack on the *Deepwater Horizon*'s "listing" BOP also are unsupported by the evidence. Depo. of J. Wellings, 141:11-23, 141:25-142:13.

553. The capping team examined the angle of the *Horizon* BOP and determined that it was feasible to attach a second BOP. Depo. of J. Wellings, 215:24-216:4. Transocean's engineering group ran "a BOP on BOP engineering study to make sure that was going to be safe to operate the *Enterprise* on top of the *Horizon*'s BOP," and verify that the weight of the second BOP would not present any problems. Depo. of G. Boughton, 103:22-104:20. BP did "some checks on the [*DDII*] BOP stack weight." Depo. of J. Wellings, 141:11-23, 141:25-142:13; TREX-140700.0023-.0072 (Stress Engineering Weak Point Analysis: Development Driller 2 Drilling Riser on *Horizon* Lower Stack).

554. In its BOP-on-BOP Capping Procedures, BP confirmed "that an engineering design analysis has been performed on the BOP on BOP load analysis. The analysis concluded the *DDII* could operate under tightened watch circles during this intervention. In the event the *DDII* must disconnect its LMRP, the remaining *DDII* BOP on the DWH BOP was also analyzed and found adequate to support the loads." TREX-140700.0007 (BOP on BOP Capping Procedures for MC-252 #1).

555. Because the second BOP would ordinarily be connected to a rig by a riser, the weight (or downward force) of the second BOP would not be borne by the *Horizon* lower BOP. The *Discoverer Enterprise* or *DDII* would "have to keep the riser and the BOP in tension. There's no compression. There's no–you are not squashing or structurally impeding the *Horizon*'s BOP." G. Perkin, P2 TT 271:1-9.

5. *The Risks Of Hydrates Also Had Been Mitigated.*

556. The capping team had also addressed the issue of hydrate mitigation for the BOP-on-BOP option. The capping team had the same plans for the BOP-on-BOP option that were used successfully for the capping stack. R. Turlak, P2 TT 380:11-19 (testifying that hydrate mitigation for the second BOP was "[t]he same way we did it on the capping stack"). For "[e]ither the BOP on BOP or the capping stack, [the plan was to] bring it in just above the plume, where the plume's coming out of the wellhead, and that's where the hot oil is. And so it wouldn't – it would – very unlikely to cause problems with the hydrates when you're stall – installing the cap, basically." Depo. of J. Wellings, 282:14-23.

6. *Maintenance Of The Enterprise Or DDII Bops Did Not Pose A Risk To The BOP-On-BOP Project.*

557. BP also suggested at trial that the *Enterprise* and *DDII* BOPs required maintenance before they could be deployed for the BOP-on-BOP operation.

558. The evidence indicates, however, that the maintenance issues BP has identified did not delay implementation of the BOP-on-BOP strategy.

559. By May 5, 2010, maintenance on the *Enterprise* BOP was "finished," TREX-11229.0002 (May 5 capping team meeting minutes); Depo. of J. Wellings, 146:3-11, and as of May 6, "Testing of [the] Enterprise BOP prior to deployment" was "completed." TREX-9787.0013 (BP BOP-on-BOP HAZID) ("Testing completed.").

560. *DDII* BOP testing "was completed on or around May 30th." Depo. of C. Holt, 385:15-17, 385:19-25; R. Turlak, P2 TT 407:21-408:1 ("I thought all the repairs were done much prior to the 10th of June."); R. Turlak, P2 TT 408:21-409:4 (testifying that deadman issues "had been fixed way before" June 5); I. Adams P2 Expert Rebuttal Report, TREX-11738R.005-.006 (acknowledging that repairs to the *DDII* BOP were completed by May 29) (footnote omitted).

561. Moreover, the condition of the casing shear rams on either the Enterprise or *DDII* BOPs would not have impacted the ability of either BOP to shut in the well. Unlike a BOP being used to drill a live well, the BOP-on-BOP solution did not require casing shear rams. R. Turlak, P2 TT 410:13-21 ("My point was that if you were running BOP-on-BOP, this problem really wouldn't be a problem because you wouldn't need your casing shear rams."). The capping stack used to shut in the well did not have casing shear rams. I. Adams, P2 TT 1157:7-11.

7. *The Plume Did Not Present Significant Force Or Visibility Issues For The BOP-On-BOP Option.*

562. Any purported concerns about the upward force of the plume had been identified and addressed in early May. *See* TREX-9787.0012 (HAZID Action List – Status as of 6th May 2010) (stating that Wellings "[c]ompleted" an analysis of the upward force from the plume "in order to judge whether the positioning of the Enterprise BOP, as planned, is feasible"); TREX-10517 at 2 (5/2/10 email from Chris Matrice at Stress Engineering) (explaining that the force from the plume "is relatively low as far as thrust is concerned"); Depo. of J. Wellings, 460:3-461:2; R. Turlak, P2 TT 379:8-21 ("[T]he force from that velocity based on stress engineering's work, it was the – the force would be very little . . . .").

563. While "[s]ubsea visibility and close control" were raised as risks during the Peer Assist, the Peer Assist team nonetheless concluded "that the BOP on BOP operation is feasible

and can be managed safely." TREX-10505 at 5 (MC 252 Top Preventer Peer Assist Recommendations).

564. Moreover, any concerns about visibility or the upward force of the plume are belied by the successful landing of the lighter capping stack on the Macondo well. D-26007 (video of capping stack landing); E. Ziegler, P2 TT 540:18-541:17 ("[I]f the capping had occurred back in the middle of May – ROVs with cameras had been down there and you could see there were no visibility problems. There were no hydrates that were related to the top of the well situation.").

XIX. Transocean Provided Valuable Assistance In The Response But Was Not A Decision-Maker.[2]

A. <u>Transocean Provided Substantial Support For The Capping Options.</u>

565. Transocean provided substantial equipment and expertise for the capping solutions that culminated in the successful capping of the Macondo well.

566. Immediately after the blowout, "Transocean deployed a dedicated team of Engineers and Subsea BOP Specialists to provide solutions for Capping the hydrocarbon release from the *Deepwater Horizon* Blowout Preventer." TREX-11226 at 3 (*Deepwater Horizon* Incident: Well Capping Strategies).

567. Transocean "provided the subsea expertise" for the capping team. Depo. of J. Wellings, 276:15-16, 276:18-24; R. Turlak, P2 TT 365:22-25. The capping stack was "brought up immediately" by Transocean subsea engineer John Mackay. Depo. of G. Boughton, 70:18-25.

[2] Plaintiffs, Claimants-in-Limitation, including the State of Alabama and the State of Louisiana, through Plaintiffs' Co-Liaison Counsel, Coordinating Counsel for the States, the Plaintiffs' Steering Committee, and the PSC Phase Two Trial Team, and HESI join in this section with the exception of paragraphs 574, 575, 576, 581, and 582.

568. "Transocean searched all available BOP equipment worldwide to mobilize in the capping effort," and "[e]quipment was mobilized and constructed for the capping effort." TREX-11226 at 3 (*Deepwater Horizon* Incident: Well Capping Strategies); Depo. of J. Wellings 33:8-18.

569. Transocean eventually supplied "the majority of the equipment" needed for the capping efforts. *Id*. at 256:7-8, 256:10-16. "The two-ram capping stack, that was a combination of Transocean-owned and Cameron-owned equipment. The DISCOVERER ENTERPRISE capping stack, that—that was the BOP stack from the DISCOVERER ENTERPRISE that was owned by Transocean. The three-ram capping stack, that was equipment—was actually the two-ram capping stack with another stack—another ram added. So that was Transocean and Cameron who owned that equipment. The DEVELOPMENT DRILLER II, the BOP was owned by Transocean." *Id*. at 43:6-23.

570. For the BOP-on-BOP options, Transocean mobilized numerous on and off-shore employees to manage necessary tasks for the second BOP's deployments. *See e.g.*, TREX-144951.0002 (Project Plan for *Development Driller II*–Stack on Stack option) (identifying "Sub Sea Engineering tasks" and "*DD II* rig specific activities"); TREX-144963.0002 (same).

571. BP also tasked Transocean's subsea engineers to manage numerous tasks for the three-ram capping stack. *See e.g.*, TREX-11234 at 1 (6/9/10 Wellings email re: Capping Stack Reunion); TREX-144986.0003 (5/27/10 Project Plan).

572. Transocean "kept pushing and kept building" the capping stack. Depo. of G. Boughton, 72:19-73:9. When the BOP-on-BOP was taken off the table, Jim Wellings asked Rob Turlak and David Cameron from Transocean to "see [the three-ram capping stack] through completion and testing." TREX-7104 at 3 (5/30/10 Wellings email re: Thanks For the Good

Work BOP on BOP and Capping Stack Team); R. Turlak, P2 TT 359:6-12 ("[BP] still wanted us to move ahead and try to complete the three-ram capping stack as soon as possible.").

573. For the capping stack that shut in the well, "Cameron and Transocean supplied the equipment. And then they worked with Oceaneering to provide the control systems, the ROV control systems. And [Transocean], in conjunction with, I believe it was Oceaneering, actually built the emergency disconnect system for the capping stack." Depo. of J. Wellings, 278:2-6, 278:9-16.

574. Furthermore, unlike BP, when faced with a problem, Transocean immediately and transparently addressed and corrected it. In the early days of the spill, while the state of the BOP was still unknown, several attempts were made to activate the rams of the BOP. *See e.g.*, Rec. Doc. 7076, ¶ 23, 25, 31, 33, 45-46, 49 (2:10-md-02179-CJB-SS). However, prior to the incident, BP had requested that Transocean convert the lower pipe ram into an inverted test ram. Depo. of G. Boughton, 172:6-13. The ROV panel was plumbed to the test ram rather than the middle variable bore ram. Depo. of G. Boughton, 171:16-172:5. Once Transocean discovered the misplumbing error, it told BP. Depo. of H. Thierens, 31:15-24 (a Transocean representative "was doing some diagnostic work with the ROV and relayed that information to the control room"). It was also discovered that BP and Transocean were using the original schematics rather than ones updated with the plumbing change. Depo. of G. Boughton, 172:14-22 ("[W]hen we got there and we found that it was plumbed – still plumbed to the lowest ram, and that was the original way it was drawn into the original drawings."); J. Dupree, P2 TT 603:2-7 ("[W]e had the wrong drawings."). When Transocean discovered that the schematics were wrong, it immediately located updated schematics, which it had "within the first day or two" of Transocean staff being onsite at BP. Depo. of G. Boughton, 95:24-96:3.

575. Regardless, neither the misplumbing nor the schematics caused any real delay in response efforts. Post-incident analysis showed that the variable bore rams had already been closed by the crew prior to the explosion on April 20. Depo. of G. Boughton, 172:23-173:2, 173:6-11. Phase I experts uniformly agreed that the upper and middle variable bore rams must have been closed by the drill crew at about 9:46 p.m. and that they were fully closed by about 9:47 p.m. *See* R. Davis, P1 TT 2758:18-20; G. Childs, P1 TT 5114:8-12; G. Stevick, P1 TT 6923:7-10; F. Shanks P1 Expert Report, TREX-40008 at 29.

576. Moreover, BP's witnesses testified at trial that all source control efforts were pursued in parallel. D-23231A ("Source Control Options Progressed on Parallel Tracks"); J. Dupree, P2 TT 599:21-600:12 ("[W]e [we]re engineering, as I said, everything immediately: Cofferdam, capping stack, Top Kill, BOP-on-BOP, RITT insertion tools, Top Hat, and then what we call 'containment' . . . [.]"). There is no indication that ROV intervention delayed any other effort. *See* D-23231A (showing ROV intervention taking place from April 21-May 5; relief wells started April 21; Cofferdam started April 23; capping stack started April 23; Top Kill started April 25; and BOP-on-BOP started April 27).

B. <u>BP And Cameron Recognized That Transocean Provided Valuable Assistance To Source Control Efforts.</u>

577. Charles Holt, BP's 30(b)(6) witness for BOP-on-BOP, had no complaints about Transocean's work on the capping team and agreed that "Transocean was providing quite a bit of equipment and knowledge and resources to support the well capping effort." Depo. of C. Holt, 405:1-12.

578. BP Wells Operations Manager Andrew Frazelle agreed that "there were many Transocean Engineers and BOP Specialists who were sent to BP to help both come up with solutions to cap the well and to provide equipment to cap the well." Depo. of A. Frazelle,

410:13-18. "Transocean was very heavily involved in providing and—and sourcing equipment from spares and–and were active Team Members in that process," and Transocean's participation "was very welcomed, and what they brought to the table was—was—was excellent work, yes." *Id*. 421:11-14, 421:16-422:7.

579. Cameron agreed that Transocean "provided a lot of the equipment that was used to make the capping stack," and had equipment available "shortly after the incident." Depo. of D. McWhorter, 11/16/2012, 448:25-449:20.

580. Separate from Transocean's work on the capping team, Lamar McKay, Chairman and President of BP America, testified that he thought the Transocean crews on the *DDII* and *DDIII* did a good job drilling the relief wells. Depo. of L. McKay, 481:25-482:10.

C. <u>BP, Not Transocean, Was Responsible For Source Control Efforts.</u>

581. Lars Herbst, the MMS representative for Unified Command during the response efforts, confirmed that "it was not the drilling contractor's responsibility to control the source; it was the operator's responsibility." Depo. of L. Herbst, 452:10-13, 452:15. Accordingly, in this instance, he agreed "it wasn't Transocean's responsibility to control the source; that was BP's responsibility." *Id*. at 452:16-19, 452:21.

582. Absent being designated an agent, a drilling contractor is generally not regarded as a well operator. *Id*. at 465:15-19. For the Macondo Well, Transocean was not the lessee, an MMS-approved designated agent of the lessee, or the holder of operating rights under an MMS-approved assignment. *Id*. at 465:20-466:14.

583. Transocean had no role or input in the preparation of BP's OSRP. Depo. of E. Bush, 129:20-130:19. Drilling contractors are not required to file oil spill response plans because they are not responsible for directing source control efforts. Depo. of L. Herbst, 453:5-14, 453:16; Depo. of L. McKay, 492:11-19, 492:21 (testifying that BP does not look to

Transocean to submit a response plan, and agrees that the government doesn't look to Transocean for a response plan); E. Ziegler P2 Expert Report, TREX-11578R-v2.043 ("BP is solely responsible for Source Control at Mississippi Canyon Block 252 ("MC 252") for the Macondo well.").

584. Transocean was not responsible for source control efforts following the Macondo blowout.

D. Transocean Was Not A Decision-Maker.

585. Following the period of BOP intervention,[3] any source control "procedures would have been developed by the responsible party, in this case BP with–with oversight approval by both Coast Guard and MMS at the time." Depo. of L. Herbst, 471:25-472:4, 472:6-10; *see also* Depo. of D. Barnett, 170:16-17, 170:19 (Transocean was not calling the shots); Depo. of S. Hand, 223:25-224:2, 224:4 (BP, not Transocean, weighed the risks and determined which source control methods were appropriate.); Depo. of M. McNutt, 473:16-21, 473:23 (McNutt "did not witness" Transocean acting as a decision maker for source control).

586. Transocean did not have the power to direct source control interventions. Depo. of L. Herbst, 470:7-19; TREX-9147 at 3 (Procedure Approval Process and Approval Authority). Transocean could not even conduct source control operations without approval from MMS, the U.S. Coast Guard, and BP. Depo. of L. Herbst, 471:7-16, 471:18; *see also id*. at 474:2-3, 474:5 (Transocean did not have the power to act on their own without "BP and government oversight.").

587. Transocean did not approve the Cofferdam procedure. *Id*. at 476:5-12; TREX-9121 at 1 ("Modified Cofferdam Installation Procedure with Helix Q4000 Vessel.").

[3] During the early stages of BOP intervention, formal approval processes were not in place. Depo. of L. Herbst, 471:19-24

588. Transocean did not approve the Top Kill procedure. TREX-9353.0002 (5/26/10 letter from Doug Suttles to Rear Admiral Landry regarding the Top Kill Operation); J. Dupree, P2 TT 725:3-4; Depo. of L. Herbst, 480:6-12, 486:12-15.

589. For the duration of the source control efforts, Transocean had no authority to decide whether to implement any particular source control methods.

E. <u>Transocean Did Not Have BP's Flow Rate Estimates And Analysis.</u>

590. As discussed in Section XIII, throughout the response efforts BP repeatedly concealed flow rate information both internally and externally.

591. In many instances, BP employees were specifically directed to not share flow rate information outside of BP. *See e.g.*, *supra*, XIII.K; *see also* TREX-9475.0002-.0003 (5/17/10 Lynch email) ("We remain in a position where no flow related information can be released internally or externally."); J. Wilson P2 Expert Report, TREX-11900.0033-.0034 (detailing numerous other examples); *see also* Depo. of O. Rygg, 245:8-15 (BP contractor Add Energy did not send its analysis or reports to Transocean).

592. There was no evidence presented at trial that BP's internal flow rate estimates, flow analyses, or Top Kill analyses were shared with Transocean.

XX. No Party In This Litigation Brought Forth Any Evidence Suggesting That HESI's Conduct In Relation To Source Control Was Anything Other Than Exemplary.

593. No party in this case put forth any evidence of any improper conduct on the part of HESI in connection with the attempts to stop the flow of hydrocarbons from the Macondo well during the period April 22, 2010 through September 19, 2010. Depo. of T. Allen, 610:23-611:13; Depo. of M. McNutt, 477:15-23, 477:25-478:4, 478:6-15; Depo. of M. Sogge, 479:2-480:2; Depo. of K. Cook, 599:17-600:2; Depo. of A. Ratzel, 568:22-569:3; Depo. of J. Rohloff, 325:23-326:4, 326:8-24; Depo. of M. Landry, 647:12-22; Depo. of D. Maclay, 539:8-17, 539:20-

21; Depo. of E. Bush, 134:16-25; Depo. of D. McWhorter, 11/16/2012, 477:15-478:2; Depo. of E. Shtepani, 152:10-15; Depo. of T. Lockett, 433:17-434:9; Depo. of F. Saidi, 423:13-18; Depo. of T. Hill, 538:17-539:7; Depo. of M. Mason, 530:21-531:11; Depo. of M. Havstad, 479:3-20; Depo. of M. Levitan, 429:24-430:8; Depo. of M. Gochnour, 451:15-19, 451:21-22, 451:24-25, 452:8-14; Depo. of A. DeCoste, 194:21-25; Depo. of A. Ballard, 528:11-15, 529:1-3.

594. HESI had no role in directing any source control efforts and had no approval authority in relation to the relief and/or source control efforts. Depo. of M. McNutt, 477:15-23, 477:25-478:4, 478:6-15; Depo. of S. Hand, 417:25-418:11; Depo. of L. Herbst, 556:2-17; Depo. of M. Sogge, 479:22-480:2; Depo. of T. Allen, 609:12-610:22; Depo. of J. Rohloff, 328:8-25; Depo. of R. Brannon, 272:1-13; Depo. of M. Havstad, 480:9-16; Depo. of D. McWhorter, 11/16/2012, 477:10-14; Depo of T. Allen, 608:17-609:1, 609:3-11; Depo. of L. Herbst, 556:2-17.

595. HESI and its representatives were not part of the Unified Command team. Depo of M. Landry, 648:2-649:17; Depo. of T. Allen, 608:17-609:1, 609:3-610:22; Depo. of C. Henry, 499:9-500:10; Depo. of J. Rohloff, 328:8-25.

596. No party in this case has put forward any evidence of any criticism against HESI in connection with any act or omission related to the source control efforts. Depo. of M. Mason, 531:12-18; Depo. of S. Hand, 418:12-16; Depo. of S. Chu, 235:7-236:12; Depo. of T. Lockett, 434:10-19; Depo. of S. Carmichael, 239:8-18; Depo. of E. Shtepani, 152:10-15; Depo. of A. DeCoste, 195:1-4, 195:8-17; Depo. of D. Barnett, 299:13-300:10; Depo. of E. Bush, 135:1-8, 135:12.

597. HESI had no input or involvement in relief well planning and did not assist BP in developing its oil spill response plan. Depo. of O. Rygg, 284:9-287:1; Depo. of J. Rohloff, 325:15-18; Depo. of L. Herbst, 556:2-17; Depo. of R. Vargo, 8/22/2012, 143:2-7, 143:9-10.

598. HESI had no input or involvement in the NOAA's quantification estimates or the work of the NOAA Plume Team. Depo. of C. Henry, 497:19-22, 497:24-498:5, 498:7-12, 498:15, 498:19-22, 498:24; Depo. of W. Lehr, 476:22-477:13.

599. HESI had no input or involvement in BP's quantification estimates and did not participate in BP's analysis of Macondo's flow rate. Depo. of T. Hill, 538:17-539:11, Depo. of F. Saidi, 421:15-21.

600. HESI did not give any directives related to the two-ram Capping Stack or Top Kill operations. Depo. of M. Patteson, 1/24/2013, 208:24-209:8; Depo. of D. McWhorter, 11/16/2012, 477:10-478:2.

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CERTIFICATE OF SERVICE

I hereby certify that the above and foregoing Aligned Parties' Proposed Findings of Fact and Conclusions of Law have been served on All Counsel by electronically uploading the same to Lexis Nexis File & Serve in accordance with Pretrial Order No. 12, and that the foregoing was electronically filed with the Clerk of the Court of the United States District Court for the Eastern District of Louisiana by using the CM/ECF System, which will send a notice of electronic filing in accordance with the procedure established in MDL 2179, on this 20th day of December 2013.

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