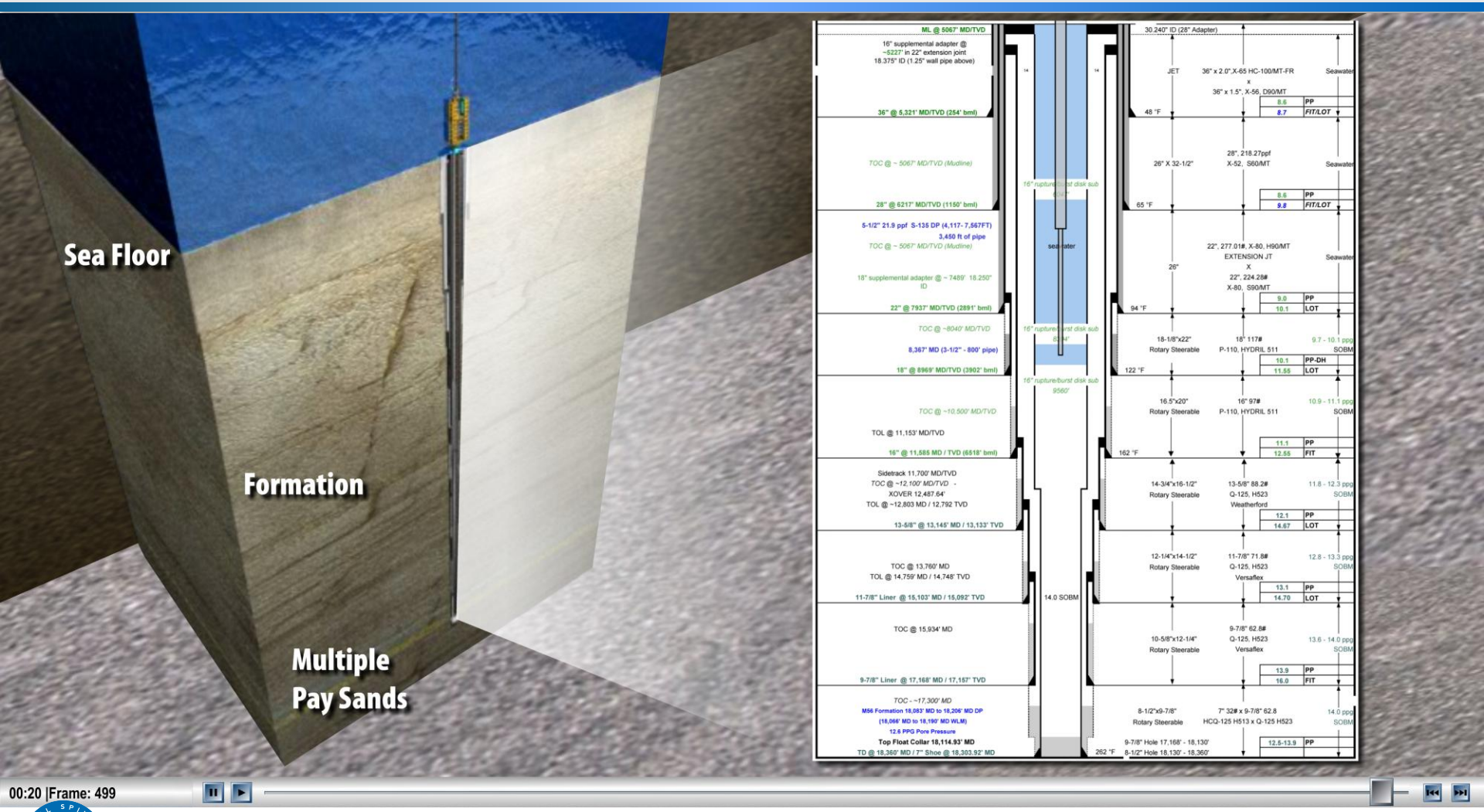
The National Commission on the

BP DEEPWATER HORIZON OIL SPILL AND OFFSHORE DRILLING

TRIAL GRAPHIX

The Deepwater Horizon

Macondo Well



00:20 |Frame: 499

Companies Involved at Macondo

bp

Rig and drilling — Transocean

HALLIBURTON | Sperry Drilling — Surface data logging

Cementing — HALLIBURTON

CAMERON — Blowout preventer

Drilling mud — MI SWACO, A Schlumberger Company

OCEANEERING® — ROV support

Well and cement logging — Schlumberger

Setting a global standard — DRIL-QUIP®

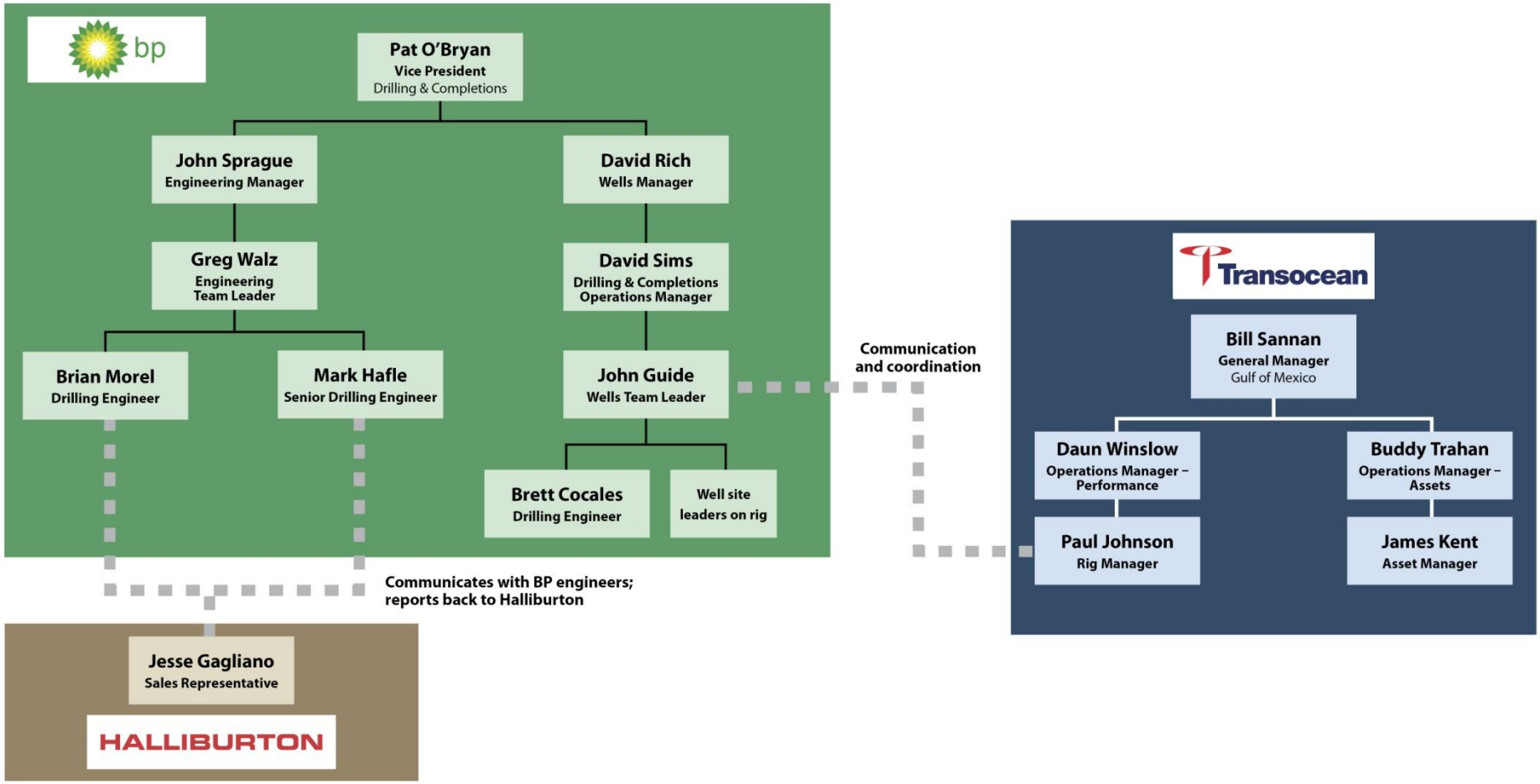
Wellhead, casing hangers

Weatherford® — Centralizers, float collar, shoe track

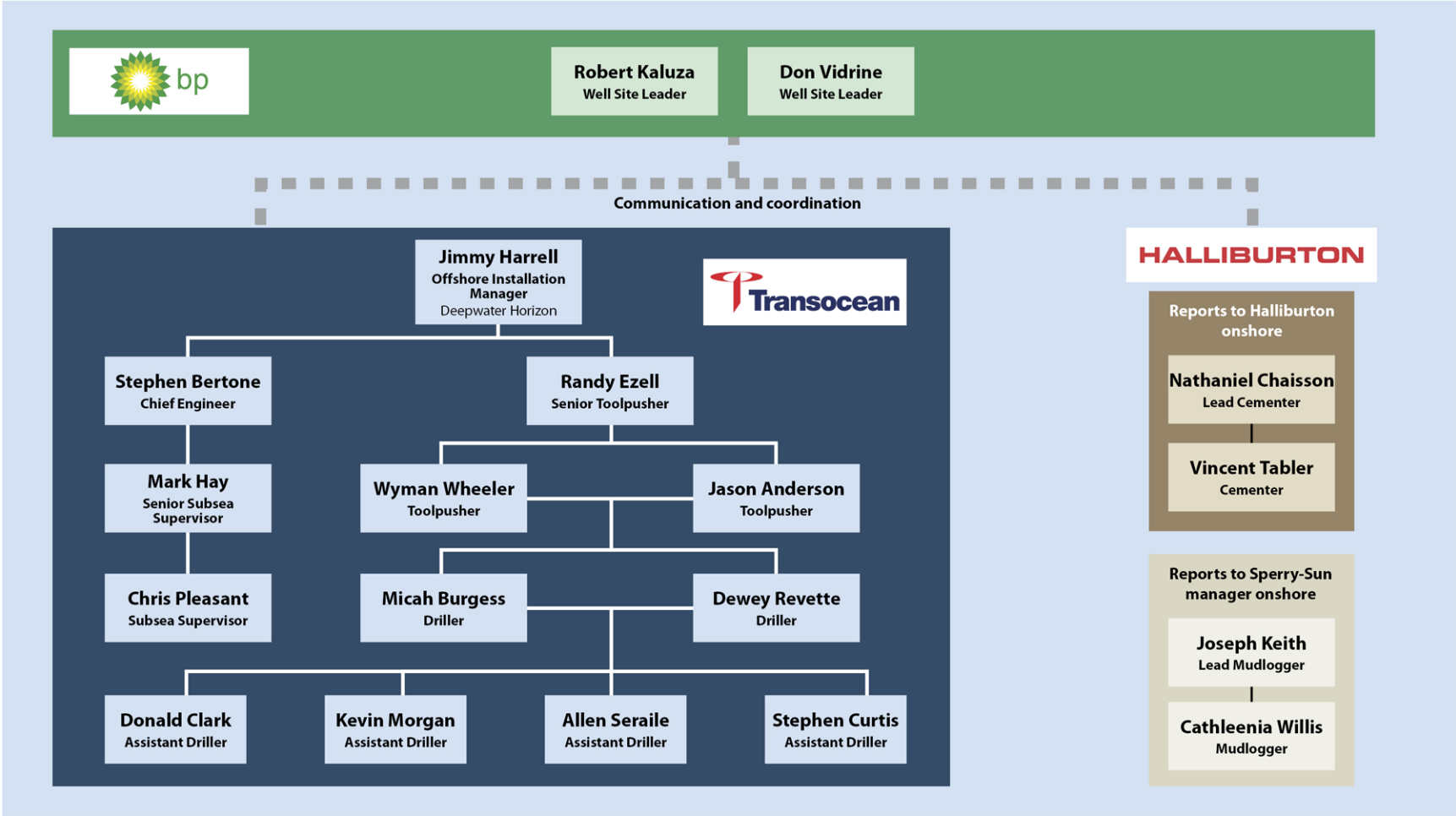
OIL SPILL COMMISSION OSC

TRIAL GRAPHIX

Onshore Organizational Chart

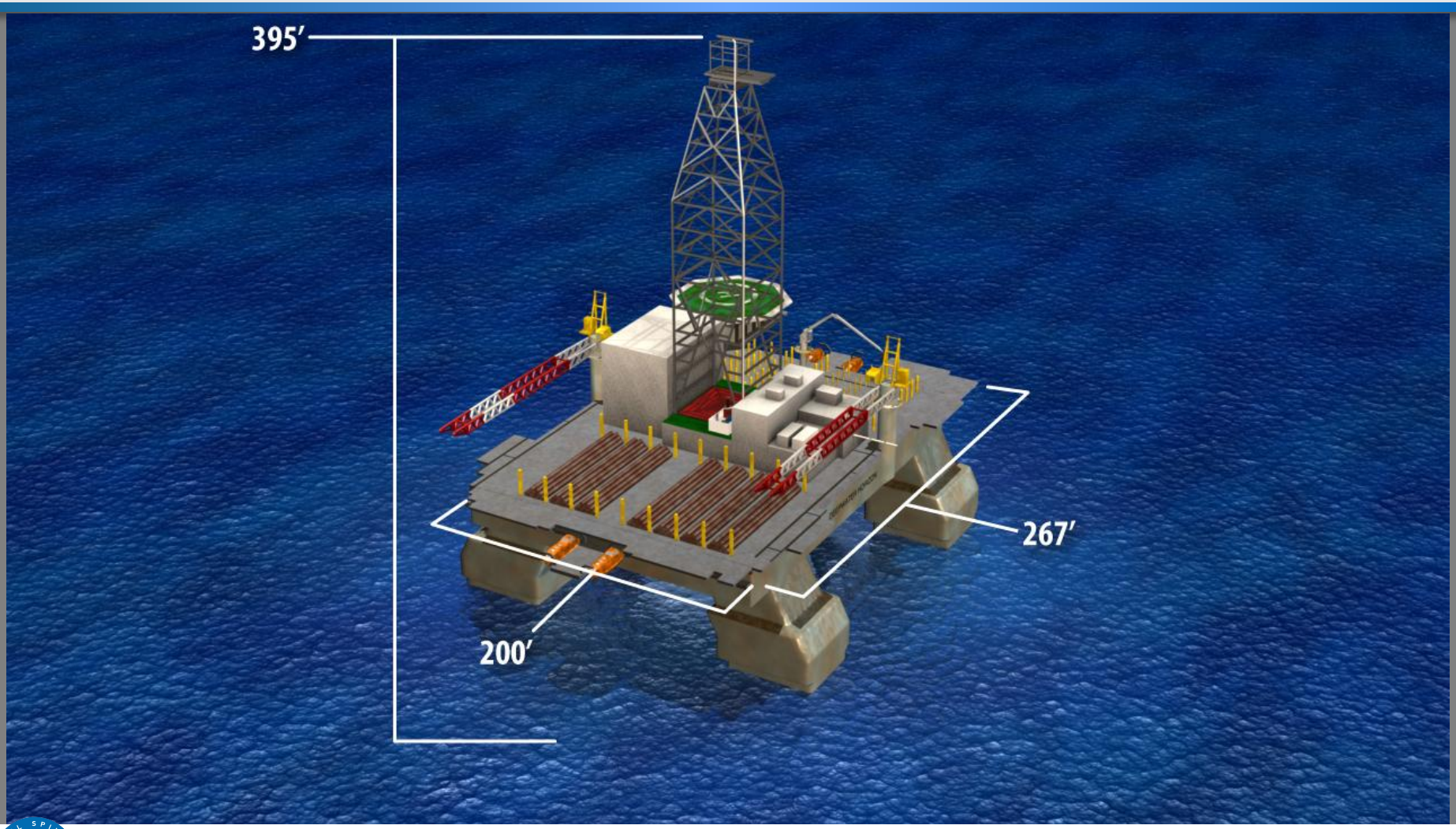


Rig Crew Organizational Chart



Deepwater Horizon

Deepwater Horizon



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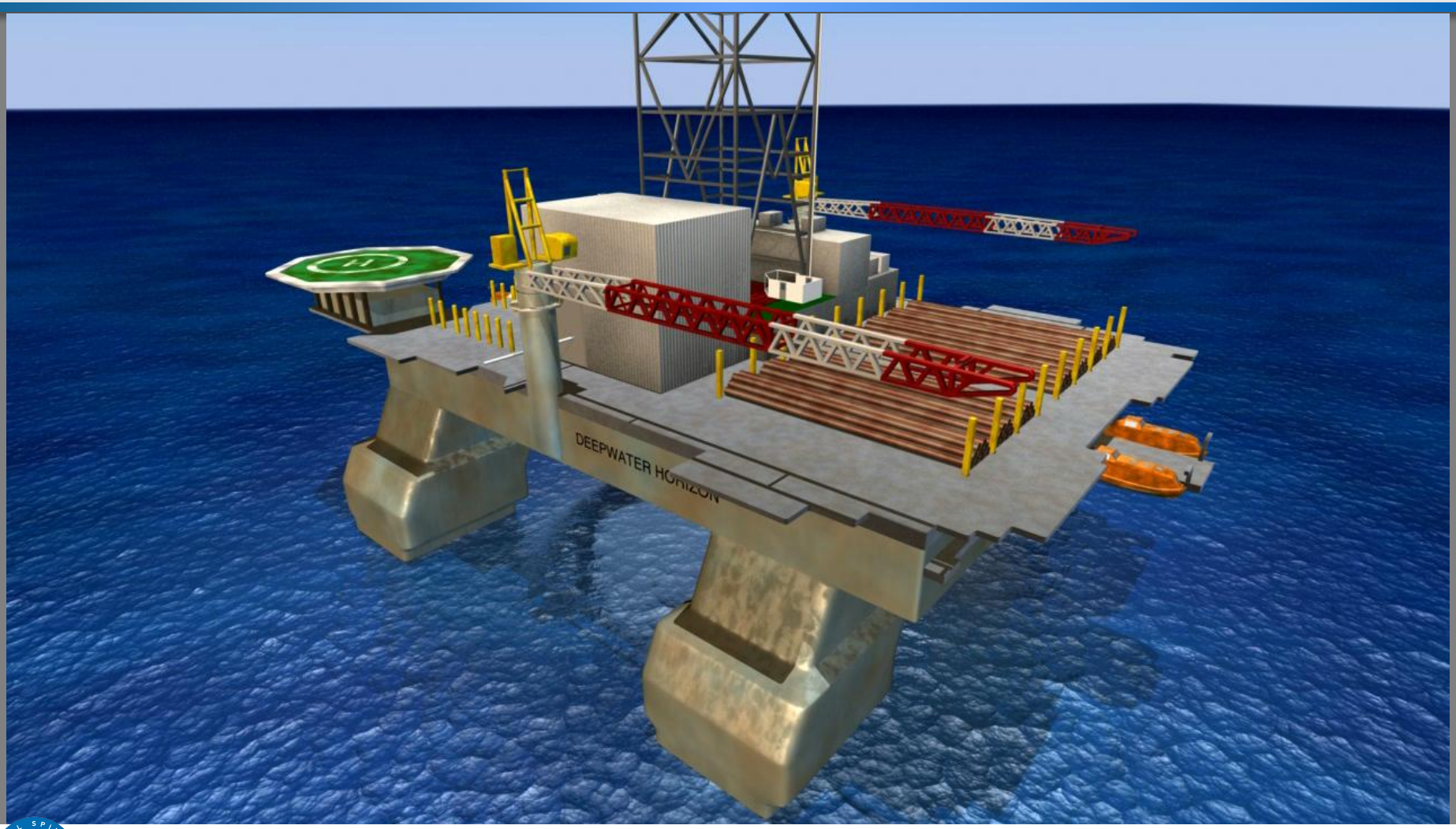
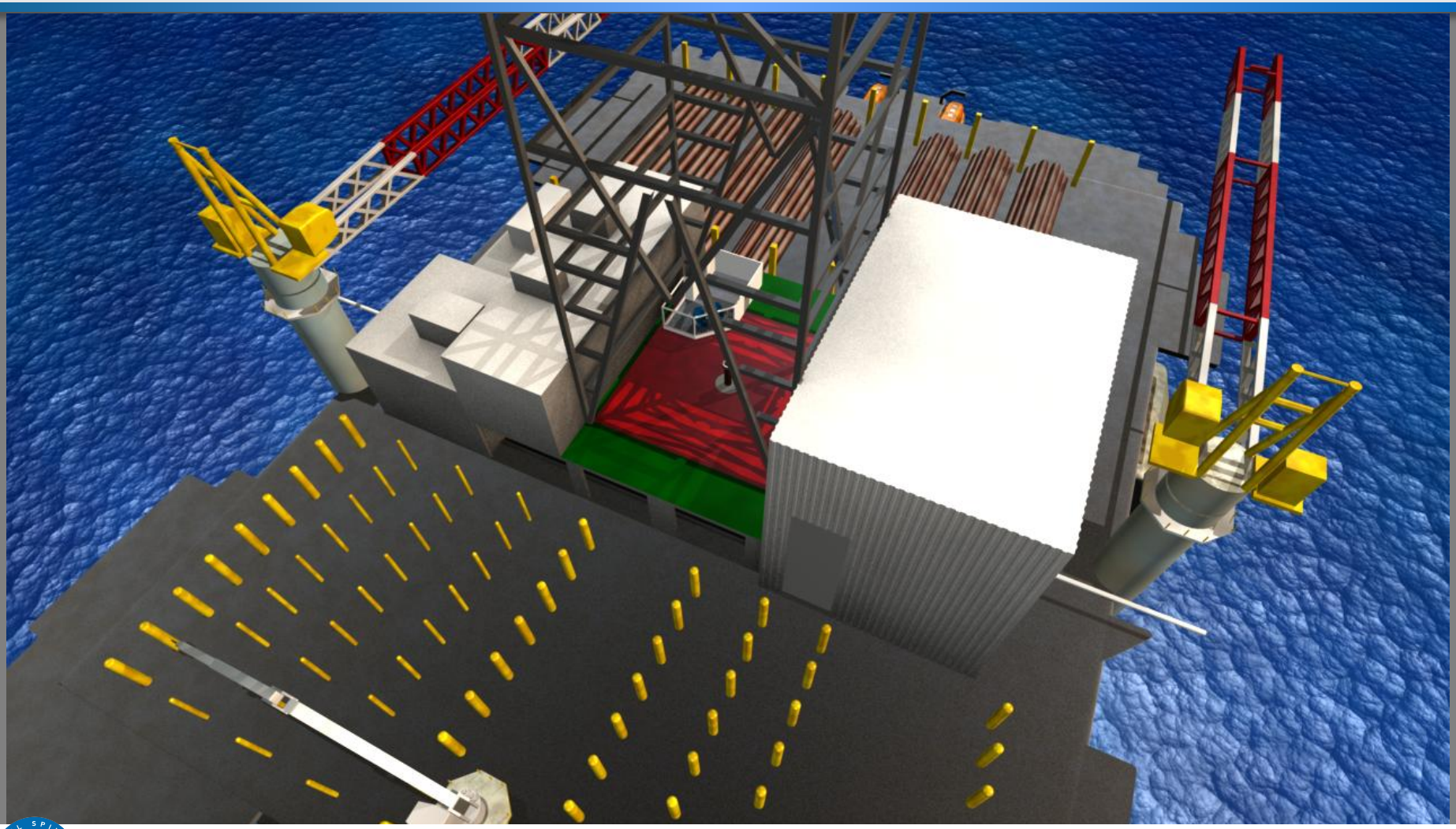
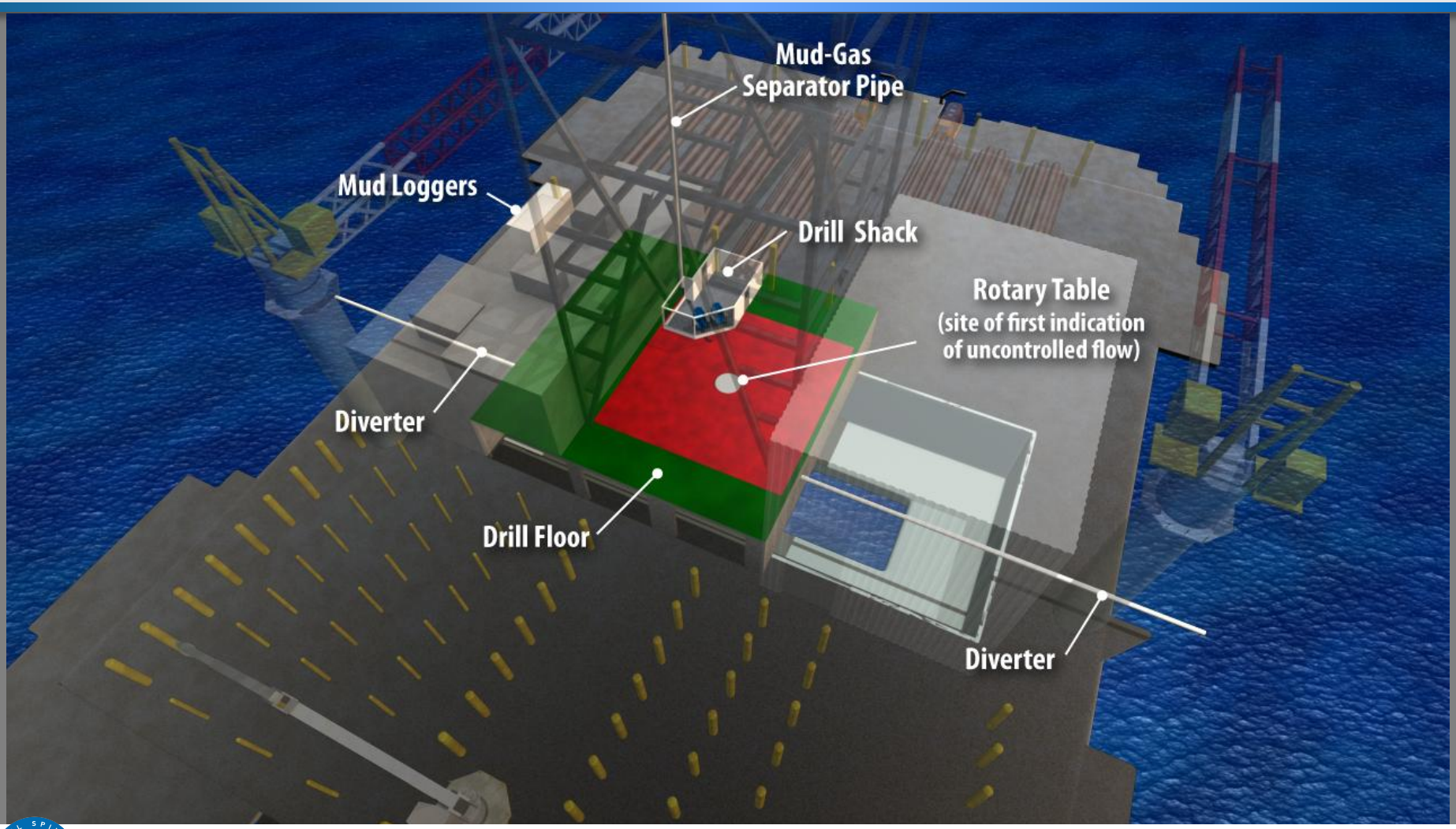


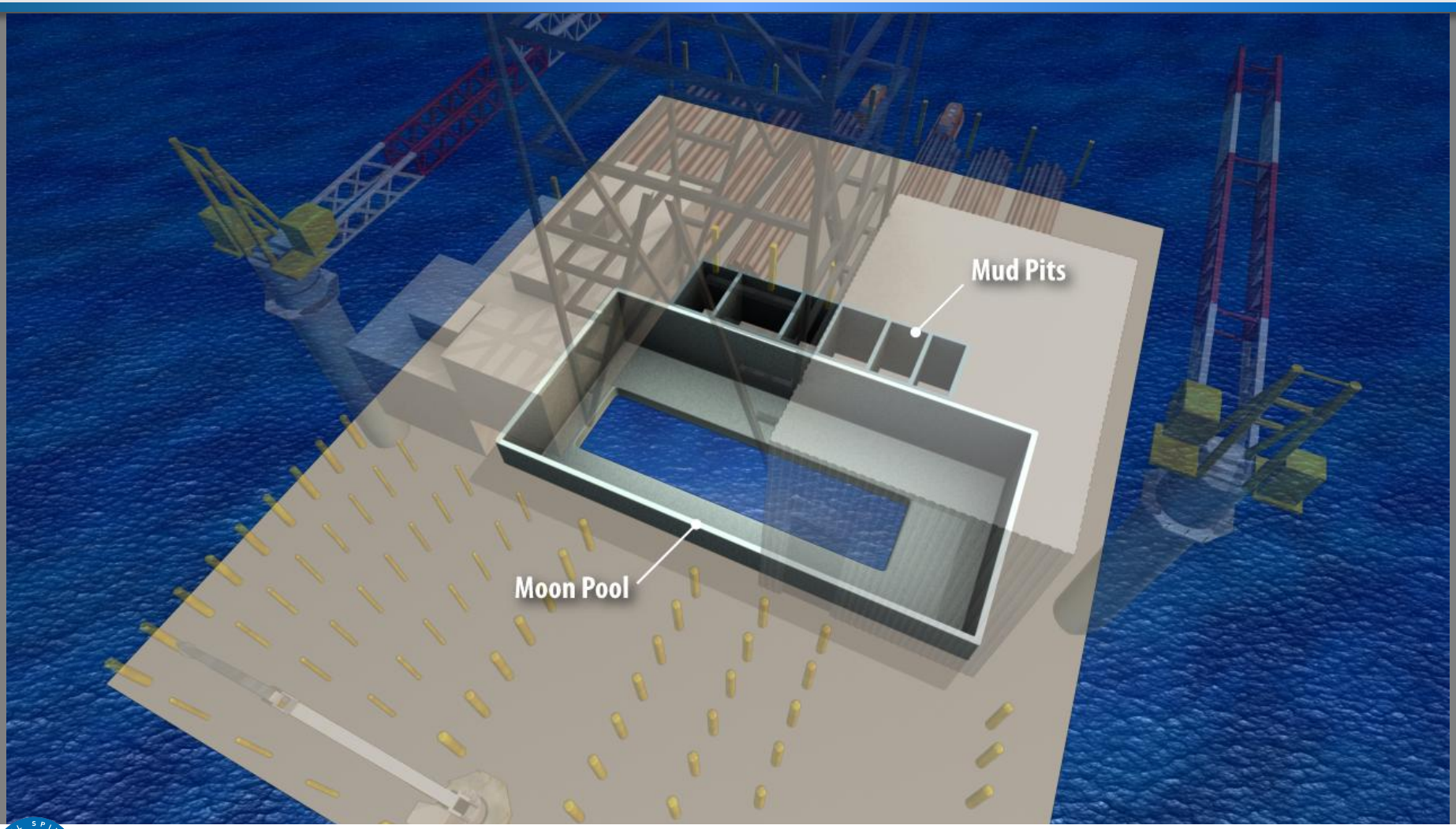
Deepwater Horizon



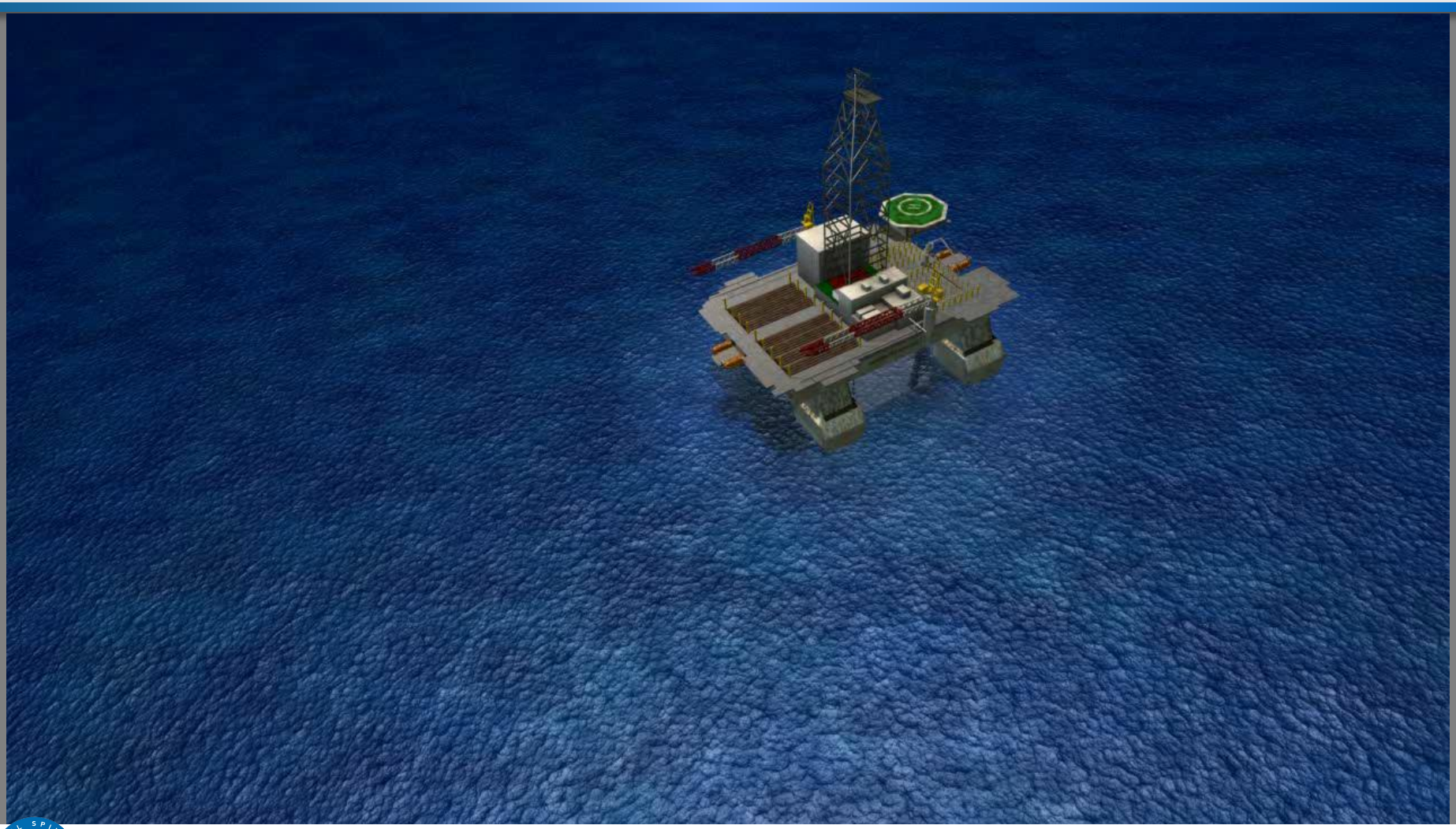
Deepwater Horizon



Deepwater Horizon

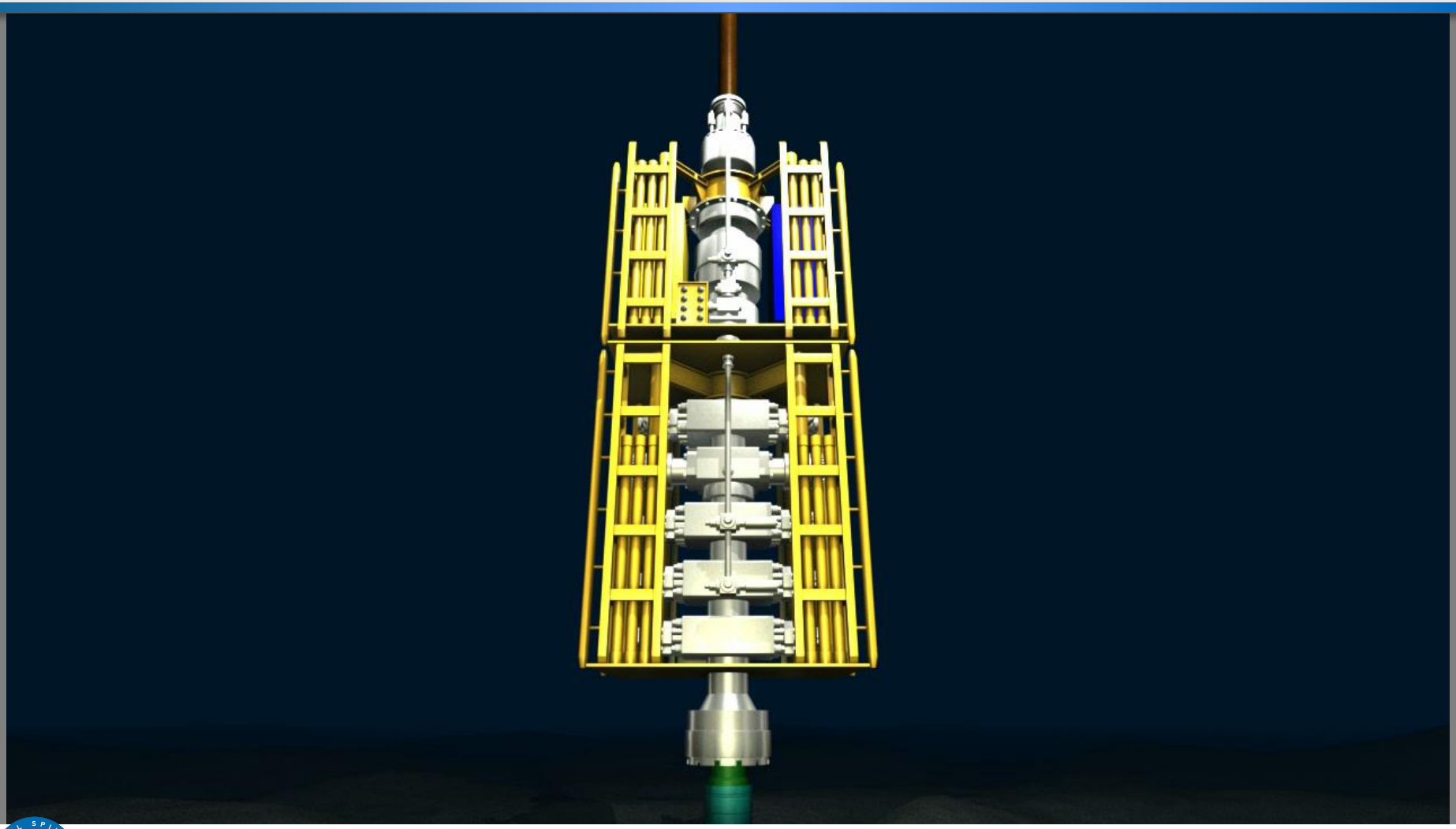


Deepwater Horizon and Macondo Well

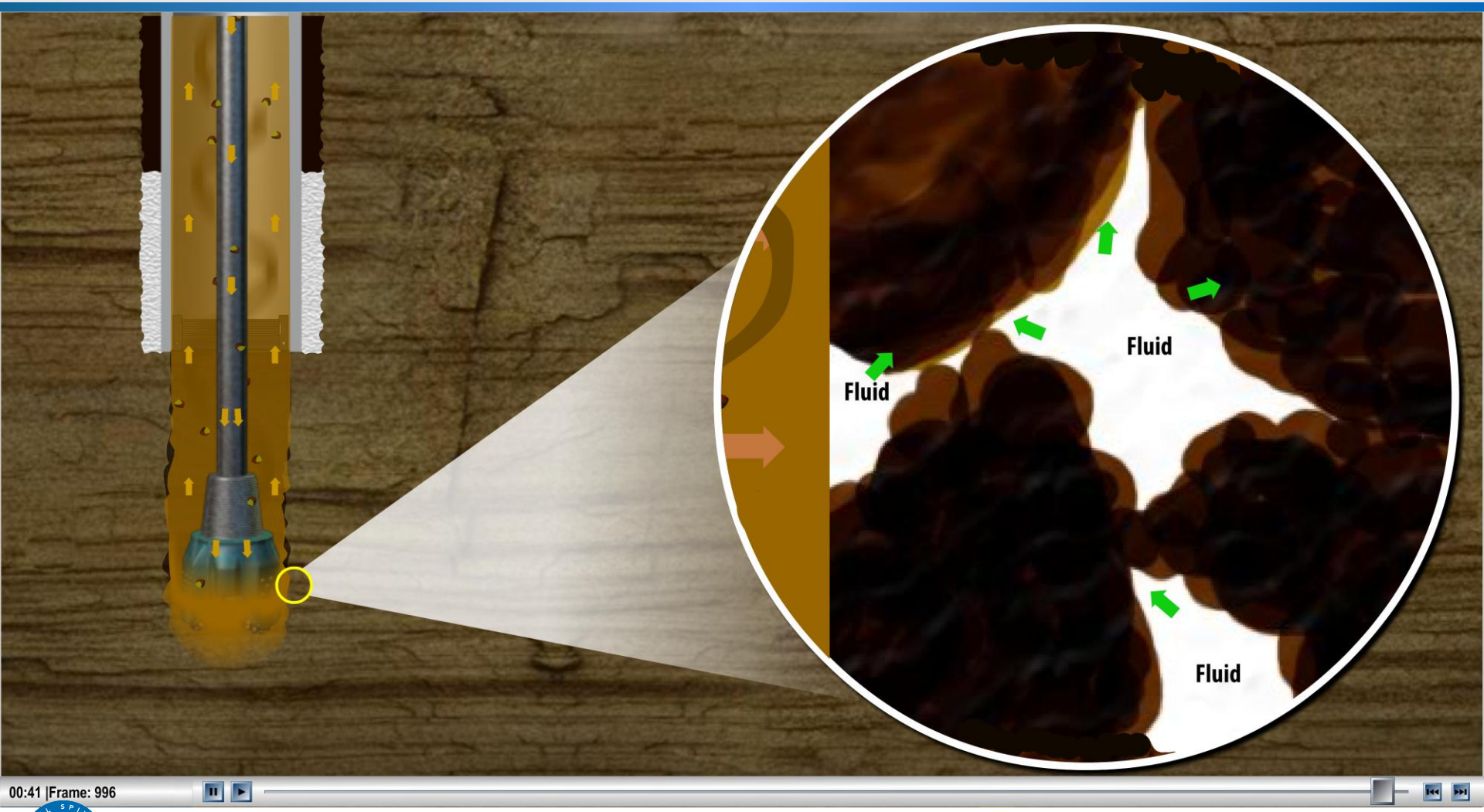


Drilling Offshore Wells

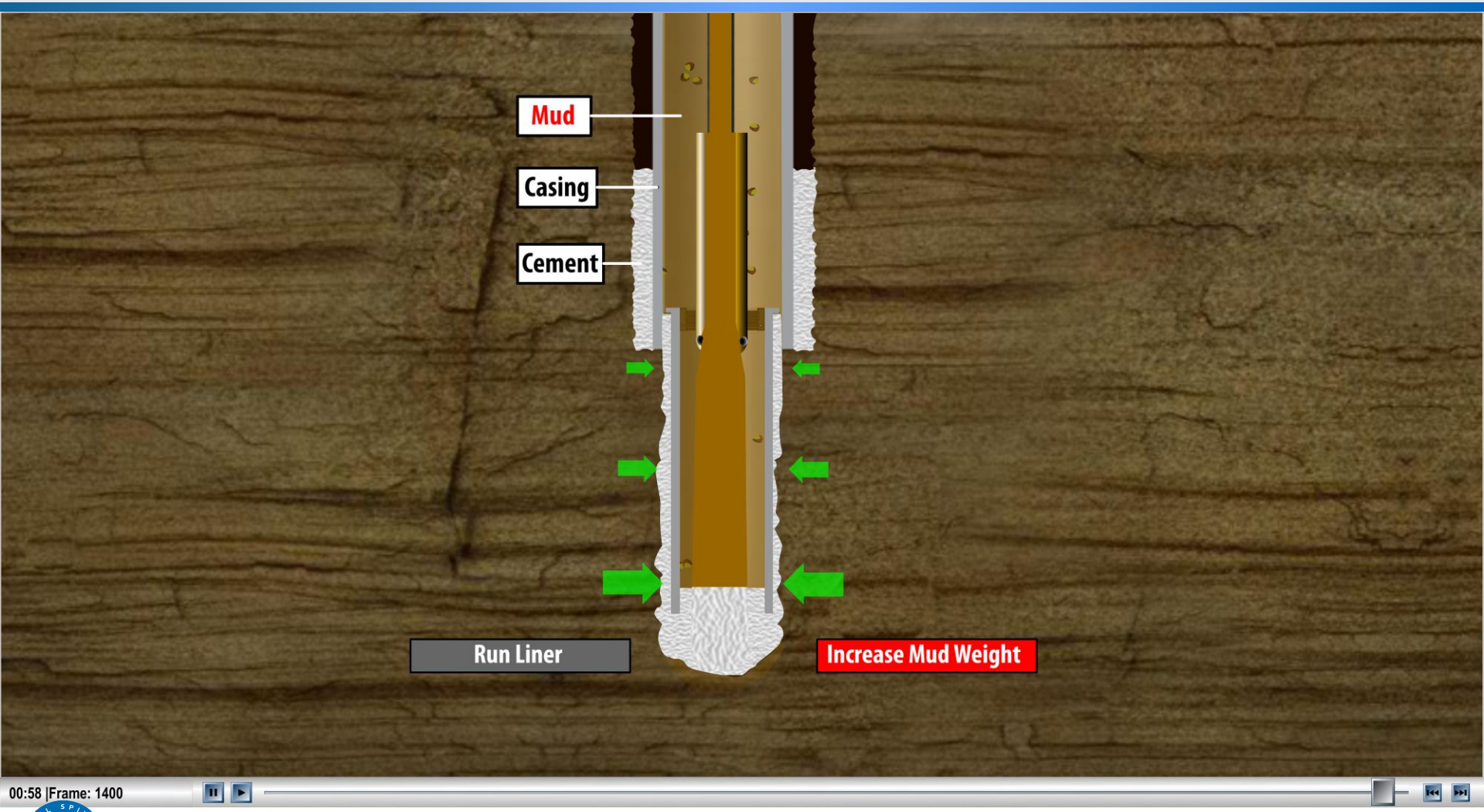
Blowout Preventer ‘BOP’



Porosity of Rock Formation



Drilling a Well



Pore Pressure vs. Fracture Gradient

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Drilling a Well

Macondo Time Line

Macondo Was a 'Difficult Well'

October 6, 2009
Marianas arrives at Macondo

October 28, 2009
Marianas reaches 9,000 feet

November 8-9, 2009
Marianas damaged by Hurricane Ida

January 31, 2010
Deepwater Horizon arrives

February 10, 2010
Deepwater Horizon drilling begins

March 8, 2010
Kick causes stuck pipe; crew begins bypass

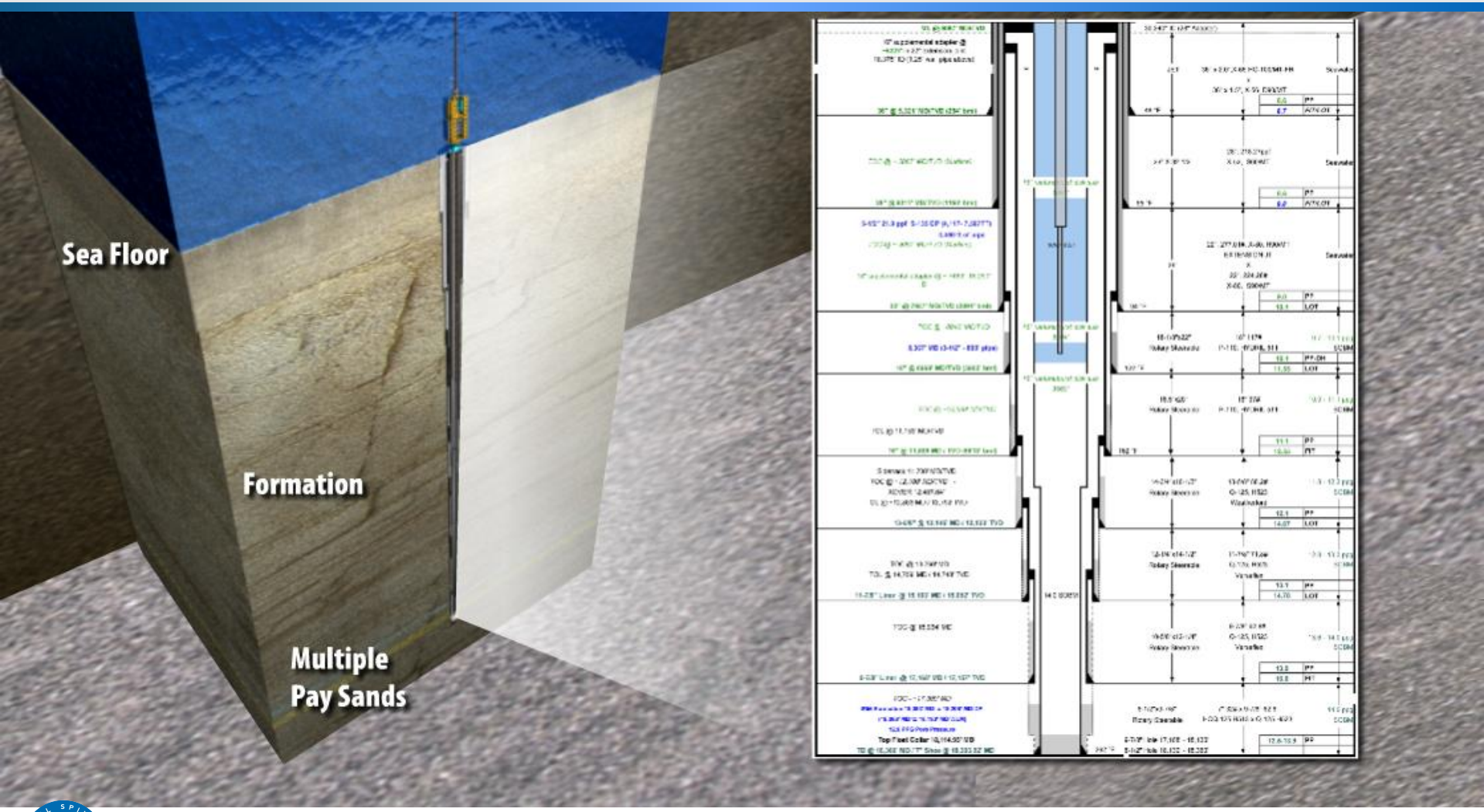
April 3, 2010
Severe lost returns

17 DAYS BEFORE BLOWOUT

2009 | 2010

Cementing the Macondo Well

Cementing the Macondo Well



Situation at Time of Cement Job – April 19, 2010

- **Difficult drilling conditions**
- Serious lost returns in the zone to be cemented
- Forced to stop drilling earlier than planned
- Difficulty converting float equipment
- Low circulating pressure after conversion
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- Cement modeling perceived as unreliable by BP
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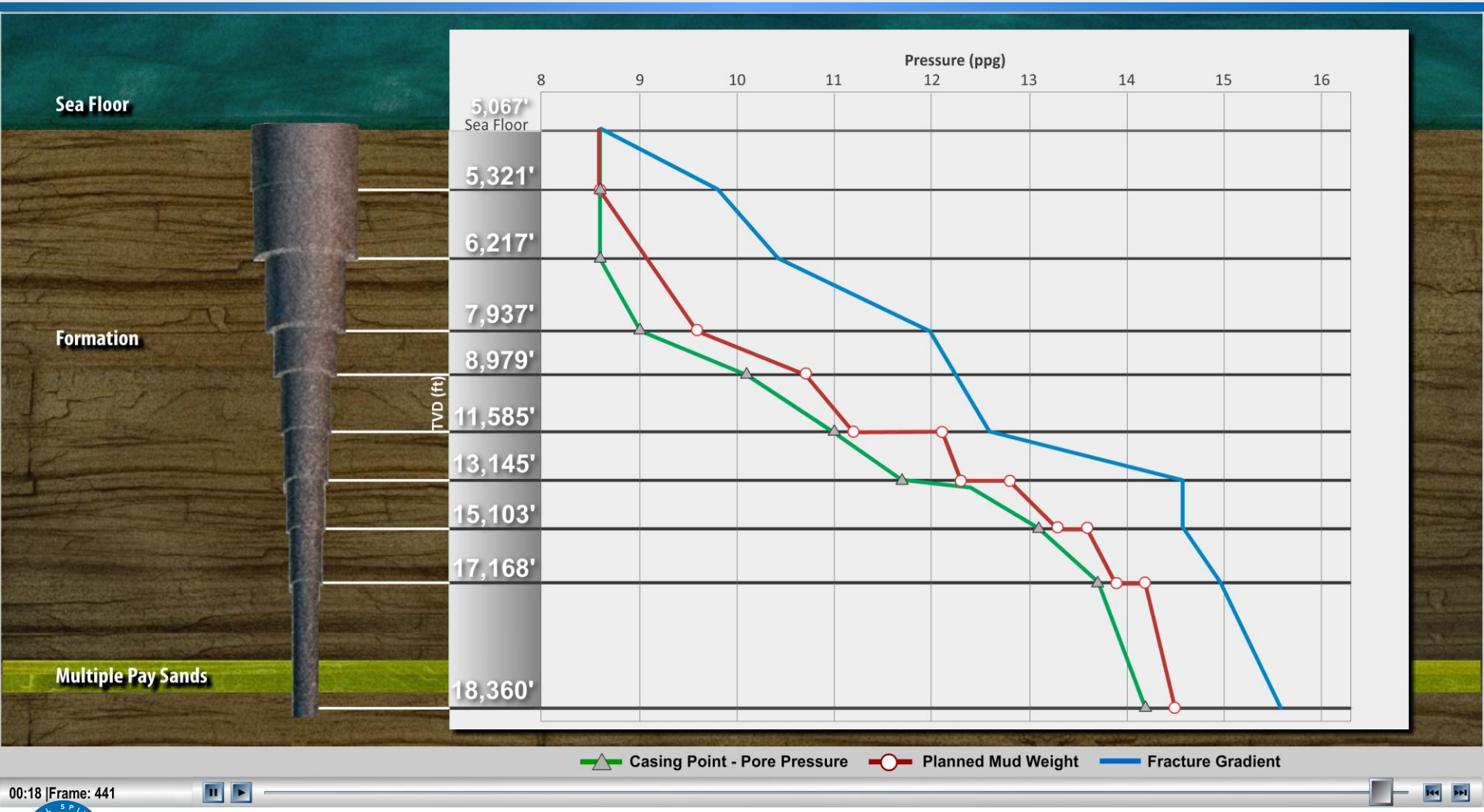
Pore Pressure vs. Fracture Gradient at Macondo



TRIAL GRAPHIX

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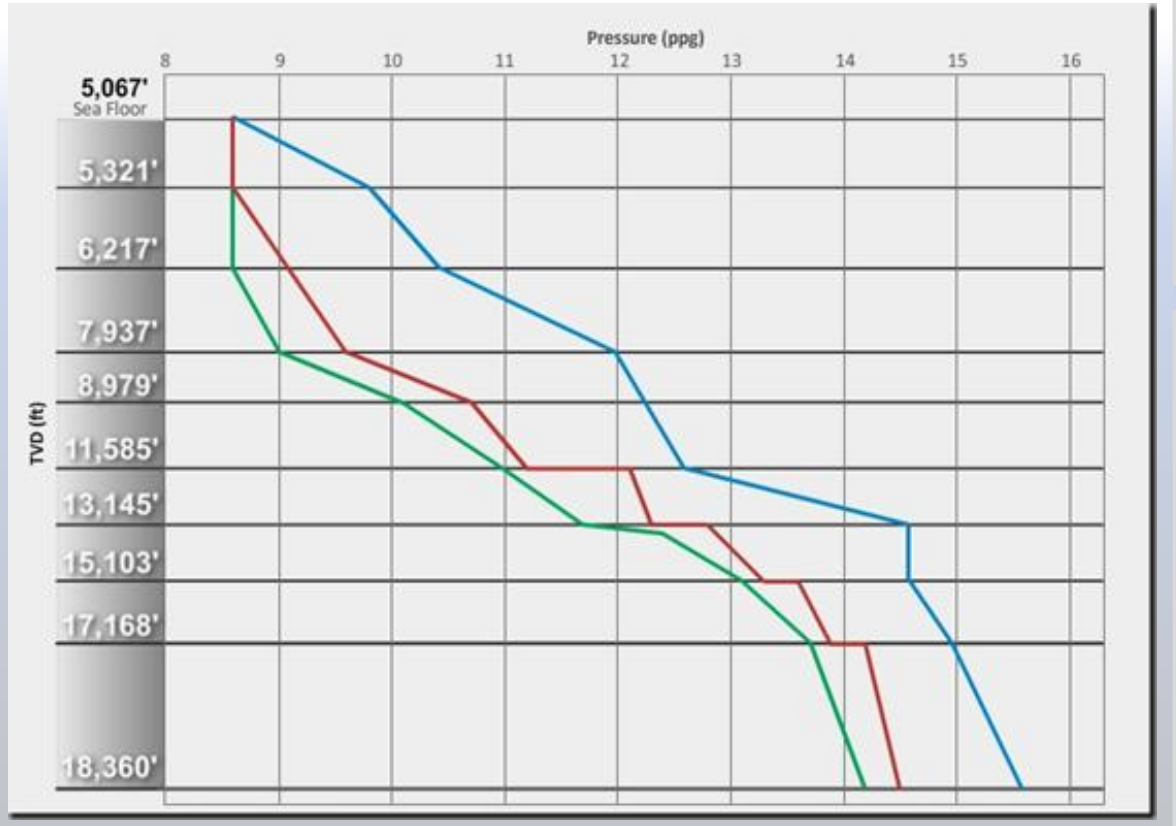


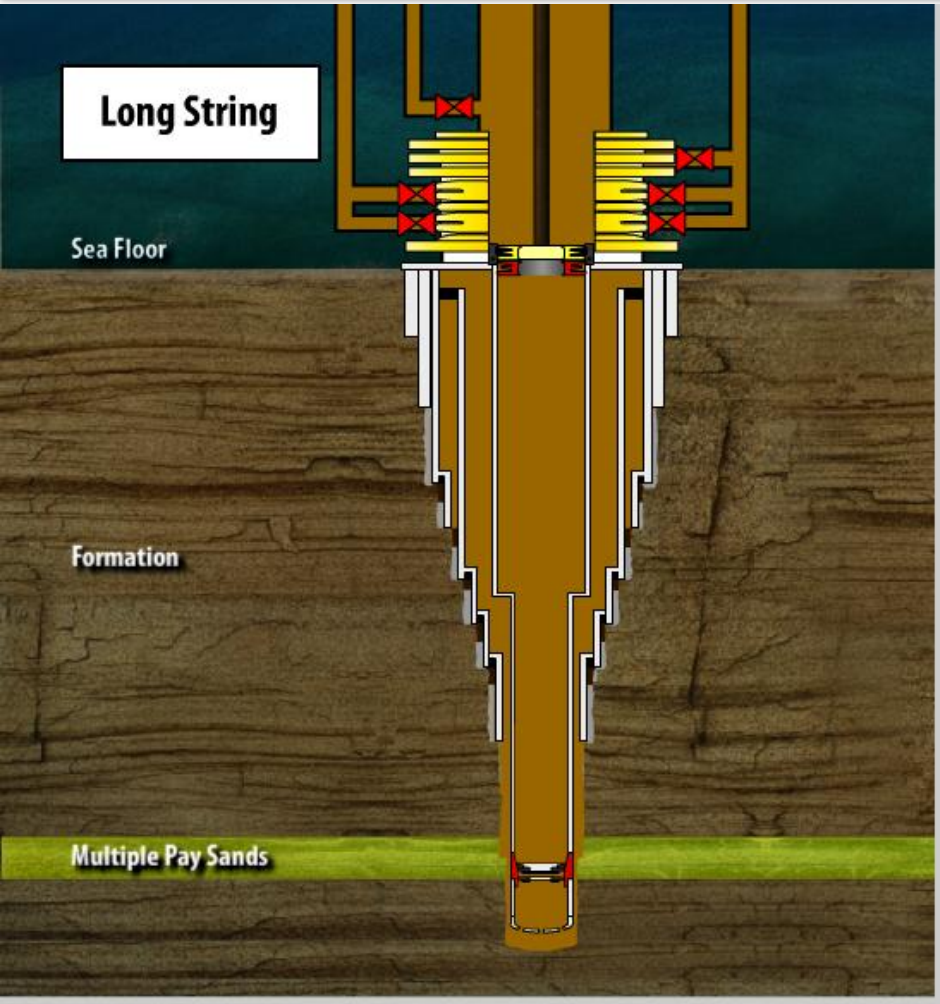
A. It was a difficult well. I wouldn't say it was worse than others. They – it was difficult.

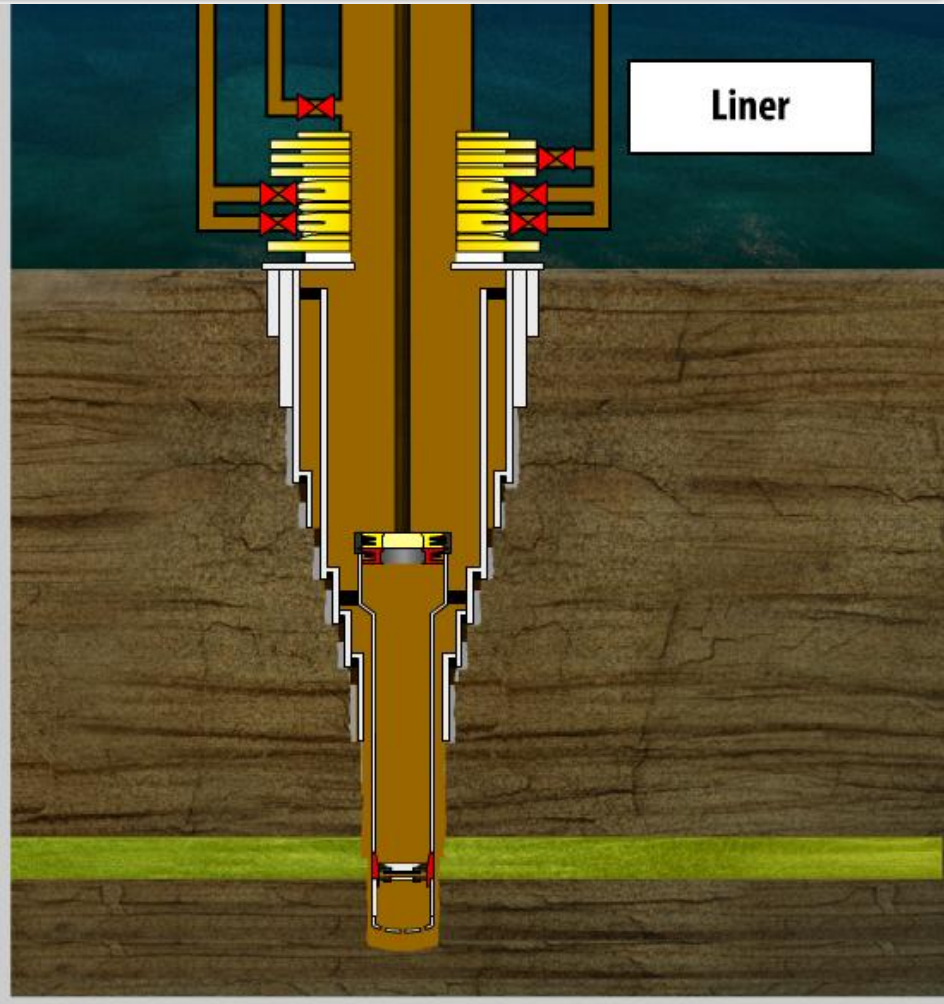
Testimony of Micah Burgess, Transocean Driller, 5/29 AM Tr. 114

Considering the narrow pore pressure and fracture gradient conditions in the Macondo well, planning the cement job to achieve effective cement placement and zonal isolation was a challenge for the BP and Halliburton personnel involved.

BP Deepwater Horizon Accident Investigation Report, Pg. 55

Well Design – Long String Compared to Liner





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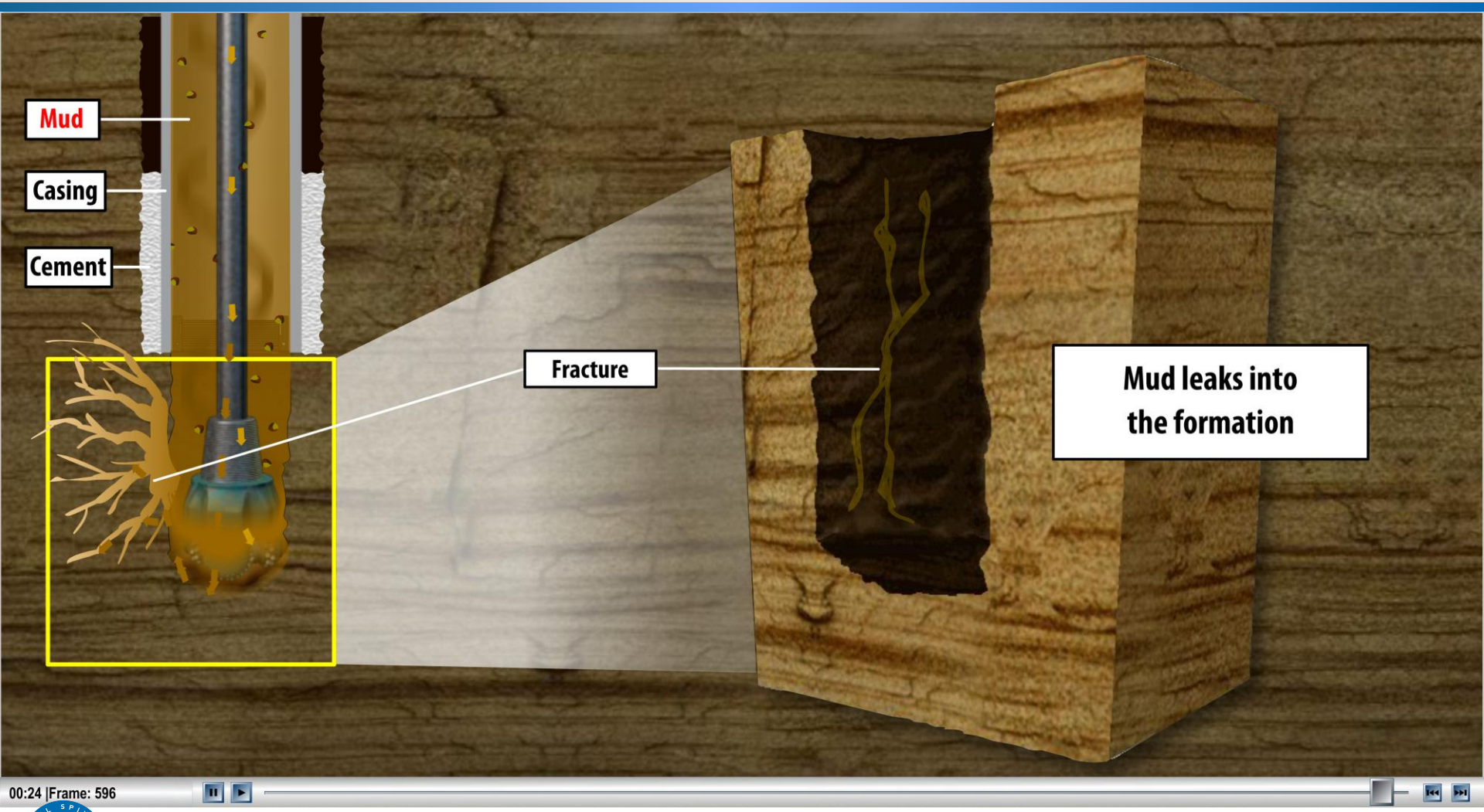
Fractures and/or Too High of a Mud Weight Cause 'Lost Returns' or 'Lost Circulation'



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The Formation at Macondo Was Tricky

April 13, 2010

From: Bodek, Robert
Sent: Tue Apr 13 13:43:50 2010
To: Beirne, Michael
Cc: Ritchie, Bryan; Haffe, Mark E
Subject: RE: Macondo TD
Importance: Normal

Michael,

While drilling in the 8.5" x 9½" hole-section, we encou
the reservoir. Up until this point, as dictated by previo
premise that sands were 0.3ppg over-pressured relative
GeoTap tool in our bottom-hole assembly (BHA) which
took a GeoTap sand pressure at 17,723' (MD). This sa
weight equivalent. At the time, we were drilling with a
14.3ppg equivalent static density (ESD), and a ~14.7 eq
through our reservoir interval to a depth of 18,260' with
penetration (ROP) had slowed significantly. The decisi
surmised that our undereamer had failed. Upon pullin
Upon monitoring the well with pumps off, we observed
applications of lost circulation material (LCM) were pu
losses. We also displaced the riser with base oil and 14
After pumping several LCM applications and cutting m
we pulled out of the hole for a new BHA. At this point,
to 18,260' (MD). At this depth, we were unsure if we h
if we had drilled out of the base of the reservoir, but the
approximately 50' of rat hole we had beneath the main
and completion. It was unanimously accepted amongst the team that approximately 100 more feet would allow us
to 1) make sure we had drilled through the entire reservoir package, 2) provide sufficient rat hole for wireline
evaluation operations, and 3) provide ample rat hole for completion procedures. We had one major problem
however. The sand that we took the initial GeoTap pre
surface mud weight we could use to cover the pore-pres
approximately a 14.2ppg ESD over the aforementioned
weight / 14.2 ESD, our equivalent circulating density (E
already experienced static losses with a 14.5ppg ESD!
was decided to trip back into the hole with a simplified
the requisite 100 additional feet of formation. We drill
our ECD values below the 14.5ppg equivalent mud wei
observed no additional pay intervals. We firmly believe
was decided that the primary target had been reached, a
wireline evaluation. Having drilled and evaluated the e
objectives of the well. Drilling ahead any further would
exposed sand, and taking losses in a 12.6ppg reservoir i
run out of drilling margin. At this point it became a we
Regards,
Bobby Bodek
BP America Inc.
Geological Operations Coordinator
Gulf of Mexico Exploration - Tiger Team
(o) 281.366.3862
(c) 713.213.7553

Confidential

BP-HZN-MBI 00126338

From: Bodek, Robert
Sent: Tue Apr 13 13:43:50 2010
To: Beirne, Michael

losses. We also displaced the riser with base oil and 14.0ppg mud to reduce the downhole hydrostatic pressure. After pumping several LCM applications and cutting mud weight in the riser, losses were no longer observed, and we pulled out of the hole for a new BHA. At this point, the team was faced with a tough decision. We had drilled to 18,260' (MD). At this depth, we were unsure if we had drilled through the reservoir in its entirety. It appeared as if we had drilled out of the base of the reservoir, but there was no way to be certain. Additionally, the approximately 50' of rat hole we had beneath the main sand package was insufficient for both wireline evaluation and completion. It was unanimously accepted amongst the team that approximately 100 more feet would allow us

observed no additional pay intervals. We firmly believed that we were at the base of the target reservoir package. It was decided that the primary target had been reached, and we were able to conduct a comprehensive, efficient wireline evaluation. Having drilled and evaluated the entire reservoir interval would fulfill the two primary objectives of the well. Drilling ahead any further would unnecessarily jeopardize the wellbore. Having a 14.15ppg exposed sand, and taking losses in a 12.6ppg reservoir in the same hole-section had forced our hand. We had simply run out of drilling margin. At this point it became a well integrity and safety issue. TD was called at 18,360' (MD).

Regards,
Bobby Bodek
BP America Inc.

Confidential

BP-HZN-MBI 00126338

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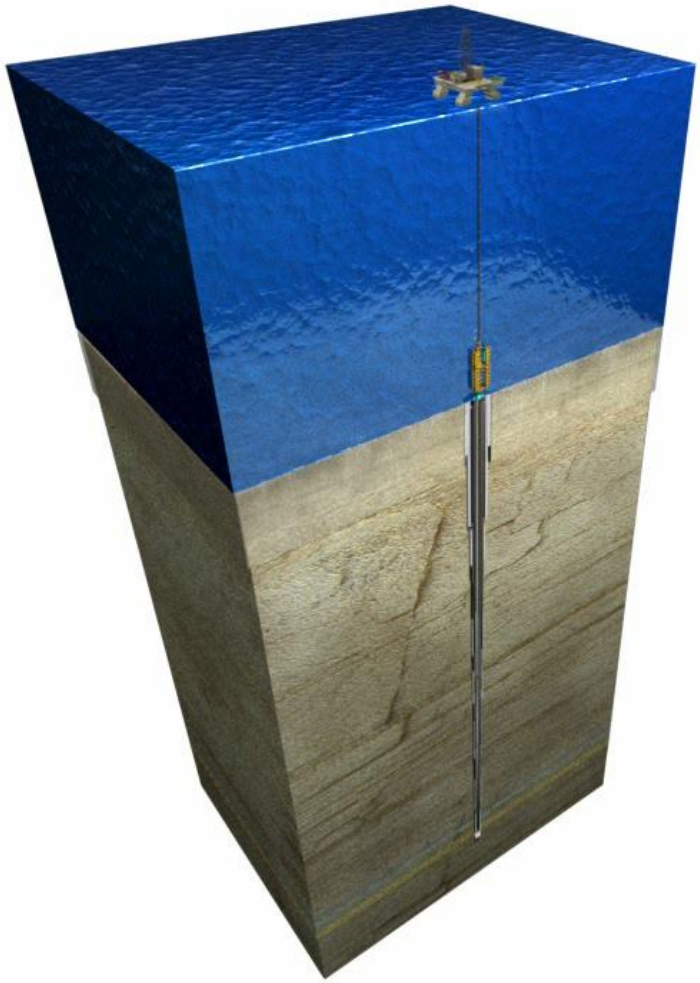
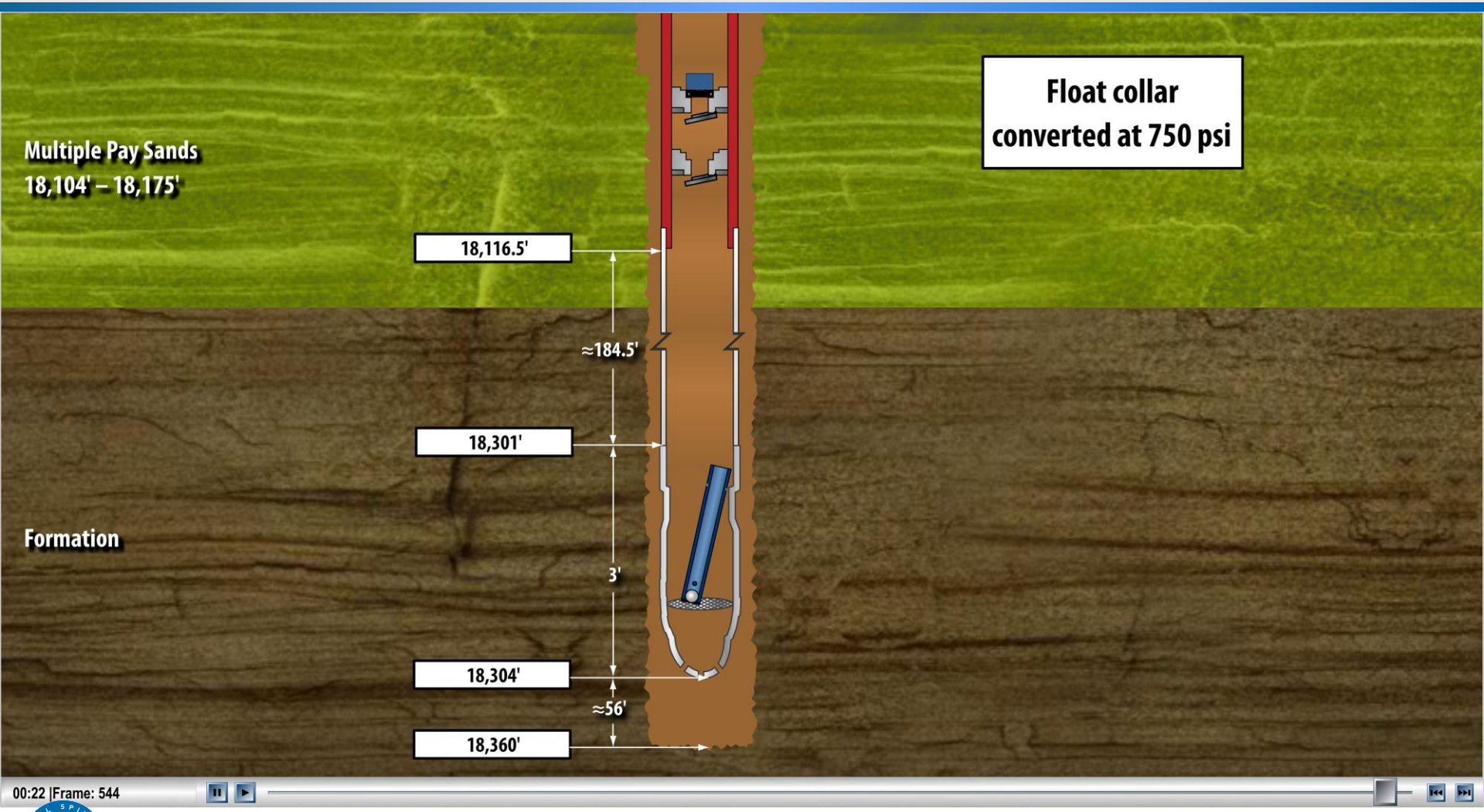
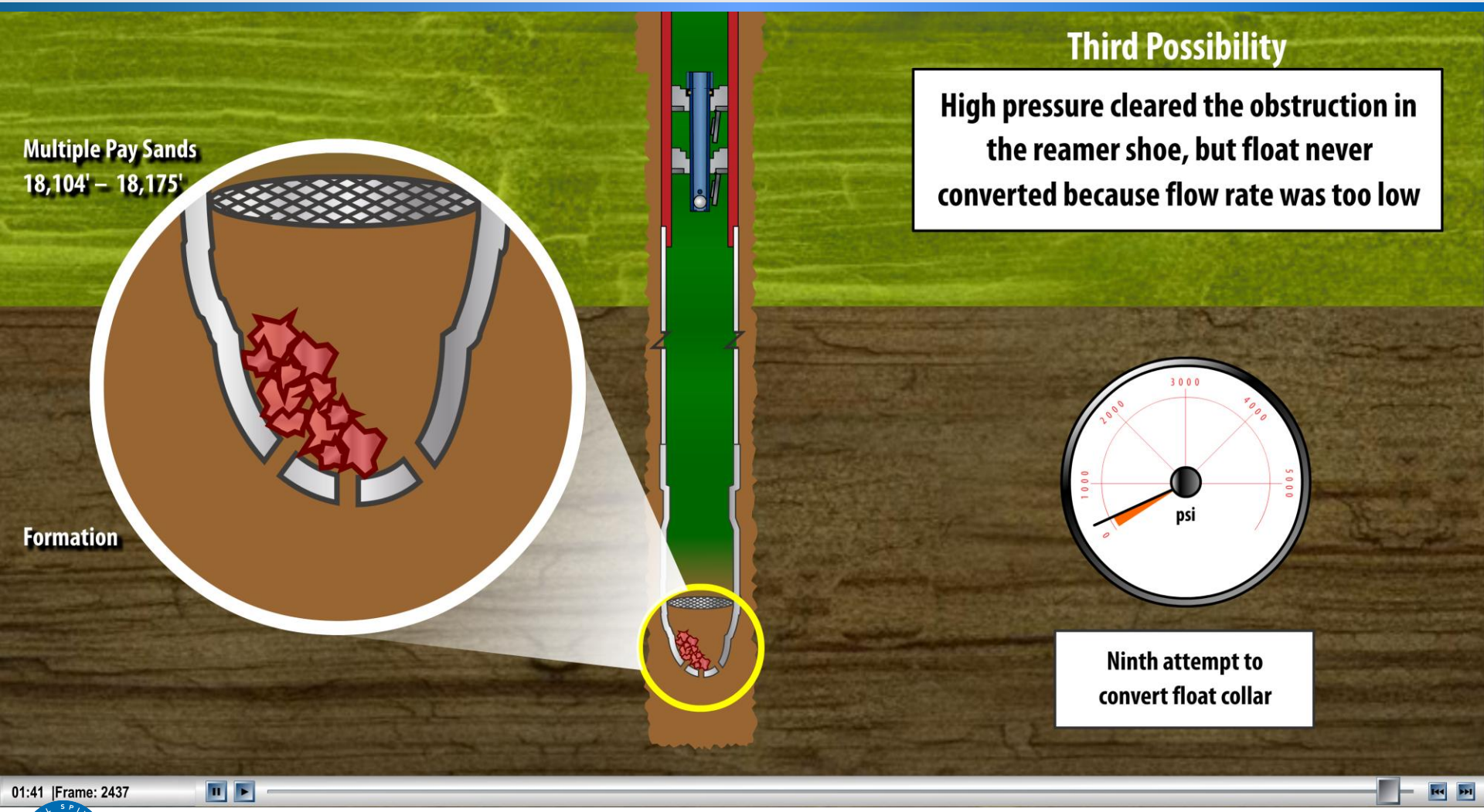
Shoe Track



Normal Float Valve Conversion



Float Valve Conversion



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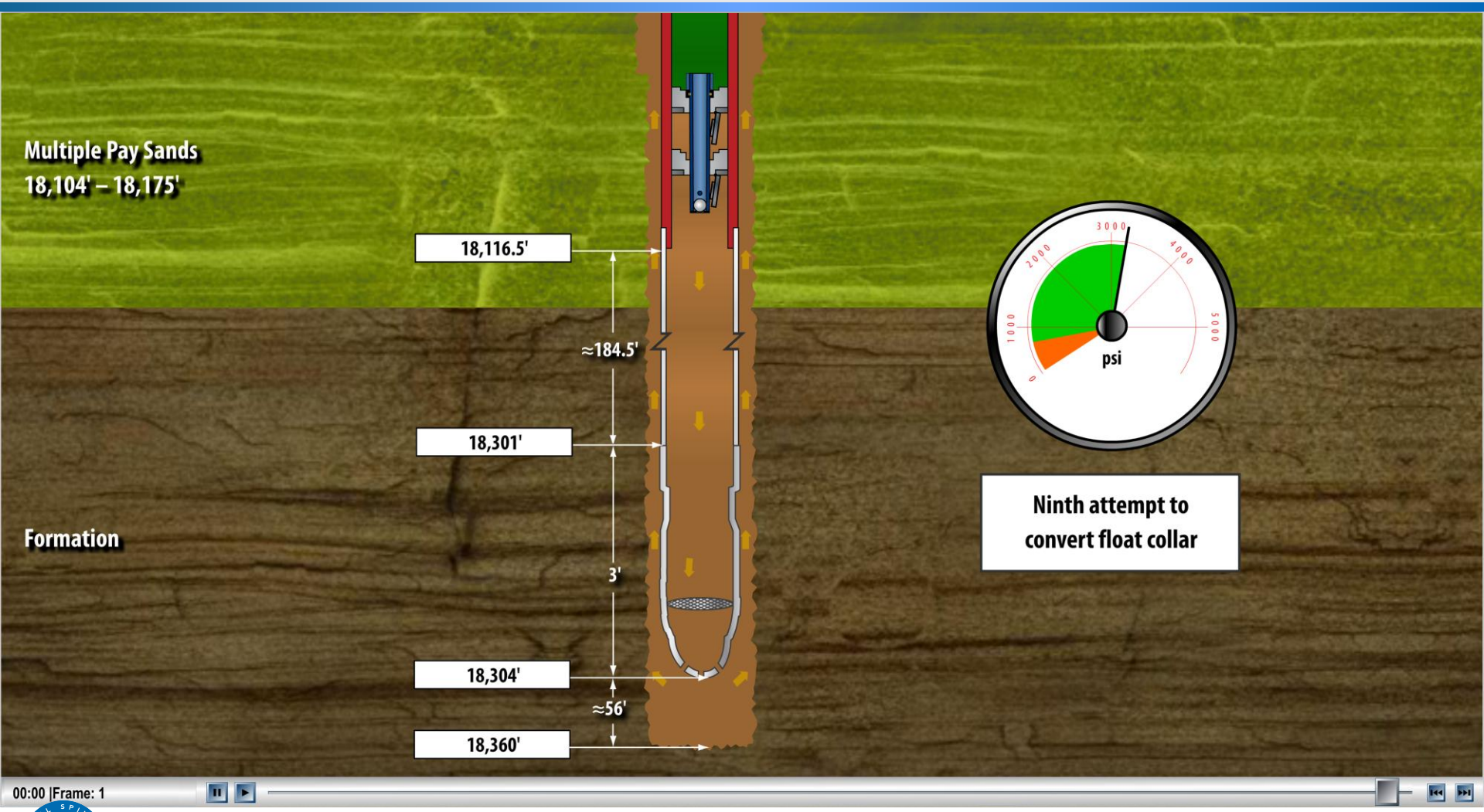
Low Circulating Pressure After Float Conversion



Uncomfortable With Circulating Pressure

April 20, 2010

HALLIBURTON

15:54	Pressure up to 2500 psi at 1 bpm while attempting to convert floats. (62 strokes / 7.8 bbls / 2500 psi).
16:03	Unsuccessful…bleed pressure off.
16:16	Pressure up to 2750 psi at 1 bpm while attempting to convert floats. (67 strokes / 8.44 bbls / 2750 psi). Pressure held at 2700 psi.

HALLIBURTON

BP America
PO Box 22024
Tulsa, Oklahoma 74121-

OCS-G-32306 , Macondo #1
Mississippi Canyon Block 252
Offshore Gulf of Mexico
United States of America

Rig Name: Transocean Horizon

9.875" x 7" Foa
Casing Post Jo

Prepared for: Jesse Gagliano

April 20, 2010

Submitted by:
Nathaniel Chaisson
Technical Professional
100 Capital Dr. Ste 200
Lafayette, LA 70508

Confidential BP-HZN-MBI00137364

16:24
Company man feels uncomfortable with the circulating pressure being this low. Spoke with Jesse Gagliano about the situation.

17:00
MI Swaco model estimates circulating pressure should be about 570 psi @ 4.0 bpm.

BP America 4 M.C. 252 OCS-G-32306 #1

BP-HZN-IIT-0004313

Confidential BP-HZN-MBI00137367

Low Circulation Pressure: Post-Conversion Conversation

Brett Cocales August 27 Testimony Indicates Low Pressure Was Not Resolved

1 pressure, for them to estimate pressure was
2 one of the most difficult things that they
3 do. They said it's very difficult just to
4 estimate a pressure directly.
5 Q. And is it accurate, or do you
6 recall -- is it fair to say that the
7 difference in these pressures was a couple
8 of hundred PSI? Does that fit with your
9 recollection?
10 A. I don't recall the exact number.
11 Q. Was there some determination made
12 as to whether these differences represented
13 a problem or didn't represent a problem?
14 How was that issue resolved?
15 A. I did not give the rig direction
16 myself, but I was in the area. But John
17 Guide was having them -- well, through a
18 conversation between John Guide and the well
19 site leaders, they tried changing pumps, so
20 that was the first thing, to see if the
21 difference in pumps would make a difference.
22 And there were some slight differences in
23 the pressures. And then they also had tried
24 a diagnostic test to make sure that it
25 wasn't leaking through the diverter valve

Page 72

Q. Was there some determination made as to whether these differences represented a problem or didn't represent a problem? How was that issue resolved?

A. I did not give the rig direction myself, but I was in the area. But John Guide was having them – well, through a conversation between John Guide and the well site leaders, they tried changing pumps, so that was the first thing, to see if the difference in pumps would make a difference. And there were some slight differences in the pressures. And then they also had tried a diagnostic test to make sure that it wasn't leaking through the diverter valve that we have as part of the, running the casing. So they put a procedure together to check that and assess that to make sure that that was not flowing across there, at the top there.

Q. And what were the results of those efforts?

A. The results were negative, that there was no flow across it. The diverter valve was considered to be closed. It was not leaking.

Q. And so what was the resolution? How did the issue get resolved?

A. I don't believe it ever got resolved, other than they felt like the gauge pressures was inaccurate.

Q. And the conversations you are just describing, sir, is it your recollection they occurred on April 19; is that correct?

A. I believe it is. I don't remember exactly on that.

Q. Did you have any conversations with anyone regarding the negative tests that were run on the rig on April 20?

A. No, I did not.

Testimony of Brett Cocales, BP Drilling Engineer, MBI Hearing 8/27 Tr. 72-73

Low Circulation Pressure: Post-Conversion Conversation

Bly Team Brian Morel Interview Note

April 27, 2010

Transcription of Brian Morel interview notes
commenced 1040 hrs 27-Apr 2010

panel: Rex Anderson, Matt Lucas, Jim Wetherbee, Warren Winters

Opening discussion:

prior experience Anadarko Basin (challenge), Mad Dog (challenge), planning Macondo
was on rig for cleanout run (Thu), stayed thru Tue AM
at start of prod hole had high FIT (formation integrity test) above OB (overburden)
once drlg prod hole encountered losses, so reduced MW (mud weight) from 14.5 to 14.3 ppg
while drlg a sand zone Geotap showed 14.12, 14.16 ppg formation pressure
while drlg a deeper producing sand Geotap showed 12.6 ppg, originally thought low hence a tool error but later confirmed correct
while drlg a subsequent sand, drlg progress stopped (suspected underreamer failure)
while losing 300-400 bbl/hr mud
pumped emergency lost circulation material without improvement
pulled into marine drilling riser, reduced mud weight, pumped Formaset
losses stopped holding 14.0 ppg mud (surface) 14.2 ppg (bottomhole due to compressibility)
ran new bottomhole assembly and drld 100 ft of rathole to provide room for logging tools
downhole ESD 14.16-14.2 ppg
logging went smoothly but rotary sidewall coring experienced differential pressure problems
encountered bridges at 12,272' and 12,280'
recorded 1100 units gas on bottoms-up, eventually decreased to 20-30 units
pumped out of hole and flow-checked at liner top
ran ca. 5800 ft 7" casing crossed-over to 9-7/8" casing
bought 7" casing from Nexen due to short lead-time
the XO came from R&M Machine
circulated, converted float equipment, diverter closed without issue
difficulty converting Weatherford float equipment but Weatherford rep. was not on rig so Allamon rep. recommended procedures to convert
called Houston (J. Guide) thinking reamer shoe was plugged so staged up pumping to clear shoe
1 bpm showed 125 psi, 4 bpm showed 400 psi which seemed low vs. modeled pressures

closed annular, pumped down C&K lines, pumped down DP and things looked okay
decided rig standpipe pressure gauge was incorrect
7bbls, 20bbls of 14.3 spacer, 5bbls cement job, 39 foam, 7 shoe track, 20 bbls spacer, 2bbls 4/m
modeled cement job in advance w/EPT assistance
did not see bottom dart release, attributed to calculation error by Allamon
saw top plug release
standpipe pressure and cementing unit pressure agreed but both were several hundred psi below model
saw 7" plug pass thru XO

Confidential Treatment Requested BP-HZN-CEC020232

decided rig standpipe pressure gauge was incorrect

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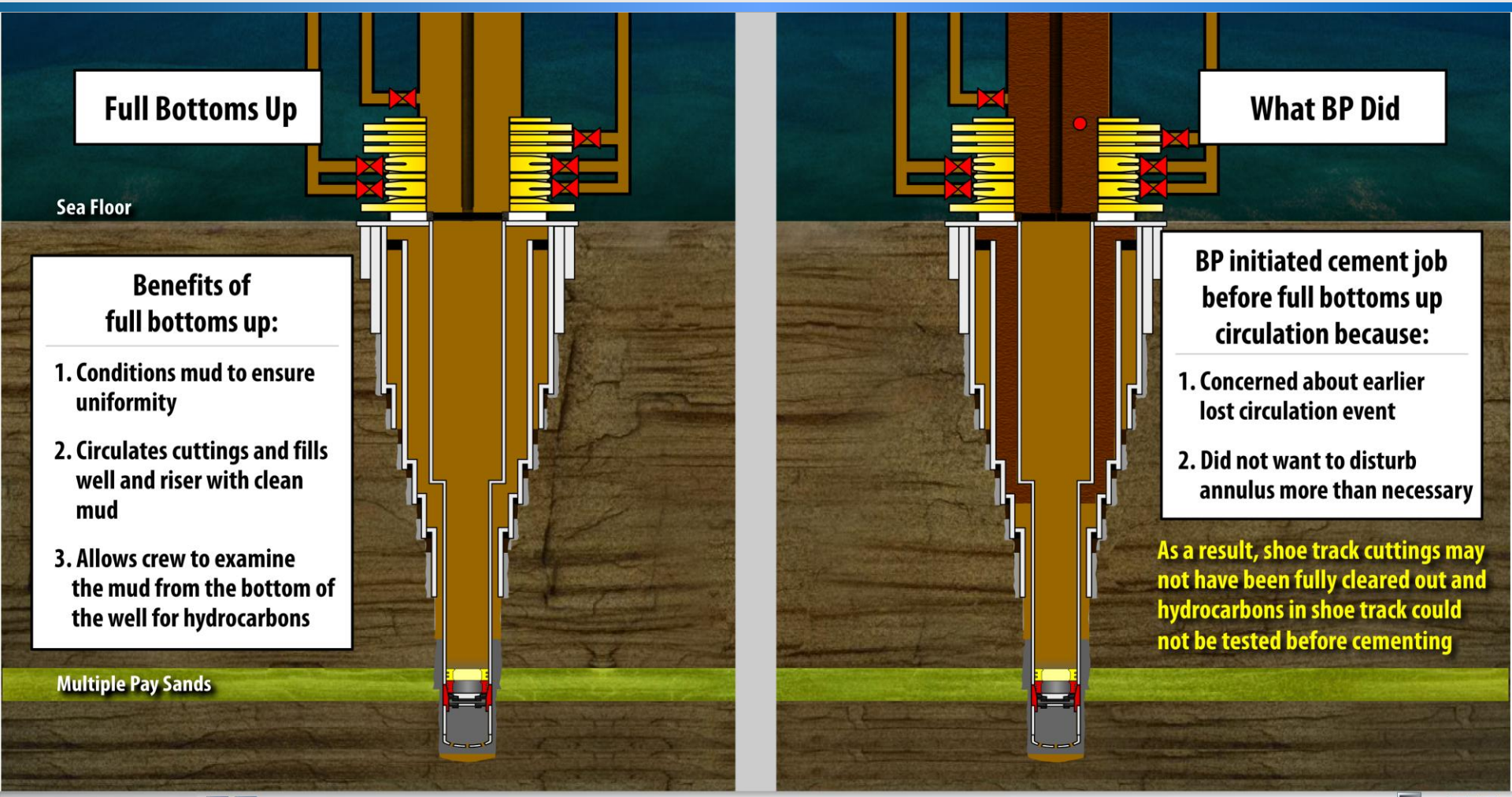
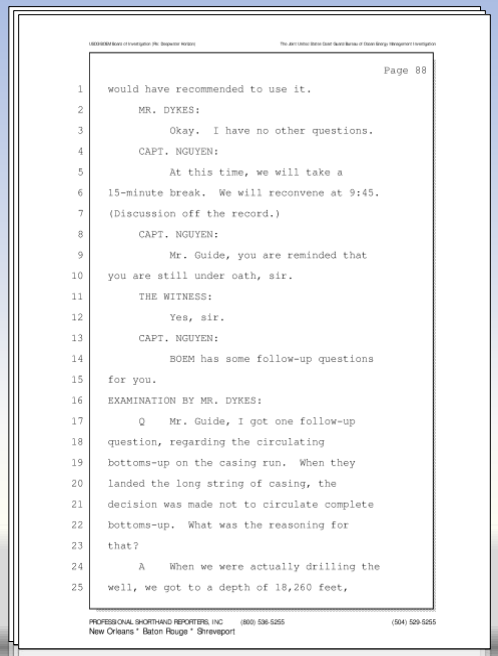
Bottoms Up Circulation



01:06 |Frame: 1602

BP Decides Against Bottoms Up

July 22, 2010



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1 would have recommended to use it.
2 MR. DYKES:
3 Okay. I have no other questions.
4 CAPT. NGUYEN:
5 At this time, we will take a
6 15-minute break. We will reconvene at 9:45.
7 (Discussion off the record.)
8 CAPT. NGUYEN:
9 Mr. Guide, you are reminded that
10 you are still under oath, sir.
11 THE WITNESS:
12 Yes, sir.
13 CAPT. NGUYEN:
14 BOEM has some follow-up questions
15 for you.
16 EXAMINATION BY MR. DYKES:
17 Q Mr. Guide, I got one follow-up
18 question, regarding the circulating
19 bottoms-up on the casing run. When they
20 landed the long string of casing, the
21 decision was made not to circulate complete
22 bottoms-up. What was the reasoning for
23 that?
24 A When we were actually drilling the
25 well, we got to a depth of 18,260 feet,

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Q. Mr. Guide, I got one follow-up question, regarding the circulating bottoms-up on the casing run. When they landed the long string of casing, the decision was made not to circulate complete bottoms-up. What was the reasoning for that?

* * *

A. The biggest risk that was associated with this cement job was losing circulation. That was the No. 1 risk.

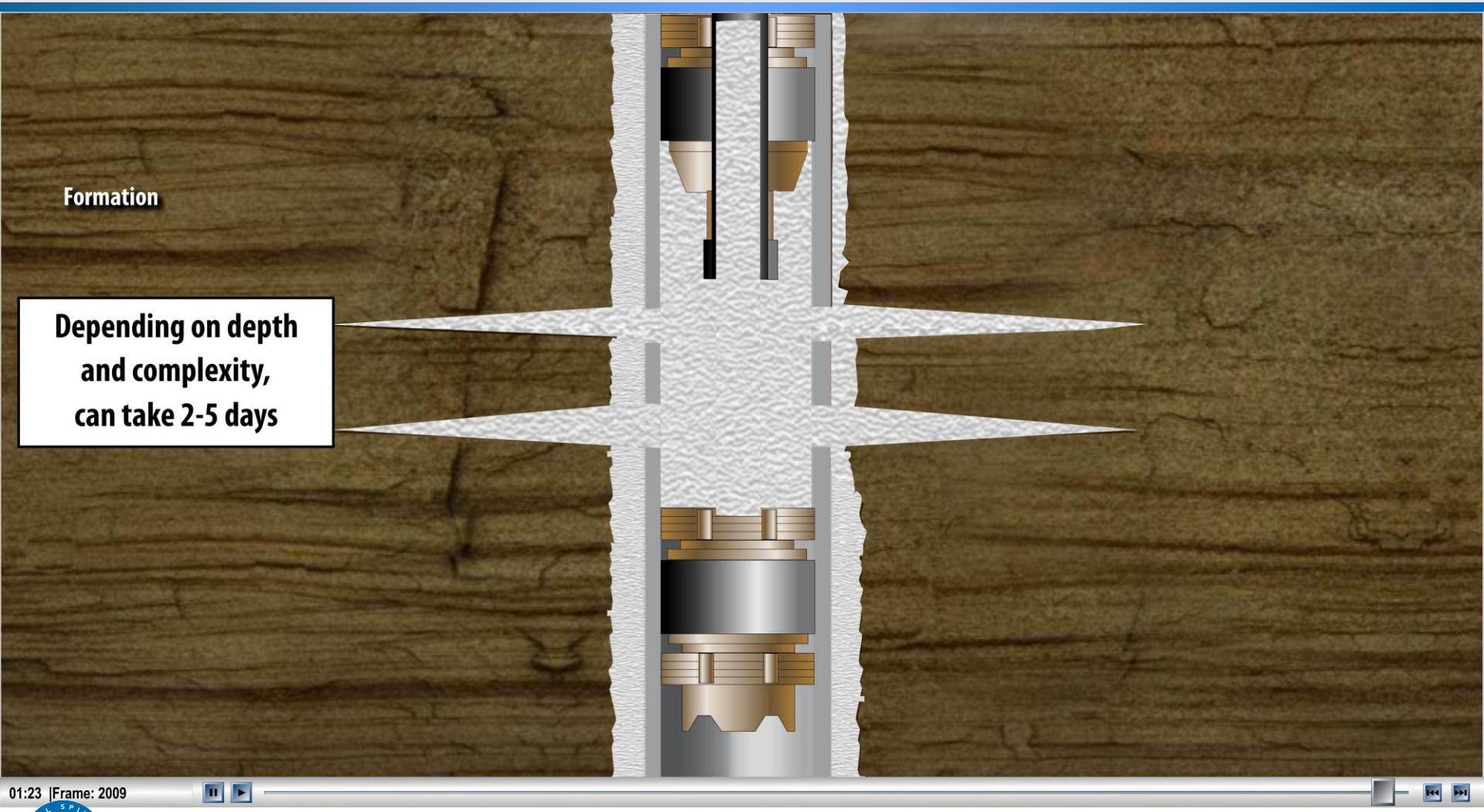
So based on the fact that we had lost circulation just like that out of the clear blue, we decided to go ahead and get circulation established, and then because of the actual volumes, we would actually have bottoms-up above the wellhead once the cement was in place, and then we would be able to circulate that out and see if there was any gas, so that was our plan.

Testimony of John Guide, BP Wells Team Leader, MBI Hearing 7/22 Tr. 88-89

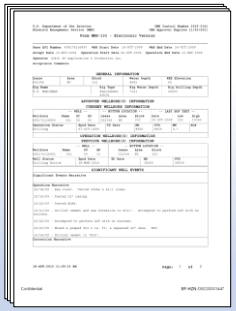
Situation at Time of Cement Job – April 19, 2010

- Difficult drilling conditions
- Serious lost returns in the zone to be cemented
- Forced to stop drilling earlier than planned
- Difficulty converting float equipment
- Low circulating pressure after conversion
- No bottoms up circulation
- **Cement jobs are known to occasionally need further work**
- Cement modeling perceived as unreliable by BP
- Complicated cement job
- Low rate of cement flow
- Low cement volume
- Uncertain centralization
- No direct indicators of cementing success and no cement evaluation log

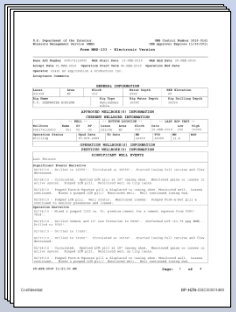
Cement Jobs May Require Repair



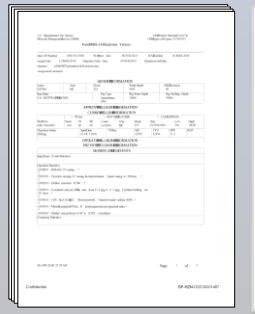
Squeeze Jobs at This Well



24-OCT-2009
Rig Name
T.O. MARIANAS
Depth
8,011
SIGNIFICANT WELL EVENTS
10/23/2009 – Mixed & pumped 923.5 cu. Ft. & squeezed 22” shoe. WOC.



20-FEB-2010
Rig Name
T.O. DEEPWATER HORIZON
Depth
9,085
SIGNIFICANT EVENTS
02/14/10 – Mixed & pumped 1120 cu. Ft. premium cement for a cement squeeze from 9085' 7814'



06-MAR-2010
Rig Name
T.O. DEEPWATER HORIZON
Depth
11,586
SIGNIFICANT EVENTS
03/05/10 – Mixed & pumped 095 cu. ft. premium cement and squeezed same.

Situation at Time of Cement Job – April 19, 2010

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Halliburton's OptiCem™ Software

CEMENTING

Integrated Cement Job Simulator

Halliburton's new OptiCem™ System helps design and simulate the optimum cement job regardless of the complexity of the wellbore or the type of program - standard or foam. Using OptiCem, you can easily identify potential problems and tune your cementing design parameters before pumping starts. OptiCem can:

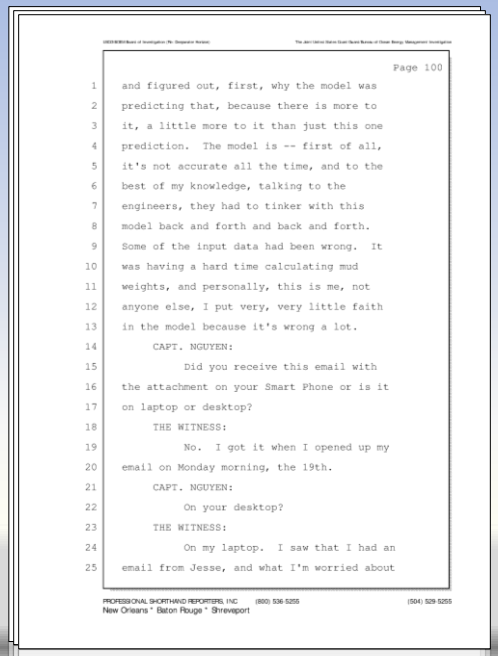
- *Optimize pump rates for maximum mud displacement*, making sure that pump rates keep fluids below fracturing pressures to help ensure well integrity, and above reservoir pressures to prevent the well from coming in.
- *Dynamically simulate cement jobs* to help produce a complete picture of the program that should be run.
- *Predict circulating pressures* at any time during the job, even during "free-fall" when the well is on vacuum and surface pressure indication is zero. Each run of the program provides pressures at the bottom of the hole and forty additional points - giving the user insight into the entire well.

In addition, OptiCem includes features to address other important aspects of cementing. It can:

- *Design centralizer placement* using any combination of holes, pipe sizes and centralizers of one or more types. Given desired standoff, OptiCem yields centralizer placement; given centralizer placement, the program calculates the resulting standoff.
- *Provide real-time analysis* during cementing, using a laptop computer. At the well site, the HalWin module gathers data (including data from slurry, nitrogen and chemicals units for foam cement jobs) and formats it for analysis by the OptiCem RealTime™ module. The RealTime module reruns the cement job simulation using this actual well data, which gives the on-site specialist downhole information that is invaluable when last-minute decisions must be made.
- *Evaluate job results* by comparing the pre-job simulation to simulation based on actual recorded data. This information can be extremely useful in planning future jobs and in trouble shooting.

BP Viewed Computer Cement Modeling as Unreliable

July 22, 2010



Page 100

and figured out, first, why the model was predicting that, because there is more to it, a little more to it than just this one prediction. The model is -- first of all, it's not accurate all the time, and to the best of my knowledge, talking to the engineers, they had to tinker with this model back and forth and back and forth. Some of the input data had been wrong. It was having a hard time calculating mud weights, and personally, this is me, not anyone else, I put very, very little faith in the model because it's wrong a lot.

CAPT. NGUYEN:

Did you receive this email with the attachment on your Smart Phone or is it on laptop or desktop?

THE WITNESS:

No. I got it when I opened up my email on Monday morning, the 19th.

CAPT. NGUYEN:

On your desktop?

THE WITNESS:

On my laptop. I saw that I had an email from Jesse, and what I'm worried about

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A. The model is – first of all, it's not accurate all the time…. …I put very, very little faith in the model because it's wrong a lot.

Testimony of John Guide, BP Wells Team Leader, MBI Hearing, 7/22 PM Tr. 100

Situation at Time of Cement Job – April 19, 2010

- Difficult drilling conditions
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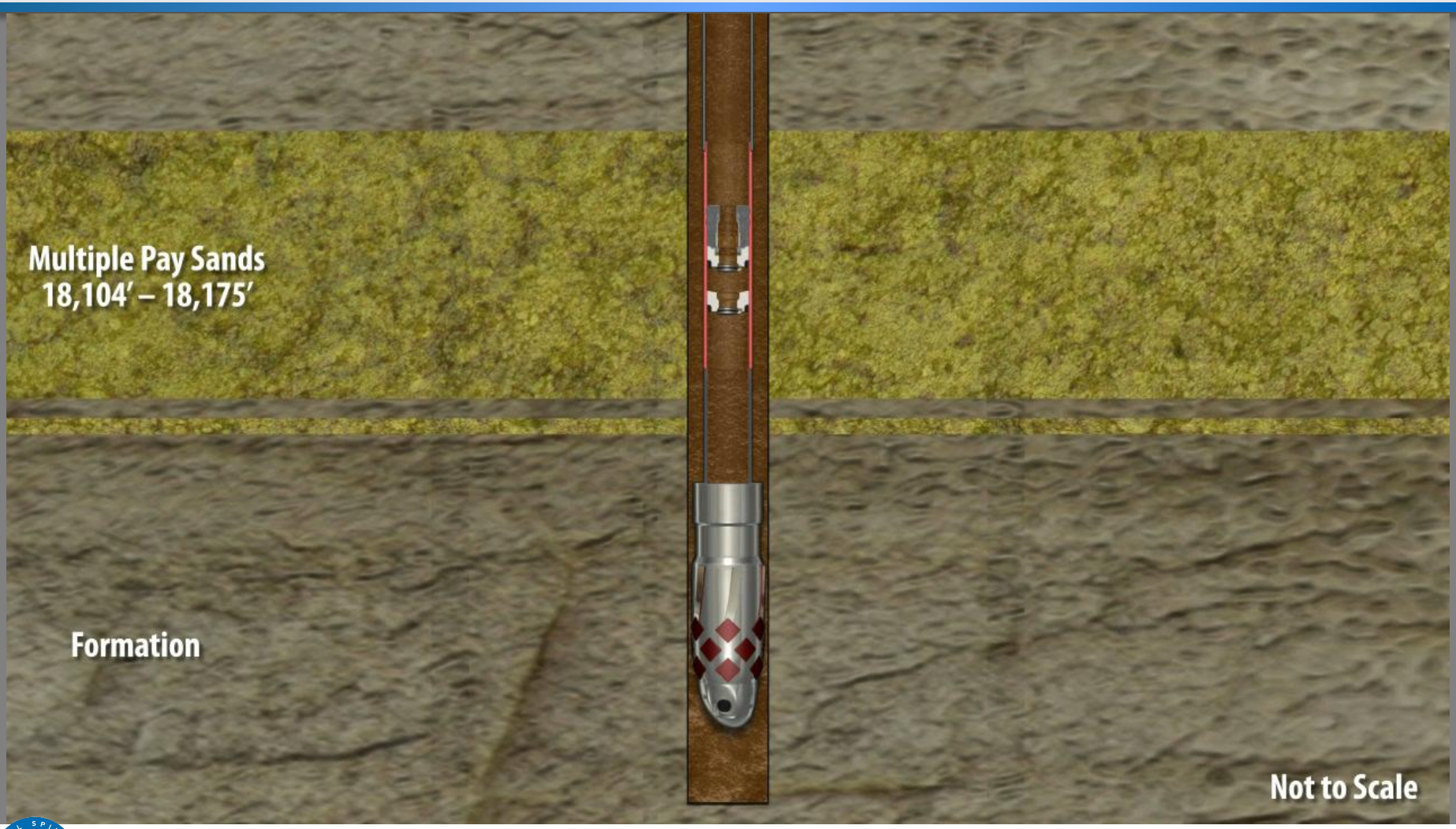
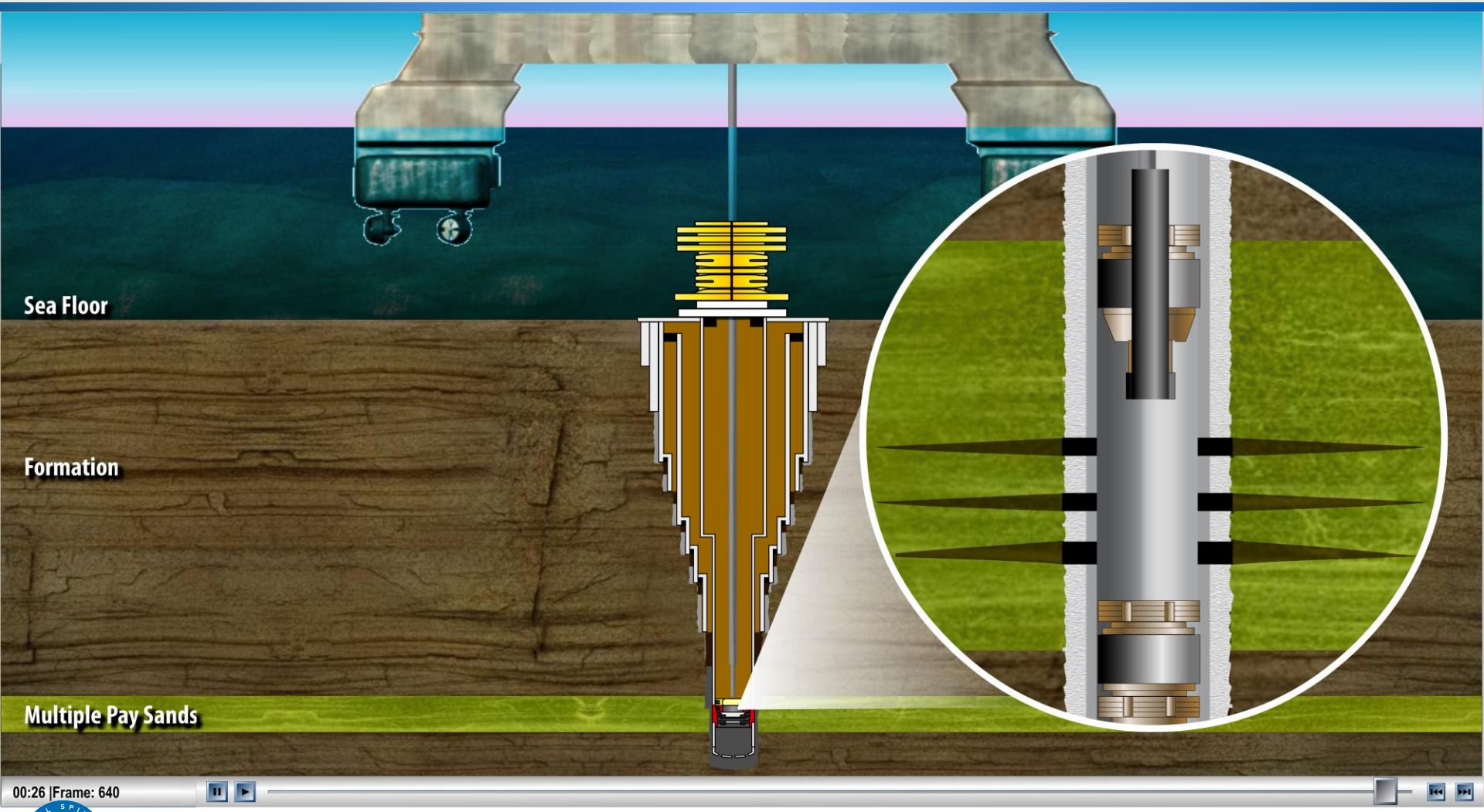
Planned Cement Job at Macondo

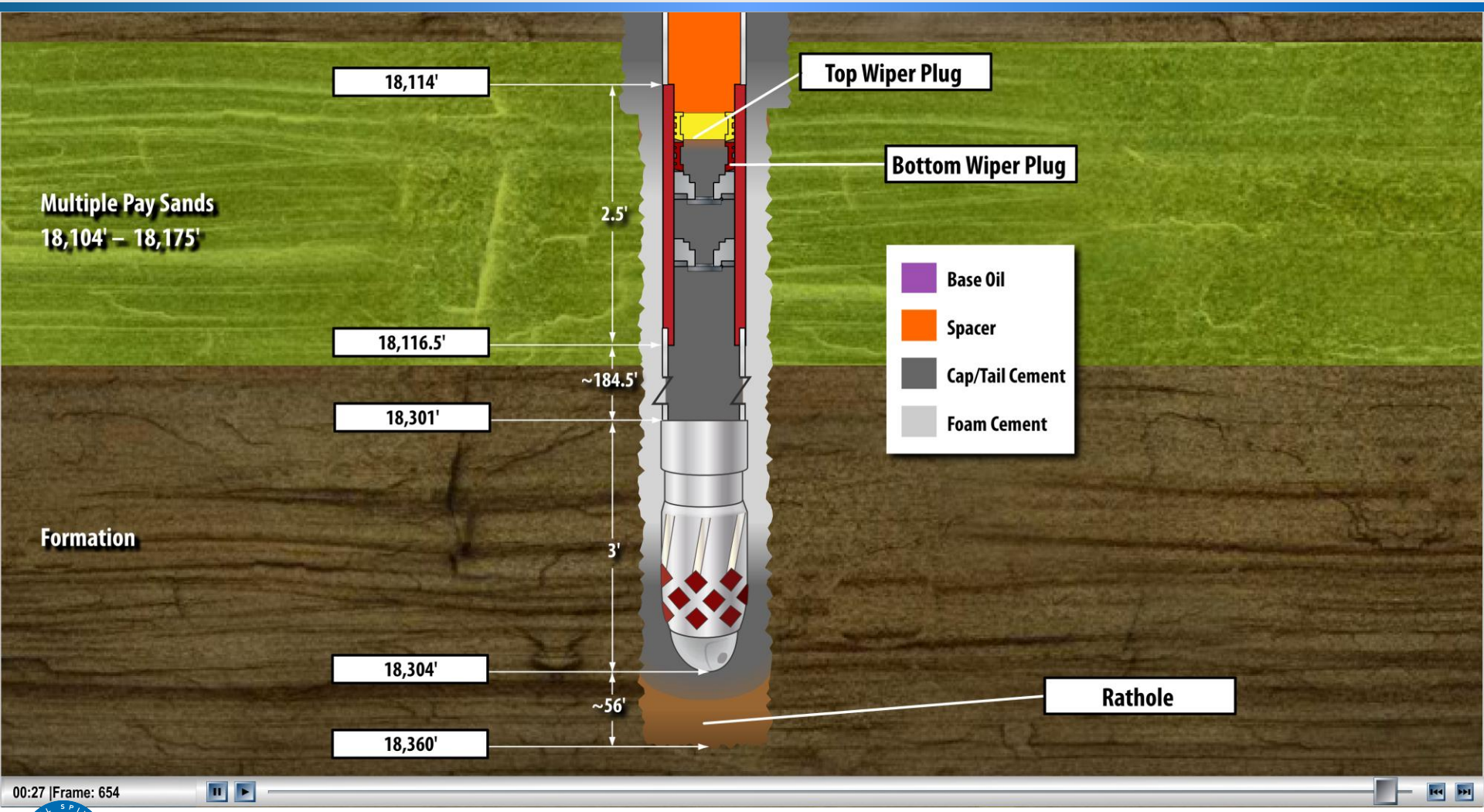


Production Well Conversion



TRIAL GRAPHIX

Planned Cement Job at Macondo



TRIAL GRAPHIX

BP Understood This Was a Complex Cement Job

April 1, 2010

Brian Morel emphasizes importance of cement:

From: Morel, Brian P
Sent: Thu Apr 01 12:10:42 2010
To: Jesse Gagliano; Hafle, Mark E; Cocales, Brett W
Cc: Quang Nguyen
Subject: RE: Out of Office
Importance: Normal

Jesse/Quang,

Can you start running some tests on the nitrogen job? This is an **important** job and we need to have the data well in advance to make the correct decisions on this job.

Thanks
Brian

September 8, 2010

2.1 Cement Design

Considering the narrow pore pressure and fracture gradient conditions in the Macondo well, planning the cement job to achieve effective cement placement and zonal isolation was a **challenge** for the BP and Halliburton personnel involved.

BP Deepwater Horizon Accident Investigation Report, Pg. 55

September 8, 2010

Cement Slurry Design

Due to the narrow margin between pore pressure and fracture gradient, the accuracy of cement placement was **critical**. Several design iterations were conducted by Haliburton using the OptiCem™ wellbore simulation application to establish an acceptable slurry design and placement plan. A **complex design** for the cement job with base oil spacer, cementing spacer, lead (cap) cement, foam cement and tail cement, was recommended and implemented.

The Halliburton and BP Macondo well team's technical reviews of the cement slurry design appear to be focused primarily on achieving an acceptable equivalent circulating density during cement placement to prevent loss returns. Other important aspects of the foam cement design, such as foam stability, possible contamination effects and fluid loss potential did not appear to have been critically assessed in the pre-job reviews

BP Deepwater Horizon Accident Investigation Report, Pg. 34

September 8, 2010

Several key factors (such as small cement slurry volume [approximately 62 bbls], narrow pore pressure/fracture gradient window and upper technical range for using nitrified foam cement) highlight the **difficulties** in designing a reliable cement slurry.

The BP Macondo well team and the Halliburton in-house cementing engineer were aware of the narrow pore pressure/fracture gradient window. This was evident by the number of OptiCem™ model runs and meetings held to discuss ECD and channeling potential.

BP Deepwater Horizon Accident Investigation Report, Pg. 67

Situation at Time of Cement Job – April 19, 2010

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- Cement jobs are known to occasionally need further work
- Cement modeling perceived as unreliable by BP
- Complicated cement job
- **Low rate of cement flow**
- Low cement volume
- Uncertain centralization
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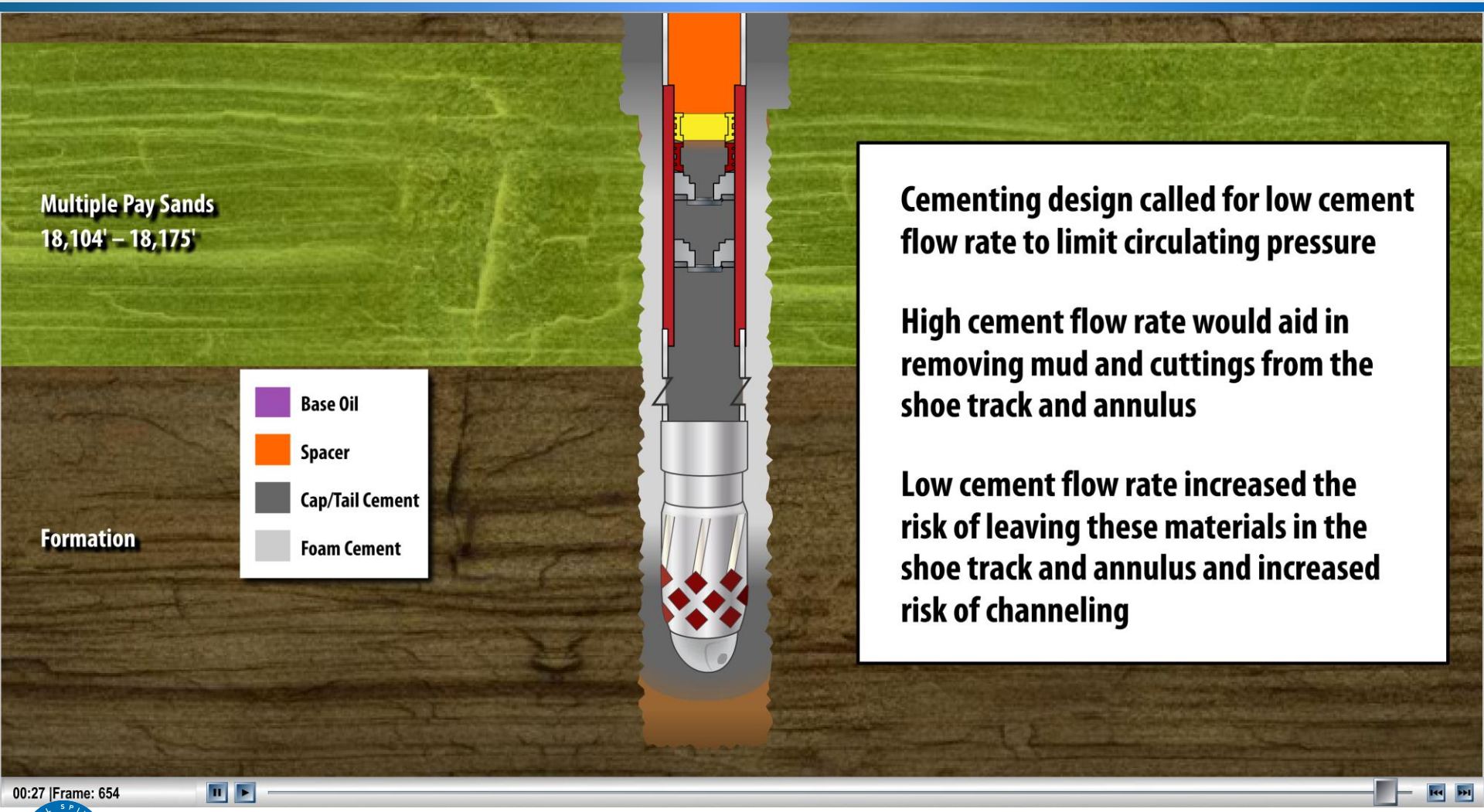
Low Cement Flow Rate



Cementing design called for low cement flow rate to limit circulating pressure

High cement flow rate would aid in removing mud and cuttings from the shoe track and annulus

Low cement flow rate increased the risk of leaving these materials in the shoe track and annulus and increased risk of channeling

Low Cement Flow Rate at Macondo

GoM Exploration Wells

MC 252 #1ST00BP01 – Macondo Prospect
7" x 9-7/8" Interval

Table of Contents

Interval Notes

Item	Comment
Bits	M-3HF 3D697Z (primary)
Underreamers	N/A
BHA	PWD, GR, RES, DOS
Special Equipment	Dril-Quip 11" (dummy) / 7" position hangers (connected) tool, Weatherford dual plug system, Allamon Diverter sub head, 7" HS13 x 9-7/8" HS23 x-over, 4 pip tags, lockdown running tool, LDS measurement tool, riser wipe brushes, 734 LOW material, IBC-CBL log equipment, Variaflex 5-
Drilling	5-1/2" 21.9 ppf S-135 x 6-5/8" 32 ppf S-135
Mud weight	14.0 ppg SOBM
Casing	7" 32 ppf HCQ-125, 0.9" wall, Hydril 513 x 9-7/8" 62.8 p
Landing string	6-5/8" 40 ppf S-135 FH x 6-5/8" 40 ppf V-150 FH
Cementing	14.5 ppg Halliburton Class H nitrogen foam cement (see detailed cement program)

Rev. H.2 Page 1 of 21 April 15, 2010

Confidential BP-HZN-CEC021281

GoM Exploration Wells

MC 252 #1ST00BP01 – Macondo Prospect
7" x 9-7/8" Interval

5. Just prior to the liner reaching open hole, record pickup, slack-off, and slow pump rates (15 – 25 – 35 spm)
6. Free drop 1-5/8" wash down ball when the liner reaches open hole (record).
7. Continue RIH with casing until 1 stand off bottom, MU top drive
8. While stacking off on the last stand prior to picking up the cement head, pressure up to 1000 psi slowly and hold for 2 minutes. Then increase to 2500 psi to yield the ball seat
9. Let ball free fall to DTD sub, repeat step 5 (ball diameter is closer)
10. Give ball time to free-fall through the liner hanger and plugs

4. MIX & pump the 14.5 ppg cement job per HES procedure (2 bpm).
   - Slow pump rates to 2 bpm while mixing foam cement (reduces surge on formation from nitrogen spike)
   - After pumping the cement job, launch the top DP dart (2.125" No Go) with 5-10 bbl of cement behind dart. Indicators should be seen from the BlackHawk cement head confirming the top dart left the head

Confidential BP-HZN-CEC021288

9.2.3 Cementing Production Casing

Test Pressures and Volumes are only as a reference, **review APD** for final values.

1. Circulate at least one (1) casing and drill pipe capacity, if hold conditions allow. Recommend circulating at reduced rates ***(3bpm)*** based on MI models to keep ECD below 14.5 ppg.

Eventually decided to pump cement at 4 bpm

Situation at Time of Cement Job – April 19, 2010

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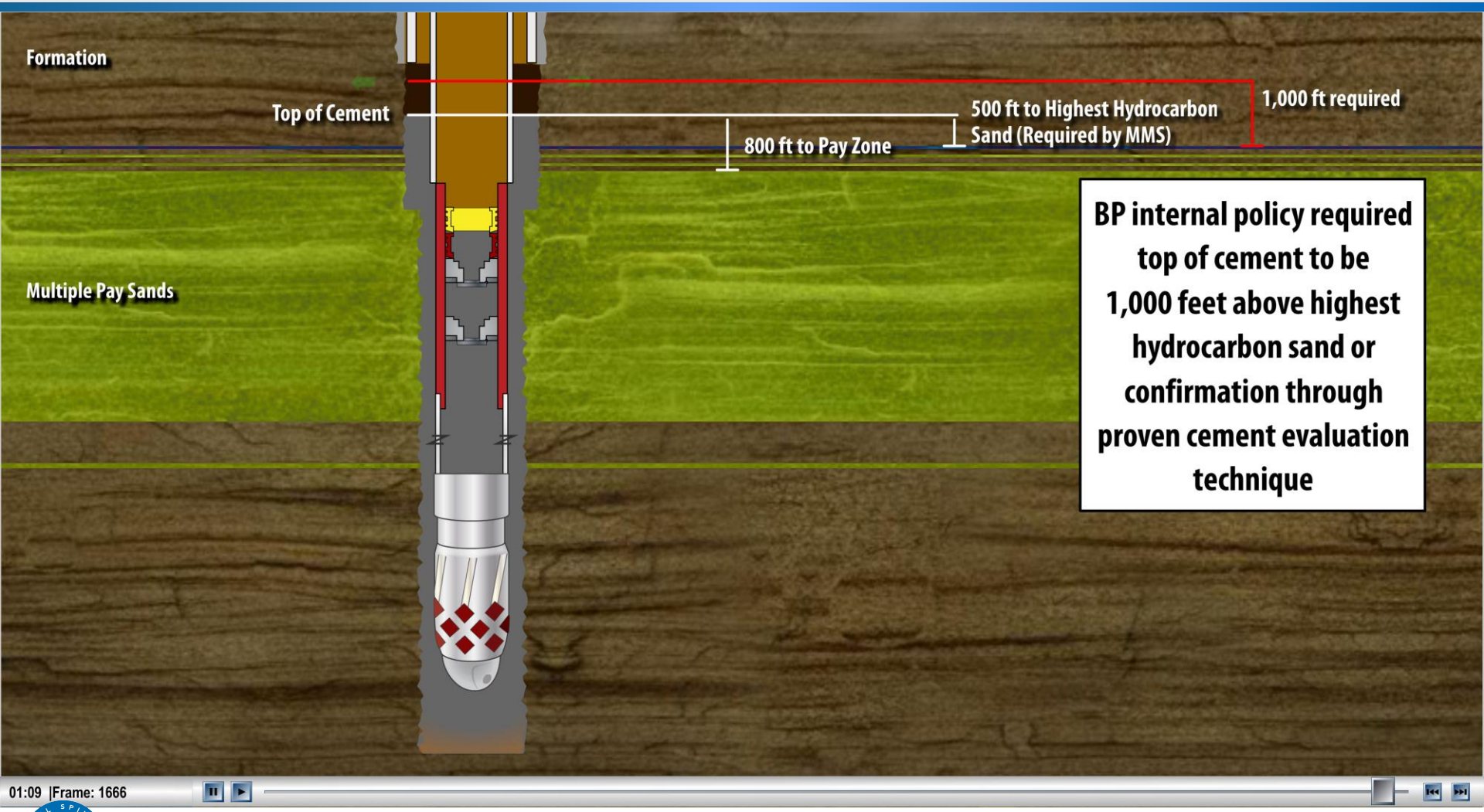
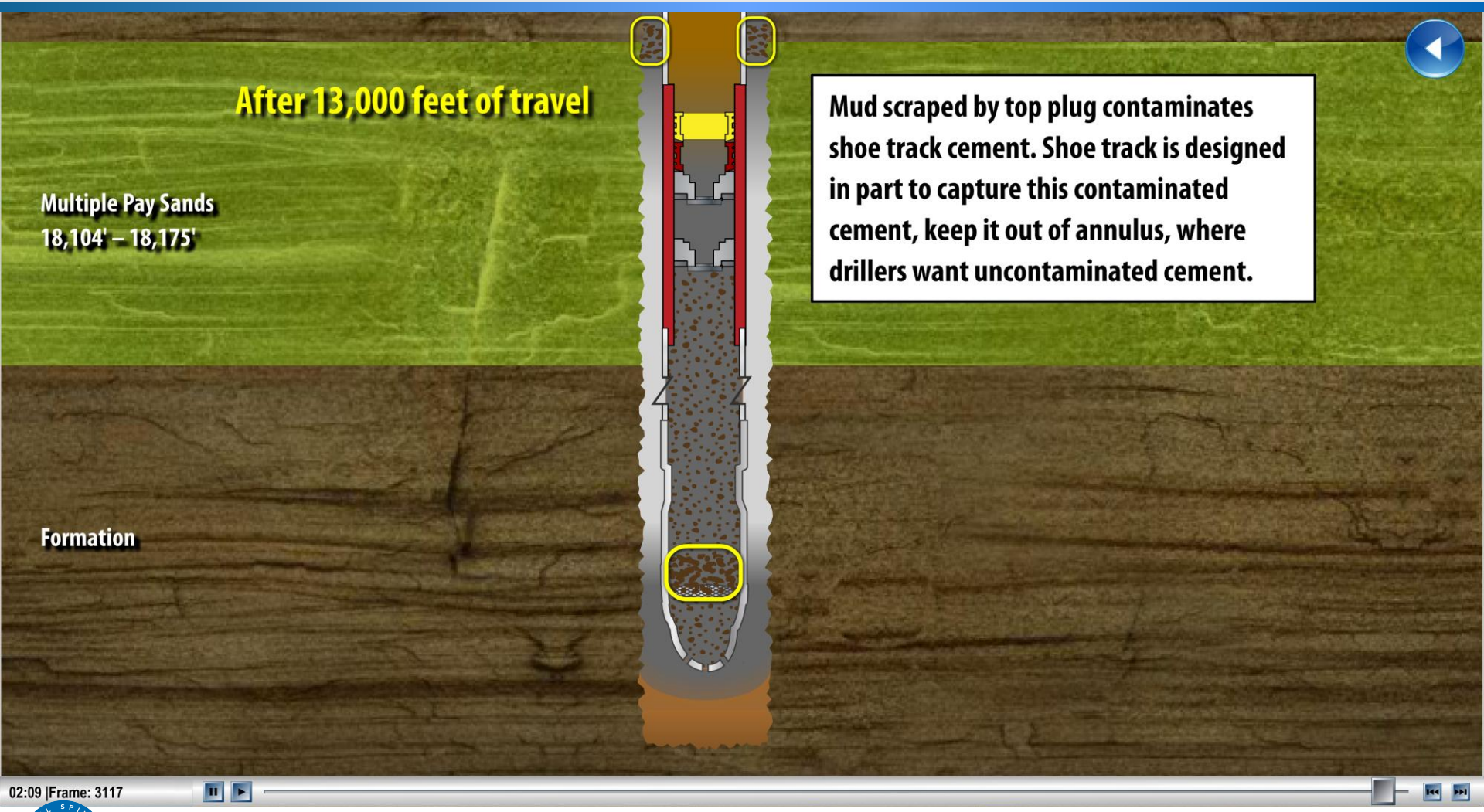
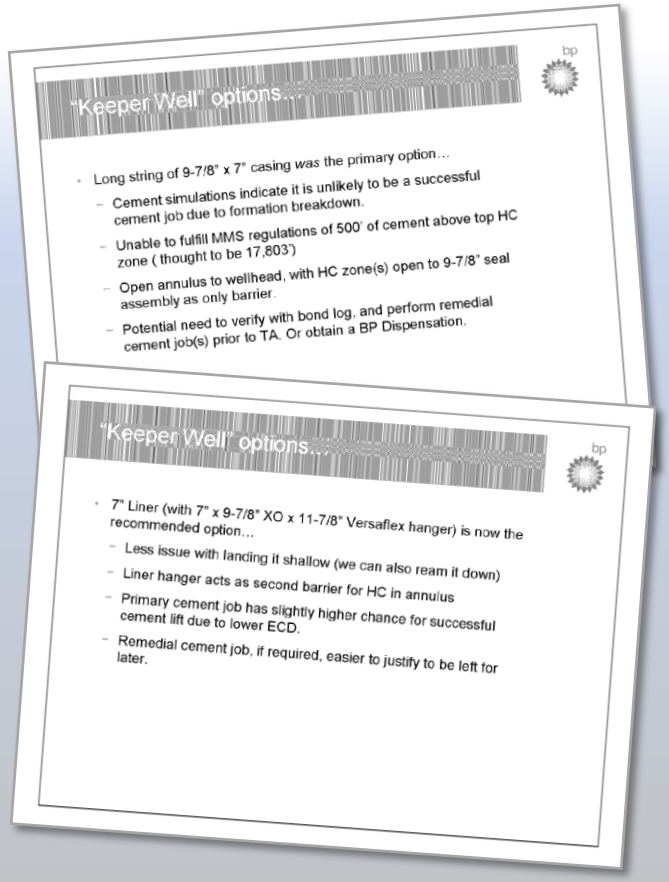
Low Top of Cement



Long String Compared to Liner



Long String vs. Liner Debate Focused on Cementing Concerns



- Original design called for long string
- Engineering personnel briefly decided to use liner because of ECD concerns
- Consulted internal BP cement expert and concluded that long string could be cemented

Situation at Time of Cement Job – April 19, 2010

- Difficult drilling conditions
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- Forced to stop drilling earlier than planned
- Difficulty converting float equipment
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- Cement jobs are known to occasionally need further work
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Centralizers

Original Design Called for Many Centralizers

GoM Exploration Wells

MC 252 #1 – Macondo Prospect
9-7/8" Casing Interval

10.5 9-7/8" Casing and Cementing Operations

10.5.1 Casing and Cement Preparation

- Prior to shipping, primary float equipment should have been bucked up and thread-locked onto a joint of pipe. Inspect shoe and float collar joints for debris prior to picking up.
- Ensure cement, additives, and fresh and seawater samples are sent to cement company lab for final lab testing.
- Prior to shipment, verify casing has been drifted to 8-1/2". Visually inspect to ensure there is no debris in pipe. A laser caliper of all joints should have been completed, engineer should supply to the rig prior to running the casing.
- Prepare 9-7/8" casing tally. Inspect threads and clean as required.
- Boost riser while rigging up casing equipment (not while running 16", as mud can flow up through casing).
- Calculate swabbsurge pressures for various running speeds. Select an acceptable speed to ensure formation breakdown pressure isn't exceeded.
- Prior to running casing, rabbit 6-5/8" running string to 2-3/4 in drift ID.
- Ensure any crossover required in landing string is rented, inspected, and has a specific request to provide material certifications to rig and engineer. These certs are to be used to verify proper load carrying capabilities.
- Ensure all crossovers in string do NOT have internal square shoulders as these have proven to hang up drill pipe darts.
- Make-up primary Drill-Quip casing hanger running tool and place on riser skate
- Ensure wellhead protector sleeve has been pulled prior to running casing.
- Ensure that a 9-7/8" Halliburton Fast drill is on location for remedial cement job or temporary abandonment.
- 750 ton equipment should be used for this section, ensure inspected and ready to use prior to running casing.
- Centralizers will be run every joint for the first 5 joints, followed by every other joint from the shoe to 500' above productive interval. Check system which is supplied to ensure it's in proper working fashion.
- Rig up Allamon Top Drive Surface Cement Equipment as follows and place on riser skate or stand back in derrick:
  - 6-5/8" DP singled (drifted to 2-5/8")
  - 15' DP pup jt
  - Full open safety valve
  - ATC dual Dart Cement Head
    - ATC 2.375" bottom DP dart (pre-installed)
    - ATC 2.5" top DP dart (pre-installed)
  - ATC positive launch indicator sub (PLI)
  - Full open safety valve
    - Function test valve to verify alignment versus the bore is centered
  - 6-5/8"DP single (drifted to 2-3/4")

Rev. 0.H | Page 9 of 17 | Jan 2010

Confidential Treatment Requested | BP-HZN-CEC020450

GoM Exploration Wells

MC 252 #1 – Macondo Prospect
9-7/8" Casing Interval

- 750 ton equipment should be used for this section, ensure inspected and ready to use prior to running casing.
- Centralizers will be run every joint for the first 5 joints, followed by every other joint from the shoe to 500' above productive interval. Check system which is supplied to ensure it's in proper working fashion.
- Rig up Allamon Top Drive Surface Cement Equipment as follows and place on riser skate or stand back in derrick:

Confidential Treatment Requested | BP-HZN-CEC020450

But…not enough centralizer "subs" available

Bow Spring Centralizers vs. Centralizer Subs

Centralizer Sub

Advantage:
Threaded onto casing, less chance of “hanging up” in wellhead or BOP

Centralizer and Stop Collars

Advantage:
Performs centralization functions and is available

OptiCem™ Models and Halliburton Personnel Recommend 21 Centralizers

April 15, 2010

BP AMERICA PRODUCTION COMPANY
PO Box 22024
Tulsa, OK 74121-2024

Macondo #1

9 7/8" X 7" Production Casing Design Report

For: Brian Morel
Date: April 15, 2010

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HALLIBURTON

BP-HZN-IIT-0004255
BP-HZN-MBI00137309

USCG/BOEM Board of Investigation (Re: Deepwater Horizon) — The Joint United States Coast Guard/Bureau of Ocean Energy Management Investigation

1 fluids in the hole, and at the bottom of the
2 schematic, the yellow here indicates --
3 Q And just so we're all on the same
4 page, is that the document on the top of the
5 easel there, sir?
6 A Yes, it's the top picture on the

1 A Okay. It says, "Attached is the
2 revised information for the upcoming nine
3 and seven-eighths by seven-inch production
4 casing job. The compressive strength is not
5 yet completed" -- "not completed yet" --
6 Excuse me -- "and currently has 34 hours.

I was actually in the office working on it, and when I noticed the problem, I printed it out, and I got up to go show BP, and when I came around the corner, I ran into Brett Cocales and Mark Hafle, and I pointed out to them, said, "Hey, I think we have a potential problem here. There's a potential for flow due to the six centralizers on joint channeling."

Testimony of Jesse Gagliano, Halliburton Sales Representative, USCG 8/24 Tr. 20

18 and I think the top response was back to you
19 from Mr. Nathaniel Chaisson. Is that what
20 you're looking at, sir?
21 A Yes.
22 Q Can you please read what your
23 e-mail says at 8:58 p.m.?
24 A The e-mail I sent?
25 Q Yes, sir.

Page 18

18 here. There's a potential for flow due to
19 the six centralizers on joint channeling."
20 I remembered the conversation,
21 that Mr. Mark Hafle was on the way out to a
22 meeting and we briefly discussed it. He
23 says, "Well, get with Brett, see what we can
24 do to fix the problem," and then Mark left
25 and I stayed behind with Brett Cocales. And

Page 20

5 (Pages 17 to 20)

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New Orleans * Baton Rouge * Shreveport

OSC OIL SPILL COMMISSION

TRIAL GRAPHIX

To 'Honor the Modeling,' BP Sends Additional Centralizers to Rig

April 16, 2010

From: Walz, Gregory S
To: Guide, John
Sent: Fri Apr 16 00:50:27 2010
Subject: Additional Centralizers

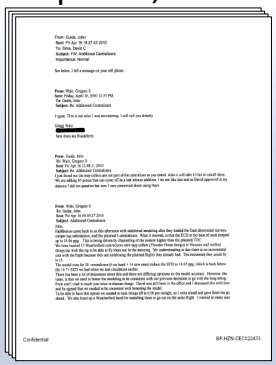
John,
Halliburton came back to us this afternoon with additional modeling after they loaded the final directional surveys, caliper log information, and the planned 6 centralizers. What it showed, is that the ECD at the base of sand jumped up to 15.06 ppg . This is being driven by channeling of the cement higher than the planned TOC.

The model runs for 20 centralizers (6 on hand + 14 new ones) reduce the ECD to 14.65 ppg, which is back below the 14.7+ ECD we had when we lost circulation earlier.
There has been a lot of discussion about this and there are differing opinions on the model accuracy. However, the issue, is that we need to honor the modeling to be consistent with our previous decisions to go with the long string. Brett and I tried to reach you twice to discuss things. David was still here in the office and I discussed this with him and he agreed that we needed to be consistent with honoring the model.
To be able to have this option we needed to kick things off at 6:00 pm tonight, so I went ahead and gave Brett the go ahead. We also lined up a Weatherford hand for installing them to go out on the same flight. I wanted to make sure that we did not have a repeat of the last Atlantis job with questionable centralizers going into the hole.
John, I do not like or want to disrupt your operations and I am a full believer that the rig needs only one Team Leader. I know the planning has been lagging behind the operations and I have to turn that around. I apologize if I have over step my bounds.

Confidential BP-HZN-CEC022434

Last-Minute Decision Not to Use Additional Six Centralizers

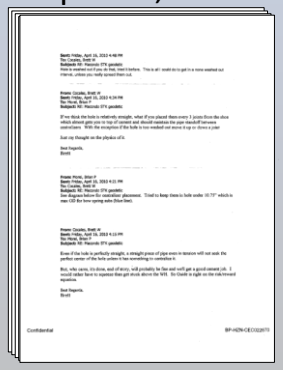
April 16, 2010



From: Guide, John
To: Walz, Gregory S
Sent: Fri Apr 16 12:48:11 2010
Subject: Re: Additional Centralizers

I just found out the stop collars are not part of the centralizer as you stated. Also it will take 10 hrs to install them. We are adding 45 pieces that can come off as a last minute addition. I do not like this and as David approved in my absence I did not question but now I very concerned about using them

April 16, 2010



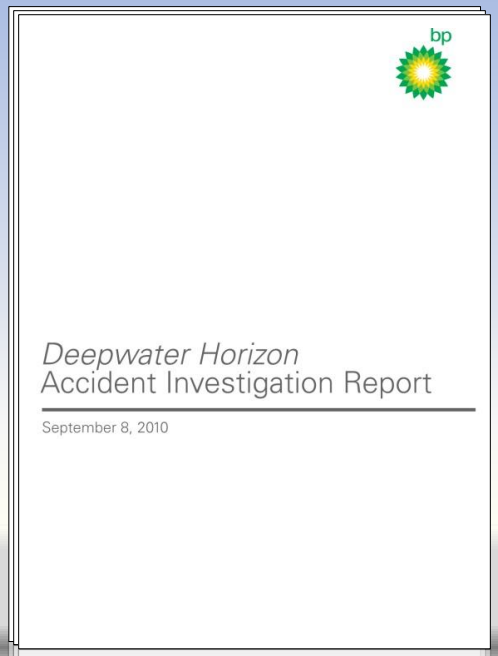
From: Cocales, Brett W
Sent: Friday, April 16, 2010 4:15 PM
To: Morel, Brian P
Subject: RE: Macondo STK geodetic

* * *

But, who cares, it's done, end of story, will probably be fine and we'll get a good cement job. I would rather have to squeeze than get stuck above the WH. So Guide is right on the risk/reward equation.

No Clarity Even Now on Whether the Additional Centralizers Should Have Been Used

September 8, 2010



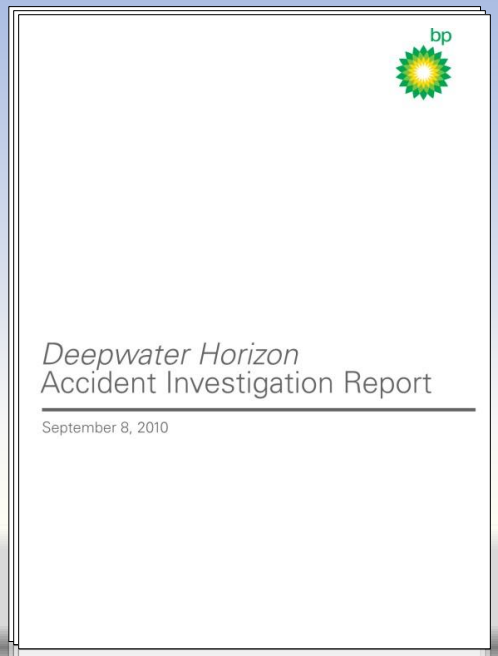
The BP Macondo well team erroneously believed that they had received the wrong centralizers.

BP Deepwater Horizon Accident Investigation Report, Pg. 35

Weatherford man on rig not consulted

BP Never Performed Modeling to Check Whether Six Centralizers Were Enough

September 8, 2010



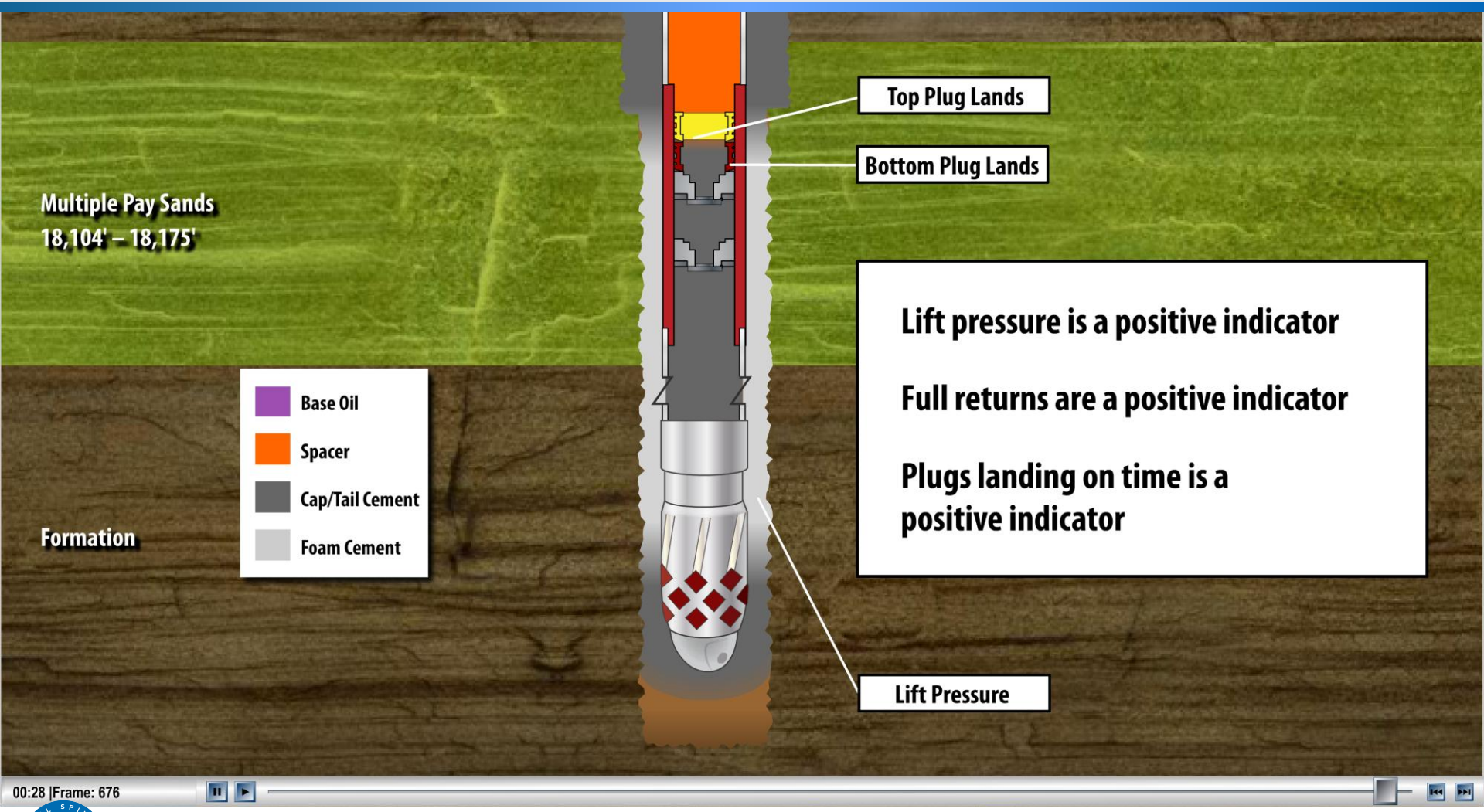
When the decision was made to proceed without the additional centralizers, the BP Macondo well team did not ask for the OptiCem™ model to be re-run.

BP Deepwater Horizon Accident Investigation Report, Pg. 64

Situation at Time of Cement Job – April 19, 2010

- Difficult drilling conditions
- Serious lost returns in the zone to be cemented
- Forced to stop drilling earlier than planned
- Difficulty converting float equipment
- Low circulating pressure after conversion
- No bottoms up circulation
- Cement jobs are known to occasionally need further work
- Cement modeling perceived as unreliable by BP
- Complicated cement job
- Low rate of cement flow
- Low cement volume
- Uncertain centralization
- **No direct indicators of cementing success and no cement evaluation log**

Indirect Cementing Indicators



Halliburton's April 20, 2010 Post-Job Report

HALLIBURTON

Significant Points

- Cement job pumped as planned.
- Chemical straps determined that additives were pumped at planned volumes
- Rig completed displacement and both plugs were bumped.

HALLIBURTON

Significant Points

- Cement job pumped as planned.
- Chemical straps determined that additives were pumped at planned volumes
- Rig completed displacement and both plugs were bumped.
- Full returns seen throughout entire job.
- Estimated 100 psi of lift pressure (350 psi circulating to 450 psi circulating), before bumping top plug.
- Floats held after job.

BP Internal Criteria for Determining Zonal Isolation

5.3. Determining zonal isolation

5.3.1. Cement evaluation logs

To accurately assess TOC and zonal isolation cement sonic and ultrasonic logs should be used.

To get accurate information from the logs they have to be run under optimum conditions (impacts of microannuli and gas can compromise log quality) and may need specialist log evaluation and / or interpretation

5.3.2. Cement column backpressure

The simplest way of estimating TOC is to determine the cement column hydrostatic by slowing the pumps down immediately prior to bumping the plug.

This will only give a very coarse estimate and where cement and mud weights are very similar (within 0.2 SG) is unlikely to provide a sufficiently accurate estimate.

5.3.3. Temperature logs

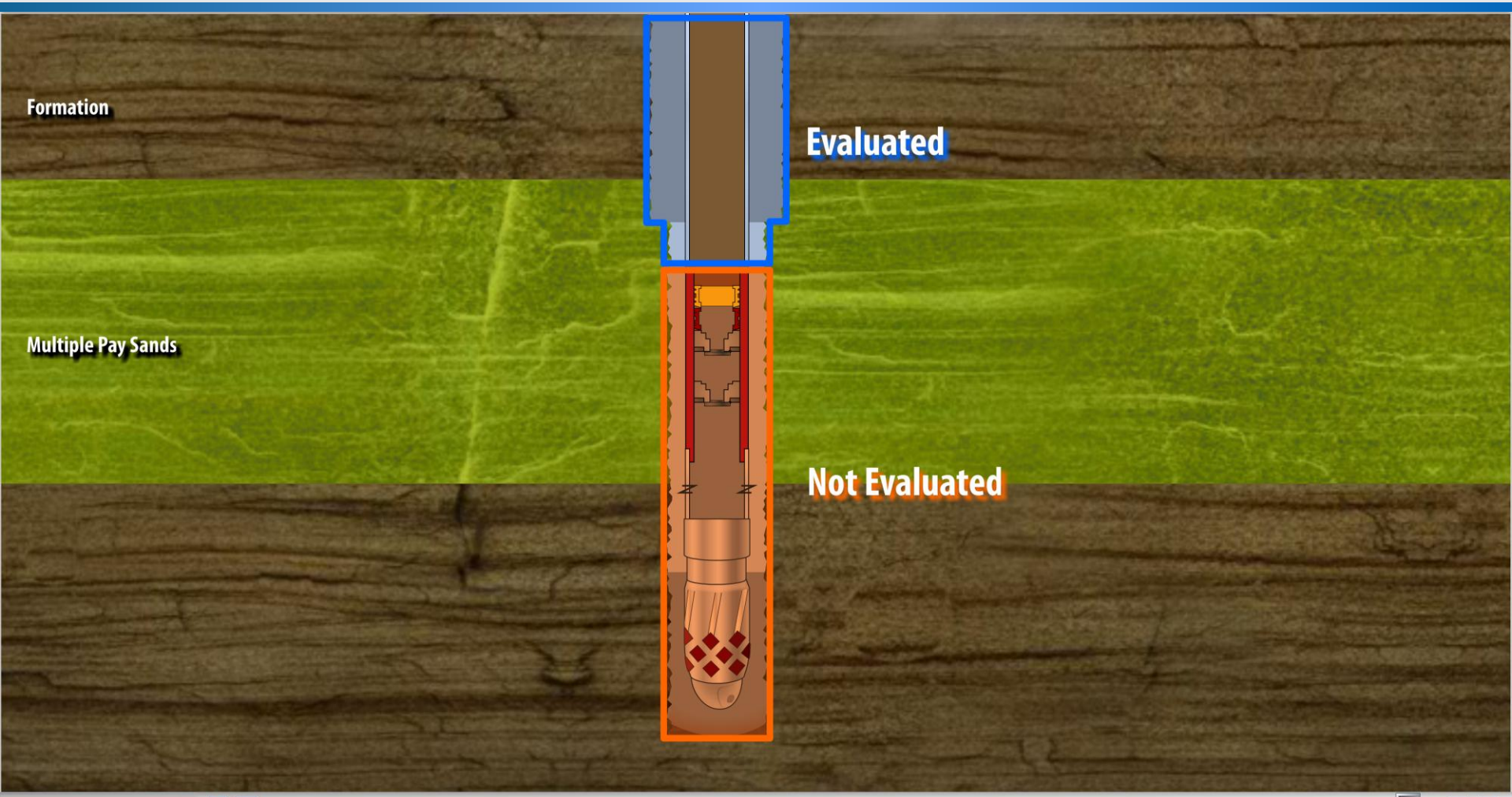
Temperature logs can give a simple estimate of the TOC when they are run soon after cementing.

They identify a temperature anomaly usually associated with the heat evolved when the cement sets but give no indication of isolation.

Highly Confidential
Confidential

BP-HZN-MBI00192558

Cement Evaluation



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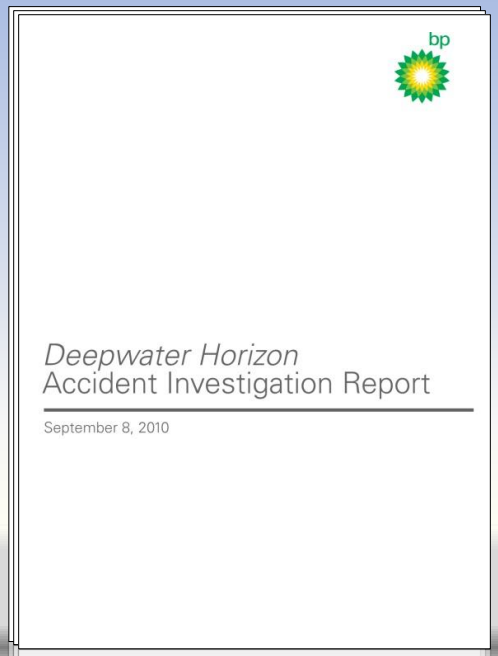
BP Didn't Conduct a Formal Risk Assessment of the Annulus Cement Barrier

September 8, 2010


bp

Deepwater Horizon
Accident Investigation Report

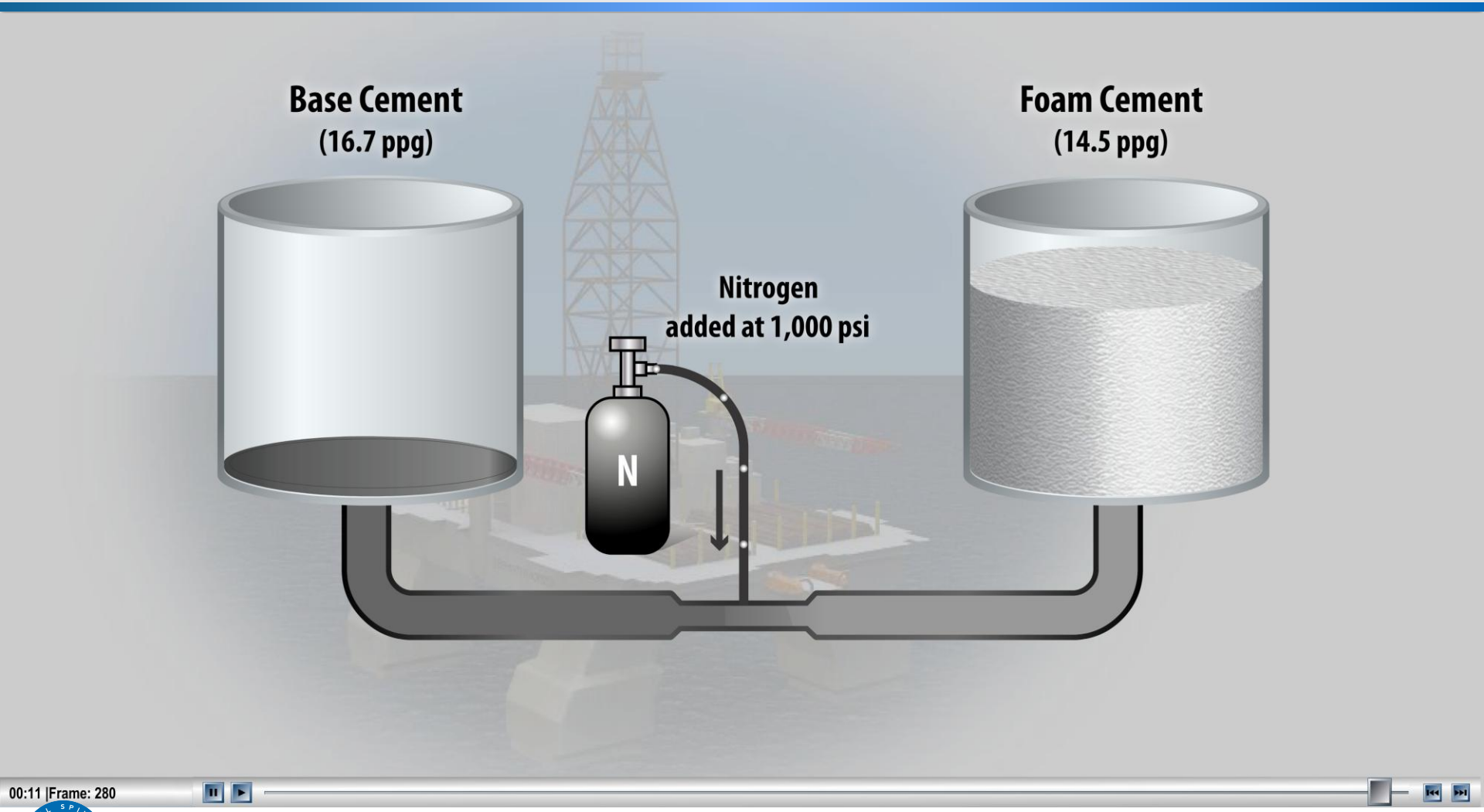
September 8, 2010

But not conducting a formal risk assessment of the annulus cement barrier per the ETP recommendation, it is the investigation team's view that the BP Macondo well team did not fully conform to the intent of ETP GP 10-60. Such a risk assessment might have enabled the BP Macondo well team to identify further mitigation options to address risks such as the possibility of channeling; this may have included running a cement evaluation log.

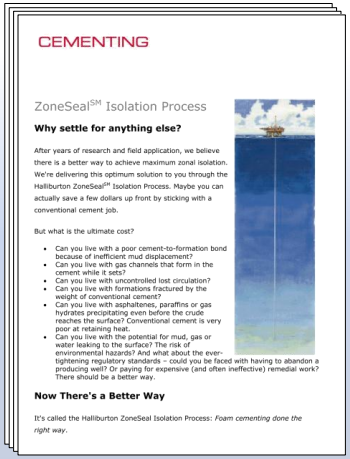
BP Deepwater Horizon Accident Investigation Report, Pg. 66

Questions About Cement

Base vs. Foam Cement



Advantages of Foam Cement



CEMENTING

ZoneSeal[SM] Isolation Process

Why settle for anything else?

After years of research and field application, we believe there is a better way to achieve maximum zonal isolation. We're delivering this optimum solution to you through the Halliburton ZoneSeal[SM] Isolation Process. Maybe you can actually save a few dollars up front by sticking with a conventional cement job.

But what is the ultimate cost?

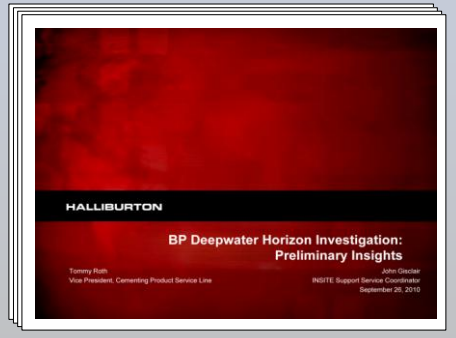
- Can you live with a poor cement-to-formation bond because of inefficient mud displacement?
- Can you live with gas channels that form in the cement while it sets?
- Can you live with uncontrolled lost circulation?
- Can you live with formations fractured by the weight of conventional cement?
- Can you live with asphaltenes, paraffins or gas hydrates precipitating even before the crude reaches the surface? Conventional cement is very poor at retaining heat.
- Can you live with the potential for mud, gas or water leaking to the surface? The risk of environmental hazards? And what about the ever-tightening regulatory standards – could you be faced with having to abandon a producing well? Or paying for expensive (and often ineffective) remedial work? There should be a better way.

Now There's a Better Way

It's called the Halliburton ZoneSeal Isolation Process: *Foam cementing done the right way.*

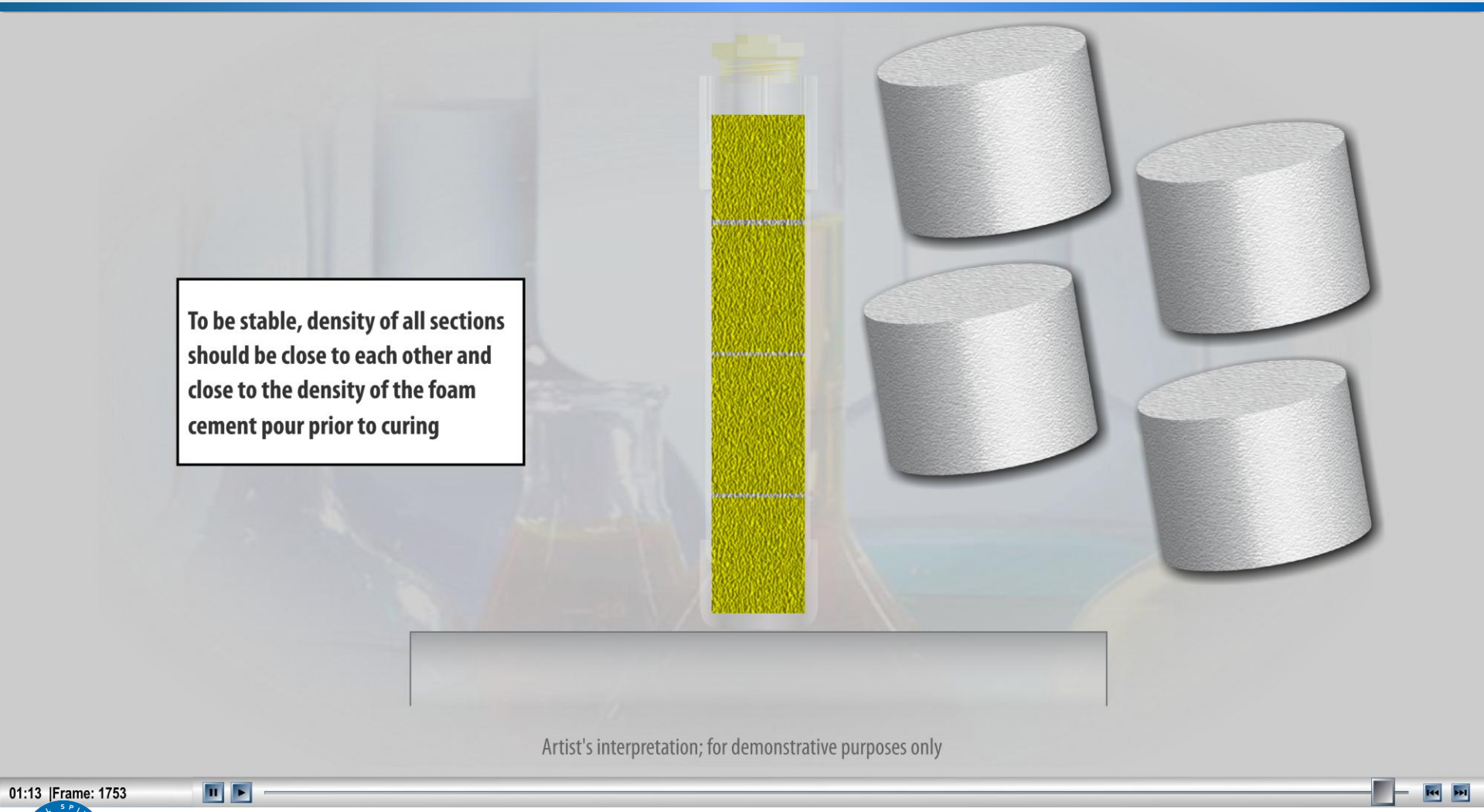
Foam cement helps improve mud displacement, helps prevent gas migration and helps protect the formation:

- Foam cement under compression is a highenergy, high-viscosity system that is more efficient than conventional slurries in displacing mud. Preflushes and spacers can also be foamed to make them more efficient. Result: Cement-formation bonds that really hold up because all the mud has been removed.
- The compressed gas bubbles in foam cement shrink or expand, but they don't move around or coalesce. Instead, they maintain pressure while the cement hydrates. Result: Virtually no gas migration into the cement, ever – while cement is being placed or while it sets.
- The bubbles actually "plate out" against the formation and form a barrier. Result: lower water loss to the formation, which helps prevent formation swelling, washouts and other damage.
- Foam cement can be mixed at very light weights – as low as 4 lb./gal. Result: A good fix for extreme lost-circulation problems where nothing else will work.
- The density of foam cement can be varied at will using the same base slurry. Result: Hydrostatic pressure that can be tailored to protect fragile formations and help prevent high-pressure zones from coming in – all within the same job.

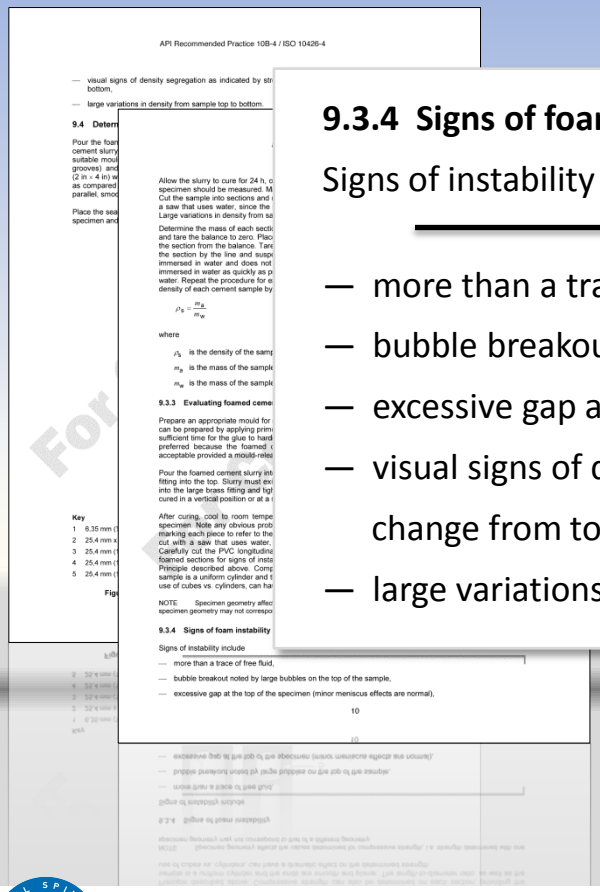


Halliburton has successfully used foam cement in over 1000 jobs, including 279 jobs at 15,000 ft. or deeper and 79 jobs at 18,000 ft or deeper.

How Foam Cement Testing Is Done



API Foam Stability Criteria


API Recommended Practice 10B-4 / ISO 10426-4

9.3.4 Signs of foam instability

Signs of instability include

- more than a trace of free fluid,
- bubble breakout noted by large bubbles on the top of the sample,
- excessive gap at the top of the specimen (minor meniscus effects are normal),

10

9.3.4 Signs of foam instability

Signs of instability include

— more than a trace of free fluid,

— bubble breakout noted by large bubbles on the top of the sample,

— excessive gap at the top of the specimen (minor meniscus effects are normal),

— visual signs of density segregation as indicated by streaking or light to dark colour change from top to bottom,

— large variations in density from sample top to bottom.

Halliburton's Pre-Job Test Results

April 12th 2010

HALLIBURTON
Cementing Gulf of Mexico, Broussard

LAB RESULTS - Primary

Job Information

Request/Slurry	73909/2	Rig Name	TRANSOCEAN HORIZON	Date	April 12th 2010
Submitted By	Jesse Gagliano	Job Type	9 7/8" X 7" Prod Casing	Bulk Plant	Fourchon-C-Port I, La, USA
Customer	BP	Location	Mississippi Cny	Well	Mississippi Canyon 252 OCS-G-32306 Macondo #1

Well Information

Casing/Liner Size	7"	Depth MD	18360 ft	BHST	210 F

UCA Comp. Strength, Request Test ID:811522

End Temp (°F)	Pressure (psi)	50 psi (hh:mm)	500 psi (hh:mm)	12 hr CS (psi)	24 hr CS (psi)	48 hr CS (psi)
210	14,458	08:12	08:40	2,301	2,966	3,099

Circulate before pouring C.S. for 3 Hrs

Operation Test Results Request ID 73909/1

Crush Compressive Strength, Request Test ID:806069

Curing Temp (°F)	Time 1 (hrs)	Strength 1	Time 2 (hrs)	Strength 2	Time 3 (hrs)	Strength 3	Foam quality
180	12	0	24	0	48	1,590	0

Condition for 1.5 hrs

FYSA Viscosity Profile & Gel Strength, Request Test ID:806074

Test Temp (°F)
80

Foam Mix and Stability, Request Test ID:813603

Time to Foam [Sec]	SG top	SG bot.	Conditioning time (hrs:min)
8	1.8	1.8	03:00

Temp (°F)	Pressure (psi)	Reached in (min)	Start BC	30 Bc (hh:mm)	40 Bc (hh:mm)	50 Bc (hh:mm)
135	14,458	83	14	07:25	07:34	07:36

Mud Balance Density, Request Test ID:811529

Density (ppg)
16.7
from part 1

Mixability (0 - 5) - 0 is not mixable, Request Test ID:811524

Mixability rating (0 - 5)
4

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Global Customer Report — Page: 1

PPG 15.0

PPG 15.0

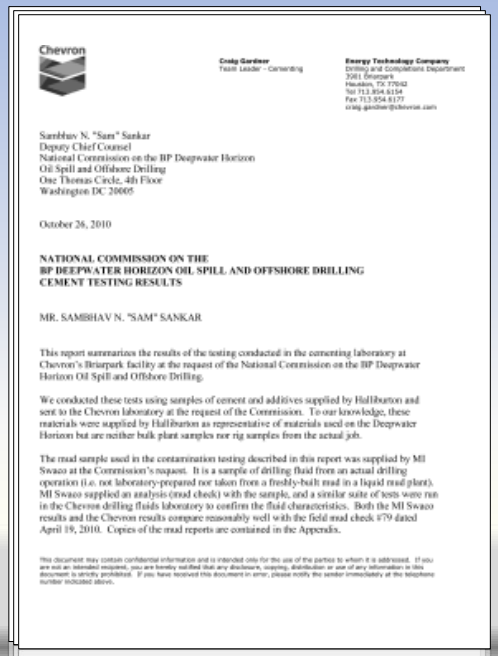
SG (specific gravity) top and bottom are the same as each other, but different than starting density

Note three-hour conditioning time

Page: 2

Results of Chevron Testing of Macondo Slurry

October 26, 2010



Chevron

Craig Gardner
Team Leader – Cementing

Energy Technology Company
Drilling and Completions Department
3081 Briarpark
Houston, TX 77042
Tel 713.954.6154
Fax 713.954.6173
craig.gardner@chevron.com

Sambhav N. "Sam" Sankar
Deputy Chief Counsel
National Commission on the BP Deepwater Horizon
Oil Spill and Offshore Drilling
One Thomas Circle, 4th Floor
Washington DC 20005

October 26, 2010

NATIONAL COMMISSION ON THE
BP DEEPWATER HORIZON OIL SPILL AND OFFSHORE DRILLING
CEMENT TESTING RESULTS

MR. SAMBHAV N. "SAM" SANKAR

This report summarizes the results of the testing conducted in the cementing laboratory at Chevron's Briarpark facility at the request of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling.

We conducted these tests using samples of cement and additives supplied by Halliburton and sent to the Chevron laboratory at the request of the Commission. To our knowledge, these materials were supplied by Halliburton as representative of materials used on the Deepwater Horizon but are neither bulk plant samples nor rig samples from the actual job.

The mud sample used in the contamination testing described in this report was supplied by MI Swaco at the Commission's request. It is a sample of drilling fluid from an actual drilling operation (i.e. not laboratory-prepared nor taken from a freshly-built mud in a liquid mud plant). MI Swaco supplied an analysis (mud check) with the sample, and a similar suite of tests were run in the Chevron drilling fluids laboratory to confirm the fluid characteristics. Both the MI Swaco results and the Chevron results compare reasonably well with the field mud check #79 dated April 19, 2010. Copies of the mud reports are contained in the Appendix.

Many of the test results were in reasonable agreement with those reported by Halliburton. However, we were unable to generate stable foam with any of the tests described in Section 9 of this report.

Results of Chevron Testing of Macondo Slurry

Test Number	Approach	Result
1, 2, 3	Used Chevron methods	Unstable
4	Used BP expert's methods	Unstable
5	With offset density correction	Unstable
6, 7, 9	Attempt to replicate Halliburton testing	Unstable
8	Used alternate cement	Unstable

Halliburton Foam Stability Testing

Halliburton's test takes a minimum of 48 hours

Test ID #	Apparent Test Date	Target Foam Density	Tested Top Density	Tested Bottom Density	Conditioning Time	Analysis	Available Before Job?	Given to BP Before Job?
73909/1	Apr. 18	14.5 ppg	15.0	15.0	3:00	Stable?	Uncertain	No
73909/1	Apr. 13	14.5 ppg	15.7	15.1	1:30	Unstable	Yes	No
65112/3	Feb. 17	14.5 ppg	15.9	15.9	2:00	Unstable	Yes	Yes, listing 0:00 conditioning time
65112/1	Feb. 13	14.5 ppg	16.8	17.6	0:00	Unstable	Yes	No

Commission Letter

National Commission on the
BP DEEPWATER HORIZON OIL SPILL
AND OFFSHORE DRILLING

Commissioners
Bob Graham, Co-Chair
William K. Reilly, Co-Chair
Frances Beinecke
Donald F. Boesch
Terry D. Garcia
Cherry A. Murray
Fran Ulmer

Richard Lazarus
Executive Director

October 28, 2010

To: Bob Graham, Co-Chair
William K. Reilly, Co-Chair
Frances Beinecke
Donald F. Boesch
Terry D. Garcia
Cherry A. Murray
Fran Ulmer

Dear Commissioners,

We write to report the results of cement testing that we have recently conducted and several conclusions we have reached based on that testing and documents subsequently provided to us by Halliburton. We wanted to report these results immediately to facilitate your consideration of their implications for offshore drilling safety.

We have known for some time that the cement used to secure the production casing and isolate the hydrocarbon zone at the bottom of the Macondo well must have failed in some manner. That cement should have prevented hydrocarbons from entering the well. For a variety of technical reasons that we will explain at the upcoming hearing, BP cemented the well with a nitrogen foam cement recommended and supplied by Halliburton. Halliburton generated the nitrogen foam cement by injecting high pressure nitrogen into a base cement slurry as it pumped that slurry into the well.

We asked Halliburton to supply us samples of materials like those actually used at the Macondo well so that we could investigate issues surrounding the cement failure. Halliburton provided us off-the-shelf cement and additive materials used at the Macondo well from their stock. Although these materials did not come from the specific batches used at the Macondo well, they are in all other ways identical in composition to the slurry used there.

Fourth Floor One Thomas Circle, NW Washington, D.C. 20005 • Tel (202) 254-2600 • Fax (202) 254-2617 • www.OilSpillCommission.gov

National Commission on the
BP DEEPWATER HORIZON OIL SPILL
AND OFFSHORE DRILLING

Commissioners
Bob Graham, Co-Chair
William K. Reilly, Co-Chair
Frances Beinecke
Donald F. Boesch

Chevron agreed as a public service to test the cement slurry on behalf of the Commission. Chevron employs some of the industry's most respected cement experts, and it maintains a state-of-the art cement testing facility in Houston, Texas. Halliburton agreed that the Chevron lab was highly

February 2010 using different well design parameters and a slightly different slurry recipe than was finally used. Both tests indicated that this foam slurry design was unstable.

Halliburton provided data from one of the two February tests to BP in an email dated March 8, 2010. The data appeared in a technical report along with other information. There is no indication that Halliburton highlighted to BP the significance of the foam stability data or that BP personnel raised any questions about it. There is no indication that Halliburton provided the data from the other February test to BP.

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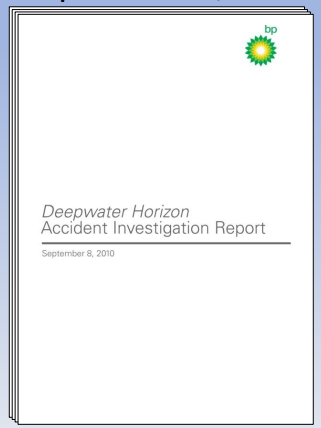
Chevron's report states, among other things, that its lab personnel were unable to generate stable foam cement in the laboratory using the materials provided by Halliburton and available design information regarding the slurry used at the Macondo well. Although laboratory foam stability tests cannot replicate field conditions perfectly, these data strongly suggest that the foam cement used at Macondo was unstable. This may have contributed to the blowout.

Consequences of Unstable Foam Cement

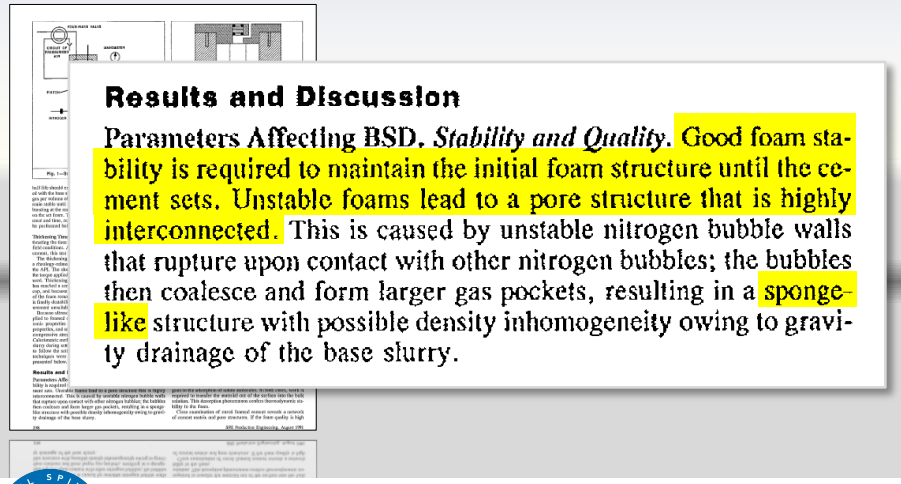
September 8, 2010



All Agree That Unstable Foam Cement Should Not Be Used, But No Agreement on Specific Consequences

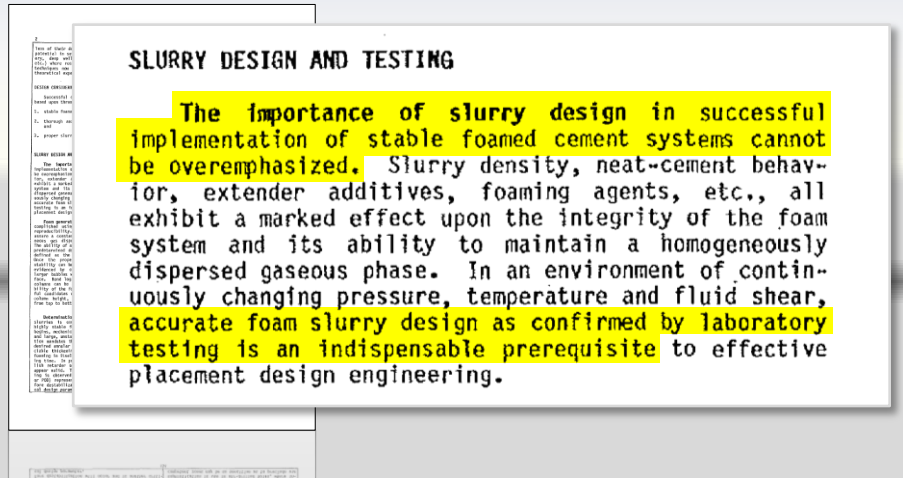
BP Report: Unstable slurry caused:

"nitrogen breakout, nitrogen migration and incorrect cement density. This would explain the failure to achieve zonal isolation of hydrocarbons. Nitrogen breakout and migration would have also contaminated the shoe track cement...."



Results and Discussion

Parameters Affecting BSD. *Stability and Quality*. Good foam stability is required to maintain the initial foam structure until the cement sets. Unstable foams lead to a pore structure that is highly interconnected. This is caused by unstable nitrogen bubble walls that rupture upon contact with other nitrogen bubbles; the bubbles then coalesce and form larger gas pockets, resulting in a sponge-like structure with possible density inhomogeneity owing to gravity drainage of the base slurry.



SLURRY DESIGN AND TESTING

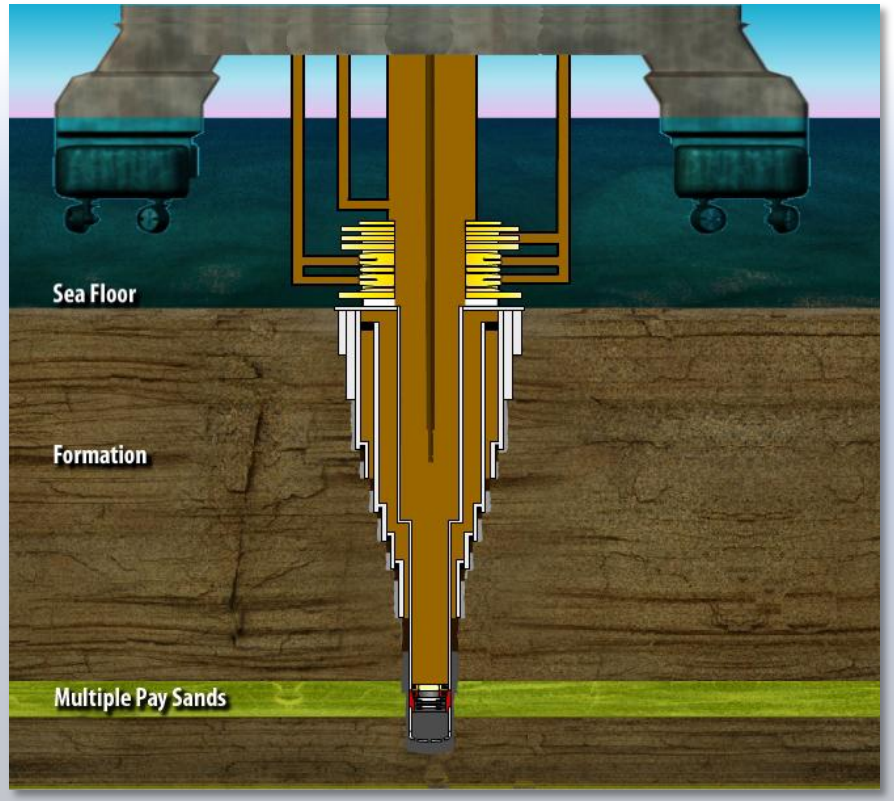
The importance of slurry design in successful implementation of stable foamed cement systems cannot be overemphasized. Slurry density, neat-cement behavior, extender additives, foaming agents, etc., all exhibit a marked effect upon the integrity of the foam system and its ability to maintain a homogeneously dispersed gaseous phase. In an environment of continuously changing pressure, temperature and fluid shear, accurate foam slurry design as confirmed by laboratory testing is an indispensable prerequisite to effective placement design engineering.

Situation at Time of Cement Job – April 19, 2010

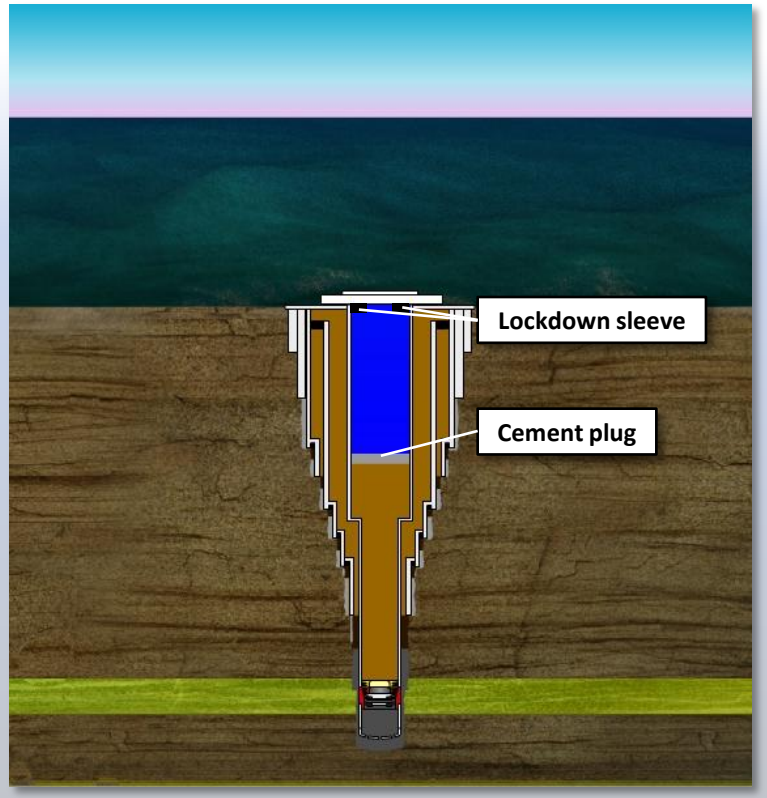
- Difficult drilling conditions
- Serious lost returns in the zone to be cemented
- Forced to stop drilling earlier than planned
- Difficulty converting float equipment
- Low circulating pressure after conversion
- No bottoms up circulation
- Cement jobs are known to occasionally need further work
- Cement modeling perceived as unreliable by BP
- Complicated cement job
- Low rate of cement flow
- Low cement volume
- Uncertain centralization
- No direct indicators of cementing success and no cement evaluation log

Temporary Abandonment

Temporary Abandonment Procedure Begins After Cement Job

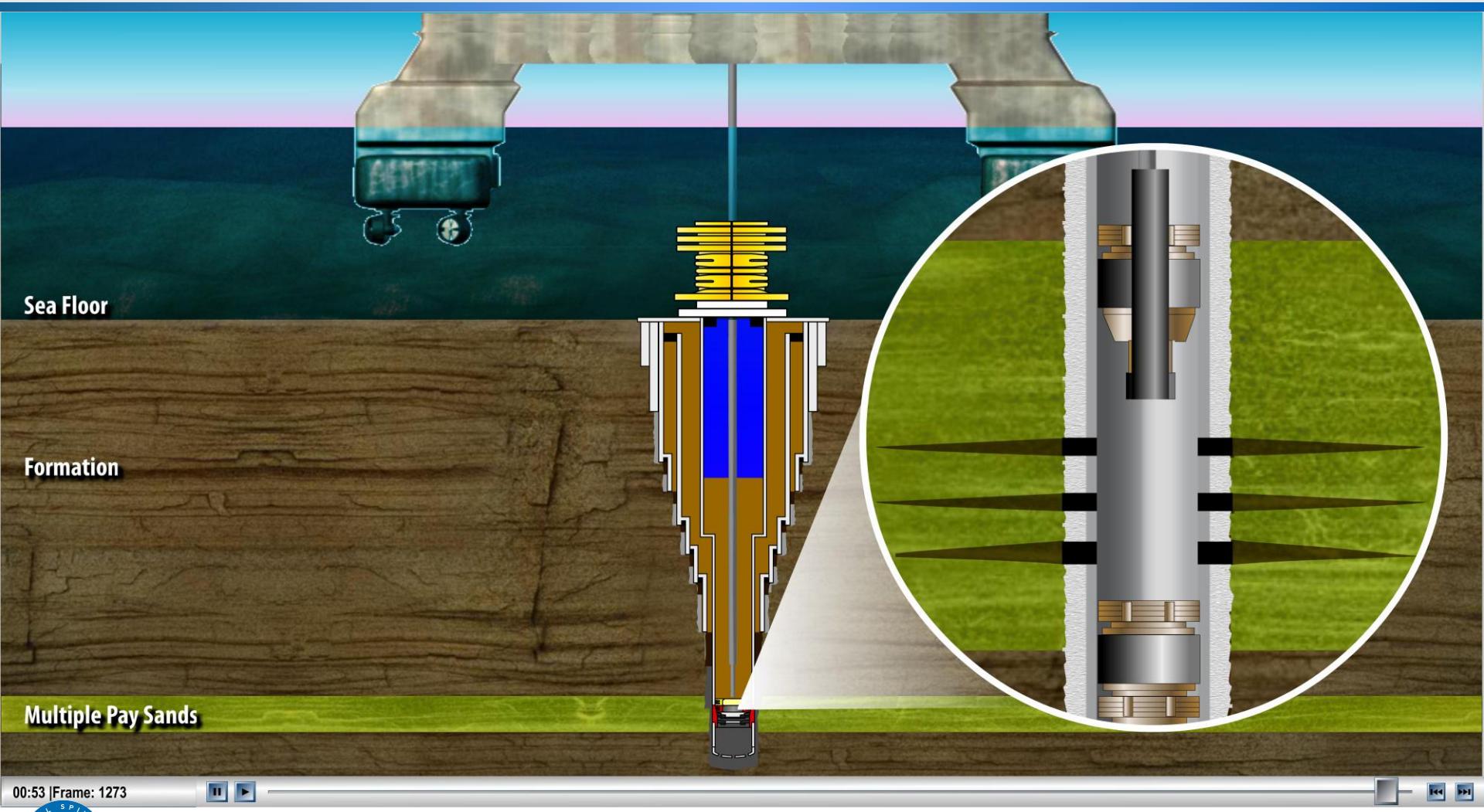


End of Cement Job



Temporarily Abandoned

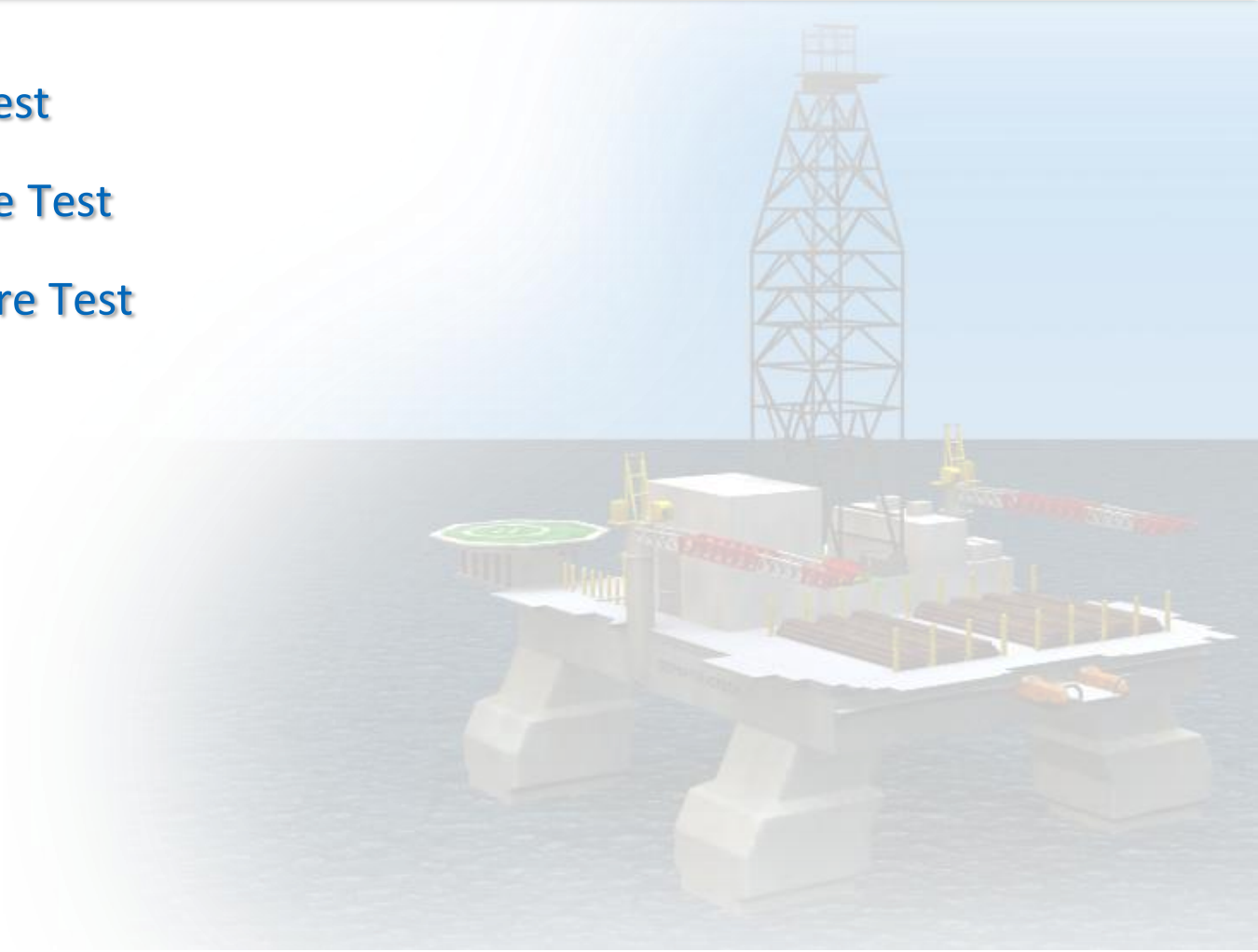
Cement is Perforated at Production Phase



TRIAL GRAPHIX

Testing Integrity of Well – Three Tests

1. Seal Assembly Test
2. Positive-Pressure Test
3. Negative-Pressure Test



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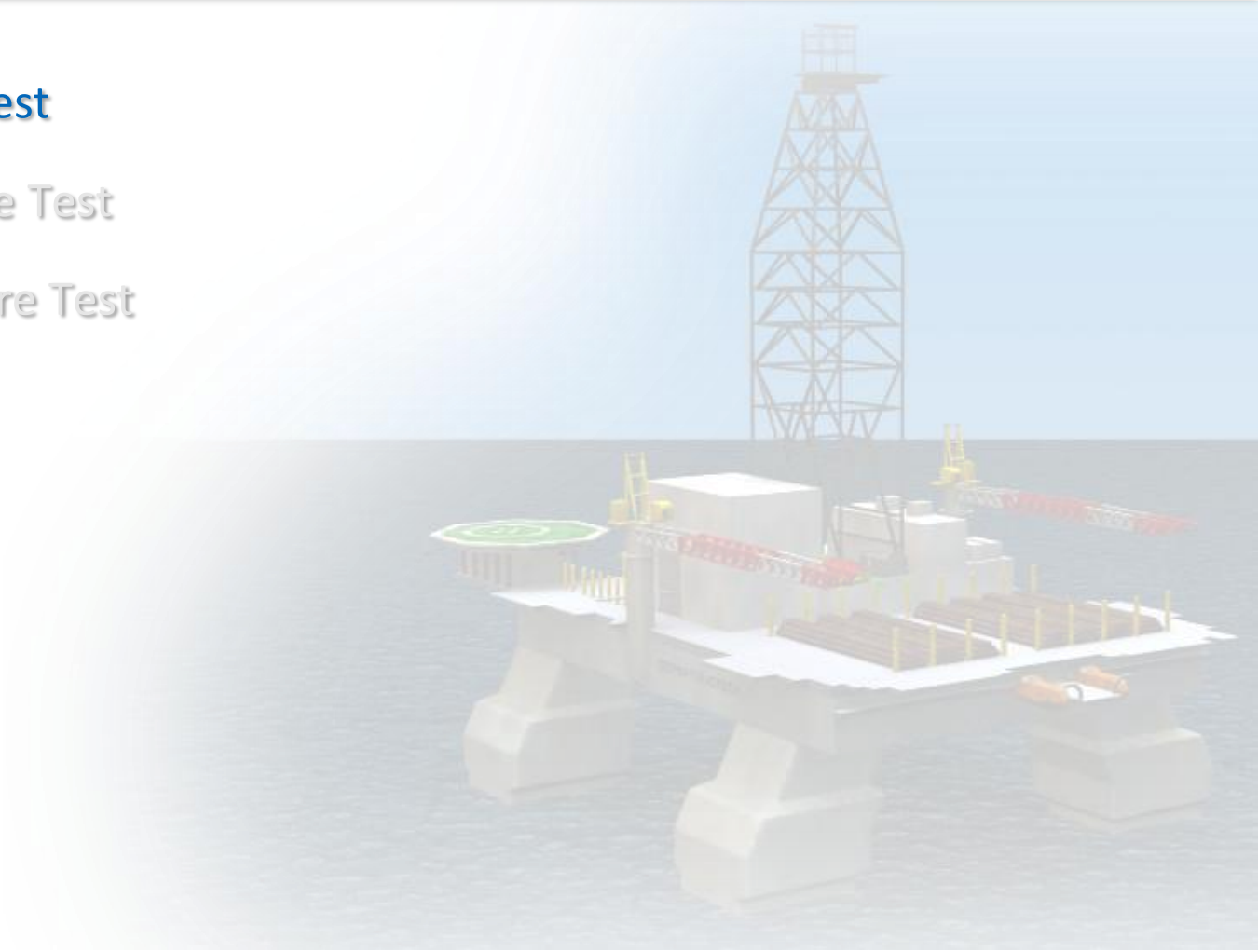
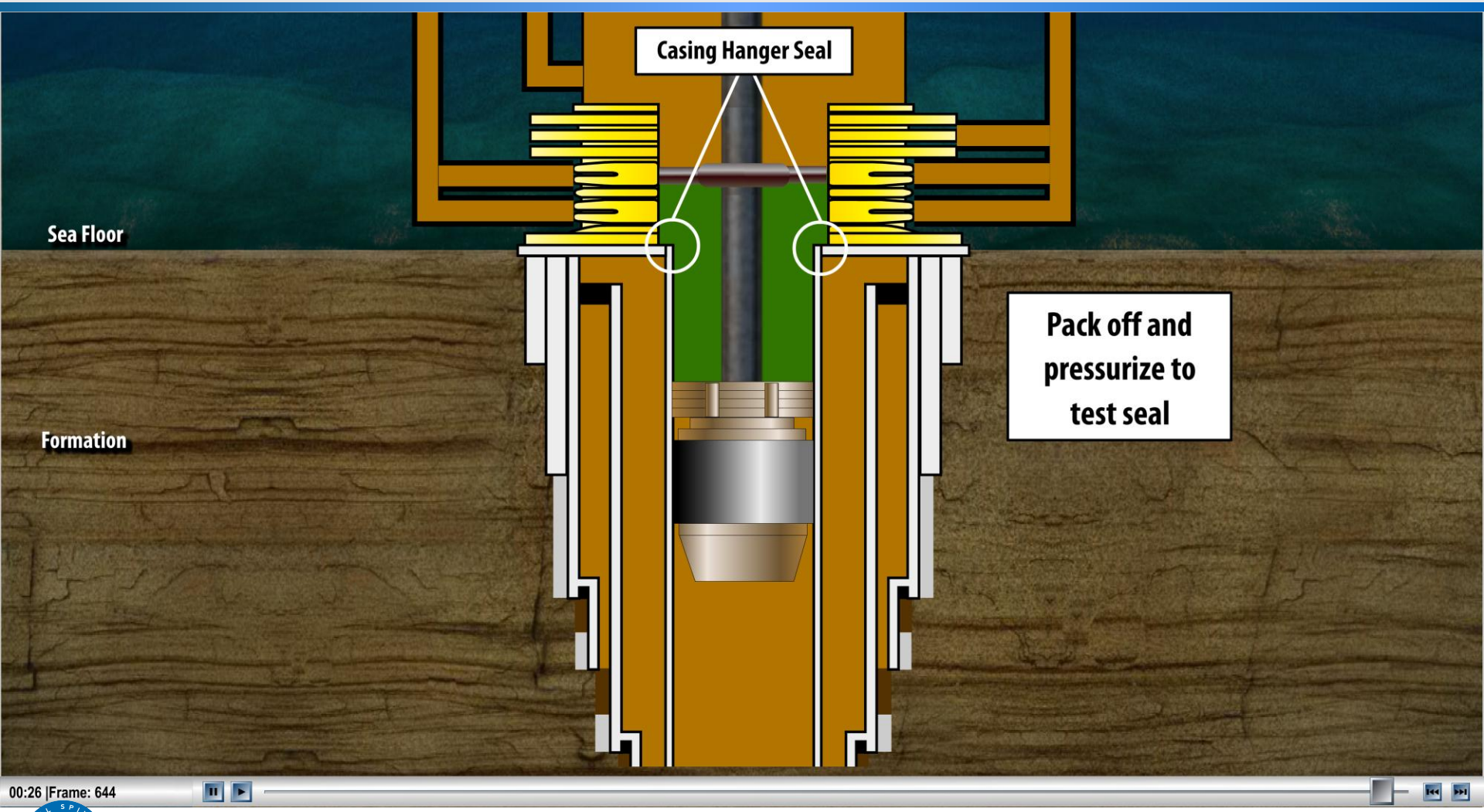


Seal Assembly Test



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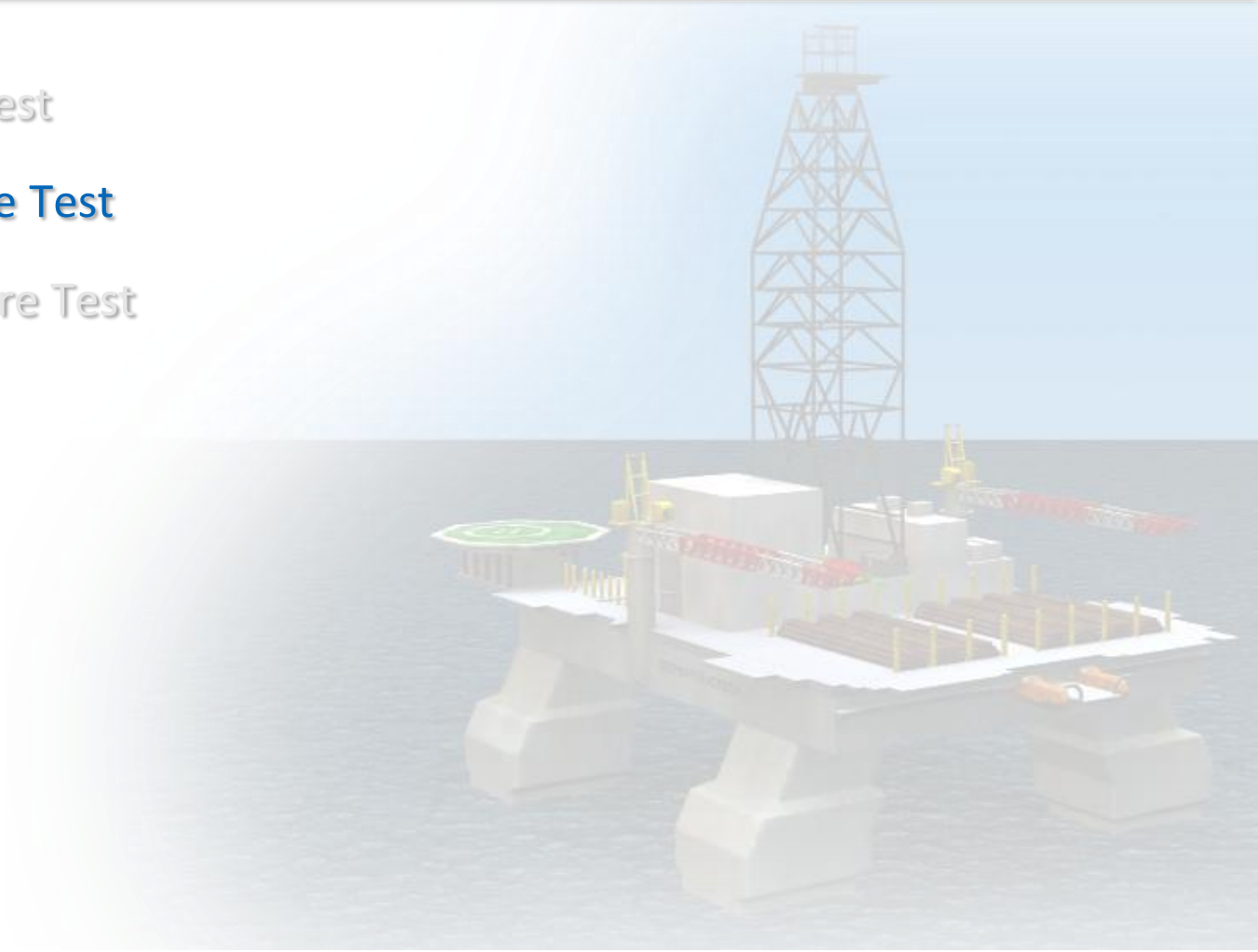
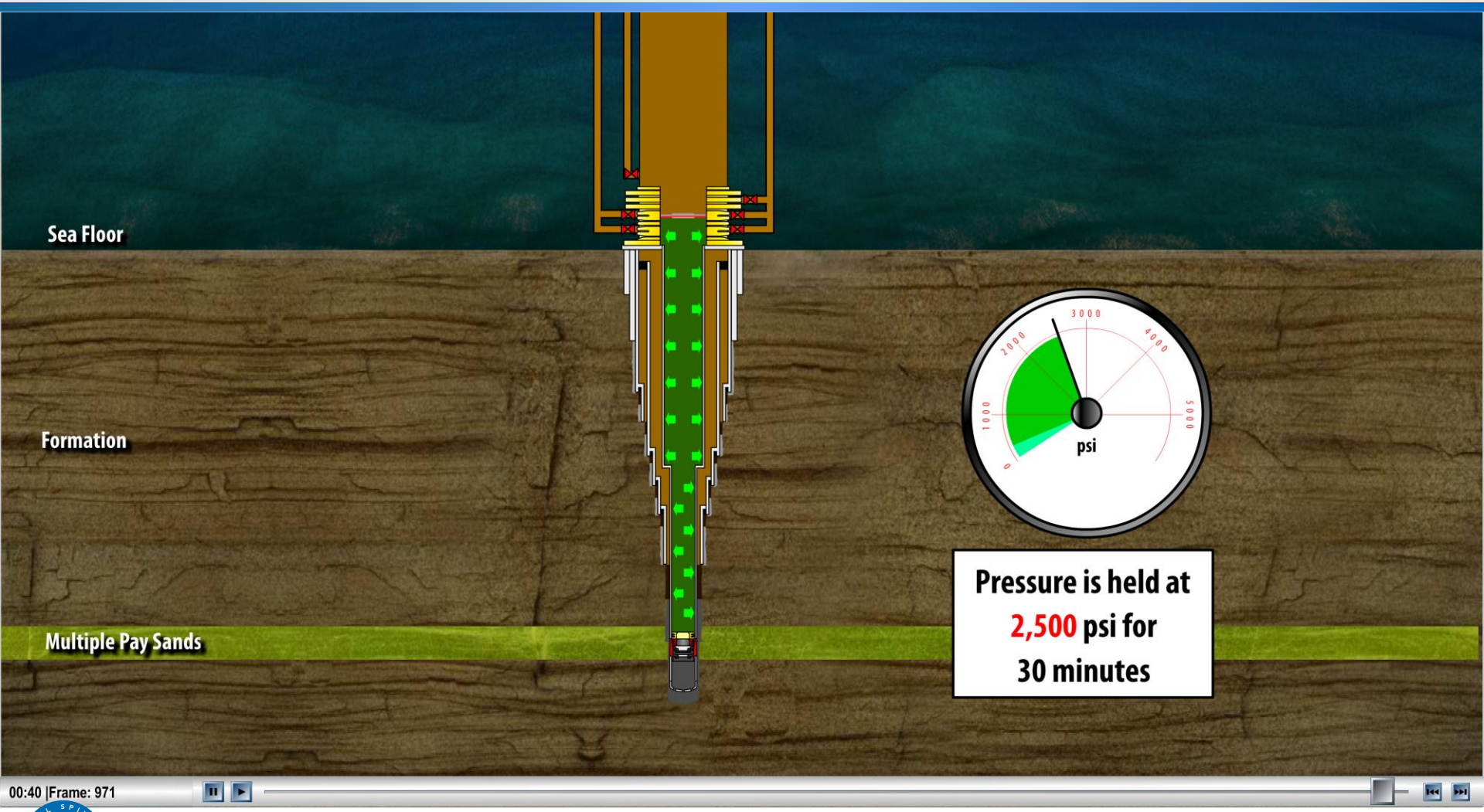


Positive-Pressure Test



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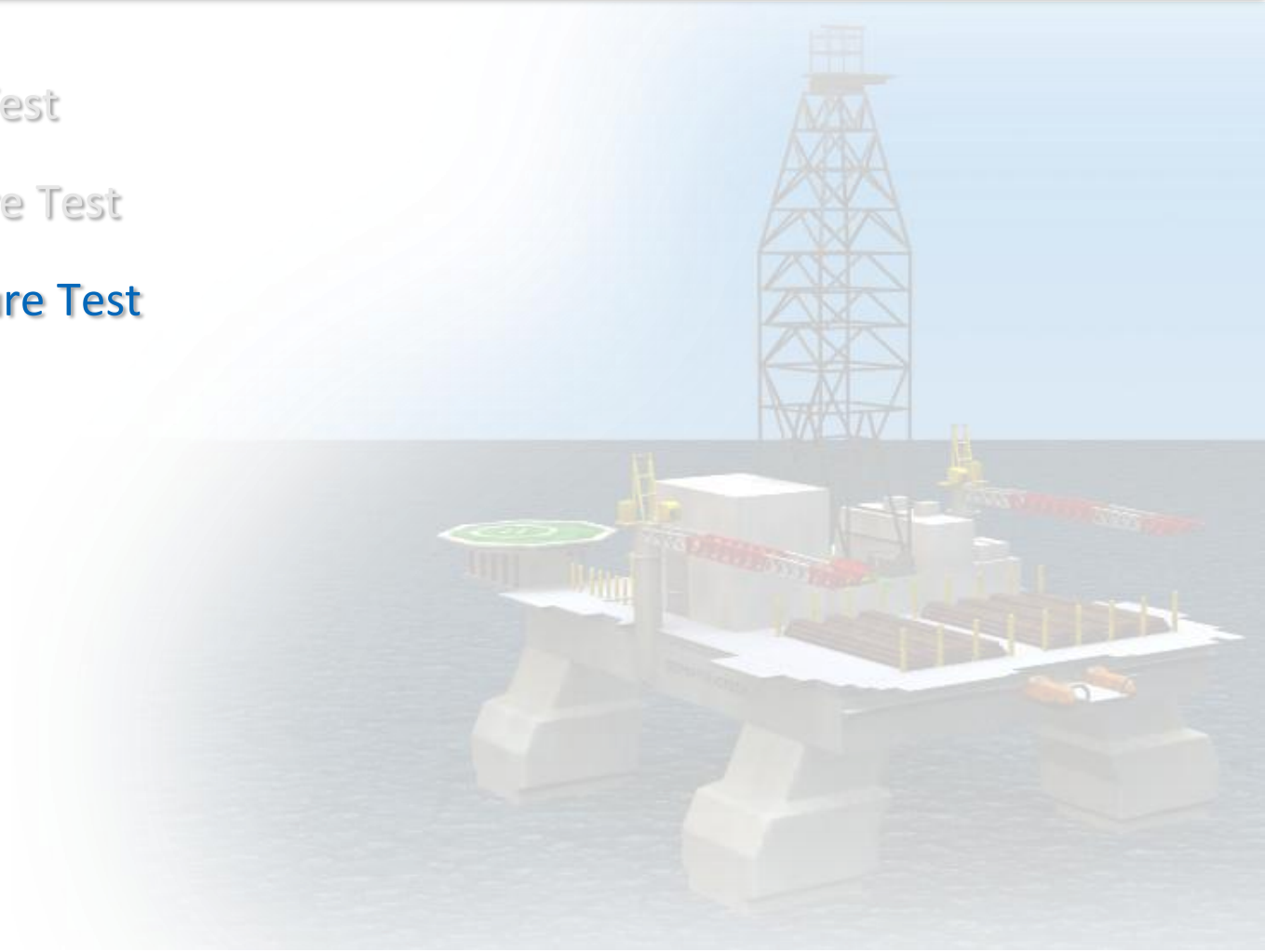
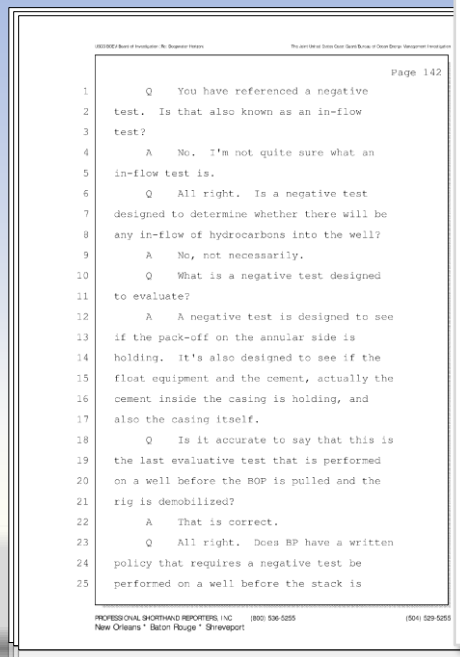


Negative-Pressure Test Is Very Important

July 22, 2010



Page 142

Q You have referenced a negative test. Is that also known as an in-flow test?

A No. I'm not quite sure what an in-flow test is.

Q All right. Is a negative test designed to determine whether there will be any in-flow of hydrocarbons into the well?

A No, not necessarily.

Q What is a negative test designed to evaluate?

A A negative test is designed to see if the pack-off on the annular side is holding. It's also designed to see if the float equipment and the cement, actually the cement inside the casing is holding, and also the casing itself.

Q Is it accurate to say that this is the last evaluative test that is performed on a well before the BOP is pulled and the rig is demobilized?

A That is correct.

Q All right. Does BP have a written policy that requires a negative test be performed on a well before the stack is

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New Orleans * Baton Rouge * Shreveport

Q. What is a negative test designed to evaluate?

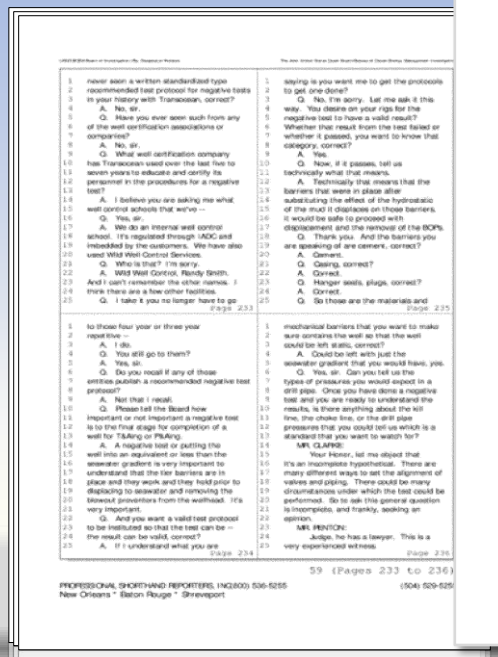
A. A negative test is designed to see if the pack-off on the annular side is holding. It's also designed to see if the float equipment and the cement, actually the cement inside the casing is holding, and also the casing itself.

Q. Is it accurate to say that this is the last evaluative test that is performed on a well before the BOP is pulled and the rig is demobilized?

A. That is correct.

Testimony of John Guide, BP Wells Team Leader, MBI Hearing 7/22 AM Tr. 142

Negative-Pressure Test Is Very Important



never seen a written standardized type
recommended test protocol for negative tests
in your history with Transocean, correct?
A. No, sir.
Q. Have you ever seen such from any
of the well certification associations or
companies?
A. No, sir.
Q. What well certification company
has Transocean used over the last five to
seven years to educate and certify its
personnel in the procedures for a negative
test?
A. I believe you are asking me what
well control schools that we've --
Q. Yes, sir.
A. We do an internal well control
school. It's regulated through IADC and
imbedded by the customers. We have also
used Wild Well Control Services.
Q. Who is that? I'm sorry.
A. Wild Well Control, Randy Smith.
And I can't remember the other names. I
think there are a few other facilities.
Q. I take it you no longer have to go

Page 233

saying is you want me to get the protocols
to get one done?
Q. No, I'm sorry. Let me ask it this
way. You desire on your rigs for the
negative test to have a valid result?
Whether that result from the test failed or
whether it passed, you want to know that
category, correct?
A. Yes.
Q. Now, if it passes, tell us
technically what that means.
A. Technically that means that the
barriers that were in place after
substituting the effect of the hydrostatic
of the mud it displaces on those barriers,
it would be safe to proceed with
displacement and the removal of the BOPs.
Q. Thank you. And the barriers you
are speaking of are cement, correct?
A. Cement.
Q. Casing, correct?
A. Correct.
Q. Hanger seals, plugs, correct?
A. Correct.
Q. So those are the materials and

Page 235

to those four year or three year
repetitive --
A. I do.
Q. You still go to them?
A. Yes, sir.
Q. Do you recall if any of those
entities publish a recommended negative test
protocol?
A. Not that I recall.
Q. Please tell the Board how
important or not important a negative test
is to the final stage for completion of a
well for T&Aing or P&Aing.
A. A negative test or putting the
well into an equivalent or less than the
seawater gradient is very important to
understand that the tier barriers are in
place and they work and they hold prior to
displacing to seawater and removing the
blowout preventers from the wellhead. It's
very important.
Q. And you want a valid test protocol
to be instituted so that the test can be --
the result can be valid, correct?
A. If I understand what you are

Page 234

mechanical barriers that you want to make
sure contains the well so that the well
could be left static, correct?
A. Could be left with just the
seawater gradient that you would have, yes.
Q. Yes, sir. Can you tell us the
types of pressures you would expect in a
drill pipe. Once you have done a negative
test and you are ready to understand the
results, is there anything about the kill
line, the choke line, or the drill pipe
pressures that you could tell us which is a
standard that you want to watch for?
MR. QUINN:
Your Honor, let me object that
it's an incomplete hypothetical. There are
many different ways to set the alignment of
valves and piping. There could be many
circumstances under which the test could be
performed. So to ask this general question
is incomplete, and frankly, seeking an
opinion.
MR. PENTON:
Judge, he has a lawyer. This is a
very experienced witness

Page 236

59 (Pages 233 to 236)

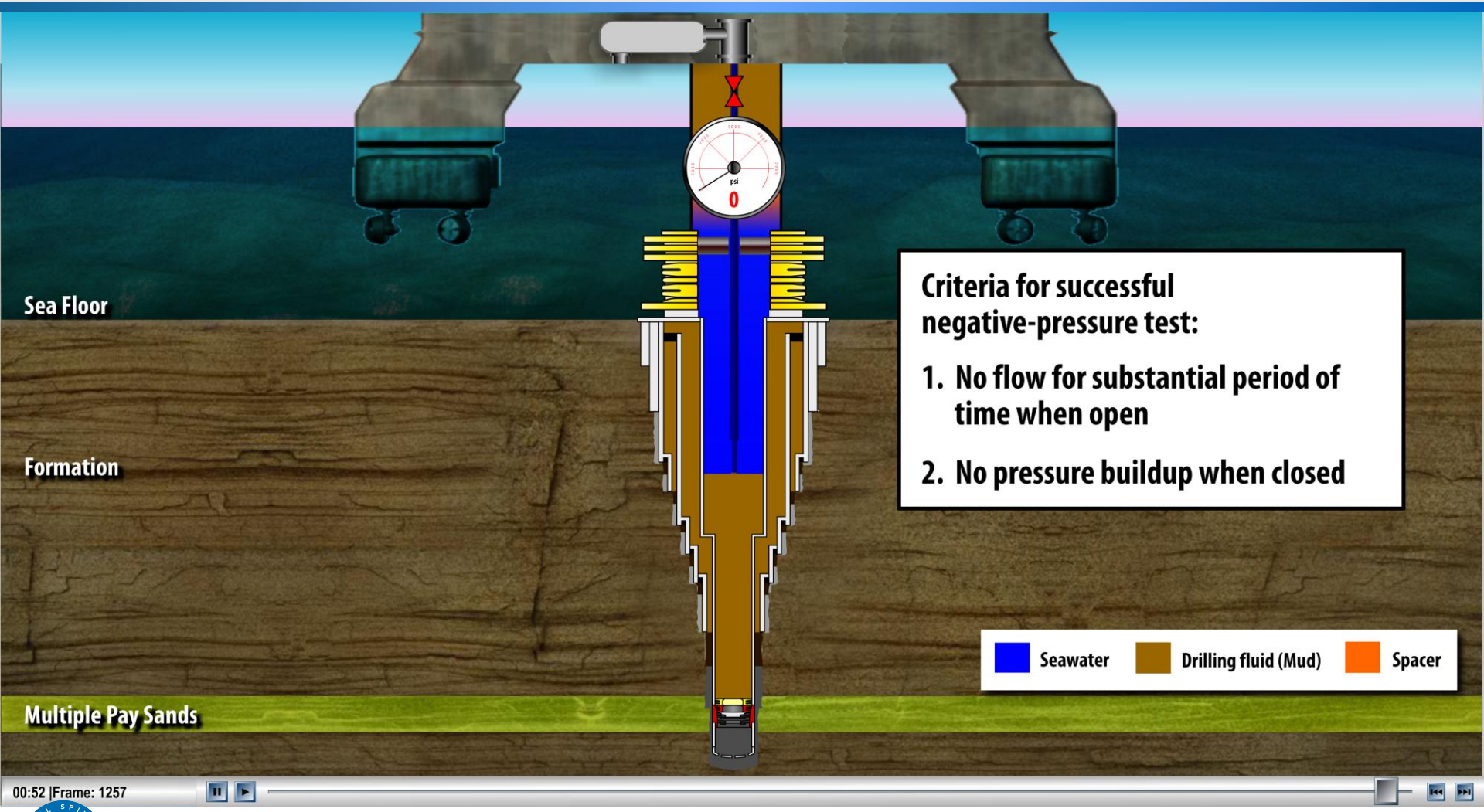
PROFESSIONAL SHORTHAND REPORTERS, INC.(800) 536-5255 (504) 529-5255
New Orleans * Baton Rouge * Shreveport

Q. Please tell the Board how important or not important a negative test is to the final stage for completion of a well for T&Aing or P&Aing.

A. A negative test or putting the well into an equivalent or less than the seawater gradient is very important to understand that the tier barriers are in place and they work and they hold prior to displacing to seawater and removing the blowout preventers from the wellhead. It's very important.

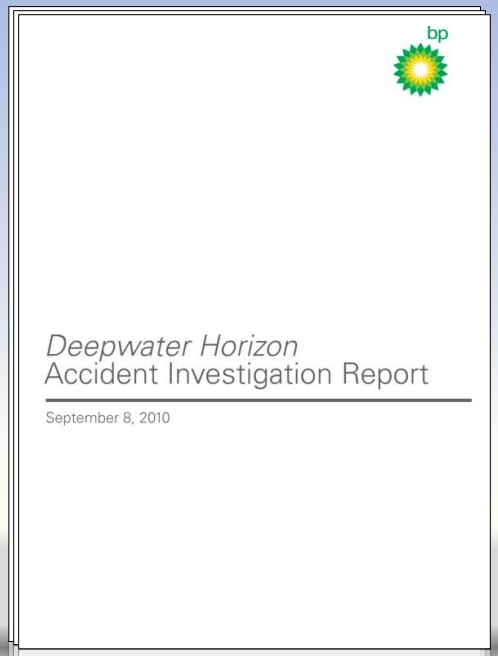
Testimony of Daun Winslow, Transocean General Manager of Gulf of Mexico, MBI Hearing 8/24 AM Tr. 234

Negative-Pressure Test



Nobody Disputes it Was a Failed Negative-Pressure Test

September 8, 2010



Abnormal pressures observed during the negative-pressure test were indicative of a failed or inconclusive test; however, the test was deemed successful.

BP Deepwater Horizon Accident Investigation Report p. 79

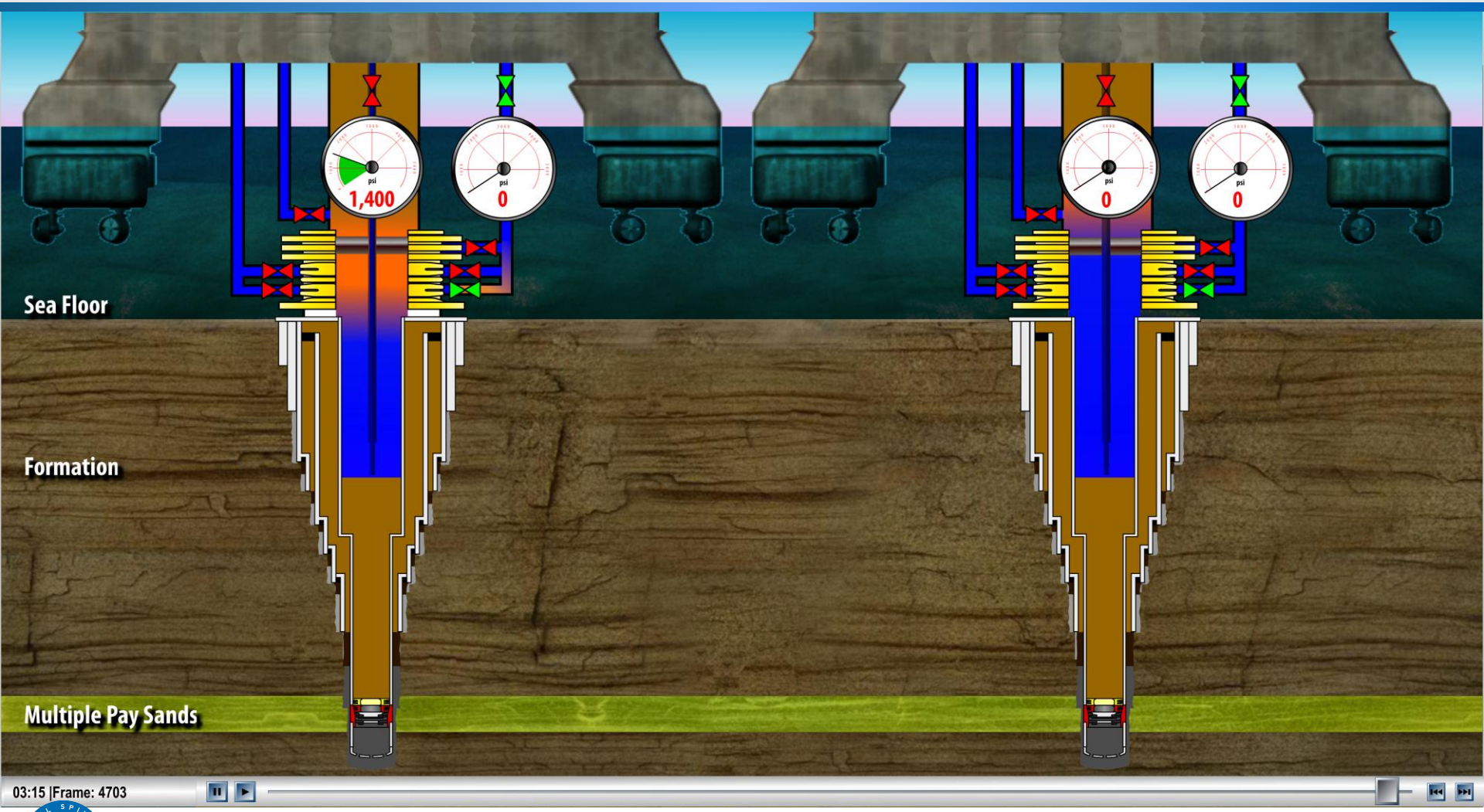
* * *

There was "1,400 psi on the drill pipe, an indication of communication with the reservoir."

BP Deepwater Horizon Accident Investigation Report p. 88

All parties agree

Negative-Pressure Test at Macondo



TRIAL GRAPHIX

No Required Negative-Pressure Test Procedures

	Yes	No
MMS		✓
bp		✓
Transocean		✓

MMS didn't require negative-pressure test at all

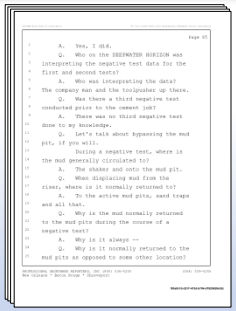
BP requires negative-pressure test but does not have set procedures; "could be different on every single rig depending on what the team agreed to"

Testimony of John Guide, BP Well Team Leader, MBI Hearing 7/22 PM, Tr. 158-159

Transocean requires negative-pressure test but does not have set procedures

Testimony of Daun Winslow, Transocean General Manager of Gulf of Mexico, MBI Hearing 8/24 AM, Tr. 232-33

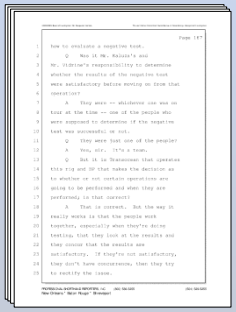
Interpretations of Negative-Pressure Test



Q. Who on the DEEPWATER HORIZON was interpreting the negative test data for the first and second tests?

A. Who was interpreting the data? The company man and the toolpusher up there.

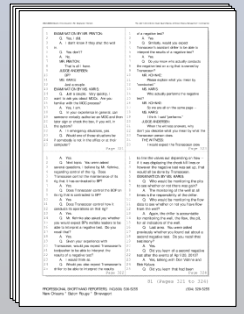
Testimony of Jimmy Harrell, Transocean Offshore Installation Manager, MBI Hearing 5/27 AM Tr. 85



Q. Was it Mr. Kaluza's and Mr. Vidrine's responsibility to determine whether the results of the negative test were satisfactory before moving on from that operation?

A. They were – whichever one was on tour at the time one of the people who were supposed to determine if the negative test was successful or not.

Testimony of John Guide, BP Wells Team Leader, 7/22 AM Tr. 167



Q. Given your experience with Transocean, would you expect Transocean's toolpusher to be able to interpret the results of a negative test?

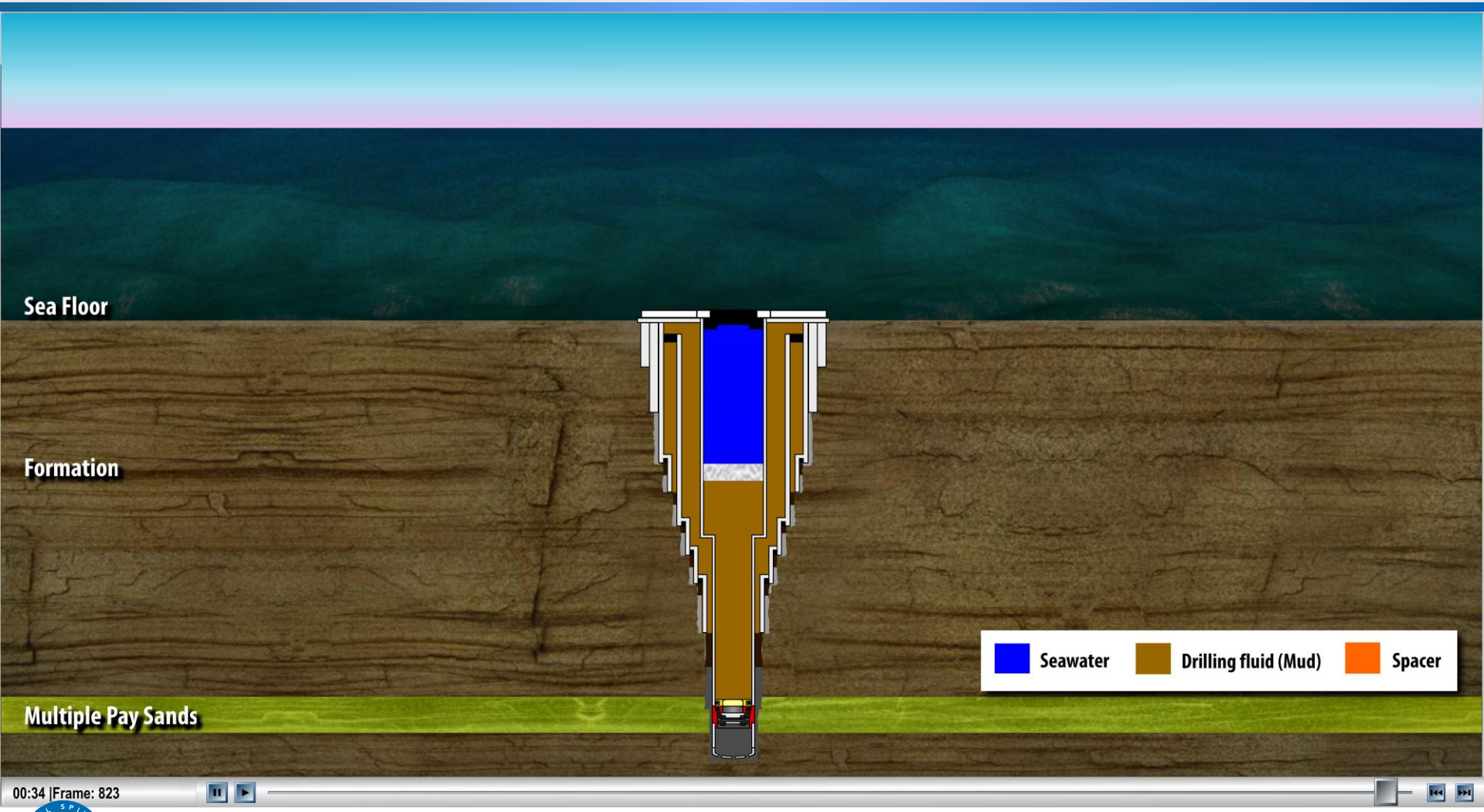
A. I would think so.

Q. Would you also expect Transocean's driller to be able to interpret the results of a negative test?

A. Yes.

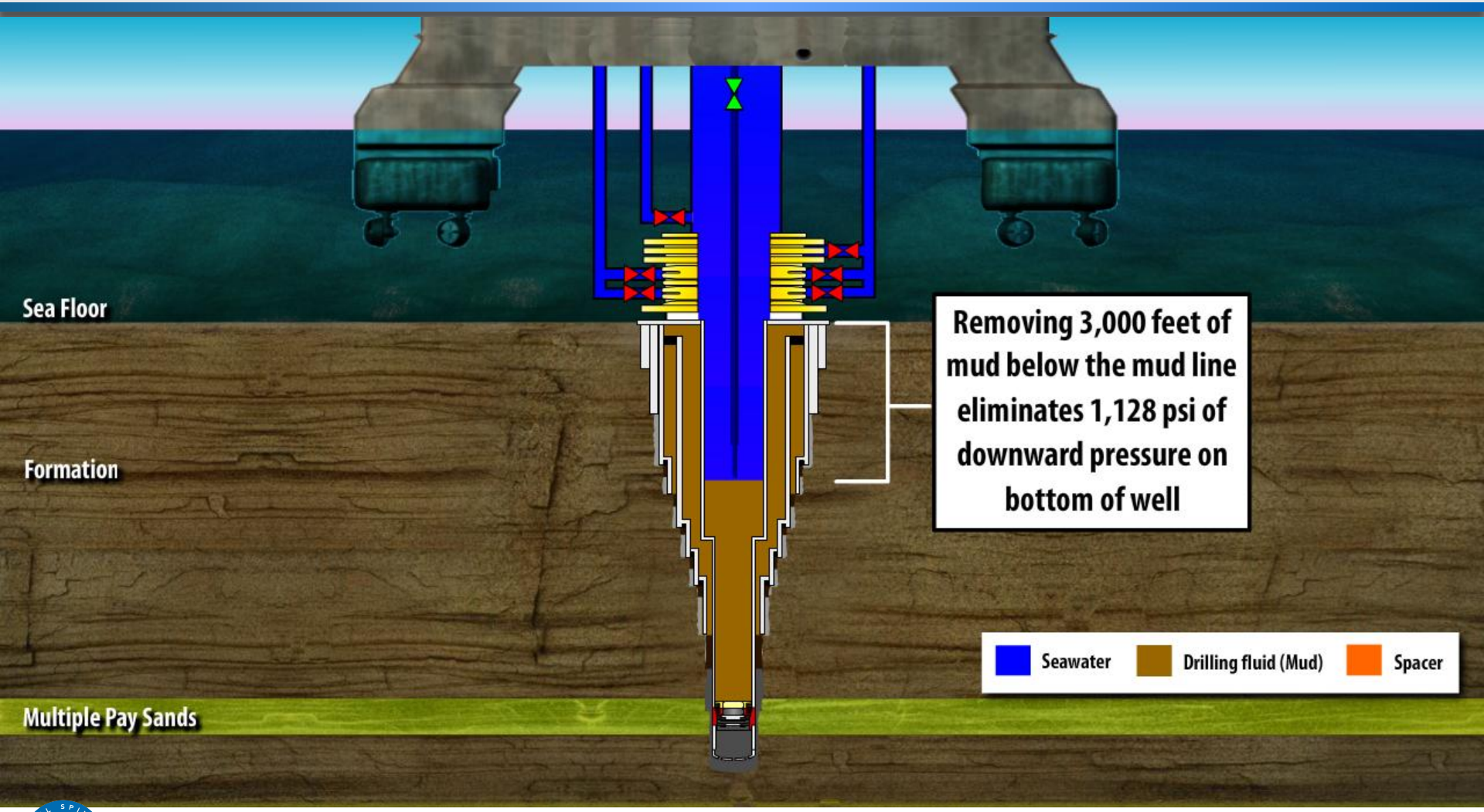
Testimony of Pat O'Bryan, BP Vice President Drilling and Completions, MBI Hearing 8/26 PM Tr. 322-323

Planned Temporary Abandonment Procedure Once Negative-Pressure Test Passed



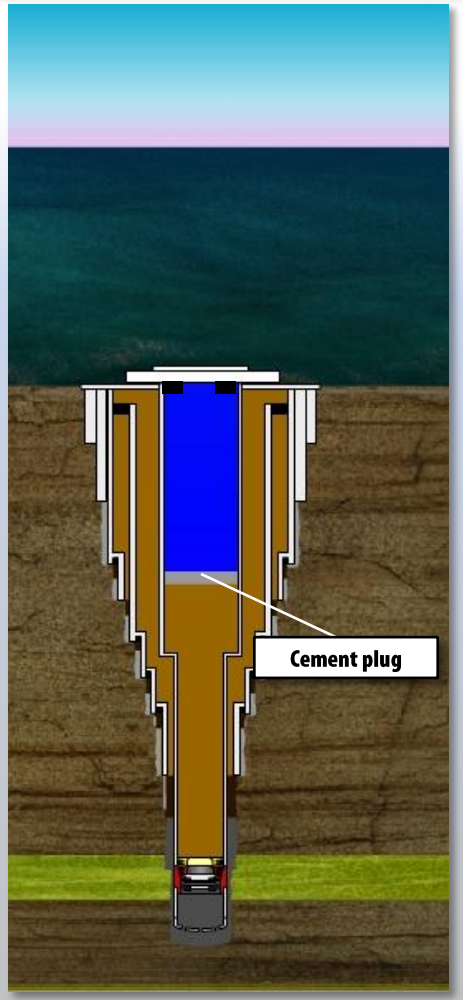
TRIAL GRAPHIX

Displacing to 8,300 Feet Underbalanced Well More Than Necessary



TRIAL GRAPHIX

Irregularity of Setting Cement Plug So Low



Q. But it was somewhere around 8300, right?
A. Yes, yes.
Q. A lot deeper than you had probably seen before, right?
A. Yes.

Testimony of Ross Skidmore, BP Contract Vendor, MBI Hearing 7/20 PM Tr. 60

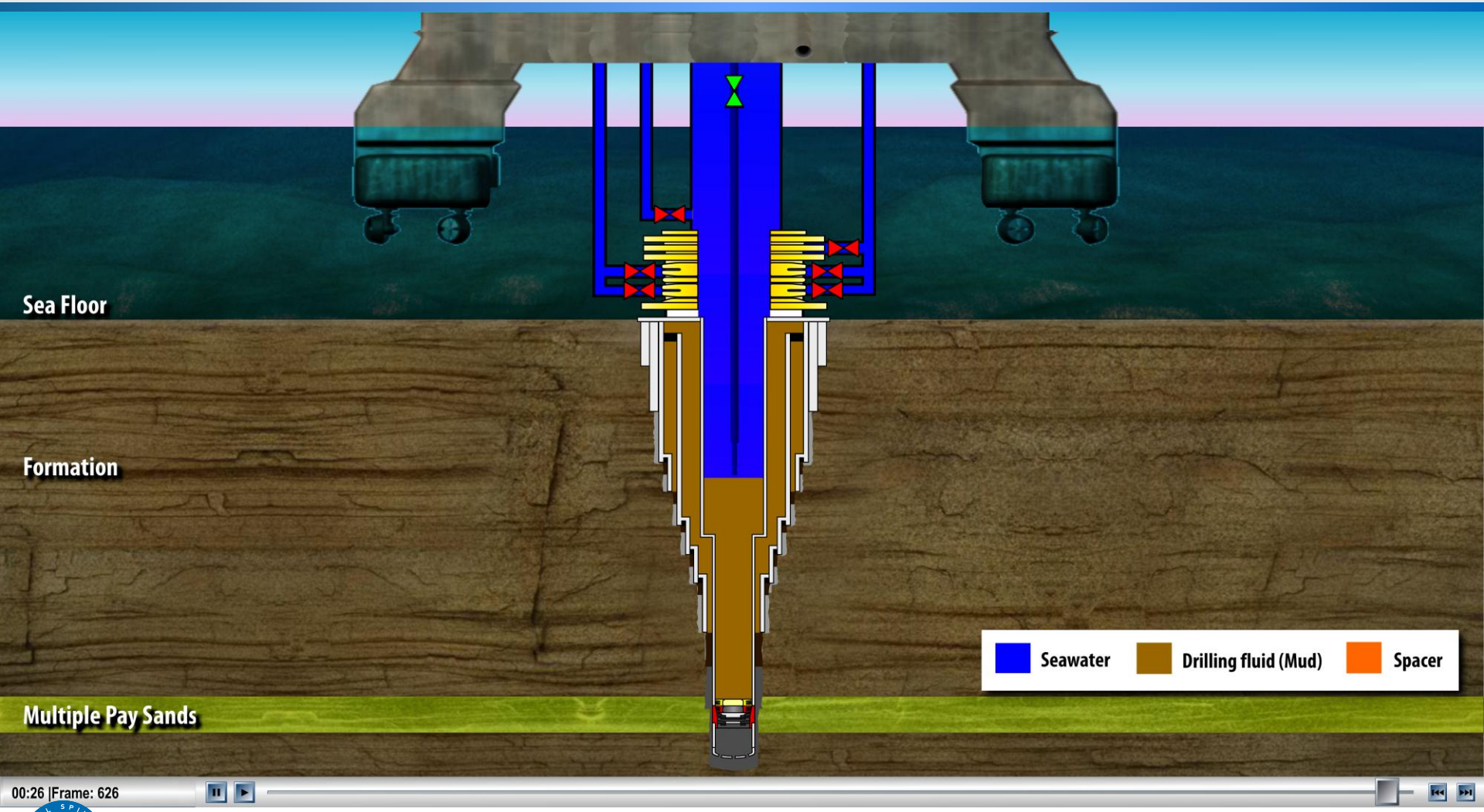
Q. You testified earlier that one of the unusual aspects of the displacement here was down to 83 –
A. 67, that's true. Usually it's 300 feet below the mud line, and 8367 is much further down than usual.

Testimony of Leo Lindner, MI-Swaco Mud Engineer, MBI Hearing 7/19 PM Tr. 86

Q. Well, the additional pressure, give the depth of this well, the displacement of mud with water in a volume much greater than is standard, is normal?
A. We were going to do a displacement at roughly 8,300 feet. It was a little bit – well, it was deeper than normal.

Testimony of John Guide, BP Wells Team Leader, MBI Hearing 7/22 PM Tr. 124

Procedure Meant Only One Barrier Besides Open BOP During Displacement



TRIAL GRAPHIX

Evolution of Temporary Abandonment Procedure

April 14 E-Mail From Morel to R. Sepulvado

From: Sepulvado, Ronald W
Sent: Wed Apr 14 19:19:15 2010
To: Morel, Brian P
Subject: RE: Forward Ops

Run RSWC #3
Make clean-out run to 18360' / short trip and CBU at 18,360'
POOH and retrieve wear bushing
Run tapered long string
POOH with landing string
RIH set wear bushing continue to 8367' set 300' cement plug
Wait on cement / tag TOC with 15k
Negative test with base oil in kill/choke line to the wellhead
POOH to 6000'
Displace to seawater
POOH and wash wellhead on the way out
Run lead impression
Run lockdown sleeve
Pull Riser

April 14 Morel E-Mail	April 16 MMS Permit	April 20 Ops Note
Run in hole to 8,367'		
Set 300' cement plug in mud BARRIER		
Negative test with base oil to wellhead		
Displace mud in well and riser from 6,000' with seawater		
Set lockdown sleeve		

Evolution of Temporary Abandonment Procedure

April 16 Application for Permit to Drill Sent to MMS

Temporary Abandonment Procedure: *(estimated start time Sunday, April 18, 2010)*

1. Negative test casing to seawater gradient equivalent for 30 min. with kill line.
2. TIH with a 3-1/2" stinger to 8367'.
3. Displace to seawater. Monitor well for 30 min.
4. Set a 300' cement plug (125 cu.ft. of Class H cement) from 8367' to 8067'.

   The requested surface plug depth deviation is for minimizing the chance for damaging the LDS sealing area, for future completion operations.

   This is a Temporary Abandonment only.

   The cement plug length has been extended to compensate for added setting depth.
5. POOH.
6. Set 9-7/8" LDS (Lock Down Sleeve)

April 14 Morel E-Mail	April 16 MMS Permit	April 20 Ops Note
Trip in hole to 8,367'	Negative test to seawater gradient (with base oil to wellhead)	
Set 300' cement plug in seawater BARRIER		
Negative test with base oil to wellhead	Displace mud in well and riser from 8,367' with seawater	
Displace mud in well and riser from 6,000' with seawater	Monitor well for 30 minutes to ensure no flow	
Set lockdown sleeve		

Evolution of Temporary Abandonment Procedure

April 20 Operations Note From Morel to Rig

Holik, Cynthia M

From: Morel, Brian P
Sent: Monday, April 26, 2010 6:40 AM
To: Holik, Cynthia M
Cc: Walz, Gregory S; Chester, Doug K
Subject: FW: Ops Note

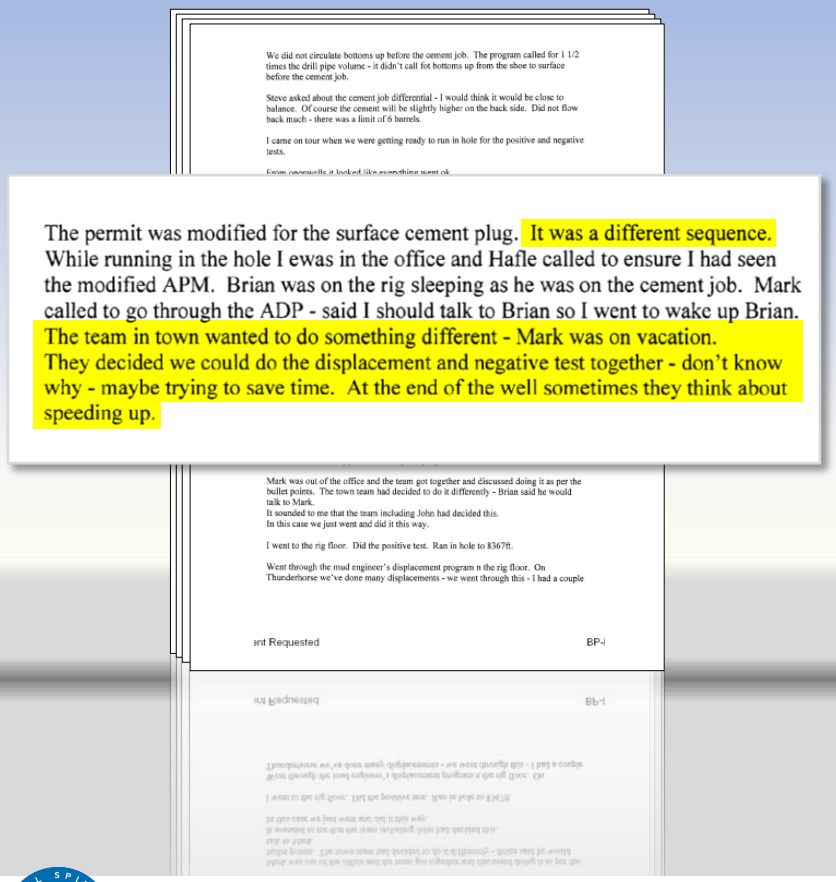
Quick ops note for the next few days:

1. Test casing per APD to 250 / 2500 psi
2. RIH to 8367'
3. Displace to seawater from there to above the wellhead
4. With seawater in the kill close annular and do a negative test ~2350 psi differential
5. Open annular and continue displacement
6. Set a 300' balanced cement plug w/ 5 bbls in DP
7. POOH ~100-200' above top of cement and drop neft ball / circulate DS volume
8. Spot corrosion inhibitor in the open hole
9. POOH to just below the wellhead or above with the 3-1/2" stinger (if desired wash with the 3-1/2" / do not rotate / a separate run will not be made to wash as the displacement will clean up the wellhead)
10. POOH and make LIT / LDS runs
11. Test casing to 1000 psi with seawater (non MMS test / BP DWOP) – surface plug
    a. Confirm bbls to pressure up on original casing test vs bbls to test surface plug (should be less due to volume differences and fluid compressibility –seawater vs sobm)
    b. Plot on chart / send to Houston for confirmation

April 14 Morel E-Mail	April 16 MMS Permit	April 20 Ops Note
Run in hole to 8,367'	Negative test to seawater gradient (with base oil to wellhead)	
Set 300' cement plug in mud **BARRIER**	Trip in hole to 8,367'	Displace mud with seawater from 8,367' to above wellhead (BOP)
Negative test with base oil to wellhead	Displace mud in well and riser from 8,367' with seawater	Negative test with seawater to depth 8,367' rather than with base oil to wellhead
Displace mud in well and riser from 6,000' with seawater	Monitor well for 30 minutes to ensure no flow	Displace mud in riser with seawater **Blowout**
	Set 300' cement plug in seawater **BARRIER**	
Set lockdown sleeve	Set lockdown sleeve	

Evolution of Temporary Abandonment Procedure

April 28 Interview
of Robert Kaluza



We did not circulate bottoms up before the cement job. The program called for 1 1/2 times the drill pipe volume - it didn't call fot bottoms up from the shoe to surface before the cement job.

Steve asked about the cement job differential - I would think it would be close to balance. Of course the cement will be slightly higher on the back side. Did not flow back much - there was a limit of 6 barrels.

I came on tour when we were getting ready to run in hole for the positive and negative tests.

The permit was modified for the surface cement plug. It was a different sequence. While running in the hole I ewas in the office and Hafle called to ensure I had seen the modified APM. Brian was on the rig sleeping as he was on the cement job. Mark called to go through the ADP - said I should talk to Brian so I went to wake up Brian. The team in town wanted to do something different - Mark was on vacation. They decided we could do the displacement and negative test together - don't know why - maybe trying to save time. At the end of the well sometimes they think about speeding up.

Mark was out of the office and the team got together and discussed doing it as per the bullet points. The town team had decided to do it differently - Brian said he would talk to Mark.
It sounded to me that the team including John had decided this.
In this case we just went and did it this way.

I went to the rig floor. Did the positive test. Ran in hole to 8367ft.

Went through the mud engineer's displacement program n the rig floor. On Thunderhorse we've done many displacements - we went through this - I had a couple

ent Requested BP-I

April 14 Morel E-Mail	April 16 MMS Permit	April 20 Ops Note
Run in hole to 8,367'	Negative test to seawater gradient (with base oil to wellhead)	
Set 300' cement plug in mud **BARRIER**	Trip in hole to 8,367'	Displace mud with seawater from 8,367' to above wellhead (BOP)
Negative test with base oil to wellhead	Displace mud in well and riser from 8,367' with seawater	Negative test with seawater to depth 8,367' rather than with base oil to wellhead
Displace mud in well and riser from 6,000' with seawater	Monitor well for 30 minutes to ensure no flow	Displace mud in riser with seawater **Blowout**
	Set 300' cement plug in seawater **BARRIER**	
Set lockdown sleeve	Set lockdown sleeve	

Kick Detection

Driller Responsibilities

Transocean | DEEPWATER HORIZON EMERGENCY RESPONSE MANUAL DWH-HSE-PR-001 | SECTION: 7 | SUBSECTION: N/A

WELL CONTROL/SHALLOW GAS BLOWOUT

2 DETECTION

Detection of a kick (intrusion of liquid or gas into the wellbore) is the responsibility of the Driller. The Driller and his crew will continuously monitor the surface system indicators (flow rate, pit level, etc.) and break downhole indications, such as mud pressure, rate of penetration (drilling break), etc., for signs of a kick. Upon detecting a kick, the Driller is trained to shut the well in quickly. In fact, the speed with which this is accomplished will determine the severity of the situation.

Title:

DEEPWA
EMERGENCY R
VOL

Revision Status:

Level: L3
Classification: RSP
Manual Number: DWH-HSE-PR-001
Issue Number: 02
Revision Number: 04
Effective Date: February 15, 2008

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Non Controlled

Transocean Gulf Coast Sector

CONFIDENTIAL TREATMENT REQUESTED BP-HZN-MBI00000943

vessel alarm. Announcement made over PA system.

2 DETECTION

Detection of a kick (intrusion of liquid or gas into the wellbore) is the responsibility of the Driller. The Driller and his crew will continuously monitor the surface system indicators (flow rate, pit level, etc.) and break downhole indications, such as mud pressure, rate of penetration (drilling break), etc., for signs of a kick. Upon detecting a kick, the Driller is trained to shut the well in quickly. In fact, the speed with which this is accomplished will determine the severity of the situation.

Factors such as excessive shut in casing pressure, may lead the Operator's Senior Representative and the Offshore Installation Manager (OIM) to realize the treatment of a given kick will not be routine. In such a case, they will decide to declare a Level Two Alert.

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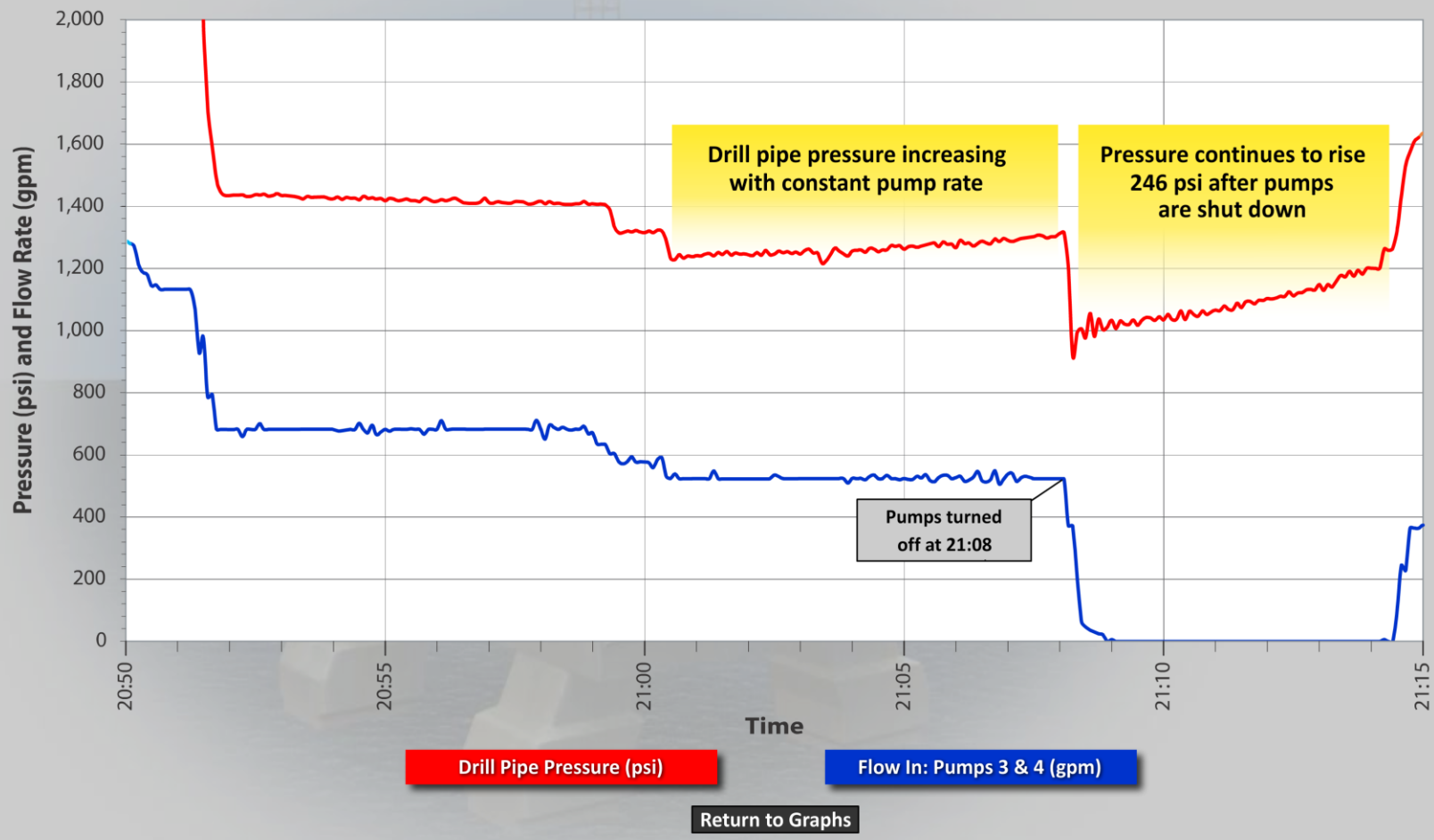
ISSUE NO:	02	REVISION NO:	01	PAGE	OF
REVISION DATE:		March 31, 2006		1	11

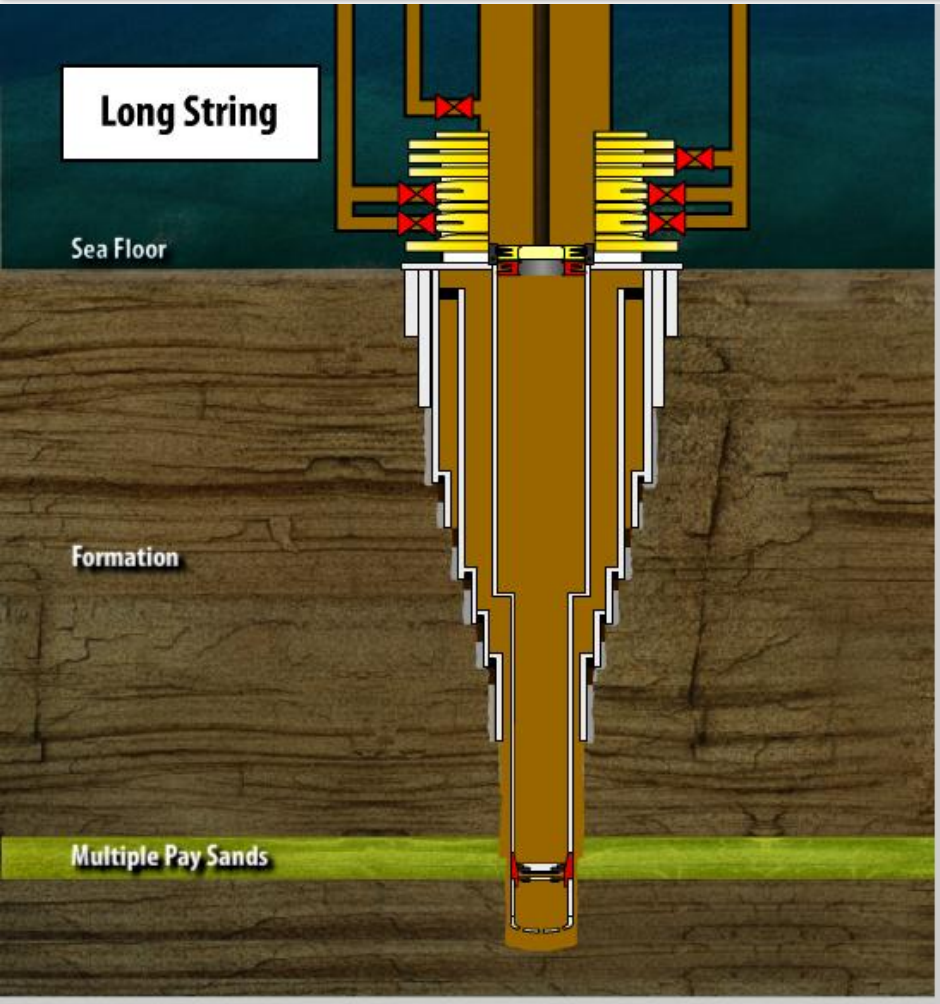
CONFIDENTIAL TREATMENT REQUESTED BP-HZN-MBI00001006

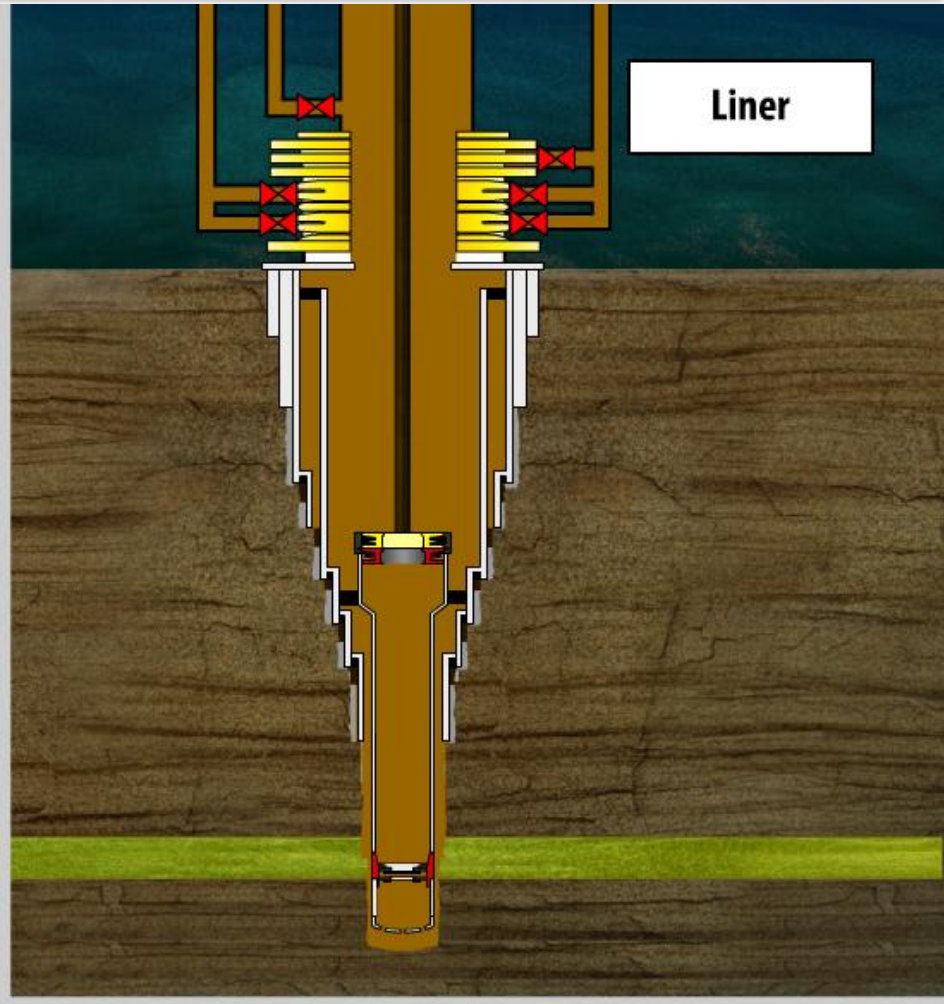
Anomalies in Data Indicate Kick



01:02 |Frame: 1491

Well Design – Long String Compared to Liner





Evidence Inconsistent With Picking Up and Dropping

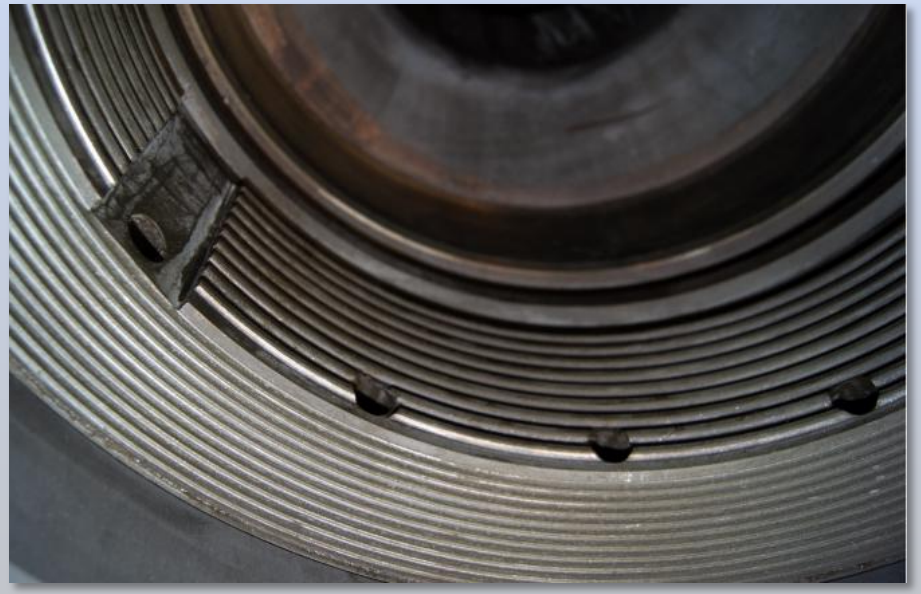
Casing hanger seal assembly was in expected position at Macondo

No apparent damage to the casing hanger seals

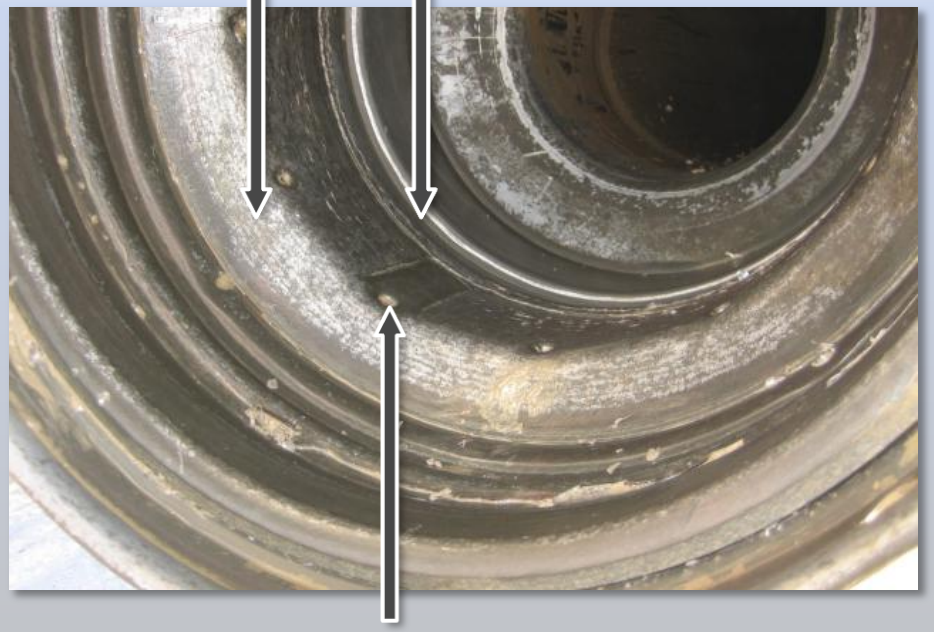
Outside

New vs. Macondo Casing Hanger Seal Assembly

Inside



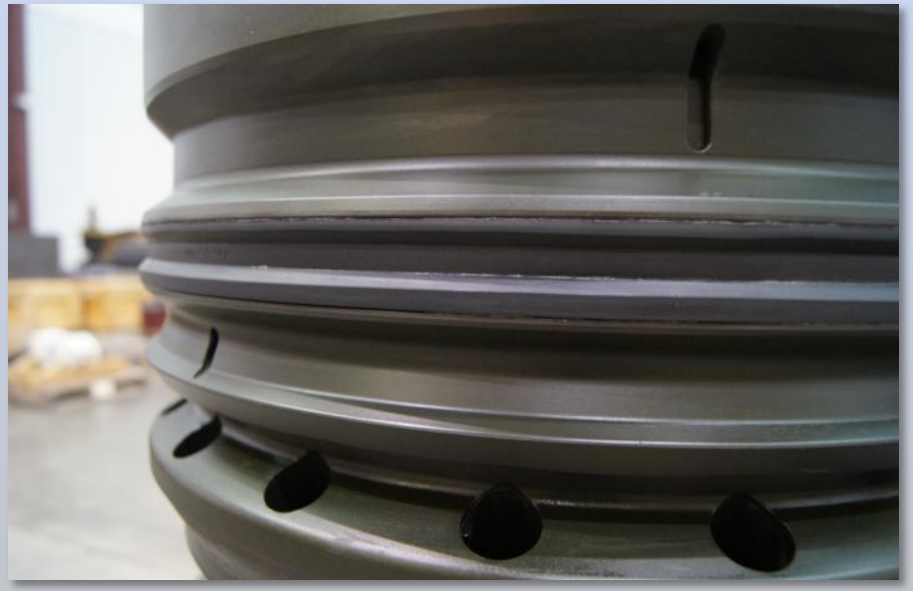
Ridges and grooves on inside appear to have been eroded away



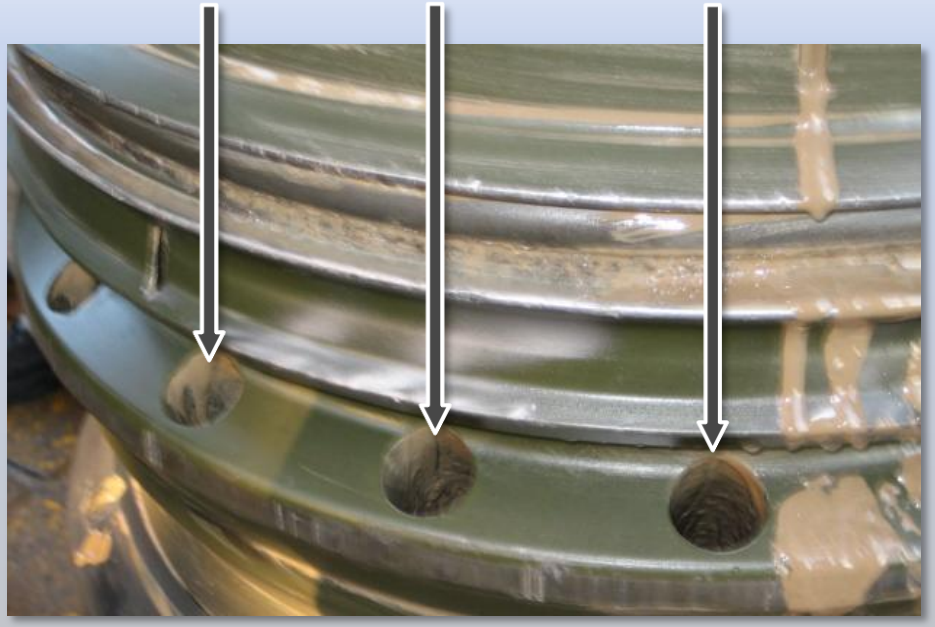
¼-inch-deep slots on inside appear eroded away

New vs. Macondo Casing Hanger Seal Assembly

Outside

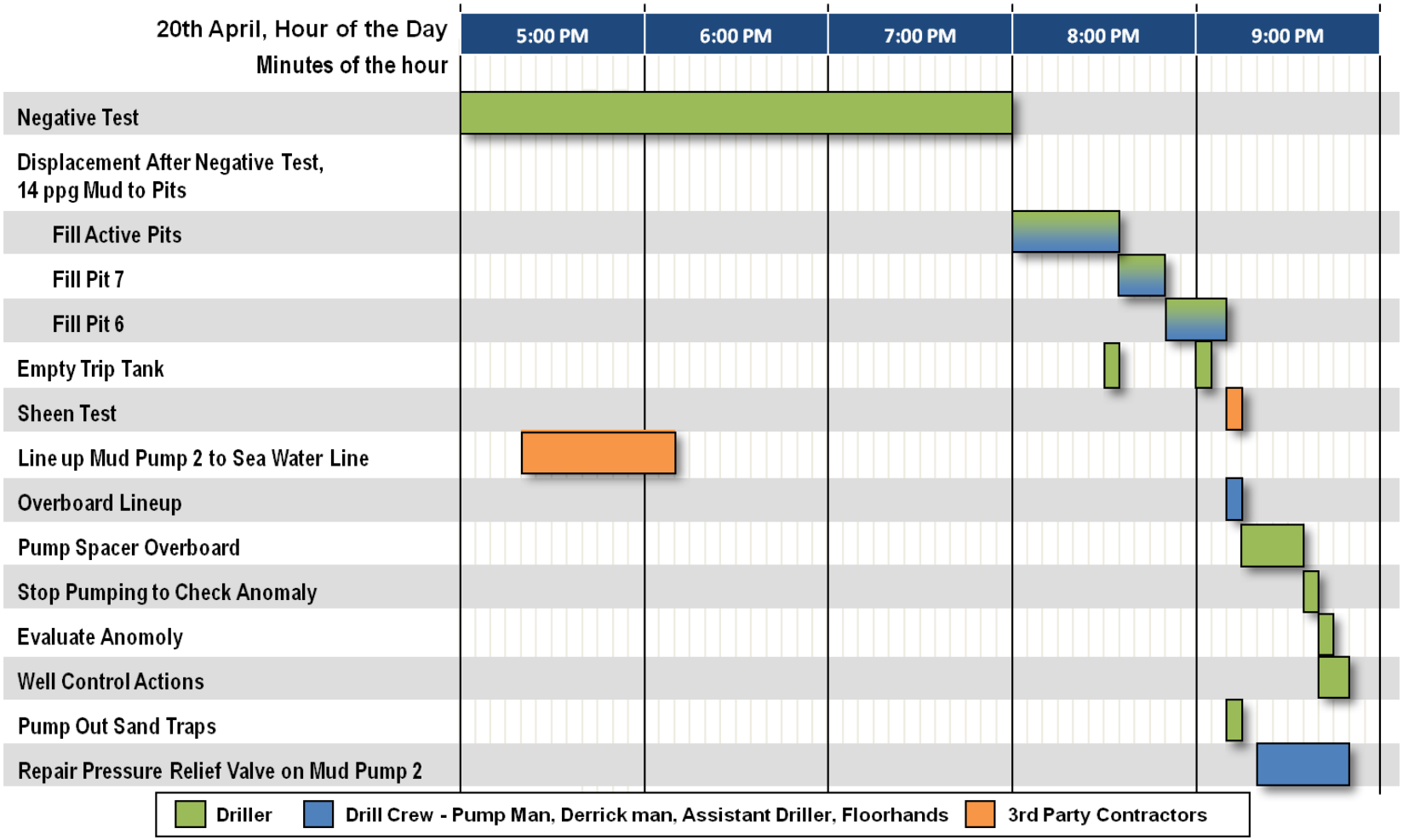


Flow from annulus would have come up through holes

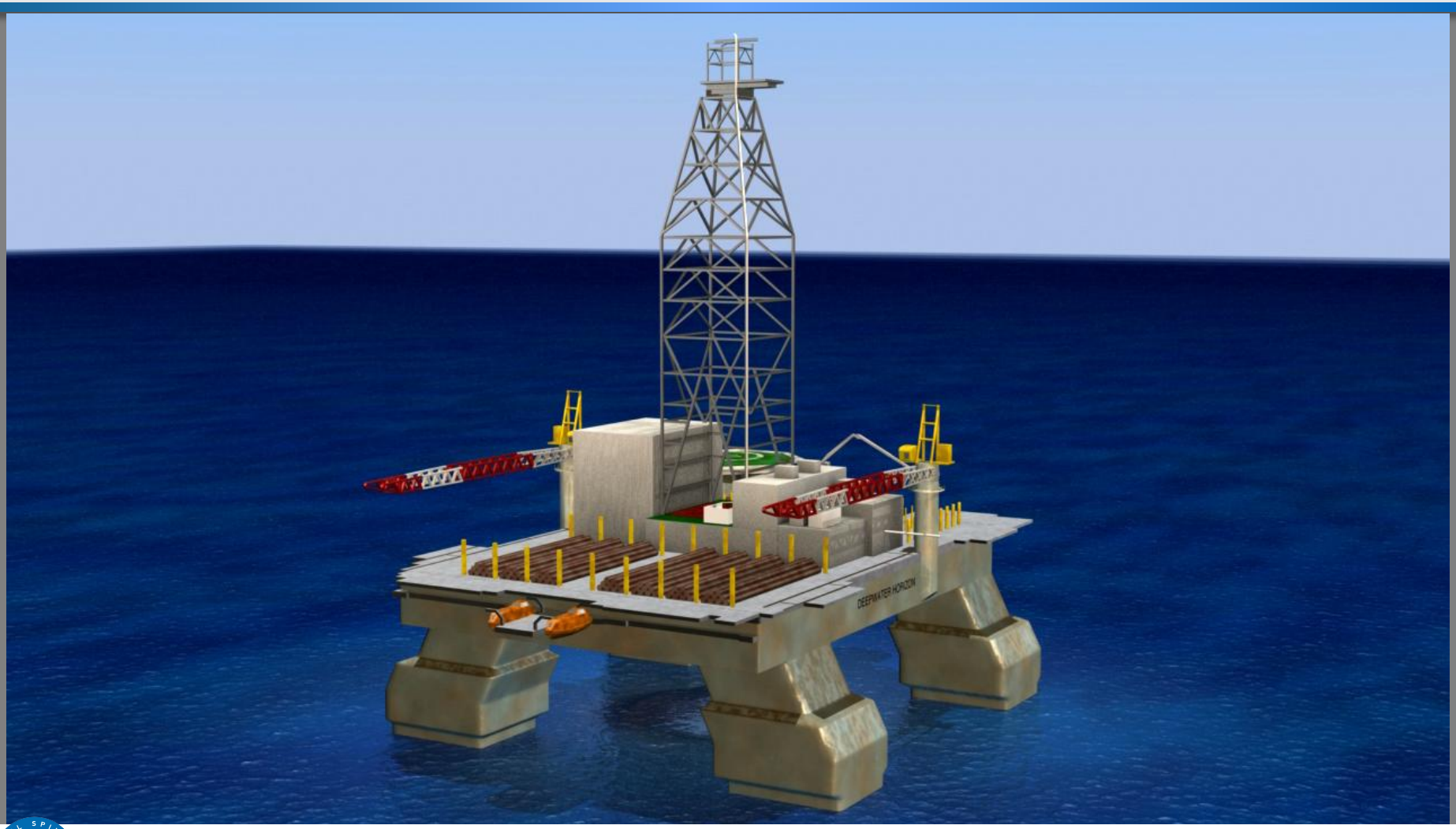


No apparent erosion on outside

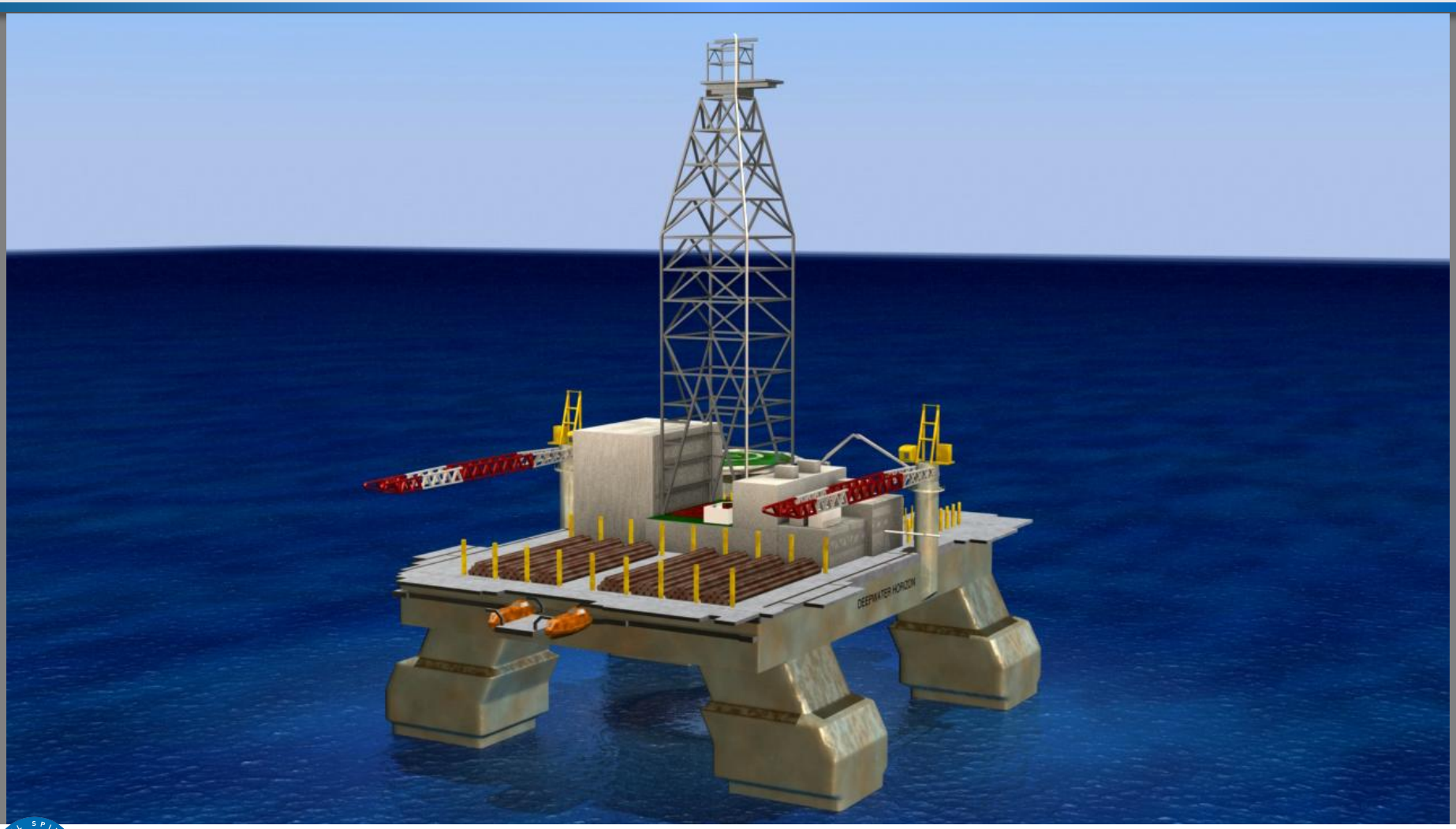
Transocean's Time Line of Last Five Hours



Crew Attempts to Divert Mud and Gas – Mud-Gas Separator



Crew Attempts to Divert Mud and Gas – Diverters



When to Divert Overboard

9.2 EQUIPMENT FOR HANDLING GAS IN THE RISER

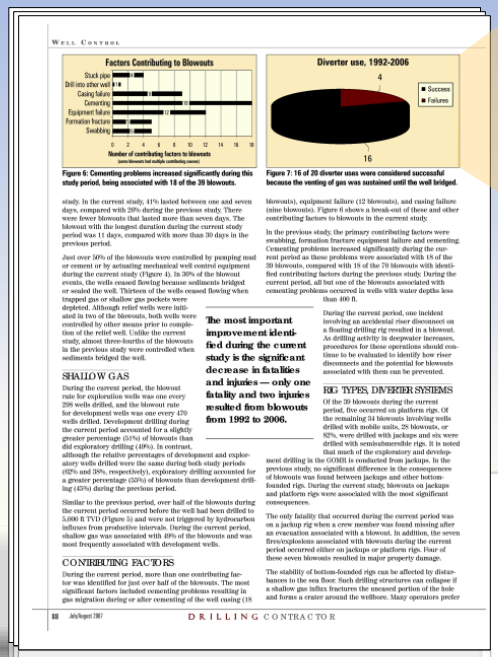
The diverter system above the telescopic joint with two (2) overboard lines and a system to remove gas from large volumes of mud and return it to the mud system (such as a mud box on the overboard line) is preferred.

The diverter and overboard lines should be designed to handle high flow rates and be as straight as possible.

This system is not designed to choke or control high gas or liquid flow; rather, it is a system to keep combustible gases safely away from sources of ignition and to remove gas from the mud.

At any time, if there is a rapid expansion of gas in the riser, the diverter must be closed (if not already) and the flow diverted overboard.

Diverting Overboard Might Have Prevented or Delayed the Explosion



WELL CONTROL

Factors Contributing to Blowouts

Stuck pipe
Drill into other well
Casing failure
Cementing
Equipment failure
Formation fracture
Swabbing

0 2 4 6 8 10 12 14 16 18

Number of contributing factors to blowouts
(some blowouts had multiple contributing causes)

Figure 6: Cementing problems increased significantly during this study period, being associated with 18 of the 39 blowouts.

Diverter use, 1992-2006

4

Success
Failures

16

Figure 7: 16 of 20 diverter uses were considered successful because the venting of gas was sustained until the well bridged.

study. In the current study, 41% lasted between one and seven days, compared with 20% during the previous study. There were fewer blowouts that lasted more than seven days. The blowout with the longest duration during the current study period was 11 days, compared with more than 30 days in the previous period.

Just over 50% of the blowouts were controlled by pumping mud or cement or by actuating mechanical well control equipment during the current study (Figure 4). In 30% of the blowout events, the wells ceased flowing because sediments bridged or sealed the well. Thirteen of the wells ceased flowing when trapped gas or shallow gas pockets were depleted. Although relief wells were initiated in two of the blowouts, both wells were controlled by other means prior to completion of the relief well. Unlike the current study, almost three-fourths of the blowouts in the previous study were controlled when sediments bridged the well.

The most important improvement identified during the current study is the significant decrease in fatalities and injuries — only one fatality and two injuries resulted from blowouts from 1992 to 2006.

SHALLOW GAS

During the current period, the blowout rate for exploration wells was one every 298 wells drilled, and the blowout rate for development wells was one every 470 wells drilled. Development drilling during the current period accounted for a slightly greater percentage (51%) of blowouts than did exploratory drilling (49%). In contrast, although the relative percentages of development and exploratory wells drilled were the same during both study periods (62% and 38%, respectively), exploratory drilling accounted for a greater percentage (52%) of blowouts than development drilling (48%) during the previous period.

Similar to the previous period, over half of the blowouts during the current period occurred before the well had been drilled to 5,000 ft TVD (Figure 5) and were not triggered by hydrocarbon influxes from productive intervals. During the current period, shallow gas was associated with 49% of the blowouts and was most frequently associated with development wells.

CONTRIBUTING FACTORS

During the current period, more than one contributing factor was identified for just over half of the blowouts. The most significant factors included cementing problems resulting in gas migration during or after cementing of the well casing (18 blowouts), equipment failure (12 blowouts), and casing failure (nine blowouts). Figure 6 shows a break-out of these and other contributing factors to blowouts in the current study.

In the previous study, the primary contributing factors were swabbing, formation fracture equipment failure and cementing. Cementing problems increased significantly during the current period as these problems were associated with 18 of the 39 blowouts, compared with 16 of the 70 blowouts with identified contributing factors during the previous study. During the current period, all but one of the blowouts associated with cementing problems occurred in wells with water depths less than 400 ft.

During the current period, one incident involving an accidental riser disconnect on a floating drilling rig resulted in a blowout. As drilling activity in deepwater increases, procedures for these operations should continue to be evaluated to identify how riser disconnects and the potential for blowouts associated with them can be prevented.

RIG TYPES, DIVERTER SYSTEMS

Of the 39 blowouts during the current period, five occurred on platform rigs. Of the remaining 34 blowouts involving wells drilled with mobile units, 28 blowouts, or 82%, were drilled with jackups and six were drilled with semisubmersible rigs. It is noted that much of the exploratory and development drilling in the GOMR is conducted from jackups. In the previous study, no significant difference in the consequences of blowouts was found between jackups and other bottom-founded rigs. During the current study, blowouts on jackups and platform rigs were associated with the most significant consequences.

The only fatality that occurred during the current period was on a jackup rig when a crew member was found missing after an evacuation associated with a blowout. In addition, the seven fires/explosions associated with blowouts during the current period occurred either on jackups or platform rigs. Four of these seven blowouts resulted in major property damage.

The stability of bottom-founded rigs can be affected by disturbances to the sea floor. Such drilling structures can collapse if a shallow gas influx fractures the uncased portion of the hole and forms a crater around the wellbore. Many operators prefer

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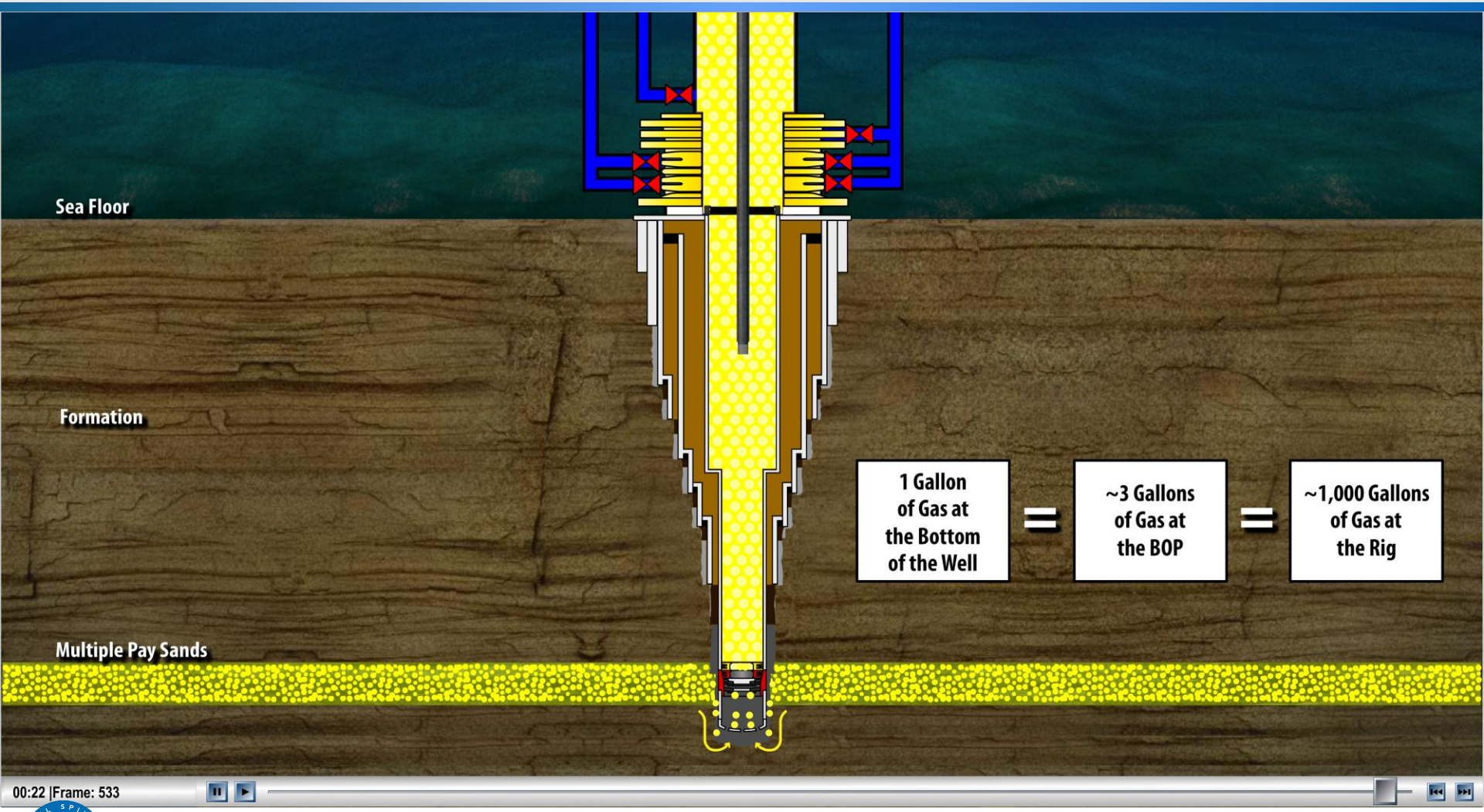
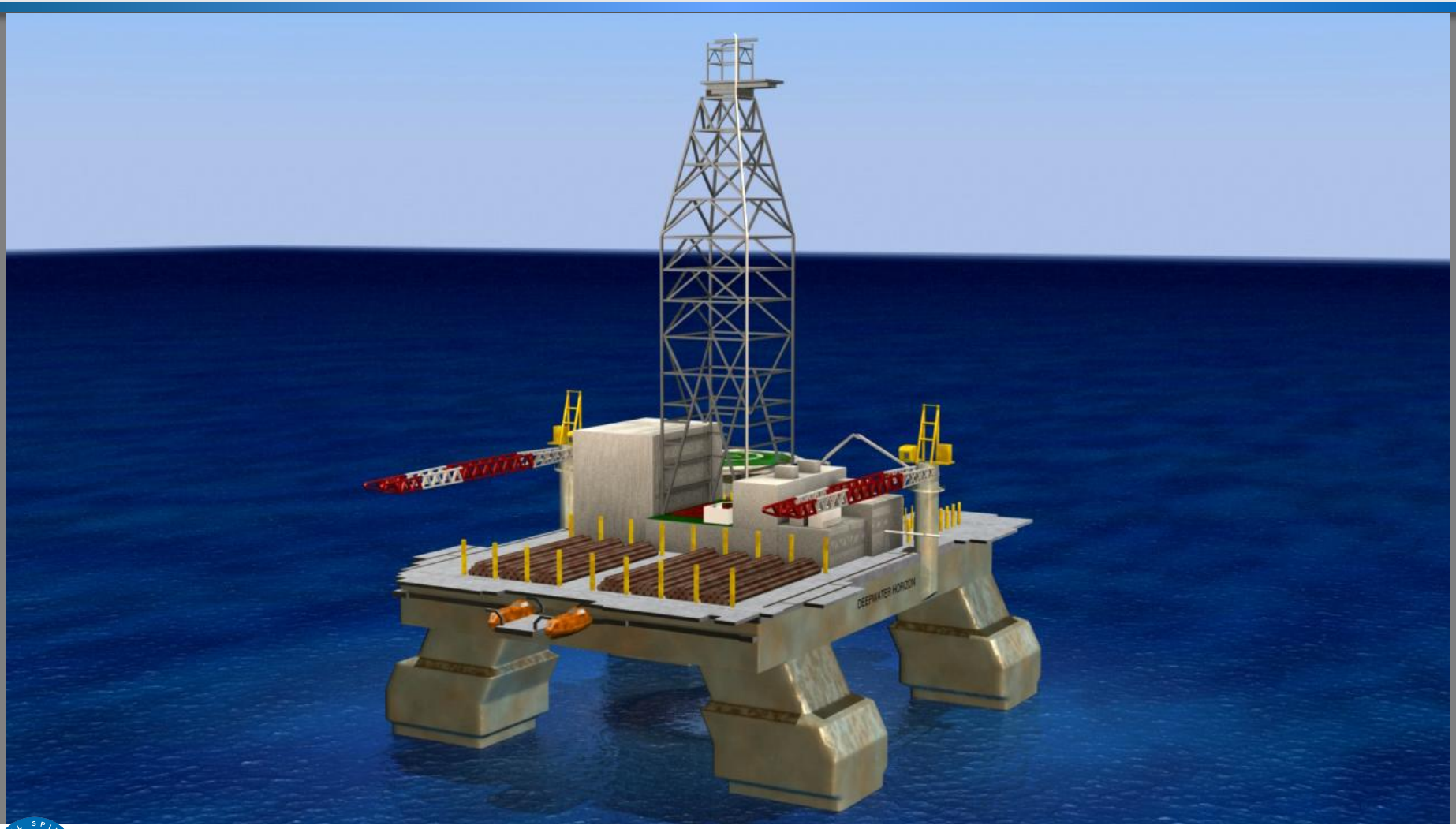
As indicated in Figure 7, the success rate for diverter systems was very high during the current period and improved significantly from the previous study. During the current period, diverters were used in 20 of the 39 blowouts. Sixteen of the 20 diverter uses were considered successful because the desired venting of gas was sustained until the well bridged, allowing all personnel to be safely evacuated. During the previous period, 22 of the 41 diverter uses were considered successful. Table 2 present information on diverter use and failures by rig type. A contributing factor to the improvement in diverter performance may be attributed to the revised diverter regulations that were published in 1988 and became effective two years later.

Gas Expands Exponentially as it Rises



Blowout

Hydrocarbons Emerge on the Rig



April 21, 2010

Photos: *Times Picayune*, *Wall Street Journal*

OIL SPILL OSC COMMISSION

TRIAL GRAPHIX

Lessons Learned From December 2009 Event

In December 2009, a Transocean rig in the North Sea experienced a well control event during completion operations

Transocean and the well's operator analyzed the event and reached a number of conclusions regarding handling of such events:

- **High vigilance** when reduced to one barrier underbalanced
- Recognize when underbalanced – **heightened vigilance**
- Highlight what the kick detectors are when not drilling

Last Two Hours: Explosion at 21:49 (9:49 PM)

BOP open – cement is only barrier

Time	Event
20:02	Negative-pressure test over, begin to remove heavy mud and replace it with lighter seawater
20:52	BP report calculates well underbalanced
21:01 – 21:08	**Anomalous drill pipe pressure: subtle increase while displacing heavy fluid with lighter fluid**
21:08 – 21:14	**Anomalous drill pipe pressure: increase while pumps off**
21:38	BP report calculates hydrocarbons in riser
21:40	Mud begins to overflow on rig floor
21:41	Annular preventer activated, BP report calculates 1,000 bbl gain
21:42	Nearby ship told to move
21:46	Gas emerges onto drill floor
21:49	First explosion, power lost, BP report calculates 2,000 bbl gain

Preliminary Conclusions – Technical

- Flow path was exclusively through shoe track and up through casing.
- Cement (potentially contaminated or displaced by other materials) in shoe track and in some portion of annular space failed to isolate hydrocarbons.
- Pre-job laboratory data should have prompted redesign of cement slurry.
- Cement evaluation tools might have identified cementing failure, but most operators would not have run tools at that time. They would have relied on the negative pressure test.
- Negative pressure test repeatedly showed that primary cement job had not isolated hydrocarbons.
- Despite those results, BP and TO personnel treated negative pressure test as a complete success.
- BP's temporary abandonment procedures introduced additional risk.

Preliminary Conclusions – Technical

- Number of simultaneous activities and nature of flow monitoring equipment made kick detection more difficult during riser displacement.
- Nevertheless, kick indications were clear enough that if observed would have allowed the rig crew to have responded earlier.
- Once the rig crew recognized the influx, there were several options that might have prevented or delayed the explosion and/or shut in the well.
- Diverting overboard might have prevented or delayed the explosion. Triggering the EDS prior to the explosion might have shut in the well and limited the impact of any explosion and/or the blowout.
- Technical conclusions regarding BOP should await results of forensic BOP examination and testing.
- No evidence at this time to suggest that there was a conscious decision to sacrifice safety concerns to save money.

The National Commission on the

BP DEEPWATER HORIZON OIL SPILL AND OFFSHORE DRILLING

TRIAL GRAPHIX