

Chapter 4.7 | Kick Detection

The Chief Counsel's team finds that rig personnel missed signs of a kick during displacement of the riser with seawater. If noticed, those signs would have allowed the rig crew to shut in the well before hydrocarbons entered the riser and thereby prevent the blowout.

Management on the rig allowed numerous activities to proceed without ensuring that those operations would not confound well monitoring. Those simultaneous activities did confound well monitoring and masked certain data.

Despite the masking effect, the data that came through still showed clear anomalies.¹ The crew either did not detect those anomalies or did not treat them as kick indicators.

Well Monitoring and Kick Detection

A **kick** is an unwanted influx of fluid or gas into the wellbore. The influx enters the wellbore because a barrier, such as cement or mud, has failed to control fluid pressure in the formation. In order to control the kick, personnel on the rig must first detect it, then stop it from progressing by adding one or more barriers.² The crew must then circulate the influx out of the wellbore. If the crew does not react properly, fluids will continue to enter the wellbore. This will eventually escalate into uncontrolled flow from the well—in other words, a blowout.³

In order to detect a kick, rig personnel examine various indicators of surface and downhole conditions. These indicators include pit gain, flow-out versus flow-in, drill pipe pressure, and gas content in the mud.⁴

Pit Gain (Volumetric Comparison)

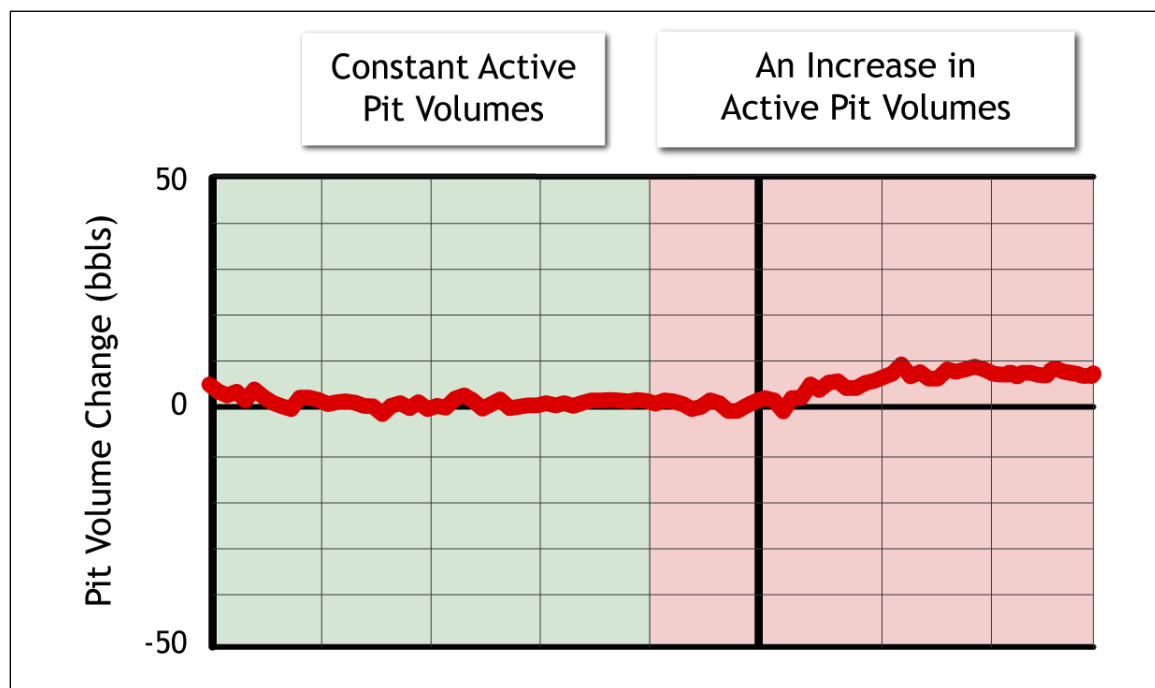
Pit gain is the difference between the volume of fluid pumped into the well and the volume of fluid pumped out of the well. If the well is stable (that is, there are no gains or losses) the two should be equal.

The easiest way to monitor pit gain is to pump fluids into the well from a single pit and route returns from the well into the same pit. This is called **single-pit monitoring**. However, when dealing with several different fluids (mud, spacer, seawater), the crew must use several different pits to prevent the fluids from mixing. In order to monitor multiple pits, the crew can use the active pit system.

Active Pit System. The **active pit system** refers to a computer setting that allows the driller (and others) to select several pits and aggregate their volumes into one “active pit volume” reading. Even though there are several different pits involved, the rig's computer system displays them as a single pit for volume monitoring purposes.⁵

There are several ways to configure the active pit system. In a closed-loop system, the fluids going into the well are taken from the active pit system, and the fluids coming out of the well are returned to the active pit system. Because volume-in should equal volume-out, the active pit volume will stay constant when the well is stable. If the active pit volume increases, that strongly indicates that a kick is under way.⁶ A volume increase should be easily detectable by a positive slope in the trend line (seen in Figure 4.7.1) or an uptick in the numerical data.

Figure 4.7.1. Active pit volume in a closed-loop system.



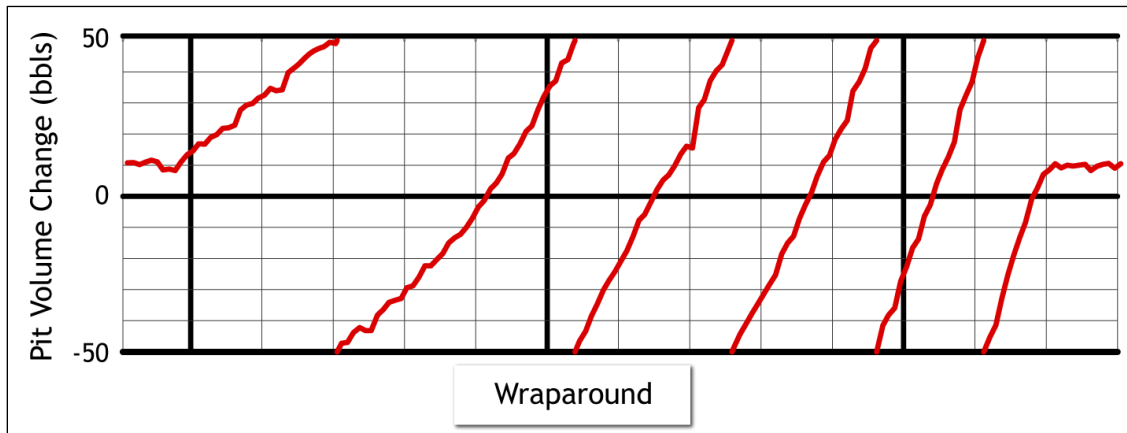
Sperry-Sun data/TrialGraphix

In a closed-loop system, active pit volume will remain constant so long as the well is stable. An increase in active pit volume strongly indicates that a kick is under way.

Monitoring pit gain in a non-closed-loop system is more complex. In a non-closed-loop system, fluids are either taken from or returned to places other than the pits on the rig. For instance, when rig crews use seawater to displace mud from a well, the rig may pump the seawater in from the ocean (and bypass the pits) but still direct mud returns back to the pits.⁷ In that case, active pit volume will increase over time because the returns are filling up the pits (seen in Figure 4.7.2).

To monitor pit gain in a non-closed-loop system, rig personnel must manually calculate the volume of seawater pumped into the well (pump strokes \times volume per pump stroke) and compare it to the volume of mud returning from the well (measured by changes in pit volume).⁸

Certain kinds of operations can make it impossible to use pit gain as a kick indicator. For example, this happens when return flow from the well goes overboard instead of into a pit. Rig personnel generally cannot measure the volume of flow overboard, so they cannot make a volume-in/volume-out comparison during such operations.

Figure 4.7.2. Active pit volume in a non-closed-loop system.

Sperry-Sun data/TrialGraphix

In a non-closed-loop system, active pit volume will increase continuously regardless of the well's stability.

Flow-Out (Rate Comparison)

Flow-in is a calculation of the rate at which fluid is being pumped into the well (pump rate × volume per pump stroke). Because it is calculated from known and reliable values, flow-in has a small margin of error. It is a trusted value.

Flow-out is a measurement of the rate at which fluid returns from the well. It is typically measured by a sensor in the flow line coming out of the well. As a result, the accuracy of the flow-out measurement depends on the quality of the sensor. It is a less reliable value than flow-in.⁹

If the well is stable, flow-in and flow-out should be equal.¹⁰ An unexplained increase in flow-out is a kick indicator. For example, if the pump rate is constant but flow-out increases, the additional flow is likely caused by fluid or gas coming into the wellbore from the formation.¹¹

The simplest application of this principle occurs when the rig is not pumping fluids into the well at all. At this point, flow-in is zero, so flow-out should also be zero. Rig personnel can confirm that flow-out is zero in two ways: by reading the data from the flow-out meter and by visually inspecting the return flow line (performing a **flow check**). If rig personnel see flow from the well at a time when the pumps are off, that is an anomalous observation. While such flow can indicate thermal expansion of the drilling fluid, rig heave, or ballooning, it can also indicate that a kick is under way.¹² In any case, further investigation is warranted.

When the rig crew first shuts pumps down, it generally takes some period of time for flow-out to drop to zero. This reflects the time it takes for the pumps to drain and for circulation to come to a stop. During this time period, there continues to be some **residual flow**.¹³

Each rig has its own residual flow-out **signature**—a pattern wherein flow-out dissipates and levels off over the course of several minutes.¹⁴ It is important that rig personnel identify that signature and monitor flow-out for a sustained period of time afterward to confirm that there is indeed no flow after the pumps have been shut down.¹⁵

Flow checks constitute an important safeguard and “double-check” ensuring that the well is secure. It is therefore a common practice to assign one member of the rig crew to always visually confirm that flow has stopped whenever the pumps have been shut down, and announce it to the rest of the rig’s personnel.

Drill Pipe Pressure

Drill pipe pressure is a measurement of the pressure exerted by fluids inside the drill pipe.¹⁶ When the rig pumps are off, drill pipe pressure should remain constant.¹⁷ When the density of fluids in the well outside the drill pipe is higher than the density of fluids inside the drill pipe, drill pipe pressure will be positive. This is because the heavier fluid outside the drill pipe exerts a u-tube pressure on the fluids inside the drill pipe.

When the rig crew turns pumps on, drill pipe pressure will fluctuate depending on the relative densities of fluids inside and outside of the drill pipe and the circulating friction generated by moving those fluids.¹⁸ When the pumps are pushing lighter fluid down the drill pipe to displace heavier fluid outside it, drill pipe pressure should steadily decrease as the lighter fluid displaces the heavier one.

Drill pipe pressure can be a difficult kick indicator to interpret because so many different factors can affect that pressure. For instance, drill pipe pressure might change because of a washout in the drill pipe or wear-out of the pump discharge valves.¹⁹ But such causes should still prompt the driller to stop and check that the rig and well are all right.²⁰

In a situation where there are changing fluid densities, changing pump rates, and changing wellbore geometry, close monitoring of drill pipe pressure can be facilitated by advance planning and charts describing what pressures to expect.²¹ Unexplained fluctuations in drill pipe pressure can indicate a kick.

Some kicks exhibit an increase in drill pipe pressure,²² although an increase can also indicate a clog in the pipe or that the crew is pumping the wrong fluids into the well.²³ More commonly, it is a decrease in drill pipe pressure that indicates a kick; lighter oil and gas flow into the annulus around the drill pipe and thereby lower the drill pipe pressure.²⁴ But a decrease in drill pipe pressure can also indicate a hole in the drill pipe.²⁵ In any case, unexplained fluctuations in drill pipe pressure are a cause for concern and warrant further investigation.²⁶

Gas Content

Gas content refers to the amount of gas dissolved or contained in a fluid. Fluid returns from a well can contain gas for several reasons. Some amount of gas is often present in a well during normal operations, depending on the mud type and the location of the well. And “trip gas” appears when tripping out of the hole and conducting a bottoms up circulation after a trip.

An increase in the gas content of fluid returns over time can indicate an increase in pore pressure,²⁷ penetration of a hydrocarbon-bearing zone, or a change in wellbore dynamics allowing more effective cuttings removal.²⁸ But unexplained increases in gas content are always a cause for concern. They can indicate either that a kick is occurring or that wellbore conditions are becoming conducive for a kick.²⁹

Sensors and Displays

Rig personnel rely on data that are recorded and displayed by proprietary sensors, hardware, and software. For the *Deepwater Horizon*, Transocean hired National Oilwell Varco (NOV) to provide Hitec-brand sensors, driller's chairs, and displays for the rig.³⁰ BP contracted Sperry Drilling, a Halliburton subsidiary, to conduct additional independent mud logging and well monitoring services.³¹

NOV placed a comprehensive set of sensors on the rig that measured various drilling parameters and surface data, including flow-in, flow-out, pit volume, drill pipe pressure, block position, and hook load.³² The Hitec system recorded and displayed only the data from the Hitec sensors. Sperry Drilling's **Sperry-Sun** system collected data from many of the Hitec sensors,³³ including the sensors for pit volumes, flow-in, drill pipe pressure, and kill line pressure.³⁴ It also collected data from separate Sperry-Sun sensors, including Sperry-Sun sensors for flow-out and gas content.³⁵

Sperry Drilling and NOV both provided BP and Transocean with proprietary displays consisting of real-time numerical data, historical trend lines, and other features like tables and charts.³⁶ Each of the systems allowed users to manually set (and constantly adjust) audible and visual alarms for various data parameters, including pit gain, flow-out, and drill pipe pressure.³⁷ The alarms could be set to trigger whenever incoming data crossed preselected high and low thresholds, and could also be shut off.³⁸

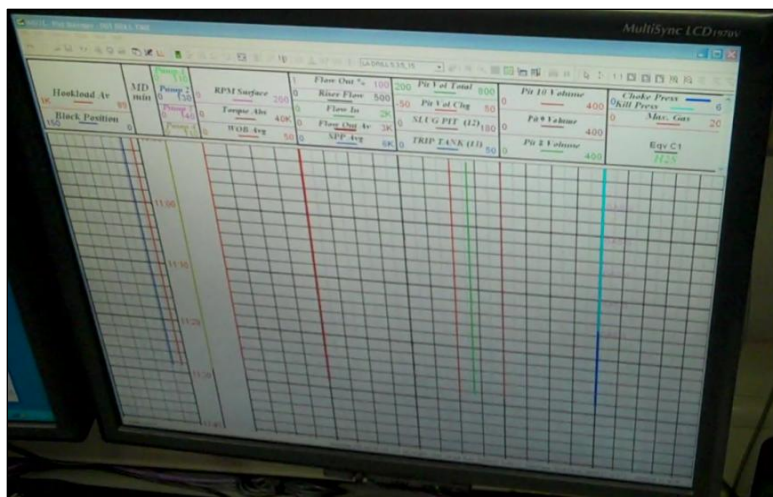
While the Hitec and Sperry-Sun data systems displayed similar data, they did so using significantly different visual design (seen in Figures 4.7.3 and 4.7.4).

Figure 4.7.3. Hitec data display.



Sambhav N. Sankar

Figure 4.7.4. Sperry-Sun data display.



Fred H. Bartlit, Jr.

Photos taken on Transocean's *Deepwater Nautilus*.

Because the two systems in many cases used the same underlying sensors, most of the numerical values should have been close if not identical.³⁹ Where they displayed data from different sensors, the differences were usually predictable and could generally be dealt with through calibration.⁴⁰

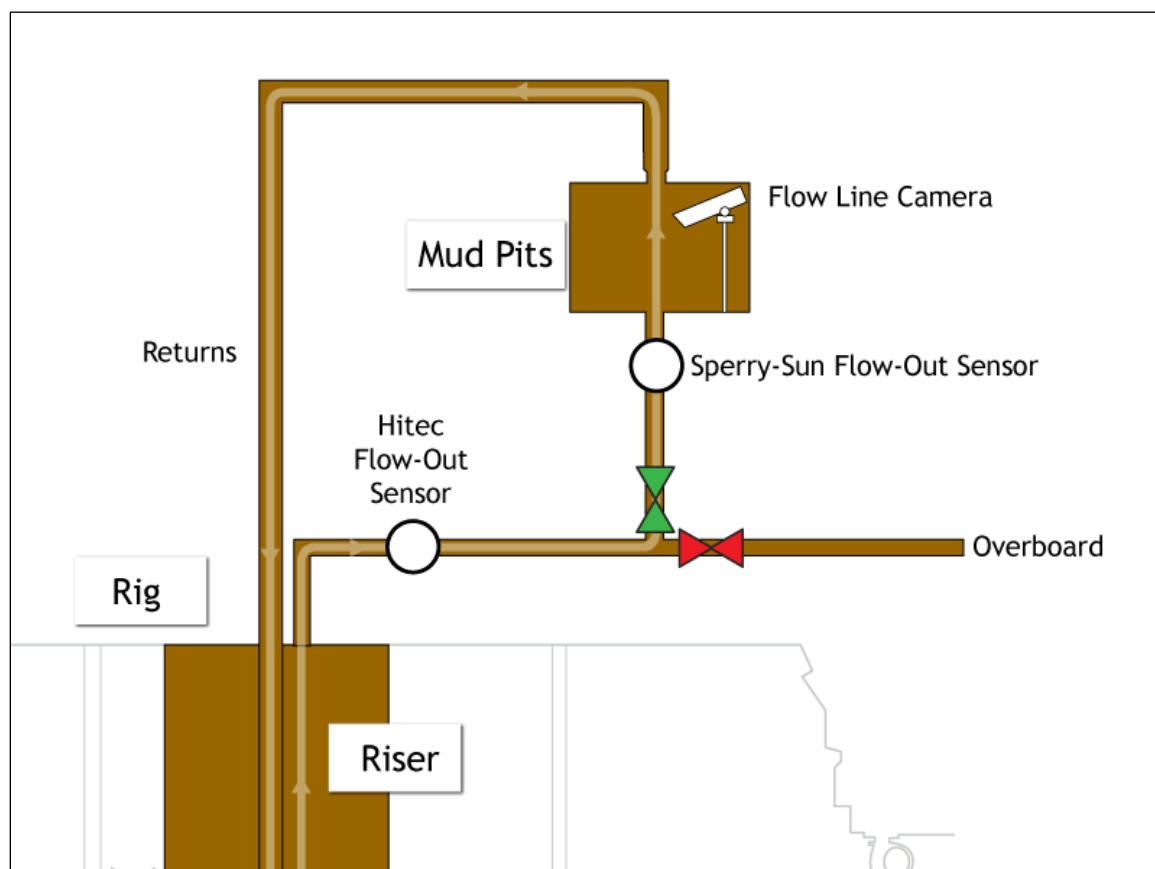
Hitec and Sperry-Sun each had its own flow-out sensor in the return flow line. These flow-out sensors differed in type, location, and format. Hitec had a paddle-type flow-out sensor.⁴¹ As fluid

rushed past, it pushed and lifted the paddle. The Hitec system inferred the rate of flow from the degree of paddle elevation. Sperry-Sun, by contrast, used a sonic-type sensor.⁴² The sensor emitted a beam to ascertain the height of the fluid. The Sperry-Sun system inferred the rate of flow from the fluid level.⁴³

The Hitec flow-out sensor was located in the return flow line before the line forked to either send returns to the pits or send them overboard.⁴⁴ The Sperry-Sun sensor was located after the fork, capturing flow-out only when returns from the well were routed to the pits.⁴⁵ (Positioning of both sensors is illustrated in Figure 4.7.5.) This means that the Hitec flow-out sensor could register returns going overboard, but the Sperry-Sun sensor could not.⁴⁶

In addition to the data display systems, the rig also had video cameras that monitored key areas and components, including the rig floor and the flow line. The flow line camera (also illustrated in Figure 4.7.5) simply pointed at the flow line. Like the Sperry-Sun flow-out sensor, this camera was located after the fork; rig personnel could use it to observe flow returning to the pits but not flow that had been routed overboard.⁴⁷ When returns were sent overboard, rig personnel could still visually inspect for flow but could not do so using the video camera. They had to physically look behind the gumbo box (which was located before the fork).⁴⁸

Figure 4.7.5. Flow-out sensors and flow line camera.



TrialGraphix

The Sperry-Sun flow-out sensor and the rig's flow line camera could not register returns going overboard. The Hitec flow-out sensor could, but data from the Hitec flow-out sensor sank with the rig.

The rig's sensors and display equipment appear to have been working properly at the time of the blowout. There is no evidence that the Sperry-Sun system malfunctioned. It continued recording and transmitting data up until the first explosion. The Hitec system was also "in satisfactory condition," as an April 12 rig condition assessment recorded in some detail.⁴⁹

The crew had expressed some complaints about the driller's and assistant driller's control chairs, known as the "A-chair" and "B-chair" respectively.⁵⁰ The computer system powering the chairs' controls and displays had "locked up" or crashed on several occasions.⁵¹ When this happened to the A-chair, the driller's screens would either freeze or revert to a blank blue screen, disabling real-time data display on the screen and requiring the driller to move to the adjacent B-chair.⁵² In response, Transocean replaced the chairs' hard drives.⁵³ This appears to have corrected the problem.⁵⁴ The April 12 assessment found that the software on all of the chairs "was stable and had not shown (excessive) crashes."⁵⁵ There is no evidence that the chairs malfunctioned on April 20.⁵⁶

Personnel and Places

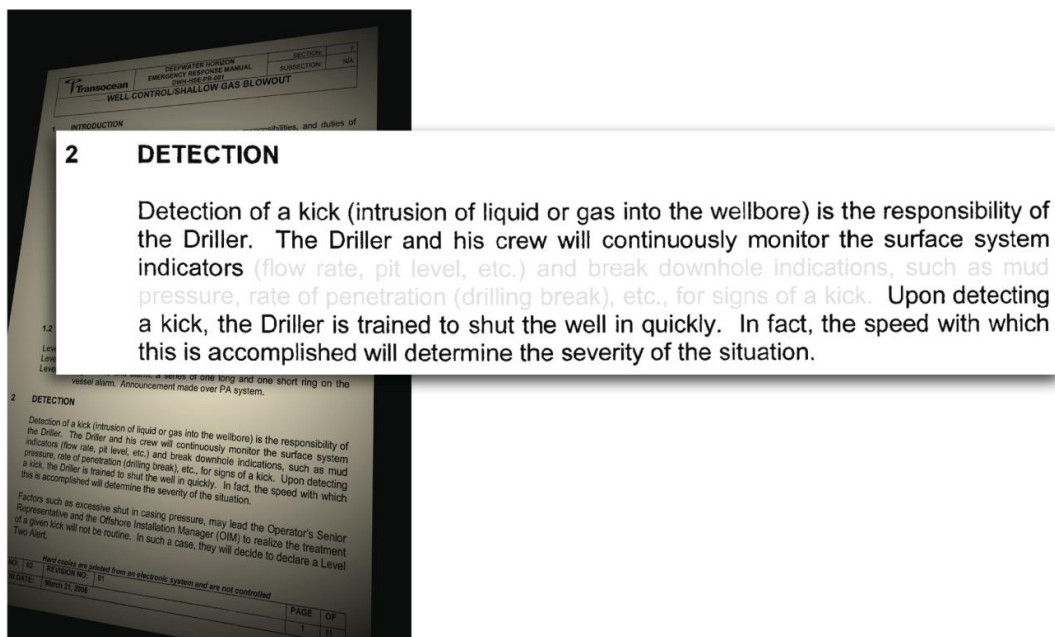
On the Rig

Rig data are available in various forms to personnel on the rig and onshore. The Hitec data, Sperry-Sun data, and video feeds were all available to personnel on the rig, in real time, anywhere there was a television.⁵⁷ Certain individuals had more extensive data displays depending on their level of well monitoring responsibility.

On the *Deepwater Horizon*, the Transocean driller and assistant driller, and the Sperry Drilling mudlogger, were directly responsible for well monitoring.

The **driller** was responsible for monitoring well conditions at all times, interpreting and responding to downhole conditions, and securing the well in a well control situation (see Figure 4.7.6).⁵⁸ The driller sat in the A-chair in the drill shack. He normally monitored three screens: two screens in front of him that displayed Hitec data and a screen to the side with

Figure 4.7.6. Transocean's *Deepwater Horizon* Emergency Response Manual.



Sperry-Sun data.⁵⁹ He also had a screen with live video feeds and a window straight ahead with a direct view of the rig floor.⁶⁰ The driller was supposed to actively look at his data screens during well operations.⁶¹ He contemporaneously recorded rig activities for each day's daily drilling report.⁶²

The driller was the central point of contact for all well control concerns: Anyone with "an understanding of something that may have indicated a well control event, would have called back to the driller, most likely, and informed him."⁶³ He was the one who had the most information about current operations on the rig and the ability to react to them.⁶⁴

The assistant driller was also responsible for monitoring the well and taking well control actions. He served as a crucial backup and assist to the driller. The assistant driller was expected to have "a comprehensive understanding of well control" and "be able to recognize the signs of a well kick or blowout before it develops into an emergency condition."⁶⁵ He assisted the driller in monitoring the drilling instrumentation and recognizing and controlling well conditions.⁶⁶ As part of that assistance, he monitored the pit volumes and from time to time would go to the pits and check in with the derrickhand to make sure all was well.⁶⁷

There were two assistant drillers on duty at any one time. One sat in the B-chair, adjacent to the driller in the drill shack.⁶⁸ He had access to the same screens as the driller. If there was activity on the deck—like pipe handling—another assistant driller would sit in the "C-chair" in the auxiliary driller's shack.⁶⁹ Although the assistant drillers had many responsibilities, at least one should have been monitoring the well at any given time.⁷⁰

The Sperry Drilling mudlogger also monitored the well, serving as a second set of eyes for the Transocean crew.⁷¹ BP specifically contracted the mudloggers for this purpose.⁷² It was the mudloggers' duty to continuously monitor operations and provide well and drilling data upon request. They watched the data but did not have any control over rig operations and could not respond directly themselves. If the mudloggers identified problems, they would notify the driller (or drill crew).⁷³

The mudlogger sat in the mudlogger's shack, one flight of stairs away from the drill shack.⁷⁴ He had 12 monitoring screens arranged in two rows of six. These screens displayed both Hitec and Sperry-Sun data.⁷⁵ Among the screens, the mudlogger had a display to the left showing all of the rig's pit volume levels. Below that, the mudlogger had a graphical log and a digital readout of the Hitec numbers.⁷⁶ He also had a screen with live video feed from the rig's cameras—he could switch between channels showing the flow line, the rig floor, and other areas.⁷⁷ In addition to monitoring the well, the mudlogger performed formation analysis when the rig was drilling and provided data printouts and reports.⁷⁸

Several individuals supervised well monitoring work by the driller, assistant driller, and mudlogger.

The BP **well site leader** had responsibility for overseeing all operations on the well. That responsibility involved delegating duties like minute-by-minute monitoring of data.⁷⁹ Some well site leaders did monitor the well during critical operations.⁸⁰ To facilitate such monitoring, the well site leaders' office had screens that constantly displayed the Hitec data, Sperry-Sun data, and live video feeds.⁸¹ The Sperry Drilling mudloggers reported to the BP well site leader.

The Transocean **toolpusher** supervised the driller and ensured that all drilling operations were carried out safely, efficiently, and in accordance with the well program.⁸² That included confirming that all well control requirements were in place, performing all well control calculations, and assisting in killing the well in emergency situations.⁸³ The toolpusher was generally on the rig floor at all times, had access to the driller’s and assistant driller’s monitors, and had a small office inside the drill shack.⁸⁴

The toolpusher reported to the **senior toolpusher**. The senior toolpusher had a similar job description as the toolpusher but was one level higher in the hierarchy.⁸⁵ Although he had no continuous role in operations and was not generally on the rig floor, the senior toolpusher was supposed to be consulted when there were anomalies or emergencies. In a well control event, the senior toolpusher organized response actions and acted as a liaison to the well site leader.⁸⁶ The senior toolpusher reported to the offshore installation manager.

The **offshore installation manager (OIM)** was the senior-most Transocean drilling manager on the rig and oversaw the entire Transocean crew. He assisted with abnormal or emergency situations.⁸⁷ Both the senior toolpusher and OIM had separate offices away from the rig floor, near their living quarters, that included data displays.⁸⁸

Onshore

Onshore, only the Sperry-Sun data were available in real time.⁸⁹ The Hitec data and video feeds did not go to shore.⁹⁰

BP personnel could view the Sperry-Sun data in their Houston offices and in an operations room for the *Deepwater Horizon* that had dedicated data displays.⁹¹ They could also view the data over a secure Internet connection.⁹² Personnel at Anadarko and MOEX could access the Sperry-Sun data onshore as well.⁹³ BP, Anadarko, and MOEX appeared to have used real-time data to examine geological and geophysical issues.⁹⁴

Sperry Drilling personnel could access the Sperry-Sun data in their Houston real-time center and Lafayette operations office.⁹⁵ They appeared to have used their access to provide customer support and quality control.⁹⁶

None of the entities receiving the Sperry-Sun data onshore appears to have monitored the data for well control purposes.⁹⁷ (Transocean did not receive data onshore.⁹⁸)

Table 4.7.1. Personnel and places with access to the rig’s Sperry-Sun data.

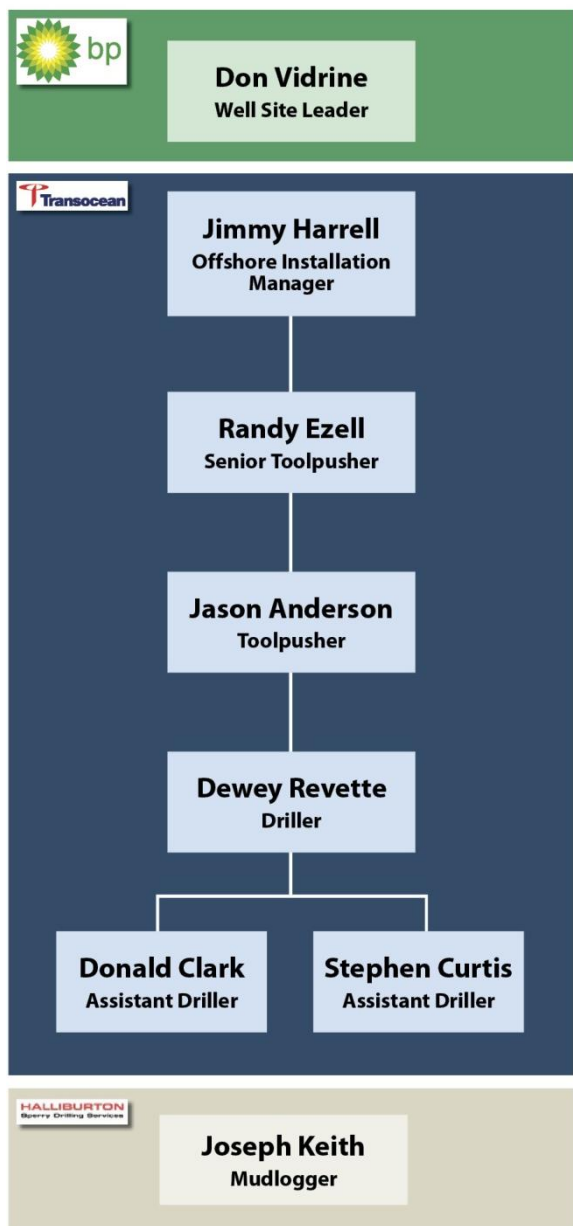
Rig: Responsible for Monitoring Data	Rig: Accountable for Operations	Onshore: Could Access Data in Real Time
<ul style="list-style-type: none"> ▪ Transocean driller ▪ Transocean assistant driller ▪ Sperry-Sun mudlogger 	<ul style="list-style-type: none"> ▪ BP well site leader ▪ Transocean OIM ▪ Transocean senior toolpusher ▪ Transocean toolpusher 	<ul style="list-style-type: none"> ▪ BP ▪ Anadarko ▪ MOEX ▪ Sperry-Sun

Well Monitoring at Macondo

It is difficult to know exactly what data screens rig personnel were looking at during their final hours on the *Horizon*.⁹⁹ There were multiple screens, with multiple data types, and each was highly customizable.¹⁰⁰ This Report relies on the Sperry-Sun historical log for its data analysis because that log is the only surviving dataset and display from the rig.¹⁰¹

The Sperry-Sun data log is valuable. This log (or something very close to it) was “the actual log that they were watching on the *Horizon*”¹⁰²—it was displayed on one of the several screens in front of the driller, assistant driller, mudlogger, and company man. The drill pipe pressure presented on the Sperry-Sun screen was collected from Transocean’s Hitec data sensors. Accordingly, the data values shown on the available Sperry-Sun screen formats would also have been shown on the Hitec screens.

Figure 4.7.7. Rig personnel on duty during the final displacement.



TrialGraphix

Witness accounts suggest that the driller, assistant driller, and mudloggers all watched the Sperry-Sun data log.¹⁰³ The numerical values reflected in the data log would have been available on other screens as well.¹⁰⁴ And one can reasonably expect that rig personnel monitoring the well would have had (or should have had) pit volumes, flow-out, flow-in, and drill pipe pressure reflected in the log somewhere on their screens—no matter the format.¹⁰⁵

At the same time, the Sperry-Sun data have significant limitations. The log is not fully inclusive: It does not contain data from the Hitec flow-out sensor. And scrutinizing the complete log carefully in retrospect is significantly different from monitoring it in real time, while the trend lines are developing.¹⁰⁶

The First Hour

After cementing the production casing and conducting pressure tests that had been deemed successful, the crew moved on to the remainder of the temporary abandonment procedure. The crew would displace mud and spacer from the riser with seawater. There were several stages in the planned displacement. First, rig personnel would pump seawater down the drill pipe to displace mud from the riser until the spacer fluid behind the mud reached the rig floor. They would then shut down the pumps and conduct a “sheen test.” That test would confirm that the crew had displaced all of the oil-based mud from the riser. The crew would then change the lineup of valves to send further returns from the well (spacer) overboard rather than to the mud pits. They would then resume the displacement until all of the spacer was out of the wellbore and the riser was full of nothing but seawater.¹⁰⁷

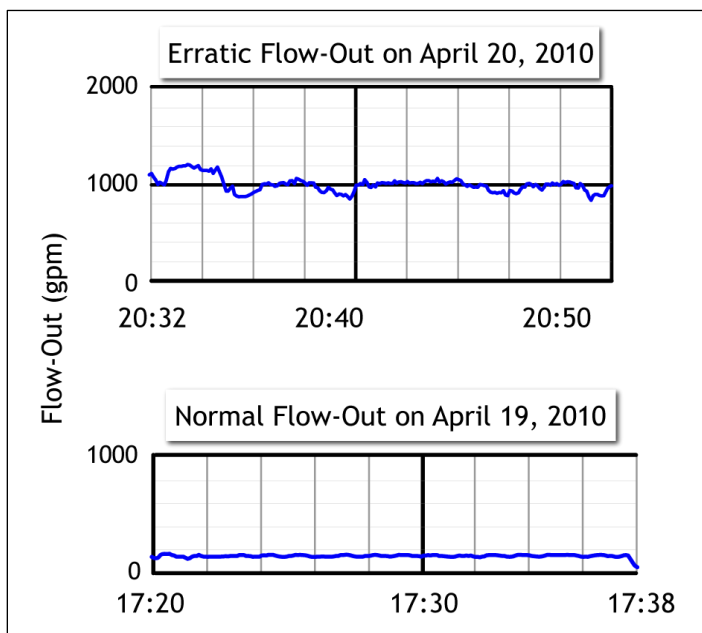
At the start of the displacement process, Transocean driller Dewey Revette was in the drill shack’s A-chair, monitoring the well. Transocean assistant driller Stephen Curtis was likely in the drill shack’s B-chair, also monitoring the well.¹⁰⁸ BP well site leader Don Vidrine was in the drill

shack to oversee the initiation of the displacement.¹⁰⁹ Donald Clark, the other Transocean assistant driller, was at the bucking unit (a machine for making up pipe) on the port aft deck, working with personnel from Transocean, Weatherford, and Dril-Quip to prepare for setting the lockdown sleeve.¹¹⁰ Sperry Drilling mudlogger Joseph Keith was in the mudlogger's shack, monitoring the well.¹¹¹

At 8:02 p.m., the crew began displacing the mud and spacer in the riser with seawater.¹¹² The pumps were not lined up in a closed-loop system. Instead, the crew was pumping seawater from the ocean through the sea chest and into the well. This bypassed the pits. Returns from the well were flowing into the active pits (in this case, pits 9 and 10).¹¹³ As a result, individuals monitoring the well could not rely on the “pit volume change” display.¹¹⁴ To monitor pit gain, rig personnel would have had to perform volumetric calculations comparing the increase in pit volume (reflecting returns) against the volume of seawater pumped into the well (pump strokes × volume per stroke).¹¹⁵ There is no evidence, one way or the other, as to whether the crew performed such volumetric calculations.

This setup should not have impaired rig personnel's ability to monitor flow-out versus flow-in. However, the flow-out readings appear to have been more erratic than readings captured the previous day (seen in Figure 4.7.8). This may be because cranes were moving on the rig's deck, causing the rig to sway and thus affecting the level of fluids in the flow line.¹¹⁶ Otherwise, flow-out appeared normal.¹¹⁷

Figure 4.7.8. Erratic vs. normal flow-out.



Sperry-Sun data/TrialGraphix

Flow-out readings appear to have been more erratic than normal during the final displacement, perhaps because crane operations were causing the rig to sway.

This setup also should not have impaired rig personnel's ability to monitor drill pipe pressure. The drill pipe pressure appears to have behaved as expected. It rose initially as the pumps turned on and then decreased gradually as lighter seawater replaced the heavier mud and spacer in the riser. At 8:10 p.m., mud engineer Leo Lindner looked at the drilling screen and “thought everything was fine.”¹¹⁸ At 8:16 p.m., the data showed an increase in gas units— not atypical at the start of circulation.¹¹⁹ The gas readings then tapered off as the last of the mud left the wellbore.¹²⁰

From 8:28 to 8:34 p.m., the crew emptied the trip tank (pit 17), with the fluid going into the flow line and pits with the rest of the returns. This complicated the monitoring of both the pits and flow-out. To accurately monitor either parameter, the crew had to perform calculations to subtract the effect of emptying the trip tank from the pit volume and flow-out readings that appeared on-screen. It is unknown whether the crew did so.

At 8:34 p.m., the crew did three things simultaneously. They (1) directed returns away from the active pits (pits 9 and 10) and into a reserve pit (pit 7); (2) emptied the sand traps into the active pits (pits 9 and 10); and (3) began filling the trip tank (pit 17).¹²¹ Each of these actions further complicated pit monitoring for well control purposes. The active pit system was eliminated as a well monitoring tool. In order to know the volume coming out of the well, the crew had to perform calculations taking into account that returns were going to two different places—the reserve pit (pit 7) and the trip tank (pit 17). In addition, routing returns to the trip tank bypassed the flow-out meter, so the flow-out reading appeared artificially low and had to be added to the rate of entry of fluids into the trip tank to ascertain actual flow-out.¹²² Again, it is unknown whether the crew was performing any such calculations. In addition, communication between the rig crew and mudlogger may have broken down at this time: The drill crew did not inform Keith about the switch in pits.¹²³ Keith did notice a slow gain in the active pits and called M-I SWACO mud engineer Leo Lindner to inquire; Lindner said they were moving the mud out of the sand traps and into the active pits.¹²⁴

At 8:49 p.m., the crew again rerouted returns, this time from one reserve pit (pit 7) to another (pit 6). At about this time, the displacement process had underbalanced the well. The combined hydrostatic pressure at the bottom of the well (generated by the mud and spacer still in the riser, the seawater in the riser and the well, and the mud remaining in the well beneath 8,367 feet below sea level) dropped below the reservoir pressure.

Transocean's post-explosion analysis estimates that the well became underbalanced at 8:50 p.m.¹²⁵ BP's post-explosion modeling estimates that the time was 8:52 p.m.¹²⁶ Given the failed bottomhole cement job, hydrocarbons would have begun flowing into the well at this time.

At 8:52 p.m., Vidrine called BP's shoreside senior drilling engineer Mark Hafle to ask about the procedure for testing the upcoming surface cement plug. Hafle asked Vidrine if everything was OK. Hafle had the Sperry-Sun real-time data up on-screen in front of him. It does not appear that the two discussed the rig crew's handling of the displacement or rig activities complicating well control monitoring.¹²⁷

In retrospect, it does not appear there were (or would have been) any signs of a kick prior to about 9 p.m. Nevertheless, between 8 and 9 p.m., rig personnel did not adequately account for whether

Trip Tank. A trip tank is a small tank. Its primary purpose is to hold fluid that the drill crew may need to rapidly send into the well, for example, to compensate for the volume removed when pulling out the drill pipe (known as tripping the pipe). The drill crew also uses the trip tank to monitor the well. The trip tank is situated between the well and the mud pits. When emptied, fluid from the trip tank goes into the return flow line, past the flow-out meters, and into the same pits as the returns from the well. The *Horizon* had two trip tanks.

and to what extent certain simultaneous operations, such as emptying the trip tanks, may have confounded their ability to monitor the well.

Indications of an Anomaly as Early as 9:01 p.m.

Just before 9 p.m., Keith left the mudlogger's shack to take a short break.¹²⁸ He notified the drill crew (by calling Curtis) and then stepped out.¹²⁹ He went downstairs, used the restroom, got a cup of coffee, and smoked half a cigarette.¹³⁰ He was apparently gone for about 10 minutes before returning to his post.¹³¹

At 8:59 p.m., the crew simultaneously decreased the pump rate on all three pumps and began emptying the trip tanks.¹³² The decrease in the pump rate should have caused a decrease in the flow-out, but because emptying the trip tanks sent additional fluid flowing past the flow-out meter, the flow-out reading actually increased. That increase potentially masked any sign of a kick from the flow-out reading.¹³³

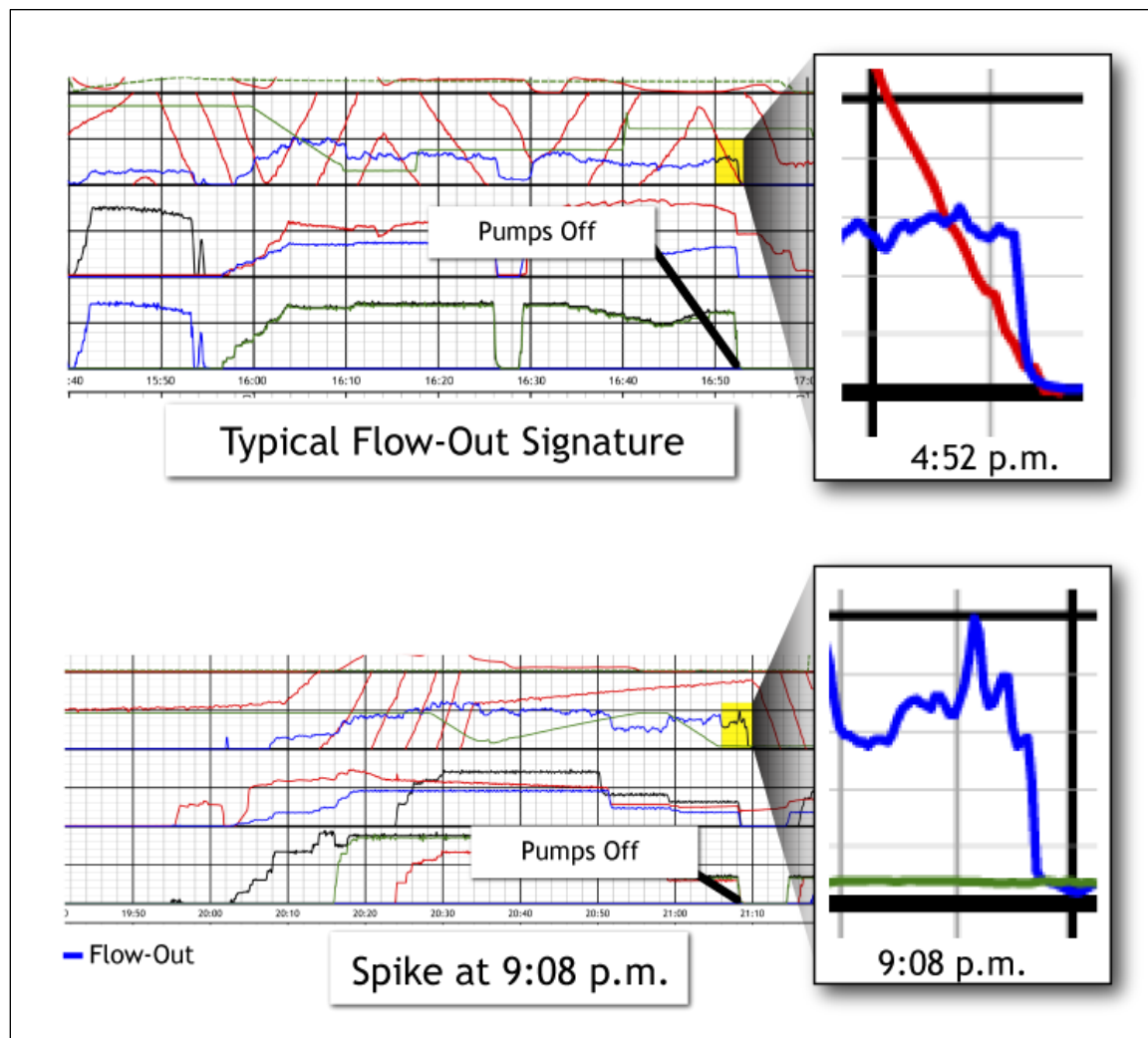
At 9:01 p.m., drill pipe pressure changed direction. Instead of continuing to steadily decline, it began to increase. This change in direction was a significant anomaly. If lighter seawater were replacing the heavier mud and spacer in the riser as should have been the case, drill pipe pressure should have continued to drop, as it had done for at least the previous 40 minutes.¹³⁴ In retrospect, this change in drill pipe pressure likely indicated that hydrocarbons were pushing heavier mud up from the bottom of the well against and around the drill pipe.

By 9:08 p.m., with the pump rates constant, drill pipe pressure had increased by approximately 100 pounds per square inch (psi). The magnitude of the increase would have appeared subtle on the Sperry-Sun screen showing only trend lines, but it likely would not have been subtle on the numerical displays.¹³⁵

The change in direction was by now clear and clearly anomalous. An individual who saw the drill pipe pressure increase should have been seriously concerned and should have investigated further.¹³⁶ But Keith, who would have returned from his break by that time, reviewed the logs for the period he was absent and did not notice any indication of a problem: "I went back over it and looked, and to my recollection, I didn't see nothing wrong."¹³⁷

At 9:08 p.m., after the top of the spacer column reached the rig, the crew shut down the pumps and switched the lineup to route returns overboard.¹³⁸ Keith looked at the video feed from the flow line camera and visually confirmed that there was no flow.¹³⁹ He likely communicated this to the rig floor.¹⁴⁰ According to Vidrine, who was on the rig floor, everything looked fine.¹⁴¹

Everything was not fine. For about a minute after the pumps stopped, flow-out continued beyond the *Horizon's* typical flow-out signature.¹⁴² This was a kick indicator (Figure 4.7.9 depicts a typical flow-out signature at 4:52 p.m. and the 9:08 p.m. spike). A driller, assistant driller, or mudlogger watching the screen could have seen it.¹⁴³ Instead, they thought they had visual confirmation of no flow, based at least on Keith's observations.¹⁴⁴

Figure 4.7.9. Typical flow-out signature vs. spike at 9:08 p.m.

Sperry-Sun data/TrialGraphix

For about a minute after the pumps stopped at 9:08 p.m., flow-out continued beyond the *Horizon's* typical flow-out signature.

There are several possible explanations for this contradiction: (1) Keith may have seen some flow but attributed it to residual flow; (2) Keith may not have looked at the camera for long enough to realize that it was not residual flow;¹⁴⁵ (3) the flow may have been too modest to detect from the video feed;¹⁴⁶ or (4) the flow may already have been rerouted overboard before Keith performed his flow check.¹⁴⁷ Rig personnel could have performed a secondary flow check by sending someone to physically look behind the gumbo box, but apparently they did not do so. On many rigs (including the *Horizon*¹⁴⁸), this would have been a common practice, especially if rig personnel had noted anomalies.¹⁴⁹

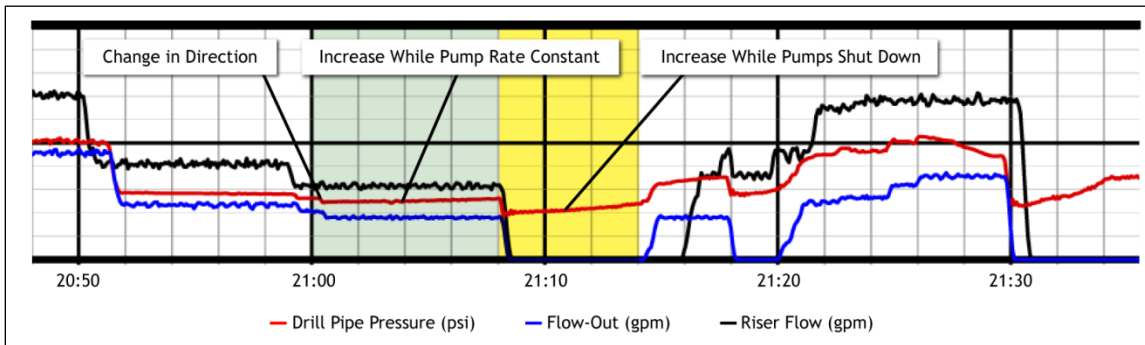
By 9:10 p.m., the crew had rerouted returns overboard. Doing so bypassed the pits, the Sperry-Sun flow-out meter, and the gas sensors.¹⁵⁰ That equipment could no longer be used to monitor the well. The flow did not bypass the Hitec flow-out meter, but for some reason—perhaps malfunction, perhaps neglect—data from that meter never alerted the crew to the kick. At about the same time that they rerouted returns overboard, the crew also transferred mud from the active pits (pits 9 and 10) to the reserve pit that had been taking returns from the well (pit 6).

The crew probably made this pit transfer to prepare for cleaning out the active pits (pits 9 and 10).¹⁵¹ The immediacy of the transfer suggests that the crew did not take the time to compare the volume of fluid pumped into the well with the volume of fluid returned from the well.

Meanwhile, the mud engineers conducted the sheen test and communicated to the drill shack that it passed. Vidrine directed the crew to get in place to start sending returns overboard and ordered the displacement to begin again. He then returned to his office and did paperwork.

During the course of these activities, drill pipe pressure gradually increased. From 9:08 to 9:14 p.m., while the pumps were shut down, drill pipe pressure increased by approximately 250 psi (see Figure 4.7.10). This was a significant anomaly.¹⁵² By 9:14 p.m., the increase would have been noticeable and a cause for concern.¹⁵³ The driller apparently missed this increase, perhaps because “having looked and seen 60 seconds of constant pressure...he may have then turned to do the next step in the process which was line up another mud pump to pump down the kill lines.”¹⁵⁴ It is unclear why the assistant driller and the mudlogger also missed the increase.¹⁵⁵

Figure 4.7.10. Drill pipe pressure anomalies from 9:01 to 9:14 p.m.



Sperry-Sun data/TrialGraphix

At 9:01 p.m., drill pipe pressure changed direction. By 9:08 p.m., with the pump rates constant, drill pipe pressure had increased by approximately 100 psi. From 9:08 to 9:14 p.m., while the pumps were shut down, drill pipe pressure increased by approximately 250 psi. Each of these changes in drill pipe pressure was an anomaly that should have prompted rig personnel to stop and investigate, but the signs apparently went unnoticed.

At 9:14 p.m., the drill crew turned the pumps back on: first, pumps 3 and 4 at 9:14 p.m., then pump 1 at 9:16 p.m. Keith called Curtis and asked why the drill crew was turning the pumps on gradually and not at full rate. Curtis replied, “That’s the way we’re going to do it this time.”¹⁵⁶ Shortly after 9:17 p.m., the crew also turned on pump 2 to pump down the kill lines. Within seconds of turning on pump 2, the pressure relief valve (PRV) on pump 2 blew.¹⁵⁷ The PRV probably blew because the crew had inadvertently started the pump against a closed kill line valve (a rare but not unheard-of mistake).¹⁵⁸

After the PRV blew, at 9:18 p.m., the crew shut down the primary pumps (pumps 3 and 4). They left the riser boost pump (pump 1) on. The driller organized a group of individuals including Clark to go to the pump room and fix the PRV on pump 2.¹⁵⁹ In addition, the driller ordered someone to open up the closed kill line valve that had caused the PRV to blow.¹⁶⁰

At 9:20 p.m., the drill crew restarted the primary pumps (pumps 3 and 4). Transocean senior toolpusher Randy Ezell called the drill shack and spoke with toolpusher Jason Anderson. He

asked how the displacement was going. Anderson said, “It’s going fine. It won’t be much longer...I’ve got this.”¹⁶¹ From 9:14 to 9:27 p.m., the data did not clearly reflect any anomalies. The return flow bypassed the pits, Sperry-Sun flow-out meter, and gas sensors. Drill pipe pressure appeared to be behaving roughly as expected—increasing as the pumps ramped up and then decreasing as seawater replaced the last of the spacer.¹⁶²

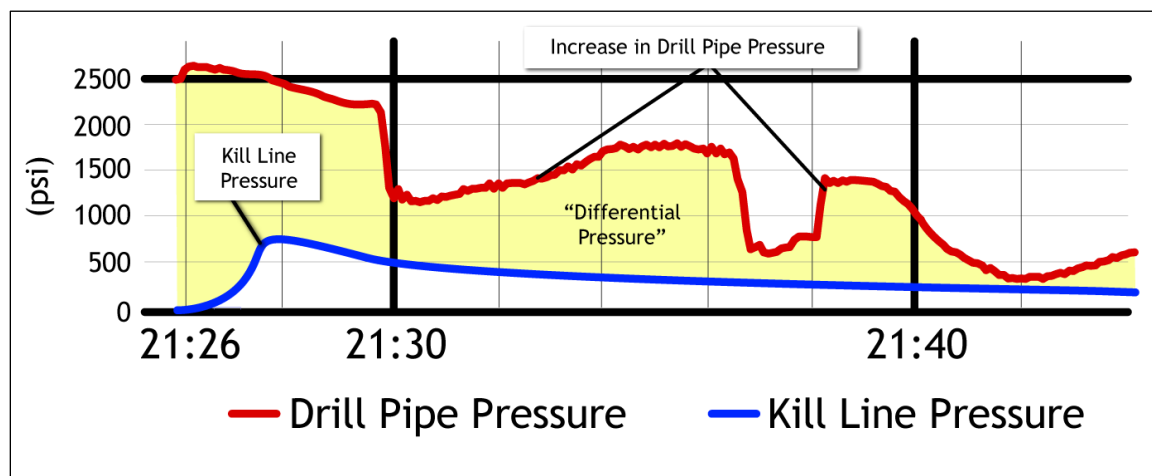
Drill Crew Notices Anomaly but Does Not Treat It as a Kick

By 9:27 p.m., an obvious anomaly appeared. The pressure on the kill line—now discernable because the drill crew had just opened up the previously closed kill line valve—rose to approximately 800 psi.¹⁶³ This kill line pressure was anomalous.¹⁶⁴ The crew noticed a “differential pressure” between the kill line (approximately 800 psi) and the drill pipe (approximately 2,500 psi).¹⁶⁵ At 9:30 p.m., they shut down the pumps to investigate.¹⁶⁶

Around that time, Transocean chief mate David Young went to the drill shack to speak with Anderson and Revette about the timing of the surface plug cement job.¹⁶⁷ Revette, sitting in the driller’s A-chair, and Anderson, standing next to him, were speaking to each other.¹⁶⁸ At times, they looked at the driller’s screens.¹⁶⁹ Revette noted that they were “seeing a differential.”¹⁷⁰ The two men appeared concerned but calm. According to Young, “It was quiet...there was no panic or anything like that.”¹⁷¹

From 9:30 to 9:35 p.m., drill pipe pressure increased by approximately 550 psi (see Figure 4.7.11). This was another significant anomaly: With the pumps shut off, there should have been no movement in the well.¹⁷² (The increase might have reflected mud continuing to travel up the wellbore with oil and gas below.)¹⁷³ Revette and Anderson were intently watching the screens, but they did not shut in the well. Instead, Revette ordered Transocean floorhand Caleb Holloway to bleed off the drill pipe pressure¹⁷⁴—apparently to eliminate the differential pressure. At 9:36 p.m., Holloway cranked open a valve on the stand pipe manifold to bleed down the pressure.¹⁷⁵ But it was taking longer than usual to bleed off.¹⁷⁶ Revette told Holloway, “Okay, close it back.”¹⁷⁷

Figure 4.7.11. Drill pipe pressure and kill line pressure anomalies from 9:27 to 9:40 p.m.



Sperry-Sun data/TrialGraphix

At 9:27 p.m., kill line pressure reached approximately 800 psi. From 9:30 to 9:35 p.m., while the pumps were shut down, drill pipe pressure increased by approximately 550 psi. After the crew attempted to bleed it down, drill pipe pressure again shot up, at 9:38 p.m., by approximately 600 psi. Each of these anomalies was a sign that fluids were moving in the well. Despite observing those signs, the crew did not yet shut in the well.

Once he did, at 9:38 p.m., the drill pipe pressure shot back up. It increased by approximately 600 psi. Again, the increase was a serious anomaly.

By this point, rig personnel had observed several serious anomalies. Each was “a sign that fluids are moving” in the well.¹⁷⁸ Those anomalies should have “caused alarm.”¹⁷⁹ But there appears to have been no hint of alarm.

The crew actively investigated the anomalies and performed diagnostic interventions. But it appears that the crew did not perform the most basic kick detection intervention—a flow check. If they had done so, they would have directly seen flow coming out of the well and should have shut in the well.¹⁸⁰ The fact that the crew apparently did not perform a flow check suggests that Revette and Anderson either did not consider or had already ruled out the possibility of a kick.

Anderson thought “it would be a little bit longer” before they figured out the differential pressure and told Young that they probably wouldn’t need him for the cement job meeting for another couple of hours.¹⁸¹ According to Young, Anderson “wasn’t sure if they were going to need to circulate.”¹⁸² Anderson then left to go to the pump room.¹⁸³ Young also left at about the same time.¹⁸⁴ He ran into Holloway, who was coming down from the stand pipe manifold; they spoke for a couple of minutes and joked.¹⁸⁵ There was no sign of concern or hurry.¹⁸⁶

Not long afterward, Holloway was leaving the rig floor and ran into Curtis. Curtis was on his way to the drill shack. He was in no rush. Curtis and Holloway spoke for a few minutes.¹⁸⁷

Throughout this period of investigation, the drill crew did not communicate with the mudlogger about the anomaly.¹⁸⁸ Nor did they contact the senior toolpusher, OIM, or well site leader to ask for their help or to notify them that something was amiss.

Mud Overflow and Recognition of the Anomaly as a Kick

Sometime between 9:40 and 9:43 p.m., mud overflowed onto the rig floor, shot up to the top of the derrick, and poured down onto the main deck.¹⁸⁹ By about that time, drill pipe pressure had decreased by approximately 1,000 psi. At 9:41 p.m., the trip tank (pit 18) abruptly gained about 12 barrels in volume. The crew likely routed flow back to the trip tank intentionally to help diagnose whether the riser was static.¹⁹⁰ The gain showed that there was still flow from the well up the riser.

At about the same time, Anderson returned to the drill shack. At 9:41 p.m., he activated the blowout preventer’s (BOP’s) annular preventer.¹⁹¹ Drill pipe pressure began to increase (as it should when a well is shut in). By now, gas would already have been in the riser, expanding rapidly on its way to the surface. This may have made it more difficult to successfully activate the blowout preventer. In any case, even if the crew had successfully shut in the well, they should have expected flow from the well to continue at least until all of the gas in the riser had escaped.

Interviews and testimony after the blowout recount what happened next. Anderson called Vidrine to say the crew was getting mud back and had diverted flow to the mud gas separator and closed the annular.¹⁹² Curtis called Ezell and said: “We have a situation. The well is blown out. We have mud going to the crown.... [Anderson] is shutting it in now.”¹⁹³ Someone, perhaps Revette, called Andrea Fleytas on the bridge, said “We have a well control situation,” and hung up.¹⁹⁴ Vidrine started for the rig floor.¹⁹⁵ Ezell did the same.¹⁹⁶ Fleytas turned to Yancy Keplinger and yelled, “We’re in a well control situation.”¹⁹⁷ Keplinger radioed the *Damon Bankston*,

alongside the rig,¹⁹⁸ and told the vessel to disconnect and move off 500 meters: The *Horizon* was in a well control situation.¹⁹⁹

Although Anderson had activated the annular preventer, that action had not fully shut in the well. Instead of reaching the expected shut-in pressure (approximately 6,000 psi), drill pipe pressure plateaued at about 1,200 psi.²⁰⁰ In response, the drill crew either tightened the annular to create a seal or activated a variable bore ram.²⁰¹ At 9:47 p.m., drill pipe pressure increased dramatically. At this point, the well may have been shut in.²⁰²

At 9:48 p.m., pit 20 abruptly gained 12 barrels in volume. The data also show an increase in active pit volume (pits 9 and 10) and several upward spikes in flow-out. Flow from gas already in the riser might have been jostling the rig or otherwise overwhelming the rig's systems.²⁰³

The first explosion happened at 9:49 p.m. At the time, Anderson, Revette, and Curtis were in the drill shack, trying to get the well under control. Vidrine had been on his way to the drill shack but, seeing mud blowing everywhere,²⁰⁴ turned back toward the bridge.²⁰⁵ Ezell was at the doorway of his office, on his way to the rig floor. Clark and three others were in the pump room; they had just finished fixing the PRV.²⁰⁶ Keith was in the mudlogger's shack, apparently surprised that anything went wrong.²⁰⁷ Transocean OIM Jimmy Harrell was in the shower, with no knowledge that there had been a well control situation.²⁰⁸

Technical Findings

The data available to rig personnel showed clear indications of a kick.²⁰⁹ The change in direction of drill pipe pressure (9:01 p.m.) and its subsequent steady increases (9:01 to 9:08 p.m., 9:08 to 9:14 p.m.) should have been a cause for concern but apparently went unnoticed. Even after the drill crew noticed an anomaly (9:30 p.m.), they do not appear to have seriously considered the possibility that a kick was occurring.

The anomaly the rig crew noticed at 9:30 p.m. and discussed occurred before hydrocarbons had entered the riser and 10 to 13 minutes before mud appeared on the rig floor. If the rig crew had at all considered that a kick might be occurring, they had plenty of time to activate the blowout preventer.

Rig Activities Potentially Confounded Kick Detection

The crew on the *Deepwater Horizon* engaged in a number of concurrent activities during displacement of the riser. Each could have interfered with the data.²¹⁰

First, rig personnel were pumping seawater directly into the well from the sea chest. The crew had to pump water in from the sea chest for the displacement. But pumping it in directly from the sea chest to the rig pumps, thereby bypassing the pits, made it harder for the crew to monitor the pits. It created a non-closed-loop system that made it impossible to detect a kick by visually monitoring pit gain. Instead, pit monitoring required volumetric calculations. The crew could have, and should have, performed those calculations²¹¹—it was the rig crew's regular practice to do so²¹²—but there is no evidence that they did so here. They also could have routed the seawater through the active pit system before sending it down the well.²¹³ That approach would have preserved visual monitoring of pit gain.

Second, rig personnel sent returns overboard during the latter part of the displacement. Sending returns overboard was an inherent part of the displacement. But pumping it directly from the well overboard—bypassing the pits, Sperry-Sun flow-out meter, and both gas meters—eliminated the crew's ability to monitor the pits and the Sperry-Sun flow-out meter for kick indicators.²¹⁴ The crew could still monitor the well by using the Hitec flow-out meter and by physically checking the overboard line whenever the pumps were stopped. But there is no evidence that they did so. The crew could also have lined up the displacement so that it did not confound well monitoring by taking returns to the pits first and then channeling it overboard.

Third, rig personnel were using the cranes. From early in the displacement (about 8:20 p.m.) until the explosion, rig personnel were operating one or both of the cranes.²¹⁵ Crane movement can cause the rig to sway,²¹⁶ affecting the flow-out levels and pit volumes,²¹⁷ and “complicat[ing] kick recognition.”²¹⁸ Rig personnel can still detect kicks when there is rig sway, but the movement increases the level of background noise in the data and thereby reduces the minimum detectable kick sensitivity with respect to flow-out and pit volumes.²¹⁹ The crane movement was not necessary for the displacement. Rig personnel could have waited until the displacement was complete to engage in crane activity.

Fourth, rig personnel appear to have begun emptying the mud pits without first checking for pit gain. During the sheen test, the rig crew began emptying the active pits into reserve pit 6. Until that point, returns from the well had been flowing to pit 6. The problem is, the crew does not appear to have measured the volume in pit 6 before emptying the active pits into it. This suggests that the crew was not mathematically comparing the actual volume of returns to the expected volume of returns to verify that there had been no gain. The apparent reason that rig personnel emptied the active pits was to prepare for cleaning them.²²⁰ It was unnecessary to clean the active pits, or even empty them in preparation for cleaning, during the displacement.

Fifth, rig personnel were emptying the sand traps into the pits.²²¹ Sand traps separate sand from mud. After a while, they fill up with clean mud. When that happens, the crew empties the mud from the sand traps into the pits. Emptying the sand traps was not problematic by itself. The problem was that the crew emptied them into the active pit system and thereby complicated pit monitoring. The crew could have simplified pit monitoring by using the active pit system to monitor the volume of fluid returning from the well and routing mud from the sand traps to a reserve pit instead.

Sixth, rig personnel were emptying the trip tanks during the displacement. It appears that the crew had to do so at this point in the displacement process.²²² It also appears that the rig's plumbing forced the crew to route flow-out from the trip tank past the flow-out meter.²²³ This flow added to pit gain and flow-out, making both figures higher than they would have been otherwise. The crew could nevertheless have preserved pit monitoring and flow-out monitoring if they calculated the effect of emptying the trip tank in this manner, but there is no evidence that they did so. Alternatively, the crew could have stopped displacing the riser while they emptied the trip tanks.

Kick Detection Instrumentation Was Mediocre and Highly Dependent on Human Factors

The data sensors on the rig had several shortcomings. First, the system did not have adequate coverage. For example, there was no camera installed to monitor returns sent overboard and no

sensor to indicate whether the valve sending returns overboard was open or closed. Therefore, while video monitoring of flow was possible when returns went to the pits, it was not possible when returns went overboard.

Second, some of the sensors were not particularly accurate. For example, electronic sensors for pit volumes can be unreliable, so much so that the crew would sometimes revert to using a string with a nut to measure pit volume change.²²⁴

Third, the sensors often lacked precision and responded to movement unrelated to the state of the well. For example, a fluctuation in flow-out might result from crane activity on the rig.²²⁵ These shortcomings can result in rig personnel not receiving quality data and, furthermore, discounting the value of the data they do receive.

The data display systems also had notable limitations. There were no automated alarms built into the displays. Rather, the system depended on the right person being in the right place at the right time looking at the right information and drawing the right conclusions.²²⁶ Although the systems did contain audible and visual alarms, the driller was required to set them manually.²²⁷ He could also shut them off. Manually setting and resetting alarm thresholds is a tedious task and not always done. For example, there is typically no alarm set for flow-in and flow-out because the pumps stop and start so often that the alarms would trigger too frequently.²²⁸

There was also no automation of simple well monitoring calculations. For example, if the displacement is set up as a non-closed-loop system, and rig personnel want to keep track of volumes, they must perform the calculation by hand (return volume – (pump strokes × volume per pump stroke)). If the rig is emptying its trip tank while taking returns, and rig personnel want to disaggregate the two activities, they must perform the subtraction by hand. Each of those calculations could easily be automated and displayed for enhanced real-time monitoring.

There was also no advance planning or real-time modeling of expected pressures, volumes, and flow rates for the displacement. Although well flow modeling has been employed in post-explosion analysis,²²⁹ there was no comparable modeling technology in place for real-time analysis.²³⁰

Finally, the displays themselves sometimes made fluctuations in data hard to see.²³¹ Indeed, in post-explosion reports and presentations, BP has consistently chosen to rotate the vertical Sperry-Sun log and enlarge it so that viewers can understand the data from April 20.

These limitations made well control monitoring unnecessarily dependent on human beings' attentions and abilities.

Management Findings

One of the most important questions about the Macondo blowout is why the rig crew and mudlogger failed to recognize signs of a kick and did not diagnose the kick even when they shut operations down to investigate a well anomaly. The Chief Counsel's team finds that a number of management failures, alone or in combination, may explain those errors.²³²

BP, Transocean, and Sperry Drilling Rig Personnel Exhibited a Lack of Vigilance During the Final Displacement

The evidence suggests that BP, Transocean, and Sperry-Sun personnel on the rig were not sufficiently alert to the possibility that a loss of well control might occur during the final displacement. There are several reasons why this might have been the case. First, kicks are not commonly associated with the temporary abandonment phase of well operations. In a 2001 study of 48 deepwater kicks in the Gulf of Mexico, the vast “majority of kicks occurred during drilling operations.”²³³ By contrast, only one kick “occurred in association with a well abandon[ment] operation.”²³⁴

Second, confidence in barriers, particularly tested barriers, can make rig personnel overconfident in the well's overall security. A satisfactory negative pressure test generally confirms that the well is secure and that hydrocarbons will not flow into the well during riser displacement operations. Once rig personnel deemed the Macondo negative pressure test a success, they may have believed that a kick was no longer a realistic hazard.²³⁵ Investigations of a 2009 North Sea blowout and a 2009 Timor Sea blowout found that rig personnel were “blinkered” by a successful negative pressure test or drew an “unwarranted level of comfort” from the presence of a barrier.²³⁶ Both attitudes “reflected and influenced a lax approach to well control.”²³⁷

Third, end-of-well activities tend to be marked by a hasty mindset and loss of focus.²³⁸ This can result simply from a desire to finish and move on, particularly when a well has been difficult to drill (like Macondo).²³⁹ Rig personnel have noted in post-blowout interviews that “[a]t the end of the well sometimes they think about speeding up.”²⁴⁰ This may be because “everybody goes to the mindset that we're through, this job is done...everything's going to be okay.”²⁴¹

Together, these factors appear to have contributed to reduced well monitoring vigilance, diminished sensitivity to anomalous data, delayed reactions, a failure to undertake routine well monitoring measures (like flow checks and volumetric calculations), and a willingness to perform rig operations in a manner that complicated well monitoring.

Such a lack of vigilance was particularly surprising at this well. Given the risk of a poor bottomhole cement job and the fact that the final displacement would severely underbalance the well, rig management—and the well site leader in particular—should have treated the displacement as a critical operation and personally monitored the data.²⁴²

Transocean Personnel Lacked Sufficient Training to Recognize That Certain Data Anomalies Indicated a Kick²⁴³

Several times during the evening of April 20, data anomalies indicated that hydrocarbons were flowing into the well.²⁴⁴ Despite noticing the anomalies—and taking time to discuss them—the rig crew did not recognize that a kick was under way.

Earlier in the evening, during the negative pressure test, hydrocarbons flowed into the well. Pressure anomalies signaled the kick. But rig personnel did not heed those signals.

During the final displacement, the pressure anomalies reappeared. Although some went unnoticed, the rig crew did recognize an anomaly at 9:30 p.m. and shut the pumps down to investigate. Over the next 10 minutes or so, the crew watched the drill pipe pressure visibly

increase—steadily at first (9:30 to 9:35 p.m.) and then, after they attempted to bleed it off, rapidly (9:38 p.m.)—even though the pumps were off. They also saw an anomalous kill line pressure. Each indicator was “a sign that fluids are moving” in the well—in other words, a sign of a kick.²⁴⁵

To a skilled observer, those anomalies “would have caused alarm.”²⁴⁶ But there appears to have been no hint of alarm. Instead, the rig crew spent at least 10 minutes “discussing” the “anomaly,” “scratching their heads to figure what was happening.”²⁴⁷ Even in retrospect, Transocean’s internal investigator asserts that it was “a very strange trend,” “a confusing signal,” explained only after “months of work.”²⁴⁸

Transocean leaves open the possibility that its rig crew “did not have the experience” or training to interpret pressure anomalies during the negative pressure test.²⁴⁹ If true, then the crew likely did not have sufficient training or ability to interpret the recurrence of those anomalies during the final displacement.

Transocean further states that its crew relied on the operator (BP) to make a final assessment of anomalies during the negative pressure test.²⁵⁰ But when those anomalies reappeared during the displacement, the rig crew did not notify BP rig personnel and ask for their help in interpreting the data.²⁵¹

BP and Transocean Allowed Rig Operations to Proceed in a Way That Inhibited Well Monitoring

BP and Transocean management on the rig allowed simultaneous operations without adequately ensuring that those operations would not complicate or confound well monitoring.²⁵²

Simultaneous activities can interfere with well monitoring in several ways. First, they can influence data that are used to monitor for kicks (for example, by altering fluid levels) and thereby obscure signals of a kick.²⁵³ Second, they can make it more difficult to interpret data because rig personnel may attribute data anomalies to rig activities instead of a kick. Third, even when simultaneous operations are necessary, such as when changing the lineup of pipes and valves or fixing a mud pump, they can distract rig personnel who would otherwise be monitoring the well.²⁵⁴ Rig personnel can reduce these difficulties by identifying relevant rig activities, calculating or otherwise predicting their probable effect, and communicating any expected effects to well monitoring personnel. Rig management should ensure that *someone* is watching the screens at all times, despite ongoing activities.

BP, Transocean, and Sperry Drilling Rig Personnel Did Not Properly Communicate Information

Insufficient communication, both prior to and during the final displacement, affected risk awareness and well monitoring on the *Deepwater Horizon*.

BP did not adequately inform Transocean about the risks at the Macondo well, particularly the risks of a poor bottomhole cement job.²⁵⁵ Transocean argues that if BP had done so, its crew might have demonstrated “heightened awareness.”²⁵⁶ But it is unlikely that this particular communication failure compromised kick detection; the crew would probably have dismissed warnings about cement risks anyhow after the successful negative pressure test.

BP and Transocean did not do enough to ensure that rig personnel were aware of the objectives, procedures, and hazards of the riser displacement operation.²⁵⁷ The individuals conducting the pre-job meetings should have emphasized that BP's temporary abandonment procedures would leave only a single barrier in the well besides the BOP and would produce an unusually underbalanced well.²⁵⁸ They should have warned against complacency stemming from the negative pressure test and emphasized that tested barriers can fail.

The pre-job meetings should also have informed well monitoring personnel that certain kick indicators such as pit gain and flow-out would be compromised or unavailable during the planned operations. Well monitoring personnel should have been told that, as a result, they would need to perform volumetric calculations to keep track of pit gain, pay special attention to other parameters (such as drill pipe pressure), and conduct visual flow checks whenever the pumps were stopped.²⁵⁹ In addition, to facilitate well monitoring, those personnel should have been given a pump schedule for the different phases of the displacement, along with guidance regarding how much deviation from that schedule should be considered anomalous.²⁶⁰

Transocean and Sperry Drilling personnel did not communicate effectively about the displacement operation.²⁶¹ And the BP well site leader did not play a sufficiently active role in ensuring such communication.²⁶² Communication broke down between the drill crew and the mudloggers on several occasions. For example, when rig personnel announced early on April 20 that they would be pumping mud to a supply boat, Cathleenia Willis (the mudlogger on shift) told Clark she was concerned that this would limit her ability to monitor pit gain.²⁶³ Clark said he would address the matter but never got back to Willis.²⁶⁴ Keith reported after the explosion that he was concerned that simultaneous activities would complicate monitoring but never expressed those concerns to others.²⁶⁵ The drill crew repeatedly failed to inform Keith of various activities that influenced well monitoring data.²⁶⁶

Even after the Transocean crew shut down the pumps to investigate an anomaly, they did not inform the Sperry Drilling mudlogger, senior Transocean personnel, or the BP well site leader of the anomaly or ask for their help in resolving it.²⁶⁷

The Chief Counsel's team cannot conclude that any one of these problems contributed to the failure to detect the kick. But together they suggest a communication breakdown that made kick detection more difficult. Knowledge of ongoing rig activity "is essential to accurate interpretation of the data."²⁶⁸ Absent that knowledge, it is difficult to ascertain whether anomalous data are benign or problematic.²⁶⁹

While BP and Transocean Management Were Taking Steps to Improve Well Monitoring, These Steps Had Not (Yet) Improved Kick Detection on the *Deepwater Horizon*

BP

BP recognized that well control was critically important to its operations. In a 2009 Major Hazard Risk Assessment, the company identified "Loss of Well Control" as first among the two "major accident risks" in drilling and completions operations.²⁷⁰

BP specifically gave the *Deepwater Horizon* a mid-range risk rating for loss of well control²⁷¹ and acknowledged the potentially severe consequences of a well control failure: "Catastrophic

health/safety incident” with the “potential for 10 or more fatalities,” “extensive” and “widespread” damage to sensitive environments, “\$1 billion - \$5 billion” in financial impact, “severe enforcement action,” government intervention, and “[p]ublic and investor outrage.”²⁷²

To address this risk, BP checked to ensure that all drilling and completions workers had well control training and certification, developed tools to further assess the risk (“BowTie diagrams,” “Risk Mitigation Plans,” “Asset-specific” risk assessments, a “Barrier Assessment Tool”), and emphasized that risk management in this area would be “under continual review.”²⁷³ The company also planned to evaluate the effectiveness of barriers with each rig’s team and train personnel in the new well control response guide.²⁷⁴

BP understood the risks presented by less severe well control events too. An April 14, 2010 presentation to the drilling and completions Extended Leadership Team noted that half of all nonproductive time in the company’s offshore drilling sector was the result of “downhole problems (wellbore instability, losses, gains, tight hole) and stuck pipe.”²⁷⁵ The presentation continued: “Post analysis of the...incidents clearly indicates that in most cases[,]...events could have been prevented or decisions influenced if the drilling data that is already generally available had been appropriately presented and analysed.” That is, “early warning indicators were usually present albeit invisible in the mountain of data.”²⁷⁶ Therefore, as Macondo senior manager David Sims stated, downhole problems were “low hanging fruit” for decreasing nonproductive time.²⁷⁷

Reviews conducted in late 2007 and early 2008 similarly showed that “the quality of monitoring, detection and reaction to downhole hazards during drilling operations” was “variable.”²⁷⁸ In response, BP planned to develop a program to facilitate Efficient Reservoir Access, the “ERA Advisor.” This ambitious program would monitor data in real time onshore, generate expert and automated advice in response to that data, and use new software and sensors to track and diagnose the data.²⁷⁹ The program’s goal was to “ensure the *right information is in the right place at the right time*.”²⁸⁰ It would focus, however, on monitoring data during the drilling of the well (not end-of-well activities).²⁸¹ BP’s Extended Leadership Team developed and endorsed the ERA in 2009; initial pilot testing of the first stage of the system was to begin in the fourth quarter of 2010.²⁸²

Even before planning its ERA program, BP contracted Sperry-Sun to relay rig data to its Houston offices. But despite recognizing the risks associated with poor well monitoring and the usefulness of onshore assistance, BP did not monitor this data for well control purposes. Even though each of its working rigs had an operations room with dedicated Sperry-Sun data displays,²⁸³ BP typically used these rooms only for meetings and the data were “not ever monitored.”²⁸⁴ Thus, before BP implemented its ERA Advisor system, it failed to take the interim step of ensuring that someone onshore was monitoring the data systems it already had in place.

This is surprising in light of the fact that BP was particularly concerned about well monitoring at Macondo. Less than two months before the blowout, on March 8, 2010, the Macondo well took a kick.²⁸⁵ The kick occurred while the rig was drilling.²⁸⁶ The “well kicked for 30 minutes before the trends were obvious enough.”²⁸⁷ The Transocean drill crew and Sperry Drilling mudlogger—indeed, the very same Revette, Curtis, Clark, and Keith—observed a gain in flow-out, a slow gain in the pits, a decrease in equivalent circulating density (ECD), and an increase in gas content.²⁸⁸ The drill crew stopped the pumps, performed a flow check, and shut in the well.²⁸⁹ The situation soon went “from bad to worse.”²⁹⁰ There were “[m]ajor problems on the well.”²⁹¹ The pipe was stuck. BP ultimately had to sever the pipe and sidetrack the well.²⁹²

After the event, BP involved its in-house Totally Integrated Geological and Engineering Resource team (the “TIGER team”), to conduct an engineering analysis, and (on March 18) distributed a “lessons learned” document to its Gulf of Mexico drilling and completions personnel.²⁹³ BP recommended that its personnel “evaluate the entire suite of drilling parameters that may be indicative of a shift in pore-pressure” (including gas, flow-out, and flow checks), “ensure that we are monitoring all relevant [pore pressure] trend data,” “have [pore pressure] conversations as soon as ANY indicator shows a change,” “no matter how subtle,” and “*be prepared to have some false alarms and not be afraid of it.*”²⁹⁴ The “lessons learned” document also specified that “[b]etter lines of communication, both amongst the rig subsurface and drilling personnel, and with Houston office needs to be reestablished. Preceding each well control event, subtle indicators of pore pressure increase were either not recognized, or not discussed amongst the greater group.”²⁹⁵

In addition, BP wells team leader John Guide initiated several conversations to address the rig’s response to the kick, which he thought was “slow and needed improvement.”²⁹⁶ Guide specifically instructed the BP well site leaders to “up their game.”²⁹⁷ He spoke with Transocean and Sperry Drilling personnel about “tighten[ing] up wellbore monitoring.”

The goal of Guide’s conversations and of the TIGER team’s involvement was to maintain heightened attentiveness “for the remainder of the Macondo well,”²⁹⁸ up to the point when the *Horizon* unlatched its BOP and left.²⁹⁹ Evidently, the team fell short of that goal. As Guide conceded after the incident, the Macondo team’s heightened attentiveness to well monitoring lasted all the way up until, apparently, the negative pressure test.³⁰⁰ This is likely because BP’s focus, once again, was on monitoring data during the drilling of the well (not end-of-well activities).³⁰¹

Transocean

Transocean also recognized the importance of well control. In a 2004 Major Accident Hazard Risk Assessment, the company gave *Deepwater Horizon* a 5B risk rating for reservoir blowout,³⁰² meaning that there was a “Low” likelihood of a blowout occurring, but if one did occur, the event would have “Extremely Severe” consequences:³⁰³ “Multiple personnel injuries and/or fatalities,” “Major environmental impact,” and “Major structural damage and possible loss of vessel.”³⁰⁴ As prevention and mitigation measures, Transocean listed (among other things) well control procedures, training of drill crew, and instrumentation indicating well status.³⁰⁵

As discussed in greater detail in [Chapter 5](#), despite those concerns, Transocean did not inform the *Deepwater Horizon*’s crew of lessons learned from an earlier well control event on another rig. On December 23, 2009, Transocean barely averted a blowout during completion activities on a rig in the North Sea. Rig personnel were in the process of displacing the wellbore from mud to seawater.³⁰⁶ They had just completed a successful negative pressure test, and they had lined up the displacement in a way that inhibited pit monitoring.³⁰⁷ During the displacement, a critical tested barrier failed, and hydrocarbons came up the wellbore, onto the drill floor, and into the sea.³⁰⁸

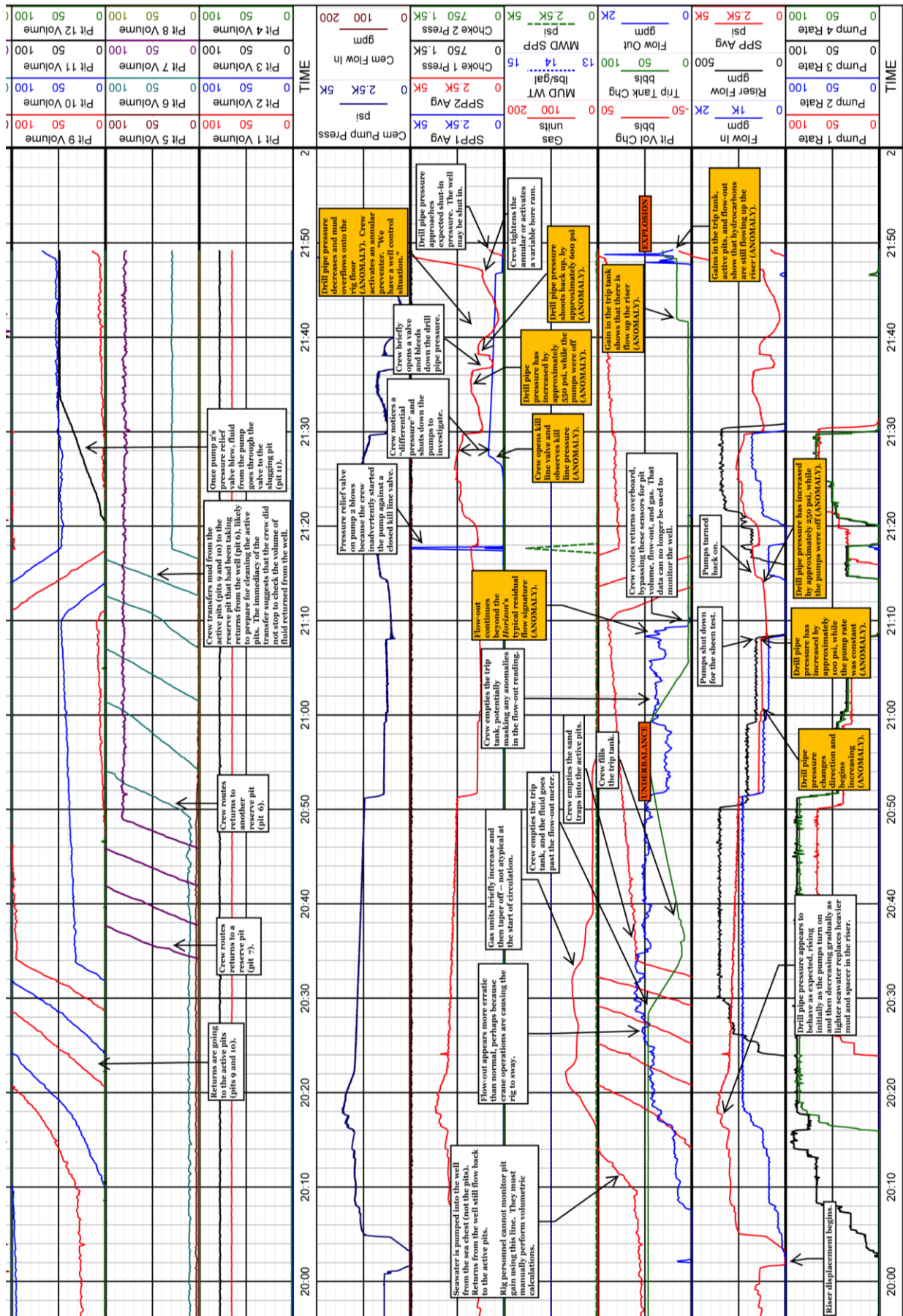
The incident differed from Macondo in some respects: It occurred during the completion phase of the well, not drilling or temporary abandonment, and the failed barrier was a mechanical valve, not cement.³⁰⁹ But the incident was identical to Macondo in crucial respects:

- the rig crew underbalanced the well while displacing mud to seawater;

- a successful negative pressure test “blinkered” the crew and produced an improper “change in mindset”;
- the crew conducted displacement operations in ways that inhibited pit monitoring; and
- the crew discounted kick indicators by attributing them to other occurrences on the rig.³¹⁰

Transocean nevertheless failed to effectively share and enforce the lessons learned from that event with all relevant personnel. The company held two conference calls and distributed an advisory for its North Sea personnel only. It also posted a shorter advisory about the event on its electronic documents platform—accessible fleetwide—but it did not alert crews of the advisory’s existence. Indeed, there is no evidence that anyone on or affiliated with the *Deepwater Horizon* knew of the North Sea incident or read any of its lessons prior to the Macondo blowout. 🔥

Figure 4.7.12. Last two hours of Sperry-Sun data.



Saritha Komatireddy Tice