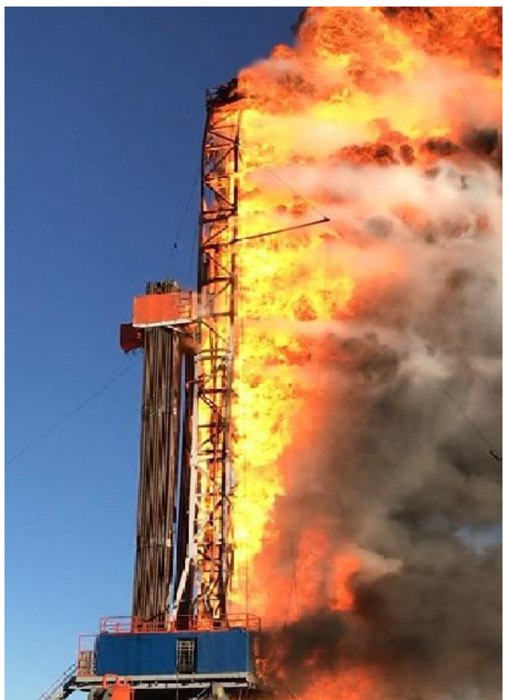
Gas Well Blowout and Fire at Pryor Trust Well 1H-9



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FDA, Inc.

Investigation Report

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KEY ISSUES:

- Poor Barrier Management
- Underbalanced Operations Performed Without Proper Planning, Procedures, or Needed Equipment
- Signs of Influx Either Not Identified or Inadequately Responded To
- Alarm System Off
- Flow Checks Not Conducted
- Gaps in Safety Management System
- Driller's Cabin Design
- BOP Could Not Close Due to Burned Hydraulic Hoses
- Lack of Safety Requirements by Regulation

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Acronyms and Initialisms

API	American Petroleum Institute
APL	Annular Pressure Loss
bbl	barrel
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blowout Preventer
CCPS	Center for Chemical Process Safety
CSB	U.S. Chemical Safety and Hazard Investigation Board
ECD	Equivalent Circulating Density
ft	feet
gpm	gallons per minute
HCR	High Closing Ratio
HP	Hydrostatic Pressure
HWDP	Heavy Weight Drill Pipe
IADC	International Association of Drilling Contractors
LCM	Lost Circulation Material
MD	Measured Depth
MOC	Management of Change
MPD	Managed Pressure Drilling
ppg	pounds per gallon
Reg	Regular
RMO	Red Mountain Operating
RP	Recommended Practice
TOFS	Time Out for Safety
TVD	True Vertical Depth
UBO	Underbalanced Operations

Glossary

The terms listed below are ***emphasized*** in the report at first usage.

Accumulator – Equipment storing high-pressure hydraulic fluid, which is used to function the blowout preventer. The accumulator is equipped with handles to close the individual devices (e.g., annular preventer, blind rams, pipe rams) on the blowout preventer.

Annular Pressure Loss (APL) – The frictional losses in the annulus when mud is being circulated through a well. The frictional losses cause the pressure exerted on the walls of the wellbore to be higher when mud is pumped down the drill string and back up the annulus than when the well is static.

Annular Preventer – Part of the blowout preventer stack. It is a device using an elastomeric seal that can seal around a variety of sizes of drill pipe or other equipment, as well as the open hole.

Annulus – The space between the wellbore walls or casing and the outside of the drill string.

Barrel – The standard measurement of volume in the drilling industry. A barrel equals 42 U.S. gallons of fluid.

Barrier (Well Control) – A type of protection to prevent a hydrocarbon blowout. The primary well control barrier for this drilling operation was the drilling fluid column in the well exerting sufficient hydrostatic pressure to prevent formation fluids from entering the wellbore. The secondary well control barrier for this operation was human detection of a gas influx by workers on the rig, including the driller and company man who is also frequently in the driller's cabin, and subsequent human-activated closure of the blowout preventer.

Blind Rams – Part of the blowout preventer stack. Two rams close to seal the well when no drill pipe is in the well.

Blowout – The uncontrolled release of gas, oil, or other well fluids from a well.

Blowout Preventer (BOP) – A stack of devices installed at the wellhead (blind rams, pipe rams, and annular preventer) to prevent or stop the escape of fluid from the well.

Bottom Hole Assembly (BHA) – The bottom part of the drill string consisting of various equipment including the drill bit.

Calculated Fill Tripping Method – Tripping method used during the tripping operation out of the horizontal section of Pryor Trust Well 1H-9. The Calculated Fill tripping method involved stopping all mud flow from the well by closing the flow line isolation valve with the pressure-containing rotating head installed. A calculated volume of mud was periodically pumped into the well with the intent to replace the calculated volume of the drill pipe removed by turning on and off the trip tank pumps.

Casing – large-diameter steel pipe inserted into a wellbore and cemented into place. Casing protects weak formations from potentially damaging pressures produced by the drilling mud.

Casing Shoe – The bottom of the casing string.

Choke Line – Piping attached to the blowout preventer stack through which drilling mud and influx fluids (e.g., gas) can be removed from the well.

Company Man – RMO's representative on the drilling rig, who supervised the drilling operation.

Continuous Fill Tripping Method – Common tripping method used in overbalanced tripping operations. Mud is pumped continuously from the trip tank into the well and excess return flow is routed through the open flow line and back to the trip tank.

Displacement Volume – The equivalent volume of liquid occupied by a solid object.

Dog House – The steel room on the rig floor from which the driller controls the drilling operation. Also called the "driller's cabin."

Drill Bit – Equipment on the bottom of a drill string used to cut through rock to drill a well.

Drill Pipe – Piping through which mud is pumped during drilling operations. The piping is rotated while drilling to rotate the drill bit, allowing the drill bit to cut through rock.

Drill String – The length of drill pipe used to lower and rotate the drill bit to drill the well. Mud is pumped down through the drill string and up through the annulus during drilling and circulating operations.

Driller's Cabin – The steel room on the rig floor from which the driller controls the drilling operation. Also called the "dog house."

Drilling Engineer – The RMO-contracted engineer who designed the well plan and monitored the progress of the drilling operation. The drilling engineer worked from Oklahoma City.

Equivalent Circulating Density (ECD) – The equivalent heavier mud density of a static fluid that would exert the same pressure of a circulating fluid in the wellbore.

Flare – Equipment that ignites gas to safely dispose of it. "Flare" also refers to the flame produced by the burning of gas by the flare equipment.

Flow Check – An operation performed to identify if formation fluids have entered the well. The drilling crew halts all operations to monitor if mud flows from the well when no mud is pumped into the well. Observed flow during a flow check could be an indication of formation fluid in the well.

Flow Line – The piping through which mud coming out of the top of the wellbore is routed to mud-treating equipment. The flow line is an inclined, gravity-flow pipe. The Patterson Rig 219 flow line was equipped with a sensor that indicated the quantity of flow (as a percentage) flowing through the flow line. The flow sensor was on the flow line downstream of the orbit valve.

Flow line Isolation Valve – An isolation valve in the flow line. "Orbit valve" is the term commonly used to describe the isolation valve by Patterson and RMO.

Formation – A distinctive geological layer of rock.

Formation Pressure – The pressure of fluids (e.g., natural gas, oil, or water) within a geological formation. Also called "pore pressure."

Gain – An increase in volume in the mud pits or trip tank, which could be indicative of a formation fluid influx into the well.

Gas Unit – API unit of measurement of gas concentration.

Hitch – The 14-day period worked by the drilling rig crews, which was followed by 14 days off.

Hydrostatic Pressure – The pressure produced by the column of fluid in the wellbore. Hydrostatic pressure is a function of the density and height of the fluid.

Influx – The uncontrolled flow of formation fluid (natural gas, oil, or water) into the wellbore from the formation. Also called a "kick."

Joint – One individual drill pipe piece. Joints of drill pipe are about 30 feet long.

Kick – The uncontrolled flow of formation fluid (natural gas, oil, or water) into the wellbore from the formation. Also called an "influx."

Kill Line – Piping through which mud can be pumped into the well by the mud pumps to control or circulate out a kick.

Lag Depth – The depth at which cuttings and entrained gas in the mud returning to surface originated.

Lost Circulation Material (LCM) – Material used during mud losses into a formation to plug areas in the wellbore wall where mud flows from the well into the formation.

Managed Pressure Drilling (MPD) – An "adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of [managed pressure drilling] to avoid continuous influx of formation fluids [1, p. 3]." In managed pressure drilling operations, the wellbore pressure is continuously managed through applied surface backpressure, fluid density, fluid level, circulating friction, or various combinations of these.

Mast – The large structure that supports the load of the drill pipe and equipment used during drilling.

Measured Depth (MD) – The length of the wellbore, as measured by the length of drill pipe used to drill the well.

Mud – Drilling fluid pumped down the drill string and up through the annulus during drilling operations. Mud can be oil or water based. The mud used for the Pryor Trust 1H-9 drilling operation was diesel oil-based.

Mud Gas Separator – Equipment used to separate entrained gas from drilling mud.

Mud Pits – Large steel tanks that hold drilling mud. The mud pits for Patterson Rig 219 were equipped with level sensors/indicators for the driller and other rig workers to determine fluid volume in each of the mud pits.

Mud Pumps – Large, high-pressure, positive displacement pumps used to pump mud down the drill string and back to the surface while drilling. Mud pumps are also used to circulate kick gas out of a well by pumping mud through the kill line.

Mudlogger – Geologist at the rig site who analyzed the rock cuttings in the mud returning to surface during drilling to build a geological log of the wellbore.

Off Driller's Side Cabin – Structure on rig floor opposite the driller's cabin that holds various equipment.

Orbit Valve – A commonly used term by Patterson and RMO to describe the flow line isolation valve.

Overbalanced Drilling – Conventional drilling operation in which the hydrostatic pressure of the drilling fluid is maintained above the formation pressure to prevent formation fluids from entering the wellbore.

Pill – A finite volume of fluid used for a special application in the wellbore, for example plugging an area in the wellbore where mud losses are occurring ("lost circulation material pill"), or for adding hydrostatic pressure to the wellbore ("weighted pill").

Pill Tank – Tank from which a "pill" is pumped into the well. The Patterson Rig 219 pill tank was equipped with a level indicator.

Pipe Rams – Part of the blowout preventer stack. Two steel rams with a half-circle hole on the edge meet inside the well to seal around drill pipe.

Pore Pressure – The pressure of fluids (e.g., natural gas, oil, or water) within a geological formation. Also called "formation pressure."

Possum Belly – Tank into which the flow line discharges. From the possum belly, the fluid is fed to the shale shakers.

Ram – A closing component of the blowout preventer stack.

Rig Floor – The elevated platform on which the rig crew conducts drilling operations.

Rotating Head (Rotating Control Device) – A rotating pressure-sealing device that seals around the drill string and is designed to hold wellbore pressure. The rotating head installed on Rig 219 could hold up to 650 psi at static conditions.

Shale Shakers – Vibrating screens used to remove rock cuttings from drilling mud.

Slips – A device used on the drilling rig floor to grip drill string when the upper portion of the drill string is disconnected from the portion of the drill string in the well.

Slug – A dense volume of mud pumped into the drill pipe. Its hydrostatic pressure is used to push mud downward and out of the bottom of a drill string. Because of its higher density, it results in the fluid level in the drill pipe to be some distance below the surface, facilitating "tripping" the pipe from the well. The slug allows drill pipe being removed during a "tripping" operation to be empty of mud (pulled "dry"). When, instead, the drill pipe segments removed from a drill string contain mud (pulled "wet"), the mud from the removed drill pipe segment empties out when the segment is disconnected from the drill string. In wet tripping operations (mud is inside the drill string), rigs often use a "mud bucket," which surrounds the drill string to collect mud from removed drill pipe segments for re-use. Wet tripping is slow and unpleasant work.

Slug Tank – Tank from which a "slug" is pumped into the well. The Patterson Rig 219 slug tank was equipped with a level indicator.

Stand – Three connected joints of drill pipe. A stand of drill pipe is about 90 feet long.

Swabbing – Reduction in pressure in a wellbore while removing pipe from the well, usually due to fluid friction between the mud and the upward-moving drill string. The reduction in pressure could cause the well to become underbalanced and allow formation fluids to enter the wellbore.

Tool Joint – The threaded end of a joint of drill pipe.

Tour – The 12-hour shift worked by rig workers. Tour is commonly pronounced "tower."

Trip Tank – A tank that holds a smaller volume of mud in comparison with the mud pits. The trip tank is used to keep the well filled with mud during tripping operations. Typically, mud is continuously circulated from the trip tank into the well, with return fluid going back to the trip tank. The driller monitors the trip tank volume while tripping to monitor if the right amount of mud is added to the well to replace the volume of pipe removed from the well, so that the hydrostatic pressure in the well is maintained. The Patterson Rig 219 trip tank was equipped with a level indicator.

Trip Tank Pumps – Centrifugal pumps that pump mud from the trip tank into the well during tripping operations.

Tripping – The act of removing or inserting drill pipe from or into a well. For example, drill pipe could be tripped out to change the drill bit.

True Vertical Depth (TVD) – The vertical distance from a location in the well to the surface.

Underbalanced – When a wellbore pressure (produced by mud density, mud level, circulating pressure, and including the effects of any gas in the annulus) is less than an adjacent formation pressure.

Underbalanced Operations (UBO) – Drilling operations in which the wellbore pressure is intentionally kept below the formation pressure so that formation fluids are brought to the surface.

Well – The hole drilled by the drill bit to reach the oil or gas reservoir. "Well" and "wellbore" are used interchangeably in this report.

1 Executive Summary

On January 22, 2018, a blowout and rig fire occurred at Pryor Trust 0718 gas well number 1H-9, located in Pittsburg County, Oklahoma. The fire killed five workers, who were inside the driller's cabin on the rig floor. They died from thermal burn injuries and smoke and soot inhalation. The blowout occurred about three-and-a-half hours after removing drill pipe ("tripping") out of the well.

The cause of the blowout and rig fire was the failure of both the primary barrier—hydrostatic pressure produced by drilling mud—and the secondary barrier—human detection of influx and activation of the blowout preventer—which were intended to be in place to prevent a blowout. Contributing to the loss of barriers were many factors including:

- Underbalanced drilling was performed without needed planning, equipment, skills, or procedures, thus nullifying the planned primary barrier to prevent gas influx;
- Tripping was performed out of the underbalanced well, which allowed a large amount of gas to enter the well;
- The driller was not effectively trained in using a new electronic trip sheet, which is used to help monitor for gas influx;
- Equipment was aligned differently than normal during the tripping operation, leading to confusion in interpreting the well data which caused rig workers to miss indications of the gas influx;
- Surface pressure was not identified two separate times before opening the BOP during operations before the blowout, when there was evidently pressure at the surface of the well. This non-identification of surface pressure contributed to the gas influx not being identified;
- A weighted pill intended to overbalance the well was apparently miscalculated. After pill placement, the well was still underbalanced;
- Both the day and night driller chose to turn off the entire alarm system, contributing to both drillers missing critical indications of the gas influx and imminent blowout. The alarm system also was not effectively designed to alert personnel to hazardous conditions during different operating states (e.g., drilling, tripping, circulating, and surface operations) and would have sounded excessive non-critical alarms during the 14 hours leading to the blowout, which likely led to the drillers choosing to turn off the alarm system;
- Key flow checks to determine if the well was flowing were not performed before the incident. Drilling rig workers performed very few of the company-required flow checks during the drilling of well 1H-9 and the previous well. The drilling contractor did not effectively monitor the implementation rate of its flow check policy;
- The drilling contractor did not test its drillers' abilities in detecting indications of gas influx through, for example, simulated pit gains. The absence of testing drillers' influx detection skills—a safety-critical aspect of well control—might have contributed to both drillers not detecting the significant gas influx leading to the blowout;

- The operating company did not specify the barriers required during operations, or how to respond if a barrier was lost. This contributed to the performance of underbalanced operations that the drilling rig and its crew were not equipped or trained to perform; and

- The safety management system in place was not effective for managing safe rig operations. There is also no drilling-specific regulatory standard governing onshore drilling safety.

In addition, the victims had no safe escape route from the driller's cabin (dog house) once the drilling mud and gas ignited. The workers were effectively trapped once the fire started.

The blowout preventer also failed to close when its activation was attempted after the fire started. The CSB determined the BOP did not function likely because the control hoses that supplied hydraulic fluid to the BOP to function the rams had burned in the fire and leaked the hydraulic control fluid, soon depleting the accumulator stored pressure to the point the blowout preventer could not be closed.

Based on the findings from this incident, the CSB issues recommendations to the Occupational Safety and Health Administration (OSHA), the American Petroleum Institute (API), Patterson-UTI Drilling Company, LLC, Red Mountain Operating, LLC, the International Association of Drilling Contractors (IADC), Pason Systems Inc., National Oilwell Varco, and the State of Oklahoma, to help prevent future catastrophic blowouts during onshore oil and gas drilling operations.

2 Background

Red Mountain Energy, LLC was the lease holder, Red Mountain Operating, LLC (RMO) was the operator of the well, and Patterson-UTI Drilling Company, LLC (Patterson) was the drilling contractor hired by RMO. Well number 1H-9 was the second well drilled on the Pryor Trust 0718 well pad, the first being well number 2H-16.[a] Patterson Rig 219 drilled both wells at Pryor Trust 0718.

2.1 Red Mountain Energy and Red Mountain Operating

Red Mountain Energy, LLC is an investment company founded in 2013, focusing on upstream oil and gas projects [2]. Red Mountain Energy has five partners and six employees.

Red Mountain Operating, LLC (RMO) was established in 2015. It has five partners and no employees. RMO contracted the ***drilling engineer*** and ***company man*** roles. Pryor Trust 2H-16 was the first well drilled under the direction of RMO, and Pryor Trust 1H-9 (incident well) was the second well drilled under its direction.

2.2 Patterson-UTI

Patterson-UTI Drilling Company, LLC (Patterson) is a land-based drilling company. It was established in 2001 through the merging of Patterson Energy and UTI Energy [3]. As of March 2019, Patterson had 171 active land-based rigs in the United States and Canada [4].

[a] Well 2H-16 is a horizontal gas well drilled to a true vertical depth of 7,700 feet and a total measured depth of 15,940 feet. Well 2H-16 was drilled through the Woodford formation.

2.3 Business Relationship Between Red Mountain Operating and Patterson-UTI

RMO was responsible for developing the well plan, including the well design, determination of casing depth and mud weights, and daily drilling and operational decisions. Patterson was contracted as an "independent contractor," and was to perform drilling operations "under the direction, supervision and control"[a] of RMO. Patterson was responsible for providing drilling equipment, drilling crew members, and performing the drilling operation. Under the direction of RMO, Patterson was also responsible for carrying out well control operations.

3 Introduction to Drilling, Personnel, and Terminology

3.1 Drilling Rig

Wells are drilled to extract oil and gas from reservoirs below the earth's surface. For land operations, a drilling rig sits on the ground directly on top of the well to perform the drilling operations. A photo of a Patterson drilling rig is shown in Figure 1. The tall structure on the drilling rig is called the ***mast***, which supports the weight of the drill pipe and drilling tools. On the drilling rig floor is the ***driller's cabin***, commonly called the ***dog house***, where the driller controls drilling operations. Directly beneath the rig floor is the ***blowout preventer*** (BOP) stack—a type of safety-critical equipment that contains devices including sets of large ***rams*** that can shut in the well to prevent a ***blowout***.

3.2 Drilling Personnel

Many different people worked on Rig 219 or in support of the drilling operation, from various companies. Descriptions of the key personnel on and off the rig are below:

- Two Patterson drilling crews worked for Rig 219 on each ***hitch***. The two crews worked two different ***tours***. Tour 1 worked daily from 6:00 am to 6:00 pm, and Tour 2 worked daily from 6:00 pm to 6:00 am. Each Patterson drilling crew included the driller, derrickhand, motorhand, and floorhands. There was also one rig manager (commonly called the "toolpusher"), working portions of each tour.[b] The two crews had been on-hitch since January 10, 2018.

- Personnel called company men also worked on the rig. They were RMO's contracted representatives on the drilling rig, responsible for directing, supervising, and controlling the drilling activities. Two company men worked each hitch, assigned to either Tour 1 or Tour 2.

- A drilling engineer, contracted by RMO, designed the drilling program and monitored the drilling progress. The drilling engineer worked from Oklahoma City.

- Other specialized personnel were on or near the rig, including directional drillers, mudloggers, mud engineers, and other contracted personnel supplying equipment, fluids, or services.

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[a] Quoted from contract between RMO and Patterson.

[b] Patterson requires drillers and rig managers to take IADC WellSharp well control training every two years. The International Association of Drilling Contractors (IADC) WellSharp program is a well control training and assessment program that teaches how to prevent, detect, and respond to well control events [67]. All Rig 219 drillers and rig managers on-hitch at the time of the incident were up to date with their required well control training. One RMO company man was up to date with his well control training. The other RMO company man's well control training expired on December 3, 2017.

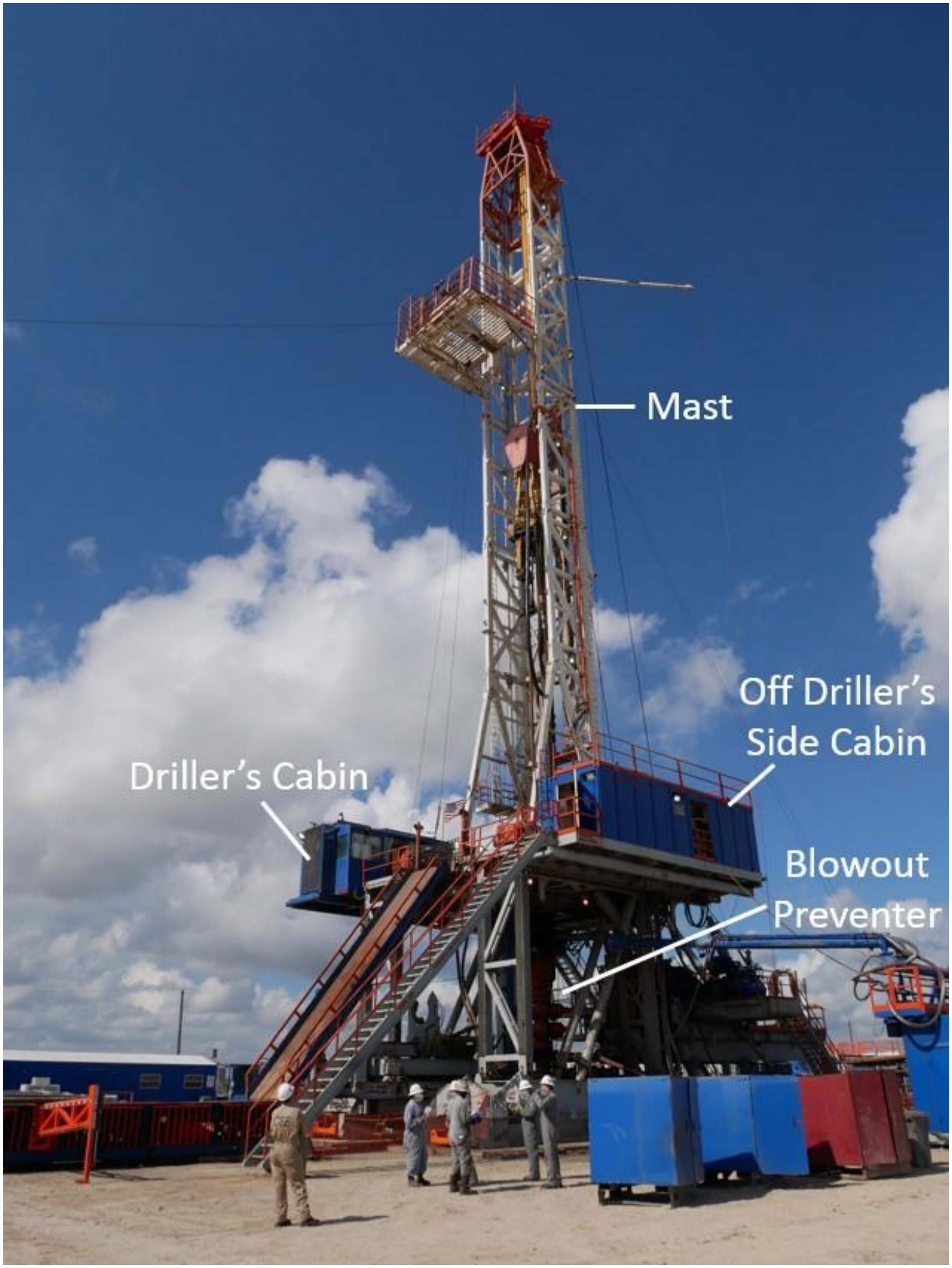

Figure 1. Photo of a Patterson drilling rig

3.3 Well Control

Oil and gas reservoirs are porous rock ***formations***. The pore spaces contain fluid (natural gas, oil, and/or water) naturally pressurized at the ***formation pressure*** or ***pore pressure***. In conventional drilling operations, drilling crews and well planners work to prevent these formation fluids from entering the wellbore and reaching the surface in an uncontrolled manner for the safety of the drilling crew. A hydrocarbon ***influx***, or ***kick***, into a well can lead to a dangerous blowout when the kick is not detected and controlled.

During drilling, ***mud***, which can be oil- or water-based, is pumped down the drill pipe and up through the well ***annulus***. One purpose of the mud is to bring drill cuttings (rock fragments) to the surface (Figure 2). The mud used for Pryor Trust well 1H-9 was diesel oil-based.

The column of drilling mud inside the wellbore is also a ***barrier***—or a type of protection—used to prevent formation fluids such as gas from entering the wellbore. This is achieved by maintaining the pressure inside the wellbore above the formation pressure by using the ***hydrostatic pressure*** produced by the column of drilling mud in the well (Figure 3). As long as the column of drilling mud inside the well exerts a pressure on the formation that is higher than the pore pressure, gas or other fluids in the formation should not flow into the well [5, p. 20].

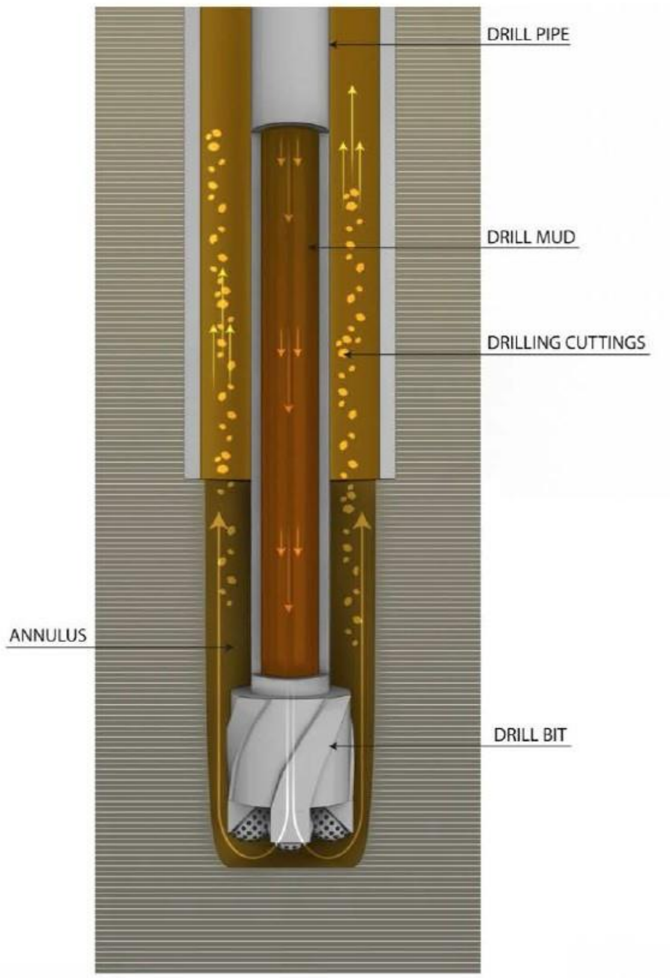

*Figure 2. Depiction of drilling operation. During drilling, mud is pumped down the drill pipe, through the **drill bit**, and then back up to the surface through the annulus.*

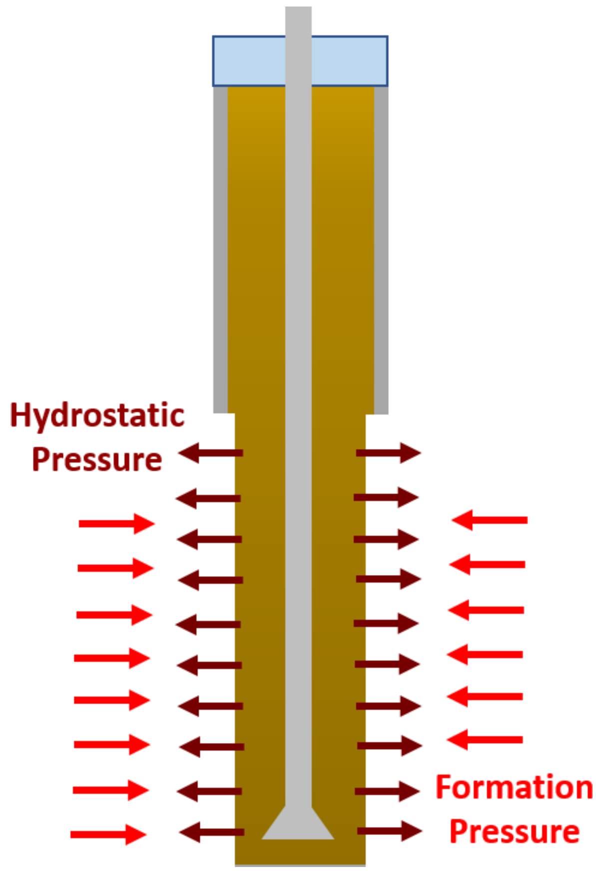

Figure 3. During conventional drilling operations, the hydrostatic pressure produced by the column of mud in the wellbore is intended to be higher than the formation pressure, preventing gas from entering the well.

The hydrostatic pressure at the various depths in the wellbore is determined by both the height of the mud column and the density of the mud. A higher density mud results in a higher hydrostatic pressure, and a lower density mud results in a lower hydrostatic pressure. When the pressure in the wellbore is too high, the formation can be fractured and result in losses of drilling mud into the formation. When the pressure in the wellbore is too low, fluids in the formation can enter the wellbore (e.g., gas influx) (Figure 4). In conventional drilling operations, also called ***overbalanced drilling***, a mud density is chosen within a range intended to keep formation fluids out of the well without fracturing any formations.

If formation fluids enter the well, indications at the surface can alert drilling crews to the influx. An influx can be detected in a well by monitoring for an increased mud volume (a ***gain***) in the ***mud pits***, or for increased flow coming out of the well through the ***flow line*** (Figure 8). During drilling operations, drilling crews periodically halt all operations and perform a ***flow check*** to monitor whether mud flows from the well when no mud is being pumped into the well. Observed flow during a flow check could be an indication of formation fluid in the well. Pit gains and increased surface flow can be caused by gas influx into the well or expansion of gas already inside the wellbore as the gas moves upward. A secondary barrier—the detection of influx by rig workers and activation of the blowout preventer—can then lead to preventing a blowout by containing the well.

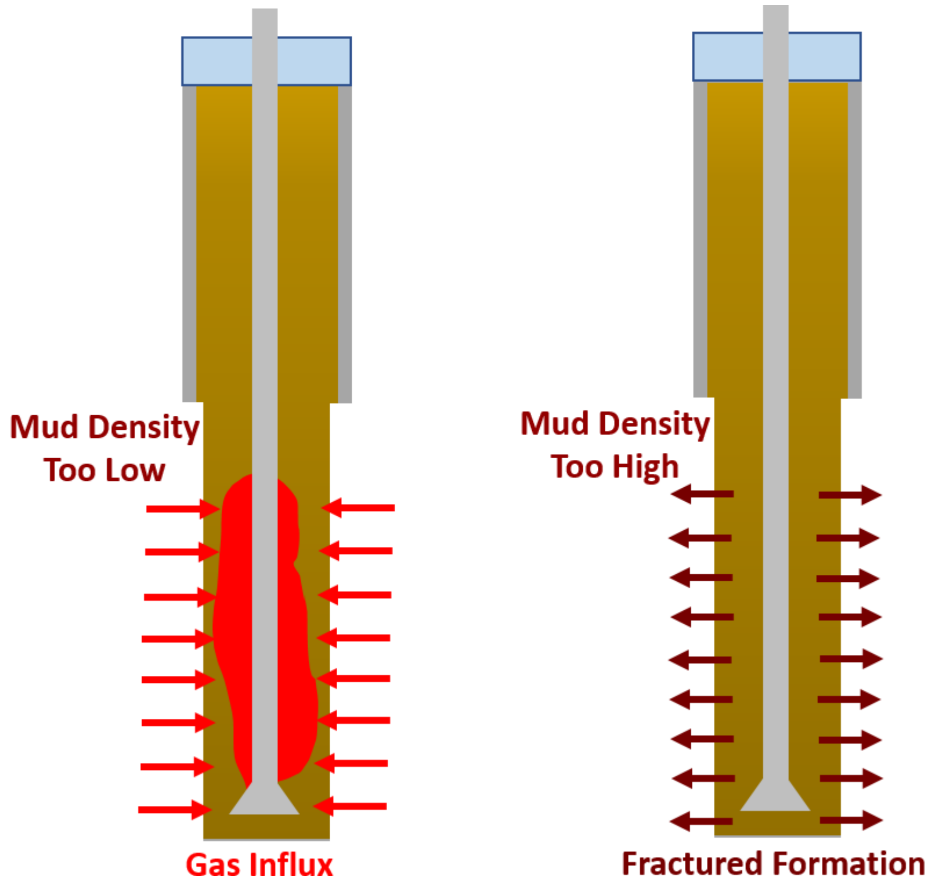

Figure 4. The schematic on the left shows that when the mud density is too low, the well pressure can be below the formation pressure and gas can enter the well. The schematic on the right shows that when the mud density is too high, the high pressure in the wellbore can fracture the rock formation, leading to mud losses.

3.4 Equivalent Circulating Density (ECD) and Annular Pressure Loss (APL)

When mud is pumped down the drill string and back up the annulus, the pressure exerted on the walls of the wellbore is higher than when the well is static (i.e., when no mud is being pumped). The additional pressure is needed to push the mud and make it flow back to the surface, thereby overcoming the frictional resistance to flow in the annulus from the bottom of the drill pipe to the surface of the well. The frictional loss in the annulus is called ***annular pressure loss (APL)***. Figure 5 illustrates how the bottom hole pressure varies from when the well is static and when the mud pumps are circulating mud through the wellbore. It is helpful to relate the higher pressure in the well when the well is being circulated to an equivalent heavier mud weight that would exert the same pressure if the well were static. This is called the ***equivalent circulating density (ECD)*** [6, p. 11] (Figure 6).

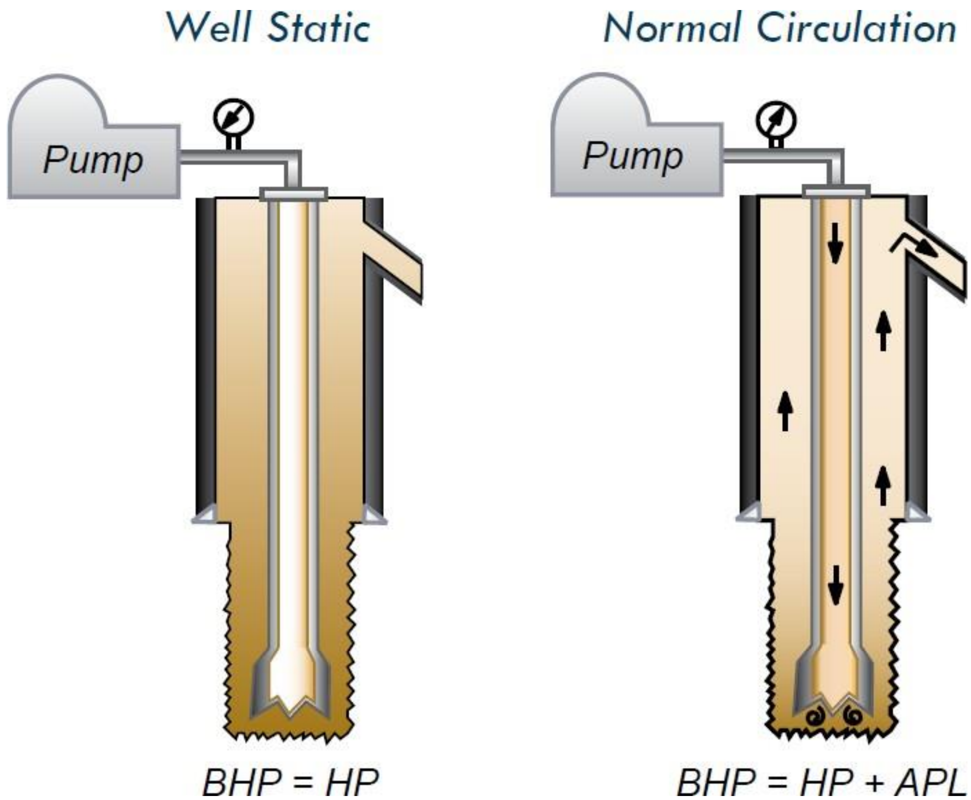

Figure 5. Depiction of differences in bottom hole pressure (BHP) when the well is static and when circulating the well. HP is "hydrostatic pressure." APL is "annular pressure loss." Source: Well Control School [7, p. 1.10]

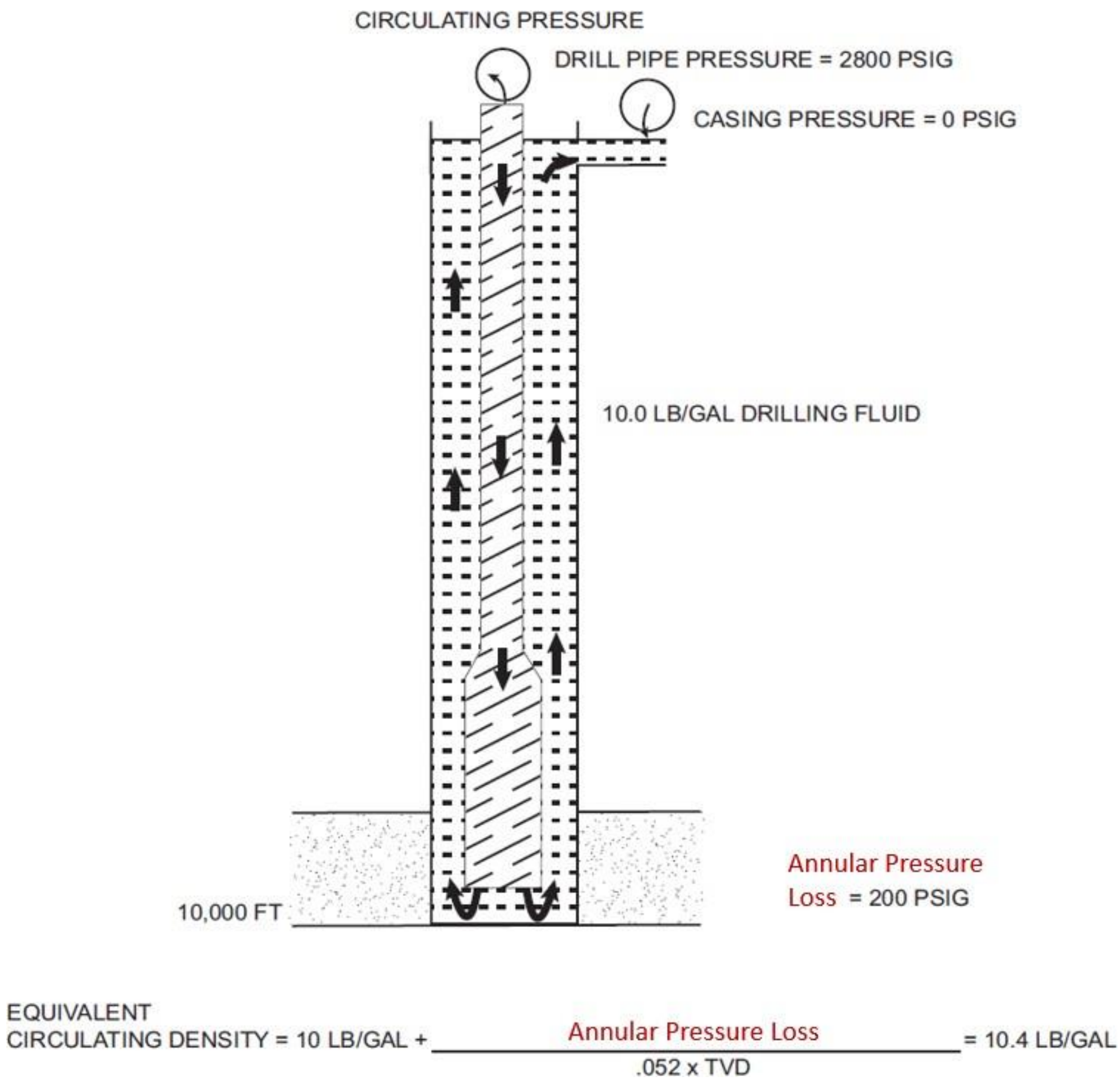

Figure 6. Illustration of Equivalent Circulating Density from API RP 59. "TVD" is "True Vertical Depth," which in the figure is 10,000 ft. The red text was added by CSB to keep terminology consistent through this report. Source: API RP 59 [6, p. 13].

3.5 Other Drilling Techniques

Conventional drilling is overbalanced drilling, where the pressure in the wellbore is kept above the formation pressure by the mud alone. There are other drilling techniques: ***underbalanced operations (UBO)*** and ***managed pressure drilling (MPD)***. In underbalanced operations, the wellbore pressure is intentionally kept below the formation pressure so that formation fluids are brought to the surface [8, p. 12]. Managed pressure drilling is an "adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of [managed pressure drilling] to avoid continuous influx of formation fluids [1, p. 3].” In managed pressure drilling operations, the wellbore pressure is continuously managed through applied surface backpressure, fluid density, fluid level, circulating friction, or combinations of these [8, p. 8]. These alternative drilling techniques can be used, for example, to minimize formation fracturing, and they require specialized planning, equipment, and skills.

4 Well Background

Well 1H-9, the incident well, was a horizontal well with a planned ***true vertical depth (TVD)*** of 7,615 feet and a ***total measured depth (MD)*** of 17,799 feet. Well 1H-9 targeted the Woodford formation, which contained natural gas.[a]

The top 2,300 feet of the well was constructed with cemented steel pipe called intermediate ***casing***, used to stabilize that portion of the well. The intermediate casing had an outside diameter of 9.625 inches, with an inside diameter of 8.921 inches. The open hole section, the portion of the well below 2,300 feet, was 8.75 inches in diameter.

The Patterson crew began drilling Well 1H-9 on January 11, 2018. By Sunday, January 21, 2018, the well had been drilled to a measured depth of 13,435 feet. A depiction of the well appears in Figure 7. A flow diagram of Patterson Rig 219 and its surface equipment is in Figure 8.

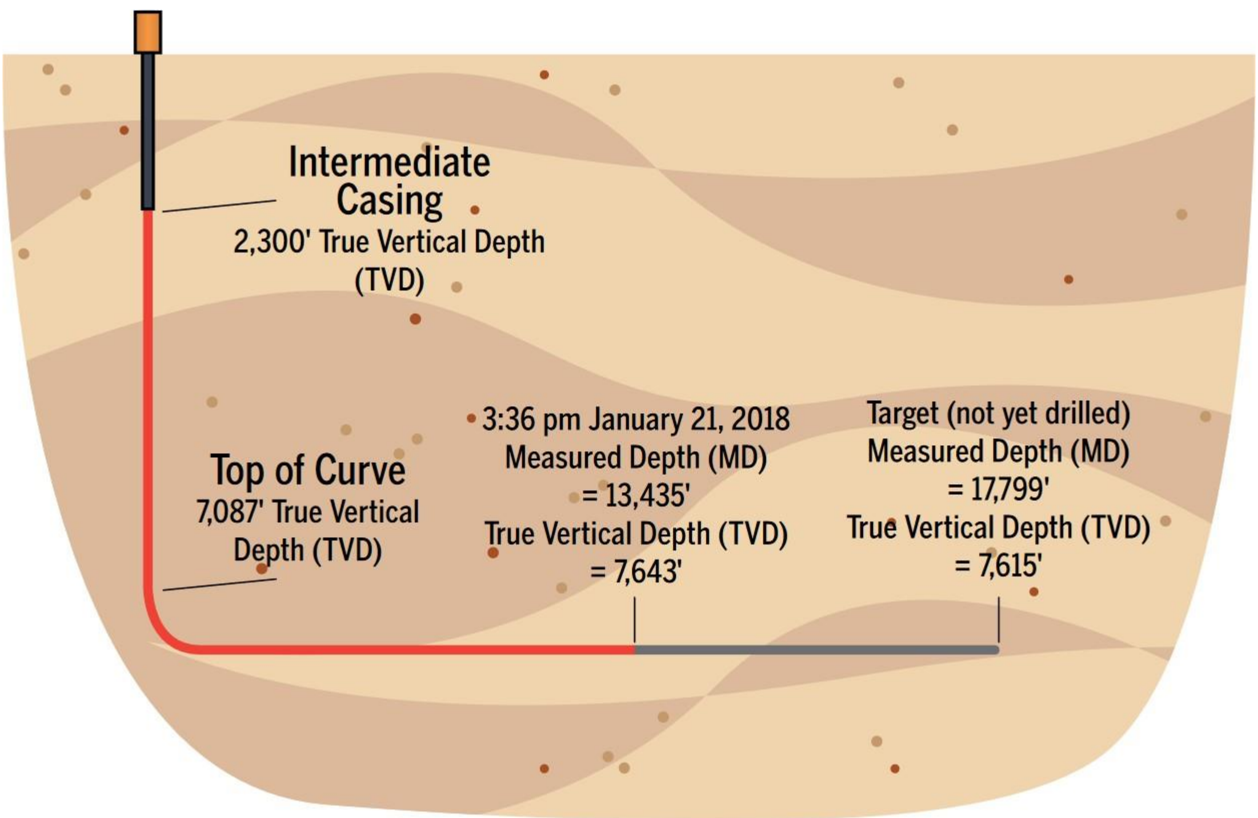

Figure 7. Pryor Trust 0718 1H-9 well schematic. The formation zones depicted are an artist’s rendition and do not depict the true locations of the geological formations.

[a] The natural gas in the Woodford formation was in the gas phase (i.e., not a liquid).

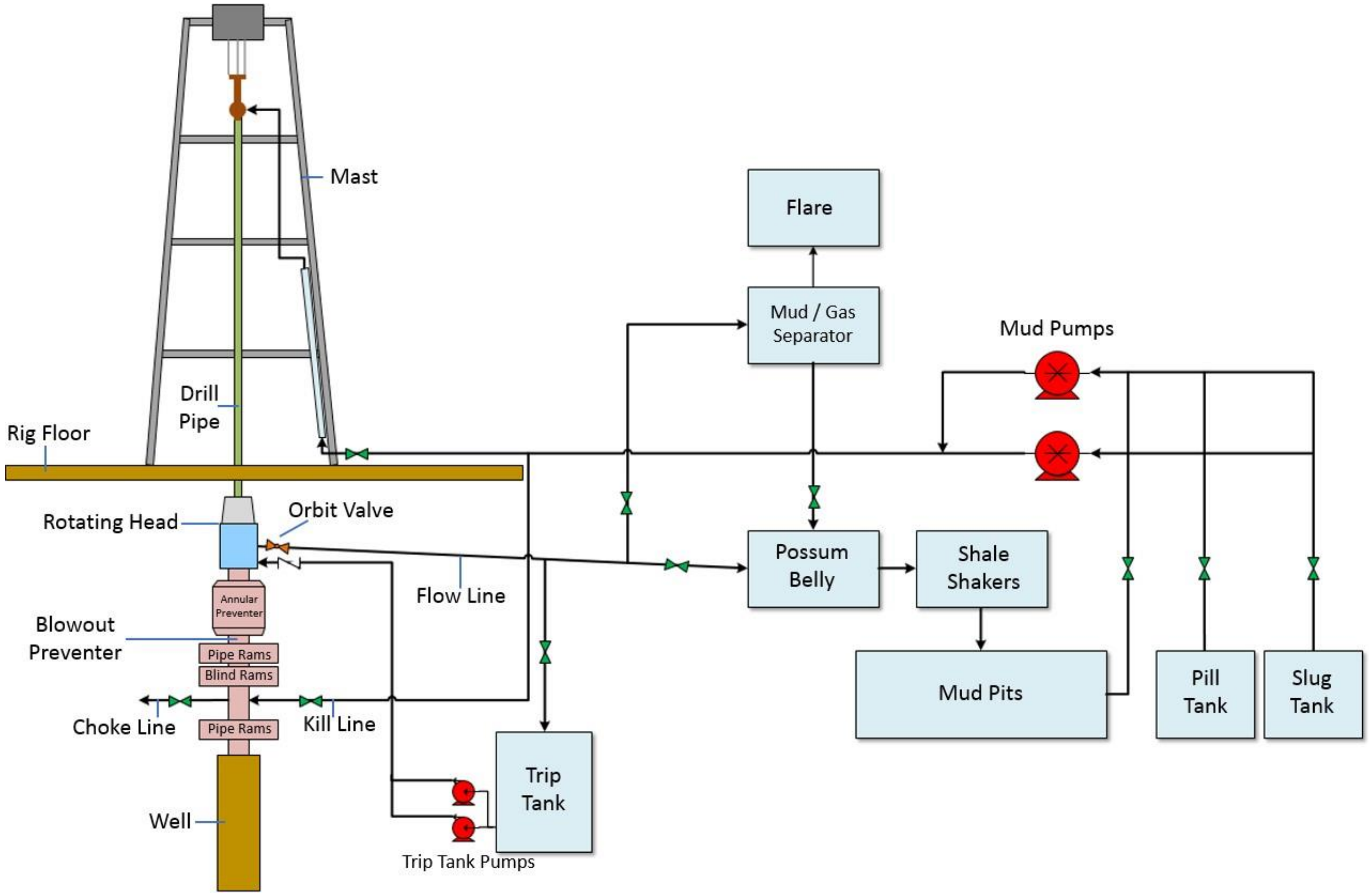

Figure 8. Flow diagram of rig and surface equipment.

5 Incident Description

On Sunday, January 21, 2018, at 6:30 am, while drilling at about 13,000 feet MD in the horizontal section of the well, gas began entering the wellbore.[a] At 7:18 am, the ***mudlogger*** sent a video to the RMO geologist showing his test results of the rock cuttings returned to surface. He had added hydrochloric acid to the rocks, which caused the rocks to form bubbles as the hydrochloric acid reacted with the rocks. The mudlogger told the CSB that the bubbling (degassing) effect occurs in rocks containing calcium carbonate. RMO had been targeting non-calcareous[b] shale, and the mudlogger told the CSB that the test result indicated that they had exited the Woodford formation and had entered new carbonaceous rock, which he thought might have been a different formation called the Mayes formation.

At 7:30 am, gas started to reach the surface of the well, showing as elevated ***gas units*** in the mud.[c] The gas in the mud caused mud to spit out of the possum belly, covering with mud a portion of the rig, the mud pits, and other equipment. After 11:00 am, the crew aligned the mud piping so that the mud was routed to the ***Mud Gas Separator***, and by 11:11 am the flare activated (Figure 9). Witnesses reported the flame from the flare at times was 20-30 feet high and at one time may have been 40-50 feet high.

The crew continued drilling, continuously flaring, until 3:30 pm, when they stopped drilling (bit depth at 13,435 feet MD) so that they could remove the drill pipe from the well to change the drill bit.[d] RMO representatives planned to also switch to a different motor that would allow them to get back into the Woodford formation.

The Patterson drilling crew began circulating the well by pumping mud down the drill string and back up the annulus to the surface. Enough mud was pumped to perform two-and-a-half "bottoms-up" circulations,[e] which replaced the mud in the annular space with fresh mud two-and-a-half times. At the end of the bottoms-up circulations, gas was still in the mud returning to the surface, causing the flare to continuously activate. This continuous flaring, which occurred between 11:11 am and about 6:30 pm, indicates that the mud weight could not prevent formation gas from entering the wellbore and that the well was likely underbalanced.[f]

During this time, the drilling engineer, the Tour 1 company man, and the Tour 2 company man discussed how to remove the drill pipe from the well.

The well profile at this point is shown in Figure 10. Post-incident analysis of the well data shows that the 11,000 feet of uncased, open wellbore included three areas where some amount of gas had entered the well while drilling, as interpreted from measured gas units during the drilling operation and the flaring at the surface that occurred on January 21.

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[a] At 7:29 am, gas units rose at the surface. The ***lag depth*** at that time was 13,090 feet MD, indicating the gas originated at a depth of 13,090 feet. The bit was drilling at a depth of 13,090 feet MD at 6:29 am.

[b] Calcareous shales contain calcium carbonate.

[c] The gas content reached 2,050 units.

[d] The entire lateral section had been drilled on a single bit and drilling speed, also called rate of penetration (ROP), had begun to decrease. The Operator (RMO company man) requested the drill bit change so that ROP could be maintained.

[e] A text message timestamp confirms that the flare was still activating at 6:21 pm, which had been after about two-and-a-half "bottoms up" circulations.

[f] The CSB considered whether the flare might have been produced by "drilled gas," which is gas contained in the drilled rock cuttings. The CSB concluded that the flare likely was not produced by drilled gas because during the two-and-a-half bottoms up circulations, most, if not all, drilled gas would be circulated out of the well. The flaring at 6:21 pm indicates the well was likely underbalanced.

Figure 9. Video still of flare at 11:10 am on January 21, 2018.

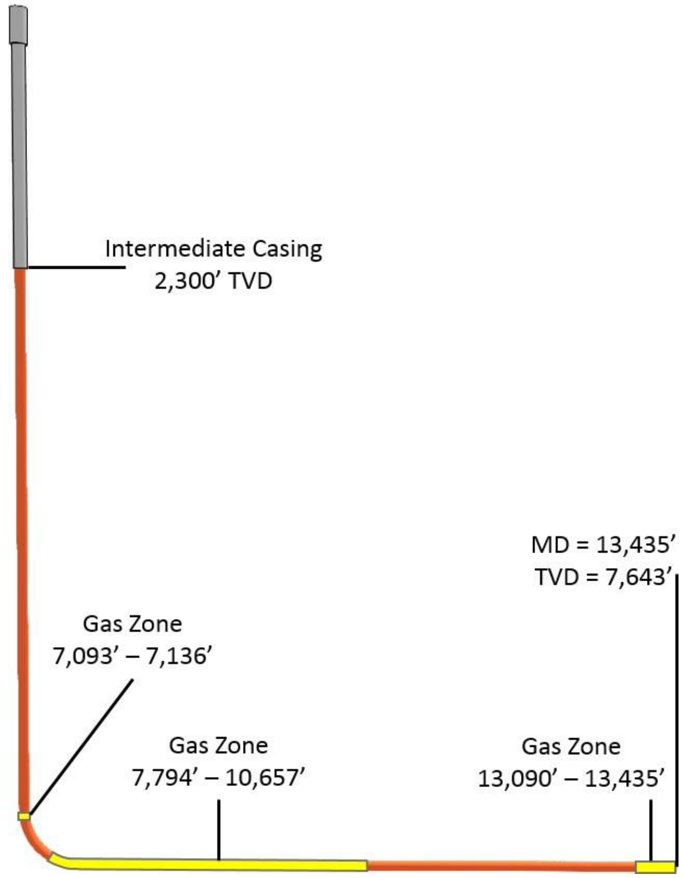

Figure 10. Areas where gas entered the wellbore while drilling.

5.1 Tripping Out of the Well from the Lateral Section to the Top of the Curve

The process of pulling the drill pipe out of the well, for example, to change the drill bit or BHA, is referred to as ***tripping***.

5.1.1 Determination of Tripping Procedure

When tripping drill pipe from a well, it is important that drilling crews replace the volume of drill pipe removed from the well with mud. Properly replacing the drill pipe ***displacement volume*** with mud maintains the level of mud in the well, which maintains the hydrostatic pressure.

In overbalanced tripping operations, drilling rigs typically pump mud continuously from the trip tank into the well and route the excess return flow through the open flow line and back to the trip tank. This is called a ***Continuous Fill tripping method*** (Figure 11). The trip tank holds a smaller volume of mud in comparison with the mud pits used during drilling, allowing for accurate monitoring for the correct mud volume going into the well to replace the drill pipe displacement volume. During Continuous Fill, the fluid column in the well is the primary well control barrier. The status of the barrier is continuously monitored by assessing volume changes in the trip tank while tripping.

For the tripping operation out of the lateral section of the well, the drilling engineer, the Tour 1 company man, and the Tour 2 company man decided that the Patterson crew would trip out drill pipe using a ***Calculated Fill*** method (also referred to by workers as a "Force Fill" or "Volumetric Fill" method).[a]

The Calculated Fill tripping method involved stopping all mud flow from the well by closing the ***flow line isolation valve*** (commonly called the ***orbit valve*** by Patterson, the drilling engineer, and the company man) with the pressure-containing ***rotating head*** installed. The plan was then to periodically pump a calculated volume of mud into the well with the intent to replace the calculated volume of the drill pipe removed by turning on and off the trip tank pumps (Figure 12). For example, for five drill pipe stands removed, the driller would need to pump 3.2 ***barrels*** of mud into the well to replace the drill pipe. The drilling engineer communicated to the CSB that, using this method, there was extra protection against gas influx into the well by, if needed, allowing surface pressure to build against the closed orbit valve and rotating head. The thinking was that if the well did flow, there would be no outlet for the mud, so this would keep the well contained.

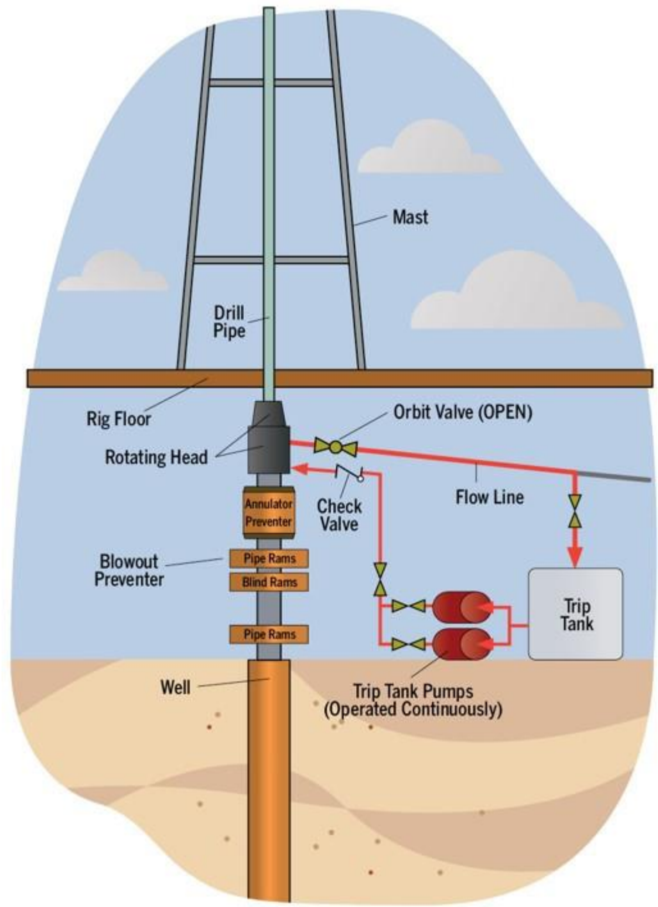

Figure 11. Typical equipment configuration during Continuous Fill tripping method.

Calculated Fill is not a standard tripping method used in conventional, overbalanced drilling. It was chosen because both the Tour 2 company man and drilling engineer had used it on other wells; the company man had frequently used it at a different company over the previous five years.

No Patterson crewmembers on that night crew had ever performed Calculated Fill tripping before, and neither Patterson nor RMO had a written procedure for it. No crewmembers were formally trained on Calculated Fill tripping, and neither Patterson nor RMO performed a Management of Change for the change in the tripping method from the typical Continuous Fill (Section 6.8).

Some Patterson rig crewmembers were uncomfortable about tripping without first increasing the mud weight to return the well to an overbalanced condition. An RMO representative and the drilling engineer communicated to the CSB that there was some concern that a higher mud weight could risk breaking down the formation, which led to their decision to use Calculated Fill. In part because no process was in place to ensure that Calculated Fill tripping was evaluated for barrier effectiveness or consistency with rig equipment, procedures, and training (Section 6.8), the Patterson crew agreed to perform Calculated Fill tripping.

[a] The drilling engineer communicated the plan to use the Calculated Fill tripping method to the company man, and the company man directed the crew to perform the tripping method.

5.1.2 Analysis of Trip Out to The Top of The Curve

The drilling crew stopped circulating the well at 6:30 pm. The flare went out at some point between 6:21 pm and 6:47 pm, but the CSB could not determine from witness interviews whether the flare went out while circulating or after changing equipment configuration to prepare for tripping, which would have prevented gas from reaching the flare. The crew then pumped a weighted ***slug*** into the drill pipe before tripping out of the hole.[a]

By 6:47 pm on January 21, 2018, the driller closed the orbit valve in preparation to trip out of the well using Calculated Fill.[b]

At 6:48 pm, the crew began tripping drill pipe out of the well, from 13,337 feet MD. The driller and the company man monitored the well data during the tripping operation, and the drilling engineer periodically looked at the data remotely from his home.

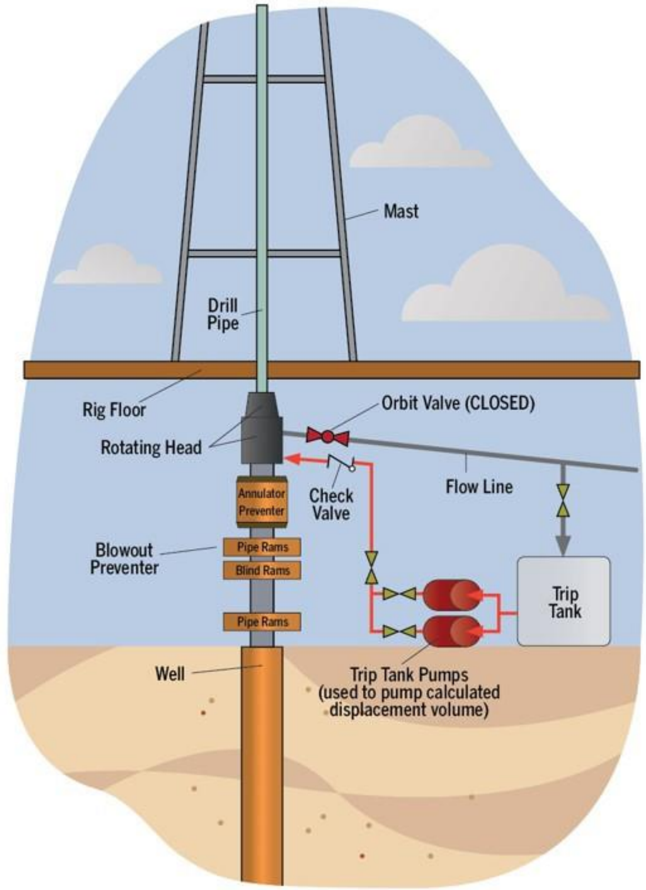

Figure 12. Equipment configuration during Calculated Fill tripping method

Discussed below, by the time the drill bit reached the top of the curve, 20 barrels of mud less than the calculated drill pipe displacement volume had been pumped into the well. While the well appeared to be filled to the surface, the volume discrepancy is an indication that gas had entered the well, occupying this 20-barrel portion of the drill pipe displacement volume (Sections 5.1.2.1 and 5.1.2.2). The company man and drilling engineer were aware the well did not take proper fill, but the full extent of the discrepancy might not have been known because the driller had difficulties with the electronic trip sheet used to track the calculated drill pipe displacement against measured fill volumes during the tripping operation (Section 6.3).

In summary, during the tripping operation out of the horizontal section of the well (1) not enough mud was pumped into the well to replace the drill pipe displacement volume, (2) there were gains in the trip tank volume likely caused by pressurized mud backflow through the trip tank pump discharge line, and (3) at one point, the trip tank pumps started deadheading against the surface pressure in the well. Post-incident, these clearly are indications that gas was in the well, but these indications were not effectively acted upon to stop operations and restore the primary well control barrier, hydrostatic pressure produced by mud.

[a] A 40 barrel weighted slug was pumped into the well at 6:29 pm, at a bit depth of 13,336 feet.
[b] Trip Tank volume stops fluctuating at 6:47 pm, which could indicate that the flow line isolation valve was closed, stopping any fluid flow from entering the trip tank.

5.1.2.1 Trip Out from 13,337 Feet to 10,237 Feet

By the time the drill bit reached 10,237 feet MD in the horizontal section of the well, there were 14.3 barrels less mud in the well than needed to replace the volume of drill pipe removed. This volume had evidently been replaced by the equivalent volume of gas entering the well.

Figure 13 below shows a graph of the trip tank volume and drill bit depth during the tripping operation, along with a plot of the trip tank volume had a mud volume equal to the calculated volume of the drill pipe removed been pumped into the well. Table 1 indicates for each group of stands of drill pipe removed from the well (1) the calculated volume of those stands on an individual and cumulative basis and (2) the measured volume of mud that was pumped into the well to replace the drill pipe individually and cumulatively. The table also indicates the cumulative difference between the measured and calculated volumes. A positive value indicates that excess mud was pumped into the well, and a negative value indicates that less mud than the calculated volume of the drill pipe was pumped into the well.

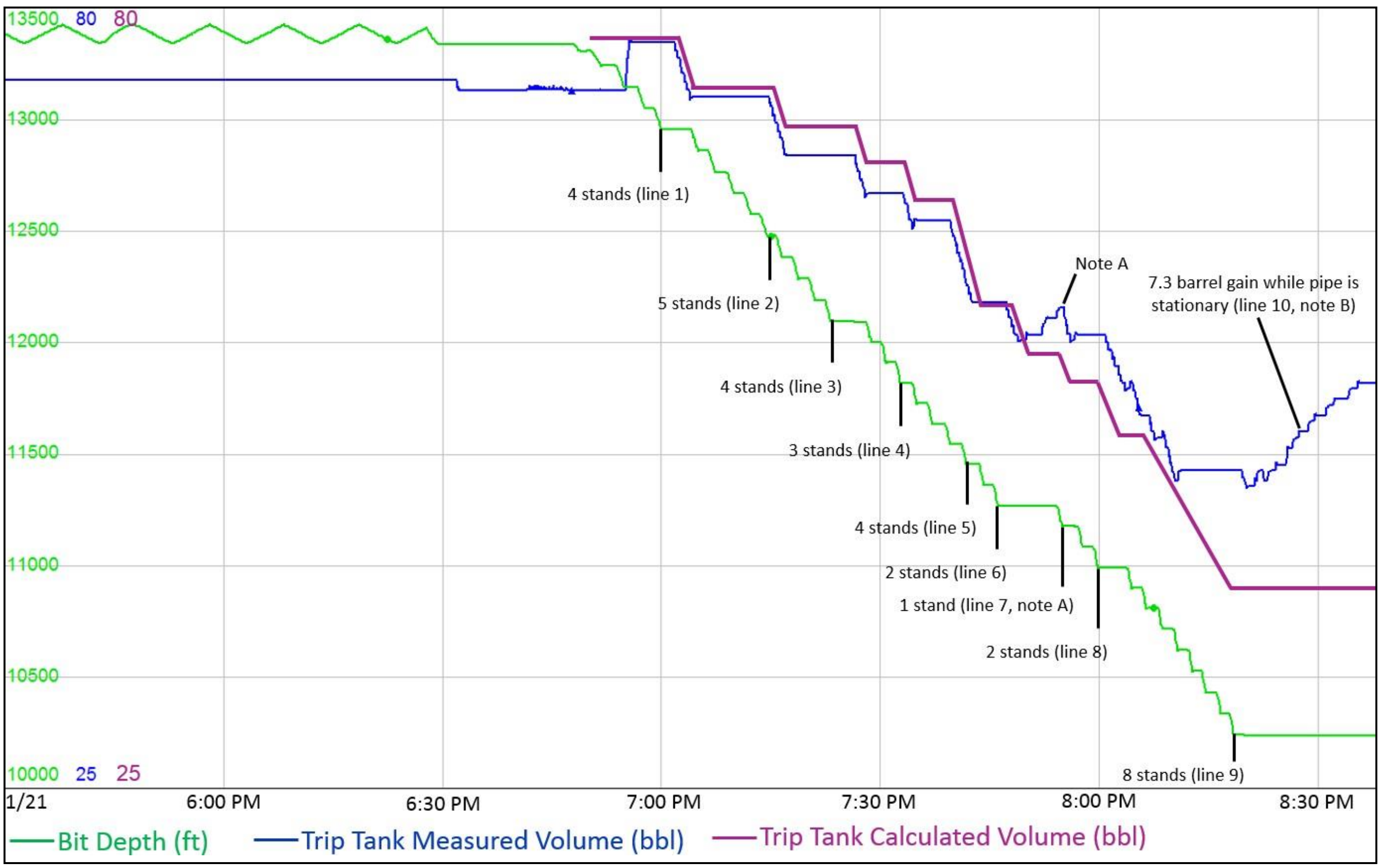

Figure 13. Rig data during the trip out of the wellbore from 13,337 feet to 10,237 feet. The blue line shows the actual, measured trip tank volume, and the purple line shows what the trip tank volume would be had a mud volume equal to the calculated volume of the drill pipe removed been pumped into the well. The line numbers and notes indicated in parentheses correspond to the line numbers and notes in Table 1 below.

Table 1. Tabulation of calculated and measured volumes of mud pumped into the wellbore during the trip out from 13,337 feet to 10,237 feet. The table accompanies the data in Figure 13. "HWDP" is "Heavy Weight Drill Pipe."

Line Number	Stands	Type	Bit Depth (feet)	Calculated Volume		Measured Volume		Cumulative Difference (barrels)	Notes
	Drill Pipe			Individual Volume (barrels)	Cumulative Volume (barrels)	Fill Volume (barrels)	Cumulative Volume (barrels)		
1	4	Reg	12954	2.5	2.5	3.9	3.9	1.3	
2	5	Reg	12478	3.2	5.7	4.2	8.0	2.3	
3	4	Reg	12095	2.5	8.2	2.7	10.7	2.5	
4	3	2 Reg, 1 HWDP	11820	3.1	11.3	1.9	12.6	1.4	
5	4	HWDP	11455	7.2	18.5	5.7	18.4	-0.1	
6	2	HWDP	11270	3.6	22.1	0.4	18.8	-3.3	
7	1	HWDP	11178	1.8	23.9	1.9	20.6	-3.2	A
8	2	HWDP	10993	3.6	27.5	3.3	23.9	-3.6	
9	8	3 Reg, 5 HWDP	10239	10.9	38.3	7.4	31.3	-7.0	
10	0		10237	0.0	38.3	-7.3	24.1	-14.3	B

A. This is the first clear indication that gas had likely entered the well during the tripping operation. Patterson did not pump enough mud into the well to replace the drill pipe, yet there was a gain in the trip tank volume. This gain was likely a result of the gas influx in the well, pushing mud backwards through the trip tank pump discharge line and into the trip tank. Post-incident testing found that the check valve installed in this line to prevent backflow was stuck in the open position, allowing backflow (Figure 14).

B. When the drill bit was stationary at a depth of 10,237 feet, there was a 7.3 barrel gain in the trip tank that was likely caused by mud backflowing through the trip tank centrifugal pump and into the trip tank. The mud backflow into the trip tank likely resulted from gas influx and subsequent vapor migration and expansion causing a pressure increase at the surface.

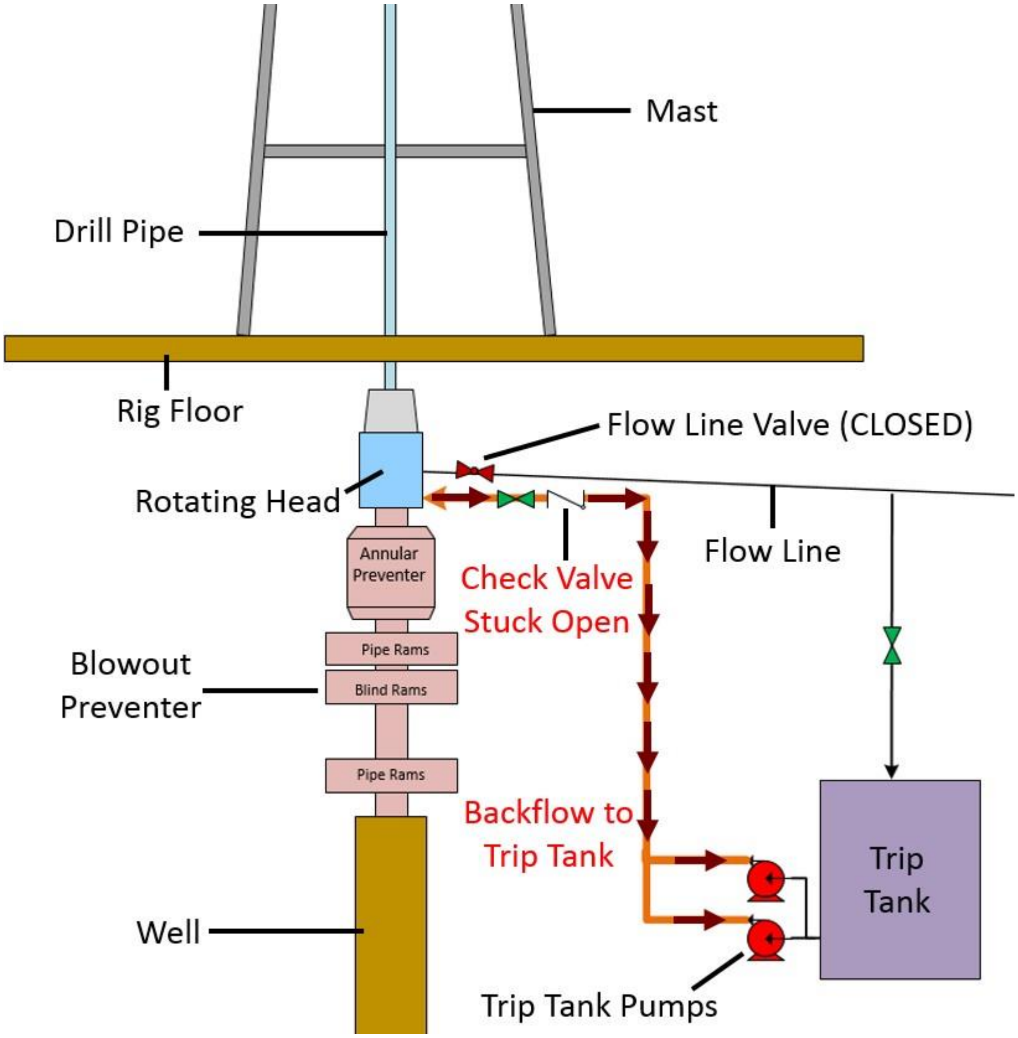

Figure 14. Pressurized mud backflowed through trip tank discharge piping, stuck-open check valve, and centrifugal pumps into trip tank.

5.1.2.2 Trip Out from 10,237 Feet to 6,905 Feet (Above Top of Curve)

During this part of the tripping operation from the mid-part of the horizontal section to the top of the curve, surface pressure increased[a] against the rotating head and closed orbit valve to the point the trip tank pumps were unable to pump against the pressure in the well (they were "deadheading"). This surface pressure was likely caused by gas influx/expansion. Because the trip tank pumps were deadheading, the drilling engineer chose to switch to the mud pumps, which generated a higher output pressure, to pump mud into the well through the ***kill line***. Both the company man and drilling engineer believed that the pressure applied to the well by the mud pumps would push any influx gas back into the formation.

[a] This surface pressure was not measured or monitored.

Figure 15 and Table 2 show the rig data and explain the operations during this portion of the tripping operation. By the time the drill bit reached the top of the curve, 20 barrels fewer than the calculated drill pipe displacement volume had been pumped into the well since the beginning of the tripping operation and had evidently been replaced by gas.

At around 10:30 pm, the drilling engineer went to sleep. He was not in contact with workers on the rig until the next morning at around 7:30 am.

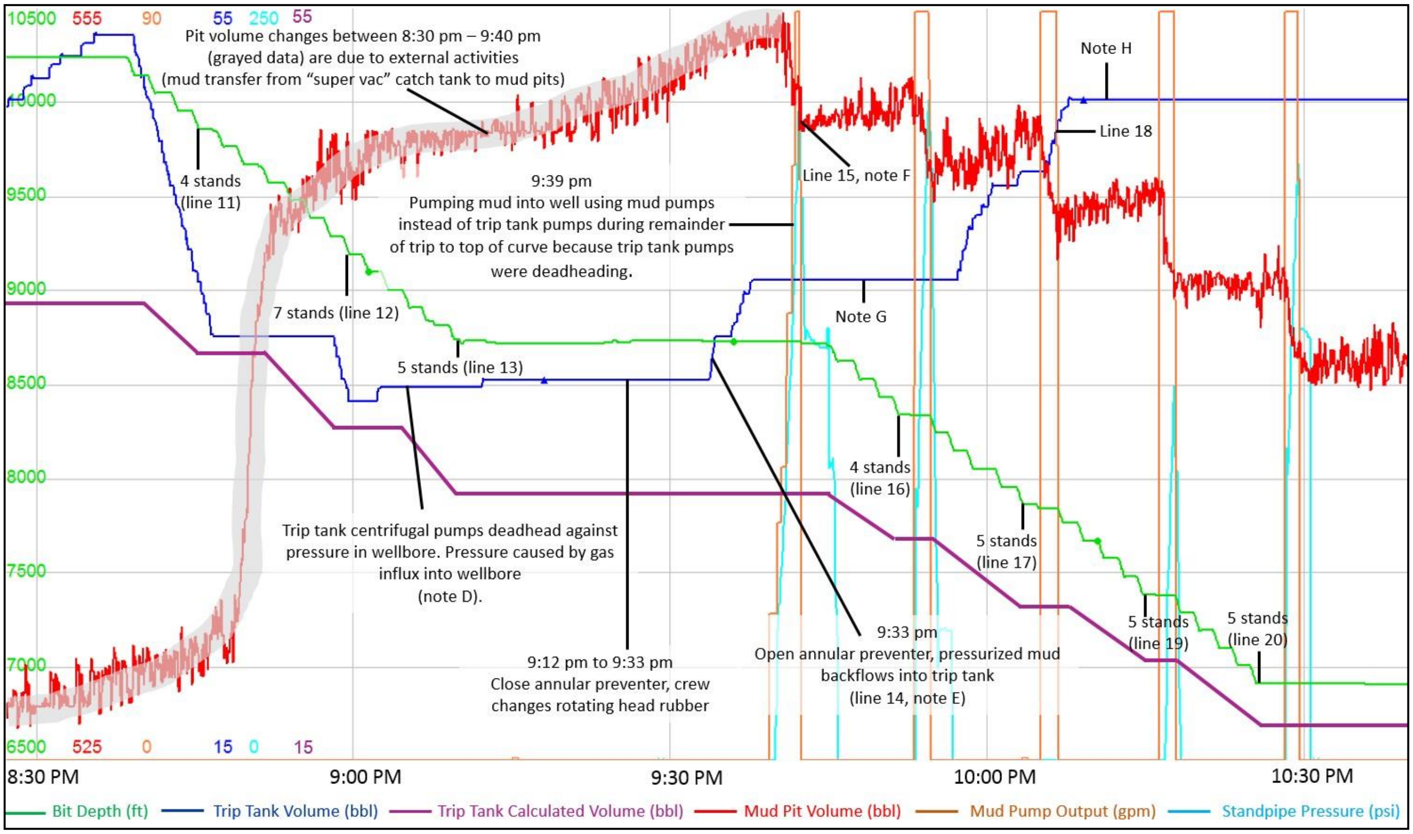

Figure 15. Rig data during the trip out of the wellbore from 10,237 feet to 6,905 feet. The blue line shows the actual, measured trip tank volume, and the purple line shows what the trip tank volume would have been had the calculated drill pipe volume been pumped into the well. The line numbers and notes indicated in parentheses correspond to the line numbers and notes in Table 2 below.

Table 2. Tabulation of calculated and measured volumes of mud pumped into the wellbore during the trip out from 10,237 feet to 6,905 feet. The table accompanies the data in Figure 15.

Line Number	Stands of Drill Pipe	Type	Bit Depth (feet)	Calculated Volume		Measured Volume		Cumulative Difference (barrels)	Notes
				Individual Volume (barrels)	Cumulative Volume (barrels)	Fill Volume (barrels)	Cumulative Volume (barrels)		
10	0		10237	0.0	38.3	-7.3	24.1	-14.3	
11	4	Regular	9859	2.5	40.9	16.0	40.1	-0.8	
12	7	Regular	9194	4.4	45.3	3.5	43.5	-1.7	
13	5	Regular	8719	3.2	48.4	-1.2	42.4	-6.0	D
14	0		8719	0.0	48.4	-5.3	37.1	-11.4	E
15	0		8719	0.0	48.4	3.5	40.5	-7.9	F
16	4	Regular	8340	2.5	50.9	0.4	41.0	-10.0	G
17	5	Regular	7843	3.2	54.1	-9.6	31.4	-22.7	
18	0		7843	0.0	54.1	2.3	33.7	-20.4	
19	5	Regular	7381	3.2	57.2	3.0	36.7	-20.5	H
20	5	Regular	6905	3.2	60.4	3.7	40.4	-20.0	

D. While removing five stands of drill pipe from the well, the trip tank centrifugal pumps deadheaded against pressure in the wellbore. The centrifugal trip tank pumps could not pump against the high pressure evidently in the well, which was likely a result of the gas influx.

After the five stands were pulled from the well, the crew closed the annular preventer so that they could change out the rotating head, which had been leaking.

E. By 9:33 pm, a new rotating head rubber was installed. A crew member opened a valve on the choke line that would allow him to read the casing (well annulus) pressure, and he told the driller he observed no pressure. The driller had expected some gas to be in the well and was surprised that there was no pressure.
The driller opened up the annular preventer to continue the tripping operation. The orbit valve is closed at this point, with the new rotating head rubber sealing around the drill pipe. Despite no casing pressure being observed, 5.3 barrels of mud from the wellbore backflowed into the trip tank through the stuck check valve, indicating pressure had been in the wellbore, likely as a result of gas influx. Possible reasons that pressure was not observed include:

1. The pressure gauge[a] made reading low pressures difficult due to the scale (0 – 10,000 psi) (Figure 16);

2. Low pressures may not have registered on this gauge and may not have caused the needle to move;

3. A valve was in the wrong position when reading the pressures, thereby isolating the pressure gauge from the well annulus;

[a] The pressure gauge on the rig floor was equipment provided by RMO.

	4. A line might have been plugged, preventing the rig workers from reading the pressure in the well annulus.
F.	At the direction of the company man, the driller began pumping mud into the well through the BOP kill line in an attempt to pump the displacement volume of mud into the well, because the trip tank pumps were deadheading. The company man and drilling engineer decided to use the positive-displacement mud pumps instead of the centrifugal trip tank pump because the mud pumps could produce a higher discharge pressure.
G.	Backflow into the trip tank ceased between 9:37 – 9:57 pm, which is anomalous compared to other backflow events. A hypothesis explaining this lack of backflow is the check valve on the trip tank pump discharge line might have closed at 9:37 and might have reopened at 9:57 pm.
H.	The crew closed a manual valve in the trip tank pump discharge piping to prevent further backflow into the trip tank.

Figure 16. Photo of casing pressure gauge on an exemplar Patterson drilling rig. The pressure gauge could indicate pressures up to 10,000 psi. Low pressures might have been difficult to read on the Rig 219 pressure gauge, or the pressure gauge might not have worked properly at low pressures. The valve on the choke system ("HCR valve") that needed to be opened to measure annular pressure might have been closed during pressure readings, or the line might have been plugged.

5.2 Well Circulation at Top of Curve

At 11:00 pm, with the drill bit above the top of the curve, the next step was to circulate the well. Mud would be pumped down through the drill string to the top of the curve, up through the annulus, and out though the flow line. Unlike during the tripping phase used up to this point, the orbit valve would necessarily be open during circulating, so the mud returning to the surface could flow through the flow line (Figure 17).

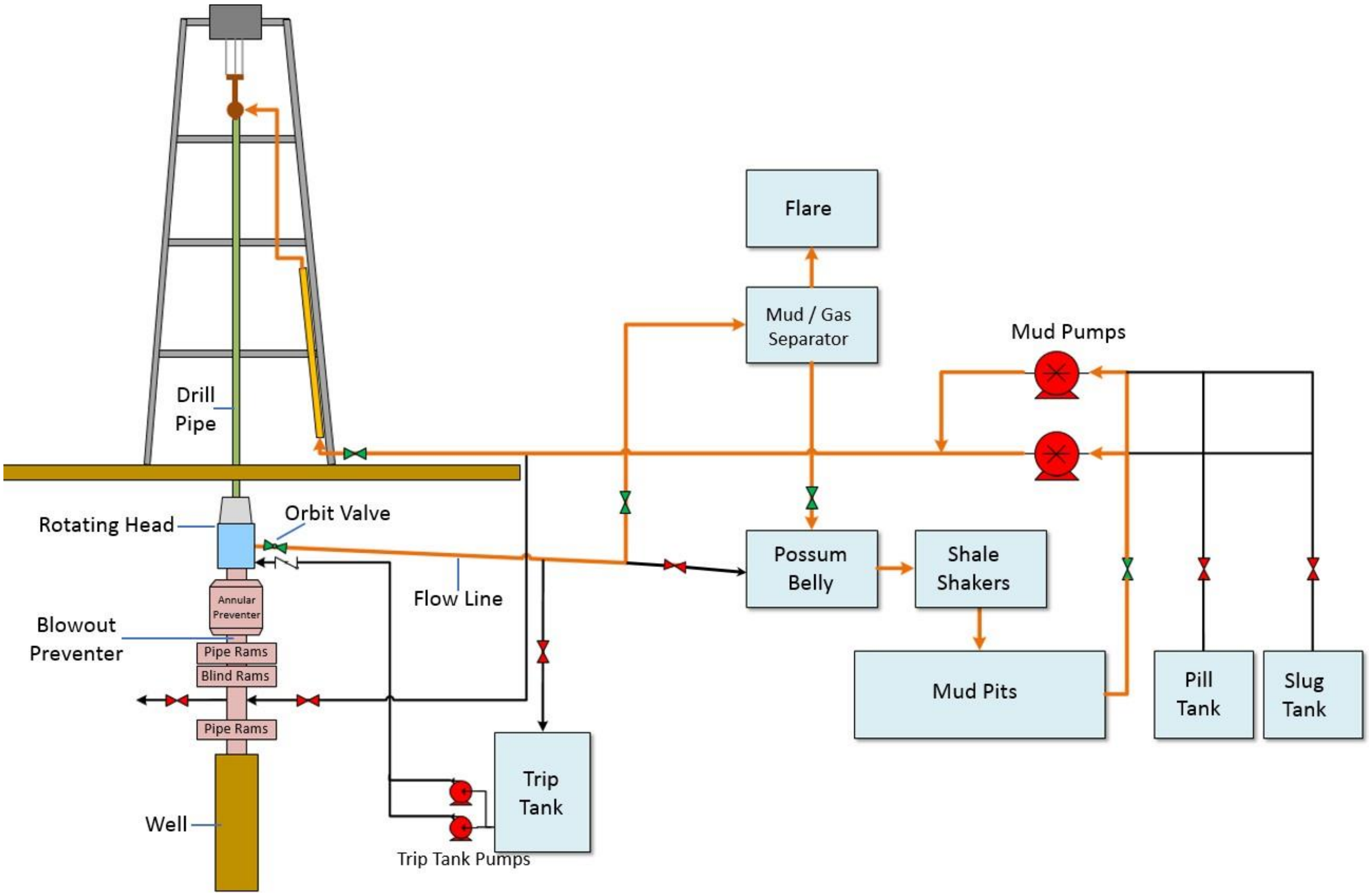

Figure 17. Flow diagram showing mud circulation path (orange lines) during circulation operation at top of curve.

Before beginning circulation, with the mud pumps off, the driller opened the orbit valve to perform a flow check. The rig data shows that a small amount of fluid flowed through the flow line, then stopped. The flow check was conducted for 45 seconds. With no flow observed, the flow check was considered to have passed (Figure 18).

The driller was surprised that the well was not flowing during this flow check. Pressure on the well side of the orbit valve was previously so high that the trip tank pumps had deadheaded. Flow would have been expected. Patterson policies require flow checks be at least 3 minutes or longer with oil-based mud (Section 6.10). A longer flow check might have resulted in a flow indication.

The CSB identified the following hypothesis that may explain the no-flow condition at the surface: A gas bubble might have been at the surface of the well when the driller opened the orbit valve at 11:01 pm. This gas bubble might have escaped from the well when the orbit valve was opened, causing the mud volume at the surface to drop below the flow return line (Figure 17). The height of mud in the well might have been increasing during this flow check, but not to the point of reaching the flow line. This hypothesis is supported by the 80-second delay between when the mud pumps were turned on and when mud began flowing through the flow line (Figure 18).

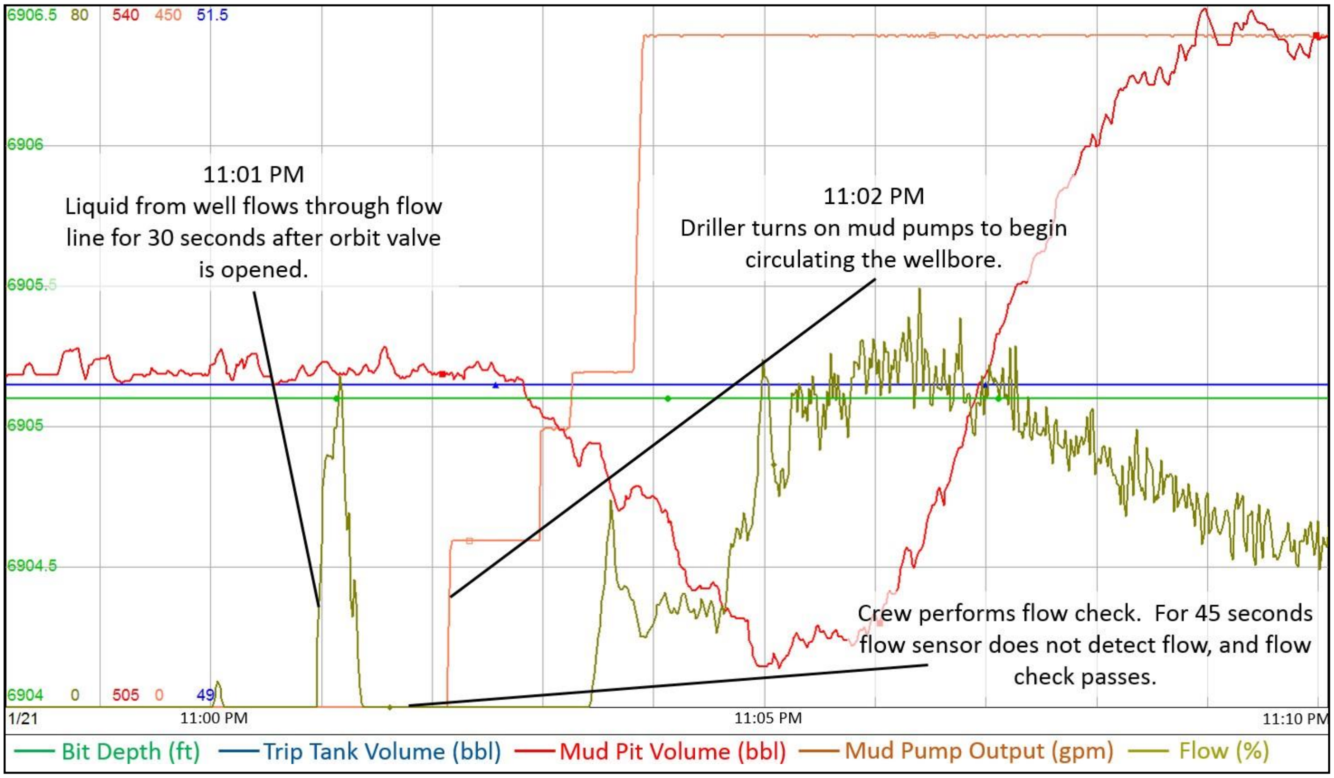

Figure 18. Rig data when the drill bit reached the top of curve. Crew performed a flow check at top of curve. No flow was observed for 45 seconds. Driller turned on pumps to circulate the well.

Accepting the indications of a successful flow check, the driller ramped up the mud pumps at 11:02 pm and proceeded with circulating the well by pumping mud down through the drill string with the mud returning to the surface and flowing through the flow line. The crew remembered the flare activating during this activity (Figure 19), indicating gas was coming out of the mud returning at the surface, and then going out at 6,700 strokes of the positive displacement mud pumps (11:57 pm) [a] (Figure 20). Appendix F shows a comparison of Figure 20 with a circulation operation performed days earlier, illustrating the difference in the appearance of the data. While circulating, the slug that had been pumped into the drill pipe at about 6:30 pm before tripping exited the drill pipe and entered into the annulus, adding additional pressure to the well until the slug was circulated out of the annulus during the operation.

[a] The driller told the CSB the flare died out at 6,700 strokes, which was at 11:57 pm.

Figure 19. Image of flare from video captured at 11:06 pm on January 21, 2018.

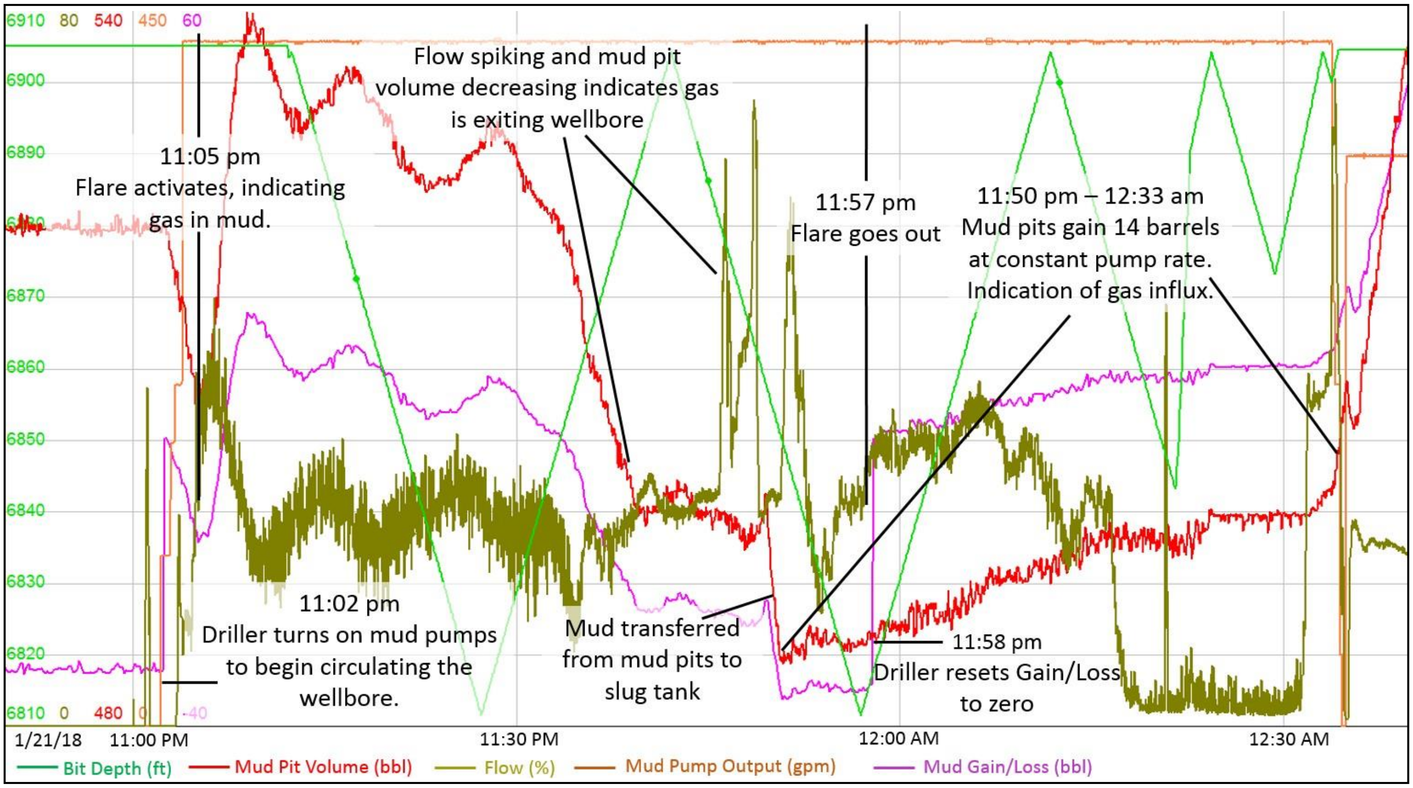

Figure 20. Rig data while circulating the wellbore at the top of the curve. The flare activated while circulating, indicating gas in the mud. Between 11:50 pm and 12:33 am, the mud pits gained 14 barrels while the mud pumps were circulating at a constant pump rate. This pit gain indicates there was gas in the well.

The driller told the CSB he observed full returns, no losses and no gains, while circulating the well. Post-incident review of the well data, however, indicates that while circulating, the mud pits were gaining mud, indicating gas was in the well; between 11:50 pm and 12:33 am, the mud pits gained about 14 barrels (Figure 20).[a]

The drilling data system is equipped with a "Gain/Loss" measurement because gain or loss in mud pit volume could be an indication of a mud loss or a gas influx. The measurement device includes an alarm which is set to activate when the mud pits have gained or lost a pre-defined volume of mud. The driller can "zero" the Gain/Loss measurement at any time to restart the Gain/Loss measurement.

Patterson policy states that the Gain/Loss alarm should be set at +/- 5 barrels. However, the entire alarm system had been turned off before the start of the tripping operation, so no audible or visual alarm activated during this 14-barrel gain.

At 12:35 am, the driller pumped a weighted pill into the well (discussed in Section 5.3).

[a] At 12:33:48 am (before the driller stopped circulating the well) the total mud volume was 499.41 barrels. At 11:50:45 pm, the total mud volume was 485.56 barrels.

5.3 Spotting Weighted Pill Above Top of Curve: Introduction of Lost Circulation Material

Figure 21. Depiction of well with gas zones and location of weighted pill.

After circulating the well portion above the top of the curve, the company man and drilling engineer planned to spot[a] a weighted pill above the top of the curve (7,087 feet). The purpose of the weighted pill was to increase the hydrostatic pressure in the wellbore beneath the pill to overbalance the well. During the circulating operation, the derrickhand was told over the radio to make a 50-barrel 10-pound-per-gallon pill. The derrickhand, however, misunderstood the communication and thought that they wanted a 10-pound ***Lost Circulation Material (LCM)*** pill instead of a weighted pill. Lost Circulation Material is used during mud losses to plug areas in the wellbore wall where mud is flowing from the well into the formation [9]. It is intended to cause plugging to prevent flow into the formation and is not intended to be used for weighted pills. The derrickhand prepared an LCM pill.

A crewmember overheard the derrickhand ask a floorhand over the radio to get LCM material, and he realized the derrickhand was preparing the wrong type of pill. The crewmember went down to the pits and told the derrickhand they wanted a weighted pill. The derrickhand was already mixing the LCM pill. Instead of starting over, he added weighting material[b] to the already-prepared LCM pill, bringing it to the 50-barrel volume and 10 pound-per-gallon density specified by RMO.

At 12:35 am, the drilling crew pumped 46 barrels of the pill into the drill pipe. Following the pill with mud, they pumped the pill out of the bottom of the drill pipe and into the annulus with the bottom of the pill at a depth of about 6,500 feet, and with the top of the pill at about 5,800 feet (Figure 21). Some of the pill material remained in the bottom of the drill pipe.

After spotting the pill, at about 1:10 am the crew performed a visual, 2-minute flow check. The flow check passed. However, the CSB could not verify that the crew observed no flow during this flow check. The return flow meter data indicates some very small flow (1% of the flowmeter scale) during this flow check (Figure 22). Despite the flow check result, gas was still entering or expanding in the well. The 50-barrel volume and 10-pound-ger-gallon weighted pill did not produce the hydrostatic pressure necessary to prevent gas from entering the vertical portion of the well. After pumping the weighted pill, the well was still underbalanced and the primary well control barrier was still not in place (Section 6.5).

[a] "Spot" means to place the pill at a specified location in the well.
[b] Barite is added to the mud to increase its density.

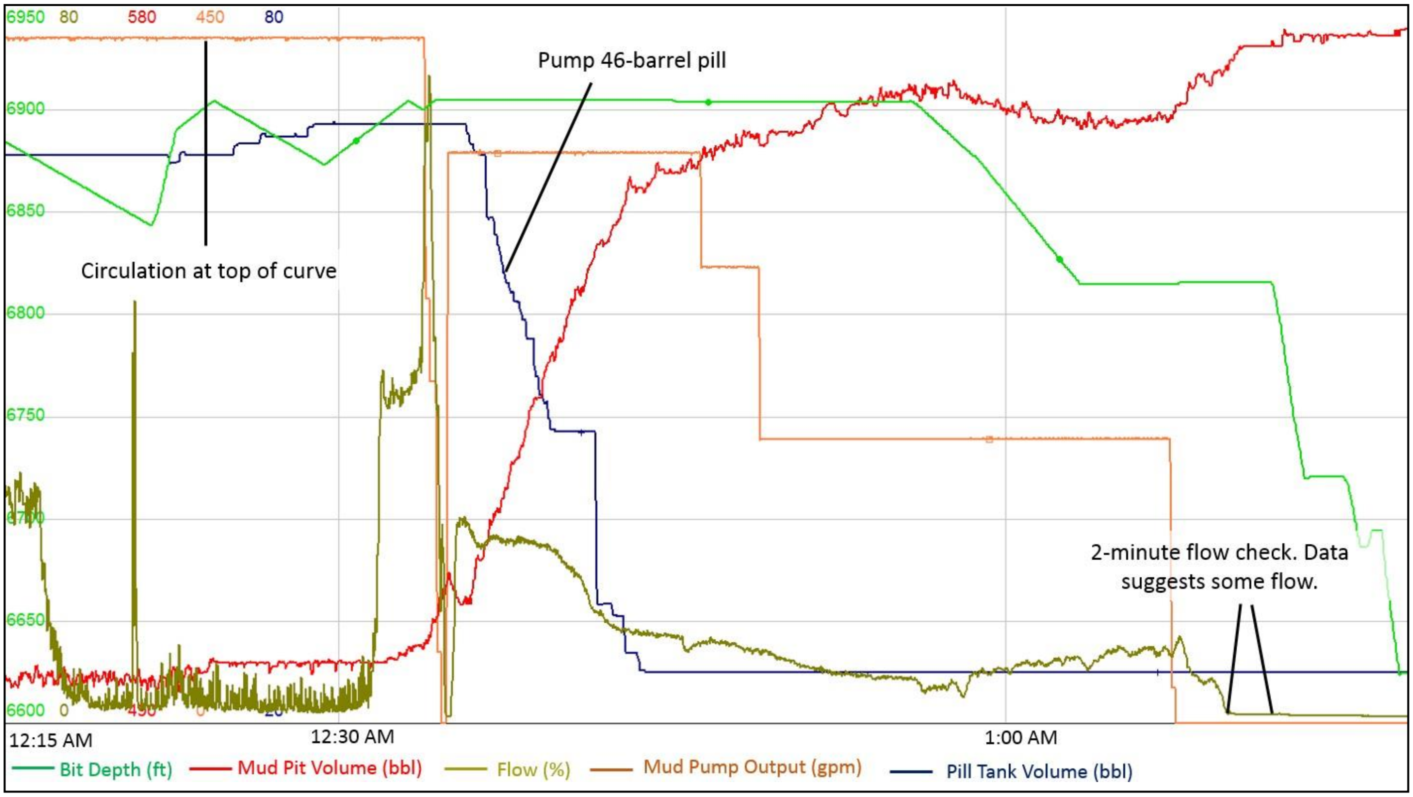

Figure 22. Data during pumping of pill and subsequent flow check.

5.4 Tripping Out of Vertical Section of Well

At 1:12 am, with the orbit valve open, the crew resumed tripping the drill pipe out of the wellbore. The crew pulled the first five stands of drill pipe without pumping in the displacement volume. The crew then pulled the next five stands with the trip tank running continuously—the typical Continuous Fill tripping procedure. The pipe stands being removed were full of mud (i.e., they were pulling wet). At 1:52 am, the driller tried to pump a slug into the drill string to push the mud and any remaining pill fluid out of the drill string so that the crew could pull the pipe dry. The drill pipe, however, was plugged by the LCM material that was in the pill, and the slug could not be pumped into the drill string. The rest of the pipe in the well had to be pulled wet, with the drill string full of mud.

By the end of the tripping operation out of the vertical section of the well, mud from the trip tank replaced less than half the volume of drill pipe removed from the well. For this tripping operation, the crew was using Continuous Fill. The fact that this method did not result in the proper fill volume should have been a key indication gas was in the well. However, as discussed below, the driller and company man did not identify this discrepancy because of difficulties interpreting the tripping data. A trip sheet for this operation was not found, but a completed paper trip sheet possibly was destroyed in the fire.

The crew also did not perform flow checks as required by Patterson well control policies (Section 6.10). Flow checks were required when the drill bit reached the casing shoe, and before pulling the ***bottom hole assembly*** (BHA)—the bottom part of the drill string consisting of various equipment including the drill bit—into the BOP. Effective flow checks might have identified that the well was flowing and prompted the crew to take action. Discussed in Section 6.10, it appears that there was a culture that accepted nonperformance of flow checks on Patterson Rig 219.

5.4.1 Driller and Company Man Had Difficulties Interpreting Data Due to Mud Bucket Alignment

The rig was equipped with a mud bucket, which is equipment used when drill pipe being removed from the well is full of mud. The mud bucket is placed around the tool joints where two drill pipe stands are screwed together. When the stand of pipe being removed is unscrewed from the rest of the drill string, the mud in that stand of pipe drains into the mud bucket, out through a flexible drain line, and into a tank chosen to collect the mud (Figure 23).

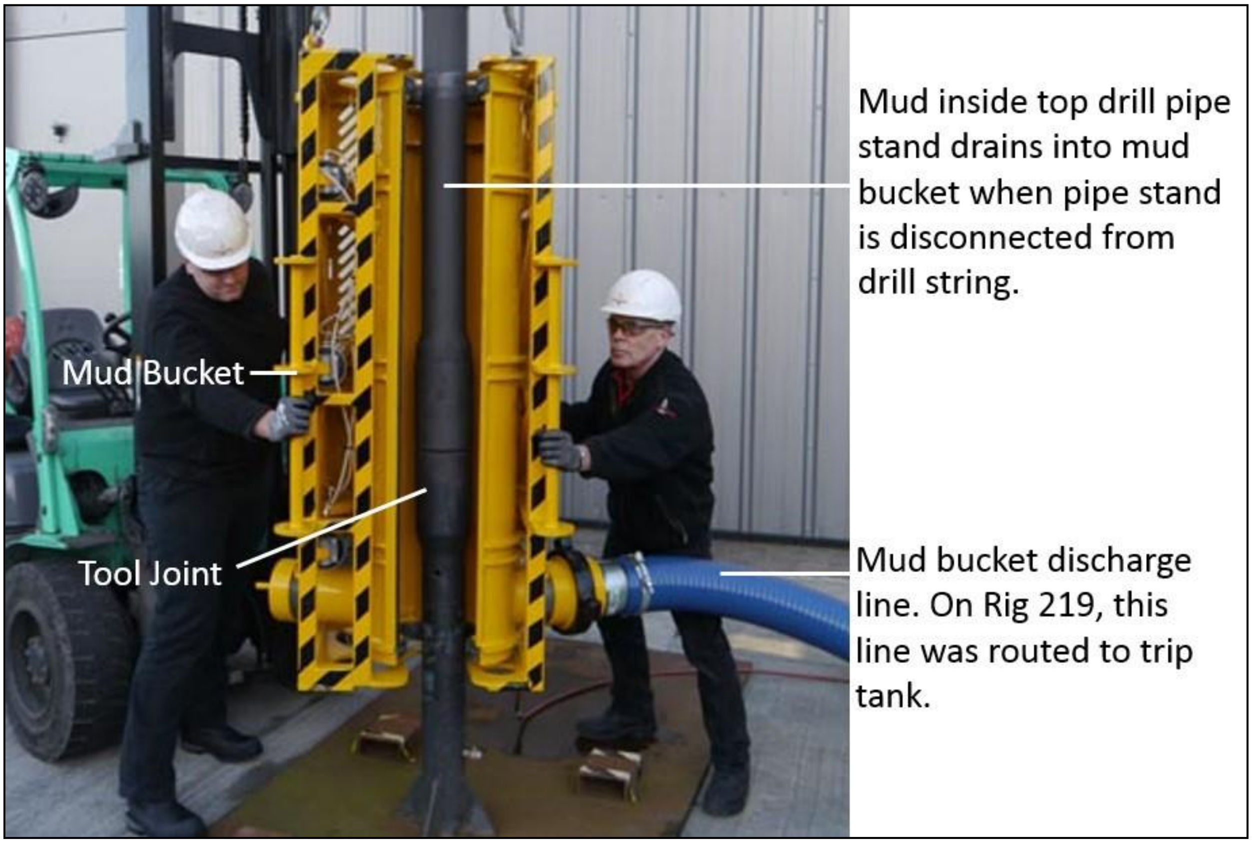

Figure 23. Photo of example mud bucket used when tripping pipe full of mud. Source: Sub-drill [72].

On Rig 219, the mud bucket discharge was routed to the trip tank. Level changes in the trip tank are a key indicator of mud gains or losses while tripping, and adding the mud into the trip tank from the mud bucket during the tripping operation confounded that information for the driller and company man. As the crew tripped out pipe, the trip tank volume fluctuated up and down from mud draining into the trip tank and from mud being pumped out of the trip tank (Figure 24). The driller communicated that he had never before tripped wet pipe out of the well with this lineup, and all of the volume fluctuations in the data made monitoring for the correct volume reduction in the trip tank difficult.

The company man was also more accustomed to the mud bucket emptying elsewhere, such as to a catch tank (a separate tank designed to collect fugitive drilling mud).

With the mud from each drill pipe stand going to the trip tank, the driller realized he would have to use the volume of dry pipe, not the volume of wet pipe, in his trip sheet calculations to monitor if the well was taking proper fill (explained in Appendix C). The driller stated this realization to the company man, and the company man—unaccustomed to this alignment—visually looked at the pipe alignment and took a moment to think through the displacement concepts. He then agreed with the driller that they should use dry pipe volume in their trip sheet calculations.

During the tripping operation, the driller and company man performed a test to determine if the well was taking proper fill. The company man wanted to double check that dry pipe volume was the correct displacement volume for their trip sheet calculations (Figure 25). They turned off the trip tank centrifugal pumps and removed five stands of drill pipe from the wellbore. They then turned on the trip tank centrifugal pumps to see if a corresponding five drill-pipe-stand volume of mud pumped into the well. The driller and company man believed they saw the proper volume of mud enter the well, and they resumed tripping normally. A review of the data, however, shows that the full calculated volume for five stands of drill pipe did not enter the well. From start to end of test, the trip tank volume should have reduced by 3.2 barrels, the volume required to replace the five stands of pipe. By the end of the test, however, the trip tank volume had actually increased by 0.8 barrels, indicating that the well did not take any fill, and in fact had gained four barrels of influx or expanded gas. It is unclear why the driller and the company man believed this test passed. The result was that, unknown to Patterson and RMO, gas continued to enter or expand inside the well during the tripping operation. By the end of the trip, less than half of the drill pipe volume removed from the well had been replaced with mud.[a] The other half of the drill pipe volume was likely replaced with hydrocarbon gas from the formation(s).

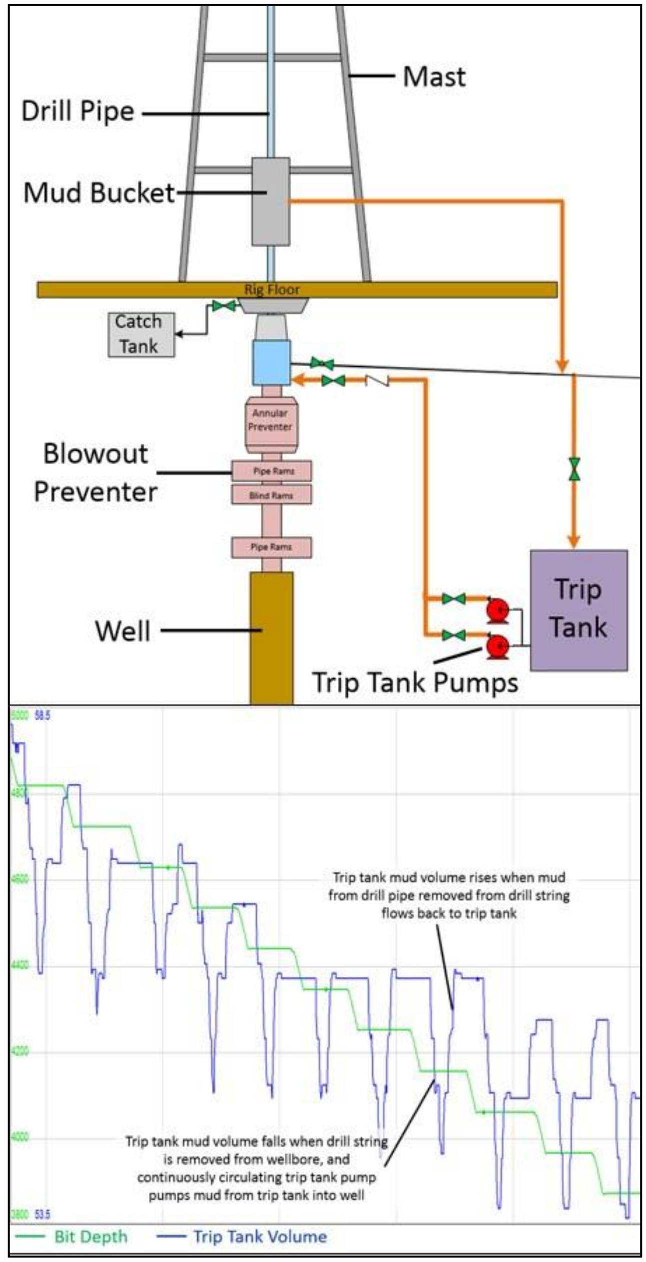

Figure 24. Rig equipment alignment and data during tripping operation out of vertical portion of well. The crew was tripping wet pipe, and the mud from the pipe stands removed drained back to the trip tank, causing the trip tank volume to fluctuate.

[a] This calculation considers the tripping operation between 2:13 am and when the final stand above the BHA reached the surface at 4:50 am. During this period, 60 stands of drill pipe were removed from the well. The last stand was plugged with the pill material. The calculated displacement volume of these 60 drill pipe stands is 39.5 barrels. About 16.8 barrels of mud were pumped into the well during this time period to replace the drill pipe removed. Only about 43% of the drill pipe volume was replaced with mud.

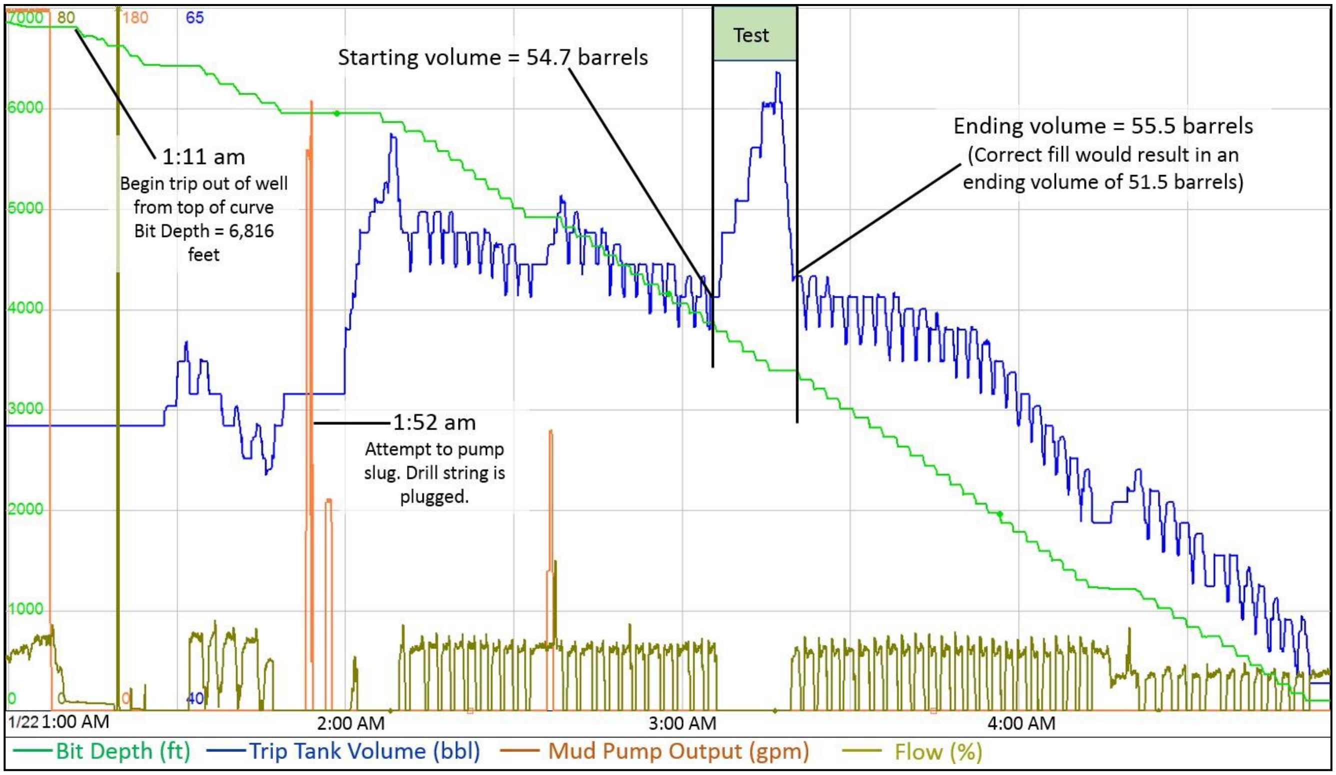

Figure 25. Rig data during trip out of vertical portion of the well on January 22, 2018. The driller and company man were confused by the trip tank volume fluctuations and about what pipe volume to use in trip sheet calculations. The company man and driller incorrectly concluded that the test they performed to determine if the well was taking proper fill had passed.

5.5 Attempt to Unplug Drill Pipe Before Shift Change

At 4:50 am on Sunday January 22, 2018, the crew had just finished pulling out the last stand of pipe above the BHA. That stand of pipe pulled dry because it was plugged within by the pill LCM material. The crew wanted to unplug this stand of drill pipe. With the BHA sitting in the wellbore with the annular preventer in the open position and with the rotating head removed, the crew spent the next hour hitting on the plugged drill pipe with hammers and at one point attempting to pump mud through it using the mud pumps. The crew ultimately was not able to unplug the drill pipe stand, so they broke it down into the three single pieces of drill pipe and laid them down on the rig floor. At about 5:45 am, the day crew came onto the rig to begin shift change.

Between 4:51 am and 6:07 am, while the crew was trying to unplug the stand of drill pipe and during shift change, the trip tank gained 31 barrels of mud (Figure 26). The well was flowing because gas was in the well. No one observed this gain in the trip tank, and no one realized the well was flowing.

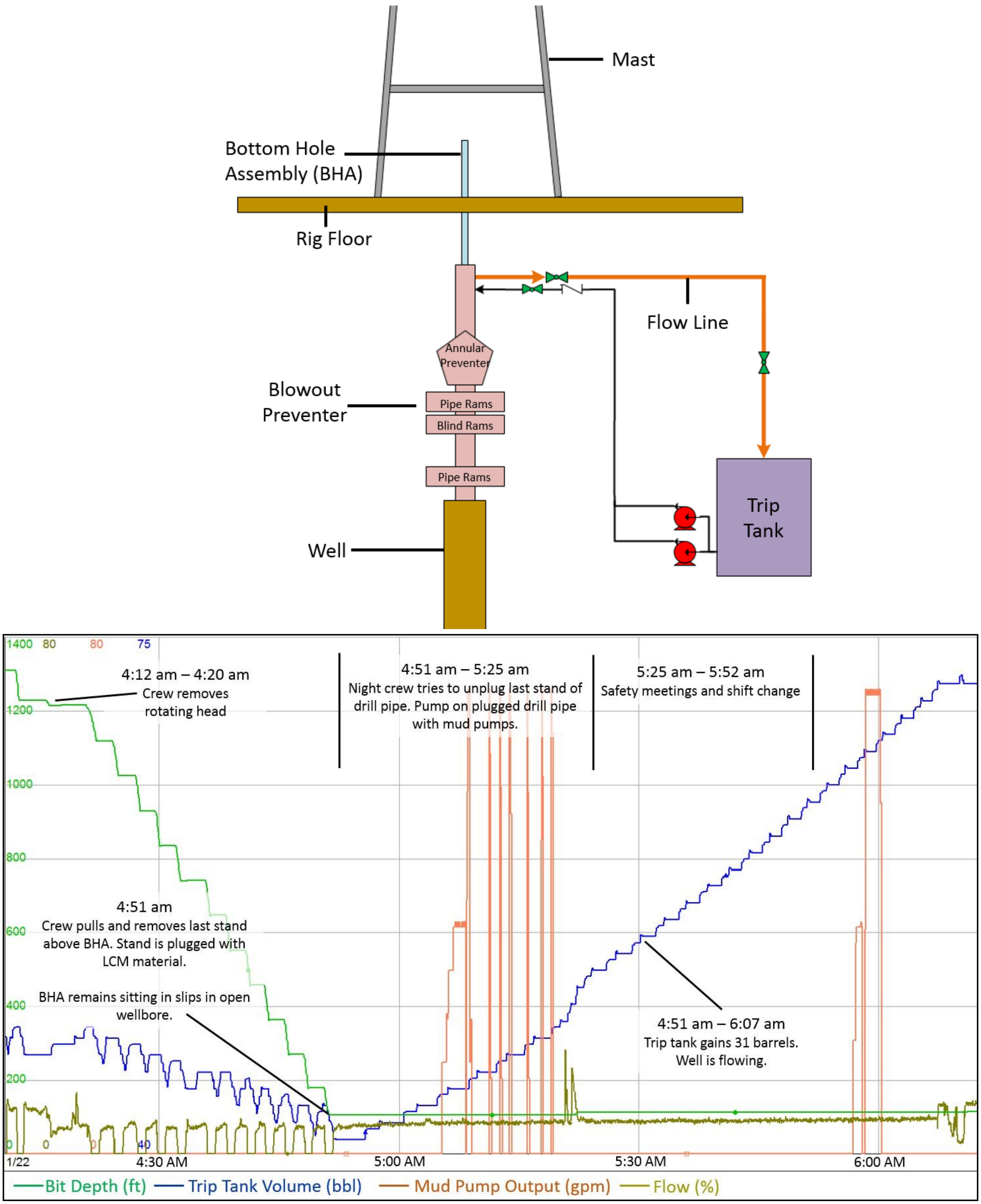

Figure 26. Rig equipment lineup and rig data between 4:10 am and 6:12 am. Between 4:51 am and 6:07 am, the trip tank gained 31 barrels of mud.

5.6 Activities During Day Tour: Monday, January 22, 2018

At 6:08 am, the day shift driller lifted the BHA out of the wellbore. At 6:10 am, with the BHA out of the wellbore, the driller closed the BOP blind rams.[a] The driller then transferred mud from the nearly-full trip tank to the mud pits. The mud pits were also nearly full of mud, and mud was transferred from the mud pits to the pill tank.

By 7:15 am, the day crew had broken apart the plugged BHA and laid it on the rig floor (Figure 27).

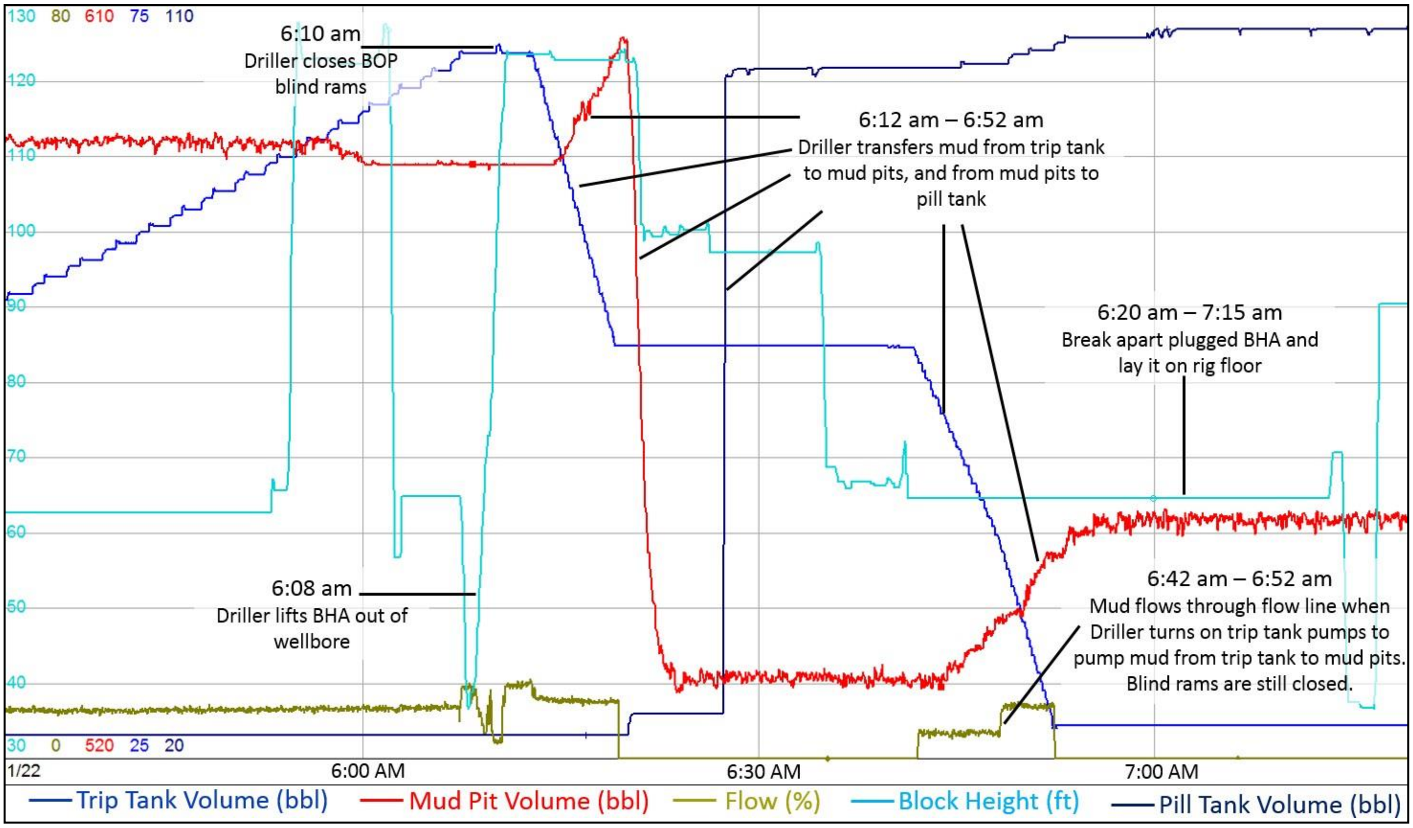

Figure 27. Rig Data between 5:32 am and 7:20 am on Monday, January 22, 2018 (day of incident).

The crew then assembled a new BHA because the original one was plugged. Before using the new BHA, the personnel who specialize in BHA equipment wanted to first test the BHA components. At 7:50 am, the driller picked up the new BHA and positioned it over the wellbore in preparation to lower it into the well to test the equipment.

As a typical safety precaution before opening the blind rams, the rig manager checked the well (annular) pressure by looking at a pressure gauge on the rig floor. The gauge showed there was no pressure, and he gave the driller a thumbs-up sign.

The driller instructed the crew to clear from the rig floor in preparation for him to open the BOP blind rams. This is a safety practice to ensure no crewmembers are near the well in case some well fluid releases from the well when the

[a] The rig manager told the CSB that in typical practice, the drilling crew closes the BOP blind rams when all equipment is removed from the well.

BOP is opened. At 7:57 am, the driller opened the BOP blind rams. Despite no pressure being seen on the well annulus, flow surged through the flow line, and the mud pits gained 5.6 barrels, likely as a result of gas in the well.[a] The CSB could not determine if any crewmember observed this gain.

The motorhand pulled away the steel plate that had been covering the hole in the rig floor over the well. He waved over another worker (who was not a member of the Patterson drilling crew or RMO), and that worker walked to the open hole and saw mud bubbling in the open wellbore, which in hindsight was evidence of gas in the mud. This worker was not a part of conversations in the driller's cabin and does not know if the mud bubbling was communicated to the driller. The rig crew continued testing the BHA.

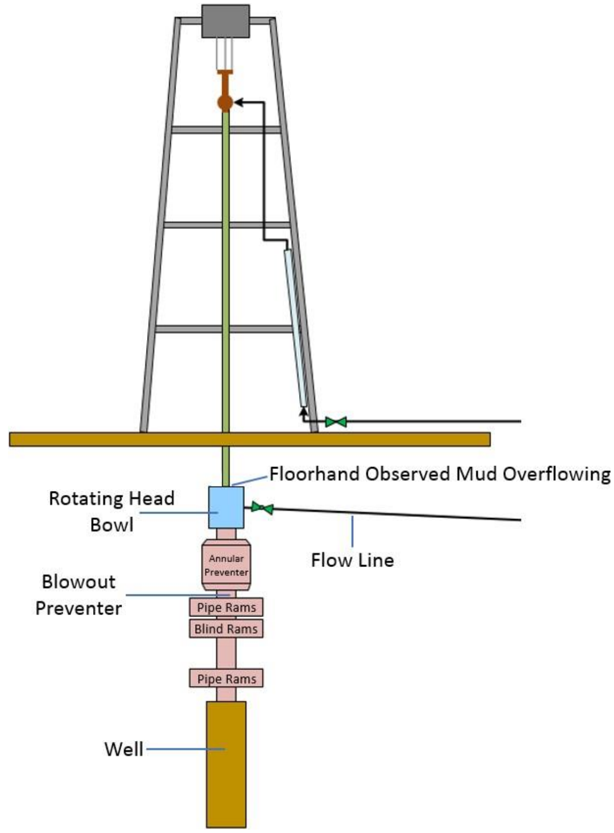

Figure 28. Depiction of where floorhand observed mud coming out of BOP stack while BHA was being tested.

The driller lowered the BHA into the well, until only about 2-3 feet of it remained above the rig floor. At 8:09 am, with the piping now aligned so that flow from the well was routed to the mud pits, the driller reset the mud Gain/Loss indicator on his rig data monitor to zero. He then turned on the pumps to test the BHA tool. A floorhand observed—and told the driller—that when the pumps turned on, mud was coming up out of the top of the rotating head bowl (Figure 28).[b] A crewmember told the CSB that this was expected because the rotating head rubber was not installed. At some point during the testing, the same floorhand observed that mud had stopped coming over the rotating head bowl. He communicated his observation to the driller.

While the BHA assembly was being tested, the entire alarm system was still off. Had the alarm system been on, critical alarms alerting of excessive flow from the well and excessive mud pit gain would have activated, warning of the gas in the well.

At 8:24 am, the BHA equipment specialist determined that the BHA test was successful. At 8:33 am, the driller began lifting the BHA out of the well so they could attach the new drill bit. By 8:35 am, the BHA assembly was fully lifted out of the well.

From the time the BOP blind rams were opened at 7:57 am through the completion of BHA testing and removal from well at 8:35 am, the mud pits gained 107 barrels of mud due to gas influx/gas expansion within the well (Figure 29), a

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[a] Possible reasons that pressure was not observed include: (1) The pressure gauge made reading low pressures difficult due to the scale (0 – 10,000 psi) (Figure 16); (2) Low pressures may not have registered on this gauge and may not have caused the needle to move; (3) A valve was in the wrong position when reading the pressures, thereby isolating the pressure gauge from the well annulus; and (4) A line may have been plugged, preventing the rig workers from reading the pressure in the well annulus.

[b] Mud also flowed through the open flow line to the mud pits.

significantly large volume. It is unknown if the driller saw this gain, which would have displayed as a number on a monitor in front of him (Figure 37). No action was taken to shut in the well.

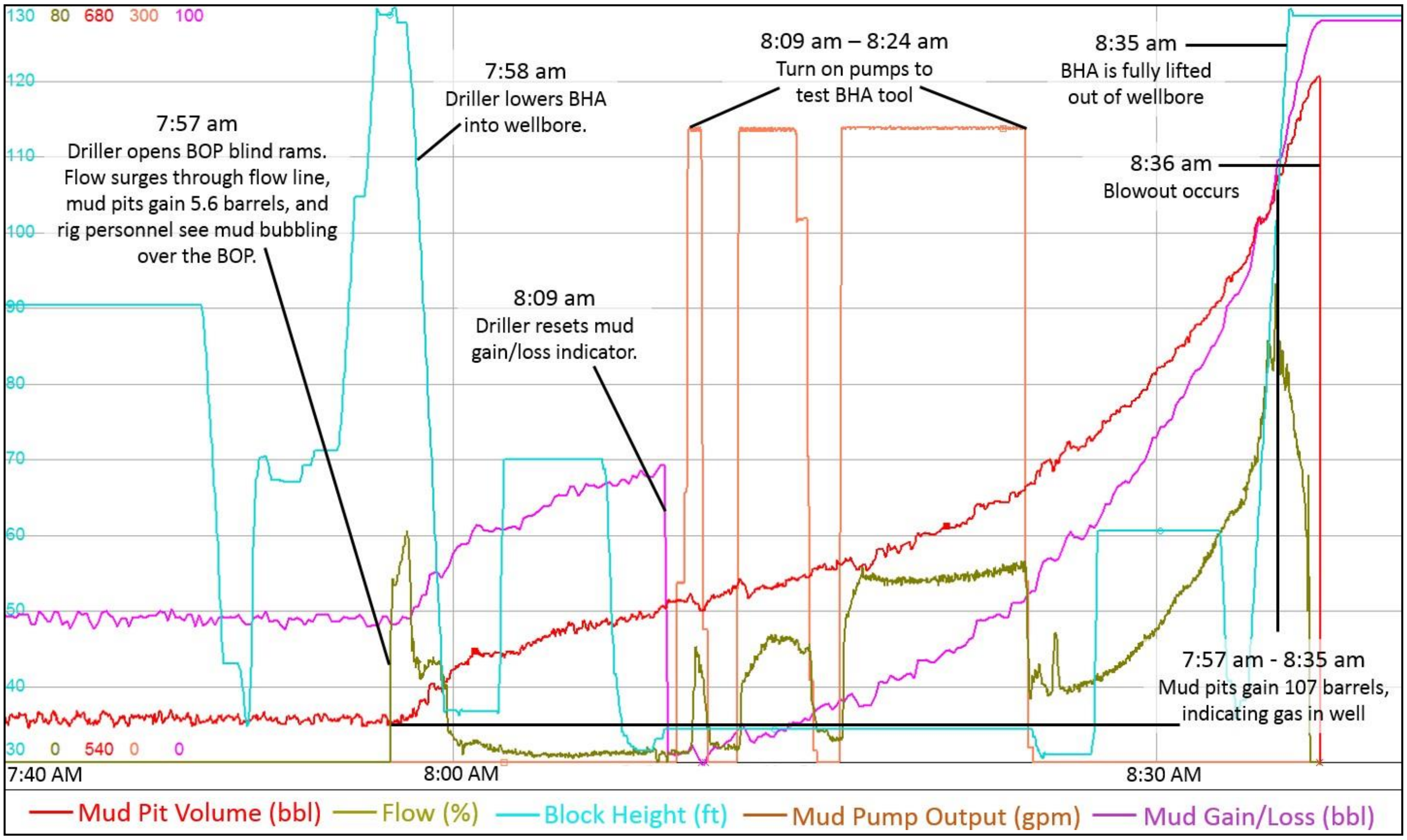


Figure 29. Rig Data between 7:40 am and 8:41 am on Monday January 22, 2018 (day of incident).

During this period, the CSB found that no other personnel, other than the driller and possibly the day-shift Company Man, were actively monitoring the rig data. There was a mudlogger on-site, who analyzed the rock cuttings in the mud returning to surface during drilling to build a geological log of the wellbore. At around 8:25 am, during the significant gains in the mud pits preceding the incident, the mudlogger was talking on the phone with the RMO geologist planning the day's operations, which may have diverted his attention from any well monitoring actives that might have identified the gain. There was also a mud engineer on-site responsible for monitoring and adjusting the mud composition as well as monitoring for gains and losses. The mud engineer was not actively working when the gains in the mud pits were occurring on January 21 and January 22. One mud engineer worked a 24-hour shift. The on-shift mud engineer had gone to sleep on the night of January 21, before the tripping operation began. He woke up at 3:00 am on January 22 to perform a mud check. He went back to bed shortly after, waking up again just before the blowout. The drilling engineer also had the ability to monitor the well. He was on a 7:30 am operations call discussing the previous day's activities and the upcoming activities for the day. He did not closely monitor the well data while the BHA testing was being performed on January 22.

5.7 Blowout and Fire

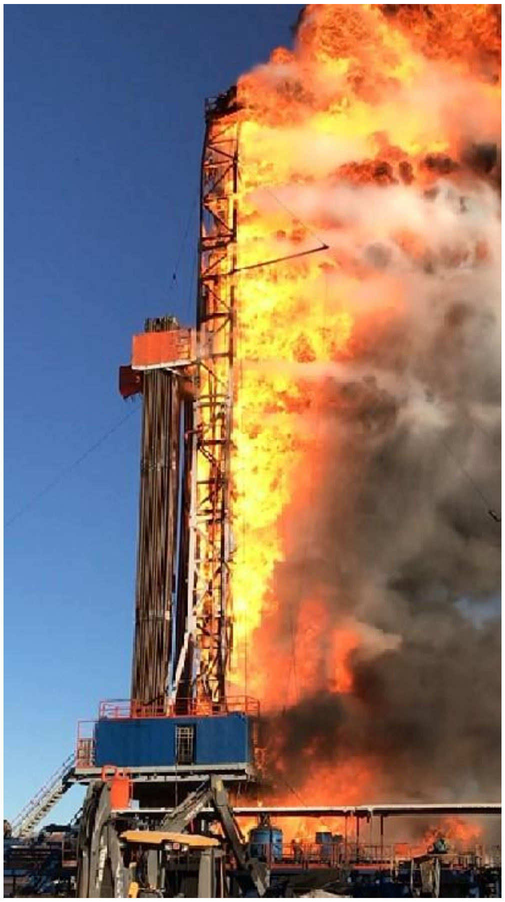


Figure 30. Video still of the blowout and fire taken shortly after it started.

At 8:35 am, the floorhand was standing over the open well hole on the rig floor when he again saw mud flowing out of the open rotating head bowl. He communicated his observation to the driller. The mud from the wellbore was shooting up steadily, getting closer to the rig floor. At this point, the driller was lowering the BHA. The crew then lowered the bottom of the BHA down onto the rig floor.

The driller told the crew through the rig intercom system that he was going to close the blind rams. The floorhand saw the driller get out of his chair in the driller's cabin to walk to the BOP controls, which were about five feet from his chair. The floorhand told the CSB that he does not believe the driller ever made it to the BOP controls.

At 8:36 am,[a] shortly after the driller communicated that he was going to close the blind rams, mud started spraying out of the well. The floorhand saw the motorhand and the second floorhand open the door to the driller's cabin so they could run into it from the rig floor. The mud continued to spray out of the well and covered the windows of the driller's cabin. The floorhand moved behind the drill pipe rack on the rig floor with the rig manager. Very quickly after the mud started spraying out of the well, the diesel oil-based mud and gas escaping the well caught on fire (Figure 30).[b] Between the removal of the BHA from the well at 8:35 am and the blowout at 8:36 am, the mud pits gained an additional 12 barrels of mud, totaling to a 119-barrel gain since the blind rams had been opened at 7:57 am.

The floorhand and the rig manager made their way to the stairs on the rig floor opposite the driller's cabin, where they were able to escape to the ground.

The derrickhand was up high in the mast at the time of the blowout and was trying to get down. He had tried to hook himself onto the slow descent line (an escape line like a "zip line") but was unsuccessful. He then threw his legs around the descent cable and shimmied down the cable toward the ground. He fell off the slow descent line near its bottom from a height of about 10 to 12 feet.

The floorhand observed fire reaching 20-30 feet above the rig crown. The rig manager called his superintendent to alert him to the blowout. The rig manager then told the floorhand to wake everyone in the crew house up. The floorhand then ran to the crew house and woke up the other crew so they could move to a safe location.

The rig manager then ran to the nearby BOP ***accumulator***, which is the equipment used to function the BOP rams. He closed the BOP control handles in the following order: (1) annular preventer, (2) top pipe rams, (3) blind rams, and (4)

[a] The last data point recorded in the well data occurred at 8:36:59 am for Flow, Total Mud Volume, and other well data, before reaching the "error" reading.
[b] Possible ignition sources include a metal object hitting another metal object to cause a spark (one witness heard metal hit metal), a heat lamp installed on the rig floor, static electricity generated from flowing liquid [74], or other sources not identified. The CSB was not able to determine if the lamp was in use at the time of the incident.

bottom pipe rams (Figure 31 and Figure 32). The BOP did not seal the well to stop the blowout. The company man from the previous shift later also tried to function the blind rams, the pipe rams, and the annular preventer, but the BOP did not seal the well. The CSB determined the BOP did not seal the well likely because the control hoses that supplied hydraulic fluid to the BOP to function the rams had burned and leaked the hydraulic control fluid, soon depleting the accumulator stored pressure to the point the BOP could not be functioned (Section 6.13).

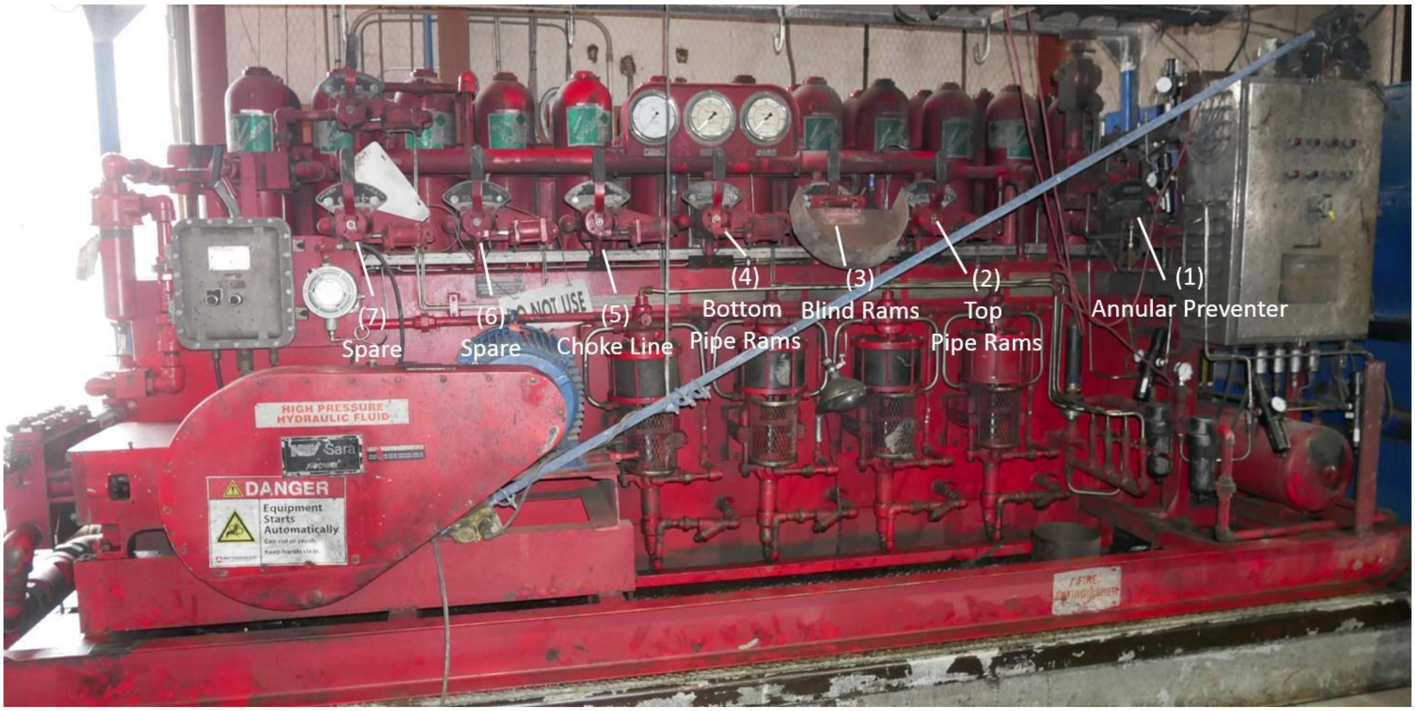


Figure 31. Photo of the BOP accumulator, which is used to function the BOP rams. The rig manager closed the BOP control handles in the following order: (1) annular preventer, (2) top pipe rams, (3) blind rams, and (4) bottom pipe rams. The blowout preventer did not seal the well to stop the blowout when the rig manager functioned the control handles.

Figure 32. Video captured at 11:51 am on January 22, 2018 shows all BOP handles in the closed position.

5.8 Emergency Response

Boots & Coots, a well control services company, responded to the scene. A Boots & Coots responder observed that one side of the blind rams was fully closed, and the other side was halfway closed (Figure 33).

A team of Boots & Coots responders and RMO representatives manually closed the blowout preventer blind rams to shut in the well at about 4:00 pm [10].

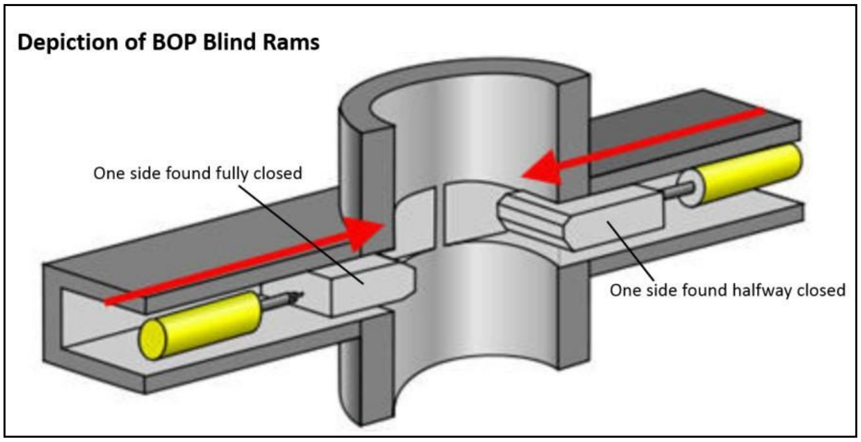


Figure 33. Depiction of BOP blind rams. A Boots & Coots responder found that the south-side blind ram was fully closed, and the north-side blind ram was halfway closed. Source: drillingformulas.com [11] with notations by CSB.

5.9 Incident Consequences

All workers who were in the driller's cabin (dog house) or ran into the driller's cabin during the blowout and fire were killed. Those workers included:

- Company Man[a]
- Directional Driller
- Driller
- Floorhand (Second)
- Motorhand

[a] A Patterson driller told the CSB that the company man and the directional driller are typically in the driller's cabin when the BHA is being tested.

6 Incident Analysis

This section discusses the areas causal to this incident, including:

- **Failure of Barriers** – Both the primary barrier, hydrostatic pressure produced by mud to keep the well overbalanced, and the secondary barrier, the human detection of the influx and closure of the blowout preventer, failed. RMO and Patterson did not have sufficient degradation controls in place to maintain these barriers (Section 6.1).

- **Underbalanced Operations Proceeded without Needed Planning, Equipment, Skills, or Procedure** (Section 6.2).

- **Driller Had Difficulties with Electronic Trip Sheet** – These difficulties impeded the driller from identifying the amount of gas that entered the well during the tripping operation out of the lateral section (Section 6.3).

- **Incorrect Determination That There Was No Surface Pressure Before Opening BOP** – Both times that no pressure was observed in the annulus before opening the BOP, the data indicates mud flowed from the well once the BOP was opened, indicating there actually was unobserved pressure at the surface (Section 6.4).

- **Weighted Pill Did Not Overbalance the Well** – The weighted pill placed at the top of the curve was not of sufficient volume or density to overbalance the lateral section of the well (Section 6.5).

- **Lack of Detail in Procedures** – The Patterson tripping procedure was overly vague such that both the "Calculated Fill" and "Continuous Fill" tripping methods technically complied with the procedure. The procedure did not detail the methods to monitor that the well was taking proper fill (Section 6.6).

- **Alarm System Was Deactivated** – Both the day and night driller elected to turn off the alarm system, which likely contributed to the crew missing key indications of the well control event. The alarm system also was not effectively designed to alert personnel to hazardous conditions during different operating states (e.g., drilling, tripping, circulating, and surface operations) and would have sounded excessive non-critical alarms during the 14 hours leading to the blowout, which likely led to the drillers choosing to turn off the alarm system (Section 6.7).

- **Deficient Policies for Controlling Abnormal / Unexpected Conditions** – The Management of Change (MOC) program was not used—and was not expected to be used by Patterson management—during the unexpected and abnormal operation conditions preceding the incident to control or correct the hazards. The Time Out for Safety (Stop Work) program also was not successful in halting operations when crewmembers raised concerns (Section 6.8).

- **Drills Did Not Test Driller Influx Detection Skills** – Both the day and night tour drillers missed or did not respond to pit gains leading to the incident. Patterson did not regularly test whether drillers would quickly identify and respond to simulated pit gains, as recommended by API RP 59 (Section 6.9).

- **Flow Checks Not Conducted Per Patterson Policy** – Crew members on Patterson Rig 219 did not perform flow checks as required by Patterson policy, performing only two out of a required 27 flow checks on well 2H-

16 and well 1H-9. Patterson-required flow checks were not performed during the tripping operation before the incident (Section 6.10).

- **Patterson Did Not Effectively Monitor the Implementation of its Policies** – The deficient or lack of implementation of several Patterson corporate safety policies contributed to the incident. Patterson did not effectively monitor the implementation rate of its policies (Section 6.11).
- **Victims Had No Safe Escape Option from Driller's Cabin (Dog House)** – While it is unknown how long the victims remained alive in the driller's cabin, they were effectively trapped inside of the driller's cabin when the mud and gas ignited. The two exit doors were blocked by flames (Section 6.12).
- **Blowout Preventer Did Not Close** – The hydraulic lines that supplied hydraulic fluid to the blowout preventer likely burned early in the incident, preventing the BOP from closing when workers attempted to function it (Section 6.13)

The graphical causal analysis (AcciMap) is in Appendix G.

6.1 Failure of Barriers

6.1.1 Well Control Barrier Philosophy

API RP 59 recommends that two barriers be maintained during drilling operations to prevent the escape of formation fluids, like gas, from a well [6, p. 54]. For the drilling of 1H-9, the two barriers were (1) a "prevention barrier" (primary barrier), which was the hydrostatic pressure produced by the mud to keep the well overbalanced, and (2) a "mitigation barrier" (secondary barrier), which was the human detection (e.g., by driller, company man, other workers) of the gas influx and human activation of the blowout preventer. These two barriers did not prevent the incident.

During the drilling of Well 1H-9, the Primary Well Control Barrier was not maintained. As a result, the well became underbalanced and gas influxes occurred. Described below are the available barriers—and lack of barriers—between 6:30 am on January 21 and the incident.

1. **Drilling and Circulating Operations from 6:30 am to 6:30 pm on January 21.** The hydrostatic pressure produced by the mud plus APL was lower than the formation pressure. The prevention well control barrier was lost, meaning no barrier was in place to prevent gas from entering the well. Thus, the only barrier in place was the secondary mitigation barrier: detection of influx and closure of BOP. Two barriers were not available. The drilling operations should have been stopped until the primary prevention barrier (hydrostatic pressure produced by mud or mud plus APL) was restored, returning the operation to having two barriers as API recommends. In addition to the absence of barriers, the drilling operation was an underbalanced operation performed without the correct equipment, procedures, and training (see Section 6.2).
2. **Trip Out to Top of Curve Using Calculated Fill Tripping Method from 6:30 pm to 11:00 pm on January 21.** The hydrostatic pressure produced by the mud was lower than the formation pressure. The prevention well control barrier was lost, meaning no barrier was in place to prevent gas from entering the well. During the tripping operation, the secondary mitigation barrier in place to prevent gas in the well from leading to a blowout was the detection of influx and closure of BOP. During this period, the well gained 20 barrels from gas influx or expansion. In addition to the absence of a primary barrier, the Calculated Fill tripping method was an underbalanced operation performed without the correct equipment, procedures, and training.

3. **Circulation at Top of Curve from 11:00 pm on January 21 to 1:00 am on January 22.** The hydrostatic pressure produced by the mud or mud plus APL was lower than the formation pressure. The prevention well control barrier was lost, meaning no barrier was in place to prevent gas from entering the well. The operation should have been stopped until the primary prevention barrier (hydrostatic pressure produced by mud or mud plus APL) was restored, returning the operation to having two barriers as API recommends. During this operation, a 14-barrel gain occurred.

4. **Trip Out to Top of BHA Using the Continuous Fill Tripping Method from 1:00 am to 5:00 am on January 22.** The hydrostatic pressure produced by the mud plus the ECD pill was lower than the formation pressure. The prevention well control barrier was lost, meaning no barrier was in place to prevent gas from entering the well. The operation should have been stopped until the primary prevention barrier (hydrostatic pressure produced by mud) was restored, returning the operation to having two barriers as API recommends. During this period, the well gained 23 barrels from gas influx or expansion.

5. **Surface Operations from 5:00 am to 6:10 am on January 22.** The hydrostatic pressure produced by the mud plus the ECD pill was lower than the formation pressure. The prevention well control barrier was lost, meaning no barrier was in place to prevent gas from entering the well. With the BHA across the BOP, only the annular preventer was available to seal around the irregular diameters of the BHA. During this period, a 31-barrel gain occurred.

6. **Blind Rams Closed After BHA Pulled from Well, from 6:10 am to 8:00 am on January 22.** At the start, the hydrostatic pressure produced by the mud plus the ECD pill was lower than the formation pressure. The prevention well control barrier was still lost, meaning there was no barrier in place to prevent gas from continuing to enter the well, and this caused surface pressure to build under the closed blind rams. The well may have reached a static surface pressure condition with downhole well pressure equaling or slightly exceeding (due to continued gas migration) the formation pressure. The only barrier in place was the secondary, mitigation barrier, which was the closed BOP. Two barriers were not in place.

7. **Opening of Blind Rams and Testing of New BHA from 8:00 am to Blowout (8:36 am) on January 22.** Opening the blind rams released surface pressure. The hydrostatic pressure produced by the mud plus the ECD pill was lower than the formation pressure. The prevention well control barrier was lost. With the BHA across the BOP, only the annular preventer was available to seal around the irregular diameters of the BHA. During this period, a 119-barrel gain occurred.

   The blowout occurred at 8:36 am January 22, one minute after the BHA was picked up above the BOP. The BOP blind rams were closed at 4:00 pm on January 22.

Between 6:30 pm on January 21 and the blowout (8:36 am) on January 22, the well gained an observed total of 207 barrels of gas from influx and expansion, a very large volume.

The CSB created a bowtie diagram (Figure 34) to illustrate the two planned barriers to prevent a blowout. Both barriers had associated degradation factors that could, and ultimately did, reduce the reliability and availability of the barriers.

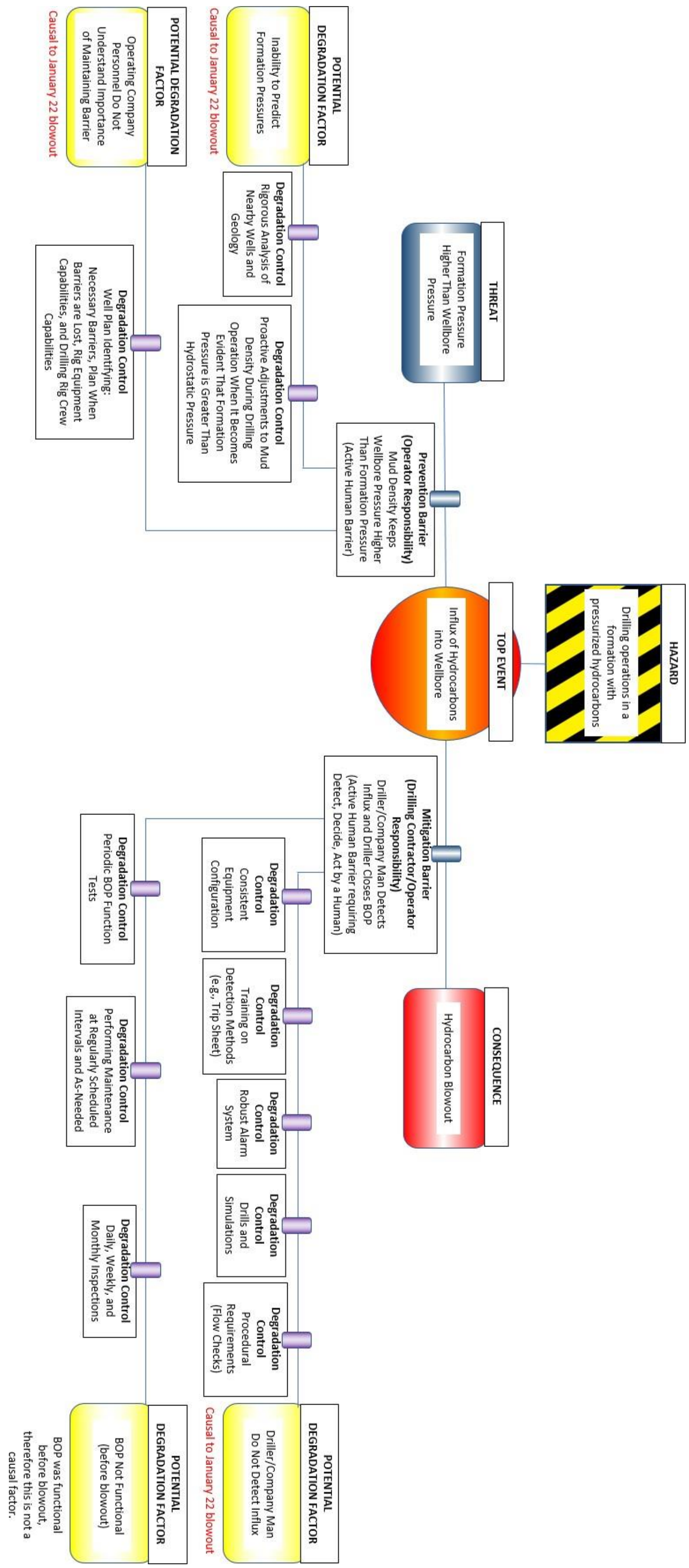


Figure 34. Bowtie diagram of Pryor Trust Well 1H-9 barriers

The CCPS Book *Bow Ties in Risk Management: A Concept Book for Process Safety* defines different types of barriers used to prevent or mitigate an unsafe event. They appear in Table 3.

Table 3. Barrier Types from CCPS Book Bow Ties in Risk Management: A Concept Book for Process Safety *[12, p. 36]*

Short Name	Barrier Type †	Description	Detect	Decide	Act	Examples
Passive	**Passive Hardware**	The barrier works by virtue of its presence.	N/A	N/A	N/A	Dike, blast wall, crash barrier, anti-corrosion paint
Active	**Active Hardware**	All elements of the barrier are executed by technology.	Technology (e.g., pressure sensor)	Technology (e.g., logic controller)	Technology (e.g., emergency shutdown valve)	Process control systems and Safety Instrumented Systems
Human ††	**Active Hardware + Human** (predominately hardware)	The barrier is a combination of human behavior and technological execution.	Technology (e.g., high-high level indicator and alarm)	Human (e.g., operator hears and responds to alarm)	Technology (e.g., emergency shutdown valve) OR Human (e.g., operator manually shuts valve)	Operator-activated ESD valve Gas alarm and decision by human to evacuate
	Active Human (predominantly human)	The barrier consists of human actions, often interacting with technology.	Human observation (e.g., operator walk around detects leak)	Human evaluation (e.g., decides to shut-down and isolate the equipment)	Human – but acting on technology (e.g., operator presses stop button or manually shuts a valve)	Operator detection and response (e.g., during structured walk arounds)
Continuous	**Continuous Hardware**	The barrier is always operating.	N/A	N/A	Technological	Ventilation system, impressed current cathodic protection

†Not all barriers can fit exactly within the barrier type model, particularly for mitigation barriers (e.g., ignition control is a blend of passive (electrical switch cubicles) and active hardware (shutdown of powered systems)).

††Active Human could be combined into Active Hardware + Human as even where all three aspects of detect-decide-act involve humans, some hardware is usually involved (e.g., in "act": a human presses a stop button to shut a valve); however, the distinction is helpful to teams to identify barriers that are predominantly human.

6.1.2 Primary, Prevention Barrier: Hydrostatic Pressure Produced by Mud, Adjusted by Rig Workers at Direction of Operator

The hydrostatic pressure produced by mud was a barrier intended to prevent a gas influx into the well (i.e., a "prevention barrier"). As shown in Table 3, this was an "active human" barrier as the drilling team had to actively manage the hydrostatic pressure produced by the mud to ensure it produced sufficient pressure to prevent formation fluids from entering the wellbore. The mud hydrostatic pressure is actively monitored by (1) workers checking the density of the returned and pumped fluid periodically, (2) the mud engineer performing mud checks at least once every shift, and (3) rig workers (e.g., driller) continuously monitoring for gains/losses to determine if the mud density should be changed.

Like any barrier, the mud barrier was subject to failure. Figure 34 shows two main degradation factors that contributed to the failure of the mud from preventing a gas influx, and no sufficient degradation controls were in place to prevent those degradation factors from leading to failure of the barrier.

One degradation factor for the mud barrier was the potential inability of the operating company to predict the formation pressures, thereby causing the mud weight to be too low. Two controls to mitigate this degradation factor include:

(1) Rigorous analysis of nearby wells and geology to predict the likely formation pressures, and

(2) Proactive adjustments to the mud density when it becomes evident that the actual formation pressures are greater than the hydrostatic pressure produced by the mud.

RMO evaluated the mud weights used in other nearby wells when creating its well plan, enacting the first control listed above. However, RMO and its contracted representatives did not respond to signs that the well had become underbalanced and that the mud barrier was no longer effective (Section 6.2).

A second degradation factor for the mud barrier is the key decision makers' underappreciation of the safety-criticality of the barrier and its role in preventing a blowout. When RMO and its contracted representatives became aware that the well had become underbalanced, they actively chose to continue the operation without increasing the mud weight to return the well to an overbalanced state. Effective degradation controls were not in place to ensure that RMO and its representatives would actively respond to signs that their primary barrier was lost.

6.1.3 Secondary, Mitigation Barrier: Human Detection of Gas Influx and Closure of Blowout Preventer

Human detection of a gas influx and subsequent human-activated closure of the blowout preventer was a barrier intended to prevent a blowout after an influx occurred (i.e., a "mitigation barrier"). As Table 3 shows, this type of barrier is an "active human" barrier which largely relies on human action. Like any barrier, this barrier also had degradation factors that could lead to failure, including:

(1) Workers do not detect gas influx (causal to incident),

(2) The BOP does not function (in this case, not causal to blowout because BOP was operating before incident)

Before the blowout, the BOP was evidently functioning normally and likely could have closed to prevent the blowout had it been activated in time.[a] No workers, however, ultimately detected and responded to the gas influx to close the BOP before the blowout, so this barrier failed.

Shown in Figure 34, a number of "degradation controls" could have been in place to reduce the likelihood that rig workers would miss the signs of gas influx. These controls include:

(1) Procedural controls, such as the consistent conduct of flow checks,

(2) Drills and simulations to test the driller's ability to detect influxes,

(3) An alarm system designed to effectively warn the driller of an influx,

(4) Training on methods to detect an influx, such as how to use a new electronic trip sheet, and

(5) Consistent configuration of equipment for operations, such as tripping.

[a] BOPs are not "fail safe." They do not fail in a safe position, which would be in a position that could seal the well. BOPs require human activation to function. Also, BOPs take time to activate. The blind rams, for example, took seven seconds to close once activated. BOPs are also not necessarily designed to close on a flowing well; a high flow rate could erode BOP ram rubber elements and prevent sealing.

The controls in place were not effective and led to failure of the mitigation barrier. Improved degradation controls could increase the likelihood that the driller, company man, or other workers detects an influx, increasing the reliability of the barrier.

6.1.4 Need for Safety Instrumented Systems in Drilling Industry

Humans are fallible. When effectively implemented, automatic controls that respond to signs of influx and close a BOP component, such as the annular preventer, could reduce the sole reliance on human detection of an influx to prevent a blowout.

The first four barrier types listed in Table 3 are in hierarchical order, in order of effectiveness. "Active Hardware" barriers, such as technologically activated barriers, are more effective than "Active Human" barriers, such as human detection of an influx and human activation of the BOP [12, p. 34].

Active hardware barriers, also called safeguards more prevalently in the process industry, are commonly used in the refining and petrochemical sector. Safety-instrumented systems are commonly designed to activate when a process parameter such as temperature, pressure, or flow reaches a pre-defined set point, to automatically bring the process into a safer state or to shut down the process. These are back-up safety systems in the event of a failure in normal operating controls, including operator response which is comparable to driller response.

The CSB is aware that safety-instrumented systems designed to automatically bring the well to a safe state in the event other barriers fail are not used in the drilling industry. While the drilling industry differs from the more steady-state process industry, the development of automatic well control systems appears to be an area that is technologically achievable, and there is a key opportunity for the drilling industry to research and develop such technology through the collaboration of drilling, engineering, and instrumentation experts. [**Recommendation 2018-01-I-OK-R2**]

6.2 Underbalanced Operations Proceeded Without Needed Planning, Equipment, Skills, or Procedure

Based on both the elevated gas levels in the mud returns from the well and the flaring that occurred while drilling and circulating, the CSB concludes that it became evident to the RMO representative on the drilling rig and Patterson on January 21 that the well had become underbalanced. Underbalanced drilling, with gas intentionally being brought to the surface, was not planned for in RMO's drilling plan, but RMO's representatives chose to continue drilling with the gas returning to surface, an indication that the well was underbalanced. Underbalanced drilling nullified the primary well control barrier and contributed to the blowout.

6.2.1 Drilling Operations Planned for Near-Balance Conditions

The Drilling Prognosis (drilling plan) indicates that RMO planned for this well to be drilled close-to-balance. Appendix D shows the full 1H-9 drilling plan.

For the vertical section of the well between 2,300 feet MD and the top of the curve, the Drilling Prognosis states:

> Be prepared for over pressured windows throughout this section, as well as losses. Offsets have shown losses in this region throughout this section, but always be prepared for hydrocarbon influxes. Utilize orbit valve on connections if necessary [CSB Note: The well could become underbalanced when mud pumps were turned off, and the use

> of the rotating head and closed orbit valve could prevent excessive influx into the wellbore when pumps were turned off during connections (when a new stand of drill pipe was added to the drill string)] and monitor all parameters closely for any key indicators. Allow the wellbore to dictate the [mud weight]. It will be vital to keep [mud weight] low throughout this section. Utilize tightest mesh shaker screens possible and run centrifuge at frequent intervals to maintain lowest possible [mud weight].

For the lateral section, the Drilling Prognosis states:

> It will be vital to keep [mud weight] low throughout this section as losses are possible. Utilize tightest mesh shaker screens possible and run centrifuge at frequent intervals to maintain lowest possible [mud weight].
>
> Woodford Tripping Procedure: Circulate hole clean. [Trip out of the hole] following sound tripping practices, in an attempt to create minimal disturbance of the wellbore. If the well is flowing, calculate/pump ECD [Equivalent Circulating Density] pill before continuing to [trip out of the hole].

6.2.2 Mud Program Selection

Mud program selection is the term used to describe the process a company uses for determining the type and weight of drilling mud planned for a new well. This is critical because if the mud is not dense enough, i.e., not high enough in pounds per gallon (ppg), it may not sufficiently prevent an influx of formation fluid into the well. If the mud is too heavy, it might fracture the formation and leak out of the wellbore, a condition called “lost returns.” Not only are lost returns costly, but a damaged formation can result in a higher risk of influx.

A common method for mud program evaluation in a region where other wells have already been drilled is to review what earlier wells have used. RMO evaluated at least six offset wells in Pittsburg County targeting the Woodford formation in its planning phase for Pryor Trust well 2H-16, the well drilled before 1H-9 (incident well). The offset wells used the following mud weights (densities) during the drilling operations (Figure 35):

1. Offset Well 1: 8.5 – 9.0 ppg.
2. Offset Well 2: 8.5 – 9.4 ppg.
3. Offset Well 3: 8.5 – 9.0 ppg.
4. Offset Well 4: 8.6 – 9.0 ppg.
5. Offset Well 5: 8.8-9.3 ppg.
6. Offset Well 6: 8.5-9.1 ppg.

RMO received six different proposals from mud companies for the mud program for Pryor Trust well 2H-16, which were based on the following mud weights for the “production zone” (2,340 ft - 15,929 ft)—the portion of the well where gas was anticipated (Figure 35):

1. 8.5-9.4 ppg
2. 8.8-9.0 ppg
3. 8.6-8.8 ppg
4. 8.8-9.2 ppg
5. 8.8-9.1 ppg
6. 8.6 - 8.9 ppg (Program selected by RMO)

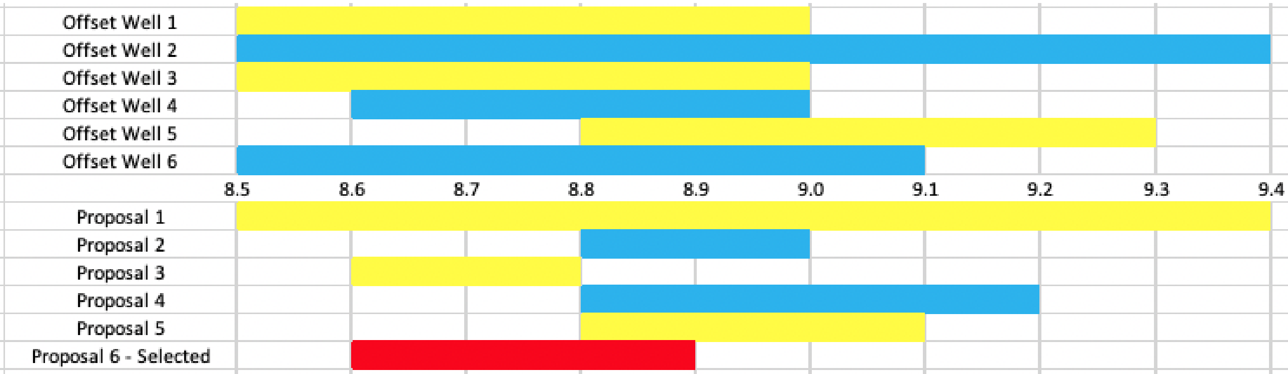


Figure 35. Comparison of the offset well mud weights, and the proposed mud weights provided in the various mud program proposals for the 2H-16 well.

During the drilling of 2H-16, the well experienced lost returns at 1,950 ft MD at a mud weight of 8.8 ppg, losing about 200 barrels of mud to a formation. After this loss event, the mud weight was reduced. The goal was "to keep [mud weight] as low as possible," and the crew used a mud weight as low as 8.15 ppg while drilling the production zone. They drilled the remainder of the well without incident.

Well 1H-9 was on the same well pad as 2H-16, the two surface holes located 15 feet apart. The 2H-16 horizontal section extended south of the well pad, and the 1H-9 horizontal section extended north of the well pad. For the 1H-9 well, RMO requested a mud program proposal only from the company that provided the mud program for the 2H-16 well. Due to the losses experienced in Well 2H-16 at a mud weight of 8.8 ppg, the mud company provided a mud program with a much lower mud weight range, between 8.2-8.6 ppg for the well depth between 2,300 ft-17,799 ft, which included the production zone. The CSB notes that this reduction in mud weight for the 1H-9 production zone based on experience from 2H-16 might have been unnecessary because the 2H-16 loss zone was behind casing in 1H-9, possibly eliminating the need to decrease mud weight for the 1H-9 production zone. During the drilling operation, the mud weight for the production zone for 1H-9 was ultimately maintained between 8.1 – 8.5 ppg.

On January 21 when the well became underbalanced, the mud weight was about 8.3 – 8.35 ppg. On January 22, the day of the blowout, the mud weight was 8.4 ppg. The mud weight in 1H-9 ultimately was not high enough to prevent gas from entering the well.

After the blowout, the drilling of the well was completed at mud weights between 8.90 – 10.50 ppg.

6.2.3 Unexpected Flaring / Decision to Continue

The unexpected elevated gas in the mud that began at 7:30 am on January 21[a] and the flaring that began by 11:11 am were signs that the formation pore pressures were higher than could be controlled by the ECD in the well and that the well was underbalanced while drilling. Underbalanced drilling with gas intentionally returning to surface was not an operation RMO had planned for in the drilling plan for 1H-9; therefore, Patterson Rig 219 was not equipped to perform this operation, the companies had not created underbalanced drilling procedures, and Patterson crewmembers did not have the necessary training or skills to drill underbalanced (next Section). However, RMO and its contracted representatives were excited about the flaring because it indicated they were in a productive gas zone. Key decision-

[a] The gas content reached 2,050 units.

makers representing RMO, including RMO-contracted personnel, exchanged the following communications by text message:

- Employee 1: "Dude this flare is blasting off like crazy now. We are off bottom to make a connection and it just shot sky high."

  Employee 2: "I'll take it all day long, hopefully it carries into sunset"

- Employee 1: "[The flare] [d]ied and came back to life."

  Employee 2: "Good deal …."

- Employee 3: "Any idea what is going on [with the flaring]? No gamma but 1200 units of gas …"

  Employee 4: "My first thought is a fault."

  Employee 3: "One not on the 3D… we really got our $ worth on that huh"

  Employee 4: "No doubt. I have instructed team to maintain course and after we discuss with geology and have all talked maybe we can come with a good plan. Pretty crazy, best gas we have seen."

- Employee 5: "I'm having to teach my boys how to drill in gas. Just having a barrel of fun but I like it."

  Employee 4: "Good deal. We'll keep [mud weight] in our back pocket."

RMO and its contracted representatives chose to continue on with the operation with the current (underbalanced) mud weight, continuing to drill for the next 8 hours after the increase in gas units that began at 7:30 am.[a] They were now deliberately performing an underbalanced drilling operation.

6.2.4 RMO and Patterson Attempted an Unplanned Underbalanced Operation

In 2008, API created a standard on underbalanced drilling, API RP 92U *Underbalanced Drilling Operations*. The standard defines underbalanced drilling as:

> A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface [8, p. 12].

API RP 92U specifies critical components of an underbalanced drilling operation, including a planning phase to "ensure the technical and safety integrity of the project," well control specifications, return flow process control

[a] They continued drilling until 3:30 pm.

equipment specifications, drill string specifications, circulating equipment specifications, well integrity specifications, underbalanced drilling operations specifications, site safety, and wellsite supervision specifications.

API RP 92U states that "[d]edicated [underbalanced drilling control devices and] flow control system components *shall be installed* for [underbalanced drilling] operations…" (emphasis added) [8, p. 51]. The industry standard also states that "[a]s a minimum requirement, all onsite personnel shall possess a certificate of completion from a training program accredited by the International Association of Drilling Contractors [Underbalanced Operations] UBO Rig Pass™ Accreditation Program, or its equivalent" [8, p. 59].[a]

RMO chose to continue with the drilling operation when it became evident that the well was underbalanced, despite not having planned for it and not meeting the requirements of the industry standard on underbalanced drilling operations. They had not developed underbalanced operations well control specifications, Rig 219 did not have the required underbalanced drilling equipment, and no personnel on the rig had taken the IADC UBO Rig Pass™ training.

Increasing the mud weight to return the wellbore to conventional, overbalanced drilling conditions would likely have prevented the incident. However, the CSB found no evidence that RMO, the drilling engineer, or company men fully considered that they were venturing into an operation they had not planned for, that personnel were not trained and the rig was not equipped to perform the unplanned underbalanced drilling operation safely, or that they had lost their primary well control barrier. Section 6.8 discusses how the two companies had not defined a process to identify and respond to abnormal conditions such as these, or how to respond to the loss of a barrier.

6.2.5 Need for Industry Tripping Guidance

The Calculated Fill tripping method decided upon by RMO to pull the drill pipe from the underbalanced 1H-9 well introduced a significant amount of influx gas into the well (20 barrels). RMO communicated to the CSB that the Calculated Fill method, using a rotating control device and orbit valve, is a common method to trip drill pipe out of horizontal wells. In this case, use of the method directly contributed to the blowout.

The CSB found limited industry guidance on how to safely trip out drill pipe for any type of drilling operation (overbalanced, underbalanced, managed pressure). Such guidance could have led to a different tripping method, such as increasing the mud weight before tripping, being selected. The drilling industry should develop operations guidance on how to safely trip out drill pipe during (1) overbalanced operations, (2) managed pressure drilling operations, and (3) underbalanced drilling operations. [**Recommendation 2018-01-I-OK-R3]**

6.3 Driller Had Difficulties with Electronic Trip Sheet

Drillers are trained to monitor whether the well is taking the correct amount of mud while tripping by filling out a "trip sheet," where the calculated volume of the pipe removed is compared to the volume of mud taken by the wellbore. If the actual volume of mud pumped to keep the wellbore full is less than the calculated volume of the pipe being removed, it could be an indication of an influx of formation fluids into the wellbore.

Patterson had just started transitioning its drillers to using electronic trip sheets instead of paper trip sheets. The electronic trip sheet had built-in functionalities, including the ability to automatically calculate parameters that the driller would manually calculate using a paper trip sheet. While one driller the CSB spoke with liked the electronic trip sheet because of the ease in populating fields, the driller who worked on the shift before the incident implied that he

[a] Drilling industry representatives communicated to the CSB that this IADC UBO RigPass training may not currently exist.

was not computer savvy and had difficulties with using the electronic trip sheet. The driller had test-used a couple of electronic trip sheets, but this was his second time fully using and relying on the electronic trip sheet during a real tripping operation.

The electronic trip report for the tripping operation out of the lateral portion of the well on January 21, 2018 is shown in Figure 36. The trip sheet auto-populated the “Number of Stands” column as 5 stands for normal drill pipe and 3 stands for heavy weight drill pipe. The driller, however, chose to monitor the well at intervals of drill pipe stands different from these values, but he did not know how to change the default number of stands on the electronic trip sheet. As a result, the values on the electronic trip sheet—“Number of Stands,” “Calculated Volume” values (“Individual Volume” and “Cumulative Volume”), and “Difference” columns—were not reflective of the actual operation. Instead, the driller attempted to track the differences between the sheet and the actual condition by making a mental note of the number of stands pulled, and he assessed the “Fill Volume” only in comparison to what he recalled the calculated volume would be for each set of stands pulled.

Contractor Name
PATTERSON-UTI DRILLING COMPANY

TRIP REPORT

RIG INFO

Well Name	PRYOR TRUST 0718 1H-9	Date	January 22, 2018 00:55
Operator	RED MOUNTAIN OPERATING, LLC	Rig Number	Pat-UTI 219

TRIP RECORD

Component	Number of Stands	Dry/Wet	Calculated Volume		Measured Volume		Difference
			Individual Volume barrels	Cumulative Volume barrels	Fill Volume barrels	Cumulative Volume barrels	barrels
5in Drill Pipe	5	DRY	3.15	3.15	3.35	3.35	0.20
5in Drill Pipe	10	DRY	3.15	6.30	3.89	7.25	0.95
5in Drill Pipe	15	DRY	3.15	9.45	2.96	10.20	0.75
Heavy Weight	18	DRY	5.40	14.85	2.28	12.49	-2.36
Heavy Weight	21	DRY	5.40	20.25	5.28	17.76	-2.49
Heavy Weight	24	DRY	5.40	25.65	1.03	18.79	-6.86
Heavy Weight	27	DRY	5.40	31.05	1.25	20.05	-11.00
Heavy Weight	30	DRY	5.40	36.45	3.44	23.49	-12.96
Heavy Weight	33	DRY	5.40	41.85	2.28	25.77	-16.08
Heavy Weight	36	DRY	5.40	47.25	1.03	26.80	-20.45
Heavy Weight	39	DRY	5.40	52.65	3.35	30.15	-22.50
5in Drill Pipe	44	DRY	3.15	55.80	-0.53	29.62	-26.18
5in Drill Pipe	49	DRY	3.15	58.95	-6.45	23.17	-35.78
5in Drill Pipe	54	DRY	3.15	62.10	16.02	39.19	-22.91
5in Drill Pipe	59	DRY	3.15	65.25	3.40	42.59	-22.66
5in Drill Pipe	64	DRY	3.15	68.40	-3.40	39.19	-29.21
5in Drill Pipe	69	DRY	3.15	71.55	-3.23	35.97	-35.58

Driller Name	[redacted]
Contractor Signature	
Operator Signature	
Date	January 22, 2018 04:45

Calculated (barrels)	71.55
Measured (barrels)	Trip Tanks: 36.15
	Mud Tanks: -0.18
Total	35.97
Difference (barrels)	-35.58

Figure 36. Electronic trip report for tripping operation out of lateral portion of well on January 21, 2018. The date and time shown on the trip sheet are in UTC time. This trip sheet was started at 6:55 pm local time on January 21 and was closed out at 10:45 pm local time on January 21.

Using this method, the driller assessed whether the well was taking proper fill on very narrow intervals, evaluating fill for each individual set of stands pulled without monitoring the cumulative “Difference” column. If at one set of stands the well did not look like it took proper fill, he would resume to the next set of stands to monitor fill. If that next set looked about right, he would continue. The driller used this method of assessing fill volume for the entire tripping operation out of the lateral section.

The cumulative fill data in the "Difference" column is very important for drillers to monitor because it shows the cumulative effect of what might only appear to be minor volume discrepancies when seen segment by segment. By not using the “Difference” column, the driller did not realize that the small variations he observed between fill volume and calculated volume added up to a 20-barrel difference over the entirety of the lateral section tripping operation, a significantly large volume indicating that the primary well control barrier (hydrostatic pressure produced by mud) had been lost and that gas was in the well.

The driller told the CSB he had never received formal training on using the electronic trip sheet, instead trying to self-teach himself about it using trial-and-error. This lack of training, in combination with Patterson not conducting performance assurance to determine if he could use the trip sheet in a practical situation, led to misusing the electronic trip sheet and contributed to the significant gas influx.

6.4 Incorrect Determination That There Was No Surface Pressure Before Opening BOP

Twice during the operations leading to the incident, rig workers checked for annular pressure before opening the BOP (Sections 5.1.2.2 and 5.6). The workers observed no pressure then opened the BOP. However, after they opened the BOP, the data showed mud flowed from the well, indicating unobserved pressure was at the surface.

Possible reasons for pressure not being observed at the surface before opening the blowout preventer include:

1. The pressure gauge made reading low pressures difficult due to the scale (0 – 10,000 psi);
2. Low pressures may not have registered on this gauge and may not have caused the needle to move;
3. A valve was in the wrong position when reading the pressures, thereby isolating the pressure gauge from the well annulus; and
4. A line may have been plugged, preventing the rig workers from reading the pressure in the well annulus.

A solution to items 1 and 2 includes the installation of a digital pressure transmitter/indicator on the choke manifold, which could allow low pressures to be identified more readily. A solution to items 1 through 4 is the use of “dissimilar verification,” [13, p. 140] by using at least two independent data points to identify if pressure is in the annulus before opening the BOP. For example, rig crews could verify (1) that there is no annular pressure and (2) that there is no flow from the well (e.g., using the choke manifold), before opening the blowout preventer.

6.5 Weighted Pill Did Not Overbalance the Well

The drilling engineer decided to place a weighted pill at the top of the curve in the well to provide additional hydrostatic pressure to the lower, lateral part of the well. The drilling engineer and the two company men worked together to calculate the pill size and density needed. The drilling engineer communicated to the CSB that they “wanted [the well pressure] to be between the current mud weight and the [last calculated] ECD, somewhere in there. […] You don’t want to break a formation or cause more issues than necessary.” They decided on a 50 barrel, 10 ppg weighted pill to be spotted at the top of the curve.

Because the well was underbalanced while drilling, placing a pill in the well that did not replace greater than the annular pressure loss exerted while drilling (explained in Section 3.4) meant that the well would still be underbalanced after pill placement. The CSB calculated that the pill the drilling engineer and company men decided on replaced only about 36% of the annular pressure loss (Appendix B). This means that the well would still be underbalanced after the pill was spotted. It is unclear why the drilling engineer and company men selected pill parameters (volume and density) that did not produce the hydrostatic pressure necessary to replace greater than the annular pressure loss to overbalance the well. The CSB notes the better option was to increase the mud weight so that the well was statically overbalanced before performing the tripping operation.

In addition to the insufficient pill volume and density, the confusion over the composition of the pill regarding the mistaken addition of LCM material (Section 5.3) reinforces that this operation was subject to random improvisation. Both of these errors could have been prevented if the operation had instead used written work instructions to clearly communicate safety-critical parameters such as pill type and composition.

6.6 Lack of Detail in Procedures

Tripping procedures should detail critical elements of the operation, including equipment lineup and well-monitoring requirements, to help ensure that tripping operations are performed using consistently safe practices and barriers are maintained, and to help prevent and mitigate influxes. Before the incident, the Patterson tripping procedure provided only minimal guidance on how to trip drill pipe out of the well or how to monitor for an influx while tripping. The tripping procedure stated:

> 1. A trip tank shall be utilized on all tripping out of the hole operations when a BOP is installed…
>
> 2. The driller shall track pipe displacement volumes and hole fill volumes for all stands pulled utilizing the Trip Schedule form.

6.6.1 Tripping Procedure for Trip Out of Lateral Section

The Patterson procedure largely relied on driller knowledge and experience on how to line up equipment and how to ensure the well was taking proper fill. The procedure was general in nature, so both the common Continuous Fill and the RMO-specified Calculated Fill/Force Fill used before the incident would technically comply even though both tripping methods required different well-monitoring techniques to identify a gas influx.

6.6.2 Tripping Procedure Did Not Specify Equipment Alignment

The night tour driller working during the tripping operation before the incident had never experienced the rig alignment used on the night of January 21 where the mud bucket discharge was routed to the trip tank.[a] In his four years working on Rig 219, he was used to the mud bucket discharging to the mud pits. The driller had difficulties determining if the well was taking proper fill while tripping out of the vertical section because as the mud bucket drained to the trip tank, the trip tank volume fluctuated up and down (see Section 5.4).

[a] The CSB was informed that the general standard in the North Sea for wet tripping is routing the fluid from the mud bucket to the trip tank so that if the float (a type of check valve preventing back flow) fails in the drill string and the well starts to kick up the drill string, the kick can be identified.

Patterson's tripping procedure did not specify the required equipment alignment during the tripping operation. Developing an appropriately detailed procedure could have prevented the confusion that contributed to the incident if it (1) specified the required equipment alignment for the tripping operation, including where to route the mud bucket discharge hose, (2) required workers to visually confirm the equipment was aligned correctly before beginning the tripping operation, and (3) included specific well monitoring instructions for wet versus dry tripping. [**Recommendation 2018-01-OK- R7**]

6.6.3 Procedures and Management of Change are Safety-Critical Components of a Company's Safety Management System

In the CSB investigation of the 2010 Macondo well blowout, the CSB identified similar deficiencies with procedures, which were causal to the incident:

- BP's development of the Macondo Temporary Abandonment plan occurred without a formal process, and BP did not review internal policies, and
- There was a lack of written work plans and safety critical procedures [14, pp. 84-85].

In the CSB investigation report on the Macondo offshore well blowout, the CSB stated:

> the operator and drilling contractor generally rely upon the knowledge and experience of their well site leaders and well operations crew, but they should focus on building a resilient process that can "adjust its functioning prior to, during or following changes and disturbances so that it can sustain required operations under both expected and unexpected conditions" [14, p. 84].

The CSB also noted in the Macondo investigation report that "[t]he consistent development and appropriate use of written operating procedures are key to managing the risk of a hazardous operation" [14, p. 92].

Beyond just providing instruction, procedures also specify the standard way of performing an operation. Procedures establish the company expectation of what is normal, making it easier to identify a situation that is not normal. When an abnormal situation arises potentially leading to deviation from a procedure, it should trigger a management of change (MOC) process (Section 6.8).

Drilling companies should create separate, appropriately detailed procedures for the different types of tripping operations that a drilling crew might perform. If the operator or drilling contractor chooses to use a different tripping method not defined by an existing procedure, then a management of change must be triggered to perform a hazard analysis on the proposed new tripping method, to develop a detailed procedure for the new method, to ensure workers are trained on the procedure, and to ensure the rig has the needed equipment to perform the operation. In this incident, tripping procedures were specifically of interest, but the need for appropriately detailed procedures and the use of management of change when deviating from procedures applies to all operations that a drilling rig crew performs.

Written procedures and management of change are critical elements of a company's safety management system. The use of detailed procedures and management of change when deviating from procedures is required by the Occupational Safety and Health Administration (OSHA) Process Safety Management (PSM) standard, which applies to the process industry but exempts drilling. No requirement for detailed procedures or management of change applies to the drilling industry, which is a major gap in the safety management of U.S. onshore drilling operations. This is discussed in Section 9.

6.7 Alarm System Was Deactivated

The driller's cabin was equipped with several monitors displaying data and camera footage essential to the drilling operation. A re-creation of the setup is shown in Figure 37. The top screen to the left of the driller displayed an aggregate of the drilling data, including drill bit depth, weight on bit, torque, stroke count, mud pit volumes, trip tank volume, gain/loss, mud return flow, and other parameters. The other monitors in front of the driller displayed data for the drawworks,[a] pump parameters, top drive parameters,[b] and camera feed to watch drill pipe latching operations.

Figure 37. Depiction of driller console on Rig 219. The upper screen to the left of the driller displayed the aggregate of the drilling data.

On the drilling data monitor (upper left monitor), the driller could adjust alarm set points, silence individual alarms, silence all alarms for all parameters by turning the alarm horn off, or completely deactivating the alarm system so that both the horn and visual indications of alarms would be disabled. The data system installed was provided by Pason,

[a] The drawworks is large spool and winch of drilling line, which supports, raises, and lowers the drill pipe in the well.
[b] The top drive is equipment hooked into the top of the drill string to rotate the drill string during drilling operations.

which is one of the two major electronic rig data companies for the onshore drilling industry, the other being M/D Totco by National Oilwell Varco (NOV). Both companies provide similar services.

In response to a formal request for information by the CSB, the rig data company provided data points recorded by the rig data alarm system in internal developer logs that included alarm status, alarm set points, and sensor data for tank volumes and flow. The rig data company communicated to the CSB that "this is the first time [the company] has … attempted to create such a document, and so the process it used has not been validated and may not have resulted in an accurate record of events." While this may be a concern, the CSB determined this data provides critical information that may explain in part why both drillers missed indications of the large gas influx before the incident. It is important for the drilling industry to understand the information contained in the post-incident data compilation effort, which is explained below.

On January 21 at 6:30 pm, the data indicates that the driller turned off the entire alarm system. With the exception of a 20-second period on the morning of January 22 when the data shows the day tour driller briefly turned on and again turned off the alarm system, the data indicates the alarm system stayed off the entire 14 hours leading to the blowout.

It is unknown why both drillers might have elected to turn off the alarm system. A plausible reason to turn off an alarm system—and to keep it off for tripping, circulating, and surface operations—is that the alarms set for the drilling operation are perceived as irrelevant or a nuisance for other operations. The data indicates that had the alarm system been on, most of the alarms that would have activated from 6:45 pm on January 21 through the incident would have been irrelevant to detecting the well control event. Set point changes, alarm benchmark changes, or alarm deactivations would have been required to silence the alarms. Appendix E shows the various alarm states based on the data provided to the CSB, from 6:45 pm on January 21 through the incident, had the alarm system been active. The appendix describes which alarms would have been indicative of the well control event and which would not.

For an alarm system to be effective, it must be configured so that the driller only receives alerts to conditions that require his or her attention. Other alarms not indicative of a hazardous condition are a nuisance that could distract from "true" alarms, or could lead to drillers ignoring alarms—a phenomenon known as "normalization of deviance." While the drillers might have adjusted set points real-time had the alarm system been turned on to silence unnecessary alarms, Patterson had not developed guidance for this set-point adjustment, or prescribed certain alarm set points for certain operations. Instead, to manage the alarm rate, both drillers apparently elected to simply turn off the alarm system.

An effective alarm system is one of the "degradation controls" shown in Figure 34 to help ensure that the mitigation barrier, the detection of an influx by rig workers and closure of the BOP, would function as expected. In this case, however, shutting down the alarm system nullified it as a degradation control, thereby increasing the likelihood that the detect-influx-and-activate-BOP mitigation barrier would fail, which is what ultimately happened. Had the alarm system been on, the existing alarm system likely also would have nullified the system as a degradation control, since most of the alarms would not have been warning of the ongoing well control event (Appendix E). The alarm system would not have been effective in alerting the driller to the imminent blowout.

Patterson had not developed procedures indicating what the alarm set points for parameters should be during tripping, circulating, and surface operations to identify a well control event. The only alarm guidance provided by Patterson required a +/- 5 barrel Gain/Loss set point (not to exceed +/- 10 barrels), and a +/- 5% flow set point. The CSB notes that neither alarm was set at the set points required in Patterson policies, according to the data compilation effort.[a]

---

[a] The Gain / Loss alarm set points were -40 / +15 barrels; the flow alarm set points were 5 % (low) and 49 % (high).

Also, for much of the operation, the alarms at these set points would have been nuisance alarms not indicative of the well control event (see Appendix E).

An alarm philosophy and performance of alarm rationalization could have led Patterson to determine what alarms at what set points were critical to identifying a well control event for the various operating states (drilling, tripping, circulating, and surface activities). Patterson did not develop an alarm philosophy or perform an alarm rationalization before the incident. The implementation of an alarm system with only the rationalized alarms active could have led to both drillers keeping the alarm system on and seeing only the alarms that were critical to detecting the well control event.

6.7.1 Industry Guidance on Alarm Management

In recent decades, recognition of the importance of well-designed alarm systems was stimulated mainly by the findings of the investigation into the nuclear incident at Three Mile Island (TMI), Pennsylvania, in 1979. The Report of the President's Commission on the TMI incident was one of the first major investigations to emphasize the critical role of the human factor in preventing and managing incidents. Regarding the ineffectiveness of the alarm systems at TMI, the report noted that:

> During the first few minutes of the accident, more than 100 alarms went off, and there was no system for suppressing the unimportant signals so that operators could concentrate on the significant alarms. Information was not presented in a clear and sufficiently understandable form… Overall, little attention had been paid to the interaction between human beings and machines under the rapidly changing and confusing circumstances of an accident [15, p. 11].

Among the recommendations made by the TMI President's commission was that:

> Equipment should be reviewed from the point of view of providing information to operators to help them prevent accidents and to cope with accidents when they occur. Included might be instruments that can provide proper warning and diagnostic information… [15, p. 72].

A significant body of fundamental and applied research was stimulated after investigators recognized the significance of a poorly designed alarm system in escalating the TMI incident. Numerous standards and guides have been published giving recommendations on the design of effective alarm systems for instrumented safety-critical systems across a range of industries and types of operations [16, pp. xx-xxi], [17], [18]. For example, detailed guidance on the design of effective alarm systems for nuclear plants was included in NUREG 0700, the Nuclear Regulatory Commission's *Human-System Interface Design Review Guidelines*, first published in 1981 [16]. The guidance in NUREG 0700 has been widely used as part of the basis for recommendations of the design, implementation, and use of alarm systems in other industries.

Today, there is a large body of guidance and recommendations on the design of alarm systems for hazardous operations. Widely-used sources relevant to the oil and gas industry in general are:

- ANSI/ISA-18.2 (2016) *Management of Alarm Systems for the Process Industries* [18]
- EEMUA 191 (2013) *Alarm systems - A Guide to Design, Management and Procurement* [19]
- API RP 1167 (2016) *Pipeline SCADA Alarm Management* [20]
- Norwegian Petroleum Directorate YA-711 (2001) *Principles for Alarm System Design* [21]

- IEC 62682 (2014) *Management of Alarms Systems for the Process Industries* [22]

ANSI/ISA 18.2, an alarm management standard widely used in the chemical processing industry, is detailed below.

6.7.1.1 ANSI/ISA-18.2 Management of Alarm Systems for the Process Industries

American National Standard ANSI/ISA-18.2 *Management of Alarm Systems for the Process Industries* details an Alarm Management Lifecycle to be used in the process industries. A depiction of the lifecycle is shown in Figure 38. This standard has requirements that would benefit drilling rig alarm management systems.

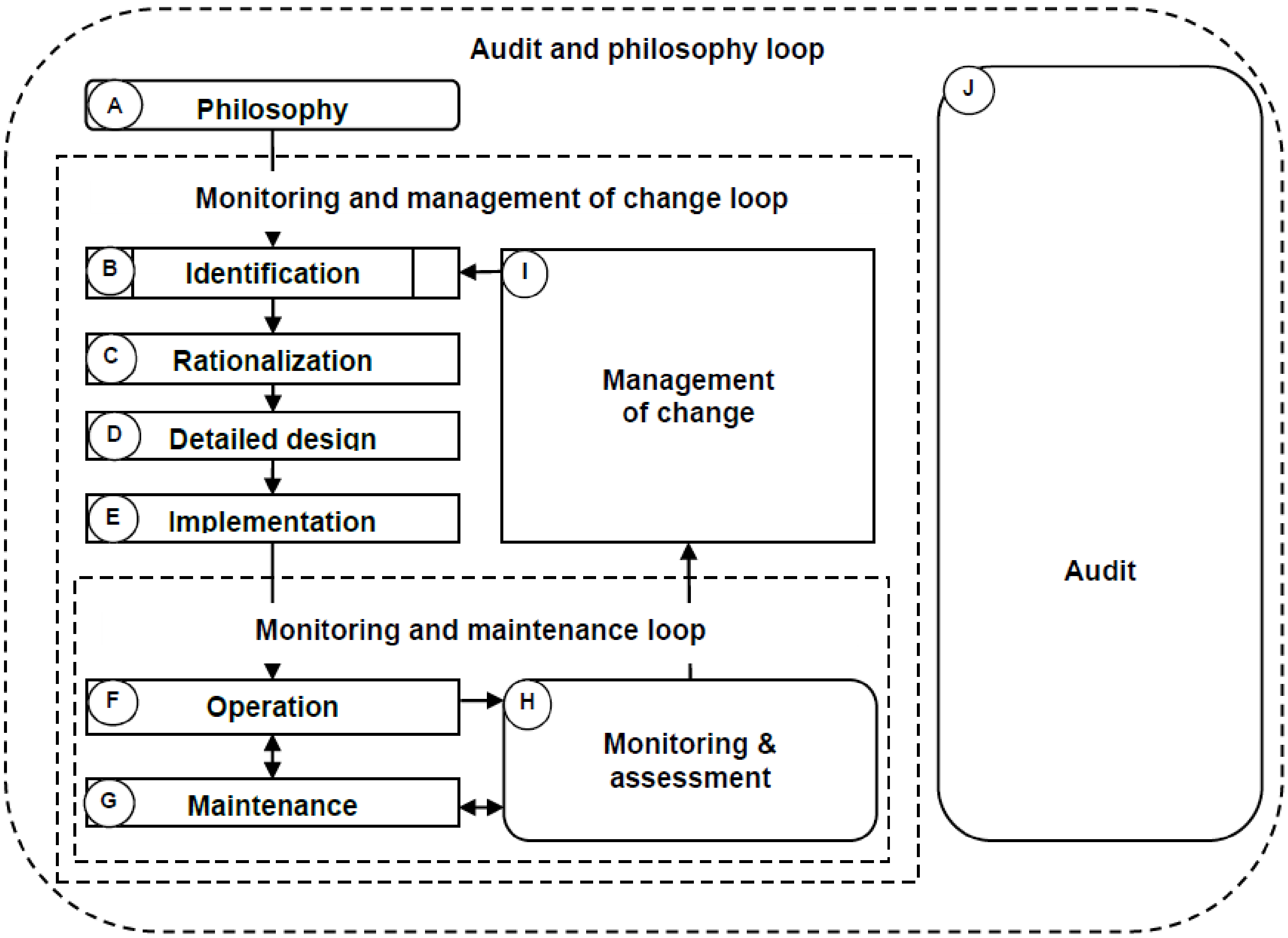


Figure 38. Alarm management lifecycle described in ANSI/ISA 18.2 Management of Alarm Systems for the Process Industries *[18, p. 27]*

The lifecycle includes important alarm management phases, including:

1. **Creating an "Alarm Philosophy"**

   An Alarm Philosophy document is the framework for the alarm management program. Among other requirements, it facilitates "consistency with risk management goals and objectives" as well as "design and management of the alarm system that supports an effective operator response [18, p. 38]."

2. Identification of Alarms

Identification is the method of determining the "possible need for an alarm or a change to an alarm." Potential alarms are identified, for examples, through hazard analyses, incident investigations, and procedure reviews [18, p. 46].

3. Alarm Rationalization

Rationalization is the process of systematically analyzing each identified alarm to determine if it meets the requirements of the Alarm Philosophy. Rationalized alarms:

a. Must be directed to the operator;

b. Must indicate a process deviation, abnormal condition, or equipment malfunction; and

c. Must require a timely response.

Alarms that meet the Alarm Philosophy criteria are then given set point(s) and expected operator action. The alarms are also prioritized based upon alarm criticality. Alarm rationalization also verifies that:

a. The alarm will not become non-critical; and

b. The alarm does not duplicate another alarm.

Alarm rationalization includes evaluating alarms considering different operational modes. Using "state-based" alarming (e.g., on a drilling rig could include different active alarms for different operations such as drilling, tripping and circulating) can prevent alarms critical to certain operations from becoming a nuisance when operating in a different state where those alarms are not needed [18, pp. 47-50].

6.7.2 State of Knowledge and Guidance Relevant to Drilling

Leading to the 2010 Macondo (BP / Deepwater Horizon) blowout, the drilling crew missed critical indications in the rig data of gas influx. The National Commission's Report to the President on the incident observed:

> In the future, the instrumentation and displays used for well control monitoring must be improved. There is no apparent reason why more sophisticated, automated alarms and algorithms cannot be built into the display system to alert the driller and mudlogger when anomalies arise [23, p. 121].

This observation has led to an increased number publications on alarm management in the drilling industry [24], [25], [26], [27]. One of these publications, a paper presented at a 2017 Society of Petroleum Engineers (SPE) / International Association of Drilling Contractors (IADC) conference, states:

> Drilling Control Alarms Systems (DCAS) leave much to be desired. Excessive alarm volumes … lead to Driller alarm blindness and exceed all industry recognized standards. … This results in critical alarms being ignored…. Safety performance personnel do not consider alarm management in their scope of consideration in efforts to educate, train and reduce incidents.

> A typical 6th generation offshore rig generates hundreds to thousands of driller alarms every day. Counts can range from 6000 to 50000+ in a seven day period. Even the best case scenario of 1 alarm per minute is deemed unacceptable by the Norwegian Petroleum Directorate [and] [o]ther recognized standards including ISA 18.2 and EEMUA 191… [25, p. 1].

The paper also states:

> [W]e have not identified any [drilling] contractor in our study that are able to produce an Alarm Philosophy … or who have performed an Alarm Rationalization exercise on their drilling rigs and facilities.
>
> Key Finding: The drilling industry needs more comprehensive Alarm Management techniques as recommended in ISA and EEMUA standards. This is [a] core weakness in our industry and likely the most significant finding in [this] paper [25, p. 11].

Patterson did not create an alarm philosophy or alarm rationalization for Rig 219 before the incident.

In December 2016, IADC published a guidance document called *Drilling Control System Alarm Management Guidelines*. The document states that the IADC Drilling Control System subcommittee identified areas needing improvement in the drilling industry relating to drilling alarm management systems, including alarm philosophy, alarm documentation, master lists of alarms, management of change, and alarm rationalization [28, p. 3]. The document summarizes the requirements in ANSI/ISA 18.2, EEMUA 191 *Alarm Systems: A Guide to Design, Management, and Procurement*; YA-711 *Principles for Alarm Systems Design*; and IEC 62682 *Management of Alarms Systems for the Process Industries*. The guidance document found that "[i]n general, the standards are designed for a static process-control environment and are not representative of the dynamic drilling environment" [28, p. 6].

The IADC alarm management guidelines document recommends that drilling contractors develop an alarm philosophy, and provides guidance on alarm rationalization, alarm documentation, and alarm management of change. The guidelines, however, do not issue requirements to the drilling industry on alarm management systems, such as those contained in ANSI / ISA 18.2 for the process industries, or discuss a state-based alarm strategy.

6.7.3 Need for Alarm Management Standard for the Drilling Industry

The CSB considers state-based alarming to be an important alarm management strategy for the drilling industry, where different alarms could be critical for different operations. A state-based alarm concept does not have to be complicated. In this case, the state-based alarm strategy could have been as simple as deactivating the mud pit and gain/loss alarms when the mud pits were not in use (i.e., while tripping using the trip tank) and adding capability to disable the flow alarm when the trip tank pumps were running. A state-based alarm system could have prevented the large quantity of anticipated non-critical alarms on Patterson Rig 219 and could have led to both drillers to keep the alarm system activated.

In 2010, following the publication of ANSI/ISA 18.2, API published API RP 1167 *Pipeline SCADA Alarm Management* [29]. It details alarm management strategies specifically for the pipeline industry, incorporating ANSI/ISA 18.2 as a normative reference. The CSB has identified no similar API standard detailing alarm management strategies specifically for the drilling industry. Such a standard could incorporate the guidance of ANSI/ISA 18.2, but provide guidance on implementation for the drilling industry. In addition to the alarm lifecycle discussed in ANSI/ISA

18.2, the drilling industry would benefit from guidance on implementing state-based alarms for different drilling operations (e.g., drilling, tripping, circulating, surface operations). [**Recommendations 2018-01-I-OK-R4, R8**]

There is also a need for alarm system providers to design the user interface to allow for easy navigation between the state-based alarm operations. Switching between operating modes on the alarm screen should be an easy action for the driller. For example, developing icons on the user-interface screen that the driller can select for the drilling, tripping, circulating, or surface operations—where alarms are already pre-configured—could provide a quick and easy method to switch between the alarm states. [**Recommendations 2018-01-I-OK-R15, R17**]

6.8 Deficient Policies for Controlling Abnormal / Unexpected Conditions

Drilling a well is a dynamic environment. It requires prediction of how the underground formations might behave in certain locations. There is always the possibility that the formation pressures and geology behave differently than predicted, and in those scenarios companies need a way to (1) identify that something is different than expected and planned for, and (2) develop a new plan on how to proceed.

In several instances during the Pryor Trust Well 1H-9 operations, an abnormal condition was not adequately assessed before proceeding:

1. *Unexpected flaring while drilling and before tripping out of the well* indicated the well was underbalanced and that the primary well control barrier (hydrostatic pressure produced by the drilling fluid) was no longer effective;

2. *Unexpected deadheading while tripping out of the lateral portion of the well* indicated gas influx into the well and ineffective well control;

3. *Two events where pressure was expected below the BOP but no pressure was observed*; and

4. *Tripping wet (mud-filled drill pipe) with the mud bucket aligned to trip tank*, an unusual equipment alignment for the driller and company man that made monitoring the well difficult.

The response to abnormal conditions, usually beginning with some type of troubleshooting activity, can be guided using robust Management of Change (MOC) and Stop Work programs. Discussed below, Patterson primarily used MOCs for equipment changes, not for operational changes, and RMO did not have its own MOC program. Also, actions in the spirit of Stop Work were taken, but they were not effective in preventing the blowout.

6.8.1 Management of Change Ineffective for Operational Changes

Patterson's Management of Change policy is specified to be performed "...when implementing temporary or permanent changes to personnel, policy, procedures, equipment or structures, or any other applicable item or activity requiring change management." While this statement specifically includes "procedures," the policy subsequently omits it and defines just the other three as "Change Request Categories":

1. Personnel

2. Policy

3. Equipment and Structures

If changes in operational procedures are wedged into these three remaining categories, the most closely related would be the "Policy" category, but procedures are not included. The Policy category is written to apply largely to changes in corporatewide policies. There is no guidance or method for conducting risk analyses, making changes, and getting formal approvals for real-time operational procedure changes that could deviate at a level well below corporate policy.

Also, there is a lack of clarity about whether the corporate MOC policy would be applied when the operating company directed rig workers to conduct an activity that was not in compliance with Patterson's own policies. A "bridging document" that aligns the operator's and drilling contractor's safety management systems (Section 7.1), which was not created between Patterson and RMO, could have helped clear some of these ambiguities.

The CSB learned that Patterson conducted MOCs primarily for changes in "equipment and structures." However, equipment changes could occur without an MOC; no Patterson MOC was performed for the addition of the orbit valve to Rig 219, which was a change in Rig 219 equipment. The orbit valve was rented and installed on Rig 219 by RMO, the operator, not by Patterson, the rig owner. RMO also failed to install the valve under the authority of an MOC because RMO did not have its own management of change policy. There is no regulatory requirement for management of change to be used in drilling operations. Management of change is an important part of companies' safety management systems. The lack of regulatory requirement for management of change is a major gap in the safety of U.S. onshore drilling operations.

6.8.2 Time Out for Safety

Patterson's Stop Work Authority program is called "Time Out for Safety." The Time Out for Safety (TOFS) policy states:

> Employees shall observe the behavior of other personnel on their jobsite and constantly be aware of both safe and unsafe behaviors.
>
> […]
>
> Any person who has a concern about their safety or the safety of another person, has the responsibility to stop the operation by calling a Time Out for Safety (TOFS). Any person that calls a TOFS shall not be reprimanded for doing so.
>
> After calling a TOFS, any person who observed at-risk behavior shall use the Safety 24/7 process to have an effective conversation with all affected personnel.
>
> All recognized unsafe acts and conditions shall be adequately addressed before the job will be allowed to continue.

RMO also has a Stop Work policy, which applies to Management, Employee/Consultants, and Contractors. It gives the following guidance:

1. Management will "[s]upport the STOP program unconditionally."
2. Employee/consultants will "[s]top any task/job immediately if observing an unsafe act being performed or any unsafe condition developing. There will be no retribution for any work stoppage that occurs due to EHS concerns."
3. Contractors have a similar requirement as employee/consultants.

Patterson employees told the CSB they generally felt comfortable and supported by Patterson in calling a Time Out for Safety. The night-tour company man also enacted a Stop Work twice during the tripping operation out of the vertical section of the well (1) when he was unsure about the mud bucket alignment, and (2) to check if the well was taking proper fill while tripping.

Other personnel on the rig who had concerns with the operation communicated their concerns to rig-site management, in the spirt of TOFS:

1. One person communicated the following to the CSB: "The possum belly was spitting out mud real good [before we routed the piping to the mud gas separator while drilling on January 21], and it covered the pits, it was shooting into the back yard. There was a large degree of gas in the hole, and you could see it in the possum belly. It was erupting with mud, it covered everything in mud. That side of the rig, the pits, the half round. Mud was erupting out of the possum belly. I saw that and knew that wasn't right. I was concerned. I was concerned about the status of the well. … I told [the driller, mud engineer, RMO geologist, and company man] what my concerns were, and I told my night hand to sleep with his clothes on."

2. Another person communicated the following to the CSB: "The flare was steady when I saw it [before the night tour on January 21]. 20-30 foot. Decent flare. […] This one had me on alert because I had not seen flaring in Oklahoma with Patterson. It was a red flag to me that something might not be right. We had the safety meeting. I said why don't we weight up. They said we want to drill underbalanced because it will be faster. They wanted to drill underbalanced. I've drilled underbalanced before. It's a different aspect when you play with that kind of thing and you know what you're doing, and you play with that kind of thing and people don't have experience with it. […] I don't like it, that's a stupid decision. […] I would tell [the driller], then talk to [the Rig Manager], and that would be the chain of command I dealt with. I didn't feel comfortable with this whole situation. Why didn't we just increase our mud weight, isolate it down to one tank, circulate that tank with heavy mud through the entire well, and we wouldn't have had to deal with anything else. I and [the driller] brought up weighting up. […] We all brought it up […]."

While no personnel requested a formal Time Out for Safety to halt rig operations, these communications were in the spirit of Time Out for Safety; personnel communicated their concerns to management. However, the mud weight was not increased before tripping because:

1. RMO leadership and its contracted representatives including the drilling engineer and company men were more excited about the gas than concerned about the implications that a barrier was lost (Section 6.2);

2. RMO leadership and its contracted representatives including the drilling engineer and company men believed they were controlling the well with their planned operations (Section 5.1.1);

3. RMO leadership and its contracted representatives including the drilling engineer and company men believed signs of influx would be identified and controlled, but the equipment lineup contributed to confusion in interpreting the trip tank volume changes, causing the driller and company man to miss signs of influx (Section 5.4.1). In addition, the alarm system was turned off (and also would have been ineffective had it been on), likely contributing to the drillers missing indications of influx;

4. RMO leadership and its contracted representatives including the drilling engineer and company men believed the rig was capable of performing its planned operations, even though the operations fell under the category of

"Underbalanced Drilling," which the rig and its personnel were not equipped or trained to do (Sections 5.1 and 6.2); and

5. Patterson did not choose to shut down the operation. It is important to note that the drilling contractor has the responsibility to shut down operations when they believe that the operator's plans would introduce unacceptable risk. The drilling contractor needs to have detailed policies and procedures in place so that rig crews can clearly see when operator plans deviate from drilling contractor safety requirements. In this case, because Patterson did not have detailed written procedures relating to the planned drilling or tripping operations (Section 6.6), the drilling rig crewmembers did not have policy and procedures to lean on to stop the unsafe operation (e.g., detailed operating procedures, requirement for management of change when deviating from procedures).

While Stop Work programs are important last resort-type programs to stop an unsafe event, they are prone to failure in correcting broader process-related hazards. Therefore, reliable systems, including detailed drilling plans with specified barriers and detailed operating procedures must be maintained, and a management of change program for real-time procedure changes must be in place to identify and control hazards before reaching the point of relying on a Stop Work program to prevent a catastrophic process event. These are critical aspects of a company's safety management system. These important safety management system elements are not required for onshore drilling operations by any regulatory standard.

6.8.3 Safety Management of Deviations from Drilling Plan

Sometimes operational excursions from original drilling plans are possible due to the inability to accurately predict geological behavior and formation pressures. Figure 39 below shows how RMO and its representatives responded to the deviation from the original drilling plan, which did not include underbalanced drilling. On January 21, when the well suddenly was underbalanced, RMO and its representatives chose to improvise a new plan as they proceeded real-time. This decision led to RMO and its representatives not fully considering the hazards of the operation or considering the need for specialized equipment and procedures.

In operations with a healthy safety management system, when deviations from the original drilling plan occur, one of two options should be enacted, as shown in Figure 39. One option is to adjust parameters to return to the original drilling plan, which in this case would have required increasing the mud weight to return to overbalanced drilling. The second option is to stop operations and create a new drilling plan—using a management of change process—ensuring that necessary procedures, equipment, training, and skills are available so that the new plan can be performed safely before proceeding.

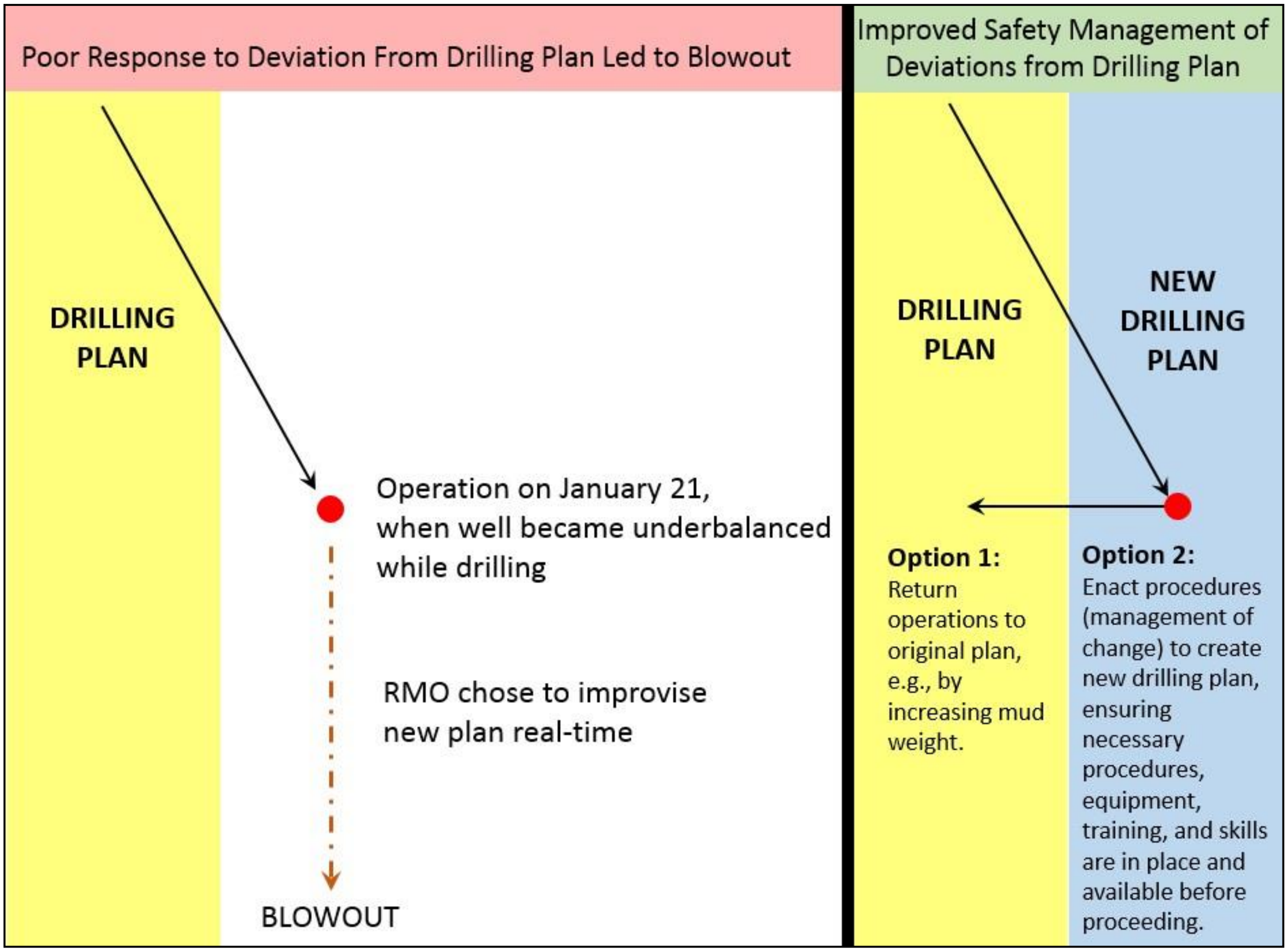


Figure 39. Depiction of RMO's and its representatives' response to deviation from drilling plan (left), and improved safety management of deviations from drilling plan (right)

6.9 Drills Did Not Test Driller Influx Detection Skills

The driller has the safety-critical role of identifying indications of an influx into the well (e.g., mud pit gain, flow increase, improper hole fill while tripping), responding effectively to stop the influx as quickly as possible (e.g., by closing the BOP), and alerting the crew to act. Both the day tour and night tour drillers missed or did not respond to significant pit gains preceding the incident:

1. While circulating at the top of the curve, there was a 14-barrel gain in the mud pits. Most of this gain occurred after the driller reset the gain/loss reading. The driller communicated to the CSB that he did not observe this gain (Section 5.2).

2. Between 4:51 am and 6:07 am on January 22, there was a 31-barrel gain in the trip tank. This gain overlapped both the day and night drillers' tours and evidently was not observed by either driller (Section 5.5); and

3. Between 7:57 am on January 22 and the blowout, the mud pits gained 119 barrels of mud. During this period, the driller had reset the gain/loss measurement, at 8:09 am. This very large gain was evidently not observed or addressed (Section 5.6).

Patterson crewmembers told the CSB that gas influxes are rare in their experience. The driller on the night tour before the incident had been a driller for about eight years and had experienced two kicks in his career, both on the same well, before January 21, 2018. The rig manager had previously been a driller for several years and had never experienced a kick. The night tour company man had experienced a kick when he was a directional driller, and a couple of kicks in his eight-years' experience as company man. The CSB was not able to determine the well control event experience of the day crew.

Kicks being a rare event could lead to drilling rig workers's reduced attentiveness to looking for signs of gas influx if they do not anticipate and rarely experience an influx. For this reason, frequent drills simulating an influx could help to keep drilling rig workers alert to signs of influx. To regularly test the driller's and rig crew's response abilities, API RP 59 *Recommended Practice for Well Control Operations* states the following:

> All concerned personnel should be familiar with the well control system components and installation and capable of reacting quickly and efficiently to potential situations requiring their use. Drills should be documented, executed, repetitive, and followed-up to correct identified problems. Drills should be clearly announced so all concerned know that a drill, not an actual event, is taking place. Drills generally enhance the crew proficiency in well control situations.
>
> […]
>
> During a routine operation, *the rig supervisor should simulate a gain in pit drilling fluid volume by raising a float sufficiently to cause an alarm to be activated.* … The drilling crew should immediately initiate [response procedures]. … The supervisor initiating the drill should record response time, which should be one minute or less [6, p. 49]. (emphasis added)

From March 2017 through the incident, Patterson Rig 219 conducted 76 drills that tested the drilling crews' abilities to respond to a gas influx. However, 59% of these drills were conducted by the driller—not the rig supervisor, as recommended in API RP 59. As such, the driller's ability to detect and respond to signs of gas influx was not tested in the bulk of these drills. Even in cases when the rig manager or other personnel conducted the drill, the drill scenario was often spoken instead of simulated, again resulting in not testing the driller's influx detection skills. The driller on tour before the incident told the CSB that it had been years since a supervisor had mimicked an influx to test his detection skills.

Shown in Figure 34, drills are an important control to increase the likelihood that the driller will detect a gas influx. Without drills, the degradation factor that "driller does not detect influx" is a greater risk, increasing the likelihood of failure of the secondary "Driller Detects Influx and Closes BOP" barrier.

Because the driller's ability to quickly identify and respond to gas influxes is a safety-critical function, drilling contractors should conduct formalized drills to regularly test, measure, and improve drillers' influx detection and response skills. [**Recommendation 2018-01-OK-R9**]

6.10 Flow Checks Not Conducted Per Patterson Policy

The Patterson Well Control Procedure requires flow checks to be performed as shown in Figure 40.

PATTERSON-UTI DRILLING COMPANY LLC		Effective:	12/12/2016
		Revision:	3.0
Manual:	Drilling Operations	Reviewer:	[redacted]
Section:	Standards	Approved:	[redacted]
Subject:	Well Control Procedures		
Policy:	DRO-800	Page:	Page 2 of 12

4.2 Conducting Flow Checks

Flow checks shall be conducted for a minimum of 3 minutes. A longer flow check time may be required while drilling with oil-based mud. It is recommended to flow check for a longer period when a coring string is at the casing shoe and when conducting open hole logging operations.

The driller shall stop and perform a flow check:

1. After a significant drilling break
2. When there is an indication of a flow increase
3. When there is an indication of a pit volume increase
4. Anytime the hole is not filled according to calculated fill values during tripping operations
5. After pulling the first 3 to 5 stands of drill pipe off bottom
6. At the lowest casing shoe when pulling out of the hole
7. Before pulling BHA into the BOP stack when tripping out of the hole
8. Additional checks as required by hole conditions

Figure 40. Patterson flow check policy (emphasis added by CSB)

These flow checks were not performed as required by Patterson policy on Patterson Rig 219. Possibly because flow checks were often not performed, no flow checks were performed during the tripping operation before the incident when required by Patterson policy. Flow checks during that operation likely would have identified that the well was flowing.

6.10.1 Flow Checks Were Rarely Performed on Patterson Rig 219

The CSB analyzed the rig data for the 1H-9 and 2H-16 wells to determine if flow checks were performed when required by Patterson policy. For the analysis, the CSB used three requirements for determining the times a flow check might have been performed, for any length of time, after drilling past the deepest casing shoe:

(1) There was no flow through the flow line;

(2) The drill bit depth was stationary; and

(3) The trip tank volume was static.

For 2H-16, the CSB identified 18 events where a flow check was required by Patterson for the following operations:

(1) After pulling the first 3-5 stands off bottom;

(2) At the lowest casing shoe, and

(3) Before pulling the BHA into the BOP stack.

Of these 18 events, the CSB found only one time where a flow check might have been performed.

For 1H-9, the CSB identified nine events when Patterson required a flow check for the operations listed above. Of those nine, the CSB found only one required time when a flow check might have been performed.[a] That one possible flow check occurred on January 15, 2018—before the gas influx into the well. While flow checks were performed before and after circulating at the top of the curve (Sections 5.2 and 5.3), no flow checks were performed when required by Patterson policy on January 21 or 22: (1) a flow check was not performed after pulling the first 3-5 stands off bottom, (2) a flow check was not performed when the drill bit reached the casing shoe, and (3) a flow check was not performed before pulling the BHA into the BOP. Flow checks at these times could have identified that the well was flowing, which in turn could have led to rig crew actions that could have prevented the blowout.

Patterson did not effectively monitor if flow checks were performed as required. One reason for this lack of monitoring was that Patterson did not require flow checks to be documented, either electronically or by paper. The required documentation of flow checks could (1) have the effect of encouraging rig workers to perform the flow checks, and (2) could provide a means for Patterson management to identify if flow checks were performed as required. **[2018-01-I-OK-R10]**

6.10.2 Flow Check Guidance

The drilling industry generally agrees on times when drilling crews should perform flow checks while tripping, including:

- Before tripping drill pipe out of the well, or after pulling the first (approximately) five stands;
- When the drill bit reaches the casing shoe; and
- Before pulling the BHA into the BOP [30] [31] [32]

Performing flow checks at these times is taught as part of the IADC WellSharp well control training program [32].

The CSB also identified regulatory bodies that require flow checks:

1. The British Columbia Oil and Gas Commission requires a 10-minute (minimum) flow check:

    (1) “After pulling approximately the first five per cent of the drill string (measured depth) from the well.

    (2) At approximately the midpoint depth (measured depth) of the well.

[a] There was one documented flow check on January 17, before a tripping operation. This flow check was performed before pulling the first 3-5 stands off-bottom. This flow check was not included in the calculation that one out of the required nine flow checks were performed, as it was not performed at the required time.

(3) Prior to pulling the last stand of drill pipe and the drill collars from the well.

(4) After all of the drill string is pulled out of the well [33, p. 81]."

2. The Bureau of Safety and Environmental Enforcement (BSEE), which regulates U.S. offshore drilling operations, requires confirmation that the well is stable before pulling the BHA through the BOP.[a]

While flow checks are a safety-critical operation to identify if a well is flowing, the CSB identified no U.S. regulatory requirements for onshore drilling rigs to conduct flow checks. [**Recommendation 2018-01-I-OK-R1 and R19**]

6.11 Patterson Did Not Effectively Monitor the Implementation of its Policies

Safety of operations in complicated operational environments is largely a function of:

1. The quality of written safety systems, policies, and procedures, and
2. The quality of implementing those safety systems, policies, and procedures.

Improving the quality of the written programs is often a function of meeting regulatory requirements, following guidance in industry best practices, and implementing lessons learned through company experience. Improving the quality of implementation comes from first measuring how the written policies are implemented, and then identifying ways to improve. These facets of the operation measured to improve implementation are called "indicators." API 75L *Guidance Document for the Development of a Safety and Environmental Management System for Onshore Oil and Natural Gas Production Operations and Associated Activities* specifically explains using indicators to monitor the quality of implementing a safety management system, to continuously improve company standards and implementation:

> Once leadership has made the commitment (and communicated such), the design of most management systems will generally follow a "plan-do-check-act" model:
>
> - *Plan*—Identify the key risk … and establish your overall policy. Develop priorities, objectives and action items with a realistic schedule.
> - *Do*—This stage begins the step-by-step action plan for conducting activities (e.g. hazard analysis, document preparation) and developing and implementing standards and procedures identified in the plan. This includes training and operational control and the documentation of the activities, procedures, and standards.
> - *Check*—Using the targets and objectives set above assess whether they are being achieved. Other tools can be used such as audits and incident data to determine the effectiveness of the [safety and environmental management system].
> - *Act*—With the knowledge gained above, take steps to continuously improve the system. For example, weaknesses exposed in the check component should be

[a] 30 C.F.R. Ch. II (7-1-16 Edition) § 250.738 (p) https://www.gpo.gov/fdsys/pkg/CFR-2016-title30-vol2/pdf/CFR-2016-title30-vol2-sec250-738.pdf.

> considered when determining the next round of priorities, objectives and action items [34, p. 3]. (emphasis added)

6.11.1 Patterson's Audit Program

Before the incident, Patterson used an audit process to "verify employees' awareness and understanding of the company's policies, procedures, and expectations" which were then used to "generate remedial work plans (RWP) to address improvement opportunities." Part of this audit process was a monthly (at minimum) comprehensive rig inspection conducted by the rig manager, with periodic inspections by the drilling superintendent and health, safety, and environment audit teams. The comprehensive rig inspection included 508 items to be assessed, falling under the following categories:

1. Drill Floor Area, including walking/working surfaces, hoisting equipment, material handling equipment, general equipment;
2. Driller's Cabin/Off Driller's Side Cabin;
3. Mast and Derrick;
4. Substructure;
5. Blowout Preventer and Choke Manifold;
6. Accumulator;
7. Cat Walk/Pipe Rack Area;
8. Mud Pump Area;
9. Mud Tanks;
10. Mixing Area and Mud House;
11. Electrical Systems;
12. Fuel/Flammable Liquid Storage Tanks;
13. Parts, Crew Changing, and Safety Houses;
14. Boiler;
15. Fire/Gas Protection;
16. Drill Site;
17. H_2S Locations;
18. Crew and Management Quarters;
19. General Safety;

20. Pollution Control/Environment; and

21. Documentation.

The audit assessed the following areas found causal to this incident:

1. *Trip schedule completed and accurate while tripping out of the hole.* The audit documentation, however, does not specify the number of trip reports assessed—or how they were to be assessed—for this audit area.

2. *All pit monitors functioning with alarms set at appropriate levels*. The audit documentation, however, did not specify which alarm set points were checked (e.g., gain/loss). Also, this was a one-time check typically before drilling began, and was not verified real-time, such as through requirements to set or check specific alarm set points in operation-specific procedures.

Periodically (less than once per year), Patterson also conducted "Comprehensive Audits" of individual rigs. The audit incorporated monitoring areas found causal to the incident, including:

1. Checking whether flow checks were conducted for a minimum of three minutes, by looking at historical rig data. Once a year, Patterson reviewed rig data for the four most recent tripping operations, evaluating if flow checks were performed as required;

2. Determining whether the flow alarm and gain/loss alarm were set at the limits required by Patterson policy; and

3. Determining whether the latest trip sheet was available and accurate.

The next comprehensive audit for Rig 219 was scheduled to take place on Monday June 26, 2017, but because the rig was moving that day, it was rescheduled for a date in 2018.

Discussed in this report, Patterson flow check and alarm set point requirements were not followed on Rig 219, and the trip sheet was not accurately completed. The Patterson audit-and-improvement (indicators) program was not successful in ensuring policy implementation on Rig 219. Enhancement of the Patterson indicators program to regularly measure a higher percentage of indicators—potentially using data analytics—could help to provide better insight into policy implementation rates, leading to programs that improve those implementation rates as needed.

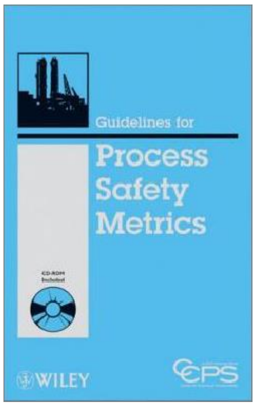
6.11.2 Industry Guidance on Indicators

In recent years, both the chemical processing industry and the CSB have published guidance and conducted forums emphasizing the importance of collecting and analyzing leading[a] and lagging[b] indicators (metrics) to help prevent

[a] Leading Indicators can help to predict future performance. API RP 754 provides leading indicator examples, including process hazard evaluations completion, process safety action item closure, training completed on schedule, procedures current and accurate, and MOC and PSSR compliance [69] (Section 8.3).

[b] Lagging Indicators are retrospective, based on incidents that have occurred. API RP 754 provides lagging indicator examples, including number of recordable injuries, loss of containment incidents, and pressure relief device discharge events [69] (Section 5.2.2 and Section 6.2.2).

process safety incidents.[a] The CSB conducted a 2012 public hearing and issued a recommendation to API to develop a consensus standard defining performance indicators for process safety to be used in the refining and petrochemical industry. (In response, API developed API RP 754, *Process Safety Performance Indicators for the Refining and Petrochemical Industries*.) The CCPS book *Guidelines for Process Safety Metrics* succinctly describes the purpose of process safety metrics:



> Process safety metrics are critical indicators for evaluating a process safety management system's performance. More than one metric and more than one type of metric are needed to monitor performance of a process safety management system. A comprehensive process safety management system should contain a variety of metrics that monitor different dimensions of the system and the performance of all critical elements […]. Good process safety metrics will reinforce a process safety culture promoting a belief that process safety incidents are preventable, that improvement is continuous, and that policies and procedures are necessary and will be followed. Continuous improvement is necessary and any improvement program must be based on measurable elements. Therefore, to continuously improve performance, organizations must develop, implement, and review effective process safety metrics [35, p. 30].

As an example of potential indicators that could be tracked in an indicators, or metrics, program, Figure 41 shows an example list of indicators for Management of Change published by CCPS [35, p. 152].

[a] Publications and events include (1) CSB Public Hearing: Safety Performance Indicators, July 23-24, 2012, Houston, Texas [70]; (2) U.S. Chemical Safety and Hazard Investigation Board, Refinery Explosion and Fire, BP Texas City, REPORT NO. 2005-04-I-TX, (March 2007) [71]; (3) API Recommended Practice 754, *Process Safety Performance Indicators for the Refining and Petrochemical Industries* [69]; (4) International Association of Oil & Gas Producers Recommended Practice, *Process Safety - Recommended Practice on Key Performance Indicators, Report No. 456*, November 2011 [72]; (5) Center for Chemical Process Safety (CCPS). *Guidelines for Process Safety Metrics;* John Wiley & Sons, Inc.: Hoboken, New Jersey, 2010 [43]; among others.

MANAGEMENT OF CHANGE	Identify Potential Change Situations	Evaluate Possible Impacts	Decide Whether to Allow the Change	Complete Follow-up Activities	Maintain a Dependable Practice
Number of incidents with management of change (MOC) as a root cause					X
Percentage of work orders/requests that were misclassified as replacement-in-kind (RIK) (or were not classified) and were really changes	X				
Percentage of temporary MOCs for which the temporary conditions were not corrected/restored to the original state at the deadline				X	
Percentage of MOCs reviewed that were in full compliance with the site's MOC procedure					X
Number of "emergency MOCs" or the ratio of 'emergency MOCs" to total MOCs					X
Percentage of MOCs for which the drawings or procedures were not updated				X	
Percentage of changes that were reviewed within the MOC system but were reviewed incorrectly		X			
Percentage of MOCs reviewed that were not documented properly				X	
Number of MOCs performed each month					X
Percentage of MOCs reviewed that did not have adequate hazard/risk analysis completed					X
Percentage of MOCs for which the workers were not informed or trained				X	
Percentage or variation in the number of changes processed on an emergency basis					X

Figure 41. Example MOC indicators published in the CCPS book Guidelines for Process Safety Metrics

Existing publications, such as those discussed above, provide good guidance for developing indicators programs that can be applied to the drilling industry. Patterson should update its indicators and metrics program to analyze indicators that could provide deeper insight into safety-critical policy implementation rates. The indicators program should specifically include the following components, which were found to be causal to the incident:

1. Measuring the compliance with the flow check policy, including how often required and optional flow checks are performed, and for what length of time. CSB-recommended flow check documentation should also be audited as part of this metric [**Recommendation 2018-01-OK-R10]**;

2. Measuring the effectiveness of the management of change program, for both equipment and procedural changes;

3. Measuring whether applicable critical alarms have been set at the proper set points for specific operations on rigs (e.g., drilling, circulating, and tripping);

4. Measuring the frequency that the alarm horn or entire alarm system is turned off; and

5. Measuring the frequency that trip sheets are completed correctly. [**Recommendation 2018-01-OK-R11**]

6.11.3 Opportunity for Data Analytics

CCPS's book *Guidelines for Process Safety Metrics,* published in 2010, states, "Many data collection tasks can be automated with the more powerful electronic control and instrumentation systems that are common in processing operations. … Automating the data collection process can provide reliable data with little increased demand for human resources [35, p. 63]." Now, in 2019, there is heavy focus on "Big Data"—finding ways to extract useful information from large volumes of data. For example, the 2019 Global Congress on Process Safety conference featured a session called "Augmenting Process Safety Performance through Big Data Digitalization [36]."

The drilling industry could use data analytics to automate the monitoring of key indicators, with potentially little additional data-gathering responsibilities for company personnel. For example, modern drilling rigs—including Patterson Rig 219—are equipped with many data sensors to monitor drilling equipment and drilling parameters, including tank volumes, drilling rate of penetration, flow rates, gas content in mud, alarm activations, and alarm set points. Using data analytics, this existing data could be configured to provide information to company management on key performance indicators such as company policy implementation. For example, it appears possible that bit depth and trip tank volume data during tripping operations could be used to automatically determine if flow checks are performed as specified in Patterson policy. This analysis could be in addition to Patterson creating an electronic flow check form requiring the user to populate the operation, length of flow check, and result in the form. This information could also be automatically analyzed and presented as an indicator to company management.

It should also be possible to use data analytics to monitor alarm data such as the frequency that alarm set points are configured as required, whether the alarm horn is on or off, and the frequency of alarm activations. However, the CSB found that this alarm data was not provided to Patterson as part of the data package it received from the drilling data company. This data could provide insight into alarm performance, providing the basis for improving alarm management for Patterson and other drilling contractors. [**Recommendation 2018-01-OK-R16 and R18**]

In summary, incorporating data analytics into Patterson's and other drilling contractors' indicators programs to measure policy implementation and other key performance indicators could provide valuable insight into company performance, with potentially minimal additional data-gathering responsibilities for company personnel.

6.12 Victims Had No Safe Escape Option from Driller's Cabin (Dog House)

At the time of the blowout when mud started erupting from the well, the motorhand and second floorhand entered the driller's cabin. The driller, company man, and directional driller were already inside the driller's cabin when the blowout started. All five personnel were victims of the blowout and post-incident were found deceased in the driller's cabin. The locations where the victims were found is shown in Figure 42. Autopsies determined that all victims died from thermal burn injuries with found or probable smoke and soot inhalation.

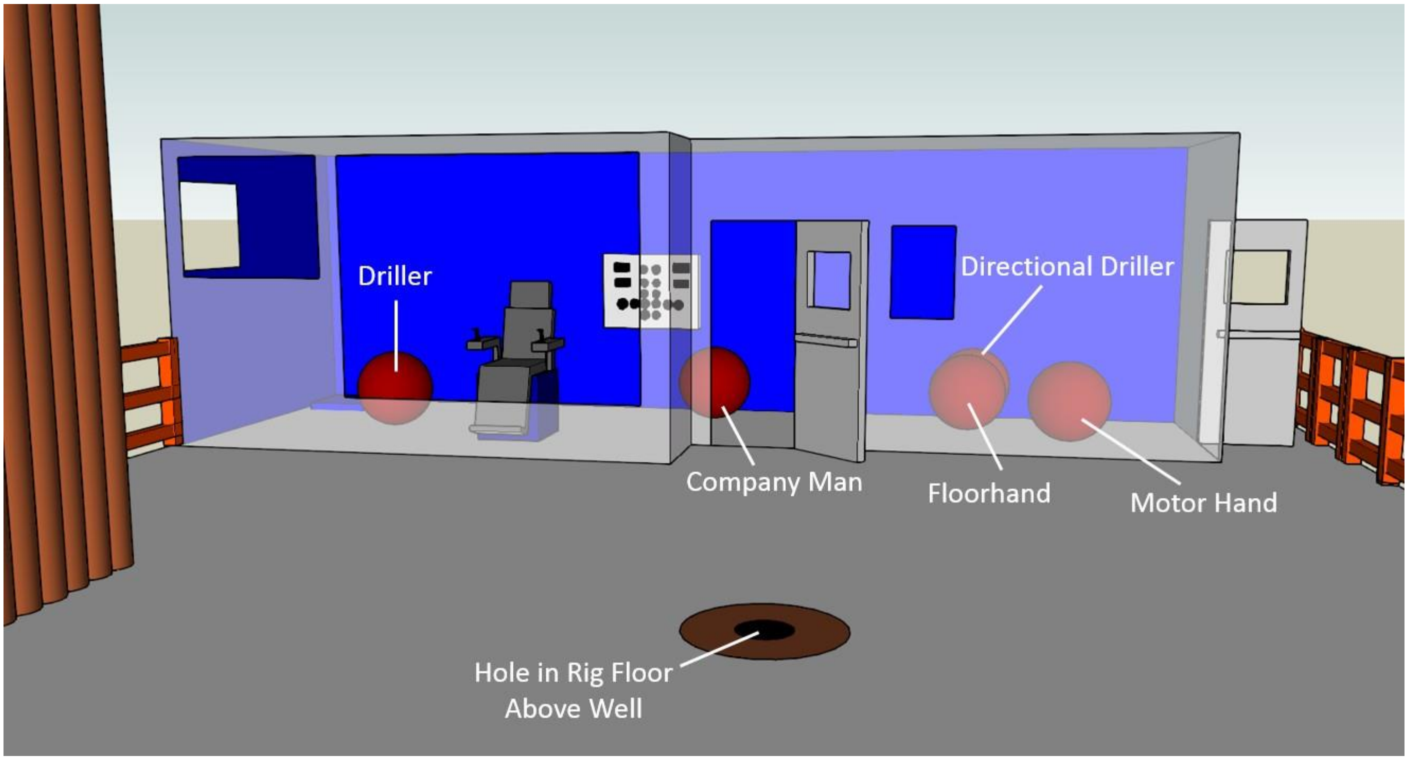


Figure 42. Locations where victims were found in the driller's cabin

Witness testimony and video taken shortly after the blowout began confirm that the ignition of the gas and mud escaping from the well occurred within seconds after the mud started erupting onto the rig floor. The fire was massive and intense, engulfing much of the rig floor and the driller's cabin (Figure 43). It is unknown how long the victims remained alive inside the driller's cabin, but they had no viable escape routes. There were two exit doors from the driller's cabin, but both of those exit doors were blocked by flames after the gas and mud ignited (Figure 44).

Post-incident, the driller's cabin was found to be severely burned. However, one wall of the driller's cabin was less affected by the flames, evident by the paint remaining on the exterior. There was no escape route at that location, and there was no escape route on the wall opposite the rig floor (Figure 45). Also, one of the exit doors was hinged such that it impeded quick evacuation. When the door was opened, the door blocked the escape path (Figure 46).

Figure 43. Still from video captured at 8:36 am, shortly after blowout started. The rig manager and floorhand can be seen escaping the rig. At this point, the fire has engulfed the driller's cabin (far side of photo).

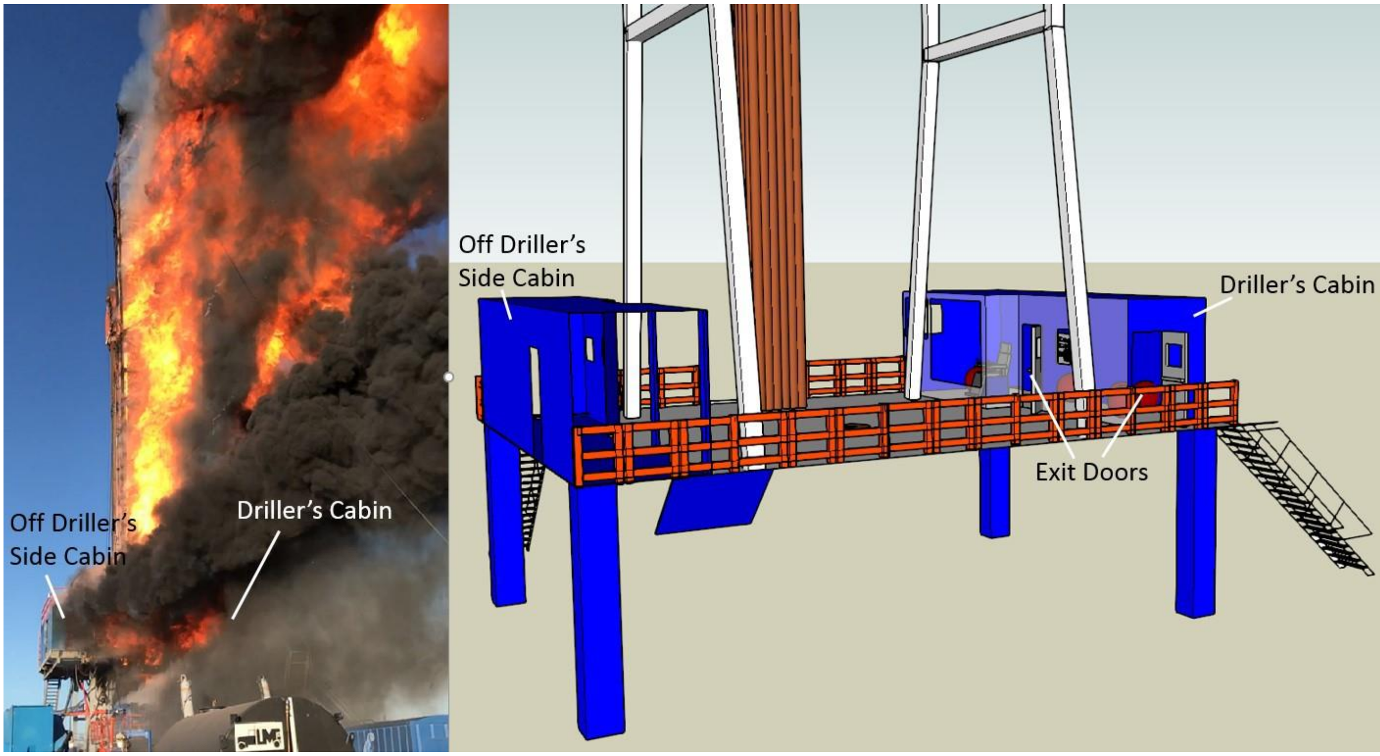


Figure 44. Both exits from the driller's cabin were engulfed by fire.

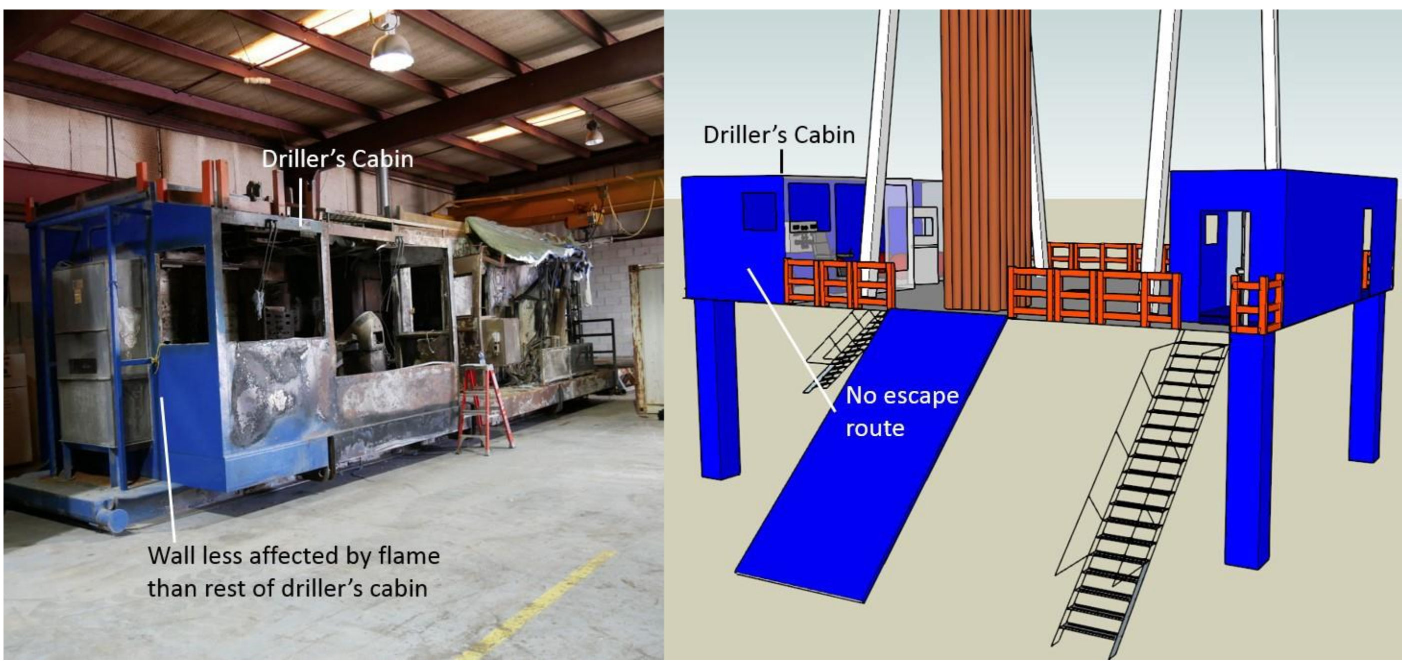


Figure 45. One part of the driller's cabin appeared to be less affected by fire, evident by the paint remaining post-incident. There was no escape route near that location.

Figure 46. The most viable exit door was hinged such that when the door was opened, the door blocked the escape path to the ground.

6.12.1 Progression of Control Room Safety in the Process Industry

The driller's cabin on a drilling rig can be compared to the control room in a chemical process facility. It is the location from which operations are monitored and controlled.

In the late twentieth century, process accidents occurred causing severe damage to occupied control rooms and resulting in employee fatalities. Some of these incidents include:

1. Flixborough Explosion (Nypro, UK) (1974). Cyclohexane released from a process facility, forming a large flammable vapor cloud. The vapor cloud found an ignition source, causing an explosion. Twenty-eight workers were killed. Eighteen fatalities occurred in the control room as a result of the windows shattering and the collapse of the roof. No one escaped from the control room [37].

2. Phillips 66 Houston Chemical Complex Explosion and Fire (1989). Process gas (isobutane, ethylene, hexane, and hydrogen) released from a valve in the facility. The gas formed a flammable vapor cloud and found an ignition source 90 seconds to two minutes after the release started, resulting in a massive explosion. Twenty-three workers were killed. The investigation report on the incident found that "[t]he site layout and the proximity of normally high occupancy structures, such as the control room and the finishing building, to large capacity reactors and hydrocarbon storage vessels also contributed to the severity of the event [38, p. 23]."

3. Hickson & Welch incident (Castleford, UK) (1992). – As a result of a jet fire impacting the building, four employees in the control building were killed [39].

In 1995, API published API RP 752 *Management of Hazards Associated with Location of Process Plant Buildings*. The latest (3rd) edition of this guidance (2009), gives the following guiding principles for the siting of permanent buildings in process plants:

a) Locate personnel away from process areas consistent with safe and effective operations;

b) Minimize the use of buildings intended for occupancy in close proximity to process areas;

c) Manage the occupancy of buildings in close proximity to process areas;

d) Design, construct, install, modify and maintain buildings intended for occupancy to protect occupants against explosion, fire, and toxic material releases;

e) Manage the use of buildings intended for occupancy as an integral part of the design, construction, maintenance, and operation of a facility [40, p. 1].

In 2003, the Center for Chemical Process Safety published a book called *Guidelines for Facility Siting and Layout*, stating:

> Separate control buildings from equipment and storage containing flammable materials to reduce the consequences of fire exposure. […] Evaluate control buildings for blast-resistant construction or locate conventional construction control buildings in an area where blast resistant construction will not be needed [41, p. 96].

The U.K.'s Health and Safety Executive Control Room Design guidance states:

> Whatever the location, control rooms should be designed to ensure that the risks to the occupants of the control room are within acceptable limits and that it is suitable for the purposes of maintaining plant control, should the emergency response plan require it, following any foreseeable, undesirable event within the plant.
>
> Events that may affect the control room are:
>
> - Vapour Cloud Explosions (VCEs)
> - Boiling Liquid Expanding Vapour Explosions (BLEVEs)
> - Pressure bursts
> - Exothermic reactions
> - Toxic gas releases
> - Fires, including pool fires, jet fires, flash fires and fire balls.
>
> […]
>
> Measures for protection from fires should ensure the control room will withstand thermal radiation effects without collapse and that smoke ingress is controlled. Materials of construction should be fire resistant for the duration of any possible fire event [42].

API also created a recommended practice document in 2007 giving guidance on locating process plant portable buildings. It followed a CSB recommendation issued to API during CSB's investigation of the 2005 BP Texas City refinery explosion, where 15 people were killed [43]. All of the victims in that incident were in or around portable trailers near the process area where the explosion occurred. The recommended practice, API RP 753 *Management of*

Hazards Associated with Location of Process Plant Portable Buildings is based on guiding principles similar to those in API RP 752. API RP 753 also poses the questions:

- Do personnel need to be located near a covered process area?
- Do personnel need to occupy a portable building?
- Can the portable building be placed further from the covered process area, while allowing the occupants to effectively perform their tasks? [44, p. 3]

6.12.2 Design Improvements Needed to Protect Driller's Cabin Occupants and Rig Floor Personnel

The design and location of the driller's cabin on Rig 219 appears to be typical across the industry. Drilling rig design changes are needed to help protect workers on the rig floor and in the driller's cabin from blowout and fire hazards, and to allow quick escape from the rig. Had the fire rating of the driller's cabin been ensured for a minimum time (e.g., 10 minutes), with emergency escape options from the driller's cabin floor (e.g., an escape hatch) or from the back wall, there could have been a better chance for the workers in the driller's cabin to survive this incident. As an example of a quick evacuation design, the CSB was informed that escape slides are required in Ukraine for the safety of drilling rig workers (Figure 47). This and other escape options would need to be evaluated by the U.S. drilling industry.

Figure 47. Example design strategy to provide quick egress from drilling rig during a blowout.

API should develop guidance on drilling rig floor and drilling cabin design to increase crew member survival during a blowout. Needed design guidance should:

(a) Protect drilling cabin occupants from blowout hazards including heat, blast overpressure, and projectiles; and

(b) Establish the minimum required evacuation methods from the drilling cabin, rig floor, and mast in the event of a blowout so personnel can quickly escape in variable hazard location conditions.

The drilling industry should also consider alternative design methods, such as locating the driller's cabin at a safe distance from the well, for example at ground level. Such a design could incorporate the use of cameras to allow the driller to view and direct rig floor activities, keeping workers in the driller's cabin out of range of fire and explosion hazards. [**Recommendation 2018-01-I-OK-R5**]

6.13 Blowout Preventer Did Not Close

During the blowout and fire, both the rig manager and the company man attempted to function the BOP by operating the handles at the BOP accumulator, but the BOP did not seal the well. Based upon findings from BOP testing, rig data showing successful usage of the BOP in the hours leading to the incident, and information from Patterson rig crew members that the blowout preventer, accumulator, and remote panel were functioning before the incident, the CSB determined the BOP likely did not seal the well as a result of the blowout and fire damaging the blowout preventer equipment. Discussed below, the hoses that transported hydraulic fluid from the accumulator to the blowout preventer were severely damaged by the fire, and this damage is likely what prevented the BOP from closing.

6.13.1 Accumulator

Blowout preventers are hydraulically operated equipment, using high-pressure hydraulic fluid stored in an accumulator.[a] A depiction of the Rig 219 accumulator is shown in Figure 48.[b] Hydraulic fluid at 3,000 psig is stored in the accumulator bottles. That pressure is reduced to 1,500 psig through a pressure regulator for the manifold. Hydraulic fluid in the accumulator manifold is used to function the blowout preventer.

Figure 49 illustrates how the accumulator is used to function the blowout preventer. When a person moves an accumulator handle to its “close” position for, for example, the blind rams, 1500 psig hydraulic fluid from the accumulator manifold is routed to the blind ram “close” hydraulic line, which then moves two pistons inside the ram body to close the rams. The pressurized hydraulic fluid that was in the “open” piston chambers and hydraulic line drains into the accumulator reservoir. When a person then moves the handle to the “open” position, high-pressure hydraulic fluid is routed to the blind ram “open” hydraulic line, which then moves the pistons in the ram body in the opposite direction to then open the rams. The pressurized hydraulic fluid that was in the “close” piston chambers and hydraulic line drains into the accumulator reservoir.

As hydraulic fluid is used in the operation of the BOP, the amount of hydraulic fluid in the accumulator bottles decreases, causing a pressure decrease in the bottles. When the accumulator bottles reach a low pressure set point (2,700 psig), the accumulator pump automatically turns on to pump hydraulic fluid from its reservoir back into the accumulator bottles to re-pressurize the bottles to their operating pressure (3,000 psig).

The post-incident BOP testing found that the accumulator and charging pumps operated[c] as described here. Also, the Patterson Rig 219 blowout preventer was evidently operating 39 minutes before the blowout. The blind rams were opened at 7:57 am, and the blowout occurred at 8:36 am (Section 5.6).

[a] “The functional requirement of the accumulator is to provide sufficient usable hydraulic fluid volume and pressure to actuate the specified well control equipment, and to provide sufficient remaining pressure to maintain sealing capability [62, p. 8].”
[b] The accumulator handle labeled “Kill Line” was not in use on Patterson Rig 219. It was effectively a spare valve.
[c] Discussed in Appendix A, post-incident testing found that the charging pump activated at an accumulator pressure of about 2,000 – 2,100 psig and automatically switched off when the accumulator pressure reached 2,800 psig. Based upon information from Patterson rig crew members that the accumulator pressurized normally to 3,000 psig pre-incident, this change to the accumulator pump set points may have been a result of the fire and post-incident activities.

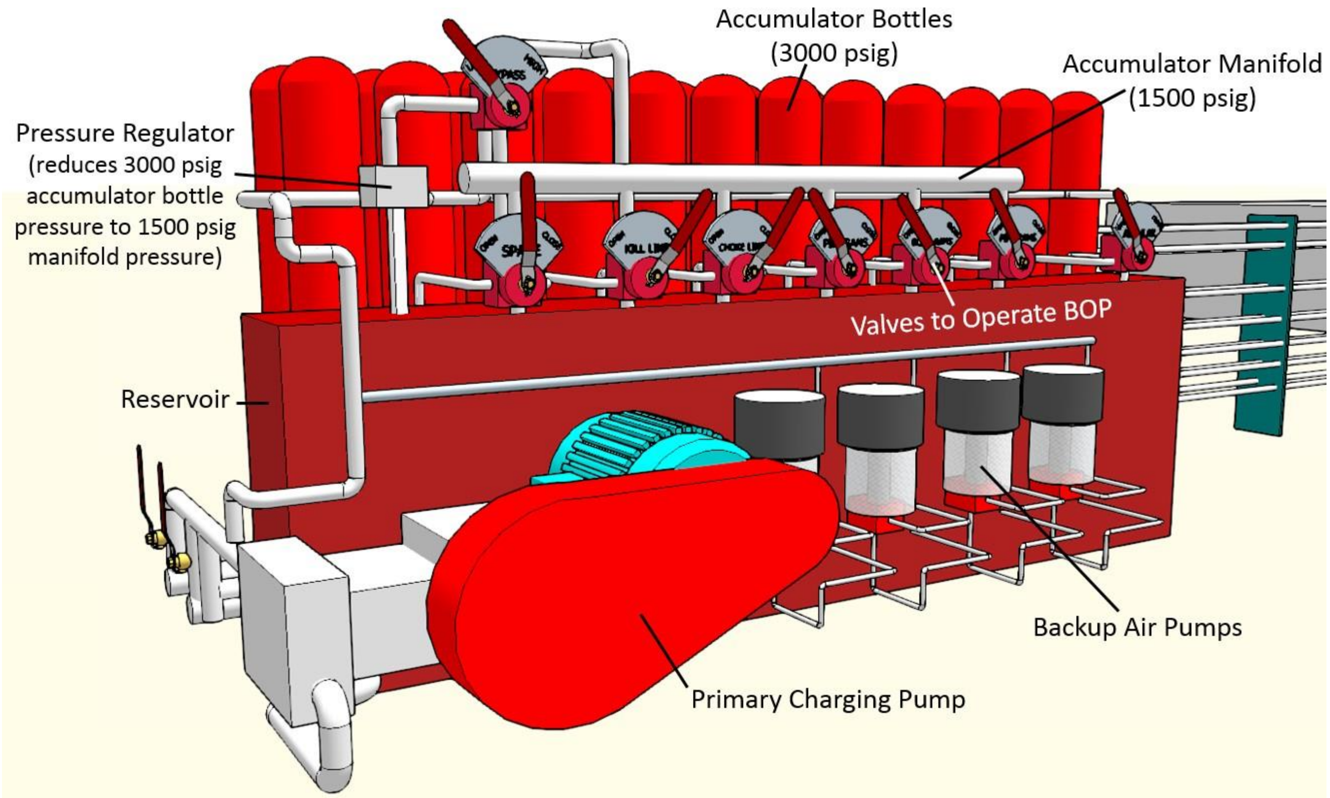


Figure 48. Depiction of the Patterson Rig 219 accumulator. The top valve on the accumulator is the Bypass valve. From left to right, the bottom valves are Spare, Kill Line, Choke Line, Bottom Pipe Rams, Blind Rams, Top Pipe Rams, and Annular Preventer.

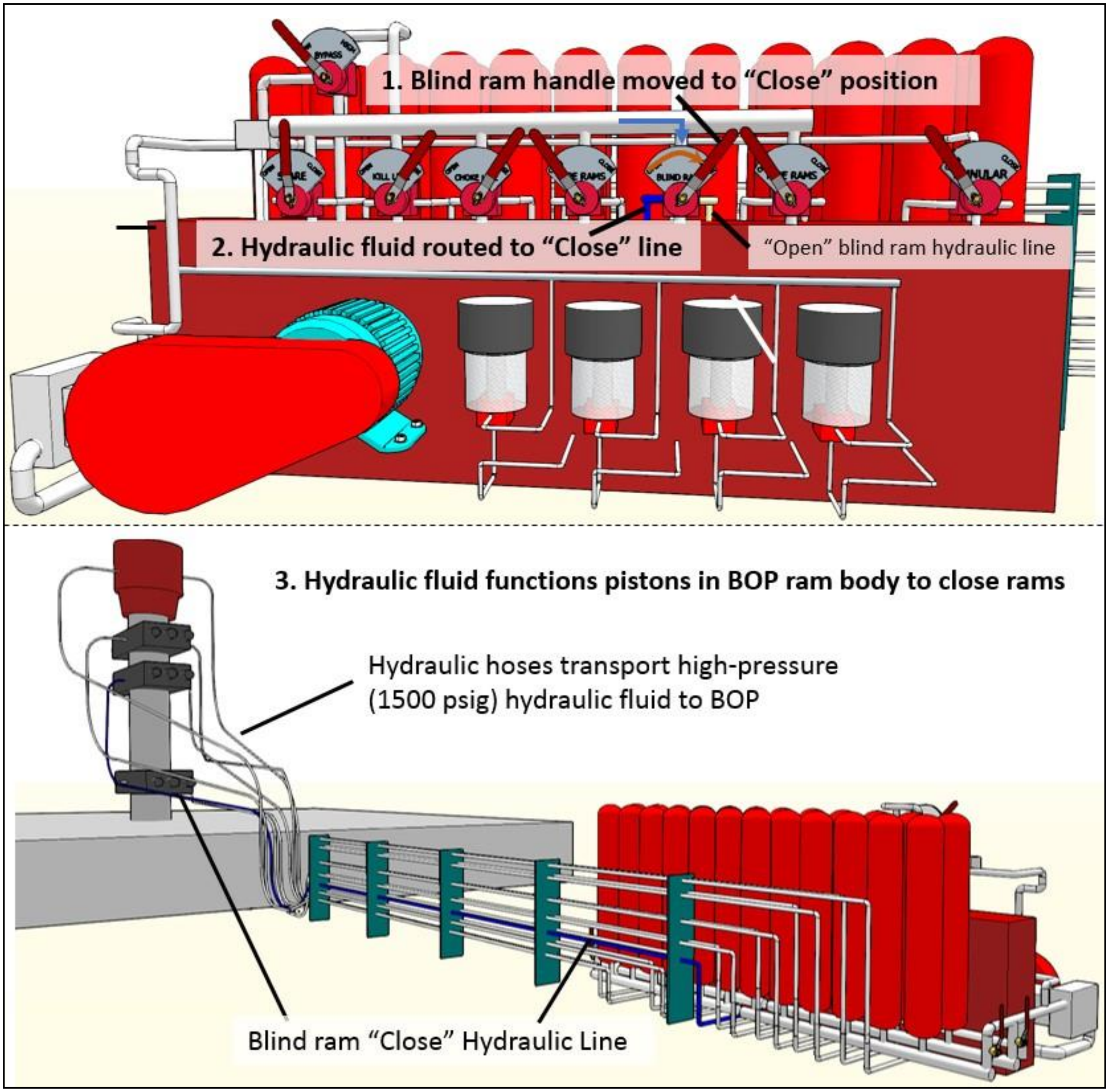


Figure 49. Illustration of how hydraulic fluid in the accumulator functions the blowout preventer blind rams when the blind rams valve is moved to the "close" position. The portion of the hydraulic lines in the support racks is hard piping, and the portion of the hydraulic lines between the support rack and the blowout preventer is flexible hose.

6.13.2 Fire Damaged Hydraulic Lines

Prior to and during the blowout, the two BOP pipe rams, blind rams, and annular preventer were open. The valve to the choke line (HCR valve) was closed. By design, the “open” hydraulic hoses and the “opening” chambers of each BOP piston are kept under pressure by the accumulator when the accumulator valve is in the open position, and the reverse is true when a valve is in the closed position. Post-incident testing found that the hydraulic hoses that would have been pressurized by hydraulic fluid with these valves in these positions were severely damaged by the fire to the point they could not hold liquid (Figure 50). The hydraulic hoses were made of synthetic rubber, fiberglass, and steel wire spiral layers, and were designed to hold the rated working pressure of the lines at a flame temperature of 1300 °F for a 5-minute period, meeting API requirements.[a] The hydraulic hoses were exposed to fire within three minutes after the blowout began (Figure 51). One video obtained by the CSB suggests the exposure to fire occurred within one minute, but due to the angle of the video it is difficult to be certain. Hydraulic fluid likely escaped from these pressurized hydraulic lines from fire damage, possibly due to flame temperatures exceeding 1300 °F,[b] exposure to flames for longer than five minutes before the BOP was attempted to be operated, or both.

As the hydraulic fluid escaped from the damaged hydraulic lines, the accumulator pressure dropped. Some witnesses reported hearing the accumulator charging pumps running during the blowout, but it was also reported by the rig manager (who attempted to activate the BOP from the accumulator) that he never heard the accumulator pumps running after the incident started. After the incident, the accumulator reservoir was found to be about 80% full of hydraulic fluid,[c] which indicates the accumulator charging pumps were not operating for any significant time period after the blowout began, likely from incident-induced damage to the electric and air systems that powered the pumps. The night tour motorhand reported that he maintained the accumulator reservoir about 75% full with hydraulic fluid, which he gauged by looking into the accumulator through a top port with his flash light. The typical hydraulic fluid level and the level found post-incident are in close agreement.

After the blowout started, the Rig Manager closed four of the handles on the accumulator, beginning with the handle closest to the rig. The order of closure was (1) annular preventer, (2) top pipe rams, (3) blind rams, and (4) bottom pipe rams. Likely due to the fire-damaged and leaking hydraulic hoses, combined with the hydraulic fluid being routed to four different BOP components, the blind rams did not fully close. A Boots & Coots responder observed during the emergency response operations that one side of the blind rams was fully closed, and the other side was halfway closed.[d] Additional information about BOP testing and findings is in Appendix A.

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[a] API Specification 16D *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment* requires “control lines … located in a division one (1) area, as defined by API RP 500 (area classification), shall be capable of containing the hose rated working pressure in a flame temperature of 1300°F (700°C) for a 5-minute period [62, p. 51].” The hoses installed were made of synthetic rubber, with a fire resistant synthetic rubber cover impregnated with fiberglass, and with reinforcement high-tensile steel wire spiral layers, designed to meet the API Specification 16D requirements.

[b] Flame temperature can be roughly approximated by color. Orange flames are reported to be about 2,010°F [73, p. 369].

[c] The accumulator reservoir is 36.5 inches tall. The post-incident hydraulic fluid level was 30 inches.

[d] The partially closed blind rams could be additionally explained by the Bernoulli effect, which could have caused the flowing fluid in the BOP to have a lower pressure than the static pressure outside of the BOP. If both opening and closing hoses were failed, this pressure difference could have led to partial closure of the rams [80].

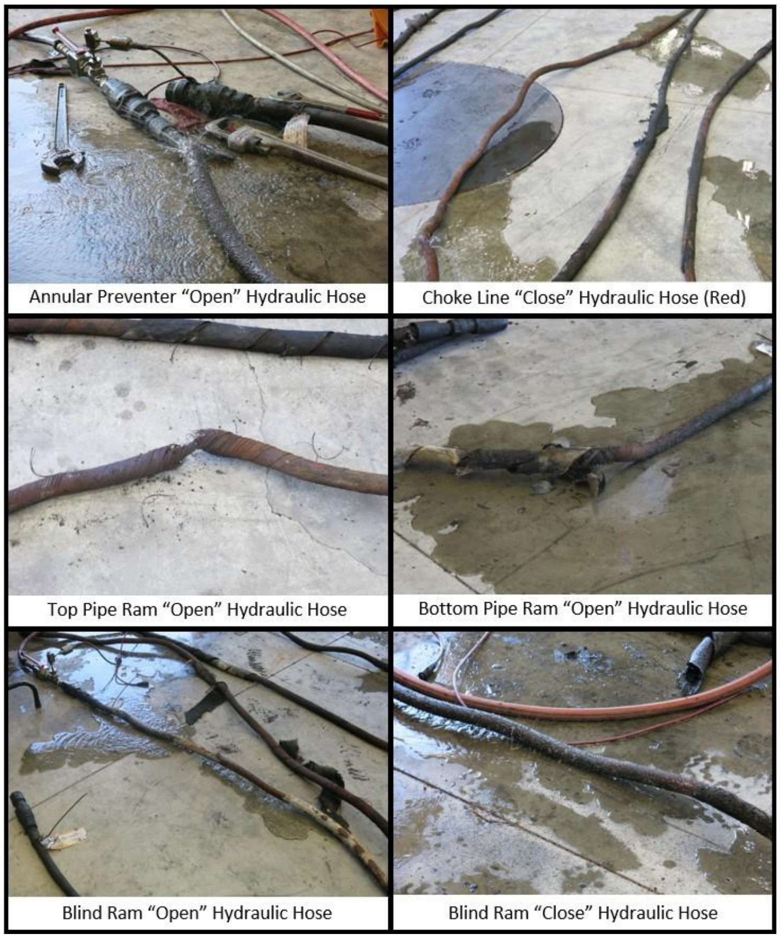

Figure 50. Photos of hydraulic hoses that were installed between the accumulator and BOP, used to send high-pressure hydraulic fluid to the BOP rams to open or close the rams. The hoses were damaged by fire. The hydraulic hoses were leak tested using 40-50 psig water, and all hoses leaked water.

Figure 51. Video still of Patterson Rig 219 fire, taken 3 minutes after blowout began.

7 Industry Standards on Drilling Operations

7.1 API Bulletin 97

Drilling an oil or gas well is a complicated operation, as it involves numerous companies with potentially varied interests and complex business relationships. Therefore, all concerned parties must establish clear roles and responsibilities before drilling operations.

In 2013, after the Macondo blowout, API developed a new publication, API Bulletin 97 *Well Construction Interface Document Guidelines*. It provides guidance on developing a Well Construction Interface Document (WCID), which is composed of (1) a "bridging document" that aligns the operator's and drilling contractor's safety management systems, and (2) a Well Plan. The purpose of the Well Construction Interface Document is to "facilitat[e] communication between the lease operator and drilling contractor regarding well construction work (drilling, suspension, completion, testing, workover, and/or abandonment). The [Well Construction Interface Document] should emphasize barrier plans and well control practices by integrating the drilling contractor's operating guidelines with the lease operator's well plan" [45, p. vii]. A depiction of the role of the Well Construction Interface Document is in Figure 52.

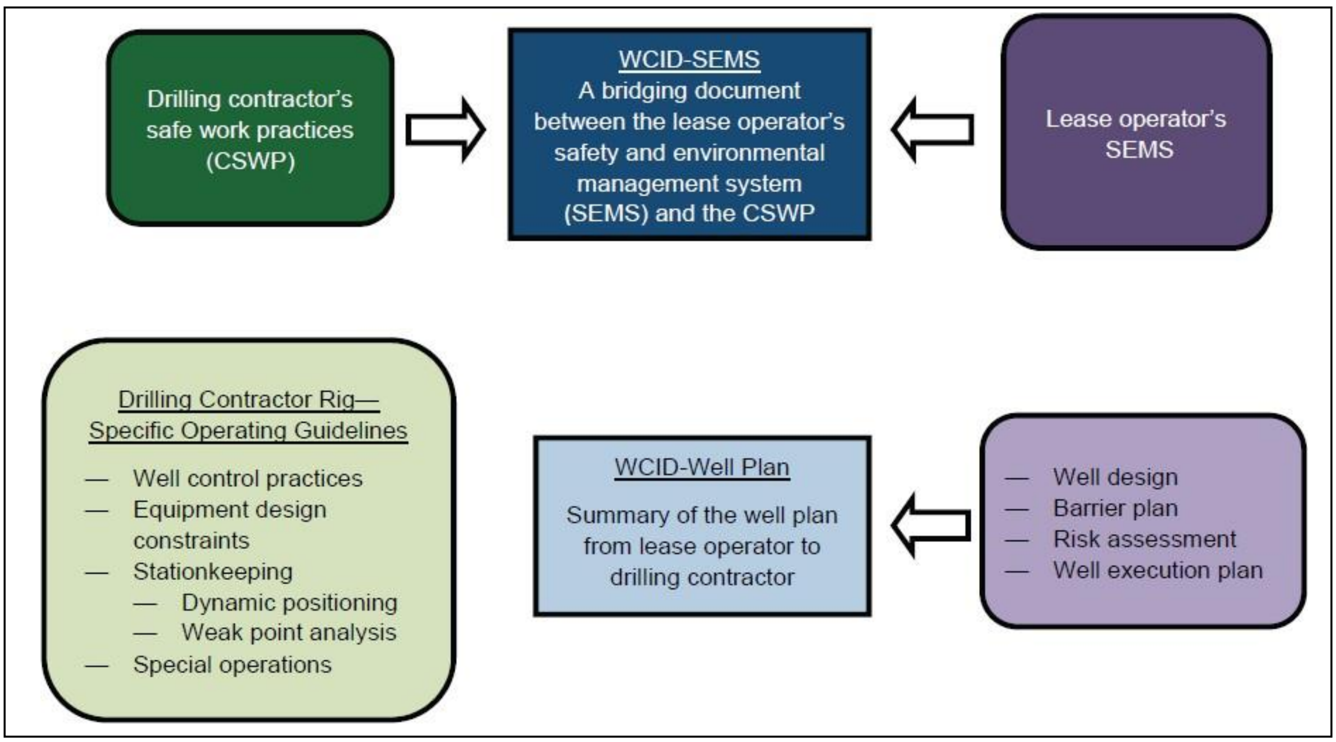

Figure 52. Well Construction Interface Document Information. Source: API Bulletin 97 [45, p. 1].

API Bulletin 97 states that the Well Construction Interface Document is to provide "acknowledgement that management of change (MOC) and risk assessment processes should be used during well construction activities;" is "a vehicle for the drilling contractor to be involved when operational changes and/or conditions are identified that could require a well activity risk assessment;" and is "a method of communicating stop work authority" [45, pp. 1-2]. The bridging document and well plan portions of the Well Construction Interface Document are discussed below.

7.1.1 Bridging Document

API Bulletin 97 states the bridging document portion of the Well Construction Interface Document should contain the following information:

> The drilling contractor and lease operator should specify the position(s) responsible for the safe and efficient operation of the rig in accordance with applicable regulations, including emergency situations. This includes the establishment of procedures for both internal and external communications of safety and environmental information. […] Completion of the [bridging document] establishes the exchange and alignment of safety and environmental information prior to commencing work [45, p. 6].

Pre-defined specification of roles, responsibilities, and communication procedures could help to clear any ambiguities of who is responsible to assess and has authority to correct a potentially hazardous situation on a drilling rig.

The bulletin states:

> Establish areas of responsibility between the lease operator and drilling contractor for hazards analyses (risk management processes) for well construction and the verification of rig capacity and capability. […] The lease operator and the drilling contractor should each have defined risk management processes. The following examples typically govern the processes.
>
> (a) For hazards analysis associated with the well plan or well construction, the lease operator's risk management process applies. The drilling contractor is included in the process.
>
> (b) For hazards analyses associated with the rig operation and capability of the rig, the drilling contractor's risk management process applies. The lease operator is included in the process [45, p. 7].

RMO and Patterson did not create a bridging document to merge the two companies' safety systems or define which company had responsibility to manage which hazards. Patterson personnel explained to the CSB that no bridging document was in place because "there was nothing to bridge to" in RMO's policies. The extent of specifying which company had what responsibility was in one sentence in the contract between RMO and Patterson, which states, "Operator agrees that Contractor's safety policies and procedures shall control." This simple sentence contains no details for handling implementation, change, or dispute resolution, and it only addresses rig operation, item (b) in the excerpt above from API Bulletin 97. It leaves completely unaddressed the hazard analysis and safety responsibilities of well construction decisions in item (a). It was this unaddressed area, including roles, responsibilities, capabilities and communications, that led to inadequate preparation for, and inadequate hazard recognition during, underbalanced drilling operations on Pryor Trust well 1H-9.

The lack of a bridging document likely contributed to the lack of hazard analysis and management of change by both companies when there were signs that the operations were veering from the original plans.

7.1.2 Well Plan

API Bulletin 97 states that the objective of the Well Plan portion of the Well Construction Interface Document is to:

> Ensure that all well construction work is carried out in a manner that protects the safety and health of all workers as well as the environment. *It should emphasize barrier plans and well control practices* by integrating the drilling contractor's rig-specific operating guidelines with the lease operator's well plan. […] The [well plan] is developed by the lease operator with input from the drilling contractor with respect to the *rig's operational capabilities and constraints* that could affect the well plan [45, p. 13]. (emphasis added)

The bulletin also states:

> The proposed drilling and completion fluid types, volumes, and properties for the well are described by hole section. *The fluids program should describe how the fluids are to be used as a physical barrier to control the formation pressure in the well* [45, p. 15]. (emphasis added)

RMO had developed a Drilling Prognosis (a type of well plan), but it did not specify what barriers were required to be maintained, or how to identify if a barrier was lost. API RP 59 recommends that two barriers to prevent flow be maintained during drilling operations [6, p. 54]. For this operation, the two barriers were (1) hydrostatic pressure produced by the mud weight to keep the well overbalanced (primary barrier), and (2) the combined function of the workers detecting a gas influx and closing the blowout preventer (secondary barrier). When the well became underbalanced on January 21, the operation lost one of its two barriers. No analysis on the loss of the barrier was performed. In addition, the RMO Drilling Prognosis did not specify that Rig 219 had only equipment and training to perform conventional, overbalanced drilling. Had a well plan been in place requiring at least two barriers, information on how those barriers were to be maintained, and that specified that the rig was equipped to perform conventional (overbalanced) drilling operations only, continuing to drill in an underbalanced manner would have been a violation of the well plan, and could have led to increasing mud weight to return to the original plan or the creation of a new plan as discussed in Section 6.8.3.

API Bulletin 97 implies it applies solely to the offshore drilling industry, not the onshore drilling industry. Application and implementation of API Bulletin 97 guidance could have helped to prevent the incident. [**Recommendations 2018-01-I-OK-R6, R12**] There is also no regulatory requirement for developing a Well Construction Interface Document for land drilling operations. Such a requirement could improve the safety of U.S. land drilling operations [**Recommendations 2018-01-I-OK-R1 and R19**].

8 Current State of Automatic Kick Detection on Drilling Rigs

In recent years, there has been some advancement of automatic systems to detect and respond to well control incidents. For example:

- Segments of the drilling industry are working toward early detection of kicks. After the 2010 Macondo incident, Shell partnered with National Oilwell Varco and Noble Drilling to develop a "smart" kick detection system. A research scientist at the U.S. National Energy Technology Laboratory invented technology to detect kicks near the drill bit. Researchers from Shell think that improvements in technology will eventually lead to automated kick detection and reaction systems [46].

- Pason—a drilling electronic data company—has developed a "Smart Alarms" system that uses predictive machine learning to detect early signs of gains and losses to reduce alarm fatigue caused by frequent false alarms [47].

- In April 2015, Hydril was granted a patent for an "automated well control method and apparatus" designed with "control logic to monitor, warn and act based on the sensor inputs. The actions may include the warning of support personnel, closing an annular blowout preventer, shearing drill pipe using a ram shear, pumping heavier fluid down choke and kill lines, disconnecting the riser or various other actions" [48].

- A 2015 paper describes a fully automated managed pressure drilling system that successfully detected and dynamically controlled a kick and circulated the kick gas out of the wellbore [49].

These advanced technologies are in various stages of development and reliability. The continued development and use of these technologies could improve early detection and response to well control events.

9 Regulatory Analysis

9.1 Lack of Federal Oversight of Onshore Drilling

Discussed in this section, there are minimal regulations governing the safety of onshore oil and gas drilling operations. The OSHA PSM standard does not apply to drilling, no separate OSHA standard covers drilling, and no other federal regulatory body oversees the safety of onshore drilling operations. Section 9.2 discusses the minimal safety focus of Oklahoma drilling regulations.

9.1.1 Occupational Safety and Health Administration (OSHA)

9.1.1.1 OSHA History Relating to Development of Drilling Standard

Historically, OSHA has long been interested in regulating oil and gas drilling and servicing operations. OSHA recognized the industry as having the potential need for specialized regulation because the oil and gas drilling and servicing industry "has some safety problems which are unique, and some which are common to all workplaces [50]." Specifically, OSHA observed the unique and numerous dangers presented by oil and gas drilling operations to workers [50]. These dangers are self-evident and include hazards related to blowouts based on the pressures at which hydrocarbon reserves are sometimes found, fires and explosions, dropped objects, crush injuries, falls from heights, dangers associated with rotary equipment, transportation-related accidents, slip and trip injuries, and myriad other hazards present at a typical drilling site.

OSHA started to focus on the drilling industry as far back as 1973, recognizing the Bureau of Labor Statistics' (BLS) findings in that year that "oil and gas well drilling and servicing ranked among the most hazardous industries" in the United States [50]. Before resorting to new and specialized regulation, however, OSHA attempted to regulate this industry under its Construction Safety Standard, found at Title 29 Code of Federal Regulations Part 1926, believing the nature of the hazards at a drill site most closely related to those found more generally throughout the construction industry [50]. However, oil and gas drillers contested application of the construction industry standards to their industry. The Occupational Safety and Health Review Commission (OSHRC) concurred, dealing a series of adverse rulings to OSHA in the late 1970s and early 1980s following the agency's attempt to use the construction standards in this way, holding that the construction standards were not applicable to oil and gas drilling, servicing or production [50]. Instead, OSHRC ruled, employers engaged in oil and gas drilling and servicing industries should be subject to the federal industry standards found in Title 29 Code of Federal Regulations Part 1910[a]—OSHA's "general industry" standards.

Following these developments, OSHA began an information gathering process related to the types and numbers of injuries and deaths occurring in the drilling industry and attempted to ascertain whether the general industry standards were adequate to protect workers. Based on BLS data, OSHA discovered that the industry had a number of special safety and health problems demonstrated by a higher-than-average injury and illness incidence rate compared to employers covered by the general industry standards.[b] OSHA then determined that the general industry standards inadequately addressed unique hazards related to drilling and servicing. Significantly, the agency also claimed that applying the general industry standards possibly even contributed to the higher injury and illness incidence rate[c] in the absence of specific regulatory coverage to guide the industry in a safer direction. At this point, OSHA resigned itself for a time to issuing Section 5(a)(1) citations for general duty clause violations of the OSH Act,[d] which requires employers to provide a place of employment "free from recognized hazards that are causing or are likely to cause death or serious physical harm to his employees." Indeed, for this incident, OSHA issued general duty clause violation citations to Patterson [51].

In 1980, the National Institute for Occupational Safety and Health (NIOSH) started a study relating to safety and health problems in the drilling industry, to which OSHA paid close attention. All the while, OSHA continued its own independent data gathering efforts on the same topic, with special emphasis on drilling operations, equipment, machinery, and overall hazards inherent in drilling, along with comparative reviews of pertinent state and international practices in foreign jurisdictions.[e]

In January 1982, in the midst of this activity, oil and gas industry stakeholders, including members of the International Association of Drilling Contractors (IADC) and the Association of Oil Well Servicing Contractors (AOSC) approached OSHA and expressed interest in assisting the agency to develop "a meaningful standard that would protect the safety and health of workers performing drilling and servicing operations," among other goals. Industry

---

[a] 48 Fed. Reg. 57,101, 57,202 (December 28, 1983), *citing, e.g., MND Drilling Corp*., No 76-4149 (1977-1978) CCH OSHD ¶ 22,289 [ALJ 1977]; *R.B. Montgomery Drilling, Inc., et al*, No. 76-2131 (1977-1978), CCH OSHD ¶21,775 (ALJ 1977]; *Fairbanks Well Services, Inc*., No. 76-4297 (1977-1978), CCH OSHD ¶ 21,740 [ALJ 1977]; *Bomac Drilling*, No. 76-450 (1977-1978), CCH OSHD ¶ 21,667 [ALJ 1977].
[b] 48 Fed. Reg. 57,101, 57,202 (December 28, 1983).
[c] 48 Fed. Reg. 57,101, 57,202 (December 28, 1983).
[d] 48 Fed. Reg. 57,101, 57,202 (December 28, 1983).
[e] 48 Fed. Reg. 57,101, 57,202 (December 28, 1983).

specifically sought to cease the asserted "widespread use of 'general duty' citations" and requested that the "proposed standard clearly state what was necessary for compliance."[a]

In the spring of 1982, on the heels of a BLS Work Injury Report study on the industry, OSHA initiated a cost/benefit analysis of its newly drafted proposed drilling standard and analyzed all closed fatality case files related to oil and gas well drilling and servicing. In June 1982, OSHA circulated a draft of its proposed rule and requested comments from field staff, state governments, trade groups and labor unions, and other interested stakeholders. In July 1982, OSHA participated in a stakeholder meeting with representatives of industry and government in Dallas, Texas, and later held ad hoc meetings with trade association groups, state and federal field staff, and incorporated feedback in the proposal.[b] OSHA issued a second draft in November 1982 for additional comment.[c] Over 100 external commenters submitted their input, with a wide variety of stakeholders represented. In the final draft, OSHA explained its position that the general industry standards inadequately addressed the unique hazards in drilling and service operations pertaining to oil and gas wells. Based on significant statistical data and its many findings concerning injuries, illnesses and fatalities, OSHA explained its view that "an industry-specific standard should be promulgated to provide adequate protection to workers in this industry."[d]

As such, on December 28, 1983, OSHA issued for notice and comment an amendment to add a new section to Part 1910 of Title 29 of the Code of Federal Regulations, proposing the addition of a new Section 1910.270 and Appendices A-D to regulate the oil and gas well drilling and servicing industry.[e]

OSHA took no final action on this proposed regulation [52], and as of the date of this report there is no drilling-specific OSHA standard.

9.1.1.2 Exemption from OSHA's Process Safety Management Standard

In 1992, OSHA enacted a new regulatory standard called Process Safety Management of Highly Hazardous Chemicals (PSM). OSHA expressed about the standard:

> Unexpected releases of toxic, reactive, or flammable liquids and gases in processes involving highly hazardous chemicals have been reported for many years. Incidents continue to occur in various industries that use highly hazardous chemicals which may be toxic, reactive, flammable, or explosive, or may exhibit a combination of these properties. Regardless of the industry that uses these highly hazardous chemicals, there is a potential for an accidental release any time they are not properly controlled. … Hazardous chemical releases continue to pose a significant threat to employees and provide impetus, internationally and nationally, for authorities to develop or consider developing legislation and regulations to eliminate or minimize the potential for such events [53, p. 1].

[a] 48 Fed. Reg. 57,101, 57,202 (December 28, 1983).
[b] 48 Fed. Reg. 57,101, 57,202-57,203 (December 28, 1983).
[c] 48 Fed. Reg. 57,101, 57,203 (December 28, 1983).
[d] 48 Fed. Reg. 57,101, 57,203 (December 28, 1983). OSHA explained that the agency determined "there now exists a sufficient body of data and information upon which a reasonable standard can be based to effectively reduce the number of injuries and deaths associated with oil and gas well drilling, servicing and special services operations." At the time of this determination, OSHA noted the existence of 5,400 rigs in operation in the United States, and approximately 95,000 workers employed in the various occupations in the oil and gas drilling and servicing business.
[e] 48 Fed. Reg. 57,101, 57,217 (December 28, 1983).

OSHA's PSM standard typically applies to any process involving a chemical at or above the specified threshold quantities list contained in the standard's Appendix A, and also applies to a process which involves a Category 1 flammable gas or liquid with a flashpoint below 100 degrees Fahrenheit on site, in one location, in a quantity of 10,000 or more pounds.[a]

In the onshore drilling environment,[b] hydrocarbons contained in a typical well being drilled for production appear to be covered by this definition, whether the well contains oil or gas, based on the quantity of reserves normally anticipated to be found underground that are to be tapped for production by drilling operations. OSHA, however, expressly exempts oil and gas drilling from regulatory coverage by the PSM standard.[c] This exception was intentional, intending coverage by a separate standard. OSHA stated:

> OSHA also proposed to exclude oil and gas well drilling and servicing operations because OSHA had already undertaken rulemaking with regard to these activities (48 FR 57202). OSHA continues to believe that oil and gas well drilling and servicing operations should be covered in a standard designed to address the uniqueness of that industry. This exclusion is retained in the final standard since *OSHA continues to believe that a separate standard dealing with such operations is necessary*.[d] (emphasis added)

Thus, even with the passage of PSM, and the opportunity PSM presented to cover the industry, there remained no specific OSHA regulation that governed onshore drilling.

9.1.1.3 Additional OSHA Action Relating to Creation of a Drilling Standard

In 1999, the following was stated in the Department of Labor Semiannual Regulatory Agenda:

> OSHA intends to propose a standard for the oil and gas well drilling and servicing industry. In 1982, OSHA proposed a standard for the industry. OSHA believed at that time that the OSHA general industry standard did not adequately address the hazards of oil and gas well drilling and servicing and that this lack of protection contributed to a high number of deaths and injuries in the industry. No final action was taken with respect to the proposed standard and, therefore, there is still no specific OSHA standard for the oil and gas well drilling and servicing industry. OSHA intends to repropose in the near future, because changes in technology, conditions in the industry, and workforce demographics necessitate the issuance of a new proposal.[e]

In 2001, the Department of Labor Semiannual Regulatory Agenda stated the following about 29 CFR 1910.270:

> OSHA is withdrawing this entry from the agenda at this time due to resource constraints and other priorities.[f]

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[a] 29 U.S.C. § 1910.119(a)(1)(i)-(ii).
[b] By contrast, offshore drilling on the outer continental shelf is regulated by an entirely different regulatory structure, which is now administered primarily by the Bureau of Safety and Environmental Enforcement. See U.S. Chemical Safety and Hazard Investigation Board, *Drilling Rig Explosion and Fire at the Macondo Well*, Vol. 4 (April 17, 2016).
[c] 29 U.S.C. § 1910.119(a)(2)(ii).
[d] 57 Fed. Reg. 36, 6356, 6369 (February 24, 1991); https://www.osha.gov/sites/default/files/laws-regs/federalregister/1992-02-24.pdf. When OSHA engauged in rulemaking, the agency reiterated its position about the uniqueness of the oil and gas drilling industry, and in recognition of past rulemaking efforts, passed on PSM coverage for drilling and servicing operations at the time despite the "necessity" for regulation of the industry.
[e] 64 Fed. Reg. 224, 64622 (November 22, 1999); https://www.govinfo.gov/content/pkg/GPO-UA-1999-11-22/pdf/GPO-UA-1999-11-22-13.pdf.
[f] 66 Fed. Reg. 232, 61884 (December 3, 2001); https://www.govinfo.gov/content/pkg/GPO-UA-2001-12-03/pdf/GPO-UA-2001-12-03-12.pdf.

In 2013, President Obama issued Executive Order 13650, *Improving Chemical Facility Safety and Security*. Section 6(e)(ii) of that Executive Order required OSHA to publish, within 90 days, an RFI designed to identify issues related to modernization of its PSM standard and other related standards needed to meet the stated goal of preventing major chemical accidents.

OSHA complied. In its RFI, the agency stated:

> In response to Executive Order 13650, OSHA requests comment on potential revisions to its Process Safety Management (PSM) standard and its Explosives and Blasting Agents standard, potential updates to its Flammable Liquids standard and Spray Finishing standard, and potential changes to PSM enforcement policies. In this Request for Information (RFI), the Agency asks for information and data on specific rulemaking and policy options, and the workplace hazards they address. OSHA will use the information received in response to this RFI to determine what action, if any, it may take [54].

Among 17 issues specified for comment on possible rulemaking concerning potential PSM standard amendments, OSHA included oil and gas well drilling and servicing [54].[a] In explaining the inclusion of oil and gas well drilling and servicing, the agency explained:

> Paragraph (a)(2)(ii) of § 1910.119 exempts oil- and gas-well drilling and servicing operations from PSM coverage. The preamble to the PSM final rule explained that OSHA excluded these operations because it had begun a separate rulemaking for oil and gas well drilling and servicing operations (48 FR 57202). However, the Agency subsequently removed the oil and gas well drilling and servicing operations rulemaking from its regulatory agenda and never promulgated a final rule for these operations. In light of this history, OSHA requests public comment on whether to retain or remove the § 1910.119(a)(2)(ii) exemption [54].[b]

Next, OSHA initiated a Small Business Advocacy Review Panel to get feedback on several potential revisions to OSHA's Process Safety Management (PSM) standard, including the potential regulation of oil and gas drilling under a revised PSM standard. OSHA convened the Panel on May 26, 2016, had a series of five conference calls held in June 2016, and then the Panel issued its report on August 16, 2016 [55].

The thrust of the feedback from the Small Entity Representatives (SERs) assigned to the Panel was that the PSM standard was not a suitable choice for regulating oil and gas drilling.[c] Specifically, SERS opined that OSHA should

[a] Section C listed all topics for regulatory consideration, including item number two, “Oil- and Gas-Well Drilling and Servicing.” Section II, Request for Data, Information, and Comments, in subsection C then posed three standardized questions for purposes of the RFI.
[b] On March 31, 2014, the CSB provided OSHA with comments in response to a Request for Information (RFI) conducted pursuant to Executive Order 13650 regarding potential revisions to various OSHA standards, including the Process Safety Management Standard [75]. In its comments, the CSB specifically provided input on changes determined to be needed at that time with respect to regulating oil and gas well drilling and production facilities. Based on the high rate of worker injuries and fatalities within these sectors, the CSB suggested eliminating the PSM exemption for oil and gas well drilling and production. This remains a potentially viable option for OSHA. Making all or at least the most pertinent parts of the PSM standard applicable to these industries would enhance safety and better protect workers far more than current reliance on citations for general duty clause violations. Development of a new standard, however, that is better tailored to the needs of the gas and oil well drilling and production industries and the unique hazards experienced by workers supporting those industries, which is also enhanced by the lessons of more recent incidents and the continued development of good industry practice guidelines, could also be effective in driving positive safety change.
[c] “Potentially affected SERs did not support the inclusion of oil and gas well drilling into the PSM Standard [56].”

follow its original logic and keep oil and gas drilling out of PSM coverage, while adopting a separate rule to address the relevant process safety hazards that are "inherent to drilling." SERs noted that the biggest dangers related to drilling involved "managing pressures," and unlike a deadly potential chemical release, such as the release at Bhopal which gave rise to legislative action in the U.S., and the creation of the PSM standard, there is no real chemical "process" involved with drilling, and the hazards present are "unrelated to hazardous chemicals," with hazards such as falling objects and fall protection issues being most pertinent. Generally speaking, SERs also found that it would not make sense to extend PSM in its entirety to oil and gas drilling [55, pp. 6-8]. Among other arguments, the SERs stated that the PSM standard is a poor fit for drilling, especially when considering how short of a time it takes for some wells to be drilled [55, pp. 6-8]. With respect to expanding the scope to include oil and gas well drilling and servicing, and resuming enforcement for oil and gas production facilities—which were considered together—the panel recommended to OSHA the following: "consider requiring compliance with only those elements of the PSM standard that it determines are appropriate for oil and gas drilling and servicing activities."

With the advent of new technologies, including horizontal drilling and high volume hydraulic fracturing, the oil and gas drilling and extraction industry is booming domestically, leading the U.S. to the forefront of global energy leaders, as the U.S. became a net exporter of oil and natural gas for the first time in December 2018, and is now the world's largest petroleum producer.[a] Recent public health research which analyzed the 2005-2009 time period, however, found that the industry has an occupational fatality rate 2.5 times higher than the construction industry, and 7 times higher than general industry, all while new hazards not previously recognized or understood (e.g., crystalline silica, particulate, benzene, noise, and radiation) are surfacing alongside the historically better recognized, serious, and unique hazards facing the industry [56].[b] Meanwhile, the industry continues to grow. As of April 2019, there are 1,046 active rigs drilling in the U.S. [57], and there are over 450,000 people at work in the industry based on the most updated data available from the Department of Labor [58].[c]

9.1.2 EPA RMP

The Environmental Protection Agency (EPA) Risk Management Plan Rule (RMP) requires that facilities holding more than a threshold quantity of an extremely hazardous substance on site, as that term is defined by the Clean Air Act, must comply with EPA's RMP, including the requirement for owners or operators of such facilities to implement a risk management program and to submit copy to EPA.[d] EPA determined, however, that RMP requirements do not apply to

[a] "America turned into a net oil exporter last week, breaking almost 75 years of continued dependence on foreign oil . . . The shift to net exports is the dramatic result of an unprecedented boom in American oil production, with thousands of wells pumping from the Permian region of Texas and New Mexico to the Bakken in North Dakota to the Marcellus in Pennsylvania. "We are becoming the dominant energy power in the world," said Michael Lynch, president of Strategic Energy & Economic Research....... The shale revolution has transformed oil wildcatters into billionaires and the U.S. into the world's largest petroleum producer, surpassing Russia and Saudi Arabia. The power of OPEC has been diminished, undercutting one of the major geopolitical forces of the last half century [77]."

[b] This research also found that the fatal injury rate "correlated with fluctuations of industry activity, as measured by the number of active drilling rigs."

[c] Data current as of 2011.

[d] Section 112(r) of the Clean Air Act Amendments requires EPA to publish regulations and guidance for chemical accident prevention at facilities that use certain hazardous substances. These regulations and guidance are contained in the Risk Management Plan (RMP) rule. The RMP rule requires facilities that use extremely hazardous substances to develop a Risk Management Plan which identifies the potential effects of a chemical accident, identifies steps the facility is taking to prevent an accident, and spells out emergency response procedures should an accident occur [81].

oil and gas well drilling operations under an exception for naturally occurring hydrocarbon mixes (including condensate, crude oil, field gas) prior to the hydrocarbon's entry into a pipeline, plant, or refining process unit.[a]

EPA does of course regulate air quality with respect to potential discharges of oil and gas into the air [59]. EPA also regulates oil and gas operations in terms of protecting water and land from wastewater discharges from field exploration, drilling, production, well treatment and well completion activities, all of which can occur on land, in coastal areas and offshore, as well as mandating protection for underground sources of drinking water from contamination caused by underground injection through regulations promulgated under the Safe Drinking Water Act.[b,c] Additionally, EPA regulates with respect to other waste that is generated by exploration and production activities related to oil and natural gas drilling activities under Subtitle D of the Resource Conservation and Recovery Act (RCRA).[d]

From a process safety perspective, however, these regulations do not serve as an aid for major accident prevention and do little to protect workers from serious hazards associated with drilling and servicing oil and gas wells.

9.2 Applicable State Law Regulation in Oklahoma

With no industry-specific guidance from federal safety regulations pertaining to oil and gas drilling, the next step of the analysis requires a review of potentially relevant state law. Pryor Trust, located in Oklahoma, fell under the jurisdiction of Oklahoma state laws [60]. Oklahoma state laws pertaining to oil and gas drilling and servicing are administered by the Oklahoma Corporation Commission [61].

The Commission's primary focus in the area of oil and gas regulation, however, appears to be on rules intended to maximize production, and to eliminate waste and the loss of hydrocarbons caused by the drilling of unnecessary wells, especially through the use of drilling and spacing unit rules [62, p. 620]. Drilling itself is guided by five published rules. These rules govern (1) required approvals of an intent to drill, (2) required notifications of spudding a new well, (3) requirements pertaining to well casing strings, (4) requirements pertaining to casing, cementing, wellhead equipment and cementing reports, and (5) specifics concerning underground storage.[e] Little to no statutory or regulatory guidance exists pertaining to protecting the health and safety of workers engaged in drilling and servicing oil or gas wells, or with respect to environmental protection through the elimination of fires and explosions, along the lines seen in the Pryor Trust blowout, explosion and fire.

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[a] 40 C.F.R. § 681.115(iii). "*Naturally occurring hydrocarbon mixtures.* Prior to entry into a natural gas processing plant or a petroleum refining process unit, regulated substances in naturally occurring hydrocarbon mixtures need not be considered when determining whether more than a threshold quantity is present at a stationary source. Naturally occurring hydrocarbon mixtures include any combination of the following: condensate, crude oil, field gas, and produced water, each as defined in § 68.3 of this part [82]. RMP is often discussed with OSHA's PSM standard due to the related and somewhat overlapping coverage of hazardous chemicals established by the Clean Air Act Amendments of 1990, with requirements imposed on both the Secretary of Labor and the Administrator of the EPA. On its face, RMP could apply to oil and gas drilling operations, similar to OSHA PSM, primarily because of the potentially large amounts of flammable hydrocarbons (oil and gas), that a driller might expect to tap in the underground reservoir. EPA, however, determined that naturally occurring hydrocarbon mixtures are not covered.

[b] 42 U.S.C. §§ 300f *et seq*.; 40 C.F.R. Parts 144-148.

[c] 40 C.F.R. Part 435 (2016).

[d] 42 U.S.C. §§ 6901 *et seq.*

[e] Despite the history of regulation and rulemaking engaged in at the state level in Oklahoma, and the strength of the Commission as a state level government entity, the focus of both the state legislature and the Commission has been on topics related to production, the prevention of waste, royalty pooling, and the protection of rights as drillers and producers seek to promote the development of the state's oil and gas resources.

9.2.1 Drilling Contracts – The De Facto Law of the Land Concerning Drilling in Oklahoma

In *The Anatomy of an Oil and Gas Drilling Contract*, published in 2013, it becomes apparent that the drilling industry in the state of Oklahoma is governed primarily by the terms of private contracts entered into among the various parties involved in drilling a well [63, pp. 360-362]. Informed by model form contracts produced by the American Petroleum Institute and the International Association of Drilling Contractors, everything from the method of payment, the allocation of roles and responsibilities during drilling, insurance requirements, questions concerning risk allocation and indemnification provisions, damages, confidentiality of information, and more, are all contractually dictated by contractual provisions that are standard throughout the drilling industry.

Like the existing state statutes and rules in Oklahoma, however, these model contracts do not contain agreed-to provisions with respect to major accident prevention, or specific health and safety requirements by which parties can protect workers. This is the case despite recognition of the fact that "the drilling of an oil and gas well is an expensive and hazardous endeavor requiring great expertise," a reality which is handled in Oklahoma through contractually established "standard of performance expected of the drilling contractor [63, p. 409]."

For example, the API drilling contract form requires the contractor to perform "with due diligence and care, in a good workmanlike manner, and in accordance with good drilling practices" and in which the drilling contractor agrees that it "is engaged in the business of drilling and completing such wells and represents that it has adequate equipment meeting specifications stated herein and in good working order and trained personnel capable of efficiently operating such equipment [63, p. 409]." IADC contracts require essentially the same standard of performance, though in less concrete terms. "IADC footage and daywork forms do not include a general standard of performance; however, a court might infer such a warranty [63, p. 409]."

Despite such provisions, however, the model contract language from both organizations only clarify legal responsibilities and related questions concerning allocation of risks for drilling accidents. These provisions do not, however, prescribe any specific techniques, equipment, or other measures intended to avoid major accidents or mandate that the parties use established good safety practices for the protection of workers.

9.3 Need for Regulatory Standard Governing Drilling Safety

As discussed throughout this report, more focused and specialized regulatory coverage for drilling is needed to protect workers from the numerous and unique hazards presented by drilling and related activities. Over time, other standards appear to have been considered and then dismissed as potential sources of regulatory coverage for the drilling industry because they proved inadequate in one or more respects. In addition, the drilling industry as a whole would benefit from greater clarity from a regulatory perspective concerning drilling, so drillers and other companies can better protect their workers and the environment from incidents in a proactive manner, rather than being cited and fined after an incident occurred. [**Recommendations 2018-01-I-OK-R1 and R19**]

10 Recommendations

To prevent future chemical incidents, and in the interest of driving chemical safety change to protect people and the environment, the CSB makes the following safety recommendations:

10.1 Occupational Safety and Health Administration (OSHA)

2018-01-I-OK-R1

Implement one of the three following options regarding regulatory changes:

(a) OPTION 1: Apply the Process Safety Management (PSM) standard (29 CFR 1910.119) to the drilling of oil and gas wells; or

(b) OPTION 2: Apply the Process Safety Management (PSM) standard (29 CFR 1910.119) to the drilling of oil and gas wells as in OPTION 1, and make the necessary modifications to customize it to oil and gas drilling operations; or

(c) OPTION 3: Develop a new standard with a safety management system framework similar to PSM that applies only to the drilling of onshore oil and gas wells that includes but is not limited to the following:

- (1) Detailed written operating procedures with specified steps and equipment alignment for all operations;
- (2) Written procedures for the management of changes (except replacements in kind) in procedures, the well plan, and equipment;
- (3) A risk assessment of hazards associated with the drilling plan;
- (4) A requirement to follow Recognized and Generally Accepted Good Engineering Practices (RAGAGEP);
- (5) Development of a Well Construction Interface Document between the operator and the drilling contractor prior to the commencement of drilling activities which at a minimum includes a bridging document and well plan specifying barriers and how to manage them;
- (6) The performance and documentation of flow checks using acceptable methods at defined points during the operation for a specified duration; and
- (7) A requirement for employee participation, similar to the Employee Participation requirement in the OSHA PSM standard.

10.2 American Petroleum Institute (API)

2018-01-I-OK-R2

Establish and convene a group of experts with drilling, engineering, and instrumentation expertise to discuss methods to achieve widespread implementation of automatic safety instrumented systems that could bring a well to a safe state in the event other operational barriers fail. Publish a technical bulletin discussing the strategies to implementing Blowout Preventer (BOP) safety instrumented systems.

2018-01-I-OK-R3

For onshore drilling operations, develop and publish a recommended practice providing guidance on safely tripping drill pipe during (1) overbalanced drilling operations, (2) managed pressure drilling operations, and (3) underbalanced drilling operations. At a minimum, include information on:

(a) Required equipment for tripping operations,

(b) Techniques and procedures for controlling or preventing formation fluid influx, and

(c) Methods to monitor the well and replace the drill pipe displacement volume with drilling fluid (e.g., mud).

2018-01-I-OK-R4

Develop a recommended practice on alarm management specifically for the drilling industry based on guidance in ANSI/ISA 18.2 *Management of Alarm Systems for the Process Industries*. The recommended practice will address the unique dynamic environment of the drilling industry and provide guidance on implementing a state-based alarm system for different operating modes (e.g., drilling, circulating, tripping, etc.). Include International Association of Drilling Contractors (IADC) in the development of this recommended practice.

2018-01-I-OK-R5

Develop a new recommended practice or modify an existing recommended practice (e.g. API RP 54 *Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations*) addressing the protection of rig workers on onshore drilling rigs from fire and explosion hazards in the event of a blowout. The recommended practice will specifically address:

(a) Protecting drilling cabin occupants from blowout hazards including heat, blast overpressure, and projectiles, such as requiring an increased fire rating for the driller's cabin that would allow enough time for occupants to evacuate during a blowout and fire;

(b) Minimum required evacuation methods from the drilling cabin, rig floor, and mast or derrick in the event of a blowout so that personnel can quickly escape in variable hazard location conditions. For example, floor exit hatches and exits on the driller's cabin wall opposite the rig floor could provide safe evacuation routes during a blowout and fire; and

(c) Proximity of the Blow Out Preventer (BOP) activation controls with the driller.

The above options could be retrofitted on existing drilling rigs. Additionally, formally evaluate alternative locations for the drilling cabin that establishes a safe distance from fire and explosion hazards (e.g., ground level).

2018-01-I-OK-R6

Update API Bulletin 97 *Well Construction Interface Document Guidelines* to specify that it applies to both onshore and offshore drilling operations.

10.3 Patterson-UTI

2018-01-OK-R7

Develop either corporate or rig-specific tripping procedure(s) that detail the required equipment configuration for tripping operations. Require that rig personnel visually verify that equipment is lined up as specified in the procedure before beginning the tripping operation. In the procedure(s), specify well-monitoring requirements for wet versus dry tripping operations.

2018-01-OK-R8

Develop an alarm philosophy and alarm rationalization for rig operations. Based on the alarm philosophy and alarm rationalization, specify necessary alarms, at a minimum, for (1) drilling, (2) tripping, (3) circulating, and (4) rig floor activities (no drill pipe in well). Additionally, develop a policy implementing the alarm philosophy and rationalization.

2018-01-OK-R9

Develop a policy that incorporates recommendations in API RP 59 *Recommended Practice for Well Control Operations* requiring the regular testing of drillers' influx detection and response skills through formalized drills, for example by "simulat[ing] a gain in pit drilling fluid volume by raising a float sufficiently to cause an alarm to be activated." In this policy, require that driller response time is monitored in the spirit of continual improvement.

2018-01-OK-R10

Develop and implement a policy requiring that flow checks be documented, either electronically or with a paper record. At a minimum the documentation will require the reporting of:

1. Operation during which flow check was performed
2. Method of performing flow check
3. Length of time flow check was performed
4. Result of flow check

Require that the proper authorities (e.g., driller, company man, rig manager) sign or approve the flow check documentation after performing the flow check and before resuming operations. Keep the flow check documentation as part of the well file.

2018-01-OK-R11

Update the Patterson metrics program to track leading and lagging indicators to measure the effectiveness of the overall safety management system. Specifically focus on measuring the effectiveness of the following safety management system components:

(a) The effectiveness of the flow check policy, including the frequency that flow checks are performed when required by Patterson policy;

(b) The frequency that flow checks are documented and approved as recommended in 2018-01-OK-R10;

(c) The effectiveness of the management of change program, for both equipment and procedural changes, including real-time procedure changes;

(d) The frequency that alarms are set at the required set points;

(e) The frequency that drilling rig alarm horns or the entire alarm system is turned off; and

(f) The frequency that trip sheets are filled out properly.

10.4 Red Mountain Operating

2018-01-OK-R12

Develop a new policy that a well-specific Well Construction Interface Document be in place before drilling operations begin, as specified in API Bulletin 97 *Well Construction Interface Document Guidelines*. Ensure the policy requires that the Well Construction Interface Document specifies the technical requirements of the rig equipment and technical qualifications of personnel (e.g., conventional drilling, managed pressure drilling, underbalanced drilling) as well as specifies which barriers must be maintained and the expected response if a barrier is lost.

2018-01-OK-R13

Develop a management of change policy governing real-time changes to operations and the drilling plan. As part of this policy, require hazard analysis and consideration of rig equipment, procedures, and personnel training and qualifications.

10.5 International Association of Drilling Contractors

2018-01-OK-R14

Participate in development of the recommended practice describe in recommendation 2018-01-OK-R4 to API.

10.6 Pason Systems Inc.

2018-01-OK-R15

Design the Pason user interface to allow drilling contractors to pre-set different alarms for different operations (e.g., different alarm configurations for drilling, tripping, circulating, and surface operations in a “state-based” alarm system).

2018-01-OK-R16

Design the Pason electronic drilling data system so that alarm information, including alarm set points, alarm activation log, alarm horn status (on or off), and alarm system status (on or off) is provided to customers.

10.7 National Oilwell Varco (NOV)

2018-01-OK-R17

Design the M/D Totco user interface to allow drilling contractors to pre-set different alarms for different operations (e.g., different alarm configurations for drilling, tripping, circulating, and surface operations in a "state-based" alarm system).

2018-01-OK-R18

Design the M/D Totco electronic drilling data system so that alarm information, including alarm set points, alarm activation log, alarm horn status (on or off), and alarm system status (on or off) is provided to customers.

10.8 State of Oklahoma

2018-01-OK-R19

Establish and implement safety regulations requiring entities who design oil and gas well drilling plans for wells in Oklahoma (e.g., operators) and entities who perform the drilling operation (e.g., drilling contractors) to develop and implement the following prior to conducting drilling operations:

(a) Detailed written operating procedures with specified steps and equipment alignment for all operations;

(b) Written procedures for the management of changes (except replacements in kind) in procedures, the well plan, and equipment;

(c) A risk assessment of hazards associated with the drilling plan;

(d) A requirement to follow Recognized and Generally Accepted Good Engineering Practices (RAGAGEP);

(e) Development of a Well Construction Interface Document between the operator and the drilling contractor prior to the commencement of drilling activities which at a minimum includes a bridging document and well plan specifying barriers and how to manage them;

(f) The performance and documentation of flow checks using acceptable methods at defined points during the operation for a specified duration; and

(g) A requirement for employee participation, similar to the Employee Participation requirement in the OSHA PSM standard.

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Appendix A — Blowout Preventer and Accumulator Findings

- The accumulator was manufactured by NOV SARA INDIA (P), LTD. It was manufactured in 2008 (Figure A-1).

Figure A- 1. Photo of Patterson Rig 219 accumulator

- The accumulator experienced some heat damage from the fire, but heat damage was not excessive. Photos of heat damage are shown in Figure A- 2.

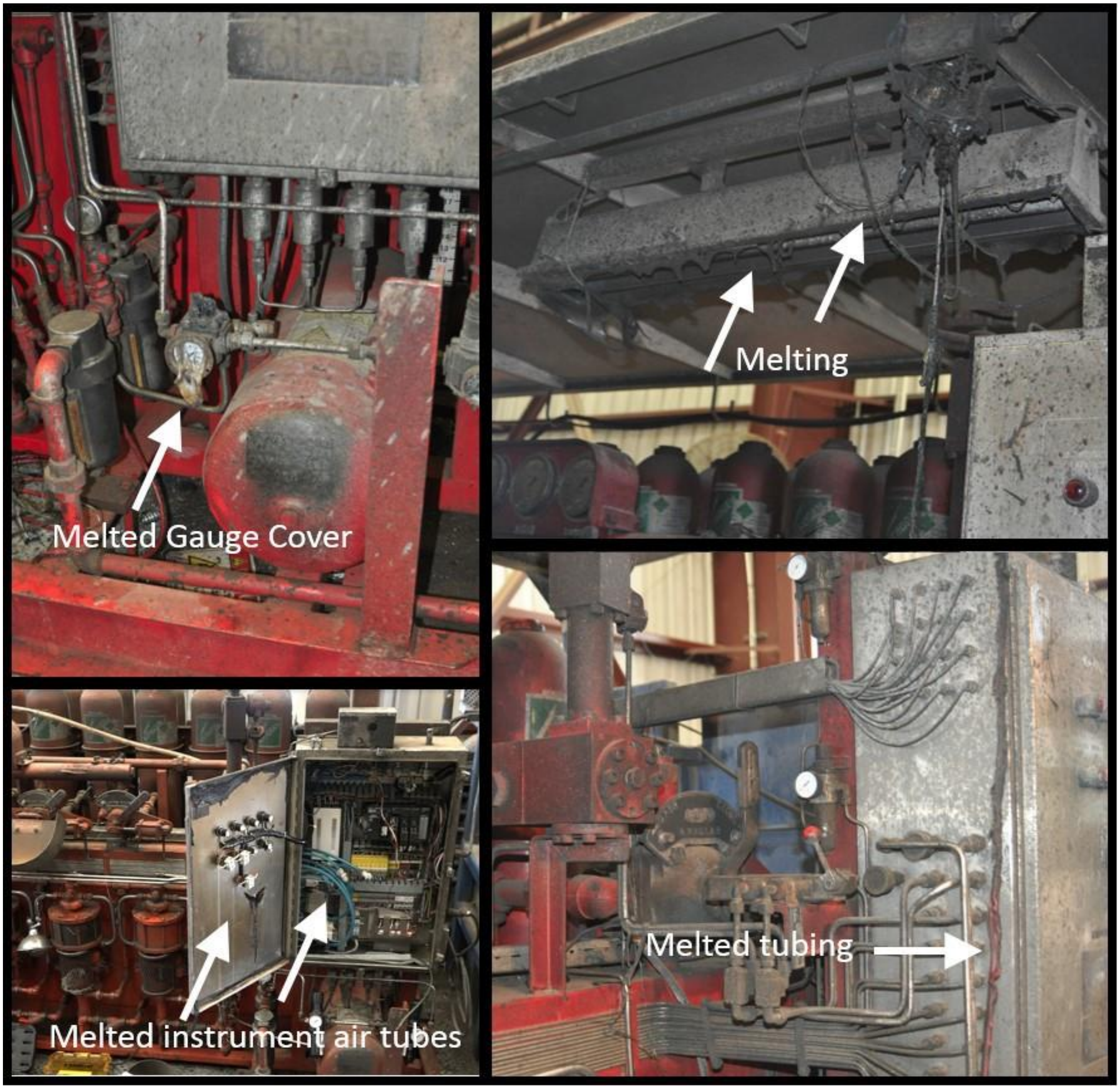
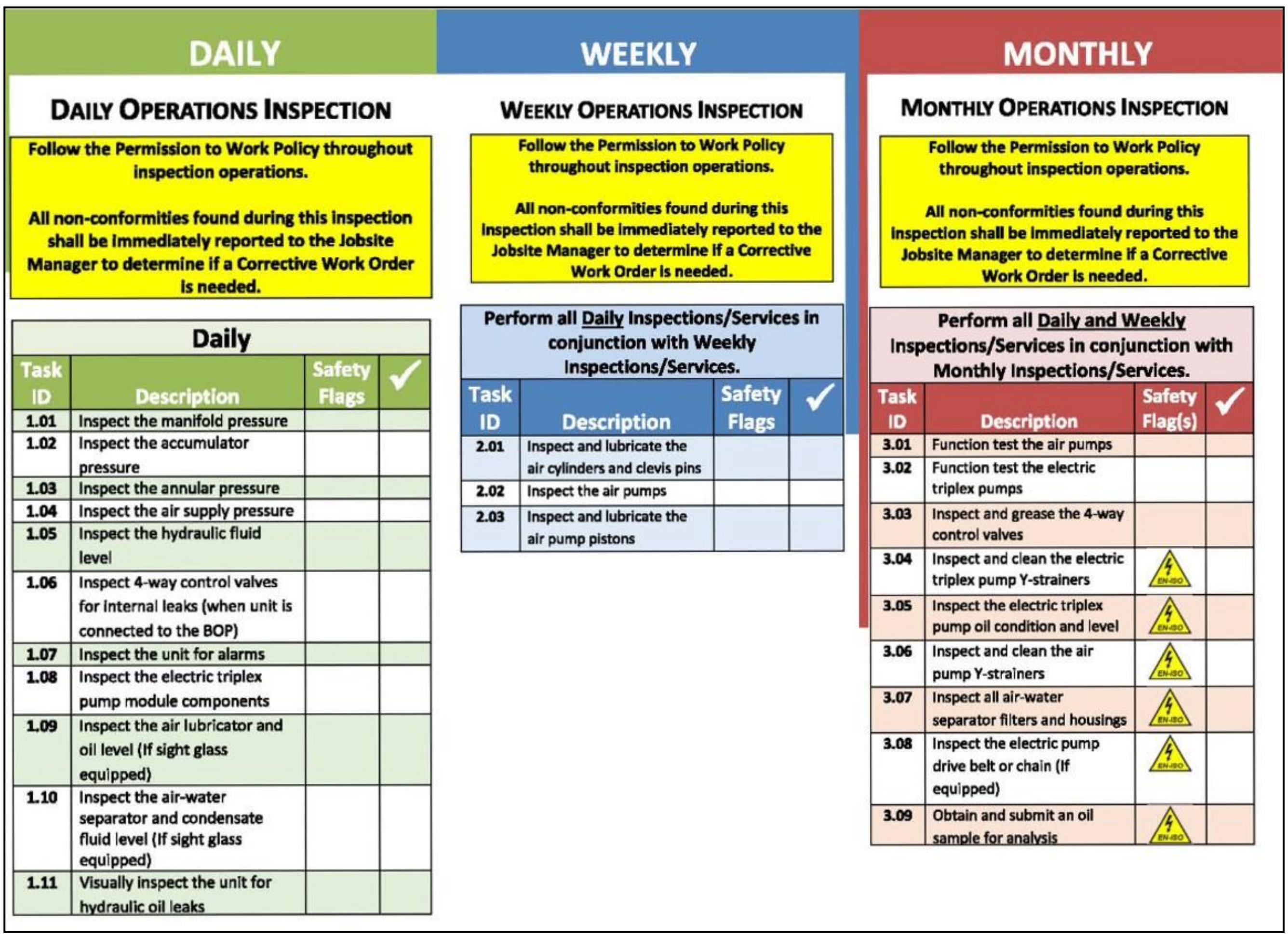


Figure A- 2. Photos of observed heat damage to Patterson Rig 219 accumulator

- The Patterson Rig 219 blowout preventer was manufactured by Horn Equipment Company, Inc.
- On January 11, 2018, before the incident, hydraulic fluid was sampled from the BOP accumulator reservoir and was tested in a laboratory. The laboratory analysis found elevated silicon in the hydraulic fluid, possibly from seals in the accumulator equipment. The laboratory analysis also found water at a “critical level” in the hydraulic fluid. The temperatures in the days leading to the incident were above the freezing temperature of

water,[a] so therefore the freezing of water in the accumulator hydraulic lines did not cause the blowout preventer to fail to function. Water contamination in hydraulic fluid can also cause corrosion problems, reduced lubrication of internal components, and changes to the hydraulic fluid viscosity, but none of these issues were found to be causal to the incident.

- The Patterson Rig 219 motorhand performed daily, weekly, and monthly inspections on the accumulator. The Patterson inspection requirements are shown below (Figure A- 3). The motorhand on the night tour performed more than one daily inspection of the accumulator during his shift before the incident, and the accumulator was functioning properly. The last monthly check performed on the accumulator was between December 24-26, 2017, less than a month before the incident. The inspection was marked "satisfactory."



DAILY

DAILY OPERATIONS INSPECTION

Follow the Permission to Work Policy throughout inspection operations.

All non-conformities found during this inspection shall be immediately reported to the Jobsite Manager to determine if a Corrective Work Order is needed.

Daily			
Task ID	Description	Safety Flags	✓
1.01	Inspect the manifold pressure		
1.02	Inspect the accumulator pressure		
1.03	Inspect the annular pressure		
1.04	Inspect the air supply pressure		
1.05	Inspect the hydraulic fluid level		
1.06	Inspect 4-way control valves for internal leaks (when unit is connected to the BOP)		
1.07	Inspect the unit for alarms		
1.08	Inspect the electric triplex pump module components		
1.09	Inspect the air lubricator and oil level (if sight glass equipped)		
1.10	Inspect the air-water separator and condensate fluid level (if sight glass equipped)		
1.11	Visually inspect the unit for hydraulic oil leaks		

WEEKLY

WEEKLY OPERATIONS INSPECTION

Follow the Permission to Work Policy throughout inspection operations.

All non-conformities found during this inspection shall be immediately reported to the Jobsite Manager to determine if a Corrective Work Order is needed.

Perform all Daily Inspections/Services in conjunction with Weekly Inspections/Services.			
Task ID	Description	Safety Flags	✓
2.01	Inspect and lubricate the air cylinders and clevis pins		
2.02	Inspect the air pumps		
2.03	Inspect and lubricate the air pump pistons		

MONTHLY

MONTHLY OPERATIONS INSPECTION

Follow the Permission to Work Policy throughout inspection operations.

All non-conformities found during this inspection shall be immediately reported to the Jobsite Manager to determine if a Corrective Work Order is needed.

Perform all Daily and Weekly Inspections/Services in conjunction with Monthly Inspections/Services.			
Task ID	Description	Safety Flag(s)	✓
3.01	Function test the air pumps		
3.02	Function test the electric triplex pumps		
3.03	Inspect and grease the 4-way control valves		
3.04	Inspect and clean the electric triplex pump Y-strainers	EN-ISO	
3.05	Inspect the electric triplex pump oil condition and level	EN-ISO	
3.06	Inspect and clean the air pump Y-strainers	EN-ISO	
3.07	Inspect all air-water separator filters and housings	EN-ISO	
3.08	Inspect the electric pump drive belt or chain (if equipped)	EN-ISO	
3.09	Obtain and submit an oil sample for analysis	EN-ISO	

Figure A- 3. Patterson accumulator inspection requirements

- The Patterson rig user manual required that the nitrogen bladder in each accumulator bottle was to be precharged to 1000 psig. Post-incident testing found the nitrogen bladder precharge pressures to be the following (Figure A- 4):

[a] On January 21, 2018 (the day before the incident) the minimum temperature was 53 °F. On January 22, 2018, the minimum temperature was 37 °F. The freezing temperature of water is 32 °F.

Bank		Bottle	Bladder Pressure Friday 6/22/2018 0800	Monday 6/25/2018 0800	Tuesday 7/10/2018 0900
INSIDE	3	1	1200	1250	1200
		2	1200	1200	1200
		3	1100	1050	900
		4	1200	1200	1200
		5	1200	1250	1200
		6	1200	1200	1200
INSIDE	1	7	1050	1100	1100
		8	1250	1250	1250
		9	1200	1250	1150
		10	1150	1200	1100
		11	1150	1200	1200
		12	1200	1200	1200
OUTSIDE	2	13	1200	1200	1200
		14	1150	1175	1200
		15	1150	1200	1100
		16	1200	1200	1200
		17	1150	1200	1200
		18	600	650	350
OUTSIDE	4	19	1050	1175	1200
		20	950	950	750
		21	1050	1200	1200
		22	1200	1225	1250
		23	1200	1250	1200
		24	1100	1150	1200

Figure A- 4. Accumulator bottle nitrogen bladder precharge pressures found post-incident

- API Standard 53 *Blowout Prevention Equipment Systems for Drilling Wells* requires “[t]he primary pump system shall automatically start before system pressure has decreased to 90 % of the system [rated working pressure (RWP)] and automatically stop between 97 % to 100 % of the RWP [64, p. 26].” The RWP for the Rig 219 accumulator was 3,000 psig. Thus, the pump system was required to automatically start when the accumulator pressure fell below 2,700 psig. The post-incident testing of the Rig 219 accumulator found that the primary pump activated when the accumulator pressure decreased to about 2,000 – 2,100 psig, and the primary charging pump automatically switched off when the accumulator pressure reached 2,800 psig. Patterson rig crew personnel told the CSB that the accumulator pressured up to its required pressure (3,000 psig) before the incident, so these lower pump activation pressures may have been a result of the incident.

- API Standard 53 *Blowout Prevention Equipment Systems for Drilling Wells* requires "[t]he cumulative output capacity of the pump systems shall be sufficient to charge the main accumulator system from precharge pressure to the system RWP within 15 minutes [64, p. 25]." Post-incident testing found that the primary electric pump could charge up the accumulator system in about 8 minutes.

- API Standard 53 *Blowout Prevention Equipment Systems for Drilling Wells* requires "[t]he BOP control system shall be capable of closing each ram BOP in 30 seconds or less" and "[c]losing time shall be 30 seconds or less for annular BOPs" [64, p. 27]. The BOP testing found that the Rig 219 accumulator, using replacement hydraulic lines, could close the Rig 219 BOP components in the following times:

  - Single bottom ram: 7 seconds to close
  - Double bottom ram: 7 seconds to close
  - Double top ram: 7 seconds to close
  - Annular preventer: 13 seconds to close

- API Specification 16D *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment* requires "control lines … located in a division one (1) area, as defined by API RP 500 (area classification), shall be capable of containing the hose rated working pressure in a flame temperature of 1300°F (700°C) for a 5-minute period [65, p. 51]." The hoses installed were manufactured to API Specification 16D requirements and were made of synthetic rubber, with a fire resistant synthetic rubber cover impregnated with fiberglass, and with reinforcement high-tensile steel wire spiral layers. The hydraulic hoses were exposed to fire within three minutes after the blowout began (Figure A- 6). One video obtained by the CSB suggests the exposure to fire occurred within one minute, but due to the angle of the video it is difficult to be certain. Hydraulic fluid likely escaped from these pressurized hydraulic lines from fire damage (Figure A- 5), possibly due to flame temperatures exceeding 1300 °F,[a] exposure to flames for longer than five minutes before the BOP was attempted to be operated, or both. As the hydraulic fluid escaped from the damaged hydraulic lines, the accumulator pressure dropped. Some witnesses reported hearing the accumulator charging pumps running during the blowout, but it was also reported by the rig manager (who attempted to activate the BOP from the accumulator) that he never heard the accumulator pumps running after the incident started. After the incident, the accumulator reservoir was found to be about 80% full of hydraulic fluid,[b] which indicates the accumulator charging pumps were not operating for any significant time period after the blowout began, likely from incident-induced damage to the electric and air systems that powered the pumps. The night tour motorhand reported that he maintained the accumulator reservoir about 75% full with hydraulic fluid, which he gauged by looking into the accumulator through a top port with his flash light. The typical hydraulic fluid level and the level found post-incident are in close agreement.

[a] Flame temperature can be roughly approximated by color. Orange flames are reported to be about 2,010°F [73, p. 369].
[b] The accumulator reservoir is 36.5 inches tall. The post-incident hydraulic fluid level was 30 inches.

- The Patterson Rig 219 blowout preventer was evidently operating 39 minutes before the blowout. The blind rams were opened at 7:57 am, and the blowout occurred at 8:36 am.

- After the blowout started, the Rig Manager closed four of the handles on the accumulator, beginning with the handle closest to the rig. The order of closure was (1) annular, (2) top pipe rams, (3) blind rams, and (4) bottom pipe rams. Due to the fire-damaged and leaking hydraulic hoses, combined with the hydraulic fluid being routed to four different BOP components, the blind rams did not fully close. A Boots & Coots responder observed during the emergency response operations that one side of the blind rams was fully closed, and the other side was halfway closed.

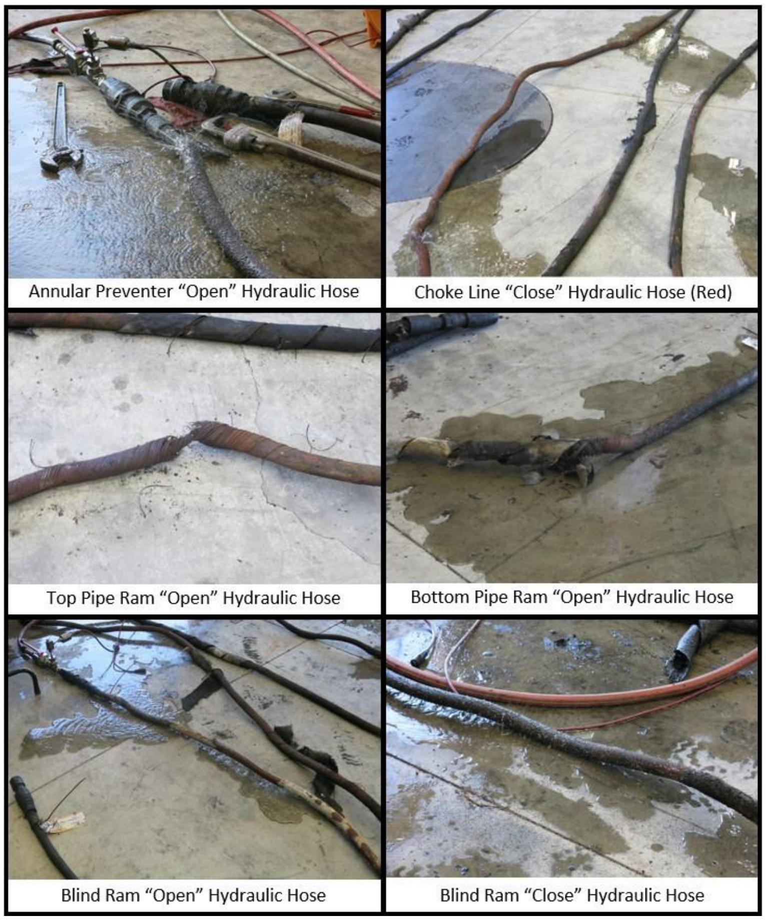


Figure A- 5. Photos of hydraulic hoses that were installed between the accumulator and BOP, used to send high-pressure hydraulic fluid to the BOP rams to open or close the rams. The hoses were damaged by the fire. The hydraulic hoses were leak tested using 40-50 psig water, and all hoses leaked water.

Figure A- 6. Video still of Patterson Rig 219 fire, taken 3 minutes after blowout began.

Appendix B — Weighted Pill Calculations

Annular Pressure Loss While Drilling at 13,340 feet MD on 1/21/2018 = 163 psi

Pill Volume = 50 barrels = 281 ft^3

Pill Density = 10 ppg

Mud Density = 8.3 ppg

Annular Diameter = 8.75 in

Annular Volume (no pipe) = 0.418 $\frac{ft^3}{ft}$

<u>Percent of Annular Pressure Loss:</u>

Pill Height = $\frac{Pill\ Volume}{Annular\ Volume\ (no\ pipe)} = \frac{281\ ft^3}{0.418\frac{ft^3}{ft}} = 672\ ft$

Additional Pressure Supplied by Pill = Hydrostatic Pressure $_{\text{Pill}}$ – Hydrostatic Pressure $_{\text{Mud of Same Volume}}$

$$= (10\frac{lb}{gal} * .052\ \frac{gal}{in^2 ft} * 672\ ft) - (8.3\frac{lb}{gal} * .052\ \frac{gal}{in^2 ft} * 672\ ft)$$

$$= 59.4\ psi$$

Percent of Annular Pressure Loss = $\mathbf{\frac{59.4\ psi}{163\ psi}\ x\ 100 = 36.4\%}$

Appendix C — Trip Tank Volume Fluctuations when Tripping Wet Pipe

- Figure C- 1 illustrates how a trip tank volume could behave when tripping wet pipe, when the drill pipe contents drain back into the trip tank as shown in Figure C- 2.

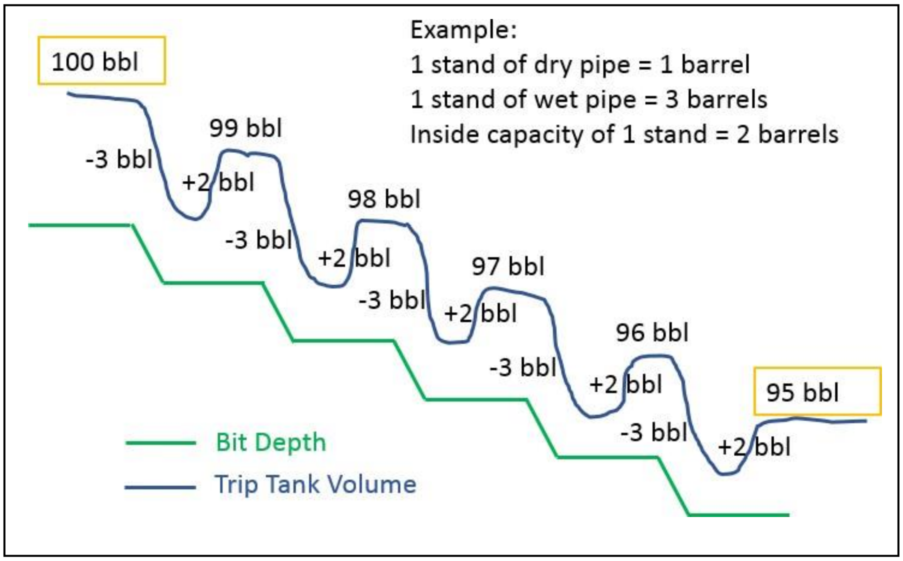


Figure C- 1. Example trip tank fluctuation pattern when tripping wet pipe when mud bucket drains to trip tank.

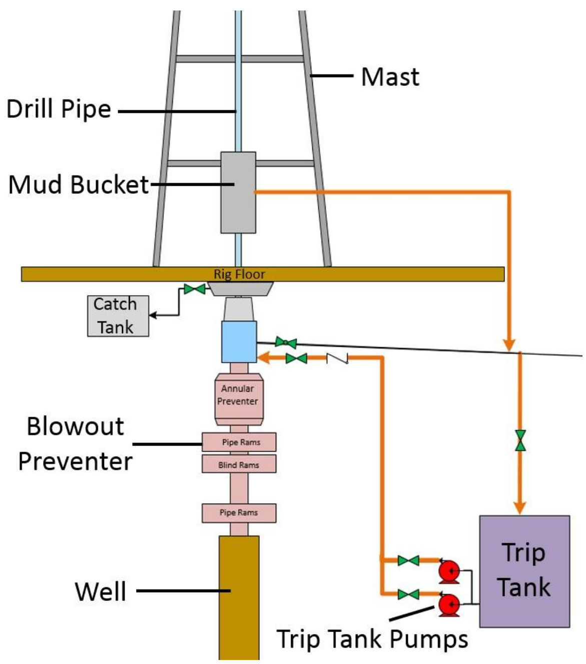


Figure C- 2. Example equipment alignment that could cause the trip tank volume fluctuations shown in Figure C- 1.

- In this example, tripping five stands of drill pipe containing mud (each stand has dry volume of 1 barrel) with the mud bucket draining to the trip tank results in a five-barrel decrease in the trip tank volume. This is a volume reduction of the *dry volume* of the drill pipe stand even though the drill pipe was being pulled "wet."

- This calculation assumes there is no mud leakage or mud spilled on the drill floor during the tripping operation.

- The *Guide to Blowout Prevention*, created by the company Well Control School (WCS) states:

  > If the pipe is pulling wet (fluid remains in the pipe), and a mud bucket is used to drain away from the hole, trip tank or pits, then the combined volume of the steel pipe and the internal capacity of the pipe are removed [from the well]. This results in a larger amount of fluid being required to fill the hole than when pulling dry pipe. However, if the mud bucket drains back into the hole [or] trip tank […] then the amount to fill would be the same as pulling dry pipe (providing mud bucket does not leak) [66].

- Routing drill pipe/mud bucket drainage elsewhere (e.g., a catch tank) requires usage of wet volume for trip sheet calculations. This will also reduce trip tank volume fluctuations and can reduce crewmember confusion. The CSB was informed, however, that the general standard in the North Sea for wet tripping is that the fluid from the mud bucket is routed to the trip tank so that if the float (a type of check valve preventing back flow) fails in the drill string and the well starts to kick up the drill string, then the kick can be identified.

  Wet pipe volume can also be used for trip sheet calculations with this equipment alignment when calculations are made for single stands of drill pipe.

Appendix D — Pryor Trust 1H-9 Drilling Plan

RED MOUNTAIN ENERGY, LLC

DRILLING PROGNOSIS

Pryor Trust 0718 1H-9
East Lake / Woodford
Patterson 219
Surface Hole Location
341' FNL & 290' FEL Sec 17-7N-18E
PUPP
165' FSL & 880' FWL Sec 9-7N-18E
Bottom Hole Location
165' FNL & 880' FWL Sec 4-7N-18E
Sections 17, 9 & 4 T7N-R18E
Pittsburg / Oklahoma
API
121 24801

PATTERSON 219

RIG PHONE [redacted]

Well:	Pryor Trust 0718 1H-9	AFE: 170004		VP Operations:	[redacted]
Prospect:	East Lake / Woodford	Property #: 17090718-1H		Drilling Engineer:	
County:	Pittsburg / Oklahoma			Completions:	
Surface:	341' FNL & 290' FEL Sec 17-7N-18E			Geology:	
PUPP:	165' FSL & 880' FWL Sec 9-7N-18E			Land:	
PBHL:	165' FNL & 880' FWL Sec 4-7N-18E	GL: 618'	KB: 645'	API:	

RED MOUNTAIN ENERGY, LLC

9-5/8" Intermediate

17-1/2"

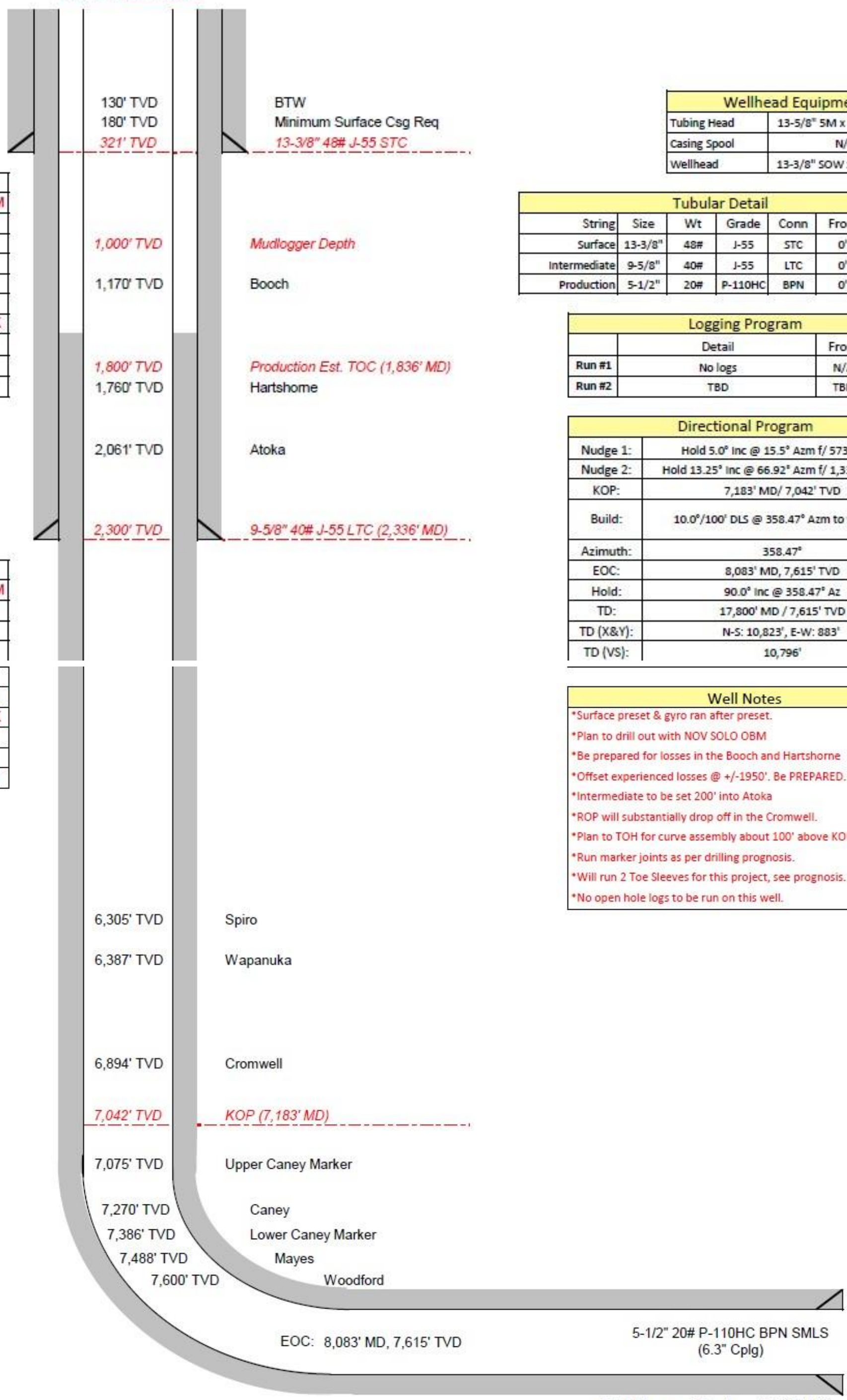
Mud Summary
Surface Preset

12-1/4"

Mud Summary	
Type	NOV OBM
MW	8.4-9.0
6 Rpm	6-9
PV	8-14
YP	8-12
ES	300-400
WPS	205-215K
OWR	75-25
LGS	<8.0
GPM	650-750

8-3/4"

Mud Summary	
Mud Type	NOV OBM
MW	8.4-9.0
6 Rpm	6-9
PV	8-14
YP	8-12
ES	300-400
WPS	205-215K
OWR	75-25
LGS	<8.0
GPM	500-600



Total Measured Depth: 17,799' MD
True Vertical Depth: 7,615' TVD

Wellhead Equipment	
Tubing Head	13-5/8" 5M x 7-1/16" 10M
Casing Spool	N/A
Wellhead	13-3/8" SOW x 13-5/8" 5M

Tubular Detail

String	Size	Wt	Grade	Conn	From	To
Surface	13-3/8"	48#	J-55	STC	0'	321'
Intermediate	9-5/8"	40#	J-55	LTC	0'	2,336'
Production	5-1/2"	20#	P-110HC	BPN	0'	17,800'

Logging Program

	Detail	From	To
Run #1	No logs	N/A	N/A
Run #2	TBD	TBD	TBD

Directional Program	
Nudge 1:	Hold 5.0° Inc @ 15.5° Azm f/ 573' - 793'
Nudge 2:	Hold 13.25° Inc @ 66.92° Azm f/ 1,335' - 6,139'
KOP:	7,183' MD/ 7,042' TVD
Build:	10.0°/100' DLS @ 358.47° Azm to 90.0° Inc
Azimuth:	358.47°
EOC:	8,083' MD, 7,615' TVD
Hold:	90.0° Inc @ 358.47° Az
TD:	17,800' MD / 7,615' TVD
TD (X&Y):	N-S: 10,823', E-W: 883'
TD (VS):	10,796'

Well Notes

*Surface preset & gyro ran after preset.
*Plan to drill out with NOV SOLO OBM
*Be prepared for losses in the Booch and Hartshorne
*Offset experienced losses @ +/-1950'. Be PREPARED.
*Intermediate to be set 200' into Atoka
*ROP will substantially drop off in the Cromwell.
*Plan to TOH for curve assembly about 100' above KOP.
*Run marker joints as per drilling prognosis.
*Will run 2 Toe Sleeves for this project, see prognosis.
*No open hole logs to be run on this well.

Pryor Trust 0718 1H-9

17-1/2" Surface Hole

****Send SURFACE CASING REQUEST email 3 days prior to running casing****

1 Perform pre spud inspection with drilling contractor. Ensure everything is RU completely and functioning properly before spudding in.

2 Contact the OCC 24 hrs prior to spud and notify of spud. Note the time, date, and operator you spoke with in the DDR. Also, note time/date when rig was accepted as well as spud date/time on DDR.

****NOTE - IF SURFACE IS PRESET SKIP SURFACE SECTION OF PROCEDURE. WE WILL NU BOPE AND BEGIN AT 12-1/4" INTERMEDIATE SECTION.**

3 PU the following BHA to drill surface

BHA Detail

1	
2	
3	
4	
5	
6	

4 Pump Setup

Pump #1			Pump #2		
Liner Size	5.5	in	Liner Size	5.5	in
Stroke Length	12	in	Stroke Length	12	in
Eff	0.95	%	Eff	0.95	%
Output	0.0837986	bbl/stk	Output	0.083799	bbl/stk
Pump Rate	299	gpm @85 stk/min	Pump Rate	299	gpm @85 stk/min
Pump Rate	387	gpm @110 stk/min	Pump Rate	387	gpm @110 stk/min
Pressure Rating	5000	psi (90% of max)	Pressure Rating	5000	psi (90% of max)

5 Drill 17-1/2" surface to +/- 321'

- Take surveys every 250' to TD, contact Engineer if deviation exceeds 3 degrees. In the event severe losses are encountered, contact engineer and discuss options.
- In order to assure a successful surface hole is drilled, a rigorous sweep regime will be followed as per mud program.
- Pump +/-800 gpm, vary WOB (25-50K) and RPM (100-120) to maximize penetration rate. These are optimal "proposed" parameters for this hole size. We will use common sense and ease into our optimal parameters. We must be proactive in an attempt to prevent any unnecessary events (mainly lost circulation and deviation).
- Sweep hole clean at TD prior to TOH. A wiper trip will be made to surface, prior to running casing.

6 Mud Properties (see attached mud program for details)

From Spud to Surface TD	MW	8.3-8.7	ppg
	Vis	32-40	sec/qt
	PV	3-12	cp
	YP	4-14	lb/100ft sq
	API FL	NC	mL/30min
	Solids	3-5	%

7 RU casing crew and run 321' of 13-3/8" 48# J-55 STC casing.

- Run guide shoe, 1 joint of casing, & float (tack weld float euipment)
- Centralize first 3 joints and every other joint to surface

13-3/8" 48# J-55 STC					
Collapse (100%)	770	psi	Annular	0.6946	cuft/ft
Burst (100%)	1,730	psi	Annular	0.12372	bbl/ft
Yield (100%)	322,000	lb	Capacity	0.1571	bbl/ft

8 RD casing crew and rig up cementers (O-Tex). Have 1" tubing available for top out. **Pump the following volumes**
Top of cement calculated to surface. Confirm cement volumes with fluid caliper prior to pumping.

Pre Flush:	**20**	bbl	Gel Spacer
Tail	**340**	sks	100% Class C, 2% CaCl2, 0.25 lb/sk Cello-Flake
Density	14.8	ppg	
Yield	1.35	cuft/sk	
Mix H2O	5.18	gal/sk	
Excess	100%		
Displacement	**43.8**	bbls	Freshwater

• Recalculate displacement volumes to float collar once casing is landed. Do not over displace.
• Release pressure and verify that float is holding. If float does not hold, pressure up and check again. If float still does not hold, trap final displacement pressure + 500 psi for 4 hours.
• *Note: if cement is not circulated to surface, notify engineer. Contact OCC and call out wireline truck for temp survey. Have WL truck bring perforation guns, in the event they are needed.*

9 Install 13-3/8" SOW x 13-5/8" 5M starting head with 2" 5M ball valve on one outlet and bull plug on the other, test head to 750 psi. NU BOPE and test with 3rd party company to 250 psi low/5000 psi high (annular to 250 psi low/ 2000 psi high). Keep charted tests on file for duration of well.

• Install wear bushing prior to drilling out.

RED MOUNTAIN ENERGY, LLC

12-1/4" Intermediate Hole

****Send INTERMEDIATE CASING REQUEST email at least 3 days prior to running casing****

1 PU the following BHA (see attached detailed BHA);

BHA Detail

Bit #1	12-1/4" Ulterra CF616 (1.1-1.5 TFA)
Drilling Motor - Bent	8" Motor, 7:8, 4.0, 1.72° FBH, 0.16 rpg, 12" Stb Slv
Float Sub	Float Sub
UBHO Sub	8" Skyline UBHO
NMDC	8" NMDC
NMDC	8" NMDC
Drill Collars	(3) 8" Drill Collars (If available, if not utilize 6-1/2")
XO	XO
Drill Collars	(12) 6-1/2" Drill Collars
HWDP	(15 Stds) 5" HWDP

2 **Pump Setup**

Pump #1			Pump #2		
Liner Size	5.5	in	Liner Size	5.5	in
Stroke Length	12	in	Stroke Length	12	in
Eff	0.95	%	Eff	0.95	%
Output	0.0837986	bbl/stk	Output	0.083799	bbl/stk
Pump Rate	299	gpm @85 stk/min	Pump Rate	299	gpm @85 stk/min
Pump Rate	387	gpm @110 stk/min	Pump Rate	387	gpm @110 stk/min
Pressure Rating	5000	psi (90% of max)	Pressure Rating	5000	psi (90% of max)

3 Prior to TIH to drill out run a Gyro Survey to determine drift of surface interval, if required.

4 TIH to float collar, test casing to 500 psi for 30 min prior to drilling out float equipment.
• OCC Regulations: Pressure test casing to the lesser of 0.2 psi/ft to casing shoe or 1500 psi for 30 minutes.

5 Drill shoe track and drill ahead following sound drilling practices.
• Drill out with NOV SOLO OBM. It is vital that MW remain low (<8.6 ppg) through the intermediate section. Losses have been known to be severe if excessive MW's are allowed throughout the section. Utilize solids control equip to maintain low MW's. See attached mud program and below for properties.
• Pump +/-700 gpm and vary WOB and RPM to maximize ROP. These are optimal "proposed" parameters for this hole size. We will use common sense and ease into optimal parameters. We must be proactive in an attempt to prevent any unnecessary events (mainly lost circulation).
• Maintain 500-600 psi differential, if hole conditions allow.
• Planned nudge: **Hold 5.0° Inc @ 15.5° Azm f/ 573' - 793'** Take surveys every +/-90'.
• Have mudloggers on by ***1,000' TVD***
• Be prepared for losses across the Booch (1170') and Hartshorne (1760'). Losses were experienced @ 1950' on the offset. We will have a 25 ppb LCM pill prebuilt prior to drilling through these intervals. We will also, control drill at 50 fph, until collars have crossed into the intervals and losses are not observed. If losses are observed and severe we will discuss bypassing shakers and loading system with LCM. Follow all LCM pill requirements as per NOV/Mud Engineers.
• Planned TD for this hole section is **2,300' TVD** . Confirm casing point with geologist and engineer prior to TOH. Be sure to drill +/-20' of rathole so casing can be landed in the wellhead.
• Once TD, circulate hole clean, make a WIPER TRIP to collars prior to TOH for casing.

6 Mud Properties (see attached mud program for details)

	Type	NOV OBM	
WBM f/ Drillout to Intermediate TD	MW	8.4-9.0	ppg
	6 Rpm	6-9	sec
	PV	8-14	cp
	YP	8-12	lb/100 sqft
	ES	300-400	V
	WPS	205-215K	ppm
	OWR	75-25	
	LGS	<8.0	%

• Allow well to dictate MW

RED MOUNTAIN ENERGY, LLC

7 R/U casing crew and run 9-5/8" 40# J-55 LTC casing as follows:
- **Pull wear bushing before running casing!**
- 9-5/8" 40# LTC Weatherford Float Shoe
- 1 joint - Centralized (12-1/4" x 9-5/8" Weatherford Bow Spring)
- 9-5/8" 40# LTC Weatherford Float Collar
- Do not rush and risk breaking down formations by running casing at excessive speeds. Follow good practices and use fluid displacement as a guideline. If for whatever reason the wellbore displacement reduces or quits, stop and circulate. Fill pipe and break circulation every 30-40 joints.
- Centralize casing every 3rd Joint to surface shoe (12-1/4" x 9-5/8" Weatherford Bow Spring).

Confirm casing tally with engineer prior to running

9-5/8" 40# J-55 LTC						
Collapse	2,570	psi	Annular Vol.	12-1/4" x 9-5/8" csg	0.3132	cuft/ft
Burst	3,950	psi	Annular Vol.	13-3/8"csg x 9-5/8"csg	0.3765	cuft/ft
Yield	630,000	lb	Capacity	9-5/8" 40# J-55 LTC	0.0758	bbl/ft

- Tag bottom to verify hole depth.
- Before making up mandrel and landing joint, verify correct number of joints were left out.
- Verify casing landed properly through sight ports in wellhead, confirm with Wellhead Tech.

8 RD casing crew and rig up cementers (O-Tex). Circulate 1.5 times casing capacity to ensure casing is clear.

Pump the following volumes

Final cement volumes will be emailed out prior to running casing.

Pre Flush:	**20**	bbl	Gel Spacer w/ Dye
Lead:	**220**	sks	Class C w/ 2% Gypsum, 2% C-45, 1% CaCl2, 0.25 lb/sk Cello-Flake, 0.125 lb/sk Fiber X
Density	11.4	ppg	
Yield	2.92	cuft/sk	
Mix H2O	18.01	gal/sk	
Base of Lead	1,536'	feet	
Surface Shoe	321'	feet	
Top of Cement	0'	feet	Excess 35%

Tail	**270**	sks	Class C w/ 0.25 lb/sk Cello-Flake, 0.125 Fiber X
Density	14.8	ppg	
Yield	1.33	cuft/sk	
Mix H2O	6.31	gal/sk	
Fill	800'	feet	Excess 35%

Displacement **21.1** bbls OBM
- Recalculate displacement volumes to float collar once casing is landed.
- Bump plug to 500 psi over final displacement psi. Release pressure to verify floats will hold.
- If plug does not bump at calculated displacement, discuss options before overdisplacing.
- If floats do not hold, pressure up and check again. If floats still do not hold, trap final displacement pressure + 500 psi for 4 hrs.

9 RD cementers and set pack off with wellhead representative
- Test upper and lower seals to 5000 psi.

8-3/4" Vertical/Nudge Section

1 PU the following BHA

BHA Detail

Bit	8-3/4" Ulterra U713M
Drilling Motor - Bent	6-3/4" Motor, 7:8, 2.9, 1.75 FBH, 0.29 rpg, 8.25" Stabilizer
Float Sub	6-3/4" Float Sub
UBHO	6-3/4" UBHO Sub
NMDC	6-3/4" NMDC
NMDC	6-3/4" Flex NMDC
XO	Cross-Over (4-1/2" XH Pin - 4-1/2 IF Box)
HWPD	(15 Stands) 5" HWDP (4-1/2 IF)

2 TIH to drill ahead

• Test casing before drilling out to 1,000 psi for 30 minutes. If surface pressure loss is greater than 10% of initial test pressure, contact engineer.

• OCC Regulations: Pressure test casing to the lesser of 0.2 psi/ft to casing shoe or 1500 psi for 30 minutes.

• Drill ahead following sound drilling practices to KOP. Take surveys every +/-90'. Be prepared for over pressured windows throughout this section, as well as losses. Offsets have shown losses in this region throughout this section, but always be prepared for hydrocarbon influxes. Utilize orbit valve on connections if necessary and monitor all parameters closely for any key indicators. Allow the wellbore to dictate the MW. It will be vital to keep MW low throughout this section. Utilize tighest mesh shaker screens possible and run centrifuge at frequent intervals to maintain lowest possible MW.

• Maximize drilling parameters to optimize ROP. If hole conditions allow run 400-500 differential psi and 500-600 gpms. Use common sense and ease into optimal parameters.

• Planned nudge: **Hold 13.25° Inc @ 66.92° Azm f/ 1,335' - 6,139'**

• Planned KOP for this section is **7,042' TVD** . Plan to kick off 50-100' early.

• At KOP circulate hole clean and TOH f/ curve assembly.

• TOH following sound tripping practices. If the wellbore has excessive over pull stop and circulate, utilize the top drive to TOH, do not continue to TOH and risk becoming stuck.

3 **Mud Properties (see attached mud program for details)**

OBM f/ Drillout to KOP	Mud Type	NOV OBM	
	MW	8.4-9.0	ppg
	6 Rpm	6-9	sec
	PV	8-14	cp
	YP	8-12	lb/100 sqft
	ES	300-400	V
	WPS	205-215K	ppm
	OWR	75-25	
	LGS	<8.0	%

• Allow well to dictate MW

8-3/4" Curve Section

Send PRODUCTION CASING REQUEST email at least 3 days prior to running casing

1 PU the following Curve BHA

BHA Detail

Bit	8-3/4" NOV 28APDGH2 or Halliburton MMD74DC (1.1-1.5 TFA)
Drilling Motor - Bent	6-3/4" Mud Motor, 6:7, 5.0, 2.38 FBH, 0.29 rpg, 8.25" Stab
Float Sub	6-3/4" Float Sub
UBHO	6-3/4" UBHO Sub
NMDC	6-3/4" NMDC
NMDC	6-3/4" Flex NMDC
XO	Cross-Over (4-1/2" XH Pin - 4-1/2 IF Box)
HWPD	(15 Stands) 5" HWDP (4-1/2 IF)

2 **Pump Setup**

Pump #1			Pump #2		
Liner Size	5.5	in	Liner Size	5.5	in
Stroke Length	12	in	Stroke Length	12	in
Eff	0.95	%	Eff	0.95	%
Output	0.0837986	bbl/stk	Output	0.083799	bbl/stk
Pump Rate	299	gpm @85 stk/min	Pump Rate	299	gpm @85 stk/min
Pump Rate	387	gpm @110 stk/min	Pump Rate	387	gpm @110 stk/min
Pressure Rating	5000	psi (90% of max)	Pressure Rating	5000	psi (90% of max)

3 Drill ahead following sound drilling practices.
- Pump maximum gpm and vary WOB to maximize ROP.
- Kick off 50-100' above planned KOP @ 7,042' TVD
- Build curve per attached directional plan.
- Slide 100% until the first survey is seen. Adjust rotate/slide ratio based on motor yield.
- If at any point while building the curve motor is yielding less than DLS required to land on target, call and discuss with Engineer. Do not continue to drill ahead and risk landing well below planned target.
- Plan on taking surveys every +/-30', unless utilizing Range III DP then discuss +/-45' survey intervals.
- Once curve is landed, circulate hole clean and TOH f/ lateral assembly. TOH following sound tripping practices. If excessive over pull is observed stop and circulate, if needed pump assembly out of the hole, utilize top drive, do not continue to TOH and risk getting stuck.

4 **Directional Details:**

KOP:	7,183' MD/ 7,042' TVD
Build:	10.0°/100' DLS @ 358.47° Azm to 90.0° Inc
Azimuth:	358.47°
EOC:	8,083' MD, 7,615' TVD
Hold:	90.0° Inc @ 358.47° Az
TD:	17,800' MD / 7,615' TVD

5 **Mud Properties (see attached mud program for details)**

OBM f/ KOP to EOC	Mud Type	NOV OBM	
	MW	8.4-9.0	ppg
	6 Rpm	6-9	sec
	PV	8-14	cp
	YP	8-12	lb/100 sqft
	ES	300-400	V
	WPS	205-215K	ppm
	OWR	75-25	
	LGS	<8.0	%

- Allow well to dictate MW

8-3/4" Production Lateral

1 PU the following BHA

BHA Detail

Bit	8-3/4" MMD74DC Halliburton (1.1-1.5 TFA)
Drilling Motor - Bent	6-3/4" Mud Motor, 6:7, 5.0, 1.75 FBH, 0.29 rpg, Slick Sleeve
Float Sub	6-3/4" Float Sub
UBHO	6-3/4" UBHO Sub
NMDC	6-3/4" NMDC
NMDC	6-3/4" Flex NMDC
XO	Cross-Over (4-1/2" XH Pin - 4-1/2 IF Box)
DP	25 Stds - 75 Jts 5" DP
Agitator/Shock Sub/Safety Jt	6-1/2" NOV Agitator
DP	5" DP
HWPD	(Minimum 15 Stands) 5" HWDP (4-1/2 IF)

2 **Pump Setup**

Pump #1			Pump #2		
Liner Size	5.5	in	Liner Size	5.5	in
Stroke Length	12	in	Stroke Length	12	in
Eff	0.95	%	Eff	0.95	%
Output	0.0837986	bbl/stk	Output	0.083799	bbl/stk
Pump Rate	299	gpm @85 stk/min	Pump Rate	299	gpm @85 stk/min
Pump Rate	387	gpm @110 stk/min	Pump Rate	387	gpm @110 stk/min
Pressure Rating	5000	psi (90% of max)	Pressure Rating	5000	psi (90% of max)

3 Drill ahead following sound drilling practices.

- Drill lateral per attached directional plan
- Target Window: As Per Geology
- Pump maximum gpm and vary WOB and RPM to maximize ROP.
- Monitor PU, SO, and ROT weights and TQ while drilling the lateral for hole cleaning indications.
- Maximize RPM as per K&M best practices for optimal hole cleaning.
- It will be vital to keep MW low throughout this section as losses are possible. Utilize tighest mesh shaker screens possible and run centrifuge at frequent intervals to maintain lowest possible MW.
- Perform clean-up cycles every +/- 1,000' (or as needed) @ minimum 550 gpm / 85 rpm
- **Woodford Tripping Procedure:** Circulate hole clean. TOH following sound tripping practices, in an attempt to create minimal disturbance of the wellbore. If well is flowing, calculate/pump ECD pill before continuing to TOH. If excessive drag is observed or hole is packing off, **STOP** and circulate hole clean before continuing to TOH! If at any point unusual drag is observed, stop and circulate.
- USE DP SCREEN ANYTIME PUMP IS ON THE HOLE!!

4 **Directional Details:**

Target TVD @ TD	7,615'
Target Window	As Per Geology
TD:	17,800' MD / 7,615' TVD
TD (X&Y):	N-S: 10,823', E-W: 883'
TD (VS):	10,796'
Inc:	90.00°

5 **Mud Properties (see attached mud program for details)**

OBM f/ EOC to TD	Mud Type	NOV OBM	
	MW	8.4-9.0	ppg
	6 Rpm	6-9	sec
	PV	8-14	cp
	YP	8-12	lb/100 sqft
	ES	300-400	V
	WPS	205-215K	ppm
	OWR	75-25	
	LGS	<8.0	%

- Allow well to dictate MW

6 **Clean-up Cycle / TOH @ TD Procedure**
- TD well at BHL per directional plan, confirm TD with Engineer
- Circ 1.0 hrs for every 1,000' of lateral @ 550 gpm/85 rpm. Reciprocate pipe during clean-up cycle.
- Record PU/SO/ROT string weights and TQ every hour (in clean-up cycle spreadsheet) and send to Engineer for review prior to TOH.
- TOH and ensure hole is taking proper fill. If well is flowing, pump ECD pill before continuing to TOH. If excess drag is seen or hole is packing off, **STOP** and circulate hole clean before continuing to TOH!
- **USE DP SCREEN ANYTIME PUMP IS ON THE HOLE!!**
- Begin LD drill pipe @ KOP

7 **Production Casing Requirements**
- Torque Turn must be utilized while running casing
- Thread rep must monitor casing run if premium thread is utilized

8 R/U casing crew and run 5-1/2" 20# P-110HC BPN casing as follows;
- Pull wear bushing before running casing!
- Weatherford 5-1/2" Float Shoe - BTC, followed by 1 joint of 5-1/2" 20# P-110HC BPN Casing
- Weatherford latch down style Float Collar - BTC, followed by 1 joint of 5-1/2" 20# P-110HC BPN Casing
- #1 Nine Energy SmartStart Toe Valve, followed by 1 joint of 5-1/2" 20# P-110HC BPN Casing
- #2 Nine Energy SmartStart Toe Valve
- Centralize shoe track and every 3rd joint to TOC w/ Weatherford 8-3/4" x 5-1/2" Solid Body Centralizers.
- 5-1/2" 20# P-110HC BPN marker joints to be ran @ middle of lateral and 100' above KOP

Confirm casing tally with engineer prior to running

5-1/2" 20# P-110HC BPN						
Collapse	12,770	psi	Annular Vol.	8-3/4" x 5-1/2" csg	0.2526	cuft/ft
Burst	12,640	psi	Annular Vol.	9-5/8"csg x 5-1/2" csg	0.2607	cuft/ft
Yield	641,000	lb	Capacity	5-1/2" 20# P-110HC BPN	0.0222	bbl/ft

- Tag bottom to verfiy hole depth.

9 RD casing crew and rig up cementers (O-Tex). Circulate 1.5 time casing capacity to ensure casing is clear.

<u>Pump the following volumes</u>

Final cement volumes will be emailed out prior to running casing.

Pre Flush:	30	bbl	Mud Wash
Mud Push:	85.2	bbl	O-Tex OBMR mixed @ 9.0 ppg
Lead:	930	sks	50:50:2 (Poz:H:Gel) w/ 2% Gel, 0.4% FL-4, 0.2% C-51, 0.2% X-Air, 0.125 lb/sk Fiber X
Density	12.5	ppg	
Yield	1.81	cuft/sk	
Mix H2O	9.71	gal/sk	
KOP	7,042'	feet	
Interm Shoe	2,336'	feet	
Top of Cmt	1,836'	feet	Excess 30%
Tail	2380	sks	50:50:2 (Poz:H:Gel) w/ 2% Gel, 0.4% FL-4, 0.2% C-51, 0.03% - TX20, 0.2% X-Air, 0.25 lb/sk Cello Flake
Density	13.6	ppg	
Yield	1.43	cuft/sk	
Mix H2O	6.89	gal/sk	
Fill	10,758'	feet	Excess 25%
Displacement	394.2	bbls	Freshwater

- Recalculate displacement volumes to float collar once casing is landed.
- If plug does not bump at calculated displacement, discuss options w/ Engineer before overdisplacing.
- Release pressure and verify that float is holding. If float does not hold, pressure up and check again. If float still does not hold, trap final displacement pressure + 500 psi for 4 hours.

10 ND BOPE and NU 13-5/8" 10M x 7-1/16" 15M tubing head and test to 5,000 psi. Note tubing head specs and test details in DDR.

11 Clean pits and prep to release rig. Clear location of trash and verify mouse hole is properly covered or abandoned.

Appendix E — Summary of Alarm System Data

In response to a formal request for information by the CSB, the rig data company provided data points recorded by the rig data alarm system in internal developer logs that included alarm status, alarm set points, and sensor data for tank volumes and flow. The rig data company communicated to the CSB that "this is the first time [the company] has … attempted to create such a document, and so the process it used has not been validated and may not have resulted in an accurate record of events." While this may be a concern, the CSB determined this data provides critical information that may explain in part why both drillers missed indications of the large gas influx before the incident. It is important for the drilling industry to understand the information contained in the post-incident data compilation effort. A summary of the data is below.

The alarm system was off, but the data indicates when alarms would have sounded had the system been on, based on drilling alarms and setpoints used prior to the alarm system being disabled. Once a parameter exceeded its alarm set point, an audible or visual alarm would be continuously active (e.g., continuous horn beeping) until the parameter went below the set point. The sections below discuss the alarms that would have activated during the approximately 14 hours leading to the blowout had the alarm system been on.

1/21 Between 6:45 pm and 10:30 PM, Tripping out of the Lateral Section

Figure E- 1 depicts what alarms would have been active during this period. Each line on the top of Figure E- 1 does not indicate a separate alarm; instead, each alarm line is simply a recorded data point above the alarm set point in the data provided to the CSB. The figure is to be interpreted that when those lines for that parameter are visible, that alarm would have been active as a continuous beeping. Had the alarm system been on during the tripping operation out of the lateral part of the well on January 21, between 6:45 pm and 10:30 pm, alarms would have activated for Gain Loss High, Total Mud, Flow Low, Standpipe Pressure Low, and Torque (Figure E- 1). While these alarms and set points would have been important during a drilling operation, none were not applicable to the tripping operation in alerting to a well control event. More information about the specific alarms is in Table E- 1.

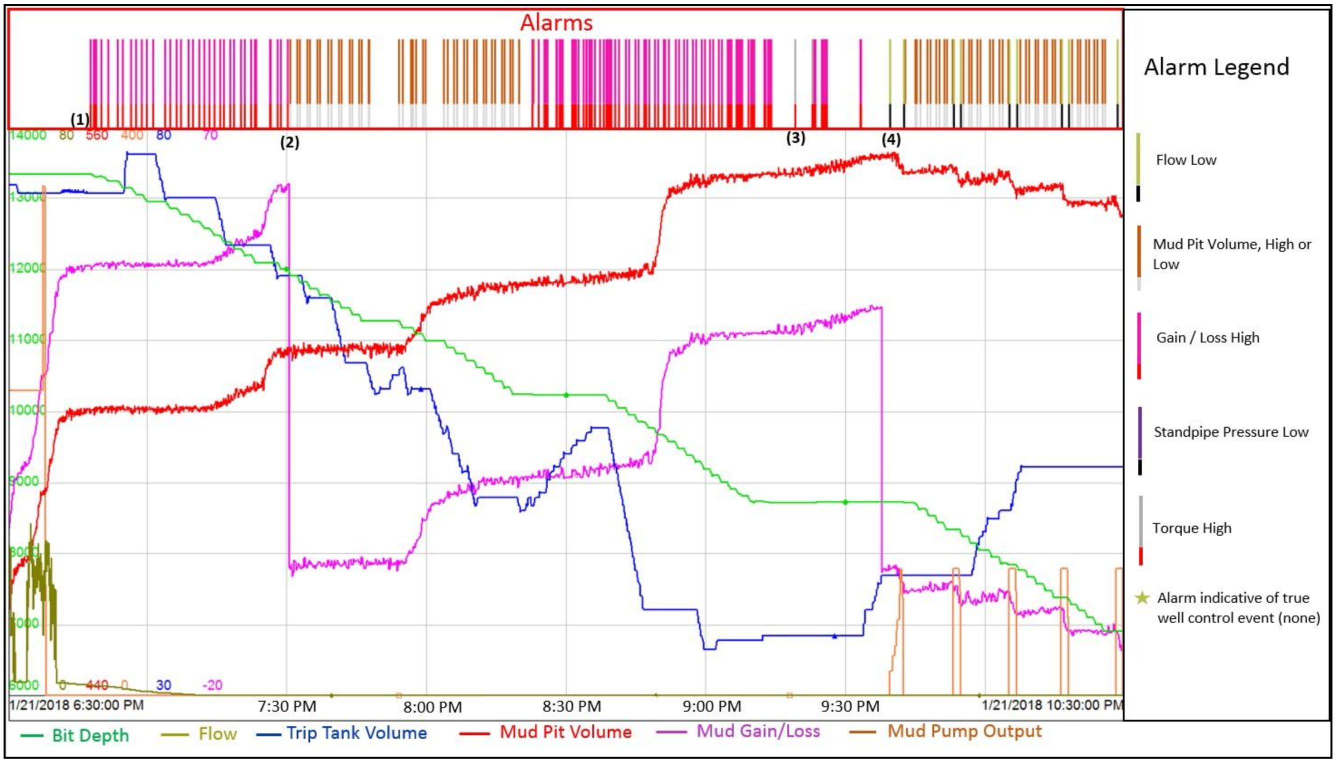


Figure E- 1. Information from alarm system data, indicating what alarms would have activated between 6:45 pm and 10:30 pm during the trip out of the lateral section, had the alarm system been turned on. Information about the specific alarms is in Table E- 1 below. The numbers in parentheses correspond with the note numbers in Table E- 1.

Table E- 1. Information about the specific alarms shown in Figure E- 1. The note numbers correspond with the numbers in parentheses in Figure E- 1.

(1) During the trip out of the lateral part of the well, the orbit valve in the flow line was closed. This valve alignment prevented any mud to flow from the well into the mud pits. The Gain/Loss alarm activates when a significant change occurs in the mud pit volume (the alarm was set to activate at a change of minus 40 or plus 15 barrels. Because the orbit valve was closed, the changes in mud pit volume during this tripping operation were caused by other operations, such as mud transfers, unrelated to the tripping operation. The Gain/Loss alarm would not have been indicative of the gas influx in the well and would therefore have been a nuisance or non-critical alarm.

(2) Use of the Mud Pit Volume alarm is another alarm, in addition to the Gain/Loss alarm, to monitor for increases in mud volume due to gains from the well. Because the orbit valve was closed, no mud was flowing to the mud pits from the well during the tripping operation. All changes in mud pit volume were a result of other operations, such as mud transfers, unrelated to the tripping operation. The alarming of the Mud Pit Volume alarm would have been a nuisance or non-critical alarm.

(3) "Torque" is a measurement of the amount of rotational force applied to the drill string. Torque measurement is useful during drilling operations, when a change in torque can indicate a well control event. In this tripping operation, however, there was no use for a torque alarm, which would have been non-critical to detecting a well control event during the tripping operation.

(4) The flow alarm was set to alert low flow when the mud pumps were running and the flow value was less than 5%. When the driller turned on the mud pumps during the tripping operation, the closed orbit valve prevented mud flow through the flow line. The low flow alarm would not have been indicative of a well control event. (Note: this alarm could still indicate a hazardous equipment lineup if the driller did not intend to close the orbit valve, which was not the case here.)

(5) Gains in the trip tank volume were a result of pressure at the surface of the well caused by a gas influx pushing mud to the trip tank through the trip tank discharge line. There were no alarms on the trip tank to alert the driller to the trip tank volume gain. The trip tank was equipped only with a high- and low-volume alarm to alert the driller when the trip tank was almost full or almost empty. The driller is expected to identify indications of gas influx by completing a trip sheet, comparing the calculated volume of mud expected to be pumped to the actual amount of mud pumped into the well from the trip tank. The CSB was told that the general standard in the North Sea is the driller can set a gain/loss alarm for trip tank level.

Alarms 1/21 10:30 pm through 1/22 1:10 am, Circulating at Top of Curve

The Patterson drilling crew began circulating the well at the top of the curve at about 11:00 pm. Circulating the well is a different operation from the earlier tripping operation, when different parameters and alarm set points could be important for monitoring the well.

While circulating at the top of the curve, had the alarm system been active, some of the active alarming would have been potentially indicative of the well control event, but the bulk of the active alarming would have been non-critical alarms (Figure E- 2). More information about the specific alarms is in Table E- 2.

Figure E- 2 depicts what alarms would have been active during this period. Each line on the top of Figure E- 2 does not indicate a separate alarm; instead, each alarm line is simply a recorded data point above the alarm set point in the data provided to the CSB. The figure is to be interpreted that when those lines for that parameter are visible, that alarm would have been active as a continuous beeping.

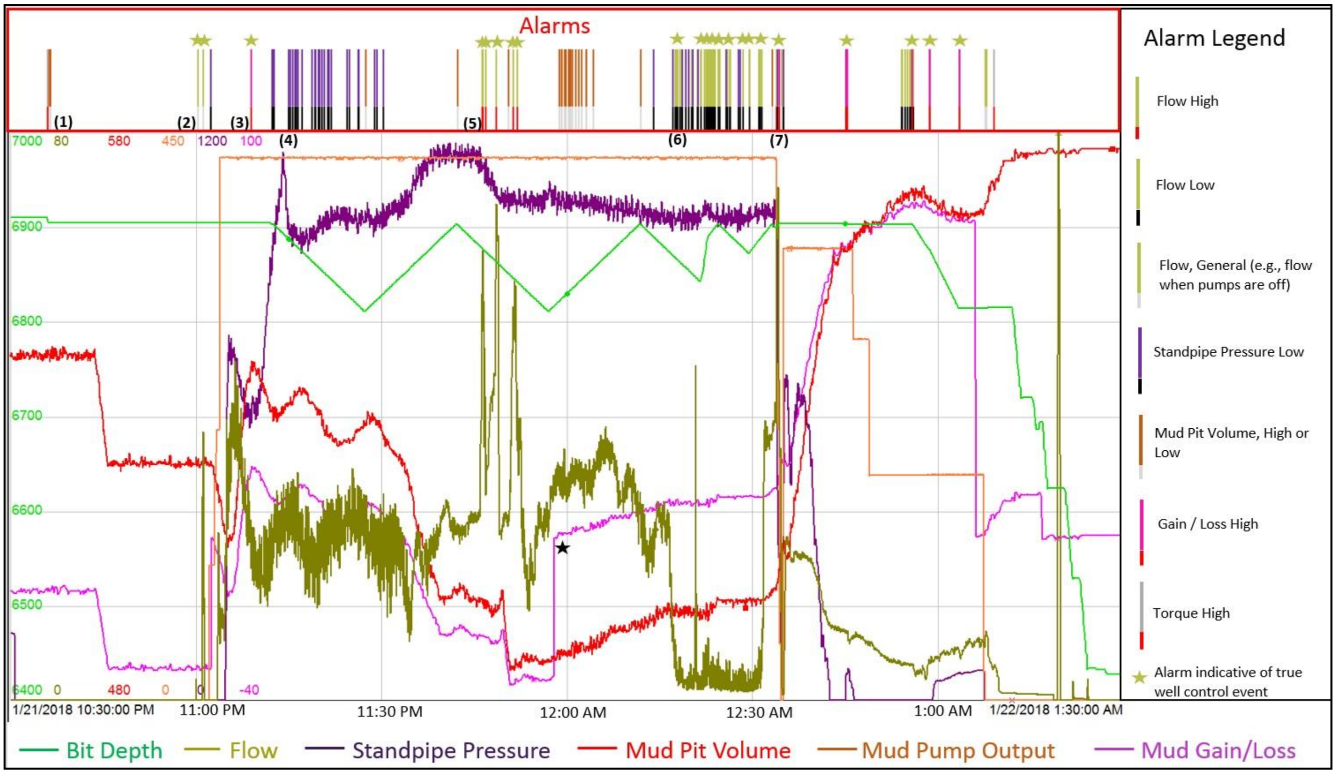


Figure E- 2. Information from alarm system data, indicating what alarms would have activated between 10:30 pm and 1:10 am while circulating at the top of the curve, had the alarm system been turned on. Some of these alarms could have alerted to the well control event. Information about the specific alarms is in Table E- 2 below. The numbers in parentheses correspond with the note numbers in Table E- 2.

Table E- 2. Information about the specific alarms shown in Figure E- 2. The note numbers correspond with the numbers in parentheses in Figure E- 2.

(1) The Mud Pit Volume alarm that would have sounded had the system been on was not significant. The Mud Pit Volume alarm was set by specifying a benchmark Mud Pit Volume (449 barrels), and the alarm was triggered at a value 40 barrels below or above the benchmark (409 barrels or 489 barrels). Before circulating, the total mud volume was 521 barrels, a value that would trigger the Mud Pit Volume alarm. The benchmark value was not reset before the circulating operation. Even at times when the Mud Pit Volume was below the starting circulating volume, the high-volume alarm would have still triggered because the volume was still above 489 barrels. As such, this alarm would have had limited meaningful significance, and its activations during the circulation operation would not have been warning of the well control event.

(2) The Flow General alarm would have activated when the orbit valve was opened before circulating the wellbore. The mud pumps were not on, but mud flowed out of the well. The Flow General alarm was set to activate when there was greater than 2 % flow and the mud pumps were not on. This alarm would have been a true indication of a potential well control event.

(3) The Gain/Loss High alarm would have activated shortly after the mud pumps were turned on to circulate the wellbore. The mud pit gain early during the circulation might have been an indication of gas influx into the well.

(4) The Standpipe Pressure Low alarm would have been triggered early during the circulation operation. The standpipe pressure increased again between 11:30 pm and 12:00 am during the well circulation, corresponding to a gas release from the well (Section 5.2), which would have caused the low pressure alarm to stop activating. Had the alarm system been active, the standpipe pressure alarm could have been used as a well control event indication if the setpoints been adjusted to make the information significant. At the current set points, however, this alarm would not have been warning of the well control event.

(5) The flow spiked during circulation, corresponding with a gas release (Section 5.2). The Flow High alarm would have been a correct indicator of the increase in flow and the implication of that flow as being a potential well control event.

(6) The flow suddenly dropped during circulation, and would have triggered the Flow Low alarm. The Flow Low alarm would have been a correct indicator of the decrease in mud flow from the well. While it is unclear what caused this drop in flow, this alarm would need driller attention.

(7) The Gain/Loss High alarm activation would have been a true indicator of a gain in the mud pit volume due to increased flow from the wellbore, signifying a well control event. The alarm set point, however, was set outside of the Patterson recommended limits. Patterson required that this alarm be set at +/- 5 barrels, but it was set to alarm at plus 15 barrels and minus 40 barrels. The driller reset the Gain/Loss measurement to zero at 11:58 pm (black star). The Gain/Loss High alarm would have activated when the Gain/Loss reached 15 barrels, at 12:34 am.

1/22 1:10 am to 4:50 am, Tripping Operation out of Vertical Section of Well

The tripping operation out of the vertical portion of the well occurred between 1:10 am and 4:50 am. During this period, alarms would have activated had the alarm system been on for parameters including mud pit volume, flow, Gain/Loss high, differential pressure, standpipe pressure, and torque. These alarms would have been activated by other rig operations (e.g., transferring mud) or parameters that would be pertinent to the drilling operation but were irrelevant to the tripping operation. As such, all alarming would have been non-critical alarms not indicative of the well control event. No alarms would have activated that warned of a potential well control event during the tripping operation.

Figure E- 3 depicts what alarms would have been active during this time period. Each line on the top of Figure E- 3 does not indicate a separate alarm; instead, each alarm line is simply a recorded data point above the alarm set point in the data provided to the CSB. The figure is to be interpreted that when those lines for that parameter are visible, that alarm would have been active as a continuous beeping. More information about the alarms is in Table E- 3.

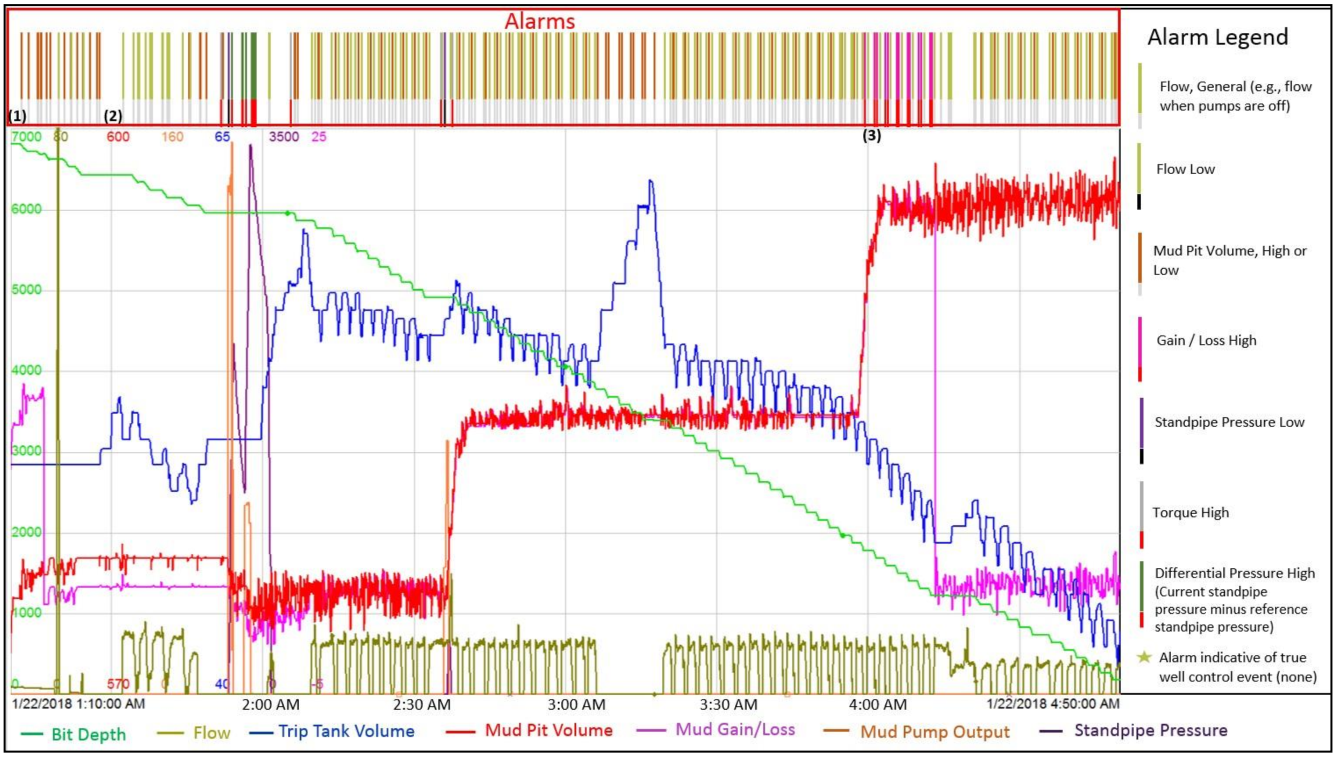


Figure E- 3. Information from alarm system data, indicating what alarms would have activated between 1:10 am and 4:50 am while tripping out of the vertical section of the well, had the alarm system been turned on. None of the alarms would have alerted to the well control event. Information about the specific alarms is in Table E- 3 below. The numbers in parentheses correspond with the note numbers in Table E- 3.

Table E- 3. Information about the specific alarms shown in Figure E- 3. The note numbers correspond with the numbers in parentheses in Figure E- 3.

(1) During the trip out of the vertical section of the well, all flow was routed to the trip tank. No flow was routed to the mud pits. While increases in mud pit volume could be indicative of a well control event during drilling operations when mud is flowing to the mud pits, monitoring and having active alarms on the mud pit were not pertinent to identifying a well control event during the tripping operation. Therefore, the mud pit volume alarm, had the system been on, during this tripping operation would have been non-critical and would not have warned of the well control event.

(2) The Flow General alarm would have activated when flow was detected and when the mud pumps were not operating. During tripping, flow was expected through the flow line when the mud pumps were not operating because the trip tank pumps were operating. Had the alarm system been turned on, the Flow General alarms would have been non-critical alarms that would not have alerted the driller to a potential well control event.

(3) During the trip out of the vertical section of the well, all flow was routed to the trip tank. No flow was routed to the mud pits. The Gain/Loss alarm is activated when a significant change occurs in the mud pit volume (at this time, minus 40 or plus 15 barrels). The changes in mud pit volume during this tripping operation were caused by mud transfers unrelated to the tripping operation. The Gain/Loss alarms that would have activated were non-critical alarms that would not have alerted the driller to a potential well control event.

1/22 4:50 am – 7:50 am, Rig Floor Operations

At 4:50 am, all drill pipe except the BHA had been removed from the well, and the BHA remained in the wellbore. From 4:50 am through 7:50 am, the drilling crew worked to unplug the drill pipe, transferred mud, and prepared the new BHA for testing. This period saw a significant 31-barrel gain in the trip tank due to gas in the wellbore. While alarms would have been activating during this time had the alarm system been on, none of the alarms would have alerted to the actual well control event in progress, and all alarms would have been non-critical (Figure E- 4).

The CSB was told that the general standard in the North Sea is the driller can set a gain/loss alarm for trip tank level. Adding a trip tank gain/loss alarm for use when flow is routed to the trip tank could alert drillers to unexpected trip tank gains such as this one.

During this period a shift change occurred at around 6:00 am. At 6:42 am, the alarm system was reactivated, likely by the new driller on tour. Non-critical alarms would have been continuously sounding while the alarm system was on. Twenty seconds after the alarm system was turned on, it was turned off again. The alarm horn remained off through the blowout at 8:36 am.

Figure E- 4 visually depicts what alarms would have been active during this period. Each line on the top of Figure E- 4 does not indicate a separate alarm; instead, each alarm line is simply a recorded data point above the alarm set point in the data provided to the CSB. The figure is to be interpreted that when those lines for that parameter are visible, that alarm would have been active as a continuous beeping.

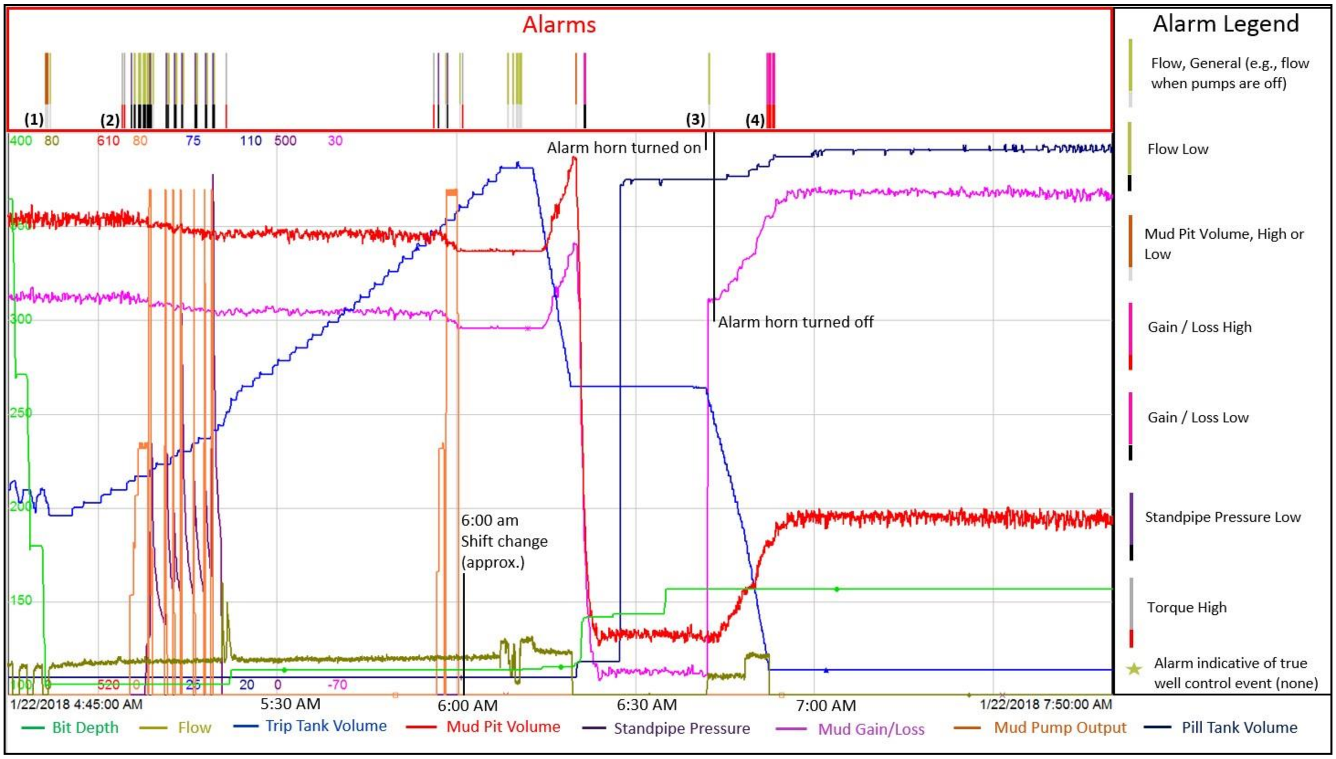


Figure E- 4. Information from alarm system data, indicating what alarms would have activated between 4:50 am and 7:50 am during the rig floor operations, had the alarm system been turned on. None of the alarms would have alerted to the well control event. Information about the specific alarms is in Table E- 4 below. The numbers in parentheses correspond with the note numbers in Table E- 4.

Table E- 4. Information about the specific alarms shown in Figure E- 4. The note numbers correspond with the numbers in parentheses in Figure E- 4.

(1) The Mud Pit Volume high alarm would have activated during this period. During this time, flow was routed to the trip tank, so any increases in mud pit volume were unrelated to flow coming from the wellbore. Also during this time, the Flow General alarm would have activated as a result of flow being detected when the mud pumps were off. The flow was caused in part by the trip tank pumps circulating mud through the flow line. While some of this flow was a result of a gas influx causing the trip tank gain, this alarm would not have alerted of the gain as it would have activated regardless of whether there was an ongoing well control event.

(2) The Torque, Flow Low, and Standpipe Pressure alarms would have activated when the drilling crew attempted to pump the plugging material out of the drill pipe stand. These alarms would not have alerted to a potential well control event.

(3) The alarm system was turned on, likely by the driller on the day tour, at 6:42 am. The alarm system was turned off about 20 seconds later. Non-critical alarms would have been continuously beeping while the alarm system was turned on.

(4) Due to a mud transfer from the trip tank to the mud pits, the Gain/Loss High alarm would have activated. This alarm would not have alerted to a well control event.

7:50 am - 8:36 am (Blowout)

Between 7:50 am and the blowout at 8:36 am, alarms would have activated for Flow, Mud Pit Volume, Standpipe Pressure, Gain/Loss, and Torque. This time, almost all of the alarming would have been indicative of the true well control event.

Figure E- 5 depicts what alarms would have been active during this period. Each line on the top of Figure E- 5 does not indicate a separate alarm; instead, each alarm line is simply a recorded data point above the alarm set point in the data provided to the CSB. The figure is to be interpreted that when those lines for that parameter are visible, that alarm would have been active as a continuous beeping.

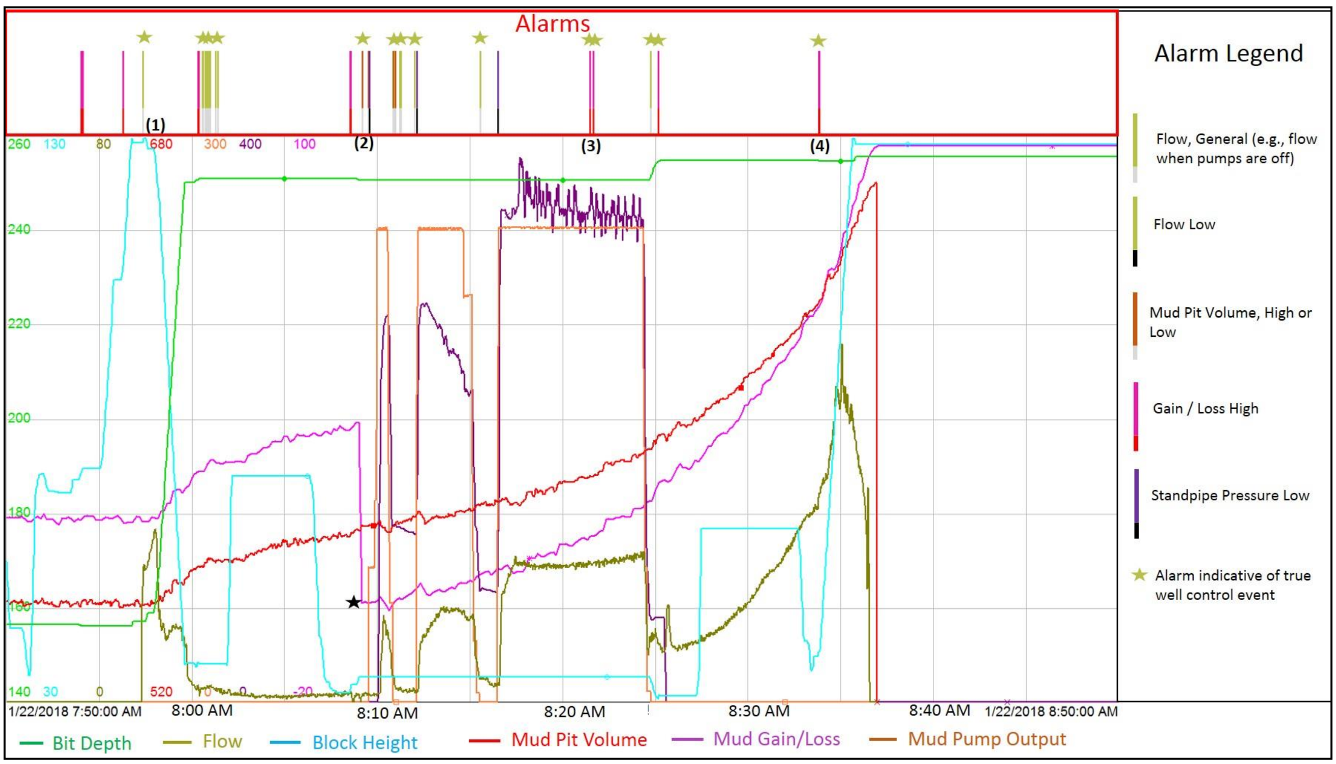


Figure E- 5. Information from alarm system data, indicating what alarms would have activated between 7:50 am and 8:36 am (blowout), if the alarm system was on. Almost all of the alarms would have alerted to the well control event. Information about the specific alarms is in Table E- 5 below. The numbers in parentheses correspond with the note numbers in Table E- 5.

Table E- 5. Information about the specific alarms shown in Figure E- 5. The note numbers correspond with the numbers in parentheses in Figure E- 5.

(1) The "Flow General" alarm would have activated when flow was detected and when the mud pumps were not operating, after the driller opened the blind rams in preparation to lower the new BHA into the wellbore (Section 5.6). The initial flow spike is an indication pressure had built up in the well (due to gas influx / expansion) while the blind rams were closed. These Flow General alarms would have been an indication of a true well control event.

(2) The driller set the "Mud Pit Volume" alarm benchmark point to 529.75 barrels between 6:27 am – 6:28 am on January 22. The alarm was set to activate at 40 barrels above the benchmark (569.75 barrels). About 20 barrels of the gain in mud pit volume from the time the benchmark point was set came from an earlier mud transfer from the trip tank to the mud pits (6:41 am), but the additional 20-barrel gain by 8:09 am was from mud flowing from the well. The Mud Pit Volume alarm would have been an indication of the gas influx.

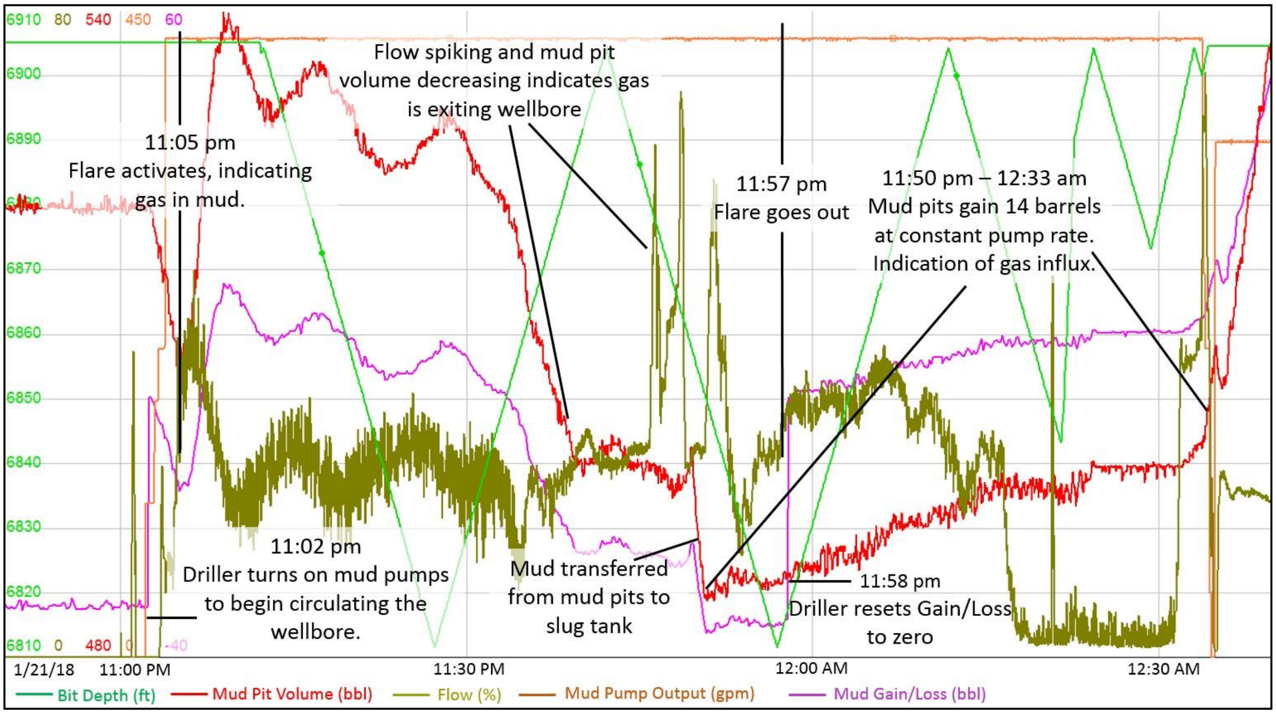
(3) The "Gain/Loss High" alarm was programmed to activate at plus 15 barrels. The driller reset the Gain / Loss calculation to zero at 8:09 am (indicated by black star above). All Gain/Loss alarming after 8:09 am would have been indicative of a well control event.

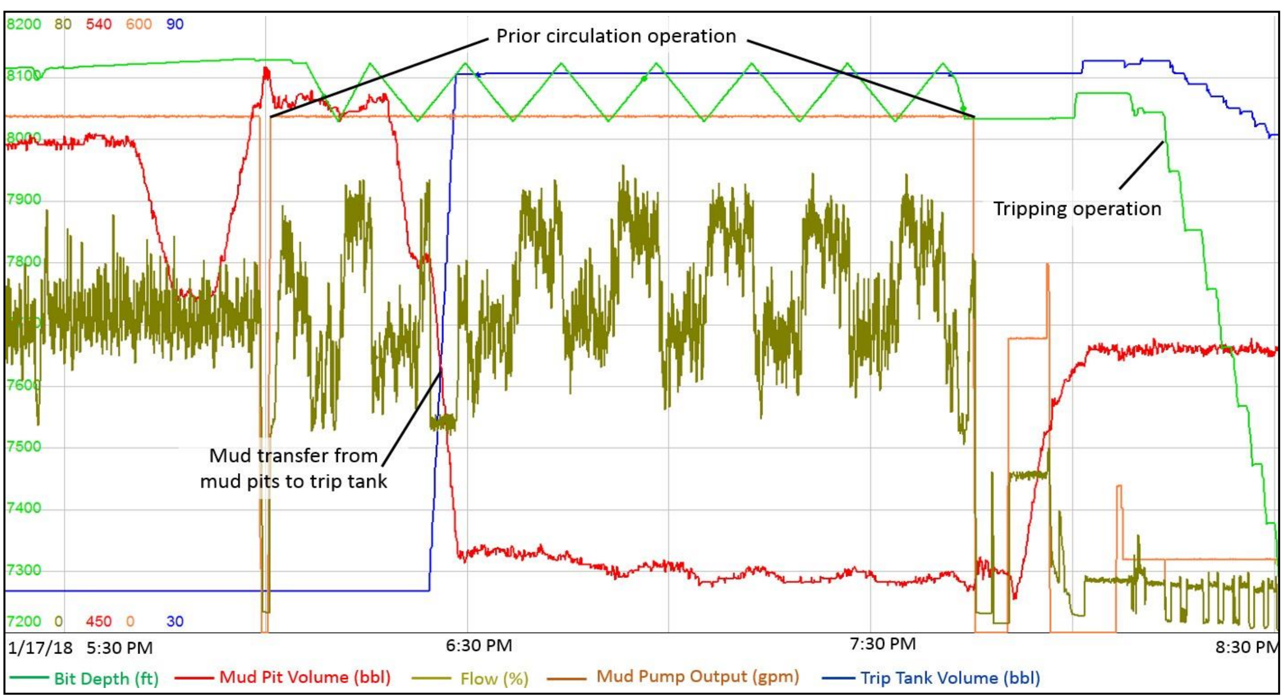
The Gain/Loss High alarm would have been activating at 7:53 am, before the blind rams were opened, due to a 20-barrel mud transfer from the trip tank to the mud pits at 6:41 am. While there was additional gain in the mud pits beginning at 7:57 am when the blind rams were opened, increasing the Gain/Loss reading, the alarm would have continued to activate even without this true gain from the well. As such, the Gain/Loss High alarms before 8:09 am would not have been a clear indication of a well control event.

(4) The Gain/Loss alarm would have been sounding until the blowout, alerting to the well control event.

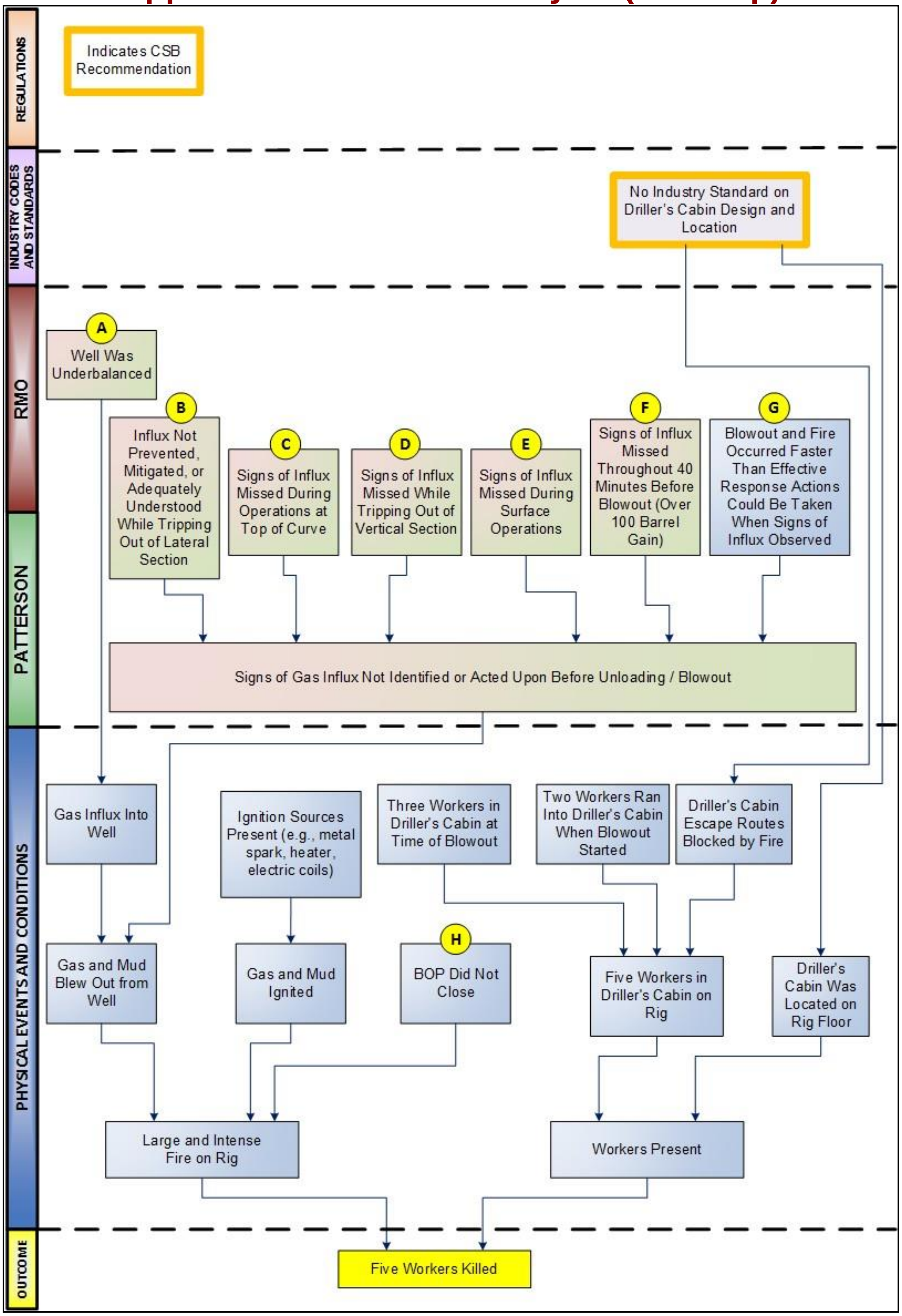
Appendix F — Comparison of Two Circulation Operations on Well 1H-9

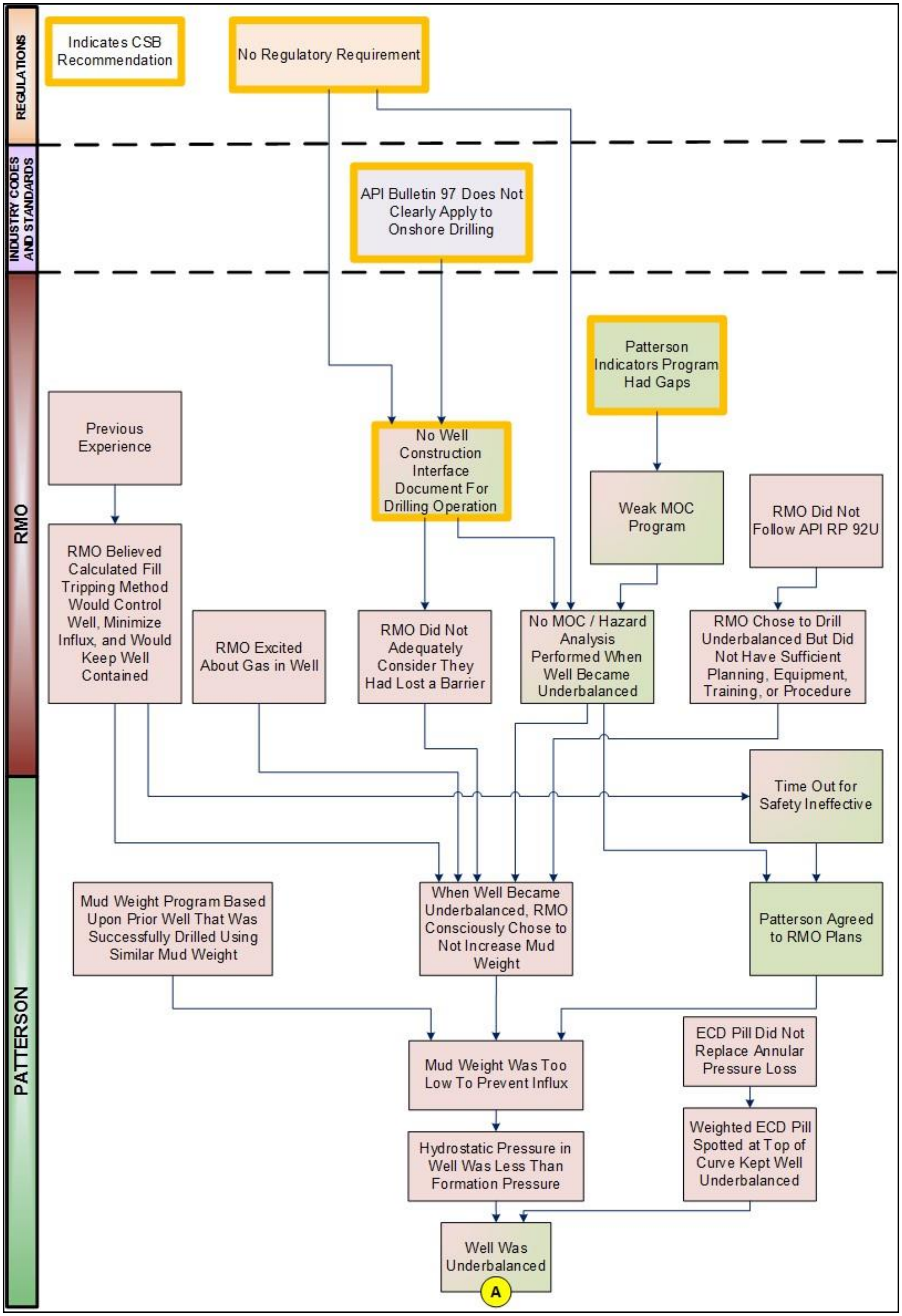
The top graph below shows rig data while circulating the wellbore at the top of the curve. The flare activated while circulating, indicating gas in the mud. Between 11:50 pm and 12:33 am, the mud pits gained 14 barrels while the mud pumps were circulating at a constant pump rate. This pit gain indicates there was a gas influx (kick). For comparison purposes, the bottom graph shows a normal circulation operation performed on January 17, 2018 on Pryor Trust Well 1H-9.

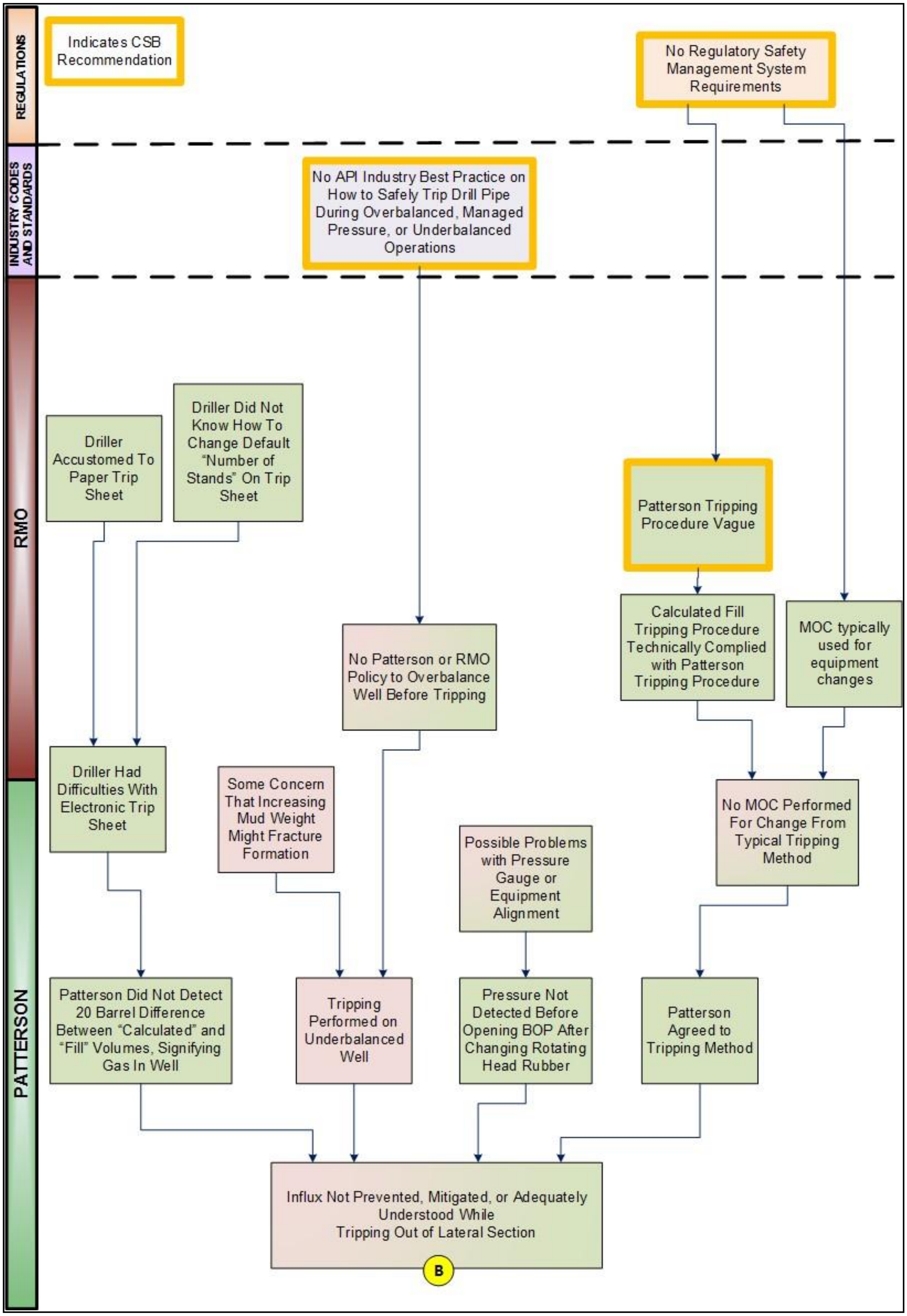


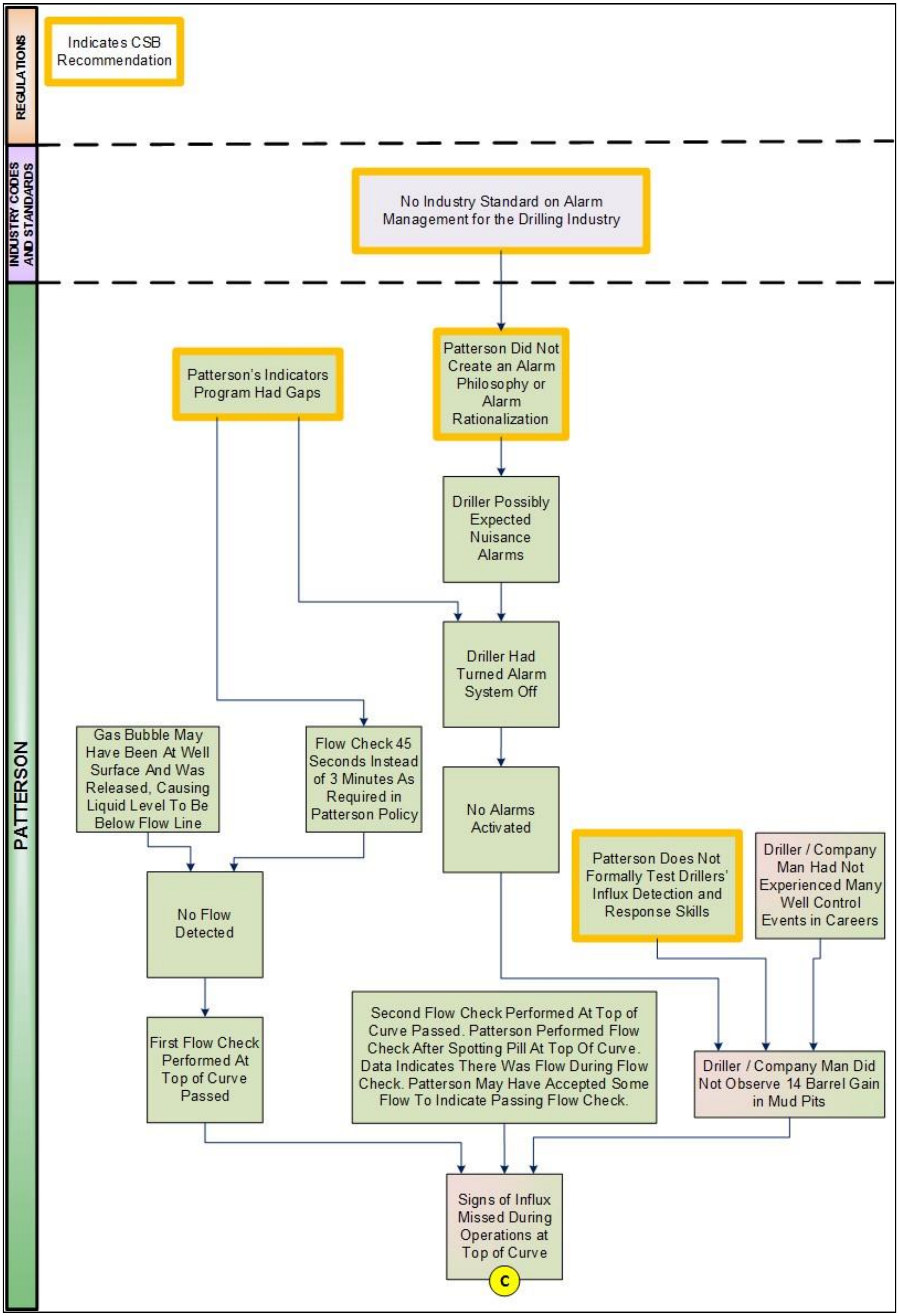


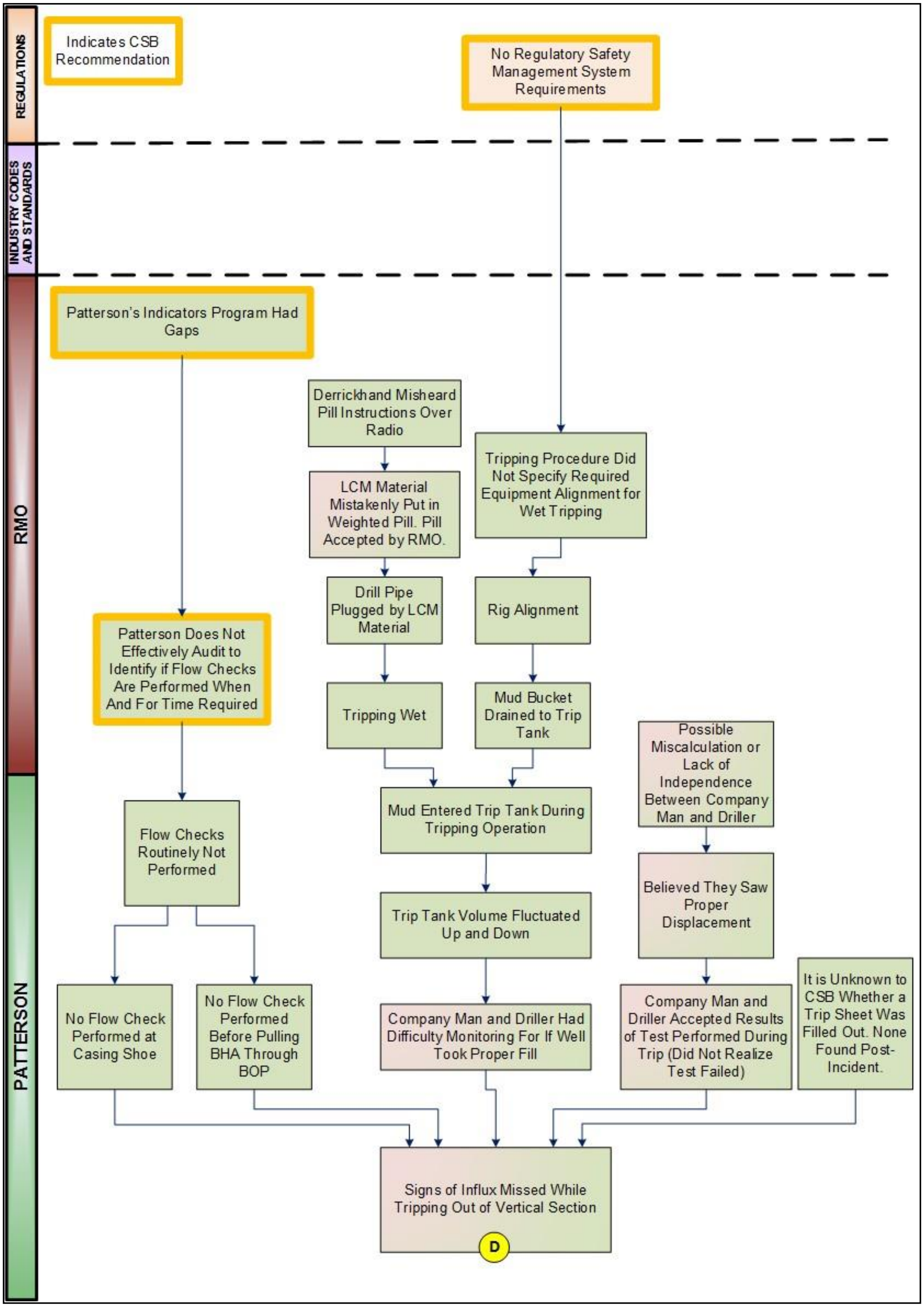
Appendix G — Causal Analysis (AcciMap)

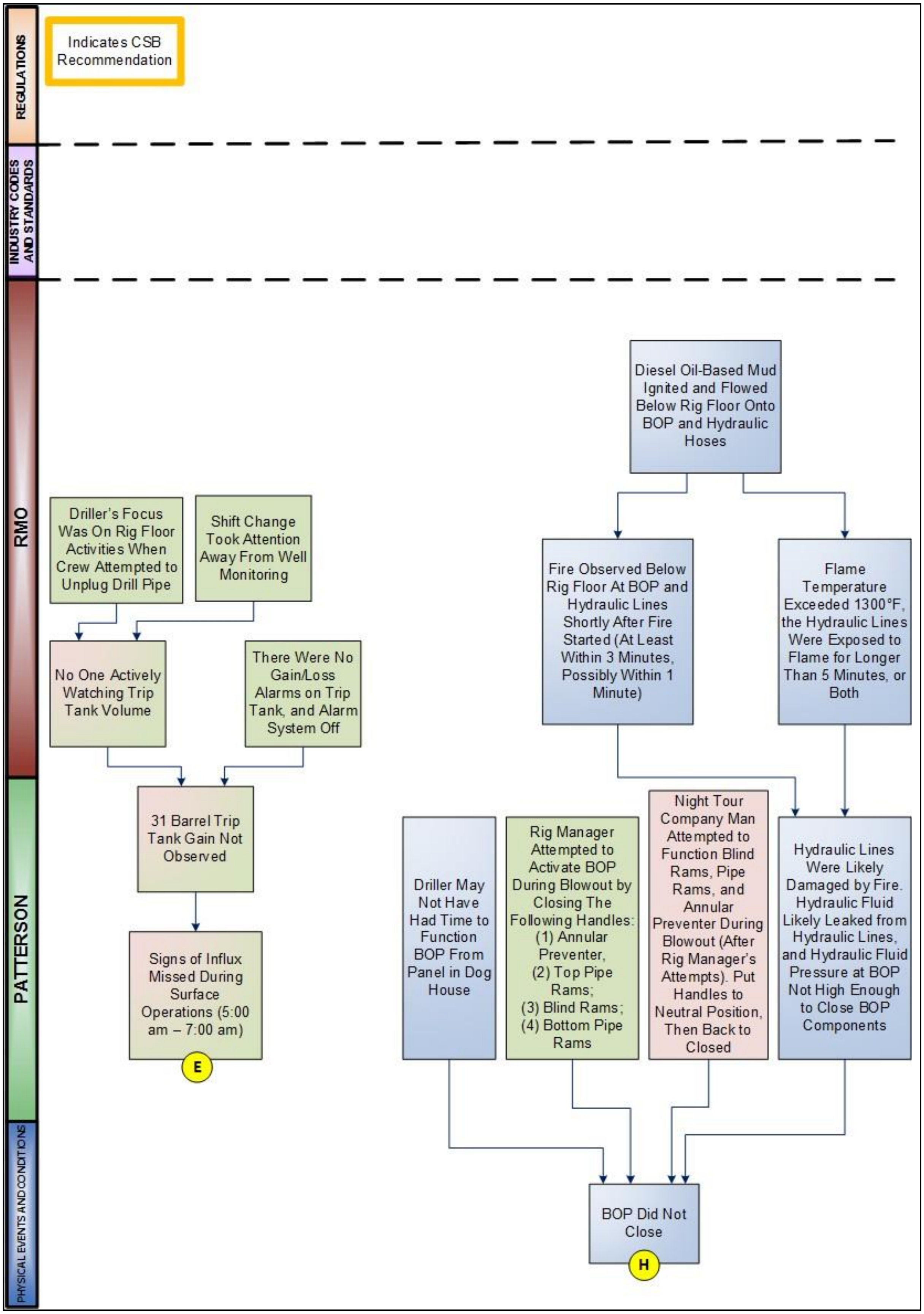


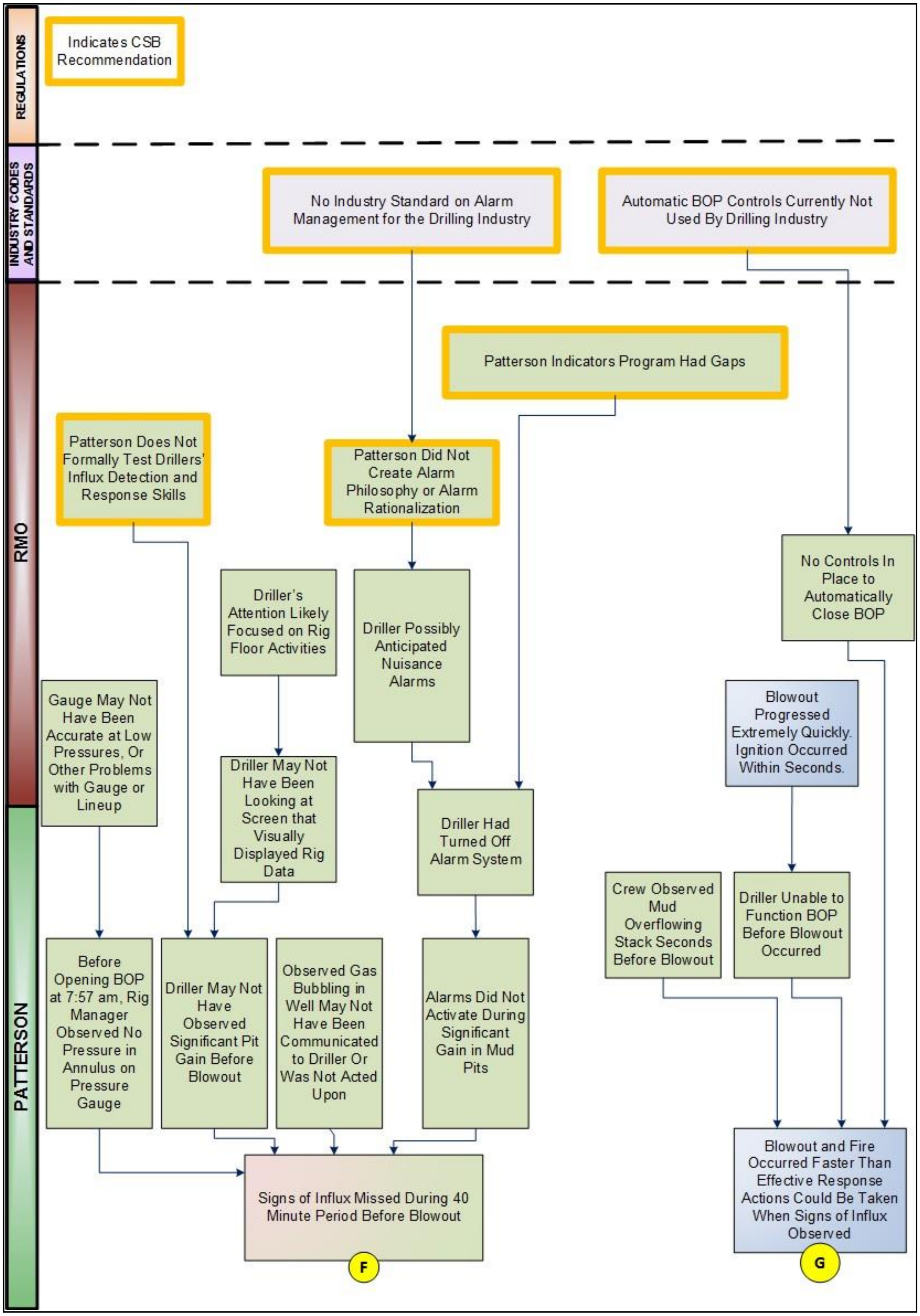

REGULATIONS
INDUSTRY CODES AND STANDARDS
RMO
PATTERSON
Indicates CSB Recommendation
No Regulatory Requirement
API Bulletin 97 Does Not Clearly Apply to Onshore Drilling
Patterson Indicators Program Had Gaps
Previous Experience
No Well Construction Interface Document For Drilling Operation
Weak MOC Program
RMO Did Not Follow API RP 92U
RMO Believed Calculated Fill Tripping Method Would Control Well, Minimize Influx, and Would Keep Well Contained
RMO Excited About Gas in Well
RMO Did Not Adequately Consider They Had Lost a Barrier
No MOC / Hazard Analysis Performed When Well Became Underbalanced
RMO Chose to Drill Underbalanced But Did Not Have Sufficient Planning, Equipment, Training, or Procedure
Time Out for Safety Ineffective
Mud Weight Program Based Upon Prior Well That Was Successfully Drilled Using Similar Mud Weight
When Well Became Underbalanced, RMO Consciously Chose to Not Increase Mud Weight
Patterson Agreed to RMO Plans
ECD Pill Did Not Replace Annular Pressure Loss
Mud Weight Was Too Low To Prevent Influx
Weighted ECD Pill Spotted at Top of Curve Kept Well Underbalanced
Hydrostatic Pressure in Well Was Less Than Formation Pressure
Well Was Underbalanced
A


REGULATIONS
INDUSTRY CODES AND STANDARDS
RMO
PATTERSON
Indicates CSB Recommendation
No Regulatory Safety Management System Requirements
No API Industry Best Practice on How to Safely Trip Drill Pipe During Overbalanced, Managed Pressure, or Underbalanced Operations
Driller Accustomed To Paper Trip Sheet
Driller Did Not Know How To Change Default "Number of Stands" On Trip Sheet
Patterson Tripping Procedure Vague
Calculated Fill Tripping Procedure Technically Complied with Patterson Tripping Procedure
MOC typically used for equipment changes
No Patterson or RMO Policy to Overbalance Well Before Tripping
Driller Had Difficulties With Electronic Trip Sheet
Some Concern That Increasing Mud Weight Might Fracture Formation
Possible Problems with Pressure Gauge or Equipment Alignment
No MOC Performed For Change From Typical Tripping Method
Patterson Did Not Detect 20 Barrel Difference Between "Calculated" and "Fill" Volumes, Signifying Gas In Well
Tripping Performed on Underbalanced Well
Pressure Not Detected Before Opening BOP After Changing Rotating Head Rubber
Patterson Agreed to Tripping Method
Influx Not Prevented, Mitigated, or Adequately Understood While Tripping Out of Lateral Section
B


REGULATIONS
INDUSTRY CODES AND STANDARDS
PATTERSON
Indicates CSB Recommendation
No Industry Standard on Alarm Management for the Drilling Industry
Patterson's Indicators Program Had Gaps
Patterson Did Not Create an Alarm Philosophy or Alarm Rationalization
Driller Possibly Expected Nuisance Alarms
Driller Had Turned Alarm System Off
Gas Bubble May Have Been At Well Surface And Was Released, Causing Liquid Level To Be Below Flow Line
Flow Check 45 Seconds Instead of 3 Minutes As Required in Patterson Policy
No Alarms Activated
Patterson Does Not Formally Test Drillers' Influx Detection and Response Skills
Driller / Company Man Had Not Experienced Many Well Control Events in Careers
No Flow Detected
First Flow Check Performed At Top of Curve Passed
Second Flow Check Performed At Top of Curve Passed. Patterson Performed Flow Check After Spotting Pill At Top Of Curve. Data Indicates There Was Flow During Flow Check. Patterson May Have Accepted Some Flow To Indicate Passing Flow Check.
Driller / Company Man Did Not Observe 14 Barrel Gain in Mud Pits
Signs of Influx Missed During Operations at Top of Curve
C


REGULATIONS
INDUSTRY CODES AND STANDARDS
RMO
PATTERSON
Indicates CSB Recommendation
No Regulatory Safety Management System Requirements
Patterson's Indicators Program Had Gaps
Derrickhand Misheard Pill Instructions Over Radio
Tripping Procedure Did Not Specify Required Equipment Alignment for Wet Tripping
LCM Material Mistakenly Put in Weighted Pill. Pill Accepted by RMO.
Drill Pipe Plugged by LCM Material
Rig Alignment
Patterson Does Not Effectively Audit to Identify if Flow Checks Are Performed When And For Time Required
Tripping Wet
Mud Bucket Drained to Trip Tank
Possible Miscalculation or Lack of Independence Between Company Man and Driller
Mud Entered Trip Tank During Tripping Operation
Flow Checks Routinely Not Performed
Believed They Saw Proper Displacement
Trip Tank Volume Fluctuated Up and Down
No Flow Check Performed at Casing Shoe
No Flow Check Performed Before Pulling BHA Through BOP
Company Man and Driller Had Difficulty Monitoring For If Well Took Proper Fill
Company Man and Driller Accepted Results of Test Performed During Trip (Did Not Realize Test Failed)
It is Unknown to CSB Whether a Trip Sheet Was Filled Out. None Found Post-Incident.
Signs of Influx Missed While Tripping Out of Vertical Section
D


REGULATIONS
INDUSTRY CODES AND STANDARDS
RMO
PATTERSON
PHYSICAL EVENTS AND CONDITIONS
Indicates CSB Recommendation
Driller's Focus Was On Rig Floor Activities When Crew Attempted to Unplug Drill Pipe
Shift Change Took Attention Away From Well Monitoring
No One Actively Watching Trip Tank Volume
There Were No Gain/Loss Alarms on Trip Tank, and Alarm System Off
31 Barrel Trip Tank Gain Not Observed
Signs of Influx Missed During Surface Operations (5:00 am – 7:00 am)
E
Diesel Oil-Based Mud Ignited and Flowed Below Rig Floor Onto BOP and Hydraulic Hoses
Fire Observed Below Rig Floor At BOP and Hydraulic Lines Shortly After Fire Started (At Least Within 3 Minutes, Possibly Within 1 Minute)
Flame Temperature Exceeded 1300°F, the Hydraulic Lines Were Exposed to Flame for Longer Than 5 Minutes, or Both
Driller May Not Have Had Time to Function BOP From Panel in Dog House
Rig Manager Attempted to Activate BOP During Blowout by Closing The Following Handles: (1) Annular Preventer, (2) Top Pipe Rams; (3) Blind Rams; (4) Bottom Pipe Rams
Night Tour Company Man Attempted to Function Blind Rams, Pipe Rams, and Annular Preventer During Blowout (After Rig Manager's Attempts). Put Handles to Neutral Position, Then Back to Closed
Hydraulic Lines Were Likely Damaged by Fire. Hydraulic Fluid Likely Leaked from Hydraulic Lines, and Hydraulic Fluid Pressure at BOP Not High Enough to Close BOP Components
BOP Did Not Close
H


REGULATIONS
INDUSTRY CODES AND STANDARDS
RMO
PATTERSON
Indicates CSB Recommendation
No Industry Standard on Alarm Management for the Drilling Industry
Automatic BOP Controls Currently Not Used By Drilling Industry
Patterson Indicators Program Had Gaps
Patterson Does Not Formally Test Drillers' Influx Detection and Response Skills
Patterson Did Not Create Alarm Philosophy or Alarm Rationalization
Driller's Attention Likely Focused on Rig Floor Activities
Driller Possibly Anticipated Nuisance Alarms
No Controls In Place to Automatically Close BOP
Gauge May Not Have Been Accurate at Low Pressures, Or Other Problems with Gauge or Lineup
Driller May Not Have Been Looking at Screen that Visually Displayed Rig Data
Driller Had Turned Off Alarm System
Blowout Progressed Extremely Quickly. Ignition Occurred Within Seconds.
Crew Observed Mud Overflowing Stack Seconds Before Blowout
Driller Unable to Function BOP Before Blowout Occurred
Before Opening BOP at 7:57 am, Rig Manager Observed No Pressure in Annulus on Pressure Gauge
Driller May Not Have Observed Significant Pit Gain Before Blowout
Observed Gas Bubbling in Well May Not Have Been Communicated to Driller Or Was Not Acted Upon
Alarms Did Not Activate During Significant Gain in Mud Pits
Signs of Influx Missed During 40 Minute Period Before Blowout
F
Blowout and Fire Occurred Faster Than Effective Response Actions Could Be Taken When Signs of Influx Observed
G

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