OCS Report
MMS 2006-039

Investigation of Loss of Well Control South Timbalier Block 135, Well No. 6 OCS 0462 1 December 2005

Gulf of Mexico
Off the Louisiana Coast

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U.S. Department of the Interior
Minerals Management Service
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Glenn Woltman – Chair
Leslie Peterson
Tom Perry

U.S. Department of the Interior
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Investigation and Report

Authority

During November and December of 2005, the Diamond Offshore Drilling, Inc. (hereinafter referred to as “Contractor” or “Diamond”) jack-up rig *Ocean Drake* (hereinafter referred to as the “Rig”) was engaged in open water drilling operations for Chevron Exploration & Production Inc. (hereinafter referred to as ‘‘Operator’’) on South Timbalier (ST) Block 135 Well No. 6.

A loss of well control occurred in the conductor hole section on location in the Operator’s Lease OCS 0462, South Timbalier Block 135, in the Gulf of Mexico, offshore the State of Louisiana. Pursuant to Section 208, Subsection 22 (d), (e), and (f), of the Outer Continental Shelf (OCS) Lands Act, as amended in 1978, and Department of the Interior Regulations 30 CFR 250, Minerals Management Service (MMS) is required to investigate and prepare a public report of this accident. By memorandum dated 19 December 2005, the following personnel were named to the investigative panel:

Glenn Woltman, Chairman – Technical Assessment and Operations Support, GOM OCS Region
Leslie Peterson – Houma District, Field Operations, GOM OCS Region
Tom Perry – Accident Investigation Board, Office of Offshore Regulatory Programs, HQ

Procedures

During the afternoon of 01 December 2005, personnel from MMS visited the site of the incident to assess the situation. On 15 December 2005, panel members requested various data from the Operator and collected data from various sources. Panel members reviewed the incident by telephone and met on 06 February 2006 to prepare for interviews.

On 06 and 07 February 2006, interviews were conducted with Operator personnel and with Contractor personnel on the rig and in subsequent telephone conferences. In addition to the interviews, Operator personnel answered specific questions by e-mail. Other information was gathered at various times from a variety of sources. This information included the following reports and statements:

- Daily Drilling Reports, 25 November 2005 – 10 December 2005 for Well No. 6
- Operator’s Drilling Plan, Well No. 6
- Operator’s Application for Permit to Drill, Well No. 6
- Operator’s ST-135 No. 6 Incident Investigation Report
- Operator’s Pre-Job Safety Meeting Checklist, Well No. 6
- Operator’s schematics of Well No. 6
- Operator’s Mud Schedule for Well No. 6
- Operator’s Gas Detector Certification of Calibration of Well No. 6
- Interviews with Operator drilling management and engineering and operational personnel, Contractor drilling management, operational supervisors, and operational personnel
- Diamond Offshore’s Job Safety Analysis Worksheet, Well No. 6
- BOP Configuration Schematic, Well No. 6
- Diverter System Schematic, Well No. 6
- Archeological and Hazard Survey Block 135, South Timbalier Area
- TIMS Data System for Block 135, South Timbalier Area
- Conversation with Dr. Shubert, Texas A&M University, on continuing research project for MMS regarding conductor setting depths and shallow gas hazards

Introduction

Background

Lease OCS 0462 covers approximately 5,000 acres and is located in South Timbalier Block 135, Gulf of Mexico, off the Louisiana Coast *(for lease location, see Attachment 1).* The lease was issued effective 1 January 1955 to Gulf Oil Corporation. Chevron U.S.A. Inc. assumed operatorship on 19 July 1985, as 100-percent interest leaseholder.

Forty-six (46) wells have been drilled on this block since the late 1950's. Over two-thirds of these wells had been drilled prior to the year 2000. Until this most recent drilling campaign, the last open water location was drilled in March 1991. A total of seven (7) wells have been drilled from open water locations, with the remaining 39 wells drilled from five (5) existing platform structures.

On 25 November 2005, Chevron U.S.A., Inc. (hereafter referred to as Operator) contracted Diamond Offshore Drilling, Inc. (hereafter referred to as Diamond or Contractor) to conduct and supervise the drilling operations of the South Timbalier Block 135 Well No. 6 (the "Well"). Development drilling activities were started from the Well's surface location by using the jack-up drilling rig *Ocean Drake*, owned and operated by Diamond (*See Attachment 2*). The Rig was moved onto the well location, jacked-up on location, and the well was spud at 0230 hours on 01 December 2005.

Brief Description, Loss of Well Control

While drilling ahead beneath drive pipe in open water on 01 December 2005 on Well No. 6, at a depth of 1,027 feet, the Contractor observed a background gas reading of 224 units with corresponding mud weight loss from 9.8 pounds per gallon to 9.6 pounds per gallon. Mud was weighted up to 10.2 pounds per gallon and drilling continued. At a depth of 1,318 feet in the conductor hole section of Well No. 6 (*See Attachment 3*), while the prescribed mud weight up schedule was being followed, the well became unstable and released a pocket of gas. Contractor personnel noted gas emanating from the drive pipe by drill pipe annulus. The well was shut in at 1600 hours on 01 December 2005 and placed on the diverter system (*See Diverter System Schematic, Attachment 4)* at that point. Contractor personnel on the Rig continued to pump kill weight mud while monitoring the well. As a precaution, at 1645 hours, all non-essential personnel were evacuated to the *M/V Randall McCall.* Within two hours, the non-essential personnel were allowed to return to the rig. The well continued to "burp" gas over the next day, but remained under control while on diverter. Operations continued over the next five days, circulating heavy weighted mud approaching 11 pounds per gallon, while washing to bottom and back-reaming to prevent stuck pipe. With approval from MMS, on 07 December 2005, the Operator washed to total depth of 1,318 feet and mixed and spotted a barite plug. After tripping to bottom to circulate and clean up the hole, approval was obtained from MMS by the Operator to set the 20-inch conductor casing at 1,274 feet, significantly higher than had originally been programmed in view of the hole conditions. The original plan had been to drill down to 1,700 feet prior to setting the conductor pipe. The Operator received verbal approval from MMS at 1700 hours on 12 December 2005, to obtain a Formation Integrity Test (FIT) below 20-inch conductor casing in the 26-inch "rat-hole" after washing barite plug without drilling 10 feet of new formation. It was also agreed to drill ahead with a 12.8 pound-per-gallon FIT and reduce the safe drilling margin to 0.3 pound per gallon.

After the conductor casing was set, the Operator continued to face gassy returns during drilling of the surface casing hole. The Operator received approval to set surface casing at 1,930 feet rather than the planned 2,600 feet APD-approved depth.

Findings

Drilling Activities — Spud, Loss of Control, Regaining Control

(From drilling morning reports and interviews)

OCS 0462 Well No. 6

25 Nov – Rig under tow to South Timbalier 135. Spot rig on location. Jacked-up to a 59-foot air gap and cantilevered out. Started to pick up drill pipe.

26 Nov – Offload 30-inch drive pipe. Rigged up hammer. Picked up and ran 30-inch by 1-inch drive pipe to mud line at 219 feet. Free fall and drive 30-inch to 338 feet.

27 Nov – Continued to drive 30-inch pipe to 548 feet. This represents 329 feet of penetration at 202 blows per foot. Rigged down hammer, and installed +10 valve on 30-inch drive pipe.

28 Nov – Held pre-job safety meeting with crews, discussing well plan, potential hazards, and H2S contingency plan. Secured drive pipe, nippled-up diverter, take on mud. Ten-inch insert packer failed.

29 Nov – Offload diverter packer and installed same. Rigged up test assembly. Attempted four times to test diverter package, but unable to get test. Clean-out cap initially leaking as was 6-foot extension on port side. Next starboard diverter valve leaking. Pulled diverter packers, and performed pressure wash. Not able to get test.

30 Nov – Installed diverter valve. Function tested diverter to 200 psig for 5 minutes. Rigged down test equipment, and picked up 26-inch bit and bottomhole assembly. Started to wash out drive pipe down to 474 feet.

01 Dec – Continued to wash out drive pipe to 520 feet. Circulated and conditioned mud. Cut mud weight back to 9.4 pounds-per-gallon. Continued to wash drive pipe to shoe at 548 feet.

> ***0230 hours -*** Started to drill new hole down to 1,027 feet. Background gas at 224 units. Weight up mud to 10 pounds per gallon, and drilling ahead to 1,318 feet. Weighting up mud to 10.2 pounds per gallon while drilling, with no increase in gas while drilling or on connection.
> ***1600 hours -*** The well started flowing. Put well on divert with 10.2 pounds-per-gallon mud. Swapped over to 11.5 pounds-per-gallon kill weight mud and continued pumping and diverting. Swapped over to active pit with 10.2 pounds-per-gallon mud. Shut pumps down and weight-up mud to 11 pounds per gallon while monitoring situation. Started pumping again from active pit. Total mud pumped 608 barrels. Stopped pumping to monitor well. Well was belching.
> ***1645 hours -*** Non-essential personnel were evacuated to *M/V Randall McCall.* Monitoring well while filling up backside and mixing kill mud.
> ***1830 hours –*** Non-essential personnel return to rig.

2030 hours – Mixing kill mud and monitoring vent line and filling up backside
2130 hours – Total mud pumped while diverting now 1,133 barrels.

02 Dec – Over the next 24-hours, personnel continued to make flow checks, circulate and weight up mud to 11.2 pounds per gallon. Reports of losing mud to well.

03 Dec – Continuing to circulate 11.2 pounds per gallon while building kill weight mud to 11.5 pounds per gallon. Monitoring well with no mud cut.

04 Dec – Washed down to 1,318 feet. Circulated 11.3 pounds-per-gallon mud. Would shut down pumps and check flow. Well flowing with mud cut. Back reaming and washing down while circulating 11.4 pounds-per-gallon mud. Made flow check. Slight flow. Check well for fill. No fill.

05-06 Dec – Continuing to experience bottoms-up gas intermittently, with mud weight cut. Continuing to circulate 11.5 pounds-per-gallon mud while washing down to 1,318 feet. Back reaming because of tight hole and hole packing off. Preparing to spot barite plug.

07 Dec – Back reaming hole. Washing down to 1,318 feet. Small flow with mud cut. Rigged up Halliburton and mix barite plug in slug pit. Spotted Barite plug on bottom. Pulled up to 1,160 feet to allow plug to fall. Hole still tight and packing off.

08 Dec – Back-reaming to drive pipe shoe. Tripped in hole to barite plug at 1,274 feet. Circulated bottoms up. Circulated out of hole. Preparing to run 20-inch conductor casing.

09 Dec – Ran 20-inch K55 conductor casing to 1,274 feet. Performed cement job. Had full returns during job. Circulated 470 barrels to surface. Cleaned surface line while waiting on cement.

10 Dec – Cut 30-inch pipe and 20-inch pipe. Nippled down diverter.

Operator’s Well Plan

The Operator planned to drill the Well No. 6 to the primary target at a depth of approximately 4500 feet. This was an open water drill, with the surface location chosen optimally for drilling subsequent wells and future installation of a production platform. This location required drilling through the Timbalier Trench, a geologically unpredictable environment that has proven troublesome in previous drills. The base of the Trench was estimated being at +/- 2500 feet, with the initial design calling for setting conductor pipe above and surface casing below this depth. Based on offset well information, no previous drilling problems had occurred above approximately 1900 feet. The Operator planned on setting conductor pipe at 1700 feet measured depth.

According to information obtained from the Operator, seismic and shallow hazard data was utilized in the area that Well #6 was drilled. However, due to the overall geologic uncertainty of the Trench, it was difficult to establish an accurate earth model. The shallow hazard data reviewed included magnetometer, side scan sonar, fathometer, sub bottom profiler and seismic profiler data from high-resolution geophysical surveys conducted by Fugro GeoServices in May, 2004. Proprietary 3-D seismic lines were also evaluated for shallow hazards. No surface or shallow sub bottom hazards were identified from the surveys.

According to testimony given by the Operator's Engineering Manager, Phased Process Planning started when both the geological and reservoir engineering groups made a recommendation to drill the well back in January 2005, on the basis of the economic viability of the project. Preliminary design well work commenced at that time. Action items were developed with definite deadlines for completion of all geological and engineering activities. As the process moved forward and the detailed design was finalized, the Engineering Manager indicated that the project was presented to the Decision Review Board (Board) in March 2005. Upon approval by the Board, all long-lead items and supplies were ordered, and the Contractor's *Ocean Drake* jack-up rig was targeted to drill this well, since the *Ocean Drake* was already working the South Timbalier area on two tie-back wells. When questioned about detailed pre-planning and the geology reviews, the Engineering Manager testified that drilling engineers looked more at offset well information for casing and pore pressure information and design planning than at the geological and geophysical data. He further indicated that, on the basis of this review, shallow-gas hazards were not identified in the offset wells.

According to the Operator's Drilling Manager, the final planning phase to drill this location ended up being a rush job. Testimony revealed that the Diamond Offshore Drilling jack-up unit *Ocean Drake* had been on a previous location, and because of a dry well drilled early in that program, further drill locations had been cancelled. The Rig moved into the queue for the South Timbalier Block 135 area campaign much earlier than the Operator had expected. Contrary to earlier testimony, the drilling manager verified that it was his understanding that the well design considerations were based on offset well information reviewed by geologists and engineers. He further stated that this was his first experience with any drilling project within the South Timbalier trench. Although he noted that the Operator was aware of the potential of shallow hazards, his testimony revealed that the Operator was taken by surprise that pore pressures were as high as they were in the top hole section of the well. In follow-up discussions with the geo-technical group, the drilling manager indicated that Operator's geologists did not have any real reflectivity in the shallow seismic to predict where these shallow zones might have occurred. When questioned about measures that could have been implemented to mitigate this event, the drilling manager stated that perhaps in hindsight they should have stopped drilling when the background gas noted in the mud returns exceeded 200 units, and commenced circulating and building mud weight before drilling ahead. He further stated that perhaps the Operator should have evaluated setting casing at that point instead of forging ahead, since contingency planning had included additional casing strings for this kind of event. The drilling manager further noted that background gas units are an indicator of potential problems during drilling, but other measures are equally as important. His testimony indicated that these measures include flow checks at each connection and mud weight measurements, since gas units by themselves do not always show signs of gas influx.

Information obtained during telephone interviews with the Operator's earth scientist and geologist suggested some concern about drilling through potential shallow hazards in the South Timbalier Trench Area. Testimony revealed that the two wells drilled on the South Timbalier Block 135 in early 1970 had experienced similar problems with shallow gas, and that the mud weight had been significantly cut on both wells during drilling through shallow intervals above 2,000 feet. Specifically, the No. 3 Well had taken a kick at 1,930 feet and again at 2,011 feet.

Testimony given by the Operator's drilling engineer on this project indicated that he was notified of the incident via a telephone call from the onsite rig consultant during the afternoon of 01 December 2005 after the well had been placed on the diverter system. The drilling engineer noted that the rig consultant indicated to him that heavy kill weight mud was being circulated to control the well. After receiving this telephone call from the Rig, the drilling engineer stated that he placed a telephone call to the drilling superintendent. He indicated that the drilling superintendent asked him to review all offset well information to see if any similar occurrence(s) had happened in the past. The Operator's drilling engineer testified that it was his recollection that most of the previous wells drilled had been side-tracked from existing well locations below the South Timbalier trench, thereby not experiencing the same situation as the current well. The drilling engineer initially indicated that it was his opinion that sufficient contingencies were in place to address shallow-gas concerns. Such contingencies, he testified, included a mud weight-up schedule intended to mitigate shallow-gas influx. However, when questioned further about the well plan, the drilling engineer testified that, in hindsight, the Operator should have planned on setting the conductor casing at a higher point. He also stated that they should have had additional kill weight mud on location at the time of the blowout.

Regulatory Review of the Well Plan

The APD was approved by the MMS on 22 November 2005. Contrary to the Operator's inability to develop an accurate earth model, MMS geological and geophysical experts noted several shallow gas hazards. Approval of the APD was given subject to the proviso to drill the top hole section with caution due to possible shallow gas at 470 and 700 feet sub sea, while maintaining kill weight mud in the pits as drilling proceeds through the possible shallow gas hazards noted. The Operator programmed drilling the 26-inch conductor hole with water-based mud weighing 8.9 pounds per gallon. The fracture gradient was expected to be about 13.3 pounds per gallon at the conductor casing shoe depth, so no tight margins were anticipated.

According to the MMS Regional Geological and Geophysical Analysis Unit in the Technical Assessment and Operations Support Section, when a surface plan is submitted for approval, a geophysical review is conducted followed by a geological review. Surveys and plots of the area are usually performed by a third-party contractor, and an evaluation of the seafloor is conducted to address hazards such as shipwrecks, pipelines, marine life, shallow gas, faulting, and the like. A more detailed review is conducted when the Application for Permit to Drill (APD) is requested. Additional information gathered in the review includes the target depths and the geo-pressures.

Archeological and Hazard Survey on Block 135

Fugro GeoServices, Inc. acquired the high-resolution geophysical data aboard the *R/V L'Arpenteur* during the period 17-19 May 2004 across Block 135 in the South Timbalier Area. The study area is located in an area designated as the Texas-Louisiana Continental Shelf of the Gulf of Mexico. The study area is located in the vicinity of one of the world's largest delta complexes, the Mississippi River delta complex. Results of the study, given the panel on request, indicated that geo-technical data from near-bottom sediments down to about ±250 feet below the mudline were analyzed, rendering geophysical interpretation of the deeper, and presumably more hazardous zones below 250 feet, not reviewed.

Seafloor or subbottom sediment cores were not obtained in this survey. Statements concerning descriptions and properties of seafloor and subbottom sediments in the Fugro report were based on regional studies and sediment samples or borings collected in nearby leases. *As mentioned in the Fugro study, sediment type and precise geotechnical properties of the bottom sediments within the survey area could be obtained only with cores.*

The study thus reported by Fugro is solely based on interpretation of subbottom profiler and analog 2D high-resolution air gun records. The analog 2D records displayed a strong seafloor reflector, which results in ringing of signal through the data. Seismic amplitude anomalies were not seen on the analog air gun profiles, mostly because of the poor penetration of signal and ringing effects.

Signal attenuation is limited by saturation of deposits by methane gas, resulting in enhanced, irregular, and high-amplitude reflectors, as well as acoustically transparent and amorphous zones in shallower deposits.

Drive Pipe Requirements

Subsequent to the moving of the rig on location, the jacking up and cantilevering out, a D-62 hammer was rigged up and 30-inch by 1-inch by 309 pound-per-foot drive pipe offloaded. The drive pipe was run to the mudline at 219 feet. The weight of the pipe coupled with the near mudline soil conditions allowed the pipe to free-fall 24 feet to 243 feet. A total of 13 joints were then driven to 548 feet by the evening of 27 November 2005, or some 329 feet of penetration with final blows of 202 blows per foot.

As a measure of driving pipe to the point of refusal, certain hammers are selected on the basis of the calculated yield of the pipe and expressed as allowable “blow counts per foot.” For API 5L Grade B 30-inch by 1-inch pipe used on this well, with a D-62 hammer, the Drive Pipe Yield Chart (*See Attachment 5*) would suggest that 288.47 blows per foot might be the level necessary to drive the pipe to the point of refusal. Records indicate that, on this well, the Operator drove pipe to 202 blows per foot.

The Incident

According to testimony from the rig site consultant, during a pre-spud meeting on 26 November 2005, the Operator shared their concerns with Contractor representatives regarding the possibility of encountering shallow-gas hazards and H2S gas, and having to implement diverter operations. Drilling parameters with the controlled drilling plan were reviewed, and the mud weight schedule was discussed as well as issues surrounding any gumbo attacks, at the pre-spud meeting. The consultant further mentioned that a separate meeting was held with the rig tool pusher to review the bridging document and all procedures when placing the well on diverter. The rig consultant indicated that the offset well information presented to him by the engineering department and used for this well plan was from a well drilled in the late 1960's or early 1970's.

According to the rig consultant's testimony, post-spud activities were normal, following the pre-approved drilling schedule, according to the mud weight schedule sanctioned, and under a controlled drilling rate of about 50 feet per hour. No indication of background gas was noted during the early portion of the top hole section, according to the rig consultant. This statement was later confirmed by the day driller on duty station during the preceding 12-hour period before the diverter event.

The consultant initially mentioned that he noticed indications of background gas only after reaching about 1,318 feet while drilling with a 10.2 pounds-per-gallon mud weight. He mentioned that orders were given to increase the mud weight to 10.4 pounds-per-gallon. Shortly after directing these orders, he mentioned that a message on the rig radio alerted personnel on the rig floor that the gumbo box was overflowing for unknown reasons. He further indicated that the driller immediately stopped operations to undertake a flow check. Within minutes of this action, mud was seen flowing out of the rotary table. According to the consultant, the tool pusher then ordered that the well be placed on diverter. The consultant mentioned that both he and the tool pusher proceeded to the rig floor, where flow was occurring from both diverter lines. Because of wind considerations, he indicated that one diverter valve was closed to direct the flow downwind of the rig, and kill weight mud (11.5 pounds-per-gallon pre-mixed in the reserve pit) was then circulated in the well.

Under further questioning regarding information reported on the IADC drilling report, which indicated signs of background gas as high as 1,000 feet, the rig consultant mentioned that there were some gas shows right below the drive pipe shoe. Notwithstanding the testimony from the rig consultant of possible gas shows below the drive pipe (previously not reported on the IADC report), panel members inquired why the Operator continued to drill below 1,000 feet with increasing background gas while the mud weight was cut from 9.8 to 9.6 pounds per gallon. The rig consultant testified that a decision was made at that point to weight up the mud at 1,027 feet, circulate the gas out of the hole, and wait until the background gas decreased before continuing to drill down to 1,318 feet. He indicated that flow checks were made at every connection down to 1,318 feet.

Testimony from the night tool pusher with Diamond confirmed much of the scenario described by the rig consultant. The tool pusher indicated that he was awakened at the time of the incident and immediately went to the rig floor. He mentioned that the well was already on diverter as he arrived on the rig floor, and that the crew was converting over to kill weight mud. He further indicated that the crew was keeping the backside annulus full as they were mixing more mud, and that the well flow had eventually decreased from a steady flow to a periodical flow. The night tool pusher also indicated that the Contractor's policy when on diverter was to "round up" and account for all personnel on board prior to making any decision to evacuate. The decision to evacuate was made.

Testimony from the day driller indicated that there was no sign of gas or mud cut during his tour. The hole section was control-drilled without incident with about 9.8 pounds-per-gallon mud while hole sweeps were performed. He indicated that, if gas signs had been evident on his tour, he would most certainly have circulated the gas out and performed a flow check on connection, and checked mud weight in/out prior to drilling ahead.

The Regulations

According to regulations, Title 30, Chapter II, Part 250, Subpart P, Section 250.1608 (c) (1), conductor casing setting requirements "...shall be based upon relevant engineering and geologic factors including the presence or absence of hydrocarbons, potential hazards, and water depths. The proposed casing setting depths may be varied, subject to the District Manager approval to permit the casing to be set in a competent formation or through formations determined to be isolated from the well bore by casing for safer drilling operations. However, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas or, if unknown, upon encountering such formations."

Measures to Avoid Shallow-Gas Hazards

Among all potential hazards, shallow-gas flows are the most dangerous geo-hazards leading to many blowouts in Gulf of Mexico. Due to regulatory concerns, graduate research work has been funded by the MMS and is underway at Texas A&M University under the direction of Dr. Jerome Shubert entitled "Risk Assessment and Evaluation of the Conductor Pipe Setting Depth On Shallow Water Depths". According to preliminary findings from this work, geo-hazard surveys are needed to collect geologic data and determine the lithology, density, and strength of the shallow sediments. Some of the most important areas of coordination include (1) integration of clear statements of duties and responsibilities (in regard to shallow-gas contingency procedures) into the rig organizational structure, and (2) conducting an appropriate training program to ensure that the well control plans and contingency procedures are understood and can be carried out by field personnel.

Consideration must be given to implement some steps to ensure "avoidance." One way to possibly avoid these hazards is through the shallow-hazard assessment and site clearance for the specific location, based on seismic interpretation of a 2-D, high-resolution hazard survey or on conventional 3-D seismic data integrated with offset well information from seabed to the top of the salt. Another way to avoid problems would be to identify the geo-pressured zone, which requires a drilling assembly with a combination of Measurement-While-Drilling resistivity and Gamma ray as close to the bit as possible to identify the sand as quickly as possible.

Routine soil boring tests should be conducted when limited data are otherwise available to gather shallow sediment formation information prior a rig being moved to the location. The test would provide the operator with information on sediment weight and density measurements, sediment liquid and plastic limits, and sediment shear strength measurements.

Changes Incorporated by Operator on Offset Well to Mitigate Shallow Gas Hazard

The Operator successfully drilled and set conductor pipe on Well No. 7, an immediate offset well to the subject diverter incident (*See Attachment 6*). Several recommendations resulting from the Operator's initial investigation of the diverter incident on the No. 6 well had been incorporated in the well plans for subsequent development wells, including (1) setting conductor pipe above the depth where the shallow gas interval had been encountered in the No. 6 well, thus minimizing drilling into known shallow hazards with only drive pipe set; (2) modifying the mud weight schedule over the conductor hole section by utilizing the mud weights required to control gas flow in the No. 6 well; (3) driving the drive pipe to the point of refusal, thereby minimizing surface blowouts in the event of having to shut in while on the diverter system; and (4) inspecting and testing all diverter and outlet valves prior to drilling, ensuring that equipment is sound and working.

OCS-0462 Well No. 7 – Offset Well

12 Jan – Transverse upper package to starboard positioning over Well No. 7. Rigged up to run drive pipe.

13 Jan – Drive pipe to 522 feet or 303 feet of penetration and final 200 blows per foot. Rigged up and installed +10 valve on drive pipe. Rig down hammer and handling tools.

14 Jan – Cut 30-inch drive pipe. Nippled up diverter. Installed packers and function test diverter from main station and remote. Spud in well and cleaned out drive pipe. Drilling ahead.

15 Jan – Controlled drill and slide to 1,220 feet. Increased mud weight to 11.8 pounds-per-gallon. Pumped pill and circulated hole clean. Pumped out of hole and tripped back to bottom. Pumped pill and circulated hole clean. Preparing to run 20-inch conductor.

16 Jan – Ran in hole with 20-inch pipe to 1,207 feet. Circulated with casing fill-up tool. Rigged up cement unit. Pumped cement. Rigged down casing handling tools.

17 Jan – Make cut on 30-inch by 20-inch. Nippled down diverter. Installed drilling adapter. Nippled up bell nipple. Installed wellhead and diverter. Picked up bottomhole assembly.

18 Jan – Started in hole and drilled landing collar, cement, and shoe. Controlled drilled to 1,294 feet with 12.2-12.6 pounds-per-gallon mud. Drilled to 1,565 feet.

19 Jan – Drilled down to 1,821 feet checking mud weight and flow. Pulled up to 1,206 feet and washed down to 1,821 feet. Circulated and conditioned mud. Pulled out of hole.

20 Jan – Run 13-3/8-inch surface casing to 1,801 feet and cemented pipe. Set slips and cut casing and nippled down diverter.

Ten-Year Incident Rate for Loss of Well Control Events

A database of incidents for "Losses of Well Control" events is summarized for the period below. Fifty-nine (59) loss-of-well control events have occurred in the Gulf of Mexico over the last ten years. This report is based on information contained in the MMS Technical Information Management System (TIMS) for the years 1996 to present. Loss of well control is defined as either (1) an uncontrolled flow of formation or other well fluids, whereby the flow may be between two or more exposed formations or may be at or above the mudline, or (2) a flow of formation or other well fluids through a diverter. Eleven of the total loss-of-well control events have been "diverter events," not including two diverter events not shown in the table thus far for 2005.

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005 YTD
Loss of Well Control (Total) *	**4**	**5**	**7**	**5**	**9**	**10**	**6**	**5**	**4**	**4**
Uncontrolled Flows	4	2	5	3	9	9	4	4	4	4
Diverter Events	0	3	2	2	0	1	2	1	0	0

The majority of the events shown in the table above took place in less than 500 ft of water depth. Sixty-one percent of the events were related to drilling activities, while twenty-four percent occurred prior to, during, and/or just after cementing operations. Fortunately, less than five percent of these events resulted in fire and temporary abandonment of the location or rig.

According to a study of 172 blowouts worldwide by the Norwegian Sintef Research Organization, shallow geo-hazard is the most serious single cause of kicks leading to blowouts. Messrs. W. C. Goins and G.L. Ables presented an SPE Paper 16128 entitled "The Causes of Shallow Gas Kicks" at the 1987 SPE/IADC Drilling Conference in New Orleans. Findings suggested that the low margin of overbalance in shallow depth and structural overpressures, coupled with poor drilling practices, were the causes of formation kicks that could lead to losses of control of well. The poor drilling practices included, but are not limited to, a lack of attention to drilled gas, swabbing, and hole-filling that could lead to loss of circulation.

Conclusions

Loss of Well Control Event

This loss of well control and diverter incident consisted of a systemic loss of mud weight, corresponding to varying levels of increasing background gas, all encountered while drilling below the drive pipe in the conductor hole section. Original plans were to drill down to and set 20-inch conductor casing at 1,700 feet measured depth. At the conductor shoe, pore pressure anticipated was 8.9 pounds-per-gallon. Mud records indicate that the weight of the drilling fluids during washing out the drive pipe and drilling the new hole section was between 10 and 10.8 pounds per gallon, providing a comfortable margin above anticipated pore pressure to drill successfully this section of hole. However, prior to reaching the conductor casing setting point, the well experienced a sudden gas flow and was immediately placed on diverter. Crews swapped over to the kill weight mud system and continued to pump and circulate while diverting the flow. There apparently were no indications of loss or gain of mud volumes in the reserve pits, and reports do not indicate any sharp spike(s) in the levels of bottoms-up gas versus the background gas during drilling or on connection just prior to the gas flow. Non-essential personnel were evacuated within 45 minutes of this gas flow, but soon returned to location.

Cause of Loss of Control

The loss of well control of the subject well was caused by drilling into a sand lens below 1,000 feet without sufficient mud weight to offset the higher pore pressure encountered. During the permitting stages for this well, the Operator had anticipated the maximum mud weight at the 20-inch conductor shoe to be about 8.9 pounds per gallon. The well was eventually controlled through persistent circulation of kill weight mud exceeding 11 pounds per gallon.

Probable Cause of Loss of Control

Findings from this incident suggested that the low margin of overbalance at a shallow depth and structural overpressures, coupled with an inadequate and an ill-defined pre-hazard study of the geotechnical properties of the immediate area, likely led to this loss of well control event. Drilling practices should have included, but are not limited to, an awareness of drilled gas, and swabbing and hole-filling practices.

It is probable that the failure or inability to forecast adequately the presence of the sand lens below 1,000 feet through use of sparker and shallow gas hazard surveys, or by other means including offset well information, contributed to the incident. The lack of forewarning of the odd morphology probably contributed to the failure to plan for the difficult drilling problems encountered. As mentioned in the Fugro Archeological and Hazard Survey conducted during 2004, all statements concerning descriptions and properties of seafloor and subbottom sediments were based on regional studies and sediment samples or borings collected in nearby leases. No recent deep seismic information was available. Sediment type and precise geotechnical properties of the bottom sediments within the survey area could only be obtained with cores. The failure to anticipate the problems probably precluded adopting a drilling and casing plan that could have minimized the impact of the anomaly, such as the addition of new, deeper drive pipe, increased drilling fluid weight to control gas flow, and/or setting the conductor pipe before drilling into this sand lens.

Possible Contributing Cause of Loss of Control

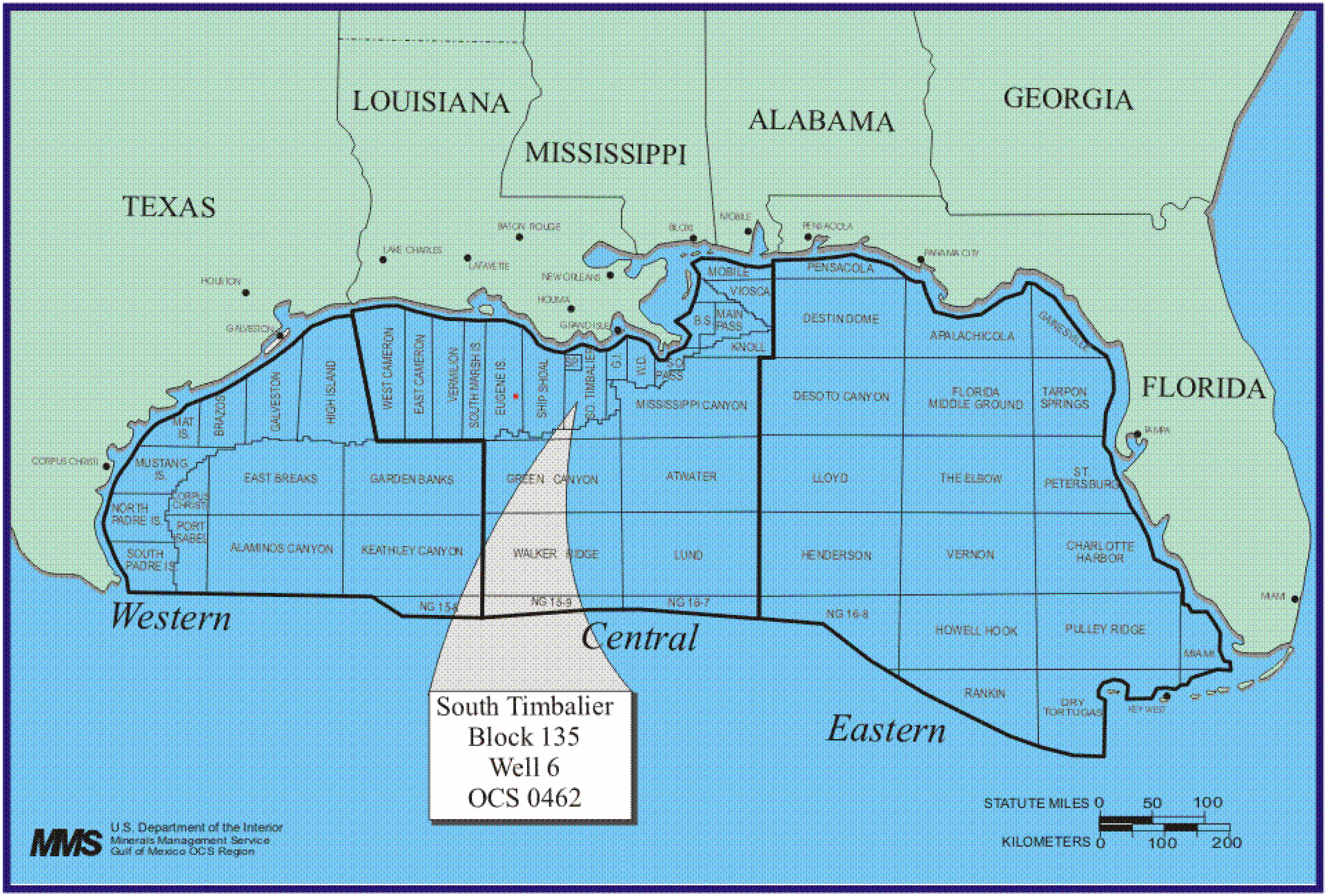
It is possible that the setting depth of drive pipe for Well No. 6 with only 329 feet of penetration at 202 blows per foot may not have been driven deep enough to allow effective isolation of any shallow gas sand. Using the guidelines in Attachment 5, the drive pipe was possibly not driven to the point of refusal. Re-visited seismic data suggest that shallow gas may have existed as high as just beneath the drive pipe shoe. The drive pipe of the subject well was possibly set at a generic depth, rather than at a depth tailored to actual well-specific requirements determined by the Operator's drilling operations. Tailoring well-specific requirements into the drilling plan may have eliminated drilling the conductor hole interval with possible shallow-gas zones exposed, thus reducing the risk of gas-cut mud and the influx of gas to surface that led to the diverter incident.

Discussions with the geological and geophysical (G&G) experts in the Gulf of Mexico Office of the Minerals Management Service suggested that modern-day seismic data and/or interpretation methods may need to be revisited, given the questionable quality of seismic data prior to 1993. MMS experts indicated that technical personnel would likely be better able to evaluate shallow hazards if all sites previously reviewed prior to 1993 are again reviewed using all modern data. This would increase the likelihood of identifying such hazards. Since there are additional concerns on shallow sands becoming charged over time, through pathways that develop as a field ages, these shallow sands pose a hazard in current times; and possibly these shallow sands would not have been identified during earlier G&G reviews.

Recommendations

It is recommended that MMS issue a Safety Alert emphasizing the need for thorough geologic review of the shallow hazards, including morphologic ones, encountered in wells drilled from previously drilled sites. Operators should not exclude the possibility that pilot holes may be necessary, in some cases, to ensure that geotechnical data are available as a prerequisite of drilling other wells in the area. In the absence of definitive shallow-hazard surveys with known geotechnical data, the Operator should assess the risk of not undertaking soil borings as a prerequisite to drilling the well and/or, at a minimum, take extra precautions ensuring containment of potential shallow hazards encountered. Extra precautions should include adequate mud weight in the hole to counter such gas flows if tight margins do not preclude it, and setting pipe (conductor and surface) before drilling into such shallow hazards.

It is also recommended that MMS Regional Geological and Geophysical Analysis Unit in the Technical Assessment and Operations Support Section revisit all modern-day seismic data and/or interpretation methods and update pertinent maps and information, given that this information has not been reviewed for some period of time. The intent of this rigorous exercise would be to increase the likelihood of identifying such shallow gas hazards, since there are additional concerns on shallow sands becoming charged over time, through pathways that develop as a field ages. Likewise, it is very possible that these shallow sands would not have been identified during earlier G&G reviews.



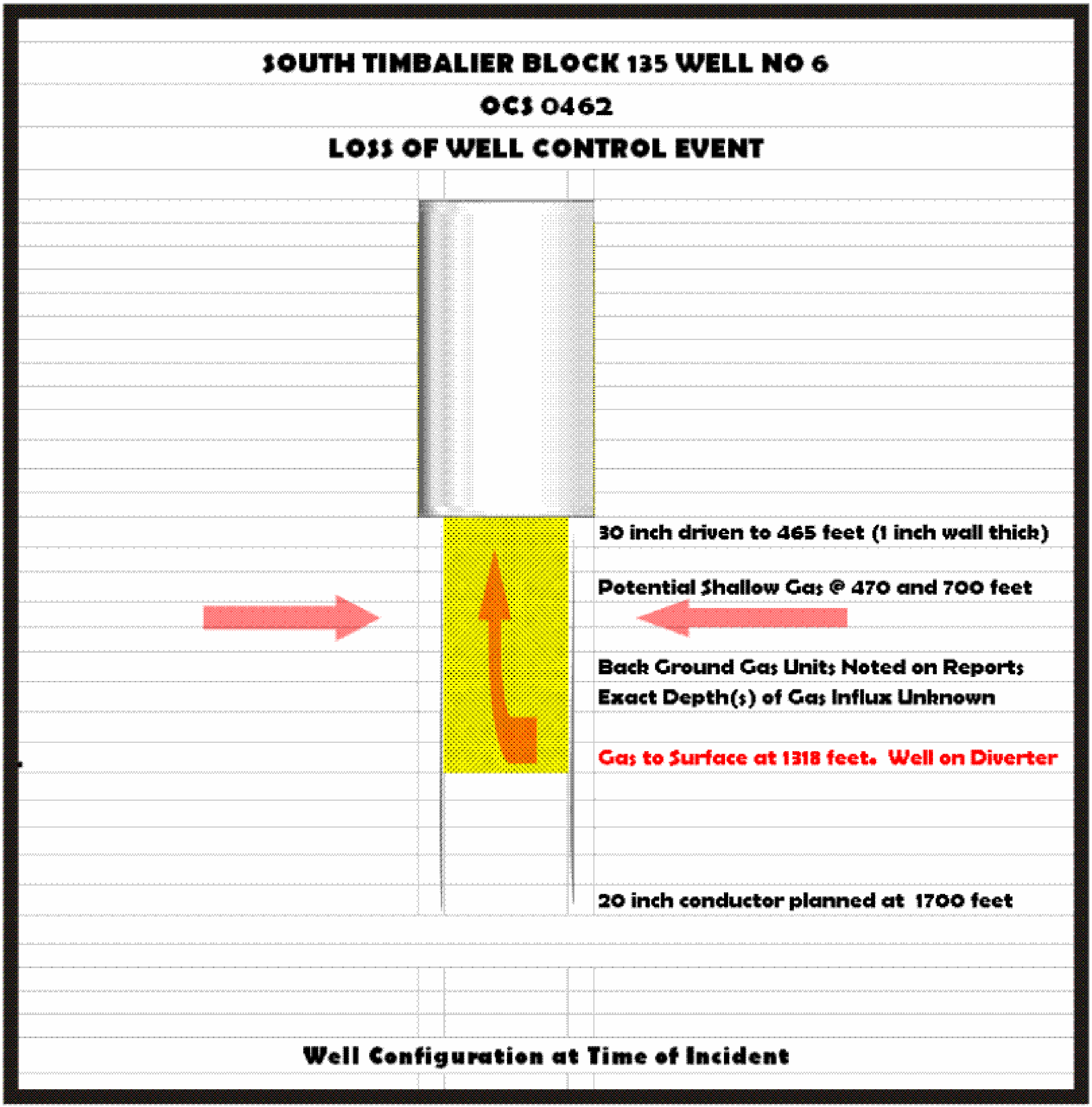
Location of Lease OCS 0462, South Timbalier Block 135, No. 6.

Attachment 1

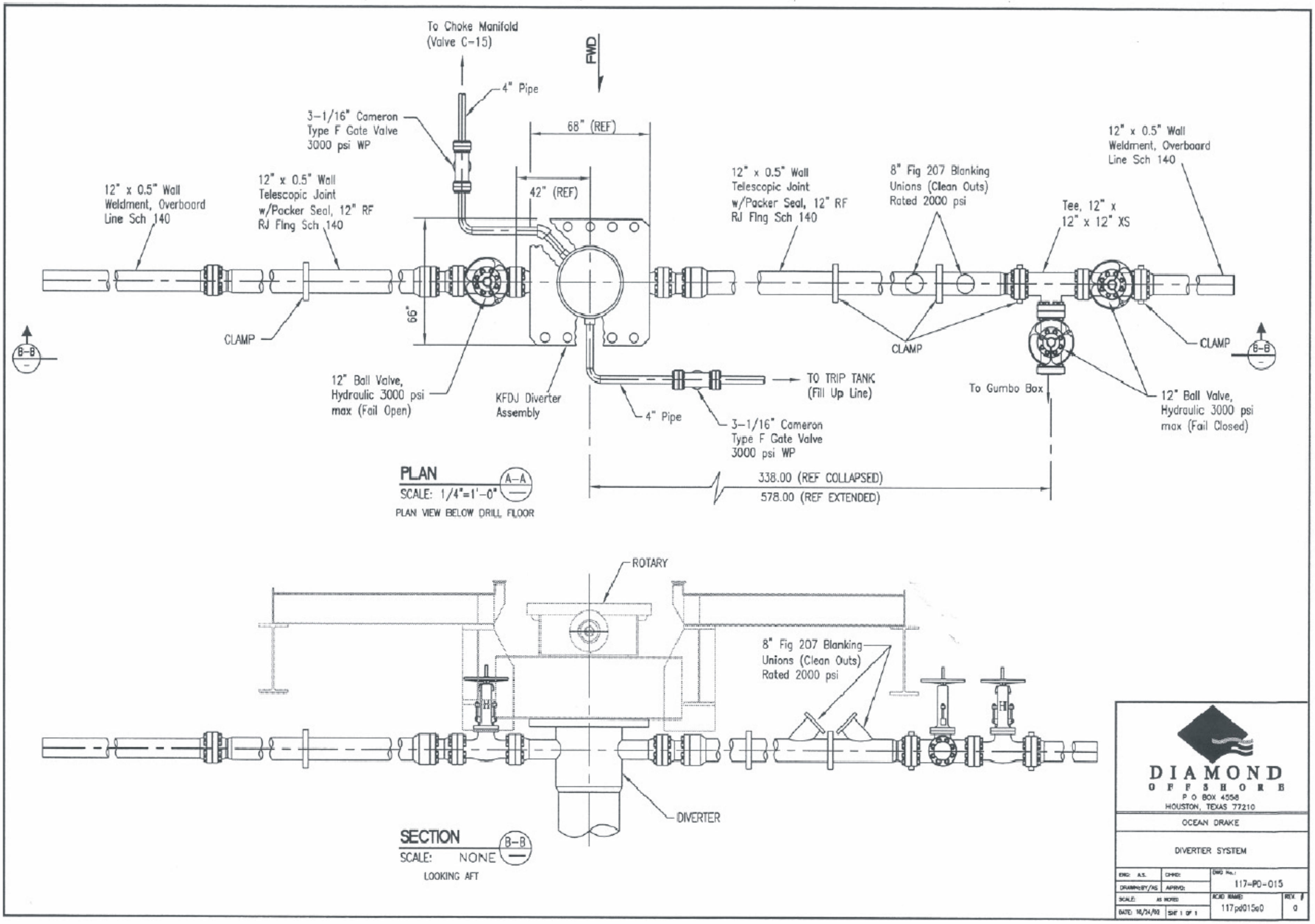
Diamond Offshore Inc. Jack-Up Rig Ocean Drake

Attachment 2

Attachment 3



South Timbalier Block 135 Well No. 6 Well Bore Configuration at Time of Incident



Diverter System Schematic on Ocean Drake

Attachment 4

Use of or reliance upon the data contained in the Drive Pipe Yield Chart(s) constitutes the following conditions, to wit:

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FRANK'S

DRIVE PIPE YIELD CHART

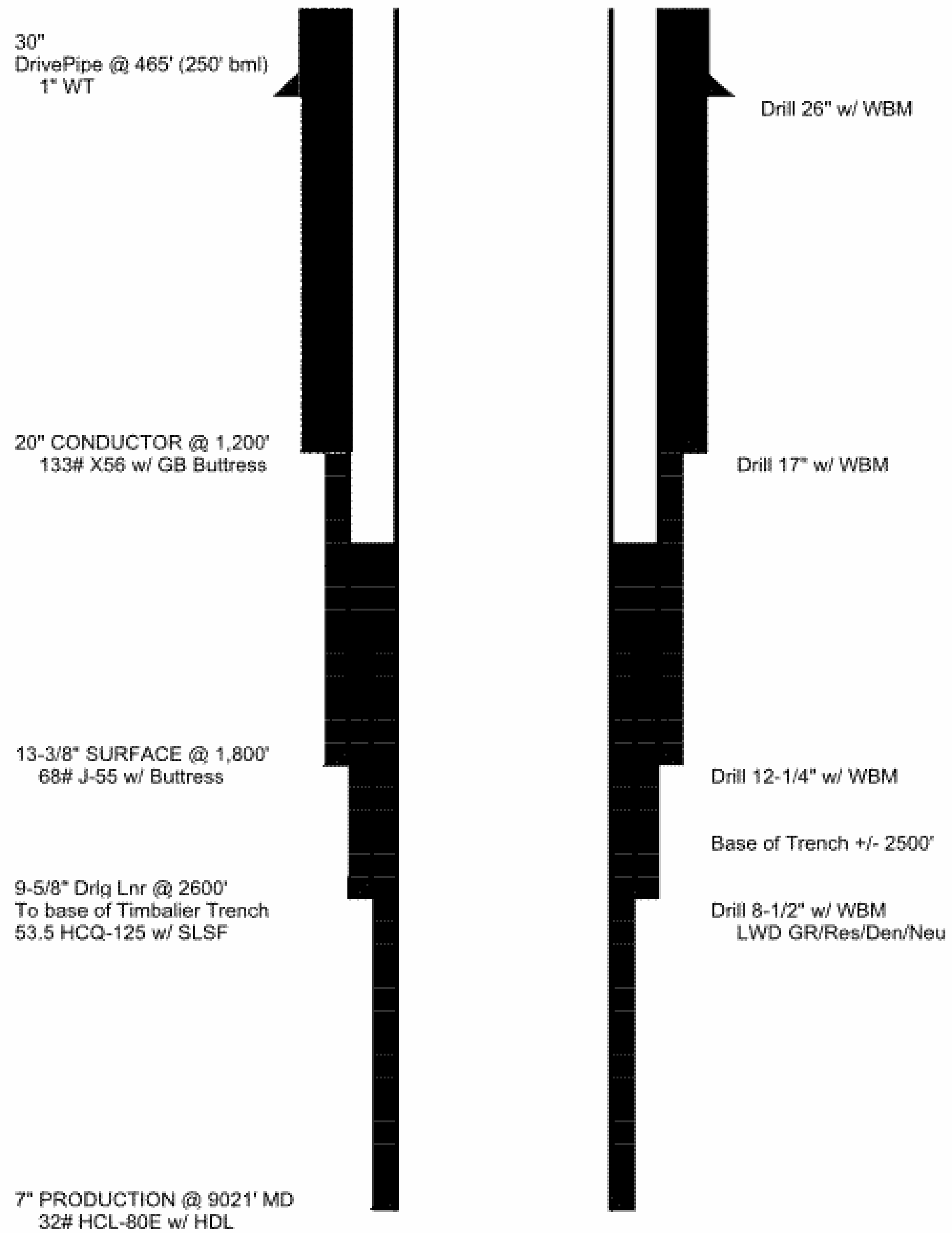
API 5L GRD. B (35000PSI)

ALLOWABLE BLOW COUNT

PIPE O.D. (IN.)	PIPE WALL (IN.)	PIPE X-SEC (SQ. IN.)	PIPE YIELD CAP (TONS)	ALLOW. BRG CAP 1.85 S.F. (TONS)	D12 22500FT#	D15 28488FT#	D22 39700FT#	D30 54250FT#	D30-02 D30-13 66100FT#	D36-02/13 D36-23/32 83100FT#	D46-02/13 D46-23/32 105000FT#	D62 D62-12/22 152538FT#	D80-12 225000FT#	D80-23 196827FT#	D100-13 300000FT#
14	0.312	13.42	234.79	126.91	***	150.80	79.87	49.59	37.90	28.31	21.36	13.93	9.10		
14	0.375	16.05	280.90	151.84	***	239.53	109.92	64.57	48.34	35.52	26.48	17.05	11.06		
16	0.312	15.38	269.09	145.46	***	211.71	101.40	60.49	45.53	33.61	25.13	16.24	10.55	12.21	
16	0.375	18.41	322.13	174.13	***	388.54	145.64	80.40	58.91	42.58	31.38	19.97	12.85	14.92	
16	0.500	24.35	426.07	230.31	***	***	316.62	135.68	92.59	63.61	45.33	27.92	17.61	20.56	
20	0.375	23.12	404.60	218.70	***	***	265.37	121.90	84.63	58.83	42.24	26.20	16.60	19.36	
20	0.500	30.63	536.03	289.75	***	***	***	241.03	145.45	92.70	63.19	37.36	23.02	27.06	
20	0.625	38.04	665.74	359.86	***	***	***	***	255.61	141.61	89.94	50.19	29.99	35.55	21.17
20	0.750	45.36	793.73	429.05	***	***	***	***	***	218.39	125.28	65.07	37.55	44.94	26.12
20	0.875	52.57	920.01	497.30	***	***	***	***	***	356.28	174.14	82.54	45.81	55.39	31.36
20	1.000	59.69	1044.57	564.63	***	***	***	***	***	***	246.06	103.34	54.85	67.09	36.92
24	0.500	36.91	645.98	349.18	***	***	***	***	233.28	132.76	85.37	48.10	28.88	34.19	20.43
24	0.625	45.90	803.18	434.15	***	***	***	***	***	225.88	128.37	66.27	38.14	45.68	26.50
24	0.750	54.78	958.67	518.20	***	***	***	***	***	***	193.24	88.57	48.51	58.86	33.04
24	0.875	63.57	1112.43	601.31	***	***	***	***	***	***	302.31	116.57	60.20	74.14	40.12
24	1.000	72.26	1264.48	683.50	***	***	***	***	***	***	***	152.79	73.46	92.04	47.78
26	0.500	40.05	700.96	378.90	***	***	***	***	303.32	159.03	98.61	54.04	31.99	38.03	22.50
26	0.625	49.82	871.91	471.30	***	***	***	***	***	292.28	153.39	75.51	42.56	51.26	29.32
26	0.750	59.49	1041.13	562.77	***	***	***	***	***	***	243.60	102.71	54.58	66.74	36.76
26	0.875	69.07	1208.64	653.32	***	***	***	***	***	***	***	138.27	68.37	85.10	44.88
26	1.000	78.54	1374.43	742.94	***	***	***	***	***	***	***	186.76	84.34	107.20	53.80
26	1.250	97.19	1700.86	919.38	***	***	***	***	***	***	***	366.63	125.28	168.38	74.51
26	1.500	115.45	2020.42	1092.12	***	***	***	***	***	***	***	***	185.14	271.61	100.20
30	0.500	46.34	810.92	438.33	***	***	***	***	***	232.26	130.95	67.27	38.63	46.29	26.81
30	0.750	68.92	1206.06	651.93	***	***	***	***	***	***	***	137.64	68.14	84.79	44.75
30	1.000	91.11	1594.34	861.81	***	***	***	***	***	***	***	288.47	110.23	145.08	67.23
30	1.250	112.90	1975.75	1067.97	***	***	***	***	***	***	***	***	175.07	252.95	96.21
30	1.500	134.30	2350.28	1270.42	***	***	***	***	***	***	***	***	287.87	***	134.96
36	0.500	55.76	975.85	527.48	***	***	***	***	***	***	202.54	91.36	49.74	60.45	33.80
36	0.750	83.05	1453.46	785.66	***	***	***	***	***	***	***	216.91	92.95	119.50	58.40
36	1.000	109.95	1924.21	1040.11	***	***	***	***	***	***	***	***	164.25	233.51	91.78
36	1.250	136.46	2388.08	1290.85	***	***	***	***	***	***	***	***	304.24	***	139.66
36	1.500	162.58	2845.08	1537.88	***	***	***	***	***	***	***	***	***	***	214.06
42	0.500	65.19	1140.78	616.64	***	***	***	***	***	***	331.28	122.58	62.53	77.24	41.49
42	0.750	97.19	1700.86	919.38	***	***	***	***	***	***	***	366.63	125.28	168.38	74.51
42	1.000	128.80	2254.07	1218.42	***	***	***	***	***	***	***	***	251.40	***	123.74
48	0.750	111.33	1948.26	1053.11	***	***	***	***	***	***	***	***	169.20	242.33	93.83
48	1.000	147.65	2583.93	1396.72	***	***	***	***	***	***	***	***	***	***	167.06
60	0.750	139.60	2443.05	1320.57	***	***	***	***	***	***	***	***	330.53	***	146.81
60	1.000	185.35	3243.66	1753.33	***	***	***	***	***	***	***	***	***	***	325.36

1) *** DENOTES THAT BLOW COUNTS IN EXCESS OF 400 BLOWS PER FOOT ARE REQUIRED TO YIELD THE PIPE.
2) THE ABOVE CHART IS BASED ON YIELD ONLY AND DOES NOT TAKE INTO ACCOUNT DEFLECTION OR MISALIGNMENT.
3) HAMMERS ARE DESIGNED FOR A MAXIMUM BLOW COUNT OF 250 BLOWS PER FOOT. ANY SITUATION REQUIRING MORE THAN 250 BLOWS PER FOOT THE NEXT SIZE HAMMER JOB SHOULD BE USED.
4) ALL BLOW COUNTS ARE CALCULATED VALUES BASED ON THE ENGINEERING NEWS FORMULA.
5) FRANK'S RESERVES THE RIGHT TO CHANGE THESE FIGURES WITHOUT PRIOR NOTICE.

Drive Pipe Yield Chart



SOUTH TIMBALIER 135
OCS 0462
WELL #7
DRILLING SCHEMATIC

WATER DEPTH: 115'
RKB-MUDLINE: +/- 215'
RKB-MSL: +/-100'
ELEV TBG HD:

API#

WELL CONSTRUCTION

Planned WB Schematic

Planned Well Bore Configuration for Offset Well No. 7

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.