OCS Report
MMS 2005-007

Investigation of Loss of Well Control Eugene Island Block 277, Well A-3 BP OCS-G 10744 9 February 2004

Gulf of Mexico
Off the Louisiana Coast

MMS
U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Regional Office

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Jack Williams – Chair
John McCarroll
Tom Basey
Glenn Woltman

U.S. Department of the Interior
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Investigation and Report

Authority

A loss of well control occurred on 9 February 2004 at approximately 2300 hrs aboard Ensco Offshore Drilling, Inc.'s (Contractor) jack-up rig *Ensco 60* (Rig) during the drilling of Well A-3 bypass (Well A-3 BP) for Energy Partners, LTD (EPL or Operator) on Lease OCS-G 10744, Eugene Island Block 277, 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 13 February 2004, the following personnel were named to the investigative panel:

Jack Williams, Chairman – Office of Safety Management, GOM OCS Region
John McCarroll – Houma District, Engineering and Field Operations, GOM OCS Region
Tom Basey – Lafayette District, Field Operations, GOM OCS Region

By later appointment, the following personnel were added to the investigative panel as staff:

Glenn Woltman – Office of Safety Management, GOM OCS Region.

Procedures

On the morning of 15 February 2004, personnel from MMS visited the site of the incident to assess the situation. Following the onsite investigation, interviews were conducted with personnel from the Contractor and the Operator, and various experts from other companies. These interviews included the following:

- 22 February 2004, representatives of the EPL management met with Office of Safety Management (OSM) personnel in the New Orleans office to review the incident.
- 2 April 2004, members of the panel interviewed members of the engineering, regulatory team from EPL.
- 20 April 2004, team members interviewed personnel from Boots and Coots well control to review the causes of the incident and details of the well control operation.
- 23 April 2004, members of the panel conducted a telephone interview with the contract EPL company-man who was on duty on the Rig during the incident. On 27 April panel members interviewed another EPL contract company-man on duty when the well incident occurred.
- 28 April 2004, Tom Basey and Jack Williams visited the Rig and interviewed the Ensco Offshore Installation Manager (OIM), Tool Pusher, and Driller on duty when the incident occurred.
- 28 May 2004, panel members interviewed senior personnel in Ensco over the phone and pursuant to the interview, forwarded written questions regarding the gauge system.
- 16 June 2004, a panel member reviewed the physical evidence with members of Wood Group rental tools on site in the Wood Group field location in Lafayette.
- 3 August 2004, conversed with senior management of Ensco and reviewed answers to the previously forwarded written questions.
- 16 August 2004, panel members interviewed the drilling engineer with EPL who designed and supervised the well.
- 26 August 2004, two panel members interviewed a geologist and senior management of EPL about the source of pressure and organizational details.
- 27 August 2004, a panel member phoned and interviewed personnel from Capitol Risk about aspects of the insurance claim for the Well.
- 28 August 2004, a panel member interviewed additional EPL personnel and MMS personnel involved in granting of waivers.

In addition to the interviews, EPL and Ensco personnel frequently answered specific questions by e-mail or telephone, and personnel of the MMS investigatory panel met a number of times to plan the investigation and discuss results. Other information was gathered at various times from a variety of sources. This information included the following reports and statements:

- Daily Drilling Reports, 17 December 2004 Wells A-3, A-3 BP;
- Operator's Drilling Plan, Wells No. A-3, A-3 BP and A-3 ST;
- Operator's Application for Permit to Drill, Well No. A-3, A-3 BP, A-3 ST.
- Operator's A-3 Incident Investigation Report;
- Operator's logs, Well A-3, A-3 BP;
- All "Applications to Modify" to MMS from EPL (7);
- Operator's schematics of Wells A-3, A-3 BP, A-3 ST;
- Proposed and actual abandonment procedure for A-3, A-3 BP;
- MMS records for all wells previously drilled from the Platform, including logs, plans, drilling summaries;
- Field Notes from Energy Partners onsite contract supervision;
- Mud Loggers Reports for Wells A-3, A-3 BP and A-3 ST;
- Cementing and Casing details for all wells;
- Pictures and diagrams of rig and results of event;
- Rig audit by Boots and Coots immediately after event;
- Study, "Failure Analysis of Casing," by T H Hill Associates;
- Technical commentary and study "Equipment Analysis Pressure Gauge Isolator" by Magnolia Global Energy, LTD (MGE);
- Actual laboratory testing, notes, and comments from Stress Engineering Services, Inc. (SES) concerning test of gauge isolator;
- Commentary on survey of gauge system by Offshore Instrumentation, Inc. (OI);
- Review of data for similar occurrences, detailed review of Canadian Petroleum Safety Council Safety Alert #23-2000.
- Answers to specific written questions forwarded by Ensco Management.

Introduction

Background

The surface and bottomhole location for Well A-3 BP is within Lease OCS-G 10744, which covers approximately 5,000 acres and is located in Eugene Island Block 277 (EI-277) Gulf of Mexico, offshore Louisiana *(for lease location, see Attachment 1)*. The lease was issued, approved, and made effective on 1 July 1989 to Sandefer Offshore Operating Company as 100-percent interest leaseholder and operator. On 1 January 1990, a platform was installed and production was initiated in November 1990.

Subsequently, Aquila Energy Resources Corporation acquired 100-percent ownership, effective 31 December 1992, and Apache Corporation assumed the role of operator. On 1 July 1995, Apache acquired 100-percent interest ownership. Effective 1 July 1997, Tri-Union Development Corporation (Tri-Union) acquired 100-percent ownership and EPL became designated operator.

On 2 May 2003, a farm-out agreement was initiated between Tri-Union and Cabot Oil & Gas Corporation (Cabot). Tri-Union subsequently filed for bankruptcy on 23 October 2003. On 10 November 2003, EPL and Palace Exploration Company (Palace) acquired a respective 50-percent and 25-percent interest in the farm out, subject to bankruptcy court approval and certain performance requirements including drilling. On 10 November 2003, the court authorized the farm-out and assumption of the lease from Tri-Union by Cabot, with EPL as Operator.

EPL initiated drilling operation in EI-277 from the "A" platform on 17 December 2003 pursuant to terms of the farm-out agreement performance requirements.

Brief Description, Loss of Well Control

In February 2004, the jack-up rig *Ensco 60* was engaged in drilling operations for EPL on Eugene Island Block 277 Well A-3 BP (the "Well" or "A-3 BP"). The Rig was in place next to the EI-277 "A" platform. Drilling operations were being conducted with the Rig cantilevered over the Platform and the Well was being drilled using an available slot on the Platform.

On 9 February 2004, the well had reached target depth for the setting of the intermediate string, and logs had been run. Approximately 11,285 ft of 9 5/8 inch casing was run and cemented.

While waiting on cement, pressure built up on the 9 5/8 inch by 13 3/8 inch intermediate by surface casing annulus (the Annulus), reaching 1,225 psi on the driller's gauges. The pressure then began to decline, reaching a gauge reading of 0 psi on both of the driller's gauges after a period of hours. With the driller's gauges reading 0 psi, 3,000 psi pressure was observed on a secondary gage monitoring the same annulus pressure. Shortly thereafter, an explosion occurred, followed by a rising cloud of gas, water, oil, sand, and debris, which enveloped the rig floor over the top of the wind walls. The rig was evacuated and flow eventually ceased. Operations then commenced to secure the well. During and after the event, a sheen was observed trailing from the platform with pollution estimated to be 5.4 barrels (bbls) condensate and oil.

Findings

Preliminary Activities – Well Plan

The EI-277 “A” Platform of the EI-258 Field sits in 165 ft of water. The four-legged, four-slot Platform was set in 1990 and two wells were drilled by the operator, Sandefer Offshore Operating Company.

In December 2003, EPL moved the Contractor’s Rig on site to drill the Well, employing a previously unused slot of the Platform.

Well A-3 was intended for a number of targets below 9,000 ft and was permitted as a deviated hole to a measured depth of 14,692 ft measured depth (MD). The Well plan called for casing strings to be installed as follows:

Conductor casing: 18 5/8 inch, 87.5 pounds per foot (ppf) H-40 set at 1,000 ft;
Surface casing: 13 3/8 inch, 68-ppf K-55 set at 4,600 ft;
Intermediate string: 9 5/8 inch, 53.5-ppf P-110 set at 11,450 ft;
Production liner: 7 inch, 32-ppf P-110 set at 14,500 ft;

The Well was designed to minimize the number of casing strings by setting the intermediate string through targets above 11,450 ft, near the mud-weight pressure limit of the anticipated leak-off of the surface casing shoe, and near the suspected transition from hydro-pressure to geo-pressure from the formations. Because pay sands were expected near the bottom of the intermediate hole, a waiver was requested by the Operator from MMS to reduce the overlap of the production liner/intermediate string from 100 ft to 70 ft. This reduction in overlap was to avoid having to produce prospective pay sand through two strings of casing.

Drilling Activities — Spud to Loss of Control

(From drilling morning reports and interviews; see Attachment 2 for Well schematic, drilling operations)

11 Dec. – 19 Dec. – Move Rig on site, rig up, drive 30-inch pipe to 589 ft with 312 ft penetration.

20 Dec. – 21 Dec. – Spud well, drill to 1,045 ft, run 18 5/8 inch, 87.5 pounds per foot (ppf) H-40 conductor, set casing at 1,032 ft, cement to surface.

21 Dec. – 26 Dec. – Drill to 4,605 ft, circulate and condition the mud, run 13 3/8 inch, 68-ppf K-55 surface casing to 4,605 ft. Set the casing with full returns and with cement received at surface.

26 Dec. – 30 Dec. – Cut casing and weld on casing head. Tested casing head to 975 pounds per square inch (psi); test failed because of an internal leak. Attempted to repair internal leaks twice by additional welding, but the casing failed to test. After the third welding repair to K-55 surface casing head, the casing tested to 975 psi.

31 Dec.2003 – 6 Jan 2004. – Drill ahead to 10,228 ft. No report of ditch magnet recovery on reports from 30 Dec. to 6 Jan.

6 Jan. – 10 Jan. – Normal drilling operations conducted. On 6 Jan. the first daily reports of metal recovery from the ditch magnets were received. Reports of metal recovery were recorded daily through 10 Jan.

10 Jan. – 11 Jan. – Drill to 11,570 ft log well, circulate and condition (CC) the mud because of a high gas cut; well began to flow. The flow increased; shut well in. Raised the mud weight to 13.0 ppg, circulated to attempt to kill well, and discovered the drilling string was stuck. Continued well control operations while attempting to free stuck pipe.

Ran logs through the drill string to attempt to determine if below-surface flow was occurring. Ran a free-point test and determined the approximate depth of the stuck pipe. As a result of the logs and free point, and with the approval of the MMS, on 11 Jan. the decision was made to abandon the lower hole because of possible below surface flow and stuck pipe. No ditch magnet metal recovery was recorded during this time period.

11 Jan. – 15 Jan. - Set three plugs at depths of 11,343 ft, 9,363 ft, and 7,252 ft. Set a plug at 4,710 ft, cut drill pipe, and recovered 4,717 ft of drill pipe. When well was plugged back, 6,187 ft of drill pipe and the bottomhole assembly were left in the hole. No ditch magnet metal recovery was recorded during this time.

16 Jan. – 22 Jan. – Begin drilling A-3 BP out of surface casing, kicked well off at 4,710 ft. No ditch magnet metal recovery was recorded during drilling operation from 16 Jan. to 23 Jan.

23 Jan. – 27 Jan. – Normal drilling operations, ditch magnet recovery on morning reports averaged approximately 0.25 to 0.36 pounds of metal recovery per day, continued through 5 Feb.

27 Jan. – Request from EPL to MMS for a waiver of the requirement to test surface casing every 30 days; next test scheduled for 30 Jan. Waiver was to be for a period until 4 Feb. Waiver was granted by MMS on 28 Jan.

27 Jan. – 4 Feb. – Continued normal drilling operations, metal recovery from ditch magnets continued to be approximately 0.25 to 0.36 pounds of metal per day.

4 Feb. – EPL requested the MMS grant an extension of the previous waiver from the requirement to test surface casing every 30 days. Request was to extend the testing date from 4 Feb. until the completion of running intermediate casing. The departure was granted on 4 Feb.

4 Feb. - 9 Feb. – Drill to 11,285 ft, run a hole-opener, log Well A-3 BP. Make wiper trips and prepare to cement intermediate casing. Run and set 9 5/8 inch, 53.3-ppf HCP-110 casing at 11,285 ft.

Drilling and Activities, During and After Loss of Control

9 Feb., 1745 hrs – Opened annular blow-out preventer (BOP) after 11 hrs waiting of cement. Found pressure on Annulus to be 0 psi but observed bubbling fluid, which shortly started to flow. Shut in (SI) Annulus at 1748 hrs.

1830 hrs – 2020 hrs – Pressure on Annulus built to 470 psi in 30 min., when the pressure began to fluctuate. The crew bled off pressure and observed buildup several times while analyzing the cause of pressure and alternatives to cure the problem. The fluctuation continued with pressure generally building. Crew members were stationed to watch the seals and the wellhead. Two men were assigned by Ensco driller to observe the casing valve below the wellhead.

2040 hrs – The pressure reached 1,265 psi but shortly afterwards began to drop somewhat erratically, but trending lower *(see Attachment 3)*.

2225 hrs – Pressure on Annulus reached 0 psi as measured on gauges in driller's console. Crew members watching below deck were pulled up and assigned other tasks. After consultation with EPL management, the crew prepared to fill the Annulus with mud, to be followed by pumping mud and then cement directly into the Annulus against the pressure. The pumping would override the pressure, forcing it back into the formation (bull-heading).

2300 hrs – Pressure on driller's console gauges continued to read 0 psi. Opened well choke, had dry gas flow with pressure, immediately shut in the well. A supervisor checked the choke manifold and observed that a reading of 3,000 psi was indicated on the Annulus on the 2-inch gauge mounted on the choke manifold. Almost immediately, while the supervisor was moving to re-check the driller's console gauges, an explosion occurred in the wellhead area.

After the explosion, a cloud of mist, mud, sand, and debris rose above the wind walls with gas blowing from below the rig floor. The flow was directed to the sides of the rig by the unusually large base plate, which acted as a shield, keeping the main force of the flow from directly impacting the bottom of the rig floor. The well was then shut in at the choke, and personnel prepared to evacuate while the uncontrolled flow continued.

Evacuation was initiated by using the port crane and personnel basket to move three loads, totaling 18 personnel, onto the motor vessel *Kelly Ann Candies*. Ensco supervisors then made observation of the well bay area from the rear of the Rig. It was seen that the well was blowing from below the wellhead and that no control of any type was possible. Therefore, movement of personnel off the rig by crane was halted. The remaining 28 crew members departed the Rig by using only the starboard life boat, as the port life boat was blocked from being lowered by the work boat. Full evacuation of the rig took approximately 30 minutes.

The M/V *Kelly Ann Candies* met the life boat after approximately 30 minutes and assisted in the recovery of the crew onto the vessel. A head count confirmed that all personnel were accounted for.

Activities to Regain Control

9 Feb., 2350 hrs – M/V *Kelly Ann Candies* made a pass around the Rig, and supervisory personnel viewed the area with binoculars and spot lights. The Well appeared to be static. The crew from the Rig landed and boarded Eugene Island 258 “A” platform.

10 Feb., 0740 hrs – A helicopter arrived at EI-258 “A” Platform and picked up supervisory personnel from EPL and Ensco to observe the condition on the Rig. A thin slick was observed 300 meters by 0.5 mile drifting to N/NW. The group agreed conditions appeared to be safe to land.

0825 hrs – The helicopter landed on the Rig, and supervisory personnel went to the stern of the Rig and observed that the Well appeared to be static. The wellhead was observed to be surrounded by a buildup of mud, sand, and cement with an oily residue, the pile being approximately 3 ft by 10 ft by 10 ft sloping to 4 inches at the kick rail *(See Attachments 4 and 5)*. Oil was observed on deck and a slick continued to trail from platform. The group returned to EI-258 “A.”

1040 hrs – A group of five Ensco personnel departed from EI-258 “A” Platform and landed on the Rig. The wellhead appeared to be static. Personnel prepared to start the emergency generator. Instructions were received from EPL to clear the debris from the wellhead area immediately. A check with a hand-held gas detector found no evidence of gas at the wellhead.

1425 hrs – Personnel from Boots and Coots well control arrived and organized a complete check of the area and found no gas detected with hand-held gas detectors. Boots and Coots personnel conducted a rig safety audit while well control operations were prepared, staged, and initiated.

11 Feb. – 17 Feb. – All personnel conducted well control, evaluation, and P&A procedures. Gas detector readings inside of the 30-inch annulus were at 100 percent; no gas reading was found outside of annulus. The crew periodically bled pressure off the 9 5/8 inch casing from approximately 185 psi to 0 psi. They then assessed damage and discovered that the 13 3/8 inch casing was parted, split, and pealed back below wellhead. *(See Attachments 6, 7, and 8 for pictures of split casing and damage to connection to wellhead on site.)* They continued to bleed off gas periodically from the annulus and to test with a detector. Positive readings continued to be registered in the 30-inch annulus.

Personnel checked the other two wells on the Platform for presence of gas in the casing and all annuli of each well, and found no gas evident from a check with a gas detector.

The crew cut the casing and installed a wellhead with blind rams. They ran logs to determine subsurface flow but the logging tools failed to pass approximately 3,650 ft. A casing collapse was suspected. After logging the Well to the surface, they set a mechanical plug at 3,608 ft, pumped 3 bbls salt water and 330 sacks (sx) class H cement. The 9 5/8 inch casing was then cut with a cold cutter at 550 ft, the casing was pulled, and the Well was plugged and abandoned (P&A'd).

Findings – Source of Pressure

Testimony and written accounts state that after the driller's gauges were registering 0 psi on the Annulus, the choke was opened to check for flow, and high pressure was found. Only then, just prior to the explosion that led to the loss of control, was a third gauge on the choke manifold observed to be registering approximately 3,000 psi. This pressure had two possible sources: (1) pressure that migrated upward from a shallow sand that was not covered by the intermediate casing cement; or (2) pressure that was carried upward as a bubble on top of the cement from a reservoir deeper in the well.

Source of Pressure, Shallow Gas Sand

The 13 3/8 inch casing was set during drilling of the original A-3 Well. That well was lost after approximately 23 days of drilling operations because of a kick taken during drilling of a rat hole at the designed setting depth for the intermediate string. As noted above, this kick led to stuck drill pipe, causing the original well A-3 to be plugged back to a depth of approximately 4,700 ft, or approximately at the shoe of the surface casing.

After the bottomhole assembly was stuck in the A-3 well, it has been noted that a number of production logs were run through the stuck drill pipe to determine the possibility of underground flow. At that time, the Operator determined that no conclusive evidence of underground flow was indicated by the production logs and the well was subsequently plugged back.

Following the loss of control incident on the successor well, the A-3 BP, the Operator again reviewed all the logs from both the A-3 and A-3 BP. According to an Operator's geologist, the logs from the two wells indicate that a shallow sand may have become charged with hydrocarbons during the A-3 stuck pipe and plug-back event. As proof, the Operator's geologist testified that a stringer of sand at approximately 5,300 ft was gas productive in the A-3 BP logs. But that same stringer had been interpreted to be wet in the logs of the original A-3 well *(See Attachment 9)*.

The Operator's personnel testified that the source of the Annulus gas pressure could have come from the charged sand at 5,300 ft in the A-3 BP, which was possibly above the top of the cement column used to set the intermediate string. Geologists and the management of EPL testified that the charging of the shallow sand, as evidenced from the resistivity shown on the A-3 BP logs, was overlooked.

From a review of the drilling reports and from interviews with the supervisory personnel on the Rig during drilling of the A-3 BP, no evidence of a gas productive sand at approximately 5,300 ft was seen on the mud drilling record of the A-3 BP during drilling. No surface evidence, such as gas-cut mud, drilling breaks, or other indication of a gas charged zone was seen some weeks later during drilling of the replacement well, the A-3 ST. All three wells, A-3, A-3 BP, and A-3 ST, drilled this section of the hole with 11 ppg or greater mud, which could have been sufficient to hold back the over-pressure of the charged sand. Testimony indicates that the electric logs of the A-3 ST did not find the zone at approximately 5,300 ft gas charged or productive.

Statements by MMS geologists agree that the logs of the 5,300 ft sand indicate the sand is wet in Well A-3. The MMS geologists also agree that the logs of the A-3 BP show the same sand to have gas productive characteristics.

The pressure observed in the Annulus of the A-3 BP was approximately 3,000 psi as measured on the choke gauge. The normal pressure gradient in this area would indicate that a dry gas column with pressure enough to generate a surface pressure of 3,000 psi would originate from a minimum depth of approximately 7,000 ft true vertical depth (TVD). The only way a higher pressure could be encountered is if the zone were abnormally pressured or were a small enclosed reservoir that had been charged preferentially by high-pressure gas from a deeper sand.

From calculations, if this 5,300 ft stringer had been charged by an underground flow from the previously experienced kick in Well A-3, it would need to be preferentially charged to at least approximately 2 ppg higher than the normal gradient to deliver 3,000 psi at the surface.

EPL personnel stated that, for the pressure experienced on the A-3 BP to have originated from the 5,300 ft stringer, the abnormal pressure would have had to remain for over three weeks. The time elapsed between the kick and loss of hole experienced in the A-3 and the Annulus pressure/burst casing event that occurred in A-3 BP was three weeks. Despite some indications, there was no conclusive evidence found of continuing underground flow before the A-3 well was plugged and abandoned. That well was plugged in accordance with MMS approved procedure.

From morning reports and testimony, the only surface evidence that would indicate a charged sand at 5,300 ft in the A-3 during plug-back operations was the presence of gas and slight flow experienced after a plug was set at 7,000 ft and before a plug was set at 4,700 ft. Operator personnel did not feel this was enough to conclude underground flow had occurred, or was ongoing.

Source of Pressure, Deep Hydrocarbon Sand

The A-3 BP penetrated a number of higher pressured hydrocarbon sands below 9,500 ft that were logged as gas or oil productive. The deepest productive sand was drilled with 12.8-ppg mud, indicating a possible bottomhole pressure (BHP) as high as 6,200 psi. These sands were to be isolated behind the intermediate string by the cement job on the 9 5/8 inch casing.

No evidence was collected that affirms or denies the effectiveness of the cement in isolating these higher pressure sands from each other. No evidence either affirms or denies the possibility of communication between a deeper production zone and the Annulus via a micro-annulus in the cement.

Findings – Measurement of Pressure

Measurement of Pressure, Driller Console Gauges

The Rig had three gauges on the drill floor to measure the pressure of the various well components during operations. These were the driller's gauge and annulus gauge *(see Attachment 10)*, which were located adjacent to each other on the driller's console in the driller's shack, and the choke gauge located on the choke outside of the driller's console *(see Attachment 11).*

The two gauges on the driller's console had been in use throughout the drilling of A-3 and A-3 BP with no apparent malfunction. They are the main gauges used to monitor operations. However, both gauges were connected to a single pressure sensor and system reservoir and, while waiting on cement, both were monitoring the Annulus pressure. The hydraulic transmission of pressure from the sensor located on the choke manifold to the gauges is via pressure lines connected to a fluid reservoir (*see Attachment 11 and 12*). The lines are filled with hydraulic fluid by a hand pump. The separate gauge on the choke was connected directly to a different sensor, not connected to the hydraulic system supporting the driller's console gauges. *(See Attachment 13 for schematic of setup of gauges and hydraulic system.)*

The driller's console gauges recorded similar readings during the rise in pressure on the casing Annulus, and likewise tracked each other during the subsequent fall in that pressure from approximately 1,265 psi to 0 psi. According to testimony, this fall in Annulus pressure to 0 psi was thought to be evidence that the shoe of the surface casing had broken down and the gas was bleeding into the normally charged sands near the shoe.

When the pressure reached 0 psi, the two crewmen who had been assigned to observe the casing valves on the deck below the wellhead were reassigned to other tasks, as it was thought that continuing to monitor the pressure on the casing was unnecessary. The crew, acting under the assumption that pressure on the surface was negligible, received orders from the Operator management to pump or bull-head a top-job cement plug down the Annulus to seal off whatever shoe or formation breakdown may have occurred.

Casing Failure and Gauge Readings

As part of the preparation to pump kill mud, followed by cement, a crew member opened the choke slightly to test for residual pressure. Testimony from crew members states that upon the opening of the choke, high-pressure gas flow caused the crewman to shut the choke valve back in immediately. Simultaneously, a supervisor for EPL testified that he noticed the independent choke gauge was reading approximately 3,000 psi Annulus pressure. This observation was immediately followed by the bursting of the surface casing below the wellhead.

The pressure bursting of the surface casing of the Well indicates that the two driller's console gauges were returning an erroneous pressure reading of 0 psi immediately prior to the explosion. Testimony was received that these two gauges had been continuously used throughout the drilling operation without any overt indications of faulty performance. Therefore, Operator and Contractor personnel expressed the opinion that the single common pressure sensor controlling both of these gauges could have developed a problem, causing the erroneous pressure readings. Testimony also was received that a pressure sensor problem usually evidences itself catastrophically, rather than as seen in the gradual decline in pressure experienced on the console gauges.

Testimony was given that the failure of the driller's console gauges to indicate the true pressure on the Annulus accurately is a reason the pressure was allowed to build up to the point of casing failure. Statements were made by management of EPL that, had the true pressure buildup been known, alternative courses of action to control the pressure, such as early "bull-heading" kill fluid or "lubricating and bleeding" the Annulus would have been initiated.

To check the possible failure of the gauges, inspections were performed after the fact, and a portion of the system responsible for relaying the pressure data from the sensor to the driller's console gauges was laboratory tested. The onboard examination of the gauges was conducted by Boots and Coots, Swaco, and Oilfield Instruments (OI) and the laboratory tests were performed by Magnolia Global Energy (MGE) with technical measurement by Stress Engineering Services, Inc. (SES).

Operational Setup of Gauges

As previously stated, the gauges were connected to the flow system as shown in *Attachment 13*. Testimony and documentation provided by the Contractor state the gauges and system in question were installed in the shipyard in November 2003. The Contractor publishes a recommended maintenance and testing schedule for the gauge systems, which was adhered to, according to documentation. However, after the loss of control event and efforts to regain control and plug the Well, the sensor and the hydraulic pressure system for these gauges were damaged, altered, or removed prior to having a full inspection for possible malfunction on the rig.

Audit of Gauge System Immediately After Event

On 17 February 2004, personnel from Boots and Coots conducted a safety audit of the Rig as part of well control operations. If Boots and Coots conducted a detailed review of the gauge pressure system, it was not documented. However, the audit made note of the common sensor and system that controlled both of the driller's console gauges and recommended "a full inspection of the existing sensor should be done by a qualified service person to insure it is installed and working properly." In addition, the memorandum from Boots and Coots to the Operator after the inspection stated the following:

"…a failure in this sensor could give a false reading on both gauges. Also …any loss of hydraulic oil in either line could result in a false pressure reading on both gauges. I removed and inspected the sensor and saw no obvious damage in the piston. I inspected the hydraulic lines running from the sensor to the gauges. Under the choke panel where that line connects to the gauge there was hydraulic oil residue on the line. This could indicate a leak in that area….a slow leak in hydraulic oil from this line could reflect a slow loss in pressure on the gauges."

During after-the-fact interviews with Boots and Coots personnel, testimony was given that a small leak was found in the hydraulic system that could have resulted in a loss of 100 psi per hour. It is not known if these comments referred to the later tests by OI and Swaco, or were estimates, or were the result of actually gauged tests conducted by Boots and Coots.

Subsequent Review and Test of Gauges and System

Swaco personnel were reportedly sent to check the operation of the actual gauges and, from documents provided by EPL, found no problems with the gauges themselves. On 24 February, OI sent two technicians to the Rig to survey the choke manifold sensor, system, and gauges. Their report states as follows:

"These are the discoveries made by OI USA's technicians with a visual observation. The hose for the SWACO casing pressure gauge was pumped up to 4,000 psi and isolated with stainless steel value[valves?] at 7:30 PM. At 7:40 pm the gauge read 3,860 psi. At 7:50 pm the gauge read 3,780 psi. The gauge was also slow on the bottom end by 100 psi. Gauge was replaced by SWACO hand and tested to 4000 psi for 20 minutes. Tested the Oilfield Instrumentation sensor hose and EMS III screen to 4,000 psi for 20 minutes. All tests were witnessed….

"It is impossible to determine the exact cause of the bleed off since the original equipment and conditions are no longer available. It is our understanding that the original sensor was checked by Contractor and pumped up to 5,000 psi which held. The original sensor was removed and is currently in the OIM's office."

Laboratory Test of Gauge System

To test the possibility that the console gauges delivered a false reading because of the failure of a common sensor, on 23 March, the Operator sent a portion of the sensor and pressure system to be tested by MGE However, only the gauge isolator was sent with the note that *"Both SWACO and Oilfield Instruments evaluate [d] the conditions of the hydraulic line from the sensor to the gauges and both gauges and lines were without leaks [note: see OI report above]*." The actual sensor was not sent for testing and its location is unknown.

After extensive and complete analysis, the MGE report found the sensor equipment provided for testing, termed a "pressure gauge isolator," to be functional. MGE used a specialist, third party company, SES, to perform the actual tests. The summary of the report stated the following: *"Based on the test results, the pressure gauge isolator was functioning properly. The device held pressure from the input side indicating the isolator mechanism was preventing any contaminants from migrating into the output side. The isolator mechanism was also capable of transferring the load from one side to the other via movement of the isolation mechanism within the housing."*

The report to MGE from SES discussed the failure to send the actual sensor for tests, fully discussed the usual way such systems operate, and discussed the possible causes of system failure. A part of their report reads as follows:

"If your gage line end fittings leak gage fluid into the atmosphere, you're likely to run out of fluid in the line. With applied choke manifold pressure, the bladder cannot move upward far enough to completely replace what leaked out of the line, and the gage reads zero (regardless of choke manifold pressure). If the bladder leaks, wellbore fluid simply bypasses the bladder seal and pressurizes the gage directly. The gage will read properly unless the line is plugged.

"…A more likely cause of the gage not reading choke manifold pressure is the lack of proper fluid level in the gage line. The bladder simply moved to the end of its "stroke" and there was nothing left but air in the gage line. This condition is….the most typical in operations…"

The report goes on to discuss the situation on the Rig as follows:

"When the gage line and pressure gage were removed, the best evidence to support a conclusion was lost. If the gage line was broken and only a small amount of fluid leaked out…or no fluid, lack of fluid in the gage line is the likely culprit."

"….My personal opinion is that the fluid level was low in the gage line and the bladder simply was not able to move far enough to transmit pressure to the gage."

SES Expert Opinion of System Failure

Finally a memo from SES personnel, whose opinions on the subject failure were solicited by the Operator after reviewing the tests of the gauge system, communicated the following:

"…My hunch is that the line between the sensor (the part you just tested) and the gage, was not properly filled with fluid and bled. It will remain a hunch as there's no way we can prove it. When the line was removed, the evidence was lost.

"…The exact same problem has been happening to me for the last 24 years…right up to the point where the gage on [a major oil company's new gage on a tension legged platform] exhibited the same problem (and it was the standpipe pressure gage as a matter of fact). "

Findings – Casing Wear

Inspection after the well bridged revealed that the casing had split vertically for a distance of at least 20 ft beginning immediately below the slip-on wellhead. The casing had also ballooned out and completely peeled away from the slip-on wellhead where the two were joined (*see Attachments 7, 8, 15, 16*).

The casing that failed was K-55 68-ppf grade, purchased new and fully inspected according to records. The nominal burst rating of such casing is 3,450 psi, considerably above the pressure noted prior to the failure.

From drilling reports and other testimony, the same surface casing was used for drilling of the

A-3 and the A-3 BP wells. At the time of the failure, it had been subjected to a total of 40 days of Rig operations during the drilling of the two wells, while drilling penetration through the casing was a total of approximately 14,000 ft. From morning reports, some trouble had been encountered when welding the slip-on wellhead onto the surface casing when it was installed after the surface casing was initially cemented into place. Two pressure tests of the wellhead failed and the entire head had been internally welded a third time before a successful pressure test was obtained.

Following the setting of the surface casing, drilling operations through the surface casing commenced on 31 December 2003. The morning reports are erratic in their report of recovery of metal from the ditch magnets *(see Attachment 14)*. No report was made of any recovery until 6 January, when the A-3 reached 10,288 ft measured depth, or about 5,700 ft of penetration through the surface casing. On 6 January, the morning report reported the first ditch magnet recovery of 2 pounds of metal. Thereafter, the morning reports recorded ditch magnet recovery on a daily basis through 10 January, when a cumulative total of 13.46 pounds had been recovered.

From 11 January through 22 January, no report of metal recovery was mentioned on the drilling report. Reports of metal recovery resumed on 23 January, with approximately one-third pound of recovery reported daily through 5 February. As of 30 January, total recovery reported was over 25 pounds of metal. As of 4 February, cumulative metal recovery reported was almost 28 pounds. From 30 December to 6 January, and 11 January to 22 January, it is unknown if metal was being recovered from the ditch magnets but not recorded on the morning reports.

Testimony from interviews revealed that, after the loss of control event, the rig was discovered misaligned by “several” degrees, the exact misalignment being unknown. Testimony and statements from the Contractor and the Operator indicate a wear bushing was used during drilling of this portion of the Well(s), and that the wear bushing was later found to have wear on one side. Testimony from other experts who observed the wellhead and burst casing after it was recovered and shipped onshore was that the wear pattern observed on the casing and casing head made it difficult to conceive of a wear bushing being systematically used.

Following the burst surface casing, the top of the casing, slip-on wellhead, and spool were recovered and returned to shore for analysis. Severe wear was found on the interior surface of the burst casing, which was heavily grooved in the area where the casing ultimately split.

Immediately above the casing, the spool was also found to have been heavily worn in an area in line with the vertical wear seen on the casing stub *(see Attachments 15, 16, 17, 18, and 19).*

Subsequently, the casing was sent for analysis to T H Hill Associates to perform a failure analysis of the 13 3/8 inch, 68-ppf K-55 casing joint. T H Hill reported a summary of their findings as follows in part:

"The 13 3/8" casing burst failure occurred because of eccentric wear of the casing internal surface. The wall thickness near the burst region was worn down to as low as 0.191" (nominal wall thickness is 0.480"). This reduced wall thickness significantly decreased the internal pressure capacity of the casing.

"Three dimensional non-linear finite element analysis (FEA) of the casing in the worn condition with pressure load applied to the internal surface indicated that a minimum threshold pressure of 2,300 psi was required to cause through-wall yielding of the casing joint. This internal pressure is the load at which the burst failure was most likely to occur.

"Chemical analysis, tensile testing, Charpy V-notch impact testing and hardness testing of the failed casing material indicated that the casing material met the chemical composition and minimum strength and toughness requirement of API specification 5CT. The casing failure was not caused by material deficiency."

A number of visual attachments were included with the T H Hill Associates report, three of which are included as *Attachments 20, 21 and 22***.**

The T H Hill report did not address the failure of the casing where it was welded to the slip-on wellhead. While the report concluded that the metal of the casing was to specifications, no analysis was reported on the portion of the casing that separated from the wellhead. Therefore, it is not known whether the weld to the wellhead failed or the metal of the surface casing parted at this point.

Findings – Failure to Test Surface Casing

A part of the regulatory requirements for drilling operations in the Gulf of Mexico includes the requirement to test casing for pressure retention every 30 days. The regulation at 30 CFR 250.423 states that surface, intermediate, and production casing will be tested to a minimum of 70 percent of its minimum internal yield and, if the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, the casing must be re-cemented, repaired, or an additional casing string must be run to provide a proper seal.

According to morning reports, the subject casing was successfully pressure tested to a pressure of 2,375 psi for 30 minutes upon its installation on 30 December 2003. A new test of the casing was required by regulations on 30 January 2004.

On 27 January 2004, at the request of EPL, the MMS granted a waiver of the requirement to test the surface casing. The waiver extended the date of the test from 30 January to 4 February 2004. The reason for the requested extension given in communication was that the total rotating hours on the string were low because of well control operations and rig repair.

On 4 February, an additional waiver of the requirement to test the casing, or extension of the previously granted waiver, was sought by the Operator and granted by MMS. The waiver was requested to enable the Operator to trip out of the hole and then conduct logging operations prior to running and setting the intermediate string of 9 5/8 inch casing. The number of actual rotating hours was the reason for asking for the waiver.

According to interviews, no discussion of the amount of metal recovered from the ditch magnet was made when the departure was requested. The information on metal recovery was not made available to MMS when the waiver was requested. Testimony was received that the Operator's personnel who requested the waiver were unaware of metal recovered from the ditch magnet.

Findings – Summary of a Previous Similar Incident

An incident that bears similarity to the loss of control on the A-3 BP occurred in late 1999 and was investigated by the Canadian Petroleum Safety Council, which published a report in June 2000 and issued Safety Alert #23-2000.

In that event, uncontrolled sweet natural gas was released through a rupture in the surface casing immediately below the casing head while operations were being conducted to circulate out a kick. The report stated the surface casing ruptured immediately below the casing head at a pressure that was approximately 20 percent of the new casing rating.

In that event, an independent metallurgical consulting company completed an inspection of the failed casing and reached the following conclusions among others:

- Internal pressure caused the catastrophic burst;
- No manufacturing or material defects were present that contributed to the failure;
- The wall thickness at the failure site had been reduced to 10 percent of original;
- The portion of the casing inside the casing head had been worn completely through;
- The casing head and lower BOP spool showed similar indications of wear;

The subject report concluded that the following were the main causes, among others, of the casing wear:

- The crews reported a slight rig misalignment existed.
- Despite the fact that significant casing wear was experienced, there were no obvious indications of wear to the rig personnel, i.e., no reported steel filings and/or excessive noise in the cellar while drilling.
- According to statements of the crews, the maximum rig misalignment was in the order of 6 inches.

Conclusions

The loss of control incident consisted of a series of independent events. All these events contributed to the incident. These events were as follows:

1) Pressure built up in the 9 5/8 inch by 13 3/8 inch casing Annulus after cementing of the 9 5/8 inch string;
2) The gauges on the driller's console failed to measure and record the pressure accurately;
3) In part, because of the false pressure readings, appropriate actions to mitigate the rising pressures were not initiated; and
4) The 13 3/8 inch casing failed catastrophically at pressures below design.

Cause of Loss of Control

Pressure on Annulus – Pressure reached the surface of the Annulus after cementing. This pressure ultimately caused the casing to burst.

Gauge Failure and Failure to Detect Annulus Pressure – Two gauges monitoring the buildup in the pressure on the Annulus of the casing strings erroneously indicated the pressure peaked at 1,265 psi and declined to 0 psi. A third gauge on the choke manifold checked immediately before the loss of control indicated the actual pressure on the Annulus in fact continued to rise above 3,000 psi. The two primary gauges failed simultaneously and returned a false reading of pressure decline.

Casing Wear and Failure – When exposed to 3,000 psi, the surface casing failed below its rated burst pressure of 3,450 psi because of heavy wear in the casing that was not detected. The wear reduced the burst rating of the casing from 3,450 psi to a laboratory tested 2,300 psi.

Failure to Detect Casing Wear – The casing wear was not detected and, as a result, no actions were taken to mitigate the pressure buildup because of the following:

(1) The metal recovery from the ditch magnets was reported irregularly on the morning reports (as provided to the investigatory panel) and was either not thought to be significant or was overlooked entirely by drilling management and supervisors.

(2) The required test of the casing that may have revealed the wear in the casing was postponed for 11 days when a waiver from the regulations requiring a 30-day test was requested and granted. The information concerning metal recovery was not included by EPL in the data used to request the waiver.

Probable Causes of Loss of Control

Pressure Build-up, Failure to Identify Potential Source from Logs – The pressure experienced at the surface, possibly as great as 3,000 psi, would usually indicate a source from a depth greater than 7,000 ft TVD, which would have been deeper than the calculated top of the cement used to set the surface casing. However, a shallow zone may have been gas productive in the Well and is the most likely source of the pressure. This zone was possibly charged by flow during a loss-of-hole incident in the predecessor A-3 well. The charging and pressure potential of this zone was evident in the logs of the A-3 BP but was overlooked during analysis of the log. Because of the failure to notice the pressure potential of the shallow gas zone, no adjustment in cementing program was made to isolate that zone from communication with the 9 5/8 inch by 13 3/8 inch annulus.

Gauge Failure and Pressure Monitoring of Casing, Hydraulic Leak – The gauges in the driller's console failed to record the proper pressure, giving a false reading. This failure was probably the result of a hydraulic leak in the control lines from the sensor to the gauges. This leak was not identified or recognized by personnel on the operation site.

Gauge Failure and Pressure Monitoring of Casing, Lack of Redundancy – Both of the gauges in the driller's console were tied into the same sensor and hydraulic system. No redundancy was available on the driller's console to check the pressures. However, a third gauge was available on the choke from a redundant sensor. This gauge was not monitored or checked by supervisory personnel until immediately prior to the failure of the casing.

Casing Wear – Misalignment of the rig probably contributed to the wear on the casing. The extent to which the Rig was misaligned, or when or how it occurred and was not corrected, is unknown. The extent to which casing wear bushings were employed during operations is unconfirmed. However, if they were employed, the severe casing wear experienced indicates that they were employed incorrectly, or were not regularly examined for indication of wear, or indications of wear were misinterpreted or ignored.

Possible Contributing Cause of Loss of Control

Inadequate Review or Oversight of Operations – Many of the contributing factors in the loss-of-control incident involve management or human oversights, or errors in monitoring data, systems, and events. These include

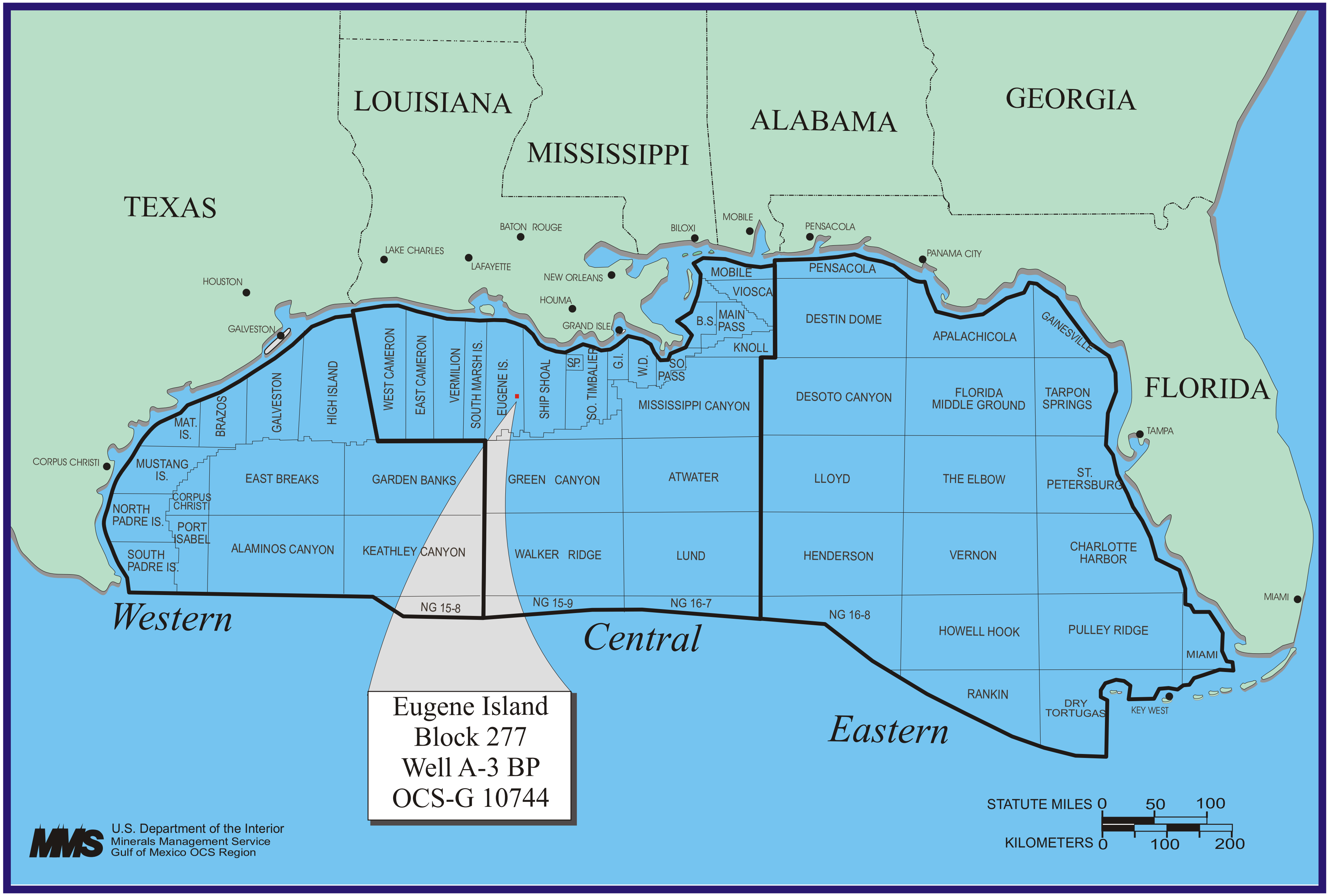
- Probable rig misalignment;
- Incomplete reports of ditch magnet recovery of metal;
- Failure to consider ditch magnet recovery when requesting and granting waivers to test the casing;
- Failure of the gauges because of the probable fluid leaks and common systems;
- The failure to monitor the choke gauge as a redundant check after significant unanticipated pressure appeared;
- Failure to recognize the gas productive nature of the sand at 5,300 ft while analyzing the logs from the A-3 vs. A-3 BP wells, and the resulting failure to adjust the cement program; and
- Failure to monitor and review properly the effect of drilling operations on the wear bushing.

.**Recommendations**

It is recommended that MMS issue a Safety Alert(s) emphasizing the following:

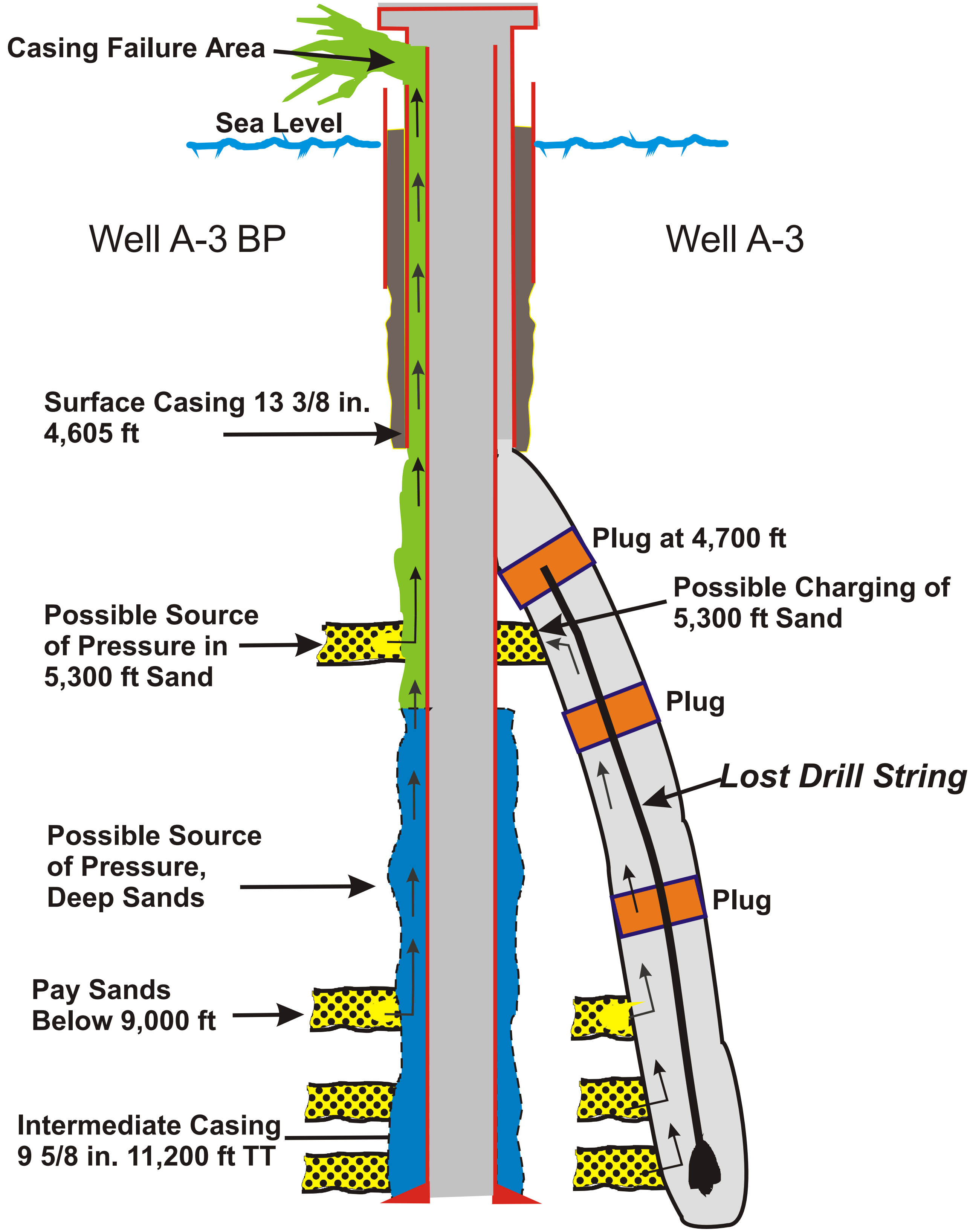
1) Careful attention to rig alignment and periodic checks of same;
2) Monitoring of ditch magnets and other evidence for wear in casing;
3) Redundant capacities, systems and/or sensors for gauges;
4) Frequent routine checks of hydraulic systems for gauges;
5) Detailed analysis of logs to identify unexpected pressure and productive zones, especially shallow gas; and
6) Pressure tests of casing at or near the required dates.

Attachment 1



Location of Lease OCS-G 10744, Eugene Island Block 277, Well A-3 BP.

Attachment 2



Schematic: Eugene Island Block 277 Well A-3, Well A-3 BP.

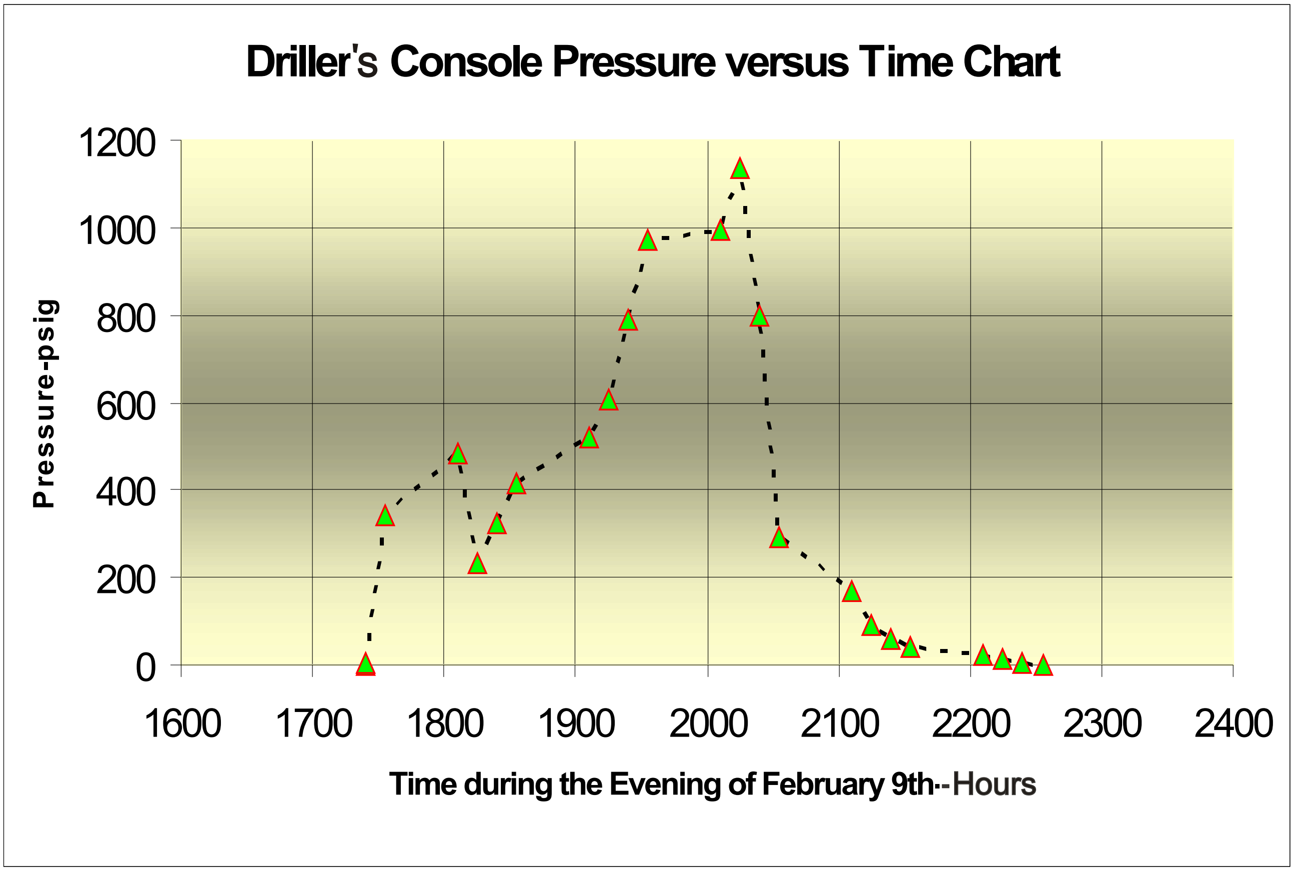
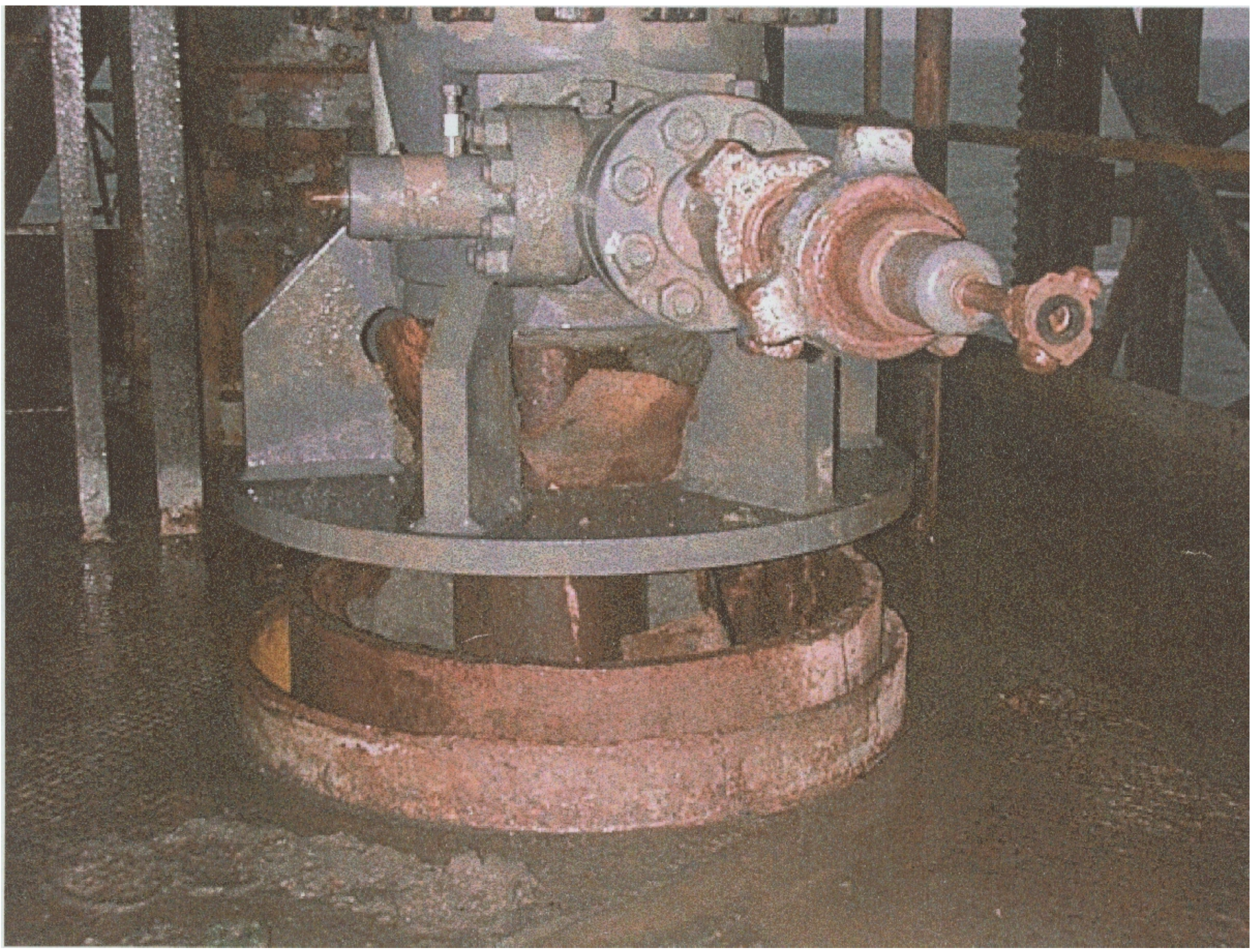


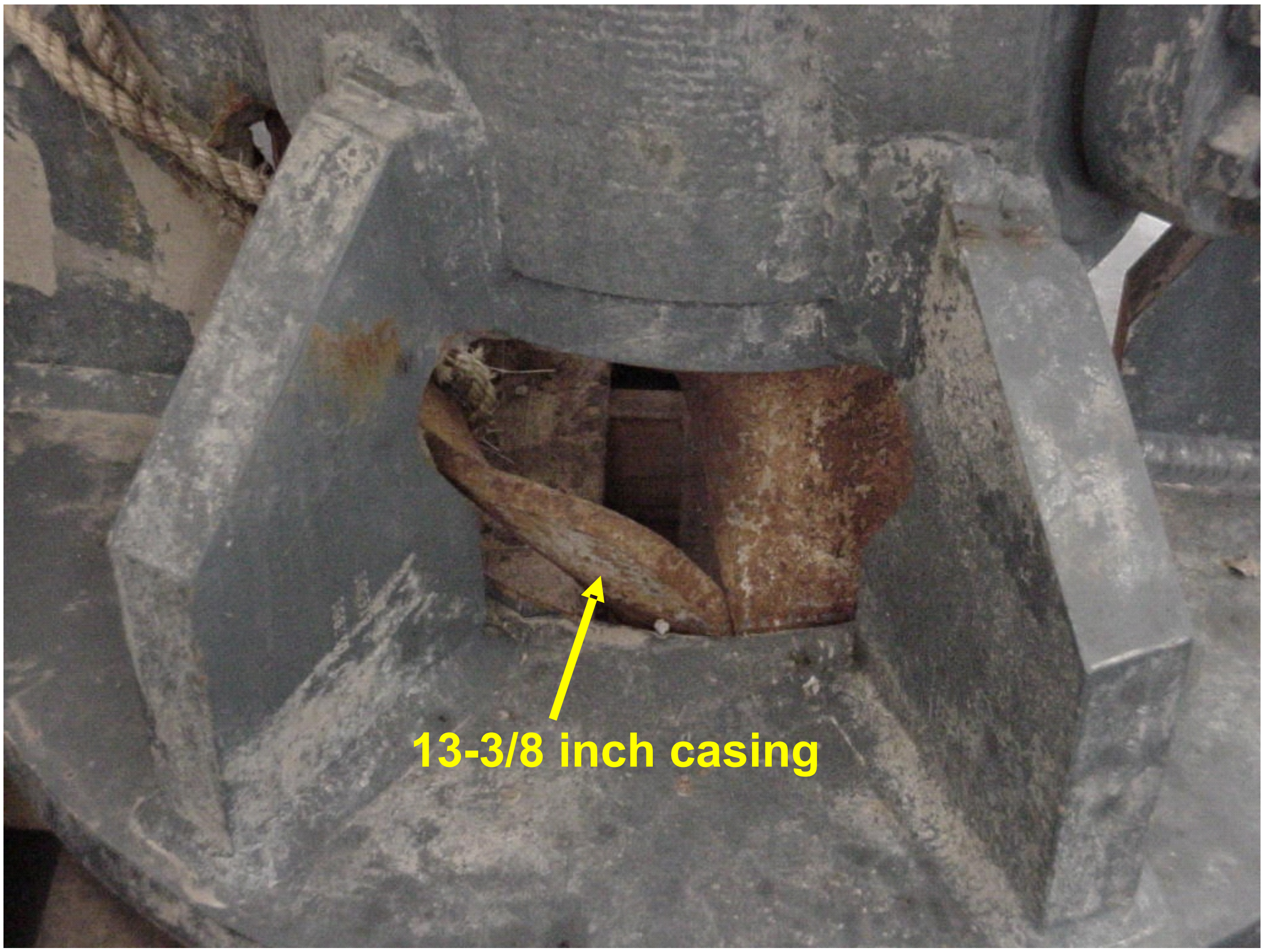
Chart: Driller’s console pressure versus time chart.

Buildup of debris on platform after incident.

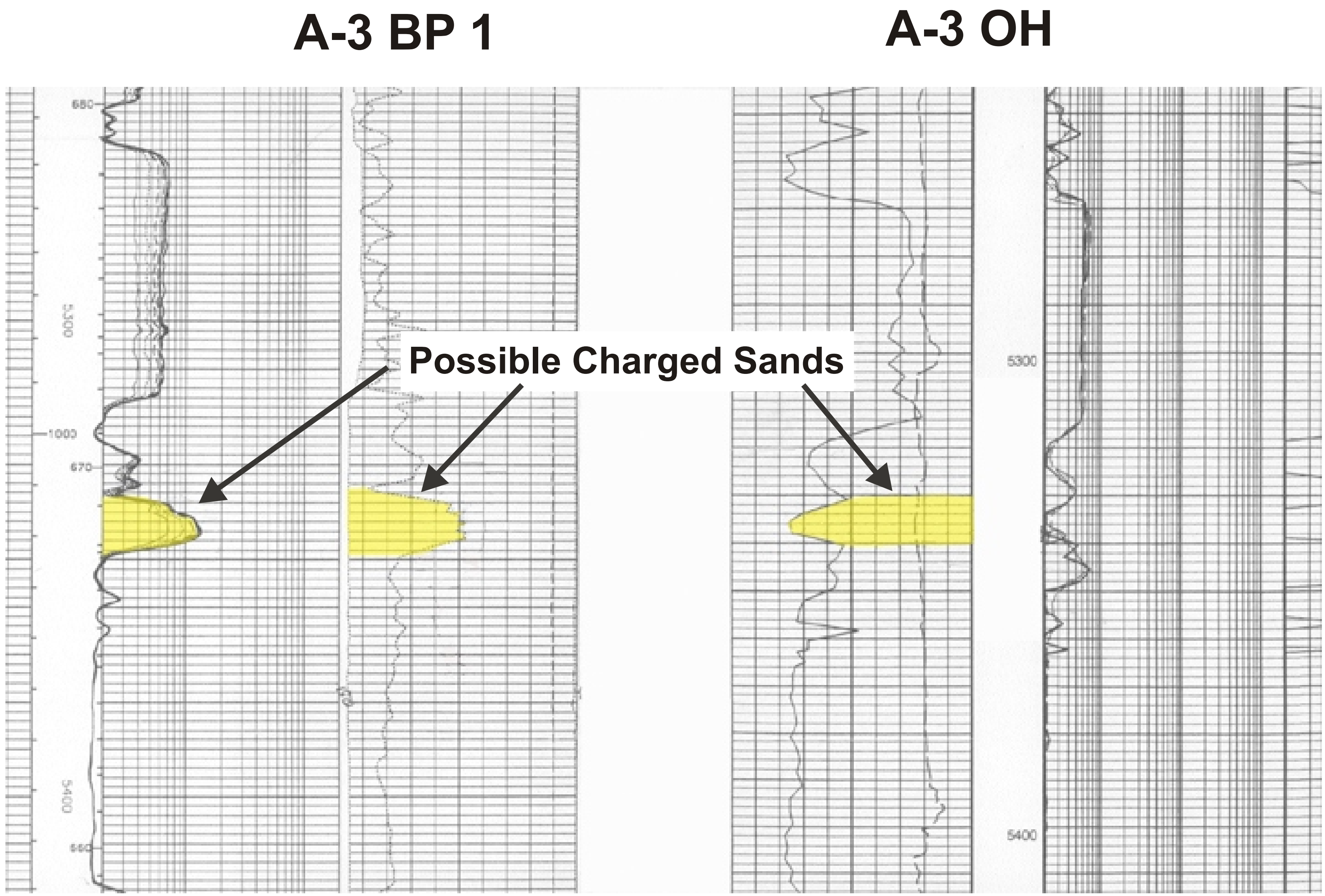
Buildup of debris on platform after incident.



Wellhead: After the incident, showing parted casing.

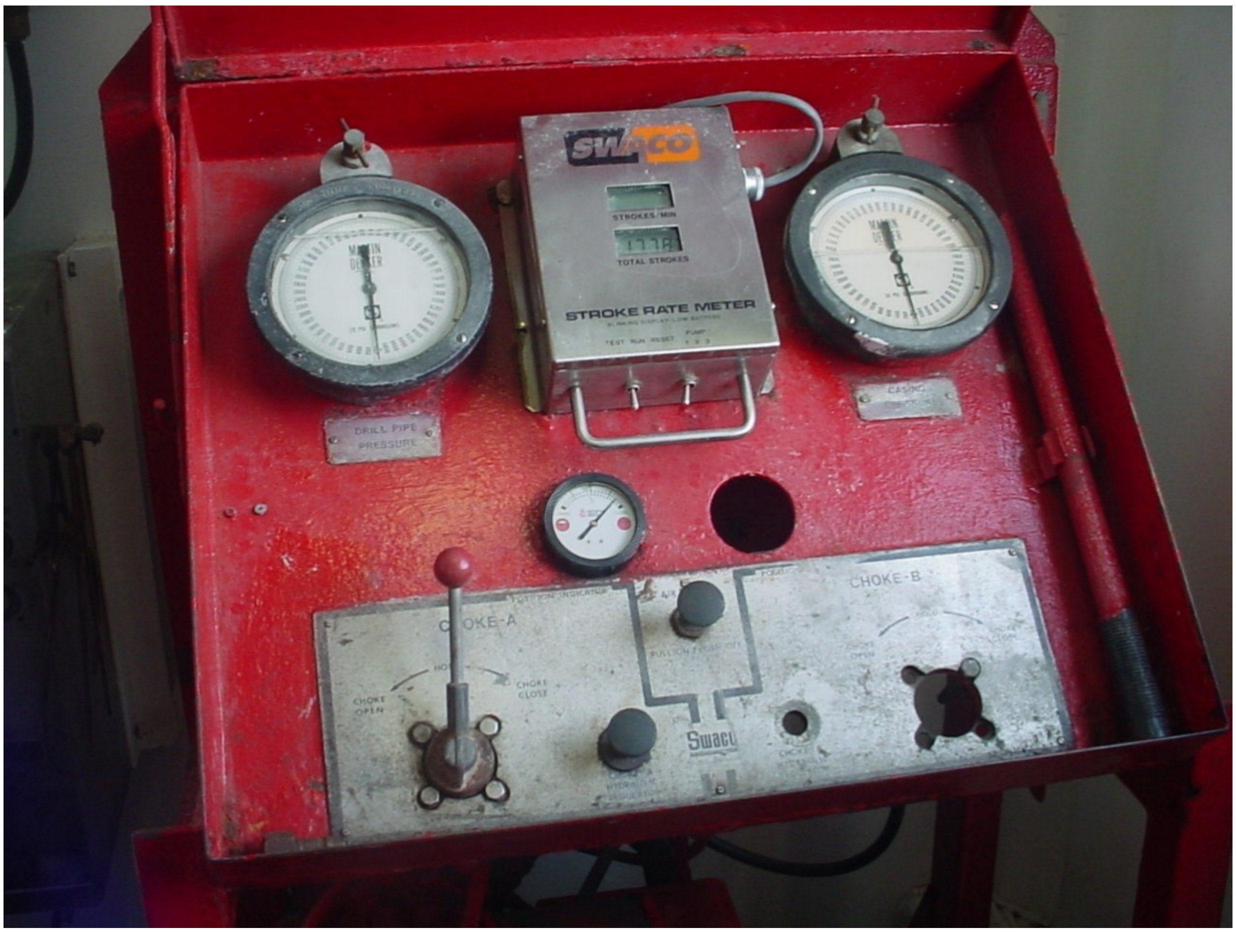


Damaged 13 3/8 inch slip-on wellhead (SOW) and casing.



Logs on Well A-3 and A-3 BP showing possible charged sands.

Attachment 9



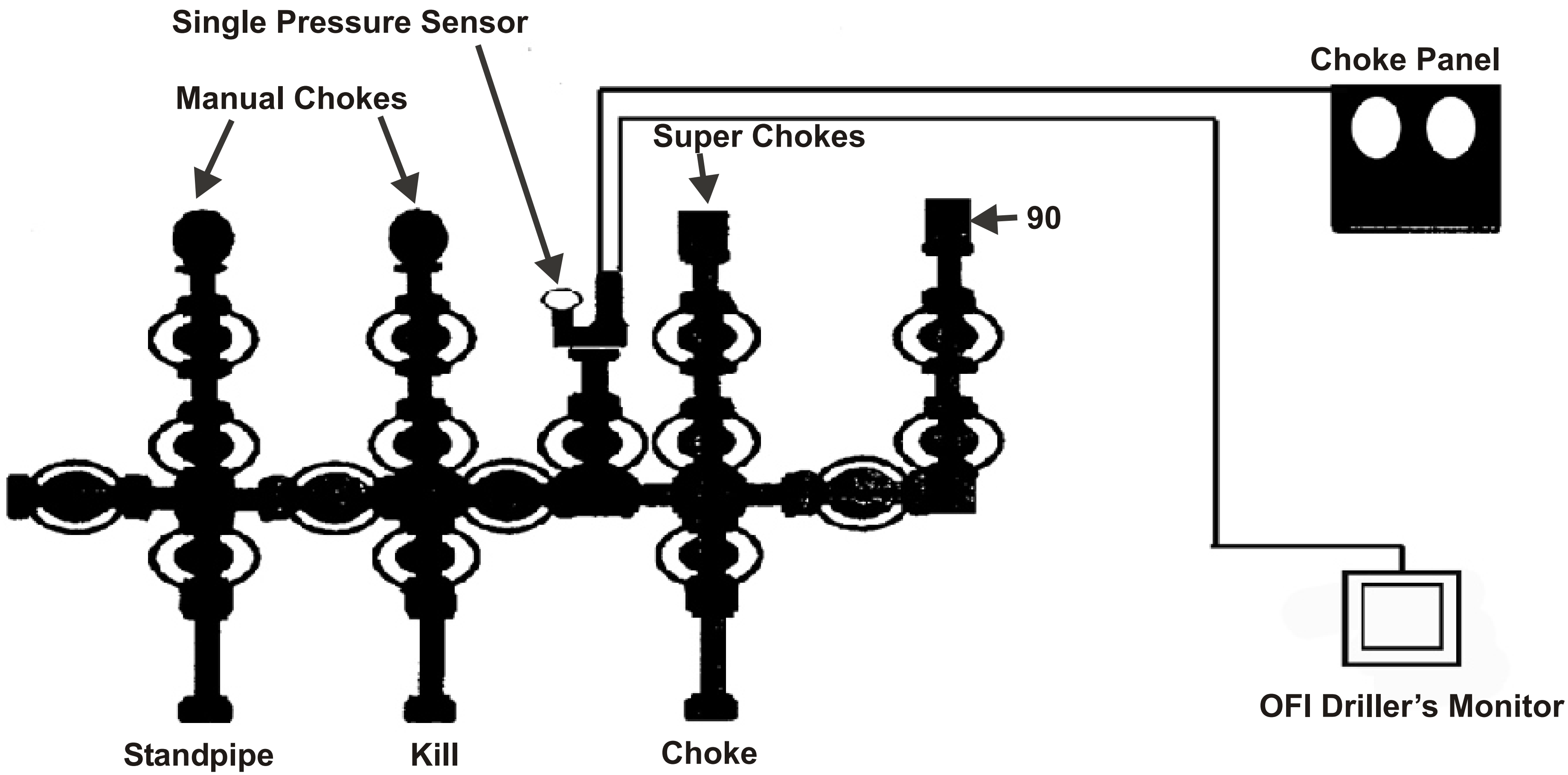
Driller’s console gauges.

Attachment 10

Connections for gauges on choke manifold.

Attachment 11

Hydraulic line to driller's console gauges and reservoir, after incident.



Schematic: Setup of gauges and hydraulic system.

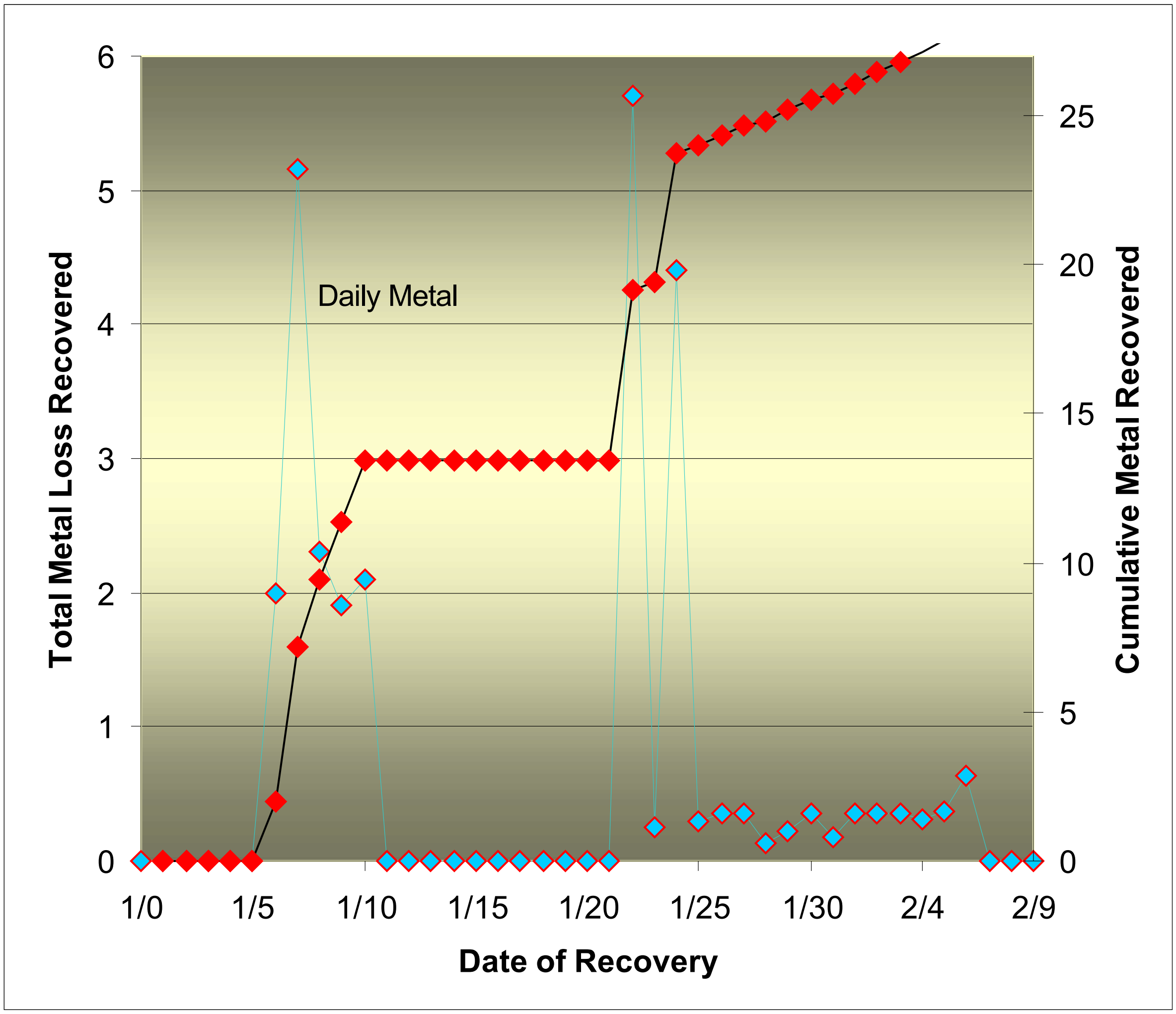
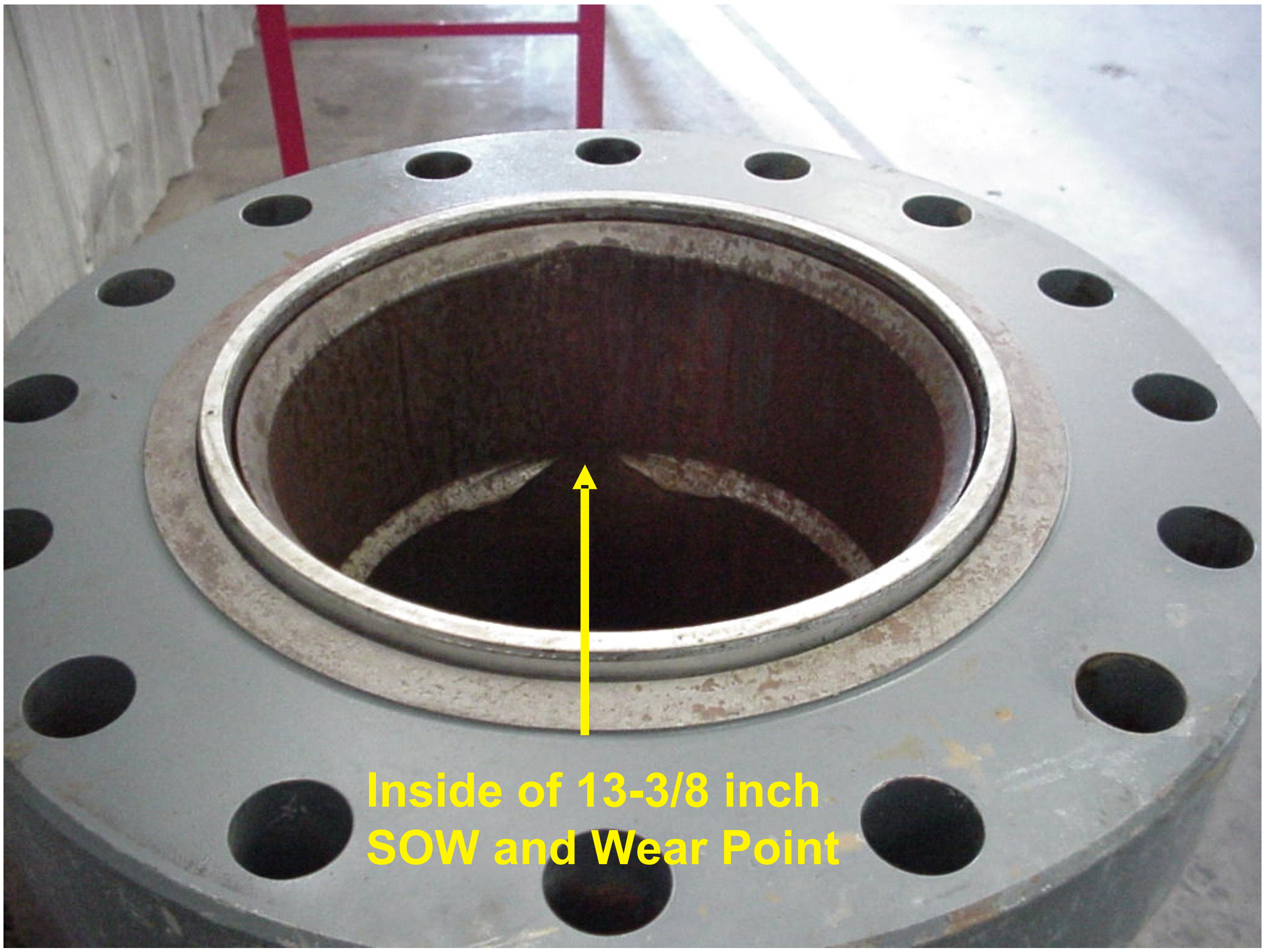
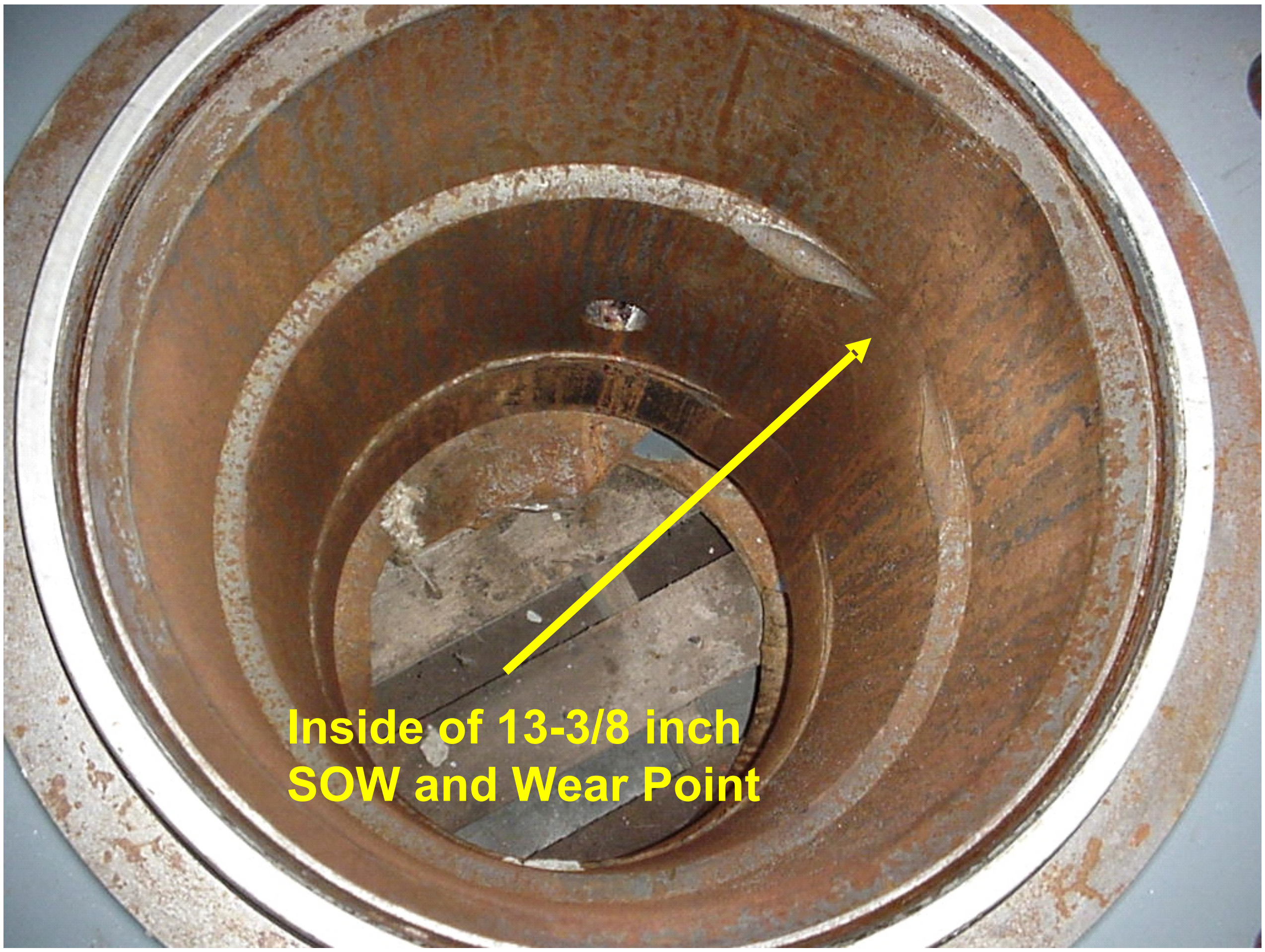


Chart: Ditch magnet metal recovery versus time.

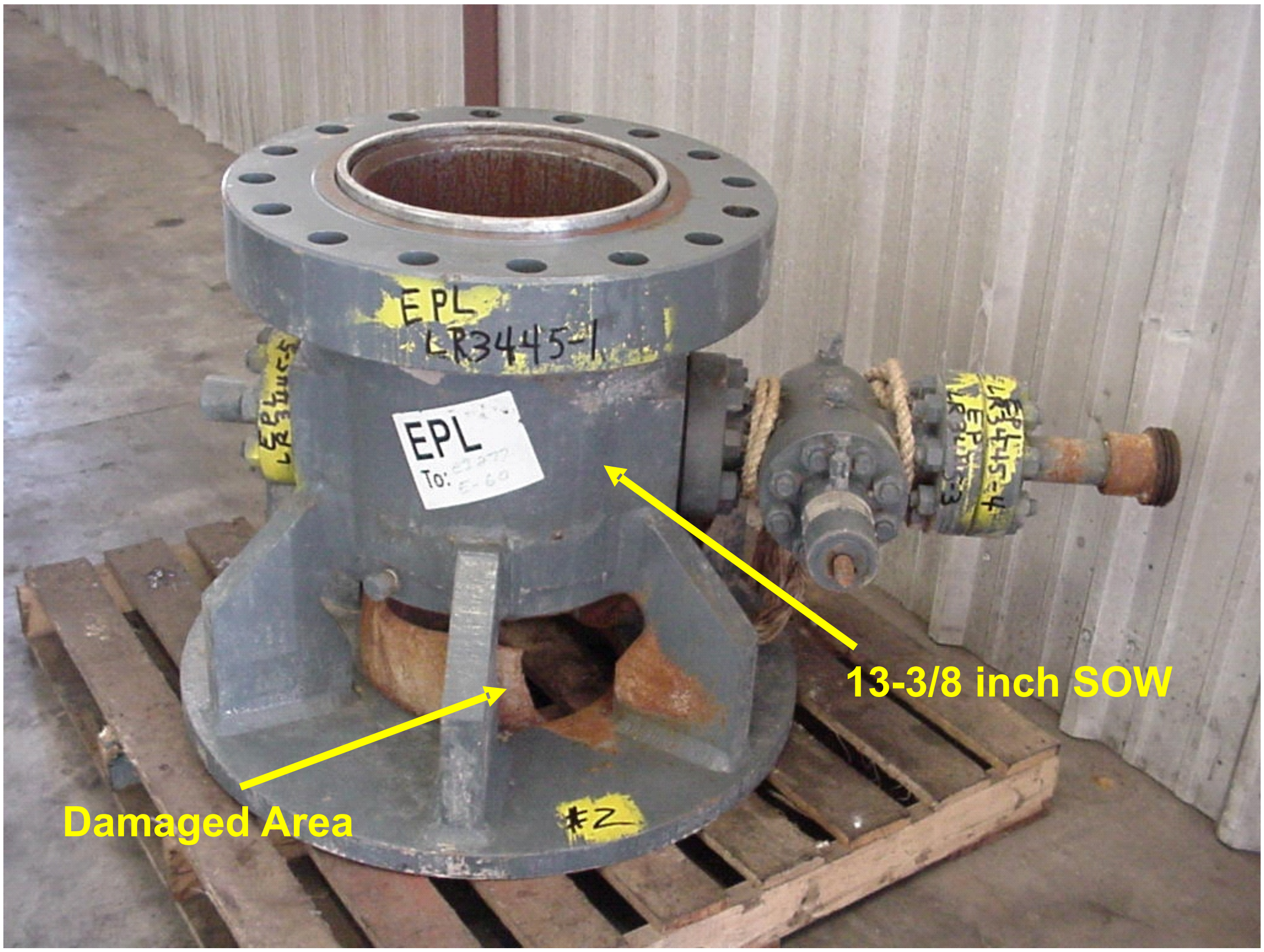
Attachment 14



Worn and damaged 13 3/8 inch SOW.



Worn and damaged 13 3/8 inch SOW, inside details.

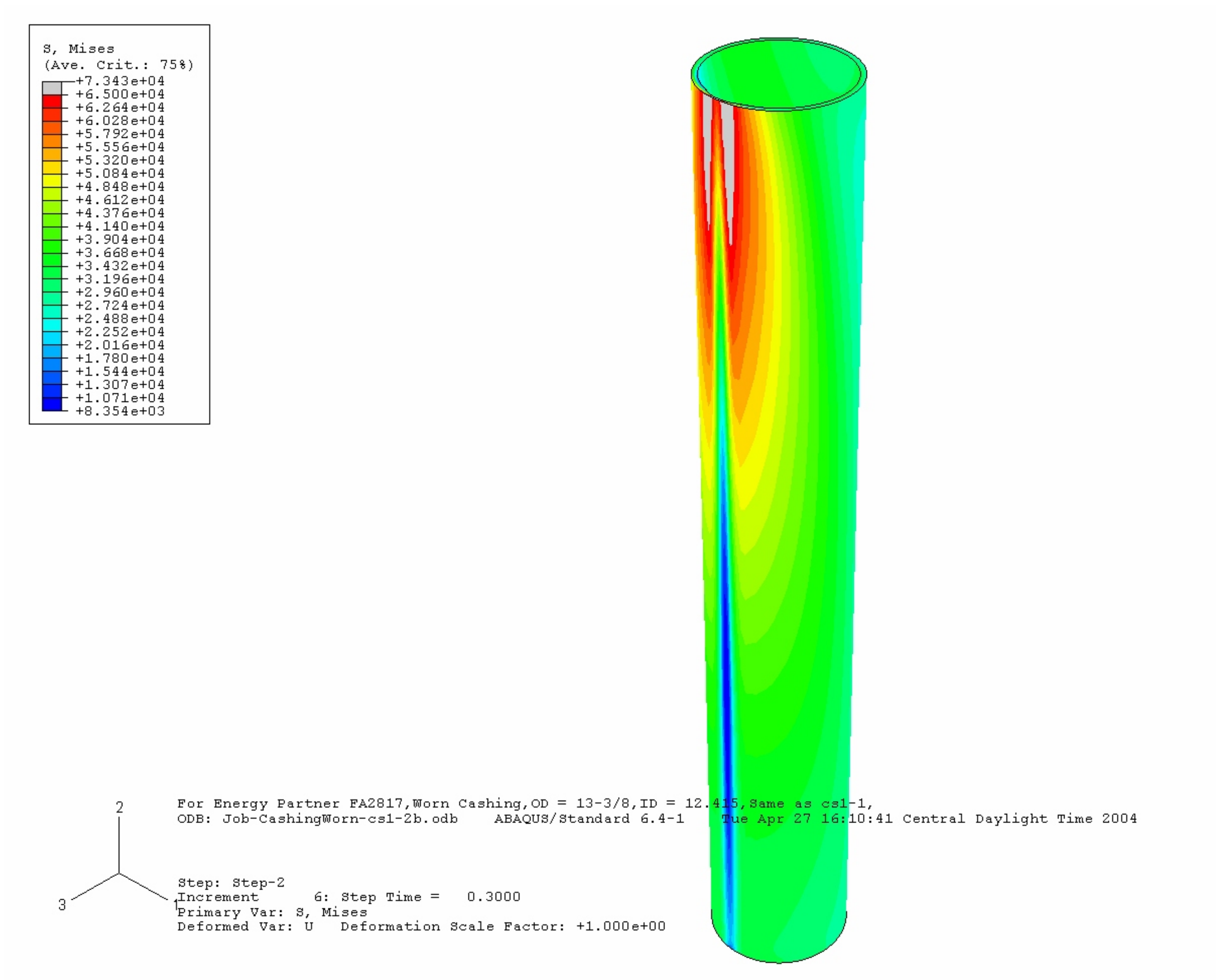


Damaged SOW and top of 13 3/8 inch casing.

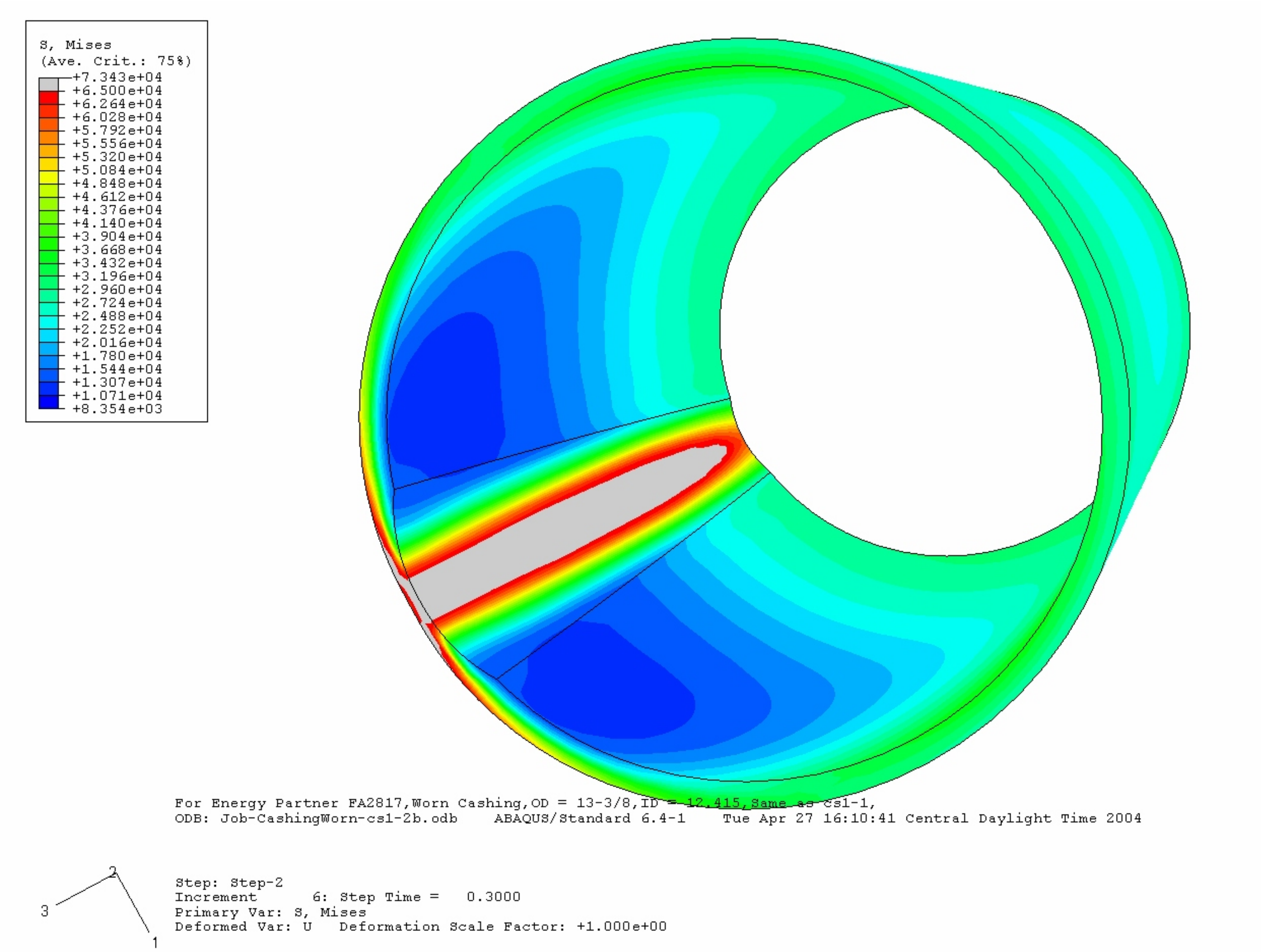
Split, ballooned, and parted 13 3/8 inch casing.

Attachment 18

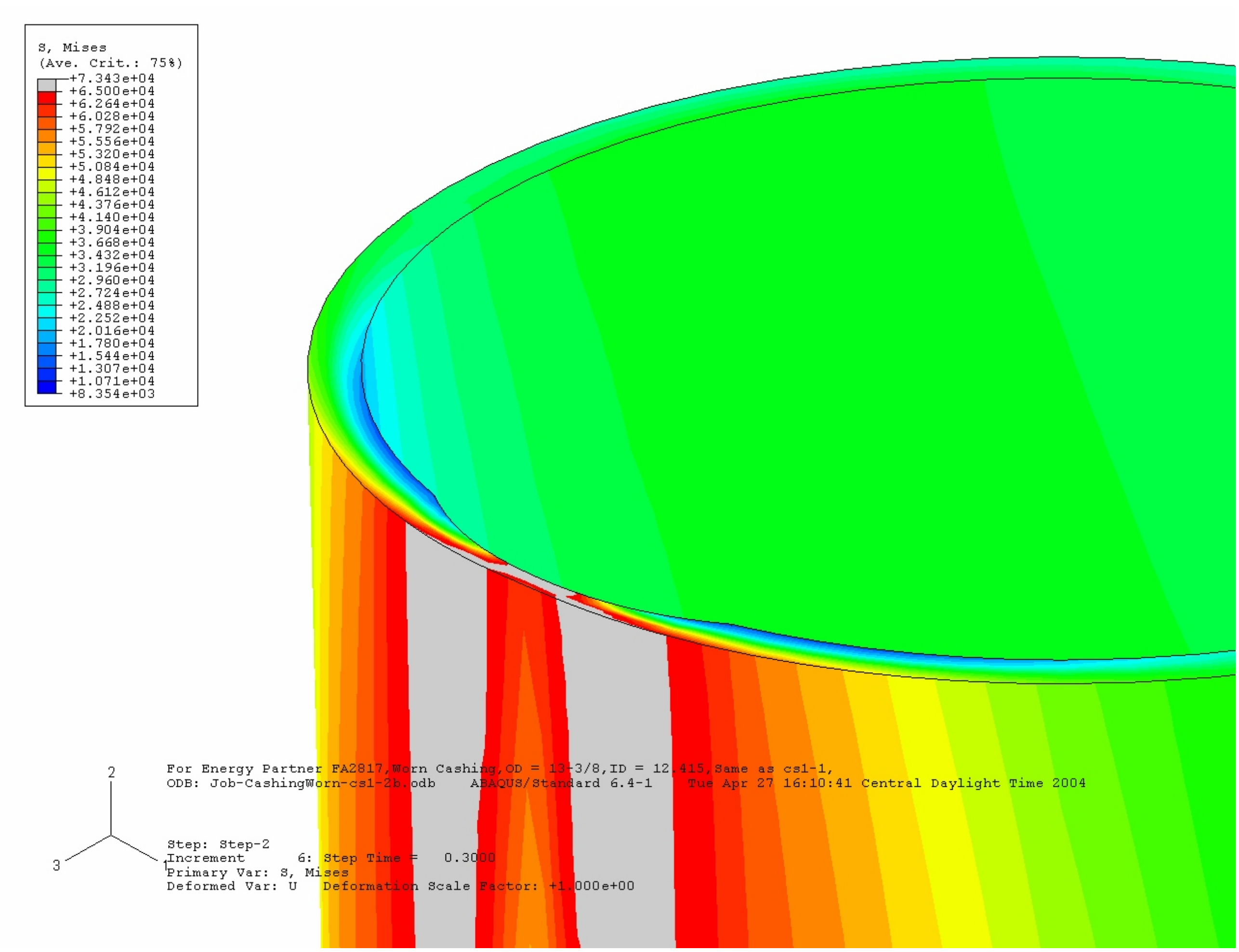
Damaged casing.



Stress distribution along the outside surface of the worn casing [From T. H. Hill].



Stress distribution along the inside surface of the worn casing [From T. H. Hill].



Internal pressure of 2,300 psi produced through-wall yielding of the worn casing joint [From T. H. Hill].

MMS Securing Ocean Energy &
Economic Value for America

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.