

**Investigation of Loss of Well Control
Eugene Island Block 107, Well B-1 Workover
OCS-G 15241
8 March 2003**

**Gulf of Mexico
Off the Louisiana Coast**



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

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Jack Williams – Chair
Tom Basey
Marty Rinaudo

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Investigation and Report

Authority

In March 2003, the Pride Offshore Drilling, Inc. (hereinafter referred to as “Contractor” or “Pride”) jack-up rig *Pride New Mexico* (hereinafter referred to as the “Rig”) was engaged in workover operations for Anadarko Petroleum Corporation (hereinafter referred to as “Operator”) on Eugene Island Block 107 Well B-1 (hereinafter referred to as the “Well”). The Rig was in place next to the Eugene Island “B” platform (hereinafter referred to as the “Platform”). Workover operations were being conducted with the Rig cantilevered over the Platform.

After the tree had been removed and the blowout preventer (BOP’s) installed, during preparations to clean out the hole, high pressure was abruptly observed to be rising on the tubing and production casing annulus. When the pressure reached approximately 6,150 pounds per square inch (psi), the Cameron (hereinafter referred to as “Manufacturer”) manufactured tubing hanger and approximately 600 feet of tubing were suddenly ejected from the well through the BOP’s, and subsequently the well flowed out of control through the BOP stack. Attempts to control the well with the BOP’s were unsuccessful because of tubing lodged across the BOP stack.

The event occurred 8 March 2003 at approximately 2245 hrs on the surface location in Operator’s Lease OCS-G 15241, Eugene Island Block 107, 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 27 March 2003, the following personnel were named to the investigative panel:

Jack Williams, Chairman – Office of Safety Management, GOM OCS Region

Tom Basey – Lafayette District, Field Operations, GOM OCS Region

Marty Rinaudo – Lafayette District, Field Operations, GOM OCS Region

Procedures

On the following dates, personnel from MMS met to review collected data, interviewed personnel, and/or received laboratory and written responses to requests for data on the subject loss of control of Well B-1.

- 10 March 2003, personnel from the MMS visited the site of the incident to assess the situation.
- 14 May 2003, representatives of the Operator met with Lafayette District personnel to review the incident.
- 22 May 2003, members of the Panel met to analyze data and review events.
- 29 August 2003, members of the panel received and/or collected Operator documentation regarding the loss of control event.
- 23 January 2004, members of the panel reviewed the incident by telephone with personnel of the Operator.
- 30 January 2004, members of the Panel requested and received additional photographic and other documentation on the event and reviewed the company report on the incident.
- 5 February 2004 and 4 March 2004, members of the panel interviewed Operator personnel and the Manufacturer's Director of Engineering.
- 2 September 2003, 28 January 2004, 6 February 2004, and 4 March 2004, Operator personnel answered specific questions by e-mail.
- 12 March 2004, Tele-interviews were held with Operator's Rig supervisory and investigatory personnel, and Manufacturer's Director of Engineering.

Other information was gathered at various times from a variety of sources. This information included the following reports and statements:

- Daily Drilling Reports, 3 March 2003 – 10 April 2003 for Well B-1;
- MMS production and test records of Well B-1;
- Operator's Review of Original Intervention Program;
- Operator's Plan of Operation, Well B-1 workover;
- Contract engineering review of original procedure;
- Operator's Application for Permit to Modify, Well B-1 workover;
- Operator's EI-107 Well B-1 Incident Summary;
- Operator's Barrier Review;

- Manufacturer's Safety Alert, and drawings;
- Schematics of Well B-1, including wellhead and hanger;
- Interviews with Operator drilling management and engineering and operational personnel, Contractor drilling management, operational supervisors, and operational personnel, Manufacturer's Director of Engineering;
- Operator's photographic record of equipment and incident;Contract engineering metallurgical and failure analysis;
- Contract engineering tensile and hardness testing results;
- Written summary of events by Operator's personnel;
- Notes and reports, Manufacturer's on-site representative;
- Transcript of testimony re: casing failure, Mobile Bay, Alabama Oil and Gas Board.

Introduction

Background

The surface and bottomhole location for Well B-1 is within lease OCS-G 15241, which covers approximately 5,000 acres and is located in Eugene Island Block 107 (EI-107) Gulf of Mexico, offshore Louisiana (*for lease location, see Attachment 1*). In 1995, the lease OCS-G 15241 was issued to Norcen Exploration and Production, Inc. (hereinafter referred to as “Norcen”). Subsequently, in 1998 the lease was transferred to Union Pacific Resources who became operator of record following the acquisition of Norcen. In July 2000, Union Pacific Resources was acquired by Anadarko Petroleum Corporation (hereinafter referred to as “Anadarko” or “Operator”), who became operator of record.

The B-1 Well was originally drilled as a straight hole by Norcen in 1996 and completed as a single completion in the “P” sand with perforations from 17,630 ft to 17,662 ft and from 17,678 ft to 17,694 ft (*see Attachment 2 for schematic of Well, pre-workover*). The Well initially tested at a rate of approximately 25 MMcfpd, 305 barrels of condensate or oil per day (bcpd), with a flowing tubing pressure (FTP) of 7,300 psi on a 60/64-inch choke. Production commenced on 07 June 1996.

At the time of the proposed workover, the “P” sand had produced significant quantities of gas under a general pressure depletion drive. Bottomhole pressure (BHP) had declined to an estimated 2,500 psi [2.7 pounds per gallon (ppg) equivalent mud weight (EMW)] with a maximum shut-in tubing pressure (max SITP) estimated at 1,250 psi. Other potentially productive sands or re-completion targets were isolated behind unperforated, cemented, 5½ -inch, 26 pounds per foot, Q-125 production casing. These included the following:

Sand	Depth (ft)	BHP (psi)	EMW (ppg)	Max SITP (psi)	Temp °F
“O” sand	17,514-580	est 13,900	15.3	est 11,225	293
“F” sand	16,350-370	est 12,850	15.1	est 10,938	283
“E” sand	16,288-306	est 12,800	15.1	est 10,360	282
“B” sand	15,690-700	est 12,400	15.1	est 10,065	277
“A” sand	15,340-350	est 12,100	15.1	est 9,837	274

Just prior to the workover, according to Company records, the B-1 was flowing at a rate of 3.8 MMcfpd, 20 bcpd, and 15 barrels water per day (bwpd). The well had sustained production casing pressure of 1,200 psi attributed to tubing leaks. Several attempts to isolate these leaks by installing pack-offs in the tubing had failed.

Brief Description of Loss of Well Control

The objective of the workover was to replace parted tubing and return the well to production of gas from the "P" sand. The "P" sand had been pressure depleted to a gradient of approximately 2.7 pounds per gallon (ppg) by seven years of production. Because of the under-balanced, depleted pressure of the formation, and the need to retain productivity with minimum formation damage, the workover employed light-weight fluid. Workover fluid losses were to be controlled by spotting gel lost circulation material (LCM) pills.

During the workover of the Well, after the tree had been removed and the blowout preventer (BOP's) installed, preparations to begin recovering the tubing down to a suspected break or part at about 1,900 ft were initiated. High pressure was then unexpectedly observed to be abruptly rising on the tubing and production casing annulus. When the pressure reached approximately 6,150 pounds per square inch (psi), the tubing hanger and approximately 600 feet of tubing were suddenly ejected from the well through the BOP's. Subsequently, the well flowed out of control through the BOP stack. Attempts to control the well with the BOP's were unsuccessful because of the tubing lodged across the BOP stack. The BOP stack was not equipped with shear rams.

The Rig was subsequently evacuated and the Well then flowed uncontrolled for between one and four hours, when flow ceased and the Well bridged over. Normal well-control operations were then commenced and the Well was subsequently controlled, the perforations isolated, and the Well re-completed to a shallower sand. No injuries were sustained by the crew and no significant damage was sustained by the Rig. From calculations by the Operator, only a portion of the "O" Sand would have been open to sustained flow after the initial casing blowdown. Therefore, the Operator estimates approximately 1 MMcf and 10 barrels of condensate were blown out of the Well with the uncontrolled gas flow, most of which is assumed to have spilled into the ocean.

According to testimony, as a result of the spill, a light, broken, streaky sheen measuring approximately 2 miles by ½ mile was visible the next morning. Following the incident, the Fast Response Unit (FRU) motor vessel *Bastin Bay* from Clean Gulf Associates was mobilized and arrived approximately 10 hours after the loss of control. No recoverable oil was on the water and the sheen fully dispersed or evaporated by noon. Pollution control operations by the FRU were not deemed feasible and were not commenced. However, the *Bastin Bay* remained on site for approximately one week on stand-by in case additional problems developed during well-control operations.

Findings

Well History (from Operator reports)

1996 – Well B-1 drilled and completed by Norcen as a single completion in the “P” sand. Production was initiated 07 June 1996, Norcen as operator.

Apr 1998 – Norcen acquired by Union Pacific Resources.

July 2000 – Union Pacific Resources acquired by Anadarko Petroleum Corporation.

02 Nov. 2000 – Shut-in casing pressure (SICP) was found, MMS issued Operator an Incidence of Non-Compliance (INC) on 27 April 01 for the SICP.

11 Dec 00 – Caliper run through tubing of the Well, indicated general corrosion and isolated pitting in the production tubing. The most severe corrosion was located from 0 ft to 3,000 ft, leaks were not definitively identified.

24 Jan 01 – The leak in tubing was identified at 1,221 ft using wireline.

26 Jan 01 – A through-tubing pack-off was installed 1,207-1,240 ft, SICP bled to 0 psi.

08 Mar. 01 – Casing pressure was again found on Well B-1.

01 May 01 – Wireline investigation of source of annulus pressure identified tubing leaks at 11,314 ft – 11,335 ft. Another pack-off was installed by wireline in the tubing across the leaks. SICP was found to be steady at 692 psi and would not bleed off.

20 Aug 02 – SICP found to have increased from 692 psi to 1,188 psi.

15 Dec. 02 – After pulling the pack-off at 1,231 ft, wireline investigation identified possible parted tubing at approximately 1,900 ft.

24 Feb. 02 – Workover plan submitted to the MMS on 18 Jan. 03, approved.

05 Mar. 03 – Rig moved on site for workover.

Significant Issues for the Workover

According to Operator documents, the plan for the workover considered a number of specific problems that complicated operations. The main problem to be dealt with was the depletion of the “P” sand reservoir from the original bottomhole pressure of approximately 14,000 psi to approximately 2,500 - 2,800 psi, or 2.7 pounds per gallon (ppg) equivalent hydrostatic fluid pressure. As the lightest workover fluid available was 8.5 ppg potassium chloride (KCl), the over-balance of a full column of fluid at the perforations of the “P” sand was expected to be 5,300 psi or +5.8 ppg.

Secondly, the existing tubing was in poor condition primarily because of suspected carbon dioxide (CO₂) corrosion, which was thought to have caused the extensive pitting and leaks above 3,000 ft. The caliper log of the well run in January 2001 indicated only moderate damage below 3,000 ft, but a through-tubing pack-off had also been set across a suspected tubing leak at 11,314 ft. Additionally, after the pack-off (s) had been set, the tubing was found to be possibly parted at approximately 1,900 ft, where the most serious damage to the tubing had been identified by the caliper log. Because of the parted tubing, the pack-off(s) at 11,314 ft could not be retrieved and a through-tubing plug could not be set to isolate the under-balanced “P” sand during the initial stages of tubing retrieval.

Thirdly, the “P” sand, though extensively pressure depleted, retained significant reserves and flow capacity. Therefore, minimizing formation damage was an important goal during the workover to maintain the productivity of the reservoir. This required careful use of lost circulation materials (LCM) in the fluid during the workover. The possibility that the overbalanced hydrostatic pressure of a full column of workover fluid could exceed fracture gradient of the “P” sand was also analyzed. In such a situation, uncontrolled fluid loss to the “P” sand, followed by influx of gas, could place well control at risk during the workover. But the parted tubing, packoffs, and the existence of other possible holes in the tubing made precise placement of LCM pills and accurate workover fluid calculations difficult to predict.

Finally, future completion zones had been isolated behind cemented 5½-inch casing in the B-1 Well, all of which were pressured in a range from 13,900 psi BHP to 12,100 psi BHP. These zones were significantly higher pressure than the depleted “P” sand. Tubing leaks and communication with the wellbore annulus had possibly already led to a loss of an unknown amount of the original 13.7 ppg inhibited CaBr₂ packer fluid to the pressure-depleted “P” sand, thus reducing the inside-casing hydrostatic pressure. The inside/outside casing pressure differential (the difference between inside-casing hydrostatic plus “P” sand communication pressures vs. “O” sand alternate zone pressure) could possibly approach 10,000 psi. This led the Operator to spend time reviewing the casing integrity and the barriers to the higher pressure gas migration, or intrusion, from the alternate sands. The Operator concluded that the barriers to any higher pressure migration, such as the casing cement sheath, casing integrity, and workover fluid, were sufficient to contain the higher pressured alternative sands.

Preparation of the Well Plan

The preparation of the well plan included actions to mitigate the problems expected to be encountered. The key elements of the well plan, as submitted to the MMS, are summarized below.

1. Shut-in the well, record SITP, close the surface controlled subsurface safety valve (SCSSV), bleed down pressure. Mobilize the Rig, rig up (RU) on tree connection with 10,000 (10K) psi manifold and circulating system, test system, pump in to equalize pressure across the SCSSV and lock SCSSV open with hydraulic pressure.
2. RU slickline, lockout SCSSV. Pump down annulus with 8.6 potassium chloride (KCl) workover fluid to begin killing well. If annulus is successfully filled, or if losses to the depleted “P” sand are acceptable after using a calcium carbonate LCM pill, install a back-pressure valve in the tubing hanger, nipple down (ND) the tree, nipple up (NU) a blowout preventer (BOP) stack.
3. Fish 2 7/8-inch production tubing using normal workover methodology. Clean hole to parted tubing and obstruction at 1,900 ft. Use overshot, wash over and make outside cut at 1,960 ft. Recover tubing and obstruction. Clean out tubing to 4,500 ft, below the suspected CO₂ pitting. Conduct normal workover/re-completion operations to clean the hole to the through tubing installed pack-off at 11,314 ft. Wash over and recover tubing and pack-off. Pull remaining tubing, mill out packer at 16,100 ft. Log Well, complete

as per results of log, with a new packer installed above the last known productive sand, the “A” sand, at about 15,100 ft.

4. Install 15,000-psi tree, RU coil tubing, acidize “P” sand to restore production and remove effects of LCM pills. Jet Well in with coil tubing and nitrogen, rig down (RD), demobilize Rig.

Workover Activities, Through Loss of Control

(From drilling morning reports, Operator documents, interviews, and Operator Accident Review and Manufacturer representative notes)

Activities to Advent of High Pressure at Surface

6 March – Moved Rig on location, rigged up.

7 March – Took on 9.6 ppg KCl fluid, cut to 8.6 ppg and filter. Began to kill 1,100 psi on both tubing and annulus by pumping 85 barrels (bbl) 8.6 ppg KCl workover fluid down the annulus. Pressure dropped to 0 psi, stayed static, monitored for 45 min. Pumped 20 bbls down annulus, well went on vacuum. Rigged-up wireline and attempted to lock out SCSSV.

Pressure of 500 psi found on both tubing and annulus, killed by pumping 200 bbls 8.6 ppg KCl down tubing, no returns on annulus. At this point, Well was taking 32 barrels per hour (bph) through-tubing. Losses in annulus were unknown. Well took 600 bbls of fluid on gravity feed. Shut-in tubing pressure (SITP) and shut-in casing pressure (SICP) were 0 psi after pumping. Pumped 30 bbl 11.5 ppg solids-free LCM pill and 65 bbl 8.6 ppg KCl chaser, gravity feeding annulus, unable to fill up.

8 March – Manufacturer’s representative replaced hold-down lock screws (pins) on tubing spool with 0 psi pressure on annulus and tubing. Re-torqued all 12 hanger hold-down pins, measured to ensure they were in the “in” position. Pumped open the SCSSV, installed test stem in back pressure valve (BPV), ND tree, NU and tested 10,000-psi risers and BOP’s. Some fluid back flow was observed.

Activities after Advent of High Pressure at Surface

9 March: 0600 hrs – 1800 hrs. – Prior to testing BOP's, found 1,900 psi on annulus, presumed to be gas migration and expansion. Bled pressure off until fluid hit surface, lowering pressure to 200 psi. Tested BOP's, monitored annulus pressure, pressure rose to 3,000 psi and stabilized at 2,700 psi, gas. Attempted to bleed off pressure, bled about 2 bbls fluid, closed the annulus. Manufacturer's representative re-tightened all hanger pins, some moving only 1/8 turn, all measuring full "in" position.

1800 – 2100 hrs – Begin attempt to circulate down tubing holding 200+ psi over-balance pressure on annulus and circulate fluid around.

2100 hrs – 2230 hrs – Pumped down tubing, established shut-in tubing pressure (SITP) to be 4,100 psi, same as casing pressure. Began pumping at ½ barrels per minute (bpm) and observed no increase in annulus pressure. Increased rate to 1 bpm, annulus pressure climbed to 4,300 psi and stabilized. Cracked choke to vent gas, began getting fluid returns. Monitored returns, got full returns, pressure began to fall on annulus. At 35 bbls pumped, annulus pressure read 3,500 psi. At 45 bbls pumped, annulus pressure fell to 3,300 psi and with 50 bbls pumped, annulus pressure was 3,200 psi. When 60 bbls had been pumped, annular pressure stabilized at 3,125 psi. Shut in well at 2224 hrs.

2245 hrs – During consultations on the next step, pressure on annulus and tubing rose to 5,800 psi in 21 minutes, and continued to climb to 6,150 psi.

Loss of Control and Abandonment of the Rig

2245 hrs - Pressure on the hanger rose above 6,000 psi. During attempts to control pressure by bleeding, and during preparations to swap valves to lubricate annulus, the hanger and tubing attached to it were suddenly ejected from the wellhead. The ejection was followed by an uncontrolled flow of gas, water, condensate, blowing as high as the crown block, according to testimony. The hanger was later found lodged near the crown block within the derrick (*see Attachment 3*). Approximately 600 ft of 2 7/8-inch production tubing and the surface controlled subsurface safety valve (SCSSV) were found to be wrapped around and through the derrick (*see Attachments 4-6*).

When the blowout occurred, the personnel on the rig floor were the night “company-man,” night “tool pusher,” and the driller. No personnel were in the derrick. The drill floor personnel activated the ESD, shutting in all systems, and then sounded the alarm. According to testimony, the blind rams were first closed to try to contain the flow. These pushed the tubing to one side. Subsequently, the pipe rams were then closed but because the tubing was not centered, a seal was not achieved. Gas, water, condensate continued to blow at a high rate through the parted 2 7/8- inch production tubing stub protruding from the BOP’s, and around the pipe ram interface with the tubing.

2245 – 0300 hrs – The crew assembled at the evacuation points, and using the up-to-date manifests, accounted for all 47 personnel on board. Two escape capsules were launched after an inspection of the living quarters to ensure full evacuation. Weather conditions were calm, approximately 1-ft seas, but according to testimony, visibility was very low, possibly only 10 feet in places, because of fog. By 0045 hrs, the field boat, the *Madeline B*, located and recovered the personnel from the escape capsules.

Once on board the *Madeline B*, a second head count ensured all were present. The *Madeline B* took the escape capsules in tow, tied them off on an unmanned platform, and evacuated the crew to the EI-107 “A” Platform.

Workover Activities to Regain Control and Complete Well

10 March: 0330 hrs – Operator and Rig supervisory personnel traveled by boat to observe the Rig. They found the Well had bridged over. Waited on well-control specialists.

0900 - Traveled from EI 107 “A” platform to Rig. Inspected Rig at water line for possible broaching. No sign of broaching or flow was sighted. Accompanied by well-control specialists, Operator personnel boarded Rig by accessing the production platform +10 deck, reaching the Rig by climbing the wellhead into the drilling bay, using a portable gas detector to check for the presence of gas. They assessed damage and checked the living quarters with the gas detector. The Well was found to be dead. The operator assumed that the Well was probably bridged over, and tubing and annular pressures were found to be 0 psi. No residual gas indications were found by the portable gas detector. Started emergency generator, began restoring the Rig to operational status. With advice of the well-control specialists, the crew began well-control operations.

11 March – Cleaned Rig, added shear rams to BOP stack.

12 March – Cleaned Rig, began cutting tubing blown out of well, removed tubing, hanger, SCSSV from derrick. Cut tubing protruding from kelly above the floor, installed check valve. Continued to remove tubing from derrick, recovered 598 ft tubing. MMS representatives visited and inspected damage.

13-14 March – Continued to prepare Rig for operations. Laid down two joints of tubing (about 60 ft), one crimped from action of rams, pulled 1,106 ft tubing, total tubing accounted for at this point was 1,766 ft.

15 – 16 March – Found top of tubing fish at 2,050 ft, grappled tubing, ran wireline to 5,078 ft. Approximately 284 ft of 2 7/8-inch production tubing remained unaccounted for and, according to testimony, was assumed to be blown overboard after being ejected by the force of the uncontrolled flow.

17 – 20 March – Continued fishing operations, recovered 2,033 ft, top of tubing at 4,085 ft Tubing still found to be heavily pitted by corrosion.

21-24 March – Fished well to 5,811 ft near top tubing obstruction (This later proved to be the thru-tubing pack-off supposedly installed about 11,314 ft. Whether this pack-off was inadvertently installed at 5,078 ft, or had been moved up the hole by pressure from 11,314 ft is unknown). Washed-over tubing with an outside cutter. Cut tubing at 5,905 ft, below tubing pack-off, well came in. Conducted well-control operations to control 6,000 psi SITP and 5,730 psi SICP, raised mud weight to 18.5 ppg.

25 March – Recovered about 95 ft of tubing with 20 ft of pack-off isolating packer assembly inside.

25 March – 12 April – Continued fishing operations with periodic well-control actions necessary using 18.5 ppg mud. No evidence of fluid loss to formations, only gas influx, gas cut mud, etc. No through tubing pack-off assembly was found at 11,314 ft. Fished well of all equipment to 17,300 ft.

14 April – Determined casing to be damaged below 17,300 ft, clean-out operations suspended, could not complete well in “P” sand, casing opposite “O” sand suspected to have collapsed and to be the source of the high pressures encountered in the Well. The Well was logged, operations to complete well in “B” sand initiated.

Review of Barriers to Loss of Control

According to documents and testimony, as a company policy the Operator prepares a “barrier review” prior to workovers or recompletions to ensure the integrity of well control. After the loss of control in the B-1 Well, the Operator also conducted a post-event evaluation that reviewed the barrier concept and the failures that led to the loss of control.

According to the Operator’s report, the “barrier review” is a “philosophy of blowout prevention... [to ensure] having some means to contain the well pressure...but also to have some insurance or ‘backup’ system...when the primary system no longer has integrity.” “Barriers” include all mechanical systems and/or well conditions that prevent the well from flowing.

According to documentation, for a high-pressure gas well in a remote location, such as the subject Well, the Operator requires three barriers, either “positive” (mechanical or definitive control) or “conditional,” defined as one that works under certain conditions. The preparation for the workover of the B-1 included a barrier review that identified two positive barriers to loss of control. These were (1) cemented and unperforated casing across the high-pressure up-hole sands, and (2) a fluid of sufficient weight to contain the pressure of the perforated reservoir, the “P” sand, that was the target for the workover. One of these was applicable to any source of pressure.

In addition to the positive barriers, the Operator identified three conditional barriers that included the BOP pipe rams, the Hydril annular BOP when the pipe was in the hole, and a back-pressure valve (BPV) in the tubing hanger (TH) in conjunction with the TH itself.

The assumptions that made the above barriers applicable included (1) the cemented and unperforated casing across the up-hole sands effectively separated the fully pressured alternates from the wellbore and the pressure depleted “P” sand, and (2) the workover fluid was of sufficient weight to hold the pressure of the “P” sand.

The Operator’s Well plan discussion noted that the pre-workover conditions in the B-1 Well interfered with the installation of additional barriers to loss of control prior to the clean-out of the well bore. Through-tubing pack-off assemblies had been installed by wireline in the production tubing of the Well at

approximately 1,207 ft and at approximately 11,314 ft. But no intermediate landing nipples had been included in the production tubing string between 501 ft and 11,455 ft when the string was originally run (*see Attachment 2*). Therefore, in order to isolate the productive but pressure depleted “P” Sand by setting a wireline plug in a mandrel or installing a bridge plug, it was first necessary to fish the well clear below the depth of the parted tubing, and then retrieve the pack-off at 11,314 ft. To do this required the initial fishing to be done with the pressure depleted “P” sand subject to the hydrostatic pressure of the tubing and annulus packer fluid.

In addition, while the parted tubing prevented the retrieval of the deep pack-off assembly by wireline, it also decreased the hold-down tubing weight applied to the TH. This loss of tubing weight acting on the hanger effectively shifted the retention force applied to the TH, in case of annular pressure, entirely to the hold-down pins.

The part in the production tubing at 1,900 ft and holes in the severely corroded tubing above 3,000 ft greatly complicated the well-control portions of the workover itself, as noted in the Operator’s Well plan. Being unable to isolate the under-pressured “P” sand by mechanical means because of the inability to use through-tubing methods, the workover plan was reduced to using fluid LCM pills applied to the “P” sand perforations, to enable the retention of a full column of workover fluid. The choice of LCM materials was somewhat limited because of the need to retain the ability of the “P” sand to produce after the completion of the workover. The need first to fish corroded tubing from a shallow depth reduced the ability to circulate out a pressure kick completely should the fluid containment level be reduced because of losses to the “P” sand.

A blind, after-the-event review of the original well plan by an independent engineering consulting firm concluded that the original plan was sound. This review (contracted for that purpose by the Operator) extensively discussed the problems inherent with the low pressure in the “P” sand and the probability of losing fluid to the open formation. It also noted that the problems of cleaning out the wellbore were exacerbated by the pack-offs in the well. The tight tolerances imposed while fishing 2 7/8-inch tubing within 5½-inch casing, especially if an outside cut was required to retrieve the tubing pack-offs, were also discussed.

The review also noted the need for careful attention to the composition of the LCM’s (because of the need to maintain “P” Sand producibility) counterbalanced by the need for fluid retention.

The independent review discussed other methods of isolating the producing zone and high-pressured alternates to allow a clean-out of the well below the depth of the last tubing pack-off. As in the well plan, a number of methods were considered and found to be flawed. The parted/leaky tubing meant no bridge plug could be set above the perforations or alternate productive zones. A temporary cement plug could not be placed because the leaks in the tubing and the tubing pack-offs made it impossible to ensure the cement would be placed in the proper location to isolate the problems.

However, the Operator's review of the barriers to loss of control available prior to the workover concluded that enough redundancy was included to go forward with the workover. The independent review, conducted after-the-fact, also arrived at that conclusion.

Review of Significant Problems Encountered

In the course of the workover, the Operator's review of events noted the progressive failure of the barriers designed to ensure control of the Well. The initial failure apparently became evident when the shut-in casing pressure rose above 2,500 psi, after the tree was nipped down and the BOP's nipped up. This was the first evidence that the main positive barrier to loss of control, the definitive isolation of the upper high-pressure alternate sands from the low-pressure "P" sand (and the wellbore itself) by cemented unperforated casing, had failed. At this point, the second well-control barrier, the maintenance of a column of workover fluid sufficient to control the pressure, was also compromised. Pressure from any of the alternate sands was obviously too high to be contained by the workover fluid weight in the hole, which was designed to restrain the under-pressured "P" sand.

When higher than expected pressure indicated possible feed-in from the high-pressured alternate sands, according to Operator policy the operations were paused to consider how to create additional methods to ensure control of the well. However, the pressure in the well continued to build to >6,000 psi while plans were being considered. Shortly after the pressure rose above 6,000 psi, the last barrier to loss of control, the tubing hanger seals and downhole safety valve (and check valve) were lost when the hanger and > 600 ft of tubing were ejected from the Well. The manner of ejection compromised the ability of the BOP's to control the flow.

The ejection of the hanger along with tubing attached to it meant that the blind rams and pipe rams, though shut by the crew, could not control the well because tubing was across the rams and no shear rams had been installed. Evacuation of the Rig was then initiated.

Review of Design and Installation of Tubing Hanger

The cause of the ejection of the hanger and tubing was the subject of an internal Operator investigation in conjunction with an investigation by the Manufacturer of the hanger. These reviews determined through inspection of the tubing hanger spool and tubing hanger lockdown lock screws (or hold-down pins) that the hold-down pins holding the tubing hanger in place failed when the pressure reached approximately 6,100 psi (*see pictures, Attachments 7, 8 and 9, diagrams, Attachment 10 and 11*).

The hanger installed in the B-1 Well was a Cameron-produced mandrel hanger that provided a metal-to-metal seal, as well as an elastomer backup seal. It was designed for use in critical service applications including high pressures up to 15,000 psi, and was rated to resist corrosive and erosive effects associated with well flow. The subject hanger spool was a 7 1/16" API 15,000 psi, top flange, Type C with a 1 1/16-inch T-40-CL hanger, holding the Well's 2 7/8-inch tubing set in tension.

When the annulus pressure in the Well suddenly rose, it was contained within the wellbore by the seal elements of the hanger, but because of the parted tubing at 1,900 ft, all of the pressure forces placed on the hanger were restrained only by the hanger hold-down lock screws (hold-down pins). As has been noted, the hanger in the B-1 Well was designed to sustain over twice the >6,000 psi pressure measured on the annulus of the B-1 Well, even with just the hold-down pins opposing the well pressure.

However, in the B-1 well, shortly after the annulus pressure in the wellbore rose above 6,000 psi, the nose of the hold-down pins retaining the hanger in place sheared off (*see pictures, attachment 8 and 9*). The failure allowed the ejection of the hanger followed by loss of well control. According to well service reports, shortly prior to the failure, the hold-down pins of the hanger had been replaced by a representative of the hanger manufacturer, torqued and the settings were re-checked. The hold-down pins hold the tubing hanger in place and energize the sealing elements of the hanger as shown in *Attachment 11 and 12*.

The manufacturer's representative had replaced the 12 pins, 3 at a time, six hours prior to the advent of pressure, to manufacturer's specifications according to testimony. However, the pins obviously failed to hold the hanger in place under the well conditions encountered and were found to have their noses sheared off. The pins removed prior to the failure were not sheared. Furthermore, the tubing hanger showed evidence of scraping against the sheared lock screws as it was ejected (*see Attachments 6, 7, and 8*).

The hold-down pins, hanger, and hanger mandrel were sent by the Operator to a private professional engineering analysis firm who in turn employed the assistance of a metallurgical engineering analysis firm specializing in failures associated with metal equipment.

The engineering firms reported back to Operator that the lock-down (hold-down) pins holding the hanger in place failed by shear forces placed on the hanger by the annulus pressure greater than 6,000 psi. Further, the engineering analysis found that the pins as installed would have been expected to fail at about a pressure of 6,100 psi, even though the hanger was rated to contain up to 15,000 psi. A conclusion of the metallurgic and failure studies also found that the reason the pins failed "*was the result of only partial engagement between the [hold-down pins] and energizing ring of the tubing hanger. At the time of failure, the [hold-down pins] were at 39 percent of full engagement. [The engineering report] conclude[d] the partial engagement of the [hold-down pins] was the major contributory factor to the failure.*"

The report also indicates the reason for the failure of the hold-down pins to engage the energizing ring fully. It says, "*the calculated engaged length of the [hold-down pins] (0.173 inches) at failure conditions agrees well with the difference between the nominal drawing dimension for overall length and the measured length of [hold-down pins] (.015-.017 inches) which were sheared in the failure. ... Full engagement of the [hold-down pins] (0.438 inches) is necessary to satisfy the [manufacturer] design criterion for shear (0.53 of yield strength) at the rated working pressure of 15,000 psi with a blind hanger.*"

The conclusion of the technical reports, after full analysis of hardness, tensile properties, diameters, and lengths of the hold-down pins that failed, and additional data, was that the hold-down pins were of proper length and design but were installed so that only a portion of the nose of the pins engaged the tubing hanger. The Manufacturer's representative on the Rig recorded that he had torqued the pins to the proper

setting and had re-checked the pins by measuring the depth of setting according to company specifications.

Manufacturer Safety Alert

After a study of the failure of the hold-down pins to retain the hanger in place, the Manufacturer issued a safety alert describing the failure and warning industry about certain design flaws inherent in the subject hanger (*see Attachment 10*). The Manufacturer concluded that the hold-down pins had failed to engage the energizing ring fully, even though they were installed by a representative of the Manufacturer to the requisite specification.

According to testimony, the reason the pins failed to engage the ring to the designed depth, enabling the hanger to contain the designed pressure, lay in a flaw in the design of the hanger as it mated with the hanger spool and energizing ring. The metal-to-metal mate between the hanger and the spool, and between the energizing ring and the hanger, were designed at a 45-degree angle. However, the actual mating of the hanger and spool caused the hanger energizing ring to sit too high in the spool to allow the hold-down pins to be fully run-in.

Under a certain series of circumstances as in this loss of control event, the design would cause the hanger to fail to hold the pressure because the engagement of the nose of the hold-down pins was insufficiently complete. The Manufacturer noted that the absence of the hold-down force of the weight of a tension-set string of tubing, the removal of the well-head (which also acts to hold the hanger in place), combined with high pressures on the annulus, are the events that all must be present for the design flaw to cause the hanger to fail.

As changing the spools already installed in the field is prohibitive, to address the flaw, the Manufacturer re-designed the hanger to shorten the height of the bottom flange and the distance to the top of the energizing ring (*see Attachments 10, 11, and 12*). This change now allows the hold-down pins to be fully run-in, restoring the hangers to the advertised pressure rating. However, according to testimony, recovery or even identifying all the hangers already in the field worldwide that are at risk is made difficult, given the number of mergers and acquisitions that have complicated identifying the chain of ownership of at-risk wells. A number of the at-risk hangers/hanger spool combinations are installed throughout the Gulf

of Mexico (GOM), and the Manufacturer issued its safety alert warning of the inability to retain rated pressures to its customers of record only.

The Manufacturer's safety alert recommended avoiding excessive pressure on the hanger by bleeding the annulus pressure to zero prior to removing the christmas tree and installing the BOP's. According to testimony, this can be accomplished using a design feature of the hanger that allows the pressure to be bled off through a port that can connect the annulus into a vent or back through the choke using temporary piping, chocks, etc.

The Manufacturer safety alert also warned industry that hangers with certain dimensions, such as the one that was ejected from the Well, would not sustain advertised pressures and recommended a re-designed hanger that allowed full engagement of the hold-down pins. The safety alert notes that the design flaw has been corrected in new hangers of this type and warns that hangers manufactured to the previous specification should not be used. The Manufacturer also advises that hangers manufactured and installed to the previous specifications will not hold design pressure under certain circumstances and re-iterates the need to bleed down the pressure fully prior to tree removal.

In a November 24, 2003 letter to the Operator, Manufacturer noted the following: "Design Review: *Review of the 1996 vintage Ingram Cactus manufacturing drawings indicates that the tiedown screws were not capable of retaining the full rated working pressures below the hanger in the absence of additional tubing loads. This situation applies to the Ingram cactus 7 1/16 in Nom. T-40, T-40-CL, CXS, and CT hangers as well as the 7 1/16-inch Type C Tubing Spools in pressure ratings of 2000 to 15,000 psi. The majority of these types of Ingram Cactus designed hangers were corrected in 1998 to increase the amount of tiedown screw [hold-down pin] engagement and therefore, to increase their pressure retention capacity.*

Conclusions

A series of dependent events led to the loss of control of the Well. Absent one of the events or a change in order of the events, it is probable that Well control would have been maintained.

Cause of Loss of Control

1. A workover of the Well was required because extensive CO₂ pitting and corrosion caused communication between the production tubing and the annulus. The pitting and corrosion were exacerbated because the tubing string originally installed was not designed to resist CO₂ corrosion.
2. In an attempt to isolate the holes in the tubing caused by the corrosion, a number of through-tubing pack-offs were set. While these pack-offs failed to end the communication, they remained an impediment to through-tubing operations during any workover.
3. Subsequent suspected parted tubing was found after the pack-offs had been set. The parted tubing made retrieving the pack-offs impossible and the presence of the pack-offs made it impossible to use through-tubing means to isolate the under-pressured “P” sand that was the target of the workover, until the tubing could be fished to a depth that allowed conventional well- control methods.
4. The inability to isolate the communication between the annulus, tubing, and depleted “P” sand caused severe pressure differential to be created across from the “O” sand. The differential possibly reached a high of approximately 10,000 psi. Because of the pressure differential, the high pressured “O” sand then breached the isolation barriers between the reservoir and the well annulus by either compromising the cement sheath or casing integrity or both.
5. When the pressure from the “O” sand was observed at the surface, no effective method of circulating the kick existed because of the tubing string damage. Therefore, the only way to control the increasing pressure was to pump directly against the pressure, down tubing and annulus. This method was of questionable effectiveness because the severely under-pressured “P” sand would not support the hydrostatic head unless an LCM pill was able to lockup the “P” sand. However, the extensive

communication between the tubing and annulus made accurately spotting an LCM pill into the “P” sand perforations difficult. This in turn made it difficult or impossible to control the high pressure from “O” sand hydrostatically until the “P” sand could be completely isolated.

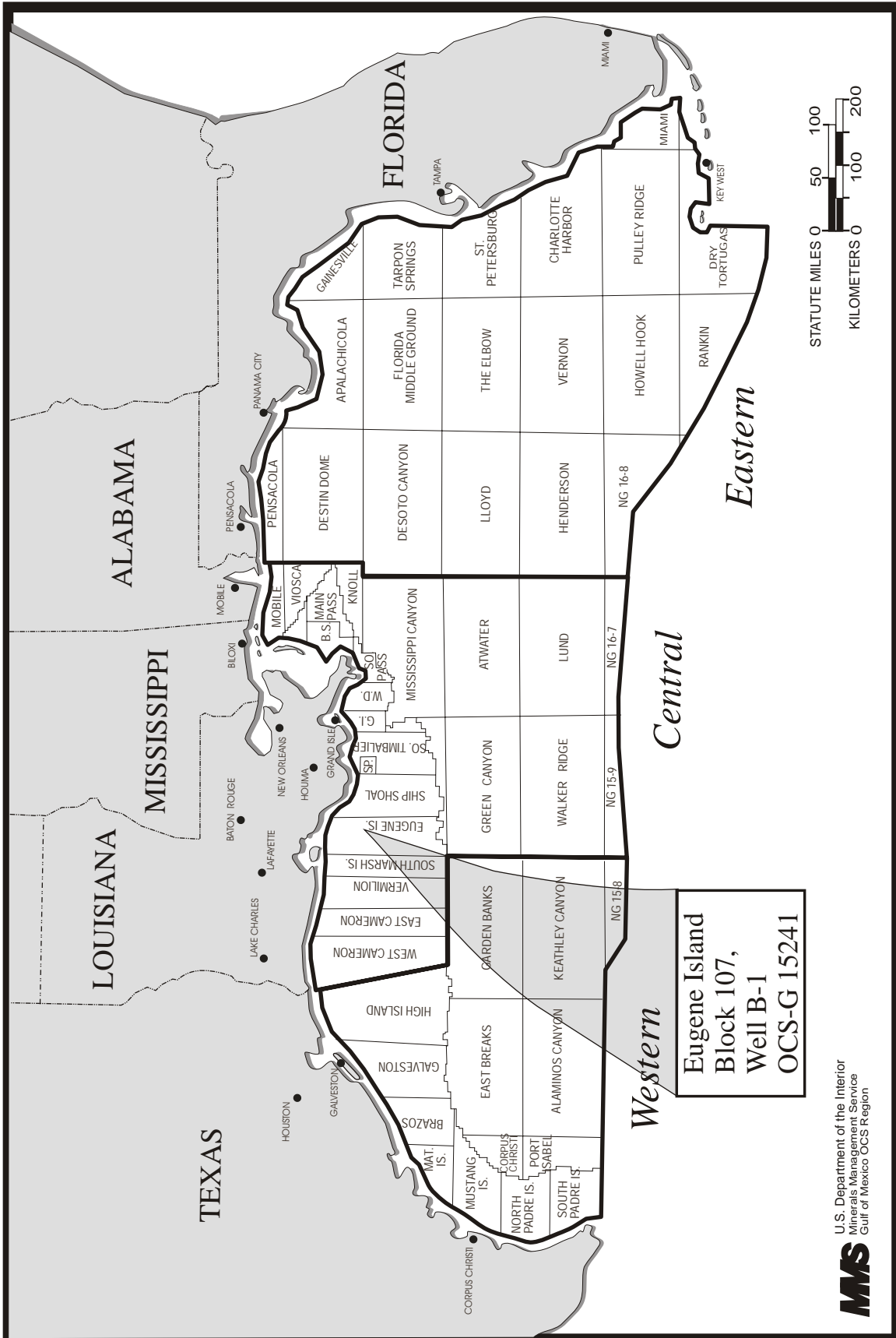
6. Before initiating a direct attempt to pump an LCM pill and heavier mud into the annulus to kill the high pressure, the last containment of the pressure, the tubing hanger hold-down pins failed. This failure was due to a fundamental Manufacturer design flaw. The ejection of hanger and tubing and loss of control were caused by this design flaw, the lack of suspended tubing weight, and the removal of the tree. The fact that no shear rams were installed prevented any control of the Well by use of the BOP's, once tubing was lodged across the stack.

Recommendations

It is recommended that the MMS issue a Safety Alert noting the failure of the hanger hold-down pins and the products involved, referring the operators to the Manufacturer's safety alert.

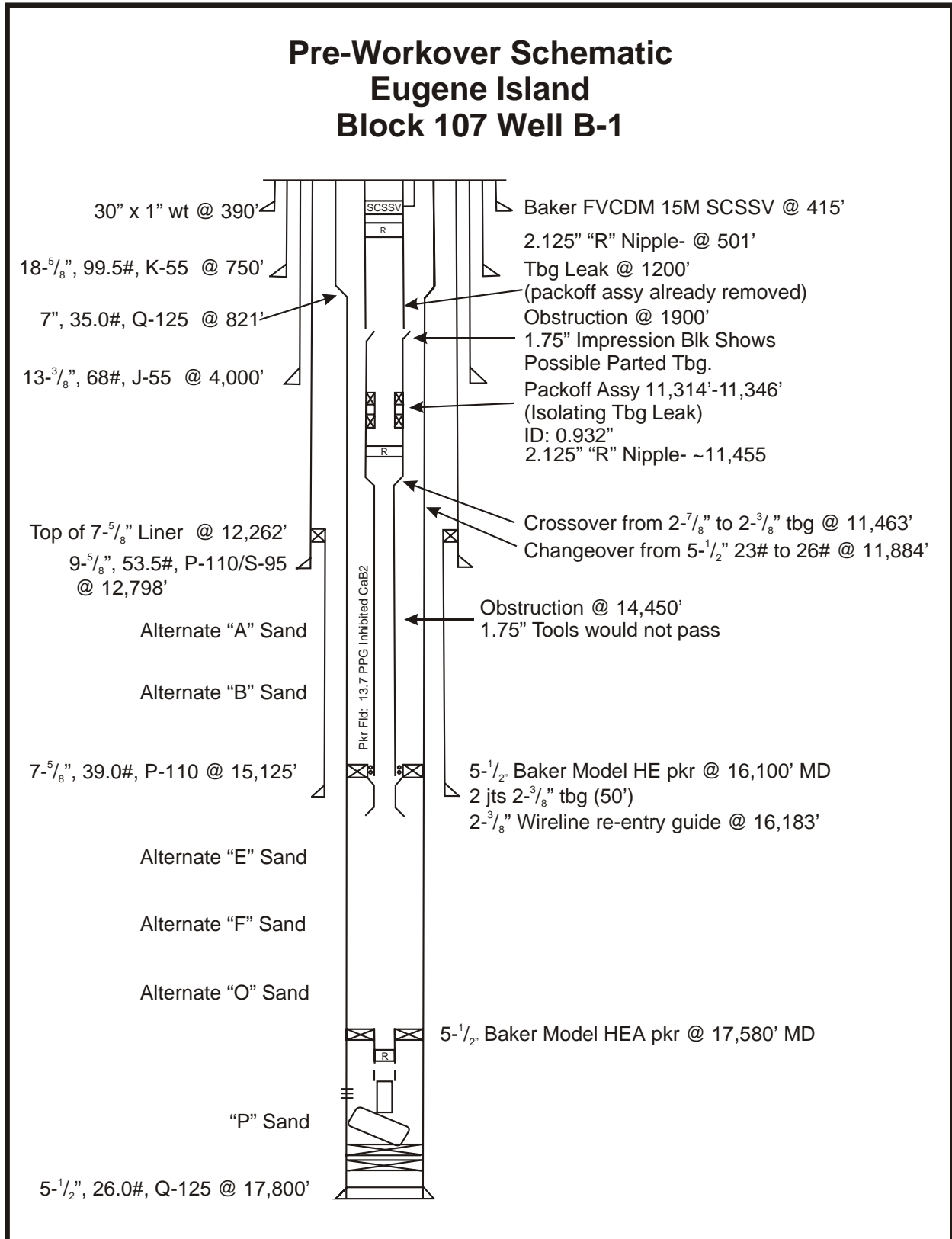
Operators should consider installing shear rams in their BOP stacks when working over wells that present unusual control problems. One such example is the presence of unusually high pressure differentials between alternate zones penetrated by the well. Shear rams will limit the duration and magnitude of loss of control events such as occurred in this incident.

When planning workovers or recompletions in wells that penetrate sands with high pressure differentials in alternate zones, operators should explicitly recognize and prepare for the potential worst-case control problems that may be encountered.



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

Location of Lease OCS-G 15241, Eugene Island Block 107, Well B-1



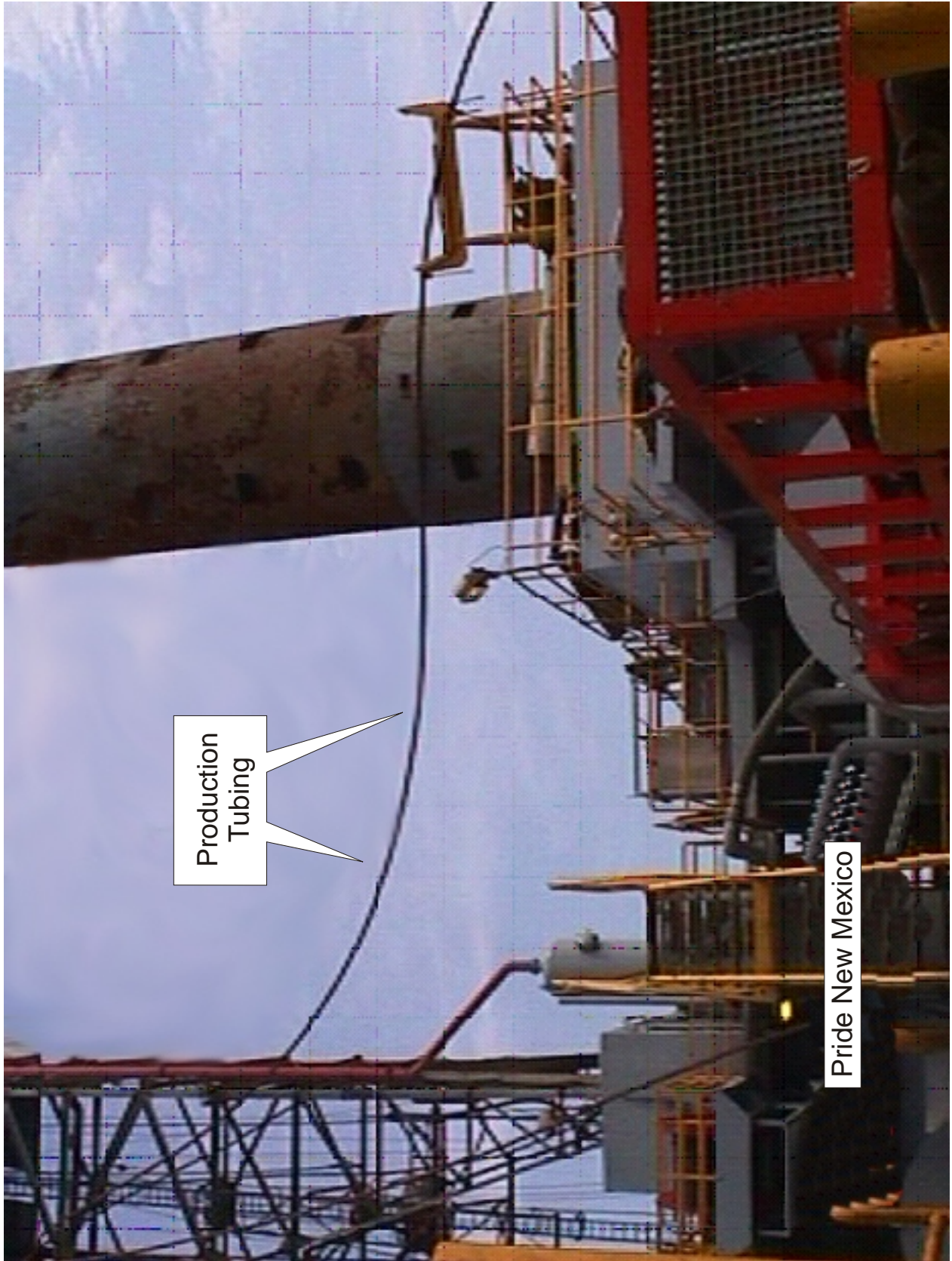
EI Block 107 B-1 Completion Schematic, Pre-workover



Production Tubing Hanger

Pride New Mexico

Eugene Island Block 107, Well B-1, Hanger Ejected from Well into Derrick



Eugene Island Block 107, Well B-1, Ejected 2 7/8" Tubing



Production Tubing

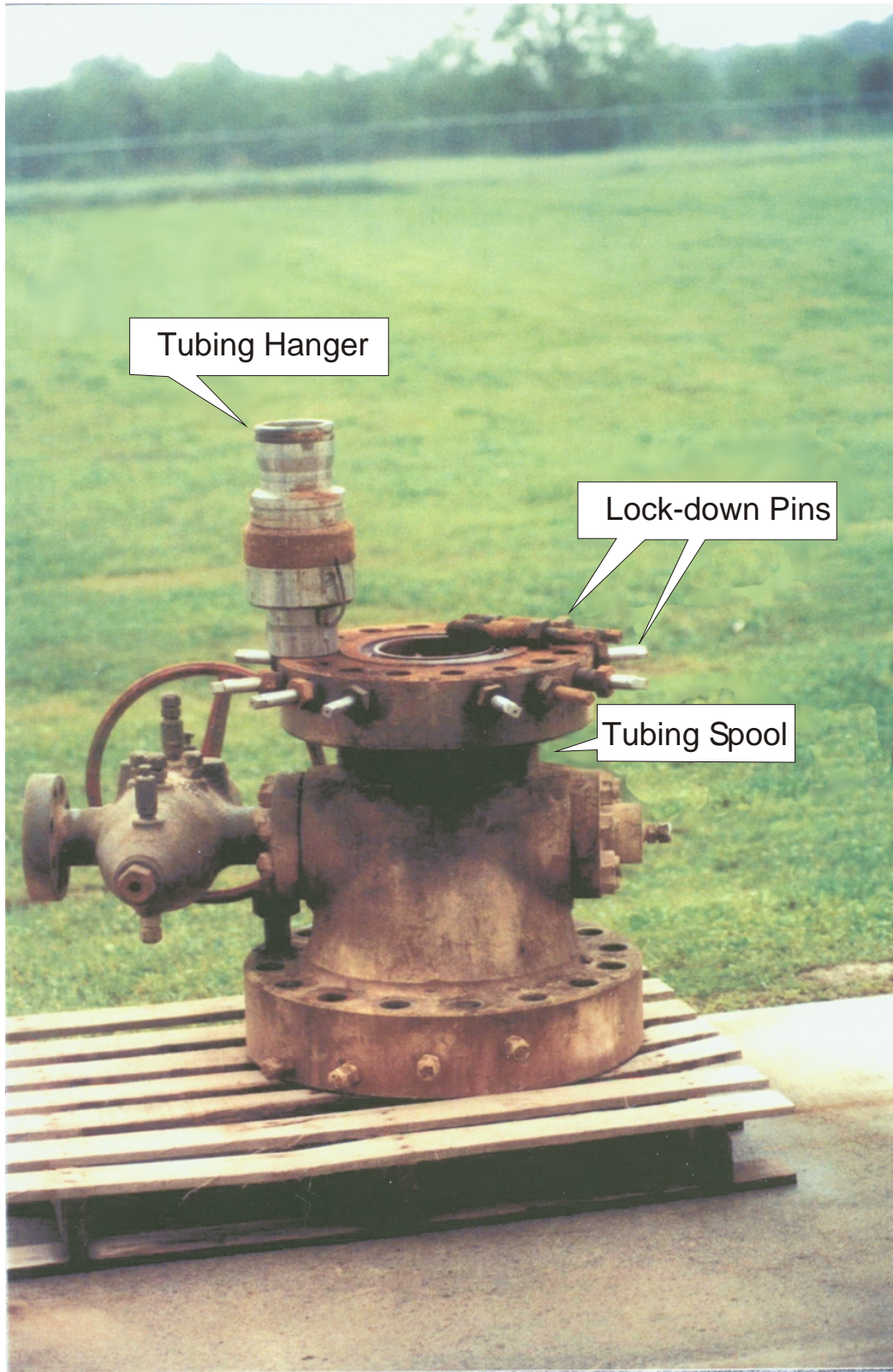
Pride New Mexico

Eugene Island Block 107, Well B-1, Tubing Ejected into Derrick

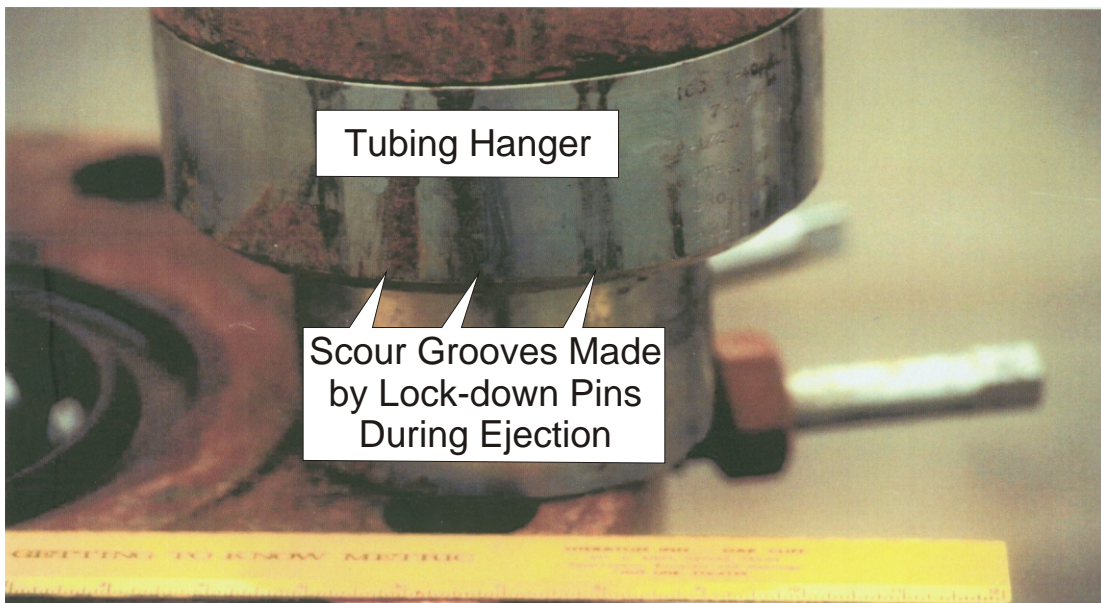
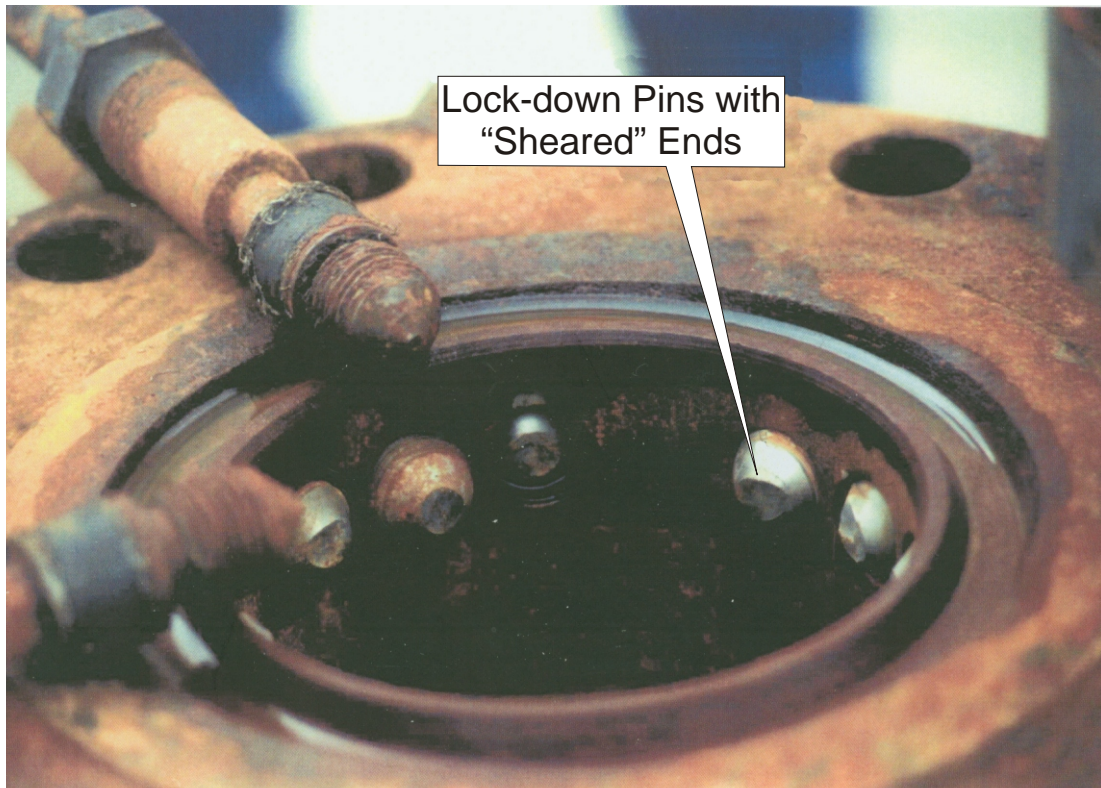


Eugene Island Block 107, Well B-1, Tubing Ejected from Well
Outside of Derrick

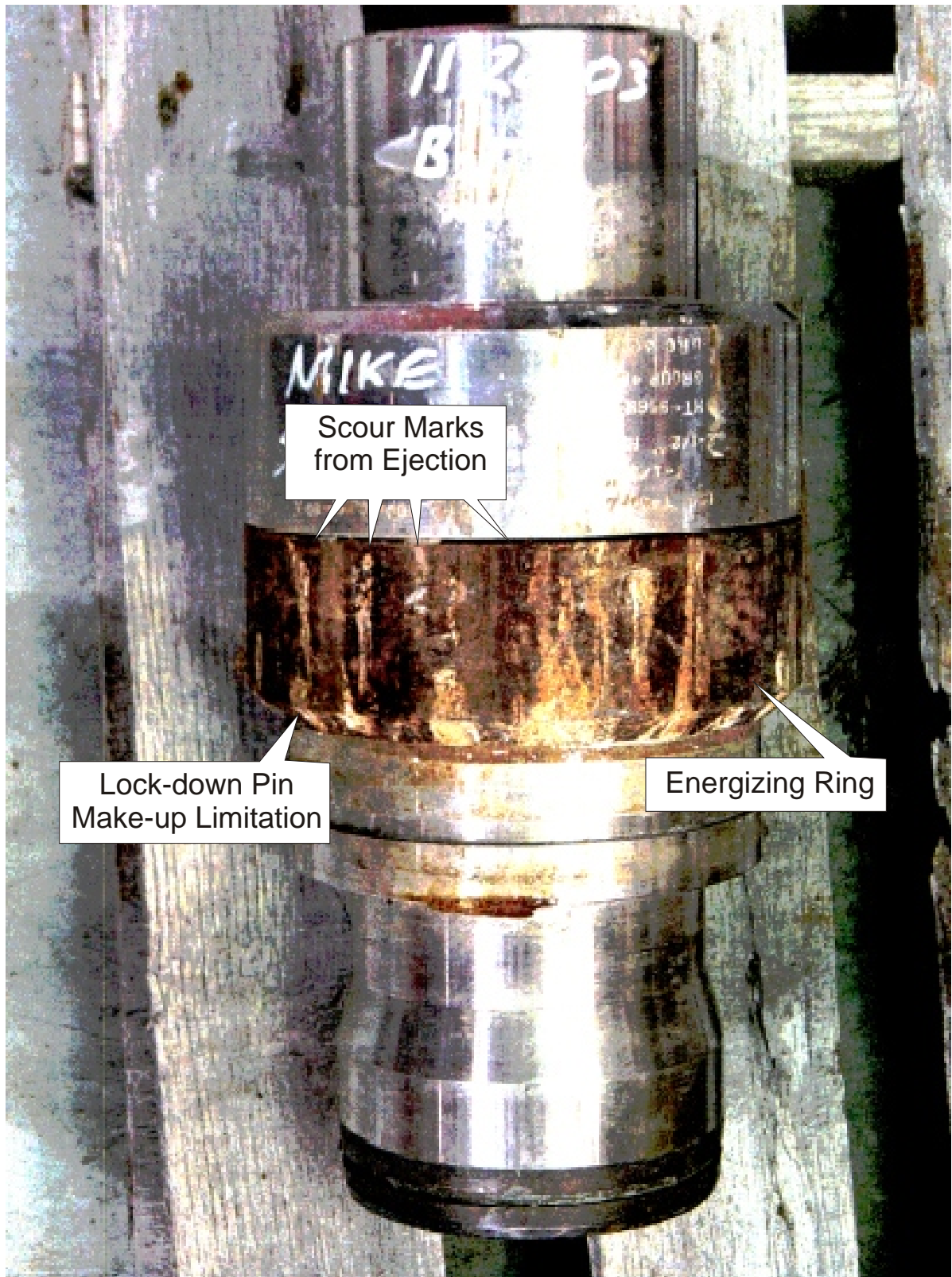
Pride New Mexico



Tubing Hanger, Spool, and Lock-down pins from EI Block 107, Well B-1



Sheared Lock-down Pins, Ejected Tubing Hanger, EI Block 107, Well B-1



Eugene Island Block 107, Well B-1, Tubing Hanger Showing Energizing Ring Ejection Markings



CAMERON

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Attachment 10

Safety Alert # 014086

Subject: 7-1/16" Nom. Type C Tubing Spools and Tubing Hangers

Products Affected:

Type C Tubing Spools/Housings:
API 6A Top Connection Size: 7-1/16" Nominal
Pressure Rating: 2000 to 15,000 psi
Styles: Type C

Tubing Hangers:
API 6A Nominal Size: 7-1/16"
Styles: T-40, T-40CL; CXS, CT

Eugene Island Block 107, Well B-1
Cameron Safety Alert
#014086,
RE: Design Flaw in Tubing Spools/
Housings, Hangers

Safety Alert:

The intent of this safety alert is to notify users of these products of possible safety concerns that could occur during workover operations.

The tiedown screws used in the subject spool / hanger combinations having with certain hanger dimensions **may** not be capable of retaining the full rated working pressure acting across the tubing hanger annulus seal diameter. It should be noted that a tubing hanger will rarely see this set of operating conditions since high annulus pressures are uncommon and suspended tubing weight serves to counteract annulus pressure end loads.

Users of this equipment are notified that tubing annulus pressure should be bled completely to zero whenever possible, **prior** to removal of the Christmas tree. Steps should also be taken to prevent possible pressure buildup below the tubing hanger during re-installation of the workover BOP and subsequent removal of the hanger from the tubing spool. Cameron will assist in determining tiedown screw retention capacity for unique situations where complete annulus pressure bleedoff is not possible. Note that while the tubing head adapter/seal flange is installed, the hanger will function properly and safely.

Prior to using **any** of these products, whether in a new installation or in a workover situation, the tubing hanger should be dimensionally inspected to verify the proper location of the seal support shoulder and energizing ring. Figure 1 illustrates the dimensions to be inspected. If requested, Cameron can assist in the inspection of these hangers. Hangers manufactured with 2.38" and 5.40" dimensions shown in Figure 1 are **unacceptable** and should **not** be placed in service. Most hangers manufactured prior to 1998 will likely fall into this category.

Safety Alert # 014086

Page 2 of 3

Hangers manufactured with 2.21" and 5.22" dimensions shown in Figure 1 are designed such that the tiedown screws will retain the hanger at full rated working pressure. These hangers are suitable for service.

Background:

During a recent work-over involving an Ingram Cactus 7-1/16" API 15,000 psi top flange Type C tubing spool and a 7-1/16" T-40-CL tubing hanger, the tubing hanger was accidentally ejected from the tubing spool.

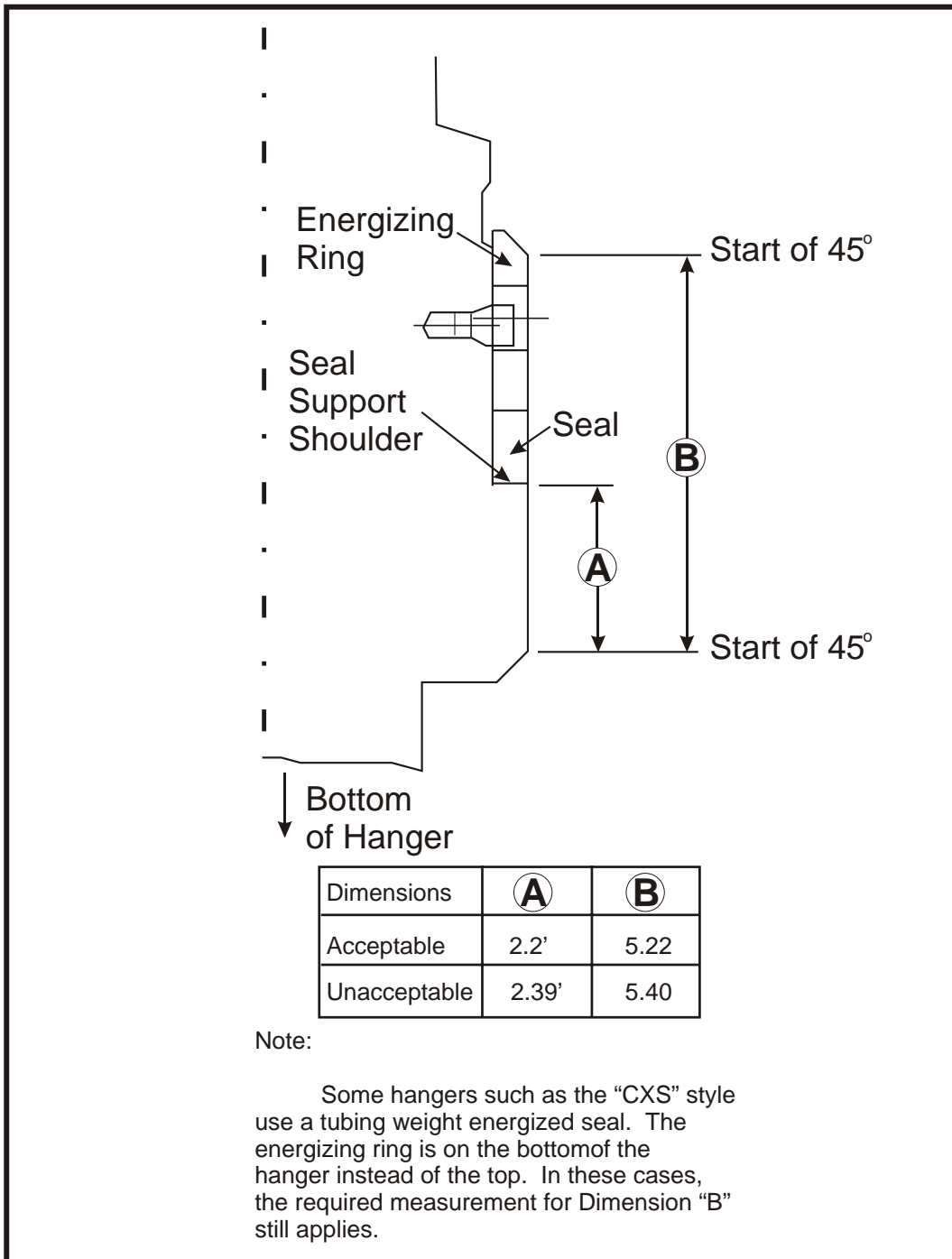
The tubing hanger was originally installed in 1996. At the time of failure, the recorded annulus pressure was below the rated working pressure of the spool. Analysis of the returned parts as well as a review of the 1996-vintage manufacturing drawings indicates that the tiedown screws were not be capable of retaining the full rated working pressure below the hanger in the absence of additional tubing loads.

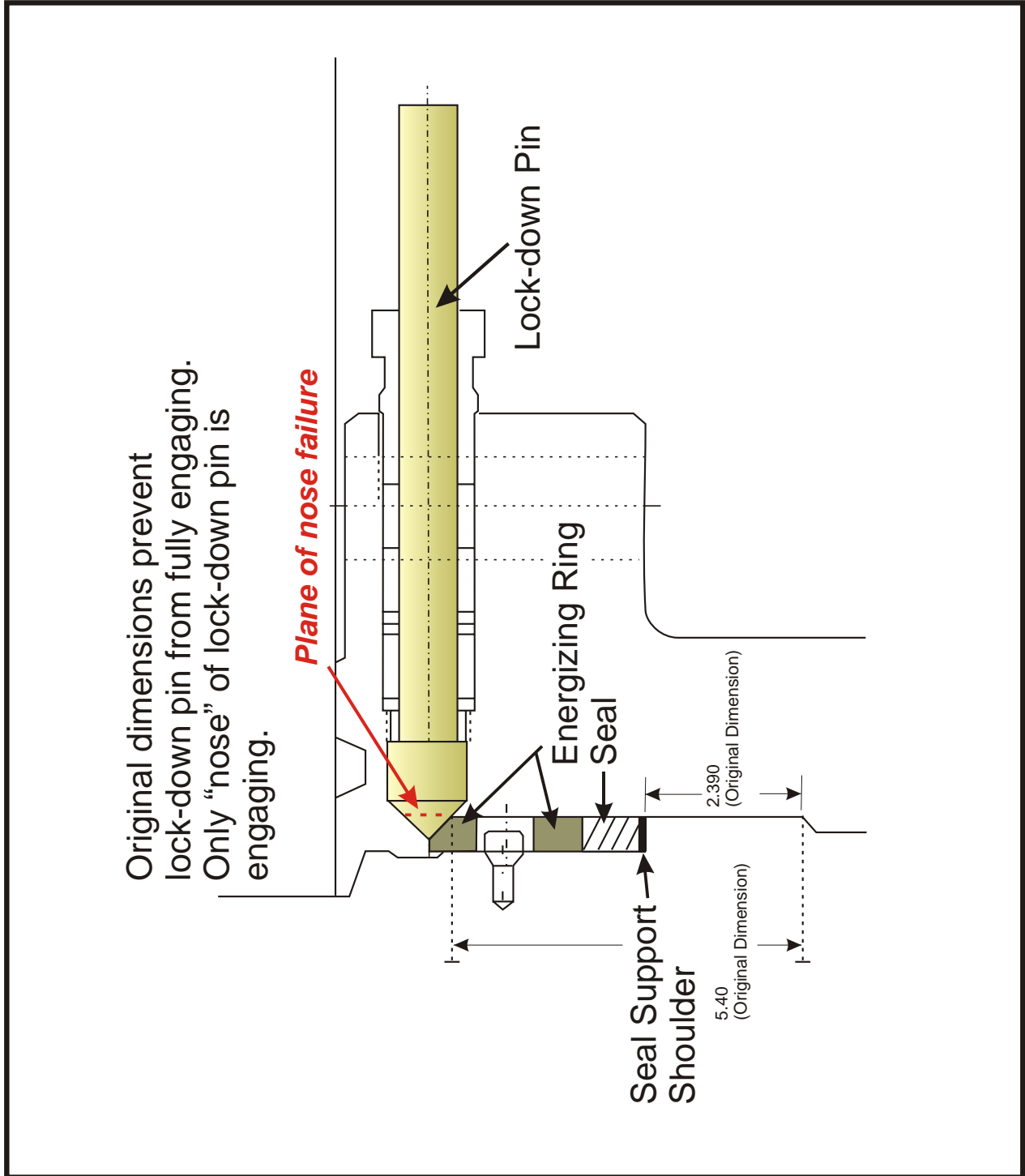
The majority of these types of Ingram Cactus designed hangers were corrected in 1998 to increase the amount of tiedown screw engagement and therefore, to increase their pressure retention capacity. Cameron has adopted the Ingram Cactus Type C design as part of their standard product offering.

Please do not hesitate to contact your local Cameron representative should you have any questions.

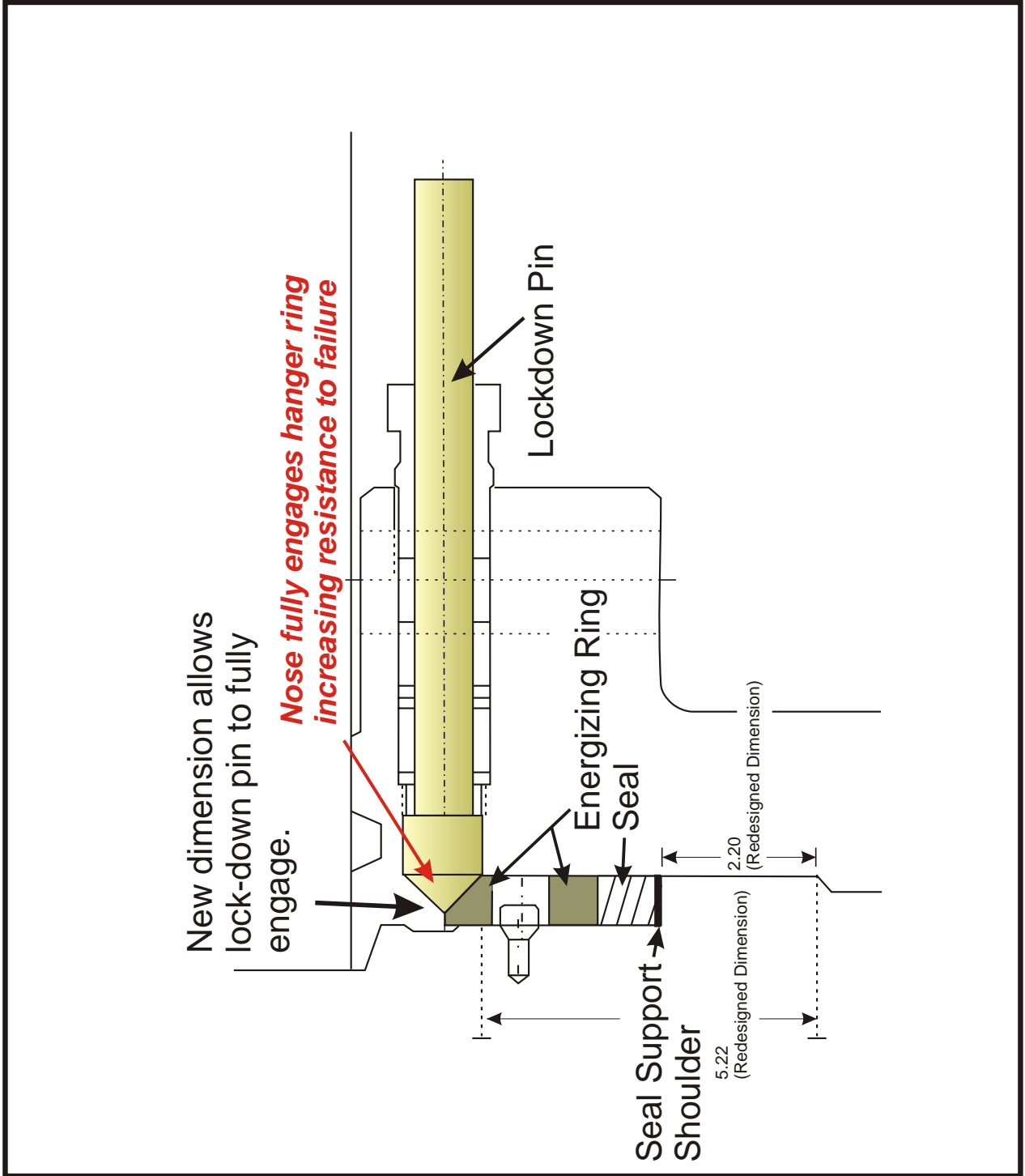
Mark Crews 08/20/03
CS
Mark Crews
Vice President Technology

Safety Alert #014086
Page 3 of 3



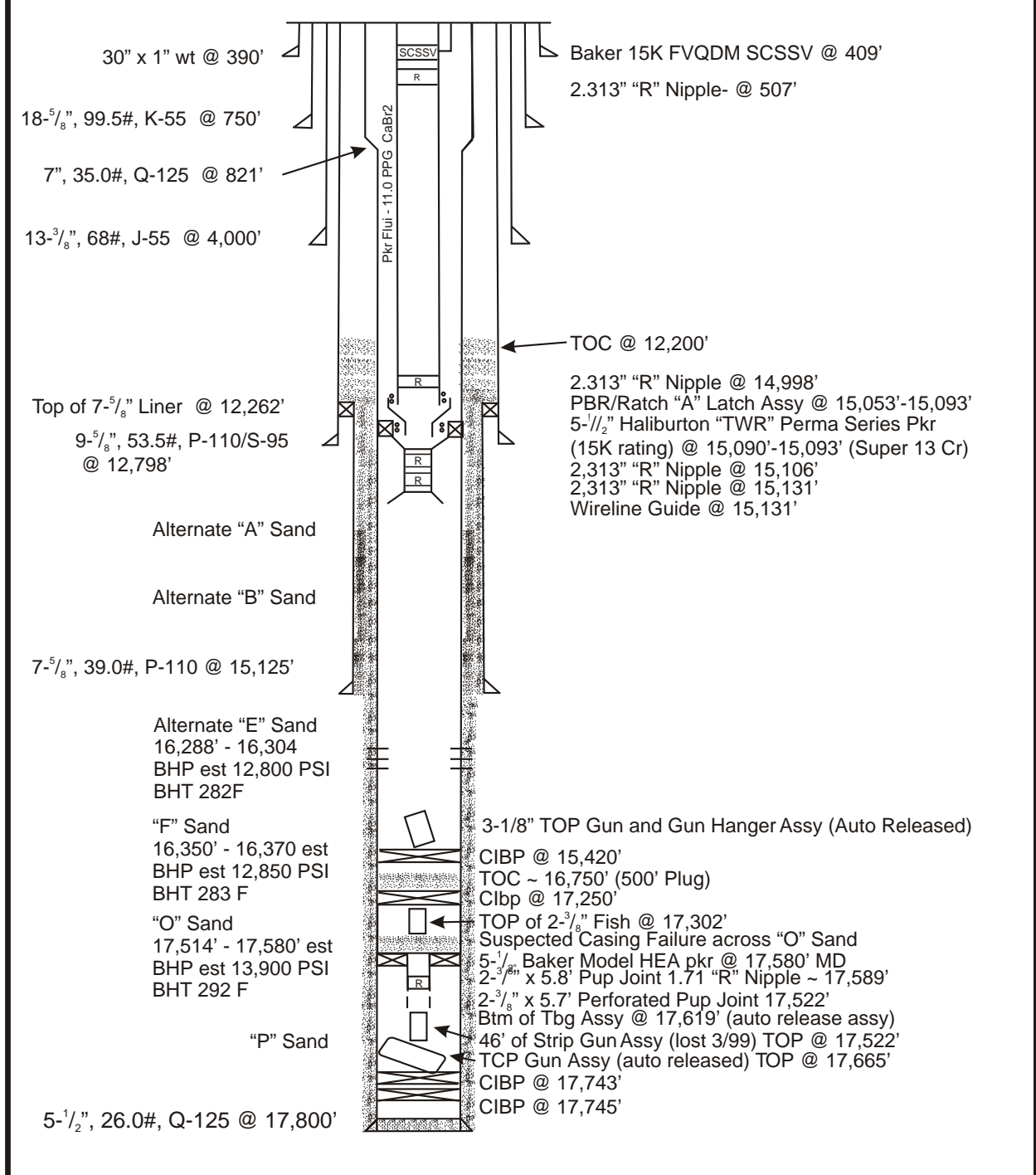


Schematic and Original Dimensions of Engagement of Hanger and Lock-down Pin.



Redesigned Dimensions and Engagement of Hanger and Lock-down Pin.

Post Recompletion Schematic Eugene Island Block 107, Well B-1



EI Block 107 Well B-1, Completion Schematic, Post Re-completion



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.