OCS Report
MMS 2008-049

Investigation of Blowout
Eugene Island Block 28 Well No. 4
OCS-G 05479
December 03, 2007

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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Randall Josey – Chair
David Stanley
Johnny Serrette
Mark Hasenkampf

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

New Orleans
October 2008

Contents

Executive Summary

An incident that resulted in a brief loss of well control occurred on Rooster Petroleum's Lease OCS G-05479, Well No. 4, Eugene Island Block 28, in the Gulf of Mexico, offshore the State of Louisiana, on December 03, 2007, at approximately 1200 hours. Rooster Petroleum hired a consultant through Petroleum Solutions and contracted the Blake 101 Jack Up drilling rig to perform workover operations on Well No. 4 of the above lease.

The operator was attempting to pull the tubing free of the seal assembly in a Baker SC-2 packer set at 10,830 feet to repair the Surface Controlled Subsurface Safety Valve (SCSSV) set at 350 feet (RKB) or 232 feet below mud line. In the attempt to retrieve the hanger, the 2 7/8-inch, P-105 tubing parted at approximately 4300 feet while working the pipe up and down. The 2 7/8-inch tubing began getting pushed out of the hole by well pressure and fluid in the annulus began flowing. The tool pusher shut the well in by closing the annular preventer and the upper pipe rams to stop and prevent the cycling of the 2-7/8- inch tubing and contain the pressure in the annulus. Since the tubing parted below the SCSSV, this prevented taking any returns through the open ended tubing. In addition, 2600 pounds per square inch (psi) registered on the 7-inch, 29 pounds per foot (ppf) production casing which had an internal yield of 8160 psi. As a result of the high casing pressure, numerous unsuccessful attempts were made to top kill the well using the feed and bleed method (pump kill fluid in, bleed gas off). The snubbing unit was rigged up on location; the well was brought under control, and normal workover operations resumed by January 14, 2008.

The investigative panel has concluded, based on information in the report findings, that the personnel on board performed their duties in a skillful manner. The loss of well control was contained in text book fashion with no injuries to personnel and no pollution to the environment. Rooster Petroleum submitted the three tubing sections (pin break and two pieces where tubing parted) to Partek Laboratories, an independent metallurgical testing facility, for their comments concerning the failures. Partek concluded based on available information and laboratory observation, the first tubing most likely failed as a

result of fatigue cracking that would greatly reduce the load carrying capacity of the tubing. It is unknown whether or not the fatigue crack found in the pin was present when the production string was initially ran or is a result of the work being performed in this operation. The second tubing section failed as a result of ductile tensile overload most likely because the load carrying capacity was decreased as a result of the extreme flow cuts which occurred as a result of production from 1991 to the present.

Introduction

Authority

An incident that resulted in a brief loss of well control occurred on Rooster Petroleum, LLC Lease OCS-G 05479, Well No. 4, Eugene Island Block 28, in the Gulf of Mexico, offshore the State of Louisiana, on December 03, 2007, at approximately 1200 hours. 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 incident. By memorandum dated January 07, 2008, the following personnel were named to the investigative panel (panel):

Randall Josey, Chairman—Office of Safety Management, GOM OCS Region
David Stanley—Lake Charles District, Field Operations, GOM OCS Region
Johnny Serrette—Lafayette District, Field Operations, GOM OCS Region
Mark Hasenkampf—New Orleans District, Field Operations, GOM OCS Region

Background

Lease OCS-G 05479 covers approximately 5000 acres and is located in Eugene Island Block 28 (EI 28), Gulf of Mexico, off the Louisiana Coast. (*For lease location, see attachment 1.*) The lease was issued to Kerr-McGee Corporation, effective July 1, 1983. Rooster Petroleum, LLC became owner and designated operator of the lease on May 21, 2007 and was the operator of record at the time of the incident.

Findings

Well History

Well No. 4 was drilled and completed in April of 1991. MMS records indicate this was the original completion string with no history of having any problems requiring workover operations. This project required pulling the production string to repair the Surface Controlled Subsurface Safety Valve (SCSSV) located at 350 feet.

Preliminary Activity

On December 02, 2007 the Blake Rig 101 moved on location and rigged up for workover operations to be performed on Well No 4. A back pressure valve was set, the production tree was removed and the blowout preventers were installed on the wellhead. The blowout preventer rams were tested to 10,000 psi high, 250 psi low and the annular preventers were tested to 5,000 psi high and 250 psi low.

The Incident

On December 03, 2007 the testing of the blowout preventers was completed, the tubing was latched onto and the Blade Rig 101 began operations of pulling on the production tubing in an attempt to pull the seals from the production packer located at 10,830 feet. The hanger pulled free of the wellhead with 54,000 pounds (kips) pull and pulling continued to 80 kips (string weight) and stopped. Pulling continued at 10 kips increments up to 110 kips and stopped. The seals were anticipated to release between 83 to 85 kips. When the seals failed to release the operator began working the pipe from 60 kips to 110 kips with no success. When the operator pulled 120 kips and stopped, the tubing parted at a depth of approximately 4,300 feet. The tubing string was 2 7/8- inch, 6.5 lb/ft P-105, CS Hydril with a yield of 190 kips. The maximum pull was calculated at 70% (using the API recommended factor of 1.80) of the maximum yield or 133 kips. The tubing parted at 120 kips, which was 63% of the maximum yield. The annulus was full of

11.0 ppg CaCl2 but because the tubing parted at 4,300 feet there was not enough hydrostatic head to contain the well bore pressure. The 4,300 feet of tubing was being ejected (pushed out of the hole by pressure) when the Blow Out Preventer (BOP) was activated, closing the pipe rams and the annular preventers, thus stopping the ejection of tubing and containing the pressure in the annulus. A total of 4 1/2 joints, 135 feet of 2 7/8-inch tubing was ejected from the well, snapping in two at the tool joint between the space out pup joint and the second joint of tubing. This left one full joint of 2 7/8-inch open ended tubing above the rotary table. At this point there was no ball valve on the end of the tubing and the only containment for the tubing volume was the damaged SCSSV. Attempts were made to kill the well by pumping down the annulus without success. Constant seepage around the tubing was noted and Rooster Petroleum decided snubbing operations would need to be employed to kill the well.

On December 05, 2007, Rooster Petroleum started making arrangements to use a snubbing unit to kill the well because the annular preventer started leaking between the tubing and the annular rubber. The following 30 days were spent locating, organizing and rigging up the snubbing unit with frequent delays due to inclement weather. The snubbing unit was rigged up and the well was killed by bullheading 15.3 ppg ZnBr. The 16 inch casing, 7 inch casing, and the 2 7/8-inch tubing were checked for pressure and all read 0 psi. By January 14, 2008, the well was secured and routine operations resumed.

Post Incident Examination

Rooster Petroleum submitted the three tubing sections to Partek Laboratories, an independent metallurgical testing facility, for their comments concerning the failures. The following is taken in part from Partech's summary report:

> **"Macroexamination:**
> The fracture surface of the first tubing section (pin at 4300 feet) was cleaned using a mild caustic solution to remove all traces of surface contamination/oxidation and staining. This surface was then examined using an

optical microscope at magnifications up to 20X. The fracture exhibited a relatively flat, fine-textured area for approximately ½ of the circumference and 45 degrees shear for the remaining surface area. There was evidence that progressive crack growth had occurred prior to failure. There was also evidence of deep surface gouges most likely the result of subsequent fishing operations. All of these features are suggestive of a fatigue type failure.

The sections 2 & 3, (135 feet above rotary) which represent the second failure, were examined and found to exhibit extreme wall thinning, the result of flow cuts.

Conclusion:
Based on available information and laboratory observation the first tubing most likely failed as a result of fatigue cracking that would greatly reduce the load carrying capacity of the tubing. The second tubing section failed as a result of ductile tensile overload most likely because the load carrying capacity was decreased as a result of the extreme flow cuts".

Post Incident Discoveries

The Rooster Petroleum Consultant in charge on site had 27 years experience with 95% being in workover and completion. The panel reviewed the following certificates of the Rooster Petroleum Consultant:

- WCS Wellcap Supervisor Drilling & Workover,
- API RP 2D 5th Edition Rigger Training,
- First Aid CPR,
- Personal Safety & Social Responsibilities,
- Basic Firefighting,
- H2S Safety Training,
- Work Permit Training,
- Numerous Management training classes.

The Blow Out Preventers (BOP) were installed as required by 30 CFR 250.615 and consisted of pipe rams, blind rams, pipe rams, and annular preventer. The rams were tested to 10,000 psi high 250 psi low and the annular preventer was tested to 5,000 psi high 250 psi low on December 02, 2007 as required in the Permit to Modify approved by MMS.

A Job Safety and Environmental Analysis (JSEA) was performed every day as required in 30 CFR 250.506 covering the work to be performed that day. The purpose of this job was to pull the tubing and replace the SCSSV. On the day of the incident the JSEA covered rigging up the floor to pull tubing, using proper slings to handle the tubing, using tag lines, and proper tools for the job. Also discussed were the STOP Work Authority, Job Site Inspection, Inspections of Tools & Equipment and Required Personal Protection Equipment (PPE). There was no mention of the requirements for pulling the work string.

The panel reviewed the activities of Rooster Petroleum and found that they did follow their “Proposed Workover Operation” procedures prior to the event and acted accordingly when the pipe parted. The day driller and the night driller tally book reports were made available and they confirmed the daily reports submitted by Rooster Petroleum.

Conclusions

The Incident

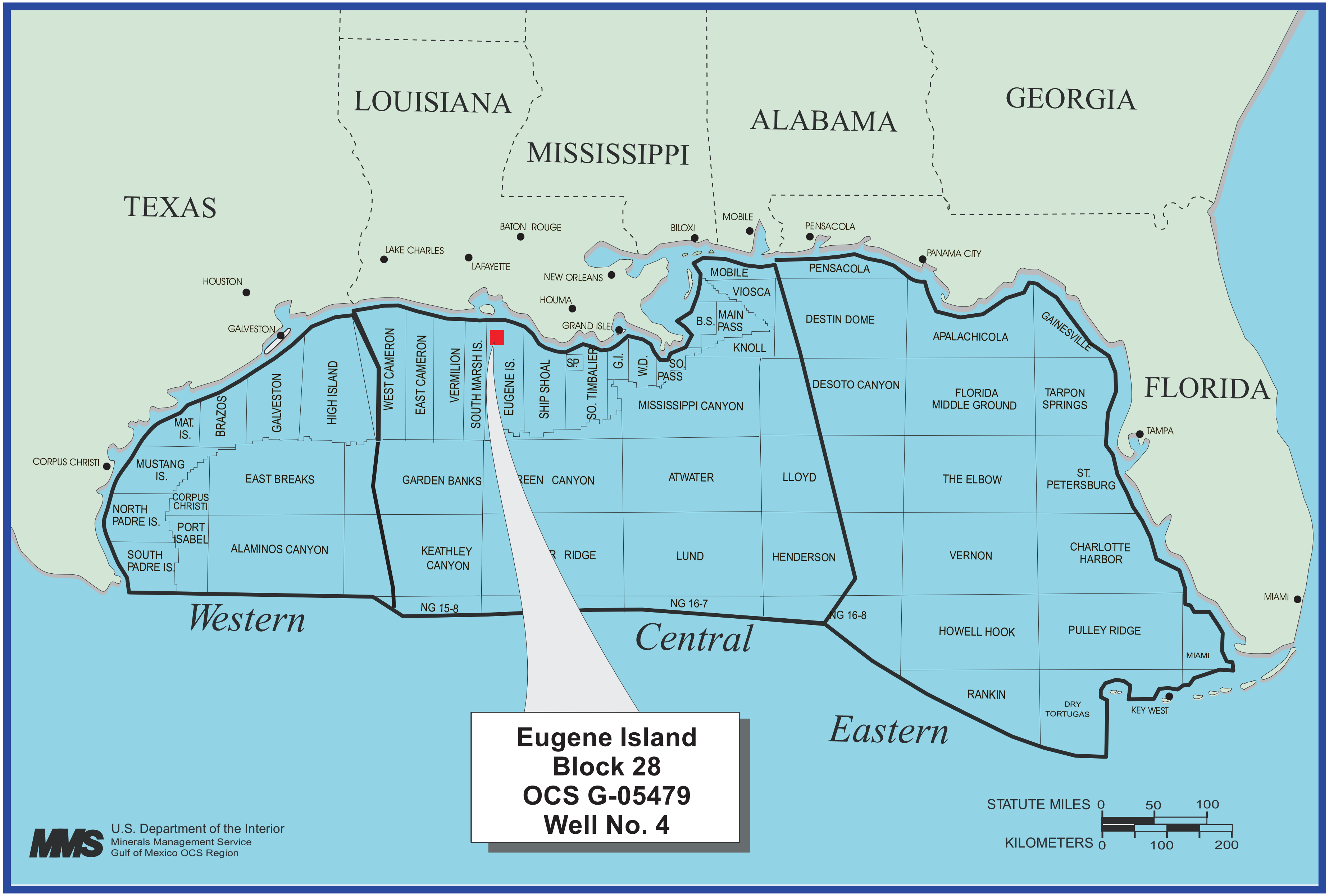
It is the conclusion of this investigative panel that the operation was being conducted using the standard operating procedures. All the safety precautions appear to have been taken, as well as safety equipment being in place and tested as required in 30 CFR 250.615. The tubing parted at such a shallow depth (4,300 ft) that reaction time would have been reduced considerably. Given the circumstances and the evidence submitted, this panel also concludes that the personnel involved reacted in a prudent manner possibly preventing injury to personnel and probably preventing pollution to the environment.

The findings of the Partek Laboratory tests indicate the parted tubing was the result of fatigue cracking and wall thinning.

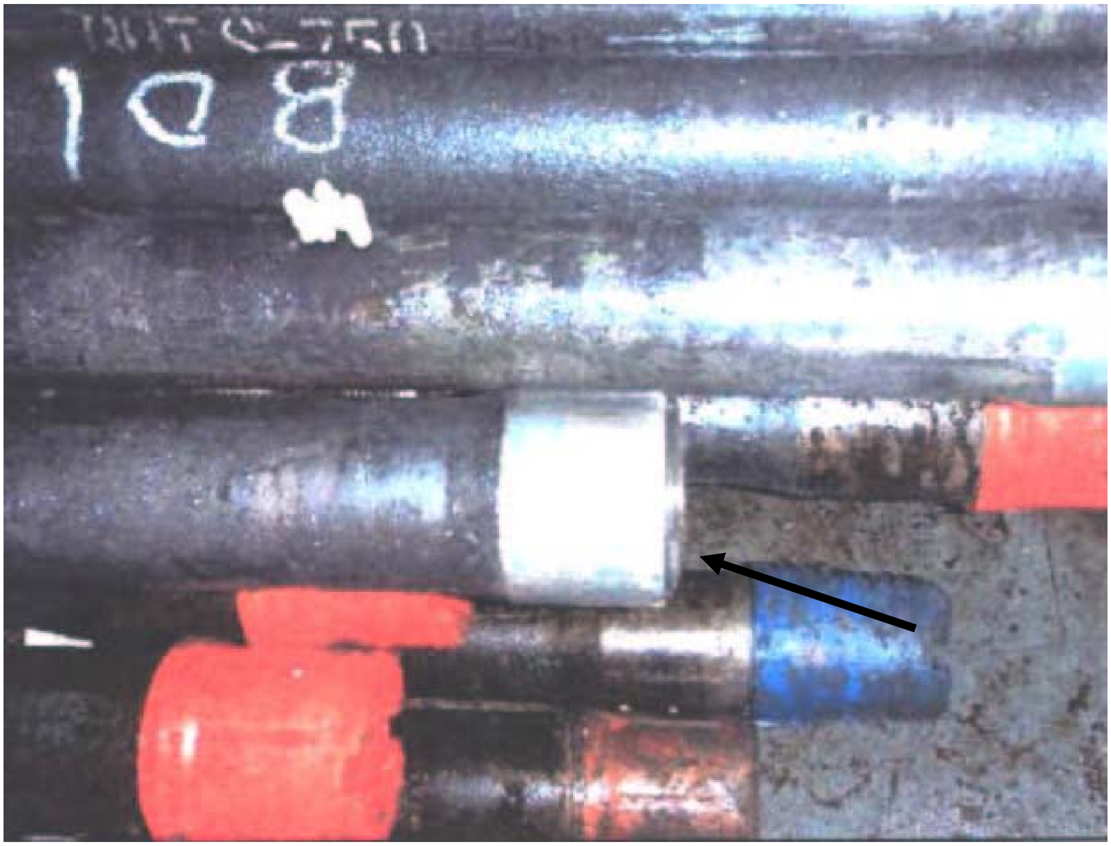
Recommendations

Due to the specific and unique nature of the events described in this report, the Panel recommends that no general Safety Alert be issued. As described in this report, the events leading to this incident are covered adequately by current regulations and industry practice. The Panel recommends no further actions by the MMS.

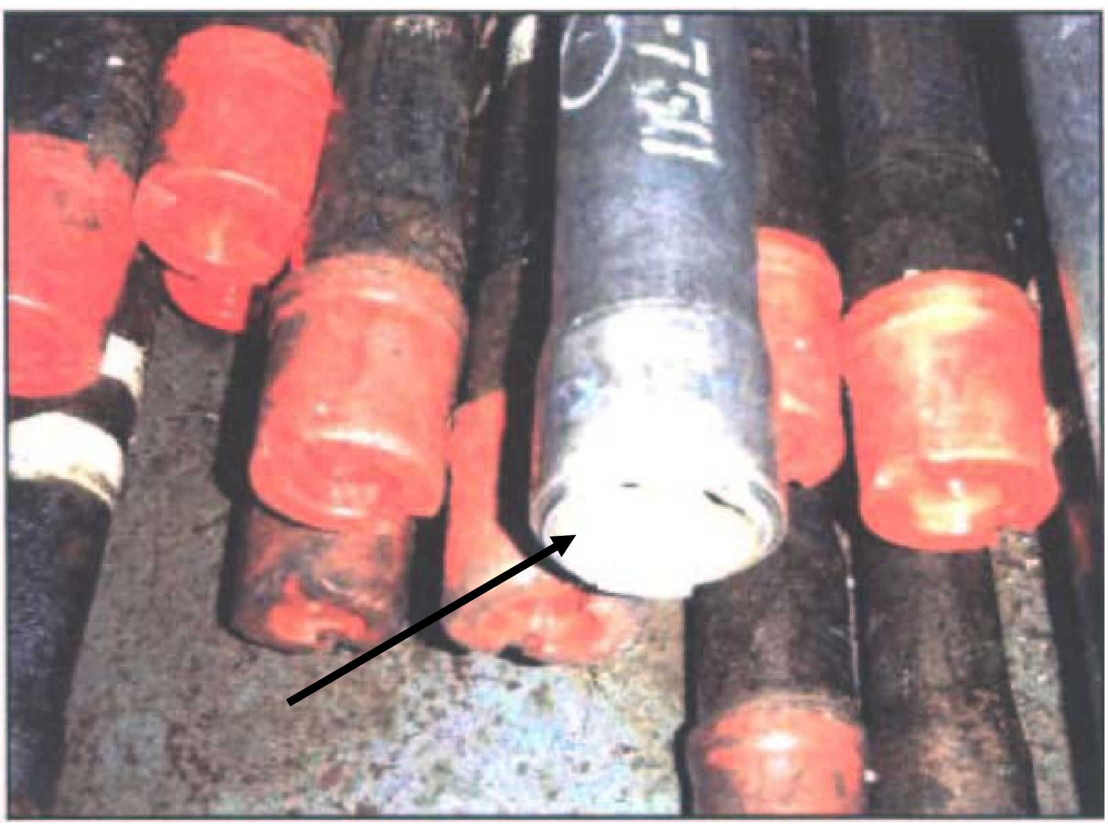
Attachment 1



Location of Lease OCS G-05479, Eugene Island 28, Well No. 4.



Side View of Broken Connection



End View Showing Pin Twisted Off

Three (3) – Failed Tubing Sections **Partek Job #62210-FA-001**

Rooster Petroleum **Sheet 1 of 5**

Attention: Tod Darcey **24 June, 2008**

BACKGROUND:

Rooster Petroleum provided three (3) tubing sections which represented two (2) separate failures removed form Eugene Island Block 28. The first section was from the first failure and Sections 2 & 3 represented the second failure. Partek Laboratories, Inc. was asked to comment concerning the failures

MACROEXAMINATION:

The fracture surface of the first tubing section was cleaned using a mild caustic solution to remove all traces of surface contamination/oxidation and staining. This surface was then examined using an optical microscope at magnifications up to 20X. The fracture exhibited a relatively flat, fine-textured area for approximately 1/2 of the circumference and 45^o shear for the remaining surface area. There was evidence that progressive crack growth had occurred prior to failure. There was also evidence of deep surface gouges mostly likely the result of subsequent fishing operations. All of these features are suggestive of a fatigue type failure. Reference photographs are attached to this report.

The sections 2 & 3, which represent the second failure, were examined and found to exhibit extreme wall thinning the result of flow cuts. Reference photographs are attached to this report.

CONCLUSION:

Based on available information and laboratory observation the first tubing most likely failed as a result of fatigue cracking that would greatly reduce the load carrying capacity of the tubing. Final failure was the result of ductile tensile overload. The second tubing section failed as a result of ductile tensile overload most likely because the load carrying capacity was decreased as a result of the extreme flow cuts.

Respectfully Submitted,

R.L.Sutton

R.L.Sutton, P.E.
Staff Metallurgist
Reg. No. 24078

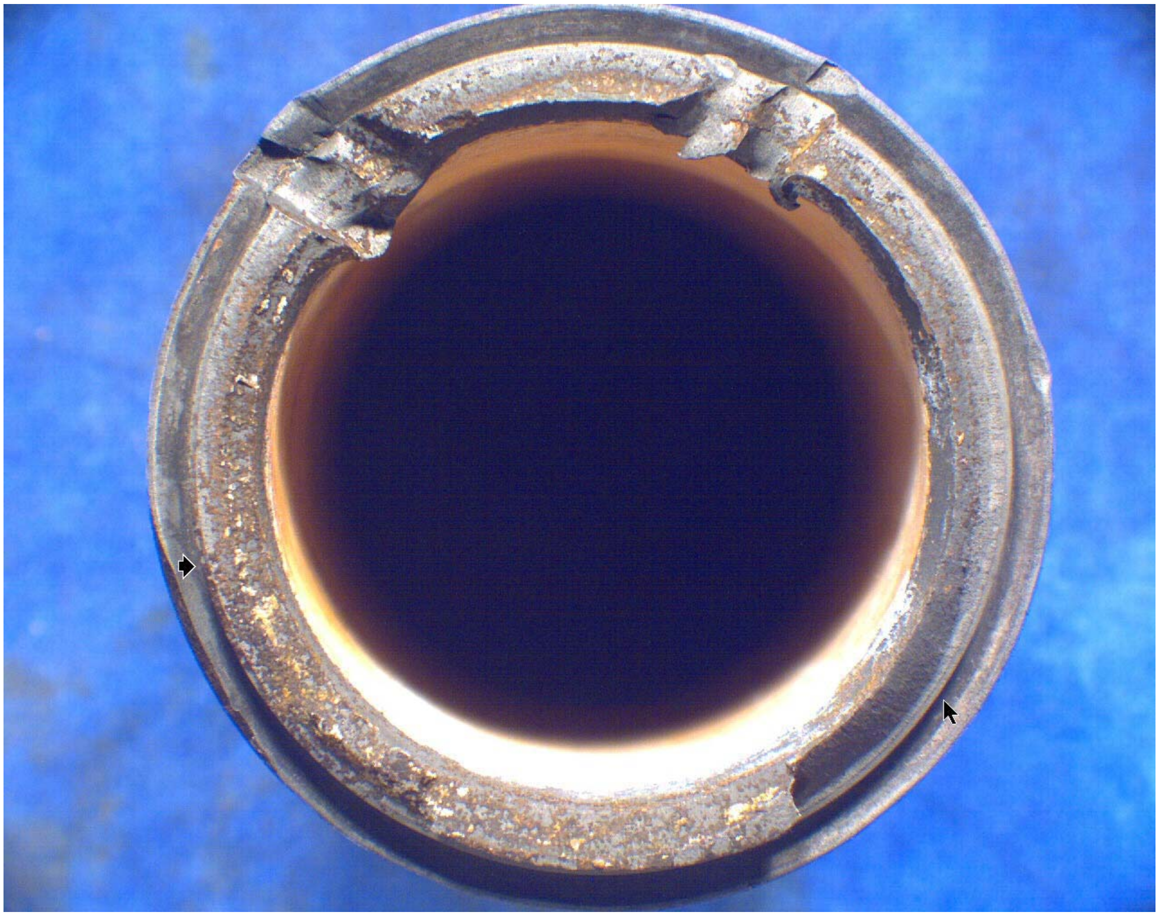
Photograph 1

Photograph showing the as-received tubing sections.

Photograph 2

Photomacrograph showing the facture surface of the first failed tube prior to cleaning. Note the deep indentations most likely the caused by the fishing operation.

Photograph 3



Photomacrograph showing the fracture surface of Piece# 1 shown in Photograph# 2 after cleaning. Note the flat fine textured area between the arrows. This feature is typical of fatigue type cracking which would greatly reduce the load carrying capacity of the tubing.

Photograph 4

Photomacrograph showing the fracture surface of Piece#2. Note the extreme flow cut areas which caused extreme wall thinning. This would also greatly reduce the load carrying capacity of the tubing.