OCS Report
MMS 85-0050

Investigation of October 20-27, 1983 Blowout, Eugene Island Block 10, Lease OCS-G 289.2 Gulf of Mexico

U.S. DEPARTMENT OF THE INTERIOR/MINERALS MANAGEMENT SERVICE

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by

Maurice Stewart

Jack Hendricks

Robert Whitaker

Robert Meurer

Ronald Prehoda

1985

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ATTACHMENTS

I. AUTHORITY AND PROCEDURES FOR THE INVESTIGATION AND PUBLIC REPORT

A. Authority

A blowout and fire occurred during the period of October 20-27, 1983, resulting from workover operations on Well No. 3, Lease OCS-G 2892, Eugene Island Block 10, Gulf of Mexico, off the Louisiana Coast. Pursuant to Section 208 (Subsection 22(d), (e), and (f) of the Outer Continental Shelf Lands Act Amendments of 1978), and the United States Department of the Interior Regulations, 30 CFR Part 250, an investigation and public report must be made. The following Minerals Management Service (MMS) personnel were assigned as an investigative panel to investigate and prepare a public report:

Maurice Stewart
Jack Hendricks
Robert Whitaker
Robert Meurer
Ronald Prehoda

B. Procedures

An informal hearing was held at Transco Exploration Company's office, Houston, Texas, on August 29, 1984. Transco Exploration Company, Penrod Drilling Company, and Texas Iron Works were represented at the hearing. Individuals who attended the hearing are listed in Attachment No. 1.

The investigative panel informally questioned witnesses. Some of the initial questions were directed to Transco Exploration Company and Penrod Drilling Company personnel who were on the rig, Portal 40, immediately before the accident occurred. Questions near the close of the hearing were more concerned with the possibility of different or new industry safety practices, procedures, and/or technology that could be used in offshore workover operations to help prevent recurrence of similar accidents.

On November 17, 1983, at Houston Metal Cutting, Houston, Texas, the panel observed while T. H. Hill and Associates disassembled the Texas Iron Works ball-type, manually operated drill string safety valve (TIW safety valve) recovered from Portal 40 rig, for the purpose of conducting a failure analysis of the valve, known to be pertinent to the accident which damaged the drilling rig.

II. INTRODUCTION

A. Background

Lease OCS-G 2892 covers 2,302.24 acres. It is in the southerly portion of Block 10 in the Eugene Island Area, Gulf of Mexico, off the Louisiana Coast, immediately adjacent to the Federal-State boundary (See Attachment No. 2). The lease was issued effective December 1, 1974, to Shell Oil Company (75%), Florida Gas Exploration Company (4.1666%), Freeport Minerals Company (4.1667%), Transcontinental Production Company (4.1667%), Southland Royalty Company

(6.2500%), Eason Oil Company (4.1667%), and Crown Central Petroleum Corporation (2.0833%). The cash bonus totaled $960,000 with a fixed royalty rate of 16 2/3 percent and an annual rental of $3 per acre. On April 7, 1975, Transcontinental Production Company filed a notice of change of name to Transco Exploration Company, effective March 10, 1975.

Transco Exploration Company was designated operator by the other lease interest holders. Transco Exploration Company contracted with Penrod Drilling Company to conduct the initial drilling and subsequent workover operations on Well No. 3, Lease OCS-G 2892.

A Plan of Exploration for Lease OCS-G 2892 was submitted by Transco Exploration Company on January 30, 1980, and was approved by the Oil and Gas Supervisor, Operations Support, on February 29, 1980. The plan proposed the drilling of two wells, one being the subject No. 3 well. The Application for Permit to Drill (Form 9-331C) was submitted to the Lafayette District Office on September 8, 1980, and was approved on September 15, 1980, by the Lafayette District Supervisor. The well was to be drilled vertically from a surface location 1,750 feet from the south line and 1,350 feet from the west line of Eugene Island Block 10 to a proposed total depth of 16,000 feet true vertical depth.

B. Description of Incident

1. Well Spudded

On June 23, 1981, Well No. 3 was spudded by Portal 40, a posted-barge, submersible-type mobile drilling rig. Thirty-six inch pipe was driven to approximately 250 feet measured depth (MD), or 198.4 feet below the mud line. Twenty-inch conductor casing was set and cemented at 815 feet MD; 16-inch surface casing was set and cemented at 4,505 feet MD; and an 11 3/4-inch intermediate casing string was set and cemented at 11,550 feet MD. Two casing liners were used in the well. A 9 5/8-inch liner was set and cemented with the bottom at 13,997 feet MD and the top at 11,351 feet MD. A 7-inch liner was set and cemented at the well's total depth of 15,573 feet MD, with the top at 13,768 feet MD. The well was temporarily abandoned on October 9, 1981. The final mud weight to drill to total depth was 18.1 pounds per gallon (ppg).

2. Initial Well Condition

On May 20 and 25, 1982, Transco Exploration Company received approval from the Lafayette District Supervisor to reenter the well, tie back the 7-inch casing liner to the surface, and begin completion work. The well was temporarily abandoned a second time on June 30, 1982. Final completion work to reenter and perforate the well was approved by the Lafayette District Supervisor on February 3, 1983. The well was completed on February 23, 1983, as a shut-in gas well with an initial test of 8,400,000 cubic feet of gas per day, with 294 barrels of condensate at a flowing tubing pressure of 10,250 pounds per square inch (psi). The well began production in March 1983 with 990 psi pressure on the 3 1/2- by 7-inch tubing-casing annulus. During August 1983, the well was shut in, and by September 1, 1983, a casing pressure in excess of 4,000 psi had developed. Attempts to return the well to production and to continue monitoring the casing pressure were unsuccessful because the wellhead master valve could not be opened without major repair work involving a hot tap of the valve.

3. Operation Plan and Implementation

On September 22, 1983, Transco Exploration Company received approval from the Lafayette District Supervisor to workover Well No. 3, to repair the failed master valve, and to correct the well's casing pressure problem. Penrod's Portal 40 rig was contracted again by Transco Exploration Company to do the well work, and operations began on September 29, 1983.

The gate of the failed master valve was successfully drilled, and communication with the tubing string was established on October 3, 1983. A pump-through tubing plug was set in the tubing at a depth of 15,098 feet in a tubing nipple. The tubing was first bled from 10,000 psi to 3,000 psi, and the tubing was then loaded with 140 barrels of 11.6 ppg calcium chloride fluid ($CaCl_2$). The tubing pressure was then bled to 0 psi.

The tubing was perforated at 14,983-90 feet, and the well was reverse circulated with 17.4 ppg kill mud, until dead on both the tubing and casing. A backpressure valve was installed; the christmas tree was removed; and a 7 1/16-inch, 15,000 psi working pressure blowout preventer (BOP) stack was rigged up and tested to 12,000 psi. After all of the production tubing and associated down-hole tools were pulled from the well, a new production packer assembly--consisting of a 30-foot seal bore extension, one joint of 3 1/2-inch tubing with a corrosion barrier ring (CB), and a pump-out plug rated at 1,500 psi shear down pressure--was set at a depth of 14,945 feet using an electric line.

After the packer was set, a cementing squeeze tool was run in the hole on a work string, and the casing-tubing annulus was tested to 500 psi for 30 minutes. The 17.4 ppg mud was displaced with seawater by pumping down the work string through the cementing squeeze tool bypass to create a negative differential of 6,300 psi across the packer. The bypass was closed; the work string was bled to 0 psi and observed for 30 minutes with no build-up in pressure. The seawater was then reversed out with mud, and the work string and cementing squeeze tool were laid down.

Equipment was rigged up to begin running the 3 1/2-inch, 10.30-pounds-per-foot internal plastic coated corrosion bond production tubing back into the well. Each tubing connection was made up to 3,000 foot-pounds using torque control, and was internally gas tested to 12,000 psi. The seal bore assembly was landed in the packer, and 10,000 pounds of weight were set down on the packer. The casing-tubing annulus was tested to 2,500 psi, with no increase in tubing pressure.

4. Problem on Displacement

The tubing string was picked up to approximately 7 feet above the packer, to the depth of 14,938 feet (See Attachment No. 3). Displacement of the

17.4 ppg mud was initiated down the tubing by pumping three spacer pills followed by 9.0 ppg $CaCl_2$ packer fluid.

The displacement pressure had reached a maximum of 6,600 psi, and steadily decreased to 3,900 psi after pumping 306 barrels (bbls) of the packer fluid. At this time, between 6 a.m. and 7 a.m. on October 20, 1983, the well was observed to be flowing. The well was shut in by closing the annular BOP and choke. (The BOP stack and wellhead arrangement are shown in Attachment No. 4.) At this point the shut-in tubing pressure (SITP) was 5,500 psi and the shut-in casing pressure (SICP) was 8,000 psi, with 311 bbls of 17.4 ppg mud having been recovered, compared to the 306 bbls of 9.0 ppg $CaCl_2$ water pumped.

5. Remedial Sequence to Bring Well Under Control

The decision was made, upon shutting the well in, to displace the 9.0 ppg $CaCl_2$ fluid by reverse circulating the 17.4 ppg mud. At this point, all equipment was retested to 10,000 psi, including the TIW safety valve.

With an SITP of 5,800 psi and an SICP of 8,000 psi, reverse circulation was initiated by pumping 17.4 ppg mud down the annulus, using the cementing pump, and by taking 9.0 ppg $CaCl_2$ returns from the tubing through the choke and gas buster. Surface equipment is shown in Attachment No. 5.

After 24 bbls of 17.4 ppg mud were pumped into the annulus, water followed by gas started leaking from the threads between the crossover sub and the TIW safety valve. Pumping operations were suspended with the choke in an open position. A shut-in casing pressure of 7,100 psi and a tubing pressure of 6,600 psi were observed. The leak in the crossover thread sealed without any attempt by the rig crew to stop it. At this time, it was decided to investigate the connection leak, which required shutting the well in.

6. Rig Evacuated

When the crew attempted to close the TIW safety valve, the movement was hard, and the valve stopped solidly after moving less than a quarter of a turn. A strong flow of gas immediately started from the TIW safety valve actuator stem. An attempt was made to return the valve to the open position, but the movement was just as hard as in the attempt to close the valve. In a final effort to close the TIW safety valve, four men using a 36-inch wrench for additional leverage were unsuccessful. Gas continued to leak through the actuator stem during the attempts to close the TIW safety valve, making working conditions unacceptably dangerous. The rig was ordered abandoned at approximately 10:35 a.m. on October 20, 1983.

All 40 of the personnel on the Portal 40 rig immediately evacuated to a workboat and were transported to Transco Exploration Company's Eugene Island Block 10 Production Platform A, located approximately one-half mile towards the southeast.

During the blowout, Transco Exploration Company secured and mobilized 46 marine vessels to the site, including boats with spray capability. At approximately 3 p.m. on October 22, 1983, while being sprayed with water, the gas flow ignited. The ignition source is unknown.

7. Well Control Operations

Several kill plans were studied, and the decision was made to use a plan which called for pumping down the annulus and taking returns through the tubing. The plan would also necessitate close monitoring of pumping rates and pressures to prevent losing returns due to fracturing the formation through the well's perforations, or to avoid rupturing the casing down hole. By 3 p.m. on October 26, 1983, all the necessary equipment to begin the well-killing operation was in place, and all equipment that would be subjected to pumping and/or well pressure, such as piping and connections, had been tested to 15,000 psi. One hour later, pumping operations were started by circulating seawater into the annulus at a rate of 1.2 barrels per minute (bpm) with 9,000 psi pump pressure. Subsequently, the rate was increased to 18.0 bpm, at which point the pressure reached a maximum of 10,000 psi before starting to drop. The pressure dropped steadily to 7,250 psi, and then increased to 8,000 psi as water reached the surface. As seawater discharged from the tubing, the fire was extinguished, and the pumping of 18.0 ppg mud was started. The pressure increased to a maximum of 9,000 psi as mud entered the casing-tubing annulus.

When a volume of mud equal to the casing-tubing annulus volume had been pumped, the pump rate was reduced according to the schedule calculated to prevent excessive down-hole pressures on the casing and the formation. (The pumping schedule is shown in Attachment No. 6.) After mud reached the surface, the gas content appeared to be increasing. The pump rate was increased to compensate for the increased flow of gas and mud, but was then reduced to 6.0 bpm, as mud weighing 15.5 ppg was caught on the rig floor. The pump rate was further reduced to 1 1/2 bpm when it appeared the well killing operation was successful. All pumping was stopped, and at 10 p.m. on October 26, 1983, the well was dead on both the annulus and the tubing. Workover operations were then completed, and the well was placed on production.

III. FINDINGS

A. Preliminary Activities

In September 1983, Well No. 3 remained shut in, with a pressure of 4,500 psi on the tubing-production casing annulus. This pressure could not be bled off.

In order to monitor the casing pressure while producing, attempts were made to return the well to production. However, the master valve could not be opened, and attempts to repair the valve and actuator were unsuccessful. A decision was made to perform a workover to:

1. Repair the failed master valve, and

2. Repair the down-hole leak.

Transco was given approval by the Lafayette District Office to perform the workover. Utilizing Penrod Drilling Company's Portal 40 rig, Transco planned the following sequence of events:

1. Establish communication with the tubing by drilling a hole, under pressure, through the gate of the closed valve.

2. Kill the well by loading both the casing and annulus with 17.4 ppg mud.

3. Pull the production tubing from the well and inspect it.

4. Mill out and remove the existing production packer from 15,140 feet.

5. Run a new packer with a pump-out plug installed below the packer for pressure isolation.

6. Displace the mud with 9.0 ppg calcium chloride ($CaCl_2$) completion fluid.

7. Install the christmas tree, release the pump-out plug, and retest the well.

B. Workover Operations Summary to Time of Loss of Well Control

On September 29, 1983, workover operations began on Eugene Island Block 10, Well No. 3 with the Portal 40 rig.

The wellhead master valve was hot tapped, and the tubing string was killed with 17.4 ppg mud. All production equipment, including the Baker "DB" packer, was retrieved from the well.

Recompletion was initiated by the electric line installation and pressure testing of a new "DB" packer equipped with a pump-out plug, set at 14,945 feet. Tubing (3 1/2") was run in the hole with a packer seal assembly on bottom and landed in the packer bore. The tubing-casing annulus was successfully pressure tested, following which the tubing was picked up out of the packer to allow displacement.

During displacement of the tubing with 9.0 ppg $CaCl_2$, the well was observed to be flowing from the annulus. The annular preventer, Swaco choke, and tubing TIW valve were closed with 5,800 psi on the tubing and 8,000 psi on the annulus. At this point, reverse circulation was initiated by pumping 17.4 ppg mud down the annulus, with tubing returns through the Swaco choke. After reverse circulating 24 bbls, water followed by gas began leaking from threads connecting the crossover sub and TIW valve.

An attempt was then made to close the TIW valve to facilitate repair of the thread leak. However, the ball stopped solidly after the valve stem was moved less than a quarter turn, and a strong flow of gas to the atmosphere immediately started from around the TIW safety valve actuator stem. The ball also refused to move during attempts to open the valve. Therefore, efforts to close the valve were resumed. Four men using the valve wrench and a 36-inch wrench for additional leverage could not close the TIW valve. Gas continued to leak through the actuator stem during attempts to close the valve.

The replacement Halliburton valve and TIW valve were opened with the Swaco choke closed. The kill-line valve on the BOP stack and Swaco choke were opened.

With an SITP of 5,800 psi and an SICP of 8,000 psi, reverse circulation was initiated by pumping 17.4 ppg mud down the annulus, using the Halliburton pump, and taking 9.0 ppg $CaCl_2$ returns from the tubing through the Swaco choke and gas buster.

The Halliburton pump was stopped and an SICP of 7,100 psi was recorded. With the choke left in an open position, a tubing pressure of 6,600 psi was observed.

The leak in the crossover thread sealed without any attempt by the rig crew to stop it. The decision was made to investigate the connection leak, which required shutting the well in.

C. Loss of Control and Fire

When it became obvious the valve could not be closed, and the leaking gas made working conditions unacceptably dangerous, the Transco drilling foreman ordered the rig abandoned. At the time of abandonment, gas was flowing from the leaking actuator, through the choke, the gas buster vent, and the shale shaker.

Immediately, all 40 of the personnel on the Portal 40 rig were placed on a workboat and taken to Transco's Eugene Island Block 10 Production Platform A, located approximately one-half mile southeast. No incidents occurred during the accident or during the evacuation to the production platform.

By early Friday, October 21, the tubing-mounted equipment had parted between the TIW safety valve and the crossover sub. Gas was observed to be blowing vertically through the derrick and horizontally out of the TIW safety valve body.

The idea of using an external tester to seal the TIW valve actuator leak was no longer feasible, as there was no way to hold back pressure on the system. The intensity of the gas flow precluded removing the bell nipple and installing a riser to the rig floor, and then mounting BOPs on top of the riser. This also prevented installing a set of BOPs upside down over the TIW valve body. From measurements of the tubing above the rig floor and the BOP stack, it was also determined that the lower set of pipe rams could not be closed, since the upset tubing connection was opposite the rams. This prevented installing the shear rams in any but the top set of pipe rams, which would not allow any provision to install a set of blind rams above the shear rams.

The risk of starting a fire by moving any of the traveling or rig floor equipment out of the gas flow was deemed to be too great, due to the intensity of the gas flow.

On Saturday, October 22, the well ignited, and the derrick collapsed about an hour later.

D. Damage

The fire resulted in major damage to the Portal 40 rig. The derrick collapsed about an hour after the well ignited. The costs incurred as a result of the loss of well control and fire amounted to:

1.	Rig Damage	-	$3,135,000
2.	Well Costs	-	4,470,000
	TOTAL		$7,605,000

E. Subsequent Findings

1. The initial well kick apparently occurred as a result of the packer plug being "pumped out" or removed from the bore of the packer. The "pump out" type plug was secured in position by shear pins designed to require 1,500 psi pressure differential to cause removal of the packer pins. It is Transco's conclusion that the rated strength of the shear pins must have been accidently exceeded at some point while displacing the tubing with packer fluid, although Transco is unable to determine that a differential pressure of the necessary magnitude occurred during the displacement operation.

2. Part of a teflon CB ring apparently wedged between the ball and the seal of the TIW safety valve, jamming the valve and preventing it from closing. The wedged CB ring fragment also caused a misalignment of the TIW valve actuator stem, which allowed gas to escape past the O-ring of the stem, thus flow-cutting the valve and resulting in uncontrolled flow from the well (See Attachment No. 7).

IV. CONCLUSIONS

A. The proximate cause of the incident was loss of well control. The loss of well control resulted from:

1. The pump-out at the Baker plug sometime during the pressure testing, circulating, or displacement process, which allowed gas to enter the well bore and start the well flowing, and

2. The lodging of foreign material in the TIW safety valve, leaving the valve inoperative and nonsealing. Under the continued, leveraged force exerted to close the valve, the actuator stem began leaking and control was lost. (Photographs of the analysis of the TIW safety valve are included as Attachment No. 7.)

3. There is a very small chance that a CB ring could become dislodged from a tubing joint and ultimately cause serious damage to the TIW valve. How this could have happened is open to speculation; over-torquing is a possibility.

B. The proximate cause of the ignition of the escaping gas is unknown.

C. Relationship of incident to regulations.

A determination was made that Transco did not violate any regulations.

V. RECOMMENDATIONS

A. The panel recommends that an evaluation be made of drill string safety valves to identify designs which best meet criteria for safety, reliability, and operational flexibility for workover operations.

B. The panel recommends that an evaluation be made of packer pump-out plugs relative to design reliability and the range of pressure variations which may be safely tolerated without risk of failure.

C. The panel recommends that tubing-running procedures be evaluated to assure permanency of rig installations where CB or similar such rings are inserted in tubing joints as corrosion protection.

D. The panel recommends that this case be closed with the submission of this report.

Attachment No. 1

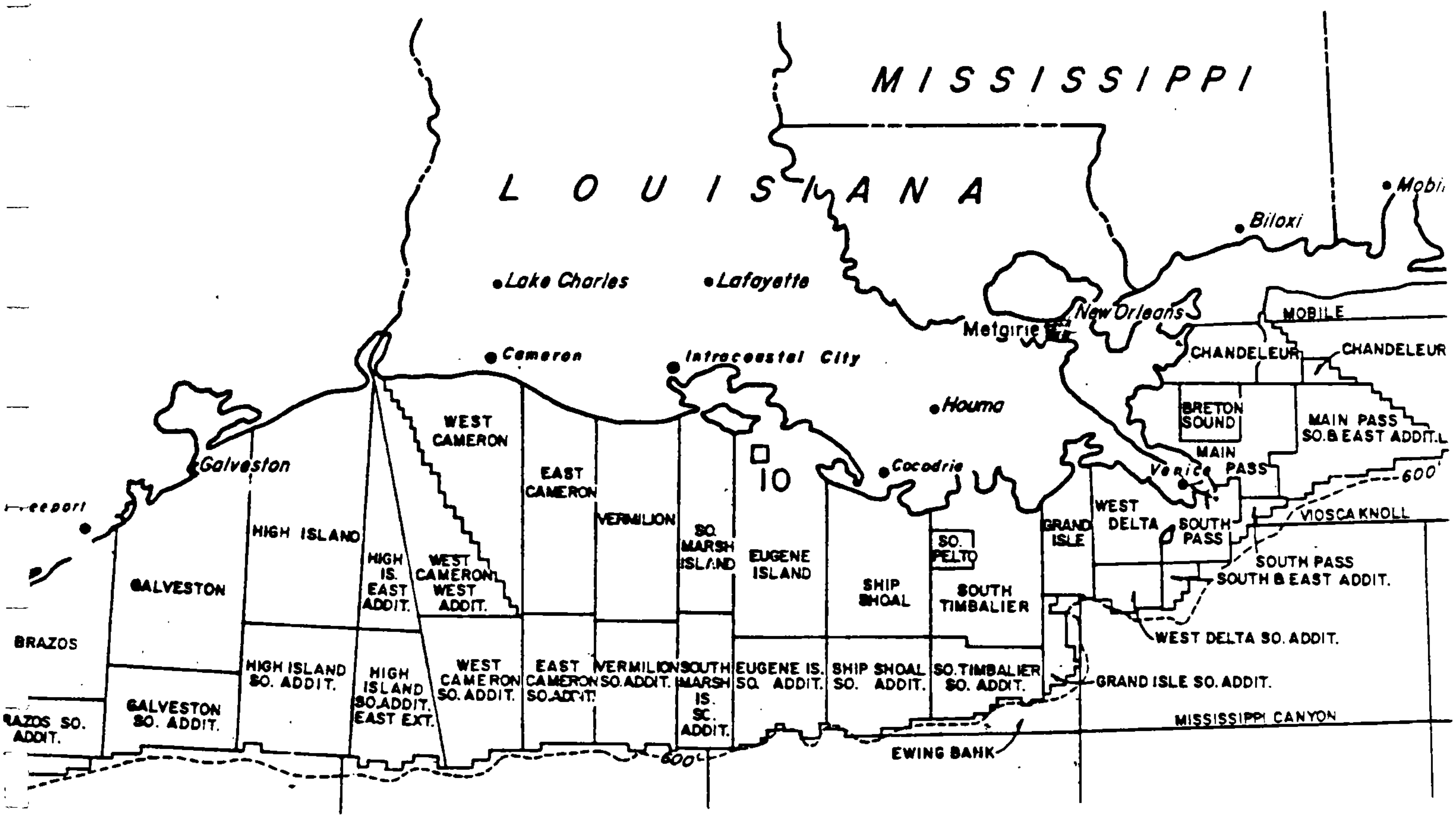
PERSONNEL ATTENDING INFORMAL HEARING

EUGENE ISLAND BLOCK 10, WELL NO. 3

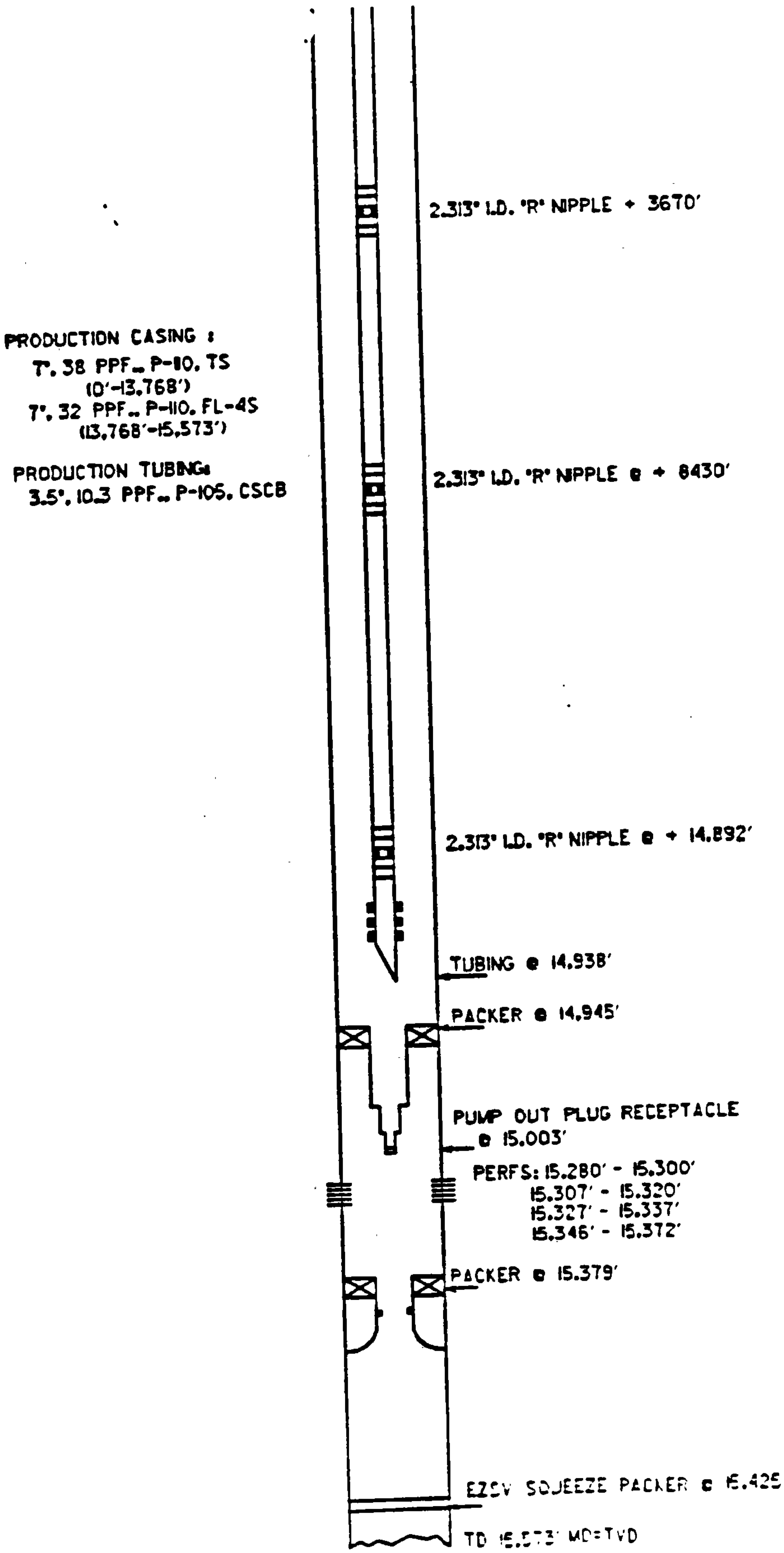
TRANSCO EXPLORATION COMPANY
WEDNESDAY, AUGUST 29, 1984

	Name	Organization/Company
1.	Bill Bruha	Transco Exploration Company
2.	Maurice Stewart	Minerals Management Service
3.	Jack Hendricks	Minerals Management Service
4.	Robert Whitaker	Minerals Management Service
5.	Ronnie Arnold	Texas Iron Works
6.	Kay Morgan	Transco Exploration Company
7.	Kent Rogers	Transco Exploration Company
8.	Chris Record	Transco Exploration Company
9.	Randy Bailey	Transco Exploration Company
10.	Bill Picquet	Transco Exploration Company
11.	Darrell Molnar	Transco Exploration Company
12.	E. J. Petre	Penrod Drilling Company
13.	I. C. Hunt	Penrod Drilling Company
14.	Robert Meurer	Minerals Management Service
15.	Ross Spencer	Transco Exploration Company
16.	Joe S. Davis	Transco Exploration Company
17.	Darrell Elston	Transco Exploration Company

OCS - G 2892 WELL NO. 3
EUGENE ISLAND BLOCK 10
VICINITY MAP

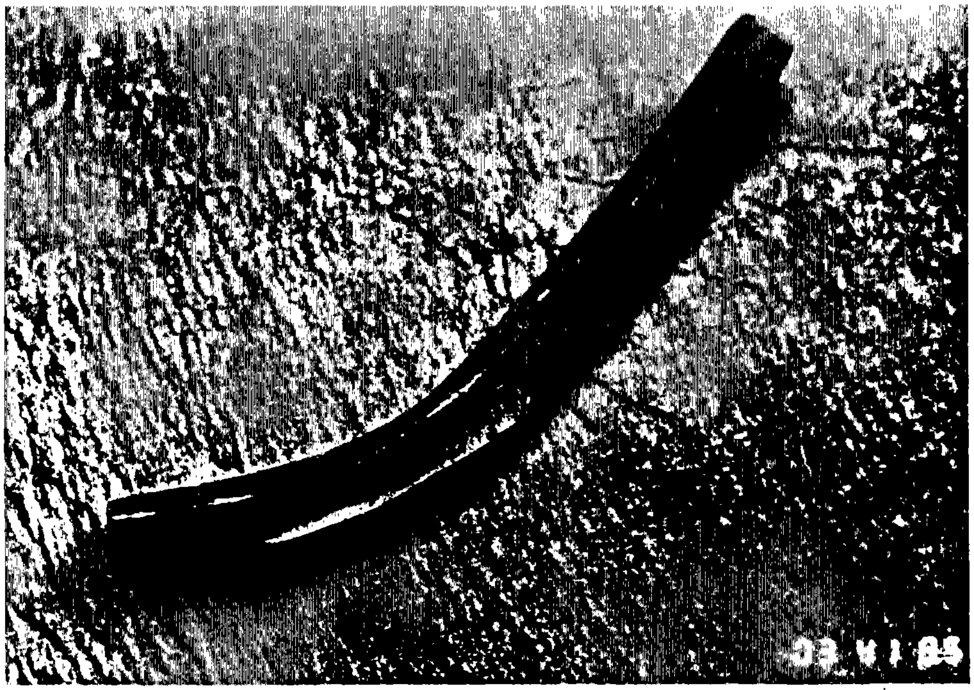


DOWNHOLE EQUIPMENT ARRANGEMENT AT TIME OF LOSS OF CONTROL

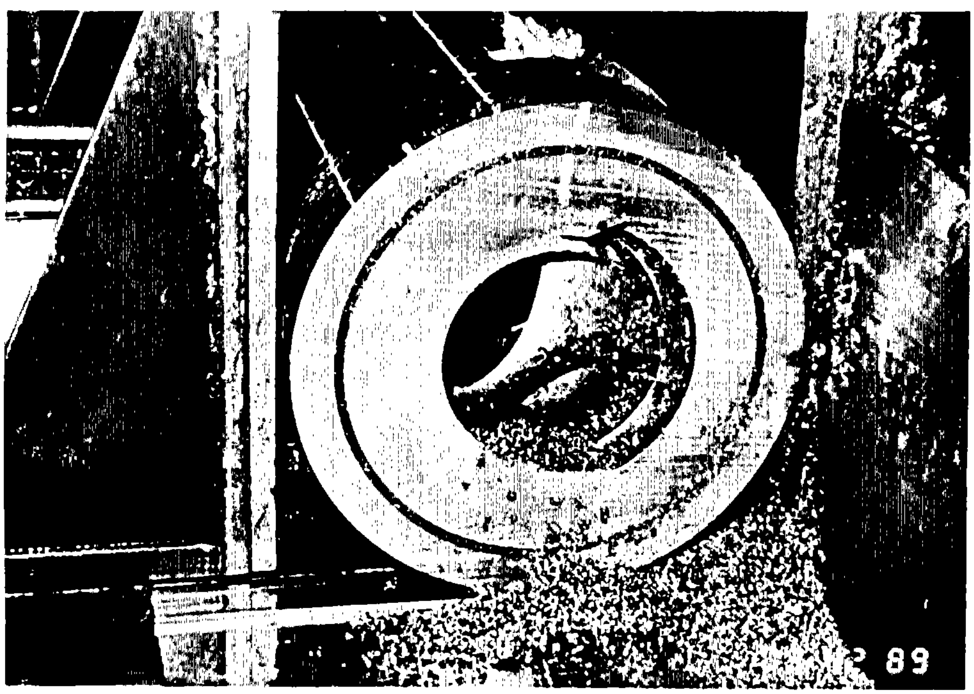


As received condition of safety valve.

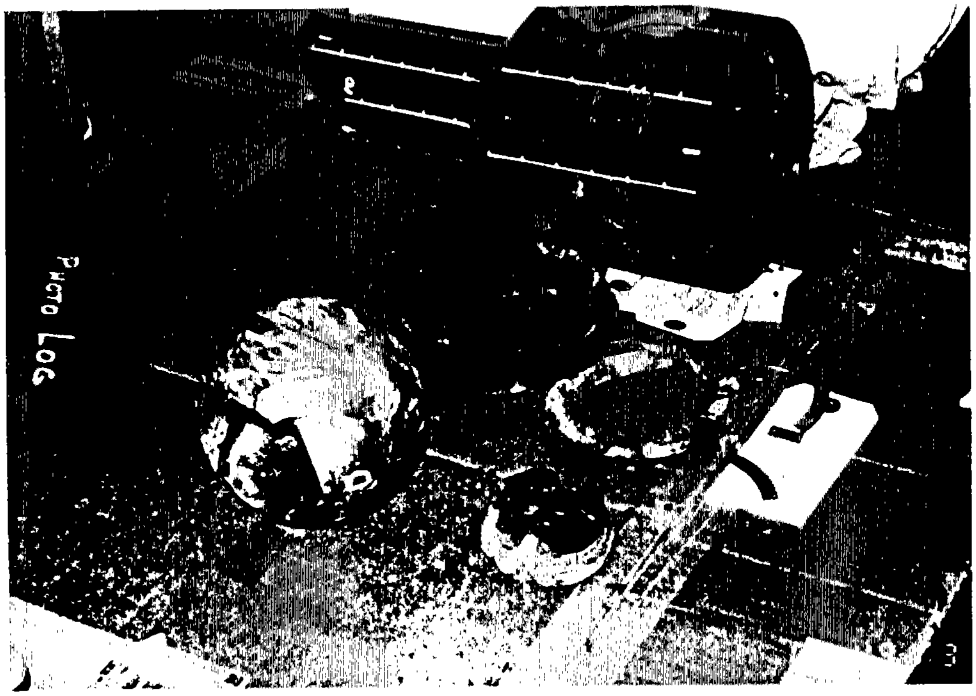
As received condition of safety valve.



CB ring fragment found in the valve (2.5X).



Valve immediately after sectioning.



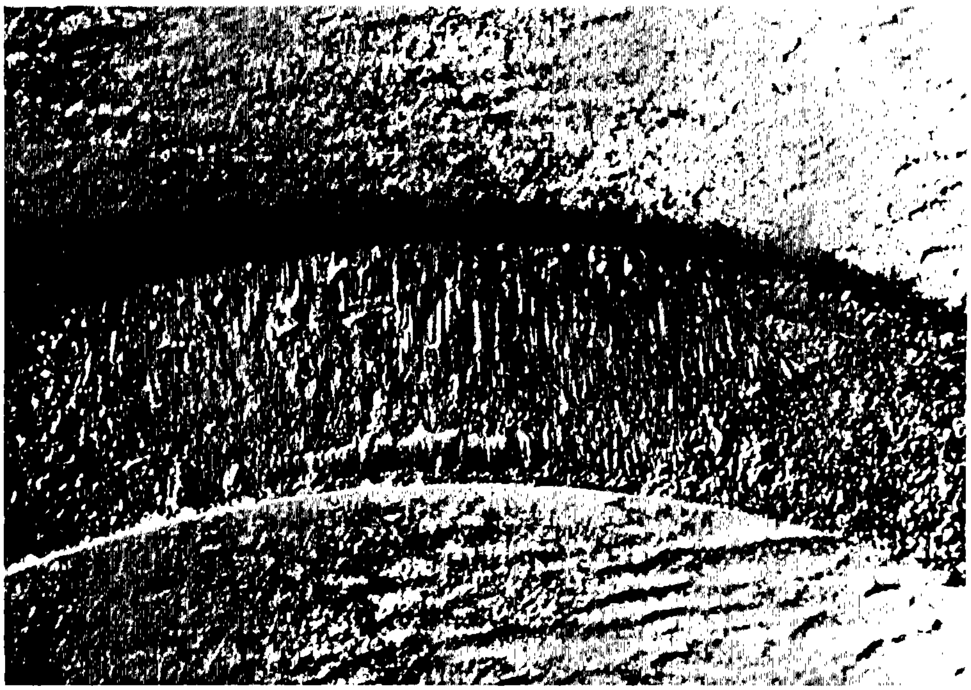
Valve components after sectioning.

Damage on face of ball and key slot.

Closeup view of CB ring mark on ball (3X).

Misalignment and interlocking of stem and ball at point of mechanical damage (2X).

Detail of contact point between ball and floating insert (3X). Contact pressure prevented flow erosion.



Radial flow cutting on upper side of spring (3X).

Attachment No. 8

GLOSSARY

<u>Annulus</u> -- The space between the surface casing and the producing or well bore casing.

<u>Blowout</u> -- A sudden, violent expulsion of oil, gas, and mud (and sometimes water) from a drilling well, followed by an uncontrolled flow from the well.

<u>Bridging</u> -- Caving of walls and accumulation of formation materials in some interval of the hole, thus preventing access to the bottom of the well.

<u>Cement</u> -- The substance used to fix the casing in the hole. Cement is pumped into the hole between the walls of the hole and the outside of the casing. Upon hardening, it keeps the casing stationary in the hole and prevents leakage between the different formation strata penetrated when drilling the hole.

<u>Casing</u> -- Heavy steel pipe used to seal off formation fluids from the hole and to keep the hole from caving in. There may be several concentric strings of casing (one inside the other) installed and cemented in a single well.

<u>Diverter System</u> -- An assembly of piping and valves (frequently air-operated) connected by welding to a well's surface or conductor casing to facilitate venting of gas kicks frequently encountered at relatively shallow depths in the course of drilling the well.

<u>Mud</u> -- A special mixture of clay, water, and chemical additives pumped downhole through the drillpipe and drill bit. The mud cools the rapidly rotating bit, lubricates the drillpipe as it turns in the well bore, carries rock cuttings to the surface, and serves as a plaster to prevent the wall of the borehole from crumbling or collapsing. Drilling mud also provides the weight or hydrostatic head to prevent extraneous fluids from entering the well bore, and to control downhole pressures that may be encountered.

<u>Kick</u> -- Loss of normal fluid circulation caused by formation pressure from below, in excess of that exerted by the drilling fluid (mud) being pumped into the well. If efforts to control a kick are unsuccessful, violent and uncontrolled expulsion of the drilling fluid from the hole may lead to a blowout.

<u>Blowout Preventer</u> -- A heavy casing head assembly (stack) consisting of valves equipped with special gates or rams which can be closed around the drill pipe, or which completely close the top of the casing to control well pressure in the event of a kick or blowout.

<u>Drill Pipe</u> -- In rotary drilling, the heavy seamless tubing used to rotate the drill bit and to circulate the drilling fluid (mud).

<u>Spudding</u> -- To start the actual drilling of a well.

<u>Trip Tank</u> -- Tank used to measure drilling mud used to fill drill pipe while pulling the pipe out of the hole.

<u>Well Bore</u> -- The hole in the earth made by the drill; the uncased drill hole from the surface to the bottom of the well.