

Investigation of Blowout and Fire
Eugene Island Block 284
OCS-G 0991 Well A-13
March 1, 2001

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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Investigation and Report

Authority

An uncontrolled flow on Well A-13, resulting in a blowout and fire, occurred aboard the rig *Ensco 51* during drilling operations on Forest Oil Corporation's Lease OCS-G 0987 Platform A, Eugene Island Block 273, in the Gulf of Mexico, offshore the State of Louisiana, on March 1, 2001, at approximately 0100 hours. The bottom hole location of Well A-13 is Lease OCS-G 0991, Eugene Island Block 284. Pursuant to Section 208, Subsection 22(d), (e), and (f), of the Outer Continental Shelf (OCS) Lands Act, as amended in 1978, and the Department of the Interior Regulations 30 CFR 250, the Minerals Management Service (MMS) is required to investigate and prepare a public report of this accident. By memorandum dated March 1, 2001, the following MMS personnel were named to the investigation panel:

Buddy Stewart, Lafayette, Louisiana (Chairman)

John McCarroll, Houma, Louisiana

Tom Basey, Lafayette, Louisiana

Marty Rinaudo, Lafayette, Louisiana

Procedures

On the morning of March 4, 2001, personnel (two engineers and two inspectors) from the MMS Lafayette District conducted an aerial reconnaissance of the platform and drilling rig. The MMS personnel then proceeded to Eugene Island Block 292, Platform B, where Forest personnel had set up their offshore command center. The MMS personnel were able to interview Forest's Representative and several Ensco personnel. Later that day, Forest relocated their offshore command center to the dynamically

positioned *D/B 50*, which had been brought on location to be used as a staging/support vessel. MMS personnel monitored the response effort from the *D/B 50*.

On March 5, 2001, two MMS engineers returned to the incident location for an update on the response effort. The *D/B 50* was on location and Forest, Ensco, and Wild Well Control were continuing operations to assess the site. MMS personnel were able to interview an additional Ensco person.

On March 16, 2001, an MMS engineer and inspector returned to the incident location for an update on the response effort.

On April 11, 2001, the Panel Members met at Forest Oil Corporation's office in Lafayette, Louisiana, and the following individuals were interviewed:

Brian Roney, Ensco International

David Harper, Ensco International

Billy Whisenhunt, Ensco International

Danny Hawkins, Ensco International

Wayne Hession, Ensco International

On April 25, 2001, the Panel Members met at Forest Oil Corporation's office in Lafayette, Louisiana, and the following individuals were interviewed:

Harold Cody, Ensco International

Reggie Howard, BJ Services

Jim Steward, Forest Oil Corporation

On May 9, 2001, the Panel Members visited Seaboard International in Lafayette, Louisiana, and examined their wellhead design.

On May 16, 2001, the Panel Members met at Forest Oil Corporation's office in Lafayette, Louisiana, and the following individuals were interviewed:

Darin Hebert, Cameron

Ned Shifflett, Forest Oil Corporation

Cecil Colwell, Forest Oil Corporation

The panel members met at various times throughout the investigative effort and, after having considered all of the information, produced this report.

Introduction

Background

Lease OCS-G 0991 covers approximately 5,000 acres and is located in Eugene Island Block 284, Gulf of Mexico, off the Louisiana coast. (*For lease location, see Attachment 1.*) The lease was issued effective June 1, 1962, and Forest became the designated operator of the lease on June 8, 1962. Platform A was installed in 1970.

Brief Description of Accident

On March 1, 2001, during an attempt to weld the casing head of a slip-on wellhead, gas flow was noticed coming from the +10 valve. Later, unsuccessful attempts were made to stop the flow, which was then coming from the drive pipe/surface casing annular region. The gas flow eventually ignited and caused extensive damage to the platform. The well bridged over and kill operations were completed. There were no injuries.

Findings

Activities Prior to Loss of Well Control

Planning

February 9, 2001 – The MMS Lafayette District approved Forest Oil Corporation’s Eugene Island Block 284, Lease OCS-G-0991, Well A-13 Application for Permit to Drill (APD). In the APD, Forest Oil Corporation proposed drilling Well A-13 to a measured depth (MD) of 5,476 feet and a true vertical depth (TVD) of 5,153 feet, using the *Ensco 51* jack-up rig. The well would be located in 191 feet of water. Forest Oil Corporation anticipated driving the 24-inch drive pipe to a measured depth of 441 feet MD (441 feet TVD), drilling a 22-inch conductor hole and setting 16-inch conductor casing at 650 feet MD (650 feet TVD), drilling a 14¾-inch surface hole and setting 10¾-inch surface casing at 1,900 feet MD (1,900 feet TVD), and drilling a 9-7/8 inch production hole and setting 7-5/8 inch casing at 5,476 feet MD (5,153 feet TVD).

Summary of Drilling Operations

February 16, 2001 – The *Ensco 51* rig arrived on location and began preload operations. It is important to point out that Forest normally conducts simultaneous operations when drilling on pre-existing platforms. During this drilling operation, extra precaution was used by installing back-pressure valves in all 12 wells located on the platform.

February 22, 2001 – The 24-inch drive pipe was driven to 460 feet MD. A starter flange was installed on the 24-inch drive pipe and a 6-inch, air-

operated, remotely controlled full opening valve was installed at the +10 level.

February 23, 2001 – The 21¼-inch diverter was installed, function tested, and Well A-13 was spudded.

February 24, 2001 – A 22-inch hole was drilled to 670 feet MD/TVD. The hole was circulated clean and a 16-inch scab liner was run to 633 feet MD/TVD and cemented with full returns taken at the +10 valve (*see Attachment 2, for well schematic*).

February 25, 2001 – The diverter system was rigged up on the 24-inch drive pipe and the 16-inch conductor casing was successfully tested to 200 psig.

February 26, 2001 - The diverter system was function tested and drilling operations continued to a depth of 1,700 feet MD/TVD. The well was circulated for one hour, approximately two bottoms up. The well was checked for flow; none was detected. A pill was pumped and the drill pipe was pulled out of the hole.

February 27, 2001 – A Schlumberger wireline unit was rigged up and the 14¾-inch hole was initially logged from 1,694 feet MD/TVD to 633 feet MD/TVD. A second log was run over the same section of hole. The logs showed sands at 710 feet MD/TVD and 1,170 feet MD/TVD. Once the logging tools were pulled out of the hole, a 14¾-inch hole opener was picked up and run in the hole to 1,700 feet MD/TVD, and no fill was detected.

February 28, 2001 – Running tools for the 10³/₄-inch surface casing were picked up, and the 10³/₄-inch surface casing was run in the hole to 1,700 feet MD/TVD. The BJ cement head was rigged up and the well was circulated with a 9.4-ppg mud (pumped two bottoms up). No gas-cut mud was detected and operations proceeded to cement the 10³/₄-inch surface casing (cement in place at 0930 hours). The drilling program then called for the washing of cement in the 24-inch drive pipe by 10³/₄-inch surface casing annulus (*see attachment 2*). This was accomplished by opening the +10 valve and running 1¹/₄-inch wash pipe to a depth of 200 feet from the rotary-kelly-bushing (RKB). The drilling program also called for waiting on cement (WOC) a minimum of 8 hours before cutting off casing. During the period of WOC, the rig crew laid down the 1¹/₄-inch wash pipe, removed the diverter lines, laid down the bell nipple, and rigged up to pick up the diverter. After WOC for 8 hours, the +10 valve was opened to drain the fluid in the 24-inch drive pipe by 10³/₄-inch surface casing annulus. The diverter was then picked up (1730 hours) to make a rough cut on the 10³/₄-inch surface casing. A hot work permit was filled out, the area was sniffed for gas, and a fire watch was established before welding/cutting operations began. The 10³/₄-inch surface casing was cut and the excess was laid down. After removing the diverter, a rough cut was made on the 24-inch drive pipe and the excess laid down. Final cuts began on the 24-inch drive pipe and 10³/₄-inch surface casing.

**Loss of Well
Control**

March 01, 2001 – Final cuts on the 24-inch drive pipe and 10¾-inch surface casing were completed. While final cuts were being made by the welder, the night tool pusher and night driller went down to the boat landing to examine a means of removing the +10 valve. The well was static at this time. The 10¾-inch slip-on wellhead (SOW) by 11-inch, 5,000-psi casing head was lowered down to the wellbay for installation. The SOW was set on the 24-inch drive pipe and 10¾-inch surface casing. The SOW was leveled. The area was sniffed for gas and the welder tacked the 24-inch base plate in four places. The SOW was preheated, with some grease present. Once the SOW was preheated, the welder began to weld on the inside of the SOW. After the 3rd welding rod was burned, a small blue flame was observed. The fire was extinguished and thought to be caused by grease from the wellhead. The area was sniffed for the presence of gas, resulting in no detection of any gas. Operations resumed welding inside the SOW; a second flame ignited and was larger than the previous flame. The flame was extinguished and the area sniffed for the presence of gas, resulting in the gas detector showing a maximum level of gas present. Approximately 0130 hours, the night driller observed a slight flow at the +10 valve.

**Attempts to Stop
Well Flow**

March 01, 2001 - The onsite Forest Company representative was alerted and was informed that gas and fluid were escaping from the +10 valve. The Forest Company representative immediately instructed the crew to close the +10 valve to establish additional hydrostatic head by using 8.6-ppg seawater. An attempt was made to add seawater to the annulus through a ½ -inch gap located between the base plate and 10¾-inch surface casing (*see Attachment #3*). Because of the size of the opening on the base plate and the

rate of 8.6-ppg water being added, sufficient volume could not be added to slow down the current well flow. At this point, rig personnel attempted to install another hose to add 9.2-ppg mud to the 24-inch drive pipe by 10¾-inch surface casing annulus. The flow of the well continued at an increasing rate. An attempt to increase the mud weight to 17.0 ppg was planned. Because of the rapid increase in flow, it was decided to add what was being mixed in the slug pit, which at that time was 16.0 ppg mud. It became difficult for the mud to flow at a steady rate because of the density and the size of the opening between the 24-inch base plate and 10¾-inch casing. As a last attempt to control the well, the Forest Company representative decided to open the +10 valve to allow the 16.0-ppg mud to displace the lighter fluid present inside the 24-inch drive pipe by 10¾-inch surface casing annulus. With the flow of the well increasing and all attempts of adding mud to the 24-inch drive pipe by 10¾-inch surface casing annulus failing, the +10 valve was closed. At approximately 0300 hours, a decision was made to evacuate the rig, and the +10 valve was opened in an attempt to divert flow away from the platform and rig (*see Attachment 4 & 5*). The rig/platform was then abandoned.

Evacuation and Rescue

March 01, 2001 - Personnel abandonment of the *EnSCO 51* and the Eugene Island Block 273 Platform A was accomplished in a safe and orderly fashion. The rig abandonment alarm was activated at approximately 0300 hours. Personnel mustered at the escape capsules and all 43 personnel were accounted for prior to departing the rig. Personnel boarded two escape capsules. In transit to BP-Amoco Eugene Island 273 Platform B, personnel maintained two-way hand-held communication. Personnel were later

transferred to Forest's Eugene Island 292 Platform B. There were no injuries as a result of the incident.

**Subsequent
Activities**

On March 1, 2001, the Forest Spill Management Team was mobilized to respond to the incident. Representatives from Wild Well Control were called in for expert support and to plan and carry out capping and kill operations. Several boats deployed to the location by the Spill Management Team to spray the platform.

On March 2, 2001, 0330 hours, fire erupted on the Eugene Island 273-A Platform; source of ignition is unknown (see Attachment 6). *Ensco 51's* derrick collapsed on the Eugene Island 273 A platform at 0345 hours (see Attachment 7). Because of the excessive heat, boats were unable to spray the platform continuously. Because the hydrocarbon flow was dry gas, dispersant application was not initiated and recovery action was not attempted.

On the morning of March 2, 2001, representatives from Wild Well Control flew to the scene to begin investigations and plan kill operations. The dynamically positioned derrick barge *DB-50* was contracted for well control support. The *Ensco 55* jack-up drilling unit was mobilized to the location to stand by to drill a relief well if needed.

On March 3, 2001, the well partially bridged and the fire went out. An initial visit was made to the platform by Wild Well Control representatives to

assess the situation. The well flowed sporadically until the well bridged on March 5, 2001.

Numerous visits to the platform were made to remove debris around the wellhead to allow the installation of a Ventura Type “sliplock connection” over the 24-inch drive pipe. Once the Ventura Type “sliplock connection” was installed over the 24-inch drive pipe, a diverter and a BOP stack were installed to allow for safe kill operations (*see Attachment 8*).

A portable crane was mobilized to the location and installed on the *Ensco 51* to allow for further removal of debris. Wells A-1 and A-5 were prepared for back-up relief wells. Stimulation boats were mobilized to the location for kill operations. A snubbing unit was mobilized to the location and rigged up. Using a 2-3/8 work string, well A-13 was reentered and cemented to the mudline on June 15, 2001.

Damages

The *Ensco 51* substructure and derrick were completely destroyed in the blowout and subsequent fire. There was severe damage to the production platform and associated production equipment.

Cement Operations

Cementing of 16-inch scab liner:

The 16-inch liner was cemented with a total of 1,035 cubic feet of cement. A spacer of 20 bbls of seawater was used followed by 100 sacks, yield 3.07, of Class-H lead cement mixed at 11.4 ppg (55 barrels of slurry) and 668 sacks,

yield 1.09, of Class-H cement mixed at 16.4 ppg (129 barrels of slurry). After pumping 119 bbls of tail cement, the +10 valve was opened and the cement job was completed with full returns taken at the +10 valve. The cement was displaced with 11.5 bbls of 8.9-ppg mud and the plug was bumped with 1,000 psi. The pressure was released and the float equipment was holding.

Cementing of 10³/₄ inch casing:

The 10³/₄-inch surface casing was cemented with a total of 1,796 cubic feet of cement. A spacer of 20 barrels of seawater was used followed by 487 sacks, yield 3.07, of Class-H lead cement mixed at 11.4 ppg (266 barrels of slurry) and 276 sacks, yield 1.09, of Class-H cement mixed at 16.4 ppg (54 barrels of slurry). Cement was displaced with 5 barrels of seawater. The seawater was followed by 160 barrels of 9.2-ppg mud and the plug was bumped with 1,000 psig. Full returns were observed during the entire cementing procedure, with a total of 30 barrels of cement returns observed at the +10 valve. The pressure was released and the float equipment was holding.

Although both the 700-foot and the 1,200-foot were known to be present in the original well planning, the above 10³/₄-inch casing cement design did not include any additives for shallow-gas control. Further, the cement was not redesigned for the presence of shallow gas after the well was logged; the only change was the reduction in cement volume based on the caliper log.

The cementing company representative was never made aware of any shallow-gas hazards. He stated that if he had been made aware of the shallow

hazards he would have “requested a lab report from their engineering department so that they could redesign their slurry to combat gas.”

Gas flow was not apparent at the surface after the 10¾-inch surface casing was cemented, but flow did occur from either the 700-foot and/or the 1,200-foot sand. Uncontrolled flow occurred when the cement went through the gelation phase. The cement column lost its ability to transmit hydrostatic pressure onto the formation, allowing the gas to migrate into the cement, which formed channels.

Management

Forest Management did not review the drilling program developed by the drilling engineer prior to its implementation. When Forest Management was asked, “if you had to drill the well over what would you change?” the response was that the drilling program would have been revised.

Forest did not conduct a prespud meeting prior to conducting drilling operations. When Forest was asked about having a prespud meeting for this well, the response was they feel prespud meetings are important, but in this case they didn’t have enough time because of the level of activity.

Communication was incomplete between Forest Management and the cementing company representative. Forest Management stated that “a form” is used to communicate pertinent information to the cement service company, such as shallow-gas hazards. The investigation could not determine whether the form was not used or the form was used but without a reference to shallow-gas hazards. When Forest Management was asked why the cement

service company didn't recommend revising the cement design appropriate for controlling shallow-gas hazards, the response was "I think there was obviously a communication breakdown there."

Conclusions

The Accident

The most vulnerable period for the cement is immediately after placement and prior to its setting. It is during this time that cement, while developing gel strength, becomes self-supporting and loses its hydrostatic pressure. This hydrostatic pressure loss is responsible for the well reaching an under-balanced condition, which can lead to gas invasion. Slurries must be designed with the idea of minimizing this vulnerable time when an under-balanced condition exists.

Formation gas migrated from the 700-ft sand and/or the 1,200-ft sand through the cement between the 24-inch drive pipe and the 10³/₄-inch surface casing, because of the above mentioned loss of hydrostatic pressure.

Contributing Causes

1. Failure of Forest Personnel to communicate the presence of shallow-gas hazards to the contract cement service company. This resulted in cement not being properly designed to prevent gas migration into the cement.
2. A prespud meeting was not conducted to communicate known shallow-gas hazards to all parties involved in drilling operations.
3. Once the hole section was logged and showed the presence of shallow gas, the well log information was not analyzed to verify that the cement program was properly designed for shallow gas.

4. Opening of the +10 valve allowed the fluid level in the 24-inch drive pipe by 10³/₄-inch surface casing annulus to fall, reducing the hydrostatic pressure on the cement, which could have contributed to gas migrating into the wellbore.

Recommendations

Safety Alert

The Gulf of Mexico OCS Region should issue a Safety Alert recommending the following:

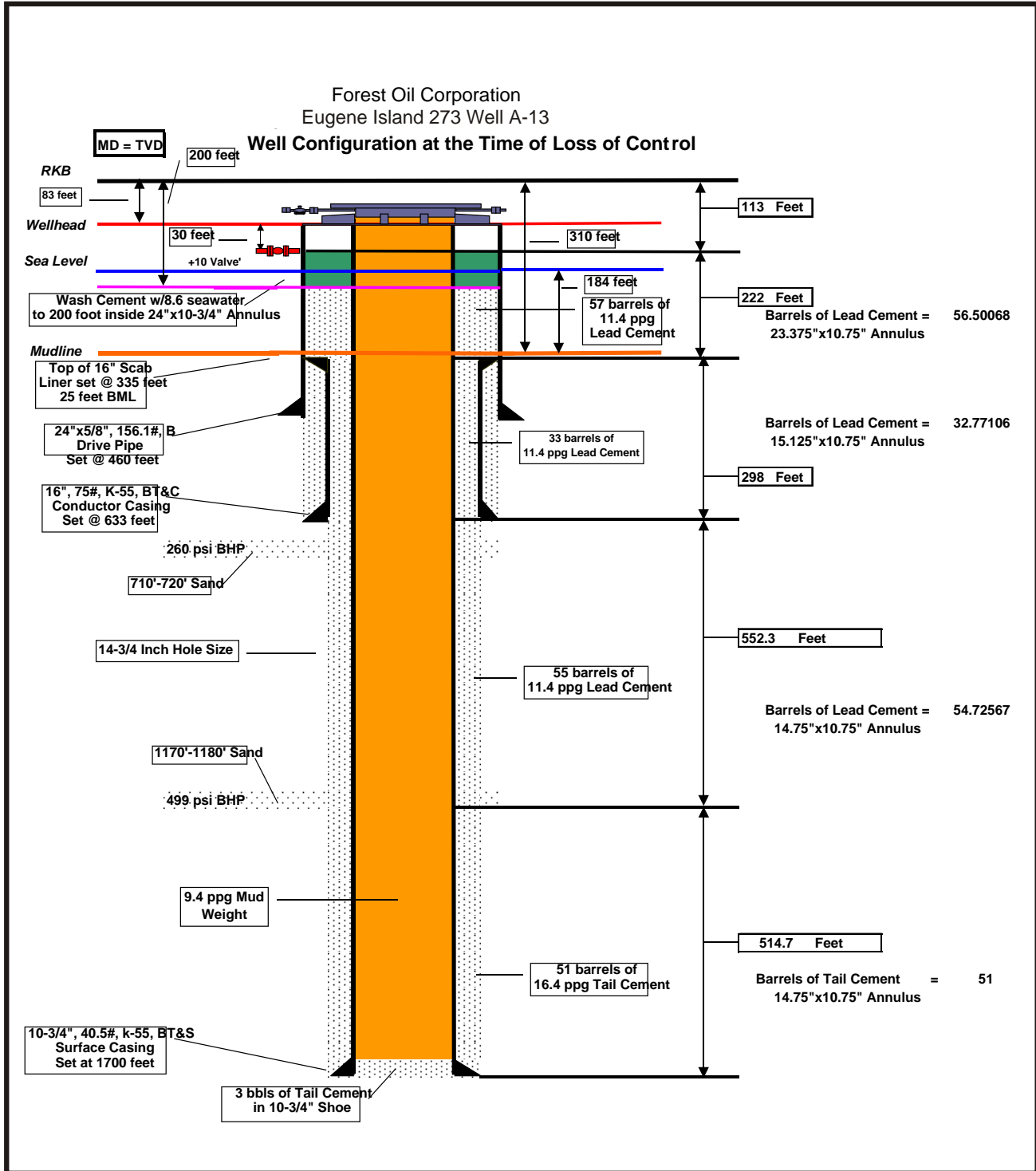
1. Designated operators should develop specific strategies to prevent gas migration into the cement column. These strategies include the use of special slurries with physical and chemical properties that inhibit or block the invasion of gas.
2. Designated operators should implement methods to improve communication of any presence of shallow-gas hazards to the contract cement company. Through proper communication, cement companies can design proper cement for gas migration.
3. Designated operators should develop and put into practice a policy of having prespud meetings on all wells with shallow-gas hazards.
4. Designated operators should design a procedure to ensure that log information indicating shallow gas is used to verify proper cement designs.
5. Designated operators should analyze the safe use of the +10 valve where shallow-gas hazards are known to exist.

Study

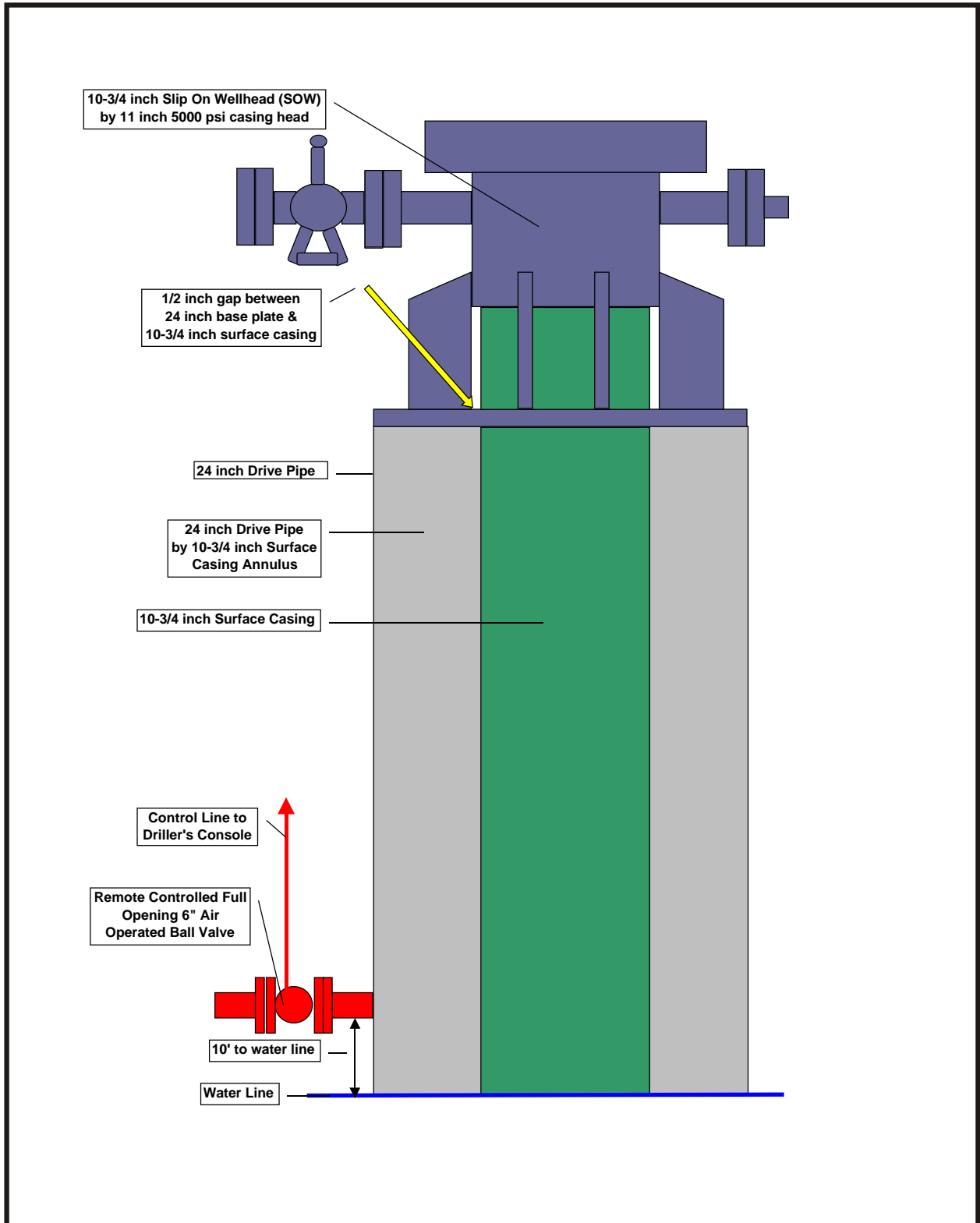
The Panel recommends that the Gulf of Mexico OCS Region should conduct a study on the complexity of effectively controlling annular flow when a scab liner is used where shallow-gas hazards exist.



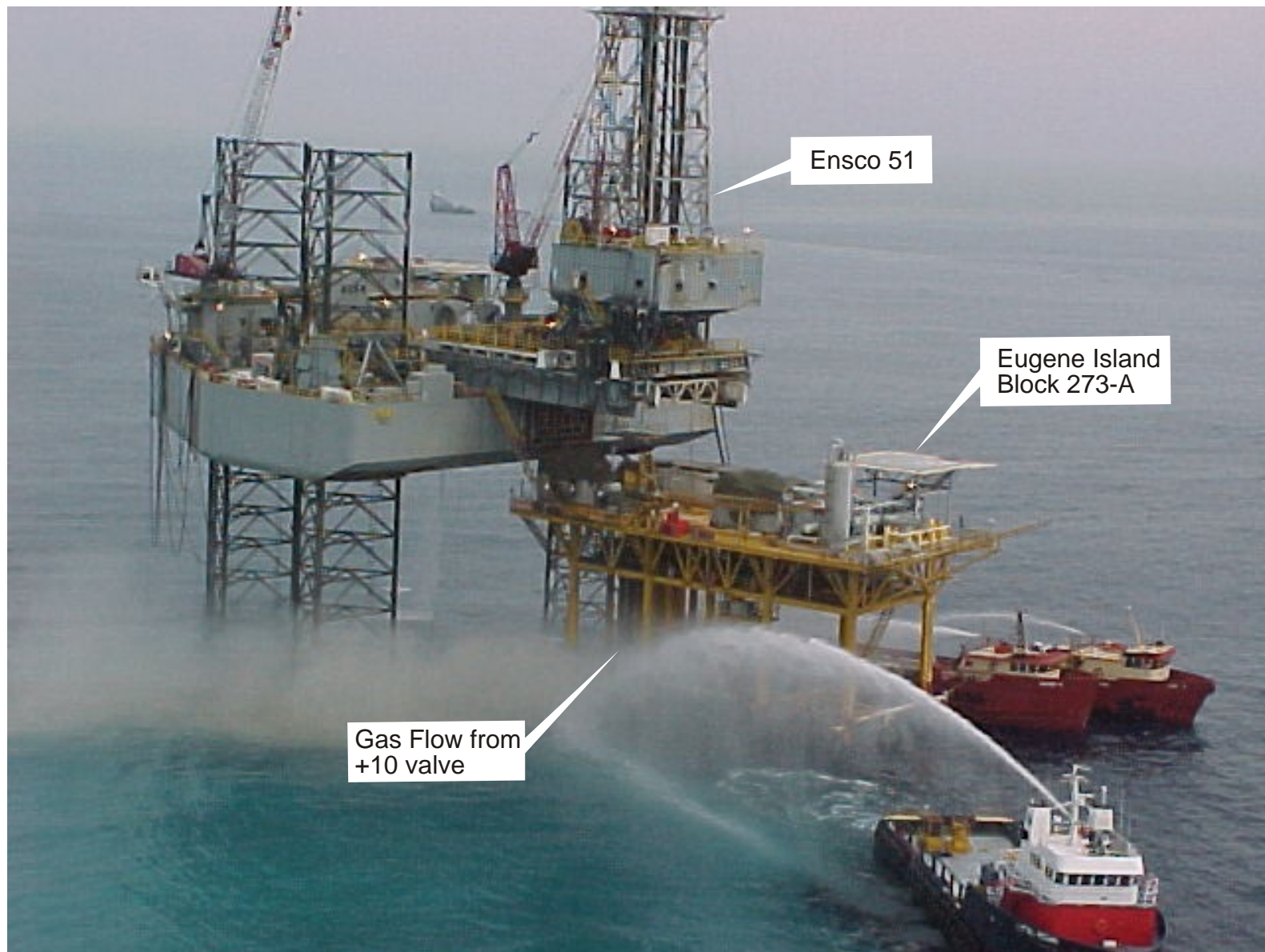
Location of Leases OCS-G 0987 Eugene Island Block 273 (surface location) and OCS-G 0991 Eugene Island Block 284(bottom hole location)



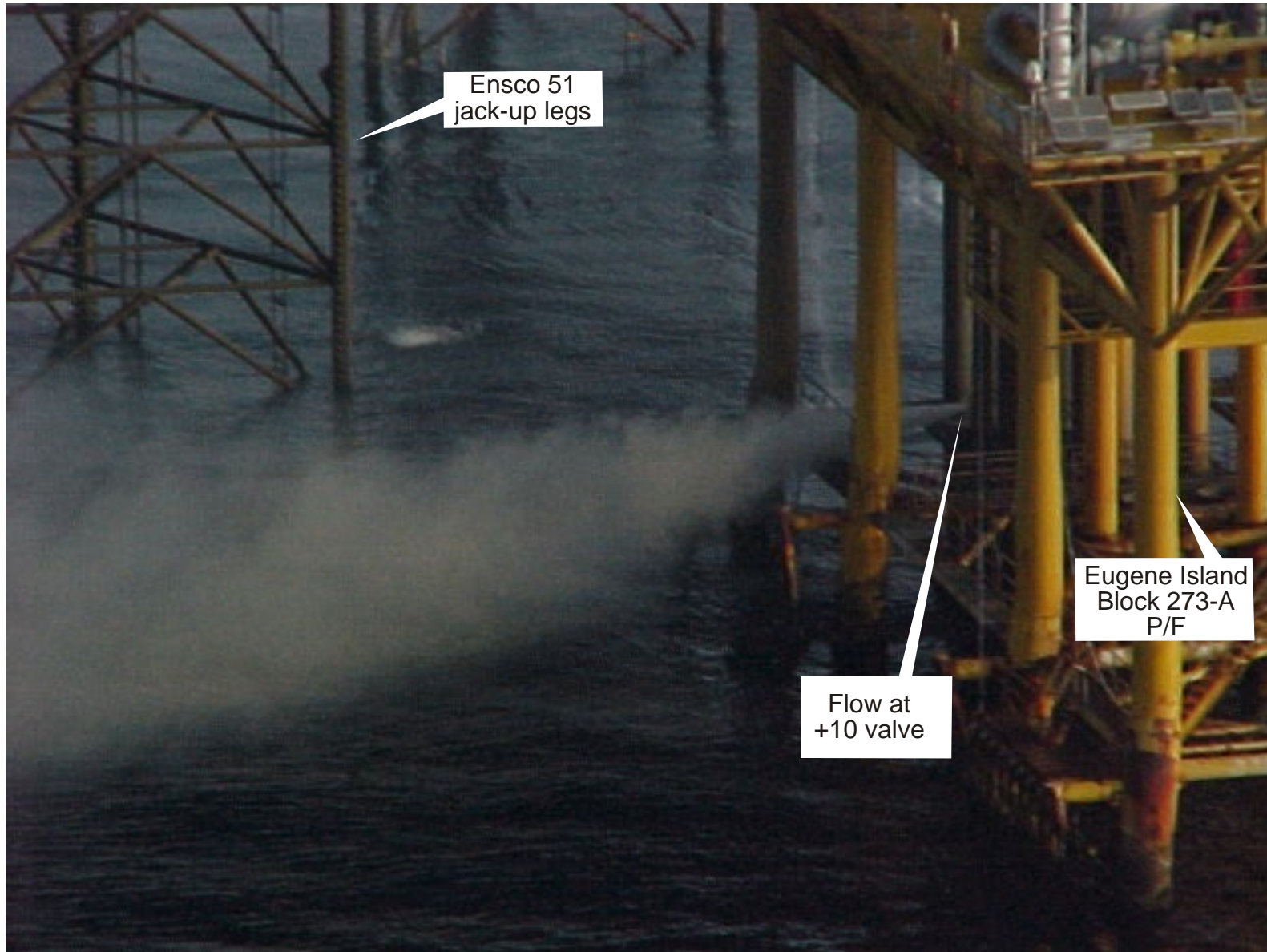
Eugene Island Block 273, Well A-13, wellbore schematic



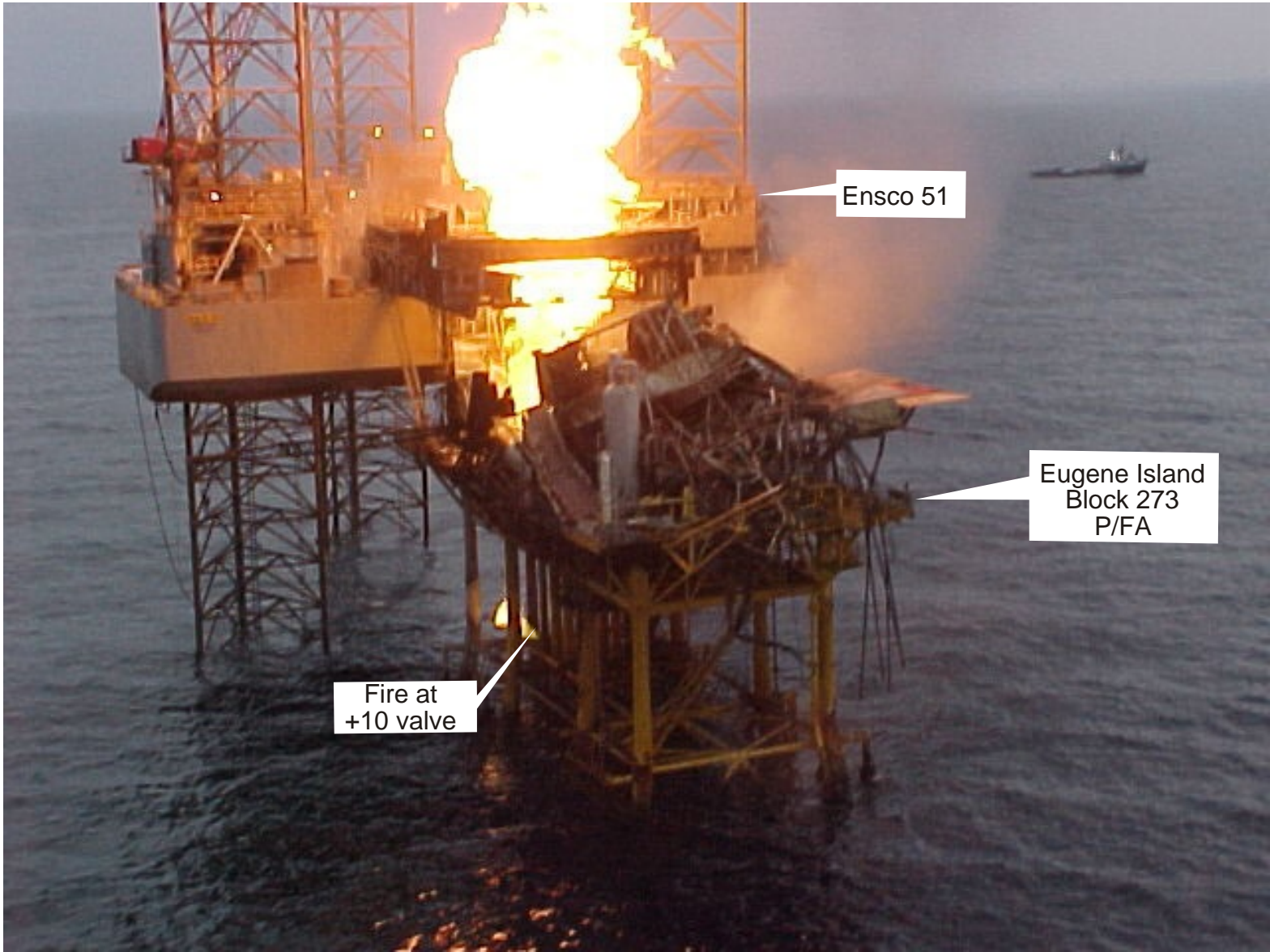
Slip-on wellhead schematic and +10 valve schematic



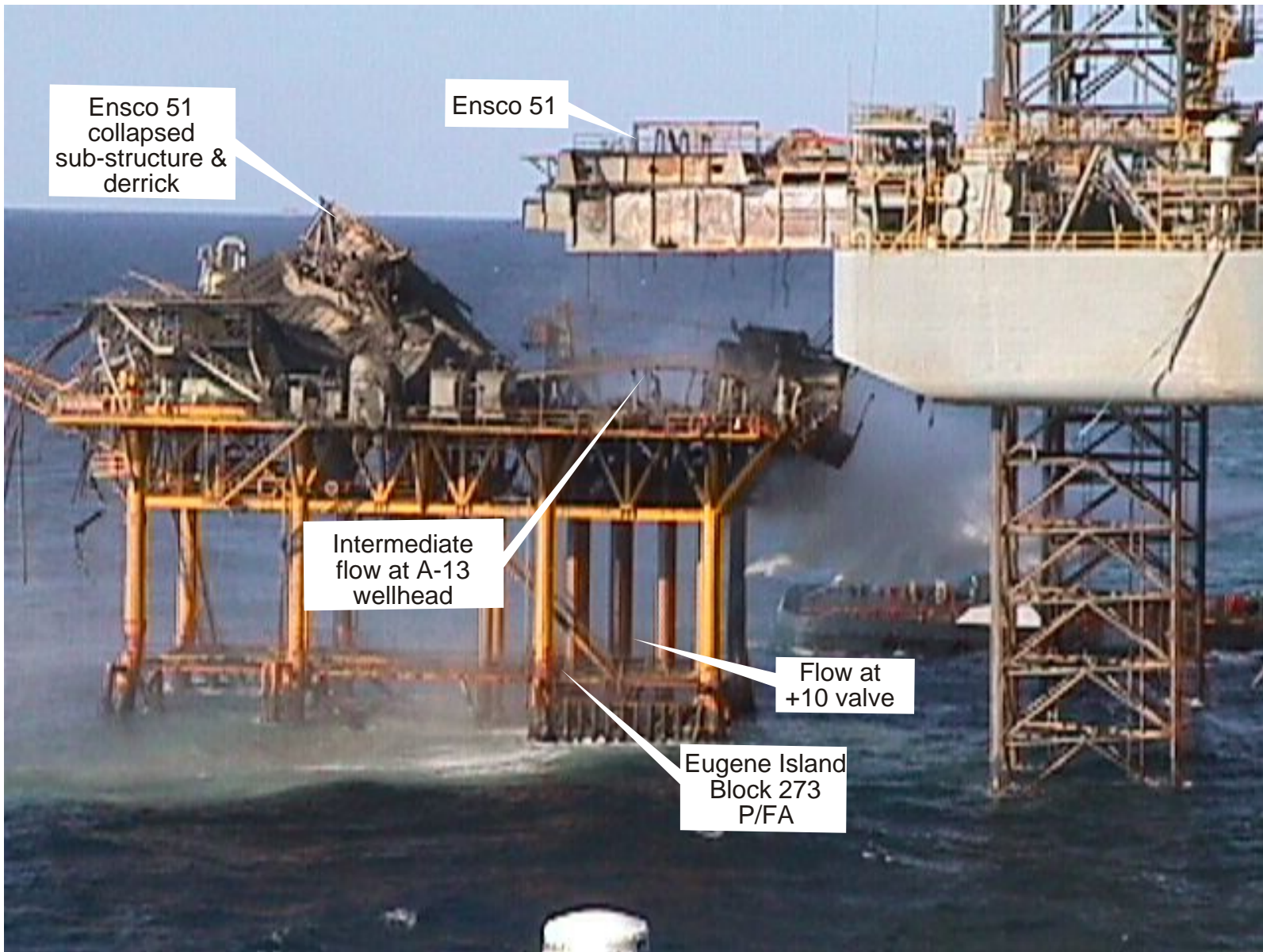
Flow at +10 valve and fire monitors on location



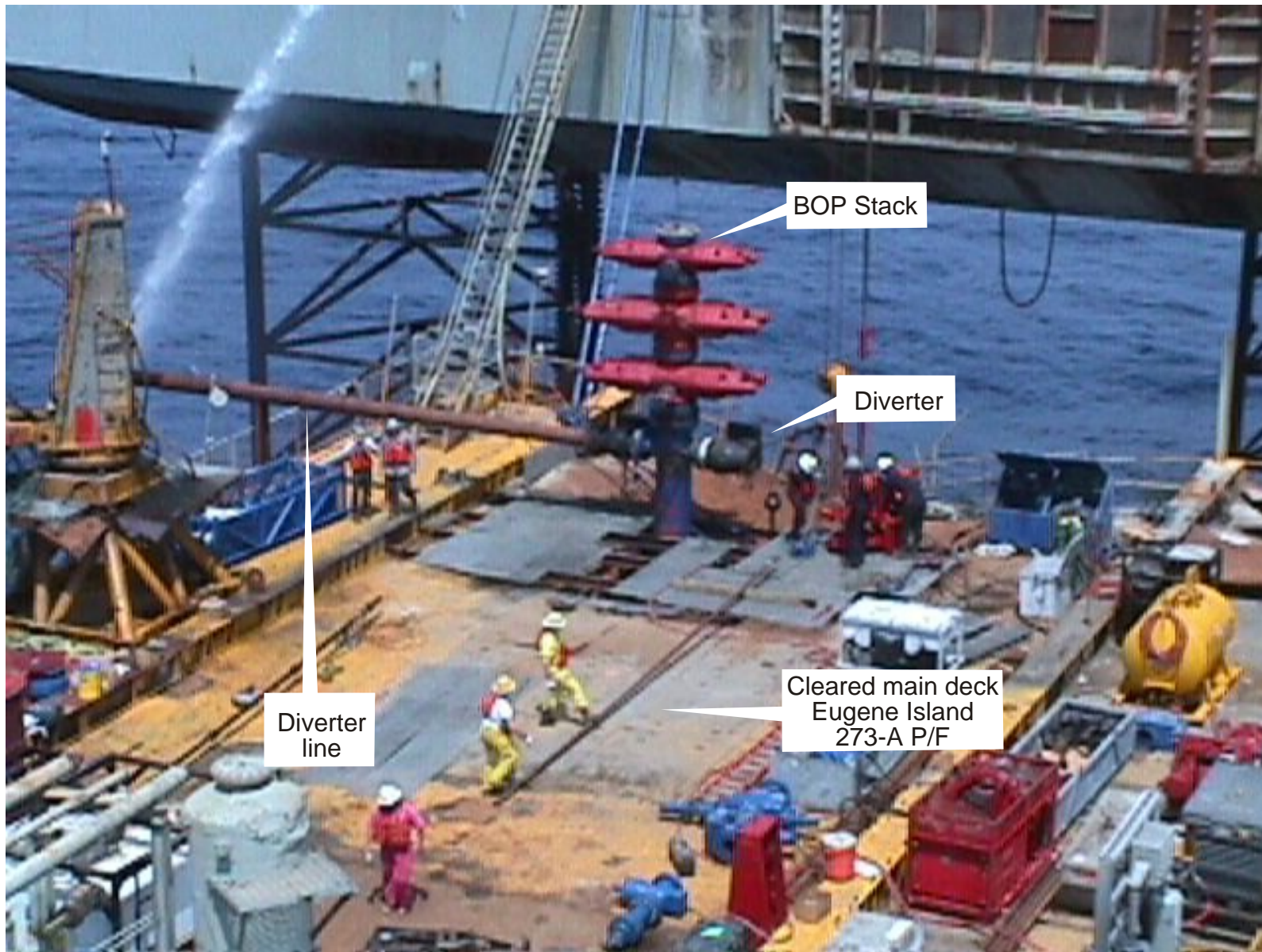
Flow at +10 valve



Platform/rig on fire



Damage to platform and rig resulting from fire



BOP Stack

Diverter

Diverter line

Cleared main deck
Eugene Island
273-A P/F

Installation of diverter system and BOP stack