

**Investigation of Blowout and Fire
Ship Shoal Block 354
OCS-G 15312 Well A-2
September 9, 1999**

**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

Uncontrolled flow of Well A-2 during coiled tubing operations occurred on Newfield Exploration, Inc.'s (NFX) Lease OCS-G 15312, Platform A, Ship Shoal Block 354, in the Gulf of Mexico, offshore the State of Louisiana, on September 9, 1999, at approximately 1545 hours. 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 September 10, 1999, the following personnel were named to the investigation panel:

Joe Gordon	New Orleans, Louisiana (Chairman)
David Dykes	New Orleans, Louisiana
Mike Saucier	Houma, Louisiana
Leslie Monahan	Houma, Louisiana

Procedure

On the afternoon of September 10, 1999, an inspector of the MMS Houma District conducted an aerial reconnaissance of the platform to assess the situation.

On the morning of September 11, 1999, an inspector of the MMS

Houma District arrived at Ewing Bank Block 947, Platform A, where NFX personnel had set up their initial incident command center. Several members of NFX's incident command team briefed the inspector on the incident.

On September 12, 1999, an MMS inspector returned to the incident location to get an update on the response effort. The derrick barge *Hercules* had been brought on location to be used as a staging/support vessel, and was subsequently used as NFX's incident command center.

On September 20, 1999, Panel Members of the Accident Investigation Team were present at OSCA's Lafayette, Louisiana, office to witness the tear-down of the blowout preventer (BOP) stack and associated equipment.

On October 7, 1999, a meeting attended by representatives of NFX and MMS was held at the MMS Regional Office in New Orleans. At the meeting, the status of the investigation was discussed, as were a recap of the incident and emergency responses to the incident. MMS received copies of the eyewitness statements and requested a copy of the investigation report being prepared by a consulting firm, SAS Industries, Inc., contracted by NFX to investigate the incident. Signed

witness statements were obtained from the following personnel:

- NFX Onsite Supervisor (Chalmers, Collin & Alwell)
- District Manager (High Pressure Integrity, Inc.)
- Tool Specialist (High Pressure Integrity, Inc.)
- Wireline Supervisor (Cardinal Wireline)
- Coiled Tubing Supervisor (OSCA)
- Coiled Tubing Operator (OSCA)
- Pumping Supervisor (OSCA)
- Blender Operator (OSCA)
- Service Technician (Schooner Petroleum Services, Inc.)

On October 28, 1999, a meeting attended by OSCA representatives and MMS was held at the MMS Regional Office in New Orleans. At this meeting, OSCA's performance history was discussed, along with operational changes OSCA had made as a result of the accident.

On November 16, 1999, MMS received the investigation report from NFX.

On August 9, 2000, additional information was requested from OSCA. Several subsequent requests were also made.

On November 9 and 15, 2000, meetings were held with High Pressure Integrity Inc. (HPI) and HPI Thru Tubing Services personnel concerning the sequence of events as well as HPI's and HPI Thru Tubing Services' roles.

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 15312, covers approximately 5,000 acres and is located in Ship Shoal Block 354, Gulf of Mexico, off the Louisiana coast. (*For lease location, see Attachment 1.*) The lease was issued effective July 1, 1995 and NFX became the designed operator of the lease in February 1996. Platform A was installed in 1997.

Brief Description of Accident

On the afternoon of September 9, 1999, while coiled tubing was being snubbed into Well A-2, it encountered an unknown obstruction that caused it to stop abruptly. Upon coming to a stop or shortly thereafter, the coiled tubing buckled and parted between the stripper assembly and the injector head resulting in the release of hydrocarbons to the atmosphere. (*For coiled tubing rig up, see Attachment 2.*) The pipe rams were closed and the shear rams were subsequently closed, thereby cutting the coiled tubing. The coiled tubing was then pulled back onto the coiled tubing reel. However, a section of coiled tubing remained between the shear rams and the injector head, where the original part had occurred. The blind rams were then closed but did not stop the flow of hydrocarbons because the coiled tubing stub was located across the blind rams. Attempts were then made to secure the well by closing the bottom manual valve on the BOP riser assembly, the crown (swab) valve, the surface safety valve, the bottom master valve, and the

subsurface safety valve. The valves did not fully close because the coiled tubing remained below the shear rams and across the valve assemblies, and the well continued to flow uncontrolled. The platform emergency shutdown system (ESD) was then activated and all personnel evacuated the platform. The well ignited on September 12, 1999, and burned intermittently until September 17, 1999. The well was killed on September 20, 1999.

Findings

Activities Prior to Loss of Well Control

Planning

Well tests and a bottom hole pressure survey presented data that indicated that a stimulation should be performed on Lease OCS-G 15312, Well A-2, Ship Shoal Block 354, in order to restore the well back to its original performing state.

July 15, 1999 – OSCA presented its stimulation recommendation for Well A-2. This recommendation was for the xylene/acetic acid stimulation utilizing coiled tubing for conveyance and nitrogen as the carrier.

August 5, 1999 – NFX obtained documentation showing the run history of the 1½-inch coiled tubing string (#11066). Included in the string fleet documentation was information pertaining to the 1¼-inch string (#9875).

August 6, 1999 – NFX received approval from MMS Houma District for the stimulation operation using coiled tubing.

August 13, 1999 – OSCA submitted a revised optional HF/HCL coiled tubing stimulation to NFX.

August 16, 1999 – Pre-job meeting took place in Intracoastal City, Louisiana, to review procedures. In attendance were NFX's production engineer (engineer in charge) and production foreman; OSCA's coiled tubing supervisor, pump supervisor and PLM-coiled tubing matrix stimulation supervisor; the MSI Crane and Equipment Company representative; and a Chalmers, Collins, and Alwell, Inc., representative (NFX onsite company representative and supervisor). The meeting reviewed the procedure as well as logistical concerns including the running of BPV's on all coiled tubing runs.

Summary of Operations

August 17, 1999 – OSCA coiled tubing equipment with 1½-inch coiled tubing and crew, along with the consultant, were mobilized by boat to Ship Shoal Block 354 to perform stimulation on Well A-2. They arrived on location at 12:00 p.m. and offloaded equipment onto the platform. Prior to offloading of the boat, a safety meeting was held.

August 18, 1999 – Rigged up and pickled the coiled tubing. BOP's were tested to 250 psi low and 7,500 psi high as noted on the two charts dated August 18, 1999, and signed by OSCA's well servicing operator and NFX's onsite supervisor. The coiled tubing unit was pull tested to 14,000 lbs. A mule shoe assembly with dual BPV's was made up and the

injector head was made up and re-tested to 250 psi low and 7,500 psi high. The well was shut-in during operations and put back on line once daylight operations were complete.

August 19, 1999 – The decision was made to bullhead stimulation to lower perforations and circulate remaining stimulation across upper perforations. The stimulation was xylene with 10 percent acetic acid pumped with nitrogen. The injection rate was done at 850 SCF @ ½ BPM with a total volume pumped of 10½ bbls. Pressures were 6,200 psi on the well and 6,400 psi on the coiled tubing. The reel was loaded with stimulation fluid and pumped as the coiled tubing was pulled out of the hole to 13,500 feet. Once depth was reached, operations were shut down for one hour to allow the stimulation to soak. After one hour, started back in hole pumping nitrogen, a total of 174,799 SCF was pumped. Pressure started at 6,500 psi, broke back to 6,000 psi and went back up to 6,300 psi.

August 20, 1999 – A Simultaneous Operations Safety Meeting was held. The ESD line was installed at the reel. The well was shut-in and OSCA started in the hole with coiled tubing. Well pressure was 2,100 psi initially. They stopped at 6,800 feet and pumped nitrogen filling coiled tubing. They started back in the hole and tagged solid at 13,644 feet.

This depth matched with the 1.875-inch I.D. seal bore sub at 13,645 feet. While pulling out of the hole with 176 feet of coiled tubing still in the hole and 6,300 psi on the coil (trapped as a result of dual BPV's), the 1½-inch coil tubing developed a split near the reel and released the nitrogen from the reel. The nitrogen hit the windshield of the operator's console and blew in the window. The SCSSV was closed, the BPV's held, and the coiled tubing was bled off to zero. The tubing was bled to 5,900 psi, and the coiled tubing was pulled out of the hole in 30-foot sections. No injuries occurred and the crew finished laying out coiled tubing. The SCSSV was opened and the well was opened to production.

August 21, 1999 – A level safety high on the test separator occurred because Well A-2 produced sand and filled the test separator. Well A-2 was subsequently shut-in.

August 22, 1999 – Waiting on 1¼-inch coiled tubing to arrive.

August 23, 1999 – After OSCA was apprised of the sand production by Well A-2, OSCA submitted a flow analysis for a sand wash job using 1¼-inch coiled tubing. OSCA also submitted a procedure pertaining to the sand wash job. A NFX prognosis for the coiled tubing sand wash procedure was faxed to the MMS Houma District and verbal approval

was obtained. NFX received the approved Sundry Notice on August 30, 1999. The 1¼-inch coil tubing unit mobilized to platform.

August 24, 1999 – Finished offloading boat. Rigged up 1¼-inch coiled tubing equipment and tested to 250 psi low and 7,500 psi high as noted on the chart dated August 24, 1999, and signed by NFX onsite supervisor.

August 25, 1999 – OSCA submitted two tubing forces analysis based on 6,000 psi wellhead pressure/7,000 psi circulating pressure and 1,500 psi wellhead/4,000 psi circulating pressure. Washing operations began on this date with a reached depth of 6,684 feet. Although no major bridges were encountered, a large amount of sand was received in the returns.

The operation was stopped and a hydraulic choke, along with a manifold and hydraulic valves on the return line, were installed and tested.

Received also on this day was a run analysis on this coil (#9875). After sand washing operations were concluded, coiled tubing personnel were sent in, and an attempt to run a GR/CCL on the electric line in order to run a through tubing bridge plug (TTBP) was made but proved unsuccessful.

August 26, 1999 – Manual choke manifold and flow valves were

replaced with hydraulic valves and power choke. New equipment was tested to 250 psi low and 7,500 psi high, as noted on the chart dated August 26, 1999, and signed by the NFX onsite supervisor and the OSCA representative.

August 27, 1999 – Washed down to 13,633 feet (coiled tubing measurement) hitting light bridges and circulating excessive sand. The pick-up weight increased on bottom by 2,000 lbs.

August 28, 1999 – Short trip coiled tubing, circulated out, and pulled coiled tubing out of the hole. Rigged up slick line and attempted a gauge ring run (1.7815”O.D.), but unable to get past 13,418 feet and subsequently rigged down slick line unit.

August 29, 1999 – Changed out pump unit and tested unit to 250 psi low and 7,500 psi high. RIH with 1¼-inch coiled tubing to 13,633 feet and pulled out of the hole. Rigged up slick line and ran in hole with 1.7813-inch gauge ring. Unable to get past 13,418 feet and pulled out of the hole with slickline.

August 30, 1999 – Rigged up slickline and 1.5-inch O.D. tapered gauge. Ran in the hole to 13,654 feet and pulled out of the hole with slickline

and rigged down. Rigged up electric line and started in the hole with gamma ray and collar log.

August 31, 1999 – Continued in the hole with gamma ray and collar log and worked tools down to 13,595 feet. Ran a strip log and then pulled out of the hole. Rigged up electric line and ran 1.4375-inch O.D. gamma ray and collar log with four knuckle joints. Reached 13,585 feet and logged interval to 12,900 feet, but unable to get deeper. Rigged up slickline and made two runs to 13,650 feet and 13,180 feet.

September 1, 1999 – Demobilized coiled tubing crews. Rigged up and ran slickline 3½-inch nipple locator and located “X “ nipples at 896 feet, 8,544 feet, and 13,100 feet. Tagged 3½-inch x 2 7/8-inch crossover at 13,128 feet. After reviewing depth runs with slickline, electric line, and coil tubing (both 1¼-inch and 1½-inch), a meeting at NFX’s Houston office was held with OSCA, HPI, Inc. and NFX to discuss the running of through tubing bridge plugs on coiled tubing. NFX's onsite supervisor was not present for this meeting. Topics of discussion were setting tools, setting pressures, and size of setting balls in hydraulic tools in order to clear the BPV's.

September 2, 1999 – Ran 1 3/8-inch impression block to 13,576 feet. A

meeting between NFX, OSCA, and HPI was held to determine actual pressure settings of the bridge plug. Nominal pressure at 4,800 psi surface was determined. Once again, the clearance of BPV's and setting balls was stressed.

September 3, 1999 – Coiled tubing crew returned to the platform and rigged up and pull-tested coiled tubing to 14,000 lbs. Tested BOP's and all lines to 250 psi low and 7,500 psi high (the test chart and OSCA BOP test form were lost in the fire).

September 4, 1999 – Made 3½-inch locator run with coiled tubing and located “X “ nipples at 947 feet, 8,570 feet, and 13,138 feet. Pulled out of hole with coiled tubing and made up HPI Thru Tubing Services wash tool.

September 5, 1999 – The shut-in tubing pressure was 2,500 psi. Ran in the hole with coiled tubing and HPI Thru Tubing Services wash tool (including dual BPV's) with 9.8 ppg KCL. The KCL fluid level was at 13,454 feet. Unable to work coil up at this depth but able to go deeper. Activate hydraulic disconnect and disconnect from wash tools. Pulled out of the hole with coiled tubing. Rigged up slick line and recovered remaining tools.

September 6, 1999 – Ran in hole with coiled tubing and HPI Thru Tubing Services wash tool to 13,575 feet. Washed through four minor bridges and attempted to wash deeper but failed. Pulled out of the hole with coiled tubing.

September 7, 1999 – Made up HPI's Magna Range Bridge plug on coiled tubing and ran in the hole to 13,575 feet and attempted to set the bridge plug. It appeared that the bridge plug had set with 3,400 psi. Upon being pulled out of the hole, the bridge plug was recovered after not setting.

September 8, 1999 – Ran in hole with another HPI Magna Range Bridge Plug and attempted to set same at 13,575 feet. Pressured up to 8,200 psi with no indication of a set. Pulled out of the hole with coiled tubing leaving setting tool, firing head, and bridge plug in the hole. The SITP was 2,250 psi.

September 9, 1999 – Rigged up the slick line and ran in hole with a JDC pulling tool. Attempt was made to get below 13,544 feet, but was unable to do so. Attempted another run but could not get below 13,562 feet. Made up HPI Elite Bridge Plug on coiled tubing. Ran in the hole to 915 feet and lost weight on coil tubing. The operator noticed a gas flow

above the stripper rubber and attempted to shut-in the well but the gas flow continued. The platform was evacuated by the *M/V International Carrier* and the crew was transferred to Ewing Bank Block 947.

Loss of Well Control

At approximately 1500 hours on September 9, 1999, a tool string consisting of an HPI Elite tubing plug, associated setting tool and firing head, hydraulic disconnect, and crossover sub assembly was assembled by HPI personnel in the presence of the NFX onsite supervisor. A ball drop test was performed with a 9/16-inch ball for each component of the tool string while it was being assembled. Once assembled, the tool string was handed over to the OSCA coiled tubing operator. The tool string did not include the dual BPV's as specified by NFX. It was also OSCA's policy at the time of the accident to include BPV's on every coiled tubing run unless otherwise requested by the company representative; this request was to be documented in writing. The coiled tubing operator installed the tool string on the coiled tubing and the assembly was deployed into the wellbore. This run followed two previous, unsuccessful attempts in setting HPI Magna Range bridge plugs to achieve zonal isolation. According to the OSCA coiled tubing operator and the OSCA supervisor, the initial deployment speed was approximately 30 to 35 feet per minute and the initial pump pressure was 4,400 psig at 0.23 barrels per minute. OSCA personnel also said that the

pump pressure was subsequently increased to 5,900 psi at 0.46 barrels per minute while maintaining 1,500 psi on the injector chain skates, 1,000 psi on the stripper, and -4,500 pounds on the weight indicator. A statement by an HPI employee recounts a conversation that he had with either the OSCA coiled tubing operator or the OSCA supervisor, in which the HPI employee was told that the coiled tubing was being run into the hole at 60 to 70 feet per minute. A final report written for NFX after the blowout calculated the "run in hole" speed for the first five minutes to be 100 feet per minute. Because of the discrepancies in the various accounts of the "run in hole" speeds, the panel was unable to determine conclusively the exact deployment speed.

NFX's final report indicates that the 1.25-inch OD, 0.134-inch wall thickness, 100 grade coiled tubing that was being used has a calculated maximum recommended thrust load of 15,423 lbs. The calculation uses the Secant formula and an unsupported length of approximately 13 inches, while assuming a safety factor of 1.25. (*For schematics of unsupported coiled tubing length, see Attachments 3 & 4.*) The report also indicates that for the HR-440B injector in high gear, the calculated maximum pressure setting for the injector hydraulic control pilot valve was 2,150 psi, based on a maximum injector thrust force of 15,423 lbs. The maximum pressure setting for the injector hydraulic control pilot

valve in low gear is 1,070 psi. According to NFX's report, the injector hydraulic control pilot valve setting on the prime mover of the OCSA coiled tubing unit was found to be set at or above 3,100 psi.

OCSA calculates a max snub force for 1.25-inch, 0.134-inch wall thickness, 100 grade coiled tubing of 11,968 lbs. OSCA's calculation, which is based on Society of Petroleum Engineers (SPE) paper No. 46007, uses an unsupported length of 10 inches and includes a 50 percent safety factor and 80 percent of minimum yield stress of the pipe. (*For schematics of unsupported coiled tubing length, see Attachments 3 & 4.*) OSCA uses a standard setting of 1,700 psi for the injector pilot valve for 1.25-inch coiled tubing. According to OSCA personnel, the injector pilot valve pressure setting is performed by OSCA in the shop prior to a job as part of the procedure for setting the maximum in-hole and out-hole pressures for the injector head. Further, according to OSCA personnel, any changes to these standard settings is to be documented, and this same procedure is used offshore if an increased snub or pull pressure setting is needed. Despite the panel's multiple requests of OSCA's legal representatives, the panel was unable to obtain statements from OSCA personnel pertaining to the documentation of pilot valve settings or any changes in the pilot valve settings made offshore. Because the panel considers the information currently in the case file to be sufficient for

determining the causes of the accident, the panel decided to conclude its investigation without the benefit of the requested information.

While running in the hole with an HPI Elite bridge plug on its end, the coiled tubing came to an abrupt halt at approximately 915 feet. Upon seeing it come to a stop, the coiled tubing operator attempted to pick up the coiled tubing and observed the weight indicator register zero. The coiled tubing operator then tried to move the pipe back down and observed the weight indicator registering – 4,500 pounds, as it had before coming to a stop. Within minutes, a flow of liquid and gas was detected coming from the vicinity of the bottom of the injector head.

Attempts to Stop Well Flow

Upon noticing the flow, the OCSA supervisor instructed the coiled tubing operator to close both tubing rams. The operator closed both rams and went outside to observe the indicator pins on the BOP's to verify that the BOP rams were closed. The pins were in, indicating they had closed. However, the flow continued uncontrolled. The OSCA supervisor, who was at the console, next tried opening the tubing rams and closing them again. The well control procedures did not initially include setting the slip rams on the tubing as specified in Appendix C, Emergency Responses and Contingency Planning, Section C.13, Coiled Tubing Parted Between Injector and Stripper Assembly, of API RP 5C7. In

addition, the kill line was not hooked up to the BOP stack assembly or pump. The NFX onsite supervisor, after discussions with the coiled tubing operator and the coiled tubing supervisor, instructed them to shear the pipe. The coiled tubing supervisor closed the shear rams, and then opened the shear rams and the tubing rams in order to let the coiled tubing fall down the well. During the inspection of the BOP stack at OSCA's Lafayette facility, one shear ram was found to be installed upside down. As documented in NFX's final report, subsequent tests on a similar BOP stack with at least one of the shear ram blades installed upside down revealed that the shear blades were still capable of shearing the tubing. The coiled tubing supervisor pulled up on the coiled tubing to clear the blind rams, and then closed the blind rams. The coiled tubing operator, positioned at the BOP stack, communicated to the coiled tubing supervisor that the pins closed only $\frac{3}{4}$ of the way, indicating that the coiled tubing still remained across the blind rams. The well was still flowing. The coiled tubing supervisor then closed the tubing rams again and packed off on the stripper. However, the well continued to flow.

The coiled tubing supervisor proceeded to the wellbay, where the coiled tubing operator and two Island Operating production operators had assembled. The coiled tubing supervisor told a production operator to close the manumatic valve (SSV). The pressure was bled off the SSV in

order to close it, but it would not close. He then tried to close the SCSSV, first at the well control panel, and then at the tree. At the same time, the coiled tubing operator tried to close the crown valve. The crown valve closed only 7-9 rotations. The coiled tubing operator then attempted to close the rental gate valve and could only close it 7-9 rotations. The coiled tubing operator then removed the cap off the manumatic valve and instructed a production operator to function it, in an attempt to cut the coiled tubing. Upon functioning the manumatic valve, the valve did not cut the tubing and the well continued to flow. The well was left with the valves partially closed against the coiled tubing.

According to information supplied by NFX in a letter dated November 15, 1999, "Tests subsequent to the incident showed that any of the four gate valves could have been used to shear the coil tubing and shut off the flow from the well. None of the personnel on location were aware of this fact or the methodology to perform this operation. To accomplish this task requires a heavy pipe wrench (36") with a short 'cheater' pipe and takes approximately 5 minutes. The operation essentially forces the slab gate through the pipe, shearing the pipe in two places and placing the gate across the flow area." A production operator proceeded to shut in the other two flowing wells, A-1 and A-3, by closing the wing valves and the bottom master valves.

As personnel were in the process of evacuating the platform, the coiled

tubing operator returned to the work deck to verify that the pipe rams were closed, and observed that the blind ram indicator pins were $\frac{3}{4}$ closed. There was no indication that an attempt was made to lock the rams closed manually.

A production operator pulled the ESD at the boat landing and then boarded the boat. All personnel had boarded the boat by 1600 hours.

Evacuation and Rescue

Personnel abandonment of the platform was accomplished in a safe and orderly fashion; however, there was no indication that the abandon platform alarm was activated. The personnel boarded the field support vessel M/V *International Carrier* and transferred to Ewing Bank Block 947, Platform A. From Ewing Bank Block 947, Platform A, notifications were made to the Houston NFX office. No injuries occurred during the evacuation.

Subsequent Activities

The NFX Spill Management Team was called together and mobilized to respond to the incident. Two Fast Response Units (FRU) from Clean Gulf Associates were dispatched to the field along with 2,000 feet of Expandi boom, two 100-barrel tanks, and personnel required to operate the equipment. Because of the light gravity of the condensate, the ambient temperature, and wave action, all condensate evaporated from

the water. As a result, dispersant application was not initiated and recovery actions were not attempted.

Representatives from Boots and Coots were called in for expert support and to plan and carry out capping and kill operations. On the morning of September 10, 1999, representatives from NFX and Boots and Coots flew to the scene to begin investigations and plan kill operations.

The dynamically positioned derrick barge *Hercules* was contracted for well control support. The *Ocean Voyager* semi-submersible drilling unit was mobilized to the location to begin drilling a relief well.

An initial visit was made to the platform by Boots and Coots representatives to assess the situation and attempt to shut in the well with the lower master valve. The attempt was unsuccessful since the lower master valve was already flow cut. The well ignited on September 12, 1999, and burned intermittently until September 17, 1999. Numerous visits to the platform were made to remove debris around the tree to allow the installation of a “Venturi” tube made from 30-inch and 24-inch casing. Once the tube was lowered over the stub of the tree, the well flow was directed above the top deck allowing hot work to be performed on the cellar deck.

A portable crane was mobilized to the location and welded in place to install the capping stack on the tubing hanger flange. A stimulation boat was mobilized to the location for the purpose of pumping the kill fluid into the well. Once the capping stack was installed, 13.9 pound-per-gallon CaBr kill fluid was bull-headed into the well and the well was killed. The drilling of the relief well was suspended, and plug and abandonment operations began on the relief well.

A snubbing unit was mobilized to the location and rigged up. Using 1¼-inch coiled tubing, the tubing was cleaned out and the perforations cement squeezed. The cement top was left to allow the well to be sidetracked at a later date.

Damages

Major structural damage was limited to one main deck beam over the wellbay area. Other damage included the complete destruction of the well head assembly, the mezzanine deck area in the wellbay, the coiled tubing riser assembly and injector head, the coiled tubing operator's console and the coiled tubing power unit, and the platform living quarters.

Conclusions

The Accident After careful study of the information obtained during the course of this investigation, it is the conclusion of this panel that at approximately 3:00 p.m. on September 9, 1999, a third attempt to set an HPI Elite bridge plug using coiled tubing was made in well A-2. In the course of running in the wellbore, the coiled tubing came to an abrupt stop at approximately 915 feet. Upon coming to a halt or shortly thereafter, the coiled tubing buckled and subsequently parted between the stripper assembly and the injector head, resulting in the release of hydrocarbons to the atmosphere. Several attempts were made to shut in the well using the BOP stack and production tree, but flow continued up the coiled tubing string and into the atmosphere. The magnitude and duration of the erosion forces of the well stream flow cut the BOP stack and the production tree, resulting in the uncontrolled flow. The uncontrolled flow ignited on September 12, 1999.

Cause The immediate **cause** of the accident, which led to the uncontrolled flow, was the parting of the coiled tubing above the stripper assembly and the subsequent inability to contain the wellbore fluids.

Contributing Causes *Mechanical*

The cause of the coiled tubing coming to an abrupt stop at approximately 915 feet can not conclusively be explained by this panel. NFX's final

report also was unable to determine the cause of the sudden stop of the coiled tubing as it was run into the wellbore. Upon coming to an abrupt stop, the coiled tubing experienced an excessive compressive load, which resulted in the buckling and parting of the tubing. The force required to buckle the coiled tubing is a function of several factors, including the coiled tubing geometry and material specifications, the unsupported length of tubing between the stripper and injector, as well as the alignment of the injector chains and stripper. The compressive load or forces were applied to the coiled tubing by the injector chains, which gripped the coiled tubing and thrust the tubing through the stripper and into the wellbore. The magnitude of the forces applied to the coiled tubing by the injector chains is regulated by the injector hydraulic control pilot valve settings. On the basis of the available information, this panel concluded that the pressure settings for the injector pilot valves exceeded the maximum allowable limits for 1.25-inch coiled tubing.

Failure to install BPV's in the coiled tubing string is also considered a **contributing cause** of the blowout. Upon parting of the tubing, the lack of the BPV's allowed flow up the tubing string with no means of isolating and containing the flow. Once flow had commenced up the tubing, erosion forces of the flow acting on the inside of the tubing string compromised the integrity of the tubing and exposed the flow to the bore of the BOP stack.

The erosion forces of the flow then apparently eroded the body of the BOP stack and production tree, thereby creating an unrestricted flow path to the atmosphere, which subsequently ignited.

Management

Although a significant amount of planning had been done by NFX and the various contractors for this workover procedure, breakdowns in the implementation of the well plan occurred during critical situations. The need to install redundant BPV's in the tool string was an integral topic of the first meeting dealing with the initial stimulation designs and procedure between NFX, HPI, OSCA, and NFX's onsite supervisor. The need to install the BPV's, as well as operational issues resulting from the valves being in the tool string, were also discussed in a subsequent meeting between NFX, HPI, and OSCA. Despite the detailed discussions and preparation, the BPV's were not installed during the three bridge plug runs. According to NFX's final report, the BPV's were in the stimulation runs. The breakdown appears to be in part caused by NFX's lack of ensuring that their requirements were enforced by their onsite representative and implemented by their contractors. Specifically, NFX's onsite supervisor did not verify the presence of the BVP's in the tool string for the bridge plug runs. It was NFX's policy to run dual BPV's on all coiled tubing string runs. The ultimate responsibility for ensuring that operations are conducted in accordance with its guidelines is NFX's.

Contributing to the breakdown in the implementation of the well plan was OSCA's onsite supervisor's failure to verify the use of BPV's in the tool string. It was OSCA's policy at the time of the accident to require BPV's on all coiled tubing runs unless otherwise directed by the company representative. This policy was developed as a result of OSCA's prior involvement with a blowout resulting from BPV's not being installed in the coiled tubing workstring. According to OSCA personnel, OSCA has since modified its internal policy to now require BPV's in the tool string on all coiled tubing runs with no exceptions.

In addition to not installing BPV's or verifying their presence, there was inadequate preparation for well control situations on the part of NFX and OSCA. OSCA did not have site specific, written well control procedures in hand prior to beginning operations. NFX, again ultimately responsible for all phases of the operation, did not confirm the existence of proper well control procedures. Industry-recognized well control practices, as outlined in API RP 5C7, were not followed in responding to the well control situation or in configuring the well control equipment. Specifically, the slip rams were not set, pipe rams were not manually locked, and the kill line was not installed. Although not currently referenced by the *Code of Federal Regulations*, the industry guidelines provide safe and prudent

practices that should be followed.

Communication

A breakdown in communication between NFX and its contractors was a contributing cause of the accident. Discussions in the pre-planning stages stressed the need for dual BPV's to be used on all coiled tubing runs.

When the scope of the project changed from setting the bridge plug with wireline, to setting it with coiled tubing, a communication failure occurred between NFX, OSCA, and HPI. HPI Thru Tubing Services had provided BPV's in their assembly during the sandwash operations, but HPI did not do so during the setting of the bridge plug. The coiled tubing supervisor stated that he thought HPI had included BPV's in the bridge plug operations, because HPI Thru Tubing Services had supplied the BPV's during the sand wash operations.

From witness statements, it appears that the three runs to set the bridge plug did not have a BPV in the BHA. On the last run, which resulted in the blowout, the NFX onsite supervisor and the two HPI representatives measured the BHA, which included a cross-over sub, a hydraulic disconnect, firing head, and the plug. No one noticed at this time that BPV's were missing. They handed the assembly to the OSCA coiled tubing operator, who attached the assembly to the coiled tubing and deployed the assembly into the wellbore.

Recommendations

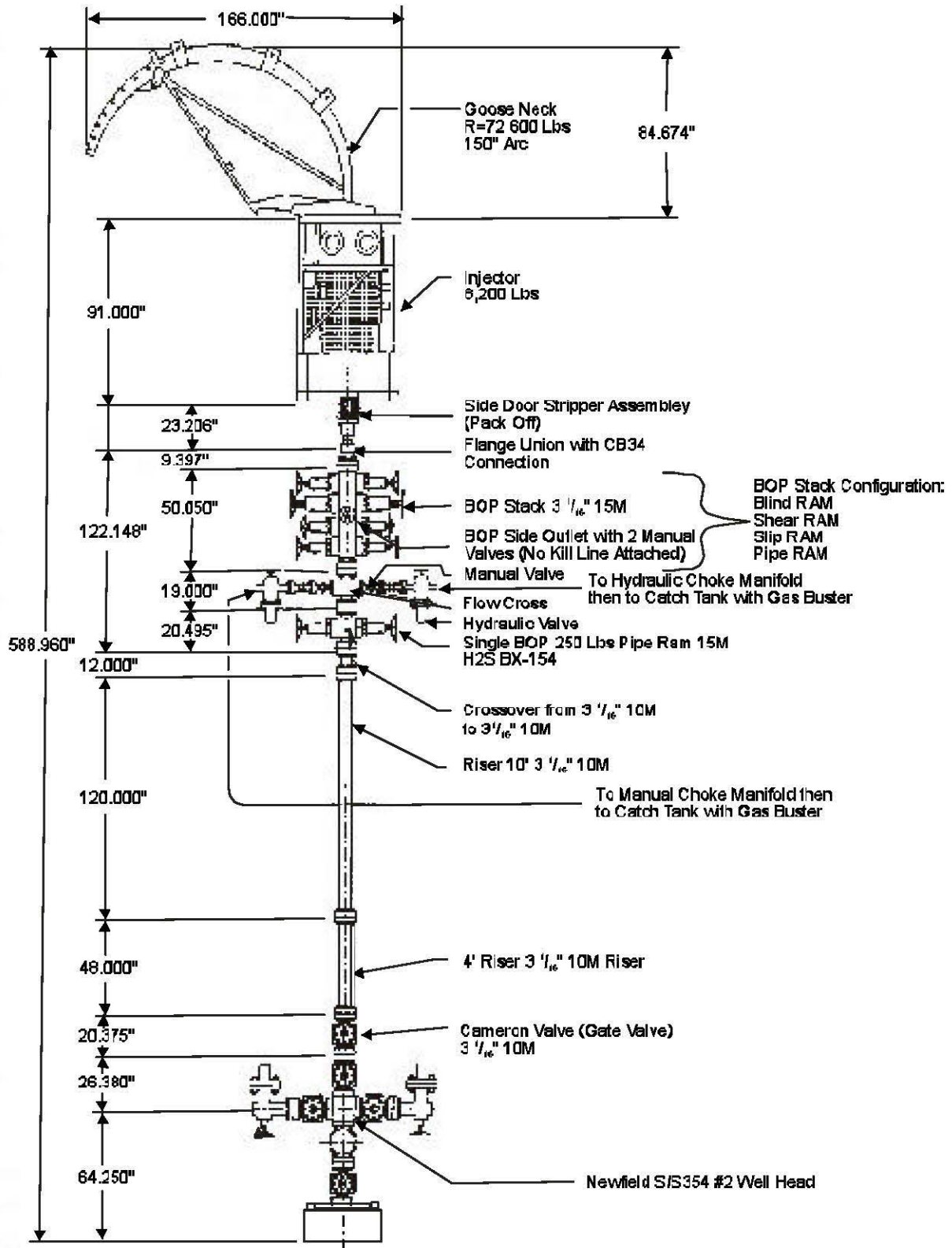
Safety Alert MMS issued a Safety Alert (No. 187) on April 3, 2000, regarding the subject incident. A Safety Alert was issued prior to the completion of this report because of the routine nature of the activity involving the incident and MMS's concern for the potential for similar such incidents. The panel has evaluated the recommendation of that Safety Alert as still being appropriate. *For a copy of the Safety Alert, see Attachment 5.*

Regulatory Change The panel recommends that MMS should review the applicability of API RP 5C7 and incorporate this document into the *Code of Federal Regulations* as a referenced document. MMS should also consider the Department of Energy publication *Coiled Tubing Safety Manual* in the proposed revision to the *Code of Federal Regulations*.

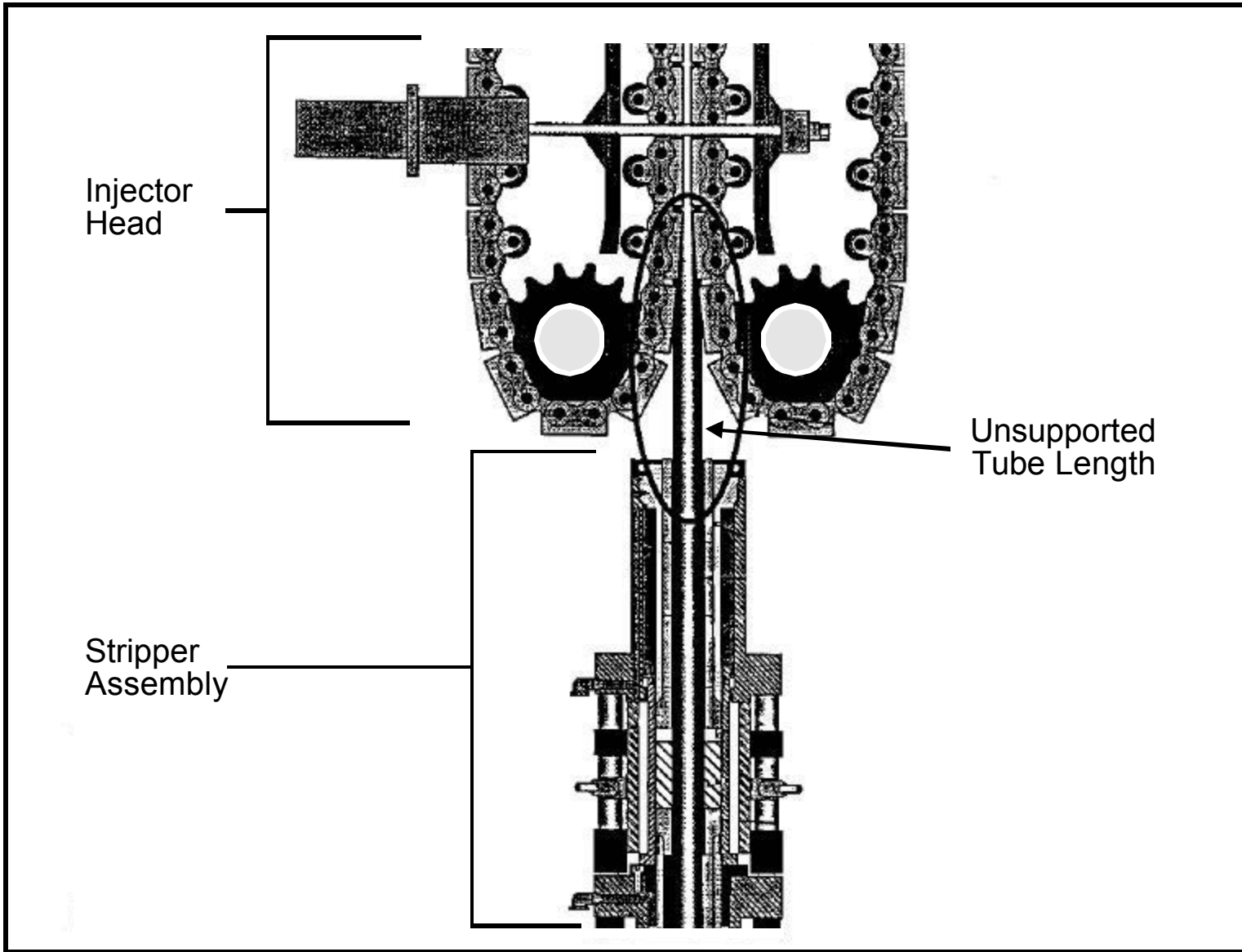


Location of Lease OCS G 15312 Ship Shoal Block 354.

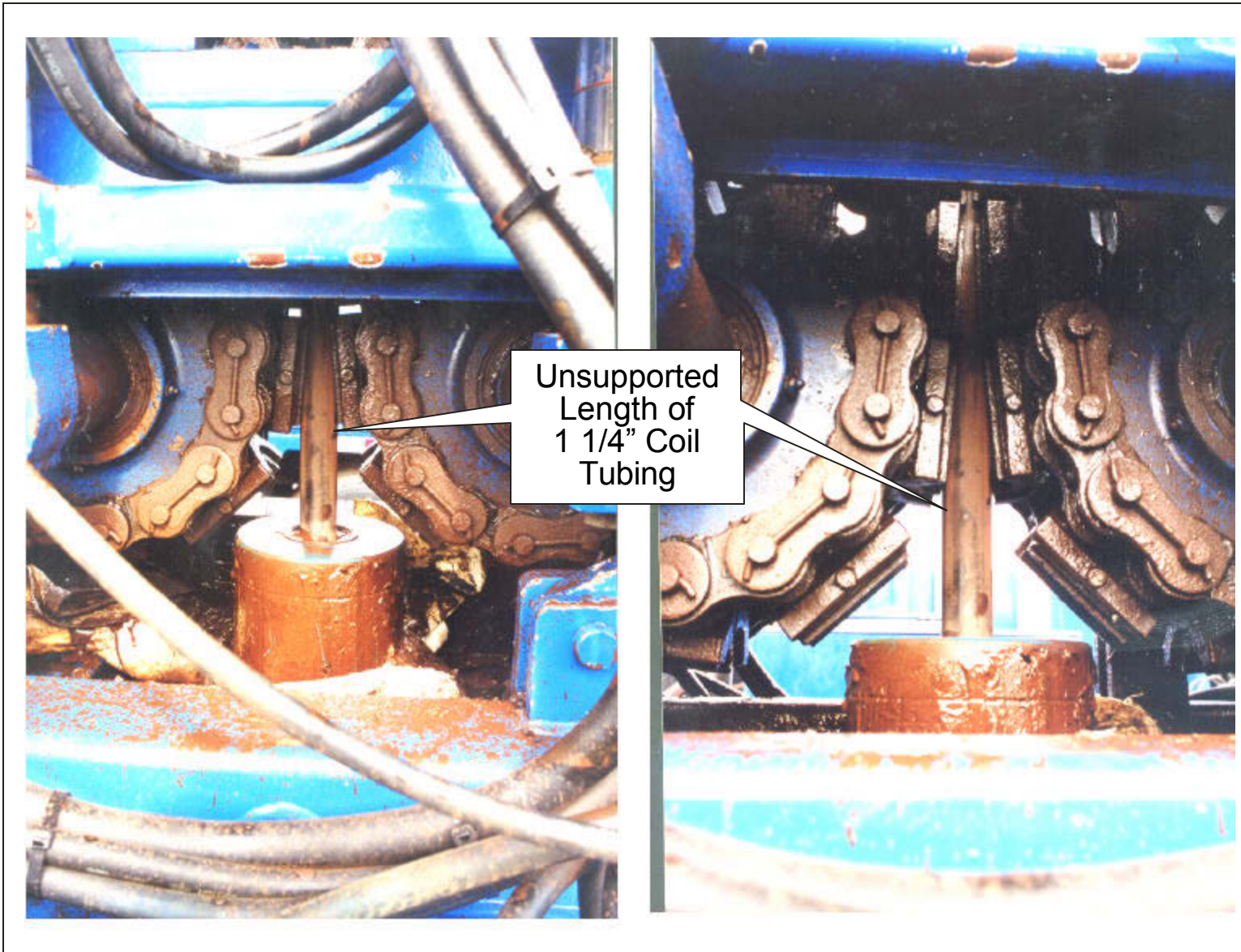
Attachment 2



Schematic of 1 1/4" Coil Tubing Rig Up for Ship Shoal 354 Well A-2



Schematic of Coil Tubing Unsupported Length Between Stripper Assembly and Injector Head



Photographs of Coil Tubing Unsupported Length Between Stripper Assembly and Injector Head



SAFETY ALERT

Safety Alert No. 187
April 3, 2000

Contact: Joe Gordon
504-736-2923

Coiled Tubing Incidents

Two recent coiled tubing operations in the Gulf of Mexico experienced similar operational problems that culminated in uncontrolled well flow events. In both situations, coil tubing was being snubbed into the wellbores when the coiled tubing strings encountered unknown obstructions, causing the coiled tubing to stop abruptly. The abrupt stop and resulting compression of the coiled tubing caused the tubing to part between the injector head and the stripper assembly. In both situations, the blowout preventer (BOP) was activated, but BOP intervention failed. The tubing was successfully sheared in both cases but could not be pulled because the pipe had parted above the stripper assembly, thereby leaving a section of tubing across the blind rams. In addition, back-pressure valves were not installed in the coiled tubing strings, thereby allowing flow up the tubing. Attempts were made to shut in the wells using the valves on the tree and, in one case, the tubing-retrievable, surface-controlled, subsurface safety valve, but with no success. Coiled tubing remained across the valve assemblies. Both situations escalated into uncontrolled flow and personnel were forced to evacuate the platforms.

Safe coiled-tubing operations should begin with planning that includes a job safety analysis (JSA) to identify all potential hazards pertinent to the operations (including but not limited to backflow up the coiled tubing, obstructions in the wellbore, kinking of the pipe between injector head and stripper assembly, wellbore geometry, coiled tubing fatigue history, well conditions).

Once the hazards are identified, procedures should be developed or altered to remove the hazards or minimize the consequence of these hazards. Procedures should include, but are not limited to, the following:

- Setting hydraulic snubbing and pulling force sufficiently below coiled tubing minimum yield to prevent buckling or parting of the pipe. These calculations should include, but are not limited to, wellbore geometry and running speed. They should be verified by a second party.
- Use of a back-pressure valve to prevent backflow up the coiled tubing. In cases where reverse circulation is required, contingencies should be in place to offer the same level of protection such as:
 - Use of sealing blind/shear combination rams.
 - Use of a manual two-way valve capable of shearing the coiled tubing. (See API RP 5C7 Section 6.8.14.1 and the U.S Department of Energy publication *Coiled Tubing Safety Manual*, by Walter Crow, 1999, DOE/SW/41286-1.)

Critical to any operation is communication between all personnel involved in the operation. As a minimum, the following practices should be adhered to:

1. The supervisory personnel should monitor and verify that operations are being carried out according to plans.
2. Should a personnel change occur during a job, it is imperative to communicate critical information. If possible, personnel should be consistent through out the project.