

Investigation of H₂S Gas Release Platform Hermosa, OCS-P 0316 Pacific OCS Region

August 3, 1999



Investigation of H₂S Gas Release Platform Hermosa, OCS-P 0316 Pacific OCS Region

August 3, 1999

Prepared By

Catherine Hoffman
Roy Bobbitt
Michael Else
Richard Ensele
(Headquarters Liaison)



Contents

Investigation and Report	1
Authority	1
Procedures	1
Introduction	2
Brief Description of Incident	2
Background	2
Findings	4
Incident.....	4
History of Ultrasonic Testing (UT) of Piping.....	5
Training and Experience	5
Operations Plan to Review UT Inspection Results.....	6
Safety Issues.....	6
Breathing Equipment	6
Building Inlet Devices	6
On-Scene Findings.....	7
Chevron’s Metallurgical Analysis	8
Chevron’s Analysis of Scale Deposits in Flowline.....	8
Description of Piping	9
MMS Analysis of Data	9
API 570	9
Conclusion.....	12
Cause.....	12
Possible Contributing Causes.....	12
UT Inspection Surveys.....	12
Chevron’s Procedures to Review UT Inspection Results.....	12
MMS Regulations.....	13
Carbon Dioxide.....	13
Process Changes	13
Insulation on Flowline	13
Chevron’s Corrective Actions.....	14
Operator Change	15
Recommendations	16
MMS Actions.....	16
Safety Alert.....	16
Inspections	16
Maintenance Requirements.....	17
Regulations	17
Process Modifications.....	17
Pacific OCS Operator Actions	17
H ₂ S Contingency Plan	17
Maintenance and Testing.....	17
H ₂ S Drills.....	18
Operations Plan.....	18

Appendix

Arthur D. Little Summary of H₂S Footprint Analysis A.1
Map of Point Arguello Unit A.2
UT History and Piping Schematic A.3
Letter From Scott Lavan to Bob Lukavsky (Chevron) A.4
Photograph of Ruptured Elbow A.5
Photograph of Ruptured Elbow A.6
Notes from MMS-Conducted Interviews of Platform Personnel A.7
Photograph of Scale Build-up in Flowline A.8
Photograph of Removable Insulation on Flowline A.9
Arguello Inc.'s UT Reporting Form A.10
August 12, 1999, Letter from Chevron Summarizing Corrective Actions..... A.11

Illustrations

1 Elbow Thickness Upstream of Rupture 11
2 Elbow Thickness Downstream of Rupture 11

Investigation and Report

Authority

An 8-inch high pressure sour gas flowline ruptured on Chevron U.S.A. Inc.'s Platform Hermosa on August 3, 1999, at approximately 2:00 p.m., resulting in an H₂S release. Pursuant to Section 208, Subsections 22(d), (e), and (f), of the Outer Continental Shelf (OCS) Lands Act, as amended in 1978, and the Department of the Interior regulations at 30 CFR Part 250, the Minerals Management Service (MMS) initiated an investigation and preparation of a public report of the accident. On August 4, 1999, the following MMS personnel were named to investigate the incident:

Catherine Hoffman	Camarillo, California (Chairperson)
Roy Bobbitt	Santa Maria, California
Michael Else	Camarillo, California
Richard Ensele	Headquarters Liaison

Procedures

On August 5, 1999, MMS personnel visited the scene of the incident at Platform Hermosa and inspected the ruptured elbow and surrounding damage. On August 12, 1999, the MMS visited Platform Hermosa to again inspect the ruptured elbow, which had been removed from the process line, and to meet with Chevron personnel working the day of the incident.

The MMS conducted interviews with the following Chevron employees and contractors:

Rick Whittington	Operator, Chevron
Sterling Delavallade	Operator, Chevron
Gabe Perez	Head Operator, Chevron
John Figueroa	Operator Trainee, Chevron
Terry Botlowski	Champion Technologies Inc.
Mike Reardon	Pacific Technical Services
John Fitzgerald	Pacific Technical Services
Colm Walsh	Pacific Technical Services

Chevron's final investigation report of the accident, dated September 30, 1999, was submitted to the MMS on October 6, 1999, as was Chevron's laboratory metallurgical analysis of the failed elbow (Appendices B.1 & B.2). The MMS observed the testing of the failed elbow at Chevron's laboratory.

The Team met at various times throughout the investigative effort, considered all the information available, and produced this report.

Introduction

Brief Description of Incident

On August 3, 1999, at about 2:00 p.m., an 8-inch high pressure gas flowline on Platform Hermosa ruptured, resulting in a sour gas release. (Sour gas is natural gas contaminated with hydrogen sulfide [H₂S] or other sulfur compounds.) The break occurred on the mezzanine deck, about 64 feet above the ocean, downstream of a third-stage discharge scrubber, V-14, and just prior to the glycol contactor inlet, V-16. The drop in pressure activated the automatic safety system on the platform, which shut in oil and gas production. Platform Hidalgo, whose pipelines transport oil and gas to Platform Hermosa, was also shut in.

The released gas had an H₂S concentration of about 18,000 ppm (see Appendix A.1–Arthur D. Little Summary of H₂S Footprint Analysis). The H₂S alarms on Platform Hermosa activated. No one on Platform Hermosa was harmed. No harm to seabirds or other wildlife was observed.

The flowline failed due to internal corrosion, which reduced the wall thickness until it could no longer support the normal operating pressure. Corrosion was caused by condensed liquid water reacting with H₂S gas to form a corrosive acid gas.

Background

Lease OCS-P 0316 covers approximately 9 square miles and is located in the Point Arguello Unit, Pacific Region, off of Vandenberg Air Force Base. (For lease location, see Appendix A.2.) The lease was originally issued on June 29, 1979, to the Point Arguello partners with Chevron U.S.A. Inc. designated as the operator. On July 1, 1999, Chevron sold all its interest in the Point Arguello Unit to Plains Resources, Inc. At the time of the incident, Chevron was acting as the unit operator and was in the process of turning over operatorship to Arguello Inc.

The segment of the 8 inch line that failed was a schedule 80 Hackney elbow manufactured by Trinity Fitting and Flange Group, Inc. in 1984. The line had been in service since Platform Hermosa's startup in 1991, as a high pressure gas line between the V-14 3rd Stage Discharge Scrubber and the V-16 Glycol Contactor. The gas carried in the line is saturated and contains 1.8% H₂S and 4-5% CO₂. Nominal temperature is 75-85° F and operating pressure is 1180-1200 psi. Gas flowrate averages 2 MMSCFD for Platform Hermosa.

The original nominal wall thickness of the flowline was 0.50 inch. The thickness at the rupture was 0.14 inch. Per ASME B31.3, the minimum allowable operating thickness for 1209 psi is 0.26 inch and the burst thickness is 0.11 inch.

During the investigation, the Point Arguello Unit changed operatorship from Chevron to Arguello Inc. It should be noted that Chevron kept Arguello Inc. informed of all

proposed corrective actions and commitments. Arguello Inc. is required to continue the corrective actions initiated by Chevron.

Findings

Incident

On August 3, 1999, there were 31 persons on Platform Hermosa. At approximately 2:00 p.m., several workers heard a whistling noise. Within seconds, the elbow ruptured with a loud explosion. The H₂S and pressure safety low alarms sounded immediately.

The SCADA (Supervisory Control And Data Acquisition) system immediately activated the Emergency Shutdown (ESD) system and shut Platform Hermosa and the pipelines from Hidalgo to Hermosa down. The SCADA system routinely monitors the platform for upset conditions and will activate alarms, component shutdown systems, and platform shutdown systems if such conditions are detected.

Mr. Gabe Perez, Head Operator, instructed platform personnel over the intercom that this was not a drill and to report to their safe briefing area. From the control room, Mr. Perez manually shut the platform down with the ESD buttons. (This is redundant as the SCADA system automatically shuts the platform down.) Mr. Perez called Platform Hidalgo to shut down their operations (Hidalgo sends production to Hermosa) and then called Platform Harvest to stand by. The SCADA system on Platform Hidalgo would eventually have shut down Hidalgo when it detected that Hermosa was not accepting production from the pipelines.

Using the appropriate breathing equipment, Mr. Perez directed pairs of people to check the systems on Platform Hermosa. Gabe and three others went to the area of the explosion to check for people down and for damage. They confirmed that no one was hurt but could not locate the exact location where the explosion had occurred. The H₂S level was still high, so they left the area until it was safe to return. Mr. Perez returned to the control room.

The group entered the area a second time without Mr. Perez and saw the ruptured elbow. They reported back to him that gas was continuing to escape from the hole, likely due to the depressurizing of other vessels upstream of the failed flowline, residual gas in the piping, condensate from the scrubbers flashing off, etc. He then tripped the valves to continue blowdown of all vessels to flare and closed the recycle valves. (The ESD does not do this.)

Review of the SCADA system data confirmed that there was not a pressure surge in the flowline prior to the incident.

History of Ultrasonic Testing (UT) of Piping

Since 1992, Chevron has been performing annual A-scan surveys on Platform Hermosa's process piping. In those A-scan UT, only a number of points were tested over the length of the flowline that failed, not the entire surface area. The inspection did not show where the flowline wall was thinnest. The elbow that ruptured was not tested because it was located in an area not easily accessible.

Until 1999, the surveys showed very little change in wall thickness. But on July 18, 1999, just 16 days prior to the incident, Mr. Mike Reardon, a technician contracted by Chevron to perform an A-scan survey on the Point Arguello Unit platform piping, found two areas where the wall thickness had decreased significantly since 1998. (For UT History and Piping Schematic, see Appendix A.3.) Upon detecting readings of 0.24 inch and 0.22 inch (original wall thickness was 0.5 inch), Mr. Reardon notified the operator in charge of platform maintenance, Mr. Steve Garrison, of the low readings that same day. However, no immediate corrective action was taken by Chevron. It should be noted that neither Platform Hermosa personnel nor Mr. Reardon knew the flowline's minimum allowable wall thickness at the time of the UT.

Mr. Reardon remained on the Point Arguello Unit platforms until July 20, 1999, to complete the UT survey. No one from Chevron approached him during that time regarding the low readings. On July 21, 1999, Mr. Reardon faxed Chevron Engineer Scott Lavan his inspection report, pointing out the flowline between V-14 and V-16 as an "area of concern."

On September 8, 1999, MMS Inspector Roy Bobbitt spoke with Mr. Garrison about Mr. Reardon's UT findings and confirmed that Mr. Reardon did inform Mr. Garrison of the low wall thickness readings on July 18, 1999.

On July 30, 1999, Mr. Lavan sent the results of the July UT survey to Mr. Bob Lukavsky, the platform supervisor (see Appendix A.4). The memorandum did not discuss shutting in of the line, calculating the line's minimum wall thickness, or other corrective actions or analysis.

Training and Experience

H₂S gas is highly toxic and flammable. Knowing the high consequence of an H₂S release, and as required by MMS regulations, Chevron developed a comprehensive H₂S Contingency Plan. The Plan helps inform and train all personnel of Chevron's policies and procedures for operations where the presence of H₂S or SO₂ presents a hazard.

All personnel on the Point Arguello Unit platforms are required to take H₂S training annually, with discussion of all changes to equipment or procedures at monthly safety meetings. All personnel are trained to operate a resuscitator and respiration equipment.

According to Chevron's H₂S Contingency Plan, a practice drill is to be conducted every 7 days where emergency breathing equipment is to be used. During the August 3, 1999, incident, the H₂S Contingency Plan was generally followed and the platform secured. However, several safety concerns surfaced during this investigation, as discussed below.

Operations Plan to Review UT Inspection Results

At an August 11, 1999, meeting, Chevron explained their procedures for reviewing the results of UT inspections. The technician is to send the survey results to the appropriate Chevron engineer, who in turn would review them and act on them as appropriate. There are no established timeframes for the engineer to review the inspection results or criteria for when immediate action is warranted (e.g. minimum allowable wall thickness).

Safety Issues

Breathing Equipment

Mr. Rick Whittington and Mr. Sterling Delavallade were running samples in the cut lab on mezzanine deck where the flowline ruptured. Immediately after the explosion, Mr. Whittington saw through the cut lab window a grayish cloud moving towards them and flashing red beacons indicating an H₂S release. Not finding breathing equipment in the cut lab, Mr. Whittington and Mr. Delavallade ran to the control room without donning breathing equipment. They were not aware that a 30-minute air pack was located right outside the cut lab door and four 15-minute air packs were located on the side of the cut lab opposite the H₂S plume and adjacent to the stairs that they took to the control room. When Mr. Whittington and Mr. Delavallede saw the gas coming toward them, their immediate reaction was to run away from the gas plume. Neither Mr. Whittington nor Mr. Delavallede had been in the cut lab area during an H₂S drill.

Although Chevron conducts weekly practice drills, it is apparent from talking to platform personnel that emergency breathing equipment is hand carried to safe briefing areas, but is rarely, if ever, donned during the drills. Personnel generally practice simulating a platform shutdown and reporting to their assigned safe briefing area.

Building Inlet Devices

Several night crew personnel said they were awakened by the H₂S alarms and the pungent smell of sulfur. The living quarters are in a positive pressure building equipped with air intake valves designed to shut the intakes if H₂S gas is detected. It was determined that the valves were not operating properly. Chevron immediately replaced the broken parts. The MMS inspections found these devices to be working properly on Platforms Harvest and Hidalgo.

With these exceptions, the H₂S Contingency Plan was followed properly. Workers assessed the situation in teams, most used the appropriate breathing equipment, and the platform was properly shut down.

On-Scene Findings

Because of thick fog, the MMS inspectors were unable to fly to Platform Hermosa until August 5, 1999. Inspectors Roy Bobbitt and Bob Hime flew to the platform in the morning and Cathy Hoffman met them there in the afternoon. Platform Hermosa was shut-in. The MMS examined the 5 inch by 7 inch hole in the elbow of the V-14 to V-16 flowline and the damage to the surrounding equipment (see Appendices A.5 & A.6-- Pictures of Ruptured Elbow). The Pro Mag Indicator on the V-14 and V-16 level bridles, pressures gauges, and the cooling water line on the K-12 main gas compressor were damaged from the force of the explosion and flying debris. The explosion also stripped insulation and aluminum shielding from the V-17 vessel and associated piping.

The MMS received a partial copy of employee interviews conducted by Chevron immediately following the explosion.

On August 7, 1999, Inspector Bob Hime issued Chevron an Incident of Noncompliance (INC) for violating 30 CFR 250.120 (a) and (b)¹ (PINC Nos. G-111 and G112):

250.120(a): The lessee shall perform all operations in a safe and workmanlike manner and maintain all equipment in a safe condition for the protection of the lease and associated facilities, the health and safety of all persons, and the preservation and conservation of property.

250.107(b): The lessee shall immediately take all necessary precautions to control, remove, or otherwise correct any hazardous oil and gas accumulation or other health, safety, or fire hazard.

The INC also informed Chevron that Platforms Hermosa and Hidalgo were to remain shut-in until the MMS determined that the facilities could commence operations safely (see Appendix A.7--Copy of INC issued on August 7, 1999).

On August 12, 1999, the MMS conducted interviews with Chevron personnel on Platform Hermosa. Mr. Dave Lauenstein, Chevron Safety lead, was present during the interviews (see Appendix A.7--Notes from MMS Conducted Interviews of Platform Personnel).

The flowline from the V-14 to the V-16 had been removed and Chevron was in the process of installing the replacement flowline. The MMS took photographs and interviewed four Chevron operators who were working at the time of the incident and a

¹ Subsequent to the August 3, 1999, incident, the regulations at 30 CFR 250 Subpart A were updated effective January 27, 2000. The content of §250.120(a) and (b) regulations can now be found at §250.107(a) and (b).

representative of Champion Technologies Inc., the company Chevron hired to install a new corrosion inhibitor program for the line.

The MMS observed the flowline installation and the x-ray inspections of the welds.

Chevron's Metallurgical Analysis

Chevron's metallurgical analysis concludes that the elbow failed due to internal corrosion, with the wall thickness decreasing until the flowline could no longer support the normal operating pressure. The results from the metallurgical analysis showed that the corrosion was caused by the presence of condensed water reacting with H₂S gas, forming a corrosive acid gas. Some of the corrosion patterns exhibited features of CO₂ corrosion; however, no iron carbonate scale was found inside the flowline to indicate that CO₂ played a major role in the failure. The test results indicated that it is likely that CO₂ helped reduce the pH of the water phase, but did little else to contribute to the mechanism.

The following describes the tests Chevron performed on the ruptured flowline, the test purpose, and the results:

TEST	PURPOSE	RESULTS
Magnetic Particle Inspection	To expose potential preexisting defects	Negative
Metallurgical Analysis	To determine if elbow was properly manufactured	All features shown are typical of ASTM A234 WPB material
Chemical Analysis	To determine chemical make-up of the elbow's material	Results are within limits specified by ASTM A234 WPB

In addition, Chevron photographed the elbow as received at the lab, during test preparation, and at various stages of testing, and did a thorough visual examination. An ultrasonic thickness mapping was done on the piping with B-scan equipment.

The MMS witnessed all testing except for the chemical composition test, which was performed at an independent laboratory, and the X-ray Diffraction tests on the scale, which required multiple samples, each with a 4-hour preparation time.

Chevron's Analysis of Scale Deposits in Flowline

Heavy scale deposits were present in areas of the piping, especially in the elbows. Scale deposits were up to 3 inches thick in one elbow, reducing the internal cross-sectional area

by an estimated 36.5% (see Appendix A.8--Photograph of Scale Build-up in Flowline). Scale from four locations in the piping system was sampled and subjected to Energy Dispersive X-ray Analysis and X-ray Diffraction (XRD) to determine the composition of the scale.

The results of the scale analysis confirm that H₂S was responsible for the corrosion. In three of the four scale samples analyzed, the XRD showed major iron sulfide (FeS) present with minor FeS present in the fourth sample. The FeS is a by-product of corrosion occurring in the flowline ($\text{Fe} + 2\text{H}_2\text{S} \Rightarrow \text{FeS} + 2\text{H}_2$).

Since there was no iron carbonate found in the scale deposit, it is believed that CO₂ played only a minor or secondary role in causing the corrosion.

Description of Piping

The symbol "HJ5KA" stamped on the elbow identified the pipe as a Hackney elbow manufactured by Trinity Fitting and Flange Group, Inc. Mr. Mike Prescott, who works in the Quality and Improvement Division for Trinity, was able to trace the elbow's origin and composition through the Hackney assigned heat code, J5KA, and the Material Test Report (MTR) that includes the chemical makeup and physical properties required by applicable codes. The MTR for this particular elbow verified that the elbow met or exceeded code requirements and that the elbow was manufactured in 1984.

MMS Analysis of Data

API 570

The MMS regulations do not incorporate standards for design and/or inspection of process piping. However, the Team contacted petroleum service companies and Pacific OCS operators concerning the methods and standards used to monitor, measure, and manage corrosion in process piping. In general, industry uses ASME B31.3 to design process piping and API 570 to inspect in-service process piping. Depending on operating conditions and other factors, additional standards may be used, such as NACE MRO175 for high H₂S concentration conditions, similar to those on Platform Hermosa.

The API 570 was developed for the petroleum refining and chemical process industries, offering methods for monitoring and measuring degradation to process piping, and recommendations for inspection, repair, alteration, and rerating procedures for in-service metallic piping systems. The API 570 recommends that inspection intervals for piping be established and maintained using the following criteria:

- A. Corrosion rate and remaining life-calculations,
- B. Piping service classification,
- C. Applicable jurisdictional requirements, and

- D. Judgement of the inspector, the piping engineer, the piping engineer supervisor, or a corrosion specialist, based on operating conditions, previous inspection history, current inspection results, and conditions that may warrant supplemental inspections.

It is common practice among all Pacific OCS Region facility operators to use the A-scan UT to spot check wall thickness at predetermined points along process piping (e.g., every second or third fitting and pipe length). Chevron followed this commonly used practice, but the elbow that failed was never tested. The wall thickness of the ruptured elbow was nearly half the thickness reading found on the elbows just upstream and downstream of the failure.

Using criteria A above and the UT data collected by Chevron from 1992 to 1998, the piping at Platform Hermosa was graphed. These graphs, shown in Figures 1 and 2 on the following page, use data collected immediately before and after the ruptured elbow. The trend lines, identified in the legend as "linear (Elbow T)," project that at the current rate of corrosion upstream of the ruptured elbow, the piping would reach its replacement thickness, 0.026 inch, in the year 2000 and would burst in the year 2005 if left unchecked (Figure 1). Figure 2 shows that the portion downstream of the ruptured elbow would reach its replacement thickness in 2005 and would not reach the burst thickness until after 2010.

In addition, Chevron failed to heed the following cautionary statement in criteria B of API 570: "For services with high potential consequences if failure were to occur, the piping engineer should consider increasing the required minimum thickness above the calculated minimum thickness to provide for unanticipated or unknown loadings, undiscovered metal loss, or resistance to normal abuse."

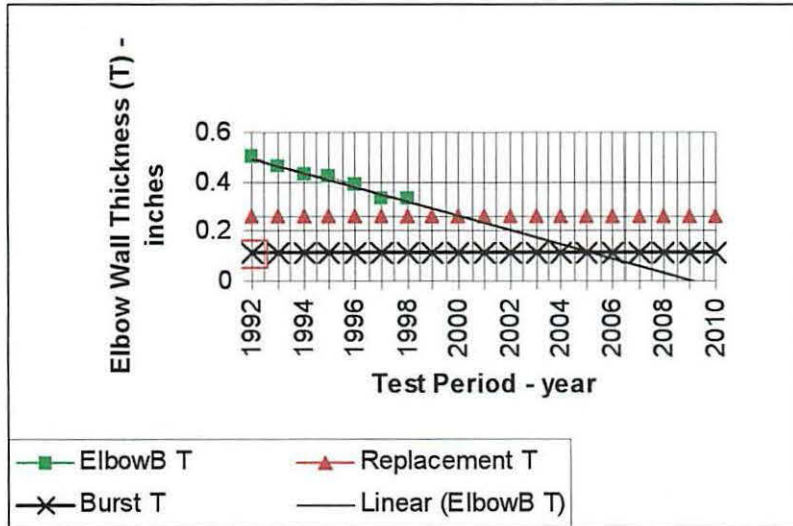


Figure 1. Elbow Thickness Upstream of Rupture.

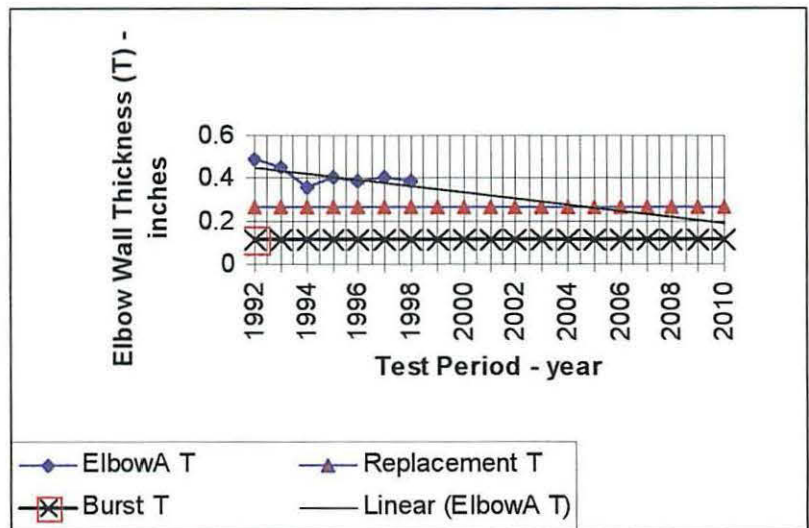


Figure 2. Elbow Thickness Downstream of Rupture.

Conclusion

Cause

After extensive review of the circumstances of the incident, along with Chevron's root cause analysis and metallurgical analysis, the Team finds it is clear that the elbow failure was caused by acid gas corrosion (i.e., H₂S dissolved in condensed water). The elbow's wall thickness was insufficient to hold the normal operating pressure and ruptured.

The flowline was designed to handle wet gas with a high concentration of H₂S as long as no water was present. The Team and Chevron can only speculate about the cause of the water. Theories include reduced gas flow rates, reduced cross-sectional area (pressure drop) of the flowline due to scale deposit, process changes, and flowline was partially insulated resulting in a temperature drop.

The heavy FeS scale deposition upstream of the failure location is a by-product of the corrosion occurring in the flowline. Chevron believes that similar scale also existed in the failed elbow, but was dislodged by the force of the rupture.

Possible Contributing Causes

UT Inspection Surveys

Although Chevron's internal program tested at frequencies in excess of that recommended by API 570, their program failed because it did not utilize the full set of tools available. Had Chevron followed API 570's Criteria A using the corrosion rate and remaining life calculations, they would have been able to forecast the rate of corrosion and could have immediately responded to the 1999 UT data.

Chevron's Procedures to Review UT Inspection Results

It is apparent that Chevron lacked a comprehensive operations plan to evaluate the results of the UT inspections. At an August 11, 1999, meeting, Chevron explained their procedures for reviewing the results of UT inspections. The technician is to send the survey results to the appropriate Chevron engineer, who in turn would review them and act on them as appropriate. There are no established timeframes for the engineer to review the inspection results or criteria for when immediate action is warranted (e.g. minimum allowable wall thickness).

This lack of a comprehensive operations plan contributed to Chevron's nondiligence in responding to the UT inspection results. Had Chevron established comprehensive review procedures for the inspection results that included specific timeframes and criteria for when immediate action is necessary, Chevron's engineer may have acted more appropriately on the inspection results.

MMS Regulations

Chevron failed to adhere to the MMS regulation at 30 CFR 250.417(q)(7) *Corrosion Mitigation* which states “You (Operator), must use effective means of monitoring and controlling corrosion caused by acid gases (H₂S and CO₂) in both the downhole and surface portions of a production system. You (Operator) must take specific corrosion monitoring and mitigating measures in areas of unusually severe corrosion where accumulation of water and/or higher concentration of H₂S exists.” Had a corrosion inhibitor program similar to that used on Platform Harvest been in place at Platform Hermosa, the rupture could have been avoided.

Carbon Dioxide

Some of the corrosion patterns found in the flowline exhibited features of CO₂ corrosion; however, no iron carbonate scale was found to indicate that CO₂ played a major role in the failure. It is likely that CO₂ helped lower the pH of the condensed water phase, but did little else to contribute to the corrosion that led to the elbow’s failure.

Process Changes

Chevron’s metallurgical analysis concludes that the corrosion rate was most likely accelerated by the recent increased H₂S concentration. This higher concentration may be attributed to equipment and/or process changes that occurred during the last 12 to 18 months before the line ruptured: Hidalgo oil production being processed through Hermosa, the July 1998 installation of a crude oil stabilizer, and the commission of a condensate stabilizer, V-5. Chevron’s conclusion is supported by the flowline’s inspection history, which showed accelerated corrosion rates during the last 12 months before the failure, about the time the process changes were made.

In addition to increasing the H₂S concentration, the process changes at Platform Hermosa may have caused condensation in the flowline, a condition that was not evaluated in the original design of Platform Hermosa’s process equipment.

Section 4: Management of Change, of API RP 75 “Recommended Practice for Development of a Safety and Environmental Management Program for OCS Operations and Facilities” recommends that an operator establish procedures to identify and control hazards associated when process changes in a facility cause conditions different from those in the original process design. Chevron did not analyze process changes to determine if a higher H₂S concentration would accelerate corrosion in the platform’s flowlines or if the process changes could cause condensation in the process flowlines, a condition that was not evaluated in the original process design.

Insulation on Flowline

Insulation wrapping portions of the piping prevented those areas from being inspected. The lack of insulation on other portions of the flowline may have contributed to the water condensation.

Chevron's Corrective Actions

On August 11, 1999, Chevron and Arguello Inc. met with the MMS to discuss the incident, their root cause analysis, proposed corrective actions and the start-up of Platforms Hermosa and Hidalgo. Chevron implemented corrective action in the areas of maintenance, inspection, and procedural changes.

It should be noted that Chevron kept Arguello Inc. informed of all proposed corrective actions and commitments. Arguello Inc. is required by the MMS to continue the more frequent UT inspections, the inhibitor program and other corrective actions implemented by Chevron.

Chevron has implemented a comprehensive chemical treatment program to inhibit internal corrosion for piping segments of concern on Platforms Hermosa and Hidalgo. The Team looked at similar programs on other platforms and discussed this course of action with Chevron's materials engineer, Rich Thompson, and chemical engineer Terry Botlowski of Champion Technologies, Inc. It is generally believed that this type of corrosion is easy to inhibit and that Chevron's inhibitor program, if administered correctly, will greatly reduce corrosion. The success of such a program is demonstrated at Platform Harvest where a corrosion inhibitor program has been in place since the beginning of platform operations. Recent UT inspection of similar service piping on Harvest showed negligible wall thickness changes.

To ensure that the chemical treatment program is effective, Chevron will conduct follow-up "B-scan" ultrasonic inspections at 6-month intervals. To facilitate a more complete inspection, Chevron installed special insulating blankets that can be easily removed for the ultrasonic test (see Appendix A.9--Removable Insulation on Flowline). Chevron has modified the data reporting forms to include the allowable minimum wall thickness, so it will be easier for platform personnel to immediately identify a potential problem and act on information in a timely manner. Arguello Inc.'s UT report form includes the minimum allowable wall thickness (see Appendix A.10--Arguello Inc.'s UT Reporting Form).

The UT technician showed the person in charge of maintenance the low readings immediately, but platform personnel took no corrective action and did not bring the problem to the attention of Chevron's engineers or the platform supervisor. Chevron has proposed improvements to the reporting process to help ensure any areas of significant concern will be brought to the attention of the appropriate platform supervisor. At this point, Chevron's response seems vague other than that the allowable minimum wall thickness would be included on the data reporting forms.

Chevron's corrective actions are summarized in their August 12, 1999, letter to the Santa Maria District Supervisor (see Appendix A.11).

Operator Change

Concerns have been expressed that the sale of the Point Arguello Unit to Plains Resources and the change of operator from Chevron to Arguello Inc. may have affected the morale of platform personnel. However, after speaking with several employees working on the platform, the Team did not detect a lax attitude toward safety. Chevron's nondiligence in responding to the UT inspection results appears to be more attributed to a false sense of security since historically the flowline showed negligible wall loss.

Recommendations

MMS Actions

Safety Alert

The MMS should issue a Safety Alert to lessees concerning this incident. The Safety Alert should emphasize the importance of UT inspections on flowlines containing corrosive and toxic products. The Safety Alert should also recommend the following:

1. Review of UT inspection results should be given a high priority.
2. The minimum allowable wall thicknesses should be determined prior to UT inspections and conveyed to both the UT inspection technician and appropriate platform personnel.
3. The platform foreman should have authority to shut down any equipment and/or the platform immediately if a UT inspection identifies a flowline with a wall thickness at or near the minimum allowable.
4. All platforms with H₂S should have the air inlet H₂S detection device for the living quarters tested regularly.

The Safety Alert should also emphasize the importance of H₂S drills and the use of breathing equipment during those drills.

Inspections

The MMS should consider incorporating the following into inspections of platforms with H₂S:

1. Test air inlet heads that detect H₂S on all positive pressure buildings to ensure proper working order.
2. Conduct periodic unannounced H₂S drills, similar to the oil spill drill exercises, and debrief personnel on platform response. This will help keep the element of surprise and minimize complacency among platform personnel with respect to drills.
3. Consider API 570's External Inspection Checklist for Process Piping and determine if the Checklist would be useful in platform process piping inspections.

Maintenance Requirements

The MMS should consider requiring operators to submit inspection plans for process piping and pressure vessels, including test methods, test areas, test frequency and inspection results.

Regulations

The MMS should review ASME B31.3, API 570, and other appropriate industry standards and determine if such documents should become a Document Incorporated by Reference.

Process Modifications

Before the MMS approves any changes in operating conditions different from those in the original design, the MMS should ensure that the operator has closely analyzed the effects of the proposed changes on separate but inter-related upstream or downstream facilities (e.g., pipelines, process equipment), per API RP 75. Process modifications can introduce new hazards or compromise the safeguards built into the original design. Care must be taken to understand the process facility and personnel safety and environmental implications of any changes.

Pacific OCS Operator Actions

The Team has the following recommendations for Pacific OCS Region operators of platforms processing H₂S gas.

H₂S Contingency Plan

As required by MMS regulations:

1. H₂S contingency plans should be updated to reflect the numbering changes in MMS's regulations.
2. Emergency Notification and Telephone Lists should include all agencies that need to be notified in the event of an H₂S release.

Maintenance and Testing

Pacific OCS Region operators should consider incorporating the guidelines of API 570 and API 510 into their maintenance and testing program, where applicable.

H₂S Drills

A debriefing after H₂S drills should be conducted to give platform personnel feedback on platform response.

Platform personnel should don breathing equipment during H₂S drills.

Operations Plan

Operations plan should include some procedure for utilizing critical information to avert accidents. This should include established timeframes to review inspection results and established criteria for when immediate action is necessary. The plan should prescribe procedures to initiate an emergency shut-in of facility or component when an UT inspection shows wall loss anomalies in high-pressure and/or toxic material flowlines at or near its minimum thickness.

APPENDIX

Arthur D Little

Arthur D. Little, Inc.
3916 State Street, Suite 2A
Santa Barbara, California
93106-3137 U.S.A.

Telephone (11) 805.563.7660
Fax (11) 805.563.7870

August 13, 1999

Mr. Scott Martindale
Chevron USA Production Company
646 County Square Drive
Ventura, California
93003

Re: Consequence Modeling Results for Platform Hermosa Offshore Sour Gas Release
on August 3, 1999

Dear Scott:

This letter report contains the results of the consequence modeling that Arthur D. Little conducted of the offshore sour gas release that occurred at platform Hermosa on August 3, 1999 at about 1400 hours (2:00 PM). Consequence modeling was conducted for both H₂S and flammable hazards. The letter report is divided into four main sections. The first section covers the release conditions. The next two sections discuss the impact criteria and consequence models respectively. The last section presents the consequence modeling results.

A. Release Conditions

The sour gas release occurred at Platform Hermosa, which is located about 17 miles offshore from Point Conception in Santa Barbara County California. Table 1 provides the release conditions that were used in the consequence modeling. The release condition data was provided by Chevron.

Table 1 Release Condition Data

Item	Value
Release Date and Time	August 3, 1999/1400 hours
Release Size	6" hole in an 8" pipe
Initial Release Pressure	1,200 psig
H ₂ S Concentration	18,000 ppm
Release Duration	10 minutes
Estimated Volume of Gas Released	32 mscf
Wind Speed and Direction	28 Knots/300° (from the North-West)

August 3, 1999 Release Characteristics

<i>Time</i>	<i>Elapsed Time (s)</i>	<i>Observed Pressure (Pa)</i>	<i>Instantaneous Release Rate (kg/s)</i>	<i>Cumulative Mass Released (kg)</i>	<i>Cumulative Average Release Rate (kg/s)</i>
14:01:43	0	8434789	288	0	288.0
14:01:47	4	4009575	128	832	208.0
14:01:51	8	1597075	49.7	1187	148.4
14:02:18	35	666539	20.6	2136	61.0
14:02:48	65	259861	8.08	2276	35.0
14:02:52	69	248075	7.64	2308	33.4
14:02:52	69	204718	6.38	2490	26.2
14:03:18	95	184039	5.71	5018	9.8
14:10:17	514	163361	4.91	5034	9.7
14:10:20	517	108218	2.8	5065	9.8
14:10:28	525	101325	2.5	5263	6.8
14:11:43	600				

Arthur D Little

August 13, 1999 Page 2
Mr. Scott Martindale
Chevron USA Production

B. Impact Criteria

In evaluating the hazard zones associated with serious injury and threat to life due to exposure to H₂S gas the following have been used for the impact criteria.

ERPG-3 (100 ppm) - The maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing life-threatening health effects. This value is based on human experience, e.g., a report of unconsciousness and decreased blood pressure in an otherwise healthy individual exposed to an estimated concentration of 230 ppm H₂S for 20 minutes. In addition, after exposure to 200-300 ppm for 1 hour, individuals experienced marked conjunctivitis and respiratory tract irritation, but no deaths occurred. This level represents life threatening exposure.

ERPG-2 (30 ppm) - The maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take protective action. This value is based upon animal studies where no deaths occurred when rats were exposed to 45 ppm for 4 hours but unconsciousness and cardiac irregularities were reported in rabbits exposed to 72 ppm for 1.5 hours. This level represents the exposure level needed for serious injury.

IDLH (100 ppm) - The maximum airborne concentration to which a healthy male worker can be exposed for as long as 30 minutes and still be able to escape without loss of life or irreversible organ system damage. IDLH values take into account acute toxic reactions such as severe eye irritation, which could prevent escape.

These levels of concern are well-established standards for exposure to H₂S, and represent levels that have the potential to lead to serious injury or a threat to life.

For flammable hazards the lower flammability limit (LFL) was used.

C. Atmospheric Dispersion Modeling Description

In order to simulate the lighter and denser-than-air gas releases, the consequence analysis utilized a modeling system based on the SLAB dispersion model developed by Lawrence Livermore National Laboratory (Ermak, 1989). This model has the additional advantages of being: (1) available in the public domain, (2) subjected to scientific peer

Arthur D Little

August 13, 1999 Page 6
 Mr. Scott Martindale
 Chevron USA Production

D. Consequence Modeling Results

Results of the consequence modeling are presented in Table 2. Figure 1 shows a plot of the H₂S toxic hazard zones. These results indicate that hydrogen sulfide concentrations exceeding the ERPG-3 level, which could be life threatening, would be limited to the vicinity around the platform with the hazard zone extending approximately 177 feet (53.9 meters) from the platform. The hazard zone would have had a maximum width of approximately 13 feet (3.9 meters). At the farthest downwind distance the plume would have been approximately 115 feet (35 meters) above the water level. Therefore, the H₂S toxic cloud would not have represented a hazard to boaters in the area.

Potential serious injuries, as represented by the ERPG-2 level, would also be limited to an area near the platform. The ERPG-2 hazard would extend approximately 354 feet (108 meters) from the platform. The hazard zone would have had a maximum width of approximately 31 feet (9.4 meters). At the farthest downwind distance the plume would have been approximately 112 feet (34 meters) above the water level. Therefore, the H₂S toxic cloud would not have represented a hazard to boaters in the area.

The flammable hazard zone would have extended to a downwind distance of approximately 179 feet (54.6 meters). The flammable hazard zone would have had a maximum width of approximately 16 feet (5 meters). At the farthest downwind distance the plume would have been approximately 115 feet (35 meters) above the water level. Therefore, the flammable cloud would not have represented a hazard to boaters in the area.

Table 2 Summary of Consequence Modeling Results for the 8/3/99 Release

Exposure Criteria	Level Of Concern (ppm/minutes)	Worst-Case Averaging Time (sec)	Maximum Downwind Distance (meters)	Maximum Crosswind Distance (meters)	Height of Plume Above Water Surface at Maximum Downwind Distance (meters)
IDLH	100/30	600	72.7	5.7	34
ERPG-2	30/60	600	108.0	9.4	34
ERPG-3	100/60	600	53.9	3.9	35
I.F.L.	-	60	54.6	5.0	35

Arthur D Little

August 13, 1999 Page 7
Mr. Scott Martindale
Chevron USA Production

In no case did the hazard zones come anywhere near the shoreline. Appendix A provides a list of references that were used as part of this study. Appendix B provides the detailed modeling input and output files.

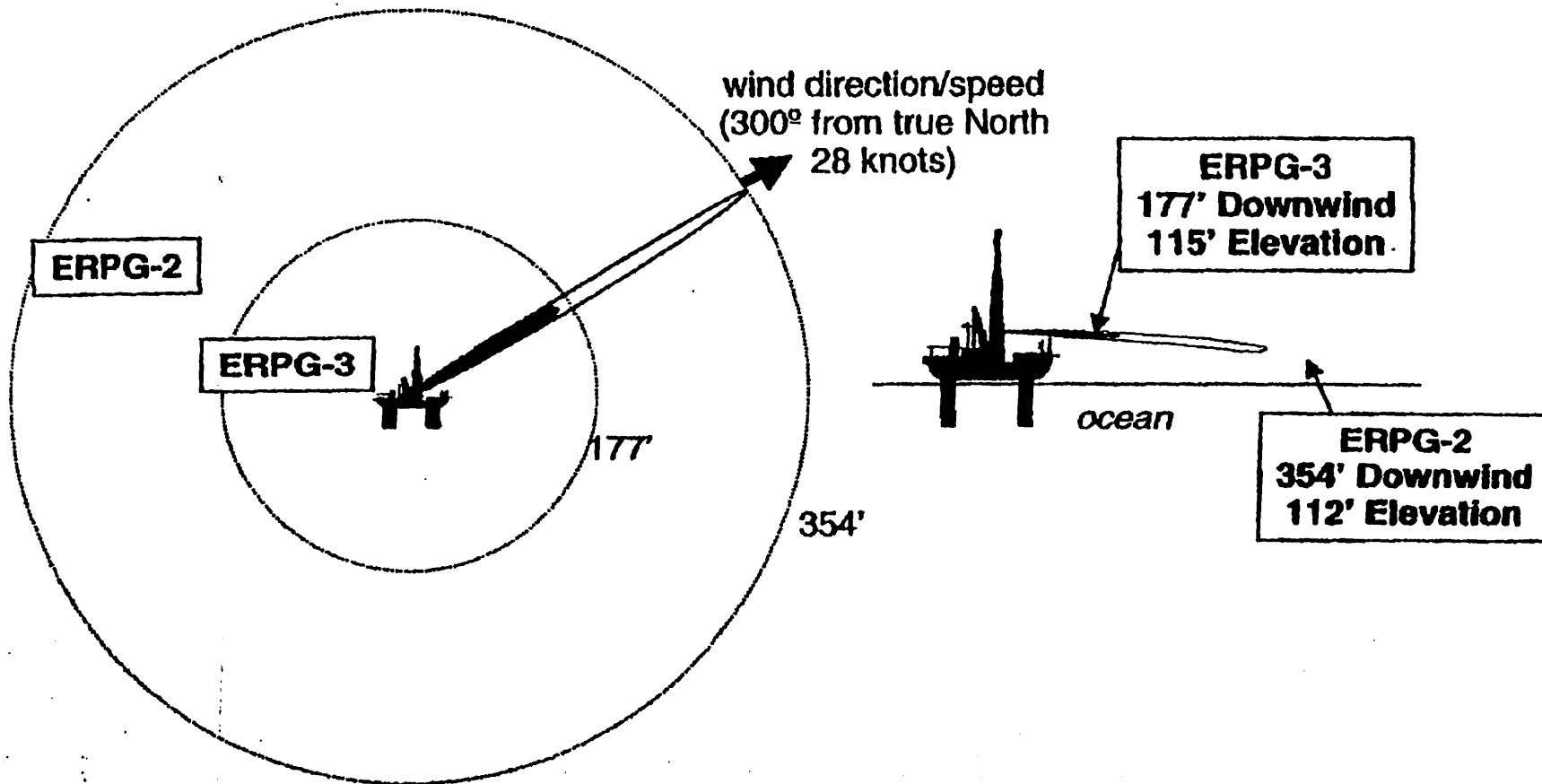
Should you have any questions or need additional information, please give Steve Radis or myself a call.

Best Regards,

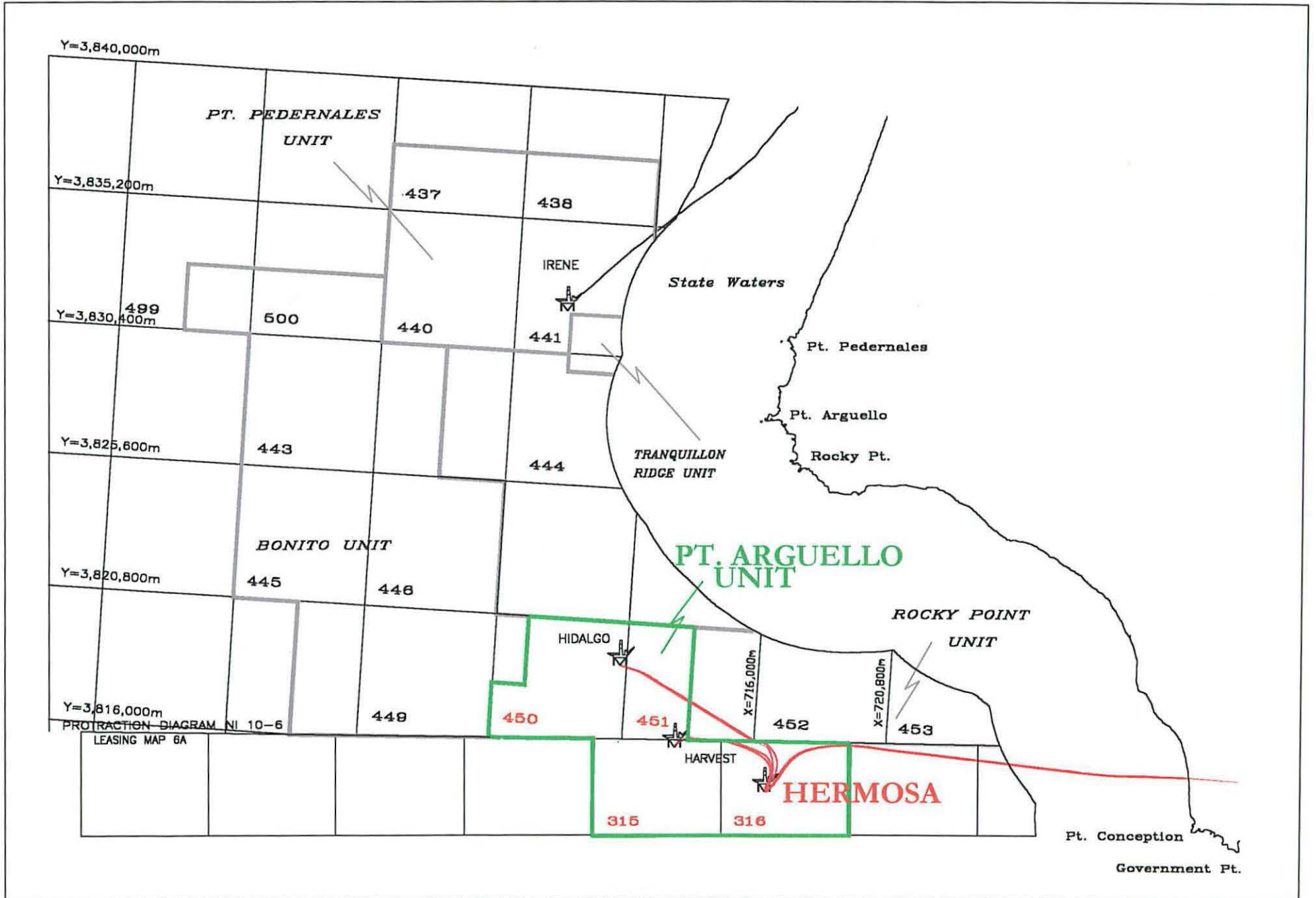


John F. Peirson, Jr.
Director
Environmental, Health and Safety

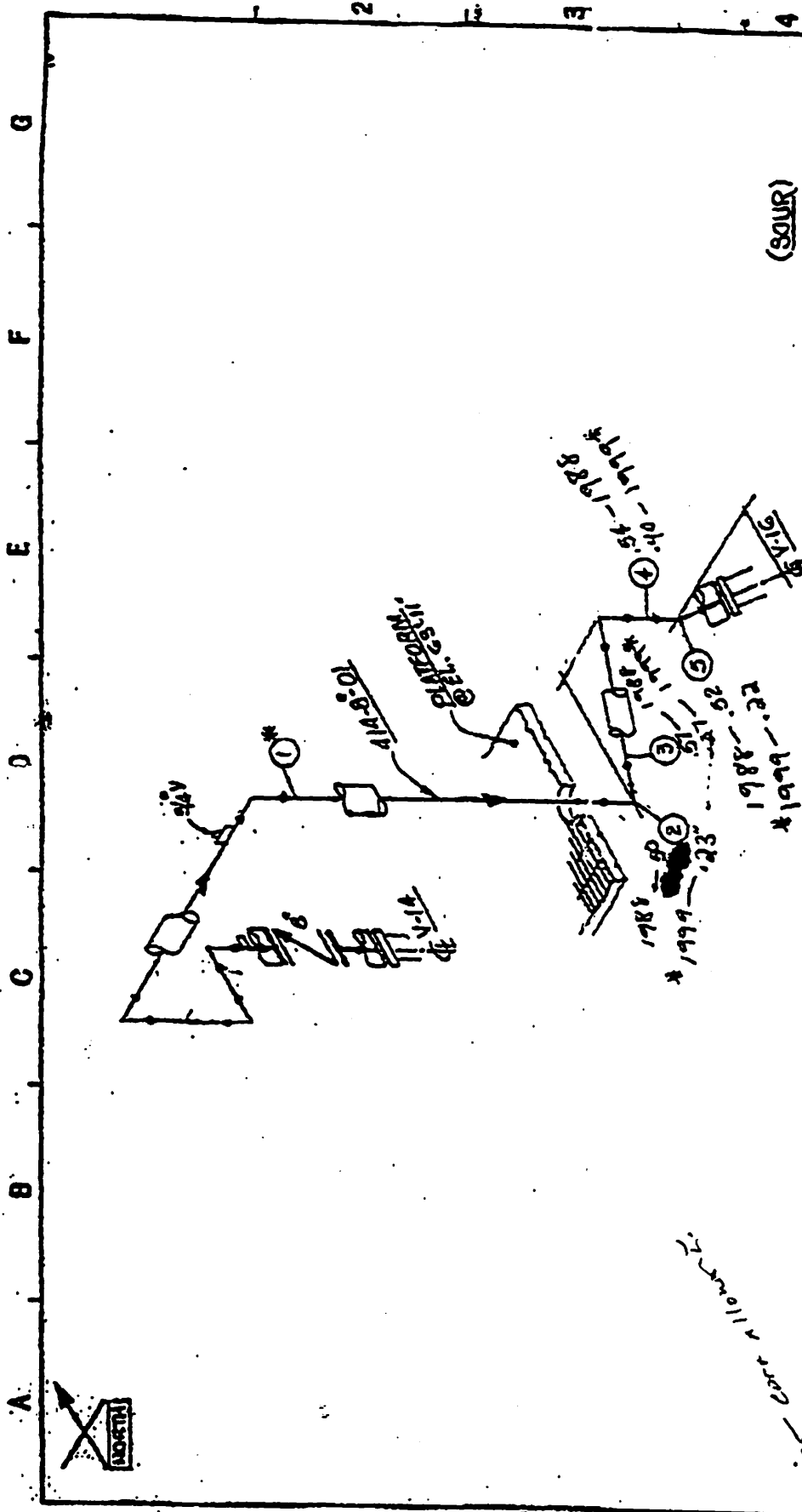
Figure 1 H₂S Toxic Hazard Footprints for Point Arguello Offshore Gas Release on August 3, 1999



Arthur D Little



Appendix A.2-Map of Point Arguello Unit



G.I. PRODUCED GAS (SOUR)

5 TEST POINTS.
* 1 HOLE TO BE CUT IN INSULATION.

PLATE 2000
ISOMERIC EMG FOR V.I.

NO.	DATE	BY	CHKD.	REVISIONS



MOBILE

DATE FIELD

194

MOBILE, ALA. 36688-0001



Chevron

CHEVRON USA
646 County Square Drive
Ventura, CA 93003

FAX COVER SHEET

TO: Bob Lukavsky (fax x4598)
FROM: Scott Lavan *SL* (x4334; fax 658-4460)
DATE: Friday, July 30, 1999
RE: Hermosa Annual UT Piping Inspection – Areas of Concern
PAGES: 7 (including this cover)

Attached is information that Mike Reardon faxed me following his recent annual UT survey of Hermosa piping systems. These are the problem areas he observed. I assume that he has also notified you on these areas, but wanted to forward this information to you just in case.

The rest of the piping, he told me verbally, was of no concern. He will send me a copy of his final, bound report for the VPC files with documentation on the entire survey.

Please call or e-mail if you wish to discuss further.

faxHgrm37.doc

Chevron U.S.A.
Platform Hermosa
Annual Ultrasonic Inspection.

The annual Ultrasonic Inspection of Platform Hermosa was completed on 7-20-99 by Pacific Technical Services. Technicians Mike Reardon, Robert Drummond, and Darrgh Lawlor all certified A.S.N.T. Level II. The equipment used to perform the inspection was a Krautkramer USK-7 with a 5 MHz, .375" & .50" Dia. dual element and pulse echo type Transducers.

Overall the piping on Platform Hermosa appears to be in good condition with very little change since last inspection. The only Exception are the areas listed below.

Areas of concern:

Drawing 154, Sour Produced Water Out Of V-1 The pipe to elbow weld upstream of U.T. point No. 4 appears to have a small pin hole leak on weld, no severe corrosion occurring on base metal. This was noted last year.

Drawing 194 Sour Produced Gas Out Of V-14 Into V-16 This 8" carbon steel schedule 80 line is showing signs of severe accelerate corrosion. The line in 1988 was a 1/4" thick and in 1999 has a remaining wall of .22" with a avg. low of .24" to .26". More then half wall has occurred.

Drawing 204, Glycol off V-19 The 3" line has a low reading of .10" on the top part of the tee and a .14" on the pipe above the tee. These readings have not changed since last years inspection.

Drawing 225 Piping Off P-72 low Volume Sump Pump. Minor corrosion on points 1, 4 and 5. I feel no action is required at this time, but pay close attention to this line next inspection.

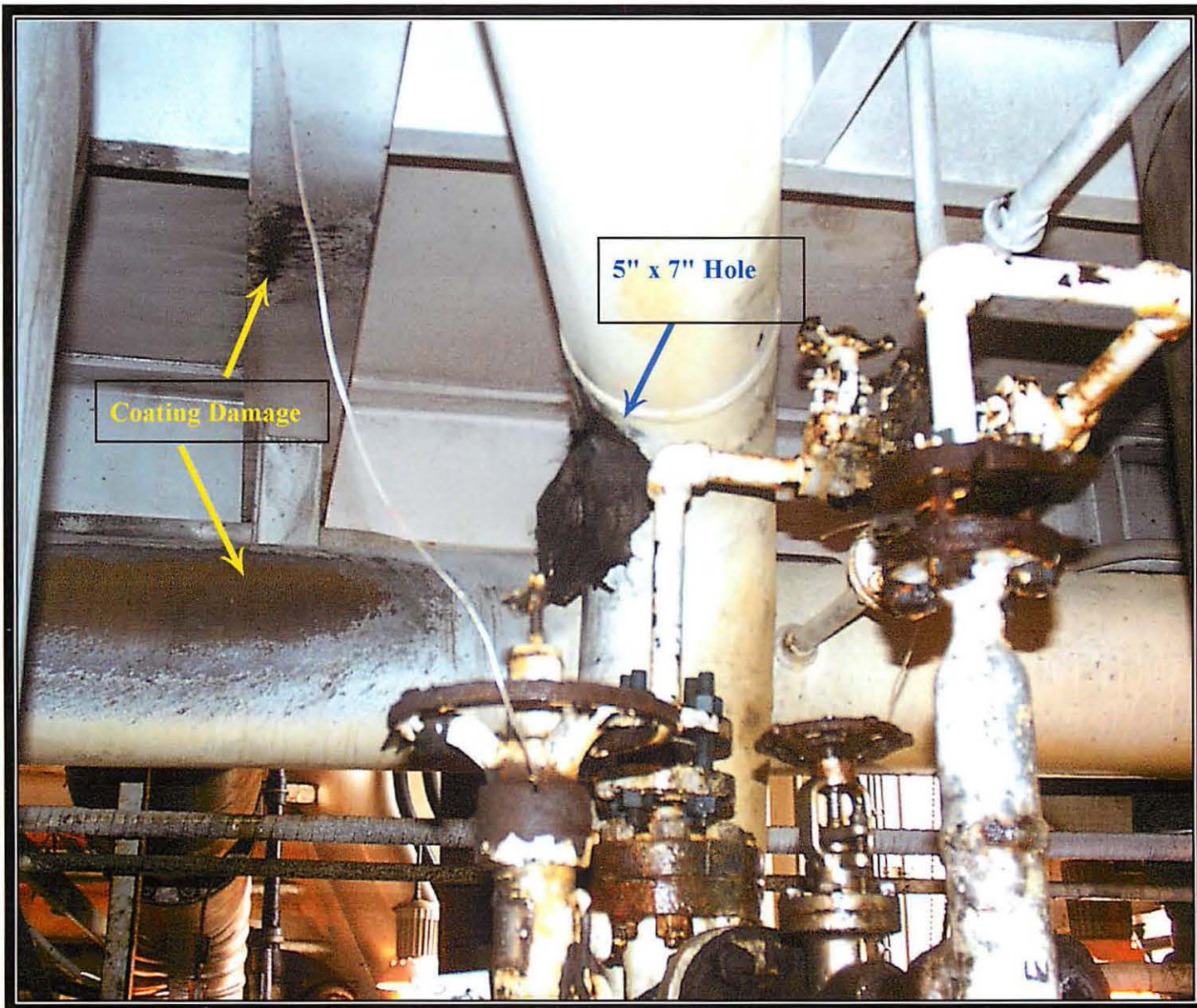
Polymer Injection Points: The 3 polymer injections points were 100% scanned with ultrasonic's and the results are as follows:

Injection point on 10" line up stream of M-31. This line holed through and was patched up at an earlier time. The area around the patched has a wall thickness of .34" and is in good condition at this time. It is recommended to continue to check up on this line, including the patch for any wall that could occur.

Injection point by V-01. This area has severe corrosion with a remaining wall thickness of .12" (1/8") on the bottom and sides. These are the same readings has last year. The quills on the injectors have been replaced and are not creating any further wall loss

Injection point by V-02. This area has severe corrosion on the bottom and has a remaining wall thickness of .10". These are the same readings has last year. The quills on the injectors have been replaced and are not creating any further wall loss

Mike Reardon _____

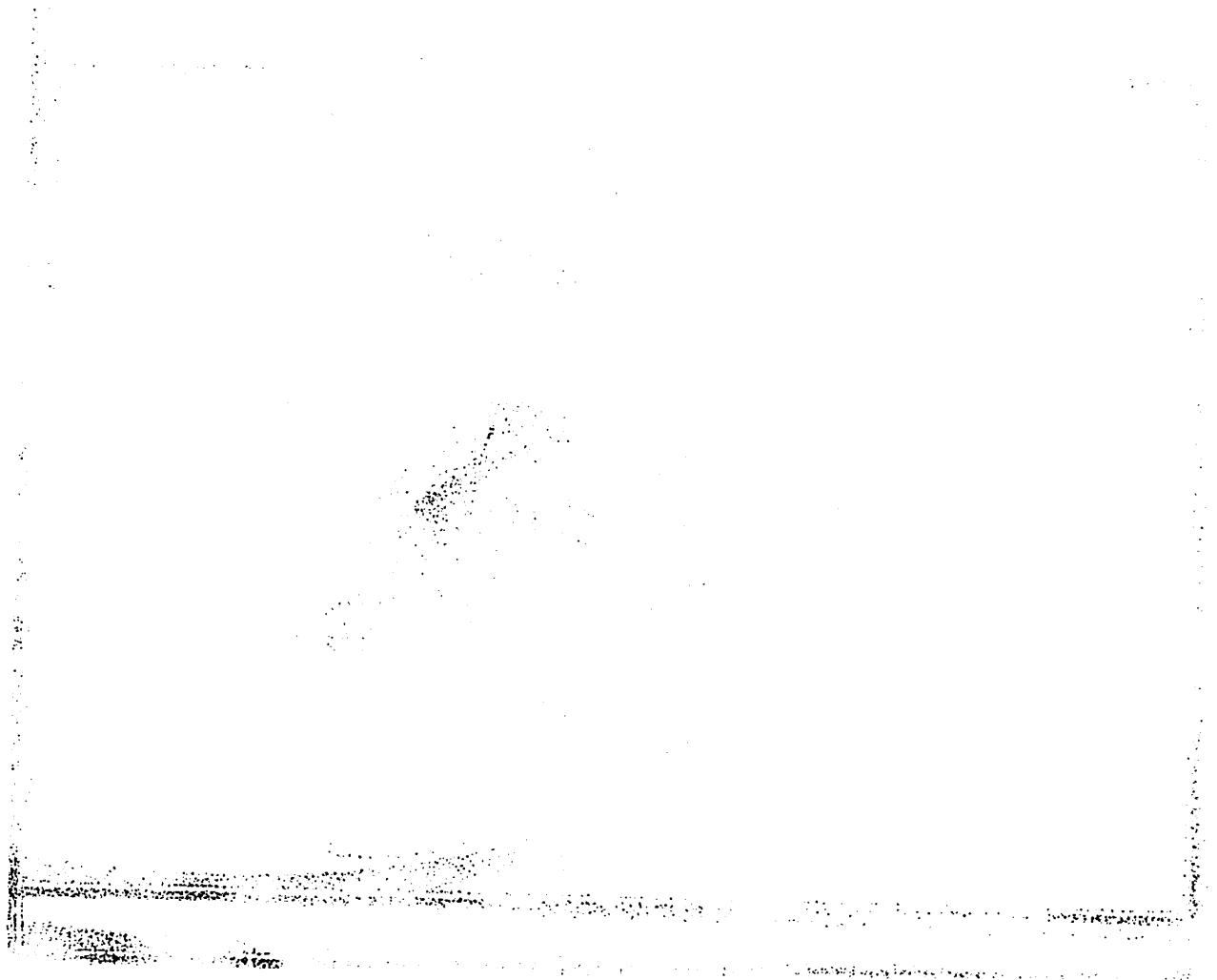


Appendix A.5-Ruptured Elbow and Surrounding Damage





Appendix A.6-Ruptured Elbow



NOTES FROM 8/12/99 INTERVIEWS ON PLATFORM HERMOSA

Rick Whittington (Chevron A-Operator)

Interview time: 2:35 pm

Rick and Sterling were running samples in the cut lab when the explosion happened. Immediately before the explosion, they heard a hissing sound lasting 2-4 seconds. The explosion sounded like a loud bang.

Immediately after the explosion, Rick looked through the cut lab window in the direction of the explosion sound and saw a greyish cloud moving his way and the beacons lighting red indicating an H₂S release. Although Rick works regularly in the area, he has never been in the cut lab during an emergency drill. After looking around the cut lab for breathing equipment, Rick and Sterling chose to run to the control room (safe area) without donning breathing equipment. The path they chose was a way from the plume.

After arriving at the control room, Rick, Gabe and others went down to investigate (approximately 5 minutes after the explosion). Rick noted that the light was not sufficient to see much. We asked about the light. He said he didn't recall if there is a light in the area or if the light exists but may have been damaged during the explosion. The H₂S level was still high (over ranging on hand-held monitors); although, there was no noticeable gas coming from the pipe. The team stepped way to a safer (lower reading) area.

About 5 minutes later they returned to the area. Although readings were still high, the team looked around to see if anyone was down or whether something needed to be isolated.

Rick stated during the interview that after the incident, he was reminded that there was a 30 minute pack right outside the cut lab door and four 15 minute packs mounted on the outside of the cut lab facing away from the H₂S plume. John and Sterling passed the air packs on their way to the control room.

Ricks Overall Assessment and Comments

He assessed that everyone responded to the safe areas very quickly. However, the second time the team entered the V-16 area, it was difficult to keep the "buddy system" in check since each individual wanted to investigate, taking them away from each other.

Comments

Cathy and Mic's tour of the facility noted the existence of breathing air packs stations mounted outside the cut lab. The stations were fully stocked at the time of our tour.

Action Items

We need to find out what happened to the lighting in the explosion area.

Sterling DeLavallade (Chevron A-Operator)

Interview time: 3:15 pm

Sterling has only been working on the platform 1-1.5 years. Sterling was in the cut lab with Rick Whittington at the time of the explosion. Like Rick, he looked around the cut lab for breathing equipment, didn't see anything so he held his breath and ran up the stairs to the control room. When he got to the control room deck above, he said he could still see the gas plume below them.

During practice drills, Sterling said that people don't don air packs until they arrive at the control room (emergency response room). He said in normal drills, they do not look for the nearest equipment. Sterling referred to the Galley as the safe briefing area.

After Sterling reported to the control room, he and David Sondoza went to close the wing valves and confirm that the wells shut in automatically. He also checked SSV to see that the stem was out (meaning it was tripped). Everything shut down as designed.

Sterling's Assessment

Sterling feels that an improvement to Hermosa's response would be to muster near the Whitaker capsule (life boat) as has been the case on other platforms he has worked on.

Comments

Dave Lauenstein responded to Sterling's statement that Chevron should consider mustering at the Whitaker capsule area. Chevron had done this in the past but found that depending on the weather, instructions/communications announced both at the capsule area and over the intercom system can be difficult to hear.

Action Items

Check H2S contingency plan to see what it says about donning H2S equipment.

Terry Botlowski (Champion Technologies Inc.)
Orcutt District Office
(805) 680-2529

Interview Time: 3:40 pm

Terry will be administering the inhibitor program on the V-14 to V-16 line. Terry stated that the inhibitor program will only work if corrosion caused the wall loss. If it's erosion, then the inhibitor program will not be effective. The only way to reduce erosion is to reduce the water. Erosion is caused by the presence of water suspended in gas (i.e. water spray nozzle under 1200 psi).

The inhibitor will be injected into the line just after the V-14 vessel at which point it will vaporize (atomize) within the gas. The inhibitor will react (be absorbed into) with water in the line so that the water will not react with CO₂ or H₂S to create acid. Champion will also set up a grab spot at V-16 to see if the corrosion inhibitor is reaching the entire length of the pipe.

Chevron will use an "off the shelf" inhibitor and adjust accordingly after doing an analysis of the water in V-14 and executing a computer model of the system. The wall thickness will be monitored every six months with UT; although, Terry recommends that it be monitored every 30 days until Champion has verified the effectiveness of the chemical treatment. Terry feels that UT is the best way to monitor the wall thickness, better than coupons.

The chemical system is being delivered to the platform tonight and should be set up by August 15, 1999. A similar system will be set up on Hidalgo. A chemical inhibitor program has been used on Harvest since day one. Recent UT of Harvest confirmed that Harvest has not experienced the wall loss seen on Hermosa and Hidalgo.

Comments

We suspect that Terry's statement on erosion caused by water suspended in gas at 1200 psi is equally (if not more) dependant on the flow rate than on the pressure.

Action Items

Have Roy Bobbit or Bob Hime confirm that the inhibitor program is in place on Hermosa and Hidalgo, including a grab spot near V-16.

Gabe Perez (Chevron Head operator)

Interview time: 4:20 pm

Gabe was in the control room with Dave Figueroa at the time of the incident. Around 2:01 pm, Gabe heard something he thought was a leaky air hose/line and then a loud explosion followed by an H₂S alarm. Over the intercom system, Gabe told the entire platform to report to their safe briefing area and that this was not a drill. At the same time, Gabe began manually shutting the platform down (although the ESD had already been activated by the SCADA system, Gabe manually deactivated various panel switches as a precaution.) Gabe had difficulty lifting the cover of one of the systems while on the phone so David Sanchez assisted to successfully lift cover and shut down system.

Gabe called Harvest to stand by and Hidalgo to shut down. He then directed pairs of people to check the systems on the platform and he and three others went to the area of the explosion to check for people down and for damage. They entered the area and confirmed that no one was down. The H₂S level was still high so they evacuated the area. Gabe returned to the control room while the rest of the team stayed behind. The team (without Gabe) entered the area a second time and found the ruptured pipe. They noticed gas continuing to escape from the hole which was probably from the depressuring of other vessels upstream of the damaged pipe, or residual gas in the piping, condensate from scrubbers flashing off, etc. The team reported this to Gabe in the control room who then came to the area a second time to view the hole and escaping gas. Gabe returned to the control room to trip valves to continue blowdown of all vessels to flare and close recycle valves (the ESD does not do this).

Gabe's Assessment

Gabe said the safety equipment/system operated properly. Everyone did a good job of reporting to their mustering areas, which made Gabe's job easier to stabilize the situation. Gabe stated that this was a "real experience" for him.

Gabe did not feel that the weekly drills made employees complacent. Everyone knew it was not a drill from the tone of Gabe's voice, no mention of drill over intercom, the sound of the explosion and the gas going to flare.

Gabe does not think that platform personnel are donning the masks as they should if

they have to cross the danger area during the drills.

Gabe said that although the drills will not fully prepare you for the real thing, they certainly helped. He suggested a debriefing be held after every safety drill and that a person be in the field to critique the drill-possibly the MMS.

Gabe feels that more can be done to improve the UT measuring and reporting methods.

Comments

None

Action Items

Consider developing an MMS Emergency Response Drill similar to Oil Spill Response Drills.

Consider having Operators submit UT results to the MMS and have our inspectors monitor records to confirm that such measurement are being performed per recognized standard frequencies.

Consider having Operators submit their plans on how they will ensure the integrity of their process piping (flow lines), pressure vessels, and tanks.

John Figueroa (Contracting A-Operator Trainee)

Interview time: 5: 40 pm

John was in the control room at the time of the rupture. He heard the explosion.

About an hour before the incident, John was de-icing a control valve on the V-14 by injecting methanol and pouring hot water on the valve. The valve tends to ice-up because of the pressure drop from 1200 psi to 600 psi. The valve controls the level of condensate in the V-14. The vessel remained operational (placed in bypass) during the work. The icing of this valve has been a continuous problem on V-14. John feels that the servicing of the valve on this day did not cause a pressure change in the vessel or the line and did not contribute to the pipe rupture.

John stated his concern that H₂S gas was smelled in the galley and sleeping quarters and his concern that the deluge did not come on after 2 sensors went off (fear that H₂S could ignite.)

When asked if he dons the breathing equipment during H₂S drills, John said that he doesn't since he usually tries to stay upwind on the way to the control room.

Comments

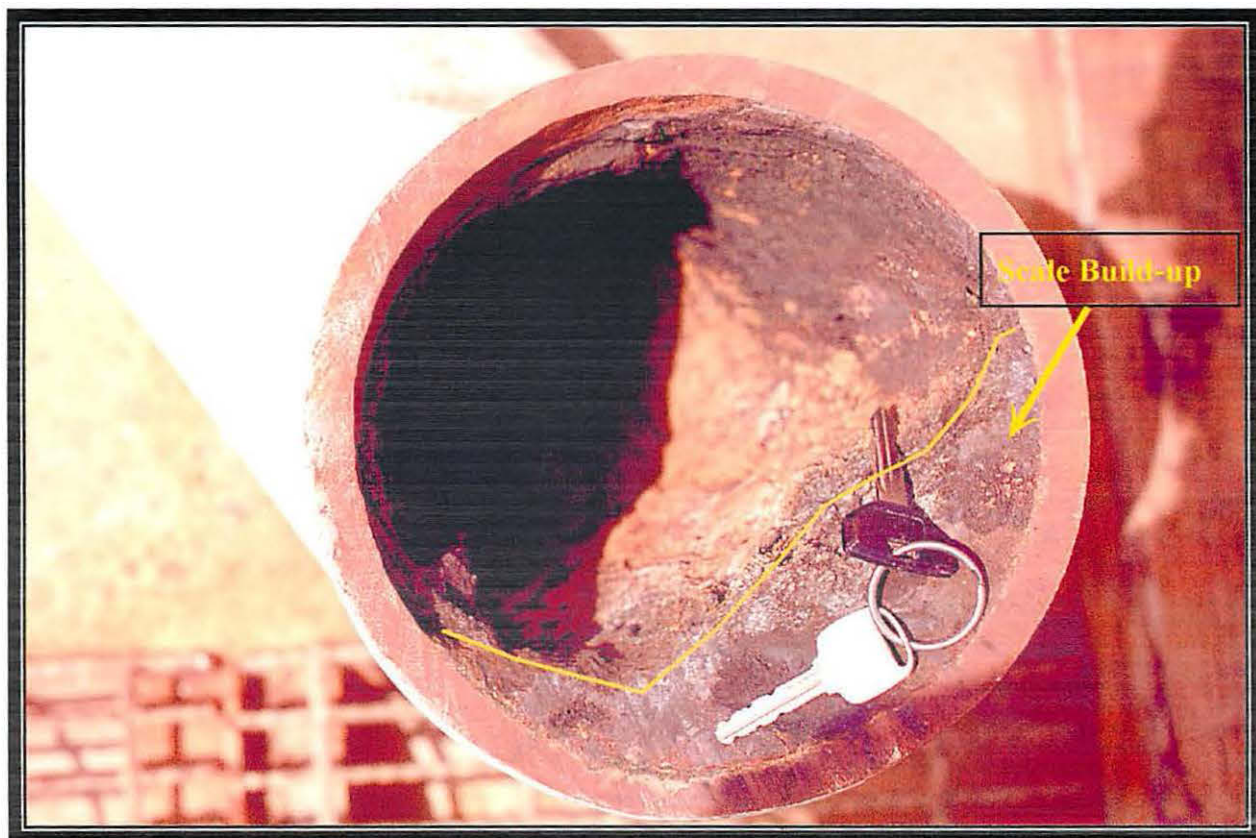
One of the inlet heads on the living quarters appears to have failed which is why there was a strong H₂S smell reported. Roy Bobbit reported that the heads were not working properly when checked after the incident.

Action Items

Make certain that the air intake heads are working on Harvest and Hidalgo.

Determine industry standard as far as whether the deluge system normally activates during H₂S alarms and/or when two or more sensors activate.

Determine whether the freezing of the V-14 valve can effect control of the water level of V-14 enough to increase the presence of water in the flow line thus leading to greater corrosion.



Appendix A.8-Scale Build-up in Flowline

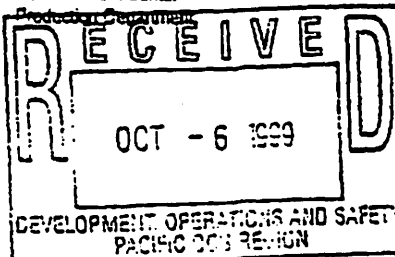


Appendix A.9-New Removable Insulation



Chevron U.S.A. Production Company
646 County Square Drive
Ventura, California 93003

D. Patterson
Point Arguello Asset Team Supervisor
Ventura Profit Center



Minerals Management Service
MMS District Office
222 W. Carmen Lane, Suite 201
Santa Maria, California 93458

Attention: Mr. Phil Schroeder

Re: Approval to Return Platforms Hermosa and Hidalgo to Service

Gentlemen:

Thank you for taking the time to meet with Chevron and Arguello Inc. yesterday to discuss the Hermosa piping failure and gas release on August 3. The purpose of this letter is to seek your concurrence on our plans for corrective actions and the restart of Platforms Hermosa and Hidalgo.

As discussed, our investigation into the August 3 incident is continuing, but we have identified that the primary cause of the failure was internal corrosion due to wet acid gas. To correct the immediate problem and to prevent a similar incident from occurring in the future, we will complete the following actions on Platform Hermosa:

- Installation of a new carbon steel gas line between V-14 and V-16
- 100% X-ray of this new gas line section
- Visual inspection of V-14
- Visual inspection of V-16
- Repair of the 4" branch of inlet line to V-13

A thorough follow-up Hermosa B-scan UT testing conducted after the gas release has shown no pipe wall thickness deficiencies outside of the V-14 to V-16 line section. A copy of this testing data is attached.

We have also conducted a thorough follow-up B-scan UT inspection of Platform Harvest and did not identify any areas of concern. A copy of this data is attached.

A similar Hidalgo B-scan UT testing program has highlighted some corrosion areas in Platform Hidalgo's gas line section between V-14 and V-16. No other pipe wall thickness deficiencies were found. A copy of this testing data is attached. We will install a new carbon steel gas line to replace this entire line section between V-14 and V-16 on Platform Hidalgo. An on-platform X-ray will then be performed.

Immediately after startup, we propose to perform in-service pressure tests as specified in applicable piping codes on the new gas lines on both platforms using produced natural gas at the normal (approximately 1200 psi) operating pressure.

We also propose to design and install chemical corrosion programs for the V-14 to V-16 piping segments on both Platform Hermosa and Hidalgo and we will have the equipment in operation as quickly as possible. Additionally, we intend to make all of these modifications using our

standard Management of Change process, and perform a documented pre-startup safety and environmental review on all new and replacement equipment.

In the future, we propose that both of the new V-14 to V-16 lines will undergo B-scan inspections on a six-month schedule to determine trends and to monitor the effectiveness of our chemical corrosion programs. We may propose a different testing frequency as a result of the data which will be collected. We have discussed and received concurrence from Arguello Inc. regarding this increase in future UT testing requirements. They have agreed to conduct the testing and submit actual data results to your office in a timely manner. Additionally, as discussed in the meeting, we will modify the existing field inspection data sheets to include the minimum wall thicknesses. This will allow the UT inspection company representatives to quickly identify any areas of potential concern.

Regarding a concern which was raised at the meeting, we believe the cause of this incident was completely independent of the ongoing transition from Chevron to Arguello, Inc.. Chevron, as the current operator of record, is fully committed to the safety of its employees and contractors, protecting the environment and maintaining safe and secure operations. The operational staff on the platform during the incident was found to have no causal effect on the incident itself.

Chevron will fully cooperate with the MMS Investigation Team as they collect additional data and prepare their independent review. As part of that process, we plan to address the specific concerns raised in the meeting regarding agency notifications, and locations of breathing air packs.

We hereby request your approval to restart Platforms Hermosa and Hidalgo once we have successfully completed installation and testing of the new piping sections between V-14 and V16.

Should you have any questions or need additional information, please contact me at (805) 658-4426.

Cordially,

Doris Patten

cc: Tom Gladney - Arguello Inc.

Attachments



The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.



The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The **MMS Royalty Management Program** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.

