



INTERIM INVESTIGATION REPORT

CHEVRON RICHMOND REFINERY FIRE



CHEVRON RICHMOND REFINERY

RICHMOND, CALIFORNIA

AUGUST 6, 2012

KEY ISSUES

- INHERENTLY SAFER DESIGN
- DAMAGE MECHANISM HAZARD REVIEW
- EFFECTIVE ANALYSIS OF PROCESS SAFEGUARDS IN PROCESS HAZARD ANALYSIS

DRAFT FOR PUBLIC RELEASE

Summary

On August 6, 2012, the Chevron U.S.A. Inc. Refinery in Richmond, California, experienced a catastrophic pipe failure in the #4 Crude Unit. The pipe ruptured, releasing flammable, hydrocarbon process fluid which partially vaporized into a large vapor cloud that engulfed nineteen Chevron employees. All of the employees escaped, narrowly avoiding serious injury. The flammable portion of the vapor cloud ignited just over two minutes after the pipe ruptured. The ignition and subsequent continued burning of the hydrocarbon process fluid resulted in a large plume of unknown and unquantified particulates and vapor traveling across the Richmond, California, area. In the weeks following the incident, approximately 15,000 people from the surrounding area sought medical treatment due to the release. Testing commissioned by the CSB and the California Division of Occupational Safety and Health (Cal/OSHA) determined that the pipe failed due to thinning caused by sulfidation corrosion, a common damage mechanism in refineries. As a result of the incident, the Chevron Richmond Refinery crude unit remains out of commission over eight months later. In addition, Cal/OSHA issued the refinery 17 citations related to the incident and eight additional citations, with a total proposed fine of nearly one million dollars. In this interim report, the CSB is issuing recommendations to Chevron, the City of Richmond, Contra Costa County, Cal/OSHA, the State of California, and the United States Environmental Protection Agency, addressing the need for inherently safer design, rigorous and documented damage mechanism hazard reviews, and thorough analyses of process safeguards.

This interim investigation report contains detailed analyses of and makes recommendations to Chevron and regulatory bodies at the local, state, and federal level. The CSB believes the findings and recommendations presented in this report can be applied to refineries, chemical plants, and other industries nationwide to improve process safety.

The CSB plans to release a comprehensive Final Investigation Report later in 2013 that will include analyses and recommendations relating to technical and regulatory investigation findings which are not included in this interim report. The Final Investigation Report will cover topics including: the importance of having a competent, well-funded regulator and an adaptable regulatory regime; Chevron safety culture; process safety indicator data collection and reporting; emergency planning and response; stop work authority; and recommendations for improvement of petroleum industry standards and recommended practices. Some of these issues are previewed at the end of this interim report under *Additional Issues Currently Under Investigation*.

Table of Contents

| | |
|---|----|
| Background and Findings | 8 |
| Sulfidation Corrosion | 16 |
| Sulfidation Corrosion Inspection Techniques..... | 21 |
| Chevron Sulfidation Corrosion Knowledge and Expertise | 24 |
| Other Significant Sulfidation Occurrences | 27 |
| Process Hazard Analysis | 31 |
| Operational Changes | 33 |
| Chevron Sulfidation Corrosion Inspection and Mitigation | 36 |
| Inherently Safer Systems | 39 |
| Regulatory Oversight | 46 |
| Recommendations | 53 |
| Additional Issues Currently Under Investigation | 58 |
| Regulatory Oversight..... | 58 |
| Emergency Planning and Reporting | 60 |
| Emergency Response..... | 61 |
| Safety Culture | 61 |
| References | 63 |

Figures

| | |
|--|----|
| Figure 1. The burned remains of the fire truck that was consumed by the fire..... | 9 |
| Figure 2. Vapor cloud over Richmond area and smoke from Chevron Richmond Refinery fire | 10 |
| Figure 3. Initial vapor cloud formation and subsequent ignition | 11 |
| Figure 4. C-1100 Crude Unit Atmospheric Column and Upstream Process Equipment..... | 12 |
| Figure 5. Overhead view of the equipment in the #4 Crude Unit | 13 |
| Figure 6. 4-sidecut line configuration..... | 14 |
| Figure 7. Photo of rupture on 4-sidecut 52-inch component | 15 |
| Figure 8. Graph showing how corrosion rates increase in carbon steel..... | 18 |
| Figure 9. 4-sidecut piping sample | 20 |
| Figure 10. Modified McConomy Curves from API RP 939-C..... | 23 |
| Figure 11. Chevron’s key sulfidation events between 1974 and 2013. | 25 |
| Figure 12. Schematic of failed piping from the Chevron Salt Lake Refinery. | 28 |
| Figure 13. Failed piping component that resulted in the 2007 Richmond crude unit fire..... | 29 |
| Figure 14. Percentage increase of the sulfur content in the 4-sidecut..... | 34 |
| Figure 15. Key events at the Richmond refinery between 1998 and 2013. | 36 |
| Figure 16. Hierarchy of controls..... | 40 |

Acronyms and Abbreviations

| | |
|-------------|---|
| ALARP | As Low As Reasonably Practicable |
| API | American Petroleum Institute |
| ASTM | American Society for Testing and Materials |
| BIN | Business Improvement Network |
| bpd | Barrels Per Day |
| BPTC | BP Texas City |
| CAA | Clean Air Act |
| Cal/OSHA | California Division of Occupational Safety and Health |
| CCPS | Center for Chemical Process Safety |
| CCR | California Code of Regulations |
| Chevron ETC | Chevron Energy Technology Company |
| CML | Corrosion Monitoring Locations |
| CSHO | Compliance Safety and Health Officers |
| CWS | Community Warning System |
| EPA | Environmental Protection Agency |
| °F | degree Fahrenheit |
| HSE | Health and Safety Executive |
| ISO | Industrial Safety Ordinance |
| ISS | Inherently Safer Systems |
| IST | Inherently Safer Technology |
| KPI | Key Process Indicator |

| | |
|-------|---|
| LEPC | Local Emergency Planning Committee |
| LOPA | Layers of Protection Analysis |
| MOC | Management of Change |
| NEP | National Emphasis Program |
| OSHA | Occupational Safety and Health Administration |
| P&P | Policy and Procedures |
| PHA | Process Hazard Analysis |
| PMI | Positive Materials Identification |
| psig | Pounds Per Square Inch Gauge |
| PSM | Process Safety Management |
| RLOP | Richmond Lube Oil Project |
| RMP | Risk Management Plan |
| TML | Thickness Monitoring Locations |
| UK | United Kingdom |
| USW | United Steelworker International Union |
| wt. % | Weight Percent |

Background and Findings

1. On August 6, 2012, the Chevron U.S.A. Inc. Refinery in Richmond, California (Chevron Richmond Refinery), experienced a catastrophic pipe rupture in the #4 Crude Unit (crude unit). The ruptured pipe released a flammable hydrocarbon process fluid which then partially vaporized into a large vapor cloud that engulfed nineteen Chevron U.S.A. Inc. (Chevron) employees. At 6:33 pm, approximately two minutes after the release, the flammable portion of the vapor cloud ignited.ⁱ Eighteen of the employees safely escaped from the cloud just before ignition; one employee was inside a fire engine that caught fire when the vapor cloud ignited (Figure 1). Because he was wearing full body fire-fighting protective equipment, he was able to make his way to safety. Six Chevron employees suffered minor injuries during the incident and subsequent emergency response efforts.

ⁱ Surveillance footage provided by Chevron. Chevron clarified to CSB that video time is approximately 5 minutes out of sync. The video can be found at <http://www.csb.gov/videoroom/detail.aspx?VID=69> (accessed February 8, 2013).

2. The ignition and subsequent continued burning of the hydrocarbon process fluid resulted in a large plume of unknown and unquantified particulates and vapor traveling across the Richmond, California, area (Figure 2 and Figure 3). This resulted in a Community Warning System (CWS) Level 3 alertⁱ and a shelter-in-placeⁱⁱ was issued at 6:38 pm¹ for the cities of Richmond, San Pablo, and North Richmond. It was lifted later that night at 11:12 pm after the fire was fully under control. In the weeks following the incident, nearby medical facilities received over 15,000 members of the public seeking treatment for ailments including breathing problems, chest pain, shortness of breath, sore throat, and headaches. Approximately 20 people were admitted to local hospitals as inpatients for treatment.



Figure 2. Vapor cloud (white) over Richmond area and smoke (black) from Chevron Richmond Refinery fire as seen from San Rafael in Marin County.²

ⁱ A Community Warning System Level 3 alert indicates that a facility within Contra Costa County has had a release that has offsite impact and is categorized by any of the following:

1. Off-site impact that may cause eye, skin, nose and/or respiratory irritation to the general population.
2. Fire, explosion, heat, or smoke with an off-site impact. Example: On a process unit/storage tank where mutual aid is requested to mitigate the event and the fire will last longer than 15 minutes.
3. Hazardous material or fire incident where the incident commander or unified command, through consultation with the Contra Costa Health Services Hazardous Material Incident Response Team, requests that sirens should be sounded.

See http://cchealth.org/hazmat/pdf/incident_notification_policy.pdf (accessed April 9, 2013).

ⁱⁱ Contra Costa County considers a shelter-in-place to include going inside a home or nearest building, closing doors and windows, and turning off heating, ventilation, and air conditioning. See <http://cchealth.org/emergencies/shelter-in-place.php> (accessed February 6, 2013).



Figure 3. Initial vapor cloud formation (white cloud) and subsequent ignition (black smoke) as seen from a pier in San Francisco, California.

3. The incident occurred from the piping referred to as the “4-sidecut” stream, one of several process streams exiting the C-1100 Crude Unit Atmospheric Column (Figure 4).ⁱ A plot plan of the crude unit shows the leak location relative to C-1100 (Figure 5). As shown in Figure 6, light gas oil (the crude unit 4-sidecut process fluid) exits the atmospheric column via a 20-inch nozzle and is split into a 12-inch line and an 8-inch line. The August 6, 2012, pipe rupture (Figure 7) occurred on a 52-inch long componentⁱⁱ of the 4-sidecut 8-inch line (the 52-inch component). The line operated at a temperature of 640 degrees Fahrenheit (°F)ⁱⁱⁱ and had an operating pressure of approximately 55 pounds per square inch gauge (psig) at the rupture location. At the

ⁱ The atmospheric column separates crude oil feed into different streams through distillation. These streams are further processed in other units in the refinery.

ⁱⁱ The term “component” refers to a portion of piping between welds or flanges. It includes straight run piping and pipe fittings.

ⁱⁱⁱ The auto-ignition temperature for this process, the temperature at which a material will combust in the presence of sufficient oxygen without an ignition source, was also 640 °F. This number is based on the Chevron Light Gas Oil Material Safety Data Sheet. Chemical testing of 4-sidecut samples after the incident indicated lower auto-ignition temperatures; however, these samples may not have been representative of typical 4-sidecut process fluid.

time of the incident, light gas oil was flowing through the 8-inch line at a rate of approximately 10,800 barrels per day (bpd).ⁱ

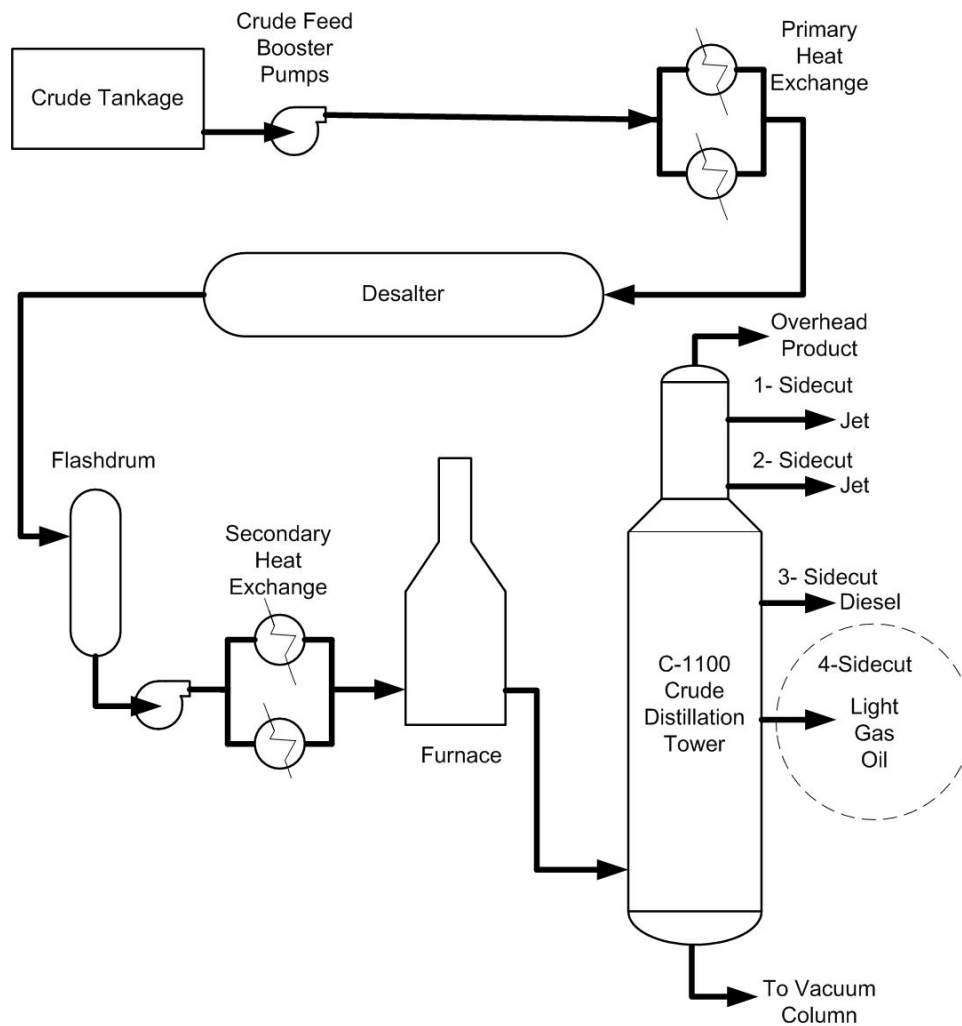


Figure 4. C-1100 Crude Unit Atmospheric Column and Upstream Process Equipment

ⁱ This is the equivalent of 315 gallons per minute (gpm). A barrel equals 42 gallons.

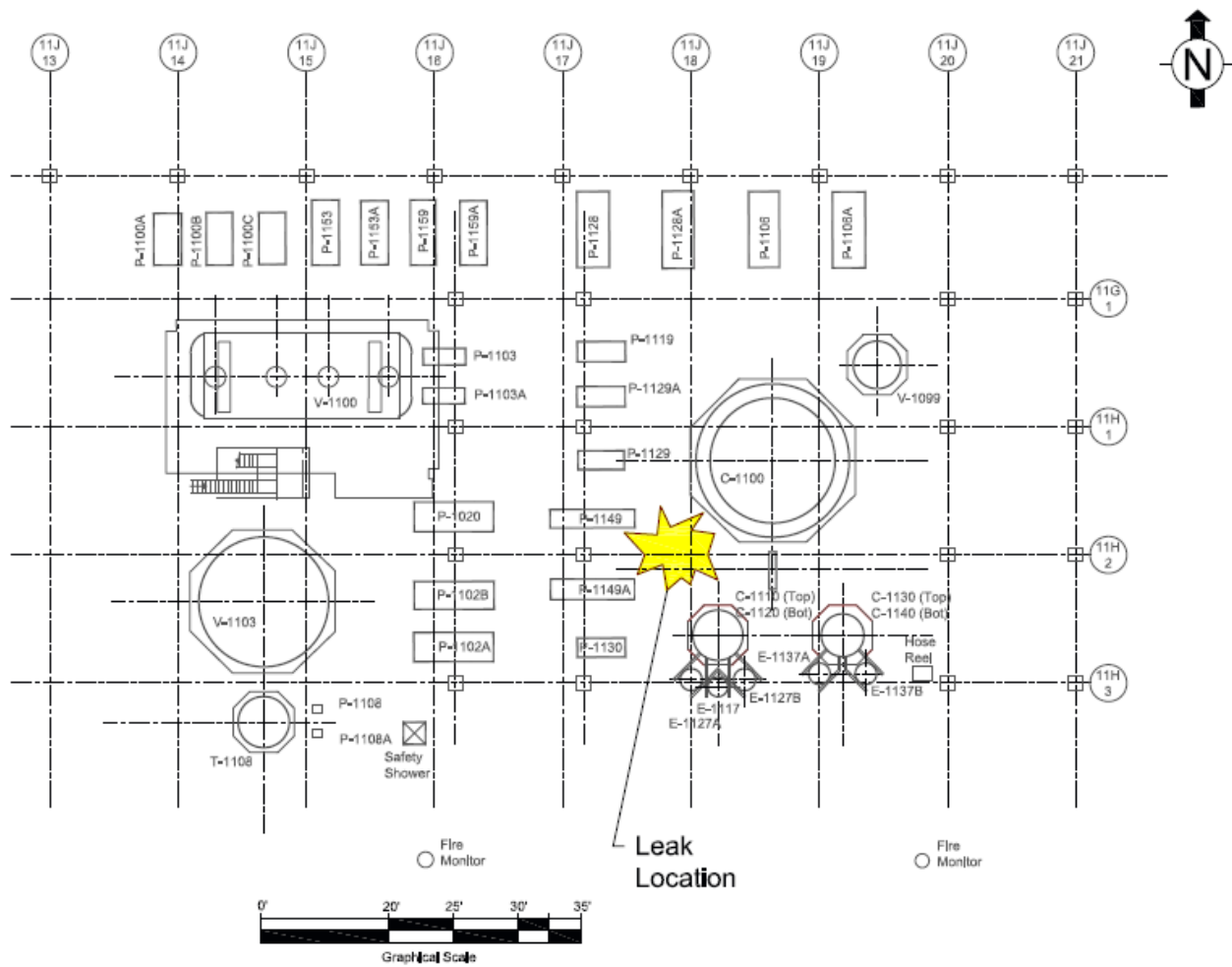


Figure 5. Overhead view of the equipment in the #4 Crude Unit showing the leak location, commonly referred to as a plot plan.

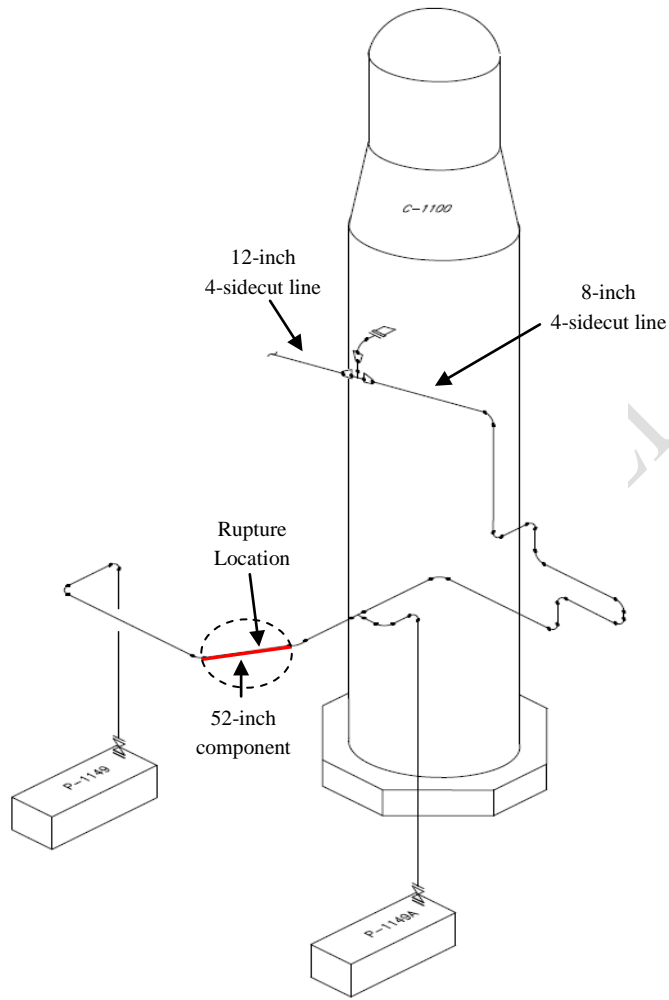


Figure 6. 4-sidecut line configuration and rupture location

4. The CSB commissioned Anamet, Inc., a materials engineering and laboratory testing company, to conduct testing of the 4-sidecut pipe, including the failed 52-inch component. The testing concluded that the rupture was due to pipe wall thinning caused by sulfidation corrosion,³ which is discussed below.
5. Anamet's metallurgical analysis found that the 52-inch component where the rupture occurred had experienced extreme thinning; the average wall thickness near the rupture location was approximately 40 percent thinner than a dimeⁱ (the thinnest American coin). Between 1976 and 2012, the 52-inch piping component had lost, on average, 90 percent of its original wall thickness in the area near the rupture. The piping had an initial nominal wall thickness of 0.322-inchⁱⁱ when it was installed in 1976.



Figure 7. Photo of rupture on 4-sidecut 52-inch component

ⁱ The U.S. Mint reports that a dime has a thickness of 1.35 mm, or 0.053 inches. Information can be found at http://www.usmint.gov/about_the_mint/?action=coin_specifications (accessed February 14, 2013).

ⁱⁱ This portion of the 4-sidecut line was constructed of 8-inch Schedule 40 carbon steel piping.

Sulfidation Corrosion

6. Sulfidation corrosion is a damage mechanismⁱ that is well understood in the refining industry. The sulfidation corrosion industry guidance document, American Petroleum Institute (API) Recommended Practice (RP) 939-C *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*ⁱⁱ notes:

[Sulfidation] ...is not a new phenomenon, but was first observed in the late 1800s in a pipe still (crude separation) unit, due to the naturally occurring sulfur compounds found in crude oil. When heated for separation, the various fractions in the crude were found to contain sulfur compounds that corroded the steel equipment.⁴

7. Sulfidation corrosion, also known as sulfidic corrosion,⁵ is a damage mechanism that causes thinning in iron-containing materials, such as steel, due to the reaction between sulfur compounds and iron at temperatures ranging from 450 °F to 800 °F.⁶ This damage mechanism causes pipe walls to gradually thin over time. Sulfidation corrosion is common in crude oil distillationⁱⁱⁱ where naturally occurring sulfur and sulfur compounds found in crude oil feed, such as hydrogen sulfide,^{iv} are available to react with steel piping and equipment. Process variables that affect corrosion rates include the total sulfur content of the oil, the sulfur species present, flow conditions, and the temperature of the system. Virtually all crude oil feeds contain sulfur compounds and, as a result, sulfidation corrosion is a damage mechanism present at every refinery that processes crude oil. Sulfidation corrosion can cause thinning to the point of pipe failure when not properly monitored and controlled.
8. The reaction between sulfur and iron produces a layer of iron sulfide scale^v on the inside surface of piping.⁷ This reaction can be compared to that of oxygen and iron which also produces a scale, commonly known as rust. The type of scale formed by sulfidation corrosion is dependent upon the components contained in the steel. Certain scales formed are protective and actually

ⁱ Piping damage mechanisms are any type of deterioration encountered in the refining and chemical process industry that can result in flaws/defects that can affect the integrity of piping (e.g. corrosion, cracking, erosion, dents, and other mechanical, physical or chemical impacts). See API 570. "Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems." 3rd ed., Section 3.1.1.5, November 2009.

ⁱⁱ API RP 939-C is one of several relevant American Petroleum Institute recommended practices and standards under evaluation by the CSB as part of this investigation. To the casual observer API RP 939-C appears to obligate the industry to take significant actions. However, the CSB concluded it was written to be permissive so that industry compliance with specific provisions would not be required. The complete findings from this evaluation will be included in the CSB's Final Report.

ⁱⁱⁱ Distillation separates mixtures into broad categories of its components by heating the mixture in a distillation column where different products boil off and are recovered at different temperatures. See <http://www.eia.gov/todayinenergy/detail.cfm?id=6970> (accessed April 4, 2013).

^{iv} Hydrogen sulfide is the most aggressive sulfur compound that causes sulfidation corrosion.

^v Scale is a nonmetallic layer on the surface of metals and is often a result of corrosion.

reduce the reaction rate between sulfur compounds and iron, minimizing sulfidation corrosion rates. For instance, sulfidation corrosion affecting steel alloys containing greater than two weight percent (wt. %) chromium produces a protective scale that inhibits the reaction between the iron and sulfur compounds, thereby reducing corrosion rates.ⁱ With increasing percentages of chromium, the reaction is further slowed, greatly diminishing corrosion rates.^{8,ii} For example, stainless steel (an 18 wt. % chromium alloy) is nearly 15 times more resistant to sulfidation corrosion than 9-Chrome (a 9 wt. % chromium alloy).⁹ Conversely, sulfidation corrosion rates are significantly higher in steels containing very little chromium. Carbon steel, the Chevron 4-sidecut line material of construction, was manufactured with a maximum concentration of 0.40 % chromium.¹⁰ The scale formed on carbon steel is less protective and allows continued reaction between the sulfur compounds and iron.¹¹ Thus, carbon steel corrodes at a rate that is significantly faster than other materials of construction, such as high chromium steels.

9. In addition to its inherently faster rate of sulfidation corrosion when compared with higher chromium steels, carbon steel also experiences significant variation in corrosion rates due to variances in silicon content, a component used in the steel manufacturing process. Carbon steel piping containing silicon content less than 0.10 wt. % can corrode at accelerated rates,¹² up to sixteen times faster than carbon steel piping containing higher percentages of silicon as shown in Figure 8. This figure shows how carbon steel corrosion rates can greatly vary depending on silicon content.

ⁱ At greater than two wt. % chromium, sulfur compounds react with the steel to form FeCr_2S_4 scale. This scale provides more protection than the FeS scale that forms on carbon steel piping. See Niccolls, E. H., J. M. Stankiewicz, J. E. McLaughlin, and K. Yamamoto. "High Temperature Sulfidation Corrosion in Refining." *17th International Corrosion Congress*. Las Vegas: NACE International, 2008.

ⁱⁱ It has also been found that chromium "poisons" the decomposition of sulfur compounds to hydrogen sulfide which also slows down the sulfidation corrosion rate. See Couper, A.S. "High Temperature Mercaptan Corrosion of Steels." *19th Annual Conference of the National Association of Corrosion Engineers*. Pages 396t-401t, New York: March 1963.

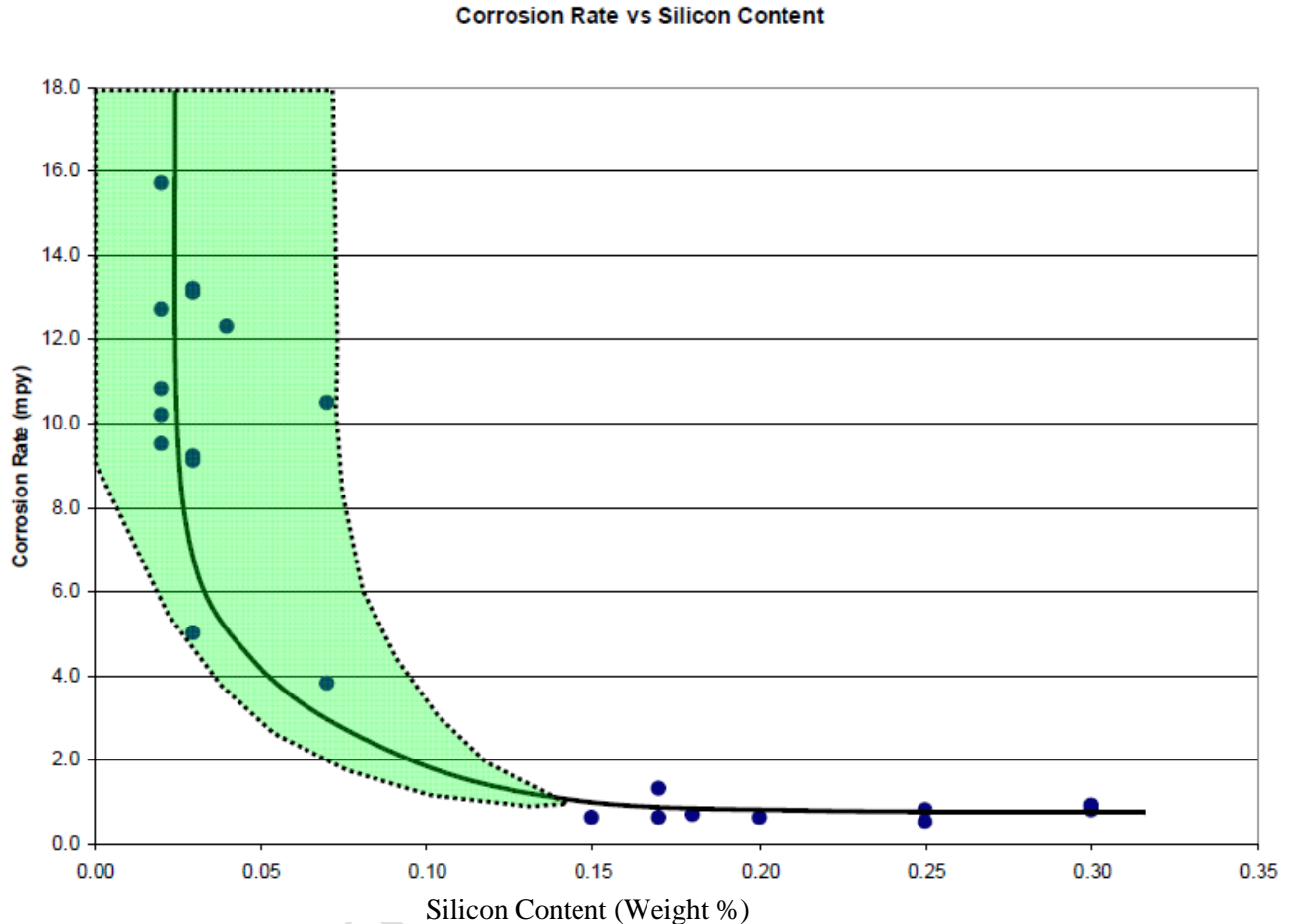


Figure 8. This graph shows how corrosion rates increase in carbon steel containing decreasing percentages of silicon. This information can be found in Annex C of API RP 939-C.ⁱ

10. The refining industry has been aware of increased rates of sulfidation corrosion in low-silicon carbon steel piping since as early as 1974,¹³ nearly 40 years before the August 6, 2012, incident and two years before the Chevron crude unit was constructed. Prior to the incident, Chevron documented its understanding of the significant consequences of sulfidation corrosion. This is reflected in Chevron's *Corrosion Prevention and Metallurgy Manual*, which states:

Sulfidation corrosion has caused severe fires and fatalities in the refining industry, primarily because it causes corrosion over a relatively large area, so failures tend to involve ruptures or large leaks rather than pinhole leaks. It can be insidious in that moderately high corrosion rates can go undetected for years before failure. Finally, process changes that

ⁱ The y-axis of this figure is in units of mils per year (mpy). A "mil" is 1/1000 inch.

increase the temperature or sulfur content can creep up over time and multiply corrosion rates so that what was thought to be a low corrosion rate system becomes corrosive enough to fail before the increased corrosion rate is recognized.

11. Carbon steel piping is manufactured to meet certain specifications, including American Society for Testing and Materials (ASTM) A53B,¹⁴ ASTM A106,¹⁵ and API 5L.¹⁶ ASTM A53B and API 5L do not contain minimum silicon content requirements for carbon steel piping,¹⁷ while ASTM A106 requires the piping to be manufactured with a minimum silicon content of 0.10 wt. %. As a result, manufacturers have used different levels of silicon in the carbon steel pipe manufacturing process. Thus, depending on the manufacturing specification for carbon steel susceptible to sulfidation corrosion, corrosion rates could vary depending on the silicon content within the steel.
12. In the mid 1980s, pipe manufacturers began to simultaneously comply with all three manufacturing specifications (ASTM A53B, ASTM A106, and API 5L) when manufacturing carbon steel piping. The majority of carbon steel piping purchased following this time period likely has a minimum of 0.10 wt. % silicon content. However, piping purchased and installed prior to the mid-1980s could still contain low silicon components that are susceptible to high, variable sulfidation corrosion rates.
13. Over 95 percent of the 144 refineries in operation in the U.S., including the Chevron Richmond Refinery,ⁱ were built before 1985,¹⁸ and thus before piping manufacturers began producing carbon steel in compliance with all three manufacturing specifications. Therefore, the original carbon steel piping in these refineries is likely to contain varying percentages of silicon content and may experience highly variable sulfidation corrosion rates.
14. The Chevron Richmond Refinery 4-sidecut piping circuit containing the 52-inch component that failed was constructed of ASTM A53B carbon steel, which had no minimum specification for silicon content. Post-incident testing of samples of the 4-sidecut piping from the Chevron Richmond Refinery identified silicon content ranging from 0.01 wt. % to 0.2 wt. %. Of twelve samples taken from the 8-inch and 12-inch 4-sidecut line, six had a silicon concentration of less than 0.10 wt. %. The 52-inch pipe component that ruptured on the day of the incident, had a silicon content of only 0.01 wt. %. The elbow component directly upstream of the 52-inch component that failed had a silicon concentration of 0.16 wt. % and showed considerably less thinning (Figure 9).

ⁱ The Chevron Richmond Refinery was constructed in 1902.

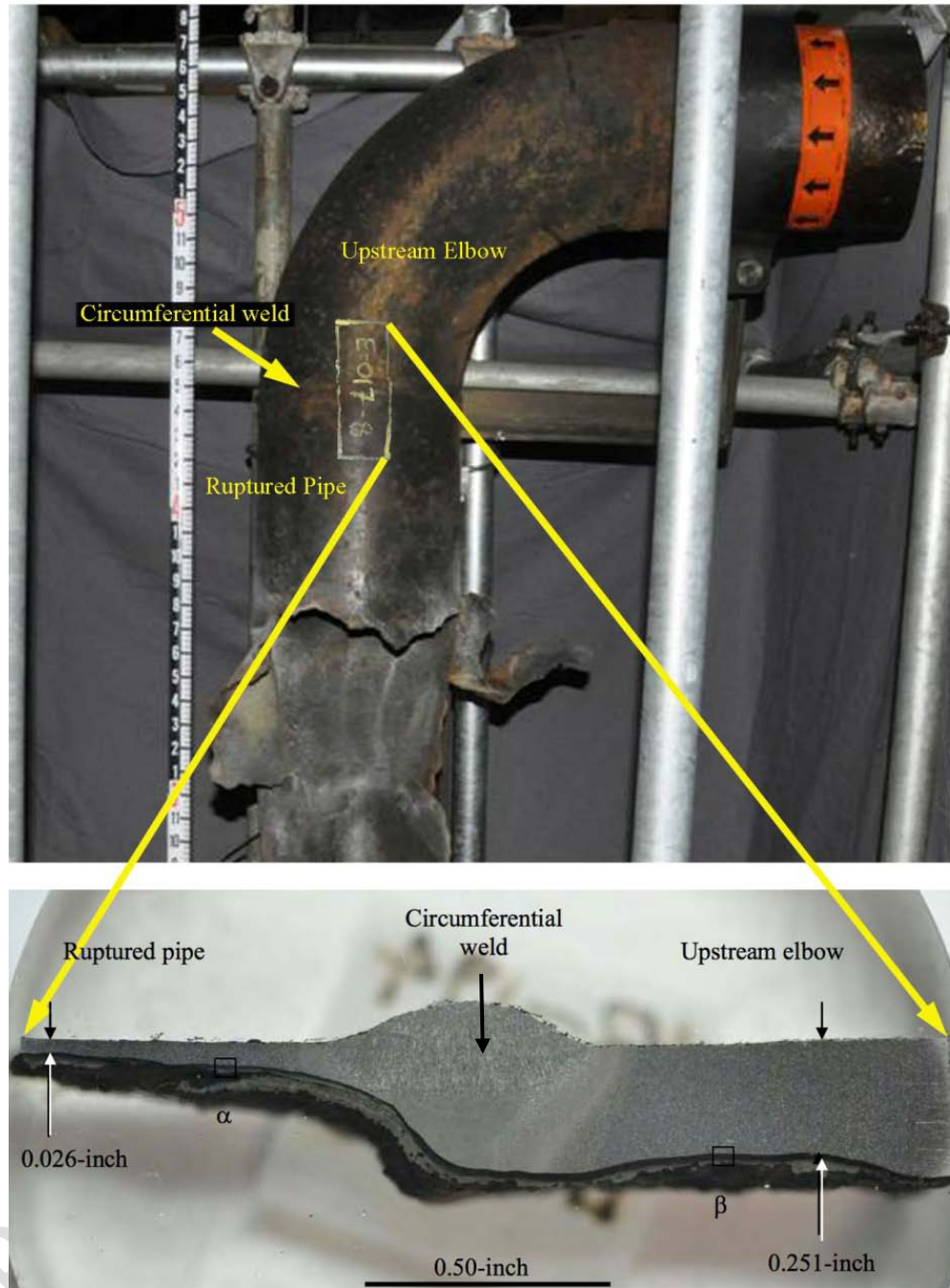


Figure 9. 4-sidecut piping sample (E-017-8) analyzed by Anamet Labs showing the relative thickness of low silicon piping on the left and the high silicon piping on the right. The ruptured pipe component (left) contained 0.01 % silicon and the upstream elbow component (right) contained 0.16 % silicon.¹⁹ The initial nominal thickness of this piping was 0.322-inch.

Sulfidation Corrosion Inspection Techniques

15. As evidenced by the chemical analysis performed on the Chevron 4-sidecut piping post-incident, carbon steel piping components within a single circuitⁱ can contain varying percentages of silicon, resulting in a large variation in sulfidation corrosion rates by component. Historically, sulfidation corrosion monitoring techniques required the measurement of pipe thickness at only a minimal number of permanent Condition Monitoring Locations (CMLs)ⁱⁱ along the piping. These CMLs are most frequently placed on elbows and fittings.ⁱⁱⁱ However, due to details of the manufacturing process, carbon steel pipe fittings generally contain high percentages of silicon.²⁰ When measurements are only taken at high-silicon containing fittings, the measurements can fail to identify high corrosion rates within a pipe circuit caused by low-silicon components. At the Chevron Richmond Refinery, the 4-sidecut piping had a total of 24 CMLs^{iv} on piping and fittings. The CSB found that there were no CMLs placed on the low silicon piping component that failed. Chevron identified accelerated corrosion in the 52-inch component in a 2002 inspection. However, no CML was added to ensure future monitoring, and the 52-inch component was not inspected again. Instead, the CSB found that Chevron relied on inspection data gained primarily from high silicon pipe-fitting components, such as elbow components. This inspection data did not reflect the corrosion rates of the lower-silicon components of the 4-sidecut piping. Relying on the limited inspection data from the CMLs on the high silicon components, Chevron management denied multiple recommendations to replace the 4-sidecut line. As illustrated by the Chevron incident, inspection techniques alone may not accurately identify the most aggressive corrosion rates throughout an entire circuit of carbon steel piping. Low-silicon components can remain uninspected and unidentified until failures such as the August 6, 2012, Chevron incident occur. As will be discussed below, upgrading metallurgy is a more effective means of managing sulfidation corrosion.
16. Determining silicon content in existing carbon steel piping and equipment in the field is a difficult undertaking. To properly characterize the silicon content in each component in a piping circuit, every component must be inspected. This is known as 100 percent component inspection. Two techniques are currently used to determine silicon content in existing carbon steel piping circuits with unknown chemical composition: chemical analysis and pipe wall thickness measurements of every component.

ⁱ A piping circuit is a length of pipe and the fittings associated with a particular process service and operating at similar conditions. A circuit usually begins and ends at either a branch or a piece of process equipment such as a vessel or a pump. Reference to piping by circuits allows piping to be grouped conveniently by proximity and operating service. Piping circuits may also be referred to as piping runs.

ⁱⁱ A condition monitoring location (CML) is a designated area where periodic thickness examinations are conducted. Each CML represents as many as four inspection locations located circumferentially around the pipe. CMLs are also referred to as thickness monitoring locations (TMLs).

ⁱⁱⁱ A fitting is a piping component usually associated with a change in direction or diameter.

^{iv} Many of these CMLs were added during the 2011 turnaround.

17. Many field-portable instruments used for positive material identification cannot adequately identify silicon content.²¹ If original manufacturing quality assurance dataⁱ are not available, as is generally the case with older plants, then chemical verification requires destructive testing. Metal shavings must be taken from each carbon steel piping component for chemical analysis in a laboratory.²² This method requires that the insulation be removed for access to the piping so that each individual piping component can be sampled and verified.
18. Carbon steel components containing low concentrations of silicon can also potentially be identified by performing thickness measurements of every component within a carbon steel circuit.²³ This practice is only useful if the piping circuit has been exposed to sulfidation corrosion for a long enough time period so that variances in corrosion rate caused by differences in silicon content may be detected. Chemical analysis is therefore the most accurate technique to identify low-silicon carbon steel components. As with chemical analysis, the thickness measurement method requires that each individual piping component be identified by removing insulation (so every weld seam can be located), a time consuming and costly undertaking, or by using non-destructive examination techniques. Thickness measurements on high temperature piping typically can only be done accurately and safely during unit turnarounds.ⁱⁱ Although these various methods were available to detect the location of the field welds, Chevron had not used them to identify the 4-sidecut pipe segment locations.
19. API Recommended Practice 939-C *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries* describes the challenges faced when attempting to thoroughly inspect carbon steel lines susceptible to sulfidation corrosion. The recommended practice states that older ASTM A53 piping, such as the Chevron piping that failed on August 6th creates a “major inspection challenge”²⁴ and that “unless the refinery is fortunate enough to have located an inspection point on that particular [low silicon] section of pipe or fitting, it is very difficult to detect the thinning component.”²⁵ It states that in some applications, carbon steel will appear to be adequate based on measured corrosion rates until failure occurs at some undocumented or unidentified low-silicon component.²⁶
20. Unlike silicon concentration, the chromium concentration of steel can easily be verified in the field using portable positive material identification instruments. In addition, steel alloys containing at least 9 wt. % chromium are more resistant to sulfidation corrosion and do not run the risk of extreme variations in corrosion rates within components in the same piping circuit.ⁱⁱⁱ

ⁱ Manufacturing quality assurance data, also known as mill data, provides the chemical composition of the steel.

ⁱⁱ A “turnaround” is a scheduled shutdown of a process unit to perform maintenance, repairs, upgrades, and inspection of process equipment.

ⁱⁱⁱ The protective scale, FeCr₂S₄, begins to be the dominant scale formed in steels containing a chromium content of five wt. %. The 5Cr steel alloy can be manufactured to contain anywhere from 4% to 6% chromium. Thus, “the sulfidation corrosion rate can vary dramatically in 5Cr steels even in the same operating environment.” See Niccolls, E. H., J. M. Stankiewicz, J. E. McLaughlin, and K. Yamamoto. “High Temperature Sulfidation Corrosion in Refining.” *17th International Corrosion Congress*. Las Vegas: NACE International, 2008.

This makes alloys with higher chromium content an inherently safer choice in high temperature sulfidation corrosion environments.ⁱ As shown in the Modified McCconomy Curvesⁱⁱ (Figure 10) from API RP 939-C, 9-Chromeⁱⁱⁱ corrodes 15 times faster than stainless steel,^{iv} and carbon steel^v corrodes 125 times faster than stainless steel.²⁷

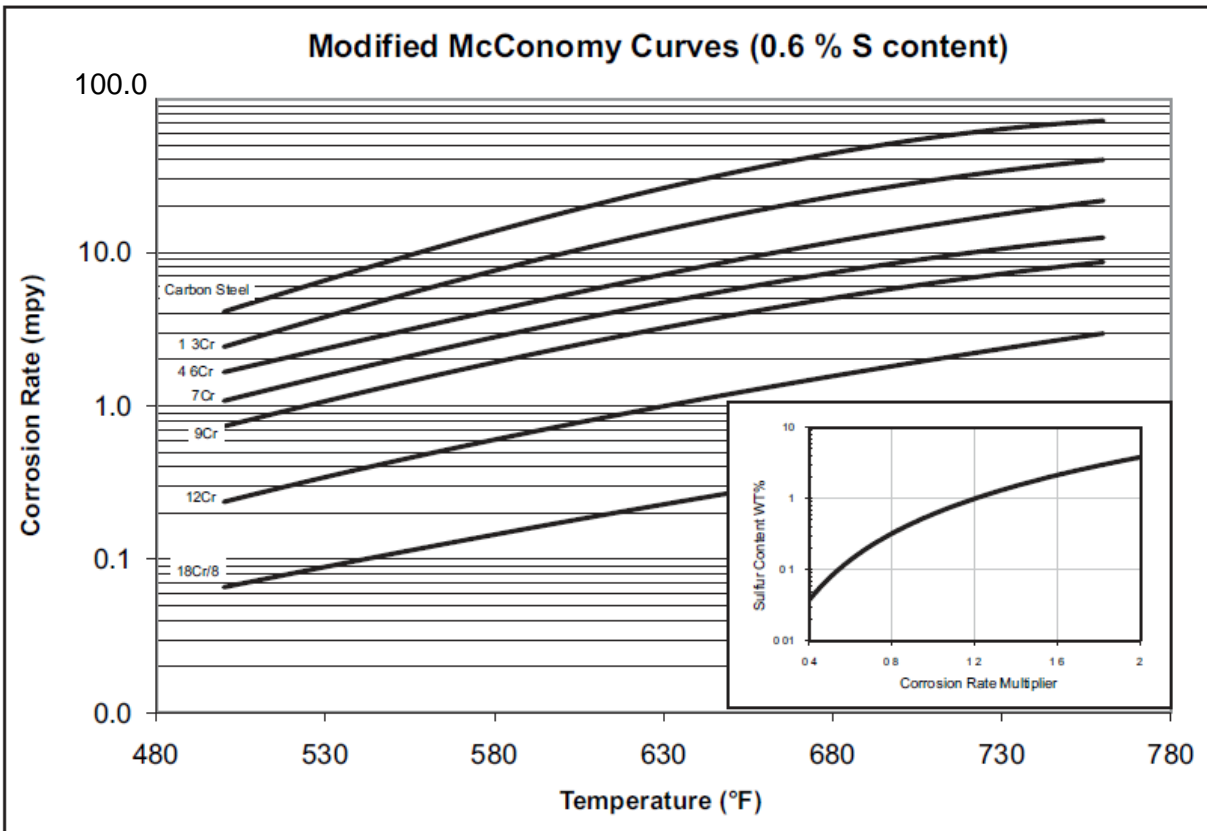


Figure 10. Modified McCconomy Curves from API RP 939-C.

ⁱ Steels with higher chromium content are inherently safer than carbon steel with respect to sulfidation corrosion. However, analysis is still required to ensure that the best material of construction is selected.

ⁱⁱ Modified McCconomy Curves are the set of curves API RP 939-C uses to predict sulfidation corrosion rates versus temperature for several steel alloys.

ⁱⁱⁱ 9-Chrome contains 9 wt. % chromium.

^{iv} Stainless steel contains 18 wt. % chromium.

^v ASTM A53B carbon steel contains a maximum of 0.40 wt. % chromium.

Chevron Sulfidation Corrosion Knowledge and Expertise

21. Figure 11 shows a timeline of Chevron's key sulfidation events. Chevron technical staff has considerable knowledge and expertise regarding sulfidation corrosion, specifically with respect to corrosion rate variations caused by differing silicon concentration in carbon steel piping. Chevron employees have authored industry papers on sulfidation corrosion and had significant influence in the development of the industry sulfidation corrosion recommended practice, API RP 939-C. This recommended practice, first published in 2009, was developed under Chevron leadership. At the approximate time of publication of API RP 939-C, Chevron Energy Technology Company (Chevron ETC)ⁱ created an internal document on the subject of sulfidation corrosion. Chevron ETC metallurgists released a formal report dated September 30, 2009 (nearly 3 years prior to the incident) to Chevron refinery-based reliability managers and chief inspectors titled *Updated Inspection Strategies for Preventing Sulfidation Corrosion Failures in Chevron Refineries*. In the Chevron ETC report, sulfidation experts acknowledged that, "Until now, Chevron has not directly addressed the risk of low Si[licon] carbon steel..."ⁱⁱ This report specifically recommends that inspectors perform 100 percent component inspection on high temperature carbon steel piping susceptible to sulfidation corrosion. However, this recommendation was not implemented at the Richmond refinery prior to the August 6, 2012, incident.

ⁱ The Chevron Energy Technology Company is a separate business unit within the Chevron Corporation that provides technology solutions and technical expertise for Chevron operations worldwide. See <http://richmond.chevron.com/home/aboutchevronrichmond.aspx> (accessed April 4, 2013)

ⁱⁱ A 2003 corporate technical newsletter recommended 100 percent component inspection of carbon steel piping susceptible to sulfidation corrosion following a 2002 Chevron Salt Lake City sulfidation corrosion incident.

Chevron Sulfidation History

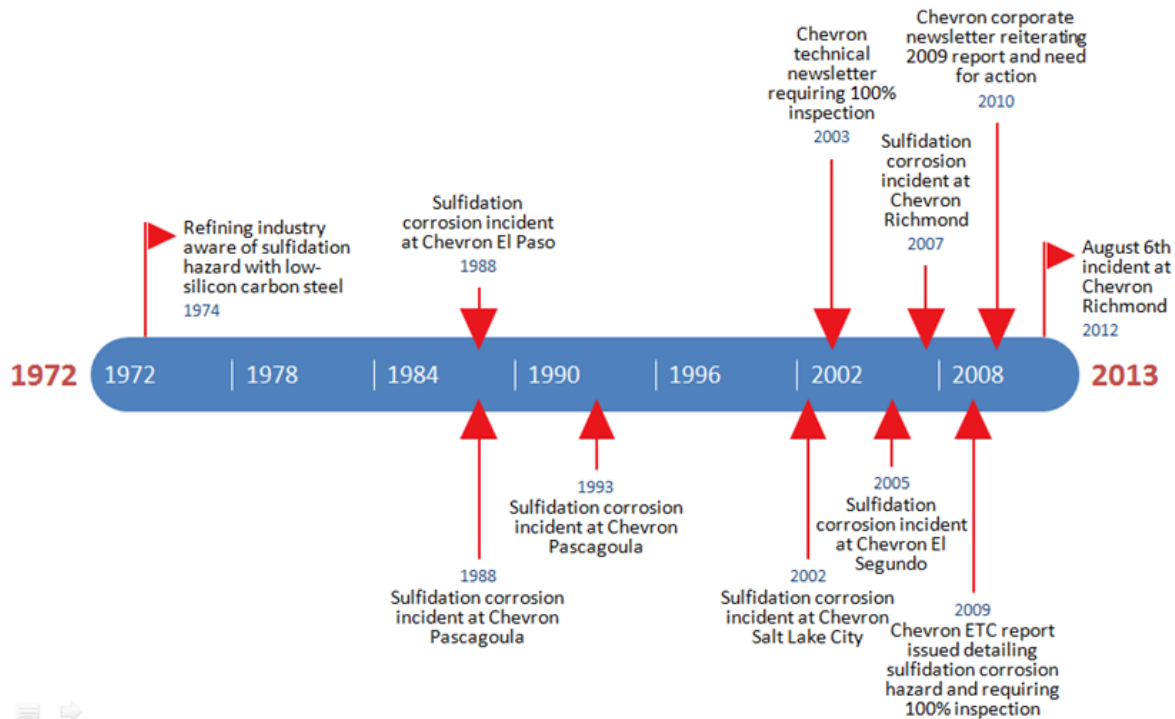


Figure 11. Chevron's key sulfidation events between 1974 and 2013.

22. The Chevron ETC 2009 report states: "The current program seeks to close these gaps and to maximize the effectiveness of our inspection." The report clearly indicates that Chevron understood both the potential consequence and the high likelihood of a rupture or catastrophic failure from sulfidation corrosion and the report calls out Chevron's need for action:

Sulfidation corrosion failures are not common in Chevron or in the industry but they are of great concern because of the comparatively high likelihood of blowout or catastrophic failure [...] . This can happen because corrosion occurs at a relatively uniform rate over a broad area so a pipe can get progressively thinner until it actually bursts rather than leaking at a pit or local thin area. In addition the process fluid is often above its autoignition temperature. The combination of these factors means that sulfidation corrosion failures frequently result in large fires. [...] [S]everal case histories of sulfidation corrosion failures that have occurred in Chevron or in the industry several of which are blowouts.

This Chevron ETC report specifically recommends that inspectors perform 100 percent component inspection on high temperature carbon steel piping susceptible to sulfidation corrosion. However, this 100 percent component inspection program was not implemented at the Richmond refinery

prior to the August 6, 2012 incident. The Chevron ETC report defines a priority ranking system to help focus the inspection implementation efforts. The process conditions of the 4-sidecut stream placed it in the highest priority for inspection.

23. Chevron ETC technical experts issued a corporate newsletter in 2010 that again warned of the potential consequence of sulfidation failures. In this newsletter, the 100 percent component inspection recommendation from the 2009 report was reiterated for piping systems such as the crude unit 4-sidecut piping. The newsletter states:

Sulfidation corrosion failures ... are of great concern because of the comparatively high likelihood of "blowout" or catastrophic failure. This typically happens because corrosion occurs at a relatively uniform rate over a broad area, so a pipe can get progressively thinner until it actually bursts rather than leaking at a pit or local thin area. In addition, the process fluid is often above its autoignition temperature. The combination of these factors means that sulfidation corrosion failures frequently result in large fires. Chevron and the industry have experienced numerous failures from this mechanism and recent incidents have reinforced the need for revised inspection strategies and a robust PMI (Positive Materials Identification) program.

The Chevron ETC 100 percent component inspection recommendation for high risk piping systems, established in 2009, was not implemented at Richmond; therefore, the thin-walled low silicon 4-sidecut piping component remained in service until it catastrophically failed on August 6, 2012.

24. Chevron and Chevron ETC metallurgists, materials engineers, and piping inspectors had expertise regarding sulfidation corrosion. They educated personnel and advocated for identification and control of damage mechanisms, including sulfidation corrosion. However, they had limited practical influence to implement their recommendations. These individuals did not participate in the crude unit Process Hazard Analysis (PHA)ⁱ and did not affect decisions concerning control of sulfidation corrosion during the crude unit turnaround process.ⁱⁱ

ⁱ A process hazard analysis is a hazard evaluation used to identify, evaluate, and control the hazards involved in a process. Facilities that process a threshold quantity of hazardous materials, such as the Chevron Richmond refinery, are required to conduct a process hazard analysis per the California Code of Regulations Title 8 Section 5189: Process Safety Management of Acutely Hazardous Materials (1992).

ⁱⁱ The turnaround process includes both the planning stage prior to the shutdown and the activities staged during the shutdown.

Other Significant Sulfidation Occurrences

25. The refining industry has experienced numerous sulfidation corrosion failures, primarily in piping.²⁸ API RP 939-C identifies 45 sulfidation corrosion failures, one third of which were found to have occurred in carbon steel piping containing low levels of silicon.²⁹
26. The August 6, 2012, Chevron Richmond Refinery 4-sidecut pipe rupture was not the first sulfidation corrosion-related incident to occur at a Chevron refinery. In 1988, a low silicon carbon steel (0.02 wt. % silicon) piping component failed at the Chevron's former El Paso Refineryⁱ in El Paso, Texas. In addition, two sulfidation corrosion incidents occurred at the Chevron Pascagoula refinery in Pascagoula, Mississippi: one in 1993 and one in 1988 on a low-silicon carbon steel component.
27. In 2002, the Chevron Salt Lake City Refinery experienced a fire when process piping failed as a result of sulfidation corrosion in a low silicon ASTM A53 carbon steel piping component. Chevron communicated the incident throughout the company in a technical newsletter. Chevron experts found that despite regular monitoring of the line for 30 years in compliance with industry standards, their inspection program failed to prevent the failure. Corrosion rates at the unmonitored failure location were found to be five times greater than corrosion rates at the monitored piping locations. The monitored locations were constructed of high silicon ASTM A106 piping (Figure 12). Chevron also found that in the years preceding the failure, both the temperatureⁱⁱ and hydrogen sulfide concentration in the process had been increasing. Each of these factors increased corrosion rates and contributed to the failure. In 2003, following this incident, Chevron experts recommended that refineries inspect every piping component (100 % component inspection) in all high-risk piping systems: those operating above 550 °F and containing hydrogen sulfide.

ⁱ The El Paso Refinery is now owned by Western Refining.

ⁱⁱ The temperature in the line had been increased by over 170 °F throughout the life of the unit. During the two years prior to failure, temperatures of the line exceeded the measurement capabilities of the temperature measurement device and so the actual temperature increase cannot be determined.

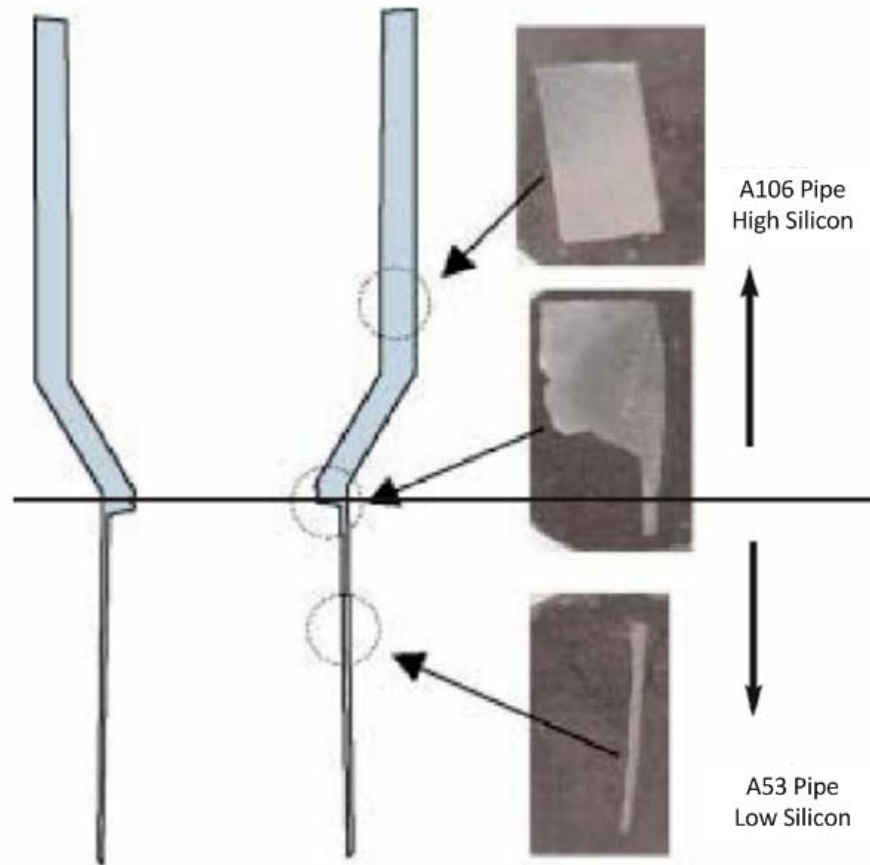


Figure 12. Schematic of failed piping from the Chevron Salt Lake Refinery. Similar to the Chevron Richmond Refinery incident, the failed piping contained low amounts of silicon and corroded significantly faster than adjacent piping components.

28. In January 2007, a failure due to sulfidation corrosion caused a serious fire in the Chevron Richmond Refinery crude unit resulting in a CWS Level 3 alert, initiating a shelter-in-place for the surrounding community. A carbon steel piping spoolⁱ failed catastrophically during operation (Figure 13). The carbon steel piping contained a low percentage of silicon (<0.005 wt. %). The process fluid ignited, injuring a nearby worker. Chevron informed Contra Costa County in a letter that the metallurgy had been upgraded following this incident as an inherently safer solution. However, the CSB learned that this upgrade was limited to only the immediate piping spool that failed. The inherently safer, more corrosion resistant metallurgy was not implemented more broadly in crude unit high temperature service as a result of this incident.

ⁱ A piping spool is a small, removable section of piping. In some cases, a pipe spool is installed or removed in order to provide a temporary connection or complete disconnection between two piping circuits.



Figure 13. Failed piping component that resulted in the 2007 Richmond crude unit fire. This carbon steel piping was found to contain less than 0.005 percent silicon.

29. Following the August 6, 2012, incident, personnel at the Chevron El Segundo, California, refinery, a near duplicate of the Richmond refinery, inspected their refinery's crude unit 4-sidecut piping. Significant thinning was discovered in the line; the piping from the atmospheric crude column to the pumps was removed and substituted with 9-Chrome, an upgraded and inherently safer material of construction.
30. On November 9, 2009, the Silver Eagle refinery in Woods Cross, Utah, experienced a catastrophic piping failure due to sulfidation corrosion in a 10-inch pipe, while conducting a temporary operation at higher than normal operating temperature. The pipe was located on the

bottom of a reactor in the de-waxing unit. The failed pipe released hydrogen which subsequently exploded, damaging over 100 homes in the nearby neighborhood.

31. On October 6, 2011, an explosion and fire resulted from a catastrophic piping failure at a Canadian refinery in Regina, Saskatchewan, injuring 52 workers. The piping component that failed was substantially thinner than neighboring components. Prior to the incident, the company's inspection data indicated that wall thickness in the overall piping system was within acceptable limits. However, the specific component that failed was not inspected. Although Canadian authorities are still investigating, metallurgical testing has indicated that hydrogen sulfide corrosion contributed to the catastrophic failure.
32. In February 2012, the BP refinery crude unit in Cherry Point, Washington, suffered a failure due to sulfidation corrosion, causing a large fire. This incident demonstrates that even when applying inherently safer concepts to reduce the potential for major hazards, it is still vital to fully understand all processes and piping configurations and incorporate a rigorous inspection program. The piping that failed was constructed of 9-Chrome. The line was used only during start-up operations and otherwise remained in-service and non-flowing. Such lines that do not have regular process flow yet remain in contact with process fluids are commonly referred to as "dead legs." The failure location was a high-point in the piping connected to the top of an operating process line. Hydrogen sulfide evolved from the process fluid and collected in the 9-Chrome piping. The concentrated vapor-phase hydrogen sulfide severely corroded the 9-Chrome, causing the failure. CMLs were located on adjacent elbow components; however, no CMLs were placed on the straight-run piping component where the failure occurred. The Cherry Point sulfidation failure demonstrates that even with more corrosion-resistant, inherently safer metallurgy, failure from sulfidation corrosion still may occur if piping is not effectively inspected or piping configurations are not adequately evaluated. In addition it is important to conduct a thorough analysis to determine the best material of construction for the process conditions.

Process Hazard Analysis

33. Chevron personnel analyze numerous deviationsⁱ for each portion of a process when conducting a Process Hazard Analysis (PHA).ⁱⁱ These include conditions such as changes in flow and temperature and pressure extremes. Specifically of interest, one of the deviations analyzed was “leak/rupture” of the particular vessel or pipe. For each deviation, the team was tasked to identify causes, consequences, safeguards, and recommendations. The 4-sidecut line was analyzed in the most recent crude unit PHA. Corrosion was *not* identified as a potential cause of a leak/rupture in the piping.
34. Despite Chevron knowledge and expertise of potential damage mechanisms (such as sulfidation corrosion), the CSB found these hazards are only identified in a PHA if the participants conducting the PHA happen to have personal knowledge of the relevant mechanism. The Chevron PHA teams do not typically seek assistance from corrosion experts.ⁱⁱⁱ The inclusion of a damage mechanism hazard review as part of the PHA is not required by the state of California, the California Division of Occupational Safety and Health (Cal/OSHA), Contra Costa County, the City of Richmond, or Chevron standards. Sometimes referred to as a corrosion review, a damage mechanism hazard review analyzes risks presented by all process failure mechanisms such as corrosion and cracking. Common process failure mechanisms are described in API 571: *Damage Mechanisms Affecting Fixed Equipment in the Refining and Petrochemical Industries*.³⁰ Such a review ensures that potential hazards caused by process conditions, process materials, and external mechanisms are properly identified, analyzed, and systems are put in place to control or eliminate the hazard. Because Chevron does not conduct, and is not required to conduct, a formal damage mechanism hazard review, damage mechanisms are only identified when the PHA team happens to have some knowledge of the mechanism. As a result, many damage mechanisms which occur in various processes are not properly addressed.
35. During a hazard analysis process such as a PHA, the evaluation team has to determine the likelihood of a hazardous consequence occurring. Then the team must identify safeguards which will reduce the risk of the hazard to an acceptable level. A recognized methodology for

ⁱ Deviations using guide words (such as no, more, less, as well as) and process parameters (such as flow, pressure, temperature) are analyzed in PHAs. See Center for Chemical Process Safety (CCPS). “Guidelines for Hazard Evaluation Procedures.” 2nd ed., Page 132, 1992.

ⁱⁱ A process hazard analysis is a hazard evaluation to identify, evaluate, and control the hazards involved in a process. Facilities that process a threshold quantity of hazardous materials, such as the Chevron Richmond refinery, are required to conduct a process hazard analysis per the California Code of Regulations Title 8 Section 5189. Process Safety Management of Acutely Hazardous Materials. PHAs are also required by the California Accidental Release Prevention Program and the federal EPA Risk Management Program (1992).

ⁱⁱⁱ The Crude Unit Business Improvement Network (BIN) Leader, a crude unit expert, reviews portions of the PHA with the PHA team. However, this review did not identify the potential for sulfidation corrosion failures in the 4-sidecut piping. A rigorous review of corrosion and damage mechanisms present in the crude unit was not performed during the PHA process.

consistently and objectively making these determinations could include the use of quantitative, semi-quantitative, or qualitative tools.³¹ Chevron does not employ a prescribed methodology for determining the likelihood that an incident will occur or whether a safeguard will be effective. Instead, Chevron relies upon the judgment of the people on the PHA team, who base their conclusions upon their collective experiences, beliefs, and areas of expertise. In its 2009 crude unit PHA, Chevron simply cited non-specific, judgment-based qualitative safeguards such as: utilizing metallurgy to minimize corrosion, having effective maintenance and inspection programs, and providing pipe wall corrosion allowances.¹ The effectiveness of these safeguards was neither evaluated nor documented; instead the safeguards were merely listed in the PHA. Had the adequacy of these safeguards been verified, improved safeguards intended to protect against sulfidation-induced failure of carbon steel piping could have been recommended.

36. Following the August 6th incident, Cal/OSHA inspected the Chevron facility and issued citations. Only one citation related to PHAs, and it was not associated with evaluating the effectiveness of safeguards. Rather, the emphasis was that Chevron's PHA did not adequately account for hazards caused by other units associated with the Crude Unit. The citation stated "The Employer [Chevron] failed to perform an effective Process Hazard Analysis [PHA] of the Crude Unit. Specifically, it failed to identify, evaluate and control potential hazards caused by upstream and downstream units that provide and receive feed from the Crude Unit."³² Had the Cal/OSHA regulation required documentation of the effectiveness of safeguards, Chevron would have been obligated to conduct this analysis and Cal/OSHA inspectors could rely on the regulation for support during inspections.

¹ Corrosion allowance refers to extra wall thickness added as a safety factor to the design of a piece of equipment beyond that needed solely for mechanical considerations such as design temperature and pressure. This extra thickness is provided to accommodate for expected loss of wall thickness due to corrosion over the life of the equipment.

Operational Changes

37. The original design of the 4-sidecut circuit included equipment which had the effect of removing dissolved hydrogen sulfide, the most aggressive sulfur compound associated with sulfidation corrosion, from the 4-sidecut light gas oil process fluid. As a result, the 4-sidecut equipment was effective in reducing the sulfidation corrosion rate. This allowed the 4-sidecut equipment to be constructed of carbon steel. In 1991, this 4-sidecut equipment was taken out of service. No management of changeⁱ (MOC) was performed to analyze the effect of the elimination of this hydrogen sulfide-removing equipment on 4-sidecut corrosion rates. Such an MOC would have ensured that the increase in sulfur concentration on the carbon steel 4-sidecut piping was reviewed prior to removing the equipment.
38. API RP 939-C states that refinery feed stock changes reduce the relevance of past inspection data when predicting future corrosion rates:

Oil refineries that processed a consistent diet of a particular crude oil or crude blend could often base future predictions on past experience. However, over the past 20+ years, global economics have resulted in many refineries processing tens of different crudes in any given year; thus, minimizing the accuracy, or even feasibility, of predictions based on historical data. Additionally, the verification of the actual corrosion rate experienced while processing a specific crude oil is very difficult.³³

39. Crude oil feedstock used at the Chevron Richmond Refinery is obtained from a variety of different sources that are blended before processing. These various crudes have different compositions, such as varying sulfur compounds and concentrations. These crudes can have differing corrosion effects on process equipment and piping. There is an increasing trend in crude oil refining to process less expensive “opportunity crudes” because they can provide significant cost savings to the company.ⁱⁱ However, these crudes may contain more undesirable characteristics such as high sulfur content, high naphthenic acid content, or very heavy hydrocarbons³⁴ that a refinery may not have been originally designed to process. Refinery equipment may not be the proper material of construction to achieve the design life of the equipment when exposed to the different operating conditions. Additional mitigation may be needed to reduce risk. In 1984, the Chevron Richmond Refinery crude oil feed contained approximately 85 volume % Alaskan North Slope (1 wt. %) crude oil. As the refinery began

ⁱ Management of change requires that employers have procedures to manage changes to process chemicals, technology, equipment, and procedures. The procedures must address the technical basis for the change, the impact on safety and health, and training required for employees affected by the change.

ⁱⁱ Crude oil costs can account for up to 90% of the operating costs in a refinery. See Qu, Dingrong, Xiaohui Liu, Xiu Jiang, Zhenggui Lan, and Guangbin Shan. “Setting Critical Operational TAN and Sulfur Level for Crude Distillation Units.” *Corrosion 2011 Conference & Expo*. Paper No. 11362. NACE International, 2011.

running more high-sulfur content crudes, the sulfur content in the 4-sidecut line steadily increased (Figure 14), as discussed below.

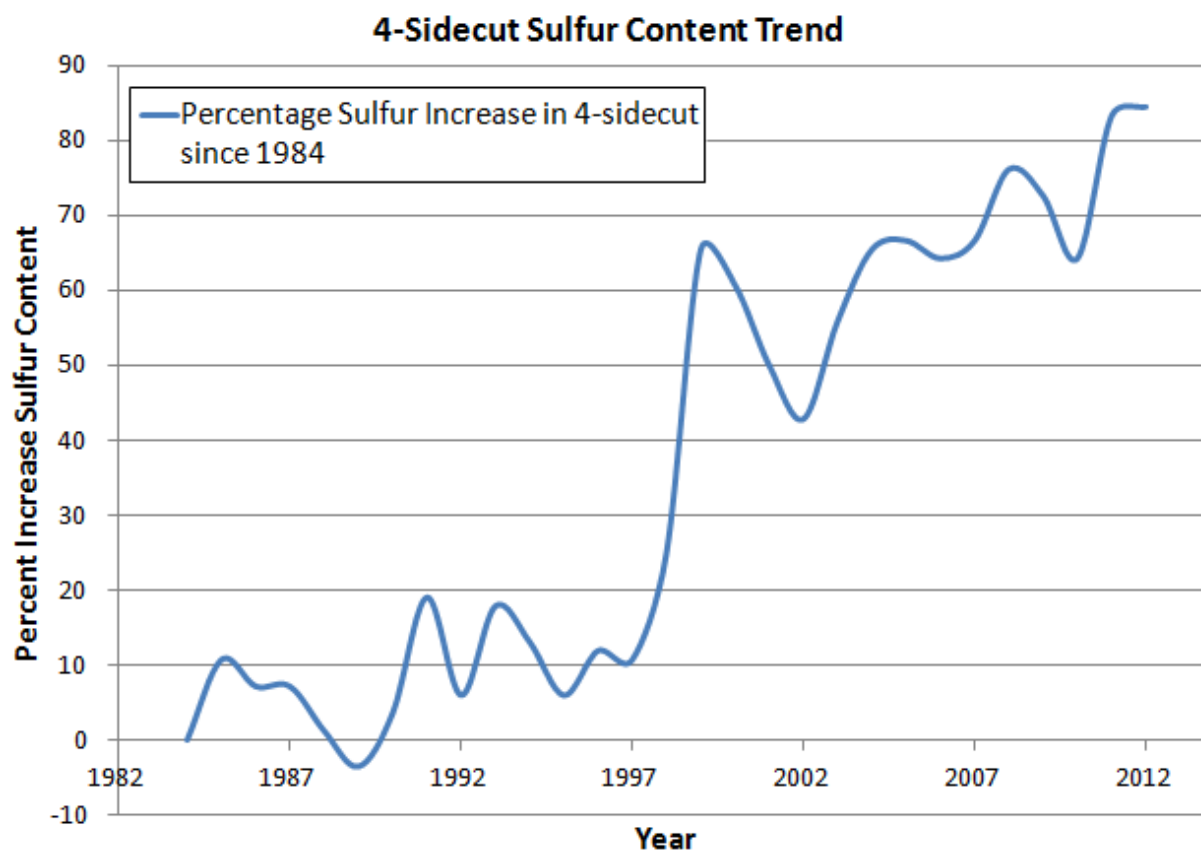


Figure 14. Graph shows the percentage increase from 1984 values of the sulfur content in the 4-sidecut.

40. When Chevron introduces a new crude, an MOC is generated to evaluate the potential impact on the refinery.ⁱ While Chevron stayed under its established crude unit design basis for total wt. % sulfur of the blended feed to the crude unit, the sulfur composition significantly increased over time. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line. Chevron did not conduct an MOC analyzing the impact that increases in sulfur composition would have on corrosion in the crude unit. Chevron also did not change its corrosion monitoring programs in response to the increased sulfur content.
41. The CSB found that increased Chevron Richmond usage of non-domestic crude feed stock over time resulted in higher sulfur content in the process fluid passing through the 4-sidecut piping. Specifically, the percentage of sulfur in the Richmond refinery crudes increased nearly 85%

ⁱ Chevron MOCs on new crudes considered general operational issues but did not analyze corrosion effects from sulfidation corrosion.

between 1984 and 2012, including a significant jump of 32% from 1998 to 1999. This increase in sulfur content corresponded with a simultaneous increase in the usage of non-domestic crude feed at the Richmond refinery.

42. Sulfidation corrosion rates increase in piping circuits as temperature and sulfur content increase. Accordingly, the 4-sidecut sulfidation corrosion rate increased between 1984 and 2012 due to the increase in sulfur content in the line. The CSB found that for the 26-year period from the installation of the piping in 1976 through 2002, the 52-inch 4-sidecut component had lost approximately 33 percent of its wall thickness. From the single inspection of the 52-inch component in 2002 to the incident in 2012 – just ten years – an additional 57 percent of the original component nominal wall thickness was lost near the rupture location due to sulfidation corrosion.ⁱ In addition to the sulfur content increase, the 4-sidecut draw temperature increased from 625 °F in 1992 to 680 °F in 2002. Corrosion rates and remaining life calculations based on past sulfur content and temperatures may not accurately reflect current corrosion rates if process conditions have changed. Inspection based on historical corrosion rates may be too infrequent to detect an increase in corrosion caused by adverse changes in process conditions, potentially leading to equipment failure.
43. *API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems*, the API standard for inspecting piping, recommends companies to incorporate process changes into inspection programs. The standard states:

The owner/user is ... responsible for implementing an effective MOC process that will review and control changes to the process and to the hardware. An effective MOC process is vital to the success of any piping integrity management program in order that the inspection group will be able to anticipate changes in corrosion or other deterioration variables and alter the inspection plan to account for those changes. The MOC process shall include the appropriate materials/corrosion experience and expertise in order to effectively forecast what changes might affect piping integrity. The inspection group shall be involved in the approval process for changes that may affect piping integrity. *Changes to the hardware and the process shall be included in the MOC process to ensure its effectiveness [emphasis added].*³⁵

Chevron failed to comply with the requirements of API 570 when it did not conduct an MOC to thoroughly evaluate the change of increasing sulfur weight percentage in crude oil feed and to assess how it might affect corrosion rates within the 4-sidecut piping circuit. After the August 6, 2012, incident, Cal/OSHA inspected the Chevron

ⁱ The 4-sidecut 52-inch component had an original wall thickness of 0.322 inches. Metallurgical analysis found the thinnest portion of the 52-inch 4-sidecut component was 0.03 inches.

Richmond Refinery and issued citations.ⁱ However, Cal/OSHA did not issue any citations for failing to perform an MOC when sulfur composition in the crude oil feed was increased.

Chevron Sulfidation Corrosion Inspection and Mitigation

44. In the ten years prior to the incident, a small number of Chevron personnel with knowledge and understanding of sulfidation corrosion made at least six recommendations (listed in the following six paragraphs and included in Figure 15) to increase inspection or upgrade the metallurgy in the 4-sidecut piping. The recommendations made by these personnel were not implemented by Chevron management.

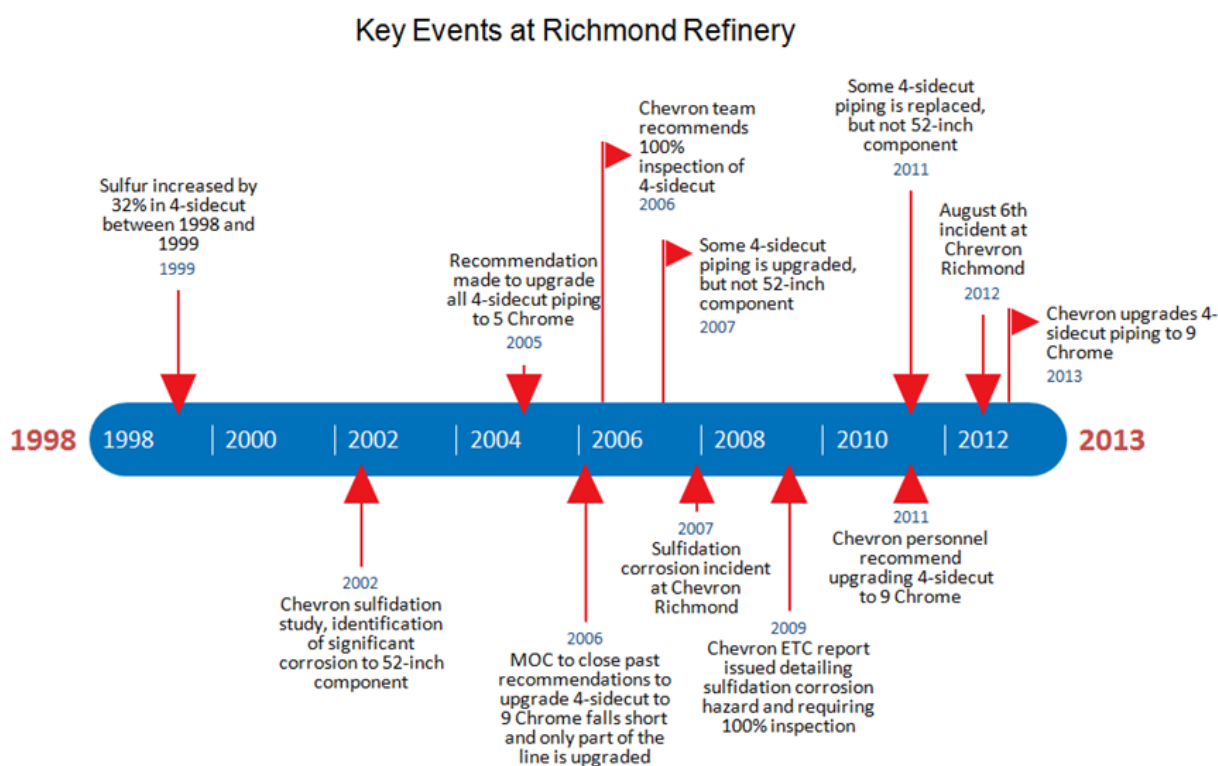


Figure 15. Key events at the Richmond refinery between 1998 and 2013.

45. In August 2002, a Chevron Richmond Refinery employee performed a study analyzing sulfidation corrosion rates in the crude unit and identifying potentially vulnerable areas. The employee discovered that the 4-sidecut operating temperature had been increased and concluded that this increase would cause more hydrogen sulfide to evolve, leading to increased sulfidation

ⁱ Cal/OSHA citations issued January 30, 2013.

corrosion rates. As a result of these findings, the employee recommended increased inspection of the 4-sidecut piping and noted that this piping might need to be upgraded from carbon steel to 5-Chrome, a steel alloy that is more resistant to sulfidation corrosion. In 2002, proactively following up on this study, the crude unit inspector conducted additional piping inspection and identified accelerated corrosion in the 52-inch 4-sidecut component. The inspector recommended upgrading this piping during the next shutdown in 2007. In the inspector's 2002 accomplishments, Chevron management acknowledged this effort to prevent a significant incident; it was characterized as "a save." However, during the 2007 turnaround the recommendation was not implemented, and because a CML was not added to the inspection program, the 52-inch component was not inspected after 2002.

46. In February 2006, a team consisting of a materials and corrosion engineer, an inspector, a process engineer, a metallurgist, and a design engineer issued a Corrosion Mitigation Plan for the Chevron Richmond Refinery crude unit. The report specifically identified the 4-sidecut piping to be at risk for high temperature sulfidation corrosion. The report described that low silicon carbon steel can corrode faster than carbon steel manufactured with higher silicon content, and recommended that 100 percent inspection be performed on the 4-sidecut line using continuous monitoring technology. During the 2007 crude unit turnaround, continuous monitoring probes were only installed on a segment of the 4-sidecut line that did not include the 52-inch component that ultimately failed. The 100 percent inspection recommended in the 2006 Corrosion Mitigation Plan was not performed.
47. During the 2007 turnaround, the crude unit inspector recommended that the refinery upgrade the entire 4-sidecut piping with 5-Chrome. The recommendation was based on findings obtained during the 2002 crude unit turnaround, where the crude unit inspector found that the 52-inch 4-sidecut component had lost one-third of its wall thickness due to corrosion. However, after evaluation, this recommendation was not accepted by the turnaround planning team. Basing its decision on limited inspection data, Chevron determined that the 8-inch portion of the 4-sidecut piping that ran from the atmospheric column to the pump, the portion which included the 52-inch component, had sufficient wall thickness to last to the next turnaround scheduled for Fall 2011.ⁱ The piping downstream of the pump, which operates at a higher pressure, was determined not to have sufficient wall thickness to last to the next turnaround. This piping was removed and replaced with 9-Chrome, an upgraded and inherently safer metallurgy. The 52-inch component of the 8-inch piping between the atmospheric column and the pump was not replaced during the 2007 turnaround even though it had been identified as thinned in 2002. Furthermore, a permanent CML was not placed on the 52-inch component, and it was not entered into the inspection database. As a result, the component was not inspected again.

ⁱ This decision was made without reinspecting or evaluating the thickness of the thinned 52-inch component identified in 2002 that prompted the recommendation.

48. In September 2009, Chevron ETC corrosion experts released a formal technical report discussing sulfidation corrosion and the specific issues associated with carbon steel, including the potential for high corrosion rates in carbon steel piping containing low percentages of silicon. In its report, Chevron ETC issued recommendations for inspection and provided guidelines for prioritizing piping circuits susceptible to sulfidation corrosion so that high-risk lines could be evaluated first. It was recommended that 100 percent component thickness testing be completed on all high priority lines one time to identify thin, low-silicon components to establish a baseline of corrosion rate and risk for failure. Following the release of the report, the Chevron Richmond Refinery materials group completed the risk-ranking of the carbon steel piping in the Richmond Lube Oil Project (RLOP) and in the crude unit, two units known to be susceptible to sulfidation corrosion. The group identified the crude unit 4-sidecut line as a high risk line per the report ranking guidance. Instead of completing the 100 percent component inspection, the 4-sidecut was recommended for replacement with 9-Chrome. However, the replacement recommendation was denied because the available, limited inspection data indicated the piping would last until the next turnaround. Subsequently, the alternative 100 percent component inspection was also never performed.
49. Chevron conducts “Intensive Process Reviews” prior to turnarounds. This process involves knowledgeable individuals including Business Improvement Network leaders, process engineers, metallurgical engineers, design engineers, and turnaround planners. The purpose of the review is to identify key unit issues that should be addressed and repaired during the unit turnaround. Prior to the 2011 crude unit turnaround, Chevron personnel conducted an Intensive Process Review of the crude unit and specifically recommended that the 4-sidecut carbon steel piping “should be upgraded to 5 Cr [5-Chrome]... due to sulfidation.” Although the Intensive Process Review identified sulfidation problems in the 4-sidecut line, this activity was ineffective. The 4-sidecut piping was not upgraded during the 2011 crude unit turnaround.
50. In preparation of the work list for the 2011 crude unit turnaround, the crude unit inspector and crude unit metallurgist recommended that the 4-sidecut line be replaced with an upgraded metallurgy, 9-chrome, the metallurgy recommended in the Chevron new construction guidelines for piping in high temperature and high sulfur service. The recommendation was based on the high priority ranking of the 4-sidecut line, corrosion history, and both Chevron and industry recommended best practice. However, the turnaround management team determined that the inspection data available for the 4-sidecut piping, from CMLs on elbow components which are less prone to sulfidation corrosion, did not support a material upgrade during the 2011 turnaround.^{i, i} The lack of data on the more susceptible 4-sidecut straight-run piping components was not considered.

ⁱ This decision was made without reinspecting or evaluating the thickness of the 52-inch component identified in 2002.

Inherently Safer Systems

51. The Center for Chemical Process Safety (CCPS) is a corporate membership organization that identifies and addresses process safety needs within the chemical, pharmaceutical, and petroleum industries.³⁶ Chevron is a corporate member of CCPS.³⁷ The CCPS book *Inherently Safer Chemical Processes, 2nd ed.* defines inherently safer design as the process of identifying and implementing inherent safety in a specific context that is permanent and inseparable.³⁸ In the book *Guidelines for Engineering Design for Process Safety, 2nd ed.*, CCPS states “inherently safer design solutions eliminate or mitigate the hazard by using materials and process conditions that are less hazardous.”³⁹
52. Inherently safer technologies are relative; a technology can only be described as inherently safer when compared to a different technology with regard to a specific hazard or risk.⁴⁰ A technology may be inherently safer with respect to one risk but not safer from another risk. For this reason, it is important to carry out a comprehensive, documented hazard analysis to determine the individual and overall risks in a process and assess how the risks can be effectively minimized to control hazards. An inherently safer systems review details a list of choices offering various degrees of inherently safer implementation. The review should include risks of personal injury, environmental harm, and lost production, as well as evaluating economic feasibility.⁴¹
53. It is simpler, less expensive, and more effective to introduce inherently safer features during the design process of a facility rather than after the process is already operating.⁴² Process upgrades, rebuilds, and repairs are additional opportunities to implement inherent safety concepts. Conducting a comprehensive hazard review to determine risks and identify ways to eliminate or reduce risks is an important step in implementing an inherently safer process. Chevron training programs on inherently safer systems reflect this approach, stating “we have the greatest opportunity to eliminate or minimize hazards during the development phase of new projects or major revamps of existing facilities.”
54. After a 2007 incident caused by a pipe failure in the Richmond refinery crude unit, Chevron implemented an “Inherently Safer Solution” by upgrading the piping to metallurgy that was less susceptible to sulfidation corrosion. However, the change was implemented intuitively without a supporting inherent safety review or failure mechanism hazard review to provide a detailed documented technical rationale for the metallurgy selection. Without such a review, the material selected cannot be analyzed to determine if it is the best inherently safer solution for the process in order to minimize risk.

ⁱ A portion of the 4-sidecut 12-inch line was replaced during the 2011 turnaround with carbon steel due to thinning caused by sulfidation corrosion.

55. Following the August 6, 2012, incident, the 4-sidecut piping circuit at the Richmond refinery was upgraded from carbon steel to 9-Chrome.ⁱ However, Chevron did not produce a documented inherently safer hazard review before commencing the rebuild of the crude unit. The crude unit at the Chevron El Segundo refinery is nearly identical in construction and design to the Richmond refinery crude unit. Chevron informed the CSB that piping *downstream* of the 4-sidecut pumps in the 4-sidecut piping circuit at the El Segundo refinery was upgraded in 2001ⁱⁱ from carbon steel to stainless steel. As stated previously, after the August 6, 2012, Richmond incident, the 4-sidecut piping *upstream* of the 4-sidecut pumps at the El Segundo refinery was upgraded from carbon steel to 9-Chrome. Had a comprehensive inherently safer systems review been conducted at the Richmond refinery following the August 6th incident, a different metallurgy, such as stainless steel which was installed at the Chevron El Segundo Refinery, may have been identified as inherently safer than 9-Chrome with respect to sulfidation corrosion.
56. An effectiveness ranking of techniques used to control hazards and the risk they represent can be described as a hierarchy of controls. The further up the hierarchy, the more effective the risk reduction achieved (Figure 16). All concepts in the hierarchy of controls should be included in the process of risk assessment and reduction. Upgrading metallurgy to a more corrosion resistant material may be a high ranking, inherently safer choice for certain corrosion mechanisms, such as sulfidation corrosion. Holding other variables constant, upgrading the material of construction may reduce the severity of corrosion and the likelihood of a failure.

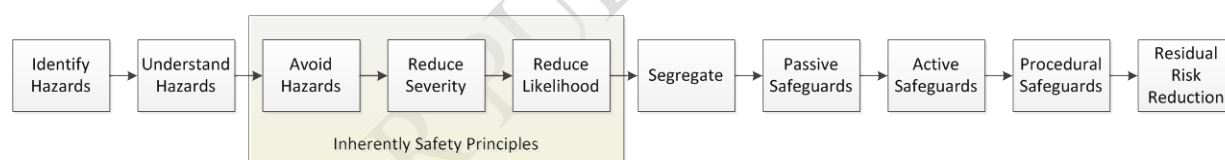


Figure 16. Hierarchy of controls. The boxes reflect inherently safer controls from left to right, based on *Process Plants: A Handbook for Inherently Safer Design Second Edition*; Kletz, Trevor Amyotte, Paul; CRC Press 2010.

57. Chevron employees have recommended implementing inherently safer designs through the MOC process, incident investigations, technical reports, and recommendations from employees in the past. However, the CSB has not identified any documented, thorough analysis of the proposed inherently safer solutions. In addition, Chevron has repeatedly failed to implement proposed inherently safer recommendations. For example, following the discovery of significant 4-sidecut piping sulfidation corrosion in 2002, a Chevron inspector issued the following recommendation to replace the piping in the 2007 turnaround:

ⁱ After the 2012 incident, the Richmond refinery stated that stainless steel was susceptible to chloride stress corrosion cracking and should not be used.

ⁱⁱ Chevron verbal estimate for date of piping installation. No MOC was conducted to review and document this change.

INFORMATION

The #4 sidecut piping from C-1100 to P-1149/A to E-1113 was RT (x-ray) inspected for hot H₂S [sulfidation] corrosion. The piping is actively corroding, particularly on the section on the discharge line from the pumps near the exchanger; the line upstream of the P-1149/A pumps is corroding as well. Corrosion rates indicate that the piping has 4 years of remaining life until the refinery throwaway thickness of 0.14" [inch] is reached. The carbon steel piping is currently running at temperatures between 650 °F on the pump suction line to 641 °F on the line just before E1113; the upper limit for carbon steel piping in this service is 550 °F. A materials upgrade to 5 chrome would raise the upper limit to between 650-750 °F. Additionally, the ABCR piping loop from the same sidecut draw line off of the column to P-1148/A to E-1111 is also carbon steel and operates at the same temperatures, rendering the ABCR piping system to E-1111 susceptible to hot H₂S corrosion as well.

Recommendation

Replace the existing #4 sidecut piping noted above from C-1100 through P-1149/A to E1113 and P-1148/A to E-1111 (approximately 700' [feet] of 12", 10", 8" and 6" piping, plus some 4" and 3" at the P-1149/P-1148 suction/discharge headers). Upgrade the pipe material from carbon steel to 5 chrome.

To implement this recommendation, Chevron initiated an MOC in 2006 to replace the piping during the 2007 Turnaround. However, the MOC supporting documents had a narrowed scope to only replace the section of piping from P-1149/A pumps to the E-1113 heat exchanger because Chevron reduced the work scope during the 2007 turnaround planning process. The Description of Change in the MOC stated:

Existing line is carbon steel in a hot service that operates in the range where high temperature sulfadation [sic] occurs. The line has been utⁱ inspected and found to be nearing tminⁱⁱ requiring replacement. Due to the higher temperature 9CR [9-Chrome] would be the preferred [sic] material.

ⁱ UT is an abbreviation used to indicate ultrasonic thickness testing inspection technique.

ⁱⁱ Tmin is an abbreviation used to indicate minimum required piping wall thickness.

Contradicting this Description of Change detailing a replacement of the entire 4-sidecut piping circuit, the MOC Summary Review and attached documentation only authorized replacement of the piping from the P-1149's to E-1113. The MOC states:

4 S/C piping has been operating hotter in recent years. The hotter temperatures 550 °F are in the high temperature sulfadation [sic] range. Additionally the section of 4 S/C piping from P-1149' s to E-1113 has been found to be nearing tmin.

The section of pipng [sic] from P-1149's to E-1113 will be replaced with 9 Cr [9-Chrome] piping.

As a result, the portion of the piping containing the 52-inch component that failed on August 6th remained in service. Although the recommendation was intended to more broadly apply inherently safer materials of construction, the final implementation by the MOC limited the application of this more corrosion resistant metallurgy.ⁱ Again, the inherently safer, more corrosion resistant, metallurgy was not implemented more broadly in crude unit high temperature service. Other examples are discussed above in the section entitled *Chevron Sulfidation Corrosion Inspection and Mitigation*.

58. In 2007, the Chevron Richmond Refinery conducted training to teach employees about the importance of complying with the City of Richmond's Industrial Safety Ordinance (ISO)ⁱⁱ inherent safety guidance. The training states "we should always strive to implement inherently safer strategies to the greatest extent feasible." However, Chevron did not regularly or rigorouslyⁱⁱⁱ apply inherently safer design strategies in opportunities including PHAs, MOCs, incident investigation recommendations, and during turnarounds.^{iv}
59. Chevron uses an inherently safer design checklist^v for PHAs to meet inherently safer systems analysis requirements of the Contra Costa County and the City of Richmond ISO. The checklist, provided by Contra Costa County, is intended to aid identification of opportunities to implement inherently safer design during the PHA process. The checklist was intended to stimulate discussion and analysis of potential opportunities to implement inherently safer design. Contra

ⁱ As discussed earlier, only the section of piping downstream of the pumps was replaced with 9-Chrome.

ⁱⁱ See the "Regulatory Coverage" section in this report.

ⁱⁱⁱ Chevron does not utilize inherent safety guidewords or checklists during the MOC or incident investigation process. Inherently safer guidewords help direct the inherently safer review process. Examples of guidewords include minimization, substitution, moderation, and simplification. These words may be applied to materials, product inventory, process controls, process piping, and siting, among others. See Center for Chemical Process Safety (CCPS). "Inherently Safer Chemical Processes – A Life Cycle Approach." 2nd ed., Table 8.3, 2009.

^{iv} As stated in the Regulatory Oversight section below, Chevron is only required to conduct inherently safer design strategies during PHAs and for the construction of new processes.

^v The Contra Costa County inherently safer systems checklist is provided as a tool by Contra Costa County which can be used during the PHA process, but the actual use of the checklist is not required.

Costa County’s guidance on the IST checklist states that some items may need to be reviewed by a team that is outside the PHA team in order to involve people with the required expertise. Chevron utilized the Contra Costa County inherently safer technologies checklist (IST Checklist) during the 2009 crude unit PHA. However, only three permissively wordedⁱ inherently safer system recommendations were made, none of which addressed sulfidation corrosion or piping metallurgy. In addition, Chevron performed the checklist analysis using the same individuals who conducted the PHA despite Contra Costa County’s guidance to involve other personnel with additional expertise. Performing a superficial analysis, Chevron failed to adequately consider inherently safer systems like improved metallurgy for corrosion resistance. For instance, the checklist prompted: “Use corrosion resistant material?” In response, Chevron stated that “vessel specifications and piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service.” No mention is given to improving metallurgy to reduce corrosion. There is also no documented analysis regarding potential materials with enhanced corrosion resistance. There was no documentation of the inherently safer technologies analysis, and no inherently safer alternatives were documented. The checklist as applied by Chevron was a “check-the-box” exercise. Chevron Richmond PHAs were thus not an effective means of driving inherent safety. The table below gives a sample of the IST checklist questions along with the associated Chevron responses.ⁱⁱ

| Contra Costa County Checklist Question | Chevron IST Analysis |
|---|---|
| Use smallest diameter piping? | Piping sizes are the smallest possible for the capacity of the unit. |
| Substitute less hazardous raw materials? | Raw materials in use are of minimal hazard. |
| Dilute hazardous raw materials? | Raw materials currently dilute where applicable. |
| Minimize off-site impacts? | #4 Crude Unit is located at a distance from public areas. |
| Easy operation of valves designed to prevent inadvertent error? | In general, valves are arranged in a logical manner. |
| Increasing wall strength? | Piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service. |

ⁱ All began with “consider” and two began with “consider evaluating” which does not require any action by Chevron.

ⁱⁱ The comprehensive list of IST checklist questions and Chevron’s corresponding answers are provided separately on the CSB website.

60. Contra Costa County inspected the Chevron Richmond Refinery in 2011, auditing Chevron's implementation of the county's inherently safer systems analysis requirements in the PHA process. The inspectors determined that Chevron's PHAs "follows the requirements specified by ... ISS [inherent safety systems] guidelines." This approval by Contra Costa County conveyed to Chevron that the regulator considered that Chevron's minimal analysis of opportunities to implement inherently safer design, its "check-the-box" exercise, was sufficient.
61. Effectively implementing inherently safer technology provides an opportunity for preventing major chemical incidents. The August 6, 2012, incident at Chevron and other incidents⁴³ throughout the refining industry highlight the difficulty in preventing failure caused by sulfidation corrosion in low silicon carbon steel piping solely through inspection, a procedural safeguard that is low on the hierarchy of controls. Using inherently safer design concepts to avoid issues such as variation in corrosion rate in carbon steel piping due to hard-to-determine silicon content will reduce future similar failures in refineries. Chevron and other process plants' implementation of inherently safer systems to the greatest extent feasible would provide a higher degree of protection from incidents like the one that occurred on August 6, 2012.
62. It is essential that MOCs incorporate hazard analyses and the assessment of opportunities to implement inherently safer systems. This process can be assisted through the use of guidewords to trigger the thought process. CCPS states that "by including inherent safety guidewords in a management of change program, the MOC protocol recognizes inherent safety as both a driving force for - and as an opportunity during - implementation."⁴⁴
63. Layer of Protection Analysis (LOPA) is a well-recognized hazard analysis methodology that is intended to determine if a sufficient number of safeguards or layers of protection exist to protect against a particular hazard or accident scenario.⁴⁵ As the potential consequence of a particular scenario increases, the number of safeguards or protection layers must increase to reduce the risk of the scenario to what is considered an acceptable or tolerable level.⁴⁶ LOPA can be used to help an organization decide if the risk of a scenario or hazard has been reduced to a level that is "as low as reasonably practicable" (ALARP).⁴⁷ ALARP is a risk reduction goal, where risk reduction efforts are continued until the incremental effort to further reduce risk becomes grossly disproportionate to the level of additional risk reduction.⁴⁸ By rigorously reviewing accident or hazard scenarios, evaluating the potential consequence of the scenario, and identifying the safeguards or layers of protection necessary to drive risk to as low as reasonably practicable, LOPA becomes an effective organizational tool for implementing a Process Safety Management (PSM) mechanical integrity program.⁴⁹ LOPA also helps an organization decide which safeguards to focus on during operation, maintenance, and training.⁵⁰ In addition, the LOPA

methodology includes provisions allowing an organization to determine the availabilityⁱ and effectiveness of a safeguard or layer of protection in reducing the risk of a potential scenario.⁵¹

Regulatory Oversight

64. The Contra Costa County Industrial Safety Ordinance (Contra Costa County ISO) requires that regulated facilitiesⁱ within the county implement safety programs to prevent chemical incidents. Since the inception of the ISO in 1998, Contra Costa County has continued to make improvements to the implementation of the prevention program's elements.
65. The purpose of the Contra Costa County ISO is to "prevent accidental release of hazardous chemicals; improve accident prevention by soliciting participation from industry and the community; require industry to submit a Safety Plan; and conduct audits of the plan and inspections of the industrial plants."⁵²
66. The City of Richmond is in Contra Costa County, but the county does not have jurisdiction within the city limits. Thus, the county ordinances, such as the Contra Costa County ISO, are not enforceable within the city. Instead, in 2001, the City of Richmond adopted an ISO that is almost identical to the Contra Costa County ISO.^{53,ii} The City of Richmond ISO covers the Chevron Richmond Refinery and General Chemical West Richmond Works.⁵⁴ However, the Contra Costa County Hazardous Materials Program team inspects these two facilities and implements the City of Richmond ISO pursuant to an agreement between the two parties.⁵⁵
67. Both the Contra Costa County ISO and City of Richmond ISO contain identical provisions that address the use of inherent safety concepts. The Contra Costa County and Richmond ISOs define inherently safer systems as "feasible alternative equipment, processes, materials, lay-outs, and procedures meant to eliminate, minimize, or reduce the risk of a major chemical accident or release by modifying a process rather than adding external layers of protection."⁵⁶ The Contra Costa County ISO and the City of Richmond ISO also both require that:

For all covered processes, the stationary source shall consider the use of inherently safer systems in the development and analysis of mitigation items resulting from a process hazard analysis and in the design and review of new processes and facilities. The stationary source shall select and implement inherently safer systems to the greatest extent feasible. If a stationary source concludes that an inherently safer system is not

ⁱ The Contra Costa County ISO applies to oil refineries and chemical plants within the county jurisdiction that are required to submit a Risk Management Plan to EPA and are program level 3 stationary sources as defined by the California Accidental Release Prevention (CalARP) Program. There are seven facilities covered by the Contra Costa County ISO, five of which are refineries.

ⁱⁱ At the time of the August 6th incident the City of Richmond ISO did not include amendments made to the Contra Costa County ISO in 2006. The 2006 amendments required an expansion of human factors programs, expanded management of organizational change reviews, security vulnerability analyses, and safety culture assessments. These amendments were subsequently adopted by the City of Richmond in February 2013. *See* <http://cchealth.org/hazmat/iso/> (accessed on April 9, 2013).

feasible, the basis for this conclusion shall be documented in meaningful detail.⁵⁷

68. The apparent intent of the Contra Costa County and the City of Richmond ISO regulations is to require companies to evaluate their processes in order to identify opportunities to implement inherently safer systems. However, the plain language contained within these regulations conflicts with this intent. Both the Contra Costa County and the City of Richmond ISO regulations contain the following permissive language: “the stationary source *shall consider* the use of inherently safer systems...”⁵⁸ This language does not require companies to conduct a comprehensive analysis and implement inherently safer systems even where feasible. It only requires such an analysis be considered. The regulations allow companies to merely engage in an activity contemplating the potential use of inherently safer systems.
69. The language within the Contra Costa County and the City of Richmond ISO regulations also requires effective action to implement inherently safer systems “to the greatest extent feasible.”⁵⁹ If an inherently safer system is not implemented, the regulations require that the basis for this decision be “documented in meaningful detail.”⁶⁰ However, the regulation does not require documentation supporting the adequacy of existing “inherently safer”⁶¹ claims. Chevron’s compliance with this regulation is indicative of this deficiency. In its inherently safer systems checklist, Chevron simply concluded that its systems were inherently safer to the extent that no modifications were necessary. However, the company offered no documentation to substantiate these claims. Had the ISO required analysis of inherently safer systems regardless of what the site already had in place, Chevron may have implemented the inherently safer recommendations made by technical staff to replace the 4-sidecut with an inherently safer metallurgy.
70. The inherently safer systems requirements of the Contra Costa County and the City of Richmond ISOs are only triggered by the conduct of a PHA or the construction of a new process.⁶² Rebuilds, repairs, MOCs, and the implementation of incident investigation corrective actions do not require the analysis and application of inherently safer systems.
71. The Contra Costa County PHA guidance document presents four categories of risk reduction:ⁱ inherent, passive, active, and procedural (Figure 15).ⁱⁱ It states that all four categories should be used in the development of recommendations from process hazard analyses.⁶³ It reiterates the CCPS statement that all may contribute to the overall safety of a process, but that inherent safety

ⁱ The guidance document uses CCPS definitions for the identified categories of risk reduction.

ⁱⁱ Inherent risk reduction involves eliminating the hazard by using materials and process conditions that are non-hazardous. Passive risk reduction is defined as minimizing the hazard through process and equipment design features that reduce the frequency or consequence of the hazard without active functioning of any device. Active risk reduction includes using controls, alarms, safety instrumented systems, and mitigation systems to detect and respond to process deviations from normal operation. Procedural risk reduction achieves the lowest level of risk reduction and involves using policies, operating procedures, training, administrative means, emergency response, and management approaches to prevent incidents and minimize the effects of an incident.

is the most effective.⁶⁴ It goes on to state “The inherent and passive categories should be implemented when feasible for new processes and facilities and used during the review of Inherently Safer Systems for existing processes if these processes could cause incidents that could result in a Major Chemical Accident or Release.”⁶⁵ This wording in the guidance document demonstrates the importance Contra Costa County places on risk reduction and prevention such as metallurgy upgrades; however, as a guidance document, it is non-mandatory. The regulation only requires inherently safer systems reviews during PHAs and for construction of new facilities and processes. The ISO does not encourage the application of both the hierarchy of controls and the use of inherently safer strategies in other circumstances.

72. The California Division of Occupational Safety and Health (Cal/OSHA) has jurisdiction over employee safety in California.⁶⁶ Cal/OSHA is a division of the California Department of Industrial Relations and has operated a state plan industrial health and safety program since 1973 under a delegation from the U.S. Occupational Safety and Health Administration (OSHA). Cal/OSHA conducts inspections of California workplaces in response to industrial accidents, safety complaints, or as part of an inspection program targeting specific industries.⁶⁷ Consideration of inherently safer processes is not currently a required component of any Cal/OSHA (or federal OSHA) standard or regulation.ⁱ
73. The State of California has promulgated process safety regulations similar to OSHA⁶⁸ for the prevention or minimization of the consequences of the accidental release of acutely hazardous chemicals.⁶⁹ These regulations require that covered employers perform a PHA to identify, evaluate and control hazards involved in the process using recognized methodologies.⁷⁰
74. California regulations, however, do not provide for a specific review of the effectiveness of the proposed safeguards to control the hazards identified in the PHA using recognized methodologies such as Layers of Protection Analysis (LOPA).⁷¹ Additionally, California regulations do not have any requirements for the use of inherently safer systems analysis and the hierarchy of controls for establishing safeguards for identified process hazards. Cal/OSHA, like federal OSHA, also does not require damage mechanism hazard reviews as part of the PHA process.
75. The United Kingdom’s (UK) Health and Safety Executive (HSE), the industry regulator in the UK, provides guidance on damage mechanism hazard reviews in the UK’s offshore petrochemical industry. The HSE guidance states that effective management of corrosion will contribute towards equipment integrity and reduce risk from safety and environmental hazards.⁷² Damage mechanism hazard reviews should provide a structured framework for identifying risks associated with corrosion and developing suitable risk reduction measures.⁷³ These reviews should cover failure mechanisms including but not limited to corrosion, environmental cracking,

ⁱ This is also the case for US EPA Risk Management Program and the California Accidental Release Prevention Program regulations.

erosion, and mechanical damage such as vibration induced fatigue.⁷⁴ Corrosion risk assessment allows threats and their potential consequences to be identified and to quantify the risk they present.⁷⁵ HSE guidance states that a formal, documented quantitative and logic based assessment should be used when conducting corrosion reviews.⁷⁶ The HSE guidance states that during the design of a process, a corrosion review can be used to eliminate risks and achieve inherent safety.⁷⁷ After the design stage, risk reduction measures can be chosen and implemented to lower risk to an acceptable level.

76. Under a rule issued by the U.S. Environmental Protection Agency (EPA),⁷⁸ a facility with a tank, drum, pipe, or other processⁱ that contains an extremely hazardous toxic or flammable substance listed at 40 CFR §68.130 in an amount above the “threshold quantity” specified for that substance, is required to conduct a hazard assessment as well as develop a prevention program and an emergency response program. These requirements are documented in a Risk Management Plan (RMP) that is submitted to EPA. Covered facilities must implement the RMP and update their RMPs periodically or when certain changes occur. The goal of EPA’s Risk Management Program is to prevent accidental releases of substances that can cause serious harm to the public and the environment from short-term exposures, and to mitigate the severity of releases that do occur.⁷⁹
77. The EPA RMP program provisions build on the planning and preparedness groundwork laid by the Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA). EPCRA establishes requirements for federal, state, and local governments, as well as industry, regarding emergency planning and “Community Right-to-Know” reporting on hazardous toxic chemicals. EPCRA “help[s] increase the public’s knowledge and access to information on chemicals at individual facilities, their uses, and releases into the environment.”⁸⁰ According to the Chemical Emergency Preparedness and Prevention Office, transparency between industry and the public will improve community safety:

Both EPCRA and the CAA [Clean Air Act] section 112(r) Risk Management Program encourage communication between facilities and the surrounding communities about chemical safety and chemical risks. Regulatory requirements, by themselves, will not guarantee safety from chemical accidents. Information about hazards in a community will allow local emergency officials and the public to work with industry to prevent accidents.⁸¹

The CCPS also notes that governments and advocacy organizations have been successful in driving performance improvement by using public disclosure to make safety information available to the public.⁸²

ⁱ “Process” means “any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances, or combination of these activities...” 40 CFR §68.3 (1997).

78. Under the RMP program's hazard assessment requirement, a facility must prepare a worst-case release scenario analysis⁸³ and complete a five-year accident history.⁸⁴ A covered facility must also develop and implement an emergency response program that includes procedures for informing the public and local agencies about accidental releases and procedures and measures for emergency response after an accidental release.⁸⁵ Officials and the public, including local emergency planning committees (LEPCs) can use this information to understand the chemical hazards in the community and then work with industry to address and mitigate those hazards. With both EPCRA and the Risk Management Program, the regulatory purpose and substantive provisions emphasize the importance of transparency, sharing of process safety data, and public participation to prevent chemical accidents. The CSB notes that post-incident during the decision-making related to piping repairs to the Crude Unit, the public, worker representatives, regulators and governmental bodies played a key role driving transparency, accountability and improved risk reduction.
79. Workforce involvement is a key element of process safety and effective chemical accident prevention. In the Center for Chemical Process Safety publication, *Guidelines for Risk Based Process Safety*, it lists workforce involvement as one of 20 essential management systems necessary to reduce process safety risks and prevent chemical accidents.⁸⁶ CCPS states that:

...workers are potentially the most knowledgeable people with respect to the day-to-day details of operating the process and maintaining the equipment and facilities and may be the sole source for some types of knowledge gained through their unique experiences. Workforce involvement provides management a mechanism for tapping into this valuable expertise.⁸⁷

This CCPS publication discusses general areas of workforce involvement in risk assessments, inspections, audits, and performance reviews. The CCPS notes that participation leads to empowerment, management responsiveness, and process safety performance improvement.⁸⁸ The OSHA PSM Standard emphasizes the importance of participation by workers and their representatives. It requires employers to develop a written plan of action, consult with employees, and make available all process safety information.⁸⁹ In previous investigation reports, the CSB has identified that workers and their representatives play a very important role in major incident prevention. For example, in the BP Texas City oil refinery investigation report, the CSB recommended that BP and the United Steelworkers International Union (USW) establish a joint program to report incidents and near misses, and to ensure that recommendations made during investigations were implemented. The CSB also recommended

that API and the USW work together to develop a safety standard addressing leading and lagging process safety indicators.ⁱ

80. In July 2012, the CSB held a public hearing on process safety indicators to explore how companies and regulators use process safety metrics to manage risks and drive continuous safety improvements. The CSB stated that, following the 2005 BP Texas City accident, both the CSB and Baker Panelⁱⁱ reports noted the lack of focus by BP on process safety and inadequate performance measurement indicators. The CSB also noted that one goal of process safety indicators is to drive continuous process safety improvement, and that regulators can utilize these indicators to focus inspections, audits, and investigations.
81. Process safety management systems are critical for reducing process safety incidents. Process safety indicators are a significant element of these systems. Indicators measure the strengths and weaknesses of process safety management systems, to achieve and maintain safe and reliable operations.⁹⁰ Properly selected and managed indicators will identify the successes and point out the flaws of the system.⁹¹
82. In 2008, the CCPS published a guidance document for the development of leadingⁱⁱⁱ and lagging^{iv} process safety indicators to assist industry in avoiding catastrophic chemical incidents.⁹² While process safety indicators are an important tool for major accident prevention, the simple activity of identifying and recording process safety metrics will not drive process safety improvement. CCPS notes that these metrics must be “collected, analyzed, communicated, understood, and *acted upon*.”⁹³
83. The UK HSE has published a guidance document to help chemical and major hazard industries develop process safety indicators. HSE states that:

Most systems and procedures deteriorate over time, and system failures discovered following a major incident frequently surprise senior managers, who sincerely believed that the

ⁱ Process safety indicators are also referred to as safety performance indicators, metrics, key process indicators (KPI), performance measures, indicators, etc...

ⁱⁱ See http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/SP/STAGING/local_assets/assets/pdfs/Baker_panel_report.pdf (accessed April 12, 2013).

ⁱⁱⁱ Leading indicators are measurements that predict future performance to ensure that safety protection layers and operating discipline are being maintained, including unsafe behaviors or insufficient operating discipline equipment selection, engineering design, specification of inspection frequency, and technique. See Center for Chemical Process Safety (CCPS), *Guidelines for Process Safety Metrics*, Page 20. 2010.

^{iv} Lagging indicators are facts about previous events, such as process safety incidents, that meet the threshold of severity and should be reported as part of the process safety metric. See Center for Chemical Process Safety (CCPS), “Guidelines for Process Safety Metrics,” 2010; Page 20.

controls were functioning as designed. Used effectively, process safety indicators can provide an early warning, before catastrophic failure, that critical controls have deteriorated to an unacceptable level.⁹⁴

84. The public can play an important role in monitoring safety management systems. In its recent guidelines, the CCPS promoted the sharing of process safety indicators with the public:

Sharing performance metrics and results broadly can engage the public as a partner in holding the organization accountable for process safety performance. Making metrics and performance public can be an especially powerful way of maintaining upper management commitment since it will likely be the CEO or other senior managers who will be called to account by the public if goals are not met or performance declines. Communicating process safety successes also demonstrates to employees and the public that positive change can be, and are being, made within an organization.⁹⁵

Recommendations

Under 42 U.S.C. 7412(r)(6)(C)(ii), the U.S. Chemical Safety and Hazard Investigation Board is charged with “recommending measures to reduce the likelihood or the consequences of incidental releases and proposing corrective steps to make chemical production, processing, handling and storage as safe and free from risk of injury as possible” The CSB makes recommendations based on the findings and conclusions of the investigation. Recommendations are made to parties that can affect change to prevent future incidents, which may include the company, contractors, industry organizations responsible for developing good practice guidelines, regulatory bodies, and/or organizations that have the ability to broadly communicate lessons learned from the incident, such as trade associations or professional societies.

Chevron U.S.A (Urgent)

2012-03-I-CA-R1

At all Chevron U.S. refineries, engage a diverse team of qualified personnel to perform a documented damage mechanism hazard review. This review shall be an integral part of the Process Hazard Analysis cycle and shall be conducted on all PSM-covered process piping circuits and process equipment. The damage mechanism hazard review shall identify potential process damage mechanisms and consequences of failure, and shall ensure safeguards are in place to control hazards presented by those damage mechanisms. Analyze and incorporate into this review applicable industry best practices, Chevron Energy Technology Company findings and recommendations, and inherently safer systems to the greatest extent feasible.

2012-03-I-CA-R2

At all California Chevron U.S. refineries, report leading and lagging process safety indicators, such as the action item completion status of recommendations from damage mechanism hazard reviews, to the federal, state, and local regulatory agencies that have chemical release prevention authority.

Mayor and City Council, City of Richmond, California

2012-03-I-CA-R3

Revise the Industrial Safety Ordinance (ISO) to require that Process Hazard Analyses include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards

intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R4

Revise the Industrial Safety Ordinance (ISO) to require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new processes, process unit rebuilds, significant process repairs, and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R5

Periodically monitor and confirm the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R1), so that needed mechanical integrity work at the Chevron Richmond Refinery is identified and completed in a timely way.

**Board of Supervisors
Contra Costa County, California**

2012-03-I-CA-R6

Add language to the Industrial Safety Ordinance (ISO) requiring that Process Hazard Analyses include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R7

Require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new processes, process unit rebuilds, significant process repairs and in the development of corrective actions from incident investigation recommendations.

**California State Legislature,
Governor of California**

2012-03-I-CA-R8

Revise the California Code of Regulations, Title 8, Section 5189, Process Safety Management of Acutely Hazardous Materials, to require improvements to mechanical integrity and process hazard analysis programs for all California oil refineries. These improvements shall include engaging a diverse team of qualified personnel to perform a documented damage mechanism hazard review. This review shall be an integral part of the Process Hazard Analysis cycle and shall be conducted on all PSM-covered process piping circuits and process equipment. The damage mechanism hazard review shall identify potential process damage mechanisms and consequences of failure, and shall ensure safeguards are in place to control hazards presented by those damage mechanisms. Require the analysis and incorporation of applicable industry best practices and inherently safety systems to the greatest extent feasible into this review.

2012-03-I-CA-R9

For all California oil refineries, identify and require the reporting of leading and lagging process safety indicators, such as the action item completion status of recommendations from damage mechanism hazard reviews, to state and local regulatory agencies that have chemical release prevention authority. These indicators shall be used to ensure that requirements described in 2012-03-I-CA-R8 are effective at improving mechanical integrity and process hazard analysis performance at all California oil refineries and preventing major chemical incidents.

2012-03-I-R-10

Establish a multi-agency process safety regulatory program for all California oil refineries to improve the public accountability, transparency, and performance of chemical accident prevention and mechanical integrity programs. This program shall:

1. Establish a system to report to the regulator the recognized methodologies, findings, conclusions and corrective actions related to refinery mechanical integrity inspection and repair work arising from Process Hazard Analyses, California oil refinery turnarounds and maintenance-related shutdowns;
2. Require reporting of information such as damage mechanism hazard reviews, notice of upcoming maintenance-related shutdowns, records related to proposed and completed mechanical integrity work lists, and the technical rationale for any delay in work proposed but not yet completed;

3. Establish procedures for greater workforce and public participation including the public reporting of information; and
4. Provide mechanisms for federal, state and local agency operational coordination, sharing of data (including safety indicator data), and joint accident prevention activities. The California Department of Industrial Relations will be designated as the lead state agency for establishing a repository of joint investigative and inspection data, coordinating the sharing of data and joint accident prevention activities.

2012-03-I-CA-R11

Require that Process Hazard Analyses required under California Code of Regulations, Title 8, Section 5189 Section (e) include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R12

Require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new process, process unit rebuilds, significant process repairs and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R13

Monitor and confirm the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R1 and 2012-03-I-CA-R2), so that needed mechanical integrity work at all California Chevron Refineries is identified and completed in a timely manner.

The U.S. Environmental Protection Agency

2012-03-I-CA-R14

Jointly plan and conduct inspections with Cal/OSHA, California EPA and other state and local regulatory agencies with chemical accident prevention responsibilities to monitor the effective implementation of the damage mechanism hazard review and disclosure requirements under 2012-03-I-CA-R8 and 9 above.

The Board of Supervisors, Contra Costa County, California, 2012-03-I-CA-R15;

The Mayor and City Council, City of Richmond, California, 2012-03-I-CA-R16;

The California Air Quality Management Divisions, 2012-03-I-CA-R17;

The U.S. Environmental Protection Agency, 2012-03-I-CA-R18; and

The California Environmental Protection Agency, 2012-03-I-CA-R19;

Participate in the joint regulatory program described in recommendation 2012-03-I-CA-R10. This participation shall include contributing relevant data to the repository of investigation and inspection data created by the California Department of Industrial Relations and jointly coordinating activities,

Additional Issues Currently Under Investigation

The following section highlights additional issues which the CSB has identified to date in its investigation of the Chevron Richmond Refinery fire and major hydrocarbon release that occurred on August 6, 2012. These issues relate to the ongoing CSB investigation of the management and regulation of health and safety at refineries. The CSB will present detailed findings and analyses in a final report on the incident, to be released later in 2013.

Regulatory Oversight

The CSB noted in its BP Texas City (BPTC) Final Investigation Report (issued in March 2007) the importance of having a well-resourced, competent regulator consisting of individuals with the necessary training, education, and experience to conduct planned comprehensive and robust inspections of facilities with the goal of preventing catastrophic accidents. In a 1992 compliance directiveⁱ the federal Occupational Safety and Health Administration (OSHA) stated that the primary enforcement model for the Process Safety Management of Highly Hazardous Chemicals (PSM) standard would be planned, comprehensive, and resource-intensive Program Quality Verification (PQV) inspections to help prevent catastrophic accidents.⁹⁶ However, the CSB report noted that for the 10-year period prior to the Texas City incident, federal OSHA had conducted no planned PQV inspections in oil refineries. Regular planned inspections appropriately emphasize the prevention of accidents that are potentially catastrophic. Issuing fines and prosecuting companies post-incident are not acceptable substitutes for prevention. As a result, CSB recommended in its report that OSHA strengthen the planned enforcement of the OSHA Process Safety Management (PSM) standard by developing more highly trained and experienced inspectors to conduct more comprehensive inspections similar to those under OSHA's PQV program at facilities presenting the greatest risk of a catastrophic accident.

Spurred in part by the CSB's recommendations, OSHA issued the Petroleum Refinery Process Safety Management National Emphasis Program (NEP) on June 7, 2007.ⁱⁱ The NEP was a federal program that established guidelines for inspecting petroleum refineries to assure compliance with the PSM standard, 29 CFR §1910.119.⁹⁷ Unlike the PQV approach to inspections, which "employs a broad, open-ended inspection strategy and uses a more global approach to identify compliance deficiencies...",⁹⁸ the NEP "provide[d] a specific tool to evaluate compliance with the [PSM] standard...[which] identifies a particular set of requirements from the PSM standard from which CSHOs [Compliance Safety and Health Officers] are to review documents, interview employees, and verify implementation for specific processes, equipment, and procedures."⁹⁹ While the CSB called for an ongoing comprehensive inspection

ⁱ Compliance directives are the main method OSHA uses to communicate plans, inspection methods, and compliance expectations to their Compliance Safety and Health Officers (CSHOs) for enforcing a new regulation.

ⁱⁱ Originally Directive Number CPL 03-00-004. Extended August 18, 2009 as Directive Number CPL 03-00-010 to allow more time to complete NEP inspections under the original CPL 03-00-004.

program, inspections being conducted pursuant to the NEP were terminated in 2011. The CSB recommendation to OSHA remains Open.ⁱ

OSHA State Plan Statesⁱⁱ were strongly encouraged but not required to implement the NEP. California's Division of Occupational Safety and Health (Cal/OSHA) did not adopt the NEP "because of its dedicated PSM Unit."¹⁰⁰ Cal/OSHA informed the CSB that federal OSHA approved this decision in 2007. In lieu of conducting NEP inspections, Cal/OSHA's PSM has conducted and continues to conduct a full range of programmed, accident, complaint, and referral inspections of PSM-covered facilities in the state of California pursuant to the California Labor Code, Title 8 regulations, and Cal/OSHA's Policy and Procedures (P&P) Manual C-17 "Process Safety Management,"ⁱⁱⁱ to ensure these facilities are complying with PSM requirements.

Between 2006 and August 6, 2012, Cal/OSHA conducted three planned inspections of the Chevron Richmond facility, totaling only 150 inspector hours of effort. None of these inspections resulted in citations or fines. In contrast, according to statistics provided by OSHA, federal NEP refinery inspections conducted between 2007 and the end of 2011 lasted roughly 1,000 inspector hours each and resulted in an average of 11.2 violations and \$76,821 in penalties per inspection. OSHA noted that hours spent on a typical federal refinery NEP inspection were 40 times greater than the average OSHA inspection. These numbers indicate a major disparity in thoroughness and comprehensiveness between the planned inspections conducted by Cal/OSHA and the NEP inspections conducted by OSHA and other OSHA State Plan States.

The safety case is a rigorous prescriptive and goal-setting regulatory regime that is highlighted by its adaptability and requirements for continuous improvements in risk reduction for high hazard industrial facilities. The approach is used widely overseas but not used currently for U.S. process industries. The CSB is currently examining whether the implementation of the safety case regime could be a more effective regulatory tool for Cal/OSHA in its effort to ensure that California refineries are identifying and controlling hazards and ultimately driving risk to as low as reasonably practicable (ALARP). Utilizing the safety case requires effective implementation by an independent, competent, well-funded regulator. Experience and competence of the regulator in technical areas such as chemical engineering, human factors, and process safety are necessary to provide effective auditing and regulatory oversight for prevention. To ensure effective implementation of the safety case, industry standards and guidelines must be rigorous and up-to-date as well. The CSB notes that relevant and applicable industry standards and guidelines – such as API RP 939-C – currently contain voluntary and permissive language. The CSB will

ⁱ Open - Awaiting Response or Evaluation/Approval of Response (O - ARE/AR) - The recipient has not submitted a substantive response, or the evaluation by CSB staff of a response is pending, or the Board has not yet acted on staff recommendation of status.

ⁱⁱ Section 18 of the Occupational Safety and Health Act of 1970 encourages States to develop and operate their own job safety and health programs, referred to informally as an OSHA State Plan. OSHA approves and monitors State plans and provides up to 50 percent of an approved plan's operating costs.

ⁱⁱⁱ Issued June 6, 1994. Revised August 1, 1994 and May 19, 2007.

be examining the need for more effective good practice standards and guidelines containing the necessary requirements to prevent catastrophic accidents.

In addition to the issues discussed above, the CSB will also be examining the need for and effectiveness of the reporting and use by the regulator of leading and lagging process safety indicators; workforce and stakeholder involvement in regulatory oversight of refineries; and the thoroughness of Contra Costa County's safety auditing of the Chevron facility.

Emergency Planning and Reporting

According to information provided by Contra Costa Emergency Medical Services, 15,213 individuals sought emergency medical attention between August 6 and August 23, 2012, due to the Chevron refinery major hydrocarbon release and fire.

CSB Investigation Team members visited local hospitals the week of the incident to better understand the impact on the surrounding community. Officials at Doctor's Medical Center (DMC) in San Pablo, California, informed the CSB that in the days following the incident they were inundated with emergency room visits and found it difficult to handle the influx due to a lack of funding and staffing. Officials at both DMC and Kaiser Permanente Hospital (KP) in Richmond told the CSB that they lacked specific knowledge of the chemicals released as a result of the incident, complicating efforts to evaluate and treat individuals.

The California Code of Regulations (CCR) requires that owners and operators of hazardous waste facilities make "arrangements to familiarize local hospitals with the properties of hazardous waste handled at the facility and the types of injuries or illnesses which could result from fires, explosions, or releases at the facility."¹⁰¹ The CSB is currently evaluating ways to ensure that hospitals have the information necessary to properly evaluate and treat individuals that may be exposed to releases from facilities in Contra Costa County.

Following the incident, Contra Costa County's Community Warning System (CWS) notified the surrounding community of a hazardous material incident and ordered a Shelter-in-Place (SIP). The CWS uses sirens, the news media, and phone calls to residents in order to initiate the SIP. Contra Costa County issued the SIP on August 6, 2012, at 6:38 pm for the cities of Richmond, San Pablo, and North Richmond, California, and lifted the SIP later that evening at 11:12 pm. However, the CSB has learned that some phone calls notifying residents of the SIP did not occur until over four hours after the release.

It is essential that responders, community residents and hospitals in the areas surrounding industrial facilities be aware of what hazardous materials exist at these facilities, what specific chemicals are released into the community in the event of an incident, and what is known about the potential acute and chronic health impacts. The CSB will be analyzing ways to strengthen current regulations and policies to

ensure there is proper emergency planning and reporting for industrial facilities in Contra Costa County and the State of California.

Emergency Response

OSHA provides guidance on emergency response in its *Hazardous Waste Operations and Emergency Response* standard, known as HAZWOPER, under 29 CFR §1910.120 (p) and (q). Under 29 CFR §1910.120(q)(6), the HAZWOPER standard contains requirements for training and qualification of all individuals involved in emergency response related to their roles and responsibilities.

Good safety practice dictates that individuals responding to emergencies should have the technical knowledge to give input into shutdown decisions, set up an incident command structure, establish boundary limits, and evaluate the “hot zone.” Access to the hot zone must be strictly limited to personnel with higher degrees of specific training, experience, and appropriate personal protective equipment—all others must be removed to a safe location away from chemical hazards. Hot zone boundaries must be established to anticipate the possible escalation of releases and the positioning of firefighting equipment such as fire trucks.

The CSB will be looking at the sufficiency of regulatory requirements and guidance, industry standards and good practices in addition to evaluating emergency response decision-making such as unit shutdown, prohibitions on access to hazardous areas and the training and qualifications of all individuals who responded to the leak and subsequent piping rupture, major hydrocarbon release and fire and whether improved requirements and guidance are needed in this area.

Safety Culture

The Center for Chemical Process Safety (CCPS) defines process safety culture as the “combination of group values and behaviors that determines the manner in which process safety is managed.”¹⁰² As the CSB noted in its BP Texas City Report, safety culture can be influenced by management changes, historical events, and economic pressures. After reviewing evidence and decisions made relating to materials of construction and mechanical integrity within the crude unit at the Chevron refinery, as well as the response to the leak on August 6, 2012, the CSB has determined that issues relating to safety culture are relevant to this incident. The CSB will examine the Chevron Richmond Refinery’s approach to safety, its safety culture and any organizational deficiencies, to determine how to best prevent future incidents.

The CSB notes that on August 6, 2012, following discovery of the leak on the 4-sidecut piping, Chevron hoped to forestall a shutdown by installing a leak repair clamp.ⁱ Chevron’s mechanical integrity

ⁱ Chevron’s leak repair clamp vendor was called out to the scene of the leak to help determine potential clamping options.

management system has not been fully successful in detecting and replacing deteriorated piping components prior to failure, resulting in the company's frequent use of leak repair clampsⁱ to externally stop process fluid leaks. Chevron's reliance on such clamps to mitigate process piping component leaks identifies serious questions about its mechanical integrity program. The CSB determined that Chevron has more than 100 clamps on hydrocarbon and other process piping components at the Richmond refinery. The leak repair clamp is typically relied upon to prevent further leaking until the next unit turnaround, when the deteriorated piping component can be repaired. However, Cal/OSHA citations following the August 6, 2012, fire in the crude unit identified that Chevron has not always replaced these clamps during unit turnarounds and these devices then remain in service significantly longer than originally intended. The CSB determined that Chevron has leak repair clamps in place on piping components containing hazardous flammable process fluids including applications where the process material is above the autoignition temperature. Some of these leak repair clamp applications are in locations where a permanent repair would not have required a unit shutdown. The CSB will further evaluate the frequent use of leak repair clamps by Chevron and the potential that the deviance of a weak mechanical integrity management system has been normalized.ⁱⁱ

ⁱ Leak repair clamps are mechanical devices designed and installed to stop a leak from a piping component such as piping, valves, flanges, and instrumentation. These devices are typically intended to provide a temporary repair while a process continues operation until a plant shutdown takes place and a permanent repair can be made.

ⁱⁱ Normalization of deviance is a long-term phenomenon in which individuals or work teams gradually accept a lower standard of performance until the lower standard becomes the norm. It is typically the result of conditions slowly changing and eroding over time. *See* Center for Chemical Process Safety (CCPS), *Recognizing Catastrophic Incident Warning Signs in the Process Industries*, Page 4, 2012.

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