Naphtha Hydrotreater
E-6600E Failure

12:35 a.m.

April 2, 2010

Anacortes Refinery, Washington

TOP Investigation Team Report

Incident Tracking # 100402OPR038

Executive Summary

Summary of the Incident

On April 2, 2010, at approximately 12:35 a.m., a heat exchanger, E-6600E, in the Naphtha Hydrotreater unit at the Tesoro Anacortes Refinery ruptured, releasing a mix of hydrogen and naphtha. The dispersed material auto-ignited, causing an explosion and fire which fatally injured seven employees who were in the area while a parallel bank of E-6600s were being placed in service. Following the incident and subsequent shutdown of the NHT unit, the refinery was shut down for over six months. New heat exchangers were designed and rebuilt. Additionally, other equipment was repaired or replaced.

Analysis of post-failure laboratory data showed advanced stages of high temperature hydrogen attack near the fracture surfaces in E-6600E.

Summary of Contributing Factors

1. Seven personnel were in the area at the time of the failure.

2. At times over the life of E-6600E, sufficient hydrogen partial pressure and temperature existed for high temperature hydrogen attack (HTHA).

3. E-6600E shell was fabricated of carbon steel and was not post-weld-heat-treated.

4. High temperature hydrogen attack (HTHA) damage was not detected prior to failure.

5. Stress existed in the E-6600s sufficient to cause rupture of the high temperature hydrogen attack (HTHA) damaged shell.

Table of Contents

Investigation

Investigation Team

Consistent with Tesoro Anacortes Safety Regulations, a team was assembled to investigate the Naphtha Hydrotreater Incident on April 2, 2010 at 9:00 a.m. Investigation team members* contributing to this report were:

John Nowakowski
Hourly Representative
TOP Coordinator, Tesoro Anacortes Refinery

Rick Dowrey
Zone A Operations Training Supervisor, Tesoro Anacortes Refinery

Allen Meyers
Inspection Supervisor, Tesoro Alaska Company

Gerald Pineda
TOP Investigator - Staff Representative
Senior Health and Safety Professional, Tesoro San Antonio

John Smith
Pressure Equipment Engineer, Tesoro Los Angeles Refinery

Robert Vogel
Hourly Representative
TOP Coordinator, Tesoro Mandan Refinery

Tom Weber
Technical Services Manager, Tesoro Kapolei Refinery

Resources

Sam McFadden
Metallurgist, Anamet, inc.

**TOP investigation team biographies can be found in Appendix C.*

Expectations for the Investigation Team

The TOP investigation team's charter (see Appendix B) lays out the expectations for the investigation team as follows:

1. Develop the sequence of events (timeline).

2. Use the TOP incident investigation methodology and tools.

3. Identify contributing factors to prevent this or similar incidents.

4. Develop corrective actions that directly address the causes of this incident. Corrective actions that address Items of Note should be kept separate from direct contributing factor corrective actions.

5. Produce clear documentation of the investigation.

Background

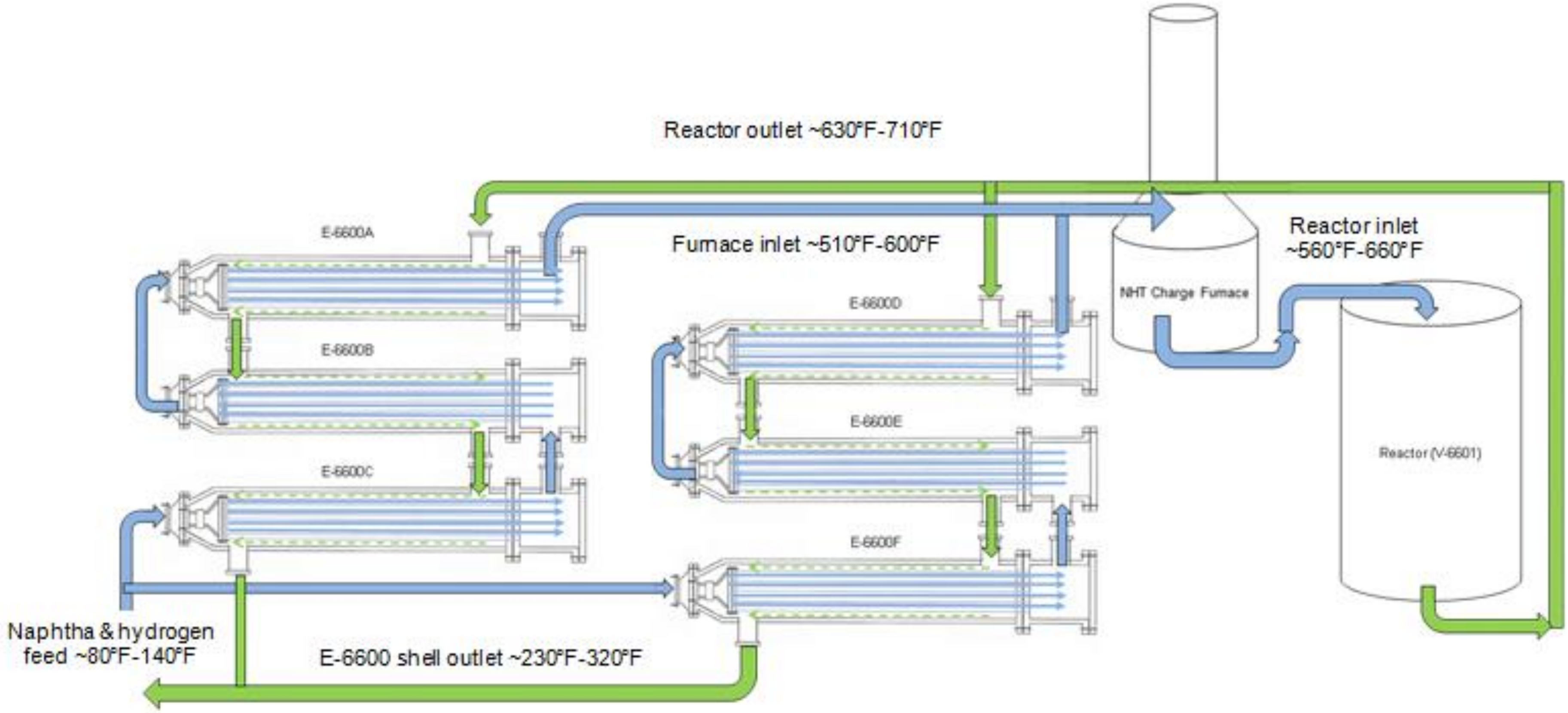
The Refinery Process

Tesoro's Anacortes Refinery has a total crude-oil processing capacity of 120,000 barrels per day (bpd). The refinery produces gasoline, jet fuel and diesel for markets in Washington and Oregon, and also manufactures fuel oil, liquefied petroleum gas and asphalt. It receives crude oil feedstock via pipeline from Canada and by tanker from Alaska and foreign sources.

Crude oil is separated into several unfinished products in the Crude Distillation unit. Subsequent steps in the refining process convert the unfinished products into finished gasoline, jet fuel, and diesel. The Naphtha Hydrotreater (NHT) is part of the process for converting naphtha, a light fraction of crude oil, into gasoline.

The NHT removes sulfur and nitrogen from the raw naphtha before the naphtha goes through another process to produce a high octane gasoline component. The removal of sulfur and nitrogen requires the naphtha to be heated to 630-700°F at 600 psig (pounds per square inch pressure) and mixed with hydrogen. After reaction, the naphtha and hydrogen (effluent) are cooled in a series of feed/effluent heat exchangers (E-6600s) in which the reactor effluent is used to pre-heat the incoming feed to the unit.

Figure 1: The Naphtha Hydrotreater (NHT) Process

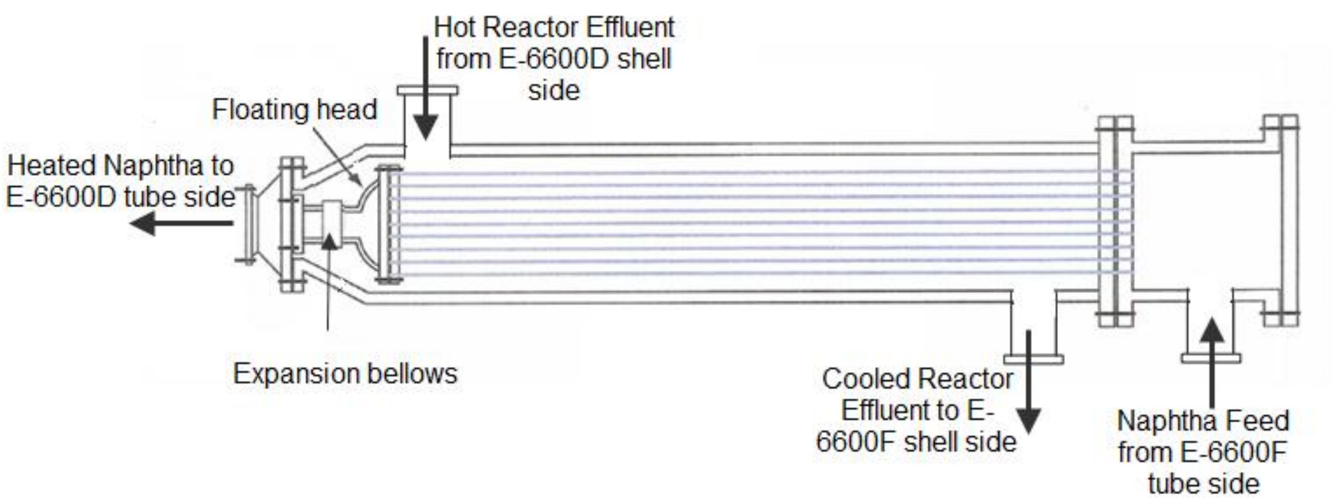


Feed/Effluent Exchangers (E-6600s)

The exchanger system consisted of two parallel banks of three exchangers (E-6600A/B/C, and E-6600 D/E/F) designed for maintenance while the process continued to operate. E-6600s are shell and tube heat exchangers. Shell and tube heat exchangers consist of a series of tubes within the exchanger shell. In this system, the tubes contain the incoming feed that must be heated. The hot reactor effluent runs over the tubes on the shell side and is cooled by the feed.

The feed/effluent exchangers were installed at the site in 1971 as part of the original construction of the Naphtha Hydrotreater (NHT) unit. In 1972, the NHT was rated at 24,800 barrels per day (bpd), which was the original design. Subsequent changes brought the NHT to its current capacity of 42,000 bpd. At the time of the rupture of E-6600E, the parallel bank of exchangers E-6600A/B/C were in the final stages of being brought back online after cleaning. These feed/effluent exchangers will be referred to as E-6600s on subsequent pages.

Figure 2: Feed/Effluent Exchanger E-6600E



High Temperature Hydrogen Attack

High temperature hydrogen attack (HTHA) can occur when steel is exposed to atomic hydrogen (H) at elevated temperatures and pressures. Under these conditions, some hydrogen molecules (H_2) break apart into individual hydrogen atoms (H). Individual hydrogen atoms can diffuse into steel at high temperatures and react with carbon (C) in the steel, forming methane (CH_4). Because methane molecules are too large to diffuse through steel, the methane accumulates, forming extremely high pressure bubbles which connect to create micro-fissures at grain boundaries. In advanced stages of HTHA, fields of micro-fissures connect to form cracks. The chemical combination of carbon and hydrogen results in decarburization of the steel. Decarburization is the loss of carbon from the steel, reducing the strength of the metal.

Industry codes and standards rely on data compiled in the American Petroleum Institute (API) Recommended Practice 941 to determine combinations of hydrogen partial pressures and temperatures for which HTHA is not expected to occur (reference 1). The data are summarized in curves, often called "Nelson curves", named after a metallurgist who conducted early studies in the subject. The Nelson curves were developed from industry experience and have been adjusted over time to reflect new reports of HTHA. For a given type of steel, combinations of hydrogen partial pressure and temperature below the Nelson curve are considered to be safe with respect to HTHA.

When discussing HTHA, the pressure of hydrogen in the system is described in terms of partial pressure. Partial pressure is the pressure of the system, multiplied by the percent of hydrogen in the vapor. For instance, if a gas at 400 psia contains 25% hydrogen, the hydrogen partial pressure is 100 psia.

The most definitive diagnosis of HTHA is based upon microstructural evidence of methane bubbles, micro-fissures, and decarburization as observed under microscopic examination.

Recently, there have been several industry reports of HTHA cracking in carbon steel operating below the Nelson curve. A paper presented in July 2010 at the ASME conference discussed HTHA-like piping failures and proposed maintaining a safety margin of 50°F/50 psia below the carbon steel Nelson curve (reference 2). At a May 2011 API meeting, presentations of HTHA failures in carbon steel were made to the API 941 subcommittee by three oil companies in addition to Tesoro (reference 3). The cases presented contained a number of common features:

- The metallurgy was carbon steel.
- The welds were not post-weld-heat-treated.
- The damage was characterized by micro-fissuring along the heat affected zones of the welds.

The damage was not detected prior to failure, but was identified by laboratory analysis after failure.

Figure 3: Nelson Curve

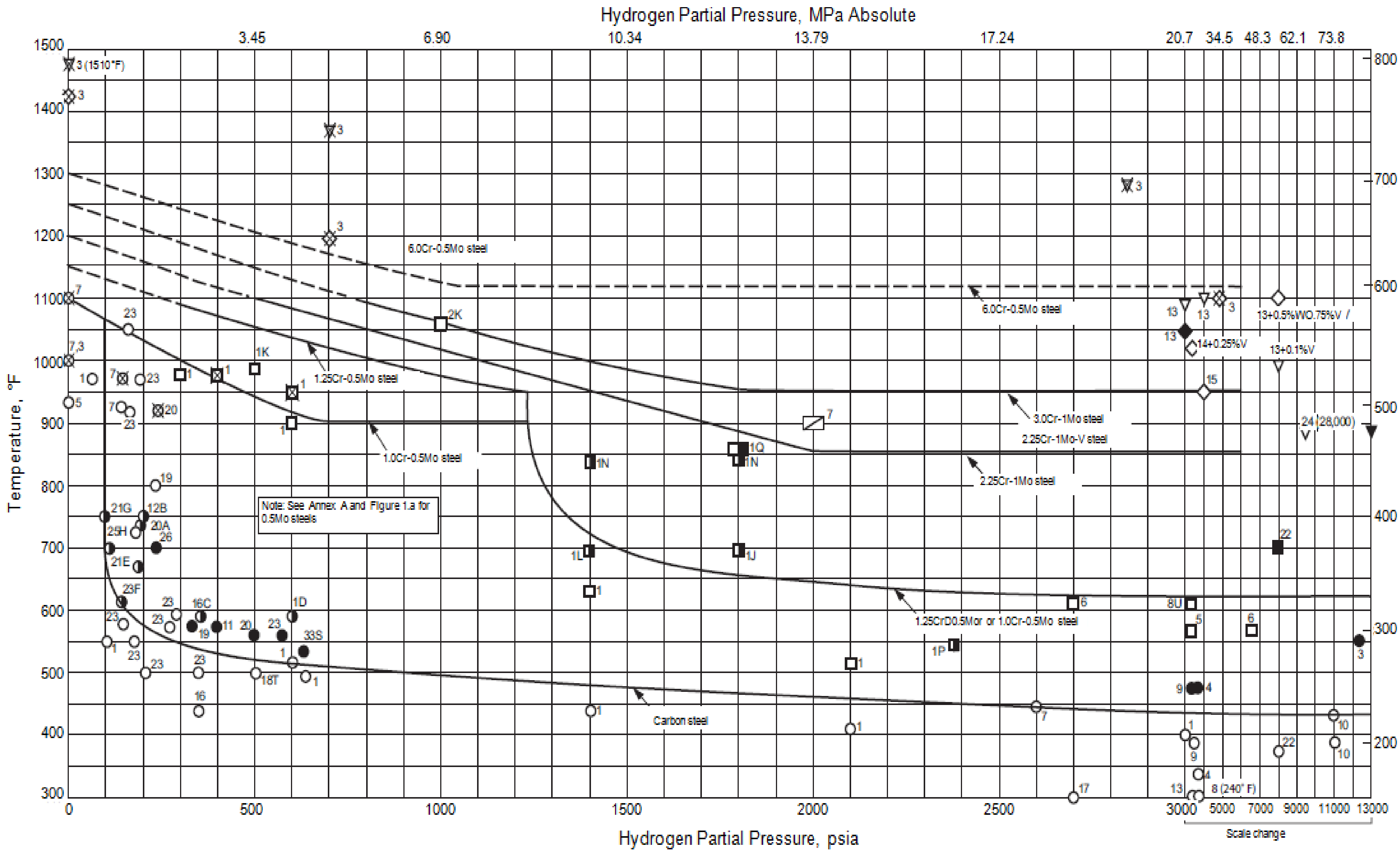
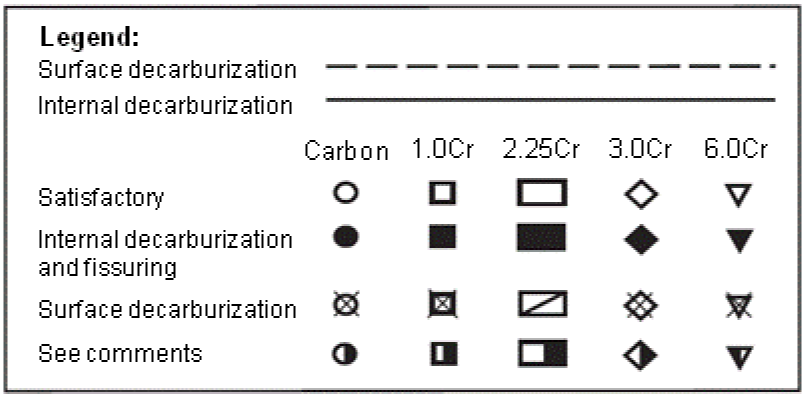


Figure 3: Nelson Curve (continued)



Notes:

1. The limits described by these curves are based on service experience originally collected by G.A. Nelson and on additional information gathered by or made available to API.

2. Austenitic stainless steels are generally not decarburized in hydrogen at any temperature or hydrogen pressure.

3. The limits described by these curves are based on experience with case steel as well as annealed and normalized steels at stress levels defined by Section VIII, Division I, of the ASME Code. See 5.2 and 5.3 in text for additional information.

4. Several failures of 1-1/4Cr-1Mo steel have been reported in the satisfactory region. See Annex B for details.

5. The inclusion of the 2.25Cr-1Mo-V class of steels is based on 10,000+hr laboratory tests where these alloys were at least equal to the 3Cr-1Mo steel. See Reference 22 listed in the bibliography.

“Operating Limits for Steels in Hydrogen Service to Avoid Decarburization and Fissuring” as published in API Recommended Practice 941, Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants, 7th Edition (2008). (Figure 1, reference 1).

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Incident

Description of Event

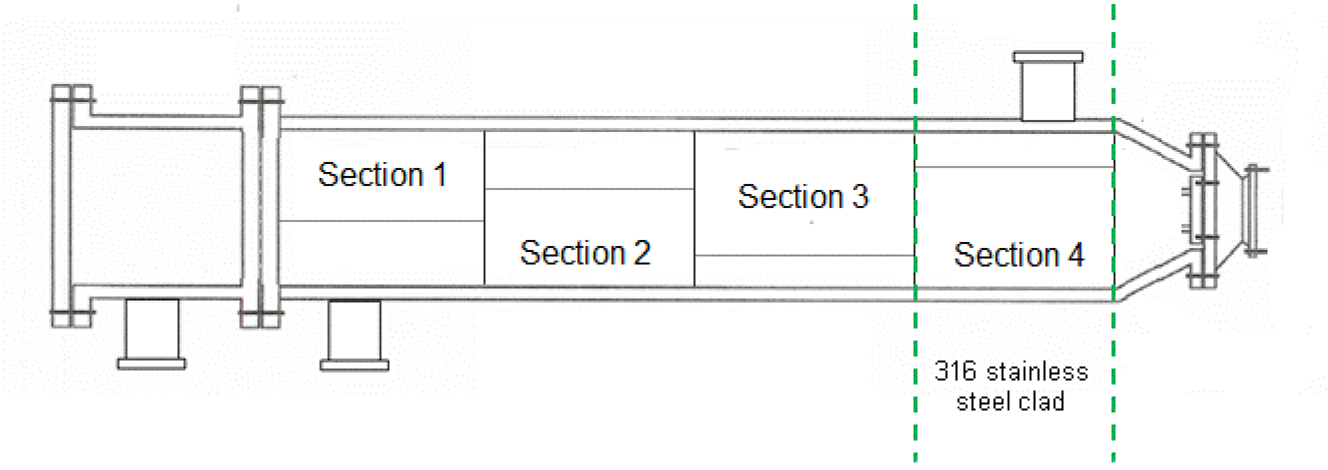
On April 2, 2010, at approximately 12:35 a.m., Exchanger E-6600E at the Anacortes site ruptured, releasing a mixture of hydrogen and naphtha (reactor effluent). The dispersed effluent auto-ignited, causing an explosion and fire that fatally injured seven employees who were in the area. Following the incident, the refinery was shut down for over six months and new exchangers were designed and constructed. Additionally, other rebuild activities were conducted in order to bring the Naphtha Hydrotreater (NHT) unit back into operation.

Photos of Failed Exchanger

Photo 1: Sections 1-3 [from left] showing failure locations

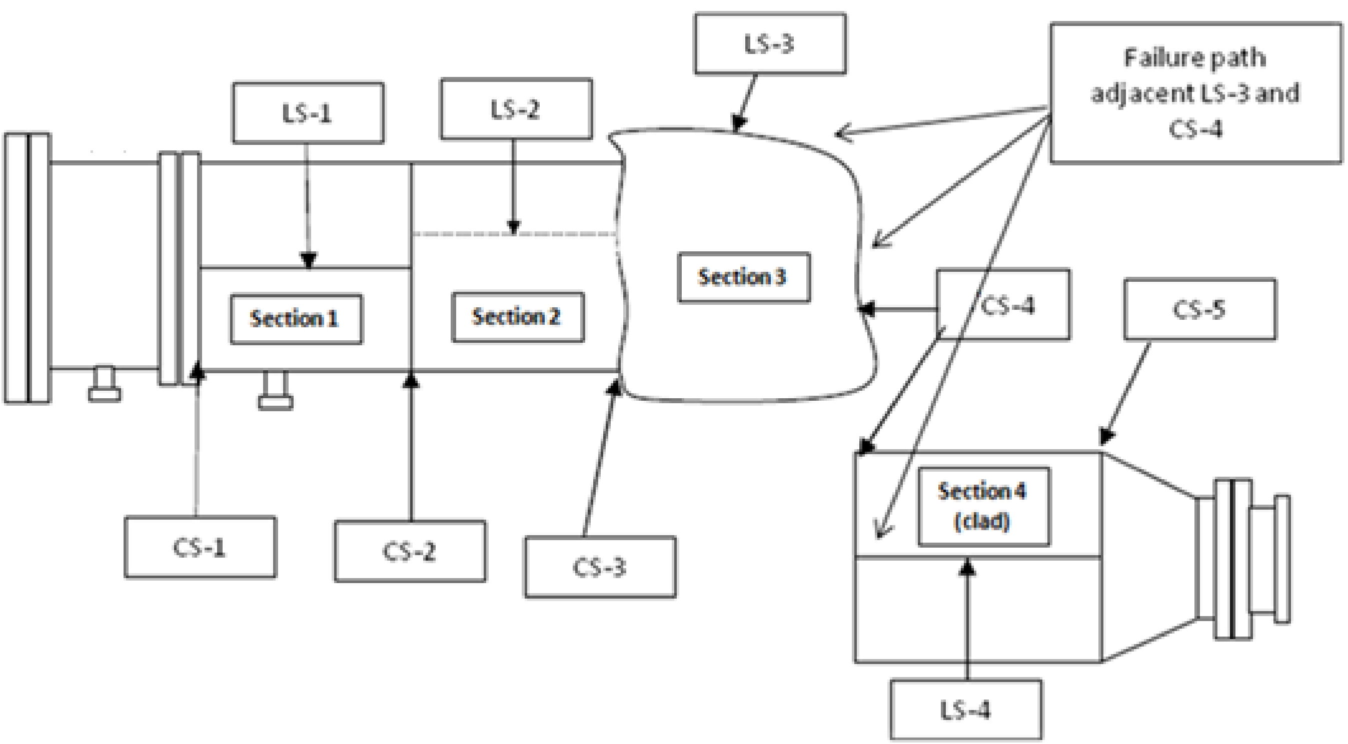
Photo 2: Section 4, shown separated from shell sections 1-3

Figure 4: E-6600E sections



(Pre-incident view of E-6600E)

Figure 5: E-6600E Weld Seams and Failure Locations



The exchanger ruptured adjacent to longitudinal weld seam LS-3 and circumferential weld seam CS-4 due to damage from advanced high temperature hydrogen attack (HTHA).

Anacortes Naphtha Hydrotreater (HT) Unit Timeline

1955	• Shell Oil Company built an oil refinery at Anacortes, WA.
1971-1972	• Naphtha Hydrotreater (NHT) unit constructed. • Unit online and rated for 24,800 barrels per day (bpd).
1982	• E-6600A and D re-rated for maximum temperature range (715-750 F).
Jan 1990	• Naphtha Hydrotreater Corrosion Review issued.
Dec 1993	• Naphtha Hydrotreater Corrosion Review updated.
1995	• Added H_2 Recycle Gas Compressor J-6655.
1998	• Tesoro Corporation purchased the stock of Shell Anacortes Refining Company from an affiliate of Shell Oil Company.
1999	• Shell Westhollow issued the Naphtha Hydrotreater Corrosion Control Document.
2003	• Five year review of the Shell Westhollow Naphtha Hydrotreater Corrosion Control Document.
2005	• NHT 42,000 bpd capacity achieved as a result of incremental projects completed since unit placed in service.
Oct 2008	• LR Capstone issued Naphtha Hydrotreater Corrosion Review.
Aug 2009	• E-6600s cleaned online.
April 2010	• Refer to incident timeline for event details (below).

E-6600E Incident Timeline

3/24/10	• Night shift initiated E-6600A/B/C "Lock Out-Tag Out" (energy isolation) and other preparation for upcoming work.
3/28/10	• 05:00 NHT feed reduction initiated for removing E-6600A/B/C exchanger bank for cleaning. • 08:05 E-6600A/B/C taken offline.
3/28/10	• 10:07 E-6600A/B/C depressured.
3/28/10	• 12:01 Purge step initiated.
3/29/10	• 07:04 E-6600A/B/C drained, and blind installation process started.
3/30/10	• Hydro-blast cleaning of the tube side of exchangers. • Visual inspection of the exchangers for cleanliness .
3/31/10	• E-6600A/B/C re-assembled.
4/1/10	• 14:47 Initiated start up procedure for the E-6600A/B/Cexchangers.
4/1/10	• Called pipefitters to connect temporary warm up lines. • 20:15 Started air free purge and pressure check of the exchangers with nitrogen.
4/1/10	• 23:00 Tube and shell side open to process. • One inch warm up line open to process.
4/2/10	• 00:09 Start opening final block valves, per procedure, to place E-6600A/B/C exchanger bank online. • Opening of shell and tube block valves alternately to maintain furnace inlet temperature.
4/2/10	• The final isolation valve was open 40% to 60%, indicating full process flow; E-6600A/B/C were up to operating temperatures and pressures. (Valve position discovered post-incident)
4/2/10	• 00:35 E-6600E ruptured, resulting in a release, fire, explosion and fatal injury of seven workers.
4/2/10	• 00:38 Emergency alarm sounded.

Data Collection & Analysis

Description of Inspection & Testing

Protocols for evidence preservation, site control, field inspections, and laboratory testing/evaluation were agreed to between the Division of Occupational Safety and Health of the Washington State Department of Labor and Industries (DOSH), the U.S. Chemical Safety and Hazard Investigation Board (CSB), and the Tesoro Refining and Marketing Company (Tesoro), referred to here as the directing parties. These protocols conformed to accepted industry standards applied to accident investigation and failure analysis. Execution of the inspection and testing outlined in the protocols was performed by third parties under the direction of representatives from DOSH, CSB, and Tesoro.

BETA Laboratory was selected by DOSH, CSB and Tesoro to conduct laboratory tests on the E-6600B/E exchangers, pursuant to the written protocols. As a neutral laboratory, BETA Laboratory did not provide interpretation, but instead presented the test results in reports issued simultaneously to Tesoro and the agencies. The TOP investigation team was provided with a copy of each report issued.

The TOP investigation team did not participate in setting the inspection protocol, the field inspections or laboratory testing. In March 2011 and again in May 2011, a representative from Exponent retained by Tesoro and present for much of the BETA Laboratory testing gave a short presentation to the team with a summary of results and conclusions (references 4 & 5). The following interpretation of data from testing of E-6600B/E is that of the independent metallurgist retained by the TOP investigation team.

Surveys of the damaged Naphtha Hydrotreater (NHT) immediately after the incident identified a rupture of the E-6600E shell as the physical origin of the fire and resulting fatalities. On-site field visual inspection, ultrasonic testing, and magnetic particle testing documented the post-incident condition (reference 6). Ultrasonic testing of E-6600E detected cracks in the shell weld heat affected zones (HAZ) adjacent to the fractures and at other locations in the HAZ of weld seams LS-3, CS-3, LS-2/CS-3 tee, and CS-4 (reference 6). Cracks in E-6600E were visible in photographs produced in the BETA Laboratory report (reference 7) adjacent to the fracture surfaces located at weld seams LS-3 and CS-3. Subsequent comparison with the parallel exchanger E-6600B shell led the TOP investigation team to determine that these cracks likely were not detectable by visual inspection prior to the event.

In June 2010, E-6600E was shipped to the Halvorsen Company warehouse in Ohio, in preparation for third party laboratory testing. After a receipt inspection, regions of interest were identified by the directing parties, sectioned from the shell, and taken to BETA Laboratory. Wet fluorescent magnetic particle testing (WFMT) and fluorescent dye penetrant testing (FPT) were performed on the samples sectioned from E-6600E. The FPT and WFMT laboratory results were in agreement with results of similar field testing prior to shipment.

Metallographic specimens were prepared from locations of interest in both fractured and intact regions of the samples from E-6600E. Metallography in the as-polished and etched condition revealed clear evidence of HTHA in the form of micro-fissures and local decarburization within the heat affected zones (HAZ) of weld seams CS-4, LS-3, CS-3, and LS-2 (see Figure 5). Evidence of high temperature hydrogen attack (HTHA) directly adjacent to the inside surface breaking cracks indicated that they were caused by joining of HTHA micro-fissures, which indicated advanced stages of HTHA. Examples of HTHA evidence in E-6600E are shown in Figure 6.

Fracture surfaces from E-6600E were covered with thick oxide that likely formed during the fire. After the as-received condition had been documented, fracture surface specimens were cleaned for examination using scanning electron microscopy (SEM). Evidence of ductile fracture was observed in some of the SEM micrographs. However, it is likely that the extent of damage to key features on the surfaces that could provide evidence of the fracture initiation sites and fracture directions had been destroyed by the fire. Further efforts at fractography were not pursued, presumably due to the loss of information caused by oxidation.

Post-incident WFMT and ultrasonic inspections of E-6600E prior to lab work detected cracking but did not identify the damage as HTHA. HTHA was identified after sections of the E-6600E shell was cut out of the exchanger and inspected in cross section under optical and scanning electron microscopes (references 6 & 8). Laboratory metallographic analysis identified HTHA in E-6600E.

The TOP investigation team did not perform an industry-standard external or internal visual inspection of E-6600E post-incident; instead, the team interviewed others who performed such visual inspections (references 9 & 10).

Figure 6: CS-4 Specimen from E-6600E

FirstEnergy

BETA Laboratory
ISO 9001 Registered

METALLURGICAL LABORATORY

BETA LAB NO. M10198- CS4-02	TESORO REFINING AND MARKETING COMPANY ANACORTES REFINERY 10200 W. MARCH POINT ROAD T91WA4428 ANACORTES, WA 98221	CUSTOMER P.O. NO.: 4501667904
PART: 6600-E HEAT EXCHANGER CS4 PART 19 & 20		DATE: AUGUST 5, 2010
		PAGE 26 OF 57

LABORATORY REPORT-CS4

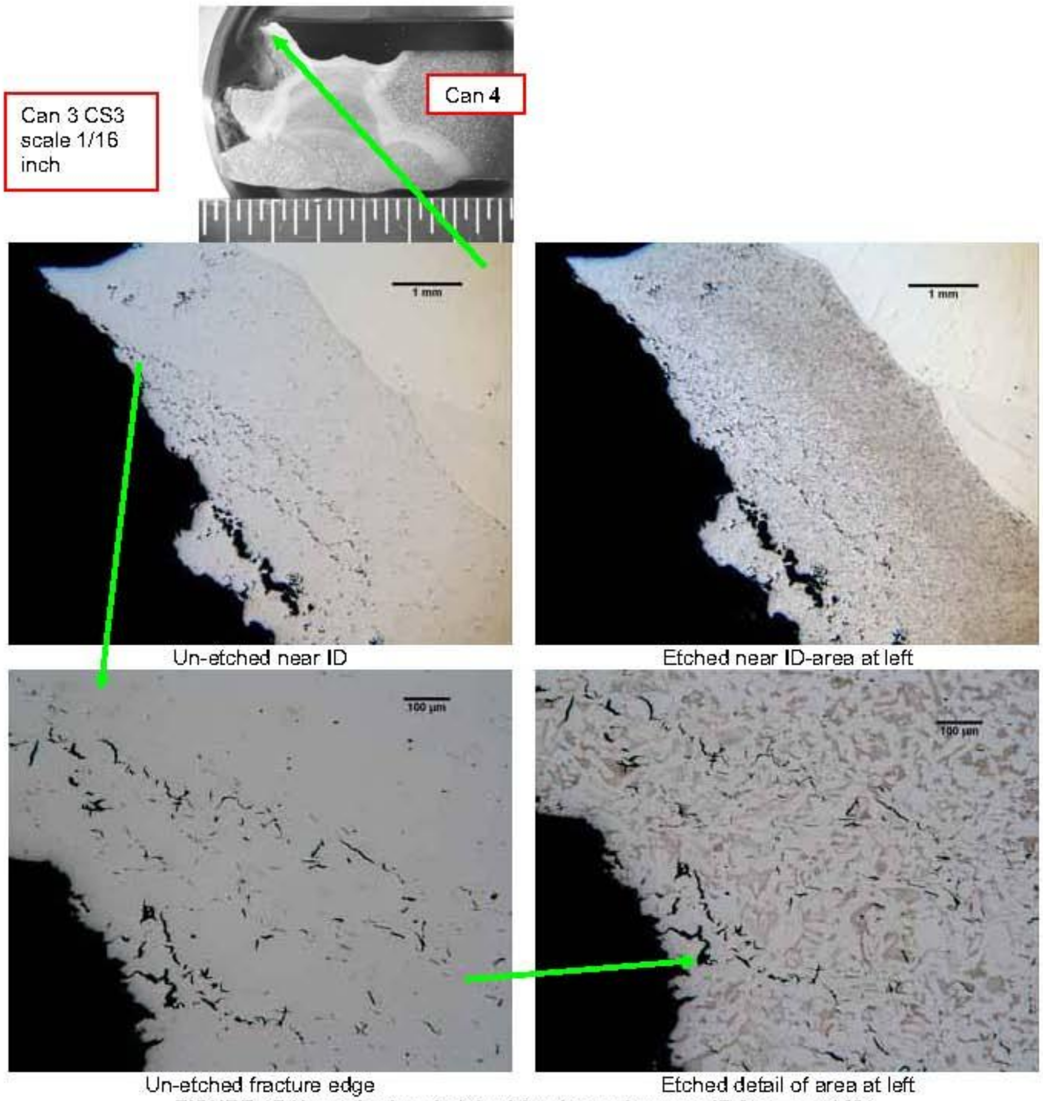


FIGURE 17 Un-etched and etched fracture edge near ID for mount M1

6670 Beta Dr., Mayfield Village, OH 44143, Tel: (440) 604-9843, Fax: (440) 604-9800, e-mail: jblough@firstenergycorp.com

HTHA micro-fissures and decarburization were observed adjacent to the fracture surface in the heat affected zone (HAZ) of weld seam CS-4 of E-6600E (reference 7).

Quantitative chemical analysis was performed in the laboratory on specimens from the E-6600E shell. The results indicated that the shell base metal and cladding met the chemical composition requirements specified in the design. Weld metal compositions were consistent with those used to join carbon steels.

Mechanical testing in the form of Rockwell hardness, Vicker's 500 g load microhardness, Charpy impact, bending, and tensile was performed on specimens from unclad sections 1-3 (see Figure 4). Although E-6600E had been exposed to high temperatures during the fire, the measured properties of the shell were consistent with the requirements of materials specified in the design.

In August 2010, a second reactor feed/effluent exchanger E-6600B was shipped to the Halvorsen Company warehouse in Ohio. Its position relative to the failed exchanger E-6600E is illustrated in Diagram 1. This exchanger was nominally identical to E-6600E in construction and service history and, therefore, provided an opportunity to view it as representative of E-6600E just prior to the incident. Although E-6600B had not ruptured, it was exposed to the fire that resulted from the E-6600E rupture. Testing and inspection protocols equivalent to those agreed upon for E-6600E were adopted for E-6600B. The results presented in the BETA Laboratory reports indicated that E-6600B was in a microstructural condition similar to that of E-6600E, including HTHA in the heat affected zones (HAZs) from the CS-4 to the LS-2 weld seams, as shown in Figure 7.

The TOP investigation team did not perform an industry-standard external or internal visual inspection of E-6600B post-incident; instead, the team interviewed others who performed such visual inspections (references 9 & 10).

Figure 7: C-4 Heat Affected Zone Specimen from E-6600B

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ISO 9001 Registered | METALLURGICAL LABORATORY

BETA LAB NO.M10329, TESORO EXCHANGER E6600B EXAMINATION DATA	TESORO REFINING AND MARKETING COMPANY ANACORTES REFINERY 10200 W. MARCH POINT ROAD T91WA4428 ANACORTES, WA 98221	CUSTOMER P.O. NO.: 4501667904, CHANGE ORDER #1
PARTS: 6600B HEAT EXCHANGER, PARTS 1B, 2B, AND 3B		DATE: DECEMBER 27, 2010
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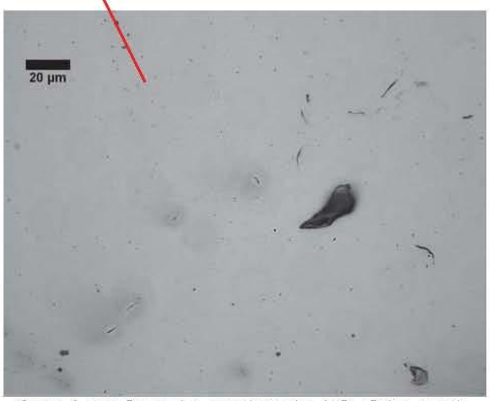
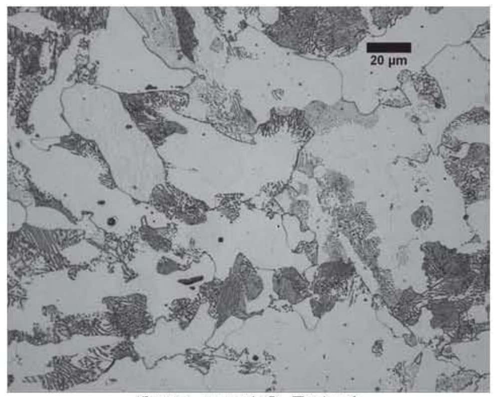
LABORATORY REPORT

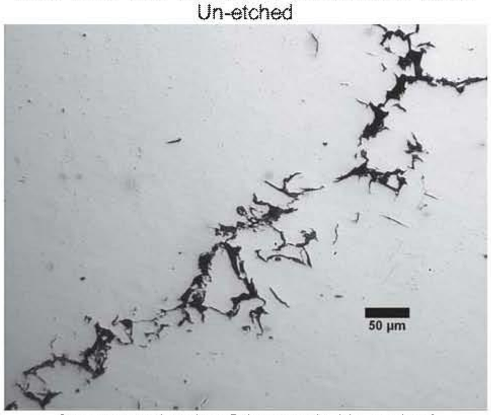
PART 1B, WELD CW4, SAMPLE CH4.
METALLOGRAPHY

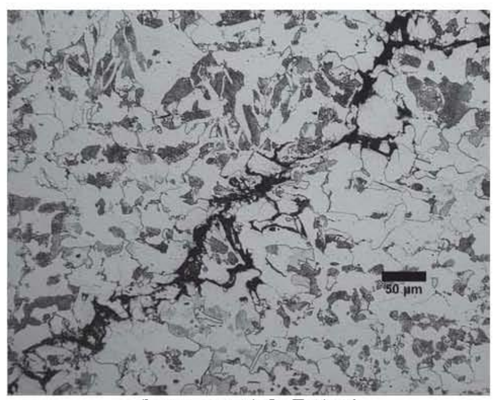




Area 4 mm from the crack to the left of the crack. Un-etched

Same as at left. Etched





Area near the tip of the crack. Un-etched

Same as at left. Etched

Figure 25

6670 Beta Dr., Mayfield Village, OH 44143, Tel: (440) 604-9843, Fax: (440) 604-9800, e-mail: jblough@firstenergycorp.com

HTHA micro-fissures and decarburization were observed within the heat affected zone (HAZ) of weld seam CS-4 (referenced as CW-4 above) of E-6600B (reference 7).

Discussion of Contributing Factors

1. Seven personnel were in the area at the time of failure.

On the night of the incident, seven personnel were in the field area bringing E-6600A/B/C online after cleaning. In addition to the two field operators typically required for this task, the supervisor was also present, as were four additional personnel. According to TOP investigation team interviews (reference 11), it is believed that the additional personnel were in the area for training purposes. All personnel present had received general zone training on the Naphtha Hydrotreater (NHT). Two of the operators involved in the startup (one in the field and one on the control board) were Job, Knowledge and Skill qualified as NHT unit operators.

Typical practice was to clean the tubes about once every six months due to fouling. The incoming feed historically contained contaminants that gradually deposited on the inside of the tubes, reducing heat transfer efficiency.

Valves were in place to allow one set of three E-6600s to be shut down at a time for cleaning, while the process continued to operate on the remaining set of three E-6600s. The Naphtha Hydrotreater (NHT) was designed to make the E-6600s accessible for cleaning without having to shut down the entire NHT unit.

After cleaning a bank of three heat exchangers, the operators would return the bank to service following an established procedure. On the night of the incident, there is no evidence indicating operator error contributed to the E-6600E failure.

Continuous petroleum or chemical processes operate most effectively when they are in a steady state. Non-routine activities, including startup or shutdown, can create additional risks because parameters such as flow, temperature and pressure are in a state of flux. To minimize exposure to both people and equipment due to these higher risk periods, we recommend the following:

a) Re-design the NHT reactor feed/effluent exchanger train to eliminate the need for online exchanger cleaning, reducing the risk presented by non-steady state operation.
b) Develop expectations and a training policy relative to startup and shutdown activities which will control the number of people in a high exposure area.

2. At times over the life of E-6600E, sufficient hydrogen partial pressure and temperature existed for high temperature hydrogen attack (HTHA).

Summary:
High temperature hydrogen attack (HTHA) occurs at sufficient hydrogen partial pressure and temperature combinations for a given metallurgy. Metallographic evaluation of samples from the failed exchanger E-6600E shell, as well as from the E-6600B shell, confirmed the presence of HTHA, leading the team to determine that the hydrogen partial pressure and temperature was sufficient to cause the damage in the non-post-weld-heat-treated carbon steel. (Refer to previous section on HTHA). With the limitations of the Naphtha Hydrotreater (NHT) process data, the TOP investigation team was not able to definitively determine where E-6600B/E operated in relation to the carbon steel Nelson Curve (above or below).

Background:
Third party experts and refinery staff conducted a number of corrosion reviews for the NHT to understand the types of corrosion that could be expected and where the corrosion would be likely to occur. HTHA was one corrosion mechanism, out of several, that was reviewed and analyzed.

a. The first corrosion review for the NHT was completed in 1990 (reference 12) and updated in 1993 (reference 13). At that time, the refinery was owned by Shell Oil Company.
b. In 1998, the Anacortes Refinery was acquired by Tesoro in a purchase of the stock of the Shell Anacortes Refining Company. An in-depth corrosion review, known as a Corrosion Control Document (CCD), was developed in 1999 (reference 14) by Shell Westhollow Technology Center under contract to Tesoro Anacortes Refinery. It was updated in 2003 (reference 15) by Shell Westhollow Technology Center.
c. The most recent Corrosion Study was developed by Lloyds Register Capstone in 2008 (reference 16).

The above documents identified that HTHA was a concern in the two hottest exchangers, E-6600A/D, which were constructed of C-Mn-0.5Mo alloy. The documents did not identify a concern for HTHA in E-6600B/E, which were constructed of carbon steel.

a. The 1990 study (reference 12) referred to the C-Mn-0.5Mo exchangers E-6600A/D, recommending they be inspected for HTHA. A memorandum dated 1991(reference 17) establishes a list of 11 items to be inspected for HTHA, including E-6600A/D. The carbon steel exchangers E-6600B/E/C/F were not recommended for HTHA inspection.
b. The 1993 study (reference 13) affirmed the 1990 study.
c. The 1999 and 2003 studies (references 14 & 15) noted that A/D were susceptible to HTHA, and mentioned only the piping between A/B and D/E as being susceptible to HTHA "if operated above the Nelson curve".
d. The 2008 study (reference 16) noted that A/D were susceptible to HTHA. Referring to E-6600E/B it stated "there is no concern about HTHA in these and also in the E-6600C/F shells."

Temperature:
Because there was no intermediate temperature instrumentation between the individual exchangers, there is limited data on the actual operating temperatures in E-6600B/E. The original 1970 design manual (reference 18) indicates that the intermediate temperature between E-6600A/D and E-6600B/E was 504°F when the reactor outlet temperature (inlet to the shell side of the E-6600 exchangers) was at the end-of-run condition of 715°F. Our review of the reactor outlet temperature data shows that the reactor was operated as designed with a typical outlet temperature range of 670°F to 710°F. There were documented occurrences where temperatures exceeded 715°F for periods of very short duration.

Table 1: Reactor Outlet Temperature Exceeding 715°F, 1987-2010

Date Range	Frequency of available data	716°F-720°F	>720°	>740°
January 1987 – March 1989	3x/ month	5 events	none	1 event
April 1989 – December 2002	2x/ month	6 events	1 event	none
January 2003 - December 2007	Daily	4 events	1 event	1 event
January 2008 - April 2010	Hourly	9 events	7 events	none

From January 1987 to December 2007, an event was a day on which one or more of the temperatures were above 715°F. From January 2008 to 2010, an event was an episode where temperatures were continuously above 715°F for some period of time. Typically these events lasted a few minutes. However, one of these events did last for four days, but only reached a maximum temperature of 719°F.

There is a record of one occurrence of a reactor temperature excursion to 1150°F in March 1988, which was likely a short duration event, although records of the occurrence are incomplete (reference 19).

At the combined E-6600 shell outlet, there was a thermometer in a thermal well. The temperature indicated by the thermometer was entered through a data logger into the refinery data historian. The range of this data was typically 250°F to 310°F, which is consistent with the 1970 design manual (reference 18) showing 270°F. Intermediate process temperature for E-6600B/E data does not exist, although some field surface temperature data was taken as shown below:

a. To support one of the corrosion studies, a nozzle surface reading was taken between the upper and middle exchangers in October 1998. This reading was recorded at 455°F (reference 20).
b. In support of ultrasonic thickness measurements, 120 field surface measurements were taken on E-6600B and 112 field surface measurements were taken on E-6600E between 1992 and 2010. Nine of these measurements (six for E-6600B and three for E-6600E) were over the estimated end-of run temperature of 504°F (ranging from 522°F to 565°F). These nine readings were all at the conical head or inlet end of the exchanger shell. Eight of the temperatures were recorded on October 13, 2004; the other was recorded on April 10, 2006.

Ultrasonic thickness measurements taken above ambient temperature require a temperature correction. Ultrasonic thickness measurements with temperature readings were taken every two years. This data, when charted, does show that E-6600B and E-6600E temperatures track similarly, whether high or low, on a given day (reference 21). The temperature readings associated with ultrasonic thickness measurements were taken solely in support of the ultrasonic thickness process and reported as corrected thickness, not temperature. There was no evidence that the engineers assessing the exposure to HTHA would have had access to this temperature information or would have been expected to review that data.

Absolute temperature for the E-6600s likely varied depending on many factors, including catalyst life and exchanger fouling. The E-6600s were generally cleaned every six months due primarily to tube side (feed) fouling. Notionally, the top or hottest exchangers (E-6600A/D) were the most fouled, based on maintenance records. Fouling causes the temperature profile to move down through the exchangers, making the successive exchangers hotter.

Lacking actual process temperature measurements between the E-6600s, it is difficult to draw conclusions about individual shell operating conditions. The historical operating data and design manual indicate that the six-exchanger train cooled the effluent by approximately 400-450°F. In summary, the temperature data was not adequate to draw definitive conclusions on the temperature profile within the exchanger train.

Hydrogen Partial Pressure (H2pp):
The 1970 design manual (reference 18) provides a design H2pp value of 291 psia at the reactor outlet. A 2003 process study conducted by Mustang Engineering during the low sulfur gasoline study indicated 232 psia (reference 22). The various corrosion studies quoted the following:

a. 1990 study---450 psia (reference 12 & 23)
b. 1993 study---450 psia (reference 13 & 23)
c. 1999 study---partial pressure not stated (reference 14)
d. 2003 study---partial pressure not stated (reference 15)
e. 2008 study---240 psia (reference 16)

The 2010 redesign identifies a H2pp at reactor outlet of 285 psia (reference 24).

With the disparity and range of H2pp values between the different corrosion reviews and the redesign value, the TOP investigation team reviewed actual process data related to hydrogen concentrations and flows via the Distributed Control System (DCS). With assistance from Anacortes process engineering, we attempted to estimate actual H2pp from the present back to the 4Q2007. However, we do not have confidence in the accuracy of this estimate due to the lack of information regarding historical feed composition related to hydrogen consumption in the reactor.

Additionally, H2pp varies with purity of the makeup hydrogen, system pressure, intermediate exchanger temperatures and operation of the recycle compressor. The TOP investigation team discussed whether the construction of a process model of the reactor system calculating hydrogen partial pressure should be considered to assist with the analysis. Given the number of assumptions that would be needed to build a useful model, we ultimately decided that it would not add measurably to our conclusions.

Hydrogen partial pressure and temperature:
With the limitations of the data, the TOP investigation team was not able to definitively determine where E-6600B/E operated in relation to the carbon steel Nelson Curve (above or below).
The lack of information on actual hydrogen partial pressure, combined with the lack of actual operating temperature for E-6600B/E, does not allow us to determine operating conditions with certainty.

The exchanger train was designed so that the second and third exchanger would be operated at temperatures and pressures that would not lead to HTHA in carbon steel. Since there was no temperature indication within the exchangers, operations and corrosion reviews relied on the safe operating limits of the reactor outlet and the calculated temperature profile of each exchanger bank in considering the potential for HTHA. Hydrogen partial pressure must be determined from complex calculations and although periodic calculations were done, the TOP investigation team believes that additional safeguards could be established for controls related to hydrogen partial pressure and temperature.

Because HTHA did occur and to reduce the likelihood for future HTHA damage, we recommend the following:

a) Install temperature and pressure instrumentation on the inlet and outlet of each reactor feed/effluent heat exchanger in the NHT.
b) Analyze similar hydroprocess units to determine if additional instrumentation is needed to manage HTHA.
c) Establish an integrity operating window (IOW) for hydrogen partial pressure and temperature in hydroprocess units utilizing carbon steel and C-Mn-0.5Mo alloys.
d) Establish a Distributed Control system (DCS) calculated indication for managing the integrity operating window (IOW) for HTHA in units with equipment susceptible to HTHA potential and provide a means to alert operations.
e) Increase the standard safe operating margin, for equipment in hydrogen service, below the Nelson Curve as defined by Tesoro Engineering Standard (reference 25).
f) Incorporate unit specific corrosion training for appropriate operational and technical staff to improve their knowledge and understanding of potential damage mechanisms affecting fixed equipment in their area(s) of responsibility.
g) Implement a strategy to reduce the maintenance cycle due to fouling in the redesigned reactor feed/effluent exchangers.

3. E-6600E shell was fabricated of carbon steel and was not post-weld-heat-treated.

E-6600B/E shells were fabricated of carbon steel. Carbon steel operated above a certain temperature and hydrogen partial pressure has lower resistance to high temperature hydrogen attack (see discussion on HTHA) than alloy steels, such as 1.25Cr-0.5Mo steels (reference 1).

Further, post-weld-heat-treating can reduce susceptibility to HTHA that occurs in the heat affected zones (HAZs) of welds as seen in E-6600E (reference 1). E-6600B/C/E/F shells were not post-weld-heat-treated. Original design parameters and engineering standards from 1970 did not indicate the need for post-weld-heat-treatment of these exchangers (reference 18).

There was a metallurgy change between E-6600A/D and E-6600B/E. E-6600A/D were fabricated from post-weld-heat-treated C-Mn-0.5Mo steel and clad with 304 stainless steel. E-6600B/E were fabricated of carbon steel. The inlet section (section 4) and inlet nozzle of E-6600B/E was clad with 316 stainless steel. The remainder of E-6600B/E (sections 1-3) was not clad.

To reduce the likelihood of future HTHA damage, we recommend the following:

a) Construct replacement exchangers with a metallurgy/design that protects against HTHA for potential operating conditions.
b) Ensure that Process Hazard Analyses (PHAs), Management of Change and corrosion studies review specification break locations (such as transitions of metallurgy, pressure, or temperature) for design versus actual operating conditions.

c) Review specification break locations and conduct an engineering review to determine whether existing instrumentation/controls are sufficient to ensure that the downstream equipment is operated within its established limits.
d) Identify other non-post-weld-heat-treated equipment in hydrogen service and apply appropriate Mechanical Integrity inspection strategies (reference 26).

4. High temperature hydrogen attack (HTHA) damage was not detected prior to failure.

Specific inspection techniques capable of detecting HTHA damage, as described in API RP 941 (reference 1), were not performed on E-6600B/E since corrosion studies performed by experts did not recommend these exchangers to be included in the HTHA program (see Contributing Factor 2).

Susceptibility of the E-6600s to HTHA was evaluated in five separate corrosion studies (references 12-16). The corrosion studies limited recommendations for HTHA inspections to the two hottest exchangers E-6600A/D, which are fabricated of C-Mn-0.5Mo steel. Inspection for HTHA in E-6600B/E was not recommended because it was believed that E-6600B/E did not operate under conditions that could lead to HTHA (see Contributing Factor 2).

In order to improve the ability to identify material degradation mechanisms, we recommend the following:

a) Complete implementation of Tesoro's Reliability-Based Mechanical Integrity (RBMI) Program and HTHA Inspection Strategies for equipment in HTHA service, as defined by the Tesoro Refining Standards (references 25 & 27).
b) Review and update the Corrosion Study (reference 16) for the Naphtha Hydrotreater (NHT), Catalytic Reformer, Clean Fuels Hydrotreater, and Diesel Hydrotreater, including a revalidation of the range of operating conditions.
c) Install temperature and pressure instrumentation on the inlet and outlet of each reactor feed/effluent heat exchanger in the NHT (see Contributing Factor 2, Recommendation a).
d) Develop a Guidance Document for calculating hydrogen partial pressure.
e) Revalidate the hydrogen partial pressures in hydrogen processing units.
f) Establish a Distributed Control System (DCS) calculated indication for managing the integrity operating window (IOW) for HTHA in units with equipment susceptible to HTHA potential and provide a means to alert operations (see Contributing Factor 2, Recommendation d).

5. Stress existed in the E-6600s sufficient to cause rupture of the high temperature hydrogen attack (HTHA) damaged shell.

The final rupture occurred because the strength of the E-6600E shell had been sufficiently reduced by HTHA damage such that it could not withstand the total stress that existed at the time of the failure. The total stress on the E-6600s resulted from operating pressure, residual stresses and thermal stresses that were consistent with the historical operation of the E-6600s.

Operating Pressure:
Stress from operating pressure results from normal operation of the exchanger. The operating pressure within E-6600E at the time of the rupture was within normal operating parameters (reference 28).

Residual Stress:
Residual stress is a result of the welding process during fabrication. Post-weld-heat-treating reduces residual stress in the weld heat affected zones (HAZs). E-6600B/C/E/F shells were not post-weld-heat-treated. Original design parameters and engineering standards from 1970 (reference 18) did not indicate the need for post-weld-heat-treatment of these exchangers.

Thermal Stress:
Thermal stress is caused when constrained metal experiences temperature changes. Documented flange leaks, although not causal to the incident, suggest that there were thermal stresses imposed on the exchanger equipment during return to service after online cleaning (references 29 & 30). Conversely, the team did not discover documented incidents of leakage after a full unit startup. Full unit startups result in a more gradual temperature change compared to startups after online cleaning. Full unit startups occur when the entire system is brought online after being shut down as a unit for catalyst change or unit turnaround.

Discussion:
Based on fracture mechanics, in order for this rupture to have occurred, either an existing HTHA crack within the interior of the carbon steel had grown to a critical flaw size for startup operation stress consistent with historical operations, or the stress increased to a critical threshold for an existing crack size. The TOP investigation team was unable to determine whether a change in crack size or a change in stress caused the rupture. The timing of the failure, with the coincident return to service of the parallel bank of E-6600s after cleaning, could not be explained with certainty.

In order to decrease the stress from the startup/shutdown on the Naphtha Hydrotreater (NHT) feed/effluent exchangers, we recommend the following:

a) Re-design the NHT reactor feed/effluent exchanger train to eliminate the need for online exchanger cleaning, reducing the risk presented by non-steady state operation (see Contributing Factor 1, Recommendation a).
b) Identify pressure equipment that has a higher startup/shutdown/bypass frequency than the unit as a whole for a joint-discipline review of operation, inspection, and maintenance strategies to mitigate risks and consider improvement opportunities.
c) Identify other non-post-weld-heat-treated equipment in hydrogen service and apply appropriate Mechanical Integrity inspection strategies (see Contributing Factor 3, Recommendation d).

Table 2: Contributing Factors & Recommendations

Contributing Factors	Supporting Rationale	System of Safety	Recommendations
Contributing Factor #1 Seven personnel were in the area at the time of failure.		Design & Engineering	a) Re-design the NHT reactor feed/effluent exchanger train to eliminate the need for online exchanger cleaning, reducing the risk presented by non-steady state operation. (2)
Background Typical practice was to clean the tubes about once every six months due to fouling. The incoming feed historically contained contaminants that gradually deposited on the inside of the tubes, reducing heat transfer efficiency.	After cleaning a bank of three heat exchangers, the operators would return it to service following an established procedure.	Training & Procedures	b) Develop expectations and a training policy relative to startup and shutdown activities which will control the number of people in a high exposure area. (4)
Valves were in place to allow one set of three E-6600s to be shut down at a time for cleaning, while the process continued to operate on the remaining set of three E-6600s. The Naphtha Hydrotreater (NHT) was designed to make the E-6600s accessible for cleaning without having to shut down the entire NHT unit.	According to TOP investigation team interviews (reference 11), it is believed that the additional personnel were in the area for training purposes. All personnel present had received general zone training on the NHT. Two of the operators involved in the startup (one in the field and one on the control board) were Job, Knowledge and Skill qualified as NHT unit operators.		
After cleaning a bank of three heat exchangers, the operators would return it to service following an established procedure.	On the night of the incident, there is no evidence indicating that operator error contributed to the E-6600E failure. Continuous petroleum or chemical processes operate most effectively when they are in a steady state. Non-routine activities, including startup or shutdown, can create additional risks because parameters such as flow, temperature and pressure are in a state of flux.		

Contributing Factors	Supporting Rationale	System of Safety	Recommendations
Contributing Factor #2 At times over the life of E-6600E, sufficient hydrogen partial pressure and temperature existed for high temperature hydrogen attack (HTHA).	Metallographic evaluation of samples from the failed exchanger E-6600E shell, as well as from E-6600B shell, confirmed the presence of HTHA, leading the team to determine that the hydrogen partial pressure and temperature was sufficient to cause the damage in the non-post-weld-heat-treated carbon steel.	Warning Devices	a) Install temperature and pressure instrumentation on the inlet and outlet of each reactor feed/effluent heat exchanger in the NHT.(2)
Background High temperature hydrogen attack (HTHA) occurs at sufficient hydrogen partial pressure and temperature combinations for a given metallurgy.	With the limitations of the Naphtha Hydrotreater (NHT) process data, the TOP investigation team was not able to definitively determine where E-6600B/E operated in relation to the carbon steel Nelson Curve (above or below).	Warning Devices	b) Analyze similar hydroprocess units to determine if additional instrumentation is needed to manage HTHA.(3)
Third party experts and refinery staff conducted a number of corrosion reviews for the NHT to understand the types of corrosion that could be expected and where the corrosion would be likely to occur. HTHA was one corrosion mechanism, out of several, that was reviewed and analyzed.	The corrosion reviews identified that HTHA was a concern in the two hottest exchangers, E-6600A/D, which were constructed of C-Mn-0.5Mo alloy. The documents did not identify a concern for HTHA in E-6600B/E, which were constructed of carbon steel.	Training & Procedures	c) Establish an integrity operating window (IOW) for hydrogen partial pressure and temperature in hydroprocess units utilizing carbon steel and C-Mn-0.5Mo alloys.(3)
Temperature: Because there was no intermediate temperature instrumentation between the individual exchangers, there is limited data on the actual operating temperatures in E-6600B/E. The original 1970 design manual (reference 18) indicates that the intermediate temperature between E 6600A/D and E-6600B/E was 504°F when the reactor outlet temperature (inlet to the shell side of the E-6600	At the combined E-6600 shell outlet, there was a thermometer in a thermal well. The temperature indicated by the thermometer was entered through a data logger into the refinery data historian. The range of this data was typically 250°F to 310°F, which is consistent with the 1970 design manual (reference 18) showing 270°F. Intermediate process temperature for E-6600B/E data does not	Warning Devices	d) Establish a Distributed Control System (DCS) calculated indication for managing the integrity operating window (IOW) for HTHA in units with equipment susceptible to HTHA potential and provide a means to alert operations.(3)

Contributing Factors	Supporting Rationale	System of Safety	Recommendations
exchangers) was at the end-of-run condition of 715°F. Our review of the reactor outlet temperature data shows that the reactor was operated as designed with a typical outlet temperature range of 670°F to 710°F.There were documented occurrences where temperatures exceeded 715°F for periods of very short duration.	exist, although some field surface temperature data was taken.		
Absolute temperature for the E-6600s likely varied depending on many factors, including catalyst life and exchanger fouling. The E-6600s were generally cleaned every six months due primarily to tube side (feed) fouling. Notionally, the top or hottest exchangers (E-6600A/D) were the most fouled, based on maintenance records. Fouling causes the temperature profile to move down through the exchangers, making the successive exchangers hotter.	Lacking actual process temperature measurements between the E-6600s, it is difficult to draw conclusions about individual shell operating conditions. The historical operating data and design manual indicate that the six-exchanger train cooled the effluent by approximately 400-450°F. In summary the temperature data was not adequate to draw definitive conclusions on the temperature profile within the exchanger train.	Warning Devices	e) Increase the standard safe operating margin, for equipment in hydrogen service, below the Nelson Curve as defined by Tesoro Engineering Standard (reference 25).(4)
Hydrogen Partial Pressure (H2pp): The 1970 design manual (reference 18) provides a design H2pp value of 291 psia at the reactor outlet. A 2003 process study conducted by Mustang Engineering during the low sulfur gasoline study indicated 232 psia (reference 22). Partial pressures from the corrosion studies are quoted in the discussion. The 2010 redesign identifies a H2pp at reactor outlet of 285 psia (reference 24)	With the disparity and range of H2pp values between the different corrosion reviews and the redesign value, the TOP investigation team reviewed actual process data related to hydrogen concentrations and flows via the Distributed Control System (DCS). With assistance from Anacortes process engineering, we attempted to estimate actual H2pp from the present back to the 4Q2007. However, we do not have confidence in the accuracy of this estimate due to the lack of information regarding historical feed composition	Training & Procedures	f) Incorporate unit specific corrosion training for appropriate operational and technical staff to improve their knowledge and understanding of potential damage mechanisms affecting fixed equipment in their area(s) of responsibility.(3)

Contributing Factors	Supporting Rationale	System of Safety	Recommendations
	related to hydrogen consumption in the reactor.		
	Additionally, H2pp varies with purity of the makeup hydrogen, system pressure, intermediate exchanger temperatures and operation of the recycle compressor. The TOP investigation team discussed whether the construction of a process model of the reactor system calculating hydrogen partial pressure should be considered to assist with the analysis. Given the number of assumptions that would be needed to build a useful model, we ultimately decided that it would not add measurably to our conclusions.	Warning Devices	g) Implement a strategy to reduce the maintenance cycle due to fouling in the redesigned NHT reactor feed/effluent exchangers.(2)
Hydrogen Partial Pressure and Temperature: The exchanger train was designed so that the second and third exchanger would be operated at temperatures and pressures that would not lead to HTHA in carbon steel. Since there was no temperature indication within the exchangers, operations and corrosion reviews relied on the safe operating limits of the reactor outlet and the calculated temperature profile of each exchanger bank in considering the potential for HTHA. Hydrogen partial pressure must be determined from complex calculations.	With the limitations of the data, the TOP investigation team was not able to definitively determine where E-6600B/E operated in relation to the carbon steel Nelson Curve (above or below). The lack of information on actual hydrogen partial pressure, combined with the lack of actual operating temperature for E-6600E/B, does not allow us to determine operating conditions with certainty.		

Contributing Factors	Supporting Rationale	System of Safety	Recommendations
Contributing Factor #3 E-6600E shell was fabricated of carbon steel and was not post-weld-heat-treated.		Design & Engineering	a) Construct replacement exchangers with a metallurgy/design that protects against HTHA for potential operating conditions.(1)
Background E-6600B/E shells were fabricated of carbon steel.	Carbon steel operated above a certain temperature and hydrogen partial pressure has lower resistance to high temperature hydrogen attack than alloy steels (reference 1).	Maintenance & Inspection	b) Ensure that Process Hazard Analyses (PHAs), Management of Change and corrosion studies review specification break locations (such as transitions of metallurgy, pressure, or temperature) for design versus actual operating conditions.(3)
E-6600B/C/E/F shells were not post-weld-heat-treated. Original design parameters and engineering standards from 1970 did not indicate the need for post-weld-heat-treatment of these exchangers (reference 18).	Further, post-weld-heat-treating can reduce susceptibility to high temperature hydrogen attack (HTHA) that occurs in the heat affected zones (HAZs) of welds as seen in E-6600E (reference 1).	Warning Devices	c) Review specification break locations and conduct an engineering review to determine whether existing instrumentation/controls is sufficient to ensure that the downstream equipment is operated within its established limits.(3)
E-6600A/D were fabricated from post-weld-heat-treated C-Mn-0.5Mo steel and clad with 304 stainless steel. E-6600B/E were fabricated of carbon steel. The inlet section (section 4) and inlet nozzle of E-6600B/E was clad with 316 stainless steel. The remainder of E-6600B/E (sections 1-3) was not clad.	There was a metallurgy change between E-6600A/D and E-6600B/E.	Maintenance & Inspection	d) Identify other non-post-weld-heat-treated equipment in hydrogen service and apply appropriate Mechanical Integrity inspection strategies (reference 26).(3)

Contributing Factors	Supporting Rationale	System of Safety	Recommendations
<u>Contributing Factor #4</u> High temperature hydrogen attack (HTHA) damage was not detected prior to failure.		Maintenance & Inspection	a) Complete implementation of Tesoro's Reliability-Based Mechanical Integrity (RBMI) Program and HTHA Inspection Strategies for equipment in HTHA service, as defined by the Tesoro Refining Standards (references 25 & 27).(4)
<u>Background</u> Susceptibility of the E-6600s to HTHA was evaluated in five separate corrosion studies (references 12-16). The corrosion studies limited recommendations for HTHA inspections to the two hottest exchangers E-6600A/D, which are fabricated of C-Mn-0.5Mo steel. Inspection for HTHA in E-6600B/E was not recommended because it was believed that E-6600B/E did not operate under conditions that could lead to HTHA (see Contributing Factor 2).	Specific inspection techniques capable of detecting HTHA damage, as described in API RP 941 (reference 1), were not performed on E-6600B/E since corrosion studies performed by experts did not recommend these exchangers to be included in the HTHA program (see Contributing Factor 2).	Training & Procedures	b) Review and update the Corrosion Study (reference 16) for the Naphtha Hydrotreater (NHT), Catalytic Reformer, Clean Fuels Hydrotreater, and Diesel Hydrotreater, including a revalidation of the range of operating conditions.(4)
		Warning Devices	c) Install temperature and pressure instrumentation on the inlet and outlet of each reactor feed/effluent heat exchanger in the NHT (see Contributing Factor 2, Recommendation a).(2)
		Training & Procedures	d) Develop a Guidance Document for calculating hydrogen partial pressure.(4)
		Training & Procedures	e) Revalidate the hydrogen partial pressures in hydrogen processing units.(3)
		Warning Devices	f) Establish a Distributed Control System (DCS) calculated indication for managing the integrity operating window (IOW) for HTHA in units with equipment susceptible to HTHA potential and provide a means to alert operations (see Contributing Factor 2, Recommendation d). (3)

Contributing Factors	Supporting Rationale	System of Safety	Recommendations
<u>Contributing Factor #5</u> Stress existed in the E-6600s sufficient to cause rupture of the high temperature hydrogen attack (HTHA) damaged shell.		Design & Engineering	a) Re-design the NHT reactor feed/effluent exchanger train to eliminate the need for online exchanger cleaning, reducing the risk presented by non-steady state operation (see Contributing Factor 1, Recommendation a).(2)
<u>Background</u> The total stress on the E-6600s resulted from operating pressure, residual stresses and thermal stresses that were consistent with the historical operation of the E-6600s.	The final rupture occurred because the strength of the E-6600E shell had been sufficiently reduced by HTHA damage such that it could not withstand the total stress that existed at the time of the failure.	Maintenance & Inspection	b) Identify pressure equipment that has a higher startup/shutdown/bypass frequency than the unit as a whole for a joint-discipline review of operation, inspection, and maintenance strategies to mitigate risks and consider improvement opportunities.(3)
Operating Pressure: Stress from operating pressure results from normal operation of the exchanger.	The operating pressure within E-6600E at the time of the rupture was within normal operating parameters.	Maintenance & Inspection	c) Identify other non-post-weld-heat-treated equipment in hydrogen service and apply appropriate Mechanical Integrity inspection strategies (see Contributing Factor 3, Recommendation d).(3)
Residual Stress: Residual stress is a result of the welding process during fabrication. Post-weld-heat-treating reduces residual stress in the weld heat affected zones (HAZs).	E-6600B/C/E/F shells were not post-weld-heat-treated. Original design parameters and engineering standards from 1970 (reference 18) did not indicate the need for post-weld-heat-treatment of these exchangers.		
Thermal Stress: Thermal stress is caused when constrained metal experiences temperature changes	Documented flange leaks, although not causal to the incident, suggest that there were thermal stresses imposed on the exchanger equipment during return to service after online cleaning (references 29 & 30). Conversely, the team did not discover documented incidents of leakage after a full unit startup. Full unit startups result in a more gradual temperature change compared to startups after online cleaning. Full unit startups occur when the entire system is brought		

Contributing Factors	Supporting Rationale	System of Safety	Recommendations
Discussion: Based on fracture mechanics, in order for this rupture to have occurred, either an existing crack grew to a critical flaw size for a given stress, or the stress increased to a critical threshold for an existing crack size.	online after being shut down as a unit for catalyst change or unit turnaround. The TOP investigation team was unable to determine whether a change in crack size or a change in stress caused the rupture. The timing of the failure, with the coincident return to service of the parallel bank of E-6600s after cleaning, could not be explained with certainty.		

Table 3: Summary of Contributing Factors Recommendations

The following recommendations are written specifically for the Anacortes Refinery. These recommendations will be reviewed for company-wide impact in accordance with the Tesoro Standard TSHS-006 (reference 31) and the specific requirements of the "Learning From Experience" work process that is part of the Tesoro Standard. This work process includes direction on the evaluation of site investigation reports, notifications, corrective actions and communication and information sharing at a company-wide and site level.

Contributing Factor No.	Rec. Level*	Recommendation Description	Responsible Department	Due Date**
1.a & 5.a	2	Re-design the Naphtha Hydrotreater (NHT) reactor feed/effluent exchanger train to eliminate the need for online exchanger cleaning, reducing the risk presented by non-steady state operation.	Projects	Complete
1.b	4	Develop expectations and a training policy relative to startup and shutdown activities which will control the number of people in a high exposure area.	Operations	3 months
2.a & 4.c	2	Install temperature and pressure instrumentation on the inlet and outlet of each reactor feed/effluent heat exchanger in the Naphtha Hydrotreater.	Projects	Complete
2.b	3	Analyze similar hydroprocess units to determine if additional instrumentation is needed to manage high temperature hydrogen attack (HTHA).	Technical Services	3 months
2.c	3	Establish an integrity operating window (IOW) for hydrogen partial pressure and temperature in hydroprocess units utilizing carbon steel and C-Mn-0.5Mo alloys.	Technical Services	3 months
2.d & 4.f	3	Establish a Distributed Control System (DCS) calculated indication for managing the IOW for HTHA in units with equipment susceptible to HTHA potential and provide a means to alert operations.	Technical Services	6 months
2.e	4	Increase the standard safe operating margin, for equipment in hydrogen service, below the Nelson Curve as defined by Tesoro Engineering Standard (reference 25).	Inspection/ Technical Services	Complete
2.f	3	Incorporate unit specific corrosion training for appropriate operational and technical staff to improve their knowledge and understanding of potential damage mechanisms affecting fixed	Engineering	6 months

		equipment in their area(s) of responsibility.		
2.g	2	Implement a strategy to reduce the maintenance cycle due to fouling in the redesigned NHT reactor feed/effluent exchangers.	Projects	Complete
3.a	1	Construct replacement exchangers with a metallurgy/design that protects against HTHA for potential operating conditions.	Projects	Complete
3.b	3	Ensure that Process Hazard Analyses (PHAs), Management of Change and corrosion studies review specification break locations (such as transitions of metallurgy, pressure, or temperature) for design versus actual operating conditions.	Safety/ Engineering	3 months
3.c	3	Review specification break locations and conduct an engineering review to determine whether existing instrumentation/controls are sufficient to ensure that the downstream equipment is operated within its established limits.	Technical Services/ Engineering	6 months
3.d & 5.c	3	Identify other non-post-weld-heat-treated equipment in hydrogen service and apply appropriate Mechanical Integrity inspection strategies (reference 26).	Inspection	3 months
4.a	4	Complete implementation of Tesoro's Reliability-Based Mechanical Integrity (RBMI) Program and HTHA Inspection Strategies for equipment in HTHA service, as defined by the Tesoro Refining Standards (references 25 & 27).	Inspection	6 months
4.b	4	Review and update the Corrosion Study (reference 16) for the NHT, Catalytic Reformer, Clean Fuels Hydrotreater, and Diesel Hydrotreater, including a revalidation of the range of operating conditions.	Inspection	1 year
4.d	4	Develop a Guidance Document for calculating hydrogen partial pressure.	Technical Services	1 month
4.e	3	Revalidate the hydrogen partial pressures in hydrogen processing units.	Technical Services	3 months
5.b	3	Identify pressure equipment that has a higher startup/shutdown/bypass frequency than the unit as a whole for a joint-discipline review of operation, inspection, and maintenance strategies to mitigate risks and consider improvement opportunities.	Operations	1 year

Contributing Factors Recommendations Summary Notes

*Recommendations are categorized by the TOP investigation team to assist in company-wide evaluation and to aid continual improvement in the recommendation management portion of the investigation work process. Level 1= Addresses the Causal Factor, Level 2= Addresses the Intermediate Causes of the Specific Problem, Level 3= Fixes Similar Problems, Level 4= Corrects the Process That Creates These Problems. The levels (1-4) are further defined in TSHS-006 (reference 31).

**Dates from release of this report.

Discussion of Items of Note

1. E-6600E was designed with the reactor effluent on the shell side.

The reactor effluent was on the shell side of the E-6600s; the feed was on the tube side (see Figure 2). The reactor effluent was released when the E-6600E shell failed and auto-ignited. A common industry practice places the hotter, higher risk fluid on the tube side of an exchanger. Other considerations, such as the need for online cleaning of fouled surfaces, may cause the designer to reverse the arrangement, as appears was the case for the design of the E-6600s. Each case must be considered individually.

To reduce the risk of release of reactor effluent, we recommend the following:

a) Redesign Naphtha Hydrotreater (NHT) reactor feed/effluent exchangers with reactor effluent on the tube side.

2. Operational excursions are not formally tracked and reported.

Operational excursions may result in process conditions outside the integrity operating window (IOW). Although operational excursions may be short in duration, they can have an effect on mechanical integrity. There is currently no formal process in place for tracking and reporting such excursions to ensure they are considered in determining an appropriate inspection strategy.

In order to ensure that this information is considered in determining an appropriate inspection strategy, we recommend the following:

a) Develop and implement a process to ensure that information regarding operational excursions over the life of equipment is tracked, documented and used to determine appropriate operations, inspection, and maintenance strategies.

Table 4: Items of Note & Recommendations

Items of Note	Supporting Rationale	System of Safety	Recommendations
<u>Item of Note #1</u> E-6600E was designed with the reactor effluent on the shell side. <u>Background</u> The reactor effluent was on the shell side of the E-6600s; the feed was on the tube side (see Figure 2). The reactor effluent was released when the E-6600E shell failed and auto-ignited.	A common industry practice places the hotter, higher risk fluid on the tube side of an exchanger. Other considerations, such as the need for online cleaning of fouled surfaces, may cause the designer to reverse the arrangement, as appears was the case for the design of the E-6600s. Each case must be considered individually.	Design & Engineering	a) Redesign Naphtha Hydrotreater (NHT) reactor feed/effluent exchangers with reactor effluent on the tube side. (1)

Items of Note	Supporting Rationale	System of Safety	Recommendations
<u>Item of Note #2</u> Operational excursions are not formally tracked and reported. <u>Background</u> Operational excursions may result in process conditions outside the integrity operating window (IOW). Although operational excursions may be short in duration, they can have an effect on mechanical integrity.	There is currently no formal process in place for tracking and reporting such excursions to ensure they are considered in determining an appropriate inspection strategy.	Training & Procedures	a) Develop and implement a process to ensure that information regarding operational excursions over the life of equipment is tracked, documented and used to determine appropriate operations, inspection, and maintenance strategies.(3)

Table 5: Summary of Items of Notes Recommendations

The following recommendations are written specifically for the Anacortes Refinery. These recommendations will be reviewed for company-wide impact in accordance with the Tesoro Standard TSHS-006 (reference 31) and the specific requirements of the "Learning From Experience" work process that is part of the Tesoro Standard. This work process includes direction on the evaluation of site investigation reports, notifications, corrective actions and communication and information sharing at a company-wide and site level.

ION No.	Rec. Level	Recommendation Description	Responsible Department	Due Date
1.a	1	Redesign Naphtha Hydrotreater (NHT) reactor feed/effluent exchangers with reactor effluent on the tube side.	Projects	Complete
2.a	3	Develop and implement a process to ensure that information regarding operational excursions over the life of equipment is tracked, documented and used to determine appropriate operations, inspection, and maintenance strategies.	Technical Services/ Inspection	6 months

Items of Note Recommendations Summary Notes

*Recommendations are categorized by the TOP investigation team to assist in company-wide evaluation and to aid continual improvement in the recommendation management portion of the investigation work process. Level 1= Addresses the Causal Factor, Level 2= Addresses the Intermediate Causes of the Specific Problem, Level 3= Fixes Similar Problems, Level 4= Corrects the Process That Creates These Problems. The levels (1-4) are further defined in TSHS-006 (reference 31).

**Dates from release of this report.

Attachments

1. Pre-Startup Recommendations
2. Mechanical Integrity Process Map
3. Report to the TOP Investigation Team Regarding Laboratory Results from the Failed Exchanger E6600-E and the Parallel Exchanger E6600-B from the Naphtha Hydrotreater Unit, Anacortes Refinery (Report No. 5004.4914-A) by Anamet, Inc. dated March 11, 2011
4. NHT Incident Cause Map

References

1. API Recommended Practice 941 Seventh Edition, August 2008 (Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants) **Not available electronically**
2. Paper presented in July 2010 at the ASME conference, titled “Cracking of Non-PWHT’d Carbon Steel at Conditions Below the Nelson Curve”
3. Phone call with John Reynolds on May 23, 2011
4. Presentation to the Chemical Safety Board, Metallurgical Analysis of Failed Heat Exchanger 6600-E, August 9, 2010 (TSO-CSB-034521) **Not available electronically**
5. Phone call with Jim McVay and Rob Carnahan on May 9, 2011
6. Exchanger Inspection Reports by Spectrum Inspection dated June 24, 2010 (E-6600B), May 21, 2010 (E-6600E), and May 20, 2010 (E-6600E)
7. BETA Laboratory reports for E-6600B and E-6600E
8. Email from Danny Wang to Allen Meyers and Jim McVay dated March 3, 2011
9. Phone call with Danny Wang on May 10, 2011
10. Phone call with John Reynolds on May 11, 2011
11. Interviews conducted by the TOP Investigation Team
12. Memorandum from R.L. Merritt to J.M. Wion dated January 26, 1990: Naphtha Hydrotreater Unit (NHT) Corrosion Review
13. Memorandum from R.L. Merritt to L.P. Tavoularis dated December 6, 1993: Naphtha Hydrotreater Unit (NHT) Corrosion Review
14. The Corrosion Control Document for the Naphtha Hydrotreater dated March, 1999
15. The Corrosion Control Document for the Naphtha Hydrotreater Tesoro Anacortes Refinery dated September 18, 2003
16. Corrosion Study for Naphtha Hydrotreater (NHT) and Catalytic Reformer (CR) Units, Capstone Project CAP0700268 dated October 8, 2008
17. Anacortes internal memorandum dated 1991 discussing 11 pieces of equipment to be inspected for HTHA 1970 **Not available electronically**
18. Anacortes Refinery Catalytic Reformer Naphtha Hydrotreater Process and Design Specifications 1970 **Not available electronically**
19. Records of occurrence 1150°F in March, 1988 **Not available electronically**
20. Hand-written table of hydrogen partial pressure of NHT equipment **Not available electronically**
21. Data on UT measurements taken on E-6600B/E

22. Summary of Mustang Engineering study dated 2002
23. Engineering notes referencing Anacortes Refinery Hydroprocess Operating Conditions **Not available electronically**
24. Material Selection Diagram D66A-619 dated September 2010
25. Tesoro Refining Standard TRS-663: HTHA Mitigation and Inspection of Existing Equipment in Hot Hydrogen Service
26. Tesoro Refining Standard TRS-662: Risk-Based Inspection Corrosion Studies
27. Tesoro Refining Standard TRS-661: Risk-Based Inspection for Fixed Equipment
28. A Distributed Control System screen shot of trends and NHT operating conditions (temperature & pressure) at time of failure **Not available electronically**
29. Investigation Report Summary: CR/NHT Series of Level 1 Fires (Incident Tracking number: 071216OPR149) dated November 26, 2008
30. E-6600E Inspection Reports dated 1972 to present
31. Tesoro Safety and Health Standard TSHS-006: Incident/ Near Miss Investigation, Management and Reporting

Appendix A: Glossary

Channel: The sections of a shell & tube heat exchanger at the inlet and outlet of the tubes.

CCD: Corrosion Control Documents (CCDs) contain all the necessary information to understand materials degradation issues in a specific type of operating process unit.

Contributing Factor: A fact, in common with others, which causes or allows the product of a result.

DCS: Distributed Control System (DCS) is a computer-based digital system for process management.

Decarburization: A result of high temperature hydrogen attack in which iron carbides are consumed to form methane, reducing the strength of a base metal.

Directing Parties: Division of Occupational Safety and Health of the Washington State Department of Labor and Industries (DOSH), the U.S. Chemical Safety and Hazard Investigation Board (CSB), and the Tesoro Refining and Marketing Company (Tesoro).

Effluent: Product exiting the reactor.

Fractography: Analysis of the appearance of a fracture surface to deduce the operating fracture mechanisms, directions of fracture, and physical origin of fracture.

HAZ: The heat affected zone (HAZ) is the area of base material, either a metal or a thermoplastic, which has had its microstructure and properties altered by welding or heat intensive cutting operations. The heat from the welding process and subsequent re-cooling causes this change in the area surrounding the weld. The extent and magnitude of property change depends primarily on the base material, the weld filler metal, and the amount and concentration of heat input by the welding process.

IOW: An established Integrity Operating Window (IOW) level is defined as one that if exceeded over a specified period of time could cause some specified undesirable risks (potential equipment damage or release) to occur. At the standard IOW limit level, the operator will generally have some predetermined action to take, which may vary from process control to seeking operating guidance from supervisors or appropriate other technical personnel.

Item of Note: A cause that did not directly lead to the incident but was uncovered during the investigation.

Mechanical Integrity: Mechanical Integrity (MI) comprises all the management systems, work practices, methods and procedures established in order to protect and preserve the integrity of operating equipment.

Partial pressure: Pressure exerted by one component or element of an ideal gas.

PHA: Process Hazard Analysis (PHA) is a line-by-line review of a petroleum or chemical process to identify safety hazards associated with process operations.

PWHT: Post-weld-heat-treatment (PWHT) is performed by heating the welded steel at a controlled rate to temperatures near 1100°F, holding at the maximum temperature for a defined time, typically 1 hour per inch of material thickness, and cooling again at a controlled rate. Particular rates and maximum temperature are specified by design codes and depend on the type of steel. The primary purpose of PWHT is to reduce residual stresses caused by welding.

RBMI: Reliability-Based Mechanical Integrity (RBMI) is used to determine an inspection and maintenance plan for fixed equipment based on risk. Risk is a function of the probability of failure and the consequence of failure. The probability of failure is a function of the identified failure mechanisms, the rate of deterioration, and the effectiveness of inspection. The safety consequence of failure of the item is a function of the type of fluid the equipment contains, how much might be released in the event of a failure, and the effect of such a release. As the risk increases, the frequency and coverage of inspections is increased.

Shell: The portion of a shell & tube heat exchanger that surrounds the tubes.

Specification Break: A specification (spec) break occurs when operating parameters (such as temperature, pressure, metallurgy) or chemical characteristics (such as composition of fluid handled) change.

Appendix B: Investigation Charter page 1

Incident ID #:	**100402OPR038**		
Unit Involved:	Naphtha Hydrotreater (NHT)	**Equipment Involved:**	E-6600E
Incident Date:	April 2nd, 2010	**Investigation Initiation Date:**	April 2nd, 2010
Tesoro Investigation Matrix Classification: **List consequences lowest to highest*	• Level-5 Injury • Level-5 Fire • Level-5 Explosion • Level-5 Business Impact • Level-5 Mechanical Integrity		
PSM Classification:	This event has been classified as a process safety incident.		
Incident Summary: **Ensure a clear description with details sufficient to determine what occurred.*	On April 2, 2010, at approximately 12:35 a.m., E-6600E in the Naphtha Hydrotreater (NHT) unit ruptured, releasing a mixture of hydrogen and naphtha (reactor effluent). The dispersed effluent auto-ignited, causing an explosion and fire that fatally injured seven employees who were in the area.		
Charter Review and Approval Date:		**Approved By:**	

Expectations:	1. Develop the sequence of events (timeline). 2. Use the TOP incident investigation methodology and tools. 3. Identify Contributing Factors to prevent this or similar incidents. 4. Develop corrective actions that directly address the causes of this incident. Corrective actions that address Items of Note should be kept separate from direct Contributing Factor corrective actions. 5. Produce clear documentation of the investigation.

Investigation Charter page 2

Scope:	1. The scope of this investigation should be limited to the primary cause(s). 2. The team shall develop corrective actions. 3. This incident will be investigated as a Tesoro Level 5 Investigation. A Level 5 investigation commands “rigor and specificity” within the causal logic. 4. Mike Johnson, Manager HSE is a reference regarding these requirements. 5. Complete the investigation, including the final report, in accordance with agreed upon timelines of refinery sponsor.
Deliverables:	1. Verbal progress reports shall be made monthly or as directed by refinery sponsor. 2. Interim reports will be issued as directed by refinery sponsor. 3. A final written report meeting Level 5 requirements will be reviewed and approved in accordance with company standards. 4. A final report out by the team will be made to the refinery sponsor.
Team Responsibilities:	1. The team shall meet to ensure that deliverables are completed on schedule. The Team Leader has primary responsibility for schedule compliance. Routine status shall be reported to Mike Johnson. 2. The team should schedule the interim and final report outs as early as possible to ensure open calendars of all desired participants. 3. Ask questions of the refinery sponsor where needed to gain clarity on the charter and the expectations of the team. 4. Work in an open, cross-functional, and fact-based environment.
Sponsor Accountabilities:	1. Assure the team has adequate resources 2. Remove any constraints that may prevent successful completion of the team’s investigation. 3. Demonstrate the importance of the investigation. 4. Provide final approval of the investigation report. 5. Publish timely Safety Insights. 6. Initiate corrective action tracking within 30 days of final approval of the investigation report. 7. Ensure PSM communications take place.
Investigation Status Reporting:	1. The Investigation Team Leader shall issue a periodic communication to all stake holders regarding the investigation status.

Investigation Charter page 3

Sponsor	Don Sorensen, Vice President, Tesoro Anacortes Refinery
Team Members (**identify which members are qualified on methodology)	
Investigation Team Leader	John Nowakowski**, TOP Coordinator, Tesoro Anacortes Refinery
Member	Rick Dowrey, Zone A Operations Training Supervisor, Tesoro Anacortes Refinery
Member	Allen Meyers, Inspection Supervisor, Tesoro Alaska Company
Member	Gerald Pineda, Senior Health and Safety Professional, Tesoro San Antonio
Member	John Smith, Pressure Equipment Engineer, Tesoro Los Angeles Refinery
Member	Robert Vogel, TOP Coordinator, Tesoro Mandan Refinery
Member	Tom Weber, Technical Services Manager, Tesoro Kapolei Refinery
Support Resources	Sam McFadden, Metallurgical Engineer, Anamet, inc.
TOP Facilitator	John Nowakowski, TOP Coordinator
Investigation Facilitator	Jon Bernardi, ThinkReliability
Technical Writer	Angela Griffith, ThinkReliability

Appendix C: TOP Investigation Team Biographies

John Nowakowski is the USW TOP Program Coordinator at Tesoro Northwest Company. He is one of the hourly representatives on the TOP investigation team. He has received TOP Coordinator, Train the Trainer and TOP Investigator training. He worked in operations for 11 years, maintenance for 1 year, and has been the TOP Coordinator for the last 10 years, all at the Anacortes Refinery. He participates in an average of 12 investigations per year locally and assists with all other TOP investigations within the Anacortes Refinery.

Rick Dowrey is the Zone A Training Supervisor at Tesoro Anacortes Refinery. He has worked in Zone A operations at the Anacortes refinery since 1990. He has been in a supervisor role since 2000.

Allen Meyers is the Mechanical Integrity SME, Senior Inspector and R&I Inspection Supervisor at Tesoro Kenai Refinery in Alaska. He is an American Petroleum Institute certified inspector and holds certifications in API 510, API 570, and API 653. He has 29 years of experience working within the Petrochemical, Nuclear and Mining Industries.

Gerald Pineda is a Senior Health and Safety Professional at Tesoro Companies, Inc. He is the salaried representative on the TOP investigation team. He has received TOP Investigator training. He has worked in refining for 13 years. He has spent 11 years at the Los Angeles Refinery, and 2 years at the San Antonio Headquarters. He has participated in investigations for the past 11 years and is currently the corporate work process owner for investigations.

John Smith is a Senior Pressure Equipment Engineer at the Tesoro Los Angeles Refinery. He has been at the Los Angeles Refinery since 2004 (first for Shell, then for Tesoro after Tesoro acquired the refinery). Prior to that, he worked at the Shell Deer Park Chemical Plant as a Pressure Equipment Engineer and Supervisor for 10 years. Prior to that, he worked at the Shell Westhollow Technology Center developing non-destructive techniques to inspect pressure vessels and piping for 5 years. He has participated in several TOP investigations.

Robert Vogel is the USW TOP Program Coordinator at Tesoro Mandan Refinery. He has received TOP Coordinator, Train the Trainer and TOP Investigator training. He worked for 15 years as a hydroprocess unit operator and relief supervisor, and 6 years as the TOP Program Coordinator, all at Mandan. He participates in an average of 8 investigations per year and assists with all other TOP investigations within the Mandan Refinery.

Tom Weber is the Manager of Technical Services at the Tesoro Kapolei Refinery in Hawaii. He has worked at Kapolei for 3 years, and worked at the Los Angeles Refinery for 10 years prior to that (first for Shell, then for Tesoro after Tesoro acquired the refinery). He has worked in refining since 1976, primarily in process engineering and operations.

Sam McFadden, PhD (materials science and engineering) is Associate Director of Laboratories at Anamet, inc. He has directed metallurgical failure analysis for 4 years. Prior to that, he worked in a Mechanics of Materials group at Sandia National Laboratories for 6 years. He has a background in non-destructive evaluation.

Appendix D: The TOP Program

The TOP (Triangle of Prevention) Program is a system based safety program. TOP is a worker driven, worker led, company supported Health and Safety Program. TOP uses a three prong approach on hazards recognition and elimination in the work place. This is primarily accomplished through a team investigation process of incidents and near misses that occur in the facility. The TOP program works to:

- Identify the failed Systems of Safety (SOS),
- Make recommendations to correct failed SOS,
- Track the recommendations from incident investigations and near miss reports to completion, and
- Publish and share the findings from these reports in the form of Lessons Learned reports to prevent reoccurrence of similar events at other facilities.

Systems of Safety are proactive systems that actively seek to identify, control, and/or eliminate workplace hazards. In the hierarchy of control, elimination of the hazard, through design and engineering, is the most effective level of protection. Other systems are also available to further minimize and control hazards and even protect when the higher level systems fail. (See chart on the following page.)

Table 6: TOP Program Safety Systems and Subsystems Examples

Major Safety Systems	Design & Engineering	Maintenance & Inspection	Mitigation Devices	Warning Devices	Training & Procedures	Personal Protective Factors
Level of Prevention	**Highest—the first line of defense**	**Middle—the second line of defense**				**Lowest—the last line of defense**
Effectiveness	**Most Effective**					**Least Effective**
Goal	***To eliminate hazards.***	***To further minimize and control hazards.***				***To protect when higher level systems fail.***
Examples of Safety Sub-Systems*	**Technical** Design and Engineering of Equipment, Processes and Software Management of Change (MOC)** Chemical Selection and Substitution Safe Siting Work Environment HF **Organizational** Staffing HF Skills and Qualifications HF Management of Personnel Change (MOPC) Work Organization and Scheduling HF Allocation of Resources Codes, Standards and Policies**	Inspection and Testing Maintenance Quality Control Turnarounds and Overhauls Mechanical Integrity	Enclosures, Barriers and Containment Relief and Check Valves Shutdown and Isolation Devices Fire and Chemical Suppression Devices	Monitors Process Alarms Facility Alarms Community Alarms Emergency Notification Systems	Operating Manuals and Procedures Process Safety Information Process, Job and Other Types of Hazard Assessment and Analysis Permit Programs Emergency Preparedness and Response Training Information Resources Communications Investigations and Lessons Learned	Personal Decision-making and Actions HF Personal Protective Equipment and Devices HF Stop Work Authority

Appendix E: Logic Tree