U.S. Chemical Safety and
Hazard Investigation Board

Fatal Naphtha Release and Fire at BP-Husky Toledo Refinery

Oregon, Ohio | *Incident Date: September 20, 2022* | **No. 2022-01-I-OH**

Investigation Report

Published: June 2024

Safety Issues:

- Liquid Overflow Prevention
- Abnormal Situation Management
- Alarm Flood
- Learning from Incidents

U.S. Chemical Safety and Hazard Investigation Board

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The September 20, 2022, naphtha release and fire at the BP-Husky Toledo Refinery fatally injured two employees, who were brothers:

Ben Morrissey

Max Morrissey

Contents

Abbreviations

°F	degrees Fahrenheit
ACM	Alarm Configuration Manager
ANSI	American National Standards Institute
API	American Petroleum Institute
ASAP	as soon as possible
ASM	Abnormal Situation Management
ASM®	Abnormal Situation Management® [Consortium]
ASME	American Society of Mechanical Engineers
AST	Absorber Stripper Tower
BPCS	Basic Process Control System
BP	BP Products North America Inc.
CCPS	Center for Chemical Process Safety
CFR	Code of Federal Regulations
CGP	Coker Gas Plant
CO	carbon monoxide
CSB	U.S. Chemical Safety and Hazard Investigation Board
DCS	Distributed Control System
EEMUA	Engineering Equipment and Materials Users Association
EMS	Emergency Medical Services
EPA	U.S. Environmental Protection Agency
ERT	Emergency Response Team
FCC	Fluid Catalytic Cracker
FGMD	Fuel Gas Mix Drum
GWR	Guided Wave Radar
HAZOP	Hazard and Operability Study
HCS	Hazard Communication Standard
HE	heat exchanger
HSSE	Health, Safety, Security & Environmental
HVGO	Heavy Vacuum Gas Oil
IPL	Independent Protection Layer
ISA	International Society of Automation
LLC	Limited Liability Company
LEL	lower explosive limit
LFL	lower flammability limit
LOPA	Layer of Protection Analysis

LPG	Liquefied Petroleum Gas
LVN	Light Virgin Naphtha
MAWP	maximum allowable working pressure
MAWT	maximum allowable working temperature
MOC	Management of Change
NHT	Naphtha Hydrotreater
NIOSH	National Institute for Occupational Safety and Health
ORC	Ohio Refining Company LLC
ORR	Operational Readiness Review
OSHA	U.S. Occupational Safety and Health Administration
OWS	Oily Water Sewer
PHA	Process Hazard Analysis
PSIG	pounds per square inch (gauge)
PSM	Process Safety Management
PSV	pressure safety valve
RMP	Risk Management Program
ROEIV	Remotely Operated Emergency Isolation Valve
SCBA	Self-Contained Breathing Apparatus
SDS	Safety Data Sheet
SIF	safety instrumented function
SIS	safety instrumented system
TAR	turnaround
TFO	Toledo Fuels Optimization
TIU	Toledo Integrated Unit
USW	United Steelworkers
WWTU	Wastewater Treatment Unit

Executive Summary

On September 20, 2022, at approximately 6:46 p.m., a vapor cloud ignited causing a flash fire[a] at the BP-Husky Refining LLC ("BP-Husky") refinery in Oregon, Ohio. The vapor cloud formed when two BP Products North America Inc. ("BP") employees released flammable liquid naphtha from a pressurized vessel to the ground.

As a result of the fire, both BP employees, who were brothers, were fatally injured. In addition, the events of the day caused approximately $597 million in property damage including loss of use.[b] BP estimated over 23,000 pounds of naphtha were released during the event. No off-site impacts were reported. To date, this is the largest fatal incident at a BP operated petroleum refinery since the fatal accident at the BP Texas City Refinery in 2005, which resulted in the deaths of 15 workers and injured 180 other people.[c]

The vessel typically contained only vapor (fuel gas for furnaces and boilers). However, during the incident, the vessel filled with liquid naphtha when an upstream tower overflowed naphtha into a vapor bypass line directly to the vessel. The upstream tower overflowed liquid naphtha through the vapor bypass line after a board operator opened a closed valve sending liquid naphtha to the tower operating in a vapor-only mode. Other refinery units had been shut down due to a loss of containment incident that occurred earlier that morning.

The initial process upset, the subsequent events and operational decisions made on September 20, 2022, led to liquid naphtha filling the vessel, which normally contained fuel gas. The vessel then overflowed into vapor piping feeding downstream furnaces and boilers. While draining the overflowing vessel as fast as they could pursuant to the board operator's directive communicated via radio, the BP employees opened the vessel and released liquid naphtha to the ground.

The refinery is located in Oregon, Ohio east of the city of Toledo and was operated by BP at the time of the incident. However, it is now owned and operated by Ohio Refining Company LLC ("ORC") an ultimate subsidiary of Cenovus Energy Inc. ("Cenovus").[d] This report will refer to the refinery as the "BP Toledo Refinery".

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[a] A flash fire "spreads by means of a flame front rapidly through a diffuse fuel, such as […] the vapors of an ignitable liquid, without the production of damaging pressure" [55].

[b] Property damage means damage to or the destruction of tangible public or private property, including loss of use of that property. *See* 40 CFR Part 1604 - Reporting of Accidental Releases.

[c] BP Products North America Inc. ("BP") also operates refineries in Whiting, Indiana, and Cherry Point, Washington, in the United States. *See* Refineries | What we do (bp.com).

[d] In 2021, Cenovus Energy Inc. ("Cenovus") merged with Husky Energy Inc. ("Husky") and became the indirect owner of the Husky Oil Toledo Company. On August 6, 2022, Husky Oil Toledo Company announced an agreement to purchase BP's ownership interest in the BP-Husky Refining joint venture. The transaction closed on February 28, 2023, making Husky Oil Toledo Company the sole owner of the refinery. After the closing, BP-Husky Refining LLC was renamed Ohio Refining Company LLC ("Ohio Refining Company"), which became both the owner and operator of the Toledo Refinery.

Safety Issues

The CSB's investigation identified the safety issues below.

- **Liquid Overflow Prevention.** Although the BP Toledo Refinery conducted Hazard and Operability Studies, a process hazard analysis (PHA) methodology, to assess the risk of liquid overflow events and identify safeguards, the refinery did not have sufficient safeguards to prevent the initiating event. In some cases, the BP Toledo Refinery relied on human intervention to respond to process upsets and deviations. Despite the BP Toledo Refinery's reliance on human intervention as an identified safeguard for overflow of the Absorber Stripper Tower to the Fuel Gas Mix Drum, the refinery did not adequately consider potential hazards that could exist if the drum contained high levels of flammable liquid (such as naphtha) and needed to be drained. Nor did the BP Toledo Refinery have procedures, written instructions, or documented corrective actions for operators to respond to or troubleshoot a high liquid level in the Fuel Gas Mix Drum during either normal operations or process upsets if liquid entered the drum. Furnace safety instrumented systems and emergency pressure-relief valves were also identified as safeguards in the BP Toledo Refinery's PHAs for overflow of the Absorber Stripper Tower to the Fuel Gas Mix Drum, but neither were effective in preventing liquid overflow to the fuel gas system Additionally, the industry lacks sufficient guidance on protective systems for a Fuel Gas Mix Drum despite it being an integral part of a refinery's fuel gas system. (*See* Section 4.1)

- **Abnormal Situation Management.** An abnormal situation is a process disturbance with which the basic process control system cannot cope. Abnormal situations can create a stressful environment for the operators. If abnormal situations are not effectively managed, they can escalate into a more serious incident. In its book, *Guidelines for Managing Abnormal Situations,* the Center for Chemical Process Safety (CCPS) states: "[s]udden, potentially dangerous situations can affect human performance (the "startle" factor), leading to a "fight or flight" response that can lead to inappropriate action being taken" [1, pp. 87-88]. In the 24 hours leading up to the incident, the BP Toledo Refinery experienced a number of abnormal situations across several units, escalating to overfilling the Fuel Gas Mix Drum. This prompted two BP employees to release the Fuel Gas Mix Drum contents to the ground, ultimately cascading to the vapor cloud, fire, and fatal injuries. (*See* Section 4.2)

- **Alarm Flood.** Board operators at the BP Toledo Refinery were receiving far more than 10 alarms in 10 minutes on average, a situation in which more alarms were annunciating than a human can effectively respond to, for nearly 12 hours preceding the incident. Between 6:50 a.m. and 6:49 p.m. September 20, 2022, a total of 3,712 alarms were recorded. Continued operation in an alarm flood state contributed to the incident by causing delays and errors in responding to critical alarms and shift-to-shift communications. Had the Tuesday, September 20, 2022, night shift board operators been less overloaded with alarms, they might have identified that the Coker Gas Plant Absorber Stripper Tower was overflowing naphtha through the Coker Gas Plant bypass piping directly to the Fuel Gas Mix Drum and stopped liquid flow to the Fuel Gas Mix Drum, preventing or mitigating the incident. (*See* Section 4.3)

- **Learning from Incidents.** The final recommendation of the report of the BP U.S. Refineries Independent Safety Review Panel in 2007 ("the Baker Panel Report") stated: "BP should use the lessons learned from the Texas City tragedy and from the Panel's report to transform the company into a recognized industry leader in process safety management" [2, p. 257].[a] In its investigation of the September 20, 2022, naphtha release and fire, the CSB found similarities between the overflow events of the BP Toledo Refinery incident and the findings from the fatal explosions in 2005 at the BP refinery in Texas City, Texas. Catastrophic incident warning signs existed prior to the September 20, 2022, incident at the BP Toledo Refinery, and had BP effectively recognized and acted upon the warning signs following a 2019 incident, the company could have provided more effective safeguards to prevent the overflow of multiple vessels during a refinery upset such as the September 20, 2022, incident. (*See* Section 4.4)

See Appendix B for the accident map (AcciMap), which provides a graphical analysis of this incident.

Cause

The CSB determined the cause of the incident was operators opening valves and removing a flange on the pressurized Fuel Gas Mix Drum to release a flammable liquid, naphtha, directly to the ground. After being released to the ground, the flammable liquid formed a vapor cloud that reached a nearby ignition source resulting in a flash fire.

Contributing to the incident were 1) the refinery's failure to implement effective preventive safeguards for the overflow of towers and vessels in various pieces of equipment which led to an over-reliance on human intervention to prevent incidents; 2) the refinery's failure to implement a shutdown or hot circulation through the use of Stop Work Authority or otherwise; 3) the refinery's ineffective policies, procedures, and practices to avoid and control abnormal situations; 4) the refinery's alarm system which flooded operators with alarms throughout the day resulting in poor decision making; and 5) the refinery's failure to learn from previous incidents.

Recommendations

To Ohio Refining Company LLC

2022-01-I-OH-R1

Revise the safeguards used in the refinery's process hazard analyses high level and overflow scenarios. At a minimum, establish effective preventive safeguards that use engineered controls to prevent liquid overfill and do not rely solely on human intervention.

2022-01-I-OH-R2

Revise the Abnormal Situation Management policy to incorporate guidance provided by the ASM Consortium and the Center for Chemical Process Safety (CCPS). The revised policy should include, at a minimum:

[a] In 2005, the CSB issued an urgent safety recommendation to the BP Group Executive Board of Directors that it convene an independent panel of experts to examine BP's corporate safety management systems, safety culture, and oversight of the North American refineries. BP accepted the recommendation and commissioned the BP U.S. Refineries Independent Safety Review Panel [31, pp. 27-28]. BP Group means BP p.l.c. and its subsidiaries and affiliates [56].

a) A broader definition of abnormal situations, such as that defined by the CCPS,

b) Additional predictable abnormal situations and their associated corrective procedures. At a minimum include the following abnormal situations:

    1) unplanned crude slate changes,

    2) continued operation of the Crude 1 unit with the naphtha hydrotreater unit shut down, and

    3) an emergency pressure-relief valve opening.

c) Guidance to determine when an abnormal situation is becoming too difficult to manage and the appropriate actions to take, such as shutting down a process, putting it into a circulation mode, or implementing proper procedures for bringing it to a safe state.

2022-01-I-OH-R3

Develop and implement a policy or revise existing policy that clearly provides employees with the authority to stop work that is perceived to be unsafe until the employer can resolve the matter. This should include detailed procedures and regular training on how employees would exercise their stop work authority. Emphasis should be placed on exercising this authority during abnormal situations, including alarm floods.

2022-01-I-OH-R4

Revise the 'Toledo Alarm Philosophy' by incorporating the Engineering Equipment and Manufacturers Users Association (EEMUA) guidance for alarm rate following an upset and not limiting alarm performance to a single metric averaged over a month. In addition to including analyzing individual alarm flood events, the revised philosophy document should improve refinery alarm performance to reduce alarm flood duration and peak rate for events similar to the September 20, 2022, incident. Consult EEMUA Publication 191, Chapter 6.5.1, for guidance regarding abnormal condition performance levels. Apply the improved performance levels where applicable, but specifically to the Crude 1 control board alarm performance.

To American Petroleum Institute (API)

2022-01-I-OH-R5

Develop a new publication or revise an existing publication, such as API Recommended Practice 556 *Instrumentation, Control, and Protective Systems for Gas Fired Heaters,* to incorporate the process hazards associated with Fuel Gas Mix Drum overflow. The publication should include the following at a minimum:

a) Description of the process hazards associated with Fuel Gas Mix Drum overflow and the consequential impacts on equipment using fuel gas,

b) Guidance for Fuel Gas Mix Drum design and sizing criteria which includes consideration of condensation, entrainment, overflow, and draining,

c) Guidance for instrumentation to detect high level to prevent overfilling of Fuel Gas Mix Drums, and

d) Recommended practices for selecting preventive safeguards to prevent overfilling of Fuel Gas Mix Drums.

2022-01-I-OH-R6

Develop a publication that addresses preventing the overflow of pressure vessels such as towers and drums. The publication should be applicable to both new and existing pressure vessels. Include the following at a minimum:

a) Description of typical overflow events that could result during normal, upset, or transient operations (startup, shutdown, standby) including the formation of a vapor cloud,
b) Recommended practices for instrumentation to monitor and detect a pressure vessel overflow,
c) Process hazard analysis guidance for pressure vessel overflow scenarios,
d) Recommended practices for safeguards to prevent a pressure vessel overflow,
e) Recommended field and board operator process safety training topics and methods to prevent a pressure vessel overflow,
f) Guidelines for process safety assessments to prevent a pressure vessel overflow, and
g) Incorporate lessons learned from this CSB investigation and the CSB's BP Texas City Refinery investigation throughout the document.

To International Society of Automation (ISA)

2022-01-I-OH-R7

Revise American National Standard ANSI/ISA 18.2-2016, *Management of Alarm Systems for the Process Industries*, to include performance targets for short-term alarm flood analysis so that users can evaluate alarm flood performance for a single alarm flood event. The performance targets should include:

a) number of alarm floods,
b) duration of each flood,
c) alarm count in each flood, and
d) peak alarm rate for each flood.

At a minimum, a target peak alarm flood rate should be defined, such as in the guidance provided by the ASM Consortium or Engineering Equipment and Materials Users Association (EEMUA), to establish trigger points that require alarm performance improvement actions.

1 Background

1.1 BP Toledo Refinery

The BP Toledo Refinery is located east of the city of Toledo, in Oregon, Ohio. The refinery sits on 586 acres and has operated since 1919 [3]. The refinery can process approximately 160,000 barrels of crude oil per day, producing gasoline, diesel, jet fuel, propane, asphalt, and other products [4]. As of September 2022, the refinery employed 588 people.[a]

Figure 1 shows the various units of the BP Toledo Refinery divided into six zones. The star in the red outlined Crude 1 unit shows the approximate location of the September 20, 2022, naphtha release and fire from the Fuel Gas Mix Drum.

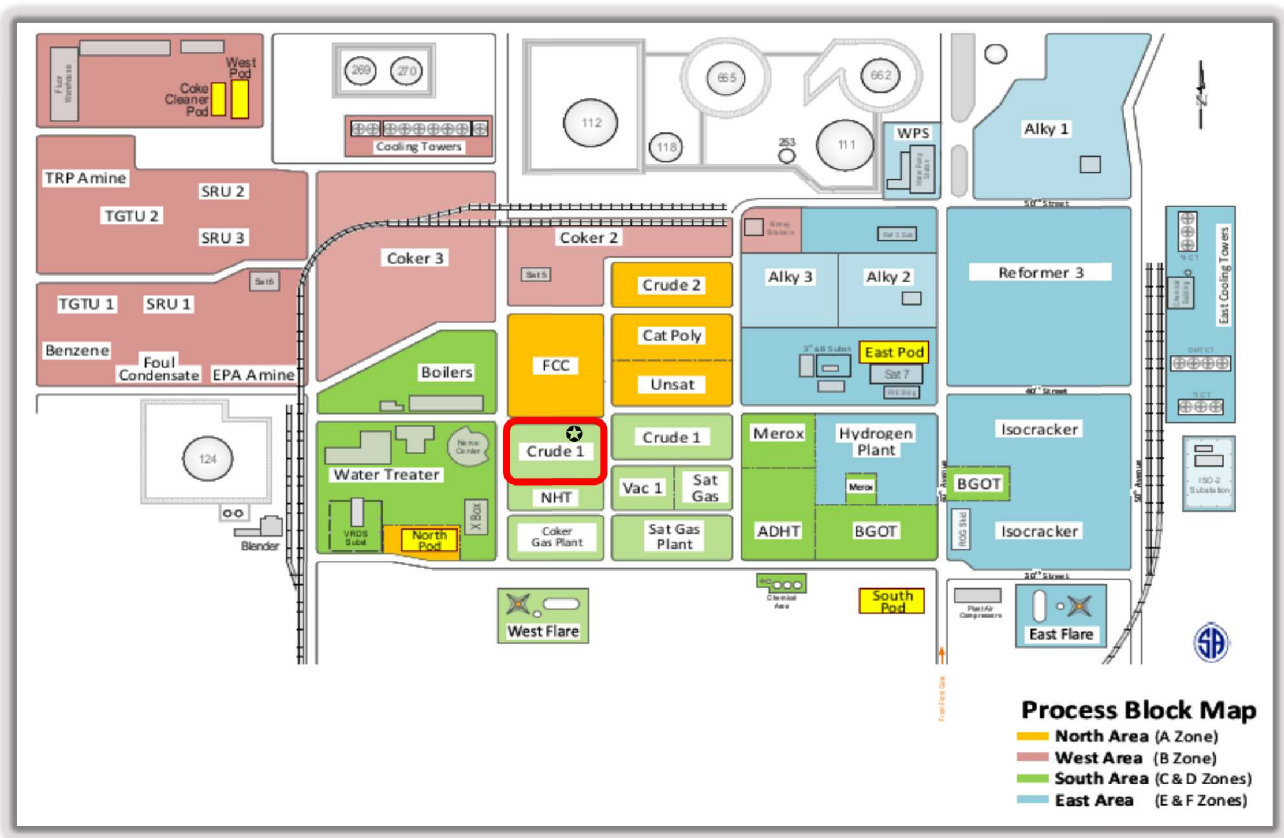

Figure 1. BP Toledo Refinery Process Block Map. (Credit: BP)

A simplified schematic of the relevant portion of the BP Toledo Refinery is shown in **Figure 2**. Crude oil is pumped from storage tanks to the Crude 1 Tower (*See* **Section 1.6**). After the Crude 1 Tower overhead is

[a] The United Steelworkers (USW) represented approximately 355 of the BP Toledo Refinery workers as of September 2022.

cooled, the liquid naphtha from the Crude 1 Overhead Accumulator Drum (*See* **Figure 4**) can be sent to three places:

1. to the Naphtha Hydrotreater unit ("the NHT unit"),
2. to the Coker Gas Plant to treat wet coker gas[a] (*See* **Section 1.8**), and
3. to Light Virgin Naphtha Storage.

Naphtha from the Coker Gas Plant goes to the Naphtha Hydrotreater Feed Surge Drum ("NHT Feed Surge Drum"). The stream from the NHT Feed Surge Drum combines with the naphtha from the Crude 1 Overhead Accumulator Drum to enter NHT Preheat.[b]

Wet coker gas from the Coker Gas Plant combines with various other refinery fuel gas streams in the Toledo Integrated Unit Fuel Gas Mix Drum ("the Fuel Gas Mix Drum") (*See* **Section 1.5**). The fuel gas is burned in various refinery boilers and furnaces.

[a] Coker wet gas is from the refinery Coker units. Coking is a physical process that occurs at pressures slightly higher than atmospheric and at temperatures greater than 900 °F that thermally crack the feedstock into products such as naphtha and distillate, leaving behind petroleum coke. *See* Coking is a refinery process - U.S. Energy Information Administration (EIA).

[b] "NHT Preheat" is used in this report to describe a series of seven shell and tube heat exchangers used to heat naphtha from the Crude 1 unit prior to entering the NHT unit for processing.

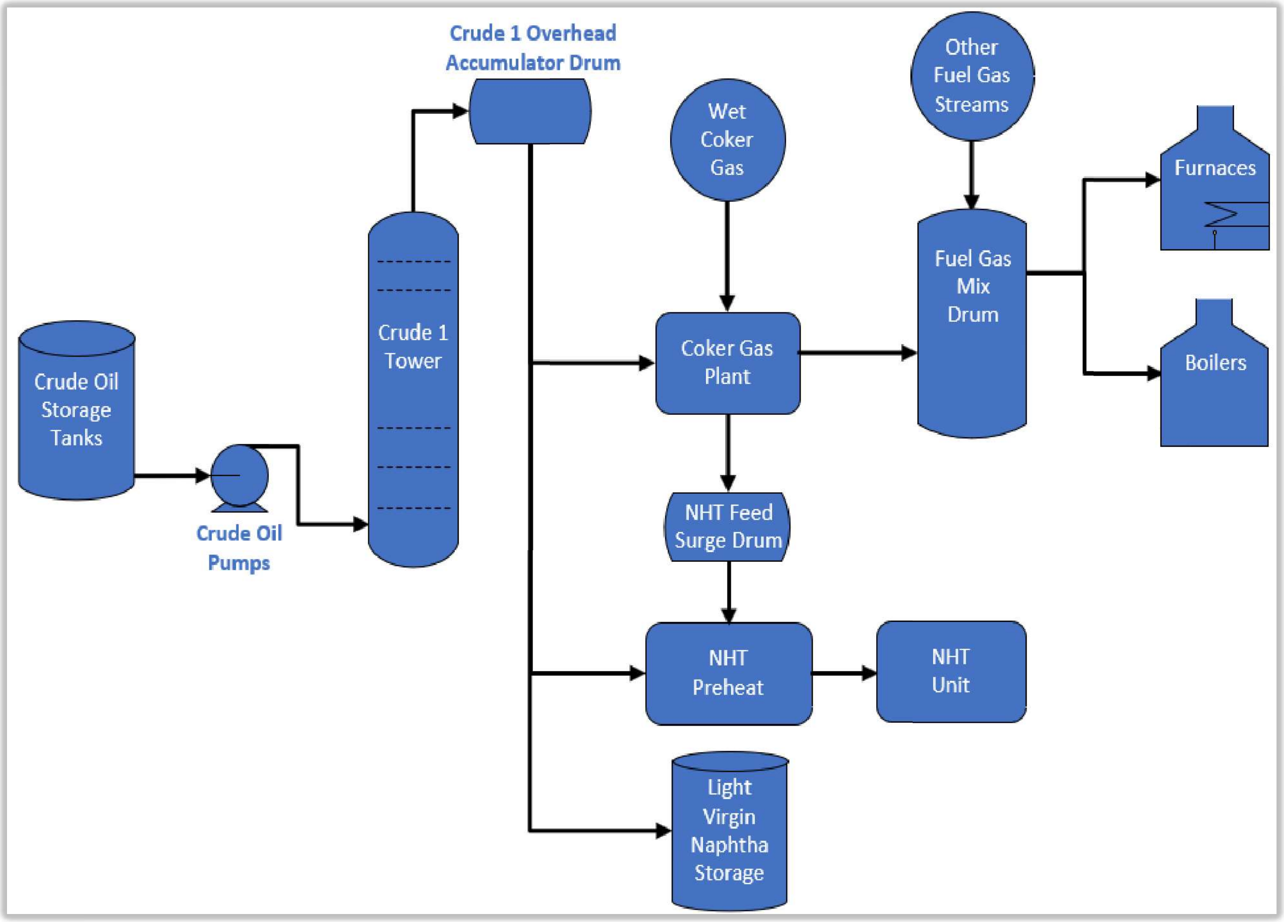

Figure 2. BP Toledo Refinery. Simplified schematic of the parts of the refinery involved in the September 20, 2022, incident. (Credit: CSB)

1.2 Owner and Operator

In 2008, BP-Husky Refining LLC ("BP-Husky") acquired the BP Toledo Refinery from BP Products North America Inc. ("BP").[a] BP-Husky Refining LLC was a 50/50 joint venture formed by the Toledo Refinery Holding Company, a subsidiary of BP and the Husky Oil Toledo Company, an indirect subsidiary of Husky Energy Inc. ("Husky") [5]. BP operated the BP Toledo Refinery for the joint venture, and refinery personnel were BP employees operating under established BP policies, practices, and procedures.

In 2021, Cenovus Energy Inc. ("Cenovus") merged with Husky and became the indirect owner of the Husky Oil Toledo Company [6]. On August 6, 2022, Husky Oil Toledo Company announced an agreement to purchase BP's ownership interest in the BP-Husky Refining joint venture. The transaction closed on February 28, 2023, making Husky Oil Toledo Company the sole owner of the refinery [7]. After the closing, BP-Husky Refining LLC was renamed Ohio Refining Company LLC ("Ohio Refining Company"), which became both the owner and operator of the Ohio Refining Company Toledo Refinery.

[a] BP acquired Sohio and the Toledo Refinery in 1987 [46].

1.3 Naphtha

Naphtha is a fraction of crude oil that includes hydrocarbons ranging from C_5 to C_{12} and comprises approximately 15-30 weight percent of raw crude oil [8, p. 2]. The vapor density of naphtha is three to four times heavier than air. Naphtha can contain hydrogen sulfide (H_2S), a toxic and flammable gas.

Naphtha is a flammable liquid.[a] The BP Safety Data Sheet (SDS) for naphtha lists the boiling point range as 20 degrees Fahrenheit (°F) to 450 °F and the flash point as −45 °F.[b] Liquids with a flash point of less than 23 °F and initial boiling point less than 95 °F fall into the highest flammable liquids hazard category of the U.S. Occupational Safety and Health Administration (OSHA) Hazard Communication Standard (HCS).[c]

1.4 Refinery Fuel Gas

Fuel gas is typically produced as a vapor by-product in various refinery units, including catalytic reforming, hydrotreating and hydrocracking, catalytic cracking, and coking [9]. According to the U.S. Environmental Protection Agency (EPA) National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, a refinery fuel gas system includes the off-site and on-site piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery [10].[d] Fuel gas is typically piped directly to each individual combustion device, and the fuel gas system typically operates above atmospheric pressure. These gaseous hydrocarbon streams commonly contain a mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species.

1.5 Fuel Gas Mix Drum

A Fuel Gas Mix Drum is typically used to prevent operational problems in fuel-using systems, such as boilers or furnaces, and mixes fuel gas streams from various refinery units. Fuel-using systems are typically designed to accept a certain degree of change in the fuel gas supply; however, their burners can be sensitive to the rate of change. The mixing of fuel gas from various refinery units limits the effects of changes in fuel gas composition, properties, or pressure in fuel-using systems [11].

Figure 3 is a simplified drawing of the Fuel Gas Mix Drum and associated level instrumentation at the BP Toledo Refinery. The fuel gases from multiple refinery units mix in the drum before going to refinery boilers

[a] The U.S. Occupational Safety and Health Administration (OSHA) states that a flammable liquid means any liquid having a flash point at or below199.4 °F (93 degrees Celsius [°C]). *See* 29 C.F.R. § 1910.106(a)(19).

[b] Flash point means the minimum temperature at which a liquid gives off vapor within a test vessel in sufficient concentration to form an ignitable mixture with air near the surface of the liquid. *See* 29 CFR § 1910.106(a)(14).

[c] *See* OSHA Hazard Communication Standard (HCS) at Hazard Communication - Appendix B | (osha.gov).

[d] At the BP Toledo Refinery, butane is vaporized as a source of gas to blend with the refinery fuel gas.

and furnaces. Any liquid from entrainment or condensation is detected by level instrumentation and a sight glass.[a] Liquid is manually drained to a Flare Knockout Drum or an Oily Water Sewer.[b]

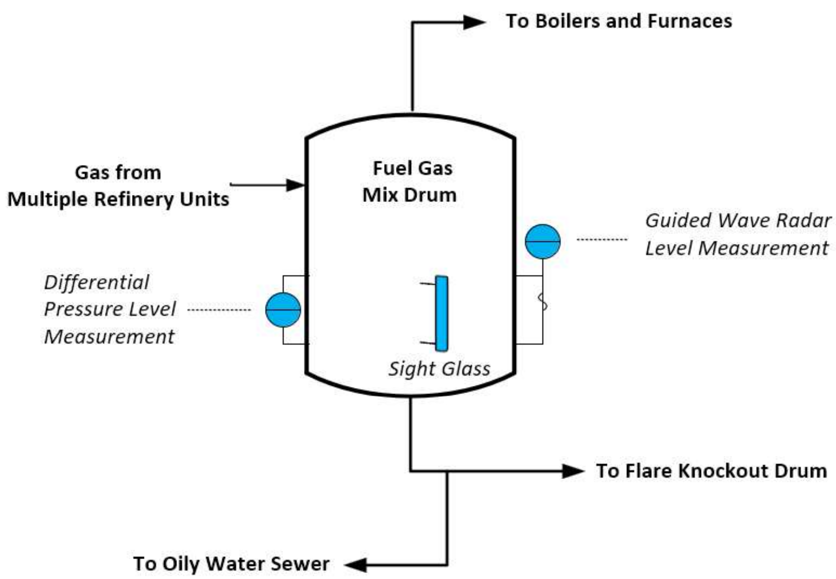

Figure 3. Simplified drawing of the BP Toledo Refinery Fuel Gas Mix Drum and associated level instrumentation.[c] (Credit: CSB)

Condensed liquids must be removed from fuel gas streams. Proper removal and disposal of fuel gas condensate from a fuel gas system is an important consideration for safe operation [9]. BP's Process Safety Series *Safe Furnace and Boiler Firing* explains:

[a] Condensation in piping, or carryover or overflow from towers, can be responsible for the presence of liquid hydrocarbons in fuel-gas systems [12, p. 32]. Fuel gas can become saturated with water when processed in an amine treating unit [9]. High gas velocity through an absorbing tower can entrain liquid and cause carryover, or a faulty bottom level controller can permit tower overflow [12, p. 32]. Additional condensation can occur when the fuel gases are used in cold climates [9]. Condensate can be a mixture of water, hydrocarbons, or amine. Hydrogen sulfide can be present in condensate.

[b] The Oily Water Sewer System is a regulated system in the refinery designed to collect process wastewater, cooling tower blowdown, stormwater runoff, storage tank water drawdowns, and other process waste streams. These wastewaters are treated at the refinery Wastewater Treatment Unit (WWTU) prior to passing through a permitted outfall. All refinery process areas drain by gravity directly to the main 84-inch Oily Water Sewer to the WWTU. The BP Toledo Refinery Health, Safety, Security & Environmental (HSSE) Handbook Revision #7 issued February 1, 2020, states that regulations that apply to the sewer system or materials that are drained to the sewer system include 40 CFR Part 60 Subpart QQQ - Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems and 40 CFR Part 61 Subpart FF - National Emission Standard for Benzene Waste Operations.

[c] The Fuel Gas Mix Drum has two liquid level instrument measurement devices. One was a guided wave radar level measurement which is "independent of most liquid properties, especially density" [63, p. 133]. The other was a differential pressure meter since "liquid level can be measured (inferred) by measuring a differential pressure caused by the weight of a fluid column in a vessel balanced against a reference" [64, p. 454].

> liquid in the fuel-gas system may enter [a] burner, put out the fire and create a severe explosion hazard in [a] furnace [12, p. 52].[a]

BP's Process Safety Series *Hazards of Oil Refining Distillation Units* describes the hazard of an unscheduled or emergency shutdown and the draining of a fuel gas system. This booklet describes a 1984 incident at a Singapore refinery where a major process upset resulted in liquid entering the fuel gas system. An explosion occurred when workers attempted to drain the fuel gas system [13, p. 23 and 78]. [b]

1.6 Crude Oil and Crude Slate

Crude oil is a mixture of many hydrocarbon compounds and impurities that must be processed and purified in order to make useful products such as gasoline and diesel fuel [14, pp. 13, 15], [15, p. 13]. There are many grades of crude oil, but for the purposes of this report, they can be divided into two: light and heavy. "Light crude" oil is crude oil that contains more low molecular weight components, is more volatile and less viscous, and flows more easily. "Heavy crude" oil, by contrast, contains higher molecular weight components, and is less volatile and more viscous than light crude oil [14, pp. 13, 15], [15, p. 13].

A refinery's crude slate is defined as "the mix of crude oils used as inputs" [15, p. 36]. In this report, the "crude slate" refers to the crude oil feed composition to the Crude 1 unit. The refinery processed various compositions of crude oil, but the crude slate feeding the Crude 1 unit typically included a percentage of light crude at any given time. The light crude, having lighter hydrocarbon components, tended to exit the Crude 1 Tower at or near the top, and the heavy crude components tended to exit the tower from the lower sections.

1.7 Crude 1 Tower

Crude oil is delivered to the BP Toledo Refinery via pipelines and is stored in tanks. The crude oil is pumped from storage tanks, preheated in a series of heat exchangers, and heated in a furnace before flowing to the Crude 1 Tower. The Crude 1 Tower separates the crude oil into six basic product boiling ranges. A simplified schematic of the Crude 1 Tower is shown in **Figure 4**.

[a] The BP Process Safety Series is a collection of booklets describing hazards and how to manage them.

[b] Incidents list | Serial number 113.

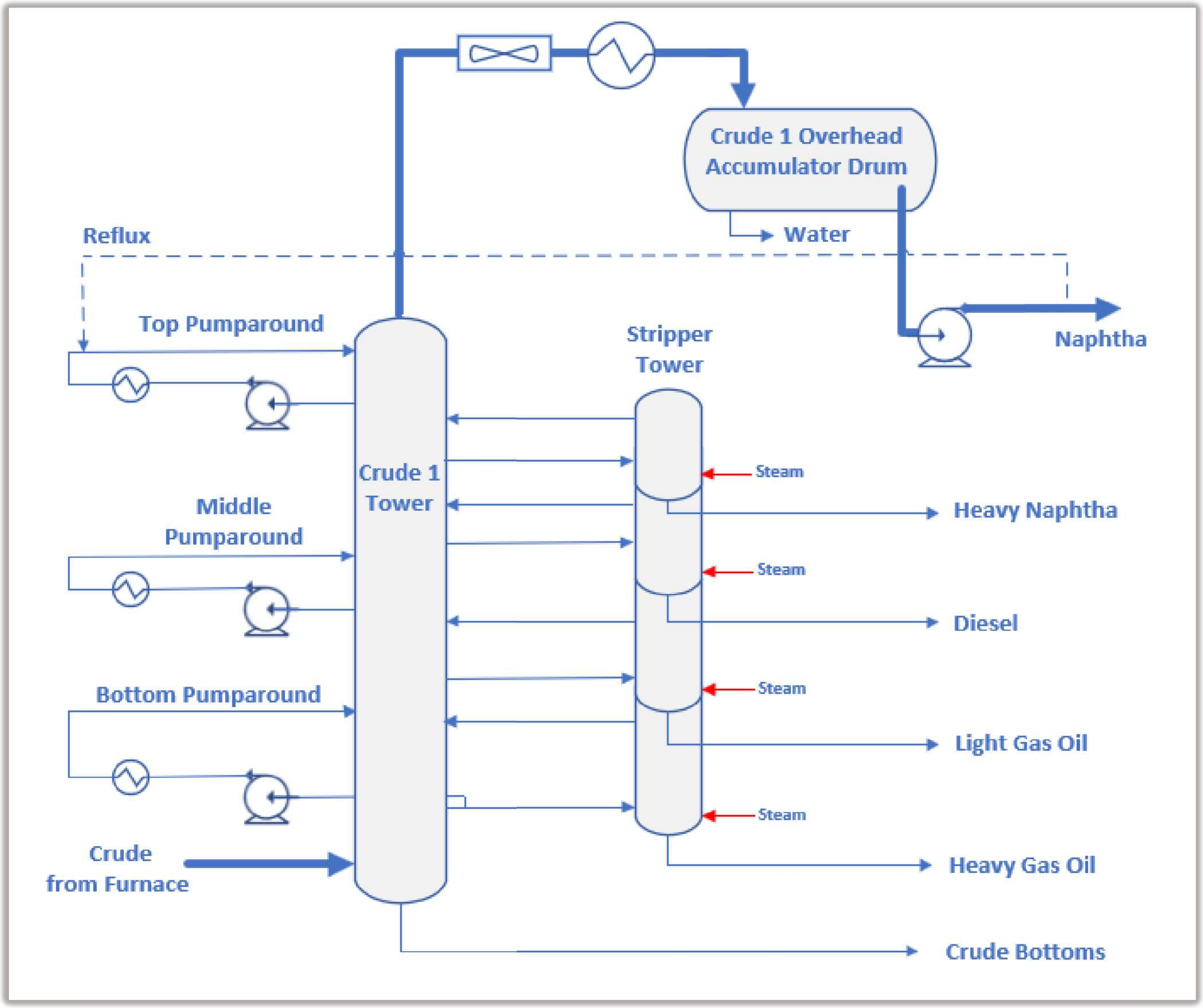

Figure 4. Crude 1 Tower. This simplified schematic shows the crude tower BP used to separate crude oil into various products. (Credit: CSB)

The lower boiling point materials travel to the top of the Crude 1 Tower as vapor, and the higher boiling point materials travel to the bottom of the tower. The top, middle, and bottom pumparounds remove liquid products and heat from the Crude 1 Tower. The pumparounds return cooled liquid, which condenses some of the rising vapors and provides reflux, which compensates for removing product streams. The Stripper Tower has four side strippers inside that use steam to strip lighter hydrocarbons from the heavy naphtha, diesel, light gas oil, and heavy gas oil product draws.

The lightest material, naphtha, is partially condensed and separated in the Crude 1 Overhead Accumulator Drum. The heaviest of the components drop to the bottom of the Crude 1 Tower and are pumped as feed to a vacuum distillation unit.

The naphtha in the Crude 1 Overhead Accumulator Drum is routed most commonly to the NHT unit and the Coker Gas Plant. The streams to the Light Virgin Naphtha Storage and Crude 1 Tower reflux are normally closed but available for use.

Figure 5 is a simplified schematic of where naphtha in the Crude 1 Overhead Accumulator Drum could be sent.[a]

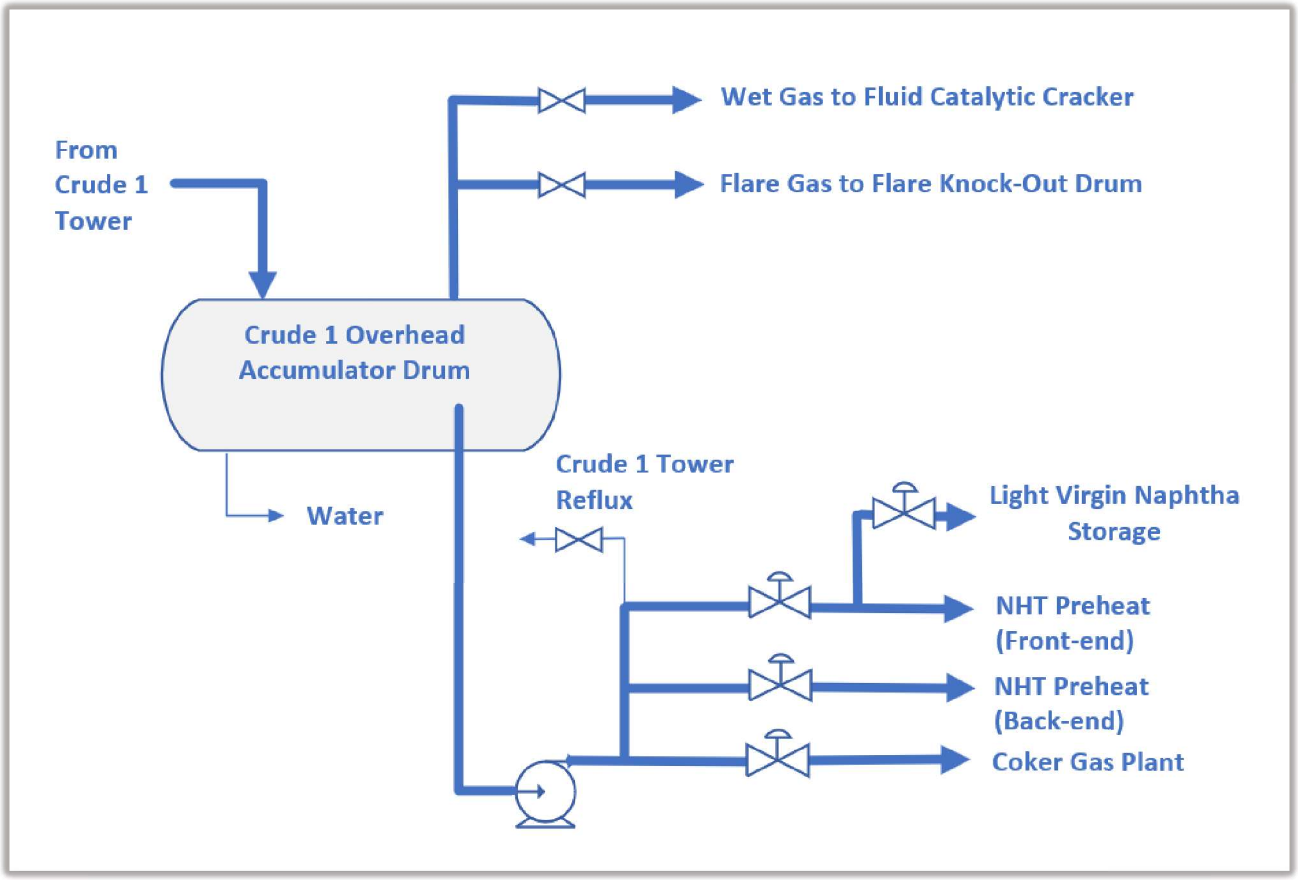

Figure 5. BP Toledo Refinery Crude 1 Overhead Accumulator Drum. This simplified schematic shows the various places BP could send liquid naphtha. (Credit: CSB)

1.8 Coker Gas Plant

To reduce sulfur emissions from furnaces at the BP Toledo Refinery, BP designed and built a Coker Gas Plant, which was integrated into the refinery in 2018.[b] The Coker Gas Plant removes mercaptans and other sulfides

[a] Naphtha can be sent to directly to NHT preheat on the front end or preheated in another series of heat exchangers and combined with the naphtha exiting NHT preheat on the back end.

[b] In order to meet U.S. Environmental Protection Agency's (EPA) Operating Permits issued under Title V of the Clean Air Act, BP developed a processing scheme to segregate and treat coker generated gas to reduce overall BP Toledo Refinery fuel gas total sulfur levels to 120 ppm by volume or less on an annual average basis.

from coker wet gas, a major sulfur contributor to refinery gas.[a] Removal of the mercaptans and other sulfides is accomplished using naphtha from the Crude 1 Overhead Accumulator as an absorbing medium in the Coker Gas Plant Absorber Stripper Tower. Entrained water in the coker wet gas feed is removed from the Absorber Stripper Tower using a Foul Condensate Draw Off Drum. **Figure 6** shows a simplified schematic of the Coker Gas Plant.

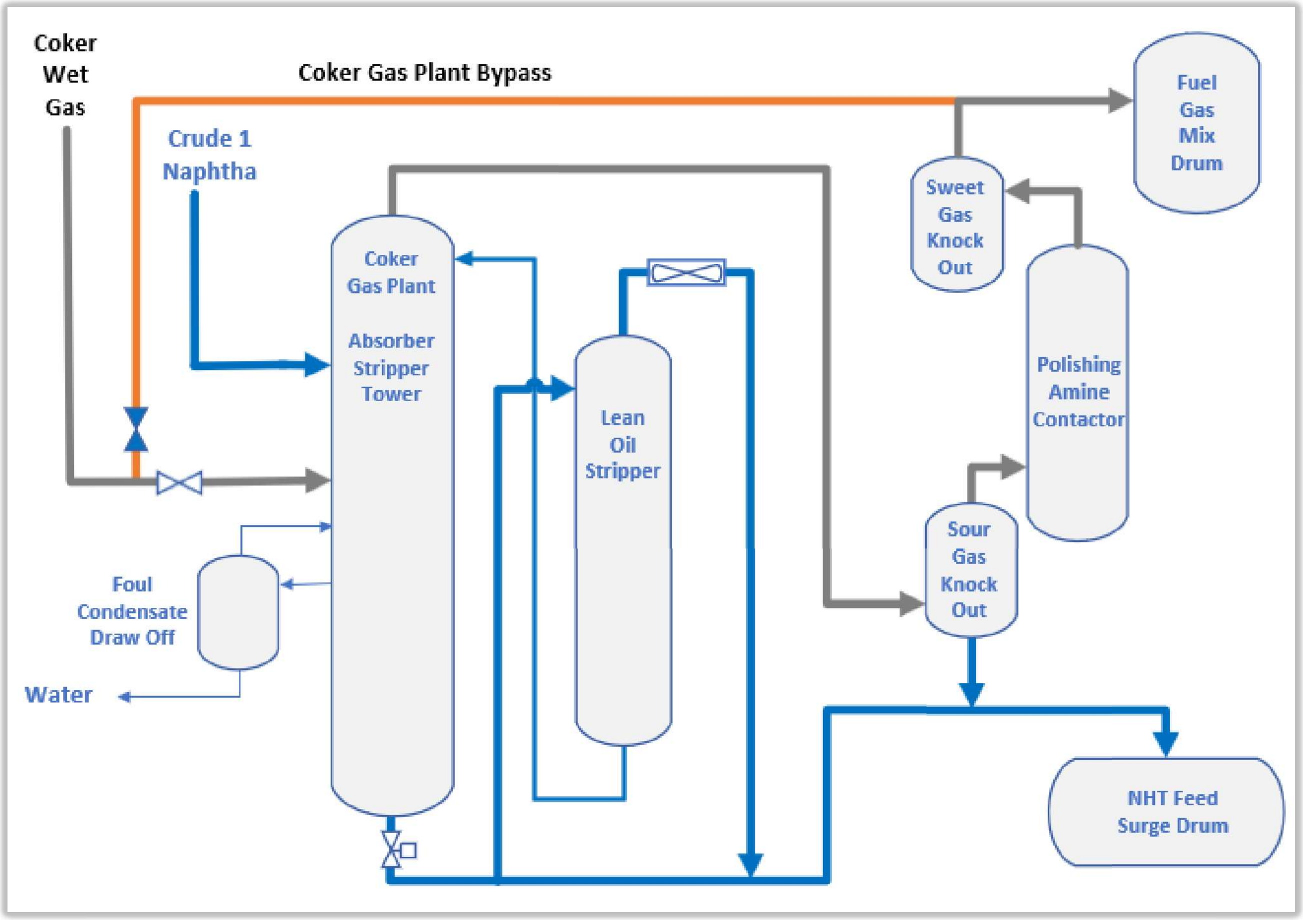

Figure 6. Coker Gas Plant. A simplified schematic of BP's process to remove sulfur from coker wet gas. (Credit: CSB)

A portion of the Absorber Stripper Tower bottoms liquid is sent to the Lean Oil Stripper as feed. The Lean Oil Stripper Tower removes mercaptans from the Absorber Stripper Tower bottoms, producing mercaptan free lean oil (naphtha). The lean oil is returned to the Absorber Stripper Tower to further reduce the mercaptans and other sulfides in the coker wet gas.

The remaining Absorber Stripper Tower bottoms liquid is sent to the NHT Feed Surge Drum. The NHT Feed Surge Drum accumulates naphtha from multiple sources and sends it to the NHT unit.

[a] Coker wet gas from the coker wet gas compressor is water washed and amine treated to remove the majority of hydrogen sulfide (H_2S) before entering the Coker Gas Plant. The water wash prevents salt build up.

After being processed in the Absorber Stripper Tower, treated coker wet gas is sent to the Sour Gas Knockout Drum to remove any entrained liquid. Next it is treated in the Polishing Amine Contactor to further remove hydrogen sulfide before flowing to the Fuel Gas Mix Drum. The Fuel Gas Mix Drum receives gas from multiple refinery sources and provides fuel gas to boilers and furnaces throughout the refinery.

The coker wet gas can also bypass the Coker Gas Plant and flow directly to the Fuel Gas Mix Drum as shown in **Figure 6** in orange. The bypass line allows untreated coker wet gas to be directly sent to the Fuel Gas Mix Drum when the refinery needs to perform maintenance on the Coker Gas Plant.[a]

1.9 Shift Operations Staffing

Operations personnel normally worked on one of four rotating 12-hour shifts. Operators rotated through multiple jobs within their assigned areas. Typically, only one board operator[b] was assigned to monitor and control the control room consoles for the Crude 1 unit, the Vacuum 1 unit, the NHT unit, the Saturated Gas Plant, the Coker Gas Plant, and the West Flare.[c]

During the night shift of September 20, 2022, two board operators were assigned to operate these consoles in the control room. The regularly scheduled board operator had been only recently qualified as a board operator and had worked in the control room alone for less than a month. The second board operator told the U.S. Chemical Safety and Hazard Investigation Board (CSB) that they had received a call earlier in the day to come in and help. The second board operator had worked six years as a board operator. As always, a refinery coordinator was working with all the board operators on the night shift.[d]

An operator trainee, who had started working at the BP Toledo Refinery in March 2022, stayed over from the day shift to the night shift to assist three regularly scheduled outside operators,[e] one of whom was his brother who had been working at the BP Toledo Refinery since 2020. In this report, an outside operator and outside shift supervisor refer to BP employees who primarily work outdoors (or in the field) at the BP Toledo Refinery. These three outside operators were covering the Crude 1 unit, where the Fuel Gas Mix Drum was located, and surrounding areas. The outside operators reported to an outside shift supervisor.

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[a] After the Coker Gas Plant start-up in 2018, a control valve was added to the Coker Gas Plant bypass line to prevent foaming in and amine carryover from the Polishing Amine Contactor (*See* **A.2.6.2**).

[b] Situation awareness is "[a]n important responsibility of console [board] operators is to prevent and respond to abnormal situations. The nature of the abnormal situation may be of minimal or of catastrophic consequence; it is the job of the operations team to identify the cause of the situation and execute compensatory or corrective action in a timely and efficient manner. Abnormal situations extend, develop, and change over time in the dynamic process control environments increasing the complexity of the intervention requirements. Proactively maintaining their situation awareness of the process, where it is, where it is going, and how quickly it is going there, is what is required of both console [board] and field [outside] operators to effectively prevent and respond to abnormal situations when they arise. Successfully responding to abnormal situations depends upon both console [board] and field [outside] operators knowing not only what tasks to perform and how to perform them, but also when to perform them. To become proficient, an operator must know what to watch, how frequently to watch, what to do, how to do it, and when to do it—all components of knowledge that contribute to effective situation awareness" [66]. (*See* **Section 4.2**).

[c] The Fuel Gas Mix Drum, located in the Crude 1 unit, is monitored by the board operator.

[d] A refinery coordinator is in charge of the refinery control room and the feeds in and out of the refinery.

[e] Outside operators, also known as field operators, are BP employees who perform manual tasks on unit equipment.

The refinery coordinator and outside shift supervisor reported directly to a shift superintendent. The BP Toledo Refinery shift operations staffing for September 20, 2022, is shown in **Figure 7** below.

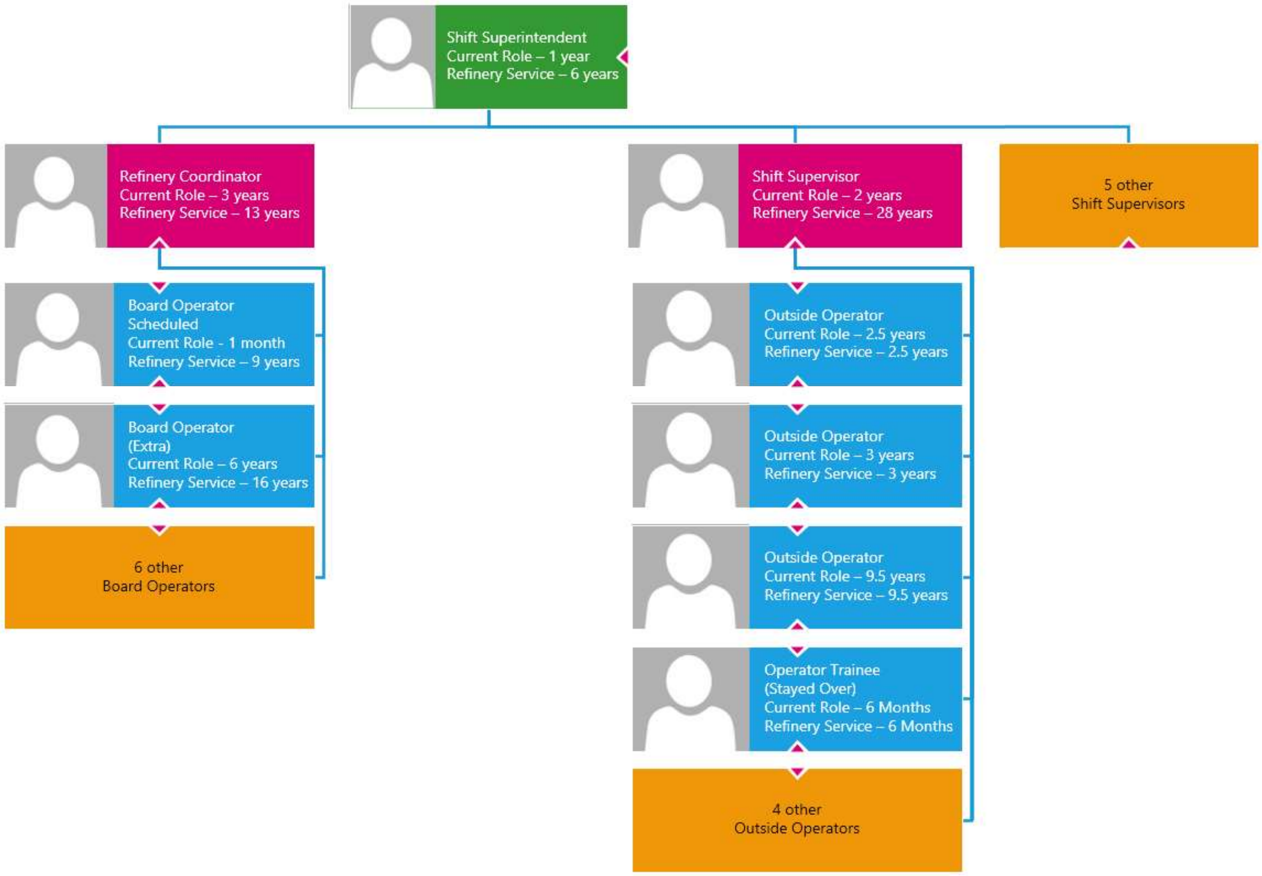

Figure 7. BP Toledo Refinery shift operations staffing. The BP Toledo Refinery shift operations personnel assigned to operate the Crude 1 unit, the Vacuum 1 unit, the NHT unit, the Saturated Gas Plant, the Coker Gas Plant, and the West Flare are shown in blue. (Credit: CSB).

1.10 Federal Safety Regulations

BP records show that the BP Toledo Refinery was covered by both the OSHA Process Safety Management (PSM) standard and the EPA Risk Management Program (RMP) rule [16].

1.10.1 OSHA Process Safety Management Standard

OSHA's PSM standard establishes procedures for process safety management to "protect employees by preventing or minimizing the consequences of chemical accidents involving highly hazardous chemicals" [17].

BP considered all the units within the refinery to be covered by the OSHA PSM standard.[a]

[a] The PSM standard covers chemicals deemed hazardous because of their chemical composition and quantity or because of their flammability characteristics. *See* Appendix A of 29 C.F.R. § 1910.119(a)(1)(ii).

On March 15, 2023, OSHA issued a Hazard Alert Letter to BP concerning the practice of job rotation, which is utilized at the refinery. The OSHA Hazard Alert Letter stated that: “rotating process operators among multiple positions, instead of a single position, can reduce the level of expertise and knowledge of operators on the unit for which they are initially qualified. In the event of a process upset condition or catastrophic incident, this decrease in expertise can negatively affect incident response efforts, posing a higher likelihood of exposure to toxic vapor/gas, fire and explosion hazards.” (*See* **Appendix D**.)

The Hazard Alert Letter also recommended that BP obtain input from employees and employee representatives on the effectiveness of the job rotation staffing pattern in place at the refinery, including determining the impact that the job rotation policy has on operator morale and employees’ ability to respond to process safety incidents.

On March 13, 2023, OSHA issued a number of citations to BP and its successors related to the September 20, 2022, incident with a proposed penalty of $156,250. The OSHA citations are summarized in **Appendix E**.

1.10.2 EPA Risk Management Program Rule

The EPA’s RMP rule requires facilities using extremely hazardous substances to develop a risk management plan [18]. According to the EPA, these plans:

- identify the potential effects of a chemical accident,
- show the steps the facility is taking to prevent accidents, and
- outline emergency response procedures [19].

The RMP rule defines three Program levels (Program 1, 2, or 3) based on the potential consequences to the public and the effort needed to prevent accidents [20, p. 1]. Of these three Program levels, Program 1 is the least stringent, and Program 3 is the most rigorous.

BP filed a risk management plan with the EPA on July 17, 2018 [16]. BP included flammable mixtures in its risk management plan, and the company identified its Crude 1 unit as being a Program Level 3 [16, p. 11]. BP’s risk management plan submission also demonstrates that the BP Toledo’s Refinery Crude 1 unit was regulated by both the EPA RMP rule and the OSHA PSM standard [16, p. 2].

BP combined the Crude 1 unit and the NHT unit in the risk management plan because the location of the units is shared meaning “that an event [in] either of these processes could involve the other; therefore, they are considered one covered process.” The risk management plan identified overfilling as one of the major hazards identified in the Crude 1 unit and Coker Gas Plant.

1.11 Description of Surrounding Area

Figure 8 shows the area surrounding the BP Toledo Refinery.[a] The circle diameters are set at one (blue), three (orange), and five (red) miles from the Fuel Gas Mix Drum. Summarized demographic data for the seven census

[a] No off-site impacts were identified by monitoring conducted by BP after the September 20, 2022, incident.

blocks within a three-mile vicinity are shown in **Table 1**.[a] Census data showed there were about 18,750 people residing in about 8,635 housing units within this area. In general, the local population was predominantly white, living in single-unit housing, with 23 percent below the poverty level. Detailed demographic data are included in **Appendix C**.

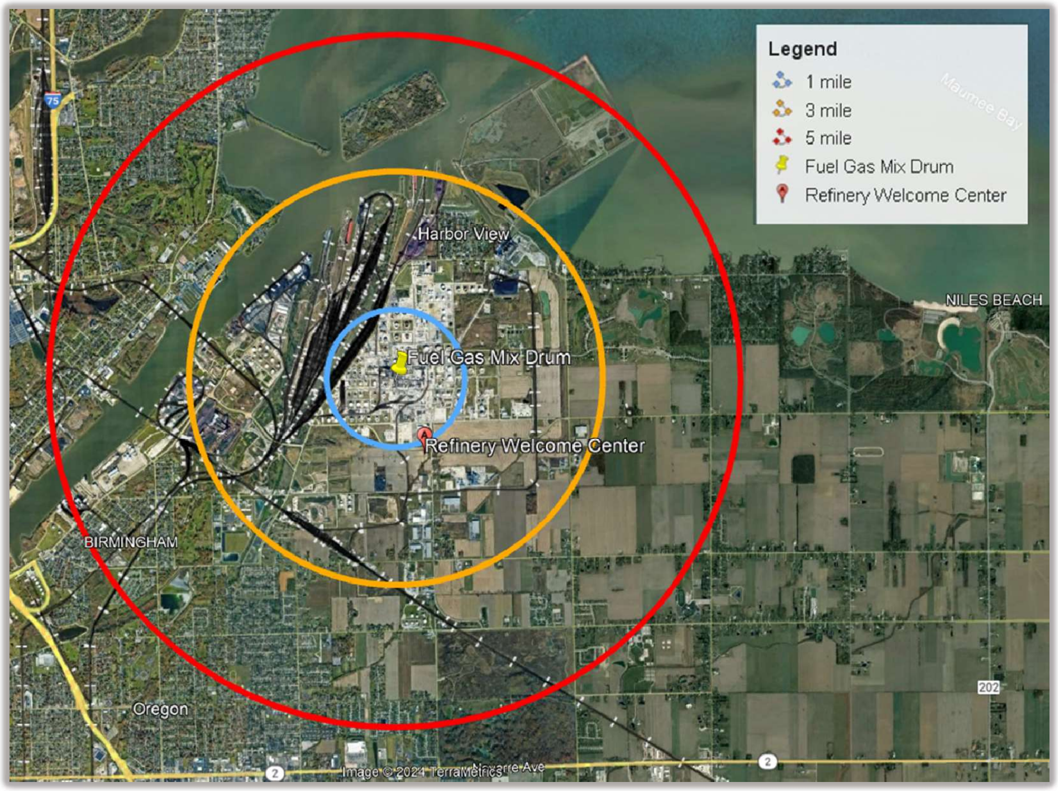

Figure 8. Overhead satellite image of the BP Toledo Refinery and the surrounding area. (Credit: Google with annotations by CSB)

[a] This information was compiled using 2021 Census data from the United States Census Bureau [45].

Table 1. Summarized demographic data.

Population	Race and Ethnicity (%)		Per Capita Income ($)	Poverty (%)	Number of Housing Units	Types of Housing Units (%)	
18,755	White	71	47,628	23	8,635	Single Unit	75
	Black	16				Multi-Unit	24
	Native	0				Mobile Home	1
	Asian	0				Boat, RV, Van, etc.	0
	Islander	0					
	Other	4					
	Two+	9					
	Hispanic	12					

2 Incident Description

On September 20, 2022, at approximately 6:46 p.m., a vapor cloud ignited a fire in the Crude 1 unit. The vapor cloud formed when two BP employees, an outside operator and operator trainee, who were brothers, opened the pressurized Fuel Gas Mix Drum releasing flammable liquid naphtha to the ground. The vapor cloud ignited when it found an ignition source, resulting in the deaths of the two BP employees.

2.1 Events Leading Up to the Incident

The CSB found that events preceding the incident led to an abnormal refinery status when the Tuesday night shift arrived on September 20, 2022, and contributed to the incident. As described below, the incident was the last in a series of cascading events that started roughly 24 hours before, beginning with a relatively minor process upset during the previous night's shift. These events eventually led to the incident.

The sequence of process events that led up to the vapor cloud ignition are introduced below and are described in greater detail in **Section 3.1**.

Water Overflow into Crude 1 Naphtha

On the Monday night shift of September 19, 2022, shortly after 7:00 p.m., water began to accumulate in the Crude 1 Overhead Accumulator Drum, which, several hours later, began to overflow into the naphtha stream that normally exited the drum. Excess water in the naphtha stream then began to accumulate downstream in the Coker Gas Plant Foul Condensate Draw-Off Drum. This drum began to overflow water into the Coker Gas Plant Absorber Stripper Tower. The water overflow and resulting liquid flow increase out of the Absorber Stripper Tower bottoms and into downstream equipment led to a downstream pressure increase in NHT Preheat.

Naphtha Hydrotreater Preheat Leak

The pressure increase in NHT Preheat was enough to open two emergency pressure-relief valves shortly after 7:00 a.m. on the Tuesday day shift of September 20, 2022.[a] [b] A severe piping vibration began as a result of one of the emergency pressure-relief valves opening. A ¾-inch drain line[c] broke off the main naphtha piping, which led to a liquid naphtha loss of containment. The naphtha did not ignite but resulted in an emergency shutdown of the NHT unit and bypass of the Coker Gas Plant. The Crude 1 unit continued to operate.

Crude 1 Tower Process Upsets

The NHT unit emergency shutdown led to a Crude 1 Tower upset throughout much of the rest of the Tuesday day shift. With the NHT unit shut down and the Coker Gas Plant bypassed, naphtha from the Crude 1 Overhead

[a] "NHT Preheat" is used in this report to describe a series of seven shell and tube heat exchangers used to heat naphtha from the Crude 1 unit prior to entering the NHT unit for processing.

[b] This report uses the term emergency pressure-relief valve, however the terms *pressure relief valve*, *safety relief valve*, *pressure safety valve (PSV)*, *relief valve,* or *safety valve* can be used interchangeably. For a specific application, however, readers should know that these other names can reflect different operating characteristics and using precise terminology for a specific application may be appropriate.

[c] The ¾-inch drain line was a short branch pipe off the bottom of the six-inch main naphtha piping, typically only used in preparation for maintenance.

Accumulator Drum could be sent only to Light Virgin Naphtha Storage. The Crude 1 Tower experienced several losses of pumparound cooling, a Crude 1 Overhead Accumulator Drum level upset, and 11 instances of Crude 1 Tower overpressure on day shift after the NHT shutdown.

Crude 1 Tower Feed Changes

As operations personnel worked throughout the day to stabilize the Crude 1 Tower, they made several crude slate adjustments to the tower feed. At 4:56 p.m., the oncoming Tuesday night shift made another crude slate change, which removed all light crude oil from the Crude 1 Tower feed.

High Level in Crude 1 Overhead Accumulator Drum

During the Tuesday night shift, another Crude 1 Tower process upset began due to the rapid and complete loss of light crude oil feed. The Crude 1 Tower upset caused a high level of liquid in the Crude 1 Overhead Accumulator Drum. To address the rapidly increasing level of liquid in the drum, board operators began transferring the excess liquid to the Coker Gas Plant Absorber Stripper Tower.

Absorber Stripper Tower Overflow to Fuel Gas Mix Drum, Furnaces, and Boilers

Once the board operator intentionally opened the flow control valve from the Crude 1 Overhead Accumulator Drum to the Coker Gas Plant (the "naphtha flow control valve to the Coker Gas Plant"),[a] liquid naphtha flowed from the drum to the Absorber Stripper Tower. With the naphtha flow control valve to the Coker Gas Plant open, naphtha began to fill the Coker Gas Plant Absorber Stripper Tower, and eventually overflowed through the Coker Gas Plant bypass line to the Fuel Gas Mix Drum. Once the Fuel Gas Mix Drum was liquid full, the naphtha flowed to the downstream furnaces and boilers.

Figure 9 shows the liquid naphtha overflow from the Crude 1 Overhead Accumulator Drum to the Absorber Stripper Tower, the overflow from the Absorber Stripper Tower to the Fuel Gas Mix Drum, and the overflow to the furnaces and boilers downstream of the Fuel Gas Mix Drum.

[a] This report uses "naphtha flow control valve to the Coker Gas Plant" to describe the naphtha flow control valve from the Crude 1 Overhead Accumulator Drum to the Coker Gas Plant Absorber Stripper Tower.

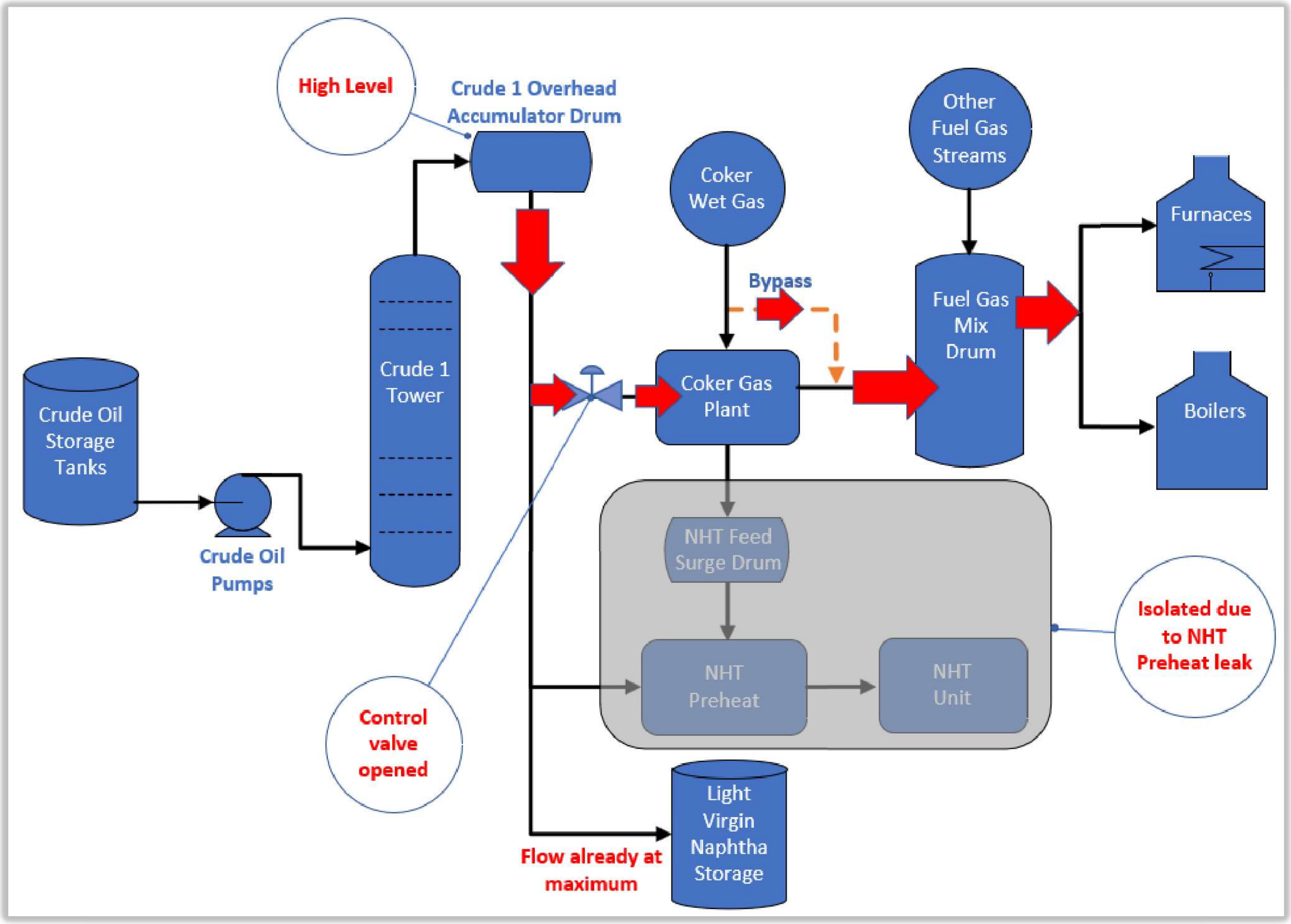

Figure 9: Summary of overflow from the Crude 1 Overhead Accumulator Drum to the Absorber Stripper Tower in the Coker Gas Plant, and on to the Fuel Gas Mix Drum and downstream furnaces and boilers. (Credit: CSB)

2.2 The Incident

By 6:09 p.m., the Fuel Gas Mix Drum level had begun to increase. The board operator noticed the Fuel Gas Mix Drum level alarm on the Distributed Control System (DCS) alarm screen and radioed the outside operators to check the level in the Fuel Gas Mix Drum at 6:16 p.m.[a] Four outside operations personnel arrived at the Fuel Gas Mix Drum. Another outside operator began draining the Fuel Gas Mix Drum to the Flare Knockout Drum

[a] *See* **A.2.9.4.22** to **A.2.9.4.25**.

and Oily Water Sewer.[a] The radio traffic captured the following conversation between outside operators and board operators regarding level in the Fuel Gas Mix Drum:

> [Board] Hey, level in the Mix Drum. You're going to want to check that ASAP.
>
> [Outside] Got it.
>
> [Outside] I'm not even in the sight glass on the Mix Drum.
>
> [Board] Did you say the Mix Drum level is above the sight glass?
>
> [Outside] That is correct.
>
> [Board] Copy that, just drain it as fast as you guys can.
>
> [Outside] We are.

The outside operators attempted to empty the Fuel Gas Mix Drum through the following flow paths:

- With four operations personnel present, one of them fully opened the valve on the two-inch line to the Flare Knockout Drum (a closed system) at approximately 6:17 p.m.;
- The same four personnel were present while one of them opened the Fuel Gas Mix Drum two-inch drain to the Oily Water Sewer, designed for this purpose, at approximately 6:17 p.m. At a later unknown time, a second one-inch drain line from the Fuel Gas Mix Drum guided wave radar level transmitter to the Oily Water Sewer was opened;

---

[a] Although the BP Toledo Refinery had a refinery-wide procedure for "Draining of Process Equipment and Lines", the refinery did not have any procedures, written instructions, or documented corrective actions for board operators or outside operators to respond to or troubleshoot a high liquid level in the Fuel Gas Mix Drum, during either normal operations or process upsets, if liquid entered the drum. The draining procedure in place at the time of the incident required a number of steps to be taken before draining could be done and was not followed in this emergency situation. The procedure stated:

"Before releasing or draining a material, an evaluation must be made of the following:

- Potential environmental impact of the material,
- Is or will the material be below the environmental targeted value?
- Is there a better way to prevent the release or draining of the material?

Once it has been determined draining or releasing the material is the best way, follow the steps below".

1.0 Assess the Material to be Drained.
Which included determining if hydrogen sulfide is present, reviewing the Safety Data Sheet and a **Caution** which stated, "Many materials are reportable if released or drained. Minimize all material drained to the sewer or purged to atmosphere and never drain material to the ground […]".

2.0 Isolate the equipment or Line to Be Drained.
Use BP Toledo Refinery lock-out and tag-out procedure "to properly isolate the line or equipment to be drained".

3.0 Determine How & Where to Drain the Product.
Which included having a discussion "with the supervisor the location that he/she would like the material drained, the method to use, and the level of PPE you both think is necessary to prevent personal exposure…".

3.3 Communicate the "intention to drain material to the Refinery Coordinator. Any material more than two [barrels] to the Oily Water Sewer requires notification of the BP Toledo Refinery Waste Water Treatment Unit. Once proper notifications to affected areas are given, the Refinery Coordinator shall grant permission to commence".

Procedure Deviations "Any deviations, omissions, or additions to this operating procedure as written (including steps that may not be applicable), and have been reviewed for safety and health considerations, must require supervisor approval by signature or initials on this procedure".

- Two of the operations personnel left the area around the Fuel Gas Mix Drum to check on the Sweet Gas Knock Out Pot in the Coker Gas Plant, leaving two BP employees, one outside operator and an operator trainee who were brothers, at the Fuel Gas Mix Drum to finish draining it. These BP employees opened two ¾-inch bleed valves to the ground at approximately 6:32 p.m.: one at the Fuel Gas Mix Drum differential pressure level transmitter,[a] and one at the Fuel Gas Mix Drum sight glass; and

- Unbeknownst to anyone, the outside operator and operator trainee began releasing liquid from the Fuel Gas Mix Drum directly to the ground (while wearing a Self-Contained Breathing Apparatus [SCBA] and a hydrogen sulfide [H_2S] gas detector)[b] from a two-inch valve on the side of the Fuel Gas Mix Drum just before 6:39 p.m. This valve normally had a blind flange bolted on the discharge end during refinery operation.[c] These BP employees removed the blind flange from the two-inch valve in order to release liquid from the Fuel Gas Mix Drum.

Figure 10 below shows where the Fuel Gas Mix Drum was drained to the Flare Knockout Drum and Oily Water Sewer, and where the valves and flange were opened to release material to the ground. Despite all the openings to drain and release liquid from the Fuel Gas Mix Drum, liquid continued to overflow the Fuel Gas Mix Drum into downstream furnaces and boilers.

[a] When outside operators opened the bleed at the differential pressure level transmitter, the opened bleed altered the pressure differential, causing the level measurement to indicate zero percent. This gave the false impression that the Fuel Gas Mix Drum was emptying, when in fact it was still full, despite the draining attempts.

[b] One outside operator told the outside operator draining the Fuel Gas Mix Drum to the Oily Water Sewer to put on an SCBA to mitigate any hydrogen sulfide (H_2S) inhalation hazards. SCBA was additional PPE, beyond the norm. Hydrogen sulfide (H_2S) monitors were standard PPE in the refinery process areas (*See* **A.2.9.4.36**).

[c] This valve on the side of the Fuel Gas Mix Drum was only intended for access by maintenance as part of turnaround or maintenance activities.

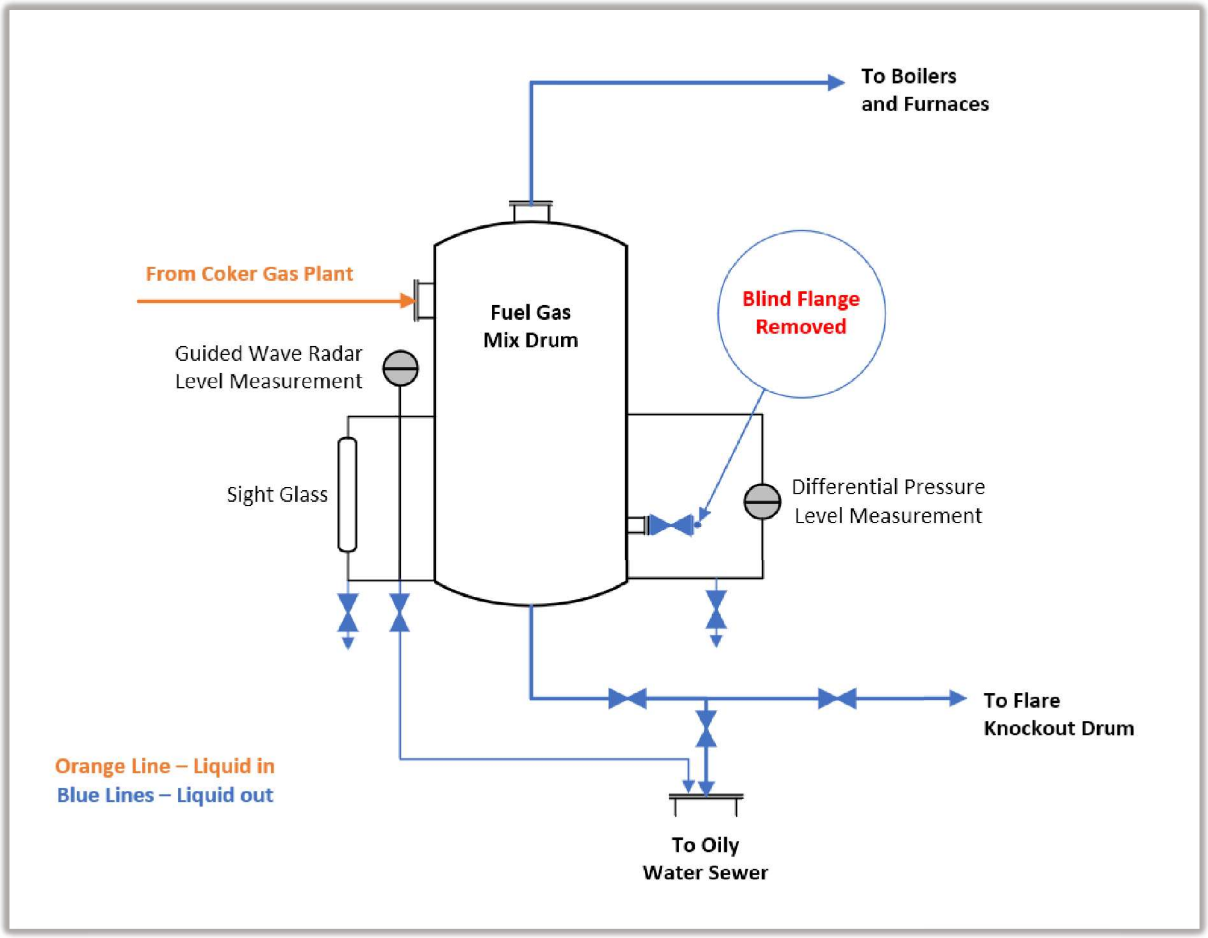

Figure 10: Fuel Gas Mix Drum during overfill and attempted emptying. Liquid exit locations are shown in blue. (Credit: CSB)

At 6:39 p.m., likely as a result of naphtha releasing to the ground and vaporizing, a flammable gas detector near the Fuel Gas Mix Drum indicated 100 percent of the lower flammability limit (LFL).[a] This detector only alarmed locally, not in the control room. The CSB determined that the alarm had been inadvertently disabled[b] to the DCS, and therefore only the local alarm horn and lights were functional at the time of the incident, although the DCS console did provide an analog reading of the percent of LFL. The alarm horn for the detector was audible in the background of a radio transmission at 6:40 p.m., but there was no evidence that anyone inside the control room was aware that the two BP employees were releasing liquid from the Fuel Gas Mix Drum to the ground.

A worker standing nearby saw the two workers near the Fuel Gas Mix Drum along with a visible vapor cloud, stating to the CSB in an interview after the incident:

[a] Most flammable gas detectors "give a reading of the %LEL (or %LFL)" [49, p. 29]. The LFL is defined as the "lowest concentration of a flammable gas in air capable of being ignited by a spark or flame" [49, p. 35].

[b] There was no LFL alarm in the control room as the alarm was set to "Disabled" due to an Alarm Configuration Manager (ACM) enforcement configuration error that was enforcing the alarm into the "disabled" state. Although the audible and visual board alarming was disabled, the LFL detector readings would have still shown in the control room.

> It looks like someone is draining product from the mix drum. And I seen water being sprayed on it. […] I saw product coming out of the drain. It was like somebody was draining it to the sewer. They laid something on…to kind of deflect the stuff spraying out, so it'll stay […] going into the sewer, instead of spraying everywhere. So at first, originally, I thought it was a flange or something had let loose. But, no, it was somebody was draining it. And strong, strong smell. And I saw that vapor cloud coming from it […] I decided to back up and I […] stepped back about 20 feet and then it went boom.

An approaching rainstorm shifted the wind, which likely directed the vapor cloud toward the nearby Crude 1 Furnace, the likely ignition source. The vapor cloud ignited at 6:46 p.m., as shown in **Figure 11**. **Figure 12** shows the Crude 1 Furnace's proximity to the Fuel Gas Mix Drum, the area of the naphtha release, and the eyewitness's location.

Figure 11: Vapor cloud ignition and the ensuing six seconds. Ignition at Crude Furnace (circled in red, upper left photo). (Credit: BP with annotations by CSB)

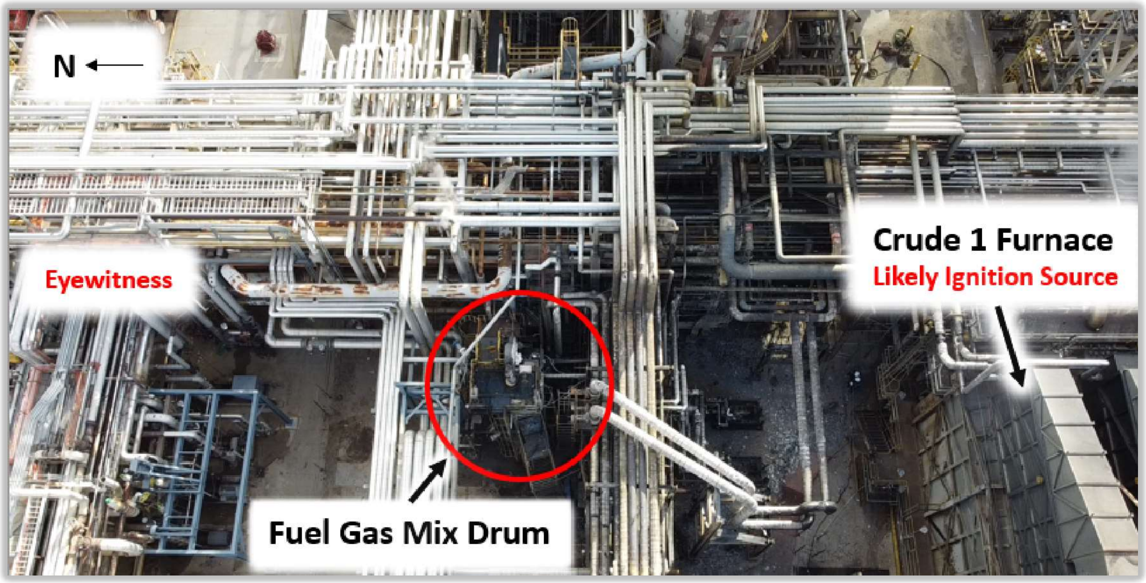

Figure 12: Overhead view of naphtha release, likely ignition source, and eyewitness location. (Credit: BP with annotations by CSB)

2.3 Emergency Response

After the vapor cloud ignited at 6:46 p.m., the BP Toledo Refinery Emergency Response Team (ERT) reported to the scene at 6:54 p.m. At 7:04 p.m., a board operator realized that naphtha was flowing to the Fuel Gas Mix Drum from the Crude 1 Overhead Accumulator Drum through the Coker Gas Plant. The board operator closed the naphtha flow control valve to the Coker Gas Plant, which was allowing naphtha to flow to the Coker Gas Plant Absorber Stripper Tower and Fuel Gas Mix Drum. This was the same flow control valve that had been opened earlier in the attempt to alleviate the high level in the Crude 1 Overhead Accumulator Drum. The ERT assembled three separate teams to approach the Fuel Gas Mix Drum and close the open drain points where fire was emanating from the drum. To extinguish the fires, emergency responders had to close all the Fuel Gas Mix Drum valves that had been opened by the two BP employees:

- to the flare system,
- to the Oily Water Sewer,
- at the sight glass,
- at the differential pressure level measurement,
- at the guided wave radar device to the Oily Water Sewer, and
- the two-inch valve on the side of the Fuel Gas Mix Drum that had had the blind flange removed.

Figure 13 shows the Fuel Gas Mix Drum after the incident.

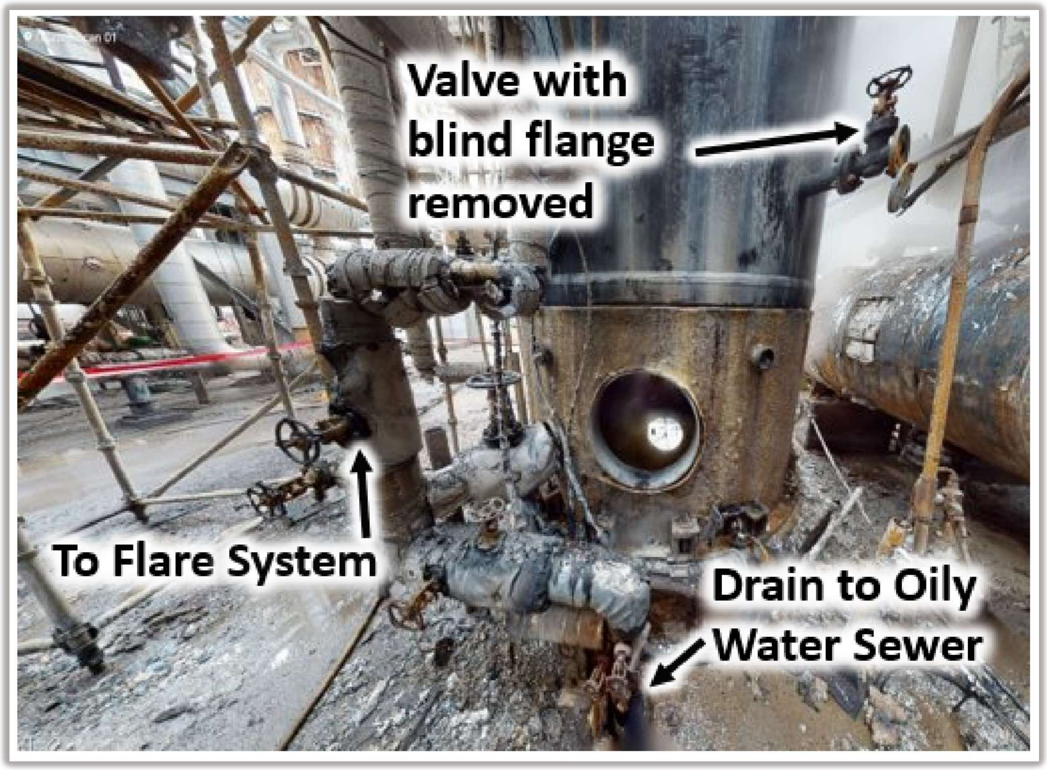

Figure 13: Fuel Gas Mix Drum post-incident. (Credit: BP with annotations by CSB)

The fire was extinguished by 10:10 p.m. BP estimated that 23,502 pounds of naphtha and 66,889 pounds of fuel gas were released during the incident.

The two BP employees who were draining the Fuel Gas Mix Drum were fatally injured from burns they received in the fire.

3 Incident Analysis

3.1 Incident Progression

As described in **Section 2**, the CSB investigated the events leading up to the incident. The CSB found that the events, actions, and decisions preceding the incident led to an abnormal refinery status when the night shift arrived and contributed to the incident. The sequence of events that led up to draining the Fuel Gas Mix Drum are described in detail in this section.

3.1.1 Naphtha Standpipe Overflow

The Crude 1 Overhead Accumulator Drum included multiple level measurement devices. Among these was a measurement for the water phase in the bottom of the drum, which was separate from the other devices measuring total level in the drum. During a turnaround at the refinery in 2022,[a] the water phase level measurement technology was changed to a guided wave radar. Although the change used the same vessel connections, the new device was calibrated differently from the previous one. This change meant that water would overflow the naphtha standpipe at 69 percent indicated level, rather than at an indicated 100 percent level, with the original level device. This change in level indication had not been communicated to operators,[b] and had been in service for approximately six weeks before the incident occurred. Consequently, operations personnel were likely unaware that the 69 percent water phase level meant that water could carry over into the naphtha stream.

On the evening of September 19, 2022, at approximately 7:10 p.m., the Crude 1 Overhead Accumulator Drum water phase level began to increase because a board operator had partially closed the Crude 1 Overhead Accumulator Drum water level control valve in order to increase water flow to the Crude 2[c] unit. With the water level control valve in manual mode, the water phase level in the Crude 1 Overhead Accumulator Drum steadily increased. The water phase level indicator plateaued at 69 percent at approximately 11:45 p.m. Although the Crude 1 Overhead Accumulator Drum normally contained some water, the water phase reached the height of the naphtha standpipe inside the Crude 1 Overhead Accumulator Drum at 69 percent water phase level. As a result, water carried over to downstream naphtha users, as shown in **Figure 14** below.

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[a] *See* **A.2.9** for a timeline of these events. The level measurement technology was changed from a displacer to a guided wave radar as part of a piping change during a four-month maintenance outage, called the "2022 Turnaround," which lasted from April to August 2022.

[b] While the Management of Change (MOC) itself was communicated to operators before starting up after the change, the communication did not include that this level would read differently than it did before.

[c] The BP Toledo Refinery operates two crude units. This report refers to them as Crude 1 and Crude 2.

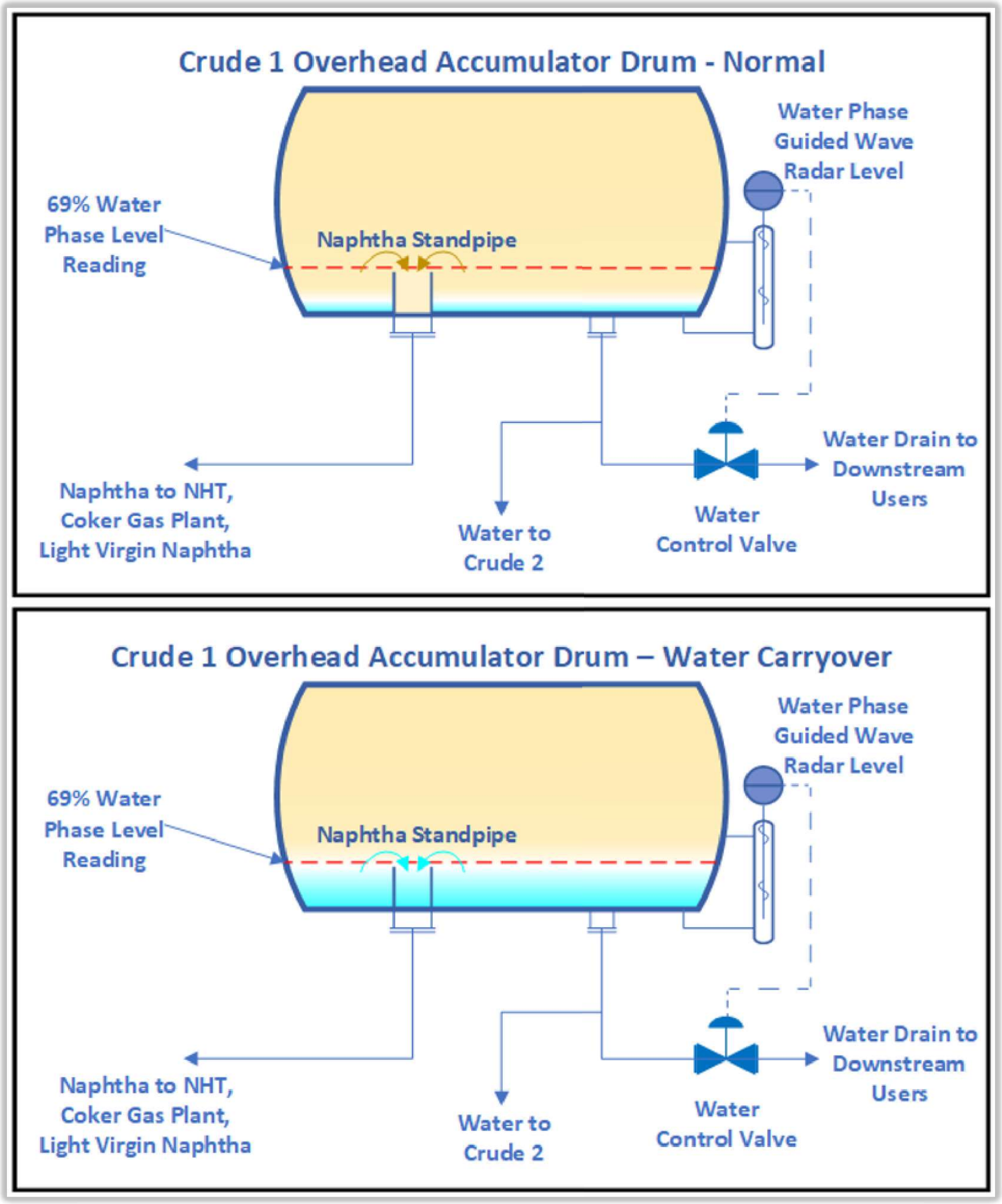

Figure 14: Crude 1 Overhead Accumulator Drum water phase level before water control valve adjustment (top) and during water carryover into naphtha stream (bottom). (Credit: CSB)

Downstream of the Crude 1 Overhead Accumulator Drum, the flow of water-laden naphtha to the Coker Gas Plant Absorber Stripper Tower resulted in water collecting in the Coker Gas Plant Foul Condensate Draw Off Drum, which plateaued at 100 percent at approximately 2:12 a.m. on September 20, 2022. Once the drum was full, the water began to backflow and return to the Absorber Stripper Tower. The water in the Absorber Stripper Tower reduced the reboiler exit temperature, which decreased the vapor flow up the tower. The lower vapor flow allowed the liquid on the Absorber Stripper Tower trays to de-inventory and drop liquid down to the bottom of the tower, increasing the bottoms level. The Absorber Stripper Tower bottoms level control valve opened to remove the excess level, causing increased liquid level in the NHT Feed Surge Drum. This NHT Feed Surge Drum level increase resulted in higher flow and pressure to NHT Preheat when the NHT Feed Surge Drum level control valve in turn opened further.[a] **Figure 15** shows this water overflow and resulting liquid flow increase out of the Absorber Stripper Tower bottoms and into the NHT Feed Surge Drum.

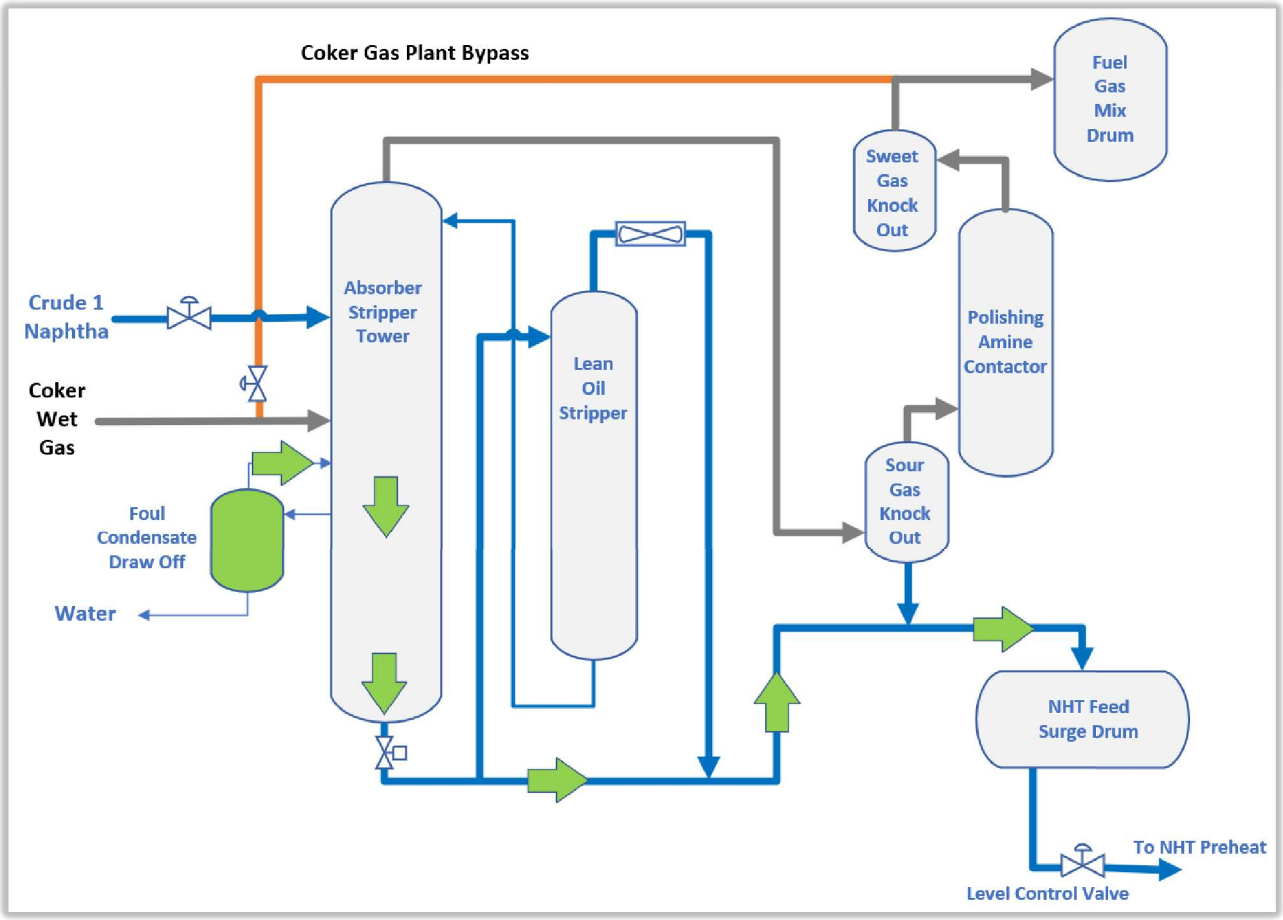

Figure 15: Water overfill in Coker Gas Plant Absorber Stripper Tower and flow increase to NHT Feed Surge Drum (green arrows). (Credit: CSB)

The increased liquid flow into NHT Preheat resulted in a downstream pressure increase to the series of heat exchangers (HE) downstream of the NHT Feed Surge Drum. As a result, at approximately 3:20 a.m. on Tuesday, September 20, 2022, emergency pressure relief-device PSV-D, which had the lowest set pressure in the heat exchanger train,[b] opened (*See* **Figure 16**). The night shift[c] operations personnel were able to isolate the emergency pressure-relief valve from the NHT Preheat process and reseat the emergency pressure-relief valve.

[a] The NHT Feed Surge Drum level control valve, which had been operating at approximately 30-40 percent open at steady state, peaked at 56 percent open at 3:27 a.m.

[b] A timeline of this event can be found beginning at **A.1.4.6.3.**

[c] Night shift ended and day shift began at approximately 4:30 a.m.

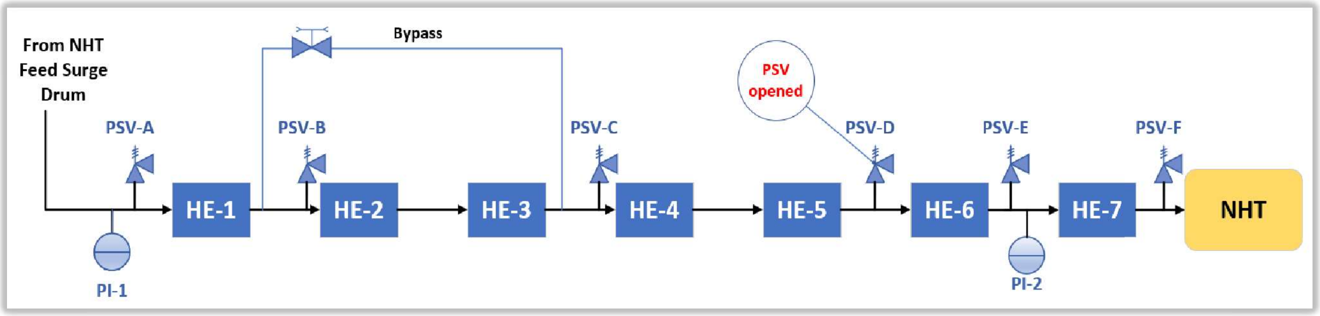

Figure 16: Location of first emergency pressure-relief valve (labeled as PSV-D) opening on NHT Preheat heat exchangers (each labeled as HE).[a] (Credit: CSB)

The CSB concludes that water carryover from the Crude 1 Overhead Accumulator Drum initiated a cascade of events that caused the emergency pressure-relief valve in NHT Preheat to open.

3.1.2 Naphtha Hydrotreater Preheat Leak

On day shift, at approximately 7:13 a.m., outside operators noted PSV-D opening due to a second liquid flow and pressure increase into NHT Preheat, similar to what had occurred on the previous shift. The day shift was aware of PSV-D opening on the previous night shift. Another valve, PSV-B, upstream of PSV-D, also opened at approximately this time and chattered.[b] The inlet piping to PSV-B began vibrating severely. One outside operator later described it to the CSB:

> I've seen a lot of PSVs lift. I've never seen a PSV lift like this. The design of that PSV, there's something the matter, you know. So […] the closest I can explain is if you've ever seen the…put a jackhammer on the front of a Bobcat to break up concrete. The force that that has, that's the force that this PSV was lifting at. It was just shaking and rattling and everything. Insulation was falling off. Valve handles are rattled off. Valves are opening and closing. It was…it was incredibly bad.

The vibration was strong enough that the bypass valve around the heat exchangers and PSV-B inlet in NHT Preheat vibrated open at least twice. The emergency pressure-relief valve chatter continued as operations personnel attempted to troubleshoot and reduce pressure in the system. At approximately 7:54 a.m., a leak developed near a ¾-inch drain valve on the vibrating piping. One outside operator charged[c] a nearby fire monitor and started the monitor water flow on the leak. Another outside operator later told the CSB about the situation:

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[a] All emergency pressure-relief valves (shown as PSVs) in NHT Preheat discharged to the West Flare (not shown).

[b] Chattering is "the rapid opening and closing of a pressure-relief valve. The resulting vibration may cause misalignment, valve seat damage, and if prolonged, mechanical failure of valve internals and associated piping" [48].

[c] Fire monitors are devices used for manual firefighting or in automatic fire protection systems to "discharge large volumes of water and have good straight stream range. Discharge can be controlled by the type and size of adjustable nozzle or diameter of straight stream nozzle" [17, p. 369]. The process of "charging" a fire monitor involves filling piping from a nearby water source and placing it under pressure so that the water can be directed, through a nozzle, toward the fire site when needed.

> We can't… stay like this. We can't leave this thing lifting. If I can't block it in, we're going to tear something up. That's when I told the operators I was with, I'm like, "We got to go charge the fire monitors." Because we… You just knew that something was going to fail as hard as everything was shaking.

The refinery coordinator attempted to reduce the NHT Preheat pressure by maximizing cooling in NHT Preheat, among other things, stating, "we're forcing more feed through the [NHT Preheat] exchangers, carrying more heat away" to outside operators over the radio. Outside operators requested to bypass the chattering PSV-B and its associated heat exchanger at 7:48 a.m., but the refinery coordinator did not approve at first. By the time the refinery coordinator in the control room authorized the bypass at 7:55 a.m., outside operators could not access the bypass valve. The leak was too severe and too close to the bypass valve to allow outside operators access.

The shift superintendent left the control room and went outside to NHT Preheat to assist. This superintendent observed the vibration along with outside operators, and alerted the BP Toledo Refinery ERT, who reported to the scene.[a]

The continuing piping vibration then caused the branch connection to the drain valve to fail completely, and the ¾-inch bleed broke off at approximately 8:12 a.m., 18 minutes after the first smaller leak began. With this loss of primary containment, the naphtha leak was significantly larger. Operations personnel decided to implement an emergency depressurization and shut down of the NHT unit. **Figure 17** shows the locations of the ¾-inch bleed failure where the loss of containment occurred, and both emergency pressure-relief valves that opened.

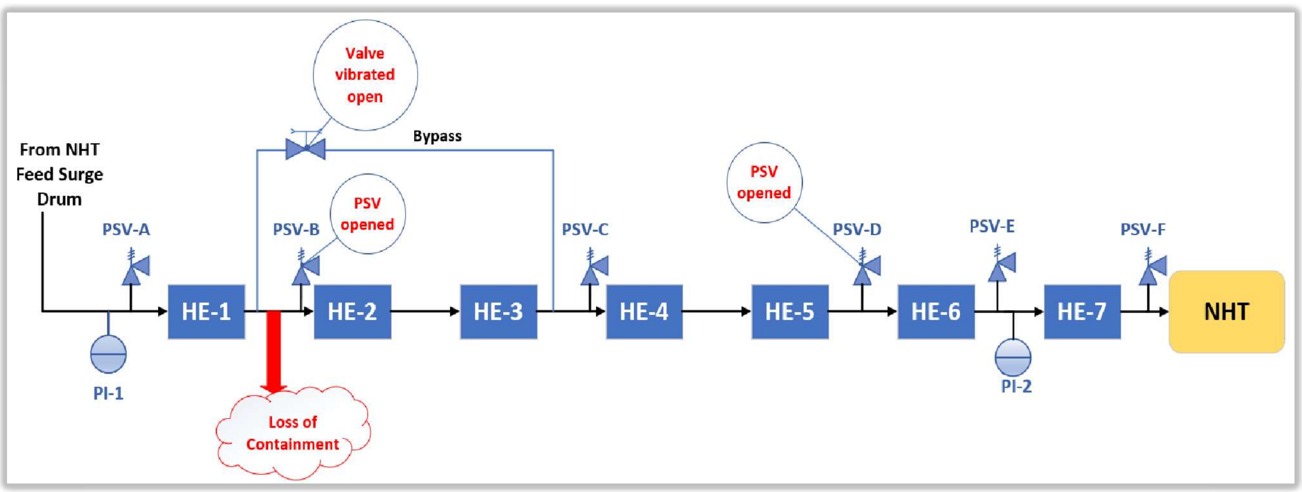

Figure 17: NHT Preheat loss of containment and emergency pressure-relief valve (each labeled as PSV) openings at NHT Preheat heat exchangers (each labeled as HE). (Credit: CSB)

At this point, outside operators directed significant amounts of water onto the release. Their quick action likely prevented ignition of the naphtha.[b] As a result of the incident and response, the containment area around NHT Preheat filled with a water-naphtha mixture. Four operations personnel received first aid for skin irritation due to

[a] The loss of containment was contained with water spray and did not ignite.

[b] *See* **A.1.4.6.15** to **A.1.4.6.19**.

contact with this water-naphtha mixture as they worked to isolate the leak. BP later estimated that the failure released an estimated 63,625 pounds of naphtha.

The CSB concludes that vibration from the NHT Preheat emergency pressure-relief valve chatter caused the leak in NHT Preheat.

The CSB also concludes that had the BP Toledo Refinery bypassed the affected heat exchangers in NHT Preheat in response to the initial leak, it might have avoided the pipe failure. The pipe failure caused an emergency shutdown of the NHT unit.

3.1.3 Coker Gas Plant Bypass

Operations personnel successfully isolated the naphtha leak, shut down the NHT unit, and bypassed the Coker Gas Plant since naphtha could no longer flow to the NHT unit. To bypass the Coker Gas Plant, operators fully opened the control valve in the coker wet gas bypass line in manual mode, but the Absorber Stripper Tower coker wet gas inlet was also still open.[a] Both the gas flow path entering the Absorber Stripper Tower and the gas bypass flow path remained open, meaning that the Coker Gas Plant was not fully isolated (or bypassed). The naphtha flow control valve to the Coker Gas Plant was closed to stop the liquid naphtha flow into the Absorber Stripper Tower. **Figure 18** below shows this "bypass mode" configuration.[b] The Crude 1 unit continued to operate while refinery teams began to evaluate a repair plan for the failed branch connection.

[a] A control valve was installed in the Coker Gas Plant bypass line in 2019 to control the pressure differential of the Coker Gas Plant Polishing Amine Contactor to prevent Coker Gas Plant process upsets. (*See* **A.2.6.2**)

[b] While the bypass mode isolated liquid naphtha flow from the Coker Gas Plant, it did not isolate gas flow into the Coker Gas Plant. Gas flow continued through both the bypass line and through the Coker Gas Plant simultaneously.

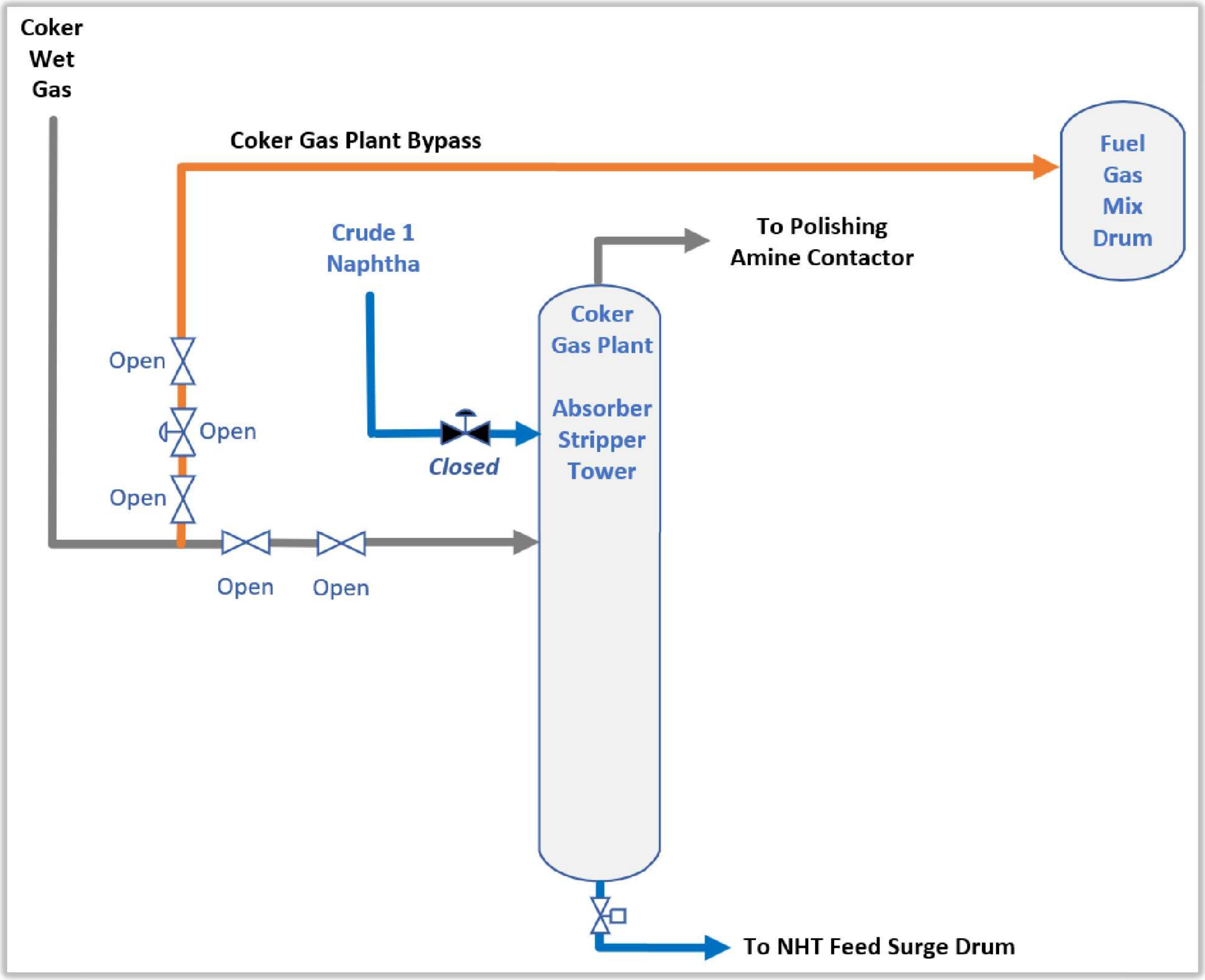

Figure 18: Coker Gas Plant bypass configuration on the day of the incident. (Credit: CSB)

The CSB concludes that the NHT unit emergency shutdown necessitated bypassing the Coker Gas Plant, but the Coker Gas Plant was not fully isolated, even though its operational state was considered "in bypass." Bypassing the Coker Gas Plant left an open flow path from the Absorber Stripper Tower to the Fuel Gas Mix Drum.

3.1.4 Crude 1 Overhead Accumulator Drum Level Control

With the NHT unit shut down and the Coker Gas Plant bypassed, naphtha from the Crude 1 Overhead Accumulator Drum could be sent only to Light Virgin Naphtha Storage, as shown below in **Figure 19**. However, the liquid level in the Accumulator Drum could not be maintained with the Light Virgin Naphtha flow control valve solely. For the majority of time between 1:30 p.m. and 3:30 p.m., while the flow control valve was near or at its fully open position, the accumulator drum level exceeded its high-high alarm setpoint, and the flow reading to the Light Virgin Naphtha Storage was above the meter's range, as shown below in **Figure 20**.

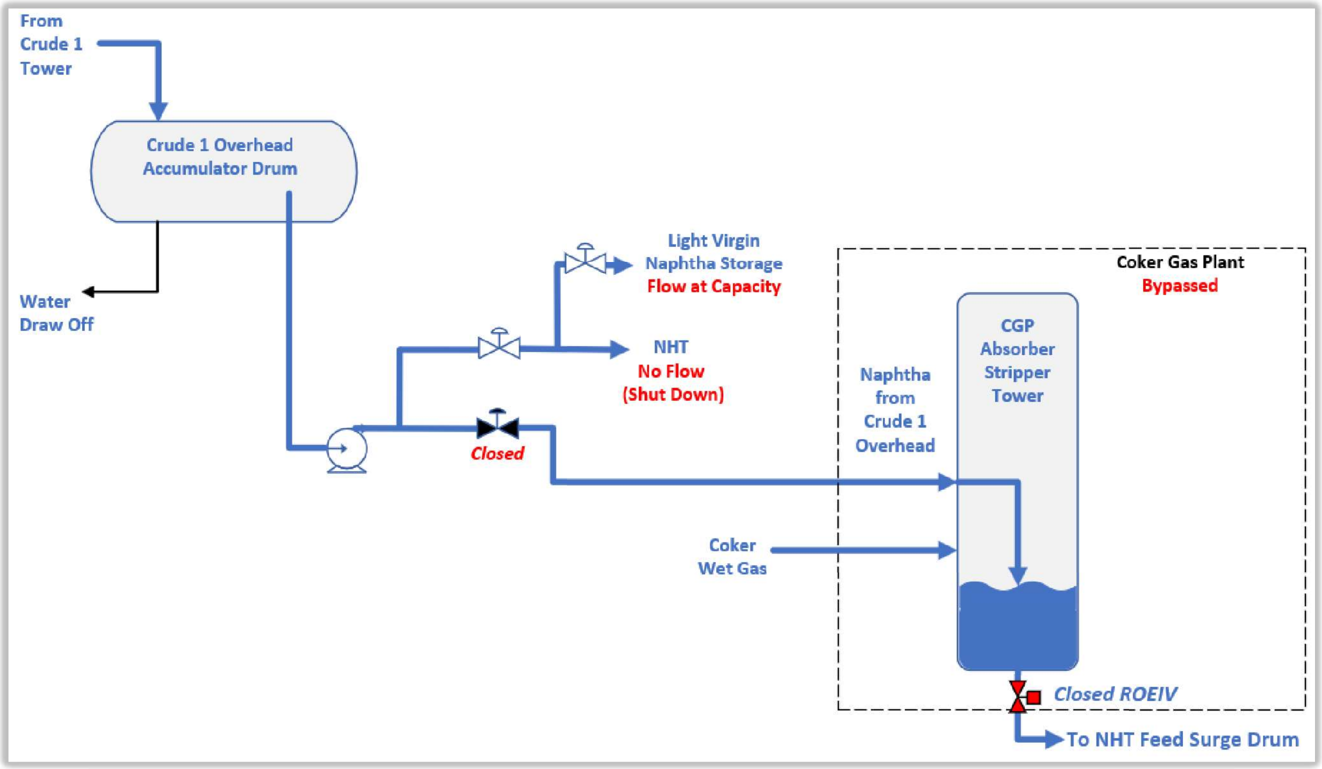

Figure 19: Liquid naphtha flow paths out of the Crude 1 Overhead Accumulator Drum. (Credit: CSB)

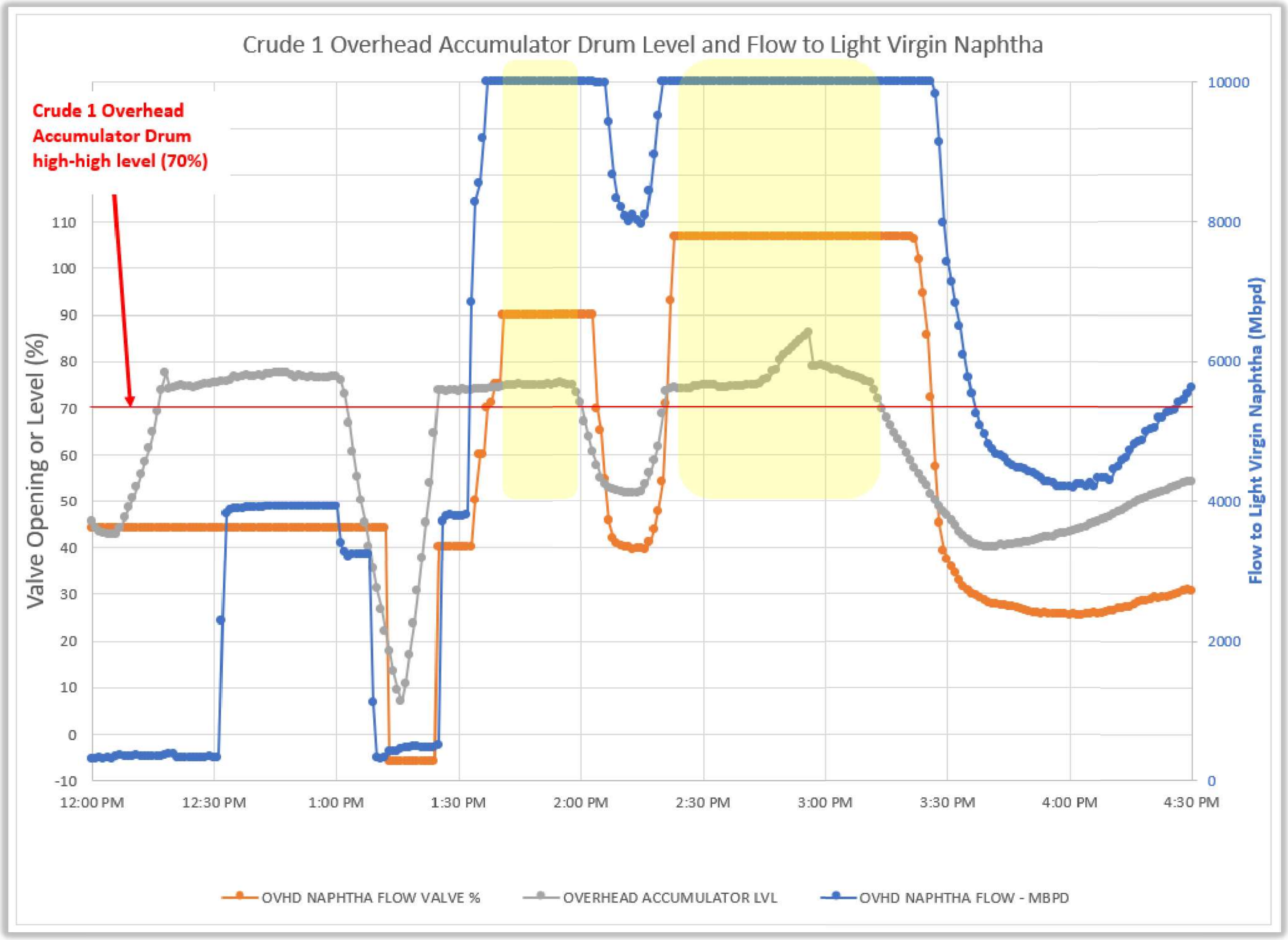

Figure 20: Crude 1 Overhead Accumulator Drum level control and flow to Light Virgin Naphtha. The yellow shaded areas indicate periods of accumulator level (gray) over the high-high alarm setpoint, while the flow meter to Light Virgin Naphtha (blue) was out of range and the flow control valve (orange) nearly or fully opened. (Credit: CSB)

The CSB concludes that there was only one destination available for Crude 1 Overhead flow after the NHT unit was shut down and the Coker Gas Plant was bypassed.

The CSB concludes that the Crude 1 Overhead Accumulator Drum level could be managed under normal conditions with only one destination available by sending it to Light Virgin Naphtha Storage, but the upset or excess flow conditions in the Crude 1 Tower in this incident exceeded the control valve capacity to Light Virgin Naphtha, meaning that the Crude 1 Overhead Accumulator Drum level could not be well controlled.

3.1.5 Crude 1 Tower Instability

After the NHT unit shutdown, throughout the late morning and afternoon, workers continued to attempt to stabilize the Crude 1 Tower. While they did so, top pumparound[a] and middle pumparound flows dropped to zero

[a] The Crude 1 Tower and pumparounds are described above in **Section 1.7**.

several times.[a] **Figure 21** shows the Crude 1 Tower overpressures[b] and loss of pumparounds that day, beginning shortly after the NHT unit shutdown. Operations personnel worked through the afternoon to stabilize the Crude 1 Tower overhead pressure, temperature profile, and pumparound flows. By 4:30 p.m., as night shift began reporting to the refinery for shift turnover, the Crude 1 Tower was beginning to stabilize, although the tower pressure was still much closer to the emergency pressure-relief valve set pressures than it had been that morning, before the NHT unit emergency shutdown: 25 to 28 pounds per square inch gauge (psig) before compared with over 36 psig at shift change. The last Crude 1 Tower overpressure event to occur on day shift ended at approximately 4:17 p.m. The Crude Tower overhead pressure reached the high alarm point, set at 32 psig, at approximately 10:00 a.m., and remained in alarm until approximately 6:00 p.m. In other words, the alarm was sounding continuously for roughly eight hours.

[a] A complete loss of all three pumparounds leads to a loss of cooling resulting in high Crude 1 Tower temperatures and high Crude 1 Tower vapor velocities making it difficult to re-establish the pumparounds.

[b] The Crude 1 Tower overhead line contained five emergency pressure-relief valves, set at staggered pressures ranging from 38 to 40 pounds per square inch gauge (psig).

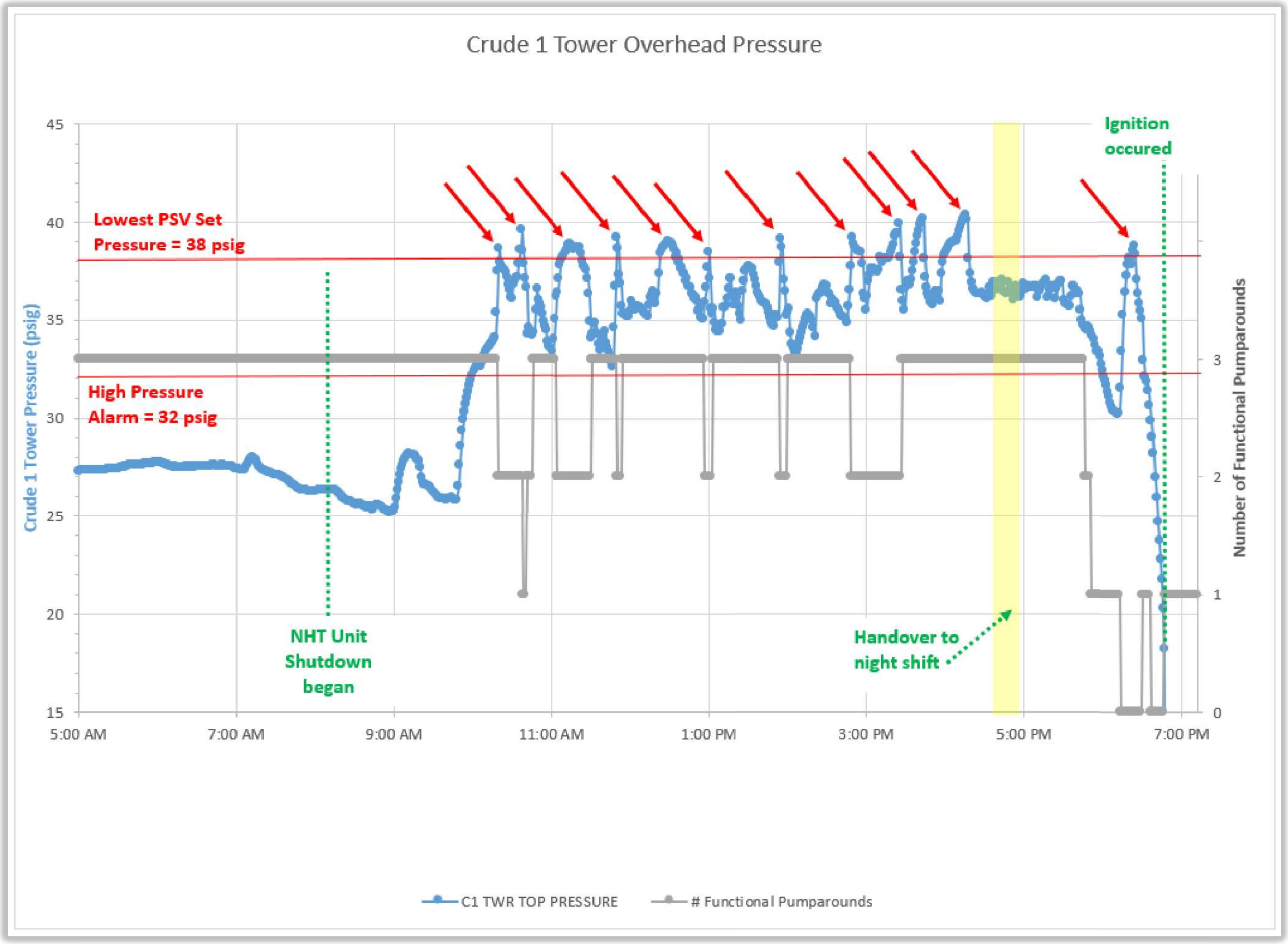

Figure 21: Crude 1 Tower overhead pressure. Red arrows indicate likely emergency pressure-relief valve(s) (PSV) opening. Crude 1 Tower pressure (blue trend) was above the high alarm point (32 psig) for much of the day. (Credit: CSB)

The CSB concludes that as a result of the NHT unit emergency shutdown, the Crude 1 Tower operation was unstable throughout the day of the incident. This was demonstrated by high Crude 1 Tower overhead pressure with Crude 1 Tower emergency pressure-relief valves opening multiple times, multiple losses of pumparound cooling, and inability to control Crude 1 Overhead Accumulator Drum level.

In the mid-afternoon, between approximately 3:00 p.m. and 4:00 p.m., refinery leadership and process engineering personnel[a] met to address Crude 1 Tower instability and to discuss plans for oncoming night shift support, among other things. During the meeting, these personnel discussed shutting down Crude 1 or putting Crude 1 in "circulation,"[b] among other options, in an effort to stabilize Crude 1 Tower operation with the NHT

[a] The Interim Asset Superintendent, the Process Engineering Superintendent, and the Production Planning Superintendent told CSB investigators they attended the meeting.

[b] The BP Toledo Refinery defined "hot circulation," or simply "circulation" as a process configuration, typically for startups, in which feed was turned off to the Crude 1 Tower, but oil was recirculated, at least partial reflux was maintained, and the Crude 1 Furnace remained on but at temperature lower than normal. Although located in a startup procedure, written guidelines were available for this process configuration on the day of the incident.

unit shut down and the Coker Gas Plant bypassed. Ultimately, it was decided that neither shutdown nor circulation would be done at that time, which allowed the crude oil feed to Crude 1 to continue, even though the Crude 1 Tower had overpressured eight times (**Figure 21**), and the Crude 1 Overhead Accumulator Drum level had been above the high-high alarm point for approximately two hours (**Figure 20**), by 3:00 p.m.

Moreover, although one of the participants in the meeting summarized the meeting's outcome in an email, the email was never sent. Further, the CSB found no evidence that the actions agreed upon in the meeting were ever conveyed to the night shift refinery coordinator or board operators, either verbally or in writing. Although reducing feed temperature to the Crude 1 Tower and putting the tower on circulation were discussed in the meeting as possible actions, the night shift operations did not have these items in the turnover notes, and the night shift operators did not indicate to the CSB that they were aware of these options as possible corrective actions. The night shift refinery coordinator told the CSB that with "the crude tower on, sat gas plant, coker gas plant, NHT down," he had "never seen it operate like that" and "had no technical guidance on how to operate it."

The CSB concludes that on the day of the incident, BP Toledo Refinery personnel involved in the afternoon meeting regarding Crude 1 Tower instability did not adequately communicate the guidance to safely operate the Crude 1 Tower from that meeting to the oncoming night shift personnel. This left night shift board operators to decide how to operate the tower under the given conditions. Had the BP Toledo Refinery considered this process instability that occurred throughout the day, and had there been better communications through shift change, there could have been safeguards put in place before or early in the night shift.

3.1.6 Crude 1 Tower Crude Slate Change

In response to the NHT unit shutdown and Coker Gas Plant bypass earlier that day, the crude slate to the Crude 1 Tower had been adjusted several times throughout the day as operations personnel worked to stabilize the tower. Night shift personnel arrived at approximately 4:30 p.m. on September 20, 2022, and shortly afterward, a significant crude slate change to the Crude 1 Tower occurred. Light crude oil flow was 26,000 barrels per day, or approximately 32 volume percent of the total feed, at 4:56 p.m., but it was eliminated entirely by 5:10 p.m. A board operator cut the light crude feed because he thought the light crude oil flow was too high given that the NHT unit was down. Another online crude oil pump, connected to heavy crude oil storage, automatically increased speed to maintain the total feed flow rate to the Crude 1 Tower. Abruptly replacing light crude oil feed with heavy crude oil created a large and rapid change in the crude oil composition, which reached the Crude 1 Tower approximately 40 minutes later. **Figure 22** shows the crude oil compositions and flow rates feeding the Crude 1 Tower before and after the light crude oil flow stopped.

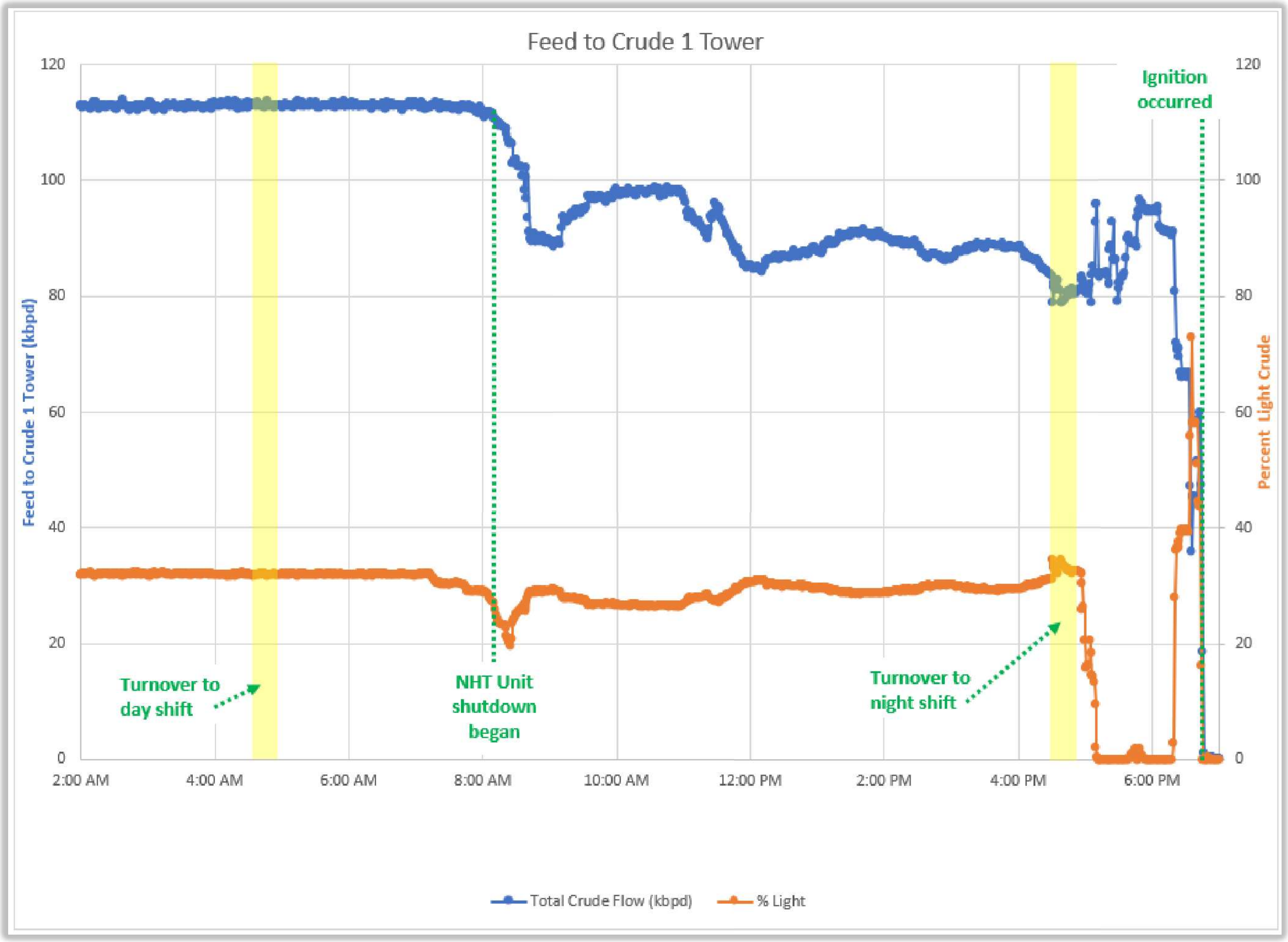

Figure 22: Crude 1 Tower Feed rate (blue) and percent light feed composition (orange) day of incident. The yellow bars indicate shift change turnover. (Credit: CSB)

At approximately 5:30 p.m., Crude 1 Tower temperatures began to increase rapidly, initiating the Crude 1 Tower upset, as shown in **Figure 23** below.

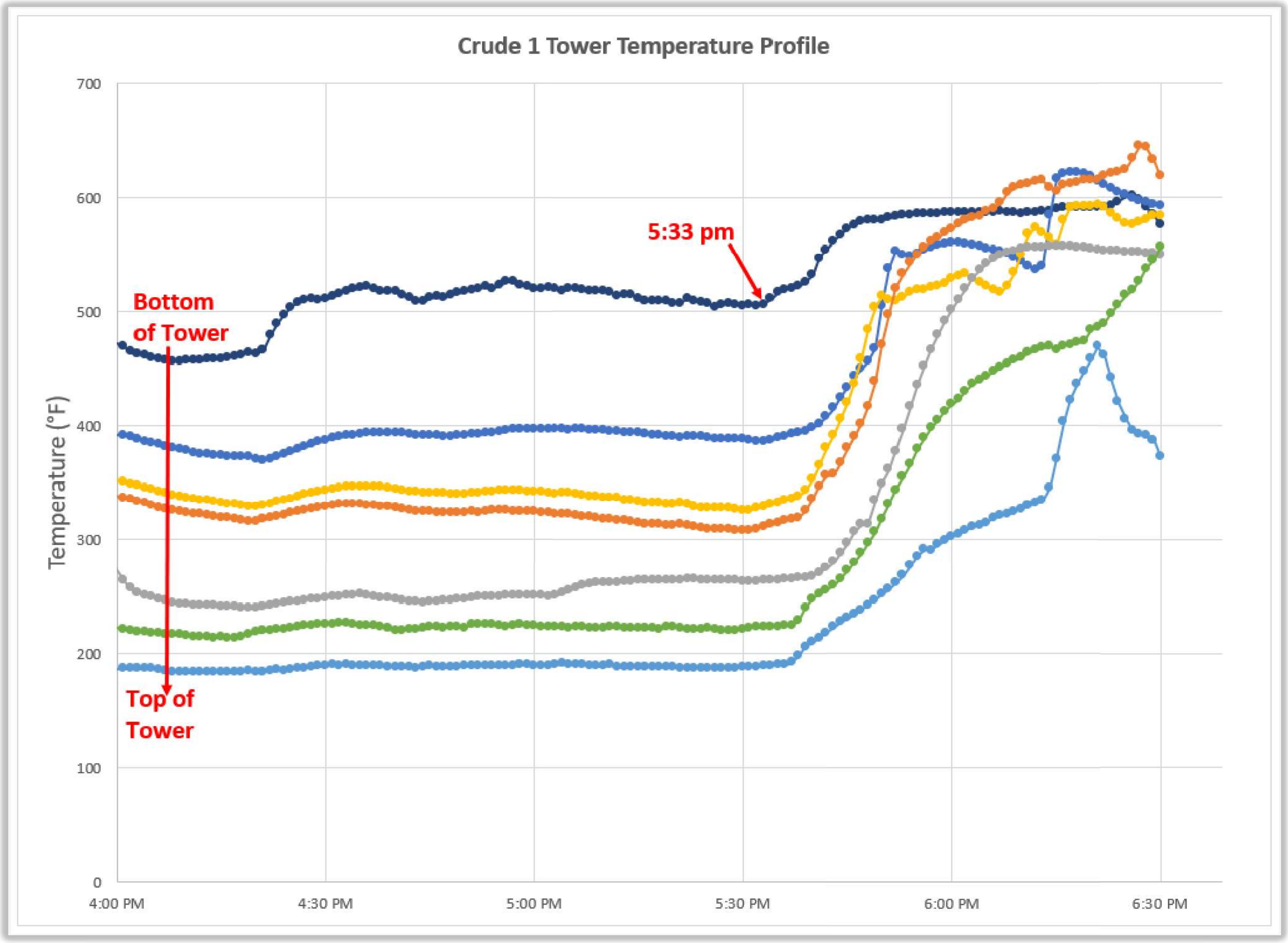

Figure 23: Crude 1 Tower temperature profile. Before the upset, temperatures are hottest at the bottom of the tower and decrease going up the tower, normal for any distillation tower. (Credit: CSB)

As tower temperatures increased, there was not enough liquid volume in the Crude 1 Tower pumparound circuits to maintain the vapor-liquid interface in each section of the Tower and to ensure sufficient cooling. As the pumparound flows successively dropped to zero (bottom at 5:41 p.m., middle at 5:47 p.m., and top at 6:13 p.m.), the Crude 1 Tower temperature profile further increased. Volatile materials in the tower flashed due to the increased temperatures, which led to high level in the Crude 1 Overhead Accumulator Drum as the increased vapor flow condensed in the overhead coolers.

The CSB concludes that the night shift board operator removed all light crude feed from the Crude 1 Tower in an effort to reduce the overhead naphtha flow, in response to the limited destinations available for naphtha.

The CSB concludes that rapidly eliminating all the light crude oil feed to the Crude 1 Tower initiated another process upset during the night of the incident. This change created a rapid increase of vapor flow up the tower and led to 1) high level in the Crude 1 Overhead Accumulator Drum, 2) loss of pumparound cooling, and 3) increased temperatures throughout the tower.

3.1.7 Crude 1 Overhead Accumulator Drum High Level

The Crude 1 Tower upset created a tower overhead flow surge a few minutes later, which in turn filled the Crude 1 Overhead Accumulator Drum. Within a five-minute period, the Crude 1 Overhead Accumulator Drum level rose from a steady state of 47 percent to 68 percent (the high level alarm), to 70 percent (the high-high level alarm), and finally to 89 percent level at 5:40 p.m. The Crude 1 Overhead Accumulator Drum level increased so rapidly that the level indication went from 65 percent to 89 percent in less than two minutes. In response to this rapid level increase, the board operators searched for ways to reduce level in the drum quickly. With other liquid naphtha flow paths out of the Crude 1 Overhead Accumulator Drum already either at full capacity or shut down,[a] a board operator opened the naphtha flow control valve to the Coker Gas Plant in an effort to reduce the Crude 1 Overhead Accumulator Drum level even though the Coker Gas Plant was intended to be bypassed at the time. **Figure 24** below shows this valve opening (in red) and the Crude 1 Overhead Accumulator Drum's rapid level increase and resulting decrease (in blue) after the naphtha flow control valve to the Coker Gas Plant was opened.

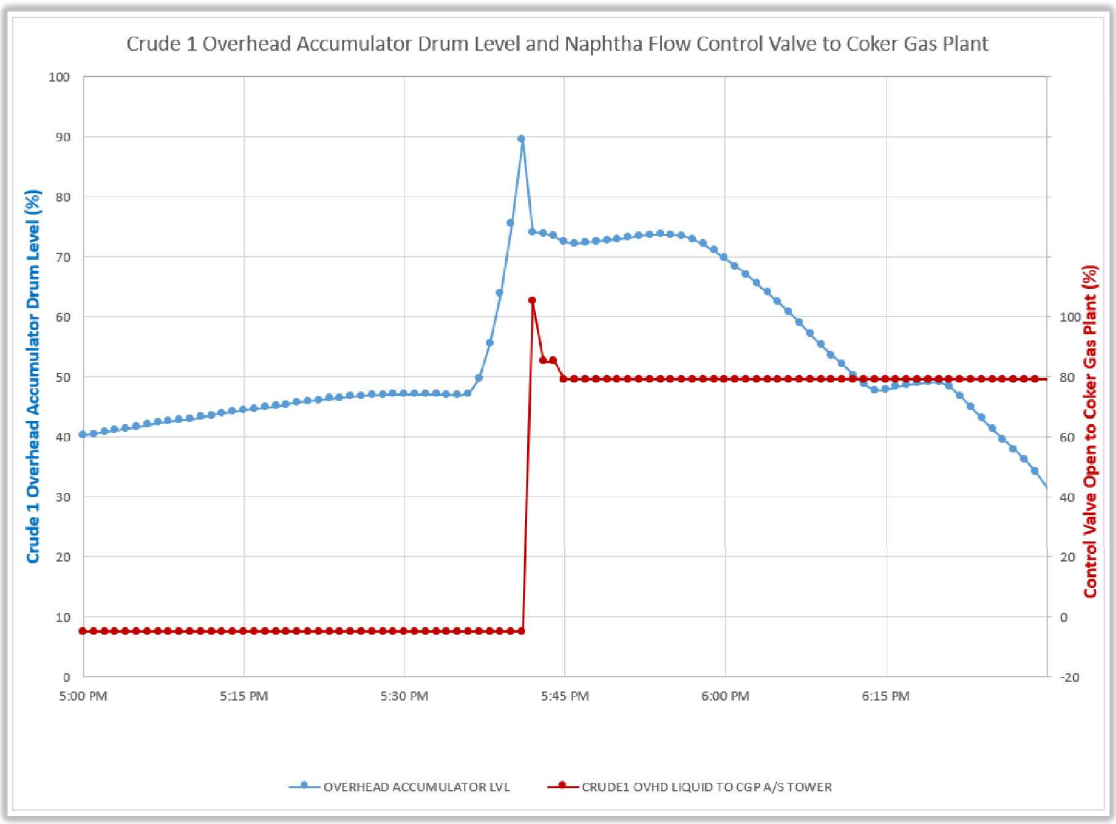

Figure 24: Crude 1 Overhead Accumulator Drum level (blue) and naphtha flow control valve to the Coker Gas Plant opening (red) in response to the high level. (Credit: CSB)

[a] The control valve to Light Virgin Naphtha Storage did have a bypass around it that could only be opened in the field. However, this manual bypass valve was valve had a sticker on it that read "Open with Caution" and the refinery coordinator considered the flow to Light Virgin Naphtha Storage to be "maxed out" while the bypass remained closed. Since the bypass could only be opened in the field, there may have been insufficient time available to open the bypass in this case. The CSB could find no operating procedure referencing opening of this bypass. Therefore, the CSB did not consider this manual bypass to be a viable option.

One board operator later explained to CSB investigators that overfilling the Crude 1 Overhead Accumulator Drum could send liquid to a downstream compressor, which would shut down another refinery unit:

> …our [Crude 1 Tower] overhead was filling up and, you know… The [Light Virgin Naphtha] valve […] was wide open. So that was, like, the only place we were going with the overhead, or could go, and it was filling up. […] And I don't know what percentage we were at [on the Crude 1 Overhead Accumulator Drum level], but all I know is we were pushing 80 percent, or maybe we were over, but… We looked at each other and we were like, you know, what do we do? And so I started looking at other units and I said, well, the gas plant, the Coker Gas Plant is open. I mean, the [NHT] feed drum[a] is only at, like, 36 percent. I was like, let's send it to the Coker Gas Plant. Even though it's down, we can store the feed in there, you know? And that way we don't trip the compressor off.

The CSB concludes that the board operators did not have clear instructions about how to manage Crude 1 Overhead Accumulator Drum high level. With only one destination available for naphtha, and the control valve to Light Virgin Naphtha at maximum capacity, the improvised solution by the board operators was to transfer excess Crude 1 Overhead Accumulator Drum level to the bypassed Coker Gas Plant.

The CSB concludes that opening the naphtha flow control valve to the Coker Gas Plant while the bypass valves were open allowed liquid naphtha to flow into the Coker Gas Plant and then overflow into the Fuel Gas Mix Drum and proceed to furnaces and boilers.

3.1.8 Absorber Stripper Tower Overflow

The night shift board operators were unaware that earlier that day, the day shift had closed a valve on the Coker Gas Plant Absorber Stripper Tower bottoms piping, known as a Remotely Operated Emergency Isolation Valve (ROEIV). This closed valve prevented flow through the Absorber Stripper Tower bottoms into the NHT Feed Surge Drum, so the liquid naphtha began to fill the Coker Gas Plant Absorber Stripper Tower more quickly than if the ROEIV had remained open. **Figure 25** illustrates the flow path from the Crude 1 Overhead Accumulator Drum to the Coker Gas Plant Absorber Stripper Tower.

[a] The NHT Feed Surge Drum and the Crude 1 Overhead Accumulator Drum were of similar volumes, each approximately 14,000–16,000 gallons.

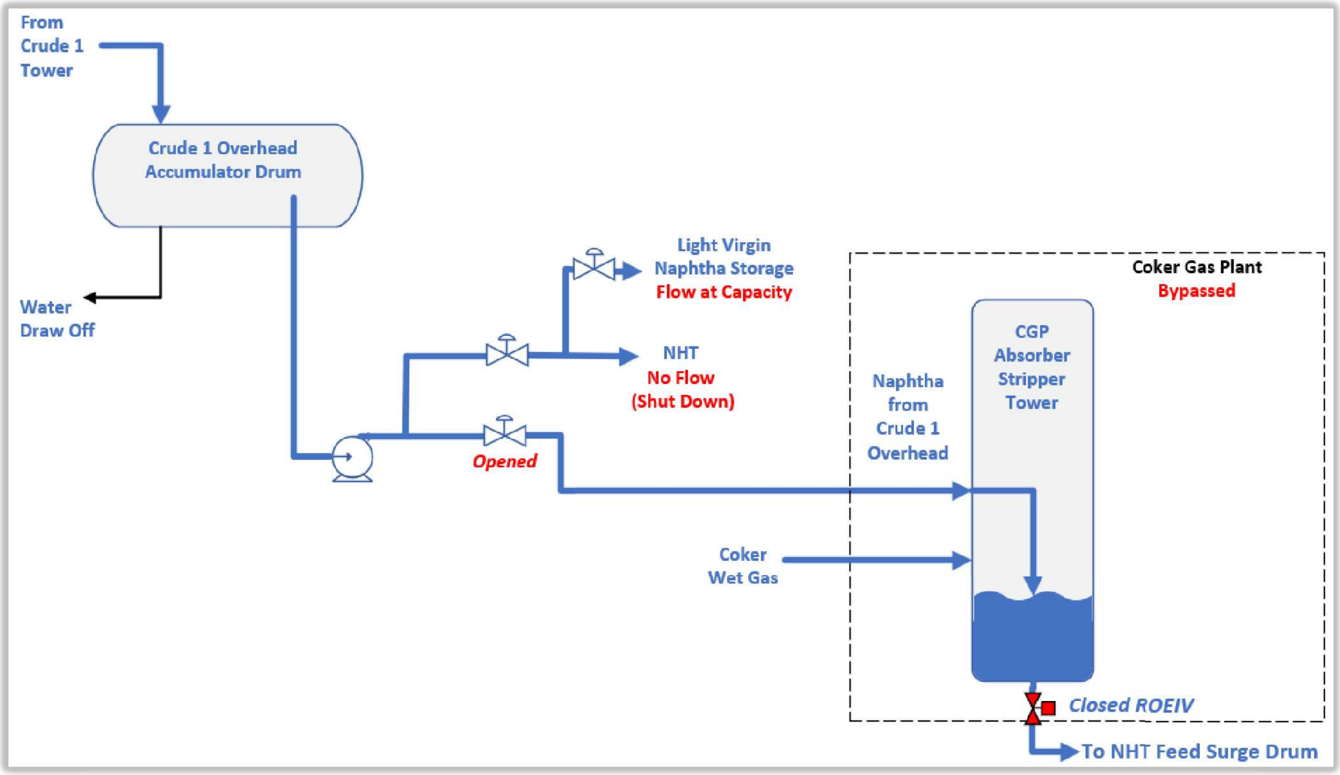

Figure 25: Flow path from Crude 1 Overhead Accumulator Drum to Coker Gas Plant. (Credit: CSB)

Once the Absorber Stripper Tower filled with liquid naphtha up to the elevation of the coker wet gas inlet piping, a line normally for gas flow only, the liquid naphtha overflowed into the Coker Gas Plant bypass piping and into the Fuel Gas Mix Drum. **Figure 26** below shows the overflow path from the Coker Gas Plant Absorber Stripper Tower to the Fuel Gas Mix Drum.

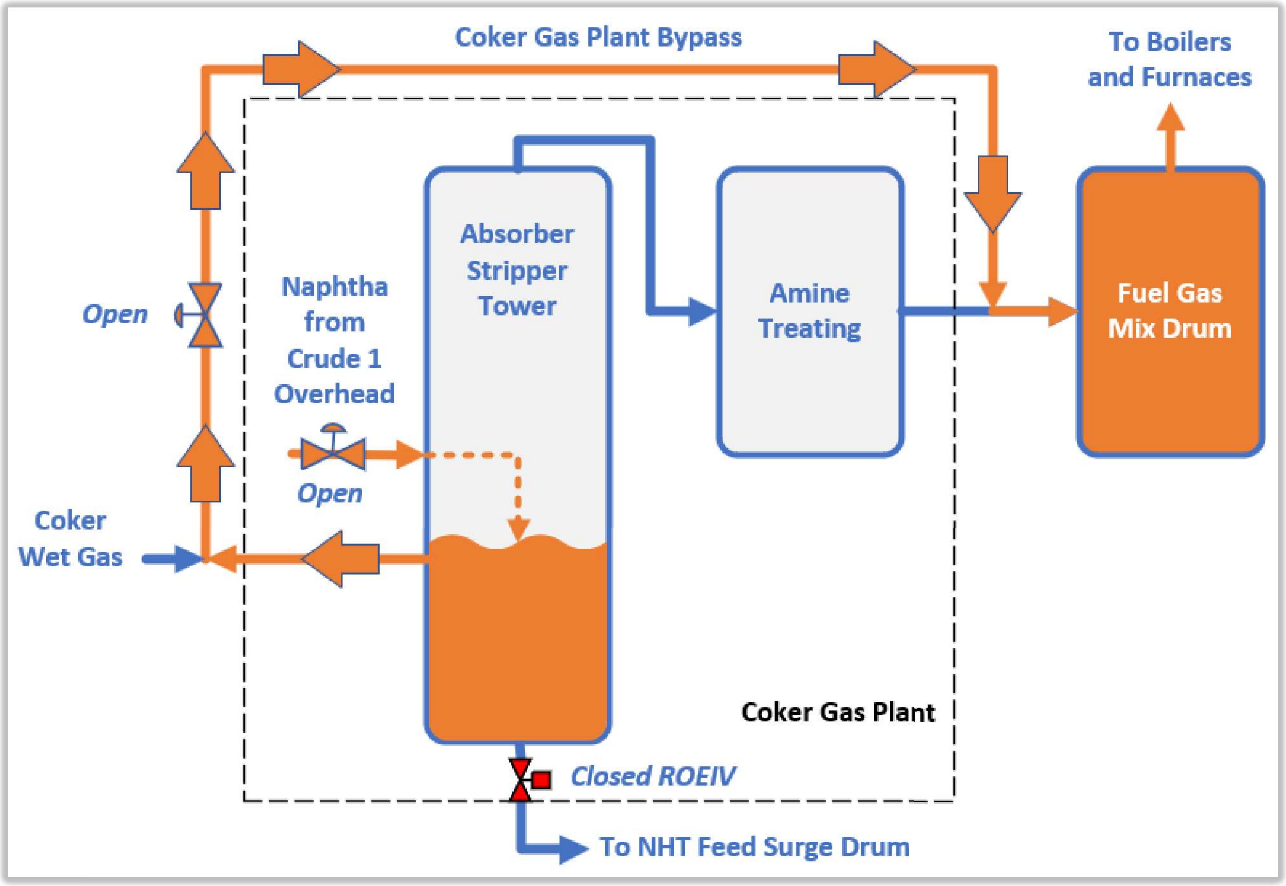

Figure 26: Overflow path from Coker Gas Plant to Fuel Gas Mix Drum (orange arrows).[a] (Credit: CSB)

The closed ROEIV hastened the overflow into the Fuel Gas Mix Drum through the open bypass line, but the overflow likely would have occurred even if the ROEIV had been open. This was demonstrated in a 2019 near miss,[b] similar to the September 20, 2022, incident, in which the ROEIV was open, but the overflow from the Absorber Stripper Tower, through the Coker Gas Plant bypass, to the Fuel Gas Mix Drum still occurred. This indicates that the inflow to the Absorber Stripper Tower was greater than the outflow from it even with the ROEIV open.

The CSB concludes that the closed ROEIV on the Absorber Stripper Tower bottoms caused the overflow through the Coker Gas Plant bypass line to the Fuel Gas Mix Drum to occur more quickly than it otherwise would have, giving board operators less time to troubleshoot and respond.

[a] The Coker Gas Plant bypass piping elevation was not above the top of the Absorber Stripper Tower. The drawing shows the process connectivity only and is not intended to be an elevation drawing.

[b] *See* **Section 4.4.1**.

3.1.9 Fuel Gas Mix Drum Overflow

The Absorber Stripper Tower began overflowing into the Fuel Gas Mix Drum at approximately 6:09 p.m. While the outside operations personnel were draining the Fuel Gas Mix Drum (*See* **Section 2.2**), refinery workers in various other units communicated by radio that they observed smoke coming from furnace and boiler stacks. The Crude 1 Furnace started emitting black smoke from its stack first, at 6:20 p.m. A boiler stack emitted green smoke at 6:22 p.m. Smoke from several other boilers and furnaces followed over the next 30 minutes (approximately). The smoke indicated that the Fuel Gas Mix Drum was overflowing liquid hydrocarbons (naphtha) to the furnaces and boilers by 6:20 p.m. Approximately 11 minutes elapsed from the time that liquid naphtha began to enter the Fuel Gas Mix Drum to the time that the naphtha reached the Crude 1 Furnace (at 6:20 p.m.).

When the naphtha entered the furnaces, the night refinery coordinator announced on the radio, "We got liquid in the fuel gas system. Keep away from those furnaces." The smoke coming from the boiler and furnace stacks caused the night shift refinery coordinator to assert on the radio to shut down the refinery, including stopping fuel flow to all furnaces and boilers, at 6:27 p.m. The refinery coordinator later told the CSB that he took these actions due to the potential for "an explosion in the furnace." By this time, however, it was too late to prevent the consequences from the excess liquid that already had flowed into the Fuel Gas Mix Drum.

A furnace fire was reported at approximately 6:24 p.m. under the Coker 2 furnace. This indicates that not only was liquid in the fuel gas system, but also that all furnaces and boilers were fire hazards with liquid overflowing to the fuel gas system.

The night shift supervisor and other operations personnel later told the CSB that while draining material to the Flare Knockout Drum and Oily Water Sewer, they believed the material to be an amine-water solution, not naphtha. The night shift supervisor stated that he mentioned to the outside operator and operator trainee to get SCBAs nearby out of concern they could need supplied air due to the potential hazard of hydrogen sulfide (H_2S) in the amine-water solution. The two BP employees who released the Fuel Gas Mix Drum to the ground may have believed that the material was amine-water solution, rather than naphtha, just as other operations personnel did. The outside operations personnel were not aware of the actions by the board operator that led to naphtha overflowing from the Absorber Stripper Tower to the Fuel Gas Mix Drum.

The CSB concludes that the BP Toledo Refinery recognized the potential for furnace fires or explosions if liquid entered the fuel gas systems.

The CSB concludes that the two BP employees who released naphtha from the Fuel Gas Mix Drum to the ground may have believed that the material was an amine-water solution just as other operations personnel did. Because the BP Toledo Refinery lacked established corrective actions for the situation, the two BP employees may have improvised a solution in real time without being aware of the consequences of releasing to the ground.

Figure 27 shows a summary timeline of some of the key events in the hour preceding the incident, showing limited time available to refinery personnel for decision-making. **Appendix A.2.9.4** contains a detailed timeline of the event.

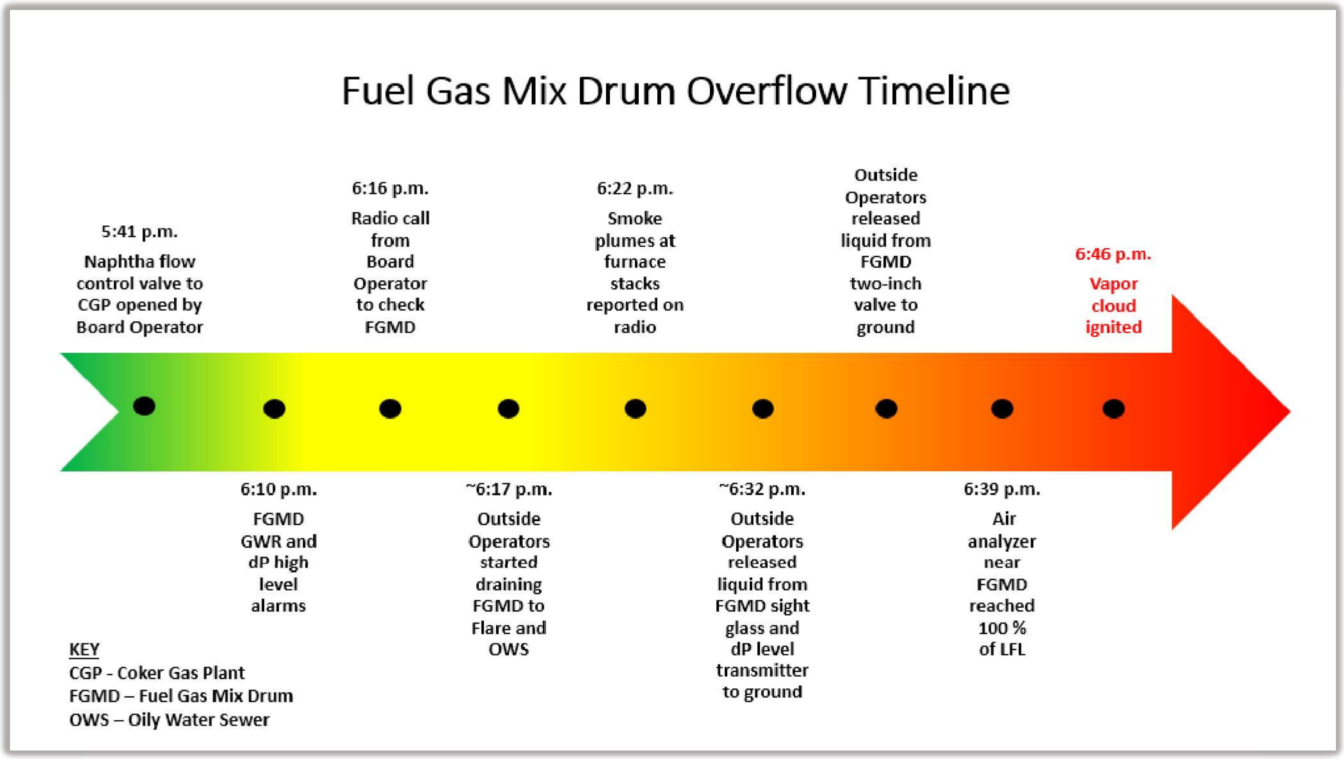

Figure 27: Summary timeline of some key events for the hour preceding the incident. (Credit: CSB)

3.2 Draining and Liquid Release

As discussed in **Section 1.5**, the BP Toledo Refinery Fuel Gas Mix Drum collects entrained liquids from the refinery fuel gas system. The Fuel Gas Mix Drum has a two-inch line to dispose of those liquids to the Flare Knockout Drum as shown below in **Figure 28**. A two-inch line connected to the line to the Flare Knockout Drum allowed direct draining to the refinery Oily Water Sewer. A guided wave radar level instrument had a hard piped drain to the Oily Water Sewer. However, on the day of the incident, there were additional valves on the Fuel Gas Mix Drum opened and used by two BP employees to release liquid naphtha to the ground including a ¾-inch tap from the differential pressure level instrument, a ¾-inch drain from the sight glass, and a two-inch gate valve with a bolted closed blind flange on the side of the Fuel Gas Mix Drum which was located approximately seven feet from the ground.[a]

[a] This two-inch gate valve with a bolted closed blind flange was to be used for steaming out the vessel for maintenance activities or turnaround.

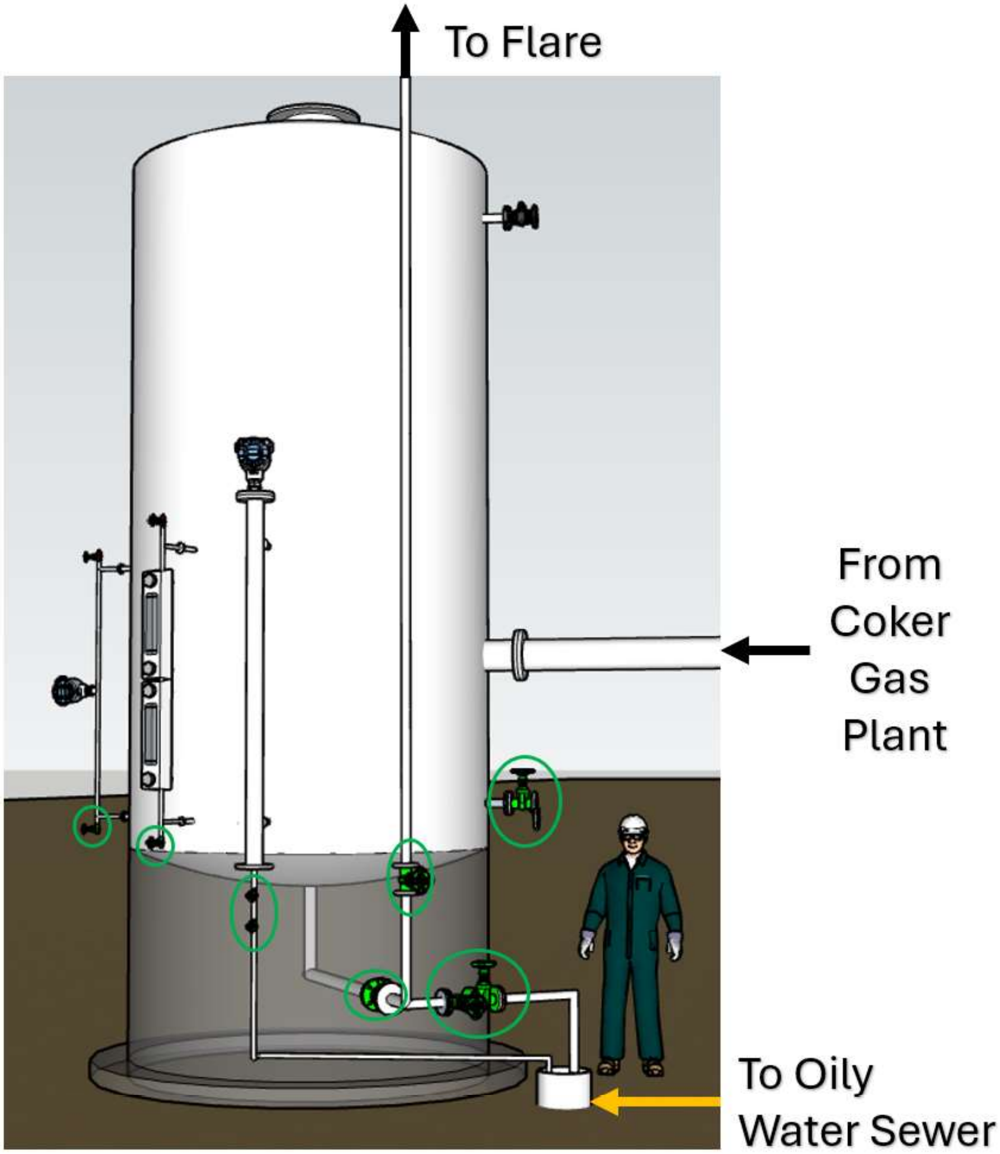

Figure 28. BP Toledo Refinery Fuel Gas Mix Drum. Valves circled in green were opened to drain and release naphtha. (Credit: CSB)

The Fuel Gas Mix Drum at the BP Toledo Refinery had a diameter of seven feet and eleven inches and a seam-to-seam height of nearly fourteen feet and nine inches. Consistent with industry standards,[a] the liquid level measurement from the sight glass, differential pressure level, and guided wave radar all measured only the bottom six-foot span of the Fuel Gas Mix Drum and could not indicate a liquid height greater than that.

---

[a] API Recommended Practice 551 Second Edition (API RP 551) *Process Measurement,* Section 3.4 Instrument Selection provides guidance for instrument selection and identifying expected operating cases such as normal flow as well as emergencies and upsets [63, p. 18]. Section 7.2.2 of API RP 551 provides guidance for range selection and states to "determine the maximum process liquid level, for most services, a liquid holdup time of between 5 to 10 minutes is used to ensure controllability and safety. Consequently, there is between 2 ½ and 5 minutes between the normal mid-rage set point and loss of measurement" [63, p. 112].

Figure 29 shows the rapid progression of overflow events after the naphtha flow control valve to the Coker Gas Plant was opened by a board operator. In approximately 14 minutes the Coker Gas Plant Absorber Stripper Tower reached 100 percent level and approached overflow through open bypass piping. In approximately seven minutes, naphtha from the overflowing Coker Gas Plant Absorber Stripper Tower filled the six-foot span in the Fuel Gas Mix Drum.

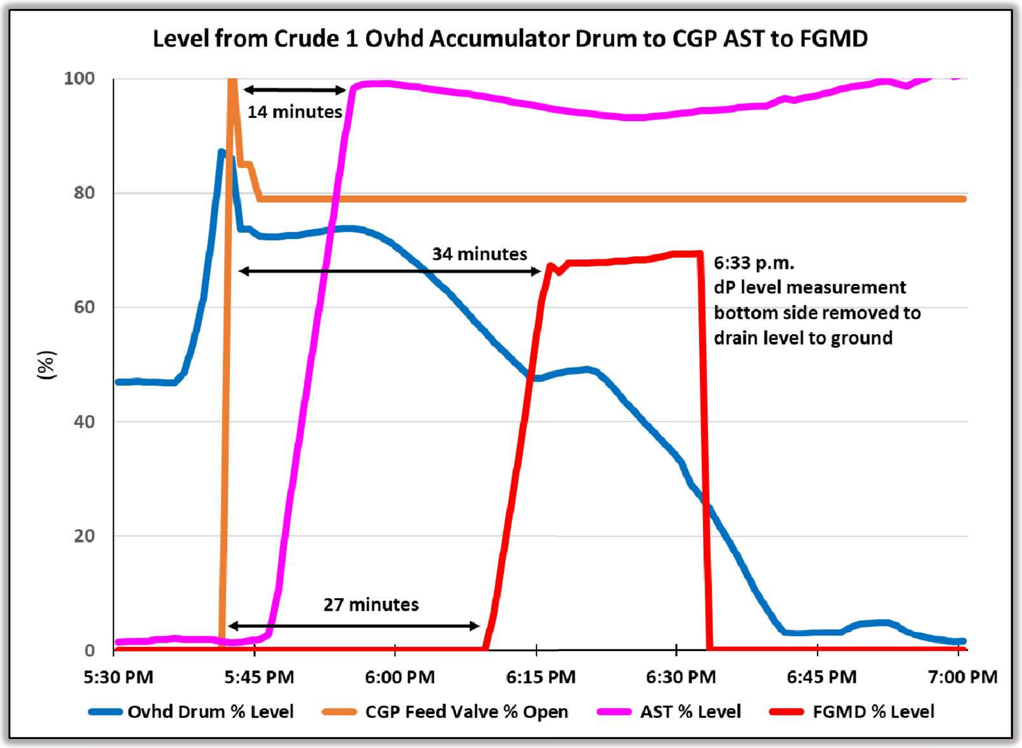

Figure 29. Overflow progression. Decreasing level in the Crude 1 Overhead Accumulator Drum and increasing levels in the Coker Gas Plant Absorber Stripper Tower and Fuel Gas Mix Drum.[a] (Credit: CSB)

At this point, the guided wave radar and sight glass indicated the liquid level in the Fuel Gas Mix Drum had reached the top of the measured six-foot level span around 6:15 p.m.[b] As the liquid continued to fill the Fuel Gas Mix Drum, these instruments could not provide any indication that the drum was overflowing liquid into the fuel gas piping.

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[a] The Fuel Gas Mix Drum differential pressure (dP) level is shown. The Fuel Gas Mix Drum guided wave radar level was working during the September 20,2022, incident, however, the data points were not recorded by the BP Toledo Refinery process data historian. (*See* **A.2.8.2**)

[b] The Fuel Gas Mix Drum differential pressure level indication plateaued at around 67 percent of the six-foot span even though the guided wave radar level instrument and sight glass showed the Fuel Gas Mix Drum at capacity. This incorrect indication was due to the density of naphtha being less than the density of the typical amine-water solution used to calibrate the differential pressure level meter. The BP SDS for naphtha lists the relative density of straight run naphtha at 0.72 relative to water. The differential pressure level measurement was calibrated with a density of 0.998. Consequently, the Fuel Gas Mix Drum differential pressure level measurement never reached the Fuel Gas Mix Drum high-high level alarm point or indicated liquid was overflowing to the fuel gas piping.

The measured naphtha flow rate to the Coker Gas Plant exceeded 18,700 barrels per day after the naphtha flow control valve to the Coker Gas Plant was opened to lower the liquid level in the drum. This flow rate into the Fuel Gas Mix Drum was more than the 9,800 barrels per day estimated to be draining from the Fuel Gas Mix Drum to the Flare Knockout Drum.[a]

The volume of the naphtha flow into the Fuel Gas Mix Drum exceeded the capacity out of the Fuel Gas Mix Drum to the Flare Knockout Drum, a closed system.[b] The Fuel Gas Mix Drum two-inch drain to the Oily Water Sewer provided an additional estimated draining capacity of 15,600 barrels a day.[c,d,e]

The CSB concludes that the Fuel Gas Mix Drum drain piping did not have enough capacity to drain naphtha overflowing from the open Coker Gas Plant in a closed system to the Flare Knockout Drum.

The CSB concludes that limiting or stopping the flow of naphtha to the Coker Gas Plant would have been required to prevent an overflow of the Fuel Gas Mix Drum since more naphtha could flow into the Fuel Gas Mix Drum through the Coker Gas Plant bypass than could be removed to a closed system.

[a] BP estimated the rate of naphtha being drained from a fully open two-inch valve to the flare at 9,792 barrels per day.

[b] A closed system consists of piping and vessels connected to selected hydrocarbon drains for the containment, recovery, or safe disposal of collected liquids, which would otherwise cause hazardous releases of hydrocarbon or toxic vapors such as hydrogen sulfide to the atmosphere or to an oily water drainage system [57, p. 190].

[c] BP estimated the rate of naphtha being drained from a fully open two-inch valve to the Oily Water Sewer at 15,624 barrels per day.

[d] The bottom drain out of the Coker Gas Plant Absorber Stripper Tower was a ten-inch nozzle which reduced to a four-inch line to the NHT Feed Drum.

[e] After the September 20, 2022, incident, Ohio Refining Company LLC estimated the flow control valve to be able to be open enough to flow 30,000 barrels a day.

3.3 Stop Work Authority

The Center for Chemical Process Safety (CCPS) notes that "Leaders should make it clear that any employee can stop work or shut down the process if they perceive a potentially unsafe situation" [21, p. 87]. This is commonly referred to as "Stop Work Authority."[a] At the time of the incident, the BP Toledo Refinery had a procedure called "Handling Employee Health/Safety Concerns of Assigned Work," which stated:

- All workers at BP Toledo Refinery have the right to a safe work environment.
- All BP refinery employees and all contractor employees have the right and the responsibility to STOP any work that may be UNSAFE.

Additionally, some BP Toledo Refinery operating procedures stated (in their introductions): "All qualified unit operators have the full authority to take action (including shutting the unit down) when conditions are unsafe to continue to operate."[b]

Some BP Toledo Refinery operations personnel told the CSB that they felt they could invoke Stop Work Authority, and some stated that they had already done so in the past. On the morning of the incident, the NHT unit emergency shutdown was initiated (**Section 3.1.2**). That same evening, as soon as liquid was known to be in the fuel gas piping and inside furnaces, the night shift refinery coordinator initiated a shutdown of the refinery, although by this time, it was too late to prevent the consequences from the excess liquid that already had flowed into the Fuel Gas Mix Drum. The refinery coordinator explained to CSB investigators:

> We obviously had liquid in the fuel gas. But at that point, it was a very easy decision for me because reports were coming that the furnaces were…were getting rich. Starting with the crude furnace. And that's when I was like, "Pull the fuel gas." We're…just pull the fuel gas out of the furnace. We're going to lose [shut down] this refinery.

KEY LESSON

Companies must ensure (through training, clearly written procedures, and other means) that employees not only are clearly empowered to exercise Stop Work Authority, but that employees also clearly understand they are expected to do so. However, companies should not rely on Stop Work Authority programs alone to prevent a catastrophic process incident since they require humans to take action to shut down a job or a process. Stop Work Authority is not a substitute for effective process safety management systems.

[a] The CSB has addressed Stop Work Authority previously in its 2015 investigation of the Chevron Richmond Refinery Fire and its 2001 investigation of the Tosco Avon Refinery Petroleum Naphtha Fire. Additionally, as outlined in the CSB's October 26, 2022, comments submitted to the EPA on the EPA's then-proposed revisions to the RMP rule: "The CSB has always stated that facilities must also have effective measures in place for incident prevention that will foster a "culture of safety" wherein workers are encouraged and empowered to advocate for their safety on the job. The CSB believes that any program that does not appropriately enable workers to feel free to exercise stop work authority in necessary circumstances would allow risks to occur and accumulate." *See* Notice of Proposed Rulemaking Status Change Letter (csb.gov)

[b] Operators must take the written qualification test to achieve qualification, and requalification training is provided at least every three years through the administration of a field test to ensure the operator understands and adheres to the current operating procedures of the process they are assigned.

Moreover, some operators had communicated concerns to refinery management about operations on the day of the incident. For example, on the morning of the incident, before the NHT Preheat loss of containment, an outside operator communicated several statements of serious concern on the radio, all within a two-minute window, approximately 25 minutes before the ¾-inch bleed severed from the naphtha piping in NHT Preheat (**Section 3.1.2**):

> "I don't know how much longer we can let this go…it's going to tear something up…Somebody needs to make a call out here ASAP."
>
> "We're going to hose some stuff up for real here if we let this go much longer."
>
> "I really need somebody to ok me to block that PSV in."
>
> "I don't know how much longer this pipe can take this. It's getting beat up really bad."

Although no operators appear to have explicitly invoked Stop Work Authority for the NHT Preheat leak the morning of the incident, the radio traffic above indicates that operations personnel did communicate concerns about continuing to operate the NHT unit consistent with the purpose of Stop Work Authority. Although an emergency shutdown of the NHT unit was conducted, it occurred too late to prevent the loss of containment in NHT Preheat and led to the subsequent cascading upsets. Additionally, as noted, although the night shift refinery coordinator initiated a shutdown as soon as liquid was known to be in the fuel gas piping and inside furnaces, by the time the night shift refinery coordinator acted, it was too late to prevent the consequences from the excess liquid that already had flowed into the Fuel Gas Mix Drum.

If BP had implemented actions to stabilize operations, the Crude 1 unit could have already been in a safe state by the time night shift operators arrived, and the Crude 1 Tower upset on the night shift could have been avoided. If the Crude 1 Tower upset on night shift had been avoided, the excess liquid in the Crude 1 Overhead Accumulator Drum, the Absorber Stripper Tower, and the Fuel Gas Mix Drum would have also been avoided, and the fatal incident would not have occurred.

Critically, no action, following the Crude 1 Tower upset, was taken to prevent naphtha from overflowing into the fuel gas piping. Instead, as one board operator told CSB investigators, it was viewed as just a "normal upset", despite the cascading process upsets and rapidly deteriorating conditions, and he thought at the time that "we can get this."

The board operator's statement illustrates that key personnel at the BP Toledo Refinery did not understand the dire nature of the events that were rapidly unfolding, and, as such, no one invoked Stop Work Authority in time to prevent the occurrence of the catastrophic incident on September 20, 2022. In this instance, Stop Work Authority would have been not only appropriate, but absolutely necessary in light of the unsafe conditions that existed at the time and would continue to worsen thereafter.

While Stop Work Authority is an extremely important program that companies should have in place to stop an unsafe event, it is important to recognize that it is fundamentally a "last resort" type human-initiated action, prone to failure in correcting broader process-related hazards, as illustrated by the incident at the BP Toledo Refinery. By design, Stop Work Authority is a decision process embedded into the chaos of a process safety event, often in a stressful atmosphere in which an individual employee must assert a dissenting viewpoint against a group. Therefore, reliable systems, including automated preventive overfill safeguards, must be implemented and maintained. A robust risk-based process safety program must also be in place to identify and prevent hazards before reaching the point of relying on Stop Work Authority to prevent a catastrophic process event.

Regardless of whether the BP Toledo Refinery had adequate Stop Work Authority procedures in place that might have provided a means for personnel to take action to prevent the situation from worsening, the fact is that no effective steps were taken at any point to prevent the fatal incident.

4 Safety Issues

The following sections discuss the safety issues contributing to the incident, which include:

- Liquid Overflow Prevention
- Abnormal Situation Management
- Alarm Flood
- Learning from Incidents

4.1 Liquid Overflow Prevention

Vessel overflow events can harm workers, communities, and the environment, damage equipment, and lead to catastrophic events.

Many companies, including BP, use hazard analysis techniques, including process hazard analyses (PHAs) to:

- identify hazards,
- evaluate worst-case/high-severity scenarios, and
- select necessary prevention and mitigation measures for the risks.

The hierarchy of controls[a] and layer of protection analysis (LOPA)[b] methodologies are used to determine the adequacy of available safeguards and select prevention and mitigation strategies when the current safeguards are deemed insufficient. Prevention and mitigation measures include but are not limited to instrumentation, process controls, and safety instrumented systems (SISs).

Although the BP Toledo Refinery conducted PHAs to analyze liquid overflow events and LOPAs[c] to determine the effectiveness of identified safeguards,[d] the refinery's safeguards were not effective in preventing liquid naphtha from overflowing the Coker Gas Plant Absorber Stripper Tower to the Fuel Gas Mix Drum and into the fuel gas piping, as described in **Section 3.1.8**. In addition, the BP Toledo Refinery did not have effective administrative controls such as written procedures and adequate training for operations personnel to recognize and prevent liquid overflow events.

4.1.1 Ineffective Safeguards

Prior to the incident, the BP Toledo Refinery had identified the liquid overflow of process vessels, including liquid overflow from the Fuel Gas Mix Drum to the fuel gas system, as a process deviation that could lead to a

[a] The National Institute of Occupational Safety and Health (NIOSH) defines the hierarchy of controls as "a way of determining which actions will best control exposures [to hazards in the workplace]" [47].

[b] A layer of protection analysis (LOPA) is "an approach that analyzes one incident scenario (cause-consequence pair) at a time, using predefined values for the initiating event frequency, independent protection layer failure probabilities, and consequence severity, in order to compare a scenario risk estimate to risk criteria for determining where additional risk reduction or more detailed analysis is needed. Scenarios are identified elsewhere, typically using a scenario-based hazard evaluation procedure such as a HAZOP Study" [68]. LOPAs evaluate risks and the sufficiency or effectiveness of protection layers in reducing the frequency and/or consequence severity of hazardous events.

[c] The BP Toledo Refinery completed its Coker Gas Plant LOPA of Record Report in February 2020. "Applicable Generic Suite LOPAs were reviewed by the [BP Toledo Refinery] team and applied, localized to reflect actual site conditions."

[d] A safeguard is "any device, system, or action that interrupts the chain of events following an initiating event or that mitigates the consequences" [54].

safety hazard in its PHAs. The refinery conducted multiple PHAs[a] on its Crude 1 unit and Coker Gas Plant between 2014 and 2020.[b]

BP Guidance

The BP Safety and Operational Risk Group provided written liquid overfill hazard management guidance in its publication, *Overfill of Process Vessels and Columns Risk Assessment and Mitigations for Downstream*. The guidance lists acceptable Independent Protection Layers (IPLs) that can be used for liquid overfill hazards. Among these are:

1. An independent high level alarm as part of:
    a. Operator response to a safety related alarm, if sufficient operator response time would be available in the scenario;
    b. A basic process control system IPL "that stops or redirects flow into the vessel or that provides a secondary outflow path can be utilized with the independent high level alarm;"
2. A pressure relief system (PSV and associated piping, structure, etc.) designed for liquid overfill and that discharges to a safe location;
3. A safety instrumented function (SIF)[c] that shuts down flow, "that stops or re-directs all feeds away from the vessel, or that provides a secondary path for flow out of the vessel/column."

For the scenario of Absorber Stripper Tower overflow to the Fuel Gas Mix Drum, the BP Toledo Refinery implemented high level alarms coupled with operator response and emergency pressure-relief system valves as safeguards. The BP Toledo Refinery, however, did not implement automatic or engineering controls to stop flow into the Absorber Stripper Tower or Fuel Gas Mix Drum.

4.1.1.1 Preventive versus Mitigative Safeguards

Safeguards are used to reduce the risk from potential hazardous scenarios, either by preventing the initiating event from occurring or mitigating the consequences of the process deviation. *Preventive* safeguards keep loss events,

[a] The BP Toledo Refinery generally used the Hazard and Operability Study (HAZOP) technique to conduct its PHAs. HAZOP is a "systemic qualitative technique that identifies process hazards and potential operating problems using a series of guidewords to study process deviations. A HAZOP is used to question every part of a process to discover what deviations from the intention of the design can occur and what their causes and consequences may be" [71].

[b] The BP Toledo Refinery conducted PHAs on its Crude 1 unit in 2014 and 2019. The BP Toledo Refinery conducted PHAs on the Coker Gas Plant in 2015, 2018, and 2020.

[c] A safety instrumented function (SIF) is a "system composed of servers, logic servers, and final control elements for the purpose of taking the process to a safe state when predetermined conditions are violated" [70].

such as fires, explosions, and toxic releases, from happening "when an initiating event causes a process to deviate from normal operation." On the other hand, *mitigative* safeguards "can reduce the impact of loss events," even though the event itself still may occur. PHAs are performed to determine the preventive and mitigative safeguards needed for the identified hazardous scenarios and consequences. While safeguards are used to prevent and mitigate loss events, they may not necessarily prevent the initiating event, as was the case at the BP Toledo Refinery for the overflow of vessels.

KEY LESSON

PHA scenarios should consider both preventive and mitigative safeguards and not unrealistically rely on human intervention.

The safeguards identified in the BP Toledo Refinery's PHAs for Absorber Stripper Tower overflow to the Fuel Gas Mix Drum were not effective safeguards to prevent overflow. One type of identified safeguard included a furnace SIS that aligns with the American Petroleum Institute Recommended Practice 556 (API RP 556) *Instrumentation, Control, and Protective Systems for Gas Fired Heaters* guidance. SISs take "automated action to keep a plant in a safe state, or to put it into a safe state when abnormal conditions are present" [22].[a] However, the SISs identified in the 2020 Coker Gas Plant PHA to prevent the consequences of liquid overflow[b] into furnaces were all downstream of the Fuel Gas Mix Drum and could not take action until liquid was already inside the fuel gas piping downstream of the Fuel Gas Mix Drum, as shown in **Figure 30**. No SIS prevented the Absorber Stripper Tower overflow to the Fuel Gas Mix Drum by stopping naphtha flow into the tower once a high level of liquid in the tower was detected.

Emergency pressure-relief valves are a second type of safeguard the PHA identified. Emergency pressure-relief valves are safeguards designed to protect process equipment during a process overpressure. The identified emergency pressure-relief valve safeguards at the BP Toledo Refinery were intended to protect the Absorber Stripper Tower against potential overpressure. These emergency pressure-relief valves were installed on the overhead line exiting the top of the Absorber Stripper Tower. As such, the Absorber Stripper Tower emergency pressure-relief valves were not designed to prevent the process overflow into the bypass line, just the hazard of potential overpressure arising from an overflow scenario.

A third type of safeguard identified during the PHAs relied on human intervention response to address alarms from the Absorber Stripper Tower level and differential pressure instrumentation to mitigate the potential for naphtha overflow of the Absorber Stripper Tower into the Fuel Gas Mix Drum and furnaces. As discussed further in **Section 4.3**, human intervention can be unreliable depending on the workload of the operator. As such, in certain situations, human intervention as a safeguard can prove to be ineffective.

[a] The International Society of Automation (ISA) Standard 61511 *Functional Safety – Safety Instrumented Systems for the Process Industry Sector* contains "requirements for the specification, design, installation, operation and maintenance of a safety instrumented system (SIS)" to achieve and maintain a safe state of the process [58, p. 9]. Its SIS Design and Engineering section states, "Where the SIS operator interface is via the BPCS [Basic Process Control System] operator interface, account shall be taken of credible failures that may occur in the BPCS operator interface" [58, p. 59].

[b] The consequence of liquid overfill in furnaces is further discussed in **Section 4.1.4**.

Figure 30 illustrates the Absorber Stripper Tower safeguards identified in the 2020 Coker Gas Plant PHA in red, along with the unit or safeguard changes noted above.

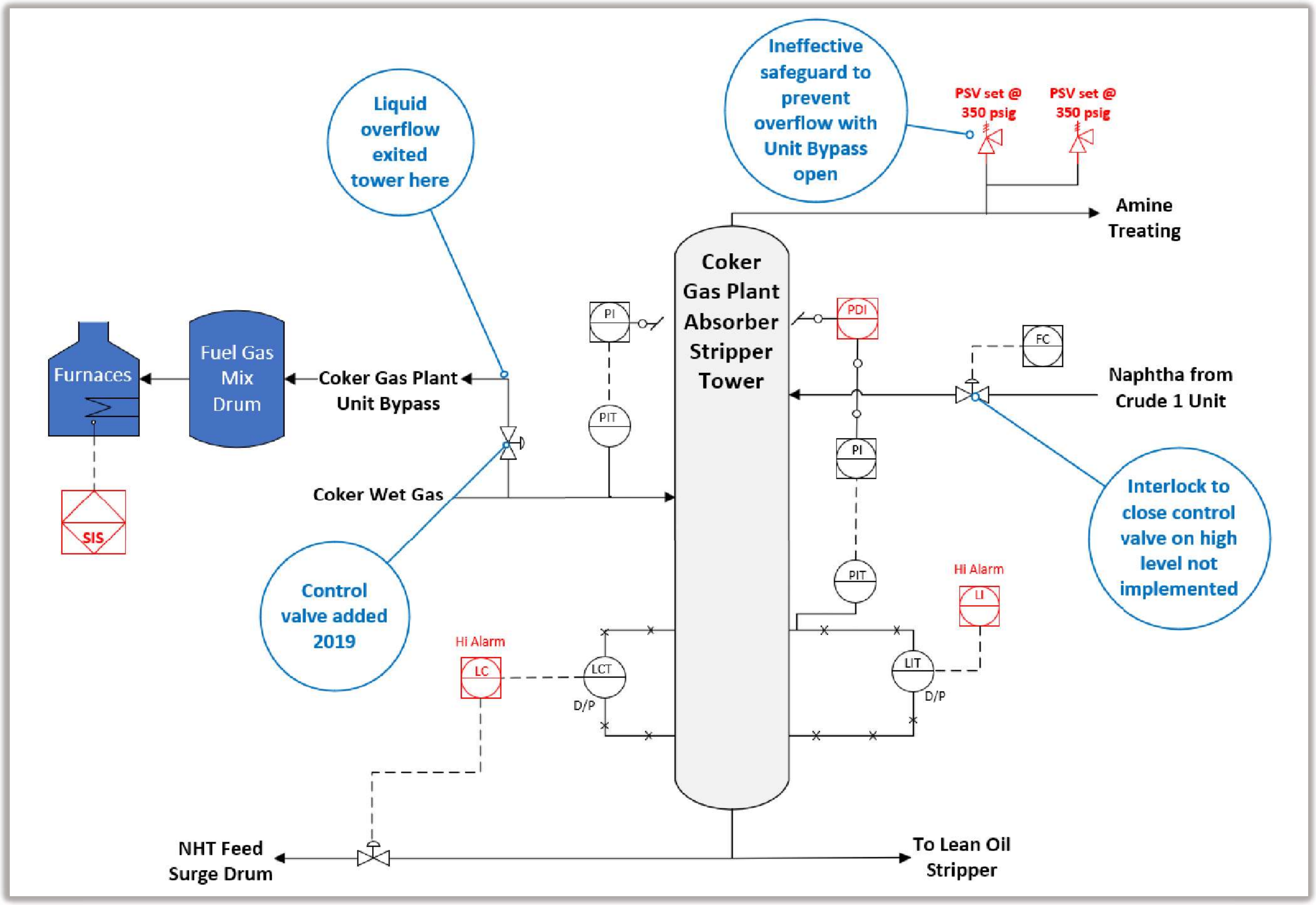

Figure 30: Absorber Stripper Tower safeguards identified in the 2020 Coker Gas Plant PHA, shown in red. (Credit: CSB)

The CSB concludes that the Absorber Stripper Tower emergency pressure-relief valves and the refinery furnaces' safety instrumented systems would not prevent a vessel overflow event. Instead, they just protected equipment after an overflow has already occurred.

The CSB also concludes that had the BP Toledo Refinery recognized the likelihood of liquid overflow to the Fuel Gas Mix Drum, it could have implemented more effective preventive safeguards, such as a high level interlock to close the naphtha feed valve to the Absorber Stripper Tower.[a] Such an interlock would have automatically stopped the identified liquid overflow events instead of relying on alarms that require human intervention, emergency pressure-relief valves, and downstream safety instrumented systems.

[a] An interlock is a protective response that is initiated by an out-of-limit process condition [67].

4.1.1.2 MISSED OPPORTUNITIES TO PREVENT OVERFLOW

The BP Toledo Refinery completed at least two plant modifications and investigated at least one incident of liquid naphtha overflow into the Fuel Gas Mix Drum, prior to the September 2022 incident, in which the refinery could have identified high liquid level scenarios and implemented effective safeguards to prevent overflow of naphtha into the fuel gas system.

Initial Coker Gas Plant Project PHAs

Before starting up the new Coker Gas Plant in 2018, the BP Toledo Refinery performed a series of PHAs on the new unit. These PHAs identified scenarios in which the Absorber Stripper Tower reached high level from a variety of causes, and they listed the consequences as "potential overpressure, damage, leak, hydrogen sulfide (H_2S) exposure, fire, injury, fatalities." However, these PHAs did not identify any potential scenario in which liquid naphtha in the Absorber Stripper Tower would overflow into the Fuel Gas Mix Drum. Since this scenario was not considered, the 2016 design PHA team may have actually deleted an identified preventive safeguard before it was ever implemented—an interlock that would have closed the naphtha flow control valve to the Coker Gas Plant when the liquid level in the Absorber Stripper Tower was high. A comment included in Coker Gas Plant project documentation stated:

> Per Generic LOPA, only PSV needed to mitigate scenario. BPCS [Basic Process Control System] closure of [naphtha flow control valve to the Coker Gas Plant] is good design, not IPL. No SIF [safety instrumented function] needed here.[a]

KEY LESSON

PHAs should evaluate overfill hazards and consider scenarios in which a vessel may not overfill to the top but may instead overflow or backflow through other piping connections.

Operational Changes to Coker Gas Plant Bypass

After the initial Coker Gas Plant startup and commissioning, the BP Toledo Refinery found that the Coker Gas Plant Polishing Amine Contactor experienced upsets when treating high flow rates of coker wet gas. To resolve this and prevent Coker Gas Plant upsets, the BP Toledo Refinery began to operate the Coker Gas Plant with the bypass partially open, to allow a portion of the coker wet gas flow to bypass the Coker Gas Plant to achieve stable operation. However, operating the Coker Gas Plant with the bypass continually open created two flow paths, and the safeguards identified in the Coker Gas Plant PHAs were not effective in preventing overflow in this new operating configuration.

In 2019, the BP Toledo Refinery replaced a manual gate valve installed in the Coker Gas Plant bypass piping with an automatic valve that would control the Polishing Amine Contactor differential pressure by bypassing gas around the unit. This new control valve fundamentally changed how the Coker Gas Plant had previously operated. Previously, with the manual valve, only outside operators (and not board operators) could respond,

[a] A Basic Process Control System (BPCS) is a "system that responds to input signals from the process and its associated equipment, other programmable systems, and/or from an operator, and generates output signals causing the process and its associated equipment to operate in the desired manner and within normal production limits" [69].

and they had to manually open or close the bypass valve during a Coker Gas Plant upset. The replacement valve enabled automatic control and allowed for a quicker response by board operators.

The MOC documentation for implementing the new automatic control valve identified coker wet gas as the normal process material and stated that an "Evaluation Team" had confirmed that neither "flows" nor "backflow" would be a concern or problem with the change to the automatic valve.[a] It did not specify or reference any concerns with liquid naphtha overflow through piping connections or valve failure. However, the BP Toledo Refinery's 2019 Crude 1 PHA did not evaluate potential liquid overflow scenarios into the Fuel Gas Mix Drum[b] related to the change. Additionally, during the CSB's investigation, the CSB was provided with documentation that included a "PHA Team Review Comment," stating, "No new or increase in existing hazards resulted from this change." During the evaluation of the change to the automatic control valve, the BP Toledo Refinery missed an opportunity to thoroughly analyze and address the backflow scenario through the bypass line.

<u>2019 Absorber Stripper Tower Incident</u>

In November 2019, a Fuel Gas Mix Drum high level incident occurred following a refinery-wide loss of steam header pressure[c] (*See* **Section 4.4.1** below). In this incident, a board operator opened the naphtha flow control valve to the Coker Gas Plant while responding to high level in the Crude 1 Overhead Accumulator Drum. Liquid naphtha overflowed into the Coker Gas Plant bypass piping, ultimately reaching the Fuel Gas Mix Drum. In contrast to the September 2022 incident, operators troubleshooting the 2019 overflow at the time closed the naphtha flow control valve to the Coker Gas Plant before liquid naphtha reached the downstream furnaces and boilers. After the 2019 incident, the BP Toledo Refinery did not identify or implement any new engineering controls as preventive safeguards for a process upset in which naphtha overflowed into the Fuel Gas Mix Drum.

The CSB concludes that had the BP Toledo Refinery implemented additional preventive safeguards to prevent liquid overflow from the Coker Gas Plant to the fuel gas system, the incident in September 2022 may not have happened.

The CSB recommends that Ohio Refining Company LLC revise the safeguards used in the refinery's process hazard analyses high level and overflow scenarios. At a minimum, establish effective preventive safeguards that use engineered controls to prevent liquid overfill and do not rely solely on human intervention. (*See* Recommendation **2022-01-I-OH-R1**).

[a] The MOC document stated, "[t]he process is not changing."

[b] The Fuel Gas Mix Drum is included in the Crude 1 PHA scope.

[c] The 2019 Fuel Gas Mix Drum incident occurred after the 2019 Crude 1 PHA had been completed.

4.1.2 Reliance on Human Intervention

The Challenge with Relying on Human Intervention

People may make poor choices that can lead to accidents in part because of flaws in human decision-making. Instituting good process and job design can help reduce the consequences of such flaws and "can eliminate the root cause of accidents and occupational exposure to hazards in many different ways" [23, p. 709]. As discussed in the *Handbook of Human Factors and Ergonomics*, "models of human information processing" suggest that time pressure or lack of awareness or knowledge, among other things, can cause errors.[a] Abnormal situations can also contribute to human error, as further discussed in **Section 4.2**.

At the time of the 2022 incident at the BP Toledo Refinery, human action was required to drain liquid from the Fuel Gas Mix Drum, regardless of the liquid's destination, and human errors contributed to the magnitude and severity of the incident. In the book, *An Introduction to System Safety Engineering* (2023), Nancy Leveson explains:

> Different problems occur when humans are part of the system. One common complication is that assumptions may be made that the [operators] will not only recognize the failure (or hazard) but will also respond appropriately. Ironically accidents are often blamed on inadequate […] operator behavior while at the same time assuming they behave correctly in the hazard or risk assessment.
>
> Clearly, there are many cases where this assumption that the human operator will "save the day" does not hold. The mental model of the system operator plays an important role in accidents [24, p. 410].

Leading up to the incident, the BP Toledo Refinery relied on safeguards that required operator intervention to respond to process upsets and deviations. In some cases, the refinery depended on the board operator to acknowledge an alarm and radio outside operators to verify and address the issue, as was done, for the high level in the Fuel Gas Mix Drum during the 2022 incident. Draining the Fuel Gas Mix Drum and attempting to address the high level through manual draining possibly led the refinery employees to release liquid from the Fuel Gas Mix Drum to the ground, which created a vapor cloud that ignited and caused the fire that resulted in the BP employees' deaths.

Operators Manually Draining Vessels

On the evening of the incident at 6:10 p.m., less than 30 minutes after the board operator opened the naphtha flow control valve to the Coker Gas Plant (**Section 2.2)**, liquid naphtha filled the Fuel Gas Mix Drum and activated a high level alarm on the drum. The board operator noticed a high-level alarm and radioed the outside operators to check the level in the drum. The outside operators arrived at the Fuel Gas Mix Drum, checked the sight glass, and began draining the drum manually. Draining vessels was a common task for outside operators. An operator explained to CSB investigators that before attempting to correct high level in the Fuel Gas Mix Drum,

[a] Errors can also be caused by lapses in attention, distractions, forgetting, or information overload and can be shown to differ depending on the level of task performance [23, p. 708].

> […] We [outside operators] got a call from the inside board to check the level in the Fuel Gas Mix Drum. So, we immediately responded. Upon arriving at the drum, […] the sight glass was completely clear with no definitive line or level in it. So, my first response was to…drain or to check the level in the sweet gas knockout, and then I opened the flare valve on the fuel gas mix drum 100 percent. And then, I opened the drain valve on the Fuel Gas Mix Drum approximately maybe two to three turns. And my reasoning for opening it to the sewer a couple turns was due to the sight glass being clear. We were checking to see if there was, in fact, a liquid in there or if it was lying to us, you know if we could get bubbles in there.

To address high level in the Coker Gas Plant Sweet Gas Knockout Drum, an operator explained to CSB investigators,

> When I [an outside operator] got to the sweet knockout pot, it was full. So, I grabbed the dead man valve and pulled it and held it and it took a while for the level to come down in the sight glass and to drop out of it. But then, once I got it to where the level was out of the sight glass, I released the dead man valve, and it just started filling right back up.[a]

These tasks were not new or unfamiliar to the outside operators. Board operators at the BP Toledo Refinery had to call outside operators on the radio in order to address overflow events, such as high levels in the Fuel Gas Mix Drum and other Coker Gas Plant downstream equipment. A board operator described his normal interaction with the outside operators whenever he noticed a high level on the DCS screen, as follows:

> […] We just call over the radio [to the outside operators], Hey, I have a high level. Can you help me? … and they'll [the outside operators] be like, okay, let me go look. And then, you know, you'll see the level go away, and you'll know they helped you.

The CSB concludes that manually draining vessels was a common task for outside operators at the BP Toledo Refinery.

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[a] A dead man valve, also known as a spring closing lever valve, is a manual valve that a human has to hold open by use of the lever handle, which will automatically close when the lever is released. Typically used to prevent leaving a valve unattended, such as during manual draining, a dead man valve can be defeated by securing the handle in the open position [52, p. 25]. (*See* **A.2.9.4.30**).

2019 Crude 1 PHA

In 2019 the BP Toledo Refinery performed a cyclic PHA of the Crude 1 unit.[a] The PHA methodology used by the BP Toledo Refinery was a Hazard and Operability Study (HAZOP). HAZOPs may not evaluate the hazards of job tasks to determine safe work practices, such as how to drain the Fuel Gas Mix Drum. Consequently, the PHA did not identify the hazards associated with manually draining the Fuel Gas Mix Drum to the Oily Water Sewer or the Flare Knockout Drum, whether the liquid was hydrocarbon or an amine-water mixture.

KEY LESSON

Companies should evaluate their PHAs for opportunities to implement additional safeguards to prevent initiating events that reduce the reliance on human intervention.

The PHA did include a high level deviation caused by failure to drain the Fuel Gas Mix Drum while the drum contained non-flammable amine-water solution and determined that it was "reasonable to expect that the situation will be detected before the hazard is manifested."[b] However, the 2019 PHA did not consider potential hazards that could exist if the drum contained flammable liquid (such as naphtha) and did not include any details or remarks regarding the refinery's policy or expectation of how or to where operators should drain the Fuel Gas Mix Drum or whether this task was even safe to perform.

Procedures

The BP Toledo Refinery had procedures for preparing equipment for maintenance and returning it to service. In addition, there was a procedure for draining process equipment and lines, which stated: "Many materials are reportable if released or drained. Minimize all material drained to the sewer or purged to atmosphere and never drain material to the ground."[c] These procedures instructed outside operators to use lock-out and tag-out procedures to properly isolate equipment before draining it. However, the BP Toledo Refinery did not have any procedures, written instructions, or documented corrective actions for board operators or outside operators to respond to or troubleshoot a high liquid level in the Fuel Gas Mix Drum, during either normal operations or process upsets, if liquid entered the drum. Had there been training on how to troubleshoot and address high level in the Fuel Gas Mix Drum, such as identifying the source of the liquid and stopping the flow, board operators may have taken different actions instead of calling the outside operators to respond to a high-level alarm in the Fuel Gas Mix Drum. Outside operators did not have adequate procedures for how to address a high liquid level in the Fuel Gas Mix Drum. High level in the Fuel Gas Mix Drum, especially above the top of the sight glass, is not normal operation.

The BP Toledo Refinery could have provided operators with instructions, such as instructing board operators to confirm the material in the vessel based on the differential pressure level indication and the guided wave radar level indication and to determine the source of the liquid causing the high liquid level before asking outside operators to check the level in the pressurized vessel.[d] Once the board operators identified the source of liquid and stopped the liquid from flowing to the Fuel Gas Mix Drum, outside operators could have then been

---

[a] As an OSHA PSM-covered process, the Crude 1 unit was required to undergo a PHA every five years.

[b] The Crude 1 PHA also evaluated the consequences of "failure to drain liquid to amine sump at EPA Sweet Gas Knockout drum."

[c] See footnote a on page **34** for additional details regarding this procedure.

[d] *See* 4.1.3 Post-Incident Actions for the deviation alarm between the level measurements.

instructed to drain to either the Flare Knockout Drum or the Oily Water Sewer. If instructions such as these existed at the BP Toledo Refinery on September 20, 2022, board operators and outside operators may not have made their own decisions in real time about how to drain the high level from the Fuel Gas Mix Drum.

The 2023 CCPS Monograph, *Human Factors Primer for Front Line Leaders*, provides guidance to help managers and supervisors enable workers to make good decisions and perform work successfully when draining liquid from a pressurized vessel as shown in **Figure 31** below [25, p. 2].

Decision

There is a need to drain unwanted liquid from a pressurized system.
What do I need to assure the operator is **competent** to perform the draining safely?

Key Human Factors Concepts for Operational Competency Management

- Has the task been adequately **risk-assessed** by an appropriate HIRA methodology or protocol? Has it been analyzed by Safety Critical Task Analysis? *(HFH 11.3)*
  - How frequently is this task performed?
  - How complex is the plant system? Are there interconnections to consider?
  - Has the appropriate level of task verification been specified? *(HFH 18.6.5)*
- Have the **competency requirements** been established? What knowledge, skills and practical experience are needed by the operator?
- Has the operator been **assessed as competent** for this task?
  - Is the operator's competency assessment record up to date?
  - How recently has the operator performed this task?
  - What level of monitoring and supervision is required?

Incidents to Learn From

Feyzin Refinery LPG spheres fire and explosions – France 1966 (HSE, 2023a)
Longford Gas Plant fire and explosion - Victoria, Australia 1998 *(HFH B3)*
Flash Fire at the Delaware City Refinery - DE, USA 2015 (CSB, 2017)

Potential Actions and Tools

Review the organization's system of **Operational Competency Management**
- Check that all **safety critical tasks** are covered
  - Is task difficulty, importance and frequency adequately covered?
- Check that the **competency requirements** are defined for each task
- Check the **competency records** of all people performing safety critical tasks
  - Is refresher training and competency re-assessment up to date?
  - Is operator recency of performing tasks adequately covered?

Figure 31: Draining unwanted liquid from a pressurized system. (Credit: CCPS)

In **Figure 31** above, the CCPS states that the task of draining a pressurized vessel should be adequately risk-assessed by considering the frequency of the task, the complexity of the system including interconnections, and the levels of required task verification. Had the BP Toledo Refinery conducted a similar assessment of the task of manually draining the Fuel Gas Mix Drum, it may have identified the potential for naphtha filling the drum and provided written procedures for determining the cause of the liquid level and how to drain it. While the CCPS Monograph, *Human Factors for Frontline Leaders*, was published in 2023, after the September 20, 2022, incident, the concept of conducting risk assessments on operational tasks is not new, and guidance for completing a Safety Critical Task Analysis is described in the 2020 Energy Institute publication *Guidance on human factors safety critical task analysis* (second edition) [26].

The CSB concludes that had the BP Toledo Refinery 1) conducted a thorough risk assessment of the operational task of draining or addressing high level in the Fuel Gas Mix Drum, 2) provided its operators with the necessary written instructions and consistent training, and 3) ensured the competency of operations personnel to perform the task safely, BP employees may have made different decisions on September 20, 2022.

4.1.3 Post-Incident Actions

The Ohio Refining Company LLC told the CSB that post-incident the company "reviewed scenarios to ensure equipment is adequately sized and designed to handle upset conditions" and made "equipment modifications and updates to provide inherently safer designs." Below are some of the changes that have been implemented at the refinery since the September 20, 2022, incident:

1. An automated system[a] for draining the Fuel Gas Mix Drum to the Flare Knockout Drum was installed.
2. A spectacle blind was added to the branch to the Oily Water Sewer to prevent draining to the sewer during normal operations.
3. A level deviation alarm[b] was added to the Fuel Gas Mix Drum to provide a warning that the liquid level is likely to be hydrocarbon.
4. New Fuel Gas Mix Drum procedures were established, including draining procedures.
5. Installed a control-based maximum stop of 41 percent open, which corresponds to a flow rate of approximately 10,000 barrels per day[c], on the naphtha flow control valve to the Coker Gas Plant to prevent Absorber Stripper Tower overfill.

The modified Fuel Gas Mix Drum is shown below in **Figure 32**.

[a] An automated full port ball valve activates when the Fuel Gas Mix Drum reaches five percent level indication. The valve remains open based on a timer function that closes the valve once the timer expires. In the event that the drum is not draining below five percent, the valve will remain open and not close. Operations has the ability to open or close the valve, but this ability will be interlocked out if the situation stated above is occurring. Operations can bypass this automatic draining by activating a bypass controller.

[b] The differential pressure (dP) level instrument is calibrated to read the level based on the specific gravity of an amine-water solution. The guided wave radar (GWR) level instrument will read the liquid level regardless of the specific gravity or type of material. A liquid level of hydrocarbon will result in the level indications not matching. When the corresponding alarm to a level deviation of greater than 10 percent activates there is a strong indication of hydrocarbon being present in the Fuel Gas Mix Drum.

[c] The flow control valve is estimated to be able to open enough to flow 30,000 barrels a day.

Figure 32. Toledo Refinery Fuel Gas Mix Drum with modifications made after the September 20, 2022, incident. (Credit: CSB)

4.1.4 Industry Guidance

The BP Toledo Refinery had protective systems for its downstream furnaces in accordance with API Recommended Practice 556 (API RP 556) *Instrumentation, Control, and Protective Systems for Gas Fired Heaters*. However, the BP Toledo Refinery did not have sufficient preventive safeguards to prevent overflowing the Fuel Gas Mix Drum into the downstream fuel gas system.

In addition to API RP 556, the API has published other industry documents that provide general instrumentation guidance and specific design considerations to mitigate hazards arising from overfill events for certain systems, including the following:

1. API Standard 521 Seventh Edition (API 521) *Pressure-relieving and Depressuring Systems* in Section 4.4.7,[a]
2. API Standard 2350 Fifth Edition (API 2350) *Overfill Prevention for Atmospheric Storage Tanks in Petroleum Facilities*,[b]

[a] The API 521 standard provides mitigation guidance for liquid overfilling scenarios related to pressure-relieving and vapor depressuring systems [43]. Although the standard is intended for designing overpressure protection systems, it includes general design considerations and mitigation measures such as 1) installing a safety instrumented system (SIS) to prevent liquid overfill, 2) operator training and procedures, and 3) level instrumentation and alarms [43, pp. 22 - 23].

[b] API Standard 2350 Fifth Edition, September 2020, Errata 1, April 2021

3. API Recommended Practice 14C Eighth Edition (API RP 14C) *Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms* in Section 6.2.2.4, and

4. API Recommended Practice 551 Second Edition (API RP 551) *Process Measurement* in Section 7.

However, the API does not have guidelines for protective systems to prevent Fuel Gas Mix Drum liquid overfill that can directly impact downstream fuel gas systems.

The CSB reviewed API RP 556[a] as part of this investigation to determine its effectiveness in providing guidance for process hazards from liquid overflow of fuel gas mix drums to downstream gas fired heaters, causing a potential flameout condition. A flameout condition is present when the flame on a gas fired heater "burner goes out while fuel is still being charged to the firebox" [27]. A flameout can be a dangerous situation, and "when not noticed and left unattended, flameout [may] result in the explosion of the fired heater" [27].

API RP 556 addresses "primary measuring and actuating instruments, controls, alarms, and protective systems as they apply to fired heaters." In the *General* section, API RP 556 states,

> Instrumentation and control applications incorporate systems and devices to satisfy equipment specific requirements […] [including] safety, process control, data collection, […].

The recommended practice also lists design considerations and protective functions for process hazards, such as the accumulation of combustibles within the firebox potentially due to a loss of flame, that could lead to "an explosion which may result in the partial or total destruction of the fired heater and which may be hazardous to personnel in the operating area" [28, p. 29]. It explains,

> Process deviations that precede flameout are typically associated with operational limits. Approaching or exceeding operational limits can lead to rapid accumulation of combustibles within the firebox. For example, loss of flame may result in the rapid accumulation of combustibles to an unacceptable hazard level in less than 10 seconds. Process deviations that precede flame out include […] slug of liquid in fuel gas system that causes loss of flame [28, pp. 29 - 30].
>
> […]
>
> Alarms may be set to alert operators of abnormal process conditions that are approaching operational limits which may lead to flameout and the rapid accumulation of combustibles within the firebox. The alarms may be triggered by […] high liquid level in an upstream fuel gas drum [28, p. 31].

and

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[a] API RP 556 provides guidance for instrumentation and protective systems for gas-fired heaters in petroleum production, refineries, and petrochemical and chemical plants [28, p. 1].

> Once a rapid accumulation event is initiated, it may be challenging to achieve safe state within the process safety time [28, p. 32].[a]

However, despite this level of detail relating to flameout-related concerns in gas-fired heaters, API RP 556 does not provide any guidance for instrumentation, preventive safeguards, and recommendations on preventing liquid from overfilling a fuel gas mix drum into the fuel gas system, which could ultimately result in an accumulation of combustibles.

The CSB concludes that although the API Recommended Practice 556 *Instrumentation, Control, and Protective Systems for Gas Fired Heaters* provides industry guidance for alarms and protective functions to address process hazards associated with the accumulation of combustibles in gas fired heaters, API RP 556 lacks guidance to implement preventive safeguards for liquid overflow from a fuel gas mix drum which may lead to a flameout and rapid accumulation of combustibles in gas fired heaters.

The CSB concludes that had industry guidance for preventive safeguards, such as safety instrumented systems and controls, been available to prevent liquid overflow from the Fuel Gas Mix Drum, and had the BP Toledo Refinery incorporated such guidance, the BP Toledo Refinery could have eliminated reliance on human intervention to drain liquid from the Fuel Gas Mix Drum.

The CSB recommends that the American Petroleum Institute develop a new publication or revise an existing publication, such as API Recommended Practice 556 *Instrumentation, Control, and Protective Systems for Gas Fired Heaters,* to incorporate the process hazards associated with Fuel Gas Mix Drum overflow. The publication should include the following at a minimum:

a) Description of the process hazards associated with Fuel Gas Mix Drum overflow and the consequential impacts on equipment using fuel gas,

b) Guidance for Fuel Gas Mix Drum design and sizing criteria which includes consideration of condensation, entrainment, overflow, and draining,

c) Guidance for instrumentation to detect high level to prevent overfilling of Fuel Gas Mix Drums, and

d) Recommended practices for selecting preventive safeguards to prevent overfilling of Fuel Gas Mix Drums. (*See* Recommendation **2022-01-I-OH-5**).

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[a] Process safety time is the time interval between the initialing event leading to an unacceptable process deviation and the hazardous event [28, p. 26].

4.2 Abnormal Situation Management

The Abnormal Situation Management® Consortium (ASM Consortium) is a group of companies and universities "that have jointly invested in research and development to create knowledge, tools, and products designed to prevent, detect, and mitigate abnormal situations that affect process safety in the control operations environment" [29, p. iv].[a] BP has been a member of the ASM Consortium since 1994.

In its guideline publication, *Effective Operations Practices* (2019), the ASM Consortium defines abnormal situations as "undesired plant disturbances or incidents with which the control system is not able to cope, requiring a human to intervene to supplement the actions of the control system" [29, p. iv]. Accurately identifying when abnormal situations are occurring and appropriately responding to them are key to ensuring the abnormal situations are mitigated and not exacerbated. In its book, *Guidelines for Managing Abnormal Situations* (2023) the CCPS states:

> Process operation during abnormal situations can create a high-pressure environment for the operators. Efficient management and the correct handling of the situation are key in preventing its escalation into a more serious incident. Sudden, potentially dangerous situations can affect human performance (the "startle" factor), leading to a "fight or flight" response, that can lead to inappropriate action being taken [1, pp. 87-88].

In the 24 hours leading up to the incident, the BP Toledo Refinery experienced a large number of abnormal situations across several units, eventually leading to the Fuel Gas Mix Drum overfilling, which in turn resulted in two refinery employees releasing flammable liquid from the Fuel Gas Mix Drum to the ground, ultimately cascading to the vapor cloud and fatal fire at 6:46 p.m. on September 20, 2022. As discussed above in **Section 2** and **Section 3**, among these abnormal situations were:

1. Water accumulation in the Crude 1 Overhead Accumulator Drum.
2. Coker Gas Plant Foul Condensate Draw Off Drum overfilling into the Absorber Stripper Tower, which led to tower level control instability.
3. Emergency pressure-relief valves opened in NHT Preheat, one of which chattered, causing a loss of containment.
4. The loss of containment in the morning led to an NHT unit shutdown.
5. Operating Crude 1 while the NHT unit was shut down and Coker Gas Plant was bypassed left the Crude 1 Tower with abnormally limited destination options and flow capability available for the overhead naphtha stream.
6. Multiple instabilities in Crude 1 Tower as a result of the NHT unit emergency shutdown, such as loss of cooling (pumparounds) and overpressure, including Crude 1 Tower emergency pressure-relief valves opening as late as approximately 4:17 p.m. that day.

[a] ASM and Abnormal Situation Management are U.S. registered trademarks of Honeywell International, Inc.

7. Rapidly eliminating the light crude feed to the Crude 1 Tower caused the final Crude 1 Tower upset, as described in **Section 3.1.6**. This upset resulted in high vapor flow up the Crude 1 Tower, which caused high level in the Crude 1 Overhead Accumulator Drum.

8. A board operator opened the naphtha flow control valve to the Coker Gas Plant in response to the high level in the Crude 1 Overhead Accumulator Drum, even though the Coker Gas Plant was bypassed at the time.

9. The Coker Gas Plant overflowed liquid naphtha through the Coker Gas Plant bypass line to the Fuel Gas Mix Drum. This was abnormal both because liquid in the Fuel Gas Mix Drum was unusual and because previously when liquid had gotten into the Fuel Gas Mix Drum, it was typically a nonflammable amine-water solution, with a significantly different specific gravity compared with naphtha.

10. The Fuel Gas Mix Drum overflowed liquid naphtha to furnaces, causing excessive smoke to exit multiple furnace and boiler stacks and shutting them down.

11. The two BP Toledo Refinery employees opened valves on the pressurized Fuel Gas Mix Drum to release the drum's contents to the ground.

Given the interconnectivity of equipment in the refinery, other, additional abnormal situations likely occurred elsewhere in the refinery, some of which required site personnel to manage. Thus, the abnormal situation management workload was likely unusually high that day.

As described below, the abnormal situations began as relatively minor issues or process upsets, but ultimately progressed to two significant liquid naphtha releases and a fatal fire. So many abnormal situations occurred during a single shift that day that a shift operator with over 18 years of experience told the CSB:

> Even before the explosion when we lost our guys, […] That was the worst day of my life. Inside or outside, anywhere […] it was bad."

4.2.1 BP Toledo Refinery's Abnormal Situation Management

At the time of the incident, the BP Toledo Refinery had an Abnormal Situation Management (ASM) policy, created in 2015. According to the policy, its purpose was to describe "the process for managing abnormal operations" and provide "a template for assessing, mitigating potential risks, and determining the overall risk level after safeguards are put in place."

The refinery's ASM policy indicated that for certain conditions or situations, an ASM form was to be completed and that "[o]nce documentation is complete, personnel can continue operation in a mode which was not anticipated." The form included prompts for abnormal situation description, analysis, and risk ranking, and required varying levels of approval signatures based on risk ranking.

However, the BP Toledo Refinery ASM policy narrowly defined abnormal operations as the following situations:

- Losses of instruments that impact a safety system;

- Losses of field actuators (control valves, dampers, etc.) that impact a safety system;
- "Abnormal" line-ups in the [tankage] area that are not on the "normal line-up" list and not covered in a procedure;
- Bypassing equipment that would normally be in service, without an associated procedure;
- Changes to the normal operation of refinery wide systems;[a]
- Continuing operation with a valve leaking through when the valve is part of a safety system; and
- Bypassing Independent Protection Layers (IPLs).

In effect, the BP Toledo Refinery's ASM policy was more of an emergency MOC procedure than instructions for truly handling abnormal situations as the ASM® Consortium defines them.[b] This is shown in the BP Toledo Refinery ASM policy itself, in **Figure 33** below, where it is indicated as a type of MOC.

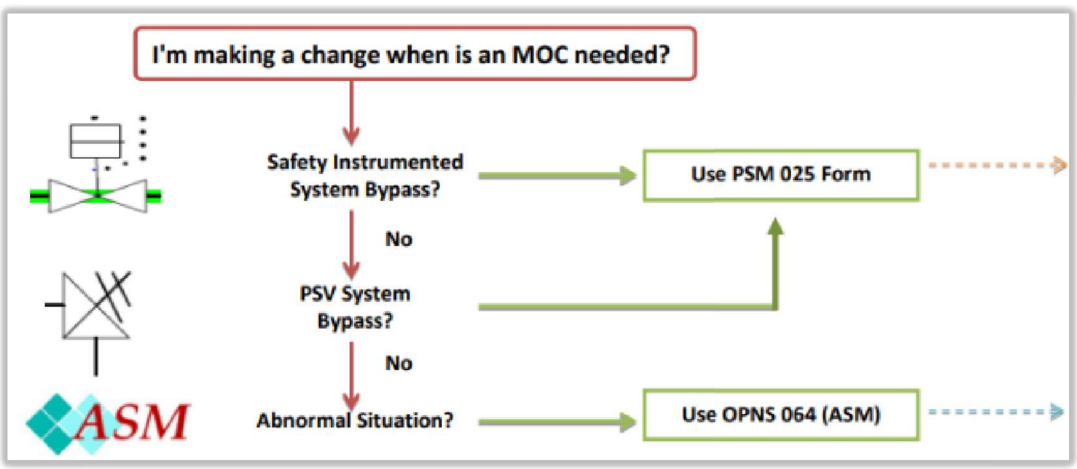

Figure 33: Excerpt of the BP Toledo Refinery ASM procedure, indicating its relation to MOC. (Credit: BP)

Because the refinery had a procedure to bypass the Coker Gas Plant and the NHT unit emergency shutdown procedure included switching the Crude 1 Tower overhead flow to Light Virgin Naphtha, these situations did not constitute "abnormal situations" by the policy's definition. Moreover, other abnormal situations that occurred that day, such as those listed above, were not recognized as such by refinery personnel during the day of the incident.

[a] "Refinery wide systems" refer to systems that were not contained in a single processing unit, but connected to multiple processes across the refinery, such as the fuel gas system, steam systems, or nitrogen supply system.

[b] The ASM Consortium definition of abnormal situations, as described above in **Section 4.2**, is "undesired plant disturbances or incidents with which the control system is not able to cope, requiring a human to intervene to supplement the actions of the control system" [29, p. iv].

The CSB concludes that the BP Toledo Refinery Abnormal Situation Management policy was not effective for proactive recognition of abnormal situations. The policy narrowly defined abnormal situations such that process disturbances that occurred before the incident did not fit the policy's definition, even though the basic process control system was unable to cope with these situations.

On the day of the incident, the Crude 1 Tower and downstream equipment experienced several abnormal situations with which the basic process control system was unable to cope. For example:

- The Crude 1 Tower overhead became overpressured at least 11 times, opening at least one of the five emergency pressure-relief valves each time (*See* **Section 3.1.5** above). Additionally, the Crude 1 Tower overhead pressure was over the high alarm point continuously for roughly eight hours, from approximately 10:00 a.m. to 6:00 p.m., with alarms sounding throughout this time. This indicated that the Crude 1 Tower pressure was unstable for several hours that day.

- The Crude 1 Tower overhead naphtha flow rate to Light Virgin Naphtha was at maximum for over an hour that afternoon on day shift (*See* **Section 3.1.4** above), while the Crude 1 Overhead Accumulator Drum level increased. This indicated that excess overhead flow could not flow through the Light Virgin Naphtha control valve fast enough to prevent overfilling the Crude 1 Overhead Accumulator Drum.

- Extremely high alarm rates occurred on day shift for extended periods (**Section 4.3.1** below), making other abnormal situations difficult for board operators to manage manually.

The BP Toledo Refinery's operations management and process engineering personnel who participated in the afternoon review meeting, discussed above in **Section 3.1.5**, determined that putting the Crude 1 Tower on circulation or shutting Crude 1 down was unnecessary, indicating that they did not fully comprehend the magnitude of the cascading abnormal situations occurring. While the meeting apparently identified some potential action items to possibly stabilize the Crude 1 Tower, it is the CSB's understanding that this information was not communicated to the night shift.

Abnormal situations often begin with little warning and thus often do not allow for planning, training, and developing procedures as they are occurring. Consequently, procedures and policies to manage abnormal situations should be established ***before*** an abnormal situation occurs. Doing so would help operating personnel recognize abnormal situations, identify the source of the deviation, and either safely restore normal operating conditions, or determine that this is not possible and stabilize the process. Refinery leadership can then capture lessons learned to prevent or mitigate similar abnormal situations in future [1, pp. 3-4]. While not every abnormal situation may be predicted such that formal written procedures exist well in advance, well thought out same-day guidance can help fill the need if properly communicated. For example, the afternoon meeting notes included instructions to reduce Crude 1 Furnace outlet temperature "to stabilize crude tower pressure," which would reduce heat input to, and therefore pressure in, the Crude 1 Tower. Instead, in contrast, a night shift board operator's shift turnover instructions were to re-establish Crude 1 Tower pumparounds. The board operator later told the CSB "the next thing I needed to do was to get the pumparounds going again on the crude tower."

The ASM Consortium provides the following example:

> While it is not practically feasible to provide written instructions for all potential limit excursions, one site has adopted the practice of identifying the most critical

> process deviations and providing guidance on appropriate responses within the high complexity, high-risk operating procedures [29, p. 88].

The CSB concludes that on the day of the incident, the BP Toledo Refinery did not provide effective guidance for managing abnormal situations. The lack of effective guidance required operations personnel to make improvised real-time decisions. Had effective guidance been communicated to the night shift, the incident could have been avoided.

After the incident, the Ohio Refining Company LLC created a new "Loss of Pumparound Response Procedure" for the Crude 1 Tower.[a] The new procedure provides guidance for mitigating the consequences of a Crude 1 Tower upset, as well as steps to re-establish pumparound cooling. The procedure includes general safety steps, such as evacuating all non-essential personnel, and specific process stabilizing steps, such as minimizing energy input to the tower by reducing furnace outlet temperature. Crucially, the procedure also defines several abnormal situations and their proper responses, as shown in **Figure 34**.

1.0 Criteria to Continue Procedure		
	1.1	If unable to control tower top temperature or pressure, abort this procedure, trip the furnaces, and shut down or place the unit in circulation (CRD1 04.001) (VAC 04.001) (NTSG 04.001) • Crude Tower Pressure Exceeds SOL (PR151, 38 psig) and/or SDL (PR151, 44 psig) • Crude Tower Overhead Temperature Exceeds MAWT (TRC101 350 F)
2.0 Total Loss of PAR Response		**Note** **Complete Loss Of All Three Pumparounds Will Result In High Tower Temperature And High Tower Vapor Velocities, Making It Difficult To Re-establish Pumparound Flow.**

Figure 34: Excerpt from new "Loss of Pumparound Response" procedure. (Credit: Ohio Refining Company LLC)

This new "Loss of Pumparound Response" procedure provides clear and actionable guidance for when human intervention is required to shut down the Crude 1 Tower or put the Crude 1 unit in circulation mode. Importantly, this guidance would have caused the refinery to shut down the Crude 1 Tower or place the Crude 1 unit in circulation before noon on the day of the incident. The Crude 1 Tower pressure exceeded 38 psig 11 times during the day shift, and twice before 11:00 a.m., as described in **Section 3.1.5**. Thus, by the time that night shift operators arrived, the Crude 1 unit could have already been in a safe state, and the Crude 1 Tower upset on night shift could have been avoided. If the Crude 1 Tower upset on night shift had been avoided, the excess liquid in the Crude 1 Overhead Accumulator, the Absorber Stripper Tower, and the Fuel Gas Mix Drum would have also been avoided, and the fatal incident would not have occurred. This is one example of

[a] After February 28, 2023, the Ohio Refining Company LLC is the owner and operator of the Toledo Refinery. *See* **Section** 1.2

effectively providing guidance for managing an abnormal situation. **Section 4.2.3** below further discusses tools to mitigate or prevent abnormal events, using the day of the incident as an example.

4.2.2 Use of Industry Guidance

The ASM Consortium has published guidance documents for alarm management practices, Human-Machine Interface design and development, procedural practices, and operations practices [30]. The ASM Consortium Guidelines *Effective Operations Practices* (2019) state [29, pp. 3-4]:[a]

> The effective operations practices guidelines are organized under seven categories:
>
> - **Understanding Abnormal Situations -** addresses measuring, reporting, analyzing, and communicating the causes and effects associated with abnormal situations in the plant.
> - **Organization Roles, Responsibilities, and Work Processes -** addresses the influence of work culture through definition of work processes, staff roles and responsibilities, and valued behaviors.
> - **Knowledge and Skill Development -** addresses a competent work force through use of comprehensive training fundamentals and the creation of a continuous learning environment.
> - **Communications -** addresses effective daily and situational dialog between functional groups and within operations.
> - **Procedures -** addresses key challenges associated with procedural operations such as accessibility, accuracy, clarity, policy compliance, and feasibility.
> - **Operations Work Environment -** addresses factors associated with 24/7 operations that impact operator performance.
> - **Process Monitoring, Control, and Support Applications -** addresses software and hardware platforms deployed for the operator are appropriate and maintained over their lifecycles [29, pp. 3-4].

KEY LESSON

Companies should define operating limits beyond which Abnormal Situation Management procedures should be followed and clearly define those corrective actions to be followed, in order to stop a chain of abnormal events.

Based on the BP Toledo Refinery's ASM policy discussed in **Section 4.2.1**, there is no evidence that the BP Toledo Refinery utilized this ASM Consortium guidance in the refinery's ASM policy, since the site policy does not incorporate guidelines or categories from the ASM Consortium for effective operations practices and does not describe a structure or documents where the guidelines above are used.

The CSB concludes that the BP Toledo Refinery did not effectively use previously existing industry guidance, such as that available from the ASM Consortium, to develop its ASM policy. Had the refinery done so prior to

[a] The initial release of the Effective Operations Practices guideline document for members was in 2001. The content above is from the revised 2019 edition [29, p. v].

the incident, it could have had a framework to provide effective guidance to the night shift to safely operate the refinery after the NHT shutdown.

Although BP had access to the ASM Consortium guidance for at least a decade before the incident, the CCPS more recently provided a comparable list of ASM elements. In its book, *Guidelines for Managing Abnormal Situations* (2023), the CCPS provided eight tools and methods for effective management of abnormal situations, including:

- *Predictive Hazard Identification*. Potential abnormal situations should be evaluated to identify and document hazards and their consequences for all operating phases and include analysis of process design, the process control strategy for responding to process upset conditions, and inherently safer design features [1, p. 113]. Predictive hazard identification of abnormal situations is typically performed as part of the PHA [1, pp. 113-114]. To be effective, the PHA must include reviews of abnormal situations affecting the process control system (*See* **Section 4.1.1**) and historical abnormal scenarios (*See* **Section 4.4**). This may require a supplemental abnormal situation review, tabletop exercises, and simulations to see how the operating team would respond in response to upset conditions [1, pp. 114-115].

- *Process Control System.* The control system should provide an interface so that a board operator can observe trends of multiple critical parameters simultaneously. Displays providing an overview of key parameters and a "big picture" view of the process are critical to a well-designed control panel; for example, a display showing flow into and flow out of a tower. To be effective, system design should enable instruments to stay in a normal range, even during transient operations [1, p. 117]. The system should also allow for effective alarm management, such that operators are not overloaded with low priority and nuisance alarms [1, p. 119]. Alarm flood is further discussed in **Section 4.3**.

- *Policies and Administrative Procedures*. Formal, written policies must be clear to personnel regarding their authority to make timely decisions, including those which allow any personnel to halt operations over safety concerns [1, p. 126]. It is also critical to establish effective and structured communication between teams and shifts, such as the use of standardized log sheets, checklists, and a record of issues, which summarize both normal and abnormal conditions encountered during the shift [1, pp. 126-128].

- *Operating Procedures.* Procedures are the first tier of human response safeguards to unexpected situations. Operating procedures should include the safe operating conditions, provide warnings against deviations from safe limits, and include steps on how to re-establish safe status after a deviation occurs [1, pp. 130-131]. Often, operating procedures consider only routine situations and fail to provide written instructions on how to handle abnormal situations [1, p. 131]. To ensure procedures are properly written to handle abnormal situations, companies should perform an observational audit of procedures to note missed steps and confusing items [1, p. 132]. In addition, companies should perform a Procedural PHA[a]

[a] Several methods are available for execution of a Procedural PHA, such as the Transient Operations Hazard and Operability Study (TOH) [1, pp. 133-134] or by applying more traditional PHA methods such as Hazard and Operability Study (HAZOP) or Structured "What-If" Technique (SWIFT) [59, pp. 37-41, 46-48].

which focuses on operational tasks, timely identification of hazards, and procedural controls in response to abnormal situation [1, pp. 133-134].

- *Training and Drills.* Training for board and outside operators should include methods for managing abnormal situations, such as tabletop exercises covering desired responses to situations, emergency response drills, alarm response training, and process simulation [1, p. 137].

- *Ergonomics and Other Human Factors.* Control room layout, environmental conditions, graphics and displays, and human-machine interfaces should all be considered to ensure optimal operator performance and response to abnormal situations [1, p. 139].

- *Learning from Previous Abnormal Situation Incidents.* While most companies investigate incidents, abnormal situations may have occurred without becoming a major event. In addition to investigating incidents, companies should identify and investigate near-misses and address the cause through changes to the process, software controls, and procedural changes [1, pp. 148-149]. **Section 4.4** further discusses learning from previous incidents.

- *Management of Change.* Companies should ensure changes to process control systems, such as logic changes, software revisions, tuning of controllers, process control alterations, alarm setpoints, and interlock setpoints are evaluated as part of an established and effective Management of Change (MOC) process [1, p. 151].

KEY LESSON

"Abnormal situations introduce stress, and operators under stress can make poor decisions, which then exacerbate the situation. How companies prepare and equip their operators to deal with these problematic and stressful situations is critical to ensuring the return of the unit to a safe state. Often, process safety incidents are a result of organizations failing in this area." — CCPS, *Guidelines for Managing Abnormal Situations* [1, p. 24].

While this CCPS guidance was published after the BP Toledo Refinery incident, the refinery can still use the methods above to improve its outcomes when future abnormal situations occur. In addition, since the ASM Consortium guidance above was available as early as 2001, the refinery could have implemented policies and procedures more aligned with the ASM Consortium's *Effective Operations Practices* before the incident occurred.

The CSB recommends that Ohio Refining Company LLC revise the Abnormal Situation Management policy to incorporate guidance provided by the ASM Consortium and the Center for Chemical Process Safety (CCPS). The revised policy should include, at a minimum:

a) A broader definition of abnormal situations, such as that defined by the CCPS,

b) Additional predictable abnormal situations and their associated corrective procedures. At a minimum include the following abnormal situations:

   1) unplanned crude slate changes,

   2) continued operation of the Crude 1 unit with the naphtha hydrotreater unit shut down, and

   3) an emergency pressure-relief valve opening.

c) Guidance to determine when an abnormal situation is becoming too difficult to manage and the appropriate actions to take, such as shutting down a process, putting it into a circulation mode, or implementing proper procedures for bringing it to a safe state. (*See* Recommendation **2022-01-I-OH-R2**).

4.2.3 Applying Industry Guidance to the Incident

Many incidents are preventable if abnormal situations are recognized promptly, diagnosed correctly, and corrected in time, breaking the chain of events [1, p. 22]. For example, the new procedure issued by the new ownership of the Toledo Refinery after the incident, as shown in **Section 4.2.1** above, clearly instructs operations to shut down the Crude 1 Tower if prolonged, excessive tower pressure is detected.

KEY LESSON

Thinking through abnormal situations *before* they occur, having plans in place, and practicing those plans can greatly improve operator and manager confidence and decision-making during an abnormal situation. Simulators, desktop drills, incident reviews, or field walkthroughs can improve abnormal situation management skills.

As an illustration of how some abnormal situations can cascade to escalating consequences, **Figure 35** shows several abnormal situations that occurred on the day of the incident, their consequences, and how those consequences and other decisions led to the next abnormal situation, escalating throughout the day.

Throughout the day, abnormal situations continued to escalate, culminating in the release of naphtha from the Fuel Gas Mix Drum to the ground, resulting in a fatal fire. None of the decisions made that day were made in a vacuum; instead, they were frequently made in response to other previous abnormal situations and their consequences (shown in red in **Figure 35** below). These are examples of situations that can affect the performance of board operators, outside operators, or refinery management performance [1, pp. 87-88].

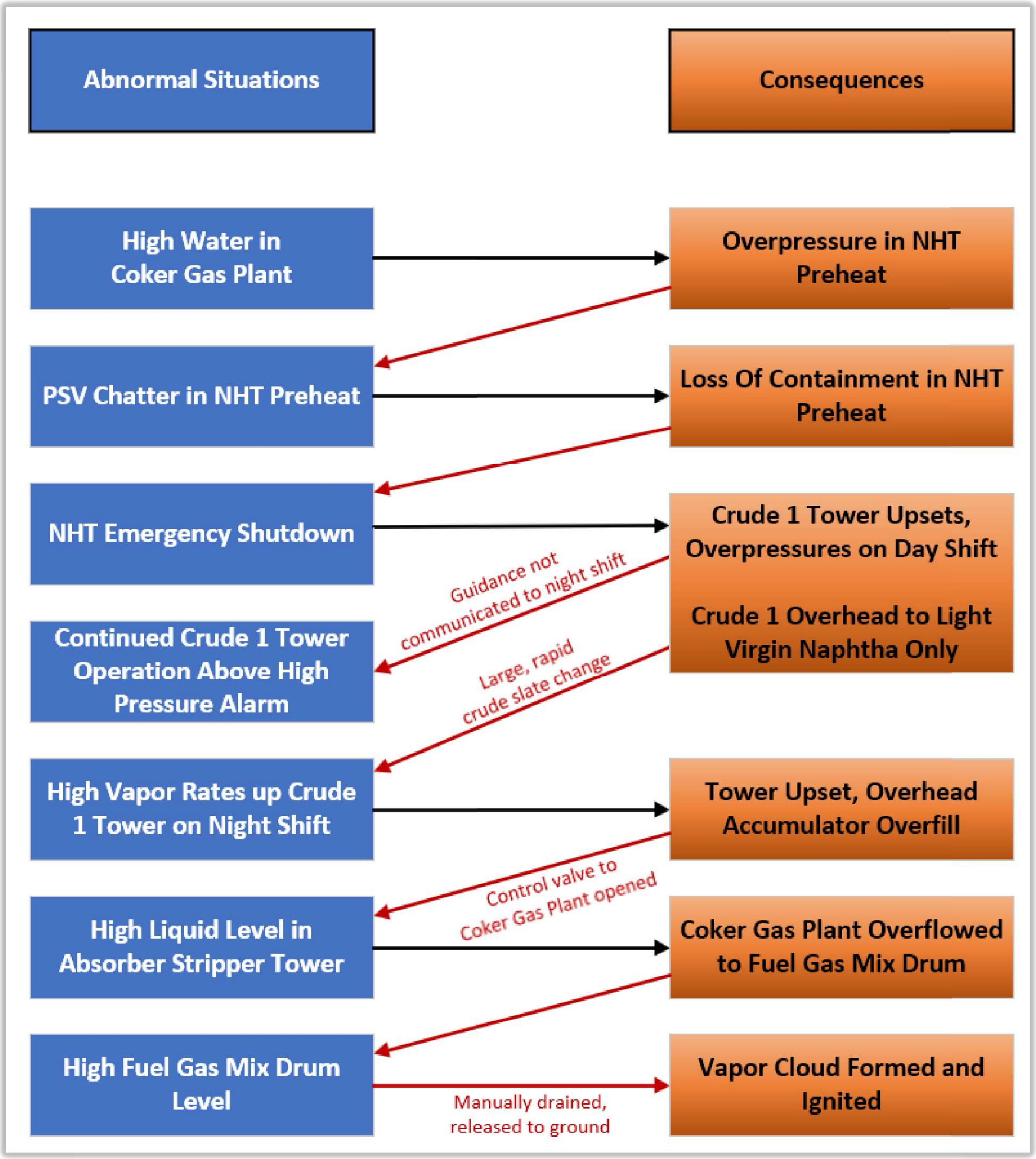

Figure 35: Examples of abnormal situations the day of the incident (in blue), and the consequences of them (in orange). Note that in some cases, consequences and decisions contributed to the next abnormal situation (in red). (Credit: CSB)

Table 2 below shows how using the CCPS abnormal situation management tools and methods described above in **Section 4.2.2** can be used to mitigate or prevent abnormal situations, using the abnormal situations the refinery encountered the day of the incident as examples.

Table 2: How CCPS tools and methods could apply to manage abnormal situations encountered leading up to the incident. (Credit: CSB)

CCPS ASM Tools and Methods to Manage	Examples from the BP Toledo Refinery Incident	Report Section
Predictive Hazard Identification Potential abnormal situations should be evaluated to identify hazards and consequences, usually in a PHA. PHAs should include reviews of abnormal situations affecting the process control system.	• In an attempt to manage high level in the Crude 1 Overhead Accumulator Drum, the naphtha flow control valve to the Coker Gas Plant was opened, which overfilled the Absorber Stripper Tower to the Fuel Gas Mix Drum and the downstream furnaces. While the PHA identified a similar scenario, it used ineffective preventive safeguards. • Crude slate changes to the Crude 1 Tower are a routine part of refinery operation. However, large and rapid changes can cause major process upsets. Such process upsets could be foreseen and prevented or mitigated through automatic controls to assist or minimize operator intervention when pumparound flow is lost, or to only allow crude slate changes in small step changes or within certain ranges (outside of emergencies) to prevent input errors.	**4.1.1** **3.1.6**
Process Control System The control system should enable instruments to stay in a normal range, even during transient operations, provide an interface so board operators can observe multiple critical parameters simultaneously, and allow for effective alarm management.	• Instruments should be calibrated to read the full range of possible values, but the Crude 1 Tower Overhead naphtha to Light Virgin Naphtha flow meter was out of range, displaying misleading information to the day shift board operator and masking the inability to reliably control Crude 1 Overhead Accumulator Drum level. • A DCS overview graphic showing a material balance[a] could allow board operators to see from where the Absorber Stripper Tower overflow was coming and could have prompted board operators to take appropriate corrective action. Adding this type of graphic was a CSB recommendation in its BP Texas City incident investigation [31, p. 215]. • The control system should allow for effective alarm filtering and suppression so as not to overwhelm board operators while still highlighting important alarms, such as high Fuel Gas Mix Drum level, in an abnormal situation.	**3.1.5** **4.4.2** **4.3**

[a] A material balance calculation can be used to determine how much total liquid is in a given unit; it is determined by comparing the amount of incoming feed to the amount of outgoing product [31, p. 83].

CCPS ASM Tools and Methods to Manage	Examples from the BP Toledo Refinery Incident	Report Section
Policies and Administrative Procedures Formal, written policies must be clear to personnel regarding their authority to make timely decisions.	• The BP Toledo Refinery's ASM policy narrowly defined an abnormal situation and did not consider other abnormal situations outside that definition ahead of time, overloading the employees in an urgent or emergent situation. At least some abnormal situations can be pre-defined, with a predetermined, written, and communicated plan in place, to reduce the mental load during abnormal situations.	**4.2.1**
Operating Procedures Should include safe operating conditions, provide warnings against deviations from safe limits, and include steps on how to re-establish safe status after a deviation occurs.	• The NHT unit emergency shutdown procedure did instruct operations to divert Crude 1 overhead naphtha to the Light Virgin Naphtha Storage but did not anticipate that the Light Virgin Naphtha Storage may not be capable of receiving all the flow in a Crude 1 Tower upset condition. • Although the Crude 1 Tower was in an upset condition for hours, and loss of pumparound cooling was not uncommon, there was no procedure for managing the loss of all pumparound cooling, and no guidance for which abnormal conditions should trigger putting the Crude 1 Tower on circulation or shutting it down. • Loss of pumparound cooling in the Crude 1 Tower was a predictable abnormal situation, and the refinery should have developed a written procedure to manage it in anticipation of such an event (and did so after the incident occurred).	**3.1.5** **3.1.5** **4.2.1**

CCPS ASM Tools and Methods to Manage	Examples from the BP Toledo Refinery Incident	Report Section
Training and Drills Training for board and outside operators should include methods for managing abnormal situations, such as tabletop exercises, emergency response drills, alarm response training, and process simulation.	• Board operators were often qualified on the Crude 1 job with minimal, if any, experience in managing process upsets. This experience was learned on the job, in real time. A simulator or mock exercises/drills would allow training to manage abnormal situations without potentially hazardous consequences, and in a lower stress environment. While at least one other unit at the refinery did have a simulator, there was no simulator for the Crude 1 Tower. Drastic changes to Crude 1 Tower crude slate, and how to control tower operation safely if such an upset did occur, could be discussed and practiced outside the operating refinery environment, rather than in real time on an operating process. • As with board operators, outside operators could have been trained using mock exercises/drills for abnormal situations such as liquid in the fuel gas system, which could have helped outside operators avoid making high-risk decisions.	**3.1.6** **3.1.9, 3.2**
Learning from Previous Abnormal Situation Incidents In addition to investigating incidents, companies should identify and investigate near-misses and address causes through process, software, or procedural changes.	• The Coker Gas Plant bypass had overfilled the Fuel Gas Mix Drum with liquid naphtha in a 2019 incident, but the 2019 investigation did not result in any engineering controls being implemented to prevent overfill recurrence and the company did not effectively communicate this incident and its consequences to board operators. • The 2019 incident could have been effectively communicated to outside operators to ensure they understood the incident and could take appropriate action should it happen again. As it was, outside operators with limited knowledge of the prior incident were left to improvise a solution during a stressful situation.	**4.4.1** **3.1.9, 3.2**

CCPS ASM Tools and Methods to Manage	Examples from the BP Toledo Refinery Incident	Report Section
Management of Change Ensure changes to process control systems (logic changes, software revisions, controller tuning, alarm and interlock setpoints) are effectively evaluated.	• For the NHT Preheat piping, the pressure relief system could have been designed to avoid chatter, and piping with a higher pressure rating could have been installed to avoid operating so close to the emergency pressure-relief valve set pressure. • The water phase level indication on the Crude 1 Overhead Accumulator Drum was changed as part of an MOC. Because this change was an unintended consequence of the MOC, it could not be communicated to operations. Operations did not know that water would overflow the naphtha standpipe at 69 percent water phase level, rather than the previous 100 percent level indicated before the 2022 Turnaround.	**3.1.2** **3.1.1**

The CSB concludes that had the BP Toledo Refinery more effectively used Abnormal Situation Management tools and methods, such as Predictive Hazard Identification, Process Control Systems, Policies and Administrative Procedures, Operating Procedures, Training and Drills, Learning from Previous Abnormal Situation Incidents, and Management of Change, the large number of cascading abnormal situations might have been stopped and the fatal incident could have been prevented.

KEY LESSON

Managing abnormal situations goes beyond PSM compliance alone. PSM tools can be used, but for abnormal situations, the tools must be applied with abnormal situations specifically in mind, particularly cascading abnormal situations.

4.3 Alarm Flood

The ASM Consortium, described above in **Section 4.2.2**, defines alarm flood as "[t]he situation where more alarms are received than can be physically addressed by a single process control operator." The specific quantity of alarms that constitute a "flood" can vary by process, site, position, and individual, but a commonly accepted performance target is that more than 10 alarms in 10 minutes (**Section 4.3.3** below) is alarm flood. According to the ASM Consortium in its *Guidelines for Effective Alarm Management*:

> [P]eople can analyze and react only to a maximum of about 10 alarms in any 10-minute period. If more than 10 alarms occur in 10 minutes, operator performance is significantly impacted and the risk level in the plant will rise dramatically.

4.3.1 Alarm Flood Day of Incident

On September 20, 2022, the board operator DCS console that included the Crude 1 unit, the Fuel Gas Mix Drum, the Vacuum 1 unit, the NHT unit, the Saturated Gas Plant, Coker Gas Plant, and the West Flare received a very large number of alarms, both on day shift and night shift.[a,b] The alarm rate was at or above 10 alarms in 10 minutes starting at approximately 7:00 a.m., and continuing throughout the day, up to and after the incident at 6:46 p.m., with the exception of two 10-minute periods (although alarms sounded during these two periods as well).[c] **Figure 36** shows this alarm rate, in 10-minute blocks throughout the day.

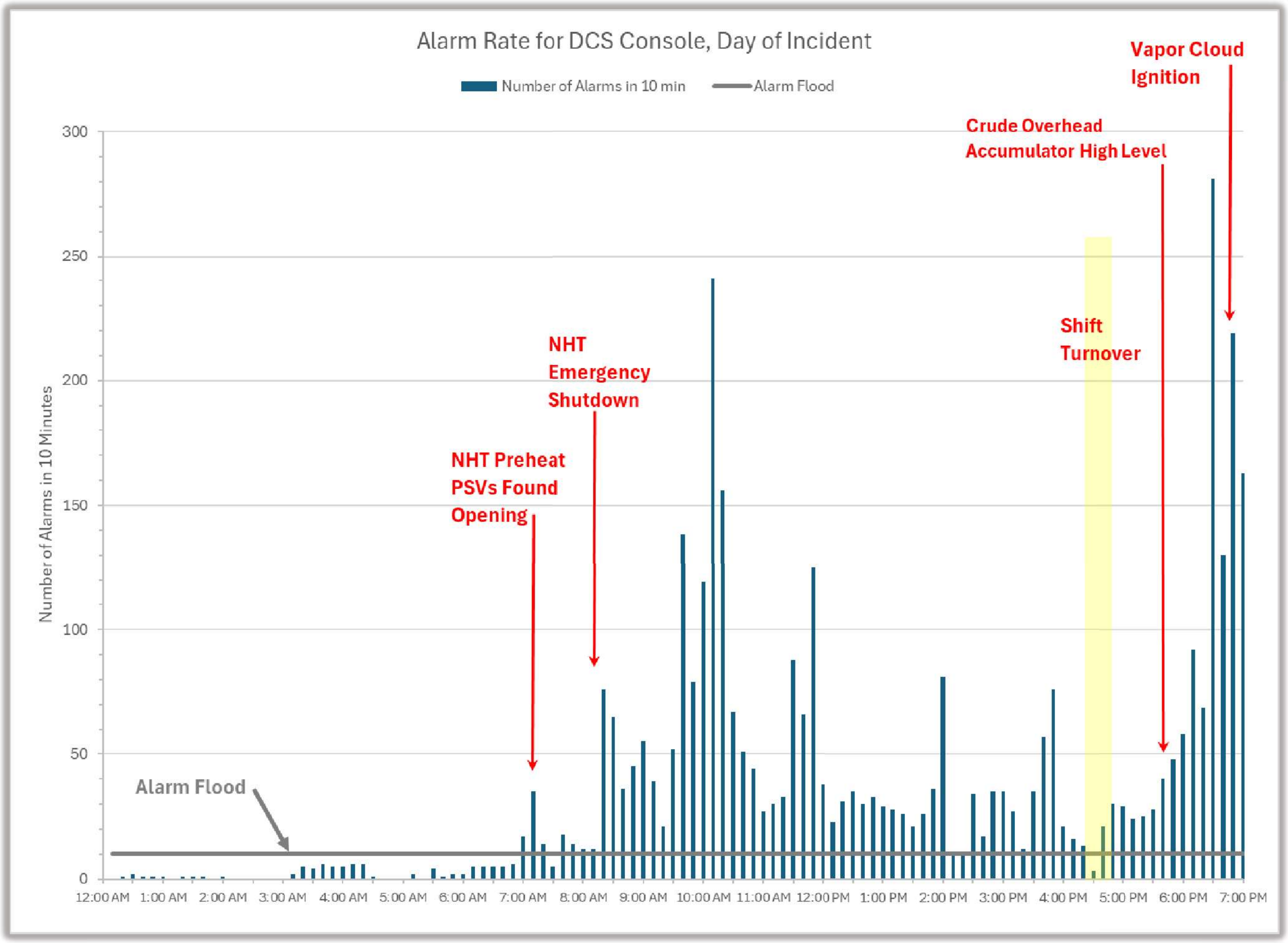

Figure 36: DCS console alarm rate on September 20, 2022, with some process events (in red). The gray line indicates alarm flood rate (10 alarms in 10 minutes). (Credit: CSB)

Figure 36 illustrates the alarm rate that board operators faced throughout the day, with many alarms annunciating at a rapid pace, sometimes for hours together, after the NHT Preheat emergency pressure-relief valve chatter and emergency shutdown that morning and leading up to the incident that evening. Such a situation is virtually impossible to manage for extended periods without missing critical alarms or errors occurring (**Section 4.3.3** below).

[a] *See* **A.1.4.6.9** for details from BP's control system event log.142

[b] Throughout this section of the report, the "DCS Console" refers to the board position that includes these same areas of the refinery: Crude 1, the Vacuum 1 unit, the NHT unit, the Saturated Gas Plant, Coker Gas Plant, the Fuel Gas Mix Drum, and the West Flare.

[c] There were five alarms between 7:20 a.m. and 7:30 a.m. and three alarms between 4:20 p.m. and 4:30 p.m. All other 10-minute periods between 7:00 a.m. and 7:00 p.m. were at or over the alarm threshold of 10 alarms in 10 minutes.

For example, the Fuel Gas Mix Drum high level alarm went off at the DCS console at 6:10 p.m., but a board operator did not radio to the outside operators until 6:17 p.m., just after the Fuel Gas Mix Drum high-high level alarm annunciated. As discussed above in **Section 4.1.1**, the Fuel Gas Mix Drum high level alarms coupled with operator response was a safeguard against a hazardous condition. For alarms that require operator response to prevent hazardous conditions, a rapid response is essential for the safeguard to be effective. The high level alarm was a high priority alarm and was color coded to indicate its high priority status, but alarm prioritization can be ineffective if the board operator is simply overwhelmed in an extreme alarm flood situation.

From 6:10 p.m. through 6:17 p.m., the DCS console had 55 alarms, the equivalent of approximately one alarm every nine seconds. Managing the alarm flood during this time likely created a delayed response to the Fuel Gas Mix Drum high level. One board operator described his perspective of the process upset before the incident to the CSB:

> Meanwhile, the [Fuel Gas Mix Drum] is high level. The alarms are coming in. And at this time, feeling very overwhelmed, I can remember. […] At this point, almost everything's in manual and alarms are still just pouring in.

As further discussed in **Section 4.3.3** below, board operators are very likely to be overwhelmed in alarm flood with so many alarms for such extended periods, such as on the day of the incident, when between 6:50 a.m. and 6:49 p.m., a total of 3,712 alarms were recorded.

Moreover, between the beginning of the night shift at approximately 4:50 p.m. and the incident at 6:46 p.m., the DCS console received between 24 and 281 alarms every 10 minutes, which is 2.4 to 28 times the alarm flood threshold.[a] The night shift alarm rates are shown in detail in **Figure 37**.

[a] Throughout this section, the alarm performance targets are based on one board operator. This position was normally staffed by a single board operator.

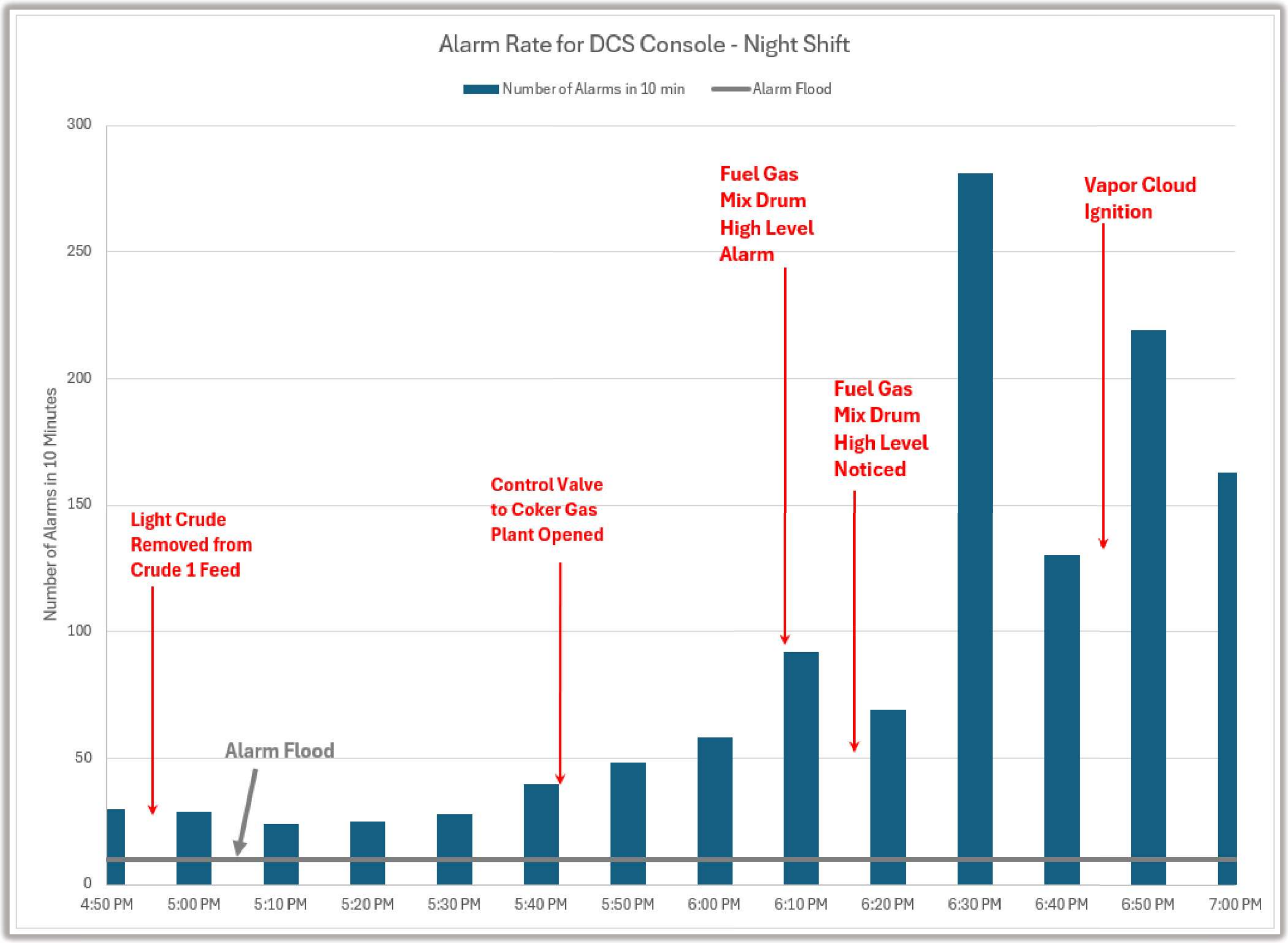

Figure 37: DCS console alarm rate on night shift, with some process events (in red). The gray line indicates alarm flood rate. (Credit: CSB)

Another major problem for the night shift board operators was that once the Crude 1 Overhead Accumulator Drum began to overfill, and a board operator opened the naphtha flow control valve to the Coker Gas Plant at 5:41 p.m., alarms were sounding at a rate of 48 per 10 minutes (**Figure 37** above) or higher until after the incident occurred at 6:46 p.m. The board operators were potentially so overwhelmed that they did not have time to process the source of overflow to the Fuel Gas Mix Drum and close the naphtha flow control valve to the Coker Gas Plant in time to prevent overflow to the furnaces and boilers. As shown in **Table 3** below, the BP Toledo Refinery averaged 254.50 alarms per hour on the day of the fatal incident. Further, as noted above, between 6:50 a.m. and 6:49 p.m. that day a total of 3,712 alarms were recorded.

The CSB concludes that the board operators experienced an alarm flood condition for nearly 12 hours preceding the incident, experiencing more than 3,700 alarms during the 12-hour period. Alarm flood contributed to the incident by overwhelming and distracting the board operators, causing delays and errors in responding to critical alarms. Had the night shift board operators been able to recognize the source of liquid in the fuel gas system during the alarm flood and closed the naphtha flow control valve to the Coker Gas Plant, they could have stopped liquid flow to the Fuel Gas Mix Drum, preventing or mitigating the fatal incident.

Invocation of Stop Work Authority (as discussed in **Section 3.3**) would have been especially important given the severe alarm flood occurring on September 20, 2022. As previously stated, board operators were in an alarm flood condition for nearly 12 hours preceding the incident, experiencing more than 3,700 alarms between 6:50 a.m. and 6:49 p.m. Alarm flood contributed to the incident by overwhelming and distracting the board operators, causing delays and errors in responding to critical alarms. A shutdown, or putting the unit in circulation mode, likely would have enabled operators and other refinery personnel to cope with the alarm flood and identify critical actions to be taken, including closing the naphtha flow control valve to the Coker Gas Plant and stopping liquid flow to the Fuel Gas Mix Drum.

The Toledo Refinery must ensure (through training, clearly written procedures, and other means) not only that the refinery's employees are clearly empowered to invoke Stop Work Authority but also that the refinery's employees clearly understand that they are expected to do so, especially during an abnormal situation, including an alarm flood, such as existed during the day of the fatal incident.

The CSB recommends that the Ohio Refining Company LLC develop and implement a policy or revise existing policy that clearly provides employees with the authority to stop work that is perceived to be unsafe until the employer can resolve the matter. This should include detailed procedures and regular training on how employees would exercise their stop work authority. Emphasis should be placed on exercising this authority during abnormal situations, including alarm floods. (*See* Recommendation **2022-01-I-OH-R3**).

4.3.2 BP Guidance

While the BP Toledo Refinery did not have site-specific guidance for managing or preventing alarm flooding at the time of the incident, BP's guidance for alarm management included two generalized documents: *Downstream Alarm Philosophy* and *Alarm System Design and Management*. BP's guidance defined alarm flood, or alarm overload, as a "situation in which more alarms are received than can be processed by a single console operator." This guidance also stated that "an alarm rate greater than 10 alarms in 10 minutes represents an alarm flood condition."

BP's alarm management guidance defined several key process indicators to track alarm system performance. Among these were alarm rate and alarm flooding. The guidance defined alarm rate, or average dynamic load, as the number of alarms going off per hour per board operator position over the time span of interest. BP's performance targets for alarm rate and flood frequency are summarized in **Figure 38**.

Metrics	Metric indicator	Performance levels		
		Target	Improving	Challenging
Primary metrics				
Average annunciated alarms per hour. (measured per control room operator handling the area of responsibility)	Alarm average dynamic load	≤6	<30	≥30
Percentage of 10 min time slots (within a month) containing more than 10 alarms (measured per control room operator handling the area of responsibility)	Alarm flooding frequency	≤1% High alarm load less than once per shift	<10% High alarm load several times per shift	≥10% High alarm load many times per shift

Metrics	Metric indicator	Performance levels		
		Target	Improving	Challenging
Secondary metrics				
Maximum number of alarms in any 10 min period	Alarm flooding extent	≤10	<50	≥50

Figure 38: BP alarm systems metrics and performance levels for alarm rate and flooding. (Credit: BP)

The BP Toledo Refinery tracked alarm system performance according to the BP guidelines. For primary performance metrics, the "challenging" performance category required weekly reviews, reporting the performance gap to entity leadership and adding the item to a site risk register, with a resourced action plan. The CSB did not determine whether the BP Toledo Refinery was within or out of compliance with the guidance long term, but on September 20, 2022, the DCS console alarms were well above the challenging threshold due to the process upsets that day. **Table 3** shows the alarm performance against primary metrics in 2022 for various available time periods. It should be noted that the refinery was in a planned outage starting in April 2022, started up from the outage in July 2022, and there was an unplanned partial Crude 1 shut down followed by a restart in August 2022. Data for these months could be skewed low due to the outage, or high due to refinery or equipment startup or shutdown.

Table 3: 2022 alarm performance data. Performance levels are listed according to BP guidance as in **Figure 38** above, to indicate target, improving, and challenging performance. (Credit: CSB)

Time Period	Average Alarms per Hour	Percentage of 10-minute Time Slots > 10 Alarms	Performance Level per BP Guidance
Jan-2022	4.85	0.18	Target
Feb-2022	5.65	0.30	Target
Mar-2022	8.13	1.32	Improving
Apr-2022 (shutdown)[a]	7.20	1.10	Improving
May-2022 (down)	2.72	0.60	Target
Jun-2022 (down)	2.44	0.53	Target
July-2022 (startup)	31.17	13.13	Challenging
Aug-2022 (startup)	15.39	3.94	Improving
19-Sep-2022	9.46	0.69	Improving / Target
20-Sep-2022	254.50	68.75	Challenging

The BP guidance specifically pointed out that process upsets were vulnerable periods for errors to occur, and should be reviewed for alarm system improvements where possible:

> Typically, the biggest alarm load and potential for an alarm flood is after a major plant upset. Such disturbances are often particularly stressful for the operator and can be relatively hazardous periods of operation. Therefore, it is particularly important to improve alarm performance during this period.

The secondary metric for flooding in **Figure 38**, the number of alarms in any 10-minute period, shows the extent of alarm flood the day of the incident. The number of alarms in any 10-minute period was far over the challenging level of performance, or greater than 50 alarms in 10 minutes, for four hours that day between approximately 8:00 a.m. and 7:00 p.m., as shown above in **Figure 36**.

The CSB concludes that on September 20, 2022, the BP Toledo Refinery alarm performance was classified as "challenging," according to BP's guidance and the high extent and duration of alarm flood likely contributed to the incident by overloading the board operators, contributing to miscommunications, errors, and missed alarms.

[a] Data for April through August 2022 could be skewed low due to the outage or high due to startup or shutdown of the BP Toledo Refinery.

4.3.3 Industry Guidance for Alarm Flood Performance

Several sources provide industry guidance for alarm management in general and handling alarm flooding in particular. The CCPS guidance in *Guidelines for Safe Automation of Chemical Processes* is consistent with BP's guidance and other industry guidance, defining alarm flood as follows:

> **Alarm flood**—The presentation of more alarms in a given period of time than an operator can effectively respond to […] (typically >10 alarms in ten minutes following an upset event). Alarm flooding is one of the most dangerous problems with alarm systems and potentially the most complex to solve. […] These alarm floods overwhelm the operator, which make it difficult to process the alarms, determine the cause and priority of the event, and to respond to new alarms due to the developing event or resulting cascade events [32, p. 427].

The ASM Consortium also recognizes the importance of preventing or minimizing alarm floods, and defines the human limits for handling floods: "If more than 10 alarms occur in 10 minutes, operator performance is significantly impacted and the risk level in the plant will rise dramatically" [33, p. 83].

The CCPS, the ASM Consortium, API, and other industry guidance organizations often simply reference the International Society of Automation (ISA) Standard 18.2, *Management of Alarm Systems for the Process Industries* (ISA 18.2), a commonly used industry guidance document for alarm systems [34, p. 1]. This standard's guidance for alarm flood is as follows:

> Alarm floods are variable-duration periods of alarm activity with annunciation rates likely to exceed the operator response capability. […] As a recommended target, an alarm system should be in flood for less than ~1 % of the time. Improvements to the alarm system and process operation may be indicated by the analysis of alarm floods. ***No targets are provided for these metrics*** [emphasis added]. Alarm flood analysis should include:
>
> a) number of alarm floods,
>
> b) duration of each alarm flood,
>
> c) alarm count in each alarm flood, and
>
> d) peak alarm rate for each alarm flood [34, pp. 75-76].

To summarize, multiple industry guidance sources, including the ISA, the CCPS, the ASM Consortium, and the BP guidance above in **Section 4.3.2**, use 10 alarms in a 10-minute time block to define alarm flood. The ISA, among other sources, also identifies that alarm flood condition should be present less than one percent of the time (but must include at least 30 days of data), as a guideline. **Figure 39** below summarizes the alarm rate and alarm flood guidelines in ISA 18.2.

Alarm performance metrics based upon at least 30 days of data		
Metric	**Target value**	
Annunciated alarms per time	Target value: very likely to be acceptable	Target value: maximum manageable
Annunciated alarms per hour per operator console	~6 (average)	~12 (average)
Annunciated alarms per 10 minutes per operator console	~1 (average)	~2 (average)
Metric	**Target value**	
Percentage of 10-minute periods containing more than 10 alarms	~<1%	
Maximum number of alarms in a 10-minute period	≤10	
Percentage of time the alarm system is in a flood condition	~<1%	

Figure 39: ISA Standard 18.2 summary of select recommended alarm performance metrics, based upon at least 30 days of data [34, p. 78]. (Credit: ISA)

The CSB concludes that on September 20, 2022, the BP Toledo Refinery alarm performance did not meet industry guidance, exceeding 10 alarms in 10 minutes for hours at a time. The high extent and duration of alarm flood contributed to incident by overloading the board operators, contributing to miscommunication, errors, and missed alarms, ultimately leading to the fatal incident. The high alarm rate was also indicative of ongoing abnormal situations.

As shown in **Figure 39** above, ISA 18.2 specifies that performance metrics should be "based upon at least 30 days of data" [34, p. 78]. It is important to note, however, when calculated for a month long period, an alarm flood condition that occurs one percent of the time would equate to approximately 7.2 hours. If one process upset occurs each month that is, for example, seven hours long but occurs on a single shift, the operator working that shift can easily be overloaded even if the site meets the one percent monthly target under ISA 18.2. As shown above in **Section 4.3.1** and in industry guidance, multiple hours of alarm flood clustered together can overwhelm board operators, contributing to errors and catastrophic incidents. As noted above, ISA 18.2 recommends that the number of alarm floods, duration of each alarm flood, alarm count in each flood, and peak alarm rate for each flood should be analyzed, but it does not provide any performance targets for such analyses.

The Engineering Equipment and Materials Users Association (EEMUA) provides short-term alarm guidance in its publication 191, *Alarm Systems: Guide to design, management and procurement* [35]. For abnormal condition performance levels such as after a major process upset, the EEMUA states that 20 to 100 alarms in 10 minutes is "hard to cope with," and over 100 alarms in 10 minutes is "definitely excessive and very likely to lead to the operator abandoning use of the system" [35, p. 215]. The ASM Consortium guidance references the EEMUA guidance, and adds that an alarm impact assessment is warranted whenever the peak alarm rate exceeds 50 alarms in 10 minutes [33, p. 23]. **Figure 40** summarizes the available guidance for alarm rate following an upset, compared with the BP Toledo Refinery alarm performance preceding the incident.

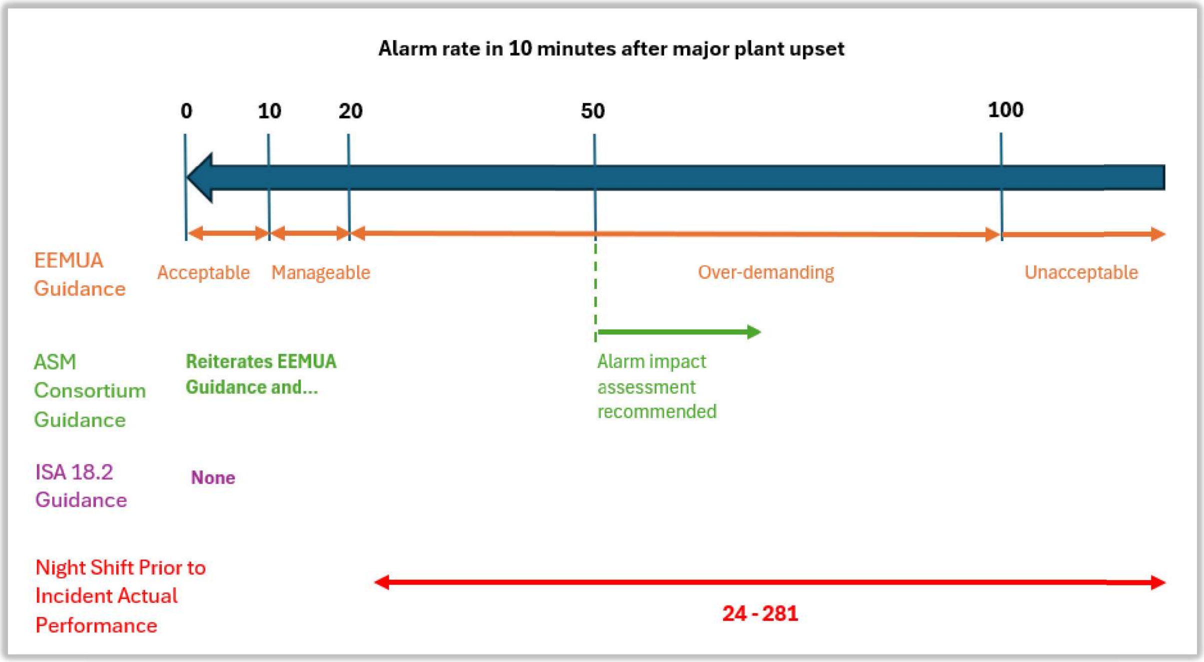

Figure 40: Alarm rate guidance and actual performance following a process upset [35, p. 103]. (Credit: CSB)

Had the BP Toledo Refinery evaluated its alarm performance following process upsets, such as, for example, the amount of time a board operator was exposed to a peak alarm rate greater than 50 alarms in 10 minutes, alarm floods in 24 hours might have been more obvious than evaluating alarm performance based solely on the percentage of time the alarm system is in a flood condition based upon at least 30 days of data could have been more obvious than evaluating performance based solely on monthly average data. On September 20, 2022, the board operators experienced alarm peak rates over 50 alarms in 10 minutes for four hours before the incident occurred.[a] **Figure 41** shows the ISA 18.2 alarm targets compared with the DCS console monthly performance, and also compared with the September 20, 2022, data (shown by a red dot). Although the two months (July and August 2022) in which refinery or unit startups occurred were outside ISA 18.2 targets, most of the months in 2022 were within the ISA 18.2 targets (in green). The September 20, 2022, data are shown compared with monthly average targets because ISA 18.2 currently does not provide any short-term targets.

[a] This is not including any alarms after 7:00 p.m., so that alarms triggered in response to the fatal incident itself would not be included in the calculation.

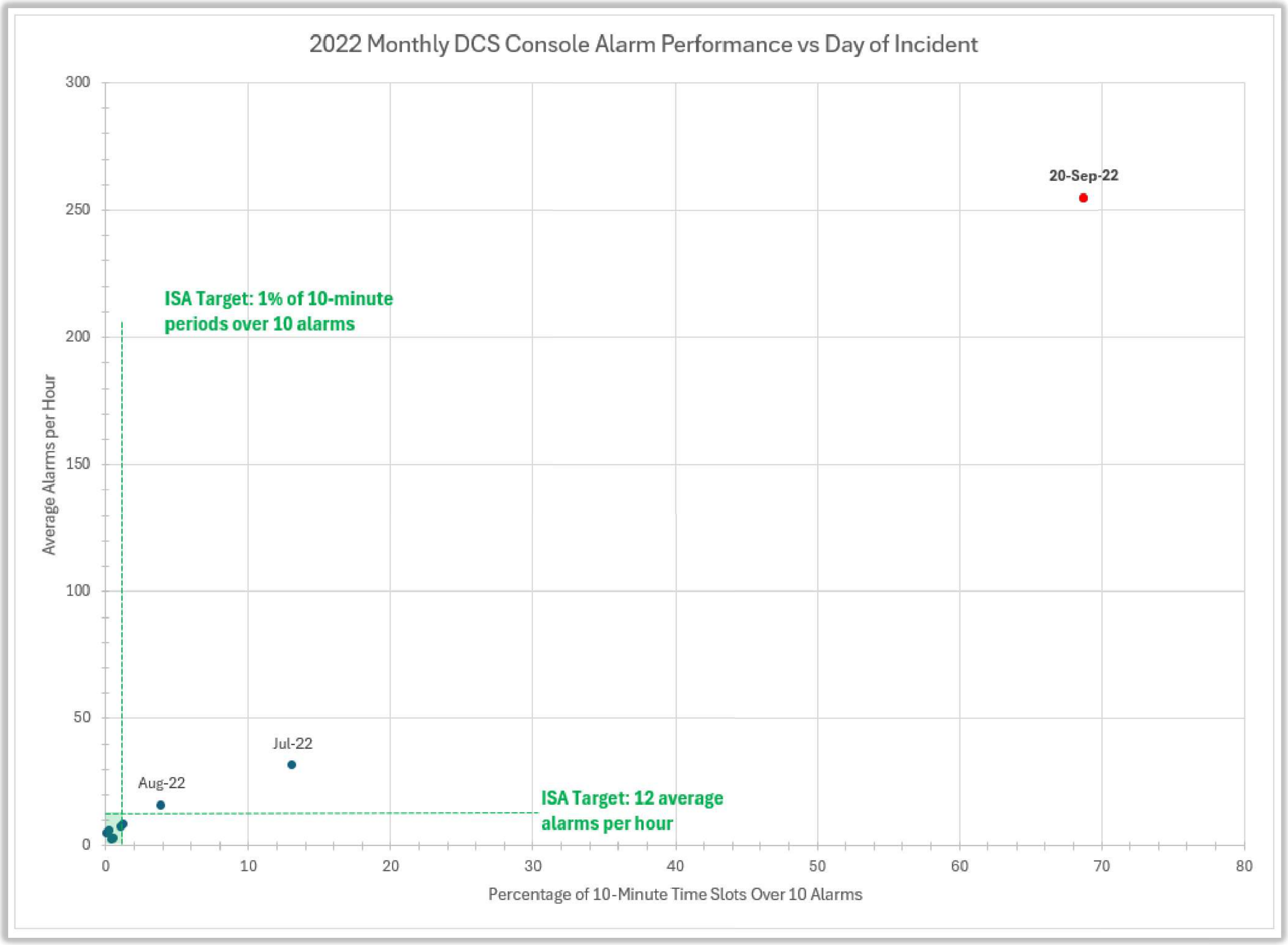

Figure 41: BP Toledo Refinery DCS console alarm performance compared with ISA 18.2 targets (green dotted lines), both monthly (blue dots) and for the day of the incident (red dot) [34, p. 78]. The green shaded area in the lower left corner shows ISA 18.2 target performance. (Credit: CSB)

The CSB concludes that while ISA 18.2 provides guidance and a performance target for an alarm flood over a period of at least 30 days, no additional targets are provided for items such as the number of alarm floods in a month, duration of each flood, alarm count in each flood, or peak alarm rate for each flood. Had such targets been established in industry guidance, the BP Toledo Refinery could have analyzed and improved alarm flood performance following a process upset, such as that occurred in the hours preceding the incident.

The CSB recommends that the International Society of Automation revise American National Standard ANSI/ISA 18.2-2016, *Management of Alarm Systems for the Process Industries*, to include performance targets for short-term alarm flood analysis so that users can evaluate alarm flood performance for a single alarm flood event. The performance targets should include:

a) number of alarm floods,

b) duration of each flood,

c) alarm count in each flood, and

d) peak alarm rate for each flood.

At a minimum, a target peak alarm flood rate should be defined, such as in the guidance provided by the ASM Consortium or Engineering Equipment and Materials Users Association (EEMUA), to establish trigger points that require alarm performance improvement actions. (*See* Recommendation **2022-01-I-OH-R7**).

4.3.4 Industry Guidance for Alarm Flood Management

ISA 18.2 identifies several basic alarm design elements that can minimize alarm load on operators, including:

- *Alarm justification* first should ensure that all alarms in a control system are necessary, will not become a nuisance, and are not duplicative. For example, any alarm for which the operator action is simply to communicate information to another person or group could be moved to another system so as not to burden the operator or the alarm system [34, p. 48].
- *Alarm prioritization* allows the critical alarms, such as safety limits, to be more visible to an operator, typically by identifying high priorities by color or alarm tone, for example [34, p. 49].
- *Alarm deadband* minimizes the number of alarm annunciations for a given abnormal condition by preventing an alarm from returning to normal state until the alarm condition clears the deadband, which is a defined range around the alarm setpoint [34, p. 52].
- *Alarm on-delay or off-delay*, also known as a de-bounce timer, can avoid unnecessary alarms when a signal temporarily overshoots the alarm setpoint by annunciating or returning to normal only after a set time delay. This reduces or eliminates multiple alarms for the same parameter when the process value is hovering near the alarm setpoint [34, pp. 52-53].
- *Shelving* allows an operator to temporarily suppress[a] an alarm they already know about and do not need repeated alarms for, with automatic controls that reinstate the alarm, usually after a set period of time.[b] Some high-priority or safety alarms may be designed to disallow shelving, however [34, p. 24].

[a] Alarm suppression is to "prevent the annunciation of the alarm to the operator when the alarm is active" [34, p. 24].

[b] Alarms were shelved on September 20, 2022. *See* **A.2.9.4.20**

In the event that alarm flood is not at target performance with only the basic alarm design elements above, ISA 18.2 also identifies "enhanced and advanced alarm methods" to mitigate alarm floods [34, p. 76]. These include additional layers of logic, programming, or modelling to modify alarms, and are used "to guide operator action during abnormal process conditions" [34, p. 64]. Specific advanced and enhanced alarm methods identified by ISA 18.2 include:

- *Alarm attribute modification* alters some alarm attributes such as setpoints or priority based on a defined set of conditions using logic such as decision trees.
- *Logical alarm suppression* uses the states of some alarms to modify the attributes of other alarms, such that under certain conditions, alarms that are not useful or are redundant can be suppressed automatically.
- *State-based alarming* modifies alarm attributes such as setpoint, priority, or suppression status based on operating states for equipment or processes. For example, while equipment or a process unit is in a shutdown mode, most of the equipment's alarms may not be necessary [34, p. 65].

KEY LESSON

Companies should ensure that alarms are well justified. While DCS technology allows alarms to be created easily, it also can cause board operators to be inundated with low priority or irrelevant information during an abnormal situation if alarms are not properly designed. This also places additional stress on board operators, reducing their effectiveness when it is needed most.

The BP Toledo Refinery used at least some of the techniques above, such as shelving,[a] prioritization, and state-based alarming. Shortly after the Crude 1 Tower crude slate change at 4:56 p.m., the board operators received many alarms in a short time. As the Absorber Stripper Tower filled with naphtha, a board operator temporarily shelved[b] the two Absorber Stripper Tower high level alarms. Shelving the high level alarms meant that the Absorber Stripper Tower level alarms would no longer appear on the DCS active alarm screens the board operators were monitoring for a period of time.

However, despite using some tools, alarm flood occurred during the September 20, 2022, process upsets as shown in **Figure 37** above. For example, from 5:30 p.m. to 6:45 p.m. (approximately from the time the Crude 1 Tower upset began to the time that the fatal incident occurred), the DCS console received 765 annunciated alarms. Out of the 203 different tags that created alarms during this time, the six most frequent alarms accounted for nearly half of the alarm annunciations (47.2 percent). The most frequent alarm went off 22 times in one minute at 6:30 p.m., or on average once every 2.7 seconds, when board operators were already overwhelmed with alarms. **Figure 42** below shows the top six most annunciated alarms during this time.

[a] Alarms were shelved on September 20, 2022. *See* **A.2.9.4.20**.

[b] Alarm shelving is defined by the Engineered Equipment and Materials Users Association (EEMUA) as "a facility where the operator is able to temporarily prevent an alarm from being displayed when it is causing a nuisance. A shelved alarm will be removed from the list and will not re-annunciate until un-shelved." At the BP Toledo Refinery, alarms could be shelved by operators for a maximum of 12 hours. Not all alarms could be shelved at all, and some could only be shelved for shorter periods. The EEMUA is "an Association established by the owners and operators of industrial assets" [35, pp. 156, ii].

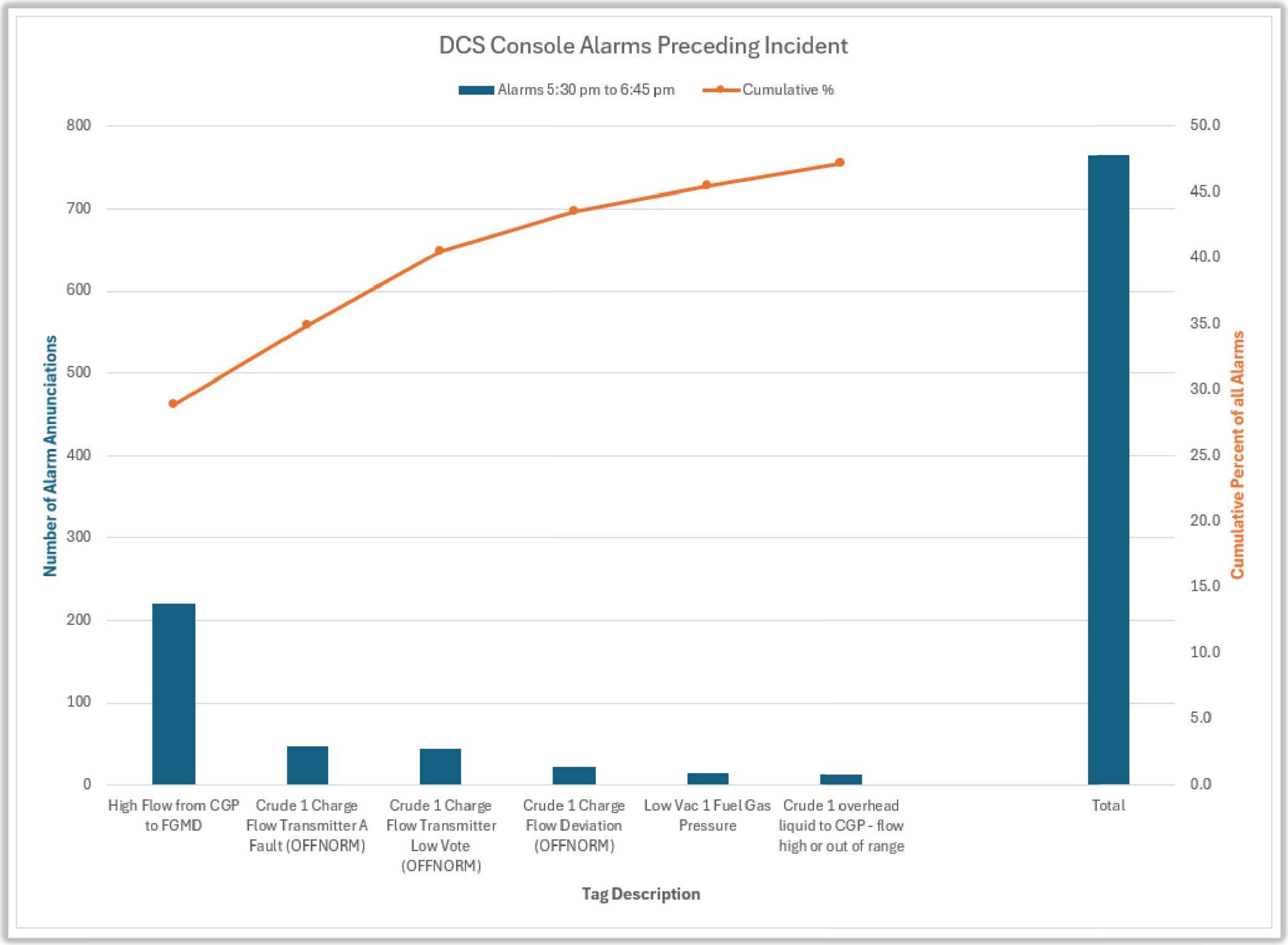

Figure 42: Most frequent alarms annunciated at DCS console between 5:30 p.m. and 6:45 p.m., the hour and 15 minutes preceding the incident. The blue bars show the number of annunciations for each tag, and the orange line shows the cumulative percentage of alarms in that time. (Credit: CSB).

The most frequent alarm, "High Flow from Coker Gas Plant to Fuel Gas Mix Drum," might have afforded board operators a clue as to the source of liquid entering the Fuel Gas Mix Drum. This flow measurement was normally in gas flow only, not liquid flow, as was occurring before the incident. Significantly, however, the CSB found no evidence that anyone in the control room acted on this alarm. Board operators may have been too overwhelmed with alarm flood to understand why the alarm was annunciating so frequently. In any case, board operators did not take corrective action until after the fatal incident occurred, as the naphtha flow control valve to the Coker Gas Plant remained open until 7:04 p.m., nearly 20 minutes after the incident.

To better reduce or eliminate alarm floods, the BP Toledo Refinery could have used alarm deadband or alarm on-delay/off-delay to reduce the number of repeat incoming alarms to the board. This would allow board operators to focus on the process upset itself, without having to sort out all the repeat alarms that they were already aware of.

The CSB concludes that had the BP Toledo Refinery more fully utilized some of the available alarm flood management techniques in ISA 18.2 prior to the fatal incident, such as deadband and on-delay/off-delay, the alarm flood on the day of the incident would have been more manageable and board operators could have prevented or stopped the flow of liquid naphtha to the Fuel Gas Mix Drum.

4.3.5 Post-Incident Alarm Flood Management

In June 2023, the Ohio Refining Company LLC issued a new Toledo Alarm Philosophy, which includes alarm flood management strategies. The document described several forms and examples of alarm flood management techniques, including state-based alarming and logical alarm suppression such as group suppression, where "alarms can be grouped using logic to present the operator with a single common alarm, such as to indicate the alarm condition of several related field sensors." The new document specifically addresses alarm suppression following a major event or trip:

> Alarm systems can be difficult to manage following a trip or major event (such as the trip of a compressor) as operators may be subjected to alarm floods. Such disturbances are particularly stressful and can be considered as relatively hazardous periods of operation. During an alarm flood, the operator's effectiveness is diminished because they can be overwhelmed and miss important information. In order to minimize the number of alarms following the trip or event, alarm flood (dynamic) suppression may be required.
>
> Alarm flood suppression is the dynamic management of pre-defined groups of alarms based on detection of equipment state and triggering events. In this technique alarms are suppressed following an event when they are not relevant or meaningful to the operator and when suppressing them cannot result in a hazardous situation.

The new policy indicated that "flood events should be analyzed for total percentage of time each month that the alarm system spends in a flood condition."[a] While this is consistent with ISA 18.2, the flood performance metric does not necessarily focus the analysis on plant upsets, which may cause alarm flooding over a period of hours, as occurred the day of the incident (**Figure 36** above).

The CSB concludes that the new 'Toledo Alarm Philosophy' follows ISA Standard 18.2 guidance but contains the same gap as the guidance: it does not include short-term targets for items such as number of alarm floods, duration of each flood, alarm count in each flood, or peak alarm rate for each flood. Such targets could provide the refinery with more appropriate tools to analyze and improve alarm performance in an alarm flood that lasts several hours, such as what occurred in the hours preceding the incident.

The CSB recommends that Ohio Refining Company LLC revise the 'Toledo Alarm Philosophy' by incorporating the Engineering Equipment and Manufacturers Users Association (EEMUA) guidance for alarm rate following an upset and not limiting alarm performance to a single metric averaged over a month. In addition to including analyzing individual alarm flood events, the revised philosophy document should improve refinery alarm performance to reduce alarm flood duration and peak rate for events similar to the September 20, 2022,

[a] According to the Ohio Refining Company LLC, the Toledo Refinery alarm rationalization program utilizing the Toledo Alarm Philosophy, evaluating if the appropriate alarms are in place, setpoints, and associated response actions for several systems, including those involved in the incident is ongoing.

incident. Consult EEMUA Publication 191, Chapter 6.5.1, for guidance regarding abnormal condition performance levels. Apply the improved performance levels where applicable, but specifically to the Crude 1 control board alarm performance. (*See* Recommendation **2022-01-I-OH-4**).

4.4 Learning from Incidents

Accident investigations sometimes seek to identify lessons, so as to ensure that an accident like the one under investigation never happens again. Nevertheless, accidents may repeat themselves [36, p. 65].

In the introduction to the BP Process Safety Series *Hazards of Oil Refining Distillation Units*, Jesse C. Ducommun, Vice-President, Manufacturing and Director of American Oil Company in 1961 and Vice - President American Petroleum Institute in 1964 stated the following:

> It should not be necessary for each generation to rediscover principles of process safety which the generation before discovered. We must learn from the experience of others rather than learn the hard way. We must pass on to the next generation a record of what we have learned [13].

4.4.1 Catastrophic Incident Warning Signs from a 2019 BP Toledo Refinery Incident

The CSB found the BP Toledo Refinery had investigated a previous incident of naphtha back flowing through a Coker Gas Plant bypass line in 2019. **Figure 43** shows the Initial Incident Report of high level in the Fuel Gas Mix Drum.[a]

[a] The common name at the BP Toledo Refinery for the Fuel Gas Mix Drum was the TIU mix drum (Toledo Integrated Unit).

Initial Incident Report

Basic Information	
Incident Number	1569890
Incident Title	The TIU mix drum level was high during the refinery upset following steam loss
Reporting Person	[redacted]
When the incident happened	
Incident Date	13.11.2019
Incident Time	1:00:00 PM
Time Zone	EST
Where the incident happened	
Region	North America
Country	United States
State/Province/ Offshore	Ohio
Site	Toledo
Sub-site	South
Area1	Crude - 1
Area2	
Area3	
Responsible Organisation	
Organisation Hierarchy	Downstream >Fuels >North America >Toledo >Operations
Organisation	OM&S / ID: 33801775
What Activity was In Progress when the Incident Happened	
Operations	
What was the Mode of Operation	
Upset	
Incident Description	
The refinery was working through a large upset following the CO Boiler trip and then loss of EAB. The TIU mix drum GWR level went to high scale at 100% and the dP level flatlined at 65% roughly (both read 50% of the drum). Several operations moves were made, but it appears the CGP Polishing Amine contactor was also full, even though it read 0%.	

DRAFT

Figure 43. BP Initial Incident Report. High level in the Fuel Gas Mix Drum during a refinery upset. (Credit: BP with annotations by CSB)

The challenge presented by a first known instance like this 2019 incident is described by the CCPS:

> In the case of setbacks, we need to know what went wrong and how we can avoid repeating the same errors. This may be the most difficult challenge. The biggest error that an organization can make is in missing these opportunities [37, p. 149].

In 2012, the CCPS published *Recognizing Catastrophic Incident Warning Signs in the Process Industries*, a book focused on recognizing when "something is wrong or about to go wrong" and then taking action to prevent a major incident [37, pp. 1-3]. A warning sign is defined as a subtle indicator of a problem that could lead to an incident [37, p. 1].

Some of the warning signs identified by the CCPS are:

- failure to learn from previous incidents,
- frequent process upsets or off-specification product,
- abnormal instrument readings not recorded or investigated,
- failure to report near misses and substandard conditions,
- superficial incident investigations resulting in improper findings,
- incident reports downplay impact, and
- environmental performance does not meet regulations or company targets [37, p. 151].

The CCPS states that:

> There is one common characteristic shared by the incident warning signs presented here: *The organization does not perceive or recognize them* [37, p. 1].

The BP Toledo Refinery had an opportunity to prevent the multiple vessel overflows that occurred in the September 20, 2022, incident following the investigation of a 2019 refinery-wide upset. The investigation of the 2019 event determined that the Coker Gas Plant had been operating with the bypass line open when the entire refinery unexpectedly lost steam. A boiler tripped as a cold front arrived in Toledo and quickly set off a series of abnormal situations. Without steam on the Coker Gas Plant Absorber Stripper Tower and Lean Oil Stripper reboilers and with all the Lean Oil Stripper overhead fans continuing to run, the temperature on the Coker Gas Plant Lean Oil Stripper overhead system became low enough to plug the Lean Oil Stripper overhead system with hydrates.[a]

During the refinery-wide upset, the Crude 1 Overhead Accumulator Drum developed a high level as the only pump available at the time to pump liquid out of the drum was a steam-driven pump, which was inadequate. The investigation found that the same naphtha flow control valve to the Coker Gas Plant as was involved in the September 20, 2022, incident (*See* **Section 3.1.7**) was opened 80 to 100 percent during the 2019 incident in an attempt to unload the high drum level to the Coker Gas Plant.

As in the September 20, 2022, incident, during the 2019 incident, naphtha began to fill the Coker Gas Plant Absorber Stripper Tower and, according to the 2019 incident investigation, the naphtha backed up through the Coker Gas Plant bypass due to high pressure that had developed in the Lean Oil Stripper from the hydrate formation. As shown in orange in **Figure 44**, naphtha flowed from the Absorber Stripper Tower through the Coker Gas Plant bypass line. A high liquid level developed in the Fuel Gas Mix Drum and the Polishing Amine Contactor Sweet Gas Knockout Drum. In the 2019 incident, the high liquid level in the Fuel Gas Mix Drum was drained to the Flare Knockout Drum and the Oily Water Sewer. Operations changed the crude slate being fed to the Crude 1 unit to reduce naphtha production and reduced the opening of the naphtha flow control valve to the

[a] Hydrates are solid compounds that can be formed during oil and gas production, causing interruptions in the flow of the produced fluids.

Coker Gas Plant.[a]

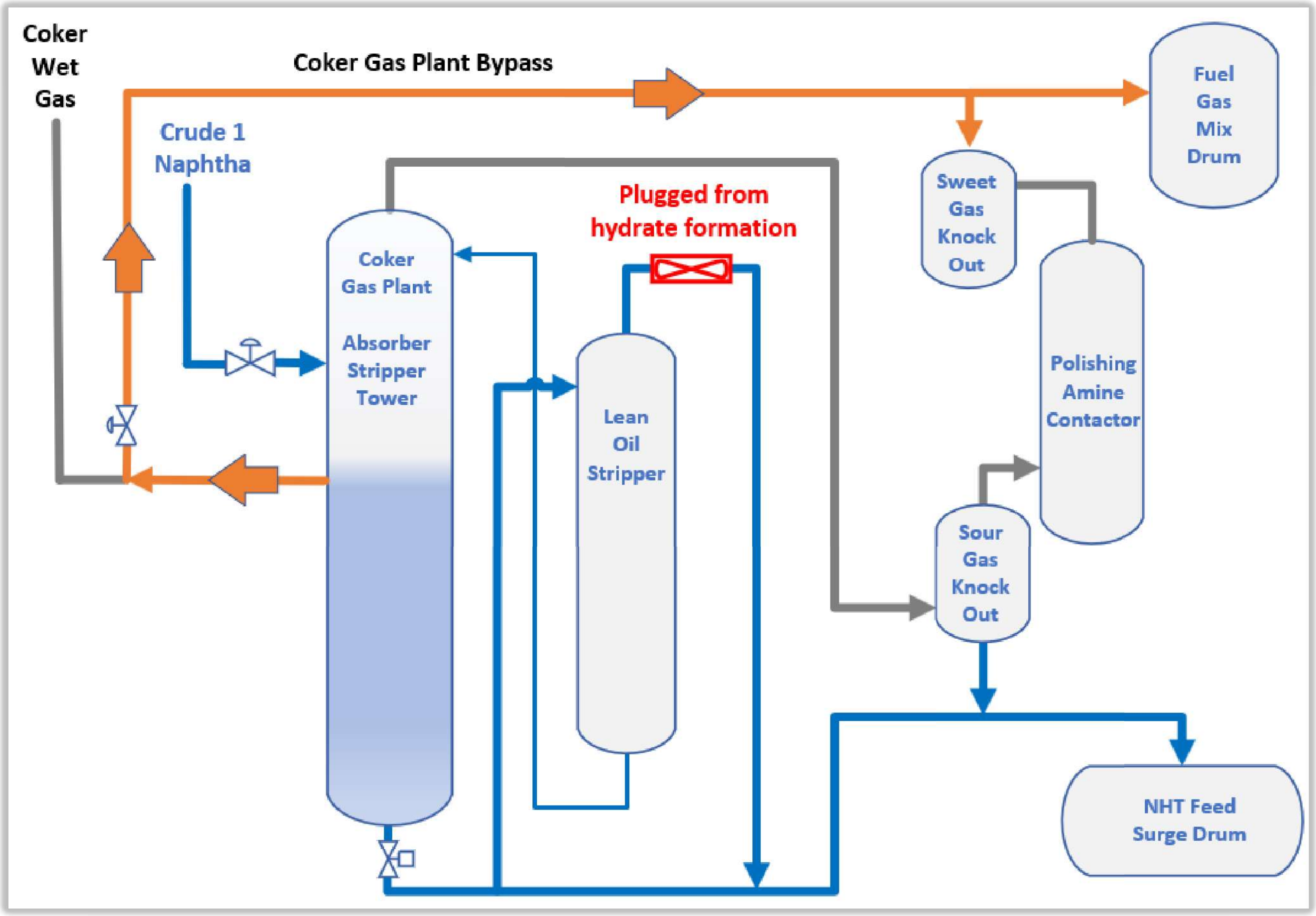

Figure 44. Coker Gas Plant. Configuration of the Coker Gas Plant during a 2019 refinery upset. (Credit: CSB)

The CSB concludes that the facts, conditions, and circumstances of the 2019 incident show that while operating the Coker Gas Plant with the bypass open, the BP Toledo Refinery did not have adequate safeguards to prevent overflow of naphtha from the Coker Gas Plant to the Fuel Gas Mix Drum.

The Initial Incident Report description in **Figure 43** above shows how in 2019 the BP Toledo Refinery identified a warning sign when abnormal instrument readings on the Fuel Gas Mix Drum level instrumentation were observed. The guided wave radar level instrument indicated 100 percent level when the liquid was above the six-foot measured span near the bottom of the Fuel Gas Mix Drum while at the same time the specific gravity-dependent differential pressure (dP) level instrument flatlined at roughly 65 percent level. This discrepancy in the Fuel Gas Mix Drum level measurements is an example of a warning sign known as an abnormal instrument reading. Abnormal instrument readings can indicate that a serious problem is occurring that can lead to incorrectly analyzing an impending critical situation, as well as human error and potential

[a] There was no release of naphtha to the ground or vapor cloud formation during this incident.

disaster [37, p. 154]. The 2019 Fuel Gas Mix Drum abnormal instrument readings are the same as described in **Section 3.2** for the September 20, 2022, incident.

As shown in **Figure 45** below, in 2019 the BP Toledo Refinery investigated the high level in the Fuel Gas Mix Drum using a Five Whys investigation methodology and developed actions to prevent future recurrence.

bp | Husky

BP - Husky Refining, LLC

Toledo Refinery
Category 3
5-Why Investigation Pro Forma

Process Incident	High Level in TIU mix drum
IRIS Record#	1569890
Incident Date & Time	11.13.2019 13:00
Submitted by:	[redacted]

<u>How</u> can a future re-occurrence be prevented? *(preventive measures / lessons learned)*

Ensure the unit is laid up appropriately when bypassed to prevent too low of temperature on the LOS Overhead system

When the unit is filling with naphtha the level indications on the polishing contactor KO drum are not representative due to gravity changes.

<u>Long Term Action Taken (To be agreed upon by Superintendent and assigned in IRIS)</u>:

Update the coker gas plant bypass procedure to include a warning on a risk for hydrates if the lean oil stripper overhead to gets to cold. [redacted]

Add low temperature alarms to the LOS overhead. [redacted]

Figure 45. BP Process Incident Investigation. The preventive measures, lessons learned, and actions taken from the 2019 incident of high level in the Fuel Gas Mix Drum. (Credit: BP, truncated with annotations by CSB)

Five Whys investigations are described in BP Toledo Refinery incident investigation procedures, but in the book *An Introduction to System Safety Engineering* (2023), Nancy Leveson explains that this technique for incident analysis "can lead an investigation team to omit important systemic causes" [24, p. 575]. The precise lineup of causes determines the outcome, and unless the causes are systematically analyzed and addressed with follow-up actions, there is a probability that the incident will recur. In fact, under slightly different circumstances the same incident may have consequences that are more serious [37, p. 151], which is what happened at the BP Toledo Refinery in 2022.

Figure 46 is a graphical representation of the 2019 Five Whys Investigation shown in **Figure 45**. The red flags indicate causes of high level in the Fuel Gas Mix Drum such as high level in Crude 1 Overhead Accumulator Drum and the open Coker Gas Plant bypass that could have prevented the September 20, 2022, incident, but were not addressed with long term actions to prevent future reoccurrence.

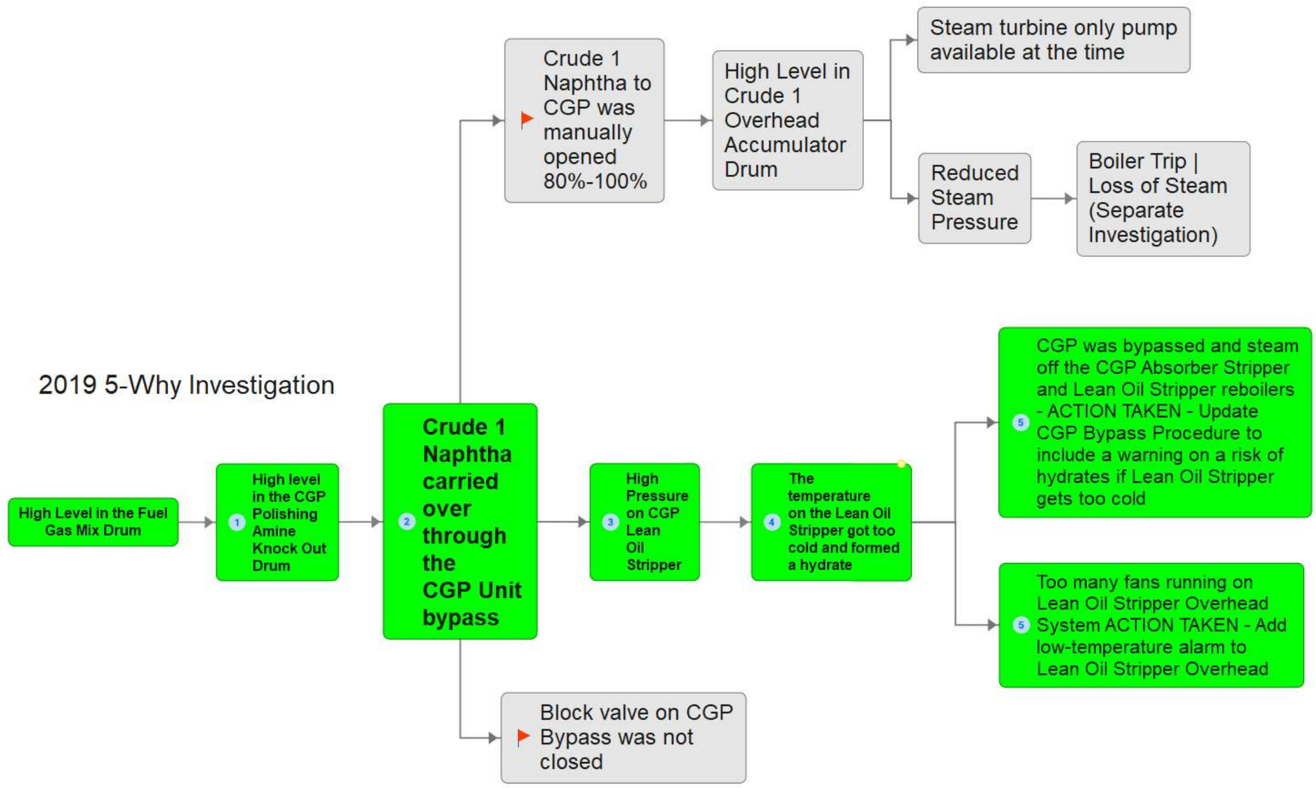

Figure 46. Graphical representation of the Five Whys investigation of high level in the Fuel Gas Mix Drum. (Credit: CSB)

Another warning sign described by the CCPS is superficial investigations. When action items are applied only to the specific equipment affected, a superficial investigation can result in improper findings and not learning from experience [37, p. 156].

Two action items were issued by the 2019 incident investigation that addressed a specific piece of equipment, the Coker Gas Plant Lean Oil Stripper overhead, which formed hydrates and plugged after the cold front arrived at the refinery. The 2019 incident investigation did not recommend any long-term actions related to the overflow of naphtha from the Coker Gas Plant to the Fuel Gas Mix Drum, however.

The CSB concludes the BP Toledo Refinery 2019 Five Whys incident investigation focused only on action items to prevent plugging in the Lean Oil Stripper overhead system, failing to learn important safety lessons from the 2019 incident. The BP Toledo Refinery did not perceive the need to issue recommendations related to overflow of naphtha through the Coker Gas Plant bypass to the Fuel Gas Mix Drum or the abnormal Fuel Gas Mix Drum level instrument readings identified in the 2019 Initial Incident Report, which could have prevented the September 20, 2022, incident.

KEY LESSON

Accident investigation techniques, such as *Five Whys*, suggest that there is only one root cause and one linear path to an accident [24, p. 291]. Using such approaches for process safety incidents, even if recommended in company safety procedures, can lead an investigation team to a superficial analysis that does not prevent an accident from recurring.

To reduce the risk of a catastrophic incident, the CCPS stated that recognizing and responding to warning signs is an important first step. The CCPS presented a call to action for companies to embrace the use of warning signs as predictors of increased danger and include warning signs within their process safety management systems. To integrate warning sign detection and prevention methods into process safety management systems, the CCPS recommended that companies:

- perform an initial survey of warning signs,
- build warning sign analysis into the safety management system,
- use the new system and track related action items,
- evaluate effectiveness in the next safety management system assessment, and
- maintain vigilance against recurring warning signs [37, pp. 175-179].

4.4.2 Findings from the Fatal 2005 Explosion and Fire at the BP Texas City Refinery

In his 1993 book *Lessons From Disaster: How Organizations Have No Memory and Accidents Recur*, process safety expert Trevor Kletz stated:

> It might seem to an outsider that industrial accidents occur because we do not know how to prevent them. In fact, they occur because we do not use the knowledge that is available [38, p. 1].

Ensuring that towers and process vessels such as the Absorber Stripper Tower at the BP Toledo Refinery do not overflow is not a new safety lesson nor a novel process safety concept. Like many others, this safety lesson could have and should have been learned from previous chemical disasters. Analyzing past disasters is important to show how we can learn from accidents and apply safety lessons to help prevent similar chemical disasters in the future [39, p. 1]. There are safety findings from the 2005 BP Texas City Refinery explosion and fire, investigated by the CSB, which fatally injured 15 workers and injured 180 others that BP could have applied at the BP Toledo Refinery to prevent the September 20, 2022, incident [31, p. 1]. Unfortunately, BP did not.[a]

> **KEY LESSON**
>
> Organizations should develop systems to ensure that learnings from internal and external incidents are incorporated throughout the organization to prevent recurring failures, such as overflow of process vessels, that can lead to a catastrophic incident.

The fatal 2005 BP Texas City incident occurred during the restart of a hydrocarbon isomerization unit after a maintenance shutdown. At the time of the incident, procedures not reflecting actual practice were used as a Raffinate Splitter Tower filled with flammable hydrocarbons and overflowed [31, pp. 2-3]. A CSB animation describes the incident, including the overflow of the Raffinate Splitter Tower.

Even with numerous alarms, refinery operators were unaware of the overflow of the BP Toledo Refinery Coker Gas Plant Absorber Stripper Tower through the vapor bypass piping and the 2005 overflow of the Texas City Raffinate Splitter into the overhead line. The BP Texas City Raffinate Splitter Tower overflowed and subsequently overfilled a blowdown drum, which discharged into the atmosphere. Flammable hydrocarbons flowed out of the Texas City blowdown drum and formed a vapor cloud that ignited [31, p. 11]. The BP Toledo Refinery Coker Gas Plant Absorber Stripper Tower overflowed in 2022 through the vapor bypass piping and subsequently overfilled the Fuel Gas Mix Drum. Two BP employees releasing flammable naphtha from the overflowing pressurized Fuel Gas Mix Drum directly to the ground formed a vapor cloud that ignited, just like the vapor cloud in the BP Texas City incident.

After the fatal Texas City Refinery explosion and fire, BP commissioned a report to look into managements' accountability for the "Texas City Isomerization Explosion."[b] This internal BP report stated:

> Finally, Texas City Refinery either did not learn or did not apply the lessons from prior incidents at Texas City and other BP refineries ... [40, p. 9].

Similarly, the CSB found that the BP Toledo Refinery did not effectively learn, apply lessons, or institutionalize the knowledge of overflow scenarios from the fatal Texas City incident, despite the warning from the final report of BP's Management Accountability Project.[c]

Table 4 lists findings from the overflow event that were either not learned or applied from the prior Texas City incident that could have prevented the September 20, 2022, incident.

---

[a] The BP Texas City Refinery and the BP Global Executive Directors closed all recommendations issued by the CSB from the BP Texas City Refinery Explosion and Fire Investigation.

[b] The Management Accountability Project Texas City Isomerization Explosion Final Report is also known as the "Bonse Report". The Bonse Report is a separate report from the Baker Panel Report. Unlike the Baker Panel Report which examined BP's safety culture across all of BP's refineries in the U.S., the task of this BP team for the Bonse Report was to examine specific individual management accountability within BP.

[c] *See* **Section 1.5** for a refinery incident of an explosion while draining a fuel gas system.

Table 4. BP Refinery incident findings comparison. Comparison of the BP Texas City Refinery and the BP Toledo Refinery overflow events.

BP Texas City Incident Finding [31, pp. 22-26]	**BP Texas City Refinery**		**BP Toledo Refinery**	
	Raffinate Splitter Tower	**Blowdown Drum**	**Absorber Stripper Tower**	**Fuel Gas Mix Drum**
Level measurement calibrated for correct fluid during start-up/shutdown/ upset conditions	**No** Calibrated with incorrect fluid specific gravity [31, pp. 131, 327]	Not Applicable (High Level Switch, [31, pp. 311,324-325])	**Yes**	**Yes** Guided Wave Radar level measurement is independent of specific gravity **No** dP level calibrated for amine-water solution and not for naphtha or other hydrocarbons in an upset condition, plateaued around 67 percent while overflowing
Overflow condition detected on a control room console display designed to provide adequate information of flows in and out to alert operators[a] (mass balance graphic)	**No** Overflow from tower overhead line to emergency pressure-relief valves discharging to the Blowdown Drum [31, p. 23]	**No** Overflow to Sewer and Atmosphere [31, p. 40]	**No** Overflow from Absorber Stripper Tower to the Fuel Gas Mix Drum	**No** Overflow determined after multiple high level alarms and not from a mass balance graphic designed to provide information of flows in and out
Engineered Control provided (Control system to prevent overfilling)[b]	**No**	**No**	**No** A safeguard to close the naphtha flow control valve to the Coker Gas Plant on high level identified but not implemented	**No** Manual draining required, closed system draining capacity inadequate for Coker Gas Plant overflow

[a] Prior CSB Recommendation 2005-4-I-TX-14 to the BP Texas City Refinery.

[b] Prior CSB Recommendation 2005-4-I-TX-14 to the BP Texas City Refinery.

BP Texas City Incident Finding [31, pp. 22-26]	BP Texas City Refinery		BP Toledo Refinery	
	Raffinate Splitter Tower	**Blowdown Drum**	**Absorber Stripper Tower**	**Fuel Gas Mix Drum**
Level high alarm provoked an appropriate response	**No** Alarm remained active for the entire period of the startup [31, p. 82]	**No** Alarm did not activate [31, p. 324]	**No** Board operator shelved tower active high level alarms after intentionally opening the naphtha flow control valve to the Coker Gas Plant	**Yes** Manual draining started to Flare Knockout Drum
Filling vessel with bottom outlet valve open	**No** Raffinate Splitter base level control valve had been closed and was later opened by a board operator [31, pp. 22-23]	**Yes** Manual drain valve to sewer was chained open [31, pp. 38-40]	**No** Absorber Stripper Tower bottoms ROEIV closed by prior shift	**No** Fuel Gas Mix Drum manual valves to Flare Knockout Drum and Oily Water Sewer were closed. These valves were later opened by outside operators in response to high level in the Fuel Gas Mix Drum.
Use of Approved Operating Procedures (For example, using informal procedures for temporary hold-up of liquid level or draining)	**No** Lack of procedure to document filling the bottom of the raffinate splitter above the range of the level transmitter (Informal practice not unusual for start-up) [31, p. 73]	**No** Lack of procedure for chaining manual valve to sewer open[a] [31, p. 332]	**No** Lack of a procedure for correcting high Crude 1 Overhead Accumulator Drum level	**No** Lack of an approved procedure for draining high level in Fuel Gas Mix Drum
Rigorously documented handover [40, p. 16]	**No** Evidenced by events on March 23, 2005 [31, p. 23], [40, p. 16]		**No** Missing Board Operator shift log on September 20, 2022	

[a] In 1998, PHA action item recommended chaining open the discharge valve to the sewer on the blowdown drum to prevent a high liquid level from increasing the backpressure on the relief valve headers. This action item was addressed by chaining open the valve without assessing its potential impacts on health and safety [31, p. 332]. The CCPS notes, in “Guidelines for Design Solutions for Process Equipment Failures,” that locking open a valve is “not merely a common sense decision; rather at an operating facility it is a design change. It is a procedural design solution that requires a documented design basis and a subsequent safety review” [73, p. 27].

The table above outlines similarities between the multiple vessel overflow events in the 2005 BP Texas City incident and the 2022 BP Toledo Refinery incident, including inadequate overflow detection, lack of engineered controls to prevent overflow, lack of adequate operating procedures, and inadequate shift handover. The final recommendation of the report of the BP U.S. Refineries Independent Safety Review Panel in 2007 ("the Baker Panel Report") stated: "BP should use the lessons learned from the Texas City tragedy and from the Panel's report to transform the company into a recognized industry leader in process safety management" [2, p. 257].[a] The occurrence of the 2022 incident at the BP Toledo Refinery is evidence that BP failed to implement vessel overflow findings from the BP Texas City incident.

Among the recommendations issued from the Baker Panel Report was a recommendation that BP should involve the relevant stakeholders to develop a positive, trusting, and open process safety culture within each U.S. refinery and "measure the effectiveness of this effort to "improve process safety culture by conducting periodically an anonymous process safety culture survey among the U.S. refineries" [2, pp. 249-250].[b] The Baker Panel Report found that "significant safety issues" existed at all five of BP's U.S. refineries, not just the Texas City refinery. The report indicated that significant portions of the Toledo workforce at that time did not believe that process safety was a core value and that BP had a weak process safety culture at Toledo. Specifically, the report stated: "Toledo has a weak safety culture, largely because of chronic morale problems and a history of poor relations between refinery management and the unionized workforce" [2, p. 118]. The report also stated: "At Toledo, higher levels of management typically stated that decisions regarding production and cost savings did not override process safety concerns, but that belief tended to change in the middle and lower ranks of the Toledo organization. Many lower and middle managers interviewed expressed skepticism about whether process safety concerns came first. Toledo hourly workers interviewed widely believed that production was a higher priority than process safety" [2, pp. 61-62].

During the investigation of the September 20, 2022, incident, BP told the CSB it was unaware of any process safety culture assessment completed at the BP Toledo Refinery since the Baker Panel Report.[c]

The BP Texas City incident is one of several publicly investigated incidents that are so iconic and impactful that they should become part of the basic knowledge of everyone across the chemical industry [41, p. 193].[d] In its 2020 book, *Driving Continuous Process Safety Improvement from Investigated Incidents*, the CCPS explains for incidents like BP Texas City:

> Even if a person cannot recite the details, if they are in the industry, they should be able to share the collective sense of vulnerability. They should then use that sense of vulnerability to motivate safe work and dedication to completing all tasks with professionalism. […] If any of the gaps that led to these incidents

[a] *See* The Report of the BP U.S. Refineries Independent Safety Review Panel.

[b] *See* The Report of the BP U.S. Refineries Independent Safety Review Panel.

[c] The CSB did not issue a recommendation to develop, implement, and maintain and effective process safety culture assessment program, such as prescribed by the California Code of Regulations, Title 8, Section 5189.1. Process Safety Management for Petroleum Refineries, due to the change of owner and operator from BP to Ohio Refining Company LLC effective February 28, 2023.

[d] In addition to the fatal 2015 explosion and fire at the BP Texas City Refinery, the CSB has investigated other incidents involving BP, including a fatal March 2001 incident at the BP Amoco Polymers plant in Augusta, Georgia and the fatal April 2010 blowout and explosion at the Macondo off-shore well in the Gulf of Mexico (where BP was the main operator/lease holder responsible for the well design). In calling on the CSB to investigate the Macondo incident, the U.S. House Committee on Energy and Commerce stated that the "CSB's past work on BP puts it in a unique position to address questions about BP's safety culture and practices." (Letter from US Representatives Henry A. Waxman and Bart Stupak to the CSB Chairman, dated June 8, 2010) [65, p. 11].

> currently exist within our operations, we should make it a priority to eliminate them [41, p. 193].

After BP Texas City, ExxonMobil sensed that “vulnerability” and concluded that there was no clear guidance available to the industry to evaluate the potential risk associated with a liquid overfill of process and storage vessels [42, p. 1].[a] Consequently, ExxonMobil developed a Liquid Overfill Risk Assessment Tool to analyze and prioritize liquid overfill risks using various probability and consequence factors. The tool included evaluating the probability of effective operator intervention. ExxonMobil analyzed approximately 500 pressure vessels and found that 30 percent required some type of mitigation to reduce risk to an acceptable level [42, pp. 8-9].

One reason that BP did not have effective safeguards in place at the BP Toledo Refinery to prevent overflowing multiple pressure vessels may be that there is a lack of good industry guidance, which will always supersede any corporate guidance or companies “forgetting” and becoming complacent again.[b]

After the BP Texas City incident, the API updated API Recommended Practice 521, *Guide for Pressure Relieving and Depressuring Systems* to ensure the guidance:

a. identifies overfilling vessels as a potential hazard for evaluation in selecting and designing pressure relief and disposal systems, and

b. addresses the need to adequately size disposal drums for credible worst-case liquid relief scenarios, based on accurate relief valve and disposal collection piping studies [43, p. 247].

The API Recommended Practice 521 guidance, however, is limited to preventing potential hazards of overfilling vessels when selecting and designing emergency-pressure relief and disposal systems. The API does not have any other guidance to prevent the potential hazards of overfilling pressure vessels.[c]

The CSB concludes that a publicly available industry publication outlining recognized and generally accepted good engineering practices to prevent the overflow of pressure vessels is needed to help drive safety improvements in chemical processing units and refineries across the United States. Had such good practice guidance been in place during the design and operation of the Coker Gas Plant, the September 20, 2022, fatal incident may have been prevented.

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[a] An attribute of a committed process safety culture is “maintaining a sense of vulnerability” [21, p. 4]. (*See* **Section 3.4**)

[b] After the 2005 raffinate splitter tower overflow incident, BP experienced another distillation tower high level incident at its Whiting, Indiana refinery. On December 13, 2005, during unit startup, a distillation tower overfilled, leading to the filling of a flare knockout drum and liquid flow into the fuel gas system, causing flames to shoot out of two furnace fire boxes. A newly installed level transmitter was found to have failed, leading to overfilling the tower while the tower outlet valve was closed. Other pressure indicators on the tower that could have provided additional information on the high-level condition were not working. The BP investigation team recommendations included installing an additional level indicator and repairing the two malfunctioning pressure indicators [31, p. 107].

[c] The API does have (1) overfill prevention guidance for storage tanks. *See* ANSI/API Standard 2350, *Overfill Prevention for Storage Tanks in Petroleum Refineries* | Fifth Edition, September 2020, Errata 1, April 2021 and (2) overfill prevention guidance for Offshore Production Platforms. *See* API Recommended Practice 14C, *Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms* | Eighth Edition, February 2017, Errata 1, May 2018.

The CSB recommends the American Petroleum Institute (API) develop a publication that addresses preventing the overflow of pressure vessels such as towers and drums. The publication should be applicable to both new and existing pressure vessels. Include the following at a minimum:

a) Description of typical overflow events that could result during normal, upset, or transient operations (startup, shutdown, standby) including the formation of a vapor cloud,
b) Recommended practices for instrumentation to monitor and detect a pressure vessel overflow,
c) Process hazard analysis guidance for pressure vessel overflow scenarios,
d) Recommended practices for safeguards to prevent a pressure vessel overflow,
e) Recommended field and board operator process safety training topics and methods to prevent a pressure vessel overflow,
f) Guidelines for process safety assessments to prevent a pressure vessel overflow, and
g) Incorporate lessons learned from this CSB investigation and the CSB's BP Texas City Refinery investigation throughout the document. (*See* Recommendation **2022-01-I-OH-6**).

5 Conclusions

5.1 Findings

Incident Progression

1. Water carryover from the Crude 1 Overhead Accumulator Drum initiated a cascade of events that caused the emergency pressure-relief valve in NHT Preheat to open.

2. Vibration from the NHT Preheat emergency pressure-relief valve chatter caused the leak in NHT Preheat.

3. Had the BP Toledo Refinery bypassed the affected heat exchangers in NHT Preheat in response to the initial leak, it might have avoided the pipe failure. The pipe failure caused an emergency shutdown of the NHT unit.

4. The NHT unit emergency shutdown necessitated bypassing the Coker Gas Plant, but the Coker Gas Plant was not fully isolated, even though its operational state was considered "in bypass." Bypassing the Coker Gas Plant left an open flow path from the Absorber Stripper Tower to the Fuel Gas Mix Drum.

5. There was only one destination available for Crude 1 Overhead flow after the NHT unit was shut down and the Coker Gas Plant was bypassed.

6. The Crude 1 Overhead Accumulator Drum level could be managed under normal conditions with only one destination available by sending it to Light Virgin Naphtha Storage, but the upset or excess flow conditions in the Crude 1 Tower in this incident exceeded the control valve capacity to Light Virgin Naphtha, meaning that the Crude 1 Overhead Accumulator Drum level could not be well controlled.

7. As a result of the NHT unit emergency shutdown, the Crude 1 Tower operation was unstable throughout the day of the incident. This was demonstrated by high Crude 1 Tower overhead pressure with Crude 1 Tower emergency pressure-relief valves opening multiple times, multiple losses of pumparound cooling, and inability to control Crude 1 Overhead Accumulator Drum level.

8. On the day of the incident, BP Toledo Refinery personnel involved in the afternoon meeting regarding Crude 1 Tower instability did not adequately communicate the guidance to safely operate the Crude 1 Tower from that meeting to the oncoming night shift personnel. This left night shift board operators to decide how to operate the tower under the given conditions. Had the BP Toledo Refinery considered this process instability that occurred throughout the day, and had there been better communications through shift change, there could have been safeguards put in place before or early in the night shift.

9. The night shift board operator removed all light crude feed from the Crude 1 Tower in an effort to reduce the overhead naphtha flow, in response to the limited destinations available for naphtha.

10. Rapidly eliminating all the light crude oil feed to the Crude 1 Tower initiated another process upset during the night of the incident. This change created a rapid increase of vapor flow up the tower and led to 1) high level in the Crude 1 Overhead Accumulator Drum, 2) loss of pumparound cooling, and 3) increased temperatures throughout the tower.

11. The board operators did not have clear instructions about how to manage Crude 1 Overhead Accumulator Drum high level. With only one destination available for naphtha, and the control valve to Light Virgin Naphtha at maximum capacity, the improvised solution by the board operators was to transfer excess Crude 1 Overhead Accumulator Drum level to the bypassed Coker Gas Plant.

12. Opening the naphtha flow control valve to the Coker Gas Plant while the bypass valves were open allowed liquid naphtha to flow into the Coker Gas Plant and then overflow into the Fuel Gas Mix Drum and proceed to furnaces and boilers.

13. The closed ROEIV on the Absorber Stripper Tower bottoms caused the overflow through the Coker Gas Plant bypass line to the Fuel Gas Mix Drum to occur more quickly than it otherwise would have, giving board operators less time to troubleshoot and respond.

14. The BP Toledo Refinery recognized the potential for furnace fires or explosions if liquid entered the fuel gas systems.

15. The two BP employees who released naphtha from the Fuel Gas Mix Drum to the ground may have believed that the material was an amine-water solution, just as other operations personnel did.

Draining and Liquid Release

16. The Fuel Gas Mix Drum drain piping did not have enough capacity to drain naphtha overflowing from the open Coker Gas Plant in a closed system to the Flare Knockout Drum.

17. Limiting or stopping the flow of naphtha to the Coker Gas Plant would have been required to prevent an overflow of the Fuel Gas Mix Drum since more naphtha could flow into the Fuel Gas Mix Drum through the Coker Gas Plant bypass than could be removed to a closed system.

Liquid Overflow Prevention

18. The Absorber Stripper Tower emergency pressure-relief valves and the refinery furnaces' safety instrumented systems would not prevent a vessel overflow event. Instead, they just protected equipment after an overflow has already occurred.

19. Had the BP Toledo Refinery recognized the likelihood of liquid overflow to the Fuel Gas Mix Drum, it could have implemented more effective preventive safeguards, such as a high level interlock to close the naphtha feed valve to the Absorber Stripper Tower. Such an interlock would have automatically stopped the identified liquid overflow events instead of relying on alarms that require human intervention, emergency pressure-relief valves, and downstream safety instrumented systems.

20. Had the BP Toledo Refinery implemented additional preventive safeguards to prevent liquid overflow from the Coker Gas Plant to the fuel gas system, the incident in September 2022 may not have happened.

21. Manually draining vessels was a common task for outside operators at the BP Toledo Refinery.

22. Had the BP Toledo Refinery 1) conducted a thorough risk assessment of the operational task of draining or addressing high level in the Fuel Gas Mix Drum, 2) provided its operators with the necessary written

instructions and consistent training, and 3) ensured the competency of operations personnel to perform the task safely, BP employees may have made different decisions on September 20, 2022.

23. Although the API Recommended Practice 556 *Instrumentation, Control, and Protective Systems for Gas Fired Heaters* provides industry guidance for alarms and protective functions to address process hazards associated with the accumulation of combustibles in gas fired heaters, API RP 556 lacks guidance to implement preventive safeguards for liquid overflow from a fuel gas mix drum which may lead to a flameout and rapid accumulation of combustibles in gas fired heaters.

24. Had industry guidance for preventive safeguards, such as safety instrumented systems and controls, been available to prevent liquid overflow from the Fuel Gas Mix Drum, and had the BP Toledo Refinery incorporated such guidance, the BP Toledo Refinery could have eliminated reliance on human intervention to drain liquid from the Fuel Gas Mix Drum.

Abnormal Situation Management

25. The BP Toledo Refinery Abnormal Situation Management policy was not effective for proactive recognition of abnormal situations. The policy narrowly defined abnormal situations such that process disturbances that occurred before the incident did not fit the policy's definition, even though the basic process control system was unable to cope with these situations.

26. On the day of the incident, the BP Toledo Refinery did not provide effective guidance for managing abnormal situations. The lack of effective guidance required operations personnel to make improvised real-time decisions. Had effective guidance been communicated to the night shift, the incident could have been avoided.

27. The BP Toledo Refinery did not effectively use previously existing industry guidance, such as that available from the ASM Consortium, to develop its ASM policy. Had the refinery done so prior to the incident, it could have had a framework to provide effective guidance to the night shift to safely operate the refinery after the NHT shutdown.

28. Had the BP Toledo Refinery more effectively used Abnormal Situation Management tools and methods, such as Predictive Hazard Identification, Process Control Systems, Policies and Administrative Procedures, Operating Procedures, Training and Drills, Learning from Previous Abnormal Situation Incidents, and Management of Change, the large number of cascading abnormal situations might have been stopped and the fatal incident could have been prevented.

Alarm Flood

29. The board operators experienced an alarm flood condition for nearly 12 hours preceding the incident, experiencing more than 3,700 alarms during the 12-hour period. Alarm flood contributed to the incident by overwhelming and distracting the board operators, causing delays and errors in responding to critical alarms. Had the night shift board operators been able to recognize the source of liquid in the fuel gas system during the alarm flood and closed the naphtha flow control valve to the Coker Gas Plant, they could have stopped liquid flow to the Fuel Gas Mix Drum, preventing or mitigating the fatal incident.

30. On September 20, 2022, the BP Toledo Refinery alarm performance was classified as "challenging," according to BP's guidance and the high extent and duration of alarm flood likely contributed to the incident by overloading the board operators, contributing to miscommunications, errors, and missed alarms.

31. On September 20, 2022, the BP Toledo Refinery alarm performance did not meet industry guidance, exceeding 10 alarms in 10 minutes for hours at a time. The high extent and duration of alarm flood contributed to the incident by overloading the board operators, contributing to miscommunication, errors, and missed alarms, ultimately leading to the fatal incident. The high alarm rate was also indicative of ongoing abnormal situations.

32. While ISA 18.2 provides guidance and a performance target for an alarm flood over a period of at least 30 days, no additional targets are provided for items such as the number of alarm floods in a month, duration of each flood, alarm count in each flood, or peak alarm rate for each flood. Had such targets been established in industry guidance, the BP Toledo Refinery could have analyzed and improved alarm flood performance following a process upset, such as that occurred in the hours preceding the incident.

33. Had the BP Toledo Refinery more fully utilized some of the available alarm flood management techniques in ISA 18.2 prior to the fatal incident, such as deadband and on-delay/off-delay, the alarm flood on the day of the incident would have been more manageable and board operators could have prevented or stopped the flow of liquid naphtha to the Fuel Gas Mix Drum.

34. The new 'Toledo Alarm Philosophy' follows ISA Standard 18.2 guidance but contains the same gap as the guidance: it does not include short-term targets for items such as number of alarm floods, duration of each flood, alarm count in each flood, or peak alarm rate for each flood. Such targets could provide the refinery with more appropriate tools to analyze and improve alarm performance in an alarm flood that lasts several hours, such as what occurred in the hours preceding the incident.

Learning from Incidents

35. The facts, conditions, and circumstances of the 2019 incident show that while operating the Coker Gas Plant with the bypass open, the BP Toledo Refinery did not have adequate safeguards to prevent overflow of naphtha from the Coker Gas Plant to the Fuel Gas Mix Drum.

36. The BP Toledo Refinery 2019 Five Whys incident investigation focused only on action items to prevent plugging in the Lean Oil Stripper overhead system, failing to learn important safety lessons from the 2019 incident. The BP Toledo Refinery did not perceive the need to issue recommendations related to overflow of naphtha through the Coker Gas Plant bypass to the Fuel Gas Mix Drum or the abnormal Fuel Gas Mix Drum

level instrument readings identified in the 2019 Initial Incident Report, which could have prevented the September 20, 2022, incident.

37. A publicly available industry publication outlining recognized and generally accepted good engineering practices to prevent the overflow of pressure vessels is needed to help drive safety improvements in chemical processing units and refineries across the United States. Had such good practice guidance been in place during the design and operation of the Coker Gas Plant, the September 20, 2022, fatal incident may have been prevented.

5.2 Cause

The CSB determined the cause of the incident was operators opening valves and removing a flange on the pressurized Fuel Gas Mix Drum to release a flammable liquid, naphtha, directly to the ground. After being released to the ground, the flammable liquid formed a vapor cloud that reached a nearby ignition source resulting in a flash fire.

Contributing to the incident were 1) the refinery's failure to implement effective preventive safeguards for the overflow of towers and vessels in various pieces of equipment which led to an over-reliance on human intervention to prevent incidents; 2) the refinery's failure to implement a shutdown or hot circulation through the use of Stop Work Authority or otherwise; 3) the refinery's ineffective policies, procedures, and practices to avoid and control abnormal situations; 4) the refinery's alarm system which flooded operators with alarms throughout the day resulting in poor decision making; and 5) the refinery's failure to learn from previous incidents.

6 Recommendations

To prevent future chemical incidents, and in the interest of driving chemical safety excellence to protect communities, workers, and the environment, the CSB makes the following safety recommendations:

6.1 Ohio Refining Company LLC

2022-01-I-OH-R1

Revise the safeguards used in the refinery's process hazard analyses high level and overflow scenarios. At a minimum, establish effective preventive safeguards that use engineered controls to prevent liquid overfill and do not rely solely on human intervention.

2022-01-I-OH-R2

Revise the Abnormal Situation Management policy to incorporate guidance provided by the ASM Consortium and the Center for Chemical Process Safety (CCPS). The revised policy should include, at a minimum:

d) A broader definition of abnormal situations, such as that defined by the CCPS,

e) Additional predictable abnormal situations and their associated corrective procedures. At a minimum include the following abnormal situations:

    4) unplanned crude slate changes,

    5) continued operation of the Crude 1 unit with the naphtha hydrotreater unit shut down, and

    6) an emergency pressure-relief valve opening.

f) Guidance to determine when an abnormal situation is becoming too difficult to manage and the appropriate actions to take, such as shutting down a process, putting it into a circulation mode, or implementing proper procedures for bringing it to a safe state.

2022-01-I-OH-R3

Develop and implement a policy or revise existing policy that clearly provides employees with the authority to stop work that is perceived to be unsafe until the employer can resolve the matter. This should include detailed procedures and regular training on how employees would exercise their stop work authority. Emphasis should be placed on exercising this authority during abnormal situations, including alarm floods.

2022-01-I-OH-R4

Revise the 'Toledo Alarm Philosophy' by incorporating the Engineering Equipment and Manufacturers Users Association (EEMUA) guidance for alarm rate following an upset and not limiting alarm performance to a single metric averaged over a month. In addition to including analyzing individual alarm flood events, the revised philosophy document should improve refinery alarm performance to reduce alarm flood duration and peak rate for events similar to the September 20, 2022, incident. Consult EEMUA Publication 191, Chapter 6.5.1, for guidance regarding abnormal condition performance levels. Apply the improved performance levels where applicable, but specifically to the Crude 1 control board alarm performance.

6.2 American Petroleum Institute (API)

2022-01-I-OH-R5

Develop a new publication or revise an existing publication, such as API Recommended Practice 556 *Instrumentation, Control, and Protective Systems for Gas Fired Heaters,* to incorporate the process hazards associated with Fuel Gas Mix Drum overflow. The publication should include the following at a minimum:

a) Description of the process hazards associated with Fuel Gas Mix Drum overflow and the consequential impacts on equipment using fuel gas,
b) Guidance for Fuel Gas Mix Drum design and sizing criteria which includes consideration of condensation, entrainment, overflow, and draining,
c) Guidance for instrumentation to detect high level to prevent overfilling of Fuel Gas Mix Drums, and
d) Recommended practices for selecting preventive safeguards to prevent overfilling of Fuel Gas Mix Drums.

2022-01-I-OH-R6

Develop a publication that addresses preventing the overflow of pressure vessels such as towers and drums. The publication should be applicable to both new and existing pressure vessels. Include the following at a minimum:

a) Description of typical overflow events that could result during normal, upset, or transient operations (startup, shutdown, standby) including the formation of a vapor cloud,
b) Recommended practices for instrumentation to monitor and detect a pressure vessel overflow,
c) Process hazard analysis guidance for pressure vessel overflow scenarios,
d) Recommended practices for safeguards to prevent a pressure vessel overflow,
e) Recommended field and board operator process safety training topics and methods to prevent a pressure vessel overflow,
f) Guidelines for process safety assessments to prevent a pressure vessel overflow, and
g) Incorporate lessons learned from this CSB investigation and the CSB's BP Texas City Refinery investigation throughout the document.

6.3 International Society of Automation (ISA)

2022-01-I-OH-R7

Revise American National Standard ANSI/ISA 18.2-2016, *Management of Alarm Systems for the Process Industries*, to include performance targets for short-term alarm flood analysis so that users can evaluate alarm flood performance for a single alarm flood event. The performance targets should include:

a) number of alarm floods,

b) duration of each flood,

c) alarm count in each flood, and

d) peak alarm rate for each flood.

At a minimum, a target peak alarm flood rate should be defined, such as in the guidance provided by the ASM Consortium or Engineering Equipment and Materials Users Association (EEMUA), to establish trigger points that require alarm performance improvement actions.

7 Key Lessons for the Industry

To prevent future chemical incidents, and in the interest of driving chemical safety excellence to protect communities, workers, and the environment, the CSB urges companies to review these key lessons:

Stop Work Authority

1. Companies must ensure (through training, clearly written procedures, and other means) that employees not only are clearly empowered to exercise Stop Work Authority, but that employees also clearly understand they are expected to do so. However, companies should not rely on Stop Work Authority programs alone to prevent a catastrophic process incident since they require humans to take action to shut down a job or a process. Stop Work Authority is not a substitute for effective process safety management systems.

Liquid Overflow Prevention

2. PHA scenarios should consider both preventive and mitigative safeguards and not unrealistically rely on human intervention.

3. PHAs should evaluate overfill hazards and consider scenarios in which a vessel may not overfill to the top but may instead overflow or backflow though other piping connections.

4. Companies should evaluate their PHAs for opportunities to implement additional safeguards to prevent initiating events that reduce the reliance on human intervention.

Abnormal Situation Management

5. Companies should define operating limits beyond which Abnormal Situation Management procedures should be followed and clearly define those corrective actions to be followed, in order to stop a chain of abnormal events.

6. "Abnormal situations introduce stress, and operators under stress can make poor decisions, which then exacerbate the situation. How companies prepare and equip their operators to deal with these problematic and stressful situations is critical to ensuring the return of the unit to a safe state. Often, process safety incidents are a result of organizations failing in this area." — CCPS, *Guidelines for Managing Abnormal Situations* [1, p. 24].

7. Thinking through abnormal situations *before* they occur, having plans in place, and practicing those plans can greatly improve operator and manager confidence and decision-making during an abnormal situation. Simulators, desktop drills, incident reviews, or field walkthroughs can improve abnormal situation management skills.

8. Managing abnormal situations goes beyond PSM compliance alone. PSM tools can be used, but for abnormal situations, the tools must be applied with abnormal situations specifically in mind, particularly cascading abnormal situations.

Alarm Flood

9. Companies should ensure alarms are well justified. While DCS technology allows alarms to be created easily, it also can cause board operators to be inundated with low priority or irrelevant information during an abnormal situation if alarms are not properly designed. This also places additional stress on board operators, reducing their effectiveness when it is needed most.

Learning from Incidents

10. Accident investigation techniques, such as *Five Whys*, suggest that there is only one root cause and one linear path to an accident [24, p. 291]. Using such approaches for process safety incidents, even if recommended in company safety procedures, can lead an investigation team to a superficial analysis that does not prevent an accident from recurring.

11. Organizations should develop systems to ensure that learnings from internal and external incidents are incorporated throughout the organization to prevent recurring failures, such as overflow of process vessels, that can lead to a catastrophic incident.

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Appendix A: Timelines[a]

A.1 Naphtha Hydrotreater Release

A.1.1 2018

A.1.1.1 February 16, 2018

A pipe failure occurred at a process unit at BP's Whiting Refinery located in Indiana. The failure occurred on a branch fitting that connected an emergency pressure-relief valve inlet line with the main process, in liquid service, running between two heat exchangers (*See* **Figure A1-1**).[b] The emergency pressure-relief valve experienced instability (e.g., chattering, cycling, and/or fluttering) during relief demands. The failure resulted in the release of flammable hydrocarbons. The unit was shut down and de-pressured to enable the leak to be isolated. There were no injuries or damage to other equipment.

Figure A1-1. Failed branch fitting from the BP Whiting Refinery. (Credit: BP)

[a] Various sources of information were relied upon to construct this incident timeline. These sources include control system information, radio logs and event logs. All times are approximate to actual time vs. source time.

[b] This report uses the term "emergency pressure-relief valve"; however, the terms *pressure relief valve*, *safety relief valve*, *pressure safety valve (PSV)*, *relief valve,* or *safety valve* can be used interchangeably. For a specific application, however, readers should know that these other names can reflect different operating characteristics and using precise terminology for a specific application may be appropriate.

A.1.1.2 September 6, 2018

BP's Safety and Operational Risk group issued a High Value Learning entitled "Effect of excessive forces on mechanical integrity of relief systems subject to pulsation" to all BP downstream refineries and petrochemical plants to share key findings of the investigation of the February 16, 2018, Whiting refinery incident. The key findings include:

- The system as designed led to frequent excursions above 90 percent of emergency pressure-relief valve set pressure and numerous relief valve demands.
- The emergency pressure-relief valve experienced instability (e.g., chattering, cycling, and/or fluttering) during relief demands.
- During the incident, the emergency pressure-relief valve was relieving the full liquid flow due to a blocked-in pump, creating large reaction forces/stresses due to fluid momentum while cycling (opening and closing).

Other downstream refineries were given action items to identify the emergency pressure-relief valves covered by the High Value Learning and develop a mitigation plan. A screening process was prescribed with the objective of identifying emergency pressure-relief valves in pumped liquid service that had the potential for failure due to dynamic loading from instability during a relief event. For these emergency pressure-relief valves, further integrity assessment requirements and appropriate mitigations were specified. Each refinery also had an action item intended to help identify and avoid the design of future installations for this failure scenario.

A.1.2 2019

A.1.2.1 NOVEMBER 2, 2019

A reduction in the feed rate to the NHT unit at the BP Toledo Refinery resulted in a temperature rise exceeding the maximum allowable working temperature (MAWT) of two heat exchangers, HE-6 and HE-7,[a] in NHT Preheat[b] (*See* **Figure A1-2**). The temperature excursions lasted approximately four hours.

Over the previous four years, the exchanger HE-7 had multiple temperature excursions above the MAWT.[c]

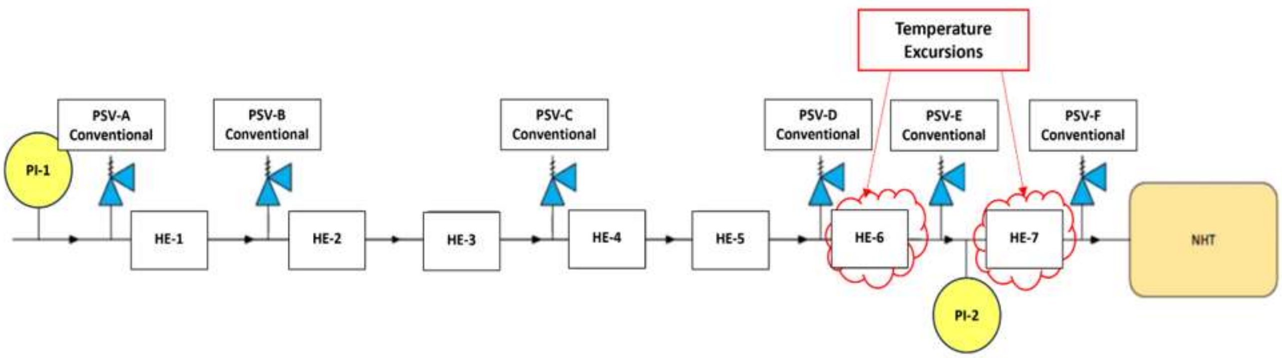

Figure A1-2. Heat exchangers that experienced temperature excursions. (Credit: BP with annotations by CSB)[d]

A.1.2.2 NOVEMBER 8, 2019

A fitness for service[e] evaluation was performed on the two NHT preheat exchangers that experienced temperature excursions on November 8, 2019. The fitness for service evaluation determined that the equipment was not damaged by the previous temperature excursions, even though exchangers 6 and 7 exceeded their MAWT by 29 °F and 34 °F, respectively.

[a] The shell side design conditions for HE-6 were 680 psig at 532 °F. The shell side operating conditions during the upset were 540 psig at 561 °F. The shell side design conditions for HE-7 were 680 psig at 550 °F. The shell side operating conditions during the upset were 540 psig at 584 °F.

[b] "NHT Preheat" is used in this report to describe a series of seven shell and tube heat exchangers used to heat naphtha from the Crude 1 unit prior to entering the NHT unit for processing.

[c] If the MAWT was 580 °F, all but five temperature excursions would have been eliminated and if the MAWT was 610 °F all but one temperature excursion would have been eliminated.

[d] In the NHT Preheat diagram, emergency pressure-relief valves are represented with PSV, heat exchangers with HE, and pressure transmitters with PI.

[e] Fitness for service is a best practice and standard (API RP 579-1/ASME FFS-1) used by the oil & gas and chemical process industries for in-service equipment to determine its fitness for continued service.

A.1.3 2021

A.1.3.1 MAY 2021

BP identified piping issues while reviewing the scope of work around PSV-E, which protected the shell side of the HE-6 and associated piping (*See* **Figure A1-2**). The set pressure of PSV-E was higher than the existing piping components' maximum design pressure.

The PSV-E emergency pressure-relief valve set pressure was 680 psig, while the piping design pressure was 635 psig at 550 °F. To achieve a pressure of 680 psig for the existing piping the design temperature would have to be lowered to 463 °F. This was not feasible due to the average inlet operating temperature of 491°F.

BP identified that the operating pressure was too close to the 680 psig emergency pressure-relief valve setpoints of PSV-D and PSV-E since the operating pressure at times would be above 600 psig. For example, the operating pressure margin for the shell side outlet was 91.2 percent (in this instance, an operating pressure of 620 psig) of the PSV-E set pressure.[a] The emergency pressure-relief valve manufacturer recommends the margin should be below 90 percent (in this instance, 612 psig) to "minimize leakage and spurious opening" of the conventional emergency pressure-relief valves.

BP determined that re-rating[b] the piping was not feasible during the 2022 turnaround (TAR) because the schedule was set and material would not be available. Instead, the project team identified a different option to replace PSV-D and PSV-E with soft seat emergency pressure-relief valves.

A MOC is approved to add a block valve and bleed valve on both the inlet and outlet of the PSV-E to be installed off the outlet of HE-6.

A.1.3.2 JUNE 2021

A project was submitted on June 8, 2021, to address fitness for service of HE-6 and HE-7 that had previously experienced temperature excursions above the MAWT. The project scope is to rerate the HE-6 shell to 630 °F and add a backing ring, and to replace HE-7 with a shell rated at 750 °F.

[a] The operating margin is the difference between the set pressure and the maximum operating pressure. The required operating margin depends on the type of relief device and the pressure control capability of the process [50, p. 69].

[b] An inherently safer design approach of re-rating the piping components to a higher temperature and pressure is a robust and reliable method of containment [72].

A.1.3.3 July 2021

A project was approved to add a second block valve and bleed valve on the inlet and outlet of conventional emergency pressure-relief valve PSV-B.[a] The project was included in the 2022 TAR scope.

A.1.3.4 August 2021

A project was approved to modify PSV-B by replacing the 2.5-inch conventional emergency pressure-relief valve with a larger three-inch conventional emergency pressure-relief valve, and to lower the set point from 681 to 675 psig. This project was included in the 2022 TAR scope.

On August 20, 2021, a scope of work for the 2022 TAR was issued to develop a MOC to eliminate threaded piping connections on the Crude 1 Overhead Accumulator Drum in order to comply with “BP’s Safety Requirements for LPG [Liquefied Petroleum Gas] Processing, Storage & Handling”. The project included replacing the existing threaded level instrument with a new flanged guided wave radar level instrument to measure the water level in the Crude 1 Overhead Accumulator Drum.

On August 21, 2021, BP determined that a “checklist style Risk Evaluation” was appropriate for the MOC for this project. Physical equipment changes such as the piping thread elimination were included in the MOC checklist risk evaluation. Changes to the way the level of water in the Crude 1 Overhead Accumulator Drum will be reported to the operators (as a result of the new guided wave radar level instrument) were not included in the MOC checklist risk evaluation.

A.1.3.5 November 2021

On November 16, 2021, BP approved a project scope to change PSV-D and PSV-E to a pilot-operated emergency pressure-relief valve[b] and lower their setpoints to 635 psig to protect the heat exchangers’ piping.

The project scope stated: “The final resolution of this problem will require the replacement/upgrading of the existing NHT Feed piping system from [class][c] 300 […] flanges to [class] 600 […] flanges (approximately 600 [linear feet] of 8” piping). If needed, the next opportunity for this will be during the 2027 TIU TAR by a separate capital project.”

[a] A conventional emergency pressure-relief valve is a direct spring-loaded emergency pressure-relief valve that is held closed by a spring force that can be adjusted within a certain range and whose operational characteristics are directly affected by changes in the backpressure which is exercised at the outlet of the valve [53, p. 30].

[b] PSV-D and PSV-E were changed from conventional emergency pressure-relief valves to pilot-operated emergency pressure-relief valves “in order to allow the operating pressure to be within 98 percent of the new PSV setpoint (635 psig).” A pilot-operated emergency pressure-relief valve has the inherent ability to maintain premium tightness close to the set pressure, allowing a higher normal system-operating pressure than with a conventional emergency pressure-relief valve [53, p. 112].

[c] The pressure rating of a flange ranges from 150# to 2500#. The term "lb," "class," and "#" are used interchangeably to designate the pressure rating of the flange. The fact is that 150 “lb” has no relation to 150 pounds per square inch (psi) and so 300 or 600 “lb” does not correlate to a 300 or 600 psi pressure rating. Pressure rating of the flange depends on the material, the heat treat condition and pressure "class." The term "class" is used here to not confuse the designation with pressure "rating" [51].

A.1.3.6 DECEMBER 2021

A PHA was completed for the NHT unit. Previous PHAs were conducted on this unit in March 2017 and April 2012.

A.1.4 2022

A.1.4.1 APRIL 2022

The 2022 TAR began on April 20, 2022, with the Crude 1 unit and the NHT unit shutting down.

Figure A1-3 shows the 2022 TAR work to NHT Preheat which made modifications to heat exchanger HE-6, replaced heat exchanger HE-7, replaced emergency pressure-relief valves PSV-D and PSV-E, and modified PSV-B.

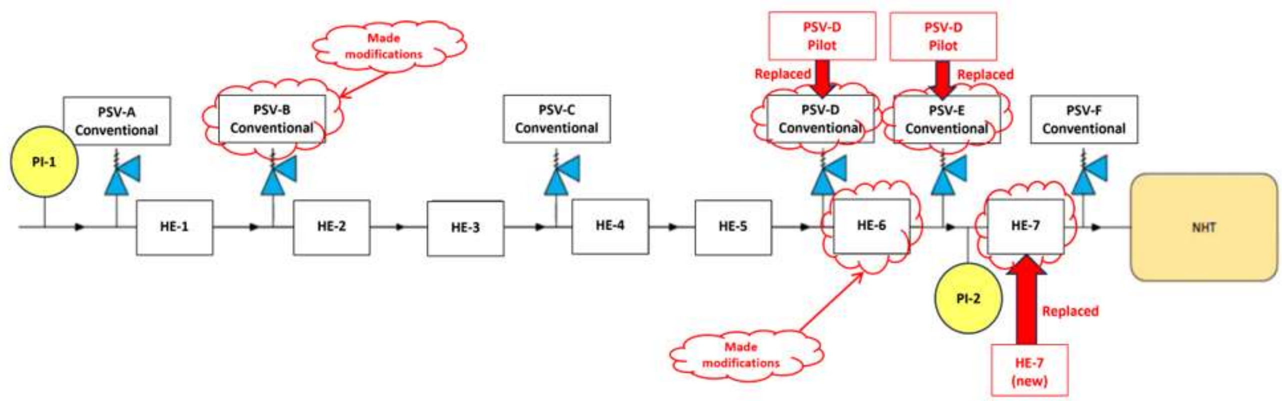

Figure A1-3. NHT Preheat changes made during 2022 TAR. (Credit: BP with annotations by CSB)

A.1.4.2 JULY 26, 2022

The 2022 TAR ended and the modified NHT Preheat started back up.

A.1.4.3 JULY 28, 2022

The Crude 1 unit started up.

A.1.4.4 AUGUST 27, 2022

PSV-D opened to the flare. Operators blocked in this emergency pressure-relief valve, allowed it to cool, and then returned it to service.[a] The BP Toledo Refinery incident report description states: "PSV lifted while stable operations were below lift set pressure."[b]

[a] PSV-D was replaced during the 2022 TAR (*See* **Section A.1.4.1**).

[b] Lift is the actual travel away from the closed position when an emergency pressure-relief valve is relieving [53, p. 32].

A.1.4.5 SEPTEMBER 19, 2022

A.1.4.5.1 7:11 P.M.

Board Operator adjusted the position of a control valve operating in manual and regulating the water leaving the Crude 1 Overhead Accumulator Drum from 54 percent open to 36 percent open.

A.1.4.5.2 10:40 P.M.

High level alarm for water in the Crude 1 Overhead Accumulator Drum sounded at 60 percent and acknowledged by the board operator.

A.1.4.5.3 11:45 P.M.

The water level in the Crude 1 Overhead Accumulator Drum continued to increase and reached the top of the internal naphtha standpipe,[a] resulting in water overflowing into the Crude 1 Overhead Accumulator Drum's naphtha stream and flowing to the naphtha preheat train early the next morning.

A.1.4.6 SEPTEMBER 20, 2022 (DAY OF INCIDENT)

A.1.4.6.1 2:12 A.M.

Naphtha and water from the Crude 1 Overhead Accumulator Drum flowed to the Coker Gas Plant Absorber Stripper Tower resulting in water collecting in the Coker Gas Plant Absorber Stripper Tower Foul Condensate Draw Off Drum (*See* **Figure 6**).[b] Once full, the Foul Condensate Draw Off Drum began to backflow and returned water back to the Absorber Stripper Tower.

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[a] The indicated liquid level from the new guided wave radar instrument plateaued at 69 percent level, and water overflowed into the standpipe, whereas before changes made during the recent 2022 TAR, water did not overflow into the standpipe until the level indicated 100 percent level. (*See* **Section A.1.3.4**.)

[b] The Coker Gas Plant Absorber Stripper Tower Foul Condensate Draw Off Drum is shown in **Figure 6**.

A.1.4.6.2 2:45 TO 3:00 A.M.

Increasing amounts of water in the Absorber Stripper Tower caused the reboiler exit temperature to drop, decreasing the vapor flow up the Absorber Stripper Tower. The lower vapor flow allowed the liquid on the Absorber Stripper Tower trays to de-inventory and increased the bottoms level, which in turn increased the liquid level in the NHT Feed Surge Drum. The level increase in the NHT Feed Surge Drum level resulted in a flow surge to NHT Preheat.

A.1.4.6.3 APPROXIMATELY 3:20 A.M.

PSV-D opened.

A.1.4.6.4 APPROXIMATELY 4:00 A.M.

The shift supervisor created an incident report of PSV-D opening in the BP Toledo Refinery incident report database.[a] The report states "Operating pressure of the NHT feed system was allowed to get up to about 621 psig. The [PSV-D] set pressure is 635 [psig]."

A.1.4.6.5 APPROXIMATELY 4:30 A.M. TO 5:00 A.M.

Shift change occurred.

A.1.4.6.6 APPROXIMATELY 6:01 A.M.

Outside operators began manually draining the water from the Crude 1 Overhead Accumulator Drum to the Oily Water Sewer.

A.1.4.6.7 6:26 A.M.

PSV-D opened again.[b]

A.1.4.6.8 6:33 A.M. TO 6:57 A.M.

Feed rate to NHT Preheat was increased from approximately 7,900 barrels per day to about 13,200 barrels per day, and the feed pressure increased from approximately 570 psig to 684 psig (*See* PI-1in **Figure A1-3**).

PSV-B was set to provide emergency pressure-relief at 675 psig.

A.1.4.6.9 6:50 A.M. TO 6:59 A.M.

BP's control system event log recorded an alarm flood state greater than 10 alarms for every 10-minute period between 6:50 a.m. and 6:49 p.m. except for five alarms from 7:20-7:29 a.m., 10 alarms from 2:00-2:09 p.m., 10 alarms from 2:10-2:19 p.m., and three alarms from 4:20-4:29 p.m. Between 6:50 a.m. and 6:49 p.m. a total of 3,712 alarms were recorded.

[a] PSV-D had lifted previously on August 27, 2022 (*See* **A.1.4.4**) and had been replaced during the 2022 TAR (*See* **A.1.4.1**).

[b] This was the second lifting of PSV-D that morning. The earlier lifting (*See* **A.1.4.6.3**) occurred at approximately 3:20 a.m.

A.1.4.6.10 6:57 A.M. TO 7:12 A.M.

The pressure of the fluid being sent to NHT Preheat began to cycle between 660 and 675 psig, likely the result of PSV-B, opening and closing.

A.1.4.6.11 APPROXIMATELY 7:13 A.M. TO 7:28 A.M.

Outside operators radioed that an emergency pressure-relief valve was opening.

Outside operators observed PSV-B opening and chattering.[a] They attempted to manually reseat PSV-B, but it continued to open and close. Outside operators described the emergency pressure-relief valve opening as “incredibly bad” and “extremely loud” consistent with chattering.

A.1.4.6.12 7:31 A.M.

The flow rate to NHT Preheat reached 21,000 barrels per day.

A.1.4.6.13 APPROXIMATELY 7:38 A.M.

PSV-D was manually re-seated by the outside operators and stopped opening.

A.1.4.6.14 APPROXIMATELY 7:45 A.M.

An outside operator charged a fire monitor in preparation to quickly respond in case of an incident, as a result of the issues they were experiencing.[b]

A.1.4.6.15 APPROXIMATELY 7:54 A.M.

Outside operator found a leak on the ¾-inch bleed valve located at the low point on the tube side inlet for HE-2 as shown in **Figure A1-4**. PSV-B continued to chatter.

Outside operator started water flow from the previously charged fire monitor.

[a] Chattering “is the rapid opening and closing of a pressure-relief valve. The resulting vibration may cause misalignment, valve seat damage, and, if prolonged, mechanical failure of valve internals and associated piping” [48].

[b] Fire monitors are devices used for manual firefighting or in automatic fire protection systems to “discharge large volumes of water and have good straight stream range. Discharge can be controlled by the type and size of adjustable nozzle or diameter of straight stream nozzle” [62, p. 369]. The process of “charging” a fire monitor involves filling piping from a nearby water source and placing it under pressure so that the water can be directed, through a nozzle, toward the fire site when needed.

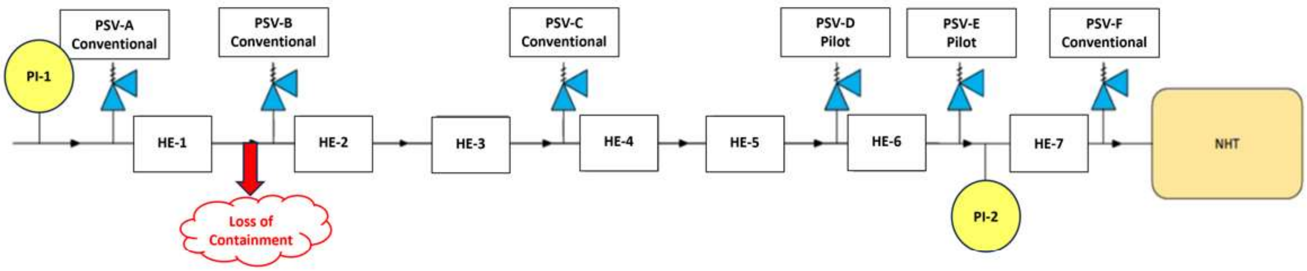

Figure A1-4. Location of loss of containment. (Credit: BP with annotations by CSB)

A.1.4.6.16 APPROXIMATELY 8:00 A.M.

Additional personnel were sent to NHT Preheat to troubleshoot and help.

Operations requested the ERT to be on standby due to the emergency pressure-relief valve chattering.

A.1.4.6.17 8:06 A.M.

Shift superintendent made a radio call stating, "we're going to have to shut the gas plant [Sat Gas Plant] down … unless we can get all the feed out of it" in order to by-pass the piping section that was leaking.

A.1.4.6.18 8:08 A.M.

The feed rate to the NHT unit was 16,200 barrels per day.

A.1.4.6.19 8:12 A.M.

Outside operators reported a significant loss of containment when the ¾-inch bleed valve severed from the piping near the PSV-B inlet (*See* **Figure A1-5**).

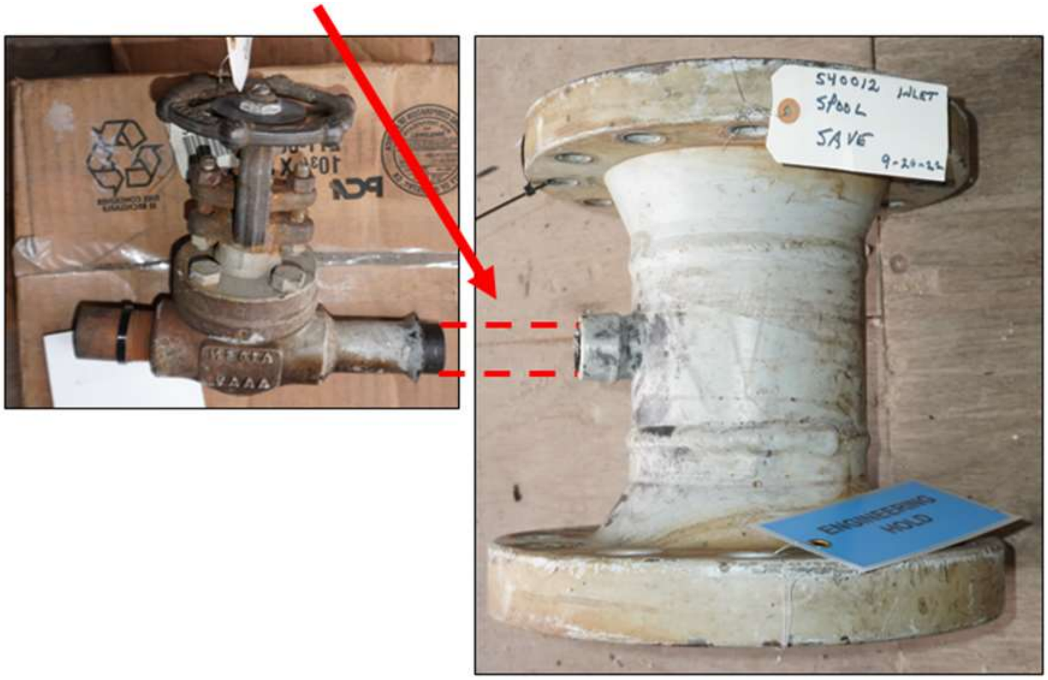

Figure A1-5. Failed ¾-inch branch fitting from the BP Toledo Refinery. (Credit: CSB)

A.1.4.6.20 8:13 A.M.

Outside operations called on radio requesting an emergency shutdown and ERT assistance. The ERT arrived shortly after requested and remained available to respond.

A.1.4.6.21 8:15 A.M. TO 9:30 A.M.

At approximately 8:15 a.m., the NHT shutdown was initiated by shutting fuel gas to the NHT feed furnace, and at approximately 8:17 a.m., the NHT unit started to be de-pressured to the flare. By approximately 9:30 a.m., the feed to the NHT unit had stopped.

A.1.4.6.22 10:27 A.M.

The ERT was released from the unit.

A.1.4.6.23 11:00 A.M.

The final entry for the Incident Activity Log states: "Radio All Call—Muster All Clear no work in process block."

A.2 Fuel Gas Mix Drum Release

A.2.1 2007

The Report of the BP U.S. Refineries Independent Safety Review Panel ("the Baker Panel Report") was issued in 2007. The Baker Panel Report indicated that significant portions of the Toledo workforce did not believe that process safety was a core value and found BP had a weak process safety culture at Toledo. Specifically, the report stated: "At Toledo, higher levels of management typically stated that decisions regarding production and cost savings did not override process safety concerns, but that belief tended to change in the middle and lower ranks of the Toledo organization. Many lower and middle managers interviewed expressed skepticism about whether process safety concerns came first. Toledo hourly workers interviewed widely believed that production was a higher priority than process safety" [2, pp. 61-62]. The report also stated: "Toledo has a weak safety culture, largely because of chronic morale problems and a history of poor relations between refinery management and the unionized workforce" [2, p. 118].

A.2.2 2011

Figure A2-1 shows how high liquid level in the Crude 1 Overhead Accumulator Drum from process upsets is routed to the Flare Knockout Drum after the Fluid Catalytic Cracker (FCC) unit wet gas compressor is isolated from the Crude 1 Overhead Accumulator Drum overhead flow.

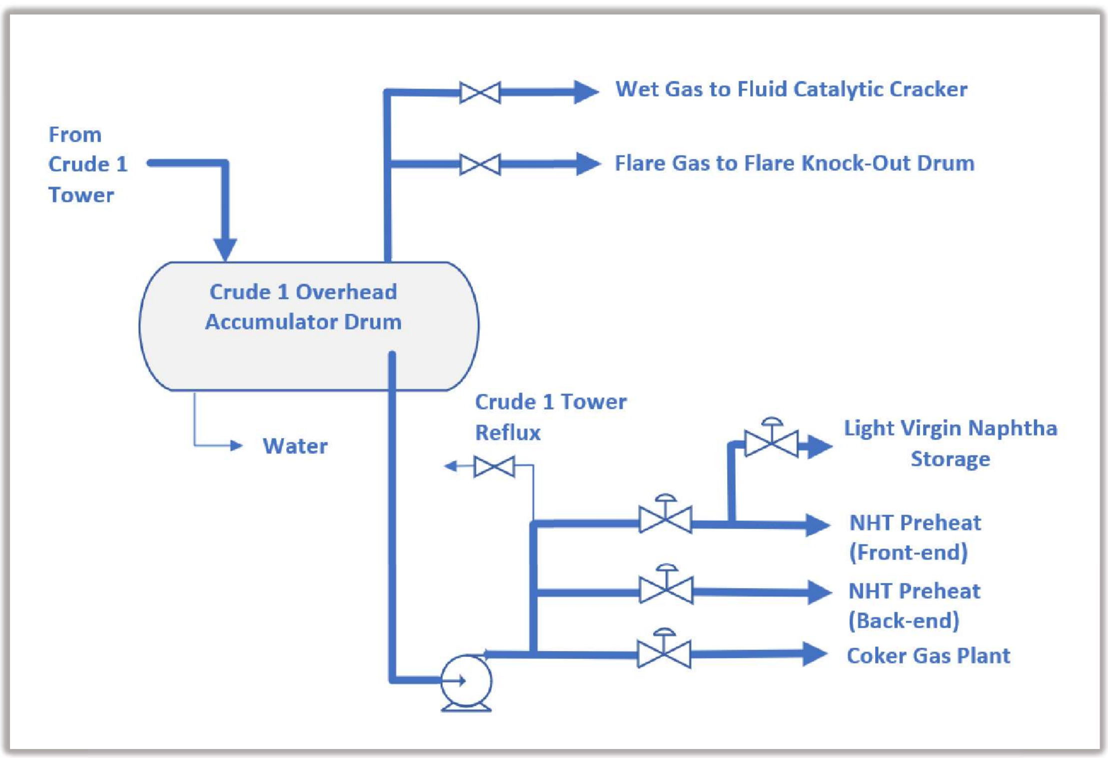

Figure A2-1. Crude 1 Overhead Accumulator Drum prior to the installation of the Coker Gas Plant. This simplified schematic shows how high level of liquid in the Crude 1 Overhead Accumulator Drum liquid can overflow to the Flare Knockout Drum. (Credit: CSB)

A.2.3 2015

A.2.3.1 May 2015

A Relief & Overpressure Inherently Safer Design Principles Toledo Fuels Optimization (TFO) Sulfur Reduction project specific document that outlines the fundamental overpressure scenarios and develops an inherently safer design approach to a relief and overpressure protection design for the TFO Sulfur Reduction project was issued for design. A Basic Process Control System (BPCS) was determined not to be needed for liquid overfill of the Coker Gas Plant Absorber Stripper Tower even though hydrocarbon would flow into the Fuel Gas System.

A.2.3.2 June 2015

A project design PHA was completed for the new Coker Gas Plant.

A.2.4 2016

A.2.4.1 January 2016

BP committed the capital to build the Coker Gas Plant.

A.2.4.2 June 2016

The Fuel Gas Mix Drum was replaced.[a] The new Fuel Gas Mix Drum is approximately the same size as the previous Fuel Gas Mix Drum with a Maximum Allowable Working Pressure (MAWP) of 150 psig and an emergency pressure-relief valve set pressure of 90 psig. The emergency pressure-relief valve was "installed to adequately relieve any overpressure scenario that will be appliable from [the Coker Gas Plant]."

A.2.4.3 September 2016

During the September 2016 Coker Gas Plant LOPA, a decision was made to delete the following safeguard: "the DCS to command FV3816 to close, based on a high level in the CGP Absorber Stripper using independent transmitter." An identified consequence for the deviation of high level is a "higher level resulting in potential overfill, overpressure, damage, leak, H2S exposure, fire, injury/fatalities."

A.2.5 2018

A.2.5.1 February 2018

The 2015 Coker Gas Plant project PHA was updated to include changes in design since the previous review. The BP PHA team met the regulatory requirements of 29 C.F.R. § 1910.119(e)(4). There was no process operator in attendance.

[a] The prior Fuel Gas Mix Drum had an MAWP of 64 psig and an emergency pressure-relief valve set pressure of 60 psig. Multiple over pressure scenarios had been identified and the prior fuel gas mix drum could no longer be equipped with an emergency pressure-relief valve to provide adequate relief.

A.2.5.2 APPROXIMATELY SEPTEMBER 2018

Training for operations was conducted before the Coker Gas Plant started up. Training consisted of one day of classroom training, pairs of operators being assigned specific activities to perform on their own to familiarize themselves with the new Coker Gas Plant, and qualification by their supervisor. Operators were able to observe construction activities.

A.2.5.3 OCTOBER 2018

An Operational Readiness Review (ORR) for the Coker Gas Plant was completed, and then the unit started up and was brought online soon afterward on October 22.

A.2.6 2019

A.2.6.1 MARCH 2019

A PHA revalidation was completed for Crude 1, which included the Fuel Gas Mix Drum. The previous PHA for Crude 1 was performed in March 2014.

A.2.6.2 MAY 2019

A six-inch butterfly control valve replaced a six-inch manual gate valve in the Coker Gas Plant bypass line. The control valve controls the Coker Gas Plant Polishing Amine Contactor differential pressure by bypassing coker wet gas around the Coker Gas Plant. The Coker Gas Plant Polishing Amine Contactor had seen foaming, the onset of jet flooding, and amine carryover at differential pressure greater than eight pounds per square inch.

A.2.6.3 NOVEMBER 2019

On November 13, 2019, a boiler trip occurred during a cold front which resulted in a refinery-wide loss of steam and the Coker Gas Plant being bypassed. A high level occurs in the Crude 1 Overhead Accumulator Drum when the only pump to remove liquid from the drum available at the time was a steam-driven pump whose performance was compromised by the loss of steam.

To lower the level in the Crude 1 Overhead Accumulator Drum the naphtha flow control valve to the Coker Gas Plant was manually opened to 80–100 percent range. Liquid flowed through the Coker Gas Plant but was blocked when high pressure developed due to the Lean Oil Stripper overhead system getting too cold and forming a hydrate.

Using a Five Whys investigation methodology, the investigation team determined that "naphtha carried over through the [Coker Gas Plant] unit bypass a filled up the KO drum and the [Fuel Gas Mix Drum]."[a] The Fuel Gas Mix Drum's liquid level indication reached 100 percent on the guided wave radar level instrument, and the

[a] When investigating unsafe acts or resulting incidents, companies will often use root-cause analysis aiming, to focus their attention on fixing whatever is determined to be the singular root cause of the unsafe act or incident. Top industry choices for investigation techniques are cause-and-effect models, such as fishbone diagrams and Five Whys methods. Cause-and-effect models that only seek a single root cause can be problematic. While the intent is positive and admirable, this approach often fails to recognize that human decision-making is complex and diverse [60, p. 25].

differential pressure (dP) liquid level instrument indication rose and flatlined at 65 percent. Outside operators manually drained the Fuel Gas Mix Drum to the Flare Knockout Drum and Oily Water Sewer. The naphtha flow to the Coker Gas Plant was stopped, and the Fuel Gas Mix Drum was eventually emptied of liquid naphtha.

Recommendations were made to prevent low temperature on the Lean Oil Stripper overhead system.

A.2.7 2020

A.2.7.1 February 2020

A PHA revalidation was completed for the Coker Gas Plant. The PHA included a review of prior Coker Gas Plant incidents. The PHA team did not review the November 2019 incident of naphtha overflow through the Coker Gas Plant bypass directly to the Fuel Gas Mix Drum since the Fuel Gas Mix Drum is part of the Crude 1 PHA (*See* **A.2.6.3**).

A.2.8 2021

A.2.8.1 June 2021

A new trainer was assigned to the Crude 1 unit. The trainer had previous experience as an operator, supervisor, and refinery coordinator[a] but had never worked as an outside operator in the Crude 1 unit.

A.2.8.2 August 19, 2021

The guided wave radar level indicator on the Fuel Gas Mix Drum stopped reporting readings to the refinery's computerized process data historian.[b] The Fuel Gas Mix Drum guided wave radar level indicator continued to read the actual measured level in the control room DCS.

A.2.9 2022

A.2.9.1 April 20, 2022

The 2022 TAR began with the Crude 1 and the NHT units shutting down.

A.2.9.2 July 2022

The 2022 TAR ended and the modified NHT Preheat train (as described in **Appendix A.1**) started up on July 26, 2022.

Crude 1 started up on July 28, 2022.

[a] A refinery coordinator is required to be qualified on all board operator jobs, including the Crude 1 unit. Additional detail on the refinery coordinator role can be found in **Section 1.9**.

[b] The configuration for recording the history of this process variable was not restored until after the incident.

A.2.9.3 AUGUST 2022

Operational issues resulted in losing all three pumparounds on the Crude 1 Tower (about one or two weeks after starting up) after a furnace tripped. Crude 1 Tower overhead fin fans were cleaned.

A.2.9.4 SEPTEMBER 20, 2022 (DAY OF INCIDENT)

A.2.9.4.1 3:11 A.M.

The level in Crude 1 Tower Overhead Accumulator Drum began to increase from 55 percent and reached 73 percent by 4:30 a.m.[a]

A.2.9.4.2 7:26 A.M.

The control valve in the Coker Gas Plant bypass line was placed in manual mode and began to be opened by the board operator (*See* **A.2.6.2**).

A.2.9.4.3 8:09 A.M.

The control valve in the Coker Gas Plant bypass line reached 100 percent open, where it remained.

A.2.9.4.4 8:12 A.M.

The differential pressure level indicator on the Fuel Gas Mix Drum began increasing (starting at a reported level of zero percent full) and reached a maximum level of 23 percent at approximately 8:18 a.m.

Crude 1 naphtha flow control valve to the NHT unit was closed, indicating the start of the NHT unit shutdown.

A.2.9.4.5 8:42 A.M.

Board operator began to close the naphtha flow control valve to the Coker Gas Plant.

A.2.9.4.6 9:17 A.M.

The Crude 1 Overhead Accumulator Drum naphtha flow to the Coker Gas Plant stopped, after the naphtha flow control valve to the Coker Gas Plant was fully closed.

A.2.9.4.7 9:47 A.M.

The differential pressure level indicator on the Fuel Gas Mix Drum read zero percent.

A.2.9.4.8 10:20 A.M.

The Crude 1 Tower overhead pressure exceeded the lowest emergency pressure-relief valve set pressure (38 psig) for the first time. The overhead pressure exceeded 38 psig 11 times altogether on day shift, with the last

[a] The level fluctuated throughout the day shift with levels varying between 6.9 percent and 87.8 percent.

overpressure occurring at approximately 4:15 p.m. The Crude 1 Tower overhead line includes five emergency pressure-relief valves, with staggered set pressures between 38 and 40 psig.

A.2.9.4.9 1:26 P.M.

The outside operator was directed to close the Coker Gas Plant Absorber Stripper Tower bottoms outlet ROEIV.[a,b]

A.2.9.4.10 1:30 P.M.

The Coker Gas Plant Absorber Stripper Tower bottoms outlet ROEIV was closed by the outside operator.

A.2.9.4.11 1:37 P.M.

The two-inch flow control valve from the Crude 1 Overhead Accumulator Drum to the Light Virgin Naphtha Storage was fully opened and remained fully opened until 7:04 p.m. A four-inch manual bypass valve around the two-inch flow control valve remained closed.[c]

The flow meter from the Crude 1 Overhead Accumulator Drum to the Light Virgin Naphtha Storage reached the instrument top of range of 10,000 barrels per day and remained there until 2:01 p.m. At 2:23 p.m., the flow meter returned to the instrument top of range of 10,000 barrels per day and remained there until 3:32 p.m.

A.2.9.4.12 3:58 P.M.

The Crude 1 Tower Overhead pressure exceeded the emergency pressure-relief valve set pressure for the last time on day shift. The pressure remained above the emergency pressure-relief valve set pressure until 4:17 p.m.

A.2.9.4.13 APPROXIMATELY 4:15 P.M.

Approximate time the shift change period started for turnover from day shift to shift personnel. Crude 1 night shift personnel arrived anywhere from 4:14 p.m. to 4:49 p.m.

A.2.9.4.14 4:56 P.M.

The light crude oil flow to Crude 1 was reduced from 26,000 barrels per day, eventually reaching a flow of 0 barrels per day by 5:11 p.m. Even though the light crude oil flow feeding Crude 1 went to zero, the pump remained turned on.

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[a] In recent reports, the CSB has referred to equipment needing to isolate a flammable or toxic release from a safe (remote) location as a remotely operated emergency isolation valve (ROEIV). Other industry standards, good practice guidance, or earlier CSB reports have described similar isolation equipment using different names, including emergency block valve (EBV), emergency isolation valve (EIV), remotely operated block valve (RBV), emergency shutdown valve (ESDV), or a remotely operated shutoff valve (ROSOV).

[b] While a ROEIV will not prevent a loss of containment event, proper application of remote isolation equipment could mitigate the severity of a hazardous chemical release [61].

[c] The four-inch manual bypass valve had a sticker on it that read “Open with Caution.”

A.2.9.4.15 5:39 P.M.

DCS high level alarm at 68 percent and high-high level alarm at 70 percent for the Crude 1 Overhead Accumulator Drum sounded and was displayed on the DCS alarm summary screen.

A.2.9.4.16 5:41 P.M.

The Crude 1 Tower lost the flow in the bottom pumparound.

At the same time, the level in the Crude 1 Overhead Accumulator Drum reached 89 percent. One board operator told the other board operator to open the naphtha flow control valve to the Coker Gas Plant to use the NHT Feed Surge Drum for naphtha storage to reduce the high level in the Crude 1 Overhead Accumulator Drum. The naphtha flow control valve to the Coker Gas Plant was fully opened and then settled in at 79 percent open at 5:45 p.m. until closed at 7:05 p.m.

Once the naphtha flow control valve to the Coker Gas Plant was opened,[a] the measured flow of the liquid naphtha rate went above the instrument's top range of 18,700 barrels per day. The flow remained above the instrument's top range until 6:42 p.m. and then reduced from 17,800 barrels per day down to 0 at 6:55 p.m.

Since the Coker Gas Plant Absorber Stripper Tower bottoms outlet ROEIV was closed (*See* **A.2.9.4.10**), the Absorber Stripper Tower level began to increase at 5:45 p.m.

The flow meter, from the Crude 1 Overhead Accumulator Drum to the Light Virgin Naphtha Storage, returned to the instrument's top of range of 10,000 barrels per day. The flow rate generally remained over 9,900 barrels per day until 6:42 p.m.

A.2.9.4.17 5:42 P.M.

A crude oil pump seal was reported to be leaking crude oil (*See* **A.2.9.4.14**). The pump, lined up to light crude oil storage, was running with no flow beginning at 5:11 p.m.

The crude oil pump was turned off after the crude oil leak was discovered.

A.2.9.4.18 5:47 P.M.

The Crude 1 Tower lost flow in the middle pumparound.

A.2.9.4.19 5:53 P.M.

The alarms for high level from the Coker Gas Plant Absorber Stripper Tower level controller and independent level transmitter sounded.

A.2.9.4.20 6:06 P.M.

A board operator shelved[b] Coker Gas Plant Absorber Stripper Tower high level alarms for the level controller and independent level transmitter.

[a] The BP Toledo Refinery process data historian shows the control valve output went directly from minus five percent fully closed to 105 percent fully open, then to 85 percent open for two minutes, before settling out at 79 percent open.

[b] Shelving alarms caused the alarms to no longer appear on the DCS active alarm page.

A.2.9.4.21 6:09 P.M.

Liquid naphtha began to flow into and quickly accumulated inside the Fuel Gas Mix Drum. The naphtha was flowing through the Coker Gas Plant bypass line, after the level of naphtha reached tray 37 in the Coker Gas Plant Absorber Stripper Tower (*See* **Section 1.8**).

A.2.9.4.22 6:10 P.M.

The high level alarm for the guided wave radar level transmitter sounded at 10 percent and the high level alarm for the Fuel Gas Mix Drum differential pressure level transmitter sounded at a level of six percent.

A.2.9.4.23 6:12 P.M.

The Crude 1 Tower lost the flow in the top pumparound.

A.2.9.4.24 6:14 P.M.

The high differential pressure alarm for the Coker Gas Plant Absorber Stripper Tower sounded at 15 psi.

A.2.9.4.25 6:15 P.M.

The high-high level alarm for the Fuel Gas Mix Drum guided wave radar level transmitter sounded at 85 percent.

A.2.9.4.26 6:16 P.M.

A board operator radioed to outside operators to check the level in the Fuel Gas Mix Drum, "Check ASAP!"

The Fuel Gas Mix Drum differential pressure level indicator reached approximately 67 percent and plateaued.[a] The differential pressure indicator for the liquid level gave a false indication that the liquid level is below the six-foot level measurement span of the differential pressure indicator and deviated from the guided wave radar indicator, which was already alarming at a high-high level. The differential pressure indicator never alarmed at the high-high liquid level (*See* **A.2.9.4.25**).

A.2.9.4.27 6:17 P.M.

Three outside operators quickly responded to the report of liquid level in the Fuel Gas Mix Drum. They first confirmed that the high liquid level in the Fuel Gas Mix Drum existed. Then one operator went immediately to "the valve going to the flare and opened it all the way." Next, they opened the valve to drain liquid to the Oily Water Sewer.

An outside operator radioed that the Fuel Gas Mix Drum was draining.

[a] The liquid (naphtha) in the Fuel Gas Mix Drum had a specific gravity of approximately 0.67. However, the Fuel Gas Mix Drum differential pressure level indicator had been calibrated using a specific gravity of 0.998 (at 60 °F).

A.2.9.4.28 APPROXIMATELY 6:17 P.M.

The shift supervisor mentioned to the outside operator to "get air by."[a] The shift supervisor also told the outside operator to keep draining to the sewer and not let the liquid splash out, and to follow the drained liquid with water to dilute the liquid "and to keep vapors down too."

A.2.9.4.29 6:20 P.M.

Crude 1 Furnace started smoking black smoke.

A.2.9.4.30 6:21 P.M.

The level indicator in the Coker Gas Plant Sweet Gas Knockout Drum reported 100 percent. An outside operator went to this drum and manually held open the drum's "dead man valve"[b] and drained the liquid to a spent amine line.

An outside operator reported on the radio that the Fuel Gas Mix Drum "level is above the sight glass." A board operator responded with "copy that, just drain it [the Fuel Gas Mix Drum] as fast as you guys can." The outside operator responded, "we are."

A board operator acknowledged the high-high Fuel Gas Mix Drum guided wave radar level transmitter level alarm.

A.2.9.4.31 6:22 P.M.

Black smoke from the Crude 1 Furnace was reported on the radio. The CO Boiler started smoking green smoke. Fuel gas was cut from the Crude 1 Furnace.

A.2.9.4.32 6:23 P.M.

Black and yellow smoke was observed on camera "coming from the units."

A.2.9.4.33 6:24 P.M.

Crude 1 Furnace stopped smoking.

A.2.9.4.34 6:25 P.M.

The shift superintendent issued an "All call" for the ERT, a full mobilization of the refinery's emergency responders.

[a] To "get air by" was later explained to CSB investigators to mean having air (an SCBA) located "close to them if they needed it" (not necessarily over the head and hanging around the neck or actually donning the SCBA mask), because "the rich amine product is pretty heavy H_2S."

[b] A "dead man valve," also known as a spring closing lever valve, is a manual valve that a human has to hold open by use of the lever handle, which will automatically close when the lever is released. Typically used to prevent leaving a valve unattended, such as during manual draining. Can be defeated by securing the handle in the open position [52, p. 25].

A.2.9.4.35 6:26 P.M.

A furnace in the diesel hydrotreater unit started smoking black smoke.

A.2.9.4.36 APPROXIMATELY 6:27 P.M.

Two BP employees, an outside operator and operator trainee who were brothers, drained the Fuel Gas Mix Drum to the Flare Knockout Drum and the Oily Water Sewer. They were both observed to be wearing an SCBA prior to the incident. One SCBA was provided by another outside operator who yelled to “put the SCBA on”. The shift supervisor later explained to CSB investigators that the SCBAs were out of a concern that hydrogen sulfide could be present in any amine-water solution drained from the Fuel Gas Mix Drum.

A.2.9.4.37 6:29 P.M.

The area LFL detector[a] reached 2.8 percent LFL, which was the first reading above zero.

The Crude 1 Furnace started smoking again and the CO Boiler stopped smoking.

A.2.9.4.38 6:30 P.M.

The area LFL detector reached 11.6 percent LFL, which exceeded the detector’s high alarm setpoint of 10 percent LFL.

An audible horn alarm triggered by the LFL detector could be heard in the radio traffic. There was no LFL alarm in the control room as the alarm was set to “Disabled” due to an Alarm Configuration Manager (ACM) enforcement configuration error that was enforcing the alarm into the “disabled” state. Although the audible and visual board alarming was disabled, the LFL detector readings would have still shown in the control room.

A.2.9.4.39 APPROXIMATELY 6:32 P.M.

A ¾-inch bleed valve on the Fuel Gas Mix Drum sight glass piping is opened by the operator and operator trainee releasing liquid naphtha directly to the ground.

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[a] Most flammable gas detectors “give a reading of the %LEL (or %LFL)” [49, p. 29]. The lower flammability limit (LFL) is defined as the “lowest concentration of a flammable gas in air capable of being ignited by a spark or flame” [49, p. 35]. This LFL detector was located approximately 19 feet southwest of the Fuel Gas Mix Drum.

A.2.9.4.40 6:32 P.M.

Fuel Gas Mix Drum differential pressure level indication decreased immediately to zero percent when a ¾-inch valve was opened by the outside operator and operator trainee releasing naphtha directly to the ground.

A.2.9.4.41 APPROXIMATELY 6:34 P.M.

The outside operator and operator trainee used water from a hose to direct the liquid draining to the ground from the Fuel Gas Mix Drum to a drain.

A.2.9.4.42 6:35 P.M.

A board operator radioed that it looks like the liquid "level might have broke" in the Fuel Gas Mix Drum. However, this was a false understanding because the differential pressure level instrument indicated zero percent because it had been opened and was releasing naphtha directly to the ground (*See* **A.2.9.4.39**).

A.2.9.4.43 6:36 P.M.

After a request for Fuel Gas Mix Drum status, an outside operator reported that a high liquid level in the Fuel Gas Mix Drum was observed in the sight glass.

A.2.9.4.44 APPROXIMATELY 6:38 P.M.

A blind flanged two-inch maintenance valve on the side of the Fuel Gas Mix Drum was opened and released naphtha directly to the ground.

A.2.9.4.45 6:39 P.M.

An area LFL detector reached 100 percent LFL, then dropped down to 21 percent LFL.

A.2.9.4.46 6:40 P.M.

The area LFL detector's audible alarm can be heard in the background during a radio call from an outside operator.

A.2.9.4.47 6:43 P.M.

The area LFL detector reached 100 percent LFL and remained at 100 percent LFL.

A.2.9.4.48 APPROXIMATELY 6:45 P.M.

An outside operator detected a "strong, strong smell" like a "distillate type naphtha or something" and observed vapors being released from the Fuel Gas Mix Drum, much "like someone is draining product from the mix drum [Fuel Gas Mix Drum], and I seen water being sprayed on it."

A.2.9.4.49 6:46 P.M. (TIME OF IGNITION)

Vapor cloud ignited.

A.2.9.4.50 APPROXIMATELY 6:47 P.M.

The outside operator, wearing his SCBA, was found on fire near the base of the Crude 1 Tower. A fellow outside operator opened a nearby fire monitor, hosed water directly onto him, which quickly put out the fire on the outside operator.

Flames on the operator trainee were also extinguished.

A.2.9.4.51 APPROXIMATELY 6:49 P.M.

Since the operator trainee could still walk, he was led to the North pod[a] where colleagues administered first aid until the trainee was evacuated from the BP Toledo Refinery by ambulance.

A.2.9.4.52 APPROXIMATELY 6:52 P.M.

A board operator requested Emergency Medical Services (EMS) at the North pod. Additional EMS were requested for the South pod.

A.2.9.4.53 6:56 P.M.

A blocked-in pipe in a nearby pipe rack ruptured, which provided additional fuel to the fire.

A.2.9.4.54 7:04 P.M.

A board operator closed the naphtha flow control valve to the Coker Gas Plant and the flow control valve from the Crude 1 Overhead Accumulator Drum to Light Virgin Naphtha Storage.

A.2.9.4.55 7:15 P.M.

Oregon EMS transported one of the burned operators to a nearby hospital.

A.2.9.4.56 7:21 P.M.

A second ambulance transported the other burned operator to the same hospital.

A.2.9.4.57 8:31 P.M.

The fire was still burning on the south side of the Fuel Gas Mix Drum.

A.2.9.4.58 8:51 P.M.

The BP Toledo Refinery ERT accepted mutual aid from a nearby refinery, which sends one “rig with six to eight firefighters.”

A.2.9.4.59 9:18 P.M.

Incident Activity Log entry states “Fire appears to be out […]”

[a] Pods were blast resistant modular buildings located in the BP Toledo Refinery.

A.2.9.4.60 9:26 P.M.

Incident Activity Log entry states "Fire is confirmed out. Investigating for additional leaks."

A.2.9.4.61 9:44 P.M.

Incident Activity Log entry states "investigating the new [fire] in the [north/south] pipe alley."

A.2.9.4.62 10:10 P.M.

Incident Activity Log entry states "Command reports small fires are out."

A.2.9.5 SEPTEMBER 21, 2022

A.2.9.5.1 12:18 A.M.

All ERT equipment and personnel were released from the area near the fires and returned to headquarters.

A.2.9.5.2 1:57 A.M.

All clear sent out and the refinery lock down was lifted.

Appendix B: Simplified Causal Analysis (AcciMap)

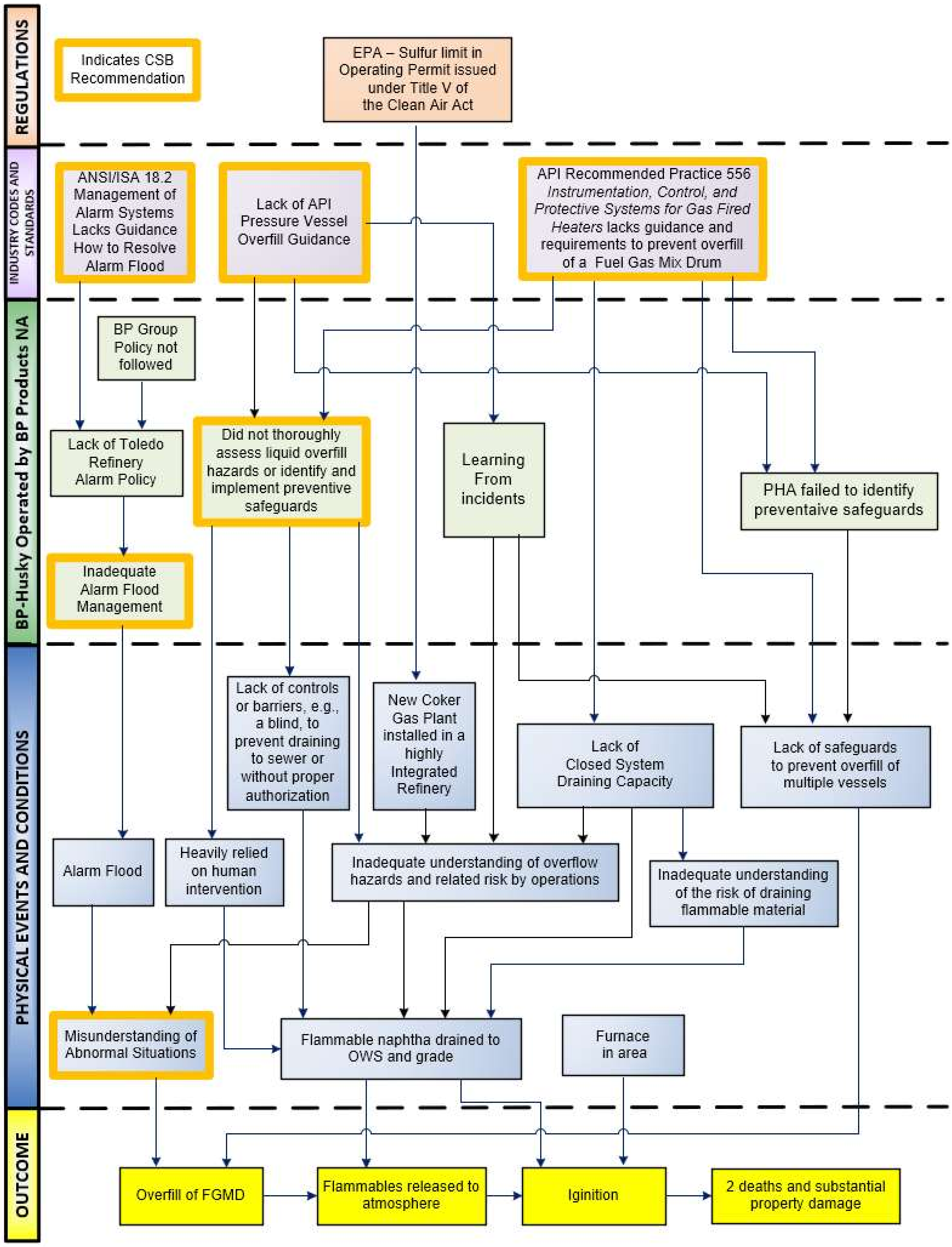

Figure B-1. AcciMap (Credit: CSB)

Appendix C: Description of Surrounding Area

Figure C-1 shows the seven census blocks within approximately five miles of the BP Toledo Refinery that the CSB reviewed [44].

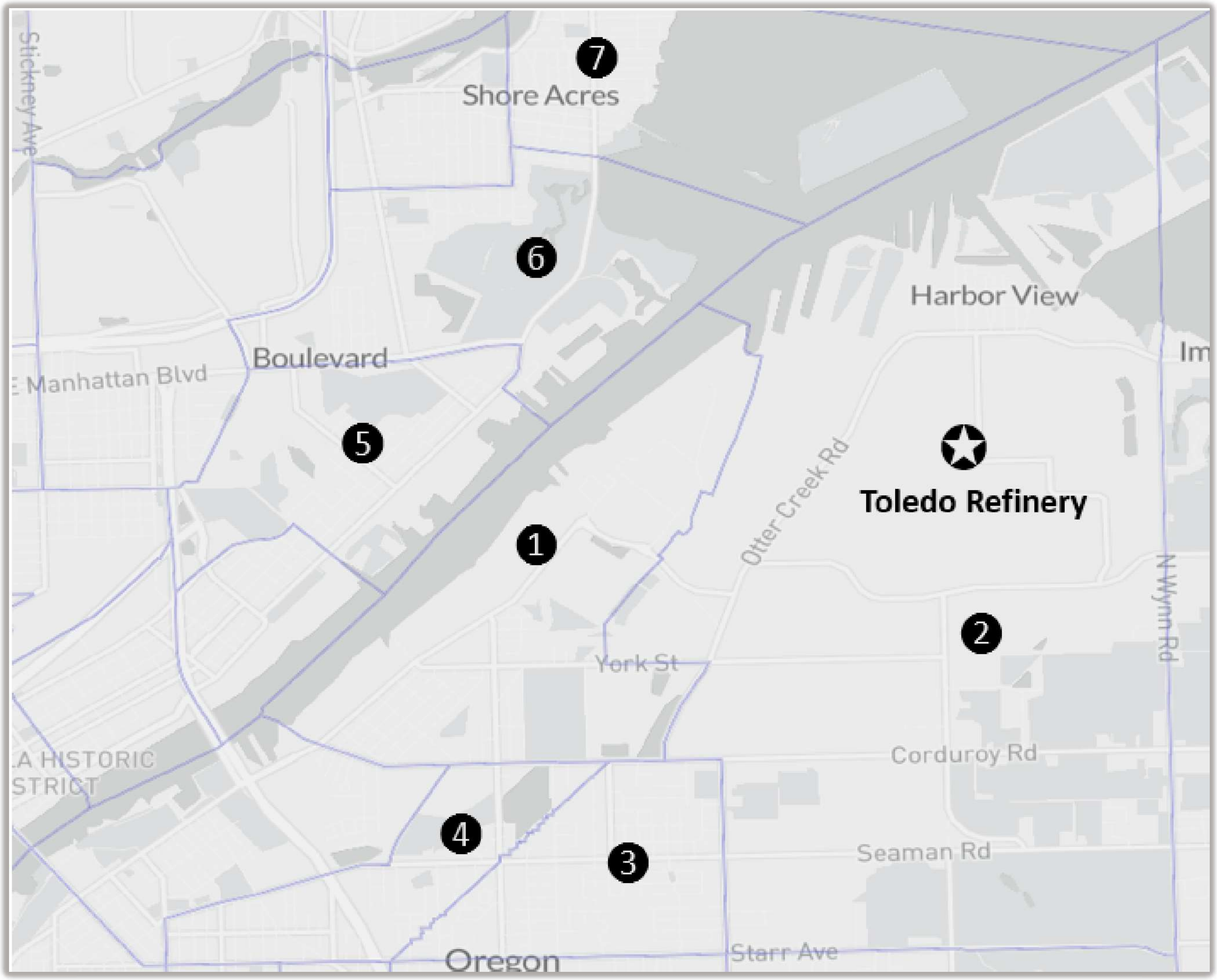

Figure C-1. Census blocks near the BP Toledo Refinery. (Credit: Census Reporter with annotations by CSB)

Table C-1 contains demographic data for these census blocks. In general, the population is predominantly white with 23 percent of the population below the poverty level.

Table C-1. Tabulation of demographic data.

Block Number	Population	Median Age	Race and Ethnicity (%)		Median Income ($)	Poverty (%)	Number of Housing Units	Types of Housing Units (%)	
1	2,169	37	68	White	36,534	25	1,044	83	Single Unit
			14	Black				17	Multi-Unit
			0	Native				0	Mobile Home
			0	Asian				0	Boat, RV, van, etc.
			0	Islander					
			7	Other					
			10	Two+					
			17	Hispanic					
2	1,096	44	89	White	60,844	12	466	96	Single Unit
			1	Black				2	Multi-Unit
			0	Native				2	Mobile Home
			0	Asian				0	Boat, RV, van, etc.
			0	Islander					
			2	Other					
			7	Two+					
			7	Hispanic					
3	3,871	45	84	White	66,887	3	1,770	83	Single Unit
			2	Black				17	Multi-Unit
			0	Native				0	Mobile Home
			1	Asian				0	Boat, RV, van, etc.
			0	Islander					
			3	Other					
			9	Two+					
			12	Hispanic					
4	3,502	33	63	White	36,534	43	1,860	48	Single Unit
			19	Black				46	Multi-Unit
			0	Native				6	Mobile Home
			0	Asian				0	Boat, RV, van, etc.
			0	Islander					
			4	Other					
			13	Two+					
			17	Hispanic					

Block Number	Population	Median Age	Race and Ethnicity (%)		Median Income ($)	Poverty (%)	Number of Housing Units	Types of Housing Units (%)	
5	2,825	31	37	White	23,500	37	997	54	Single Unit
			52	Black				46	Multi-Unit
			0	Native				0	Mobile Home
			0	Asian				0	Boat, RV, van, etc.
			0	Islander					
			4	Other					
			7	Two+					
			9	Hispanic					
6	2,247	40	72	White	57,976	16	945	80	Single Unit
			15	Black				20	Multi-Unit
			0	Native				0	Mobile Home
			0	Asian				0	Boat, RV, van, etc.
			0	Islander					
			3	Other					
			10	Two+					
			10	Hispanic					
7	3,045	44	88	White	53,798	20	1,553	96	Single Unit
			2	Black				4	Multi-Unit
			1	Native				0	Mobile Home
			0	Asian				0	Boat, RV, van, etc.
			0	Islander					
			2	Other					
			7	Two+					
			8	Hispanic					

Appendix D: OSHA Hazard Alert Letter

On March 15, 2023, OSHA issued a voluntary recommendation to BP stemming from the September 20, 2022, incident. OSHA disclosed the following hazard(s) at the refinery:

> The site utilizes a staffing pattern commonly referred to as job rotation at the refinery. The policy of rotating process operators among multiple positions, instead of a single position, can reduce the level of expertise and knowledge of operators on the unit for which they are initially qualified. In the event of a process upset condition or catastrophic incident, this decrease in expertise can negatively affect incident response efforts, posing a higher likelihood of exposure to toxic vapor/gas, fire and explosion hazards.

In the interest of workplace safety and health and the lack of an applicable OSHA standard, OSHA recommended the refinery voluntarily take steps to eliminate or materially reduce employee exposure to such hazards. OSHA stated that feasible methods of control could include:

> Conduct a feasibility study, including obtaining input from employees and employee representatives, on the effectiveness of the job rotation staffing pattern in place at the refinery, including determining the impact that such a job rotation policy has on operator morale and ability to respond to process safety incidents.

Appendix E: OSHA Citations

Citation Number	Standard Cited	Summary of Citation
Citation 1 Item 1	29 C.F.R. § 1910.119(d)(3)(ii)	a) the employer failed to ensure that it documented that equipment in the process complied with the employer's chosen recognized and generally accepted good engineering practices such as but not limited to API 520 (2020) Section 5, when the employer did not include an evaluation of excessive built-up backpressure for PSV-1457 located on the tube side of the HVGO/Crude 1 Naphtha Intermediate Reflux Shell & Tube heat exchangers (PR-544011/12). Failure to evaluate excessive built-up back pressure resulted in the exposure of employees to fire and explosion hazards from the release of flammable liquids or gasses. b) the employer failed to ensure that it documented that equipment in the process complied with the employer's chosen recognized and generally accepted good engineering practices such as but not limited to API 520 (2020) and API 521 (2015), when the employer did not include an evaluation of two phase flow and all potential relief scenarios for the TIU Fuel Gas Mix Drum (PR-510253) PSV-1464 including but not limited to overfilling of the drum. Failure to evaluate for the potential of two-phase flow and all potential relief scenarios including but not limited to overfilling of the drum, exposed employees to fire and explosion hazards from potential releases of flammable liquids or gasses. c) the employer failed to document that the level indicator instrumentation used in conjunction with the TIU Fuel Gas Mix Drum (PR510253) complied with recognized and generally accepted good engineering practices in that level instrumentation relied on for controlling liquid level accumulation in the drum was not designed and utilized for determining liquid levels of naphtha.
Citation 1 Item 2	29 C.F.R. § 1910.119(e)(1)	the employer failed to identify, evaluate, and control the hazard of high liquid level resulting from all potential flammable liquid overfill scenarios including but not limited to detecting flammables and stopping the flow of liquid naphtha to the TIU Fuel Gas Mix Drum. The Crude 1 PHA did not include the Coker Gas Plant as a source of liquid naphtha during an overfill scenario involving the Absorber Stripper Tower (PR550025), Sour Gas KO Drum (PR510286), Polishing Amine Contactor (PR550032), Sweet Gas KO Drum (PR510283) to the fuel gas header and the TIU Fuel Gas Mix Drum. Failure to control the high level in the TIU Fuel Gas Mix Drum resulted in a release of liquid naphtha, exposing employees to flammable vapor, fire, hydrogen sulfide, and explosion hazards.
Citation 1 Item 3	29 C.F.R. § 1910.119(e)(3)(iii)	the employer failed to evaluate the TIU Fuel Gas Mix Drum in the Crude 1 Unit for engineering or administrative controls needed to maintain drainage to a closed system and prevent the manual draining of liquid in the drum to the sewer. Open draining of liquid from the mix drum can expose employees to hydrogen sulfide, explosion and fire hazards.

Citation Number	Standard Cited	Summary of Citation
Citation 1 Item 4	29 C.F.R. § 1910.119(e)(3)(iv)	a) the employer failed to ensure that the PHA addressed the consequences of failure of administrative controls by not following the South/Coker Gas Plant: Bypassing and Returning to Service Coker Gas Plant Procedure (CGP 02.004). The procedure required closing FV-3816 while the Coker Gas Plant was in bypass mode. During the incident, FV-3816 was opened causing the Absorber Stripper Tower (PR-550025) and the downstream equipment including the TIU Fuel Gas Mix Drum (PR-510253) to overfill with liquid naphtha. This led to a direct path of liquid naphtha, causing an uncontrollable high level in the TIU Fuel Gas Mix Drum, exposing employees to fire, explosion hazards, and toxic gases from potential releases of fuel gas, flammable liquids, and hydrogen sulfide. b) the employer failed to ensure that the PHA addressed the consequences of failure of administrative controls by not following Coker Gas Plant and NHT Feed Surge Drum Safe Operating and Design Limits which required steps to avoid an overfill scenario of the Absorber Stripper Tower (PR-550025) to include verifying that the Absorber Stripper Tower bottom valve (XV3821) was open. Keeping this valve closed led to overfilling of the Absorber Stripper Tower (PR-550025) and the downstream equipment including the TIU Fuel Gas Mix Drum (PR-510253). This led to a direct path of liquid naphtha, causing an uncontrollable high level in the TIU Fuel Gas Mix Drum, exposing employees to fire, explosion hazards, and toxic gases from potential releases of fuel gas, flammable liquids, and hydrogen sulfide. c) the employer failed to ensure that the PHA addressed the consequences of failure of engineering controls when the high-level switch (LSH-805) was not available to detect high level of flammables in the TIU Fuel Gas Mix Drum during an overfill scenario of the Absorber Stripper Tower (PR-550025) and downstream vessels. Failure to evaluate loss of engineering controls resulted in an uncontrollable high level in the TIU Fuel Gas Mix Drum, exposing employees to fire, explosion hazards, and toxic gases from potential releases of fuel gas, flammable liquids, and hydrogen sulfide.
Citation 1 Item 5	29 C.F.R. § 1910.119(e)(6)	the employer failed to ensure that the most recent PHA revalidation reflected current process equipment and conditions, in that the high level switch (LSH-805) was not available to detect high level of flammables in the TIU Fuel Gas Mix Drum during a high liquid level event. Failure to ensure that engineering control safeguard taken credit for in PHA revalidations are in place and operational, can contribute to an uncontrollable high level in the TIU Fuel Gas Mix Drum, exposing employees to fire, explosion hazards, and toxic gases from potential releases of fuel gas, flammable liquids, and hydrogen sulfide.

Citation Number	Standard Cited	Summary of Citation
Citation 1 Item 6	29 C.F.R. § 1910.119(f)(1)(i)(C)	a) the employer failed to ensure that temporary operating procedures were developed and implemented for operation of the Crude 1 Unit while the Coker Gas Plant and SatGas/NHT Units were intended to be in a bypass condition. The lack of operating procedures for this transient operating condition contributed to carry-over of naphtha to the TIU Fuel Gas Mix Drum and led to liquid in the fuel gas system, exposing employees to fire and explosion hazards. b) the employer failed to ensure that operating procedures developed for bypassing the Coker Gas Plant were implemented. Failure to implement this established procedure (CGP 02.004 - Bypassing and Returning to Service Coker Gas Plant) contributed to FCV3816 being opened, allowing naphtha to overfill downstream process vessels and flow into the refinery's fuel gas system, exposing employees to fire and explosion hazards.
Citation 1 Item 7	29 C.F.R. § 1910.119(f)(1)(i)(D)	a) the employer failed to ensure that emergency shutdown of process equipment in the NHT/Sat Gas units occurred when requested by outside operators. Upset conditions involving the lifting and reseating of PSV-1457 and PSV-1462 caused process equipment vibration and instability. A release of naphtha during this upset condition exposed employees to explosion and fire hazards. b) the employer failed to ensure that emergency operating procedures for the Crude 1 Unit Crude Tower (PR556936) included the scenario involving the loss of all three process pumparounds on the tower simultaneously, which can inhibit process temperature control and stable operation of the tower. Failure to shutdown the Crude Unit during this process upset condition can expose employees to explosion and fire hazards.
Citation 1 Item 8a	29 C.F.R. § 1910.119(f)(1)(i)(E)	a) the employer failed to ensure that procedure PSM 025 was implemented for the closing of PSV-1457 in the SatGas/NHT Unit, for the purpose of reseating the relief valve, exposing employees to explosion and fire hazards. b) the employer failed to ensure that emergency operating procedures were developed and implemented for the safe draining of liquid from the TIU Fuel Gas Mix Drum in the Crude 1 Unit during process upset conditions. The lack of emergency operating procedures for this condition exposed employees to hydrogen sulfide, explosion and fire hazards.
Citation 1 Item 8b	29 C.F.R. § 1910.119(f)(4)	the employer failed to ensure that safe work practices were developed and implemented for the safe draining of liquid from the TIU Fuel Gas Mix Drum in the Crude 1 Unit during process upset conditions. The lack of safe work practices developed and implemented for this work activity exposed employees to hydrogen sulfide, explosion and fire hazards.

Citation Number	Standard Cited	Summary of Citation
Citation 1 Item 9	29 C.F.R. § 1910.119(f)(1)(ii)	the employer failed to ensure that the procedure for Normal Operation of Crude 1 (CRD1 02.012) included steps to avoid or correct deviations in process parameters, including for liquid level in the TIU Fuel Gas Mix Drum. The lack of detailing steps to avoid or correct deviations for all process parameters such as liquid level, exposed employees to hydrogen sulfide, explosion and fire hazards.
Citation 1 Item 10	29 C.F.R. § 1910.119(g)(1)(i)	a) the employer failed to ensure that operators in the Crude Unit were trained to respond to rising liquid levels in the TIU Fuel Gas Mix Drum located in the Crude 1 Unit, in that there was no prohibition against draining the liquid to the oily water sewer. This lack of training resulted in employees being exposed to fire, explosion and hydrogen sulfide hazards. b) the employer failed to ensure that inside and outside operators were trained to evaluate and identify the presence of naphtha in the TIU Fuel Gas Mix Drum located in the Crude 1 Unit, during transient, temporary operating conditions, including the NHT/SatGas and Coker Gas Plants being outside of normal operating conditions. The lack of training resulted in employees being exposed to fire, explosion and hydrogen sulfide hazards. c) the employer failed to ensure that inside and outside operators were trained on operating limits of the TIU Fuel Gas Mix Drum, related to liquid level, including the consequences of deviation and steps to avoid and correct liquid level outside of acceptable limits. The lack of training resulted in employees being exposed to fire, explosion and hydrogen sulfide hazards.
Citation 2 Item 1	29 C.F.R. § 1910.119(e)(3)(vi)	the employer failed to address human factors in the process hazard analysis to ensure that delays in screen loading on the South A Board in the Control Room were corrected to allow for timely operator response in the event of an upset condition. Delays in the inside board operators to access control board screens timely, can inhibit their response in the operating units in the South Area.

U.S. Chemical Safety and Hazard Investigation Board

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