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5090
Ser J00/010
February 22, 2023

Kathleen S. Ho
Deputy Director for Environmental Health
State of Hawaii Department of Health
2827 Waimano Home Road, #100
Pearl City, HI 96782

Dear Ms. Ho:

SUBJECT: JTF-RH's Responses to DOH's Additional Requests for Information Regarding Red Hill Bulk Fuel Storage Facility Defueling Plan

On January 13, 2023, Joint Task Force - Red Hill (JTF-RH) received a letter from the State of Hawaii Department of Health (DOH) with additional requests for information (RFIs) concerning the following submissions from JTF-RH:

1. Red Hill Bulk Fuel Storage Facility (RFBFSF) Defueling Plan Supplement 1.A dated September 7, 2022;

2. RHBFSF Defueling Plan Supplement 1.B dated September 28, 2022; and,

3. RHBFSF Defueling Plan Consolidated Repair/Enhancement List dated October 24, 2022.

Enclosed with this letter is JTF-RH's response to DOH's Additional RFI's with the following supporting documents:

References (a): SGH Memorandum, November 30, 2022 (copy attached)
(b): Release Event Tree Analysis, February 13, 2023 (copy attached)
(c): Red Hill Stress Analysis Clarification Memorandum, January 30 2023 (copy attached)
(d): Borescope Inspection Report. January 2023 (copy attached)
(e): Red Hill Surge Assessment Memorandum, January 17, 2023 (copy attached)
(f): DOH Conditional Approval, January 13, 2023 (copy attached)

JTF-RH intends to provide redacted versions of all final documents no later than ten business days following the date of this submission, to allow for public release without affecting national security interests.

JTF-RH will continue to refine the Defueling Plan to ensure the protection of human health and the environment, while searching for time saving efficiencies that do not increase risk. We appreciate the constructive engagements between the DOH and JTF-RH toward that objective.

We respectfully request DOH acknowledge receipt of this letter. Should you have any questions or concerns, please contact me or my Chief of Staff, Colonel Kevin Williams at kevin.j.williams56.mil@army.mil.

Sincerely,

John F. J. Wade VADM, USN
JOHN F. WADE
Vice Admiral, U.S. Navy

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JTF-RH Response to DOH Request for Information Regarding Red Hill Bulk Fuel Storage Facility Defueling Plan (January 13, 2023)

Based on the responses received, the DOH conditionally approves the following two repair deviations listed in the JTF-RH's Defueling Consolidated Repair/Enhancement List, dated October 24, 2022, and submitted on October 27, 2022. According to the repairs list, forgoing the Fuel Oil Recovery (FOR) Pipeline replacement at Hotel Pier "could reduce the overall defuel timeframe by three months and accelerate the completion of defueling from June 2024 to March 2024." Please confirm whether the expected end date for defueling will be March 2024, given the conditional approvals below.

Response: While the conditional DOH approval of the two repair deviations (see Reference (f)) is both helpful and appreciated, the repair timeline can only be reduced by acceptance of all three of our deviations, which includes forgoing the repair of the AFFF retention line. However, overall defueling timeline is driven by more than just required repairs. The JTF-RH integrated master plan ("IMP") also includes milestones for quality validation, fire suppression/response, repacking fuel lines, unforeseen repairs/maintenance post-repacking, defueling operational CONOPs, training and exercises, spill response training, exercises and response drills. VADM Wade and BG Link intend to discuss the IMP and integrated master schedule ("IMS") at the next Interagency Sync in March 2023 and gain regulator concurrence.

(Ref. DOH numbering)
1. DOH Cover Letter RFI #1) F-76 Pipeline Enhancements (SGH-PM-3/4/12): We understand the JTF-RH can complete defueling of all tanks by utilizing the JP-5 and F-24 fuel lines. Because the two tanks storing F-76 (Tanks 15 and 16) are already connected to the JP-5 line, the JTF-RH plans to reroute the F-76 product to the JP-5 line, simply by reconfiguring the flanges on those tanks. We understand from the JTF-RH's responses to the DOH's comments that the pipe laterals from Tanks 15 and 16 to the JP-5 line have already been inspected and were included in the NDAA assessment. The JTF-RH proposes that this non-intrusive adjustment would remove the need to install longitudinal restraints on the F-76 pipeline (SGH-PM-12). The DOH approves this deviation, with the understanding that the F-76 line will not be used.

Response: Acknowledged.

(Ref. DOH numbering)
2. DOH Cover Letter RFI #2) Replace Polyvinylchloride (PVC) FOR Pipeline at Hotel Pier (SGH-HP-14):
The JTF-RH's Defueling Consolidated Repair/Enhancement List states, "[t]he SGH Assessment of Red Hill Underground Fuel Storage Facility noted that the PVC FOR line under Hotel Pier potentially has joints with Nitrile seals and recommends replacing the 'PVC with appropriate materials' (SGH # HP-14). SGH designated this repair as required prior to defueling." The SGH's November 30, 2022, memorandum, "Hotel Pier PVC FOR Line Replacement Prior to Defueling the Red Hill Underground Bulk Fuel Storage Facility," described an alternative to replacement for the purposes of defueling. The DOH conditionally approves this alternative provided the JTF-RH follows all of the provisions made for this alternative, which include but are not limited to:

a. Hydrotest the existing PVC FOR pipeline to locate and repair leaks.
b. Any resulting leaks shall be appropriately repaired and retested prior to defueling.
c. Prior to hydrotesting, repair all damaged/missing hardware supporting the PVC FOR pipeline under the pier, including but not limited to damaged pipe hangers.
d. Document repair and testing for submission to the DOH.

Response: Acknowledged, will repair all damaged/missing hardware supporting the PVC FOR pipeline under the pier prior to hydrotesting. Additionally, any leaks identified during hydrotesting will be repaired and the line will be retested until it is leak free in accordance with the SGH memo dated November 30, 2022 (see Reference (a)). Documentation will be provided upon completion of the repairs and subsequent testing.

Additionally, in light of the November 29, 2022, aqueous film forming foam (AFFF) spill at the Red Hill Bulk Fuel Storage Facility, we request an updated Spill Prevention Control and Countermeasure Plan and Facility Response Plan for the repair phase of defueling. These documents should address spill prevention and response for hazardous substances, including AFFF and oil.

Response: The Response Directorate is developing specific addendums to the RHBFSF Facility Response Plan, to include addendums for AFFF, fuel and oil. The AFFF addendum will address spill prevention and responses for the two AFFF tank locations at RHBFSF and will be provided to DOH upon completion.

(Ref. DOH numbering)

2. The Hawai'i Department of Health (DOH) looks forward to reviewing the reasonable worst-case scenario discharge, mitigation to prevent discharge into the environment, the defueling spill response plan, and procedures (and subsequent results) associated with the planned sump tightness testing. Please coordinate the tightness testing scheduling with the DOH, as we would like an opportunity to observe the tightness testing. In addition, the floor drains leading to the sumps should be inspected for cracks and sealed to prevent leaks.

Response: The Response Directorate stood up a bi-weekly Interagency Spill Response Planning Team (comprised of EPA, DOH and ten other spill response entities) in order to design the most reasonable worst-case scenario discharge. Tank tightness testing and sump inspection will be coordinated with DOH and the Repair & Maintenance Directorate, with testing scheduled to take place in April 2023.

(Ref. DOH numbering)

3. The DOH requested a quantitative probability assessment to further evaluate the Navy's proposal to not repair the aqueous film forming foam (AFFF) drain line or provide a backup system to remove spilled fire suppression material or oil to the existing oil recovery system in the Lower Access Tunnel. The Joint Task Force – Red Hill's (JTF-RH's) response was provided in two parts, which are addressed in 3.a and 3.b below. Also, in light of the November 29, 2022, AFFF release, we understand the Navy is conducting an investigation regarding the incident, and the JTF-RH is reevaluating the fire plan for defueling. Please submit a revised assessment to address the anticipated new information and the following comments.

a. The response identifies three potential release scenarios:
   i. Breach in the JP-5 pipeline immediately upstream of the sectional valves, releasing approximately 30,000 gallons of fuel;
   ii. Release down-gradient of the tank gallery; and
   iii. Catastrophic release from a nozzle releasing a volume greater than 50,000 gallons.

Multiple arguments were provided for scenarios i and iii. The DOH agrees utilizing the AFFF sumps and drain line will not increase the rate of fuel removal for a spill down-gradient of the tank gallery.

Scenario i states it would take about ten minutes for the AFFF sump pumps to remove 30,000 gallons of discharge, while the groundwater pump would take about five hours. During the May 6, 2021 event, the JTF-RH confirms it took twelve hours to clean the release of about 20,000 gallons, which we understand was mostly removed by the AFFF sump pumps in less than ten minutes. However, the groundwater data collected after the May 6, 2021 release shows a striking increase in contamination, even though the majority of fuel was removed in that short amount of time. Thus, the DOH takes issue with the possibility of fuel or fire suppression material sitting in the tank gallery for five hours.

Additionally, comparing the number of days for fuel to travel from the point of release to the well head to the time fuel is sitting in the tunnel, potentially seeping into the environment, does not indicate release time is negligible. We will not discuss the November 20, 2021 incident in this comment, as any release down gradient of the tank gallery (scenario ii) would not be affected by the AFFF sump system.

For scenario iii, when a release is greater than 50,000 gallons, the JTF-RH states pump rate becomes irrelevant because the volume capacity is only about 50,000 gallons for the FOR system (42,300 gallons for Tank S311 and 9,700 gallons for the pipeline). However, the AFFF drain line and associated tank can provide an additional capacity of more than 100,000 gallons. Thus, pump rate can still play a role in spill response to a greater extent.

Response: The Response Directorate is taking this recommendation into consideration and developing the potential use of the AFFF sumps into one of the four most likely discharge scenarios. The Interagency Spill Response Planning Team, which meets bi-weekly, is conducting technical analysis which should be complete in March 2023.

(Ref. DOH numbering)

b. With regards to the quantitative assessment, we have the following preliminary comments:

i. Two of the five mitigation controls to reduce the risk of groundwater contamination take place after the groundwater has already been impacted: Groundwater treatment system and increased groundwater monitoring. We comment on these two topics below.

1. The current groundwater treatment system (also known as the granular activated carbon system) is not designed to prevent a fuel release from migrating towards other sources of drinking water supplied from groundwater wells. The system was intended to prevent outward movement of fuel that was discharged around Red Hill Shaft. There is no current indication that the pumping at Red Hill Shaft will prevent contaminant movement from any part of the facility.
2. Increased groundwater monitoring by itself does not mitigate contamination. It only provides data on groundwater quality at the given location.
3. The fuel recovery system was in place prior to the May 6, 2021 event. Additionally, removing the AFFF drain line from use is a reduction of mitigative measures, which should be considered in the evaluation.

ii. The DOH disagrees with using Table 1: Initiating Events and Corresponding Frequencies to set the initial tank failure conditions for the probability analysis because:

1. No backup data was provided to state how these numbers were developed (other than referencing the book used);
2. The known failures were due to operational errors, not catastrophic tank or pipe failures;
3. The reasonable-worst case scenario release we have been discussing to compare the AFFF pump removal rate to the groundwater pump rate (5,000 to 50,000 gallons per hour) does not necessarily involve a catastrophic tank failure. Thus, this is not the appropriate data point to start with; and
4. Most importantly, Table 1 does not concur with the initial probability for leaks in the 2018 Quantitative Risk and Vulnerability Assessment (QRVA) prepared by the U.S. Department of the Navy (Navy), which shows a yearly probability of 27% for leaks from

1,000 to 30,000 gallons and 1.3% for leaks from 30,000 to 60,000 gallons (Table ES-1).

Table ES-1. Acute Scenario Risk Results Summary

Fuel Release Volume Range Category (gallons)	Sequence Group Frequency (events/year)	Exceedance Frequency (events/year)	Sequence Group Recurrence Interval (years)	Sequence Group Probability (1 year)	Sequence Group Probability (100 years)	Potential Volume Released – Point Estimate (gal./year)
1000 to 30000	0.3230500	0.3424131	3.10	0.2760623	1.0000000	1,960
30000 to 60000	0.0129880	0.0193631	77.00	0.0129040	0.7271410	515
60000 to 120000	0.0022056	0.0063751	453.40	0.0022032	0.1979305	191
120000 to 250000	0.0011526	0.0041695	867.58	0.0011519	0.1088656	219
250000 to 500000	0.0024041	0.0030169	415.96	0.0024012	0.2136946	1,097
500000 to 1000000	0.0000622	0.0006128	16067.35	0.0000622	0.0062045	42
1000000 to 2000000	0.0003678	0.0005505	2718.94	0.0003677	0.0361109	604
2000000 to 10000000	0.0000335	0.0001828	29821.72	0.0000335	0.0033477	253
> 10000000	0.0001492	0.0001492	6701.52	0.0001492	0.0148112	1,703
Total	**0.342**	**0.342**	**2.920**	**0.290**	**1.000**	**6,584**

iii. Note that Table ES-1 in the QRVA is for the total combined acute releases (including human error), which are more relevant than chronic releases for the short period of defueling (which we are assume will take one year or less). The QRVA states on Page ES-2: "These results are developed under the mathematical assumption that the facility will effectively be operated in the current configuration with the same operating profile (fuel movement profile, processes, operating procedures and policies, maintenance, testing, and design) hypothetically for hundreds of years with no intervening risk-mitigating improvements." Thus, this seems to be the appropriate probability to start with before considering the mitigations in place (i.e., potential mitigations were not included in the QRVA, so the actual risks associated with defueling should be lower).

iv. In addition, the QRVA states: "This specific baseline QRVA is broken into four distinct phases, as follows: (1) internal events (excluding internal fire and flooding), (2) internal/external fire and flooding, (3) seismic events, and (4) other external events. The first phase of the baseline QRVA, which is the topic of this report, is designed to focus on internal events (not including the risk from internal fires or internal floods)." As we have discussed previously, the chance of fire or seismic event during the short duration of defueling is negligible. Therefore, this document appears to provide the appropriate probability assessment to evaluate the initial conditions needed to assess the difference in risk between using the FOR line versus a quicker removal method in the event of a spill of 60,000 gallons or less. Please note, larger "catastrophic" spills would have to be contained or mitigated in other ways, which may be covered in the Navy's upcoming spill response plan.

v. Other important information in the QRVA document:

1. (ES-2) – It is important to note these total "roll-up" values represent the risk from all the scenarios that fit into the associated category, including human error.

2. (ES-5) – "It is important to note these results are for events and conditions leading only to fuel release from the facility but not necessarily directly into the water table." Mitigation to prevent a release in the tunnel from reaching the environment should reduce the QVRA probability accordingly. The DOH is concerned about potential

releases into the environment and potentially contaminating the groundwater, not only the probability of impacting drinking water. Thus, the probability and mitigation assessment should end at an environmental impact.

3. Page 1-2 – Risk assessment level 2 is defined as "Frequency (and annual probability) of Uncontrolled Release of Fuel Inventory (by volume range) outside the Red Hill Bulk Fuel Storage Facility Property Boundaries that Could Impact Red Hill Groundwater Shaft Water Quality."
4. Page 1-2 – "Experience has shown that Levels 1 and/or 2 above are often adequate to facilitate effective risk management decision-making for the facility owner/operator. The QRVA described in this report focuses on a Level 2 risk assessment, as defined above."
5. Table ES-1 and the following text in the QRVA lists the items that are important to risk. Those include (roughly in order of importance):
    a. The availability of tank ullage to accommodate emergency movement of fuel from a leaking tank to a safe storage tank or other safe container is important to risk.
    b. The availability and quality of potential fuel release emergency response procedures and associated operator training are important to risk.
    c. The capability and reliability of tank fuel inventory (fuel level) instrumentation and control systems are important to risk.
    d. In response to potential fuel release scenarios, operator actions are generally more important than equipment failures to overall risk. Specific examples are identified in Sections 8 and 13 of this report.
    e. Following tank inspections and maintenance, quality control during the tank return-to-service process is important to risk.
    f. Strategies for responding to fuel releases inside the RHBFSF Lower Access Tunnel (e.g., strategies for removing and controlling fuel released into the Lower Access Tunnel) are important to risk.
    g. Potential fuel releases from the tank nozzles (the main fuel flow piping leading into and out of the main storage tanks up to the upstream flange connections for the tank skin valves) are important to risk.
    h. The capability and reliability of fuel piping isolation in response to fuel release incidents in the RHBFSF Lower Access Tunnel are important to risk.
    i. Safety management and control of specific maintenance actions at the facility (e.g., tank nozzle and skin valve maintenance) is important to risk.
    j. The design and proximity of the RHBFSF Lower Access Tunnel and the Red Hill Water Pump Area is important to risk. This is because potential fuel releases into the RHBFSF Lower Access Tunnel could potentially propagate to this area and flow (in a near-direct path) to the drinking water table.

vi. Accordingly, mitigations to any of the ten factors listed above, subsequent to this report, would lower the probability from that shown in the report.

Some of these may coincide with an additional layer of protection, as defined in the JTF-RH's initial response according to the referenced book. Based on the information provided in the QRVA, the DOH believes this is the appropriate assessment to set the initial probability of a release within a year because it includes all potential causes for a release. Mitigations subsequent to this 2018 report should reduce that overall probability.

Response: The updated risk assessment (see Reference (b)) addresses the inquiries above. Furthermore, additional coordination meetings between EPA, DOH, and JTF-RH on December 22, 2022 and January 13 and 20, 2023 were a collaborative and iterative process for development and clarification of the risk assessment.

(Ref. DOH numbering)

c. Other comments on the JTF-RH's submittal:

i. Attachment 3 (event tree) shows the risk reducing from 9.89E-05 to 9.89E-06 through the box of "preventative barriers" (response to pressure indicating transmitters, watchstanders, and procedures) but does not explain how this reduction was derived (other than referencing the book used for layers of protection). Attachment 2, which appears to list items in this "box," contains some items that do not directly impact the environment, such as groundwater monitoring and the groundwater treatment system. By the time these items come into play, the environment has already been impacted. (However, we note some of these measures may prevent drinking water wells from being impacted after a release.)

ii. Reducing the number of tanks containing fuel only prevents a release by reducing the time needed to defuel. This should be considered in the analysis. For example, if a year to defuel is assumed, like in the QRVA yearly probability, defueling in less than one year should reduce the release probability accordingly.

iii. There is no indication of how much, or if, items contribute to risk reduction, other than some general idea of a "layer," which is not defined in the response. To make the assessment easier to understand, the DOH recommends breaking risk into categories (e.g., physical repairs, updated operation procedures, added spill prevention, etc.) instead of layers.

Each category would represent a risk reduction, combining to arrive at the final probability of a release impacting the environment. This would likely be easier to follow, and even conservative assumptions may result in low probabilities when the probabilities of occurrence are multiplied together. The collective reduction in risk contributed by all the mitigation measures should first be combined, then subtracted from the respective risks of groundwater contamination when using the FOR line versus a faster method.

iv. Attachment 3 is difficult to follow beyond what is mentioned above. The piping breach includes the 10E-5 probability and is reduced to 10E-6 after the box (one layer), but then splits into true-false lines. The "true" line says 0.9% probability then goes to "release contained and mitigated." Does "true" mean if there is a release, there is a 90% probability it will reach the environment without mitigation? Or does "true" mean, even with mitigation and containment there is a 90% probability it would reach the environment? The "false" line says 0.1% and then goes to limited containment and mitigation. Does "false" mean if there is no release there is a 0.1% change of impacting the environment? It is not clear what "limited containment and mitigation" means in this case.

Response: The updated risk assessment (see Reference (b)) addresses the inquiries above. Furthermore, additional coordination meetings between EPA, DOH, and JTF-RH on December 22, 2022 and January 13 and 20, 2023 were a collaborative and iterative process for development and clarification of the risk assessment.

(Ref. DOH numbering)

5. Defueling release scenarios and the associated plan still need to be developed. The DOH looks forward to receiving an updated Facility Response Plan (FRP) with relevant worst-case scenarios for defueling, as mentioned in our response for comment 2. We look forward to participating in the interagency response planning team meetings and spill exercises for defueling.

Response: The Response Directorate is taking this recommendation into consideration and developing the potential use of the AFFF sumps into one of the four most likely discharge scenarios. The Interagency Spill Response Planning Team, which meets bi-weekly, is conducting a technical analysis which should be complete in March 2023.

(Ref. DOH numbering)

12. Please explain the status of this design contract in light of the November 29, 2022 AFFF release. What was the purpose of the new design? What enhancements were intended? We understand the Navy is investigating the cause of the AFFF release and that NAVFAC's fire system designers are currently re-evaluating the design of the fire suppression system. We look forward to receiving a copy of the investigation report when completed and the new fire plan.

Response: The Red Hill AFFF System Repair, Red Hill Bulk Fuel Storage Facility, base bid included a 4" AFFF concentrate line repair. This base bid installs approximately 275 LF of stainless-steel concentrate line. The purpose is to install a concentrate line above ground versus the existing below ground line for ease of monitoring, maintenance, and repair. JTF-RH will share the AFFF Investigation Report once approved for release.

(Ref. DOH numbering)

16. The DOH assumes the Navy will continue to complete minor repairs, and no further discussion or evaluation is required for these items. If the current repairs list will not delay the defueling end date, a reevaluation may not be necessary. However, items that appear to be more than minor, and therefore may collectively cause a delay, include the following. We appreciate notification if any of these or other repairs on this list are determined to cause delay.

Response: As of January 20, 2023, all repairs are under contract and included in our CPM schedule with projected completion timelines. None of the repairs identified below are the singular cause for overall project delay; however, JTF-RH will coordinate relief from repairs with DOH and EPA should a repair be determined to cause significant delay and/or risk to schedule. JTF-RH will seek relief from these repairs during the monthly Quality Validation Report Syncs that begin in February 2023.

Count	Description/Repair
39	For JP-5 piping between the Sectional valves near Tank 1 to PS 1: Various sections of pipe are floating from the saddles and the saddles are offset from the support frame. Reset saddles to bear the pipe and also be centered on the support frame. Assume 15 support saddles need to be reset.
40	F-24 pipeline is unsupported between supports, approximately 58 feet. Install saddle or shim the pipe or pipe supports to uniformly support the pipe.
78	Concrete has been chipped out and removed on tank side around flange for the F-24 and JP-5 lines; concrete around F-24 line has broken out (but not fallen) on opposite side. Repair concrete.
79	Concrete at F-24 line has been broken out on tanks side, no flange visible. Repair concrete.
95	Dresser coupling joints and associated joint harness at Tanks 18, 19, and 20 are damaged due to the May 6th event. Repair damaged piping. Carefully reset the mainline into its original position at the Tanks 17/18 and 19/20 cross-tunnels. Provide cross-tunnel pipe supports and frames at Tanks 18 and 20. Quantity is four (two at each of Tanks 18 and 20). Provide new frames and adjustable height low friction pipe supports. Remove existing piping and replace the cross-tunnel piping at Tank 18 and Tank 20 from (including) the reducer to the ball valve. Provide new insulated compression sleeve pipe coupling, Buna-N resilient material, and restraint harness.
113	The 2-inch FOR pipeline between the tee and gate valve at Door C is covered with a stained plastic wrap and c-clamps. This is indicating a weep at the threaded joint. Replace piping.
117	The FOR connection from the product lines is constructed out of a combination of hard pipe and hoses. Replace connections and hoses with hard pipe.
118	The tank sampling piping associated with Tanks is showing signs of minor to moderate corrosion at areas where the piping has not been upgraded. Tank 9 sample piping is severely corroded and requires replacement. Repair by replacement the small-bore tank sample piping up to the sampling stations associated with Tank 9.
120	Three temporary pipe clamps on 4-inch FOR pipeline within trench adjacent to S-23. Pipe clamp lengths are 6-inch, 16-inch, 8-inch. Also, UTT indicates pipe wall loss in this area over 55% metal loss is present. Repair pipe.
125	Condition of underground segment of the FOR pipeline is unknown. Per the 2021 CP Report, this section of buried pipe had ineffective magnesium anodes. Perform borescope examination of the underground pipeline segment to assess internal condition of the pipeline.
128	Severe corrosion and pitting at several locations between ADIT 3 and S-311. Wall Loss observed between 60%-79%. Severe corrosion also observed at pipe support cradle interfaces. Repair pipe.
143	Support completely deformed, removed from baseplate. API 570: Damaged pipe support (impacted by a moving vehicle). Replace support.
182	Non-standard repair at bulkhead. Pipe is anchored to the bulkhead using welded collars inside cast in place concrete. There is a repair sleeve through the bulkhead. The UGPH side of the bulkhead has a full encirclement sleeve. The ADIT 2 side of the bulkhead has a half sleeve. 10 ft pup to eliminate the non-standard repair in the bulkhead. The piping will need to be re-anchored. Replace piping through bulkhead.

183	Reported corrosion of 46% at the bulkhead. Pipe is anchored to the bulkhead using welded collars inside cast in place concrete. 10 ft pup to eliminate metal loss at the bulkhead. The piping will need to be re-anchored.
184	Reported corrosion of 71% at the bulkhead. Pipe is anchored to the bulkhead using welded collars inside cast in place concrete. 10 ft pup to eliminate metal loss at the bulkhead. The piping will need to be re-anchored.
188	Corrosion at bulkhead. Three separate features. Reported corrosion depths 26.8%, 30.8%, and 38.0%. Remaining thickness < minimum thickness per API 574. Remove, provide, and install 10 ft 18" pup piece to eliminate the corroded areas in the bulkhead. One repair for 18-ILI-27, 18-ILI-28, and 18-ILI- 29.
219	ILI data reports metal loss of 31.5%. Not able to assess without coating removal. 4-ft, remove coating and inspect. FFS assessment and repair if necessary.
220	ILI data reports metal loss of 32.0%. Not able to assess without coating removal. 4-ft, remove coating and inspect. FFS assessment and repair if necessary.
236	Remove and replace the elevation and alignment change spool piece at PS 20. Spool is flanged and includes two rolled 45 elbows and straight segment. [18-TG-25]
237	Remove approximately 38-inch length mainline bell connection segment between PS 22 and PS 23. Provide 5 lf welded pup replacement. [18-TG-28]
238	Between PS 38 and PS 39, remove the 12 o'clock NPS ¾ threaded pipe and valve. Replace with welded NPS ¾ Sch 80 pipe, flange, and Class 150 ball valve with threaded cap. [18-TG-34]
240	Remove approximately 46-inch length mainline bell connection segment between PS 59 and PS 60. Provide 6 lf welded pup replacement. [18-TG-41]
241	Remove the corroded mainline tee at the Tanks 5/6 cross-tunnel junction. Replace mainline as-needed to install a branch connection. Rework cross-tunnel piping as needed to connect the branch connection. Re-connect mainline to cross-tunnel piping with provision for spectacle blind. [18-TG-44]
242	Remove approximately mainline bell connection segment between PS 68 and PS 69, on both sides of the bulkhead. Provide 10 lf welded pup replacement in two segments.[18- TG-46]
243	Remove and replace approximately 96-inch length mainline segment at PS 75. Replace 6- ft above to 2-ft below PS 75. [18-TG-53] Replace the corroded pipe saddle with new.
245	Replace damaged segment of the mainline at PS3. [18-TG-2]
249	Remove and replace a 10-foot pup of JP-5 mainline at the concrete bulkhead near Sta 24+89 [18-ILI-EML-15]. Pipe is anchored to the bulkhead. A method using a reduced diameter sleeve is acceptable. Anchor new pup to concrete.

(Ref. DOH numbering)

17. The DOH did not receive an updated CPM schedule at the end of November but received one at the end of December. Thank you for the submission.

Response: Acknowledged.

(Ref. DOH numbering)

20. We look forward to receiving the results.

Response: An inspection of the buried section of the FOR pipeline was completed on November 17, 2022 by Austin Brockenbrough & Associates. Final report was received by JTF-RH on February 14, 2023 (see Reference (d)). None of the findings in Reference (d) warrant piping to be removed from service, and calculations show adequate service life and pressure capacity for continued use well past the expected Defueling Operation completion date.

(Ref. DOH numbering)

24.a. Thank you for the clarifications. Were these other pumped pipelines assessed during the NDAA evaluation and will any repairs indicated be completed prior to defueling?

Response: Yes. The pipelines from the UGPH to Hotel Pier were assessed by Austin Brockenbrough and Associates, LLC to perform an inspection of the fuel transfer system, supporting infrastructure, and appurtenances, including valves and any other corrosion prone equipment at the Hotel Pier and sections of the Red Hill Tunnel and Lower Yard Tunnel as part of the Red Hill Bulk Fuel Storage Facility. Any required urgent repairs identified in this inspection were added to the list totaling 253 consolidated repairs.

(Ref. DOH numbering)

24.b. The DOH understands different design criteria were used for the two reports. One report states surges cannot be mitigated by structural or piping modifications, yet the Navy is using structural and piping modifications to mitigate risk (in addition to operation procedures), as recommended in the second report. These statements and actions are contradictory. Further clarification by the authors is appropriate.

Response: SGH provided a supplemental surge analysis report (see Reference (e)) and EEI provided a clarification memorandum (see Reference (c)) to rectify the concern. Furthermore, additional coordination meetings between DOH, JTF-RH, and EXWC occurred to help provided clarification for the two analyses dating back to December 15 and 22, 2022 and discussed during the DTWG on January 12, 2023.

Memorandum

Date: 30 November 2022

To: [redacted] (US Navy, NAVFAC, Joint Task Force, Red Hill)

From: [redacted]

CC: [redacted]

Project: Project 221162 – Red Hill Defueling Support, Joint Base Pearl Harbor-Hickam, Honolulu, HI

Subject: Hotel Pier PVC FOR Line Replacement Prior to Defueling the Red Hill Underground Bulk Fuel Storage Facility

This memorandum is provided to present an alternative to replacing the Hotel Pier polyvinylchloride (PVC) fuel oil reclamation (FOR) pipeline at Joint Base Pearl Harbor-Hickam (JBPHH), while meeting the objectives of the Simpson Gumpertz & Heger Inc. (SGH) defueling priority (D1) rating as per our April 2022 report. Our HP-14 observation in that report recommended replacing the PVC FOR pipeline with appropriate materials prior to defueling Red Hill (Figure 1).

Item	Component	Location	Description	Photograph	Observation Type	Severity	Recommendation	
							Description	Priority
HP-14	Pipe	Under the end of Hotel Pier	PVC FOR line potentially with Nitrile seals (blue)		LI	H	Replace PVC with appropriate materials	D1

Figure 1 – SGH April 2022 HP-14 Recommendation with D1 Priority

1. BACKGROUND

Between January 2022 and April 2022, SGH conducted an independent assessment of the fuel storage and transfer systems at JBPHH for the Naval Systems Supply Command (NAVSUP).

This assessment comprised observing physical infrastructure and a review of drawings, specifications, past inspection reports, standards, and governing documents related to the JBPHH fuel system, as well as our independent analyses. SGH issued a report in April 2022 containing the results of our independent assessment, listing a number of 'defueling' recommendations to improve the condition of structural and mechanical components that are part of the JBPHH fueling system. In our opinion, these recommendations should be completed prior to defueling Red Hill unless otherwise supported by new information generated as a result of new analysis, observations, or testing. These recommendations were classified as Priority D1 ("D" for defueling). We additionally categorized numerous other (195 in total) recommendations classified as Priority P1 (implementation within twelve to twenty-four months), Priority P2 (implementation within twenty-four to forty-eight months), and Priority P3 (ongoing implementation as part of maintenance activities). We did not consider items assigned to Priorities P1 through P3 as being necessary to be completed prior to defueling Red Hill.

2. INITIAL ASSESSMENT OF HOTEL PIER PVC FOR LINE

The primary function of the PVC FOR pipeline is the collection and transfer of stormwater drainage from the secondary containment fuel trench around the perimeter of Hotel Pier. Because the PVC pipeline is tied into the secondary containment trench, it also functions as a part of the spilled fuel drainage system. In the event of a leak from the fuel transfer pipelines or valves, these PVC pipes could be filled with fuel. [redacted]

[redacted]

The premise of our April 2022 HP-14 recommendation was our review of the Enterprise Engineering, Inc. 2019 Petroleum, Oil, Lubricant (POL) Integrity Management Plan (IMP) and our on-site observations. The 2019 IMP stated that the PVC FOR pipeline at Hotel Pier uses nitrile seals, which the manufacturer states are not rated for fuel service. Enterprise Engineering, Inc. highlighted in their report that the manufacturer stated the seals could break down over time with fuel exposure leading to leakage into the harbor, possible fines, and impact to mission-critical operations. During our initial assessment, we observed that the condition of the PVC FOR pipeline appeared similar to that which Enterprise Engineering, Inc. reported in 2019. The current condition of the nitrile seals is unknown, and therefore, our April 2022 recommendation was the replacement of the PVC pipeline prior to defueling via Hotel Pier.

3. ALTERNATIVE TO REPLACEMENT

We understand that replacement of the PVC FOR pipeline under Hotel Pier prior to defueling is a long lead item that may lengthen the defueling schedule.

We believe that the risk of failure of the PVC FOR pipeline's containment functionality is related to the nitrile seals and not the PVC pipe itself and that nitrile seal deterioration occurs over time due to continued fuel exposure. On this basis, we suggest consideration of an alternative to replacement prior to defueling. This alternative involves hydrotesting the existing PVC FOR pipeline to locate and repair leaks. This approach is expected to optimize the PVC pipeline repair scope by determining the integrity of the nitrile seals and focusing on leakage points.

Given the PVC pipeline is gravity fed, with the maximum pressure contingent on the head height of fluid accumulated in the secondary containment fuel trench, a reasonable leak test could plug the downstream outlet pipe and fill the pipeline with non-toxic dyed water until the upstream trench drains to overflow. Any resulting leaks could then be suitably repaired and retested prior to defueling. Once the pipeline was deemed watertight, the PVC FOR pipeline could be qualified for use while defueling. Prior to hydrotesting, all damaged/missing hardware supporting the PVC FOR pipeline under the pier should be repaired. This includes, but is not limited to, several damaged pipe hangers that we observed to be ineffective.

4. CONCLUSIONS AND RECOMMENDATIONS

Instead of PVC pipeline replacement under Hotel Pier prior to defueling Red Hill, SGH takes no exception to gravity testing the PVC pipeline to gain confidence that no adverse leakage into the harbor will occur during defueling. Any leaks detected during testing could be appropriately repaired and the pipeline retested prior to defueling. This alternative would meet the objective of item HP-14 (Priority D1)in our April 2022 Assessment Report.

In providing this recommendation, we have assumed that the PVC pipeline, pipe connections, and pipe supports were designed to resist self-weight and pipe contents' weight when all the PVC pipes are filled with water. Prior to hydrotesting, all the missing and damaged supports (steel hangers) should be reinstated to avoid overloading some pipe sections and supports.

We hope this memorandum clarifies our recommended Priority D1 rating for the Hotel Pier PVC FOR pipeline issues and assists the Navy in communicating an alternative to replacement with the Hawaii Department of Health.

[redacted]

ENTERPRISE ENGINEERING, INC.

MEMORANDUM

TO: Naval Facilities Engineering and Expeditionary Warfare Center

FROM: [redacted], P.E., Principal/Chief Mechanical Engineer Enterprise Engineering, Inc.

SUBJECT: Clarification of Statement Regarding Surge Impacts on Stress Analysis as made in the Pipeline Stress Analysis and Structural Evaluation Report, Red Hill Lower Access Tunnel

DATE: January 30, 2023

BACKGROUND

Enterprise Engineering, Inc. (EEI) prepared the report titled *Pipeline Stress Analysis and Structural Evaluation Report – Red Hill Lower Access Tunnel* (dated September 2022) as part of the FY21 Emergent Pipeline Repair Red Hill project at the Red Hill Underground Fuel Storage Complex, JBPHH, Hawaii, as a subconsultant to APTIM for NAVFAC EXWC (Contract N39430-20-D-2225, TO N3943021F4207).

In that report, EEI made the following statements:

Executive Summary: The effects of pressure surges on piping stress and support loads were not evaluated because they cannot be mitigated by structural or piping modifications and must be prevented by operational procedures.

Section 1.0 Introduction (Objective): As fuel receipts will not be considered, no evaluation of pumping scenarios will be included, only tank pressure head, maximum allowable operating pressures, and seismic loads will be considered. The effects of pressure surges on piping stress and support loads were not evaluated. Pressure surges can create damaging impulses that cannot be mitigated by structural or piping modifications and must be prevented by operational procedures or mitigated by pressure control and relief systems.

These statements regarding the surge impacts on the piping stress have reportedly caused some confusion and may have been misunderstood. EEI stands by the original statements but offers the following clarification.

CLARIFICATION

The effects of pressure surges on piping stress and support loads were not specifically evaluated by EEI for this stress analysis. The analysis was performed in accordance with ASME B31.3 *Process Piping* code as directed by UFC 3-460-01, which allows for occasional pressure variations above the design pressure up to 33% (ASME B31.3 para. 302.2.4). This assessment is only addressing the operations associated with gravity-issue from the Red Hill tanks for the final drain-down of the facility. There are only two likely types/causes of pressure surges associated with these operations: 1) improper valve closure during a fuel transfer, and 2) collapse of a low-pressure vapor cavity in the pipelines at the start of a transfer. The stress analysis accounted for an internal pressure of 85 psig, which is the maximum normal operating pressure during gravity-issue operations due to full tank head. The analysis found that the limiting component is a miter joint with a maximum allowable working pressure (MAWP) of 193 psig, giving a safety margin of over 100 psig to accommodate typical minor pressure excursions such as the butterfly valve closure under proper operational procedures.

Per EEI's 2010 *Hydraulic Analysis and Dynamic Transient Surge Evaluation, FISC Pearl Harbor Fuel System*, the use of the butterfly valves in the Underground Pumphouse as the recommended primary means (and now established flow control operation used by FLCPH) of flow control and transfer-shutdown effectively eliminates the risk of damaging surge pressures due to valve closures within allowable limits of ASME B31.3.

The collapse of a low-pressure vapor cavity in the tunnel piping can occur when the fuel pressure in the pipeline between Red Hill and the Underground Pumphouse is allowed to relieve while the tank shell valves are closed; gravity will cause the column of fuel to fall and create a vacuum, or low-pressure pocket of fuel vapors, in the lower access tunnel piping. If a tank shell valve is opened, the rapid introduction of pressure due to the tank head will collapse the vapor cavity causing pressure spikes that are potentially orders-of-magnitude above the ratings of the piping system (surge modeling of this condition at Red Hill has not been performed, however based on EEI's experience with modeling surge caused by similar slack-line vapor cavity collapses, pressure spikes of well above 1,000 psig are common). The risk of this type of surge can be mitigated by slowly equalizing the pressure between the tank and the pipeline prior to opening the tank shell valve, or by relieving any observed low pressure situation by opening a high point vent and equalizing the line to atmospheric pressure.

Both surge scenarios have appropriate methods for mitigation through the implementation of procedural or operational controls. By contrast, ignoring such controls could lead to surge pressures that would likely require an ANSI Class 600 piping system or higher in order for the predicted surge pressures to stay within code allowable pressure excursion limits per ASME B31.3. In nearly all cases throughout the petroleum industry and DoD POL, surge risks are mitigated primarily by prevention or surge pressure relief, and not by the design of the piping and supports. Only surges (hammering) that are normal to a process and cannot be mitigated by these other means must be addressed through the design of the piping system.

The intent of the statements made in the *Pipeline Stress Analysis and Structural Evaluation Report* is to communicate that modifying the piping and structural supports (likely requiring full replacement of all lower access tunnel piping and installation of massive pipe supports) is not a viable or practical approach to address surge at Red Hill, given that operational/procedural mitigation can be effective. Therefore, evaluation and reporting of the piping stress for such surge events would be academic and would not ultimately serve the goal of emptying the Red Hill complex in a safe and timely manner.

[redacted]

Release Event Tree Analysis
Various Failure Rate Scenario

Initial Probability (from QRVA): Release 0.27

Control	Control Category	Function	Failure	Results (if control functions)
PITs	Engineering	90%	10%	No Release
Zone Watch standers	Monitoring	70%	30%	No Release
Updated Operational Procedures	Operational	80%	20%	No Release
Piping/Structural Repairs Complete	Engineering	90%	10%	No Release
Independent Validations	Monitoring	70%	30%	No Release
Hazard Analysis Conducted/Actions Addressed	Monitoring	70%	30%	No Release
Tank Outlet Valve Equalization Lines	Engineering	90%	10%	No Release
Gravity Ops Only-No Pumps (Pumps for repacking only)	Operational	90%	10%	No Release

Probability of Fuel Release (per year)	One-year Odds	
1.46E-07	1 in 6,858,711	< than 1 in 1,000,000 (see Note #3)

Notes:

1. 27% chance of release estimated in QRVA Phase 1 based on controls in place in 2018.
2. All of the above controls have been implemented since 2021 (i.e. after QRVA was completed so 27% chance of a release is less due to new controls).
3. As a guideline, the general level of acceptable risk frequency is less than 1x10^-7 (or 1 in 1,000,000 (i.e. 1 million)).
4. Engineering controls are shown in green. Operational controls are shown in blue. Monitoring controls are shown in orange.
5. Function indicates the control is working properly.
6. Failure indicates the control has failed and is relying on a follow-on layer of protection to function to prevent a release.
7. Based on 1-year occurrence since defueling is expected to take less than one year.
8. Risk of a release is determined by estimating the risk of all controls failing simultaneously (i.e. if any one control functions as designed, there will not be a release of fuel to the environment).

Controls implemented at the Red Hill Bulk Fuel Storage Facility since 2021 to reduce risk of a release

#	Control	Classification	Description	Mitigation Effort	Failure Probability	Justification
1	**Pressure Indicating Transmitters (PITs)**	**Engineering**	Seven additional PITs will be installed prior to repacking and defueling the RHBFSF to provide better indication of a vacuum forming in the pipeline. This will enable operators to better identify the need to eliminate the vacuum in the pipeline before transferring fuel. Two of the PITs will be located at high point vents in the JP-5 and F-24 pipelines. The other five PITs will be located immediately down gradient of isolation valves inside the lower tank gallery and harbor tunnel for the JP-5 and F-24 pipelines.	ID surge before system is compromised.	10%	Industry standard is that sensors will function properly at least 90% of the time.
2	**Zone Watch standers**	**Monitoring**	Additional watch standers will be located in each of the thirteen zones between the underground pump house at Joint Base Pearl Harbor-Hickam and the RHBFSF to monitor for problems and observe local pressure indications during repacking and defueling. In each zone, a trained fuel systems worker is assigned to watch the pipeline and valves within their zone for weeps, drips, etc. and any other issues and immediate report by radio to the control room to stop defueling.	ID surge before system is compromised.	30%	Human response is more prone to failure than engineering controls.
3	**Updated Operational Procedures**	**Operational**	Formal Valve Lineups: Prior to every fuel movement operation, teams of people walk the entire length of each pipeline to verify all valves, valve positions and valve numbers. Valve baselines (baseline operating orders) are then developed to show the baseline valve position and sequence for each fuel pipeline.	Reduce likelihood of operator error.	20%	Human response is more prone to failure than engineering controls. However, multiple layers of human protection reduce likelihood of failure.
			Formal Operating Procedures: Formal operating orders are developed for each fuel movement including baseline valve orders, maintenance orders and defueling orders. The orders include step by step operator actions to be taken in sequence as well as documenting the pressures, flow rates, tank levels, etc. throughout the order. A "Point and Call" system with structured radio behavior has been implemented between the assistant control room operator and all fuel workers to improve communications.	Reduce likelihood of operator error.		See above.
			Formal Training: An enhanced fuel worker competency training program has been implemented. This is a role-based training program focusing on specific fuel worker tasks. Additional environmental and safety training including spill response training, emergency response, hazard identification training, etc. has also been implemented to better equip personnel to respond to emergencies.	Reduce likelihood of operator error.		See above.
			Operational Tabletops: A new process has been implemented to to develop specific operations orders for defueling. The operations orders are rehearsed in a tabletop exercise followed by a dry run walkthrough in the field with all participants to simulate execution of the operations orders. Both the tabletop exercise and the dry run walkthrough are debriefed to look for opportunities for improvement.	Reduce likelihood of operator error.		See above.
			Formal Lockout-Tagout Program: An updated OSHA-compliant Isolation of Energy (Lockout/Tagout) instruction is now in effect. All workers are trained and tested on the new process. The Lockout-Tagout (LOTO) system is now in effect as repairs are being completed prior to repacking and defueling. Additionally, daily maintenance activities are now scheduled in advance with a centralized point of contact and broadcast out via email to all entities on site at the RHBFSF to maintain situational awareness of maintenance activities.	Reduce likelihood of operator error.		See above.
4	**Pipeline Repaired/Structural Integrity Actions Addressed**	**Engineering**	Multiple highly qualified companies are completing hundreds of pipeline repairs, including dresser coupling replacement, new sections of pipe, improved pipe support systems, etc.	Mitigate chance of release if surge does occur.	10%	Testing and independent quality control and assurance reduce likelihood of failure.
5	**Independent Validators**	**Monitoring**	Trained Independent Validators (IV) are stationed at each valve that is manually operated in the field. Each IV double checks the valve number and valve position listed in the operation order.	Reduce likelihood of operator error.	30%	Human response is more prone to failure than engineering controls.
6	**Hazard Analysis Conducted and Actions Addressed**	**Monitoring**	A consultant with industry expertise has been hired to lead Process Hazard Analyses (PHA) on all aspects of the defueling process. The PHAs identify the hazards as well as identify the existing mitigations and any additional mitigations needed to reduce risk.	Reduce likelihood of operator error.	30%	Human response is more prone to failure than engineering controls.
7	**Equalization Lines Around Tank Outlet Valves**	**Engineering**	JTF-RH is overseeing the installation of equalization lines around the tank isolation valves to enable more gradual pressure equalization to further reduce the possibility of a surge.	Mitigate risk of surge.	10%	Testing and independent quality control and assurance reduce likelihood of failure.
8	**Elimination of Pumps at Underground Pump House**	**Engineering**	Pumps in the underground pump house are currently not planned for use to repack the pipelines. Currently, fuel lines will be repacked using fuel from the Red Hill tanks.	Reduce risk of surge.	10%	Lockout-tagout system will prevent inadvertent operation of pumps along with watch stander that has been directed not to operate pumps.

Odds of dying due to injury, United States, 2020

Type of accident or manner of injury	One-year odds	Lifetime odds
All external causes of mortality, V01-Y89, *U01, *U03b	**1,161**	**15**
Deaths due to unintentional (accidental) injuries, V01-X59, Y85-Y86	**1,640**	**21**
Transport accidents, V01-V99, Y85	**7,296**	**95**
Motor vehicle accidents, V02-V04, V09.0, V09.2, V12-V14, V19.0-V19.2, V19.4-V19.6, V20-V79, V80.3-V80.5, V81.0-V81.1, V82.0-V82.1, V83-V86,V87.0-V87.8, V88.0-V88.8, V89.0, V89.2	**7,782**	**101**
Pedestrian, V01-V09	41,686	541
Pedalcyclist, V10-V19	261,495	3,396
Motorcycle rider, V20-V29	61,551	799
Occupant of three-wheeled motor vehicle, V30-V39	(c)	(c)
Car occupant, V40-V49	48,439	629
Occupant of pick-up truck or van, V50-V59	232,031	3,013
Occupant of heavy transport vehicle, V60-V69	1,076,746	13,984
Bus occupant, V70-V79	23,534,580	305,644
Animal rider or occupant of animal-drawn vehicle, V80	3,396,744	44,114
Occupant of railway train or railway vehicle, V81	(c)	(c)
Occupant of streetcar, V82	(c)	(c)
Other and unspecified land transport accidents, V83-V89	16,247	211
Occupant of special industrial vehicle, V83	(c)	(c)
Occupant of special agricultural vehicle, V84	2,792,238	36,263
Occupant of special construction vehicle, V85	*9,152,337*	*118,862*
Occupant of all-terrain or other off-road motor vehicle, V86	246,067	3,196
Other and unspecified person, V87-V89	17,547	228
Water transport accidents, V90-V94	574,014	7,455
Drowning, V90, V92	799,719	10,386
Other and unspecified injuries, V91, V93-V94	2,033,853	26,414
Air and space transport accidents, V95-V97	905,176	11,756
Occupant of private or commercial fixed-wing aircraft, V95.2-V95.3	(c)	(c)
Other and unspecified transport accidents and sequelae, V98-V99, Y85	427,901	5,557
Other specified transport accidents, V98	(c)	(c)
Unspecified transport accident, V99	(c)	(c)
Nontransport unintentional (accidental) injuries, W00-X59, Y86	**2,115**	**27**
Falls, W00-W19	7,824	102
Fall on same level from slipping, tripping, and stumbling, W01	416,541	5,410
Other fall on same level, W00, W02-W03, W18	20,872	271
Fall involving bed, chair, other furniture, W06-W08	218,057	2,832
Fall on and from stairs and steps, W10	123,449	1,603
Fall on and from ladder or scaffolding, W11-W12	572,021	7,429
Fall from out of or through building or structure, W13	661,615	8,592
Other fall from one level to another, W09, W14-W17	400,345	5,199
Other and unspecified fall, W04-W05, W19	16,931	220
Exposure to inanimate mechanical forces, W20-W49	130,437	1,694
Struck by or striking against object, W20-W22	367,728	4,776
Caught between objects, W23	1,761,947	22,882
Contact with machinery, W24, W30-W31	621,668	8,074
Contact with sharp objects, W25-W29	2,059,276	26,744
Firearms discharge, W32-W34	615,858	7,998
Explosion and rupture of pressurized devices, W35-W38	12,672,466	164,577
Fireworks discharge, W39	12,203,116	158,482
Explosion of other materials, W40	3,876,284	50,341
Foreign body entering through skin or natural orifice, W44-W45	9,152,337	118,862
Other and unspecified inanimate mechanical forces, W41-W43, W49	7,488,276	97,250
Exposure to animate mechanical forces, W50-W64	2,009,050	26,092
Struck by or against another person, W50-W52	(c)	(c)
Bitten or struck by dog, W54	5,314,260	69,016
Bitten or struck by other mammals, W53, W55	4,452,488	57,825
Bitten or stung by nonvenomous insect and other arthropods, W57	(c)	(c)
Bitten or crushed by other reptiles, W59	(c)	(c)
Other and unspecified animate mechanical forces, W56, W58, W60, W64	(c)	(c)
Accidental drowning and submersion, W65-W74	78,881	1,024
Drowning and submersion while in or falling into bathtub, W65-W66	513,215	6,665
Drowning and submersion while in or falling into swimming-pool, W67-W68	445,249	5,782
Drowning and submersion while in or falling into natural water, W69-W70	153,749	1,997
Other and unspecified drowning and submersion, W73-W74	505,344	6,563
Other accidental threats to breathing, W75-W84	48,683	632
Accidental suffocation and strangulation in bed, W75	319,887	4,154
Other accidental hanging and strangulation, W76	1,698,372	22,057
Threat to breathing due to cave-in, falling earth and other substances, W77	*11,767,290*	*152,822*
Inhalation of gastric contents, W78	983,535	12,773
Inhalation and ingestion of food causing obstruction of respiratory tract, W79	211,343	2,745
Inhalation and ingestion of other objects causing obstruction of respiratory tract, W80	107,359	1,394
Confined to or trapped in a low-oxygen environment, W81	(c)	(c)
Other and unspecified threats to breathing, W83-W84	606,785	7,880
Exposure to electric current, radiation, temperature, and pressure, W85-W99	1,132,248	14,705
Electric transmission lines, W85	4,118,552	53,488
Other and unspecified electric current, W86-W87	1,672,508	21,721
Radiation, W88-W91	(c)	(c)
Excessive heat or cold of man-made origin, W92-W93	(c)	(c)
High and low air pressure and changes in air pressure, W94	(c)	(c)
Other and unspecified man-made environmental factors, W99	(c)	(c)
Exposure to smoke, fire and flames, X00-X09	111,652	1,450
Uncontrolled fire in building or structure, X00	140,505	1,825
Uncontrolled fire not in building or structure, X01	3,581,349	46,511
Controlled fire in building or structure, X02	25,344,933	329,155
Controlled fire not in building or structure, X03	5,990,620	77,800
Ignition of highly flammable material, X04	4,224,155	54,859
Ignition or melting of nightwear, X05	(c)	(c)
Ignition or melting of other clothing and apparel, X06	3,468,254	45,042
Other and unspecified smoke fire and flames, X08-X09	1,211,339	15,732
Contact with heat and hot substances, X10-X19	3,876,284	50,341
Contact with hot tap-water, X11	10,296,379	133,719
Other and unspecified heat and hot substances, X10, X12-X19	6,216,682	80,736
Contact with venomous animals and plants, X20-X29	3,432,126	44,573
Contact with venomous snakes and lizards, X20	(c)	(c)
Contact with venomous spiders, X21	(c)	(c)
Contact with hornets, wasps and bees, X23	4,452,488	57,825
Contact with other and unspecified venomous animal or plant, X22, X24-X29	(c)	(c)
Exposure to forces of nature, X30-X39	180,837	2,349
Exposure to excessive natural heat, X30	490,304	6,368
Exposure to excessive natural cold, X31	358,525	4,656
Lightning, X33	(c)	(c)
Earthquake and other earth movements, X34-X36	*9,690,710*	*125,853*
Cataclysmic storm, X37	2,700,690	35,074
Flood, X38	8,904,976	115,649
Exposure to other and unspecified forces of nature, X32, X39	15,689,720	203,763
Accidental poisoning by and exposure to noxious substances, X40-X49	3,770	49
Drug poisoning , X40-X44	3,943	51
Opioids (including both legal and illegal), T40.0-T40.4, T40.6	5,134	67
Alcohol, X45	123,634	1,606
Gases and vapors, X46-X47	326,869	4,245
Other and unspecified chemicals and noxious substances, X48-X49	1,904,533	24,734
Overexertion, travel and privation, X50-X57	6,336,233	82,289
Accidental exposure to other and unspecified factors and sequelae, X58-X59, Y86	44,871	583
Intentional self-harm, X60-X84, Y87.0, *U03	**7,166**	**93**
Intentional self-poisoning, X60-X69	59,603	774
Intentional self-harm by hanging, strangulation, and suffocation, X70	26,369	342
Intentional self-harm by firearm, X72-X74	13,563	176
Other and unspecified means and sequelae, X71, X75-X84, Y87.0	89,925	1,168
Terrorism, *U03	(c)	(c)
Assault, X85-Y09, Y87.1, *U01	**13,407**	**174**
Assault by firearm, X93-X95	16,999	221
Assault by sharp object, X99	159,711	2,074
Other and unspecified means and sequelae, X85-X92, X96-X98, Y00-Y09, Y87.1	105,300	1,368
Terrorism, *U01	(c)	(c)
Event of undetermined intent, Y10-Y34, Y87.2, Y89.9	**54,532**	**708**
Poisoning, Y10-Y19	83,988	1,091
Hanging, strangulation, and suffocation, Y20	2,477,324	32,173
Drowning and submersion, Y21	1,076,746	13,984
Firearm discharge, Y22-Y24	823,710	10,698
Exposure to smoke, fire, and flames, Y26	1,664,061	21,611
Falling, jumping, or pushed from a high place, Y30	3,660,935	47,545
Other and unspecified means and sequelae, Y25, Y27-Y29, Y31-Y34,Y87.2, Y89.9	332,141	4,314
Legal intervention, Y35, Y89.0	**422,416**	**5,486**
Legal intervention involving firearm discharge, Y35.0	539,254	7,003
Legal execution, Y35.5	*(c)*	*(c)*
Other and unspecified means and sequelae, Y35.1-Y35.4, Y35.6-Y35.7, Y89.0	2,167,659	28,151
Operations of war and sequelae, Y36, Y89.1	**(c)**	**(c)**
Complications of medical and surgical care and sequelae, Y40-Y84, Y88.0-Y88.3	**61,459**	**798**

Source: National Center for Health Statistics.--Mortality Data for 2018 as compiled from data provided by the 57 vital statistics jurisdictions through the Vital Statistics Cooperative Program. Deaths are classified on the basis of the Tenth Revision of "The International Classification of Diseases" (ICD-10), which became effective in 1999.

Note: "n.e.c." means not elsewhere classified.

(a) Latest official figures.

(b) Numbers following titles refer to external cause of injury and poisoning classifications in ICD-10.

(c) Rates based on less than 20 deaths are likely to be unstable from year to year and are therefore not included.

[redacted]

Naval Facilities Engineering Systems Command

EXWC Engineering & Expeditionary Warfare Center

BORESCOPE INSPECTION REPORT

FINAL SUBMITTAL

FUEL TRANSFER INFRASTRUCTURE ASSESSMENT:
BURIED FOR PIPING INTERNAL INSPECTION – ADIT 3 ENTRANCE

Red Hill Bulk Fuel Storage Facility, Hawaii (RHL)

Delivery Order No. N3943022F4333
A/E Contract No. N39430-20-D-2242

Submitted to:

Naval Facilities Engineering Command
Engineering and Expeditionary Warfare Center
1000 23rd Avenue,
Port Hueneme, CA 93043-4370

January 30, 2023

Submitted by:

Austin Brockenbrough
ENGINEERING + CONSULTING

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[redacted]

[redacted]

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ACRONYMS

API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
AST	Aboveground Storage Tank
ASTM	American Society for Testing and Materials
Bbls	Barrels
CFR	Code of Federal Regulations
DBB	Double Block and Bleed [Twin-Seal Valve]
FLC	Fleet Logistics Center
IMP	Integrity Management Plan
LRUT	Long-Range Ultrasonic Testing
MAOP	Maximum Allowable Operating Pressure
MAWP	Maximum Allowable Working Pressure
MOP	Maximum Operating Pressure
NAVFAC	Naval Facilities Engineering Systems Command
NAVFAC EXWC	NAVFAC Engineering and Expeditionary Warfare Center
NAVSUP	Naval Supply Systems Command
NDAA	National Defense Authorization Act
NDE	Non-Destructive Examination
NFPA	National Fire Protection Agency
RHTF	Red Hill Tank Farm
SOW	Scope of Work
SPCC	Spill Prevention Control and Countermeasures
TRV	Thermal Relief Valve
UFGS	United Facilities Guide Specification
UT	Ultrasonic Testing
UTF	Upper Tank Farm
UTM	Ultrasonic Thickness Measurement
WO	Waste Oil

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A. EXECUTIVE SUMMARY

Austin Brockenbrough & Associates, LLC (Brockenbrough) was retained by NAVFAC EXWC under Contract No. N3943020-D-2242, Delivery Order N3943022-F-4333, Modification P002 and P004 to perform an internal inspection of an underground segment of FOR Piping using borescope technology at Joint Base Pearl Harbor Hickam (JBPHH). [redacted]

During the previous visual inspection of the FOR piping from Adit #3 to AST Tank [redacted], several areas of severe external corrosion were noted. These sections of piping were cut out and replaced for the FOR piping to be returned to service. Due to these findings, an internal inspection of the buried sections of FOR piping was recommended to determine if other areas of severe corrosion may be present on the buried section of the pipeline where external visual inspection was not possible.

For this reason, the internal borescope inspection of the buried section of FOR piping at Adit #3 was proposed and added into the inspection scope for this task order. This inspection included two site visits, the first on September 12th thru 15th, 2022: the second on November 15th thru 17th, 2022. During these two site visits, [redacted] underground FOR piping was emptied, cleaned, and inspected internally. At the end of the site inspections, all piping was returned to an operational condition and the waste generated from this project was manifested, removed from the site, and disposed of. The borescope inspection was conducted from outside of the Adit #3 entrance on the first inspection site visit, and then from the opposite end inside the Adit #3 entrance on the second inspection site visit. Accessing the piping interior from these two end locations allowed the full length of buried FOR piping to be internally inspected using the borescope equipment.

Findings from the internal inspection of the FOR piping system have been prioritized into three categories:

- Defuel Mandatory Repairs - Repairs identified as urgent are those that represent an immediate/major risk to personnel safety and/or the environment and have failed a fitness for service evaluation. These are repairs that are critical to the hydraulic and structural integrity of the piping system and should be completed as soon as possible prior to defueling the Red Hill Tank Farm (RHTF).
- Long-Term Repairs - Repairs identified as long-term are those that do not pose an immediate risk to personnel safety and/or the environment. These repairs are not critical to the hydraulic and structural integrity of the piping system.
- Other Items of Note - Repairs or upgrades that could be addressed to upgrade the system piping to meet current military criteria or improve system operations but may not be warranted based on cost-benefit considerations and timeline of defueling the RHBFSF.

The decision has been made to close and defuel the Red Hill Bulk Storage Facility's fuel systems within the next five years. Therefore, the Defuel Mandatory Repair recommendations included in this report are focused on system repairs needed to safely defuel the RHTF over the next five years. Any items that have been noted for long-term repair for the FOR piping System that should be programmed for execution after defueling operations are complete, to ensure continued service and operation into the future.

The [redacted] FOR piping was found to be standard schedule [redacted] and the interior wall was bare steel. Findings from the borescope inspection identified some internal erosion, corrosion, and pitting on the internal piping wall. These anomalies were generally grouped at the elbows of the piping and are likely the result of the water content of the product and bits of dirt and debris that are flowing within the product stream. For more details of the inspection and the findings, see the detailed Borescope Inspection Report from our sub-consultant which has been provided as Appendix B.

In conclusion, none of the anomalies identified were significant enough for the piping to be removed from service, and calculations show adequate service life and pressure capacity for continued used well past the expected Defuel Operation completion date. Future repairs may be warranted in the long term if this FOR piping is to remain in service, but the piping was found to be fully serviceable until the next inspection (IMP Update) is due in another 10-years.

Disclaimer

Report is based on information known as of the date of the report and subject to revision should new information become available.

[redacted]

[redacted]

B. INTRODUCTION

Austin Brockenbrough & Associates, LLC (Brockenbrough) was retained by NAVFAC EXWC under Contract No. N3943020-D-2242, Delivery Order N3943022-F-4333, Modification P002 and P004 to perform an internal inspection of an underground segment of FOR Piping using borescope technology at Joint Base Pearl Harbor Hickam (JBPHH). [redacted]

During the previous visual inspection of the FOR piping from Adit #3 to AST Tank [redacted], several areas of severe external corrosion were noted. These sections of piping were cut out and replaced for the FOR piping to be returned to service. Due to these findings, an internal inspection of the buried sections of FOR piping was recommended to determine if other areas of severe corrosion may be present on the buried section of the pipeline where external visual inspection was not possible.

For this reason, the internal borescope inspection of the buried section of FOR piping at Adit #3 was proposed and added into the inspection scope for this task order. This inspection included two site visits, the first on September 12th thru 15th, 2022: the second on November 15th thru 17th, 2022. During these two site visits, the approximate [redacted] underground FOR piping was emptied, cleaned, and inspected internally. At the end of the site inspections, all piping was returned to an operational condition and the waste generated from this project was manifested, removed from the site, and disposed of. The borescope inspection was conducted from outside of the Adit #3 entrance on the first inspection site visit, and then from the opposite end inside the Adit #3 entrance on the second inspection site visit. Accessing the piping interior from these two end locations allowed the full length of buried FOR piping to be internally inspected using the borescope equipment.

1. Assessment Objectives

The objective of this assessment is to conduct an internal borescope inspection of the short underground FOR piping at Adit #3 Entrance, as this underground piping segment was unable to be assessed using standard visual inspection methods. This report presents findings, recommendations, and provides an assessment of the overall condition of buried section of FOR piping.

The decision has been made to close and defuel the Red Hill Bulk Storage Facility's fuel systems within the next five years. Therefore, the Defuel Mandatory Repair recommendations included in this report are focused on system repairs needed to safely defuel the RHTF over the next five years. All the Defuel Mandatory Repairs and Long-Term deficiencies identified are recommended. The long-term deficiencies should be programmed for execution after defueling operations are complete.

C. FACILITY DESCRIPTION

1. Project Location

This pipeline assessment and inspection was performed at the buried segment of FOR piping located at the Adit #3 Entrance of the Red Hill Bulk Tank Farm at JBPHH, Hawaii.

2. System Overview

The FOR system contains untreated off-spec or contaminated product from the three main bulk fuel products (such as tank water bottoms) mixed with water from that infiltrates the tunnel system. [redacted] The FOR piping system was within the scope of the recent Fuel Transfer Infrastructure Assessment Piping Inspection, and was visually inspected as part of the project.

During the previous visual inspection, several areas of severe external corrosion were noted. These sections of piping were cut out and replaced for the FOR piping to be returned to service. Due to these findings, an internal inspection of the buried sections of FOR piping was recommended to determine if other areas of severe corrosion may be present on the buried section of the pipeline where external visual inspection was not possible.

[redacted]

D. INSPECTION METHODOLOGY

An [redacted] direct buried piping segment was inspected internally using borescope technology. This underground segment is located [redacted]

Two site visits were required to fully inspect this segment of piping. The first inspection inserted the borescope equipment through a blind flange just outside of the Adit #3 Entrance. The second inserted the borescope equipment from a flange within the Adit #3 Entrance. Investigating the underground piping segment from both ends allowed inspection of the full length of the underground piping run. The unexpected geometry of the underground piping required entry from both ends to get a complete internal inspection using the borescope equipment.

1. References

The following references were used in the collection of data, inspection, and assessment of the underground FOR piping system located outside of the Adit #3 Entrance:

- API 570 Piping Inspection Code
- API 574 Inspection Practices for Piping System Components
- API 577 Welding Inspection and Metallurgy
- API 579 Fitness for Service
- API 580 Risk Based Inspection
- ASME B31.3 Process Piping
- ASME B31G Manual for Determining Remaining Strength of Corroded Pipelines
- 40 CFR 112 Oil Pollution Prevention
- NFPA 30 Flammable and Combustible Liquids Code
- UFC 3-460-01 Design: Petroleum Fuel Facilities
- UFC 3-460-03 O&M: Maintenance of Petroleum Systems

2. Internal Borescope FOR Piping Inspection

The purpose of the internal borescope inspection is to locate conditions or areas of concern that compromise the integrity of the FOR piping. Areas of concern include for this type of inspection include internal corrosion and pitting, internal erosion, weld defects and other signs of accelerated degradation.

E. CONDITION ASSESSMENT

The current condition assessment is primarily based upon the inspection efforts made during our field investigation September and November 2022, and relevant supporting material provided in the government furnished information. We have assigned five easily understood levels of condition:

- Poor – The piping system is showing signs of significant integrity issues such as severe corrosion where significant pipe wall loss, greater than 50-percent, is present.
- Fair – The piping system is showing signs of moderate to severe integrity issues such as corrosion where pipe wall loss, greater than 40-percent but less than 50-percent, is present.
- Satisfactory – The piping system is showing signs of moderate integrity issues such as moderate corrosion where pipe wall loss, greater than 10-percent but less than 40-percent, is present.
- Good – The piping system shows signs of light to moderate corrosion where pipe wall loss, less than 10-percent, is present.
- Excellent – The piping system shows no signs of integrity issues or active corrosion.

1. FOR Piping Condition

The buried segment of FOR piping serves as the link between the FOR Aboveground Storage Tank [redacted] and the piping within the tunnel of the Red Hill Bulk Tank Farm. Fuel is transferred from various sumps and equipment drains within the tunnel, through the FOR piping and ultimately to the AST for storage and processing.

The buried segment of FOR Piping at the Adit #3 Entrance was generally found to be in satisfactory condition. The pipelines and system components appear to be fully serviceable to support the upcoming defuel operations.

F. FINDINGS AND RECOMMENDATIONS

The findings from the internal borescope inspection performed on the underground FOR piping systems located at the Adit #3 Entrance have been prioritized into three categories:

- Defuel Mandatory Repairs - Repairs identified as urgent are those that represent an immediate/major risk to personnel safety and/or the environment and have failed a fitness for service evaluation. These are repairs that are critical to the hydraulic and/or structural integrity of the piping system and should be completed as soon as possible prior to defueling the RHTF.
- Long-Term Repairs - Repairs identified as long-term are those that do not pose an immediate risk to personnel safety and/or the environment. These repairs are not critical to the hydraulic and structural integrity of the piping system.
- Other Items of Note - Repairs or upgrades that could be addressed to upgrade the system piping to meet current military criteria or improve system operations but may not be warranted based on cost-benefit considerations and timeline of defueling the RHBFSF over the next five years.

A list of all deficiencies, including long term repairs and other items of note is provided in the following pages. For photos and additional details of the borescope internal inspection, see Appendix B Borescope Inspection Report.

After compiling the findings and data, there were no Defuel Mandatory Repairs or Long Term Repairs identified which should be completed prior to defueling the facility. There was one Item of Note identified during our inspection, which should be addressed in a timely manner to improve system efficiency and longevity. All the recommended repairs are outlined in the following pages.

[redacted]

1. Defuel Mandatory Repairs

No Defuel Mandatory Repairs were identified at this time.

2. Long Term Repairs

No Long Term Repairs were identified at this time.

[redacted]

[redacted]

APPENDIX B

BORESCOPE INSPECTION REPORT

[redacted]

Inter Spec LLC

Environmental Inspection Services

464 S Independence Blvd, C-104, Virginia Beach, VA 23452

www.interspecllc.net

Office: 757-622-6299
Fax: 757-622-9103
Toll Free: 800-546-7853

Borescope Internal Inspection of Buried Section of FOR Piping at ADIT 3

Joint Base Pearl Harbor Hickam; HI

[redacted]

Prepared for

Austin Brockenbrough & Associates, LLC

1011 Boulder Springs Drive, Suite 200
Richmond, Virginia 23225

September/November 2022

API Standard 570 recommends this document containing valuable historical information be retained for the life of the piping.

[redacted]

[redacted]

General Conditions

The information referenced in this engineering report is based solely upon the area(s) agreed upon and contracted for inspection on the date of the inspection and under those present, known, same, and current conditions. This report was prepared using retrievable data from those areas that were properly cleaned, prepared, and made accessible during the inspection. Areas not contracted for inspection, not cleaned, and not made accessible are not included in this report.

The methods, standards, and regulations used by InterSpec, LLC during the inspection and preparation of this engineering report comply with the most current and widely accepted standards and regulations in the industry, in which these standards and regulations make no representation, warranty, or guarantee. The professional opinions and recommendations stated in this report, including predictability of life, maximum length of time for re-inspection, suitability for product storage, and safe fill height are conclusive approximations and are intended to serve mainly as guidelines for obtaining the utmost in spill prevention and environmental protection. The listed recommendations may not necessarily be mandatory actions but corrective actions InterSpec, LLC suggests would better preserve the owners'/operators' facility components and may contribute to safer and more convenient operations. Failure to comply with these could result in, but may not be limited to, reduction of service life, piping mishap, legal consequences, and/or fines for owners/operators. It is best advised the recommended repairs, corrective actions, and procedures be fully and accurately complied with in order to meet the required and applicable federal, state, and local regulations and to have the necessary repairs and upgrades performed prior to making any change in service, product, and/or current conditions. Some recommendations and requirements are necessary to bring the component(s) into compliance with federal, state, and local regulations. InterSpec, LLC recommends re-inspection after any corrective action, repair, or change in usage when the change is to a more severe service. Any change in facility conditions that are applicable to this inspection report such as, but not limited to, a change in service or usage could result in outdating this report. The predictability of any component in this report is a result of following the procedures in the applicable industry standard. InterSpec, LLC accepts absolutely no responsibility or liability for any mishap or failure, including any subsequent clean-up costs or legal ramifications, resulting from owners'/operators' failure to perform the required repairs, inspections, and re-inspections as they apply.

[redacted]

Executive Summary

This report contains an engineering analysis and assessment of the data collected during the borescope internal inspection of the buried section of the FOR Piping at ADIT 3 located in the Red Hill fuel complex Joint Base Pearl Harbor Hickam, Hawaii.

The inspection included securing the FOR line, cleaning the internal section of the pipe, internal visual video inspection, thickness and pitting assessment of accessible sections of the pipe, and restoring the FOR line back to service. The inspection was completed in two separate trips and included accessing the piping from the outside and inside of ADIT 3. [redacted]

The evaluation of the inspected section of the FOR line shows the remaining life of the piping, if continued in the same product service, to be in accordance with API-570. The internal section of the piping inspected did not indicate anomalies that will limit the use of the piping under the same product service and pressure.

Note two calculations were performed assuming two cases:
Case 1 (C1) is assuming the worst-case scenario, where the minimum thickness reading obtained on aboveground section minus the maximum pitting depth is estimated on the internal section of the pipe.
Case 2 (C2) is assuming the most-likely case scenario, where the average thickness reading obtained on aboveground section minus the maximum pitting depth is estimated on the internal section of the pipe.

Design and the inspection data is summarized in Table A below:

TABLE A - Summary Design and Inspection Data

MAOP* = 275 PSIG	Pipe Size (Assumed) (inches)	Nominal Wall Thickness (inches)	Minimum Required Wall Thickness (inches)	Previous Measured Wall Thickness (inches)**	Minimum Measured Wall Thickness (inches)***	Corrosion Rates (inches/Year)	Calculated Remaining Life (years)	Maximum Allowable Working Pressure at Next UT Inspection (psig)
[redacted]								

Notes:

Table is based on thickness data collected at CMLs. Localized areas of pitting and corrosion are detailed in Table D (Piping Deficiency. Exterior section of the FOR pitting and corrosion is extensive and is added to the table.

** When the design pressure or MAOP was not available, the pump dead head pressure or TRV set points are used in the working pressure calculation. The calculation was computed for the lowest CML in the NPS group. The maximum anticipated working pressure is used in the calculation (275 PSIG). MAOP of 275 PSIG (based on pedigree, specimen tests, and study performed by APTIM/EEI)*

*** Use nominal when there is no documented TML data from previous inspection record*

****Average UT of exposed pipe thickness minus the max estimated internal pitting*

[redacted]

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1.0 Introduction

1.1 Purpose

1.1.1 This report presents an analysis of data collected during an inspection conducted in September and November, 2022 of the buried section of the FOR Piping at ADIT 3 located in the Red Hill fuel complex in Hawaii. The inspection was performed by a certified API-570 inspector from InterSpec, LLC. All data was collected in accordance with the guidelines set forth in API Standard 570, the appropriate ASME Codes, 40 CFR 112, and other supporting documents.

1.2 Borescope Pipeline Inspection Procedures

1.2.1 Piping can deteriorate by several means such as internal or external corrosion and internal erosion. All POL piping evaluated by InterSpec during an API-570 inspection is classified as to risk and prioritized per API-570. Factors that are considered include: location, contents, pressure, temperature, injection points, external conditions, and areas of low flow or no flow.

InterSpec initially conducted a visual inspection of the site and planned an integrity inspection that best fulfilled the needs of the customer. For example, the customer's piping might all be the same class, or there may be portions that are more critical. In each situation, the testing procedures will be the same, but re-inspection requirements will be different.

1.2.2 **General**: Visual, ultrasonic, magnetic particle, and dye penetrant examinations are used in InterSpec's evaluation.

a. Careful visual inspection to identify deficiencies in the material condition of the piping and insulation where it exists.
b. For underground or encased piping, conduct an above grade surveillance; looking for discoloration of the soil, softening of paving asphalt, or noticeable odor.
c. Deterioration may be in the form of electrochemical, chemical, mechanical, or a combination of these and may be accelerated by temperature, stress, fatigue, impingement, high velocity, or irregularity of flow rates. When any of these conditions are present, they will be evaluated by the appropriate NDE method.

Corrosion is the prime cause of deterioration in a piping system. InterSpec evaluates the following conditions when they exist**:**

a. Caustics, inorganic acids, organic acids, and low pH water – are all leading causes of corrosion within piping systems.
b. Hydrogen sulfides attack metals and can cause hydrogen blistering and hydrogen embrittlement.
c. Atmospheric corrosion - Corrosion where humidity is above 60% allowing water to absorb oxygen at a high rate and increase rates of corrosion.
d. Corrosion under insulation ([redacted] – Sources of moisture include rain, condensation, snow etc. ([redacted] is common).
e. Check for caustic embrittlement – Commonly found on systems carrying caustic products; check fitting connections, flanges, next to weld seams, and areas of high stress.

Mechanical Forces

Mechanical Forces

a. Check for cracks, bulges, and distortions.
b. Check for fatigue failures.
c. Check where thermal expansion is causing fatigue from heating and rapid cooling.
d. Check fabrication defects.

On-Stream Inspections

a. Determine pipe sections that may be approaching minimum life and have to be replaced at a scheduled shutdown.
b. Inspect pipe supports and pipe anchors.
c. Inspect for external corrosion - piping, supports, slide shoes, and spring hangers.

Visual Inspection

a. Check for leaks, safety, and fire hazards.
b. Inspect flanged joints, packing glands, valve bonnets, and expansion joints.
c. Check misalignment: pipe support out of plumb, shifting of base-plates, or foundation breaking supports, hangers, and braces.
d. Check deterioration of protective coatings for evidence of corrosion, distortion, movement of concrete footings, failure or loose foundation bolts, restricted operation of pipe rollers, or slide plates.
e. Check branch connections that are against pipe supports as a result of thermal movement.
f. Check for damage due to hydraulic shock; check DUMMY LEGS (a weld support welded to an elbow, usually a piece of pipe or structural beam).
g. Inspect for cracks where vibration or swaying has been observed (problems at small connections with heavy valves and small lines that are tied down to a larger line).
h. Check external corrosion from sweating lines, moisture getting through insulation, or protective coatings.
i. Check for accumulations of corrosion liquids (from spills and old leaks).

Condition Monitoring Location (CML)

a. Ultrasonic thickness measurements.
b. Monitor each piping system by taking CMLs, where areas are subject to higher corrosion rates, areas are subject to localized corrosion, locate minimum thickness at CML, outside and inside radius of elbows taken (use lowest reading in calculations) establish minimum for areas of [redacted]

Determine Retirement Thickness; Calculate Thickness According To:

a. ASME B31.3 using Barlow Equation if thickness is less than D/6 and P/SE is not greater than 0.385. $t = PD/2SE$, where
   t = pressure design thickness,
   P = internal design pressure,
   D = outside diameter of pipe,
   S = allowable unit stress, and
   E = longitudinal joint efficiency.
   For valves and flanges use $t = 1.5PD/2SE$ + corrosion allowance.

Sketches

a. Develop layout or isometric drawings providing a means of recording the size of piping, piping location, process flow, thickness measurements, and areas of serious corrosion.

Inspection for Specific Types of Corrosion and Cracking (as applicable)

a. Injection points – 12” or 3 pipe diameters downstream.
b. Deadlegs –high points in hot piping.
c. [redacted] – integrity of insulation, sources of moisture, localized corrosion, chloride stress corrosion, or cracking of SS piping – areas susceptible to [redacted] areas exposed to mist over spray, steam vents, process spills, piping in intermittent service, vibrating piping, steam traced, and systems with deteriorated wrappings.
d. Erosion – occurs in areas of turbulent flow, downstream of control valves, downstream of pump discharges, and downstream of orifices.
e. Environmental cracking – causes are upset conditions, [redacted] unanticipated condensation, and exposure to wet hydrogen sulfide or carbonates (usually on SS piping).
f. Fatigue cracking – from excess cyclic stresses caused by pressure, mechanical, or thermal changes. Low-cycle fatigue from heat up and cool down, and high-cycle from excessive piping vibration (preferred method of detection is PT or MT).
g. Creep cracking – depends on time, temperature, and stress; check high stress areas, mechanical changes from temperature – most often in systems operating above 900 degrees.

Classify Piping for Next Inspection Requirement

a. Class 1 next UT/VT in 5 years.
b. Class 2 next VT in 5 years.
c. Class 2/3 next UT in 10 years.
d. 75% of Class 1, 50% of Class 2, and 25% of Class 3 piping that have areas of damaged insulation need to be inspected.

Evaluation

a. Calculate the remaining life of piping system.
b. Calculate long-term corrosion rate.
c. Calculate short-term corrosion rate (if previous data is available and submitted).
d. Evaluate locally thinned areas.
e. Conduct piping stress analysis (as applicable).

Prepare an Inspection and Engineering Report

a. Listing all references.
b. Listing name and certification number of the API-570 inspector.
c. Showing location of all thickness measurements.
d. Showing all engineering calculations.
e. Including a narrative of the aforementioned inspection, examination, and testing items.
f. Including a statement of fitness for service.
g. Including a corrosion rate and remaining life statement.
h. Including a listing of recommended repairs and/or alterations.
i. Including a statement of compliance with the API Standard 570.

[redacted]

2.0 References and Acronyms

2.1 American Petroleum Institute:

- 2.1.1 API Standard 570, Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems
- 2.1.2 API RP 574, Inspection of Piping System Components
- 2.1.3 API RP 576, Inspection of Pressure-relieving Devices
- 2.1.4 API RP 577, Welding Inspection and Metallurgy
- 2.1.5 API RP 578, Material Verification Program for New and Existing Piping Systems
- 2.1.6 API Standard 579-1/ASME FFS-1, Fitness-For –Service
- 2.1.7 API RP 580, Risk-based Inspection
- 2.1.8 API RP 1110, Pressure Testing of Liquid Petroleum Pipelines

2.2 American Society of Mechanical Engineers Codes:

- 2.2.1 Code for Pressure Piping, Chemical Plant and Petroleum Refinery Piping, ASME B31.3.
- 2.2.2 Standard for Pipe Flanges and Flanged Fittings; ASME B16.5
- 2.2.3 ASME Boiler and Pressure Vessel Code; Section V, Non-Destructive Examination
- 2.2.4 ASME Boiler and Pressure Vessel Code; Section IX, Welding and Brazing Qualifications

2.3 National Fire Protection Association:

- 2.3.1 NFPA-30, Flammable and Combustible Liquids Code
- 2.3.2 NFPA-70, National Electrical Code
- 2.3.3 NFPA 704, Standard System for the Identification of the Hazards of Materials for Emergency Response

2.4 American Society of Nondestructive Testing:

- 2.4.1 ASNT-SNT-TC-1A

2.5 Code of Federal Regulations:

- 2.5.1 CFR, Title 29, Part 1910, Process Safety Management
- 2.5.2 CFR, Title 40, Volume 21, Chapter I, Subchapter D, Part 112, Oil Pollution Prevention

2.6 Military and Host Nation References or Standards:

- 2.6.1 UFC 3-460-01, Petroleum Fuel Facilities
- 2.6.2 UFC 3-460-03 O&M Maintenance of Petroleum Systems
- 2.6.3 UFGS 33 52 43.13 Aviation Fuel Piping
- 2.6.4 UFGS-0l 35 29, Safety and Occupational Health Requirements
- 2.6.5 UFGS-0l 35 30, Safety, Health, and Emergency Response (HTRW/UST)

[redacted]

Acronyms and Abbreviations

ACRONYM	**DEFINITION**
ACVG	Alternating Current Voltage Gradient
AG	Aboveground
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
AST	Aboveground Storage Tank
CIS	Close Interval Survey
CFR	Code of Federal Regulations
CML	Condition Monitoring Locations
CP	Cathodic Protection
CR	Corrosion Rates
CS	Carbon Steel
DBB	Double Block and Bleed Isolation Valve
DC	Direct Current
DCVG	Direct Current Voltage Gradient
EPA	Environmental Protection Agency
F	Fahrenheit
FS	Filter Separator
GAL	Gallon
GPM	Gallons per Minute
HPV	High Point Vent
ICCP	Impressed Current Cathodic Protection
ILI	In-Line Inspection
LPD	Low Point Drain
LRUT	Long Range Ultrasonic Testing
LT	Long Term
MAWP	Maximum Allowable Working Pressure
MAOP	Maximum Allowable Operating Pressure
MOGAS	Motor Gasoline
MSS	Manufacturers' Standardization Society of the Valve and Fittings Industry
NFPA	National Fire Protection Association
NWGLDE	National Work Group on Leak Detection Evaluations
PAUT	Phased Array Ultrasonic Testing
PH	Pumphouse
POL	Petroleum, Oil, and Lubricants
PRT	Product Recovery Tank
P/S	Pipe Support
psig	Pounds Per Square Inch Gauge
PSV	Pressure Safety Valve
SCFM	Standard Cubic Feet per Minute
SPCC	Spill Prevention Control and Countermeasures
SS	Stainless Steel
TRV	Thermal Relief Valves
UG	Underground
UST	Underground Storage Tank
UT	Ultrasonic Testing
UV	Ultraviolet
VOC	Volatile Organic Compounds
VP	Valve Pit

3.0 Description

3.1 Job Description:

Contracted by:	Austin Brockenbrough & Associates, LLC
Job Number:	22-0114

3.2 Pipe/Location Description:

Owner/Operator:	US Navy
Location:	Joint Base Pearl Harbor Hickam; HI (Red Hill)
Pipe Identification:	[redacted]
Service	Fuel Contact Water

3.3 Part Description:

Construction Code:	ASME B31.3 (Assumed)
Manufacturer:	Unknown
Year Installed:	Circa 1971 (Assumed same as Tank [redacted] installation date)
Material:	Carbon steel (*ASTM A53; Grade B specification) ASTM A53 Grade B (TS = 60,000 PSI; YS = 35,000 PSI) *Assumed

3.4 Inspection Description:

Inspection Type:	Internal Inspection (Borescope)
Equipment Used:	Ultrasonic Thickness Unit, Borescope
Inspector(s):	[redacted]

3.5 Piping Design Parameters:

Max Pressure:	275
Last Pressure Test Date:	NA
Max Temp:	200°F
Construction:	Welded/Threaded/Flanged/Clamped (Victaulic) Joints

3.6 Equipment Description:

Ultrasonic Thickness Meter

Manufacturer:	General Electric
Model:	DMS-GO+
Calibration Methods Used:	Zeroing Procedure, Copper Coating Calibration Procedure, and Two Point Calibration Procedure

Borescope Unit

Manufacturer:	Wöhler
Model:	VIS 700
Calibration Methods Used:	Optical Measurement on target template (5 cm width at distance of 10 cm) for optical property correction of camera glass and plastic protective dome

4.0 Inspection

4.1 Results:

[redacted]

[redacted]

[redacted]

4.1.2 Inspection Code

The inspection was conducted in accordance with applicable methodology of API-570. Unless otherwise stated, API-570 refers to the Fourth Edition, dated February 2016, "Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems."

4.1.3 Integrity Testing

Ultrasonic wall thickness measurements of the piping were taken in accordance with API-570 and per the project scope. The ultrasonic testing was conducted at the accessible portion of the aboveground piping at each end of the pipe. Pit depth reading was conducted at the accessible section of the internal piping using handheld thickness gauge. Pitting located downstream of the pipe were visually assessed by comparing to a known size pith depth.

Condition of the disconnected flanges were also accessed during this inspection for any signs of deterioration. This include assessment of the flange body, gasket face, stud holes (note: new gaskets and fasteners were installed on all flanged joints that were disassembled on this project and were not).

Visual assessment of the accessible section of the welds were also achieved during this inspection. Majority of the welds inspected did not appear to have anomalies that compromised the integrity of the pipe. The welds appear to still have sufficient root penetration with minimal corrosion.

4.1.4 Findings

An internal visual inspection of the FOR piping at this facility was performed to determine the condition of the piping and associated exposed hardware. The following was observed:

a) The piping has general corrosion and pitting type corrosion with an estimated range of 0.030 to 0.080 inches. The largest pit depth and cluster were noted on the aboveground vertical section of the pipe just below the tee joint. The pitting near the tee may be due to cavitation which is sometimes noted at areas of restricted flow passages or areas were turbulent flow is experienced. The pitting has a sharp-edged appearance in this area. The remaining of the piping inspected had a combination of general and local metal loss with isolated areas of pitting at areas of mill scale loss.

b) Two areas of erosion were identified on the internal portion of the pipe. This was noted on the long radius of the 1st elbow and the short radius of the 2nd elbow. Erosion occurs when solids, liquids, or vapor (or combination of these) mechanically remove the surface material of the pipe primarily pronounced at the change of direction. Other sections of the piping did show some minor erosion-corrosion, which are areas with protective film or scale eroded as a result of corrosion and exposing metal surface for corrosion. Note: solids, both large and small, were noted in the pipe during the cleaning process, and it is assumed were the cause of the observed wear on the elbows. The metal loss at these two elbows is estimated to be 0.030 to 0.050 inches due to erosion-corrosion.

c) Some minor gasket face corrosion was noted at the 4 to 7 o'clock position of the disconnected flange located inside ADIT 3. Five areas of corrosion ranging from grove-like and isolated individual pits were noted on the flange. All the anomalies identified on the gasket face were near the inner diameter of the gasket face. These appear to be due to crevice corrosion with a [redacted]. The defect depth was evaluated per ASME PCC-1 Appendix D and found to be within the allowable defect depth of Table D-2 for soft faced gasket use.

4.1.5 Piping Construction

Documentation was not available as to whether these piping systems were designed in accordance with a national code or standard. As a basis of this report, it was assumed they were designed and installed in accordance with a previous edition of ASME B31.3, "Process Piping" Code. The intent of this inspection was not to determine compliance of the piping to ASME B31.3; rather it was to determine the current condition of the piping system and to evaluate its integrity for continued operation under normal operating conditions. However, where it was necessary to refer to a design code, B31.3 was selected.

Industrial piping can be fabricated by either rolling plate material to form a cylinder or by extruding it from a single billet of steel. In the case of the former, welding will seal the longitudinal seam created by rolling the plate. The ASTM piping specification will determine the actual welding process used. When piping is extruded, however, it has no longitudinal seam. Although the exact piping specification and nominal wall thickness used to erect the piping is unknown, the piping most likely conforms to ASTM Specification A53, "Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded, and Seamless." This specification addresses seamless piping and two types of seam-welded piping.

Wall thickness values were calculated in accordance with Equation (3a) from Paragraph 304.1.2, "Straight Pipe under Internal Pressure," of ASME B31.3, "Process Piping" Code. This formula calculates the internal pressure design thickness for straight pipe and elbows. The minimum required wall thickness of piping may be greater due to additional pipe wall stresses introduced by support spacing, concentrated loads, or other structural factors. In low pressure and temperature applications, the required thickness is calculated in accordance with Equation (3a) from Paragraph 304.1.2. This calculation may be very low, indicating that the pipe would have insufficient structural strength to support its weight. For this reason, an absolute minimum thickness (AMT) value is calculated by *InterSpec, LLC* to set the lower limits to prevent sagging, buckling, and collapse at supports. The owner may elect a more stringent lower limit. AMT value is also known as Minimum Alert Thickness (MAT). AMT or MAT are usually not intended to mean that pipe components must be retired when one CML reaches the default limit but rather to flag locations were additional engineering evaluation should be completed to assure overall piping integrity.

4.1.6 Piping Classification

The piping in this report is not considered process piping as defined in API-570; however, applying the prescribed classification will mitigate leaks, fire, hazards to personnel, and system failures. API 570 classifies piping systems into four different classes (1, 2, 3, and 4); see table B. Such a classification system allows extra inspection effort to be focused on piping systems that may have the highest potential consequence if failure or loss of containment occurs. In general, the lower classified systems require more extensive inspection at shorter intervals in order to affirm their integrity for continued safe operation. InterSpec, however, recommends the use of Class (1) since API classification is based on the consequence, not likelihood, of failure. Class (1) is proposed because any piping failure would significantly affect operation of the facility as well as have a greater potential of safety risk to environment and personnel.

4.2. Maintenance Recommendation:

4.2.1 Periodically inspect and maintain all above ground piping and appurtenances per requirements outlined in UFC 3-460-03.
4.2.2 Continue annual cathodic protection survey of the underground piping and appurtenances per requirements outlined in UFC 3-460-03.
4.2.3 Report all segments of piping where excessive vibration and swaying are noted during operation for a follow-up inspection per API STD 570.

4.3. Compliance Requirements

4.3.1 There were no mandatory repair deficiencies identified on the segment of the piping inspected.

5.0 Serviceability and Schedule

The piping systems covered by this report are certified for continued normal service. This certification is based on the data recorded, the engineering analysis and recommendations presented in the body of this report, and no change to the piping products or service. This certification is in accordance with API-570. This is a baseline assessment of the facility piping, and inspection and testing should be ongoing. This report classifies the piping systems as Class 1 in accordance with API-570. The following schedule, which is based on the previous facility wide piping assessment may be used:

5.1.1 The next <u>formal visual inspection</u> should be conducted by an API-570 inspector by May, 2027 (every five years for Class 1 piping).

5.1.2 The next <u>ultrasonic thickness evaluation</u> should be conducted by an API-570 inspector by May, 2027 (every five years for Class 1 piping).

5.1.3 The following <u>owner/user inspection</u> schedule is added to aid in the integrity of the facility pipeline and may be accomplished by facility personnel or outside contractor.

5.1.3.1 Visual inspection by maintenance personnel. (Daily)
5.1.3.2 Visual inspection with log/checklist by maintenance personnel. (Monthly)
5.1.3.3 Inspect exterior coatings by maintenance personnel. (Semi-Annually)
5.1.3.4 Thermal Relief Valve (TRV) inspection and testing by maintenance personnel (Annually).
5.1.3.5 Low Point Drains (LPDs) exercising by maintenance personnel (including dead legs when present).

Annex A
Thickness Data/CMLs and Calculations

1. Thickness Data/CMLs
2. Calculations

Table 1 - API STD 570 Thickness Data & TML

TML ID	Location/Description	Pipe Size (in.)	Pipe Sch.	Thickness Measurements (in inches) (Metal Thickness) Nom.	0º	90º	270º	180º
B28	FOR pipe inside ADIT 3 (below	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
B29	FOR pipe outside ADIT 3 (vertical	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

min = [redacted] inches
Average = [redacted] inches
max internal pit depth measured = [redacted] inches

Case 1 (min thickness - max internal pit) = [redacted] inches
Case 2 (average thickness - max internal pit) = [redacted] inches

Definitions

API 570 - PIPE EVALUATION

References:

API 570

7.1 - Corrosion Rate Determination
7.2 - MAWP Determination
7.3 - Minimum Required Thickness
(Reference API 574, Section 9)

ASME B31.3

304.1.2 - Internal Pressure Calculations
304.1.3 - External Pressure Calculations

Definitions:

A = factor determined from Figure G in Subpart 3 of Section II, Part D and used to enter the applicable material chart in Subpart 3 of Section II, Part D.

B = factor determined from applicable material chart in Subpart 3 of Section II, Part D for maximum design temperature.

C_a = remaining corrosion allowance of the pipe section under consideration, in inches.

C_r = corrosion rate of the pipe section under consideration, in inches per year.

d = inside diameter of the pipe section under consideration, in inches.

D = outside diameter of the pipe section under consideration, in inches.

D_o = outside diameter of the pipe section under consideration, in inches.

E = Quality factor from Table A-1A

L = total length of a pipe section between lines of support, in inches.

P = the design maximum allowable internal working pressure, including static head pressure, in psi.

P_a = maximum allowable external working pressure, in psi.

R_L = estimated remaining life of the pipe section under consideration, in years.

R_o = outside radius of the pipe section consideration, in inches.

S = stress value for material from Table A-1, in psi.

t = thickness of the pipe section under consideration, variable related to applicable calculation used therein, in inches.

t_{act} = minimum thickness measurement of the pipe section under consideration, as recorded at the time of inspection, in inches.

t_{eng} = an established engineering minimum thickness that considers structural support and localized corrosion, in inches.

t_{min} = minimum required thickness of pipe section, as calculated from the design MAWP at the coinciding working temperature or t_{eng} thickness, whichever is greater, in inches.

t_{nom} = design nominal thickness of pipe section, in inches.

t_{prev} = original thickness of the pipe section under consideration, as recorded at first inspection or nominal thickness if no original thickness measurements were for t_{prev}, in years.

Y = time span between thickness readings or age of the pipe section if t_{nom} is used for $tprev$, in years.

Y_n = estimated time span to next inspection of the vessel part under consideration, in years.

FOR Piping (ADIT 3 Borescope Inspection)

Pipe Wall Minimum Thickness, Remaining Life, and MAWP Calculations (Calc. 1)

A) Minimum Thickness Calculation

NPS	Schedule	t_{nom}	MAWP
[redacted]	[redacted]	[redacted]	275

P	D (OD)	S	E
275	6.625	20,000	0.8

$t_{min} = PD/2SE =$ 0.057 *inches*

$t_{eng} =$ 0.110 *inches*

$t_{use} =$ 0.110 *inches*

* t_{use} is greater of t_{min} and t_{eng}

B) Remaining Life

t_{use}	t_{act}	t_{prev}	Y
0.110	0.147	0.280	52

$C_a = t_{act} - t_{use} =$ 0.037 *inches*

$C_r = t_{prev} - t_{act} / Y =$ 0.002558 *inches/year*

$R_L = C_a / C_r =$ 14 *years*

C) MAWP at Next UT Inspection

Pipe Class: 1

Next Inspection (Y_n):

Visual Inspection: 5 *years*

UT Inspection: 5 *years*

t_{act}	Y_n	C_r
0.147	5	0.002558

$t_{req} = t_{act} - 2Y_n C_r =$ 0.121 *inches*

S	E	t_{req}	D
20,000	0.8	0.121	6.625

$P = 2t_{req} SE/D =$ 584 *psi*

FOR Piping (ADIT 3 Borescope Inspection)

Pipe Wall Minimum Thickness, Remaining Life, and MAWP Calculations (Calc. 2)

A) Minimum Thickness Calculation

NPS	Schedule	t_{nom}	MAWP
[redacted]	[redacted]	[redacted]	275

P	D (OD)	S	E
275	6.625	20,000	0.8

$t_{min} = PD/2SE =$ 0.057 *inches*

$t_{eng} =$ 0.110 *inches*

$t_{use} =$ 0.110 *inches*

* t_{use} is greater of t_{min} and t_{eng}

B) Remaining Life

t_{use}	t_{act}	t_{prev}	Y
0.110	0.187	0.280	52

$C_a = t_{act} - t_{use} =$ 0.077 *inches*

$C_r = t_{prev} - t_{act} / Y =$ 0.001781 *inches/year*

$R_L = C_a / C_r =$ 43 *years*

C) MAWP at Next UT Inspection

Pipe Class: 1

Next Inspection (Y_n):

Visual Inspection: 5 *years*

UT Inspection: 5 *years*

t_{act}	Y_n	C_r
0.187	5	0.001781

$t_{req} = t_{act} - 2Y_n C_r =$ 0.170 *inches*

S	E	t_{req}	D
20,000	0.8	0.170	6.625

$P = 2t_{req}SE/D =$ 821 *psi*

Annex C
Photographs

1. Project Photographs

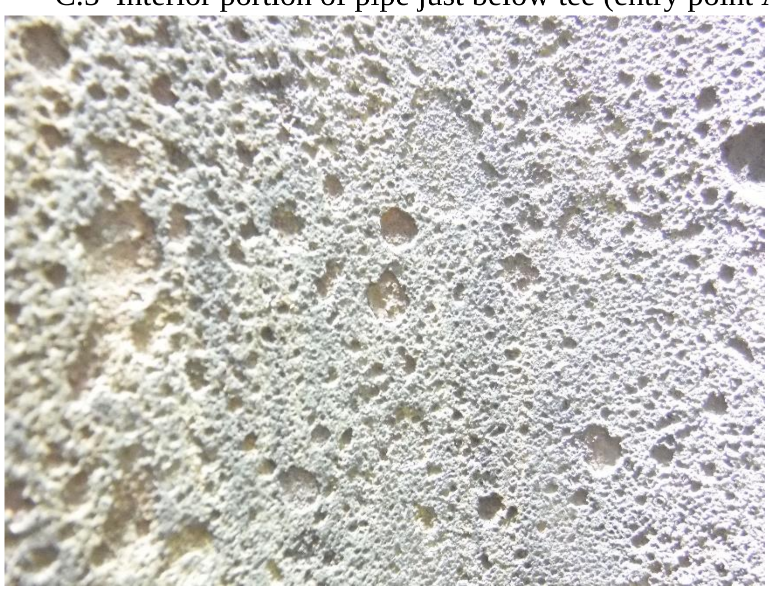
[redacted]

[redacted]

[redacted]

C.4 Borescope inspection entry point A (flange removed)

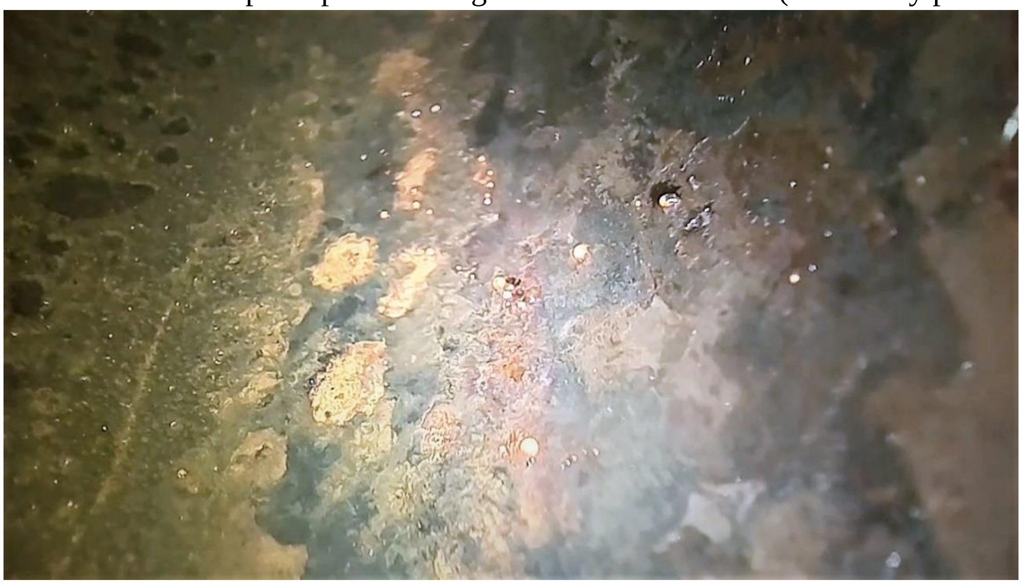
C.5 Interior portion of pipe just below tee (entry point A)



C.6 Close up of internal pitting just below tee

[redacted]

C.10 Borescope inspection image of 1st elbow erosion (from entry point A)



C.11 Borescope inspection image bottom of pipe (from entry point A)

C.12 Borescope inspection image bottom of pipe (from entry point A)

C.13 Second Elbow weld 10 – 1 o'clock (from entry point A)

C.14 Second elbow 6 o'clock (minor erosion corrosion on inner radius) (from entry point A)

C.15 Third elbow after pipe spool (from entry point A)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

C.21 Entry Flange B (Interior of pipe before cleaning)

[redacted]

[redacted]

[redacted]

C.24 Entry Flange B (Scale and debris removed from pipe)

[redacted]

C.25 Entry Flange B (Interior of pipe after cleaning)

C.26 Entry Flange B (Interior of pipe after cleaning)

[redacted]

[redacted]

[redacted]

[redacted]

C.31 Borescope inspection image, side of pipe (from entry point B)

C.32 Borescope inspection image, top of pipe (from entry point B)

C.33 Borescope inspection image, bottom of pipe (from entry point B)

C.34 Borescope inspection image, 3rd elbow weld (from entry point B)

C.35 Borescope inspection image, ERW joint and mill scale (from entry point B)

C.36 Borescope inspection image, mill scale (from entry point B)

C 37 Crevice corrosion flange gasket face 0 030″ to 0 040″ deep (entry point B)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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Memorandum

Date: 17 January 2023

To: [redacted], US Navy, NAVFAC Joint Task Force, Red Hill

From: [redacted]

CC: [redacted]

Project 221162 – Red Hill Defueling Support, Joint Base Pearl Harbor-Hickam, Honolulu, HI

Subject: Red Hill Fuel Pipelines – Surge Assessment

1. INTRODUCTION

The objective of this memorandum is to present the maximum F-24 pipeline transient surge loads that can be safely resisted by Red Hill pipelines during defueling. Since the JP-5 and F-24 pipelines share common branches, the axial surge loads can be transferred from the F-24 to the JP-5 pipeline. In this study, we investigated how the combined pipeline system responds to transient surge events that may form as a result of sudden valve closures. We used SGH's April 2022 report and the US Navy's defueling plan to determine the key inputs and assumptions for our assessment. We performed pipe stress analysis using TRIFLEX software and also performed a refined finite element analysis using ABAQUS software. We followed ASME B31.3 for our pipe stress analysis.

The outcomes of this study should help the US Navy (Navy) establish operational limits for defueling as well as help prioritize repairs. In this memorandum, we discuss surge loads, present results from our independent surge analysis, and provide recommendations on the limiting surge pressure the pipe system can safely withstand. We also summarize how various pipeline design codes that may be applicable to Red Hill address surge loads and past studies that have evaluated possible surge loads at Red Hill.

We recommend that the Navy determine the maximum flow rates using the maximum surge loads that can be resisted by the pipelines to mitigate potential surge damage. If the flow rates can be kept below these thresholds (to be calculated by others), the axial restraints recommended in our April 2022 report would not be required under the assumption that vacuum formation and related surge events will be mitigated through operational measures. The presentation that we gave the defueling team on 12 January 2023 is provided in the appendix to this memorandum.

2. LITERATURE

Transient surge loads are discussed in several pipeline design and analysis codes and standards. In this section, we provide a summary of surge load provisions in applicable industry standards and guidelines. Although these consensus standards and guideline documents have different provisions for the assessment of piping systems, they all require some type of surge assessment to qualify piping and supports against transient surge loads.

2.1 UFC 3-460-01 Change 2 (January 2022)

The Unified Facilities Criteria (UFC 3-460-01) for the design of petroleum fuel facilities stipulates that “all installation pipelines must be designed in accordance with ASME B31.3.” This code also stipulates that “interstate interterminal pipelines must be designed in accordance with ASME B31.4.”

Installation pipelines are defined as “pipelines which connect POL facilities within an installation such as a barge pier to a bulk facility and a bulk facility to an operating (ready-issue) tank. These pipelines do not cross property lines…”

Interterminal pipelines are defined as “pipelines which connect two government installations such as a Defense Energy Supply Center depot to a military installation. These pipelines cross property lines and cross public and/or private properties, streets, highways, railroads, and utility rights-of-way.”

2.2 ASME B31.3

Analysis of process piping is based on ASME B31.3, per UFC 3-460-01 (Revision Date 01-12-2022). We used the 2016 version of ASME B31.3 for our analyses. Section 302.3.6 states that for load combinations that include occasional loads, such as wind, earthquake, or transient surge loads, the sum of the longitudinal stresses is allowed to be as much as 1.33 times the Basic Allowable Stress given in Table A-1 of Appendix A. For ASTM A53 Grade B pipe, at 100°C, the Basic Allowable Stress is 20 ksi. Therefore, for load combinations, including surge conditions, the code allows the sum of the longitudinal stresses to be 26.6 ksi.

We note that ASME responded to a user question on accommodating loads due to pressure surges and published their response on the ASME website. They specifically direct users to Section 302.3.6 for increasing the allowable stress due to occasional loads (*Figure 1*). It is critical to note that this interpretation detail is related to longitudinal pipe stresses due to unbalanced loads from pressure surges, such as that can be experienced at a pipe termination (blind flange location) that is subject to pressure and movement in the axial direction.

Interpretation Detail

Standard Designation:	B31.3
Edition/Addenda:	
Para./Fig./Table No:	
Subject Description:	Loads Due to Pressure Surges
Date Issued:	09/08/1981
Record Nu ber:	
Interpretation Nu ber :	1-50
Question(s) and Reply(ies):	Question: How shall longitudinal piping stresses due to unbalanced loads from pressure surges which result in anchor displacements be evaluated in B31.3? Reply: Loads due to pressure surges are considered as primary loads, and longitudinal stress limits must comply with 302.3.3(c) for sustained loads or 302.3.6 for occasional loads. Pressure temperature limits of 302.2 must also be met.

Figure 1 – ASME's Interpretation Detail Related to Accounting for Surge Pressure Loads as Occasional Loads

We further note that ASME provided clarification that surges are considered occasional loads and should be considered in the assessment of longitudinal stresses (Figure 2). They direct the user to Section 302.2.4. This states in Subsection (f)(a) that it is permissible to exceed the pressure rating or allowable stress by 33% for pressure design, provided the owner approves, and the duration is no more than 10 hrs at any one time and no more than 100 hrs/yr.

Interpretation Detail

Standard Designation:	B31.3
Edition/Addenda:	
Para./Fig./Table No:	
Subject Description:	B31.3 1999 Edition (2001 Addenda), Paragraph 302.3.6, Limits of Calculated Stress Due to Occasional Loads
Date Issued:	07/01/2002
Record Number:	
Interpretation Number :	19-18
Question(s) and Reply(ies):	Question: Does paragraph 302.3.6(a) include occasional internal pressure loads, (e. g. surges, spikes, peaks, and water hammer) in the summation of longitudinal stresses due to sustained and occasional loads? Reply: Yes. In addition, all pressure variations) must also meet the requirements of paragraph 302.2.4.

Figure 2 – ASME's Interpretation Detail Related to Surge Loads Classified as Occasional Loads

2.3 ASME B31.4

Analyses of fuel transfer pipelines were based on the 2012 version of ASME B31.4 in our April 2022 report. We understand that the Navy considers ASME B31.3 as the applicable code for Red Hill pipelines, but it is worthwhile to note that surge loads are discussed in several sections of this widely-used code.

- Section 401.1.5 lists surge loads as one of the transient load cases that may occur during the operation of the pipeline.
- Section 401.2.2.2 notes that "pressure rise above maximum steady state operating pressure due to surges and other variations from normal operations is allowed in accordance with paragraph 403.3.4."
- Section 401.3 states that the most critical combination of applicable load cases, including "transient loads that can be expected to occur, shall be considered."
- Section 403.3.4 provides the criteria for transient overpressure: "Transient overpressure includes pressure rise due to surge. Surge pressures in a liquid pipeline are produced by a change in the velocity of the moving fluid that results from shutting down a pump station or pumping unit, closing a valve, or blockage of the moving fluid.

> Surge calculations should be made, and adequate controls and protective equipment shall be provided so that the pressure rise due to surges and other variations from normal operations shall not exceed the internal design pressure at any point in the piping system and equipment by more than 10%."

ASME B31.4 provides allowable stresses and load combinations for pipelines but does not provide guidelines on the calculation of transient surge loads. Although the allowable stresses in ASME B31.4 are different from those in ASME 31.3, the general requirements are similar.

2.4 Energy Institue Guidelines for the Avoidance of Vibration-Induced Fatigue Failure in Process Pipework

The Energy Institute (EI) is an industry organization based in the UK. They developed this document as part of a Joint Industry Project (JIP) in collaboration with the regulatory agency in the UK. Several major oil and gas companies, certification agencies, and service providers participated in this JIP. The guidance document covers new design, assessment of existing plants, and addressing potential problems that have been identified in an operating system using a staged approach. Both qualitative and quantitative risk assessment methods are provided for a range of excitation mechanisms, including flow-induced vibration and transient surge events. The following are direct quotes that are of interest:

- "Surge (or water hammer, as it is commonly known) is a pressure wave caused by the kinetic energy of a fluid in motion when it is forced to stop or change direction suddenly. If the pipe is suddenly closed at the outlet (downstream), a pressure wave is generated, which travels back upstream at the speed of sound in the liquid. This can give rise to high levels of transient pressure and associated forces acting on the pipework.

  High transient forces can also be generated by the rapid change in fluid momentum caused by the sudden opening or closing of a valve, e.g., fast operating of a relief valve."

- "Predictive techniques can provide a further level of quantification of excitation and response levels and can be used to explore potential modifications. Examples include structural and acoustic finite element analysis, pulsation and surge simulation, and computational fluid dynamics (CFD)."

- "Fast closure of a valve on a liquid system may generate excessive surge pressures which can generate high levels of transient vibration and/or exceed the flange rating of the pipe."

Section T2.8 of the EI guidelines provides the steps for the assessment of surge/momentum changes due to valve operation. The equation to calculate peak forces due to valve closure and the equation to get the likelihood of failure are provided in this section. The peak force is proportional to the flow rate and correlated to valve closure time and fluid density.

Section T10.8 provides guidelines to mitigate surge loads. For mainline excitation, change in operation is stated as an effective option. It is also noted that “the resulting forces on the pipework caused by the pressure wave (or surge) traveling back upstream from the closing valve can be reduced by either reducing the mean fluid velocity or slowing down the time taken to close the valve.” Furthermore, “the effect of rapid changes in fluid momentum caused by a transient flow can be reduced by minimizing the number of bends in a system and the use of long radius bends. This will result in less energy being transmitted from the fluid to the pipework.”

EI guidelines recommend using advanced predictor techniques (i.e., finite element and CFD analyses) for the calculation of surge loads in complex and long pipeline segments. The empirical equations are not applicable for pipelines longer than 328 ft (100 m).

3. PREVIOUS STUDIES

The Red Hill facility has a history of transient surge loads. Several studies have been performed by contractors to estimate the surge pressures and their effects on the integrity of the pipelines.

3.1 2000 DESP Pearl Harbor Hydraulic Surge Analysis Study [redacted]

We reviewed the October 2000 “DESP Pearl Harbor Hydraulic Surge Analysis Study 32” DFM” report by Enterprise Engineering Inc. (EEI) and observed that they established the maximum allowable working pressure (MAWP) for the three pipelines using an analytical approach.

- [redacted] F-76 Pipeline: 243 psi
- [redacted] JP-5 Pipeline: 252 psi
- [redacted] JP-8 Pipeline: 285 psi

[redacted]

According to this report, the most severe surge is not caused by the double block and bleed (DBB) valves (fire valves) but by the non-DBB valves such as gate, ball, and butterfly valves.

The 2000 surge analysis included the following recommendations:

1. Establish a maximum fuel flow rate for fuel Issues to Hotel Pier.

2. Adjust valve travel time to accommodate the piping MAWP and fuel flow rate.

3. Review the facility's operational procedures to minimize piping surges due to hydraulic shock.

4. Install ASME-certified relief valves on the piping system with pressure settings that correspond to the MAWP.

3.2 2010 Hydraulic Analysis and Dynamic Transient Surge Evaluation

We reviewed the September 2010 Hydraulic Analysis and Dynamic Transient Surge Evaluation report by EEI and conclude that this report provides valuable information for the worst-case operational scenario. The report indicates that if the Red Hill defueling operation is conducted at a lower flow rate than the maximum flow rate possible, the potential for the transient surge is reduced to levels that are within the design margin of the current piping system.

The intent of the EEI surge evaluation report was to provide a hydraulic analysis and dynamic transient surge evaluation of Pearl Harbor's fuel handling infrastructure and determine the potential risks of damage to the piping due to hydraulic surge. In addition, EEI was asked to provide a Maximum Allowable Operating Pressure (MAOP) evaluation based on the hydraulic and surge evaluation and provide recommendations for future pressure testing. [redacted]

The key points noted in this 2010 surge analysis report are summarized below.

1. The hydraulic analysis and dynamic transient surge evaluation assume that each fuel tank is full (highest fuel head) and that the gravity flow rate is at a maximum value (i.e., all valves are 100% open).

2. If the fuel system is permitted to operate at its full flow potential, there is a substantial risk of very high surge pressures, which could potentially damage the system to the point of failure. The pressures modeled at these high flow rates have a moderate risk of causing piping failure either in the Red Hill or Lower Yard Tunnels or on the piers.

3. Facility personnel is currently limiting the flow rate while issuing to the piers (generally governed by the pressure/receipt rate dictated by the receiving vessel). This reduction

in flow rate (below maximum potential) often (though not always) reduces the associated surge potential to within allowable limits, making the associated risk of piping failure much lower.

[redacted]

3.2.2 JP-5 Pipeline

EEI provided specific analysis for the JP-5 piping system and concluded the following regarding transient surges:

1. During full-flow issue operations, [redacted], closure of the Emergency Fire Valves (Red Hill tunnel valve and Lower Yard tunnel valve) has the potential to generate high surge pressures when flowing through the inner loop. One of the inner loop fire valves closes significantly faster than the rest, creating a high potential for the surge.

[redacted]

3. Full closure of the T-Valve in the UGPH generally appears to create the lowest surge pressure of any potential initiator and, therefore, should be used as the primary means of throttling and stopping flow during operations.

[redacted]

EEI recommended the following operational control options that support the safe defueling of the JP-5 pipeline:

[redacted]

2. Use the UGPH T-Valves to throttle the fuel flow.

3. Use the outer loop of the JP-5 piping system for defueling.

[redacted]

3.2.3 F-24 Pipeline

EEI provided specific analysis for the F-24 pipeline system (called JP-8 in the report) and concluded the following regarding transient surge:

1. During full-flow issue operations, [redacted], closure of the Emergency Fire Valves (Red Hill tunnel valve and Lower Yard tunnel valve) has the potential to generate surge pressures as high as [redacted]

2. Closure of the T-Valve in the UGPH, even at full flow, does not generate surge pressures above the allowable pressure for a fully qualified ANSI Class 150 line. This valve should be used as the primary throttling and/or operation-stopping valve.

[redacted]

EEI recommended the following options that support the safe defueling of the F-24 Pipeline:

1. Limit fuel issue rates (recommended flow rate was not provided).

2. Use the UGPH T-Valves to throttle the fuel flow.

EEI did not calculate a recommended flow rate that would result in transient surge events within acceptable limits. [redacted]

3.3 April 2022 SGH Analysis

SGH performed an independent assessment of the Red Hill fuel pipelines using the surge pressure estimated in the root cause analysis (RCA) report for the 6 May 2021 event (Root

Cause Analysis of the JP-5 Pipeline Damage – 7 September 2021). To the best of our knowledge, SGH's previous study may have been the only documented study where the response of the pipelines and supports to axial transient surge loads was checked. In our study, we used a transient surge pressure of 320 psi, assuming a surge event similar to that discussed in the RCA report. This pressure was the result of the collapse of a vacuum and exceeded the MAOP of the pipelines, but it was lower than many of the surge pressures estimated in EEI's surge analysis reports from 2000 and 2010. Our analysis indicated that the pipelines and supports might be overstressed and fail if they are again subjected to surge pressures similar to the 6 May 2021 event. Therefore, we recommended several axial and lateral restraints to transfer the surge loads from the pipelines to supports and foundation elements. We showed that the addition of restraints can reduce the pipeline stresses to within acceptable limits.

4. SURGE RESPONSE ASSESSMENT

We understand that operational improvements and some design changes were made at the facility. These changes are expected to reduce the risk of vacuum-related transient surge pressures. However, the pipelines can still be exposed to surge loads due to valve closures, as highlighted in the 2010 EEI surge analysis report. Although surge pressures due to valve closure can be mitigated or reduced through operational controls, we believe that the maximum surge pressures that can be resisted by the pipelines and supports can be established quantitatively. Our further assessment considers the effect of surge pressures on hoop stresses and axial stresses due to the reflection of a surge pressure wave at the blocked end of pipelines (i.e., at a blind flange).

4.1 Pipe Stress Analysis and Code Check Methodology

For our further analysis to consider the effect of surge pressures, we developed several pipeline stress analysis models for the F-24 and JP-5 fuel lines, as outlined in our memorandum of 7 December 2022. The following general defueling assumptions were provided by the fuels group:

1. The F-76 line will be abandoned in place (i.e., no repairs will be completed) down to the fire valves, and the F-76 product will be rerouted to the JP-5 line.

[redacted]

[redacted]

[redacted] [redacted]

5. JP-5 tanks [redacted] will be defueled via the JP-5 line.

6. F-24 tanks [redacted] will be defueled via the F-24 line.

7. Defects will be addressed as per the Consolidated Repair List to increase the MAOP of the JP-5 and F-24 lines.

Note that only one of Assumptions 3 and 4 in the above list will be performed, and these assumptions (3 and 4) are under final consideration by the Navy. Therefore, we assessed different pipeline configurations in our models based on whether Assumption 3 or Assumption 4 will be in effect.

Our analyses aim to ascertain the pressure limits of the F-24 and JP-5 fuel lines when subject to transient loads. We represent a potential transient load as a force applied at discrete blind flanges in the pipeline system and back-calculate the corresponding pressure that results in a demand-to-capacity (DCR) ratio of 1.0 anywhere in the analyzed fuel pipelines. A DCR of 1.0 indicates that the maximum stress induced in the pipeline system by the applied loading (due to the operating loads of gravity, temperature, and pressure) equals the code allowable stress. It does not represent pipeline failure.

At all pipeline segments where the F-24 and the JP-5 pipelines run parallel, they are tied together at each tank lateral via double tee risers, the exception being at [redacted] which only have F-24 and F-76 pipeline connectivity. We analyzed the pipeline system in the tank gallery specifically because of the 2021 spill history and the propensity for pressure surges to occur.

We used the TRIFLEX and ABAQUS software packages for our pipe stress analysis, which are discussed in more detail in the following sections. Our models represent discrete sections of the fuel system, defined at specific tanks, between tanks and concrete anchor block supports, and represent variations in potential fuel line packing scenarios. We developed the following three pipe stress analysis models:

1. Model 1: Pipeline segments from the concrete anchor downstream of [redacted] to the concrete anchor upstream of [redacted] including the trunklines and laterals at [redacted]

2. Model 2: Pipeline segments at [redacted] modeled between the concrete anchor downstream of [redacted] and the concrete anchor upstream of [redacted]

3. Models 3 and 4: Pipeline segments between [redacted] and [redacted] (the end of the F-24 line), modeled between the concrete anchor downstream of [redacted] and the concrete wall upstream of [redacted]

In our first model (Figure 3), we assess whether a transient surge pressure may impact the pipeline laterals in the [redacted] galleries. In our April 2022 report, we found that a [redacted] surge load occurring at the closed ball valve at the [redacted] lateral overstressed the pipeline due to the piping bends. The pipe stress analysis presented in this memo estimates the maximum allowable surge force if a surge occurred at this closed ball valve at the [redacted] lateral.

[redacted]

[redacted]

Our second model (Figure 4) evaluates the pipeline performance for the representative tank laterals at [redacted] where the smaller and larger pipelines are tied together. Although the F-76 pipeline will not be used for defueling, at some laterals, it is tied into the F-24 and JP-5 lateral lines and is part of the load path for the other two fuel lines. We have two variations for this second model, each representing an alternative location of impact for the transient load on either the closed ball valve on the small diameter pipe at [redacted]

[redacted]

Our final model (Figure 5) evaluates the response of the entire F-24 fuel line between [redacted] considering whether Assumptions 3 or 4 described previously are in effect. In this case, the transient load is either applied to the new blind flange upstream of [redacted] or applied at the blind flange at [redacted]

We used a friction coefficient of 0.3 in the pipe stress analysis models.

[redacted]

Figure 5 – Entire F-24 Pipeline Stress Analysis Model

We used TRIFLEX for our pipe stress analyses and ASME B31.3 code checks. Additionally, we performed detailed analyses using ABAQUS to corroborate our TRIFLEX results. We developed local models in ABAQUS, which required axial spring stiffnesses of the entire F-24 line from the TRIFLEX model to simulate the boundary conditions of the local models. Three-dimensional (3D) modeling and analysis capabilities of ABAQUS are better able to capture local stress concentrations in the pipe joints and can more accurately predict local stresses compared to pipe stress analysis software with one-dimensional pipe elements.

4.1.1 Detailed Finite Element Analysis

The objective of this analysis is to develop a detailed finite element (FE) model that can capture the stress intensification effects and pipeline nonlinearity to determine more accurate allowable surge pressures at the header of the F-24 line at [redacted] or at the new pressure rated blind flange at [redacted]

ABAQUS is a general-purpose, nonlinear FE analysis software developed by Dassault Systems. It contains a wide range of one-dimensional, planar (two-dimensional), and solid (three-dimensional) elements with the capability to incorporate nonlinear geometric and material properties to simulate structural responses under various loading scenarios. ABAQUS is widely used to perform complex analyses of civil, structural, and mechanical systems in critical applications, including in the aerospace, nuclear, and petroleum industries.

4.1.1.1 Analysis Model for the F-24 Pipeline at [redacted]

Figure 6 shows the ABAQUS FE model used to simulate the structural response under a surge load at the header of the F-24 line at the new pressure-rated blind flange, which would be installed at the present location of the downstream skillet near [redacted] This analysis model is based on Assumption 4 in Section 4.1 being implemented, i.e., that the skillet near [redacted] will be replaced with a pressure-rated blind flange, and the F-24 trunkline will be reconnected immediately upstream of the new blind flange.

[redacted]

Shell elements were used in the tee connection region (to capture the stress intensification effects), and beam/pipe elements were used beyond the highly stressed tee connection region.

Gravity loads, a temperature gradient, and internal pressure were applied prior to the application of the surge pressure.

[redacted]

4.1.1.2 Analysis Model for the F-24 Pipeline at [redacted]

Figure 7 shows the ABAQUS FE model used to simulate the structural response under surge load at the header of the F-24 line at [redacted]. This analysis model is based on the assumptions that 1) the skillet near [redacted] will be removed but will not be replaced with a pressure-rated blind flange, and 2) additional axial restraint will not be provided. In this case, only one spring boundary condition is needed to simulate the presence of the F-24 line downstream of the pipe anchor on the JP-5 line.

[redacted]

[redacted]

The pipe anchor of the JP-5 pipeline was modeled as a “pinned” boundary condition. [redacted]

4.2 Load Cases and Combinations

The pipeline load cases include dead, thermal, operating, and transient loads based on ASME B31.3 (Process Piping) and ASME B31.4 (Transfer Pipelines). Dead loads consider the weight of the pipe and the weight of the contents. Thermal loads consider a 10°F delta (see SGH Memorandum dated 30 November 2022), and operating pressures consider an 85 psi pressure representing the pressure from a full head in the tanks. Transient loads are iteratively determined to back-calculate a DCR of 1.0 in the analyzed pipelines.

4.3 Material Properties

In May 2000, Pond C/M engaged Finaly Testing Laboratories, Inc., to conduct tensile testing of coupon samples from the Red Hill fuel pipelines [redacted] This testing was part of addressing emergent repairs highlighted in a Thermal Engineering Corporation (TEC) November 1999 report (PRL 93-9 and 93-10 Repair Red Hill Tunnel Pipelines FISC Peral

Harbor, Hawaii, Amendment No. 16). Finaly tested ten coupons per pipeline size, with yield strength averages of [redacted] for the [redacted] fuel pipelines, respectively. In August 2000, Engineering Design Group, Inc., and Dmitrijev & Associates issued a Final Inspection and Construction Report (SPAWAR Contract No. 65236-01-D-7827 DO No. 001) for the emergent repairs. In this report, minimum yield strengths for the pipelines are specified as the Finaly test averages modified according to ASME B31.4 437.6.7 [redacted]

In 2019, EEI clarified assumptions in the Engineering Design Group, Inc., and Dmitrijev & Associates' August 2000 report, updating minimum yield strengths for the [redacted] Through destructive testing, EEI determined that ASTM A53 Grade B piping was a reasonable approximation for future analytical assessments.

In EEI's subsequent analyses (Pipeline Stress Analysis and Structural Evaluation Report – Red Hill Lower Access Tunnel 2022), they used ASTM A53 Grade B material properties for all pipelines in the Red Hill tunnels. The analysis presented in this memorandum uses material properties consistent with EEI's material type determination.

We note that the ASTM A53 Grade B material characteristics are slightly less conservative than using the ASME B31.4 modified Finaly test data as the yield strength [redacted] However, in our April 2022 Report, we compared the analysis results for the [redacted]. pipeline using the two different material characteristics described above and found that the performance of the pipeline was not altered. Although the [redacted] pipeline will not be used for defueling the F-76 fuel, it is tied into the F-24 and the JP-5 fuel lines at some locations, and therefore, for the analysis presented in this memorandum, we find that the use of ASTM A53 Grade B is acceptable.

We take the F-24 specific gravity as 0.84 in the TRIFLEX and ABAQUS models. For the ABAQUS model, we used elastic, perfectly plastic material models for ASTM A53 Grade B steel, typical for the nonlinear analysis of carbon steel pipes.

4.4 Maximum Allowable Pressure Rating

EEI April 2016 Inspection and Repair of Red Hill Pipelines Report notes the locations of both ANSI Class 150 and Class 300 carbon steel flanges in the Red Hill tunnels. ASME B16.5 for Pipe Flanges and Flanged Fittings lists ANSI Class 150 carbon steel pipe (ASTM A105 steel with a yield strength of 36 ksi) as having a pressure rating of [redacted] for temperatures under 100°F. This is in accordance with UFC-3-460 Table 9-1 “Allowable Pressure Table – ANSI Class 150 Flanged Joints.” The pressure rating of flanges may exceed the pressure rating of pipelines due to section loss and other factors. We understand that the pressure rating of pipelines will be increased through the implementation of consolidated repairs.

4.5 Geometry

Analysis inputs related to the layout of the Red Hill pipelines were determined from reviewed documents and our measurements at the site.

4.6 Corrosion and Defect Allowance

We did not consider defects affecting the capacity of the pipelines and supports. Instead, we assumed that any deficient parts of the system would be repaired prior to defueling the Red Hill tanks, as per our April recommendations and the consolidated repair/enhancement list compiled on 24 October 2022 by the Navy's Red Hill Joint Task Force.

4.7 Flexibility and Stress Intensification Factors

We considered flexibility and stress intensification factors (SIFs) where necessary in our pipe stress analysis. The software TRIFLEX applied code-specific flexibility and SIF values to bends and branch connections in accordance with ASME B31.3. The branch connections at the tees consist of unreinforced fabricated tees at the header pipe riser and welded tees at the lateral pipe branch. The unreinforced tees have high SIF values calculated up to a factor of 9.8. Our analysis results, as discussed in Section 5, indicate the SIF values contribute to high stress at the unreinforced tee locations (pipeline riser at the base of the tee connection).

SIF values are dependent on the fabrication method for the pipe bends and branch connections. SIFs are used for the analysis of piping components and assemblies under service loads and fatigue conditions.

5. PIPE STRESS ANALYSIS RESULTS

5.1 TRIFLEX Analysis Results

In the following sections, we present our pipe stress analysis results from TRIFLEX for the three models described in Section 4.1.

5.1.1 Tanks 19 and 20 Piping Laterals

Our April 2022 report highlighted the pipe lateral at Tank 20 that was overstressed by about [redacted] surge pressure due to the presence of the piping bend. We re-evaluated this piping segment to determine the maximum allowable transient surge force it could withstand during defueling. Figure 8 below shows the model geometry of the piping laterals at [redacted].

[redacted]

[redacted]

We found that applying a surge force of [redacted] [redacted] together with concurrent service loads, results in stresses approximately equal to the ASME B31.3 code allowable stress for occasional loads (Section 2.2). Figure 9 below shows the maximum stress located in the piping bend.

[redacted]

[redacted]

5.1.2 [redacted] Piping Laterals

The current piping configuration at the [redacted] laterals (Figure 10) could be overstressed due to the bends in the laterals. We evaluated this configuration for surge loads acting separately at the ball valves on the [redacted] laterals.

[redacted]

[redacted]

We found that a [redacted] corresponding to a surge pressure of [redacted] acting on the small diameter pipe ball valve towards [redacted] together with concurrent operating loads, results in stresses approximately equal to the [redacted] allowable code stress. Figure 11 below shows the location of maximum stress at the location where the bend meets the F-76 lateral.

[redacted]

[redacted]

The second model, where the surge force acts on the small diameter pipe ball valve towards the [redacted] side, has similar results. Applying a surge load of [redacted] together with concurrent operational loads, results in stresses approximately equal to the [redacted] allowable code stress (Section 2.2). Figure 12 below shows the location of maximum stress at the location where the bend meets the F-76 lateral.

[redacted]

5.1.3 F-24 Pipeline [redacted]

Our April 2022 analysis indicated that a high surge load acting along the F-24 header subjects the F-24 pipeline riser at the base of the tee connection to overstress. We modeled the entire F-24 line to account for the additional stiffness from the laterals (Figure 5). The following sections discuss the two analyses we performed to determine the maximum allowable surge forces in the F-24 pipeline: 1) a blind flange is installed near [redacted] with the upstream portion of the F-24 line reconnected, and 2) a blind flange is not installed near [redacted] and the F-24 line is filled with the product up to [redacted].

5.1.3.1 Updated Results Based on Defueling Assumptions

Based on the defueling assumptions for the F-24 lines as listed in Section 4.1 (Assumptions 3 or 4), we performed a confirmatory analysis to evaluate the response due to transient surge pressure in the longitudinal direction if additional axial restraints are not installed. Figure 13 below shows the geometry of the F-24 pipeline model near [redacted]

[redacted]

[redacted]

We found that a surge load of [redacted] applied at the new pressure-rated blind flange just upstream of [redacted], together with concurrent operational loads, results in stresses approximately equal to [redacted] allowable code stress for occasional loads. Our results indicate that the pipeline joint at the base of the tee connection (connecting the JP-5 header and the laterals) experiences the maximum stress. Figure 14 below shows a line rendering of the JP-5 tee connection where maximum stress occurs.

[redacted]

If the blind flange near [redacted] will not be installed prior to defueling, we assumed that the non-pressure resisting skillets will be removed, and the F-24 line will be filled with fuel up to the end of the F-24 header near [redacted] We analyzed the maximum allowable transient surge force for the F-24 line for the case without any additional axial restraints.

[redacted]

We found that a surge load of [redacted]) applied at the header of the F-24 line at [redacted] together with concurrent operational loads, results in stress approximately equal to [redacted] allowable code stress for occasional loads. Similar to the analysis with a blind flange installed near [redacted], our results indicate that the pipeline riser at the base of the tee connection experiences the maximum stress. Figure 16 below shows a line rendering of the JP-5 tee connection where the maximum stress occurs.

[redacted]

[redacted]

5.2 Detailed FE Analysis Results using ABAQUS

5.2.1.1 Analysis Results for the F-24 Pipeline at [redacted] When a New Blind Flange is Installed at the Lower Skillet Location at [redacted]

With an applied surge load at the header of the F-24 line at [redacted], the maximum stress occurs at the intersection of the JP-5 line and the tee connection due to stress intensification effects. The analysis results can be summarized as follows:

- To limit the stress in the model within the allowable stress of [redacted] the maximum allowable surge pressure at the header of the F-24 line at [redacted] Figure 17).

- To limit the stress in the model within the elastic range (less than 35 ksi), the maximum allowable surge pressure at the header of the F-24 line at [redacted] is approximately [redacted] The pipeline system would still maintain its integrity during the defueling process if the surge pressure at the header of the F-24 line at [redacted] is kept to less than [redacted]

- Therefore, it appears that additional axial restraint is not required at this location of the F-24 line if the lower skillet near [redacted] is replaced with a pressure-rated blind flange and the pipeline is reconnected immediately upstream of the new blind flange.

[redacted]

[redacted]

In this case, the product will be allowed to pack the F-24 line up to the header at [redacted] With an applied surge load at the header of the F-24 line at [redacted], the maximum stress occurs at the intersection of the JP-5 line and tee connection due to stress intensification effects. The analysis results can be summarized as follows:

- To limit the stress in the model within the allowable stress of [redacted] the maximum allowable surge pressure at the header of the F-24 line at [redacted] is approximately [redacted]).
- To limit the stress in the model to the elastic range (with maximum stress less than [redacted]), the maximum allowable surge pressure at the header of the F-24 line at [redacted] is approximately [redacted] (Figure 20). The pipeline system would still maintain its integrity during the defueling process if the surge pressure at the header of the F-24 line at [redacted]6 is kept to less than [redacted].

[redacted]

[redacted]

6. DISCUSSION

The maximum allowable forces we determine from our analyses are the results of axial unbalanced loads due to postulated surge events from valve closures. The maximum allowable surge pressure depends on the distance between the rapidly closed valve and the location where we apply the load. At the initiation point (the valve), a maximum pressure wave is generated that travels through the product and pipelines and is influenced by the geometry, pipeline flow rate, tank heads, pipeline branches, reducers, and other valves. Because of these influences and the complex nature of transient surge events, our analysis results should be reviewed in conjunction with a follow-up hydraulic surge analysis. Such a hydraulic surge analysis should calculate the pressure wave degradation between valves and the Red Hill pipeline dead ends (blind flanges) based on the new operational constraints that will be enforced during defueling.

Our analysis results show that the controlling forces and pressures relate to the F-24 pipeline and are sensitive to the location of the last pressure-rated blind flange. We recommend implementing Assumption 4 in Section 4.1 (new blind flange installed at the lower skillet location near [redacted] followed by reconnection of the F-24 header) such that the maximum allowable pressure surge at the F-24 blind flange would be approximately [redacted] to meet [redacted] allowable stress criteria, and up to [redacted] to not exceed the nominal yield stress. If these assumed pipeline configuration changes are not implemented, the maximum surge pressure at the end of the F-24 line [redacted] reduces to approximately [redacted] allowable stress criteria and up to [redacted] to not exceed the nominal yield stress. All the above pressures are in addition to the operating pressure imposed by the fill height of the tanks [redacted]

7. CONCLUSIONS AND RECOMMENDATIONS

[redacted]

We recommend that the lower skillet in the F-24 line near [redacted] be replaced with a pressure-rated blind flange and that the upstream portion of the F-24 pipeline be reconnected. In this case, a maximum allowable surge pressure of [redacted] if the pipe is allowed to yield) can be achieved as per our detailed FE analysis.

However, if the F-24 skillet is removed but not replaced with a pressure-rated blind flange and valve closure can impose forces on the F-24 header at [redacted] greater than the maximum allowable forces we calculate (maximum allowable surge pressure of [redacted] if the pipe is allowed to yield), the following mitigation methods can be considered:

1. Provide axial restraint for the F-24 pipeline at the JP-5 pipe anchor location near Pipe Support 25 to increase the maximum allowable surge pressure at the header of the F-24 line ([redacted] to yield) (Figure 21), or

2. Use the JP-5 line to defuel the F-24 pipeline, or

3. Provide axial restraint on the F-24 pipeline per our April 2022 recommendations. (Note: this is also consistent with the repair employed by EEI/Aptim in their emergent repairs of the JP-5 header at [redacted], where the JP-5 header has been longitudinally restrained at the end of the tunnel.)

[redacted]

[redacted]

[redacted]

JOSH GREEN, M.D.
GOVERNOR OF HAWAI'I
KE KIA'ĀINA O KA MOKU'ĀINA 'O HAWAI'I

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In reply, please refer to:
File:

January 13, 2023

Rear Admiral John Wade
Joint Task Force, Red Hill
1025 Quincy Avenue, Suite 900
Joint Base Pearl Harbor Hickam, Hawaiʻi 96860-5101
[via email only: john.f.wade2.mil@us.navy.mil]

Dear Rear Admiral Wade:

SUBJECT: DOH Response to "JTF-RH Response to DOH Requests for Information Regarding Red Hill Bulk Fuel Storage Facility Defueling Plan"

On December 2, 2022, the Hawaiʻi Department of Health (DOH) received from the Joint Task Force – Red Hill (JTF-RH) responses to the DOH's November 8, 2022 comments on the U.S. Department of the Navy's Defueling Plan Supplements 1.A and 1.B and enclosures; and the JTF-RH's Defueling Consolidated Repair/Enhancement List and enclosures. The JTF-RH's response included:

- Cover letter, dated November 30, 2022, titled "JTF-RH Response to DOH Requests for Information Regarding Red Hill Bulk Fuel Storage Facility Defueling Plan;"
- Untitled document containing JTF-RH's responses to the DOH's November 8, 2022 comments;
- Attachment 1, titled "Bow Tie Diagram – Red Hill Loss of Containment, New Barriers;"
- Attachment 2, titled "Table 2: Controls implemented at the Red Hill Bulk Fuel Storage Facility;" and
- Attachment 3, untitled, containing an event tree analysis in response to the DOH comment 3.b.

In addition, on December 22 and 29, 2022, respectively, the DOH received:

- A memorandum prepared by SGH, dated November 30, 2022, titled "Hotel Pier PVC FOR Line Replacement Prior to Defueling the Red Hill Underground Bulk Fuel Storage Facility;" and
- An updated critical path method schedule, dated December 20, 2022.

Based on the responses received, the DOH conditionally approves the following two repair deviations listed in the JTF-RH's Defueling Consolidated Repair/Enhancement List, dated October 24, 2022, and submitted on October 27, 2022. According to the repairs list, forgoing the Fuel Oil Recovery (FOR) Pipeline replacement at Hotel Pier "could reduce the overall defuel timeframe by three months and accelerate the completion of defueling from June 2024 to March 2024." Please confirm whether the expected end date for defueling will be March 2024, given the conditional approvals below.

1. <u>F-76 Pipeline Enhancements (SGH-PM-3/4/12):</u>
We understand the JTF-RH can complete defueling of all tanks by utilizing the JP-5 and F-24 fuel lines. Because the two tanks storing F-76 (Tanks 15 and 16) are already connected to the JP-5 line, the JTF-RH plans to reroute the F-76 product to the JP-5 line, simply by reconfiguring the

flanges on those tanks. We understand from the JTF-RH's responses to thw DOH's comments that the pipe laterals from Tanks 15 and 16 to the JP-5 line have already been inspected and were included in the NDAA assessment. The JTF-RH proposes that this non-intrusive adjustment would remove the need to install longitudinal restraints on the F-76 pipeline (SGH-PM-12). The DOH approves this deviation, with the understanding that the F-76 line will not be used.

2. Replace Polyvinylchloride (PVC) FOR Pipeline at Hotel Pier (SGH-HP-14):
The JTF-RH's Defueling Consolidated Repair/Enhancement List states, "[t]he SGH Assessment of Red Hill Underground Fuel Storage Facility noted that the PVC FOR line under Hotel Pier potentially has joints with Nitrile seals and recommends replacing the 'PVC with appropriate materials' (SGH # HP-14). SGH designated this repair as required prior to defueling." The SGH's November 30, 2022, memorandum, "Hotel Pier PVC FOR Line Replacement Prior to Defueling the Red Hill Underground Bulk Fuel Storage Facility," described an alternative to replacement for the purposes of defueling. The DOH conditionally approves this alternative provided the JTF-RH follows all of the provisions made for this alternative, which include but are not limited to:

   a. Hydrotest the existing PVC FOR pipeline to locate and repair leaks.
   b. Any resulting leaks shall be appropriately repaired and retested prior to defueling.
   c. Prior to hydrotesting, repair all damaged/missing hardware supporting the PVC FOR pipeline under the pier, including but not limited to damaged pipe hangers.
   d. Document repair and testing for submission to the DOH.

At this time, the DOH cannot approve the proposed third deviation or the remainder of the list until our comments and concerns are fully resolved. We offer our enclosed comments on the JTF-RH's responses. Please note, for comment numbers not included in our enclosure, the DOH has no further comment.

Additionally, in light of the November 29, 2022, aqueous film forming foam (AFFF) spill at the Red Hill Bulk Fuel Storage Facility, we request an updated Spill Prevention Control and Countermeasure Plan and Facility Response Plan for the repair phase of defueling. These documents should address spill prevention and response for hazardous substances, including AFFF and oil.

Should you have any questions regarding this letter or the enclosed comments, please contact Ms. Kelly Ann Lee, Red Hill Project Coordinator at (808) 586-4226 or kellyann.lee@doh.hawaii.gov.

Sincerely,

Kathleen Ho

KATHLEEN S. HO
Deputy Director for Environmental Health

Enclosure

c: Ms. Gabriela Carvalho, U.S. Environmental Protection Agency (w/encl.) [via email

2. The Hawaiʻi Department of Health (DOH) looks forward to reviewing the reasonable worst-case scenario discharge, mitigation to prevent discharge into the environment, the defueling spill response plan, and procedures (and subsequent results) associated with the planned sump tightness testing. Please coordinate the tightness testing scheduling with the DOH, as we would like an opportunity to observe the tightness testing. In addition, the floor drains leading to the sumps should be inspected for cracks and sealed to prevent leaks.

3. The DOH requested a quantitative probability assessment to further evaluate the Navy's proposal to not repair the aqueous film forming foam (AFFF) drain line or provide a backup system to remove spilled fire suppression material or oil to the existing oil recovery system in the Lower Access Tunnel. The Joint Task Force – Red Hill's (JTF-RH's) response was provided in two parts, which are addressed in 3.a and 3.b below. Also, in light of the November 29, 2022, AFFF release, we understand the Navy is conducting an investigation regarding the incident, and the JTF-RH is reevaluating the fire plan for defueling. Please submit a revised assessment to address the anticipated new information and the following comments.

a. The response identifies three potential release scenarios:
   i. Breach in the JP-5 pipeline immediately upstream of the sectional valves, releasing approximately 30,000 gallons of fuel;
   ii. Release down-gradient of the tank gallery; and
   iii. Catastrophic release from a nozzle releasing a volume greater than 50,000 gallons.

Multiple arguments were provided for scenarios i and iii. The DOH agrees utilizing the AFFF sumps and drain line will not increase the rate of fuel removal for a spill down-gradient of the tank gallery.

Scenario i states it would take about ten minutes for the AFFF sump pumps to remove 30,000 gallons of discharge, while the groundwater pump would take about five hours. During the May 6, 2021 event, the JTF-RH confirms it took twelve hours to clean the release of about 20,000 gallons, which we understand was mostly removed by the AFFF sump pumps in less than ten minutes. However, the groundwater data collected after the May 6, 2021 release shows a striking increase in contamination, even though the majority of fuel was removed in that short amount of time. Thus, the DOH takes issue with the possibility of fuel or fire suppression material sitting in the tank gallery for five hours.

Additionally, comparing the number of days for fuel to travel from the point of release to the well head to the time fuel is sitting in the tunnel, potentially seeping into the environment, does not indicate release time is negligible. We will not discuss the November 20, 2021 incident in this comment, as any release down gradient of the tank gallery (scenario ii) would not be affected by the AFFF sump system.

For scenario iii, when a release is greater than 50,000 gallons, the JTF-RH states pump rate becomes irrelevant because the volume capacity is only about 50,000 gallons for the FOR system (42,300 gallons for Tank S311 and 9,700 gallons for the pipeline). However, the AFFF drain line and associated tank can provide an additional capacity of more than 100,000 gallons. Thus, pump rate can still play a role in spill response to a greater extent.

b. With regards to the quantitative assessment, we have the following preliminary comments:

   i. Two of the five mitigation controls to reduce the risk of groundwater contamination take place after the groundwater has already been impacted: Groundwater treatment system and increased groundwater monitoring. We comment on these two topics below.

      - The current groundwater treatment system (also known as the granular activated carbon system) is not designed to prevent a fuel release from migrating towards other sources of drinking water supplied from groundwater wells. The system was intended to prevent outward movement of fuel that was discharged around Red Hill Shaft. There is no current indication that the pumping at Red Hill Shaft will prevent contaminant movement from any part of the facility.
      - Increased groundwater monitoring by itself does not mitigate contamination. It only provides data on groundwater quality at the given location.
      - The fuel recovery system was in place prior to the May 6, 2021 event. Additionally, removing the AFFF drain line from use is a reduction of mitigative measures, which should be considered in the evaluation.

   ii. The DOH disagrees with using Table 1: Initiating Events and Corresponding Frequencies to set the initial tank failure conditions for the probability analysis because:

      - No backup data was provided to state how these numbers were developed (other than referencing the book used);
      - The known failures were due to operational errors, not catastrophic tank or pipe failures;
      - The reasonable-worst case scenario release we have been discussing to compare the AFFF pump removal rate to the groundwater pump rate (5,000 to 50,000 gallons per hour) does not necessarily involve a catastrophic tank failure. Thus, this is not the appropriate data point to start with; and
      - Most importantly, Table 1 does not concur with the initial probability for leaks in the 2018 Quantitative Risk and Vulnerability Assessment (QRVA) prepared by the U.S. Department of the Navy (Navy), which shows a yearly probability of 27% for leaks from 1,000 to 30,000 gallons and 1.3% for leaks from 30,000 to 60,000 gallons (Table ES-1).

Table ES-1. Acute Scenario Risk Results Summary

Fuel Release Volume Range Category (gallons)	Sequence Group Frequency (events/year)	Exceedance Frequency (events/year)	Sequence Group Recurrence Interval (years)	Sequence Group Probability (1 year)	Sequence Group Probability (100 years)	Potential Volume Released – Point Estimate (gal./year)
1000 to 30000	0.3230500	0.3424131	3.10	0.2760623	1.0000000	1,960
30000 to 60000	0.0129880	0.0193631	77.00	0.0129040	0.7271410	515
60000 to 120000	0.0022056	0.0063751	453.40	0.0022032	0.1979305	191
120000 to 250000	0.0011526	0.0041695	867.58	0.0011519	0.1088656	219
250000 to 500000	0.0024041	0.0030169	415.96	0.0024012	0.2136946	1,097
500000 to 1000000	0.0000622	0.0006128	16067.35	0.0000622	0.0062045	42
1000000 to 2000000	0.0003678	0.0005505	2718.94	0.0003677	0.0361109	604
2000000 to 10000000	0.0000335	0.0001828	29821.72	0.0000335	0.0033477	253
> 10000000	0.0001492	0.0001492	6701.52	0.0001492	0.0148112	1,703
Total	**0.342**	**0.342**	**2.920**	**0.290**	**1.000**	**6,584**

iii. Note that Table ES-1 in the QRVA is for the total combined acute releases (including human error), which are more relevant than chronic releases for the short period of defueling (which we are assume will take one year or less). The QRVA states on Page ES-2: "These results are developed under the mathematical assumption that the facility will effectively be operated in the current configuration with the same operating profile (fuel movement profile, processes, operating procedures and policies, maintenance, testing, and design) hypothetically for hundreds of years with no intervening risk-mitigating improvements." Thus, this seems to be the appropriate probability to start with before considering the mitigations in place (i.e., potential mitigations were not included in the QRVA, so the actual risks associated with defueling should be lower).

iv. In addition, the QRVA states: "This specific baseline QRVA is broken into four distinct phases, as follows: (1) internal events (excluding internal fire and flooding), (2) internal/external fire and flooding, (3) seismic events, and (4) other external events. The first phase of the baseline QRVA, which is the topic of this report, is designed to focus on internal events (not including the risk from internal fires or internal floods)." As we have discussed previously, the chance of fire or seismic event during the short duration of defueling is negligible. Therefore, this document appears to provide the appropriate probability assessment to evaluate the initial conditions needed to assess the difference in risk between using the FOR line versus a quicker removal method in the event of a spill of 60,000 gallons or less. Please note, larger "catastrophic" spills would have to be contained or mitigated in other ways, which may be covered in the Navy's upcoming spill response plan.

v. Other important information in the QRVA document:

- (ES-2) – It is important to note these total "roll-up" values represent the risk from all the scenarios that fit into the associated category, including human error.

- (ES-5) – "It is important to note these results are for events and conditions leading only to fuel release from the facility but not necessarily directly into the water table." Mitigation to prevent a release in the tunnel from reaching the environment should reduce the QVRA probability accordingly. The DOH is concerned about potential releases into the environment and potentially contaminating the groundwater, not only the probability of impacting drinking water. Thus, the probability and mitigation assessment should end at an environmental impact.
- Page 1-2 – Risk assessment level 2 is defined as "Frequency (and annual probability) of Uncontrolled Release of Fuel Inventory (by volume range) outside the Red Hill Bulk Fuel Storage Facility Property Boundaries that Could Impact Red Hill Groundwater Shaft Water Quality."
- Page 1-2 – "Experience has shown that Levels 1 and/or 2 above are often adequate to facilitate effective risk management decision-making for the facility owner/operator. The QRVA described in this report focuses on a Level 2 risk assessment, as defined above."
- Table ES-1 and the following text in the QRVA lists the items that are important to risk. Those include (roughly in order of importance):
    1. The availability of tank ullage to accommodate emergency movement of fuel from a leaking tank to a safe storage tank or other safe container is important to risk.
    2. The availability and quality of potential fuel release emergency response procedures and associated operator training are important to risk.
    3. The capability and reliability of tank fuel inventory (fuel level) instrumentation and control systems are important to risk.
    4. In response to potential fuel release scenarios, operator actions are generally more important than equipment failures to overall risk. Specific examples are identified in Sections 8 and 13 of this report.
    5. Following tank inspections and maintenance, quality control during the tank return-to-service process is important to risk.
    6. Strategies for responding to fuel releases inside the RHBFSF Lower Access Tunnel (e.g., strategies for removing and controlling fuel released into the Lower Access Tunnel) are important to risk.
    7. Potential fuel releases from the tank nozzles (the main fuel flow piping leading into and out of the main storage tanks up to the upstream flange connections for the tank skin valves) are important to risk.

8. The capability and reliability of fuel piping isolation in response to fuel release incidents in the RHBFSF Lower Access Tunnel are important to risk.
9. Safety management and control of specific maintenance actions at the facility (e.g., tank nozzle and skin valve maintenance) is important to risk.
10. The design and proximity of the RHBFSF Lower Access Tunnel and the Red Hill Water Pump Area is important to risk. This is because potential fuel releases into the RHBFSF Lower Access Tunnel could potentially propagate to this area and flow (in a near-direct path) to the drinking water table.

vi. Accordingly, mitigations to any of the ten factors listed above, subsequent to this report, would lower the probability from that shown in the report. Some of these may coincide with an additional layer of protection, as defined in the JTF-RH's initial response according to the referenced book. Based on the information provided in the QRVA, the DOH believes this is the appropriate assessment to set the initial probability of a release within a year because it includes all potential causes for a release. Mitigations subsequent to this 2018 report should reduce that overall probability.

c. Other comments on the JTF-RH's submittal:

i. Attachment 3 (event tree) shows the risk reducing from 9.89E-05 to 9.89E-06 through the box of "preventative barriers" (response to pressure indicating transmitters, watchstanders, and procedures) but does not explain how this reduction was derived (other than referencing the book used for layers of protection). Attachment 2, which appears to list items in this "box," contains some items that do not directly impact the environment, such as groundwater monitoring and the groundwater treatment system. By the time these items come into play, the environment has already been impacted. (However, we note some of these measures may prevent drinking water wells from being impacted after a release.)

ii. Reducing the number of tanks containing fuel only prevents a release by reducing the time needed to defuel. This should be considered in the analysis. For example, if a year to defuel is assumed, like in the QRVA yearly probability, defueling in less than one year should reduce the release probability accordingly.

iii. There is no indication of how much, or if, items contribute to risk reduction, other than some general idea of a "layer," which is not defined in the response. To make the assessment easier to understand, the DOH recommends breaking risk into categories (e.g., physical repairs, updated operation procedures, added spill prevention, etc.) instead of layers. Each category would represent a risk reduction, combining to arrive at the final probability of a release impacting the environment. This would likely be easier to follow, and even conservative assumptions may result in low probabilities when the probabilities of occurrence are multiplied together.

The collective reduction in risk contributed by all the mitigation measures should first be combined, then subtracted from the respective risks of groundwater contamination when using the FOR line versus a faster method.

iv. Attachment 3 is difficult to follow beyond what is mentioned above. The piping breach includes the 10E-5 probability and is reduced to 10E-6 after the box (one layer), but then splits into true-false lines. The "true" line says 0.9% probability then goes to "release contained and mitigated." Does "true" mean if there is a release, there is a 90% probability it will reach the environment without mitigation? Or does "true" mean, even with mitigation and containment there is a 90% probability it would reach the environment? The "false" line says 0.1% and then goes to limited containment and mitigation. Does "false" mean if there is no release there is a 0.1% change of impacting the environment? It is not clear what "limited containment and mitigation" means in this case.

5. Defueling release scenarios and the associated plan still need to be developed. The DOH looks forward to receiving an updated Facility Response Plan (FRP) with relevant worst-case scenarios for defueling, as mentioned in our response for comment 2. We look forward to participating in the interagency response planning team meetings and spill exercises for defueling.

12. Please explain the status of this design contract in light of the November 29, 2022 AFFF release. What was the purpose of the new design? What enhancements were intended? We understand the Navy is investigating the cause of the AFFF release and that NAVFAC's fire system designers are currently re-evaluating the design of the fire suppression system. We look forward to receiving a copy of the investigation report when completed and the new fire plan.

16. The DOH assumes the Navy will continue to complete minor repairs, and no further discussion or evaluation is required for these items. If the current repairs list will not delay the defueling end date, a reevaluation may not be necessary. However, items that appear to be more than minor, and therefore may collectively cause a delay, include the following. We appreciate notification if any of these or other repairs on this list are determined to cause delay.

Count	Description/Repair
39	For JP-5 piping between the Sectional valves near Tank 1 to PS 1: Various sections of pipe are floating from the saddles and the saddles are offset from the support frame. Reset saddles to bear the pipe and also be centered on the support frame. Assume 15 support saddles need to be reset.
40	F-24 pipeline is unsupported between supports, approximately 58 feet. Install saddle or shim the pipe or pipe supports to uniformly support the pipe.
78	Concrete has been chipped out and removed on tank side around flange for the F-24 and JP-5 lines; concrete around F-24 line has broken out (but not fallen) on opposite side. Repair concrete.

79	Concrete at F-24 line has been broken out on tanks side, no flange visible. Repair concrete.
95	Dresser coupling joints and associated joint harness at Tanks 18, 19, and 20 are damaged due to the May 6th event. Repair damaged piping. Carefully reset the mainline into its original position at the Tanks 17/18 and 19/20 cross-tunnels. Provide cross-tunnel pipe supports and frames at Tanks 18 and 20. Quantity is four (two at each of Tanks 18 and 20). Provide new frames and adjustable height low friction pipe supports. Remove existing piping and replace the cross-tunnel piping at Tank 18 and Tank 20 from (including) the reducer to the ball valve. Provide new insulated compression sleeve pipe coupling, Buna-N resilient material, and restraint harness.
113	The 2-inch FOR pipeline between the tee and gate valve at Door C is covered with a stained plastic wrap and c-clamps. This is indicating a weep at the threaded joint. Replace piping.
117	The FOR connection from the product lines is constructed out of a combination of hard pipe and hoses. Replace connections and hoses with hard pipe.
118	The tank sampling piping associated with Tanks is showing signs of minor to moderate corrosion at areas where the piping has not been upgraded. Tank 9 sample piping is severely corroded and requires replacement. Repair by replacement the small-bore tank sample piping up to the sampling stations associated with Tank 9.
120	Three temporary pipe clamps on 4-inch FOR pipeline within trench adjacent to S-23. Pipe clamp lengths are 6-inch, 16-inch, 8-inch. Also, UTT indicates pipe wall loss in this area over 55% metal loss is present. Repair pipe.
125	Condition of underground segment of the FOR pipeline is unknown. Per the 2021 CP Report, this section of buried pipe had ineffective magnesium anodes. Perform borescope examination of the underground pipeline segment to assess internal condition of the pipeline.
128	Severe corrosion and pitting at several locations between ADIT 3 and S-311. Wall Loss observed between 60%-79%. Severe corrosion also observed at pipe support cradle interfaces. Repair pipe.
143	Support completely deformed, removed from baseplate. API 570: Damaged pipe support (impacted by a moving vehicle). Replace support.
182	Non-standard repair at bulkhead. Pipe is anchored to the bulkhead using welded collars inside cast in place concrete. There is a repair sleeve through the bulkhead. The UGPH side of the bulkhead has a full encirclement sleeve. The ADIT 2 side of the bulkhead has a half sleeve. 10 ft pup to eliminate the non-standard repair in the bulkhead. The piping will need to be re-anchored. Replace piping through bulkhead.
183	Reported corrosion of 46% at the bulkhead. Pipe is anchored to the bulkhead using welded collars inside cast in place concrete. 10 ft pup to eliminate metal loss at the bulkhead. The piping will need to be re-anchored.
184	Reported corrosion of 71% at the bulkhead. Pipe is anchored to the bulkhead using welded collars inside cast in place concrete. 10 ft pup to eliminate metal loss at the bulkhead. The piping will need to be re-anchored.
188	Corrosion at bulkhead. Three separate features. Reported corrosion depths 26.8%, 30.8%, and 38.0%. Remaining thickness < minimum thickness per API 574. Remove, provide, and install 10 ft 18" pup piece to eliminate the corroded areas in the bulkhead. One repair for 18-ILI-27, 18-ILI-28, and 18-ILI- 29.

219	ILI data reports metal loss of 31.5%. Not able to assess without coating removal. 4-ft, remove coating and inspect. FFS assessment and repair if necessary.
220	ILI data reports metal loss of 32.0%. Not able to assess without coating removal. 4-ft, remove coating and inspect. FFS assessment and repair if necessary.
236	Remove and replace the elevation and alignment change spool piece at PS 20. Spool is flanged and includes two rolled 45 elbows and straight segment. [18-TG-25]
237	Remove approximately 38-inch length mainline bell connection segment between PS 22 and PS 23. Provide 5 lf welded pup replacement. [18-TG-28]
238	Between PS 38 and PS 39, remove the 12 o'clock NPS ¾ threaded pipe and valve. Replace with welded NPS ¾ Sch 80 pipe, flange, and Class 150 ball valve with threaded cap. [18-TG-34]
240	Remove approximately 46-inch length mainline bell connection segment between PS 59 and PS 60. Provide 6 lf welded pup replacement. [18-TG-41]
241	Remove the corroded mainline tee at the Tanks 5/6 cross-tunnel junction. Replace mainline as-needed to install a branch connection. Rework cross-tunnel piping as needed to connect the branch connection. Re-connect mainline to cross-tunnel piping with provision for spectacle blind. [18-TG-44]
242	Remove approximately mainline bell connection segment between PS 68 and PS 69, on both sides of the bulkhead. Provide 10 lf welded pup replacement in two segments. [18- TG-46]
243	Remove and replace approximately 96-inch length mainline segment at PS 75. Replace 6- ft above to 2-ft below PS 75. [18-TG-53] Replace the corroded pipe saddle with new.
245	Replace damaged segment of the mainline at PS3. [18-TG-2]
249	Remove and replace a 10-foot pup of JP-5 mainline at the concrete bulkhead near Sta 24+89 [18-ILI-EML-15]. Pipe is anchored to the bulkhead. A method using a reduced diameter sleeve is acceptable. Anchor new pup to concrete.

17. The DOH did not receive an updated CPM schedule at the end of November but received one at the end of December. Thank you for the submission.

20. We look forward to receiving the results.

24.a. Thank you for the clarifications. Were these other pumped pipelines assessed during the NDAA evaluation and will any repairs indicated be completed prior to defueling?

24.b. The DOH understands different design criteria were used for the two reports. One report states surges cannot be mitigated by structural or piping modifications, yet the Navy is using structural and piping modifications to mitigate risk (in addition to operation procedures), as recommended in the second report. These statements and actions are contradictory. Further clarification by the authors is appropriate.