Fredericks Law Firm LLC

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January 16, 2025

VIA FEDERAL EXPRESS

Mr. Adam Renfandt
Analyst, Public Utilities Division
ND Public Service Commission
600 E. Boulevard, Dept. 408
Bismarck, ND 58505-0480

RE: Information Request Response
Thunder Butte Pipeline Project, Case No. PU-24-086

Mr. Renfandt:

Thunder Butte Pipeline, LLC (TBPL) filed a 3rd Amended Consolidated Application for a Certificate of Corridor Compatibility and Route Permit for the Thunder Butte Pipeline Project ("project") dated January 5, 2024. The project has been assigned Case Number PU-24-086. An Amended Consolidated Application was filed February 19, 2024 identifying the new location of the proposed midline pump station. TBPL submitted a 3rd Amended Consolidated Application on October 26, 2024.

The Commission provided an email on November 8, 2024 with requests for information (RFIs) and/or questions. This document and attachments have been prepared to address the Commissions RFIs and questions. Please refer to the 3rd Amended Consolidated Application dated October 26, 2024 for all additional information regarding the project.

Please find attached six hard copies of this letter and its attachments and a compact disc with this letter and its attachments in PDF format.

- Attachment 1 – 2024 Agency Notifications
- Attachment 2 – Existing Pipeline Depth of Cover Summary
- Attachment 3 – Integrity Management Plan/ Operations and Maintenance Plan

In accordance with N.D.AC. 69-06-05(4) all of the foregoing will be served upon the Ward and Mountrail County Auditors. Enclosed with this letter is a Certificate of Service for such action.

If you have any questions, please let me know.

Sincerely,

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Attachments (3)

Cc: Ward County Auditor
Mountrail County Auditor

REQUESTS FOR INFORMATION/QUESTIONS AND TBPL'S RESPONSES

The Commission provided an email dated November 8, 2024, which contained requests for information (RFIs) and/or questions regarding the Thunder Butte Pipeline, LLC's 3rd Amended Consolidated Application for the Thunder Butte Pipeline Project. This document and its attachments have been prepared to address the Commission's RFIs and/or questions. TBPL's responses to the RFI's are provided below in green font.

1. The following concurrence letters should be provided:
    a. A NDSHPO letter for the existing line – An updated notification letter with copies of the Metcalf Archaeological Consultants, Inc. (Metcalf) Class III Cultural Resources Report for the proposed pipeline (2023) and the existing pipeline (2024) were sent via FedEx overnight delivery on November 20, 2024. Metcalf previously uploaded the 2023 and 2024 cultural resources reports and GIS files to the NDSHPO/SHSND ftp site. No response has been received to date.
    b. A similar letter from MHA Nation, if available – An updated notification letter with a copy of the Metcalf Class III Cultural Resource Report for the proposed pipeline (a portion of which is in the Fort Berthold Reservation) was sent to Mr. Joseph Myrick at the Tribal Historic Preservation Office (THPO) via email on November 12, 2024. An updated notification letter with a copy of the Metcalf Class III Survey Report for the proposed pipeline was also previously sent to the THPO on July 22, 2024. No response has been received to date.
    c. A USFWS letter – Arcadis submitted an updated notification letter and summary of the BHA report findings to the USFWS via email on October 25, 2024. The USFWS provided a concurrence letter dated November 6, 2024. A copy of this letter was submitted to the Commission via email on November 9, 2024. TBPL will implement USFWS's recommendations as provided at the bottom of this document (please see Item 17).
2. Provide notice of the update, along with the Biological Habitat Assessment (BHA) and Geohazard Investigation (GI), to the following agencies:
    a. ND Game and Fish – An updated notification letter with a copy of the BHA Report was sent via FedEx overnight delivery on November 15, 2024. No response has been received to date.
    b. ND Parks and Recreation – An updated notification letter with a copy of the BHA Report was sent via FedEx overnight delivery on November 15, 2024. No response has been received to date.
    c. ND Geological Survey – An updated notification letter with a copy of the Geohazard Investigation Report was sent via FedEx overnight delivery on November 15, 2024. No response has been received to date.
3. The depth of cover for the entire line has not been completed.
    a. When will this be completed and submitted? A qualified contractor will perform a depth of cover for the entire pipeline as [part of the as-built survey effort that will take place after construction of the new section of pipeline has been installed. Qualified contractors and operations personnel have done extensive work in spot locating up and down the existing pipeline to verify if there were any areas with less than 48" DOC. The few areas that the geologic contractor found to be less than 48"

were double checked in the field and verified that those depths are greater than 48" and that there must have been an issue with the geologic contractor equipment for locating the depths. All areas that have been spot checked were done using GPS line locating and ground penetrating radar depth equipment. None of the DOC measurements for the existing pipeline were less than 48". TBPL signed the affidavit for the DOC being 48" or more. A table of all the DOC measurements and a map set showing the locations of all DOC measurements are provided in **Attachment 1**. The new pipeline will be installed with a minimum DOC of 72" across the entire route. If any areas are found to be less than 48" when the as-built survey effort is completed, then Gap will repair the respective area to ensure a pipe depth of cover of a minimum of 48" prior to operation of the pipeline.

b. The application mentions this will be submitted as part of the as-built submission. Before the line goes in-service, as part of the as-built survey effort, a DOC analysis will be obtained for the entire length of the existing and new pipelines.

4. Was the new and existing pipeline corridor surveyed? The BHA on page 9 indicates "[a]ccess to portions of the Field Survey Area under active agriculture production was restricted". How much of the area was not surveyed? Please provide a map set depicting the areas not surveyed.
   Yes. the Project Corridors for both the proposed and existing pipelines were surveyed, along with a 1,000-foot-wide buffer area and the one-mile-wide Study Area as described in Section 1 in the BHA Report. The BHA on page 9 indicates "[a]ccess to portions of the Field Survey Area under active agriculture production was restricted". How much of the area was not surveyed? The areas of canola fields were observed from nearby locations; however, they could not be surveyed on foot per the landowner(s) requests. The landcover/vegetation types including cultivated crops are described in Section 4.3 and the totals acreages of each type are provided in Table 2, Land Cover Types in the in the BHA Report for Project Corridors for both the proposed and existing pipelines.
   Please provide a map set depicting the areas not surveyed.
   The landcover/ vegetation types are shown on Figures 3-1 to 3-29, Land Cover Types Maps in the BHA Report. Wetland habitat is shown on Figures 2-0 to 2-16 NHD/NWI/FEMA Map, in Appendix F of the Consolidated Application.
5. The NDGF recommended aerial surveys were to be conducted across the pipeline prior to construction to verify a lack of raptor nests, regardless of when construction occurs. Will the company follow this recommendation, as well as the other recommendations as stated in its letter of October 26, 2023? Yes. TBPL will implement NDGF's recommendations. An aerial survey of raptor nests will be conducted prior to construction regardless of when construction occurs. TBPL is currently conducting aerial surveys of the known location of an eagle and will continue to conduct aerial surveys on a routine basis.
6. Section 4.2 of the GI indicates that "Shell Creek was the waterway with the highest drainage area and the lowest measured DOC of any of the waterways within the 50-foot-wide project corridor of the existing pipeline. Please provide the Depth of Cover (DOC) of the pipeline at this location. Please disregard the DOC estimates in Appendix D to the GI. These DOC estimates are incorrect. A qualified contractor recently conducted a DOC analysis for the entire length of these areas of concern using GPS line locating and depth equipment. None of the DOC measurements for the existing pipeline were less than 48". TBPL signed the

affidavit for the DOC being 48" or more. A table of all the DOC measurements and a map set showing the locations of all DOC measurements are provided in **Attachment 1**. Shell Creek is designated as Waterway ID W11 in the Appendix B table and shown on Figure 6 of Appendix E of the GI Report. The scope of the GI and ASSET packets was to assess whether or not the pipeline is likely to encounter forces that would lead to an exceedance of the maximum allowable unsupported span length during flood events up to a 100-year flood. ASSET Analyses indicated that erosion leading to an exceedance would not occur during a 100-year flood event. Additionally, the pipelines are not estimated to become exposed or suspended at any water crossings during a 100-year flood event. This typically indicates that the pipeline is safe and does not require mitigation.

7. Please describe the mitigation measures the company will take to minimize adverse impacts resulting from the operation, location, and construction of the pipeline due to the presence of the following geologically noted areas within the GI:
    a. Landslide features: "Unstable" Feature IDs S1 and S2 and "Potentially Unstable" Feature ID AOC2 - S1 and S2 (and S3) are well outside of the 50-foot-wide Project Corridor for the existing pipeline and are not a threat to the pipeline based on their location and their downslope area of potential impact. Feature AOC2 is a 21-foot tall, steeper slope (18.4°, 3H:1V) along the south side of the existing pipeline that did not exhibit any signs of instability, therefore mitigation of AOC2 is unnecessary. The geohazards investigation included reporting slopes that were observed to be steeper than those typically occurring in the area; however, please note that Areas of Concern (AOC) are not Avoidance Areas.
        i. Why is S2 described as "conditionally stable in Appendix B to the GI? This may have been a typo. The screening outcome for S2 is "unstable" and matches Table 1 in the final GI report.
    b. Abandoned mine features: M1, M2, and M3 are listed as "unknown" in that survey did not reveal how far they traveled. Locations and extents of the mines are based on historical information assembled by the NDGS, which in these cases are "unknown". Even their coordinates are uncertain. Note that M1, M2 and M3 are located more than 400 feet from the existing pipeline. The GI field investigation confirmed that there is no visible evidence of active subsidence at the M1 and M2 underground mines. M3 was a surface (pit) mine for which the extent was observed. Mitigation of the underground mined areas (M1 and M2) is not possible without knowing the extent of the underground workings. M3 is a small surface mine and does not present an erosion threat to the existing pipeline and does not require mitigation.
    c. Railroad feature: RR1 recommends this location should be monitored. At the time of the GI field investigation, no visual signs of instability were identified at RR1. The slope above RR1 will be evaluated during design and construction of the new pipeline. During pipeline construction, the slope above the start of the railroad ditch at point RR1 will be as recommended in the GI Report and any potential stability issues will be addressed. This slope was created as part of the original railroad construction and is steeper than the natural occurring slopes in the area. TBPL will also implement pipeline integrity monitoring as described in the Integrity Management Plan (IMP) and the Operations and Maintenance Manual. These documents are provided in Attachments 2 and 3.

8. Which of the sites listed in the GI are in the project corridor? AOC1, AOC2, and RR1 appear to be in the project corridor, yet not listed as Avoidance Areas. NOTE: AOCs are not Avoidance Areas. AOC1, AOC2, and RR1 do not represent an imminent threat to the existing pipeline and are not considered Avoidance Areas within the Project Corridor for the existing pipeline. AOC1 and AOC2 are near the existing pipeline within the 50-foot-wide Project Corridor for the existing pipeline. The slope above RR1 is along the Project Corridor for the proposed pipeline and can be examined during design and construction, but it presently does not exhibit instability. The slope above RR1 was created during railroad construction which explains why it is steeper than the naturally occurring slopes in the area. There were no visual signs of instability at the time of the field study.
9. AOC1 is near W13 with a pipeline depth of 2'5". Is this a concern? If yes, what are the company's mitigation plans to minimize adverse impacts? Please disregard the DOC estimates in Appendix D to the GI. These DOC estimates are incorrect. AOC1 is not within a waterway. The main concern at AOC1 is that sparse vegetation may encourage erosion of cover during heavy rainfall events. There was no evidence of erosion of pipeline cover observed during the GI field investigation. Based on the results of the ASSET Analysis in the GI Report, no mitigating action is recommended. According to Section 6.9, Reclamation and Revegetation, of the Environmental Mitigation Plan (EMP): "For areas to be revegetated, seeding will be conducted in accordance with landowner agreements or as specified by the NRCS." Once construction is completed, AOC1 and adjacent areas and will be mitigated by reseeding in accordance with landowner agreements or as specified by the NRCS to minimize the potential for future erosion.
10. Please provide a map set and table showing the locations of all DOC measurements that are less than 48", mileposts, all locations/features studied in the tables to the GI, and jurisdictional and non-jurisdictional wetlands and waterbodies. A qualified contractor recently conducted an updated DOC analysis for the areas along the line that were of concern using GPS line locating and depth equipment. None of the DOC measurements for the existing pipeline were less than 48". The new pipeline will be installed with a minimum DOC of 72" across the entire route. A table of all the DOC measurements and a map set showing the locations of all DOC measurements are provided in **Attachment 1**.
11. Appendix D to the GI indicates the existing pipeline is buried less than 48" at the following locations:
    a. Landslide features near/in a waterway between mileposts 21 and 22:
        i. AO1 minimum DOC: 2'9"
        ii. AO2 minimum DOC: 3'7"
    b. Waterway features between mileposts 0 and 1:
        i. W1 and W2 minimum DOC: 2'2" and also seeing 0'0"
    c. Waterway feature between mileposts 13 and 14:
        i. W7: minimum DOC: 3'1"
    d. Waterway feature between mileposts 17 and 19:
        i. W9: minimum DOC: 3'0"
    e. Waterway feature between mileposts 18 and 19 (Shell Creek):
        i. W11: minimum DOC: 1'6"
    f. Waterway feature between mileposts 21 and 22:
        i. W13: minimum DOC: 2'5"

Please disregard the DOC estimates in Appendix D to the GI Report. These DOC estimates are incorrect. A qualified contractor recently conducted a new DOC analysis for the areas of concern from Appendix D to the GI using GPS line locating and depth equipment. None of the DOC measurements for the existing pipeline were less than 48". A table of all the DOC measurements and a map set showing the locations of all DOC measurements are provided in **Attachment 1**. The scope of the GI and ASSET packets was to assess whether or not the pipeline is likely to encounter forces that would lead to an exceedance of the maximum allowable unsupported span length during flood events up to a 100-year flood. ASSET Analyses indicated that erosion leading to an exceedance would not occur during a 100-year flood event. Additionally, the pipelines are not estimated to become exposed or suspended at any water crossings during a 100-year flood event. This typically indicates that the pipeline is safe and does not require mitigation.

Also, we'd like to know the company's plan on mitigating the depth issues. Before the line goes in-service, as part of the as-built survey effort, a DOC analysis will be obtained for the entire length of the existing and new pipelines. If there are areas found with a DOC of less than 48", TBPL will verify in the field with potholing, and follow up with either adding more dirt to increase the DOC or replacing that section of line depending on the current DOC.

12. The DOC survey for Waterway ID W14 to Appendix D to the GI does not show a DOC. Please supplement the application with the measurements. Waterway ID W14 is the located in the Project Corridor for the proposed pipeline and the new pipeline has not yet been constructed. DOC measurements were not taken at W14, because this waterway was within the 200-foot-wide Project Corridor for the proposed pipeline and the new pipeline does not yet exist. We completed a survey at this location to assess elevation changes at the banks and flow gradients that may encourage instability and/or erosion after installation of the new pipeline.
13. Does the existing pipeline go under any USACE waterways or wetlands? Does existing pipeline go under any USACE waterways/waterbodies in which the pipeline was buried to a depth of less than 48". The existing pipeline route does not intersect any USACE waterways. Based on the Arcadis August 2024 Aquatic Resource Report, 12 wetlands were identified within the 30.8 mile long, 50-foot-wide Project Corridor for the existing pipeline. These 12 wetlands displayed visible hydrologic surface connections to relatively permanent waters and may be considered a WOTUS. Jurisdictional determination status of the delineated wetland features can only be completed by the USACE. On October 10, 2024, Arcadis submitted a request for an Approved Jurisdictional Determination (AJD); however, USACE has not provided an AJD to date. Thus it is currently unknown if any USACE wetlands are crossed.
14. Not all water crossings (i.e., W15) were surveyed, yet listed as "likely stable". Please explain. Please provide the same explanation for ponds that are listed as "stable". Evaluations were based on visual inspection of banks and the size and depth of the crossed water feature. Many features had little vertical deviation and lacked defined banks that did not warrant a survey. Stability becomes a concern with taller, steeper banks where the driving forces are larger. Erosion is typically not a concern at pond crossings due to lack of flowing water over the pipeline. Waterways that were not surveyed were deemed "likely stable" based on engineering judgement because they had less flow, shallower or undefined banks, denser vegetation, and no visible signs of erosion compared to the waterways that were surveyed.

Ponds that were not surveyed were deemed "stable" because the banks of the pond, where stability concerns would be greatest, did not directly intersect the pipeline.

15. Provide all DOC measurements with locations that the company performed. For instance, the GI indicates that DOC measurements for all areas of concern were taken at locations that may not have been provided in the summary showing the GPS locations. Please also include those locations mentioned in the summary table, and supplement the table with milepost locations, and Feature IDs that correspond to the GI (if applicable). Please disregard the DOC estimates in the GI Report. These DOC estimates are incorrect. A qualified contractor recently conducted a new DOC analysis for the areas of concern using GPS line locating and depth equipment. None of the DOC measurements for the existing pipeline were less than 48". A table of all the DOC measurements and a map set showing the locations of all DOC measurements are provided in **Attachment 1**.
16. Winter construction plan: https://ingaa.org/wp-content/uploads/2013/12/21144.pdf
    A winter construction plan will not be submitted as it has been determined by the project to wait until the ground is no longer frozen to commence construction activities. This date will be determined based on current weather conditions, forecasted weather conditions, and frost law restrictions for heavy loads from NDDOT. Construction is anticipated to begin Spring 2025. During construction, TBPL will segregate topsoil as described in the EMP so it may be used during final reclamation of the construction ROW. Generally, up to a maximum of 12" of topsoil will be removed and segregated from the underlying subsoil to prevent mixing during construction and to allow for easy retrieval during reclamation.
17. From USFWS concurrence letter 11-6-2024 - TBPL will comply with all of USFWS' recommended mitigation and monitoring.
    - The period of concern for Dakota Skipper is June 10 to July 25. Habitat should be surveyed for Dakota skipper suitability. If it is determined that suitable habitat is present, then occupancy surveys by a permitted surveyor would need to be conducted during the period of concern. Avoidance of suitable habitat in the project area can be achieved by using HDD including a 250–500-meter buffer around the location. TBPL will implement USFWS's recommendations. If construction occurs between June 10 to July 25, occupancy surveys will be conducted by a permitted surveyor. The HDD method will be employed to avoid impacts to suitable habitat locations, as appropriate.
    - Piping plover surveys should be conducted for seven consecutive days prior to the start of construction activities, including equipment mobilization at the project location. Piping plover survey results should be immediately reported to the FWS. The period of concern is April 15 to August 15. TBPL will implement USFWS's recommendations. If construction occurs between April 15 to August 15, a piping plover survey will be conducted seven consecutive days prior to the start of construction.
    - The period of concern for eagles and other migratory birds is February 1 to July 15. TBPL will implement USFWS's recommendations as described in Section 14.3.7, Table 3, Avoidance and Minimization Measures for Potentially Affected Species, in the Consolidated Application. If construction occurs between February 1 and July 15, an aerial raptor surveys must be performed extending 0.5 mile from the construction ROW before construction begins.

CERTIFICATE OF SERVICE

The following documents were filed with the North Dakota Public Service Commission (Commission) on January 16, 2025, via Federal Express.

1. Six hard copy of Thunder Butte Pipeline, LLC's letter and attachments with responses to the Commission's RFI's and/or questions, and a compact disc with TBPL's letter and attachments in PDF format.

One hard copy and an associated compact disc of the foregoing in PDF format was also placed with Federal Express for service upon the following:

Ward County Auditor
Ms. Marisa Haman
225 3rd Street SE
2nd Floor
Minot, ND 58701

Mountrail County Auditor
Ms. Stephanie Pappa
101 N Main Street
Stanley, ND 58784

Kathryn Cloutier, M.S.
Project Manager
Arcadis U.S. Inc.
630 Plaza Drive
Highlands Ranch, CO 80129
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ATTACHMENT 1

2024 Agency Notifications

North Dakota Game and Fish Department
100 North Bismarck Expressway
Bismarck, North Dakota 58501

Arcadis U.S., Inc.
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Suite 200-102
Newport News
Virginia 23606
Phone: 757 873 8700
www.arcadis.com

Date: November 14, 2024
Our Ref: 30192665
Subject: Threatened and Endangered Species, Migratory Bird Treaty Act, and Bald and Golden Eagle Act Project Review Requests
Thunder Butte Pipeline Project, Ward and Mountrail Counties, North Dakota

To Whom It May Concern:

On behalf of Thunder Butte Pipeline, LLC (TBPL), Arcadis U.S., Inc. (Arcadis), completed a review of potential impacts to federally listed threatened and endangered (T&E) species, migratory birds, and Bald and Golden eagles for the proposed Thunder Butte Pipeline Project (Project) located in Ward and Mountrail Counties, North Dakota. A Project Location Map is provided in **Figure 1, Attachment 1** in the enclosed Biological Habitat Assessment Report (BHAR).

We previously notified NDGF last year in a letter dated September 23, 2023, and received a response letter from NDGF dated 10/18/2023. This letter serves to provide updated information from recent desktop review and field surveys and the enclosed BHAR. In a letter dated November 6, 2024, United States Fish and Wildlife Service (USFWS) provided concurrence that the proposed Project will have "*no effect on, or is not likely to adversely affect*" T&E species, migratory birds, or Bald and Golden eagles.

TBPL is submitting a Consolidated Certificate of Corridor Compatibility and Route Permit Application (Consolidated Permit Application) to the North Dakota Public Service Commission (Commission) requesting a Certificate of Corridor Compatibility and Route Permit for construction and operation of the Project. On behalf of TBPL, Arcadis, U.S., Inc. is submitting this letter and the enclosures, including the BHAR to inform your agency of the proposed Project and to request any comments or input. Any information received will be taken into consideration during the permitting and development process in conjunction with the Consolidated Permit Application process.

Background and Project Area Details

TBPL proposes the Project to transport crude oil from the existing Thunder Butte Petroleum Services, Inc. (TBPS) Crude Storage and Loading Facility (TBPS Facility) within the Fort Berthold Indian Reservation (FBIR), approximately 2.6 miles northwest of Makoti, North Dakota, to the existing Enbridge Stanley Pump Station and Terminal (Enbridge Storage Facility) in Stanley, North Dakota. The Project is a joint venture between Gap Midstream, LLC (Gap) and the Mandan, Hidatsa, and Arikara Nation (MHA Nation) /Three Affiliated Tribes (TAT) doing business as TBPL. The MHA Nation/TAT owns the TBPS Facility, and Enbridge Pipelines North Dakota (EPND) owns the Enbridge Storage Facility.

The overall Project included three sub-areas for the primary components and associated Field Survey Areas/Project Corridors:

- Construction of a new 3.84-mile-long underground crude oil pipeline (new pipeline) with a 200-foot-wide Field Survey Area (Proposed Pipeline Project Corridor) in Ward and Mountrail counties,
- Conversion of an *existing* 30.8-mile-long crude oil collector/gathering pipeline to a transmission pipeline (existing pipeline) within a 50-foot-wide Field Survey Area (Existing Pipeline Project Corridor) in Mountrail County; and
- Construction of an aboveground midline pump station on a 2-acre site adjacent to the existing pipeline in Mountrail County.

The new pipeline will commence at the TBPS Facility and terminate at the interconnection with the existing pipeline in Section 2, T152N, R88W. The existing gathering pipeline was previously owned by EPND (Line 82-111). From the interconnection point with the existing gathering pipeline approximately 2.1 miles southeast of Plaza, North Dakota, the existing gathering pipeline will transport crude oil to the Enbridge Storage Facility. All but the southern 3.84 miles of the Project is an existing gathering pipeline. TBPL will maintain 30-foot-wide permanent easements for the new and existing pipelines. With the exception of a midline pump station and one associated permanent access road, *no aboveground disturbances are anticipated to be required for conversion of the existing pipeline*.

Arcadis performed desktop analysis using available literature and geospatial resources and conducted a biological habitat field survey on August 5 through 8, 2024. The Study Area used for the desktop was 1-mile-wide area (0.5 mile on either side of the pipeline centerlines). Arcadis also conducted desktop reviews and wetland and waterbody delineation field surveys for the Field Survey Areas of the proposed and existing pipelines and the Midline Pump Station area. TBPL plans to use horizontal directional drilling (HDD) construction techniques at the locations of waters of the United States (WOUS) as identified in the United States Army Corps of Engineers (USACE) Approved Jurisdictional Determination (AJD).

The purpose of the biological habitat survey was to assess the presence or absence and/or document the extent of federally listed threatened, endangered, or candidate species habitat, to identify land cover types and state regulated noxious weed infestation areas, and to inventory tree and shrub areas within the Proposed and Existing Pipeline Project Corridors and Midline Pump Station area. Resources identified during the desktop review were field verified during the biological habitat survey as feasible.

The Study Area is characterized by a rural landscape with gently sloping hills, open fields, and actively farmed cropland; streams and other waters, including prairie pothole wetlands and linear wetland drainages, are common features observed throughout the Study Area. The Canadian Pacific Railway, developed/industrial areas, multiple roads, and residential parcels also intersect the Study Area.

Lands within and adjacent to both the proposed and existing pipelines and the midline pump station are previously disturbed lands. Land cover types included: cropland, pasture, native prairie, and other (wetlands, developed areas). In the 0.5-mile buffer area, Arcadis completed visual surveys for bald eagle nests (*Haliaeetus leucocephalus*) and confirmed the location of a previously identified bald eagle nest.

Federally Listed T&E Species

The USFWS Information for Planning and Consultation (IPaC) database via the North Dakota Ecological Services Field Office was reviewed to identify federally listed species or critical habitat that could potentially be occurring or present within the proposed Project area. The Official Species List from the USFWS is included as **Attachment 2** in the BHAR. The Official Species List identified the northern-long eared bat (*Myotis septentrionalis*), piping plover

[1] ND GameFish Notification Ltr_11-14-2024

[2]Habitat information for listed species is available at the Cornell Ornithology Laboratory's All about Birds website (https://www.allaboutbirds.org/).

(*Charadrius melodus*), rufa red knot (*Calidris canutus rufa*), whooping crane (*Grus americana*), Dakota skipper (*Hesperia dacotae*) and monarch butterfly (*Danaus Plexippus*) as potentially occurring within the project area and/or vicinity. No designated critical habitat was identified within the Field Survey Area.

Federally listed species with the potential to occur within the Study Area are listed in **Table 3** in the BHAR, alongside their suitable habitat preferences. TBPL will implement measures to minimize potential adverse effects to potentially affected federally listed species and migratory birds during construction and operation of the Project. The measures identified in **Table 6** in the BHAR will be implemented to minimize adverse impacts to federally listed species, migratory birds, and raptors.

The habitat information gathered during the field survey is summarized in **Table 7** in the BHAR. One species observation of a monarch butterfly was recorded during the field survey in the Existing Pipeline Project Corridor. No other federally listed species were observed during the field survey.

Migratory Birds

The Project is located within potential migratory corridors for piping plover, red knot, and whooping crane; therefore, there is a potential for incidental interactions during the migration season. In North Dakota, species protected under the Migratory Bird Treaty Act (MBTA) are present throughout the year; however, most of these protected species are seasonally present in North Dakota and typically nest from February 1 through July 15 annually. During the nesting period, birds are more vulnerable to human activities.

Following a review of federally listed species, their respective habitat requirements, and on-site conditions, Arcadis has made the following preliminary species affect determinations for the NLEB, piping plover, red knot, whooping crane, Dakota skipper, and monarch butterfly as shown in **Table 7** in the BHAR. These affect determinations are preliminary and have not been confirmed by the USFWS.

Construction of the proposed pipeline and midline pump station are scheduled to commence in the fourth quarter of 2024 and will take approximately 3 months to reach completion. Except for construction of the midline pump station within previously disturbed areas, conversion of the existing pipeline will not require ground-disturbing activities.

No direct disturbances to nesting or breeding birds are anticipated; however, if nesting or breeding birds are observed within 1.0 mile of an active work area, all construction within 1.0 mile of the sighting will be modified or curtailed until the bird(s) have left the area, USFWS will be consulted on how to proceed, and the NDGF and the TAT Fish and Wildlife Division will be notified. With the implementation of these guidelines, the proposed Project is not likely to adversely affect migratory species or result in fatalities including piping plover, red knot, or whooping crane.

BGEPA Species

The Bald and Golden Eagle Protection Act (BGEPA) prohibits anyone without a permit from taking a bald or golden eagle including their parts, nests, or eggs. The BGEPA defines “take” as to pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest, or disturb and includes impacts resulting from human-induced alterations near previously used nesting sites.

Proposed Pipeline: Based on review of the NDGF’s database, no eagle nests were identified in the Project Corridor or within the 1-mile Study Area for the proposed pipeline. No raptor nests were observed within ½-mile

[1] ND GameFish Notification Ltr_11-14-2024

[2]Habitat information for listed species is available at the Cornell Ornithology Laboratory’s All about Birds website (https://www.allaboutbirds.org/).

line-of-sight of the Field Survey Area. Woody vegetation within the Project Corridor is primarily limited to the banks of the East Fork of Shell Creek, and no previously used nesting sites have been identified. The HDD method will be used to minimize disturbances to the bed or banks of the East Fork Shell of Creek.

Existing Pipeline: Based on review of the NDGF's database, one eagle nest was identified approximately 375 feet from the existing pipeline Route. This eagle nest is adjacent to existing county road 49th Street NW. Conversion of the existing pipeline will not require disturbances within 0.5 of this eagle nest.

Midline Pump Station: Based on review of the NDGF eagle nest database, the bald eagle nest is approximately 2 miles northwest of the proposed new location for the midline pump station as shown on the maps in **Attachment 1** in the BHAR. No raptor nests were observed within a 0.5-mile line-of-sight of the Field Survey Area.

Conclusion

Based on the nature of the proposed Project and lack of suitable habitat within the Project area, no adverse impacts to federally listed T&E species, migratory birds, bald eagles, or golden eagles or their habitat are anticipated.

Arcadis, on behalf of TBPL, is submitting the Project review package to request concurrence from NDGF that the proposed Project will have "*no effect on, or is not likely to adversely affect*" federally listed T&E species, migratory birds, bald and golden eagles, or their critical habitat.

Please direct any questions or correspondence concerning the Project to me at Kathryn.Cloutier@arcadis.com or 303-471-3410, or Doug Anderson at 303-471-3484.

Sincerely,
Arcadis U.S., Inc.

Kathryn Cloutier
Project Manager

Email: Kathryn.Cloutier@arcadis.com
Office: 303-471-3410

Enclosures:

USFWS Concurrence Letter
2024 Biological Habitat Assessment Report

[1] ND GameFish Notification Ltr_11-14-2024

[2]Habitat information for listed species is available at the Cornell Ornithology Laboratory's All about Birds website (https://www.allaboutbirds.org/).

North Dakota Geological Survey
600 East Boulevard Avenue
Bismarck ND 58505-0840

Date: November 14, 2024
Our Ref: 30192665
Subject: Thunder Butte Pipeline, LLC: Thunder Butte Pipeline Project, Ward and Mountrail Counties, North Dakota

Arcadis U.S., Inc.
630 Plaza Drive
Suite 200
Highlands Ranch
Colorado 80129
Phone: 720 344 3500
Fax: 720 344 3535
www.arcadis.com

To Whom it may Concern,

Thunder Butte Pipeline, LLC (TBPL) is proposing the Thunder Butte Pipeline Project (Project) for transport of crude oil from the existing Thunder Butte Petroleum Services, Inc. (TBPS) Crude Storage and Loading Facility (TBPS Facility) within the Fort Berthold Indian Reservation (FBIR), near Plaza, North Dakota to an existing Enbridge crude terminal in Stanley, North Dakota. A Project Location Map is provided in the enclosed **Figure 1**.

TBPL is submitting a Consolidated Certificate of Corridor Compatibility and Route Permit Application (Consolidated Permit Application) to the North Dakota Public Service Commission (Commission) requesting a Certificate of Corridor Compatibility and Route Permit for construction and operation of the Project. On behalf of TBPL, Arcadis, U.S., Inc. (Arcadis) is submitting this letter to inform your agency of the proposed Project and to request any comments or input. Any information received will be taken into consideration during the permitting and development process in conjunction with the Consolidated Permit Application process.

We previously notified NDGS last year in a letter dated September 23, 2023, and received a response letter from NDGS dated 10/6/2023. This letter serves to provide updated information from recent field surveys to evaluate depth of cover (DOC) of the existing pipeline and the geohazard investigation. The DOC memo and the Geohazard Investigations Report (GIR) are enclosures to this letter.

TBPL proposes the Project to transport crude oil from the existing Thunder Butte Petroleum Services, Inc. (TBPS) Crude Storage and Loading Facility (TBPS Facility) within the Fort Berthold Indian Reservation (FBIR), approximately 2.6 miles northwest of Makoti, North Dakota, to the existing Enbridge Stanley Pump Station and Terminal (Enbridge Storage Facility) in Stanley, North Dakota. The Project is a joint venture between Gap Midstream, LLC (Gap) and the Mandan, Hidatsa, and Arikara Nation (MHA Nation) /Three Affiliated Tribes (TAT) doing business as TBPL. The MHA Nation/TAT owns the TBPS Facility, and Enbridge Pipelines North Dakota (EPND) owns the Enbridge Storage Facility. These two facilities are not part of the TBPL Project because they are owned by third-party entities.

The overall Project included three sub-areas for the primary components and associated Field Survey Areas/Project Corridors:

- Construction of a new 3.84-mile-long underground crude oil pipeline (new pipeline) with a 200-foot-wide Field Survey Area (Proposed Pipeline Project Corridor) in Ward and Mountrail counties,
- Conversion of an *existing* 30.8-mile-long crude oil collector/gathering pipeline to a transmission pipeline (existing pipeline) within a 50-foot-wide Field Survey Area (Existing Pipeline Project Corridor) in Mountrail County; and

- Construction of an aboveground midline pump station on a 2-acre site adjacent to the existing pipeline in Mountrail County.

The new pipeline will commence at the TBPS Facility and terminate at the interconnection with the existing pipeline in Section 2, T152N, R88W. The existing gathering pipeline was previously owned by EPND (Line 82-111). From the interconnection point with the existing gathering pipeline approximately 2.1 miles southeast of Plaza, North Dakota, the existing gathering pipeline will transport crude oil to the Enbridge Storage Facility. All but the southern 3.84 miles of the Project is an existing gathering pipeline. TBPL will maintain 30-foot-wide permanent easements for the new and existing pipelines.

Arcadis performed desktop analysis using available literature and geospatial resources and conducted a geological hazard field survey of the Project Corridors for the Proposed and Existing Pipelines, and the midline pump station area on August 5 - 7, 2024. The Study Area used for the desktop was 1-mile-wide area (0.5 mile on either side of the pipeline centerlines). TBPL plans to use horizontal directional drilling (HDD) construction techniques at the locations of waters of the United States (WOUS) as identified in the United States Army Corps of Engineers (USACE) Approved Jurisdictional Determination (AJD).

The Project is scheduled to begin construction in early 2025. The proposed pipeline will be installed using an 80-foot-wide construction right-of way (ROW), consisting of a 30-foot-wide permanent easement and an adjacent 50-foot-wide temporary construction workspace. Approximately three miles of the proposed pipeline will be within the FBIR, approximately 2.3 miles of which will be constructed abutting the existing Canadian Pacific Railway ROW. Construction of the proposed pipeline will temporarily disturb a total of approximately 40 acres on privately-owned agricultural land.

The existing pipeline is located within an existing 30-foot-wide permanent easement. *With the exception of a midline pump station and one associated permanent access road adjacent to the existing ROW, no aboveground disturbances are anticipated to be required for conversion of the Enbridge pipeline.* Lands within and adjacent to both the proposed and existing pipelines and the midline pump station area are previously disturbed agricultural land.

Please direct any questions or correspondence concerning the Project to me at 303-471-3410 or Doug Anderson at 303-471-3484.

Sincerely,

Arcadis U.S., Inc.

Kathryn Cloutier
Project Manager

Email: Kathryn.Cloutier@arcadis.com
Office: 303-471-3410

Enclosures:

Figure 1
DOC Memo
Geological Investigation Report

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North Dakota
Parks and Recreation Department
Liberty Memorial Building
604 East Boulevard Avenue
Department 750
Bismarck, ND 58505

Arcadis U.S., Inc.
700 Tech Center Parkway
Suite 200-102
Newport News
Virginia 23606
Phone: 757 873 8700
www.arcadis.com

Date: November 14, 2024
Our Ref: 30192665
Subject: Threatened and Endangered Species, Migratory Bird Treaty Act, and Bald and Golden Eagle Act Project Review Requests
Thunder Butte Pipeline Project, Ward and Mountrail Counties, North Dakota

To Whom It May Concern:

On behalf of Thunder Butte Pipeline, LLC (TBPL), Arcadis U.S., Inc. (Arcadis), completed a review of potential impacts to federally listed threatened and endangered (T&E) species, migratory birds, and Bald and Golden eagles for the proposed Thunder Butte Pipeline Project (Project) located in Ward and Mountrail Counties, North Dakota. A Project Location Map is provided in **Figure 1, Attachment 1** in the enclosed Biological Habitat Assessment Report (BHAR).

We previously notified NDPR last year in a letter dated September 23, 2023, and received a response letter from NDPR dated 10/18/2023. This letter serves to provide updated information from recent desktop review and field surveys and the enclosed BHAR. In a letter dated November 6, 2024, United States Fish and Wildlife Service (USFWS) provided concurrence that the proposed Project will have "*no effect on, or is not likely to adversely affect*" T&E species, migratory birds, or Bald and Golden eagles.

TBPL is submitting a Consolidated Certificate of Corridor Compatibility and Route Permit Application (Consolidated Permit Application) to the North Dakota Public Service Commission (Commission) requesting a Certificate of Corridor Compatibility and Route Permit for construction and operation of the Project. On behalf of TBPL, Arcadis, U.S., Inc. is submitting this letter and the enclosures, including the BHAR to inform your agency of the proposed Project and to request any comments or input. Any information received will be taken into consideration during the permitting and development process in conjunction with the Consolidated Permit Application process.

Background and Project Area Details

TBPL proposes the Project to transport crude oil from the existing Thunder Butte Petroleum Services, Inc. (TBPS) Crude Storage and Loading Facility (TBPS Facility) within the Fort Berthold Indian Reservation (FBIR), approximately 2.6 miles northwest of Makoti, North Dakota, to the existing Enbridge Stanley Pump Station and Terminal (Enbridge Storage Facility) in Stanley, North Dakota. The Project is a joint venture between Gap Midstream, LLC (Gap) and the Mandan, Hidatsa, and Arikara Nation (MHA Nation) /Three Affiliated Tribes (TAT) doing business as TBPL. The MHA Nation/TAT owns the TBPS Facility, and Enbridge Pipelines North Dakota (EPND) owns the Enbridge Storage Facility.

The overall Project included three sub-areas for the primary components and associated Field Survey Areas/Project Corridors:

- Construction of a new 3.84-mile-long underground crude oil pipeline (new pipeline) with a 200-foot-wide Field Survey Area (Proposed Pipeline Project Corridor) in Ward and Mountrail counties,
- Conversion of an *existing* 30.8-mile-long crude oil collector/gathering pipeline to a transmission pipeline (existing pipeline) within a 50-foot-wide Field Survey Area (Existing Pipeline Project Corridor) in Mountrail County; and
- Construction of an aboveground midline pump station on a 2-acre site adjacent to the existing pipeline in Mountrail County.

The new pipeline will commence at the TBPS Facility and terminate at the interconnection with the existing pipeline in Section 2, T152N, R88W. The existing gathering pipeline was previously owned by EPND (Line 82-111). From the interconnection point with the existing gathering pipeline approximately 2.1 miles southeast of Plaza, North Dakota, the existing gathering pipeline will transport crude oil to the Enbridge Storage Facility. All but the southern 3.84 miles of the Project is an existing gathering pipeline. TBPL will maintain 30-foot-wide permanent easements for the new and existing pipelines. With the exception of a midline pump station and one associated permanent access road, *no aboveground disturbances are anticipated to be required for conversion of the existing pipeline*.

Arcadis performed desktop analysis using available literature and geospatial resources and conducted a biological habitat field survey on August 5 through 8, 2024. The Study Area used for the desktop was 1-mile-wide area (0.5 mile on either side of the pipeline centerlines). Arcadis also conducted desktop reviews and wetland and waterbody delineation field surveys for the Field Survey Areas of the proposed and existing pipelines and the Midline Pump Station area. TBPL plans to use horizontal directional drilling (HDD) construction techniques at the locations of waters of the United States (WOUS) as identified in the United States Army Corps of Engineers (USACE) Approved Jurisdictional Determination (AJD).

The purpose of the biological habitat survey was to assess the presence or absence and/or document the extent of federally listed threatened, endangered, or candidate species habitat, to identify land cover types and state regulated noxious weed infestation areas, and to inventory tree and shrub areas within the Proposed and Existing Pipeline Project Corridors and Midline Pump Station area. Resources identified during the desktop review were field verified during the biological habitat survey as feasible.

The Study Area is characterized by a rural landscape with gently sloping hills, open fields, and actively farmed cropland; streams and other waters, including prairie pothole wetlands and linear wetland drainages, are common features observed throughout the Study Area. The Canadian Pacific Railway, developed/industrial areas, multiple roads, and residential parcels also intersect the Study Area.

Lands within and adjacent to both the proposed and existing pipelines and the midline pump station are previously disturbed lands. Land cover types included: cropland, pasture, native prairie, and other (wetlands, developed areas). In the 0.5-mile buffer area, Arcadis completed visual surveys for bald eagle nests (*Haliaeetus leucocephalus*) and confirmed the location of a previously identified bald eagle nest.

[2]Habitat information for listed species is available at the Cornell Ornithology Laboratory's All about Birds website (https://www.allaboutbirds.org/).

Federally Listed T&E Species

The USFWS Information for Planning and Consultation (IPaC) database via the North Dakota Ecological Services Field Office was reviewed to identify federally listed species or critical habitat that could potentially be occurring or present within the proposed Project area. The Official Species List from the USFWS is included as **Attachment 2** in the BHAR. The Official Species List identified the northern-long eared bat (*Myotis septentrionalis*), piping plover (*Charadrius melodus*), rufa red knot (*Calidris canutus rufa*), whooping crane (*Grus americana*), Dakota skipper (*Hesperia dacotae*) and monarch butterfly (*Danaus Plexippus*) as potentially occurring within the project area and/or vicinity. No designated critical habitat was identified within the Field Survey Area.

Federally listed species with the potential to occur within the Study Area are listed in **Table 3** in the BHAR, alongside their suitable habitat preferences. TBPL will implement measures to minimize potential adverse effects to potentially affected federally listed species and migratory birds during construction and operation of the Project. The measures identified in **Table 6** in the BHAR will be implemented to minimize adverse impacts to federally listed species, migratory birds, and raptors.

The habitat information gathered during the field survey is summarized in **Table 7** in the BHAR. One species observation of a monarch butterfly was recorded during the field survey in the Existing Pipeline Project Corridor. No other federally listed species were observed during the field survey.

Migratory Birds

The Project is located within potential migratory corridors for piping plover, red knot, and whooping crane; therefore, there is a potential for incidental interactions during the migration season. In North Dakota, species protected under the Migratory Bird Treaty Act (MBTA) are present throughout the year; however, most of these protected species are seasonally present in North Dakota and typically nest from February 1 through July 15 annually. During the nesting period, birds are more vulnerable to human activities.

Following a review of federally listed species, their respective habitat requirements, and on-site conditions, Arcadis has made the following preliminary species affect determinations for the NLEB, piping plover, red knot, whooping crane, Dakota skipper, and monarch butterfly as shown in **Table 7** in the BHAR. These affect determinations are preliminary and have not been confirmed by the USFWS.

Construction of the proposed pipeline and midline pump station are scheduled to commence in the fourth quarter of 2024 and will take approximately 3 months to reach completion. Except for construction of the midline pump station within previously disturbed areas, conversion of the existing pipeline will not require ground-disturbing activities.

No direct disturbances to nesting or breeding birds are anticipated; however, if nesting or breeding birds are observed within 1.0 mile of an active work area, all construction within 1.0 mile of the sighting will be modified or curtailed until the bird(s) have left the area, USFWS will be consulted on how to proceed, and the NDGF and the TAT Fish and Wildlife Division will be notified. With the implementation of these guidelines, the proposed Project is not likely to adversely affect migratory species or result in fatalities including piping plover, red knot, or whooping crane.

[2]Habitat information for listed species is available at the Cornell Ornithology Laboratory's All about Birds website (https://www.allaboutbirds.org/).

BGEPA Species

The Bald and Golden Eagle Protection Act (BGEPA) prohibits anyone without a permit from taking a bald or golden eagle including their parts, nests, or eggs. The BGEPA defines "take" as to pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest, or disturb and includes impacts resulting from human-induced alterations near previously used nesting sites.

Proposed Pipeline: Based on review of the NDGF's database, no eagle nests were identified in the Project Corridor or within the 1-mile Study Area for the proposed pipeline. No raptor nests were observed within ½-mile line-of-sight of the Field Survey Area. Woody vegetation within the Project Corridor is primarily limited to the banks of the East Fork of Shell Creek, and no previously used nesting sites have been identified. The HDD method will be used to minimize disturbances to the bed or banks of the East Fork Shell of Creek.

Existing Pipeline: Based on review of the NDGF's database, one eagle nest was identified approximately 375 feet from the existing pipeline Route. This eagle nest is adjacent to existing county road 49th Street NW. Conversion of the existing pipeline will not require disturbances within 0.5 of this eagle nest.

Midline Pump Station: Based on review of the NDGF eagle nest database, the bald eagle nest is approximately 2 miles northwest of the proposed new location for the midline pump station as shown on the maps in **Attachment 1** in the BHAR. No raptor nests were observed within a 0.5-mile line-of-sight of the Field Survey Area.

Conclusion

Based on the nature of the proposed Project and lack of suitable habitat within the Project area, no adverse impacts to federally listed T&E species, migratory birds, bald eagles, or golden eagles or their habitat are anticipated.

Arcadis, on behalf of TBPL, is submitting the Project review package to request concurrence from NDPR that the proposed Project will have "*no effect on, or is not likely to adversely affect*" federally listed T&E species, migratory birds, bald and golden eagles, or their critical habitat.

Please direct any questions or correspondence concerning the Project to me at Kathryn.Cloutier@arcadis.com or 303-471-3410, or Doug Anderson at 303-471-3484.

Sincerely,
Arcadis U.S., Inc.

Kathryn Cloutier
Project Manager

Email: Kathryn.Cloutier@arcadis.com
Office: 303-471-3410

[2]Habitat information for listed species is available at the Cornell Ornithology Laboratory's All about Birds website (https://www.allaboutbirds.org/).

Enclosures:

USFWS Concurrence Letter
2024 Biological Habitat Assessment Report

[2]Habitat information for listed species is available at the Cornell Ornithology Laboratory's All about Birds website (https://www.allaboutbirds.org/).

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State Historical Society of North Dakota
612 East Boulevard Avenue
Bismarck, North Dakota 58505

Date: November 18, 2024
Our Ref: 30192665
Subject: Thunder Butte Pipeline, LLC: Thunder Butte Pipeline Project, Ward and Mountrail Counties, North Dakota

Arcadis U.S., Inc.
630 Plaza Drive
Suite 200
Highlands Ranch
Colorado 80129
Phone: 720 344 3500
Fax: 720 344 3535
www.arcadis.com

To Whom it may Concern,

Thunder Butte Pipeline, LLC (TBPL) is proposing the Thunder Butte Pipeline Project (Project) for transport of crude oil from the existing Thunder Butte Petroleum Services, Inc. (TBPS) Crude Storage and Loading Facility (TBPS Facility) within the Fort Berthold Indian Reservation (FBIR), near Plaza, North Dakota to an existing Enbridge crude terminal in Stanley, North Dakota. A Project Location Map is provided in the enclosed **Figure 1**.

TBPL is submitting a Consolidated Certificate of Corridor Compatibility and Route Permit Application (Consolidated Permit Application) to the North Dakota Public Service Commission (Commission) requesting a Certificate of Corridor Compatibility and Route Permit for construction and operation of the Project. On behalf of TBPL, Arcadis, U.S., Inc. (Arcadis) is submitting this letter to inform your agency of the proposed Project and to request any comments or input. Any information received will be taken into consideration during the permitting and development process in conjunction with the Consolidated Permit Application process.

We previously notified SHSND last year in a letter dated September 27, 2023. We received a response letter from SHSND dated 1/2/2024 stating: "*For the portion of the project that is not on the Fort Berthold Reservation, there are no significant sites affected by the project provided it takes place in the manner described in the documentation and all borrow comes from an approved source*". This letter serves to provide updated information from the recent Class III cultural resource inventory for the existing pipeline.

Metcalf Archaeological Consultants, Inc. (Metcalf) conducted Class III cultural resource inventories of the areas of potential effects (APEs) for both the proposed and existing pipelines. No cultural resources were found within the APEs for the proposed and existing pipelines; therefore, Metcalf recommends a finding of *No Historic Properties Affected* [36 CFR 800.4(d)(1)] for this undertaking. Copies of the Class III Cultural Resource Inventory Reports for the proposed and existing pipelines (Metcalf 2023 and 2024) are enclosures to this letter. Metcalf previously uploaded these reports to the SHSND FTP site.

TBPL proposes the Project to transport crude oil from the existing Thunder Butte Petroleum Services, Inc. (TBPS) Crude Storage and Loading Facility (TBPS Facility) within the Fort Berthold Indian Reservation (FBIR), approximately 2.6 miles northwest of Makoti, North Dakota, to the existing Enbridge Stanley Pump Station and Terminal (Enbridge Storage Facility) in Stanley, North Dakota. The Project is a joint venture between Gap Midstream, LLC (Gap) and the Mandan, Hidatsa, and Arikara Nation (MHA Nation) /Three Affiliated Tribes (TAT) doing business as TBPL. The MHA Nation/TAT owns the TBPS Facility, and Enbridge Pipelines North Dakota (EPND) owns the Enbridge Storage Facility. These two facilities are not part of the TBPL Project because they are owned by third-party entities.

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- Construction of a new 3.84-mile-long underground crude oil pipeline (new pipeline) in Ward and Mountrail counties,
- Conversion of an *existing* 30.8-mile-long crude oil collector/gathering pipeline to a transmission pipeline (existing pipeline) in Mountrail County; and
- Construction of an aboveground midline pump station on a 2-acre site adjacent to the existing pipeline in Mountrail County.

The new pipeline will commence at the TBPS Facility and terminate at the interconnection with the existing pipeline in Section 2, T152N, R88W. The existing gathering pipeline was previously owned by EPND (Line 82-111). From the interconnection point with the existing gathering pipeline approximately 2.1 miles southeast of Plaza, North Dakota, the existing gathering pipeline will transport crude oil to the Enbridge Storage Facility. All but the southern 3.84 miles of the Project is an existing gathering pipeline. TBPL will maintain 30-foot-wide permanent easements for the new and existing pipelines.

The Project is scheduled to begin construction in the early 2025. The proposed pipeline will be installed using an 80-foot-wide construction right-of way (ROW), consisting of a 30-foot-wide permanent easement and an adjacent 50-foot-wide temporary construction workspace. Construction of the proposed pipeline will temporarily disturb a total of approximately 40 acres on privately-owned agricultural land.

Approximately 3 miles of the proposed pipeline will be within the FBIR, approximately 2.3 miles of which will be constructed abutting the existing Canadian Pacific Railway ROW. Lands within and adjacent to the proposed pipeline, the existing pipeline, and the midline pump station are previously disturbed agricultural land. Following construction, the new pipeline will be located within an existing 30-foot-wide permanent easement.

Please direct any questions or correspondence concerning the Project to me at 303-471-3410 or Doug Anderson at 303-471-3484.

Sincerely,

Arcadis U.S., Inc.

Kathryn Cloutier

Kathryn Cloutier
Project Manager

Email: Kathryn.Cloutier@arcadis.com
Office: 303-471-3410

Enclosures:
Figure 1
SHSND Response Letter dated January 2, 2024
Metcalf 2023. Class III Cultural Resource Inventory Report for *Proposed* Pipeline
Metcalf 2024. Class III Cultural Resource Inventory Report for *Existing* Pipeline

Cloutier, Kathryn

From: Cloutier, Kathryn
Sent: Tuesday, November 12, 2024 3:51 PM
To: jmyrick@mhanation.com
Cc: Bernie Fox; berniefox@mhanation.com; Jake Richardson
Subject: Thunder Butte Pipeline Project - Request for Consultation
Attachments: Metcalf TBPL Cultural Survey Report r2_11-20-2023.pdf; Fig01 - Revised 05172024.pdf; TBPL Letter THPO_7-22-2024.pdf

Mr. Myrick,

Please find attached an updated request for consultation on the Thunder Butte Pipeline Project in Ward and Mountrail counties. The Project is a joint venture between Gap Midstream, LLC (Gap) and the Mandan, Hidatsa, and Arikara Nation (MHA Nation)/Three Affiliated Tribes (TAT) doing business as Thunder Butte Pipeline, LLC (TBPL)

TBPL is submitting a Permit Application to the ND Public Service Commission (PSC) requesting a Certificate of Corridor Compatibility/Route Permit. On behalf of TBPL, Arcadis, U.S., Inc. is submitting the attached letter to inform your agency of the Project and to request any comments or input. Please find attached a project overview map for the Thunder Butte Pipeline Project for construction/operation of a proposed crude oil underground pipeline, *approximately 2.6 miles of the proposed pipeline is within the Fort Berthold Reservation*.

Metcalf's Class III Cultural Resource Inventory Report for the Project is attached. Archaeologist Bill Bluemle found no cultural resources in the three segment APEs; therefore, Metcalf recommends a finding of "No Historic Properties Affected" [36 CFR 800.4(d)(1)] for this undertaking.

Per PSC requirements for a "complete" application, please provide an email or letter with concurrence of Metcalf's finding of "No Historic Properties Affected" or documenting your comments regarding potential effects on cultural resources within the Fort Berthold Reservation as soon as possible.

Thank you in advance for your consideration of this request. We look forward to your response.

Thank you,
Kathryn

Kathryn Cloutier. M.S.
Senior Project Scientist | Project Manager
Arcadis U.S., Inc.
T +1 303 471 3410
M +1 720 201 0001
Kathryn.cloutier@arcadis.com

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Mountain-Prairie Region

IN REPLY REFER TO:
Arcadia-Thunder Butte Pipeline

North Dakota Ecological Services
3425 Miriam Avenue
Bismarck, North Dakota 58501

November 6, 2024

Ms. Kathryn Cloutier
Senior Project Scientist
Arcadis U.S., Inc
700 Tech Center Parkway Suite 200-102
Newport News, Virginia 23606

Dear Ms. Cloutier:

Thank you for your email of October 29, 2024, requesting comments on the Thunder Butte Pipeline project located in Mountrail and Ward Counties, North Dakota. The U.S. Fish and Wildlife Service (USFWS) has the following comments.

You requested USFWS concurrence with your "May Affect, Not Likely to Adversely Affect" determinations for the endangered Whooping crane (*Grus americana*); the threatened Red Knot (*Calidris canutus rufa*) and Dakota skipper (*Hesperia dacotae*). USFWS concurs with your determinations. In addition to the avoidance and minimization measures presented be advised that the project location falls within the 95% siting corridor for whooping crane.

The period of concern for Dakota Skipper is June 10 to July 25. Habitat should be surveyed for Dakota skipper suitability. If it is determined that suitable habitat is present, then occupancy surveys by a permitted surveyor would need to be conducted during the period of concern. Avoidance of suitable habitat in the project area can be achieved by using HDD including a 250–500-meter buffer around the location.

Piping plover surveys should be conducted for seven consecutive days prior to the start of construction activities, including equipment mobilization at the project location. Piping plover survey results should be immediately reported to the FWS. The period of concern is April 15 to August 15.

The period of concern for eagles and other migratory birds is February 1 to July 15.

There is no requirement under the implementing regulations of the ESA (50 CFR Part 402) for action agencies to receive USFWS concurrence with "No Effect" determinations or candidate species. Accordingly, we recommend the federal action agency retain the documentation for these resources in the decisional record for this federal action.

Thank you for the opportunity to comment on this project proposal. If changes are made in the project plans or operating criteria, or if additional information, including new species listings, becomes available, the Service should be informed so that the project impacts can be reconsidered. If you have any additional questions or comments, please contact Jerry Reinisch at (701) 425-2133 or via email at jerry_reinisch@fws.gov, or contact me at (701) 355-8512 or luke_toso@fws.gov.

Sincerely,

Heidi Riddle 11/6/24

For Luke Toso
ND Ecological Services Supervisor

Cloutier, Kathryn

From: Cloutier, Kathryn
Sent: Friday, October 25, 2024 9:09 AM
To: ndfieldoffice@fws.gov; sdyke@nd.gov; Drew_Becker@fws.gov
Cc: Foti, Amanda; Mageland, Katie
Subject: Thunder Butte Pipeline Project ND Public Service Commission Notification
Attachments: TBPL Letter to USFWS+NDGFD_10-25-2024.zip

To Whom It May Concern:

Thunder Butte Pipeline, LLC (TBPL) is proposing the Thunder Butte Pipeline Project (Project) for transport of crude oil from the existing Thunder Butte Petroleum Services, Inc. Crude Storage and Loading Facility within the Fort Berthold Indian Reservation, near Plaza, North Dakota to an existing Enbridge crude terminal in Stanley, North Dakota (Figure 1). TBPL is submitting a Consolidated Certificate of Corridor Compatibility and Route Permit Application (Consolidated Permit Application) to the North Dakota Public Service Commission (Commission) requesting a Certificate of Corridor Compatibility and Route Permit for construction and operation of the Project.

On behalf of TBPL, Arcadis U.S., Inc. (Arcadis) is submitting this email and attached files to inform your agency of the proposed Project and to request any comments or input. Any information received will be taken into consideration during the permitting and development process in conjunction with the Consolidated Permit Application process.

On behalf of TBPL, Arcadis completed a review of potential Project-related impacts to federally listed threatened, endangered, and candidate (T&E) species, migratory birds, Bald and Golden eagles, and their habitat in Ward and Mountrail Counties, North Dakota.

Based on the results of Arcadis' desktop review and field surveys as summarized in the attached letter, TBPL requests concurrence from the USFWS and NDGFD that the proposed Project will have no effect on, or is not likely to adversely affect, T&E species, migratory birds, or Bald and Golden eagles or their habitat.

Thank you in advance for your consideration of this request. Please feel free to contact me if you have any questions or require additional information.

Thanks again,
Kathryn

Kathryn Cloutier. M.S.
Senior Project Scientist | Project Manager
Arcadis U.S., Inc.
T +1 303 471 3410
M +1 720 201 0001
Kathryn.cloutier@arcadis.com

ATTACHMENT 2

Existing Pipeline Depth of Cover Summary

Existing Pipeline Depth of Cover Summary

Depth of cover determined using GPS line locating and depth equipment. Please see attached screenshots of survey locations.

GPS Location	Depth of Cover	Description*	DOC By
48°18'14.16"N ; 102°22'10.56"W	6' 8"	Enbridge Stanley Facility	Survey
48°18'14.26"N ; 102°22'2.22"W	5' 5"	Waterbody near Stanley Facility - West	Operations
48°18'14.21"N ; 102°21'54.82"W	5' 2"	Waterbody near Stanley Facility - Middle	Operations
48°18'14.31"N ; 102°21'45.70"W	4' 9"	Waterbody near Stanley Facility - East	Operations
48°18'13.90"N ; 102°21'12.71"W	5' 3"	Bottom of Road Ditch	Operations
48°18'12.63"N ; 102°21'8.91"W	4' 1"	Field	Survey
48°17'2.77"N ; 102°19'59.17"W	4' 2"	Field	Survey
48°16'10.53"N ; 102°18'23.66"W	5' 4"	Field	Survey
48°15'18.72"N ; 102°17'26.51"W	4' 0"	Field	Survey
48°15'1.44"N ; 102°16'59.16"W	4' 1"	Under bottom of pond in farmer field	Geologist
48°14'18.35"N ; 102°16'3.07"W	5' 0"	Bottom of Road Ditch	Survey
48°14'15.36"N ; 102°15'57.60"W	4' 2"	Under bottom of pond in farmer field	Geologist
48°14'0.60"N ; 102°15'32.04"W	4' 1"	Under pond from Geologist spot check	Operations
48°13'36.20"N ; 102°14'45.60"W	11' 10"	Section Line	Operations
48°12'40.02"N ; 102°13'21.96"W	4' 6"	Field	Survey
48°10'59.13"N ; 102°10'53.58"W	5' 3"	Field	Survey
48°10'22.48"N ; 102° 9'45.55"W	5' 1"	Wetland in middle of farmer field - West	Operations
48°10'22.22"N ; 102° 9'44.93"W	5' 1"	Wetland in middle of farmer field - Middle	Operations
48°10'21.97"N ; 102° 9'44.38"W	4' 5"	Wetland in middle of farmer field - East	Operations
48°10'19.34"N ; 102° 9'38.28"W	5' 0"	Field	Survey
48° 9'16.17"N ; 102° 8'30.09"W	5' 7"	Field	Operations
48° 9'12.43"N ; 102° 8'25.74"W	6' 5"	Section Line	Survey
48° 9'9.11"N ; 102° 8'17.25"W	7' 7"	Section Line	Survey
48° 8'20.25"N ; 102° 7'39.92"W	6' 3"	Section line in middle of field	Operations
48° 7'56.36"N ; 102° 7'21.44"W	6' 0"	Wetland in middle of farmer field - West	Operations
48° 7'55.78"N ; 102° 7'20.56"W	6' 1"	Wetland in middle of farmer field - Middle	Operations
48° 7'55.45"N ; 102° 7'20.02"W	4' 4"	Wetland in middle of farmer field - East	Operations
48° 7'47.07"N ; 102° 6'48.26"W	4' 0"	Field	Operations
48° 7'29.70"N ; 102° 6'29.20"W	4' 9"	Field	Operations
48° 7'27.67"N ; 102° 6'27.12"W	4' 0"	Field at above ground valve set	Survey
48° 7'15.17"N ; 102° 5'57.21"W	6' 10"	Shell Creek - Middle	Operations
48° 7'13.73"N ; 102° 5'51.79"W	4' 1"	Shell Creek - East	Operations
48° 6'32.74"N ; 102° 4'24.58"W	5' 5"	Bottom of Road Ditch	Survey
48° 5'47.51"N ; 102° 3'39.10"W	4' 11"	Perennial Stream w/ Steep Bank - West	Operations
48° 5'47.07"N ; 102° 3'38.33"W	6' 0"	Perennial Stream w/ Steep Bank - Middle	Operations
48° 5'46.06"N ; 102° 3'36.27"W	4' 5"	Perennial Stream w/ Steep Bank - Washout	Operations
48° 5'2.71"N ; 102° 2'14.63"W	5' 1"	Field	Operations

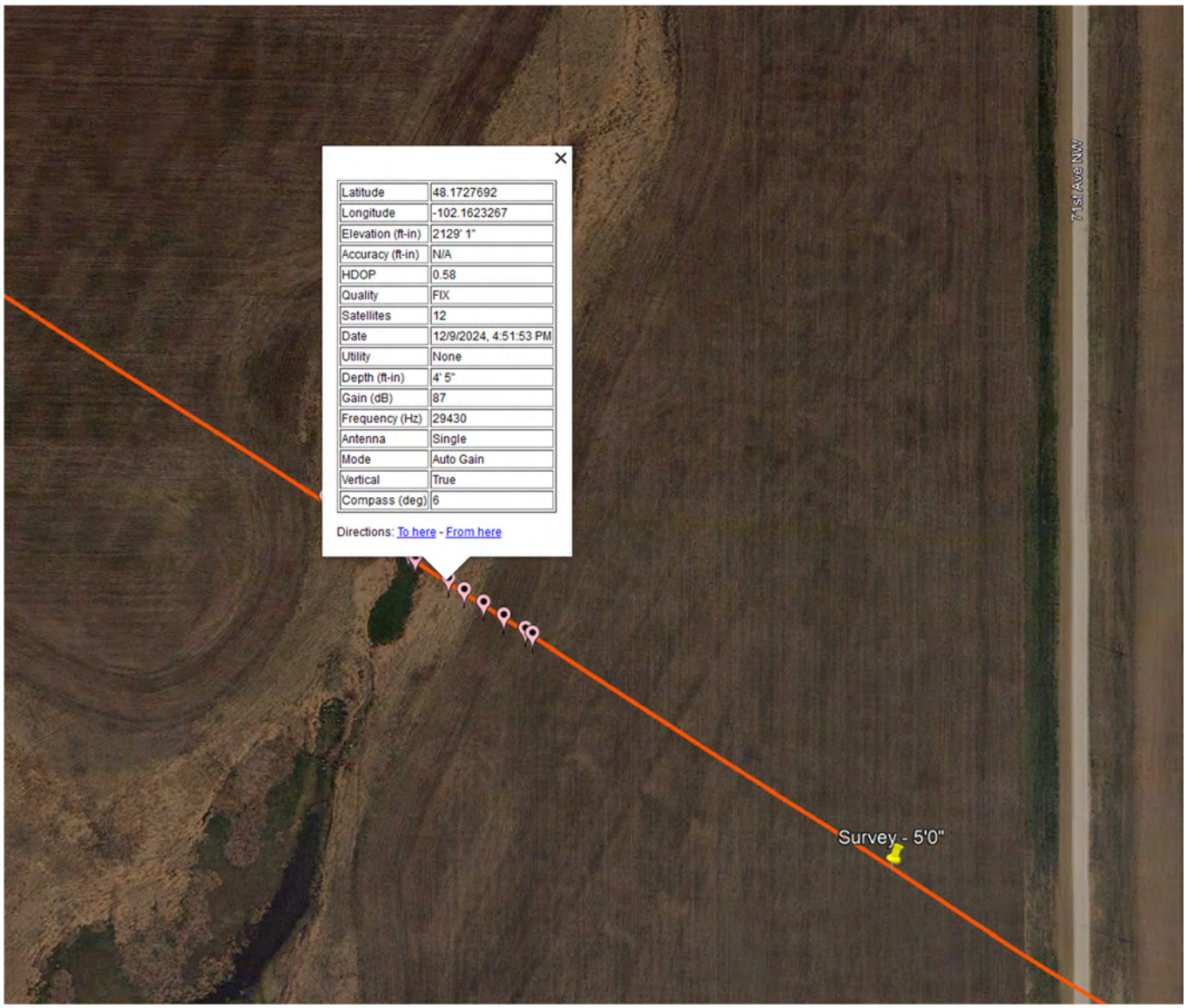
Existing Pipeline Depth of Cover Summary

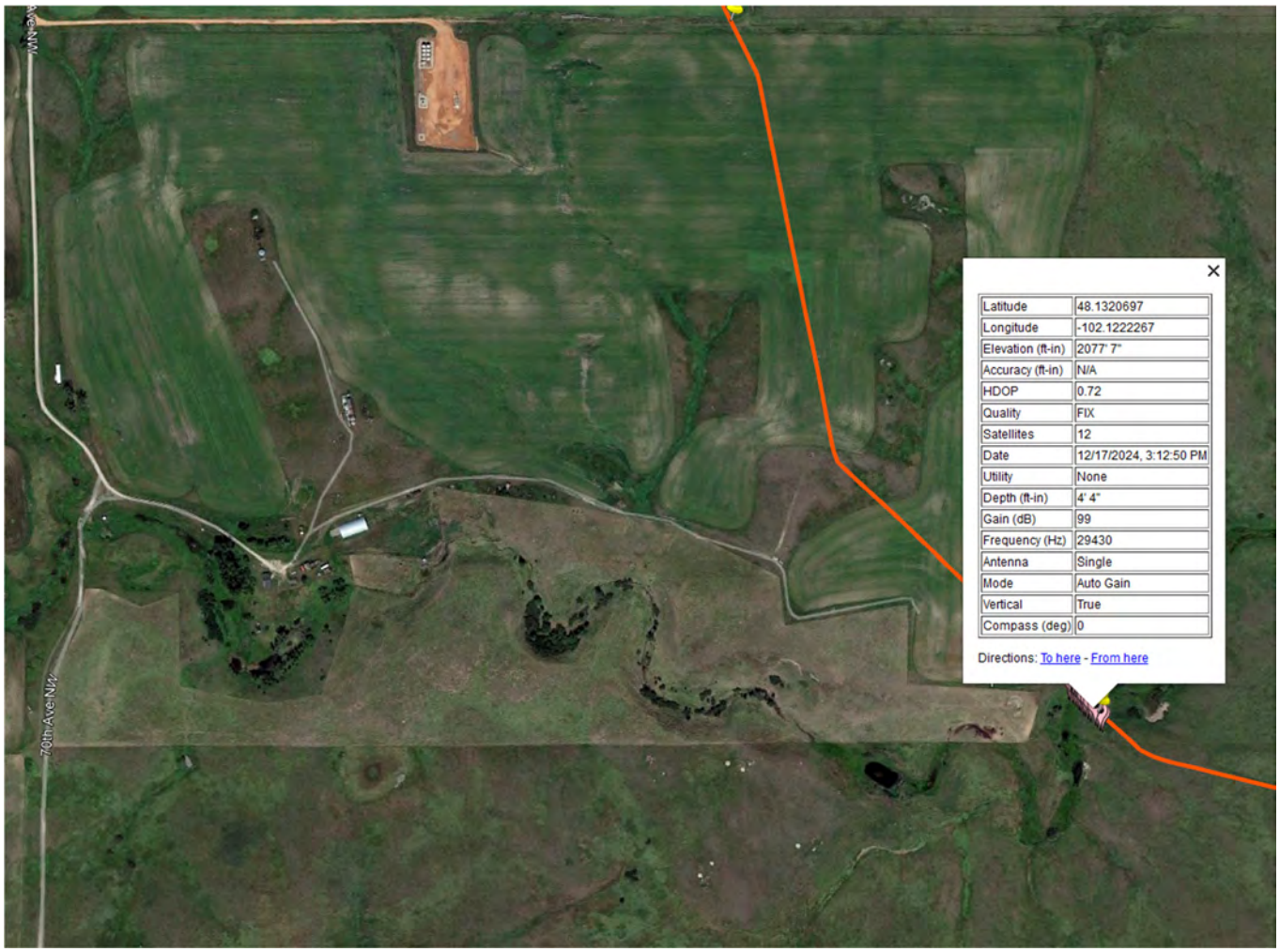
Depth of cover determined using GPS line locating and depth equipment. Please see attached screenshots of survey locations.

GPS Location	Depth of Cover	Description*	DOC By
48° 4'59.15"N ; 102° 1'48.59"W	8' 0"	Section Line	Survey
48° 3'59.96"N ; 102° 0'0.71"W	5' 9"	Bottom of Road Ditch	Survey
48° 3'23.17"N ; 101°59'13.07"W	11' 0"	Section Line	Survey
48° 2'45.05"N ; 101°57'59.05"W	4' 0"	Field	Survey
48° 2'44.39"N ; 101°57'56.08"W	5' 8"	Bottom of Road Ditch	Geologist
48° 2'44.22"N ; 101°57'53.06"W	5'0"	Field	Operations
48° 2'15.86"N ; 101°56'48.38"W	5' 0"	Bottom of Road Ditch	Survey
48° 2'4.41"N ; 101°56'37.85"W	5' 0"	Field	Survey
48° 2'4.37"N ; 101°56'37.19"W	12' 9"	Section Line	Operations
48° 1'23.41"N ; 101°55'59.53"W	16' 0"	Section Line	Operations
48° 1'22.34"N ; 101°55'59.54"W	6' 6"	Field	Survey
48° 0'37.73"N ; 101°54'54.45"W	5' 5"	Field	Survey
48° 0'36.90"N ; 101°54'48.79"W	4' 3"	Field at pig trap near Plaza, ND	Operations

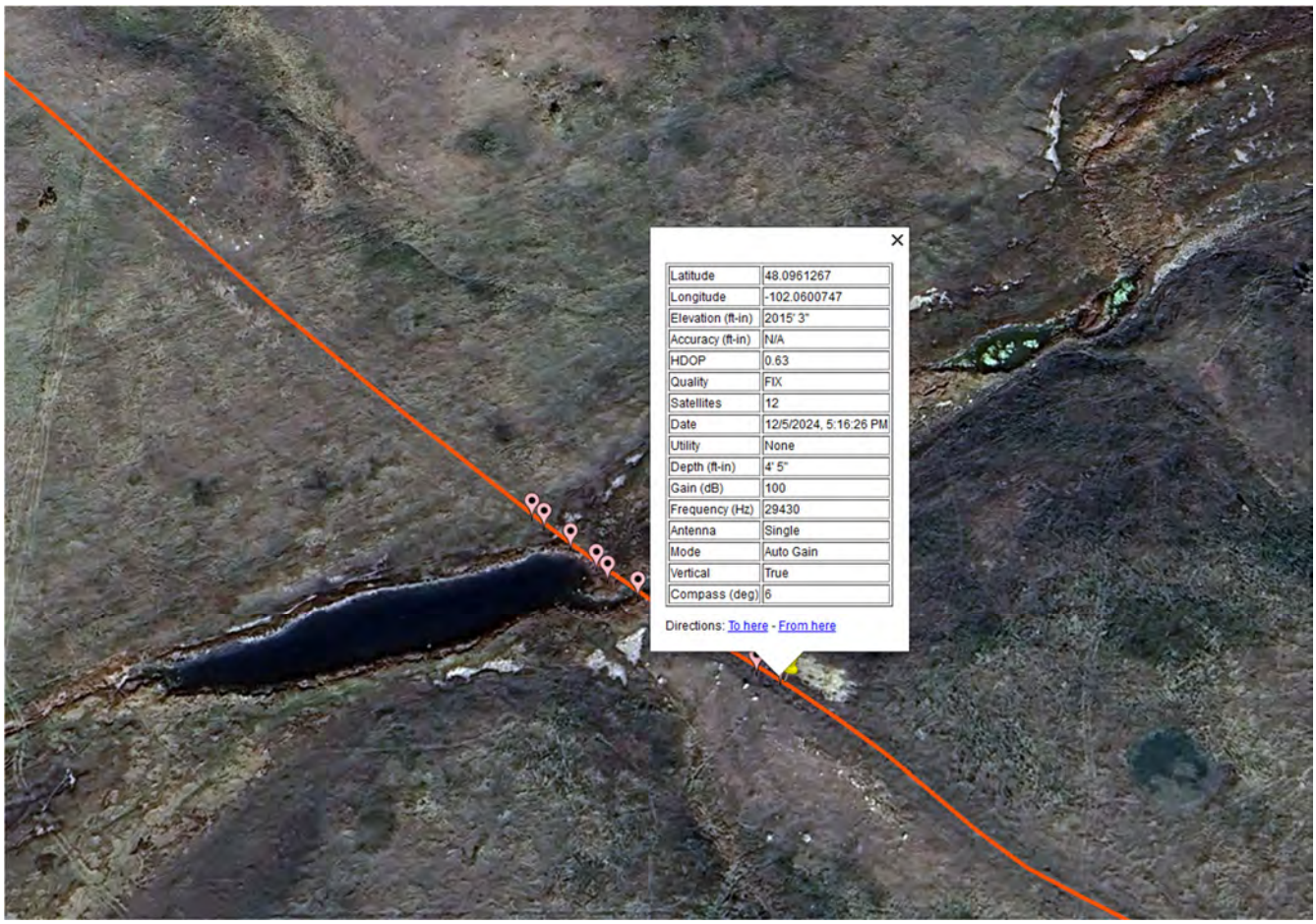
NOTE: *The entire pipeline will also be shot by survey during construction of the new line to determine a depth of cover for the entire pipeline. Any areas found to be less than 48" depth of cover will be investigated further and mitigated properly to obtain the minimum depth of cover required.*


Survey - 6'8"
Latitude 48.3039758
Longitude -102.3626955
Elevation (ft-in) 2165' 10"
Accuracy (ft-in) N/A
HDOP 0.69
Quality FIX
Satellites 12
Date 12/20/2024, 4:48:18 PM
Utility None
Depth (ft-in) 4' 9"
Gain (dB) 100
Frequency (Hz) 29430
Antenna Single
Mode Auto Gain
Vertical True
Compass (deg) 348
Directions: To here - From here


71st Ave NW
Survey - 5'0"
Latitude 48.1727692
Longitude -102.1623267
Elevation (ft-in) 2129' 1"
Accuracy (ft-in) N/A
HDOP 0.58
Quality FIX
Satellites 12
Date 12/9/2024, 4:51:53 PM
Utility None
Depth (ft-in) 4' 5"
Gain (dB) 87
Frequency (Hz) 29430
Antenna Single
Mode Auto Gain
Vertical True
Compass (deg) 6
Directions: To here - From here


70th Ave NW
Latitude 48.1320697
Longitude -102.1222267
Elevation (ft-in) 2077' 7"
Accuracy (ft-in) N/A
HDOP 0.72
Quality FIX
Satellites 12
Date 12/17/2024, 3:12:50 PM
Utility None
Depth (ft-in) 4' 4"
Gain (dB) 99
Frequency (Hz) 29430
Antenna Single
Mode Auto Gain
Vertical True
Compass (deg) 0
Directions: To here - From here


49th St NW
49th St NW
49th St NW
49th St NW
Shell Creek
Latitude 48.1204810
Longitude -102.0977203
Elevation (ft-in) 2007' 8"
Accuracy (ft-in) N/A
HDOP 0.71
Quality FIX
Satellites 11
Date 12/9/2024, 2:13:18 PM
Utility None
Depth (ft-in) 4' 1"
Gain (dB) 72
Frequency (Hz) 29430
Antenna Single
Mode Auto Gain
Vertical False
Compass (deg) 0
Directions: To here - From here


Latitude 48.0961267
Longitude -102.0600747
Elevation (ft-in) 2015' 3"
Accuracy (ft-in) N/A
HDOP 0.63
Quality FIX
Satellites 12
Date 12/5/2024, 5:16:26 PM
Utility None
Depth (ft-in) 4' 5"
Gain (dB) 100
Frequency (Hz) 29430
Antenna Single
Mode Auto Gain
Vertical True
Compass (deg) 6
Directions: To here - From here

ATTACHMENT 3

Integrity Management Plan/ Operations and Maintenance Plan

Integrity Management Plan

Hazardous Liquids 8” MHA W-E & 6” Thunder Butte Pipelines

GAP-IMP

February 20, 2024
GAP Midstream
Rev. 1

Table of Contents

1.0 REVISION PROCEDURE

1.1 AMENDMENTS / REVISIONS/REVIEW & DISTRIBUTIONS

An annual review of this Integrity Management Plan will be made, not to exceed 15 months. Ralph Anaya, Jake Richardson, or designee will approve all amendments, revisions, reviews, and distributions. This form must contain the appropriate signature. Attach any additional papers necessary to the back of this form for routing approval.

1.2 AMENDMENTS:

SUBJECT	SECTION	PAGES	DATE
Document Created			02/20/2024

1.3 REVISIONS:

SUBJECT	SECTION	PAGES	DATE

REVIEW

Date of Review: _____

Reviewed By: _____
Sign Print

Reviewed By: _____
Sign Print

APPROVAL

Approved By: _____

Date Approved: _____

2.0 GENERAL

49 CFR 195.452

API RP1160

2.1 PURPOSE:

This manual presents the Integrity Management Program documentation developed for the Thunder Butte and MHA W-E pipelines owned and operated by GAP Midstream. The Thunder Butte and MHA W-E pipelines are hazardous liquid pipelines. The purpose of the Integrity Management Program, per 49 CFR Part 195.452, is to enable GAP Midstream to comprehensively evaluate the entire range of threats to each pipeline segment's integrity by analyzing available information about the pipeline segment and the consequences of a failure in a high consequence area.

The primary goal is to proactively identify and manage risks associated with the pipelines and its facilities in a manner which ensures the safety of the public and its employees and minimizes the impact on the environment.

2.2 METHODOLOGY:

In accordance with API RP1160 Section 4, GAP Midstream will use the Plan-Do-Check-Act (PDCA) approach to manage the integrity of both hazardous liquid pipelines. The PCDA Cycle is shown in Figure 1 below.

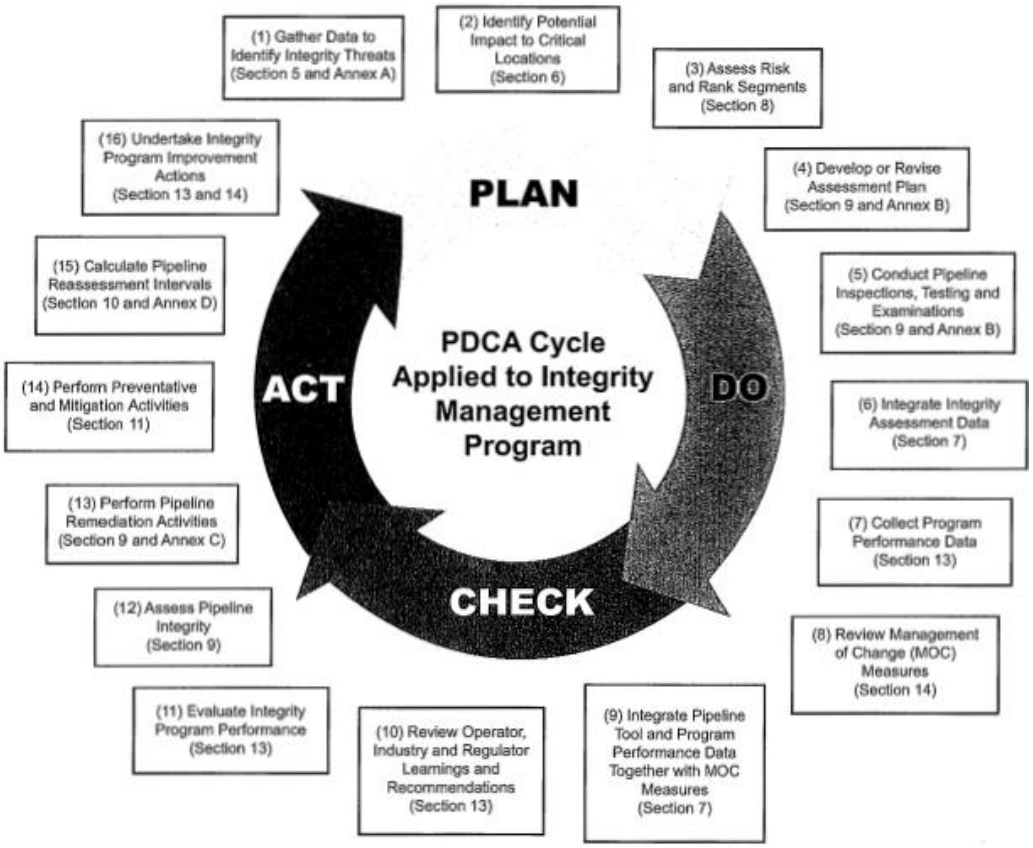


Figure 1: PDCA Cycle

2.3 THUNDER BUTTE PIPELINE:

High Consequence Area: The Thunder Butte pipeline does qualify for a high consequence area; at the north most end of the pipeline, there is a concentrated population in a town named Stanely. There is approximately 1,480 feet of pipeline inside the township of Stanley that can be considered an HCA. Criteria for High Consequence areas are listed in 49 CFR 195.450.

2.4 MHA W-E PIPELINE:

High Consequence Area: The MHA W-E pipeline contains at least one segment of HCA through New Town, North Dakota where the pipeline crosses the Missouri River, a commercially navigable waterway in accordance with 49 CFR 195.450 and described in Section 4 of this IMP.

3.0 INTRODUCTION

3.1 DEFINITIONS:

Table 1: Definitions

Term	Description
Anomaly	A possible deviation from sound pipe material or weld. Indication may be generated by non-destructive inspection, such as in-line inspection. Definition based on NACE Technical Committee Report, “In-Line Nondestructive Testing of Pipelines”, pending publication.
BAP	Baseline Assessment Plan
Contractor	Non- GAP Midstream personnel contracted to perform work on behalf of GAP Midstream
Covered Segment	A segment of gas transmission pipeline in a high consequence area.
Defect	An imperfection of a type or magnitude exceeding acceptable criteria. Definition based on API 570.
ECDA	External Corrosion Direct Assessment
Final In-Line Inspection Report	A report provided by the in-line inspection vendor that provides GAP Midstream with a comprehensive interpretation of the data from an in-line inspection.
High Consequence Area (HCA)	Those locations where a pipeline release might have a significant and adverse impact on an unusually sensitive area (see 49 CFR 195.6), a high population area, another populated area, or a commercially navigable waterway. This definition is specific to the federal regulations in the United States, see 49 CFR 450.
ICDA	Internal Corrosion Direct Assessment
IMP	Integrity Management Program
Imperfection	A flaw or other discontinuity noted during inspection that may be subject to acceptance criteria during an engineering and inspection analysis. Definition based on API 570.
Indication	A finding of a nondestructive testing or inspection technique. Definition based on NACE Technical Committee Report, “In-Line Nondestructive Testing of Pipelines,” pending publication.
ILI	In-Line Inspection
MAOP	Maximum Allowable Operating Pressure
OQ Program	Operator Qualification Program
OPS	Office of Pipeline Safety
Pipeline Integrity Group (PSI)	Pipeline Strategies and Integrity, LLC in conjunction with GAP Midstream Compliance Coordinator
Preliminary In-Line Inspection Report	A report usually produced in a short amount of time that provides GAP Midstream with a list of indications considered to be of consequence.
Qualified / Competent Person	An employee or contractor qualified to perform duties in accordance with the governing code or regulation
Risk	A measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences
Risk Management	An overall program consisting of identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and

	measuring the risk reduction results achieved
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment

3.2 COVERED SYSTEMS:

This IMP applies to the segments of the Thunder Butte and MHA W-E pipelines that fall within HCAs as defined by CFR 49 Part 195.452.

3.3 ASSET ACQUISITIONS:

Acquired assets to be covered by this IMP are to be accompanied by key integrity management documentation from the previous owner and/or operator. GAP Midstream is to work with the appropriate personnel to ensure the previous owner and/or operator provides a list of key integrity management documentation requested by GAP Midstream.

3.4 INTEGRITY MANAGEMENT PROGRAM ORGANIZATION:

The minimum elements required within the IMP, per 49 CFR Part 195.452 (f) include:

- A process for identifying which pipeline segments could affect a high consequence area.
- A baseline assessment plan meeting the requirements of 195.452 (c).
- An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see 195.452 (g)).
- Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see 195.452 (h)).
- A continual process of assessment and evaluation to maintain a pipeline's integrity (see 195.452 (j)).
- Identification of preventive and mitigative measures to protect the high consequence area (see 195.452 (i)).
- Methods to measure the program's effectiveness (see 195.452 (k)).
- A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see 195.452 (h)(2).

4.0 HIGH CONSEQUENCE AREA (HCA) IDENTIFICATION

49 CFR 195.450

4.1 IDENTIFY HIGH CONSEQUENCE AREA [195.450 & 195.6]

High consequence areas are to be identified by the following:

1. An area defied as:
    - A *commercially navigable waterway,* which means a waterway where a substantial likelihood of commercial navigation exists.
    - A *high population area,* which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile.
    - An *other populated area,* which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.
    - An *unusually sensitive area,* as defined in 49 CFR 195.6.

2. Unusually Sensitive Areas (USAs)
    - USA drinking water resource:
        a. Non-transient non-community water system (NTNCWS)
        b. Class I, Class IIa, sole surface, and or a Karst aquifer that does not have an adequate alternative water source
    - USA ecological resource:
        a. Certain coastal waters/beach
        b. Critically imperiled species or ecological community (habitat)
        c. Depleted marine mammal species
        d. Migratory waterbird concentration area
        e. Multi-species assemblage area

4.2 INITIAL RESPONSE:

Identification of HCAs according to definitions from 195.450 indicated there was one confirmed HCA along the Thunder Butte pipeline. The Thunder Butte pipeline resides near a concentrated population in Stanley, North Dakota. See the HCA study conducted on October 6th, 2023, on the Thunder Butte pipeline for reference. There is approximately 1,480 feet of pipeline inside the township of Stanley that can be considered an HCA.

The MHA W-E pipeline has at least one section of HCA in and around Four Bears Village and New Town, North Dakota. The MHA W-E pipeline runs through an *other populated area* as defined in 49 CFR 195.459 and constitutes approximately two miles of HCA. This section also crosses the Missouri River which is deemed a commercially navigable waterway and supports populations of Pallid Sturgeon, Piping Plover, and Dakota Skipper that further constitute an HCA.

Identification of drinking water sources found no sources of drinking water in the near vicinity of the Thunder Butte and the MHA W-E pipelines. The wells identified appear to all be for commercial and industrial purposes and thus do not constitute any additional HCAs.

4.3 PERIODIC REEVALUATION:

As continued surveillance is performed, any indication of change in class location or new construction will be assessed and USA's and HCA's will be re-evaluated.

4.4 RECORDS:

Records of HCA identification & supporting documentation shall be maintained for the life of the pipeline.

5.0 THREAT IDENTIFICATION

49 CFR 195.452

API RP1160, Section 4, Section 9.

5.1 POTENTIAL THREATS:

GAP Midstream will identify and evaluate all potential threats to each covered pipeline segment. GAP Midstream will utilize ILI to identify time dependent and potentially time dependent threats as outlined below. Areas of general corrosion, dents, and other with indications of metal loss that do not meet the definitions of immediate, 60-, or 180-day conditions will be monitored through reoccurring ILI's every five years. Potential threats that GAP Midstream will consider include, but are not limited to, the threats listed in API RP1160 the following groups:

- Time Dependent:
  - External Corrosion.
  - Internal Corrosion.
  - Selective Seam Weld Corrosion (SSWC), external and internal.
  - Environmental Assisted Cracking (EAC), including Stress Corrosion Cracking (SCC), Hydrogen-Induced Cracking (HIC), Stress-Oriented Hydrogen-Induced Cracking (SOHIC), and Sulfide-Stress Cracking (SSC).
  - Fatigue.

- Potentially Time Dependent
  - Manufacturing defects including defective pipe seams, hard Heat-Affected Zones (HAZ), and defective pipe including pipe body hard spots.
  - Construction and fabrication defects including defective girth welds, defective fabrication

welds, wrinkle bends, and stripped threads/broken pipe/coupling failures.

- o Mechanical damage caused by accident, negligence, or deliberate act of vandalism.

GAP Midstream will monitor flows and pressures to monitor time independent threats to the pipeline, any abnormalities in either shall result in immediate action by GAP Midstream. GAP Midstream will follow all procedures in the Operations and Maintenance Manual to ensure correct operation of the pipeline. Time independent threats include:

- Incorrect Operations.
- Equipment failure including gasket or o-ring failure, control or relief equipment failure, seal or pump packing failure, and miscellaneous
- Weather and outside forces including cold weather, lightning, heavy rains or floods, earth movements, or a combination thereof, which may cause wrinkles, buckles, cracked valve bodies, and girth weld cracks.

5.2 RECORDS:

All documents supporting Threat Identification and Risk Assessment shall be maintained for the life of the pipeline. Personnel training and qualification records shall be maintained for the life of the pipeline.

6.0 BASELINE ASSESSMENT PLAN

49 CFR 195.452

API RP1160, Section 4

6.1 IDENTIFY POTENTIAL THREATS:

GAP Midstream will identify potential threats to each Covered Segment of the Thunder Butte pipeline and the MHA W-E pipeline per Section 5, Threat Identification, of this IMP. The list of threats that pose realistic threats to the pipeline based on the baseline assessment are as follows:

- External/Internal corrosion
- Manufacturing defects
- Equipment failure
- Weather and outside forces, mainly along the bridge crossing

Each Covered Segment will be evaluated by GAP Midstream to determine the best method of evaluation. The BAP uses a risk-based approach to prioritize pipeline segments identified in Section 4. The prescribed assessment method must be capable of addressing all risk factors identified for each HCA section. A process flow chart of the different tasks conducted in planning an ILI is shown in Figure 1. Documentation

supporting assessment method decisions will be retained in the Integrity Management files.

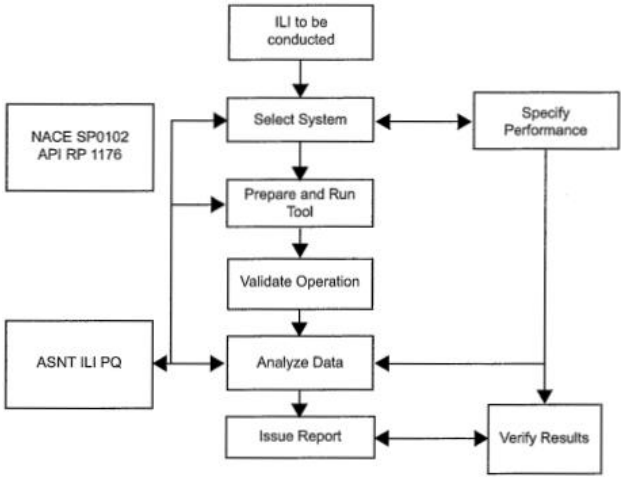


Figure 2:ILI Task List

Table 2 outlines recommended guidance to select the appropriate ILI tools for integrity assessments.

Table 2: ILI Tool Selection Guide

Tools	Applicability	Tool Type
Sizing / Dent Detection	• Bend Radius • Pipe Ovality • Dent Size	• Bend / Caliper Tool • Mapping Tool • Disc / Sizing Tool
Corrosion / Metal Loss	• Internal Corrosion • External Corrosion • Dents • Prominent Cracks	• High Resolution MFL Tool • Transverse MFL Tool • Ultrasonic (Compressed Wave)
Crack / Crack-Like	• Cracks • Longitudinal Seams • Fatigue Cracks • SCC • TGAP Midstream Cracks • Lack of Fusion • Laminations • Mill Related Anomalies	• Transverse MFL Tool • Ultrasonic (Shear Wave) Tool

	• Dents	

6.2 INTEGRITY ASSESSMENT METHODS:

Integrity assessment methods available to GAP Midstream are ILI, hydrostatic pressure test, ECDA, and other technologies.

GAP Midstream shall assess the risk of each threat based on the flowchart shown in Figure 3 Below. The flowchart outlines the different tasks conducted and the decisions made to develop the risk assessment of the pipeline.

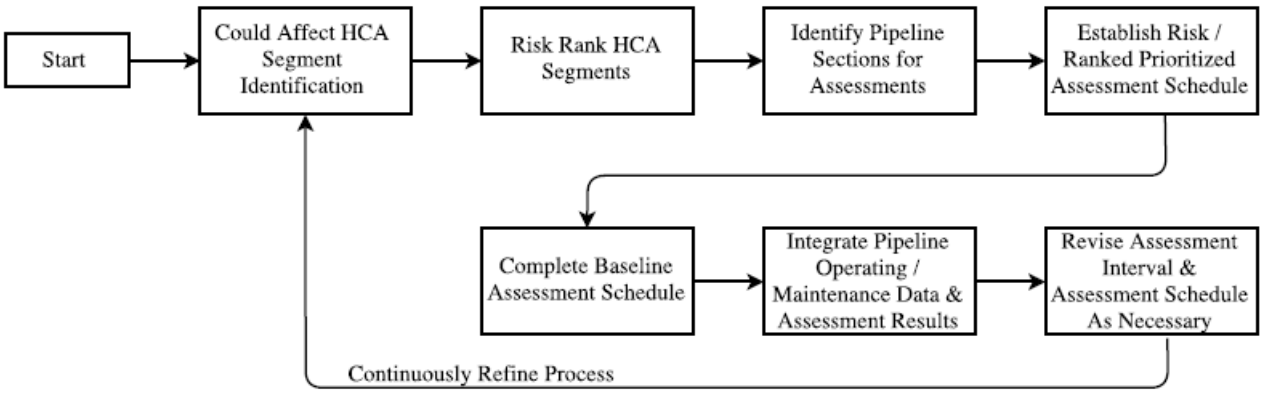


Figure 3: Baseline Assessment Flow Chart

GAP Midstream has elected to utilize ILI data to form the BAP on the Thunder Butte and MHA W-E pipelines. The baseline ILI on the Thunder Butte pipeline was performed May 29, 2013. A complete summary of the ILI can be found in the *2013 L82 PZ-SY 436887_06A MFL Final Inspection Report*. The pipeline did not have any anomalies that meet the definition of 60-, 180-day, or immediate conditions within the HCA that shall be monitored during the next ILI run. A set of anomalies to be monitored based on their relation to the HCA, relation to other anomalies, and percent wall thickness lost are shown in Table 3 below. These anomalies shall be compared in future reassessments to determine corrosion rates to adjust reassessment intervals appropriately. The Thunder Butte pipeline was reassessed on December 14, 2023. The reassessment data will be analyzed to identify any immediate conditions and determine the future

reassessment intervals.

Table 3: Thunder Butte Pipeline ILI Data Summary

Joint Number	Anomaly Type	External/Internal	Number of Anomalies in Cluster	Depth %
37280	Axial Slot	External	2	22%
15160	Pitting	Internal	2	42%
16770	Axial Slot	External	4	31-36%
33970	Pitting	External	2	30%

The baseline ILI on the MHA W-E pipeline was performed on August 13, 2018 and also did not display any anomalies that do not meet the definition of 60-, 180-day, or immediate conditions within the HCA that shall be monitored during the next ILI run. A complete set of ILI data can be found in the *2018 GLS to MTS MP95.2 to MP 164.58 ILI* report. A set of anomalies to be monitored within the HCA based on the relation to other anomalies, and percent wall thickness lost are shown in Table 4 below. These anomalies shall be compared in future reassessments to determine corrosion rates to adjust reassessment intervals appropriately. The MHA W-E pipeline is currently idle with a nitrogen blanket. Shall the MHA W-E pipeline be placed back into service, GAP Midstream will assess the integrity of the pipeline using ILI.

Table 4: MHA W-E Pipeline ILI Data Summary

Joint Number	Anomaly Type	External/Internal	Number of Anomalies in Cluster	Depth %
8655	Metal Loss	External	2	16-21%
8661	Metal Loss	External	4	14-27%
9006	Metal Loss	External	4	12-24%
9022	Metal Loss	External	5	12-16%
9231	Metal Loss	External	13	13-21%

6.3 EXTERNAL CORROSION DIRECT ASSESSMENT (ECDA):

ECDA is appropriate for the external corrosion time-dependent threat. ECDA is a four-step process that determines the integrity of the pipeline for that threat. The process involves pre-assessment, inspection using a variety of electrical survey and inspection tools, examination and evaluation of indications, and post assessment. All ECDA plans will be in accordance with NACE SP 0502 as modified by 49 CFR 195.588.

6.4 HYDROSTATIC PRESSURE TEST

In lieu of an ILI analysis, GAP Midstream may us a hydrostatic pressure test to test the integrity of the pipelines. The pipelines must be tested for at least 4 continuous hours at 125% of the maximum operating pressure and an additional 4 continuous hours at 110% of the maximum operating pressure on segments that are not visually inspected. Any hydrostatic pressure tests shall be performed by a competent person in accordance with CFR 195 Subpart E.

6.5 COMPLETION SCHEDULE:

Upon the identification of new Covered Segments, the most recent ILI data will be reviewed in accordance with the revised area classification. The previous ILI date will be used as the baseline for this IMP. The BAP completion schedule must be based on the following risk factors:

- Results of previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate.
- Pipe size, material, manufacturing information, coating type and condition, and seam type.
- Leak history, repair history, and cathodic protection history.
- Product transported.
- Operating stress level.
- Existing or projected activities in the area.
- Local environmental factors that could affect the pipeline.
- Geo-technical hazards.
- Physical support of the segment.

6.6 PERSONNEL QUALIFICATIONS:

ILI Tools shall be operated by qualified individuals. Personnel qualifications shall be reviewed and approved by a competent person.

ILI data shall be compiled and analyzed by qualified persons. Personnel qualifications shall be reviewed and approved by a competent person.

6.7 RECORDS:

The written BAP shall be maintained and retained for the life of the pipeline. All documents to support any decision, analysis, and process developed and used to implement and evaluate each element of the BAP shall be retained for the life of the pipeline.

7.0 ASSESSMENT PLAN

49 CFR 195.452

API RP1160, Section 9

7.1 INFORMATION INTEGRATION & ANALYSIS:

During the periodic integrity evaluation, the operator shall analyze all available information of the entire pipeline's integrity and the consequences of potential failure scenarios. The analysis must consider the following:

- Information and attributes of the pipeline, including:
  - Year of construction
  - Product transported.
  - Pipe diameter, wall thickness, grade, SMYS, and seam type.
  - Right of Way conditions, including
    - Soil type.
    - Soil resistivity.
    - Depth of Cover.
    - Land use.
  - Valves, flanges, fittings, dead legs, instrumentation lines, and other appurtenances.
  - Facilities, pump stations, booster stations, and terminals.
  - Highway, road, waterway, pipeline, other utility, and power line crossings.
  - Pipe coating, including girth weld coating.
  - Maximum operating pressure and temperature.
  - Endpoints of segments that could affect HCA's.
  - Hydrostatic test pressure including any known leaks or failures.
  - Results from most recent ILI.
  - Location of casings if shorted.
  - Close interval survey results and associated depths of cover.
  - Cathodic protection test point readings and locations with rectifier readings (if applicable).
  - AC/DC and foreign structure interference studies.
  - Pipe coating and coating installation method.
  - Aerial photography.
  - Foreign line crossing locations.
  - Pipe exposures resulting from repairs and encroachments.
  - Seismic activity in the area.
- Information critical to determining the potential for and preventing damage due to excavation,

including current and planned damage prevention activities, and developments or planned development along the pipeline.

- How potential failure would impact HCAs.
- The spatial distance between anomalies along the pipeline.

Gap Midstream has chosen to incorporate all the data collected from this section into the risk assessment to determine the overall risk of the pipeline. The results of the risk assessment shall be used to prioritize the completion schedule of reassessment intervals. Figure 4 below shows the Risk Matrix used to complete the risk assessment.

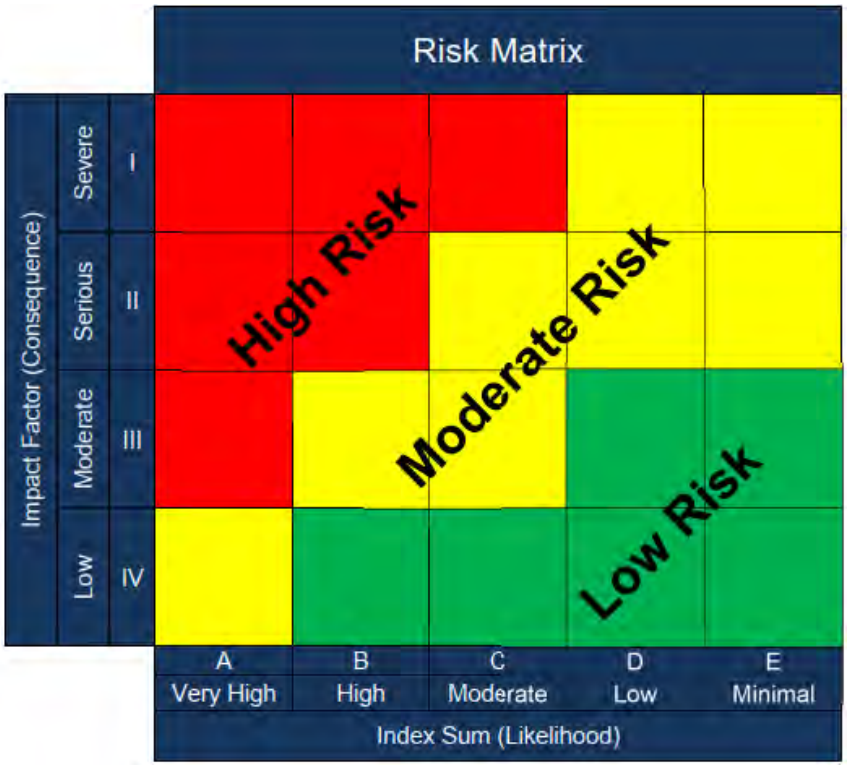


Figure 4: Risk Matrix

7.2 Thunder Butte Pipeline Information Analysis:

The Thunder Butte pipeline is a 6-inch crude oil pipeline constructed in 1990 with wall thickness of 0.156 and 0.125 inches with grades of X42 and X52, respectively. The MAOP of the line is 1,141 psig which is roughly 59% of SMYS. The Thunder Butte pipeline only has 1,480 pipes within an HCA. This section, as well as any areas with excessive corrosion, shall be monitored to identify any immediate conditions and the corrosive rates to assess the appropriate reassessment intervals. The pipeline poses a moderate risk and shall be reassessed at five-year intervals. See the Excel Document *GAP-TB-Risk Assessment-1.25.24* for the complete risk assessment.

7.3 MHA W-E Pipeline Information Analysis:

The MHA W-E pipeline is an 8-inch hazardous liquids pipeline with wall thickness of 0.188 inches in non-HCA segments, that increases to 0.250 inches, 0.375 inches, and 0.500 inches within HCA locations. The pipeline is grade X46 with an MAOP of 1,200 psig which is approximately 60% of SMYS of the sections of pipe with 0.188 inches. The MHA W-E pipeline has segments of pipe that run through Four Bears Village and New Town, North Dakota where it also crosses the Missouri River, attached to the Four Bears Memorial Bridge. The wall thickness through the HCA increases to 0.375 inches near town and 0.500 inches through the Missouri River crossing, reducing the likelihood of failure scenarios. The pipeline poses a moderate risk and shall be reassessed at five-year intervals. See the Excel Document *GAP-MHA W-E-Risk Assessment-1.25.24* for the complete risk assessment.

7.4 ASSESSMENT REVIEW PERSONNEL:

All integrity assessments must be reviewed by GAP Midstream personnel. The integrity of the pipeline shall be assessed with ILI and evaluated by a qualified person to determine if any immediate conditions exist. As part of this review, GAP Midstream shall assess the pipeline integrity in five-year intervals, unless assessments determine a shorter interval is appropriate to monitor any anomalous conditions that do not qualify as immediate conditions defined in 49 CFR 195.452 (h). Risks shall be assessed based on the information provided in the information integration and analysis.

7.5 ASSESSMENT INTERVALS:

7.5.1 Verifying Covered Segments

GAP Midstream conducted the initial risk assessment in January of 2024 and must verify all relevant risk factors identified in the Information Analysis at least once per calendar year, but not to exceed 15 months. If a risk factor is no longer valid or additional risk factors shall be included, the operator must perform a new information analysis to re-establish endpoints of covered segments.

7.5.2 Assessment Intervals

GAP Midstream must continually assess the pipeline's integrity in five-year intervals, not to exceed 68 months.

7.6 RECORDS:

Personnel training and qualification records shall be maintained for the life of the pipeline. The written Direct Assessment Plan shall be maintained and retained for the life of the pipeline. Direct assessment results and analysis shall be maintained for the life of the pipeline.

8.0 REMEDIATION PLAN

49 CFR 195.452(h)

ASME B31G

AGA Pipeline Research Committee Project PR-3-805 (RSTRENG)

8.1 ANOMALY EVALUATION AND RESPONSE TIME:

All anomalies discovered during an integrity assessment shall be evaluated to determine if detrimental effects to pipeline operating conditions exist. Remaining wall strength calculations shall be performed in accordance with ASME B31G or RSTRENG. Response times to an anomalous condition shall be determined by 49 CFR 195.452 (h).

8.1.1 Immediate Repair Conditions:

Immediate repair conditions require GAP Midstream to temporarily reduce the operating pressure or shut down the pipeline until all repairs are completed. Any indication that, in the judgment of the competent person designated to evaluate the integrity assessment, is deemed to be an immediate condition shall be treated as such per 49 CFR 195.452. The following anomalous conditions shall be treated as immediate repair conditions:

- Metal loss greater than 80% of nominal wall thickness.
- Calculated remaining strength of the pipe that has a predicted burst pressure that is less than the established maximum operating pressure.
- A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking, a stress riser, or has a depth greater than 6% of the nominal pipe diameter.
- Any anomaly assessed by GAP Midstream to require immediate action.

8.1.2 60-Day Conditions

GAP Midstream shall schedule evaluation and remediation of the following anomalous conditions within 60 days of discovery of condition.

- A dent is located on top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3% of the pipeline diameter.
- A dent located on the bottom of the pipeline that has any metal loss, cracking, or a stress riser.

8.1.3 180-Day Conditions

GAP Midstream shall schedule evaluation and remediation of the following anomalous conditions within 180 days of discovery of condition.

- A dent greater than 2% of the pipeline's diameter that affects the pipe curvature at a girth weld or a longitudinal seam weld.
- A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter.
- A dent greater than 6% of the pipeline's diameter located on the bottom of the pipeline.
- An area of general corrosion with a predicted metal loss greater than 50% of the nominal wall thickness.
- Predicted metal loss greater than 50% of the nominal wall thickness that is located at a crossing of another pipeline or is in an area with widespread circumferential corrosion or is in an area that could affect a girth weld.
- A crack on the pipeline.
- Corrosion of or along a longitudinal seam weld.
- A gouge or groove greater than 12.5% of the nominal wall thickness.

8.2 REMEDIATION ACTIONS:

All remediation actions will conform to API RP1160 and 49 CFR 195.452 where applicable. The remediation actions below shall be considered appropriate to remediate anomalous conditions discovered during an integrity review:

8.2.1 Temporary Pressure Reduction:

The pipeline pressure shall be reduced to an MAOP not to exceed the greater of the remaining wall strength, as determined by B31G or RSTENG methods, or 80% of the operating pressure at the time of discovery.

All overpressure protection devices shall be reset to reflect the temporary pressure reduction. Temporary pressure reductions shall follow the MOC Process.

PHMSA shall be notified if an anomaly cannot be remediated in the timeframe required by 49 CFR 195.452 and safety cannot be provided for by a temporary pressure reduction or other action.

8.2.2 Long-Term Pressure Reduction:

If anomaly remediation is not completed and a temporary pressure reduction lasts longer than 365 days, PHMSA shall be notified pursuant to 49 CFR 195.452.

8.2.3 Line Pipe Replacement:

Anomalies to be repaired by replacing line pipe shall be installed in accordance with the Thunder Butte

and MHA W-E Pipeline Operations and Maintenance Manual.

8.2.4 Full Encirclement Sleeve:

Sleeves shall be designed in accordance with ASME B31.4.

Sleeves shall be designed to retain full pipeline MAOP.

Sleeves shall be installed in accordance with the Thunder Butte and MHA W-E Pipeline Operations and Maintenance Manual.

8.2.5 Bolt-On Leak Clamp:

Clamps shall be designed and manufactured to retain full pipeline MAOP.

Clamps shall be installed per the manufacturer's instructions and in accordance with the Thunder Butte and MHA W-E Pipeline Operations and Maintenance Manual.

8.3 PERSONNEL QUALIFICATION:

All remediations shall be conducted by a competent person.

All remediation plans shall be written by a competent person.

Pressure reduction activities, line pipe replacements, sleeve installation, and bolt-on clamp installations shall be performed by qualified persons. All qualifications shall be reviewed and approved prior to commencing work.

8.4 RECORDS:

Personnel training and qualification records shall be maintained for the life of the pipeline. All documents to support any decision, analysis, and process developed and used to implement and evaluate any element of the Remediation Plan shall be retained for the life of the pipeline. Verification that any required documentation or notification has been provided to PHMSA shall be maintained for the life of the pipeline.

9.0 CONTINUAL EVALUATION AND ASSESSMENT PROCESS

49 CFR 195.452

9.1 REASSESSMENT PERIODS:

Upon completion of the Baseline Assessment, the Integrity Management Group will analyze the data, validate identified threats, confirm risk ranking, and prioritize segments for reassessment in accordance with Section 7 of this Integrity Management Program.

Pursuant to 49 CFR 195.452, the maximum reassessment interval of Covered Segments is five years, not to exceed 68 months, unless data indicates that reassessment must be conducted sooner.

9.2 REASSESSMENT METHODS:

Reassessment methods available to GAP Midstream are ILI, hydrostatic pressure test, external corrosion direct assessment (ECDA), or other technologies as described in 49 CFR 195.452.

Reassessment intervals for the above listed methods shall be determined as follows:

ILI ..... ***49 CFR 195.452***

Hydrostatic Pressure Test ..... ***49 CFR 195.303(g)***

ECDA ..... ***NACE SP0502-2008, Para. 6.2 & 6.3***

9.3 PERSONNEL QUALIFICATIONS:

Reassessment intervals shall be determined by competent persons as identified by GAP Midstream.

9.4 RECORDS:

Personnel training and qualification records shall be maintained for the life of the pipeline. All documents to support any decision, analysis, and process developed and used to implement and evaluate any element of the Reassessment Process shall be retained for the life of the pipeline. All documents and correspondence to support a Reassessment Interval Deviation shall be maintained for the life of the pipeline.

10.0 ADDITIONAL PREVENTATIVE AND MITIGATIVE MEASURES FOR HCA'S

49 CFR 195.452 / 195.442

10.1 RISK FACTORS:

In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:

- Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area.
- Elevation profile.
- Characteristics of the product transported.
- Amount of product that could be released.

- Possibility of a spillage in a farm field following the drain tile into a waterway.
- Ditches along side a roadway the pipeline crosses.
- Physical support of the pipeline segment such as by a cable suspension bridge.
- Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.
- Seismicity of the area.

10.2 LEAK DETECTION

GAP Midstream shall have means to detect leaks on the pipeline system, in accordance with 49 CFR 195.452(i). The leak detection method must be appropriate for length, size, product, proximity to HCA's, location of nearest response personnel, leak history, and risk assessment results.

10.3 EMERGENCY FLOW RESTRICTING DEVICES (EFRD)

GAP Midstream must analyze the swiftness of leak detection, pipeline shutdown capabilities, product, rate of potential leaks, potential volume released, topography, potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain within the HCA, and the expected benefits by reducing the spill size to determine if an EFRD is necessary. If the EFRD could decrease the risk to HCAs, then GAP Midstream shall install an EFRD.

10.4 THIRD PARTY DAMAGE:

In order to prevent third party damage, GAP Midstream will employ the following measures. Work on or around the Thunder Butte and MHA W-E pipelines will be conducted by Qualified Persons. The GAP Midstream Permit to Work and Management of Change Programs will be enforced. Information on damage to the pipeline due to third party excavations will be collected and evaluated to determine if any additional measures are necessary to protect Covered Segments. GAP Midstream is a member of North Dakota State One Call. Third party excavations adjacent to the Thunder Butte and MHA W-E pipelines will be monitored by Qualified Persons.

10.5 OUTSIDE FORCE DAMAGE:

If outside force damage in a Covered Segment is determined to be a threat, GAP Midstream shall determine if any additional measures are necessary to maintain pipeline integrity.

10.6 PERSONNEL QUALIFICATIONS:

All work on or adjacent to the pipeline shall be performed by Qualified Persons. All qualifications shall be

reviewed and approved prior to commencing work.

All third-party excavations adjacent to the pipeline shall be monitored by a Qualified Person. All qualifications shall be reviewed and approved by a Competent Person prior to commencing work.

10.7 RECORDS:

Personnel training and qualification records shall be maintained for the life of the pipeline.

All information related to excavation damage is to be retained for the life of the pipeline.

Analysis supporting additional mitigative measures resulting from third party or outside force damage shall be maintained for the life of the pipeline.

11.0 PERFORMANCE PLAN AND MEASURES

49 CFR 195.452

49 CFR 195 Appendix C (V)

API RP1160, Section 13

11.1 PRESCRIPTIVE APPROACH DATA REQUIREMENTS:

GAP Midstream has selected a prescriptive approach to integrity management. Pursuant to 49 CFR 195 Appendix C and API RP1160, Table 4 represents the Risk Assessment required Performance Metrics and is shown below for reference.

If ECDA is selected as the primary integrity assessment method as described in Section 7.3 of this document, 49 CFR 195.588 requires additional performance measures to be collected and documented.

Table 5: Performance Metrics

Threats	Performance Metrics
External corrosion	• Number of hydrostatic test failures caused by external corrosion • Number of repair actions taken due to in-line inspection results • Number of repair actions taken due to direct assessment results • Number of external corrosion leaks
Internal corrosion	• Number of hydrostatic test failures caused by internal corrosion • Number of repair actions taken due to in-line inspection results • Number of repair actions taken due to direct assessment results • Number of internal corrosion leaks
Stress corrosion cracking	• Number of in-service leaks or failures due to SCC • Number of repair replacements due to SCC • Number of hydrostatic test failures due to SCC
Manufacturing	• Number of hydrostatic test failures caused by manufacturing defects • Number of leaks due to manufacturing defects

Construction	• Number of leaks or failures due to construction defects • Number of girth welds/couplings reinforced/removed • Number of wrinkle bends removed • Number of wrinkle bends inspected • Number of fabrication welds repaired/removed
Equipment	• Number of regulator valve failures • Number of relief valve failures • Number of gasket or O-ring failures • Number of leaks due to equipment failures
Third-party damage	• Number of leaks or failures caused by third-party damage • Number of leaks or failures caused by previously damaged pipe • Number of leaks or failures caused by vandalism • Number of repairs implemented as a result of third-party damage prior to a leak or failure
Incorrect operations	• Number of leaks or failures caused by incorrect operations • Number of audits/reviews conducted • Number of findings per audit/review, classified by severity • Number of changes to procedures due to audits/reviews
Weather related and outside forces	• Number of leaks that are weather related or due to outside force • Number of repair, replacement, or relocation actions due to weather-related or outside-force threats

11.2 PERFORMANCE IMPROVEMENT:

Annual review of metrics, measurements, and periodic audits shall be conducted and modifications to the plans and program will be made as appropriate. The processes, responsibilities, and data flow will be modified as necessary to improve the efficiency and reliability of the program.

11.3 RECORDS:

All documents to support any decision, analysis, and process developed and used to implement and evaluate any element of the Performance Plan shall be retained for the life of the pipeline. Verification that any required documentation or notification has been provided to PHMSA shall be maintained for the life of the pipeline.

12.0 DISTRIBUTION RISK ANALYSIS AND/OR IMP

49 CFR 195.452 (m)

12.1 SUBMITTAL PROCEDURE:

Pursuant to 49 CFR 195.452 (m), a procedure must be in place to submit (when requested) a copy of the Risk Analysis and Integrity Management Plan. The plan can be submitted via mail or email to:

Mail:

Office of Pipeline Safety, Pipeline Hazardous Materials Safety Administration

U.S. Department of Transportation
Information Resources Manager, PHP-10
1200 New Jersey Avenue, SE
Washington, DC 20590-001

Email:

InformationResourcesManager@dot.gov

12.2 RECORDS:

Verification that any required documentation or notification has been provided to PHMSA shall be maintained for the life of the pipeline. All reports to the Office of Pipeline Safety and PHMSA, including reports of changes to the plan and performance, will be maintained by GAP Midstream in accordance with 49 CFR 195.48.

13.0 IDENTIFICATION AND ASSESSMENT OF NEWLY IDENTIFIED HCA'S AND MCA'S

49 CFR 195.452 (d)

13.1 HCA & MCA IDENTIFICATION:

New HCA's will be identified in accordance with 49 CFR 195.450, 195.452 (g), Class Location, and High Consequence Area Data Gathering by GAP Midstream. All new HCAs shall be included in the baseline assessment plan within one year of discovery. The baseline assessment must be completed within 5 years from the date the area is identified. Annual meetings with Emergency Responders will be used as an opportunity to survey and obtain information of additional potential Identified Sites in accordance with 49 CFR 195.450.

13.2 HCA ASSESSMENT:

Below are examples of conditions that will constitute an assessment of the Pipeline's Class and HCA Identification by GAP Midstream.

- Change in MAOP.
- Change in line size.
- Change in commodity being transported.
- Identification of new construction that may be intended for human occupancy.
- Identification of a concentrated population that could be affected by the pipeline
- Identification of facilities occupied by persons who are confined, have impaired mobility or would be difficult to evacuate.

- Change in the use of existing buildings.
- One or more regulated pipelines or facilities are added or removed.
- Pipelines rerouted.
- HCA boundaries are redefined by the National Pipeline Mapping System (NPMS).
- Revisions to 49 CFR 195.450 are enacted that affect this process/procedure.

GAP Midstream will utilize the information above and use the definitions in 49 CFR 195.450 to identify and locate any new HCAs. GAP Midstream will create a report based on the findings. GAP Midstream will meet at least once per calendar year not to exceed 15 months to review this information.

13.3 RECORDS:

Records of HCA identification and supporting documentation shall be maintained for the life of the pipeline.

14.0 RECORD KEEPING

49 CFR 195.452 (l)

14.1 RECORD REQUIREMENTS:

This section covers the records and supporting documentation that are part of the IMP. All records and documentation that demonstrate compliance with the requirements of 49 CFR 195.452, 195.452 appendix C, and the sections referenced therein must be kept for the useful life of the pipeline.

14.2 WRITTEN INTEGRITY MANAGEMENT PROGRAM:

GAP Midstream maintains a written integrity management program for the Thunder Butte and MHA W-E pipelines. The program will be reviewed annually and changes to the written program shall be made accordingly. The annual review will be scheduled within 15 months of the previous review.

14.3 WRITTEN BASELINE ASSESSMENT PLAN:

GAP Midstream maintains a written baseline assessment plan, see Section 5 of this Integrity Management Program. The Baseline Assessment Plan is generated on an annual basis. The plan is maintained by GAP Midstream.

14.4 DOCUMENTS SUPPORTING DECISIONS:

GAP Midstream is responsible for maintaining all documents supporting analysis and decisions and their related processes that are used to evaluate and implement each element of the baseline assessment plan and the Integrity Management Program. This documentation includes persons involved in the decision,

the date made and the date of implementation of change. These documents specifically deal with justification of decisions made where the decisions are not already contained within a policy, practice, procedure, specification, or standard.

14.5 DOCUMENTS SUPPORTING PROGRAM EVALUATION:

GAP Midstream evaluates performance of the integrity management program and its elements in accordance with Section 11, Performance Plan and Measures. Records of the evaluations are maintained by GAP Midstream.

14.6 DOCUMENTS SUPPORTING TRAINING:

GAP Midstream maintains records of training and experience for all persons who perform the following activities:

- Threat Identification,
- Risk Assessment,
- Integrity Assessment,
- Remediation Determination.

These documents are maintained separately from the Operator Qualification documents required by 49 CFR 195, subpart G.

14.7 DOCUMENTS SUPPORTING ADDITIONAL PREVENTATIVE & MITIGATIVE MEASURES:

GAP Midstream maintains records of additional preventative and mitigative measures through various data sources. These are identified on an HCA specific basis and reviewed to determine if their implementation may apply to other HCAs. Examples of data sources are:

- Pipeline Patrol Records,
- Abnormal Operating Condition Reports,
- Liaison Meetings with Public Officials and Contractors.

14.8 SCHEDULE OF REMEDIATION:

A schedule for remediation is maintained by GAP Midstream. Immediate conditions shall be remediated as soon as reasonably possible or within the 60- and 180-day windows as specified in Section 8.1. All other anomalies shall be monitored with remediation scheduled as necessary. All records pertaining to remediations shall be kept by GAP Midstream.

14.9 DIRECT ASSESSMENT DOCUMENTS:

All documents pertaining to the requirements for the Direct Assessment Plan in 49 CFR 195.588 will be maintained by the GAP Midstream.

Operations & Maintenance Manual

Hazardous Liquids 8” MHA W-E & 6” Thunder Butte Pipelines

GAP-OMM

February 20, 2024
GAP Midstream
Rev. 1

Table of Contents

1.0 REVISION PROCEDURE

195.402(a)

1.1. AMENDMENTS / REVISIONS:

1.1.1. An annual review of this Operation and Maintenance manual (OMM) will be made each year, not to exceed 15 months. Company Manager Ralph Anaya, or designee, will approve all amendments, revisions, reviews, and distributions. This form must contain the appropriate signature. Attach any additional papers necessary to the back of this form for routing approval.

1.2. REVISIONS

SUBJECT	SECTION	PAGES	DATE
Initial Creation			06/14/2023
Thunder Butte pipeline return to service – Tasks no longer deferred	ALL	ALL	02/20/2024

REVIEW

Date of Review: _____

Reviewed By: _____
Sign Print

Reviewed By: _____
Sign Print

APPROVAL

Approved By: _____

Date Approved: _____

2.0 GENERAL

2.1. PURPOSE:

2.1.1. The purpose of this Manual is to provide procedures and guidelines for personnel to safely operate and maintain two 49 CFR 195 regulated pipelines operated by GAP Midstream pipelines, the 8" MHA W-E Pipeline and the 6" Thunder Butte Pipeline.

2.1.2. GAP Midstream has a strong interest in the safety of the public, its employees, contractors, and the environment. To help prevent injury, guidelines for operations have been established which apply to all employees and contractors. The continuous cooperation and vigilance of all personnel are needed to see that operating procedures and work methods do not unnecessarily expose personnel to injury or expose property to loss or damage. Good judgment and common sense are required to supplement any safety rules.

2.2. SCOPE:

2.2.1. The Thunder Butte pipeline consists of a 6" steel pipeline that is used to transport hazardous liquids. This pipeline was idle with a nitrogen blanket but shall be brought back into service early to mid-2024.

2.2.2. The MHA W-E pipeline consists of an 8" steel pipeline that was previously used to transport hazardous liquids. The MHA W-E pipeline is currently purged of all crude oil product and sits with a nitrogen blanket in an idle state.

2.2.3. The scope of this Manual includes Operations and Maintenance activities conducted on the GAP Midstream pipelines.

2.2.4. The scope does not include the following procedures which are separate documents from but incorporated by reference in this Manual.

(1) Public Awareness (195.440) – GAP Midstream Pipeline Public Awareness Program.
(2) Damage Prevention Plan (195.442) – GAP Midstream Damage Prevention Plan
(3) Qualification of Pipeline Personnel (195 Subpart G) – GAP Midstream pipeline Operator Qualification Plan.
(4) Pipeline Integrity Management in High Consequence Areas (195.452) – GAP Midstream pipeline Integrity Management Plan.

2.3. FEDERAL REGULATIONS:

49 CFR Part 195

2.4. STATE REGULATIONS:

North Dakota Pipeline Authority

3.0 MAINTENANCE AND NORMAL OPERATIONS
195.402(c)

3.1. PURPOSE:

3.1.1. The GAP Midstream MHA W-E pipeline consists of about 69 miles of Nominal Pipe Size (NPS) 8-inch hazardous liquid pipe and is located in McKenzie, Mountrail, and Ward Counties, North Dakota. The pipeline is idle but will eventually be put back into service. The pipeline was part of a longer segment of over 250 miles of pipeline running from Laurel, MT to Minot, ND installed in the 1960s.

3.1.2. The GAP Midstream Thunder Butte Pipeline is an NPS 6-inch crude oil pipeline located in Ward and Mountrail Counties, North Dakota. The Thunder Butte pipeline originated at the Thunder Butte Petroleum Service (TBPS) Facility and flows northwest for 34.5 miles to the Enbridge Storage Facility near Stanley, ND. This pipeline is being returned to service as a crude oil pipeline.

3.1.1.This manual serves as the 49 CFR 195 compliant Operations and Maintenance Manual (OMM). The pipeline information is detailed here:

Pipeline Attribute	MHA W-E Pipeline	Thunder Butte Pipeline
Pipe Outer Diameter	8.625 inches	6.625 inches
Wall Thickness	0.188	0.156 and 0.125
Pipe Grade	X46	X42 and X52
Seam Type	ERW	ERW
Manufacturer	CAL-METAL PIPE CORP	UNKNOWN
Installation Date	1960	1990
MOP	1,200 PSIG	1,440 PSIG
Hydrostatic Test Pressure	1,419 PSIG	1,962 PSIG
% SMYS	60%	59%

3.1.2. Any new or replaced pipe or equipment must meet or exceed these standards.

3.1.3. The GAP Midstream MHA W-E 8" pipeline is NOT equipped with a launcher and receiver compatible with in-line inspection tools but rather capped at each end with a nitrogen blanket. Components – bends, fittings, valves – are designed to allow for in-line inspection tool passage, evident by previous in-line inspections.

3.1.4. The GAP Midstream MHA W-E 8" pipeline is equipped with sectionalizing block valves or aboveground appurtenances. During the 1999 year hydrotest, block valves were used for isolation of Test Section 4, Test Section 5, and Test Section 6 with Block Valves at Arnegard Station, BV 129 (Four Bears), BV 159 and Minot Terminal. The Arnegard Station and Minot Terminal are outside the capped portion of GAP's pipeline.

3.1.5. The 6" Thunder Butte pipeline has a launcher and receiver on both ends and allow for pigs and in-line inspection tools to be used to clean and inspect the line.

3.2. INACTIVE STATUS:

PHMSA issued a 2016 Issuance of Advisory Bulletin regarding clarification of terms relating to pipeline operational status defining in ADB-2016-05 to owner and operators of hazardous liquid, carbon dioxide and gas pipelines that PHMSA regulations do not recognize an "idle" status for a hazardous liquid or gas pipelines. The regulations consider pipelines to be either active and fully subject to all relevant parts of the safety regulations or abandoned.

The 8" MHA W-E pipeline is idle with a nitrogen blanket and not in service, while the 6" Thunder Butte Pipeline will be returning to service. The 8" MHA W-E pipeline has not been abandoned as it is intended to be converted back to service at a later date and has been capped and filled with nitrogen. Based on the PHMSA Advisory Bulletin for pipelines that have an expectation to continue using the pipeline in hazardous materials transportation service, it is understood that PHMSA will accept deferral of certain activities for purged but active pipelines. It is also understood that all deferred activities must be completed prior to, or as part of, any later return-to-service.

3.3. DEFERRED TASKS:

Based on the PHMSA Advisory Bulletin, this section of the O&M Manual serves as GAP Midstream's effort at coordinating the deferral in advance with regulators. Some activities required of a covered pipeline will still be completed to protect the integrity of the pipeline, but other tasks can be deferred until the pipeline is prepared to be brought back to service. The following list details some tasks that may be identified as deferred tasks for the MHA W-E pipeline that can be completed at a later date:

Operations And Maintenance Manual – Potential Deferred Tasks:

- Maintenance and Normal Operations (§195.402(c))
- Abnormal Operations (§195.402(d))
- Emergencies (§195.402(e))
- Safety Related Conditions (§195.402(f))
- Emergency Response Training (§195.403)
- Communications (§195.408)
- Pipeline Assessments (§195.416)
- Inspect and Test Overpressure Safety Devices (§195.428)
- Public Awareness (§195.440)
- Damage Prevention Program (§195.442)
- Leak Detection (§195.444)
- Control Room Management (§195.446)
- Integrity Management Plan in High Consequence Areas (§195.452)
- Valve Maintenance (§195.420)

3.4. NORMAL OPERATIONS:

195.402(c)

The MHA W-E pipeline and the Thunder Butte pipeline both have been purged of hazardous liquids and filled with a nitrogen blanket to prevent internal corrosion. At this time, the MHA W-E pipeline is not in operation but has not been abandoned because it is intended to be placed in service at a later date. The Thunder Butte pipeline is being returned to service to transport Crude Oil.

Normal operations of GAP Midstream pipelines will flow crude oil. Equipment at the Thunder Butte Service Facility will control pressure and flow in route to the Enbridge Storage Facility.

3.4.1. Damage Prevention Program:

195.442

The GAP Midstream Damage Prevention Program will be a standalone document to satisfy the requirements of 49 CFR 195.442 for both GAP Midstream pipelines. For all activities within 25 inches of the pipeline, notification is required and a GAP Representative must be on site to monitor the work. The Damage Prevention Plan has been completed and shall be utilized for both pipelines.

3.4.2. Public Awareness:

195.440

The GAP Midstream Public Awareness Plan will be a standalone document to satisfy the requirements

of 49 CFR 195.440. Since the MHA W-E pipeline is in an idle state with nitrogen, an inert gas, the pipeline will be monitored through patrols. A Public Awareness Plan has been completed and shall be utilized for both pipelines.

3.4.3. Maximum Operating Pressure:

195.406

The COMPANY Manager, or designee, is responsible for establishing maximum operating pressure (MOP) and ensuring the pipeline is operated at or below the established MOP.

The GAP Midstream MHA W-E 8" pipeline was designed and constructed in accordance with 49 CFR 195. It was not converted under §195.5. MOP was established during design at 1,200 PSIG. As part of construction, the GAP Midstream MHA W-E pipeline was hydrotested for eight hours at 1,419 for test section 6, 1,520 PSIG for Test Section 4 and 1,460 PSIG for Test Section 5 in accordance with 195.300 Pressure Testing.

The GAP Midstream Thunder Butte 6" pipeline was designed and constructed in accordance with 49 CFR 195. MOP was established during design at 1,440 PSIG. As part of construction, the pipeline was hydrotested for eight hours at 1,962 PSIG in accordance with 195.300 Pressure Testing.

4.0 PIPELINE START-UP AND SHUTDOWN

195.402

Pipeline start-up and shutdown are high-risk activities. During start-up and shutdown operations, only personnel critical to the operation shall be allowed near the pipeline.

Written plan and procedures shall be created prior to a start-up or shutdown event. In the event of emergency scenarios, the COMPANY Manager, or designee, shall be responsible for coordinating start-up or shutdown activities.

Plans and procedures involving start-up and shutdown activities shall be approved by the COMPANY Manager, or designee. Conditions and circumstances surrounding any start-up or shutdown event shall be considered before proceeding. Since the pipeline is not in service, specific start-up and shutdown procedures are identified as deferred tasks that will be completed prior to activation of the pipeline. Since the system is currently not active and filled with nitrogen, start-up and shutdown procedures are not required at this time.

4.1. EXCAVATION:

195.440(d) and 195.442

The pipeline can be excavated for purposes of operations, maintenance and encroachments or crossings by other utilities or structures. Also refer to the Damage Prevention Program.

(1) At least 48 hours prior to any excavation, notify the State One Call – 811 system.

(2) Obtain Line Locates from LOCATE COMPANY, and any other underground utility or owners of underground facilities within the excavation scope. Locate the pipeline using a pipe finder to determine its approximate location and depth following the manufacturer's instructions. Conduct a daily Job Safety Analysis (JSA) with all personnel prior to excavating or performing work within an excavation. JSAs shall be updated if conditions change during the workday.

(3) This type of work will be contracted out to a qualified pipeline contractor. The Contractor must follow the plan and procedure developed by the engineer when the pipeline is excavated.

(4) Ensure that a proper traffic control plan is in place and operational where required.

(5) All work must be performed in accordance with OSHA Advisory #29 – Excavations. Identify a "Competent Person" who has been trained to recognize soil types and recommend proper ditch profiles. Trenches deeper than 4 feet shall have the proper distances or ratios of depth to width as specified in Advisory 29 or shoring placed properly to avoid cave-ins. Spoil must be stored at least 2 feet away from the edge of ditch.

(6) Prior to entering, all excavations shall be certified by the Competent Person daily or when conditions affect the excavation.

(7) Verify the location of the pipe by hand digging or probing prior to completing safe excavation. Take care not to damage the pipe or coating while it is being exposed.

(8) Hand digging is required within two feet (2 ft.) of the pipeline.

(9) Make certain shoring, ladders, and escape ramps are installed when necessary. If a leak is suspected, check the excavation for unsafe accumulations of oil. Make available, when needed, emergency rescue equipment including a breathing apparatus and rescue harness line.

5.0 ABNORMAL OPERATIONS
195.402(d)

5.1. SUMMARY:

195.402(d)

Abnormal conditions often occur before an emergency condition. It is important that each abnormal condition be treated in accordance with the procedures outlined in this Operations and Maintenance Manual. Abnormal conditions include situations such as unexpected, unintentional, non-emergency circumstances that cause a pipeline system's operating condition or design limit to be exceeded. Examples of abnormal situations include relief valve venting, unintended valve closure, unintended shutdown of pipeline system, change in pressure or flow rate out of normal boundaries, loss of communication,

equipment function error, and the malfunction of any element of the pipeline system that could potentially result in an emergency.

5.2. UNINTENDED VALVE CLOSURE OR PIPELINE SHUTDOWN:

195.420

5.2.1. Unintended Valve Closure:

An unintended valve closure could be signaled by higher-than-normal pressures. The incident shall be investigated, and the valve returned to the correct operating position. If delivery was interrupted, it may be restored once approval is obtained from the COMPANY Manager. Pressure, flow rates, and equipment status shall be monitored carefully after the incident is corrected.

5.2.2. Unintended Shutdown of Pipeline System:

When Operations personnel notices that the pipeline system has been shut down, an investigation shall begin into the shutdown. The COMPANY Manager and On-Duty Operator shall be notified immediately.

5.3. PRESSURE OR FLOW OUTSIDE OF NORMAL OPERATING CONDITIONS:

195.402(c)(9)

Indications that a change in pressure or flow rate has occurred are abnormal pressure readings and flow meter readings. Data that asserts a change in pressure or flow rate shall be verified. Operations personnel shall evaluate the entire affected pipeline system to determine whether a problem exists. If the problem proves to be severe, Operations shall shut down the system. However, if the problem does not warrant shutting down the pipeline, then the Operator shall continue to operate the pipeline and investigate the problem. Upon resolution of the problem, the Operator shall bring the pipeline back on-line with normal start-up procedures and monitor readings closely. Since the pipeline is not currently in service, monitoring flow conditions outside of normal operating conditions is not necessary at this time.

5.4. OTHER POTENTIAL MALFUNCTIONS:

5.4.1. Personal Error of Equipment Operation:

Upon the discovery of a personnel error during the operation of equipment, the Operations personnel present will determine the severity of the situation. If an emergency circumstance is possible, Operations personnel will immediately shut down the pipeline and notify the COMPANY Manager. When the problem has been solved, Operations personnel may proceed with normal start-up procedures. If the error will not result in an emergency situation, then Operations personnel will solve the problem.

5.4.2. Malfunction of Equipment:

Malfunction of equipment or a component that could result in an emergency (including safety-related devices). Upon the discovery of the malfunction, operations personnel will immediately shut down the pipeline and notify the COMPANY Manager. When the problem has been solved, Operations personnel may proceed with normal start-up procedures.

5.5. PERSONNEL NOTIFICATION:

195.402(e)(4)

The COMPANY Manager, or designee, shall be notified when personnel become aware of an abnormal operating condition. The COMPANY Manager, or designee, shall notify all affected parties in accordance with this Manual.

5.6. REVIEWING OPERATOR RESPONSE:

195.402(e)(7)

All Abnormal Operations shall be reported. These abnormal procedures will be reviewed annually to determine their effectiveness and identify any deficiencies.

6.0 EMERGENCIES

195.402(e)

6.1. RESPONSE, INVESTIGATION, AND CORRECTION:

195.402(e)

Emergencies shall be handled by ensuring proper personnel are notified. Documentation and reports shall be created to document the event and investigation of the cause of the incident shall begin. Depending on the emergency shutdown of the pipeline may be necessary. Investigation into the cause of the incident must be determined before the pipeline can operate back under normal conditions.

7.0 EMERGENCY RESPONSE TRAINING

195.403

7.1. TRAINING:

195.403(b)

At the intervals not exceeding 15 months, but at least once each calendar year, each operator shall:

(1) Review with personnel their performance in meeting the objectives of the emergency response training program set forth in paragraph (a) of this section; and

(2) Make appropriate changes to the emergency response training program as necessary to ensure that it is effective.

(3) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under 195.402 for which they are

responsible to ensure compliance.

7.2. EMERGENCY PLANS:

195.403

The GAP Midstream pipeline emergency plans will be generated for both the 8" MHA W-E and 6" Thunder Butter pipelines. before the pipeline is put in service. This is a standalone document even though it is included in section 195 code.

8.0 SAFETY RELATED CONDITION

195.55

8.1. IDENTIFICATION:

195.55

The existence of any safety related condition will be reported. The definition of a safety related condition is defined as the following:

(1) General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) Unintended movement or abnormal loading of a pipeline by environmental causes, such as an earthquake, landslide, or flood, which impairs its serviceability.

(3) Any material defect or physical damage that impairs the serviceability of a pipeline.

(4) Any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of its maximum operating pressure.

(5) A leak in a pipeline that constitutes an emergency.

(6) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.

8.2. SAFETY RELATED CONDITION REPORTS:

195.56(a)

GAP Midstream is required to report the existence of any safety related conditions involving the GAP Midstream pipelines, such as:

(1) General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) Any unintended pipeline movement resulting from flood, landslide, or an earthquake, which may jeopardize serviceability.

(3) Any material defect or physical damage that impairs serviceability.

(4) Any leak on the pipeline that constitutes an emergency.

(5) A safety-related condition that constitutes an immediate hazard, which causes a direct or indirect remedial action by an operator, such as loss or over-pressure which initiates a pipeline shutdown.

(6) Any report submitted and the follow-up or corrective action taken in response to the condition.

8.3. FILING OF SAFETY-RELATED CONDITION REPORTS:

Reporting of safety-related conditions shall be filed in writing within five (5) working days after the safety-related condition has determined that a safety-related condition exists. However, the report shall be filed no later than ten (10) working days after the discovery of the said condition. The report shall be titled 'Safety-Related Condition Report' and include the name and address of the operator, the date of the report, the name, job title, and business telephone number of the person submitting the report and the person who determined the condition exists, date the condition was discovered, location of the condition, description of events leading to its discovery, and the corrective action taken before the report is submitted.

9.0 MAPS AND RECORDS

195.404

9.1. HYDROTEST RECORDS:

195.310

Records must be made of each pressure test and must be retained for as long as the facility is in use. This must include charts, calibration data, the name and company who performed the test, the date and time of test, minimum test pressure, test medium, a description of the facility tested and the apparatus used, the reason for any pressure fluctuations, elevation maps when elevations exceed 100 feet, and the temperature of the test medium during the test period.

9.2. MAPS:

195.404

Current maps and records shall be kept for the pipeline system identifying tanks, pump stations, valves, rights-of-way, safety devices, crossings of roads, rivers, pipelines, and buried utilities. This information will be updated as changes to the system are made. Maps, drawings, and records shall be available to any person requiring these documents to perform their pipeline duties. Pipeline maps, construction drawings, and surveys will be maintained electronically. All drawing revisions shall be approved by the COMPANY Manager or designee.

Personnel performing pipeline operations and maintenance procedures specified in this Manual are required to submit to the Compliance Lead any forms, records, reports, or drawings associated with that procedure.

9.3. CONSTRUCTION RECORDS:

Upon completion of any construction activity or repair, all records required by 49 CFR 195 and the GAP Midstream procedures shall be submitted to the COMPANY Manager. These records will be maintained electronically for the duration required by 49 CFR 195.

9.4. OPERATING HISTORY:

Operating history inspection records and forms required by this manual will be maintained electronically to the duration required by 49 CFR 195 and the GAP Midstream procedures.

10.0 MOP

195.406

10.1. DETERMINATION:

195.406

The test pressure of the pipeline shall be used to determine the Maximum Operating Pressure (MOP). At no time shall the pressure inside the pipeline exceed the MOP determined by the hydrotest records under normal operation.

11.0 COMMUNICATIONS

195.408

11.1. MONITORING:

195.408(a)

A communication system is required for the transmission of information for the safe operation of the pipeline. This system will be used to monitor operational data, receive notices about abnormal or emergency conditions, and to send information to appropriate personnel.

11.2. LOSS OF COMMUNICATIONS:

195.408

In the event of a communications loss regarding telemetry, Operations personnel shall monitor pipeline conditions immediately upstream and downstream of the telemetry failure point. Cell phones and radios can be used as back up communications.

12.0 LINE MARKERS

195.410

12.1. PIPELINE MARKERS:

195.410(c)

Pipeline Markers are used to identify the locations of the GAP Midstream pipelines to reduce the possibility

of damage or interference. The placement of temporary markers is advisable in areas of known heavy construction activities while construction is in progress.

The Pipeline Operator is responsible for proper pipeline marking. The condition of markers shall be inspected during routine patrols. Damaged or deteriorated markers shall be replaced. Pipeline markers shall be at each public road crossing, railroad crossing, and must include the words caution, danger, or warning. Name and telephone numbers to reach the operator shall be included on the marker.

12.1.1. PIPELINE MARKER CHARACTERISTICS:

(1) A pipeline marker shall be placed and maintained as close as practical over each buried pipeline at each crossing of a public road, railroad and wherever otherwise necessary to identify the location of the pipeline to reduce the possibility of damage or interference.

(2) Markers shall be anywhere the pipeline is above ground in areas accessible to the public.

(3) Line markers are not required for buried pipelines where:

(i) Offshore or at crossing of or under waterways and other bodies of water

(ii) In heavily developed urban areas such as downtown business centers where marker placement is impractical and would not serve the purpose and the local government maintains current records.

(4) Pipeline markers other than at navigable waterways must have the following characteristics:

(i) Wording must be written legibly on a background of sharply contrasting color.

(ii) The words "Warning," "Caution", or "Danger", followed by the words "Hazardous Liquid (or name of fluid transported) Pipeline," must be in letters at least one inch (1") high with one-quarter inch (¼") stroke.

(iii) Before digging in this area, call the company name and the telephone number (including area code) where the company can be reached at all times.

Where known encroachments that could affect the safety of the pipeline are anticipated or in progress near pipeline facilities, the pipeline shall be located, and the route conspicuously indicated by markers having the above characteristics. The encroaching party shall be notified of the presence of the pipeline where possible.

13.0 PIPELINE ASSESSMENTS
195.416

13.1. GENERAL:
195.416(b)

An operator must perform an initial assessment of each of its pipeline segments by October 1, 2029, and

perform periodic assessments of its pipeline segments at least once every 10 calendar years from the year of the prior assessment or as otherwise necessary to ensure public safety or the protection of the environment.

13.2. RESPONSE, INVESTIGATION, AND CORRECTION:

195.416(c)(1)

An operator must perform the integrity assessment for the range of relevant threats to the pipeline segment by the use of an appropriate in-line inspection tool(s). When performing an assessment using an in-line inspection tool, an operator must comply with §195.591. An operator must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or other equivalent methods for determining uncertainties) in identifying anomalies. If this is impracticable based on operational limits, including operating pressure, low flow, and pipeline length or availability of in-line inspection tool technology for the pipe diameter, then the operator must perform the assessment using the appropriate method(s) such as a pressure test, and external corrosion test assessment. All tests must follow the rules and regulations as per CFR 49, part 195.

13.3. OTHER TECHNOLOGY:

195.416(d)

Operators may elect to use other technologies if the operator can demonstrate that the technology will provide an equivalent understanding of the condition of the line pipe for the threat being assessed. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment by:

(1) Sending the notification, along with the information required to demonstrate compliance with this paragraph, to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590; or

(2) Sending the notification, along with the information required to demonstrate compliance with this paragraph, to the Information Resources Manager by facsimile to (202) 366–7128.

(3) Prior to conducting the “other technology” assessments, the operator must receive a notice of “no objection” from the PHMSA Information Services Manager or Designee.

13.4. DATA ANALYSIS:

195.416(e)

A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (13.1) of this section to determine if a condition could adversely affect the safe operation of the pipeline. Operators must consider uncertainties in any reported results (including tool tolerance) as part of that analysis.

13.3. DISCOVERY OF CONDITION:

195.416(f)

For purposes of §195.401(b)(1), discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination required under paragraph (e) of this section, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are impracticable to make a determination about a condition found during an assessment, the pipeline operator must notify PHMSA and provide an expected date when adequate information will become available. This notification must be made in accordance with §195.452 (m).

13.3. REMEDIATION:

195.416(g)

An operator must comply with the requirements in §195.401 if a condition that could adversely affect the safe operation of a pipeline is discovered in complying with paragraphs (e) and (f) of this section.

13.3. CONSIDERATION OF INFORMATION:

195.416(h)

An operator must consider all relevant information about a pipeline in complying with the requirements in paragraphs (a) through (g) of this section.

14.0 MAINTAINING AND REPAIRING:

195.401

14.1. MAINTENANCE:

Maintenance and repair of the GAP Midstream pipelines has a minimum standard, Title 49 Federal Regulation Part §195 – Transportation of Hazardous Liquids by Pipeline. All maintenance and repair tasks for the pipeline will be based on this regulation. Where the Federal Regulation is silent, the intent of the code or good safety practice shall be the basis of the inspection.

14.1.1. UNSAFE PIPELINE SEGMENT:

195.400

The GAP Midstream pipelines shall be maintained in accordance with this manual and other Company documents. All leaks or damage caused by external forces or detected by prescribed inspection procedures shall be repaired promptly. Any segment of the pipeline that becomes unsafe must be replaced, repaired, or removed from service.

Permanent repair of leaks and damage shall be made as soon as practicable after discovery in accordance with this Manual. If a permanent repair cannot be made within the allotted timeframe, the

operating pressure will be reduced and temporary methods capable of operating at the reduced pressure will be used.

If a leak, damage, or imperfection in the pipeline is in an area where danger to life or property exists, GAP Midstream personnel shall take immediate temporary measures to protect people first and property second.

14.1.2. PATROLLING:

195.402

The pipeline shall be patrolled to observe surface conditions on and adjacent to the pipeline right-of-way for indications of leaks, construction activity, earth movement, access, adequate line markers, and other factors that may affect the safety and operation of the pipelines. Frequency of patrols shall be determined by the size of the line, operating pressures, class location, terrain, weather, and other relevant factors, but intervals between patrols may not exceed the following:

Patrolling shall be performed by foot or vehicle. Aircraft patrols are considered an acceptable option.

Ground patrolling shall be performed at regular intervals in encroachment areas and areas of unusual activity or construction. Reports shall be made of all conditions found or reported that could adversely affect the safety, operation and maintenance of the pipeline. Each report shall include a description of the conditions found, sketches of the area, and any remedial action required or taken.

The following reports shall be prepared where applicable:

(1) Substantial changes in CP requirements.
(2) Any unusual operating or maintenance conditions.
(3) Sketches or additional data shall be used to supplement reports where necessary.

14.2. MATERIALS:

195.101

14.2.1. Steel Pipe and Components:

Steel pipe or other components shall be manufactured in accordance with a specification incorporated by reference in 49 CFR 195.

14.3. LEAKAGE:

14.3.1. Leakage Surveys:

195.55, 195.134, 195.444

Any leaks with the pipeline shall be reported and addressed as soon as reasonable possible as it

represents a safety related condition.

If any blasting occurs within 100 feet of the pipeline ROW, a special leak survey will be completed after blasting to ensure pipeline integrity. All leaks found which result from split seams or other defects in the pipeline shall be reported.

All leaks found on above ground piping shall be reported. Leaks on above ground piping shall be repaired at the time of inspection, if possible. If repair cannot be accomplished at the time of inspection, the leak should be noted, and remedial measures taken to stop the leak at the earliest opportunity.

14.3.2. Leak Classification:

Leaks of the pipeline with the nitrogen blanket would not cause a safety concern. If leaks were to be found, the following classification system will be used to prioritize leaks.

(1) Hazardous – Leaks requiring continuous monitoring where leaks would cause environmental damage – REPAIR IMMEDIATELY.
(2) Moderate – Leakage is not hazardous but may become hazardous if not repaired as soon as possible. Monitor each month until repair is made. REPAIR WITHIN 6 MONTHS.
(3) Routine – Leak is not hazardous and presents no future hazard. REPAIR WITHIN 15 MONTHS.

14.3.3. Initial Assessment:

195.416(b)

An in-line inspection was performed on the GAP Midstream 8” MHA W-E Pipeline in September 2004. For the purposes of 195.416, this inspection will be used as the baseline assessment. An in-line inspection was performed on the Gap Midstream 6” Thunder Butte Pipeline in May of 2013. For the purposes of 195.416, this inspection will be used as the baseline assessment.

14.3.4. Periodic Reassessment:

195.454

The GAP Midstream pipelines shall be reassessed every 12 months for areas inside high consequence areas (HCAs), otherwise shall be assessed once every 10 years. Areas inside HCA’s shall follow the requirements of §195.454 where pipeline integrity assessments using internal inspection technology appropriate for the integrity threats to the pipeline are completed not less often than once every 12 months.

14.3.5. Assessment Method:

195.416(c), 195.591

It is the intention of GAP Midstream to perform all reassessments via in-line inspection in accordance with 195.416(c) when the assessment is required prior to being brought back into service or on an annual basis. An operator must perform the integrity assessment for the range of relevant threats to the pipeline segment by the use of an appropriate in-line inspection tool(s). When performing an assessment using an in-line inspection tool, an operator must comply with §195.591.

14.3.6. Data Analysis:

195.416(e)

Data received as a result of pipeline assessments dictated by this 195.416 shall be analyzed by a subject matter expert. It is the subject matter expert's responsibility to analyze the data for anomalies that could affect the safe operation of the pipeline.

The subject matter expert shall identify areas of concern for further investigation via direct assessment methods. The subject matter expert shall issue a report to the COMPANY Manager, or designee, complete with:

(1) Inspection Tool Data.
(2) Tool Tolerance.
(3) Location Accuracy.
(4) Anomaly Information.
(5) Direct Assessment Recommendations.

14.3.7. Discovery of Condition:

195.416(f)

The COMPANY Manager, or designee, shall be responsible for issuing plans and procedures to corollate any potential anomalies that could affect the safe operation of the pipeline. Discovery of Condition shall be as defined by 195.416(f).

Discovery of Condition shall be completed as expeditiously as practicable but no later than 180 days after receiving the data analysis report. If Discovery of Condition cannot occur within 180 days, it is the COMPANY Manager's responsibility to document via a written report the justification for delay and document a plan to complete the tasks necessary to meet these requirements.

14.3.8. Remediation:

195.416(g)

All anomalies shall be corrected in accordance with requirements documented within this Manual.

14.3.9. Analysis of Predicted Failure Method:

195.416(e)

In the event inspections prescribed by this Manual reveal anomalies or defects, the COMPANY Manager, or designee, shall initiate data collection and analysis to determine pipeline predicted failure pressure.

14.3.10. Corrosion Metal Loss:

195.416(e)

Corrosion anomalies shall be analyzed by a knowledgeable engineer using ASME B31.G or RSTRNG.

14.3.11. Cracks and Crack Like Defects:

195.416(e) and Part 195 Appendix C

The GAP Midstream 8" MHA W-E pipeline does not have a history of cracks or crack-like defects. The pipeline operates in a steady state and is not susceptible to cyclic fatigue. The 6" Thunder Butte Pipeline also does not have a history of cracks or crack-life defects.

In the event of a crack or crack-like defect, the COMPANY Manager, or designee, shall employ a suitable engineering or metallurgy firm to perform analyses required by 195.588. The COMPANY Manager, or designee, shall then put into place remediation or re-evaluation plans.

14.4. REPAIR:

14.4.1. Repair Procedures:

195.422

Each imperfection or damage found to affect the serviceability of the GAP Midstream pipelines shall be repaired, if feasible, by cutting out the damaged pipe and replacing it in-kind with hydrostatically tested pipe. A full encirclement welded split sleeve capable of withstanding full pipeline MOP may be used if approved by the COMPANY Manager, or designee, and the split sleeve and associated welding has been designed and approved by a knowledgeable engineer.

If a pipeline imperfection or damage that affects serviceability cannot be repaired in a timely manner, the COMPANY Manager, or designee, shall plan for temporary repairs. All temporary repairs shall be designed and approved by a knowledgeable engineer.

When a pipeline under cathodic protection from a rectifier unit is to be separated to affect a repair, the electrical power supply to the unit shall be shut off and a bounding conductor installed across points where the pipeline is to be separated and the bond maintained while the pipeline is separated. All replacement pipe will be coated and cathodically protected per 49 CFR 195.563.

All welding performed on the pipeline shall be completed using welding procedures qualified in accordance with API Standard 1104. Prior to performing any online welding, an engineered design shall be developed and approved by a knowledgeable engineer.

All welds on pipe or fittings which are found unacceptable under API Standard 1104 Section 9 or Appendix A, or 49 CFR 195.214 shall be repaired in accordance with the requirements of API Standard 1104 and 49 CFR 195.228. Weld acceptance will be the sole judgement of the designated GAP Midstream welding inspector.

If defects exceed the above conditions, including a crack in a weld that is more than 8% of the weld length, the weld must be replaced by cutting out, as a cylinder, the sections of pipe containing the defective weld, and replacing that section of pipe. All welds repaired or replaced shall be non-destructively tested and inspected in accordance with this manual. If testing reveals any defect in a repair weld, the weld shall be cut out as a cylinder and replaced. Replacement pipe cylinders shall not be shorter than five feet (5ft).

Welders performing repair tasks must be qualified in accordance with 49 CFR 195.222 through 195.234. All welders must be qualified to the approved welding procedure by destructive testing within the previous six months if that welder has not welded with the approved welding procedure in that timeframe and previously qualified by destructive testing. Welder qualification by non-destructive examination is prohibited.

14.4.2. Testing of Repairs:

All repairs made by welding will be completed, tested, and inspected in accordance with API 1104. A certified inspector or equivalent will be responsible for visual inspection of the welding and for acceptance of non-destructive tests. Radiographic examination of all welds shall be used where appropriate. If radiographic examination is not appropriate, ultrasonic testing (UT) or magnetic particle (MT) may be used if approved by the COMPANY Manager or designee.

If a segment of the pipeline is repaired by cutting out the defective portion of pipe, the replacement pipe must be hydrostatically tested in accordance with 49 CFR 195.305 prior to installation. The minimum hydrostatic test pressure is 1,460 PSIG for eight hours (8 HR) if the test section can be visually observed during testing. All hydrostatic test plans and procedures shall be approved by the COMPANY Manager, or designee, prior to testing. The test section can be hydrostatically tested separately; the entire pipeline does not need to be retested.

14.4.3. Records:

A record shall be made of each abandoned facility, or inactivated facility that will not be maintained in accordance with this plan, giving a complete description of the facility abandoned or inactivated, including such items as size, grade, wall thickness, quantity and other physical characteristics, as well as occasion, dates, methods of sealing, method of purging, purge medium used, medium remaining in the pipeline, identifying job number, reference drawing numbers, reasons for abandonment or inactivation, and any other pertinent information.

15.0 VALVE MAINTENANCE

195.420 and 195.579

15.1. VALVE MAINTENANCE:

195.420

All valves required for the safe operation of the pipeline shall be in good working order at all times. They must comply with the following inspection requirements. At least twice each calendar year and at intervals not exceeding 7.5 months, each valve must be serviced, inspected, and partially operated to determine that it is in good mechanical condition.

(1) Records:

Each inspection of a valve, and repairs made to these valves shall be documented.

15.2. RUPTURE MITIGATION VALVE:

195.420 (b)

Each Rupture-Mitigation Valve (RMV), as defined in §195.2 and not contained in a gathering line, or alternative equivalent technology that is installed under §195.258(c) or §195.418, must also be partially operated. Operators are not required to close the valve fully during the inspection; a minimum 25 percent valve closure is sufficient to demonstrate compliance, unless the operator has operational information that requires an additional closure percentage for maintaining reliability. Each operator shall provide protection for each valve from unauthorized operation and from vandalism.

15.3. REMOTE CONTROL VALVE:

195.420 (d)

Each Remote Control Valve (RCV) installed §195.258(c) or §195.418, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment in accordance with §195.446(c) and (e).

15.4. RESPONSE DRILLS:

195.420 (e)

(1) Operators must achieve a response time of 30 minutes or less through an initial drill and through periodic validation. An operator must review each phase of the drill response and document the results to validate the total response time, including the identification of a rupture, and valve shut-off time.

(2) Within each pipeline system, and within each operating or maintenance field work unit, operators must randomly select an authorized rupture-mitigation alternative equivalent technology for an annual 30-minute-total response time validation drill simulating worst-case conditions for that location to ensure compliance with §195.419. Operators are not required to close the alternative equivalent technology fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with the drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, at intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph.

(3) If the 30-minute-maximum response time cannot be achieved in the drill, the operator must revise response efforts to achieve compliance with §195.419 no later than 12 months after the drill. Alternative valve shut-off measures must be in accordance with paragraph (f) of this section within 7 days of the drill.

(4) Based on the results of the response-time drills, the operator must include lessons learned in:

(i) Training and qualifications programs;

(ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and

(iii) Any other areas identified by the operator as needing improvement.

15.5. REMEDIAL MEASURES:

195.420 (f) and 195.420 (g)

Each operator must implement remedial measures as follows to correct any valve installed on an onshore pipeline in accordance with §195.258(c), or an RMV or alternative equivalent technology installed in accordance with §195.418, that is indicated to be inoperable or unable to maintain effective shut-off:

(1) Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain shut-off. An operator may request an extension of the compliance deadline requirements of this section if it can demonstrate to PHMSA, in accordance with the notification procedures in §195.18, that repairing or replacing a valve within 12 months would be economically, technically, or operationally infeasible; and

(2) Designate an alternative compliant valve within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Alternative compliant valves are not required to comply with valve spacing requirements of this part.

An operator using an ASV as an RMV, in accordance with §195.2, 195.260, 195.418, and 195.419, must document, in accordance with 195.419(f), and confirm the ASV shut-in pressures on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required by §195.419(f), at least each calendar year, but at intervals not to exceed 15 months.

The requirements of paragraphs 15.3 through 15.5 of this section do not apply to gathering lines.

16.0 CORROSION

16.1. CONTROLLING CORROSION:

195.553

All GAP Midstream pipeline corrosion control system maintenance and inspections will be performed by or under the guidance of NACE qualified personnel.

16.1.1. External Corrosion:

195.573, 195.575

To prevent external corrosion, the belowground GAP Midstream 8” MHA W-E pipeline segment is equipped with an impressed current cathodic protection system, coated with coal tar. The pipeline is electrically isolated at both ends. The aboveground pipe is coated with a two-part epoxy paint with additional coating at surface-to-air transitions.

The GAP Midstream 6” Thunder Butte pipeline is also equipped with an impressed current cathodic protection system and isolated at both ends.

The operation and maintenance of the pipeline corrosion control / cathodic protection system will be contracted out to a qualified pipeline contractor.

Whenever there is knowledge that any portion of a buried pipeline has become exposed, the exposed portion shall be examined for evidence of external corrosion, and the condition of the pipe and/or coating reported. All protective coatings will be in accordance with §195.559. An investigation of the pipeline beyond the corroded area will be performed both longitudinally and circumferentially to determine if additional corrosion is present. A report shall be made each time buried pipe is exposed regardless of whether corrosion is or is not evident and whether coating is or is not deteriorated. Where

corrosion is found as evidenced by leaks, breaks and/or pits, a report shall be made, and remedial action taken.

16.1.2. Criteria for Cathodic Protection Test Stations:

Every section of pipeline under DOT regulation that is cathodically protected must have in place either a test station or contact points for the electronic measurement of the adequacy of the cathodic protection of the line. Particular attention shall be given to the repairing or application of coating where test lead conductors are attached to the pipe. Test lead connections shall be coated even if the pipeline is bare. Coating material applied at test lead connections shall be of an electrical insulating material compatible with pipe coating and the insulation on the test lead wire.

16.1.3. Cathodic Protection Design and Installation - Electrical Isolation:

Each cathodically protected underground structure must be electrically isolated from every other underground structure unless the structures are electrically interconnected and are protected cathodically together, as a single unit. Every underground pipeline is required to be electrically isolated from pipeline casing. An exception is allowed for unprotected copper that has been inserted into ferrous pipe. For portions of pipelines that are electronically isolated, it is required that at least one insulating device be installed to facilitate corrosion control.

16.1.4. Cathodic Protection Design and Installation - Protection from Lightning and Fault Currents:

In every instance where a pipeline and/or insulating device is subject to lightning currents or fault currents, it is necessary to protect these structures from such currents. Examples of areas of concern include locations near transmission towers, ground cables, and counterpoise. Test stations shall be installed with leads per 49 CFR 195.567.

(a) Each test lead wire must be connected to the pipeline to remain mechanically secure and electrically conductive.
(b) Each test lead wire must be attached to the pipeline to minimize stress concentration on the pipe.
(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

16.1.5. Inspection and Monitoring of Cathodic Protection Systems:

All cathodic protection systems will meet the following inspection requirements:

(1) The saturated copper-copper sulfate half-cell shall normally be used as the reference electrode in contacting the soil for obtaining pipe-to-soil potential readings.

(2) Probing of buried pipelines shall be held to a minimum. An electronic type of pipeline locator shall be used wherever possible and as much as possible to reduce probing.

(3) Every pipeline that is cathodically protected must be tested for pipe-to-soil measurements to determine if the system meets the following DOT requirements:

(i) A negative voltage of at least 0.85 volts across the pipeline surface and a reference-saturated copper-copper sulfate half. Determination of this voltage will be made with the protective current applied.

(ii) A minimum voltage shift of 300 millivolts for structures that are not in contact with any metals of a different anodic potential. The voltage shift will be measured while the protective current is applied.

(iii) A polarization voltage of at least 100 millivolts.

(iv) A voltage at minimum as negative as originally established at the beginning.

(v) A net protective current from the electrolyte into the surface structure as measured by an earth current technique applied at predetermined current discharge anodic points of the structure.

(vi) Prompt remedial action to correct any deficiencies indicated is required.

(4) All cathodic protection test stations will meet following monitoring requirements:

(i) Pipe-to-Soil Potential will be tested.

(ii) Re-test of Pipe-to-Soil potential and confirm that appropriate levels of protection have been established at a frequency of every 12 months after discovery of corrosion.

(iii) Inspection of impressed current power sources with a frequency of once every 2-½ months, but at least 6 times per calendar year.

(iv) An inspection of the current diodes, interference bonds, and switches must be performed with a frequency of once every 2-½ months, but at least 6 times per calendar year.

(v) A check of all secondary bonds (Interference) must be made with a frequency of once every 15 months, but at least once every calendar year.

16.1.6. Damaged or Missing Test Stations:

All test stations found to be damaged shall be repaired in accordance with the requirements set forth in Inspection and Monitoring of Cathodic Protection Systems. In the event that a test station is found to be missing, it must be replaced with another test station in the original location, which can be determined by the station number. The test station will be tested with the requirements listed above in Inspection and Monitoring of Cathodically Protected Systems.

In the case that the above requirements listed in this section are deemed impractical, and the cathodic protection of the pipeline is not dependent upon the missing or damaged test station, then the station may be retired. In the future, if additional CP Test Stations are deemed necessary, they will be added. **Proper documentation is required stating the reason for retiring the station.**

16.1.7. Monitoring of Casings:

For each cased pipeline, the operator will measure and record the potential of the structure. The measurement instrument will be calibrated to the manufacturer's requirements.

The cathodic protection system of the cased pipeline will meet the requirements set forth in Inspection and Monitoring of Cathodic Protection Systems.

The frequency of inspection of cased pipelines will be once every calendar year with intervals not exceeding 15 months.

16.1.8. Shorted Casings:

Investigation - Electrical measurements are to be performed at each crossing as detailed in the Monitoring of Casing section above.

Evidence of shorted casings includes:

(1) Equivalent (or near equivalent) pipe-to-soil potentials and casing-to-soil potentials
(2) Casing-to-soil potential measurements that are abnormal, but not as low as the pipe-to-soil measurements.

In the case that evidence supports a shorted casing; the following test procedures shall be followed:

(1) Open Circuit potential - The open circuit potential is measured as the difference between the pipe-to-soil potential and the casing-to-soil potential. A variation of less than .1 volts is an indicator of a shorted casing.
(2) Obstruction of Rectifier Function – The obstruction test is performed by obstructing the cathodic protection on the pipeline to compare the casing-to-soil potentials and the pipe-to-soil potentials. If the casing-to-soil potential remains unchanged while the pipe-to-soil potential varies (during the interruption of the cathodic protection current) then the casing is not experiencing a short. However, if the casing-to-soil potential varies with the pipe-to-soil ratio, then there is evidence of a short in the casing.
(3) Reversing the Current of the Casing – This test to change the potential of the casing relative to the carrier pipe will indicate whether a short exists in the casing. A DC power source should be attached at the positive terminal to the casing and the negative terminal should be attached to a temporary ground bed. The source should drain less than 10 amps, but enough to allow for voltage shifts on both the casing and the carrier pipe if no resistance was present. Casing-to-soil and pipe-to-soil potentials shall be recorded with the DC power source both on and off. If the casing and pipe

potentials change concurrently in similar directions with equal differentials, there is an indication of a shorted casing. If the potential for the pipe shifts in an opposite direction, or exhibits no change, then the casing and the pipe are electronically isolated.

If an internal resistance of less than 0.01 Ohms is recorded between the carrier pipe and casing during the previous test for reversing the current, then a short exists in the casing.

The casing should be determined and documented to be in good condition or shorted. In the case of the latter, remedial action will be necessary.

If metallic contact is discovered between the casing and the carrier pipe the annular space between the carrier pipe and the casing, the casing should be filled with a filler of high dielectric properties that will serve as an inhibitor to the formation of corrosion. Remedial action shall be taken promptly to correct or replace any impediment to effective corrosion control.

16.1.9. Atmospheric Inspection:

All above ground pipelines or portions of pipelines that are exposed to the atmosphere shall be inspected for atmospheric corrosion at least once each calendar year.

Where evidence of corrosion is found or other reportable conditions are noted, reports of corrosion shall be made, and remedial action taken.

During inspections the operator must give particular attention to pipes at soil-to-air interfaces, under thermal insulation, under dis-bonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

Any areas of atmospheric corrosion found on the pipeline shall be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. §195.573 and §195.581 Replacement or repair of the pipe, reduction of the MOP (based on remaining wall thickness) or other remedial measures shall be taken as required by the severity of the corrosion.

16.1.10. Records:

Records or maps shall be maintained to show the location of cathodically protected piping, cathodic protection facilities and neighboring structures bonded to the cathodic protection system. Such records or maps and records of each test, survey or inspection required by this procedure shall be retained for as long as the pipeline remains in service.

16.1.11. Internal Corrosion:

195.579

GAP Midstream has determined that the nitrogen blanket covering the GAP Midstream MHA W-E pipeline is a non-corrosive fluid and does not pose a risk to pipeline integrity. This assessment will be monitored for future considerations. If internal corrosion conditions arise, an internal corrosion control plan will be created as part of this Manual.

17.0 Overpressure Protection

195.428

Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7 ½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

In the case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding 5 years.

18.0 Control Room Management / Communication

195.446

This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. The procedures required by this section must be integrated, as appropriate, with the operator's written procedures required by §195.402. An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraphs (b), (c)(5), (d)(2) and (d)(3), (f) and (g) of this section must be implemented no later than October 1, 2011. The procedures required by paragraphs (c)(1) through (4), (d)(1), (d)(4), and (e) must be implemented no later than August 1, 2012. The training procedures required by paragraph (h) must be implemented no later than August 1, 2012, except that any training required by another paragraph of this section must be implemented no later than the deadline for that paragraph.

18.1. ROLES AND RESPONSIBILITIES:

195.446(b)

Each operator must define the roles and responsibilities of a controller during normal, abnormal, and

emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

(1) A controller's authority and responsibility to make decisions and take actions during normal operations;

(2) A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others;

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers; and

(5) The roles, responsibilities and qualifications of others who have the authority to direct or supersede the specific technical actions of controllers.

18.2. PROVIDE ADEQUATE INFORMATION:

195.446(c)

Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) Implement API RP 1165 (incorporated by reference, see §195.3) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of API RP 1165 are not practical for the SCADA system used;

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

(3) Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months;

(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and

(5) Implement section 5 of API RP 1168 (incorporated by reference, see §195.3) to establish procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

18.3. FATIGUE MITIGATION:

195.446(d)

Each operator must implement the following methods to reduce the risk associated with controller fatigue

that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

(2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

(3) Train controllers and supervisors to recognize the effects of fatigue; and

(4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

18.4. ALARM MANAGEMENT:

195.446(e)

Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

(3) Verify the correct safety-related alarm set-point values and alarm descriptions when associated field instruments are calibrated or changed and at least once each calendar year, but at intervals not to exceed 15 months;

(4) Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan;

(5) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not exceeding 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

(6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.

18.5. CHANGE MANAGEMENT:

195.446(f)

Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

(1) Implement section 7 of API RP 1168 (incorporated by reference, see §195.3) for control room management change and require coordination between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to

pipeline equipment or configuration; and

(2) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations.

18.6. OPERATING EXPERIENCE:

195.446(g)

Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

(1) Review accidents that must be reported pursuant to §195.50 and 195.52 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to:

(i) Controller fatigue;

(ii) Field equipment;

(iii) The operation of any relief device;

(iv) Procedures;

(v) SCADA system configuration; and

(vi) SCADA system performance.

(2) Include lessons learned from the operator's experience in the training program required by this section.

18.7. TRAINING:

195.446(h)

Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

(2) Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures;

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions;

(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; and

(6) Control room team training and exercises that include both controllers and other individuals, defined by

the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this paragraph no later than January 23, 2018.

18.8. COMPLIANCE VALIDATION:

195.446(i)

Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a State, to the appropriate State agency.

18.9. COMPLIANCE AND DEVIATIONS:

195.446(j)

An operator must maintain for review during inspection:

(1) Records that demonstrate compliance with the requirements of this section; and
(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of the pipeline facility.

19.0 Damage Protection Program

195.442

The Damage Prevention Plan is a separate documents not included in this plan. This is a requirement of Part 195 but not included here. The following information is general information about pipeline monitoring and preventing damage.

19.1. CONTINUING SURVEILLANCE:

195.442

19.1.1. General:

Pipeline surveillance is conducted to discover leaks and failures, minimize corrosion damage, determine maintenance and repair requirements, monitor the operating conditions, and take appropriate actions.

19.1.2. Operations and Maintenance:

Personnel on routine and incidental assignments shall be alert for conditions that could interfere with pipeline operation. These conditions should be reported to their supervisor.

(1) Flow rate, pressure, equipment status, and other instruments will be monitored to assure normal operation of the pipeline and contractual supply and delivery specifications.
(2) Regular pipeline patrols will be conducted. During these patrols, situations that present a potentially

hazardous situation will be reported immediately.

(3) Leaks.

(4) Corrosion.

(5) Construction Near the Pipeline.

(6) Pipeline Markers.

(7) Cathodic protection system will be monitored to assure appropriate readings and system functionality.

19.1.3. Pipeline Review:

As a means of maintaining the integrity of the pipeline, surveillance through the analysis of completed maintenance and inspection records as well as operating reports and records shall be conducted to identify any abnormal or unusual operating or maintenance conditions.

COMPANY Manager or designee must periodically review the pipeline with consideration given to:

(1) Periodic visual inspections of pipeline to identify:

(i) Changes in Population Density,

(ii) Effect of Pipeline Exposure or Movement,

(iii) Changes in Topography,

(iv) Potential for or Evidence of Tampering, Vandalism, or Damage,

(v) Effects of Encroachments,

(vi) Potential for or Evidence of Excavation Activities.

(2) Periodic review and analysis of records such as:

(i) Patrols,

(ii) Leakage Surveys,

(iii) High Consequence Area Surveys,

(iv) Valve Maintenance,

(v) Pressure Regulating or Relieving Devices Inspections,

(vi) Corrosion Control Inspections or Corrosion Failures,

(vii) Relief Valve Inspections,

(viii) Pipeline Failure Investigations,

(ix) Annual Reports,

(x) Incident Reports,

(xi) Safety Related Condition Reports.

(3) Alterations or additions to the pipeline which may change pressure or flow maximums.

(4) Loss of flow efficiency or excessive pressure drops.

(5) Ability of the pipeline to handle future loads within the prescribed operating pressure ranges.

If the review indicates that the pipeline is, or will be, in unsatisfactory condition (but not hazardous), a plan for correcting the situation shall be developed and put into action. Hazardous conditions shall be corrected as soon as possible.

19.1.4. Visual Inspections:

Visual inspections are documented. HCA surveys are completed annually in accordance with Integrity Management Plan requirements. Operations personnel shall perform visual inspections on a routine basis as part of their job duties.

19.1.5. Remedial Action or Reduction in MOP:

All leaks, failures, changes in cathodic protection voltage and current levels, and operating or maintenance conditions must be brought to the COMPANY Manager's, or designee's, attention. All pipeline segments found to be in unsatisfactory condition shall be repaired or replaced as soon as practicable. In the event the condition presents a hazard, the repair or replacement shall be accomplished immediately in accordance with standards presented in this Manual. The COMPANY Manager, or designee, shall prepare plans and programs for upgrading, reconditioning, or phasing out segments that cannot be reconditioned.

If the condition cannot be reconditioned or phased out, the MOP shall be reduced, or other action taken to reduce the potential for accidents and minimize personnel / public exposure.

19.1.6. Reports and Records:

The Compliance Lead will ensure that continuing surveillance reviews occur as outlined in this Manual and are documented. This report shall include:

(1) Pipeline Name and Pipeline Segment (stationing),
(2) Reviewer Name,
(3) Review Date,
(4) Changes from Last Review and Action Taken (if Required).

20.0 Public Awareness Program

195.452

The Public Awareness Plan is a separate documents not included in this plan. This is a requirement of Part 195

but not included here. The following information is general information about public awareness programs.

20.1 REPORTS AND RECORDS:
195.452(a)

Each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, *see* §195.3).

21.0 Integrity Management in High Consequence Areas
195.452

An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.